

Attachment 1. Baseline Analysis 2012

Baselining Analysis 2012

Discovery Across Texas Project

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APPENDICES (attached as separate documents)

A, Angle Differences by Clusters

B, State Estimator – Phasor Comparison, 3 Days

C, Voltage Magnitude Box Whiskers

D, Voltage Angle Ref North7- Box Whiskers & Time Duration

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1. INTRODUCTION

The Center for Commercialization of Electric Technologies (CCET) was awarded contract DE-OE0000194 by the Department of Energy to perform the Discovery Across Texas demonstration project. Electric Power Group, LLC (EPG) received a subaward from CCET to provide professional services to perform, among other things, a substation cluster analysis, comparison of phasor data versus state estimator data, and voltage and angle difference baselining. The goal of this particular analysis was to, using 2012 data: (1) group substations having Phasor Measurement Units (PMUs) which are geographically close to each other and perform a voltage and angle difference analysis for each group (cluster analysis); (2) perform a comparison of voltage and angle differences obtained using phasor measurements versus similar results using state estimator data (phasor vs. state estimator comparison); and, (3) perform a baseline analysis for voltages and angle differences for selected pairs of substations. Alarm limits will be established and documented based on the baseline analysis.

2. PROJECT SCOPE

A. Cluster Analysis

Activities to be performed as part of this item:

1. Obtain state estimator data from ERCOT, solve cases received and extract data for analysis.
2. Group geographically close substations equipped or to be equipped with PMUs.
3. Using state estimator data analyze voltage angle differences for these groups and document results for two selected days of 2012.
4. Prepare voltage angle difference graphs for the selected substations and pairs.
5. Summarize results.

B. Phasor versus state estimator comparison

Activities to be performed as part of this item:

1. In addition to state estimator data from ERCOT obtained for part (1) above, obtain phasor data from ERCOT, download it, down-sample to one sample per second and process it for analysis.
2. Use extracted phasor and state estimator data to develop comparison graphs for phasor and for state estimator results. Comparison was performed for three days in 2012: August 1 (peak load), November 23 (low load), and December 25 (high wind output). For days where both data was not available, a third day, December 2, was selected for comparison.
3. Summarize results.

C. Baseline analysis for voltage and angle differences

Analyze historical performance of ERCOT grid, using State Estimator data plus phasor data to identify normal and abnormal voltages and angle limits across the grid. In this analysis, EPG leveraged its experience in performing similar analyses for CAISO in California and four Independent System Operators (ISOs) in the Eastern Interconnection. Activities to be performed as

part of this item:

1. Develop and utilize software to process provided state estimator (SE) data and extract key metric information (i.e., voltage, angles and angle differences).
2. Analyze extracted data and develop baseline understanding of voltage, phase angle and angle difference patterns for key substations and key pairs of substations. Substations were selected based on current or projected availability of PMUs at those substations.
3. Monitor voltages and angle differences (pairs) and develop patterns and statistics in the form of box-whisker plots and load duration curves. Substations selected for analysis of voltages are listed in Table 1 below and pairs of substations selected for analysis of angle differences are listed in Table 2 below.
4. Prepare baselining analysis results for the selected substations and pair of substations as excel spreadsheet and charts, including:
 - a. Voltage statistics (mean, maximum and minimum).
 - b. Voltage phase angle difference statistics (mean, maximum and minimum).
 - c. Voltage and phase angle distribution functions.
5. Prepare baselining analysis summary for discussion with ERCOT and the Synchrophasor Team.

D. Establishing Alarm Limits for Use in Operations

Based on the baselining analysis, recommend key substations and angle pairs for monitoring in Real Time Dynamics Monitoring System¹ (RTDMS), and recommend voltage and angle difference alarm settings for use in RTDMS to alert operators when grid stress is approaching limits. Guidelines will be linked to observed metrics using synchrophasor data and corresponding operator actions. EPG will leverage experience gained from analysis performed on phasor and SE data to establish alarm limits for a California utility in establishing alarm limits for use in the ERCOT RTDMS.

This section will not be completed in this report. A massive number of new 345 kV lines will be added to the ERCOT system in 2013 as part of the CREZ project, changing significantly the distribution of power among the existing and future transmission lines. This will result in change in limits for voltages, voltage angles, and particularly angle differences. Recommending alarm limits based in 2012 results will not be practical. EPG will conduct an analysis with 2013 data to determine the voltage and angle difference limits that will be more likely to represent current and future system conditions. Voltage and angle difference limits for use by operators will be recommended once the 2013 analysis is completed.

3. DATA SOURCES

Two sources of data were utilized to perform the analysis of voltage and angle differences in the ERCOT network: phasor data and state estimator cases. A description of these sources of data is provided below.

A. Phasor Data

¹ * Electric Power Group. Built upon GRID-3P platform, US Patent 7,233,843, US Patent 8,060,259, and US Patent 8,401,710. All rights reserved.

Initially, ERCOT, the Synchrophasor Team, and EPG agreed to use data for the 12-months of 2012. ERCOT provided EPG phasor data for these 12-months with a resolution of 30-samples per second. EPG downloaded the phasor data provided by ERCOT via hard drive and using an in-house software tool, down-sampled the data received to 1-sample per second. Due to the amount of data this process took several days to complete.

A program was developed by EPG to extract the data and compile it into a summary table, and two series of graphs. One graph (box-whisker) shows daily summaries of data, and the other time duration curves, shows values versus percent time for each study variable. The time duration curves were used to obtain the metric values corresponding to 1% and 99% exceedance (the value which was less than 1% plus inflection or greater than 99% minus inflection).

Phasor Measurement Units (PMUs) Installed and Planned in ERCOT

As of January 30, 2013 there were 26 PMUs installed in 19 locations across the ERCOT service area. Also there are another 44 PMUs planned for installation in the future at 14 additional locations.

The base analysis completed with 2012 data included state estimator data analysis for locations for which PMUs are installed and for which PMUs are planned. However, six of the locations are new and therefore there was no state estimator data available for those substations or pair of substations that included any one of these six new substations.

PMU Commitment Status

As of January 30, 2013

| TDSP | PMU Signal Name | PMU Station Name | Number of PMUs In-Service | Additional PMUs Planned | Voltage (kV) | Existing or New Substation |
|-----------|-----------------|------------------|---------------------------|-------------------------|----------------------------|----------------------------|
| AEP | Line 1 | West 10 | 1 | | 69 | Existing |
| AEP | Line 1 | Coast 1 | 1 | | 138 | Existing |
| AEP | Line 1 | South 14 | | 1 | 138 | Existing |
| AEP-ETT | Line 1 | West 14 | 1 | | 345 | Existing |
| AEP-ETT | Line 2 | West 14 | 1 | | 345 | Existing |
| AEP-ETT | Line 3 | West 14 | 1 | | 345 | Existing |
| AEP-ETT | Line 4 | West 14 | 1 | | 345 | Existing |
| AEP-ETT | Line 1 | West 15 | | 1 | 345 | New |
| AEP-ETT | Line 1 | West 16 | | 1 | 345 | New |
| AEP-ETT | Line 1 | West 3 | | 1 | 345 | New |
| AEP | Line 1 | FarWest 9 | 1 | | 138 | Existing |
| AEP | Line 1 | Coast 4 | 1 | | 345 | Existing |
| AEP | Line 2 | Coast 4 | | 1 | 345 | Existing |
| AEP | Line 3 | Coast 4 | | 1 | 345 | Existing |
| AEP | Line 1 | West 4 | 1 | | 138 | Existing |
| AEP | Line 2 | West 4 | 1 | | 138 | Existing |
| AEP | Line 3 | West 4 | 1 | | 138 | Existing |
| AEP | Line 4 | West 4 | | 1 | 138 | Existing |
| AEP | Line 1 | South 6 | | 1 | 138 | Existing |
| AEP | Line 1 | Coast 2 | | 1 | 69 | Existing |
| AEP | Line 1 | South 10 | | 1 | 138 | Existing |
| AEP | Line 1 | Coast 3 | 1 | | 345 | Existing |
| AEP | Line 2 | Coast 3 | 1 | | 345 | Existing |
| ONCOR | Line 1 | FarWest 7 | 1 | | 345 | Existing |
| ONCOR | Line 1 | West 6 | 1 | | 345 | Existing |
| ONCOR | Line 1 | FarWest 4 | 1 | | 345 | Existing |
| ONCOR | Line 1 | North 7 | 1 | | 138 | Existing |
| ONCOR | Line 1 | North 4 | 1 | | 138 | Existing |
| ONCOR | Line 1 | North 5 | 1 | | 138 | Existing |
| ONCOR | Line 1 | North 6 | 1 | | 138 | Existing |
| ONCOR | Line 1 | North 2 | 1 | | 138 | Existing |
| ONCOR | Line 1 | FarWest 8 | 1 | | 138 | Existing |
| ONCOR | Line 1 | West 11 | 1 | | 345 | Existing |
| ONCOR | Line 1 | West 9 | | 1 | 345 | Existing |
| ONCOR | Line 1 | West 12 | | 1 | 345 | |
| ONCOR | Line 1 | West 5 | | 1 | 345 | Existing |
| ONCOR | Line 1 | West 1 | | 7 | 345 | Existing |
| ONCOR | Line 1 | West 2 | | 4 | 345 | Existing |
| ONCOR | Line 1 | North 1 | 1 | | 345 | Existing |
| Sharyland | Line 1 | South 13 | 1 | | 138 | Existing |
| Sharyland | Line 2 | South 13 | 1 | | 138 | Existing |
| Sharyland | Line 1 | West 13 | | 1 | 345 | New |
| Sharyland | Line 1 | West 17 | | 1 | 345 | New |
| | | | | | | |
| LCRA | Line 1 | South 2 | | 4 | | Existing |
| LCRA | Line 1 | South 4 | | 3 | | Existing |
| LCRA | Line 1 | South 7 | | 1 | | Existing |
| LCRA | Line 1 | South 9 | | 3 | | Existing |
| LCRA | Line 1 | South 11 | | 2 | | Existing |
| LCRA | Line 1 | South 15 | | 5 | | Existing |
| | | | | | | |
| | | | | | | |
| | | | In-Service | Planned | Total Planned & In-Service | |
| | Totals | PMUs | 26 | 44 | 70 | |
| | | Locations | 19 | 20 | 39 | |

B. State Estimator (SE) Data

As per the case of phasor data, ERCOT provided EPG SE data for the 12-months of 2012. EPG used the Power World simulator provided by ERCOT via Power World, to extract about 16,000 SE cases. There were several days for which SE data was not available as shown below:

Dates for which SE data was not available

| | |
|-------------------------|----------|
| 1/10/2012 – 1/17/2012 | 8 days |
| 1/25/2012 | 1 day |
| 2/01/2012 – 3/13/2012 | 13 days |
| 5/03/2012 – 7/08/2012 | 67 days |
| 9/13/2012 – 9/17/2012 | 5 days |
| 9/28/2012 – 10/01/2012 | 4 days |
| 10/05/2012 – 10/09/2012 | 5 days |
| 10/24/2012 – 10/31/2012 | 8 days |
| 11/04/2012 – 11/06/2012 | 3 days |
| Total | 114 days |

Estimate of SE availability: 2.7 cases per hour of data available

C. Data Availability

Data availability for phasor data source varied from substation to substation; the summary table of phasor-based results shows the percent viability for each substation or each pair analyzed. As shown in Table A-1, availability varies from substation to substation and ranges from 10.4% for FarWest 7 and North 1 to greater than 95% for North 4, North 5, North 6, North 7, FarWest 4 and West 6. Box whisker plots in Appendix C provide a view of data availability on a day by day basis.

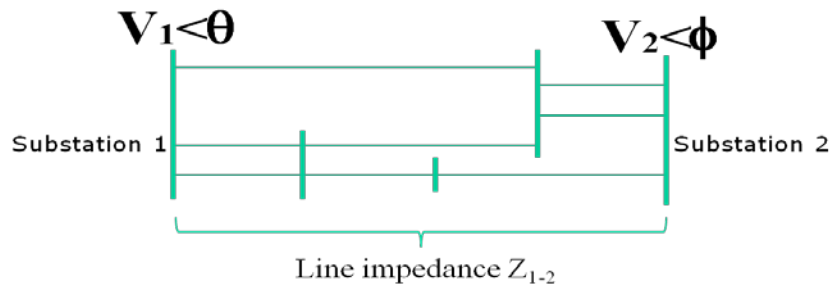
Data availability for state estimator data was low. ERCOT produces state estimator cases every 5-minutes for a total of 105,120 possible cases per year. EPG received about 16,000 cases which represent about 15.22 % data availability. Even though SE cases were available approximately 15.2% of the time, SE data was not available all of this time. The availability of SE data was approximately 13%.

Below a summary of phasor data availability from Table A-1 below:

| <u><40%</u> | <u>41% to 60%</u> | <u>61% to 80%</u> | <u>>80%</u> |
|----------------|-------------------|-------------------|----------------|
| West 14 | West 4 | West 11 | West 10 |
| North 1 | Coast 4 | Coast 1 | North 7 |
| Coast 2 | Coast 3 | FarWest 8 | North 2 |
| South 6 | South 13 | | North 4 |
| FarWest 7 | FarWest 9 | | North 5 |
| | | | West 6 |
| | | | North 6 |
| | | | FarWest 4 |

4. CLUSTER ANALYSIS

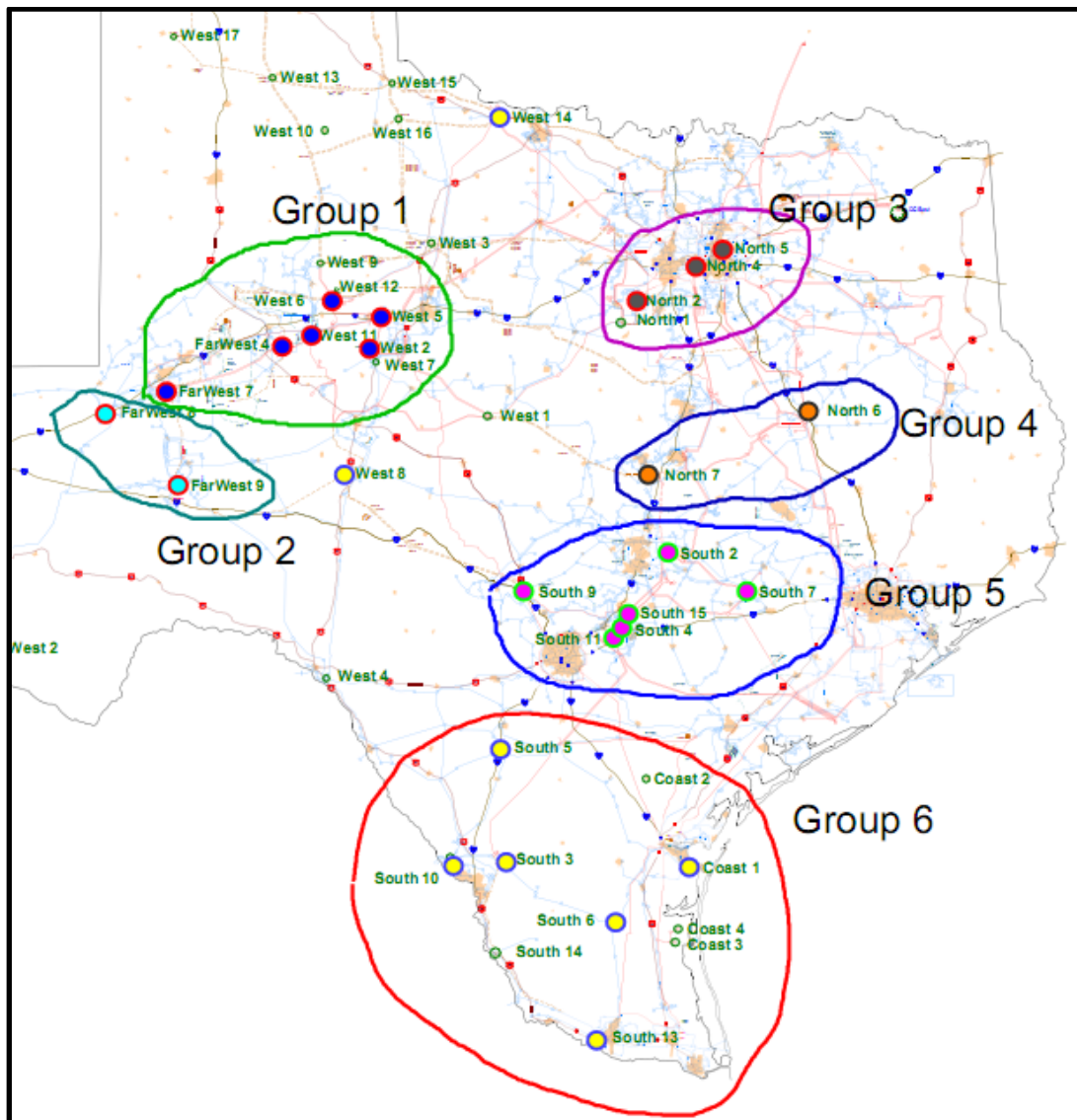
Phase angles differences are indicators of power flow and direction. Power flow follows voltage angle difference as per the following diagram and equation:



$$\text{Power flow: } P = V_1 V_2 \sin(\theta - \phi) / Z$$

Any change in Power flow or impedance will be reflected in a change in voltage phase angle difference between two locations.

EPG grouped substation based on geographical proximity as shown in the map and table below in order to find trends regarding angle differences referenced to North 7.

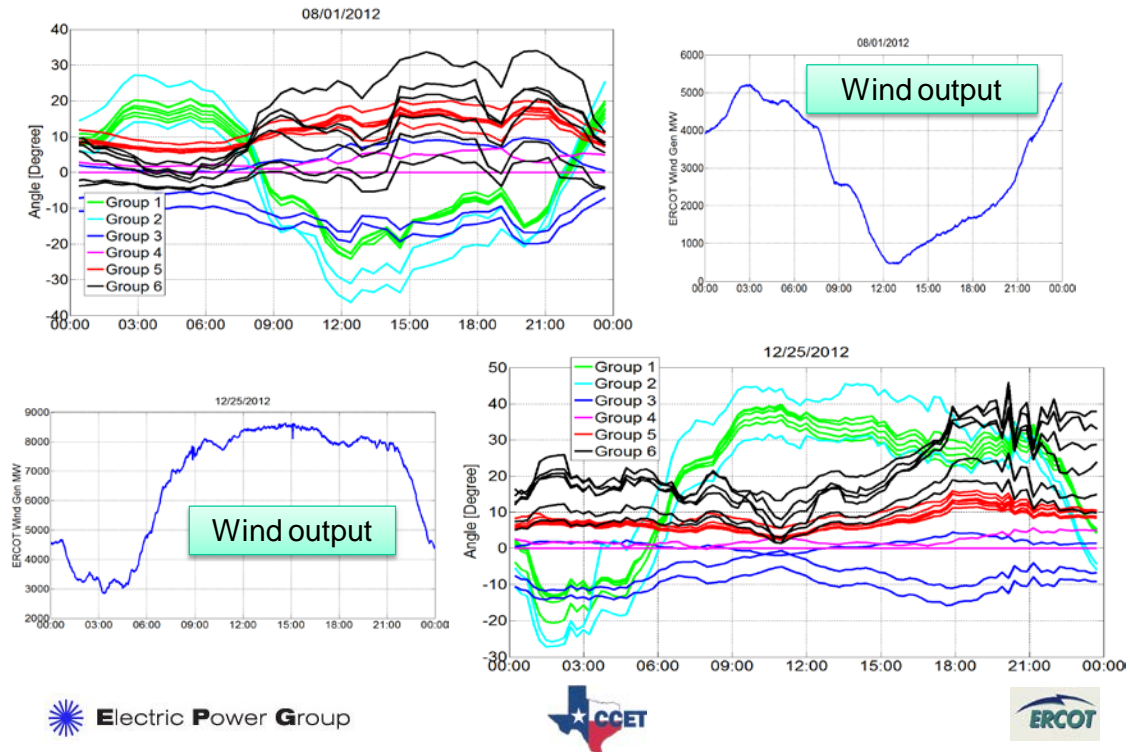


| GROUP 1 | GROUP 2 | GROUP 3 | GROUP 4 | GROUP 5 | GROUP 6 |
|--------------|--------------|------------|------------|-------------|-------------|
| a. FarWest 4 | a. FarWest 8 | a. North 2 | a. North 6 | a. South 2 | a. Coast 1 |
| b. FarWest 7 | b. FarWest 9 | b. North 4 | b. North 7 | b. South 4 | b. South 3 |
| c. West 2 | | c. North 5 | | c. South 7 | c. South 5 |
| d. West 5 | | | | d. South 9 | d. South 6 |
| e. West 6 | | | | e. South 11 | e. South 10 |
| f. West 11 | | | | f. South 15 | f. South 13 |

A summary of angle difference plots by groups is shown below:

Cluster Summary-Angle Differences: Group 1-Group 6

Angle Reference: North 7



Review of this graph shows that the angle differences for the substations in Groups 1 and 2, which are close to the wind farms follow the pattern of the wind output shown next to the angle difference curves. Further, it appears that the angles for the substations in Groups 1 and 2, referenced to North 7, turn negative for wind output levels of about 4,000 MW or less. Of course this may change depending on where wind farms are developed in the state or what wind farms are online. Note also the high range in angle difference for the days analyzed for the substations in Groups 1 and 2, it fluctuates from -35 degrees when wind output is low to approximately 45 degrees when wind output is at max.

The angles for the substations in Group 6 under low wind conditions share similar patterns but are separated from each other by several degrees, this is a reflection from the fact they are also physically separated and subject to different levels of generation and load.

More detailed information for each group is presented in Appendix A attached to this report.

5. COMPARISON OF PHASOR DATA WITH STATE ESTIMATOR DATA – DATA QUALITY

The results obtained using SE data received from the ERCOT were compared against those obtained using phasor data at one sample per second. Phasor data was compared with SE data by plotting results for the following three days:

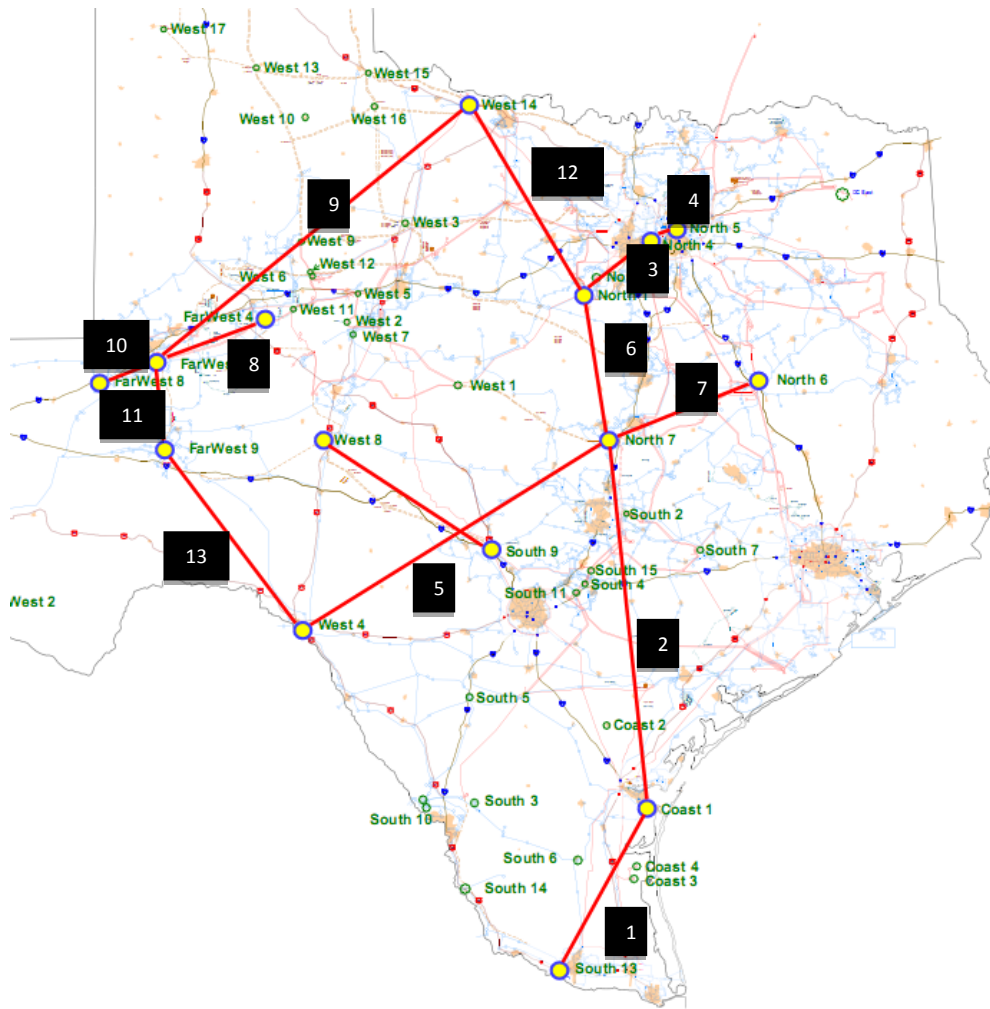
1. August 1, 2012 – Peak load day
2. November 23, 2012 – Low load day
3. December 25, 2012 – Maximum wind Day

This comparison was performed for the following 13 pairs of substations:

| Index | Substation A | Substation B |
|-------|--------------|--------------|
| 1 | Coast 1 | South 13 |
| 2 | Coast 1 | North 7 |
| 3 | North 1 | North 4 |
| 4 | North 4 | North 5 |
| 5 | West 4 | North 7 |
| 6 | North 7 | North 1 |
| 7 | North 7 | North 6 |
| 8 | FarWest 7 | FarWest 4 |
| 9 | FarWest 7 | West 14 |
| 10 | FarWest 7 | FarWest 8 |
| 11 | FarWest 7 | FarWest 9 |
| 12 | West 14 | North 1 |
| 13 | FarWest 9 | West 4 |

The location of these pairs is shown in the map below.

Location of Angle Pairs with PMUs in service



Individual comparison can be seen in the Appendix B attached to this report. State estimator data was available except for the cases for West 4 and FarWest 4. Data for these two stations was either not available, partially available, or the names of the substation changed for some of the cases provided. When possible, EPG made an effort to obtain data for those substations for which the name had been changed.

The results of this comparison indicate that the results obtained with phasor data track very well with those obtained using SE data. It seems that the PMUs under analysis are reasonable well calibrated.

Observation of the graphs in Appendix B which show phasor data for only three out of 365 days indicate that that there was no phasor data for North 1 for two of the three days. For the day that was available (December 25, 2012), the phasor data coordinated reasonable well with the SE data (within one degree). One reason why there was no data for the two days is because the availability of phasor data at North 1 was the lowest of all active PMUs. The availability for North 1 was only 10.4%. North 1 is located in a central location near Dallas; it is desirable to have high

availability and high quality phasor data at this substation, it does not have the first but seems to have the second characteristic.

Similarly, FarWest 7 PMU had no data for either August 1 or November 23 and as in the case of North 1 it was because the data availability for this PMU was also only 10.4%. Phasor data was available for December 2 and the phasor data for this day coordinated reasonably well with state estimator data. There was no SE data for December 25. FarWest 7 is located near the wind farms and is very desirable to have as much phasor data for this location to track system variables with wind output.

Further observation of Appendix B graphs shows that for West 4 phasor data was not available on November 23 and was available only five hours for December 25. It was available on peak load day, August 1, and tracked very well with SE data this day. The data availability for West 4 for 2012 was 41.3%.

6. BASELINE ANALYSIS FOR VOLTAGE AND ANGLE DIFFERENCES

The baseline analysis for voltages and angle differences was performed using the phasor data and state estimator data obtained from ERCOT for 2012. This data was processed to extract voltage magnitude and voltage angles. Min and max for these variables were documented in summary tables; box-whiskers plots and time duration curves were developed for each variable and for each type of data used. Below is an analysis of voltage magnitudes and voltage angles.

7. METHODOLOGY

For the pairs selected for study, the following work was performed:

1. Obtain and process phasor data and state estimator data.
2. Extract information to identify max, min and average values from these data sources. Prepare summary tables showing results of all data, including data saved during events.
3. Use phasor and SE data to develop weekly box-whisker graphs and time duration curves for angle differences.
4. Identify limits corresponding to normal operation; excluding events and outages. To exclude extreme values corresponding to outliers and to events, values corresponding to the metrics exceeding 1% and 99% percent of the time were identified for the entire study period, to be identified as normal operating limits. A summary showing these normal operation limits were obtained using phasor and SE data and tabulated in the same table for comparison.
5. Analyze results, identify limits, and report results for each pair selected.

8. STUDY APPROACH

Electric Power Group used the following approach:

1. Obtain available phasor data and state estimator data from ERCOT.
2. Extract phasor data and condition it for processing.
3. Solve state estimator cases and save solved cases.

4. Select substations and angle pairs of interest to ERCOT and the synchrophasor team members choosing substations that have or soon will have PMUs installed.
5. Identify the substations and subset of substations and pairs for which phasor data is available.
6. Develop statistical charts including time duration curve and box-whisker graphs for voltage magnitudes and angles and for angle pairs.
7. Perform statistical analysis to identify angle differences limits for the pairs selected under all conditions. Summarize angle difference limits.
 - Establish limits for normal operation based on the criteria described in the corresponding methodology. Summarize angle difference limits.
 - The limits for angle differences identified in this report shall be compared with ERCOT's criteria, if any, that apply to angle differences for the paths selected for this study.

9. BASELINE ANALYSIS FOR VOLTAGES MAGNITUDES

A. Substations Identified For Voltage Monitoring

EPG in consultation with ERCOT and the Synchrophasor team identified the following substations for monitoring.

| Table 1 SUBSTATIONS | | |
|-------------------------------|-----------|---------------|
| FOR VOLTAGE MONITORING | | |
| SUBSTATION | kV | REGION |
| 1 West 10 | 69 | Panhandle |
| 2 West 14 | 345 | Panhandle |
| 3 West 11 Switch | 345 | Central |
| 4 West 6 | 345 | Central |
| 5 North 7 | 138 | Central-East |
| 6 North 2 | 138 | Dallas |
| 7 North 4 | 138 | Dallas |
| 8 North 5 | 138 | Dallas |
| 9 North 1 | 345 | Dallas |
| 10 North 6 | 138 | East |
| 11 West 4 | 138 | SouthWest |
| 12 Coast 1 | 138 | Valley |
| 13 South 13 | 138 | Valley |
| 14 Coast 3 | 345 | Valley |
| 15 Coast 4 | 345 | Valley |
| 16 FarWest 8 | 138 | West Texas |
| 17 FarWest 9 | 138 | West Texas |
| 18 FarWest 4 | 345 | West Texas |
| 19 FarWest 7 | 345 | West Texas |
| 20 West 16* | 345 | Panhandle |
| 21 West 17* | 345 | Panhandle |
| 22 West 13* | 345 | Panhandle |
| 23 West 15* | 345 | Panhandle |
| 24 West 8* | 345 | Central |
| 25 West 1* | 345 | Central |
| 26 West 2* | 345 | Central |
| 27 West 3* | 345 | Central |
| 28 West 9* | 345 | Central |
| 29 West 12* | 345 | Central |
| 30 West 5* | 345 | Central |
| 31 South 15* | 345 | Central |
| 32 FarWest 2* | 69 | Central-East |
| 33 South 2* | 345 | Central-East |
| 34 South 4* | 345 | Central-East |
| 35 South 7* | 345 | Central-East |
| 36 South 9* | 345 | Central-East |
| 37 South 11* | 345 | Central-East |
| 38 Coast 2* | 69 | Valley |
| 39 South 3* | 138 | Valley |
| 40 South 5* | 138 | Valley |
| 41 South 6* | 138 | Valley |
| 42 South 10* | 138 | Valley |

B. Analysis of Data and Results

Data availability was approximately 13% for all SE cases; phasor data availability varies from bus to bus. As shown in the Table A-1 below phasor data availability varies from substation to substation and ranges from 10.4% for FarWest 7 and North 1 to greater than 95% for North 4, North 5, North 6, North 7, FarWest 4 and West 6.

Table A-1 below summarizes the min, max, and average values for voltage magnitude for the selected substations. The maximum voltage spreads observed were: 29.5 kV at the Coast 4 345 bus and 19.9 kV at the West 4 138 kV bus. The maximum voltage observed were: 368.91 kV at Coast 4 and 152.46 kV at West 4. The highest average voltages observed were: 357.3 kV at West 2 and 142.27 kV at South 6.

The voltage spreads and actual voltages obtained from phasor data were lower than those from state estimator data. However they also indicate that the highest spreads and voltages occurred at Coast 4 and West 4. As in the case of SE data results, phasor data indicates the highest average 138 kV voltage occurred at South 6 with 142.51 kV. The highest 345 kV voltage occurred at West 14 at 357.62 kV. No phasor data was available for West 2.

The summary shown in Table A-1 below shows the results for all data, including events and outages. EPG made an attempt to exclude values corresponding to events and outages by isolating the values that lie in the lower one percent and in the higher 1 percent plus minus a point of inflection in the time duration curve. The values in these regions are assumed to be extreme values resulting from outage or events. The results are summarized in Table A-2 below.

Table A-1 ERCOT DISCOVERY ACROSS TEXAS PROJECT - SUMMARY OF VOLTAGE MAGNITUDES - ALL DATA
JANUARY 1 TO DECEMBER 31, 2012

| No | Substation | Base kV | Region | PHASOR DATA | | | | | STATE ESTIMATOR DATA | | | |
|----|------------|---------|--------------|-----------------------------------------------------------------------------------|--------|---------|--------|-------------------------------------|----------------------|--------|---------|--------|
| | | | | Min | Max | Average | Spread | Percent Min Data Available | Min | Max | Average | Spread |
| | | | | | | | | | | | | |
| 1 | West 10 | 69 | Panhandle | 68.00 | 74.68 | 71.18 | 6.68 | 84.43 | 66.99 | 71.64 | 69.33 | 4.7 |
| 2 | West 14 | 345 | Panhandle | 346.64 | 366.44 | 357.62 | 19.80 | 33.82 | 348.07 | 364.84 | 357.09 | 16.8 |
| 3 | West 11 | 345 | Central | 344.28 | 359.24 | 353.04 | 14.96 | 77.72 | 346.17 | 361.28 | 355.01 | 15.1 |
| 4 | West 6 | 345 | Central | 343.80 | 360.44 | 353.37 | 16.64 | 96.11 | 346.73 | 364.08 | 356.04 | 17.4 |
| 5 | North 1 | 345 | Dallas | 341.28 | 354.29 | 349.75 | 13.01 | 10.37 | 340.69 | 358.94 | 349.64 | 18.3 |
| 6 | North 2 | 138 | Dallas | 137.38 | 144.64 | 141.55 | 7.26 | 94.04 | 138.01 | 142.37 | 140.30 | 4.4 |
| 7 | North 4 | 138 | Dallas | 138.68 | 144.12 | 141.99 | 5.44 | 96.61 | 137.34 | 147.26 | 141.65 | 9.9 |
| 8 | North 5 | 138 | Dallas | 137.94 | 145.68 | 141.04 | 7.74 | 96.42 | 136.92 | 148.05 | 139.82 | 11.1 |
| 9 | North 6 | 138 | East | 137.76 | 144.32 | 141.73 | 6.56 | 95.70 | 137.57 | 144.82 | 141.61 | 7.3 |
| 10 | North 7 | 138 | Central-East | 138.08 | 145.08 | 142.34 | 7.00 | 96.03 | 135.35 | 144.93 | 140.96 | 9.6 |
| 11 | West 4 | 138 | SouthWest | 133.30 | 147.48 | 141.76 | 14.19 | 41.27 | 132.52 | 152.46 | 141.38 | 19.9 |
| 12 | Coast 2+ | 69 | Valley | 66.56 | 72.92 | 70.15 | 6.36 | 39.61 | 65.81 | 72.33 | 69.67 | 6.5 |
| 13 | Coast 1 | 138 | Valley | 138.44 | 144.60 | 142.27 | 6.16 | 61.92 | 132.78 | 144.93 | 141.58 | 12.2 |
| 14 | Coast 4 | 345 | Valley | 342.00 | 367.44 | 354.25 | 25.45 | 40.21 | 339.45 | 368.91 | 354.48 | 29.5 |
| 15 | Coast 3 | 345 | Valley | 342.37 | 362.88 | 353.91 | 20.51 | 47.96 | 339.10 | 368.36 | 354.39 | 29.3 |
| 16 | South 6+ | 138 | Valley | 138.08 | 149.08 | 142.51 | 11.00 | 24.05 | 138.40 | 145.07 | 142.27 | 6.7 |
| 17 | South 13 | 138 | Valley | 135.76 | 146.60 | 141.91 | 10.84 | 40.64 | 135.53 | 145.69 | 141.75 | 10.2 |
| 18 | FarWest 4 | 345 | West Texas | 347.16 | 360.56 | 354.31 | 13.40 | 95.52 | 344.59 | 363.15 | 355.63 | 18.6 |
| 19 | FarWest 7 | 345 | West Texas | 341.75 | 354.57 | 350.52 | 12.82 | 10.37 | 342.79 | 360.59 | 351.78 | 17.8 |
| 20 | FarWest 8 | 138 | West Texas | 137.36 | 145.48 | 138.56 | 8.12 | 73.53 | 135.41 | 143.00 | 139.80 | 7.6 |
| 21 | FarWest 9 | 138 | West Texas | 133.84 | 146.48 | 141.25 | 12.64 | 51.65 | 134.84 | 148.92 | 141.00 | 14.1 |
| 22 | West 16* | 345 | Panhandle | No phasor data available. PMUs are planned for installation at these substations. | | | | | NOT IN SERVICE | | | |
| 23 | West 17* | 345 | Panhandle | | | | | | NOT IN SERVICE | | | |
| 24 | West 13* | 345 | Panhandle | | | | | | NOT IN SERVICE | | | |
| 25 | West 15* | 345 | Panhandle | | | | | | NOT IN SERVICE | | | |
| 26 | West 8* | 345 | Central | | | | | | 342.58 | 364.29 | 353.39 | 21.7 |
| 27 | West 1* | 345 | Central | | | | | | 343.17 | 363.08 | 354.00 | 19.9 |
| 28 | West 2* | 345 | Central | | | | | | 346.59 | 366.11 | 357.30 | 19.5 |
| 29 | West 3* | 345 | Central | | | | | | NOT IN SERVICE | | | |
| 30 | West 9* | 345 | Central | | | | | | 346.93 | 365.53 | 356.67 | 18.6 |
| 31 | West 12* | 345 | Central | | | | | | NOT IN SERVICE | | | |
| 32 | West 5* | 345 | Central | | | | | | 346.59 | 365.77 | 356.78 | 19.2 |
| 33 | South 15* | 345 | Central | | | | | | 347.86 | 361.80 | 355.65 | 13.9 |
| 34 | FarWest 2* | 69 | Central-East | | | | | | 66.93 | 72.33 | 69.32 | 5.4 |
| 35 | South 2* | 345 | Central-East | | | | | | 345.90 | 360.77 | 353.85 | 14.9 |
| 36 | South 4* | 345 | Central-East | | | | | | 348.69 | 361.42 | 355.97 | 12.7 |
| 37 | South 7* | 345 | Central-East | | | | | | 345.52 | 366.15 | 354.01 | 20.6 |
| 38 | South 9* | 345 | Central-East | | | | | | 342.31 | 364.29 | 353.69 | 22.0 |
| 39 | South 11* | 345 | Central-East | | | | | | 348.52 | 360.97 | 355.50 | 12.5 |
| 40 | South 3* | 138 | Valley | | | | | | 138.25 | 148.81 | 142.51 | 10.6 |
| 41 | South 5* | 138 | Valley | | | | | | 135.90 | 145.74 | 141.61 | 9.8 |
| 42 | South 10* | 138 | Valley | | | | | | 138.54 | 144.90 | 141.84 | 6.4 |

Note: The availability of state estimator cases was in the order of 13%. One substation, West 8, had an availability of only 3.3%.

We believe this to be an anomaly, ERCOT to provide feedback. The two substations with + came on line during the second half of 2012 and the substations with * did not have PMUs installed in 2012.

TABLE A-2 CCET DISCOVERY ACROSS TEXAS - LIMITS FOR VOLTAGES - NORMAL CONDITIONS

| No. | Bus Names | Base kV | Phasor Data | | | State Estimator Data | | | | | | | | SE Data | | |
|-----|------------|---------|----------------|------------|----------------|----------------------|-------------|---------|-----------|--------|----------|---------------|-----------|------------|------------|----------------|
| | | | Normal Min | Normal Max | Max-Min Spread | Normal Min-100% | 100% or POI | 99% Min | 99% - POI | 1% Max | 1% + POI | Normal Max-0% | 0% or POI | Normal Min | Normal Max | Max-Min Spread |
| 1 | West 10 | 69 | 68.0 | 72.40 | 4.40 | 67.05 | 99.99% | 68.09 | 98.99% | 70.64 | 1.01% | 71.59 | 0.01% | 67.05 | 71.59 | 4.55 |
| 2 | West 14 | 345 | 346.6 | 361.40 | 14.76 | 348.43 | 100.00% | 351.89 | 99.00% | 360.22 | 1.01% | 363.97 | 0.01% | 348.43 | 363.97 | 15.54 |
| 3 | West 11 | 345 | 344.3 | 356.50 | 12.22 | 347.38 | 99.99% | 351.62 | 98.99% | 358.04 | 1.01% | 360.92 | 0.01% | 347.38 | 360.92 | 13.55 |
| 4 | West 6 | 345 | 343.8 | 358.20 | 14.40 | 347.61 | 99.99% | 351.02 | 98.99% | 360.31 | 1.03% | 363.32 | 0.03% | 347.61 | 363.32 | 15.71 |
| 5 | North 1 | 345 | 341.3 | 353.40 | 12.12 | 342.54 | 99.99% | 344.89 | 98.99% | 355.09 | 1.02% | 358.78 | 0.02% | 342.54 | 358.78 | 16.24 |
| 6 | North 2 | 138 | 137.4 | 143.70 | 6.32 | 138.04 | 99.99% | 138.83 | 98.99% | 141.49 | 1.01% | 142.34 | 0.01% | 138.04 | 142.34 | 4.29 |
| 7 | North 4 | 138 | 138.7 | 143.70 | 5.02 | 137.34 | 100.00% | 138.71 | 99.00% | 143.37 | 1.01% | 146.08 | 0.01% | 137.34 | 146.08 | 8.74 |
| 8 | North 5 | 138 | 137.9 | 143.00 | 5.06 | 137.11 | 99.97% | 138.02 | 98.97% | 141.46 | 1.01% | 145.66 | 0.01% | 137.11 | 145.66 | 8.56 |
| 9 | North 6 | 138 | 137.8 | 143.40 | 5.64 | 138.95 | 99.99% | 140.20 | 98.98% | 142.92 | 1.11% | 144.49 | 0.11% | 138.95 | 144.49 | 5.54 |
| 10 | North 7 | 138 | 138.1 | 144.20 | 6.12 | 135.75 | 99.99% | 137.90 | 98.99% | 143.47 | 1.01% | 144.80 | 0.01% | 135.75 | 144.80 | 9.05 |
| 11 | West 4 | 138 | 133.3 | 146.50 | 13.21 | 133.27 | 99.98% | 136.81 | 98.98% | 145.54 | 1.02% | 151.60 | 0.02% | 133.27 | 151.60 | 18.32 |
| 12 | Coast 2+ | 69 | 66.6 | 72.92 | 6.36 | 65.81 | 100.00% | 67.26 | 99.00% | 71.50 | 1.05% | 72.12 | 0.05% | 65.81 | 72.12 | 6.31 |
| 13 | Coast 1 | 138 | 138.4 | 144.10 | 5.66 | 138.83 | 99.99% | 139.91 | 98.98% | 143.97 | 1.01% | 144.85 | 0.01% | 138.83 | 144.85 | 6.02 |
| 14 | Coast 4 | 345 | 342.0 | 362.40 | 20.40 | 341.07 | 99.99% | 347.69 | 98.99% | 362.07 | 1.01% | 368.81 | 0.01% | 341.07 | 368.81 | 27.74 |
| 15 | Coast 3 | 345 | 342.4 | 361.50 | 19.13 | 340.84 | 100.00% | 347.36 | 99.00% | 361.72 | 1.11% | 366.89 | 0.11% | 340.84 | 366.89 | 26.06 |
| 16 | South 6+ | 138 | 138.08 | 144.50 | 6.42 | 139.51 | 99.99% | 140.60 | 98.99% | 143.67 | 1.01% | 145.06 | 0.01% | 139.51 | 145.06 | 5.55 |
| 17 | South 13 | 138 | 135.8 | 144.20 | 8.44 | 137.06 | 99.98% | 138.76 | 98.98% | 144.03 | 1.01% | 145.59 | 0.01% | 137.06 | 145.59 | 8.53 |
| 18 | FarWest 4 | 345 | 347.2 | 357.70 | 10.54 | 345.27 | 99.98% | 352.29 | 98.98% | 358.57 | 1.01% | 362.57 | 0.01% | 345.27 | 362.57 | 17.30 |
| 19 | FarWest 7 | 345 | 341.7 | 353.90 | 12.15 | 343.25 | 99.99% | 346.22 | 98.99% | 356.89 | 1.01% | 359.88 | 0.01% | 343.25 | 359.88 | 16.62 |
| 20 | FarWest 8 | 138 | 137.4 | 144.30 | 6.94 | 136.22 | 99.99% | 137.34 | 98.99% | 142.05 | 1.01% | 142.92 | 0.01% | 136.22 | 142.92 | 6.70 |
| 21 | FarWest 9 | 138 | 133.8 | 144.10 | 10.26 | 136.13 | 99.97% | 138.05 | 98.97% | 143.11 | 1.05% | 147.68 | 0.05% | 136.13 | 147.68 | 11.55 |
| 22 | West 16* | 345 | NOT IN SERVICE | | | | | | | | | | | | | |
| 23 | West 17* | 345 | NOT IN SERVICE | | | | | | | | | | | | | |
| 24 | West 13* | 345 | NOT IN SERVICE | | | | | | | | | | | | | |
| 25 | West 15* | 345 | NOT IN SERVICE | | | | | | | | | | | | | |
| 26 | West 8* | 345 | N/A | | | 342.85 | 100.00% | 345.01 | 99.00% | 362.57 | 1.02% | 364.29 | 0.02% | 342.85 | 364.29 | 21.44 |
| 27 | West 1* | 345 | | | | 343.77 | 99.99% | 346.72 | 98.99% | 359.73 | 1.01% | 363.03 | 0.01% | 343.77 | 363.03 | 19.26 |
| 28 | West 2* | 345 | | | | 348.15 | 99.99% | 352.15 | 98.99% | 361.14 | 1.01% | 365.70 | 0.01% | 348.15 | 365.70 | 17.55 |
| 29 | West 3* | 345 | NOT IN SERVICE | | | | | | | | | | | | | |
| 30 | West 9* | 345 | N/A | | | 348.24 | 99.99% | 351.60 | 98.99% | 361.72 | 1.03% | 364.86 | 0.03% | 348.24 | 364.86 | 16.62 |
| 31 | West 12* | 345 | NOT IN SERVICE | | | | | | | | | | | | | |
| 32 | West 5* | 345 | N/A | | | 347.36 | 99.99% | 351.93 | 98.99% | 360.66 | 1.03% | 364.10 | 0.03% | 347.36 | 364.10 | 16.74 |
| 33 | South 15* | 345 | | | | 348.26 | 99.99% | 350.38 | 98.99% | 360.04 | 1.01% | 361.60 | 0.01% | 348.26 | 361.60 | 13.34 |
| 34 | FarWest 2* | 69 | | | | 66.93 | 100.00% | 67.74 | 99.00% | 71.16 | 1.01% | 72.32 | 0.01% | 66.93 | 72.32 | 5.39 |
| 35 | South 2* | 345 | | | | 346.30 | 99.98% | 348.21 | 98.98% | 358.20 | 1.02% | 360.34 | 0.02% | 346.30 | 360.34 | 14.04 |
| 36 | South 4* | 345 | | | | 348.82 | 100.00% | 350.78 | 99.00% | 360.15 | 1.00% | 361.42 | 0.00% | 348.82 | 361.42 | 12.60 |
| 37 | South 7* | 345 | | | | 346.17 | 99.98% | 348.04 | 98.98% | 361.66 | 1.02% | 365.80 | 0.02% | 346.17 | 365.80 | 19.63 |
| 38 | South 9* | 345 | | | | 343.11 | 99.95% | 346.27 | 98.95% | 360.04 | 1.01% | 364.21 | 0.01% | 343.11 | 364.21 | 21.10 |
| 39 | South 11* | 345 | | | | 349.44 | 99.99% | 350.82 | 98.99% | 359.55 | 1.01% | 360.77 | 0.01% | 349.44 | 360.77 | 11.33 |
| 40 | South 3 | 138 | | | | 138.30 | 100.00% | 140.34 | 99.00% | 145.88 | 1.01% | 148.55 | 0.01% | 138.30 | 148.55 | 10.25 |
| 41 | South 5* | 138 | | | | 136.52 | 99.99% | 138.24 | 98.99% | 144.15 | 1.01% | 145.47 | 0.01% | 136.52 | 145.47 | 8.95 |
| 42 | South 10* | 138 | | | | 138.59 | 99.99% | 139.73 | 98.99% | 143.86 | 1.01% | 144.85 | 0.01% | 138.59 | 144.85 | 6.25 |

Note: The two substations with + came on line during the second half of 2012 and the substations with * did not have PMUs installed in 2012.

Note that the voltage spreads at Coast 4 - 345 kV and West 4 - 138 kV buses are down to 27.74 and 18.32 kV respectively. For each SE data and phasor data, box-whisker plots and time duration curves were developed for each of the substations listed above and were used to obtain the values in the Table A-2 above. Summaries of SE-based voltage angle pairs with their corresponding box-whisker and time duration curves as well as summaries of phasor-based voltage angle pairs with their corresponding box-whisker and time duration curves are presented in Appendix C.

C. Observations

- Data availability: the availability for state estimator data was approximately 13%; for phasor data was greater overall but varied from 10.37% at FarWest 7 to 96.61% at North 4. Ten out of twenty one substations had data availability greater than 70%

- b. Maximum voltages obtained from phasor data were overall lower than those obtained with state estimator data; however, the average voltages were within 1% from each other with the only exception being West 10 whose state estimator average voltage was 97.4% of that obtained with phasor data..
- c. Both phasor data and state estimator data point to West 4 and Coast 4 as having the highest voltage and voltage spread in their class. Voltage at these substations is more volatile than at the other substations. Note Coast 3 also has high voltage spread but South 13 and South 6 which are in the neighborhood have a much lower spread.
- d. Fifteen substations out of a total of forty one show voltage spreads of higher than 15 kV and 24 substations show voltage spreads higher than 10 kV
- e. Voltage spreads for normal conditions went down by up to 5 kV (phasor) from those under all conditions.

D. **Proposed Alarm Limits for Voltages**

The limits summarized in the two tables above will change due to the massive addition of new 345 kV lines in the ERCOT system in 2013. EPG will update these results with the data collected in 2013 and then develop alarm limits for recommendation to ERCOT.

E. **Criteria to Set Alarm Limits For Voltages**

At the time when EPG has all 2013 data, EPG will use the voltage results from the SE data as the main source of information for determining alarm limits. Also, EPG will establish alarm limits only for those substations that have or will soon have PMUs associated with them as listed in the table in section 6-A.

The following criteria are proposed to be used to later determine the alarm limits for the substations selected for analysis.

- a. Determine four alarm limits for voltages: two based on maximum values obtained from SCADA data results and from System Operating Bulletin 17 (SOB-17) and the other based on minimum values obtained from the SCADA data results and from SOB-17.
- b. For high voltages, the Maximum Alarm value shall represent the highest voltage, and the Maximum Alert shall represent the second highest voltage, based on the following selection criteria:
 - i. Based on SE results, the voltage which is exceeded only 1 % of the time, if the box-whisker and time duration plots show no extreme values (outliers or values due to events in the system). If extreme values or outliers are present, a point of inflection will be determined, and the alarm will be based on the voltage corresponding to the time represented by the point of inflection plus 1% of time, based on the time duration curve.
 - ii. The maximum voltage pre-established by ERCOT operations.
- c. For low voltages, the minimum alarm value shall represent the lowest voltage, and the minimum alert shall represent the second lowest voltage, based on the following selection criteria:
 - i. Based on SE results, the voltage which is exceeded 99 % of the time, if the box-whisker and time duration plots show no extreme values (outliers or values due

to events in the system). If extreme values or outliers are present, a point of inflection will be determined, and the alarm will be based on the voltage corresponding to the time represented by the point of inflection minus 1% of time, based on the time duration curve.

- ii. The minimum voltage pre-established by ERCOT operations.
- d. Phasor data will be used for voltage alarm limits if necessary.

10. BASELINE ANALYSIS FOR VOLTAGE ANGLES (REFERENCE: North 7 Bus)

A. Substations Identified for Voltage Angle Analysis

The following substations were selected for voltage angle analysis; the substation selected as reference was North 7.

| Table 2 | | | |
|-------------------------------------------------|-------------------|-----------|---------------|
| SUBSTATIONS FOR VOLTAGE ANGLE MONITORING | | | |
| | SUBSTATION | kV | REGION |
| 1 | West 10 | 69 | Panhandle |
| 2 | West 14 | 345 | Panhandle |
| 3 | West 11 Switch | 345 | Central |
| 4 | West 6 | 345 | Central |
| 5 | North 2 | 138 | Dallas |
| 6 | North 4 | 138 | Dallas |
| 7 | North 5 | 138 | Dallas |
| 8 | North 1 | 345 | Dallas |
| 9 | North 6 | 138 | East |
| 10 | West 4 | 138 | SouthWest |
| 11 | Coast 1 | 138 | Valley |
| 12 | South 13 | 138 | Valley |
| 13 | Coast 3 | 345 | Valley |
| 14 | Coast 4 | 345 | Valley |
| 15 | FarWest 8 | 138 | West Texas |
| 16 | FarWest 9 | 138 | West Texas |
| 17 | FarWest 4 | 345 | West Texas |
| 18 | FarWest 7 | 345 | West Texas |
| 19 | West 16* | 345 | Panhandle |
| 20 | West 17* | 345 | Panhandle |
| 21 | West 13* | 345 | Panhandle |
| 22 | West 15* | 345 | Panhandle |
| 23 | West 8* | 345 | Central |
| 24 | West 1* | 345 | Central |
| 25 | West 2* | 345 | Central |
| 26 | West 3* | 345 | Central |
| 27 | West 9* | 345 | Central |
| 28 | West 12* | 345 | Central |
| 29 | West 5* | 345 | Central |
| 30 | South 15* | 345 | Central |
| 31 | FarWest 2* | 69 | Central-East |
| 32 | South 2* | 345 | Central-East |
| 33 | South 4* | 345 | Central-East |
| 34 | South 7* | 345 | Central-East |
| 35 | South 9* | 345 | Central-East |
| 36 | South 11* | 345 | Central-East |
| 37 | Coast 2* | 69 | Valley |
| 38 | South 3* | 138 | Valley |
| 49 | South 5* | 138 | Valley |
| 40 | South 6* | 138 | Valley |
| 41 | South 10* | 138 | Valley |

B. Summary of Results – All Data Included

The voltage angle results obtained from all data available, all solved SE cases, and all phasor data are summarized in Table B-1 below.

These results were obtained using all data available including event and outage conditions; under these conditions, voltage angles would be expected to be larger than under normal conditions because during event and outages conditions the angles tend to increase to reflect the changes in system conditions or changes in system configuration. The maximum Max-min spreads observed were 112.8 degrees for FarWest 9 138 kV substation and 87.7 degrees for West 11 345 kV substation. Note also that the substations close to the wind farms in groups 1 and 2 shown in yellow have over 80 degrees Max-Min spreads.

Table B-1: CCET DISCOVERY ACROSS TEXAS- BASELINING ANALYSIS - VOLTAGE ANGLES - ALL CONDITIONS

(Reference: North 7)

| No | Angle Pair FROM - TO | Base kV | Phasor Data - 1/1/12 to 12/31/12 | | | | | State Estimator Data - 1/1/12 to 12/31/12 | | | | |
|----|-------------------------|---------|---------------------------------------------------------|-------|---------|------------------|------------------|-------------------------------------------|-------|---------|------------------|----------------|
| | | | Min | Max | Average | Percent Positive | % Data Available | Min | Max | Average | Percent Positive | Max-Min Spread |
| 1 | West 10 | 69/138 | -50.62 | 86.46 | 12.32 | 64.09 | 80.76 | -28.51 | 28.34 | 2.81 | 64.31% | 56.9 |
| 2 | West 14 | 345/138 | -30.47 | 51.50 | 7.85 | 71.45 | 31.78 | -23.22 | 39.09 | 9.05 | 76.65% | 62.3 |
| 3 | West 11 | 345/138 | -38.23 | 58.28 | 9.70 | 61.95 | 76.97 | -31.81 | 56.01 | 12.55 | 67.98% | 87.8 |
| 4 | West 6 | 345/138 | -35.80 | 57.41 | 11.45 | 66.36 | 95.24 | -29.90 | 55.56 | 13.02 | 69.46% | 85.5 |
| 5 | North 1 | 345/138 | -14.24 | 27.29 | 8.28 | 88.37 | 10.08 | -14.55 | 31.48 | 9.48 | 89.13% | 46.0 |
| 6 | North 2 | 138 | -19.38 | 26.35 | 4.13 | 70.45 | 93.11 | -7.76 | 10.35 | -0.87 | 29.72% | 18.1 |
| 7 | North 4 | 138 | -22.68 | 21.60 | -0.54 | 47.73 | 95.72 | -21.23 | 21.44 | 0.70 | 55.43% | 42.7 |
| 8 | North 5 | 138 | -24.71 | 19.82 | -2.14 | 37.84 | 95.55 | -23.62 | 19.56 | -1.31 | 43.93% | 43.2 |
| 9 | North 6 | 138 | -13.81 | 46.79 | 6.81 | 98.58 | 94.80 | -5.17 | 20.77 | 7.04 | 98.92% | 25.9 |
| 10 | West 4 | 138 | -45.26 | 34.93 | -7.81 | 25.60 | 39.21 | -33.40 | 22.27 | -4.06 | 38.69% | 55.7 |
| 11 | Coast 2+ | 69/138 | -22.42 | 22.92 | -1.19 | 39.75 | 18.37 | -27.54 | 23.55 | 0.79 | 54.64% | 51.1 |
| 12 | Coast 1 | 138 | -39.23 | 54.52 | 8.06 | 76.87 | 60.29 | -30.80 | 43.67 | 10.25 | 82.02% | 74.5 |
| 13 | Coast 4 | 345/138 | -39.98 | 49.99 | 8.78 | 79.82 | 13.38 | -29.65 | 50.16 | 11.37 | 84.36% | 79.8 |
| 14 | Coast 3 | 345/138 | -29.61 | 55.00 | 7.41 | 74.96 | 43.91 | -29.68 | 49.39 | 11.11 | 84.27% | 79.1 |
| 15 | South 6+ | 138 | -35.85 | 36.26 | 6.01 | 70.64 | 22.60 | -29.81 | 38.97 | 5.82 | 72.86% | 68.8 |
| 16 | South 13 | 138 | -40.88 | 49.78 | 4.40 | 65.31 | 39.03 | -35.35 | 50.24 | 6.80 | 71.58% | 85.6 |
| 17 | FarWest 4 | 345/138 | -40.52 | 60.74 | 11.87 | 65.16 | 94.71 | -31.74 | 57.44 | 13.27 | 68.16% | 89.2 |
| 18 | FarWest 7 | 345/138 | -30.34 | 54.40 | 13.05 | 67.91 | 10.08 | -37.07 | 54.99 | 10.51 | 64.72% | 92.1 |
| 19 | FarWest 8 | 138 | -53.36 | 52.46 | -0.96 | 48.35 | 72.29 | -46.71 | 49.75 | 3.32 | 54.01% | 96.5 |
| 20 | FarWest 9 | 138 | -67.76 | 86.98 | 7.92 | 57.32 | 49.62 | -47.32 | 65.44 | 9.37 | 59.06% | 112.8 |
| 19 | West 16* | 345/138 | No phasor data available for these substations for 2012 | | | | | NOT IN SERVICE IN 2012 | | | | |
| 20 | West 17* | 345/138 | | | | | | NOT IN SERVICE IN 2012 | | | | |
| 21 | West 13* | 345/138 | | | | | | NOT IN SERVICE IN 2012 | | | | |
| 22 | West 15* | 345/138 | | | | | | NOT IN SERVICE IN 2012 | | | | |
| 23 | West 8* | 345/138 | | | | | | -23.93 | 40.46 | 8.31 | 64.12% | 64.4 |
| 24 | West 1* | 345/138 | | | | | | -26.45 | 47.04 | 9.52 | 68.03% | 73.5 |
| 25 | West 2* | 345/138 | | | | | | -28.82 | 54.09 | 12.27 | 69.34% | 82.9 |
| 26 | West 3* | 345/138 | | | | | | NOT IN SERVICE IN 2012 | | | | |
| 27 | West 9* | 345/138 | | | | | | -29.90 | 55.56 | 13.00 | 69.43% | 85.5 |
| 28 | West 13* | 345/138 | | | | | | NOT IN SERVICE IN 2012 | | | | |
| 29 | West 5* | 345/138 | | | | | | -29.36 | 54.10 | 12.74 | 69.82% | 83.5 |
| 30 | South 15* | 345/138 | | | | | | -7.68 | 18.78 | 4.00 | 86.89% | 26.5 |
| 31 | FarWest 2* | 69/138 | | | | | | -15.18 | 7.87 | -2.77 | 19.34% | 23.1 |
| 32 | South 2* | 345/138 | | | | | | -2.44 | 16.93 | 5.70 | 98.37% | 19.4 |
| 33 | South 4* | 345/138 | | | | | | -8.58 | 19.88 | 4.08 | 84.80% | 28.5 |
| 34 | South 7* | 345/138 | | | | | | -3.35 | 20.21 | 6.71 | 96.98% | 23.6 |
| 35 | South 9* | 345/138 | | | | | | -10.48 | 17.30 | 3.63 | 84.37% | 27.8 |
| 36 | South 11* | 345/138 | | | | | | -10.00 | 20.79 | 4.13 | 83.30% | 30.8 |
| 12 | South 3* | 138 | | | | | | -25.96 | 36.98 | 4.06 | 67.68% | 62.9 |
| 13 | South 5* | 138 | | | | | | -24.34 | 19.00 | -3.40 | 26.49% | 43.3 |
| 16 | South 10* | 138 | | | | | | -28.50 | 26.26 | -2.32 | 35.91% | 54.8 |

Note: The two substations with + came on line during the second half of 2012 and the substations with * did not have PMUs installed in 2012.

C. Summary of Results – Normal Conditions (Events and Outages Excluded)

The voltage angle results obtained from excluding extreme values based on analysis of the box-whiskers plots and time duration curves are shown in Table B-2 below.

Table B-2: CCET DISCOVERY ACROSS TEXAS- BASELINING ANALYSIS - VOLTAGE ANGLES - NORMAL CONDITIONS
(Reference: 138 kV North 7)

| | | | DATA RESULTS | | | | | | | | | | | | | | | |
|----|-------------------------|------------|-------------------------------------|--------------|-----------------------|------------------------|--------------------------------|-----------------------------|------------------------------------|---------------------------------|----------------------------------|-------------------------------|------------------------------|---------------------------|----------------|--------------|-------------------|--|
| No | Angle Pair FROM - TO | Base kV | Phasor-Normal | | | State Estimator Data | | | | | | | | | SE Data-Normal | | | |
| | | | Min Angle | Max Angle | Max- Min Spread | Percent Positive | Min Angle at POI or 100% | Percent (POI or 100%) | Min Angle at 99% or POI - 1% | Percent (99% or POI - 1%) | Max Angle at 1% or POI +1% | Percent (1% or POI +1%) | Max Angle at POI or 0% | Percent (POI or 0%) | Min Angle | Max Angle | Max-Min Spread | |
| 1 | West 10 | 69 | -42.66 | 74.90 | 117.6 | 64.31% | -27.18 | 99.99% | -14.48 | 98.99% | 20.70 | 1.00% | 28.34 | 0.00% | -27.18 | 28.34 | 55.5 | |
| 2 | West 14 | 345 | -25.30 | 39.97 | 65.3 | 76.65% | -21.73 | 99.98% | -14.99 | 98.98% | 31.14 | 1.01% | 38.71 | 0.01% | -21.73 | 38.71 | 60.4 | |
| 3 | West 11 | 345 | -34.48 | 56.02 | 90.5 | 67.98% | -31.81 | 100.00% | -24.79 | 99.00% | 47.41 | 1.08% | 54.43 | 0.08% | -31.81 | 54.43 | 86.2 | |
| 4 | West 6 | 345 | -31.53 | 51.34 | 82.9 | 69.46% | -29.90 | 100.00% | -22.81 | 99.00% | 46.71 | 1.08% | 53.51 | 0.08% | -29.90 | 53.51 | 83.4 | |
| 5 | North 1 | 345 | -13.47 | 23.04 | 36.5 | 89.13% | -13.46 | 99.98% | -8.02 | 98.98% | 25.22 | 1.02% | 31.48 | 0.02% | -13.46 | 31.48 | 44.9 | |
| 6 | North 2 | 138 | -17.71 | 25.01 | 42.7 | 29.72% | -7.50 | 99.97% | -5.99 | 98.97% | 7.13 | 1.01% | 10.28 | 0.01% | -7.50 | 10.28 | 17.8 | |
| 7 | North 4 | 138 | -19.82 | 19.41 | 39.2 | 55.43% | -19.96 | 99.96% | -15.44 | 98.96% | 14.81 | 1.00% | 21.44 | 0.00% | -19.96 | 21.44 | 41.4 | |
| 8 | North 5 | 138 | -23.86 | 17.02 | 40.9 | 43.93% | -22.47 | 99.97% | -17.74 | 98.97% | 13.25 | 1.02% | 19.09 | 0.02% | -22.47 | 19.09 | 41.6 | |
| 9 | North 6 | 138 | -2.74 | 18.30 | 21.0 | 98.92% | -2.98 | 99.89% | 0.08 | 98.89% | 14.94 | 1.02% | 20.76 | 0.02% | -2.98 | 20.76 | 23.7 | |
| 10 | West 4 | 138 | -36.24 | 21.75 | 58.0 | 38.69% | -31.73 | 99.93% | -26.26 | 98.93% | 16.39 | 1.09% | 21.74 | 0.09% | -31.73 | 21.74 | 53.5 | |
| 11 | Coast 2+ | 69 | -18.46 | 21.27 | 39.7 | 54.64% | -26.32 | 99.99% | -15.64 | 98.99% | 17.32 | 1.00% | 23.55 | 0.00% | -26.32 | 23.55 | 49.9 | |
| 12 | Coast 1 | 138 | -24.50 | 40.36 | 64.9 | 82.02% | -26.93 | 99.96% | -13.84 | 98.96% | 34.02 | 1.00% | 43.67 | 0.00% | -26.93 | 43.67 | 70.6 | |
| 13 | Coast 4 | 345 | -29.32 | 37.42 | 66.7 | 84.36% | -25.84 | 99.96% | -11.87 | 98.96% | 36.80 | 1.00% | 50.16 | 0.00% | -25.84 | 50.16 | 76.0 | |
| 14 | Coast 3 | 345 | -23.22 | 35.88 | 59.1 | 84.27% | -24.11 | 99.96% | -11.79 | 98.96% | 35.91 | 1.01% | 48.14 | 0.01% | -24.11 | 48.14 | 72.3 | |
| 15 | South 6+ | 138 | -19.78 | 33.86 | 53.6 | 72.86% | -28.62 | 99.99% | -13.42 | 98.99% | 27.32 | 1.01% | 38.12 | 0.01% | -28.62 | 38.12 | 66.7 | |
| 16 | South 13 | 138 | -27.63 | 45.42 | 73.1 | 71.58% | -34.00 | 99.99% | -18.44 | 98.99% | 35.70 | 1.00% | 50.24 | 0.00% | -34.00 | 50.24 | 84.2 | |
| 17 | FarWest 4 | 345 | -37.15 | 55.41 | 92.6 | 68.16% | -31.25 | 100.00% | -25.69 | 99.00% | 49.19 | 1.10% | 55.90 | 0.10% | -31.25 | 55.90 | 87.1 | |
| 18 | FarWest 7 | 345 | -29.15 | 50.17 | 79.3 | 64.72% | -37.07 | 100.00% | -30.00 | 99.00% | 45.65 | 1.12% | 52.53 | 0.12% | -37.07 | 52.53 | 89.6 | |
| 19 | FarWest 8 | 138 | -50.58 | 49.05 | 99.6 | 54.01% | -46.71 | 100.00% | -37.26 | 99.00% | 40.08 | 1.00% | 49.75 | 0.00% | -46.71 | 49.75 | 96.5 | |
| 20 | FarWest 9 | 138 | -51.72 | 64.41 | 116.1 | 59.06% | -47.32 | 100.00% | -40.02 | 99.00% | 55.41 | 1.04% | 64.58 | 0.04% | -47.32 | 64.58 | 111.9 | |
| | | | | | | | | | | | | | | | | | | |
| 21 | West 16* | 345 | No Phasor Data Available in 2012 | | | NOT IN SERVICE IN 2012 | | | | | | | | | | | | |
| 22 | West 17* | 345 | | | | NOT IN SERVICE IN 2012 | | | | | | | | | | | | |
| 23 | West 13* | 345 | | | | NOT IN SERVICE IN 2012 | | | | | | | | | | | | |
| 24 | West 15* | 345 | | | | NOT IN SERVICE IN 2012 | | | | | | | | | | | | |
| 25 | West 8* | 345 | | | | 64.12% | -21.86 | 99.97% | -16.88 | 98.97% | 36.56 | 1.09% | 39.95 | 0.09% | -21.86 | 39.95 | 61.8 | |
| 26 | West 1* | 345 | | | | 68.03% | -24.66 | 99.97% | -19.51 | 98.97% | 37.85 | 1.04% | 45.52 | 0.04% | -24.66 | 45.52 | 70.2 | |
| 27 | West 2* | 345 | | | | 69.34% | -26.19 | 99.88% | -21.56 | 98.88% | 45.40 | 1.07% | 52.14 | 0.07% | -26.19 | 52.14 | 78.3 | |
| 28 | West 3* | 345 | | | | NOT IN SERVICE IN 2012 | | | | | | | | | | | | |
| 29 | West 9* | 345 | | | | 69.43% | -29.90 | 100.00% | -22.80 | 99.00% | 46.70 | 1.08% | 53.51 | 0.08% | -29.90 | 53.51 | 83.4 | |
| 30 | West 12* | 345 | | | | NOT IN SERVICE IN 2012 | | | | | | | | | | | | |
| 31 | West 5* | 345 | | | | 69.82% | -28.65 | 99.99% | -22.77 | 98.99% | 45.43 | 1.08% | 51.84 | 0.08% | -28.65 | 51.84 | 80.5 | |
| 32 | South 15* | 345 | | | | 86.89% | -5.71 | 99.94% | -3.50 | 98.94% | 14.42 | 1.05% | 18.36 | 0.05% | -5.71 | 18.36 | 24.1 | |
| 33 | FarWest 2* | 69 | | | | 19.34% | -14.42 | 99.98% | -10.63 | 98.98% | 5.51 | 1.04% | 7.79 | 0.04% | -14.42 | 7.79 | 22.2 | |
| 34 | South 2* | 345 | | | | 98.37% | -2.25 | 99.99% | -0.38 | 98.99% | 14.06 | 1.01% | 16.86 | 0.01% | -2.25 | 16.86 | 19.1 | |
| 35 | South 4* | 345 | | | | 84.80% | -6.53 | 99.94% | -4.11 | 98.94% | 15.39 | 1.05% | 19.36 | 0.05% | -6.53 | 19.36 | 25.9 | |
| 36 | South 7* | 345 | | | | 96.98% | -3.02 | 99.94% | -1.19 | 98.94% | 17.44 | 1.10% | 19.77 | 0.10% | -3.02 | 19.77 | 22.8 | |
| 37 | South 9* | 345 | | | | 84.37% | -10.09 | 99.99% | -4.48 | 98.99% | 13.04 | 1.05% | 16.72 | 0.05% | -10.09 | 16.72 | 26.8 | |
| 38 | South 11* | 345 | | | | 83.30% | -9.29 | 99.99% | -4.78 | 98.99% | 16.13 | 1.04% | 20.10 | 0.04% | -9.29 | 20.10 | 29.4 | |
| 39 | South 3* | 138 | | | | 67.68% | -24.42 | 99.99% | -13.21 | 98.99% | 23.70 | 1.06% | 34.13 | 0.06% | -24.42 | 34.13 | 58.6 | |
| 40 | South 4* | 138 | | | | 26.49% | -23.46 | 99.99% | -17.30 | 98.99% | 9.46 | 1.07% | 17.85 | 0.07% | -23.46 | 17.85 | 41.3 | |
| 41 | South 10* | 138 | 35.91% | -27.98 | 100.00% | -18.12 | 99.00% | 14.96 | 1.00% | 26.26 | 0.00% | -27.98 | 26.26 | 54.2 | | | | |

Note: The two substations with + came on line during the second half of 2012 and the substations with * did not have PMUs installed in 2012.

Summaries of SE-based voltage angle pairs with their corresponding box-whisker and time duration curves as well as summaries of phasor-based voltage angle pairs with their corresponding box-whisker and time duration curves are presented in Appendix D.

D. Observations – Voltage Angles

- a. The voltage angles with respect to North 7 for West 10 and North 2 obtained with phasor data were significantly higher than those obtained with state estimator data. The angle spread obtained from phasor data for West 10 and North 2 were 117.7 and 42.7 degrees; whereas the same spreads obtained from SE data were 55.5 and 17.8 degrees. EPG checked historical information and found that on January 9, 2012 the angle at West 10 with reference to North 7 reached 70 degrees at approximately 2:00 a.m.
- b. Voltage angles vary over a wide range for several substations. The highest variation of 111.9 degrees (-47.3 to 64.6) occurred at FarWest 9 138 kV substation. Among the 345 kV substations, the highest angle variation over the year 2012 occurred at FarWest 7 with a range of 89.6 (-37.1 to 52.5) degrees.
- c. The highest variations occurred among the substations in the western part of the state namely: FarWest 7, West 11, West 6, FarWest 8, FarWest 9, FarWest 4, West 2, West 9 and West 5.
- d. The next highest angle variation occurred in the south part of the state namely: South 13, Coast 3, Coast 4 and Coast 1.
- e. The two highest normal angles observed were at West 10 and FarWest 9 with 74.9 and 64.4 degrees respectively.

11. BASELINE ANALYSIS FOR ANGLE DIFFERENCES

A. Pairs of substations Identified for angle difference analysis

The following pairs of substations were selected to perform the angle difference analysis (ALSO SEE MAP BELOW):

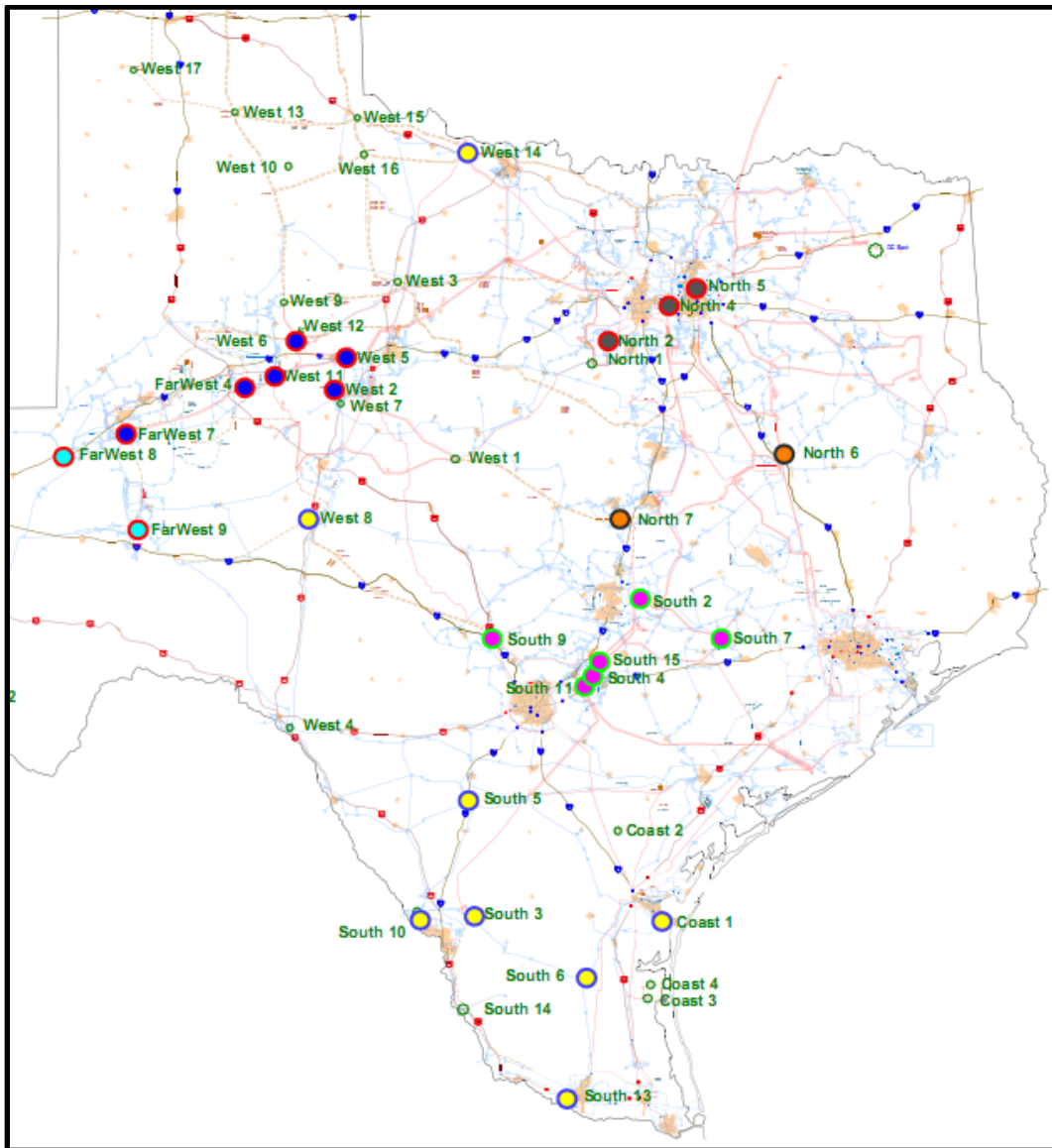
TABLE 3: ANGLE PAIRS FOR BASELINE ANALYSIS**PAIRS WITH PHASOR DATA AVAILABLE**

| Substation A | Substation B | From Region | To Region |
|--------------|--------------|--------------|--------------|
| Coast 1 | South 13 | Valley | Valley |
| Coast 1 | North 7 | Valley | Central-East |
| North 1 | North 4 | Central | Central |
| North 4 | North 5 | Central | Central |
| West 4 | North 7 | SouthWest | Central-East |
| North 7 | North 1 | Central-East | Dallas |
| North 7 | North 6 | Central-East | East |
| FarWest 7 | FarWest 4 | West Texas | West Texas |
| FarWest 7 | West 14 | West Texas | Panhandle |
| FarWest 7 | FarWest 8 | West Texas | West Texas |
| FarWest 7 | FarWest 9 | West Texas | West Texas |
| West 14 | North 1 | Panhandle | Dallas |
| FarWest 9 | West 4 | West Texas | Southwest |

PAIRS WITHOUT PHASOR DATA AVAILABLE

| | | | |
|-----------|-----------|--------------|--------------|
| Coast 1 | South 10* | Valley | Valley |
| Coast 1 | South 14* | Valley | Valley |
| North 7 | South 7* | Central-East | Central-East |
| North 7 | South 9* | Central-East | Central-East |
| North 7 | South 11* | Central-East | Central-East |
| West 8 | South 9* | Central | Central-East |
| West 11 | West 8* | Central | Central |
| West 5* | North 1 | Central | Central |
| West 5* | FarWest 4 | Central | West Texas |
| West 5* | West 10 | Central | Panhandle |
| West 5* | North 7 | Central | Central-East |
| West 14 | West 16* | Panhandle | Panhandle |
| West 14 | West 13* | Panhandle | Panhandle |
| West 14 | West 15* | Panhandle | Panhandle |
| West 14 | West 5* | Panhandle | Central |
| West 14 | West 17* | Panhandle | Panhandle |
| FarWest 9 | South 9* | West Texas | Central-East |

* Denotes substations without existing PMUs or w/o data stream



B. Summary of results – all data included

Table C-1 below contains angle difference results for all those angle pairs selected for study. This Table shows min, max and average values for angle differences obtained from all data received (all solved SE cases and all phasor data, normal and contingency conditions). Because phasor data was not available for many of the pairs selected for study, no phasor results are provided for those pairs.

Table C-1 - CCET DISCOVERY ACROSS TEXAS- BASELINING ANALYSIS- SUMMARY OF ANGLE DIFFERENCES - ALL DATA

| | | | Phasor Data - 1/1/12 to 12/31/12 | | | | | State Estimator Data - 1/1/12 to 12/31/12 | | | | | | | | | |
|----------------------------------------------------------------|---------------------|------------|----------------------------------------------|-------|----------------|--------------------|-------|-------------------------------------------|-----------|----------|----------------|-------|-----------------------------------------|-------|-------|-------|-------|
| Angle Pair | | Base kV | Min | Max | Percent % Data | | Min | Max | Percent % | | Max-Min Spread | | | | | | |
| | | | | | Average | Positive Available | | | Average | Positive | | | | | | | |
| | | | % | | | | | % | | | | | | | | | |
| 1 | Coast 1-South 13 | 138kV | -14.96 | 24.97 | 2.84 | 65.96 | 24.07 | -16.41 | 26.69 | 3.45 | 66.7% | 43.1 | | | | | |
| 2 | Coast 1-North 7 | 138kV | -39.23 | 54.52 | 8.06 | 76.87 | 60.29 | -30.80 | 43.67 | 10.25 | 82.0% | 74.5 | | | | | |
| 3 | North 1-North 4 | 345/138kV | 6.05 | 13.73 | 9.93 | 100.00 | 9.13 | 2.33 | 13.80 | 8.78 | 100.0% | 11.5 | | | | | |
| 4 | North 4-North 5 | 138kV | -4.93 | 6.99 | 1.60 | 82.27 | 95.09 | -2.71 | 6.05 | 2.01 | 89.8% | 8.8 | | | | | |
| 5 | West 4-North 7 | 138kV | -45.26 | 34.93 | -7.81 | 25.60 | 39.21 | -33.40 | 22.27 | -4.06 | 38.7% | 55.7 | | | | | |
| 6 | North 1-North 7 | 345/138 kV | -14.24 | 27.29 | 8.28 | 88.37 | 10.08 | -14.55 | 31.48 | 9.48 | 89.1% | 46.0 | | | | | |
| 7 | North 4-North 7 | 138kV | -22.68 | 21.60 | -0.54 | 47.73 | 95.72 | -21.23 | 21.44 | 0.70 | 55.4% | 42.7 | | | | | |
| 8 | North 7-North 6 | 138kV | -46.79 | 13.81 | -6.81 | 1.42 | 94.80 | -20.77 | 5.17 | -7.04 | 1.1% | 25.9 | | | | | |
| 9 | FarWest 7-FarWest 4 | 345kV | -6.83 | 3.67 | -2.69 | 6.86 | 9.12 | -17.72 | 5.71 | -2.69 | 13.9% | 23.4 | | | | | |
| 10 | FarWest 7-West 14 | 345kV | -16.79 | 23.20 | 0.73 | 47.43 | 2.92 | -26.82 | 26.07 | 0.04 | 49.1% | 52.9 | | | | | |
| 11 | FarWest 7-FarWest 8 | 345/138kV | 4.19 | 12.68 | 8.52 | 100.00 | 7.28 | 1.11 | 13.87 | 7.19 | 100.0% | 12.8 | | | | | |
| 12 | FarWest 7-FarWest 9 | 345/138kV | -19.89 | 19.66 | 2.93 | 64.83 | 9.09 | -22.95 | 24.51 | 1.15 | 56.9% | 47.5 | | | | | |
| 13 | FarWest 7-North 7 | 345/138kV | -30.34 | 54.40 | 13.05 | 67.91 | 10.08 | -37.07 | 54.99 | 10.51 | 64.7% | 92.1 | | | | | |
| 14 | West 14-North 1 | 345kV | -8.53 | 16.03 | 3.98 | 74.93 | 2.92 | -16.14 | 17.13 | 0.99 | 56.4% | 33.3 | | | | | |
| 15 | FarWest 9-West 4 | 138kV | -39.88 | 60.00 | 9.75 | 64.05 | 33.39 | -40.32 | 85.11 | 13.71 | 71.7% | 125.4 | | | | | |
| | | | Phasor data is not available for these pairs | | | | | | | | | | | | | | |
| 16 | Coast 1-South 10* | 138kV | | | | | | | | | | | -8.29 | 31.57 | 12.66 | 96.8% | 39.9 |
| 17 | North 7-South 7* | 138/345kV | | | | | | | | | | | -20.21 | 3.35 | -6.71 | 3.0% | 23.6 |
| 18 | North 7-South 9* | 138/345kV | | | | | | | | | | | -17.30 | 10.48 | -3.63 | 15.6% | 27.8 |
| 19 | North 7-South 11* | 138/345kV | | | | | | | | | | | -20.79 | 10.00 | -4.13 | 16.6% | 30.8 |
| 20 | West 5*-North 1 | 345kV | | | | | | | | | | | -25.30 | 28.24 | 3.28 | 56.1% | 53.5 |
| 21 | West 5*-FarWest 4 | 345kV | | | | | | | | | | | -9.17 | 9.25 | -0.42 | 43.3% | 18.4 |
| 22 | West 5*-West 10 | 345/69kV | | | | | | | | | | | -49.84 | 61.89 | 9.73 | 64.0% | 111.7 |
| 23 | West 5*-North 7 | 345/138kV | | | | | | | | | | | -29.36 | 54.10 | 12.74 | 69.8% | 83.5 |
| 24 | West 14-West 16* | 345kV | | | | | | | | | | | * Substation not yet in service in 2012 | | | | |
| 25 | West 14-West 13* | 345kV | | | | | | | | | | | | | | | |
| 26 | West 14-West 15* | 345kV | | | | | | | | | | | | | | | |
| 27 | West 14-West 5* | 345kV | | | | | | | | | | | -20.57 | 16.08 | -2.13 | 45.4% | 36.7 |
| 28 | West 14-West 17* | 345kV | | | | | | | | | | | * Substation not yet in service in 2012 | | | | |
| 29 | West 11-West 8* | 345kV | | | | | | | | | | | | | | | |
| 30 | West 8*-South 9* | 345kV | | | | | | | | | | | | | | | |
| 31 | FarWest 9-South 9* | 138/345kV | | | | | | -56.70 | 66.69 | 5.73 | 55.6% | 123.4 | | | | | |
| * Denotes substations without existing PMUs or w/o data stream | | | | | | | | | | | | | | | | | |

* Denotes substations without existing PMUs or w/o data stream

C. Criteria to Identify Normal Operations Limits for Angle Differences

The data received, both phasor and state estimator, provide information for all conditions during the study period including those conditions where the system experienced outages of lines or generators. This study is intended to provide angle difference limits that can be expected during normal operations, that is, when all facilities are in service. The following criteria were used to determine the angle difference limits expected during normal operations for the selected substation pairs.

- If the angle difference time duration curves show only positive angles, then two limits will be identified: one corresponding to the angle difference that occurred at about one percent of the time, and the other corresponding to the maximum value observed.
- If the angle difference time duration curves show positive as well as negative angles, then four limits will be identified, two for one direction of flow and two for the opposite direction of flow, based on the criteria below:
 - The first limit in either direction will be set using state estimator results by selecting the maximum (or minimum) angle difference observed on the

corresponding time duration curves if the box-whisker and time duration plots show no extreme values (outliers or extreme values due to events in the system). If extreme values or outliers are present, a point of inflection will be determined and the maximum or minimum angle will be set at the angle corresponding to the point of inflection.

- ii. The second maximum limit will be set at the angle difference which occurred 1% more time than the time corresponding to the selected maximum limit, based on the time duration curve. The second minimum limit will be set at the angle difference corresponding to 1% less time than the time corresponding to the selected minimum limit.
- iii. In some cases such as the cases when there was extended outage, EPG reproduced the load duration curve excluding those days when the extended outage occur to determine the angle differences corresponding to normal conditions.
- iv. The 1% values can be used to set alarms for the operators to be notified of impending maximum angle differences. The maximum and minimum values can be used to set up alarms notifying the operator that expected maximum or minimum values has been reached.
- v. The alarms so determined should be monitored for a year against actual values observed during operation. If maximum values are exceeded, the observed values should be logged and documented for further analysis.
- vi. Maximum and minimum angle differences will change as major changes occur in the system such as return to service of a large generating station such as SONGS. This analysis shall be revised based on historical information obtained with the new facility in place. Maximum and minimum values can also be estimated from many power flow cases representing different system conditions of the year.

D. Summary of results – normal conditions

The angle difference results for normal conditions are summarized in Table C-2 below.

Table C-2 --CCET DISCOVERY ACROSS TEXAS- BASELINING ANALYSIS- SUMMARY OF ANGLE DIFFERENCES - NORMAL CONDITIONS

| | | | DATA RESULTS | | | | | | | | | | | | | | | |
|----|-------------------------|---------|--------------|--------------|-----------------------|----------------------------------|--------------------------------|-----------------------------|------------------------------------|---------------------------------|----------------------------------|-------------------------------|------------------------------|---------------------------|----------------|--------------|-----------------------|--|
| | | | Phasor Data | | | State Estimator Data | | | | | | | | | SE Data-Normal | | | |
| No | Angle Pair FROM - TO | Base kV | Min Angle | Max Angle | Max- Min Spread | Percent Positive | Min Angle at POI at 100% | Percent (POI or 100%) | Min Angle at 99% or POI - 1% | Percent (99% or POI - 1%) | Max Angle at 1% or POI +1% | Percent (1% or POI +1%) | Max Angle at POI or 0% | Percent (POI or 0%) | Min Angle | Max Angle | Max- Min Spread | |
| 1 | Coast 1-South 13 | 138 | -10.30 | 21.98 | 32.28 | 66.69% | -14.47 | 99.95% | -10.27 | 98.95% | 19.79 | 1.05% | 25.33 | 0.05% | -14.47 | 25.33 | 39.79 | |
| 2 | Coast 1-North 7 | 138 | -24.50 | 40.36 | 64.86 | 82.02% | -25.13 | 99.95% | -13.81 | 98.95% | 34.01 | 1.01% | 42.49 | 0.01% | -25.13 | 42.49 | 67.62 | |
| 3 | North 1-North 4 | 345/138 | 6.62 | 13.65 | 7.03 | 100.00% | 2.33 | 100.00% | 3.90 | 99.00% | 12.41 | 1.02% | 13.62 | 0.02% | 2.33 | 13.62 | 11.29 | |
| 4 | North 4-North 5 | 138 | -3.44 | 5.65 | 9.09 | 89.84% | -2.33 | 99.95% | -1.42 | 98.95% | 5.13 | 1.01% | 6.02 | 0.01% | -2.33 | 6.02 | 8.35 | |
| 5 | West 4-North 7 | 138 | -36.24 | 21.75 | 57.99 | 38.69% | -31.73 | 99.93% | -26.26 | 98.93% | 16.41 | 1.08% | 21.82 | 0.08% | -31.73 | 21.82 | 53.55 | |
| 6 | North 1-North 7 | 345/138 | -13.47 | 23.04 | 36.51 | 89.13% | -13.46 | 99.98% | -8.02 | 98.98% | 25.22 | 1.02% | 31.48 | 0.02% | -13.46 | 31.48 | 44.94 | |
| 7 | North 4-North 7 | 138 | -19.82 | 19.41 | 39.23 | 55.43% | -19.96 | 99.96% | -15.44 | 98.96% | 14.78 | 1.02% | 20.77 | 0.02% | -19.96 | 20.77 | 40.73 | |
| 8 | North 7-North 6 | 138 | -18.30 | 2.74 | 21.04 | 1.08% | -20.31 | 99.98% | -14.94 | 98.98% | 0.03 | 1.02% | 4.57 | 0.02% | -20.31 | 4.57 | 24.87 | |
| 9 | FarWest 7-FarWest 4 | 345 | -5.91 | 2.26 | 8.17 | 13.91% | -16.35 | 99.98% | -8.79 | 98.98% | 2.27 | 1.02% | 4.11 | 0.02% | -16.35 | 4.11 | 20.46 | |
| 10 | FarWest 7-West 14 | 345 | -15.35 | 22.05 | 37.40 | 49.10% | -25.14 | 99.99% | -19.49 | 98.99% | 18.13 | 1.03% | 24.58 | 0.03% | -25.14 | 24.58 | 49.72 | |
| 11 | FarWest 7-FarWest 8 | 345/138 | 4.79 | 12.56 | 7.77 | 100.00% | 1.66 | 99.95% | 3.42 | 98.95% | 11.70 | 1.03% | 13.05 | 0.03% | 1.66 | 13.05 | 11.38 | |
| 12 | FarWest 7-FarWest 9 | 345/138 | -13.43 | 16.35 | 29.78 | 56.95% | -22.95 | 100.00% | -17.89 | 99.00% | 15.86 | 1.04% | 23.81 | 0.04% | -22.95 | 23.81 | 46.76 | |
| 13 | FarWest 7-North 7 | 345/138 | -29.15 | 50.17 | 79.32 | 64.72% | -37.07 | 100.00% | -30.00 | 99.00% | 45.67 | 1.11% | 52.64 | 0.11% | -37.07 | 52.64 | 89.71 | |
| 14 | West 14-North 1 | 345 | -7.36 | 14.50 | 21.86 | 56.42% | -15.68 | 99.95% | -11.70 | 98.95% | 12.80 | 1.02% | 16.01 | 0.02% | -15.68 | 16.01 | 31.69 | |
| 15 | FarWest 9-West 4 | 138 | -33.73 | 58.22 | 91.95 | 71.73% | -34.27 | 99.90% | -25.12 | 98.90% | 59.85 | 1.01% | 84.19 | 0.01% | -34.27 | 84.19 | 118.46 | |
| | | | | | | | | | | | | | | | | | | |
| 16 | Coast 1-South 10* | 138 | | | | 96.75% | -6.61 | 99.95% | -1.96 | 98.95% | 26.77 | 1.00% | 31.57 | 0.00% | -6.61 | 31.57 | 38.18 | |
| 17 | North 7-South 7* | 138/345 | | | | 3.01% | -20.05 | 99.98% | -17.56 | 98.98% | 1.19 | 1.06% | 3.16 | 0.06% | -20.05 | 3.16 | 23.21 | |
| 18 | North 7-South 9* | 138/345 | | | | 15.57% | -16.96 | 99.97% | -13.06 | 98.97% | 4.49 | 1.00% | 10.48 | 0.00% | -16.96 | 10.48 | 27.44 | |
| 19 | North 7-South 11* | 138/345 | | | | 16.59% | -19.61 | 99.95% | -16.12 | 98.95% | 4.80 | 1.00% | 10.00 | 0.00% | -19.61 | 10.00 | 29.61 | |
| 20 | West 5*-North 1 | 345 | | | | 56.08% | -25.21 | 100.00% | -19.75 | 99.00% | 24.51 | 1.01% | 27.94 | 0.01% | -25.21 | 27.94 | 53.15 | |
| 21 | West 5*-FarWest 4 | 345 | | | | 43.31% | -7.52 | 99.99% | -5.18 | 98.99% | 5.35 | 1.00% | 9.25 | 0.00% | -7.52 | 9.25 | 16.77 | |
| 22 | West 5*-West 10 | 345/69 | | | | 64.00% | -48.21 | 99.99% | -38.30 | 98.99% | 52.04 | 1.02% | 61.12 | 0.02% | -48.21 | 61.12 | 109.33 | |
| 23 | West 5*-North 7 | 345/138 | | | | 69.82% | -28.45 | 99.98% | -22.75 | 98.98% | 45.46 | 1.07% | 52.41 | 0.07% | -28.45 | 52.41 | 80.86 | |
| 24 | West 14-West 16* | 345 | | | | ONE BUS NOT IN SERVICE IN 2012** | | | | | | | | | N/A | | | |
| 25 | West 14-West 13* | 345 | | | | ONE BUS NOT IN SERVICE IN 2012** | | | | | | | | | N/A | | | |
| 26 | West 14-West 15* | 345 | | | | ONE BUS NOT IN SERVICE IN 2012** | | | | | | | | | N/A | | | |
| 27 | West 14-West 5* | 345 | | | | 45.42% | -19.86 | 99.96% | -16.56 | 98.96% | 11.15 | 1.00% | 16.08 | 0.00% | -19.86 | 16.08 | 35.94 | |
| 28 | West 14-West 17* | 345 | | | | ONE BUS NOT IN SERVICE IN 2012** | | | | | | | | | N/A | | | |
| 29 | West 11-West 8* | 345 | | | | 65.61% | -2.43 | 99.25% | -2.01 | 98.25% | 2.84 | 1.03% | 3.99 | 0.03% | -2.43 | 3.99 | 6.42 | |
| 30 | West 8*-South 9* | 345 | | | | 58.37% | -33.22 | 99.93% | -27.45 | 98.93% | 36.45 | 1.03% | 42.48 | 0.03% | -33.22 | 42.48 | 75.70 | |
| 31 | FarWest 9-South 9* | 345 | | | | 55.64% | -55.06 | 99.98% | -46.11 | 98.98% | 53.63 | 1.00% | 66.69 | 0.00% | -55.06 | 66.69 | 121.75 | |

NOTE: These results were obtained with 2012 data; ** West 16, West 13, West 15, West 17 and West 8 were not in service in 2012.

Box-whisker and time duration curves were developed for each of the pairs analyzed. Angle differences that may be the result of contingencies were excluded by reviewing points of inflection, that is, points that significantly deviated from the normal operation trend observed in the box-whisker plots. The value of angle difference at the point of inflection was considered to be the maximum angle during normal conditions. If no outlier points were identified, then the angle corresponding to the 0% or 100% time points will represent the maximum and minimum angles reached during normal operations in either direction of flow. Summaries of SE-based voltage angle pairs with their corresponding box-whisker and time duration curves as well as summaries of phasor-based voltage angle pairs with their corresponding box-whisker and time duration curves are presented in Appendix E.

E. Observations – Angle Differences

- a. The maximum Max-Min angle spreads under normal conditions occurred at FarWest 9-West 4 and FarWest 7-North 7 with 118.5 and 89.7 degrees respectively.
- b. The maximum voltage angles under normal conditions also occurred at FarWest 9-West 4 and FarWest 7-North 7 with 84.2 and 52.6 degrees respectively.
- c. Under normal conditions the maximum angles and the Max-Min spreads for these three pairs are:

| | | |
|-------------------|------|-------|
| FarWest 9-West 4 | 84.2 | 118.5 |
| FarWest 7-North 7 | 52.6 | 89.7 |
| West 5-North 7 | 52.4 | 80.9 |

- d. Another three pairs had a Max-Min spreads of over 60 degrees under normal conditions: West 5-West 10 with 109.33 degree, West 8-South 9 with 75.7 degrees and Coast 1-North 7 with 67.6 degrees.
- e. The remaining pairs had Max-Min spreads of less than 60 degrees, most of them significantly less.
- f. In general the maximum angle differences and the Max-Min spreads obtained using phasor data are lower than those obtained with state estimator data.
- g. The angle differences are 100% positive (power flow in one direction only) for two pairs: North 1-North 4 and FarWest 7-FarWest 8.

12. CONCLUSIONS

- a. **Data Availability was Limited:** ERCOT provided phasor and state estimator data for 2012. Phasor data availability ranged from 10% to 96%. State estimator data availability was low (13%).
- b. **Phasor and State Estimator Data Assessment:** Comparison of phasor and SE data shows phasor data seems well calibrated and the two data sets are well coordinated.
- c. **Angle Differences Track Wind Output:** Cluster analysis reveal angle differences plots for the substations close to the wind farms track well with the wind output graphs.
- d. **Highest Voltage Spreads at Two Locations:** Both phasor data and state estimator data point to West 4 and Coast 4 as having the highest voltage and voltage spread in their class. Note Coast 3 also has high voltage spread but South 13 and South 6 which are in the neighborhood have a much lower spread.
- f. **Substations with High Voltage Spreads:** Fifteen substations out of a total of forty one show voltage spreads of higher than 15 kV and 24 substations show voltage spreads higher than 10 kV.
- g. **Discrepancy Between SE and Phasor Data:** The voltage angles with respect to North 7 for West 10 and North 2 obtained with phasor data were significantly higher than those obtained with state estimator data. Phasor data for West 10 and North 2 were 117.7 and 42.7 degrees; SE data were 55.5 and 17.8 degrees. Historical on January 9, 2012 the angle at West 10 with reference to North 7 reached 70 degrees at about 2 AM.
- h. **Voltage Angle Variability at 345kV and 138kV Substations:** Voltage angles vary over a wide range for several substations. The highest variation of 112.8 degrees (-47.3 to 65.4) occurred at FarWest 9 138 kV substation. Among the 345 kV substations, the highest angle variation over the year 2012 occurred at FarWest 7 with a spread of 92.1 (-37.1 to 55) degrees.
 - a. The highest variations occurred among the substations in the western part of the state namely: FarWest 7, West 11, West 6, FarWest 8, FarWest 9, FarWest 4, West 2, West 9 and West 5.
 - b. The next highest angle variation occurred in the south part of the state namely: South 13, Coast 3, Coast 4 and Coast 1.
 - c. The two highest normal angles observed were at West 10 and FarWest 9 with 74.9 and 64.4 degrees respectively.
 - d. The maximum Max-Min angle spreads under normal conditions occurred at FarWest 9-West 4 and FarWest 7-North 7 with 118.5 and 89.8 degrees respectively.
- i. **Voltage Angles Under Normal Conditions:** The maximum voltage angles under normal conditions also occurred at FarWest 9-West 4 and FarWest 7-North 7 with 84.2 and 52.6 degrees respectively.
- j. Under normal conditions the maximum angles and the Max-Min spreads for these three pairs are:

| | | |
|-------------------|------|-------|
| FarWest 9-West 4 | 84.2 | 118.5 |
| FarWest 7-North 7 | 52.6 | 89.7 |
| West 5-North 7 | 52.4 | 80.9 |

- k. In general the maximum angle differences and the Max-Min spreads obtained using phasor data are lower than those obtained with state estimator data
- l. Limits: No limits are recommended for voltage magnitudes or voltage angles at this time since current limits will change due to the addition of many 345 kV transmission lines to the ERCOT system in 2013 as part of the CREZ project. Limits shall be recommended once all these lines are added and an updated baseline analysis is conducted.

13. RECOMMENDATIONS

- a. **Study Updates to Reflect New Lines:** EPG recommends that every four months an update of this study be performed to track the changes in voltages and angles and assess how the new transmission lines are affecting the system performance in response to wind output.
- b. **Improve Data Availability:** EPG recommends efforts are made to improve phasor data availability, if not already done, for those PMUs with less than 80% availability, particularly FarWest 7, North 1, and West 14. Coast 2 and South 6 also show availability of less than 40% but EPG believes these PMUs were only installed in the latter part of 2012.
- c. **Need for Additional SE Cases:** EPG recommends a greater number of state estimator base cases be provided by ERCOT for 2013 to improve the quality of future baseline analysis. Future baseline analysis will be provide angle differences that are more representative of future system behavior since most new CREZ lines will be completed in 2013.
- d. **Monitoring:** Actual voltage magnitudes and voltage angles should be collected while the new lines are being added to monitor change in angle differences which will provide insights into synchronization issue and solutions.
- e. **Simplifying Analysis:** Baseline analysis in the future can be simplified if two or more PMUs show very similar behavior and result in similar voltages and angle differences. EPG will prepare a proposal of reduce variables for use in future baseline analysis.
- f. **Monitoring Locations:** EPG recommends the development of a master list of substations and pairs of substations for monitoring the performance of the system in response to wind output changes and based on this analysis identify sites where it would be desirable to have PMUs installed

Appendix A

CCET Discovery Across Texas

Cluster Analysis – Angle Differences

External Version

Cluster Analysis – Cluster Groups

Group 1- 345

Central:

- FarWest 4
- FarWest 7
- West 2
- West 5
- West 6
- West 11

Group 2- W. Texas:

- FarWest 8
- FarWest 9

Group 3 - Dallas:

- North 2
- North 4
- North 5

Group 4 – East & CE:

- North 6
- North 7

Group 5 – 345 C.

East:

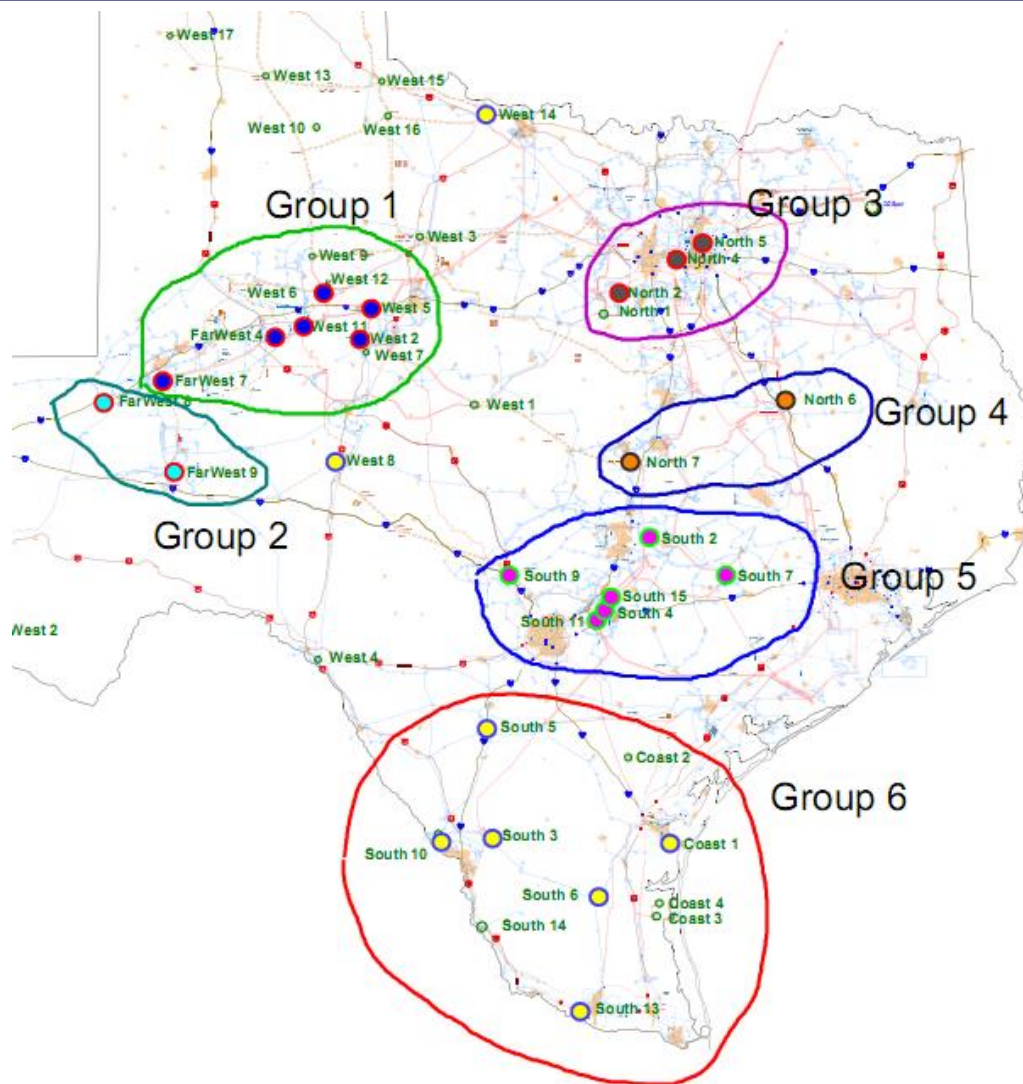
- South 2
- South 4
- South 7
- South 9
- South 11
- South 15

Group 6 - Valley:

- Coast 1
- South 3
- South 5
- South 6
- South 10
- South 13

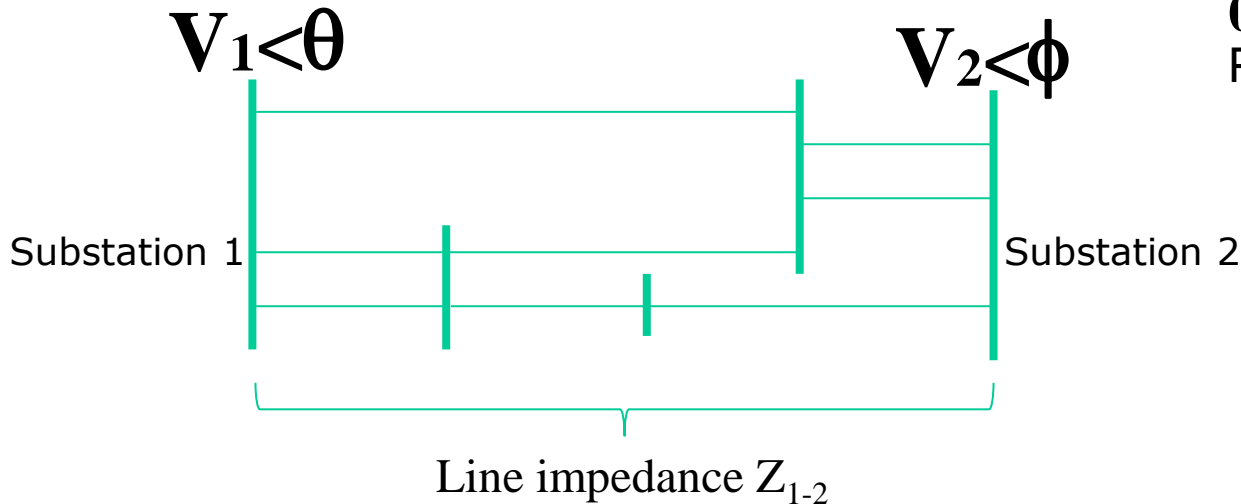
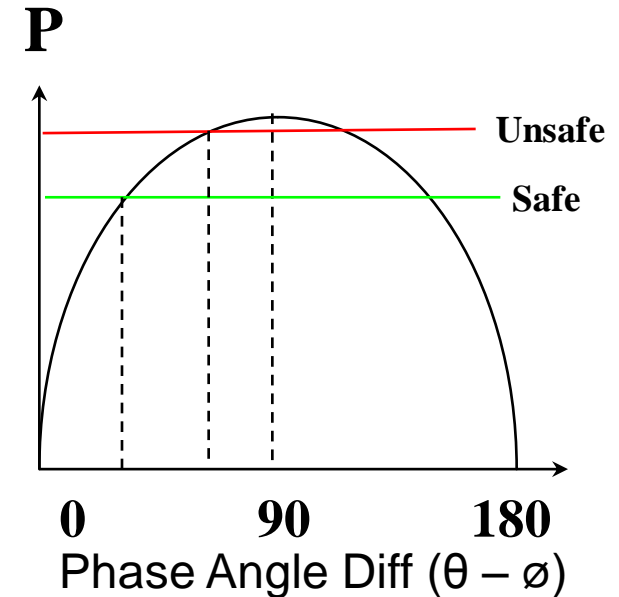
Note: This list includes existing and planned PMU locations from Oncor, AEP, Sharyland and LCRA

Cluster Locations: Group 1-Group 6



Phase angles differences as indicators of power flow

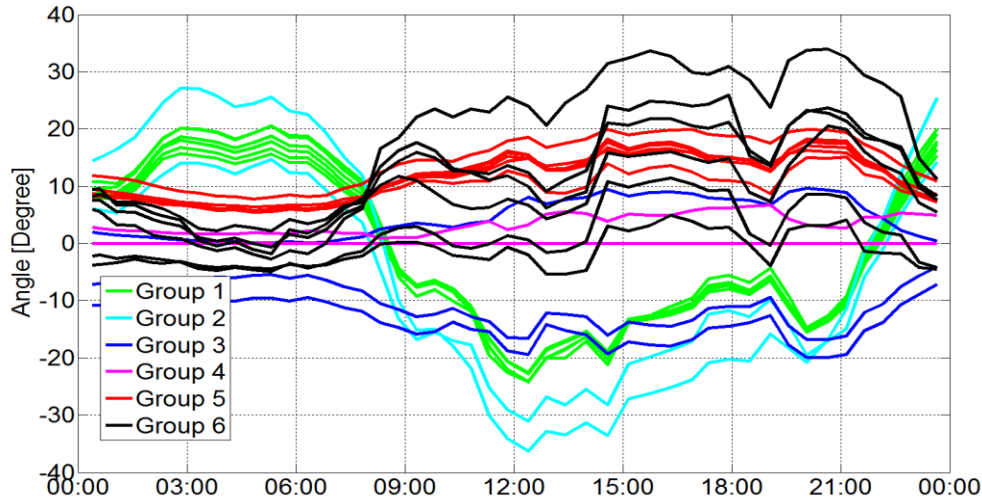
- Power flow follows voltage angle difference
 - Power flow: $P = V_1 V_2 \sin(\theta - \phi)/Z$
- Any change in Power flow or impedance will be reflected in a change in voltage phase angle difference between two locations



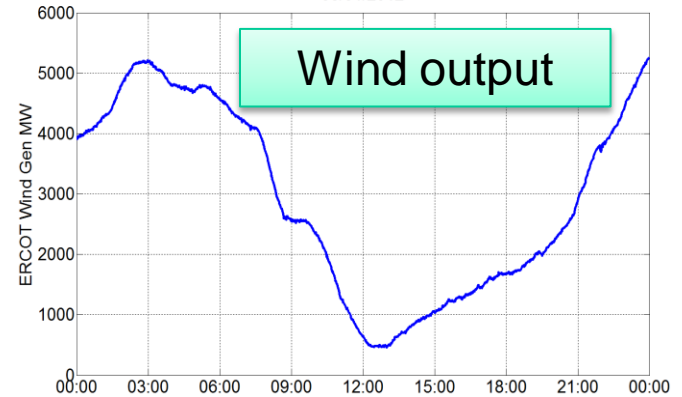
Cluster Summary-Angle Differences: Group 1-Group 6

Angle Reference: North 7

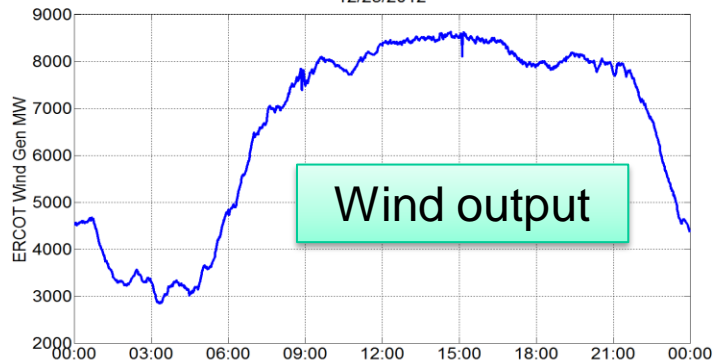
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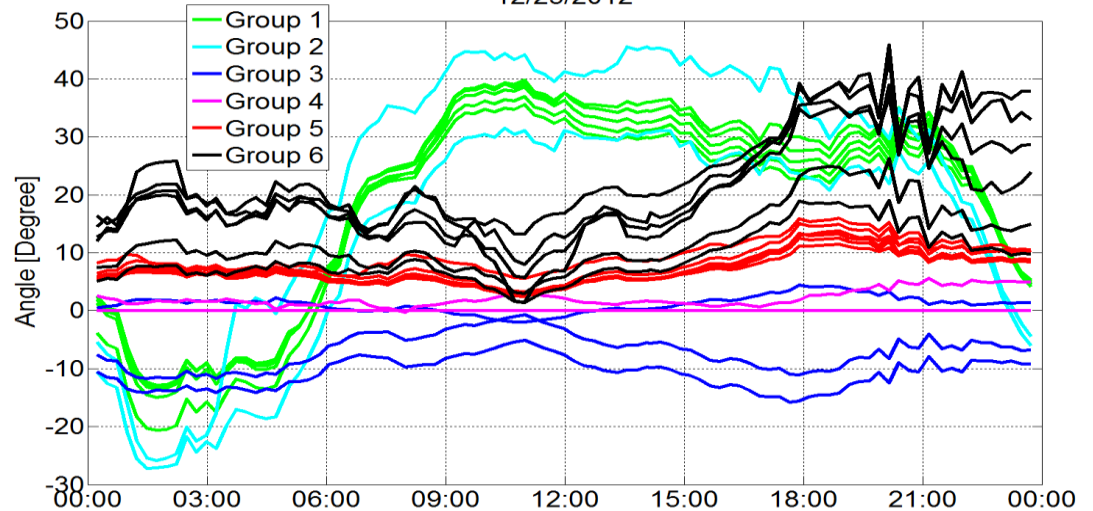
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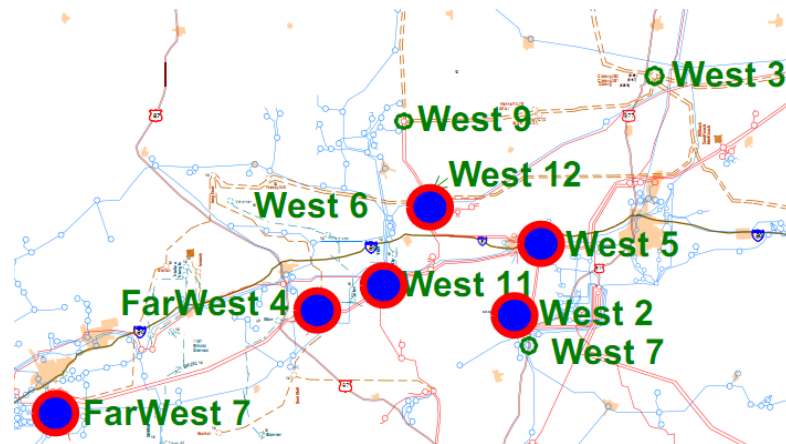
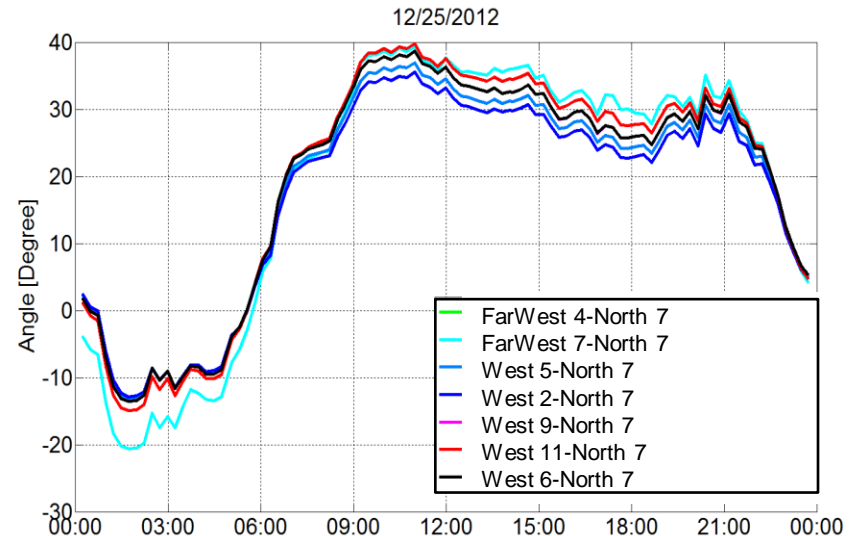
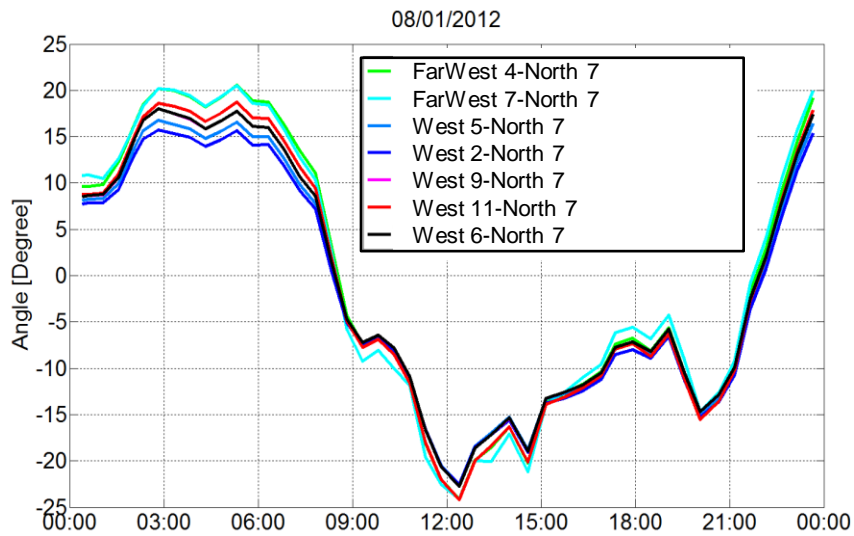
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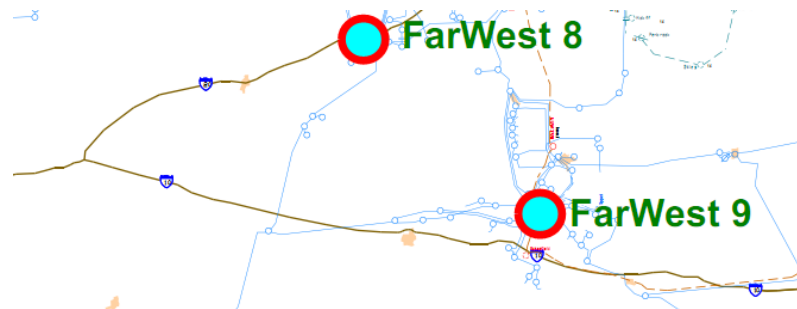
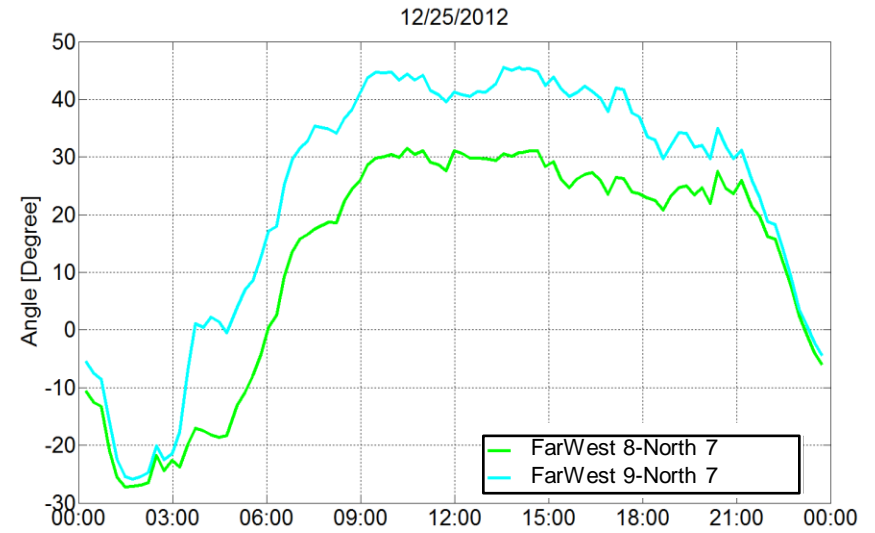
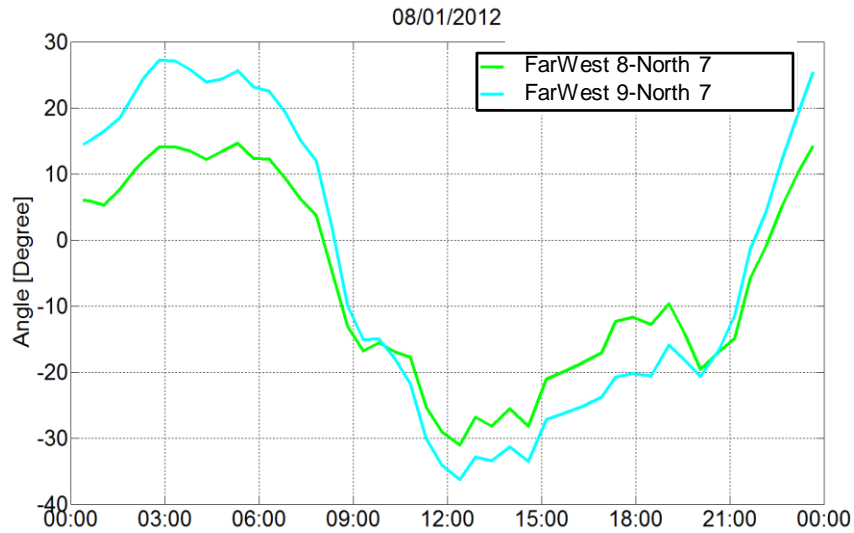
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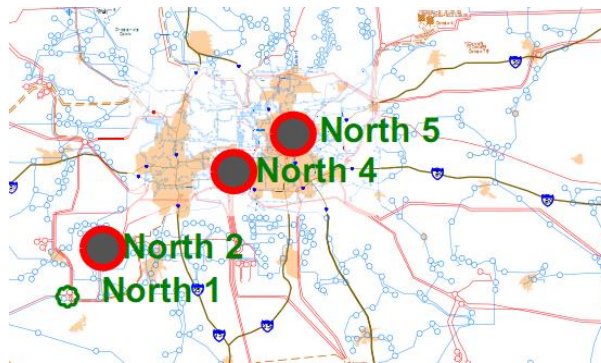
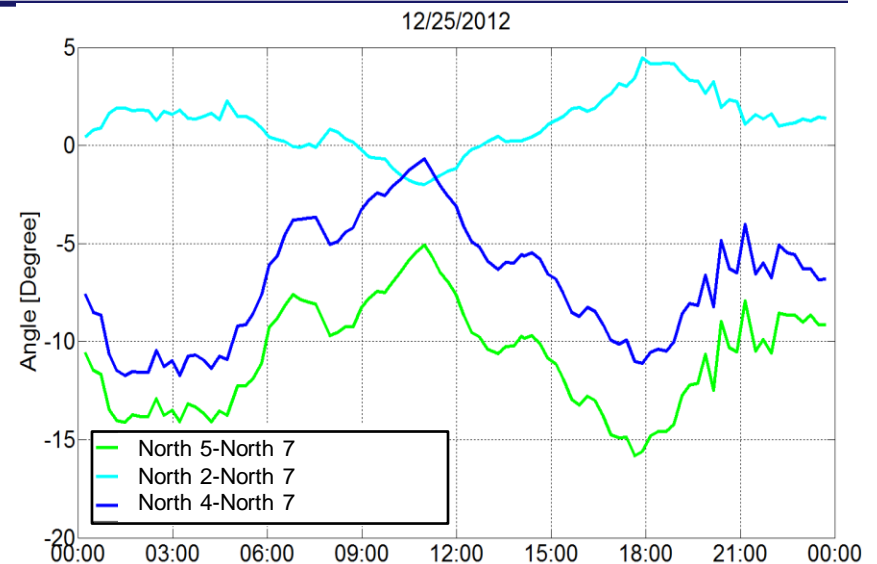
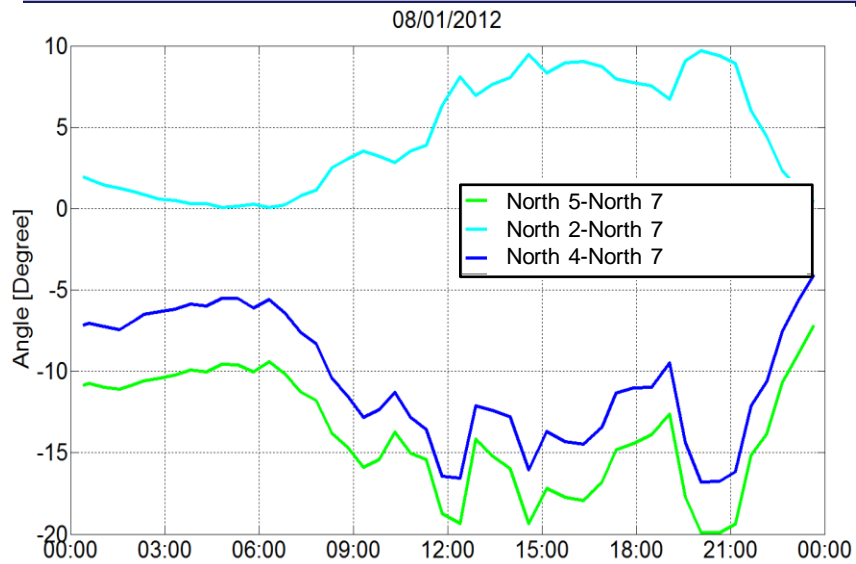
Group 1: Central



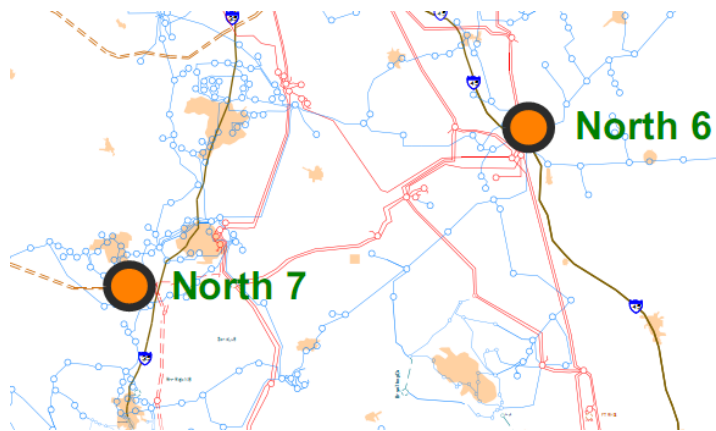
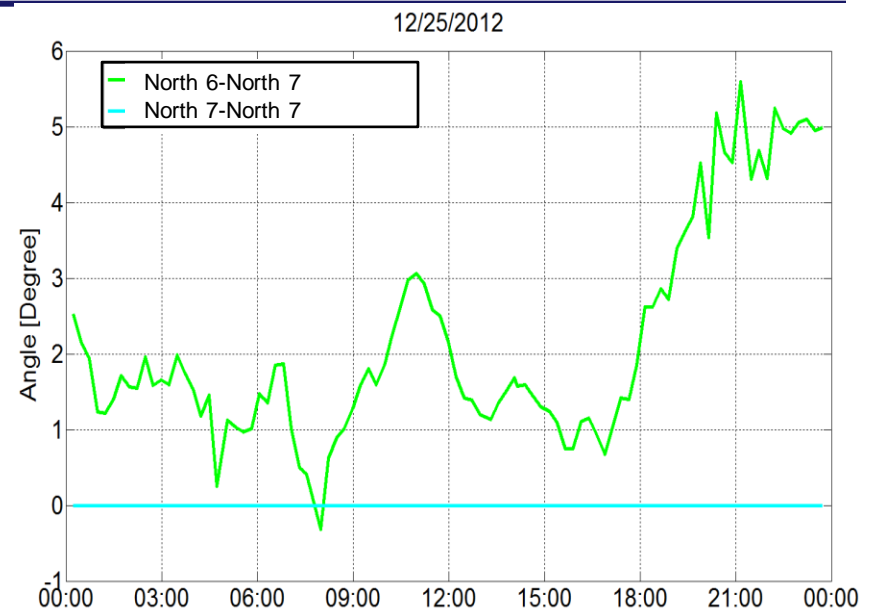
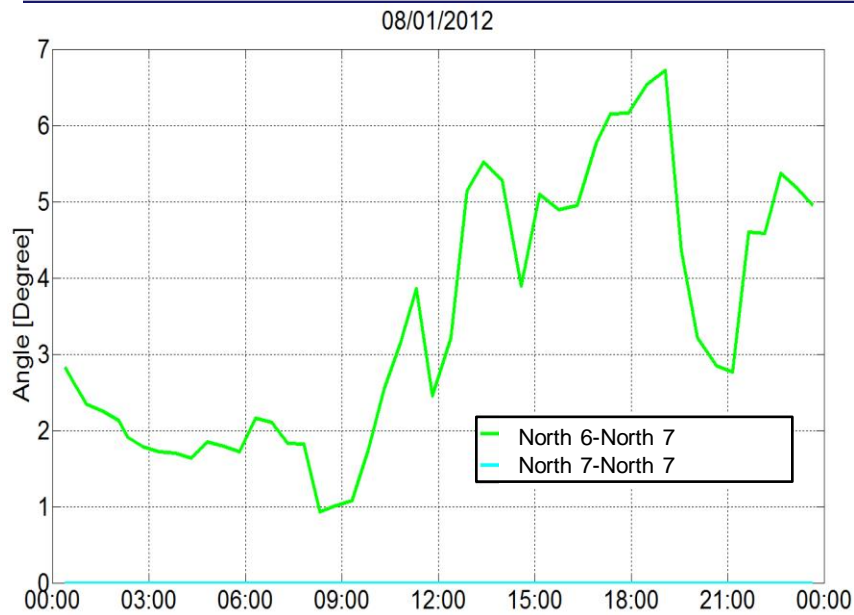
Group 2: West Texas



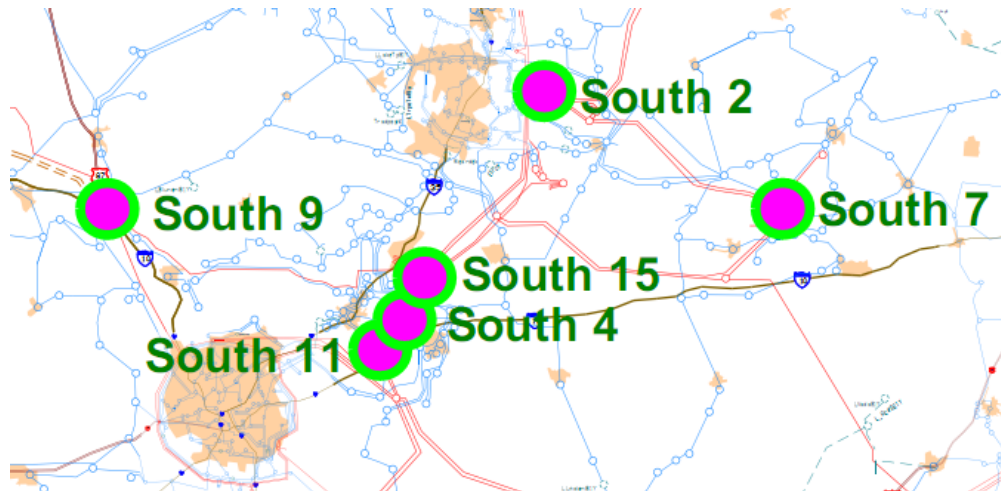
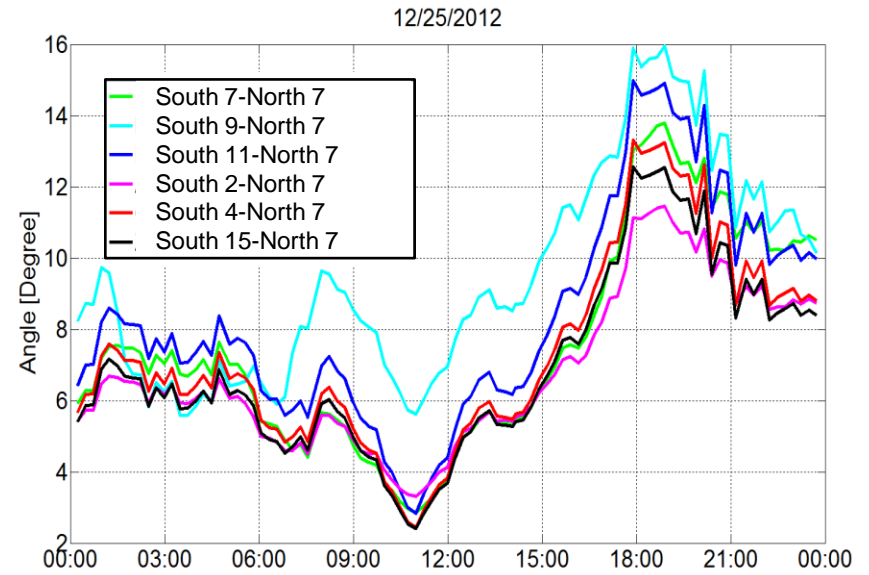
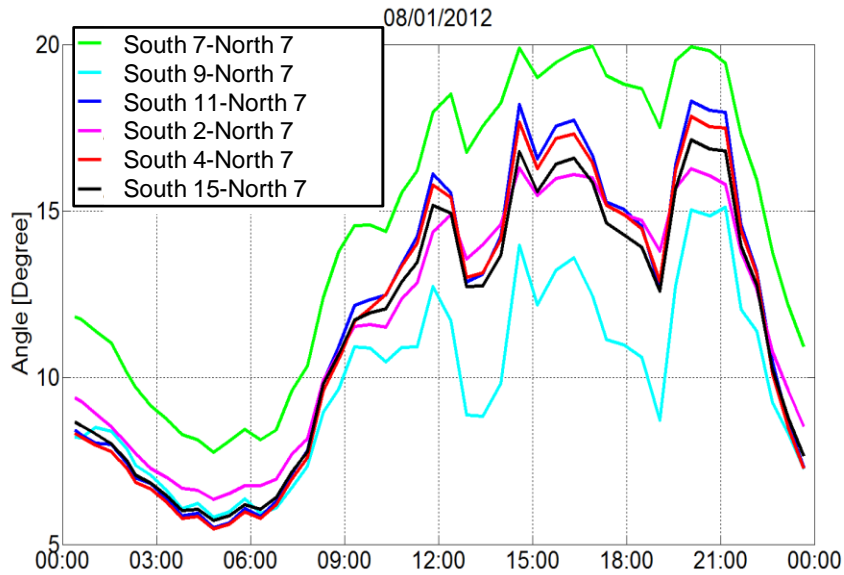
Group 3: Dallas



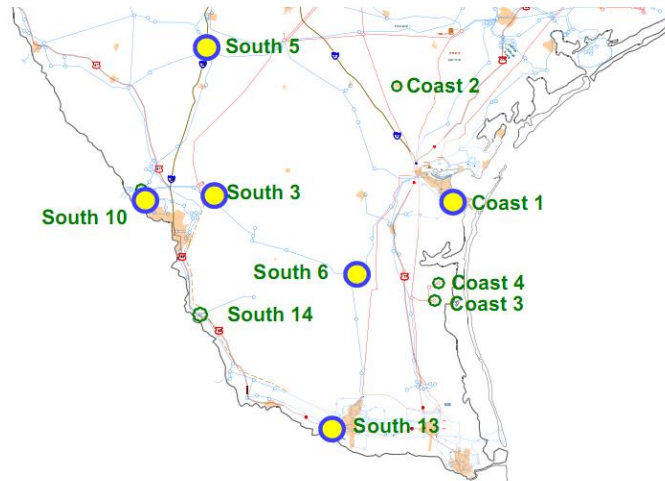
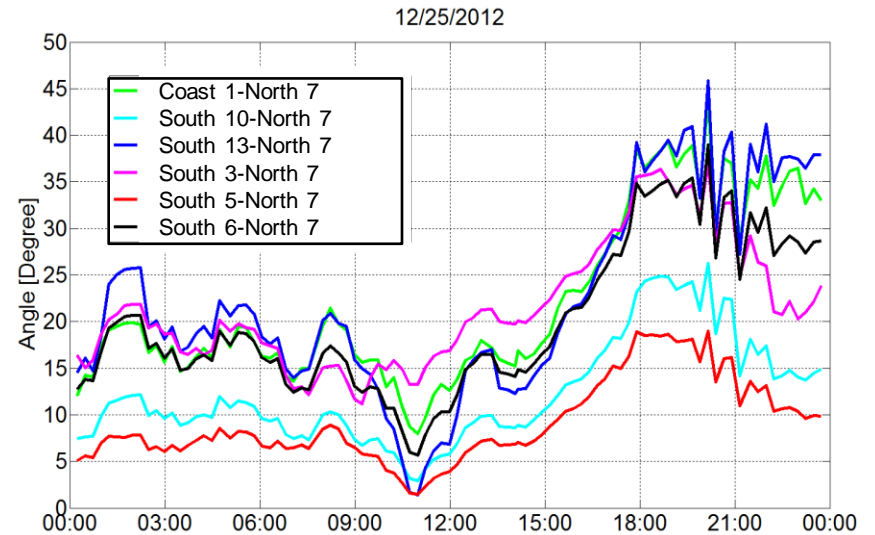
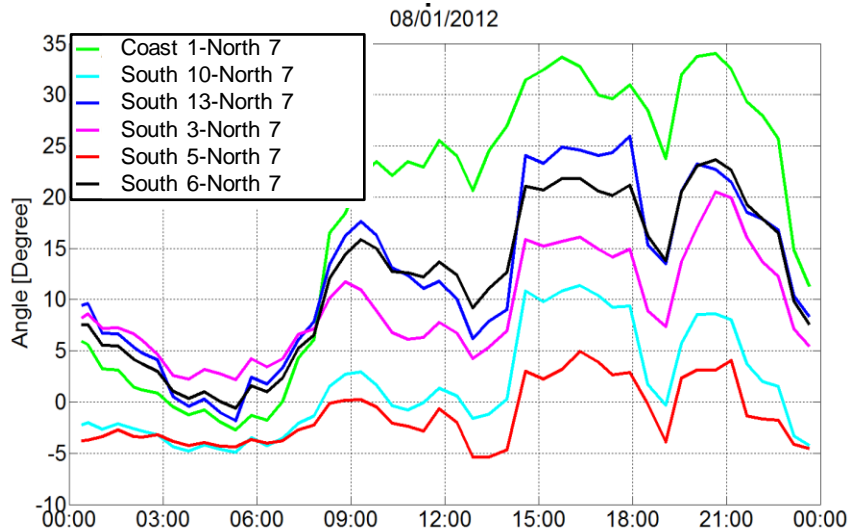
Group 4: East and Central East



Group 5: Central East



Group 6: Valley



Appendix B

CCET Discovery Across Texas

State Estimator versus Phasor Comparison

External Version



Electric Power Group



Phasor vs. State Estimator Comparison

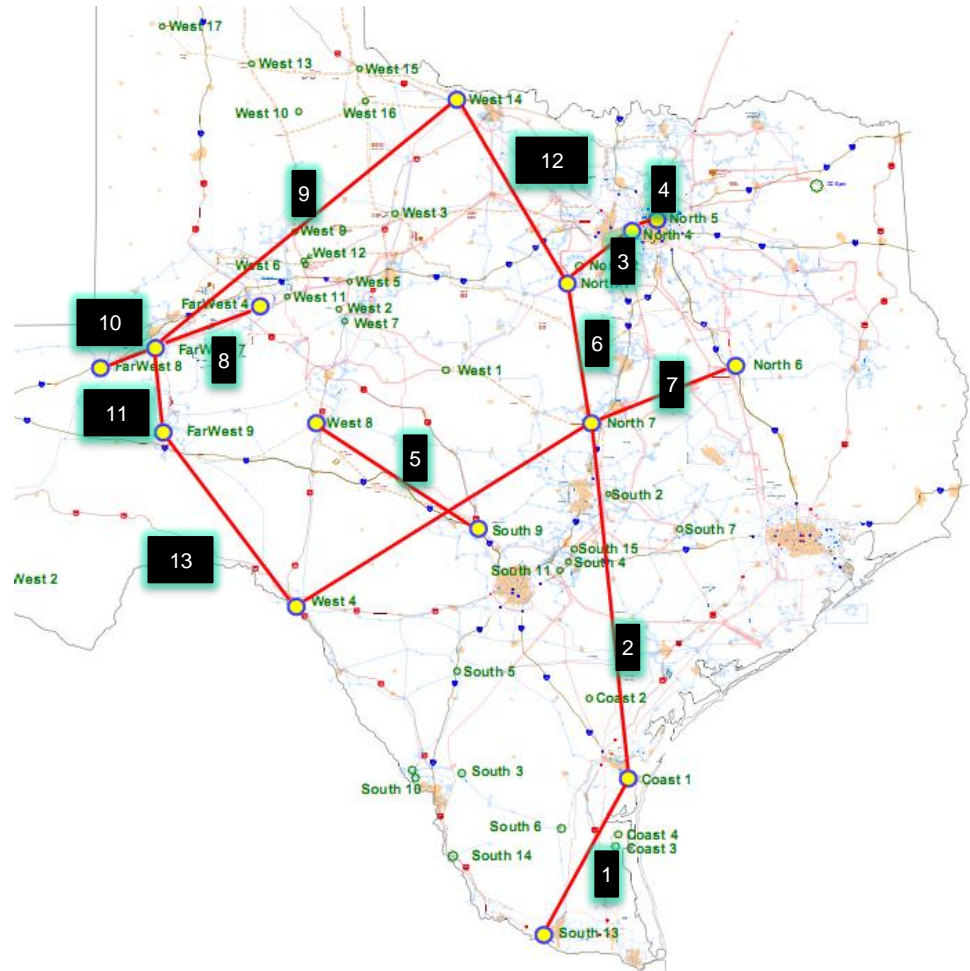
- Thirteen angle pairs were selected for comparison based on phasor measurements units availability
- Three days were selected for comparison:
 - August 1: peak load
 - November 23: low load
 - December 25: maximum wind
- Phasor data missing for one or more of the days selected: South 13, North 1, West 4, West 8, West 14 and FarWest 7
- Where both phasor and SE data was available, the comparison show a close correlation (within 1 degree) except for the North 4- North 5 pair (1.5 degrees of separation during about 7 hours on 8/1/2012).
- Observations:
 - The phasor and SE voltage angles compare very well across a wide range of locations and loads
 - The PMUs are apparently reasonably calibrated

Phasor vs. State Estimator Comparison

Angle pairs with PMUs in service

| Index | Substation A | Substation B |
|-------|--------------|--------------|
| 1 | Coast 1 | South 13 |
| 2 | Coast 1 | North 7 |
| 3 | North 1 | North 4 |
| 4 | North 4 | North 5 |
| 5 | West 4 | North 7 |
| 6 | North 7 | North 1 |
| 7 | North 7 | North 6 |
| 8 | FarWest 7 | FarWest 4 |
| 9 | FarWest 7 | West 14 |
| 10 | FarWest 7 | FarWest 8 |
| 11 | FarWest 7 | FarWest 9 |
| 12 | West 14 | North 1 |
| 13 | FarWest 9 | West 4 |

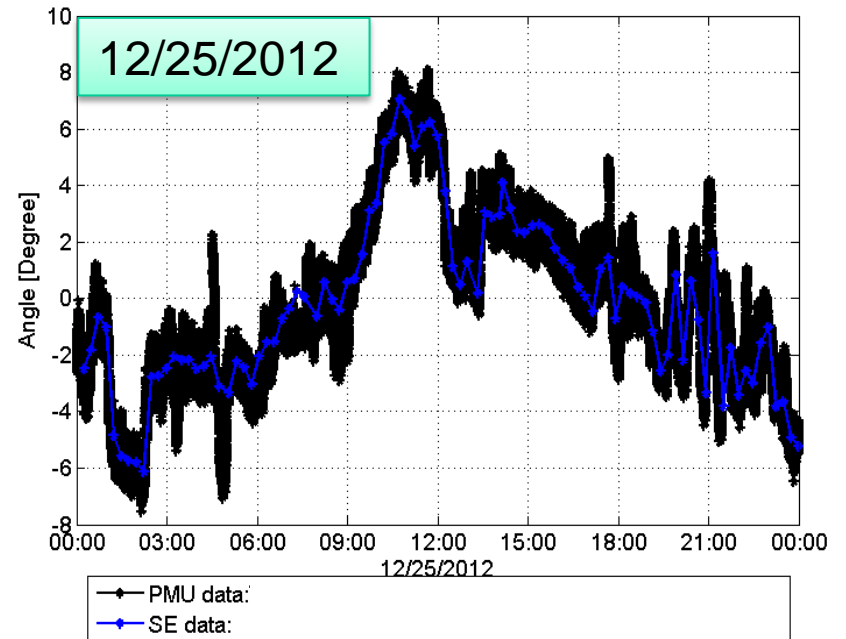
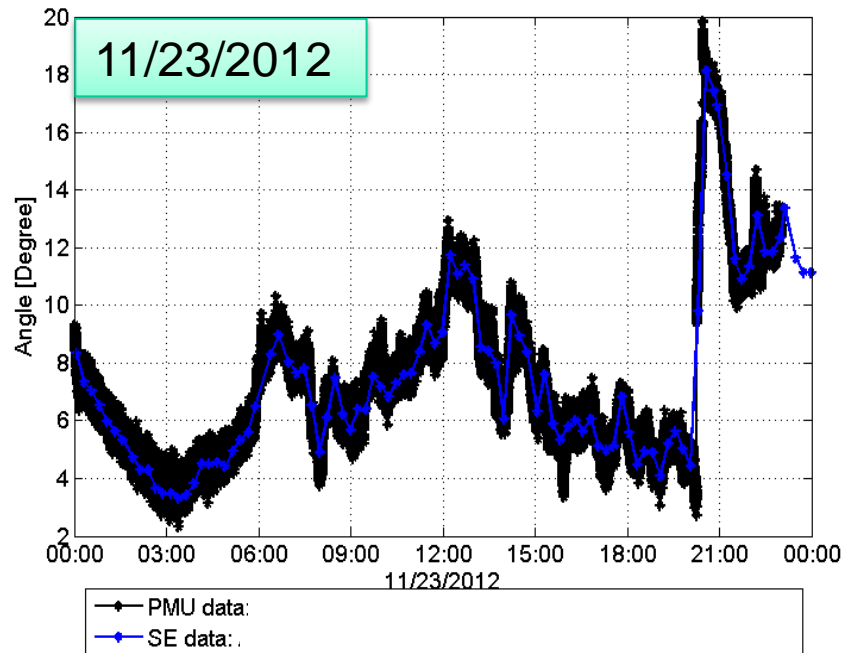
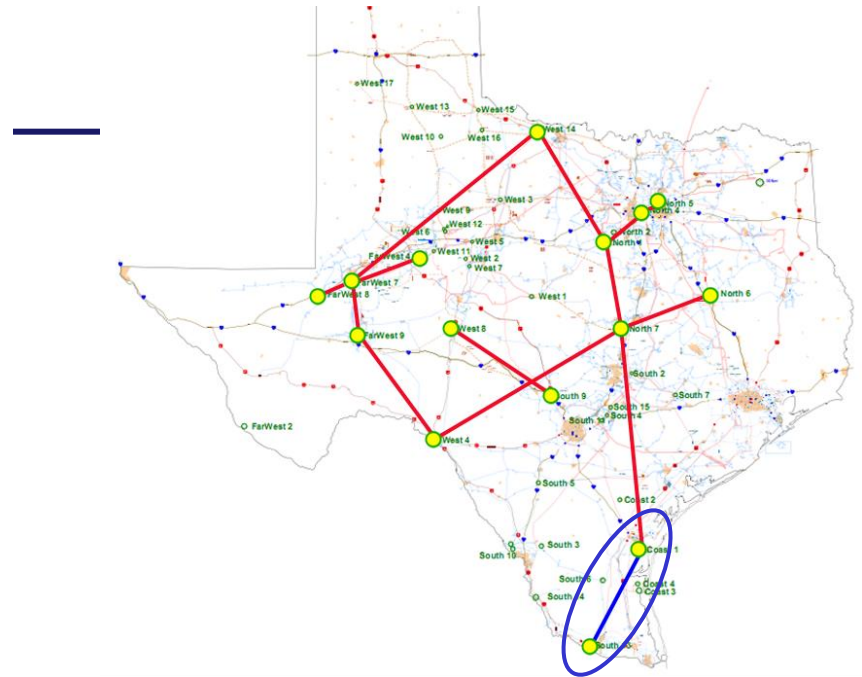
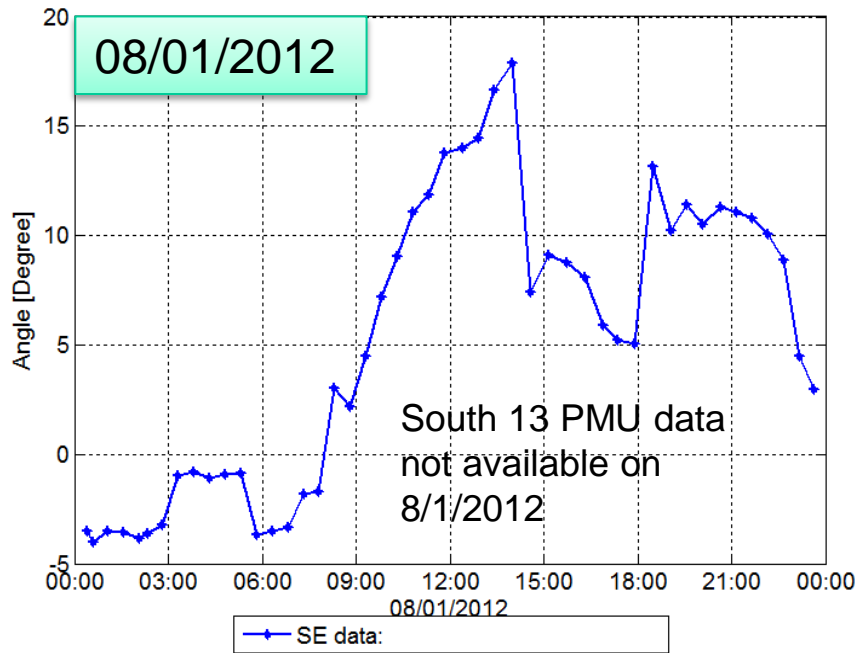
Location of Angle Pairs with PMUs in service



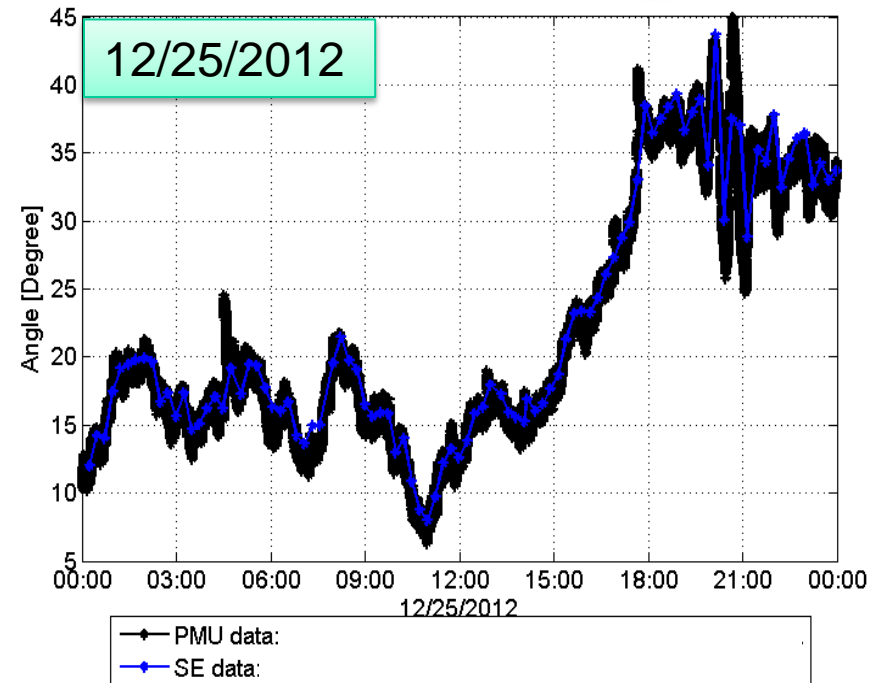
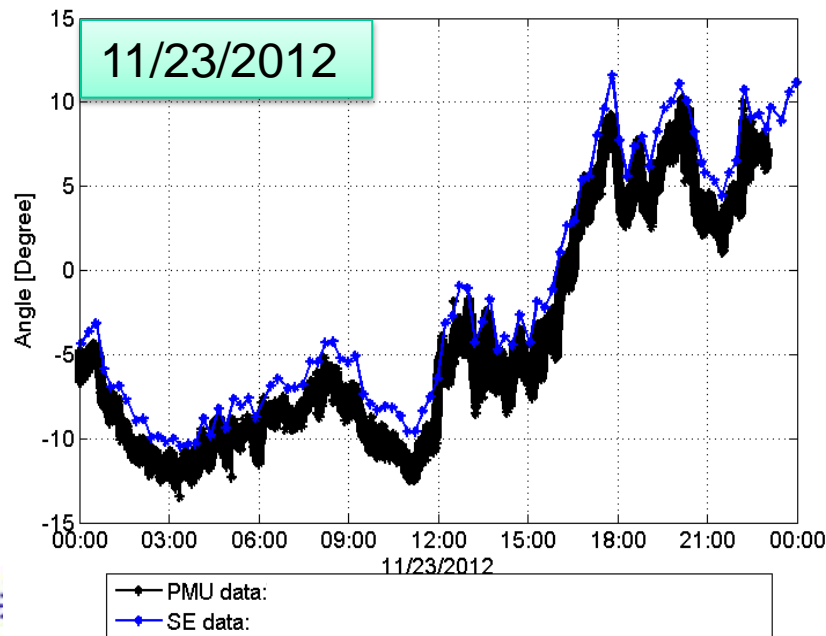
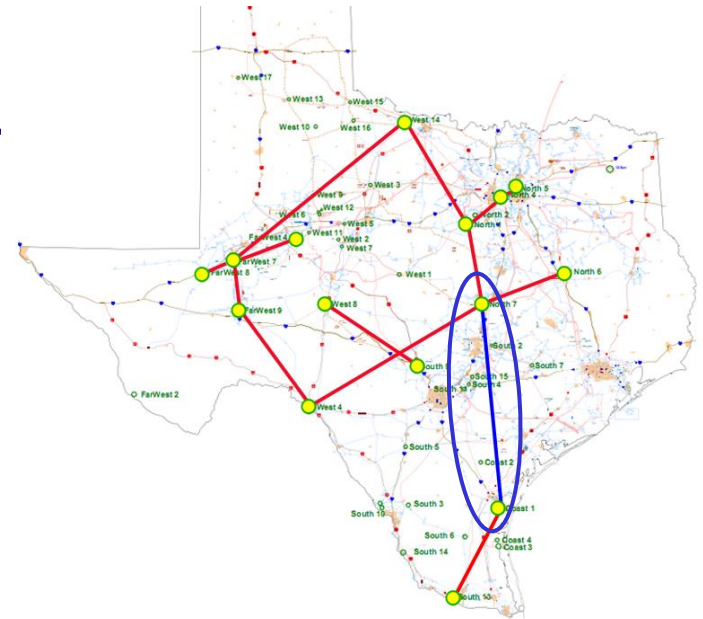
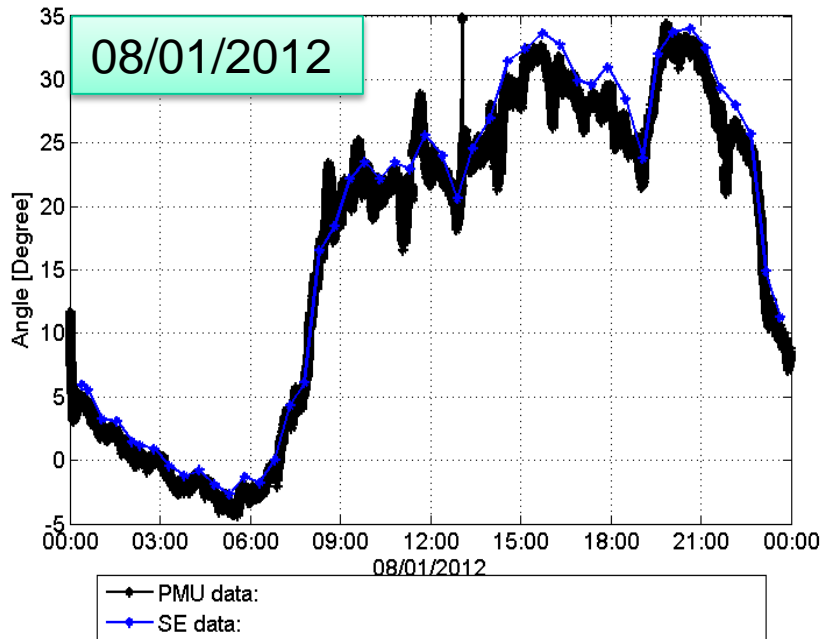
Days Analyzed:

1. August 1, 2012 (Peak load)
2. November 23, 2012 (low load)
3. December 25, 2012 (Maximum wind)

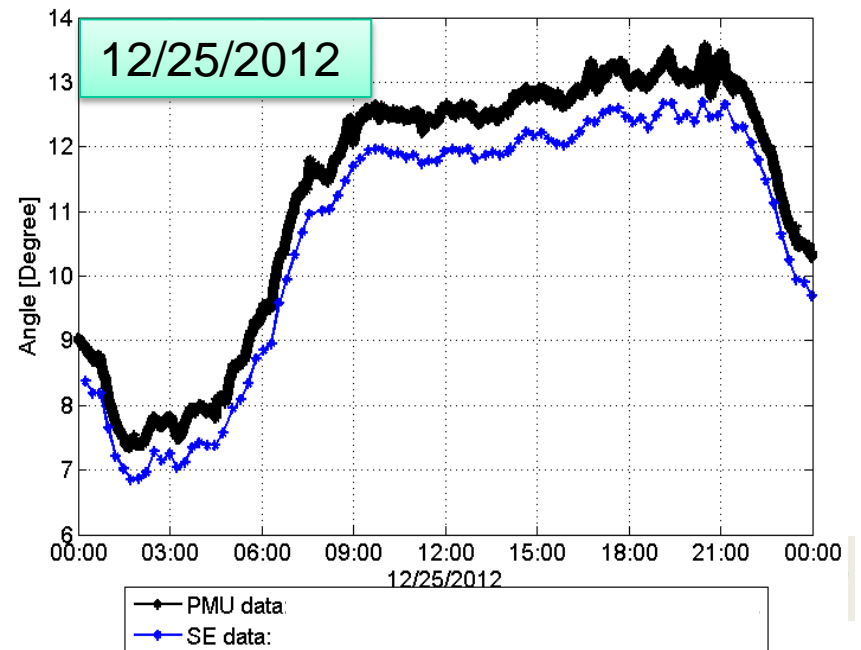
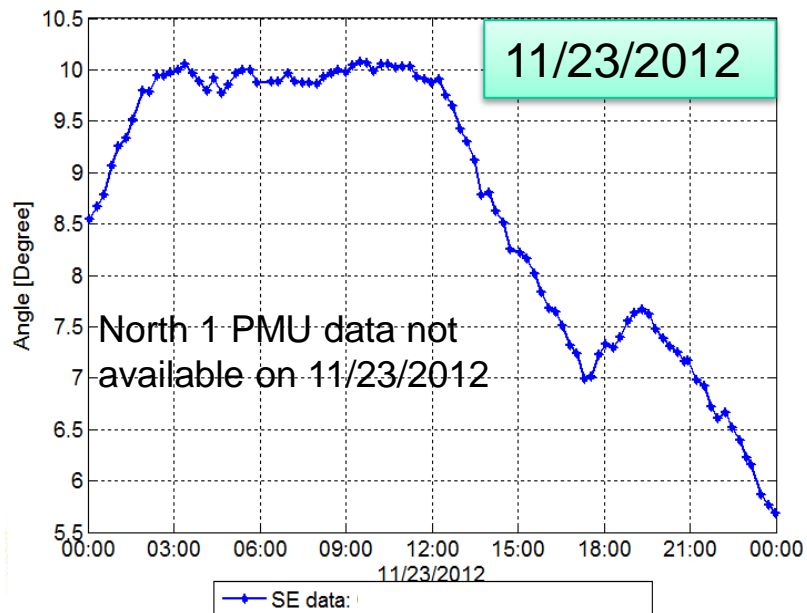
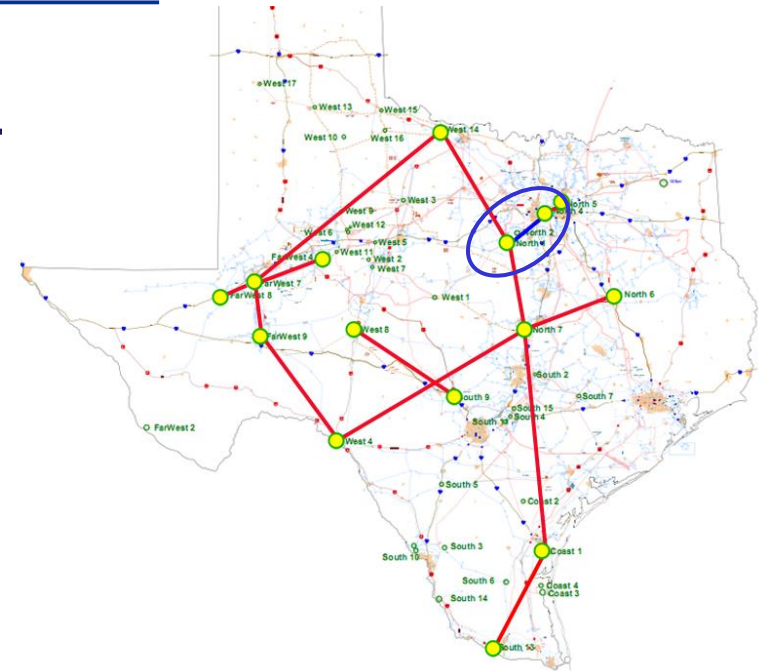
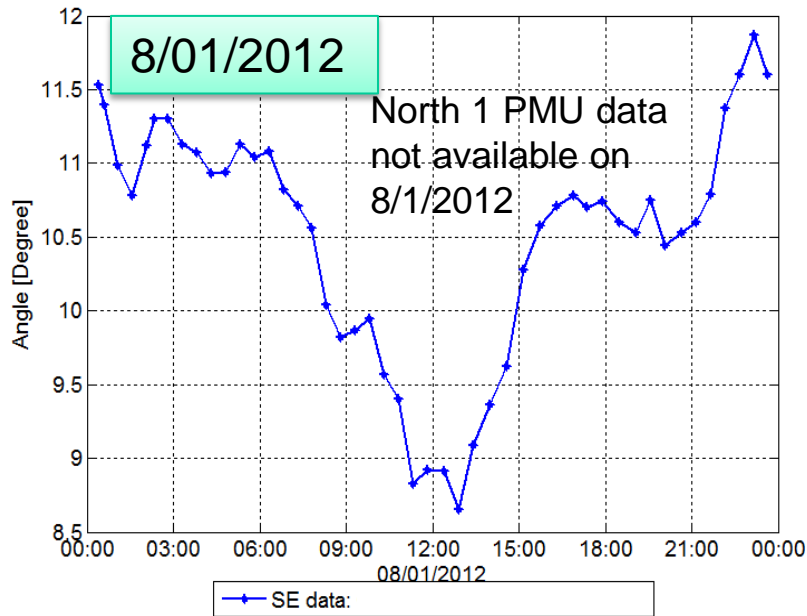
Coast 1-South 13



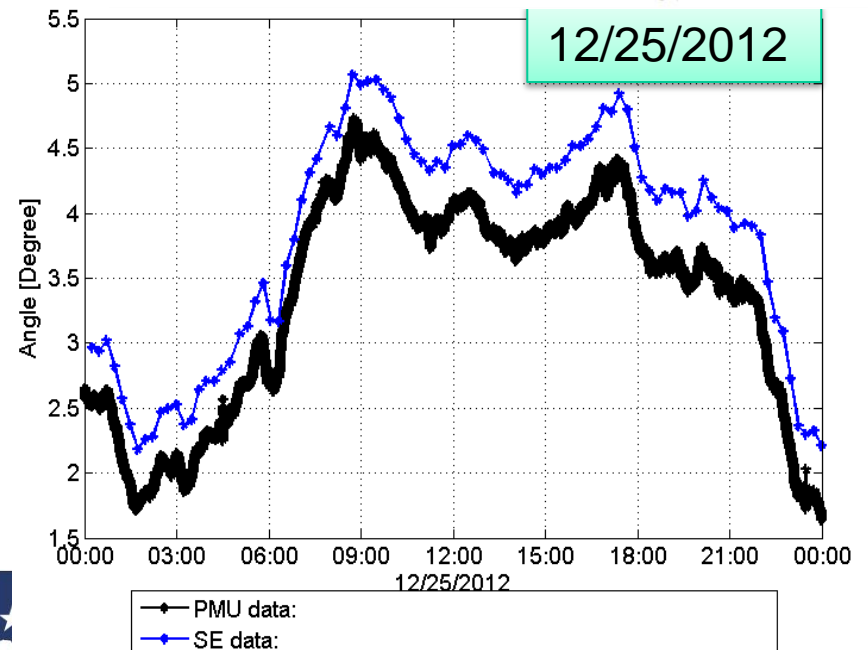
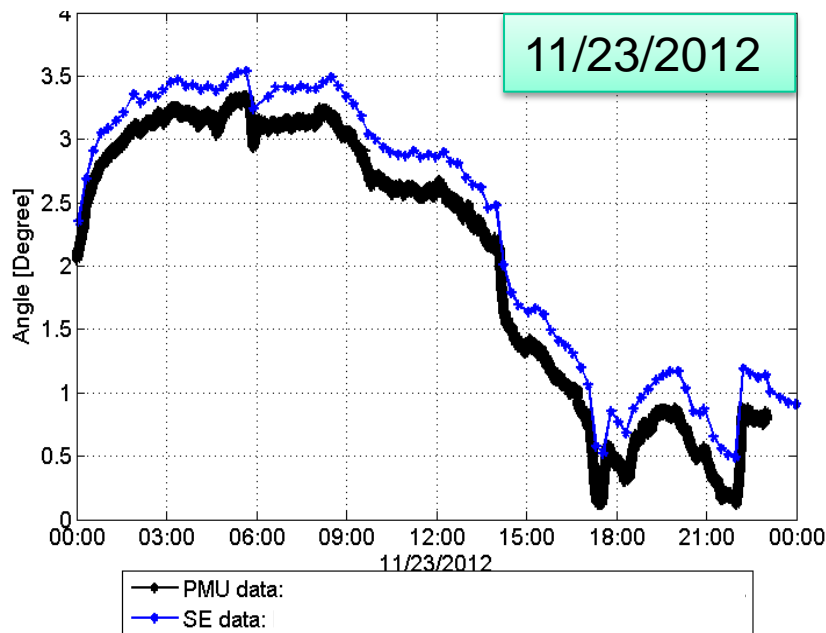
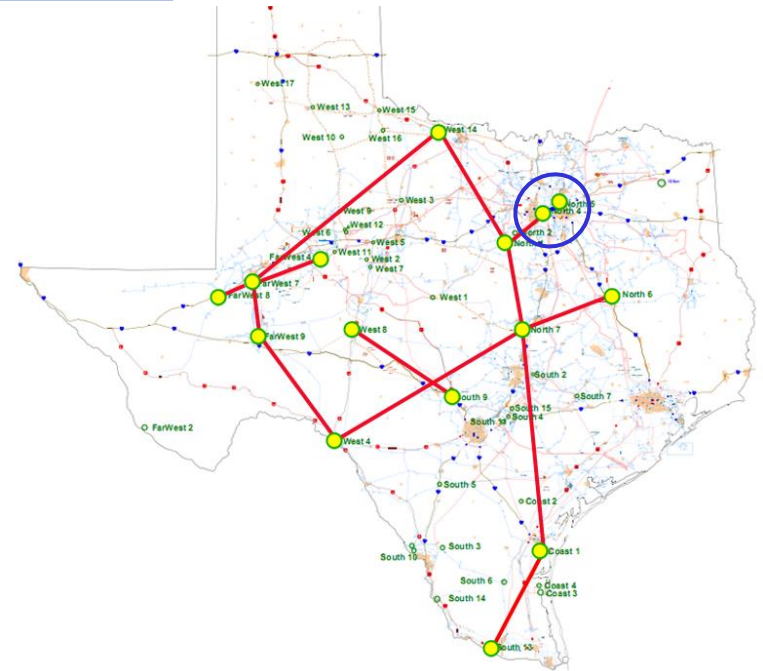
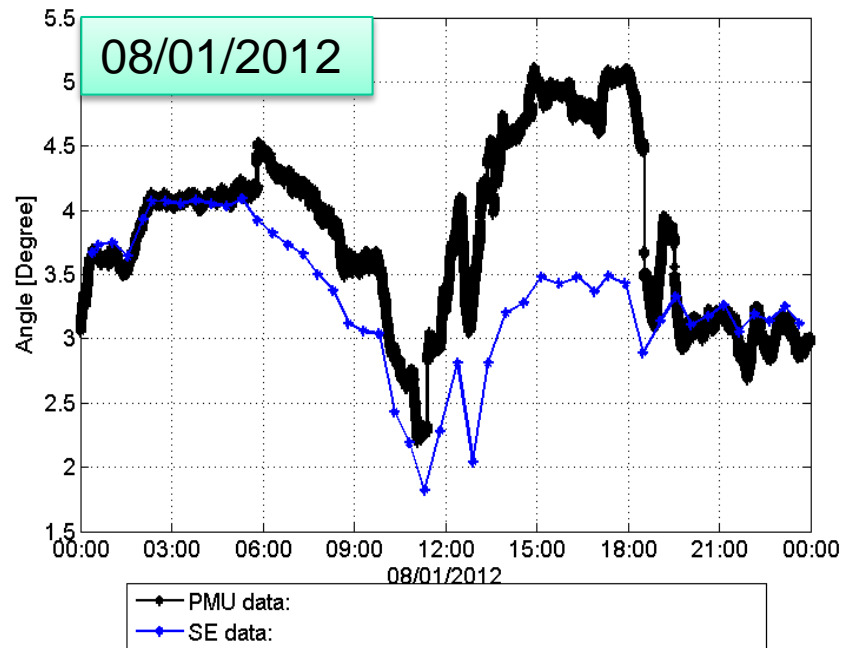
Coast 1-North 7



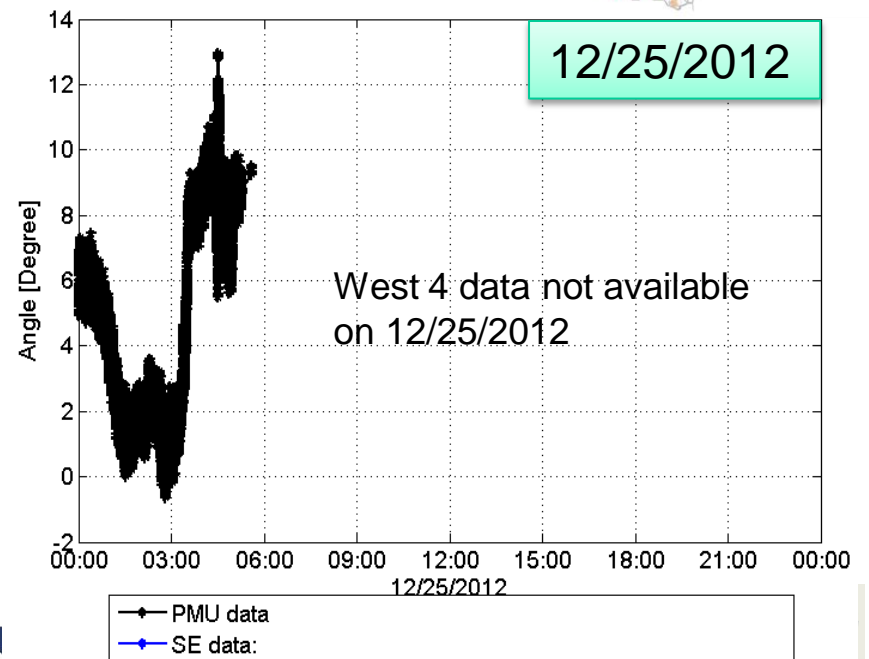
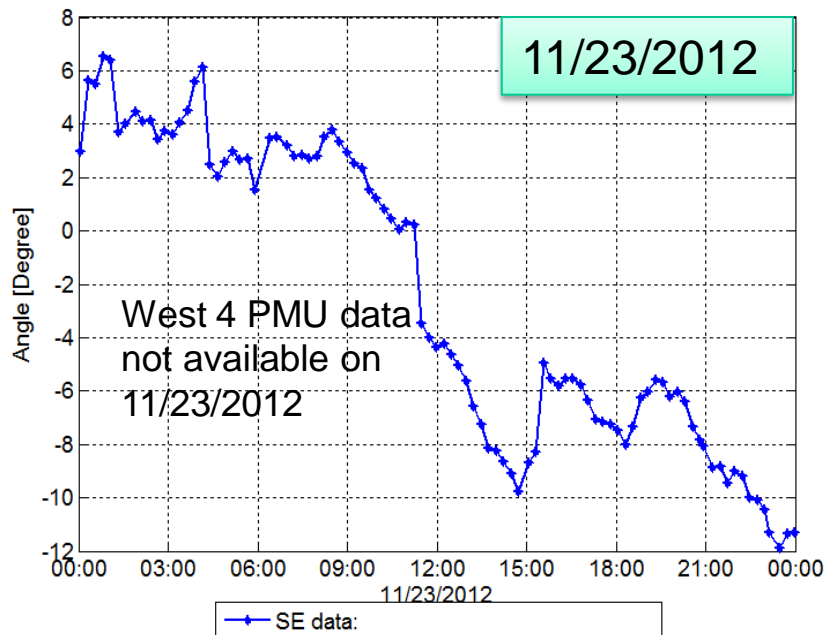
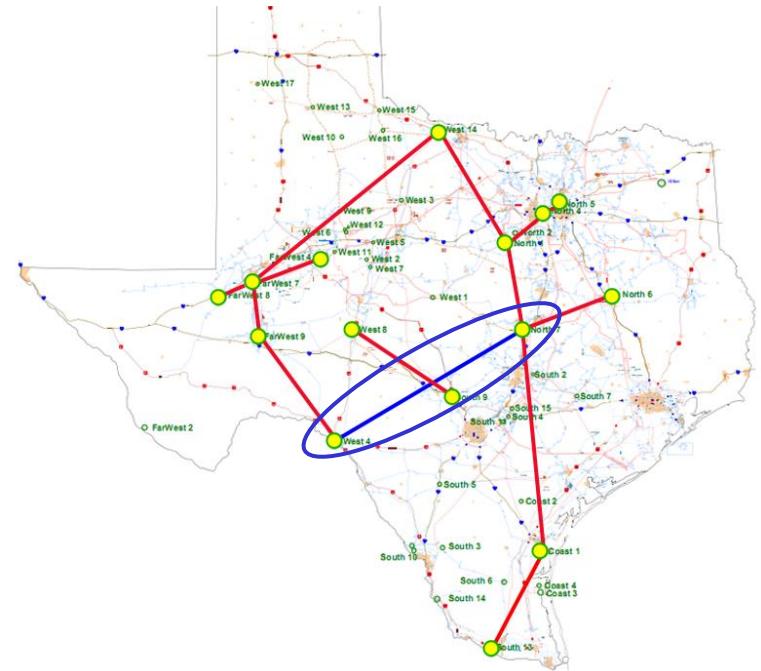
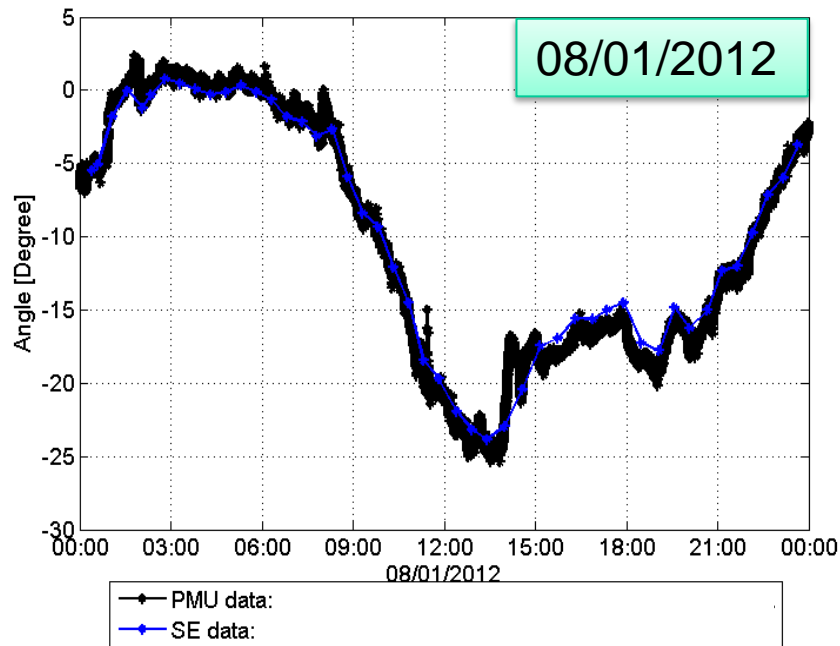
North 1-North 4



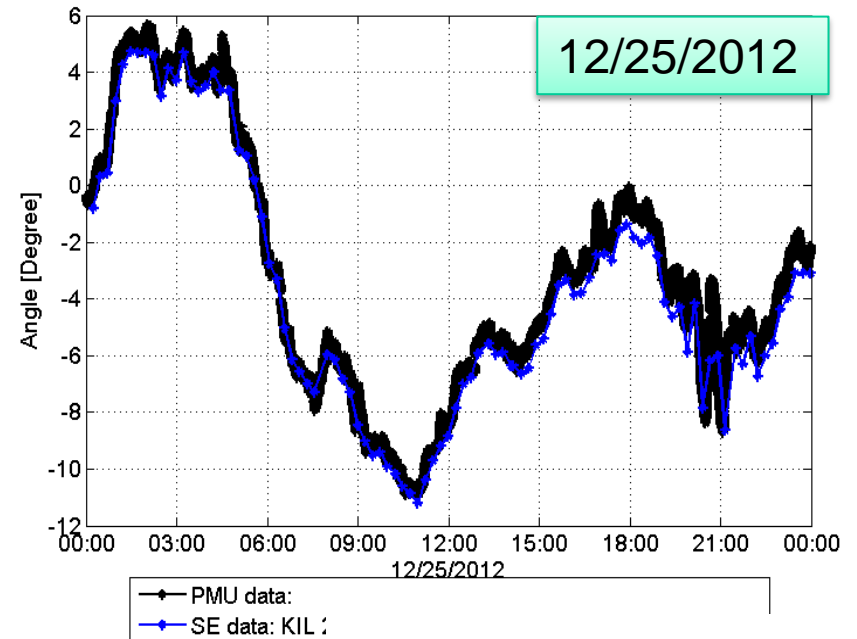
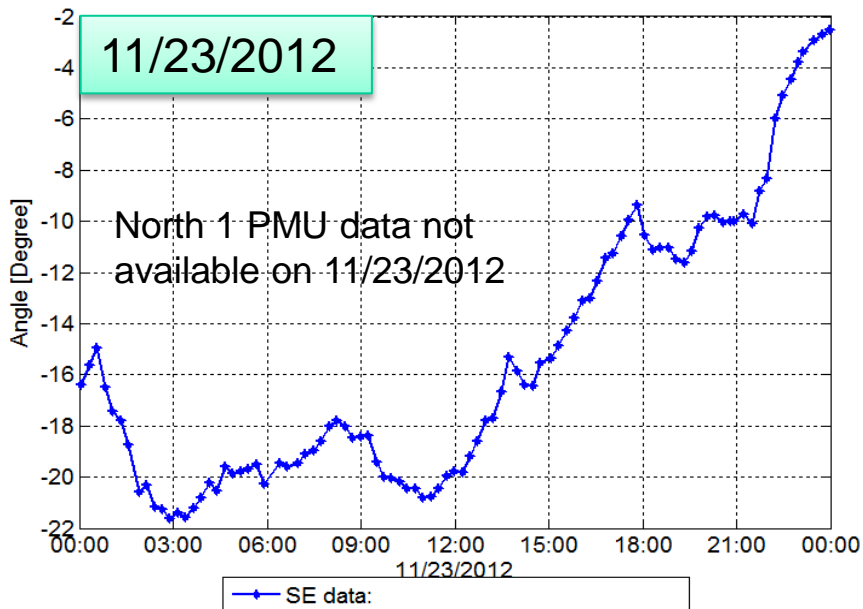
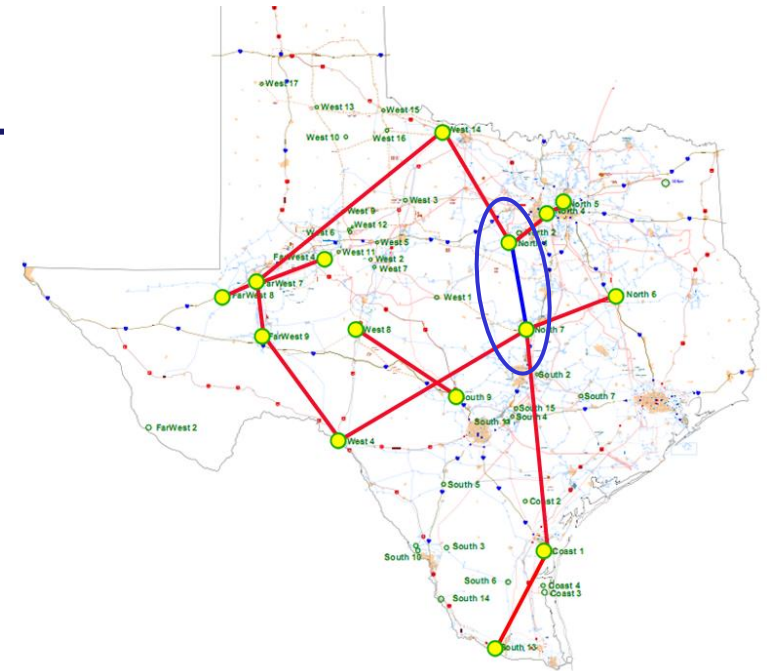
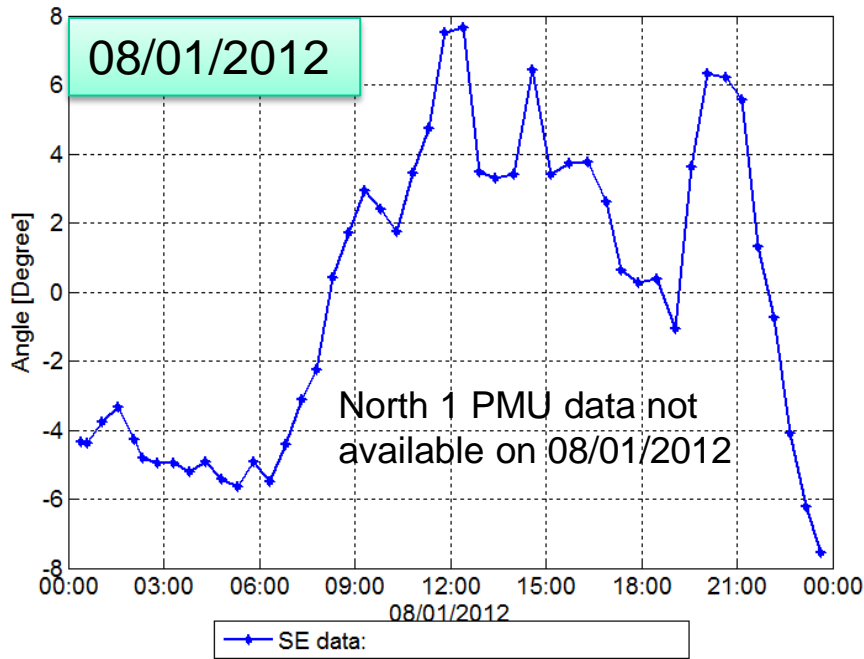
North 4-North 5



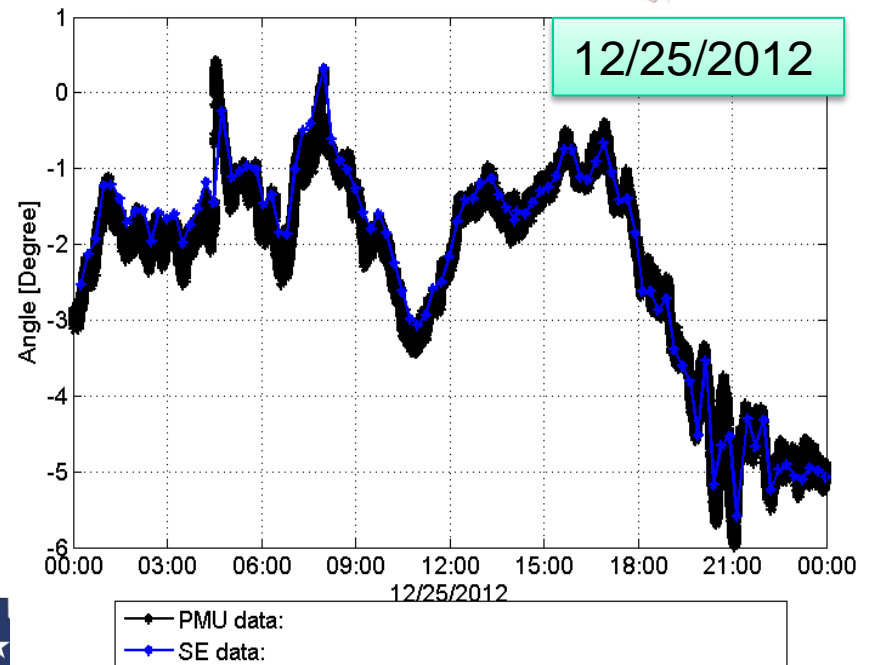
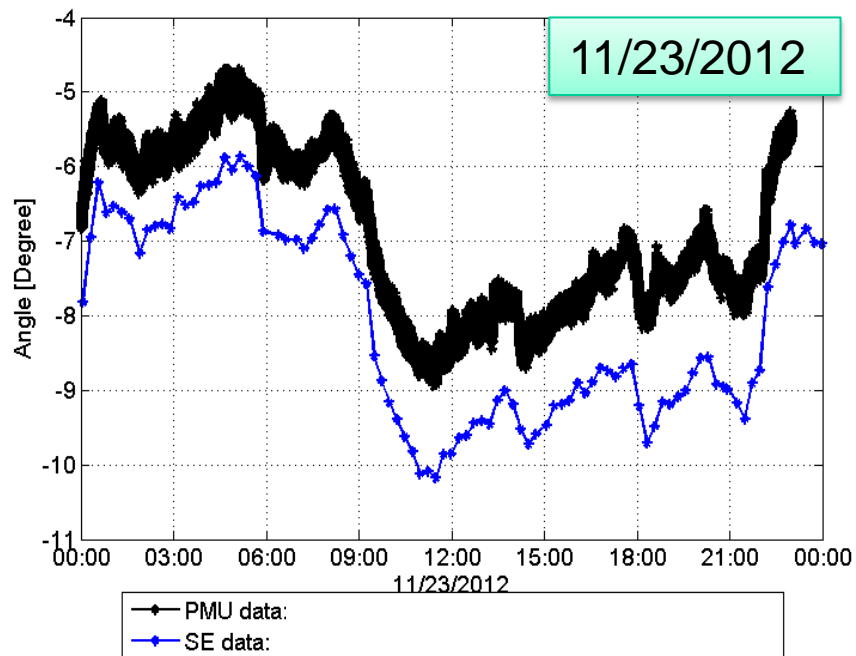
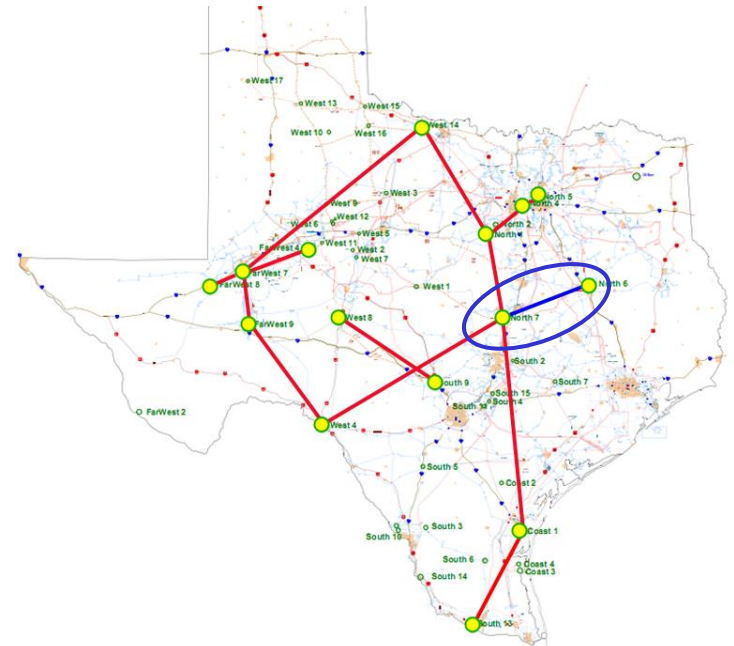
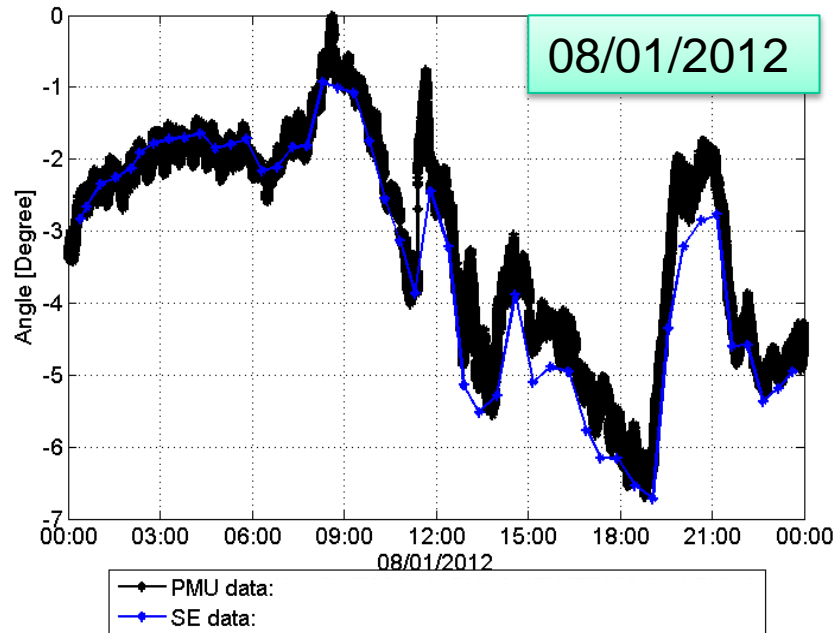
West 4-North 7



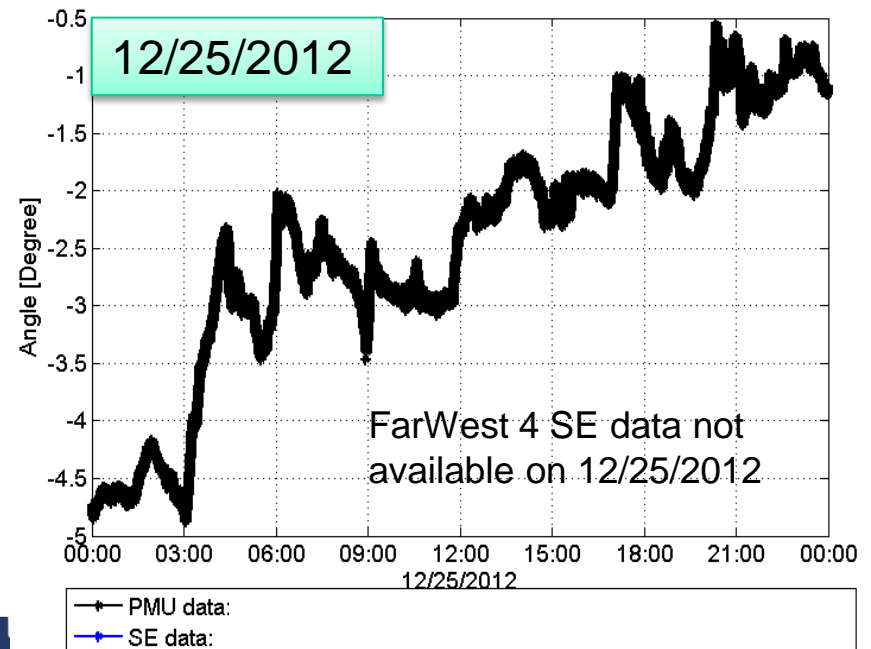
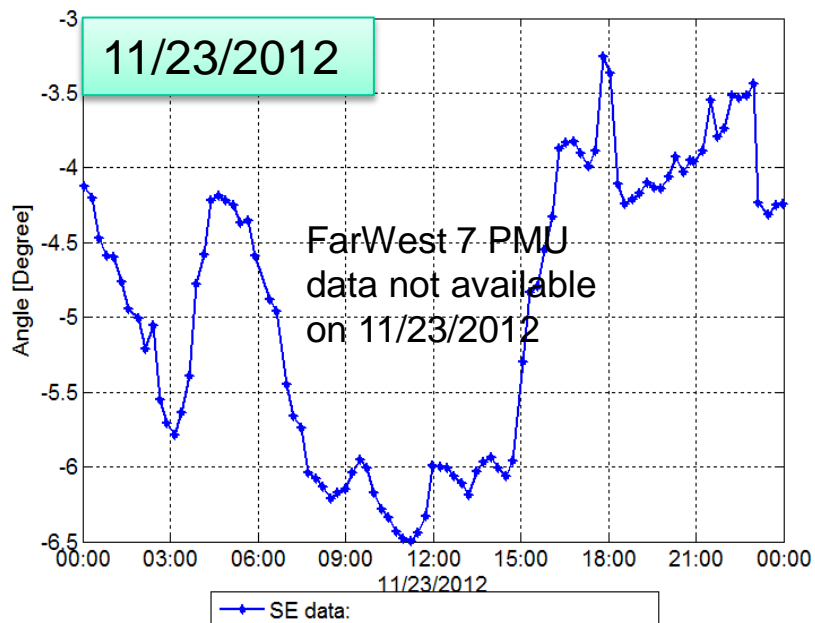
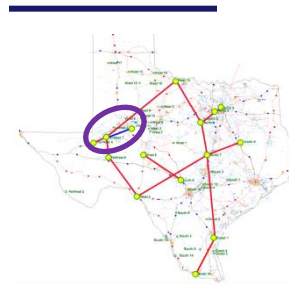
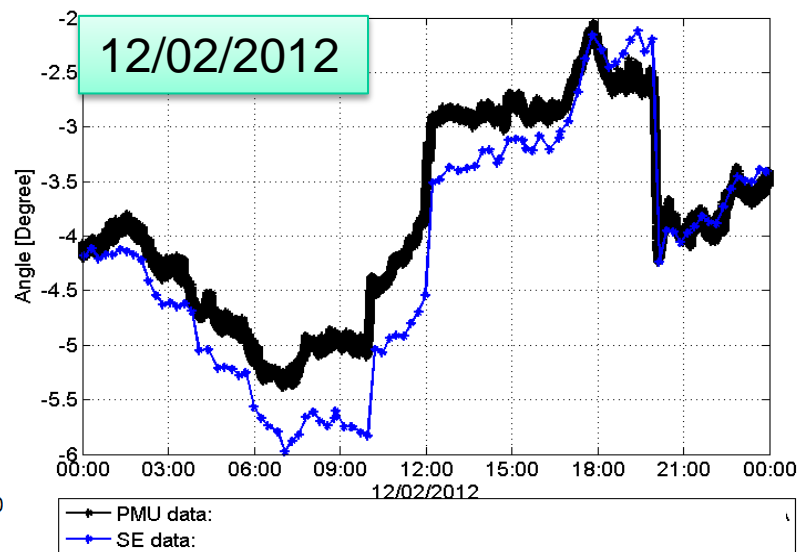
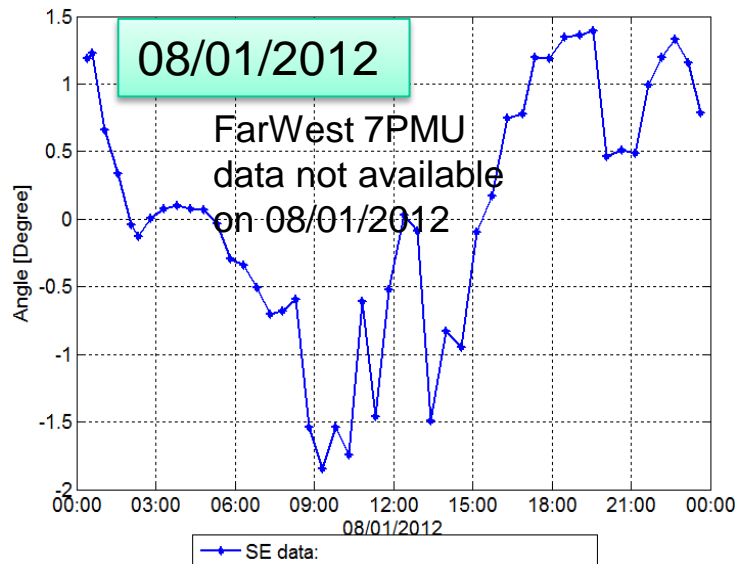
North 7-North 1



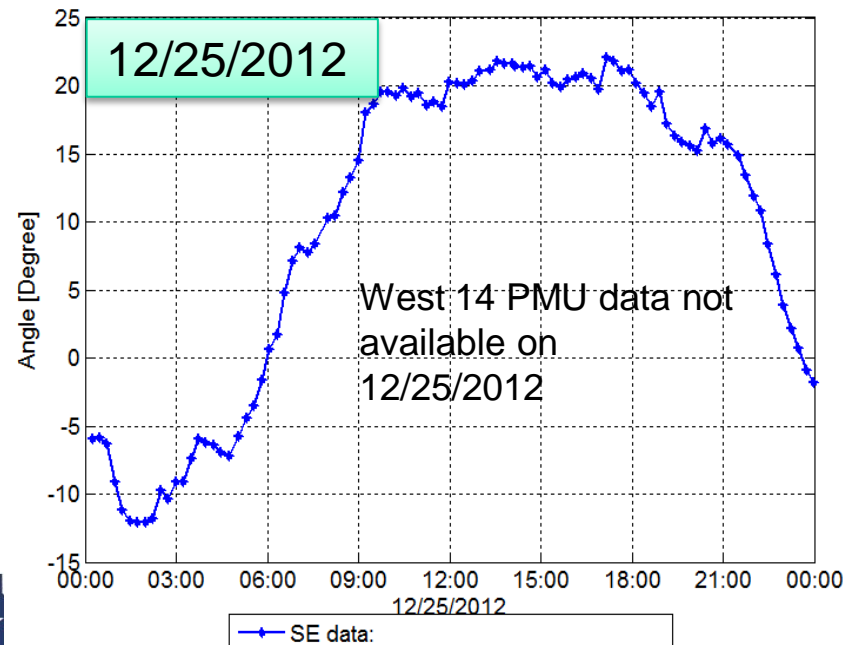
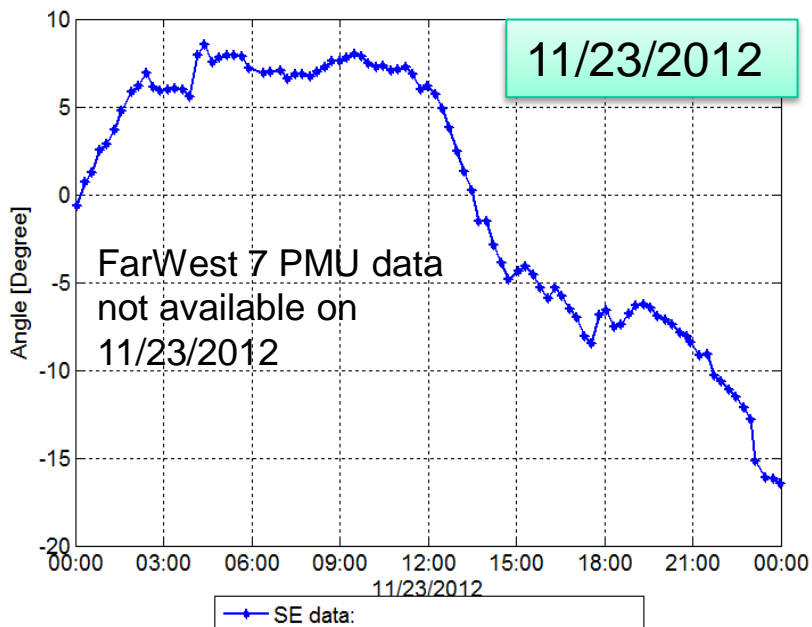
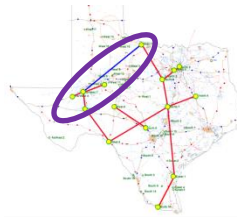
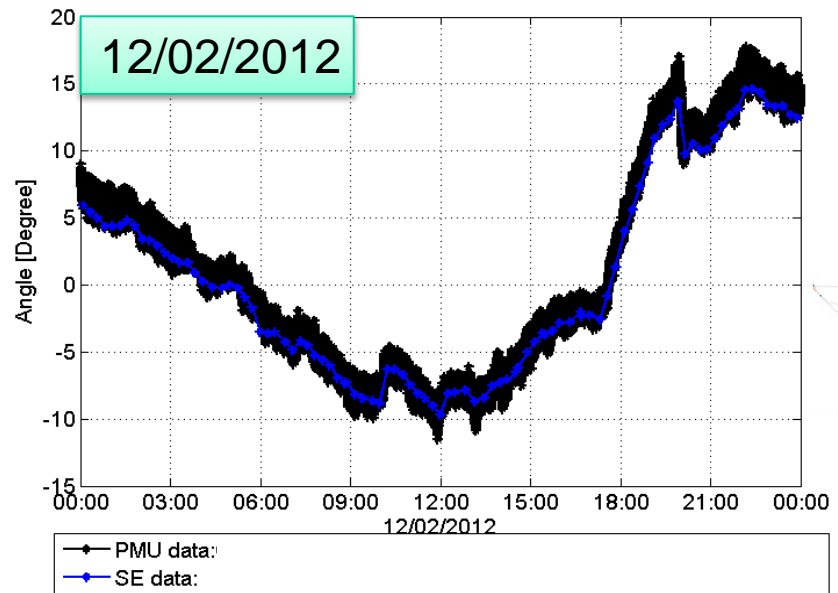
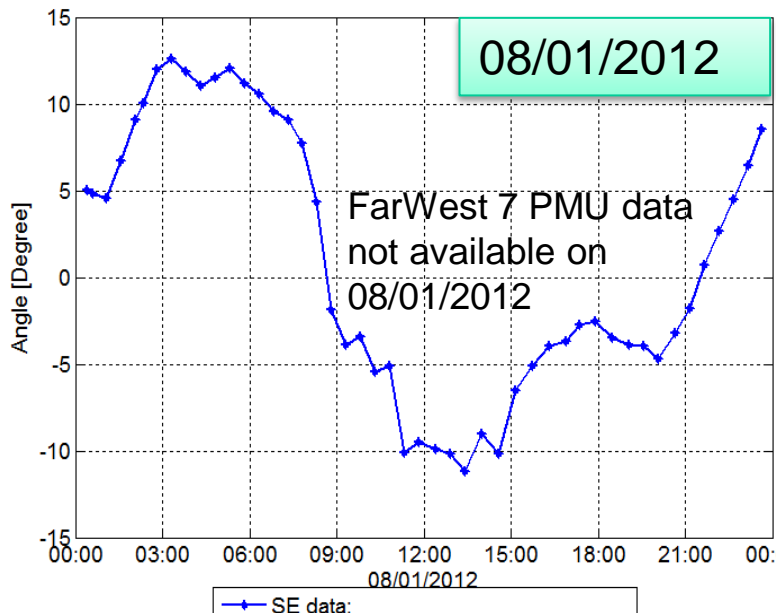
North 7-North 6



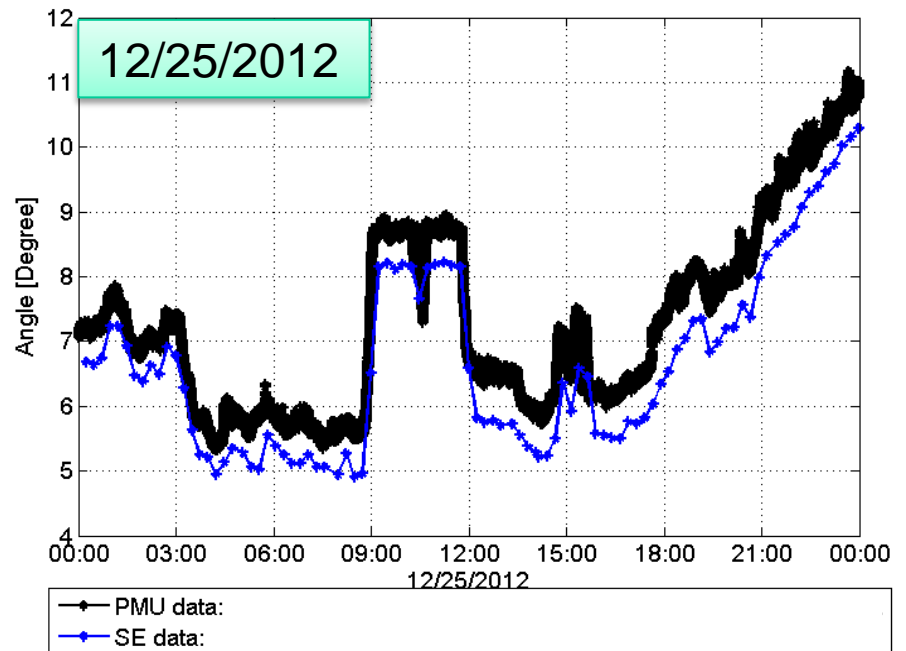
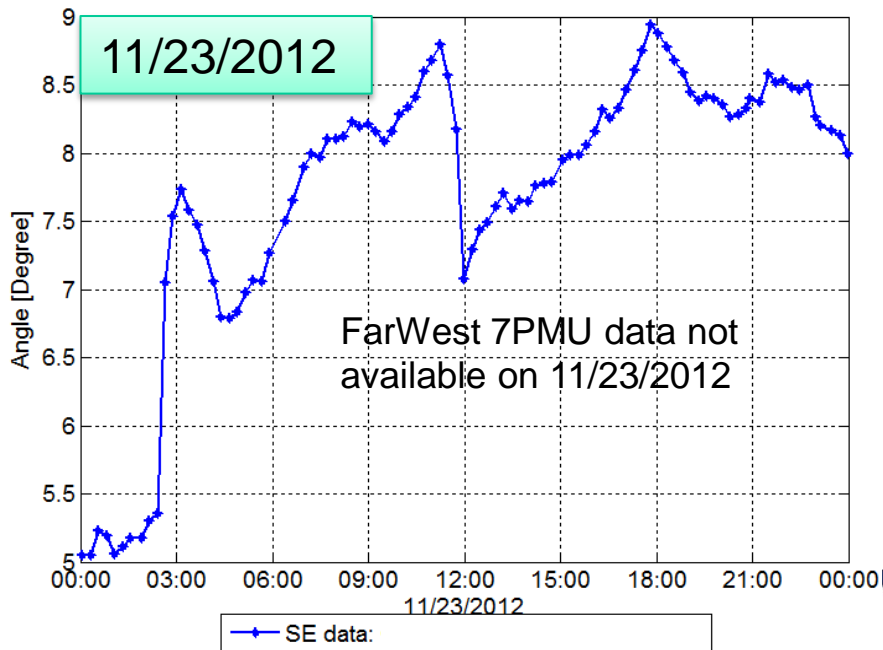
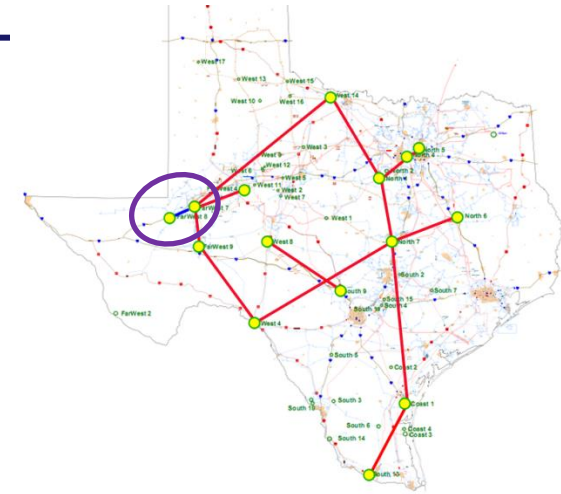
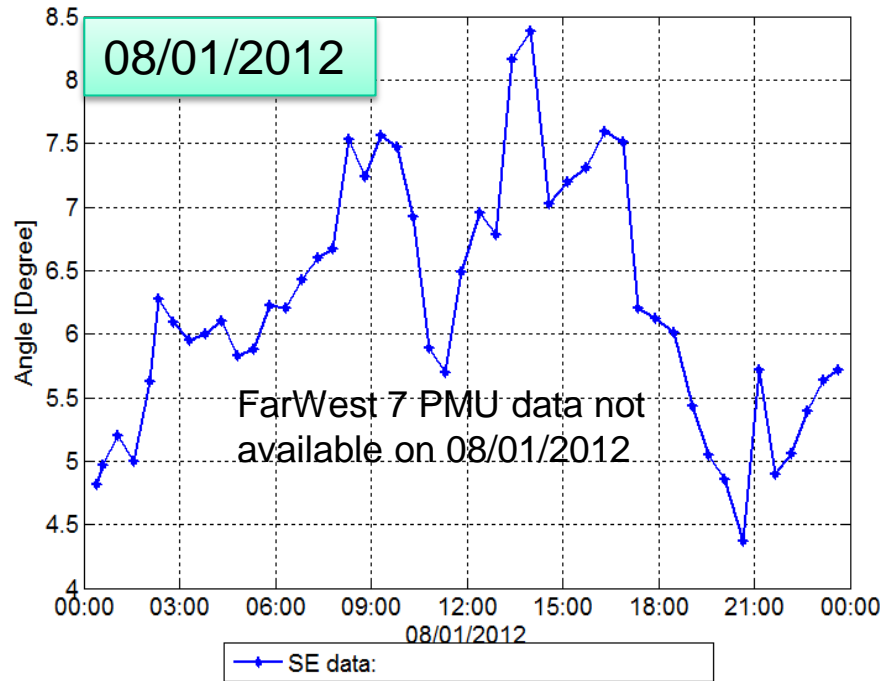
FarWest 7-FarWest 4



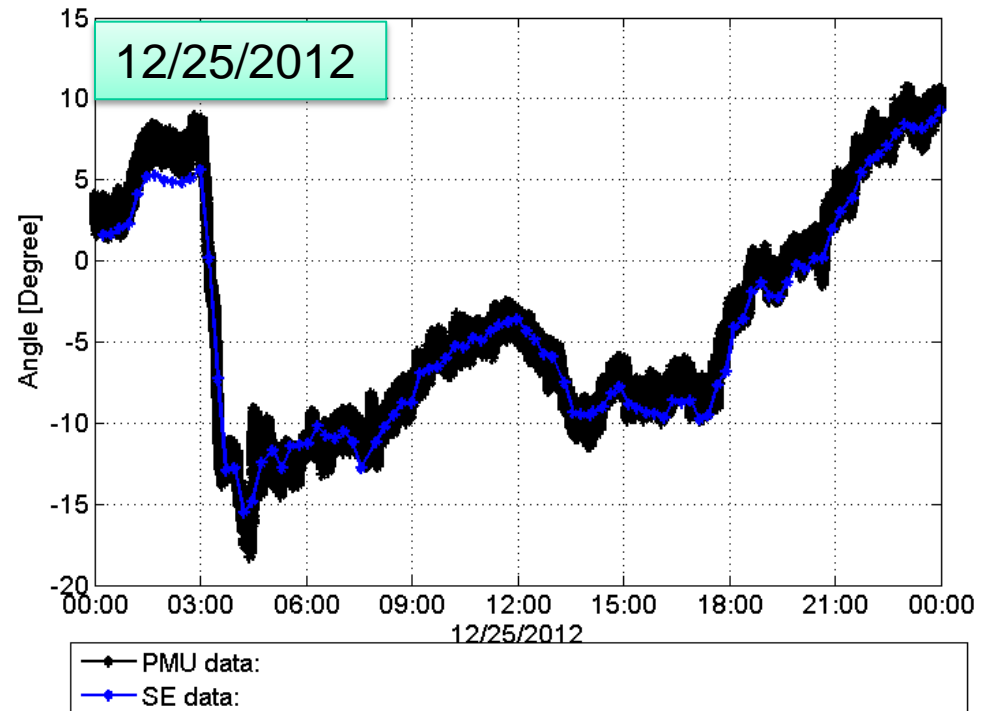
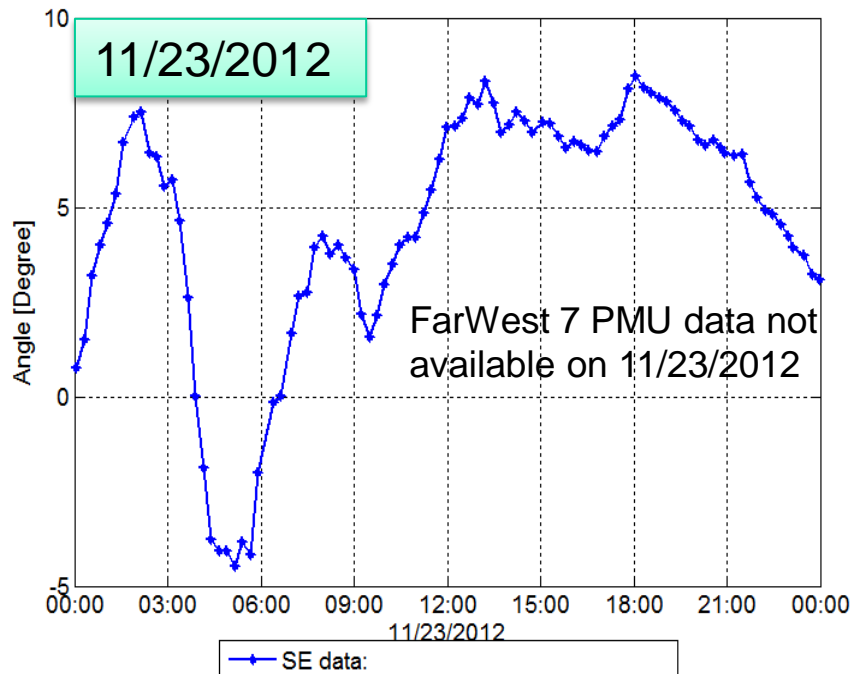
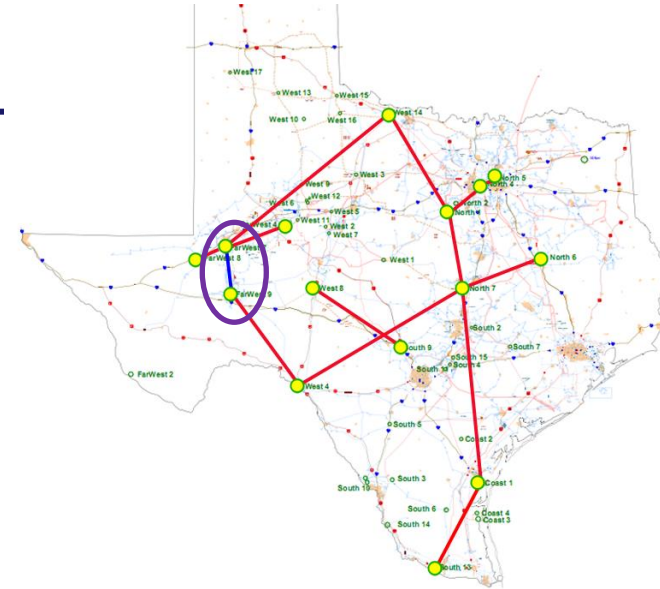
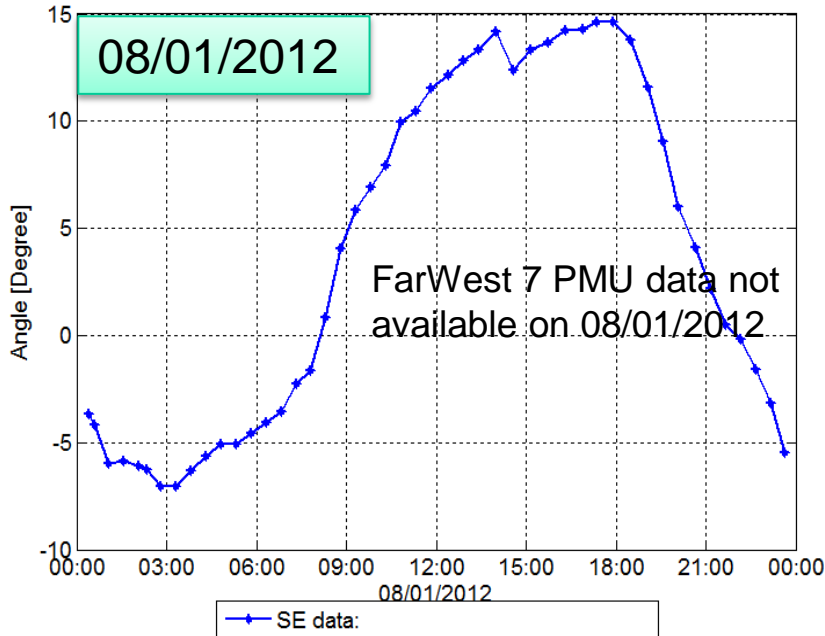
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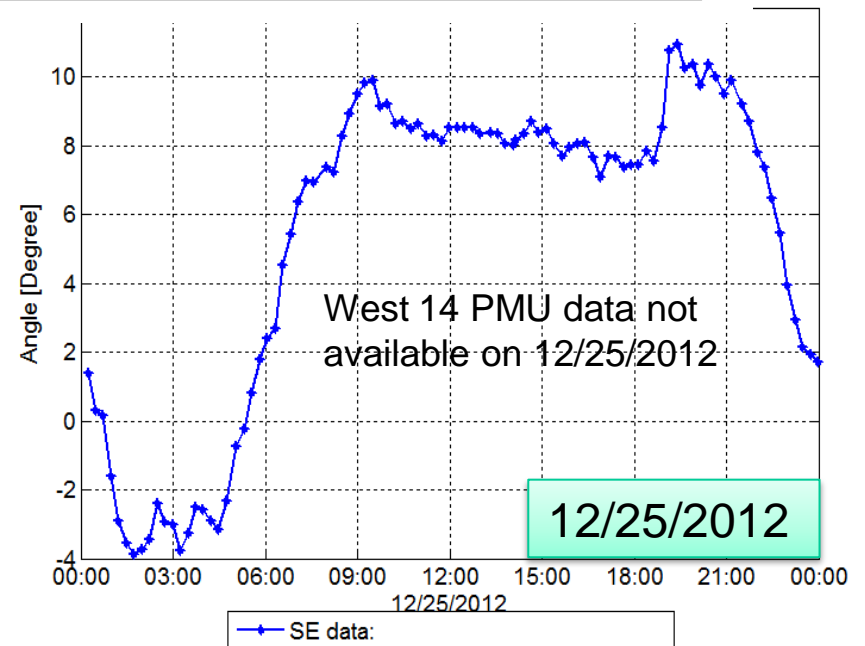
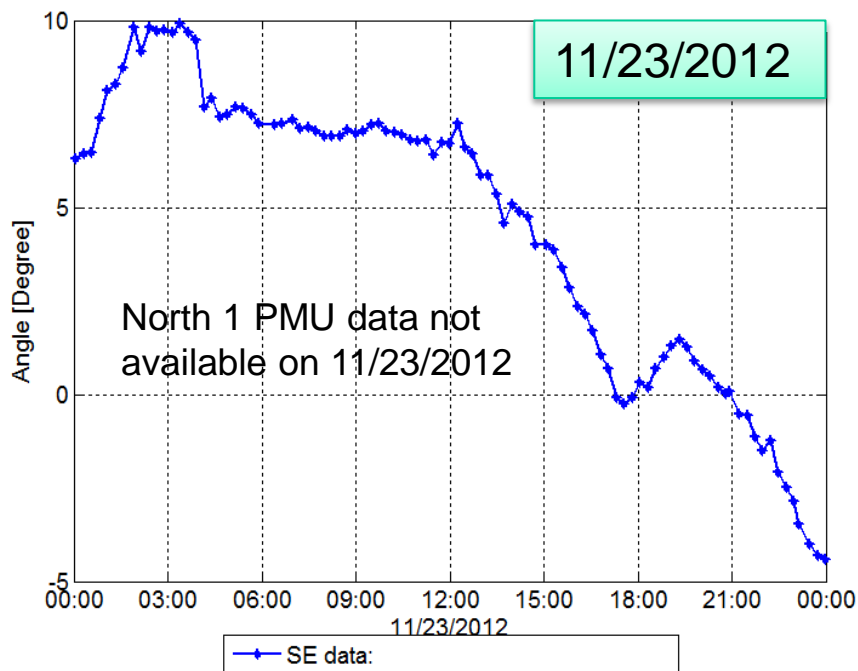
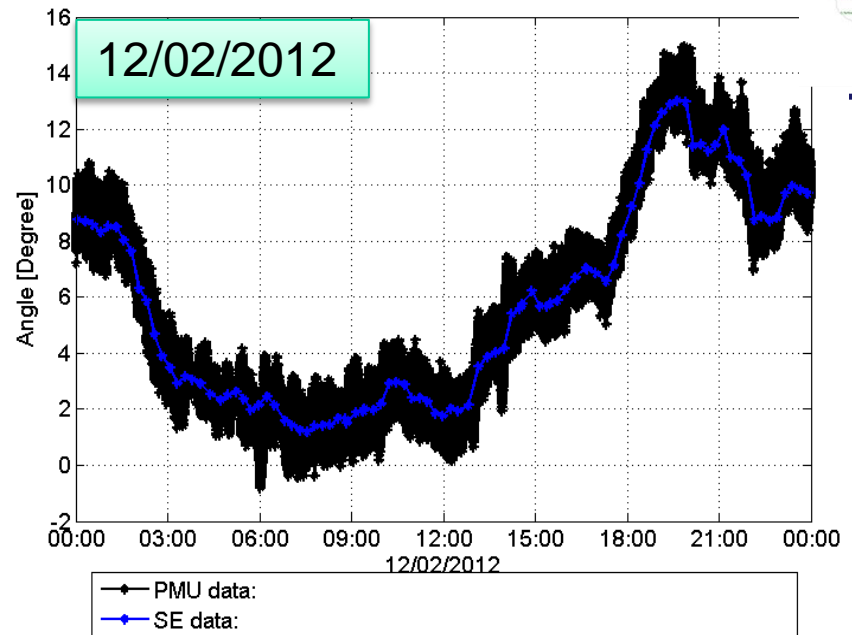
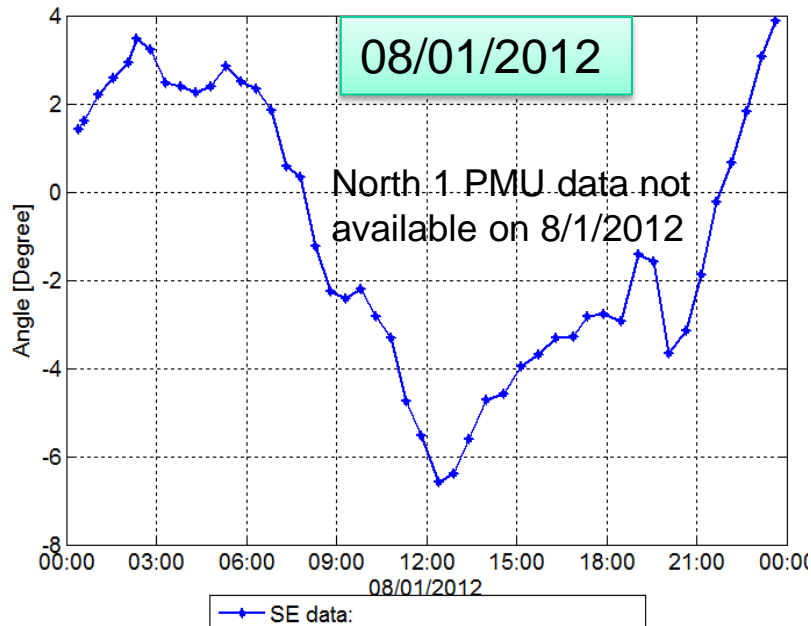
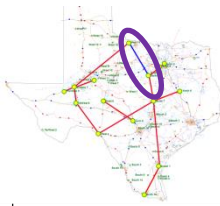
FarWest 7-FarWest 8



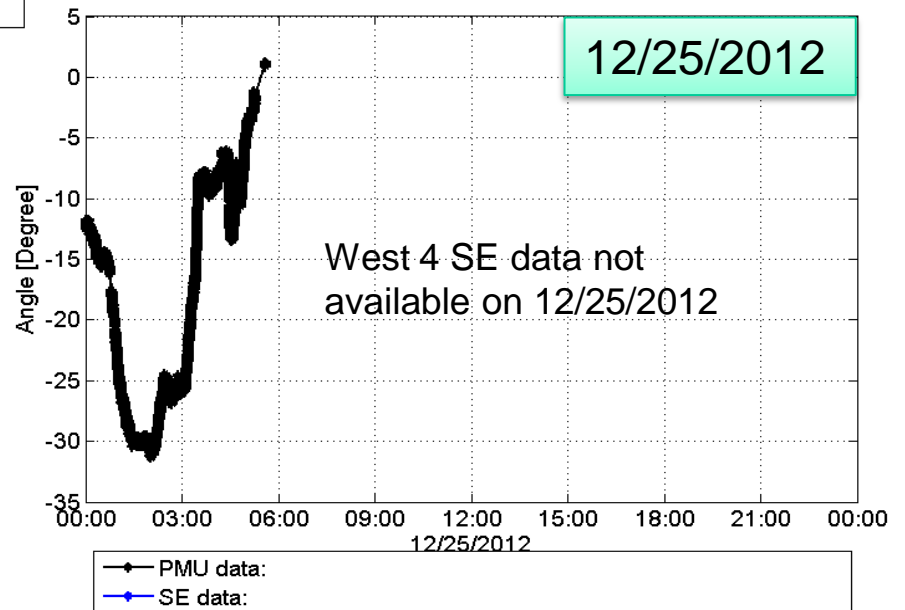
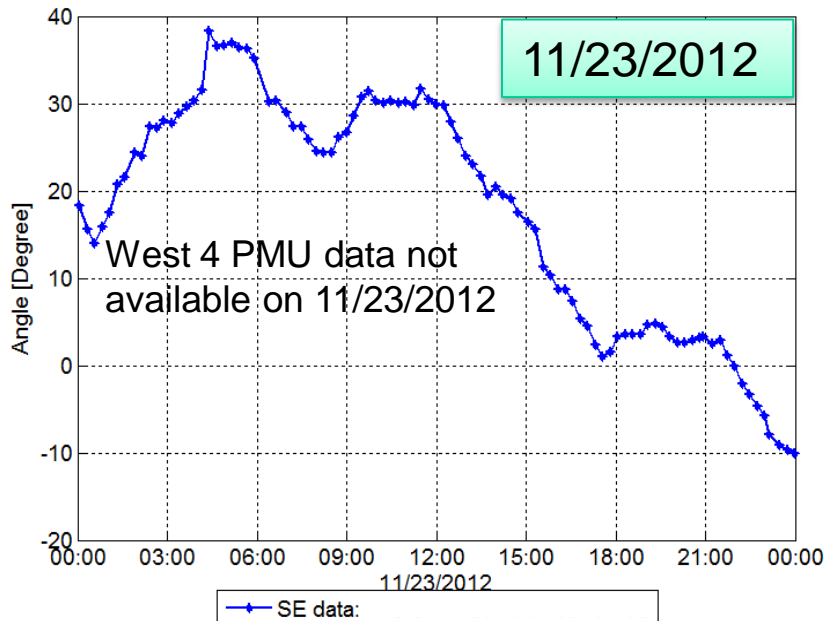
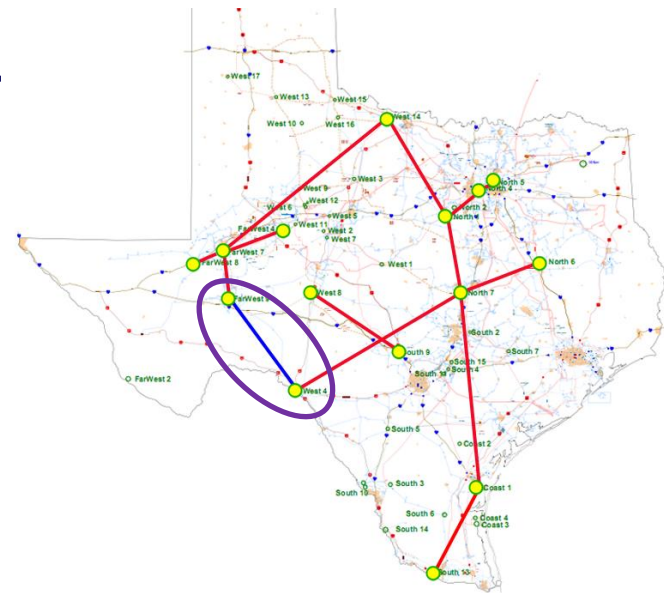
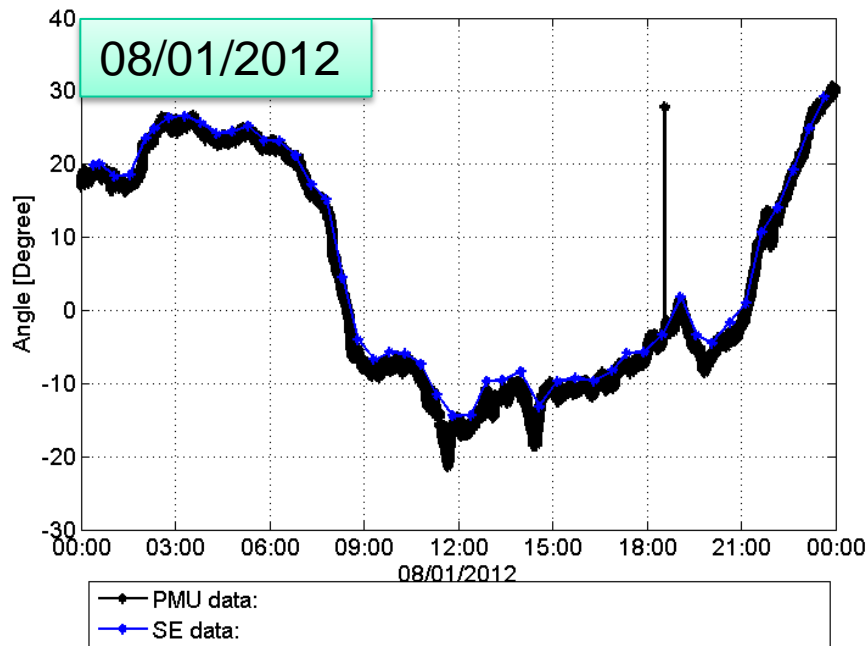
FarWest 7-FarWest 9



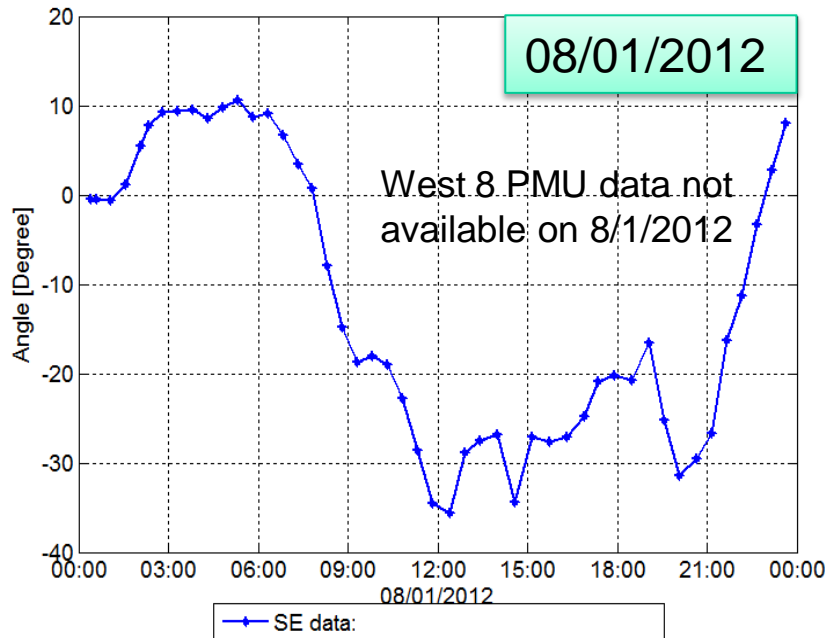
West 14-North 1



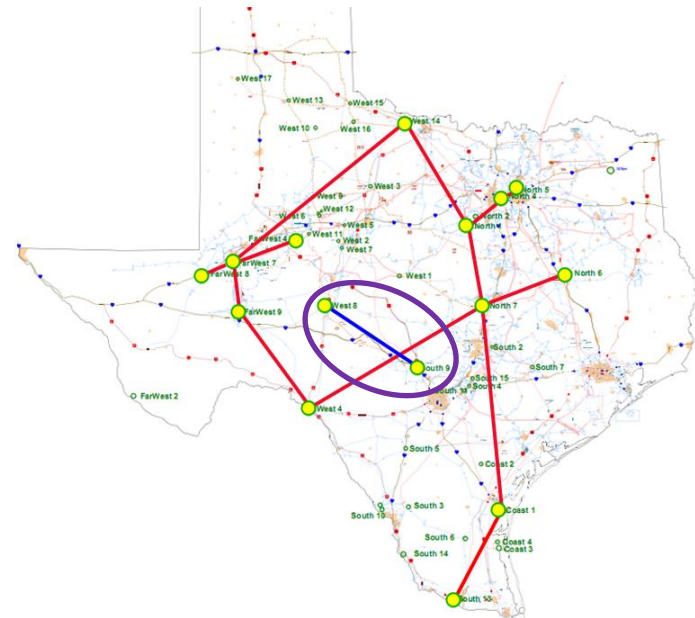
FarWest 9-West 4



West 8-South 9



West 8 PMU and SE data not available on 11/23/2012



West 8 PMU and SE data not available on 12/25/2012

Appendix C

Baseline Analysis - Voltage Magnitudes Box Whiskers and Time Duration Curves

For: CCET Discovery Across Texas Project

Available Upon Request

External Version



Electric Power Group



Appendix D

Baseline Analysis - Voltage Angles (Reference: North 7)

Box Whiskers and Time Duration Curves

Phasor Data

Available Upon Request

External Version

Appendix E

Baseline Analysis – Angle Differences Box Whiskers and Time Duration Curves

For: CCET Discovery Across Texas Project

Available Upon Request

External Version



**Attachment 2. Updated Cluster Analysis
for First Half of 2013**

**Center for Commercialization of Electric Technologies --
Discovery Across Texas**

**Cluster Analysis Update
Period of January - June, 2013**

Submitted By:



Romulo Barreno
Ajay Das
Song Xue

August 20, 2013

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APPENDICES (attached as separate documents)

A, Angle Differences by Clusters

B, Voltage Magnitude by Clusters

1. INTRODUCTION

Electric Power Group, LLC (EPG) was awarded a portion of contract DE-FOA-0000036 by the Center for the Commercialization of Electric Technologies (CCET) Discovery Across Texas project to provide professional services to, among other things, perform cluster analysis, comparison of phasor data versus state estimator data, and voltage and angle difference baselining. In June 2013, EPG completed a Baselining Study using 2012 data that included the following: (1) grouped substations having Phasor Measurement Units (PMUs) which are geographically close to each other and performed a voltage and angle difference analysis for each group (cluster analysis); (2) performed a comparison of voltage and angle differences obtained using phasor measurements versus similar results using state estimator data (phasor vs. state estimator comparison); and, (3) performed a baseline analysis for voltages and angle differences for selected pairs of substations (cluster analysis). When all the 2013 data is analyzed, alarm limits will be established and documented based on the baseline analysis.

This report summarizes the cluster analysis results obtained using the January to June 2013 data. This study update was prepared with the addition of new available PMUs (substation) to the groups to cover a wider geographical area.

2. PROJECT SCOPE

The baselining study using 2012 data showed that phase angle differences for lines in Group 1 and some in Group 5 (South 2, South 4, South 11 and South 15), followed each other closely. This update will perform analysis of the six groups to confirm if the results from the 2012 analysis are also true with 2013 data. Activities to be performed as part of this item:

1. Obtain 2013 state estimator data from ERCOT, solve cases received and extract data for analysis.
2. Group geographically close substations equipped or to be equipped with PMUs; add or subtract substations as necessary.
3. Using state estimator data analyze voltage angle differences for these groups and document results for two selected days of 2013.
4. Prepare voltage angle difference graphs for the selected substations and pairs.
5. Summarize results.

3. DATA SOURCES

State estimator data was utilized to perform the study update of the cluster analysis of angle differences in the ERCOT network. A description of this data is provided below.

A. State Estimator (SE) Data

ERCOT provided EPG with SE data for the first six months of 2013. EPG used the Power World simulator provided by ERCOT via Power World, to extract approximately 15,330 SE cases. There were eight days for which SE data was not available as shown below:

Dates for which SE data was not available (First six months of 2013)

03/23 to 03/26/2013
03/28 to 03/31/2013

4 Days
4 Days
Total 8 days

B. Data Availability

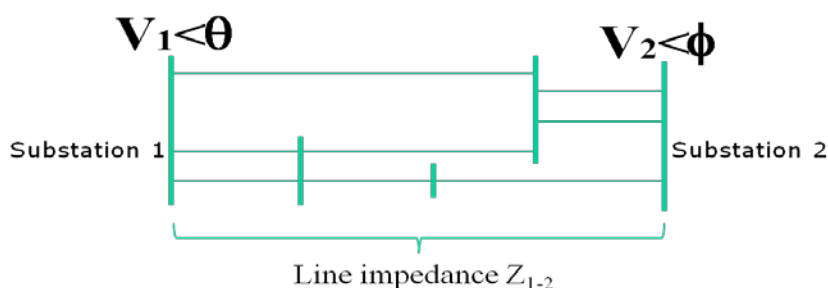
ERCOT produces state estimator cases every 5-minutes for a total of 105,120 possible cases per year. For six months the total number of possible cases is 52,560; EPG received approximately 15,330 cases, which means the availability of SE data for the first six months of 2013 was approximately 29.2 % of the maximum data availability. SE data availability for these six months improved to approximately double that of the 2012 SE data.

The estimated SE data availabilities for the two days of study were:

| | |
|---------------|-------|
| May 2, 2013 | 29.5% |
| June 27, 2013 | 27.8% |

4. CLUSTER ANALYSIS – PHASE ANGLE DIFFERENCES

Voltage phase angles differences are indicators of power flow and direction. Power flows from the higher voltage phase angle to the lower phase angle. Power flow follows voltage angle difference as per the following diagram and equation:



$$\text{Power flow: } P = V_1 V_2 \sin(\theta - \phi) / Z$$

Any change in power flow or impedance will be reflected in a change in voltage phase angle difference between two locations.

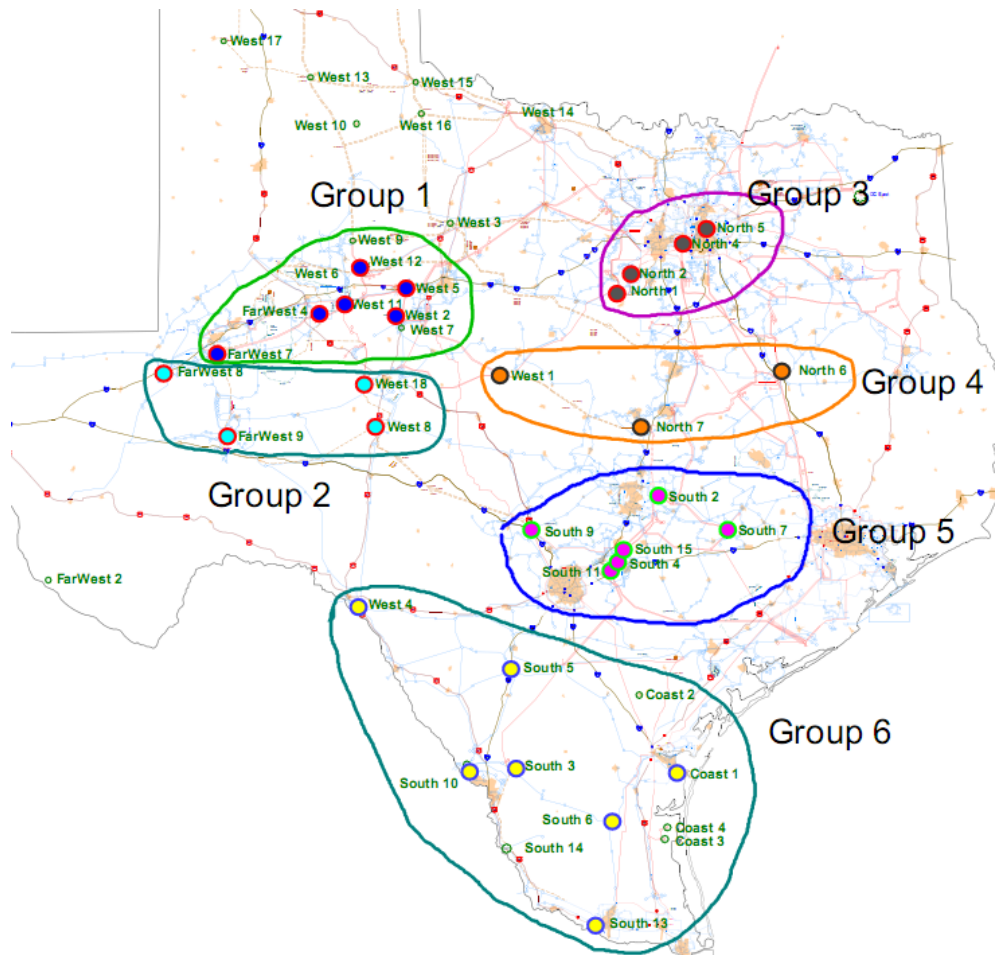
In the 2012 Baseline Study, EPG grouped substations based on geographical proximity as shown in the map and table below in order to find trends regarding angle differences referenced to North 7. The results of the 2012 study showed that there was strong correlation between the substations in Group 1 and between several substations in group 5 (South 2, South 4, South 11 and South 15). The angle difference plots for substations in Group 6 followed similar shapes but were not as close to each other as the substations in Groups 1 and 5. Angle difference plots for the other groups/substations have different, individual, patterns. This baselining study update includes a cluster analysis for the same groups with some additions as follows:

| | |
|---------|------------------------------------------|
| Group 1 | Add West 12 and remove West 9 and West 6 |
| Group 2 | Add West 8 and West 18 |

| | |
|---------|-------------|
| Group 3 | Add North 1 |
| Group 4 | Add West 1 |
| Group 5 | No change |
| Group 6 | Add West 4 |

The cluster analysis update was prepared for two days during the first six months of 2013: May 2, Maximum Wind Output, and June 27, Maximum ERCOT system load. The results of this cluster analysis update are shown below. These results corroborate the findings of the 2012 cluster analysis except for South 2. The angle curves for substations in Group 1 track very well with each other and the curves for South 4, South 11 and South 15 substations in Group 5 also track very well with each other (this time South 2 did not track all that well with these three substations). All other substations in this Group 5 and in other groups have their own unique behavior.

Below is a map with the geographical location of the substations in the groups and below it are listed the six Groups and the substations in each group.

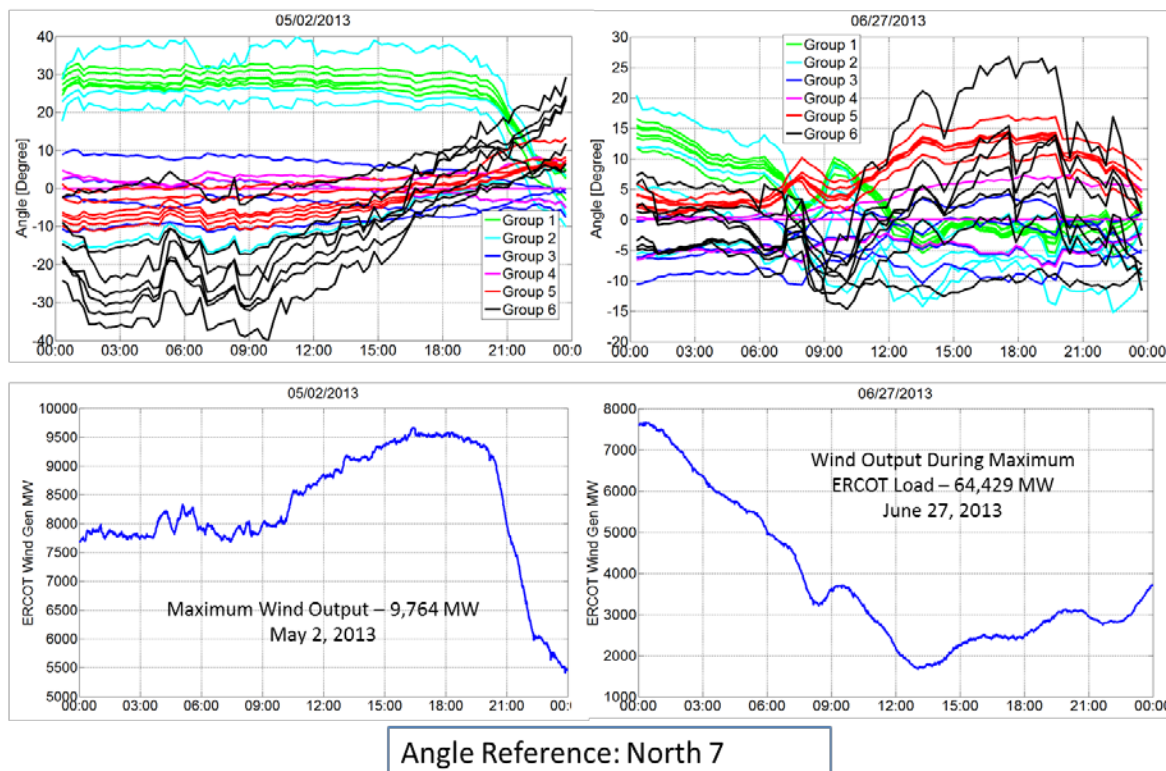


| GROUP 1 | GROUP 2 | GROUP 3 | GROUP 4 | GROUP 5 | GROUP 6 |
|--------------|--------------|------------|------------|-------------|-------------|
| a. FarWest 4 | a. FarWest 8 | a. North 1 | a. North 6 | a. South 2 | a. Coast 1 |
| b. FarWest 7 | b. FarWest 9 | b. North 2 | b. North 7 | b. South 4 | b. South 3 |
| c. West 2 | c. West 8 | c. North 4 | c. West 1 | c. South 7 | c. South 5 |
| d. West 5 | d. West 18 | d. North 5 | | d. South 9 | d. South 6 |
| e. West 11 | | | | e. South 11 | e. South 10 |
| f. West 12 | | | | f. South 15 | f. South 13 |
| | | | | | g. West 4 |

5. RESULTS

A summary of angle difference plots by groups is shown below:

Cluster Summary – Angle Difference – Groups 1-6



Review of this graph shows that the angle differences for the substations in Groups 1 and 2, which are close to the wind farms follow the pattern of the wind output curves shown at the bottom of the graph. Further, it appears that the angles for the substations in Group 6 begin increasing after 9 a.m. on both days presumably to meet the increasing load for the day. On May 2, these angles keep steadily increasing to follow the load but, at the end of the day, when the load goes down these angles are still growing probably to compensate the reduction in wind output which started at about 8 p.m. that day (5,000 MW by midnight). On June 27 the angle for substations in Group 6 began increasing at about noon time but this time began to come back down at about 8 p.m. when the load decreased and wind output increased to about 3,700 MW at midnight that day. Note also the

wind curve for May 2 shows a bump of almost 2,000 MW between 10:30 a.m. and 8 p.m. which is not reflected in the angle curves for Groups 1 and 2 which stay constant for most of the day and begin to come down at about 8 p.m. This behavior observed seems to be the result of interaction between wind production in west Texas, load in Texas, and conventional generation in the south and other parts of Texas.

The angles for the substations in Group 6 share similar patterns but are separated from each other by several degrees, this is a reflection of the fact they are also physically separated and subject to different levels of generation and load.

More detailed information for each group is presented in Appendix A attached to this report.

6. SUMMARY OF RESULTS – ANGLE DIFFERENCES

- a. **Data Availability Improved:** ERCOT provided state estimator data for the first six months of 2013. This time the average availability improved from about 13% for 2012 data to 29.2% for the six months in 2013.
- b. **Angle Differences Track Wind Output:** Cluster analysis for 2013 confirms that the angle differences plots for the substations close to the wind farms track well with the wind output graphs.
- c. The angles for the substations near the wind farms in the western part of Texas for the maximum wind output day of May 2, 2013 were in the 25 to 33 degrees range most of the day. All these angles dropped to 5 degrees or below by the end of the day, as the wind generation decreased.
- d. In Group 2, the FarWest 9 to North 7 pair operated in the 30 to 40 degrees most of the day on May 2, 2013; at the end of the day it dropped to about -7 degrees. The shape of the West 8 to North 7 pair was different in the plot for May 2; in the plot for June 27 it was closer to the other plots in the group. The West 18-West 8 line went in service on May 23, 2013, which is in between these two dates, and could have affected the relationship between West 8 and North 7. On June 27 this pair operated in the -10 to 0 degrees range.
- e. In Group 3, North 2 to North 7 pair behaves different from the other pairs in the group. Its behavior is more like those curves in Group 5; this difference could be caused by power deliveries across the East DC tie near North 8.
- f. In Group 4, North 6 to North 7 Pair is always positive (always providing power to North 7) whereas the West 1 to North 7 pair varies from positive to negative during the high wind day and is always negative during the high load day.
- g. The angle pairs in the San Antonio-Austin area began the high wind day with negative angles and ended with positive angles by the end of the day when the wind output went down. During the peak load day (June 27) these pairs were all positive indicating the power was flowing northbound from these substations.
- h. For Group 6, most of the curves in this group, except for West 4, were negative at the beginning of the day on May 2 when the wind output was strong; South 13 at the southern end of Texas fluctuated widely from -40 degrees at about 10 a.m. to about 22 degrees by the end of the day. During the peak load day, the pairs in this group seem to be responding to wind output in the

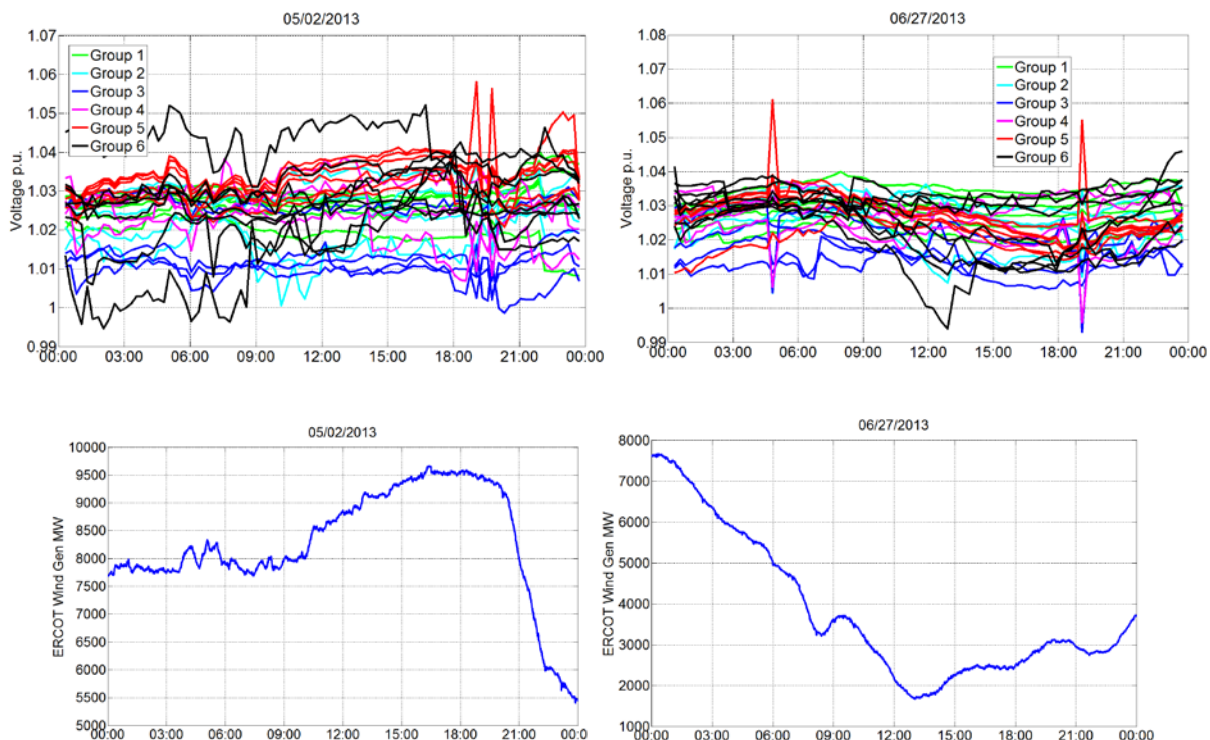
morning, to load increase in late morning to late afternoon and to load decrease and wind mild increase in the evening.

7. CLUSTER ANALYSIS – VOLTAGE MAGNITUDES

Using the same six groups as for the phase angle differences analysis, EPG performed a voltage magnitude cluster analysis. The cluster analysis update for voltage magnitudes was prepared for the two days used in the angle difference analysis: May 2, Maximum Wind Output, and June 27, 2013, Maximum ERCOT system load. A summary of the resulting graphs of this voltage magnitude cluster analysis update are shown below. More detailed graphs are shown in Appendix B.

Observation of these graphs show that most of the voltages during the peak load day (June 27) fluctuated in the 1.01 to 1.04 p.u. ranges whereas for the Maximum Wind Output, low load, day (May 2) the voltages operated within a wider range: 1 p.u. to 1.05 p.u. South 7 experienced upward spikes of up to 8 kV during both days reaching 366 kV at times. West 1, North 4 and FarWest 8 experienced downward spikes of lesser magnitude.

Cluster Summary-Voltage Magnitudes: Groups 1-6



8. SUMMARY OF RESULTS – VOLTAGE MAGNITUDES

- Group 1:** All voltages, except FarWest 7, in group 1 operated between 1.02 to 1.032 most of the day on May 2; at the end of the day FarWest 7 voltage went down 1% and the rest of the

voltages went up by up to 1%. On June 27 the voltages in this group operated in the 1.017 and 1.04 ranges. The highest voltages were at West 2 and the lowest voltages at FarWest 7.

- b. **Group 2:** On May 2 voltages in this group operated in the 1.00 to 1.03 p.u. range with FarWest 9 fluctuating the most between 1.027 and 1.00 p.u. On June 27 the voltage at FarWest 8 spiked down 1% at about 5 a.m. and the West 8 voltage stayed high until 9 a.m. and then went down to about 1.015 in the early afternoon and stayed low until about 7 p.m.
- c. **Group 3:** On May 2 the North 4 voltage stayed at around 1.026 and experienced a couple of spikes down of about 2% in the late afternoon. On June 27 the North 4 voltage stayed at around 1.026 and experienced a couple of spikes down of about 2.5%, one in the morning and one in the afternoon.
- d. **Group 4:** Voltages at West 1 spiked down in both days May 2 and June 27. On May 2 the voltage at North 7 experienced a sudden drop from 1.037 to 1.015.
- e. **Group 5:** The voltages at South 7 experienced upward spikes of up to 2.7% in both days of study.
- f. **Group 6:** West 4 in May and South 13 in June experienced the lowest voltages in the group. In both cases the voltages fell below 1.0 p.u.
- g. **Voltage Magnitude Averages:** below is a table of voltage magnitude averages for the two days analyzed.

Groups 1-6 Daily Average Voltages

| | | 5/2/2013 | | 6/27/2013 | |
|---------|-----------|-------------|---------------|-------------|---------------|
| | | Average(kV) | Average(p.u.) | Average(kV) | Average(p.u.) |
| Group 1 | FarWest 4 | 355.15 | 1.03 | 354.67 | 1.03 |
| | FarWest 7 | 351.85 | 1.02 | 352.35 | 1.02 |
| | West 5* | 355.07 | 1.03 | 355.43 | 1.03 |
| | West 2* | 355.17 | 1.03 | 357.14 | 1.04 |
| | West 11 | 354.20 | 1.03 | 353.60 | 1.02 |
| | West 12* | 353.43 | 1.02 | 355.87 | 1.03 |
| Group 2 | FarWest 8 | 140.75 | 1.02 | 141.49 | 1.03 |
| | FarWest 9 | 140.38 | 1.02 | 141.62 | 1.03 |
| | West 8* | 142.04 | 1.03 | 141.11 | 1.02 |
| | West 18 | 142.01 | 1.03 | 142.30 | 1.03 |
| Group 3 | North 5 | 139.65 | 1.01 | 140.17 | 1.02 |
| | North 1 | 139.64 | 1.01 | 140.22 | 1.02 |
| | North 2 | 139.21 | 1.01 | 139.96 | 1.01 |
| | North 4 | 141.64 | 1.03 | 141.32 | 1.02 |
| Group 4 | North 6 | 142.05 | 1.03 | 142.40 | 1.03 |
| | North 7 | 140.96 | 1.02 | 141.79 | 1.03 |
| | West 1* | 141.41 | 1.02 | 140.83 | 1.02 |
| Group 5 | South 7* | 355.45 | 1.03 | 355.29 | 1.03 |
| | South 9* | 355.76 | 1.03 | 351.98 | 1.02 |
| | South 11* | 357.15 | 1.04 | 354.68 | 1.03 |
| | South 2* | 354.61 | 1.03 | 353.50 | 1.02 |
| | South 4* | 357.00 | 1.03 | 354.70 | 1.03 |
| | South 15* | 356.73 | 1.03 | 354.26 | 1.03 |
| Group 6 | Coast 1 | 140.74 | 1.02 | 142.57 | 1.03 |
| | West 4 | 140.56 | 1.02 | 141.62 | 1.03 |
| | South 10* | 141.57 | 1.03 | 142.35 | 1.03 |
| | South 13 | 141.29 | 1.02 | 140.61 | 1.02 |
| | South 3* | 143.82 | 1.04 | 142.44 | 1.03 |
| | South 5* | 142.12 | 1.03 | 140.82 | 1.02 |
| | South 6* | 142.37 | 1.03 | 141.68 | 1.03 |

Conclusions from the above table include:

- The lowest average voltage among 138 kV substations occurred in Group 3, which includes the Dallas load and the North 1 substation. The average voltage magnitude for this group was 140.04 kV.
- The lowest average voltage among 345 kV substations occurred in Group 1, which includes the substations near wind farms. The average voltage magnitude for this group was 354.15 kV.
- Maximum group average voltages observed were in Group 6 (141.78kV) and Group 5 (356.12 kV)
- Average voltages during peak wind conditions and peak load conditions were very close to each other except for Group 5 which experienced average voltage of 2.06 kV lower during peak load conditions.
- The individual highest substation average voltages observed were at South 11 with 357.12 kV and at South 3 with 143.82 kV.

Appendix A

Center for Commercialization of Electric Technologies -- Discovery Across Texas

Updated Cluster Analysis – Angle Differences (Ref: North 7) January-June 2013 Data

Prepared by:

Romulo Barreno

Ajay Das

Song Xue

August 15, 2013

External Version

Cluster Analysis – Cluster Groups

Group 1- 345 Central:

- FarWest 4
- FarWest 7
- West 5
- West 2
- West 12
- West 11

Group 2- W. Texas:

- FarWest 9
- FarWest 8
- West 8
- West 18

Group 3 - Dallas:

- North 5
- North 4
- North 2
- North 1

Group 4 – East & CE:

- West 1
- North 6
- North 7

Group 5 – 345 C. East:

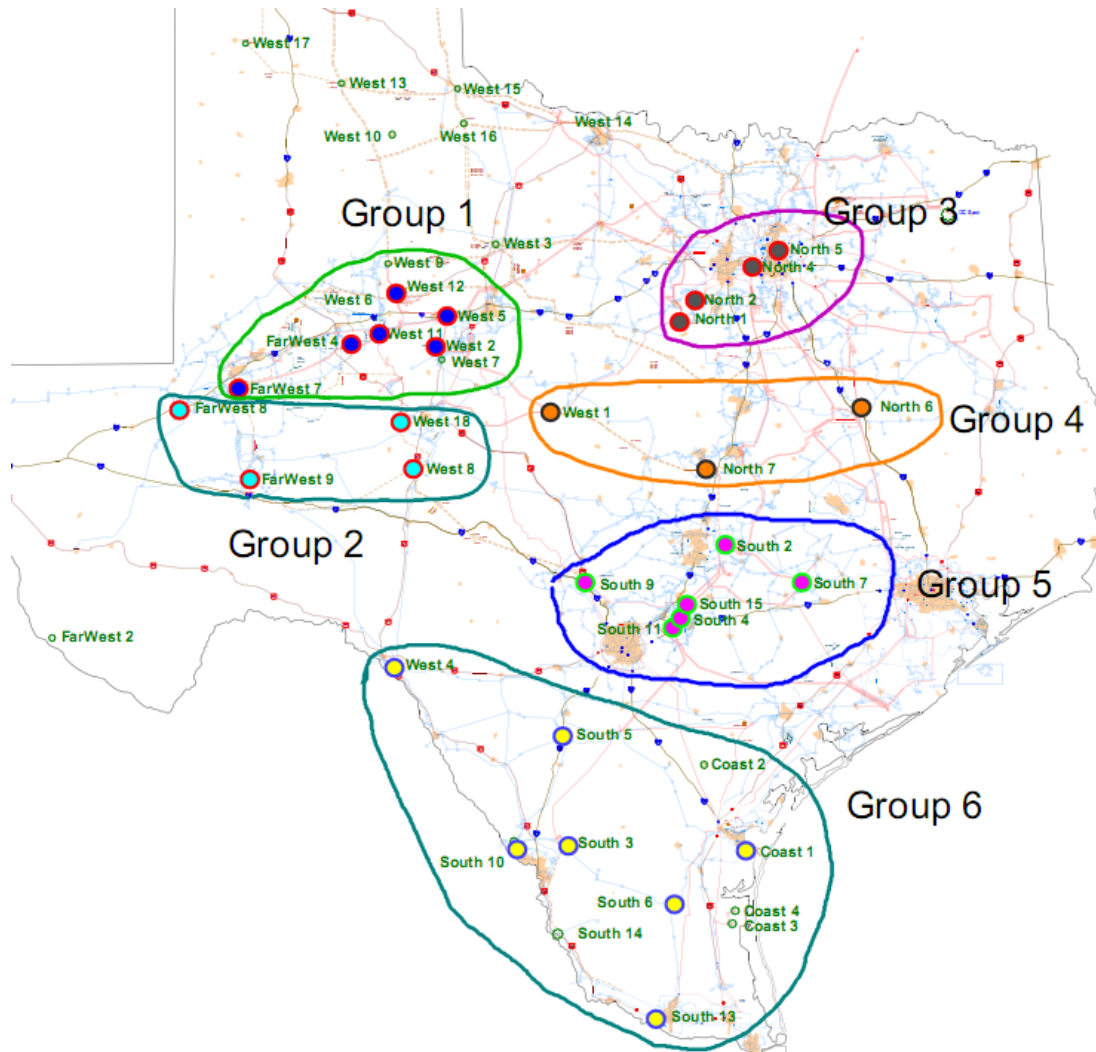
- South 7
- South 9
- South 11
- South 2
- South 4
- South 15

Group 6 - Valley:

- Coast 1
- West 4
- South 10
- South 13
- South 3
- South 5
- South 6

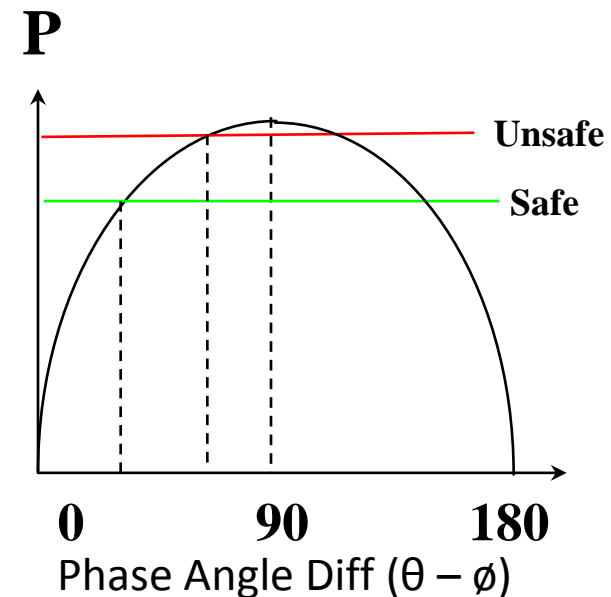
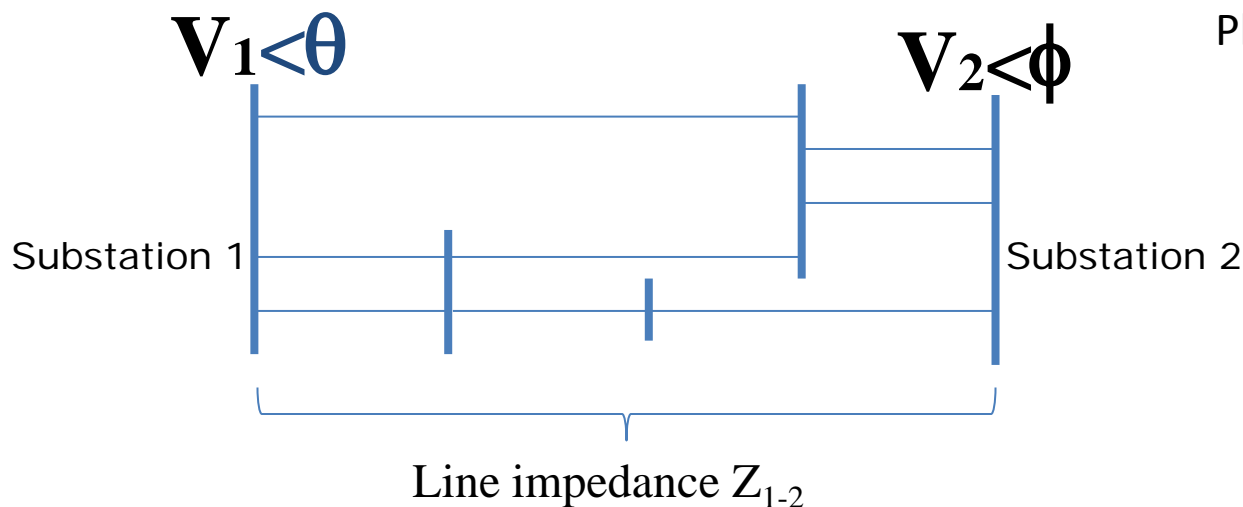
Note: This list includes existing and planned PMU locations from Oncor, AEP, Sharyland and LCRA

Cluster Locations: Groups 1-6

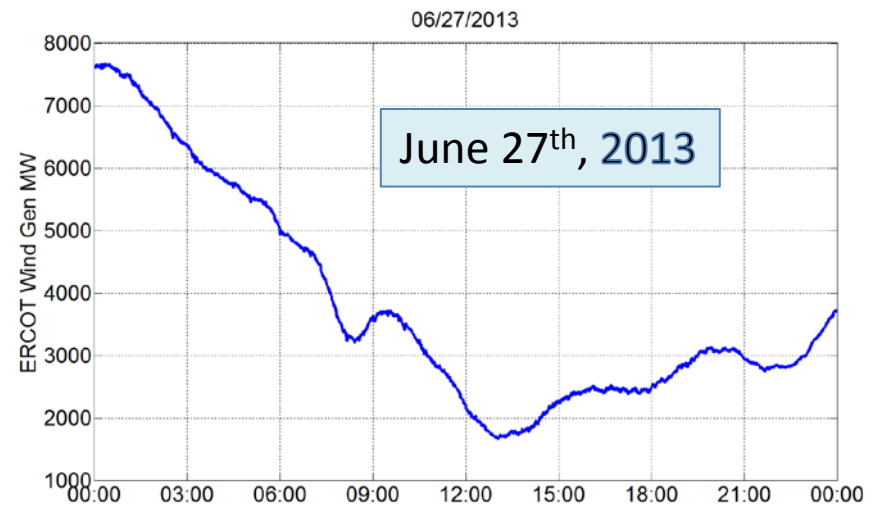
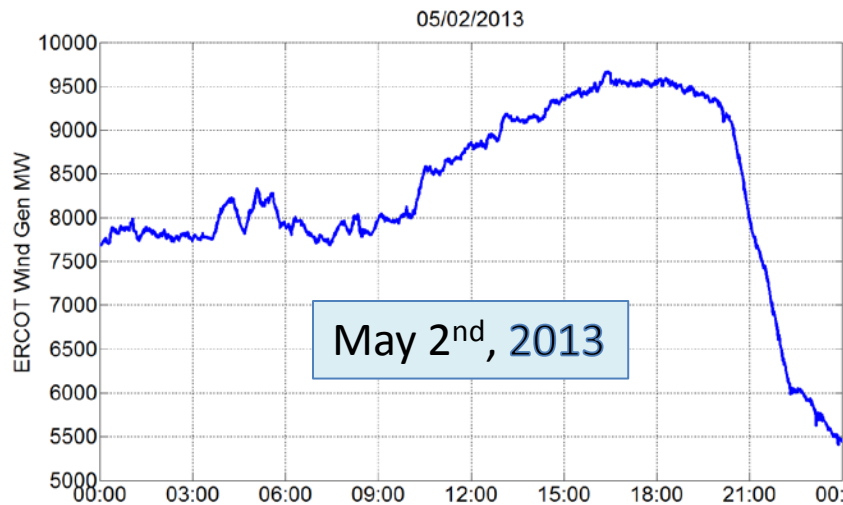
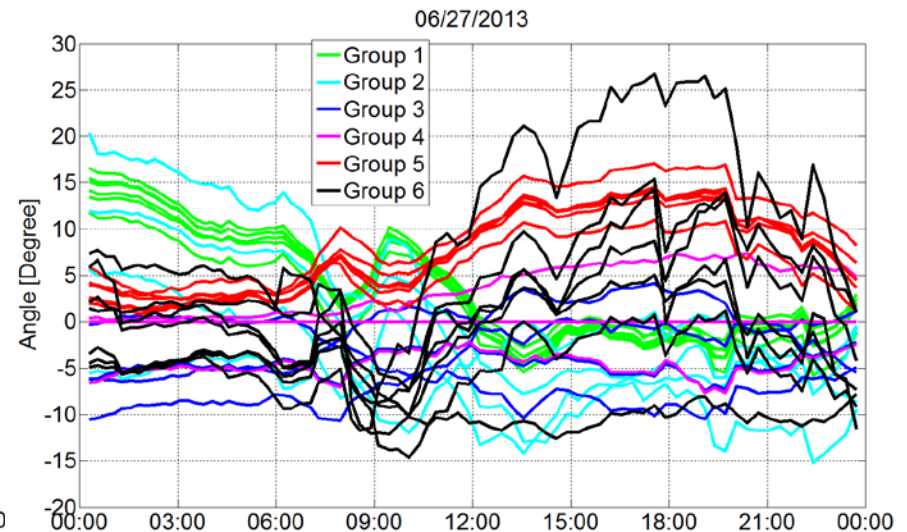
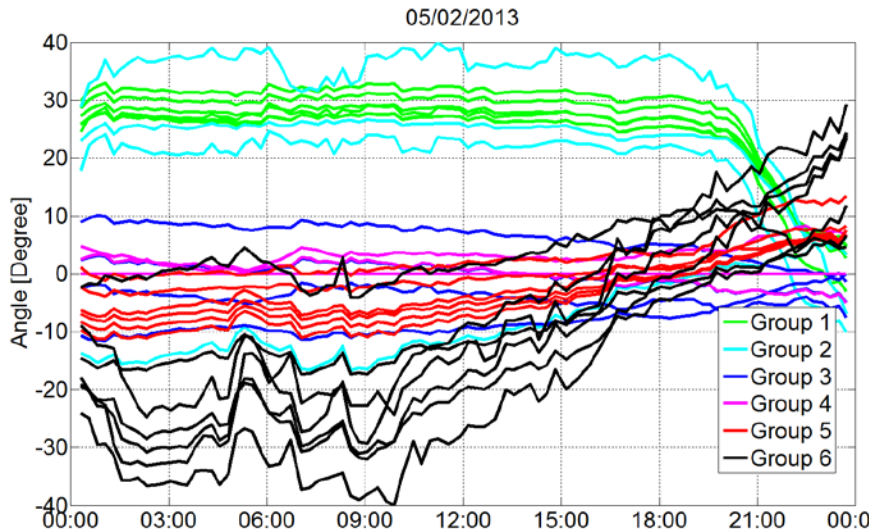


Phase Angles Differences as Indicators of Power Flow

- Power flow follows voltage angle difference
 - Power flow: $P = V_1 V_2 \sin(\theta - \phi)/Z$
- Any change in power flow or impedance will be reflected in a change in voltage phase angle difference between two locations

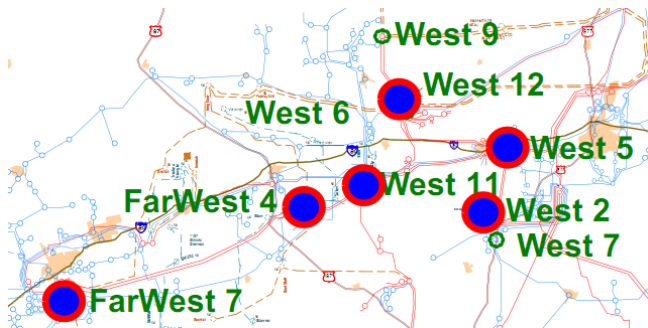
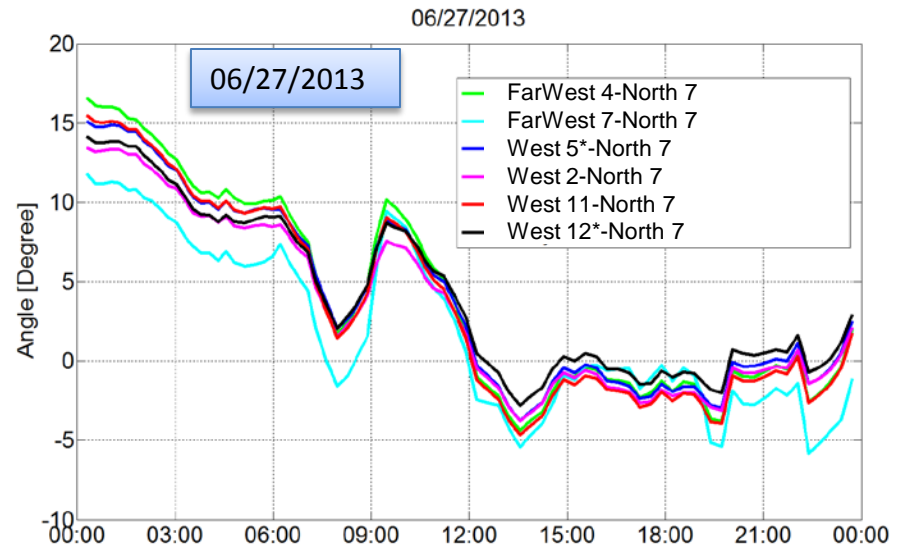
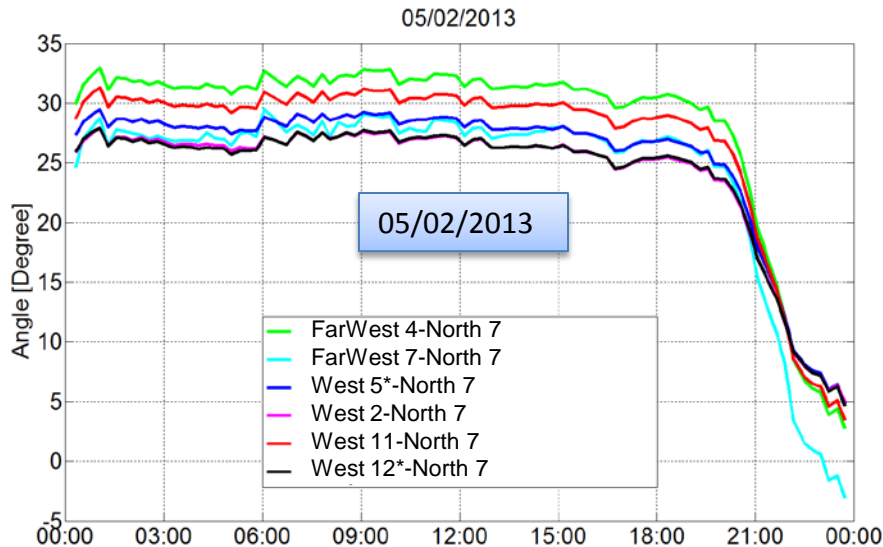


Cluster Summary – Angle Difference – Groups 1-6



Angle Reference: North 7

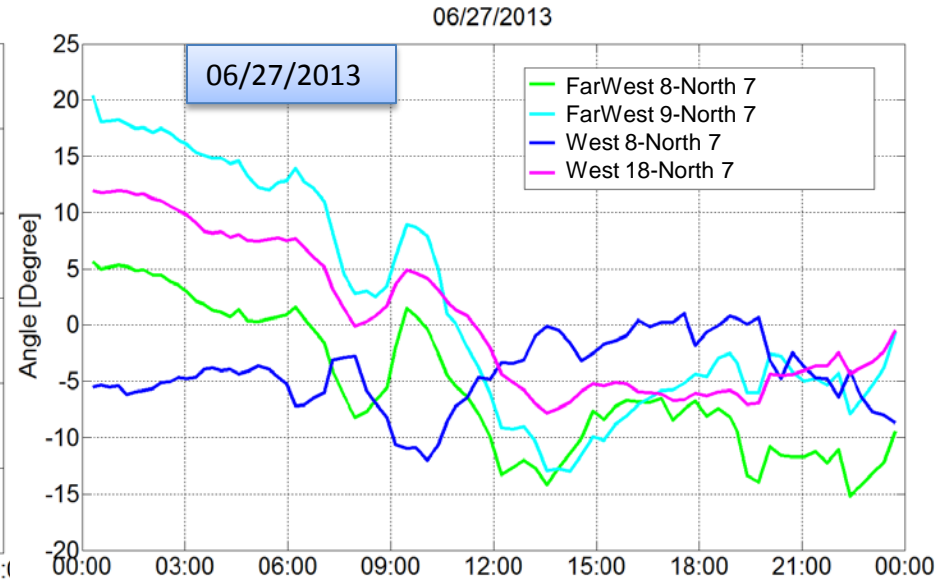
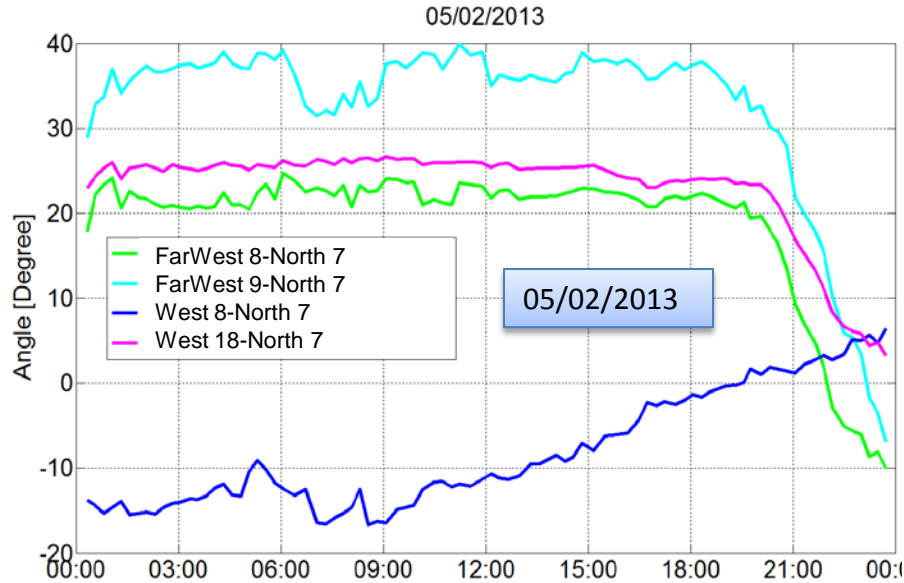
Group 1 – West Texas



New lines in the area:

1. West 12-West 21 3/06/13
2. West 21-North 9 3/20/13
3. North 9-North 8 3/21/13
4. West 19-West 20 4/15/13
5. West 13-West 19 4/29/13

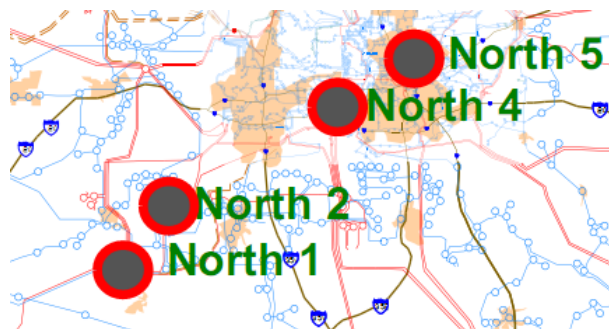
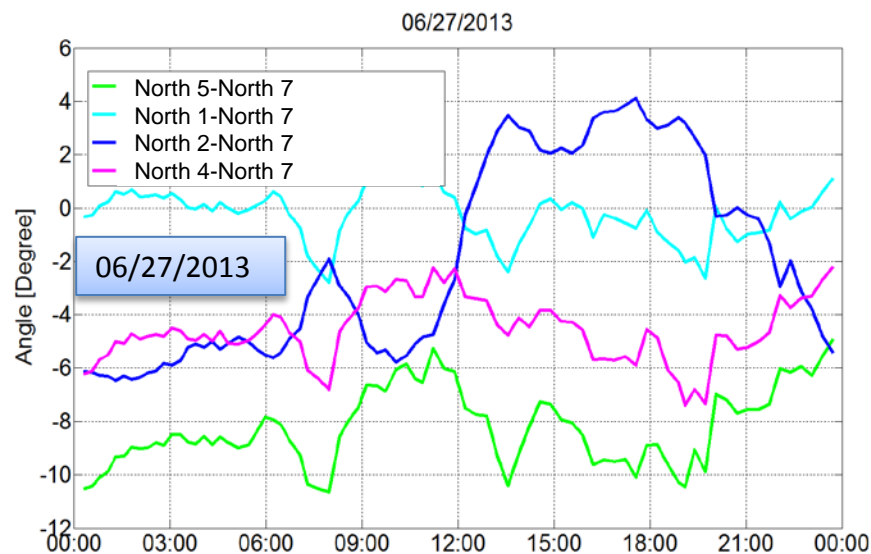
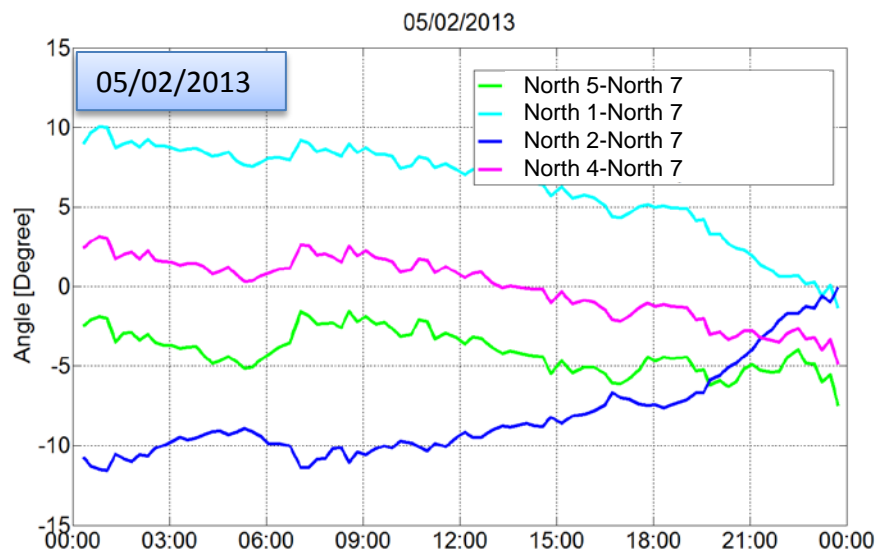
Group 2 – West Texas



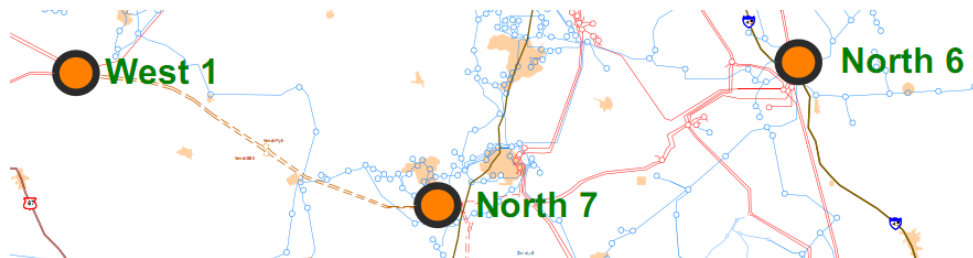
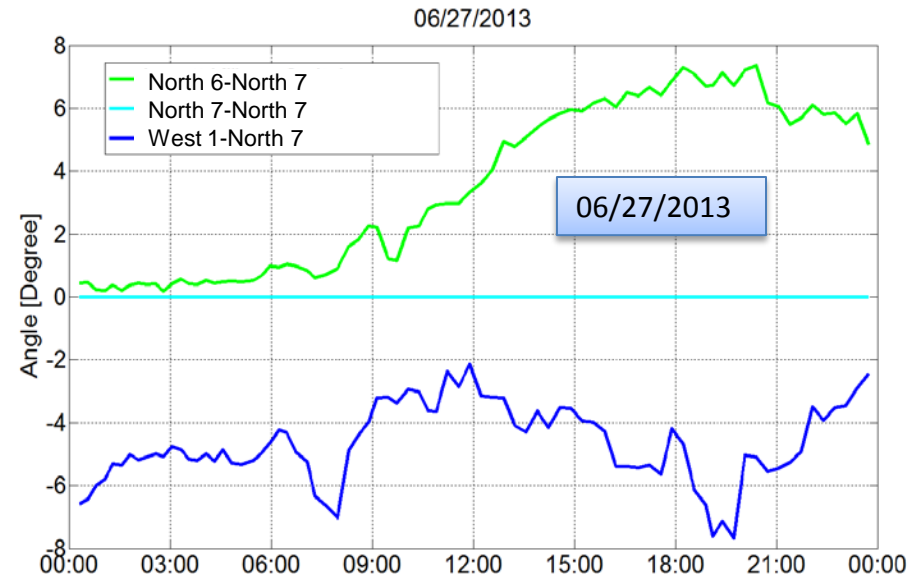
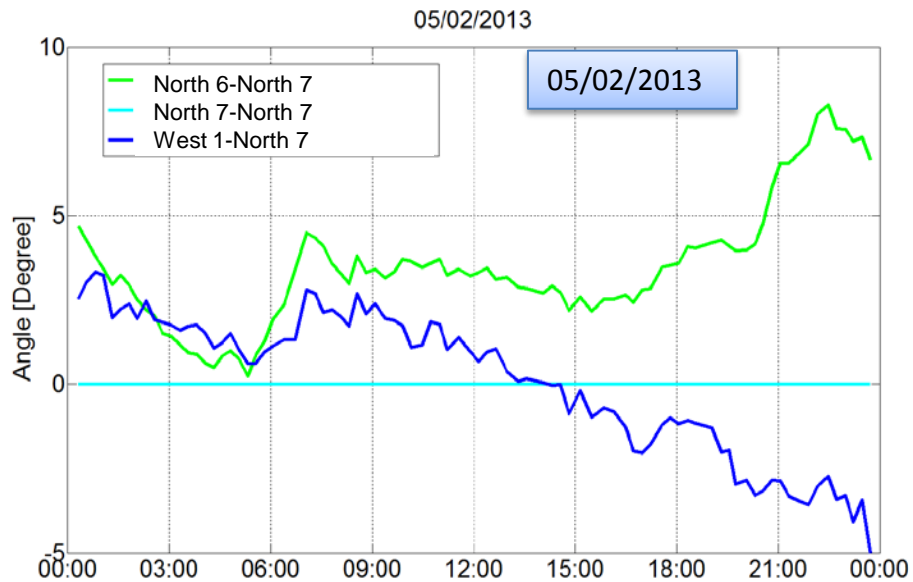
New lines in the area:

1. West 18-West 8 5/23/13

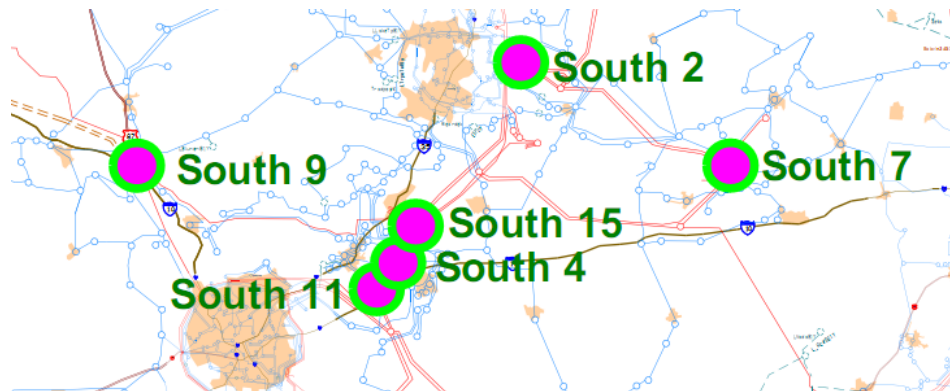
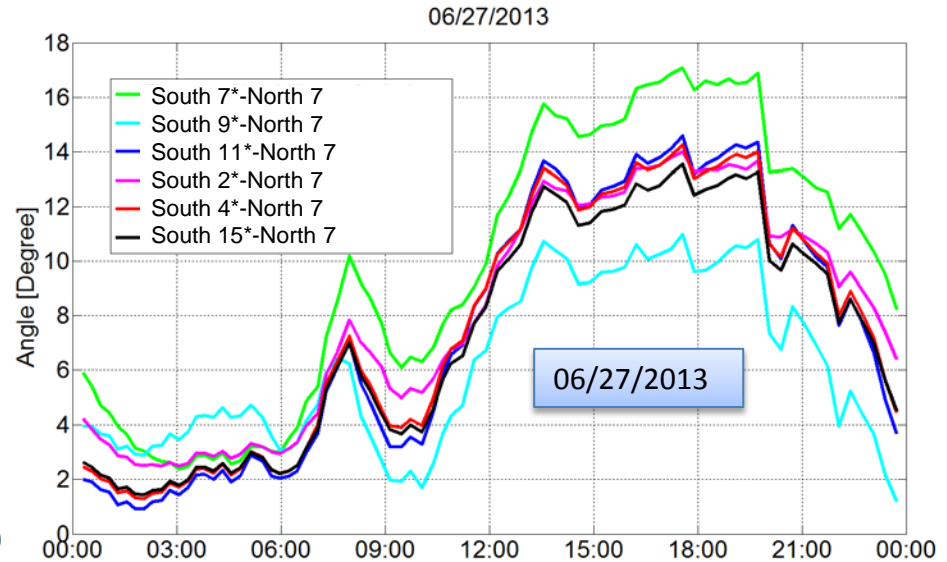
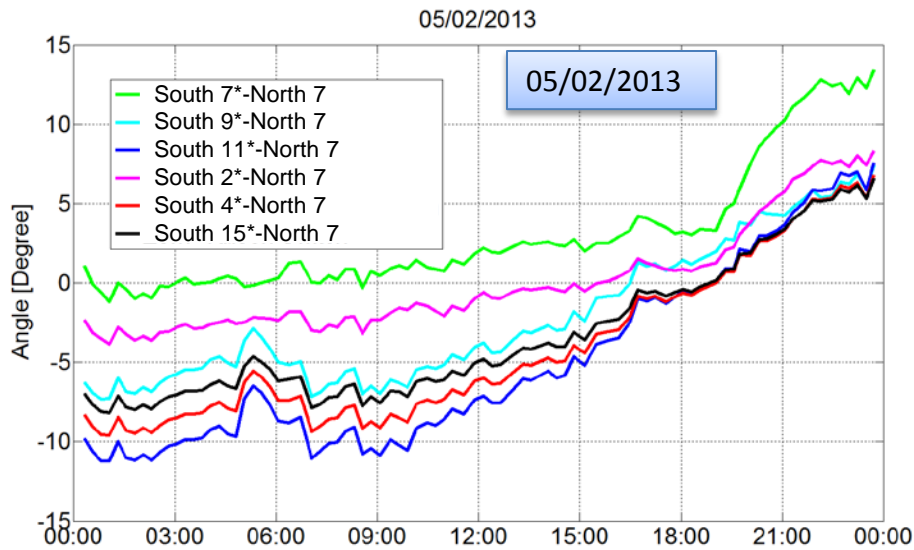
Group 3 - Dallas



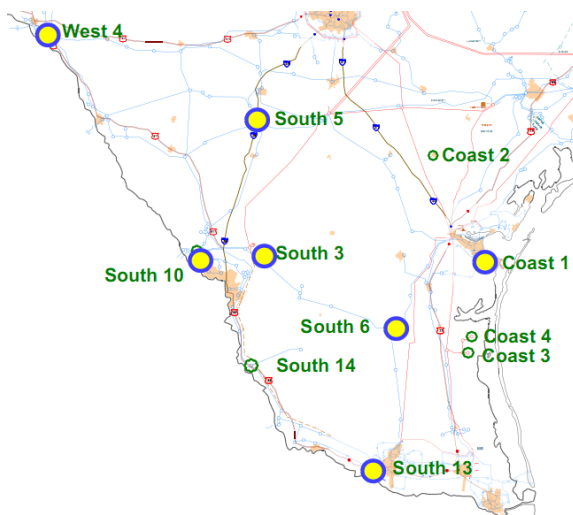
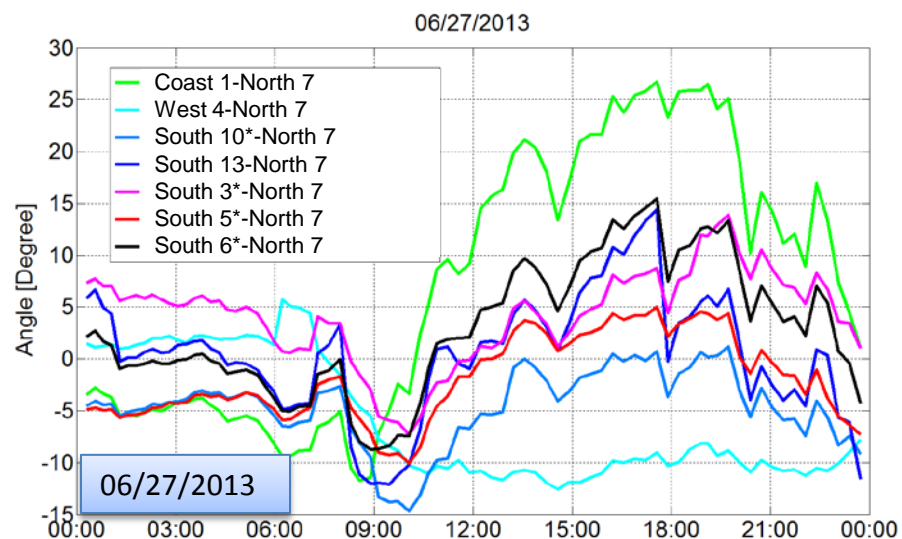
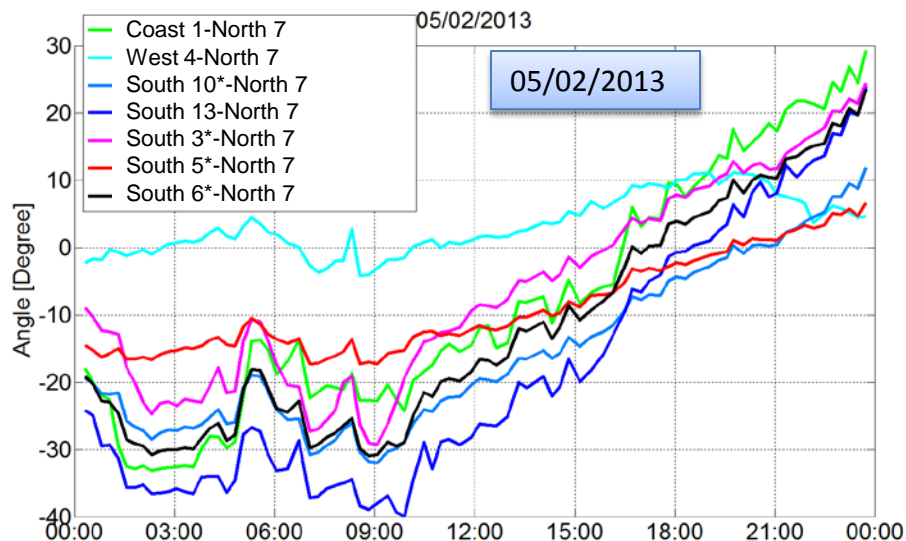
Group 4 – Central East



Group 5 – Central East



Group 6 – Valley (South)



Appendix B

Center for Commercialization of Electric Technologies -- Discovery Across Texas

Updated Cluster Analysis – Voltage Magnitudes January-June 2013 Data

Prepared by:

Romulo Barreno

Ajay Das

Song Xue

August 15, 2013

External Version

Cluster Groups

Group 1- 345 Central:

- FarWest 4
- FarWest 7
- West 5
- West 2
- West 12
- West 11

Group 2- W. Texas:

- FarWest 9
- FarWest 8
- West 8
- West 18

Group 3 - Dallas:

- North 5
- North 4
- North 2
- North 1

Group 4 – East & CE:

- West 1
- North 6
- North 7

Group 5 – 345 C. East:

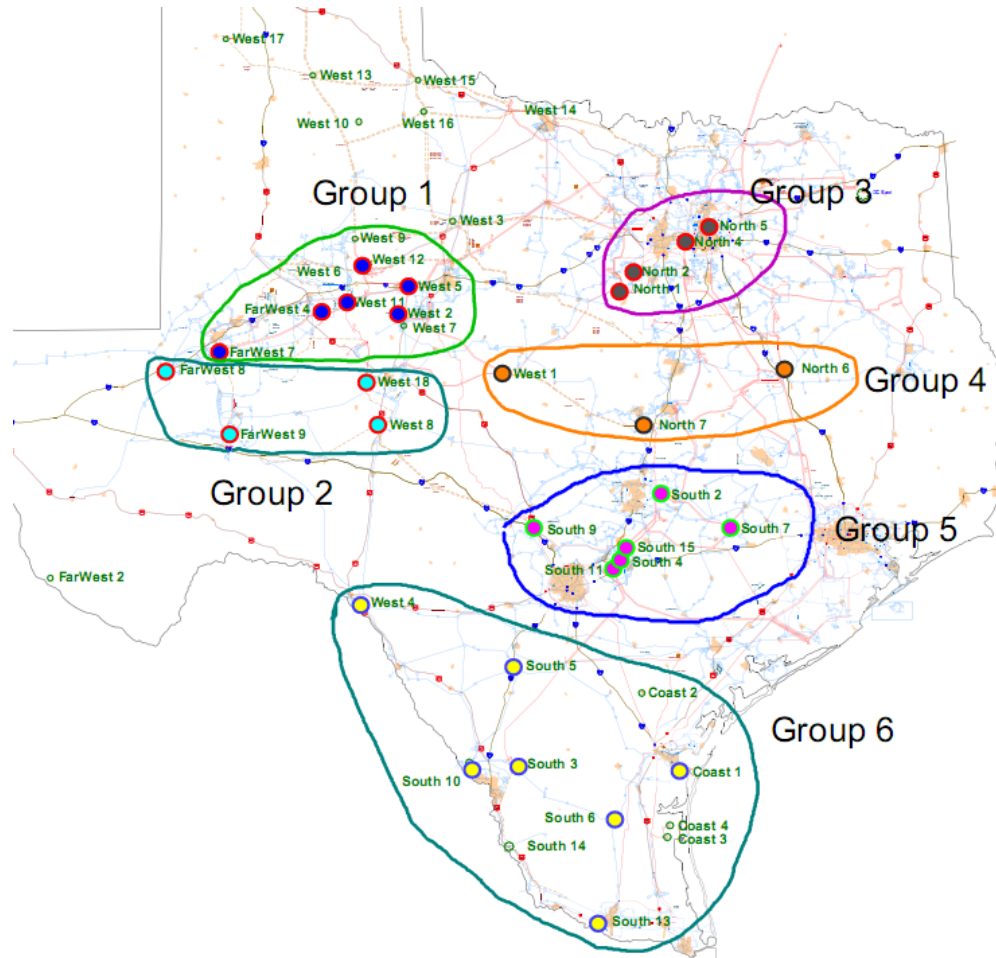
- South 7
- South 9
- South 11
- South 2
- South 4
- South 15

Group 6 - Valley:

- Coast 1
- West 4
- South 10
- South 13
- South 3
- South 5
- South 6

Note: This list includes existing and planned PMU locations from Oncor, AEP, Sharyland and LCRA

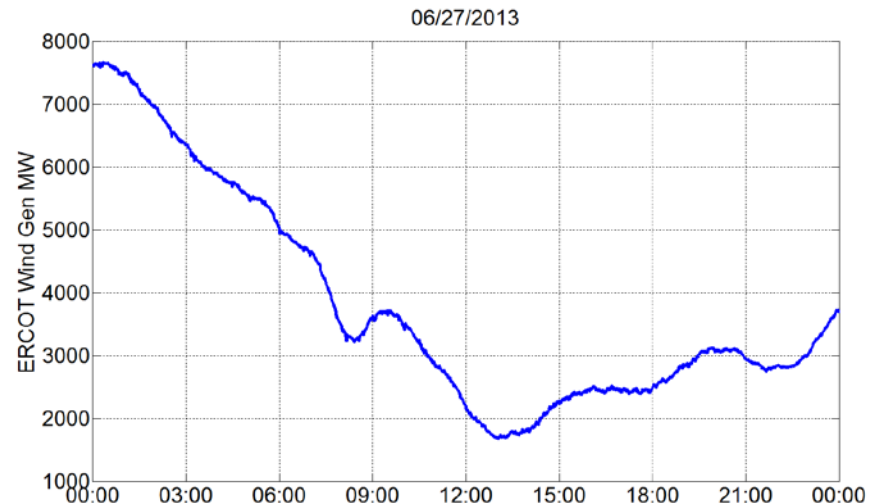
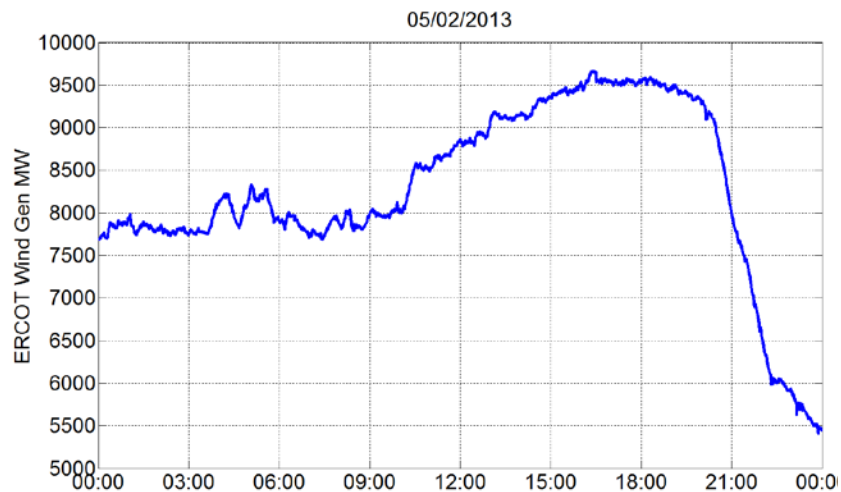
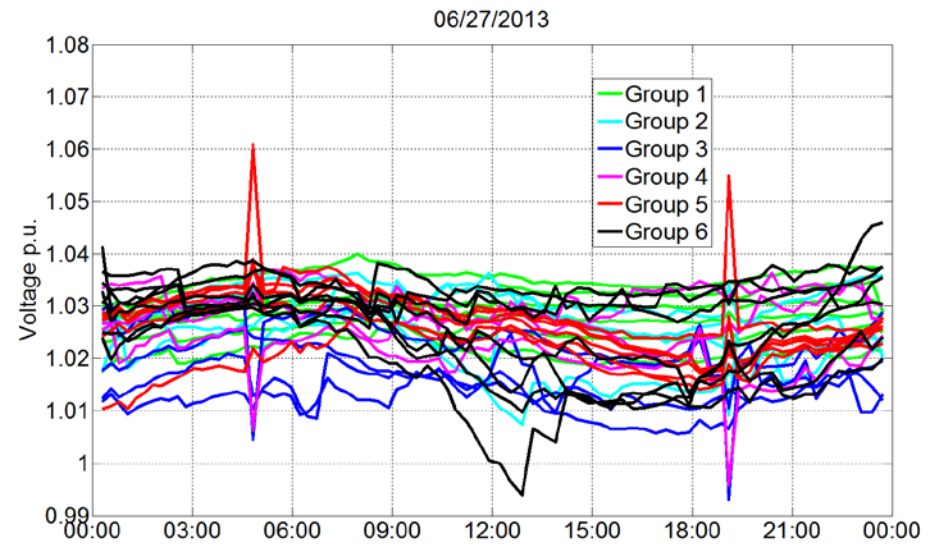
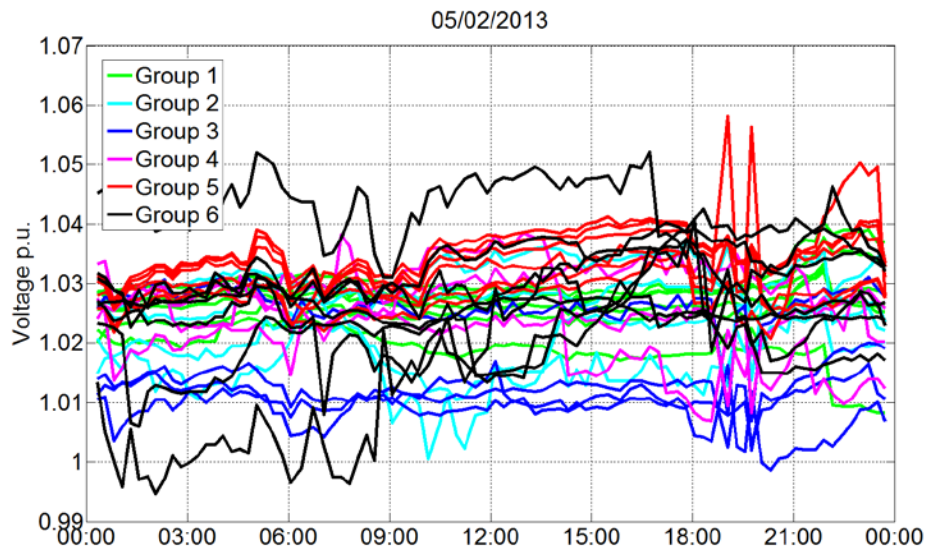
Cluster Locations: Groups 1-6



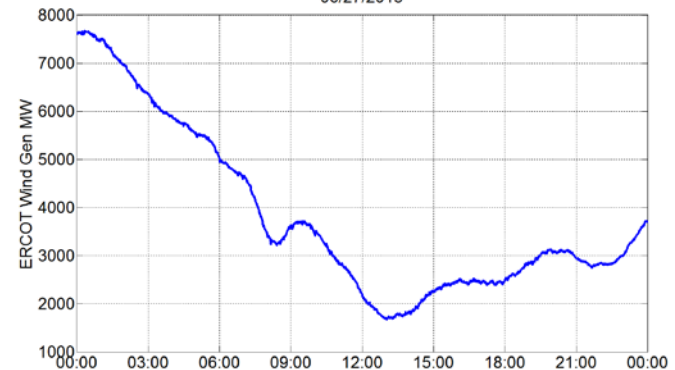
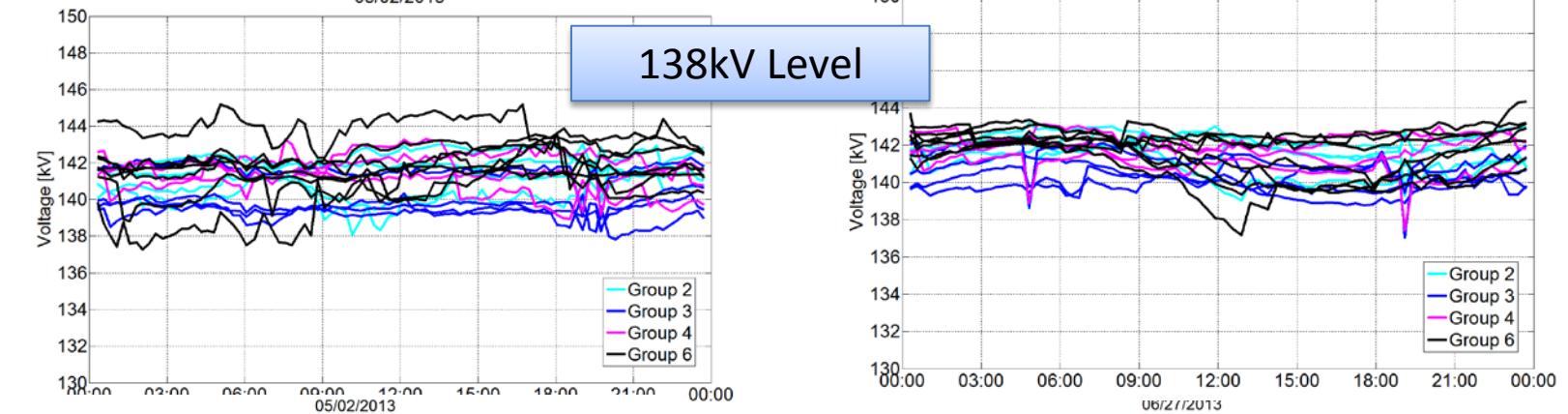
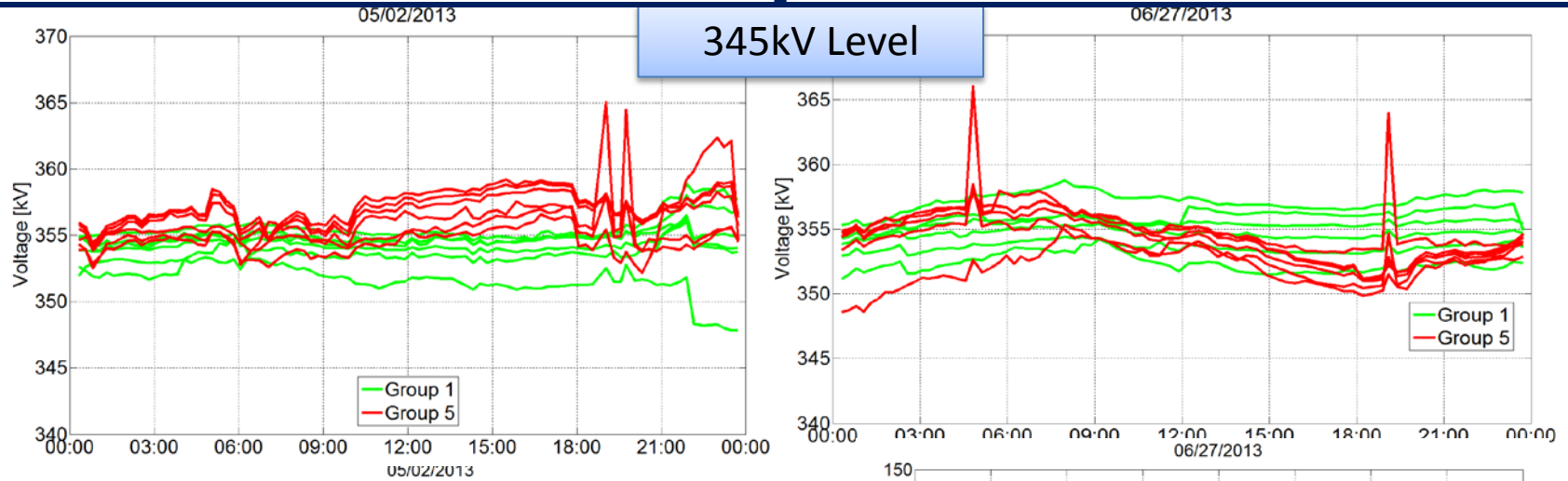
Groups 1-6 - Daily Average Voltages

| | | 5/2/2013 | | 6/27/2013 | |
|---------|-----------|-------------|---------------|-------------|---------------|
| | | Average(kV) | Average(p.u.) | Average(kV) | Average(p.u.) |
| Group 1 | FarWest 4 | 355.15 | 1.03 | 354.67 | 1.03 |
| | FarWest 7 | 351.85 | 1.02 | 352.35 | 1.02 |
| | West 5* | 355.07 | 1.03 | 355.43 | 1.03 |
| | West 2* | 355.17 | 1.03 | 357.14 | 1.04 |
| | West 11 | 354.20 | 1.03 | 353.60 | 1.02 |
| | West 12* | 353.43 | 1.02 | 355.87 | 1.03 |
| Group 2 | FarWest 8 | 140.75 | 1.02 | 141.49 | 1.03 |
| | FarWest 9 | 140.38 | 1.02 | 141.62 | 1.03 |
| | West 8* | 142.04 | 1.03 | 141.11 | 1.02 |
| | West 18 | 142.01 | 1.03 | 142.30 | 1.03 |
| Group 3 | North 5 | 139.65 | 1.01 | 140.17 | 1.02 |
| | North 1 | 139.64 | 1.01 | 140.22 | 1.02 |
| | North 2 | 139.21 | 1.01 | 139.96 | 1.01 |
| | North 4 | 141.64 | 1.03 | 141.32 | 1.02 |
| Group 4 | North 6 | 142.05 | 1.03 | 142.40 | 1.03 |
| | North 7 | 140.96 | 1.02 | 141.79 | 1.03 |
| | West 1* | 141.41 | 1.02 | 140.83 | 1.02 |
| Group 5 | South 7* | 355.45 | 1.03 | 355.29 | 1.03 |
| | South 9* | 355.76 | 1.03 | 351.98 | 1.02 |
| | South 11* | 357.15 | 1.04 | 354.68 | 1.03 |
| | South 2* | 354.61 | 1.03 | 353.50 | 1.02 |
| | South 4* | 357.00 | 1.03 | 354.70 | 1.03 |
| | South 15* | 356.73 | 1.03 | 354.26 | 1.03 |
| Group 6 | Coast 1 | 140.74 | 1.02 | 142.57 | 1.03 |
| | West 4 | 140.56 | 1.02 | 141.62 | 1.03 |
| | South 10* | 141.57 | 1.03 | 142.35 | 1.03 |
| | South 13 | 141.29 | 1.02 | 140.61 | 1.02 |
| | South 3* | 143.82 | 1.04 | 142.44 | 1.03 |
| | South 5* | 142.12 | 1.03 | 140.82 | 1.02 |
| | South 6* | 142.37 | 1.03 | 141.68 | 1.03 |

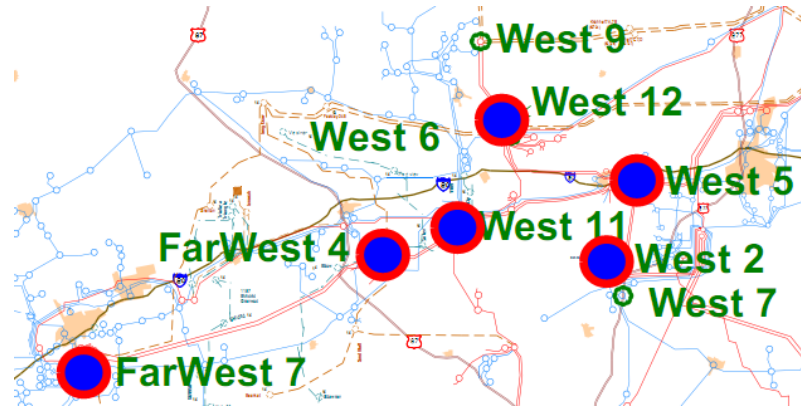
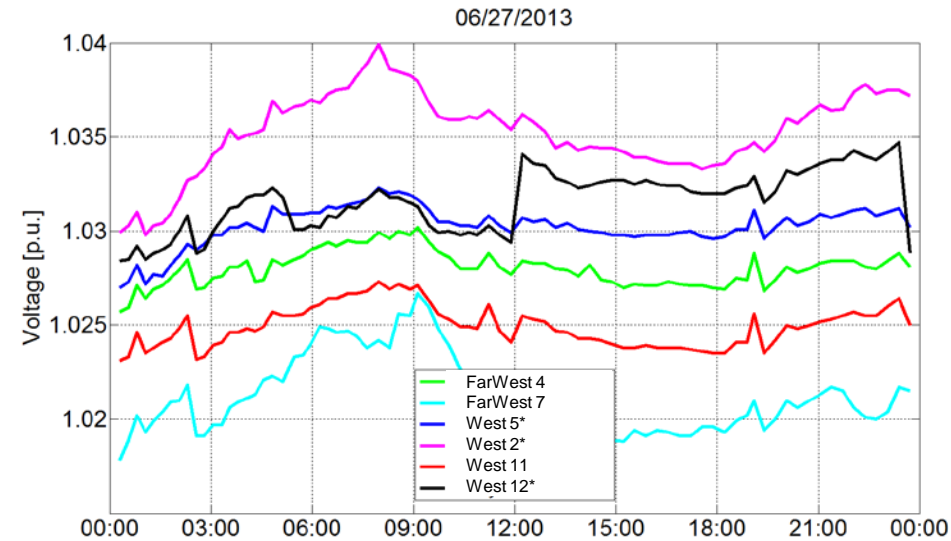
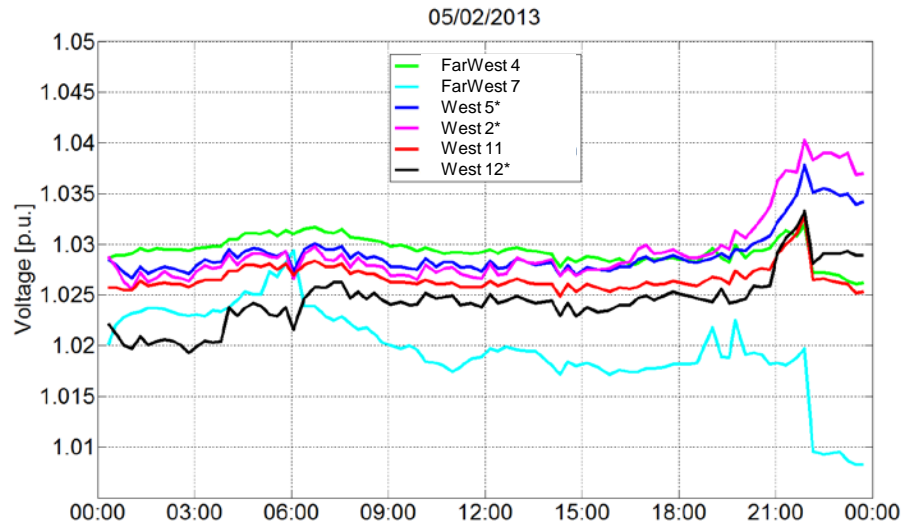
Cluster Summary-Voltage Magnitudes: Groups 1-6



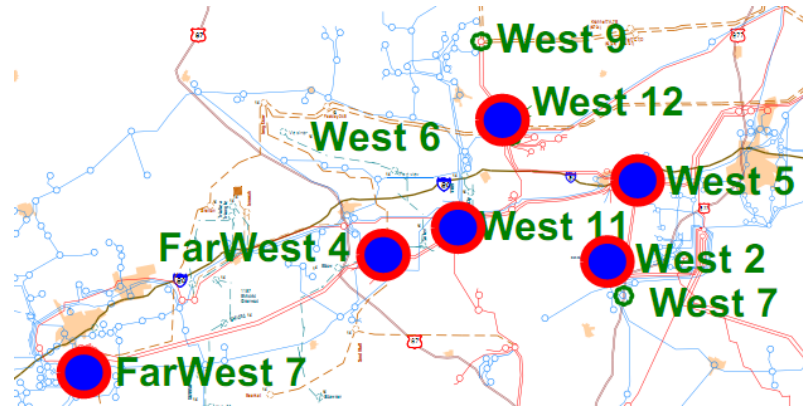
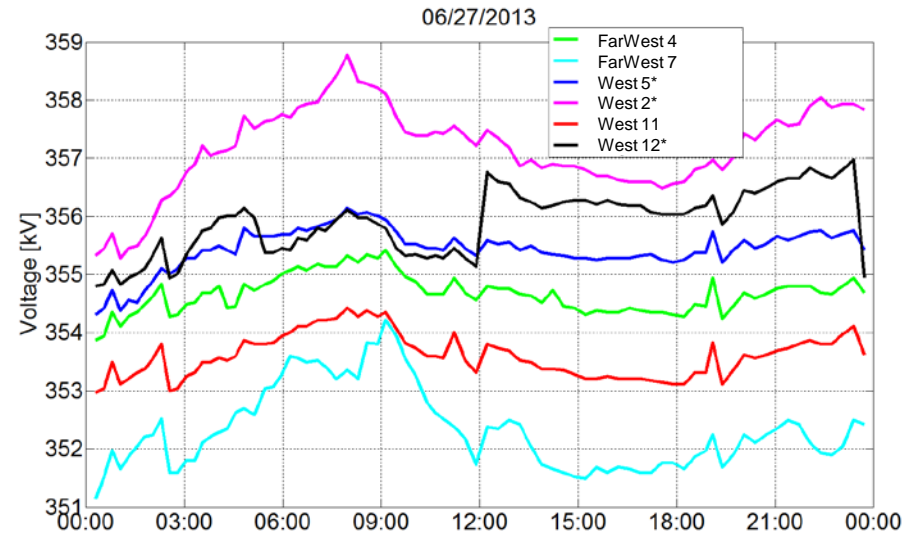
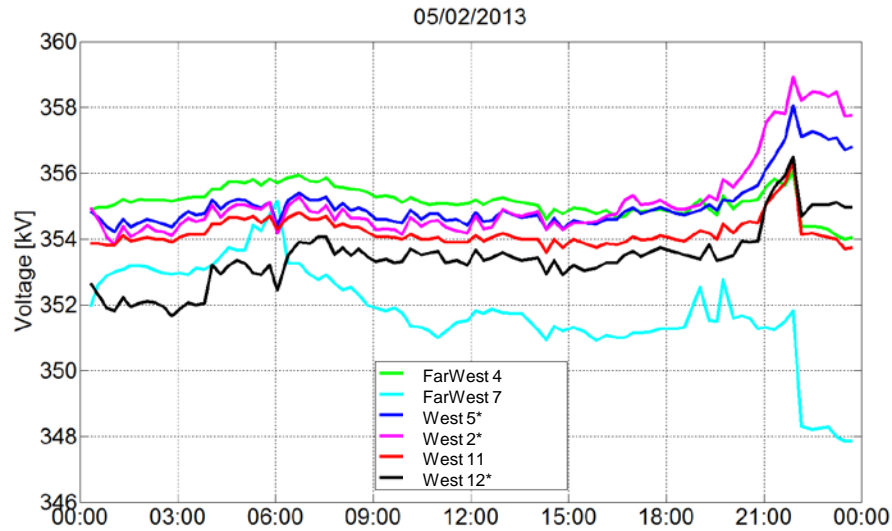
Groups 1-6



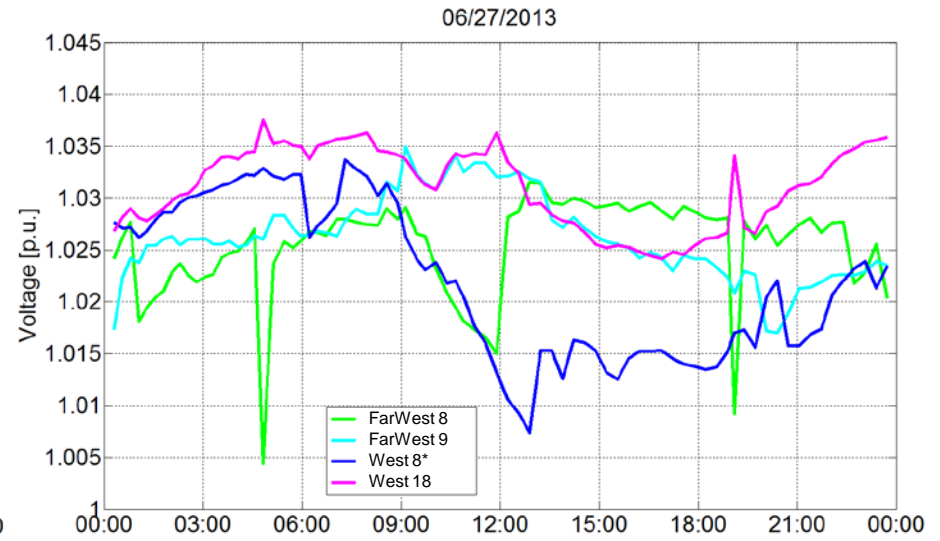
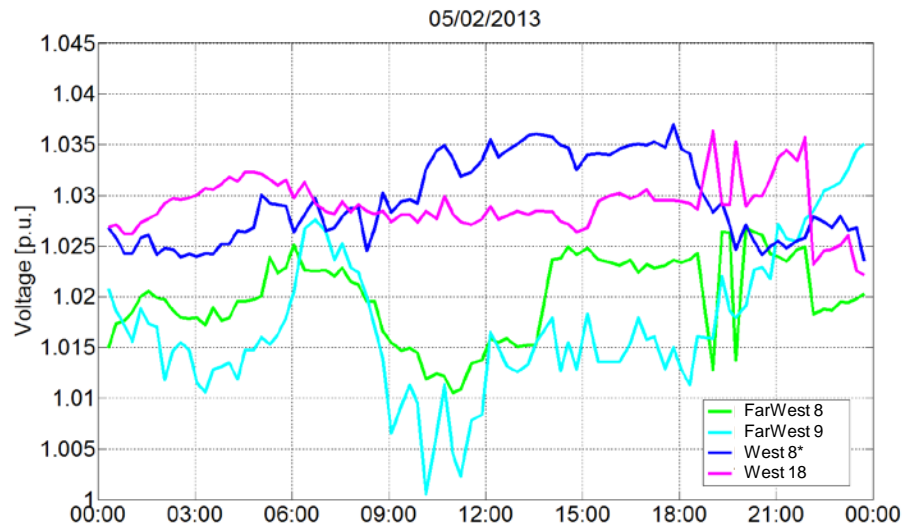
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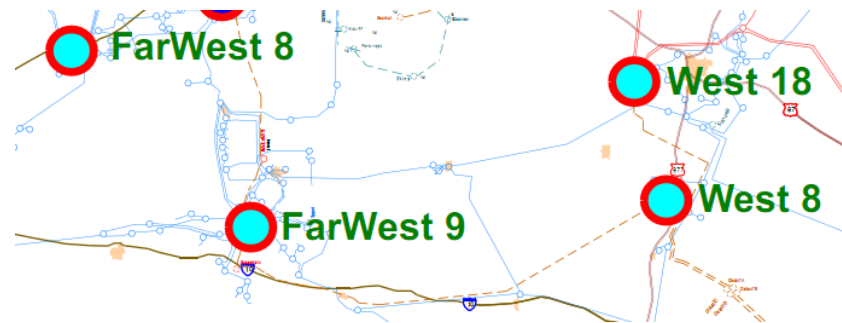
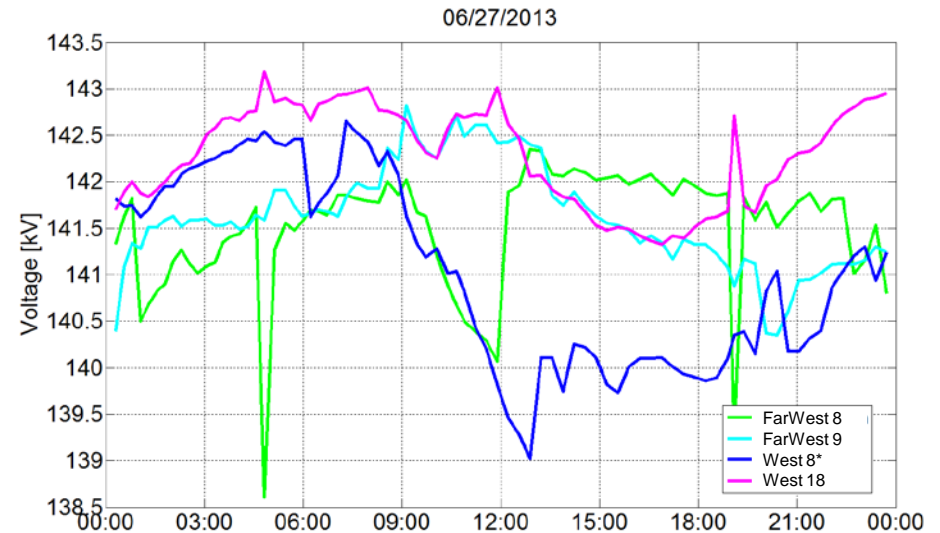
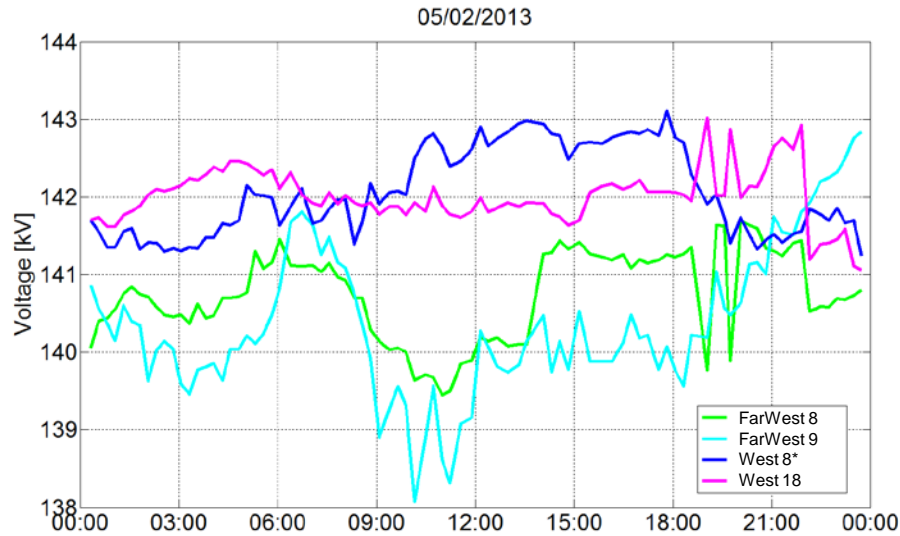
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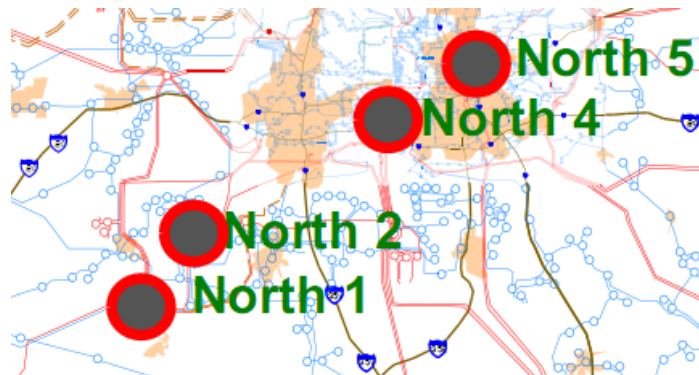
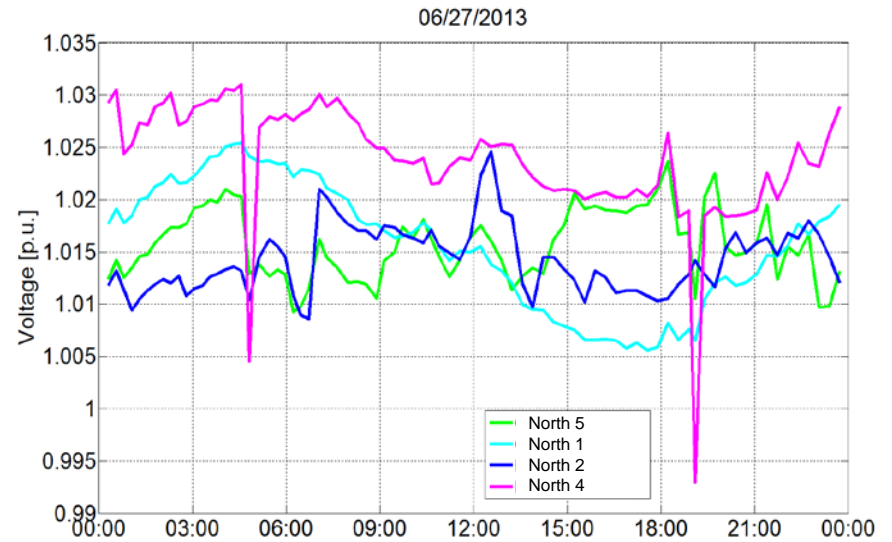
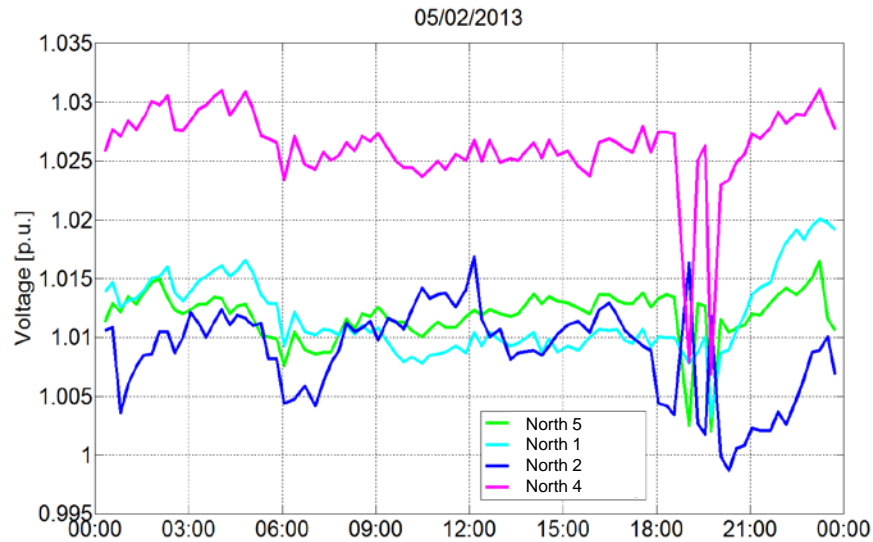
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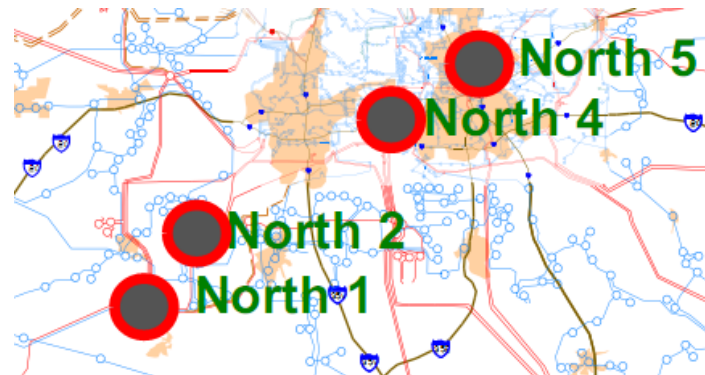
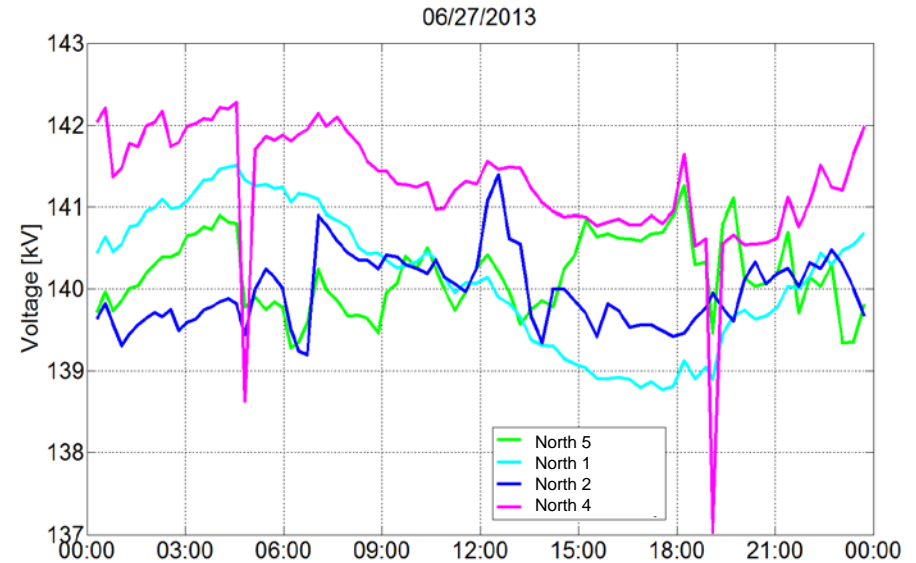
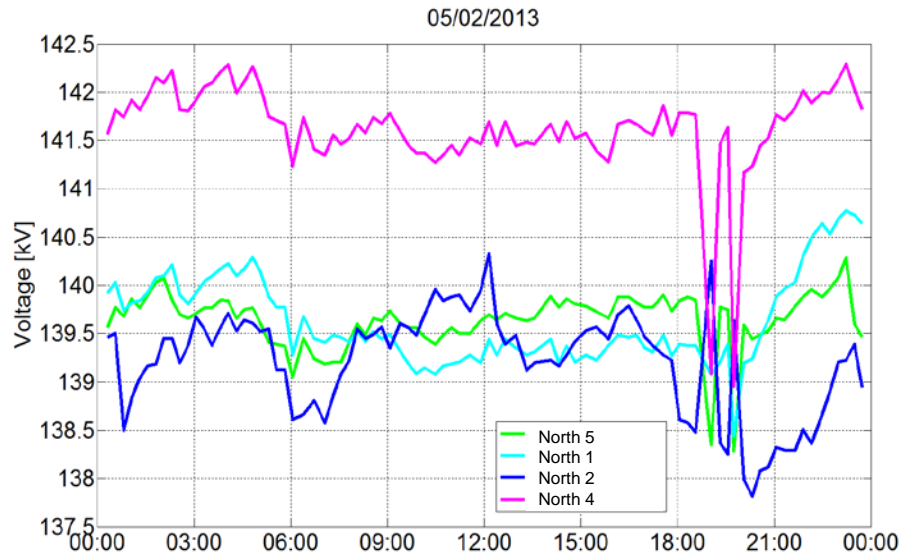
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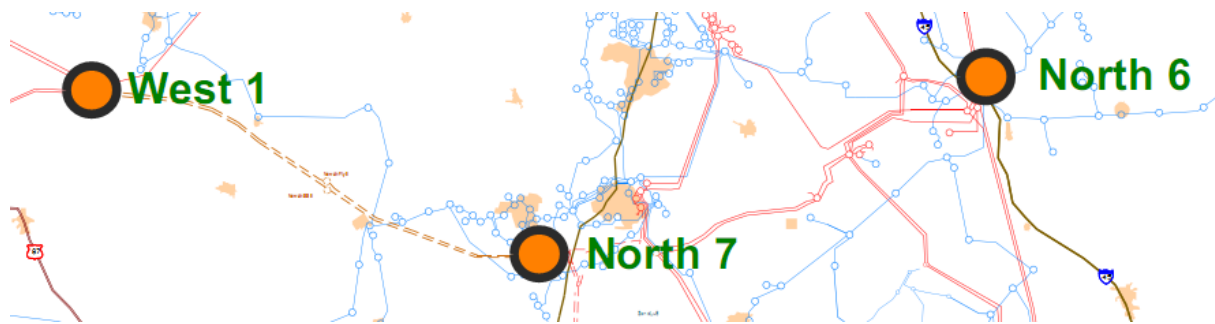
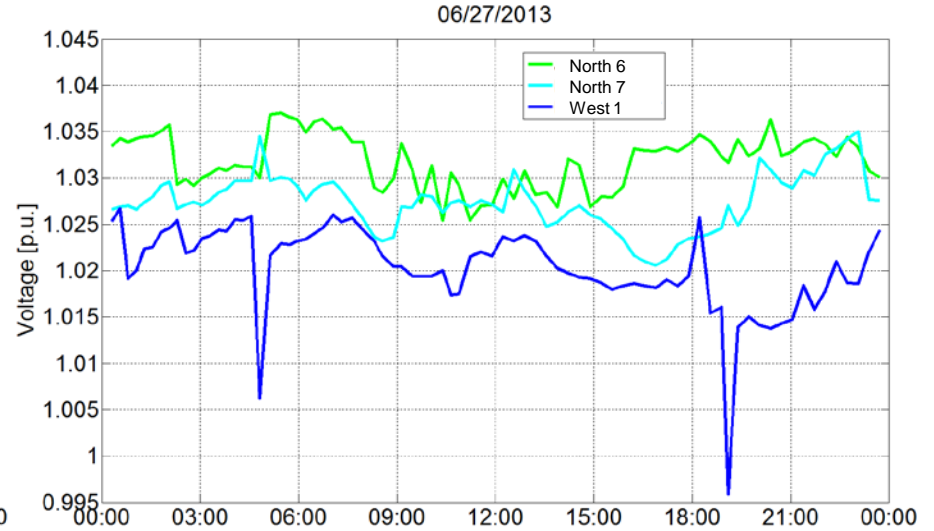
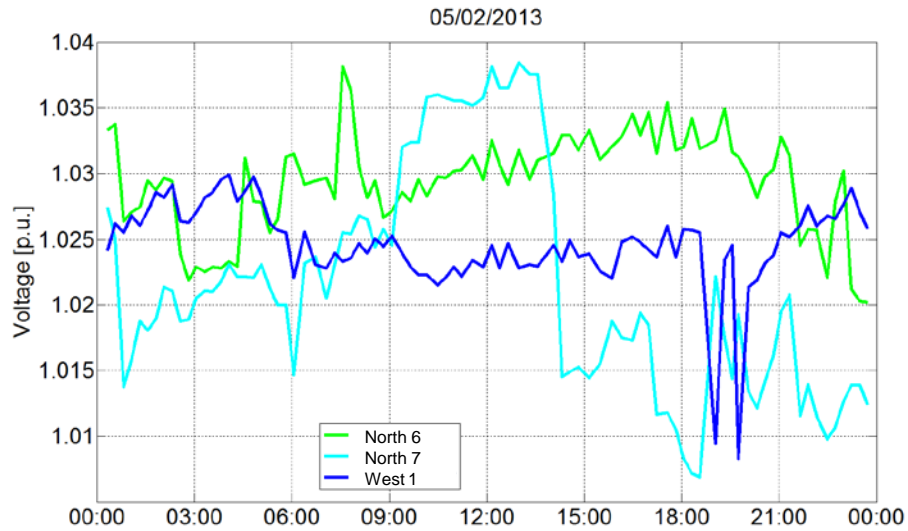
Group 3 - Dallas



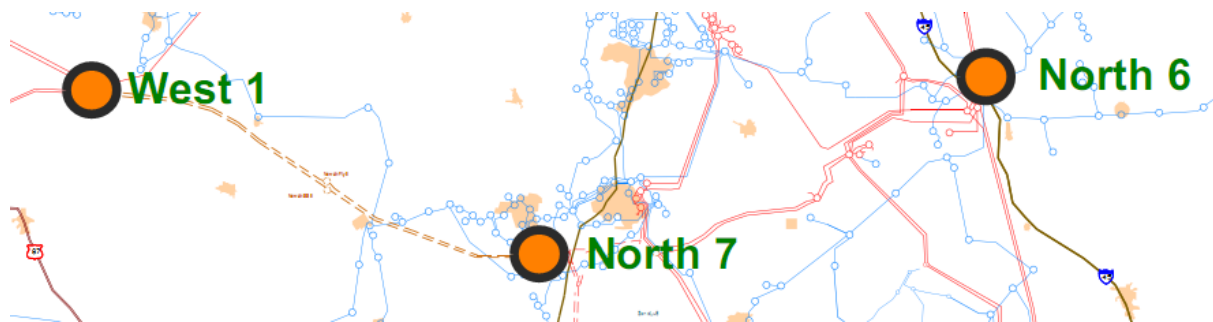
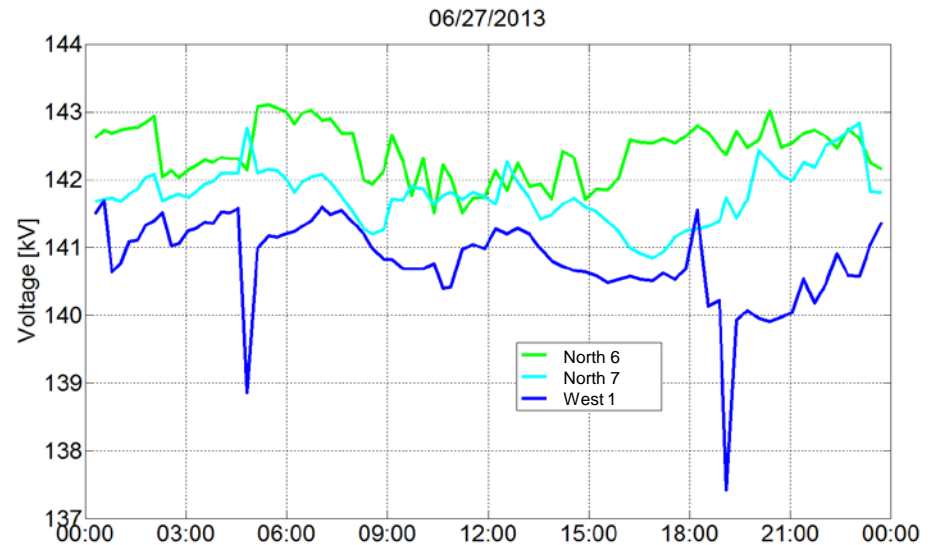
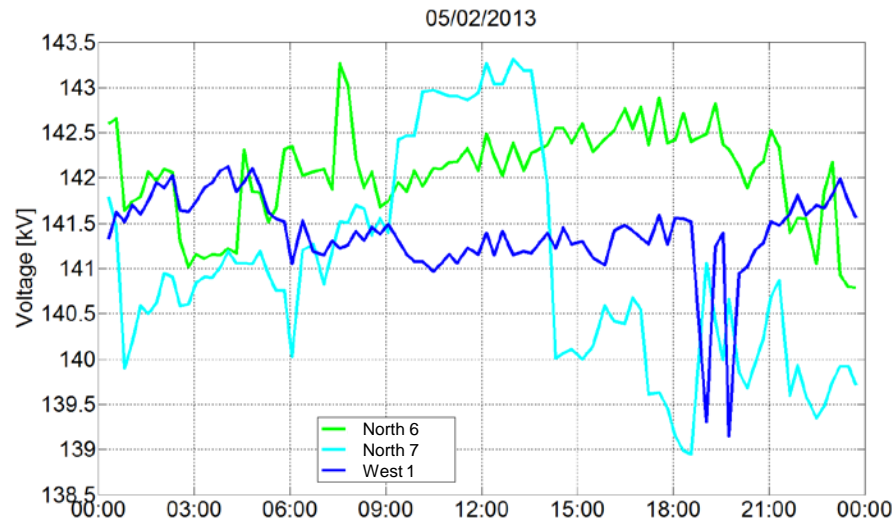
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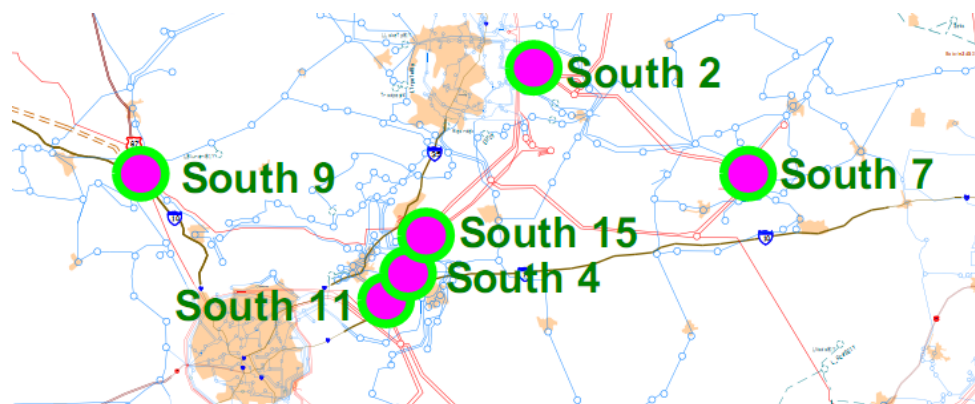
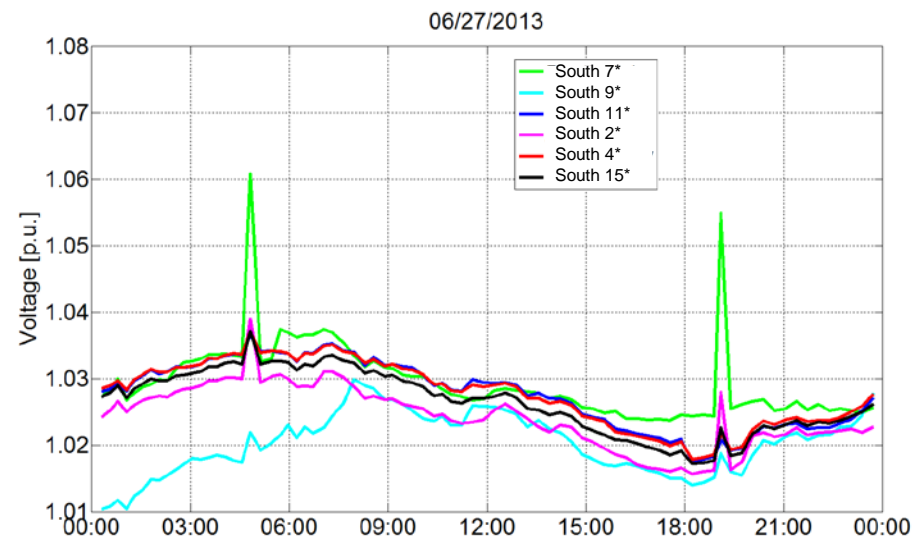
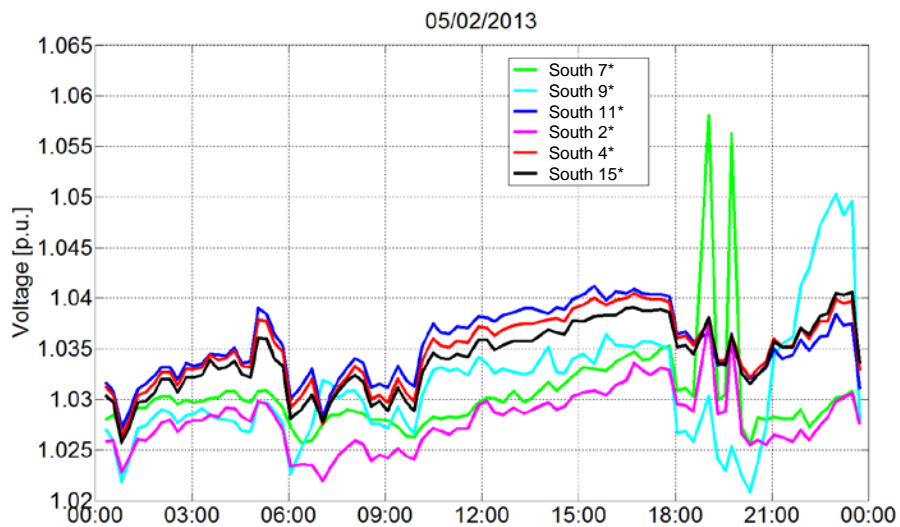
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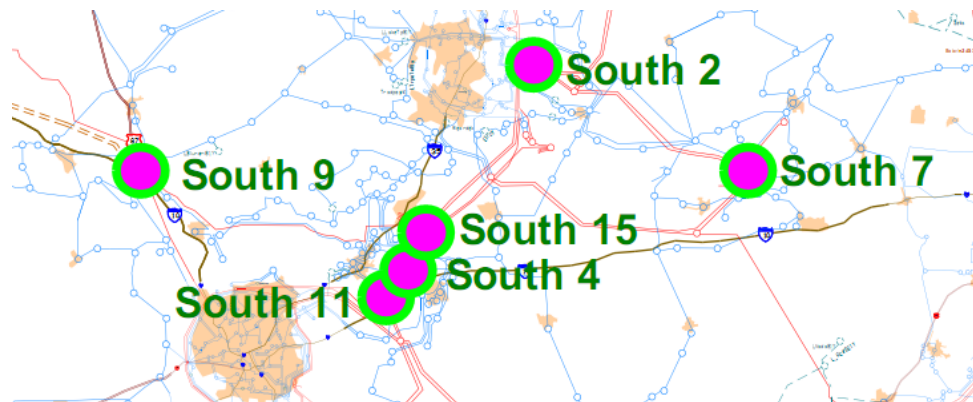
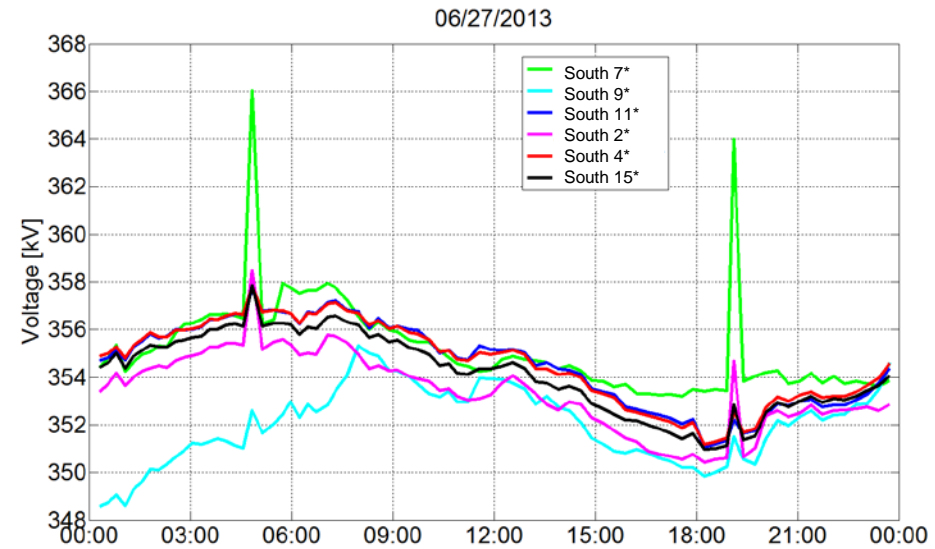
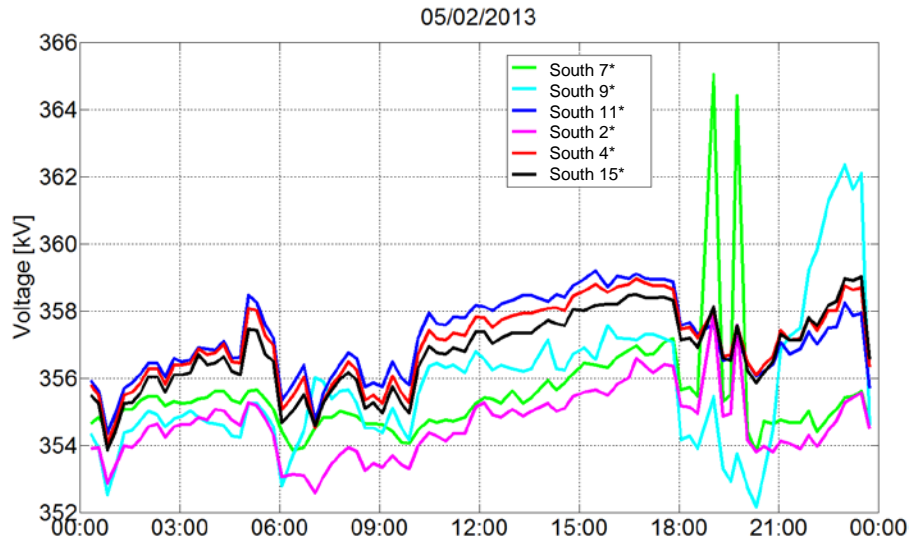
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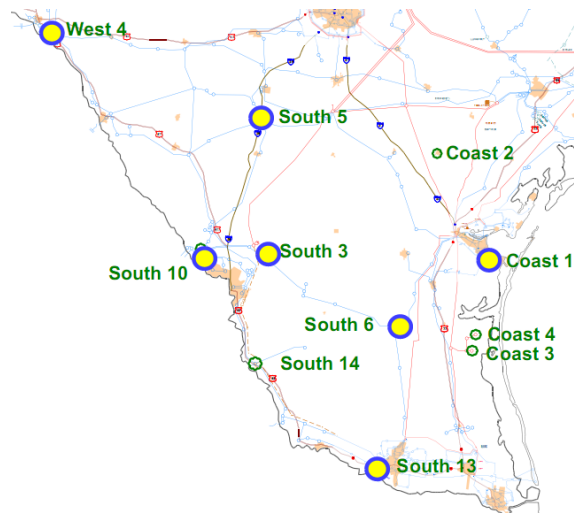
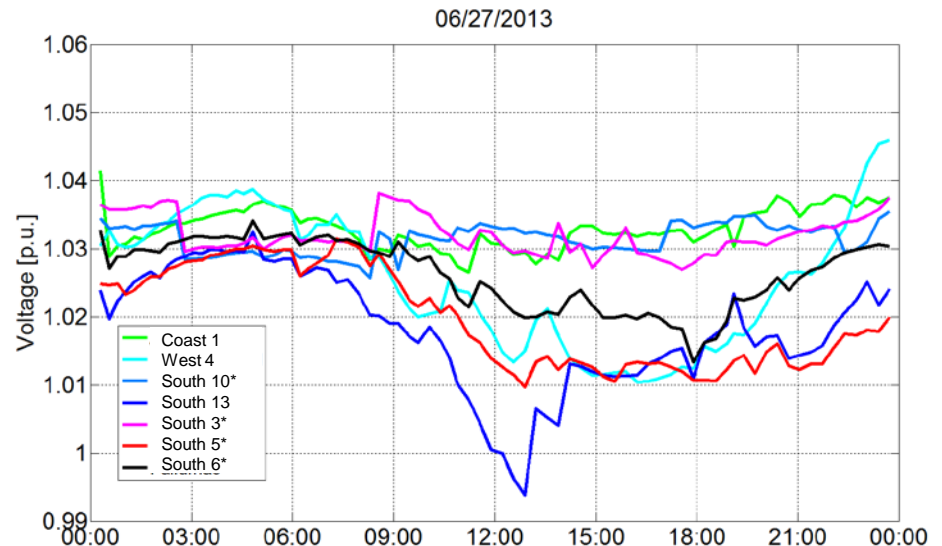
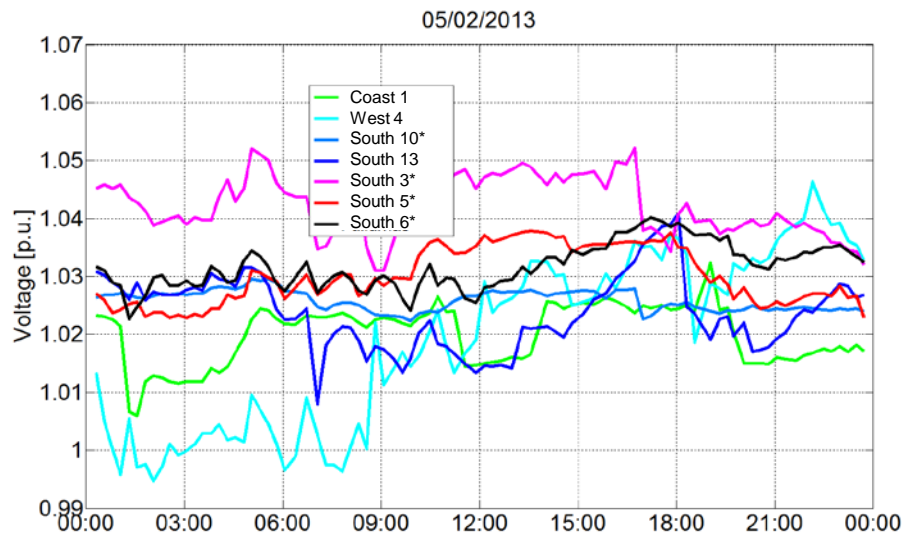
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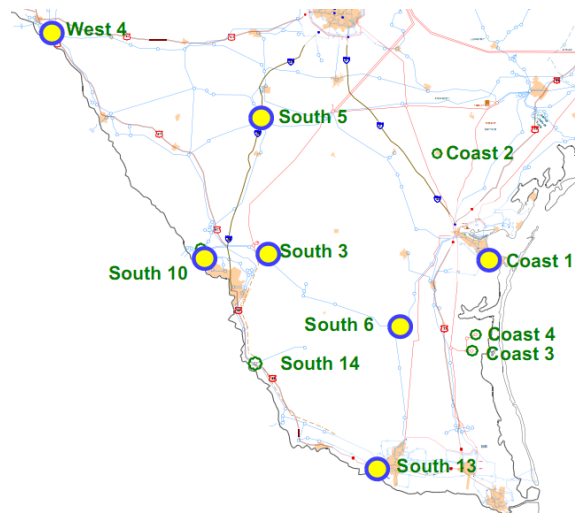
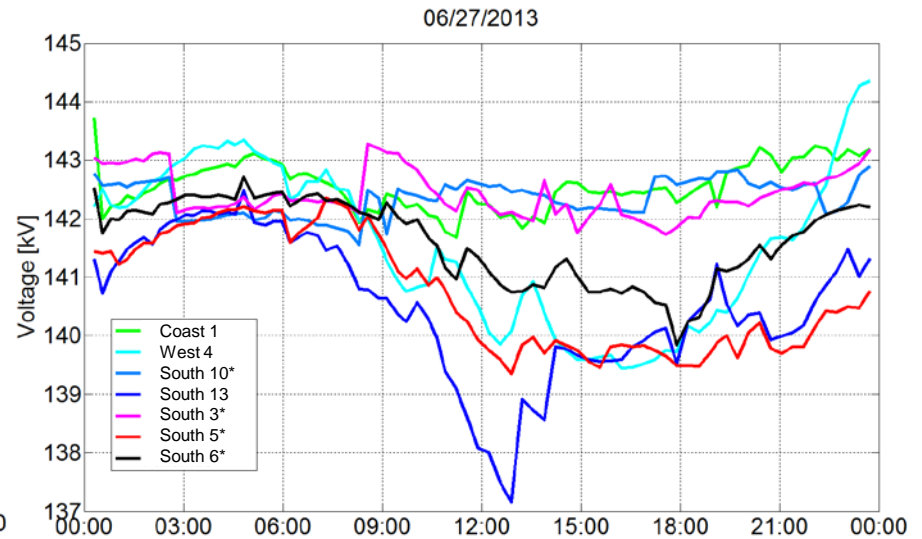
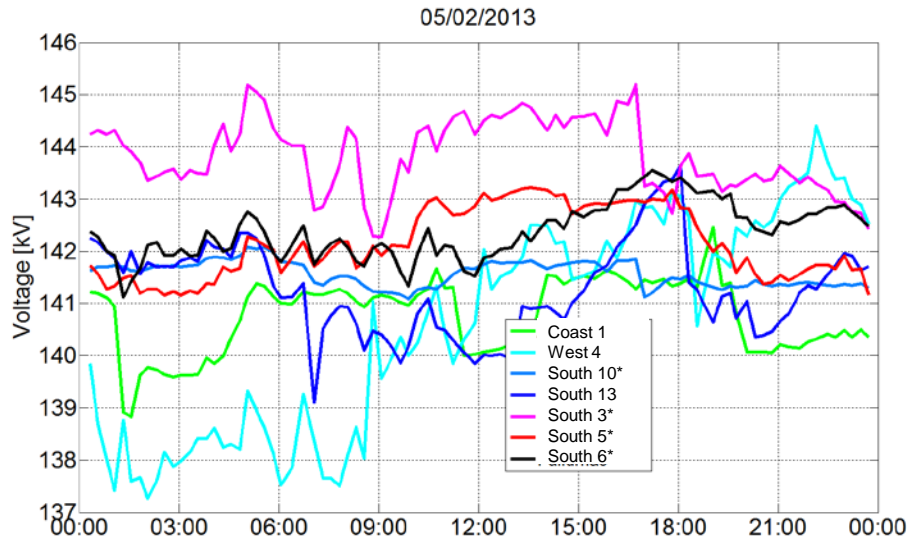
Group 5 – Central East



Group 6 – Valley (South)



Group 6 – Valley (South)



**Attachment 3. Updated Baseline Study
for First Half of 2013**

Baselining Analysis Update #1: January-June 2013 Data

Discovery Across Texas Project

Submitted By:



John Ballance
Romulo Barreno
Ajay Das
Song Xue

October 10, 2013

| | |
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APPENDICES (attached as separate documents)

A, Voltage Magnitude Box Whiskers & Time Duration

B, Voltage Angles, Ref: North 7- Box Whiskers & Time Duration

C, Comparison of Median Values for Angle Difference Pairs (Ref.: North 7) – 2012 vs. 2013

D, Angles Differences Box Whiskers & Time Duration

1. INTRODUCTION

Electric Power Group, LLC (EPG) was awarded contract DE-FOA-0000036 by the Center for the Commercialization of Electric Technologies (CCET) Discovery Across Texas project to provide professional services to, among other things, perform cluster analysis, comparison of phasor data versus state estimator data, and voltage and angle difference baselining. In June 2013 EPG completed a Baselining study using 2012 data that included the following: (1) grouped substations having Phasor Measurement Units (PMUs) which are geographically close to each other and performed a voltage and angle difference analysis for each group (cluster analysis); (2) performed a comparison of voltage and angle differences obtained using phasor measurements versus similar results using state estimator data (phasor vs. state estimator comparison); and, (3) performed a baseline analysis for voltages and angle differences for selected pairs of substations. Alarm limits were established and documented based on the baseline analysis.

A large number of CREZ 345 kV lines are being added to the ERCOT system in 2013 which will alter the results obtained with the 2012 data. Updates are being completed to corroborate the results of the 2012 study for a) Cluster Analysis, b) the Comparison Analysis and c) the Baselining Analysis. Reports with updates for the Cluster and Comparison analysis have been completed and forwarded to ERCOT for their comments. Final reports will be posted in the CCET website.

This third and final report provides results from the update analysis to track the changes in voltage magnitudes and in voltage angles caused by the addition of the several 345 kV lines added to the ERCOT system during the January to June 2013 period.

2. PROJECT SCOPE

A. Baseline analysis for voltage and angle differences

This study update analyzed historical performance of ERCOT grid, using State Estimator data plus phasor data for the January to June 2013 data to identify normal and abnormal voltages and angle limits across the grid. In this analysis, EPG compared the results obtained using 2013 data with those obtained using 2012 data and summarized the differences, if any, due to addition of the 345 kV lines added during the six months of 2013. Activities performed as part of this item:

1. Extract key metric information (i.e., voltage, angles and angle differences).
2. Analyze extracted data and develop baseline understanding of voltage, phase angle and angle difference patterns for key substations and key pairs of substations. Substations were selected based on current or projected availability of PMUs at those substations.
3. Monitor voltages and angle differences (pairs) and develop patterns and statistics in the form of box-whisker plots and load duration curves. Substations selected for analysis of voltages are listed in Table 1 below and pairs of substations selected for analysis of angle differences are listed in Table 2 below.
4. Prepare baselining analysis results for the selected substations and pair of substations as excel spreadsheet and charts, including:
 - a. Voltage statistics (mean, maximum and minimum).
 - b. Voltage phase angle difference statistics (mean, maximum and minimum).
 - c. Voltage and phase angle distribution functions.

5. Develop a comparison table to show the differences in results for voltages and angle differences using 2012 and 2013 data.
6. Prepare baselining analysis summary for discussion with ERCOT and the Synchrophasor Team.

B. Establishing Alarm Limits for Use in Operations

Based on the baselining analysis, EPG will prepare a preliminary recommendation of key substations and angle pairs for monitoring in Real Time Dynamics Monitoring System¹ (RTDMS), and voltage and angle difference alarm settings for use in RTDMS to alert operators when grid stress is approaching limits.

This section will be completed in this report on a preliminary status. A large number of new 345 kV lines will be added to the ERCOT system in the second half of 2013 as part of the CREZ project, changing significantly the distribution of power among the existing and future transmission lines. This will result in changes in limits for voltages, voltage angles, and particularly angle differences. Recommending alarm limits based on only six 2013 months data will only be preliminary. EPG will conduct an analysis with the entire 2013 data to determine the voltage and angle difference limits that will be more likely to represent current and future system conditions. Final Voltage and angle difference limits for use by operators will be recommended once the 2013 analysis is completed.

3. DATA SOURCES

Two sources of data were utilized to perform the study update analysis of voltage and angle differences in the ERCOT network: phasor data and state estimator cases. A description of these sources of data is provided below.

A. Phasor Data

ERCOT provided EPG phasor data for the first six months of 2013 with a resolution of 30-samples per second. EPG performed the following actions before the phasor data provided by ERCOT can be used for statistical analysis:

1. Download the ERCOT data provided in MySQL format
2. Convert ERCOT binary format data into alphanumeric format
3. Convert MySQL data to CSV data files for use in Matlab data analysis programs.
4. Link ERCOT data through the MySQL server to the EPG local ePDC database tool to allow downloading as CSV files to the local computer.
5. Down sample phasor data from 30 SPS to 1 SPS and download it to the local computer for analysis.
6. Apply status flag filtering to perform the first step in data cleaning
7. Develop data filtering algorithms and write code in Matlab to perform the second step of data filtering.
8. Address small data dropouts by interpolation techniques or fill dropouts with blanks.

¹ * Electric Power Group. Built upon GRID-3P platform, US Patent 7,233,843, US Patent 8,060,259, and US Patent 8,401,710. All rights reserved.

This process of data setup, downloading, cleaning and data dropout fixing takes several weeks due to the labor intensive nature of the process.

This process is being automated to reduce the time taken to process the data from the time is received to the time when the data is suitable for analysis. However for this update the manual process was used.

A program was developed by EPG to, once the data is setup, extract the information and compile it into a summary table, and two series of graphs. One graph (box -whisker) shows daily summaries of data, and the other, time duration curves, shows values versus percent time for each study variable. The time duration curves were used to obtain the metric values corresponding to 1% and 99% exceedance (the value which was less than 1% plus inflection or greater than 99% minus inflection).

Phasor Measurement Units (PMUs) Installed and Planned in ERCOT

As of July 1, 2013 there were 41 PMUs installed in 28 locations across the ERCOT service area. Please see Table 1 below.

The baselining study update #3 was completed using data from the first six months of 2013 that included state estimator data analysis for locations for which PMUs are installed and for which PMUs are planned. However, five of locations for which new PMUs are planned are new and therefore there was no state estimator data available for those substations or pair of substations that included any one of these five new substations.

Table 1 – List of PMUs Currently Connected to the ERCOT Network as of July 1, 2013

| # | Company | PMU Signal Name | PMU Station Name | Voltage (kV) | Existing or New Substation |
|----|-----------|-----------------|------------------|--------------|----------------------------|
| 1 | AEP | Line 1 | Coast 1 | 138 | Existing |
| 2 | AEP | Line 1 | Coast 2 | 69 | Existing |
| 3 | AEP | Line 1 | Coast 3 | 345 | Existing |
| 4 | AEP | Line 2 | Coast 3 | 345 | Existing |
| 5 | AEP | Line 1 | Coast 4 | 345 | Existing |
| 6 | AEP | Line 2 | Coast 4 | 345 | Existing |
| 7 | AEP | Line 1 | FarWest 2 | 69 | Existing |
| 8 | AEP | Line 1 | FarWest 9 | 138 | Existing |
| 9 | AEP | Line 1 | South 3 | 138 | Existing |
| 10 | AEP | Line 1 | South 5 | 69 | Existing |
| 11 | AEP | Line 1 | West 10 | 69 | Existing |
| 12 | AEP | Line 1 | West 4 | 138 | Existing |
| 13 | AEP | Line 2 | West 4 | 138 | Existing |
| 14 | AEP | Line 3 | West 4 | 138 | Existing |
| 15 | AEP | Line 4 | West 4 | 138 | Existing |
| 16 | AEP | Line 5 | West 4 | 138 | Existing |
| 17 | AEP | Line1 | West 7 | 138 | Existing |
| 18 | AEP-ETT | Line 1 | West 14 | 345 | Existing |
| 19 | AEP-ETT | Line 2 | West 14 | 345 | Existing |
| 20 | AEP-ETT | Line 3 | West 14 | 345 | Existing |
| 21 | AEP-ETT | Line 4 | West 14 | 345 | Existing |
| 22 | AEP-ETT | Line 5 | West 15 | 345 | Existing |
| 23 | ONCOR | Line 1 | FarWest 4 | 345 | Existing |
| 24 | ONCOR | Line 1 | FarWest 7 | 345 | Existing |
| 25 | ONCOR | Line 1 | FarWest 8 | 138 | Existing |
| 26 | ONCOR | Line 1 | North 1 | 345 | Existing |
| 27 | ONCOR | Line 1 | North 4 | 138 | Existing |
| 28 | ONCOR | Line 1 | North 5 | 138 | Existing |
| 29 | ONCOR | Line 1 | North 6 | 138 | Existing |
| 30 | ONCOR | Line 1 | North 7 | 138 | Existing |
| 31 | ONCOR | Line 1 | West 1 | 345 | Existing |
| 32 | ONCOR | Line 2 | West 1 | 345 | Existing |
| 33 | ONCOR | Line 1 | West 11 | 345 | Existing |
| 34 | ONCOR | Line 1 | West 12 | 345 | Existing |
| 35 | ONCOR | Line 1 | West 2 | 345 | Existing |
| 36 | ONCOR | Line 2 | West 2 | 345 | Existing |
| 37 | ONCOR | Line 1 | West 5 | 345 | Existing |
| 38 | ONCOR | Line 1 | West 6 | 345 | Existing |
| 39 | ONCOR | Line 1 | West 9 | 345 | Existing |
| 40 | Sharyland | Line 1 | South 13 | 138 | Existing |
| 41 | Sharyland | Line 2 | South 13 | 138 | Existing |

B. State Estimator (SE) Data

ERCOT provided EPG SE data for the first six months of 2013. EPG used the Power World simulator provided by ERCOT via Power World, to extract approximately 15,330 SE cases. There were eight days for which SE data was not available as shown below:

Dates for which SE data was not available (First six months of 2013)

| | |
|---------------------|---------------|
| 03/23 to 03/26/2013 | 4 Days |
| 03/28 to 03/31/2013 | <u>4 Days</u> |
| Total | 8 days |

C. Data Availability

Data availability for the phasor data source varied from substation to substation; the summary table of phasor-based results shows the percent availability for each substation or each pair analyzed. As shown in Table A-1, availability varies from substation to substation and ranges from 19.7% for West 1, West 2, West 9, West 12 and West 5 to greater than 95% for thirteen PMUs. No data was reported for North 2 and South 6. Box whisker plots in Appendix A provide a view of data availability on a day by day basis.

For state estimator (SE) data availability, ERCOT produces state estimator cases every 5-minutes for a total of 105,120 possible cases per year. For six months the total number of possible cases is 52,560; EPG received approximately 15,330 cases, which means the availability of SE data for the first six months of 2013 was approximately 29.2 % data availability. SE data availability for these six months improved to approximately double that of the 2012 SE data.

Below a summary of phasor data availability from Table A-1 below for 2012 and for 2013:

| Phasor Data Availability | | | |
|--------------------------|-------------------|-------------------|----------------|
| <u><40%</u> | <u>41% to 60%</u> | <u>61% to 80%</u> | <u>>80%</u> |
| 2013 | | | |
| West 1 | None | Coast 4 | West 10 |
| West 2 | | | West 14 |
| West 9 | | | West 11 |
| West 12 | | | West 6 |
| West 5 | | | North 1 |
| FarWest 2 | | | North 4 |
| South 3 | | | North 5 |
| South 5 | | | North 6 |
| | | | North 7 |
| | | | West 4 |
| | | | Coast 2 |
| | | | Coast 1 |
| | | | Coast 3 |
| | | | South 13 |
| | | | FarWest 4 |
| | | | FarWest 7 |
| | | | FarWest 8 |
| | | | FarWest 9 |
| 2012 | | | |
| West 14 | West 4 | West 11 | West 10 |
| North 1 | Coast 4 | Coast 1 | North 7 |
| Coast 2 | Coast 3 | FarWest 8 | North 2 |
| South 6 | South 13 | | North 4 |
| FarWest 7 | FarWest 9 | | North 5 |
| | | | West 6 |
| | | | North 6 |
| | | | FarWest 4 |

4. BASELINE ANALYSIS FOR VOLTAGE AND ANGLE DIFFERENCES

This baseline analysis update for voltages and angle differences was performed using the phasor data and state estimator data obtained from ERCOT for the first six months of 2013. This data was processed to extract voltage magnitude and voltage angles. Minimum and maximum values for these variables were documented in summary tables; box-whiskers plots and time duration curves were developed for each variable and for each type of data used. Below is an analysis of voltage magnitudes and voltage angles.

B. Methodology

For the pairs selected for study, the following work was performed:

1. Obtain and process phasor data and state estimator data.
2. Extract information to identify max, min and average values from these data sources. Prepare summary tables showing results of all data, including data saved during events.
3. Use phasor and SE data to develop weekly box-whisker graphs and time duration curves for angle differences.
4. Identify limits corresponding to normal operation; excluding events and outages. To exclude extreme values corresponding to outliers and to events, values corresponding to the metrics exceeding 1% and 99% percent of the time were identified for the entire study period, to be identified as normal operating limits. A summary showing these normal operation limits were obtained using phasor and SE data and tabulated in the same table for comparison.
5. Analyze results, identify limits, and report results for each pair selected.

C. Study Approach

Electric Power Group used the following approach:

1. Obtain available phasor data and state estimator data from ERCOT.
2. Extract phasor data and condition it for processing.
3. Solve state estimator cases and save solved cases.
4. Select substations and angle pairs of interest to ERCOT and the synchrophasor team members by choosing substations that have or soon will have PMUs installed.
5. Identify the substations and subsets of substations and pairs for which phasor data is available.
6. Develop statistical charts including time duration curve and box-whisker graphs for voltage magnitudes and angles and for angle pairs.
7. Perform statistical analysis to identify angle differences limits for the pairs selected under all conditions. Summarize angle difference limits.
 - Establish limits for normal operation based on the criteria described in the corresponding methodology. Summarize angle difference limits.
 - The limits for angle differences identified in this report shall be compared with ERCOT's criteria, if any, that apply to angle differences for the paths selected for this study.

5. BASELINE ANALYSIS FOR VOLTAGES MAGNITUDES

A. Substations Identified For Voltage Monitoring

EPG in consultation with ERCOT and the Synchrophasor team identified the following substations for monitoring.

| Table 2 | | | |
|-------------------------------------------|--------------------------|------------------|----------------------|
| SUBSTATIONS FOR VOLTAGE MONITORING | | | |
| | <u>SUBSTATION</u> | <u>kV</u> | <u>REGION</u> |
| 1 | West 10 | 69 | Panhandle |
| 2 | West 14 | 345 | Panhandle |
| 3 | West 1 | 345 | Central |
| 4 | West 2 | 345 | Central |
| 5 | West 9 | 345 | Central |
| 6 | West 11 | 345 | Central |
| 7 | West 12 | 345 | Central |
| 8 | West 5 | 345 | Central |
| 9 | West 6 | 345 | Central |
| 10 | North 1 | 345 | Dallas |
| 11 | North 2 | 138 | Dallas |
| 12 | North 4 | 138 | Dallas |
| 13 | North 5 | 138 | Dallas |
| 14 | North 6 | 138 | East |
| 15 | FarWest 2 | 69 | West Texas |
| 16 | North 7 | 138 | Central-East |
| 17 | West 4 | 138 | SouthWest |
| 18 | Coast 2* | 69 | Valley |
| 19 | Coast 1 | 138 | Valley |
| 20 | South 3 | 138 | Valley |
| 21 | South 5 | 138 | Valley |
| 22 | Coast 4 | 345 | Valley |
| 23 | Coast 3 | 345 | Valley |
| 24 | South 6 | 138 | Valley |
| 25 | South 13 | 138 | Valley |
| 26 | FarWest 4 | 345 | West Texas |
| 27 | FarWest 7 | 345 | West Texas |
| 28 | FarWest 8 | 138 | West Texas |
| 29 | FarWest 9 | 138 | West Texas |
| 30 | West 8* | 345 | Central |
| 31 | South 15* | 345 | Central |
| 32 | South 2* | 345 | Central-East |
| 33 | South 4* | 345 | Central-East |
| 34 | South 7* | 345 | Central-East |
| 35 | South 9* | 345 | Central-East |
| 36 | South 11* | 345 | Central-East |
| 37 | South 10* | 138 | Valley |
| 38 | West 16* | 345 | Panhandle |
| 39 | West 17* | 345 | Panhandle |
| 40 | West 13* | 345 | Panhandle |
| 41 | West 15* | 345 | Panhandle |
| 42 | West 3* | 345 | Central |

B. Analysis of Data and Results

Data availability of SE data for the first six months of 2013 was approximately 29.2 %. SE data availability for these six months improved to approximately double that of the 2012 SE data. Data availability was approximately 13% for all SE cases in 2012. Phasor data availability varies from bus to bus. Data availability for 8 new PMUs is low because these PMUs have been connected to the grid between late April and late May. On the other hand there are 17 PMUs with data availability of 90 or better percent. Two PMUs have no data: North 2 and South 6.

Table A-1 below summarizes the min, max and average values for voltage magnitude for the selected substations. The largest max-min voltage spreads observed were: 28.1 kV at the Coast 4 345 bus and 10.7 kV at the West 4 138 kV bus. The maximum voltages observed were: 368.56 kV at Coast 4 and 148.42 kV at South 3. The highest average voltages observed were: 357.14 kV at West 14 and 142.43 kV at South 6.

As in the case of SE data results, phasor data indicates the highest average 138 kV voltage occurred at North 7 with 142.52 kV. The highest 345 kV voltage occurred at West 2 with 355.98 kV.

The summary shown in Table A-1 below shows the results for all data, including events and outages.

Normal Conditions: EPG made an attempt to exclude values corresponding to events and outages by isolating the values that lie in the lower one percent and in the higher 1 percent at the point of inflection in the time duration curve. The values of voltages obtained this way are considered to be the “normal points of operation” and are summarized in Table A-2 below.

Table A-1 ERCOT DISCOVERY ACROSS TEXAS PROJECT - SUMMARY OF VOLTAGE MAGNITUDES - ALL DATA
JANUARY 1 TO JUNE 30, 2013

| No | Substation | Base kV | Region | PHASOR DATA | | | | | STATE ESTIMATOR DATA | | | |
|----|------------|---------|--------------|-----------------------------------------------------------------------------------------------------------------------|--------|---------|----------------|------------------------|-----------------------------------------------------------------------------------------------------------------------|--------|---------|----------------|
| | | | | Min | Max | Average | Max-Min Spread | Percent Data Available | Min | Max | Average | Max-Min Spread |
| 1 | West 10 | 69 | Panhandle | 67.92 | 73.16 | 70.72 | 5.24 | 97.57 | 67.50 | 72.31 | 69.95 | 4.8 |
| 2 | West 14 | 345 | Panhandle | 344.76 | 362.03 | 355.87 | 17.27 | 94.11 | 351.76 | 364.91 | 357.14 | 13.2 |
| 3 | West 1+ | 345 | Central | 343.66 | 361.94 | 355.66 | 18.28 | 19.65 | 344.48 | 362.80 | 354.24 | 18.3 |
| 4 | West 2+ | 345 | Central | 346.92 | 360.41 | 355.98 | 13.49 | 19.67 | 349.31 | 361.28 | 356.33 | 12.0 |
| 5 | West 9+ | 345 | Central | 341.68 | 361.94 | 352.99 | 20.26 | 19.67 | 345.52 | 364.04 | 354.07 | 18.5 |
| 6 | West 11 | 345 | Central | 346.23 | 358.37 | 352.89 | 12.14 | 97.39 | 349.69 | 358.01 | 353.88 | 8.3 |
| 7 | West 12+ | 345 | Central | 346.40 | 362.85 | 353.92 | 16.45 | 19.67 | 346.38 | 362.22 | 354.20 | 15.8 |
| 8 | West 5+ | 345 | Central | 346.81 | 359.88 | 355.41 | 13.08 | 19.67 | 349.52 | 360.56 | 355.66 | 11.0 |
| 9 | West 6 | 345 | Central | 345.78 | 360.56 | 353.85 | 14.78 | 97.18 | 348.10 | 361.35 | 354.75 | 13.3 |
| 10 | North 1 | 345 | Dallas | 341.37 | 354.89 | 348.91 | 13.51 | 97.75 | 344.31 | 356.76 | 350.19 | 12.5 |
| 11 | North 2 | 138 | Dallas | | | | | 0.00 | 137.30 | 142.43 | 139.81 | 5.1 |
| 12 | North 4 | 138 | Dallas | 137.99 | 144.31 | 142.00 | 6.32 | 97.94 | 138.21 | 143.44 | 141.25 | 5.2 |
| 13 | North 5 | 138 | Dallas | 136.51 | 143.83 | 141.15 | 7.32 | 97.78 | 137.35 | 141.73 | 139.70 | 4.4 |
| 14 | North 6 | 138 | East | 137.24 | 145.80 | 141.92 | 8.56 | 97.78 | 138.77 | 145.95 | 142.02 | 7.2 |
| 15 | FarWest 2+ | 69 | Central-East | 65.54 | 74.88 | 69.97 | 9.34 | 35.58 | 66.02 | 71.79 | 69.39 | 5.8 |
| 16 | North 7 | 138 | Central-East | 138.24 | 145.04 | 142.52 | 6.80 | 95.87 | 137.85 | 145.02 | 141.46 | 7.2 |
| 17 | West 4 | 138 | SouthWest | 134.99 | 148.22 | 142.30 | 13.23 | 91.52 | 136.07 | 146.75 | 141.76 | 10.7 |
| 18 | Coast 2 | 69 | Valley | 65.32 | 72.85 | 70.14 | 7.53 | 96.51 | 66.86 | 73.24 | 70.19 | 6.4 |
| 19 | Coast 1 | 138 | Valley | 138.46 | 144.25 | 142.32 | 5.79 | 97.79 | 137.93 | 144.20 | 141.49 | 6.3 |
| 20 | South 3+ | 138 | Valley | 141.81 | 142.78 | 142.31 | 0.97 | 37.42 | 139.01 | 148.42 | 143.15 | 9.4 |
| 21 | South 5+ | 69 | Valley | 68.44 | 71.73 | 70.51 | 3.29 | 35.44 | 67.44 | 73.46 | 70.67 | 6.0 |
| 22 | Coast 4 | 345 | Valley | 345.00 | 364.31 | 354.16 | 19.31 | 74.61 | 340.48 | 368.56 | 354.50 | 28.1 |
| 23 | Coast 3 | 345 | Valley | 342.88 | 363.81 | 353.50 | 20.93 | 89.29 | 340.38 | 367.87 | 354.23 | 27.5 |
| 24 | South 6 | 138 | Valley | | | | | 0.00 | 139.85 | 144.42 | 142.43 | 4.6 |
| 25 | South 13 | 138 | Valley | 133.92 | 146.88 | 141.67 | 12.96 | 97.29 | 137.02 | 146.43 | 141.92 | 9.4 |
| 26 | FarWest 4 | 345 | West Texas | 347.71 | 357.53 | 354.06 | 9.82 | 93.77 | 350.35 | 358.56 | 354.43 | 8.2 |
| 27 | FarWest 7 | 345 | West Texas | 342.38 | 355.85 | 350.45 | 13.46 | 97.90 | 344.38 | 356.04 | 350.80 | 11.7 |
| 28 | FarWest 8 | 138 | West Texas | 137.51 | 145.47 | 141.95 | 7.96 | 92.56 | 136.85 | 143.52 | 140.44 | 6.7 |
| 29 | FarWest 9 | 138 | West Texas | 135.72 | 144.17 | 141.15 | 8.45 | 95.79 | 137.20 | 144.47 | 140.99 | 7.3 |
| 30 | West 8* | 345 | Central | PMUs are planned for installation at these substations. No phasor data available for the January to June 2013 period. | | | | | 343.21 | 367.11 | 354.68 | 23.9 |
| 31 | South 15* | 345 | Central | | | | | | 349.14 | 363.46 | 356.01 | 14.3 |
| 32 | South 2* | 345 | Central-East | | | | | | 348.28 | 362.39 | 355.02 | 14.1 |
| 33 | South 4* | 345 | Central-East | | | | | | 349.66 | 363.70 | 356.33 | 14.0 |
| 34 | South 7* | 345 | Central-East | | | | | | 348.93 | 361.94 | 355.11 | 13.0 |
| 35 | South 9* | 345 | Central-East | | | | | | 343.34 | 365.32 | 354.50 | 22.0 |
| 36 | South 11* | 345 | Central-East | | | | | | 349.69 | 363.56 | 356.03 | 13.9 |
| 37 | South 10* | 138 | Valley | | | | | | 139.05 | 144.83 | 141.74 | 5.8 |
| 38 | West 16* | 345 | Panhandle | | | | | | These substations were not in service during the January to June 2013 period. No PSSE data available for this period. | | | |
| 39 | West 17* | 345 | Panhandle | | | | | | | | | |
| 40 | West 13* | 345 | Panhandle | | | | | | | | | |
| 41 | West 15* | 345 | Panhandle | | | | | | | | | |
| 42 | West 3* | 345 | Central | | | | | | | | | |

Note: The availability of state estimator cases was in the order of 13%.

The substations with + came on line during the second half of 2012 and the substations with * did not have PMUs installed by June 30, 2013.

| TABLE A-2 CCET DISCOVERY ACROSS TEXAS - LIMITS FOR VOLTAGES - NORMAL CONDITIONS | | | | | | | | | | | | | | | | |
|---------------------------------------------------------------------------------|------------|---------|-------------------------------------------------------------------------------------------------------------------------------------------|------------|----------------|-----------------------------------------------------------------------------------------------------------------------|-------------|---------|-----------|--------|----------|---------------|-----------|-----------------------------------------|------------|----------------|
| | | | Phasor Data | | | State Estimator Data - January 1 To June 30, 2013 | | | | | | | | SE Data | | |
| No. | Bus Names | Base kV | Normal Min | Normal Max | Max-Min Spread | Normal Min-100% | 100% or POI | 99% Min | 99% - POI | 1% Max | 1% + POI | Normal Max-0% | 0% or POI | Normal Min | Normal Max | Max-Min Spread |
| 1 | West 10 | 69 | 69.36 | 71.72 | 2.36 | 68.03 | 99.90% | 68.49 | 98.90% | 71.43 | 1.03% | 72.16 | 0.03% | 68.49 | 71.43 | 2.94 |
| 2 | West 14 | 345 | 350.90 | 359.80 | 8.90 | 352.21 | 99.96% | 353.16 | 98.96% | 359.96 | 4.56% | 360.24 | 3.56% | 353.16 | 359.96 | 6.79 |
| 3 | West 1+ | 345 | 349.30 | 360.10 | 10.80 | 345.37 | 99.93% | 347.23 | 98.93% | 359.39 | 1.06% | 361.04 | 0.06% | 347.23 | 359.39 | 12.16 |
| 4 | West 2+ | 345 | 351.60 | 358.70 | 7.10 | 350.68 | 99.83% | 351.91 | 98.83% | 359.42 | 1.04% | 360.71 | 0.04% | 351.91 | 359.42 | 7.51 |
| 5 | West 9+ | 345 | 349.00 | 357.10 | 8.10 | 346.84 | 99.84% | 348.40 | 98.84% | 358.12 | 5.40% | 358.40 | 4.40% | 348.40 | 358.12 | 9.72 |
| 6 | West 11 | 345 | 350.20 | 355.50 | 5.30 | 350.24 | 99.92% | 351.23 | 98.92% | 356.31 | 1.03% | 357.73 | 0.03% | 351.23 | 356.31 | 5.08 |
| 7 | West 12+ | 345 | 350.30 | 358.10 | 7.80 | 347.00 | 99.97% | 349.25 | 98.97% | 358.99 | 1.07% | 361.46 | 0.07% | 349.25 | 358.99 | 9.73 |
| 8 | West 5+ | 345 | 351.10 | 358.30 | 7.20 | 349.87 | 99.97% | 351.73 | 98.97% | 358.85 | 1.05% | 359.92 | 0.05% | 351.73 | 358.85 | 7.13 |
| 9 | West 6 | 345 | 350.40 | 357.00 | 6.60 | 349.75 | 99.79% | 350.84 | 98.79% | 358.62 | 1.07% | 359.63 | 0.07% | 350.84 | 358.62 | 7.79 |
| 10 | North 1 | 345 | 345.30 | 353.10 | 7.80 | 344.76 | 99.92% | 345.59 | 98.92% | 354.38 | 5.22% | 354.54 | 4.22% | 345.59 | 354.38 | 8.79 |
| 11 | North 2 | 138 | | | | 137.68 | 99.93% | 138.30 | 98.93% | 141.23 | 1.01% | 142.37 | 0.01% | 138.30 | 141.23 | 2.93 |
| 12 | North 4 | 138 | 140.45 | 143.30 | 2.85 | 139.78 | 96.38% | 139.92 | 95.38% | 142.66 | 1.02% | 143.40 | 0.02% | 139.92 | 142.66 | 2.75 |
| 13 | North 5 | 138 | 139.65 | 142.50 | 2.85 | 138.66 | 95.51% | 138.75 | 94.51% | 140.95 | 1.04% | 141.46 | 0.04% | 138.75 | 140.95 | 2.20 |
| 14 | North 6 | 138 | 140.15 | 143.75 | 3.60 | 139.20 | 99.94% | 140.03 | 98.94% | 143.97 | 3.98% | 144.20 | 2.98% | 140.03 | 143.97 | 3.95 |
| 15 | FarWest 2+ | 69 | 68.34 | 71.98 | 3.64 | 67.38 | 99.35% | 67.65 | 98.35% | 71.12 | 1.03% | 71.72 | 0.03% | 67.65 | 71.12 | 3.47 |
| 16 | North 7 | 138 | 140.51 | 143.99 | 3.48 | 139.83 | 95.49% | 139.96 | 94.49% | 143.50 | 2.85% | 143.68 | 1.85% | 139.96 | 143.50 | 3.54 |
| 17 | West 4 | 138 | 138.60 | 145.69 | 7.09 | 136.88 | 99.91% | 138.05 | 98.91% | 145.00 | 1.11% | 145.81 | 0.11% | 138.05 | 145.00 | 6.96 |
| 18 | Coast 2 | 69 | 68.39 | 71.76 | 3.37 | 67.39 | 99.89% | 68.24 | 98.89% | 72.05 | 1.07% | 72.59 | 0.07% | 68.24 | 72.05 | 3.81 |
| 19 | Coast 1 | 138 | 140.70 | 143.41 | 2.71 | 139.92 | 95.18% | 139.97 | 94.18% | 143.32 | 1.09% | 143.85 | 0.09% | 139.97 | 143.32 | 3.34 |
| 20 | South 3+ | 138 | 142.14 | 142.43 | 0.29 | 139.51 | 99.97% | 140.38 | 98.97% | 146.17 | 2.00% | 146.66 | 1.00% | 140.38 | 146.17 | 5.79 |
| 21 | South 5+ | 69 | 69.55 | 71.36 | 1.81 | 69.27 | 96.97% | 69.38 | 95.97% | 72.22 | 2.77% | 72.31 | 1.77% | 69.38 | 72.22 | 2.84 |
| 22 | Coast 4 | 345 | 349.00 | 359.70 | 10.70 | 347.74 | 97.17% | 348.28 | 96.17% | 360.05 | 3.75% | 360.67 | 2.75% | 348.28 | 360.05 | 11.77 |
| 23 | Coast 3 | 345 | 348.30 | 359.10 | 10.80 | 347.50 | 97.35% | 348.10 | 96.35% | 359.72 | 3.96% | 360.30 | 2.96% | 348.10 | 359.72 | 11.62 |
| 24 | South 6 | 138 | | | | 140.52 | 99.75% | 140.89 | 98.75% | 143.78 | 1.05% | 144.15 | 0.05% | 140.89 | 143.78 | 2.89 |
| 25 | South 13 | 138 | 139.30 | 143.70 | 4.40 | 138.33 | 99.83% | 139.03 | 98.83% | 144.48 | 1.08% | 145.39 | 0.08% | 139.03 | 144.48 | 5.45 |
| 26 | FarWest 4 | 345 | 351.06 | 355.93 | 4.87 | 350.49 | 99.97% | 351.55 | 98.97% | 355.95 | 4.02% | 356.13 | 3.02% | 351.55 | 355.95 | 4.40 |
| 27 | FarWest 7 | 345 | 346.30 | 353.80 | 7.50 | 345.15 | 99.93% | 346.45 | 98.93% | 354.42 | 1.10% | 355.34 | 0.10% | 346.45 | 354.42 | 7.97 |
| 28 | FarWest 8 | 138 | 140.06 | 143.80 | 3.74 | 138.71 | 97.69% | 138.86 | 96.69% | 142.40 | 1.08% | 143.15 | 0.08% | 138.86 | 142.40 | 3.54 |
| 29 | FarWest 9 | 138 | 138.80 | 143.13 | 4.33 | 137.25 | 99.95% | 138.49 | 98.95% | 143.13 | 1.07% | 143.60 | 0.07% | 138.49 | 143.13 | 4.64 |
| 30 | West 8* | 345 | PMUs are planned for installation at these substations. No phasor data available for the January to June 2013 period. | | | 346.09 | 99.65% | 346.73 | 98.65% | 359.16 | 1.25% | 359.88 | 0.25% | 346.73 | 359.16 | 12.43 |
| 31 | South 15* | 345 | | | | 350.08 | 99.90% | 351.37 | 98.90% | 359.87 | 1.05% | 361.16 | 0.05% | 351.37 | 359.87 | 8.49 |
| 32 | South 2* | 345 | | | | 349.04 | 99.92% | 350.24 | 98.92% | 359.31 | 1.07% | 360.89 | 0.07% | 350.24 | 359.31 | 9.06 |
| 33 | South 4* | 345 | | | | 350.14 | 99.93% | 351.64 | 98.93% | 360.15 | 1.03% | 361.39 | 0.03% | 351.64 | 360.15 | 8.51 |
| 34 | South 7* | 345 | | | | 350.05 | 99.90% | 351.53 | 98.90% | 358.15 | 3.39% | 358.38 | 2.39% | 351.53 | 358.15 | 6.62 |
| 35 | South 9* | 345 | | | | 343.88 | 99.95% | 346.03 | 98.95% | 361.44 | 1.09% | 364.22 | 0.09% | 346.03 | 361.44 | 15.40 |
| 36 | South 11* | 345 | | | | 350.69 | 99.74% | 351.56 | 98.74% | 359.62 | 1.04% | 360.70 | 0.04% | 351.56 | 359.62 | 8.05 |
| 37 | South 10* | 138 | | | | 139.23 | 99.93% | 139.87 | 98.93% | 143.81 | 1.09% | 144.41 | 0.09% | 139.87 | 143.81 | 3.94 |
| 38 | West 16* | 345 | | | | These substations were not in service during the January to June 2013 period. No PSSE data available for this period. | | | | | | | | No PSSE data available for this period. | | |
| 39 | West 17* | 345 | | | | | | | | | | | | | | |
| 40 | West 13* | 345 | | | | | | | | | | | | | | |
| 41 | West 15* | 345 | | | | | | | | | | | | | | |
| 42 | West 3* | 345 | | | | | | | | | | | | | | |
| Note: | | | The eight substations with + came on line late in June 2013 and the substations with * did not have PMUs installed in first half of 2013. | | | | | | | | | | | | | |

Note that the greater Max-Min voltage spreads now occur at South 9 345 kV with and West 4 138 kV buses with 15.4 and 6.95 kV respectively.

For both the SE data and the phasor data, box-whisker plots and time duration curves were developed for each of the substations listed above and were used to obtain the values in the Table A-2 above. Summaries of SE-based voltage pairs with their corresponding box-whisker and time duration curves as well as summaries of phasor-based voltage pairs with their corresponding box-whisker and time duration curves are presented in Appendix A.

C. Observations

- i. Data availability: the availability for state estimator data was approximately 29.2%; the availability for phasor data was greater overall but varied from 19.7% at West 12 to 97.94% at North 4. Nineteen PMUs out of twenty nine substations had data availability greater than 70%.
- ii. Both phasor data and state estimator data point to West 4 and Coast 4 has having the highest voltage and voltage spreads in their class. Voltages at these substations are more volatile than at the other substations. Note that Coast 3 also has high voltage spread but South 13 and South 6, which are in the neighborhood have a much lower spread.
- iii. Fifteen substations out of a total of forty one show voltage spreads of higher than 15 kV and 24 substations show voltage spreads higher than 10 kV.
- iv. Voltage spreads for normal conditions went down by up to 5 kV (phasor) from those under all conditions.

D. **Comparison of Alarm Limits for Voltages – 2012 vs. 2013 Data**

The limits summarized in the two tables above reflect system performance after the addition of the CREZ lines in the first six months of 2013. EPG has prepared a comparison table to indentify the changes in voltages due to the addition of the new 345 kV lines. Table 3 show a comparison of voltage magnitude averages as well as Max-Min spreads for 2012 and 2013.

Table 3 ERCOT DISCOVERY ACROSS TEXAS PROJECT - VOLTAGE MAGNITUDES - ALL DATA
COMPARISON 2012 vs. 2013 - JANUARY 1 TO JUNE 30

| No | Substation | Base kV | Region | STATE ESTIMATOR DATA - 2012 | | | | STATE ESTIMATOR DATA-2013 | | | |
|----|------------|---------|--------------|-----------------------------------------------------------------------------------------------------------------------|--------|---------|----------------|-----------------------------------------------------------------------------------------------------------------------|--------|---------|----------------|
| | | | | Min | Max | Average | Max-Min Spread | Min | Max | Average | Max-Min Spread |
| 1 | West 10 | 69 | Panhandle | 68.03 | 73.13 | 71.03 | 5.1 | 67.15 | 74.15 | 71.89 | 7.0 |
| 2 | West 14 | 345 | Panhandle | 348.07 | 362.15 | 355.89 | 14.1 | 351.76 | 364.91 | 357.14 | 13.2 |
| 3 | West 1+ | 345 | Central | | | | | 344.48 | 362.80 | 354.24 | 18.3 |
| 4 | West 2+ | 345 | Central | 348.17 | 366.11 | 357.56 | 17.9 | 349.31 | 361.28 | 356.33 | 12.0 |
| 5 | West 9+ | 345 | Central | 346.93 | 365.53 | 357.31 | 18.6 | 345.52 | 364.04 | 354.07 | 18.5 |
| 6 | West 11 | 345 | Central | 347.73 | 361.28 | 355.14 | 13.6 | 349.69 | 358.01 | 353.88 | 8.3 |
| 7 | West 12+ | 345 | Central | 346.17 | 364.70 | 356.50 | 18.5 | 346.38 | 362.22 | 364.20 | 15.8 |
| 8 | West 5+ | 345 | Central | 347.83 | 365.77 | 356.95 | 17.9 | 349.52 | 360.56 | 355.66 | 11.0 |
| 9 | West 6 | 345 | Central | 346.73 | 364.08 | 356.46 | 17.4 | 348.10 | 361.35 | 354.75 | 13.3 |
| 10 | North 1 | 345 | Dallas | 340.69 | 353.14 | 347.70 | 12.5 | 344.31 | 356.76 | 350.19 | 12.5 |
| 11 | North 2 | 138 | Dallas | 138.30 | 141.79 | 140.37 | 3.5 | 137.30 | 142.43 | 139.81 | 5.1 |
| 12 | North 4 | 138 | Dallas | 138.55 | 144.07 | 142.13 | 5.5 | 138.21 | 143.44 | 141.25 | 5.2 |
| 13 | North 5 | 138 | Dallas | 137.34 | 141.75 | 139.80 | 4.4 | 137.35 | 141.73 | 139.70 | 4.4 |
| 14 | North 6 | 138 | East | 138.88 | 143.53 | 141.59 | 4.7 | 138.77 | 145.95 | 142.02 | 7.2 |
| 15 | FarWest 2+ | 69 | Central-East | 67.32 | 71.53 | 69.27 | 4.2 | 66.02 | 71.79 | 69.39 | 5.8 |
| 16 | North 7 | 138 | Central-East | 139.23 | 144.46 | 142.21 | 5.2 | 137.85 | 145.02 | 141.46 | 7.2 |
| 17 | West 4 | 138 | SouthWest | 132.52 | 151.74 | 141.17 | 19.2 | 136.07 | 146.75 | 141.76 | 10.7 |
| 18 | Coast 2 | 69 | Valley | 66.58 | 71.94 | 69.61 | 5.4 | 66.86 | 73.24 | 70.19 | 6.4 |
| 19 | Coast 1 | 138 | Valley | 138.69 | 143.18 | 141.20 | 4.5 | 137.93 | 144.20 | 141.49 | 6.3 |
| 20 | South 3+ | 138 | Valley | 138.25 | 146.38 | 142.11 | 8.1 | 139.01 | 148.42 | 143.15 | 9.4 |
| 21 | South 5+ | 69 | Valley | 67.14 | 72.67 | 70.56 | 5.5 | 67.44 | 73.46 | 70.67 | 6.0 |
| 22 | Coast 4 | 345 | Valley | 341.96 | 363.32 | 353.39 | 21.4 | 340.48 | 368.56 | 354.50 | 28.1 |
| 23 | Coast 3 | 345 | Valley | 341.62 | 363.39 | 353.27 | 21.8 | 340.38 | 367.87 | 354.23 | 27.5 |
| 24 | South 6 | 138 | Valley | 139.61 | 144.00 | 142.03 | 4.4 | 139.85 | 144.42 | 142.43 | 4.6 |
| 25 | South 13 | 138 | Valley | 137.74 | 145.48 | 141.72 | 7.7 | 137.02 | 146.43 | 141.92 | 9.4 |
| 26 | FarWest 4 | 345 | West Texas | 349.45 | 360.63 | 355.81 | 11.2 | 350.35 | 358.56 | 354.43 | 8.2 |
| 27 | FarWest 7 | 345 | West Texas | 345.38 | 360.59 | 352.86 | 15.2 | 344.38 | 356.04 | 350.80 | 11.7 |
| 28 | FarWest 8 | 138 | West Texas | 135.41 | 142.35 | 139.39 | 6.9 | 136.85 | 143.52 | 140.44 | 6.7 |
| 29 | FarWest 9 | 138 | West Texas | 136.10 | 146.85 | 141.20 | 10.8 | 137.20 | 144.47 | 140.99 | 7.3 |
| 30 | West 8* | 345 | Central | | | | | 343.21 | 367.11 | 354.68 | 23.9 |
| 31 | South 15* | 345 | Central | 349.49 | 359.46 | 354.82 | 10.0 | 349.14 | 363.46 | 356.01 | 14.3 |
| 32 | South 2* | 345 | Central-East | 348.80 | 358.52 | 354.07 | 9.7 | 348.28 | 362.39 | 355.02 | 14.1 |
| 33 | South 4* | 345 | Central-East | 349.17 | 359.83 | 354.80 | 10.7 | 349.66 | 363.70 | 356.33 | 14.0 |
| 34 | South 7* | 345 | Central-East | 348.59 | 359.04 | 354.33 | 10.5 | 348.93 | 361.94 | 355.11 | 13.0 |
| 35 | South 9* | 345 | Central-East | 343.17 | 358.90 | 352.20 | 15.7 | 343.34 | 365.32 | 354.50 | 22.0 |
| 36 | South 11* | 345 | Central-East | 348.52 | 358.46 | 354.22 | 9.9 | 349.69 | 363.56 | 356.03 | 13.9 |
| 37 | South 10* | 138 | Valley | 138.59 | 144.49 | 141.46 | 5.9 | 139.05 | 144.83 | 141.74 | 5.8 |
| 38 | West 16* | 345 | Panhandle | These substations were not in service during the January to June 2012 period. No PSSE data available for this period. | | | | These substations were not in service during the January to June 2013 period. No PSSE data available for this period. | | | |
| 39 | West 17* | 345 | Panhandle | | | | | | | | |
| 40 | West 13* | 345 | Panhandle | | | | | | | | |
| 41 | West 15* | 345 | Panhandle | | | | | | | | |
| 42 | West 3* | 345 | Central | | | | | | | | |

Note: The substations with + came on-line during the second half of 2012 and the substations with * did not have PMUs installed by June 30, 2013.

Observation of Table 3 shows a few substations had voltage spreads with difference greater than 5 kV but the average voltages were not that much different. Several substations experienced slightly higher voltage magnitudes in 2013 than in 2012. No clear trends were observed for voltage magnitudes from this summary table.

E. Analysis of the Box-whisker voltage plots - 2013 Data

- a. For one day, January 10, the voltage at West 14, went up by about 5 kV and again in mid March the voltage at this substations went up again by about 3 kV. By mid April the voltage at this substation came down and was operating mostly in the 354 to 358 kV range.
- b. The voltage at West 9 fluctuates within a 16 kV range; the voltages at this substation reached the lowest points during the month of May.
- c. West 12 substation also experienced voltages operating within a wide range of 12 kV.
- d. The voltage at North 1 behaved somewhat wildly during the first six months of 2013. During the month of April the voltage jumped up 4 kV and operated in the neighborhood of 354 kV for most of the month. By the end of May the voltage came down drastically to around 347 kV and then day by day went up and ended up operating around 354 kV by the end of June.
- e. The North 4 box-whisker plot exhibits what appears to be a large number of outlier points in the lower part of the plot.
- f. The voltage at North 6 was steady during the months of January to April and then at the beginning of May jumped up a couple of kVs before coming down again in late June.
- g. Around the 20th of February the voltage at FarWest 2 dipped almost 4 kV to 64 kV.
- h. Voltage fluctuations at Coast 2 were more pronounced during May and June.
- i. The voltage at Coast 1 came down around 1.5 kV by the middle of March before going back up to 142.5 kV by the end of June.
- j. South 3: the voltage at this substation operated within a wide margin from 139.5 to 148 kV. In mid January the voltage went up to as high as 148 kV before coming down to around 143kV. In June the voltage operated in the 141 to 143 kV range.
- k. South 5: the voltage took a dip to around 68 kV around the 12 of February.
- l. Coast 4: the voltage spiked up to about 368 kV in late January and spiked down to about 341 kV in early March.
- m. Coast 3: similar to Coast 4, the voltage spiked up to about 368 kV in late January and spiked down to about 341 kV in early March.
- n. FarWest 4: one spike up (358.5 kV) and three spikes down (340.5 kV)
- o. FarWest 7: operates within a 10 kV range (345 to 355 kV) with large daily swings.
- p. South 2: operated within a 12 kV range (349 to 361 kV)
- q. South 9: voltage fluctuated within a wide range from 344 to 365 kV with a spike up around March 2nd.
- r. South 10: the median changes constantly with the few spikes up and down.

6. BASELINE ANALYSIS FOR VOLTAGE ANGLES (REFERENCE: North 7 Bus)

D. Substations Identified for Voltage Angle Analysis

The following substations were selected for voltage angle analysis; the substation selected as reference was North 7.

| Table 4: SUBSTATIONS FOR VOLTAGE ANGLE MONITORING | | | |
|--------------------------------------------------------------|-------------------|-----------|---------------|
| # | SUBSTATION | kV | REGION |
| 1 | West 10 | 69 | Panhandle |
| 2 | West 14 | 345 | Panhandle |
| 3 | West 1 | 345 | Central |
| 4 | West 2 | 345 | Central |
| 5 | West 9 | 345 | Central |
| 6 | West 11 | 345 | Central |
| 7 | West 12 | 345 | Central |
| 8 | West 5 | 345 | Central |
| 9 | West 6 | 345 | Central |
| 10 | North 1 | 345 | Dallas |
| 11 | North 2 | 138 | Dallas |
| 12 | North 4 | 138 | Dallas |
| 13 | North 5 | 138 | Dallas |
| 14 | North 6 | 138 | East |
| 15 | FarWest 2 | 69 | West Texas |
| 16 | West 4 | 138 | SouthWest |
| 17 | Coast 2 | 69 | Valley |
| 18 | Coast 1 | 138 | Valley |
| 19 | South 3 | 138 | Valley |
| 20 | South 5 | 138 | Valley |
| 21 | Coast 4 | 345 | Valley |
| 22 | Coast 3 | 345 | Valley |
| 23 | South 6 | 138 | Valley |
| 24 | South 13 | 138 | Valley |
| 25 | FarWest 4 | 345 | West Texas |
| 26 | FarWest 7 | 345 | West Texas |
| 27 | FarWest 8 | 138 | West Texas |
| 28 | FarWest 9 | 138 | West Texas |
| 29 | West 8+ | 345 | Central |
| 30 | South 15+ | 345 | Central |
| 31 | South 2+ | 345 | Central-East |
| 32 | South 4+ | 345 | Central-East |
| 33 | South 7+ | 345 | Central-East |
| 34 | South 9+ | 345 | Central-East |
| 35 | South 11+ | 345 | Central-East |
| 36 | South 10+ | 138 | Valley |
| 37 | West 16* | 345 | Panhandle |
| 38 | West 17* | 345 | Panhandle |
| 39 | West 13* | 345 | Panhandle |
| 40 | West 15* | 345 | Panhandle |
| 41 | West 3* | 345 | Central |

+ Means no PMUs installed as of June 30, 2013

* .Means substations were not in service as of June 30, 2013

E. Summary of Results - All data included

The voltage angle results obtained from all data available: all solved SE cases, and all phasor data, are summarized in Table B-1 below.

These results were obtained using all data available including event and outage conditions; under these conditions, voltage angles would be expected to be larger than under normal conditions because during event and outages conditions the angles tend to increase to reflect the changes in system conditions or changes in system configuration. The maximum Max-min spreads observed were 104.1 degrees for FarWest 9 138 kV substation and 90.8 degrees for FarWest 4 345 kV substation. Note also that the substations close to the wind farms in groups 1 and 2 shown in yellow have over 80 degrees Max-Min spreads and the angles for these substations are positive more than 74% of the time, that is, the power flows from these substations towards North 7 most of the time. These spreads are lower than those maximum spreads found in the 2012 base lining study; this is expected since the grid is now tighter with the addition of several 345 kV lines.

| Table B-1: CCET DISCOVERY ACROSS TEXAS- BASELINING ANALYSIS UPDATE - VOLTAGE ANGLES - ALL CONDITIONS (Reference: North 7) | | | | | | | | | | | | |
|---------------------------------------------------------------------------------------------------------------------------|-------------------------|---------|---------------------------------------------------------------------------|--------|---------|------------------|------------------|--------------------------------------------------------------------|-------|---------|------------------|----------------|
| No | Angle Pair FROM - TO | Base kV | Phasor Data - 1/1/13 to 6/30/13 | | | | | State Estimator Data - 1/1/13 to 6/30/13 | | | | |
| | | | Min | Max | Average | Percent Positive | % Data Available | Min | Max | Average | Percent Positive | Max-Min Spread |
| 1 | West 10 | 69 | -40.45 | 70.08 | 10.62 | 66.29 | 96.70 | -32.72 | 28.12 | -4.27 | 33.51% | 60.8 |
| 2 | West 14 | 345 | -21.43 | 37.65 | 8.48 | 85.89 | 92.23 | -18.97 | 32.46 | 7.54 | 87.87% | 51.4 |
| 3 | West 1+ | 345 | -15.92 | 33.07 | 6.01 | 81.58 | 19.63 | -24.06 | 56.73 | 7.01 | 79.85% | 80.8 |
| 4 | West 2+ | 345 | -10.52 | 27.27 | 8.20 | 78.33 | 19.66 | -26.31 | 55.73 | 9.24 | 77.77% | 82.0 |
| 5 | West 9+ | 345 | -12.37 | 33.07 | 9.43 | 80.11 | 19.67 | -27.52 | 57.18 | 10.15 | 78.59% | 84.7 |
| 6 | West 11 | 345 | -30.72 | 62.04 | 9.68 | 74.37 | 97.23 | -29.63 | 58.64 | 9.98 | 74.94% | 88.3 |
| 7 | West 12+ | 345 | -12.39 | 33.07 | 9.42 | 79.97 | 19.67 | -27.52 | 57.19 | 10.15 | 78.59% | 84.7 |
| 8 | West 5+ | 345 | -11.58 | 29.97 | 9.00 | 79.10 | 19.67 | -26.90 | 55.73 | 9.92 | 78.04% | 82.6 |
| 9 | West 6 | 345 | -28.43 | 60.40 | 10.00 | 77.52 | 97.04 | -27.52 | 57.20 | 10.33 | 78.31% | 84.7 |
| 10 | North 1 | 345 | -12.33 | 26.41 | 6.76 | 92.69 | 97.55 | -11.84 | 25.11 | 6.96 | 94.67% | 37.0 |
| 11 | North 2 | 138 | | | | | | -24.64 | 10.28 | -6.48 | 4.76% | 34.9 |
| 12 | North 4 | 138 | -18.85 | 14.43 | -2.80 | 24.37 | 97.74 | -17.84 | 13.60 | -2.18 | 28.33% | 31.4 |
| 13 | North 5 | 138 | -20.35 | 14.99 | -4.81 | 13.69 | 97.59 | -19.99 | 11.56 | -4.58 | 13.75% | 31.6 |
| 14 | North 6 | 138 | -8.67 | 17.99 | 4.44 | 87.88 | 97.56 | -10.70 | 17.25 | 3.78 | 83.10% | 28.0 |
| 15 | FarWest 2+ | 69 | -160.79 | -78.92 | -122.15 | 0.00 | 35.31 | -28.75 | 10.39 | -7.82 | 5.64% | 39.1 |
| 16 | West 4 | 138 | -32.04 | 18.95 | -5.08 | 25.21 | 90.40 | -29.75 | 16.94 | -4.93 | 25.46% | 46.7 |
| 17 | Coast 2 | 69 | -31.96 | 24.48 | -6.28 | 23.13 | 95.66 | -31.46 | 24.53 | -6.13 | 24.26% | 56.0 |
| 18 | Coast 1 | 138 | -36.75 | 50.83 | 2.59 | 57.68 | 96.44 | -35.89 | 44.81 | 2.16 | 56.10% | 80.7 |
| 19 | South 3+ | 138 | -31.70 | 50.46 | -2.67 | 39.89 | 36.98 | -31.00 | 32.95 | -0.06 | 50.88% | 64.0 |
| 20 | South 5+ | 138 | -25.25 | 14.95 | -10.34 | 7.44 | 35.05 | -29.57 | 14.27 | -7.40 | 10.35% | 43.8 |
| 21 | Coast 4 | 345 | -39.53 | 49.50 | 3.63 | 61.24 | 64.51 | -33.40 | 50.50 | 5.20 | 64.94% | 83.9 |
| 22 | Coast 3 | 345 | -34.93 | 46.65 | 4.51 | 62.39 | 87.52 | -33.40 | 49.75 | 4.87 | 64.07% | 83.2 |
| 23 | South 6 | 138 | | | | | | -34.06 | 37.63 | -0.63 | 48.46% | 71.7 |
| 24 | South 13 | 138 | -54.93 | 50.00 | -1.74 | 46.40 | 96.71 | -51.34 | 46.50 | -1.67 | 46.57% | 97.8 |
| 25 | FarWest 4 | 345 | -32.57 | 60.00 | 10.32 | 74.15 | 93.61 | -30.54 | 60.24 | 10.74 | 75.08% | 90.8 |
| 26 | FarWest 7 | 345 | -35.49 | 59.79 | 8.23 | 70.29 | 97.71 | -34.04 | 55.59 | 8.26 | 70.86% | 89.6 |
| 27 | FarWest 8 | 138 | -44.79 | 54.96 | 0.00 | 49.63 | 92.37 | -42.34 | 51.30 | 0.43 | 50.69% | 93.6 |
| 28 | FarWest 9 | 138 | -44.80 | 59.98 | 5.27 | 57.85 | 94.74 | -40.92 | 63.14 | 5.76 | 59.32% | 104.1 |
| 29 | West 8* | 345/138 | No phasor data available for these substations for the first half of 2013 | | | | | -11.24 | 27.27 | 8.87 | 78.96% | 38.5 |
| 30 | South 15* | 345/138 | | | | | | -20.01 | 15.63 | -0.60 | 42.74% | 35.6 |
| 31 | South 2* | 345/138 | | | | | | -16.81 | 18.32 | 1.85 | 67.25% | 35.1 |
| 32 | South 4* | 345/138 | | | | | | -20.47 | 16.74 | -0.81 | 41.31% | 37.2 |
| 33 | South 7* | 345/138 | | | | | | -17.89 | 21.19 | 3.23 | 73.36% | 39.1 |
| 34 | South 9* | 345/138 | | | | | | -19.23 | 16.37 | -1.17 | 37.69% | 35.6 |
| 35 | South 11* | 345/138 | | | | | | -21.08 | 17.78 | -1.03 | 40.50% | 38.9 |
| 36 | South 10* | 138 | | | | | | -35.17 | 24.79 | -7.31 | 18.65% | 60.0 |
| 37 | West 16* | 345/138 | | | | | | Substations not in service during the January to June 2013 period. | | | | |
| 38 | West 17* | 345/138 | | | | | | | | | | |
| 39 | West 13* | 345/138 | | | | | | | | | | |
| 40 | West 15* | 345/138 | | | | | | | | | | |
| 41 | West 3* | 345/138 | | | | | | | | | | |

Note: The eight substations with + came on line late in June of 2013 and the substations with * did not have PMUs installed in the first half of 2013.

F. Summary of Results – Normal Conditions (events and outages excluded)

The voltage angle results obtained from excluding extreme values based on analysis of the box-whiskers plots and time duration curves are shown in Table B-2 below.

| Table B-2: CCET DISCOVERY ACROSS TEXAS- BASELINING ANALYSIS UPDATE- VOLTAGE ANGLES - NORMAL CONDITIONS | | | | | | | | | | | | | | | | |
|--------------------------------------------------------------------------------------------------------|-------------------------|---------|----------------------------------------------------|--------------|-----------------------|--------------------------------------------------------------------|-----------------------------|------------------------------------|---------------------------------|----------------------------------|-------------------------------|------------------------------|---------------------------|-----------------------------------------------------------------------|--------------|-------------------|
| (Reference: 138 kV North 7) | | | | | | | | | | | | | | | | |
| DATA ANALYSIS RESULTS | | | | | | | | | | | | | | | | |
| | | | Phasor-Normal | | | State Estimator Data - 1/1/13 to 6/30/13 | | | | | | | | SE Data-Normal | | |
| No | Angle Pair FROM - TO | Base kV | Min Angle | Max Angle | Max- Min Spread | Min Angle at POI or 100% | Percent (POI or 100%) | Min Angle at 99% or POI - 1% | Percent (99% or POI - 1%) | Max Angle at 1% or POI +1% | Percent (1% or POI +1%) | Max Angle at POI or 0% | Percent (POI or 0%) | Min Angle | Max Angle | Max-Min Spread |
| 1 | West 10 | 69 | -36.57 | 53.16 | 89.7 | -27.69 | 99.04% | -21.75 | 98.04% | 46.66 | 1.04% | 59.74 | 0.04% | -27.69 | 59.74 | 87.4 |
| 2 | West 14 | 345 | -17.56 | 33.24 | 50.8 | -17.62 | 99.98% | -12.26 | 98.98% | 23.68 | 1.00% | 32.46 | 0.00% | -17.62 | 32.46 | 50.1 |
| 3 | West 1+ | 345 | -6.64 | 18.88 | 25.5 | -22.84 | 99.96% | -16.95 | 98.96% | 32.04 | 1.06% | 40.40 | 0.06% | -22.84 | 40.40 | 63.2 |
| 4 | West 2+ | 345 | -9.30 | 26.74 | 36.0 | -24.97 | 99.96% | -18.79 | 98.96% | 35.97 | 1.02% | 46.03 | 0.02% | -24.97 | 46.03 | 71.0 |
| 5 | West 9+ | 345 | -11.67 | 32.00 | 43.7 | -26.00 | 99.97% | -19.57 | 98.97% | 37.84 | 1.02% | 48.04 | 0.02% | -26.00 | 48.04 | 74.0 |
| 6 | West 11 | 345 | -27.34 | 49.97 | 77.3 | -27.67 | 99.96% | -21.07 | 98.96% | 38.74 | 1.02% | 48.96 | 0.02% | -27.67 | 48.96 | 76.6 |
| 7 | West 12+ | 345 | -11.67 | 31.98 | 43.7 | -26.02 | 99.97% | -19.53 | 98.97% | 37.87 | 1.01% | 49.60 | 0.01% | -26.02 | 49.60 | 75.6 |
| 8 | West 5+ | 345 | -10.42 | 29.30 | 39.7 | -25.31 | 99.95% | -19.11 | 98.95% | 36.85 | 1.02% | 45.85 | 0.02% | -25.31 | 45.85 | 71.2 |
| 9 | West 6 | 345 | -25.24 | 49.50 | 74.7 | -26.00 | 99.97% | -19.60 | 98.97% | 38.02 | 1.02% | 47.23 | 0.02% | -26.00 | 47.23 | 73.2 |
| 10 | North 1 | 345 | -10.05 | 21.40 | 31.5 | -9.90 | 99.98% | -5.63 | 98.98% | 17.45 | 1.02% | 23.22 | 0.02% | -9.90 | 23.22 | 33.1 |
| 11 | North 2 | 138 | | | | -22.69 | 99.98% | -17.51 | 98.98% | 2.67 | 1.02% | 8.80 | 0.02% | -22.69 | 8.80 | 31.5 |
| 12 | North 4 | 138 | -17.65 | 9.92 | 27.6 | -16.29 | 99.95% | -12.02 | 98.95% | 7.27 | 1.03% | 11.37 | 0.03% | -16.29 | 11.37 | 27.7 |
| 13 | North 5 | 138 | -18.07 | 10.01 | 28.1 | -19.39 | 99.96% | -14.37 | 98.96% | 6.15 | 1.02% | 11.55 | 0.02% | -19.39 | 11.55 | 30.9 |
| 14 | North 6 | 138 | -7.60 | 14.69 | 22.3 | -10.25 | 99.98% | -5.15 | 98.98% | 12.28 | 1.02% | 16.90 | 0.02% | -10.25 | 16.90 | 27.1 |
| 15 | FarWest 2+ | 69 | -155.40 | -85.97 | 69.4 | -26.74 | 99.98% | -20.54 | 98.98% | 3.53 | 1.02% | 9.79 | 0.02% | -26.74 | 9.79 | 36.5 |
| 16 | West 4 | 138 | -26.08 | 14.73 | 40.8 | -27.94 | 99.98% | -21.80 | 98.98% | 10.48 | 1.04% | 15.35 | 0.04% | -27.94 | 15.35 | 43.3 |
| 17 | Coast 2 | 69 | -30.28 | 18.03 | 48.3 | -31.46 | 99.99% | -25.46 | 98.99% | 14.11 | 1.02% | 24.20 | 0.02% | -31.46 | 24.20 | 55.7 |
| 18 | Coast 1 | 138 | -31.72 | 35.82 | 67.5 | -33.15 | 99.89% | -25.49 | 98.89% | 29.77 | 1.02% | 41.56 | 0.02% | -33.15 | 41.56 | 74.7 |
| 19 | South 3+ | 138 | -27.42 | 28.39 | 55.8 | -28.67 | 99.98% | -22.67 | 98.98% | 22.53 | 1.02% | 31.96 | 0.02% | -28.67 | 31.96 | 60.6 |
| 20 | South 5+ | 138 | -23.39 | 12.95 | 36.3 | -28.42 | 99.98% | -20.97 | 98.98% | 8.05 | 1.03% | 13.85 | 0.03% | -28.42 | 13.85 | 42.3 |
| 21 | Coast 4 | 345 | -32.91 | 40.48 | 73.4 | -32.78 | 99.98% | -25.35 | 98.98% | 35.72 | 1.02% | 49.95 | 0.02% | -32.78 | 49.95 | 82.7 |
| 22 | Coast 3 | 345 | -30.16 | 42.98 | 73.1 | -33.05 | 99.98% | -25.43 | 98.98% | 35.08 | 1.02% | 49.06 | 0.02% | -33.05 | 49.06 | 82.1 |
| 23 | South 6 | 138 | | | | -33.67 | 99.98% | -26.96 | 98.98% | 25.31 | 1.00% | 37.63 | 0.00% | -33.67 | 37.63 | 71.3 |
| 24 | South 13 | 138 | -44.74 | 42.58 | 87.3 | -48.36 | 99.98% | -36.11 | 98.98% | 33.56 | 1.02% | 45.94 | 0.02% | -48.36 | 45.94 | 94.3 |
| 25 | FarWest 4 | 345 | -28.82 | 51.33 | 80.2 | -28.52 | 99.96% | -21.56 | 98.96% | 39.99 | 1.02% | 50.47 | 0.02% | -28.52 | 50.47 | 79.0 |
| 26 | FarWest 7 | 345 | -30.90 | 46.24 | 77.1 | -32.14 | 99.97% | -23.88 | 98.97% | 35.70 | 1.02% | 46.35 | 0.02% | -32.14 | 46.35 | 78.5 |
| 27 | FarWest 8 | 138 | -40.57 | 41.77 | 82.3 | -40.77 | 99.95% | -32.53 | 98.95% | 29.79 | 1.02% | 41.50 | 0.02% | -40.77 | 41.50 | 82.3 |
| 28 | FarWest 9 | 138 | -40.43 | 55.18 | 95.6 | -39.76 | 99.97% | -32.70 | 98.97% | 41.94 | 1.02% | 52.47 | 0.02% | -39.76 | 52.47 | 92.2 |
| 29 | West 8* | 345 | No Phasor Data Available the first half of 2013 | | | -11.13 | 99.97% | -8.94 | 98.97% | 25.71 | 1.22% | 26.73 | 0.22% | -11.13 | 26.73 | 37.9 |
| 30 | South 15* | 345 | | | | -18.31 | 99.97% | -13.47 | 98.97% | 11.50 | 1.00% | 15.63 | 0.00% | -18.31 | 15.63 | 33.9 |
| 31 | South 2* | 345 | | | | -14.96 | 99.99% | -9.91 | 98.99% | 12.54 | 1.01% | 18.19 | 0.01% | -14.96 | 18.19 | 33.2 |
| 32 | South 4* | 345 | | | | -18.97 | 99.98% | -14.11 | 98.98% | 12.02 | 1.04% | 16.00 | 0.04% | -18.97 | 16.00 | 35.0 |
| 33 | South 7* | 345 | | | | -15.85 | 99.98% | -10.16 | 98.98% | 15.29 | 1.00% | 21.19 | 0.00% | -15.85 | 21.19 | 37.0 |
| 34 | South 9* | 345 | | | | -17.70 | 99.95% | -13.10 | 98.95% | 9.98 | 1.02% | 16.01 | 0.02% | -17.70 | 16.01 | 33.7 |
| 35 | South 11* | 345 | | | | -19.91 | 99.98% | -14.72 | 98.98% | 12.29 | 1.05% | 16.74 | 0.05% | -19.91 | 16.74 | 36.6 |
| 36 | South 10* | 138 | | | | -34.65 | 99.98% | -26.92 | 98.98% | 13.60 | 1.02% | 21.84 | 0.02% | -34.65 | 21.84 | 56.5 |
| 37 | West 16* | 345 | | | | Substations not in service during the January to June 2013 period. | | | | | | | | PSSE data not available during the January to June 2013 period. | | |
| 38 | West 17* | 345 | | | | | | | | | | | | | | |
| 39 | West 13* | 345 | | | | | | | | | | | | | | |
| 40 | West 15* | 345 | | | | | | | | | | | | | | |
| 41 | West 3* | 345 | | | | | | | | | | | | | | |

Note: The substations with + came on line during the second half of 2012 and the substations with * did not have PMUs installed in the first half 2013.

NOTE: the PMUs noted with a + have very limited amount of phasor data because these PMUs were connected to the ERCOT grid in the later weeks of the study period.

Summaries of voltage angle pairs with their corresponding box-whisker and time duration curves based on state estimator data and based on phasor data are presented in Appendix B.

G. Observations

1. Voltage angles vary over a wide range for several substations. The largest variation of 94.3 degrees (-48.36 to 45.94) occurred at South 13 138 kV substation. Among the 345 kV substations, the largest angle variation over the first six months of 2013 occurred at Coast 4 with a range of 82.7 (-32.78 to 49.95) degrees.

2. The largest variations occurred among the substations in the western part of the state namely: FarWest 7, West 11, West 6, FarWest 8, FarWest 9, FarWest 4, West 2, West 9 and West 5.
3. The next largest angle variation occurred in the south part of the state namely: South 13, Coast 3, Coast 4 and Coast 1.
4. The two largest normal angles observed were at FarWest 4 and FarWest 9 with 50.47 and 52.47 degrees respectively.

7. COMPARISON OF VOLTAGE ANGLES (Ref.: North 7) – 2012 vs. 2013

A. Goal

EPG performed a comparison of voltage angles for a number of pairs to determine the effect the new CREZ lines had on the performance of the ERCOT grid. Following are the results of that comparison

B. Pairs Selected for Comparison

Twelve pairs were selected to compare voltage angles between 2012 and 2013 conditions. They listed in Table 5 below.

TABLE 5: ANGLE PAIRS FOR VOLTAGE ANGLE COMPARISON

| # | Substation A | Substation B | From Region | To Region |
|----|--------------|--------------|-------------|--------------|
| 1 | West 10 | North 7 | Panhandle | Central-East |
| 2 | West 14 | North 7 | Panhandle | Central-East |
| 3 | West 11 | North 7 | Central | Central-East |
| 4 | West 6 | North 7 | West Texas | Central-East |
| 5 | North 4 | North 7 | Dallas | Central-East |
| 6 | North 5 | North 7 | Dallas | Central-East |
| 7 | North 6 | North 7 | East | Central-East |
| 8 | Coast 1 | North 7 | Valley | Central-East |
| 9 | Coast 3 | North 7 | Valley | Central-East |
| 10 | FarWest 4 | North 7 | West Texas | Central-East |
| 11 | FarWest 8 | North 7 | West Texas | Central-East |
| 12 | FarWest 9 | North 7 | West Texas | Central-East |

C. Procedure

This comparison was completed using median values to avoid as much as possible distortions in the comparison. Phasor data was collected for the six months of 2012 and 2013 and daily median values plotted for each pair for the six months period.

In addition to these daily median graphs, Box-whisker plots were developed for each pair using median values. These Box-whisker plots produced a new median for the six month periods for 2012 and for 2013.

D. Results

The results of the comparison are shown in Appendix C. Results for 2012 are shown in blue and results for 2013 are shown in red. Some pairs had not enough data in 2012; in these cases we completed the comparison using only the periods of time when data was available for BOTH years.

The daily median graphs show that for most of the days the 2013 median voltage angle difference (relative to North 7) was lower than the 2012 median. The overall six-month Box-whisker plots were more conclusive: the median of the medians for every pair for 2013 was lower than the median of the medians for 2012. See Table 6 below.

TABLE 6: VOLTAGE ANGLE COMPARISON (Median) - 2012 vs. 2013

| # | Substation A | Substation B | VOLTAGE ANGLE - MEDIAN | | Difference |
|----|--------------|--------------|---------------------------|-------|------------|
| | | | 2012 | 2013 | |
| 1 | West 10 | North 7 | 21.70 | 12.30 | -9.40 |
| 2 | West 14 | North 7 | 10.24 | 8.51 | -1.73 |
| 3 | West 11 | North 7 | 15.67 | 10.20 | -5.47 |
| 4 | West 6 | North 7 | 16.44 | 9.00 | -7.44 |
| 5 | North 4 | North 7 | 2.50 | -2.40 | -4.90 |
| 6 | North 5 | North 7 | 0.91 | -4.57 | -5.48 |
| 7 | North 6 | North 7 | 7.38 | 4.65 | -2.73 |
| 8 | Coast 1 | North 7 | 7.33 | 2.85 | -4.48 |
| 9 | Coast 3 | North 7 | 4.57 | 1.28 | -3.29 |
| 10 | FarWest 4 | North 7 | 17.03 | 9.51 | -7.52 |
| 11 | FarWest 8 | North 7 | 4.60 | 2.15 | -2.45 |
| 12 | FarWest 9 | North 7 | 10.92 | 10.01 | -0.91 |

Review of this table shows the following:

- i. The largest difference occurred on the West 10, FarWest 4 and West 6 to North 7 pairs. All these substations are located in West Texas.
- ii. The FarWest 9 and West 14 to North 7 pairs had the lowest reduction: 0.91 and 1.73 degrees respectively.
- iii. Coast 1 and Coast 3 to North 7 pairs had reductions of 4.48 and 3.29 degrees. These reductions seem significant though EPG is not aware of new lines added between the Valley and the North 7 area in the first half of 2013.

E. Conclusions

- i. The new transmission lines added since July, 2012, have tighten the ERCOT system which is reflected in the reduced voltage angle differences for the twelve pairs being lower in 2013 than in 2012.
- ii. These voltage angles will likely change again with the addition of the 345 kV CREZ transmission lines planned for the second half of 2013.
- iii. This analysis should be revised once all CREZ lines are added to the ERCOT system by the end of 2013.

8. BASELINE ANALYSIS FOR ANGLE DIFFERENCES

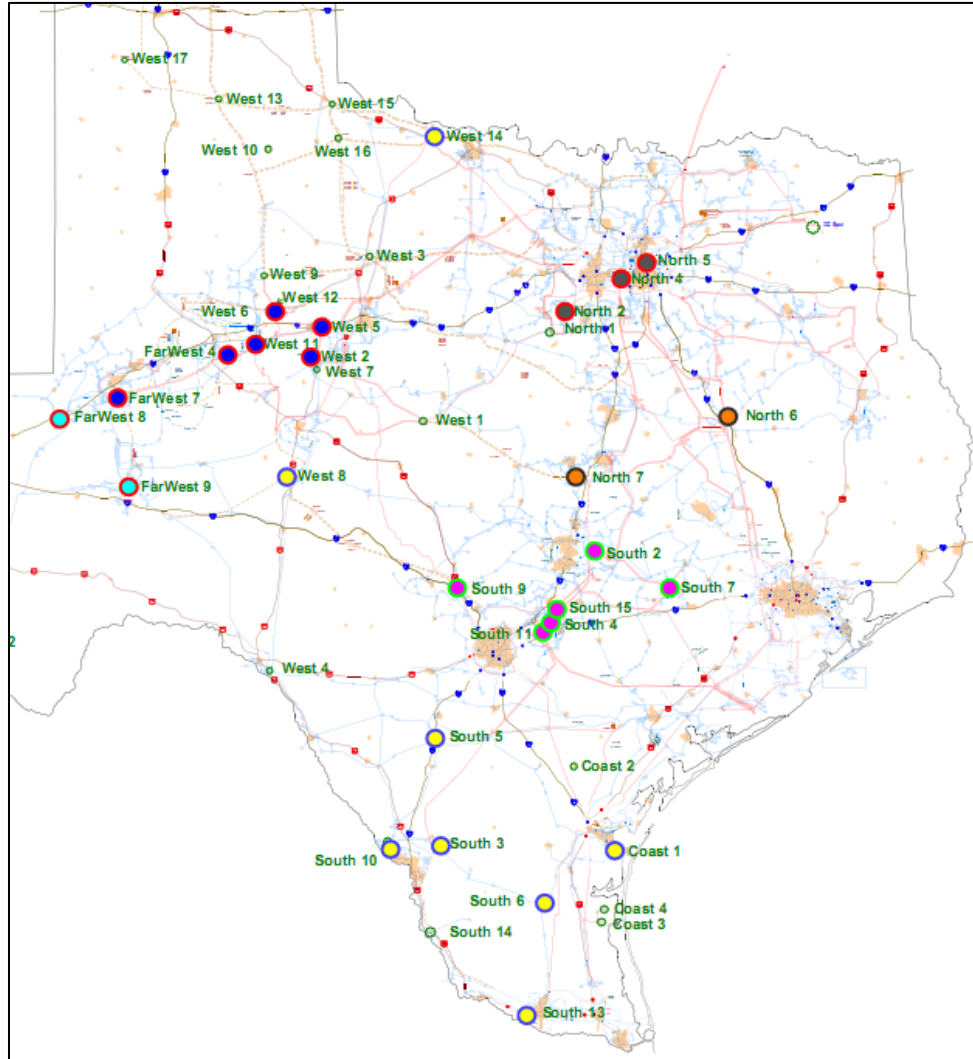
A. Pairs of substations Identified for angle difference analysis

The following pairs of substations were selected to perform the angle difference analysis (ALSO SEE MAP BELOW):

| TABLE 7: ANGLE PAIRS FOR ANGLE DIFFERENCES ANALYSIS UPDATE | | | | |
|-------------------------------------------------------------------|--------------|--------------|--------------|--------------|
| PAIRS WITH PHASOR DATA AVAILABLE | | | | |
| # | Substation A | Substation B | From Region | To Region |
| 1 | Coast 1 | South 13 | Valley | Valley |
| 2 | Coast 1 | North 7 | Valley | Central-East |
| 3 | West 5* | West 10 | Central | Panhandle |
| 4 | West 5* | FarWest 4 | Central | West Texas |
| 5 | West 5* | North 1 | Central | Central |
| 6 | West 5* | North 7 | Central | Central-East |
| 8 | North 1 | North 7 | Dallas | Central-East |
| 7 | North 1 | North 4 | Dallas | Central |
| 9 | North 4 | North 7 | Central | Central-East |
| 10 | West 4 | North 7 | SouthWest | Central-East |
| 11 | North 7 | North 6 | Central-East | East |
| 12 | FarWest 7 | FarWest 4 | West Texas | West Texas |
| 13 | FarWest 7 | West 14 | West Texas | Panhandle |
| 14 | FarWest 7 | FarWest 8 | West Texas | West Texas |
| 15 | FarWest 7 | FarWest 9 | West Texas | West Texas |
| 16 | FarWest 7 | North 7 | West Texas | Central-East |
| 17 | West 9 | FarWest 7 | Central | West Texas |
| 18 | West 9 | West 1 | Central | Central-East |
| 19 | West 9 | North 1 | Central | Dallas |
| 20 | West 14 | West 5* | Panhandle | Central |
| 21 | West 14 | North 1 | Panhandle | Dallas |
| 22 | FarWest 9 | West 4 | West Texas | Southwest |
| PAIRS WITHOUT PHASOR DATA AVAILABLE | | | | |
| 23 | Coast 1 | South 10* | Valley | Valley |
| 24 | South 3 | South 11* | Valley | Central-East |
| 25 | South 11* | North 7 | Valley | Central-East |
| 26 | North 7 | South 7* | Central-East | Central-East |
| 27 | North 7 | South 9* | Central-East | Central-East |
| 28 | West 11 | West 8* | Central | Central |
| 29 | West 8 | South 9* | Central | Central-East |
| 30 | FarWest 9 | South 9* | West Texas | Central-East |
| 31 | West 14 | West 16* | Panhandle | Panhandle |
| 32 | West 14 | West 13* | Panhandle | Panhandle |
| 33 | West 14 | West 15* | Panhandle | Panhandle |
| 34 | West 14 | West 17* | Panhandle | Panhandle |

The sign + Means PMU recently added to the ERCOT Grid

* Denotes substations without existing PMUs or w/o data stream



B. Summary of results – all data included

Table C-1 below contains angle difference results for all those angle pairs selected for study. Several PMUs were connected to the ERCOT grid during the first six months of 2013 and were streaming phasor data. As a result we had 22 pairs with phasor data included in the analysis (Total of 34). This Table shows min, max and average values for angle differences obtained from all data received for the first six months of 2013 (all solved SE cases and all phasor data, normal and contingency conditions). Phasor data was not available for some of the pairs selected for study, no phasor results are provided for those pairs.

Data availability for those pairs which had at least one PMU recently added (see those assigned a + sign to it), shows low values because the availability is calculated based on the entire six months.

Four pairs show positive angles greater than 80 degrees (high degree of one direction flow): North 1 to North 4 (100%), North 1 to North 7 (94.7%), FarWest 7 to FarWest 8 (100%) and Coast 1-South 10 (84.8%).

Observation of Table C-1 results shows the following:

- Five pairs show Max-Min angle spreads greater than 80 degrees: Coast 1-North 7, Sweetwater-North 7, FarWest 7-North 7, FarWest 9-West 4 and FarWest 9-South 9.
 - The lowest Max-Min angle spread occurred on the following pairs: North 1 to North 4, FarWest 7 to FarWest 8 and West 11 to West 8.
- Pairs with angles higher than 50 degrees are: West 5-North 7, FarWest 7-North 7, FarWest 9-West 4 and FarWest 9-South 9.

Table C-1 - CCET DISCOVERY ACROSS TEXAS- BASELINING ANALYSIS- SUMMARY OF ANGLE DIFFERENCES - ALL DATA

| | Angle Pair | Base kV | Phasor Data - 1/1/13 to 06/30/13 | | | | | State Estimator Data - 1/1/13 to 06/30/13 | | | | |
|----|---------------------|------------|----------------------------------------------|-------|---------|------------------|------------------|-------------------------------------------------------|-------|---------|------------------|----------------|
| | | | Min | Max | Average | Percent Positive | % Data Available | Min | Max | Average | Percent Positive | Max-Min Spread |
| 1 | Coast 1-South 13 | 138kV | -19.98 | 49.99 | 4.28 | 66.61 | 95.27 | -19.37 | 31.69 | 3.86 | 66.7% | 51.1 |
| 2 | Coast 1-North 7 | 138kV | -36.75 | 50.83 | 2.59 | 57.68 | 96.44 | -35.89 | 44.81 | 2.16 | 56.1% | 80.7 |
| 3 | West 5-West 10 | 345/69kV | -21.91 | 16.21 | -1.64 | 46.34 | 17.32 | -23.88 | 15.46 | -1.27 | 49.0% | 39.3 |
| 4 | West 5-FarWest 4 | 345kV | -8.26 | 5.75 | -0.60 | 47.10 | 15.75 | -10.15 | 6.36 | -0.69 | 43.6% | 16.5 |
| 5 | West 5-North 1 | 345kV | -19.30 | 25.72 | 2.24 | 50.94 | 17.34 | -18.64 | 36.19 | 2.94 | 56.9% | 54.8 |
| 6 | West 5-North 7 | 345/138kV | -11.58 | 29.97 | 9.00 | 79.10 | 19.67 | -26.90 | 55.73 | 9.92 | 78.0% | 82.6 |
| 7 | North 1-North 7 | 345/138 kV | -12.33 | 26.41 | 6.76 | 92.69 | 97.55 | -10.38 | 24.01 | 6.96 | 94.7% | 34.4 |
| 8 | North 1-North 4 | 345/138kV | 4.46 | 16.34 | 9.58 | 100.00 | 97.43 | 4.07 | 15.49 | 9.13 | 100.0% | 11.4 |
| 9 | North 4-North 7 | 138kV | -18.85 | 14.43 | -2.80 | 24.37 | 97.74 | -17.84 | 13.60 | -2.18 | 28.3% | 31.4 |
| 10 | West 4-North 7 | 138kV | -32.04 | 18.95 | -5.08 | 25.21 | 90.40 | -29.75 | 16.94 | -4.93 | 25.5% | 46.7 |
| 11 | North 7-North 6 | 138kV | -17.99 | 8.67 | -4.44 | 12.07 | 93.60 | -17.25 | 10.70 | -3.78 | 16.8% | 28.0 |
| 12 | FarWest 7-FarWest 4 | 345kV | -15.00 | 3.43 | -2.36 | 8.69 | 93.24 | -11.36 | 6.63 | -2.47 | 11.3% | 18.0 |
| 13 | FarWest 7-West 14 | 345kV | -27.18 | 28.17 | -0.17 | 47.79 | 91.86 | -25.16 | 21.19 | -0.96 | 43.9% | 46.4 |
| 14 | FarWest 7-FarWest 8 | 345/138kV | 2.00 | 13.05 | 8.19 | 100.00 | 92.03 | 1.42 | 13.22 | 7.83 | 100.0% | 11.8 |
| 15 | FarWest 7-FarWest 9 | 345/138kV | -19.98 | 29.94 | 3.08 | 61.78 | 94.45 | -17.09 | 26.89 | 2.53 | 60.2% | 44.0 |
| 16 | FarWest 7-North 7 | 345/138kV | -35.49 | 59.79 | 8.23 | 70.29 | 97.71 | -34.04 | 55.59 | 8.26 | 70.9% | 89.6 |
| 17 | West 9-FarWest 7 | 345kV | -7.65 | 10.29 | 1.57 | 69.15 | 17.34 | -10.45 | 13.94 | 1.89 | 74.9% | 24.4 |
| 18 | West 9-West 1 | 345kV | -19.35 | 23.71 | 3.42 | 76.84 | 17.31 | -6.26 | 14.61 | 3.14 | 76.1% | 20.9 |
| 19 | West 9-North 1 | 345kV | -20.51 | 28.80 | 2.67 | 51.01 | 17.34 | -19.60 | 37.64 | 3.18 | 57.1% | 57.2 |
| 20 | West 14-West 5 | 345kV | -21.62 | 12.32 | -0.23 | 58.24 | 17.13 | -21.33 | 12.24 | -0.70 | 49.8% | 33.6 |
| 21 | West 14-North 1 | 345kV | -12.27 | 16.81 | 1.80 | 63.23 | 91.69 | -9.70 | 14.86 | 2.24 | 67.5% | 24.6 |
| 22 | FarWest 9-West 4 | 138kV | -33.87 | 51.99 | 10.80 | 72.04 | 89.56 | -30.09 | 60.11 | 10.63 | 72.7% | 90.2 |
| 23 | Coast 1-South 10* | 138kV | Phasor data is not available for these pairs | | | | | -10.38 | 32.91 | 9.46 | 84.8% | 43.3 |
| 24 | South 3-South 11 | 138kV | | | | | | -21.35 | 21.54 | 0.96 | 55.3% | 42.9 |
| 25 | South 11-North 7 | 345/69kV | | | | | | -21.08 | 17.78 | -1.03 | 40.5% | 38.9 |
| 26 | North 7-South 7* | 138/345kV | | | | | | -21.19 | 17.89 | -3.23 | 26.6% | 39.1 |
| 27 | North 7-South 9* | 138/345kV | | | | | | -16.37 | 18.41 | 1.17 | 62.2% | 34.8 |
| 28 | West 11-West 8* | 345kV | | | | | | -2.84 | 5.75 | 1.27 | 75.7% | 8.6 |
| 29 | West 8*-South 9* | 345kV | | | | | | -22.35 | 30.69 | 7.87 | 71.2% | 53.0 |
| 30 | FarWest 9-South 9* | 138/345kV | | | | | | -44.29 | 64.43 | 6.85 | 59.9% | 108.7 |
| 31 | West 14-West 16* | 345kV | | | | | | * Substation not yet in service in first half of 2013 | | | | |
| 32 | West 14-West 13* | 345kV | | | | | | | | | | |
| 33 | West 14-West 15* | 345kV | | | | | | | | | | |
| 34 | West 14-West 17* | 345kV | | | | | | | | | | |

* Denotes substations without existing PMUs or w/o data stream

C. Criteria to Identify Normal Operations Limits for Angle Differences

The data received, both phasor and state estimator, provide information for all conditions during the study period including those conditions where the system experienced outages of lines or generators. This study is intended to provide angle difference limits that can be expected during normal operations, that is, when all facilities are in service. The following criteria were used to determine the angle difference limits expected during normal operations for the selected substation pairs.

- i. If the angle difference time duration curves show only positive angles, then two limits will be identified: one corresponding to the angle difference that occurred at about one percent of the time, and the other corresponding to the maximum value observed.
- ii. If the angle difference time duration curves show positive as well as negative angles, then four limits will be identified, two for one direction of flow and two for the opposite direction of flow, based on the criteria below:
 1. The first limit in either direction will be set using state estimator results by selecting the maximum (or minimum) angle difference observed on the corresponding time duration curves if the box-whisker and time duration plots show no extreme values (outliers or extreme values due to events in the system). If extreme values or outliers are present, a point of inflection will be determined and the maximum or minimum angle will be set at the angle corresponding to the point of inflection.
 2. The second max limit will be set at the angle difference which occurred 1% more time than the time corresponding to the selected maximum limit, based on the time duration curve. The second minimum limit will be set at the angle difference corresponding to 1% less time than the time corresponding to the selected minimum limit.
- iii. In some cases such as when there was an extended outage, EPG reproduced the load duration curve excluding those days when the extended outage occurred to determine the angle differences corresponding to normal conditions.
- iv. The 1% values can be used to set alarms for the operators to be notified of impending maximum angle differences. The maximum and minimum values can be used to set alarms notifying the operator that expected maximum or minimum values have been reached.
- v. The alarms so determined should be monitored for a year against actual values observed during operation. If maximum values are exceeded, the observed values should be logged and documented for further analysis.
- vi. Maximum and minimum angle differences will change as major changes occur in the system such as the addition of the 345 kV CREZ lines to the ERCOT system. This analysis should be revised based on historical information obtained with the new facilities that are in place. Maximum and minimum values can also be estimated from many power flow cases representing different system conditions of the year. Once ALL the CREZ lines are added to the ERCOT system, expected to occur by the end of 2013, this study and conclusions should be updated to reflect the impact of those significant additions.

D. Summary of results – normal conditions

The angle difference results for normal conditions are summarized in Table C-2 below. This Table was developed based on the criteria described above.

| Table C-2 - CCET DISCOVERY ACROSS TEXAS- BASELINING ANALYSIS- SUMMARY OF ANGLE DIFFERENCES - NORMAL CONDITIONS | | | | | | | | | | | | | | | | | | | |
|-----------------------------------------------------------------------------------------------------------------------------------------------------------|-------------------------|------------|---------------------------------------------------|--------------|-----------------------|-------------------------------------------------------|--------------------------------|-----------------------------|------------------------------------|---------------------------------|----------------------------------|-------------------------------|------------------------------|---------------------------|--------------|----------------|-----------------------|--|--|
| | | | DATA RESULTS | | | | | | | | | | | | | | | | |
| No | Angle Pair FROM - TO | Base kV | Phasor Data | | | State Estimator Data - 1/1/13 to 06/30/13 | | | | | | | | | | SE Data-Normal | | | |
| | | | Min Angle | Max Angle | Max- Min Spread | Percent Positive | Min Angle at POI or 100% | Percent (POI or 100%) | Min Angle at 99% or POI - 1% | Percent (99% or POI - 1%) | Max Angle at 1% or POI +1% | Percent (1% or POI +1%) | Max Angle at POI or 0% | Percent (POI or 0%) | Min Angle | Max Angle | Max- Min Spread | | |
| 1 | Coast 1-South 13 | 138kV | -16.84 | 33.55 | 50.39 | 66.73% | -18.95 | 99.98% | -11.88 | 98.98% | 21.61 | 1.02% | 28.42 | 0.02% | -18.95 | 28.42 | 47.4 | | |
| 2 | Coast 1-North 7 | 138kV | -31.72 | 35.82 | 67.54 | 56.10% | -35.10 | 99.99% | -25.75 | 98.99% | 29.78 | 1.01% | 42.08 | 0.01% | -35.10 | 42.08 | 77.2 | | |
| 3 | West 5-West 10 | 345/69kV | -17.61 | 15.49 | 33.10 | 48.99% | -17.57 | 98.32% | -17.01 | 97.32% | 13.04 | 1.08% | 14.67 | 0.08% | -17.57 | 14.67 | 32.2 | | |
| 4 | West 5-FarWest 4 | 345kV | -7.49 | 5.20 | 12.69 | 43.62% | -10.01 | 99.97% | -5.58 | 98.97% | 3.46 | 1.01% | 5.90 | 0.01% | -10.01 | 5.90 | 15.9 | | |
| 5 | West 5-North 1 | 345kV | -17.01 | 24.45 | 41.46 | 56.90% | -17.85 | 99.98% | -14.98 | 98.98% | 22.16 | 1.00% | 36.19 | 0.00% | -17.85 | 36.19 | 54.0 | | |
| 6 | West 5-North 7 | 345/138kV | -10.42 | 29.30 | 39.72 | 78.04% | -26.30 | 99.99% | -19.21 | 98.99% | 36.87 | 1.01% | 47.99 | 0.01% | -26.30 | 47.99 | 74.3 | | |
| 7 | North 1-North 7 | 345/138 kV | -10.05 | 21.40 | 31.45 | 94.68% | -9.92 | 99.99% | -5.64 | 98.99% | 17.46 | 1.01% | 23.39 | 0.01% | -9.92 | 23.39 | 33.3 | | |
| 8 | North 1-North 4 | 345/138kV | 5.47 | 15.37 | 9.90 | 100.00% | 4.43 | 99.95% | 5.45 | 98.95% | 13.58 | 1.00% | 15.49 | 0.00% | 4.43 | 15.49 | 11.1 | | |
| 9 | North 4-North 7 | 138kV | -17.65 | 9.92 | 27.57 | 28.33% | -16.81 | 99.98% | -12.03 | 98.98% | 7.29 | 1.01% | 12.66 | 0.01% | -16.81 | 12.66 | 29.5 | | |
| 10 | West 4-North 7 | 138kV | -26.08 | 14.73 | 40.81 | 25.46% | -28.46 | 99.99% | -21.88 | 98.99% | 10.56 | 1.00% | 16.94 | 0.00% | -28.46 | 16.94 | 45.4 | | |
| 11 | North 7-North 6 | 138kV | -14.62 | 7.77 | 22.39 | 16.81% | -16.88 | 99.99% | -12.29 | 98.99% | 5.16 | 1.01% | 10.59 | 0.01% | -16.88 | 10.59 | 27.5 | | |
| 12 | FarWest 7-FarWest 4 | 345kV | -8.35 | 2.66 | 11.01 | 11.25% | -10.99 | 99.98% | -8.57 | 98.98% | 2.37 | 1.00% | 6.63 | 0.00% | -10.99 | 6.63 | 17.6 | | |
| 13 | FarWest 7-West 14 | 345kV | -19.50 | 20.45 | 39.95 | 43.87% | -24.66 | 99.98% | -16.31 | 98.98% | 15.86 | 1.03% | 21.00 | 0.03% | -24.66 | 21.00 | 45.7 | | |
| 14 | FarWest 7-FarWest 8 | 345/138kV | 3.74 | 12.47 | 8.73 | 100.00% | 2.94 | 99.96% | 4.07 | 98.96% | 11.41 | 1.01% | 12.63 | 0.01% | 2.94 | 12.63 | 9.7 | | |
| 15 | FarWest 7-FarWest 9 | 345/138kV | -12.89 | 18.93 | 31.82 | 60.16% | -15.74 | 99.99% | -11.77 | 98.99% | 16.29 | 1.02% | 26.80 | 0.02% | -15.74 | 26.80 | 42.5 | | |
| 16 | FarWest 7-North 7 | 345/138kV | -30.90 | 46.24 | 77.14 | 70.86% | -32.14 | 99.97% | -23.88 | 98.97% | 35.70 | 1.01% | 48.09 | 0.01% | -32.14 | 48.09 | 80.2 | | |
| 17 | West 9-FarWest 7 | 345kV | -5.83 | 9.53 | 15.36 | 74.88% | -9.16 | 99.98% | -5.80 | 98.98% | 8.74 | 1.02% | 13.30 | 0.02% | -9.16 | 13.30 | 22.5 | | |
| 18 | West 9-West 1 | 345kV | -5.84 | 14.82 | 20.66 | 76.09% | -6.13 | 99.98% | -4.34 | 98.98% | 12.75 | 1.01% | 14.57 | 0.01% | -6.13 | 14.57 | 20.7 | | |
| 19 | West 9-North 1 | 345kV | -18.05 | 27.45 | 45.50 | 57.15% | -18.90 | 99.98% | -15.48 | 98.98% | 24.34 | 1.01% | 29.26 | 0.01% | -18.90 | 29.26 | 48.2 | | |
| 20 | West 14-West 5 | 345kV | -15.12 | 10.90 | 26.02 | 49.76% | -16.47 | 99.99% | -13.88 | 98.99% | 9.54 | 1.03% | 11.90 | 0.03% | -16.47 | 11.90 | 28.4 | | |
| 21 | West 14-North 1 | 345kV | -9.48 | 13.00 | 22.48 | 67.50% | -8.95 | 99.99% | -6.69 | 98.99% | 11.22 | 1.01% | 13.78 | 0.01% | -8.95 | 13.78 | 22.7 | | |
| 22 | FarWest 9-West 4 | 138kV | -26.26 | 48.28 | 74.54 | 72.75% | -29.69 | 99.99% | -20.41 | 98.99% | 41.67 | 1.01% | 51.61 | 0.01% | -29.69 | 51.61 | 81.3 | | |
| 23 | Coast 1-South 10* | 138kV | No phasor data is available for these pairs | | | 84.82% | -6.81 | 98.10% | -5.98 | 97.10% | 23.50 | 2.61% | 24.58 | 1.61% | -6.81 | 24.58 | 31.4 | | |
| 24 | South 3-South 11 | 138kV | | | | 55.34% | -13.71 | 97.58% | -12.88 | 96.58% | 14.49 | 2.71% | 15.35 | 1.71% | -13.71 | 15.35 | 29.1 | | |
| 25 | South 11-North 7 | 345/69kV | | | | 40.50% | -9.16 | 95.46% | -8.58 | 94.46% | 8.26 | 4.03% | 9.21 | 3.03% | -9.16 | 9.21 | 18.4 | | |
| 26 | North 7-South 7* | 138/345kV | | | | 26.59% | -12.34 | 96.56% | -11.95 | 95.56% | 6.18 | 3.14% | 7.08 | 2.14% | -12.34 | 7.08 | 19.4 | | |
| 27 | North 7-South 9* | 138/345kV | | | | 62.20% | -5.41 | 94.86% | -4.93 | 93.86% | 8.43 | 4.00% | 9.31 | 3.00% | -5.41 | 9.31 | 14.7 | | |
| 28 | West 11-West 8* | 345kV | | | | 75.74% | -1.57 | 97.67% | -1.47 | 96.67% | 5.12 | 1.25% | 5.47 | 0.25% | -1.57 | 5.47 | 7.0 | | |
| 29 | West 8*-South 9* | 345kV | | | | 71.18% | -14.84 | 97.23% | -13.84 | 96.23% | 27.90 | 1.60% | 28.78 | 0.60% | -14.84 | 28.78 | 43.6 | | |
| 30 | FarWest 9-South 9* | 138/345kV | | | | 59.87% | -30.05 | 97.44% | -28.08 | 96.44% | 42.07 | 2.17% | 44.39 | 1.17% | -30.05 | 44.39 | 74.4 | | |
| 31 | West 14-West 16* | 345kV | | | | * Substation not yet in service in first half of 2013 | | | | | | | | | | | N/A | | |
| 32 | West 14-West 13* | 345kV | | | | | | | | | | | | | | | N/A | | |
| 33 | West 14-West 15* | 345kV | | | | | | | | | | | | | | | N/A | | |
| 34 | West 14-West 17* | 345kV | | | | | | | | | | | | | | | N/A | | |
| NOTE: These results were obtained with January-June, 2013 data; ** West 16, West 13, West 15, West 17, and West 8 were not in service during this period. | | | | | | | | | | | | | | | | | | | |

NOTE: These results were obtained with January-June, 2013 data; ** West 16, West 13, West 15, West 17, and West 8 were not in service during this period.

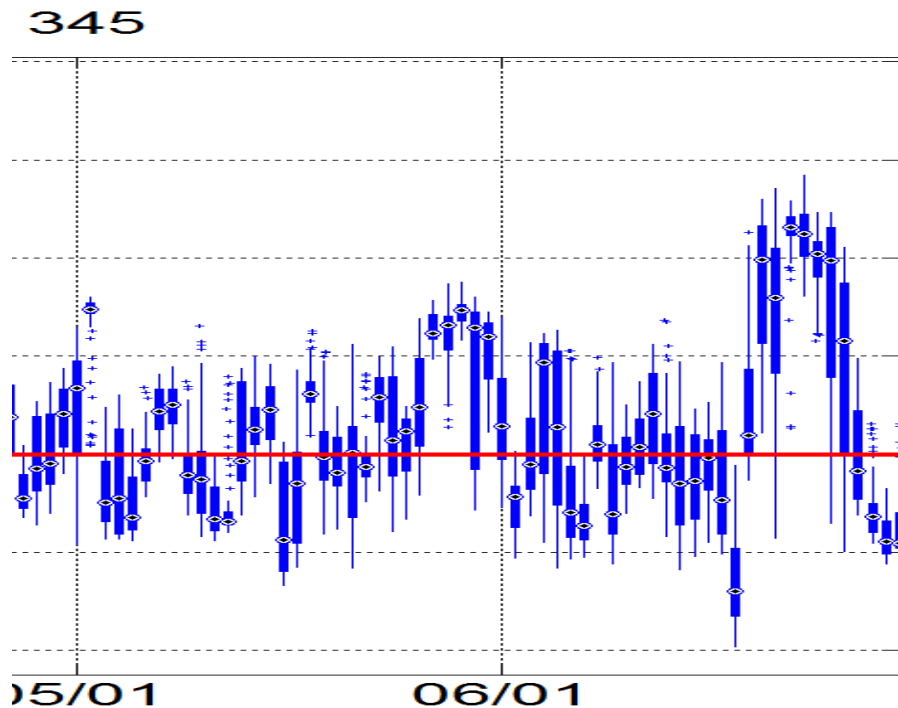
Box-whisker and time duration curves were developed for each of the pairs analyzed. Angle differences that may be the result of contingencies were excluded by reviewing points of inflection, that is, points that significantly deviated from the normal operation trend observed in the box-whisker plots. The value of angle difference at the point of inflection was considered to be the maximum angle during normal conditions. If no outlier points were identified, then the angle corresponding to the 0% or 100% time points will represent the maximum and minimum angles reached during normal operations in either direction of flow. Summaries of SE-based voltage angle pairs with their corresponding box-whisker and time duration curves as well as summaries of phasor-based voltage angle pairs with their corresponding box-whisker and time duration curves are presented in Appendix D.

E. Observations from Table C-2 above

- a. The maximum Max-Min angle spreads under normal conditions occurred at FarWest 9-West 4 (81.3), FarWest 7-North 7 (80.2), Coast 1-North 7 (77.2), FarWest 9-South 9 (74.4) and West 5-North 7(74.3).
- b. The angle pairs with Max-Min spreads less than 10 degrees are: FarWest 7-FarWest 8 (9.7) and West 11-West 8 (7.0)
- c. The maximum voltage angles under normal conditions occurred at FarWest 9-West 4 (51.6) and FarWest 7-North 7 (48.09).
- d. Seventeen pairs had maximum angles less than 20 degrees and the rest had angles between 20 and 52 degrees. Seven substations had minimum angles lower than -20 degrees: Coast 1-North 7 (-31.1), West 5-North 7 (-26.3), West 4-North 7 (-28.5), FarWest 7-West 14 (-24.7), FarWest 7-North 7 (-32.1), FarWest 9-West 4 (-29.7) and FarWest 9-South 9 (30.1).
- e. Three pairs have positive angles differences greater than 90 degrees: North 1-North 4 (100), FarWest 7-FarWest 8 (100) and North 1-North 7 (94.7).

F. Observations from Box-whisker plots

- a. Several angle pairs exhibit abrupt changes in angle that may be due to outages or construction work. Some of these changes last several days before returning to the original values. If this is the case, the “normal operations” angles differences may need to be revisited with feedback from ERCOT operation personnel.
- b. If there were extended outages EPG will need to know so that those angles are excluded when calculating the “normal limits”.
- c. Examples of those abrupt angle changes are:
 - 1. Coast 1-South 13 (late February)
 - 2. Coast 1-North 7 (early June)
 - 3. West 5-West 10 (angle changes often, large jump in early May and late June)
 - 4. West 5-FarWest 4 (angle drops in April and in June)
 - 5. West 5-North 7 (drops twice in mid January and jumps up once in late January)
 - 6. North 1-North 7 (angle changes abruptly several times)
 - 7. North 1-North 4 (significant jump in mid May)
 - 8. North 4-North 7 (experienced several changes up and down)
 - 9. North 7-North 6 (two jumps in mid February: one up and one down)
 - 10. West 9-West 1 (three jumps: early January, early April and late June)
 - 11. Several pairs experienced similar jump up in late June, perhaps due to a common event. See graph below (red line is zero degrees and lines are in increments of 10).
 - 12. EPG suggests that ERCOT operators review Appendix D, State Estimator Box-whisker plots and identify what angle differences changes were due to events in the system.



9. PAIRS FOR REAL TIME MONITORING

A. Criteria for selection of angle pairs for real time monitoring

1. Choose a few transmission paths (pairs) from the wind areas to monitor wind power delivery.
2. Choose load center such as North 1 and select transmission paths serving such loads.
3. Choose transmission paths delivering power from the Valley and from the Houston area,
4. Choose transmission paths connecting the Dallas area and the Houston and San Antonio areas.

NOTE: Because there are not enough PMUs installed in the system EPG will choose pairs that meet the criteria as close as possible.

B. Transmission Paths (PAIRS) Selected for Real Time Monitoring

The transmission paths selected for monitoring are shown in Table 7 below:

TABLE 8: ANGLE PAIRS SELECTED FOR REAL TIME MONITORING**PAIRS WITH PHASOR DATA AVAILABLE**

| # | Substation A | Substation B | From Region | To Region |
|----|--------------|--------------|-------------|--------------|
| 1 | Coast 1 | South 13 | Valley | Valley |
| 2 | Coast 1 | North 7 | Valley | Central-East |
| 3 | Coast 3 | North 7 | Valley | Central-East |
| 4 | South 5* | North 7 | Valley | Central-East |
| 5 | West 4 | North 7 | Southwest | Central-East |
| 6 | North 6 | North 7 | East | Central-East |
| 7 | West 1* | North 7 | Central | Central-East |
| 8 | North 1 | North 7 | Dallas | Central-East |
| 9 | North 1 | North 4 | Dallas | Central |
| 10 | North 4 | North 7 | Central | Central-East |
| 11 | West 5* | North 1 | Central | Central |
| 12 | West 5* | North 7 | Central | Central-East |
| 13 | West 5* | West 10 | Central | Panhandle |
| 14 | West 5* | FarWest 4 | Central | West Texas |
| 15 | FarWest 7 | FarWest 4 | West Texas | West Texas |
| 16 | FarWest 7 | FarWest 9 | West Texas | West Texas |
| 17 | FarWest 9 | West 4 | West Texas | Southwest |
| 18 | West 9 | West 1* | Central | Central-East |
| 19 | West 9 | North 1 | Central | Dallas |
| 20 | West 14 | West 5* | Panhandle | Central |
| 21 | West 14 | North 1 | Panhandle | Dallas |

* Means PMU recently added to the ERCOT Grid

C. Proposed Alarm Limits

Table 8 below shows the proposed angle limits for the paths (pairs) selected for real time monitoring. These proposed limits were selected from the results for normal conditions shown in Tables B-2 and C-2 of this report. These results are based on the data for the first six months of 2013 provided by ERCOT. Several CREZ 345 kV lines were added during this period of time which have tightened electrically the ERCOT grid. Additional 345 kV lines are being added to the ERCOT system during the second half of 2013 which will further tighten electrically the ERCOT system. EPG expects that these alarm limits proposed in this section will be wider than those expected in 2014 when all the CREZ lines have been added to the ERCOT system.

By monitoring these angle pairs, the ERCOT grid operators should have a good overview of power flow from generation centers to the load centers. It will also provide them with a good idea of ongoing power flows among the different regions of the ERCOT grid.

EPG suggests that operators document any time these limits are exceeded noting the reason if known for the deviations.

| Table 9 -CCET DISCOVERY ACROSS TEXAS- BASELINING ANALYSIS- ALARM LIMITS FOR REAL TIME MONITORING | | | | | | | | | | | |
|---------------------------------------------------------------------------------------------------------|-----------------------------------|-----------|----------------------------------|--------------|---------------------------|---------------------------|---------------------------|---------------------------|----------------|--------------|-----------------------|
| No | Proposed Angle Pairs FROM - TO | Base kV | ALARM LIMITS - NORMAL CONDITIONS | | | | | | | | |
| | | | Phasor Data | | RECOMMENDED ALARM LIMITS | | | | SE Data-Normal | | |
| | | | Min Angle | Max Angle | Minimum Angle Limit | Minimum Angle Alert | Maximum Angle Alert | Maximum Angle Limit | Min Angle | Max Angle | Max- Min Spread |
| 1 | Coast 1-South 13 | 138 | -16.84 | 33.55 | -18.95 | -11.88 | 21.61 | 28.42 | -18.95 | 28.42 | 47.4 |
| 2 | Coast 1-North 7 | 138 | -31.72 | 35.82 | -35.10 | -25.75 | 29.78 | 42.08 | -35.10 | 42.08 | 77.2 |
| 3 | Coast 3-North 7 | 345 | -30.16 | 42.98 | -33.05 | -25.43 | 35.08 | 49.06 | -33.05 | 49.06 | 82.1 |
| 4 | South 5-North 7 | 138 | -23.39 | 12.95 | -28.42 | -20.97 | 8.05 | 13.85 | -28.42 | 13.85 | 42.3 |
| 5 | West 4-North 7 | 138 | -26.08 | 14.73 | -27.94 | -21.80 | 10.48 | 15.35 | -27.94 | 15.35 | 43.3 |
| 6 | North 6-North 7 | 138 | -7.60 | 14.69 | -10.25 | -5.15 | 12.28 | 16.90 | -10.25 | 16.90 | 27.1 |
| 7 | West 1-North 7 | 345 | -6.64 | 18.88 | -22.84 | -16.95 | 32.04 | 40.40 | -22.84 | 40.40 | 63.2 |
| 8 | North 1-North 7 | 345 | -10.05 | 21.40 | -9.90 | -5.63 | 17.45 | 23.22 | -9.90 | 23.22 | 33.1 |
| 9 | North 1-North 4 | 345/138kV | 5.47 | 15.37 | 4.43 | 5.45 | 13.58 | 15.49 | 4.43 | 15.49 | 11.1 |
| 10 | North 4-North 7 | 138 | -17.65 | 9.92 | -16.29 | -12.02 | 7.27 | 11.37 | -16.29 | 11.37 | 27.7 |
| 11 | West 5-North 1 | 345 | -17.01 | 24.45 | -17.85 | -14.98 | 22.16 | 36.19 | -17.85 | 36.19 | 54.0 |
| 12 | West 5-North 7 | 345 | -10.42 | 29.30 | -25.31 | -19.11 | 36.85 | 45.85 | -25.31 | 45.85 | 71.2 |
| 13 | West 5-West 10 | 345/69kV | -17.61 | 15.49 | -17.57 | -17.01 | 13.04 | 14.67 | -17.57 | 14.67 | 32.2 |
| 14 | West 5-FarWest 4 | 345 | -7.49 | 5.20 | -10.01 | -5.58 | 3.46 | 5.90 | -10.01 | 5.90 | 15.9 |
| 15 | FarWest 7-FarWest 4 | 345 | -8.35 | 2.66 | -10.99 | -8.57 | 2.37 | 6.63 | -10.99 | 6.63 | 17.6 |
| 16 | FarWest 7-FarWest 9 | 345/138kV | -12.89 | 18.93 | -15.74 | -11.77 | 16.29 | 26.80 | -15.74 | 26.80 | 42.5 |
| 17 | FarWest 9-West 4 | 138 | -26.26 | 48.28 | -29.69 | -20.41 | 41.67 | 51.61 | -29.69 | 51.61 | 81.3 |
| 18 | West 9-West 1 | 345 | -5.84 | 14.82 | -6.13 | -4.34 | 12.75 | 14.57 | -6.13 | 14.57 | 20.7 |
| 19 | West 9-North 1 | 345 | -18.05 | 27.45 | -18.90 | -15.48 | 24.34 | 29.26 | -18.90 | 29.26 | 48.2 |
| 20 | West 14-West 5 | 345 | -15.12 | 10.90 | -16.47 | -13.88 | 9.54 | 11.90 | -16.47 | 11.90 | 28.4 |
| 21 | West 14-North 1 | 345 | -9.48 | 13.00 | -8.95 | -6.69 | 11.22 | 13.78 | -8.95 | 13.78 | 22.7 |

Note that all the pairs in the above tables have two negative numbers and two positive numbers. The negative numbers apply in the TO to FROM direction and the positive numbers apply in the FROM to the TO direction. One pair, the North 1 to North 4 pair, have all positive numbers which means that all the flow is in the FROM to the TO direction and only two alarm limits are needed to monitor this path under normal conditions (13.6 degrees alert and 15.5 degrees limit).

10. CONCLUSIONS

- a. **Data Availability was Improved in 2013:** State estimator data provided by ERCOT for 2013 had availability of 29% which was more than double the availability rate for 2012. Phasor data availability ranged from 20% to 98%. Those substations with the lower availability rates were those that began transmitting data to ERCOT at the end of the six month study period.
- b. **Highest Voltage Spreads at Two Locations:** Both phasor data and state estimator data point to West 4 and Coast 4 as having the greatest voltage and voltage spread in their class. Note that Coast 3 also has a high voltage spread but South 13 and South 6 which are in the neighborhood have a much lower spread.
- c. **Substations with High Voltage Spreads:** In the first six months of 2013, seven substations out of a total of thirty seven showed voltage spreads of greater than 15 kV.
- d. **Voltage Angle Variability at 345kV and 138kV Substations:** Voltage angles vary over a wide range for several substations. The greatest variation of 104.1 degrees (-40.9 to 63.2) occurred at FarWest 9 138 kV substation. Among the 345 kV substations, the greatest angle variation over the first six months of 2013 occurred at FarWest 4 with a spread of 90.8 (-30.6 to 60.2) degrees.
 - a. The greatest variations occurred among the substations in the western part of the state namely: FarWest 7, West 11, West 6, FarWest 8, FarWest 9, FarWest 4, West 2, West 9, West 12 and West 5.
 - b. The next greatest angle variation occurred in the south part of the state namely: South 13, Coast 3, Coast 4, South 6 and Coast 1.
 - c. The two greatest normal angles observed were at West 10 and FarWest 9 with 59.74 and 52.47 degrees respectively.
 - d. The maximum Max-Min angle spreads under normal conditions occurred at FarWest 9-South 9 and Coast 4-North 7 with 121.8 and 82.7 degrees respectively.
- e. **Maximum Voltage Angles Under Normal Conditions:** The maximum voltage angles under normal conditions occurred at FarWest 9-West 4 and FarWest 7-North 7 with 51.6 and 48.1 degrees respectively.
- f. **Voltage spreads are smaller in 2013:** The voltage spreads obtained with six months of 2013 data are smaller than those obtained with 2012 data. A result of the ERCOT system's increased tightness due to the addition of the many 345 kV new CREZ lines.
- g. **Alarm Limits for Voltage Angles:** EPG expects the voltage angles to change with the addition of many 345 kV CREZ lines in the second half of 2013 but has prepared a preliminary list of alarm limits based on result of this baselining update which was based on data from the first six months of 2013 provided by ERCOT to monitor in real time with the understanding that these limits will most likely change by 2014.

11. RECOMMENDATIONS

- a. **Ongoing Monitoring:** Actual voltage magnitudes and voltage angles should be collected while additional new lines are being added to monitor change in angle differences which will provide insights into synchronization issue and solutions.

- b. **Monitoring Locations:** EPG recommends monitoring the angle pairs shown in section 9C. The proposed alarm limits shown in this section should be used for monitoring purposes.
- c. **Need for a second update:** A new baselining update should be completed once all the CREZ 345 lines are added to the ERCOT system to obtain a more accurate set of alarm limits to be used during real time conditions.

Appendix A – Part 1

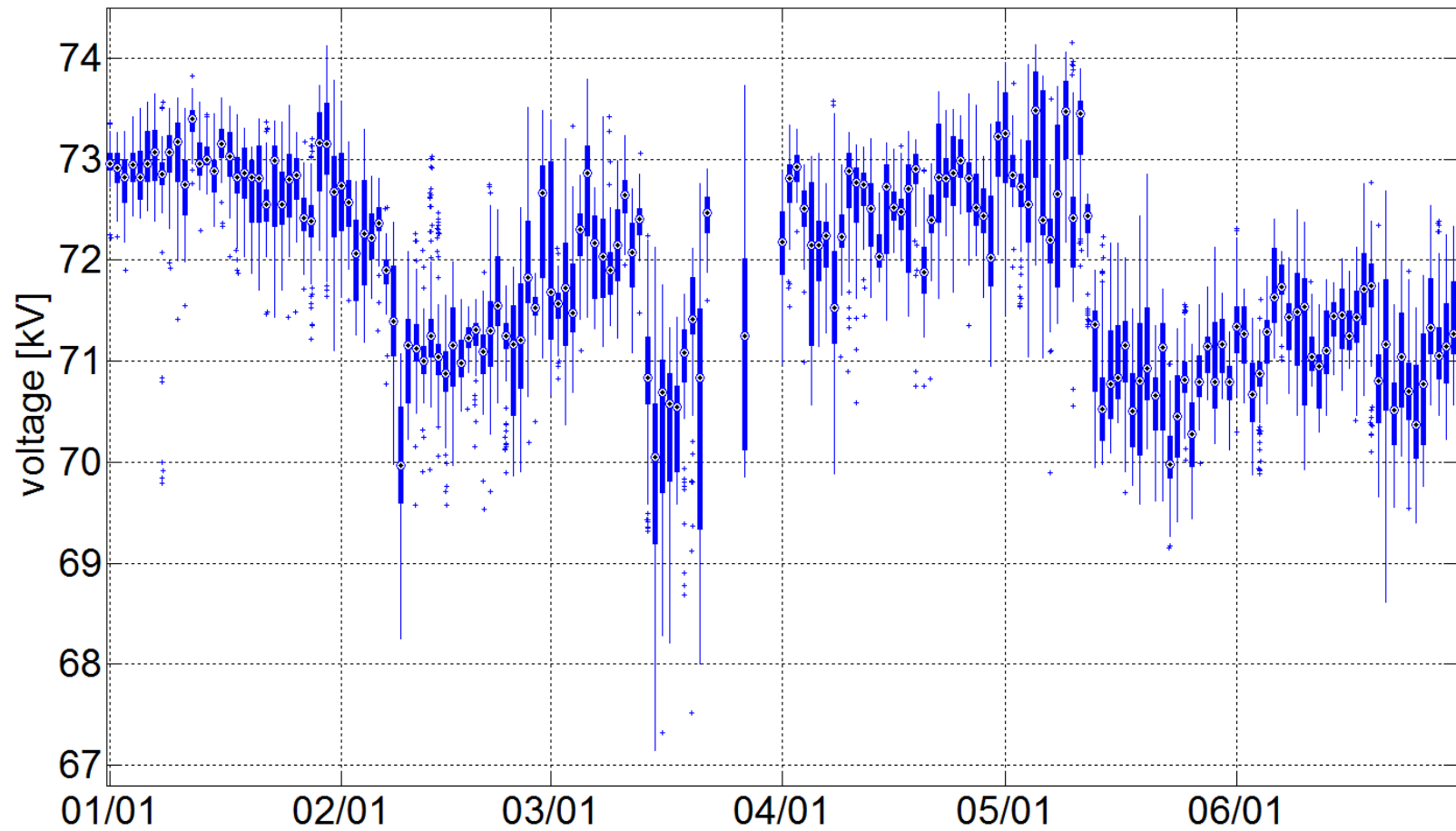
CCET Discovery Across Texas project

Baseline Analysis Update - Voltage Magnitudes

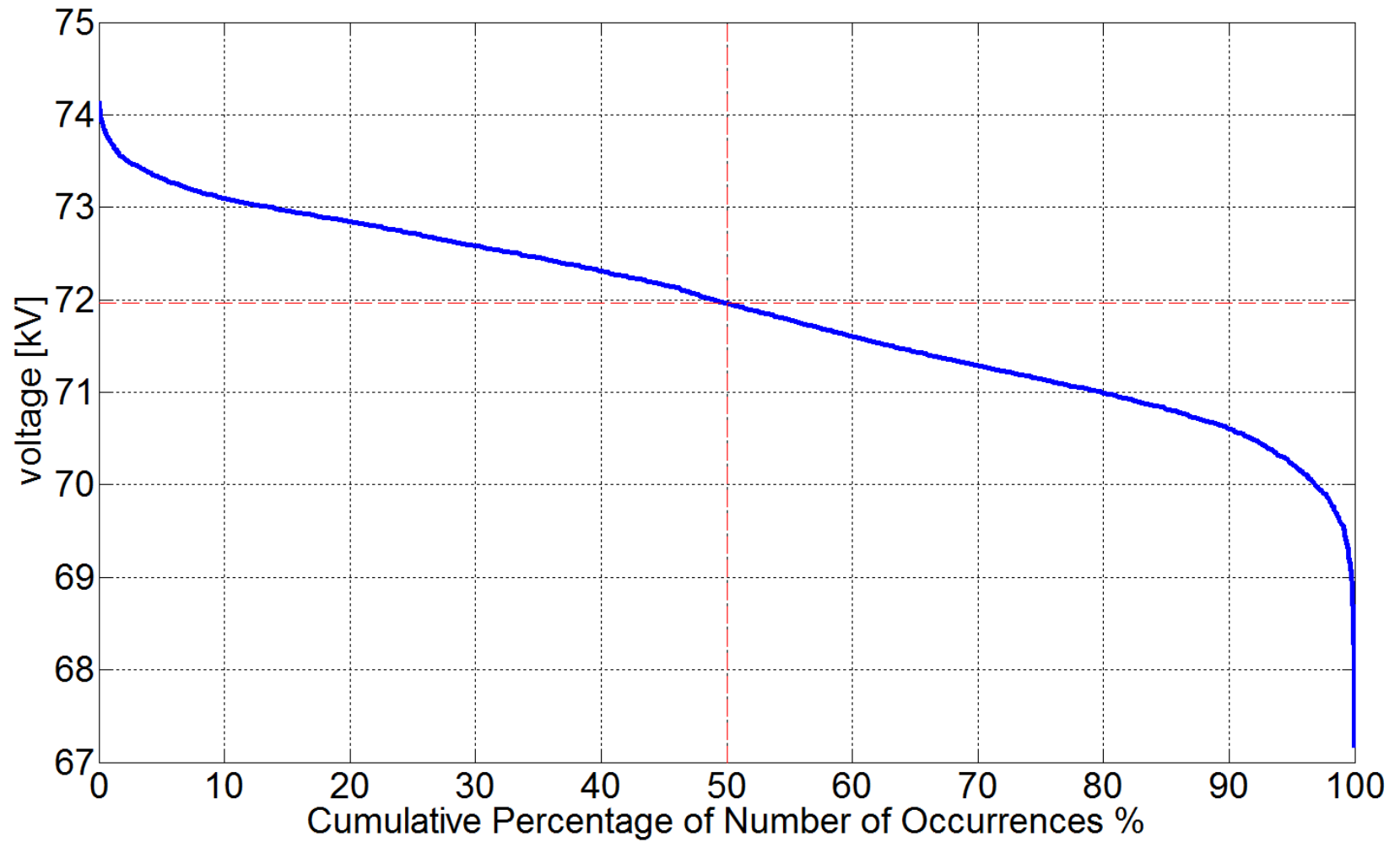
State Estimator Data: January to June 2013
Box Whiskers Plots and Time Duration Curves

External Version

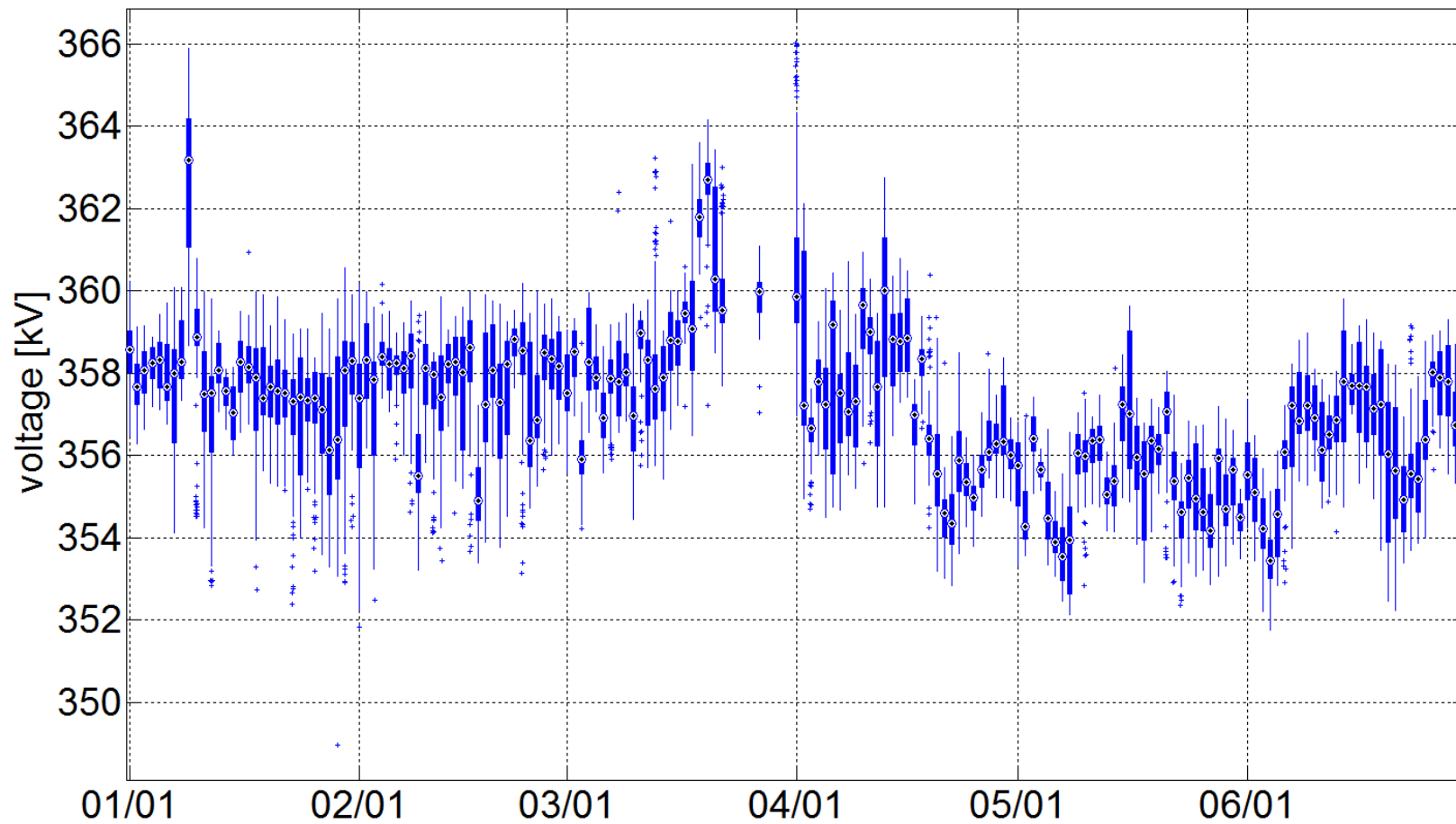
West 10



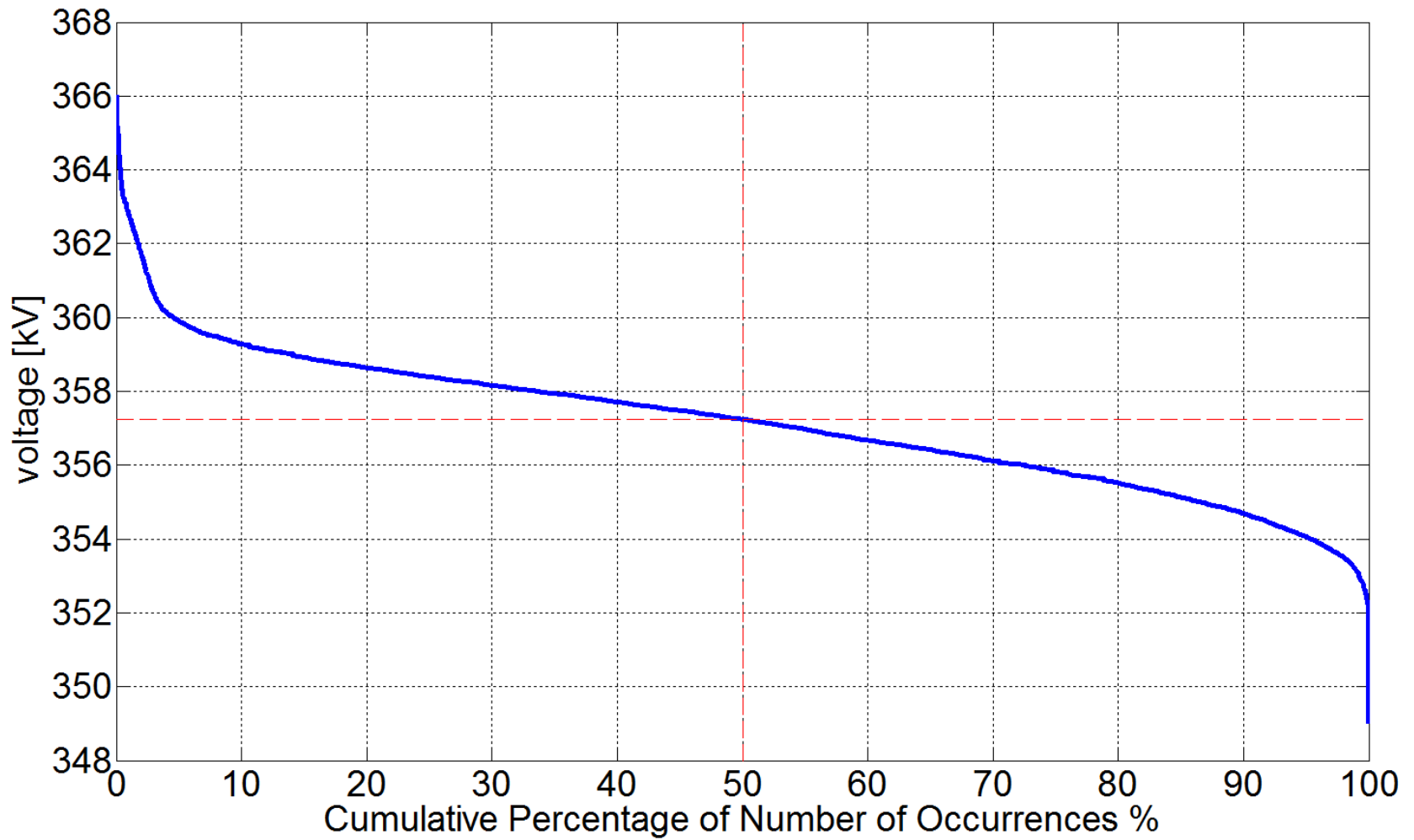
West 10



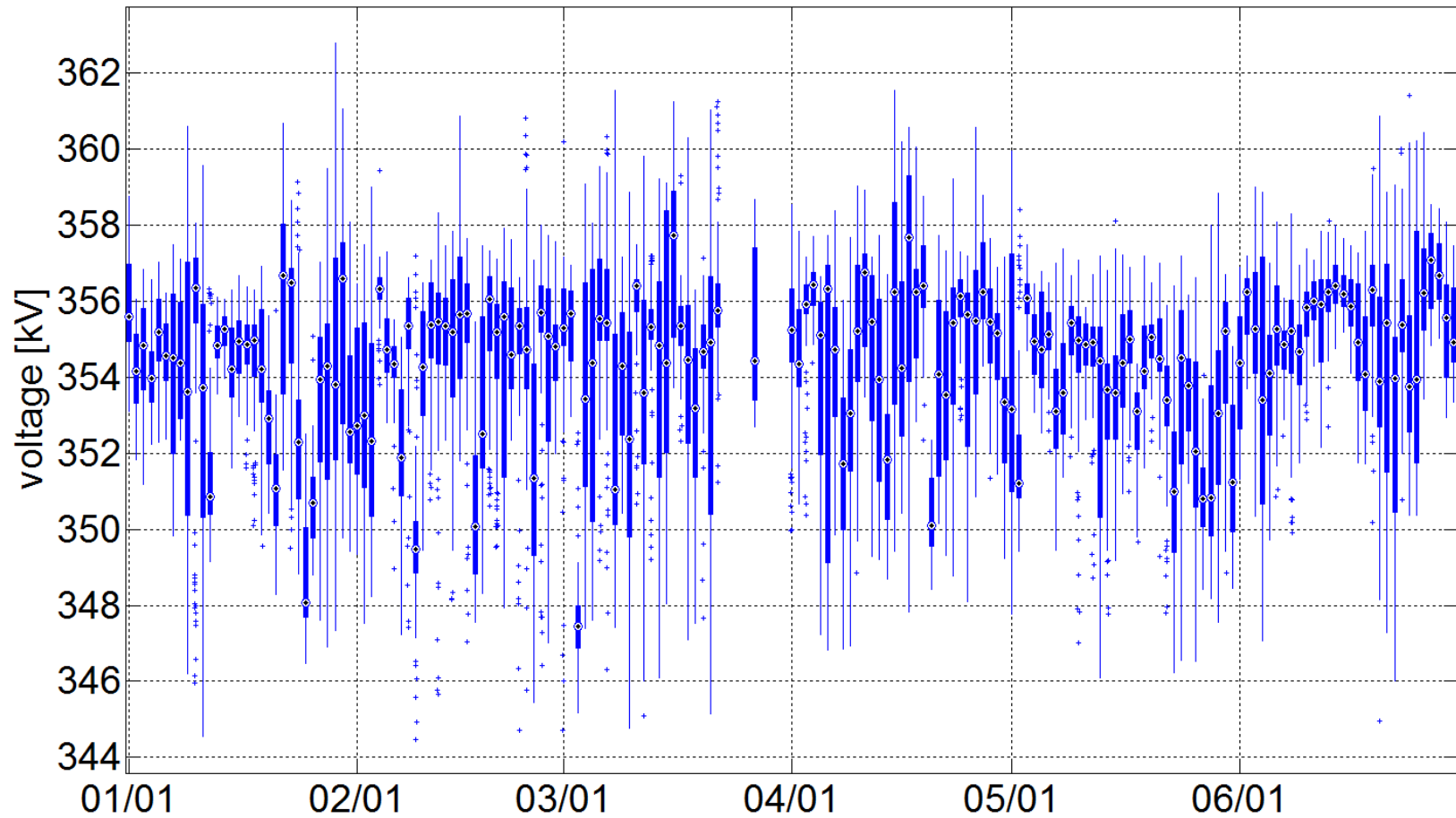
West 14



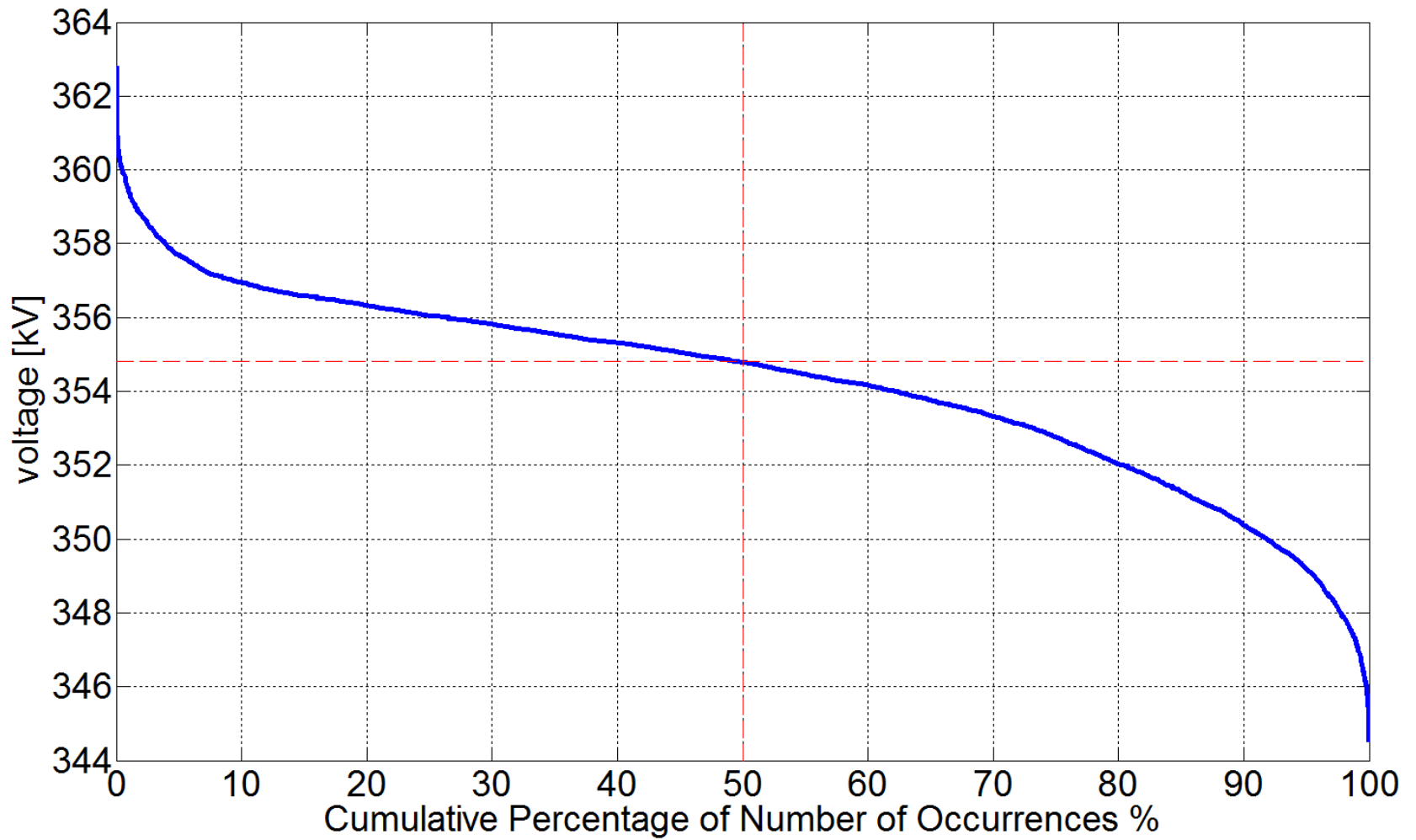
West 14



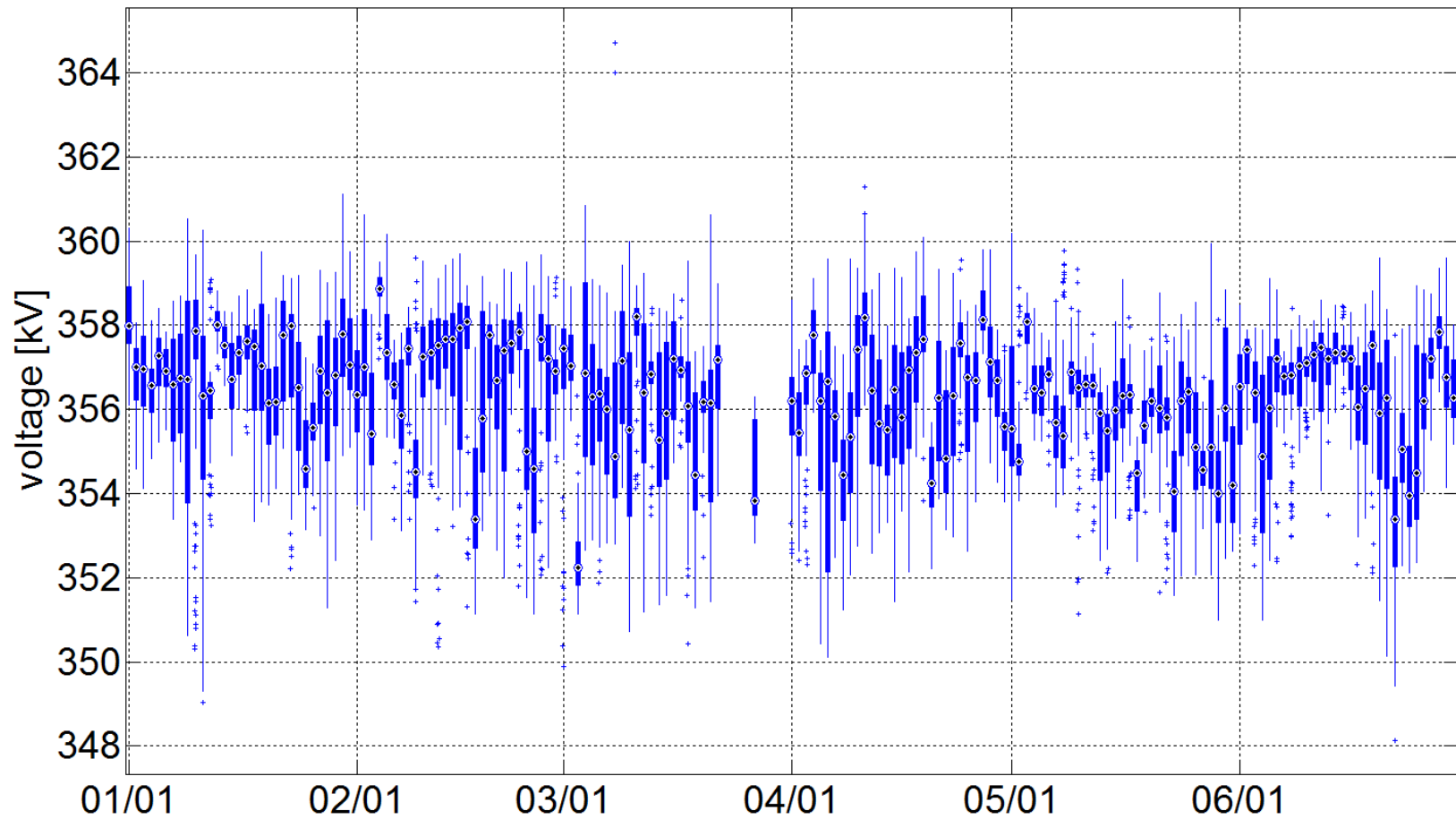
West 1*



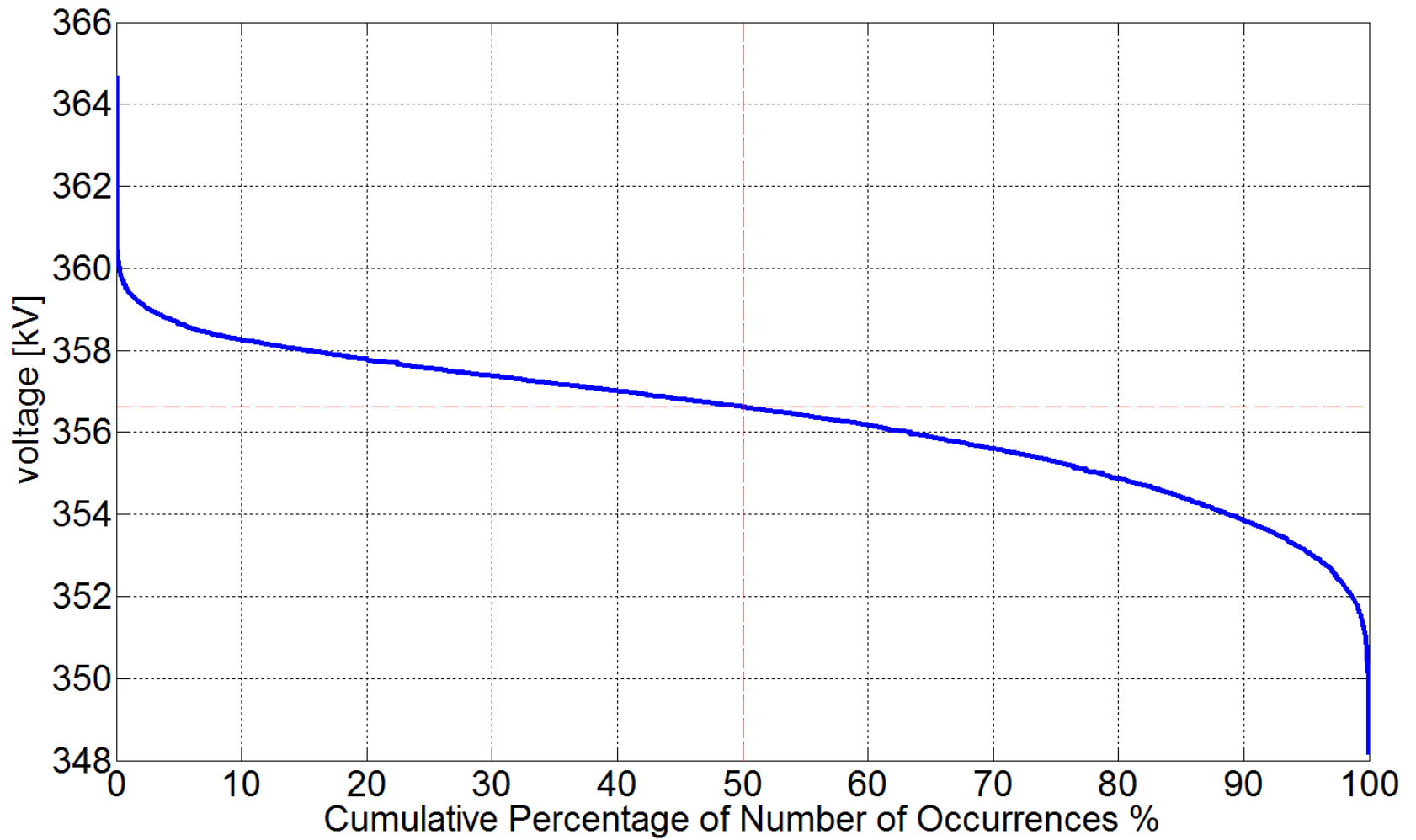
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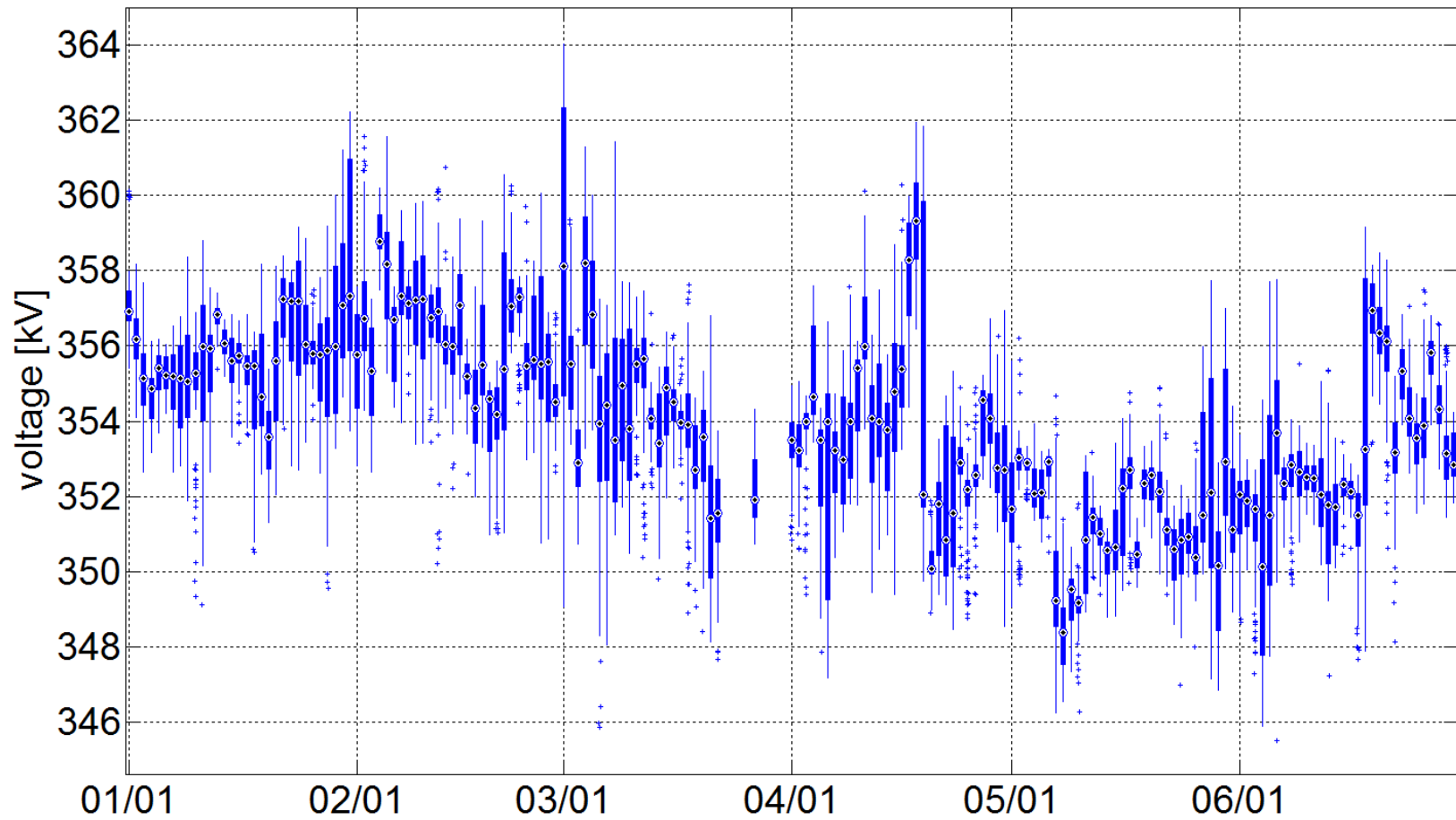
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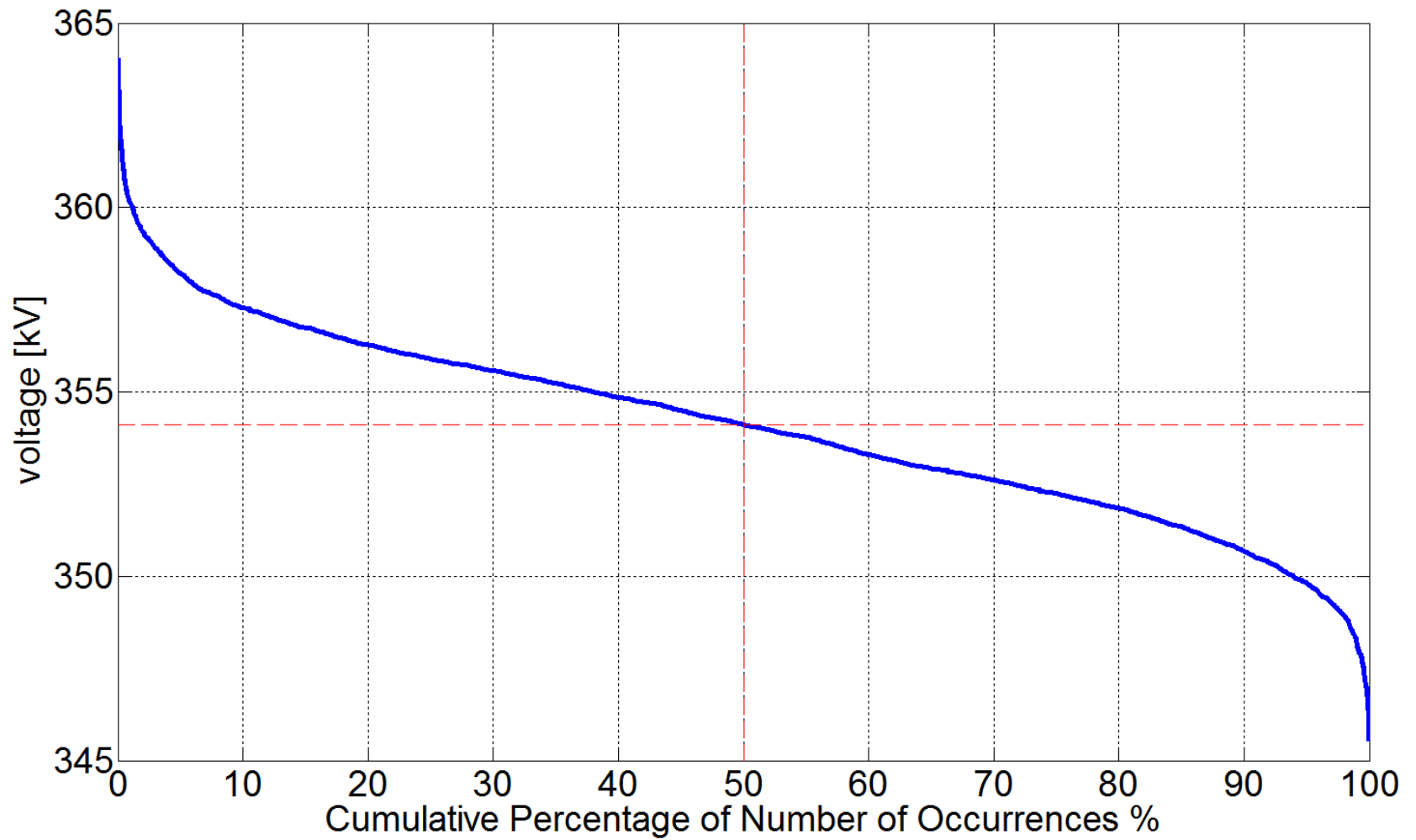
West 2*



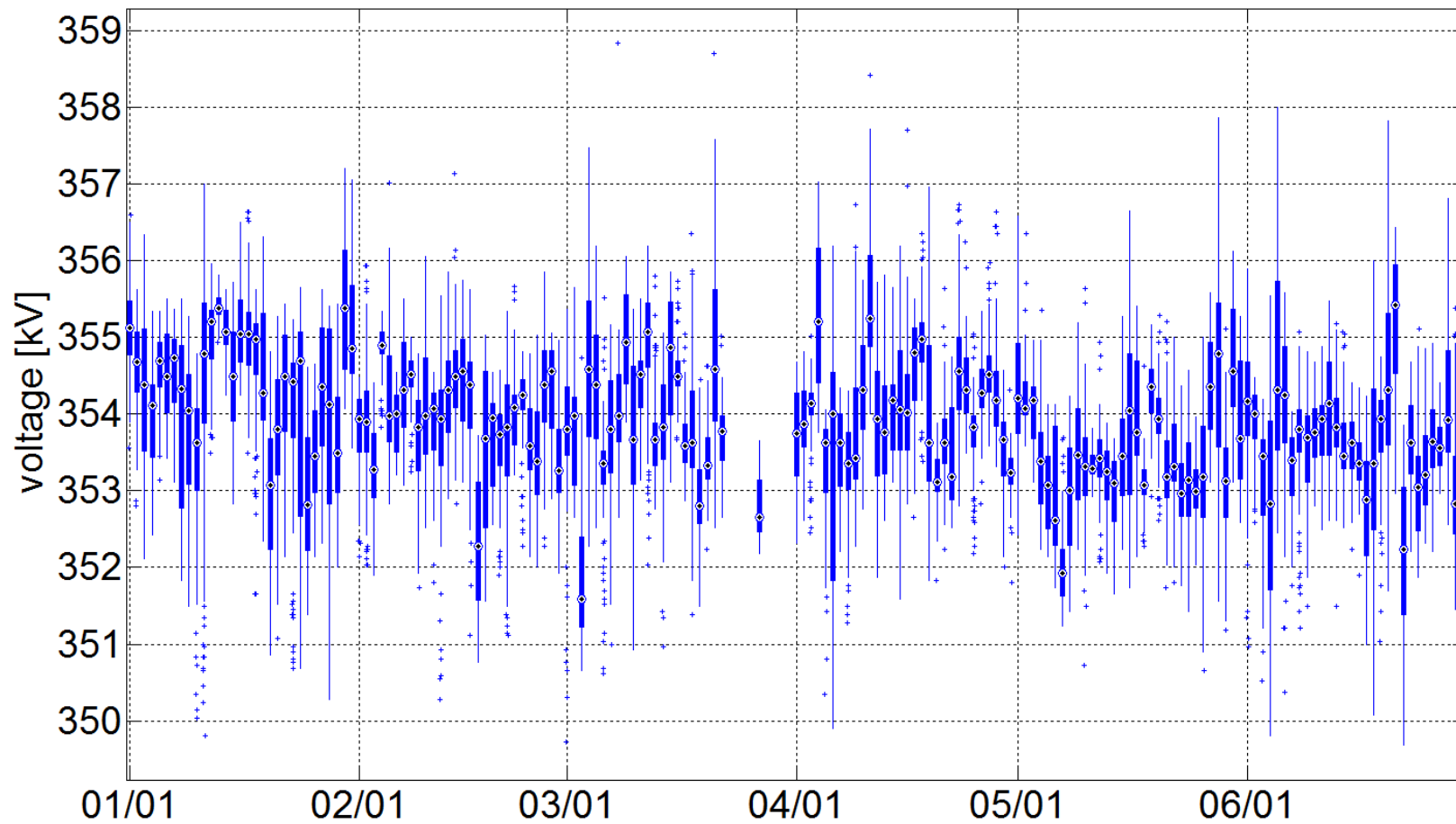
West 9*



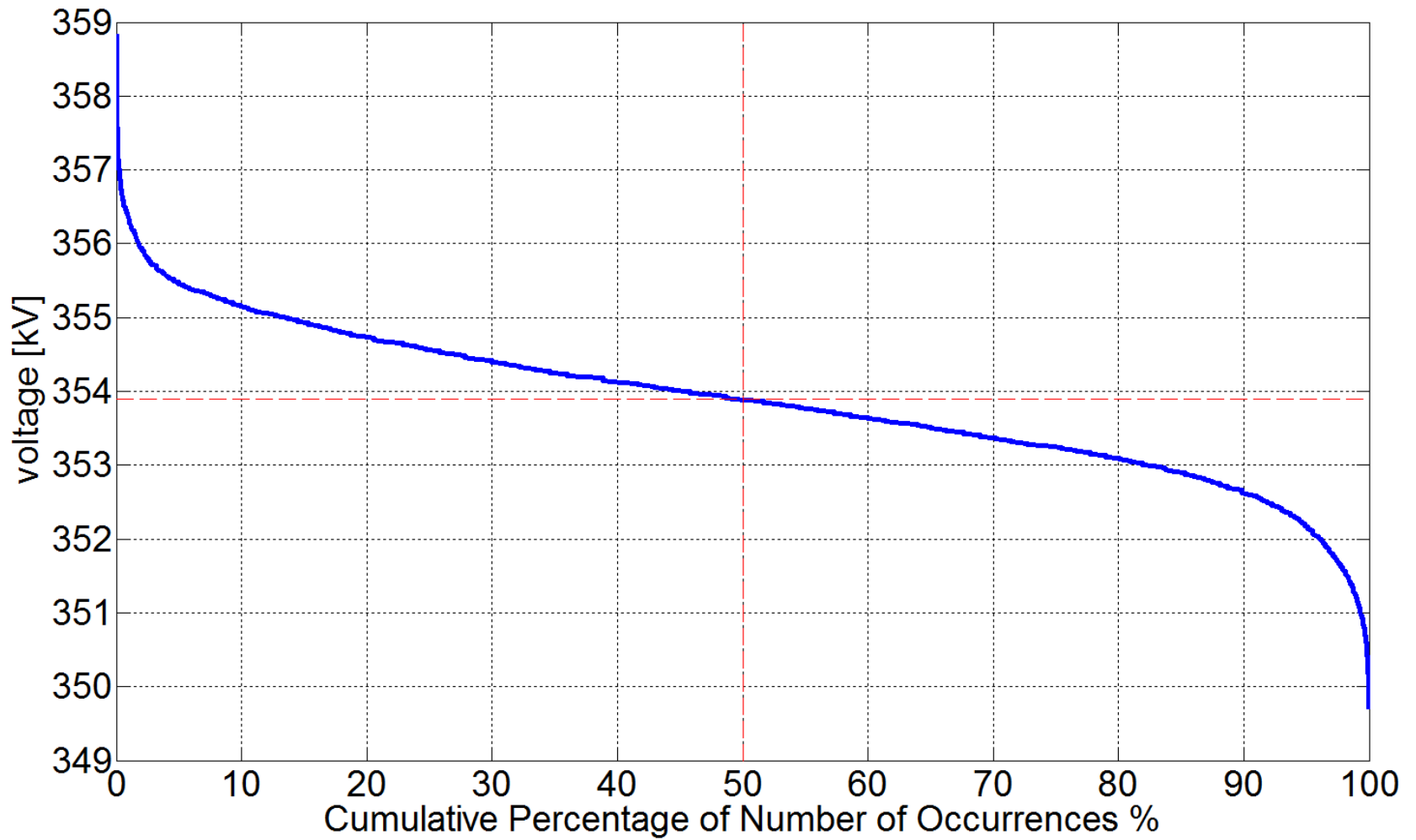
West 9*



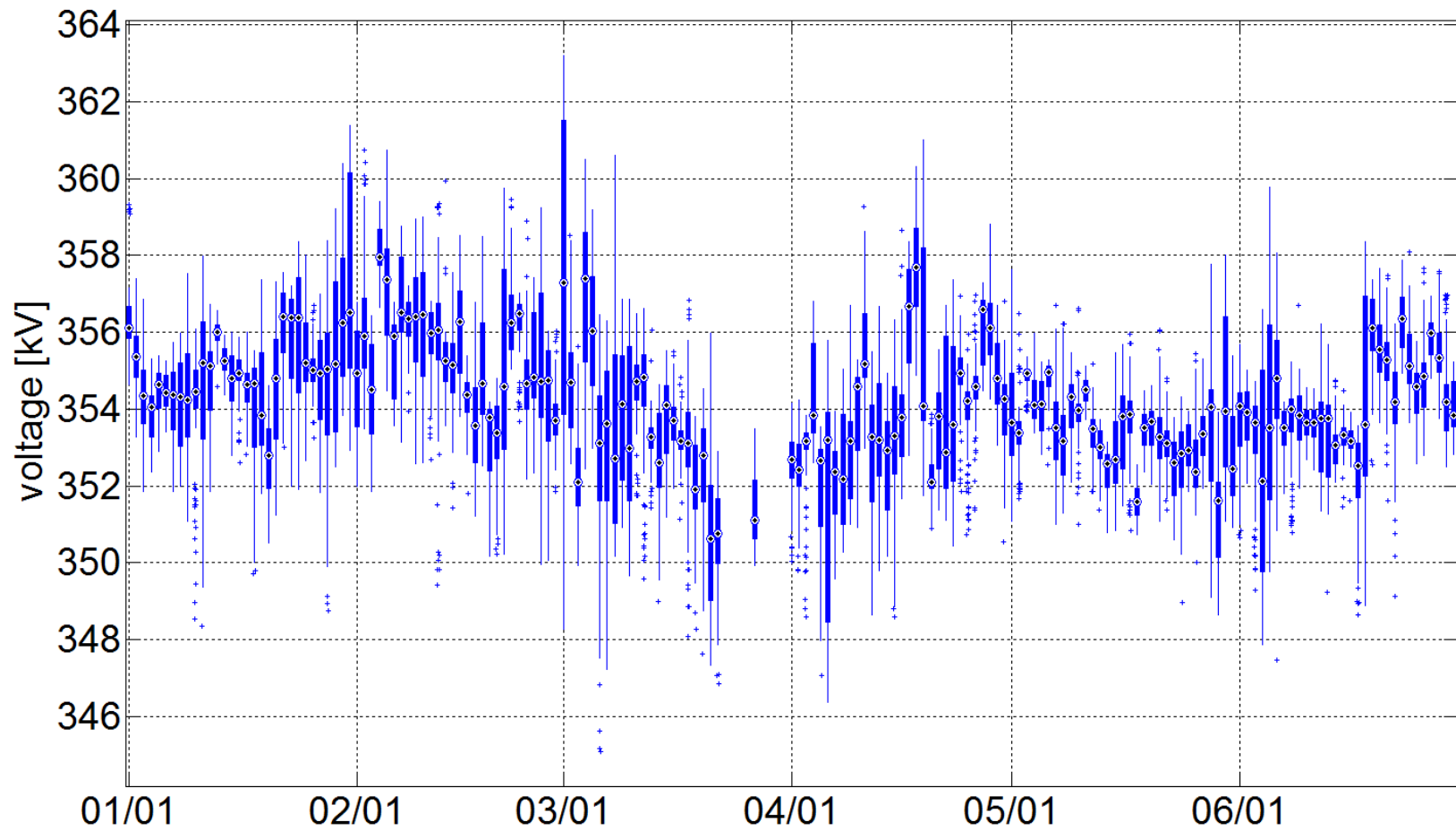
West 11



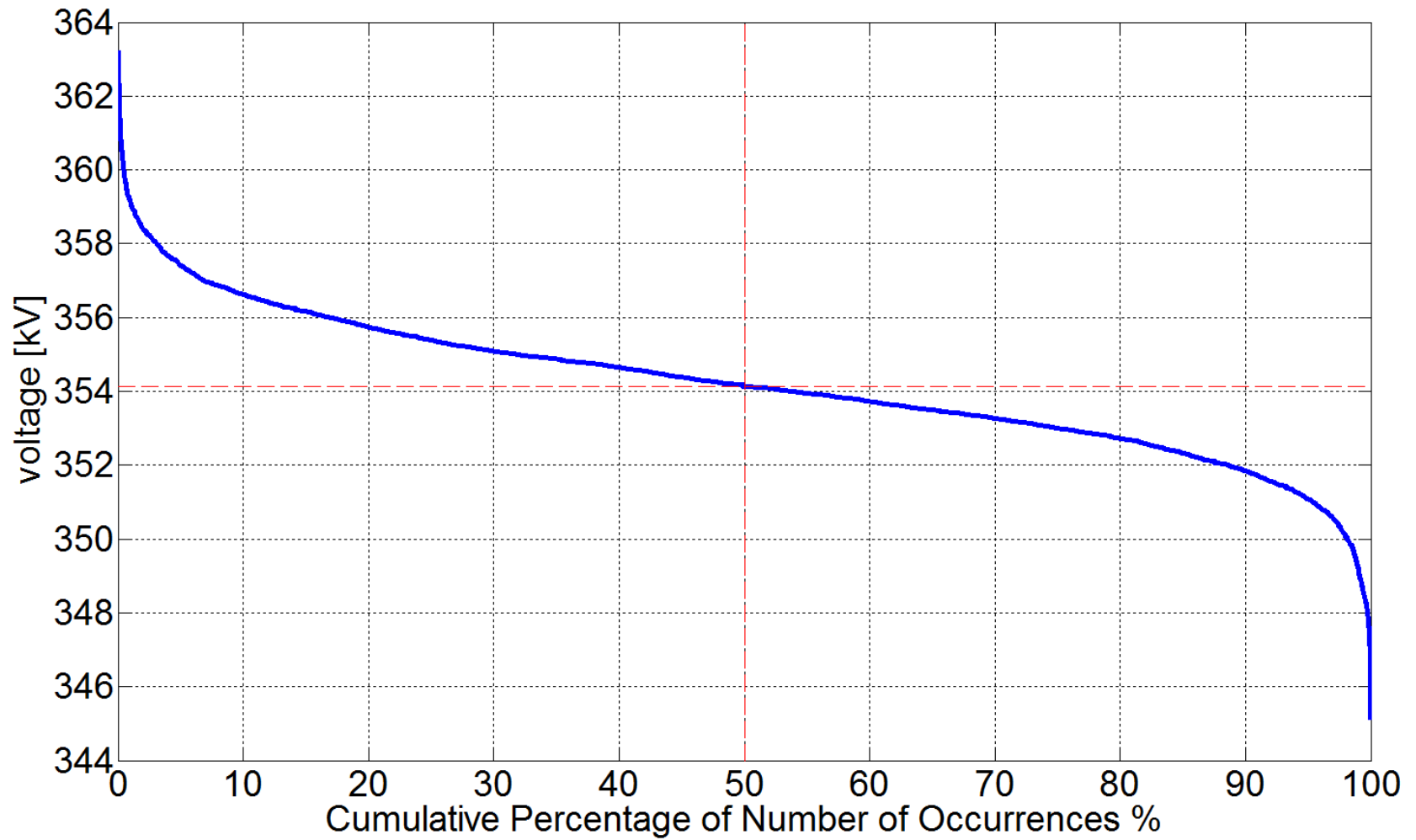
West 11



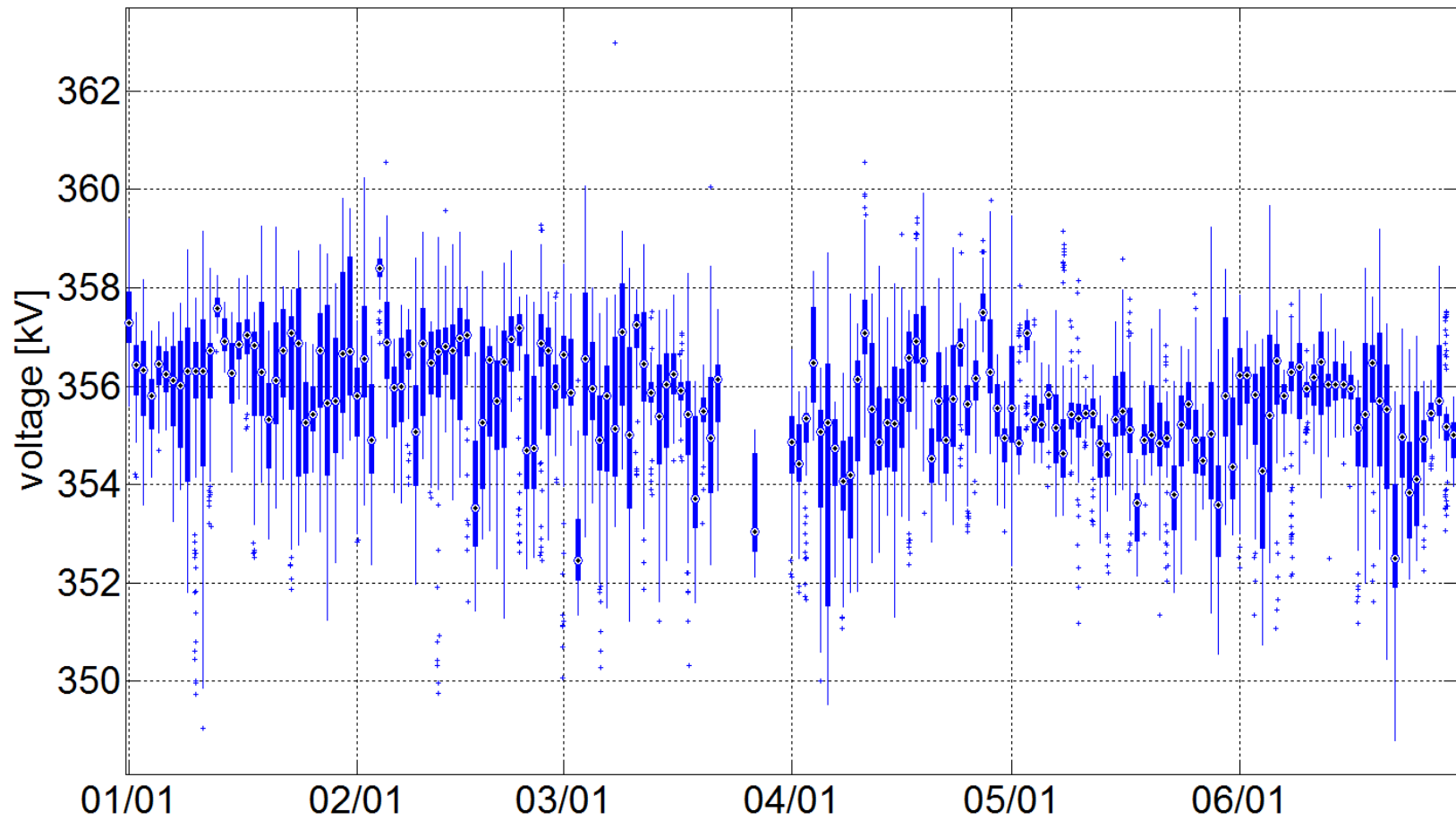
West 12*



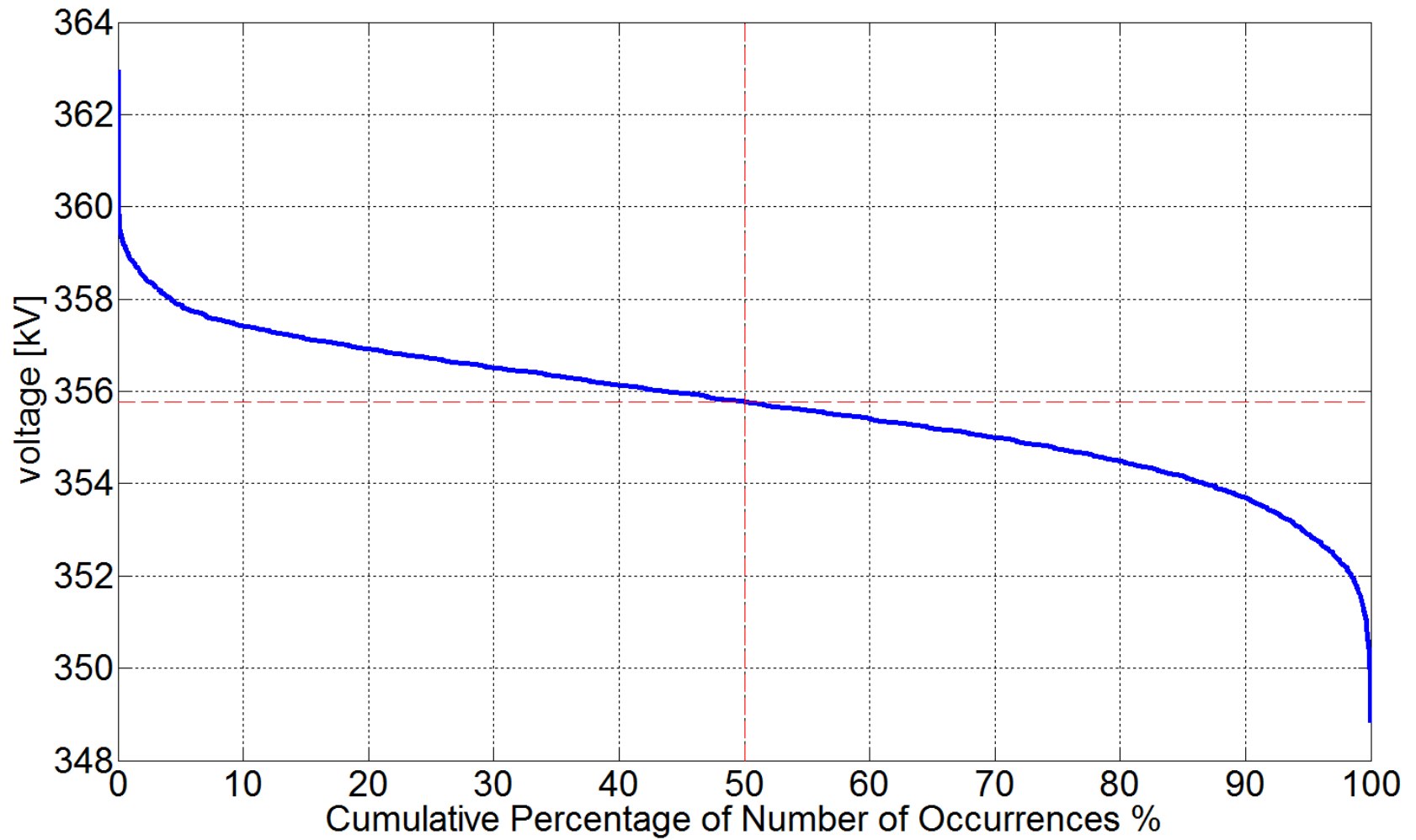
West 12*



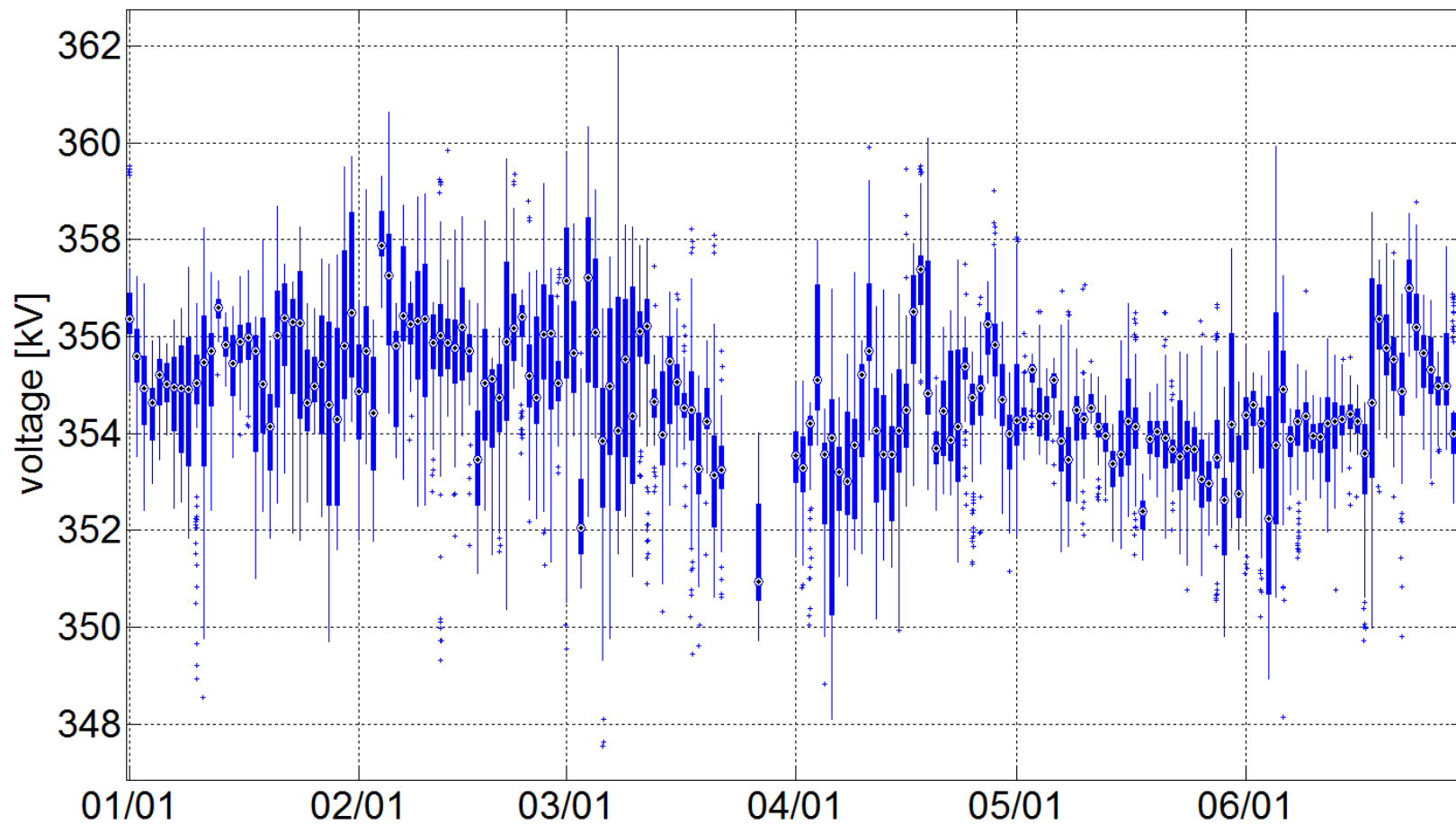
West 5*



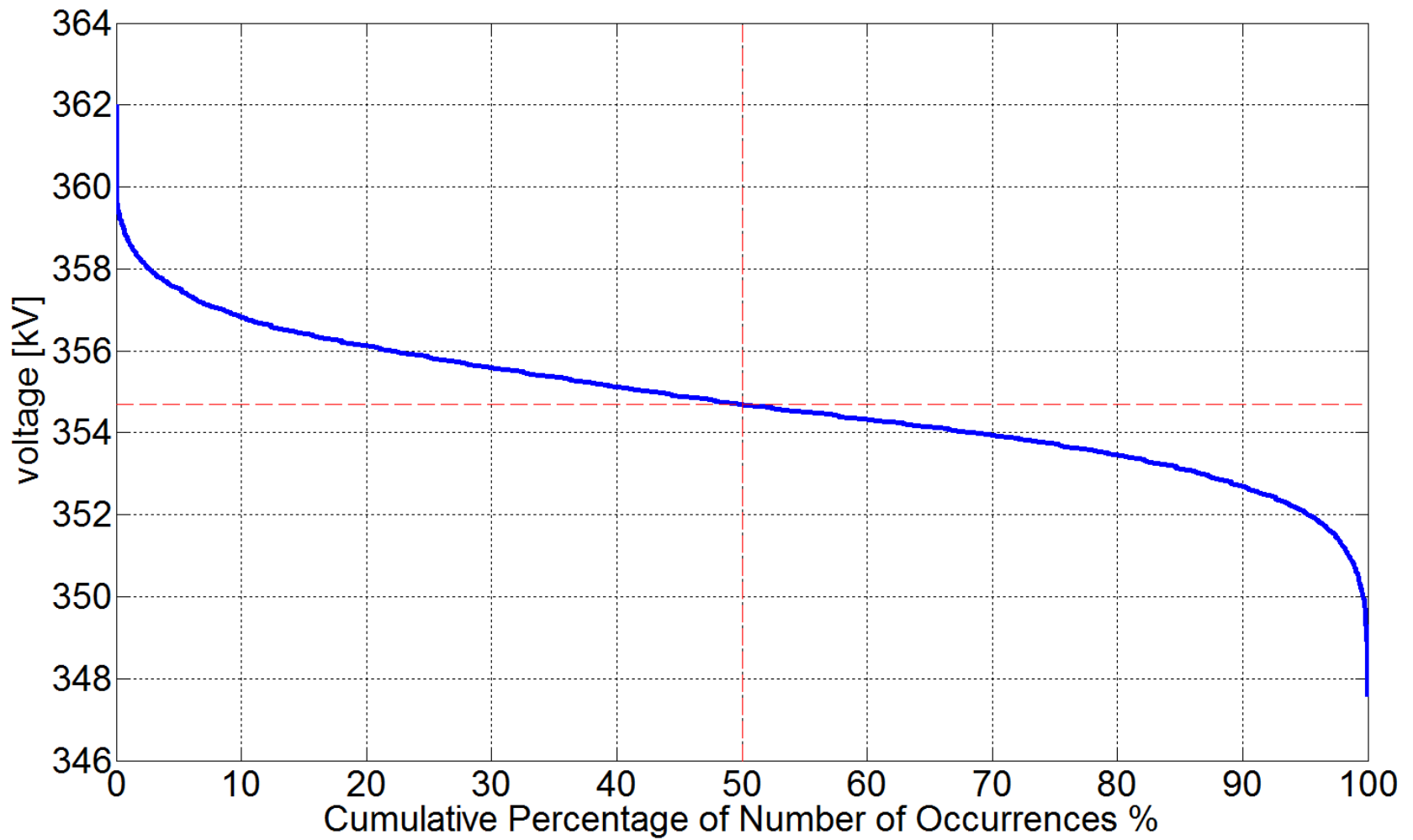
West 5*



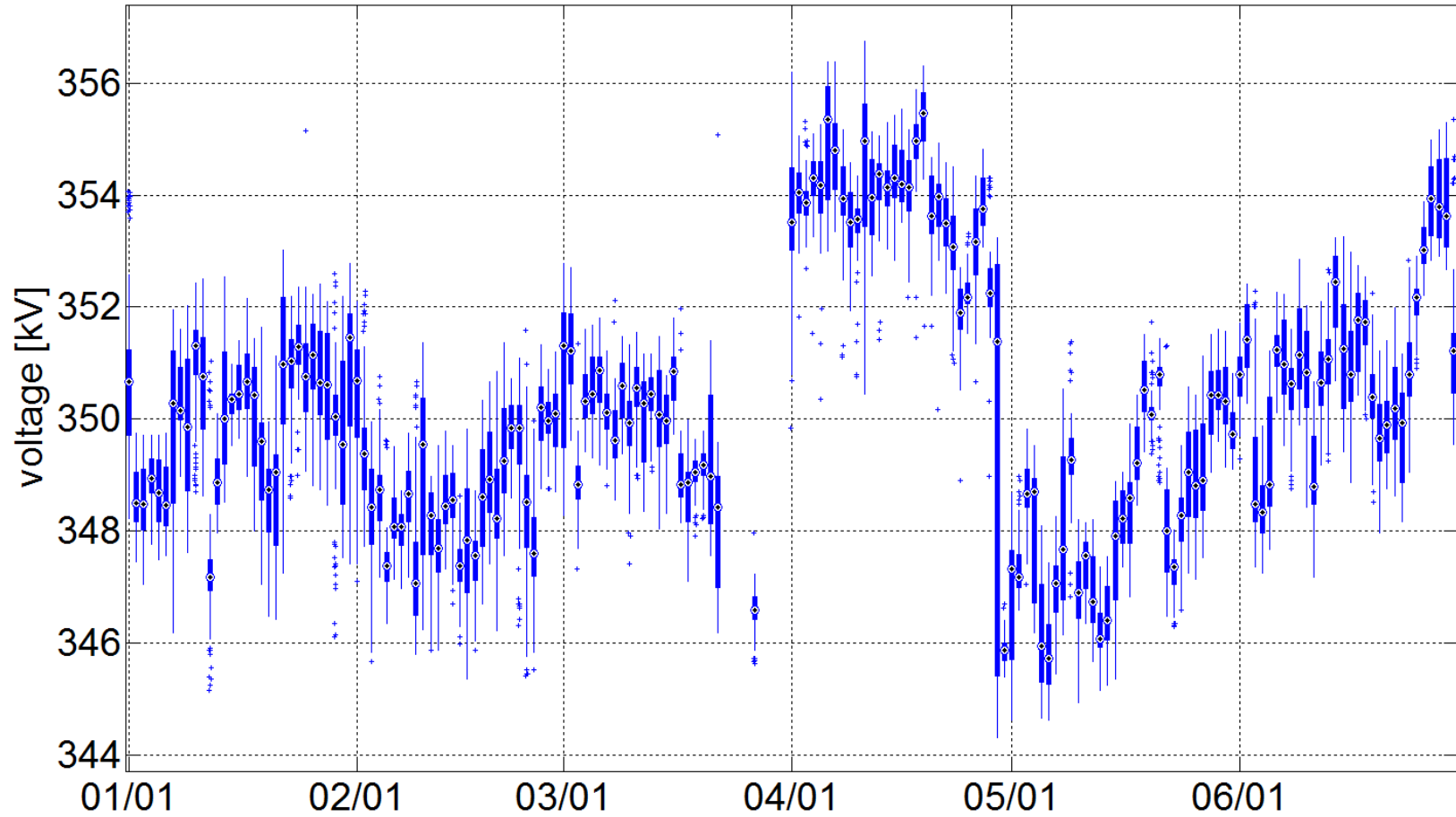
West 6



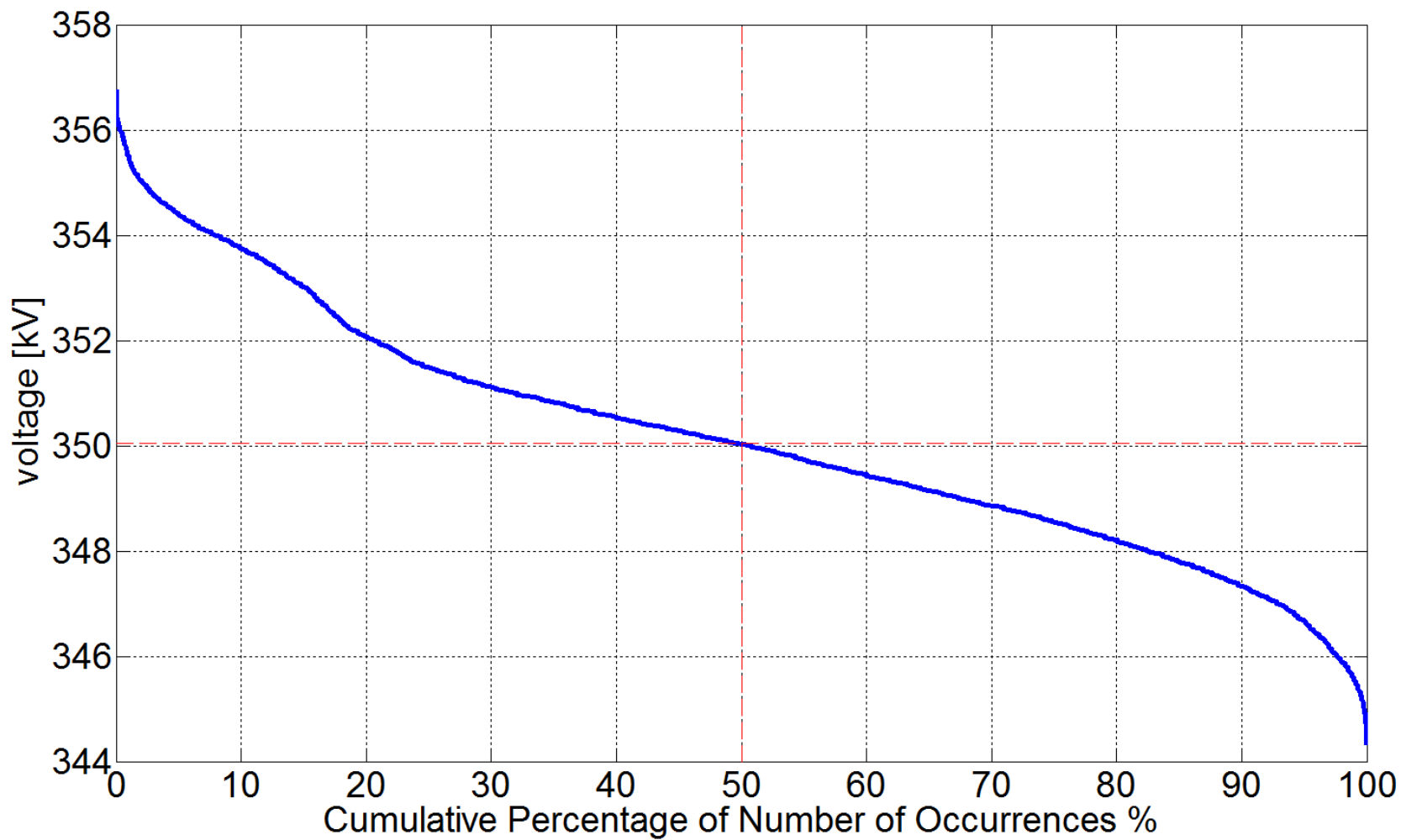
West 6



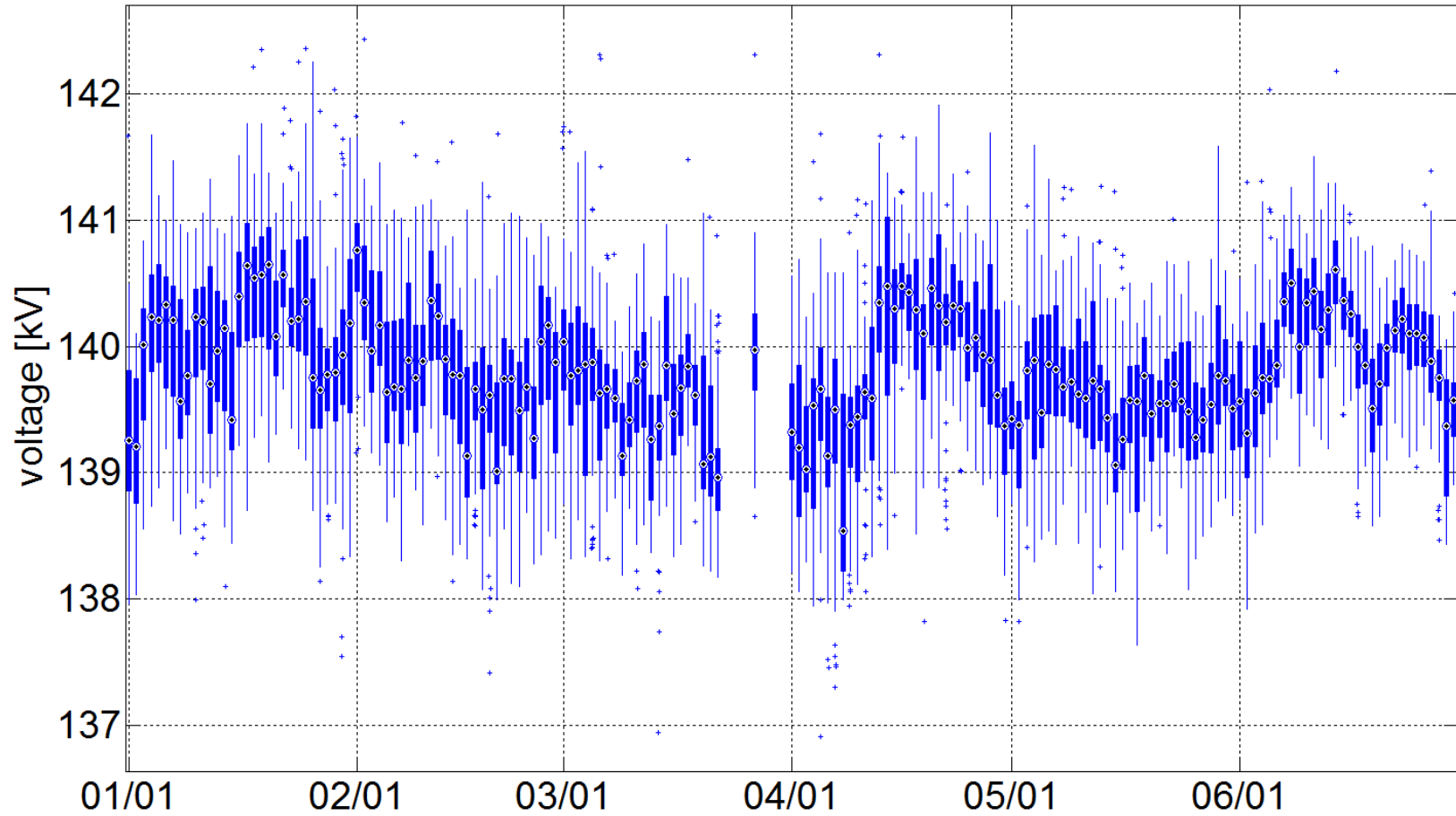
North 1



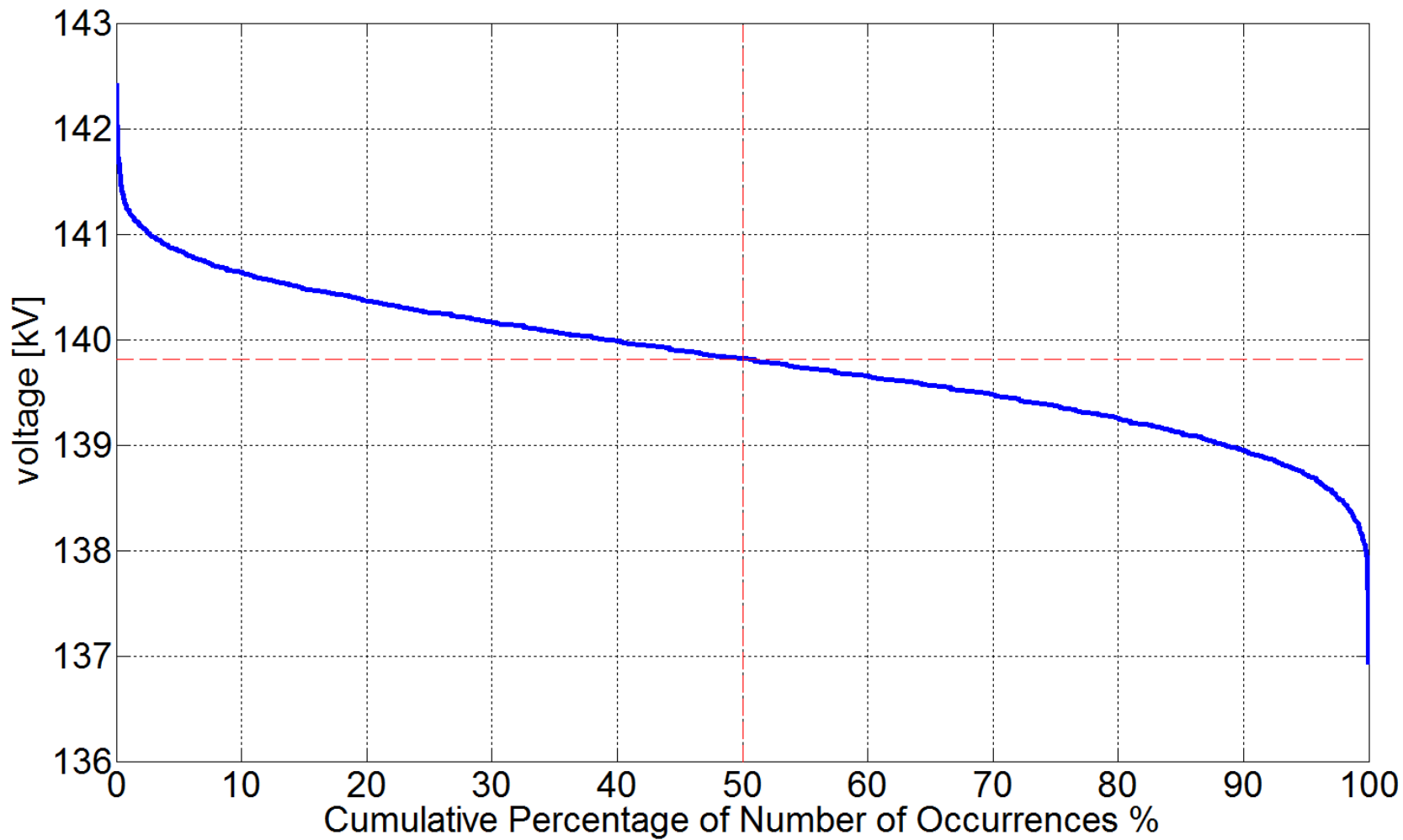
North 1



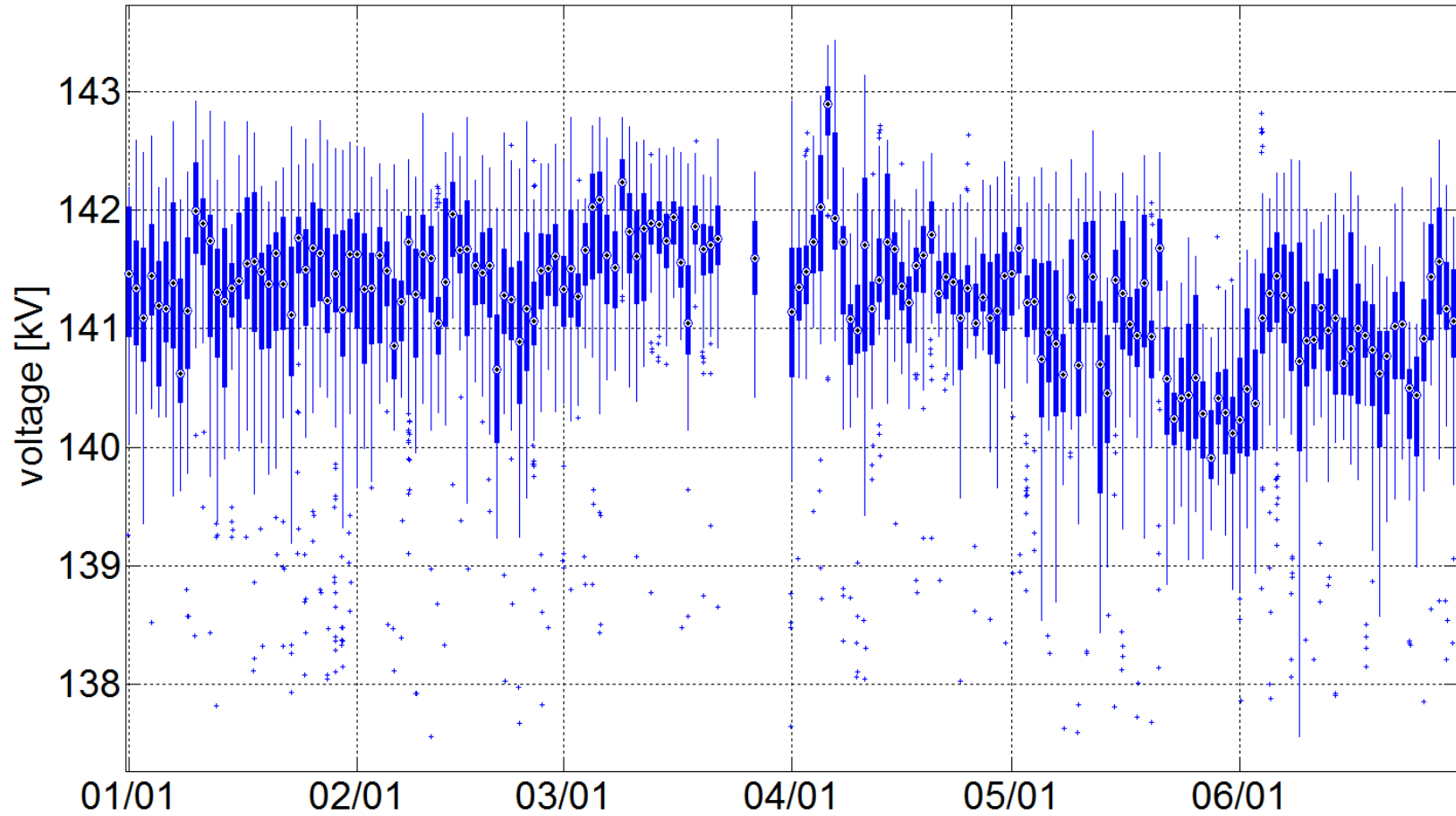
North 2



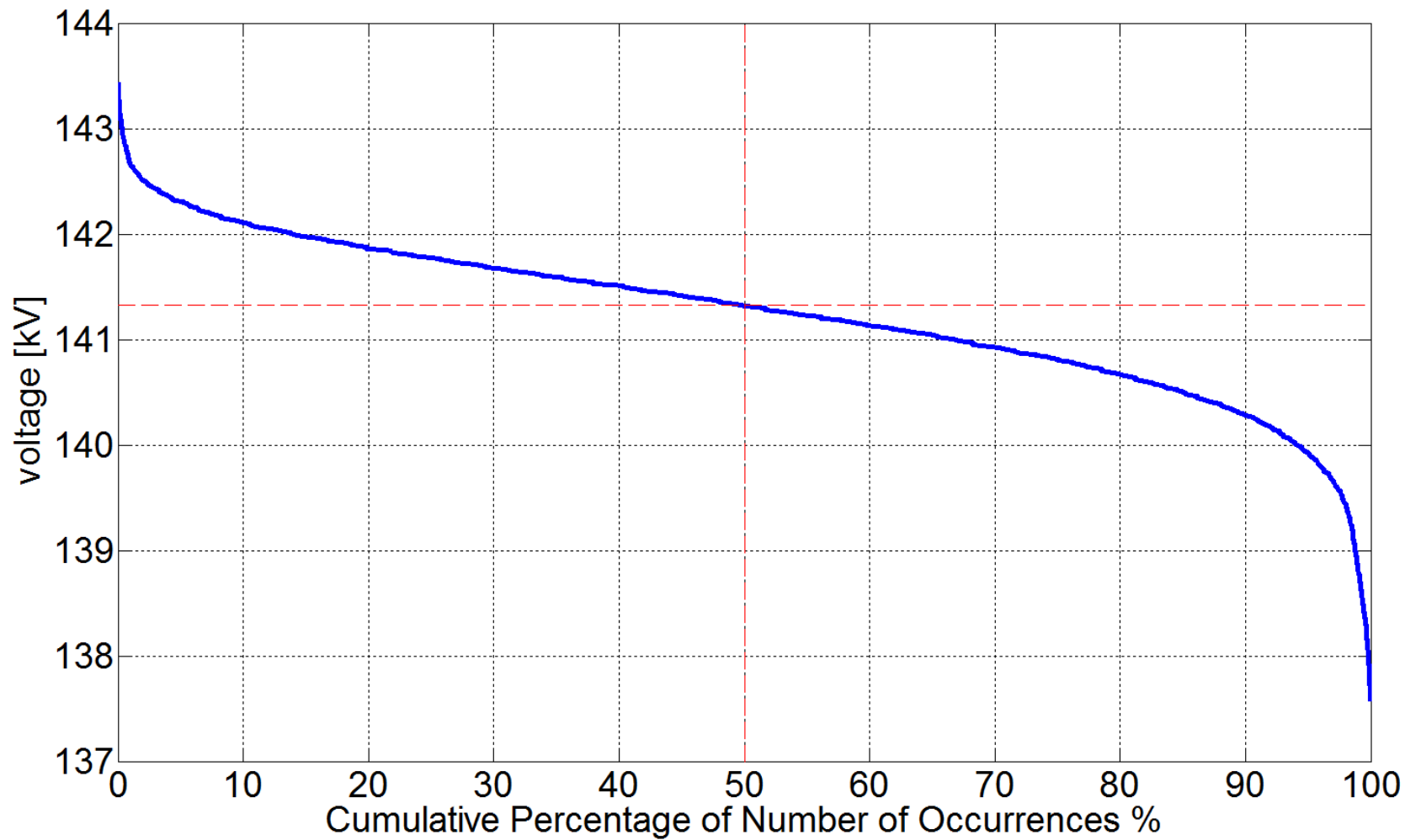
North 2



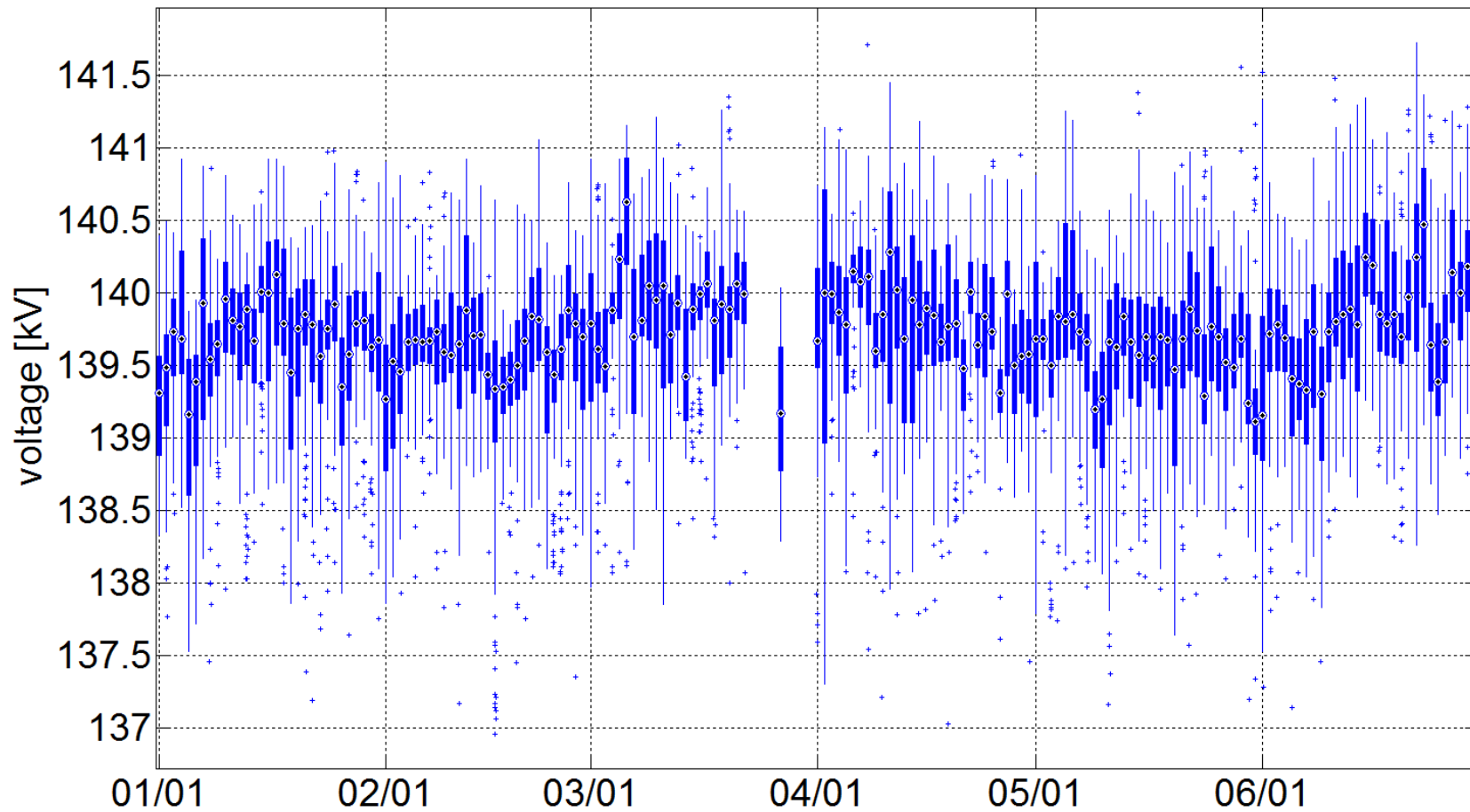
North 4



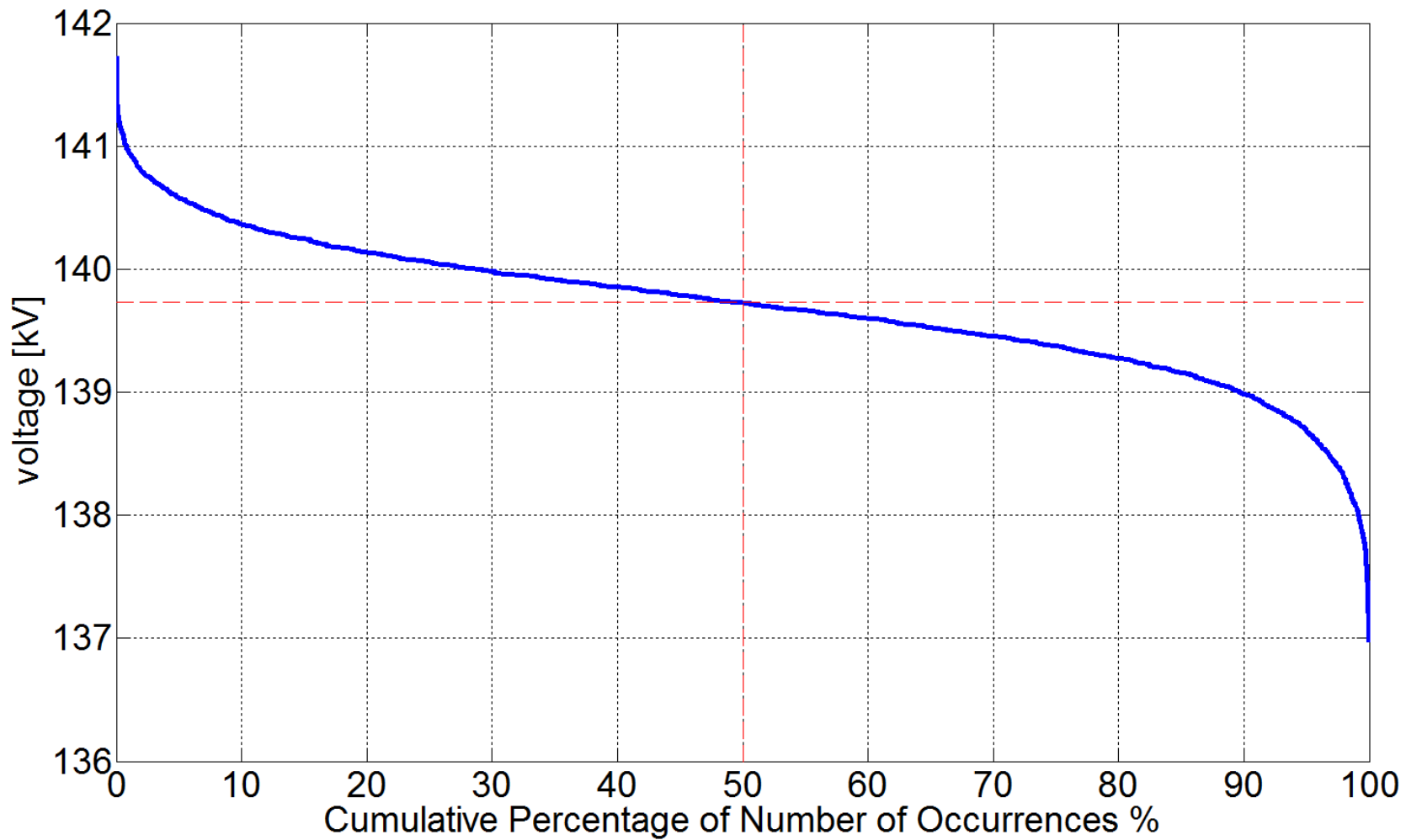
North 4



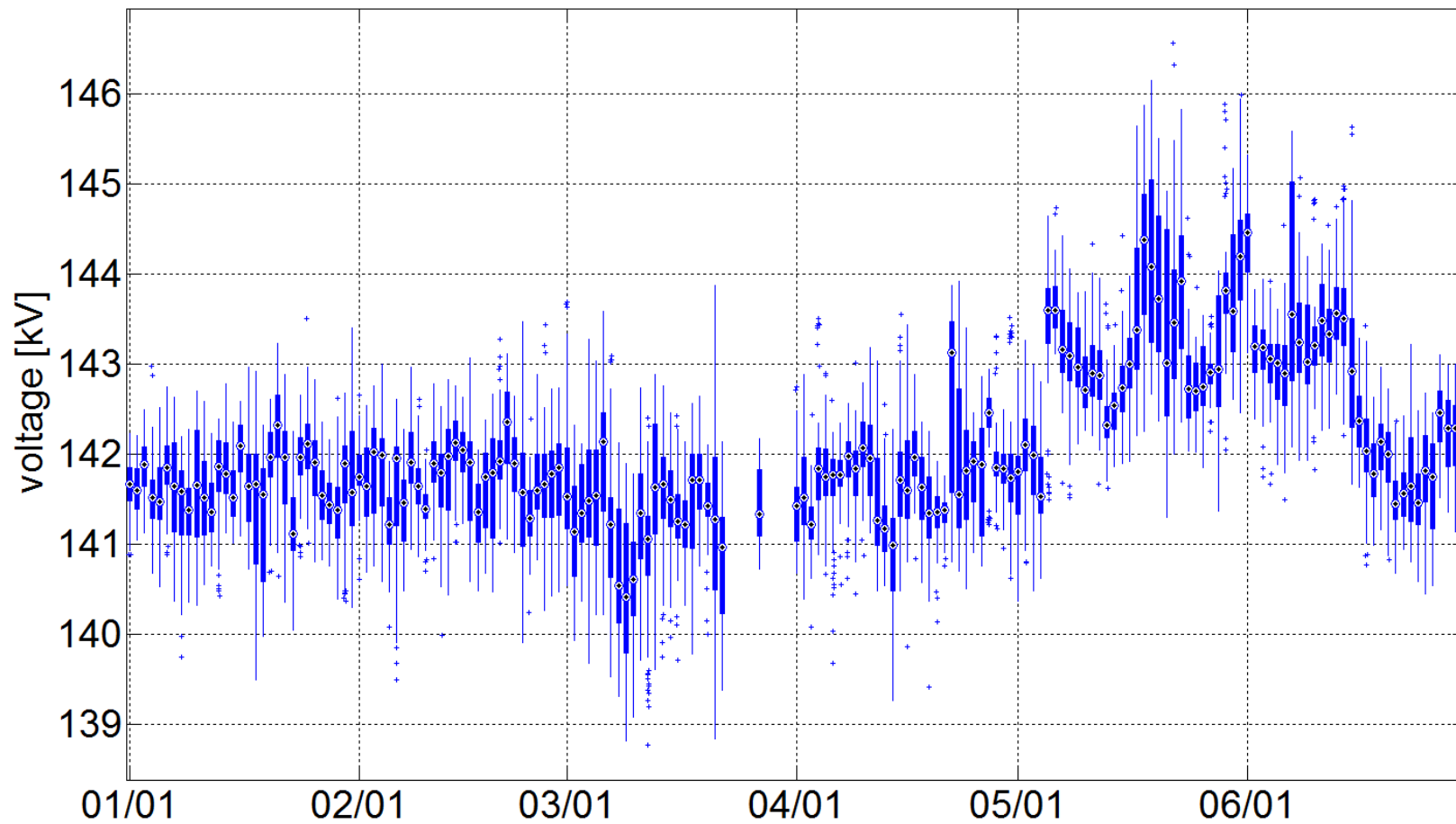
North 5



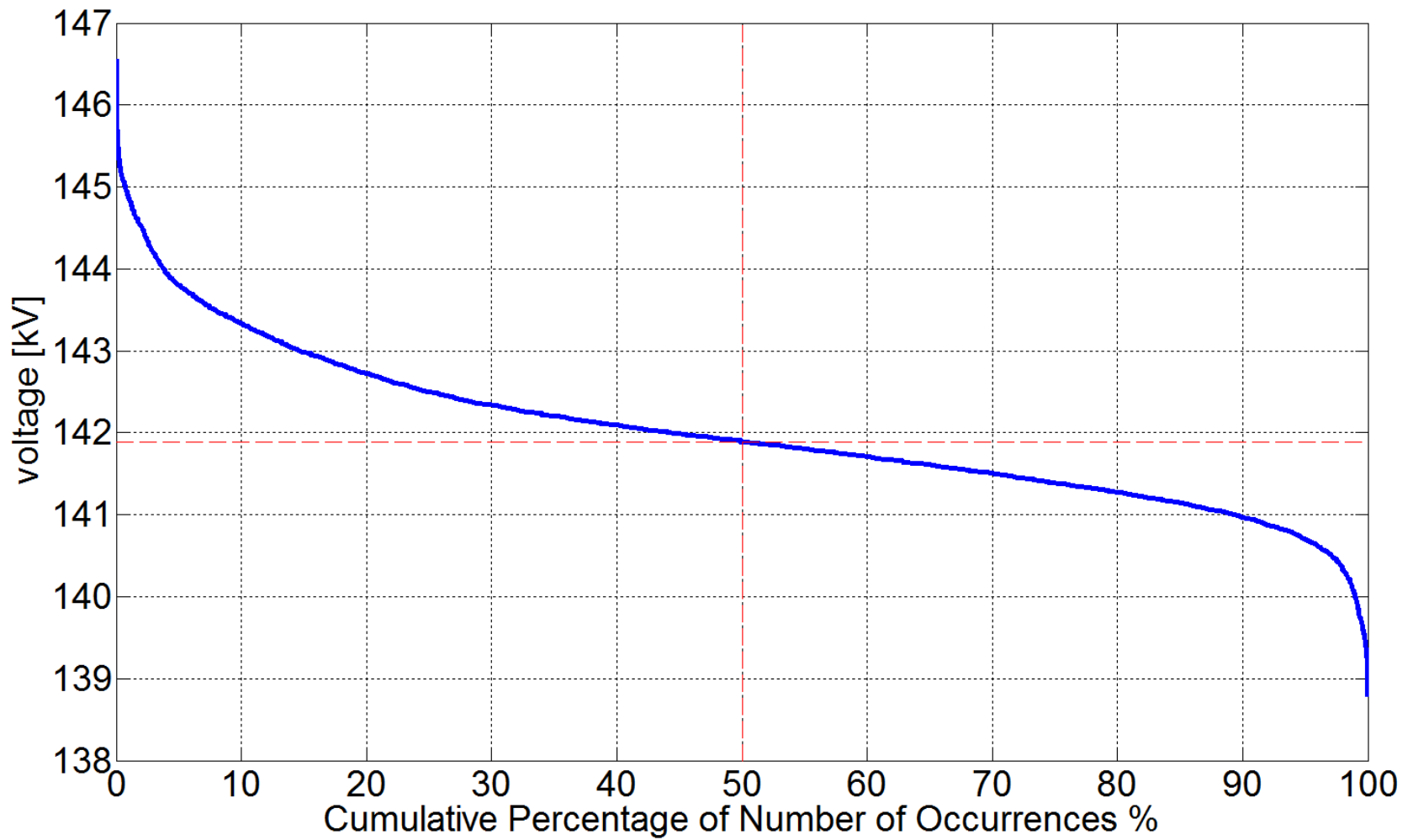
North 5



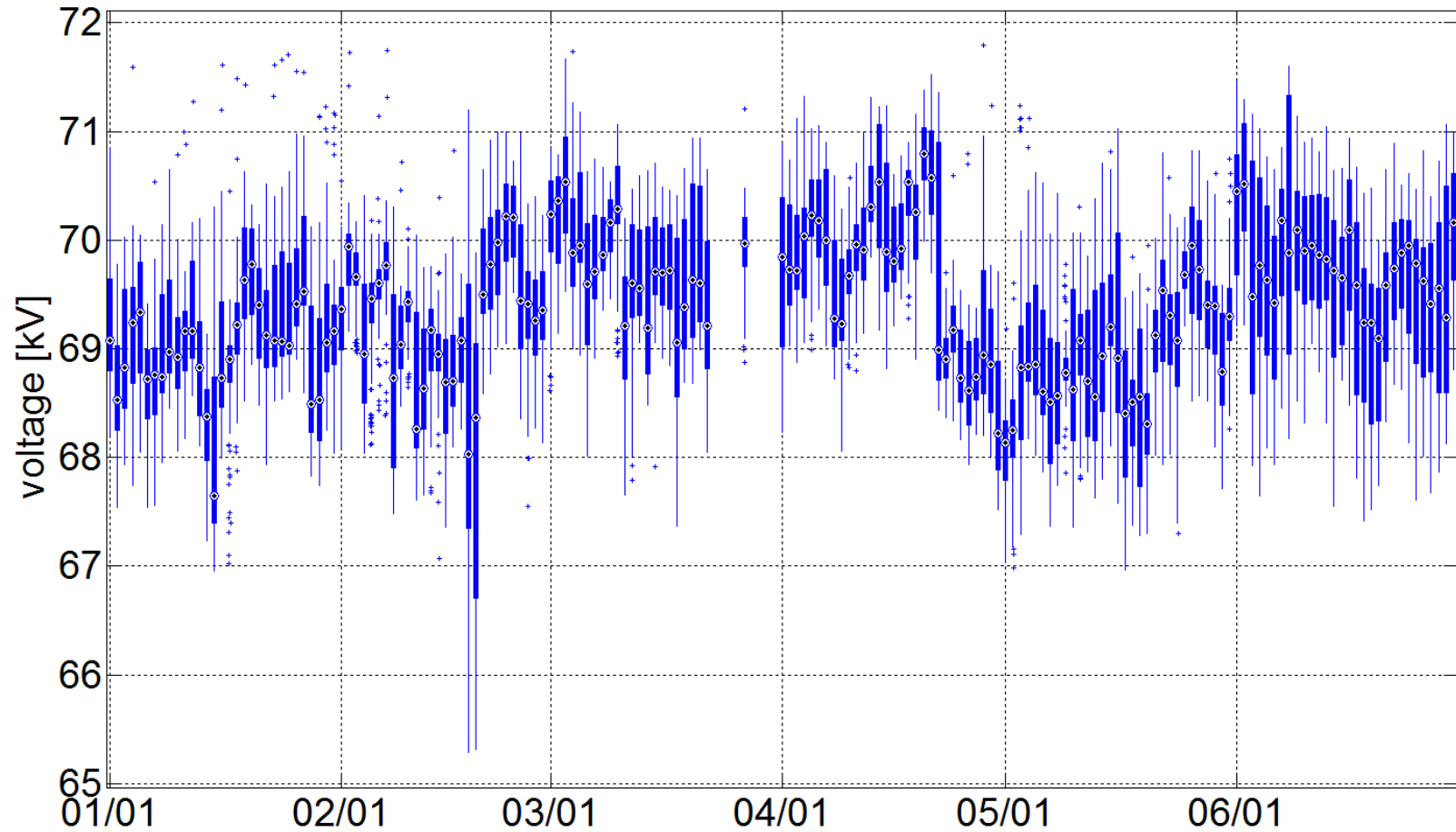
North 6



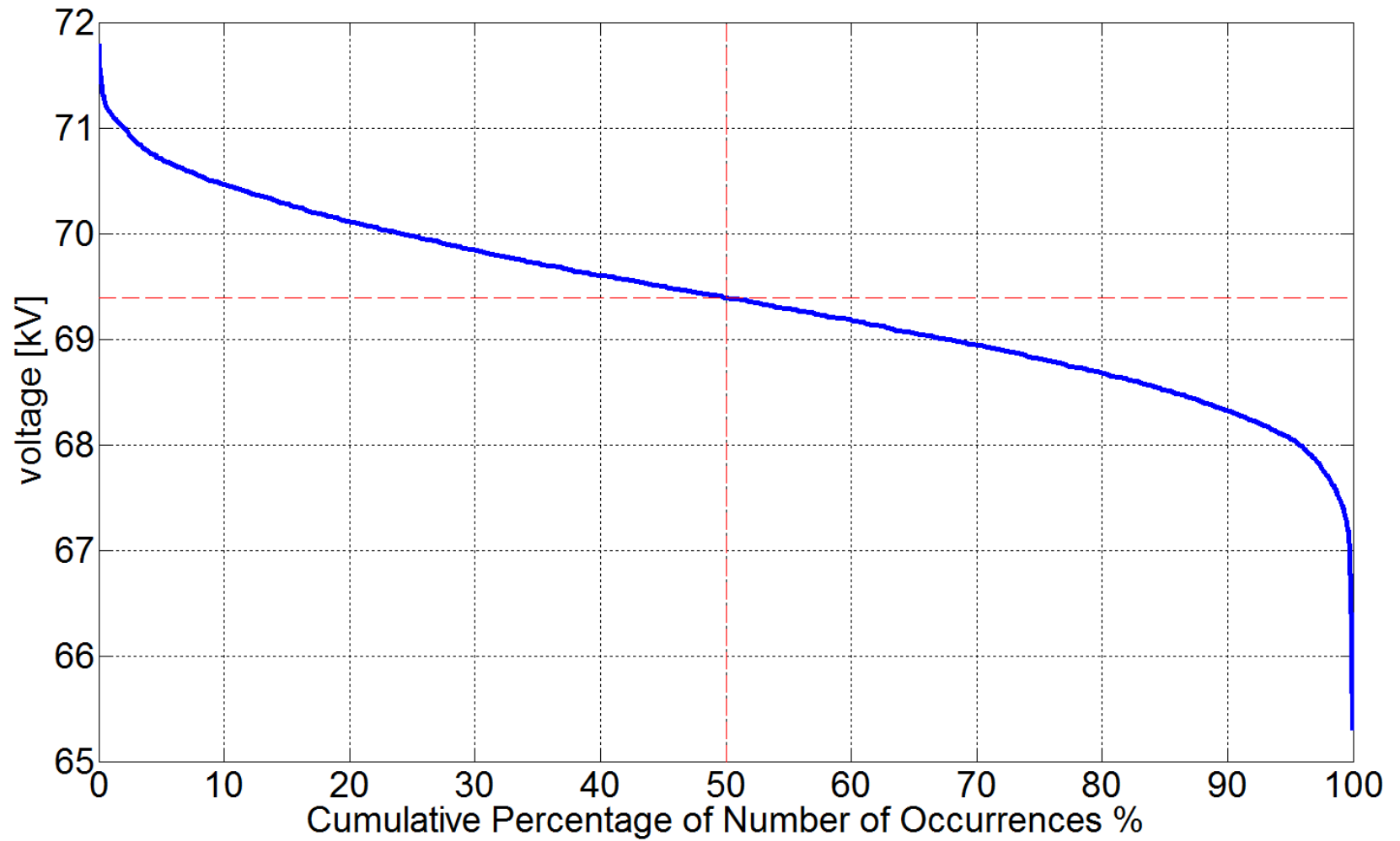
North 6



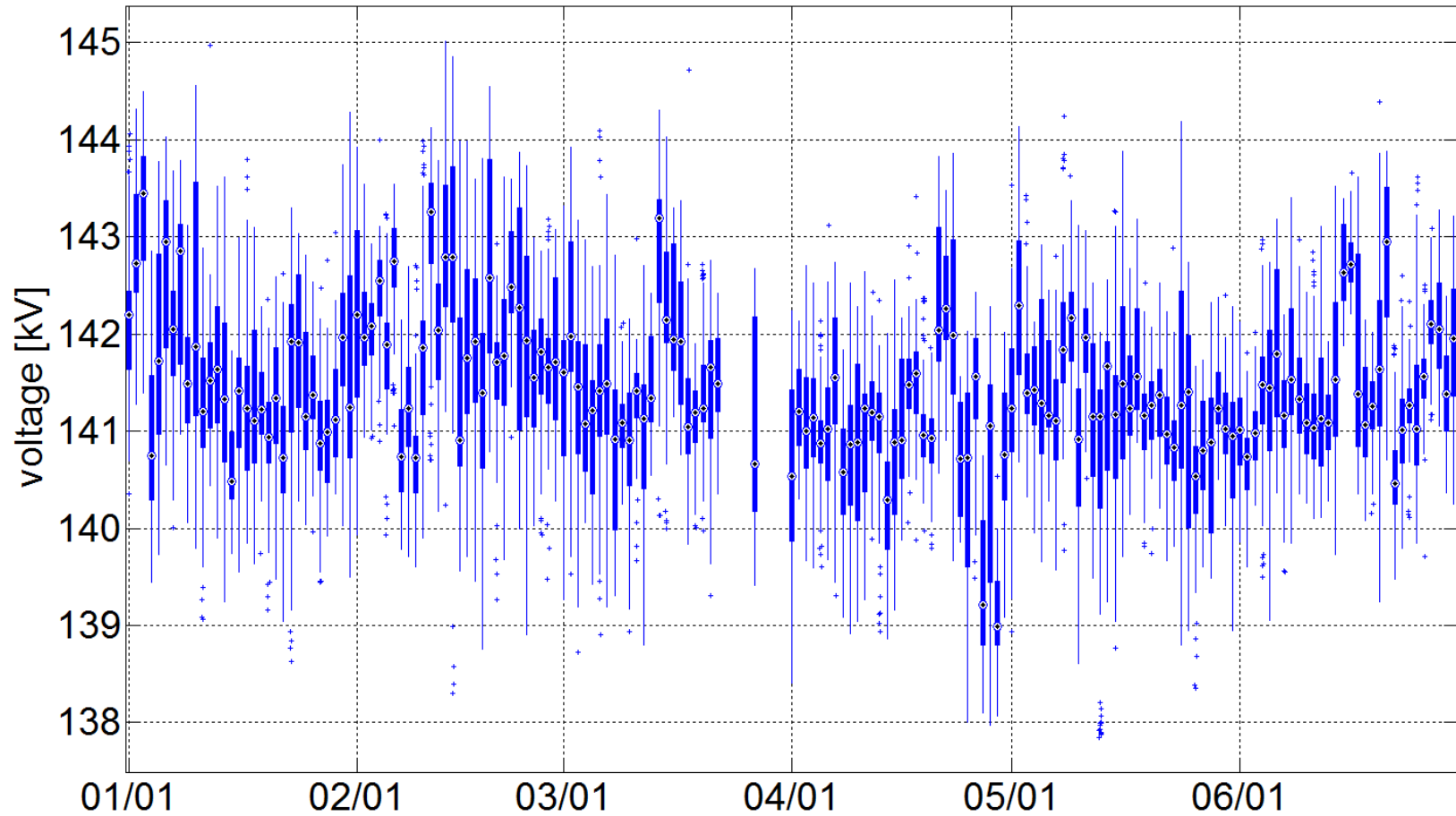
FarWest 2*



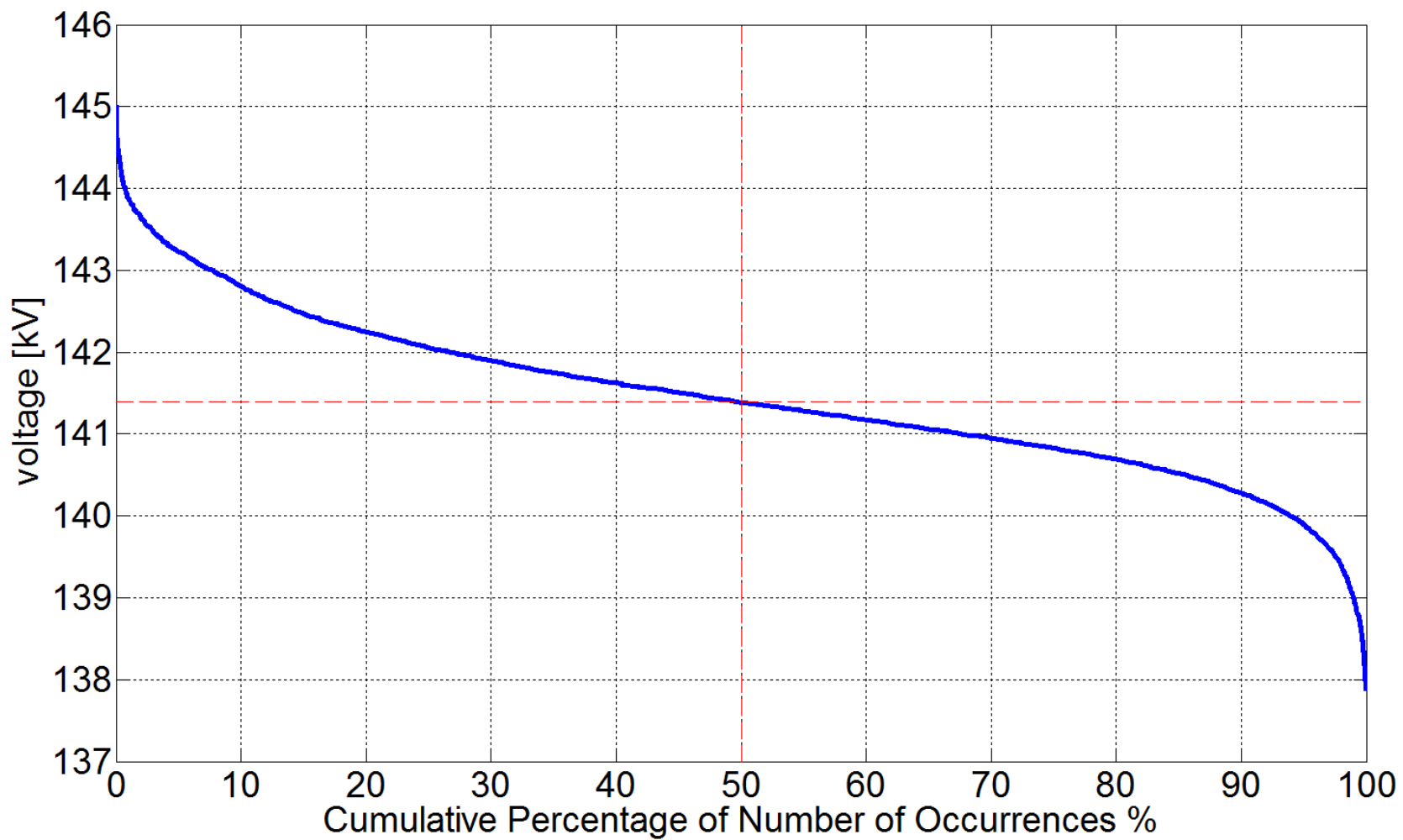
FarWest 2*



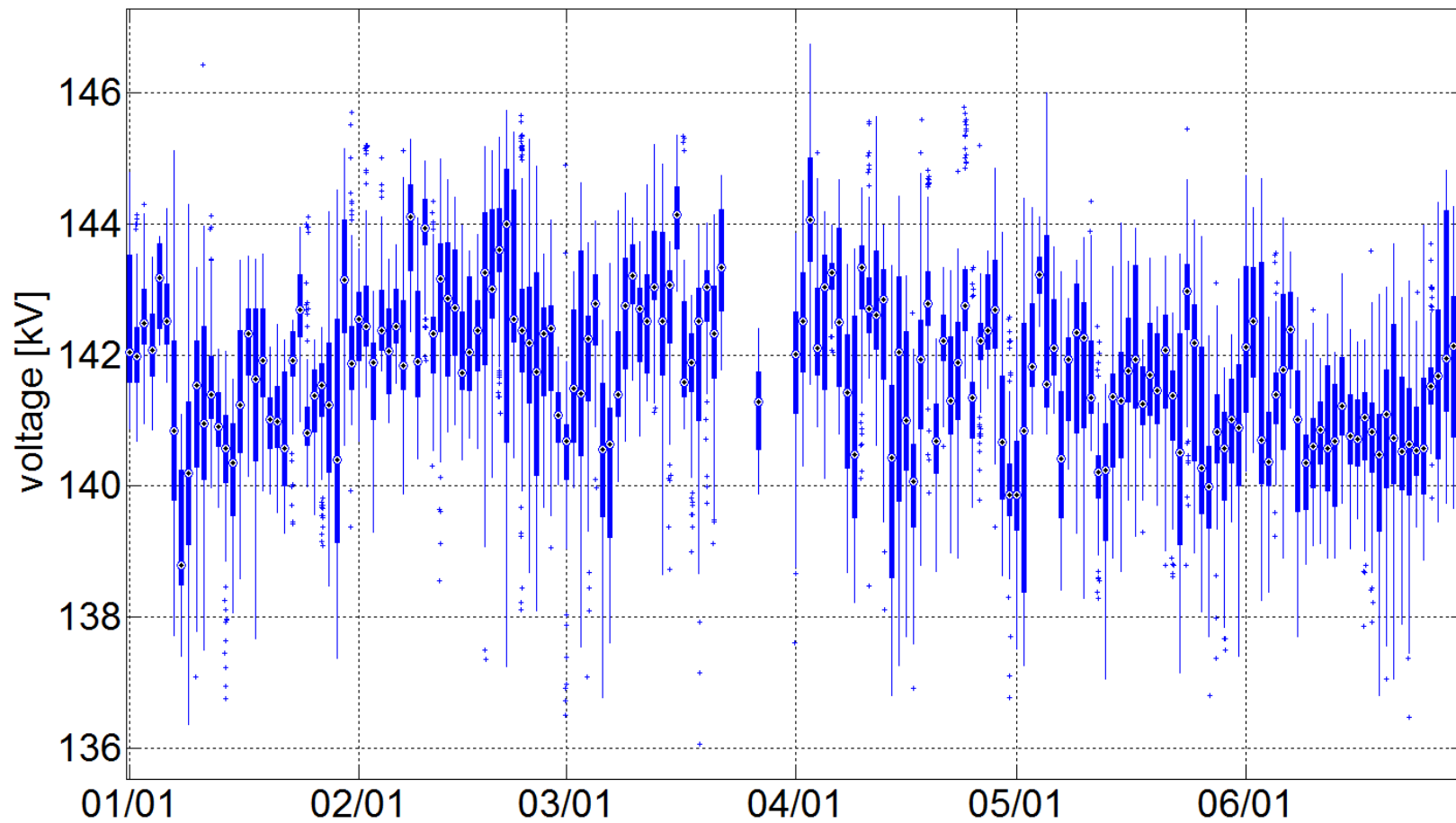
North 7



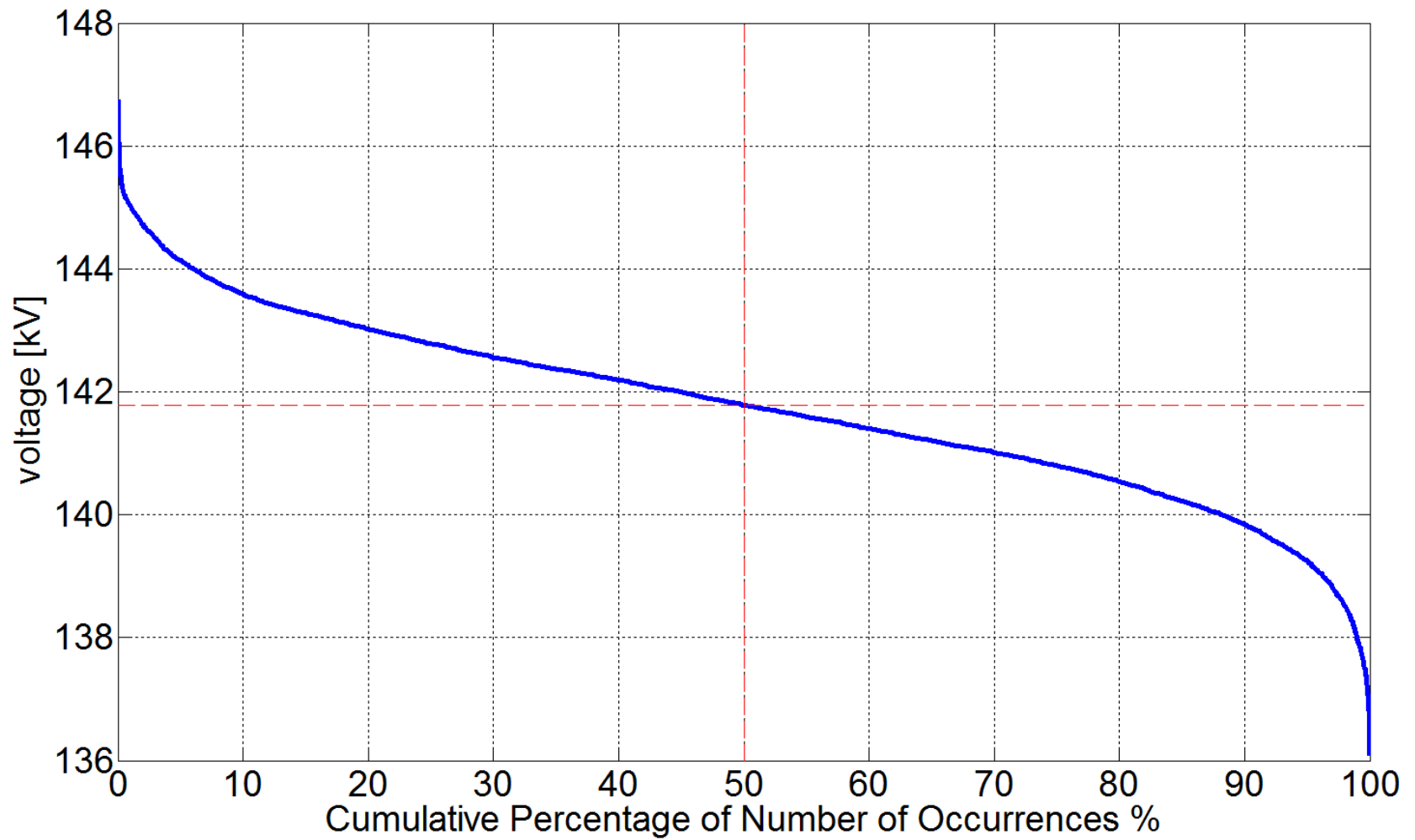
North 7



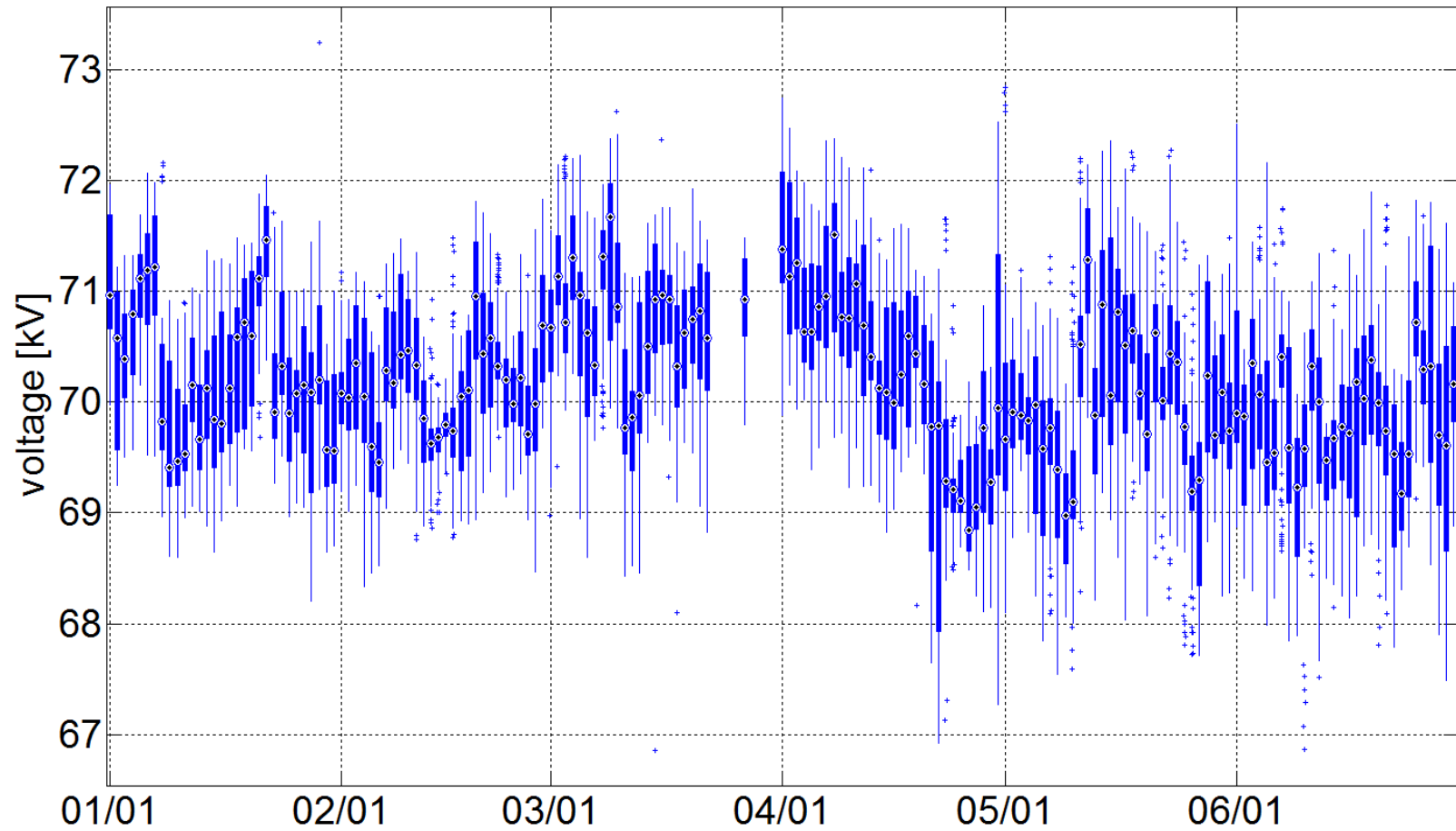
West 4



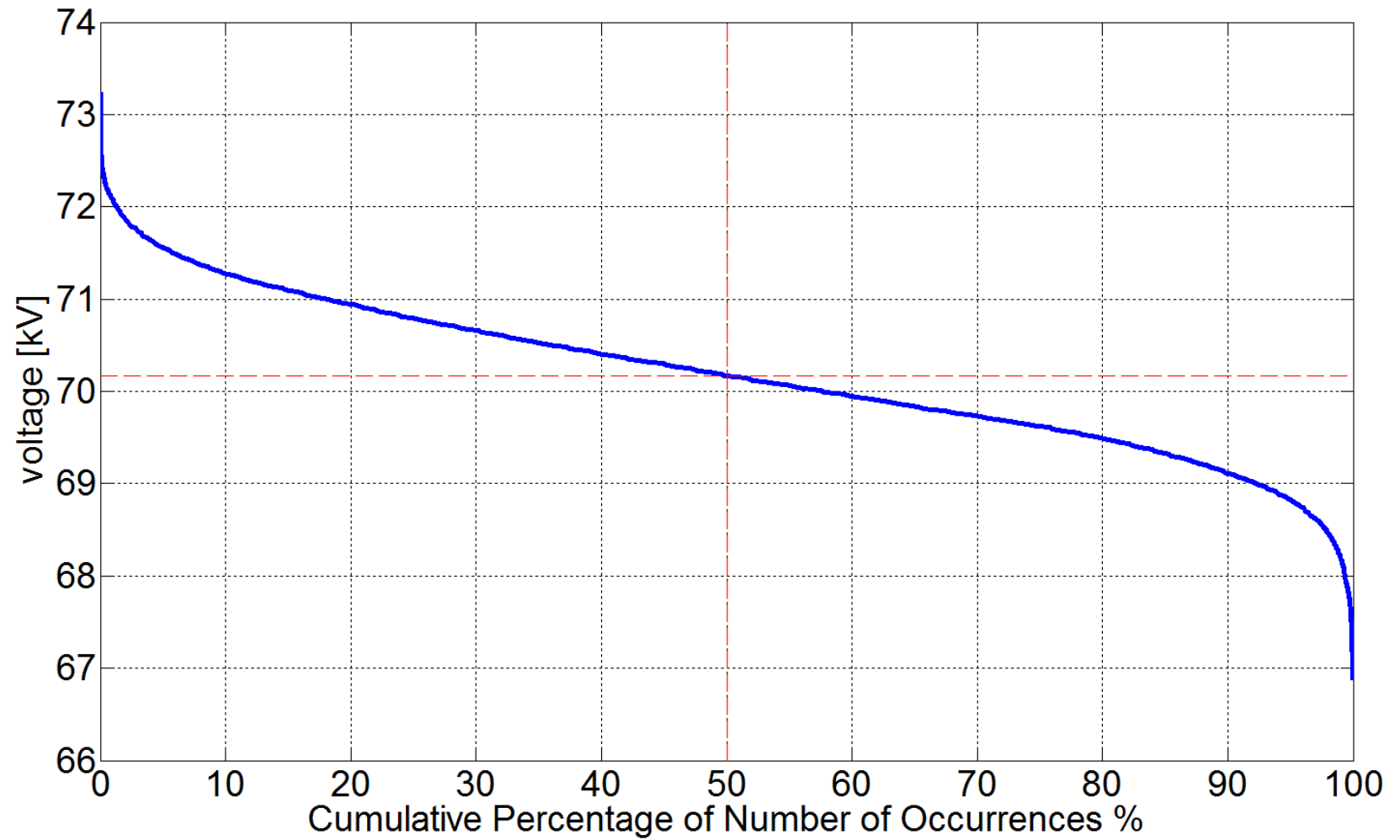
West 4



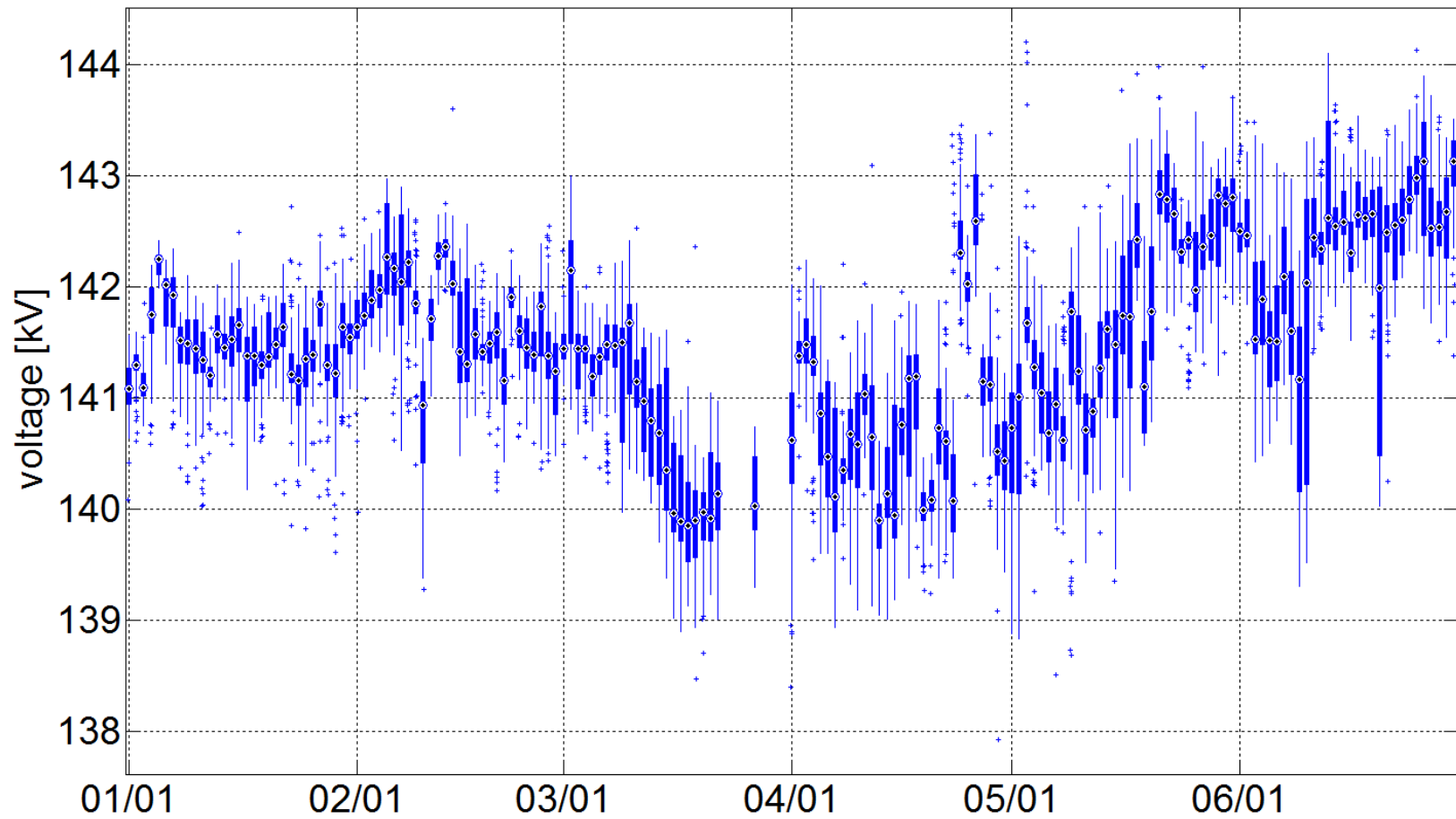
Coast 2*



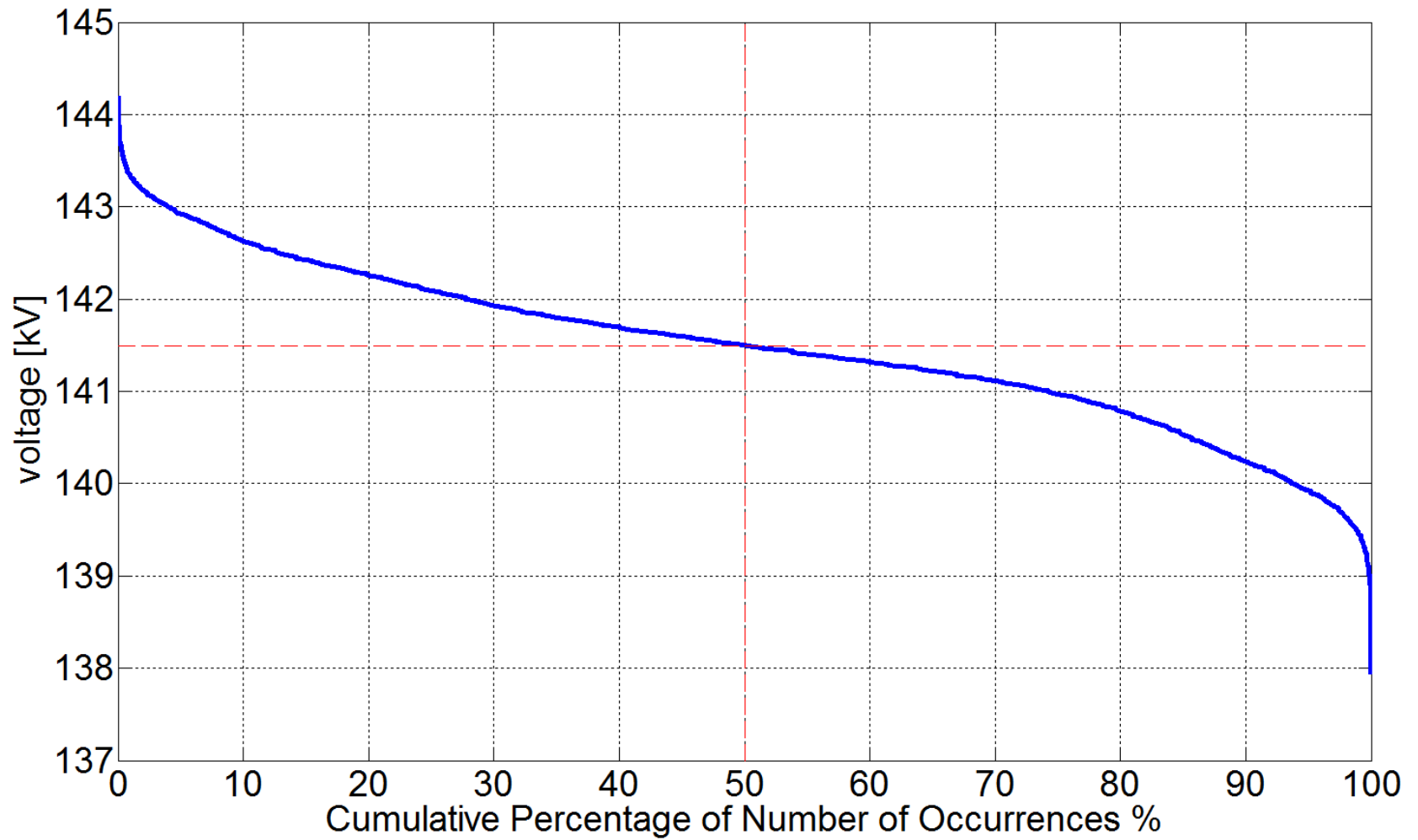
Coast 2*



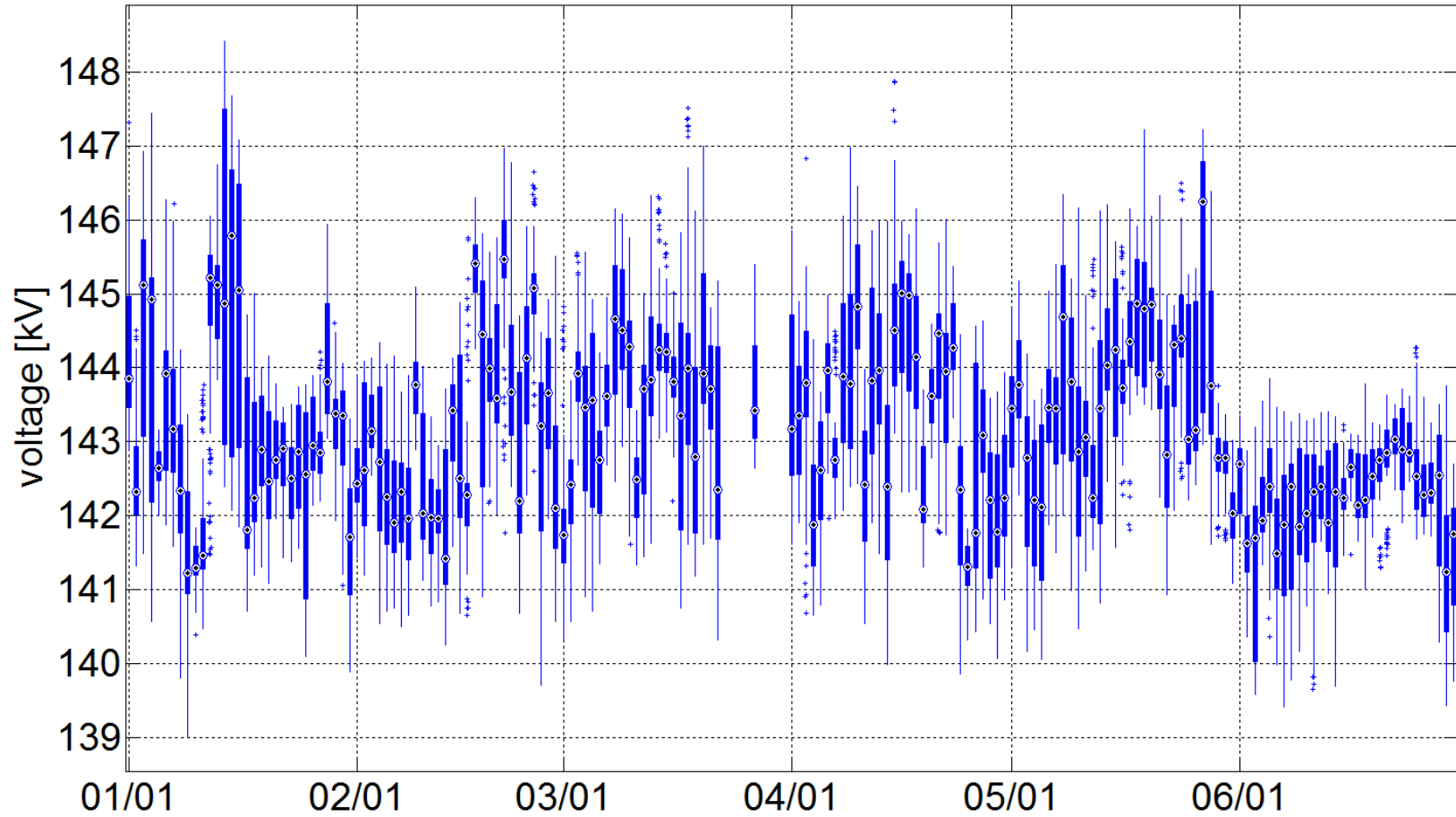
Coast 1



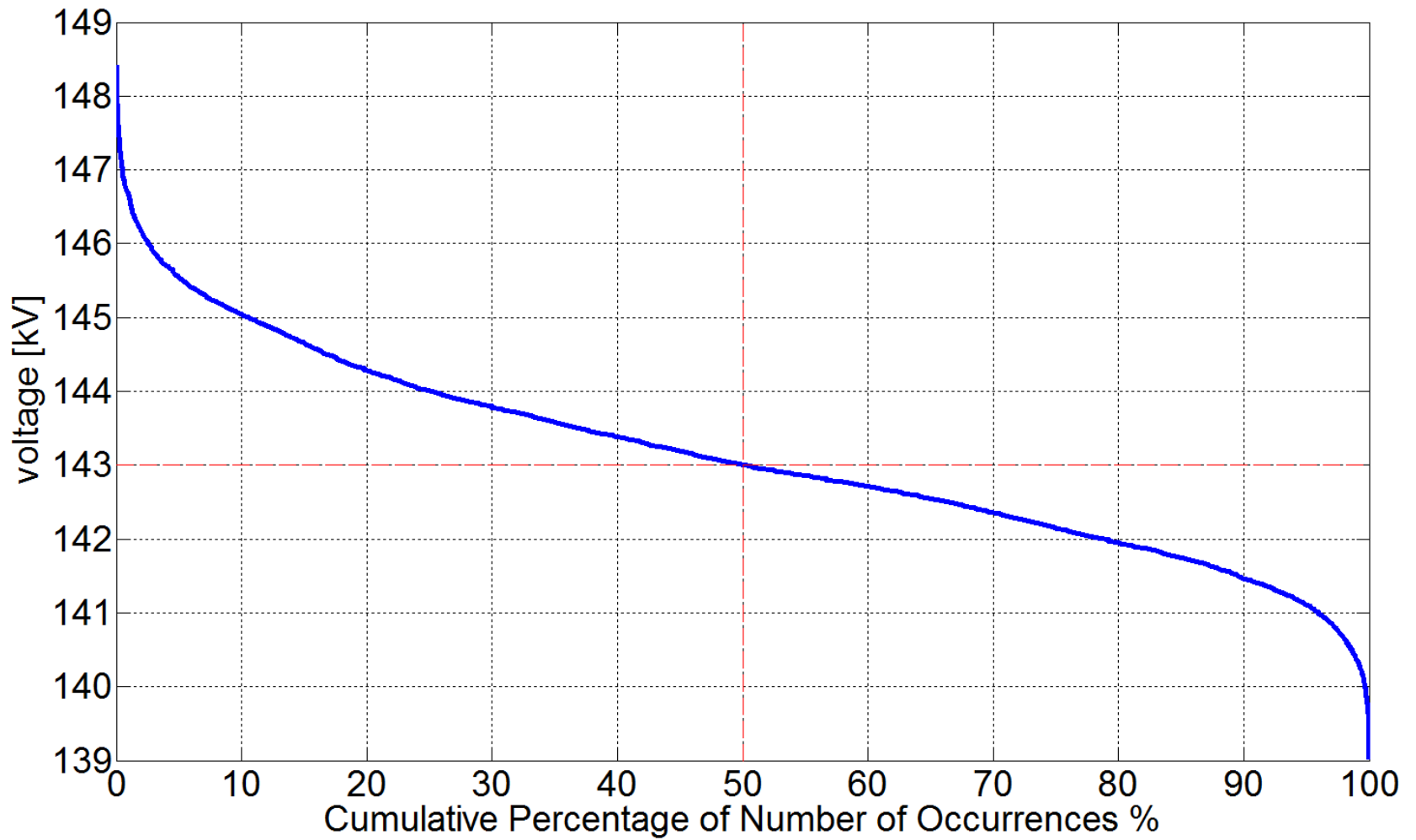
Coast 1



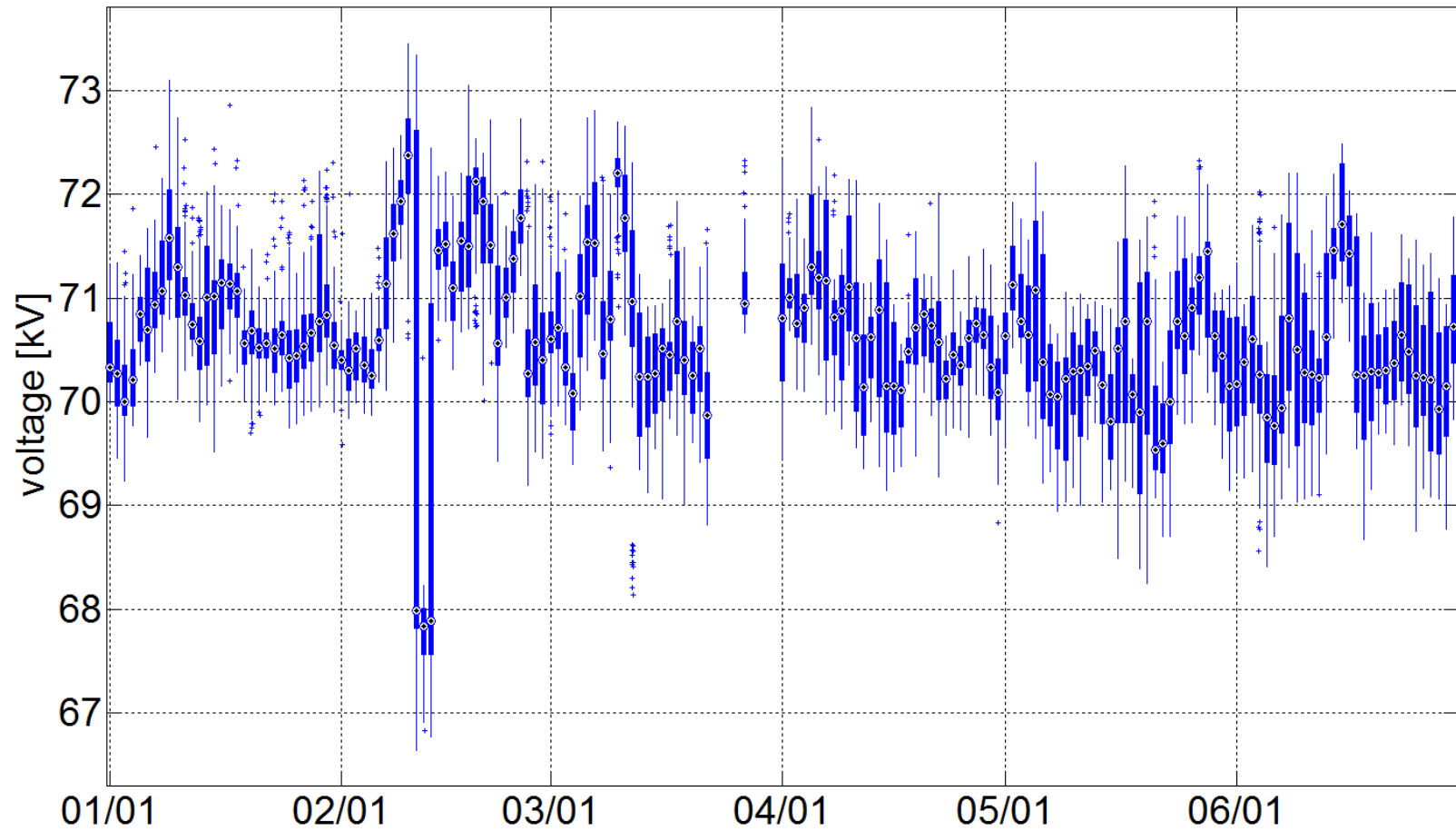
South 3*



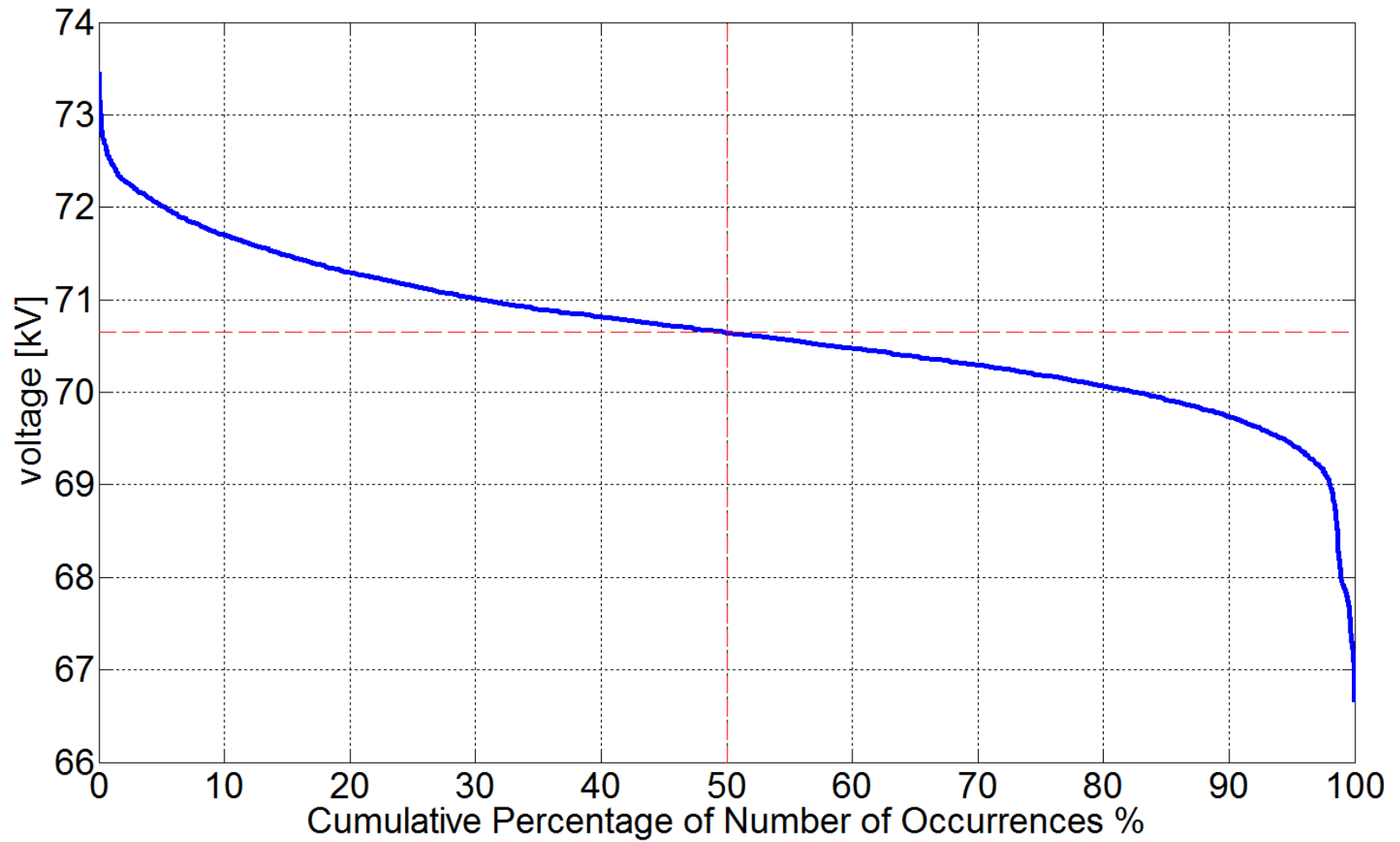
South 3*



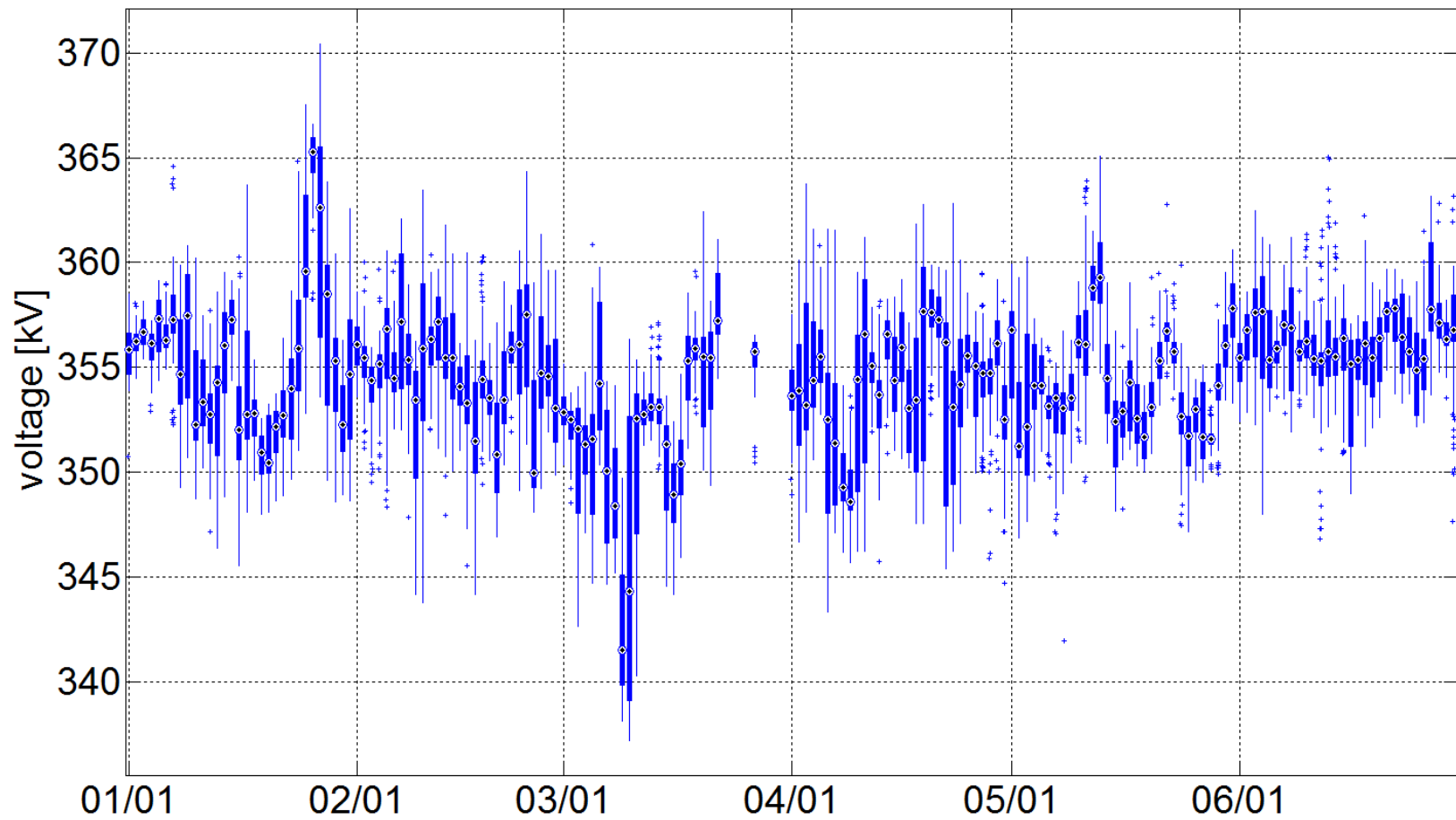
South 5*



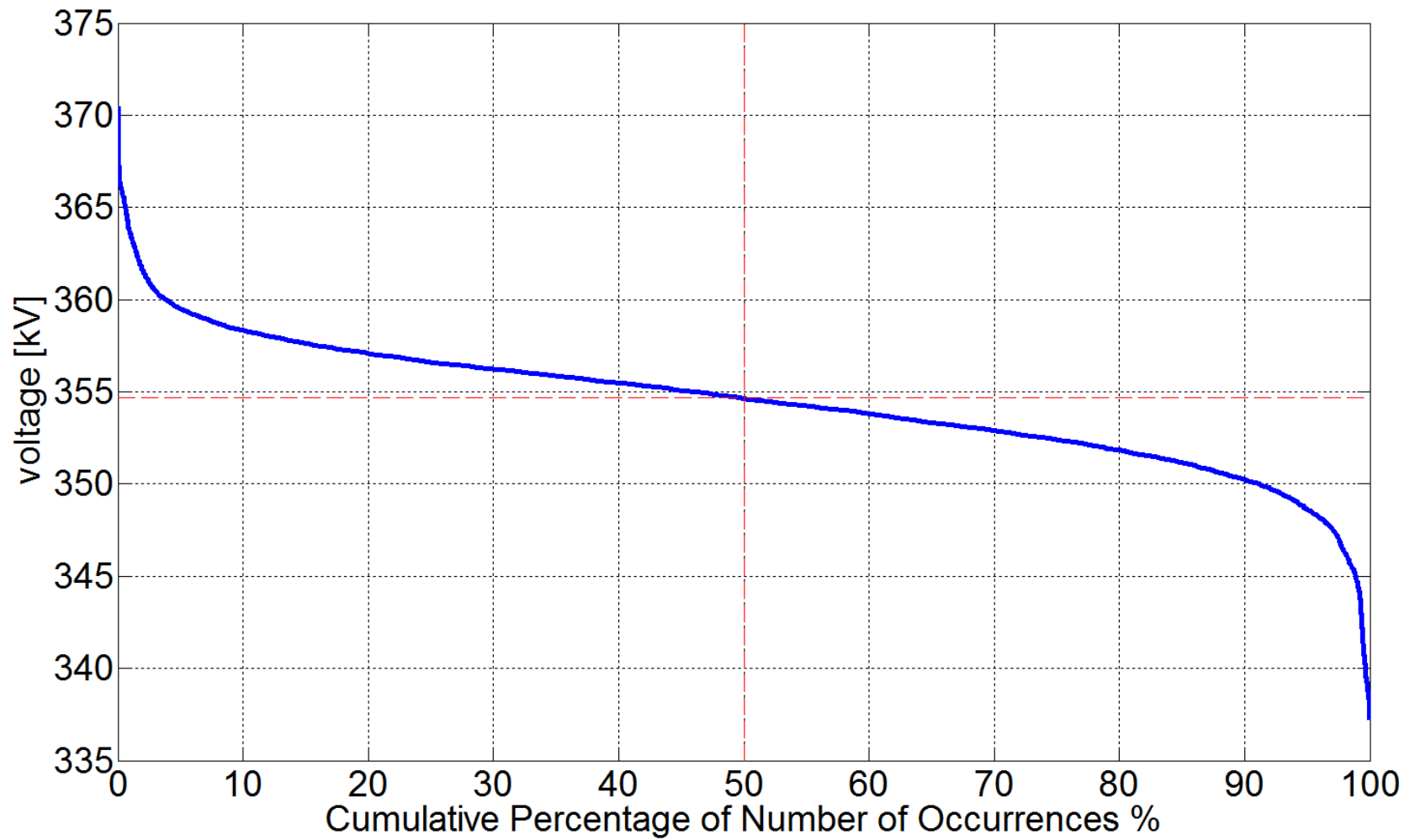
South 5*



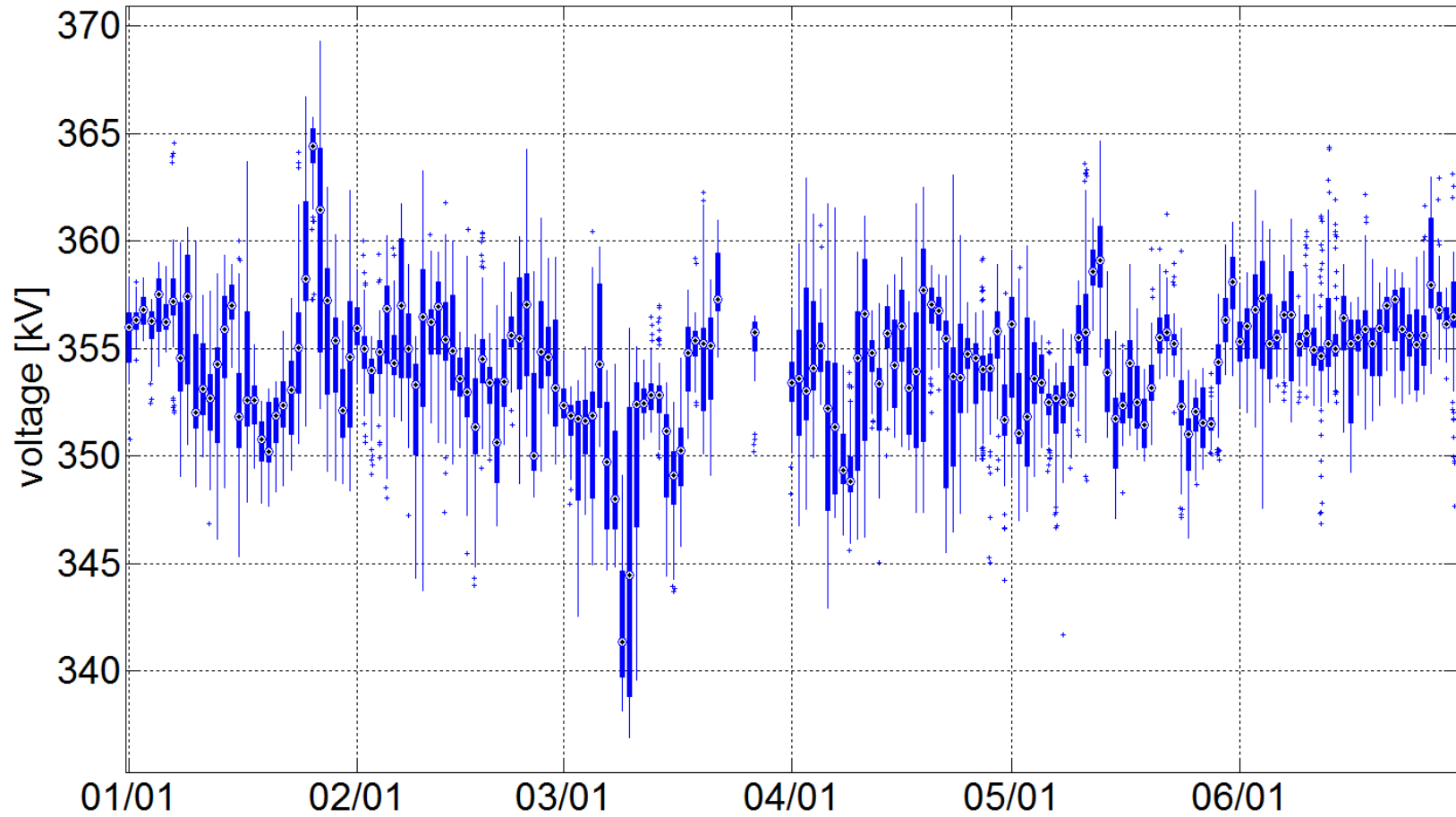
Coast 4



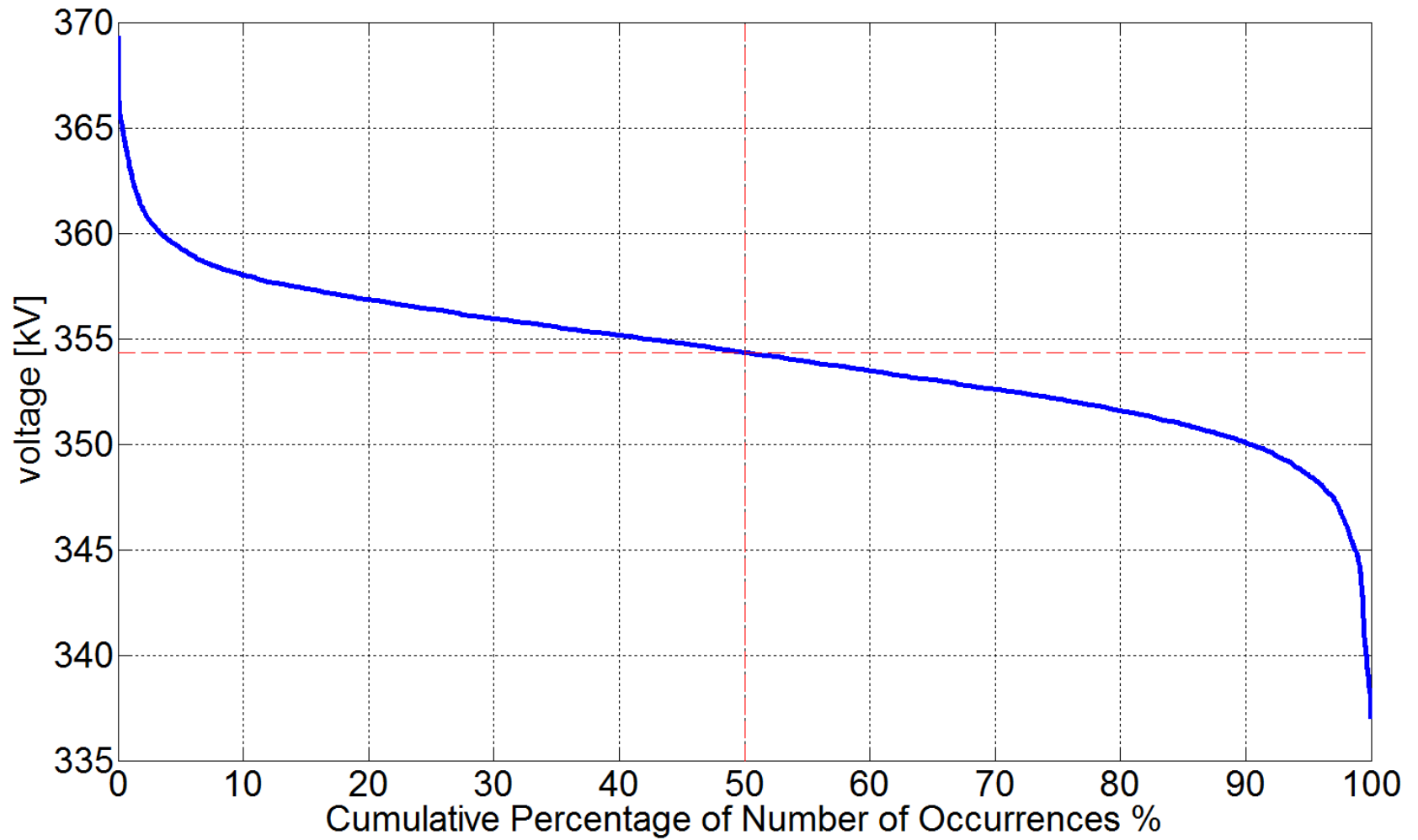
Coast 4



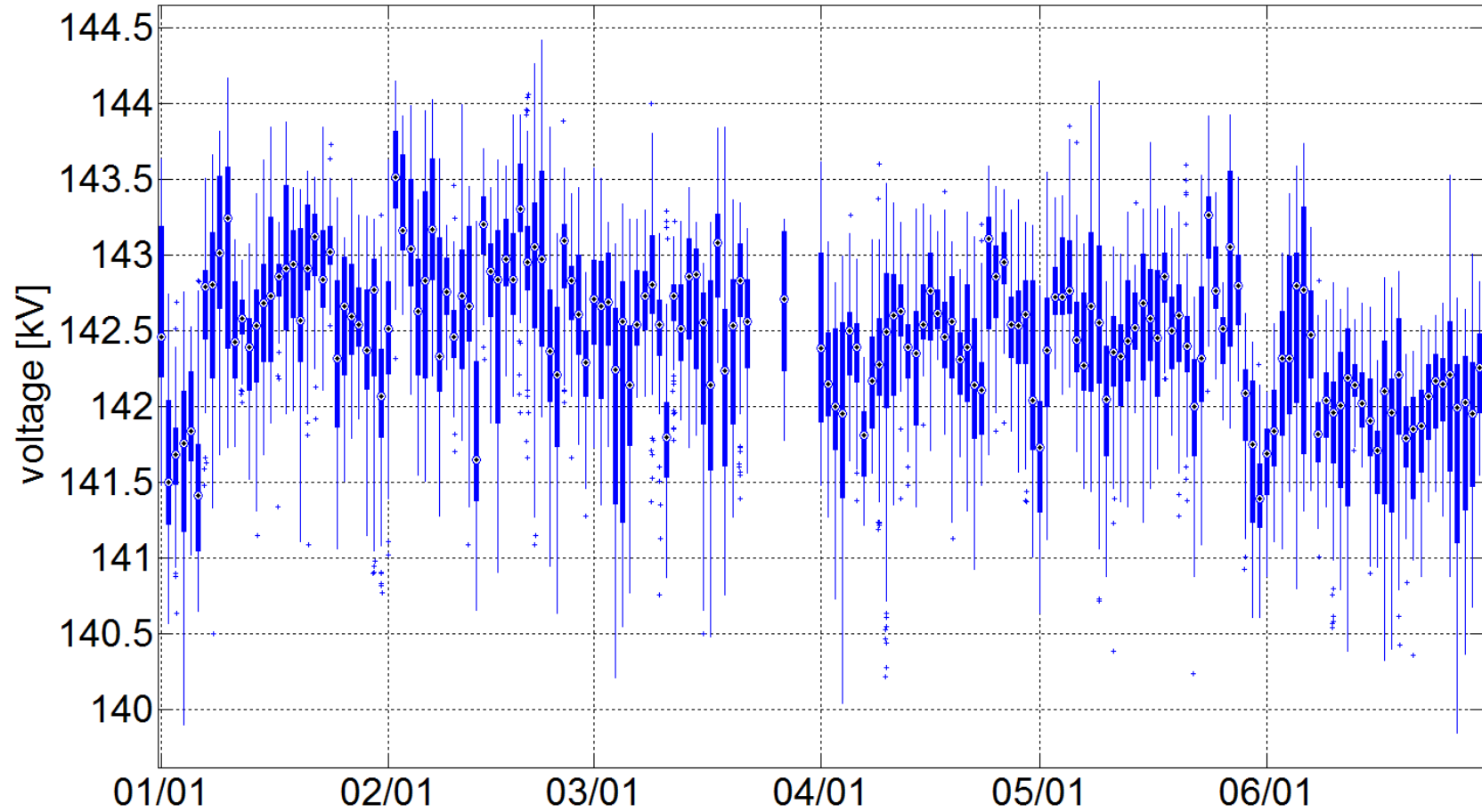
Coast 3



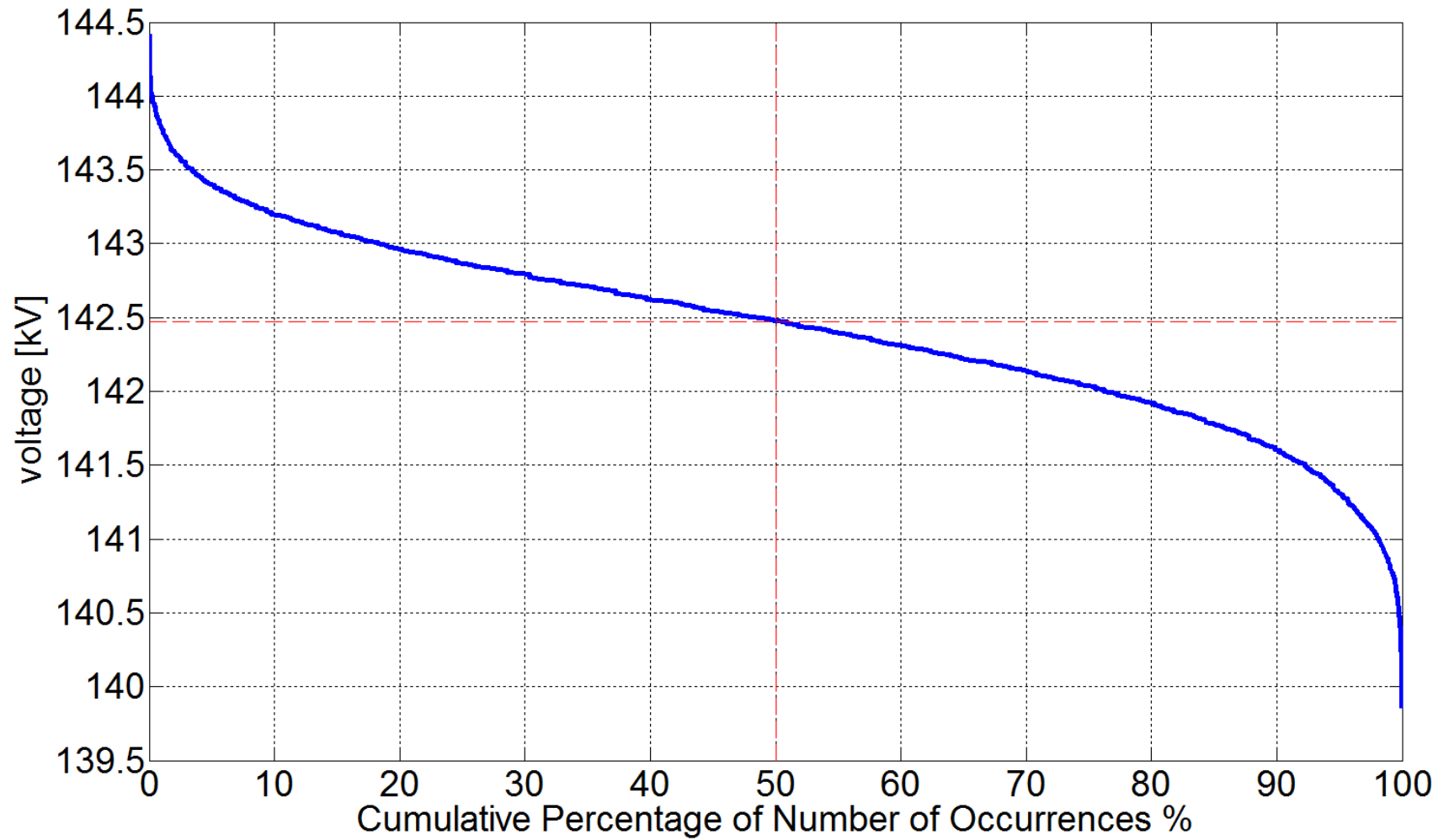
Coast 3



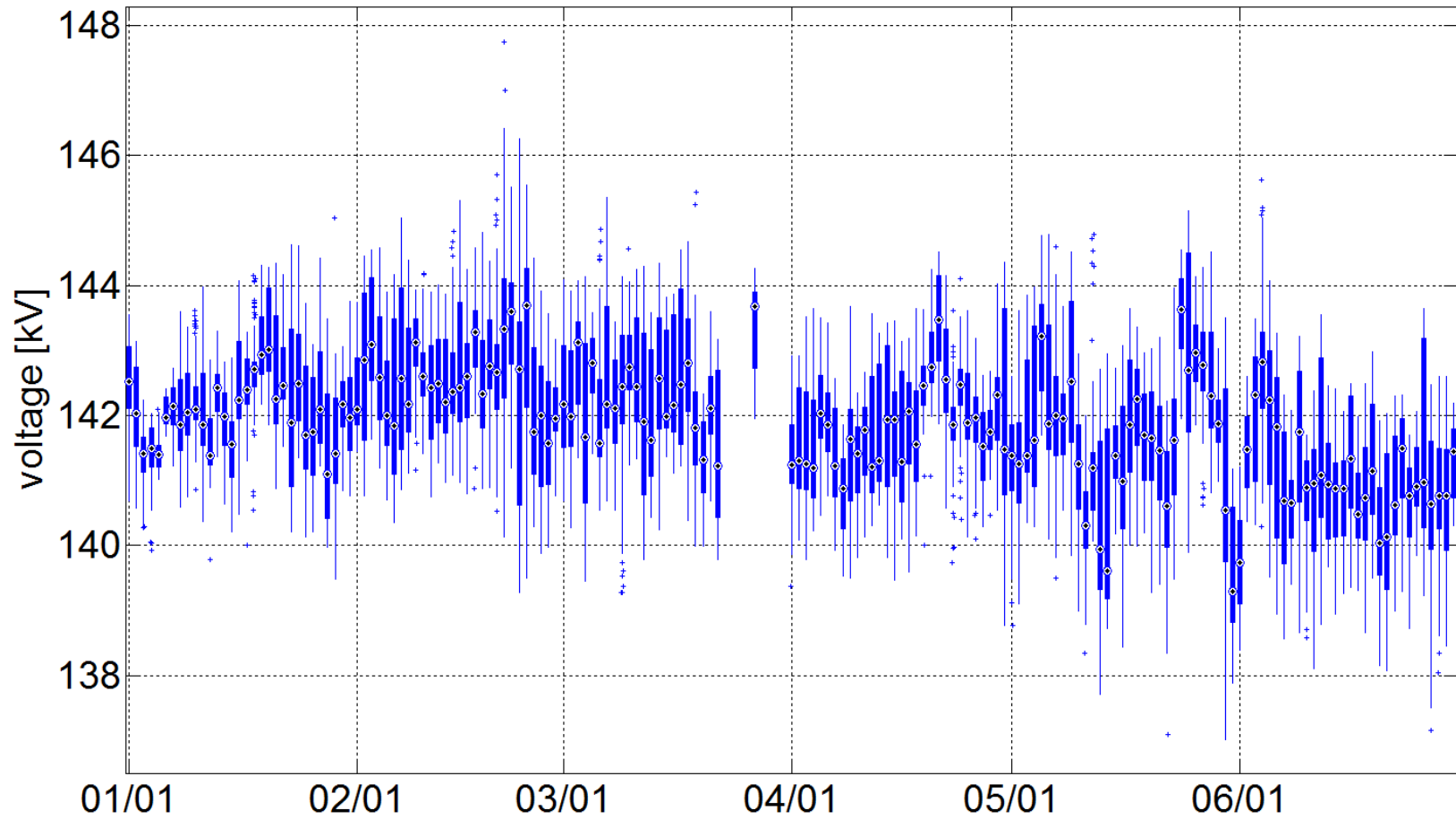
South 6*



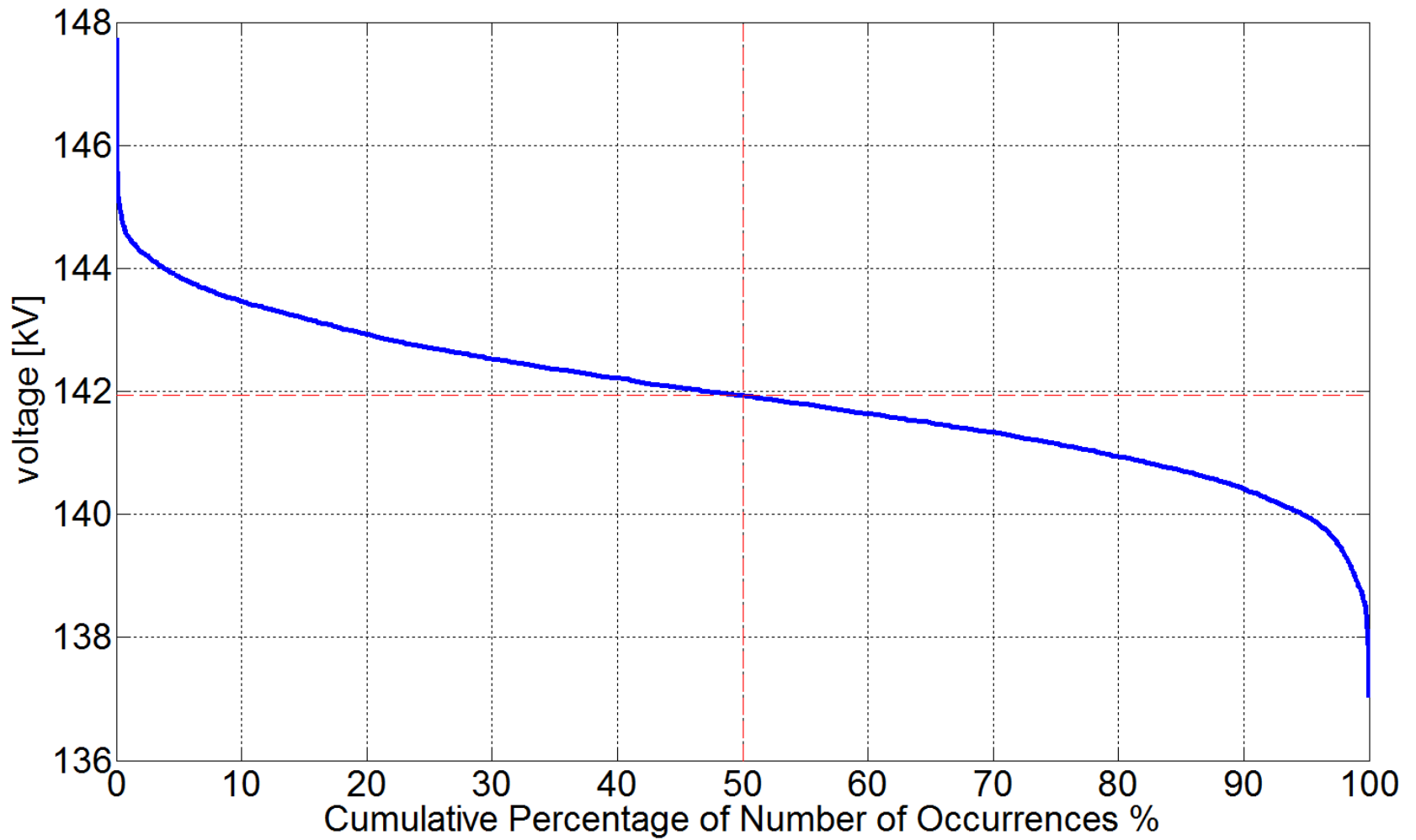
South 6*



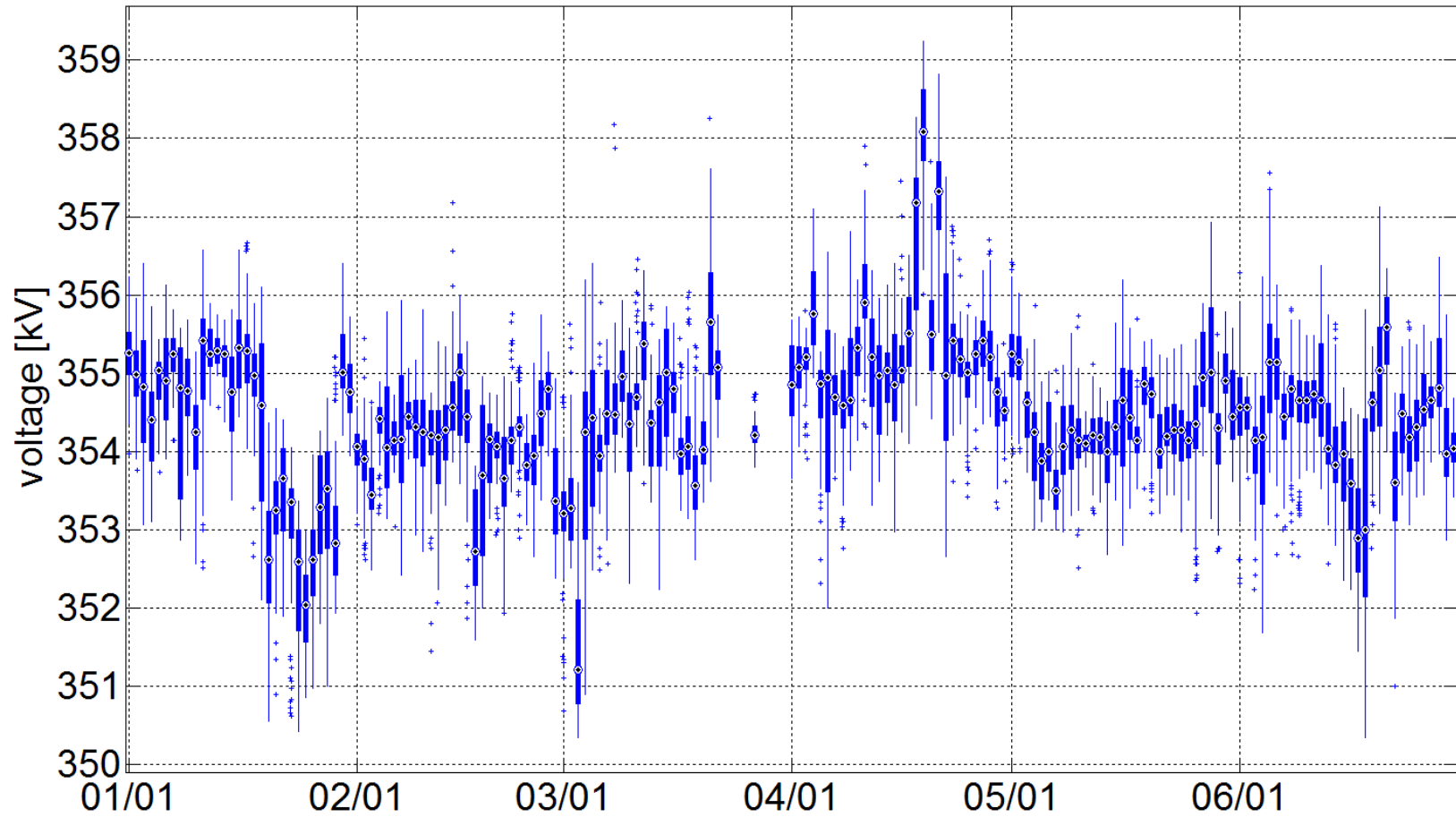
South 13



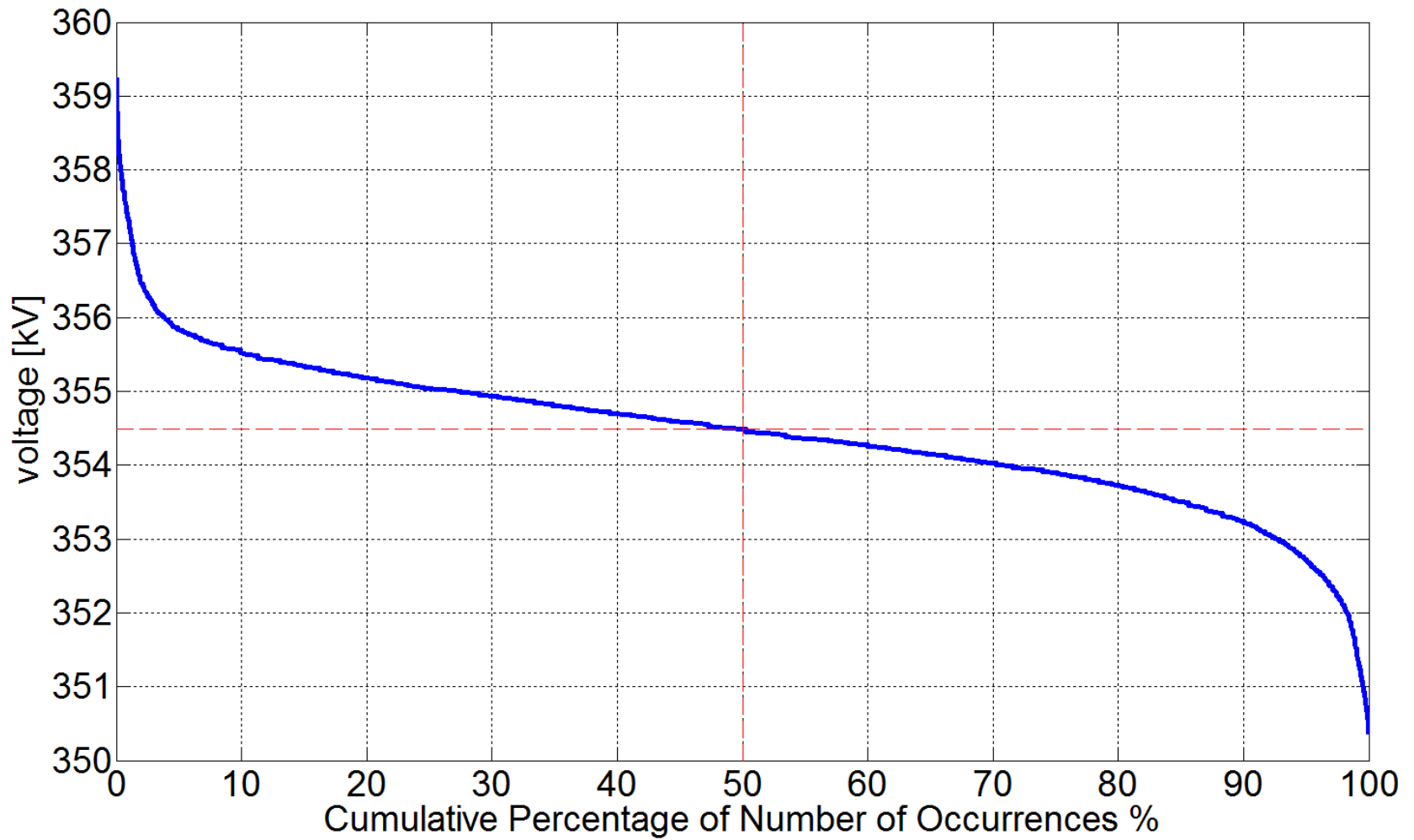
South 13



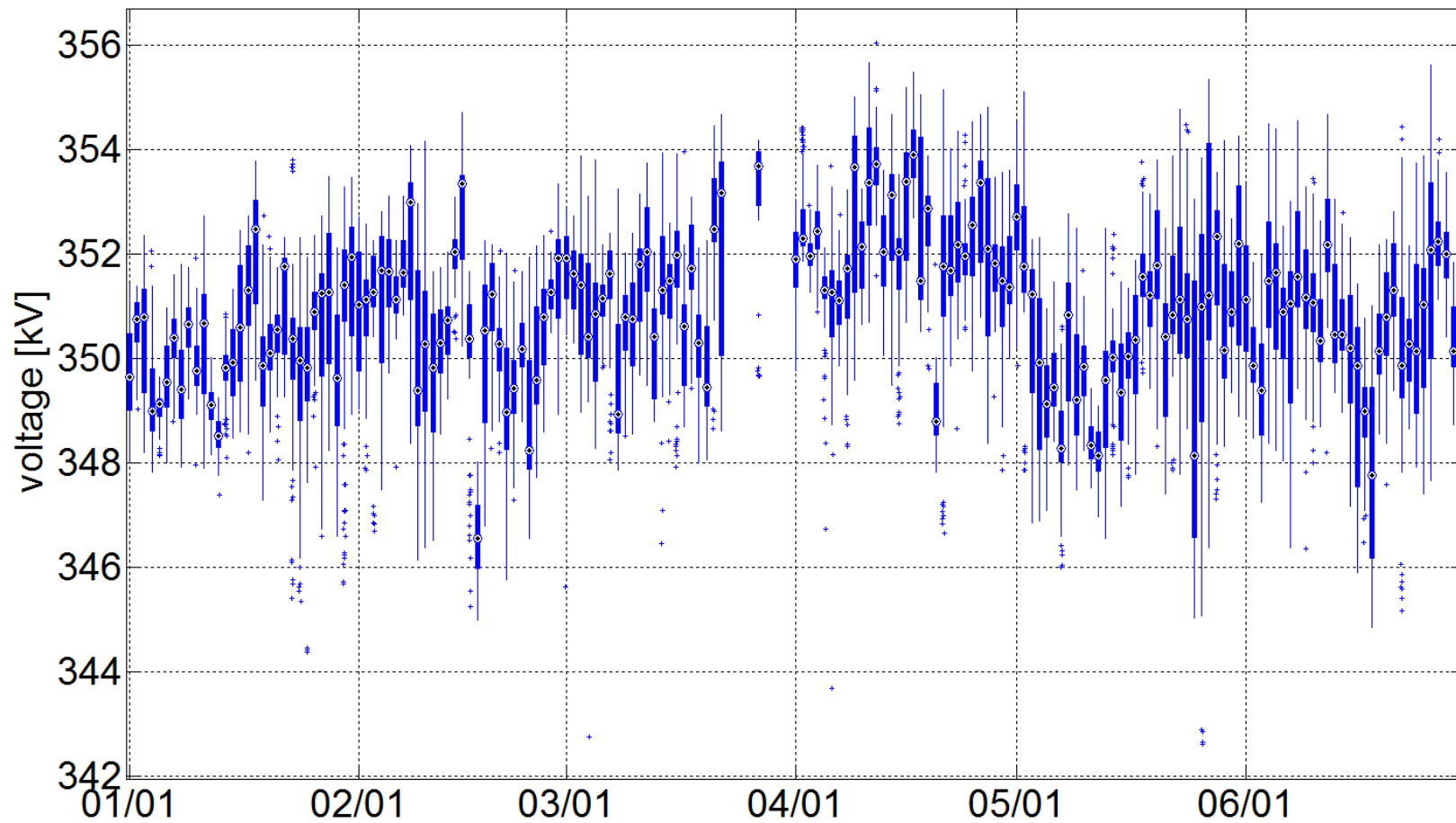
FarWest 4



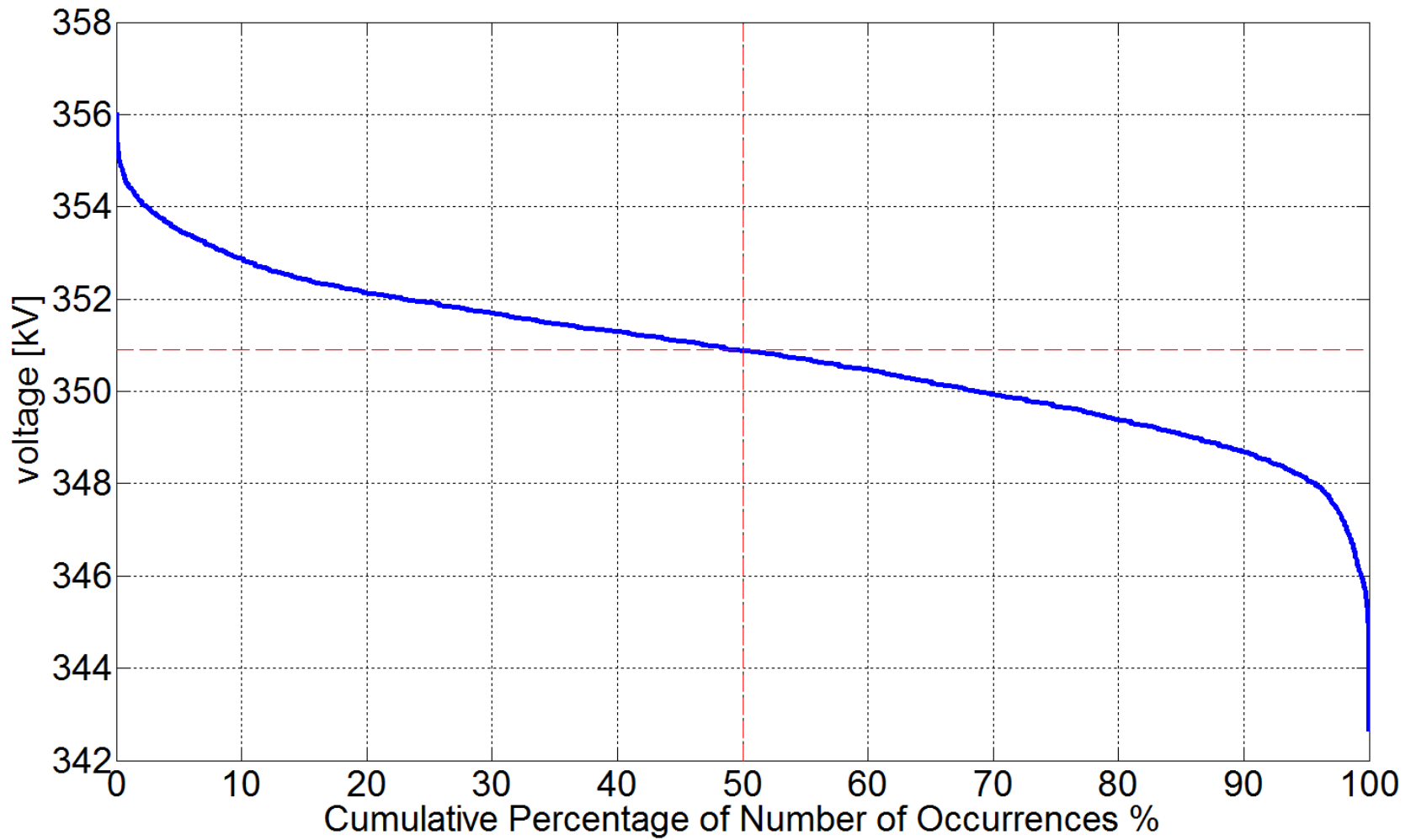
FarWest 4



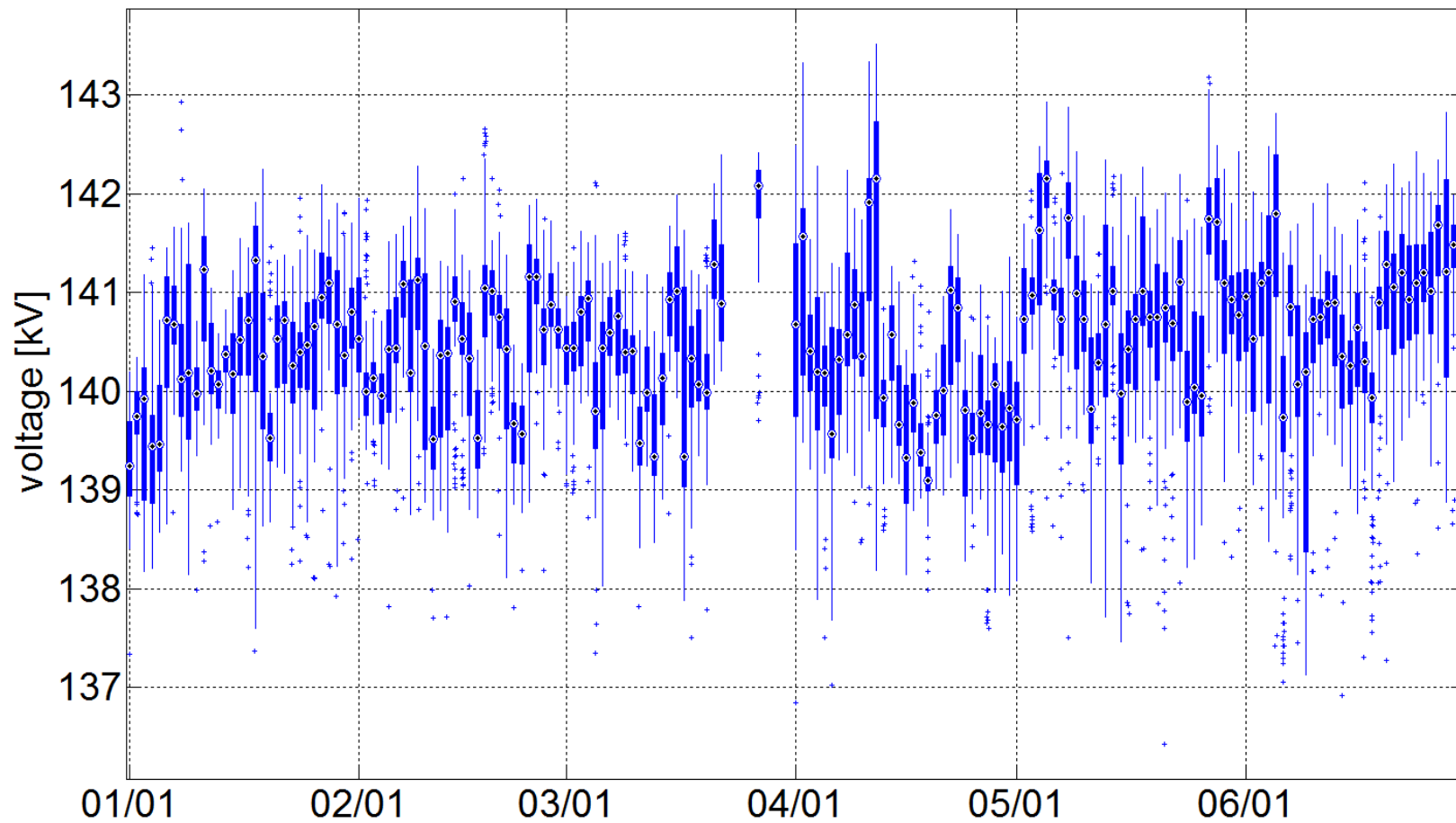
FarWest 7



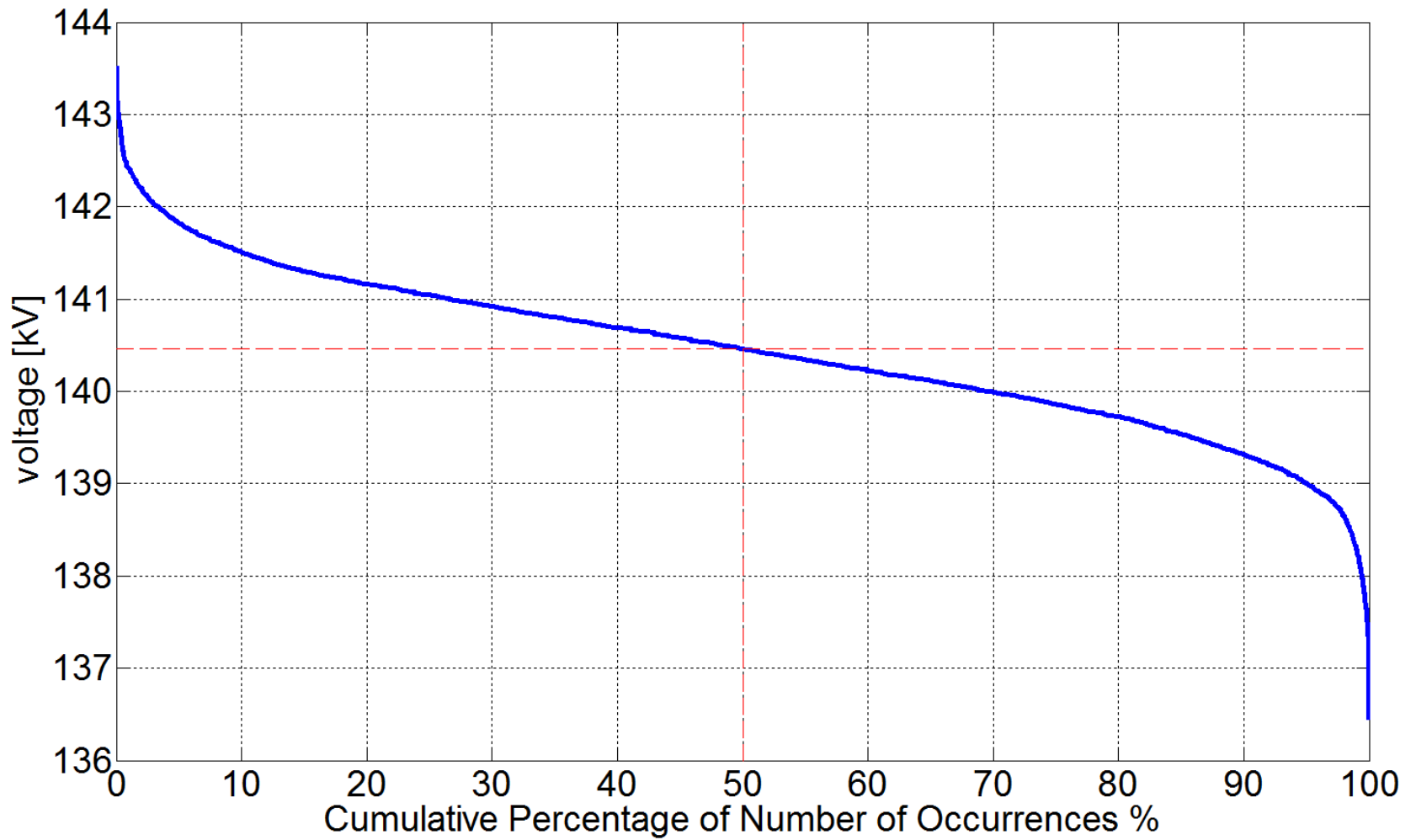
FarWest 7



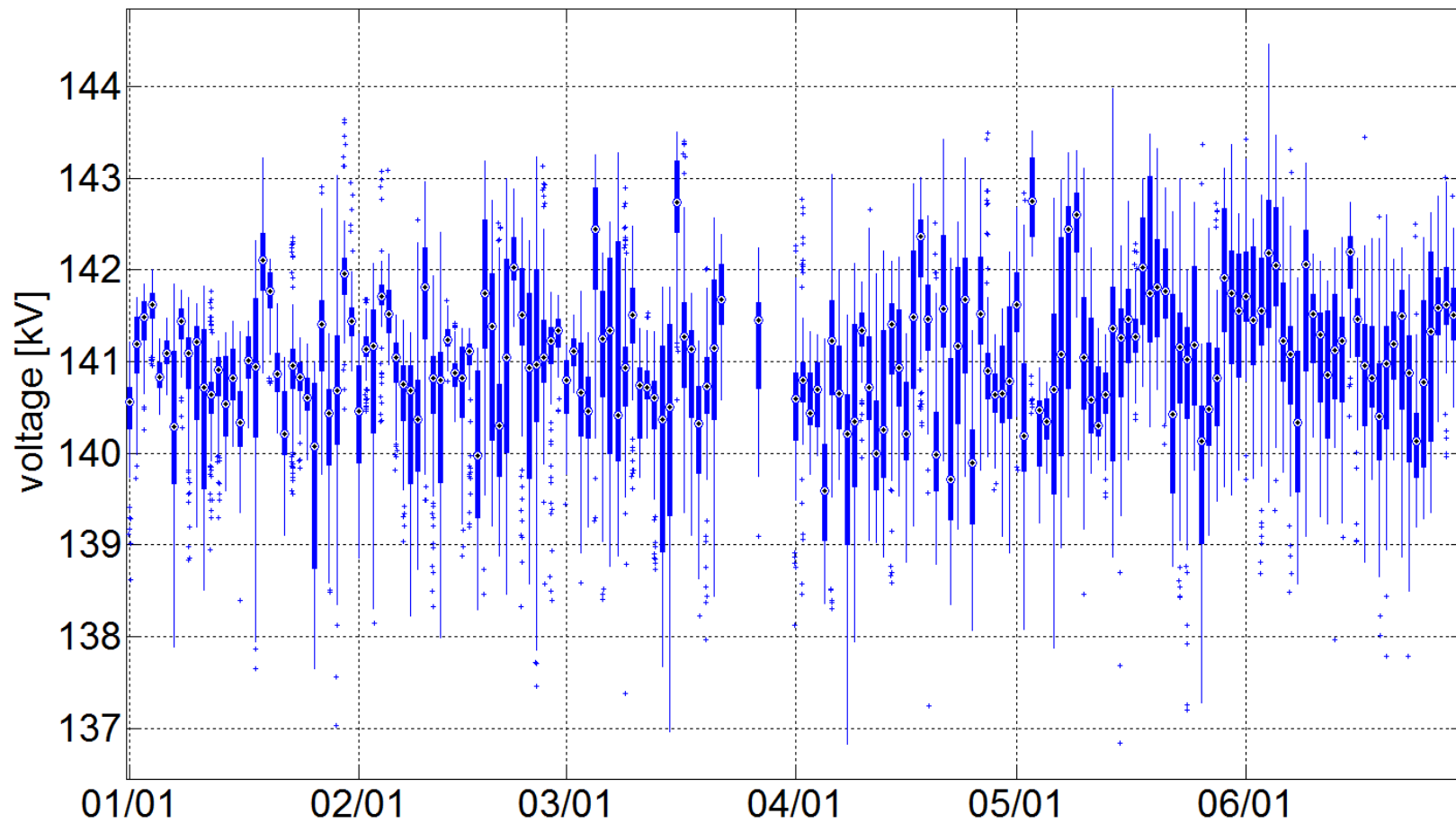
FarWest 8



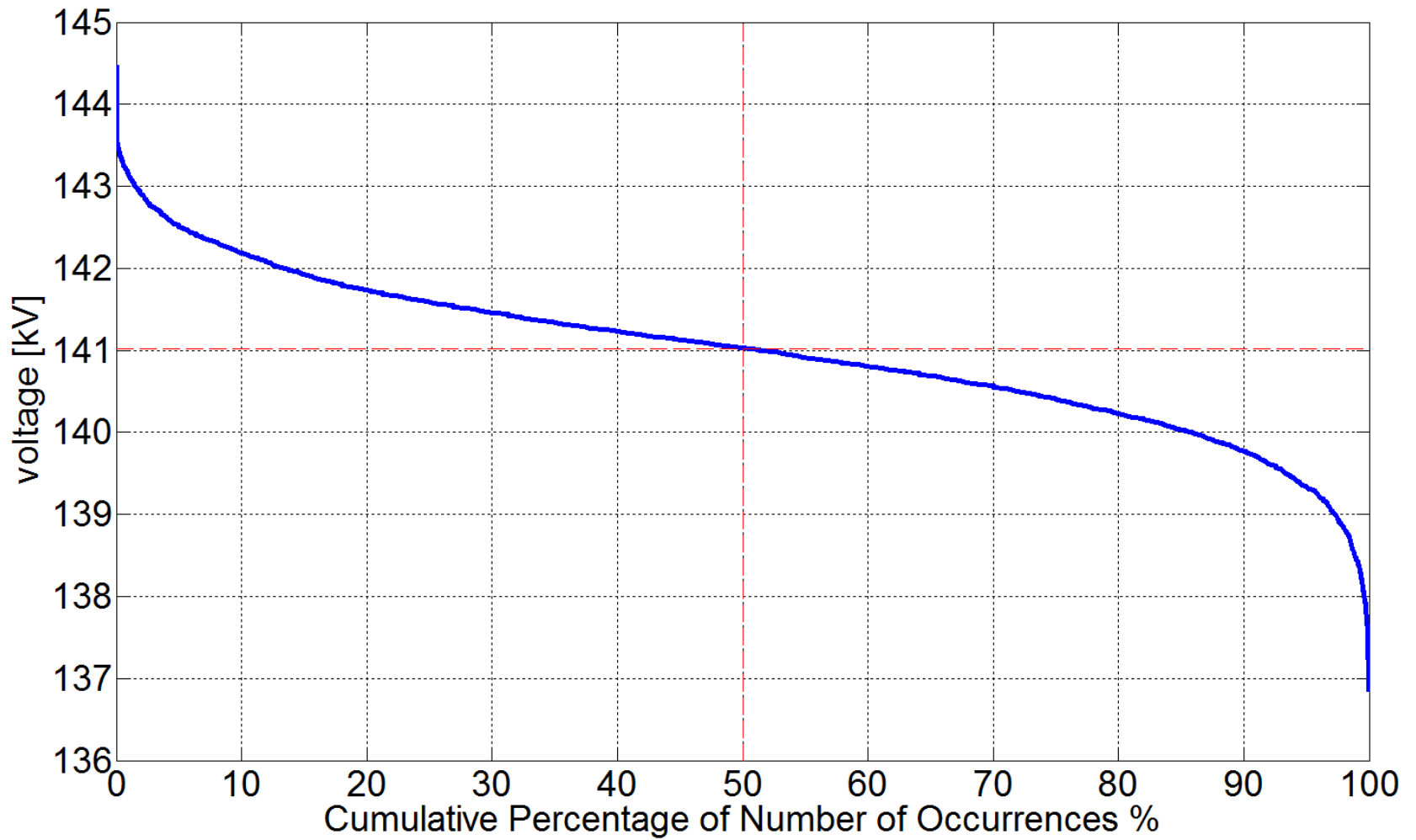
FarWest 8



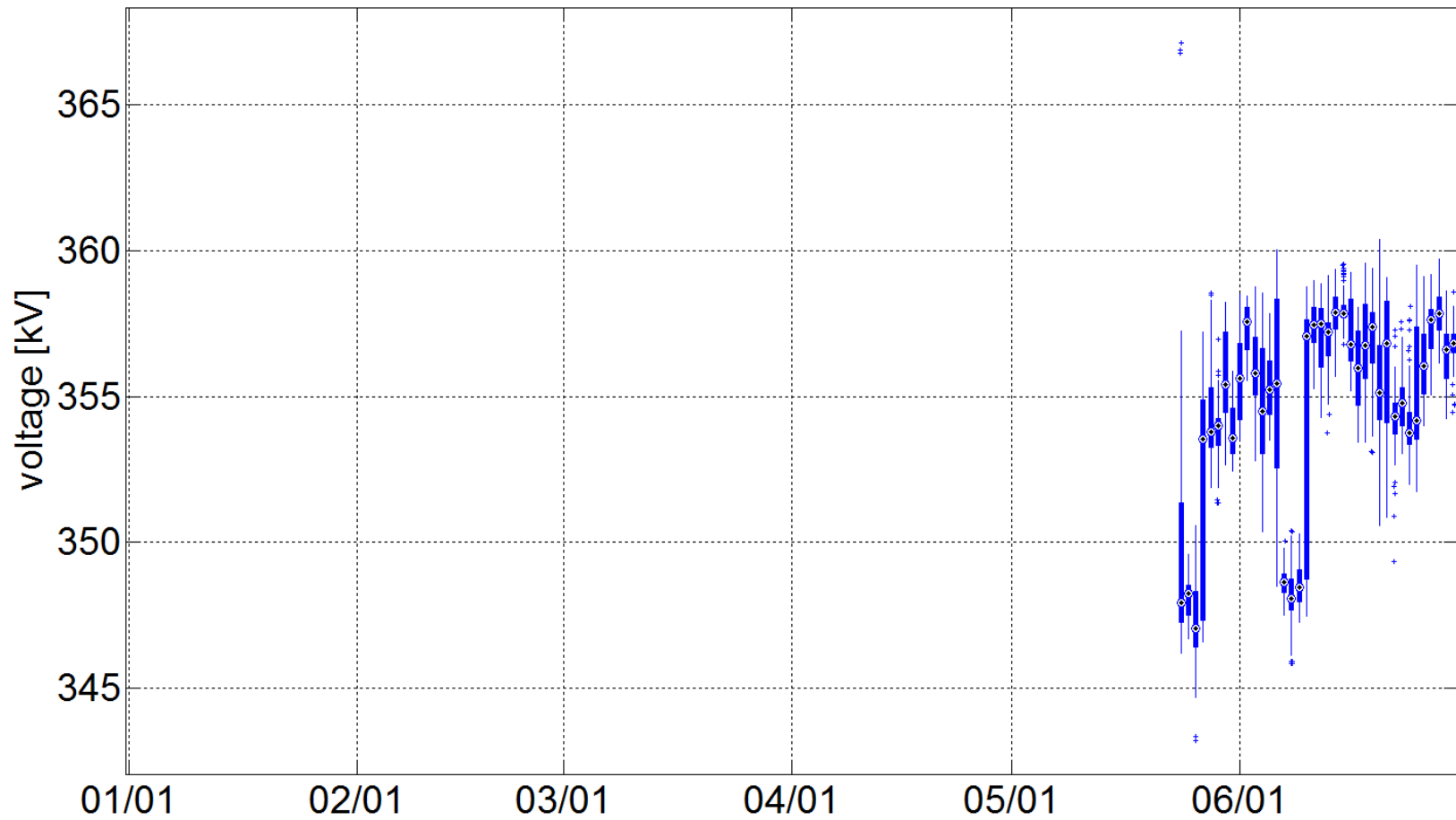
FarWest 9



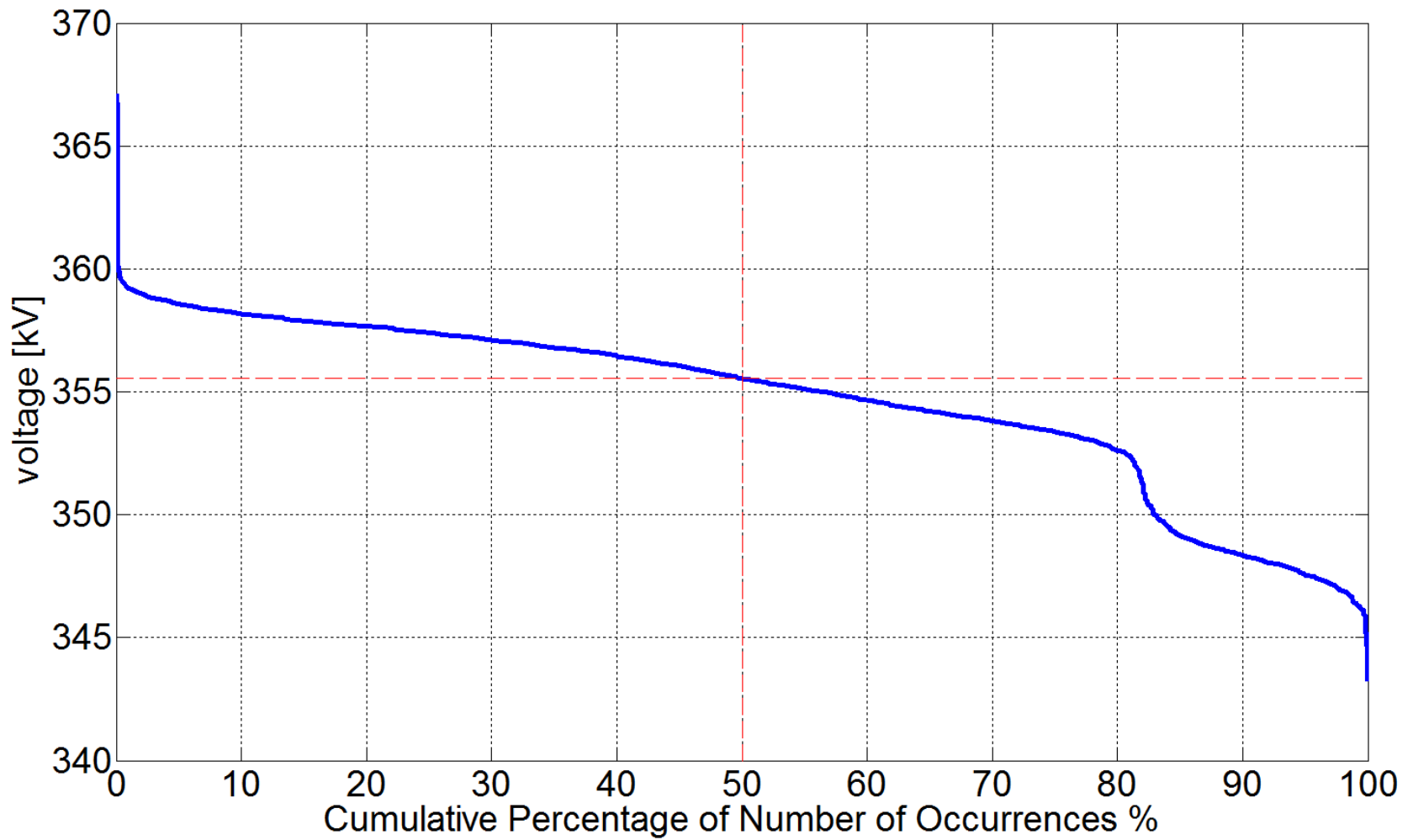
FarWest 9



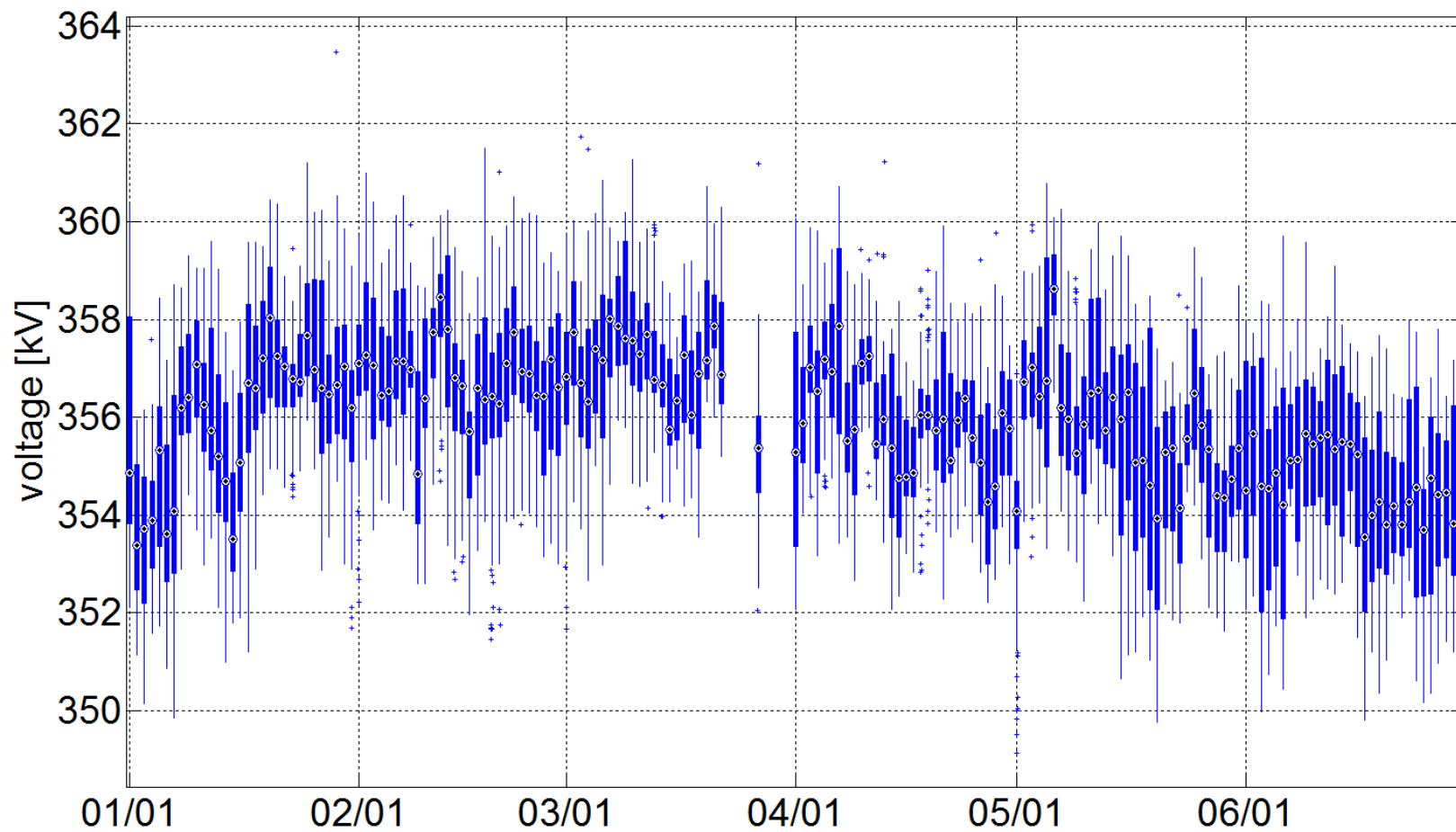
West 8*



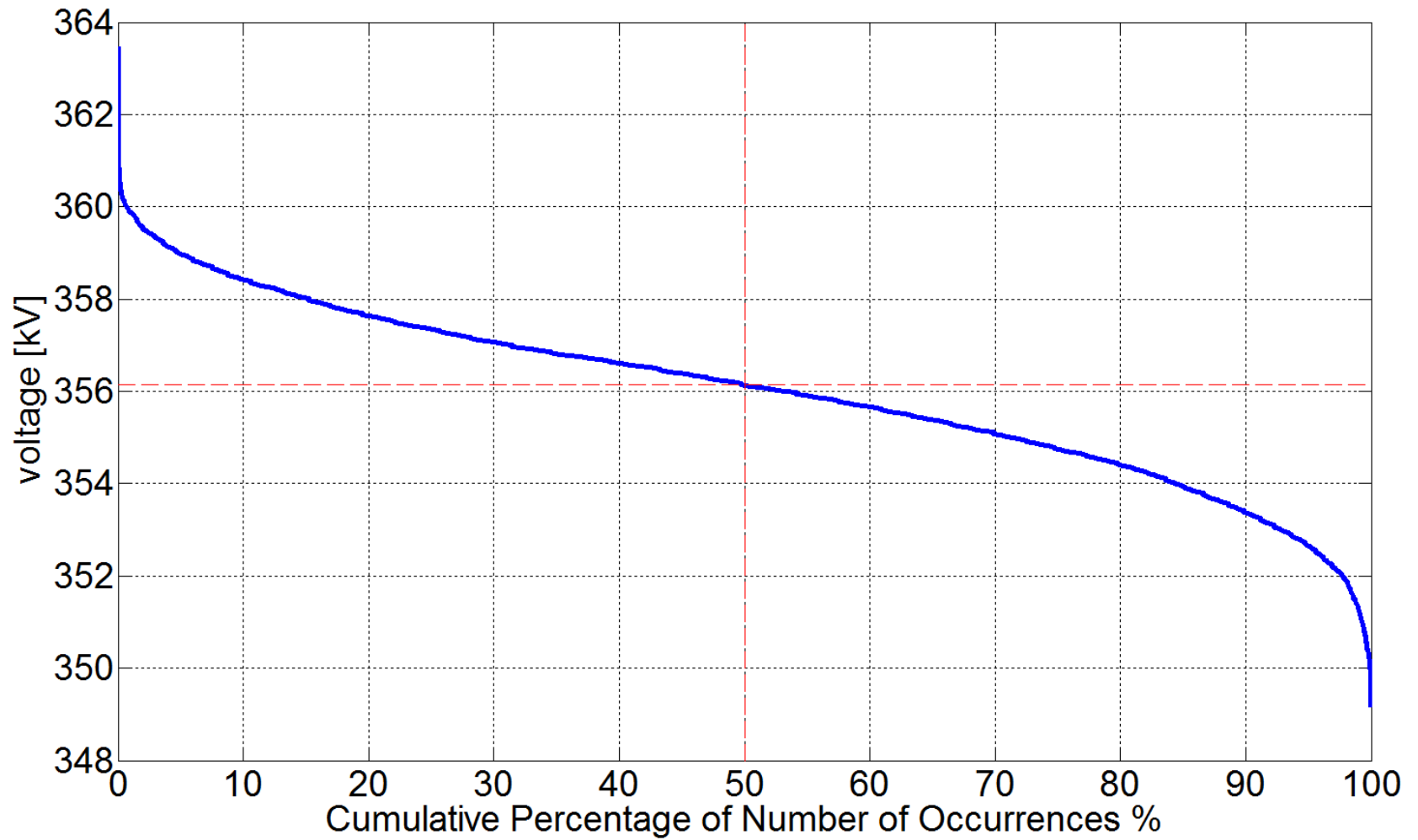
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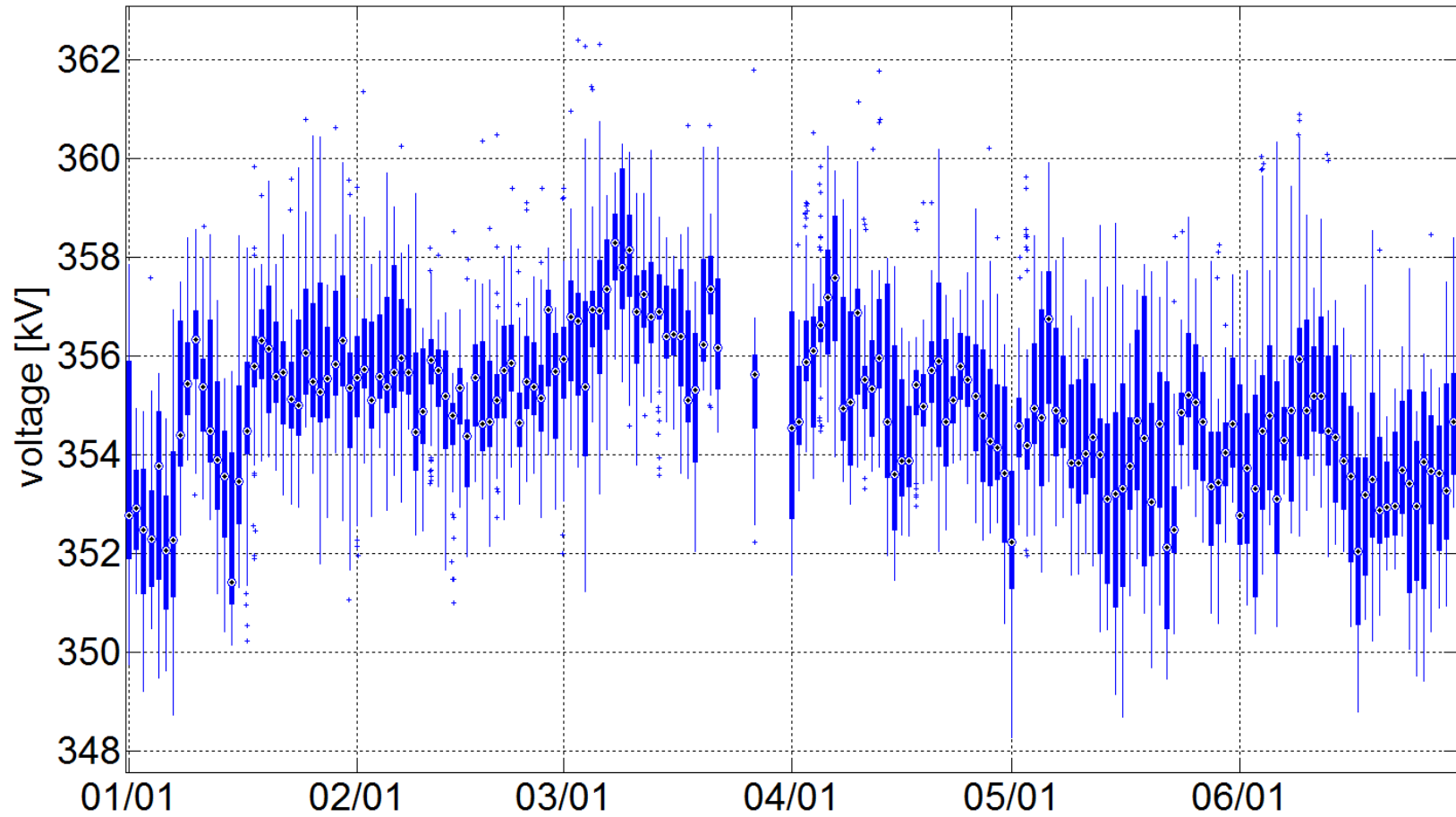
South 15*



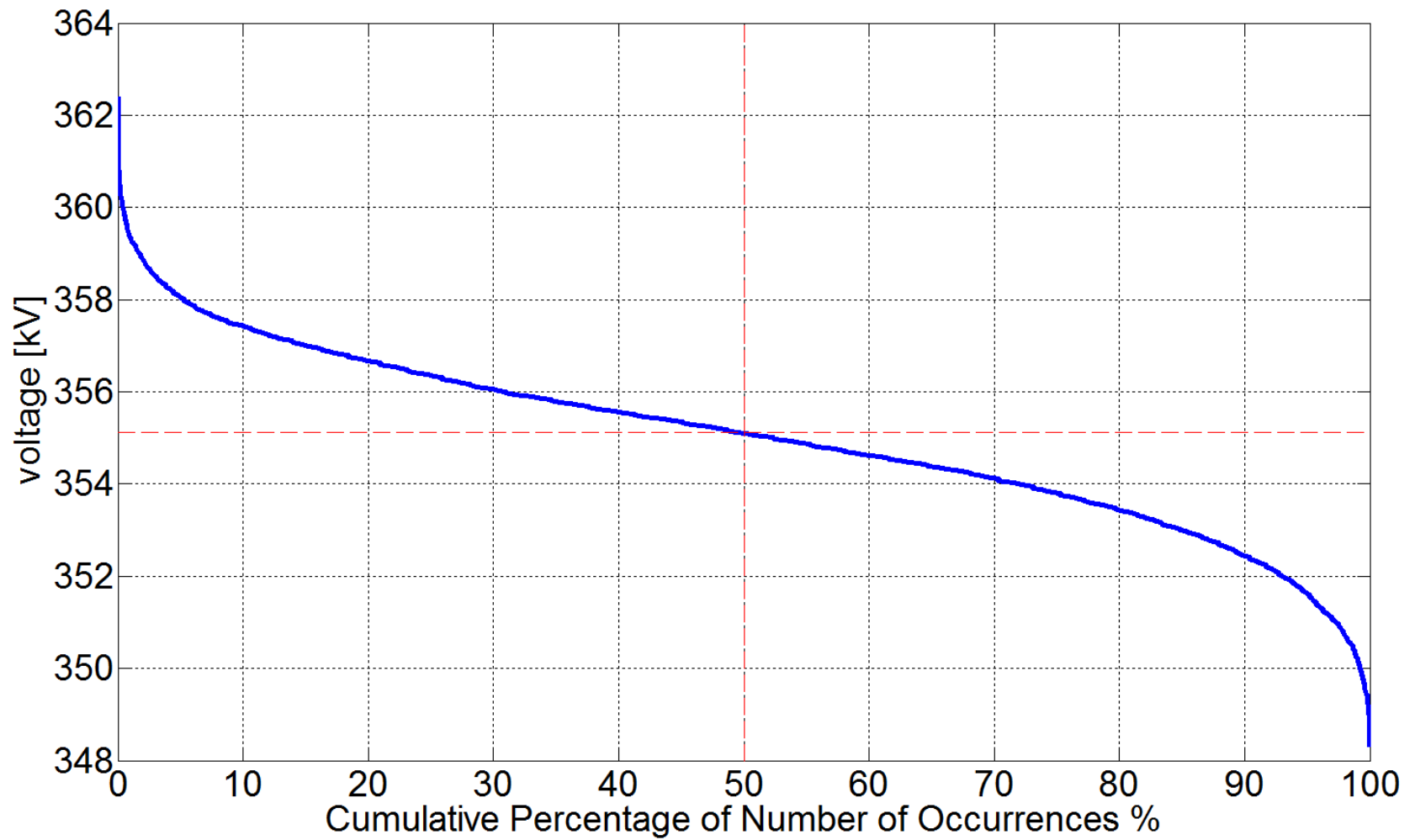
South 15*



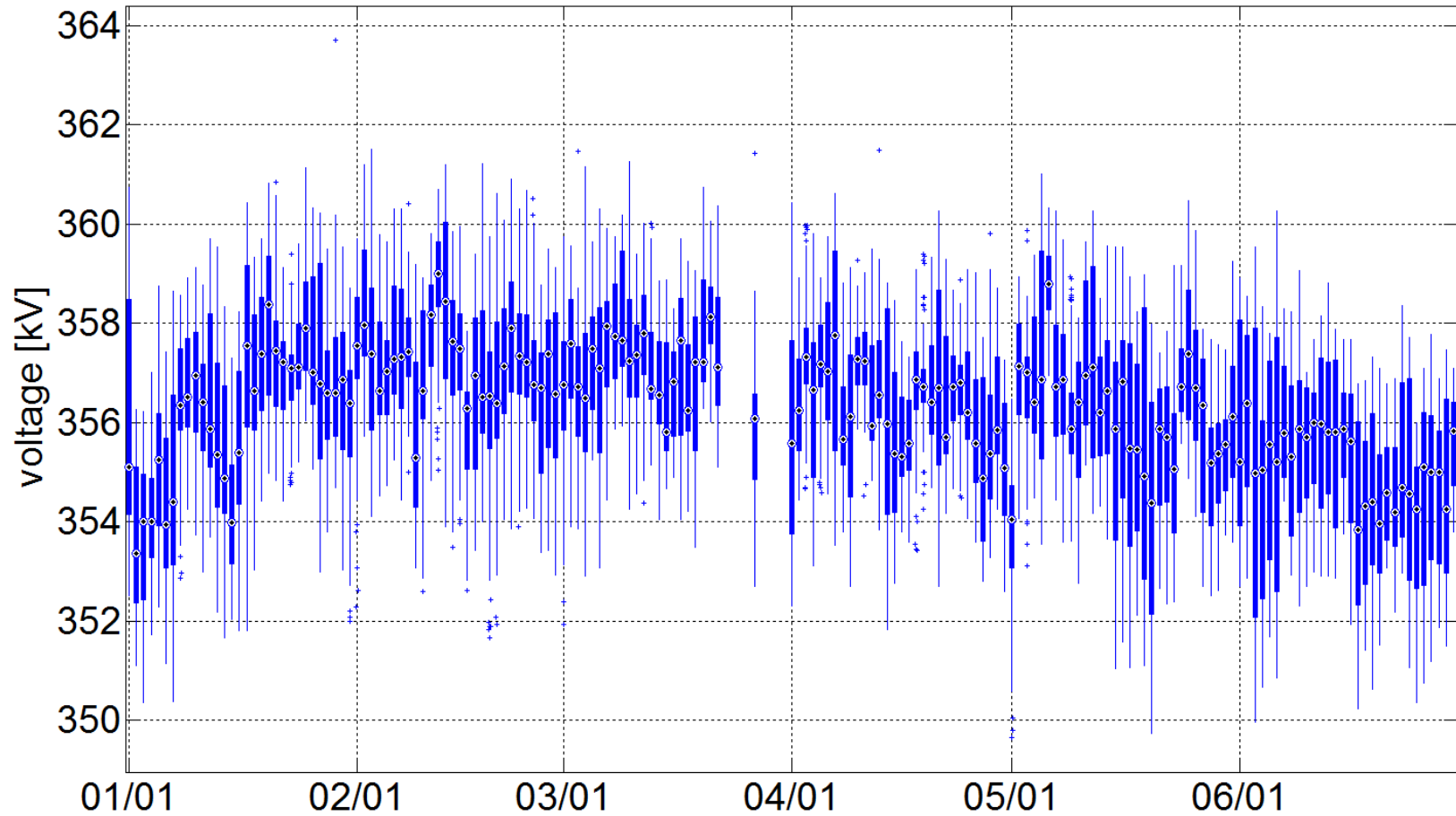
South 2*



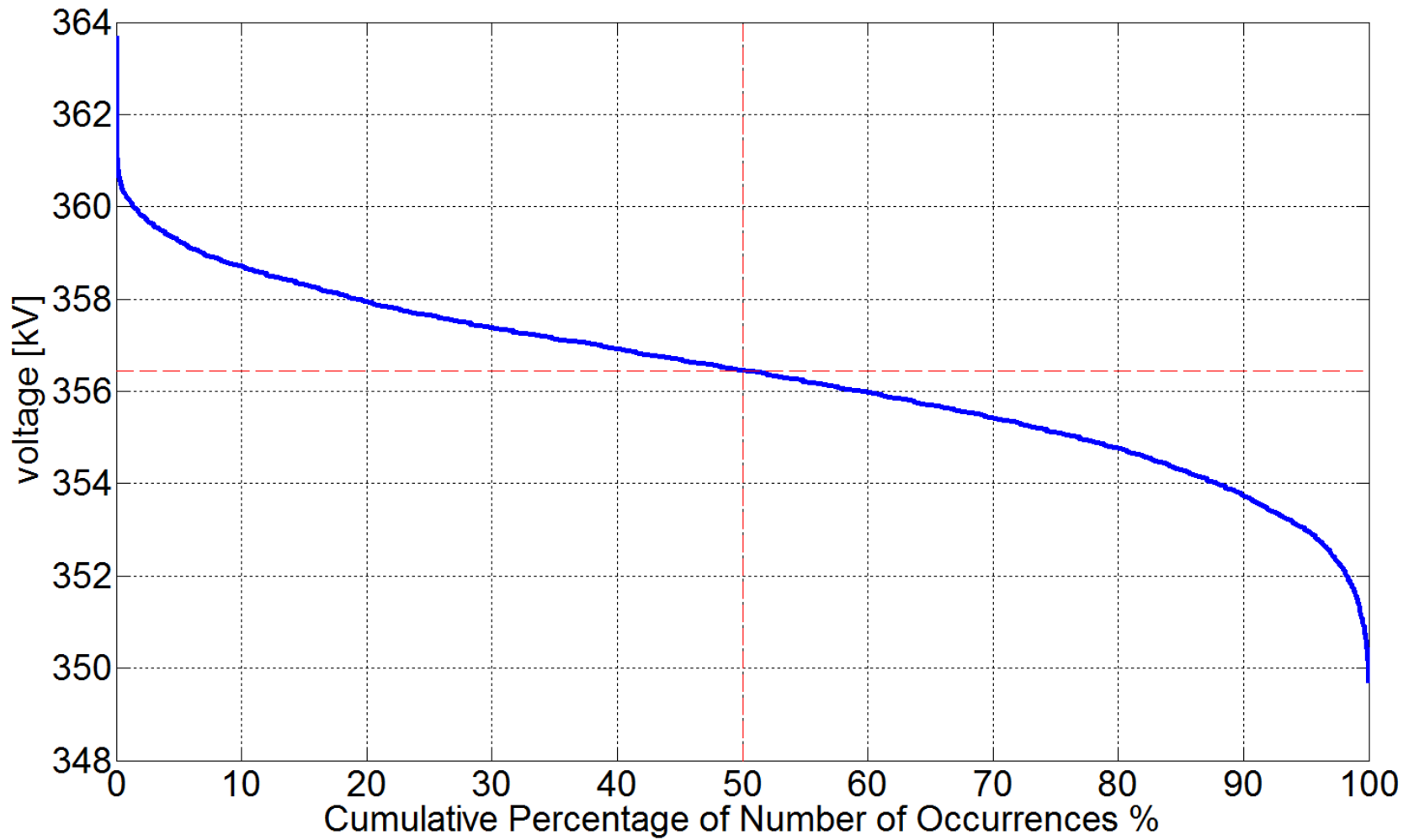
South 2*



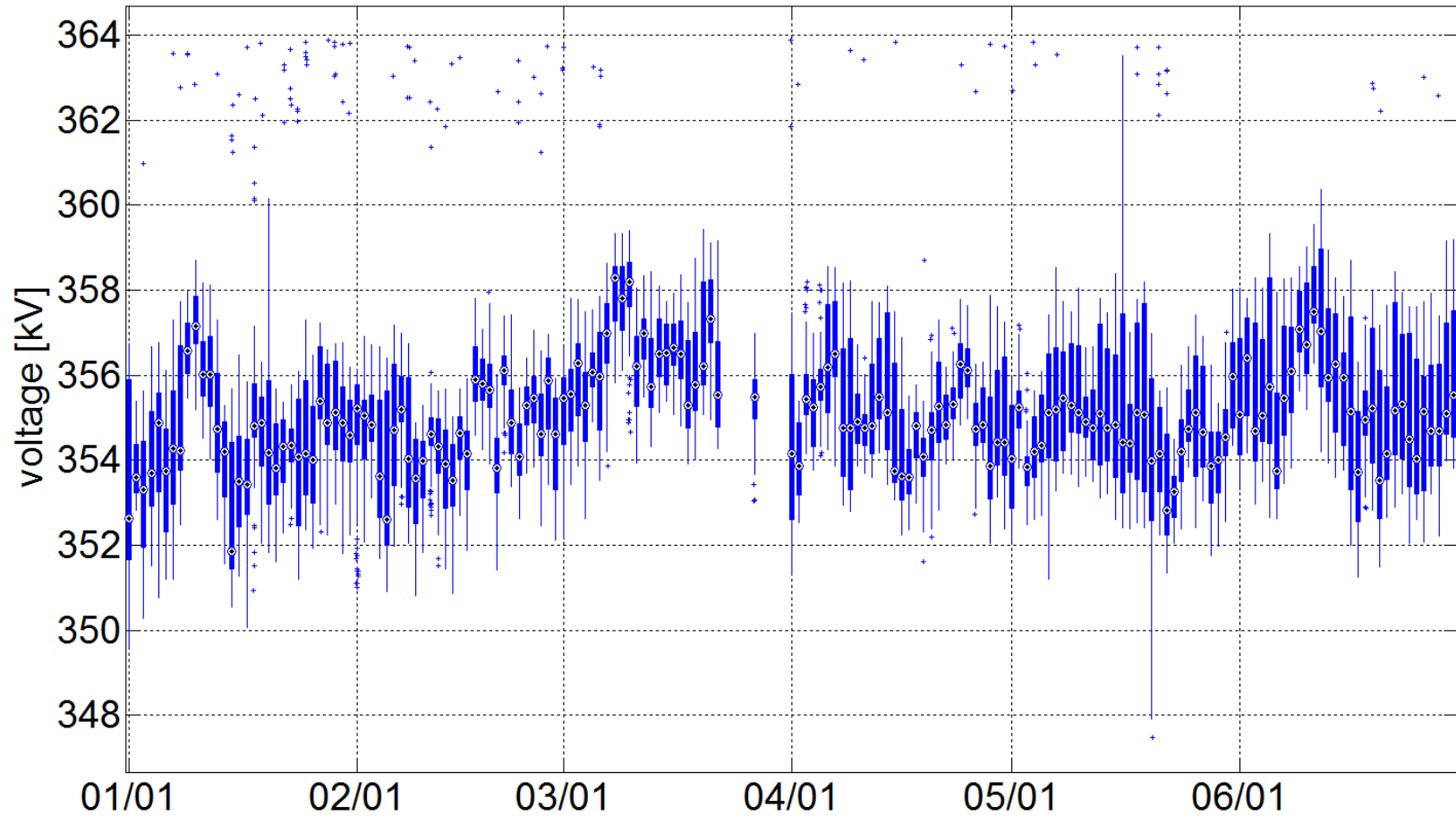
South 4*



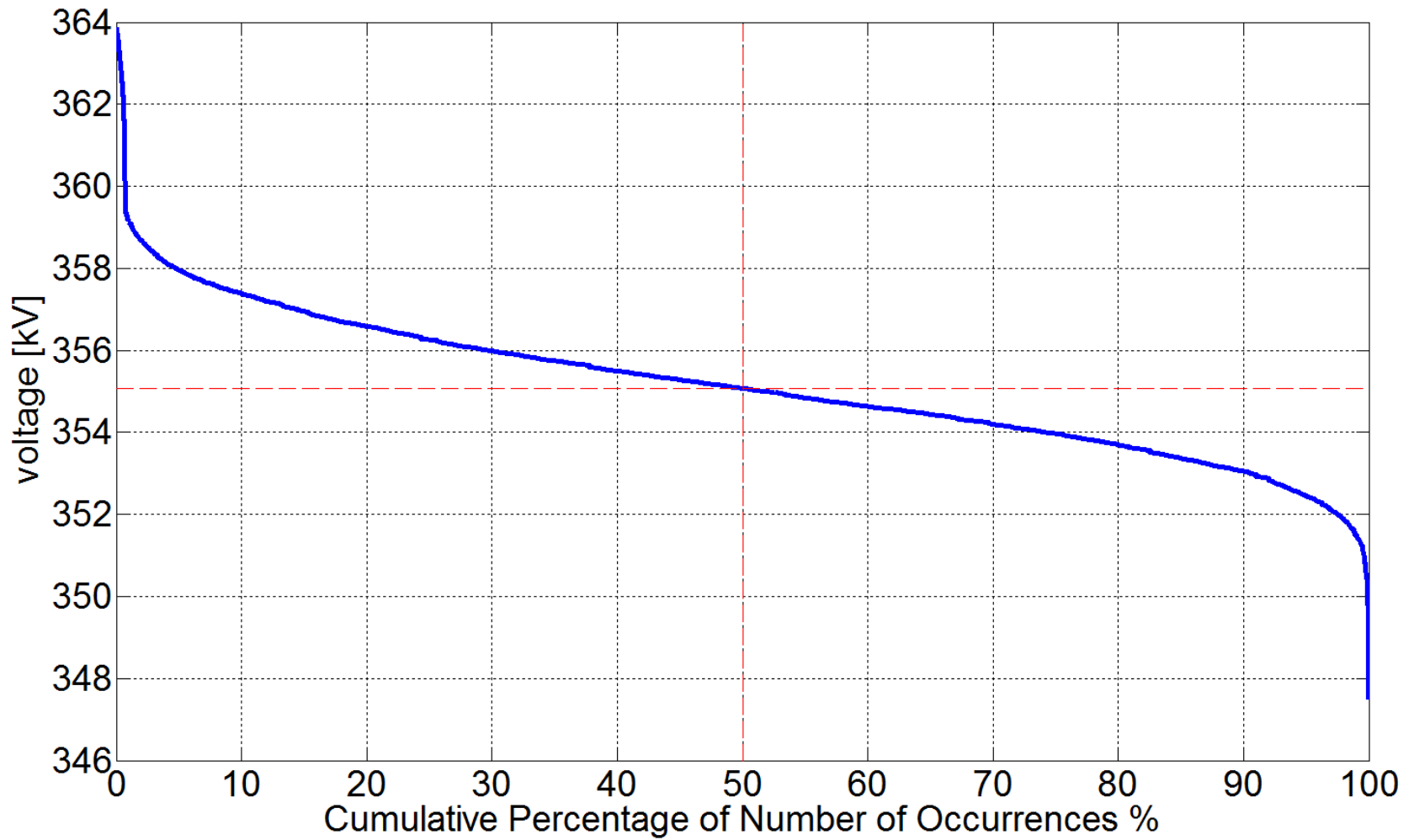
South 4*



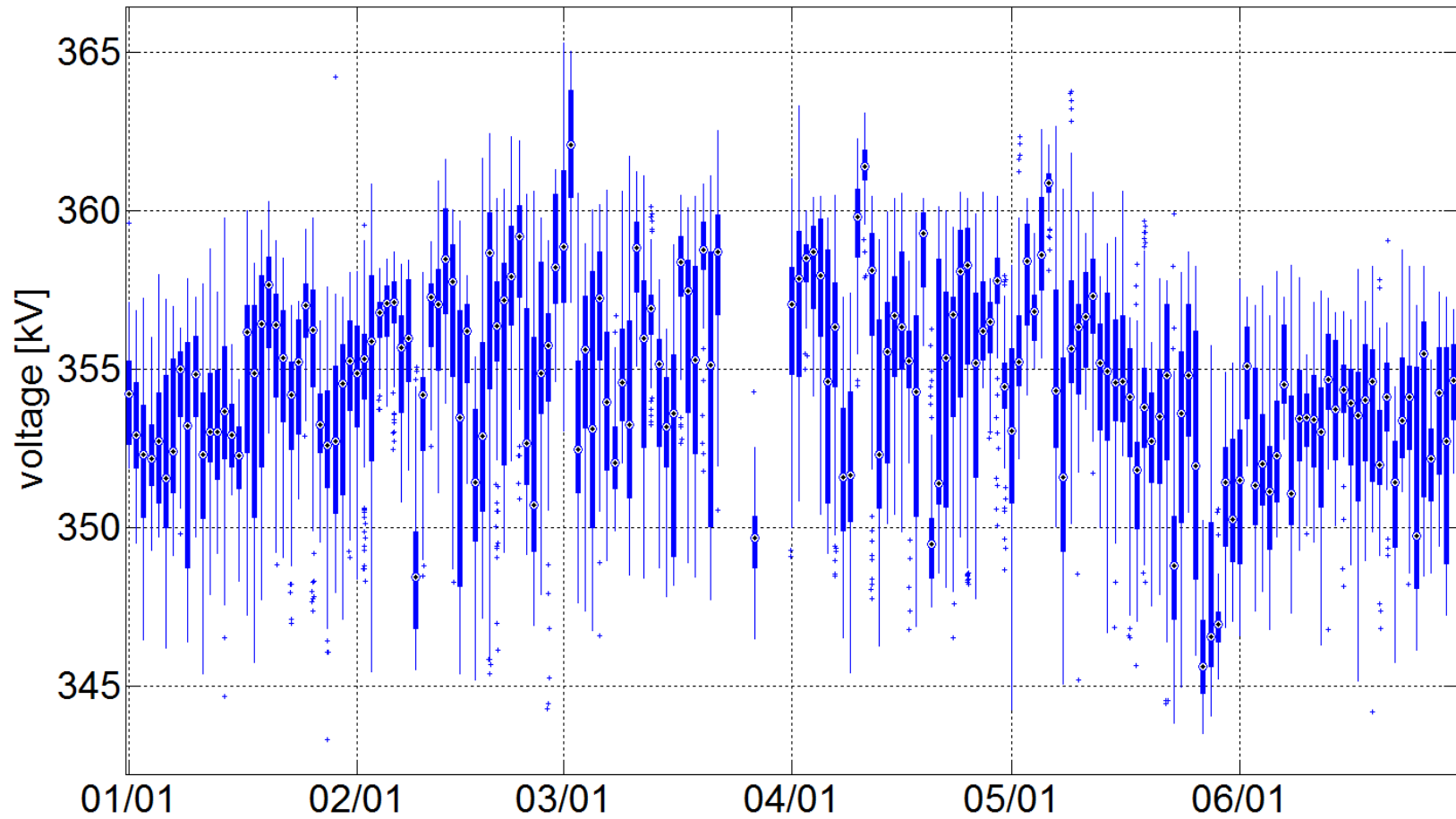
South 7*



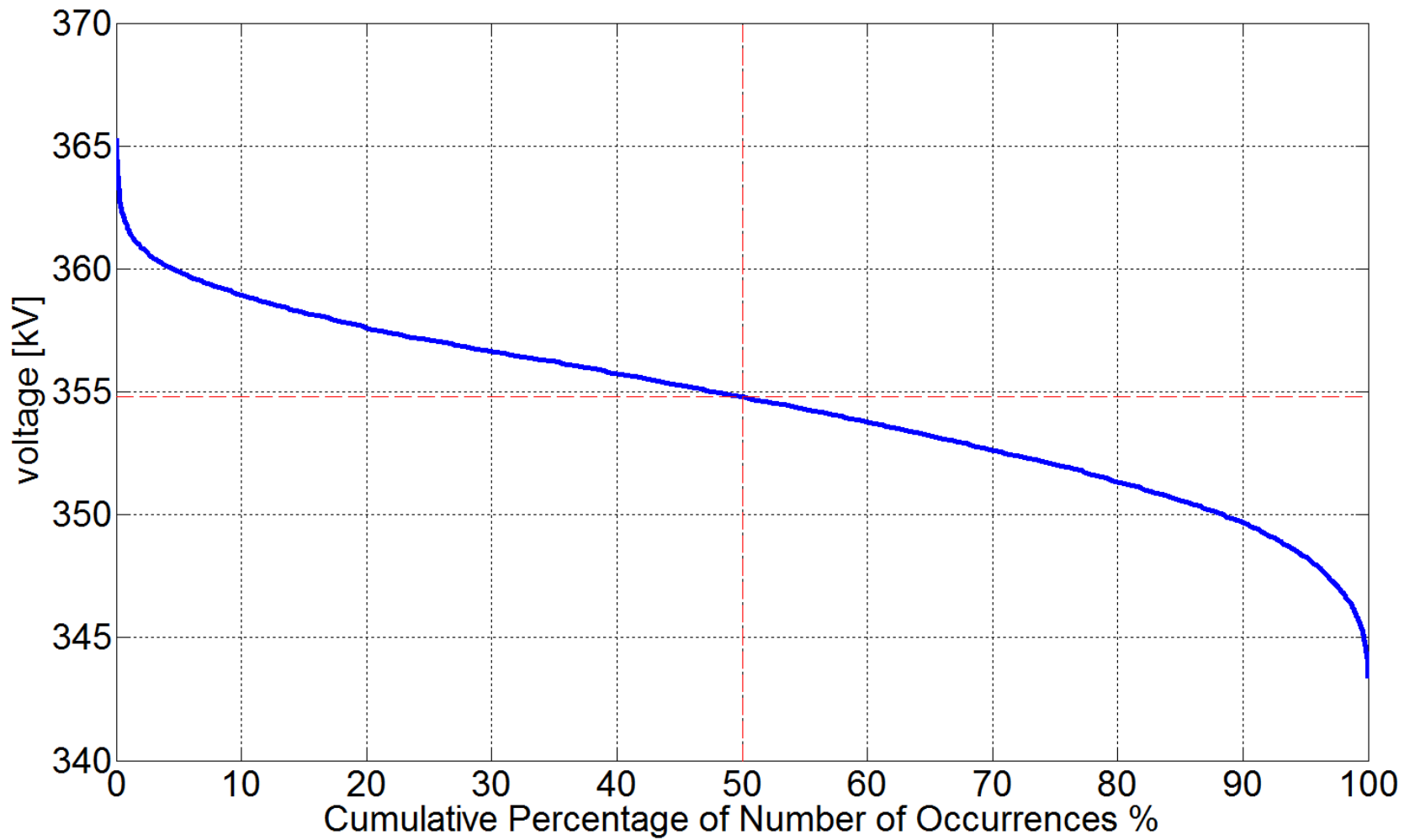
South 7*



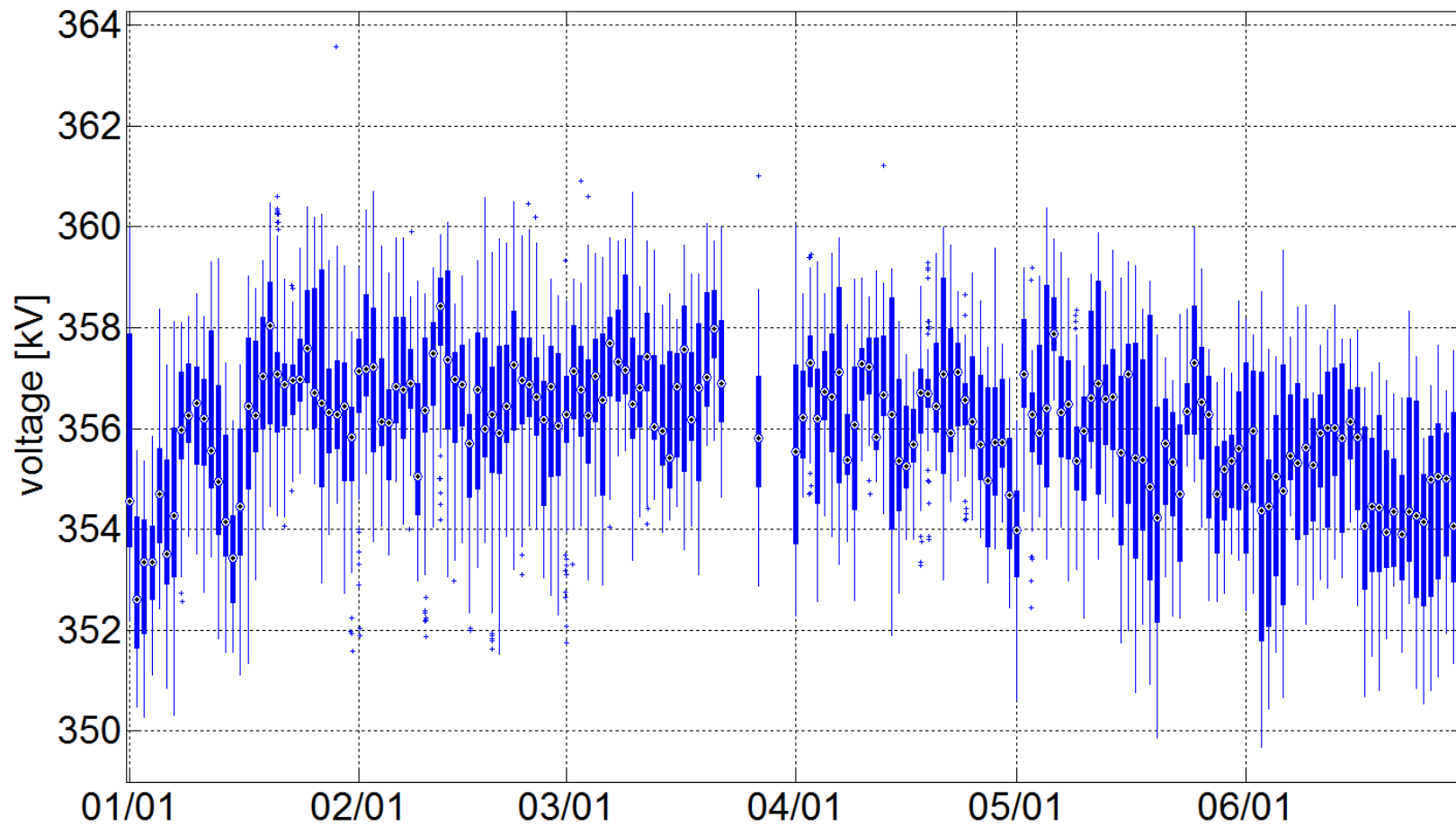
South 9*



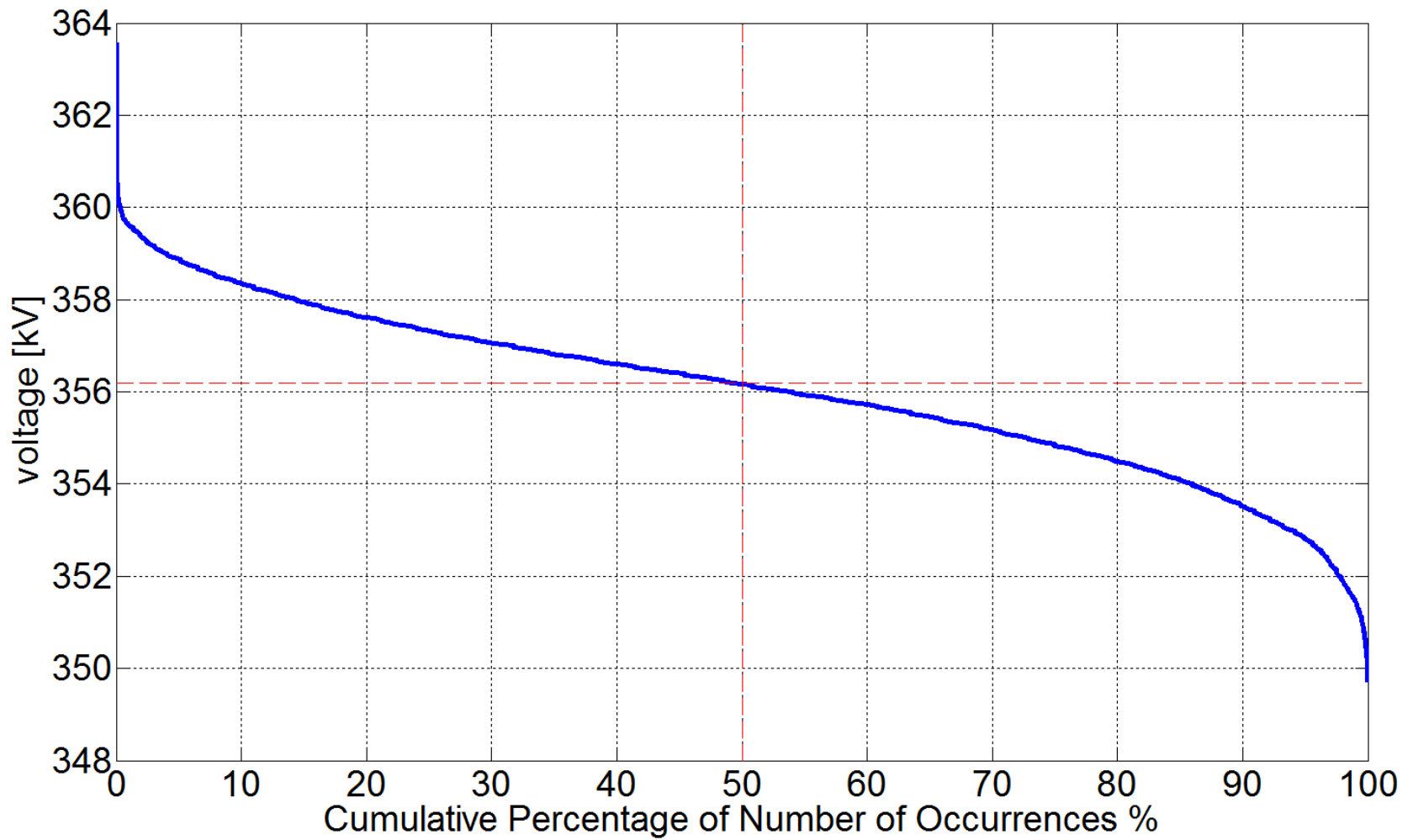
South 9*



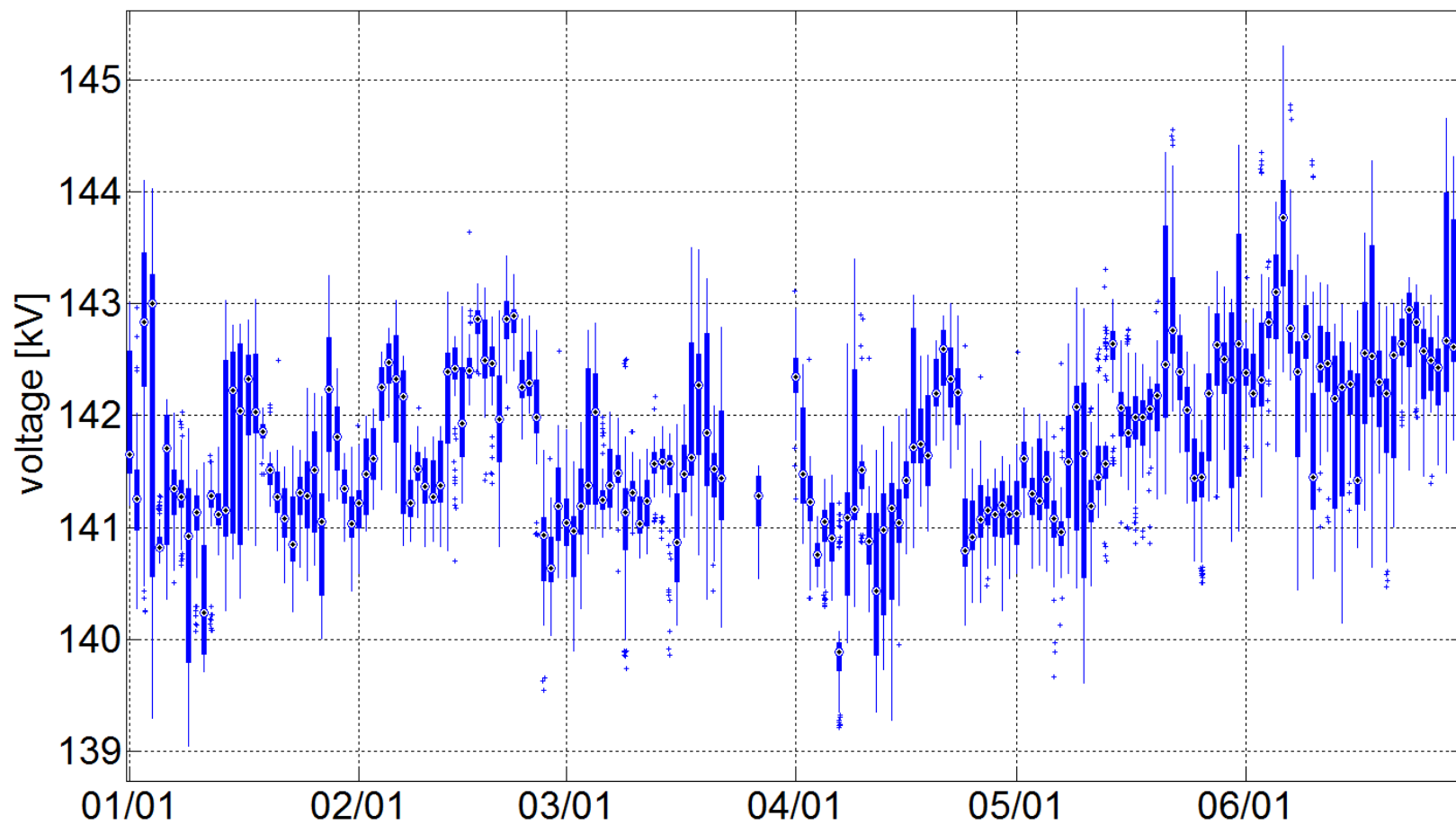
South 11*



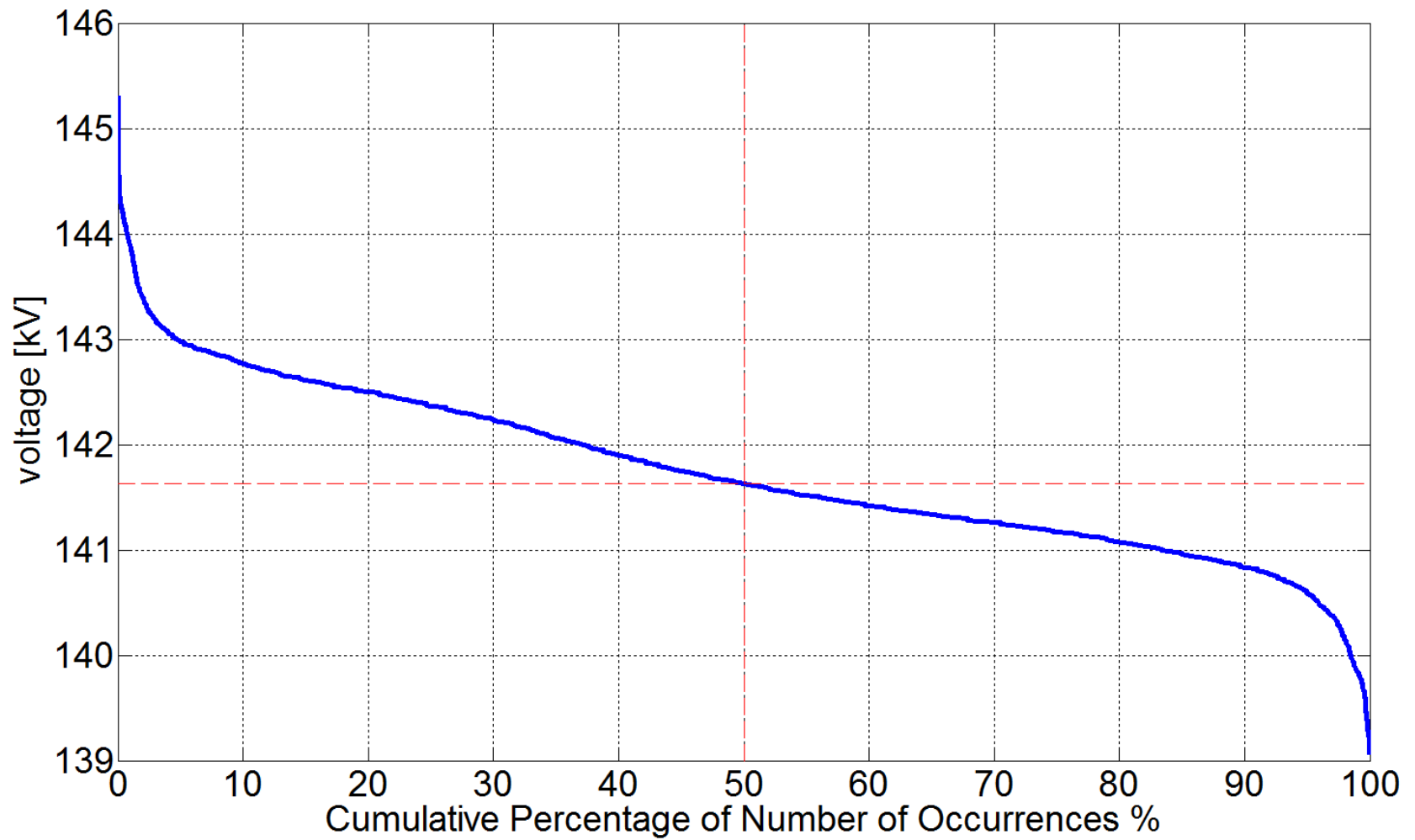
South 11*



South 10*



South 10*



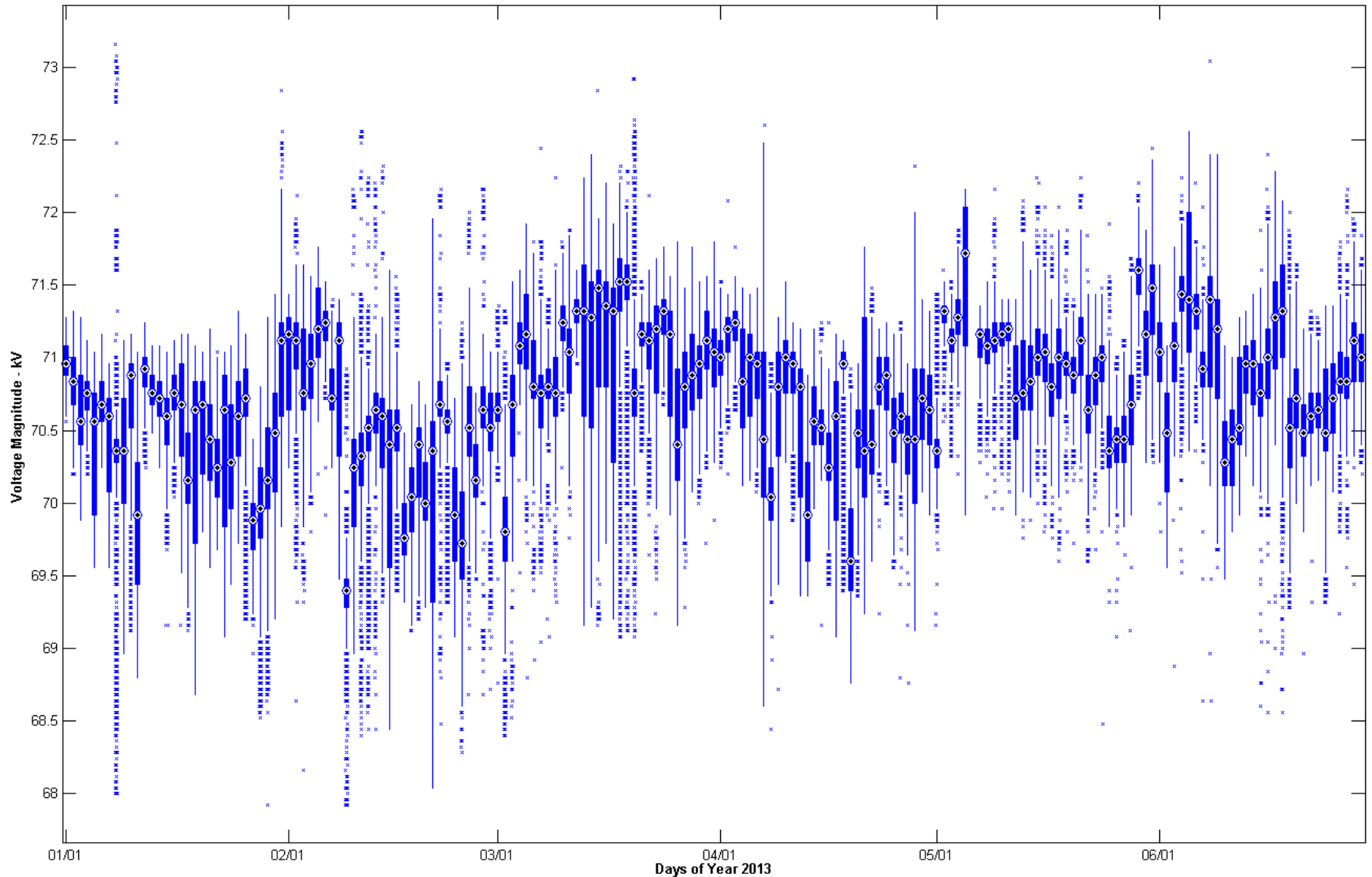
Appendix A – Part 2
CCET Discovery Across Texas project

Baseline Analysis Update - Voltage Magnitudes

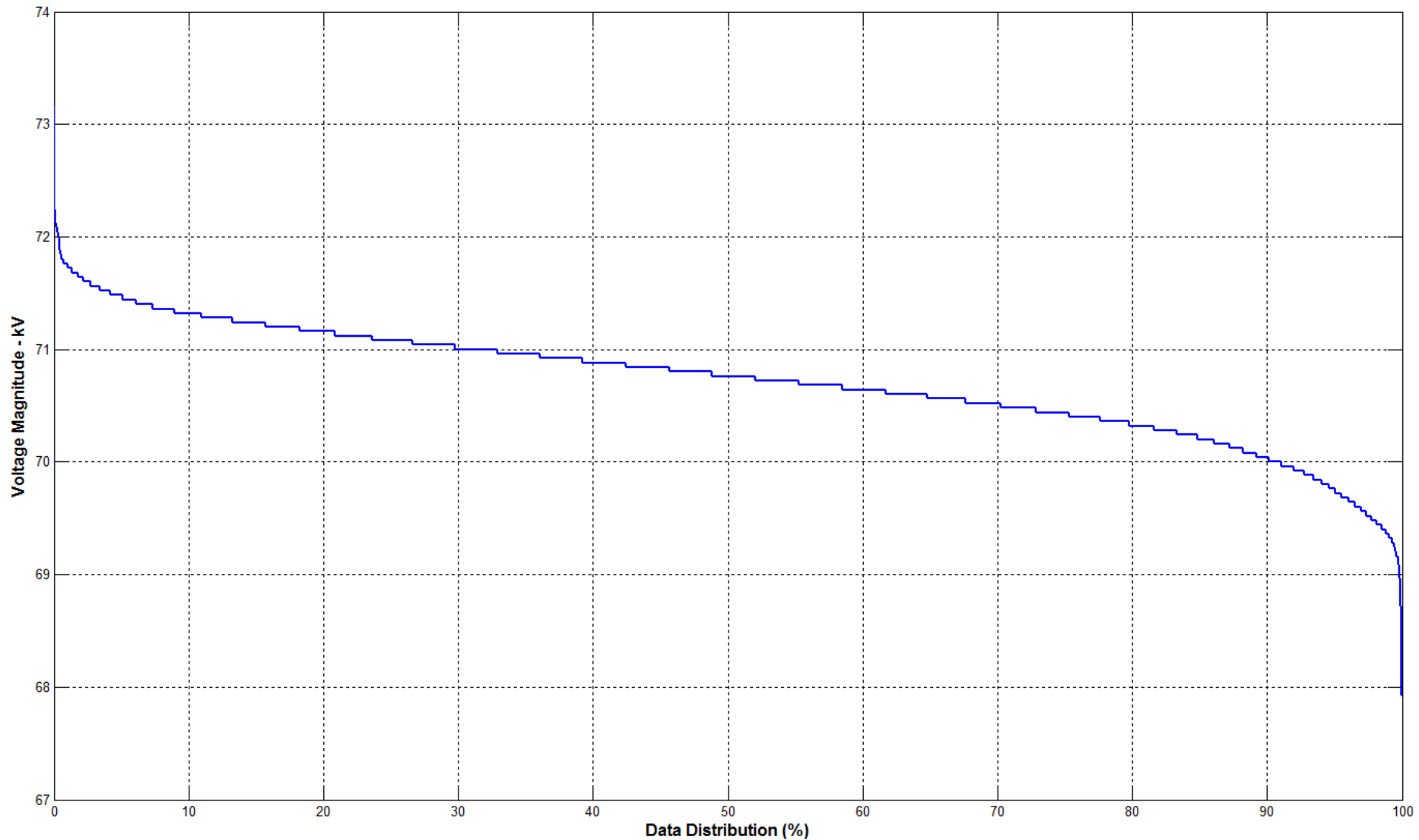
Phasor Data: January to June 2013
Box Whiskers Plots and Time Duration Curves

External Version

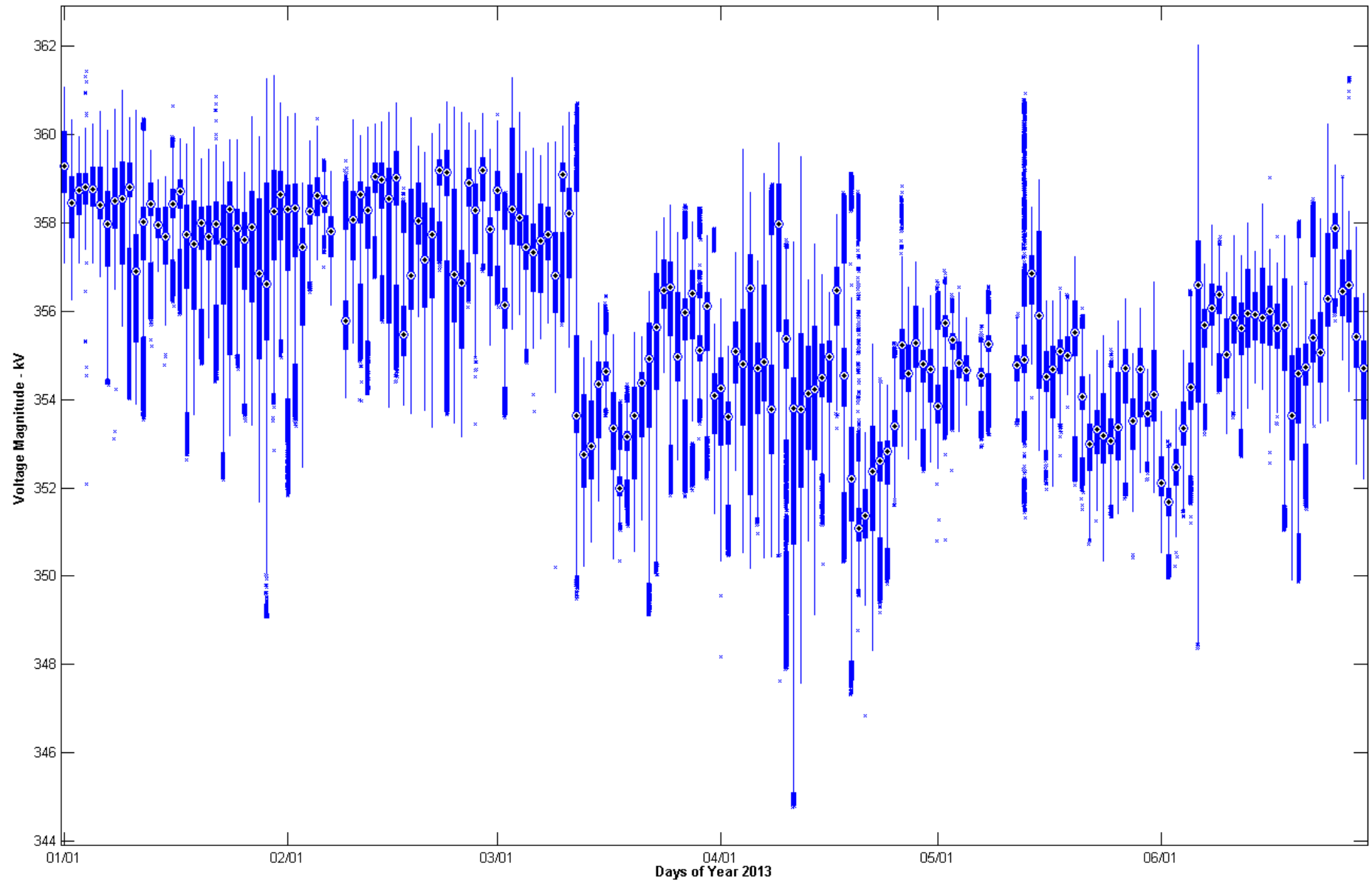
West 10 – Voltage Magnitude



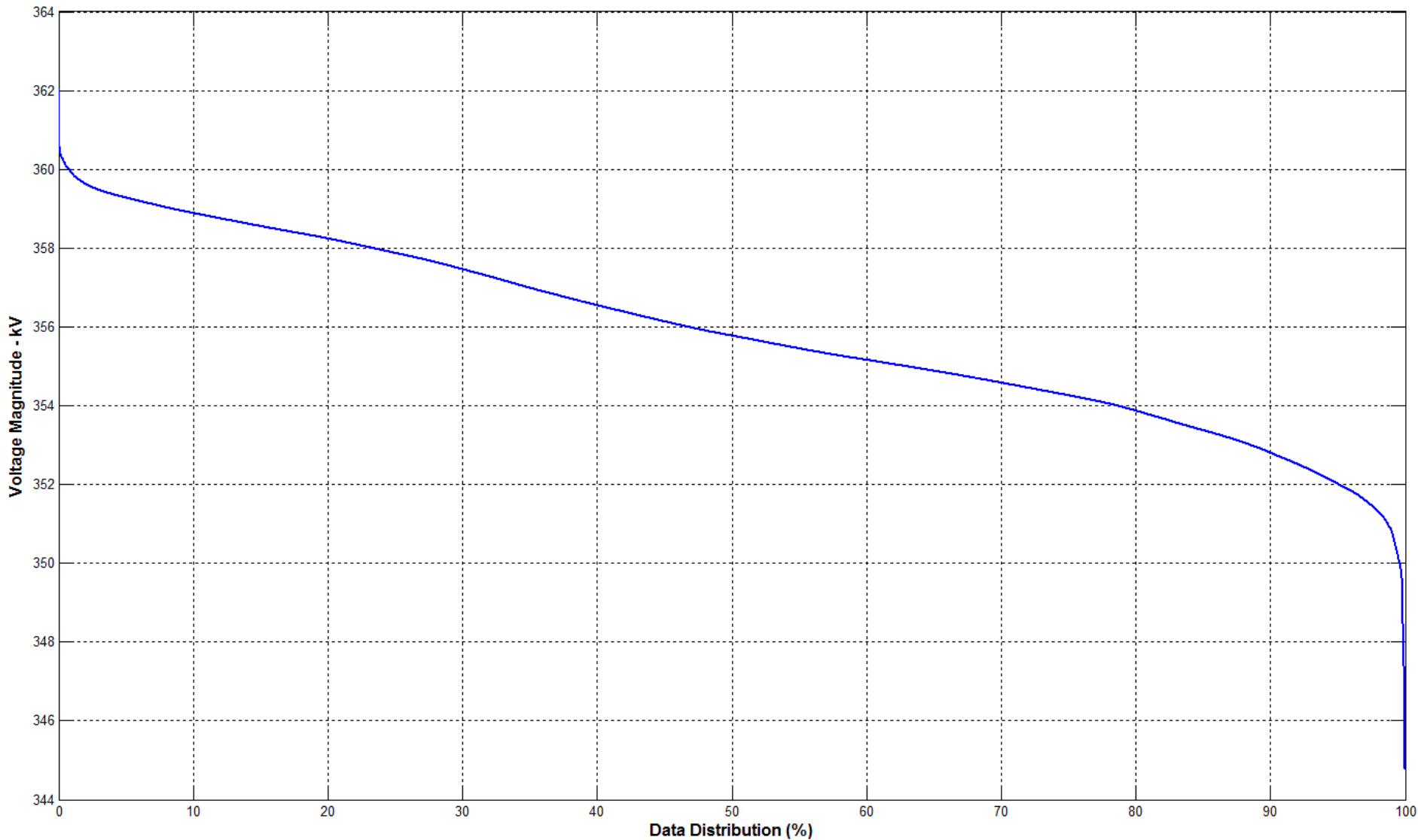
West 10 – Voltage Magnitude



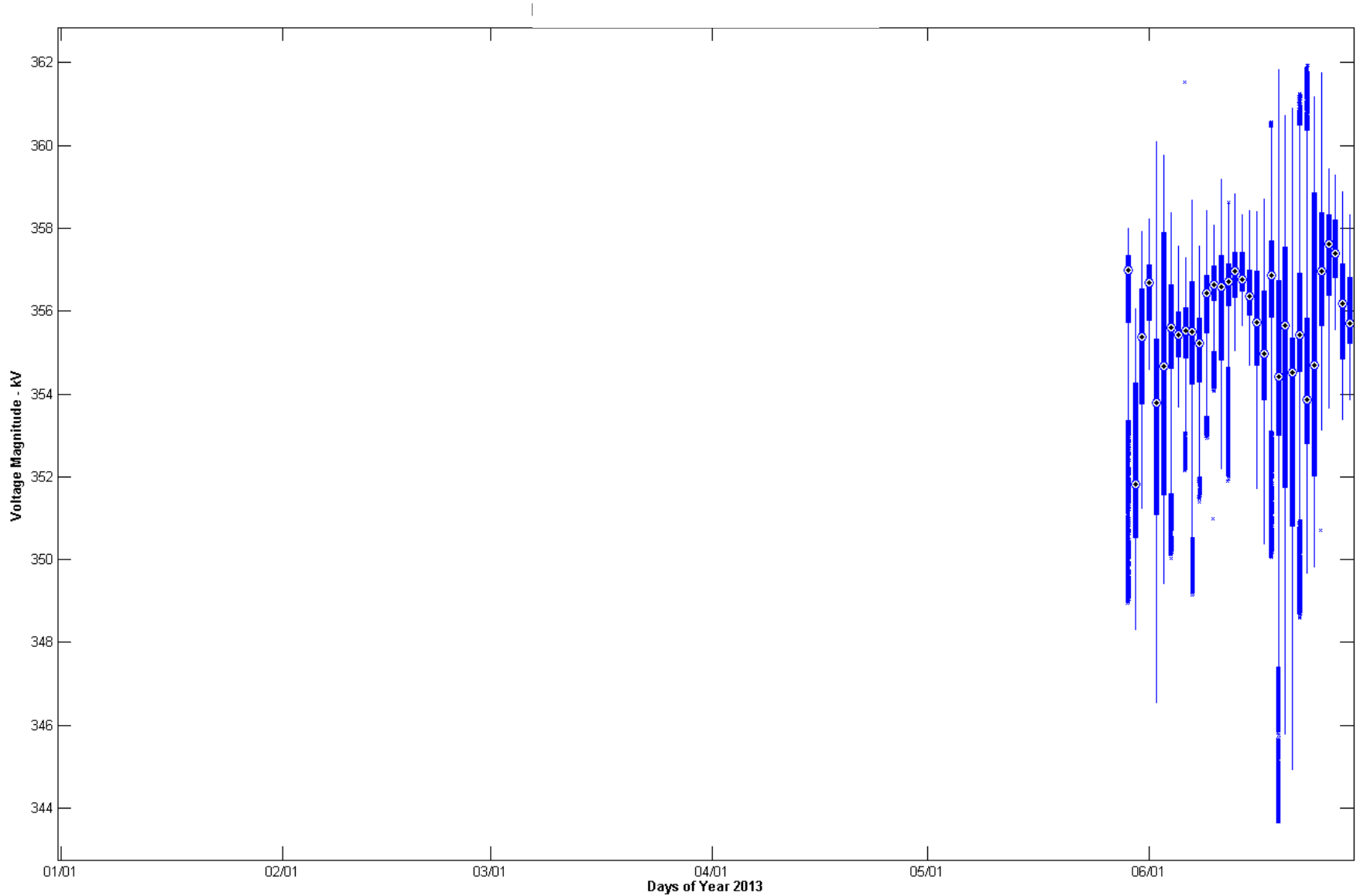
West 14 – Voltage Magnitude



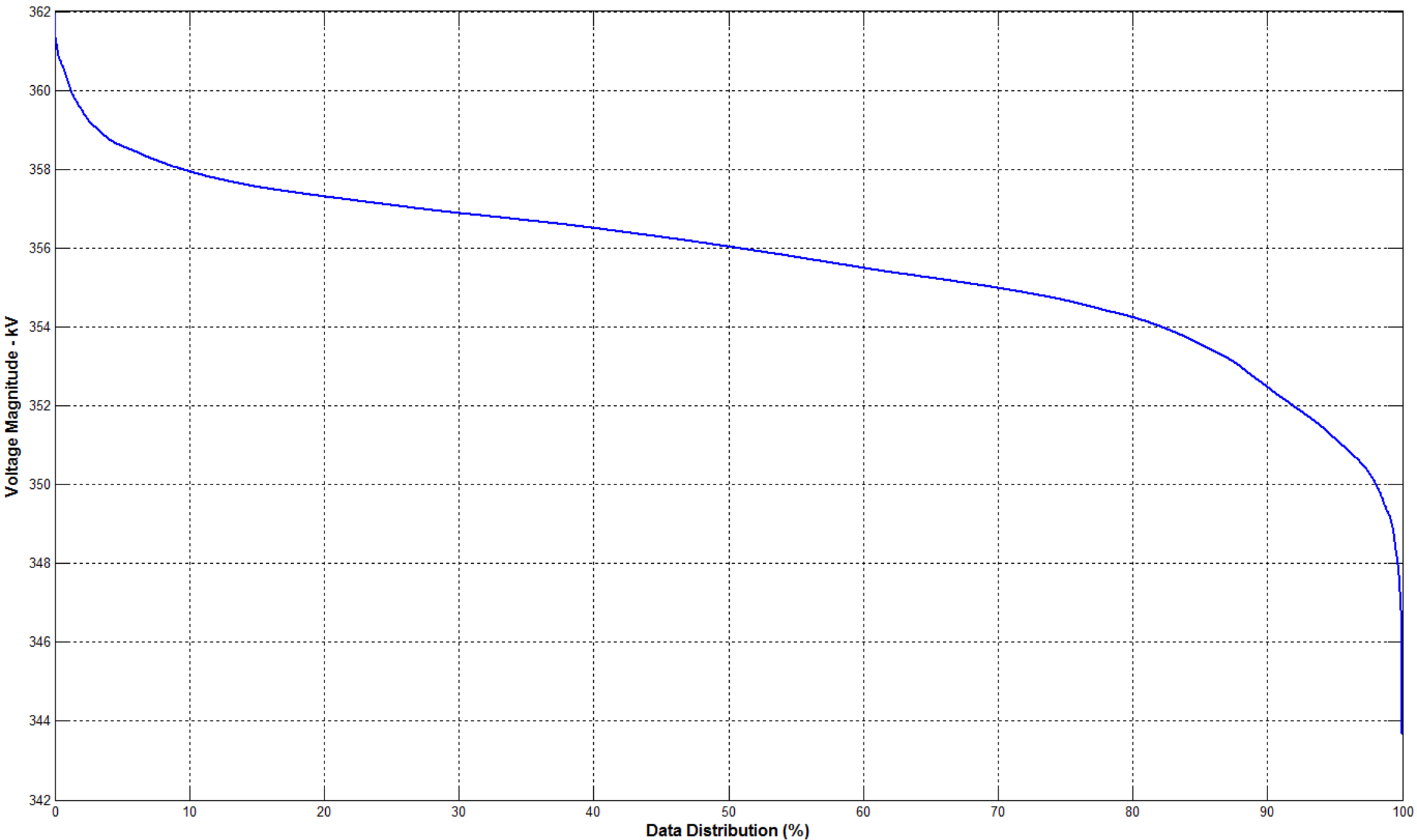
West 14 – Voltage Magnitude



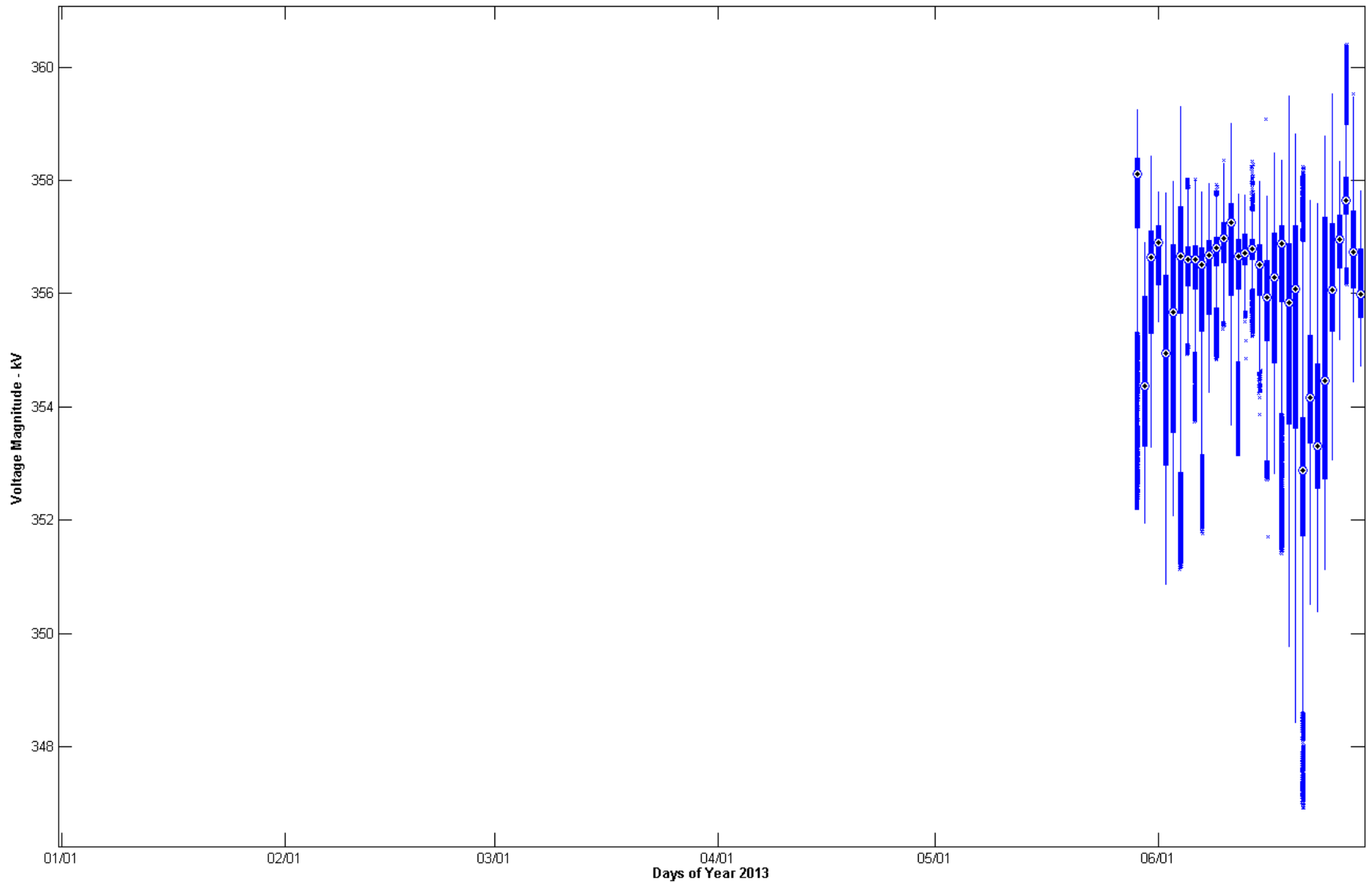
West 1 – Voltage Magnitude



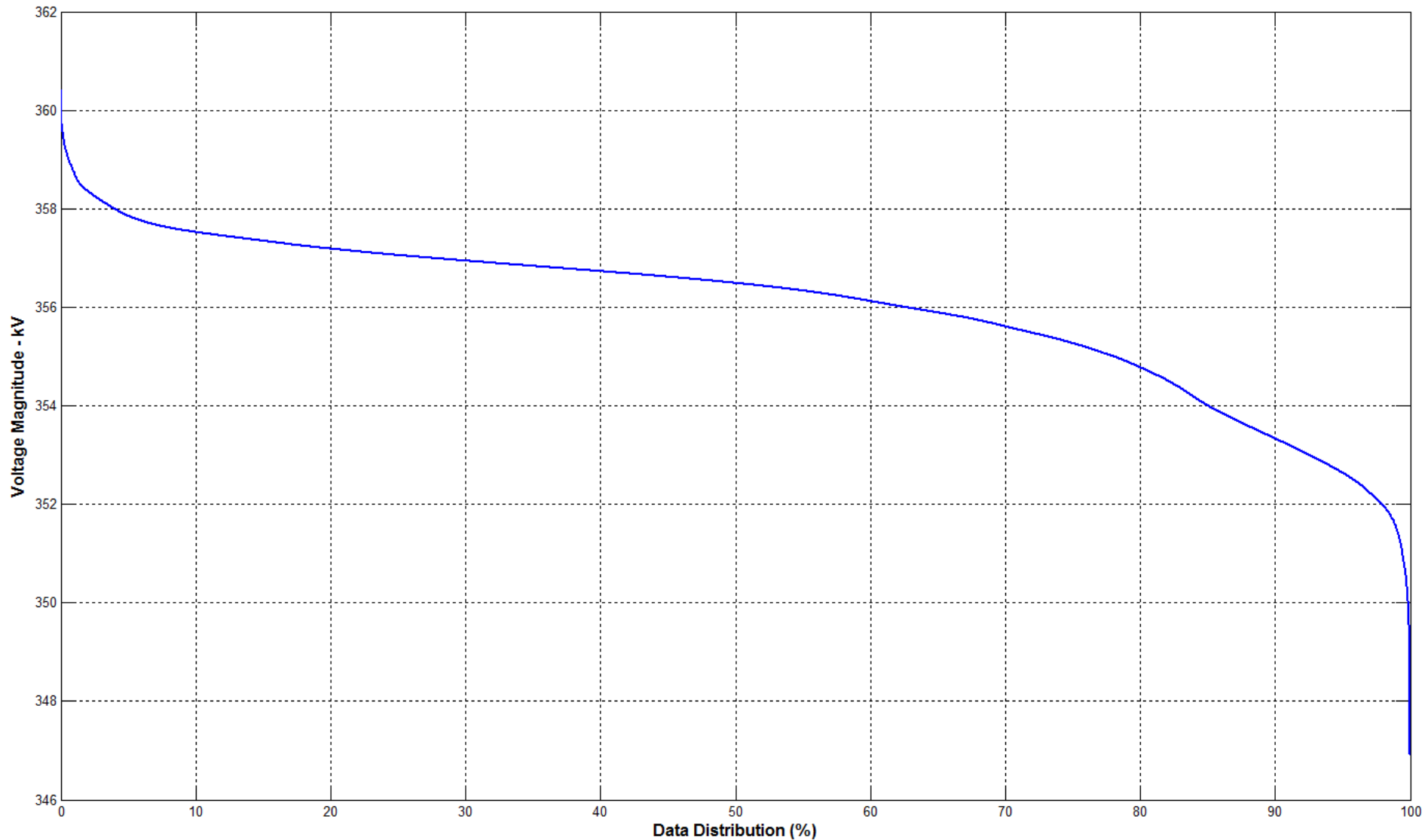
West 1 – Voltage Magnitude



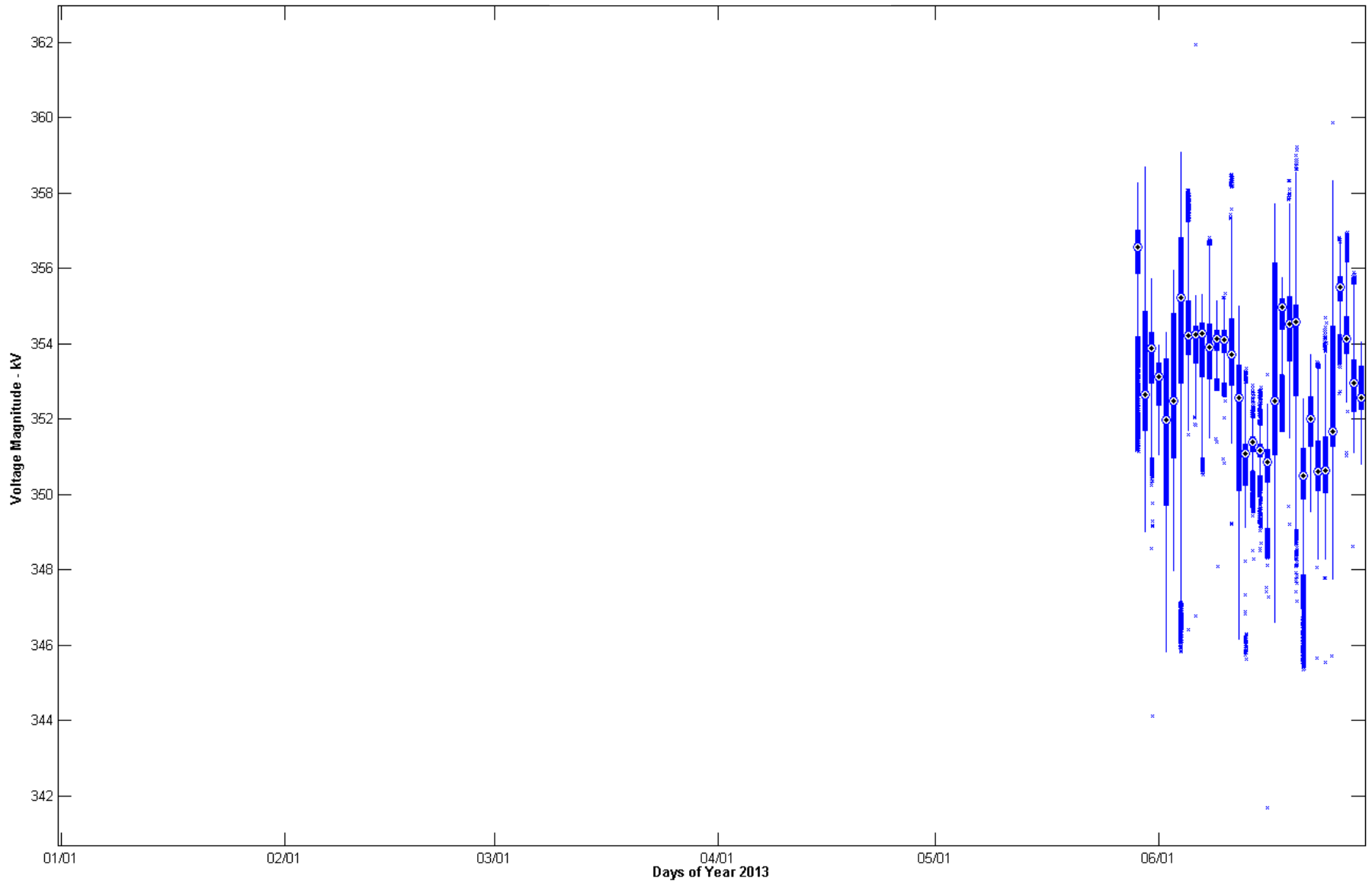
West 2 – Voltage Magnitude



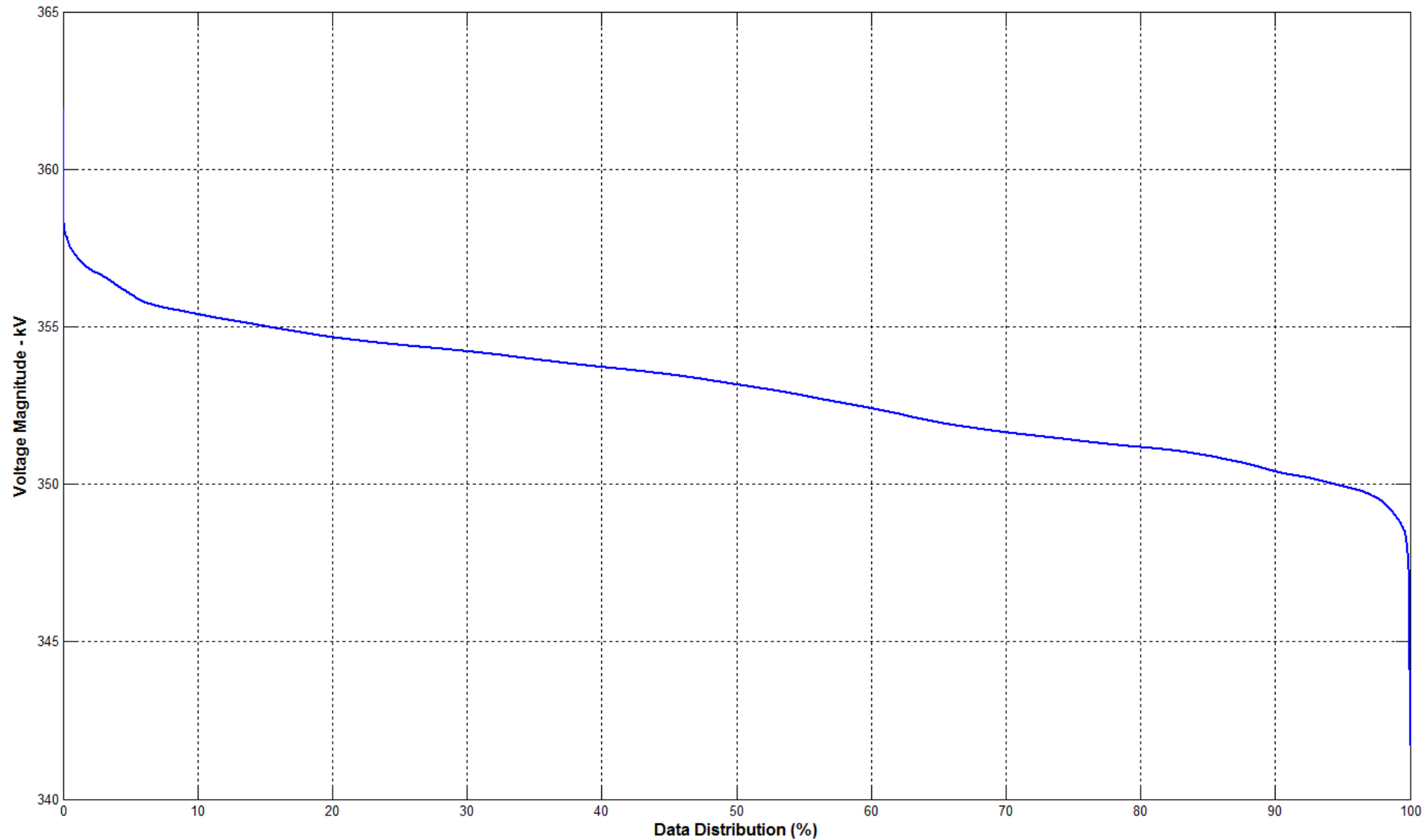
West 2 – Voltage Magnitude



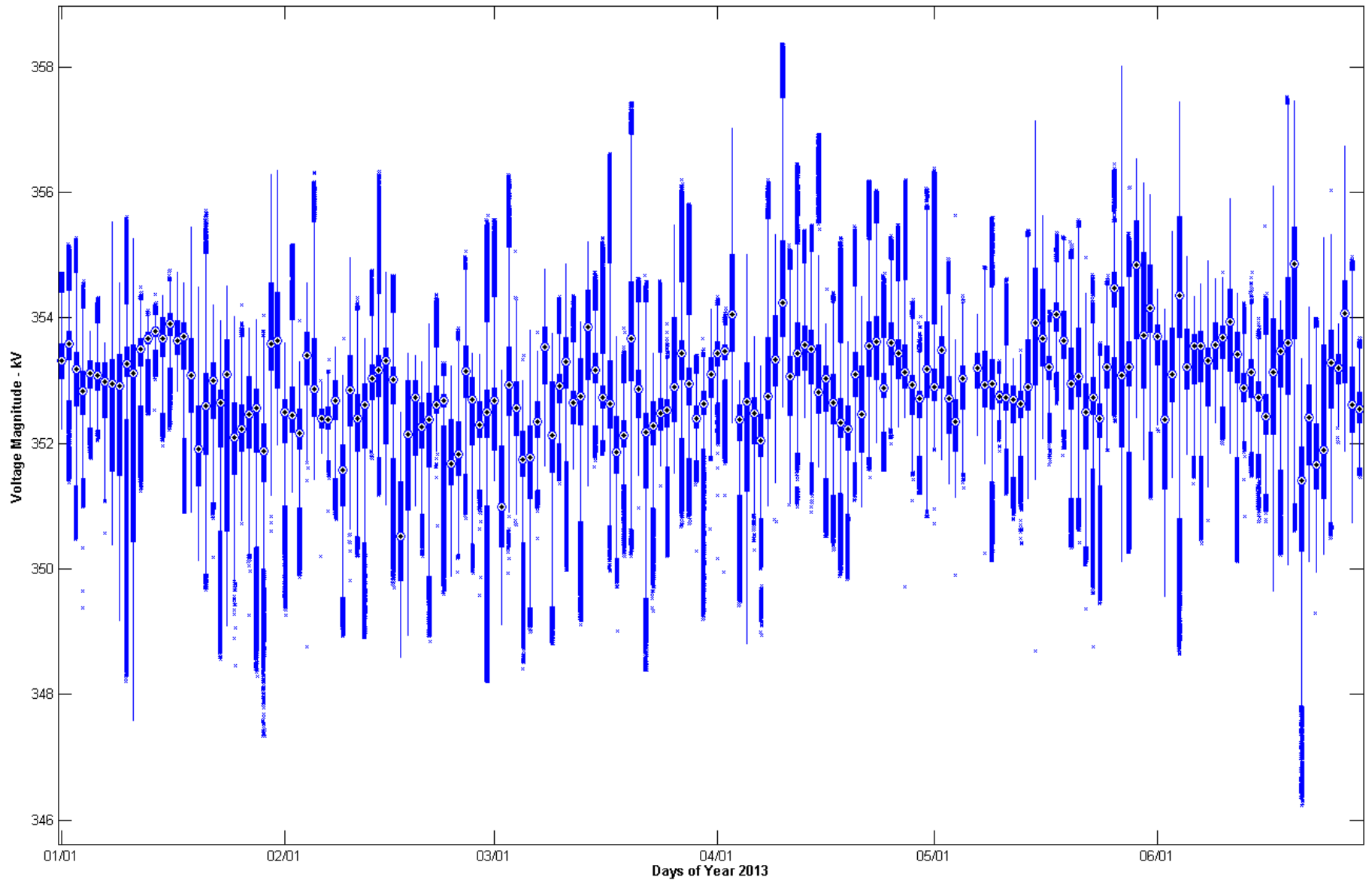
West 9 – Voltage Magnitude



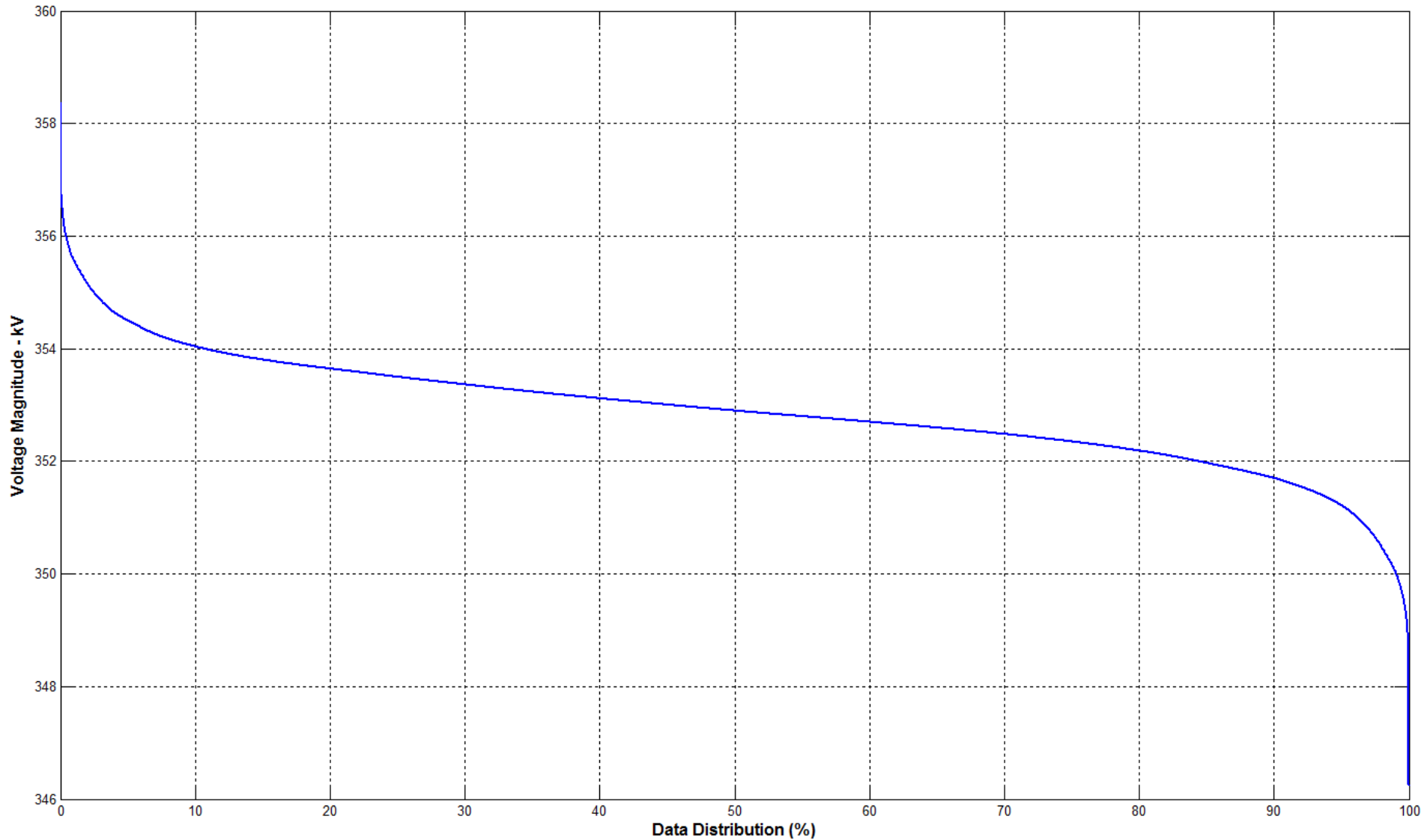
West 9 – Voltage Magnitude



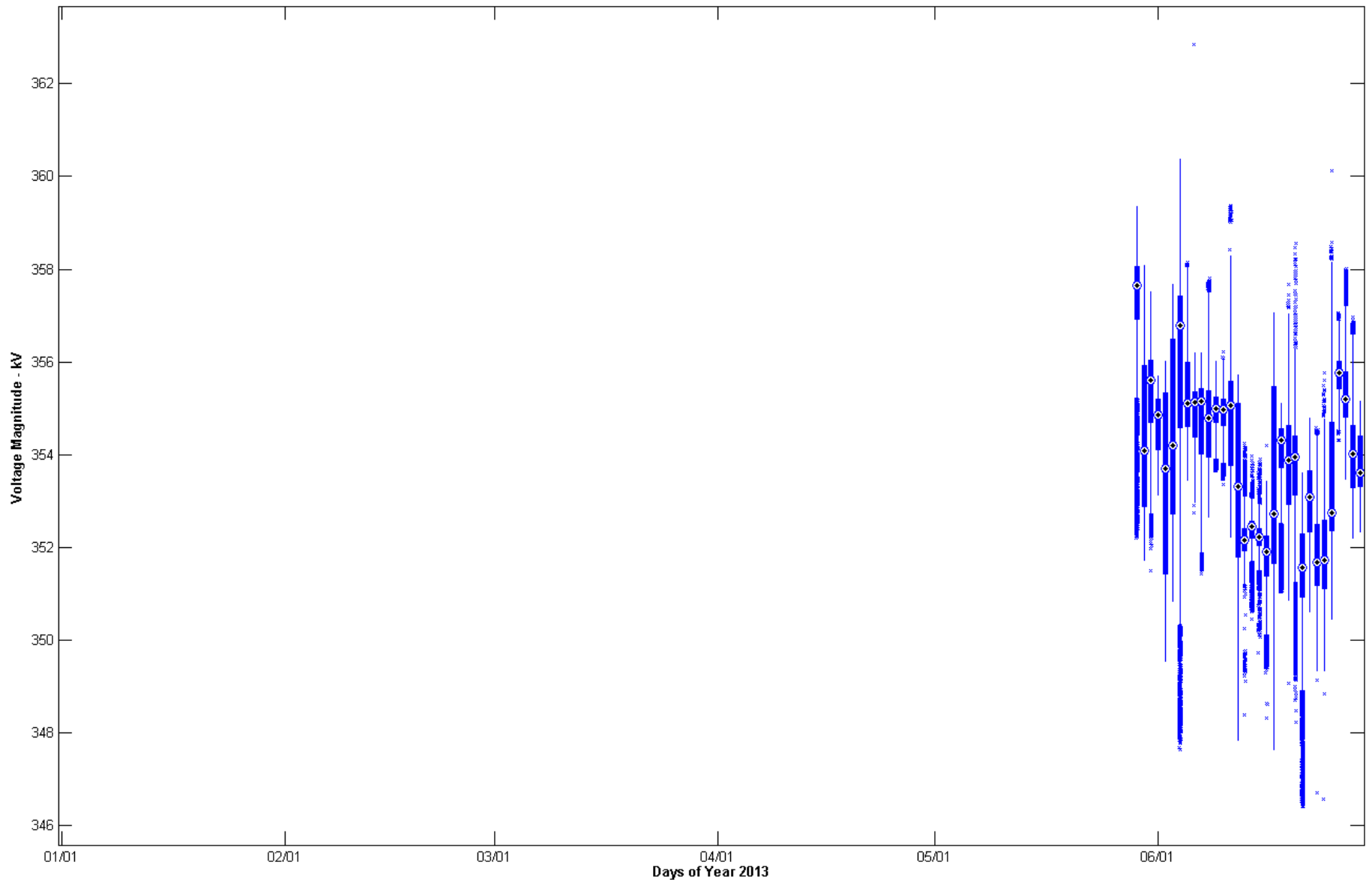
West 11– Voltage Magnitude



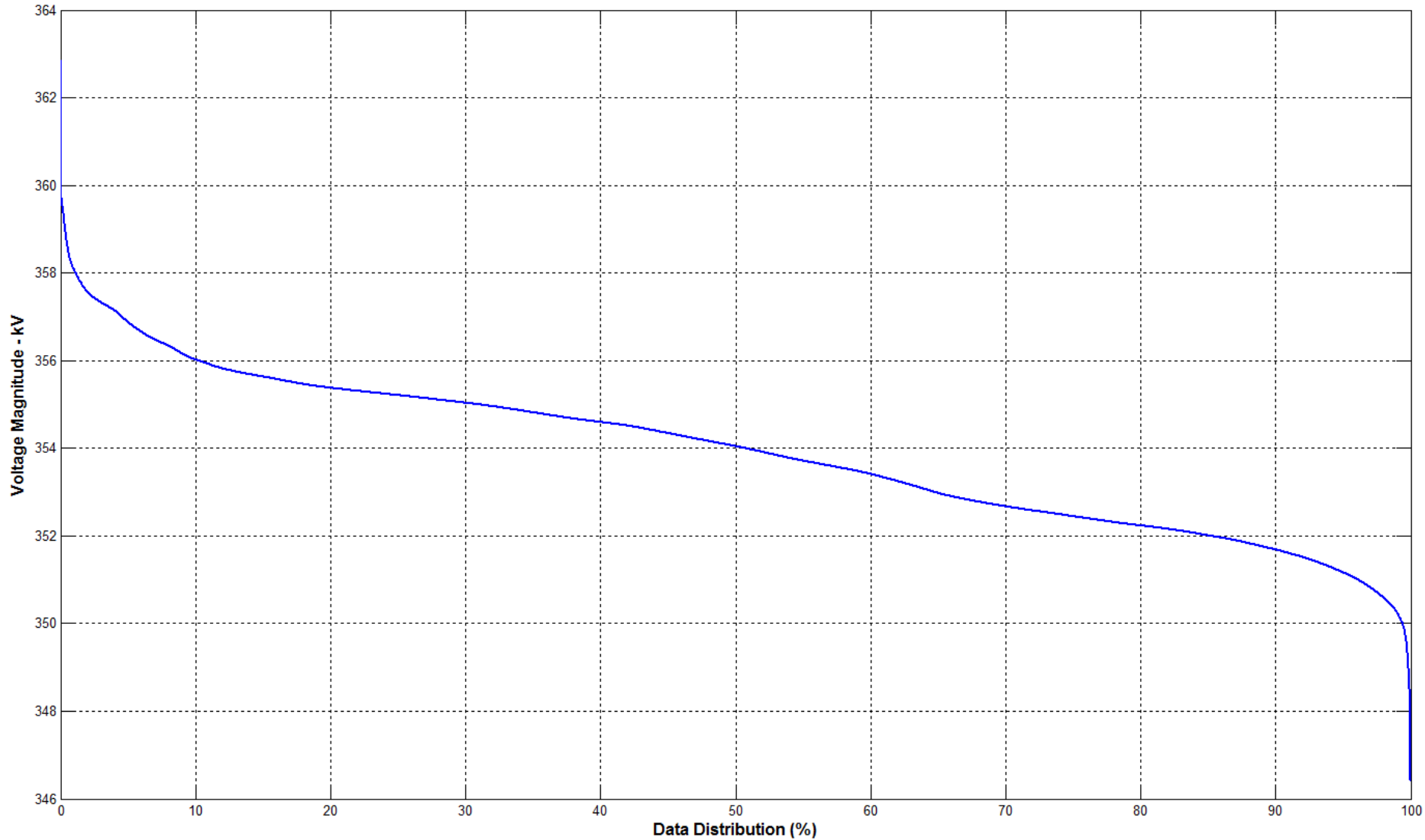
West 11– Voltage Magnitude



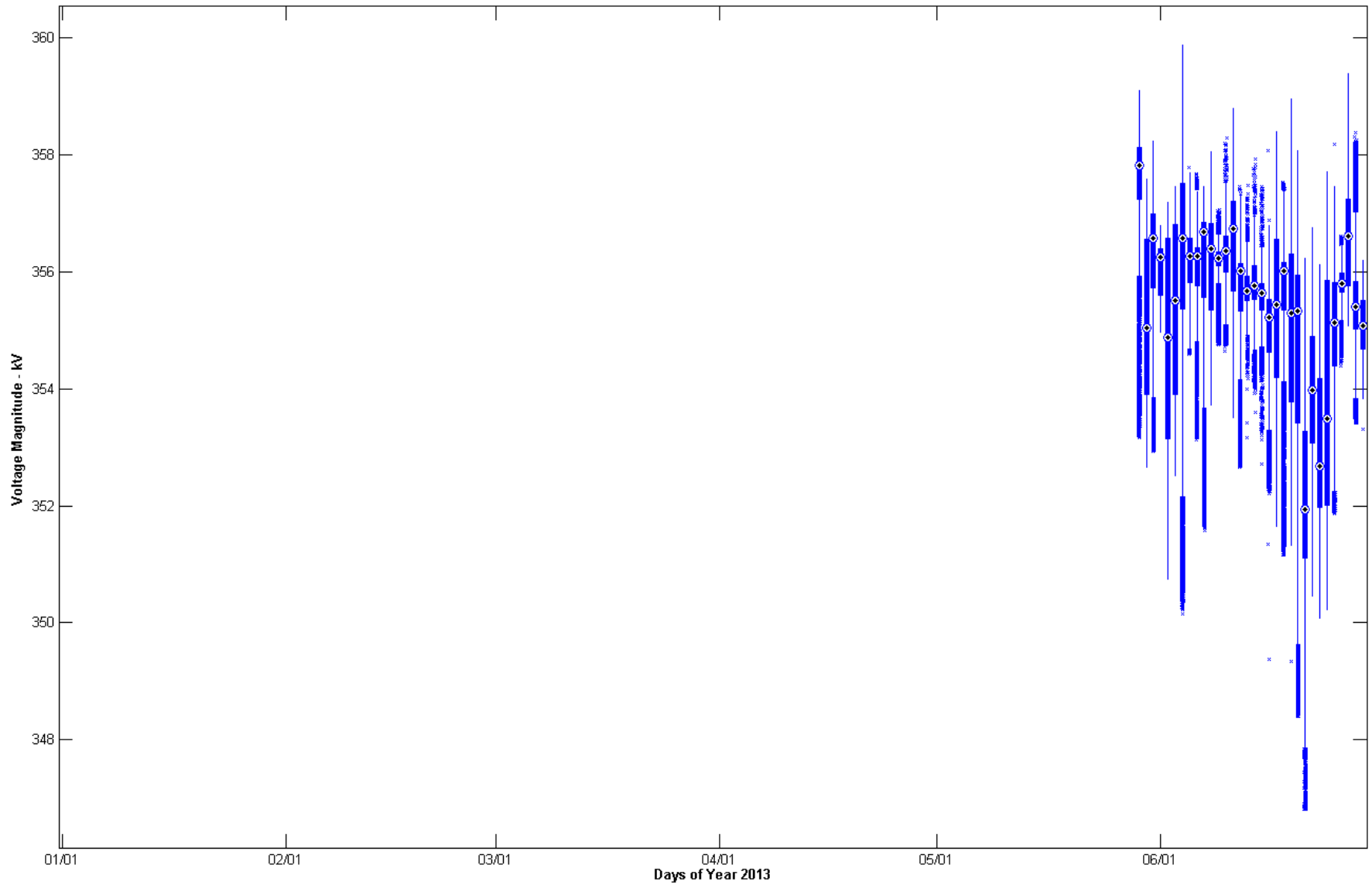
West 12– Voltage Magnitude



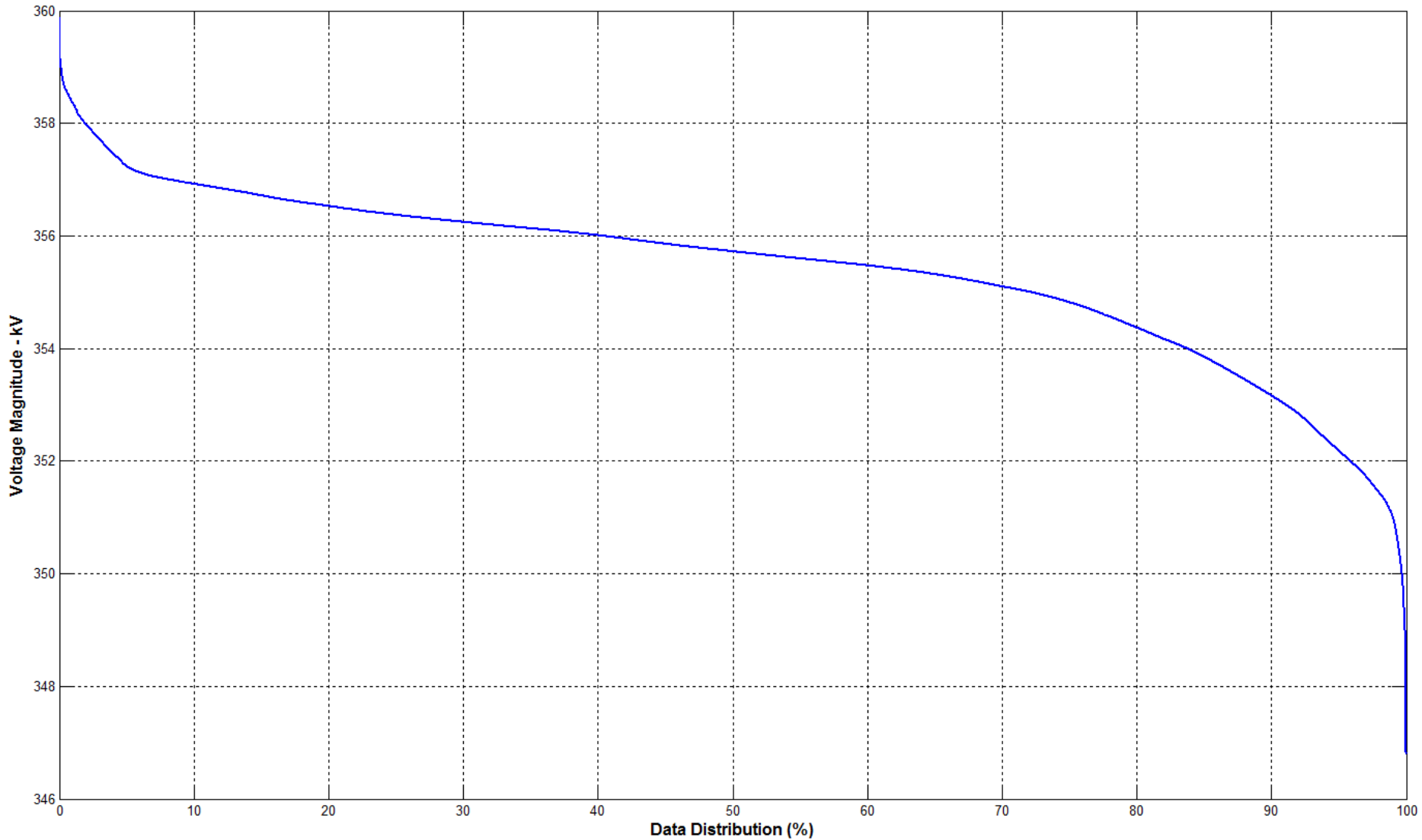
West 12– Voltage Magnitude



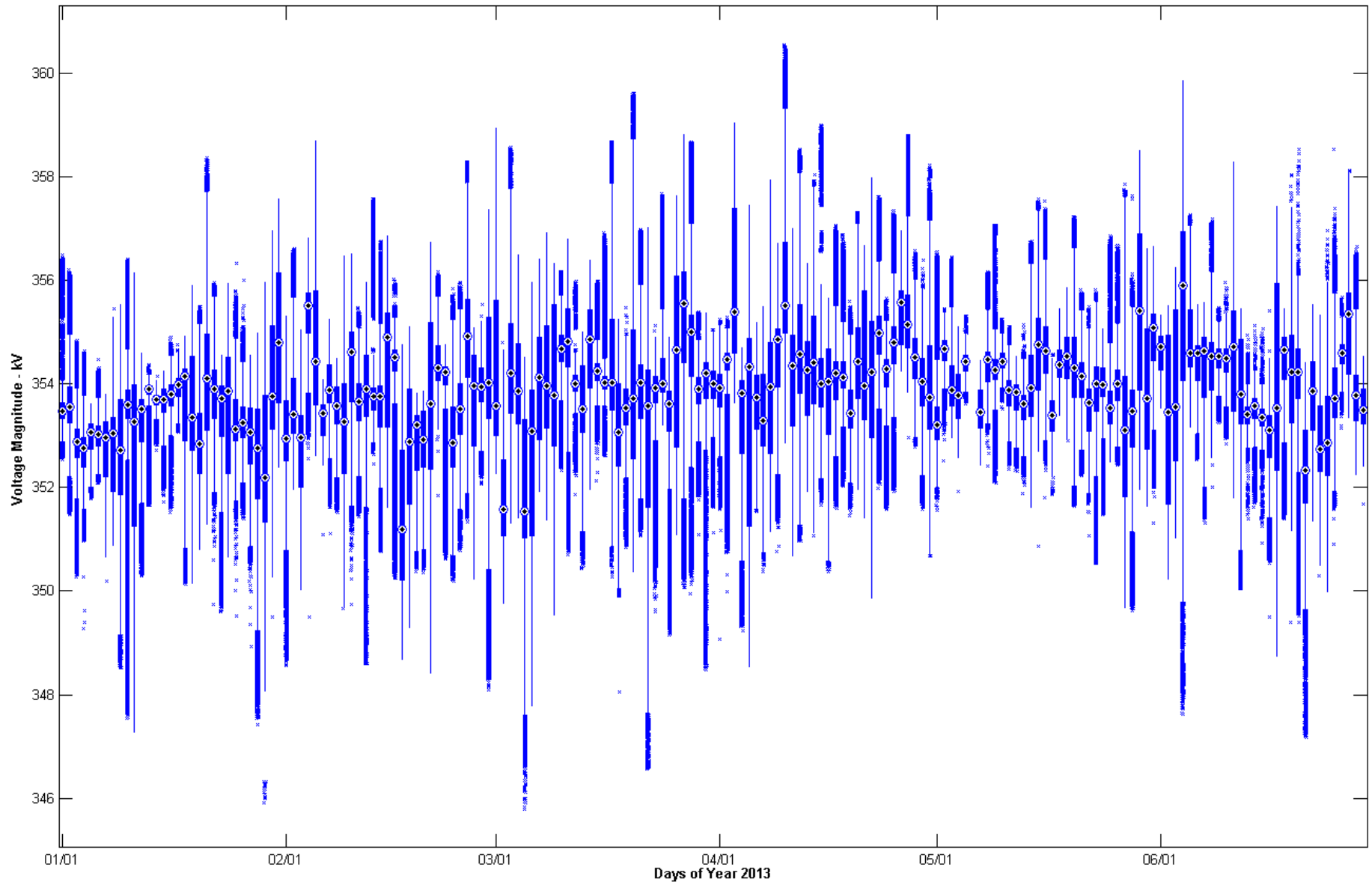
West 5 – Voltage Magnitude



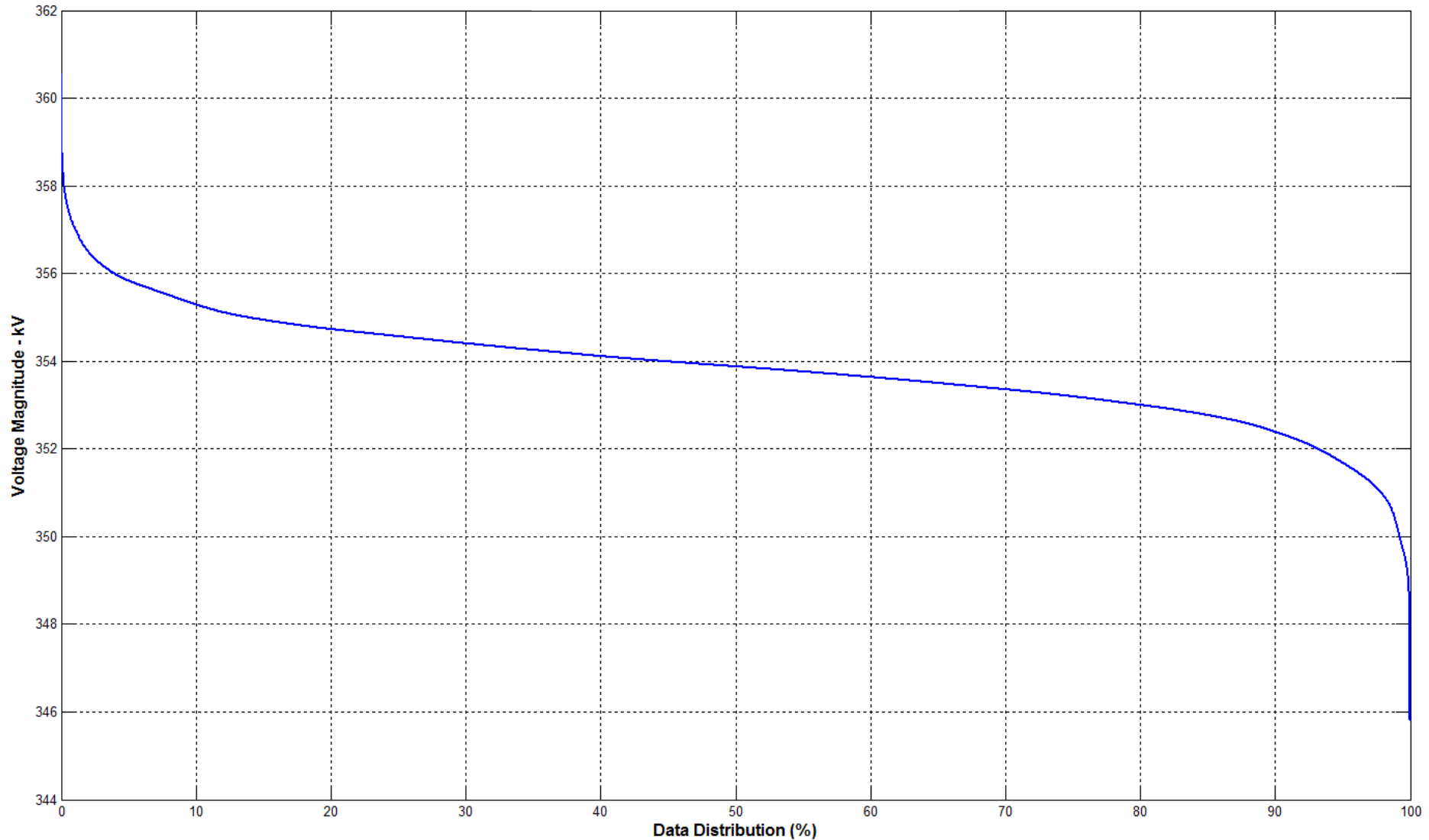
West 5 – Voltage Magnitude



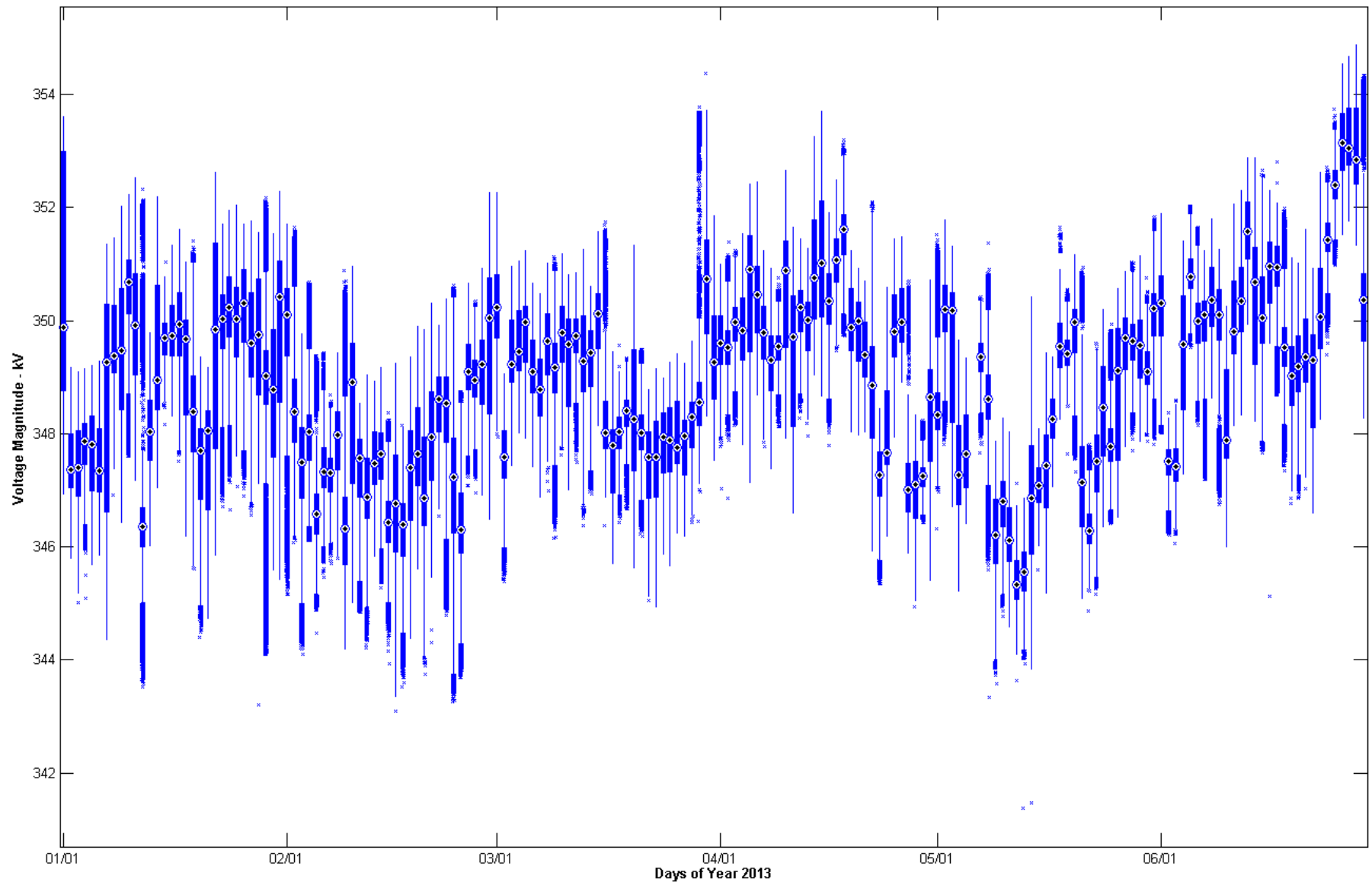
West 6 – Voltage Magnitude



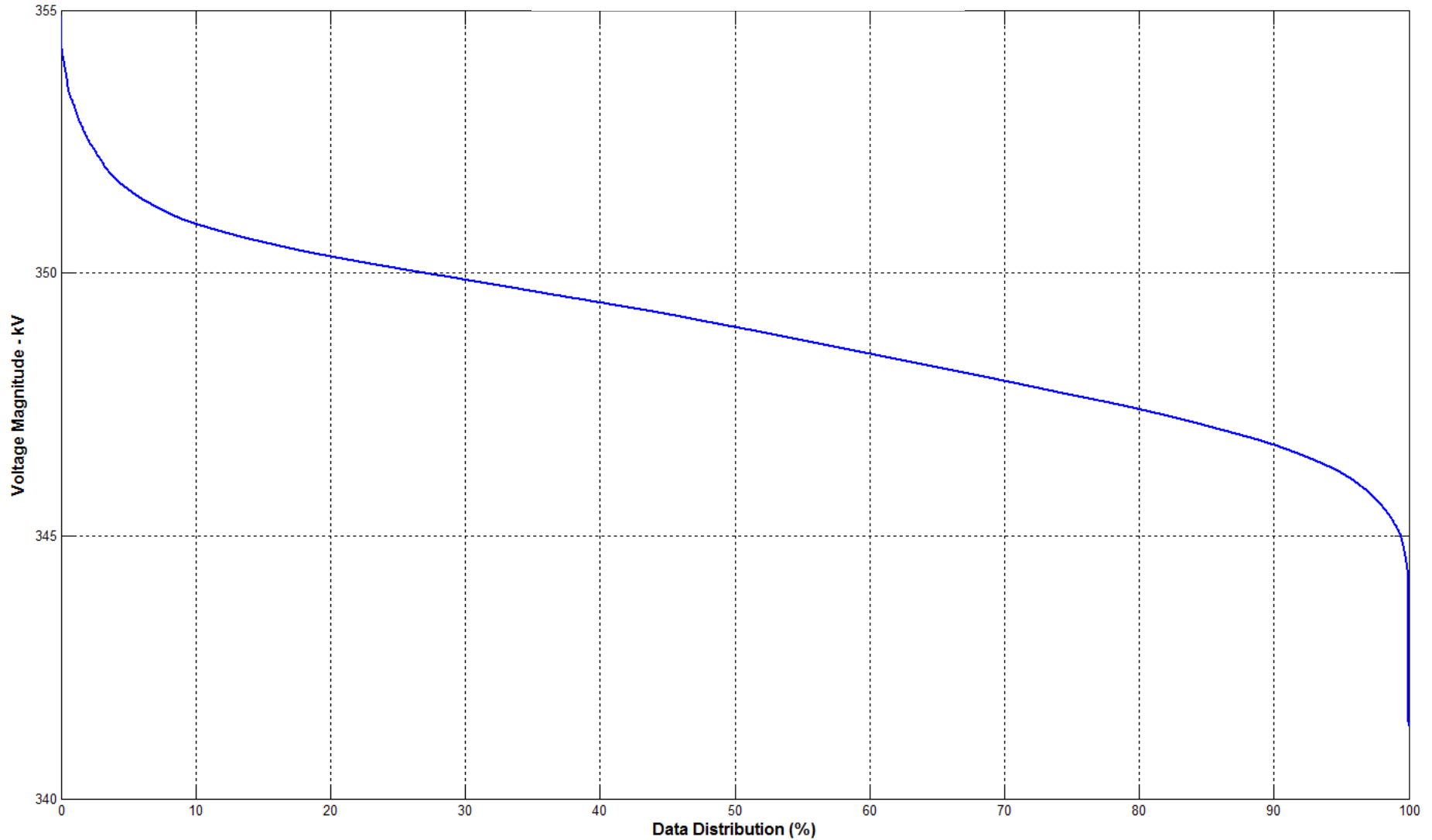
West 6 – Voltage Magnitude



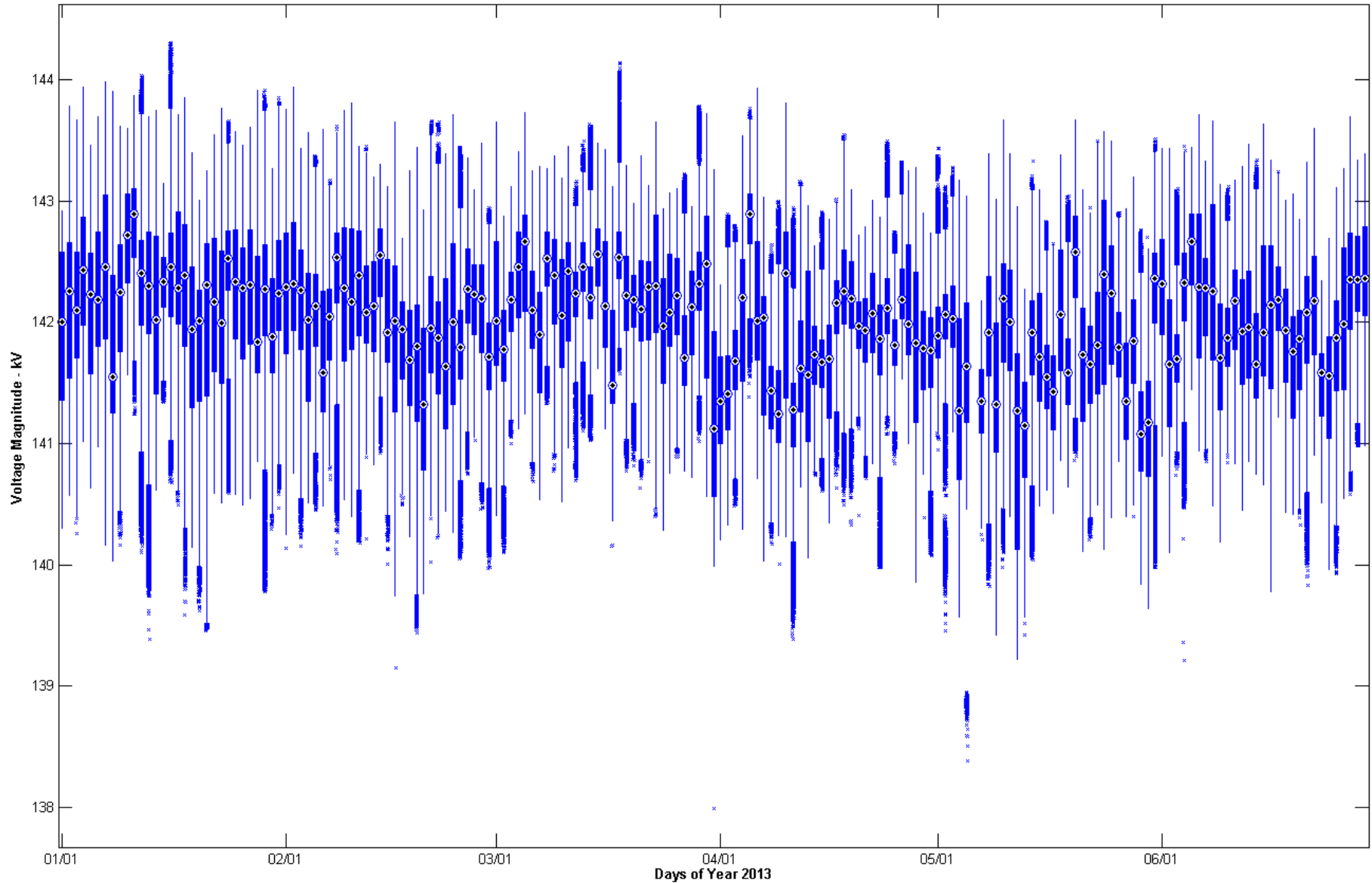
North 1 – Voltage Magnitude



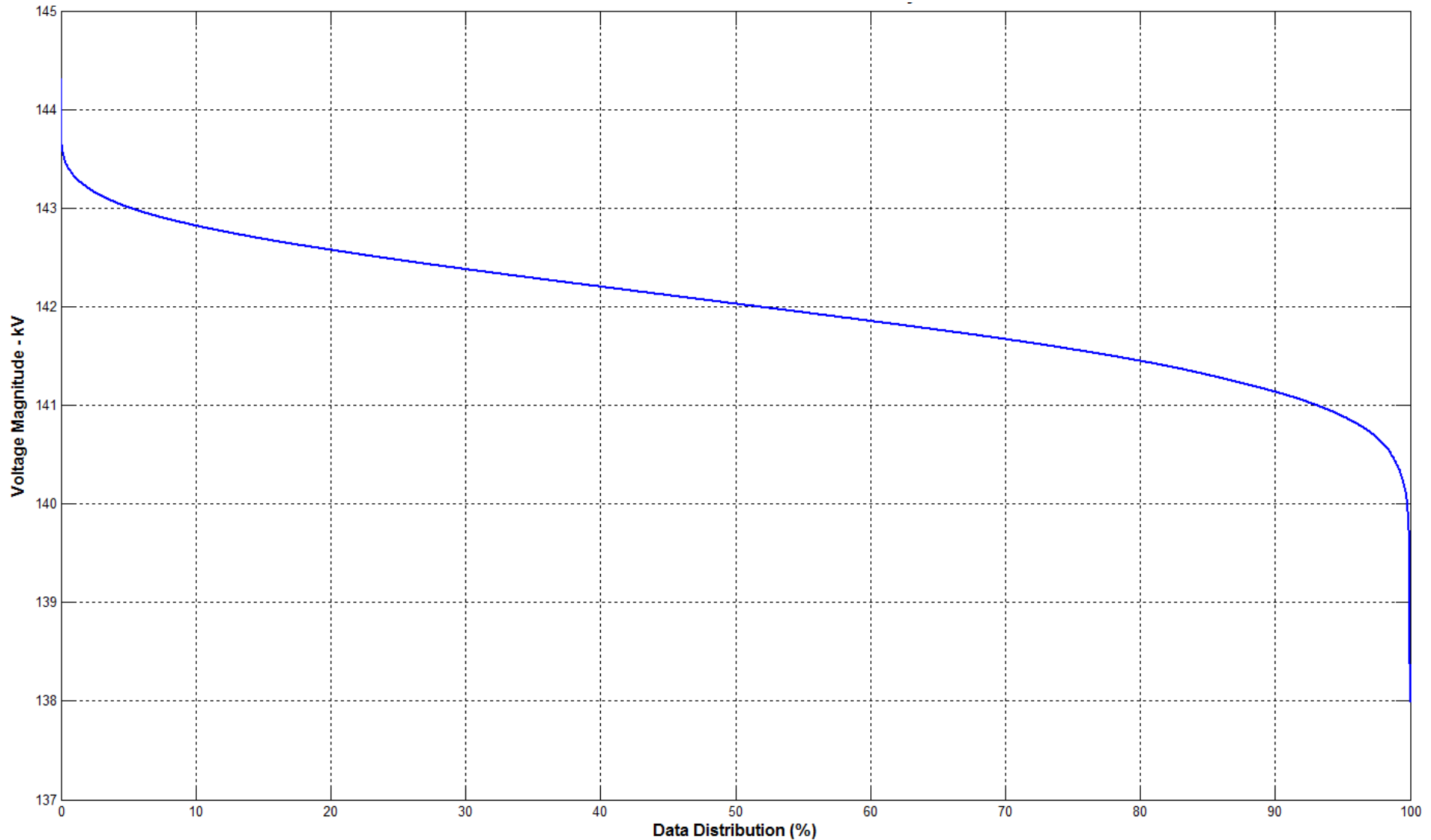
North 1 – Voltage Magnitude



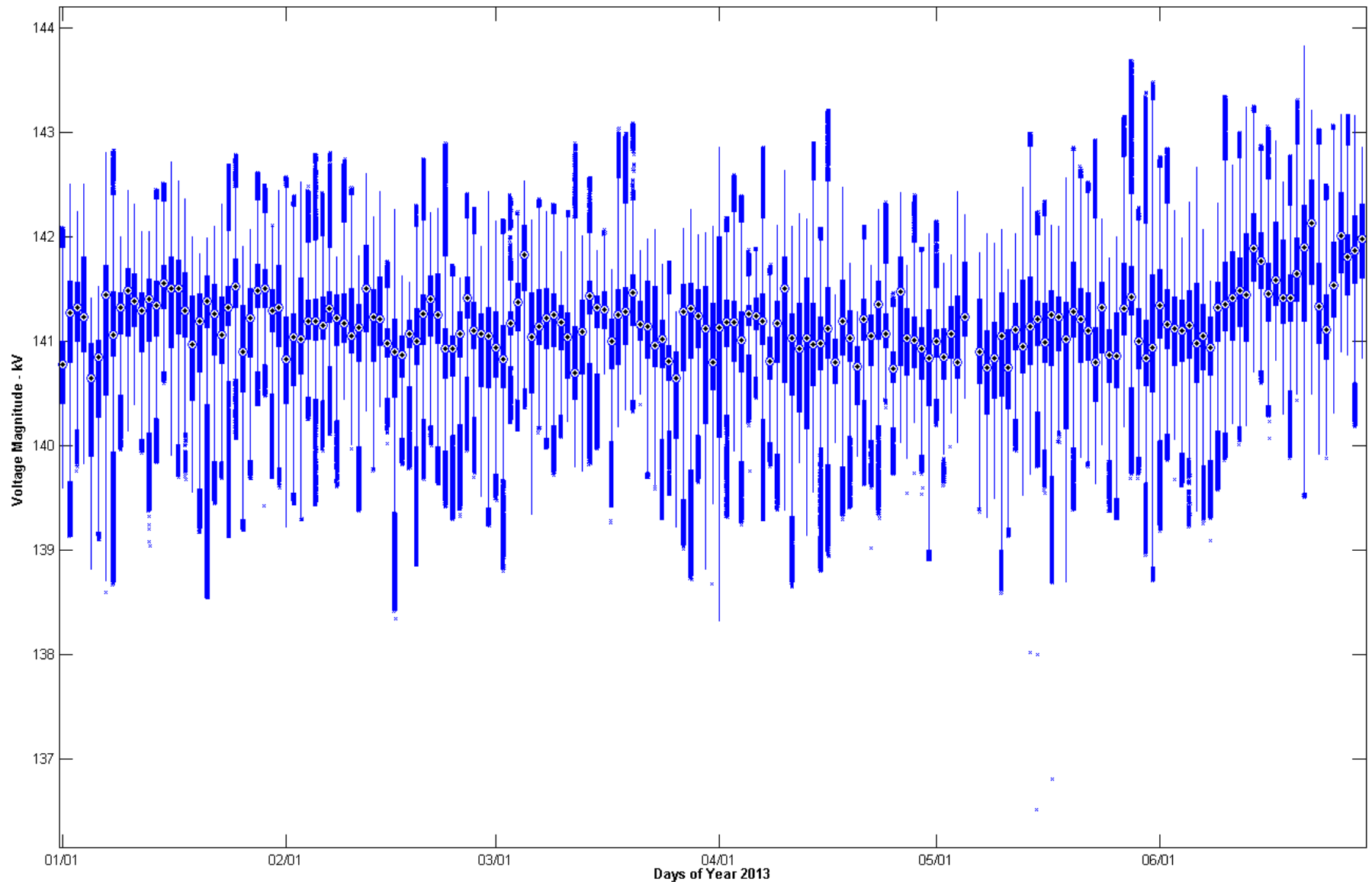
North 4 – Voltage Magnitude



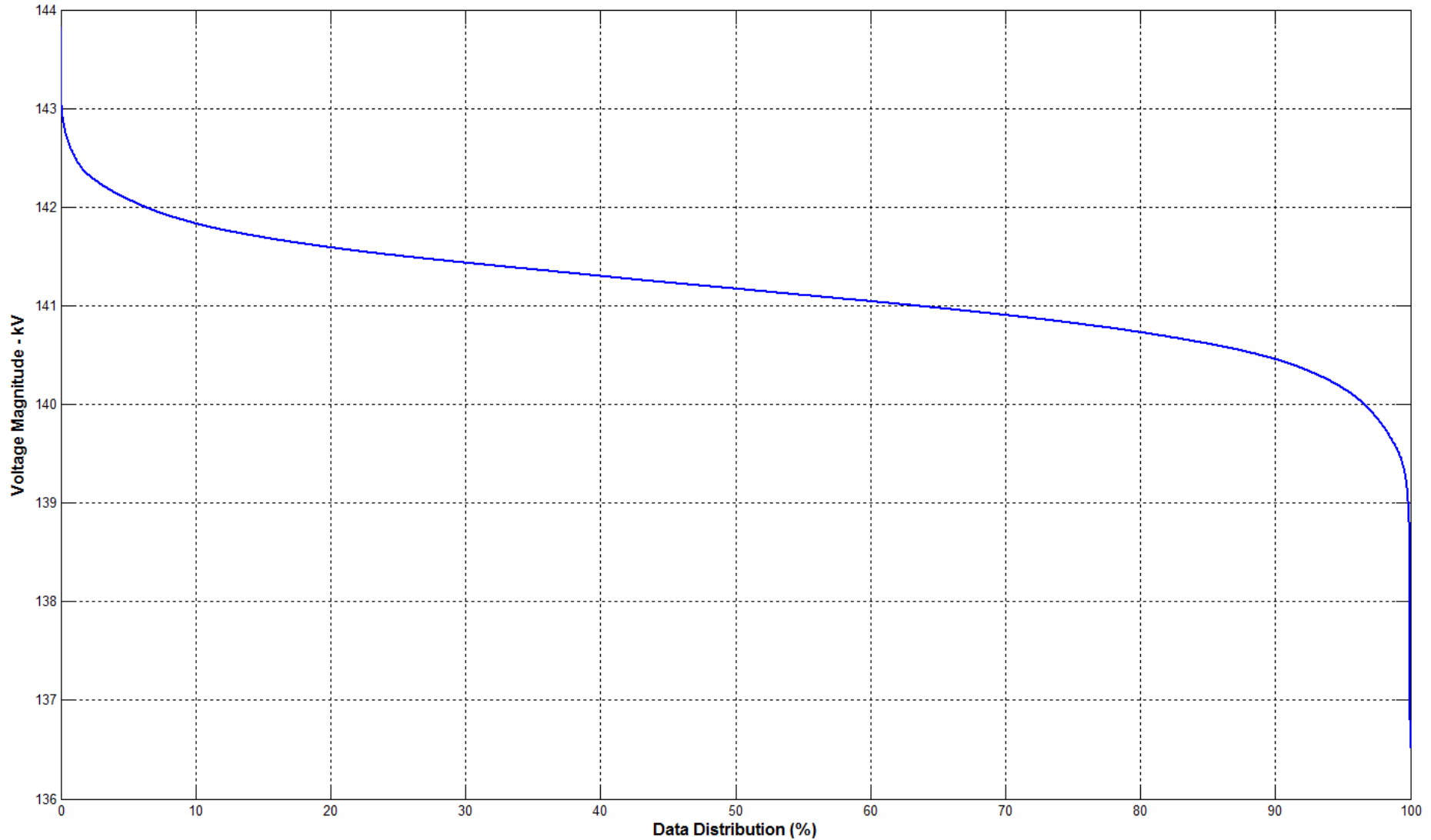
North 4 – Voltage Magnitude



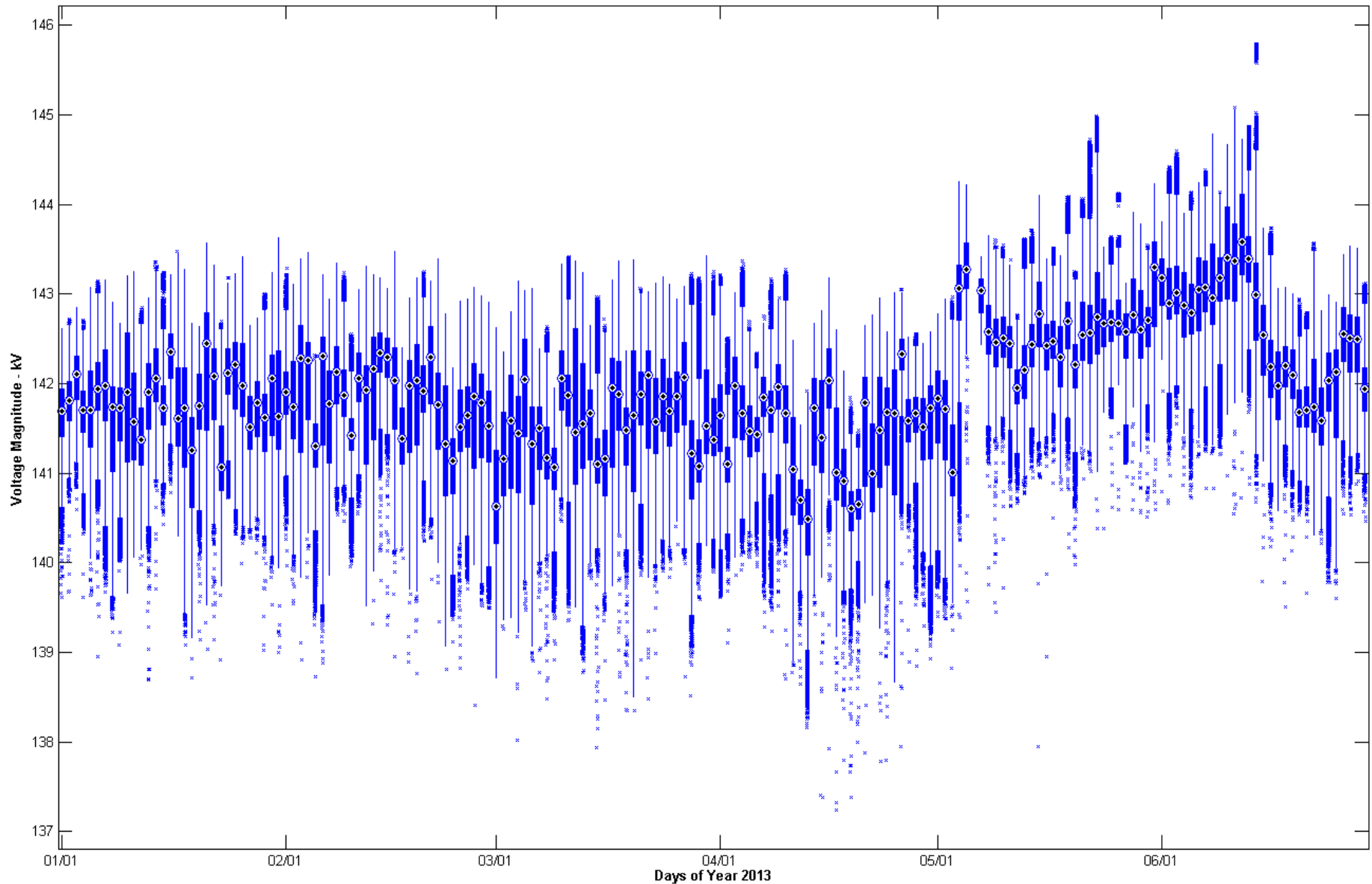
North 5 – Voltage Magnitude



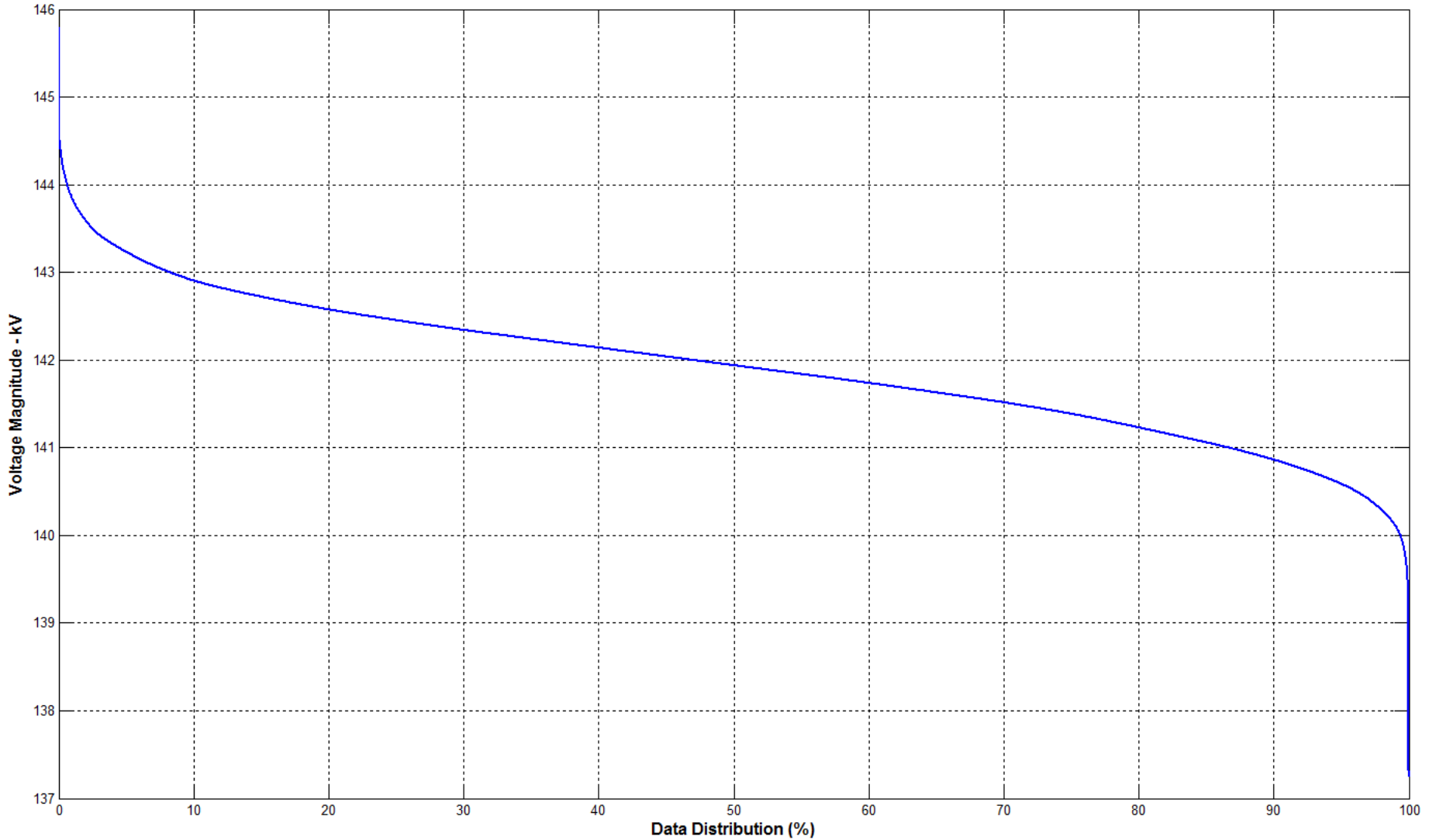
North 5 – Voltage Magnitude



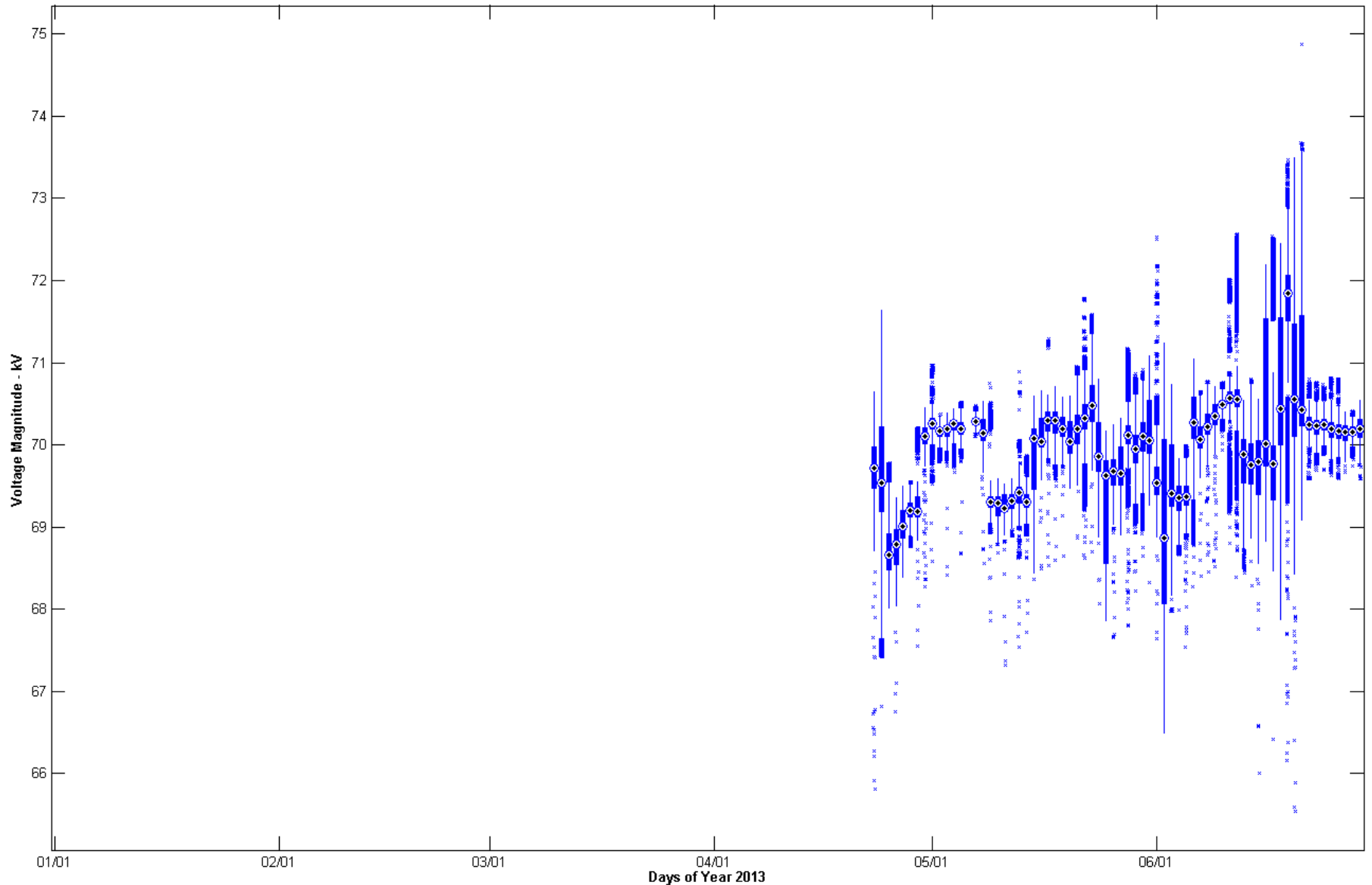
North 6 – Voltage Magnitude



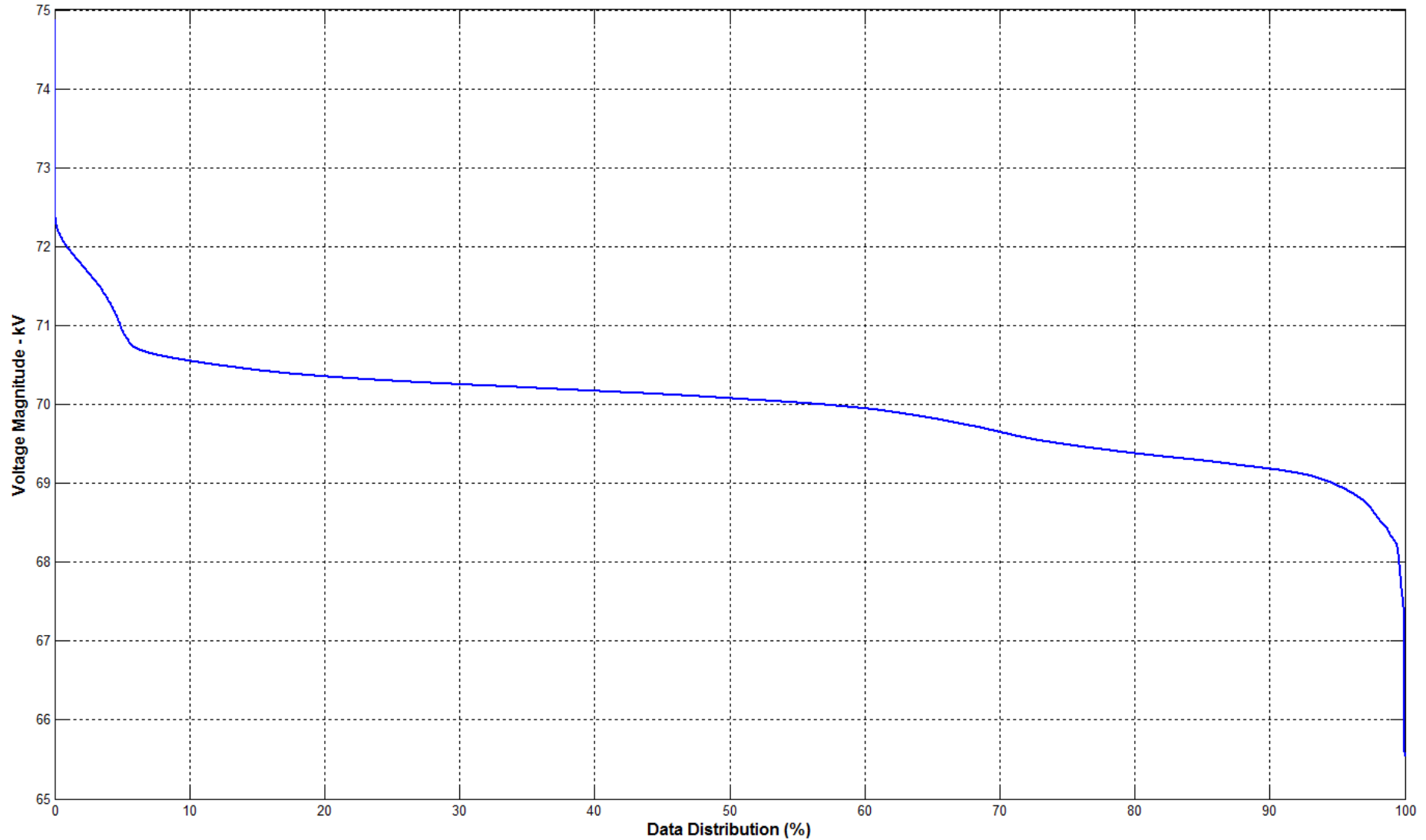
North 6 – Voltage Magnitude



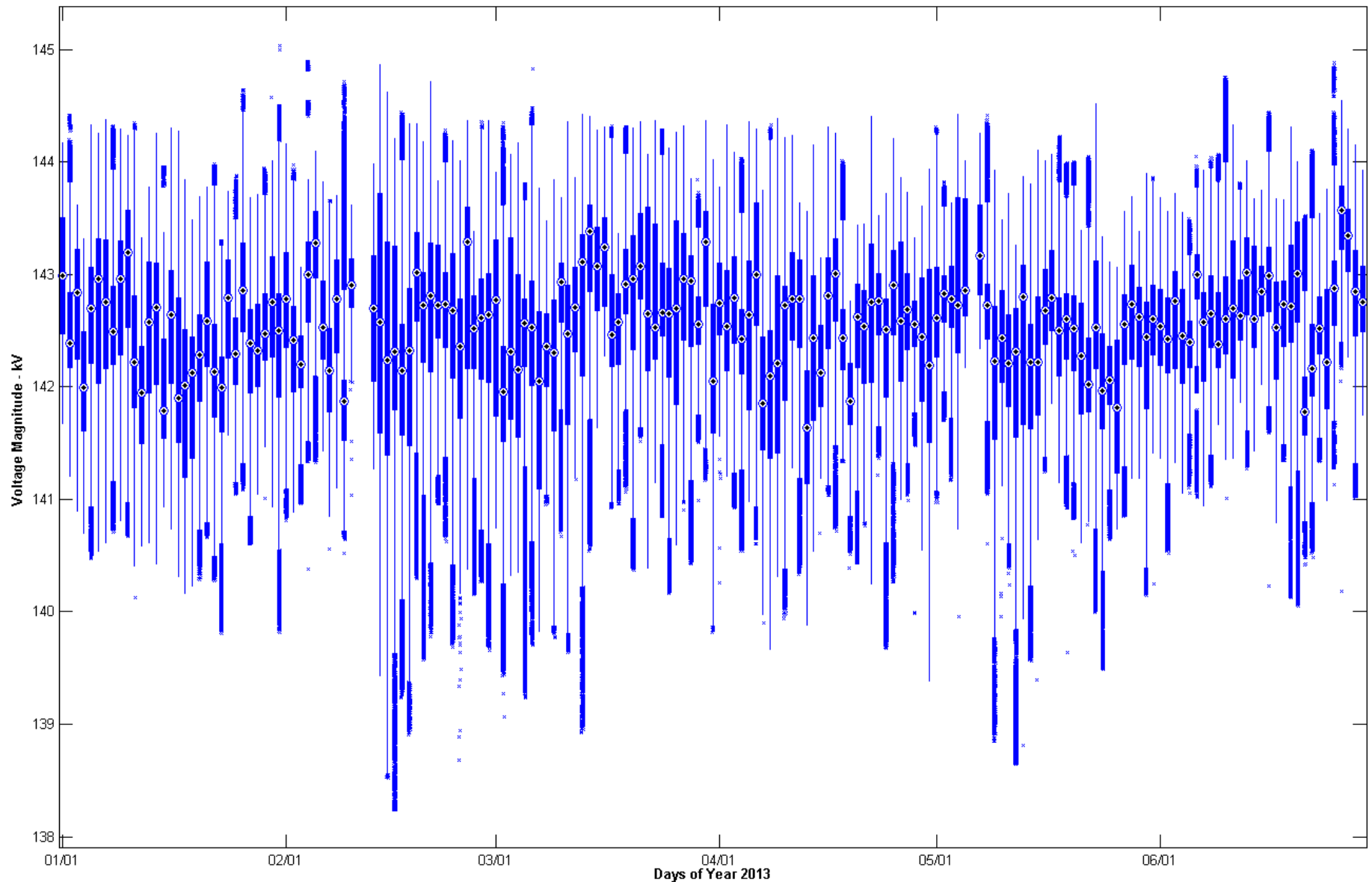
FarWest 2 – Voltage Magnitude



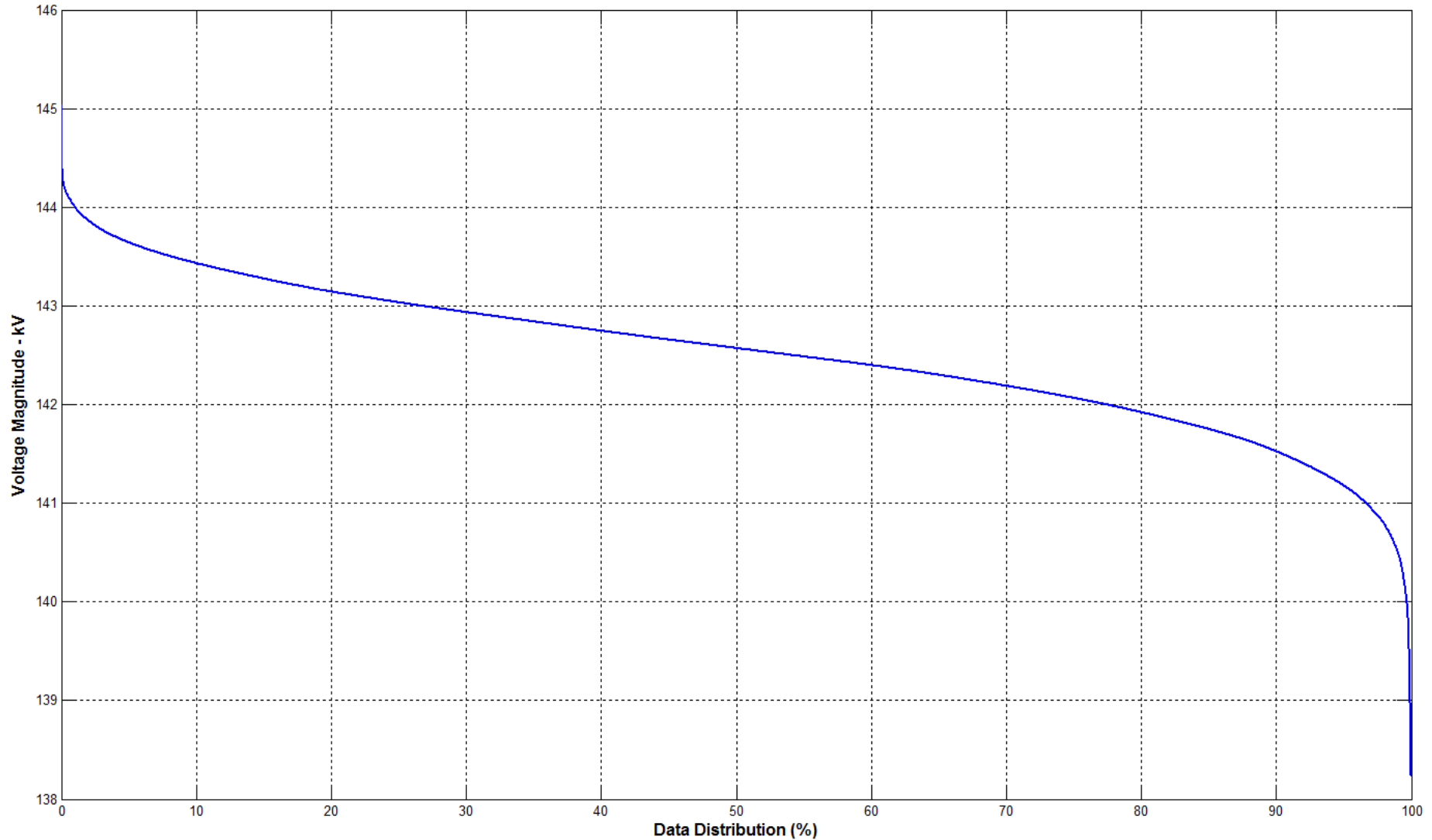
FarWest 2 – Voltage Magnitude



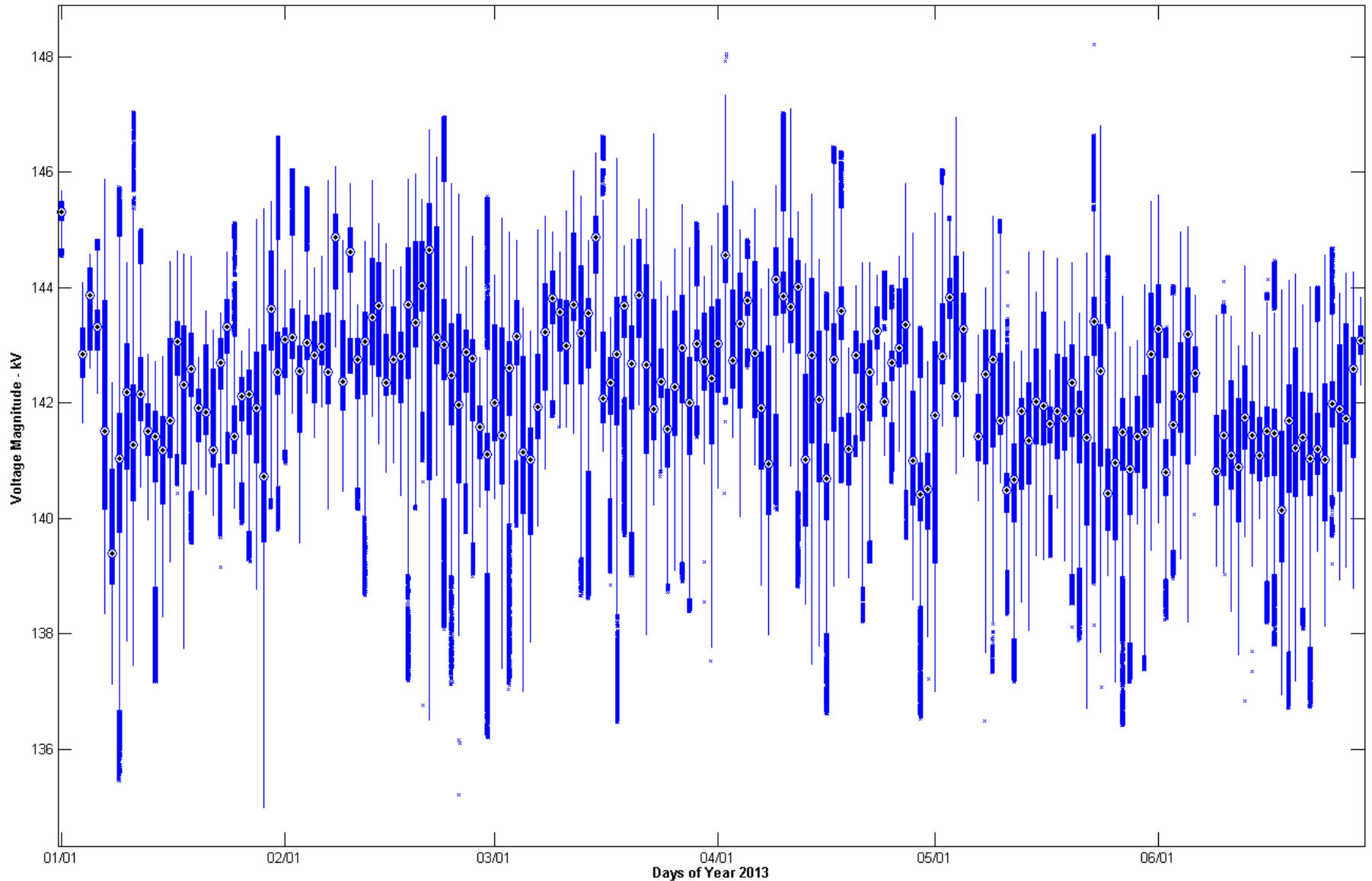
North 7 – Voltage Magnitude



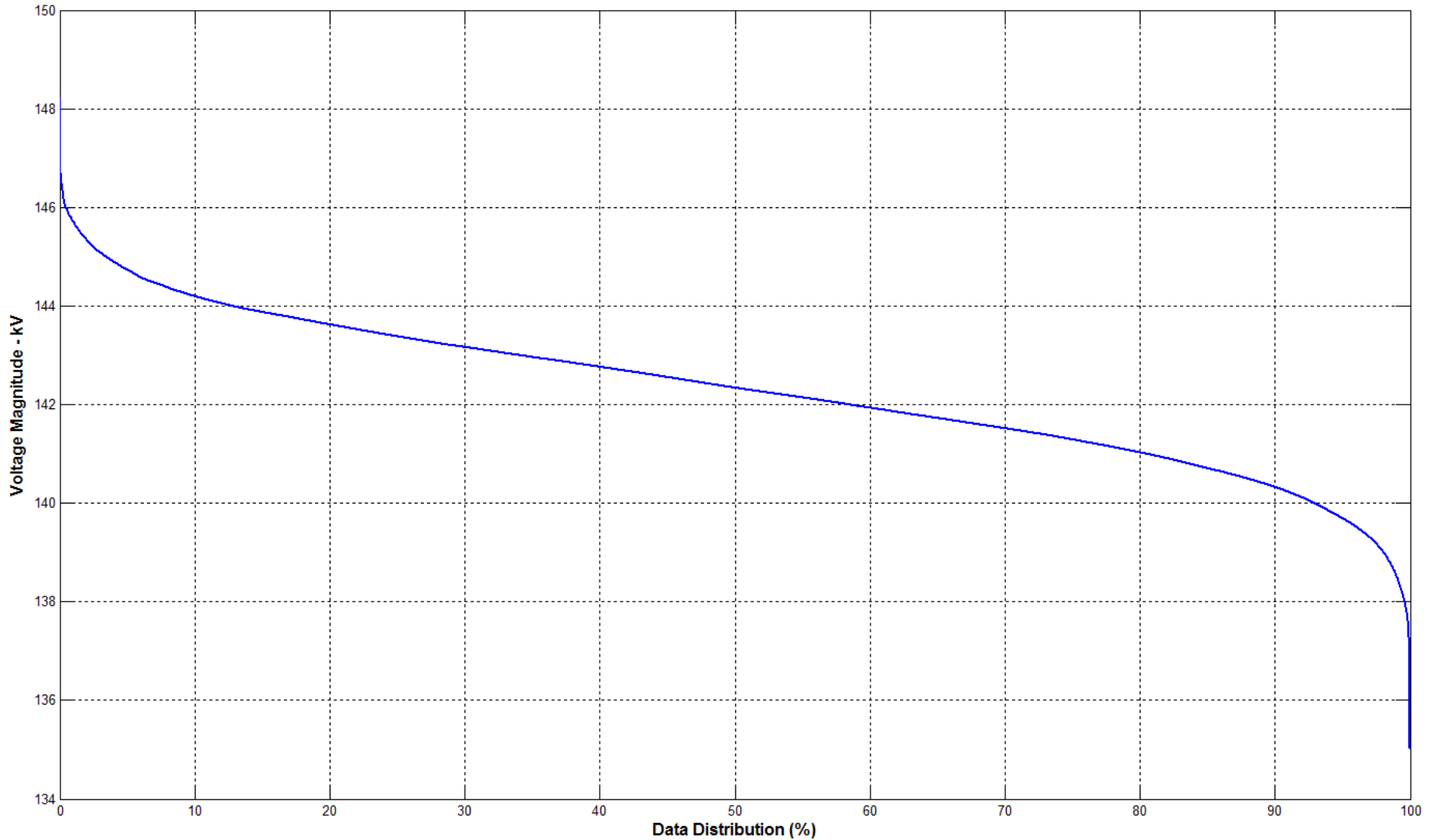
North 7 – Voltage Magnitude



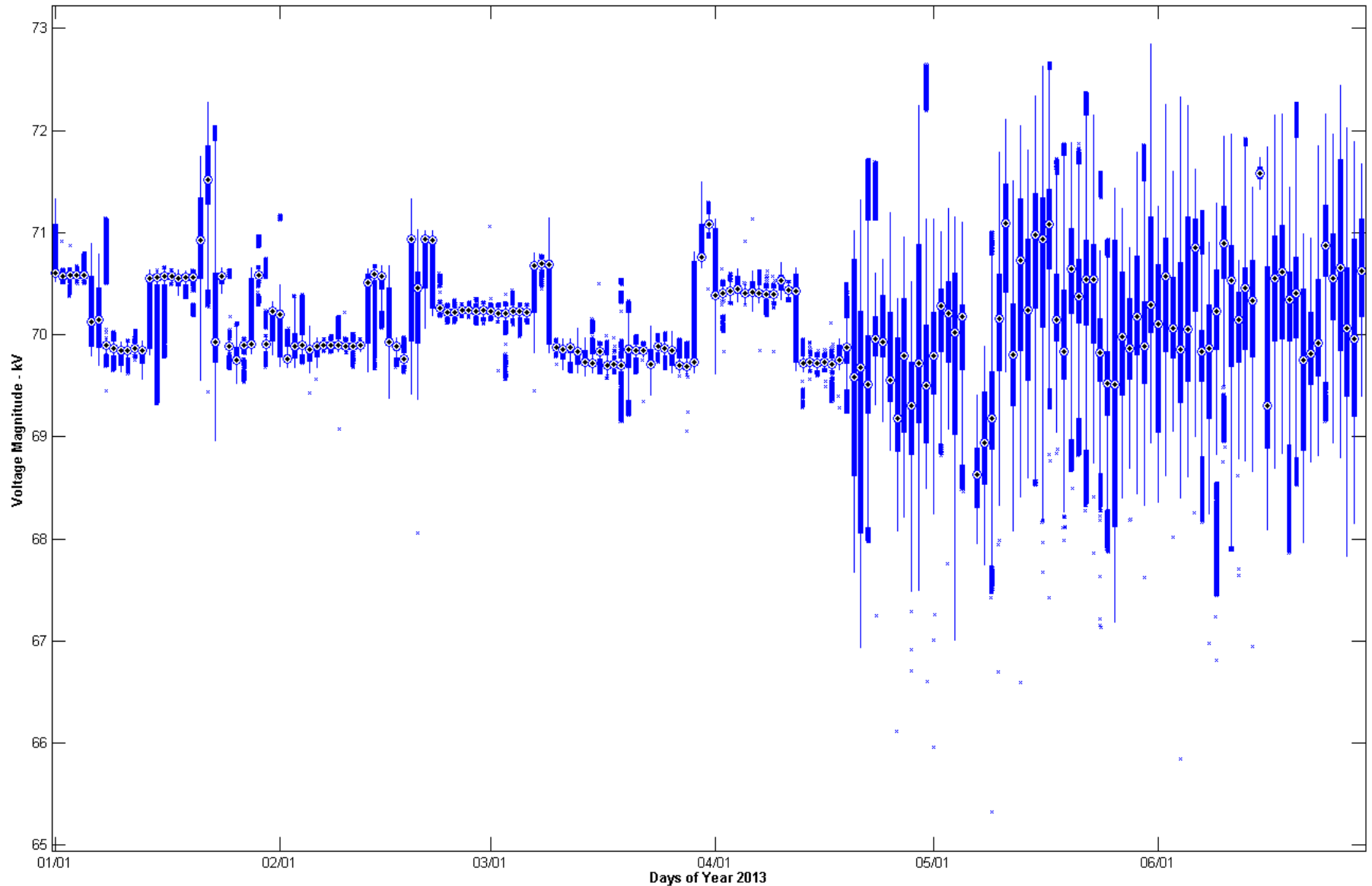
West 4 – Voltage Magnitude



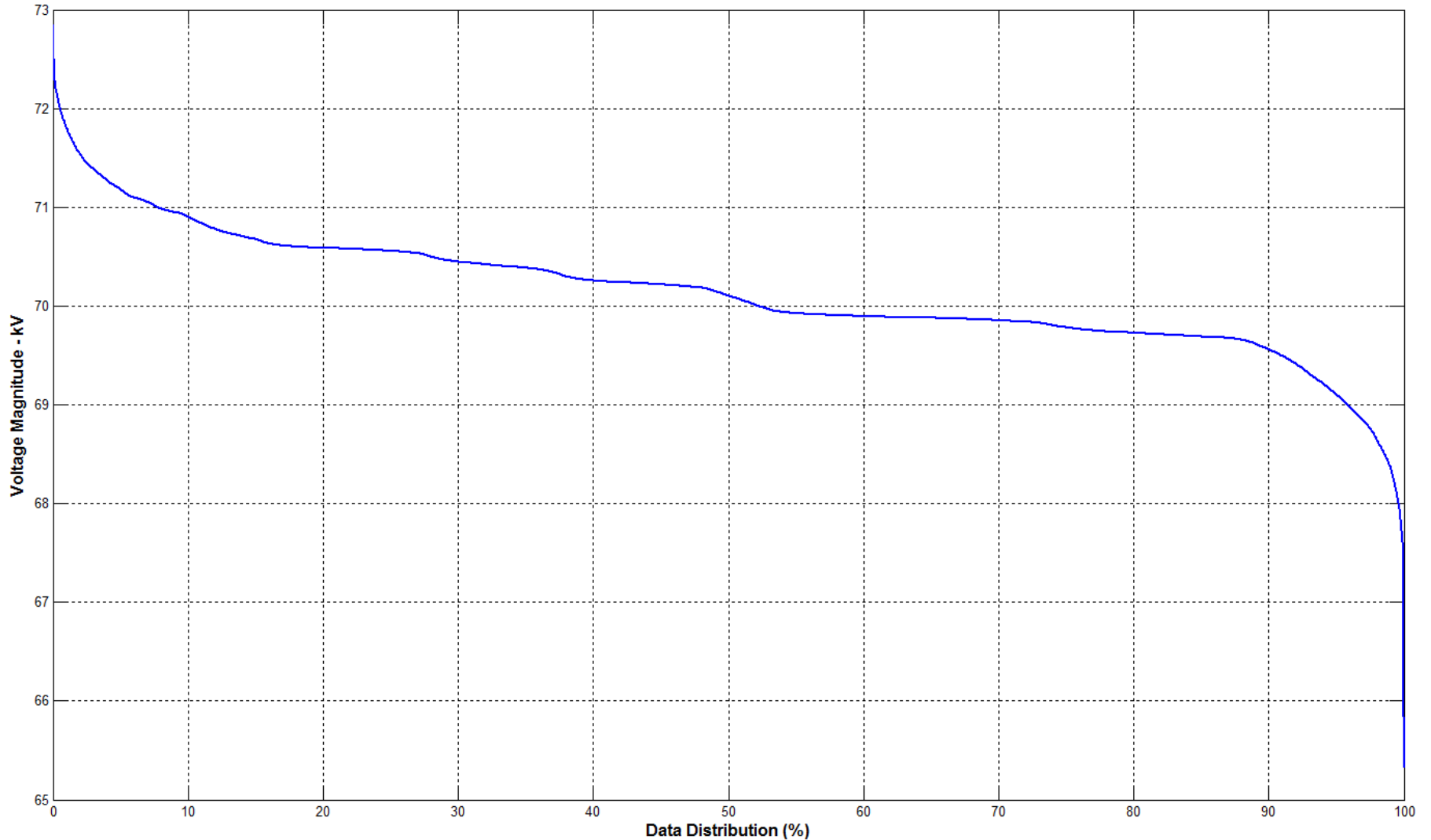
West 4 – Voltage Magnitude



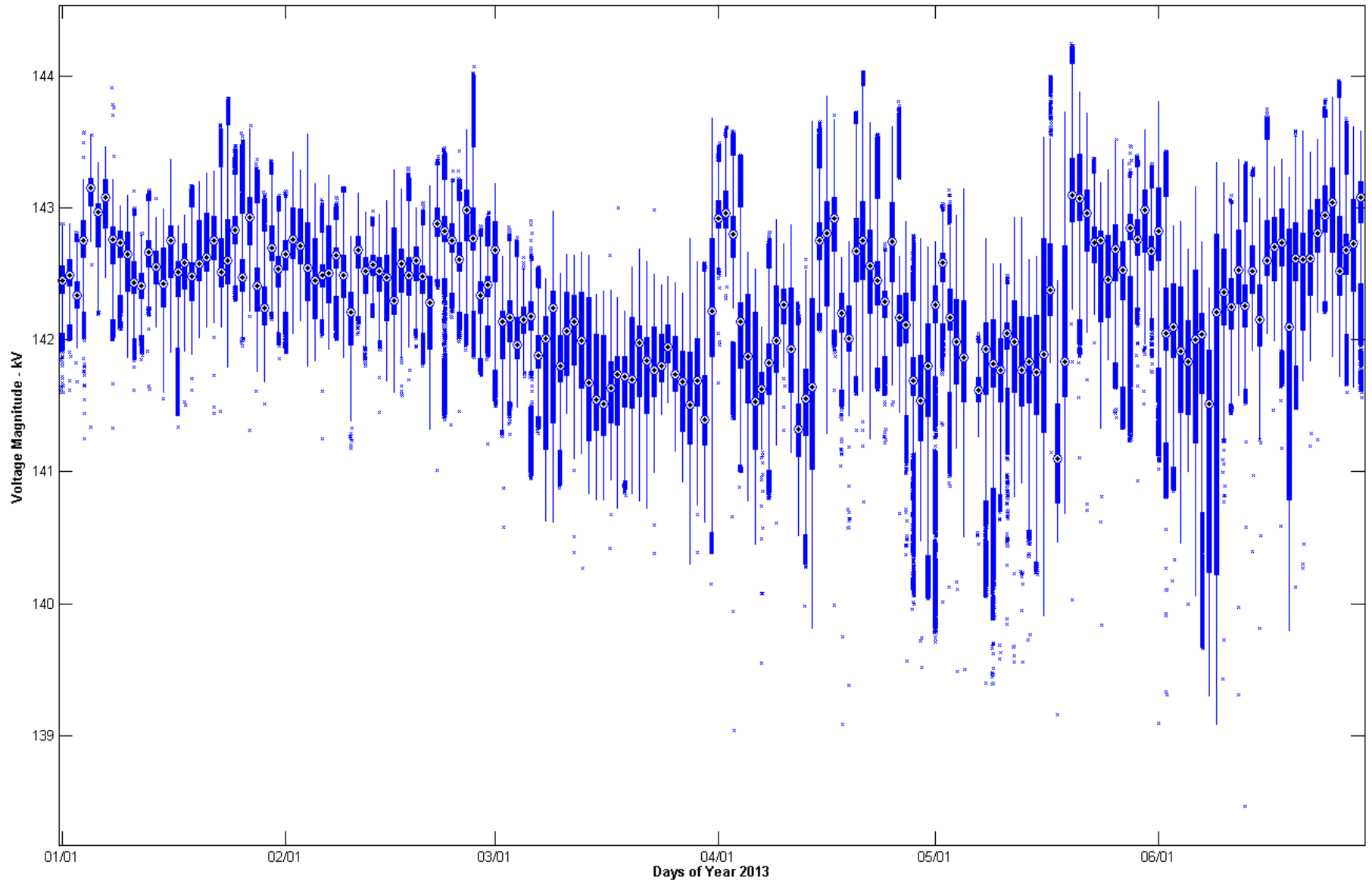
Coast 2 – Voltage Magnitude



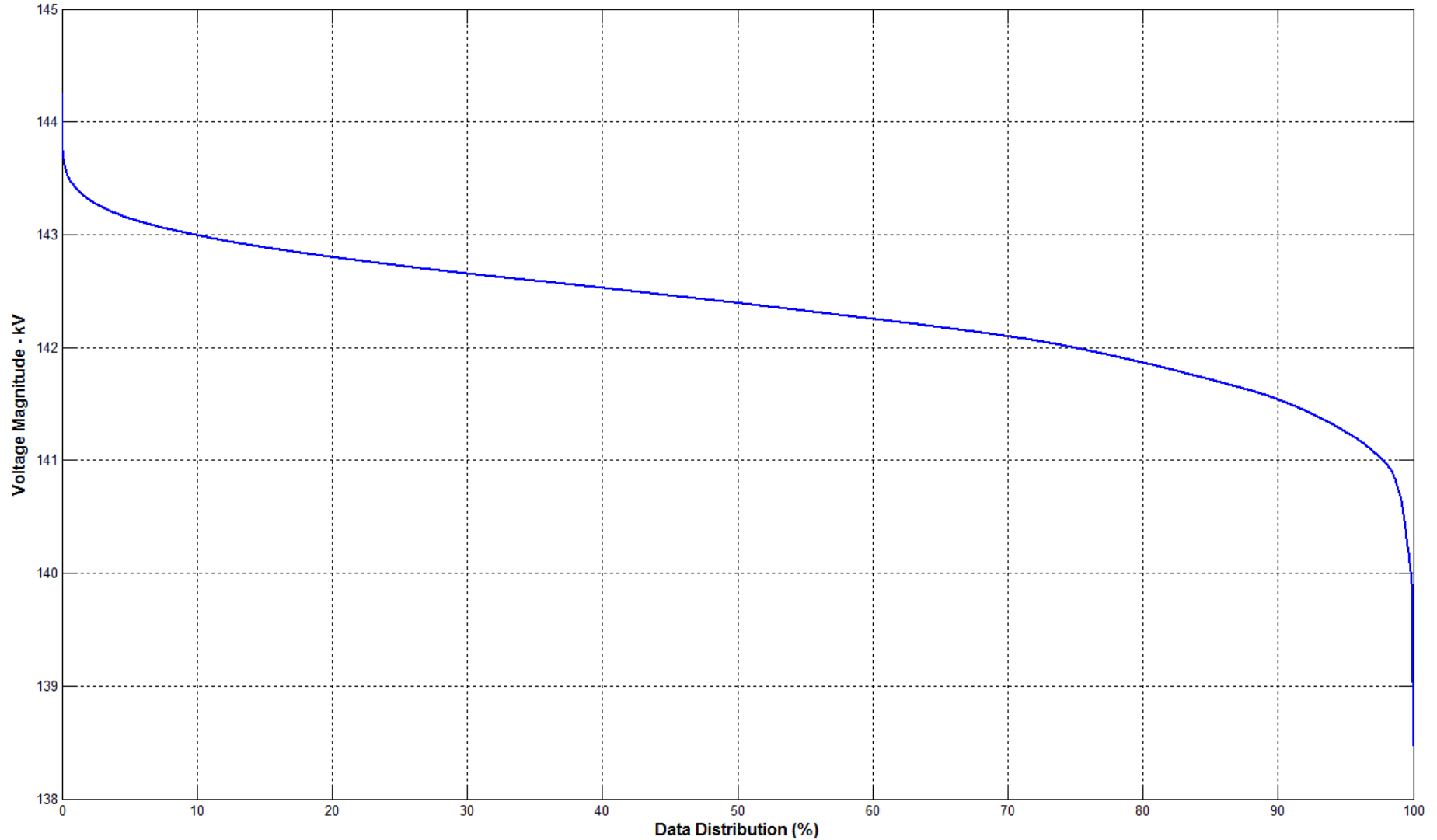
Coast 2 – Voltage Magnitude



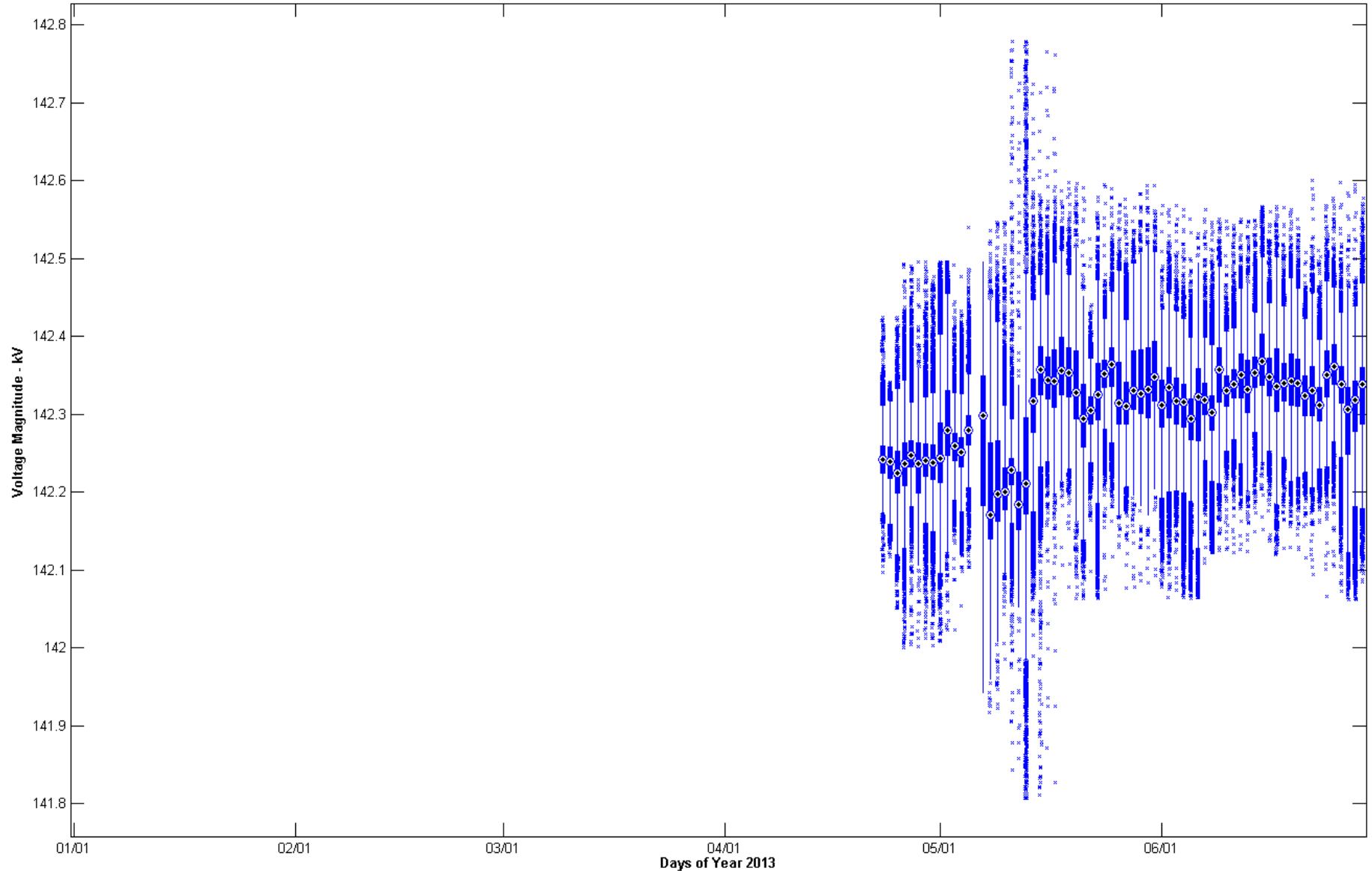
Coast 1 – Voltage Magnitude



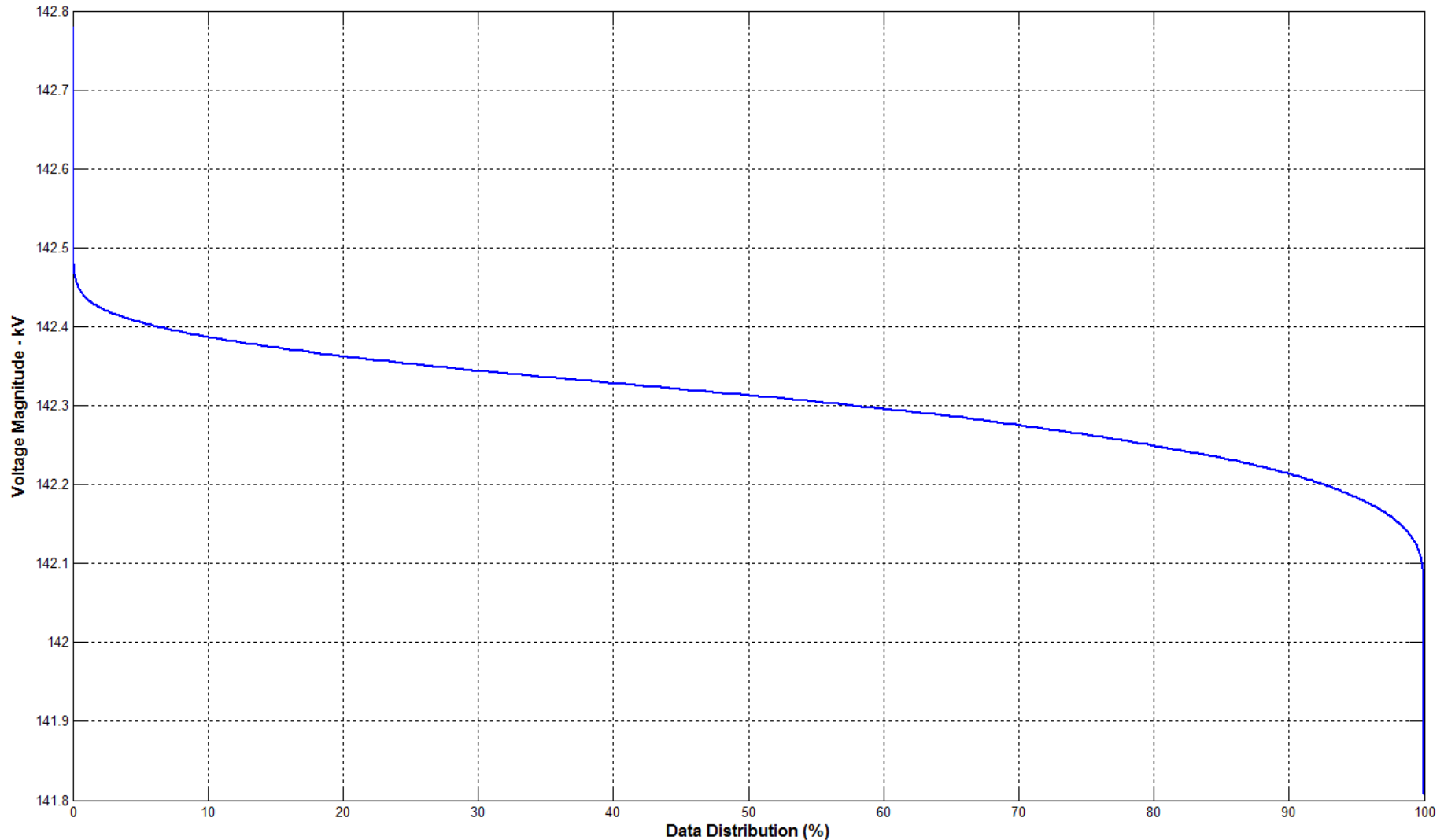
Coast 1 – Voltage Magnitude



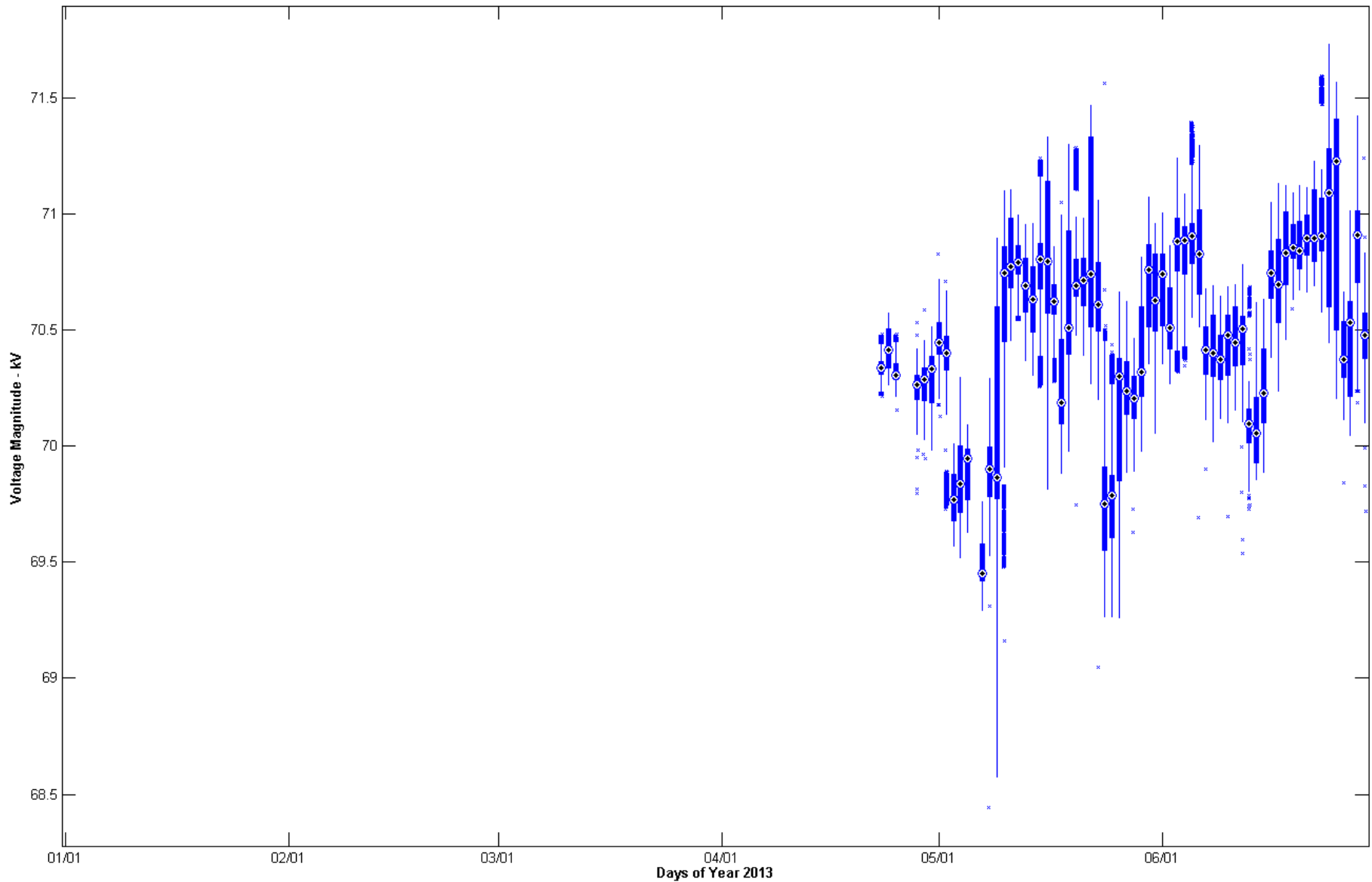
South 3 – Voltage Magnitude



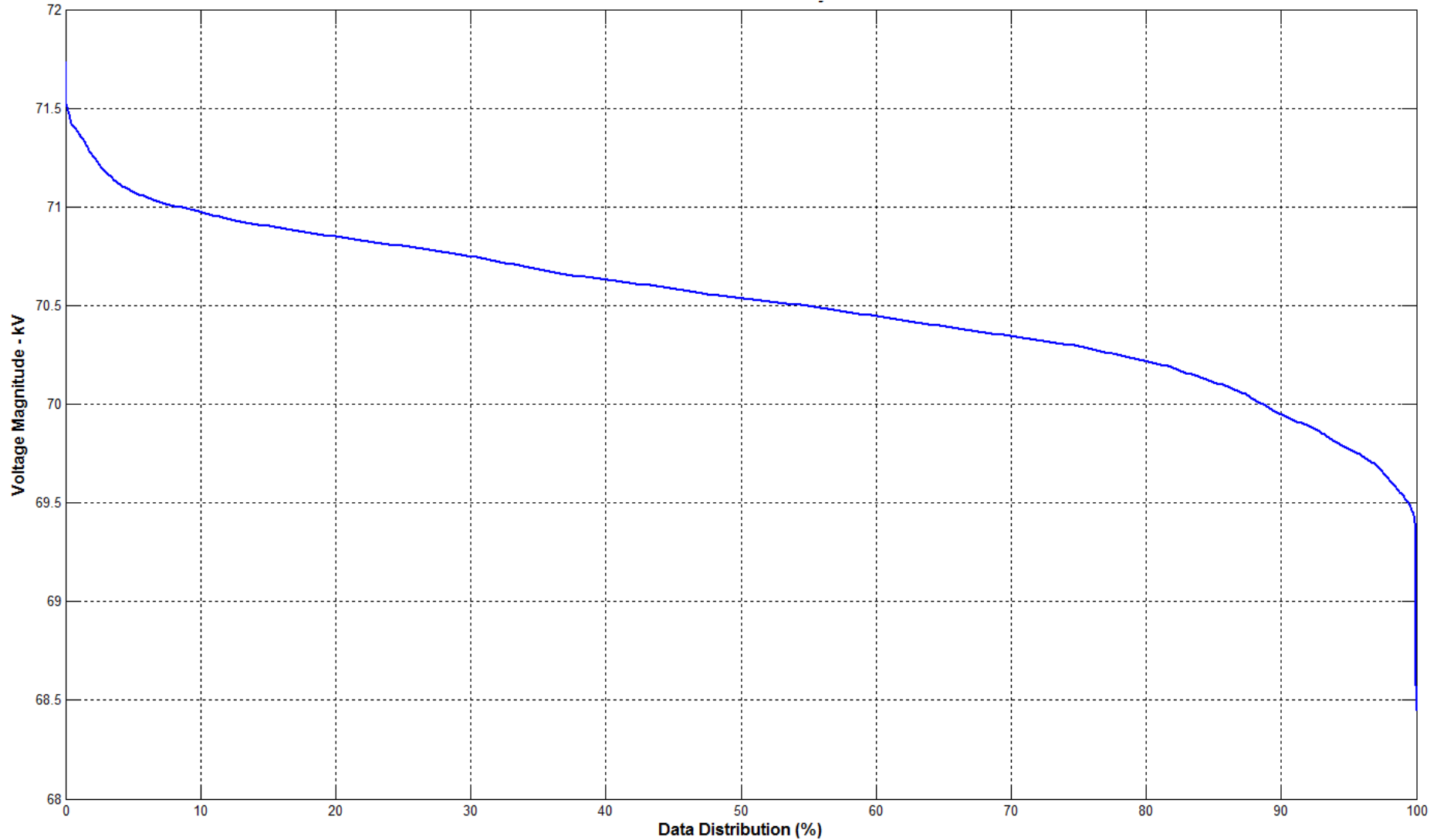
South 3 – Voltage Magnitude



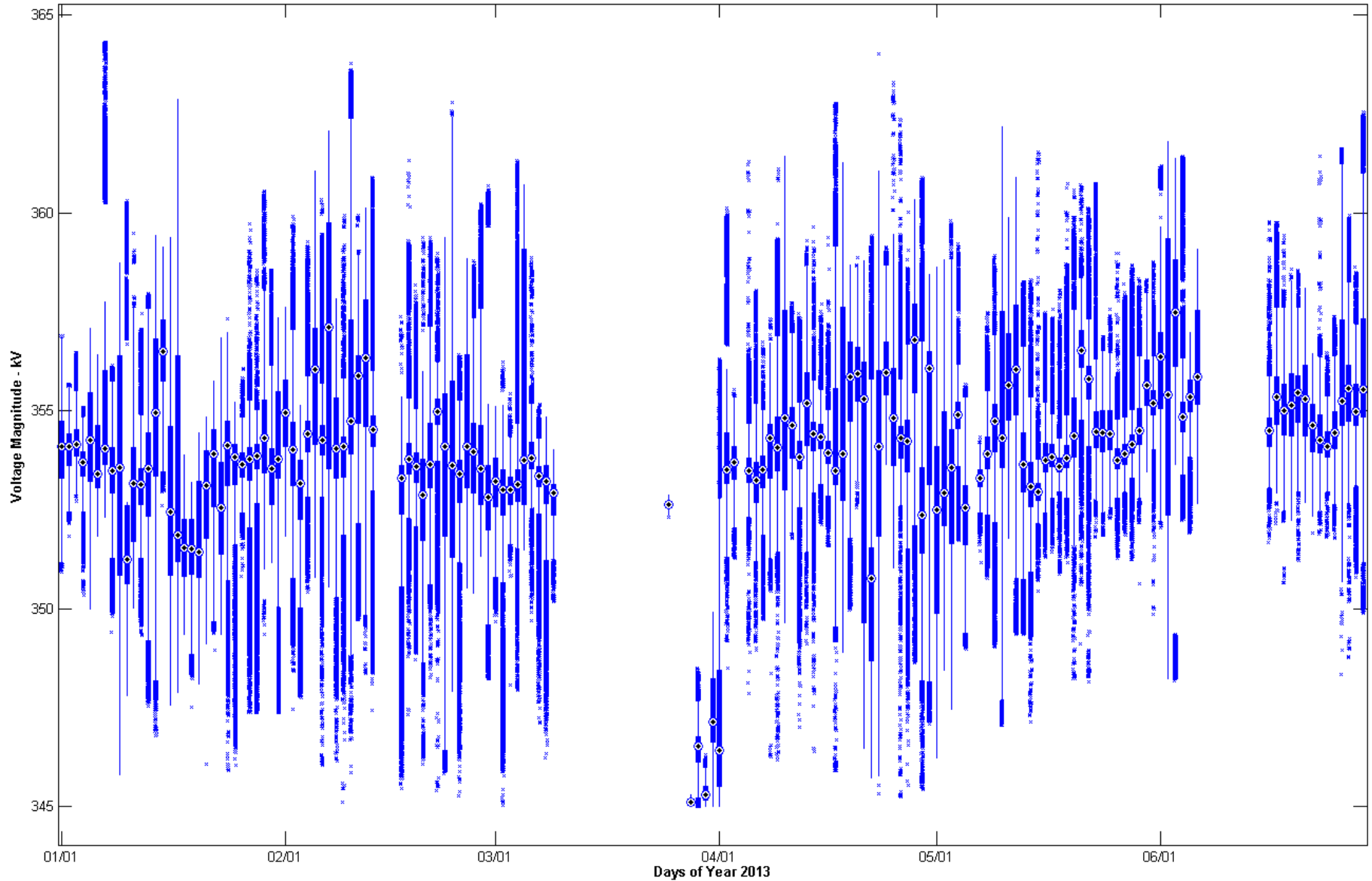
South 5 – Voltage Magnitude



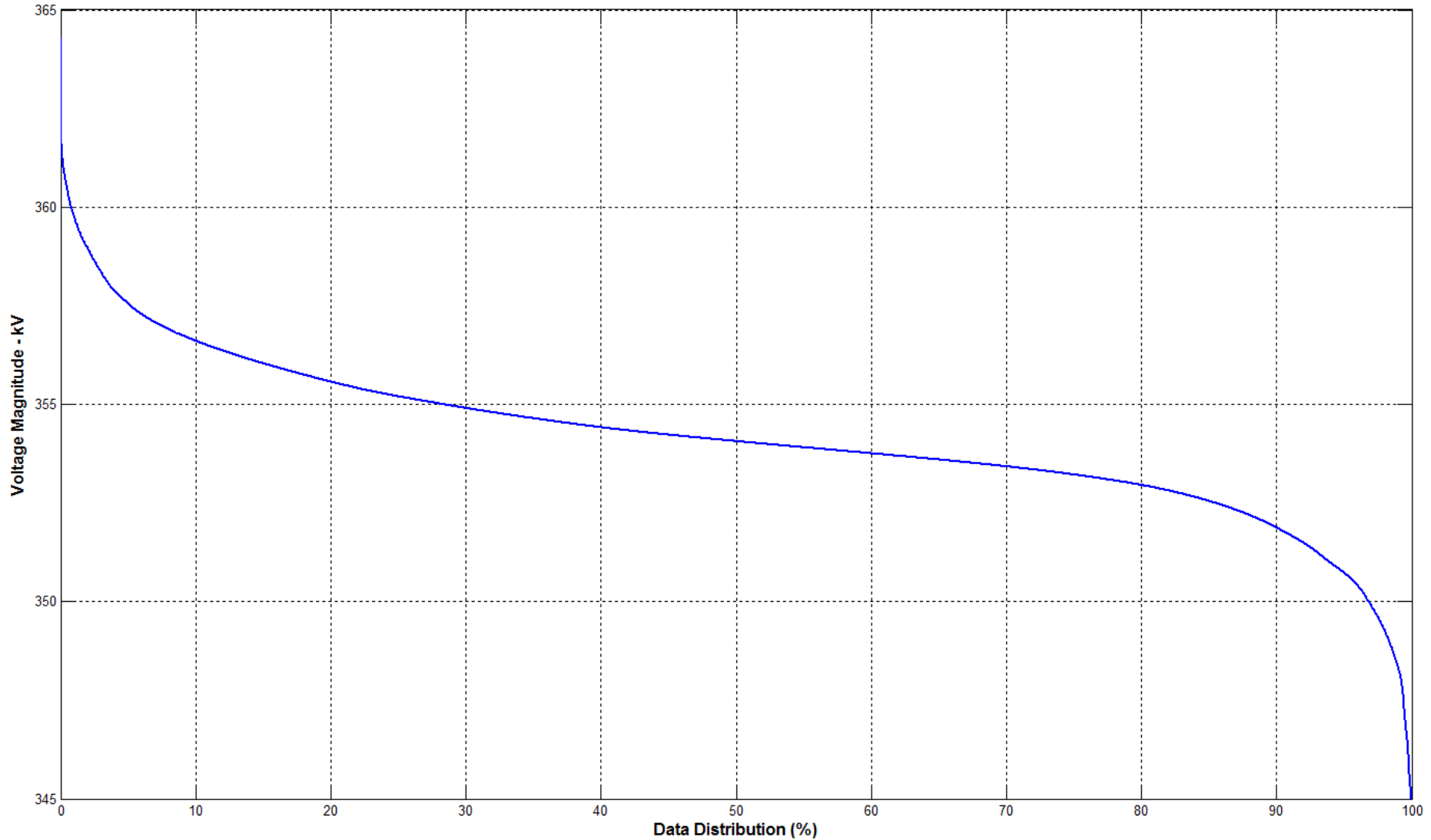
South 5 – Voltage Magnitude



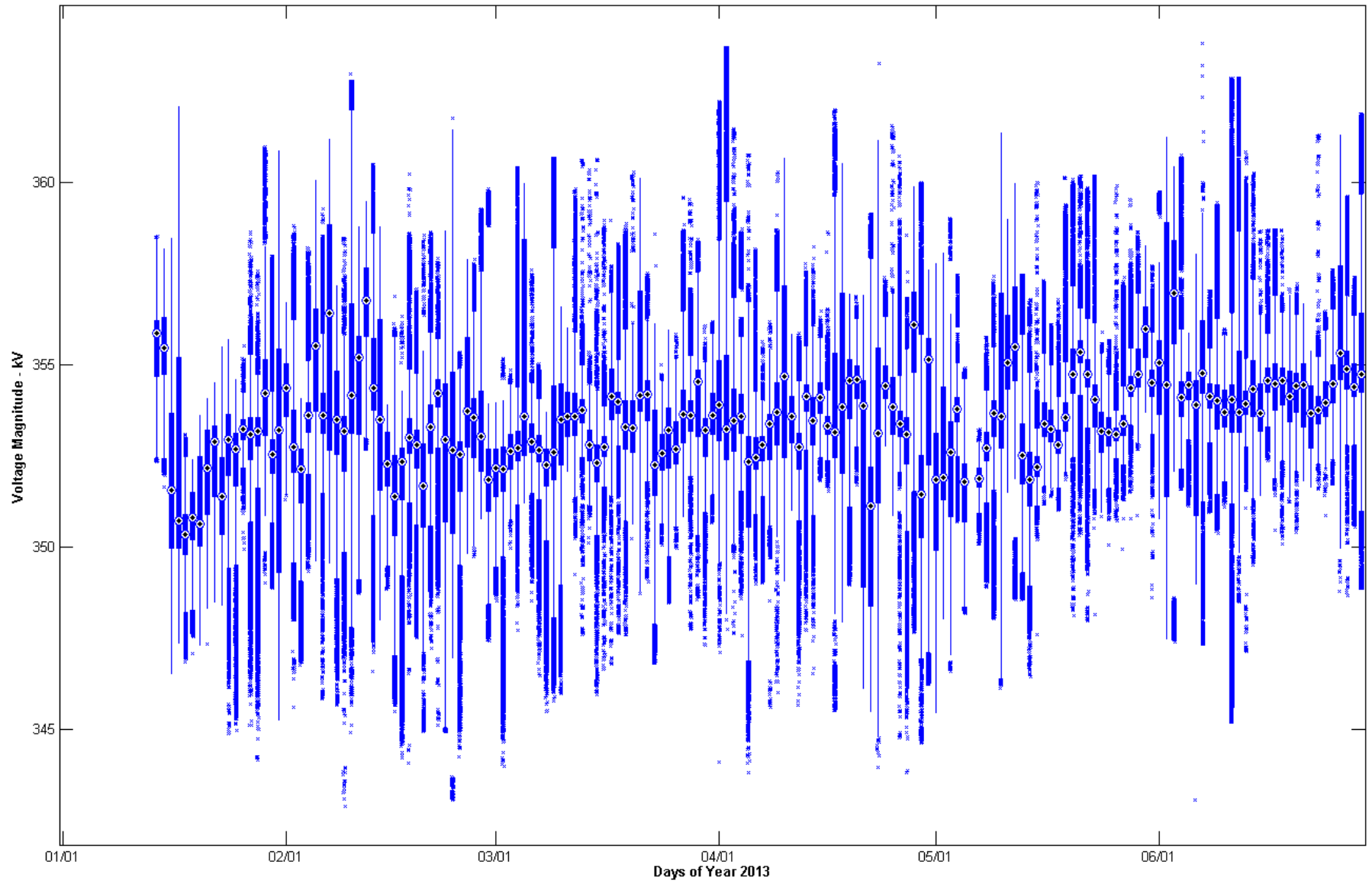
Coast 4 – Voltage Magnitude



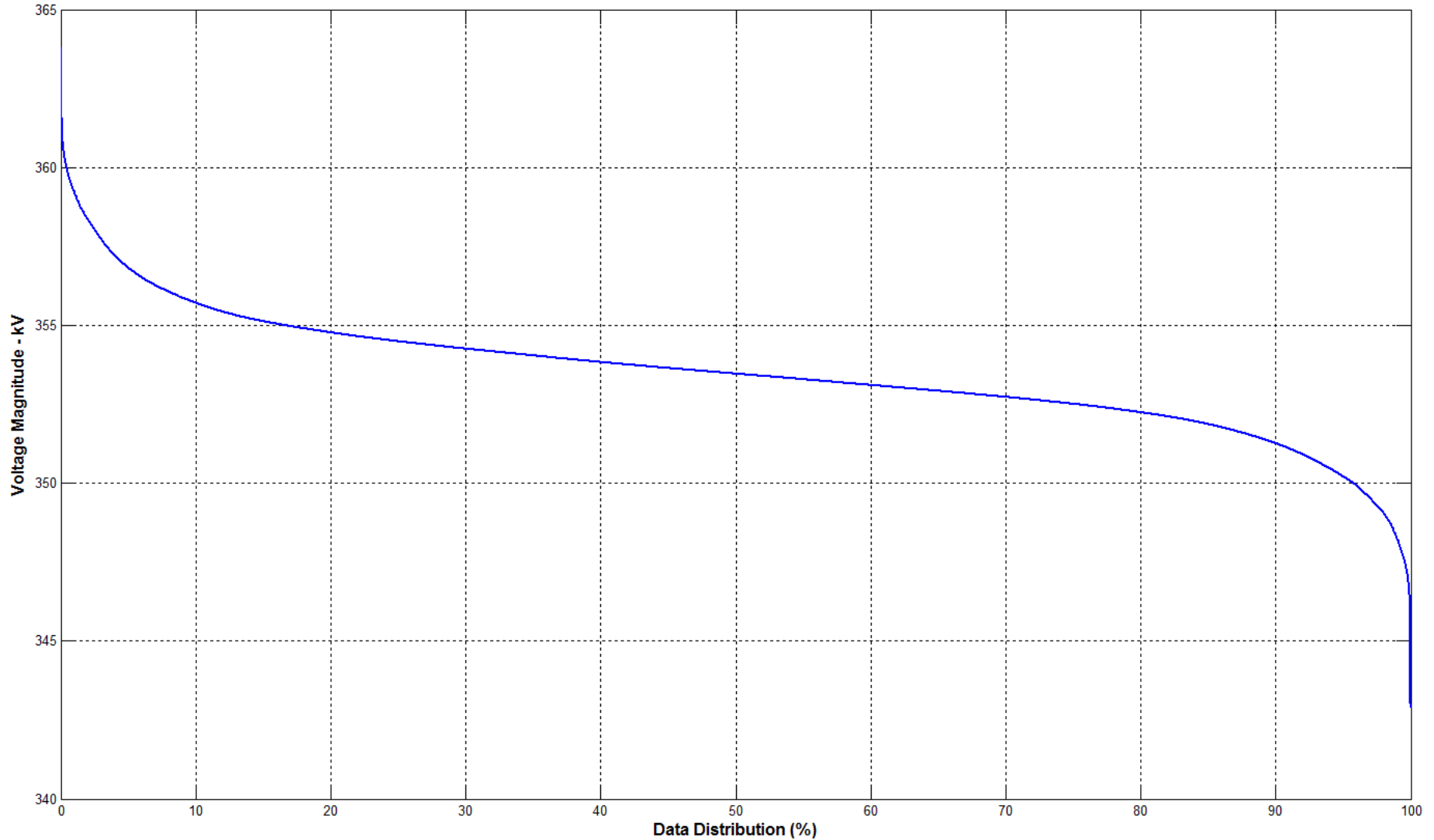
Coast 4 – Voltage Magnitude



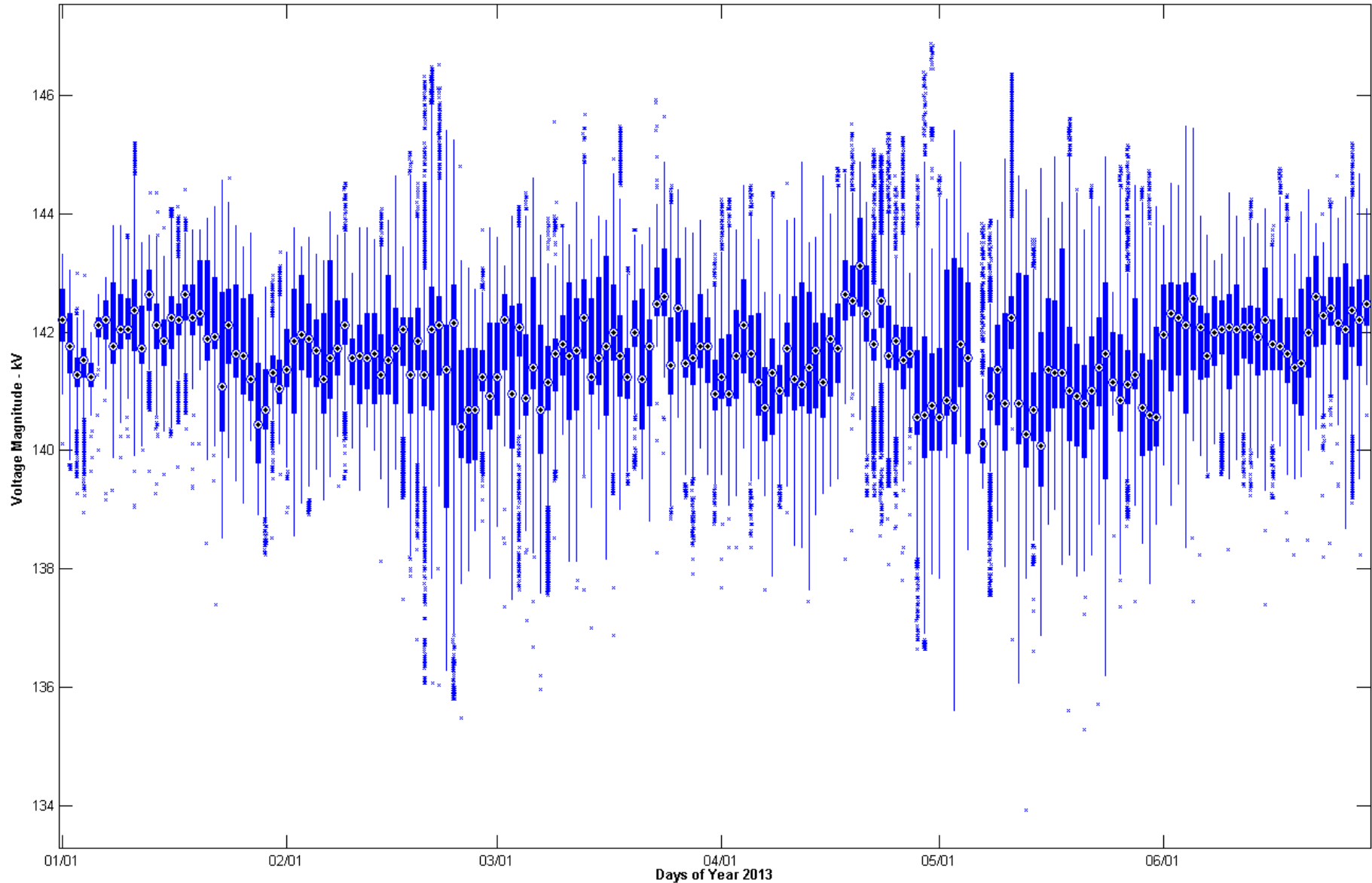
Coast 3 – Voltage Magnitude



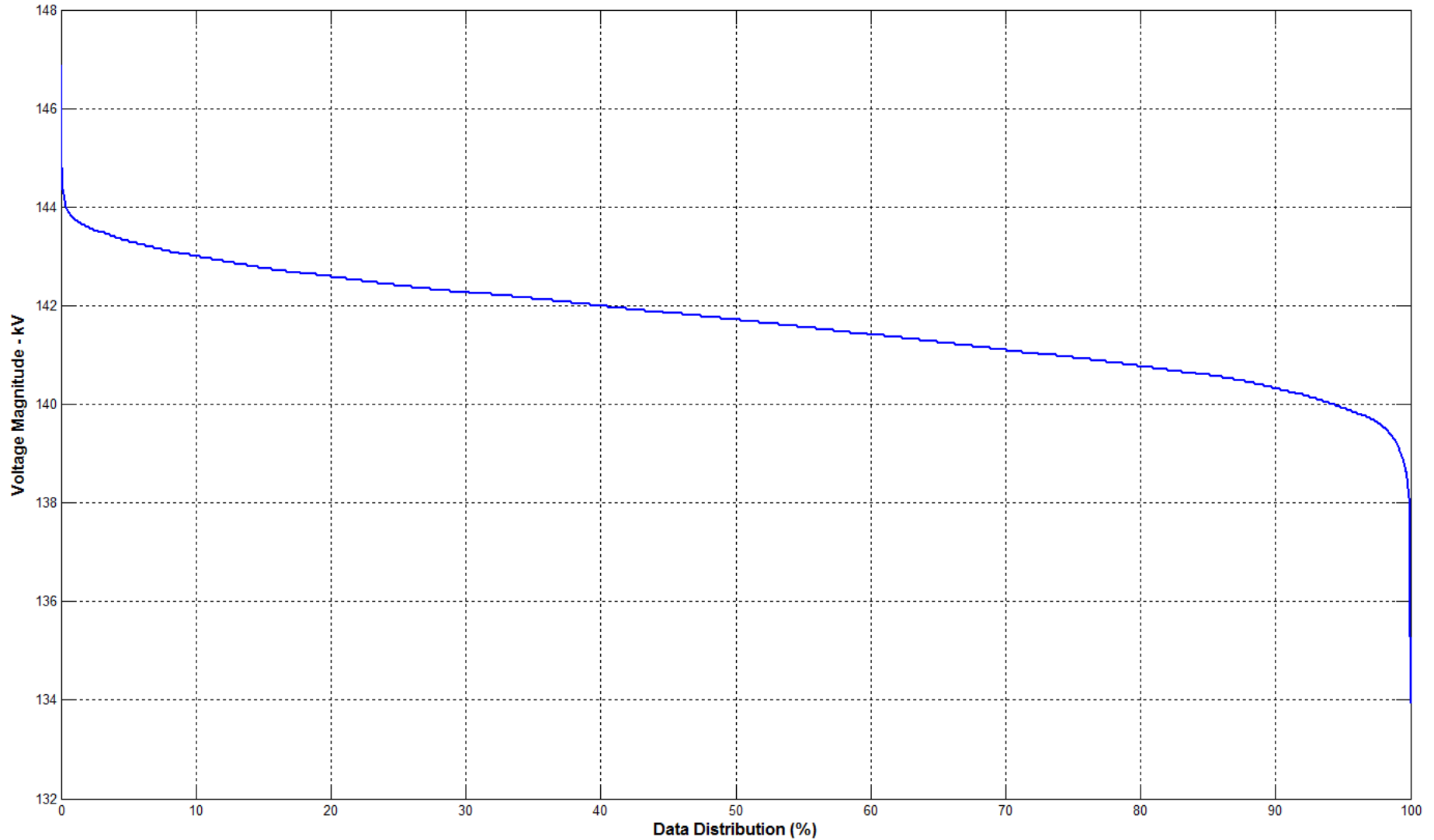
Coast 3 – Voltage Magnitude



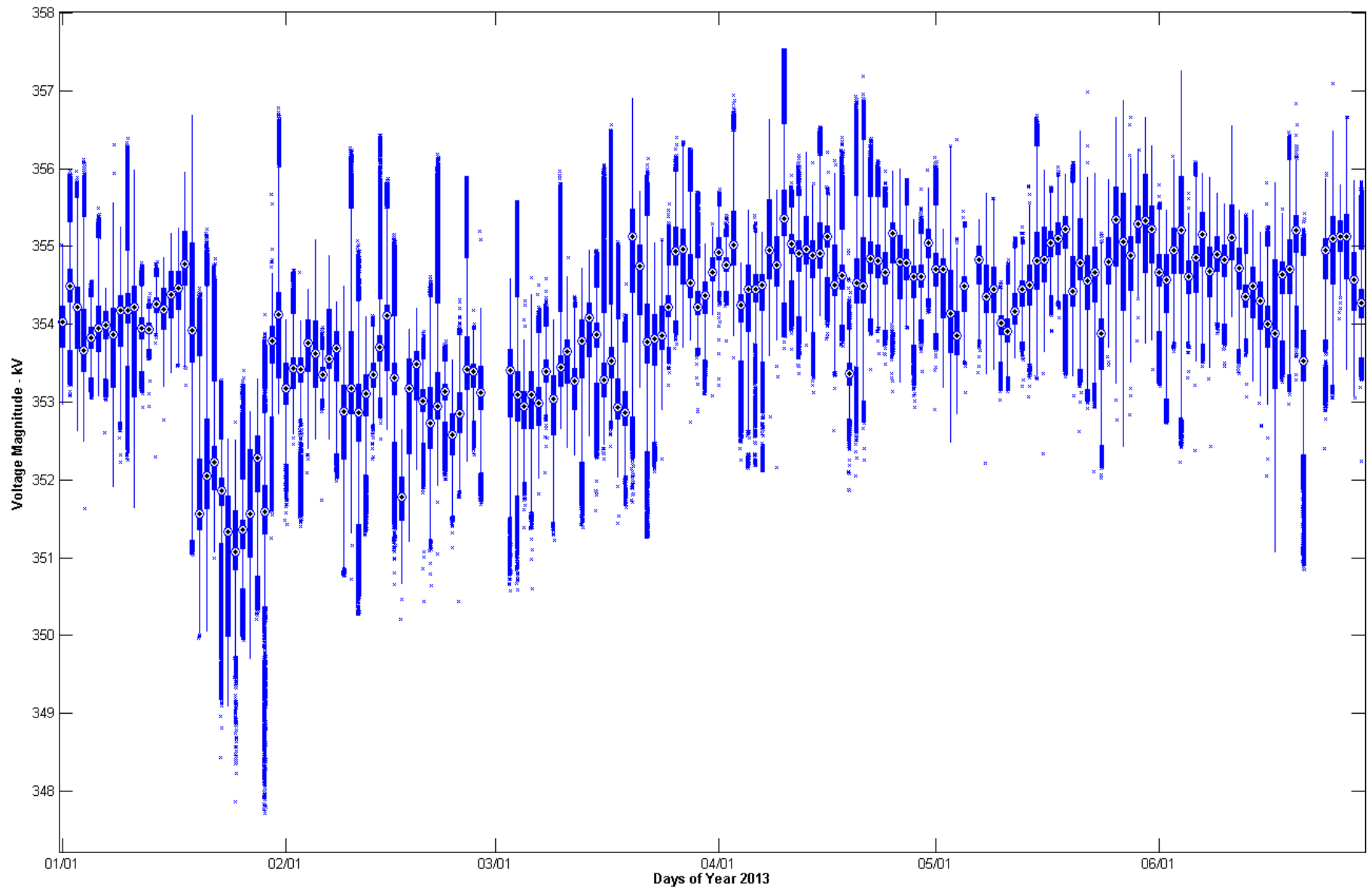
South 13 – Voltage Magnitude



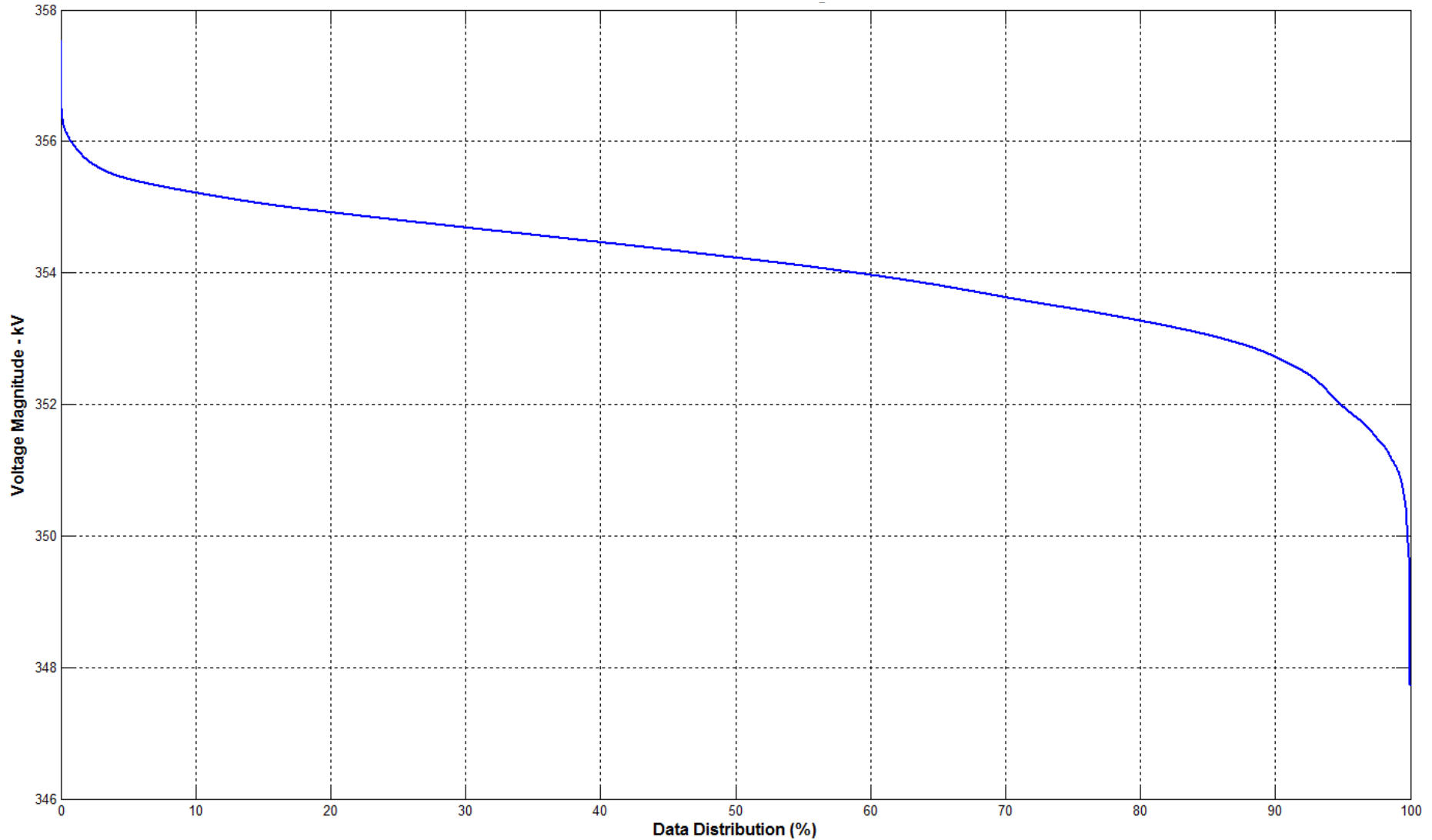
South 13 – Voltage Magnitude



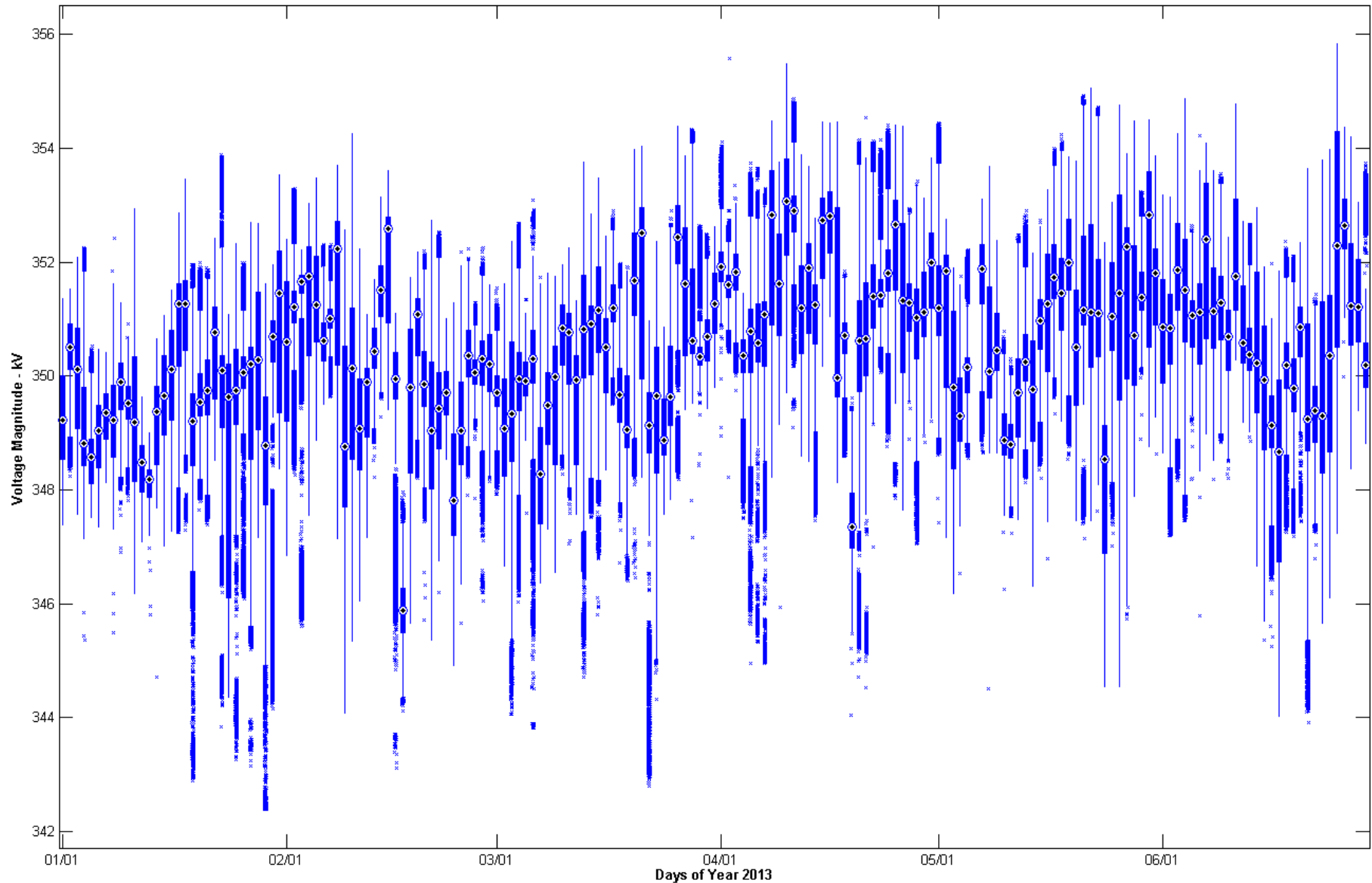
FarWest 4 – Voltage Magnitude



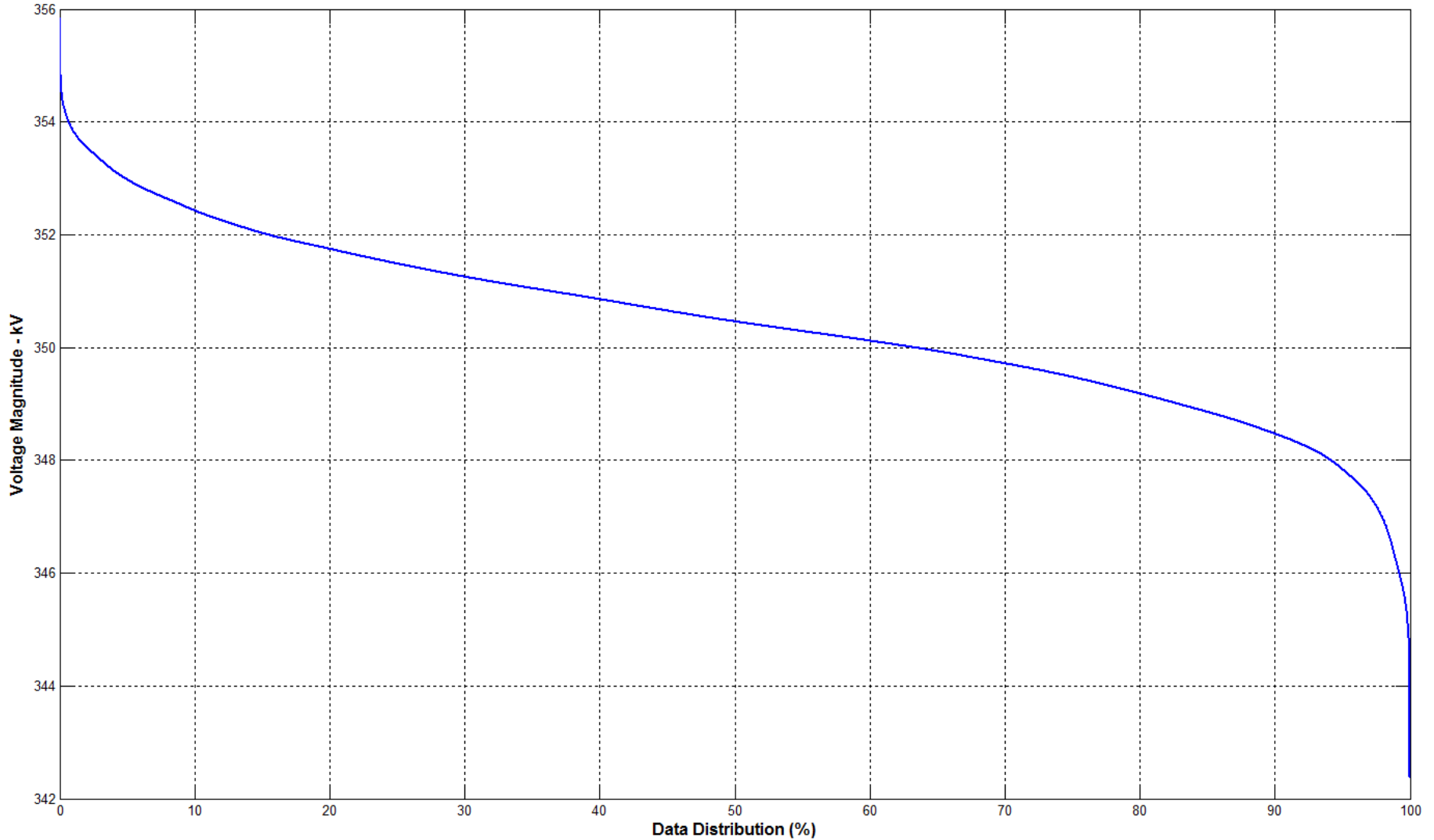
FarWest 4 – Voltage Magnitude



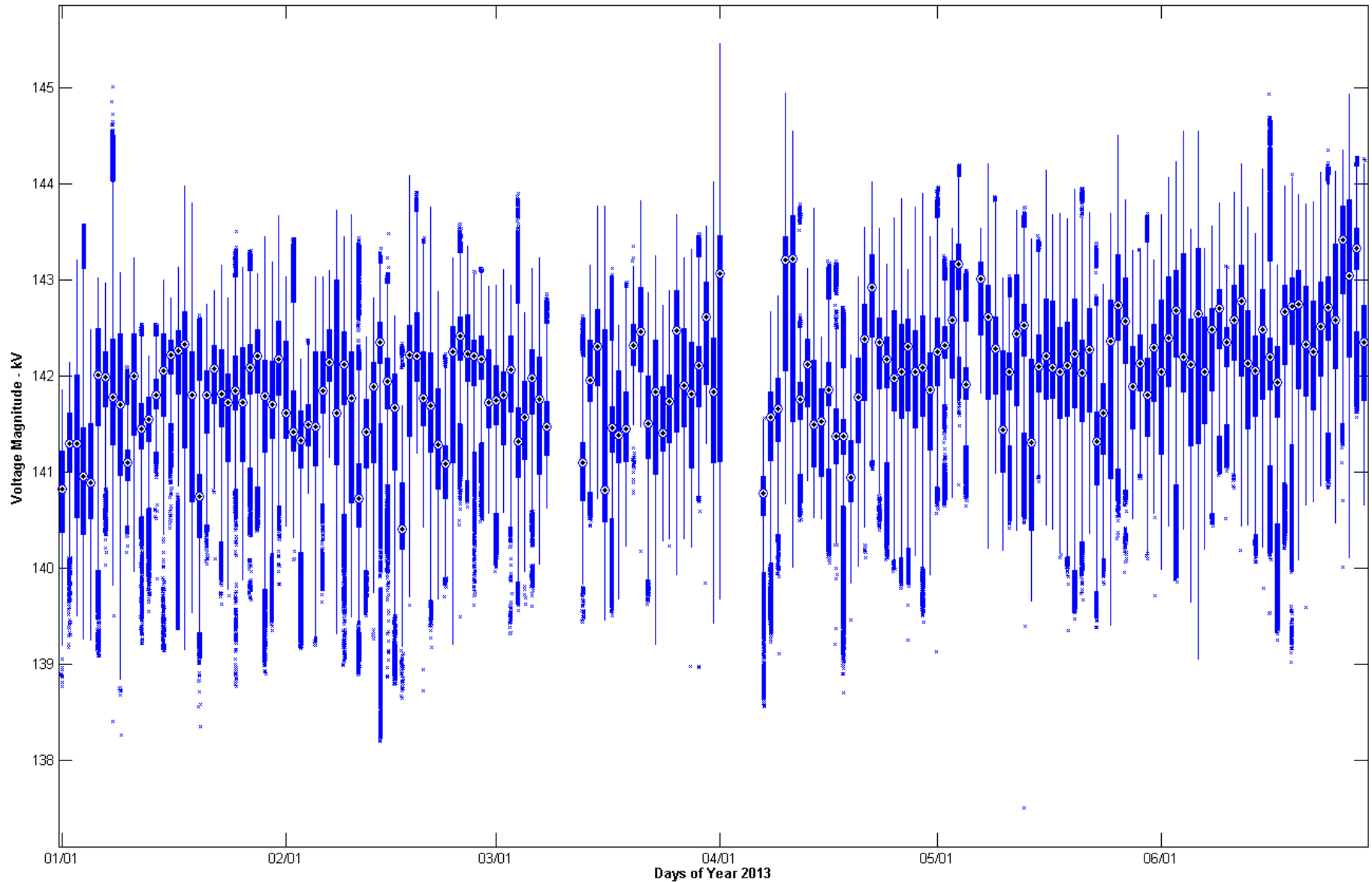
FarWest 7 – Voltage Magnitude



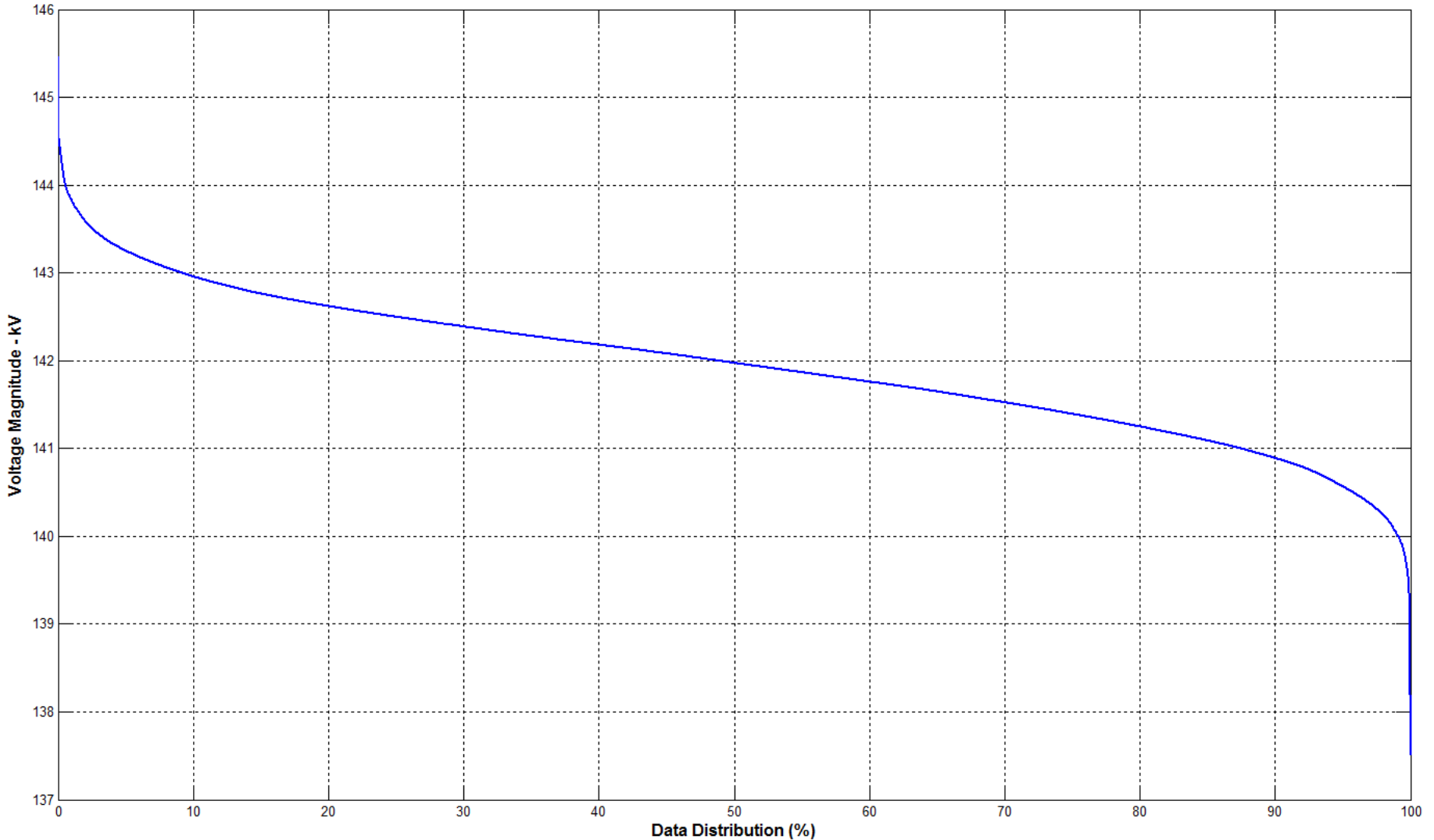
FarWest 7 – Voltage Magnitude



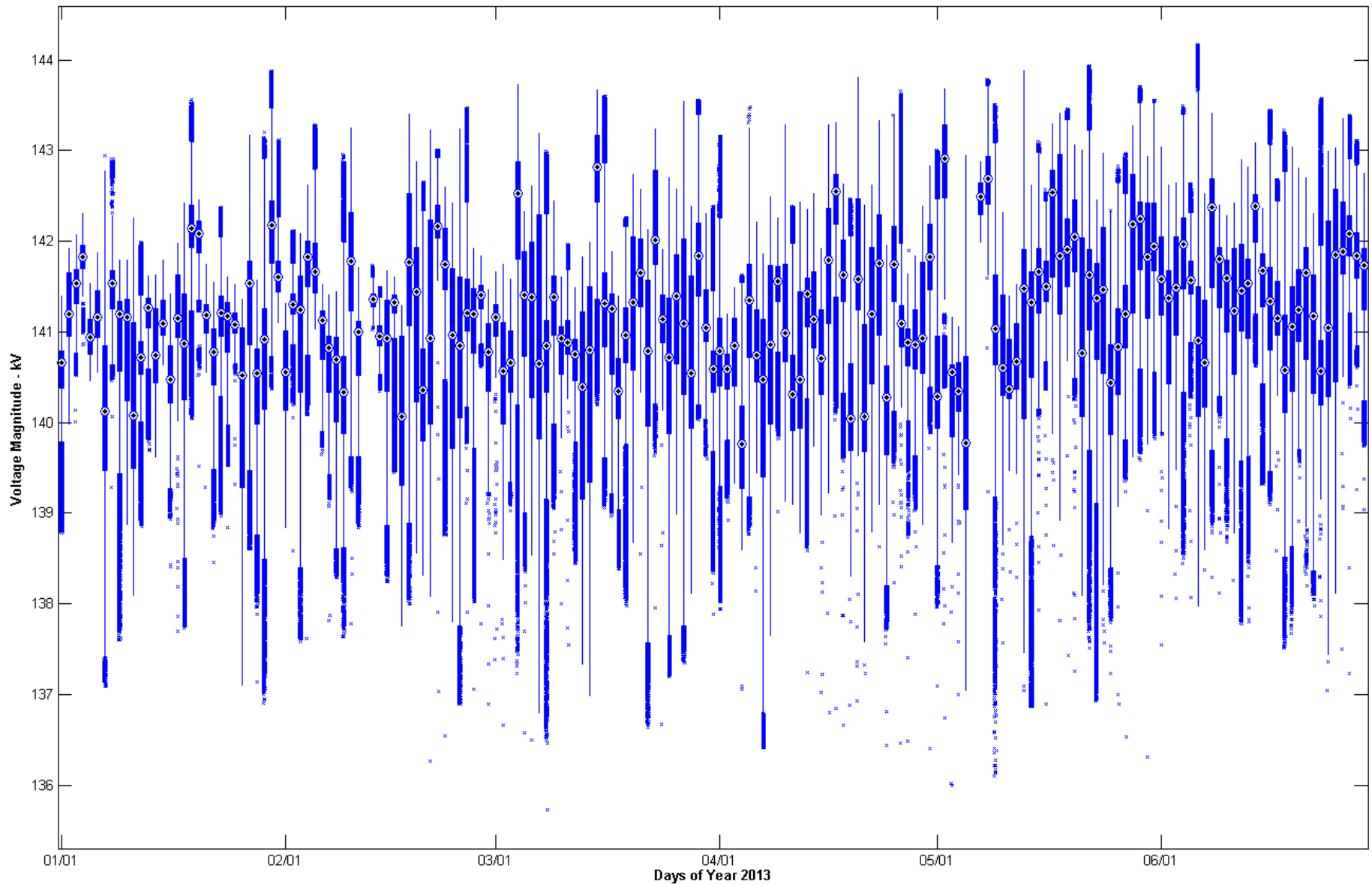
FarWest 8 – Voltage Magnitude



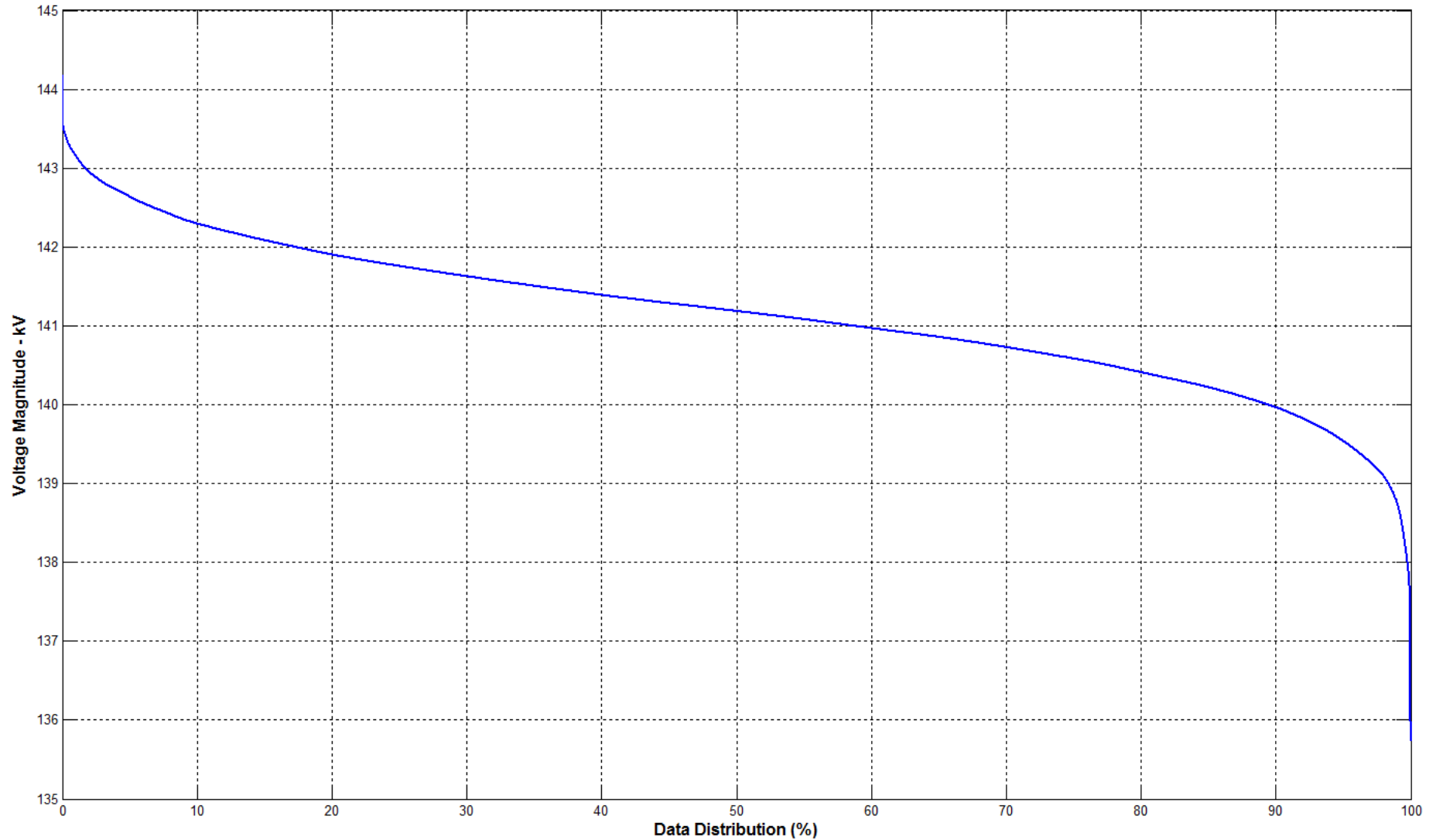
FarWest 8 – Voltage Magnitude



FarWest 9 – Voltage Magnitude



FarWest 9 – Voltage Magnitude



Appendix B – Part 1

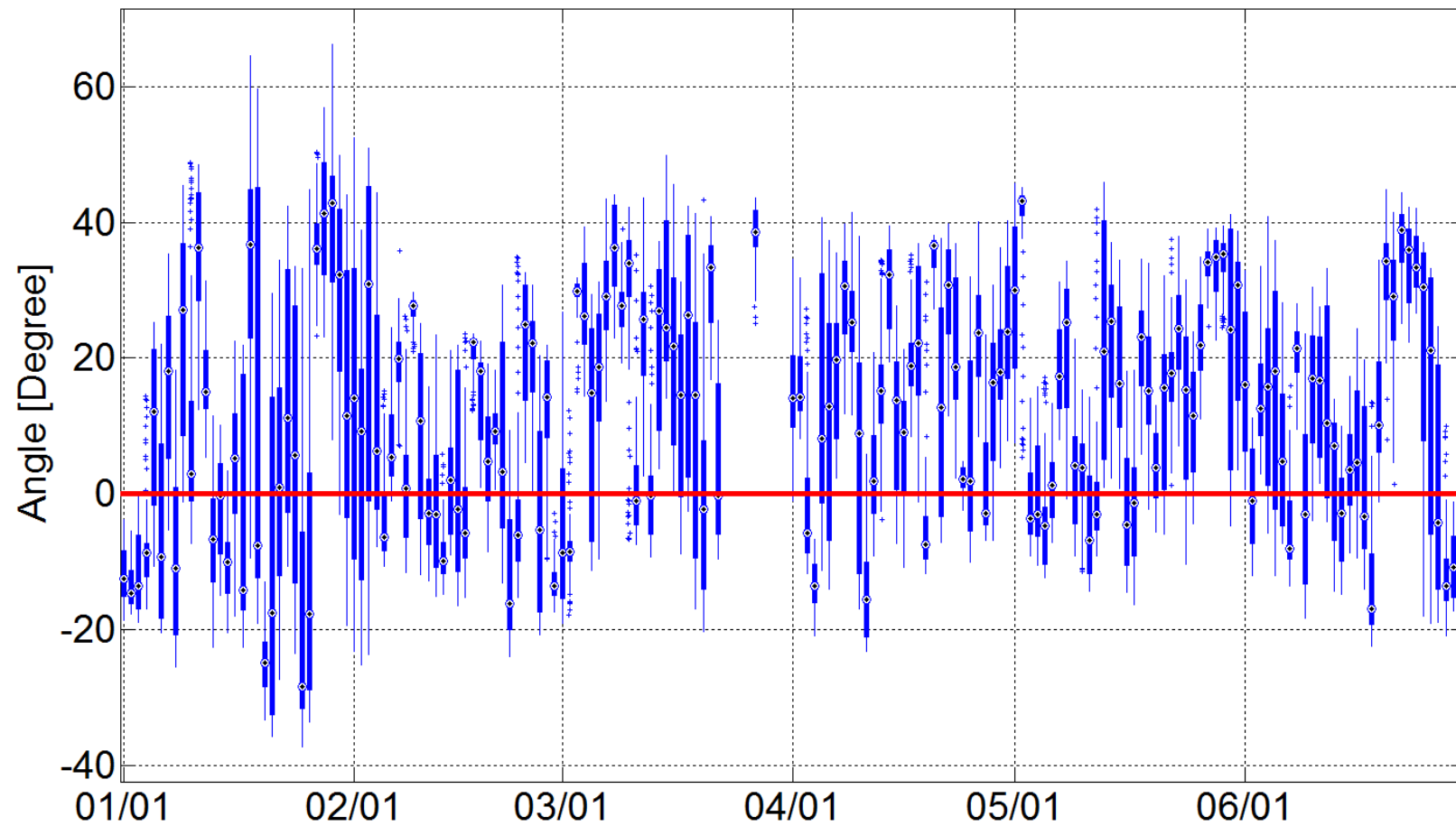
CCET Discovery Across Texas project

Baseline Analysis Update - Voltage Angles (Ref.: North 7)

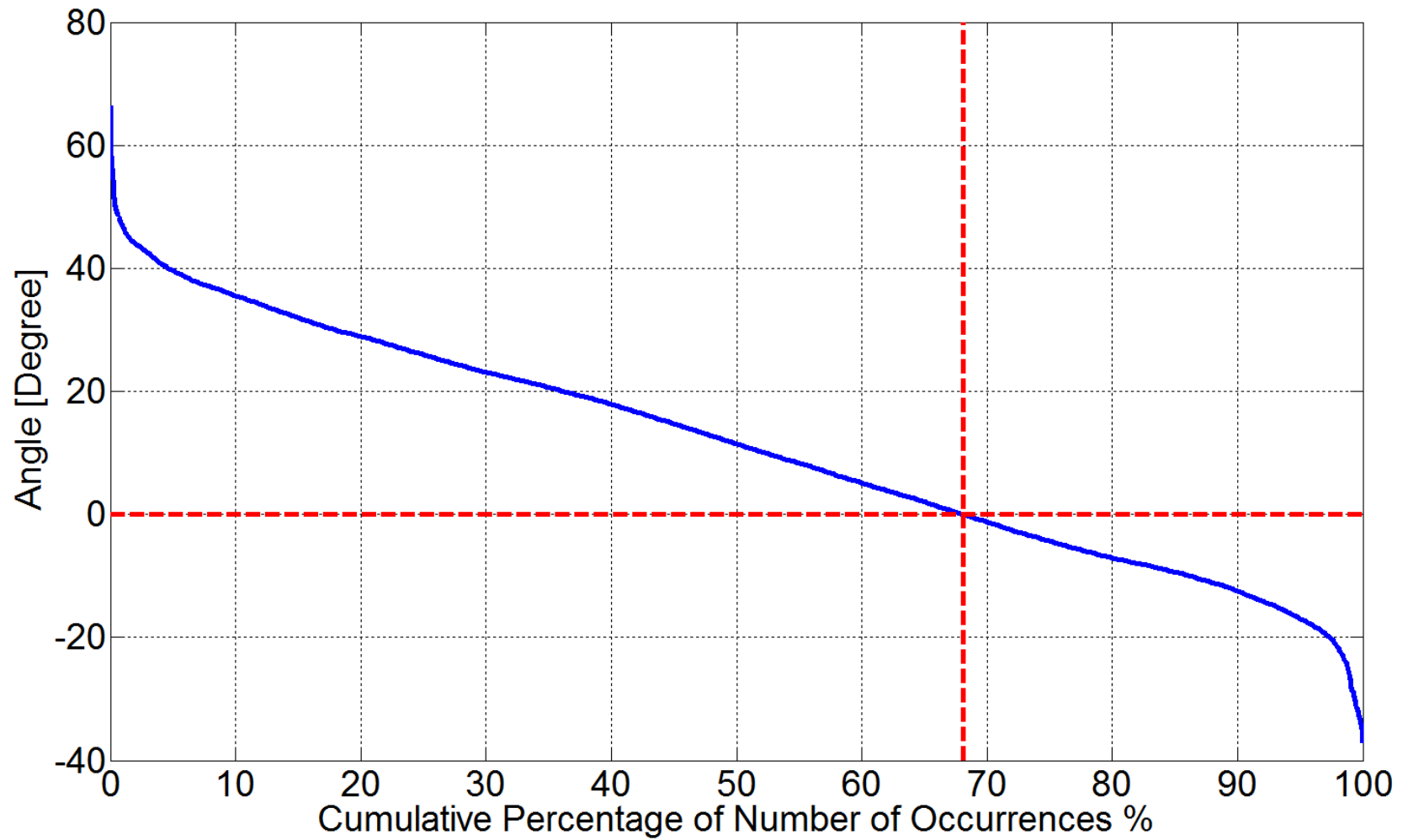
State Estimator Data: January to June 2013
Box Whiskers Plots and Time Duration Curves

External Version

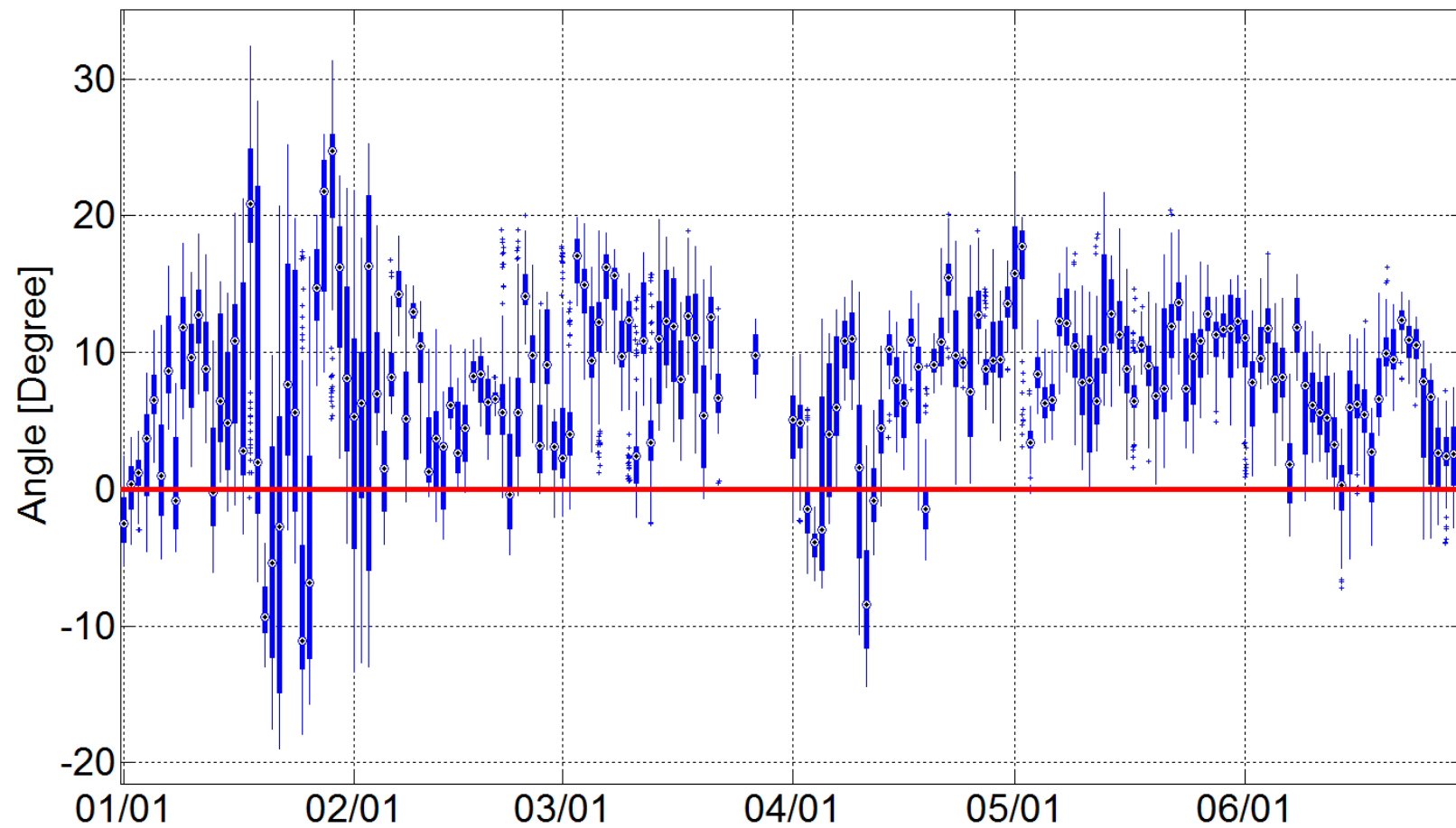
West 10-North 7



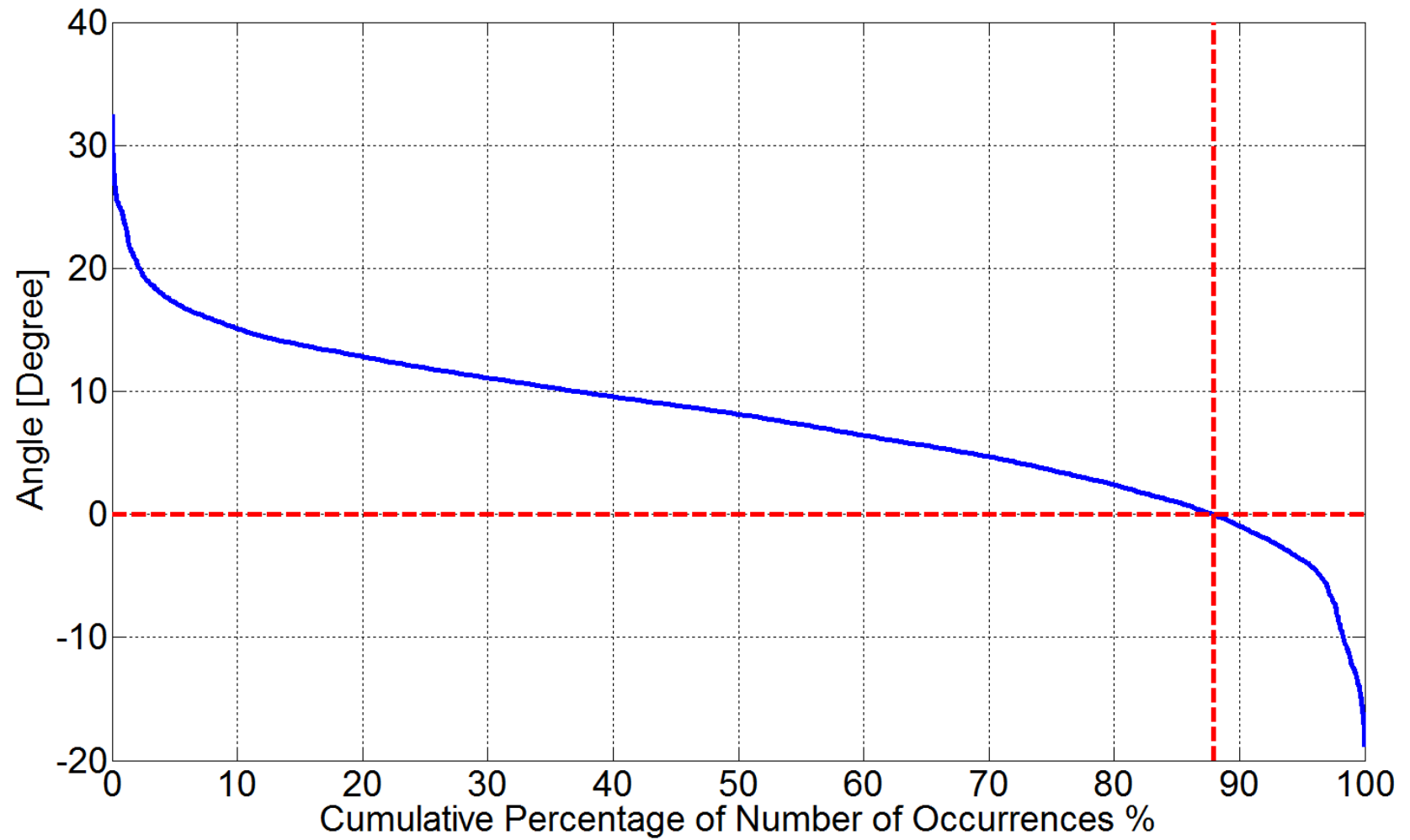
West 10-North 7



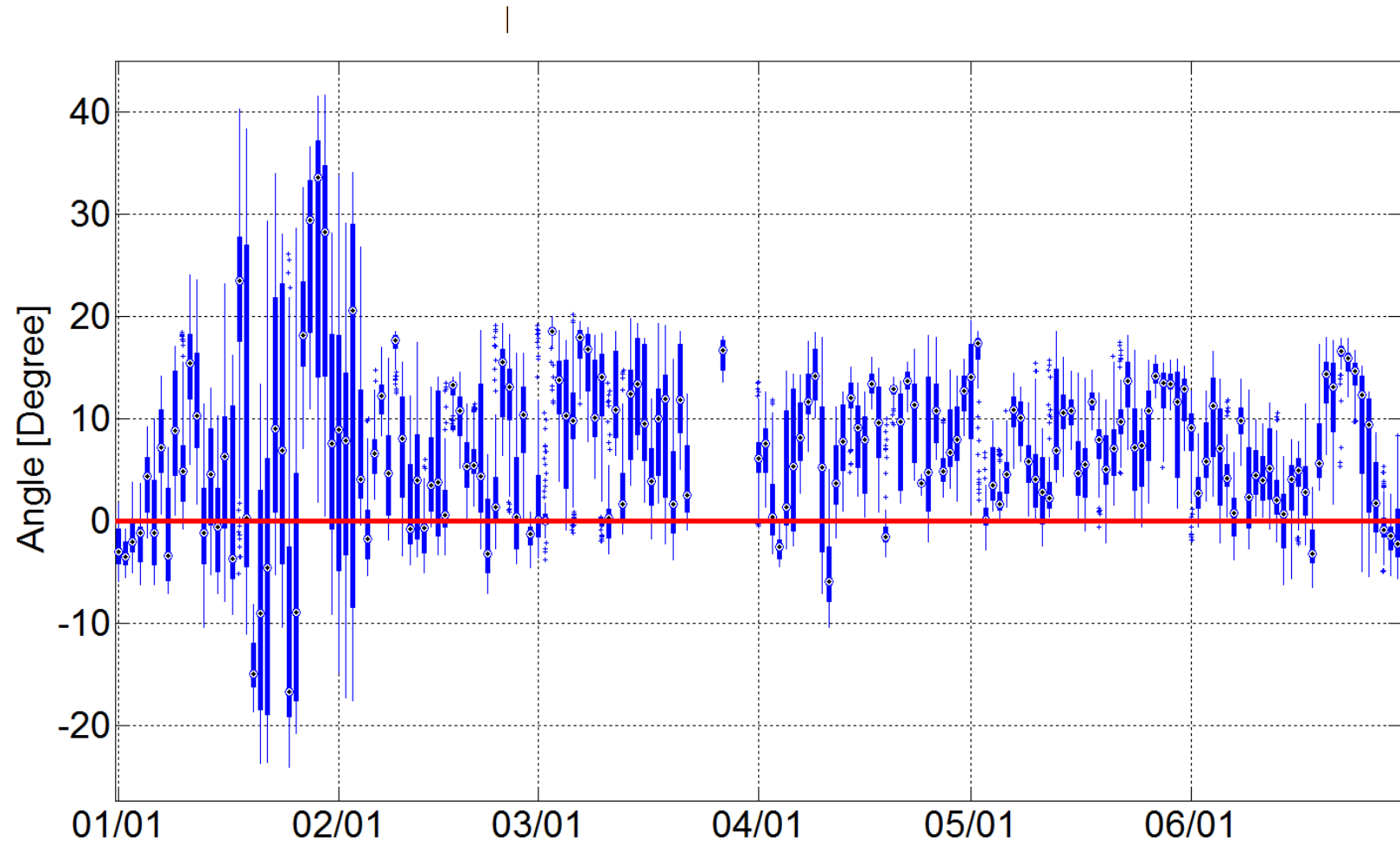
West 14-North 7



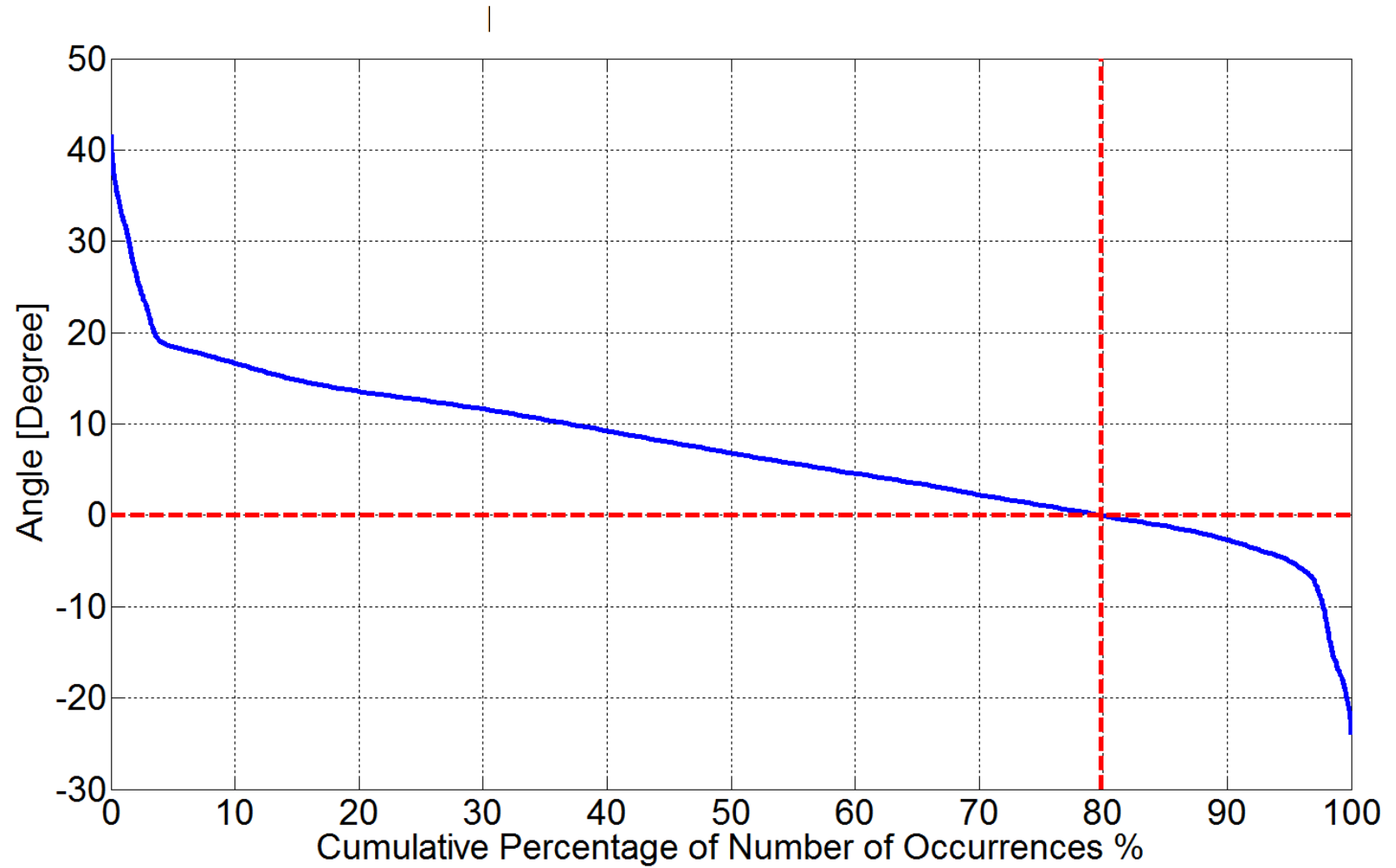
West 14-North 7



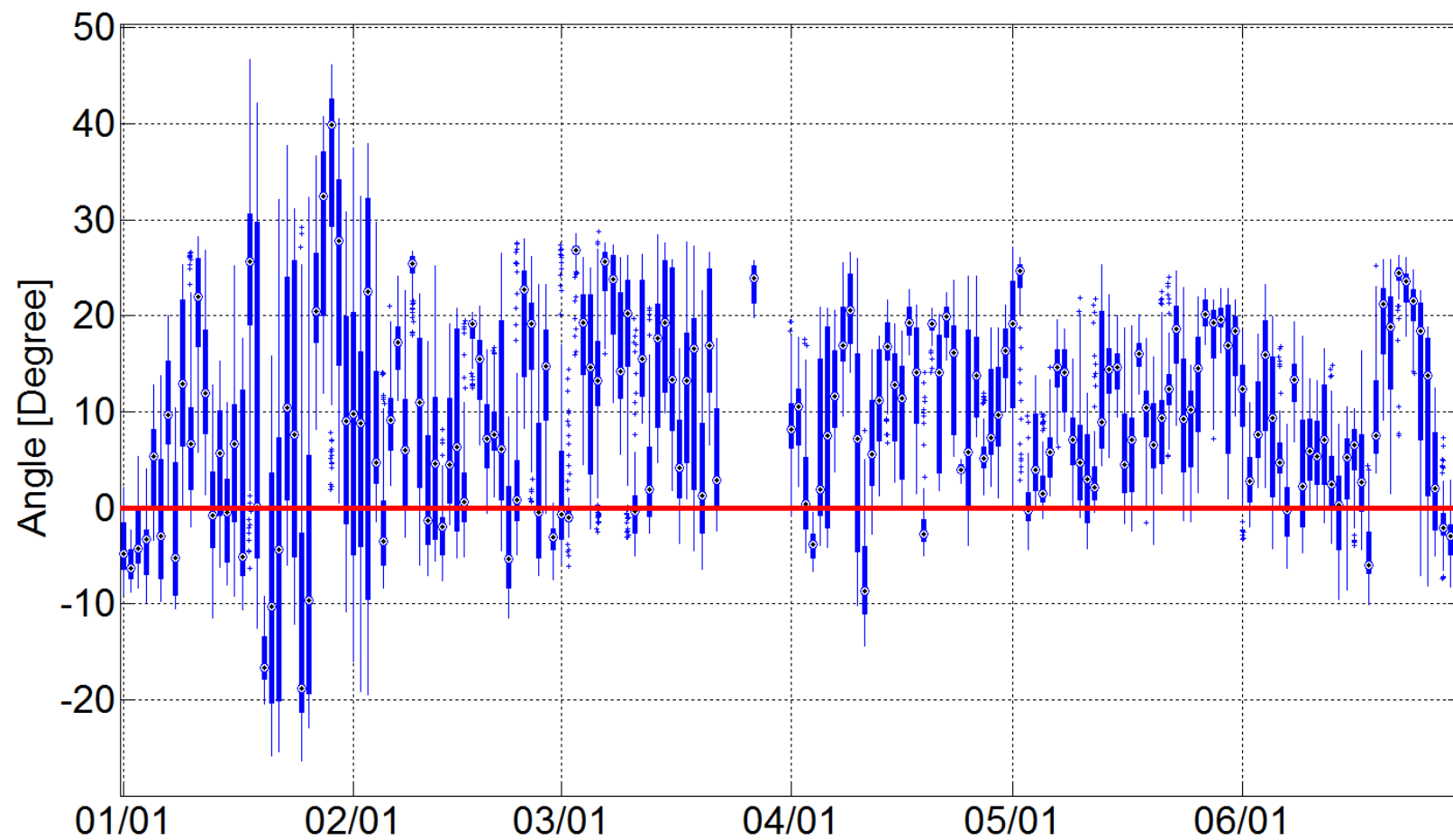
West 1*-North 7



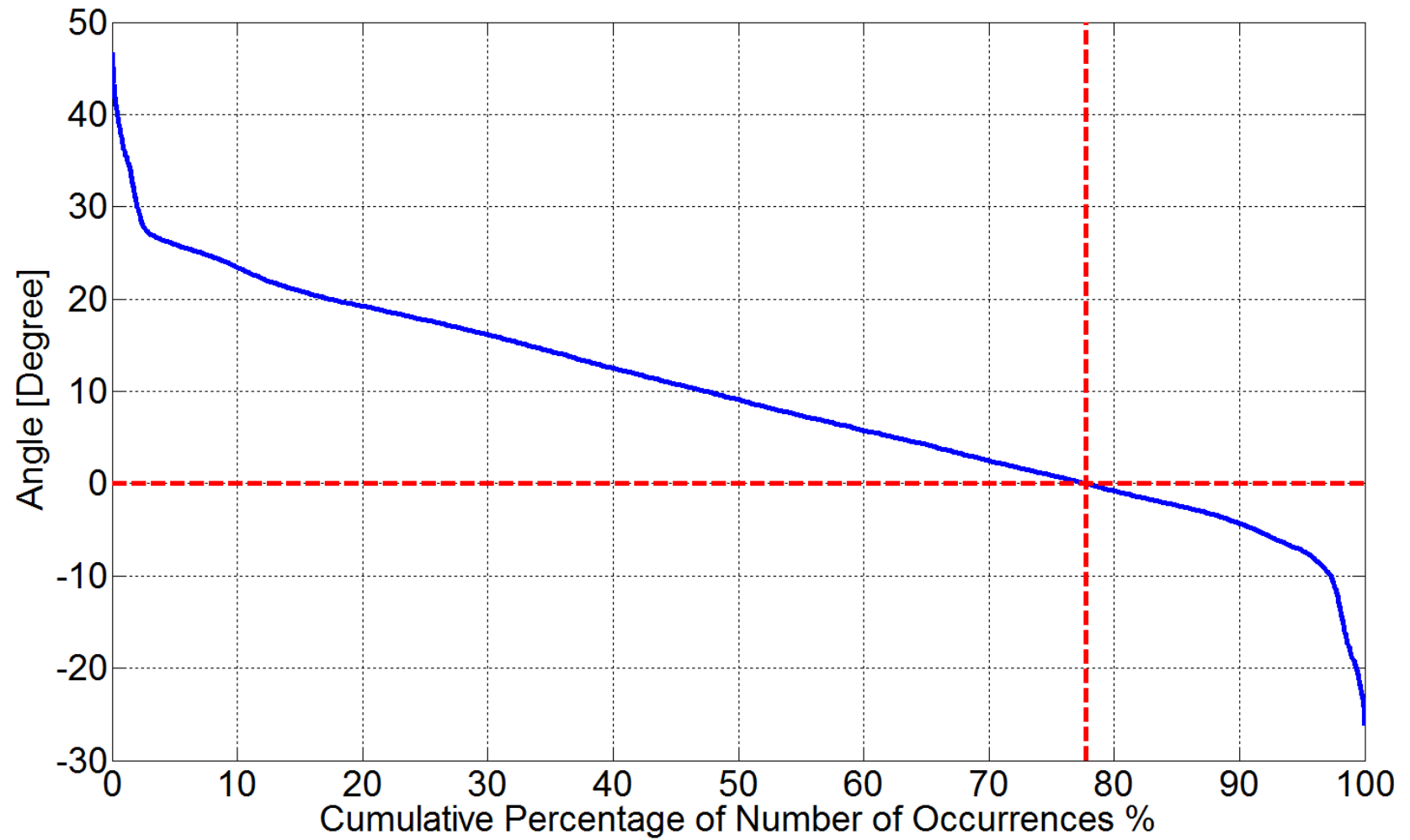
West 1*-North 7



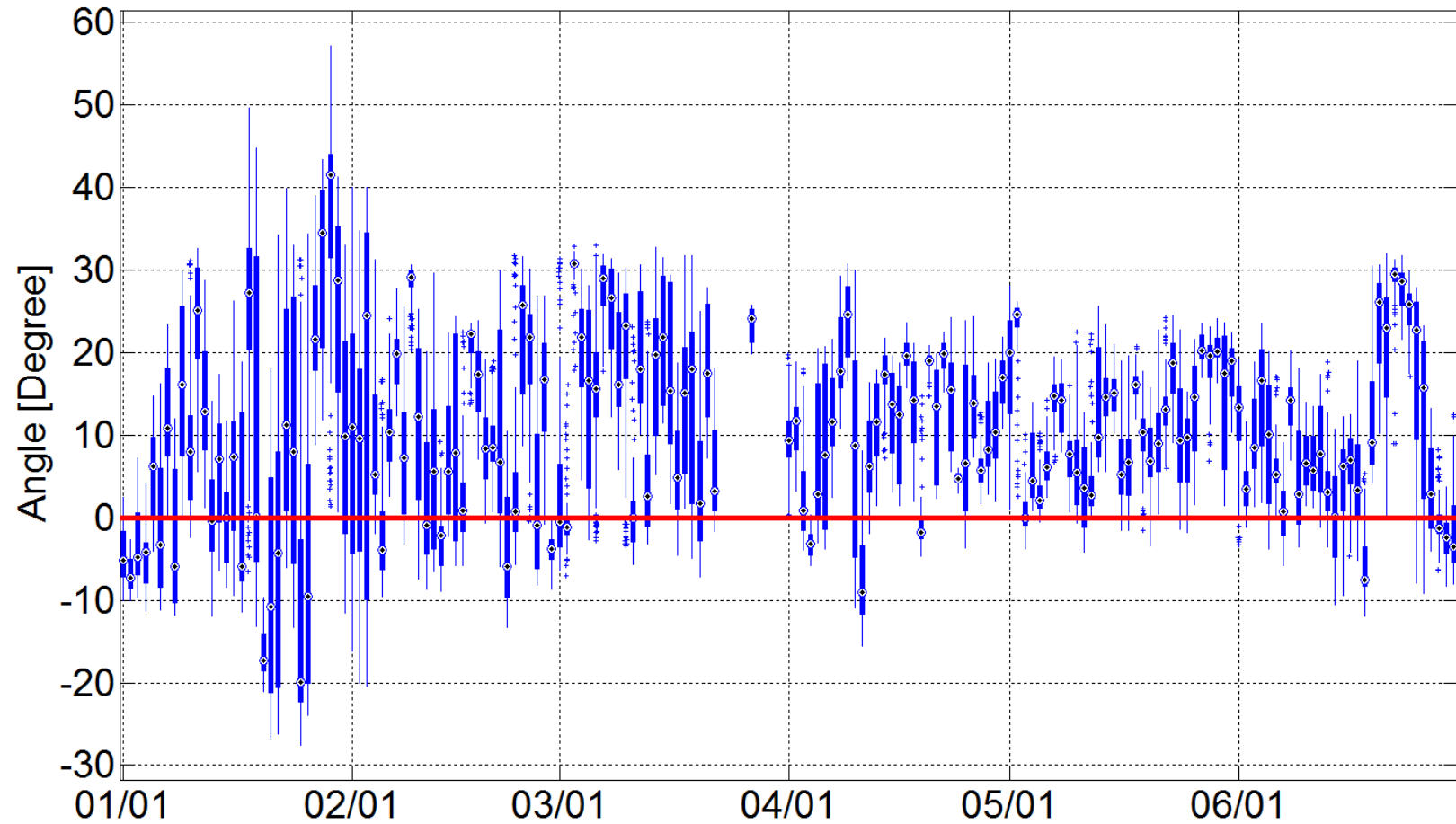
West 2*-North 7



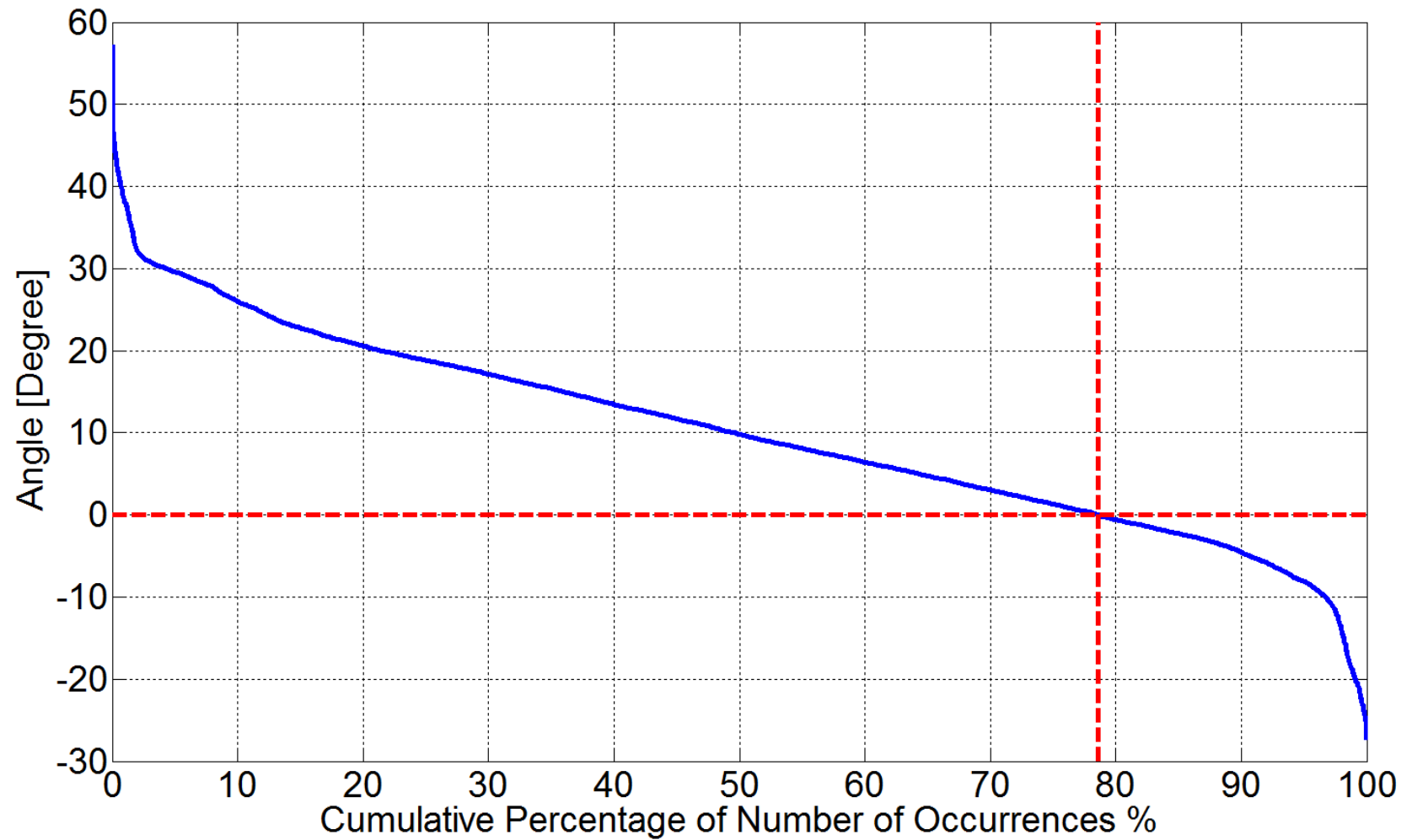
West 2*-North 7



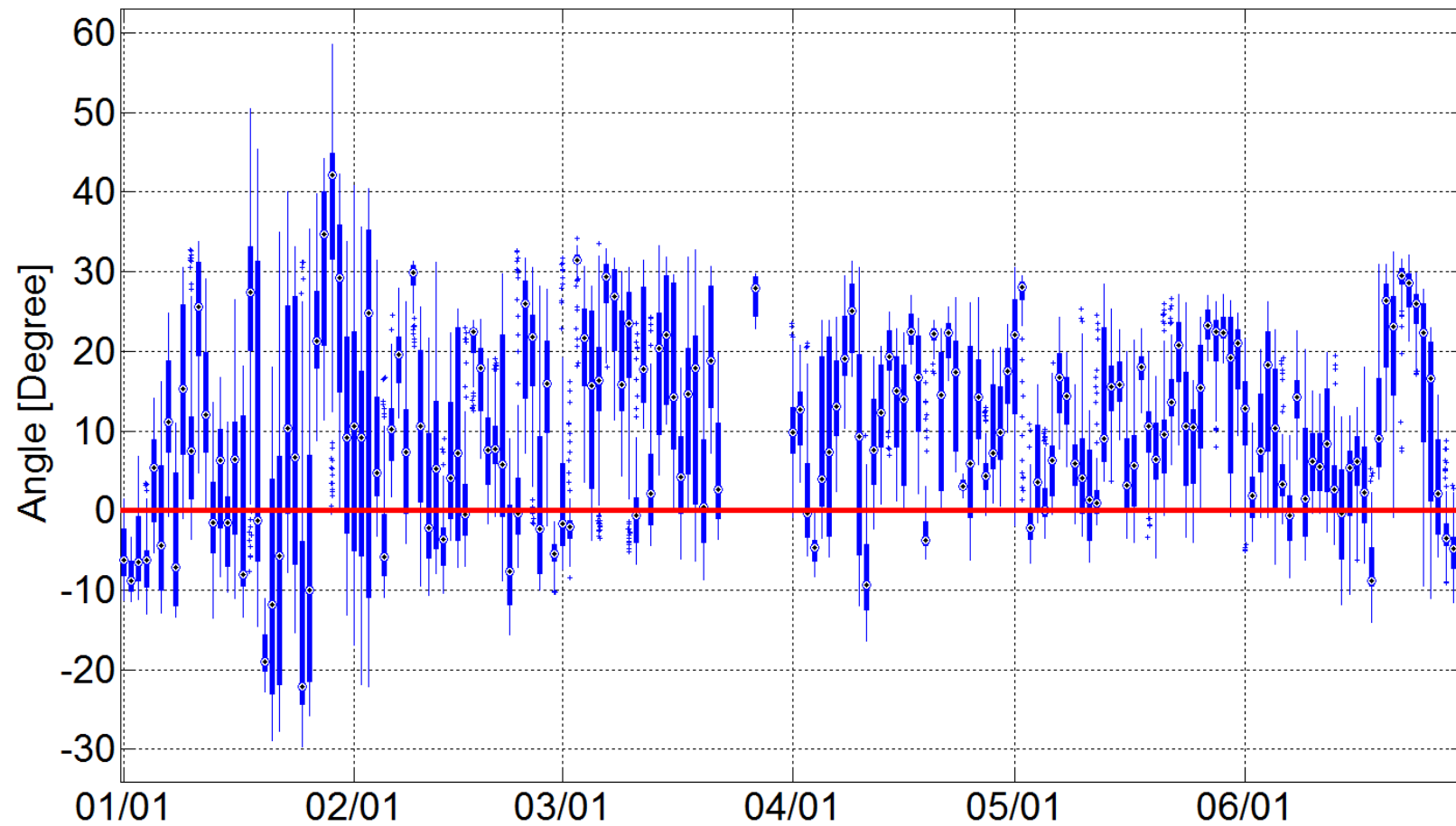
West 9*-North 7



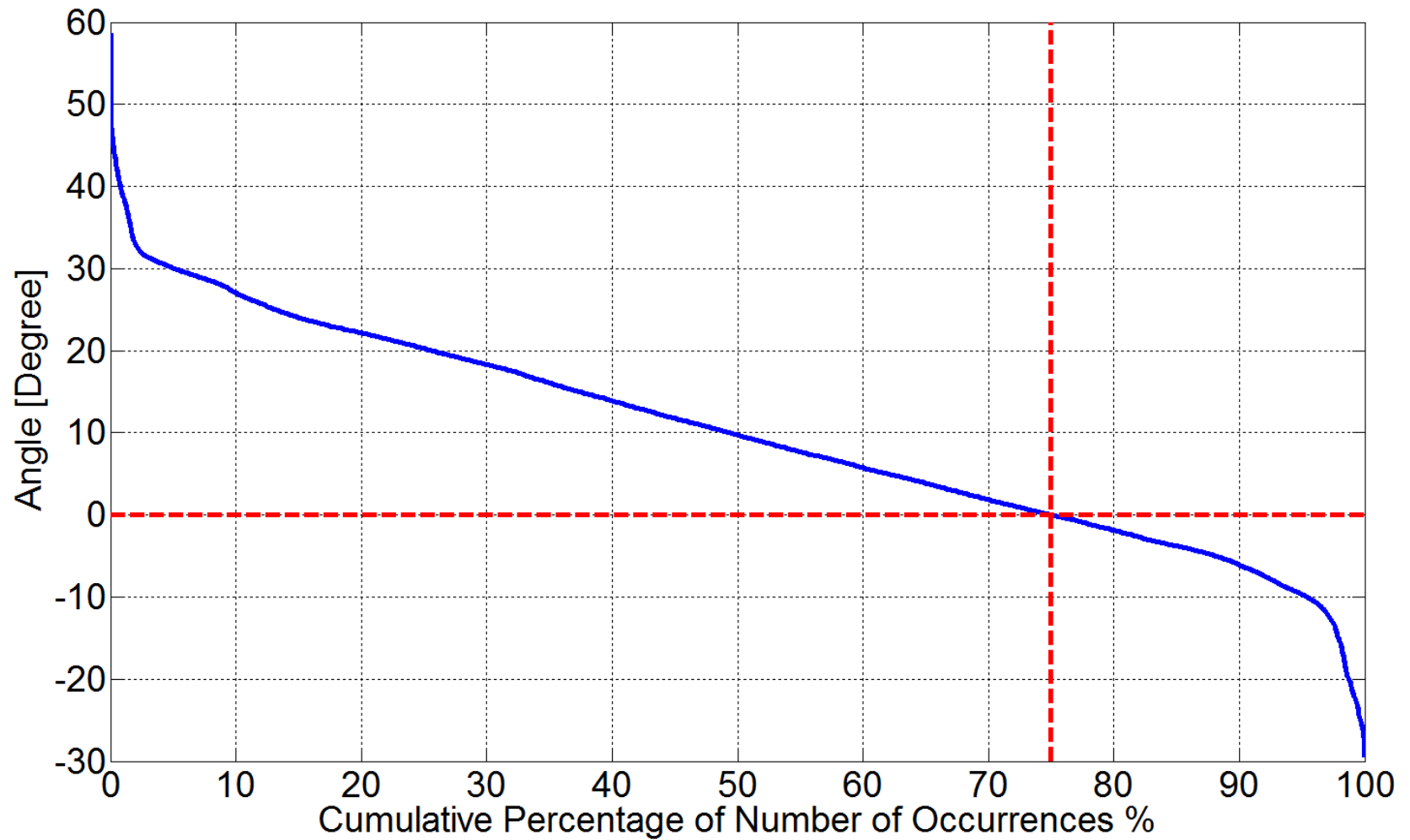
West 9*-North 7



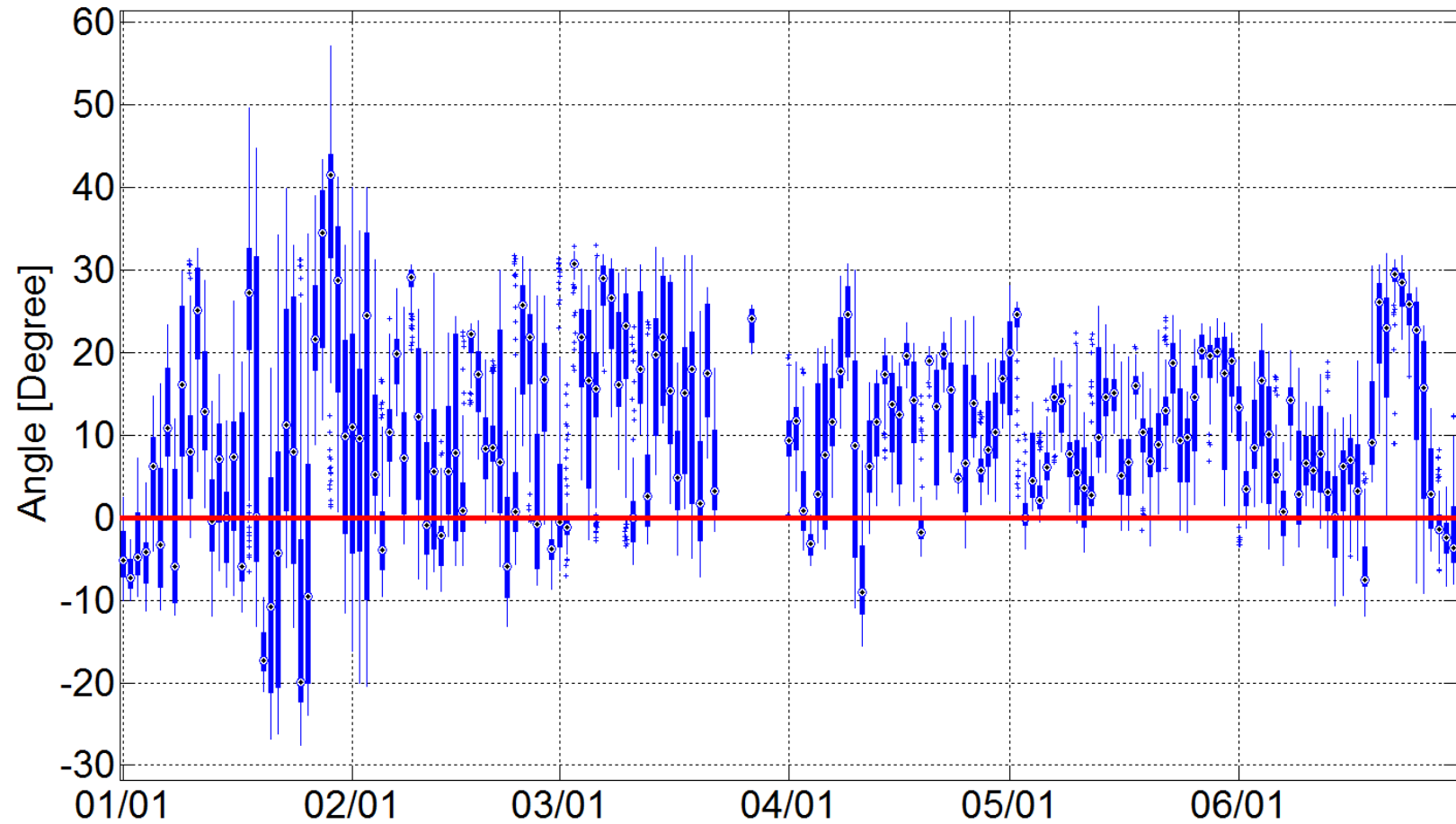
West 11-North 7



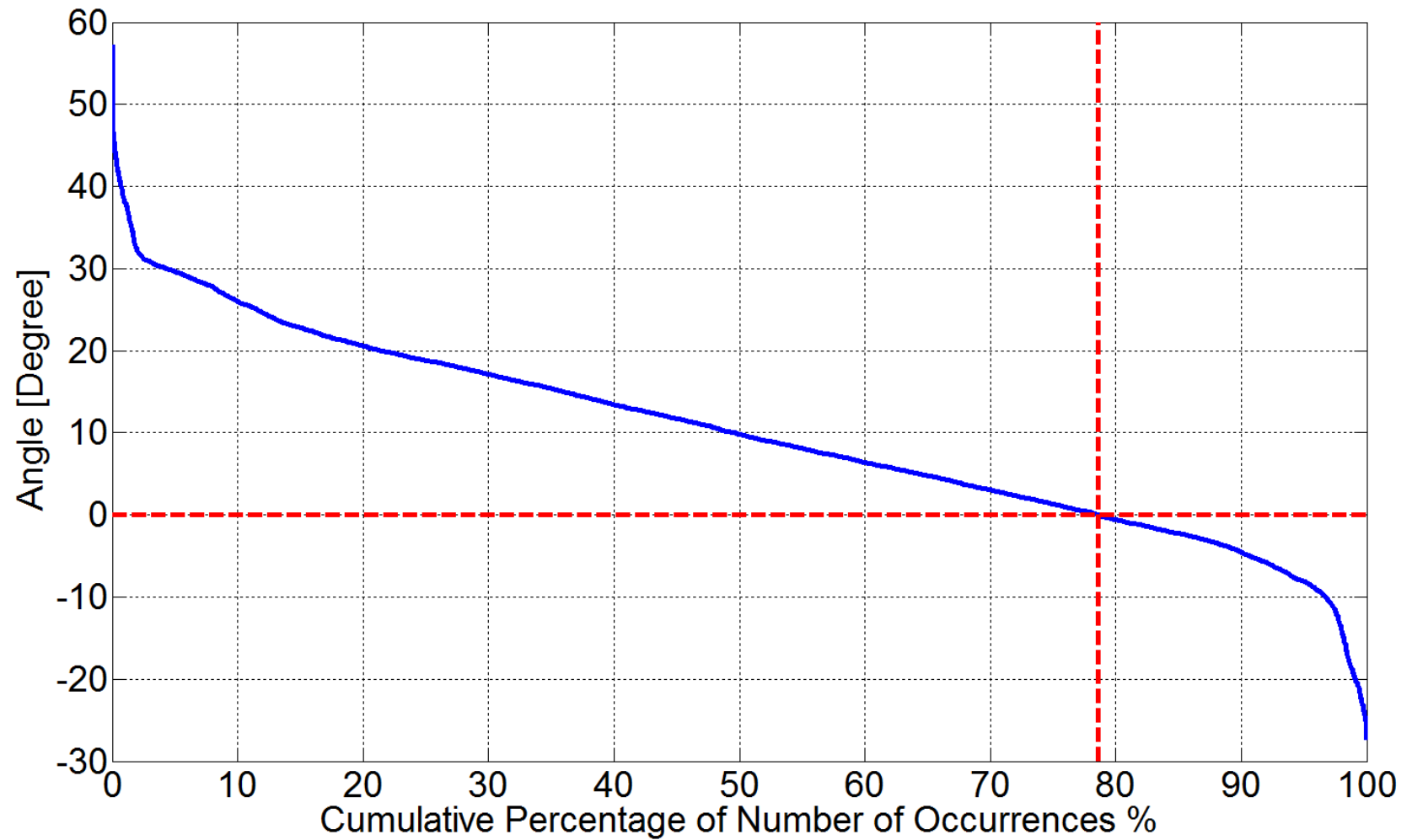
West 11-North 7



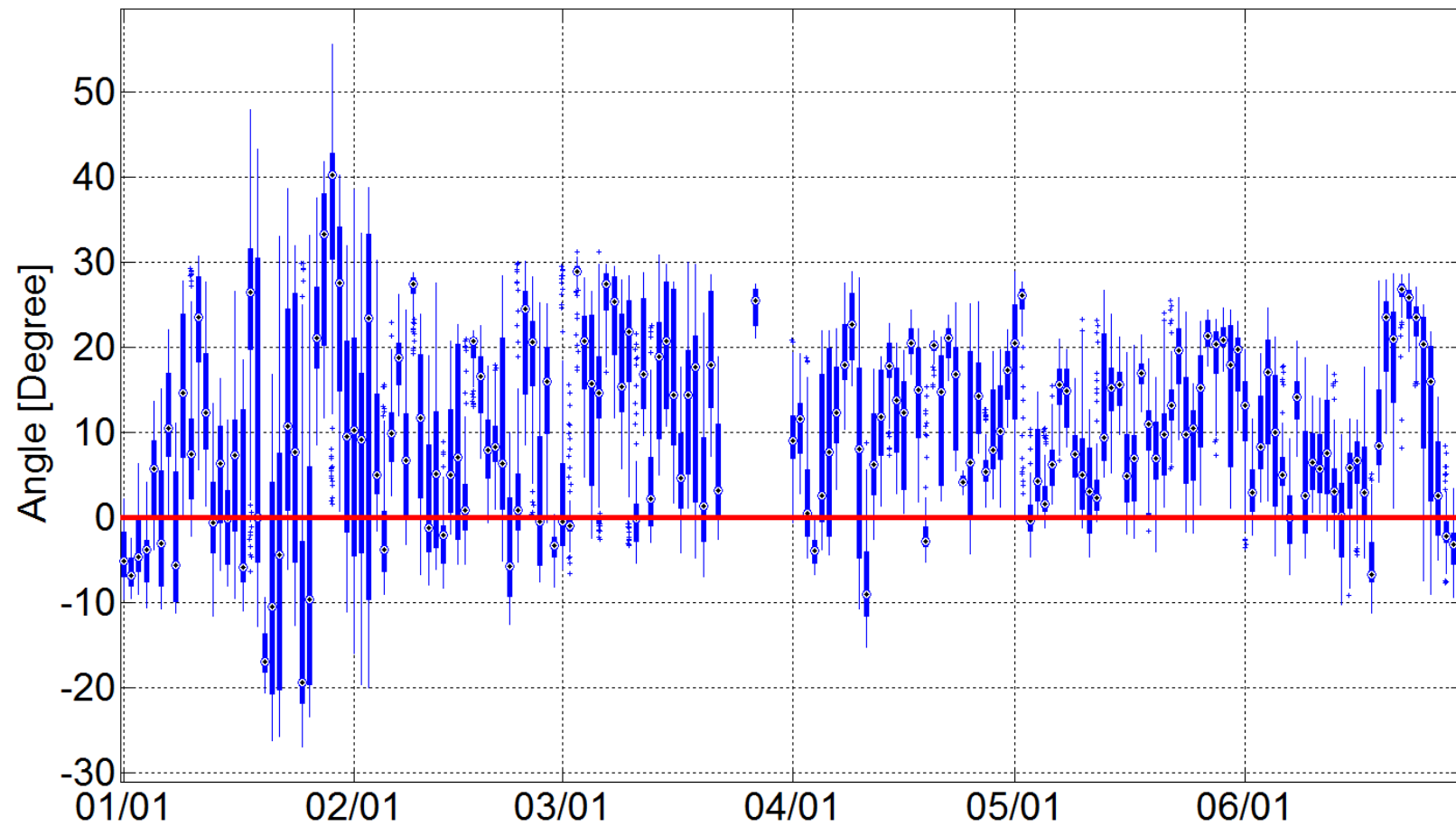
West 12*-North 7



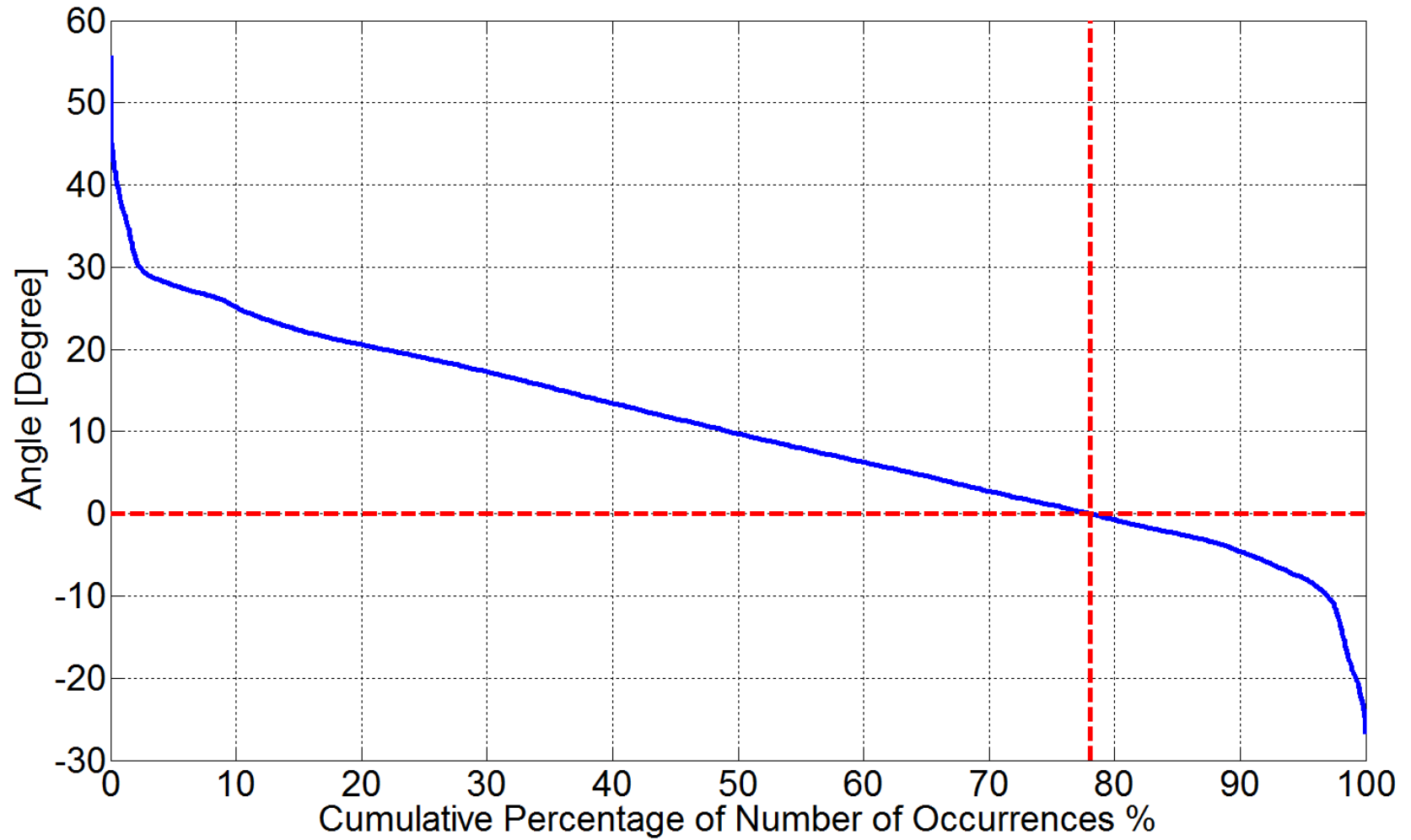
West 12*-North 7



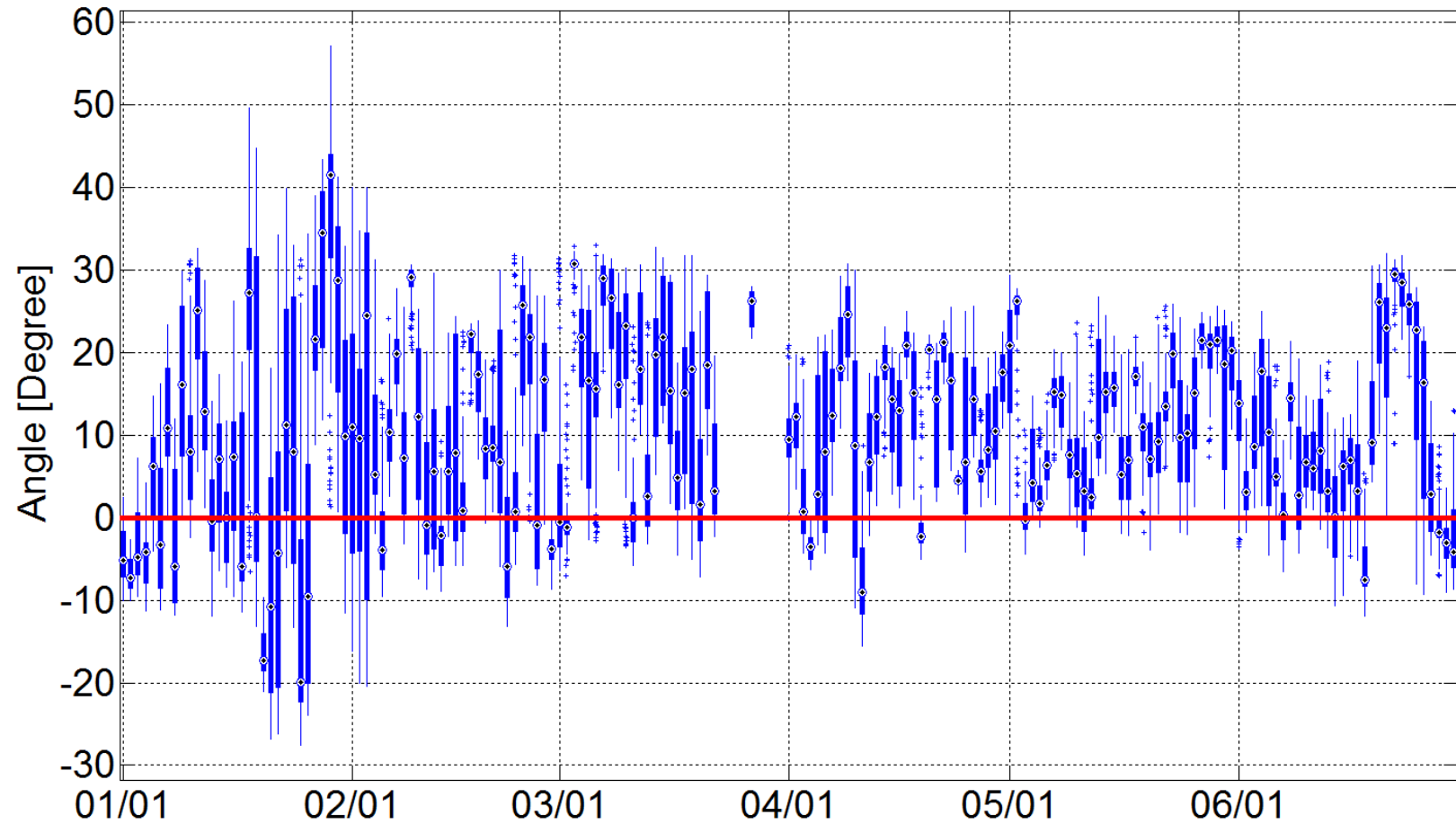
West 5*-North 7



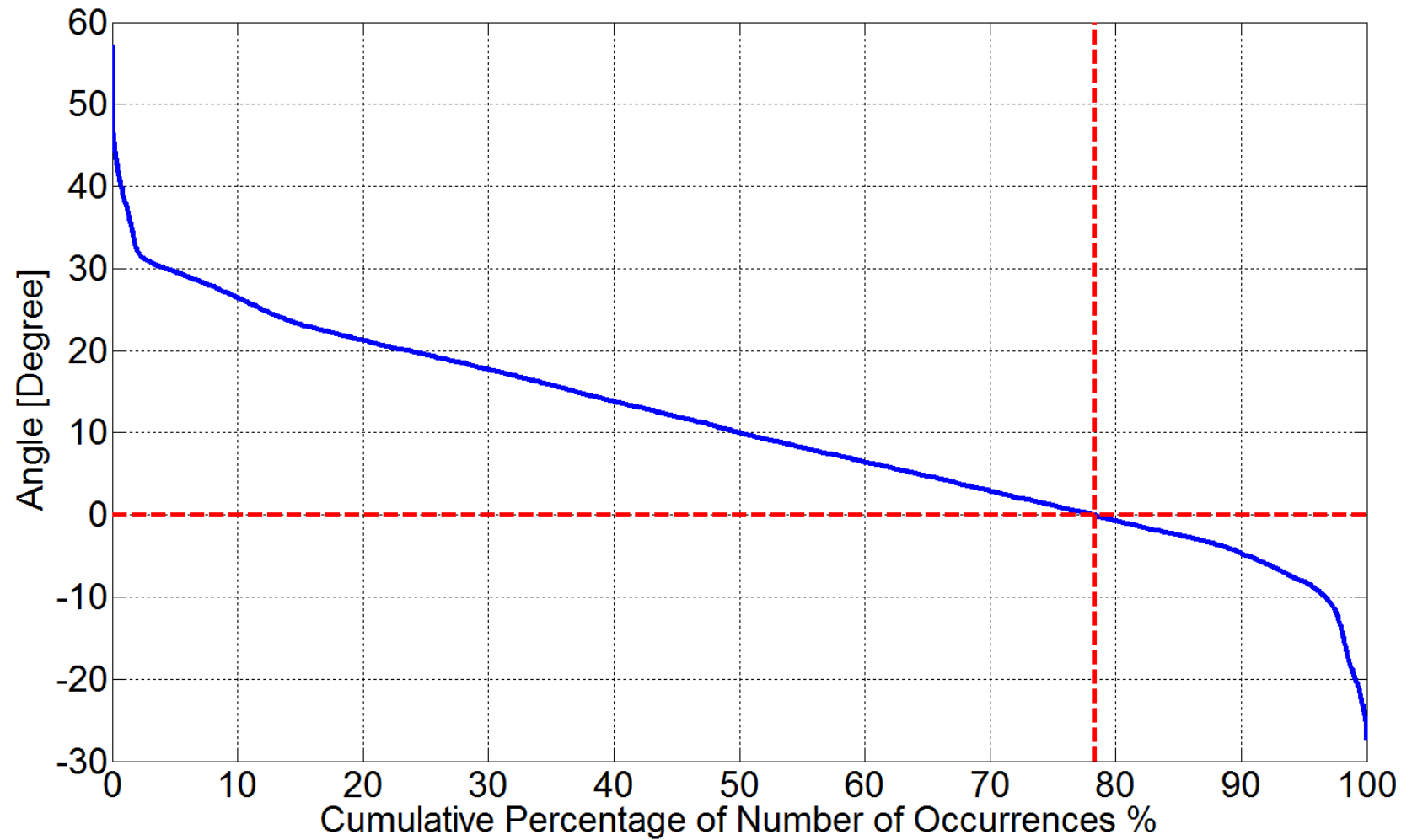
West 5*-North 7



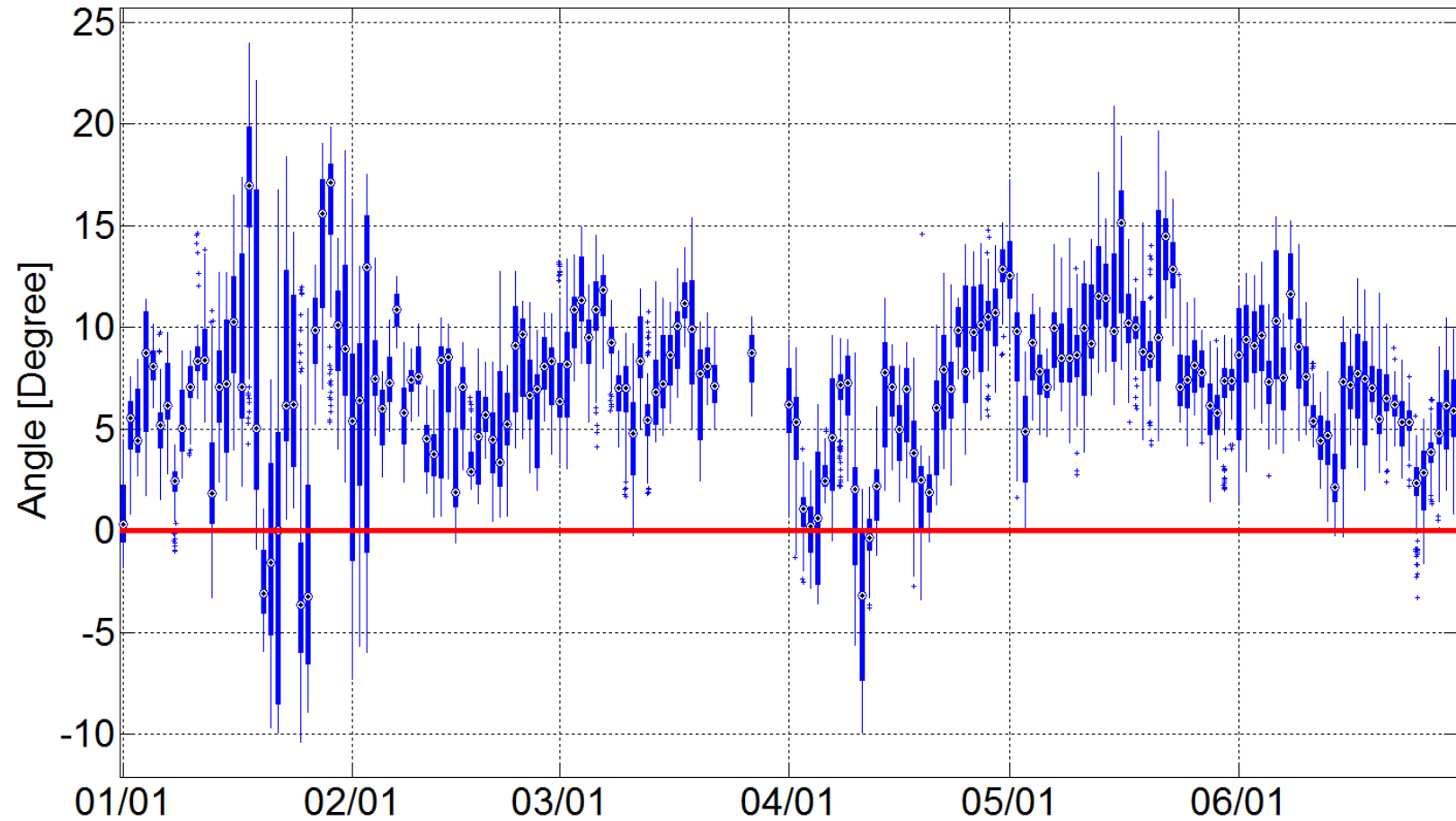
West 6-North 7



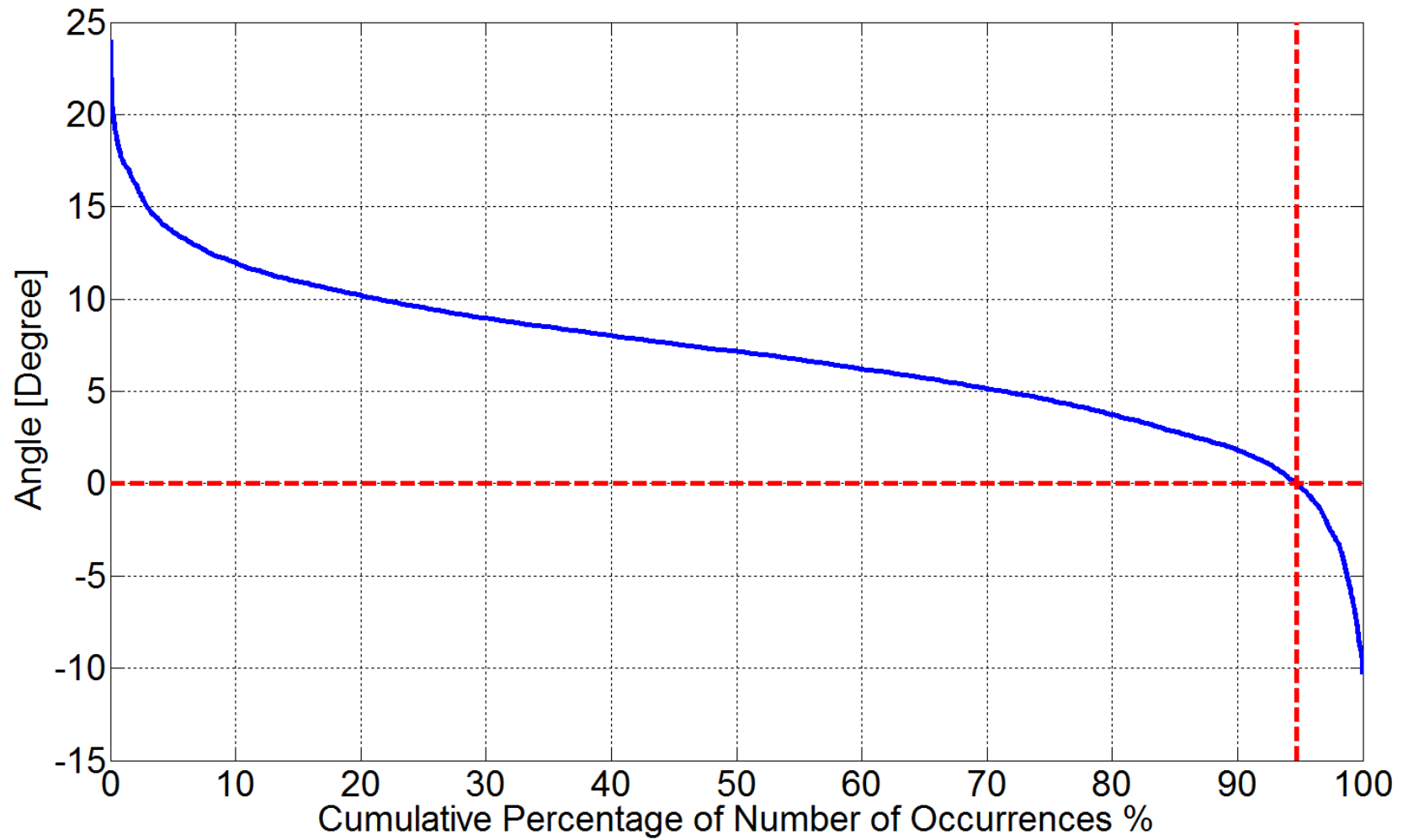
West 6-North 7



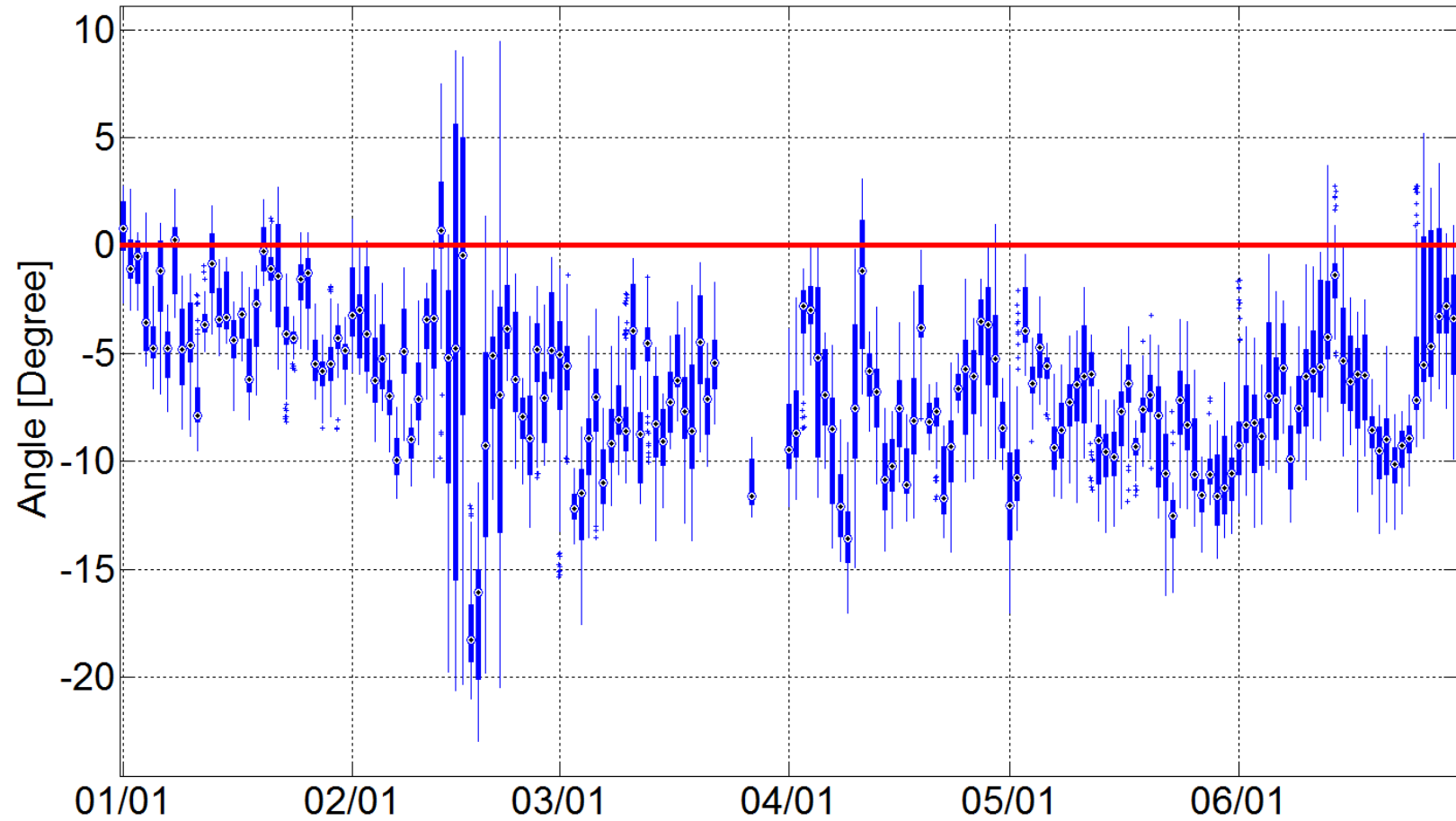
North 1-North 7



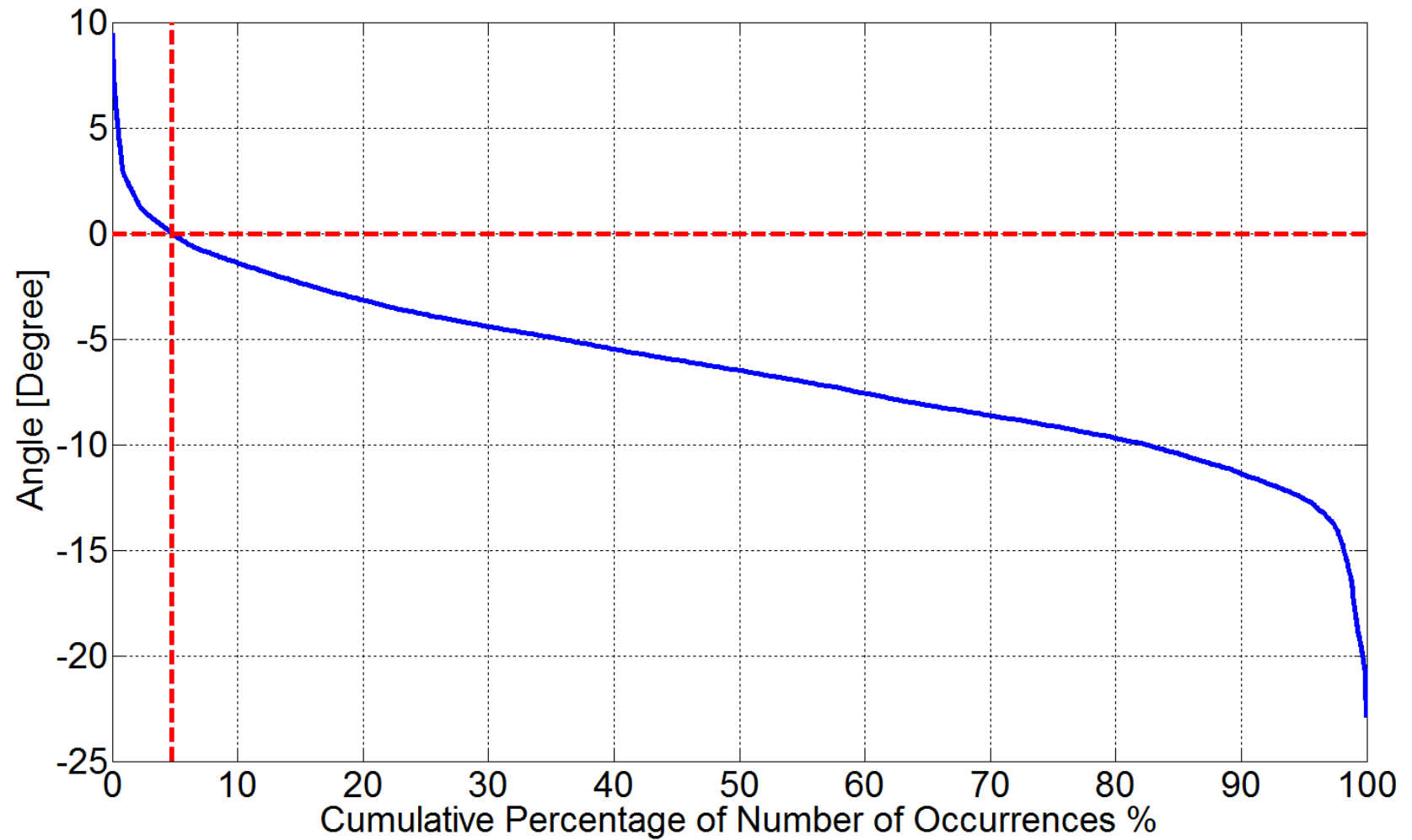
North 1-North 7



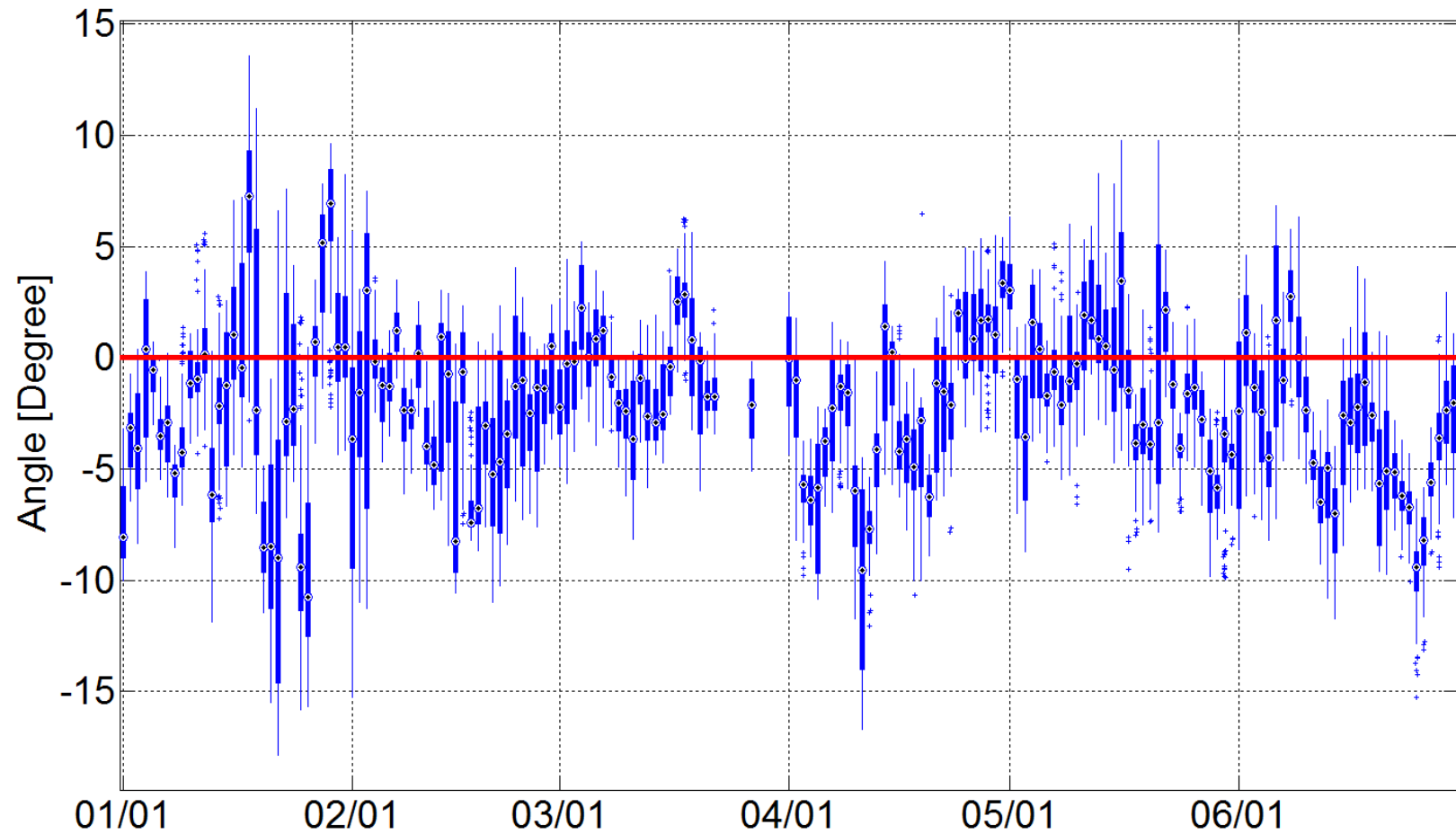
North 2-North 7



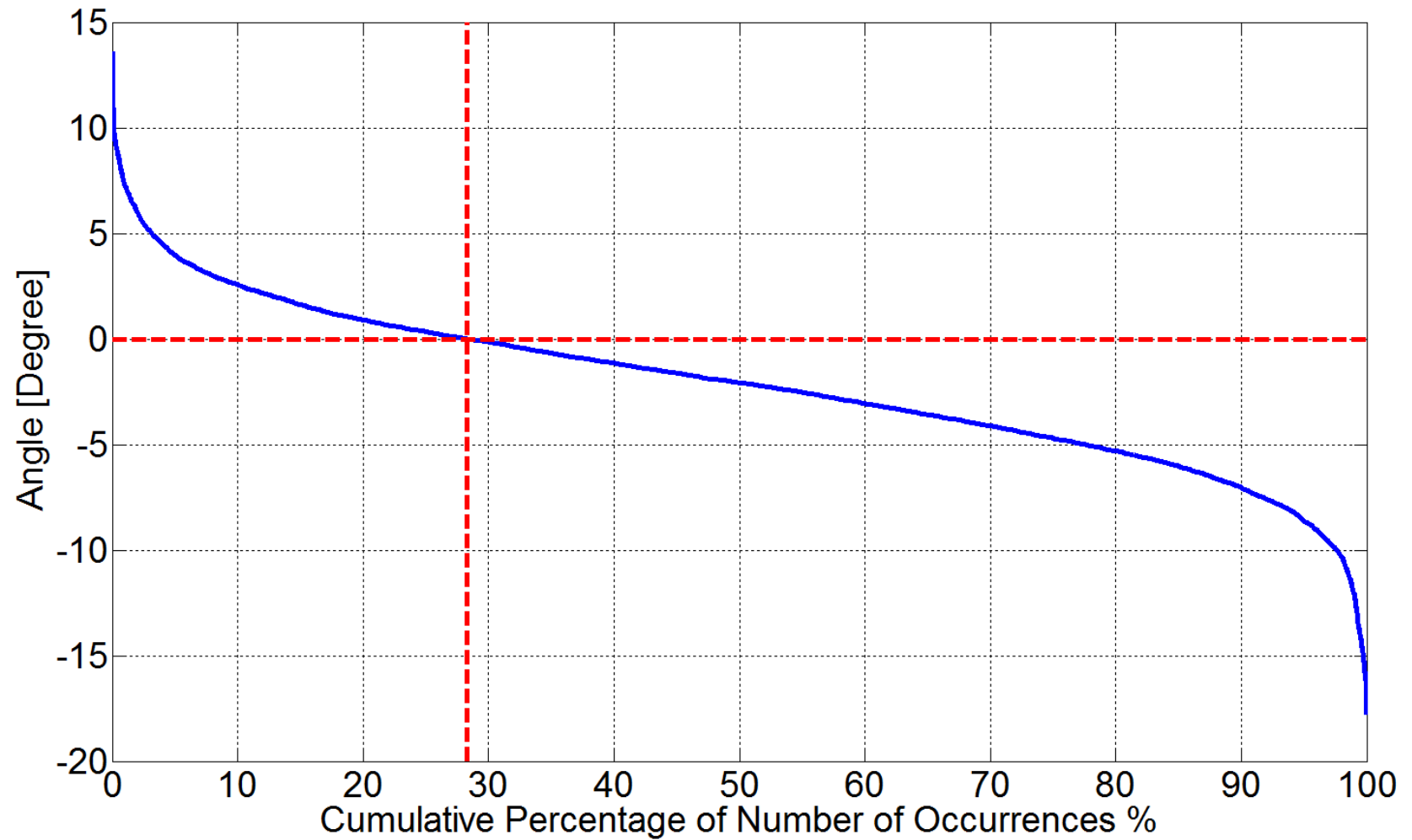
North 2-North 7



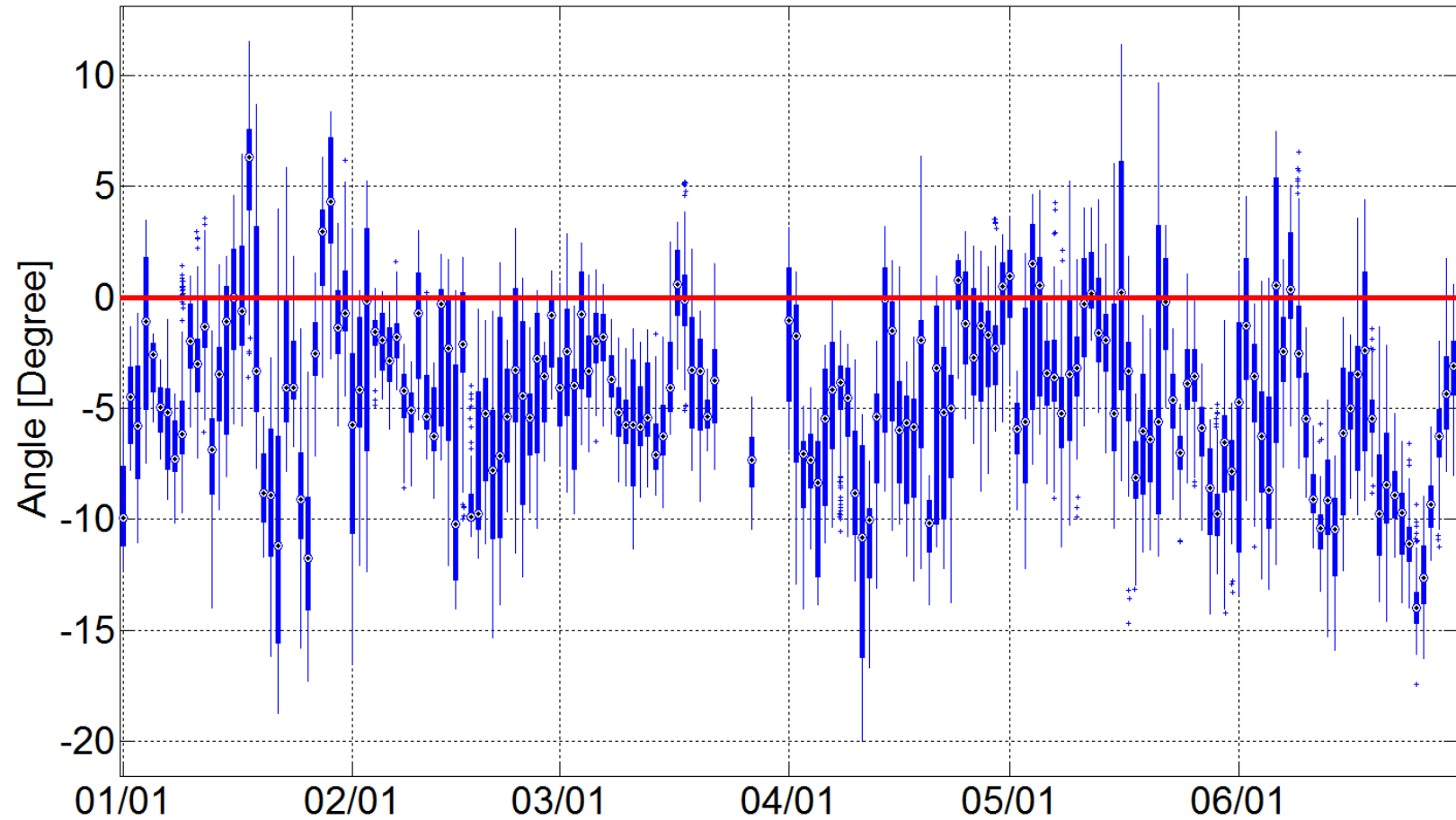
North 4-North 7



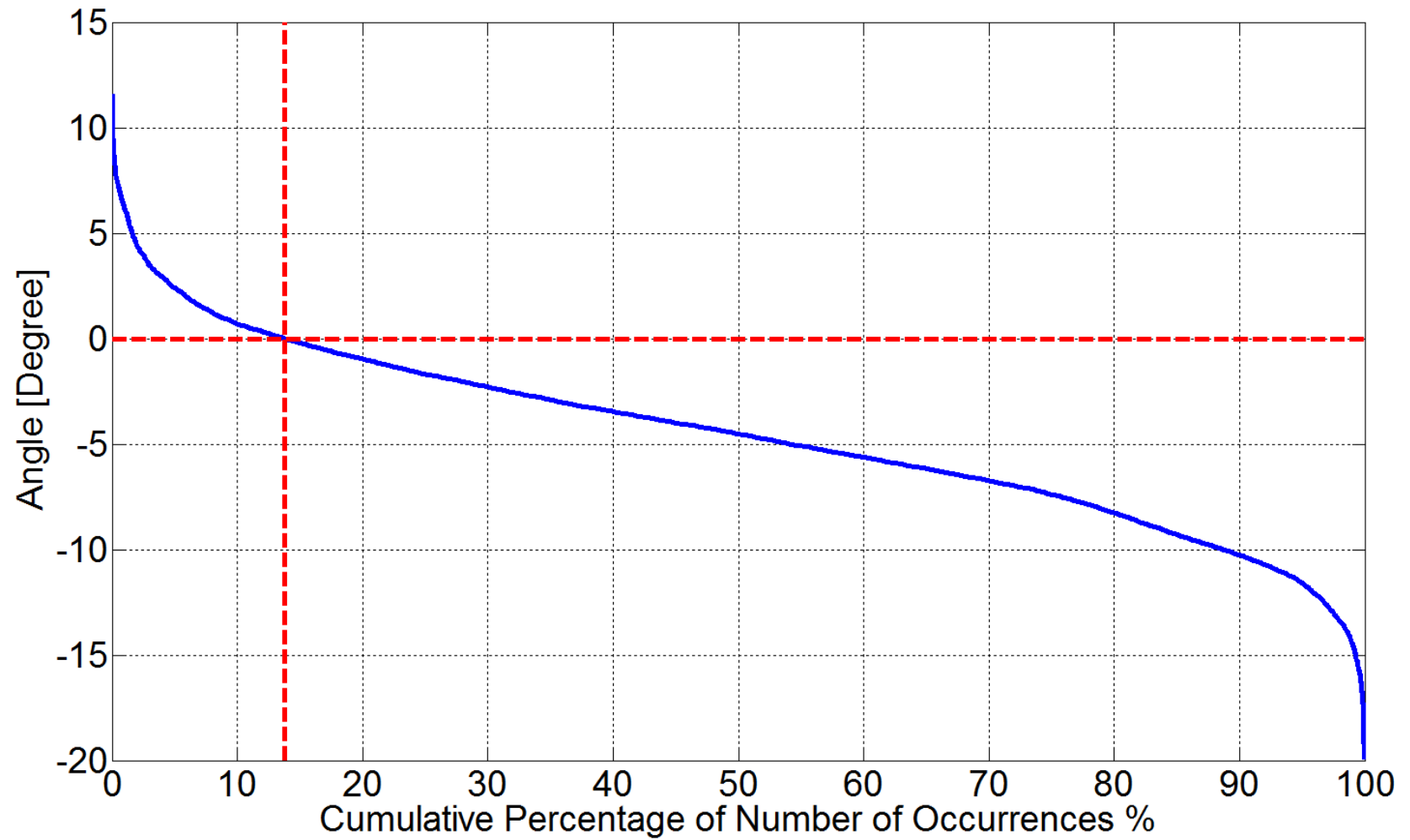
North 4-North 7



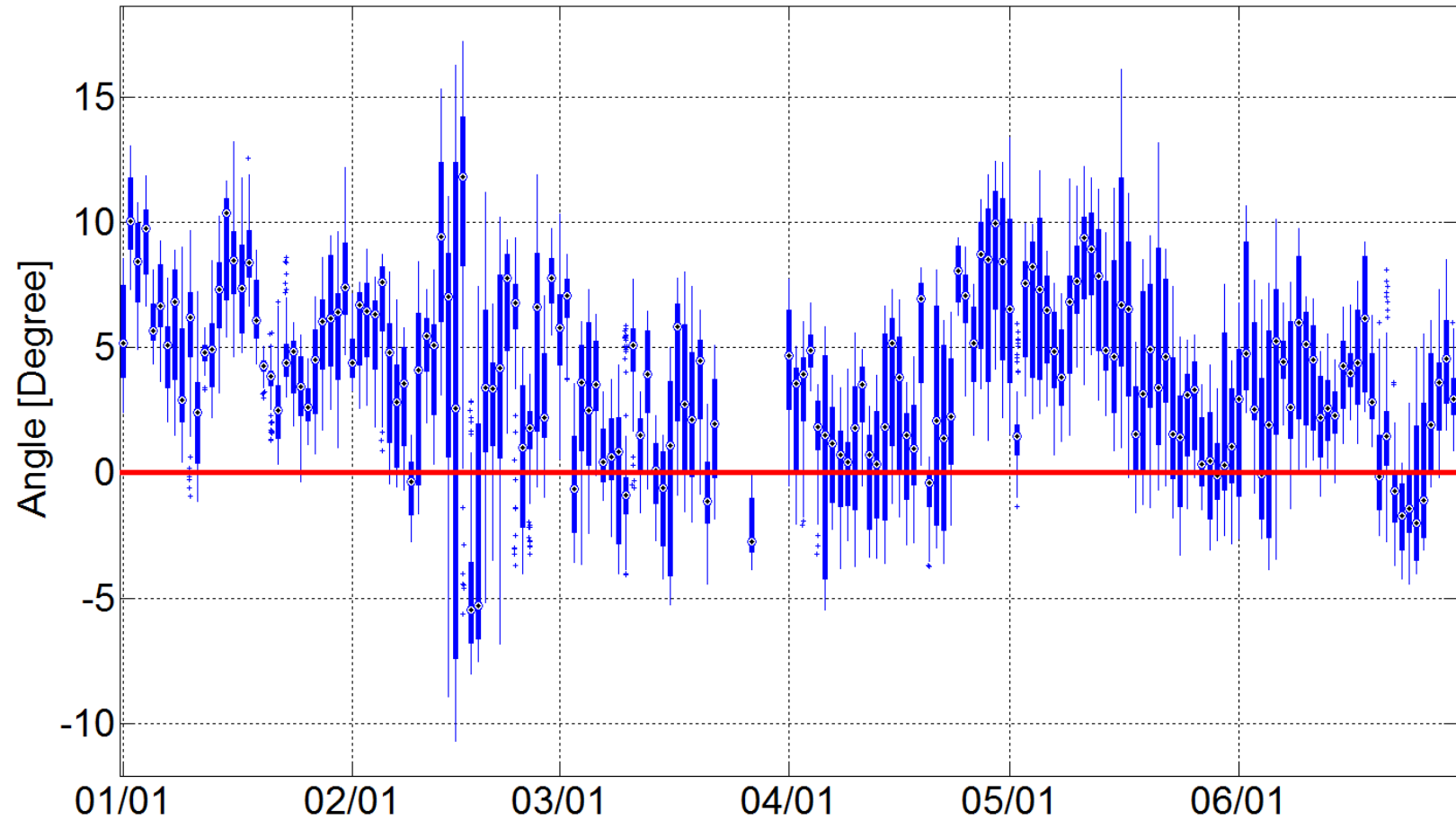
North 5-North 7



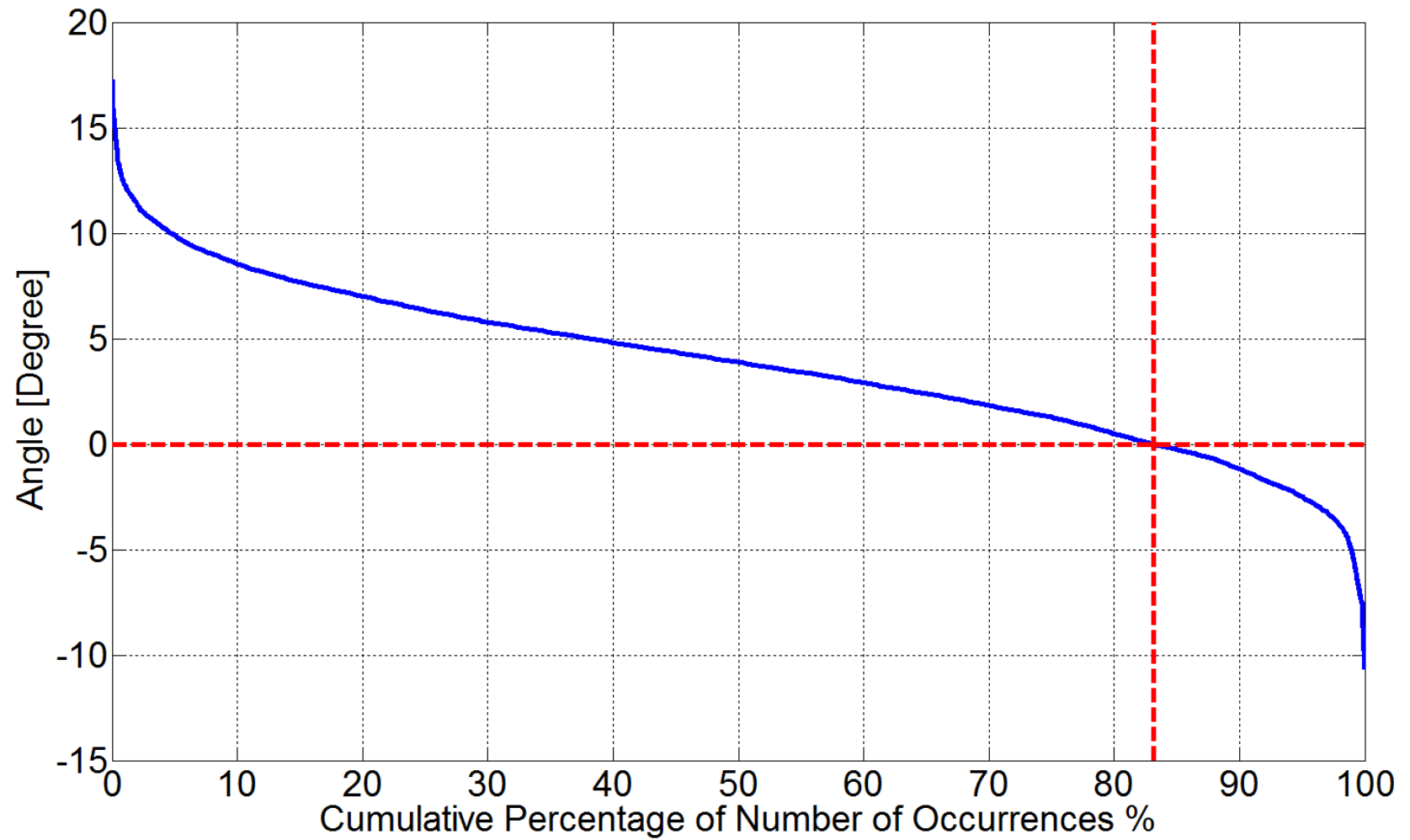
North 5-North 7



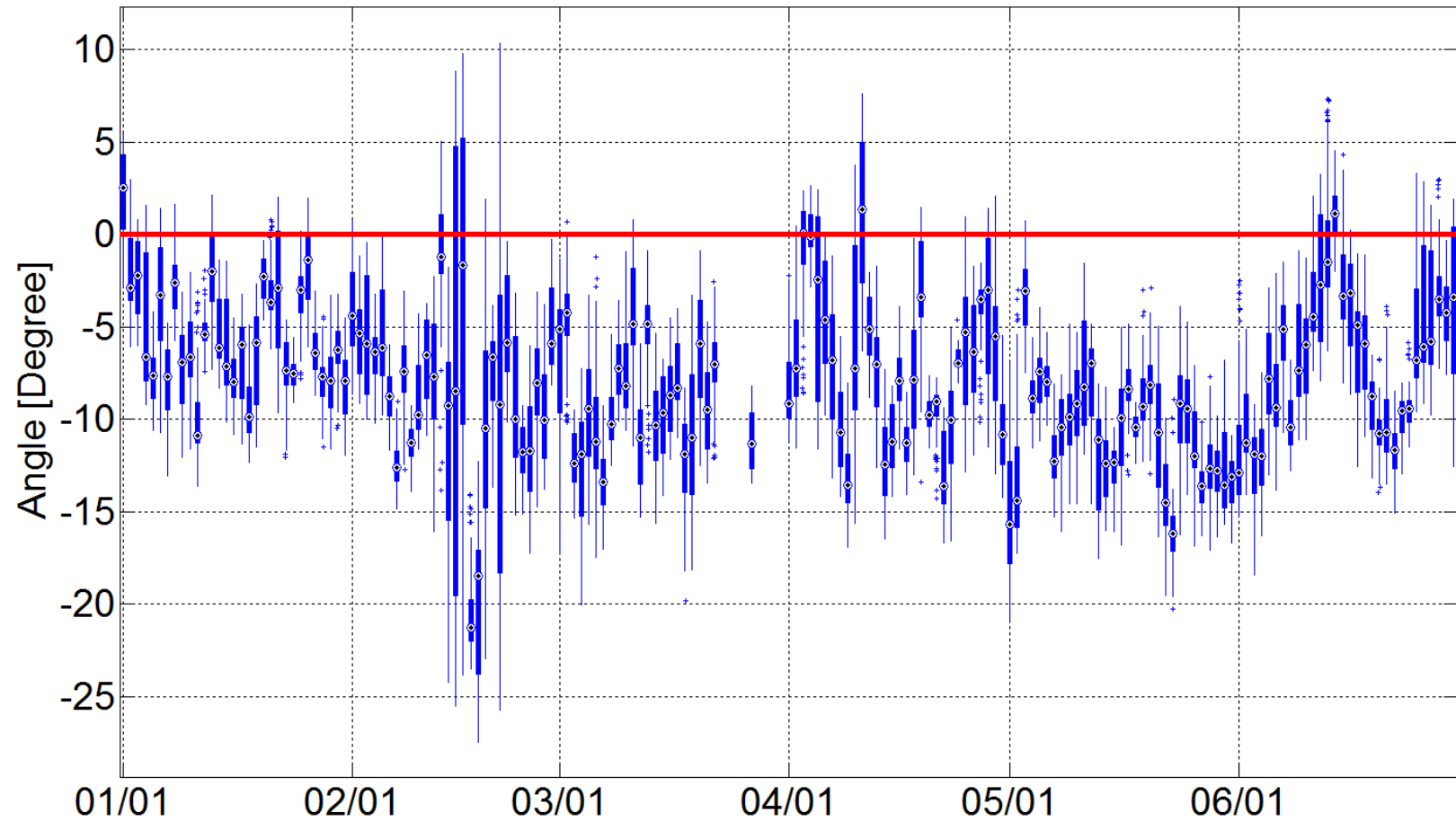
North 6-North 7



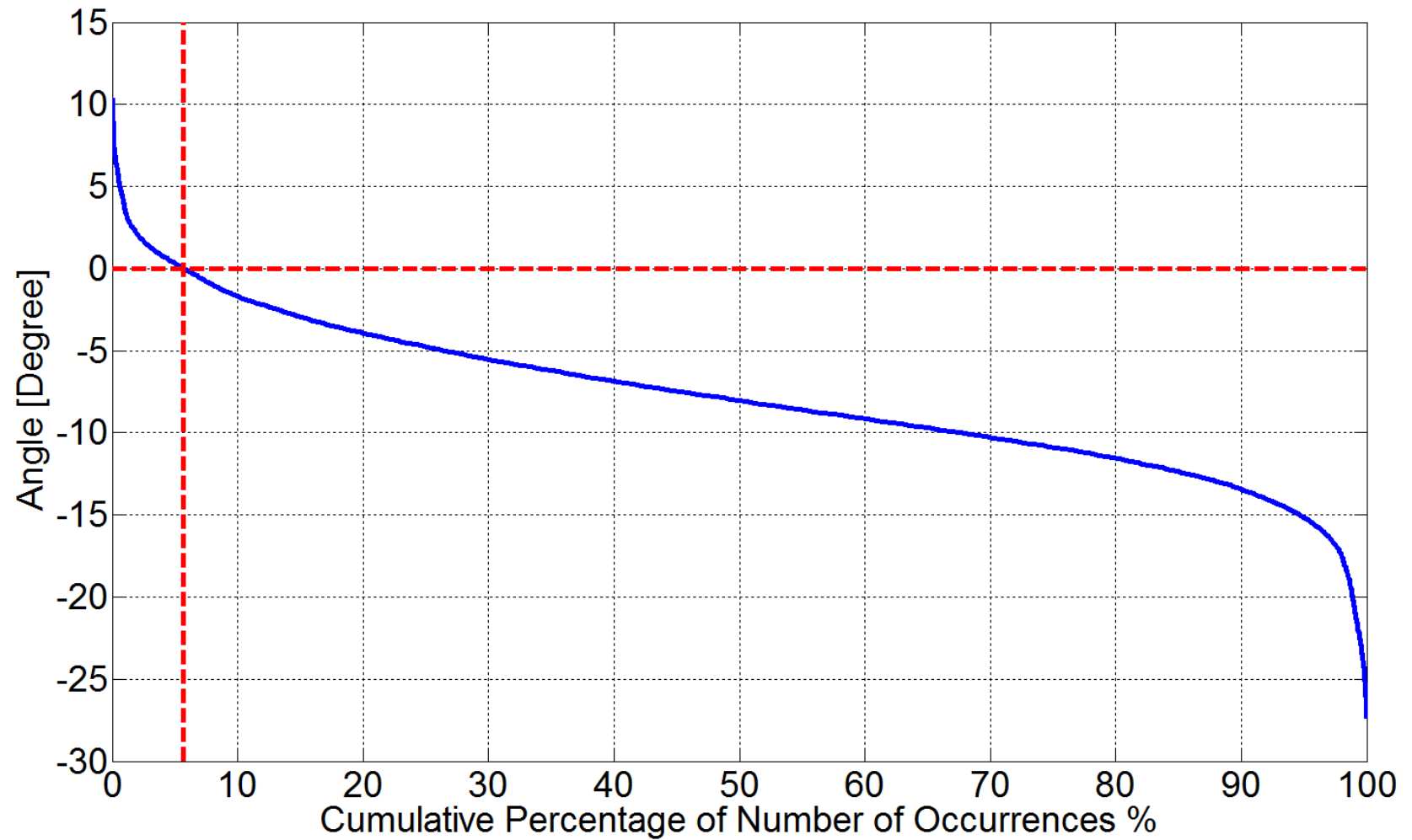
North 6-North 7



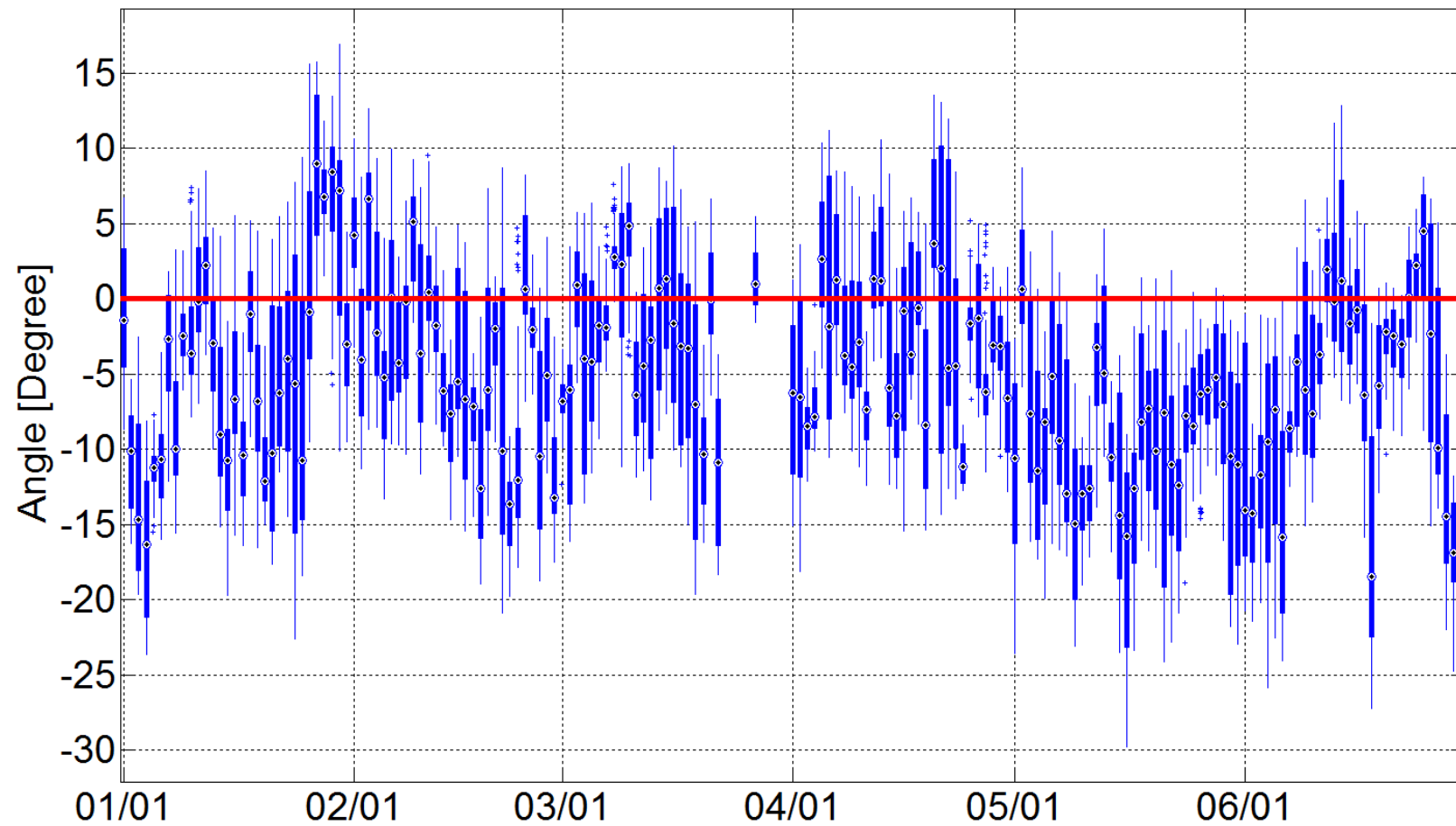
FarWest 2*-North 7



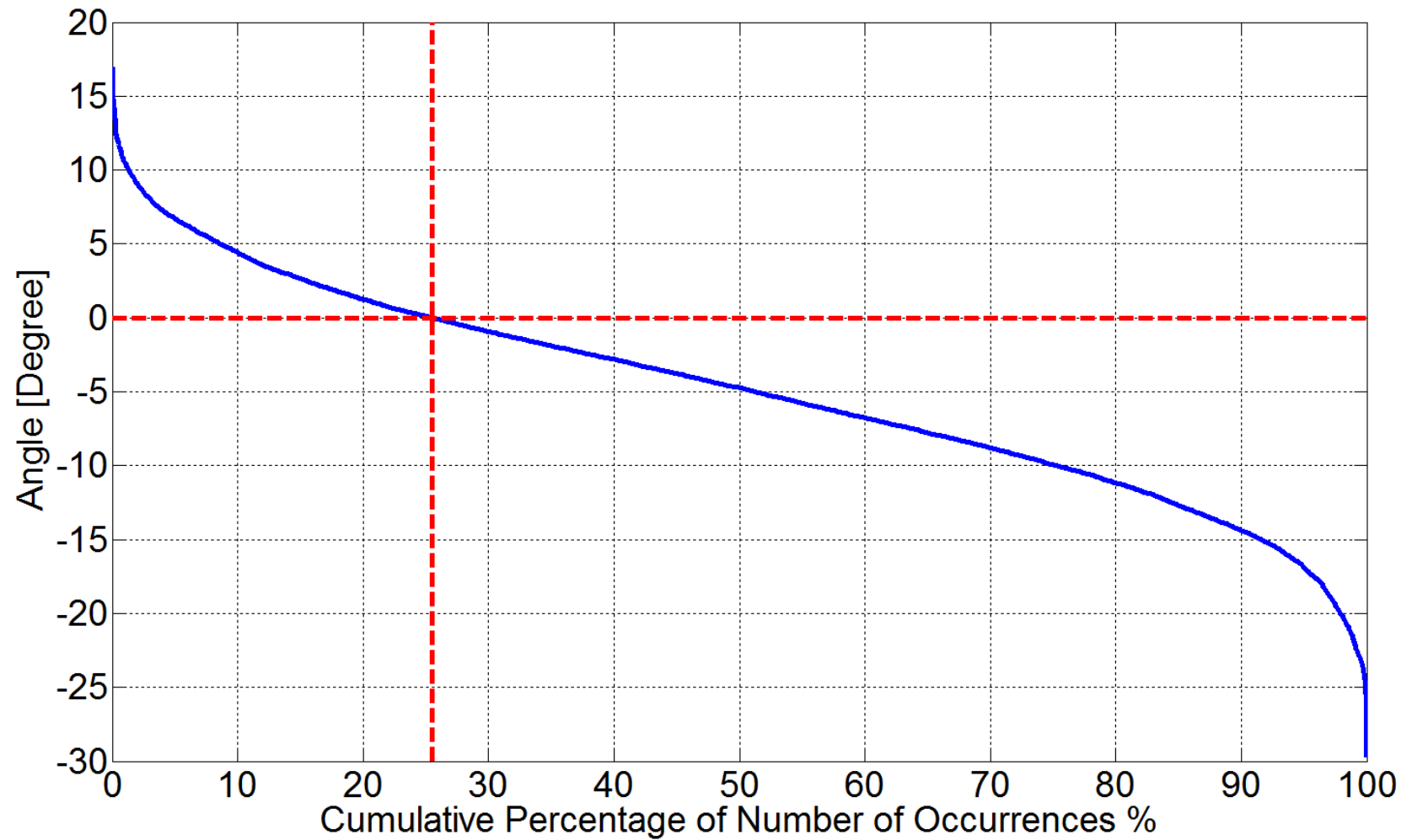
FarWest 2*-North 7



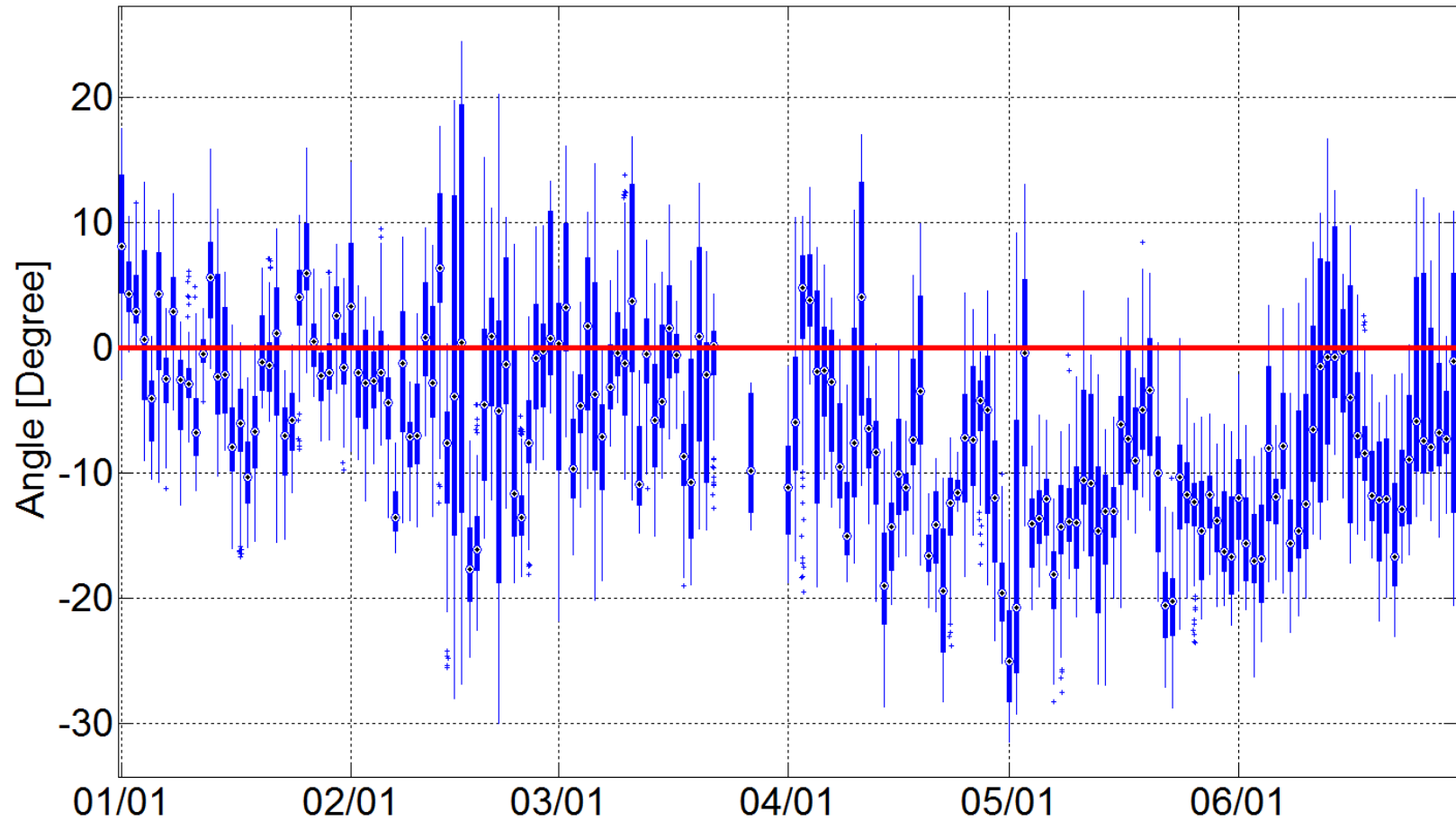
West 4-North 7



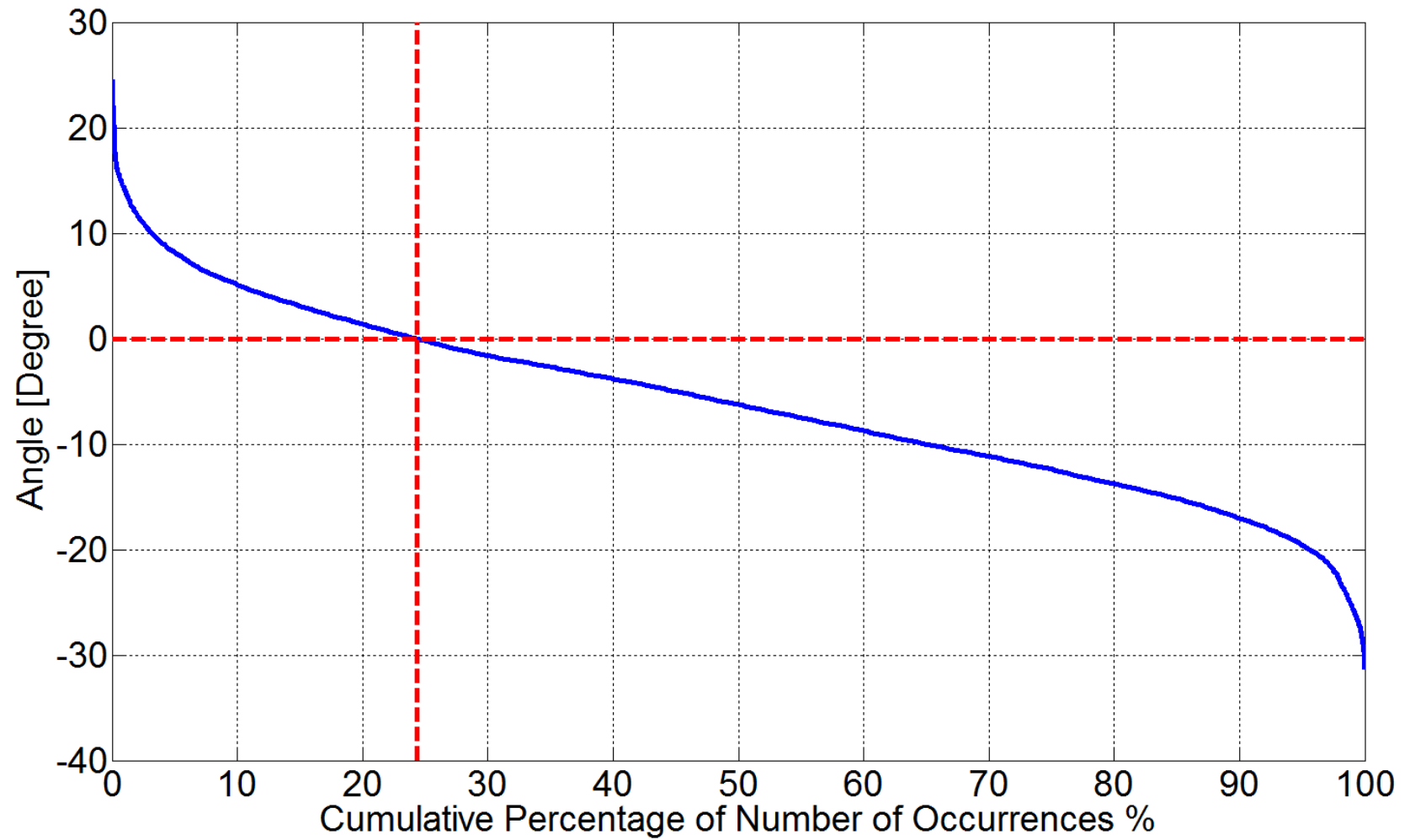
West 4-North 7



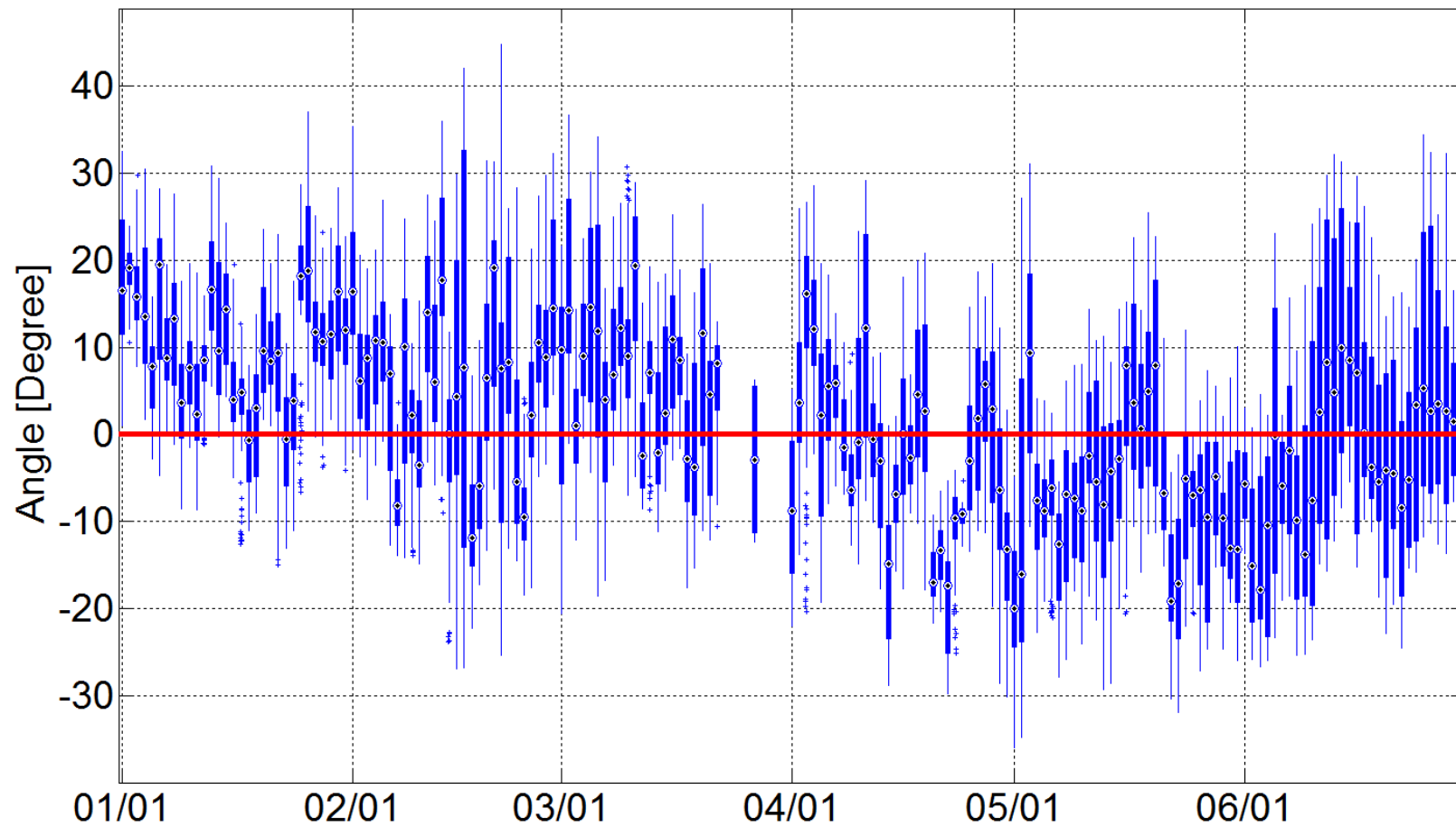
Coast 2*-North 7



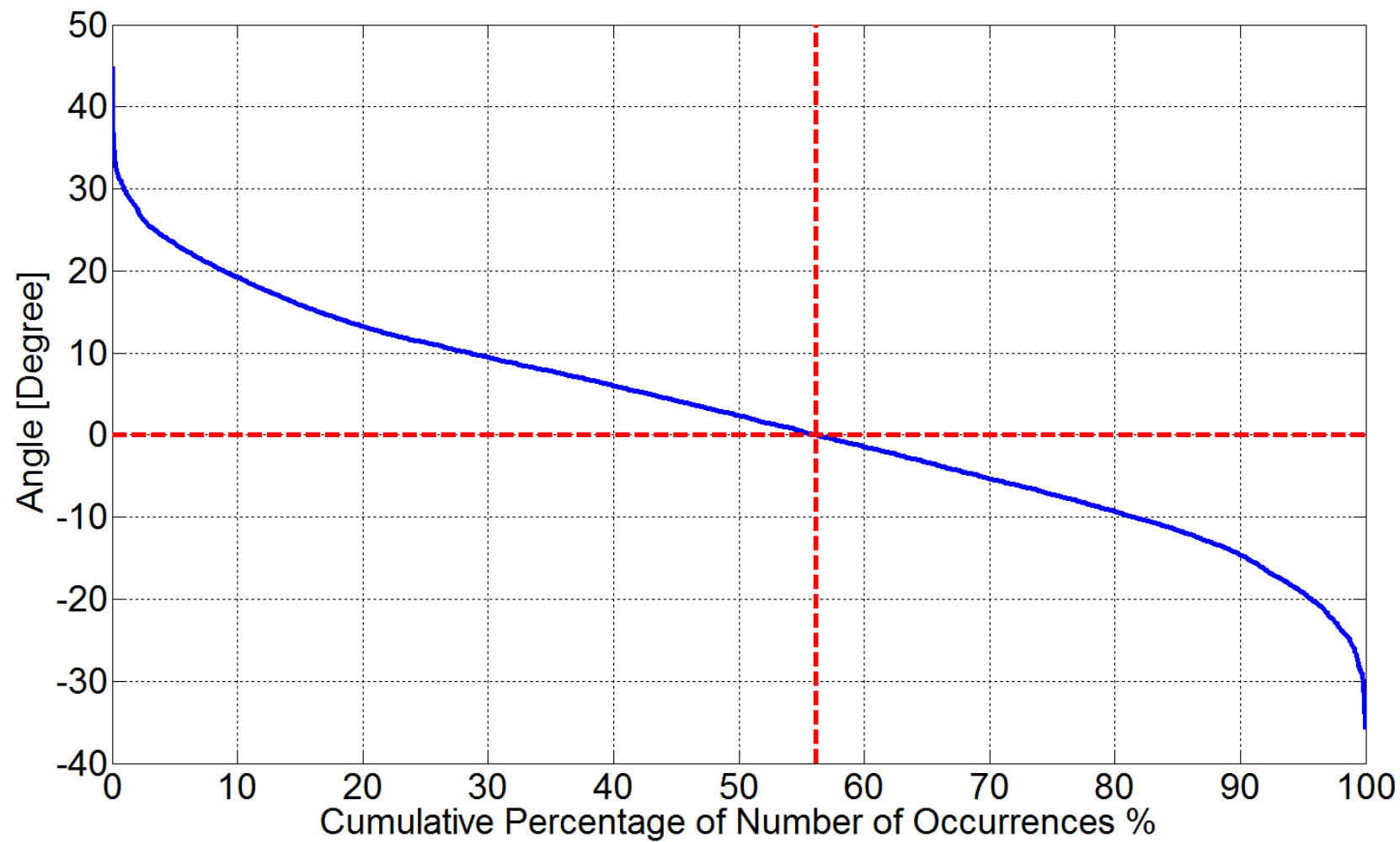
Coast 2*-North 7



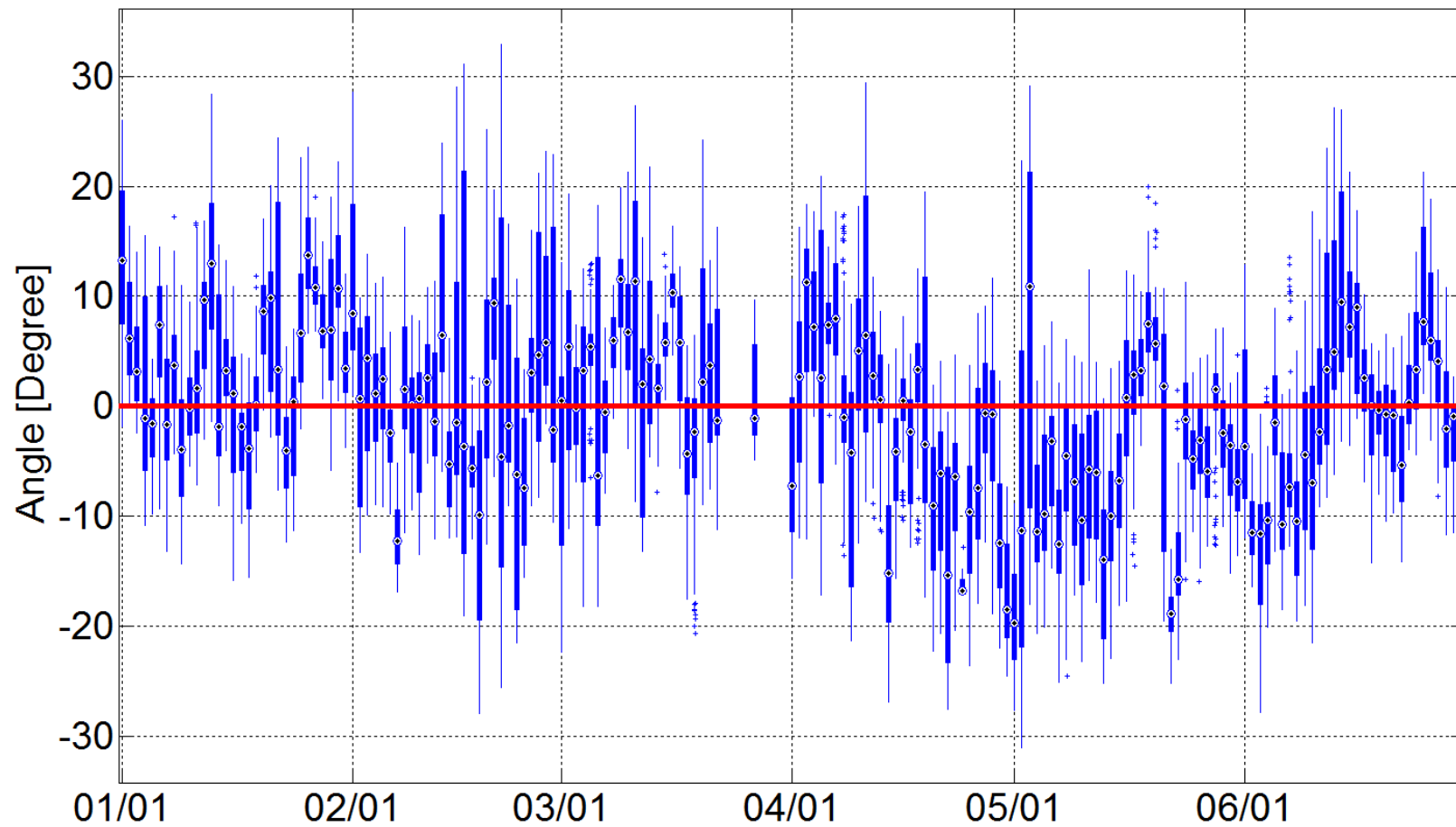
Coast 1-North 7



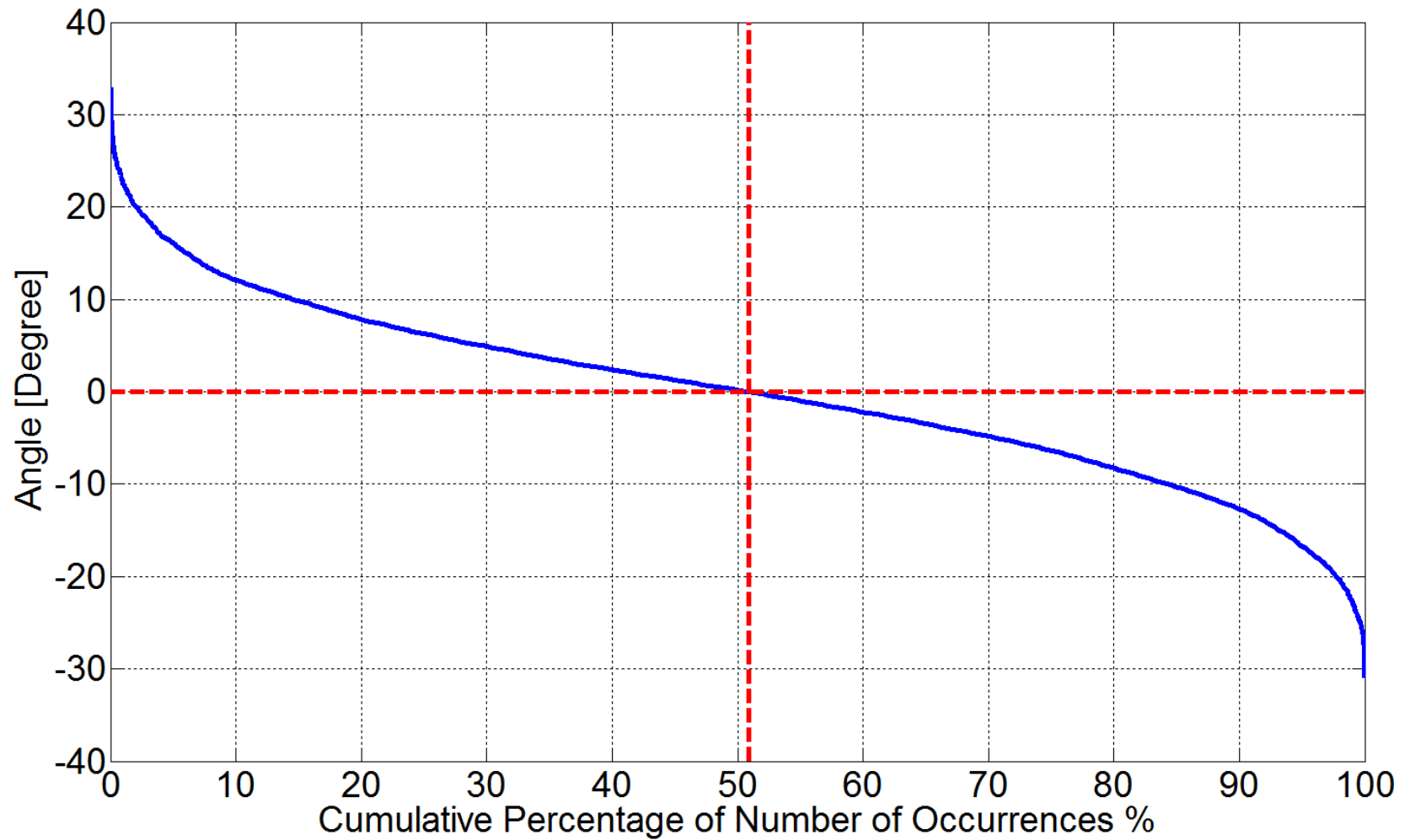
Coast 1-North 7



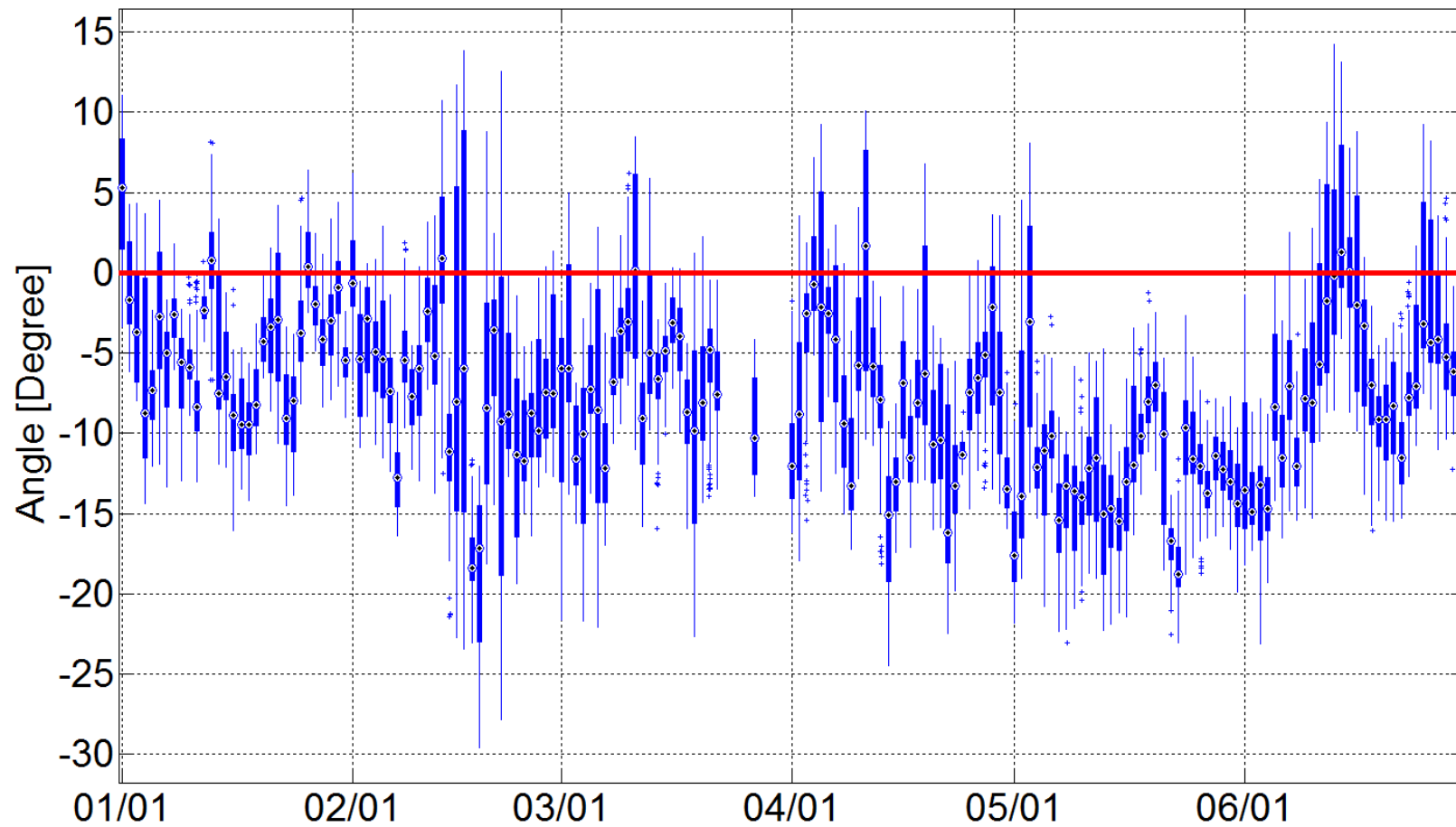
South 3*-North 7



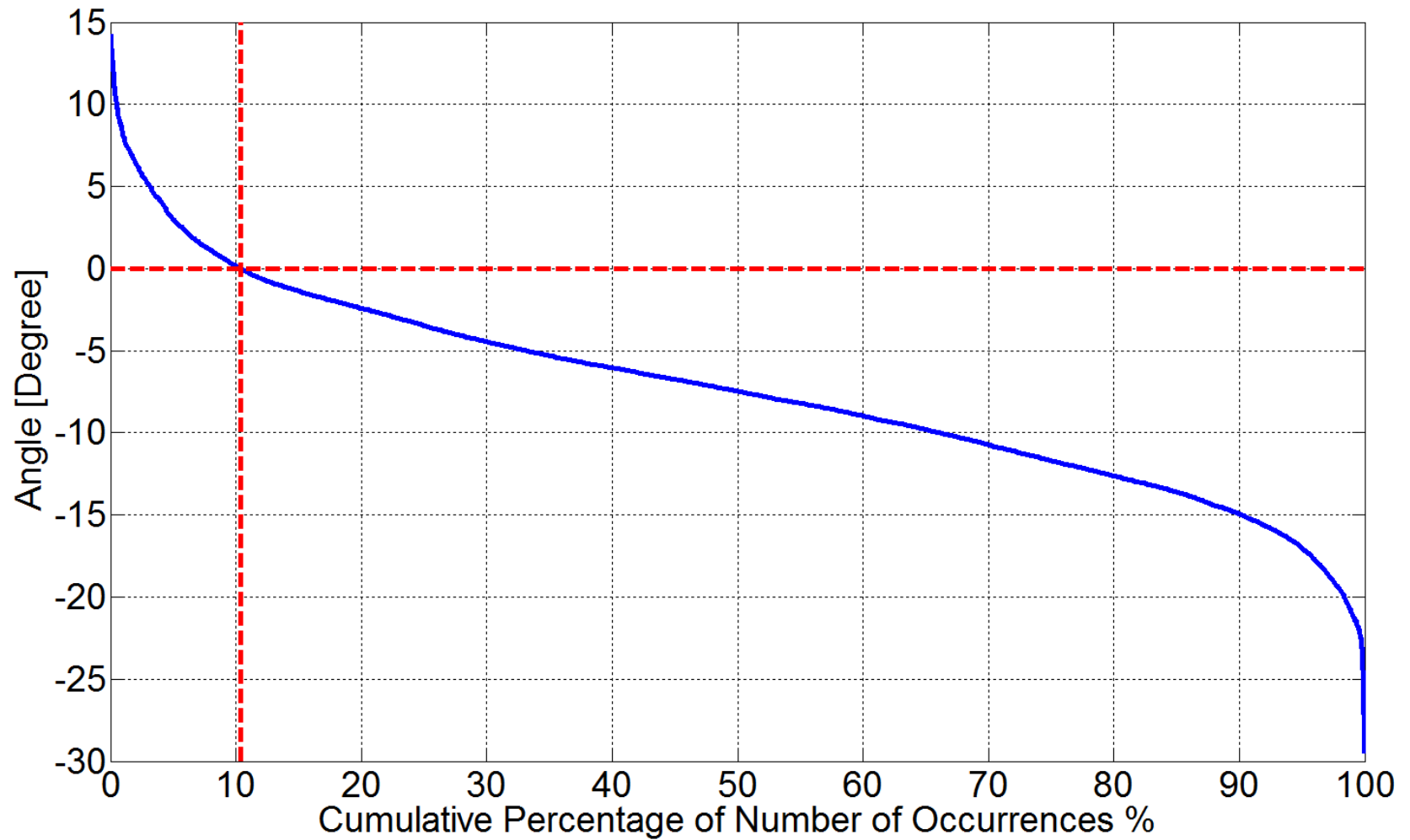
South 3*-North 7



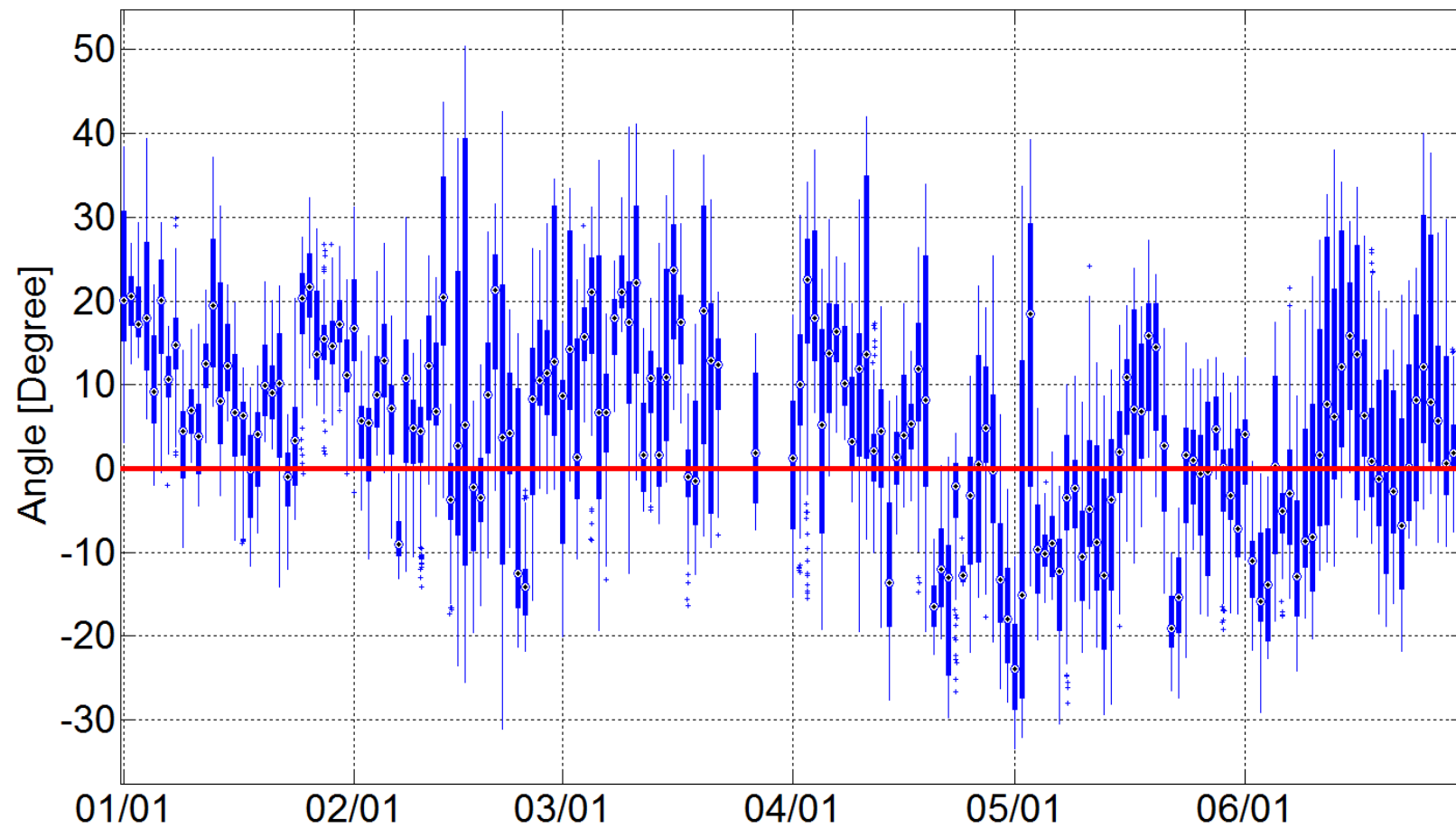
South 5*-North 7



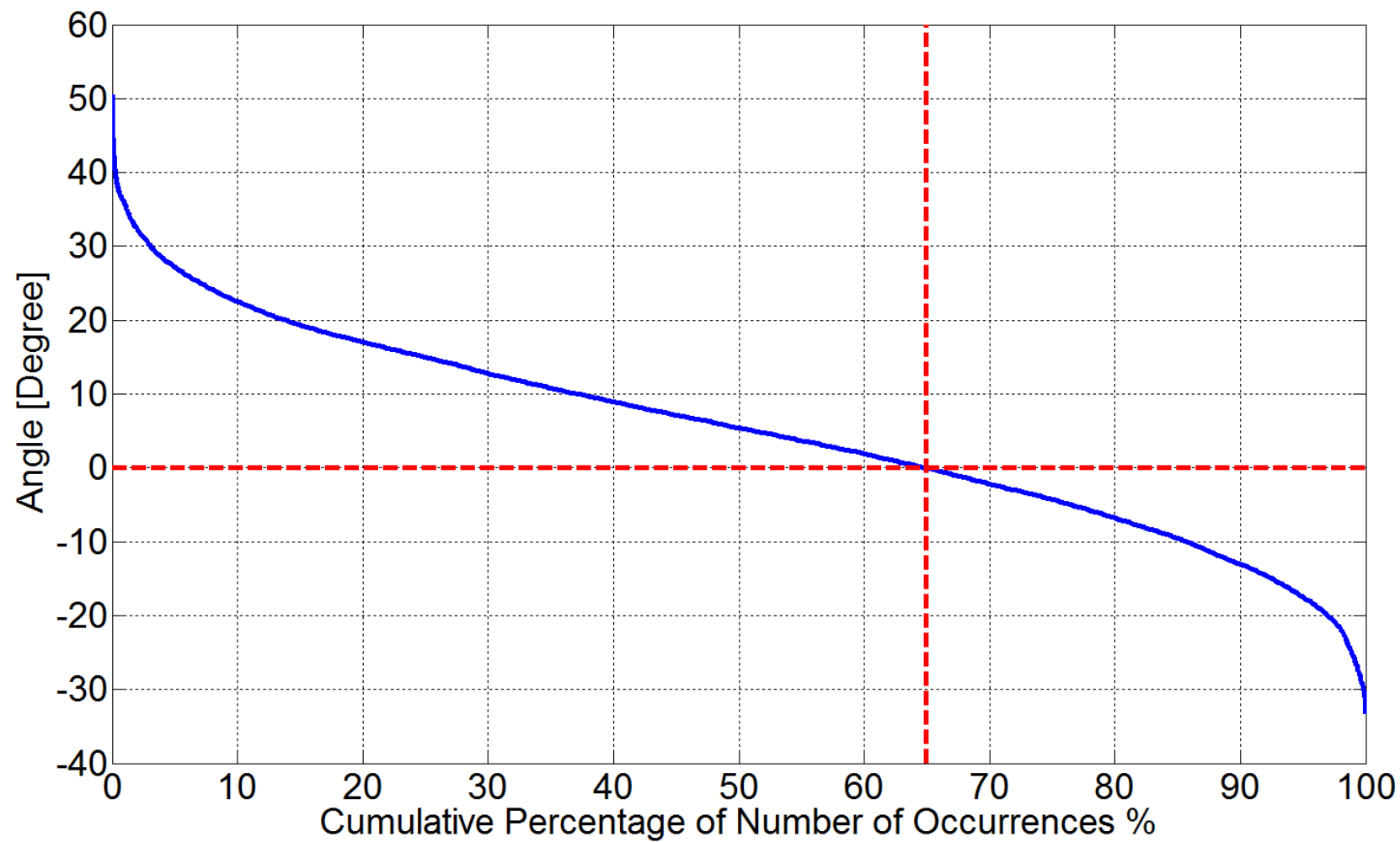
South 5*-North 7



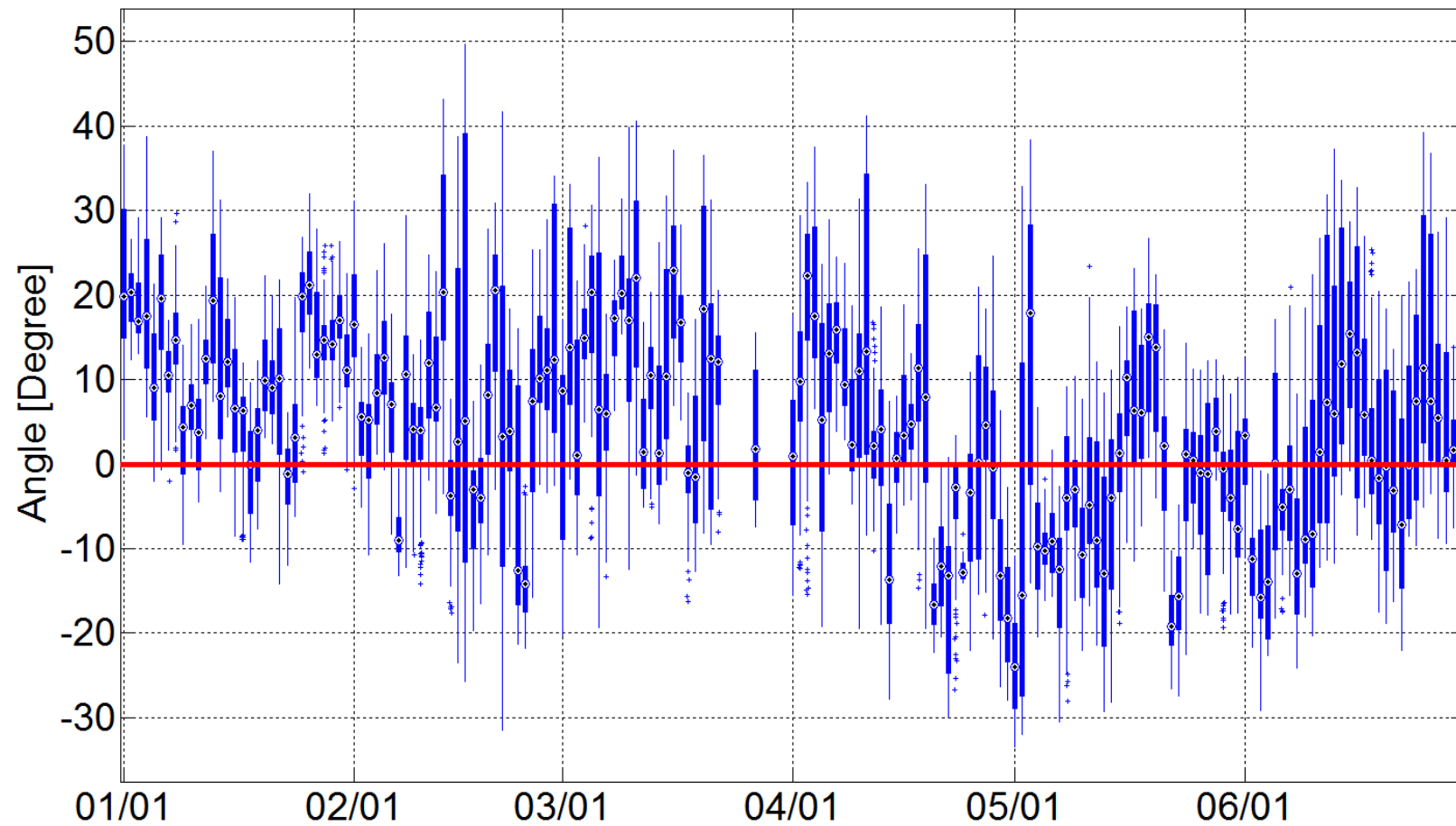
Coast 4-North 7



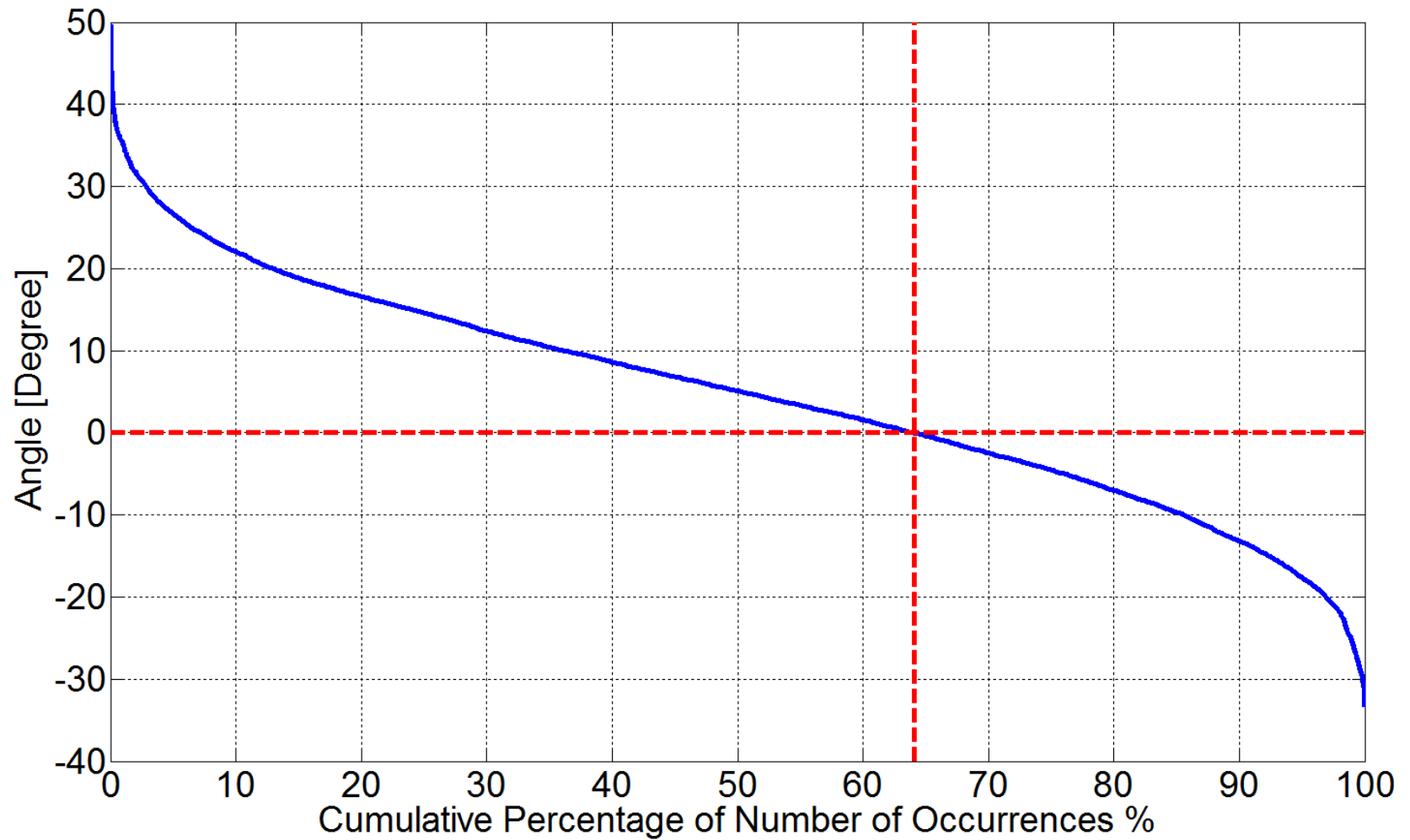
Coast 4-North 7



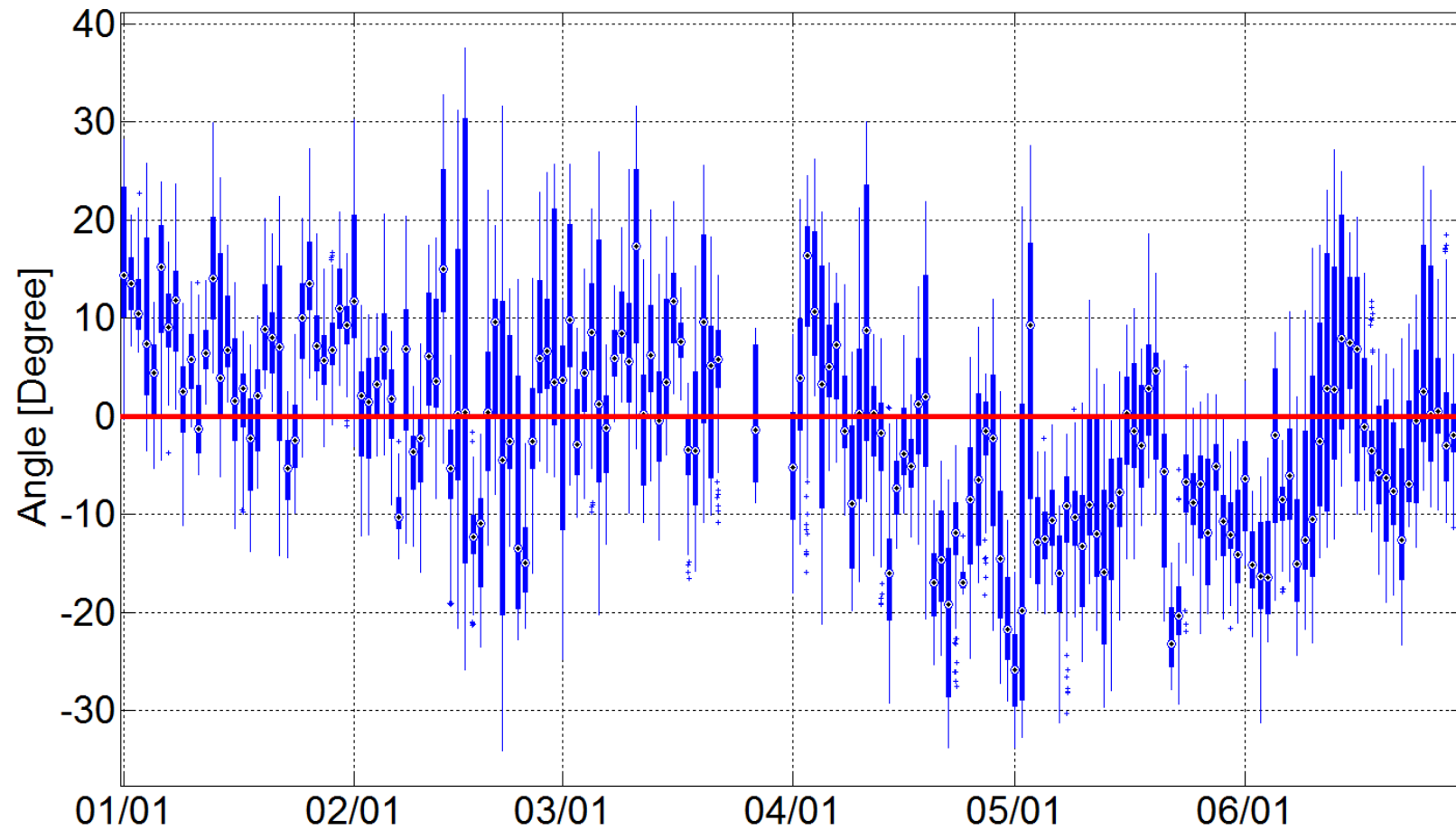
Coast 3-North 7



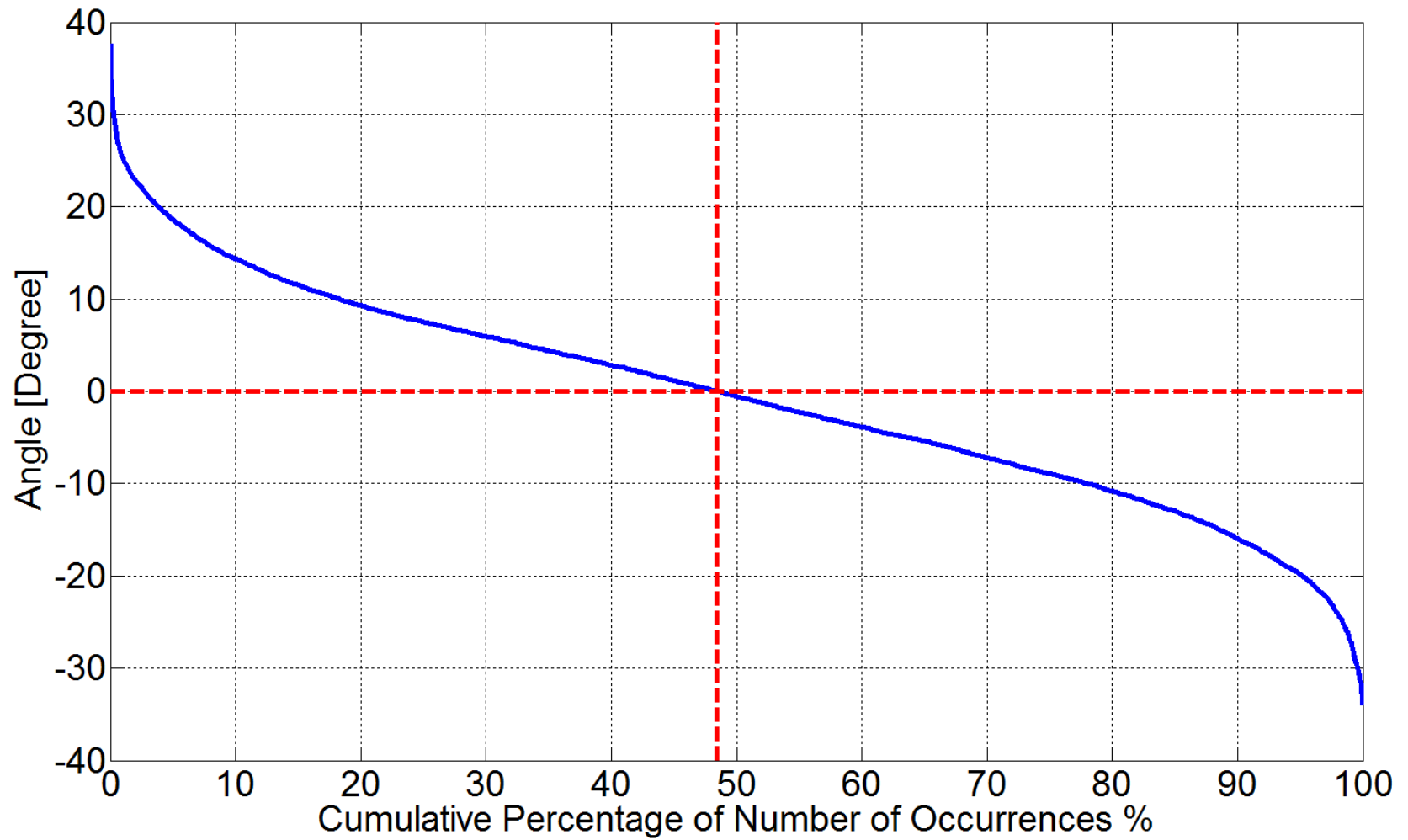
Coast 3-North 7



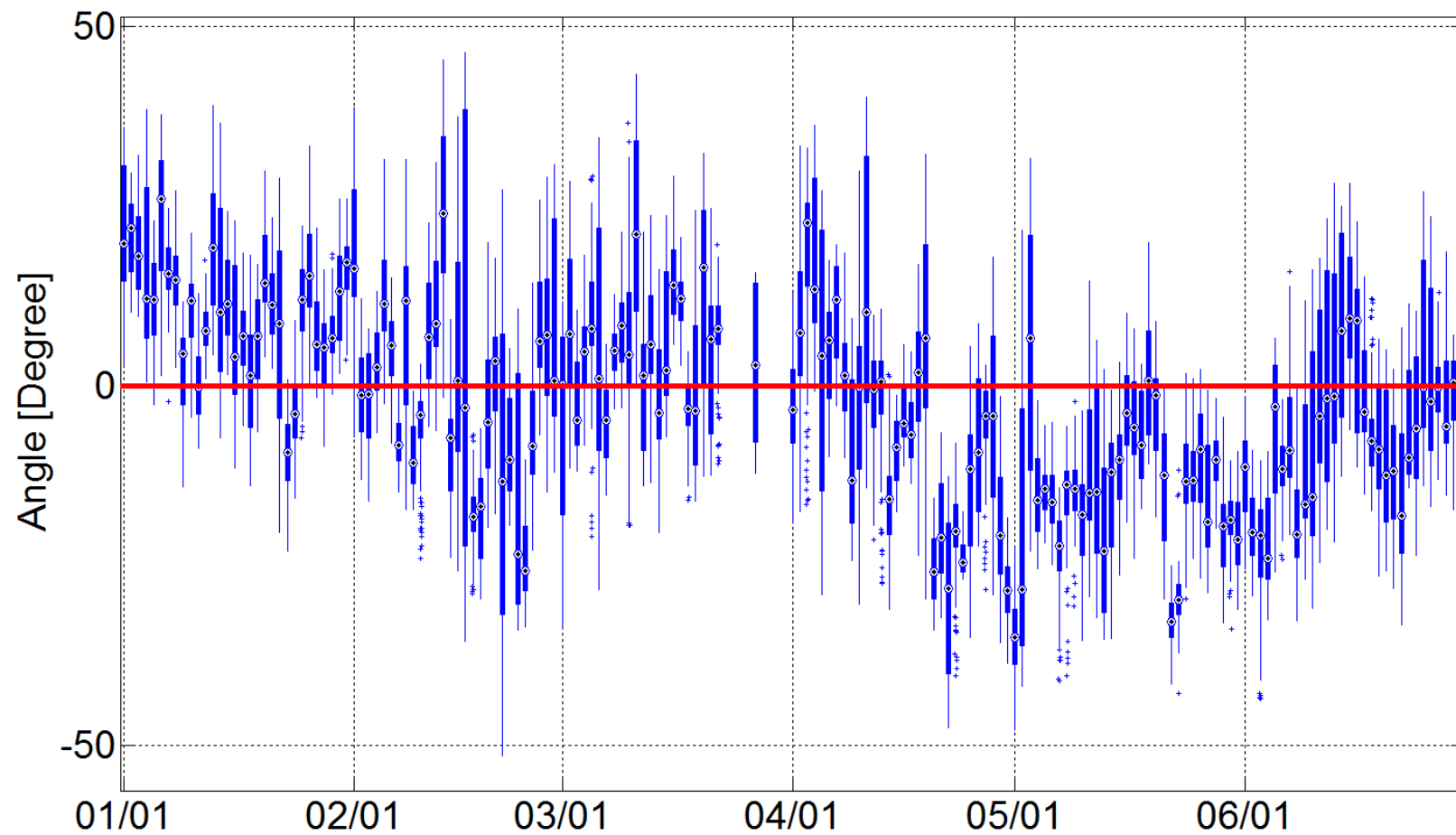
South 6*-North 7



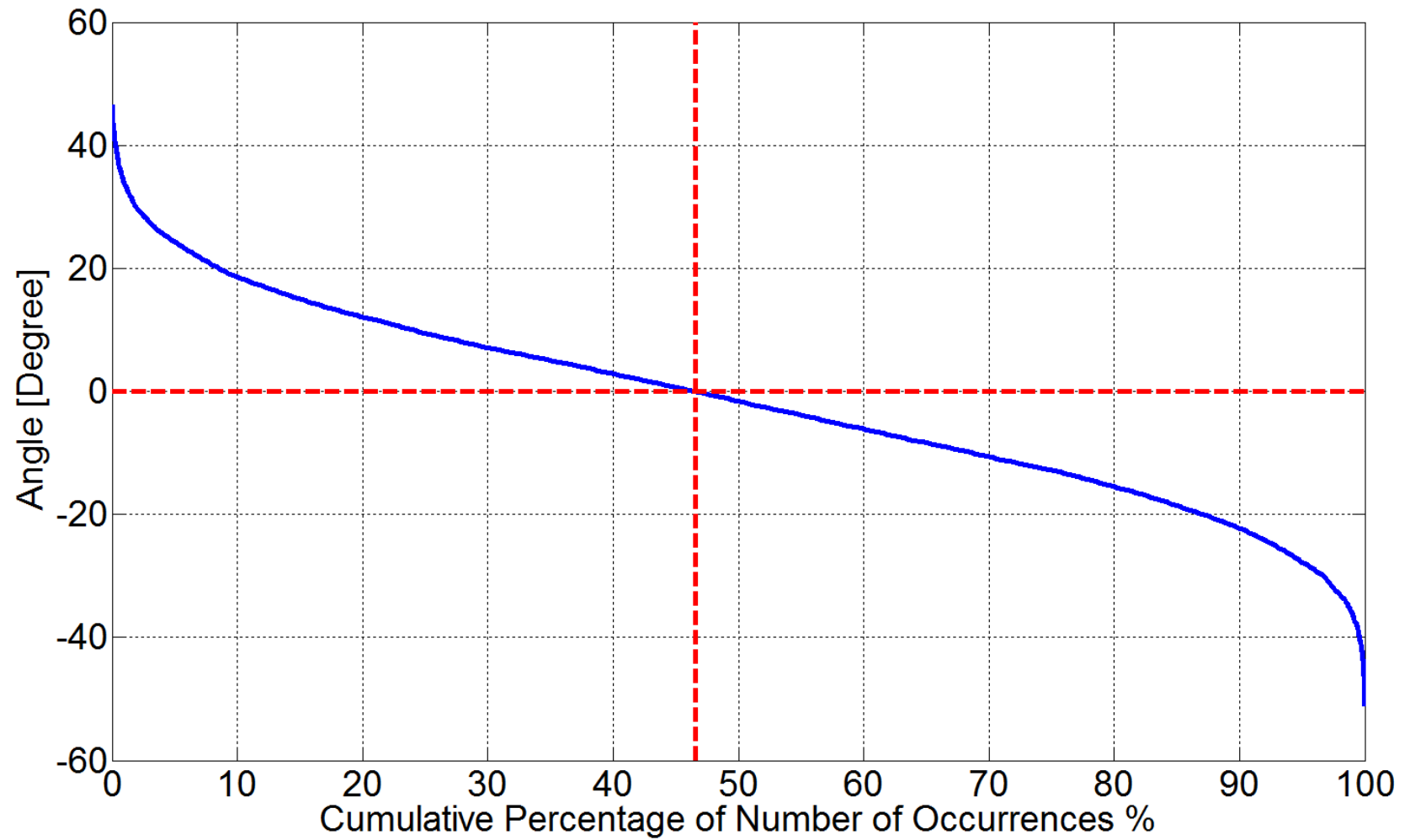
South 6*-North 7



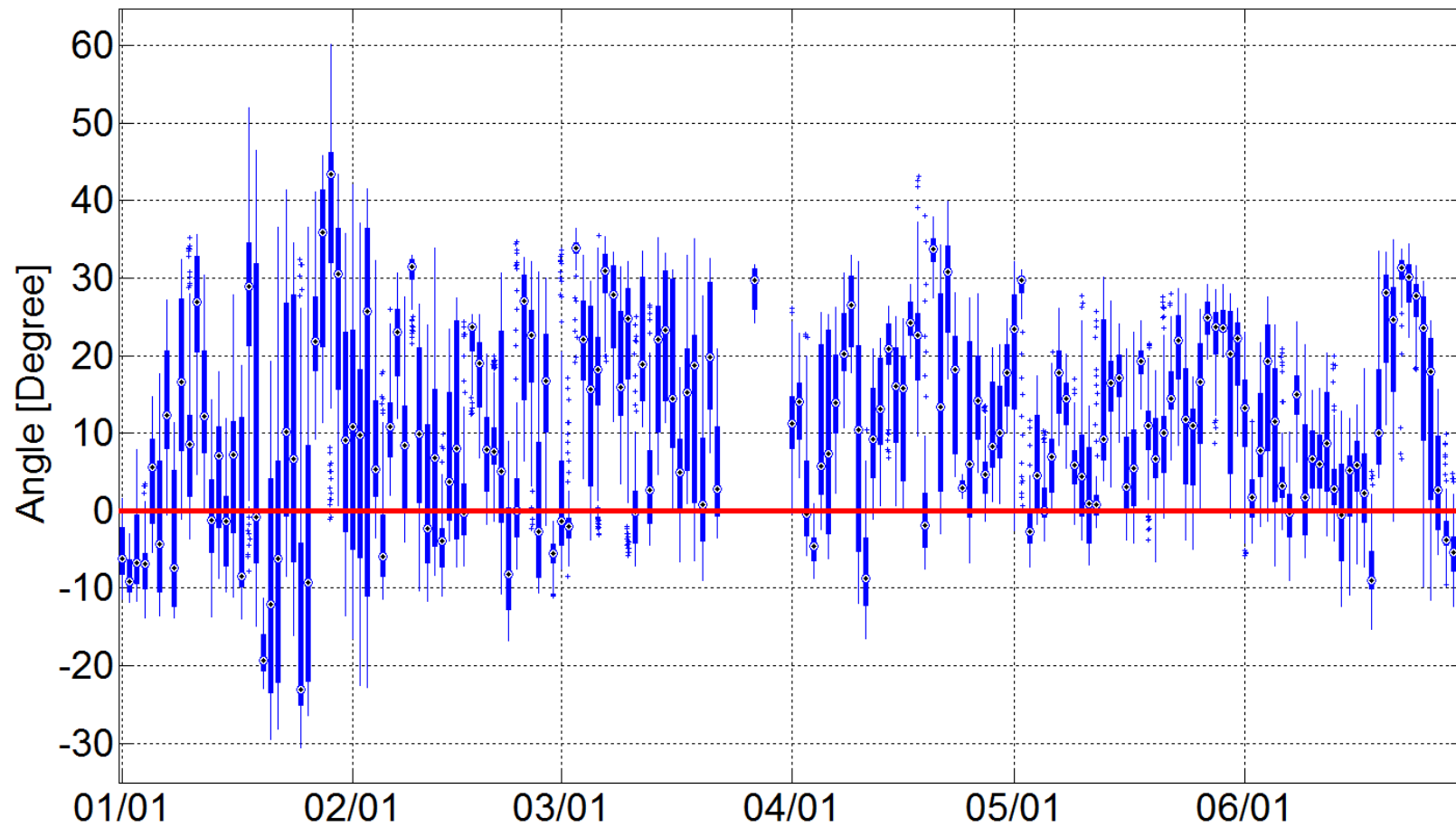
South 13-North 7



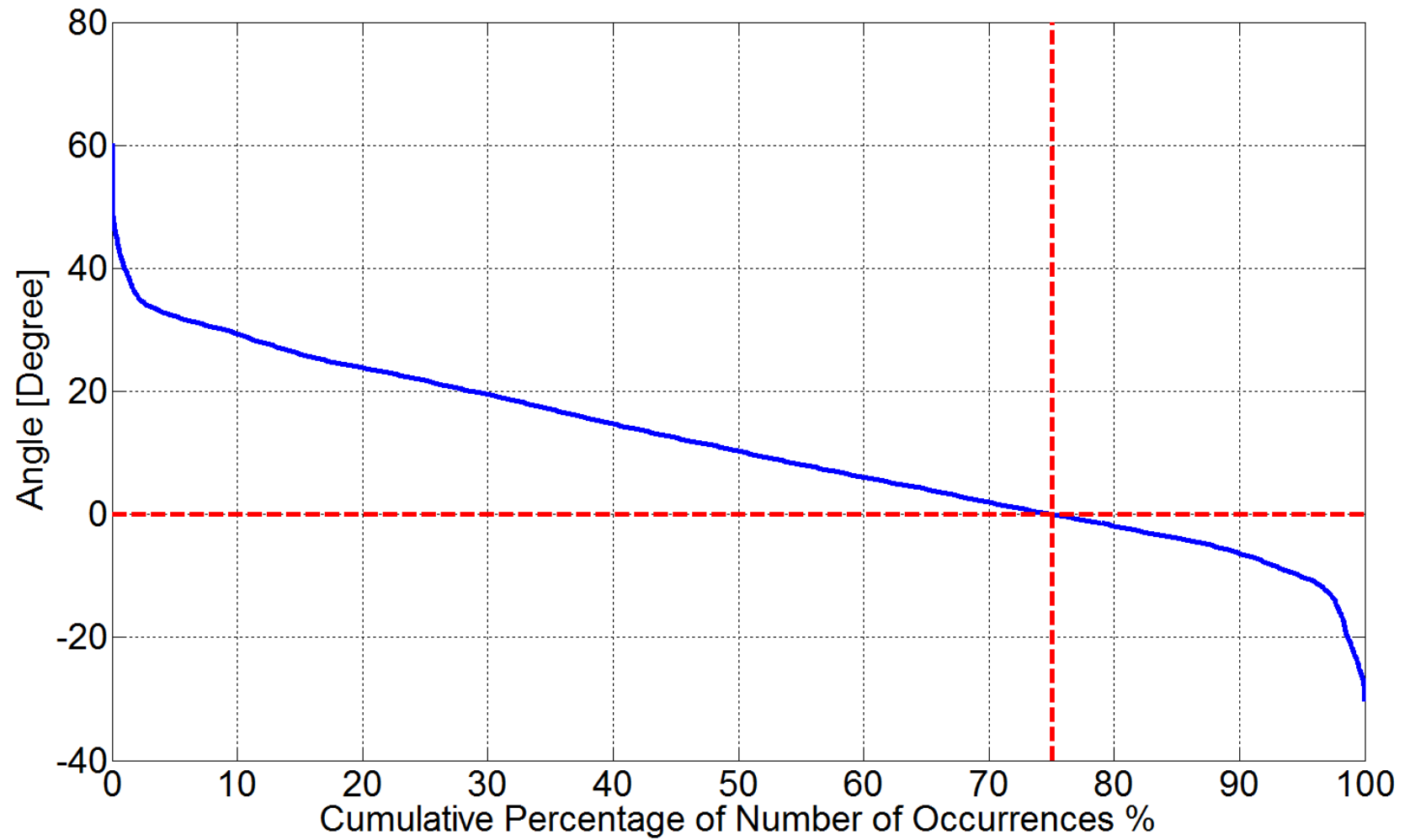
South 13-North 7



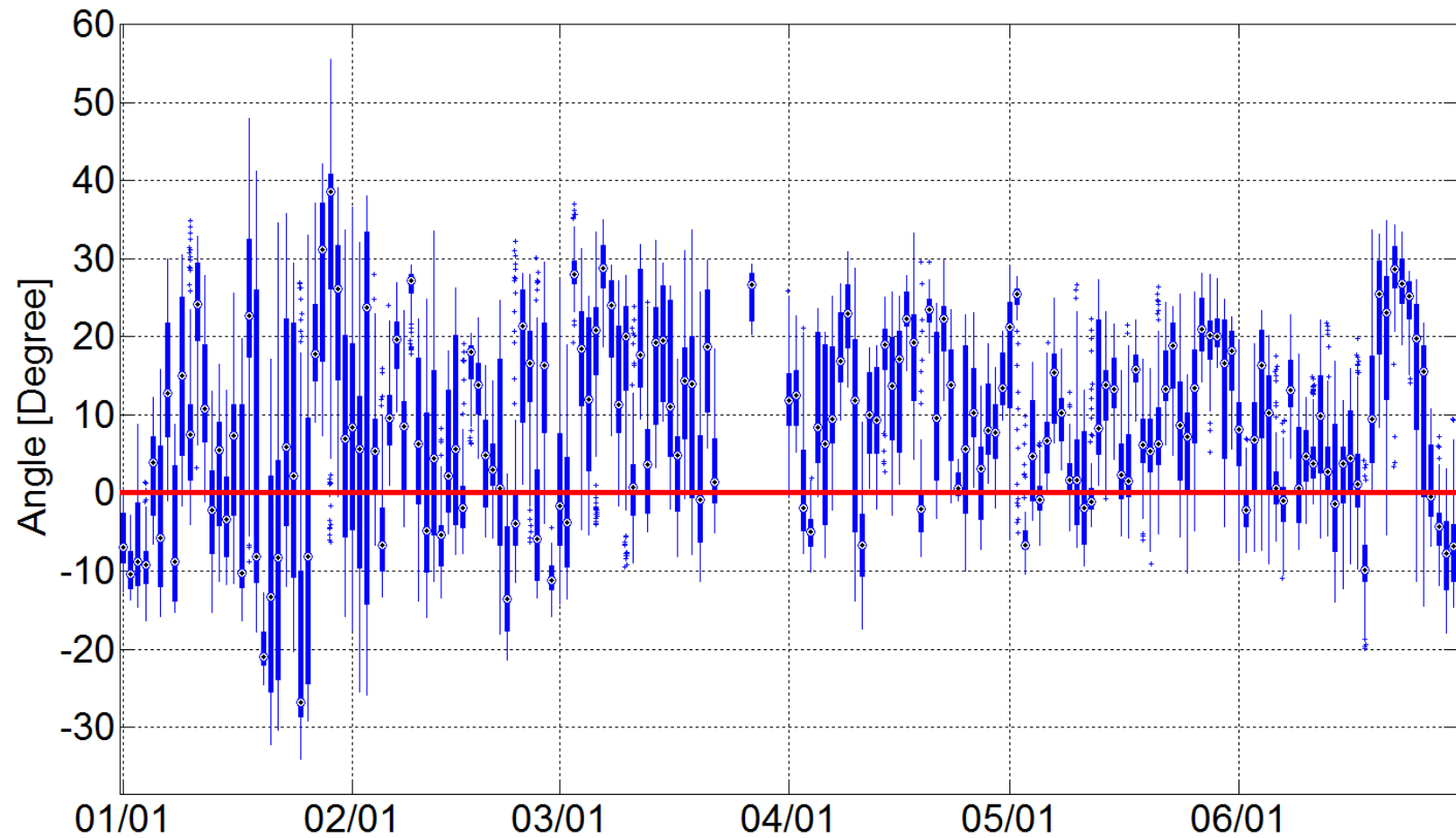
FarWest 4-North 7



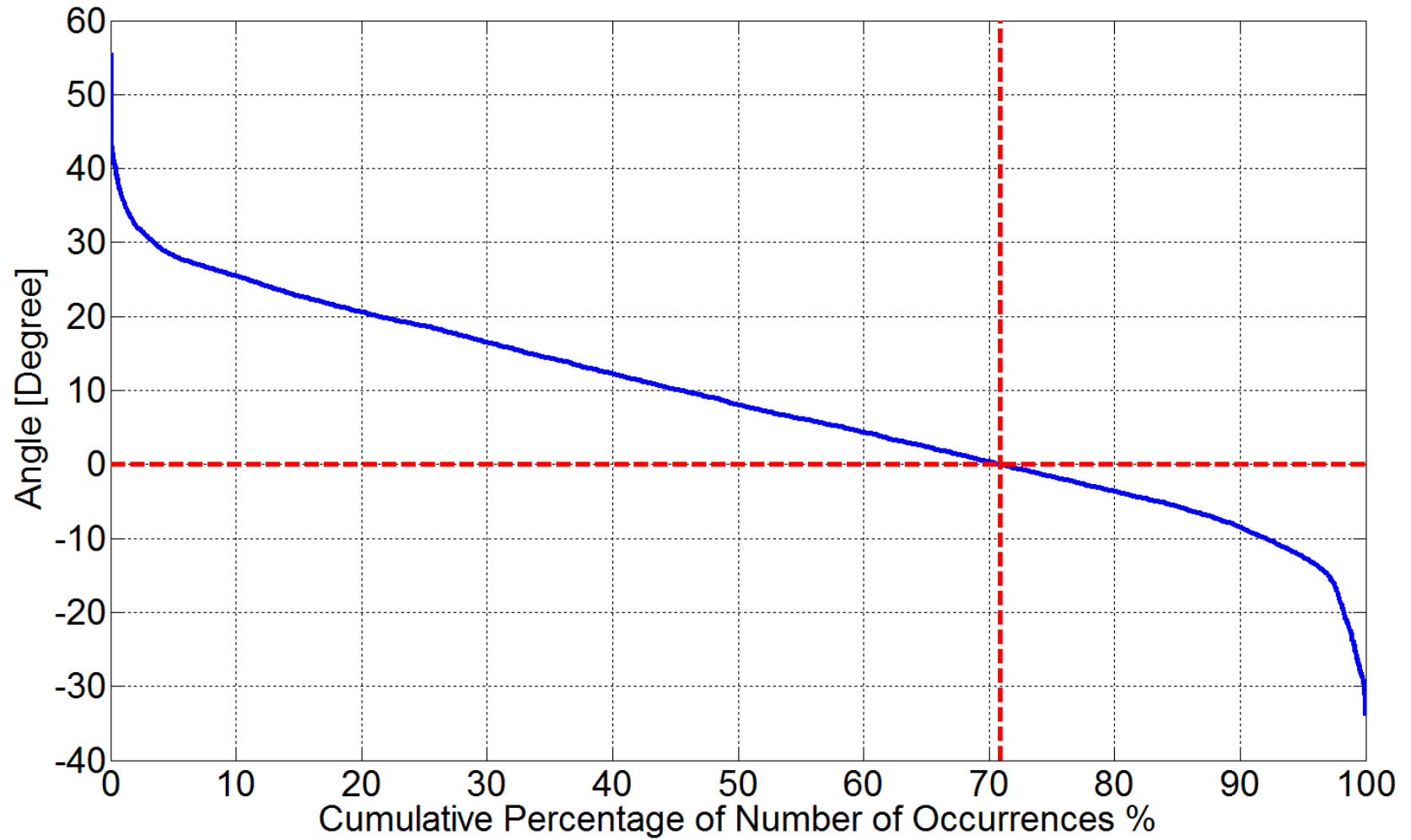
FarWest 4-North 7



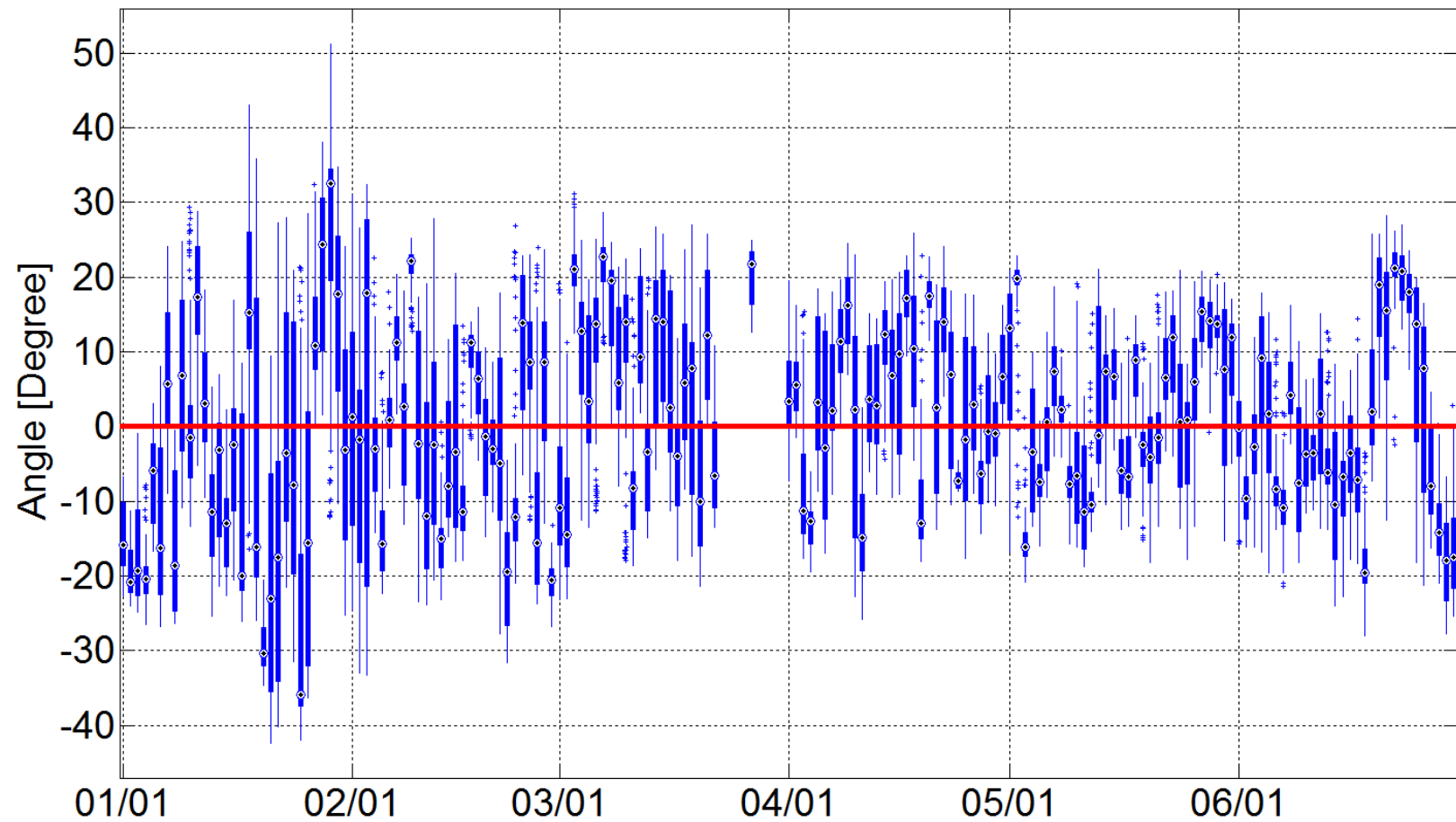
FarWest 7-North 7



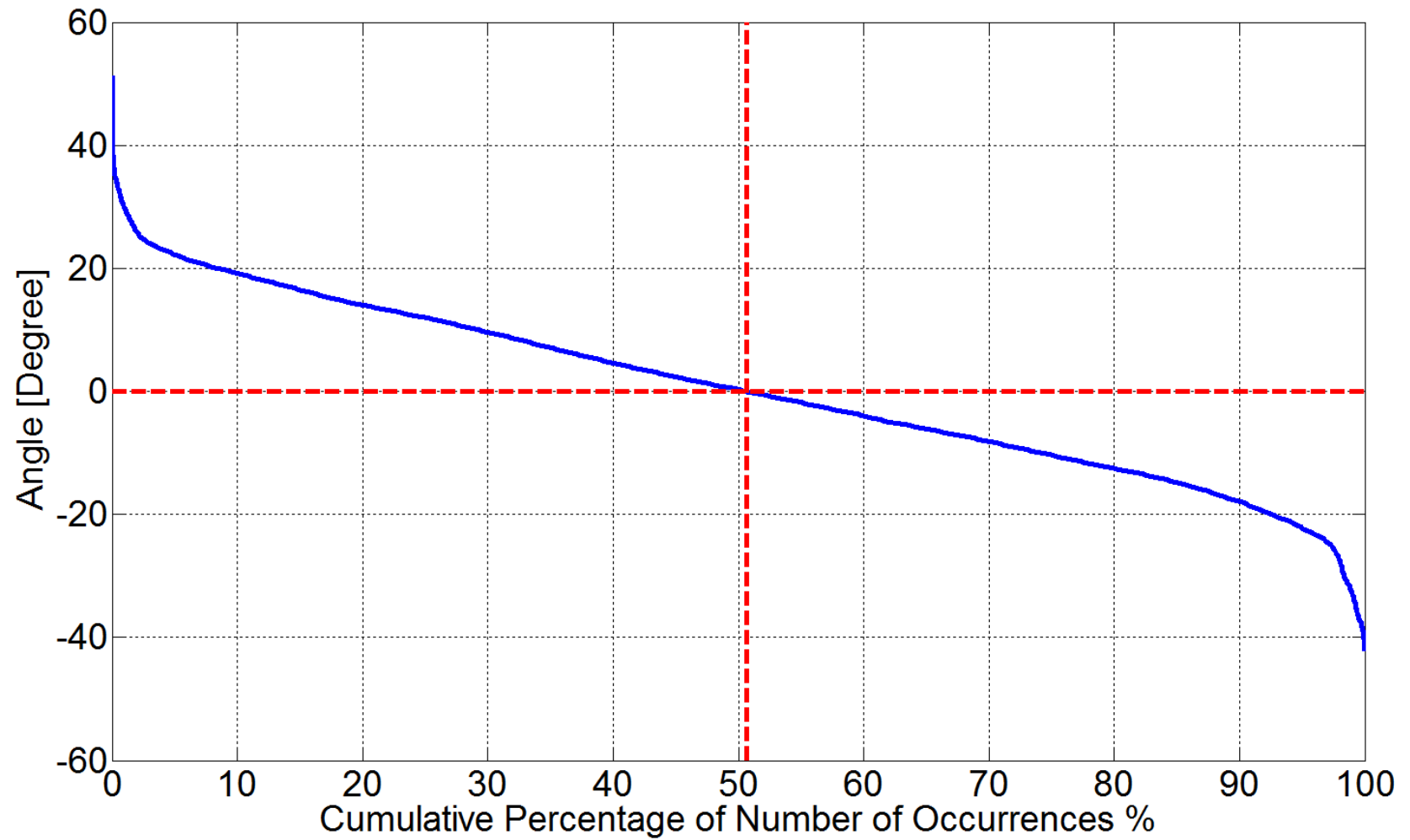
FarWest 7-North 7



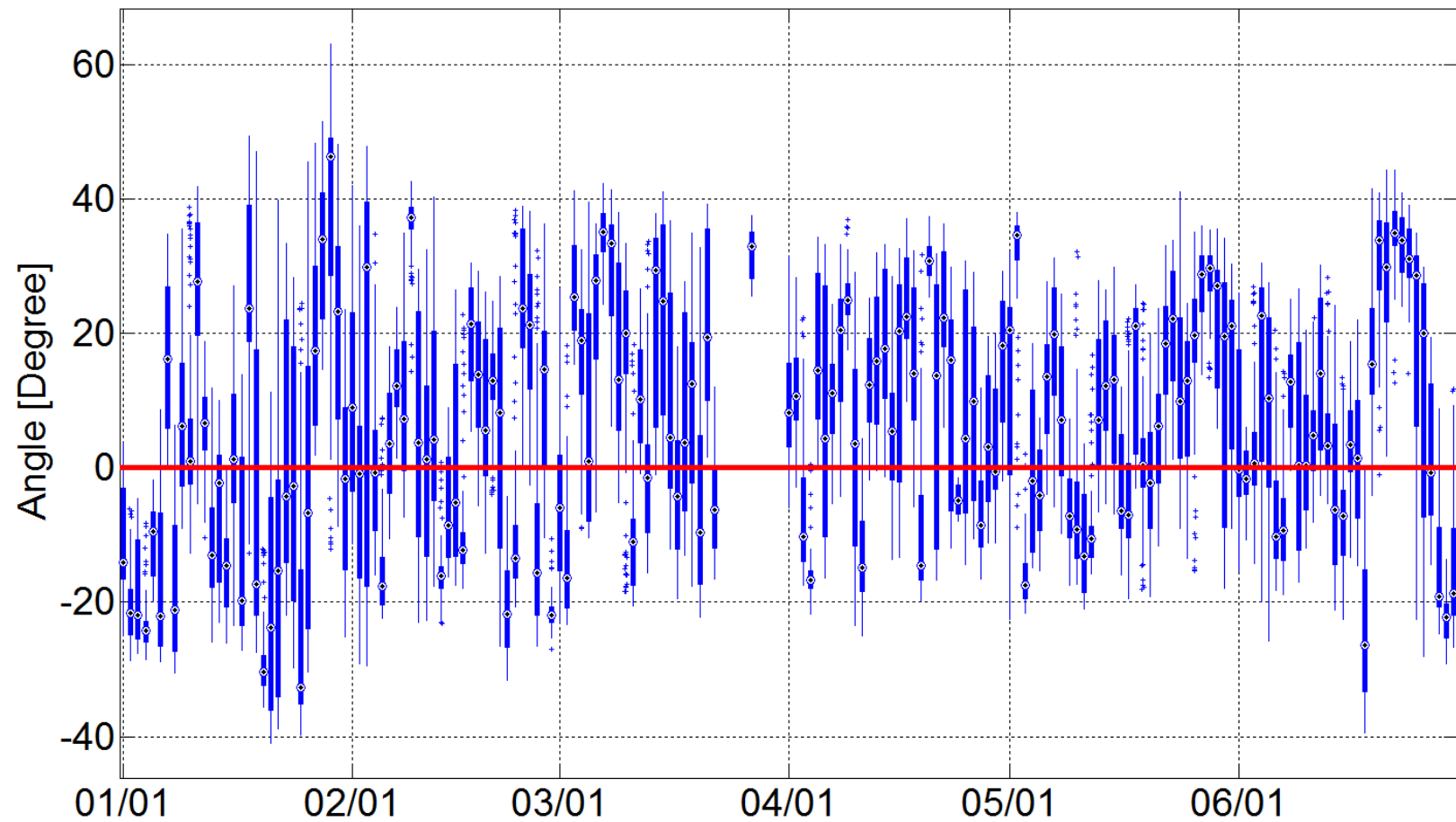
FarWest 8-North 7



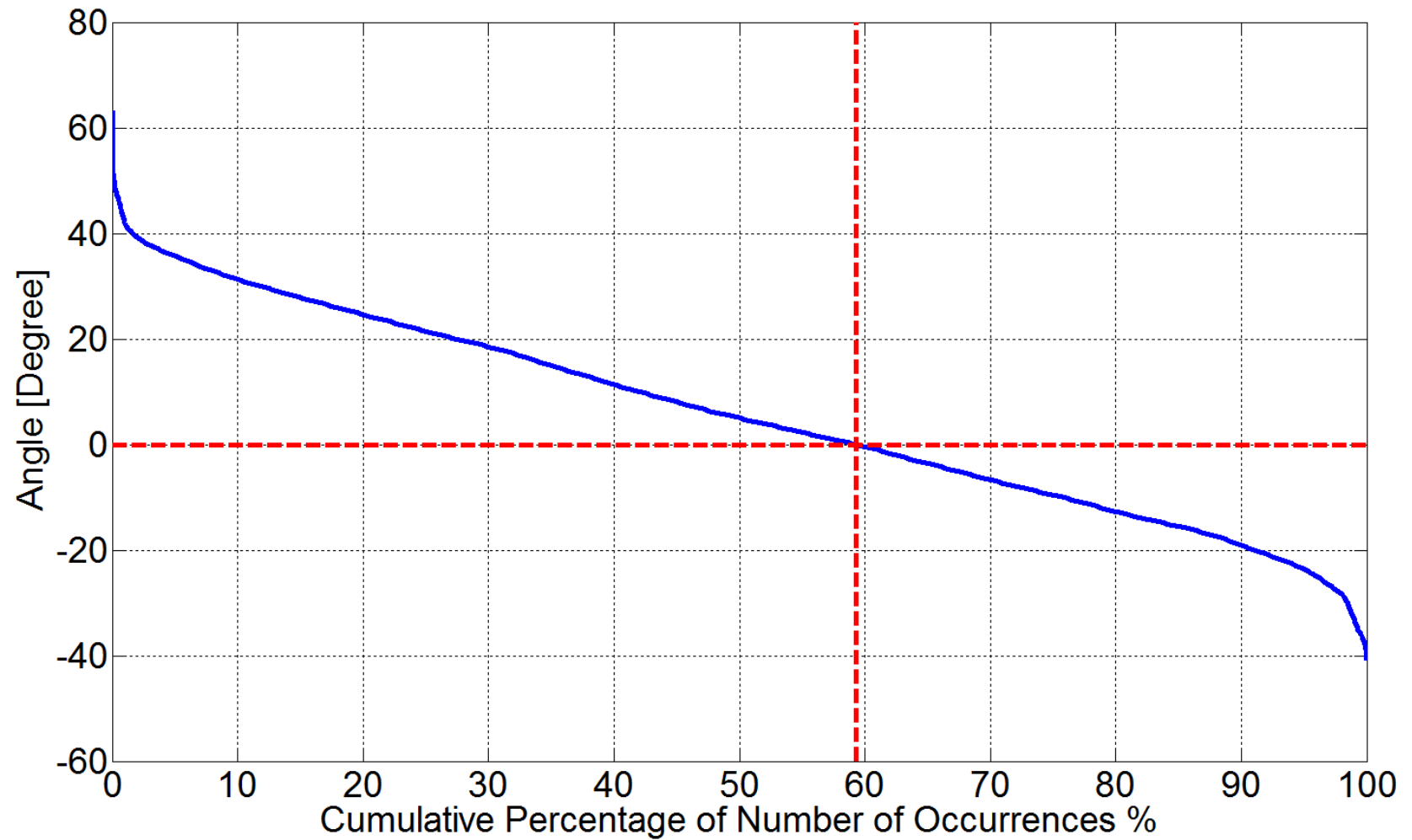
FarWest 8-North 7



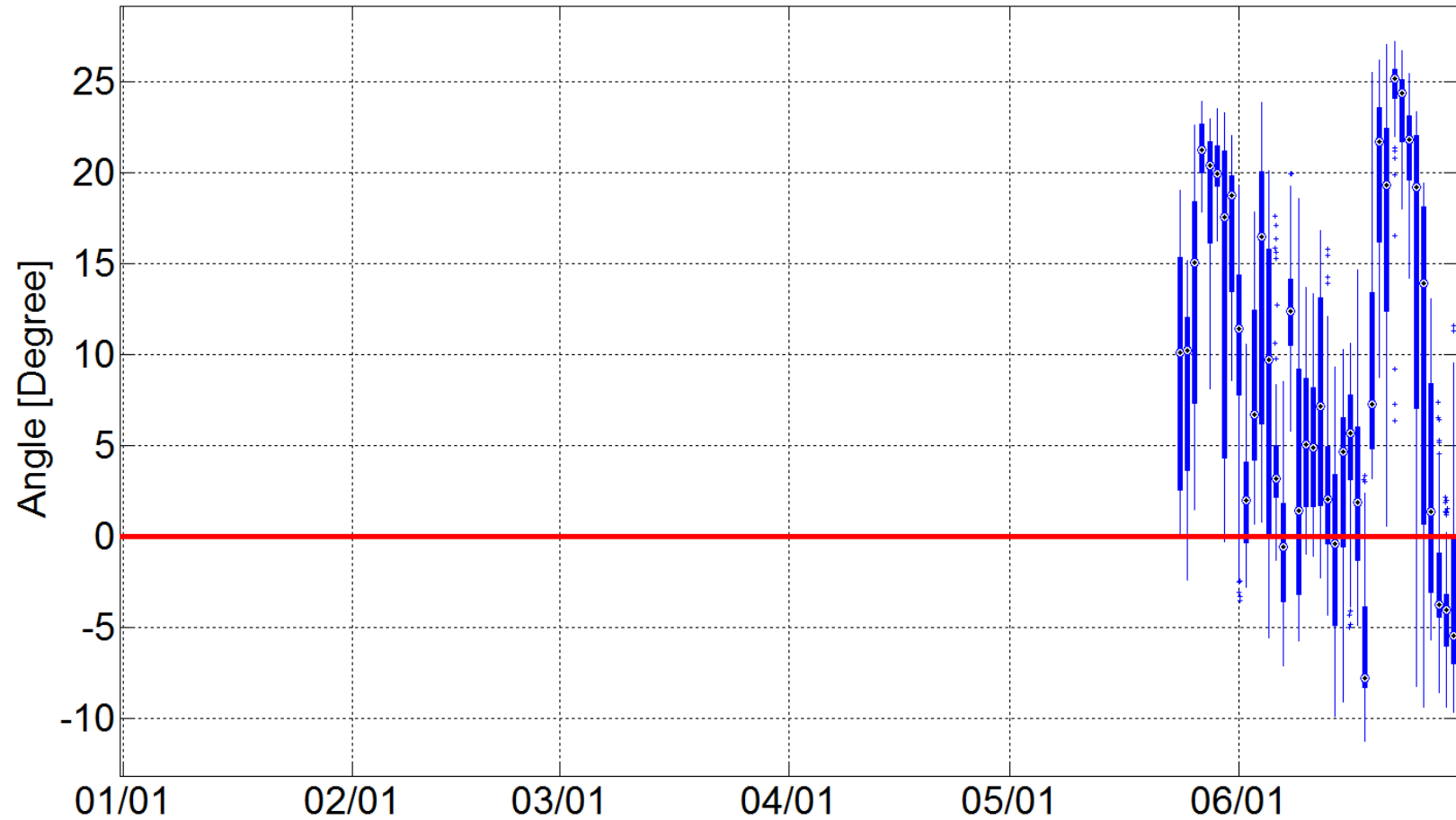
FarWest 9-North 7



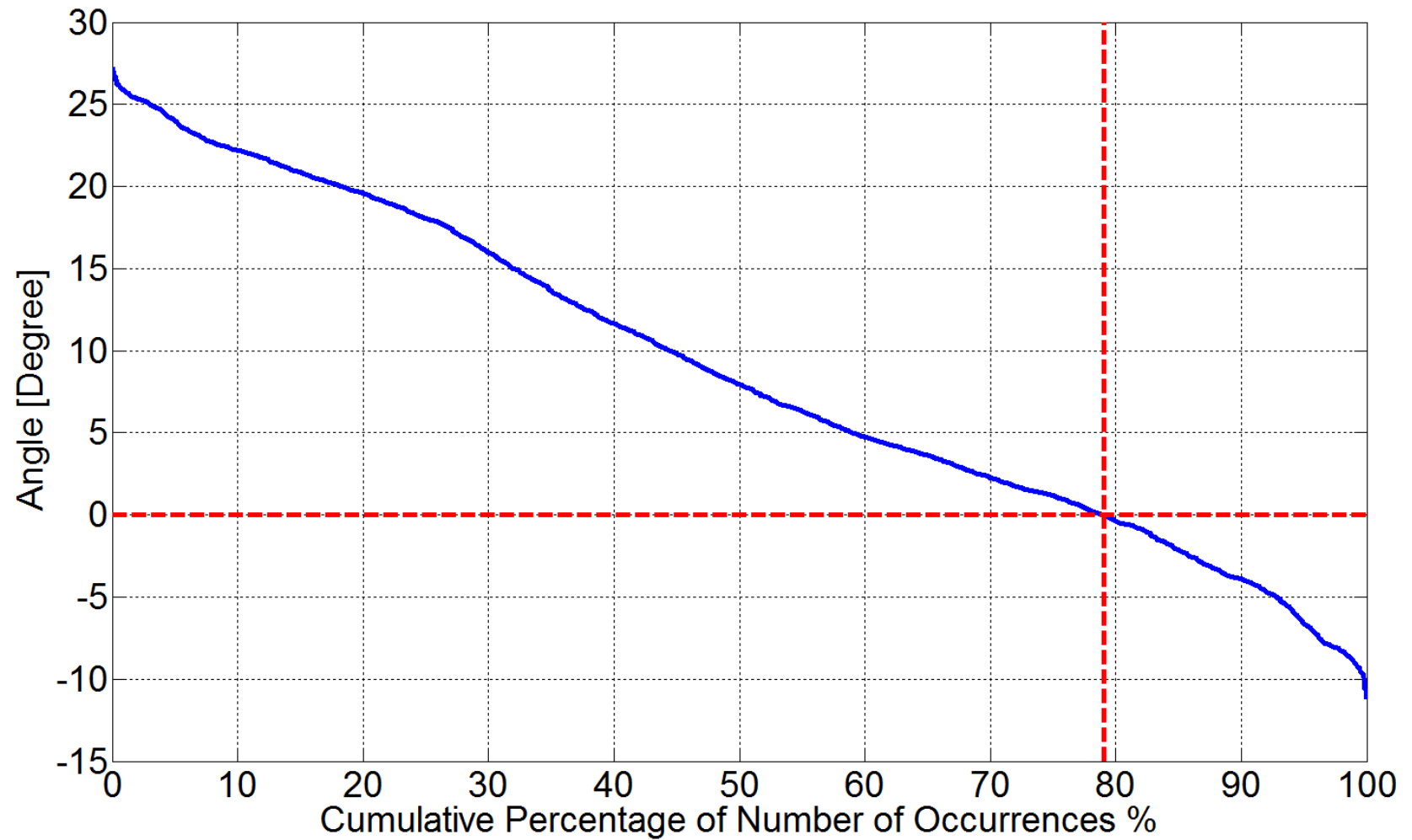
FarWest 9-North 7



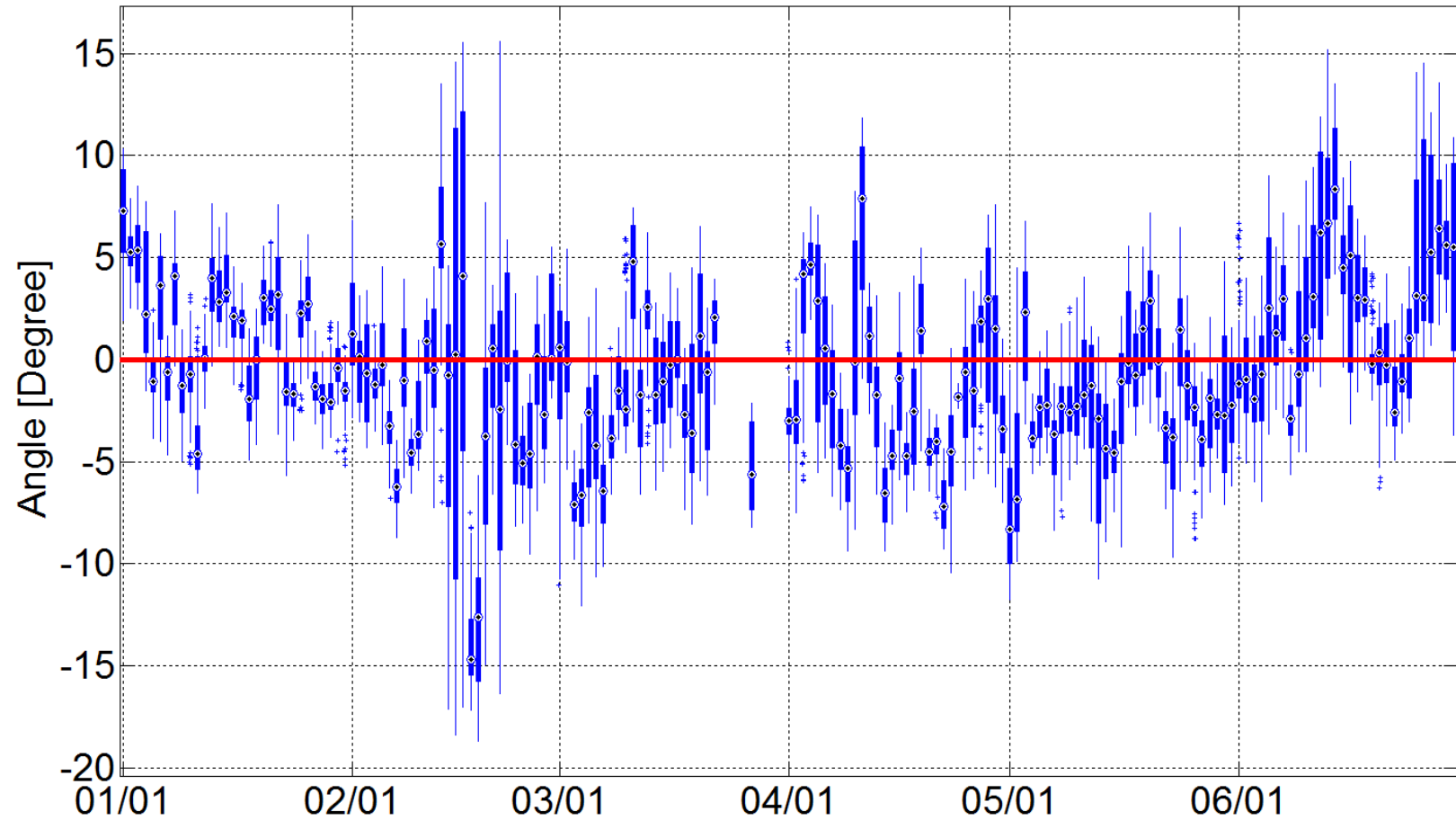
West 8*-North 7



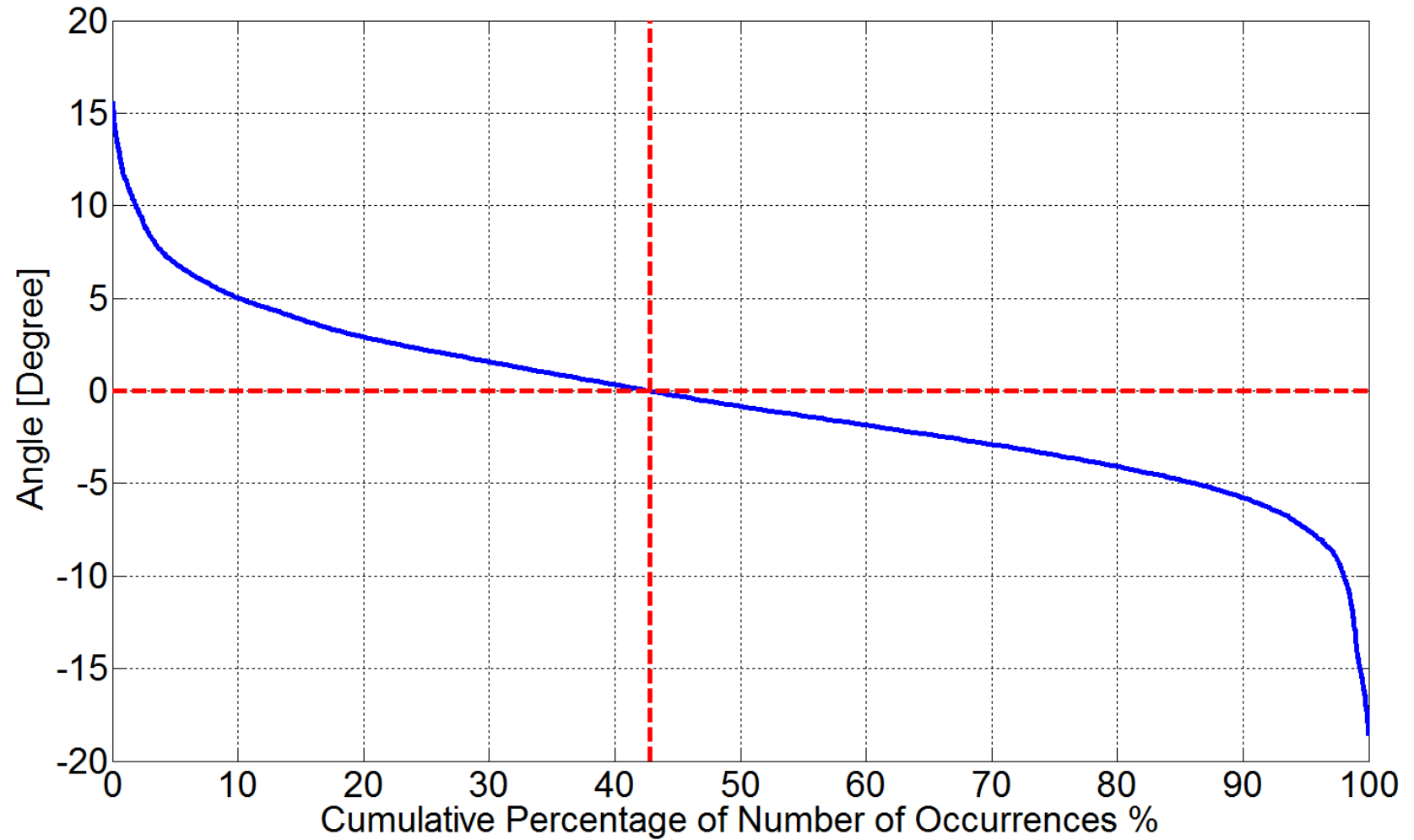
West 8*-North 7



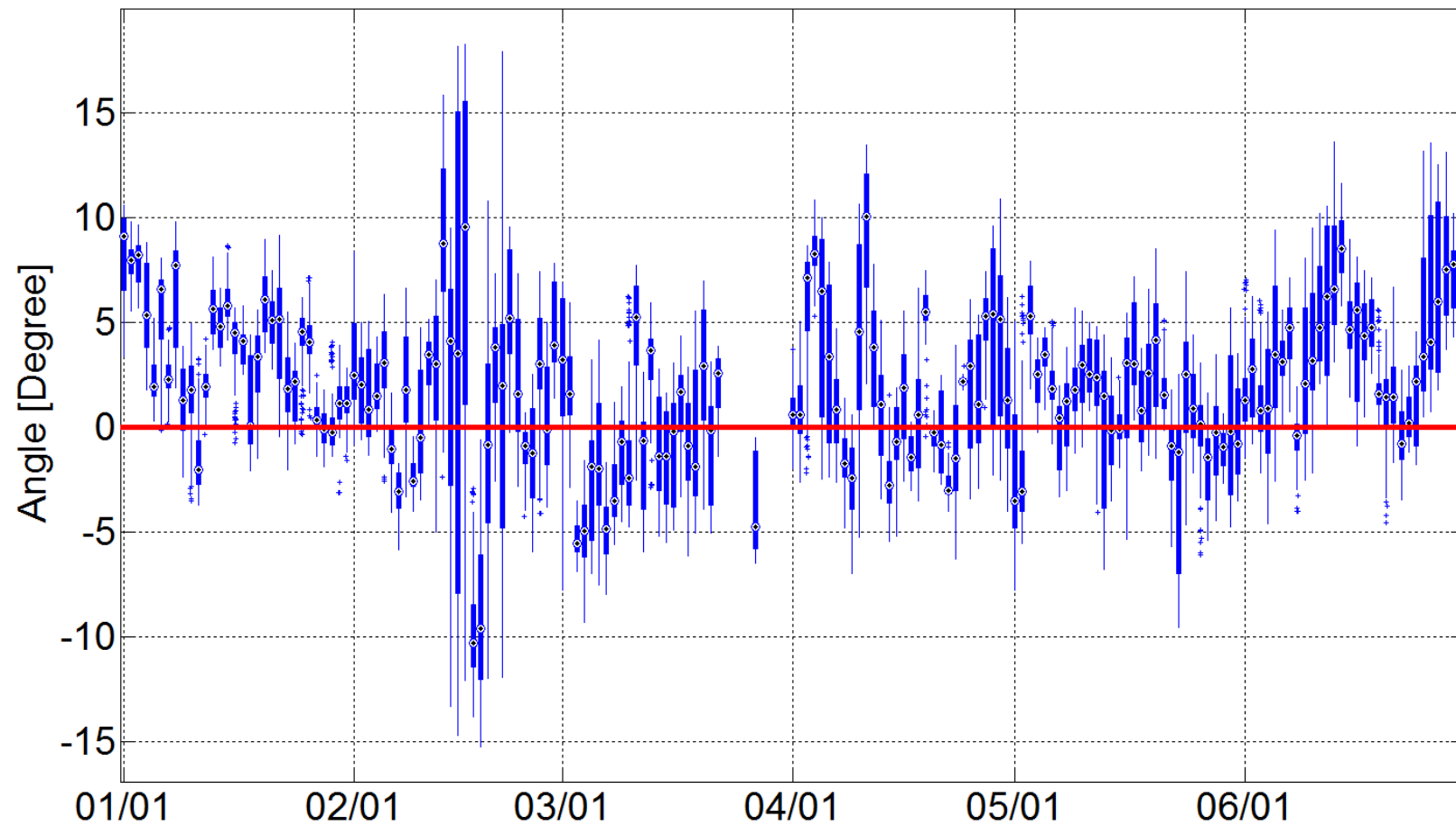
South 15*-North 7



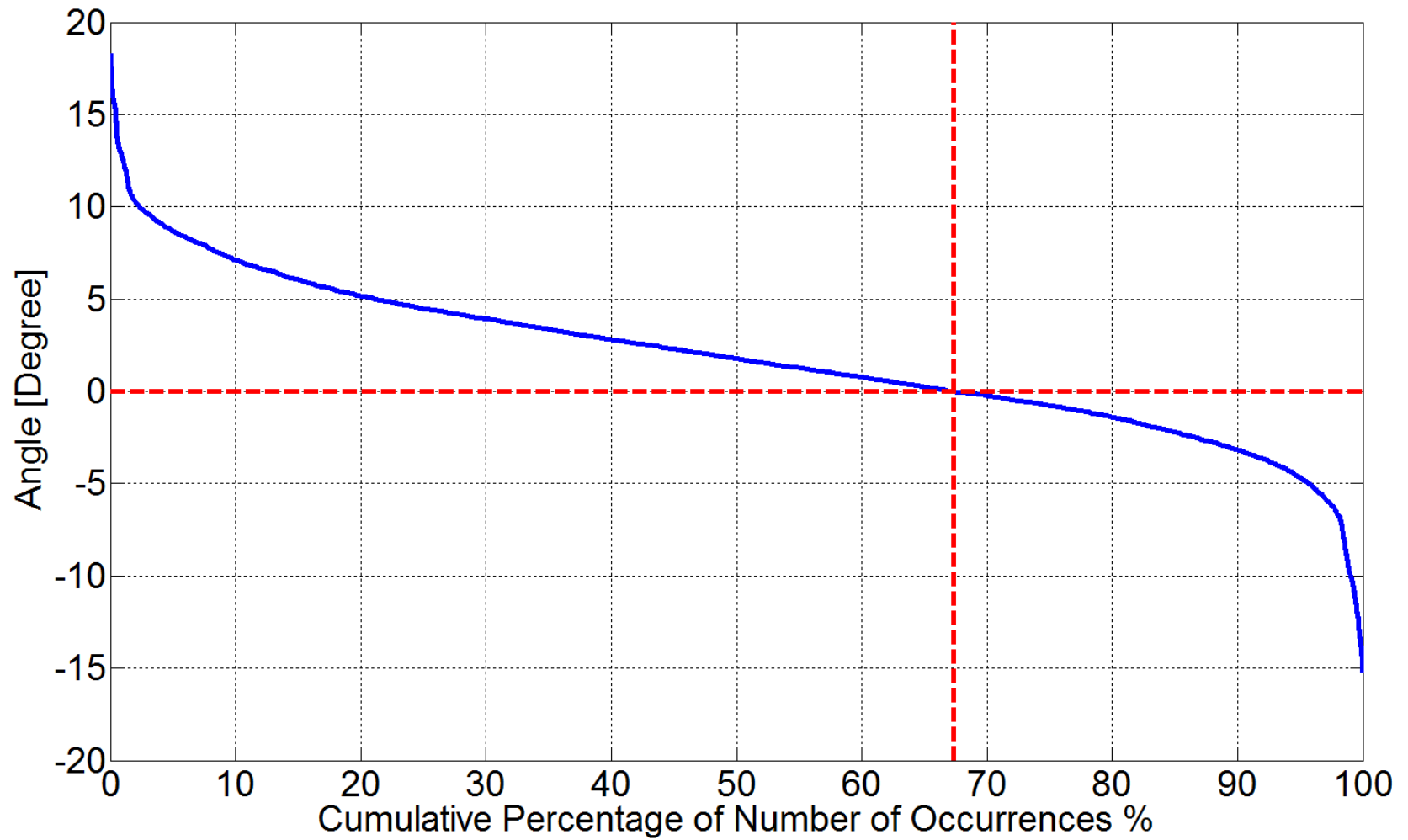
South 15*-North 7



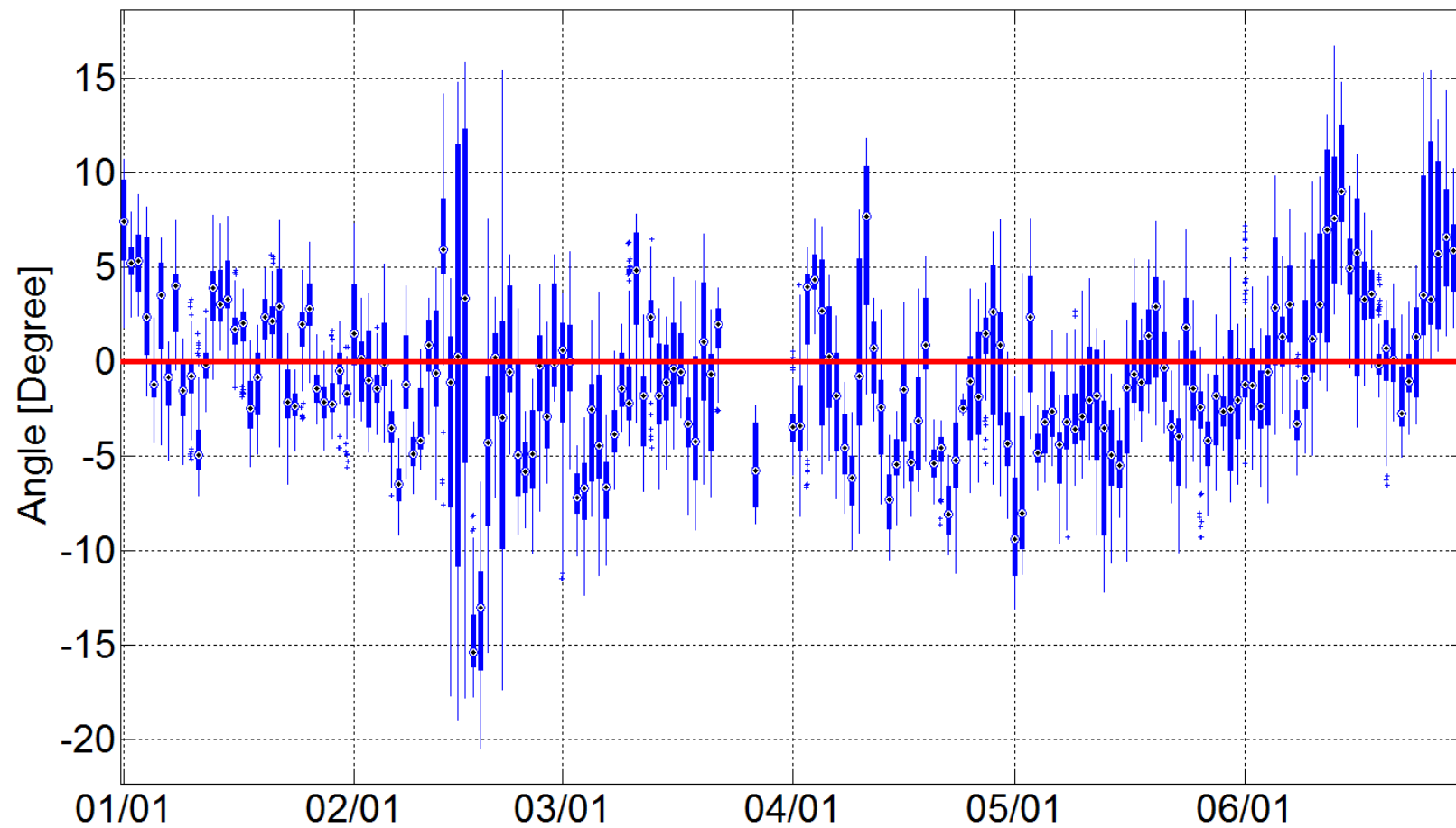
South 2*-North 7



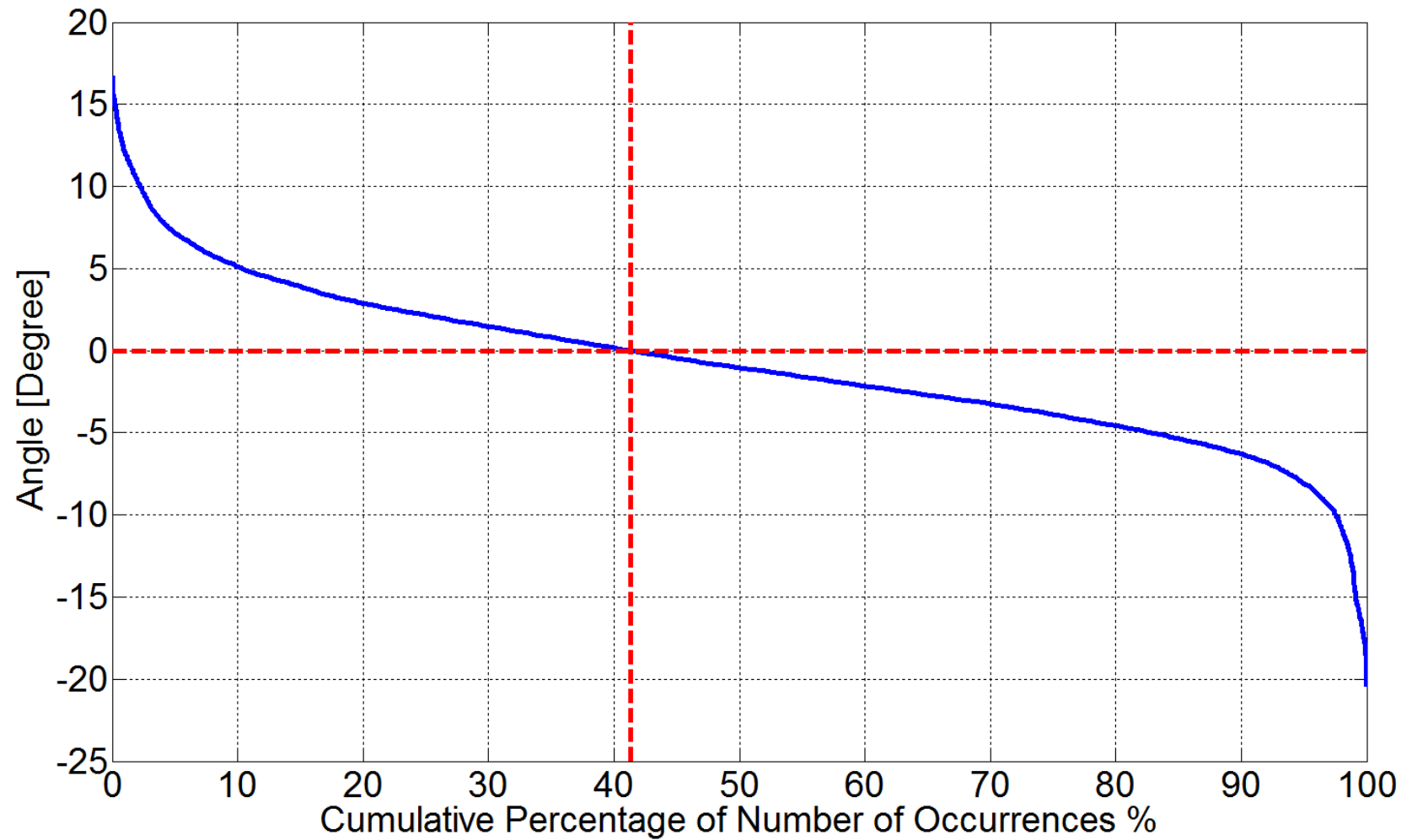
South 2*-North 7



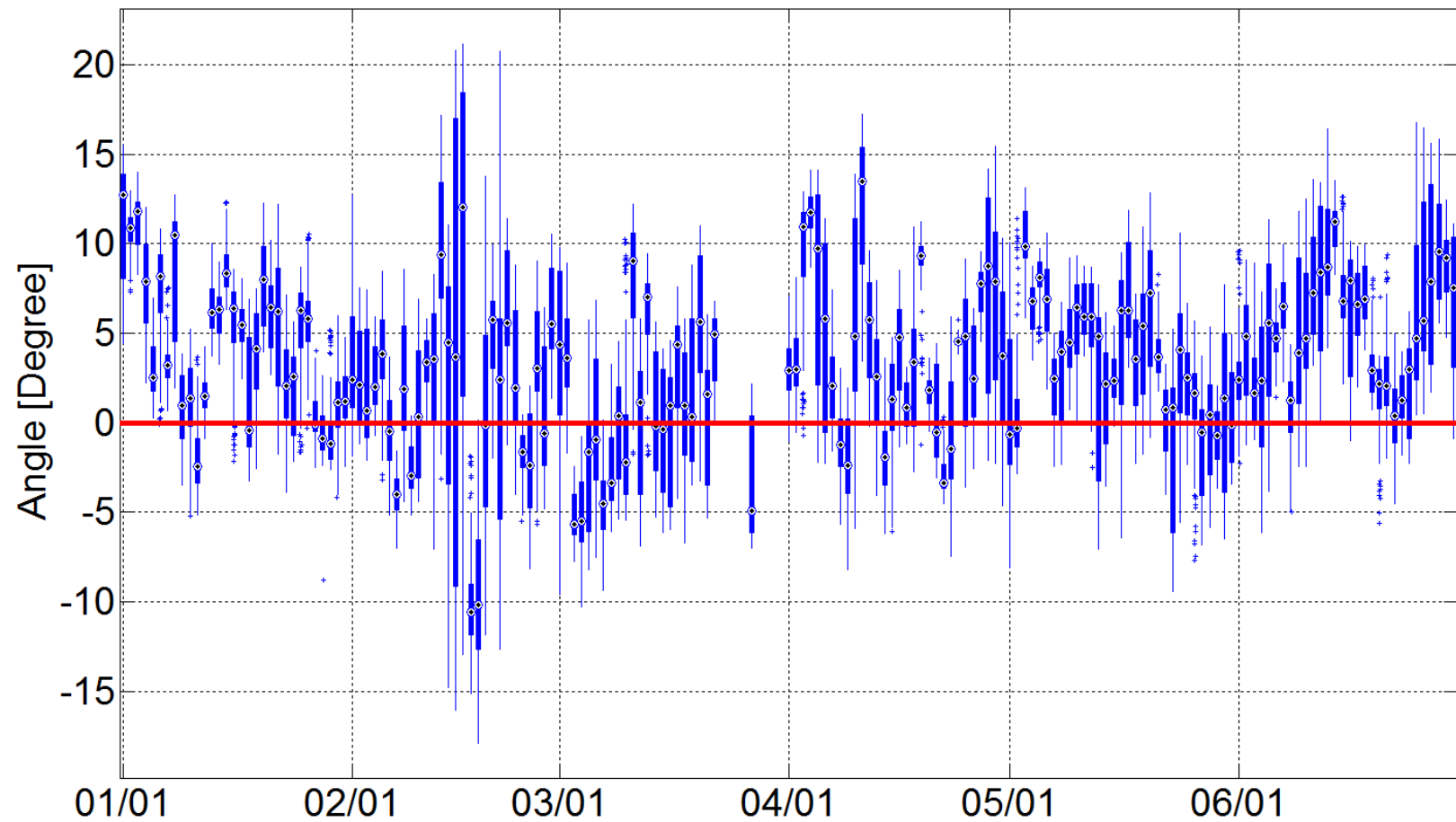
South 4*-North 7



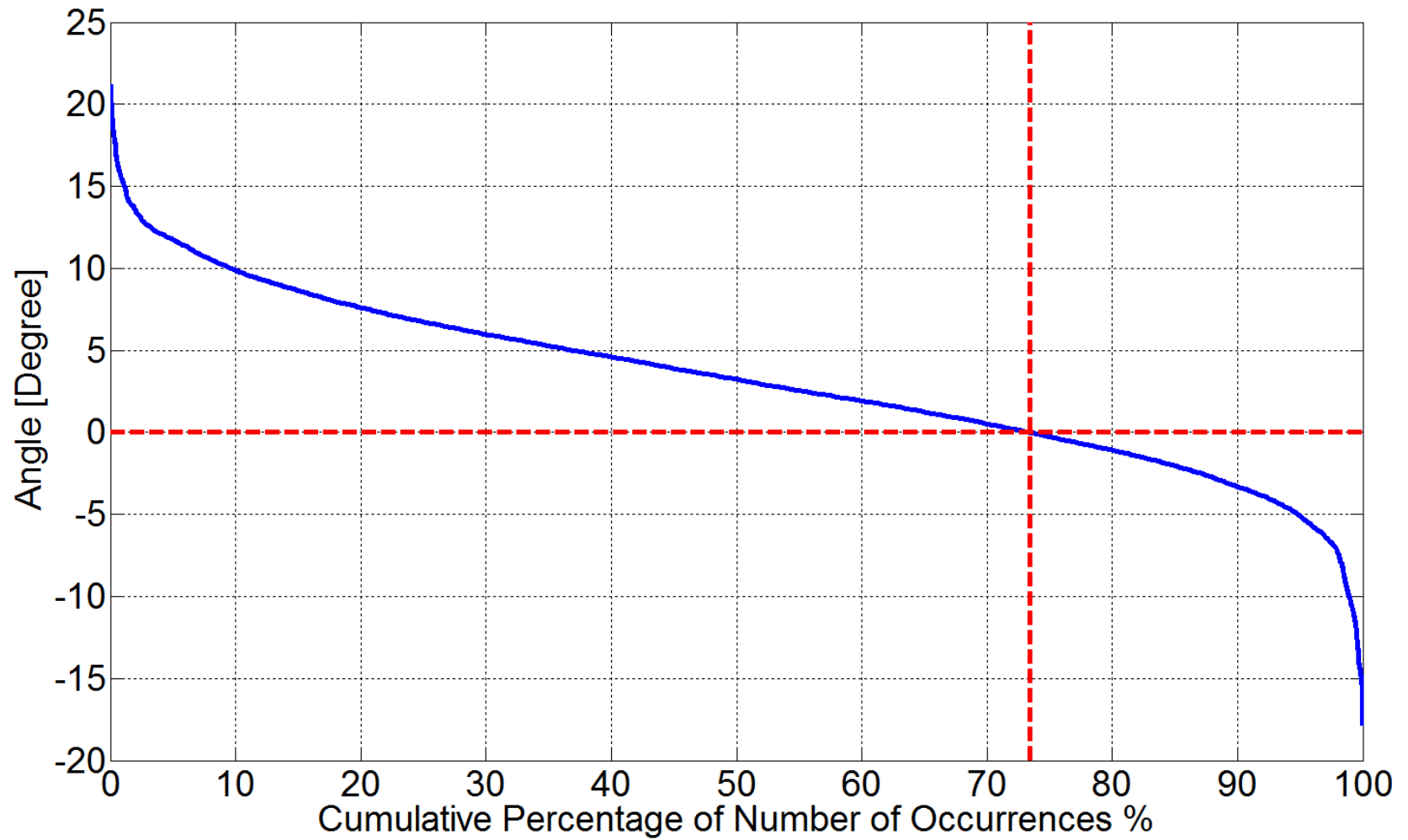
South 4*-North 7



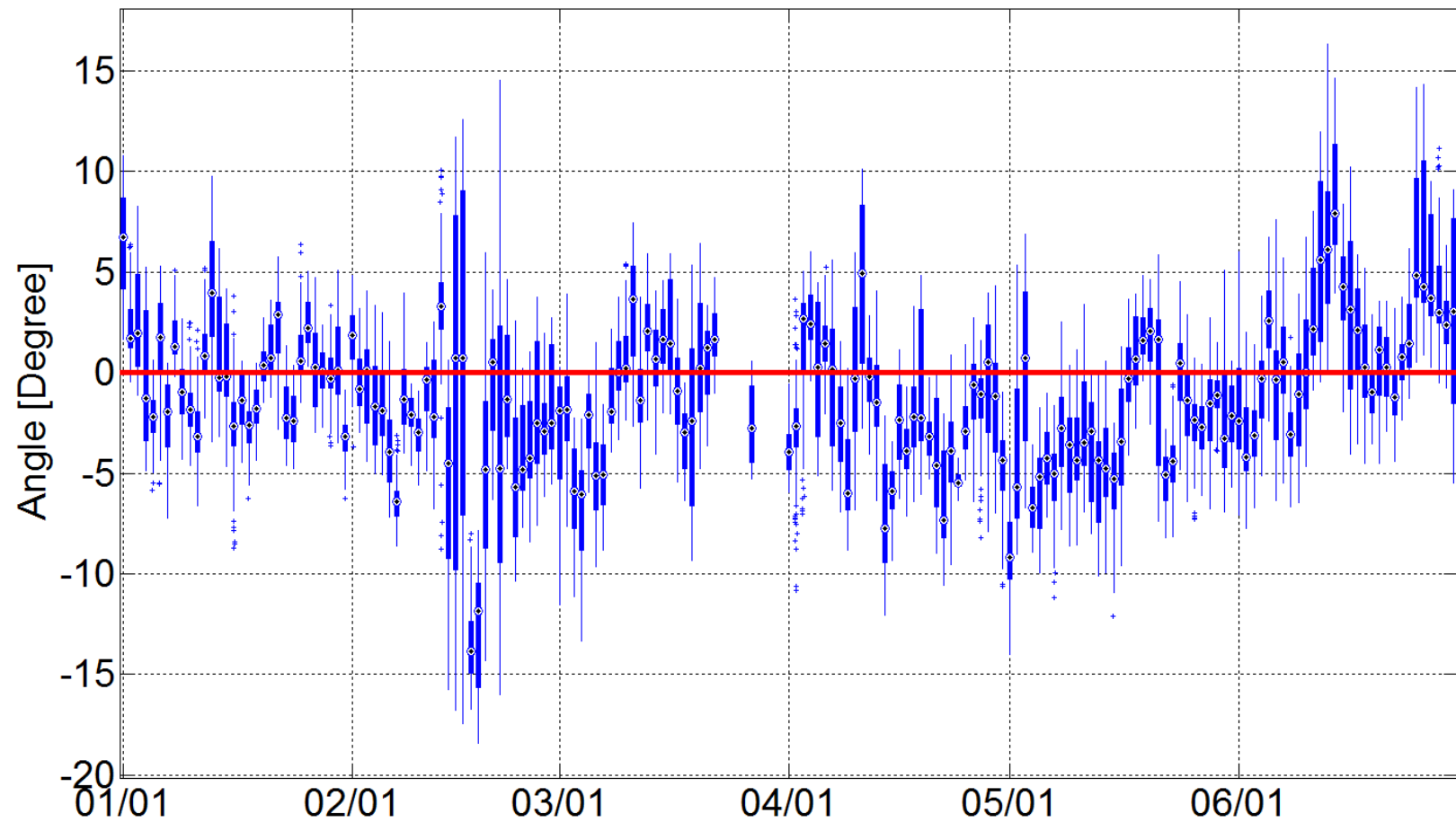
South 7*-North 7



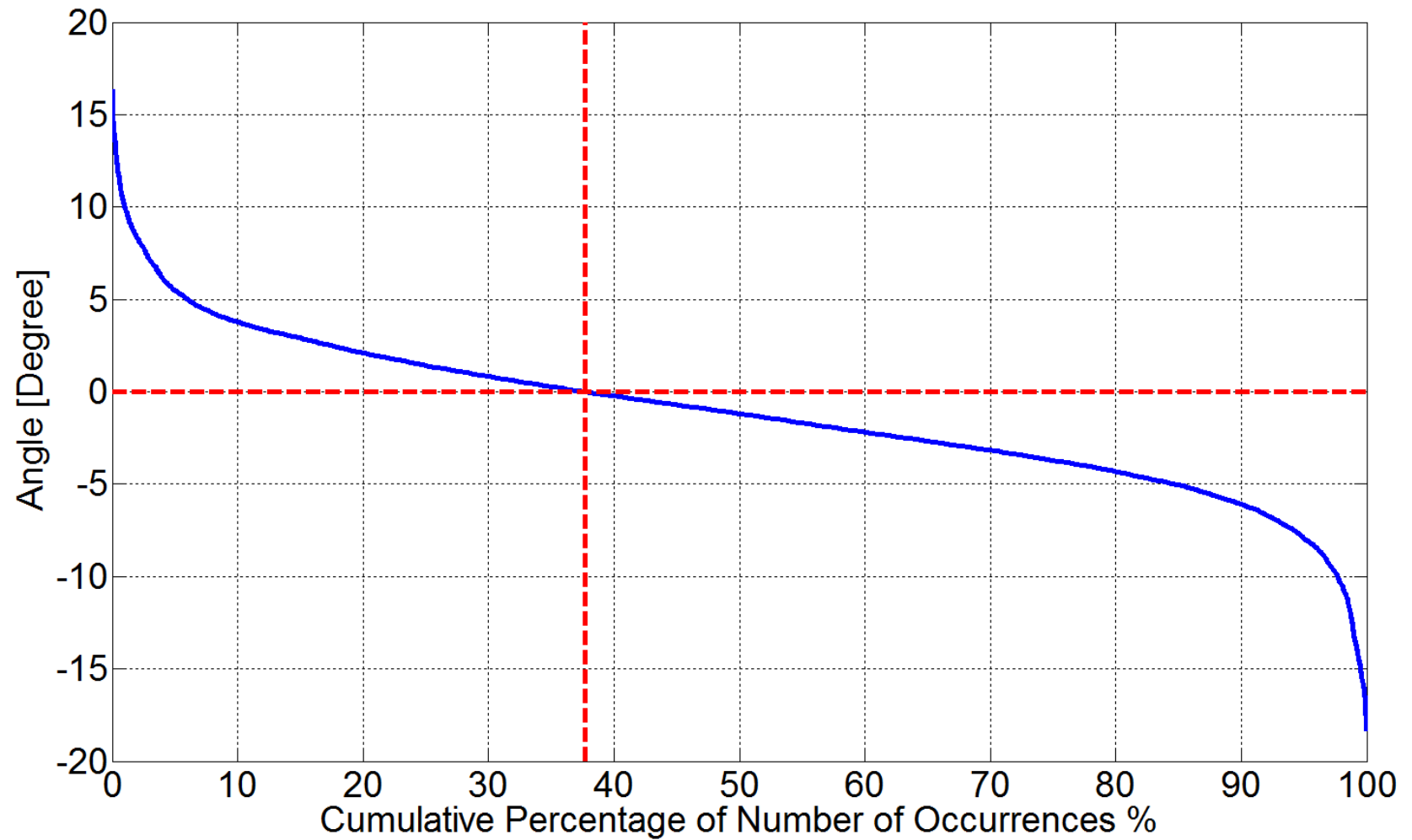
South 7*-North 7



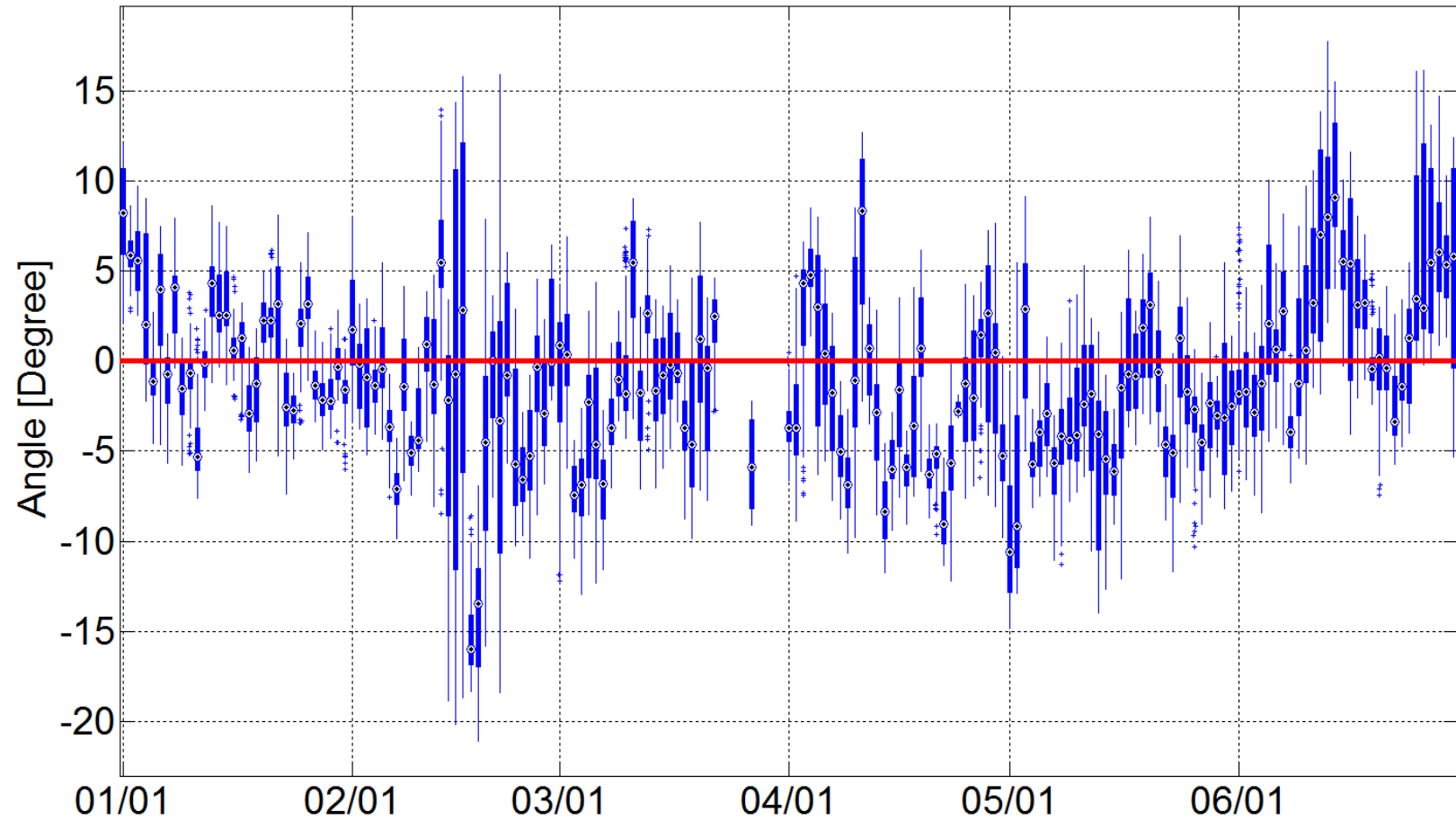
South 9*-North 7



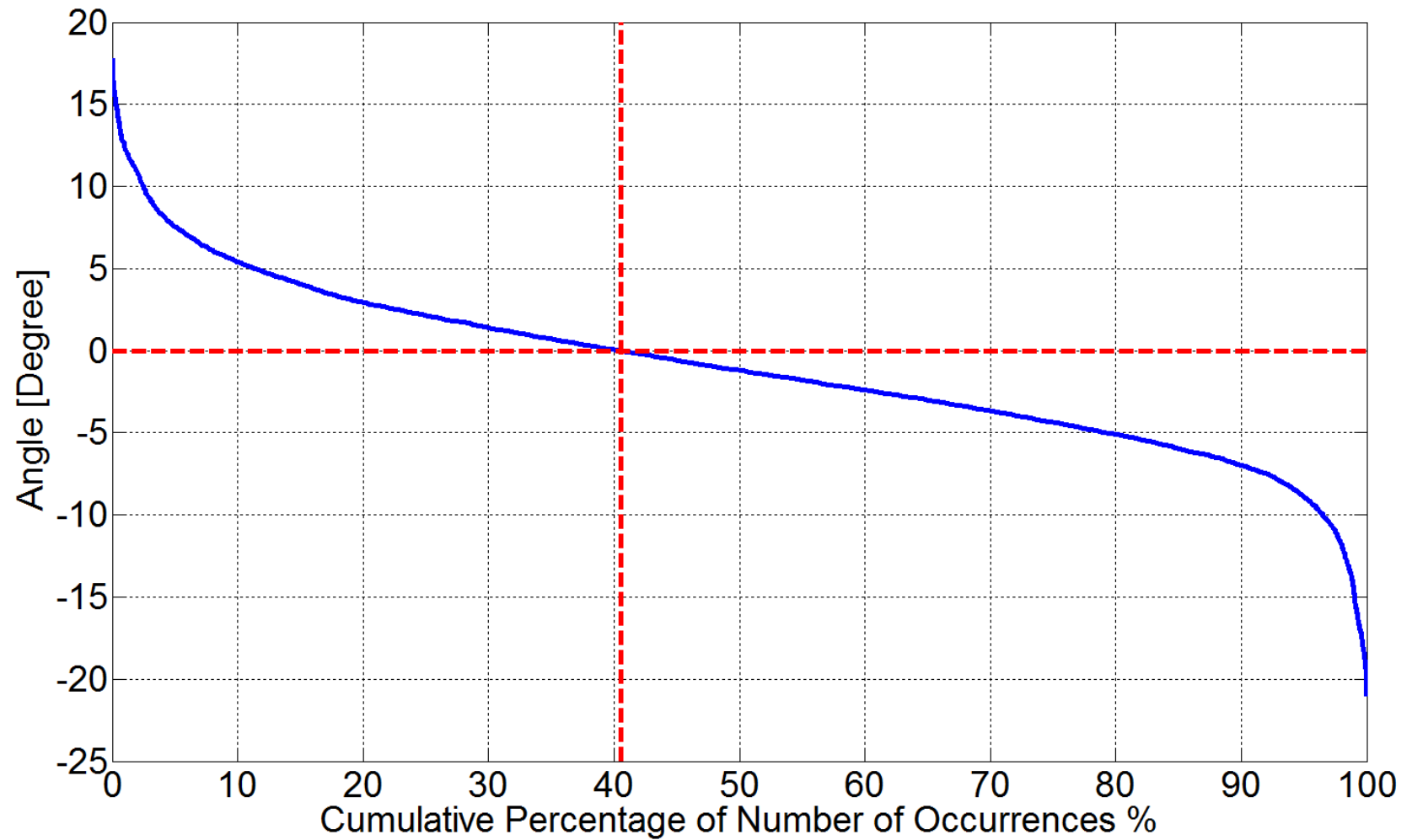
South 9*-North 7



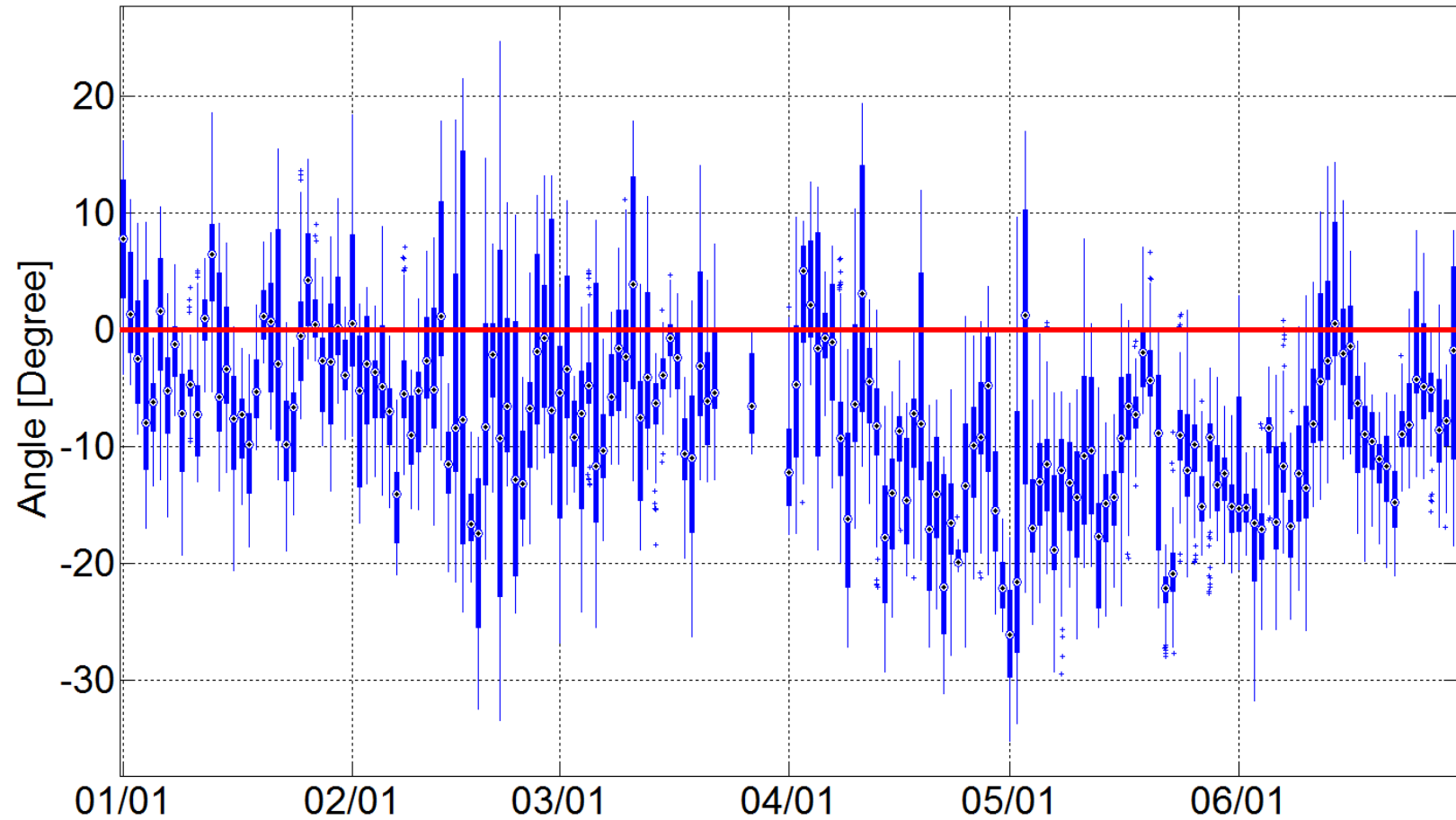
South 11*-North 7



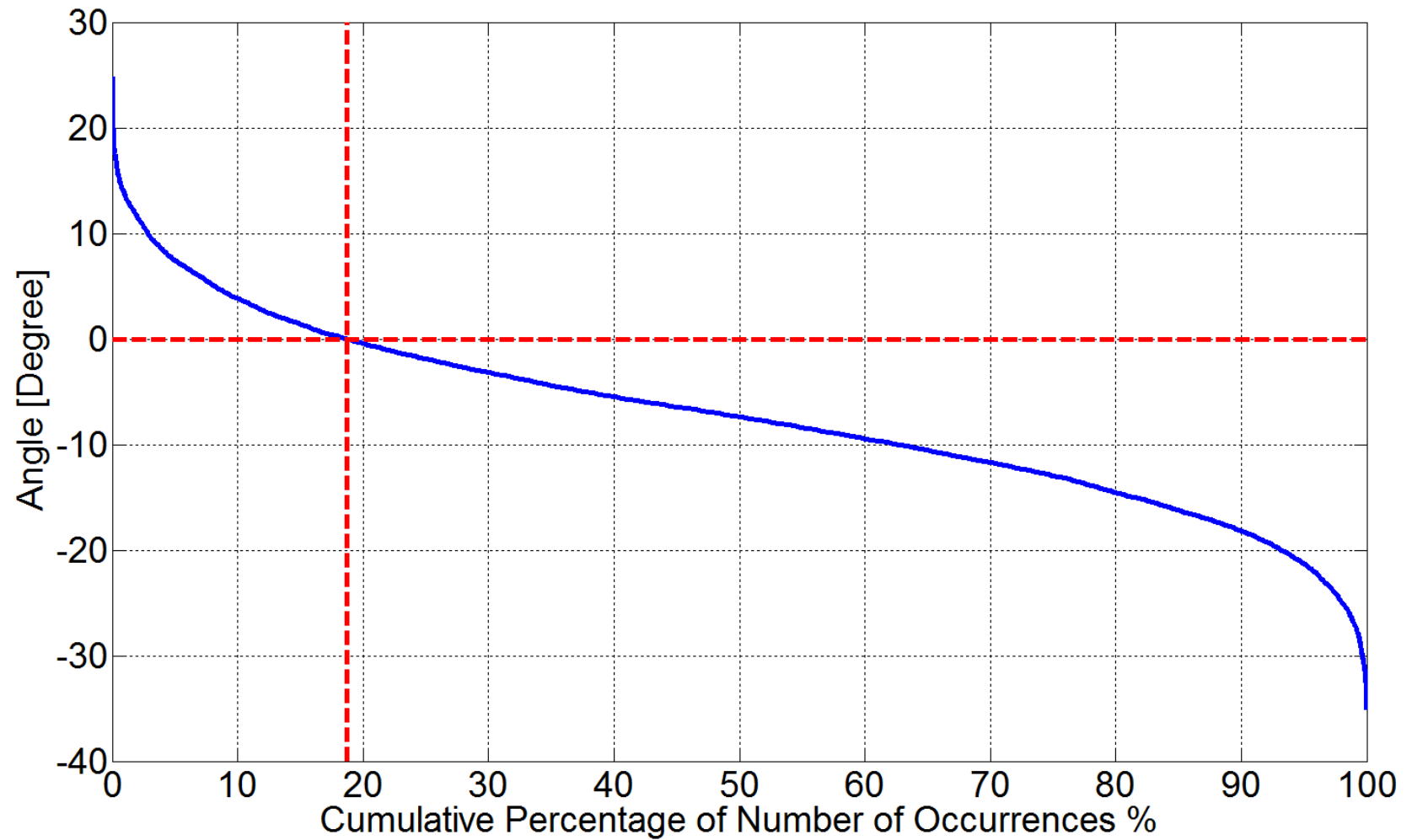
South 11*-North 7



South 10*-North 7



South 10*-North 7



Appendix B – Part 2

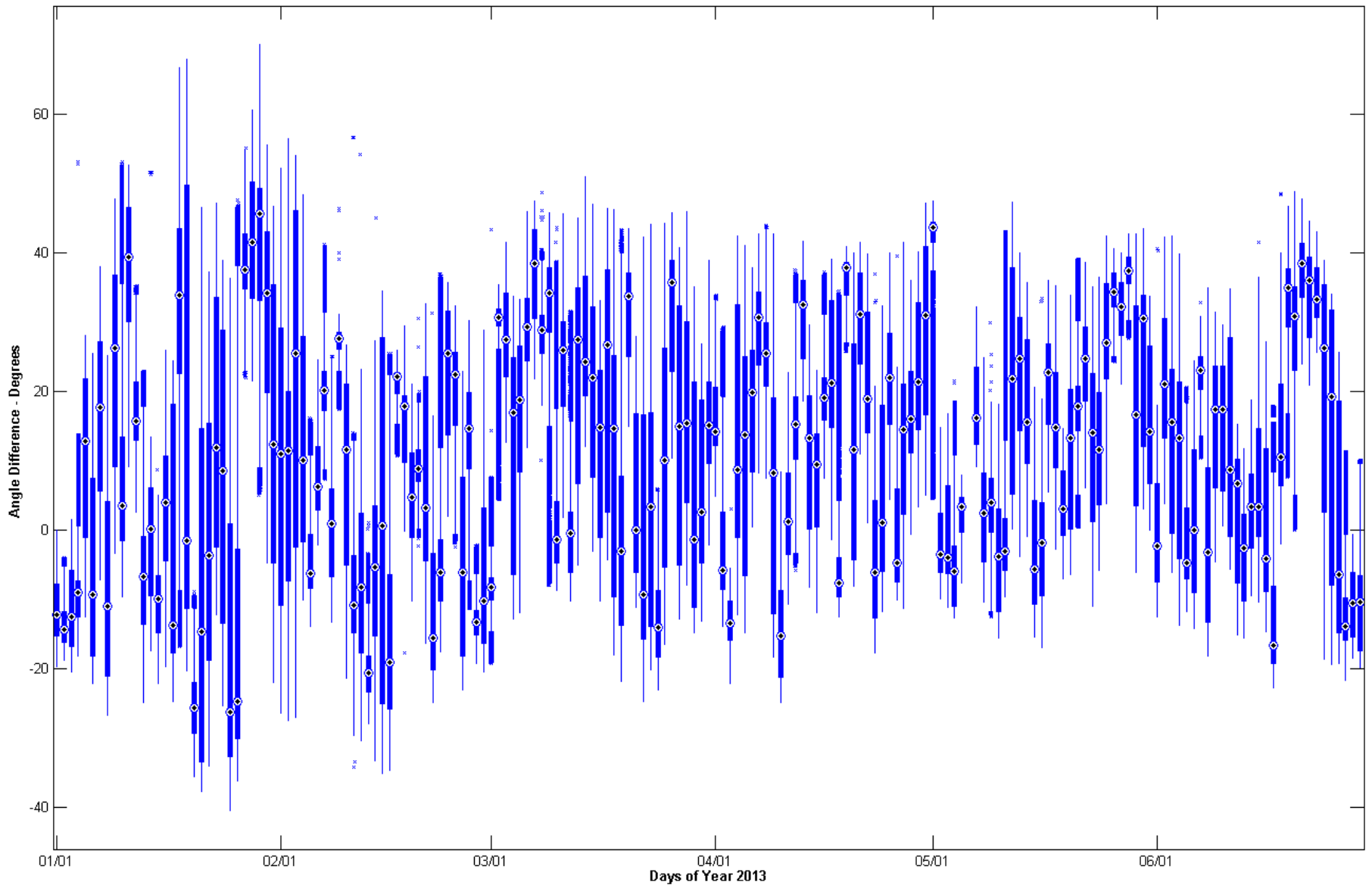
CCET Discovery Across Texas project

Baseline Analysis Update - Voltage Angles (Ref.: North 7)

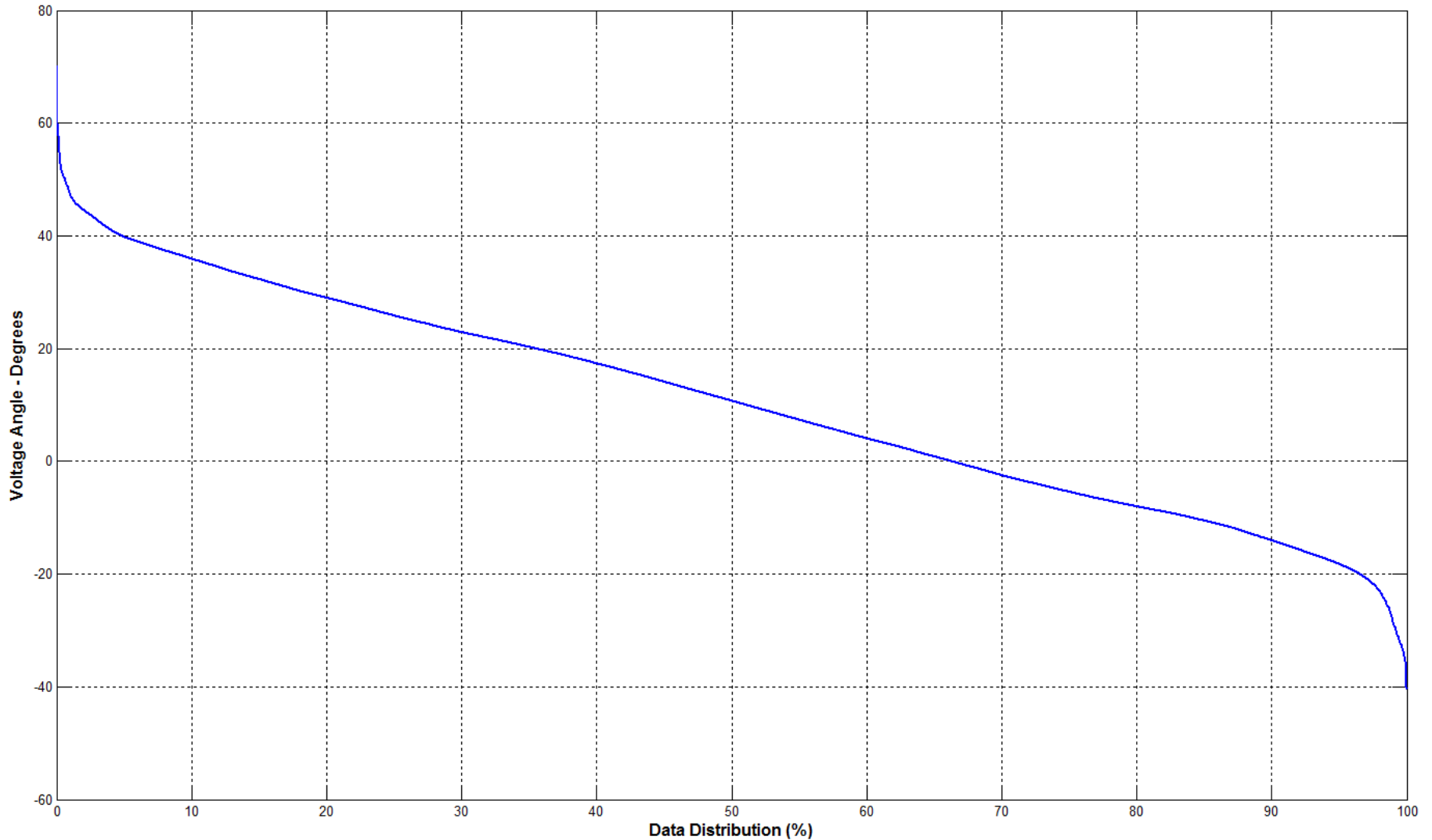
Phasor Data: January to June 2013
Box Whiskers Plots and Time Duration Curves

External Version

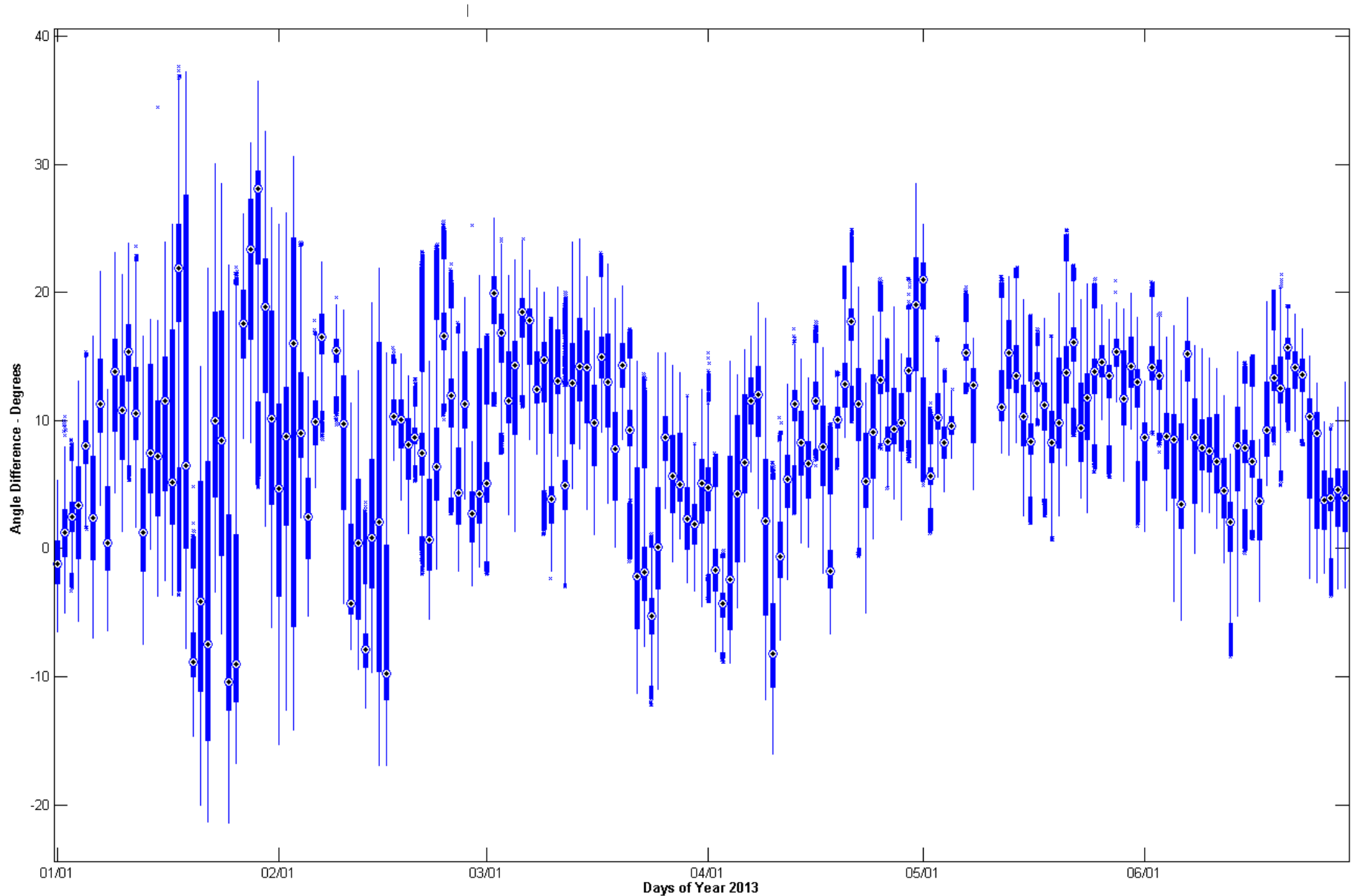
West 10 – Voltage Angle



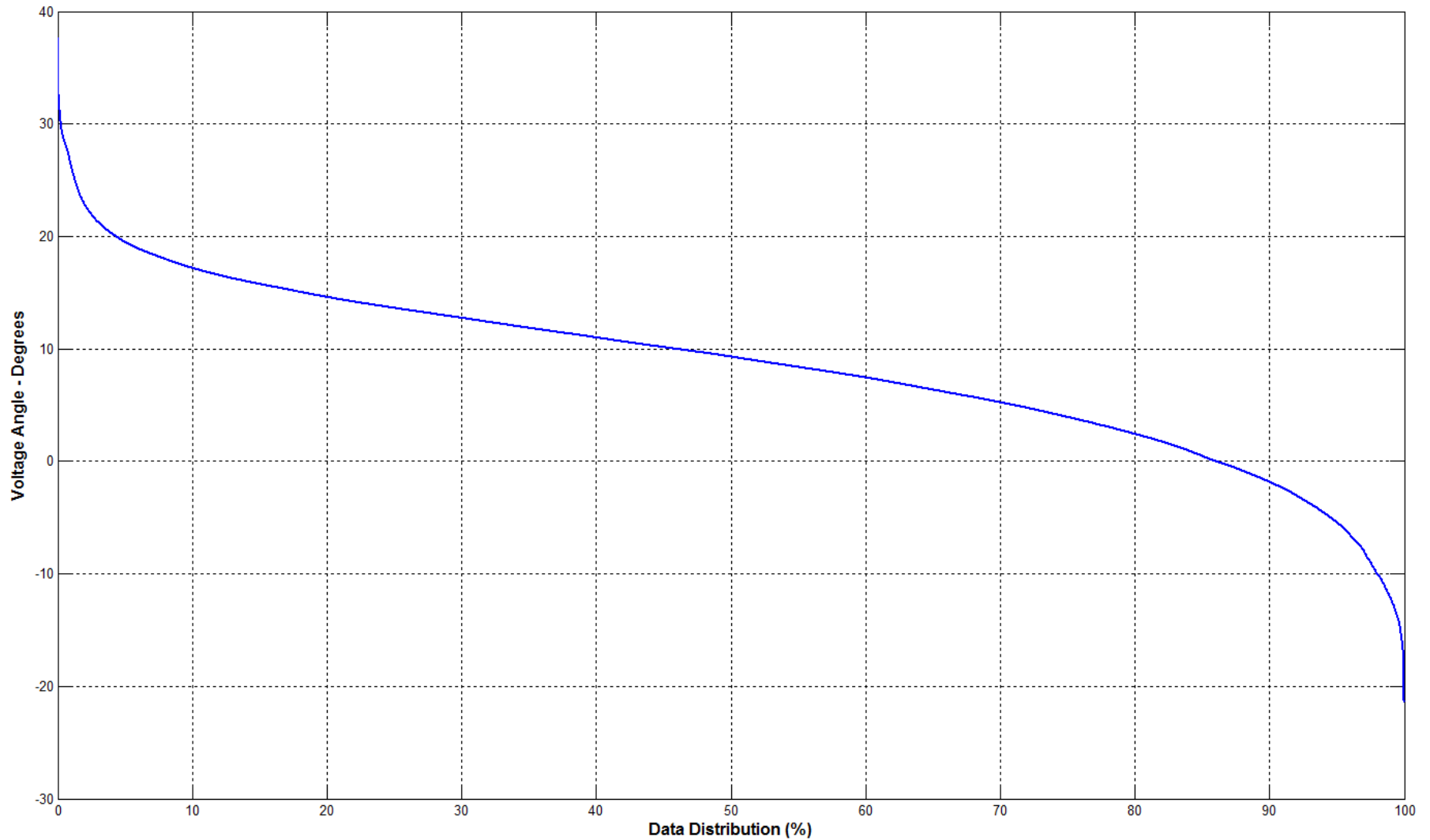
West 10 – Voltage Angle



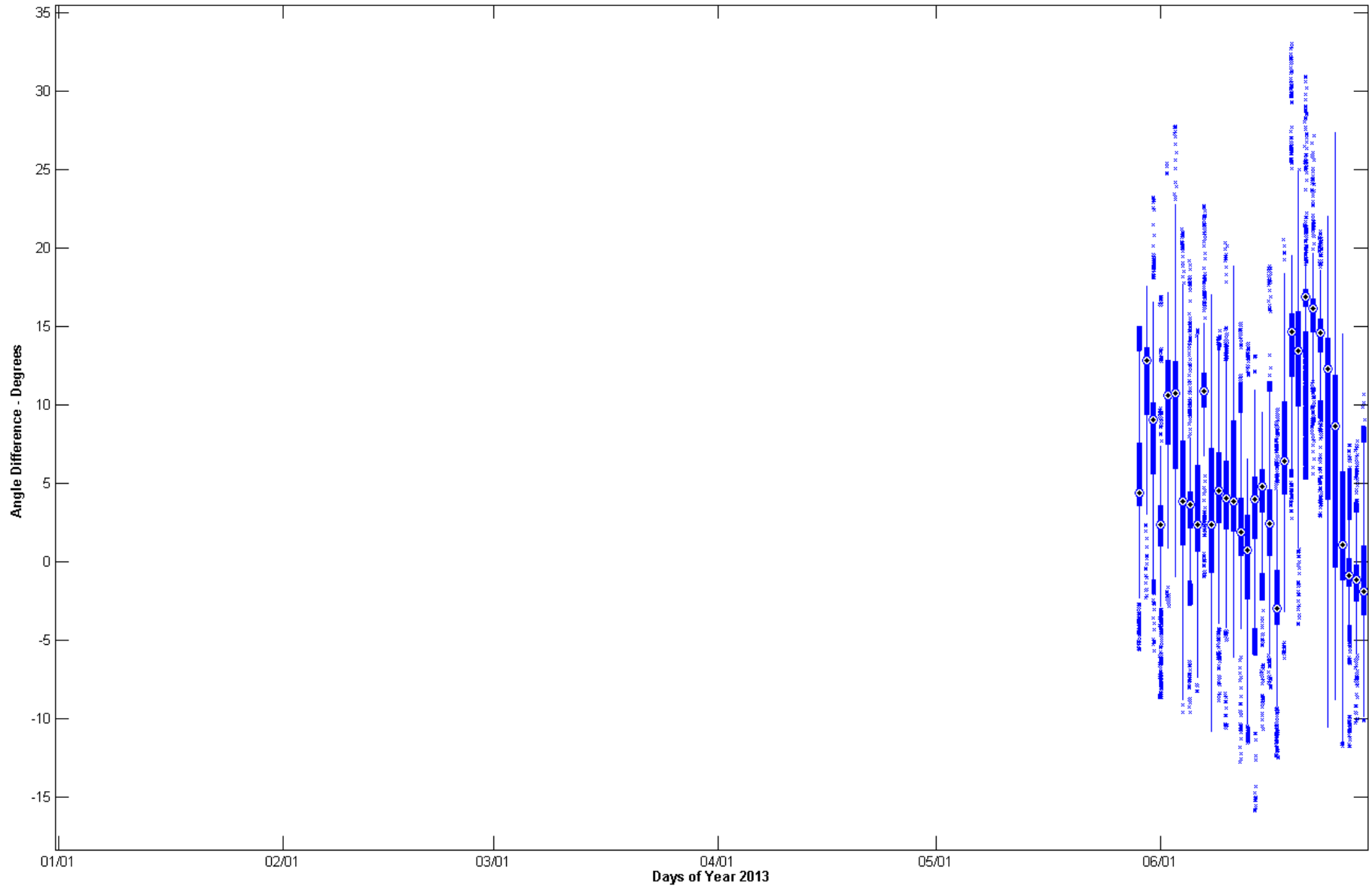
West 14 – Voltage Angle



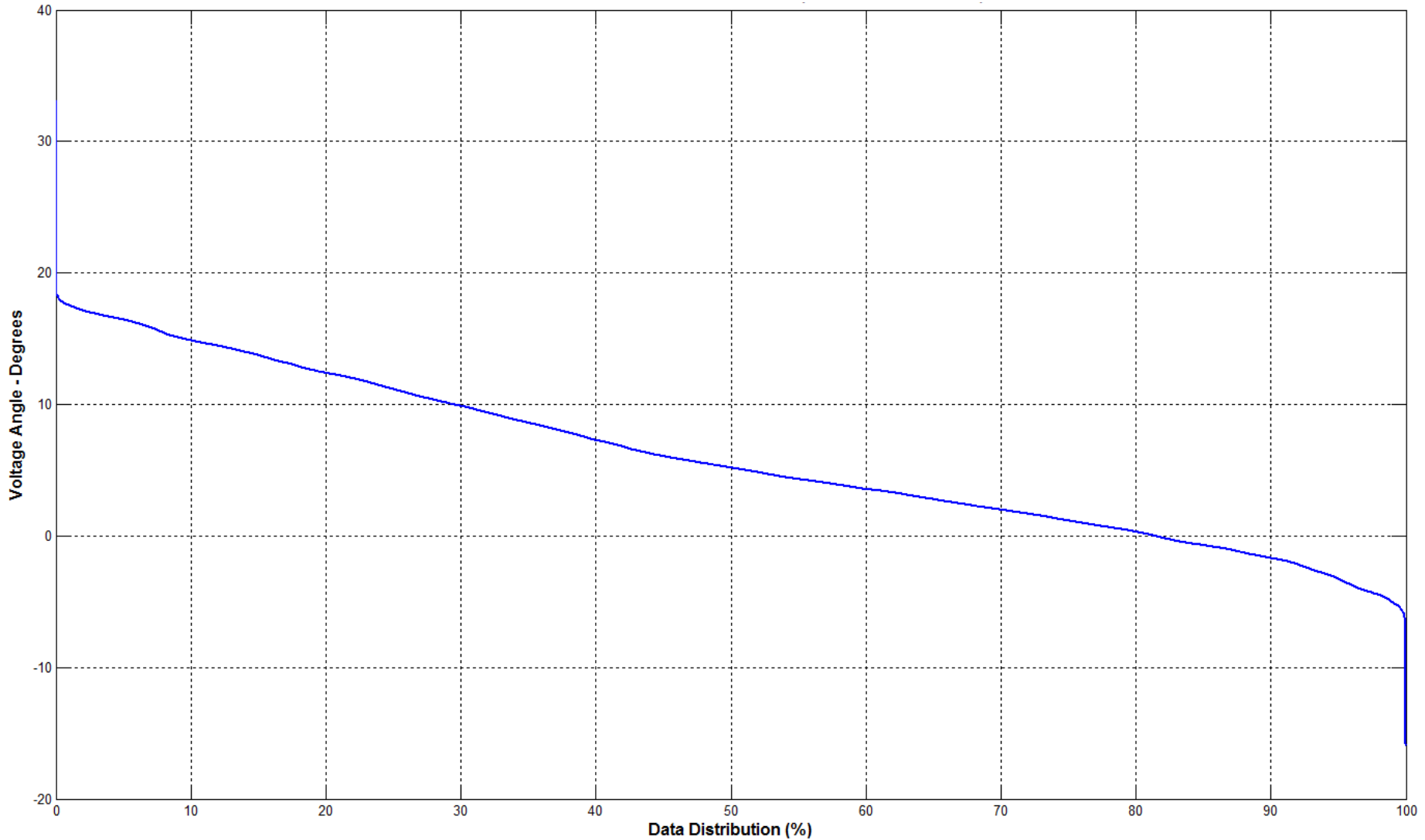
West 14 – Voltage Angle



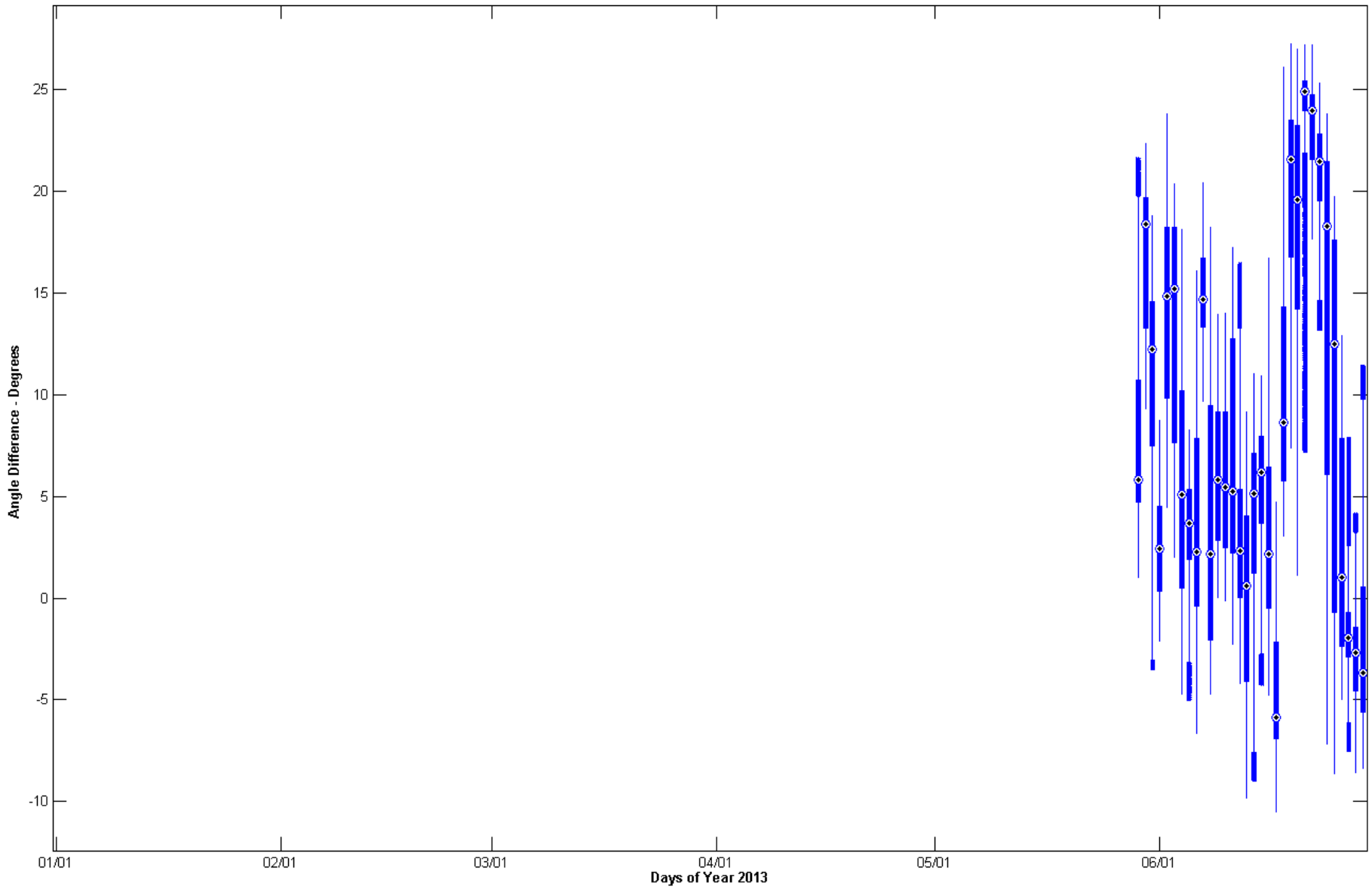
West 1 – Voltage Angle



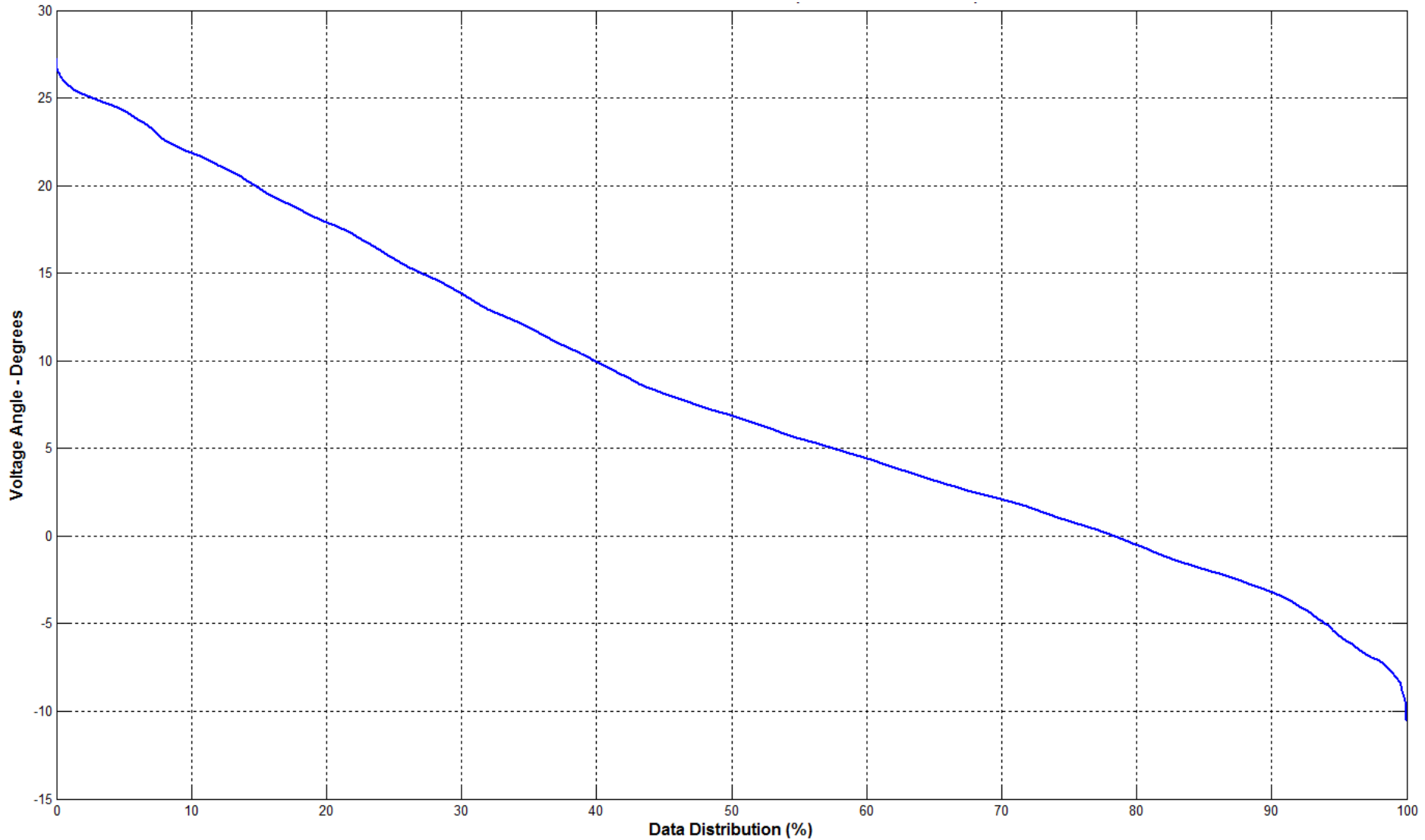
West 1 – Voltage Angle



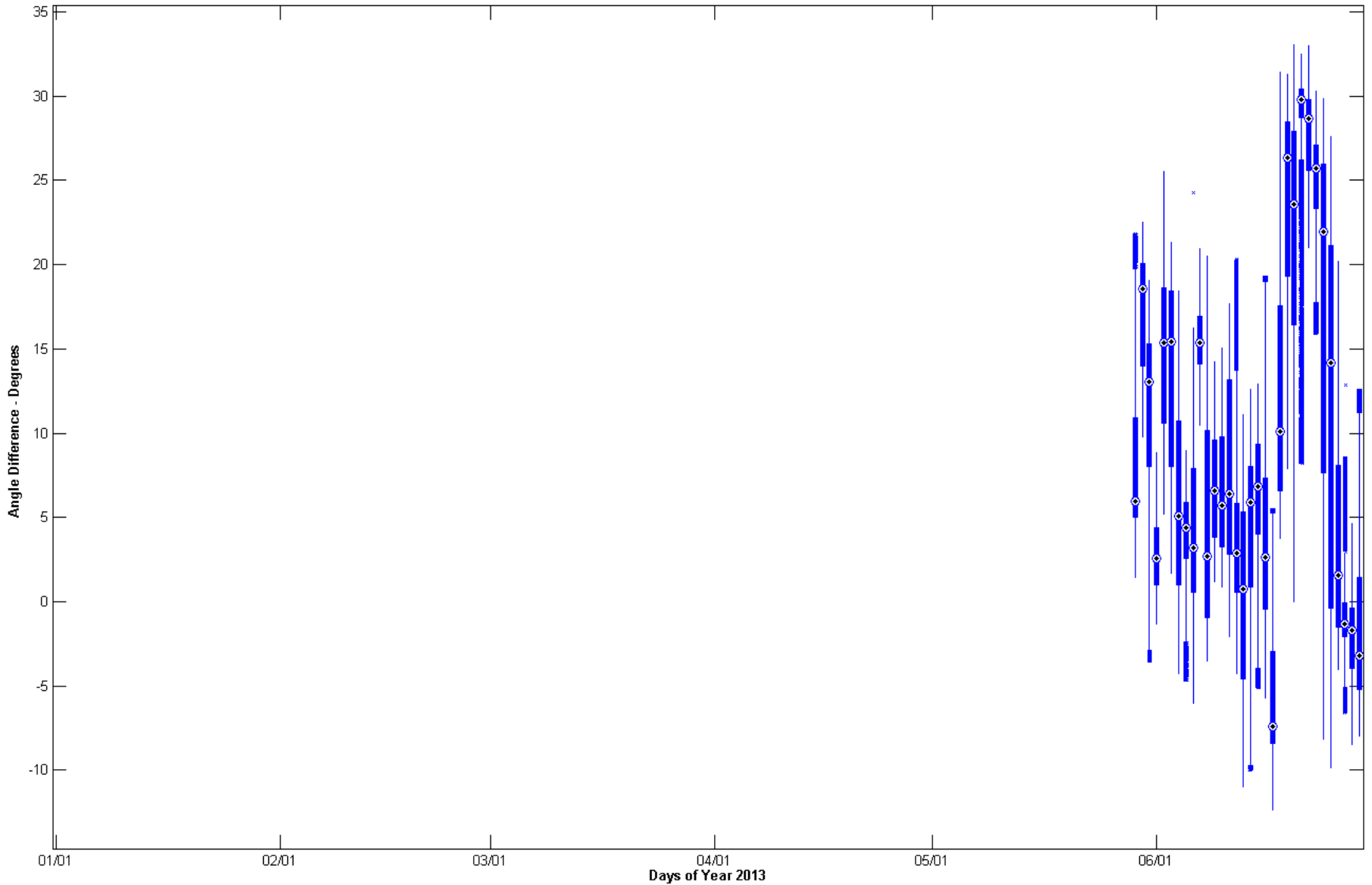
West 2 – Voltage Angle



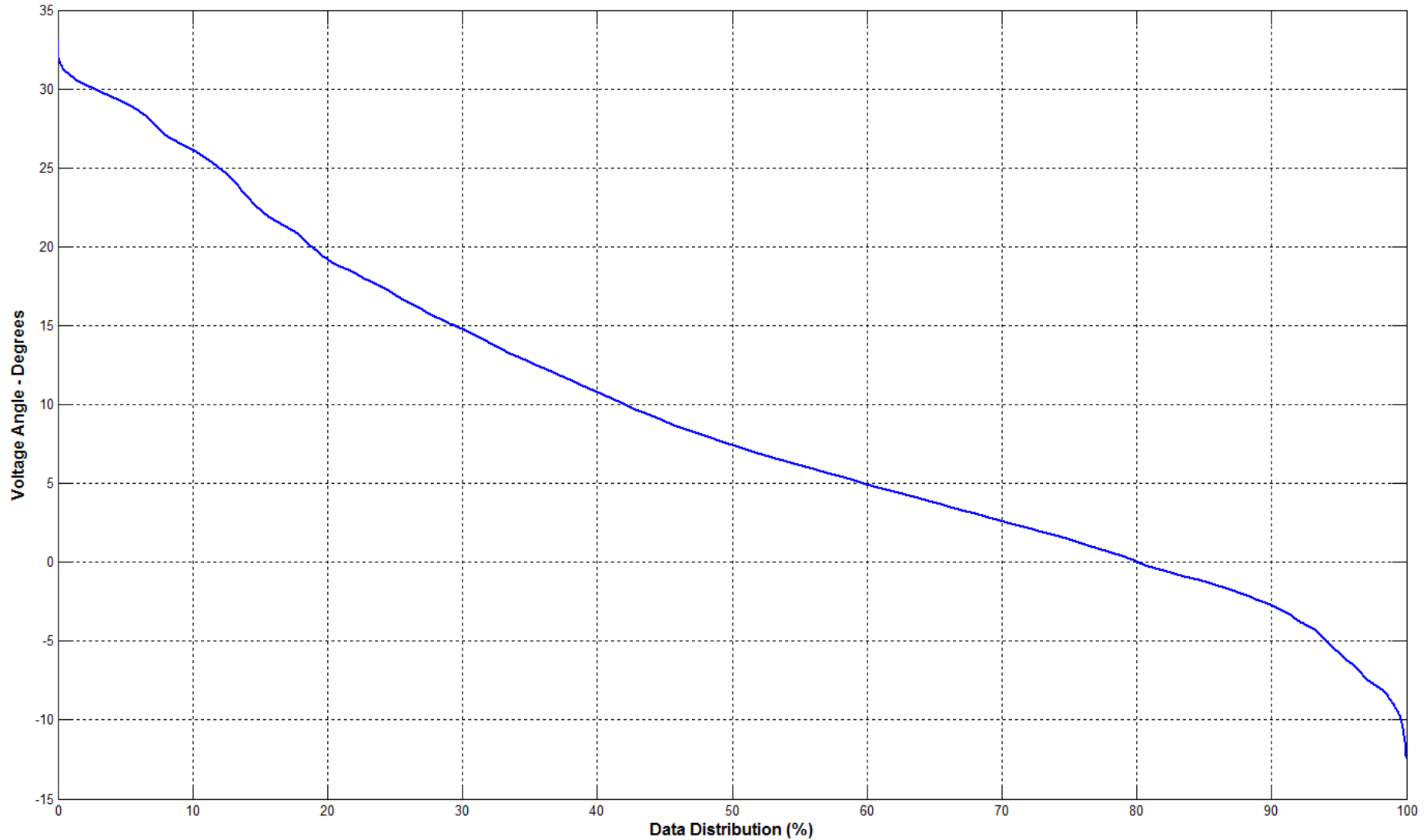
West 2 – Voltage Angle



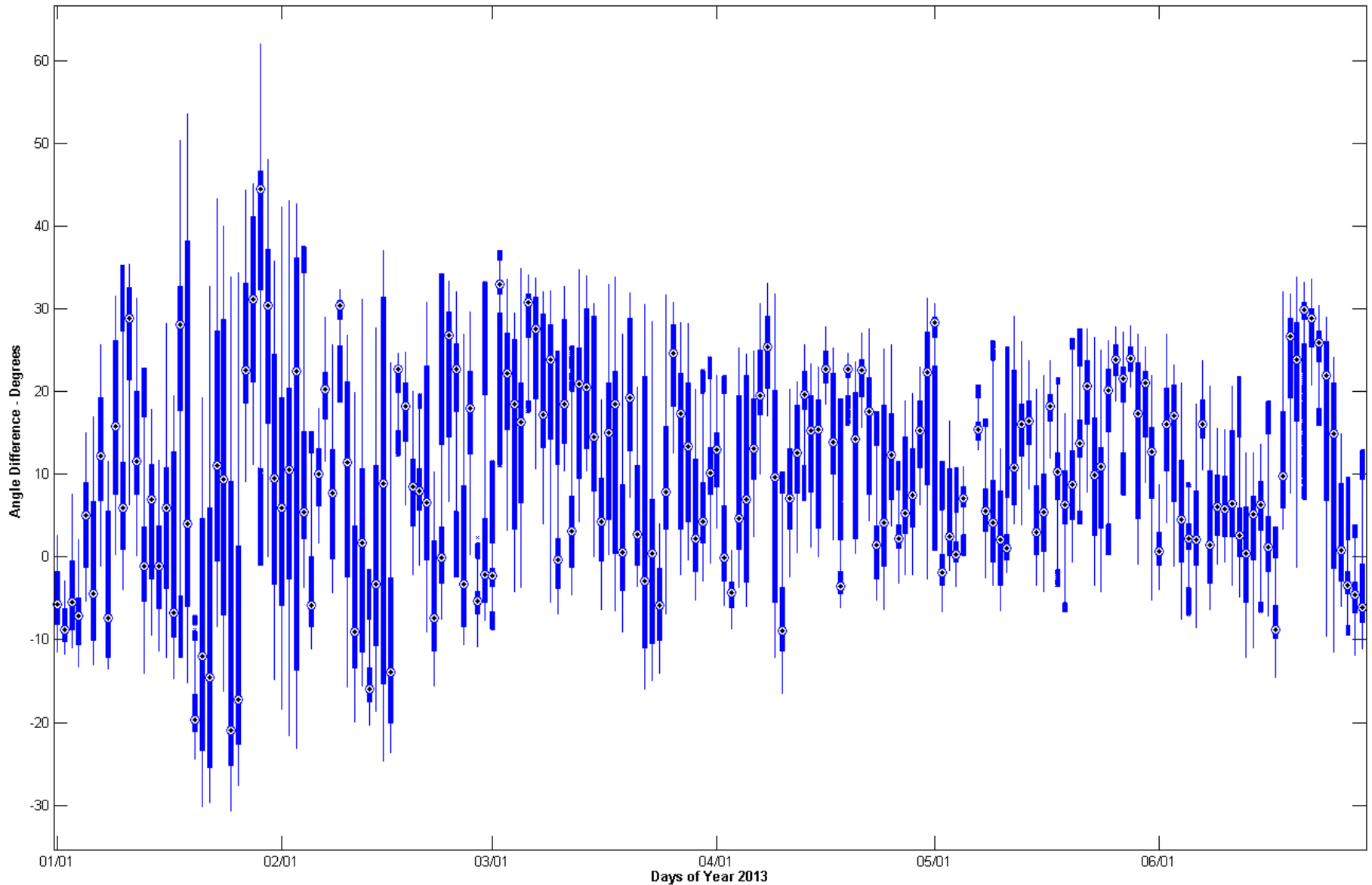
West 9 – Voltage Angle



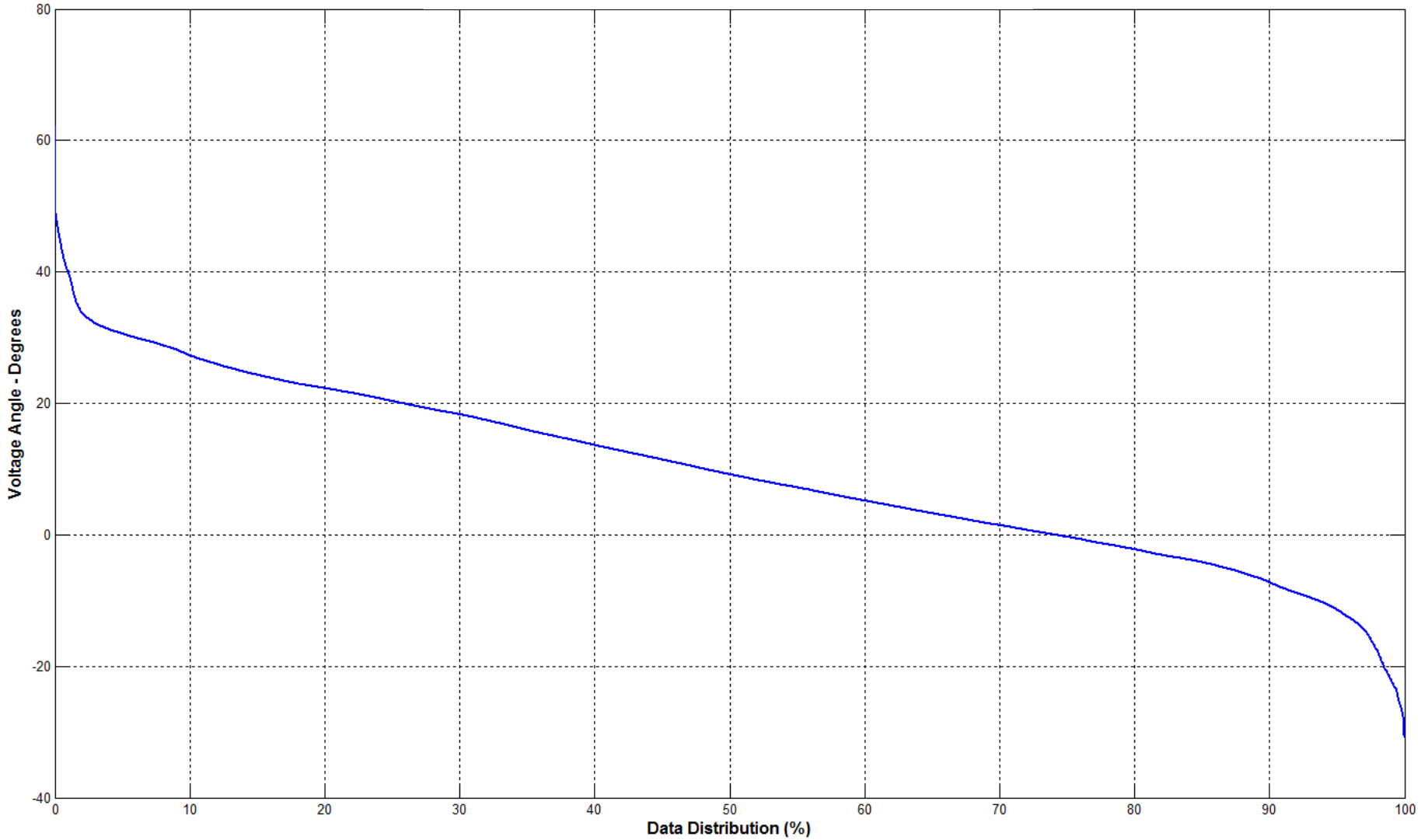
West 9 – Voltage Angle



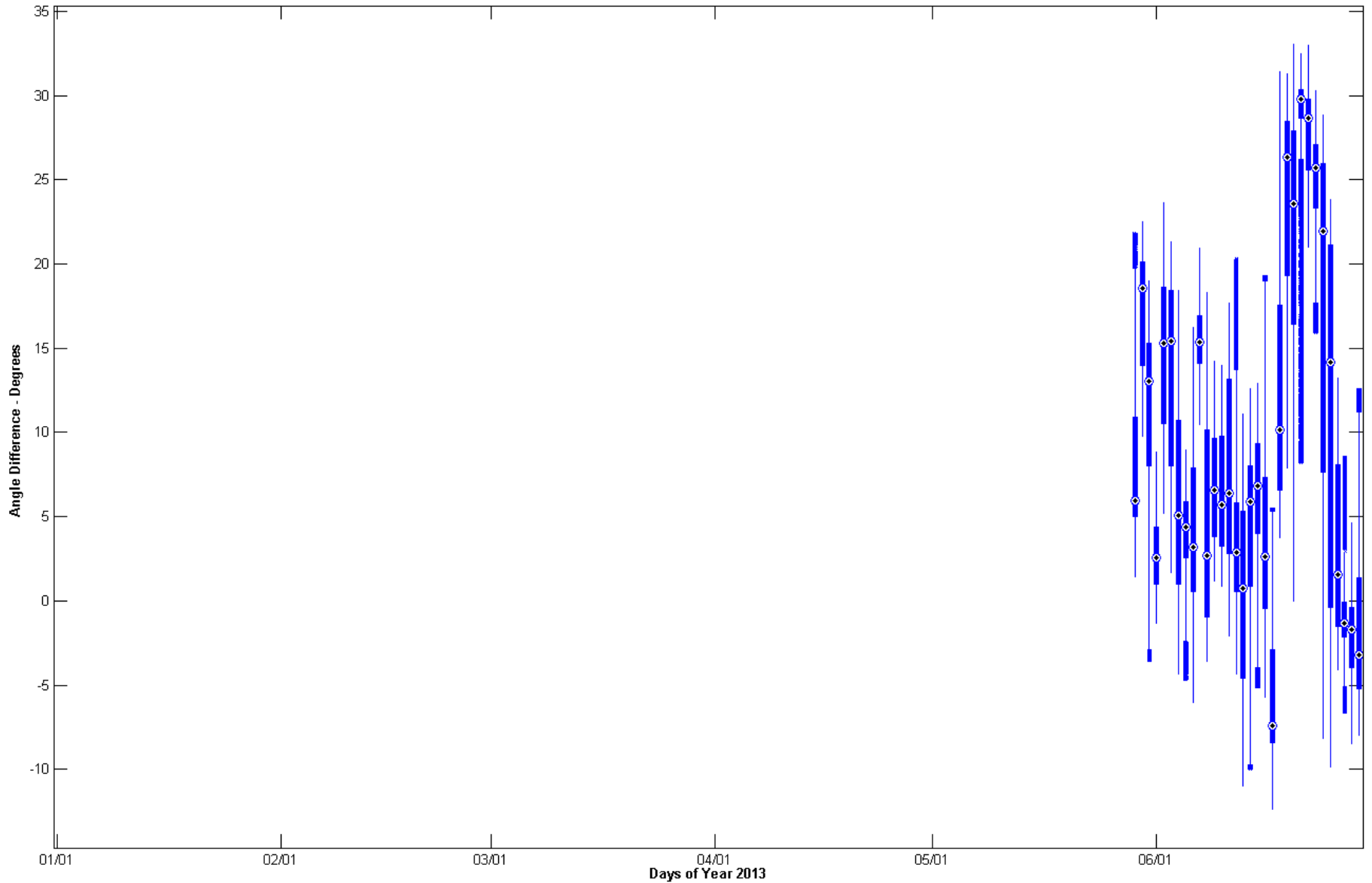
West 11– Voltage Angle



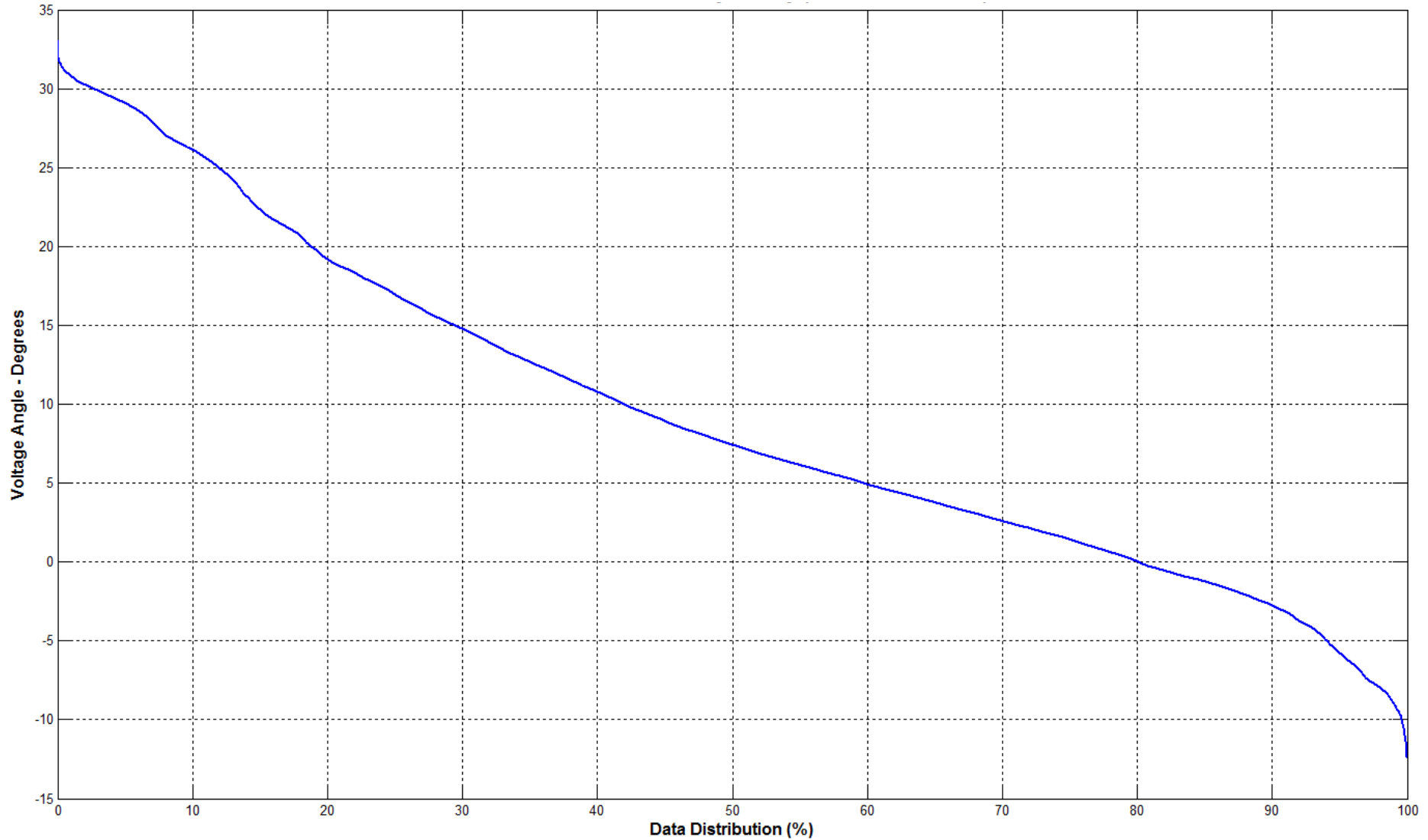
West 11– Voltage Angle



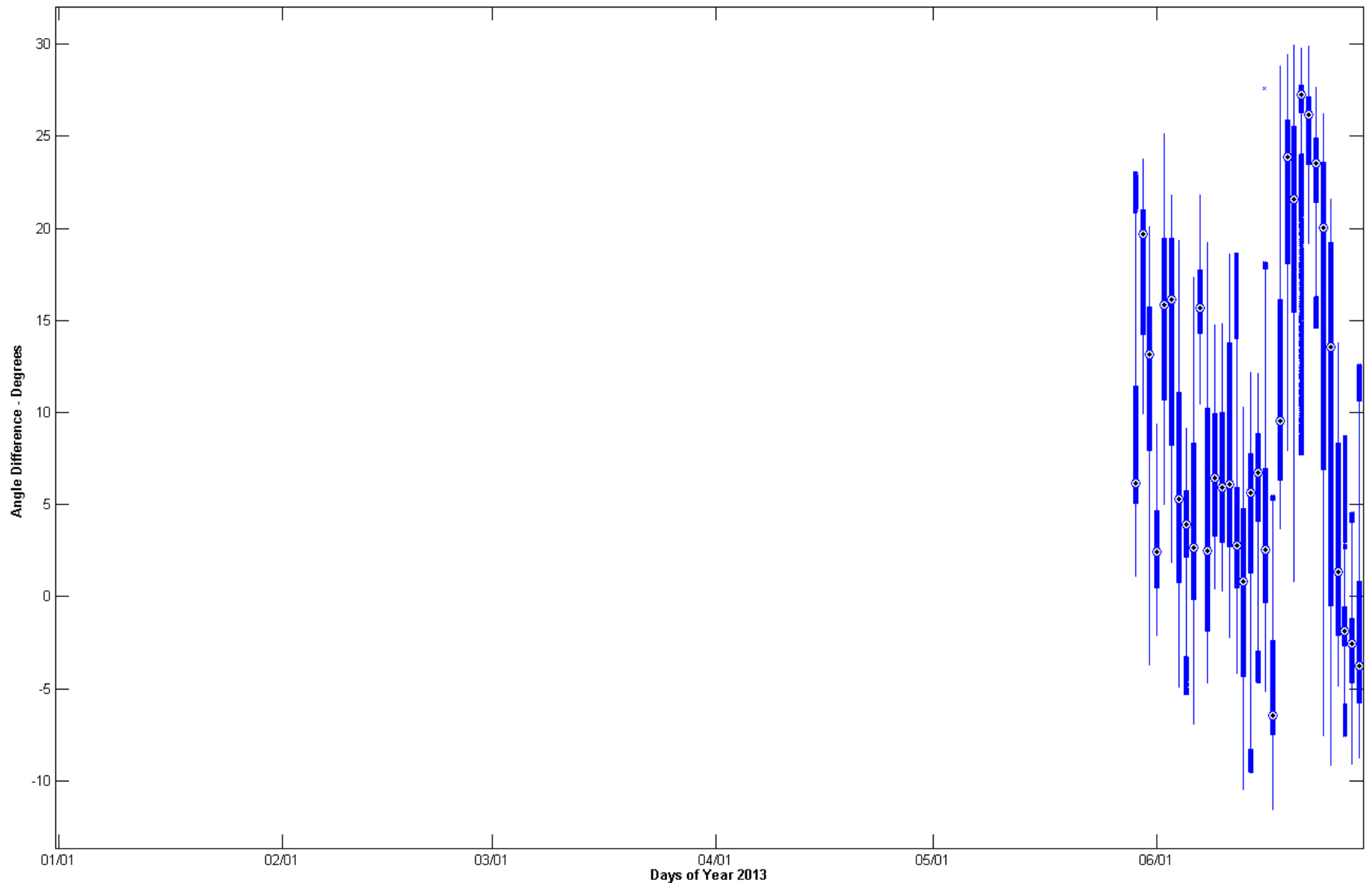
West 12– Voltage Angle



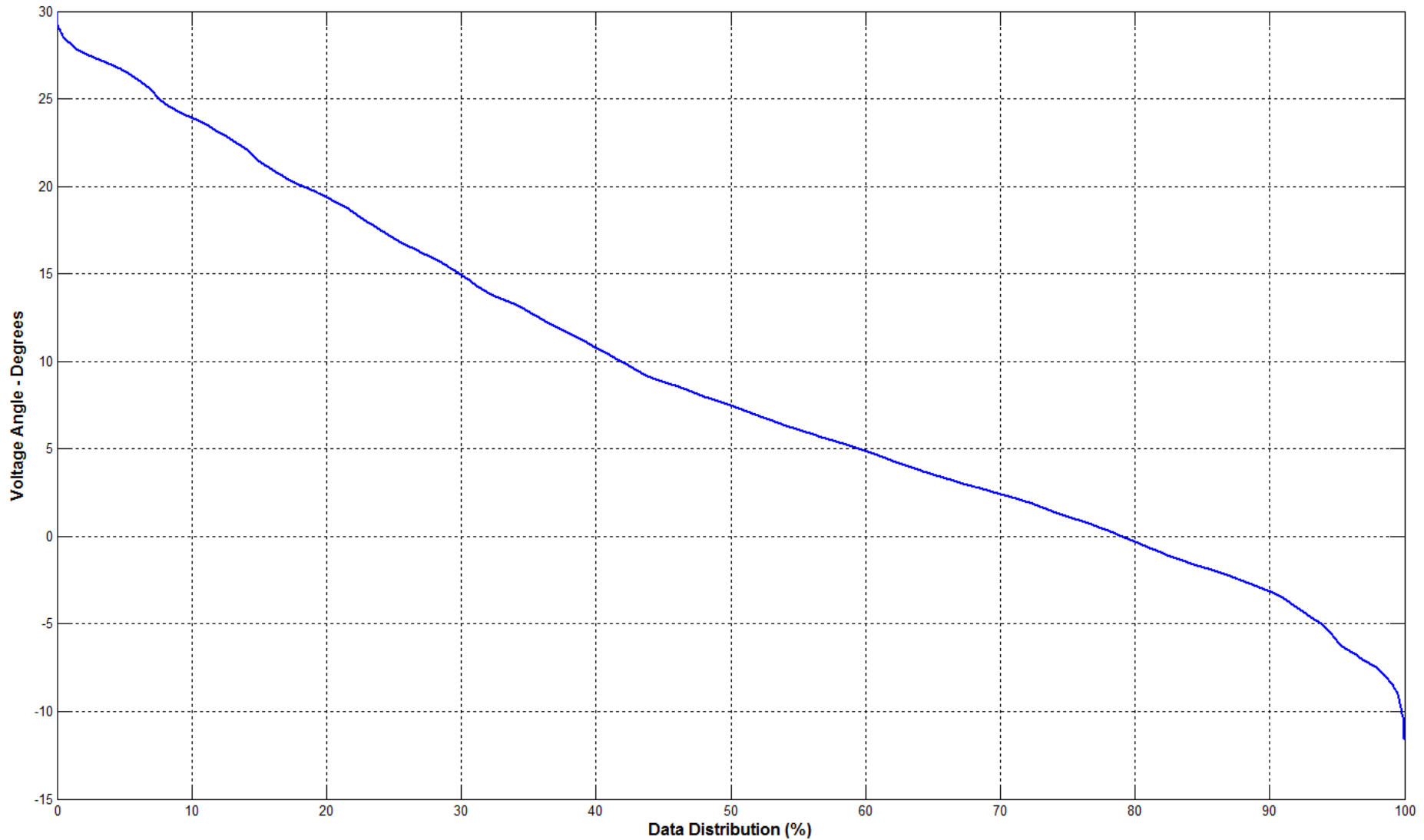
West 12– Voltage Angle



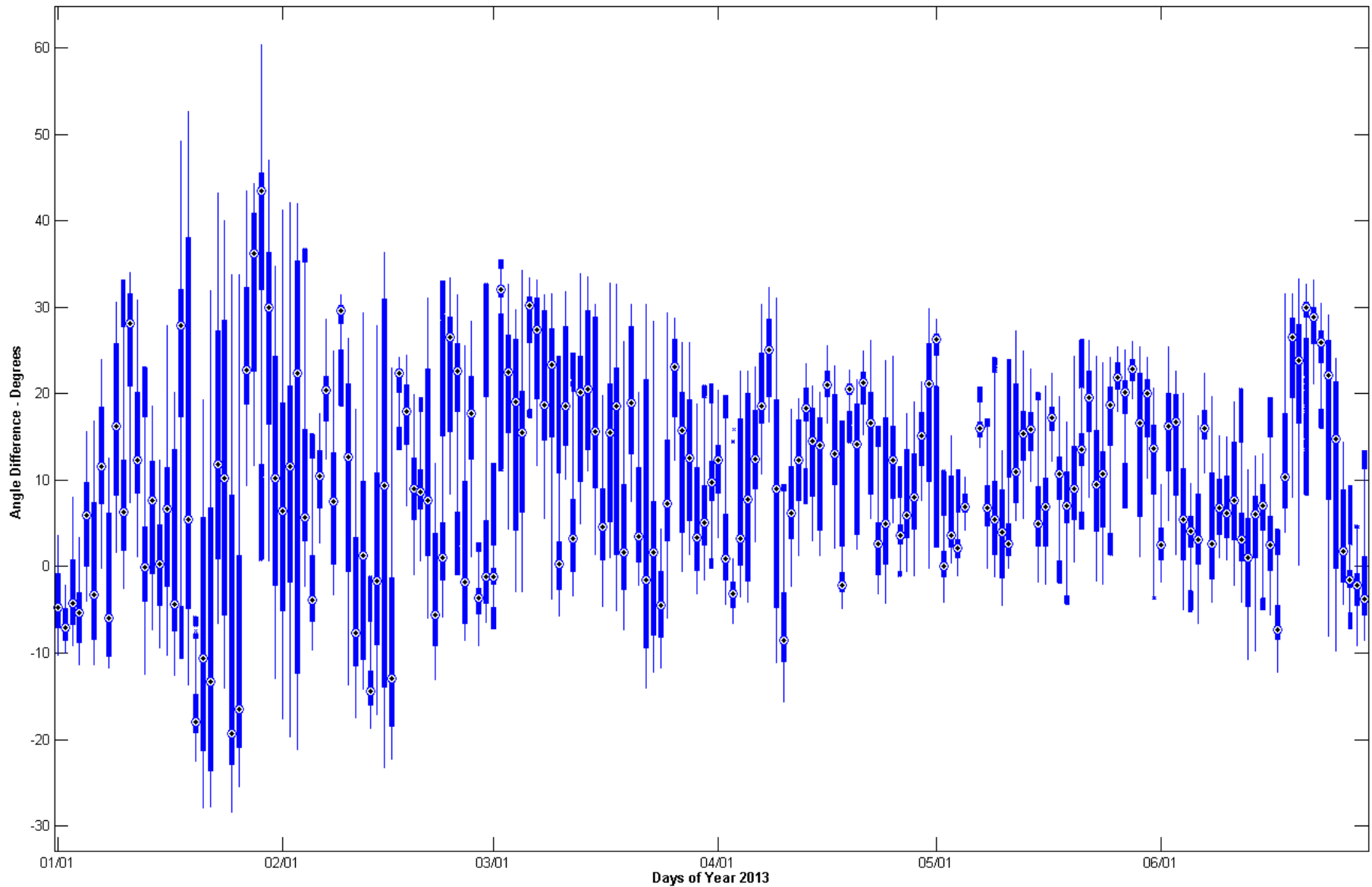
West 5 – Voltage Angle



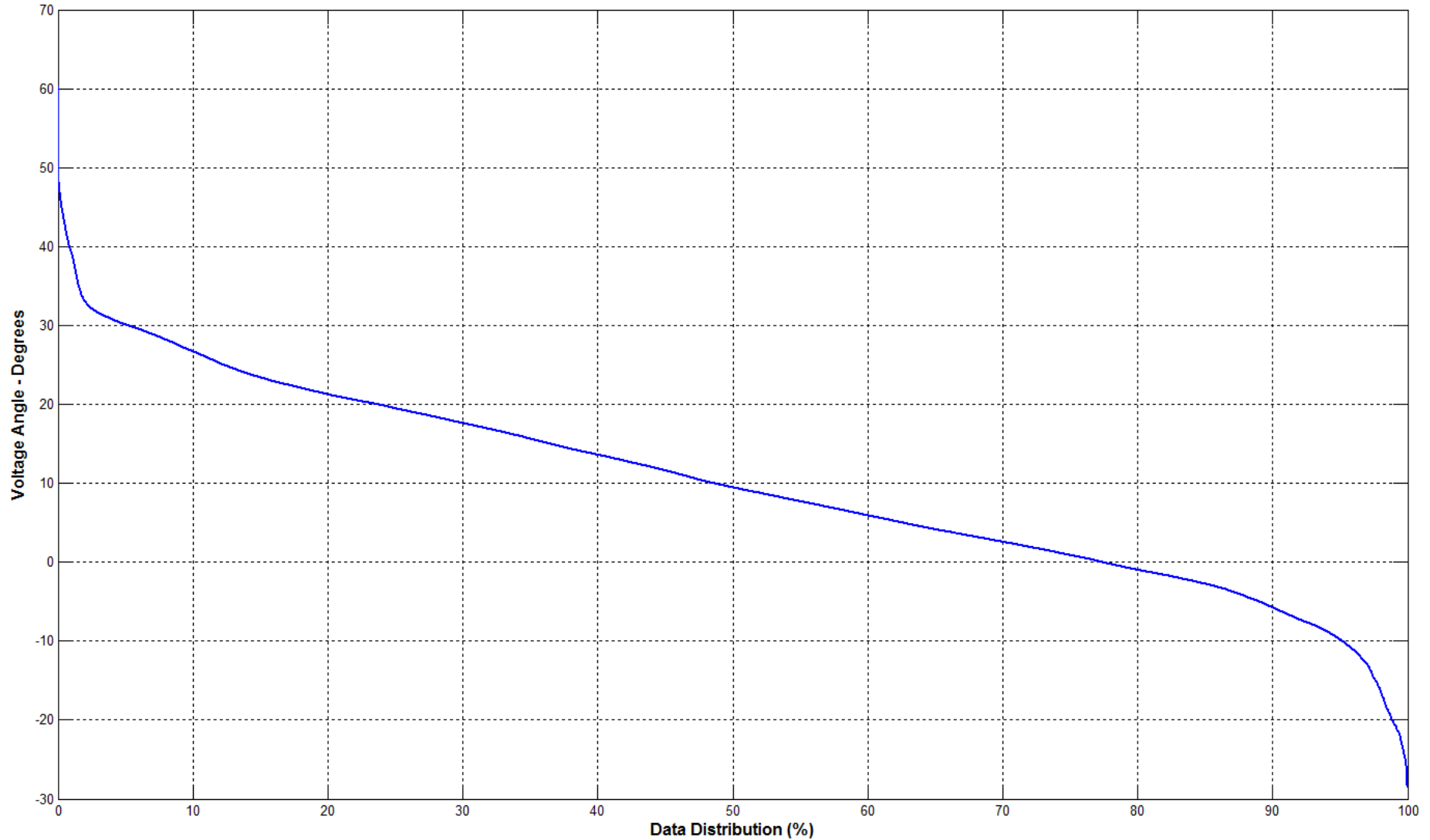
West 5 – Voltage Angle



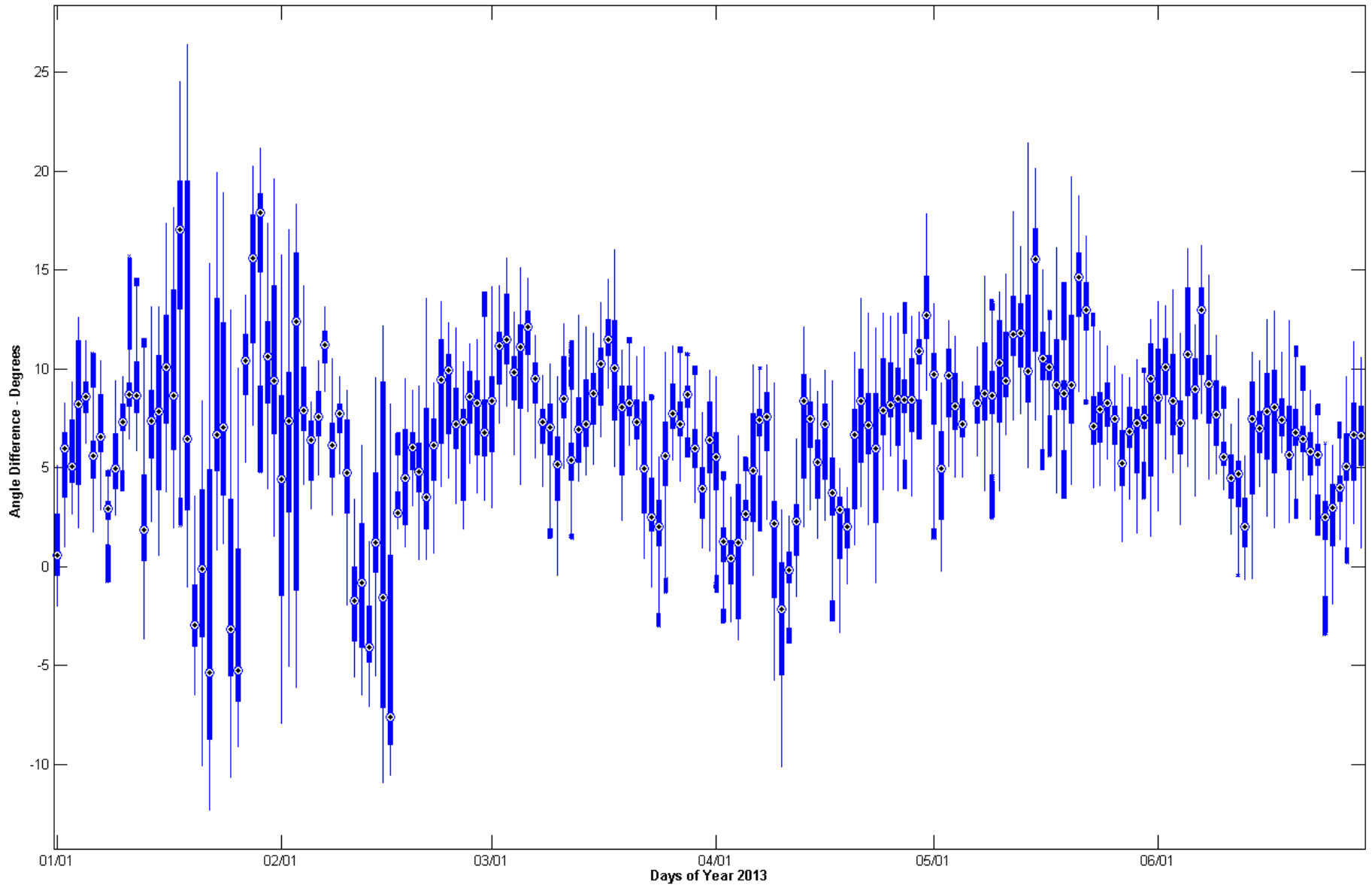
West 6 – Voltage Angle



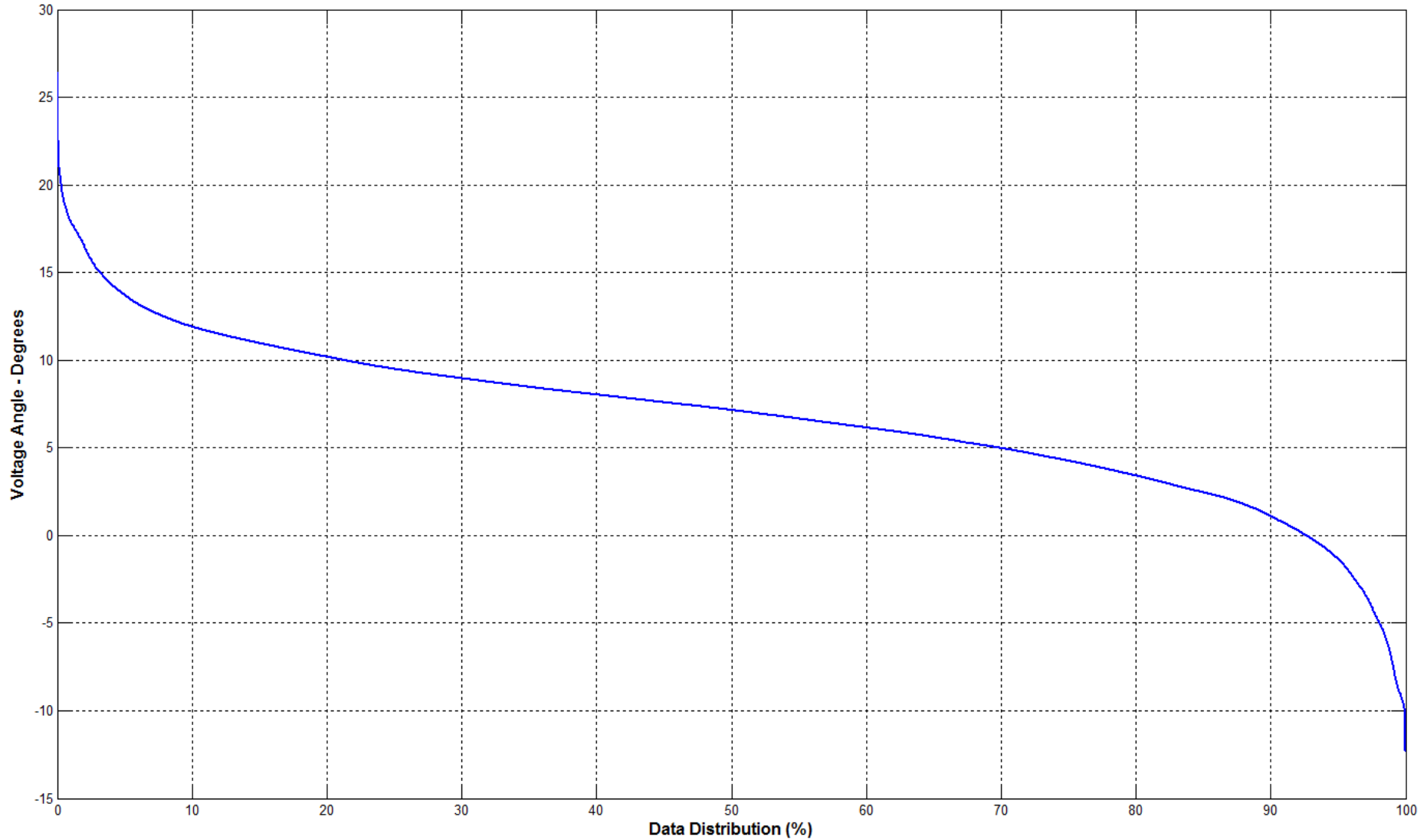
West 6 – Voltage Angle



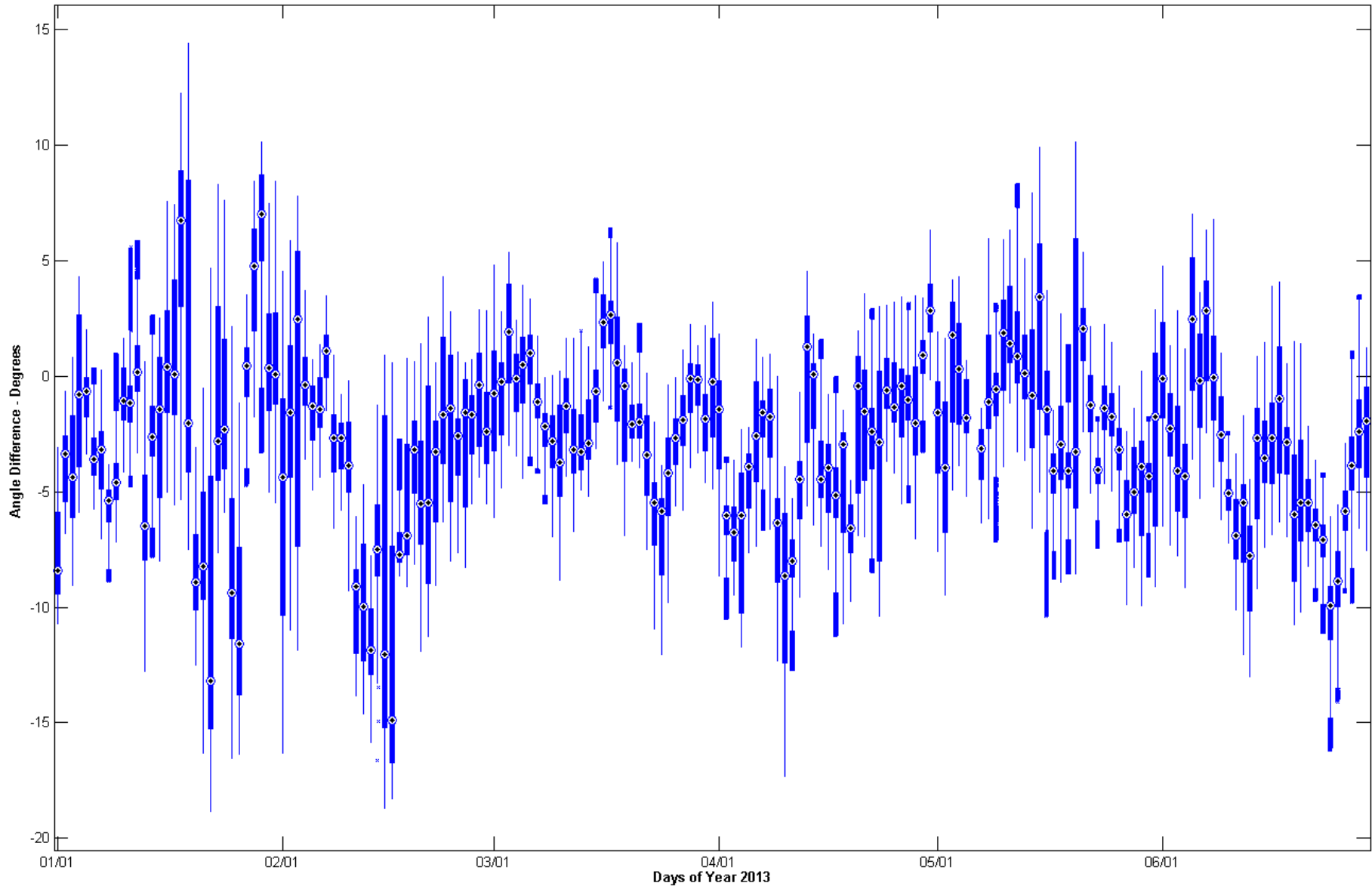
North 1 – Voltage Angle



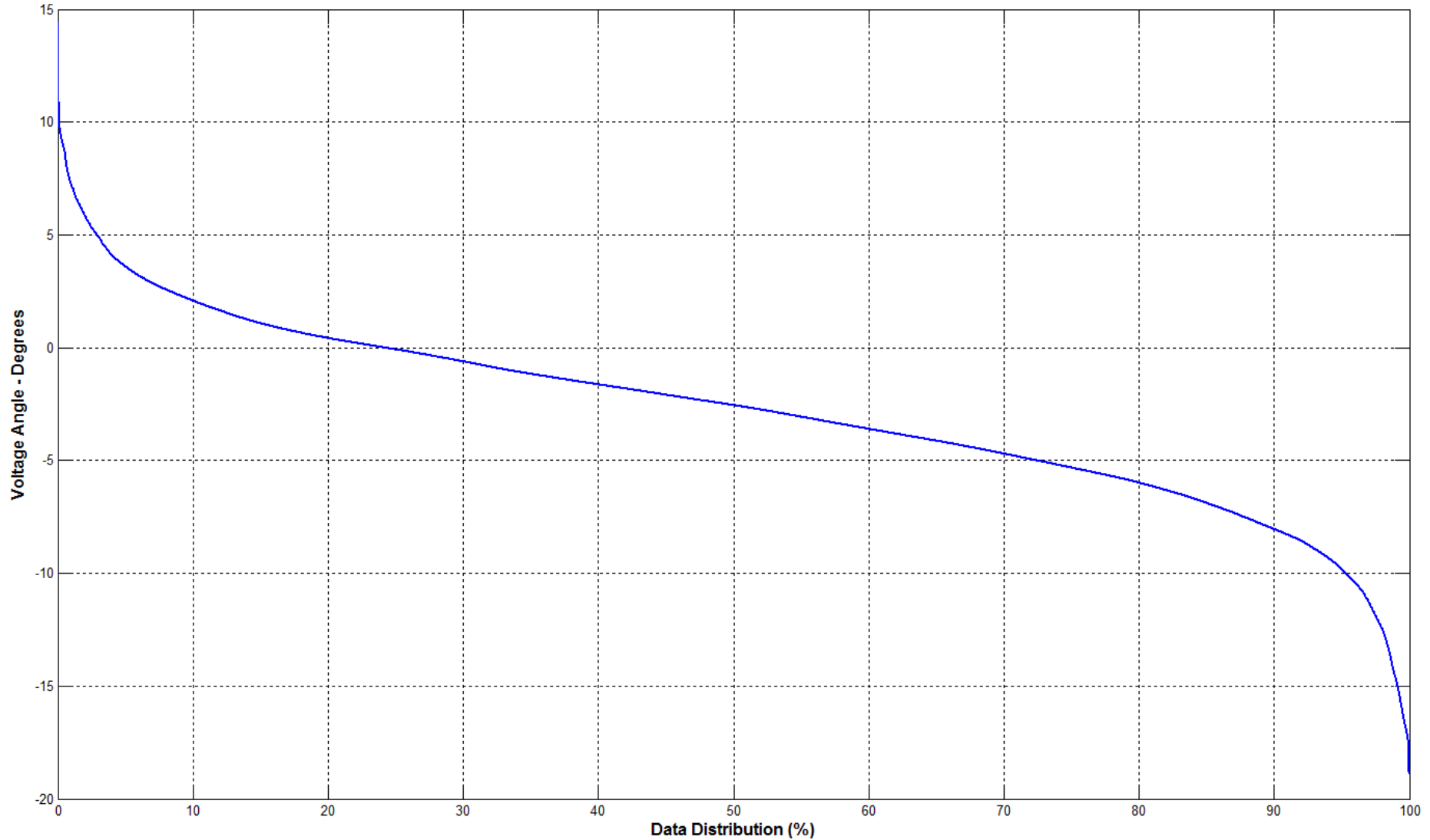
North 1 – Voltage Angle



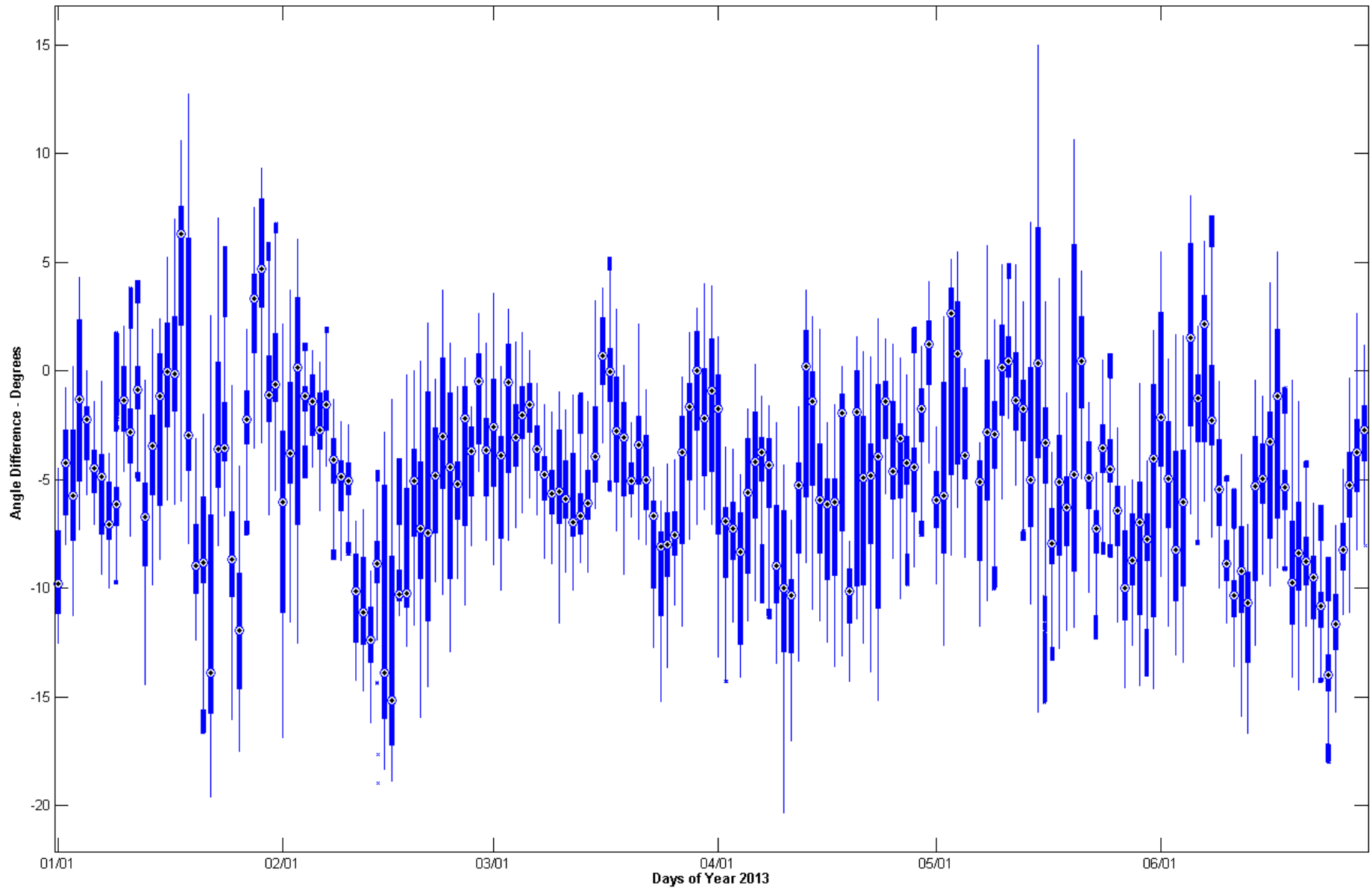
North 4 – Voltage Angle



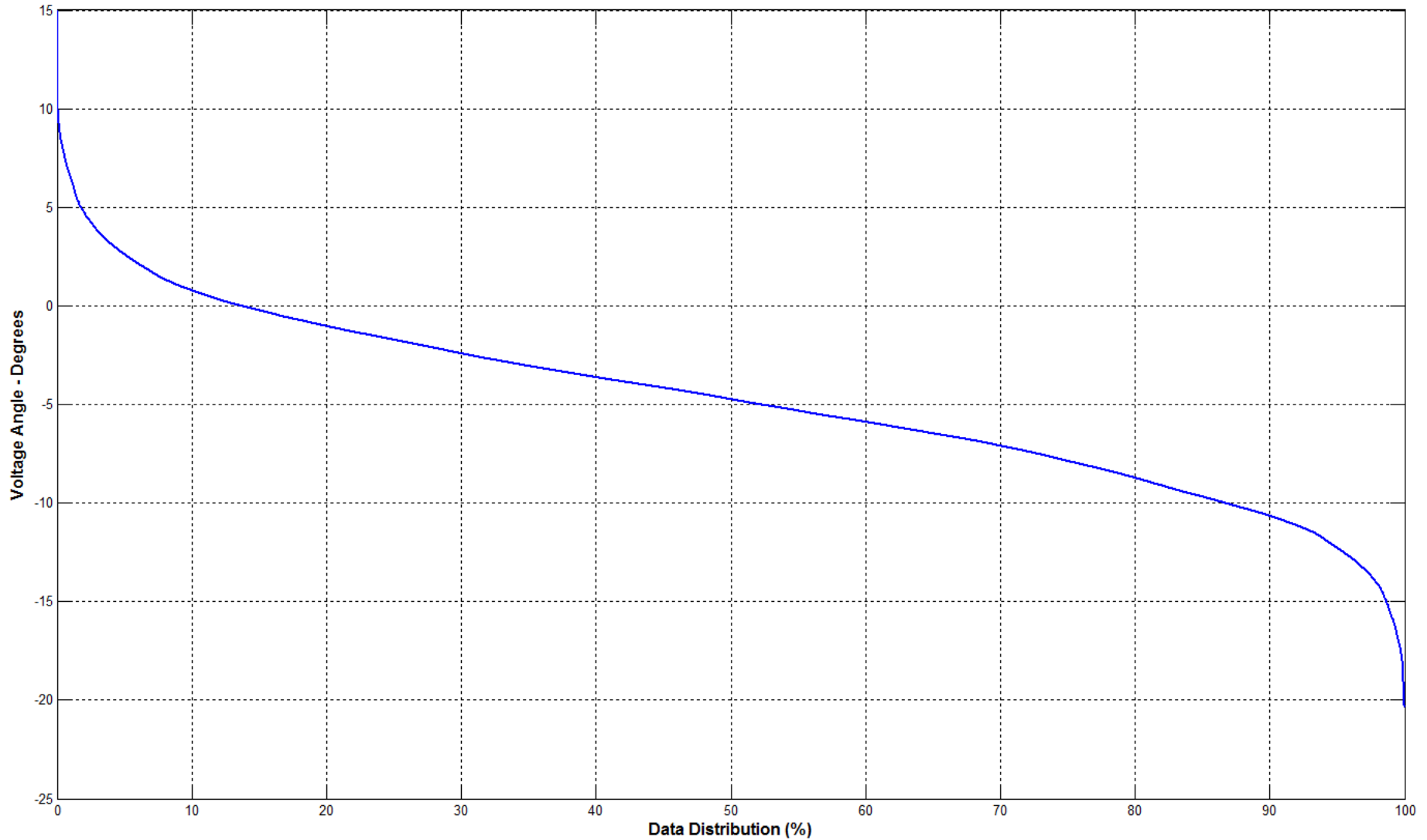
North 4 – Voltage Angle



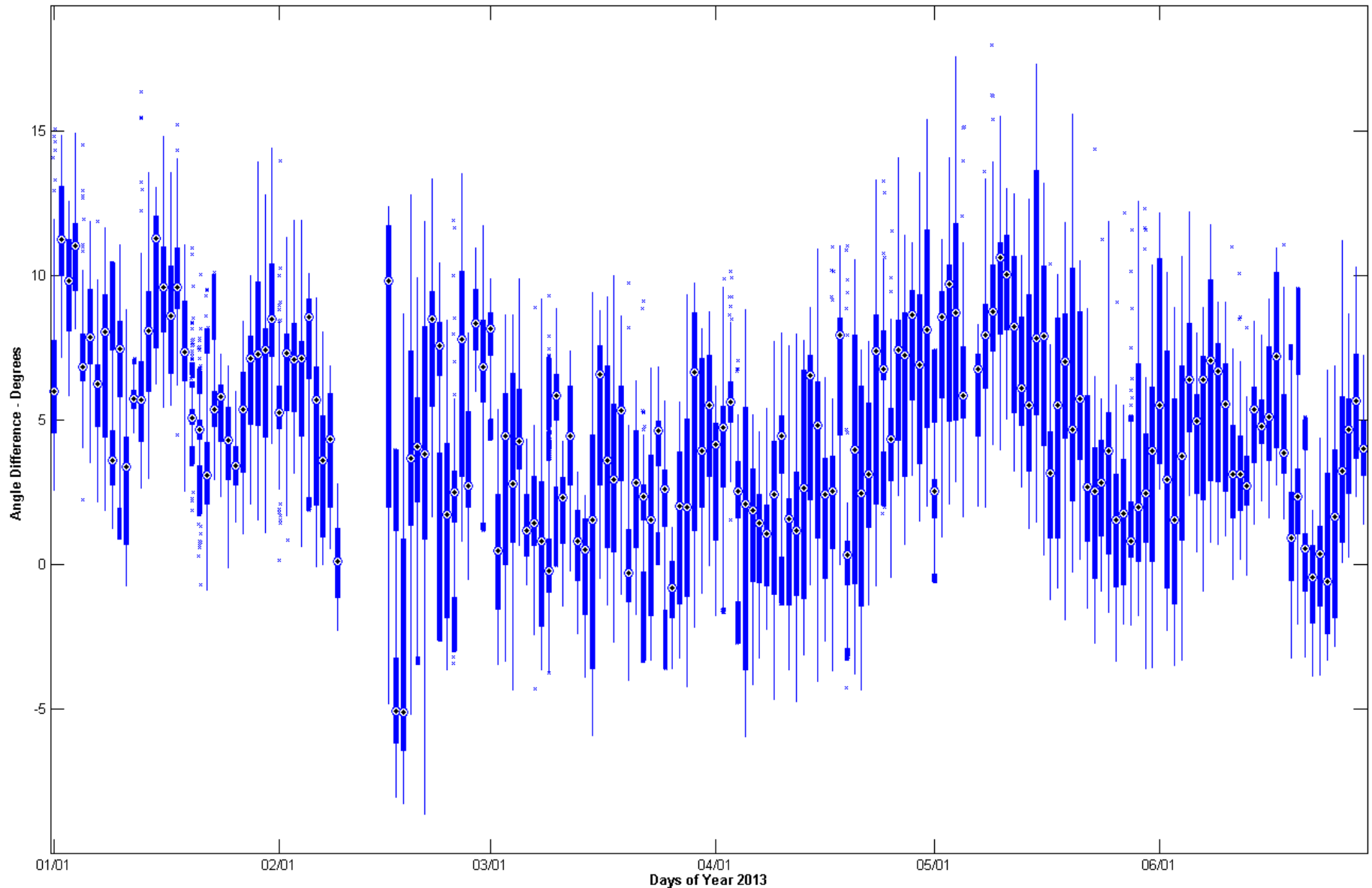
North 5 – Voltage Angle



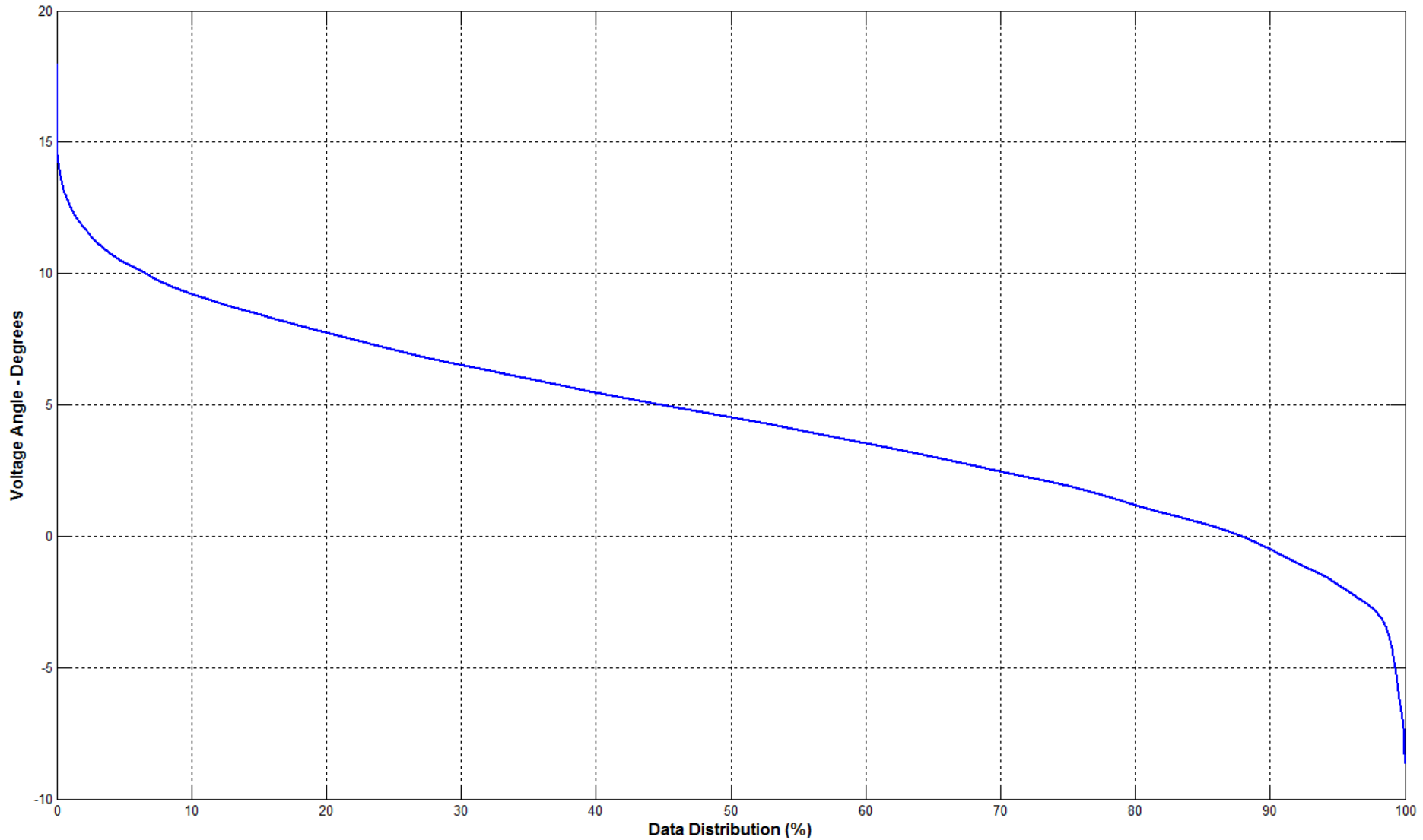
North 5 – Voltage Angle



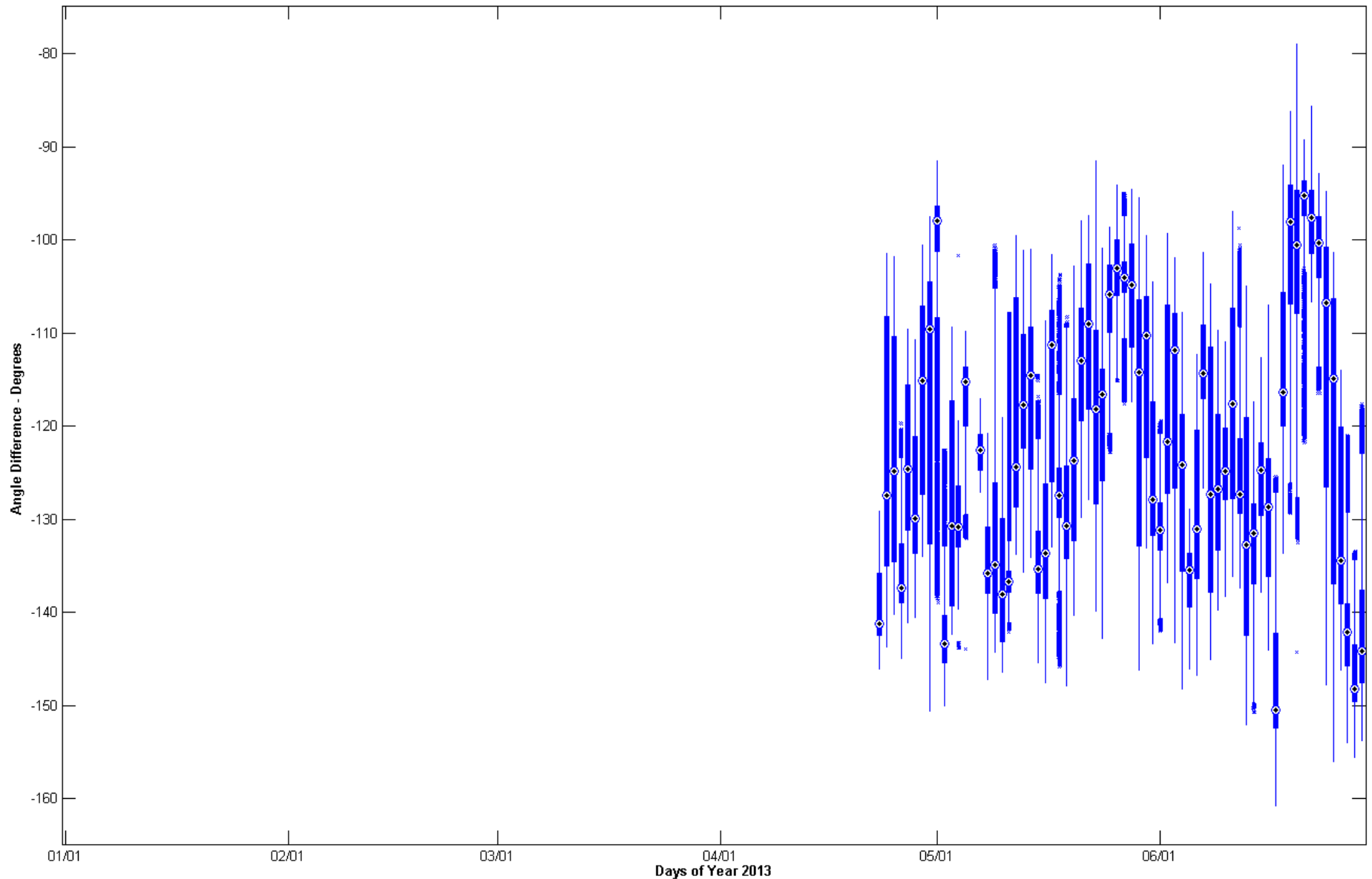
North 6 – Voltage Angle



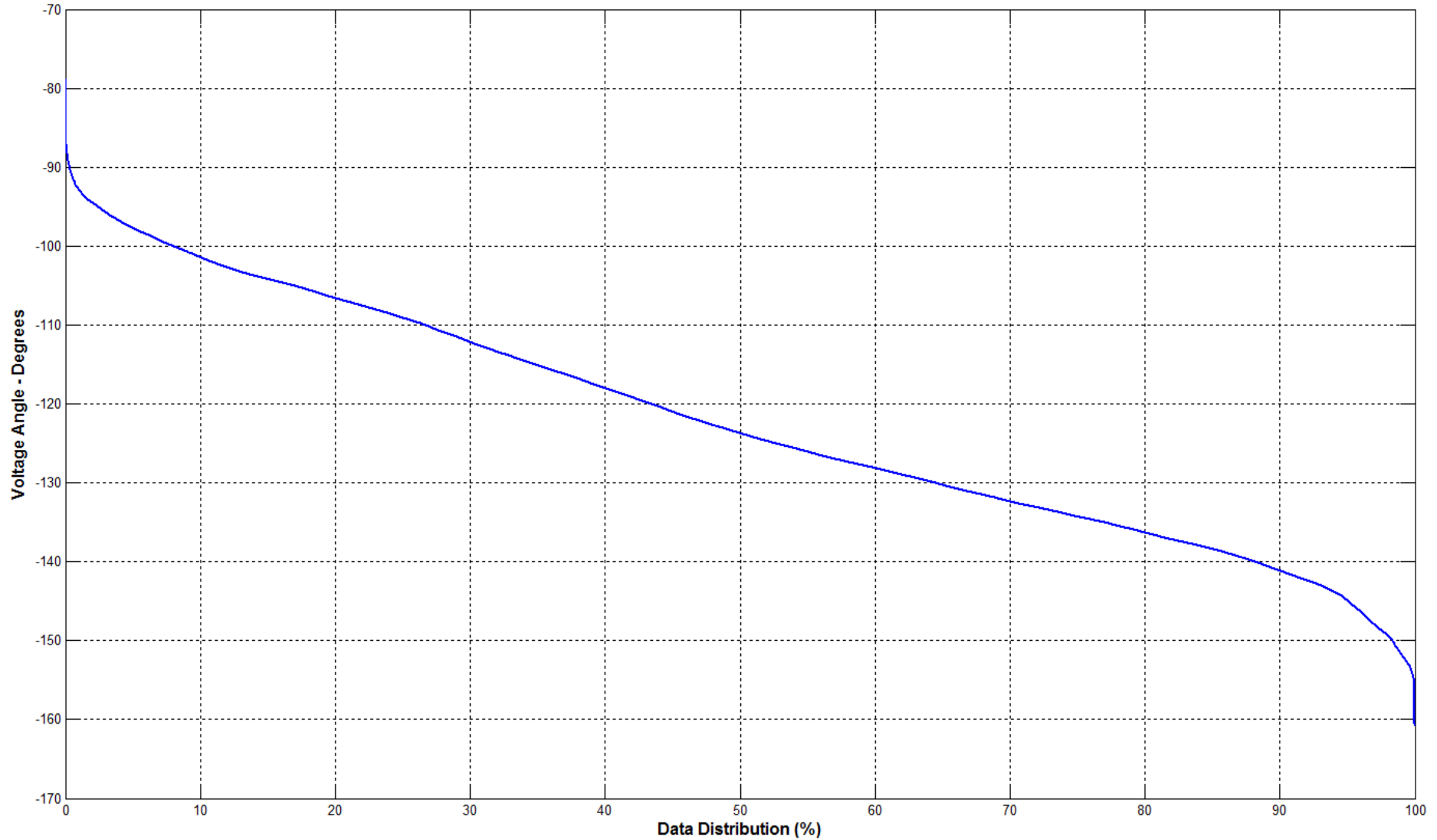
North 6 – Voltage Angle



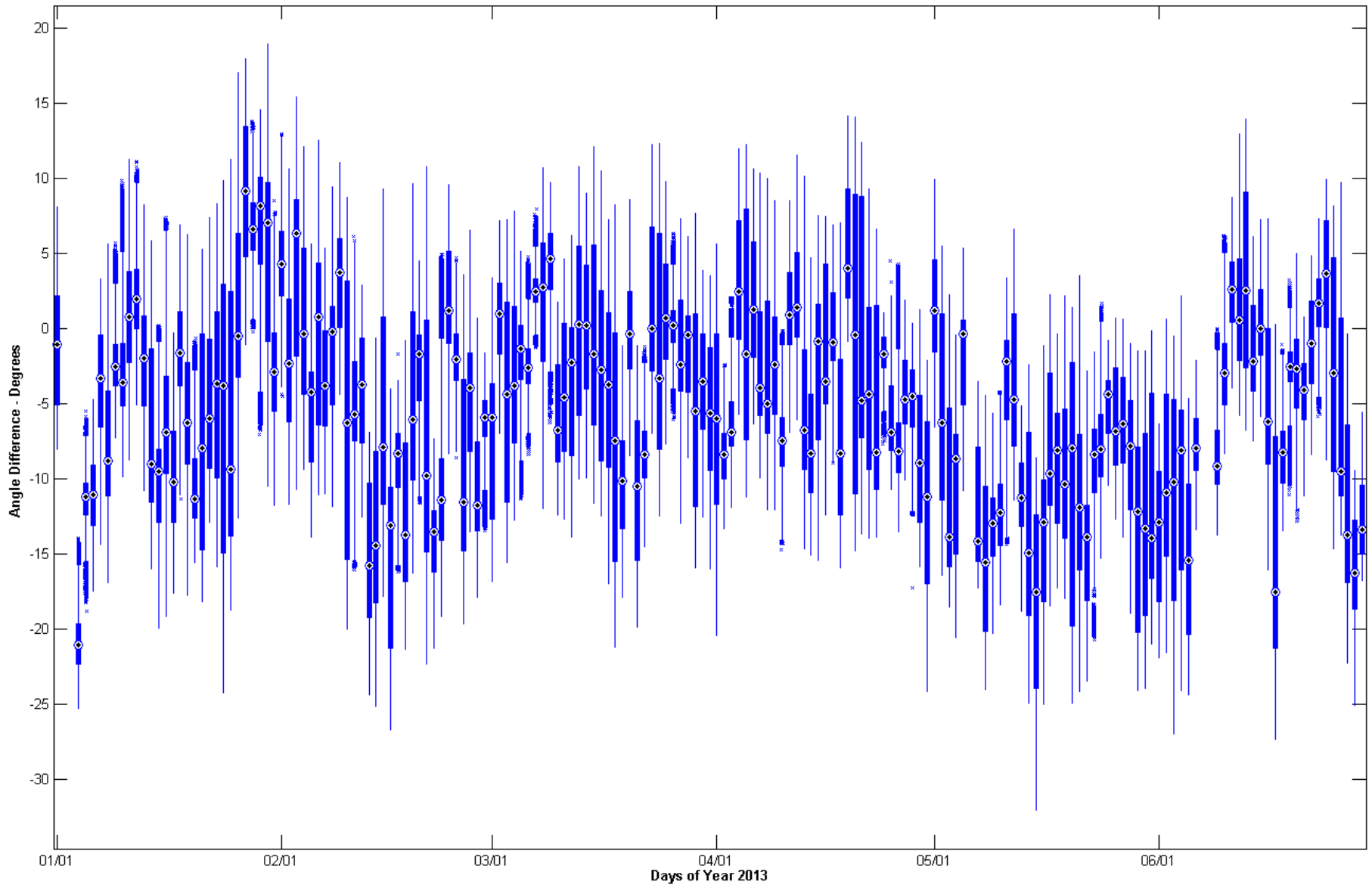
FarWest 2 – Voltage Angle



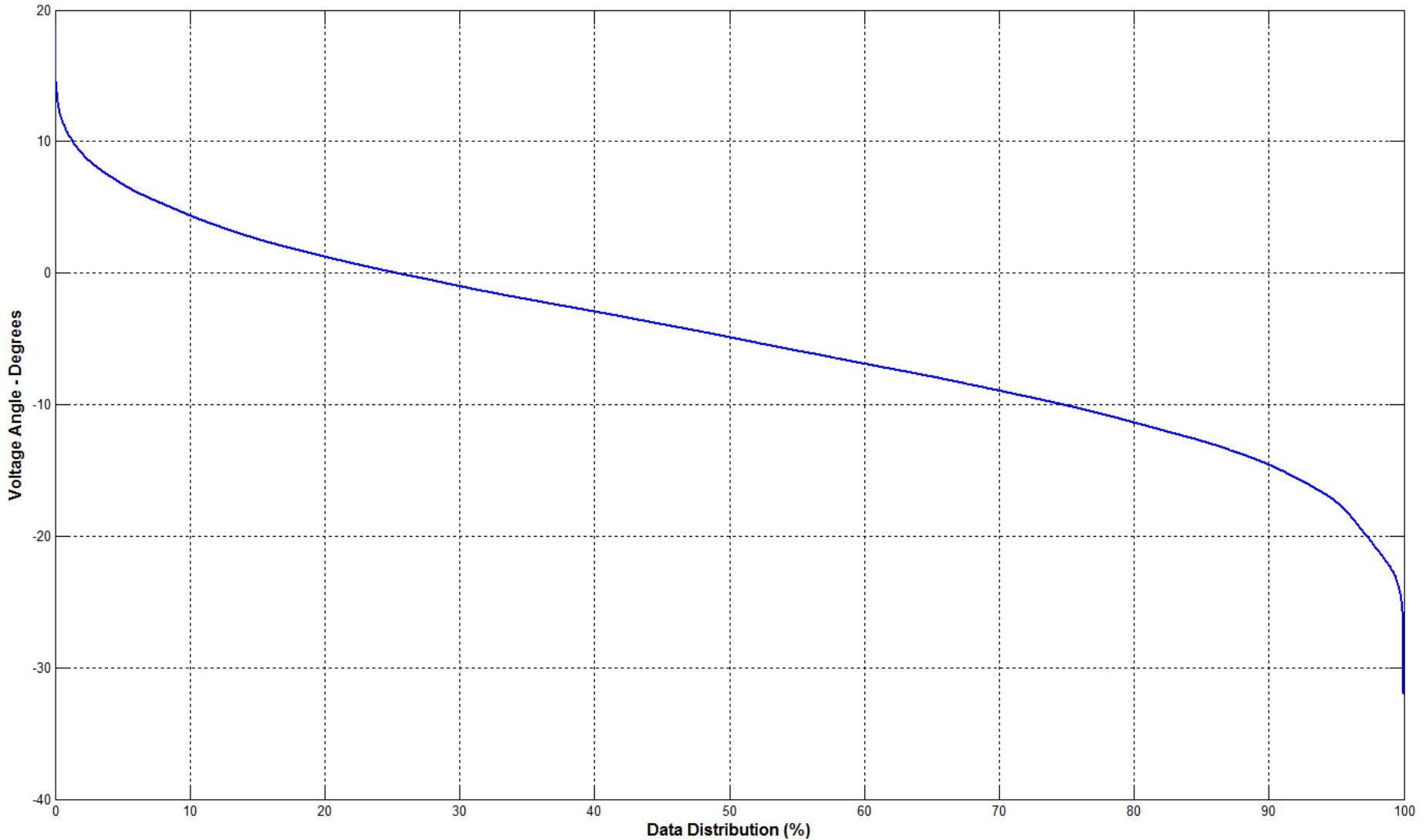
FarWest 2 – Voltage Angle



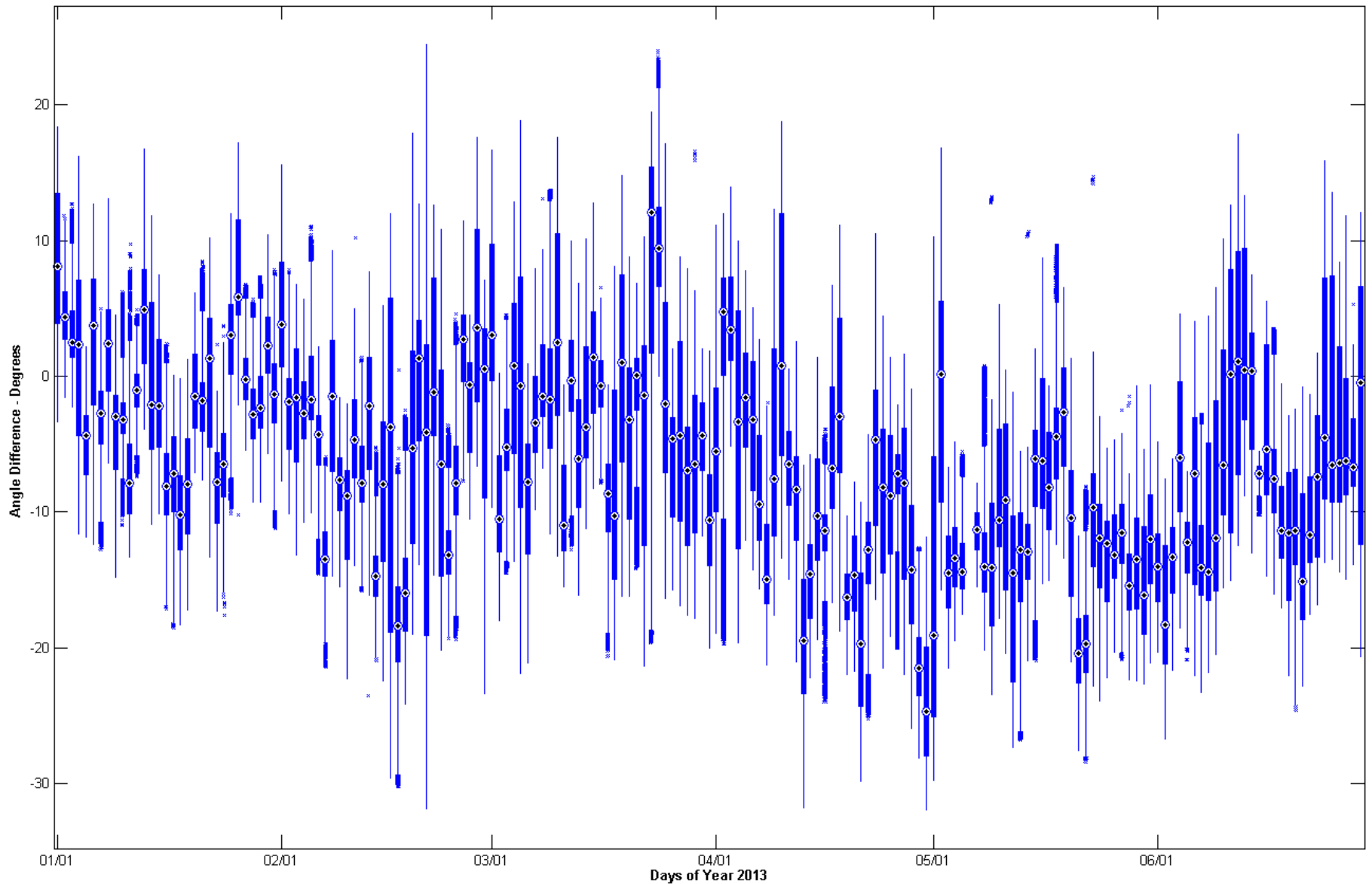
West 4 – Voltage Angle



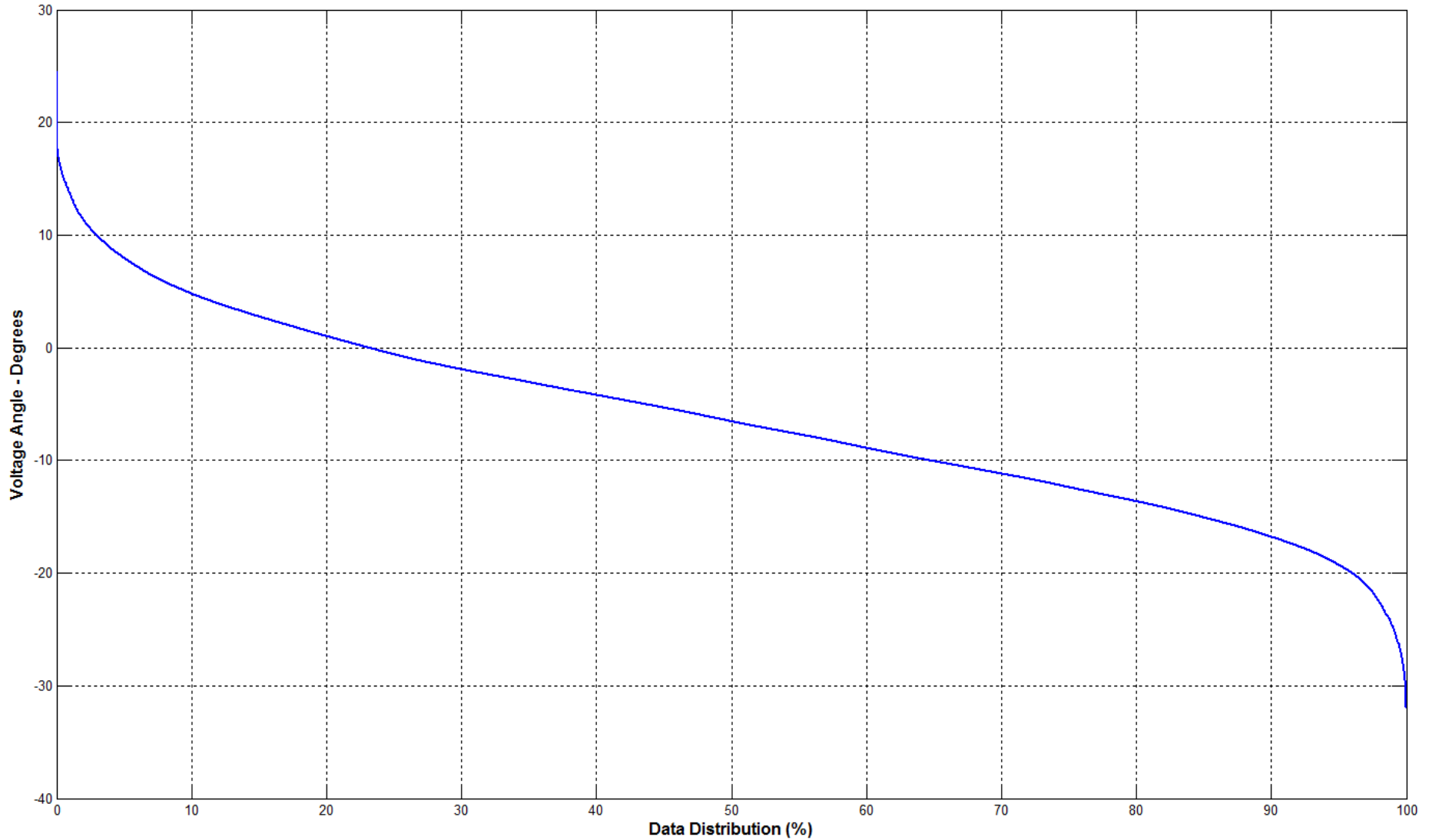
West 4 – Voltage Angle



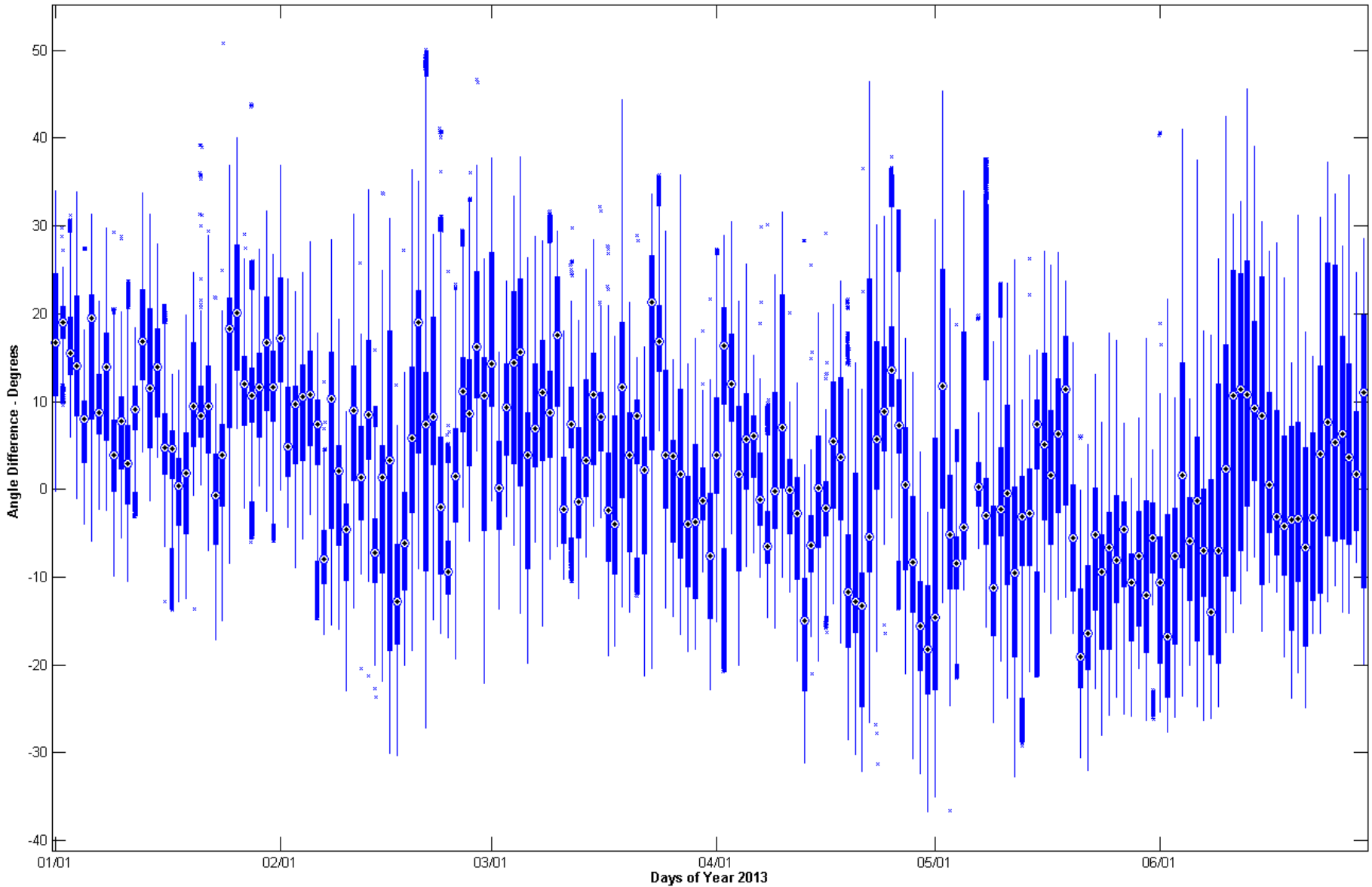
Coast 2 – Voltage Angle



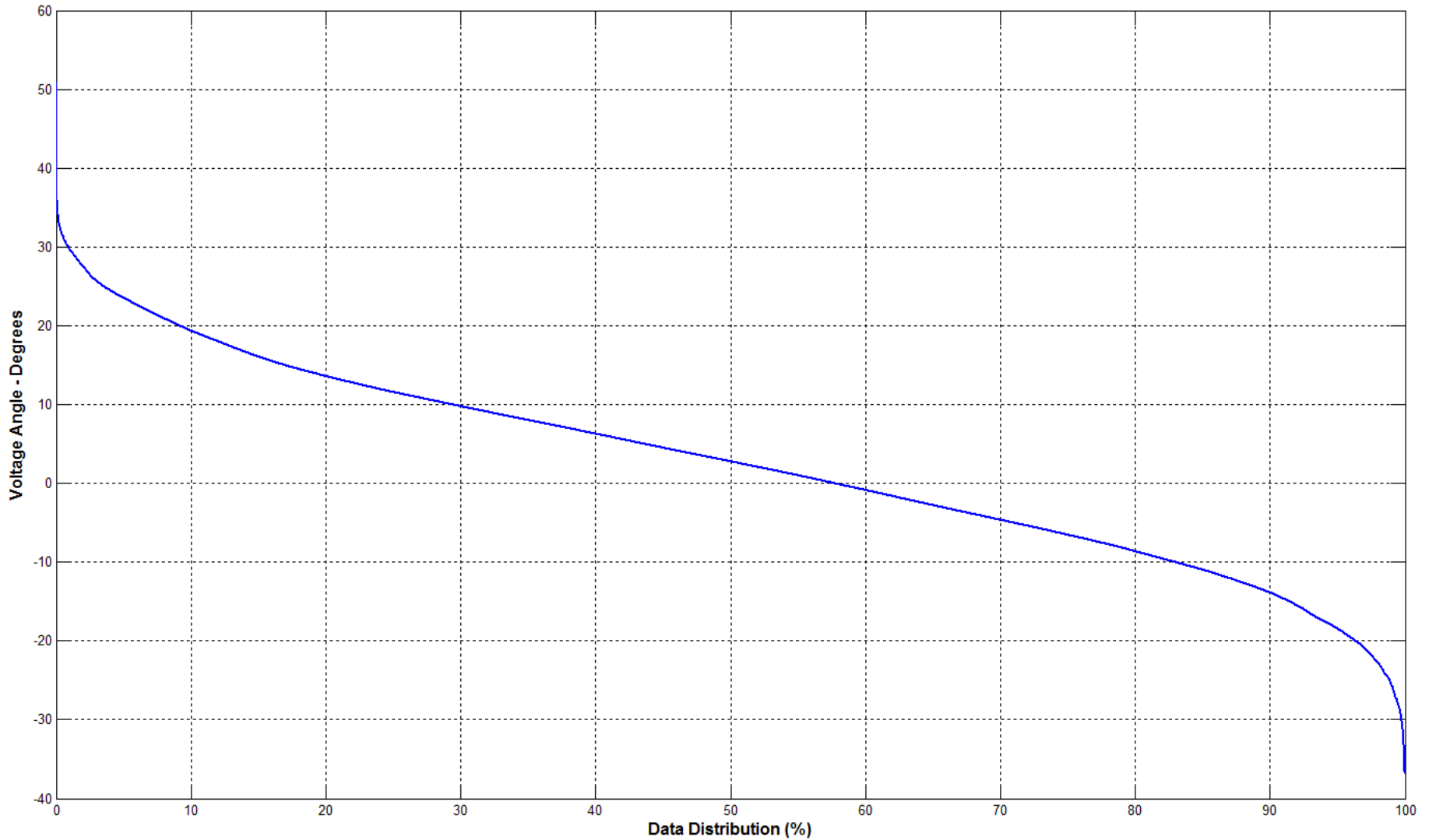
Coast 2 – Voltage Angle



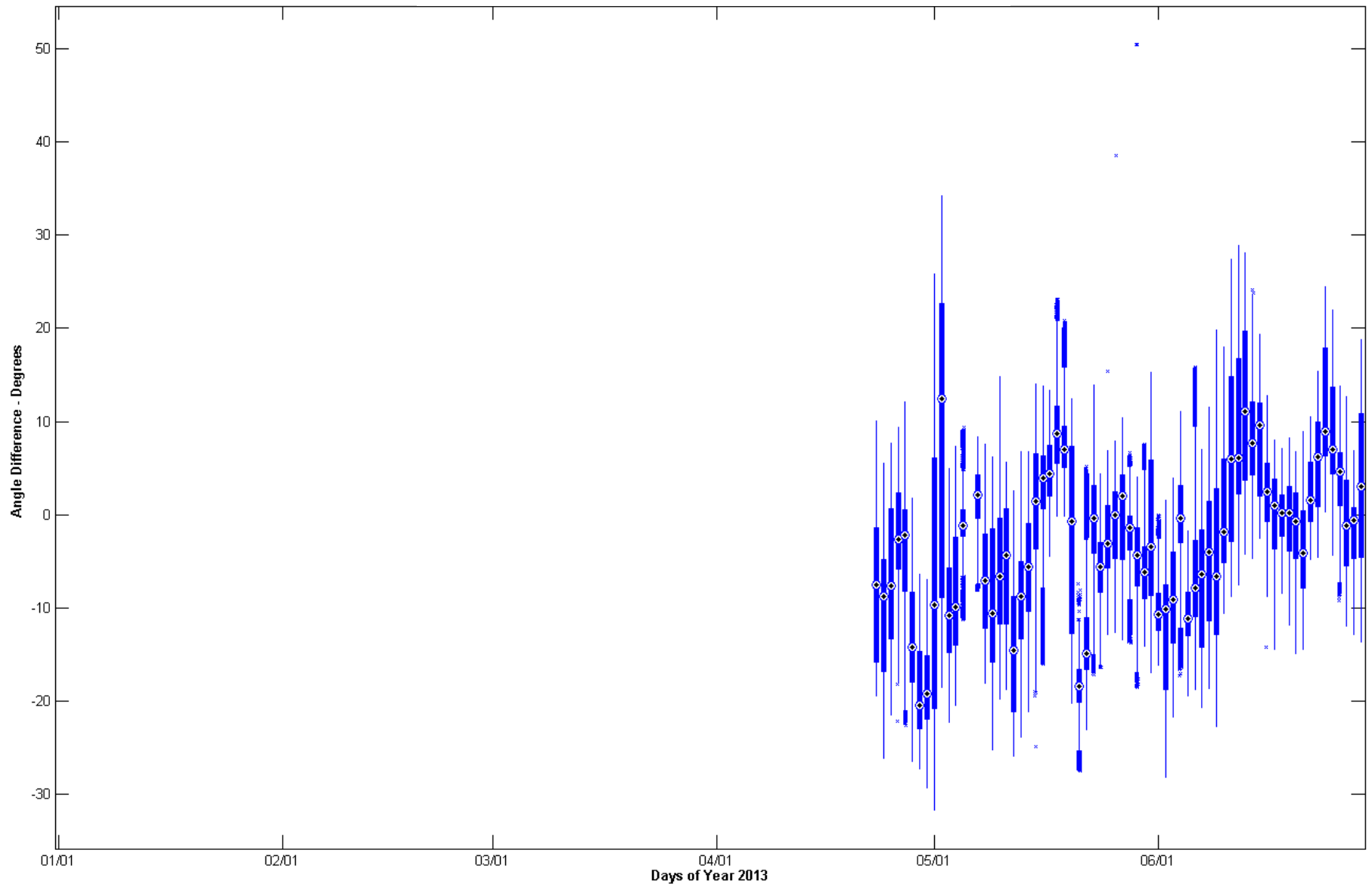
Coast 1 – Voltage Angle



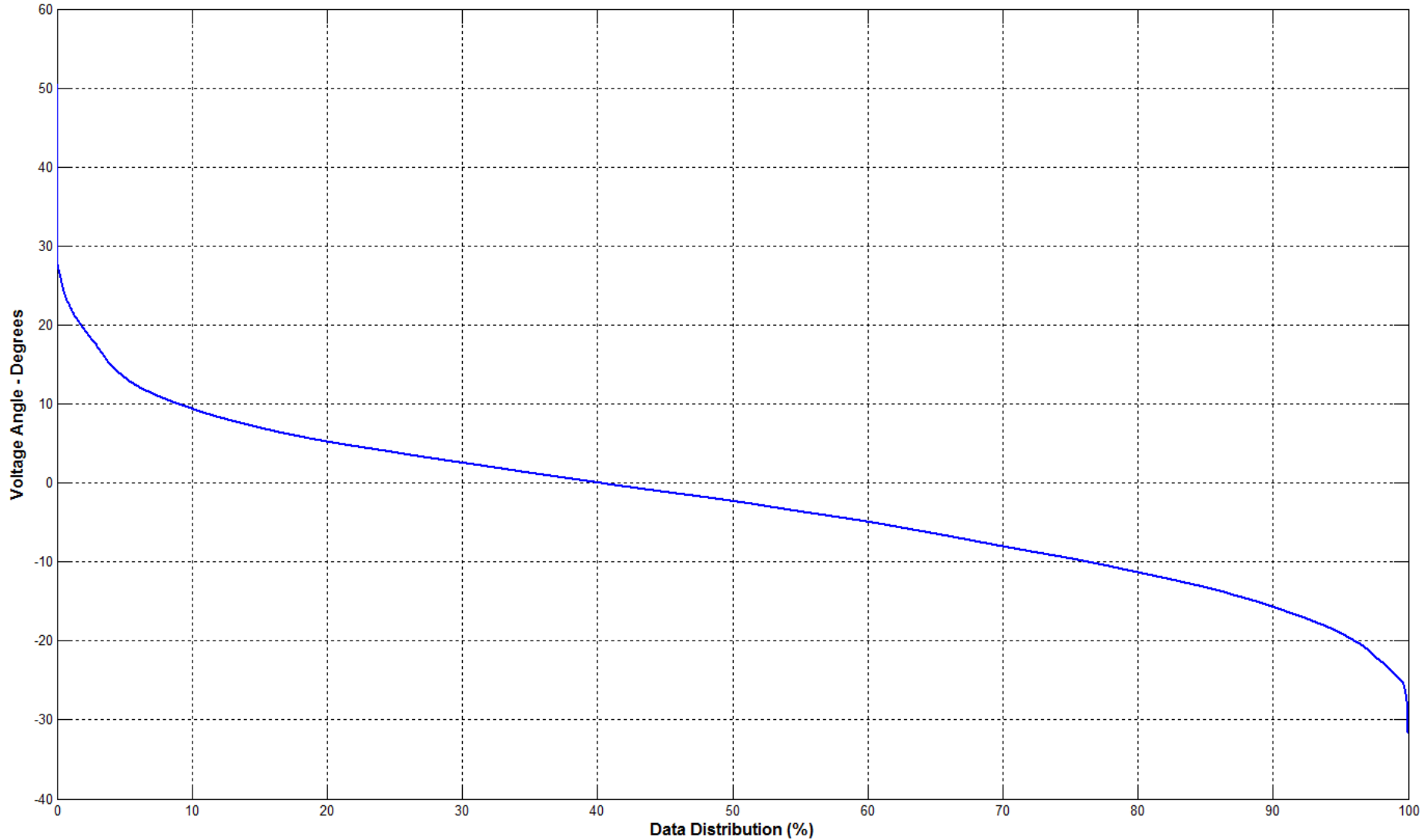
Coast 1 – Voltage Angle



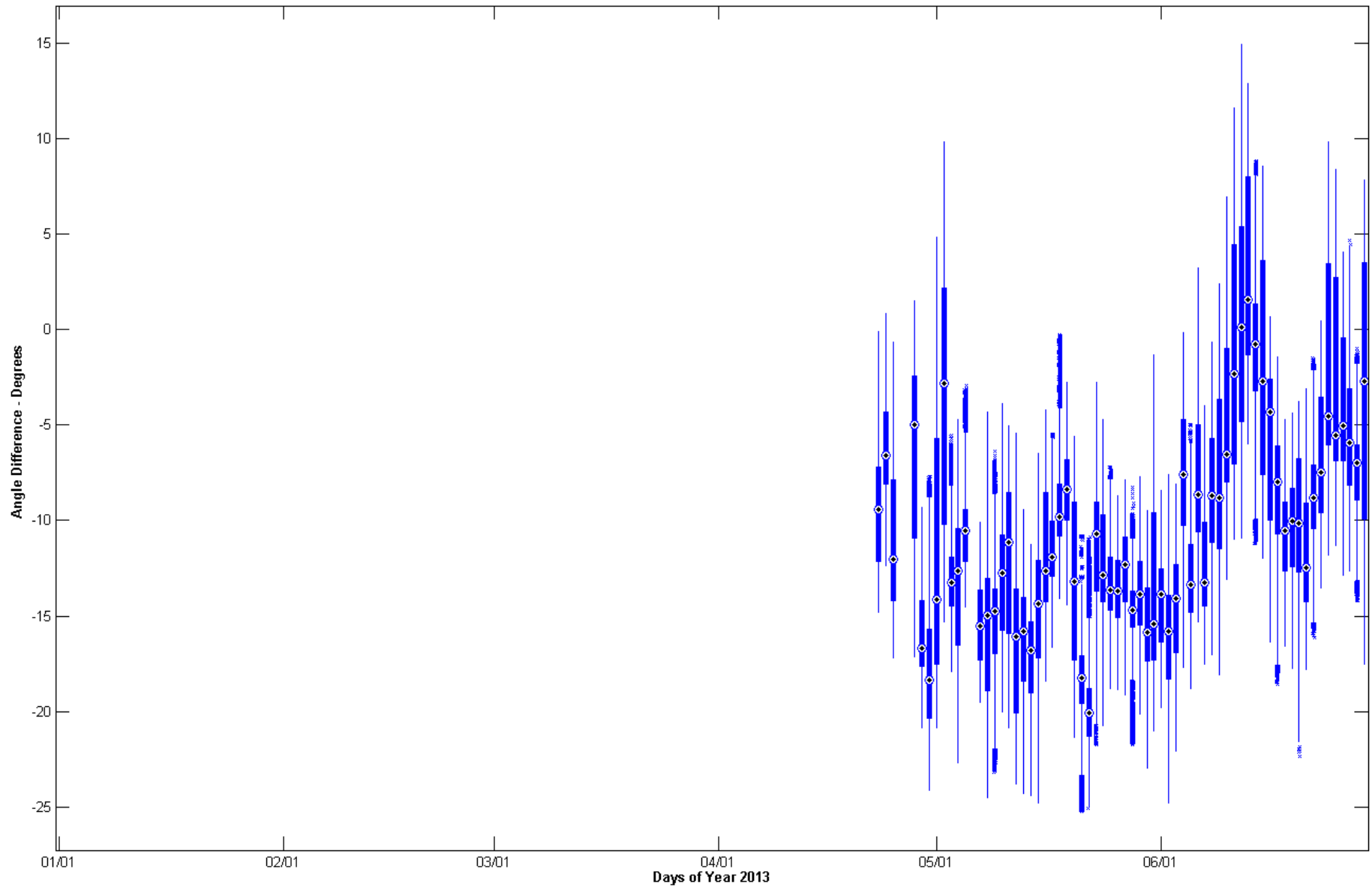
South 3 – Voltage Angle



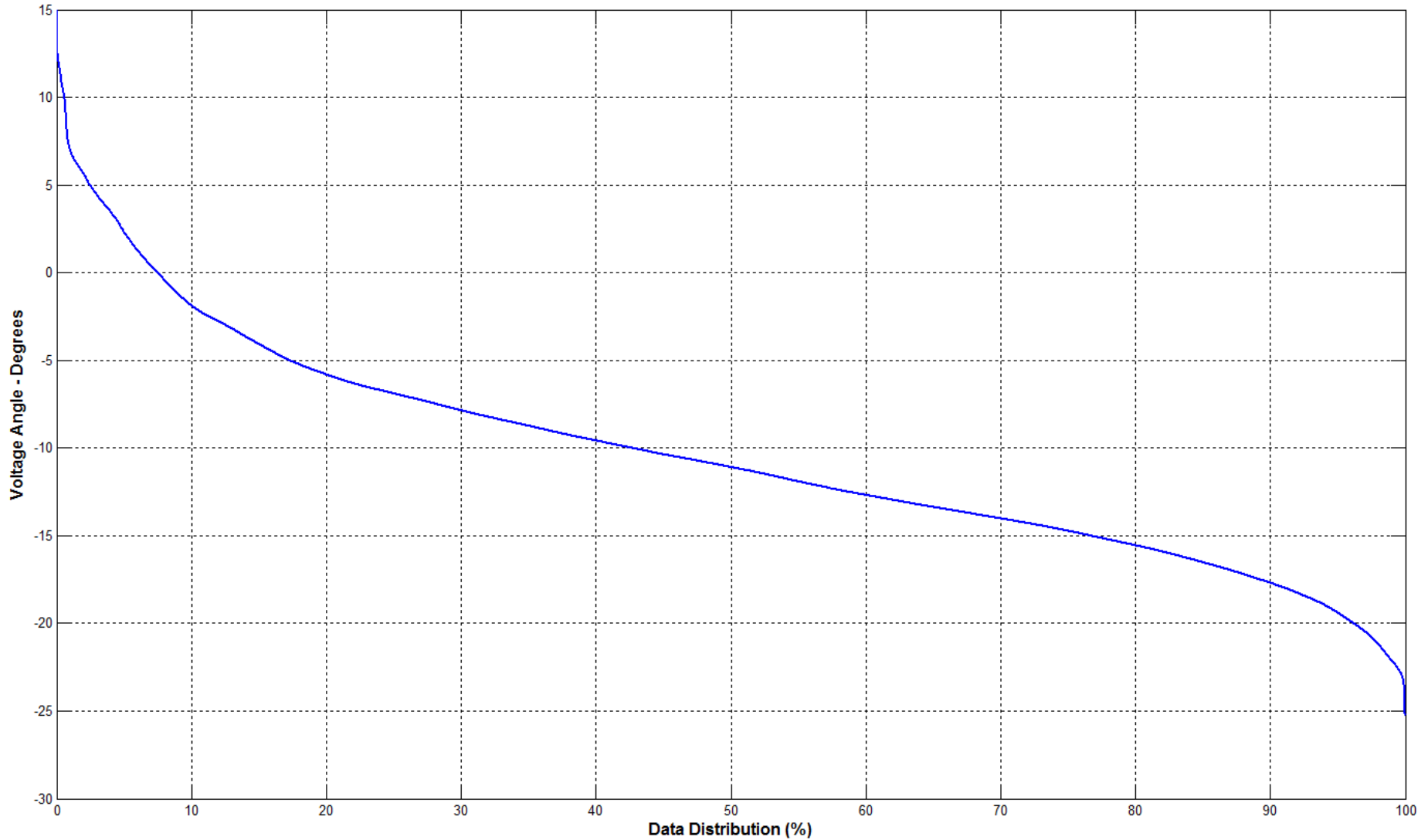
South 3 – Voltage Angle



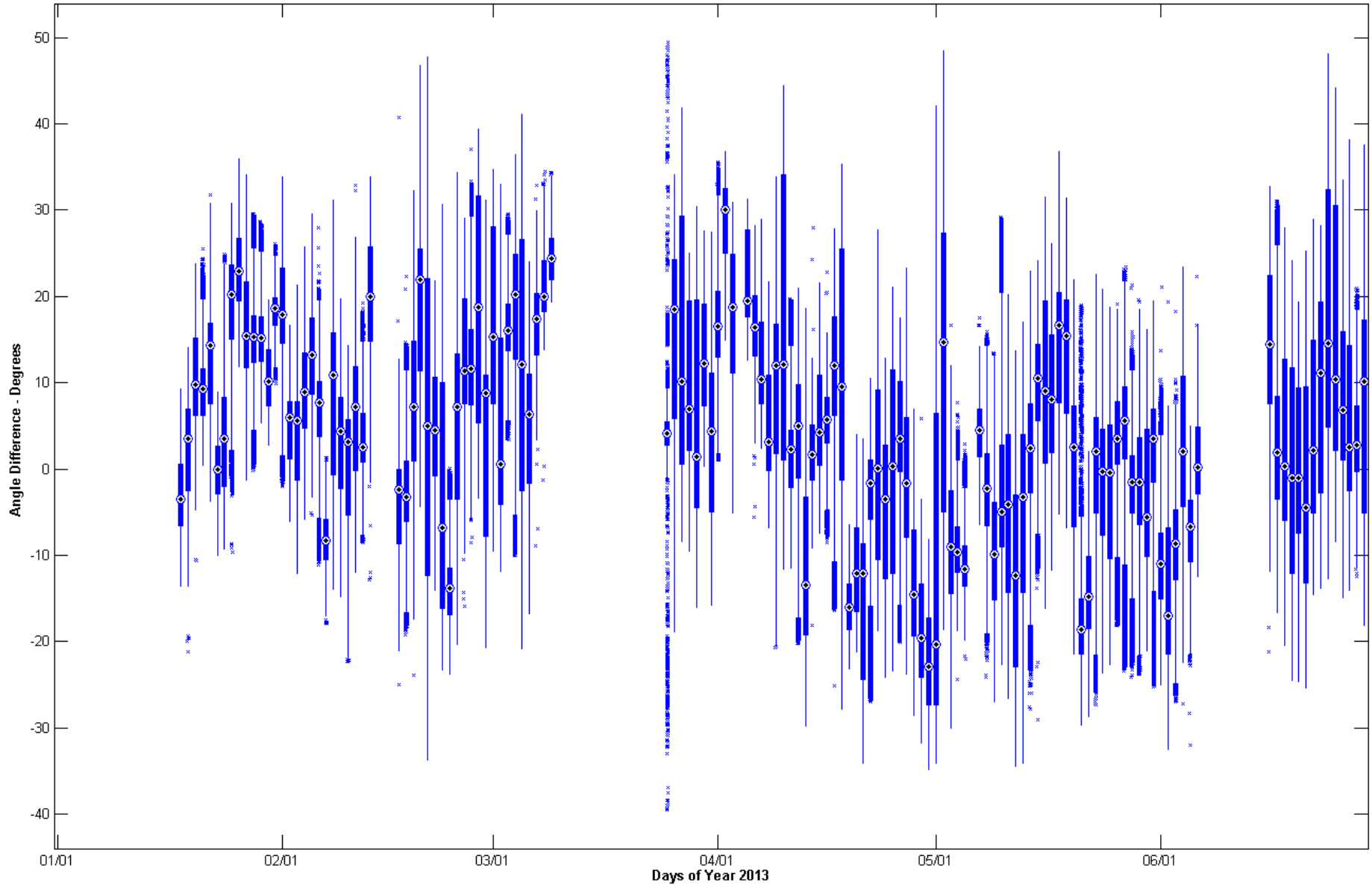
South 5 – Voltage Angle



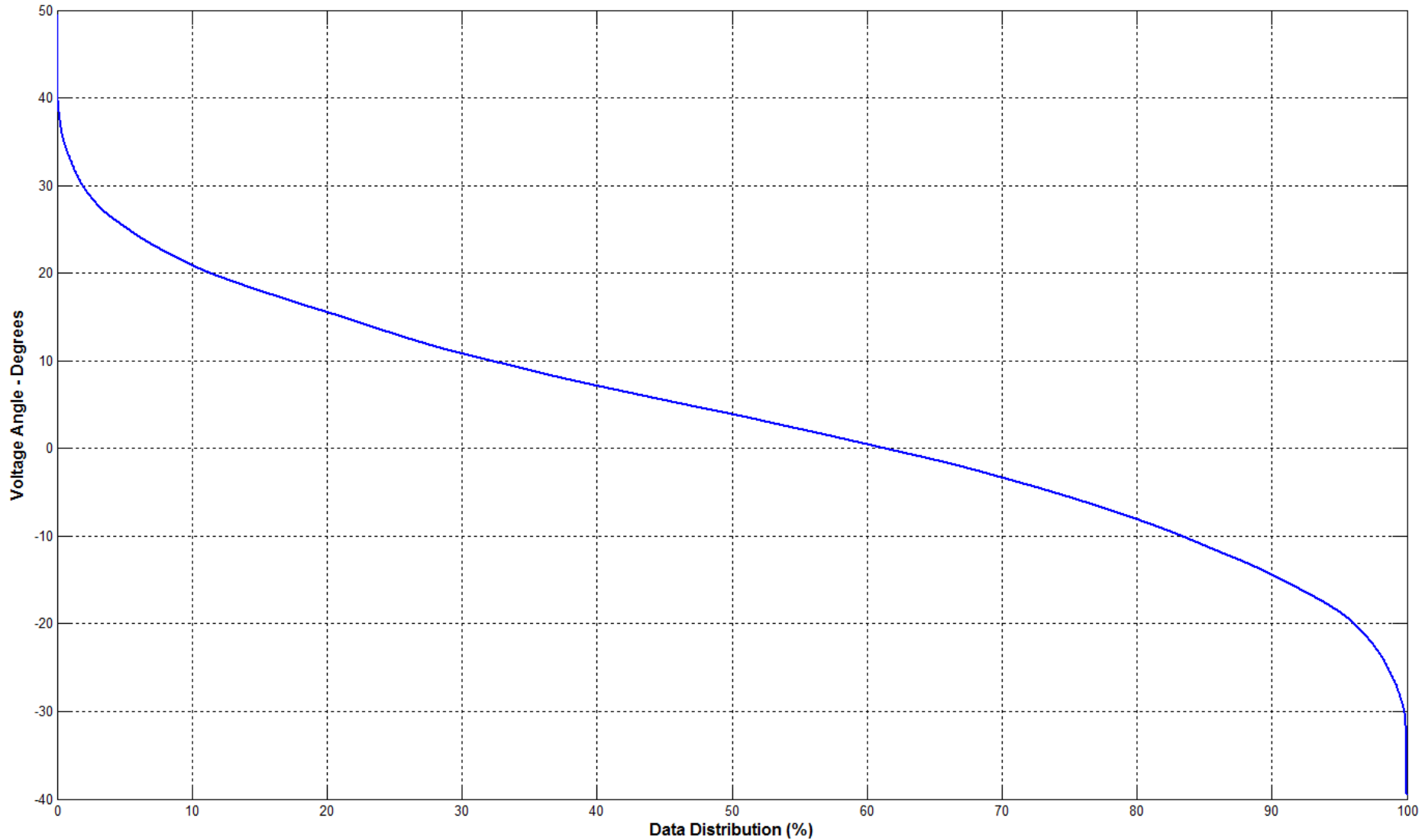
South 5 – Voltage Angle



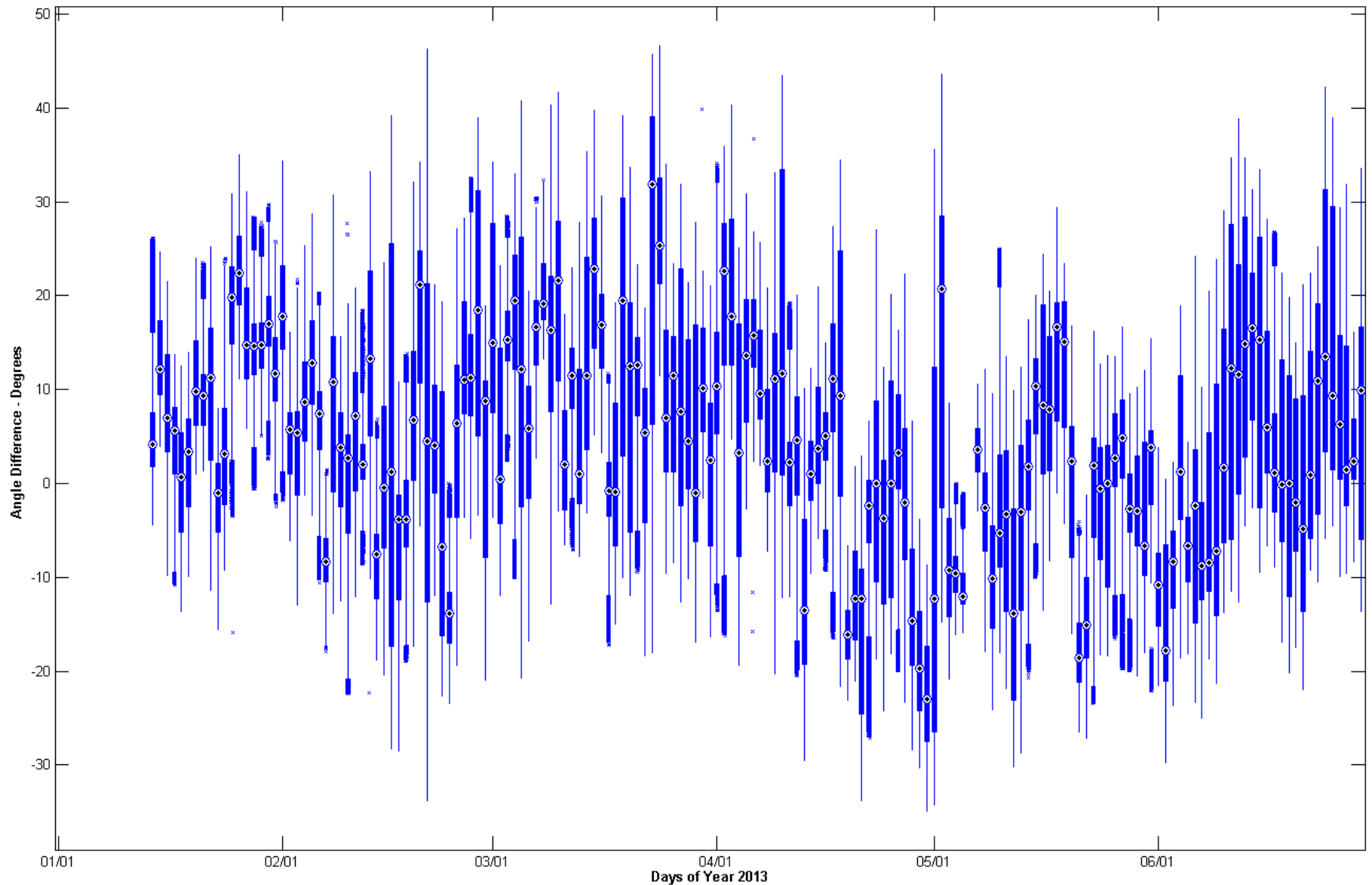
Coast 4 – Voltage Angle



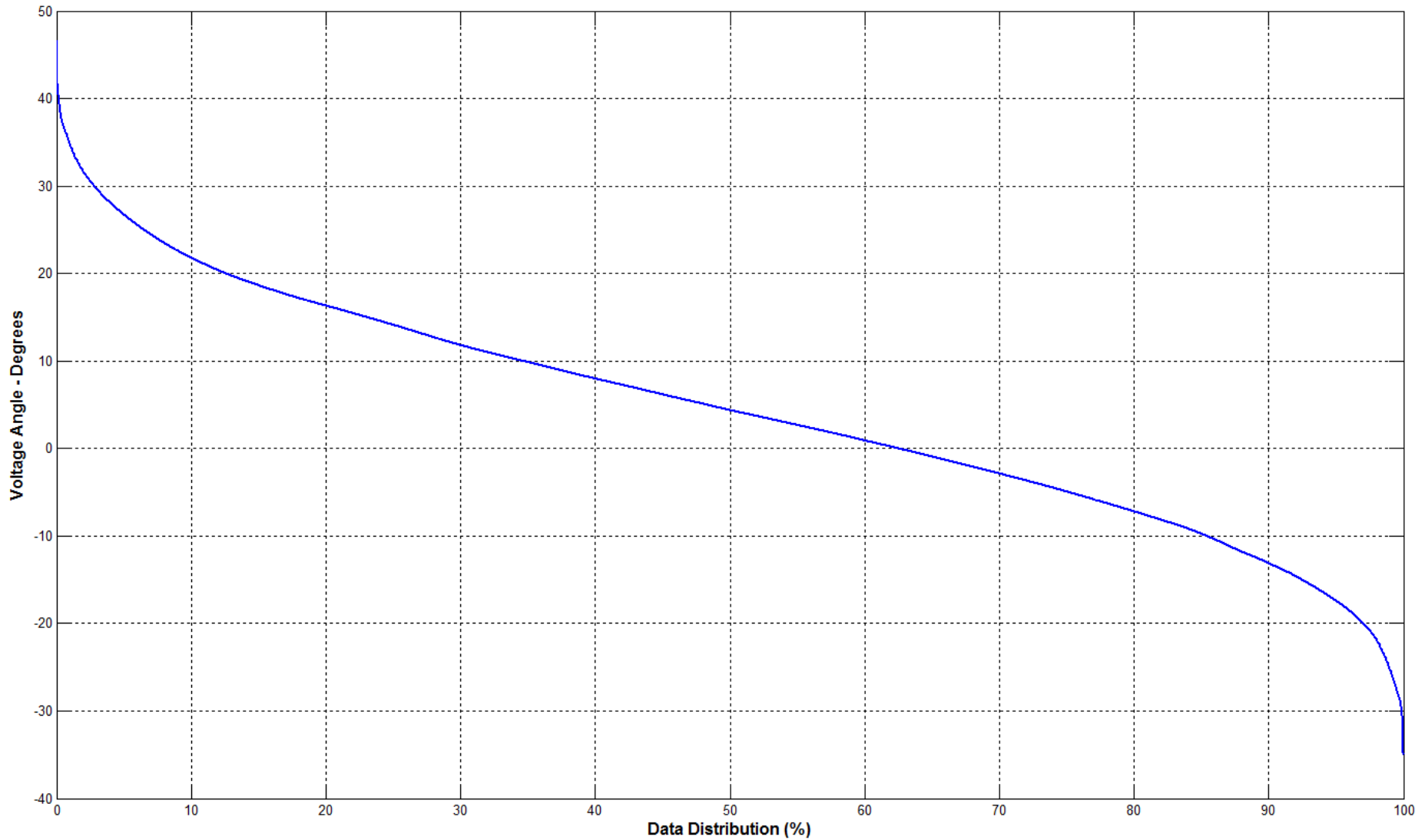
Coast 4 – Voltage Angle



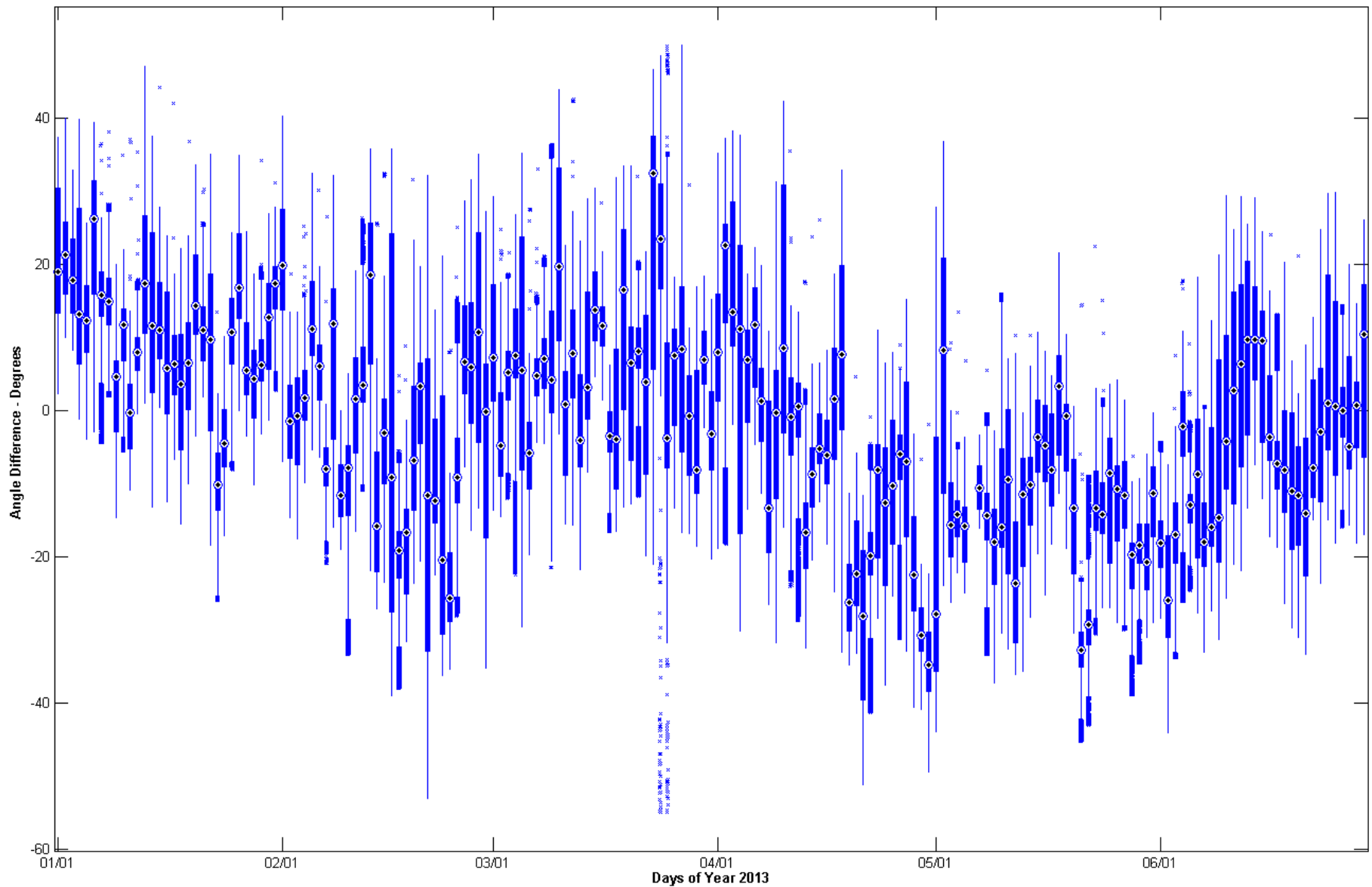
Coast 3 – Voltage Angle



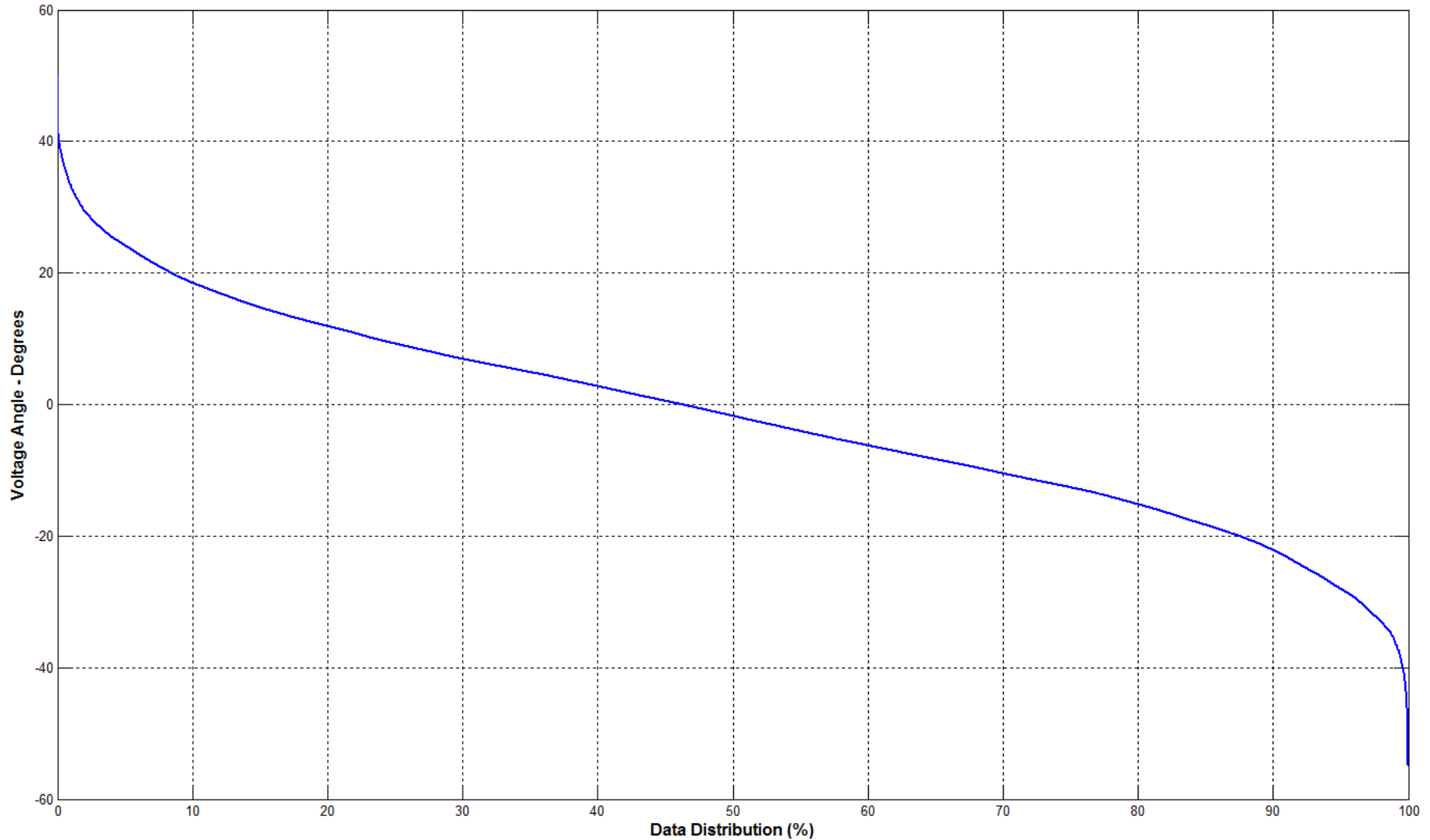
Coast 3 – Voltage Angle



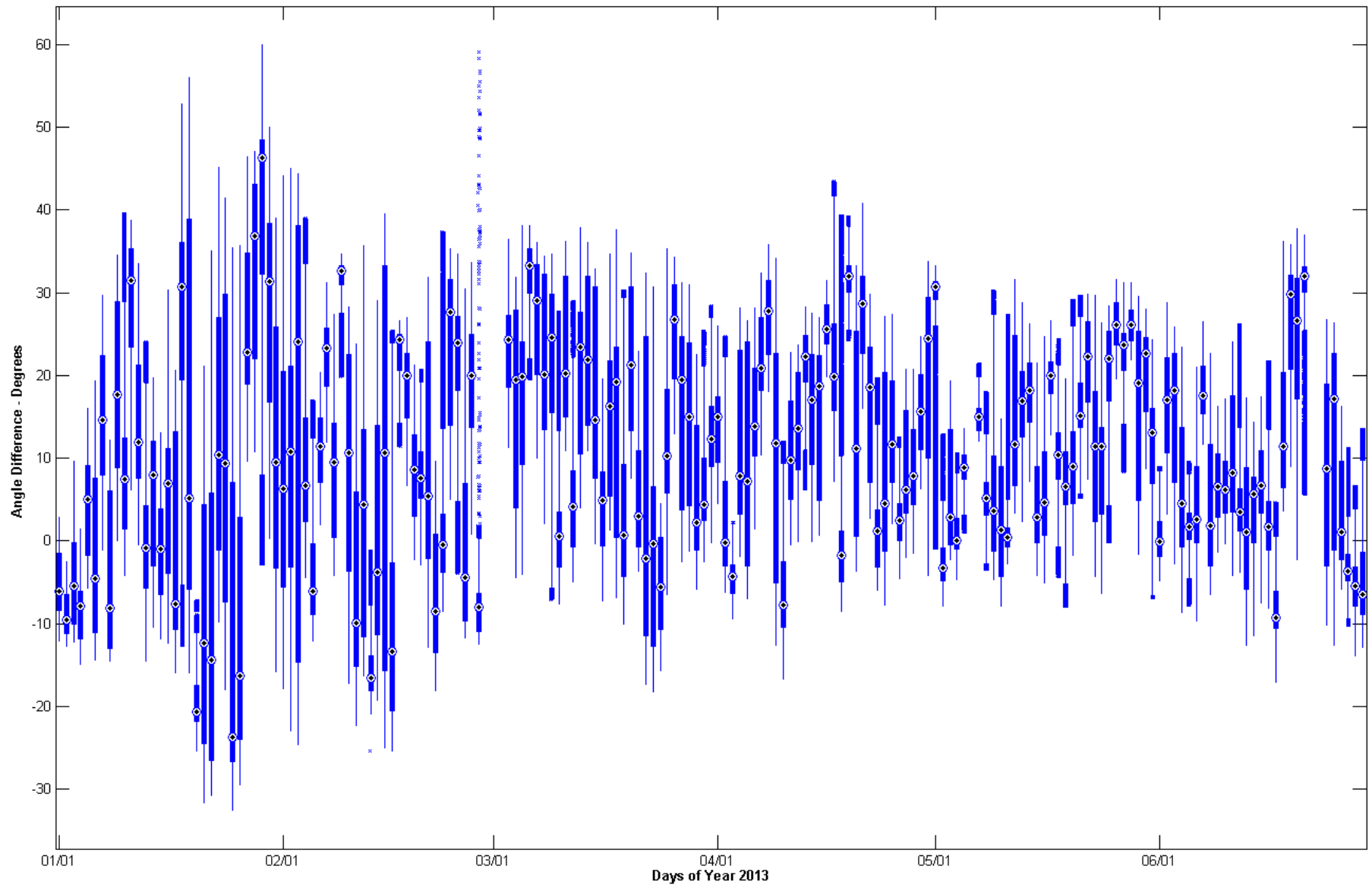
South 13 – Voltage Angle



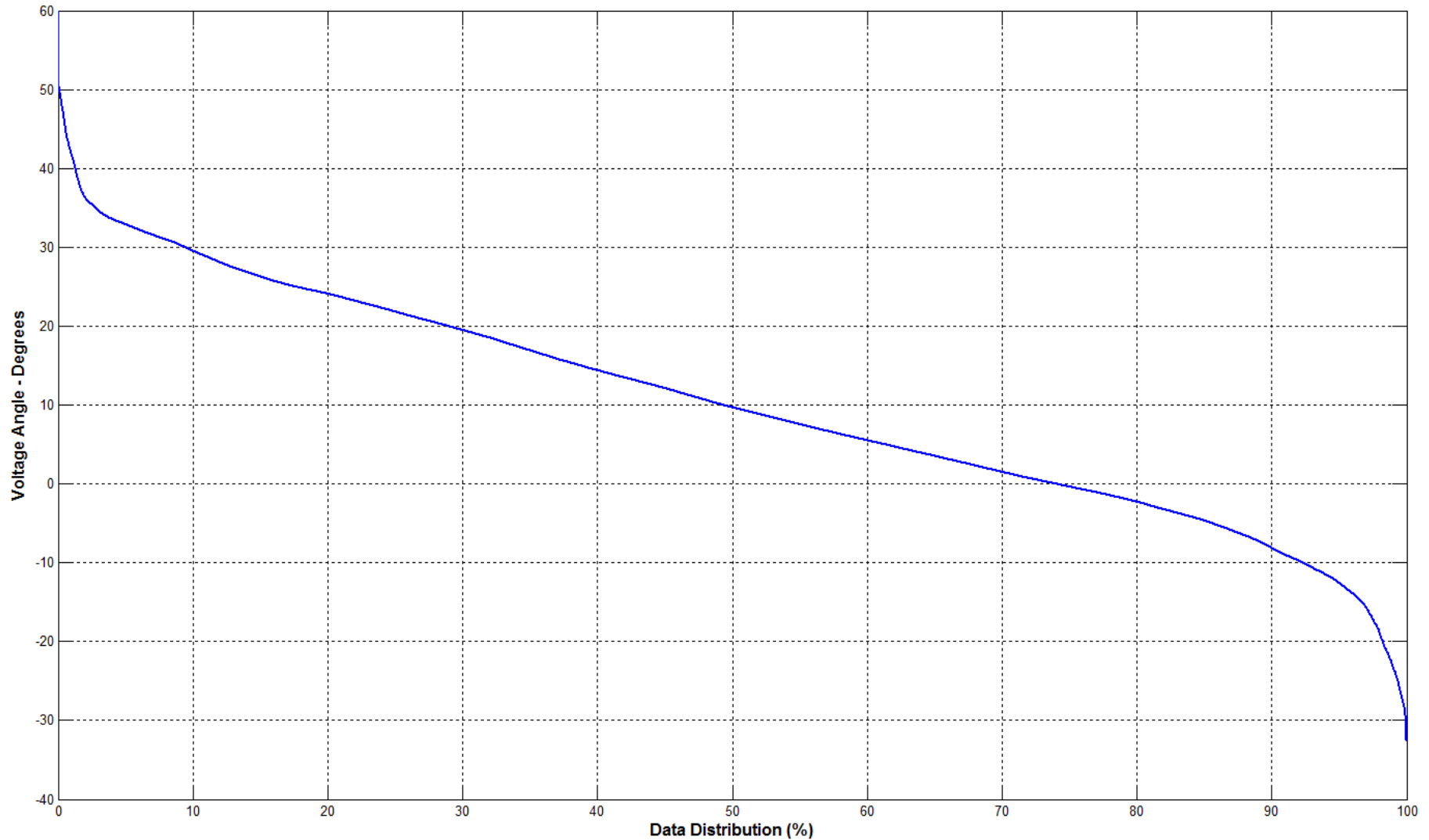
South 13 – Voltage Angle



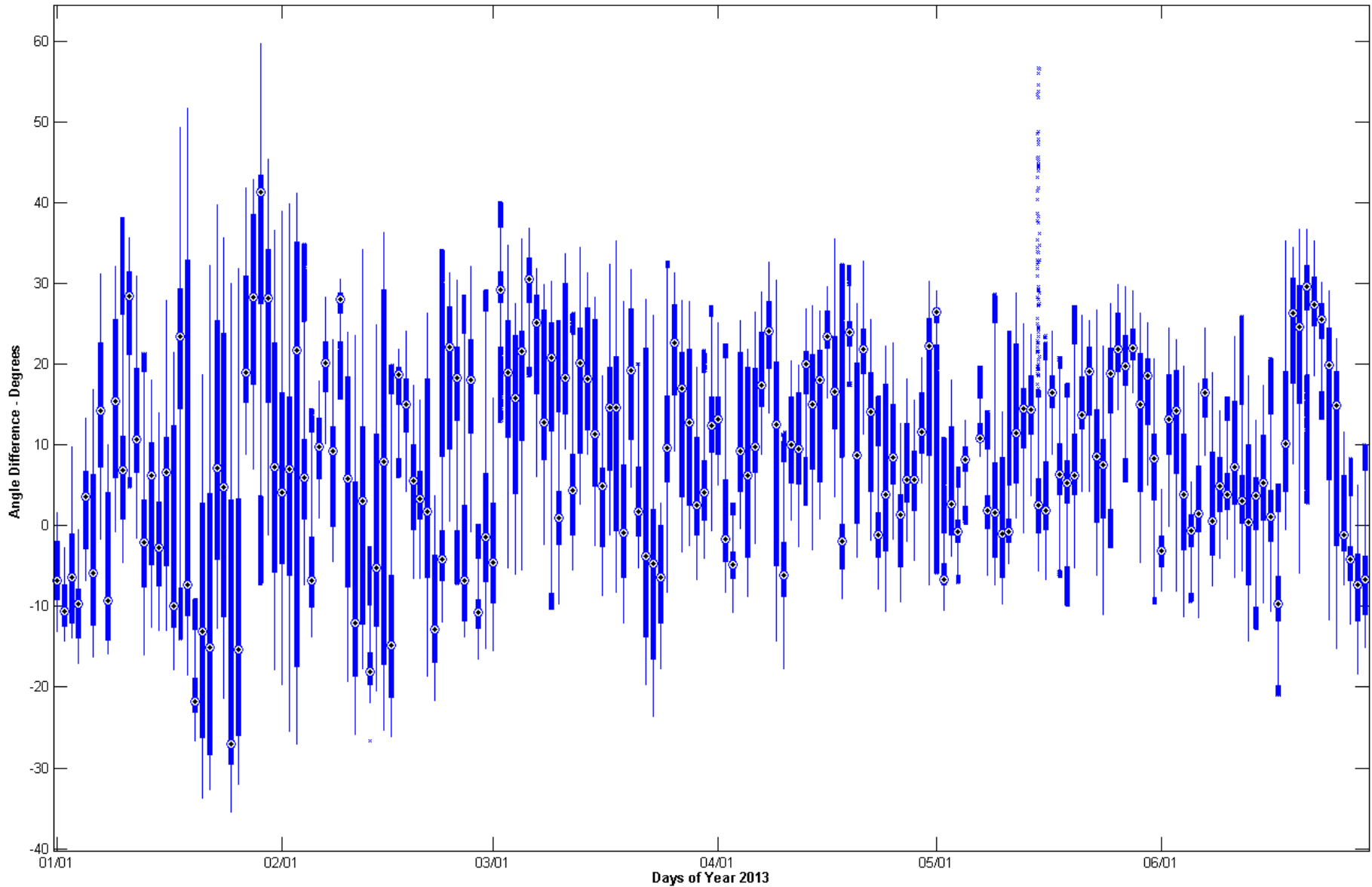
FarWest 4 – Voltage Angle



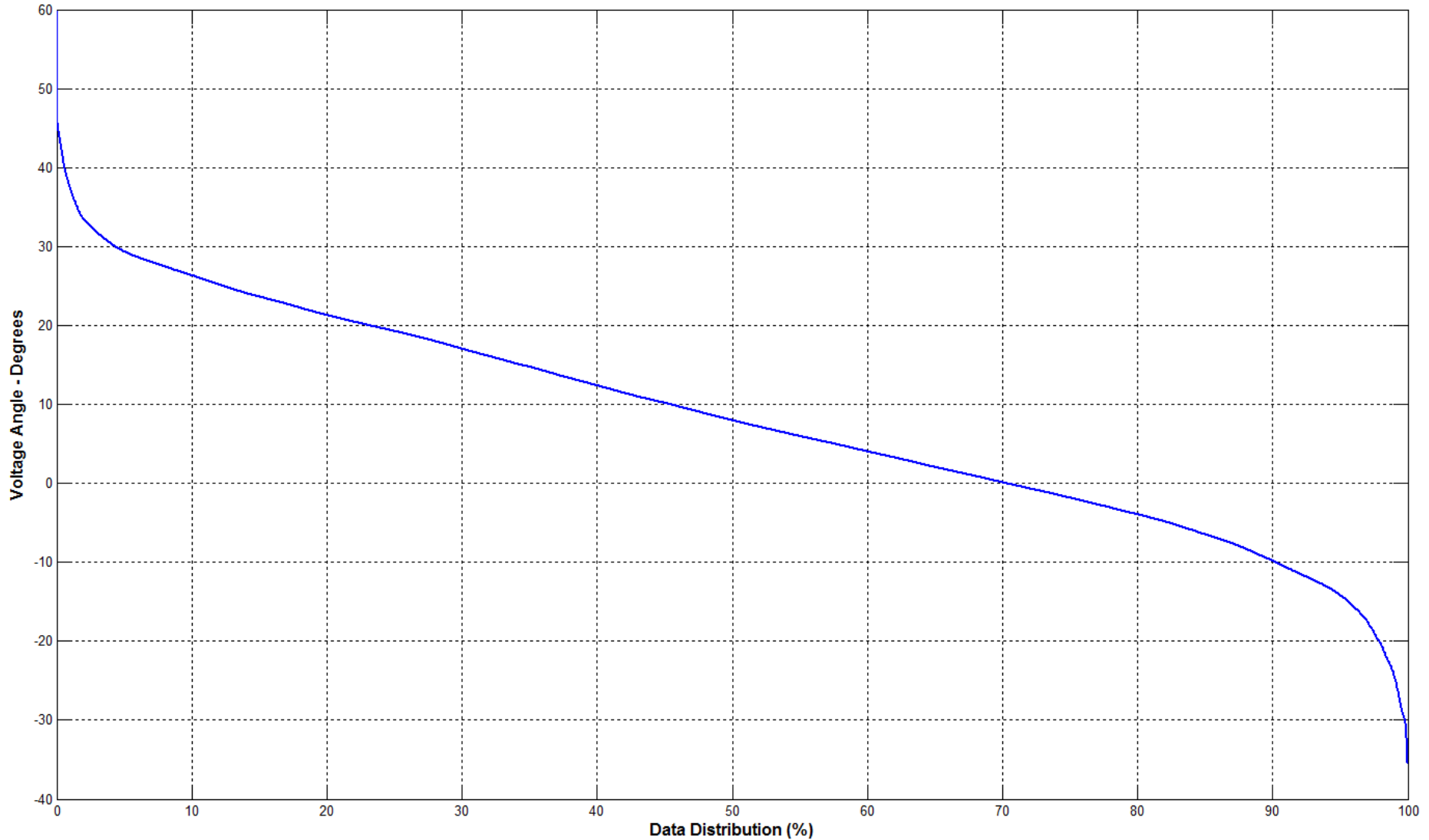
FarWest 4 – Voltage Angle



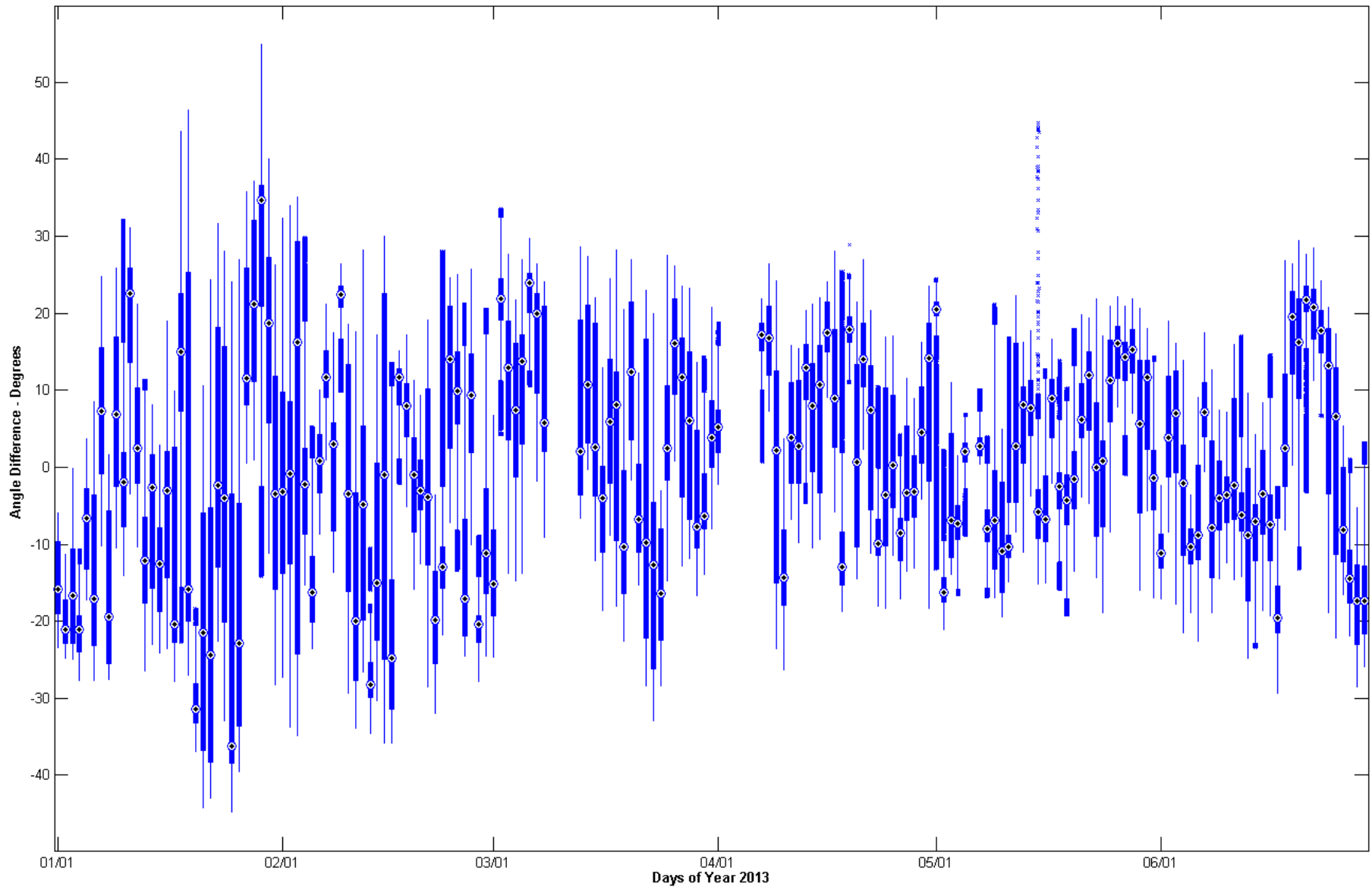
FarWest 7 – Voltage Angle



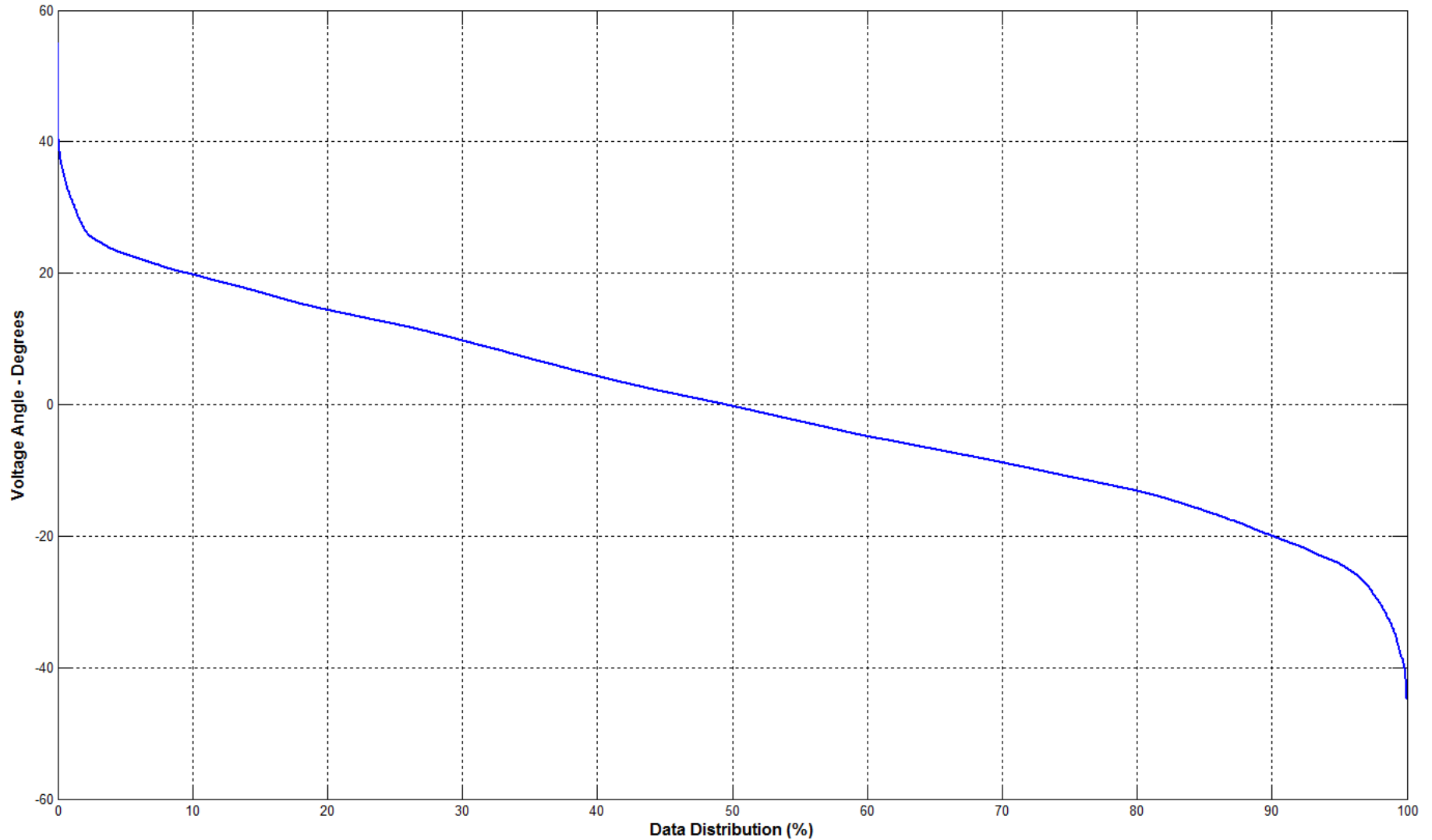
FarWest 7 – Voltage Angle



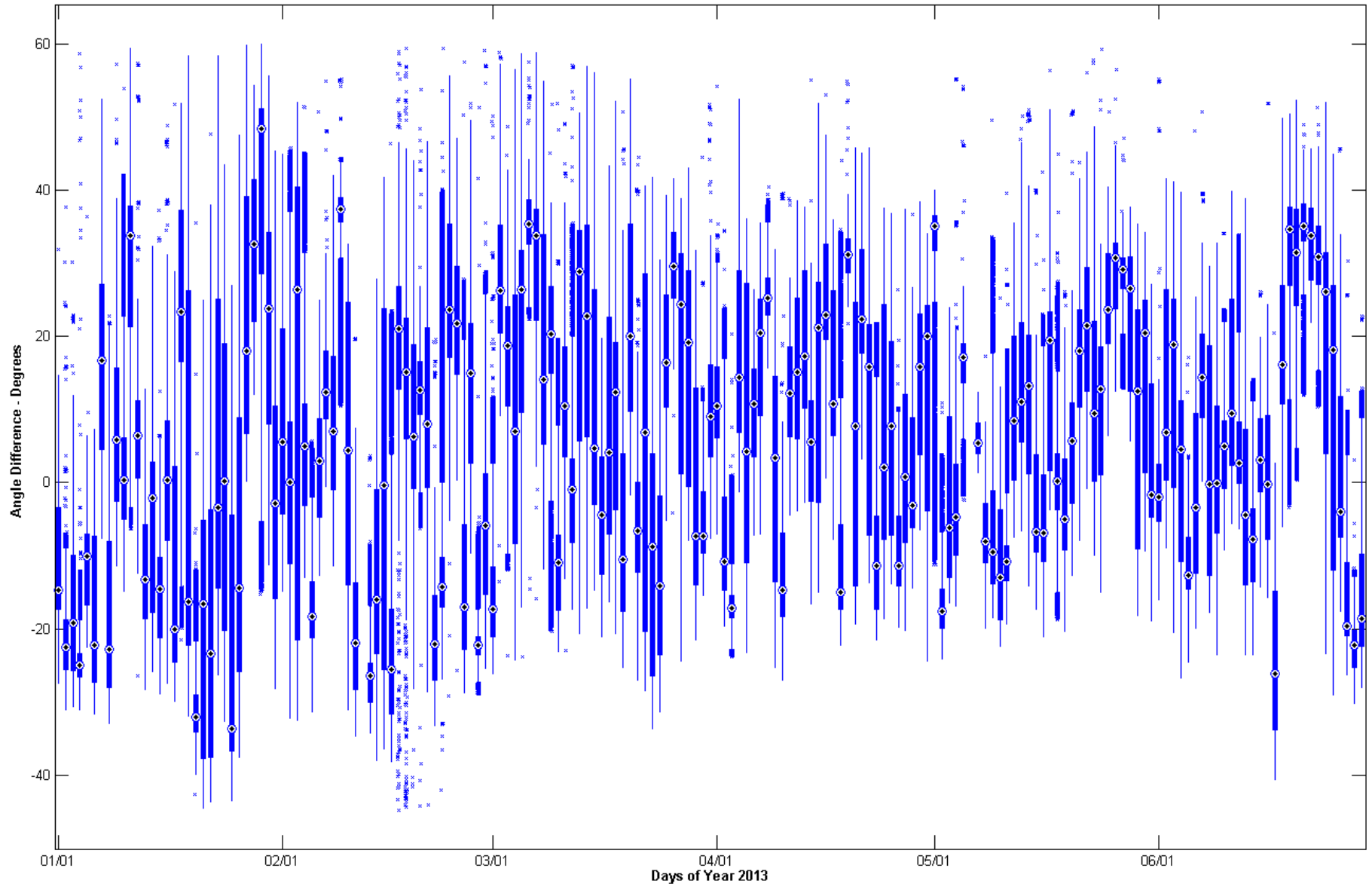
FarWest 8 – Voltage Angle



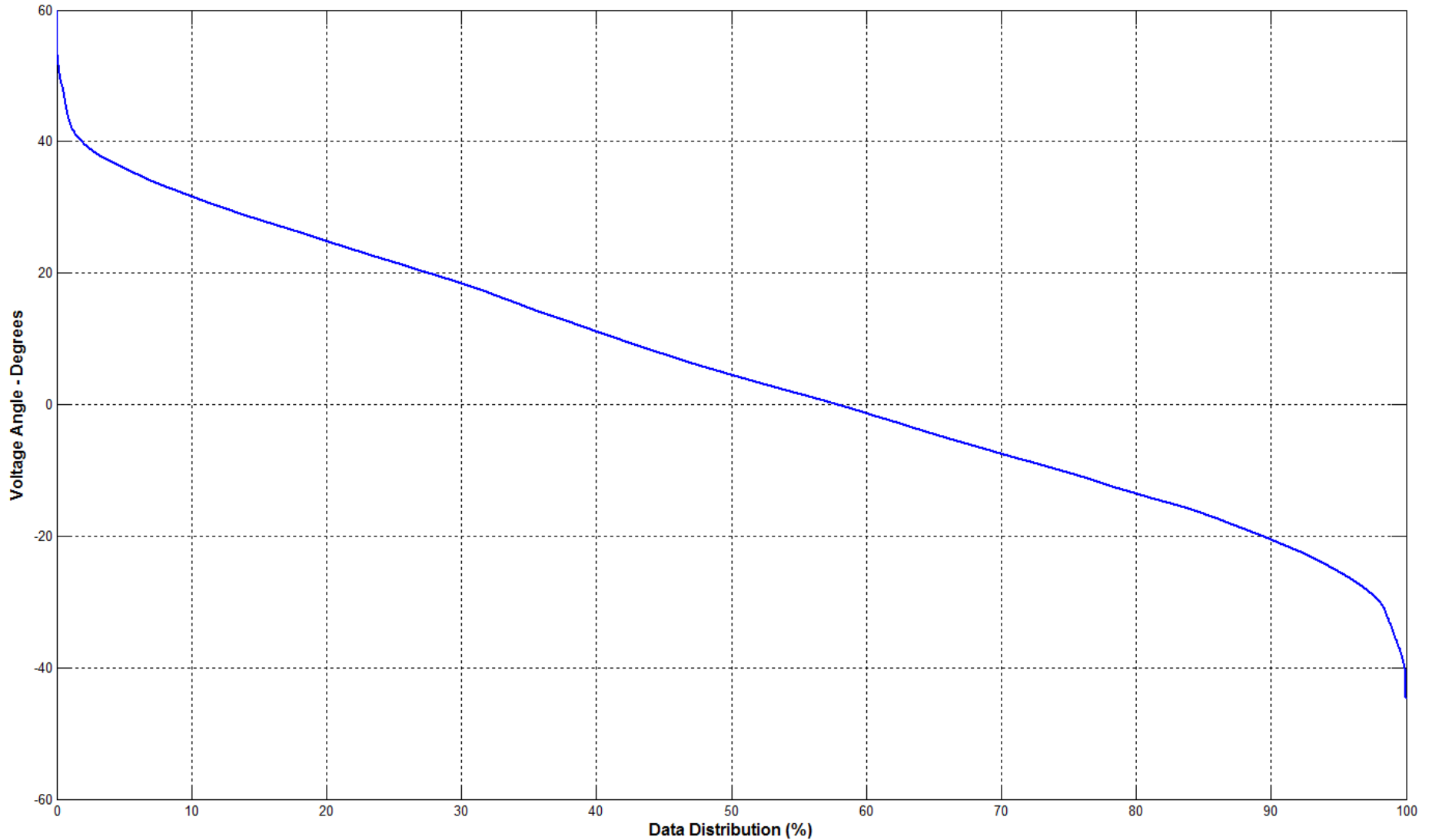
FarWest 8 – Voltage Angle



FarWest 9 – Voltage Angle



FarWest 9 – Voltage Angle



Appendix C

CCET Discovery Across Texas

Comparison of Median Values for Angle Difference Pairs – 2012 vs. 2013 (Reference: North 7)

Romulo Barreno - EPG
Ajay Das – EPG

External Version

Overview

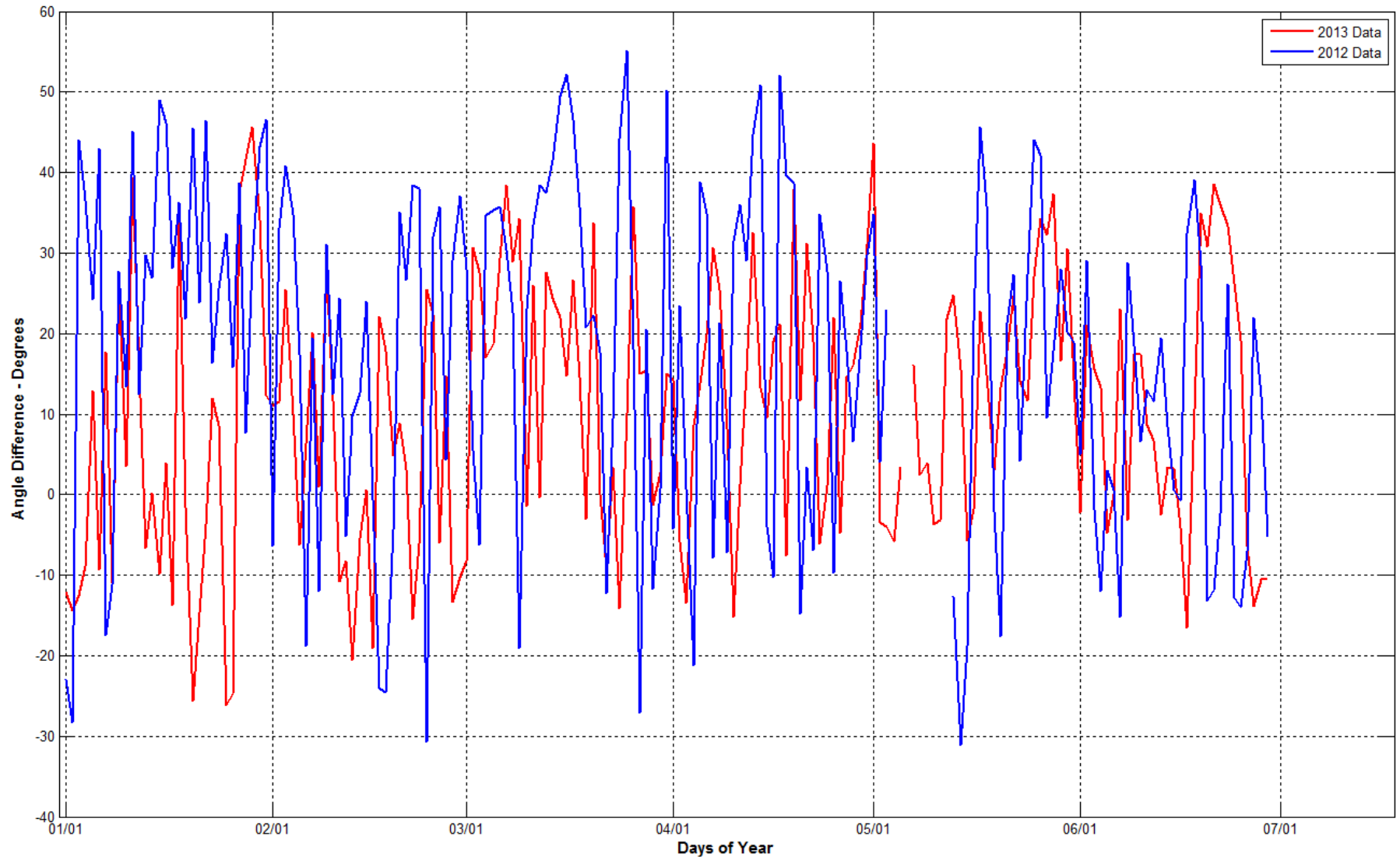
- Data plotted in the first graph are daily median values from January to June for 2012 and 2013.
- Box-whisker charts were prepared to identify the median for each angle pair selected for the first six months of 2012 and 2013 under analysis.
- When data was not available for the entire six months period, the box-whisker charts were prepared using only the period(s) of time when data was available for BOTH years.
- Observation: in all the pairs analyzed, the median for 2013 was lower than that for 2012. This trend may be attributed to reduced system stress result of the addition of the CREZ lines to the ERCOT grid during the first six months of 2013.



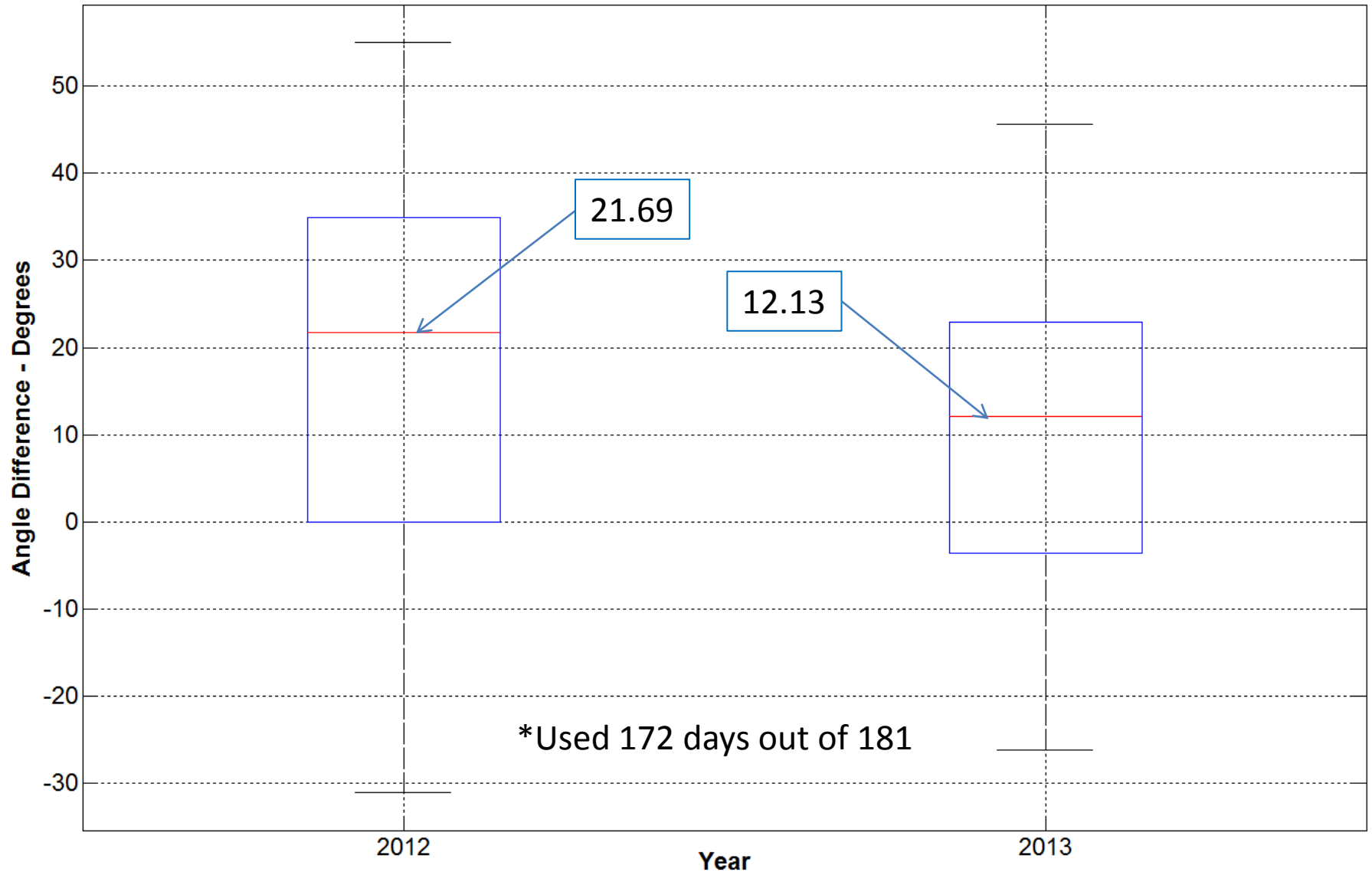
CREZ 345 kV LINES IN SERVICE THE FIRST SIX MONTHS OF 2013 (Subject to Confirmation by ERCOT)

| | | | |
|---------|----------|-----|--------------------|
| South 9 | South 16 | 345 | February 27, 2013. |
| West 12 | West 21 | 345 | March 6, 2013. |
| West 21 | North 8 | 345 | March 24, 2013. |
| North 9 | North 8 | 345 | March 21, 2013. |
| West 19 | West 9 | 345 | April 15, 2013. |
| West 13 | West 19 | 345 | April 29, 2013. |
| West 18 | West 8 | 345 | May 23, 2013. |
| West 18 | West 1 | 345 | June 14, 2013. |
| West 22 | North 11 | 345 | June 30, 2013. |
| West 14 | North 10 | 345 | June 30, 2013. |

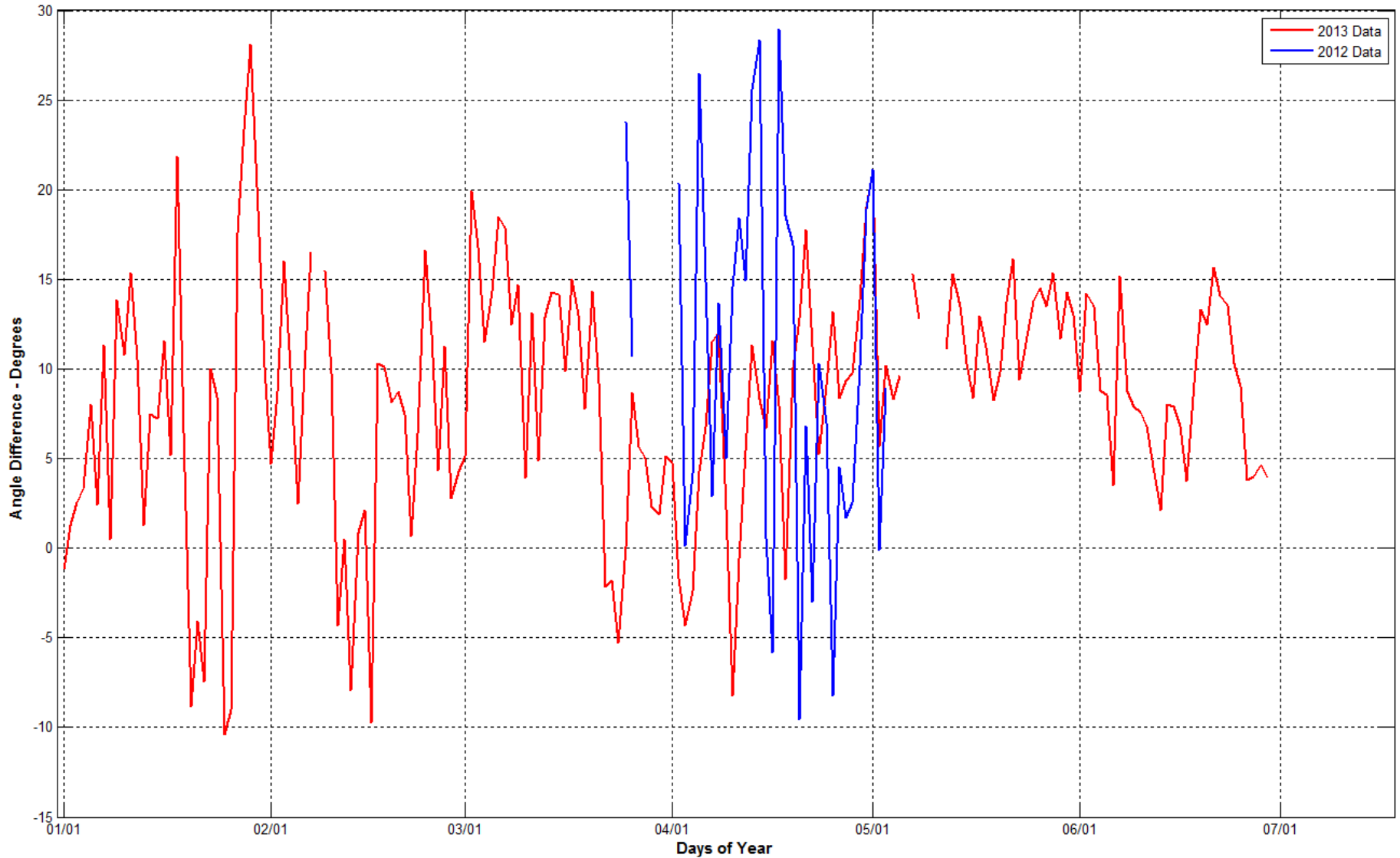
West 10 – North 7



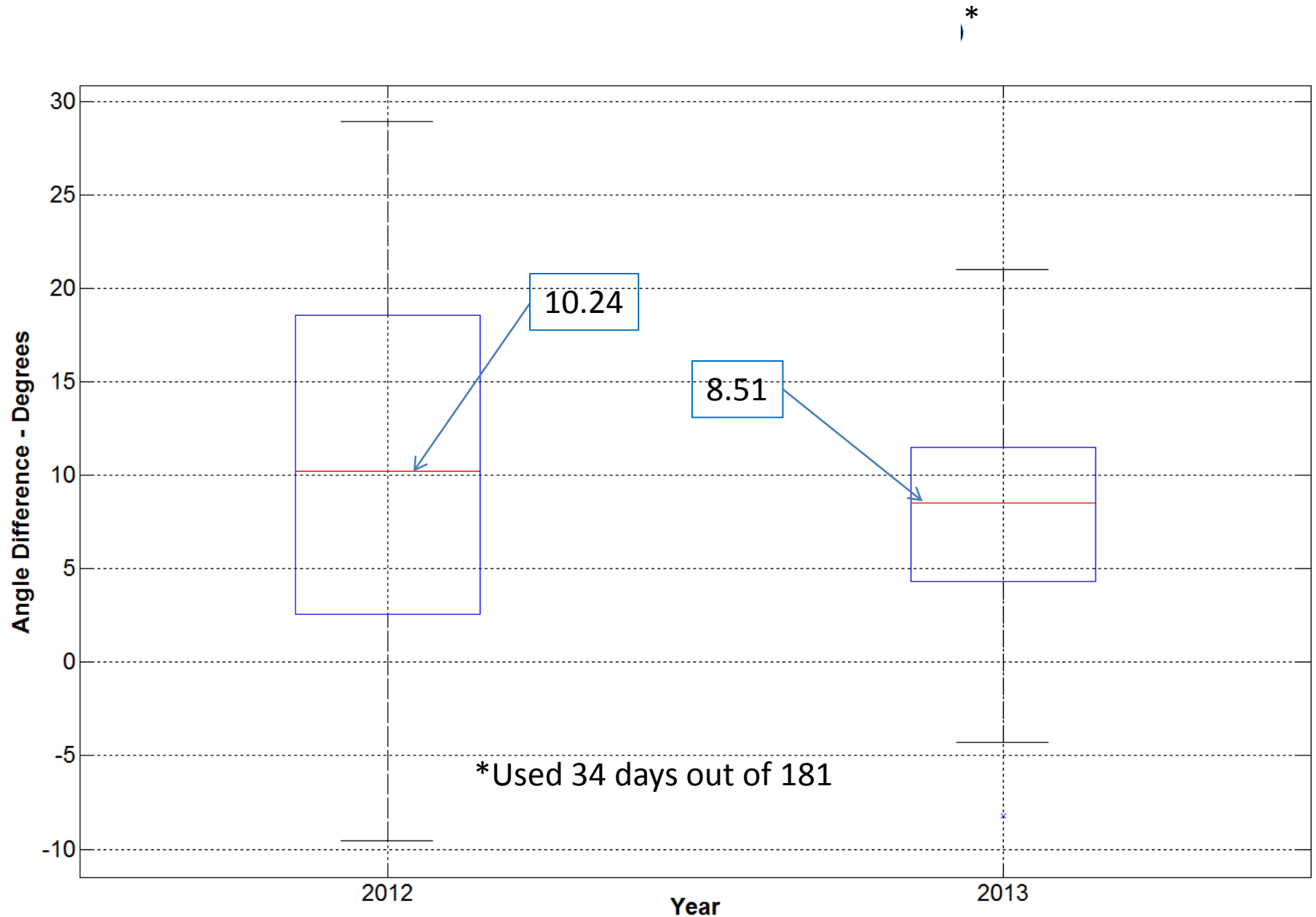
West 10 – North 7



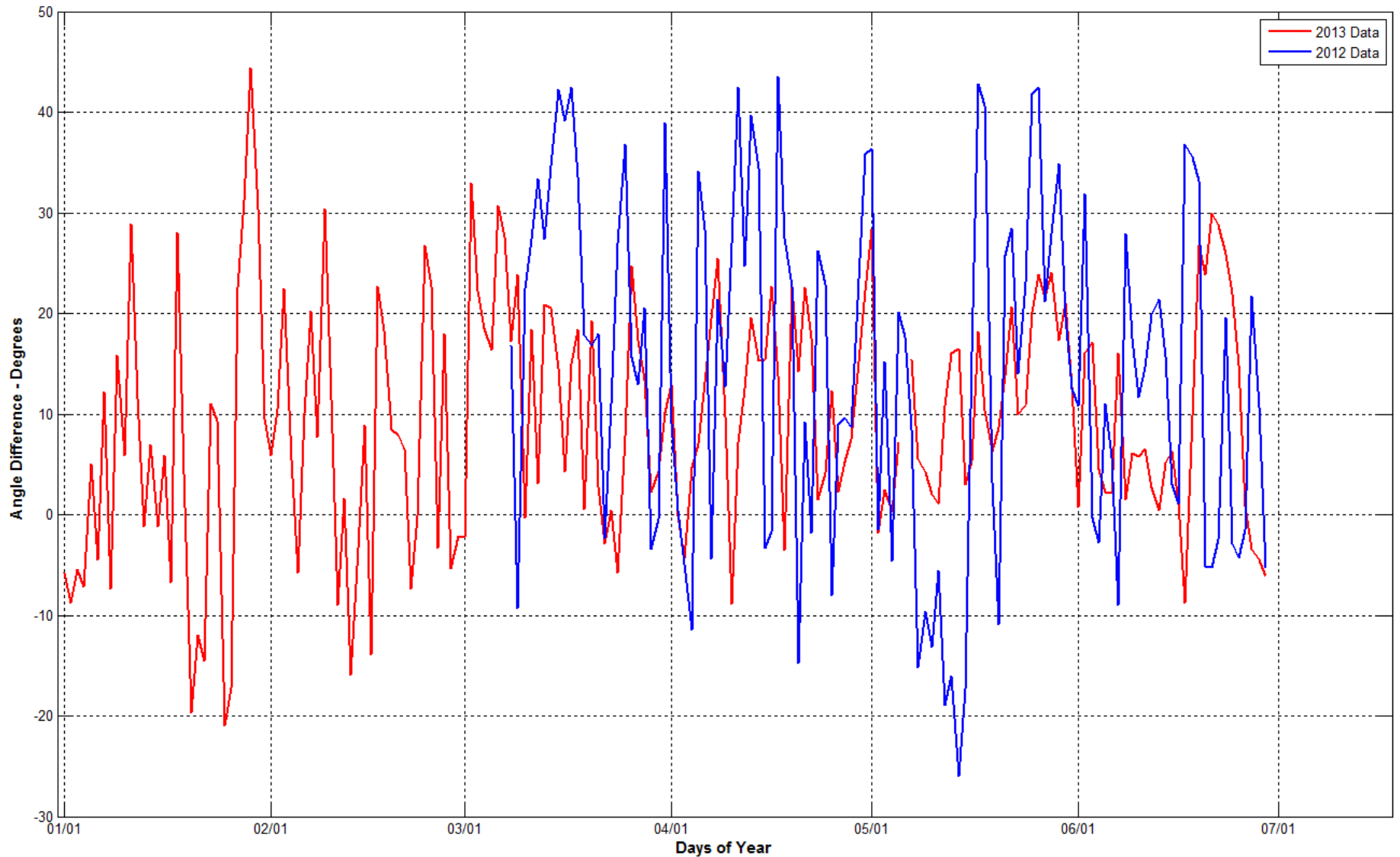
West 14– North 7



West 14 – North 7

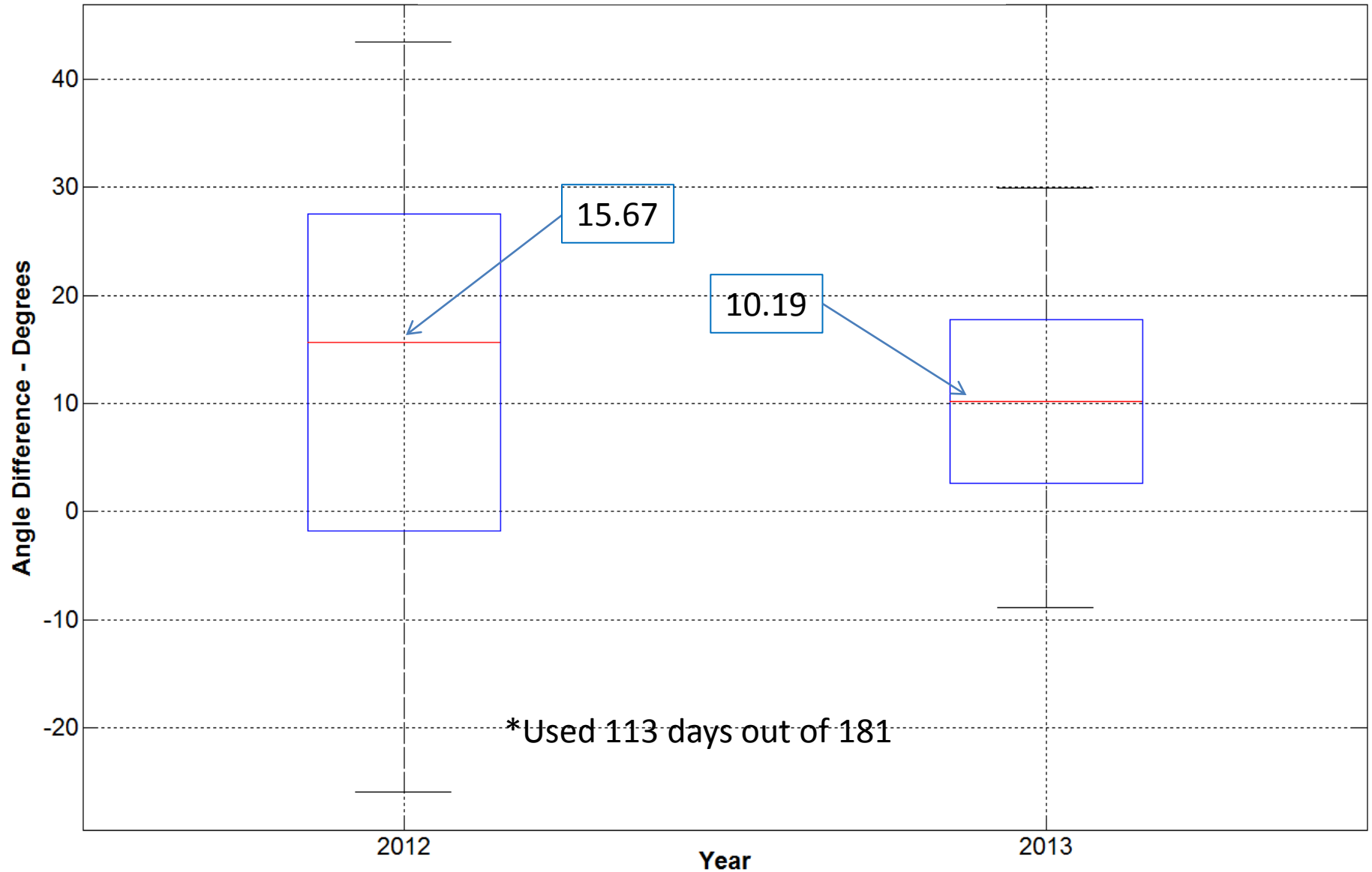


West 11– North 7

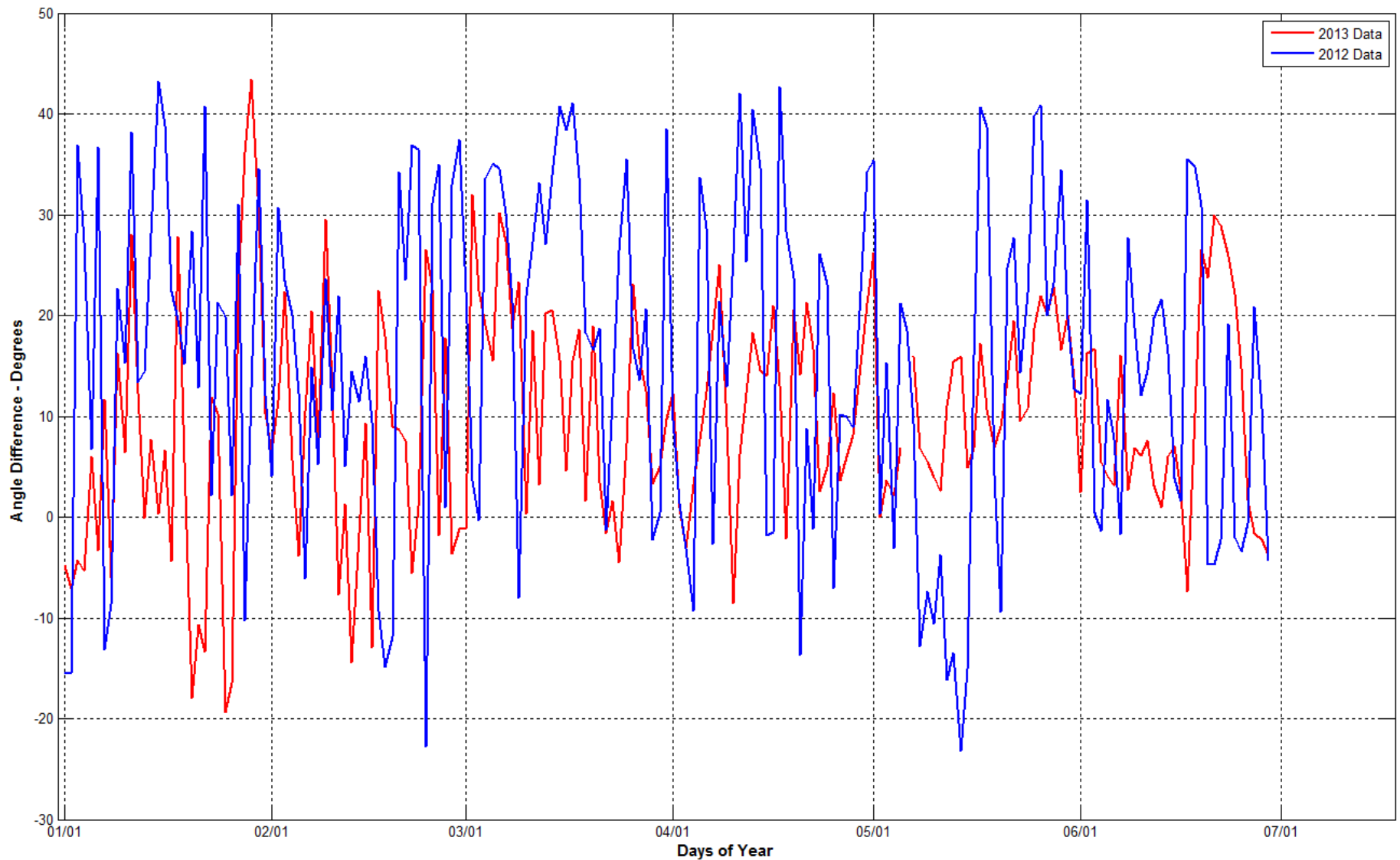


West 11– North 7

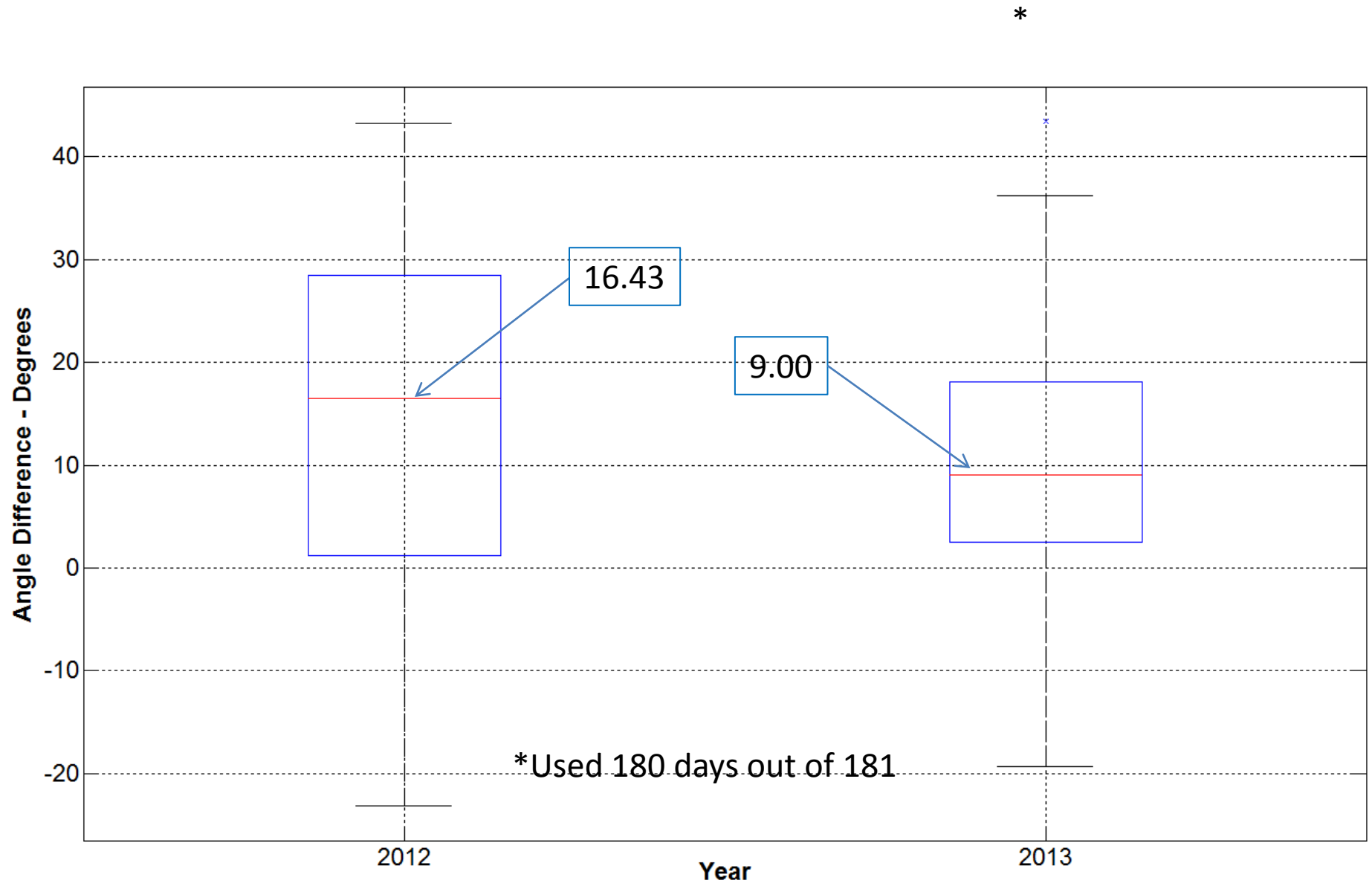
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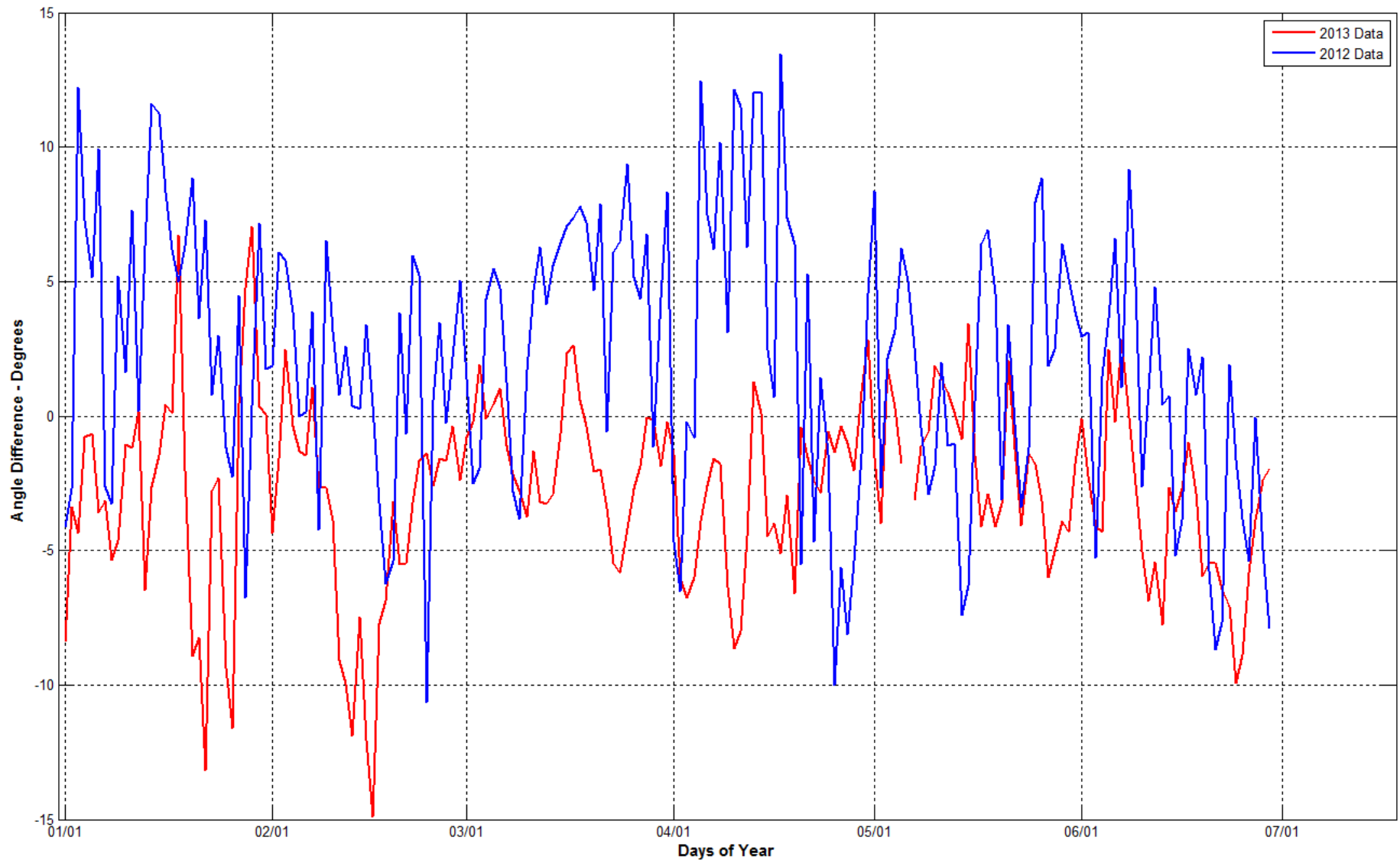
West 6 – North 7



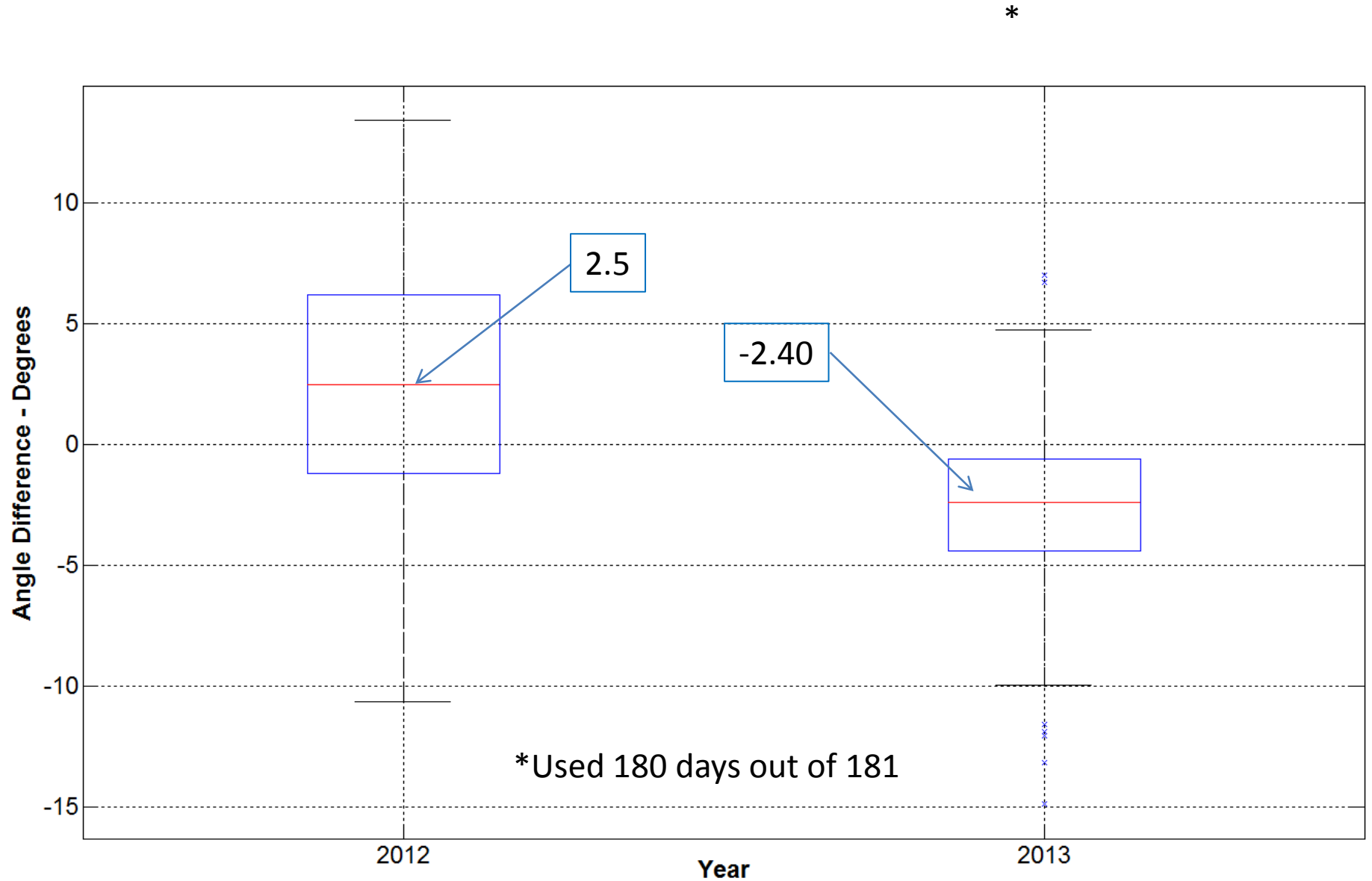
West 6 – North 7



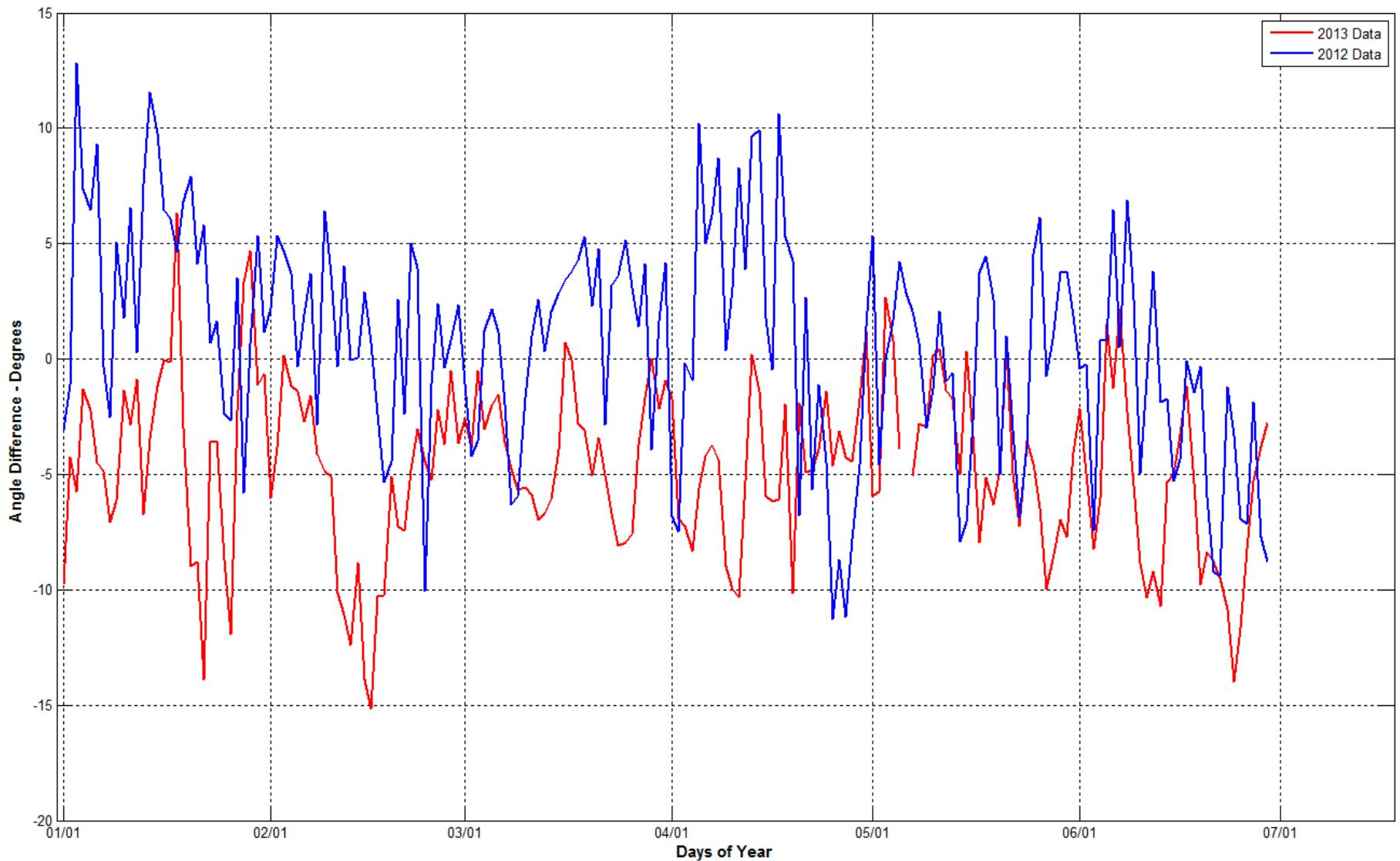
North 4 – North 7



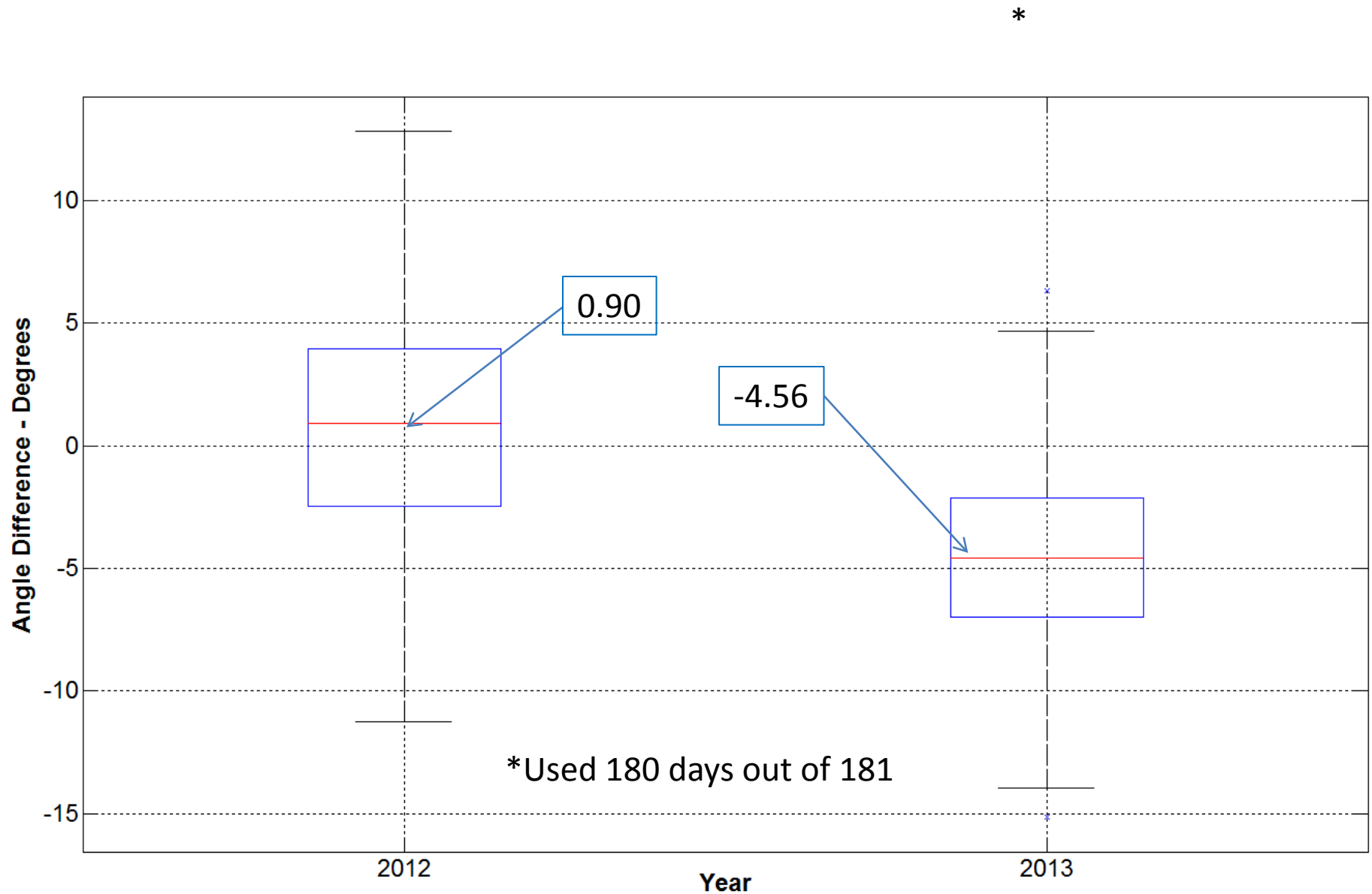
North 4 – North 7



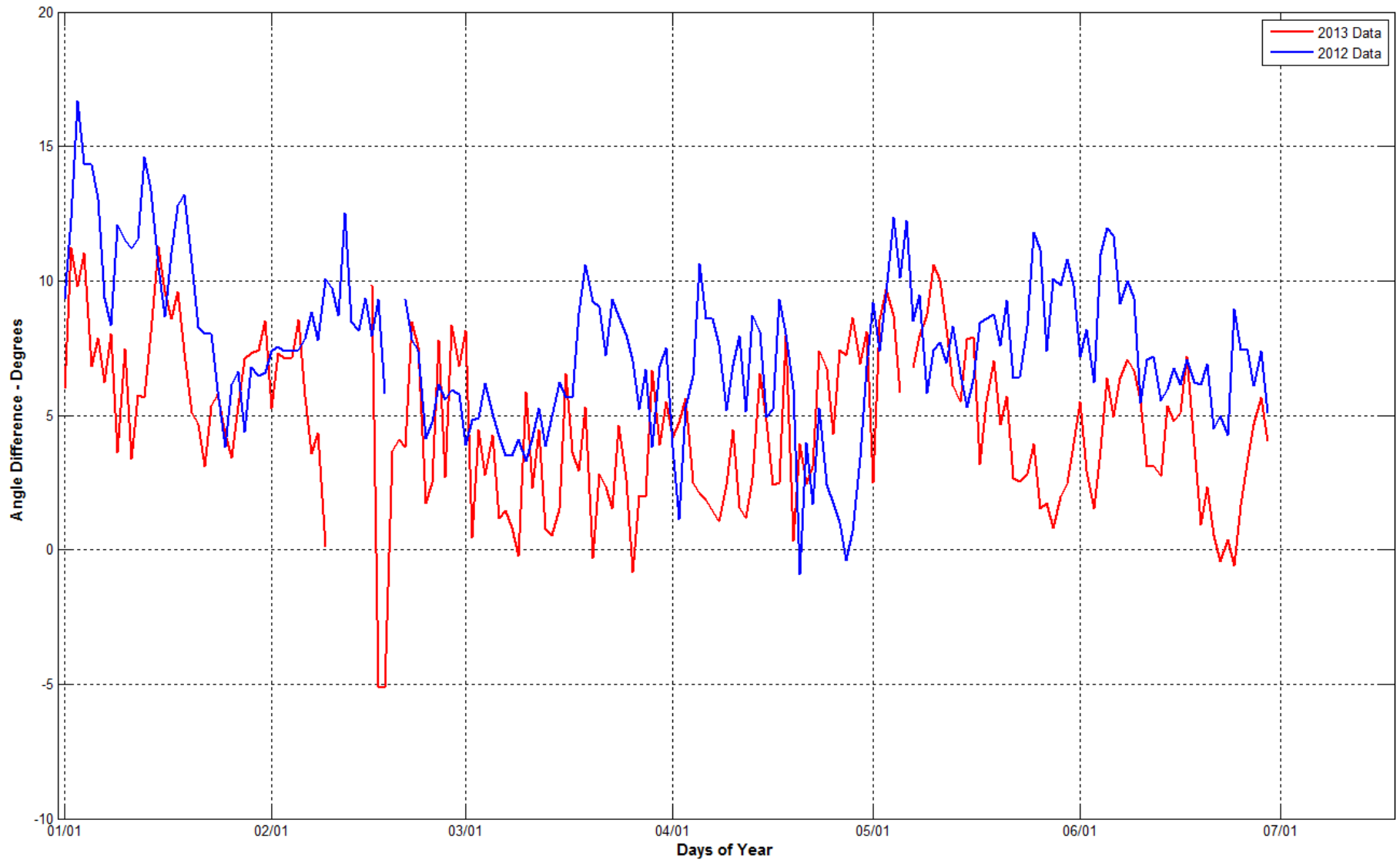
North 5 – North 7



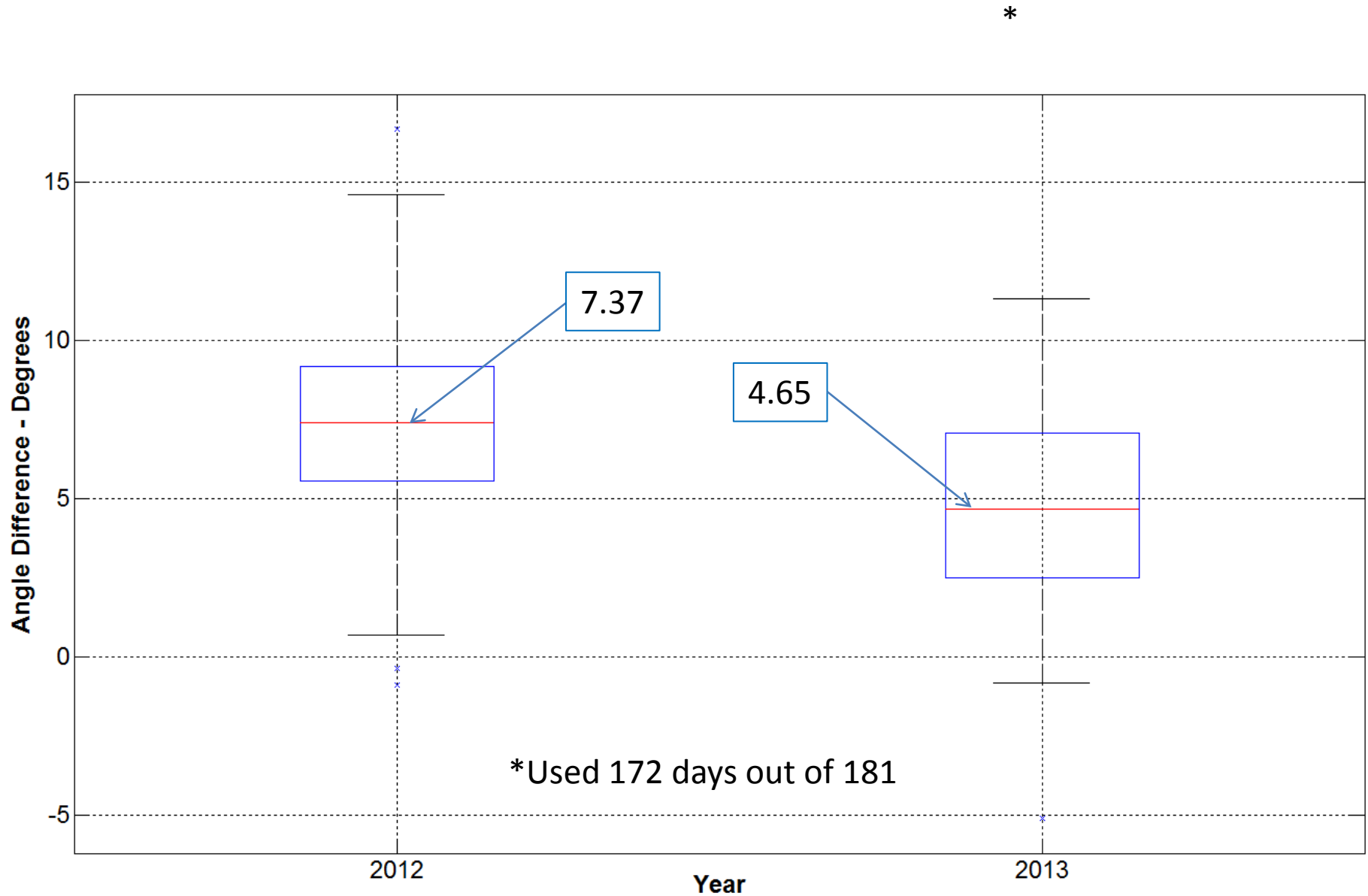
North 5 – North 7



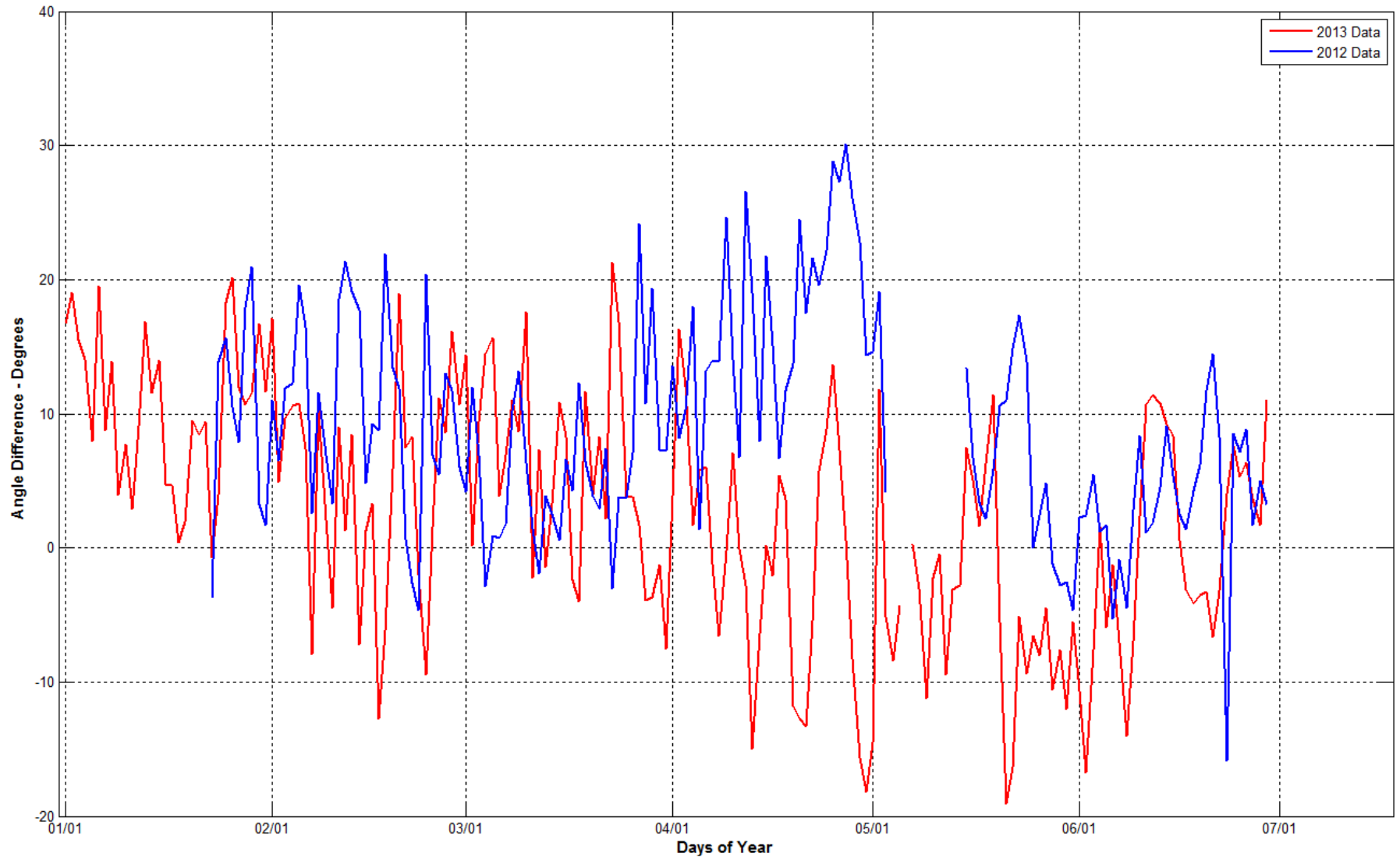
North 6 – North 7



North 6 – North 7

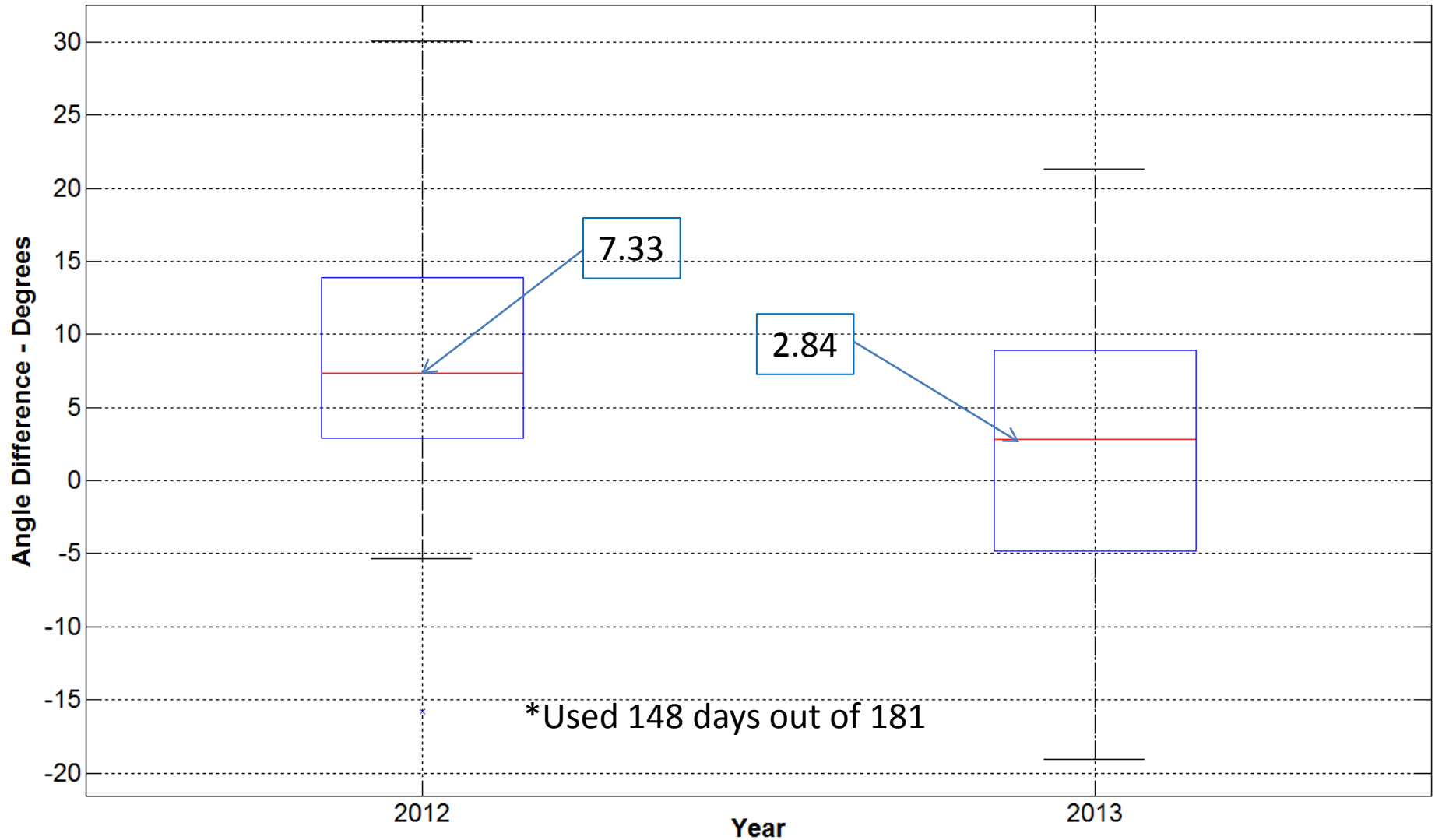


Coast 1 – North 7

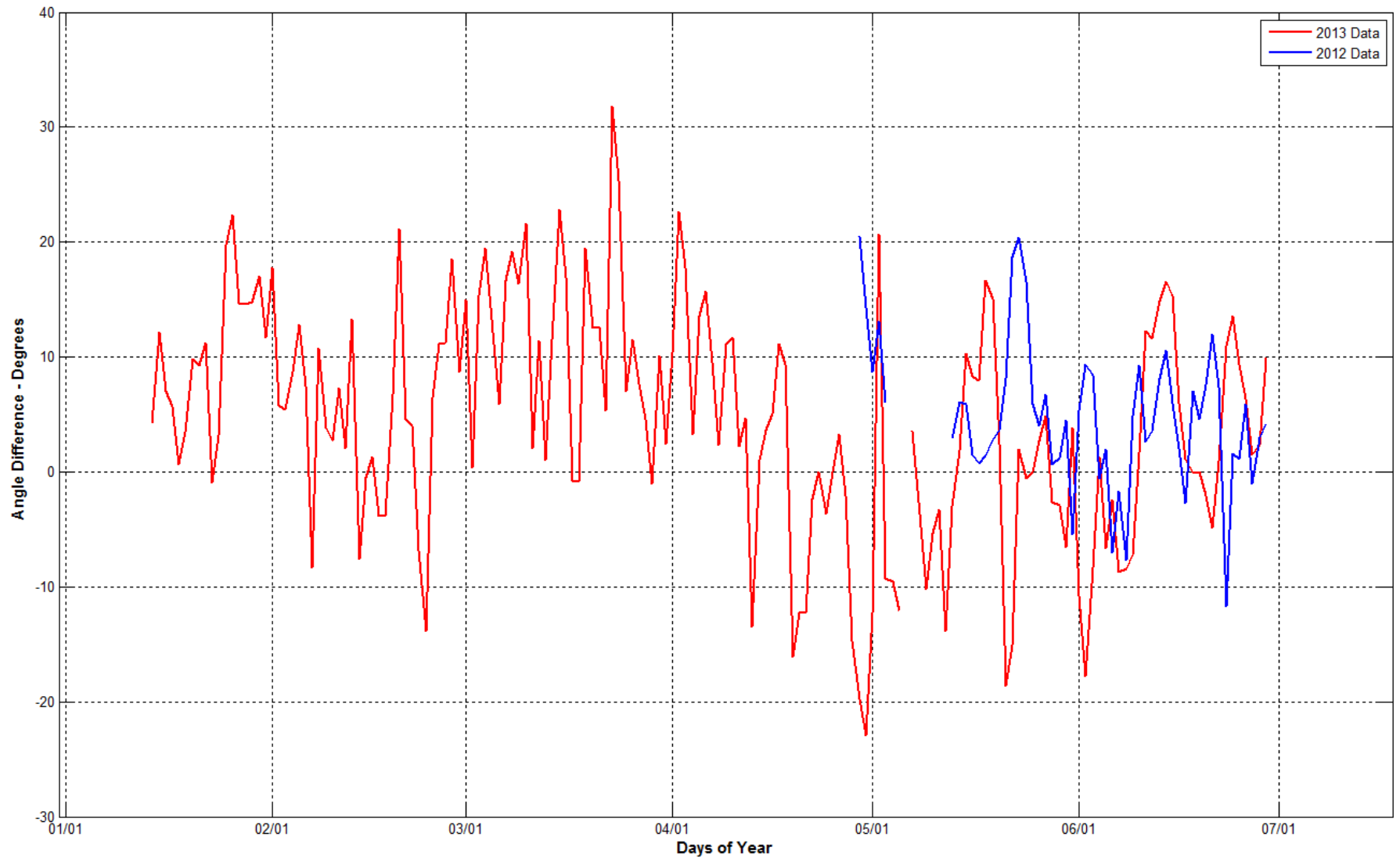


Coast 1 – North 7

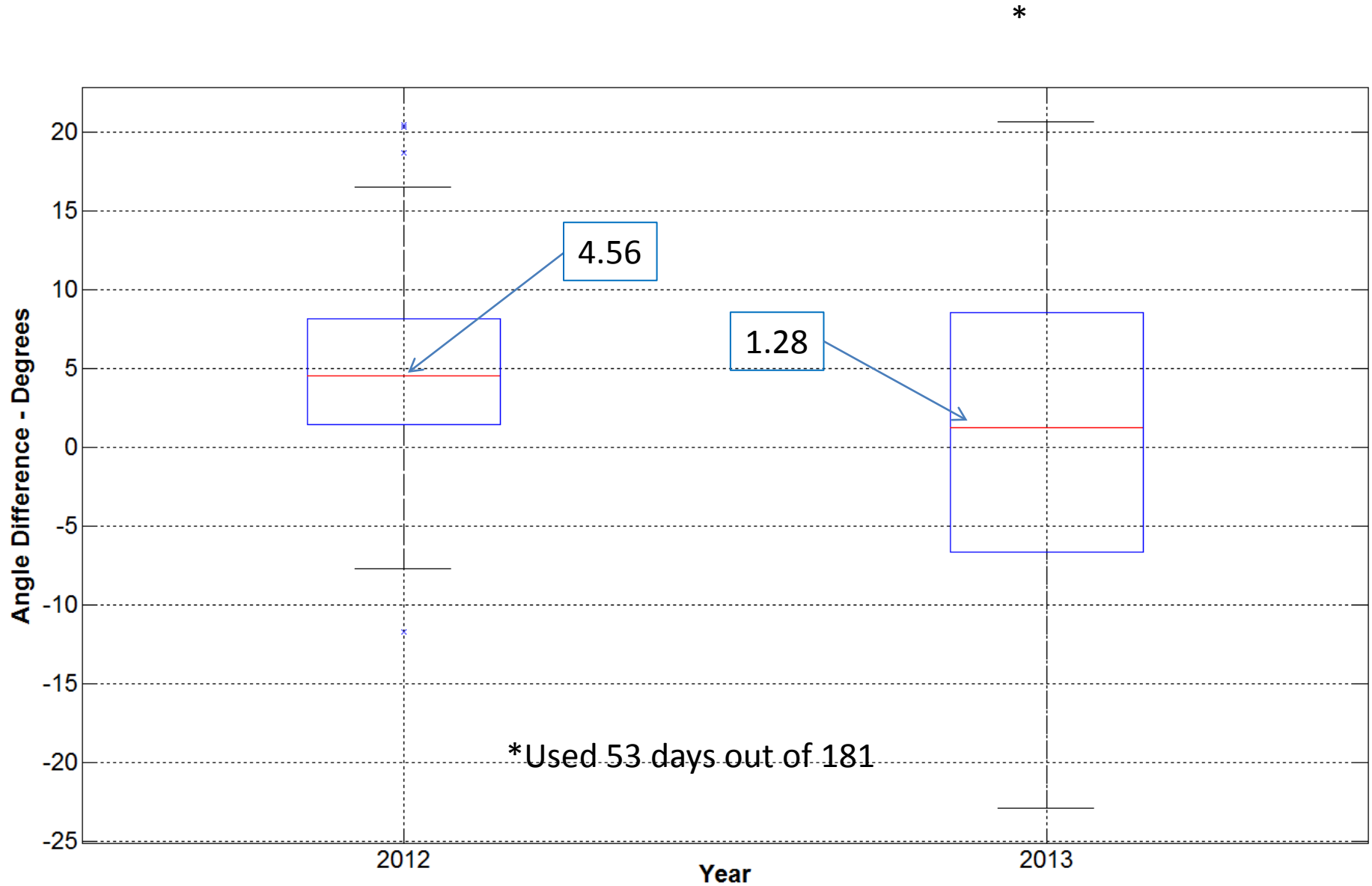
)*



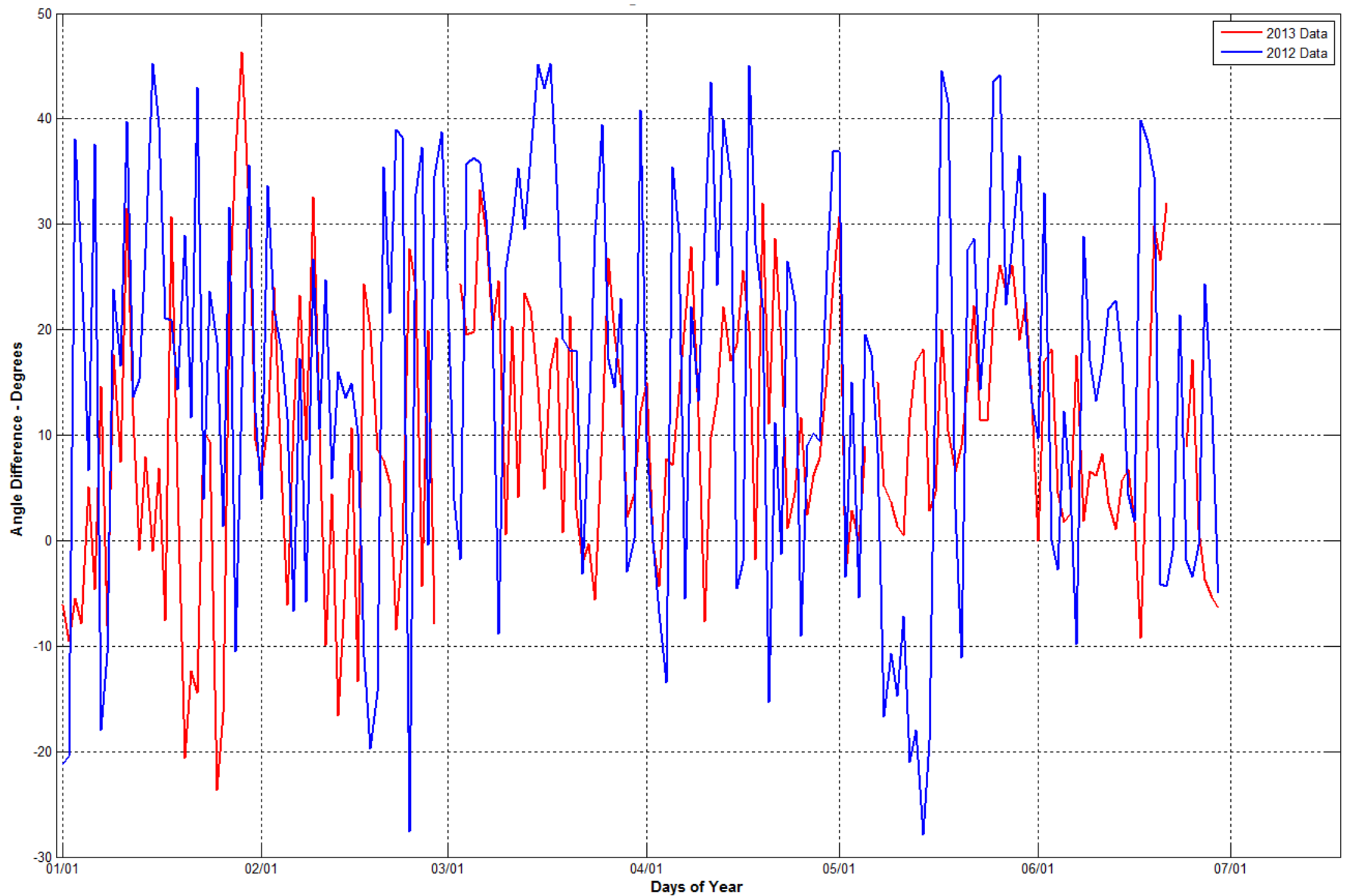
Coast 3 – North 7



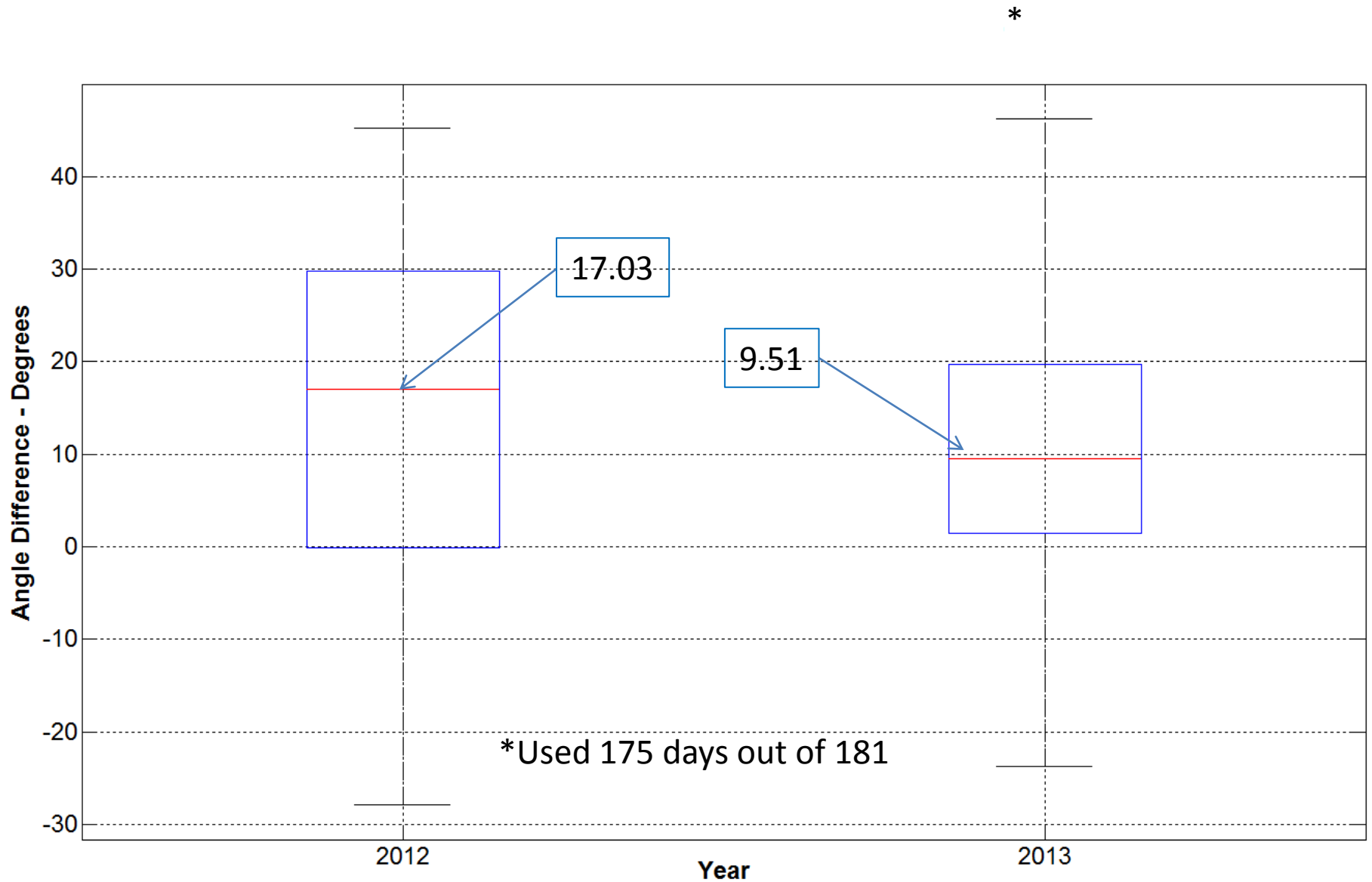
Coast 3 – North 7



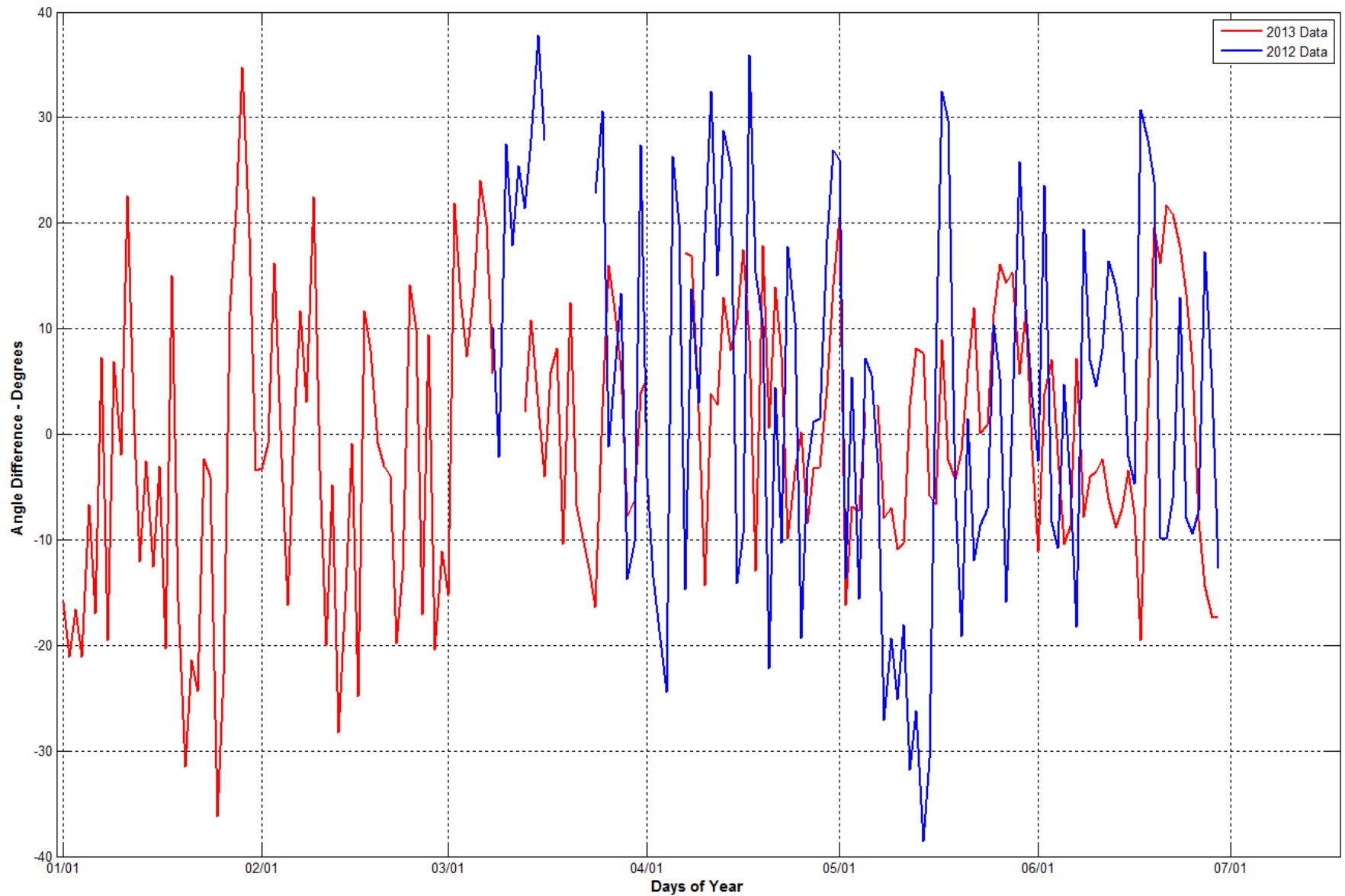
FarWest 4 – North 7



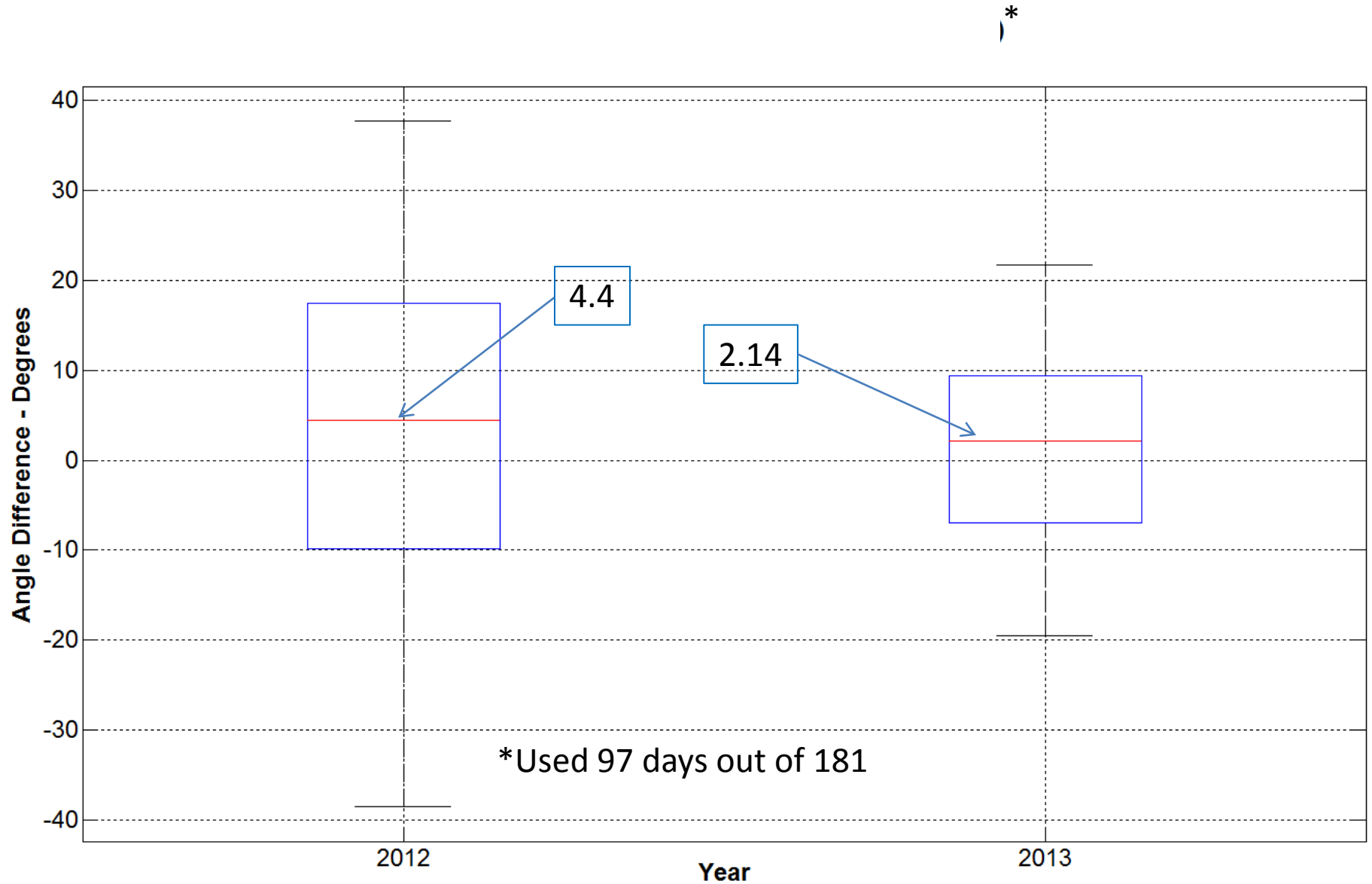
FarWest 4 – North 7



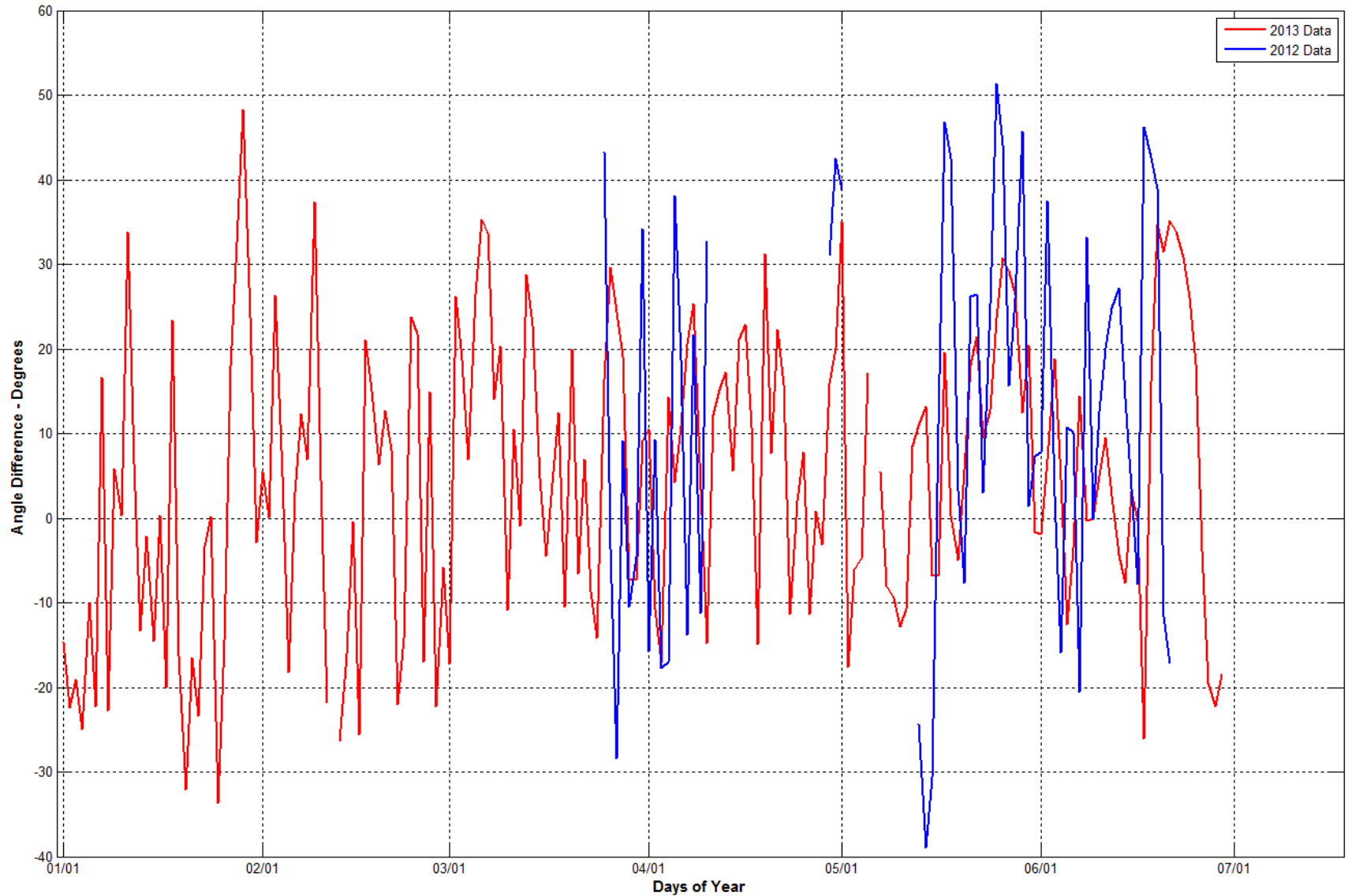
FarWest 8 – North 7



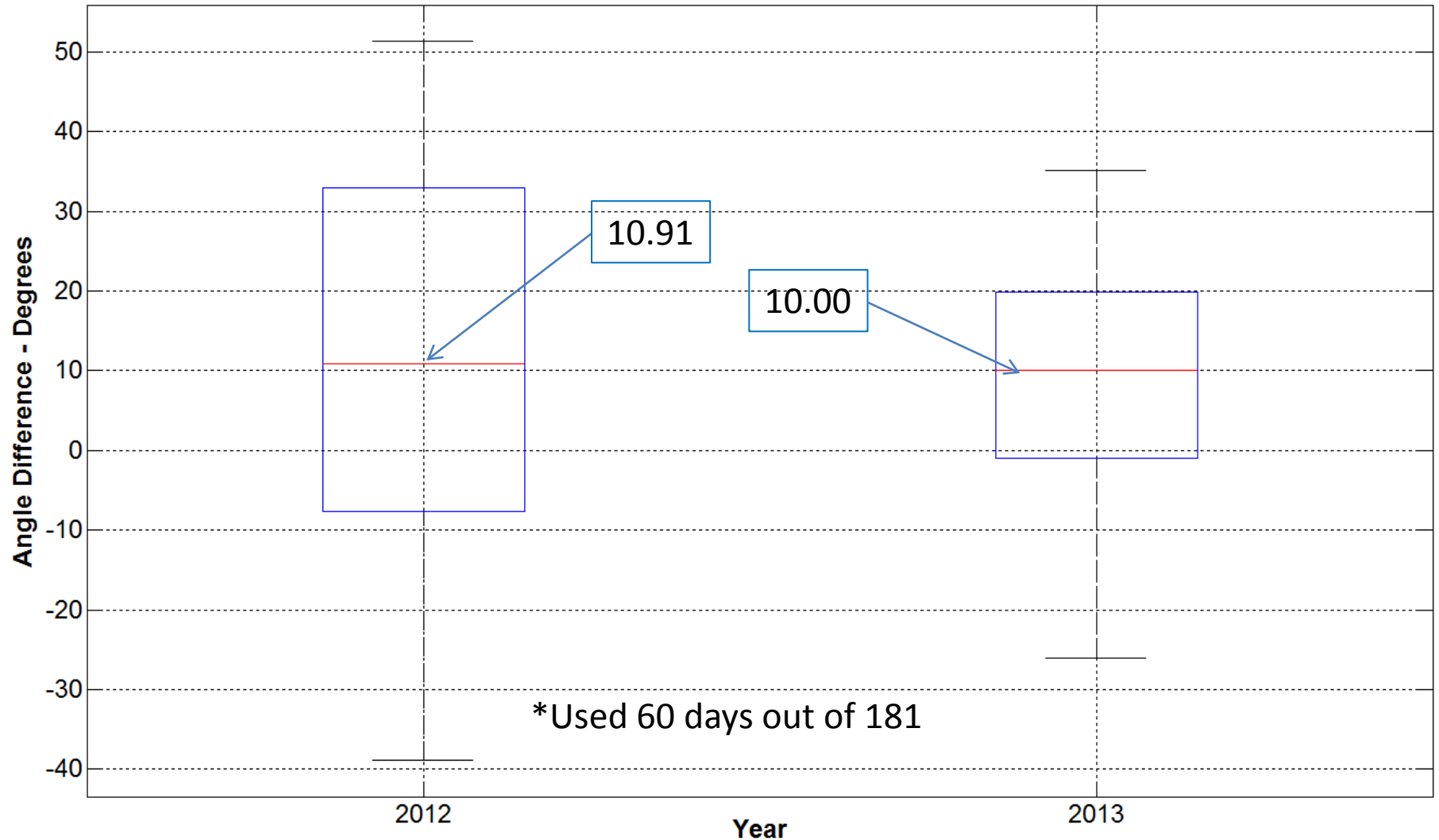
FarWest 8 – North 7



FarWest 9 – North 7



FarWest 9 – North 7



Appendix D – Part 1

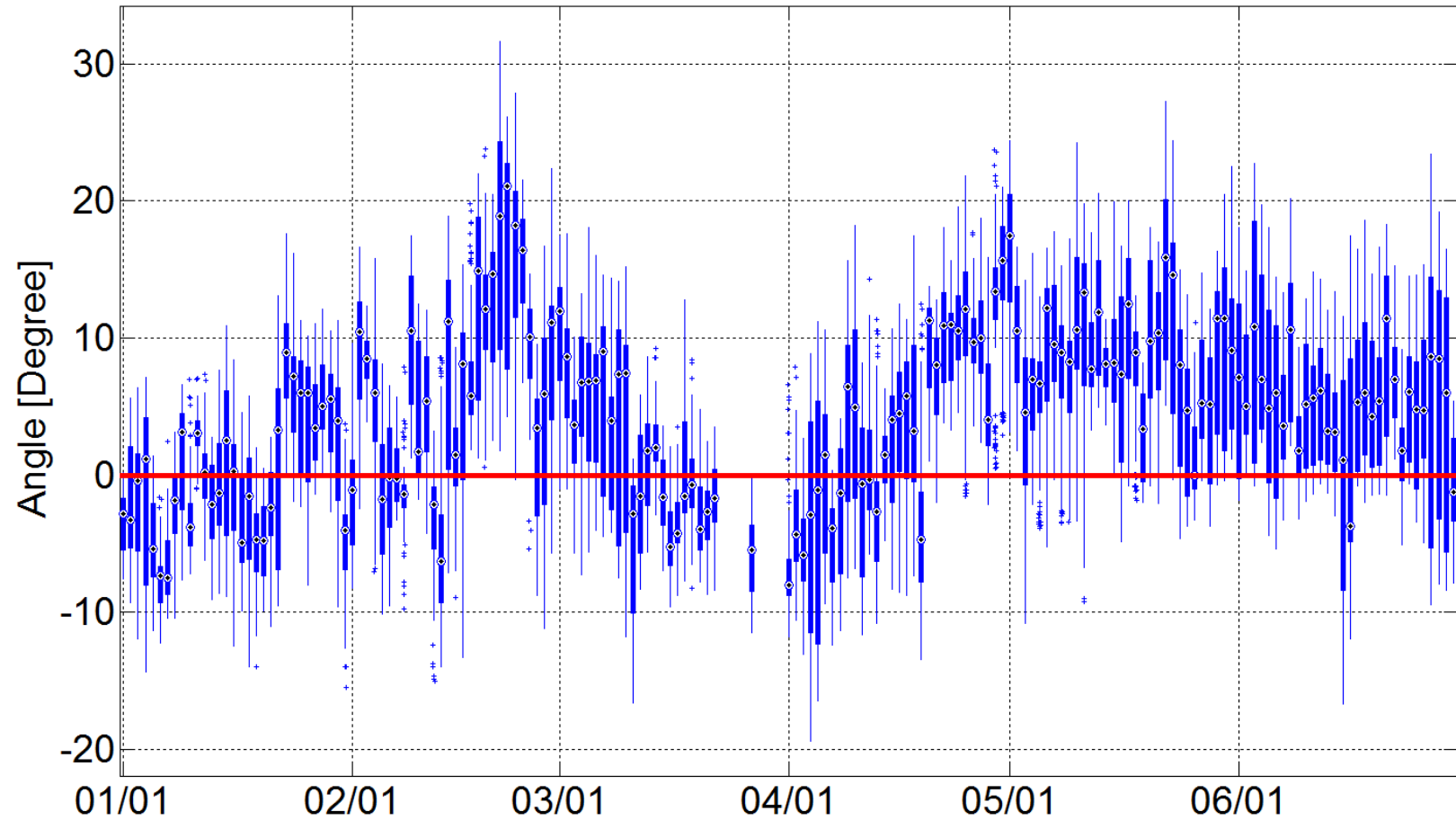
CCET Discovery Across Texas project

Baseline Analysis Update – Angle Differences

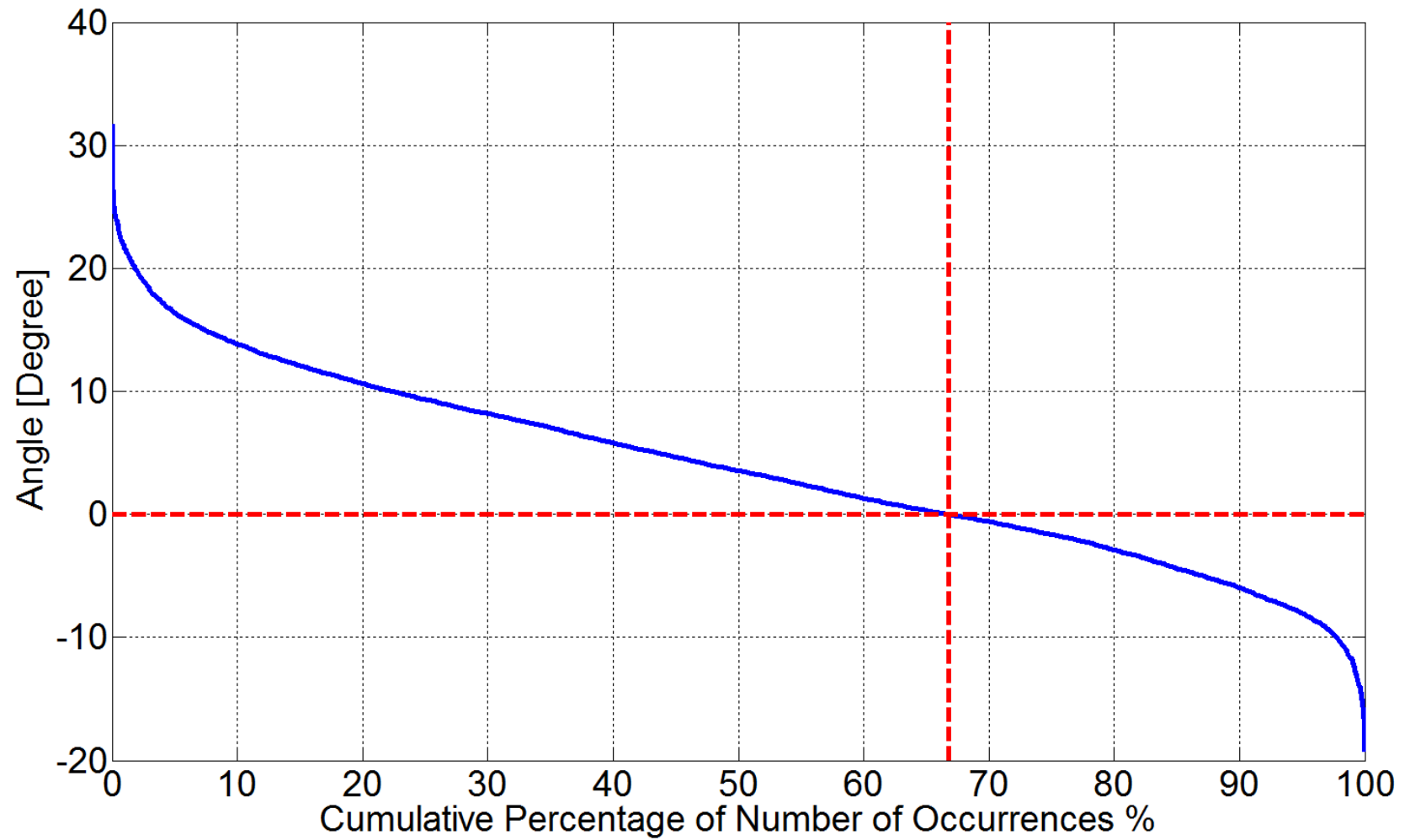
State Estimator Data: January to June 2013
Box Whiskers Plots and Time Duration Curves

External Version

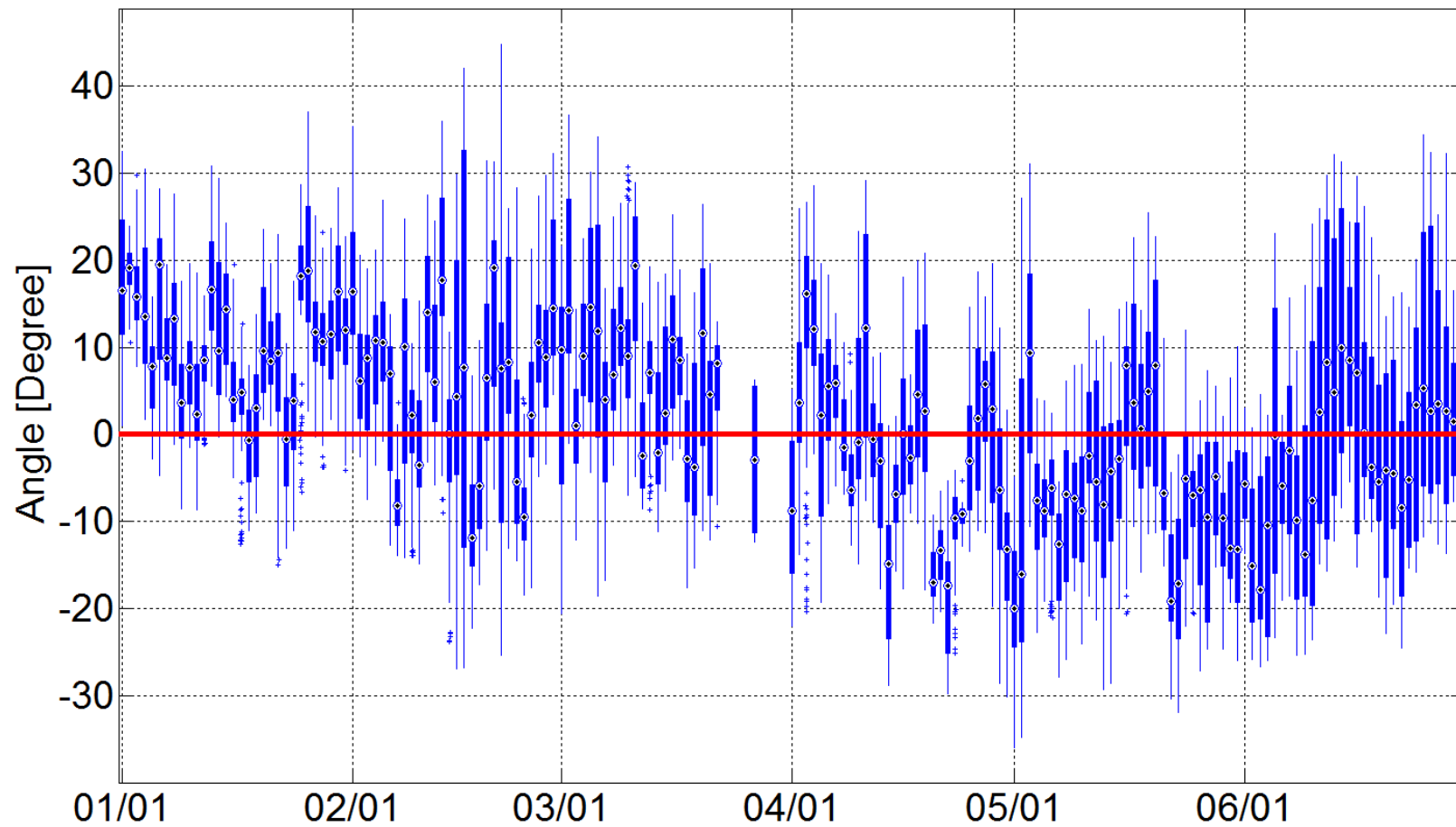
Coast 1-South 13



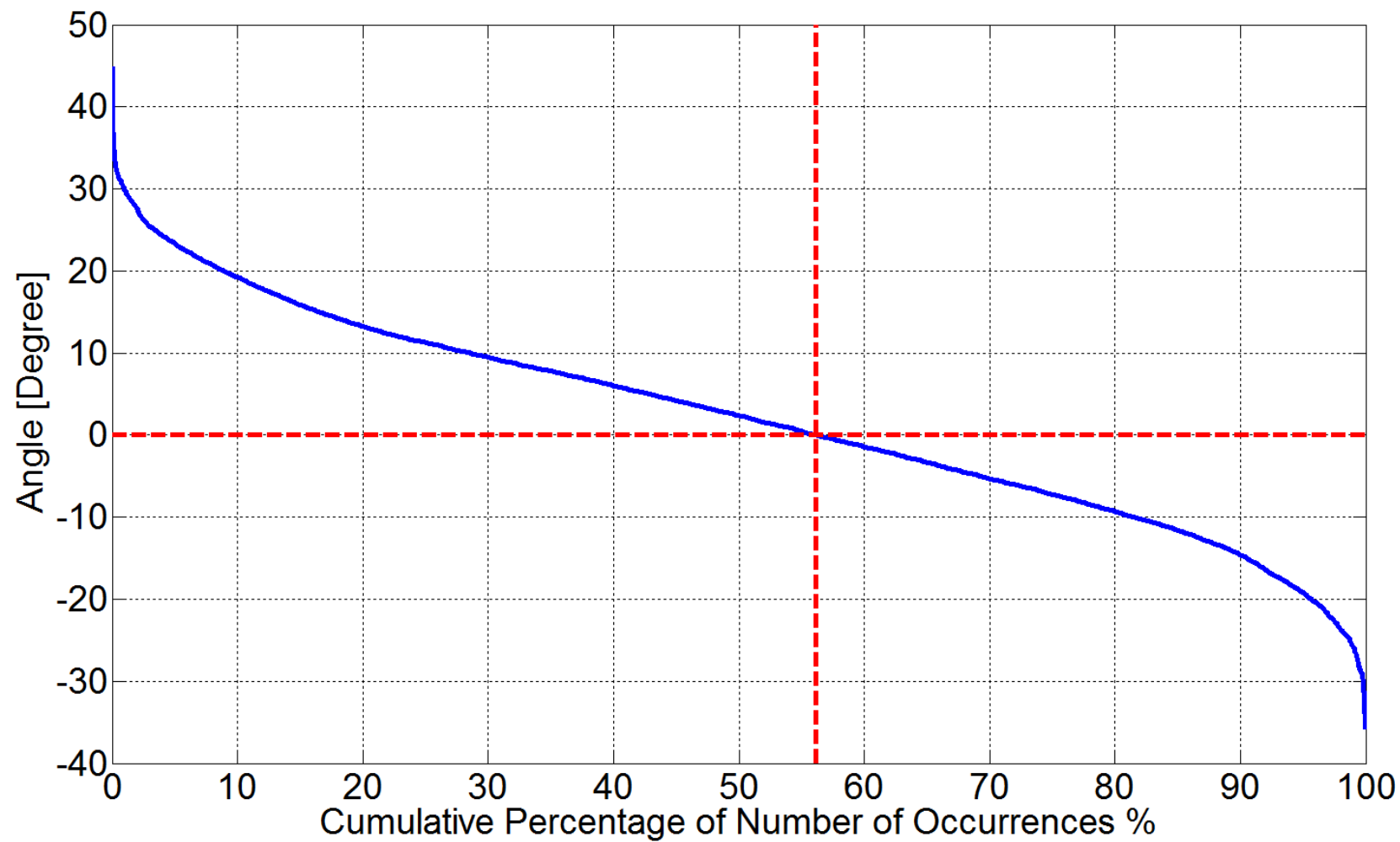
Coast 1-South 13



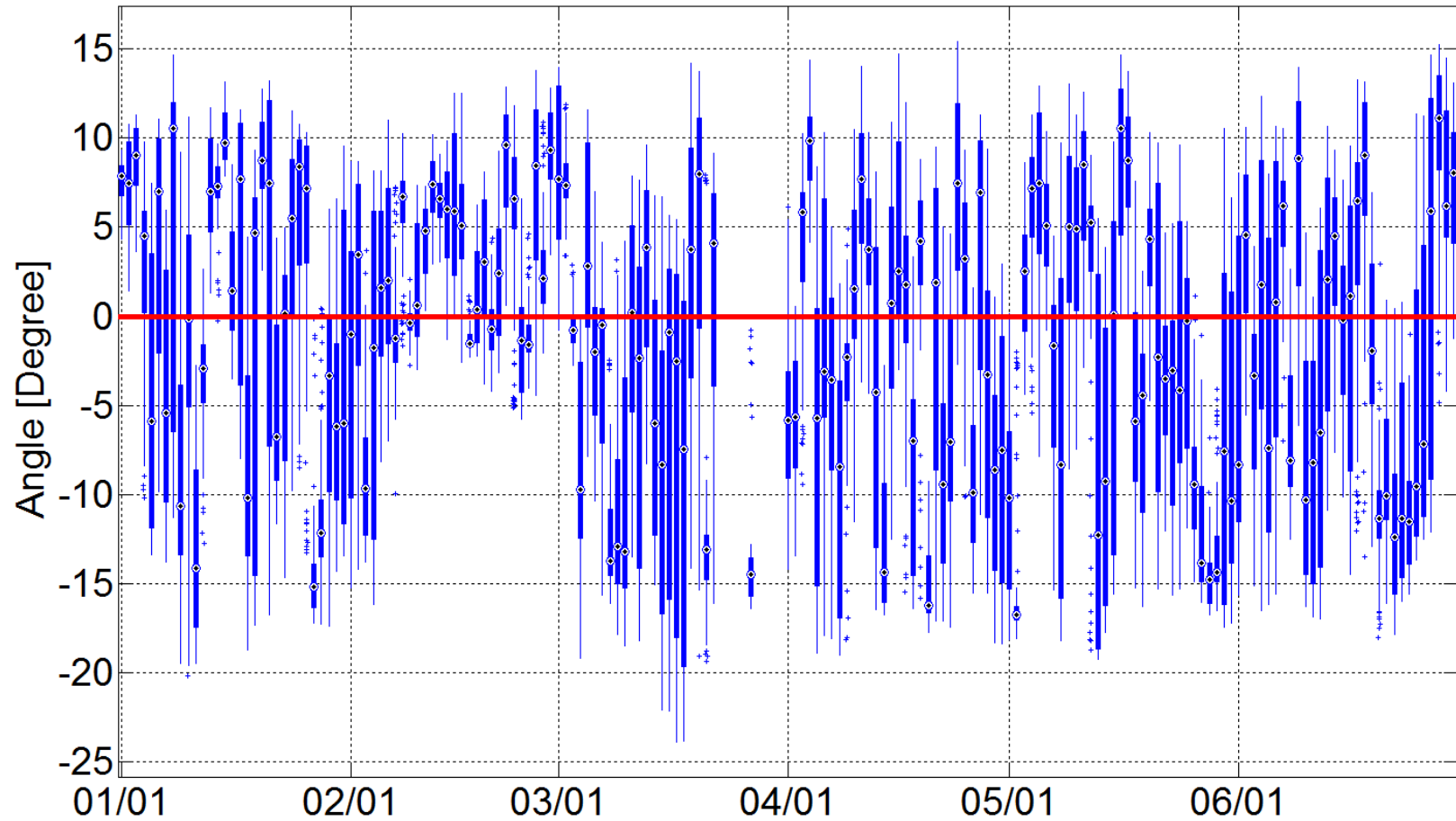
Coast 1-North 7



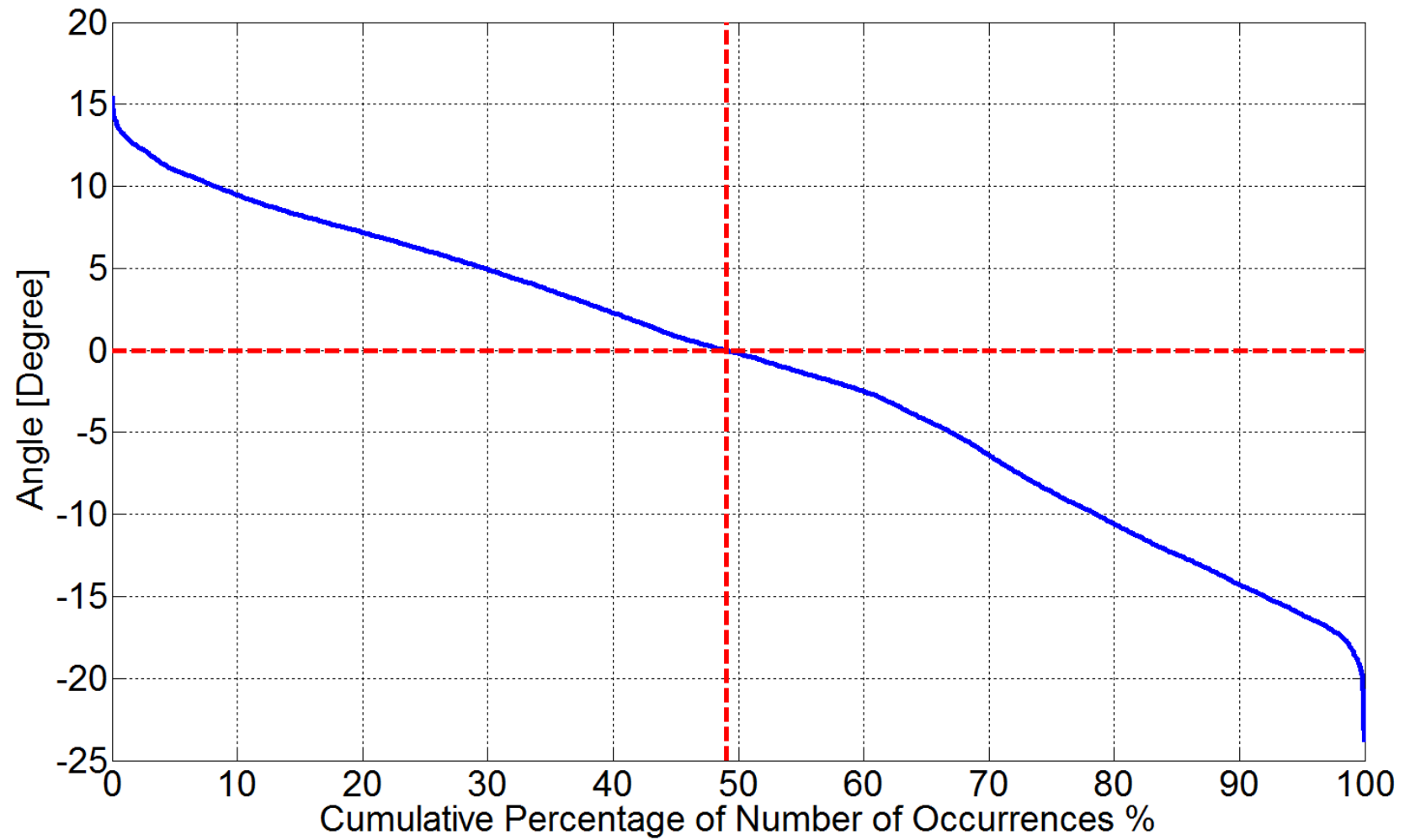
Coast 1-North 7



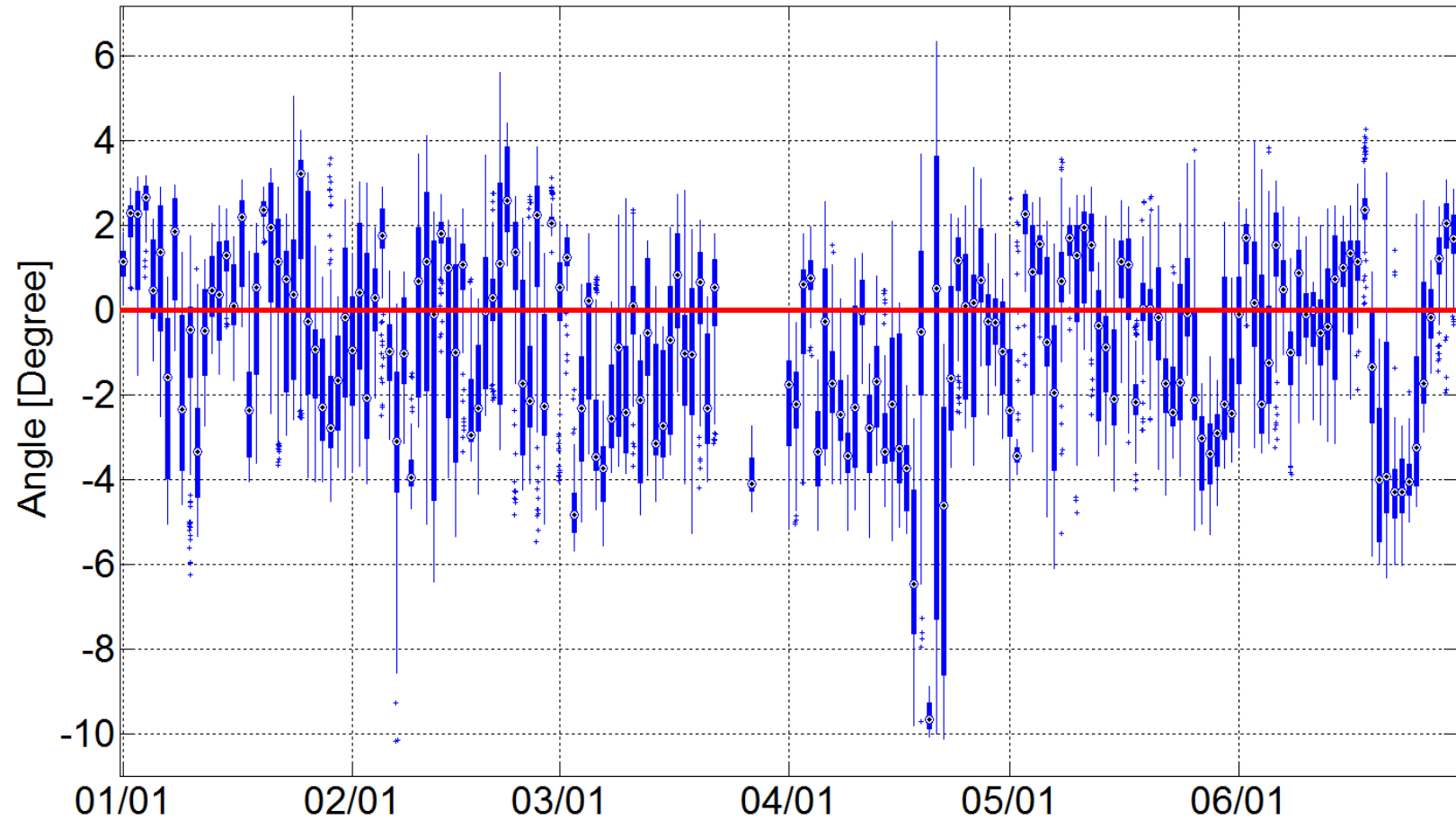
West 5*-West 10



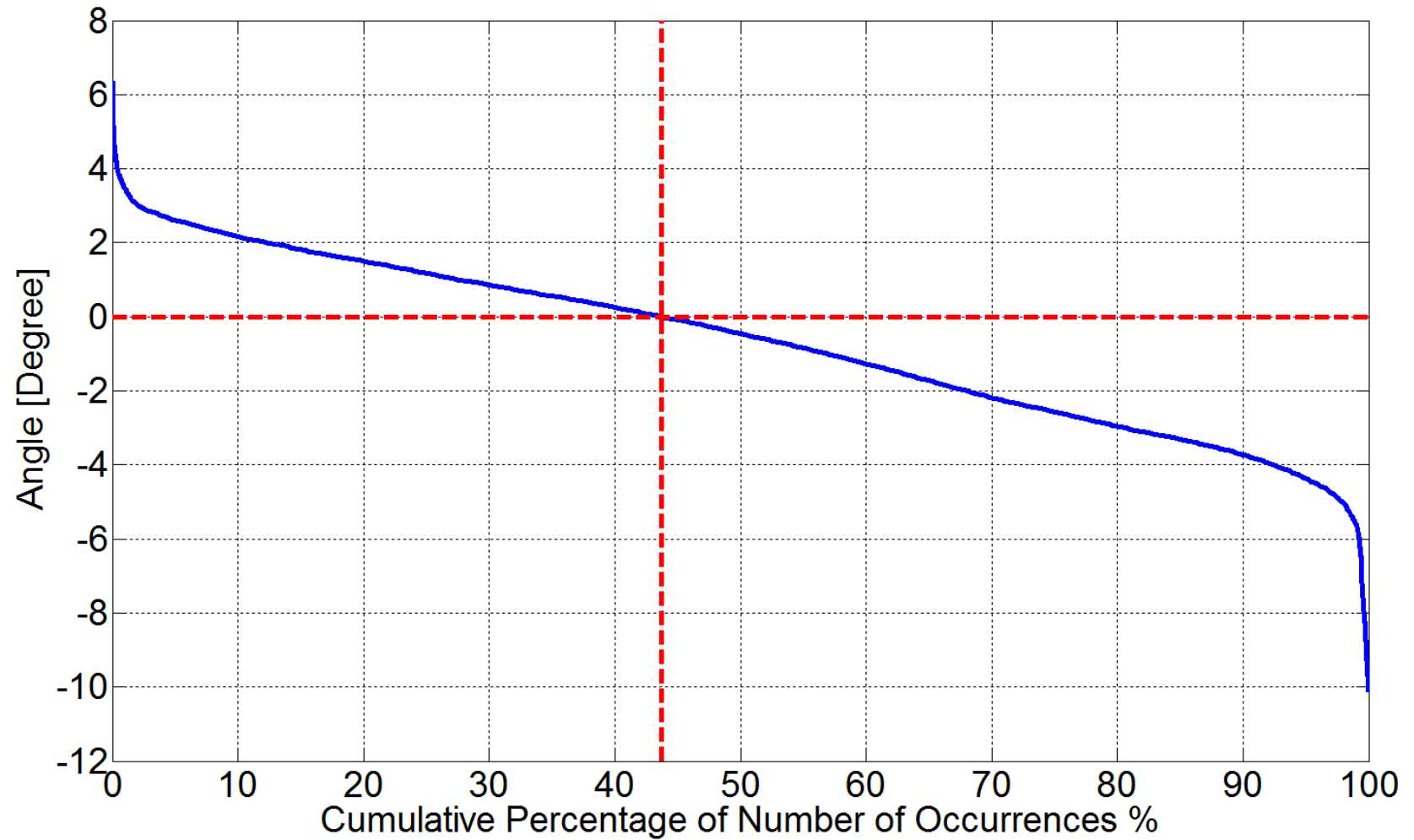
West 5*-West 10



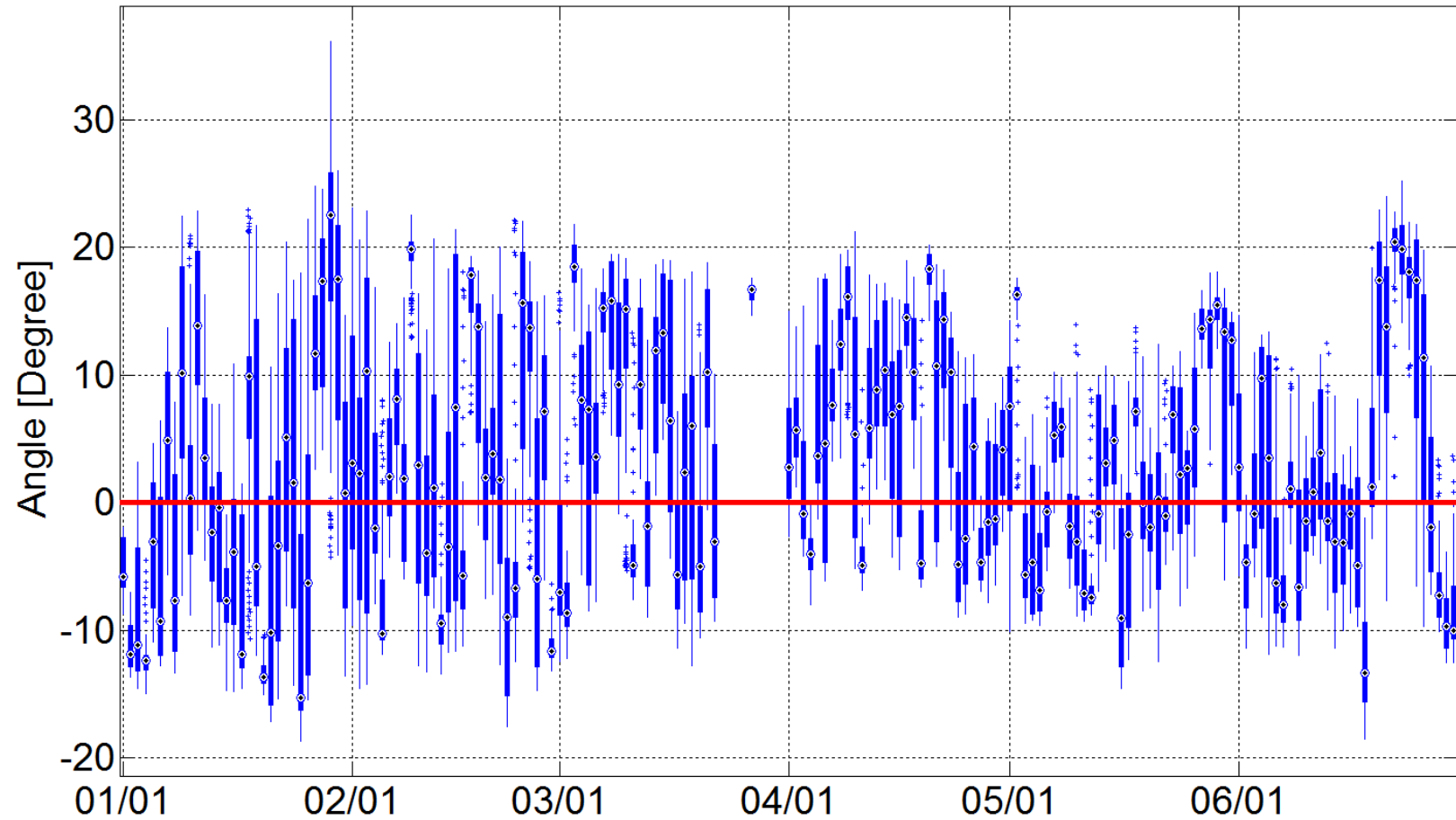
West 5*-FarWest 4



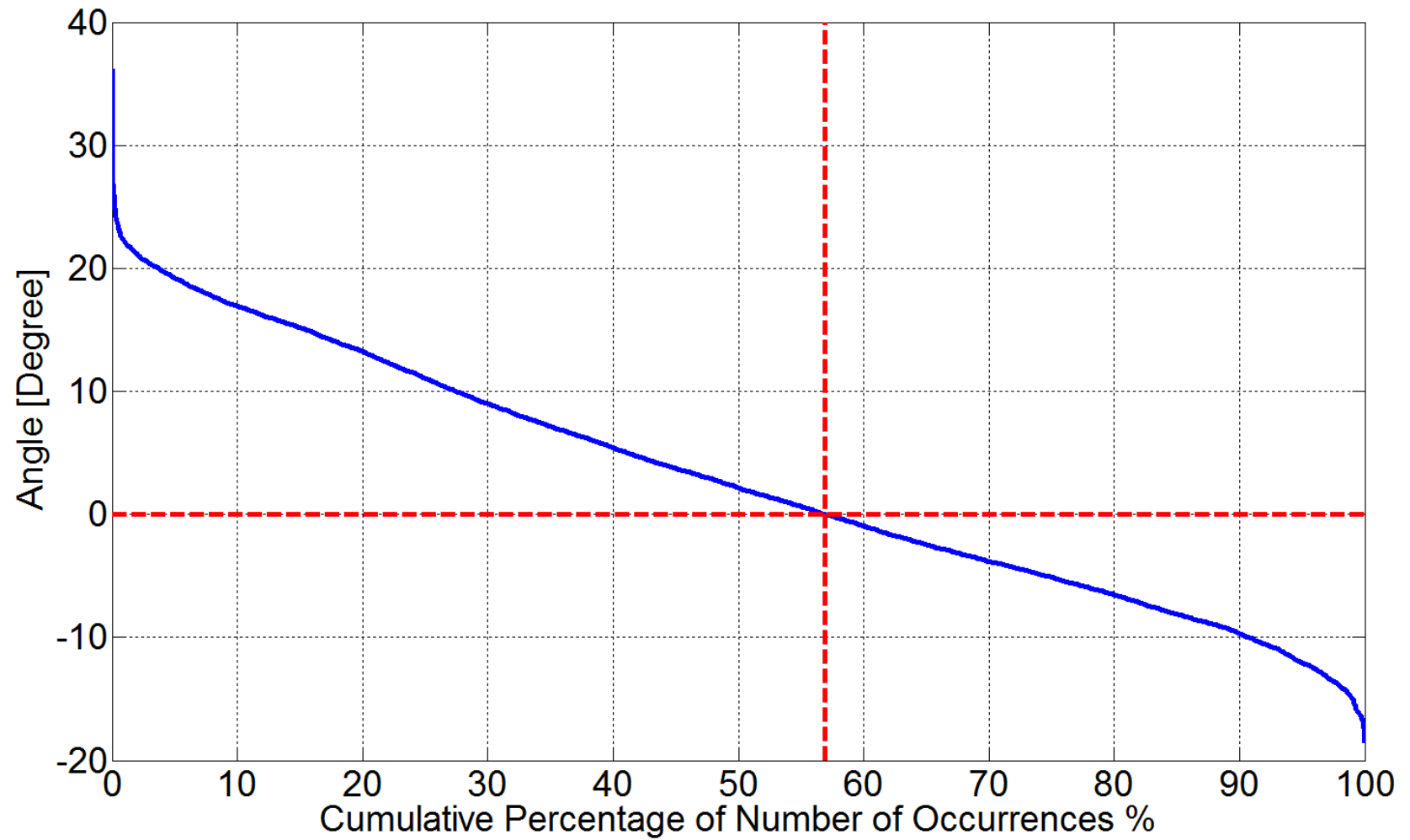
West 5*-FarWest 4



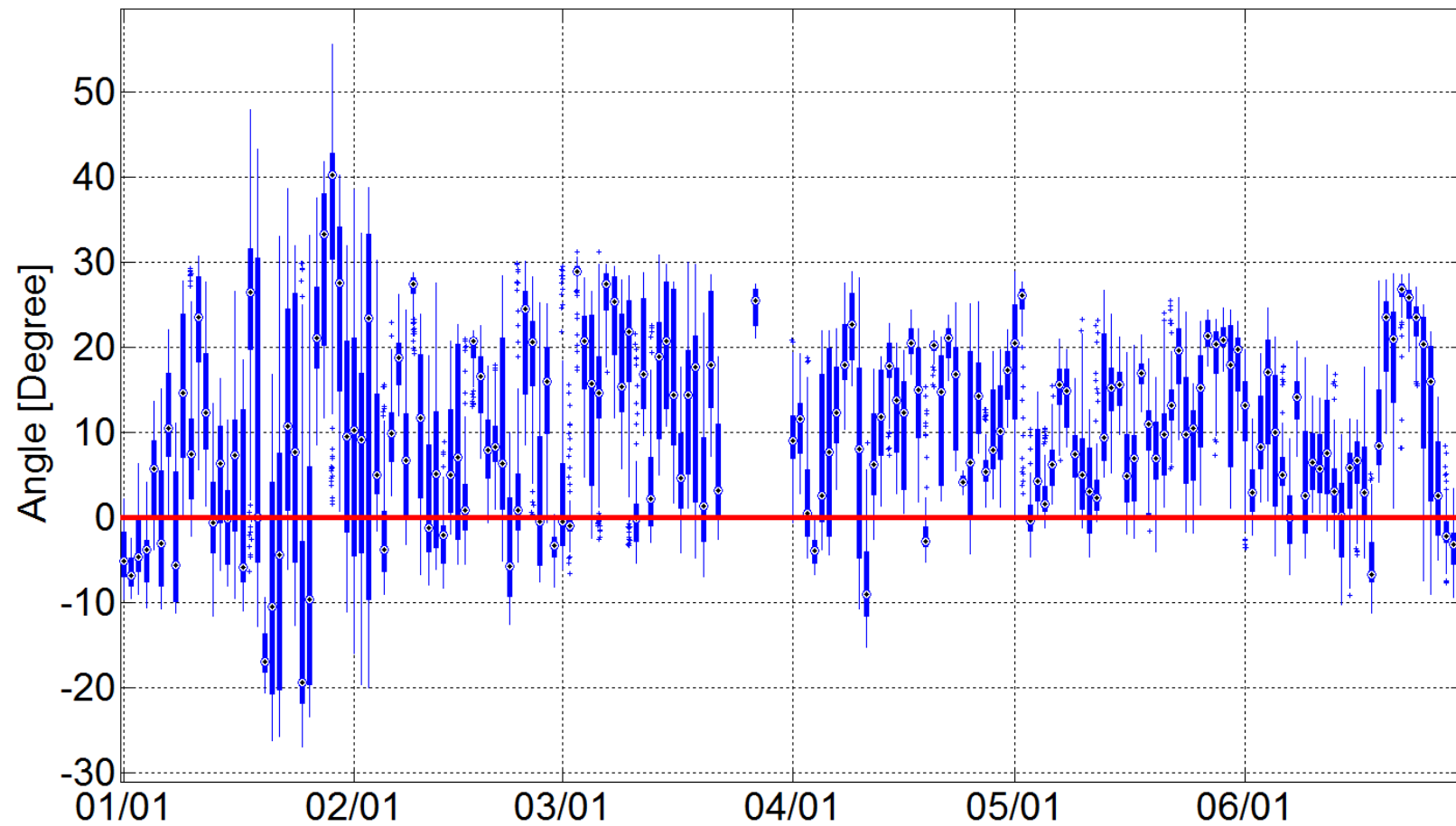
West 5*-North 1



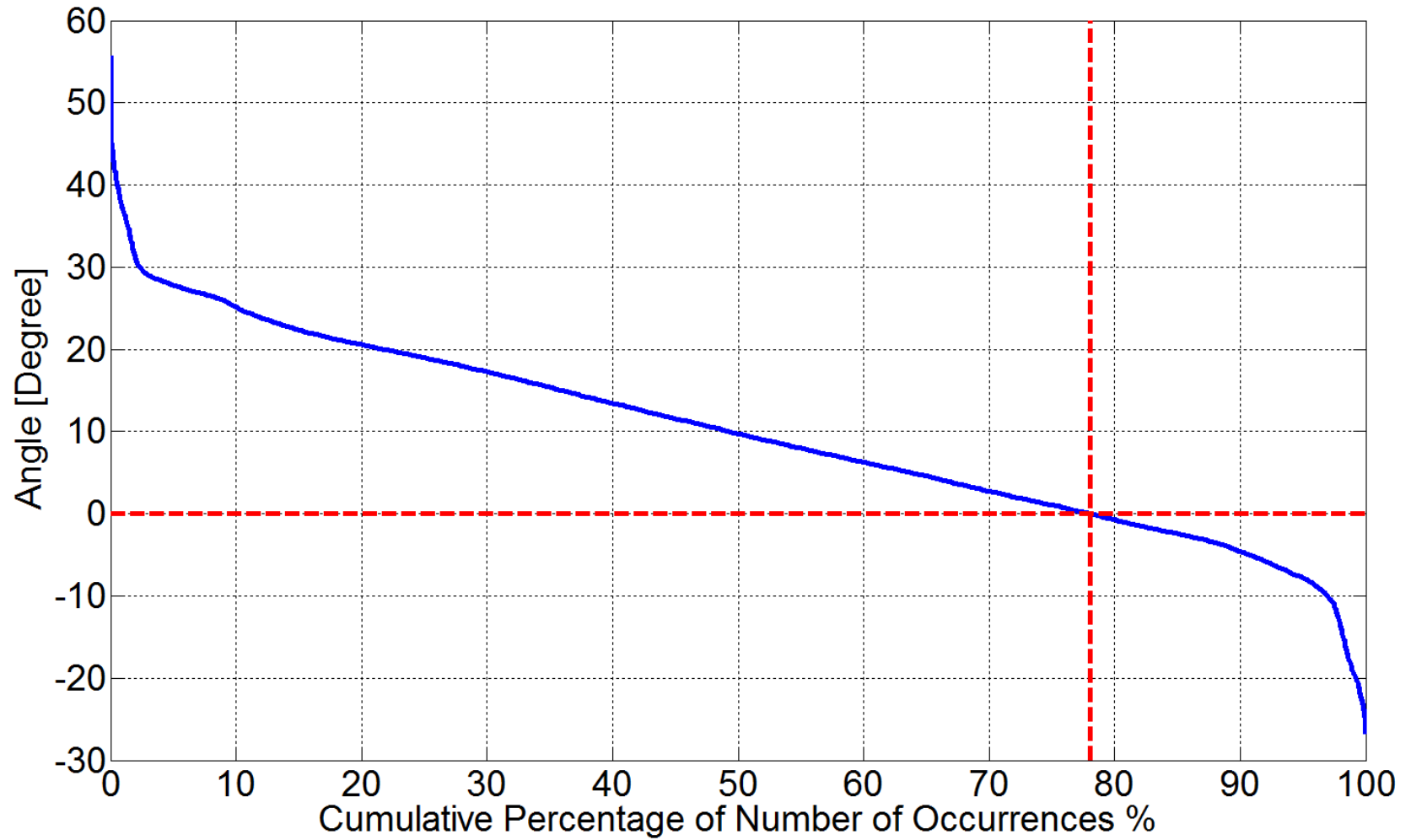
West 5*-North 1



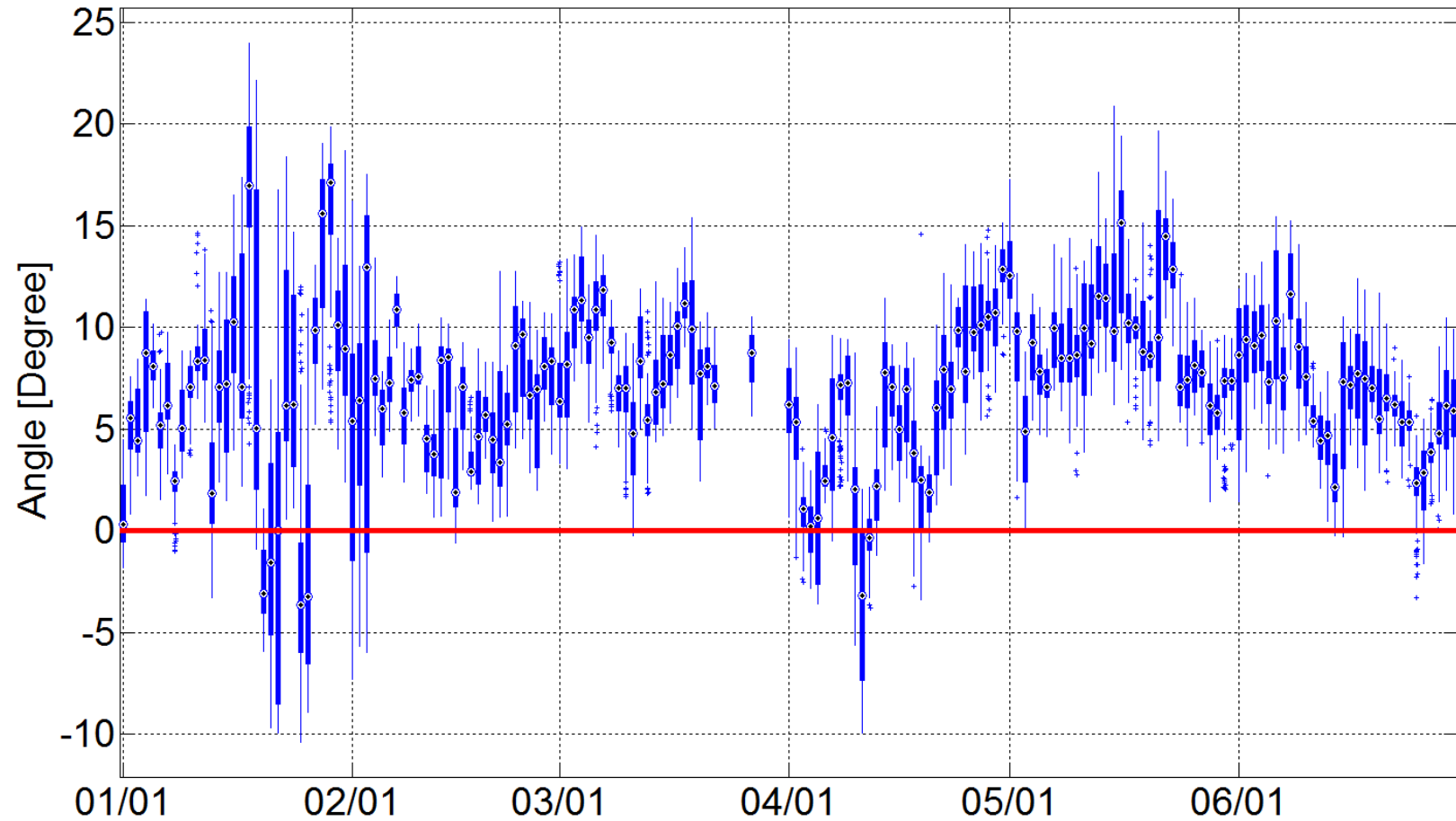
West 5*-North 7



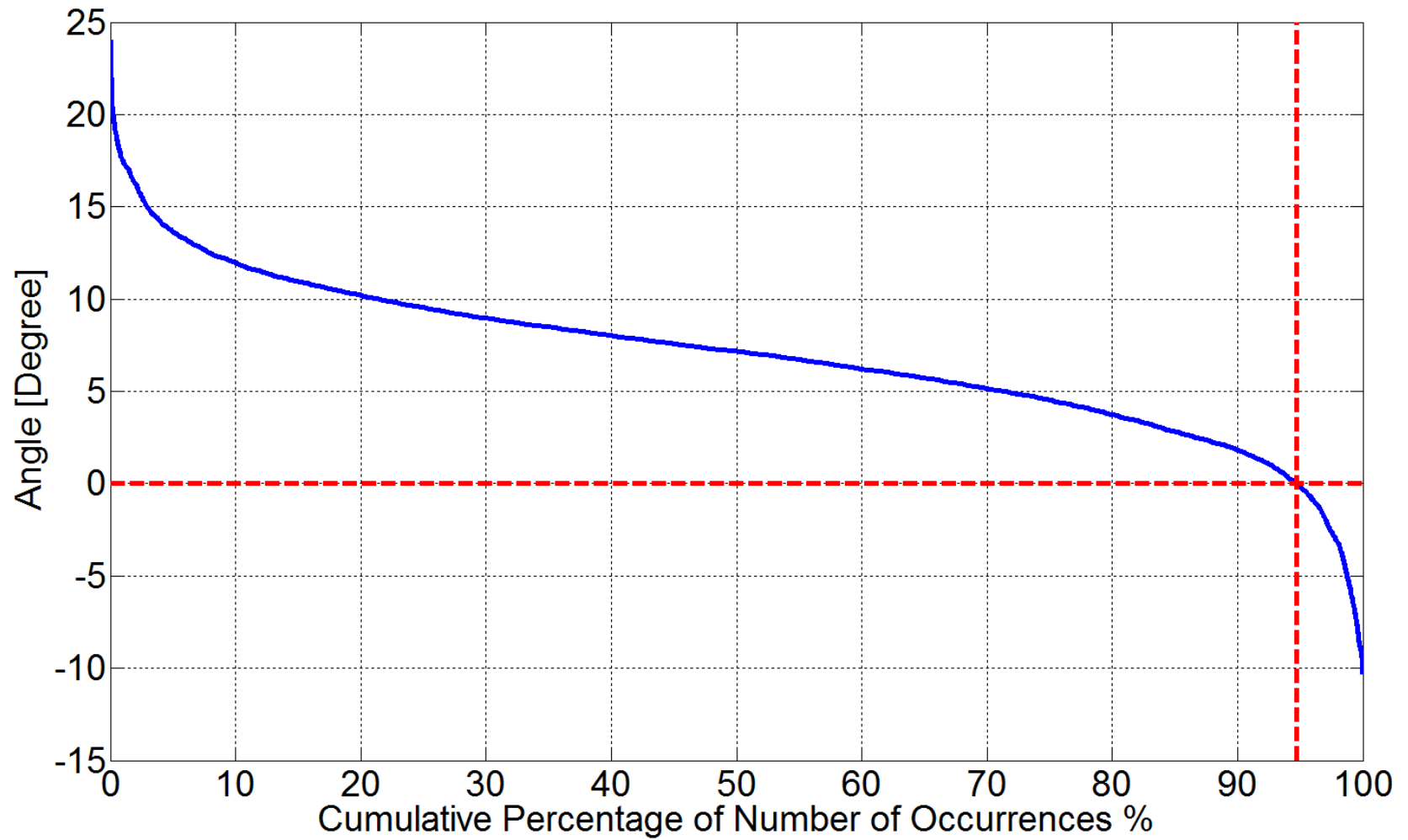
West 5*-North 7



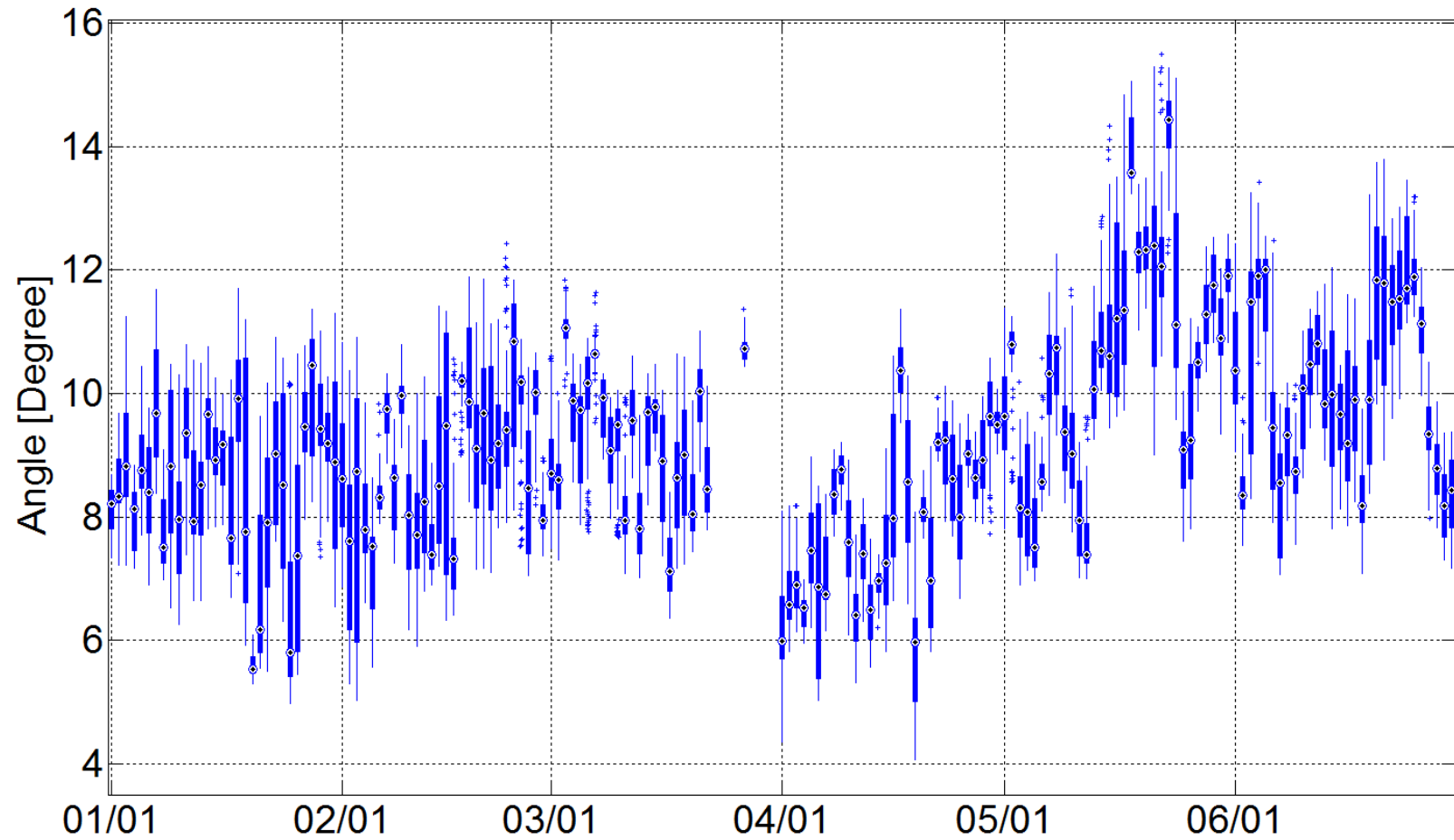
North 1-North 7



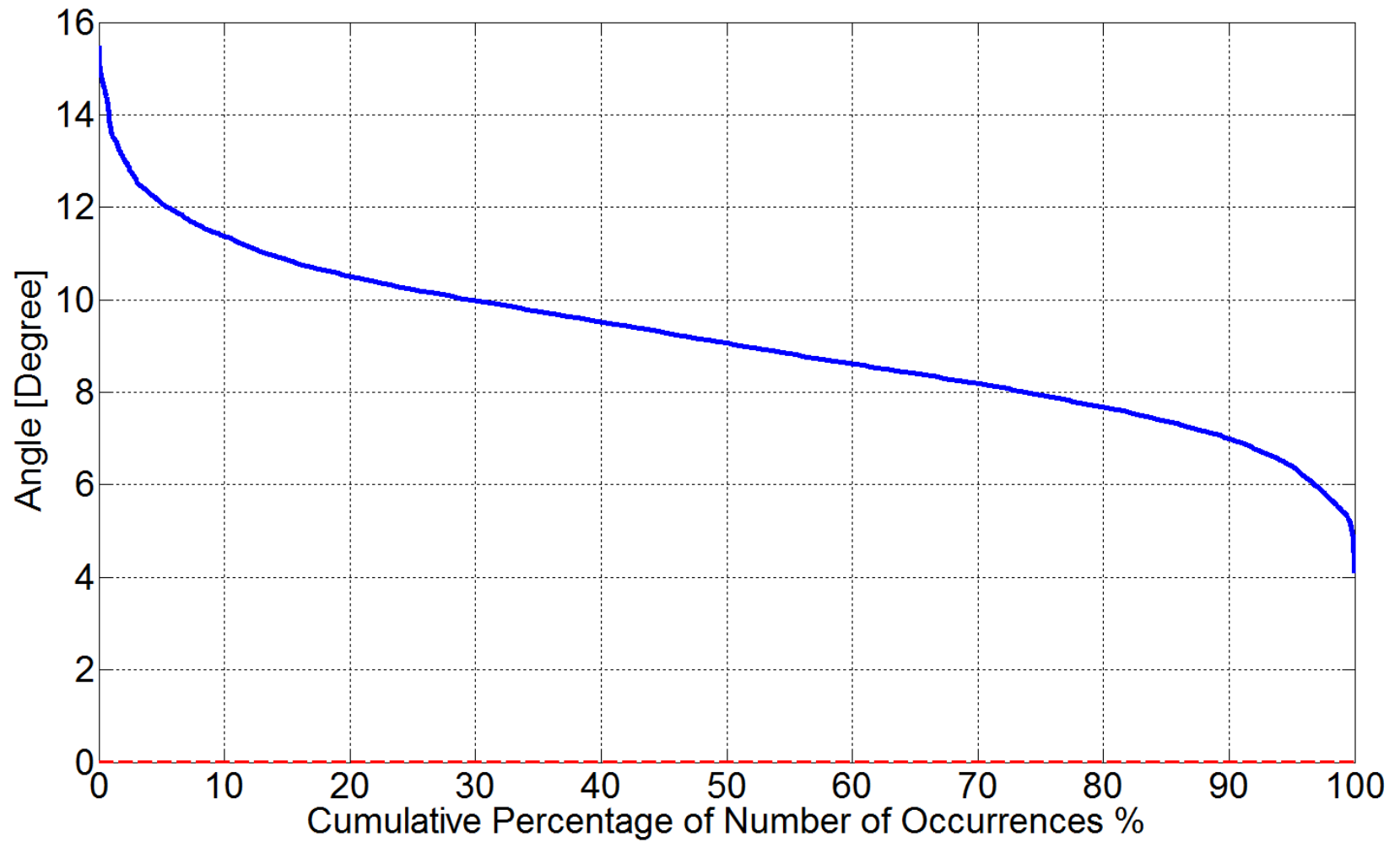
North 1-North 7



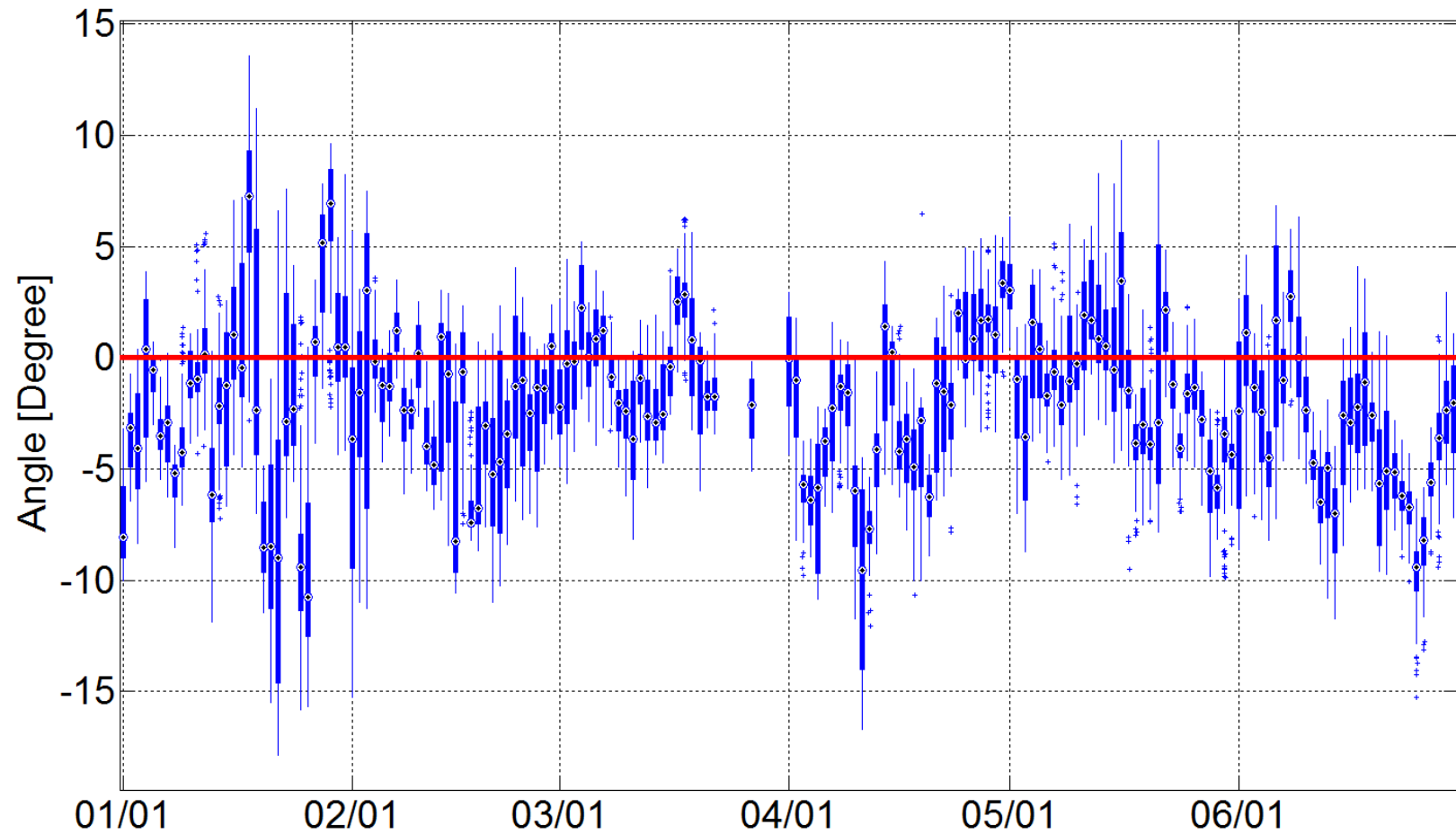
North 1-North 4



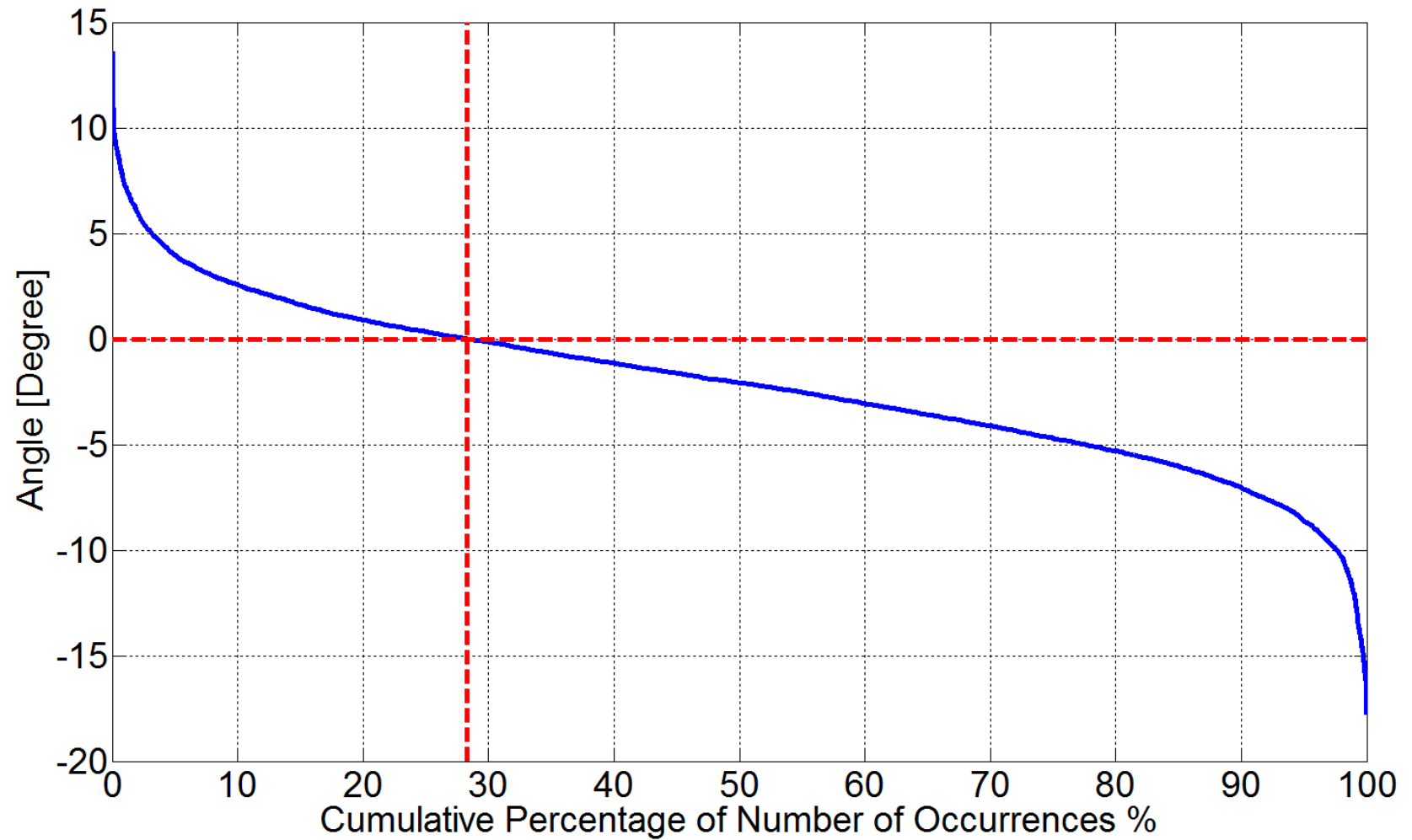
North 1-North 4



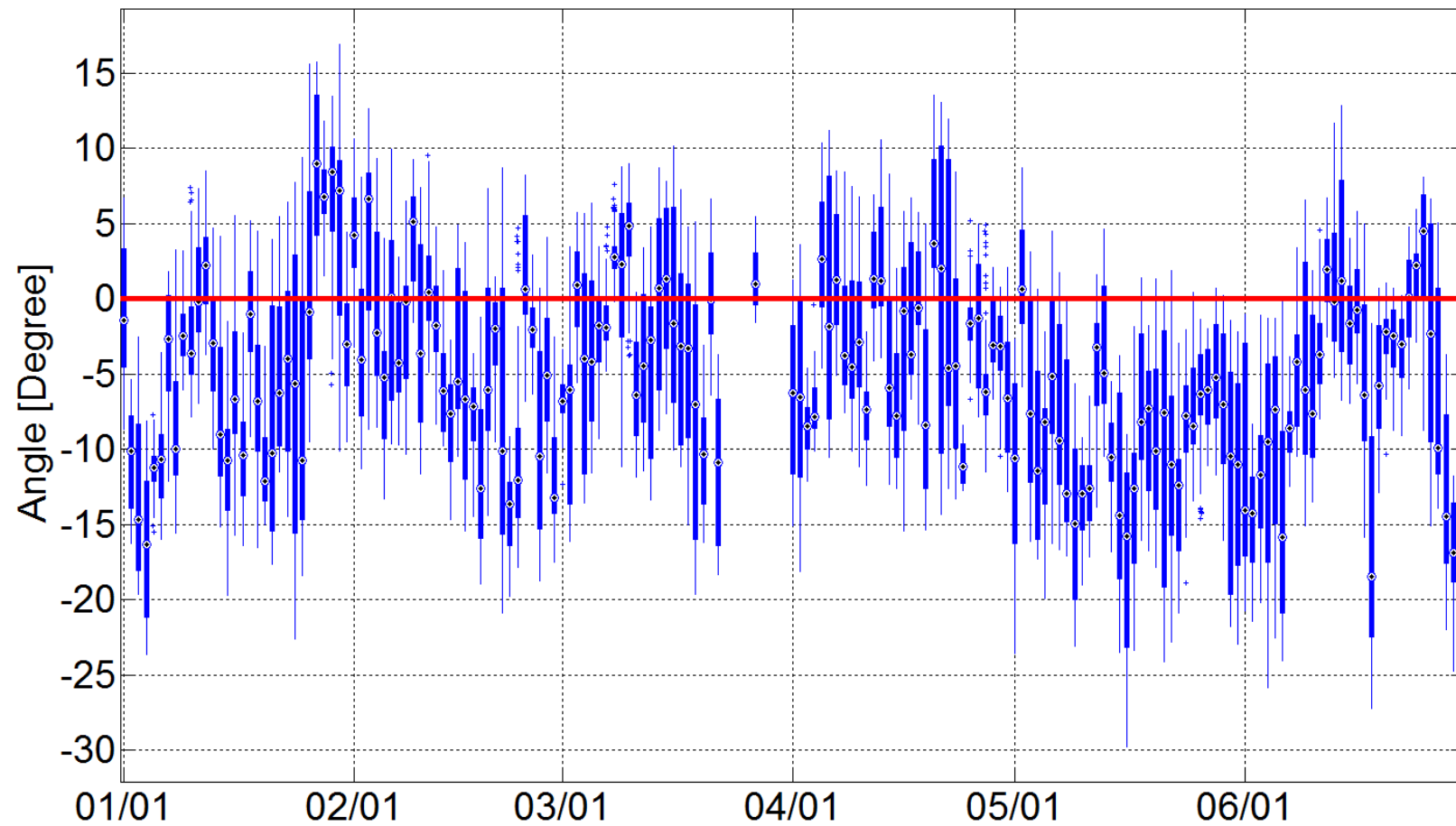
North 4-North 7



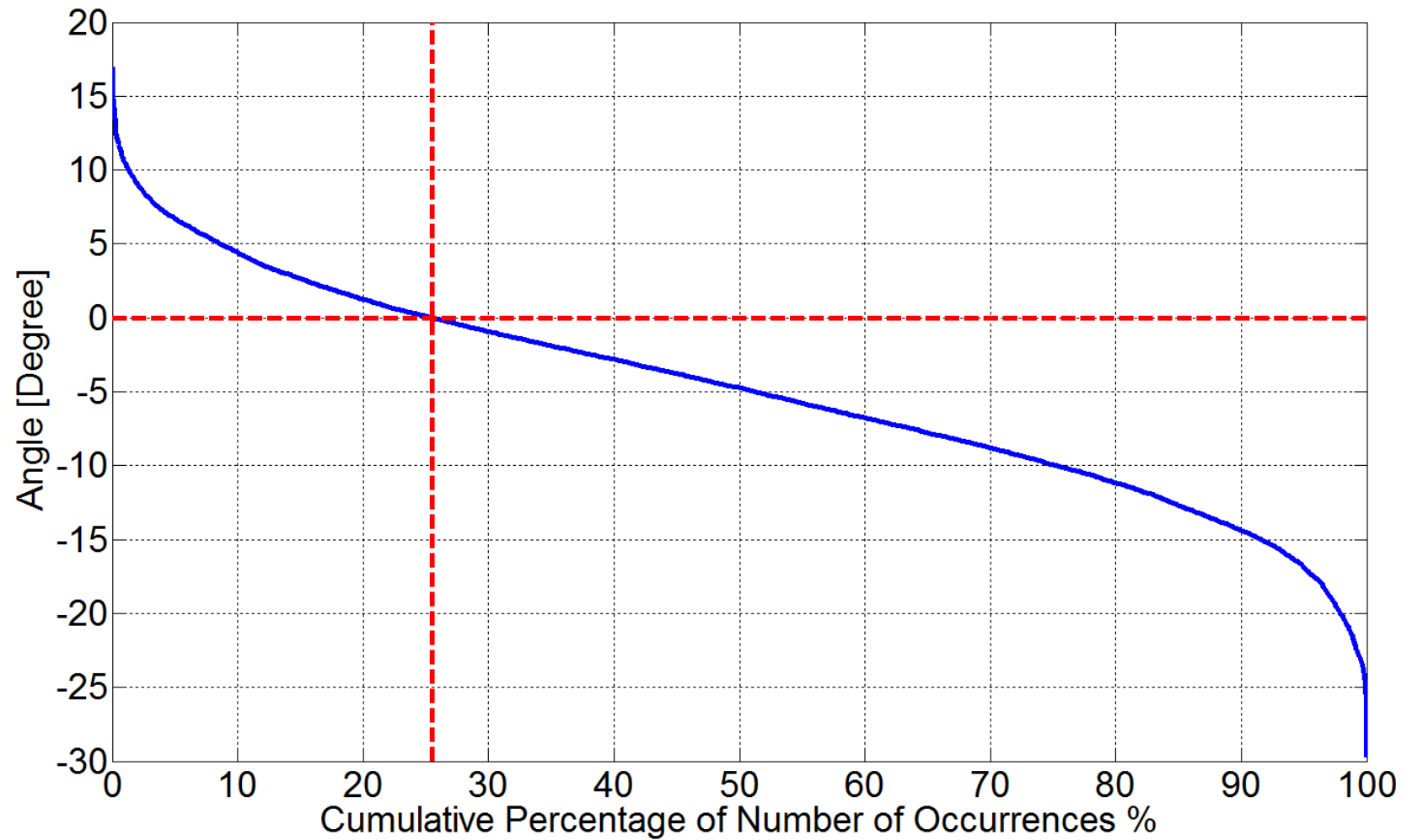
North 4-North 7



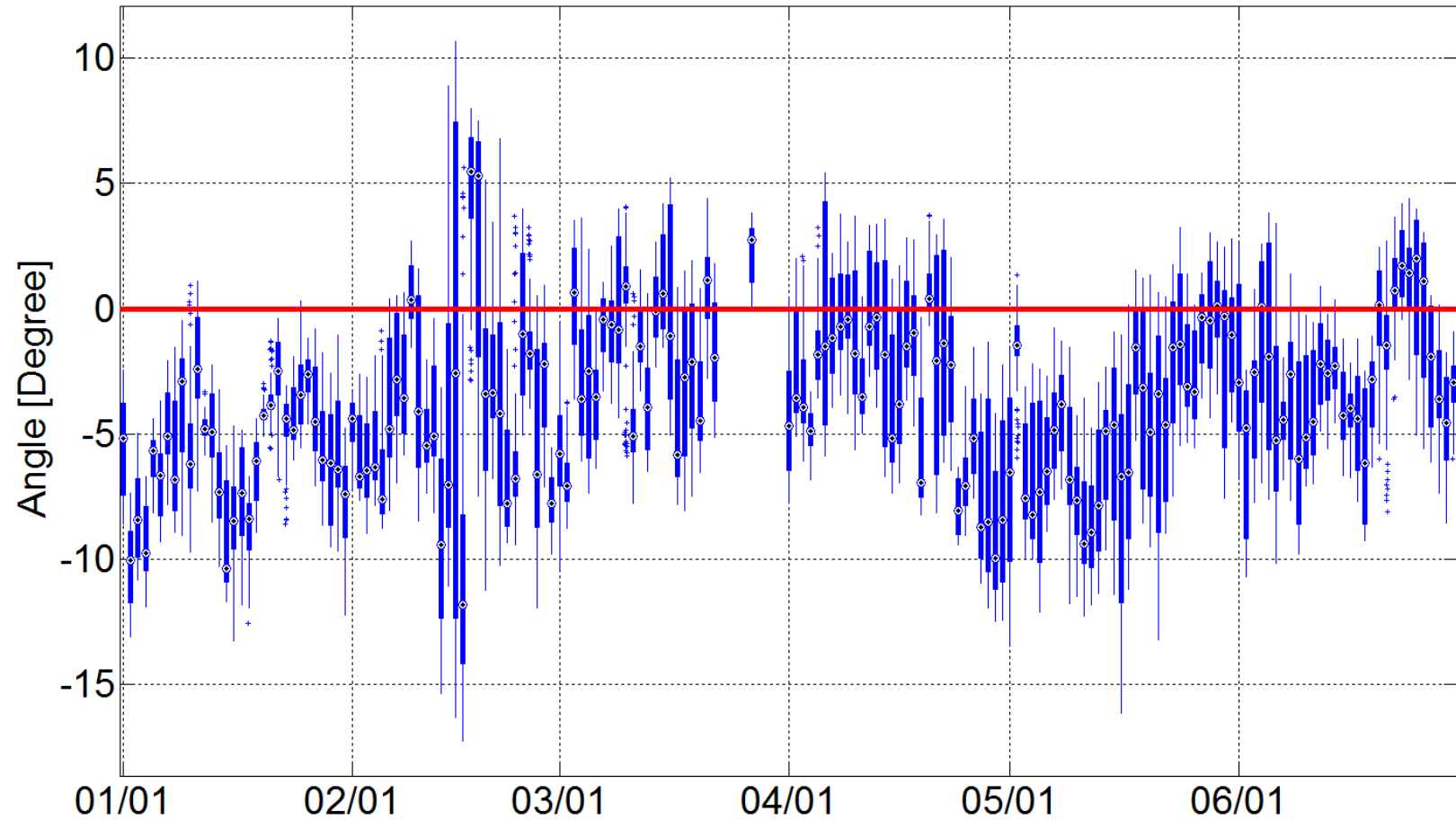
West 4-North 7



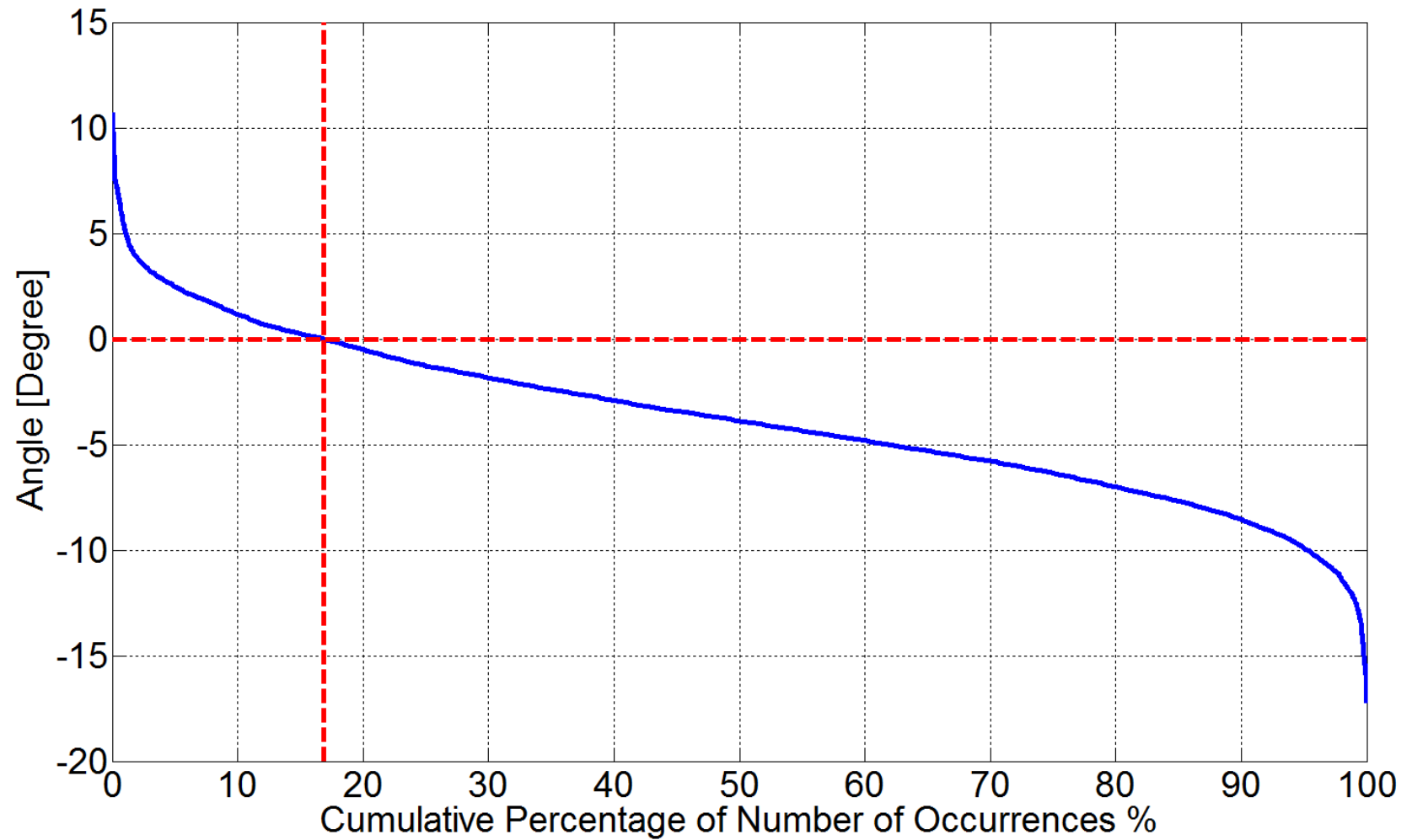
West 4-North 7



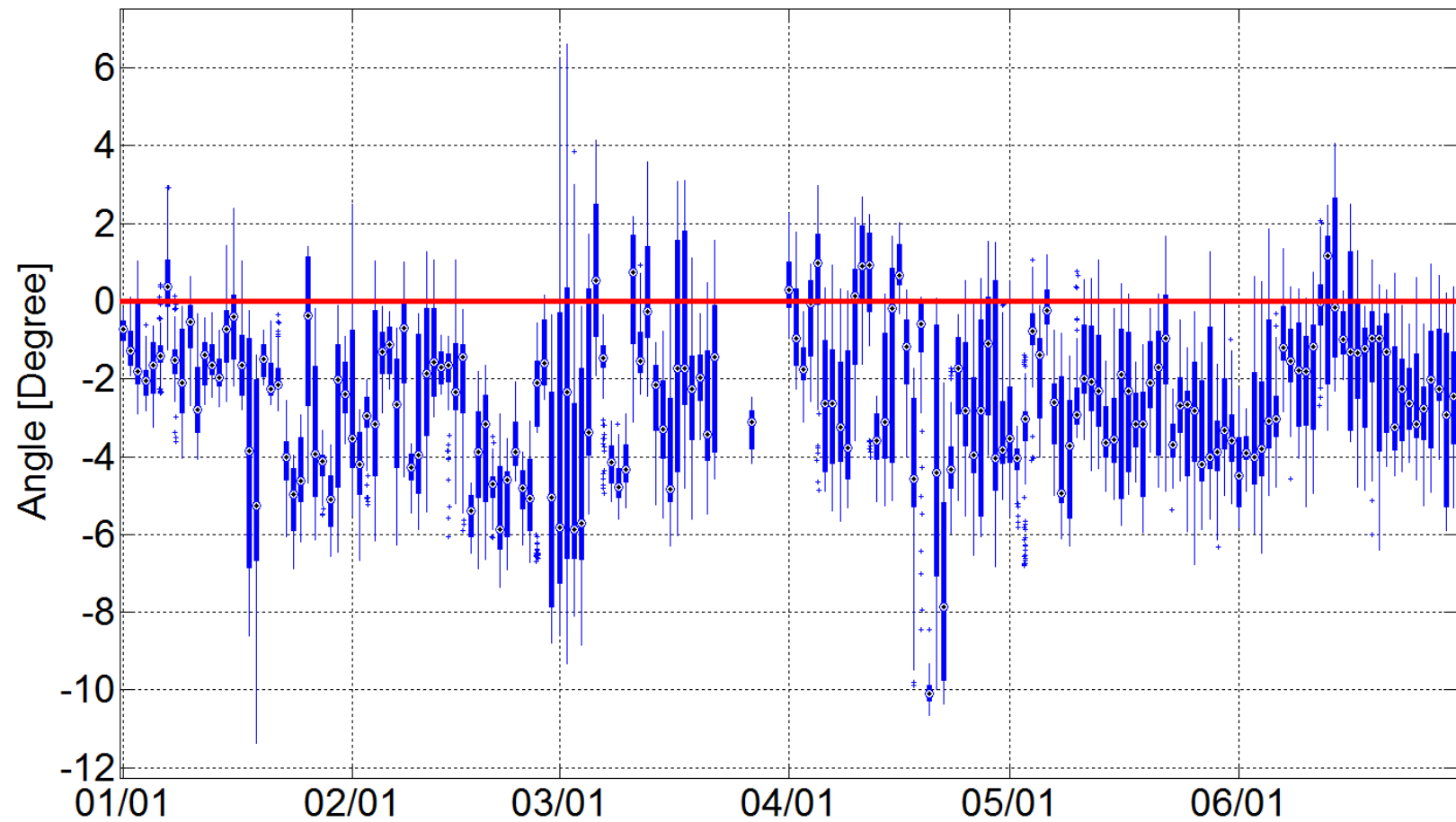
North 7-North 6



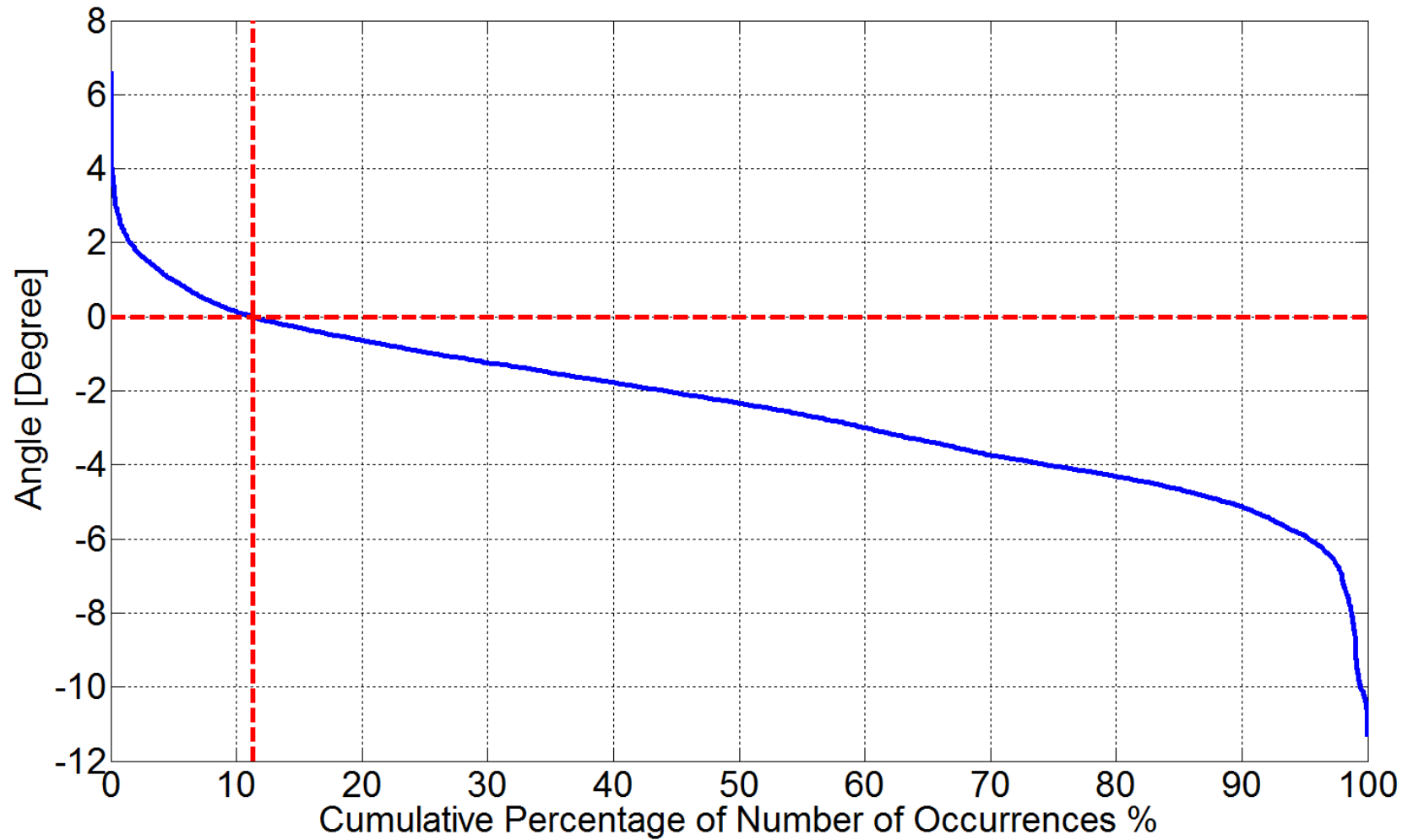
North 7-North 6



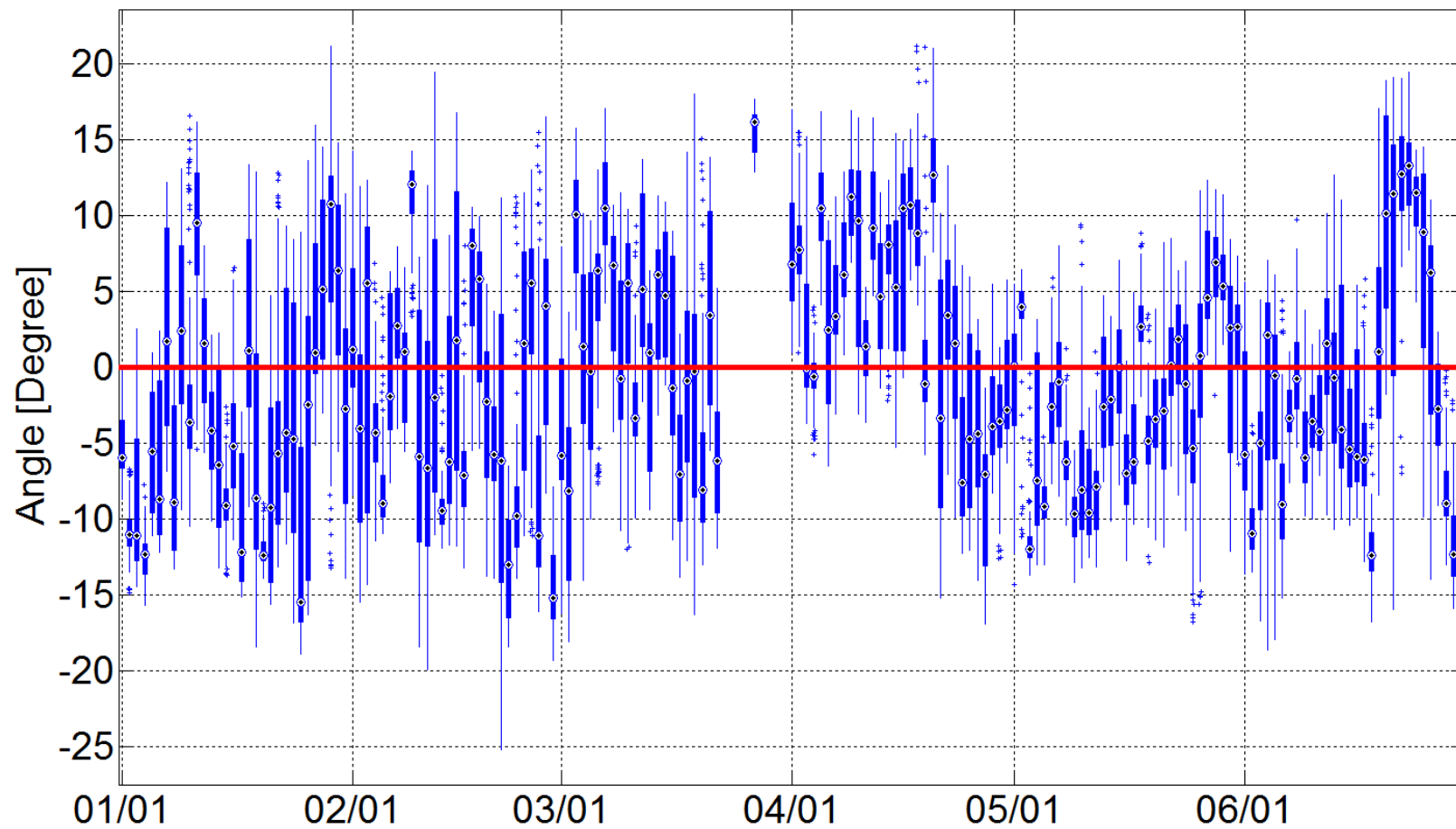
FarWest 7-FarWest 4



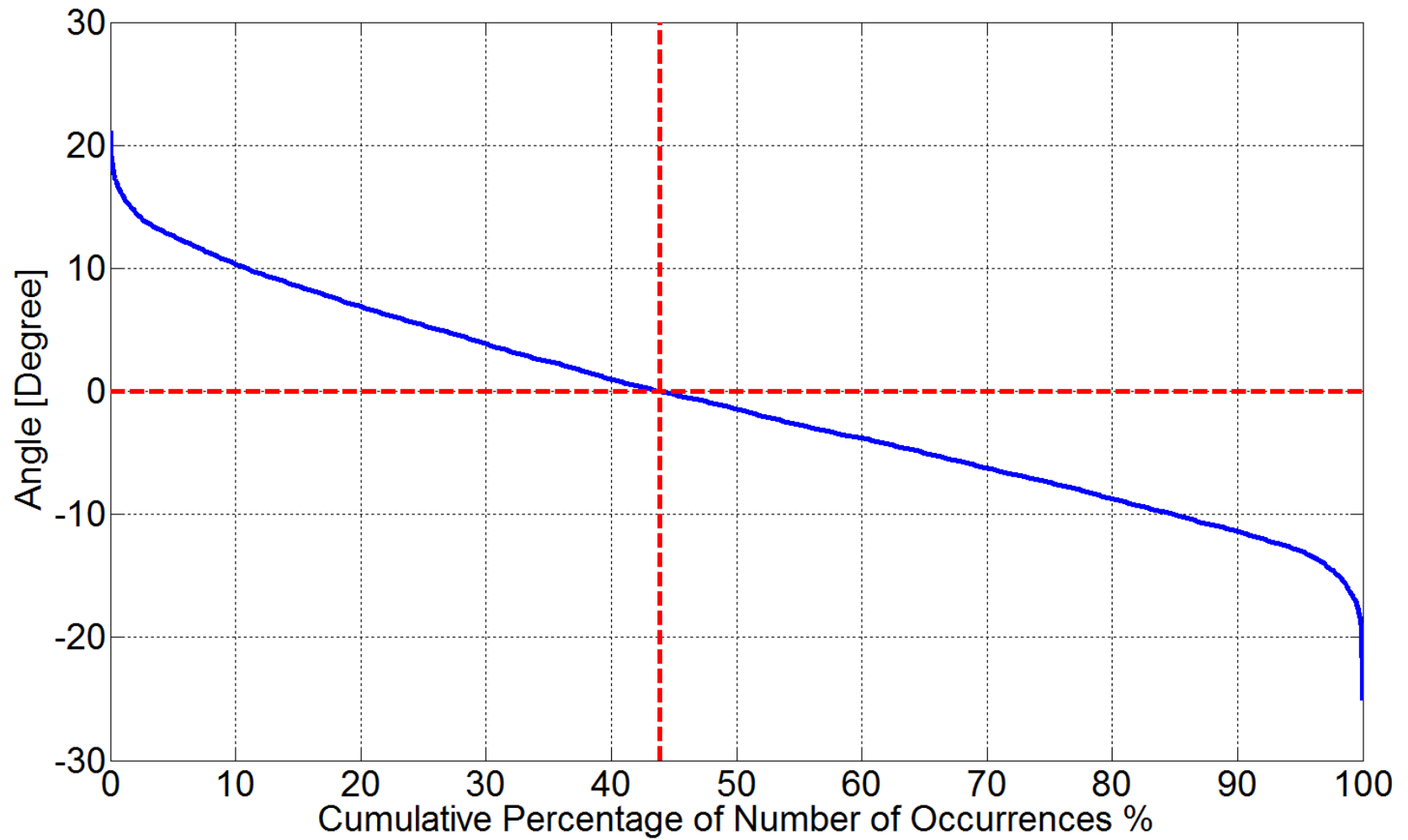
FarWest 7-FarWest 4



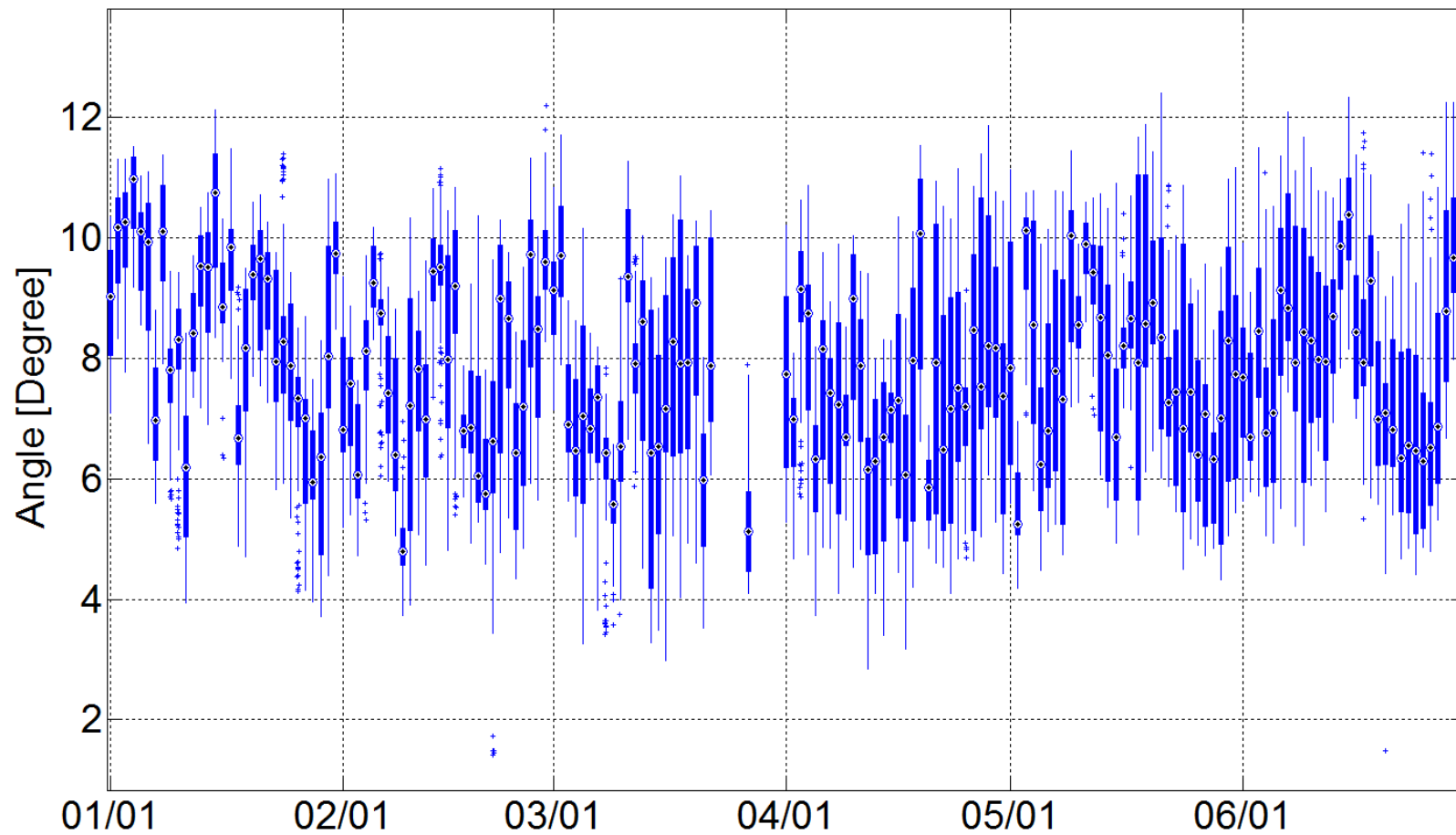
FarWest 7-West 14



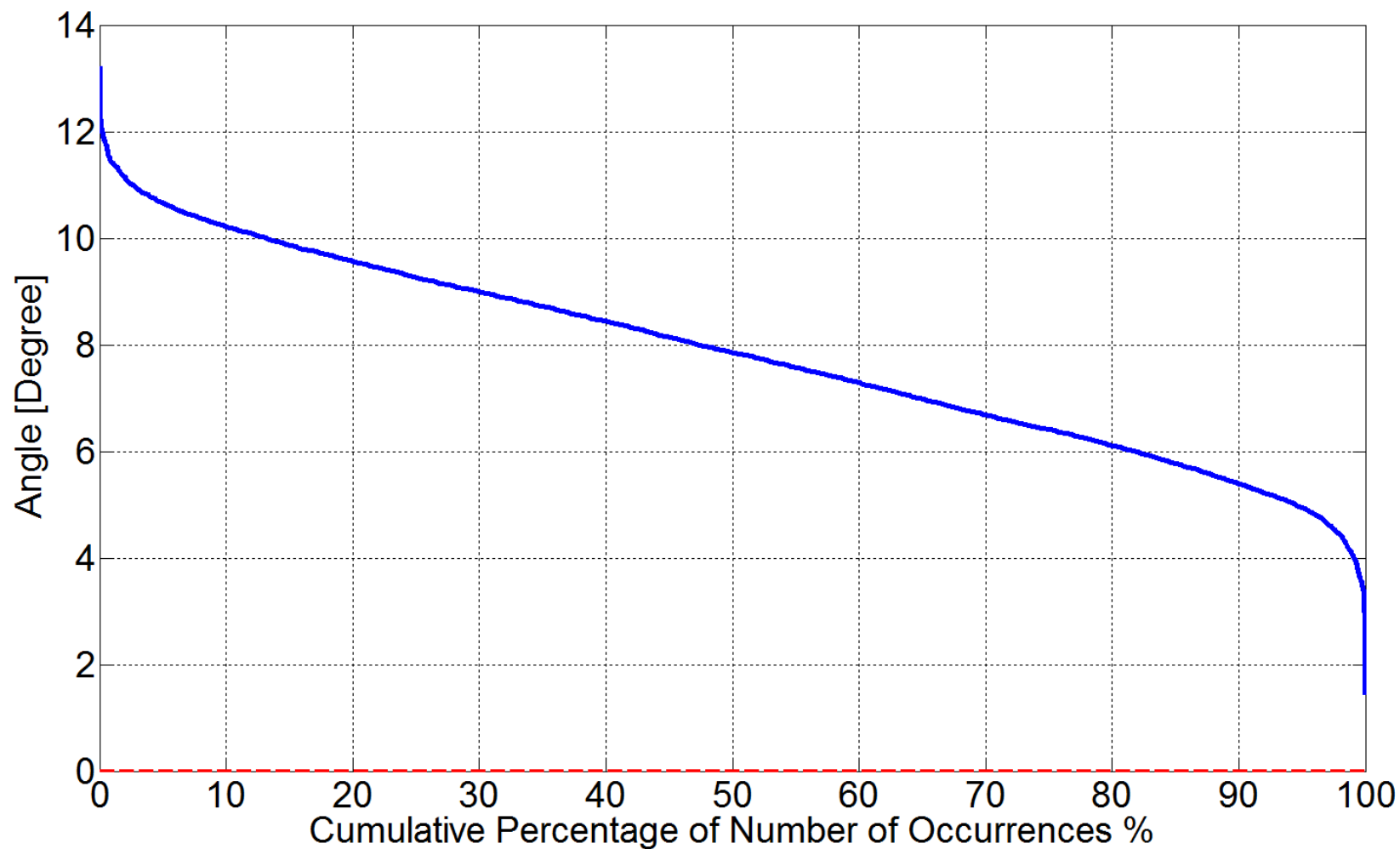
FarWest 7-West 14



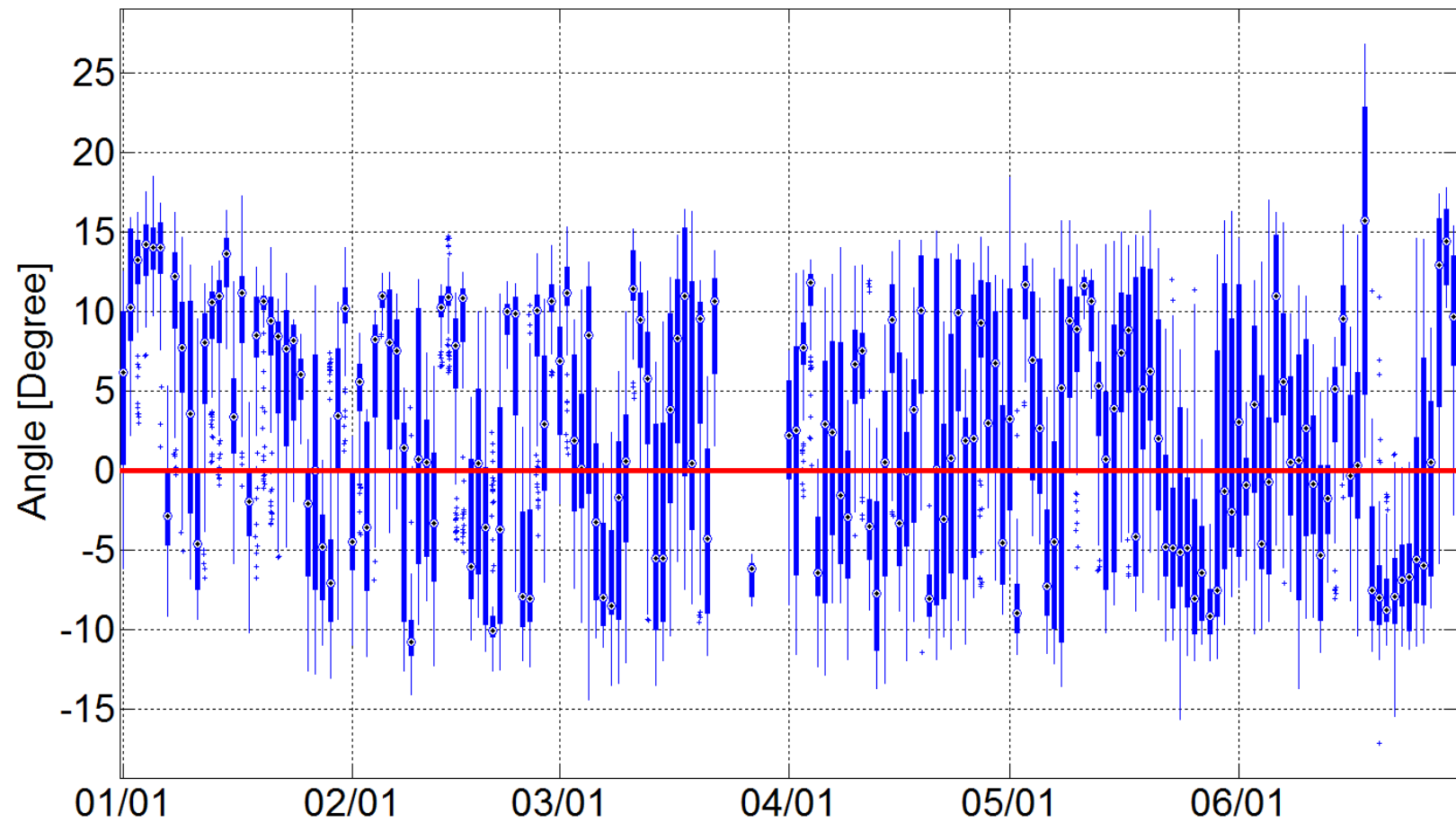
FarWest 7-FarWest 8



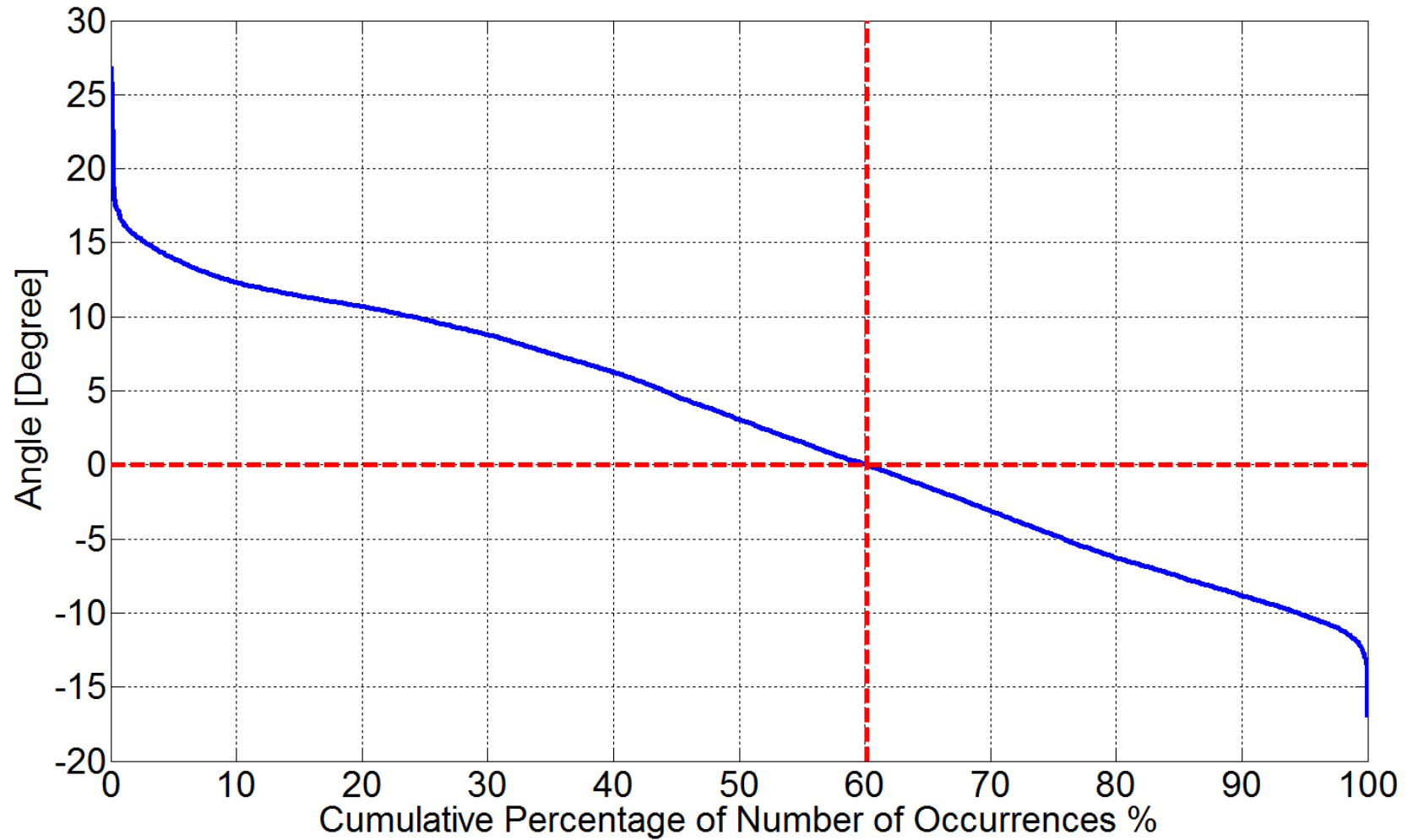
FarWest 7-FarWest 8



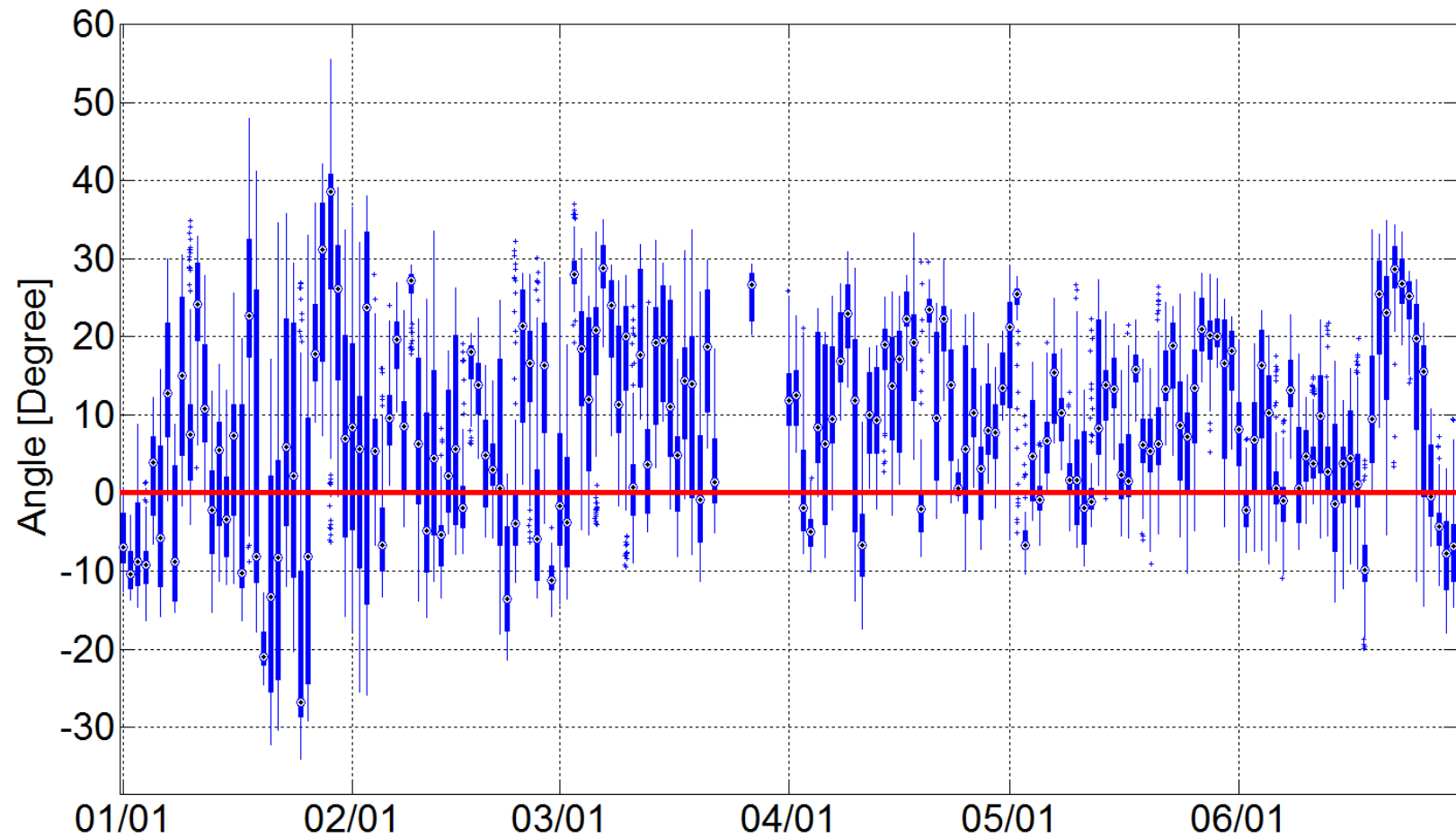
FarWest 7-FarWest 9



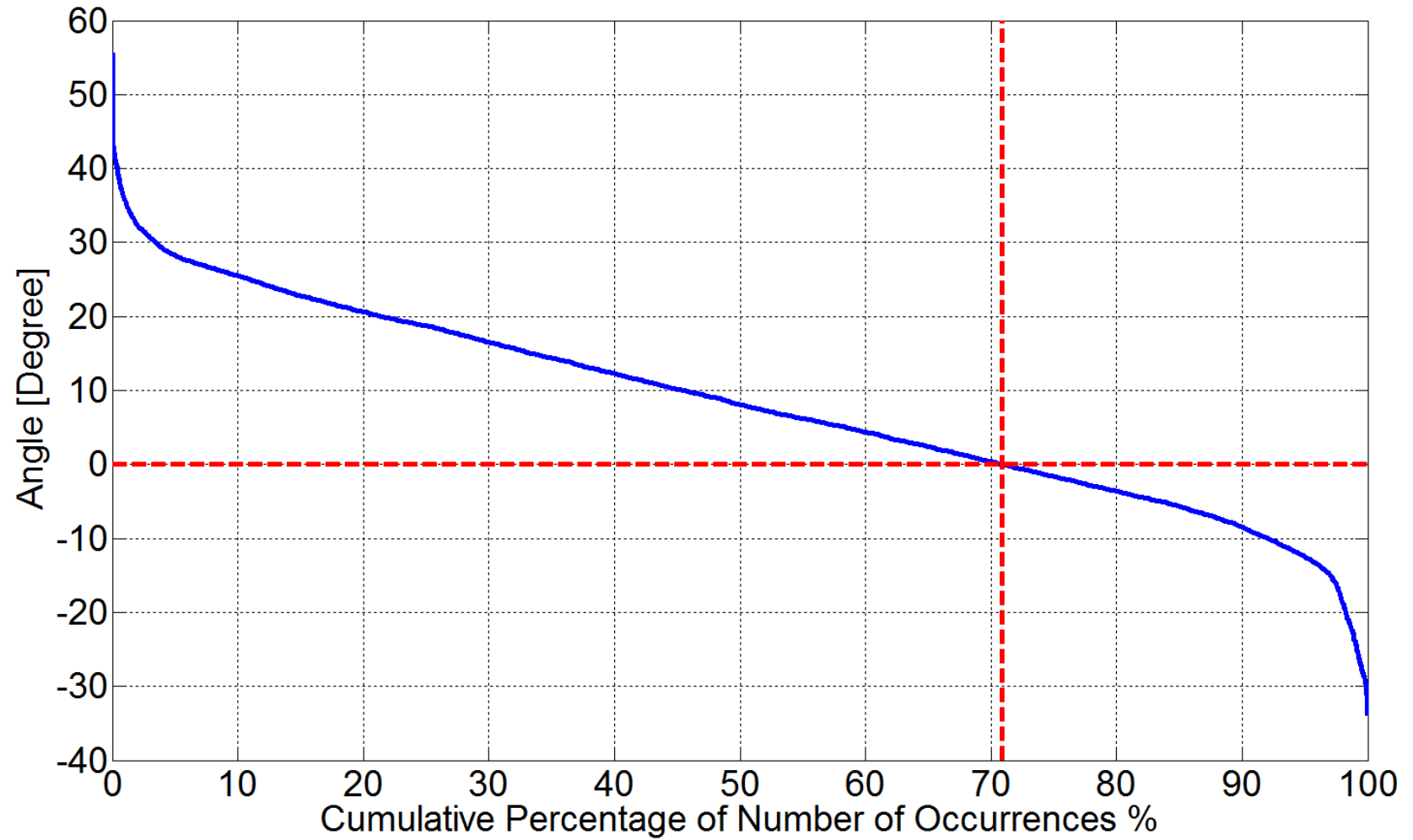
FarWest 7-FarWest 9



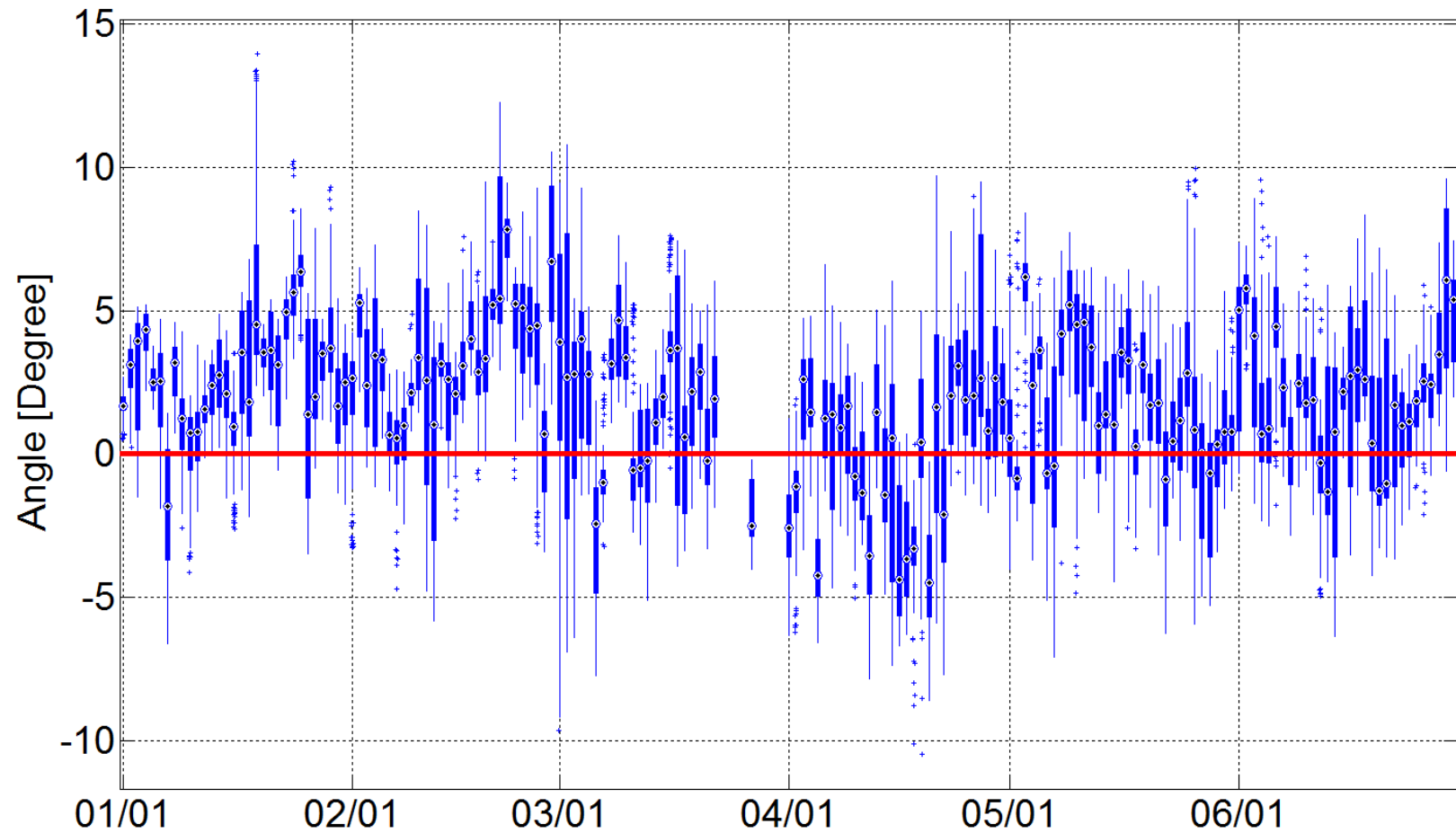
FarWest 7-North 7



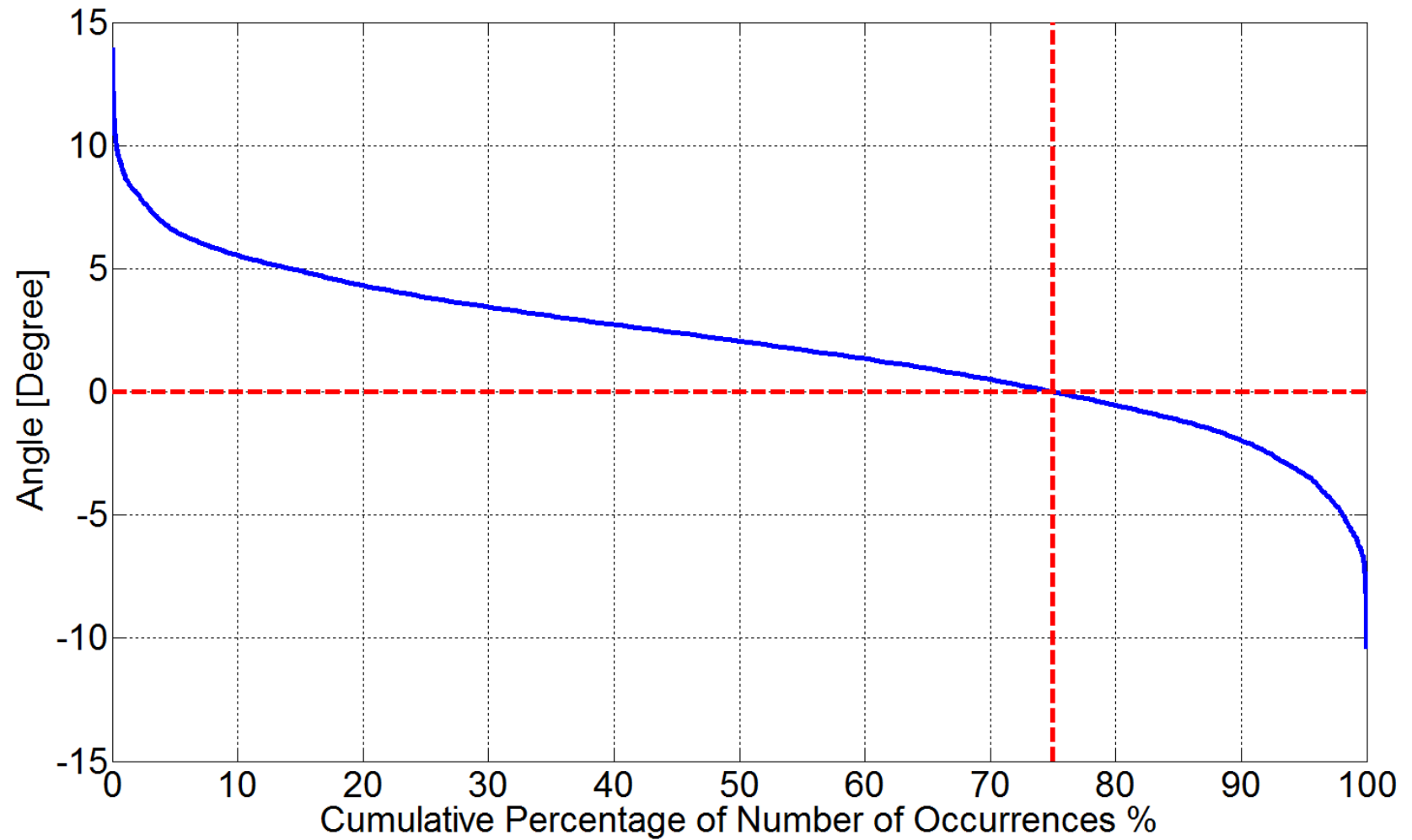
FarWest 7-North 7



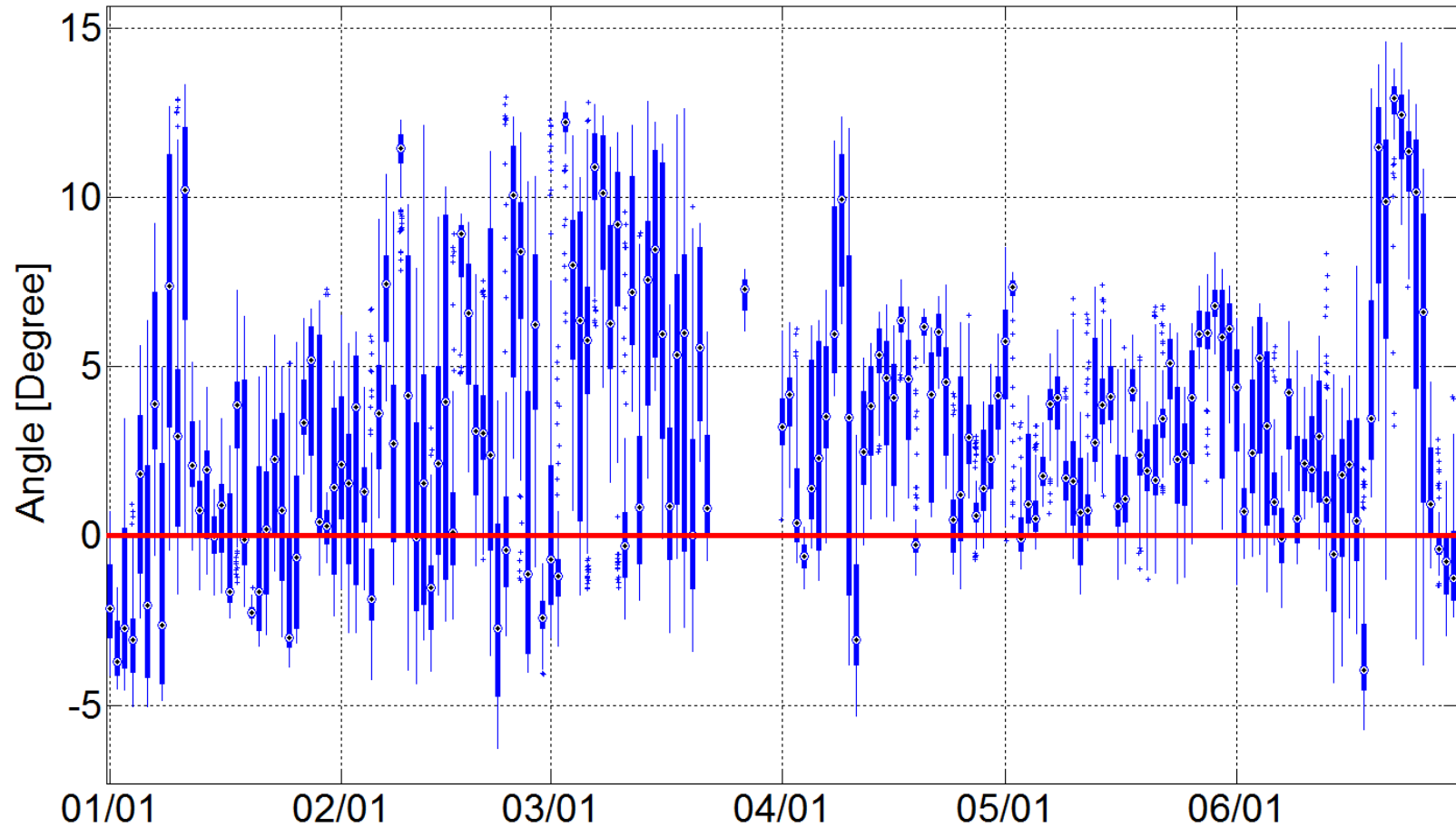
West 9*-FarWest 7



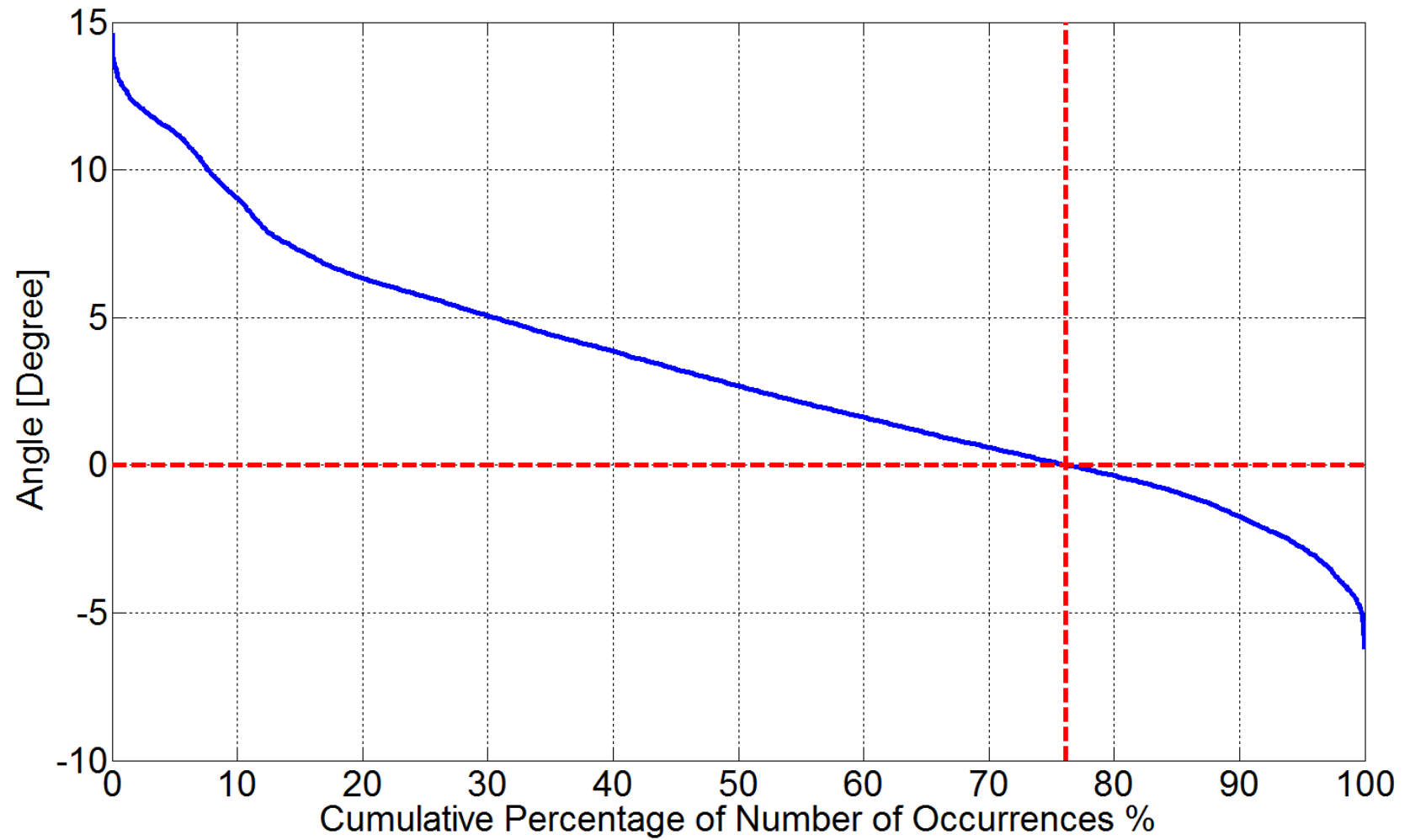
West 9*-FarWest 7



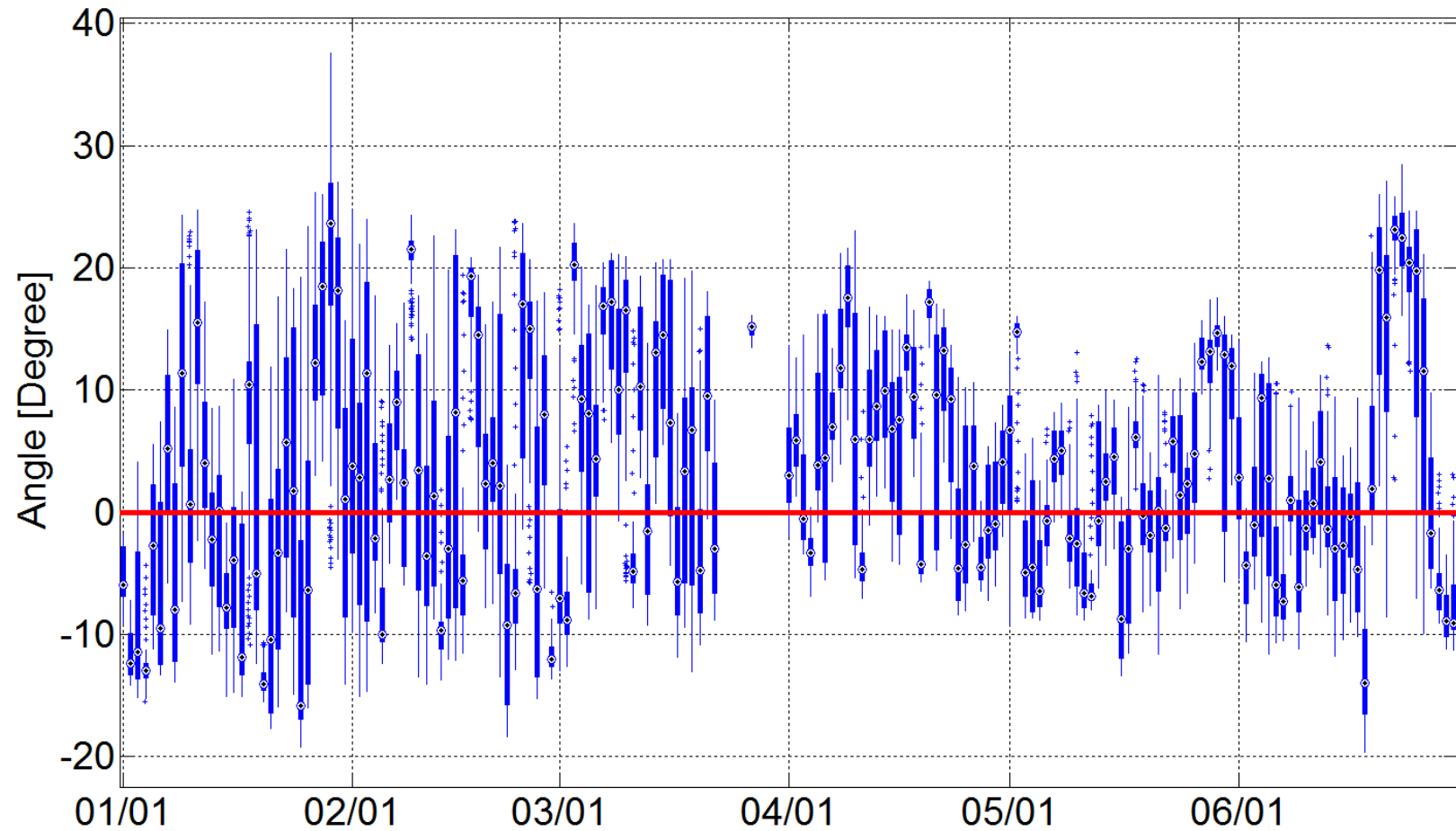
West 9*-West 1*



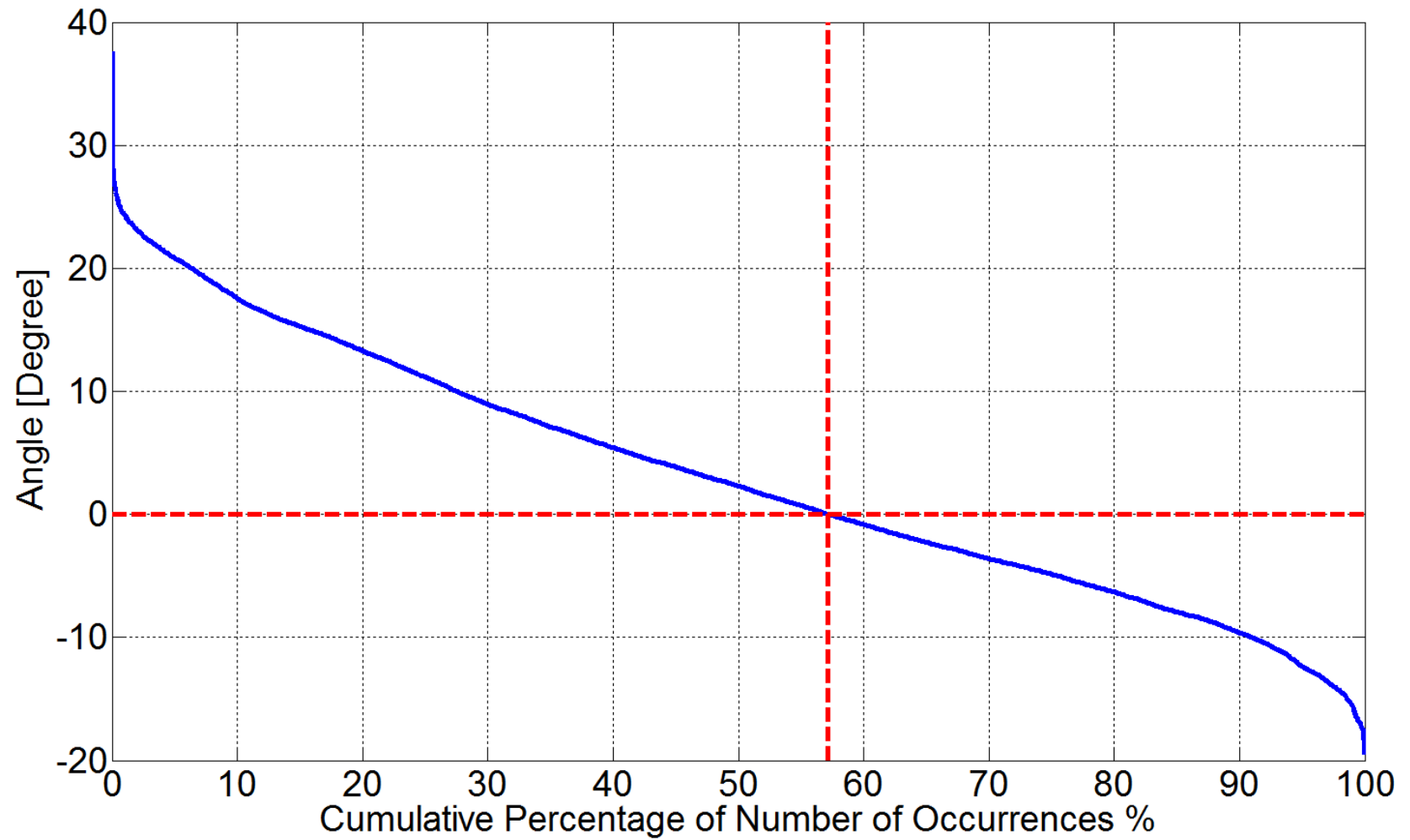
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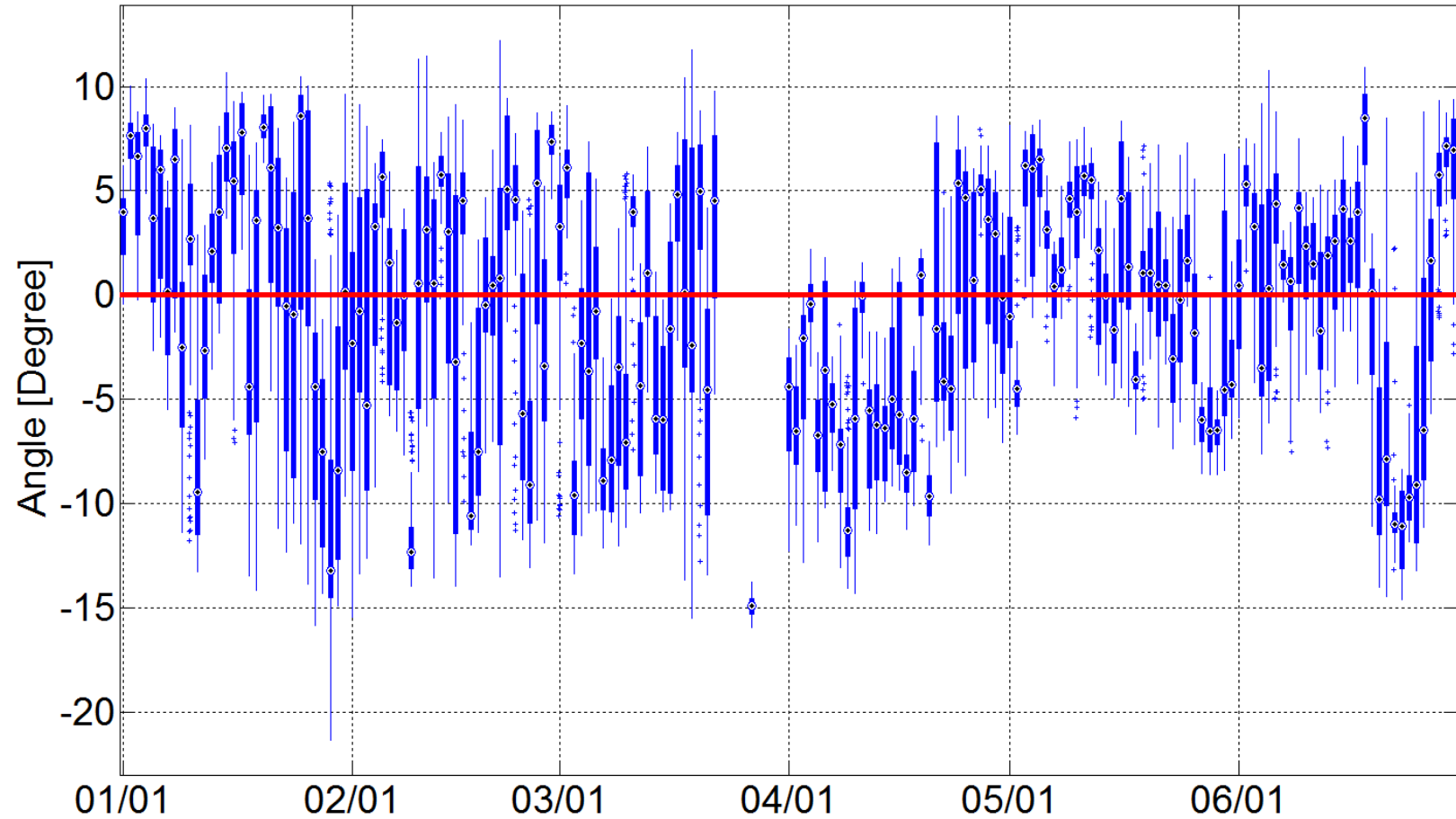
West 9*-North 1



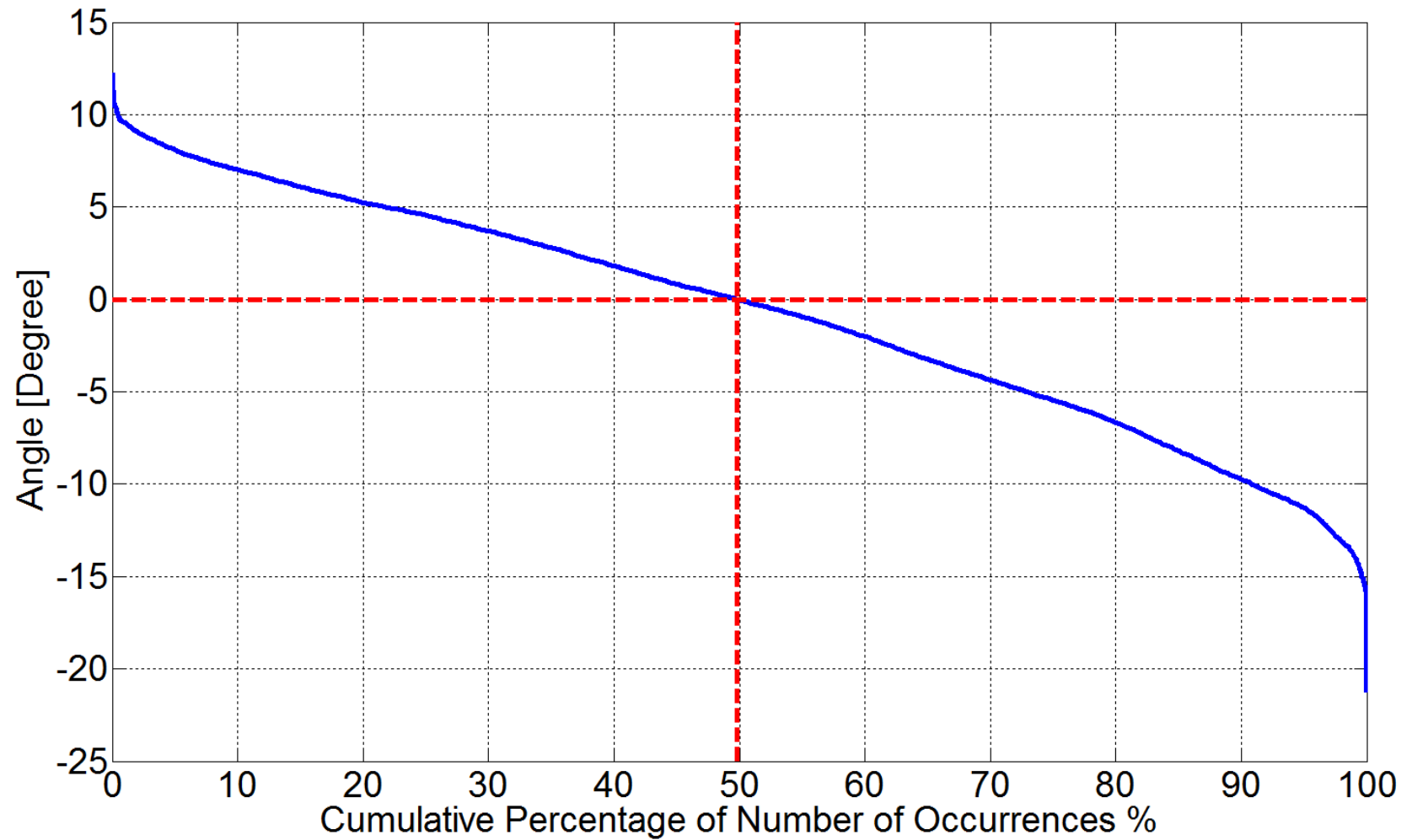
West 9*-North 1



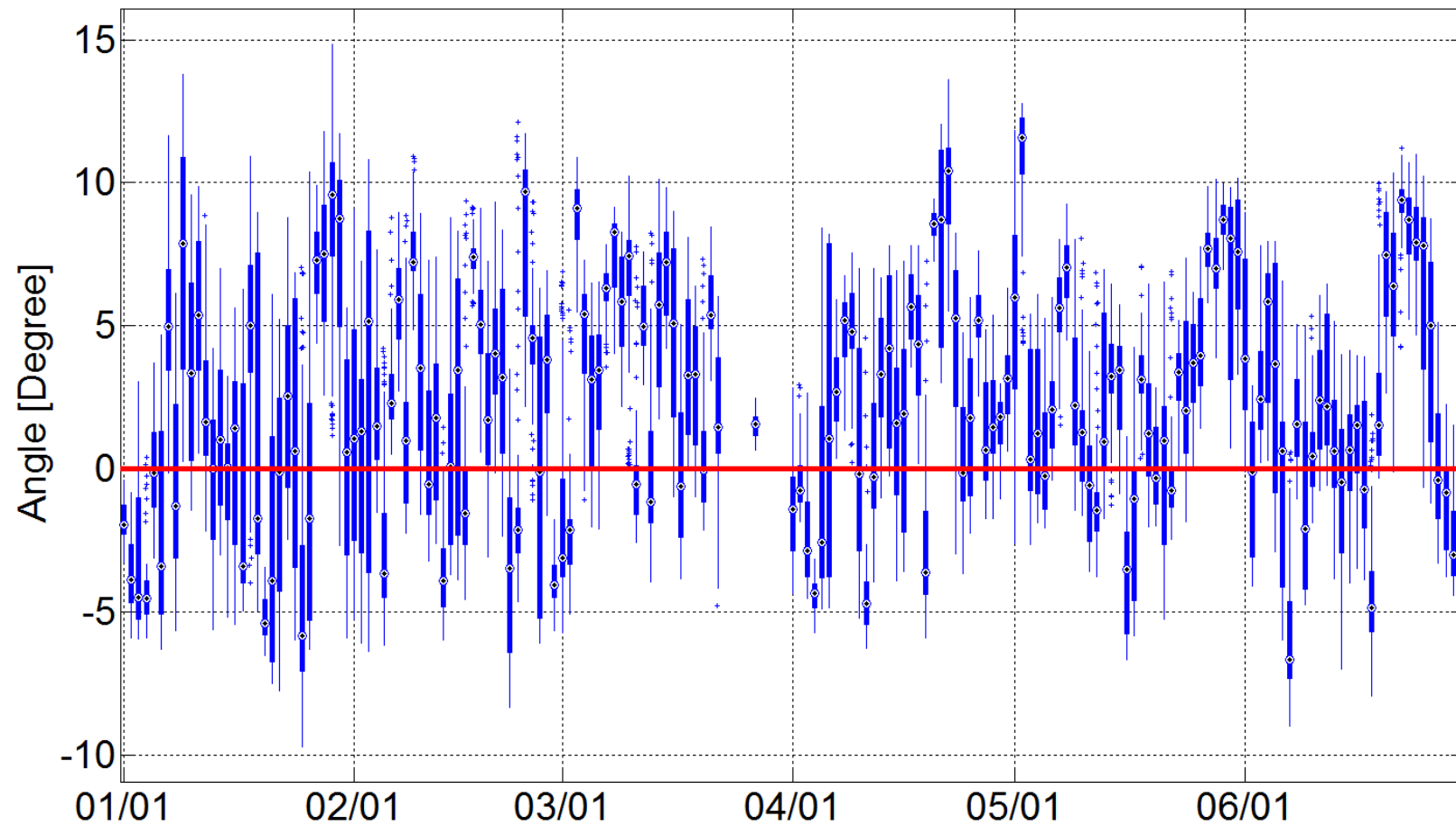
West 14-West 5*



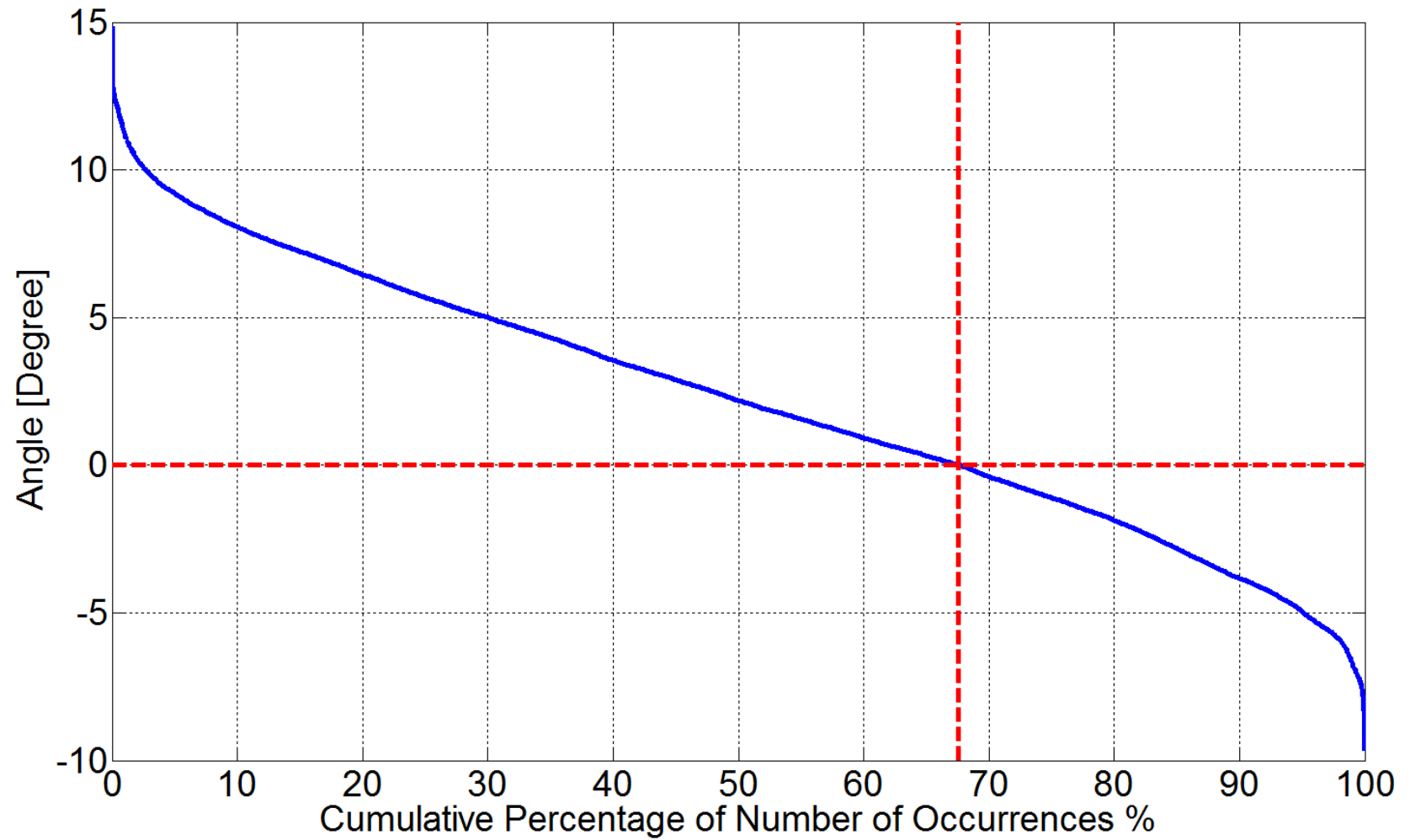
West 14-West 5*



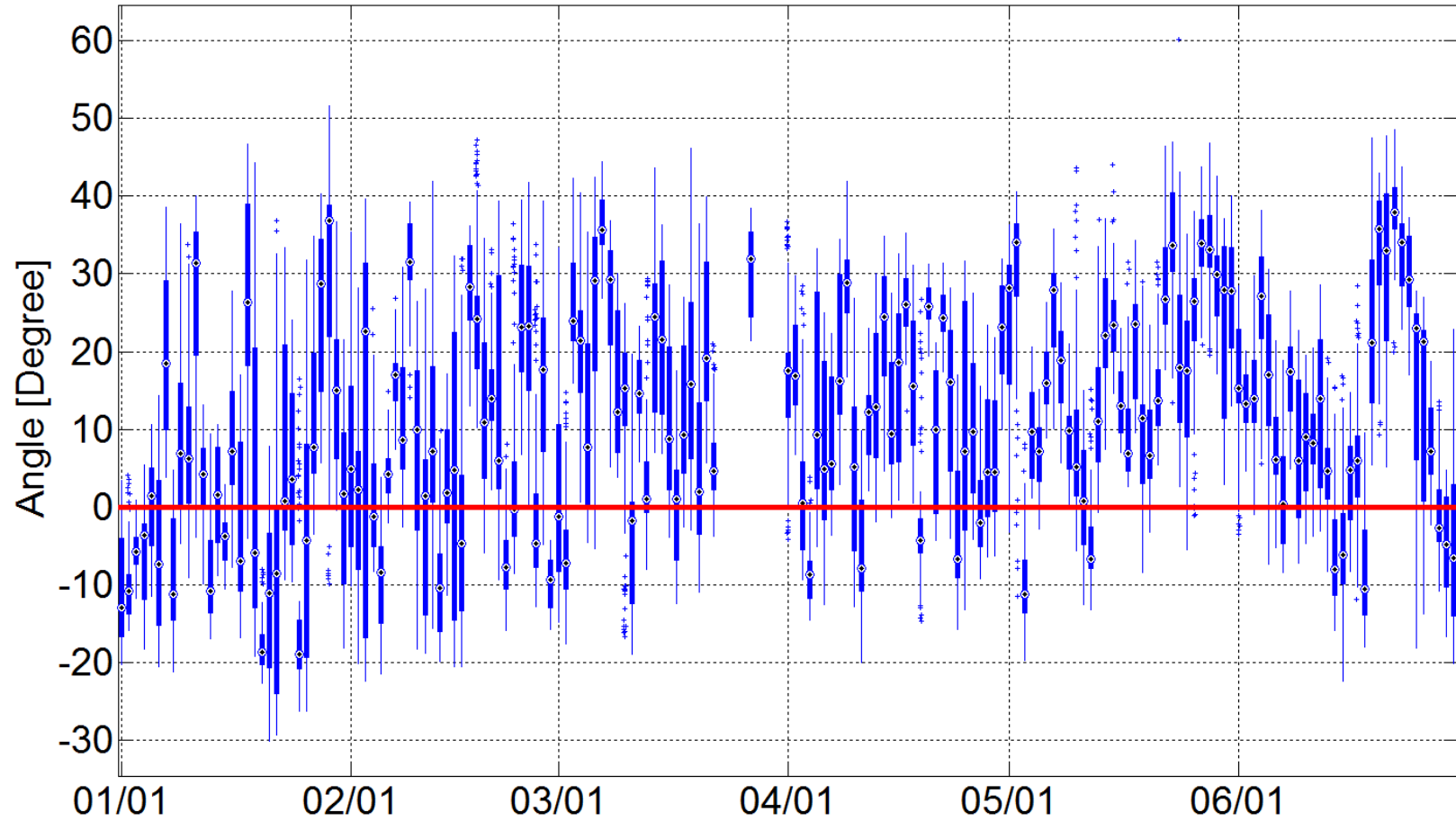
West 14-North 1



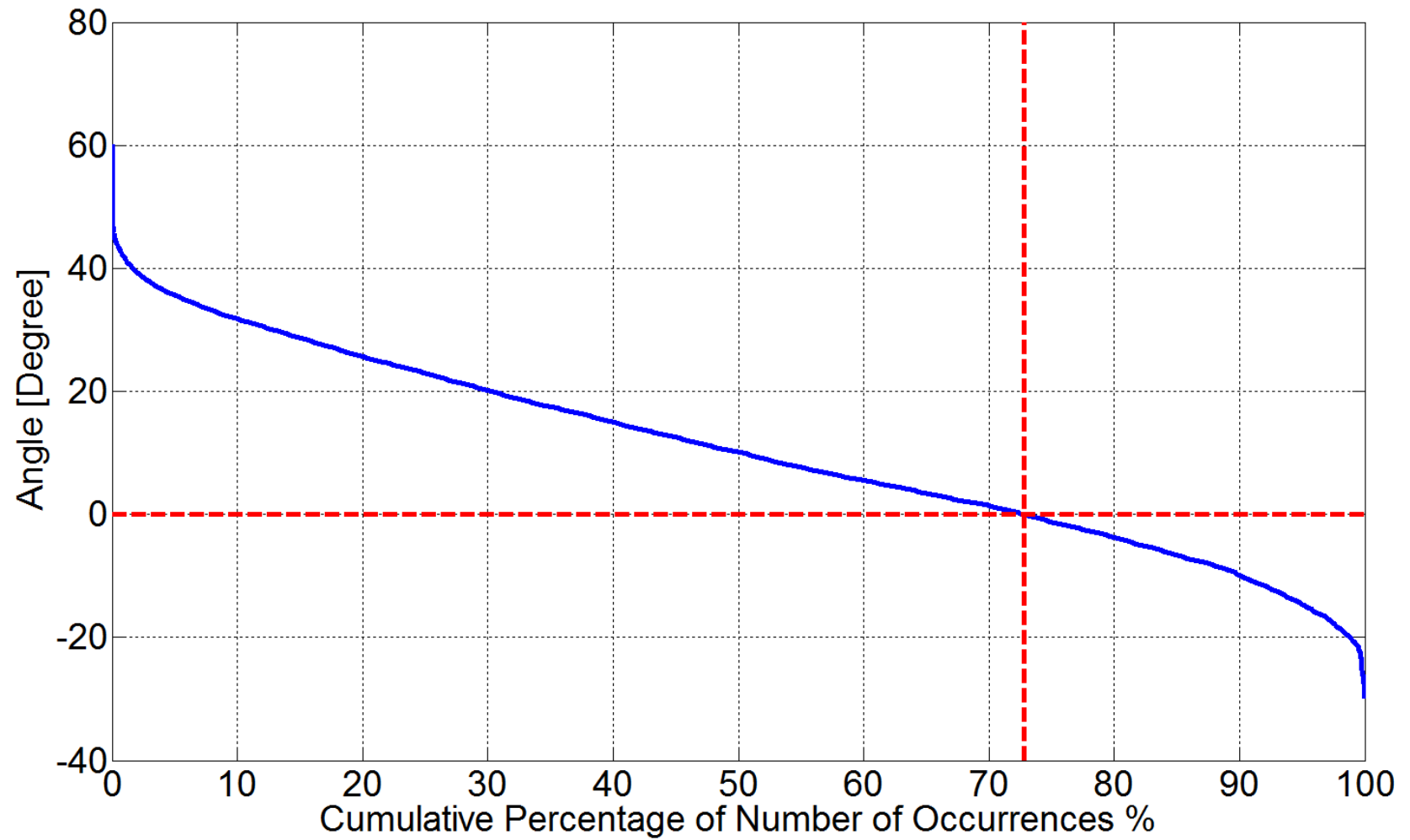
West 14-North 1



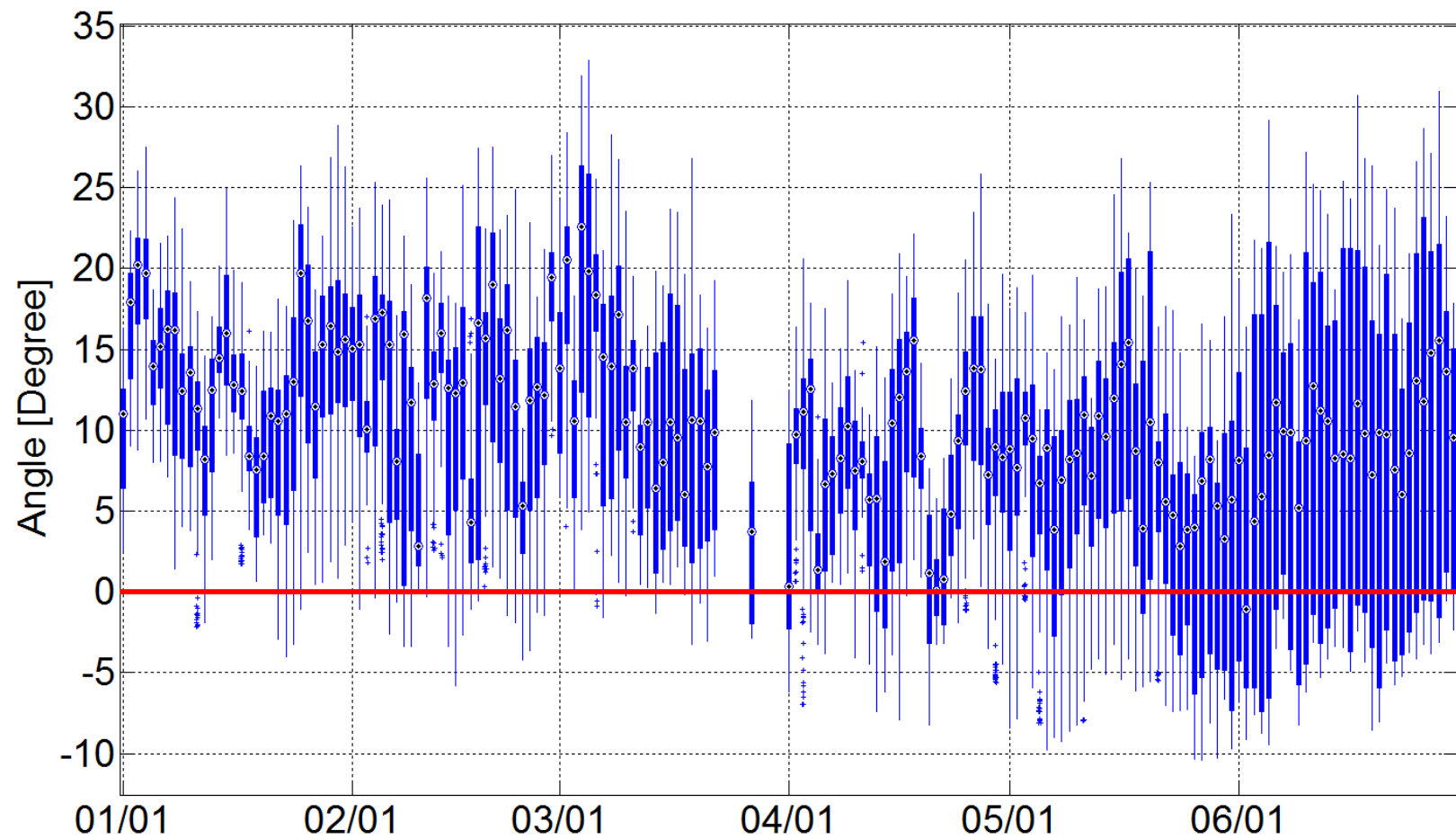
FarWest 9-West 4



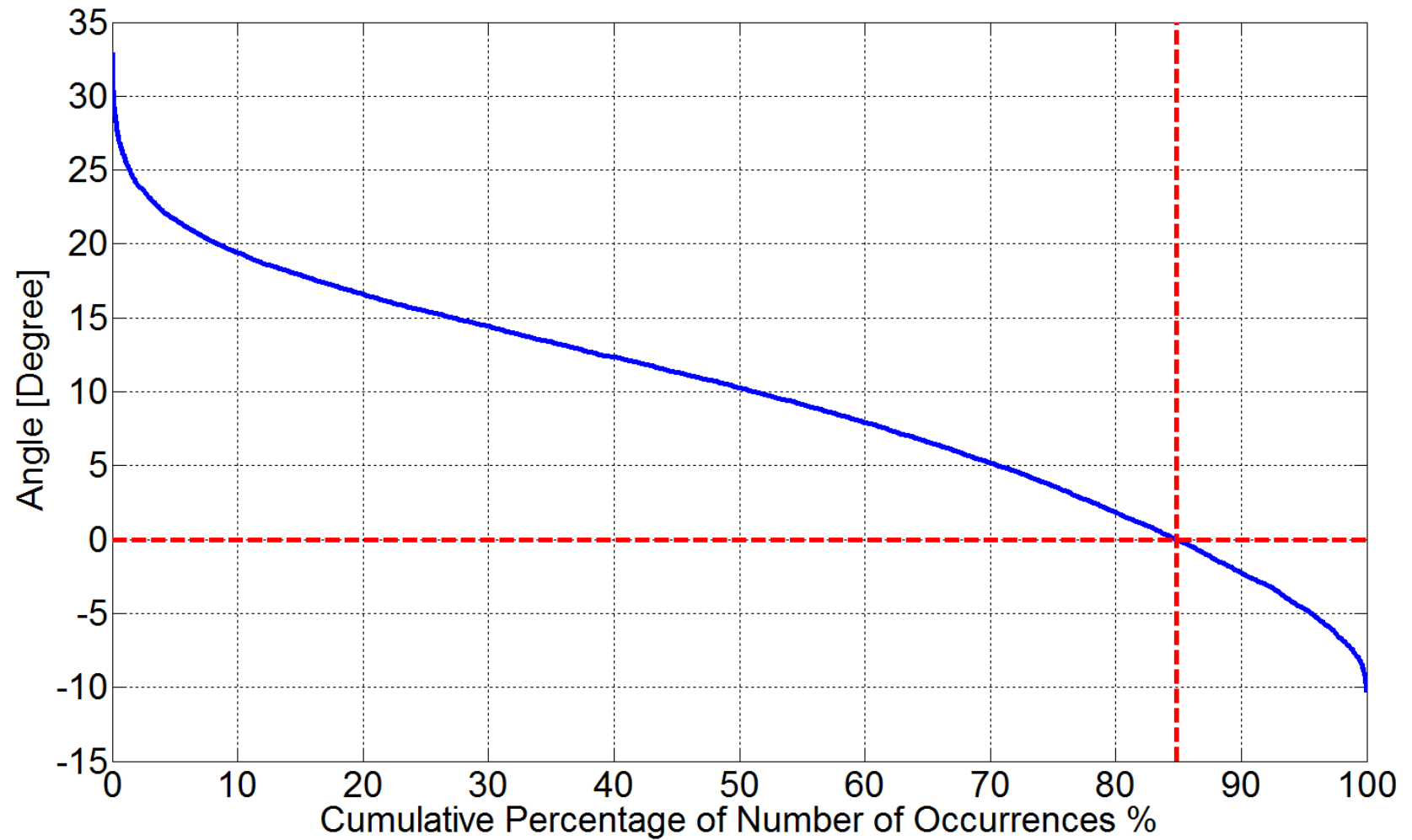
FarWest 9-West 4



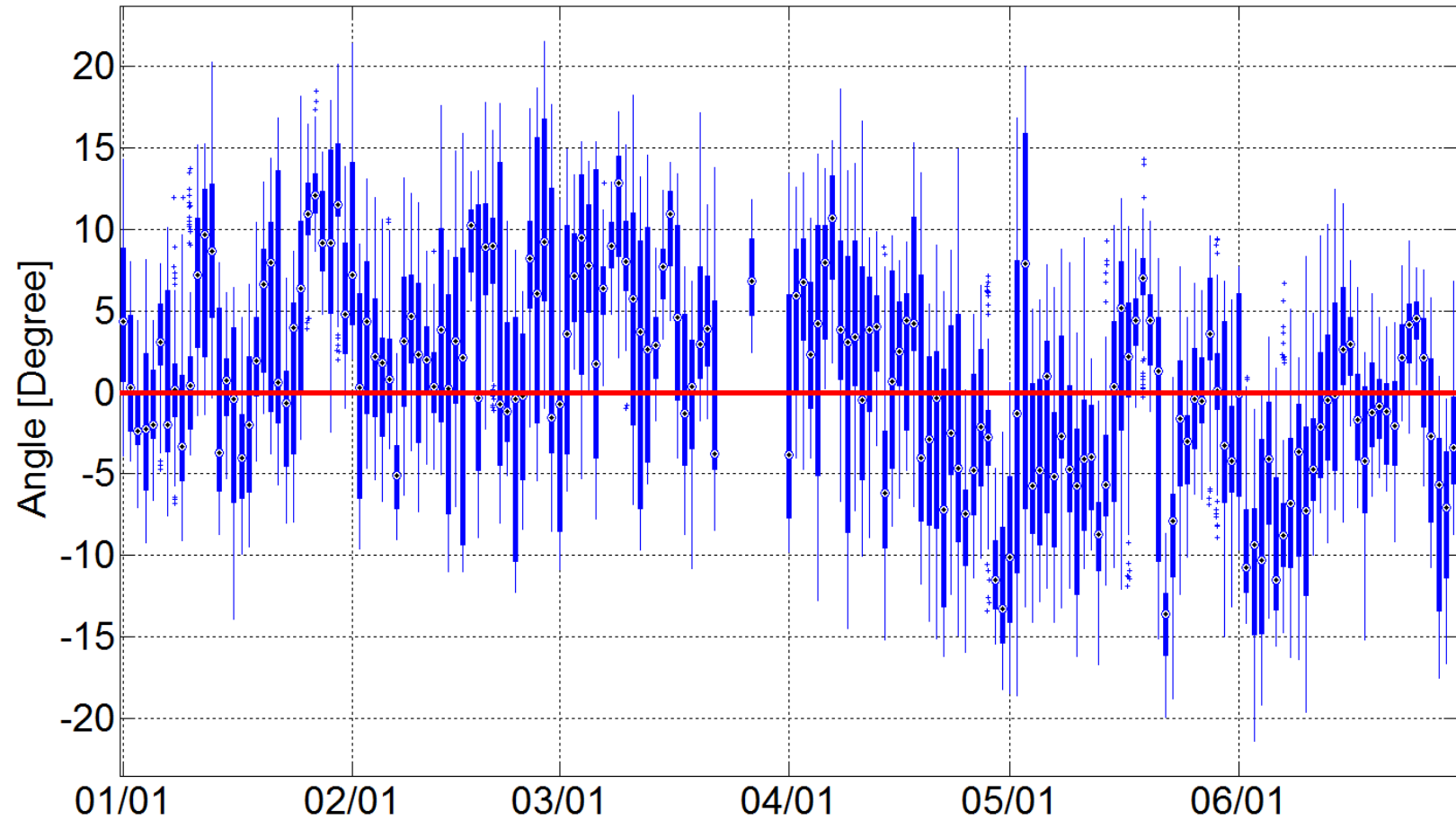
Coast 1-South 10*



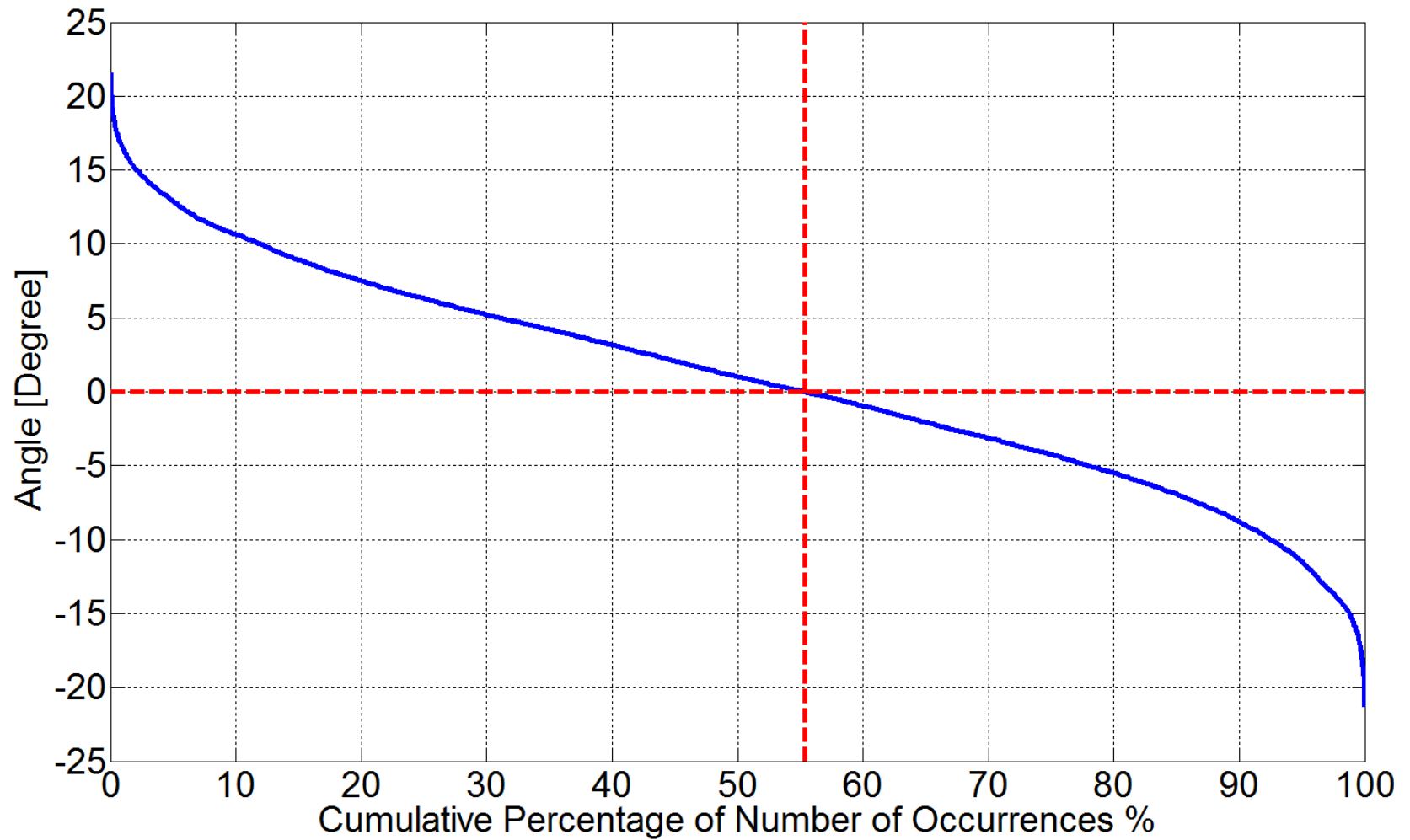
Coast 1-South 10*



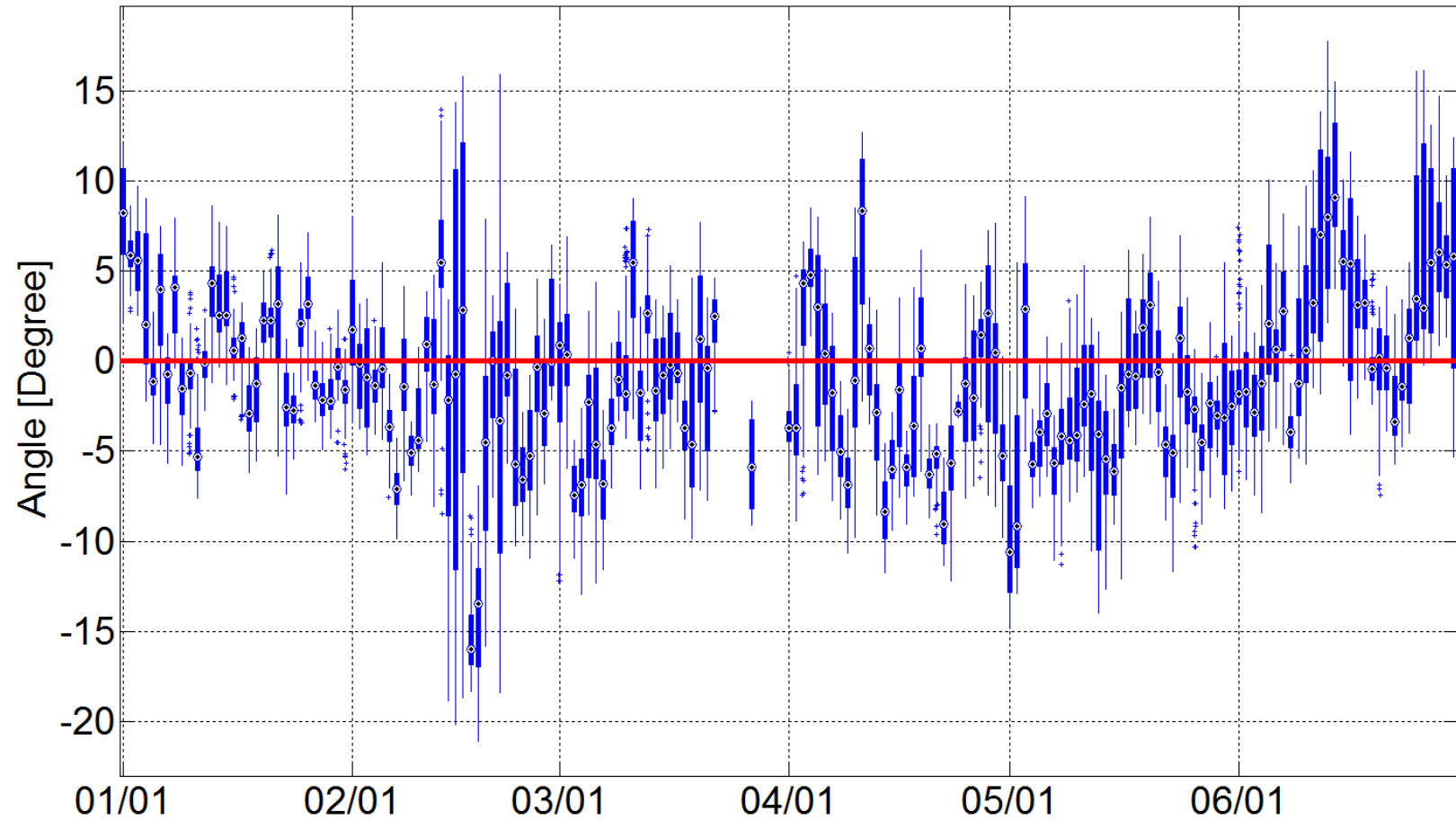
South 3*-South 11*



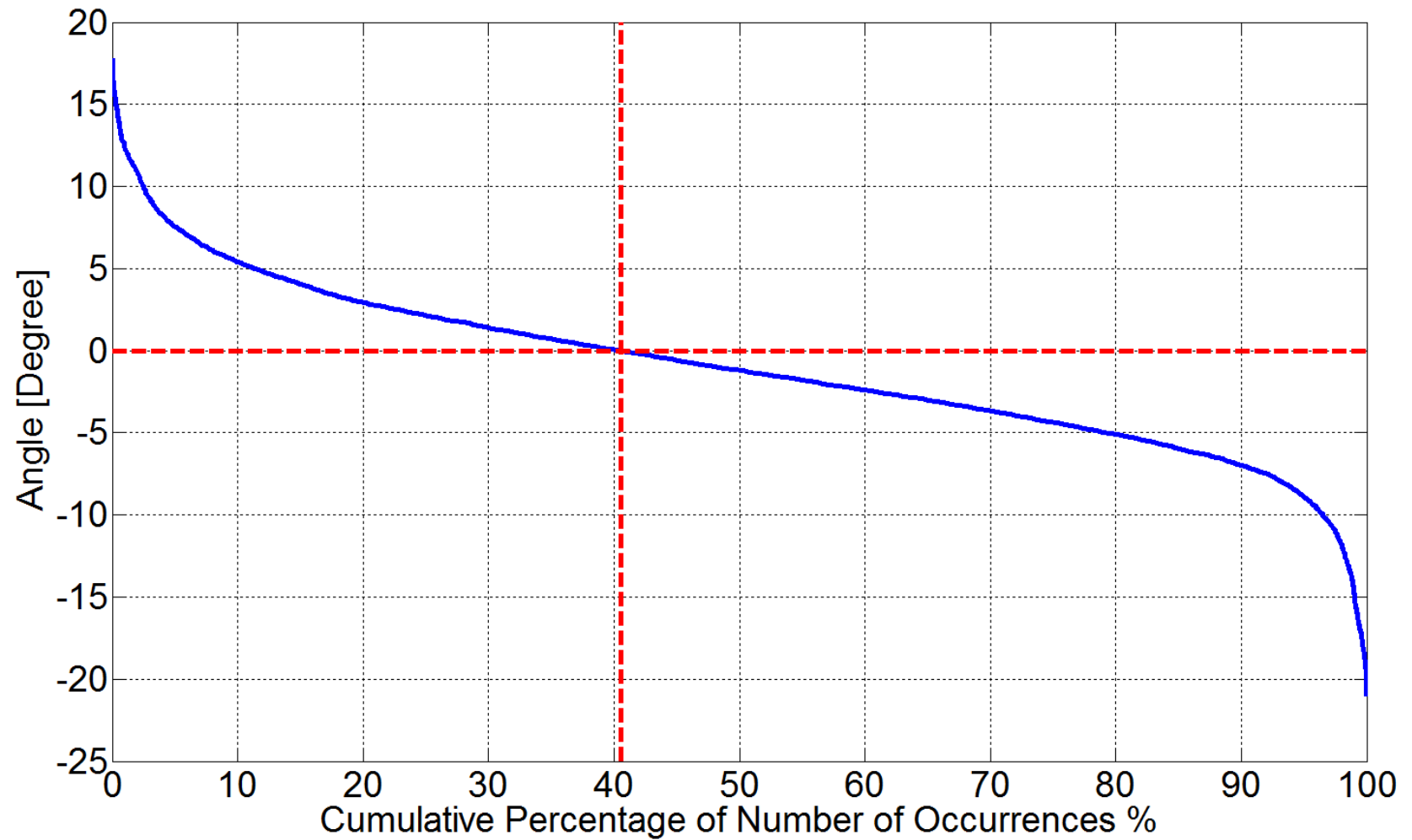
South 3*-South 11*



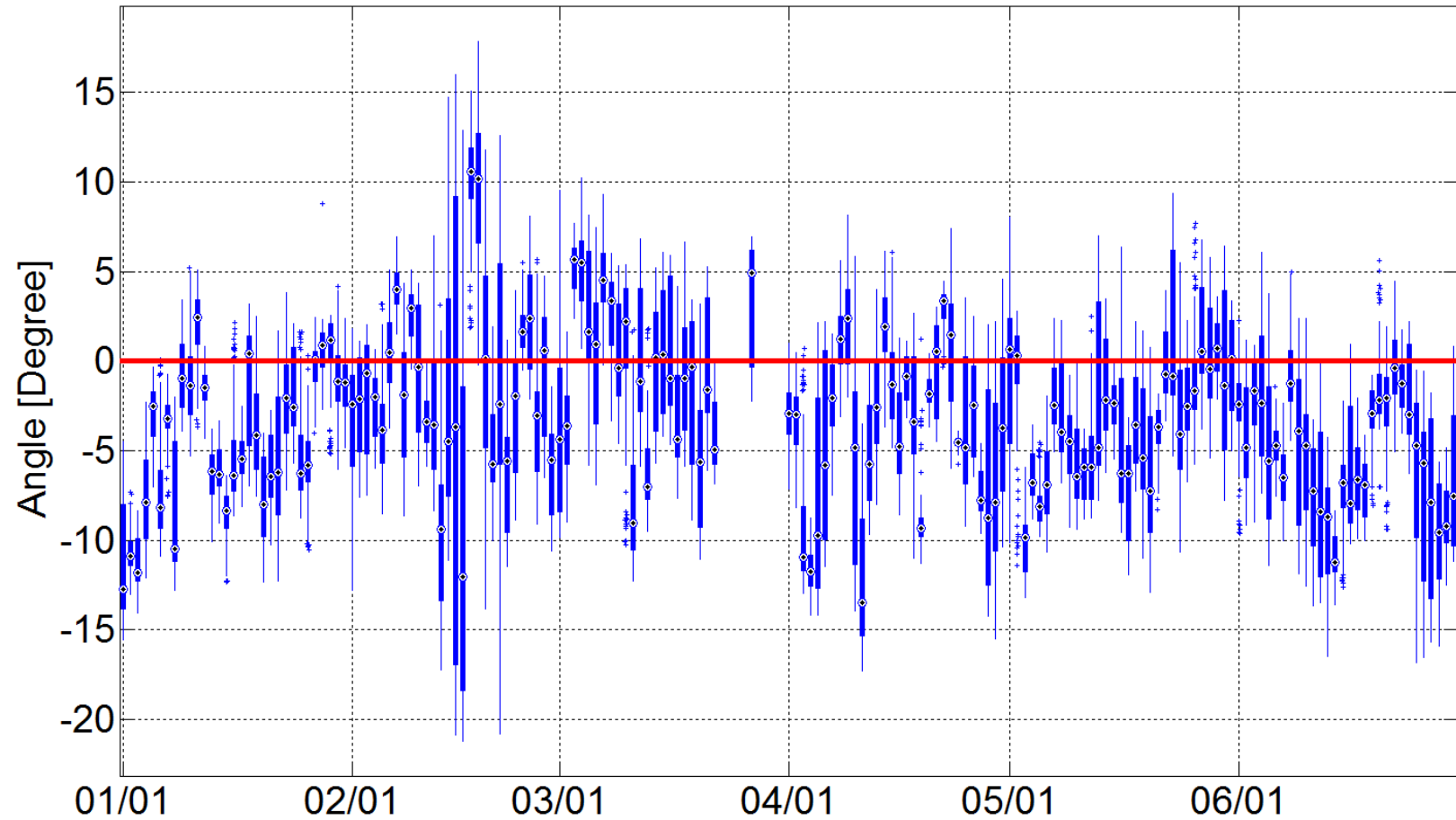
South 11*-North 7



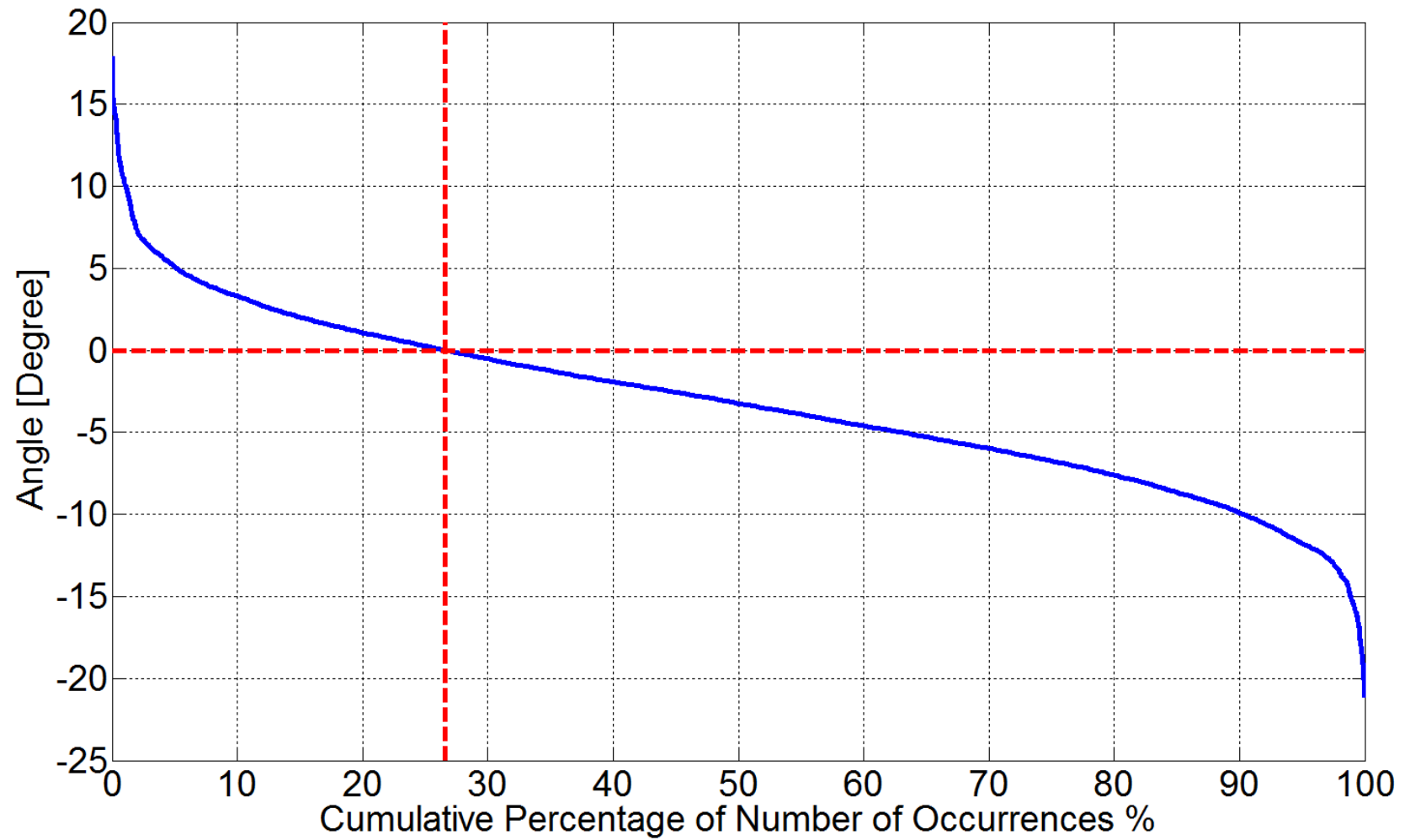
South 11*-North 7



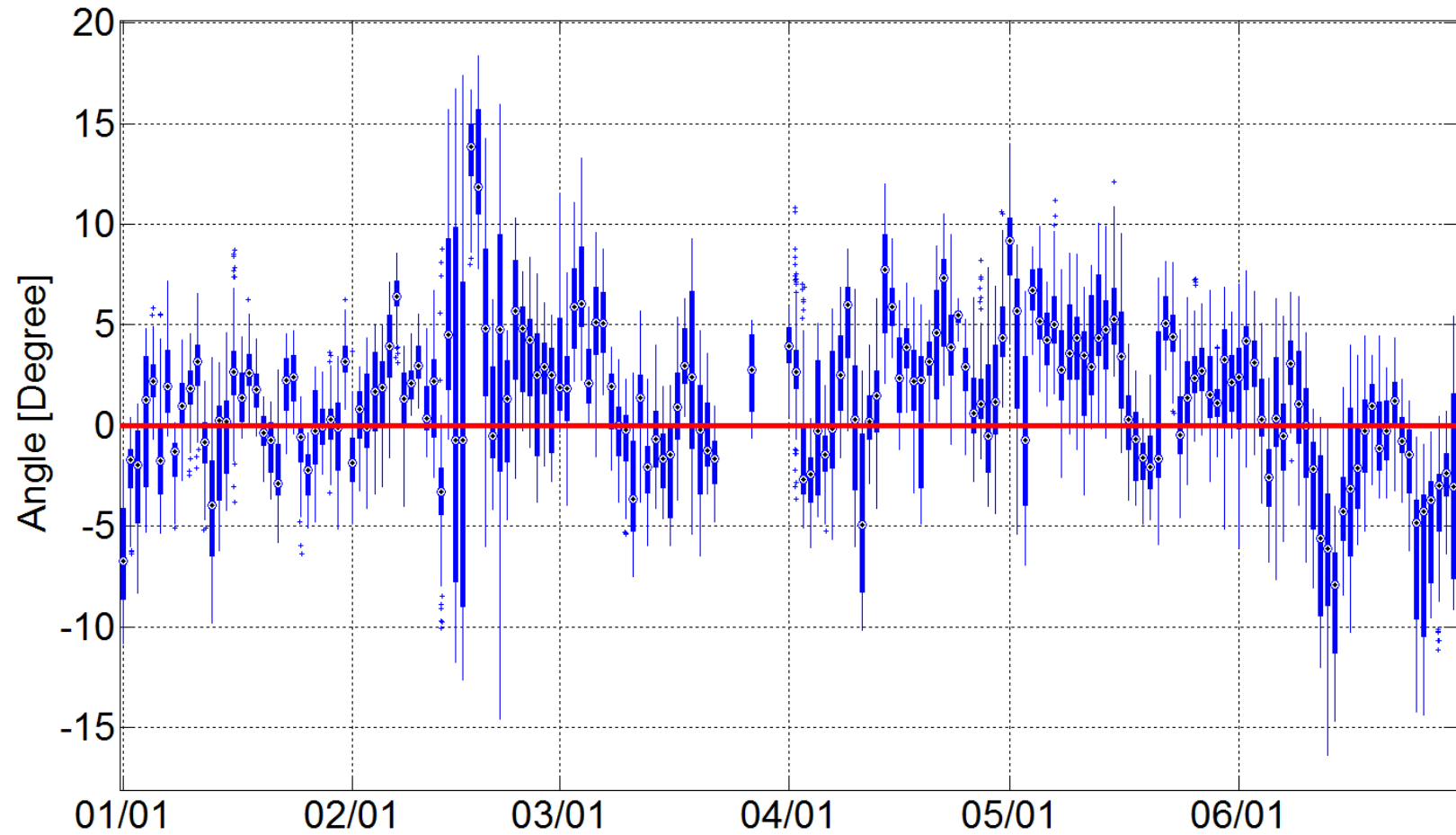
North 7-South 7*



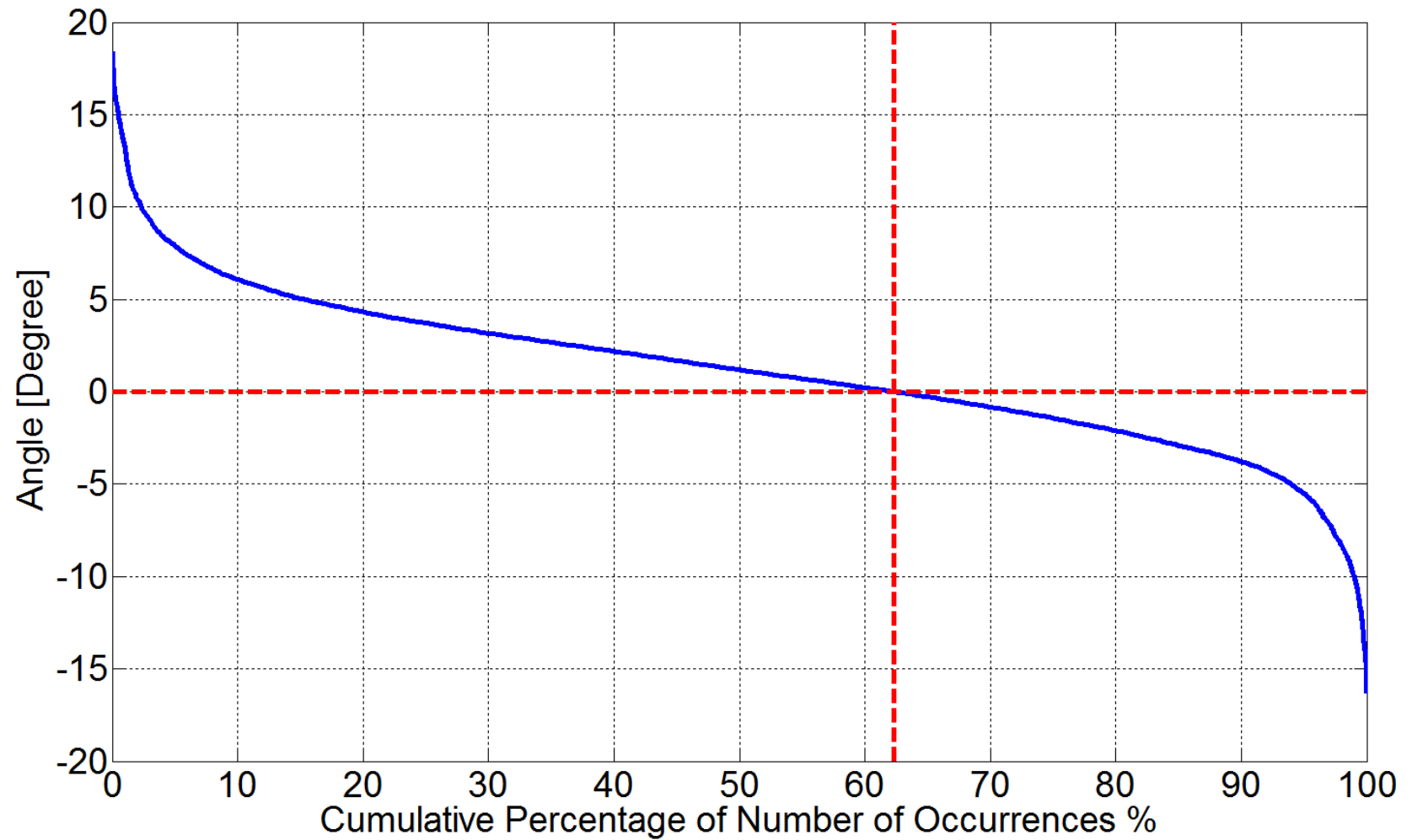
North 7-South 7*



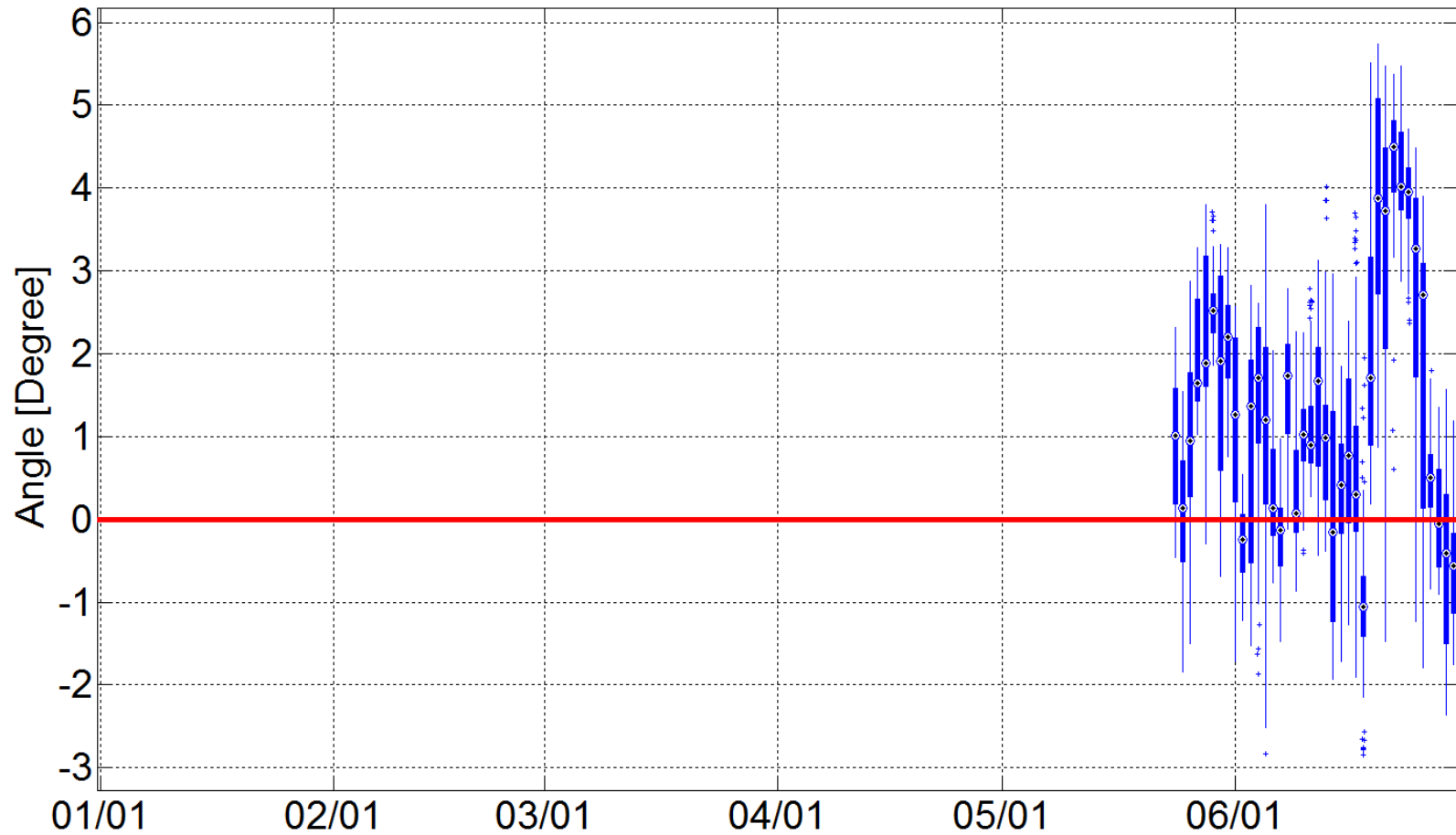
North 7-South 9*



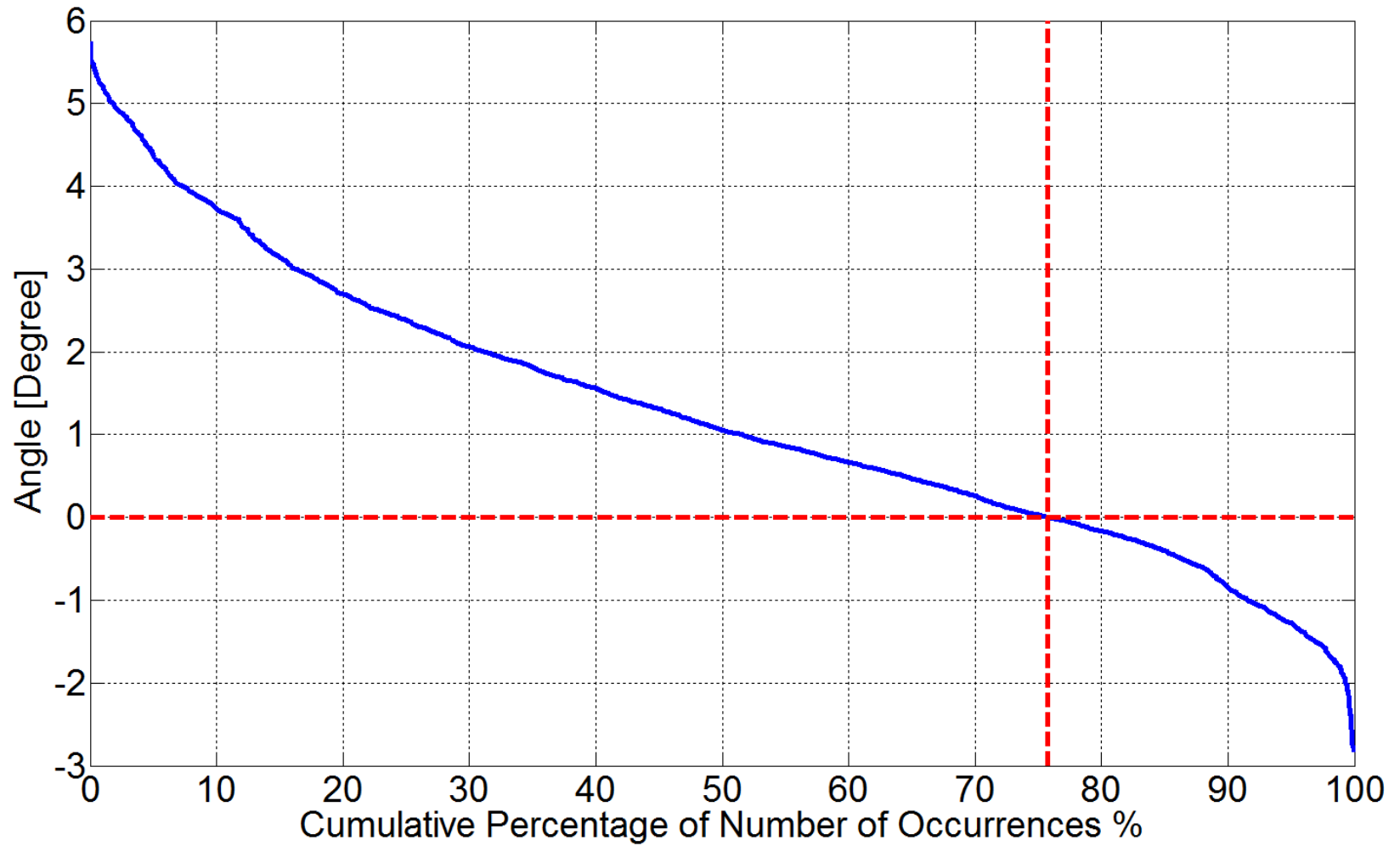
North 7-South 9*



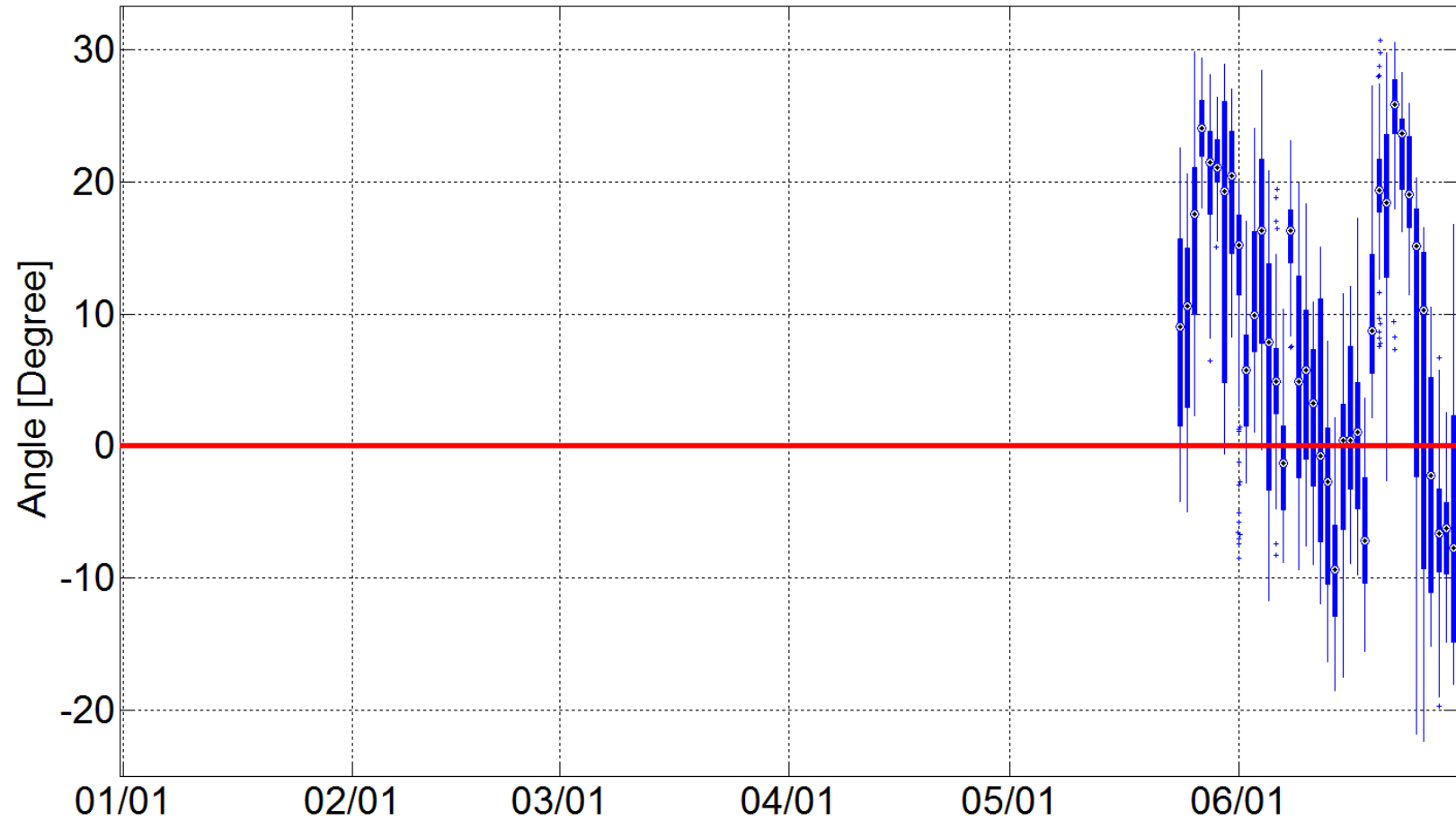
West 11-West 8*



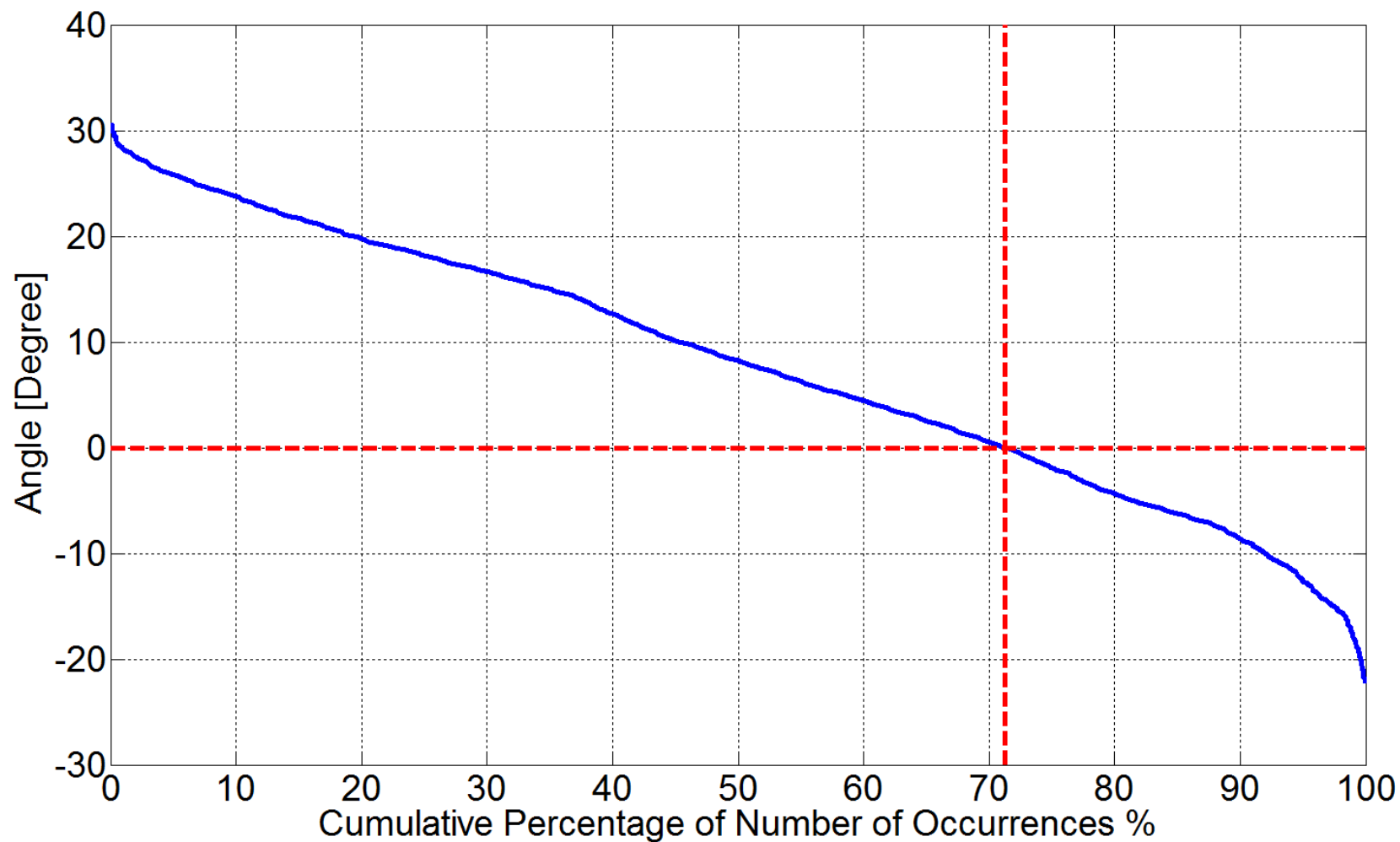
West 11-West 8*



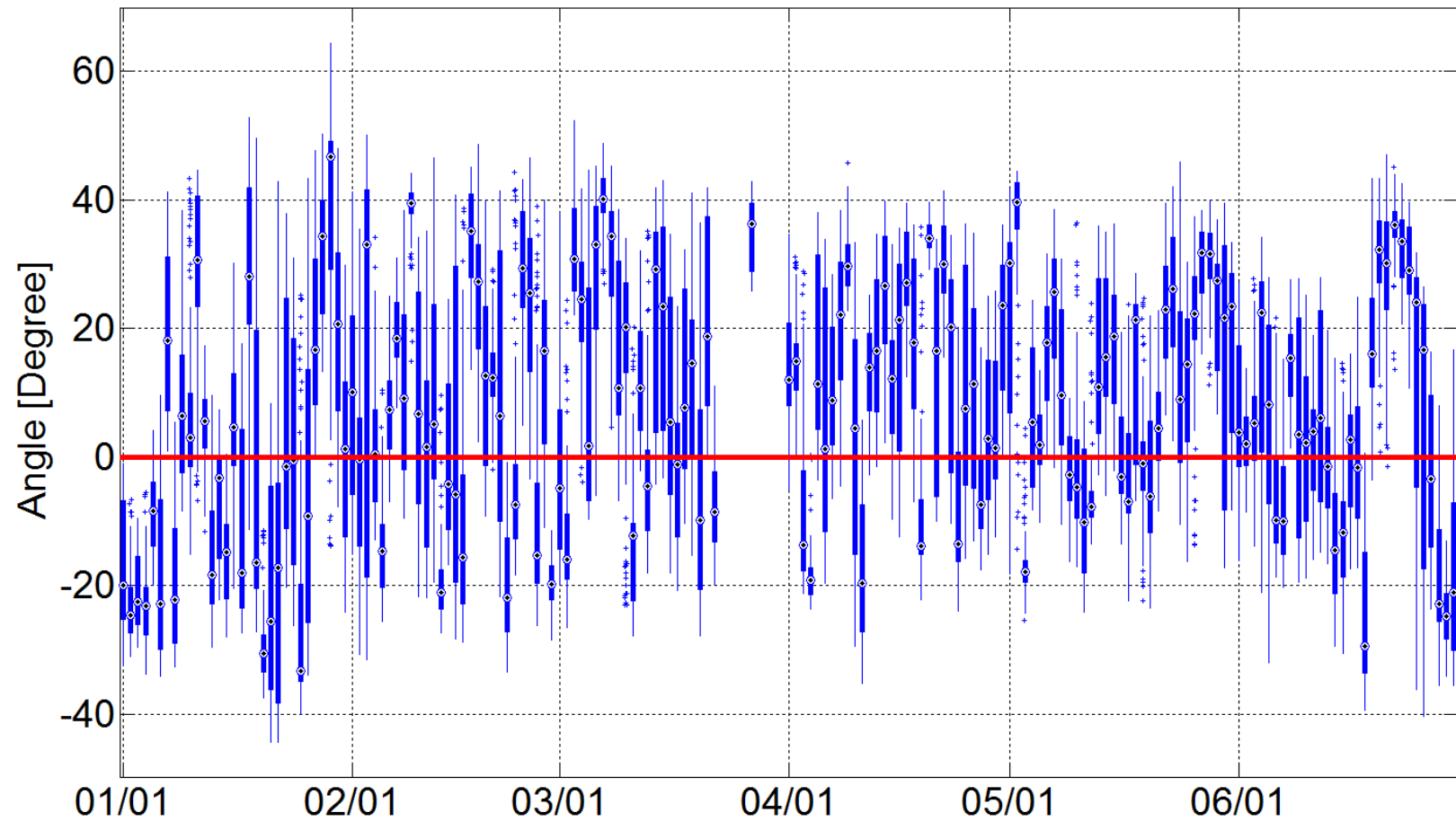
West 8*-South 9*



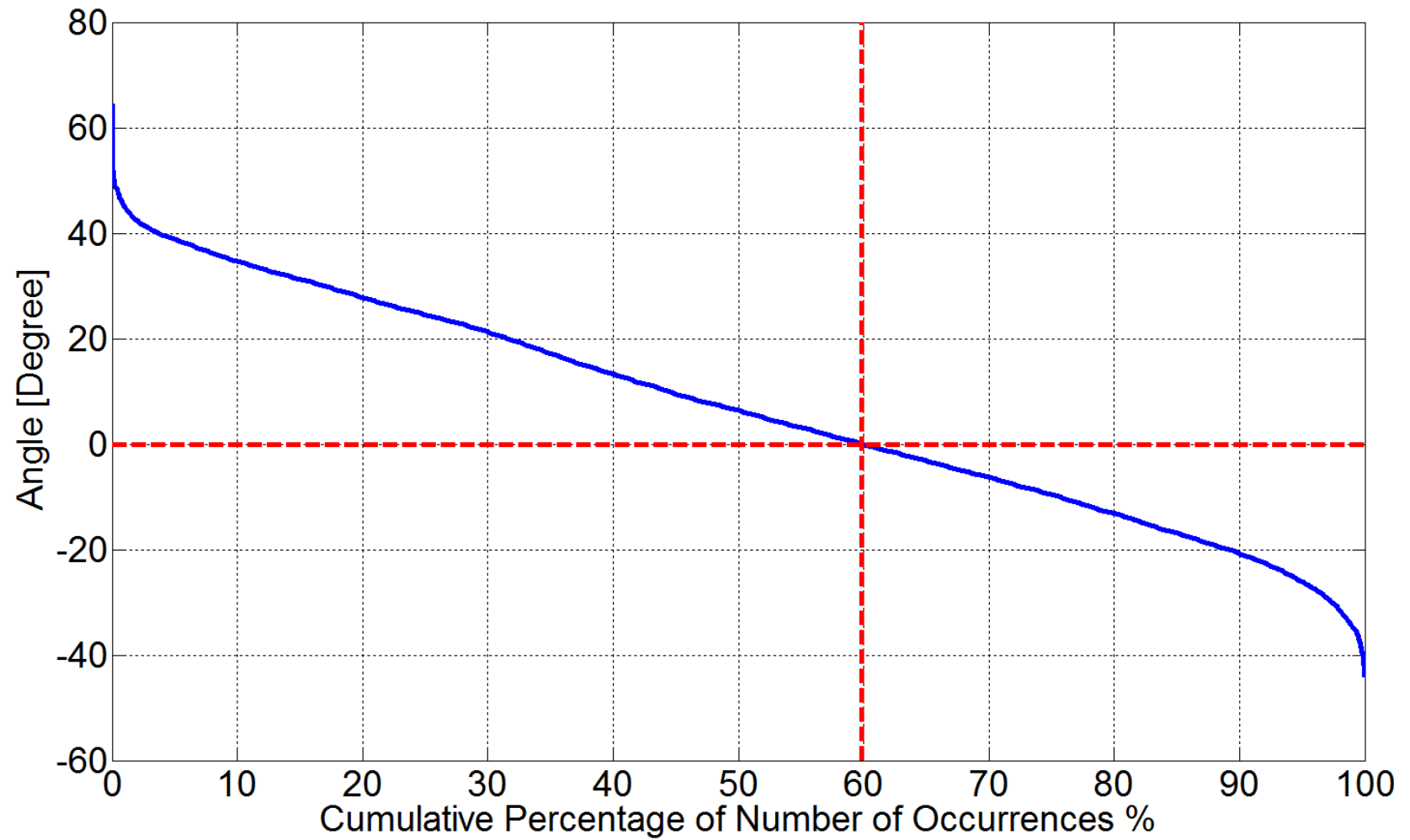
West 8*-South 9*



FarWest 9-South 9*



FarWest 9-South 9*



Appendix D – Part 2

CCET Discovery Across Texas project

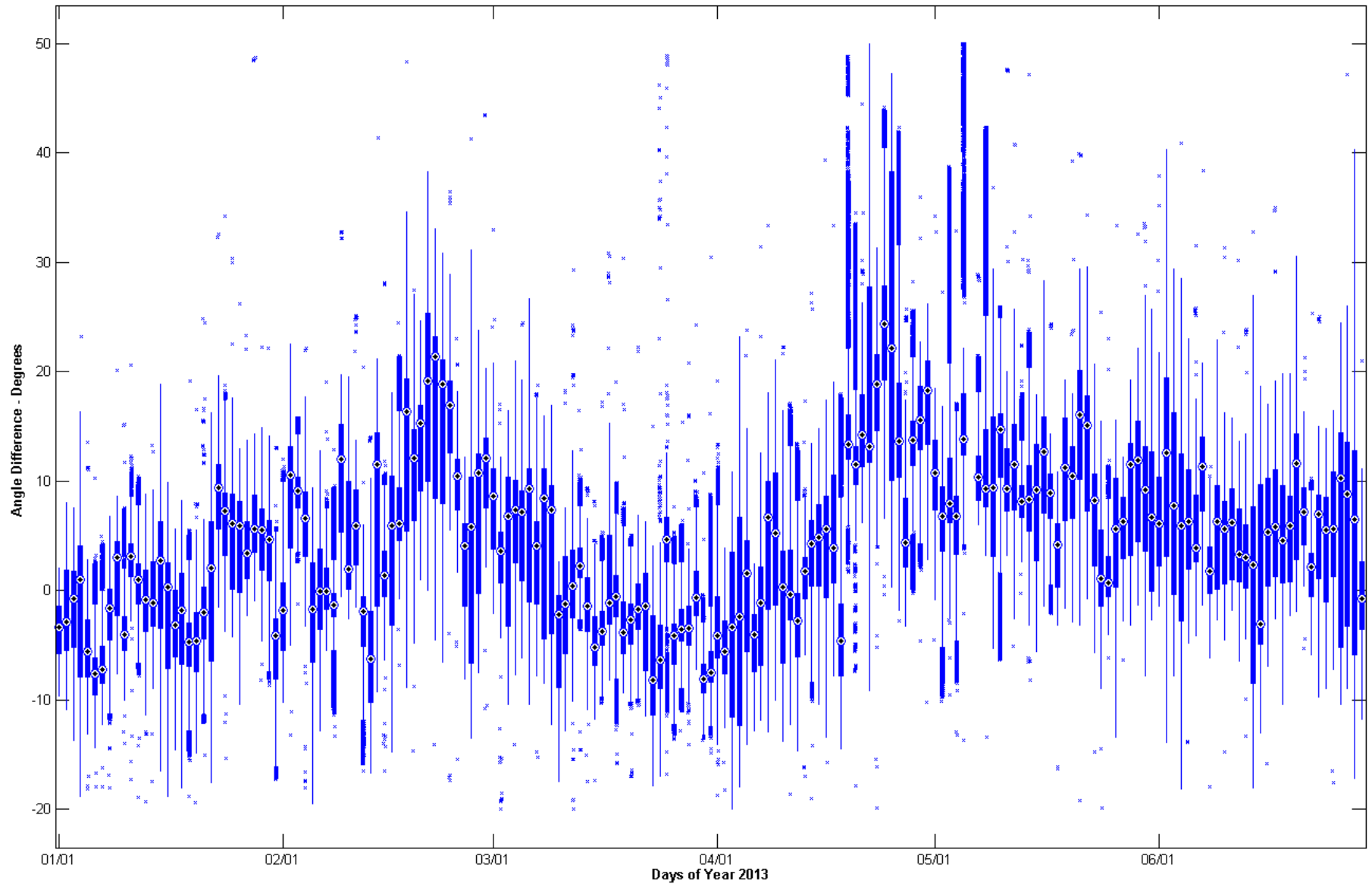
Baseline Analysis Update – Angle Differences

Phasor Data: January to June 2013
Box Whiskers Plots and Time Duration Curves

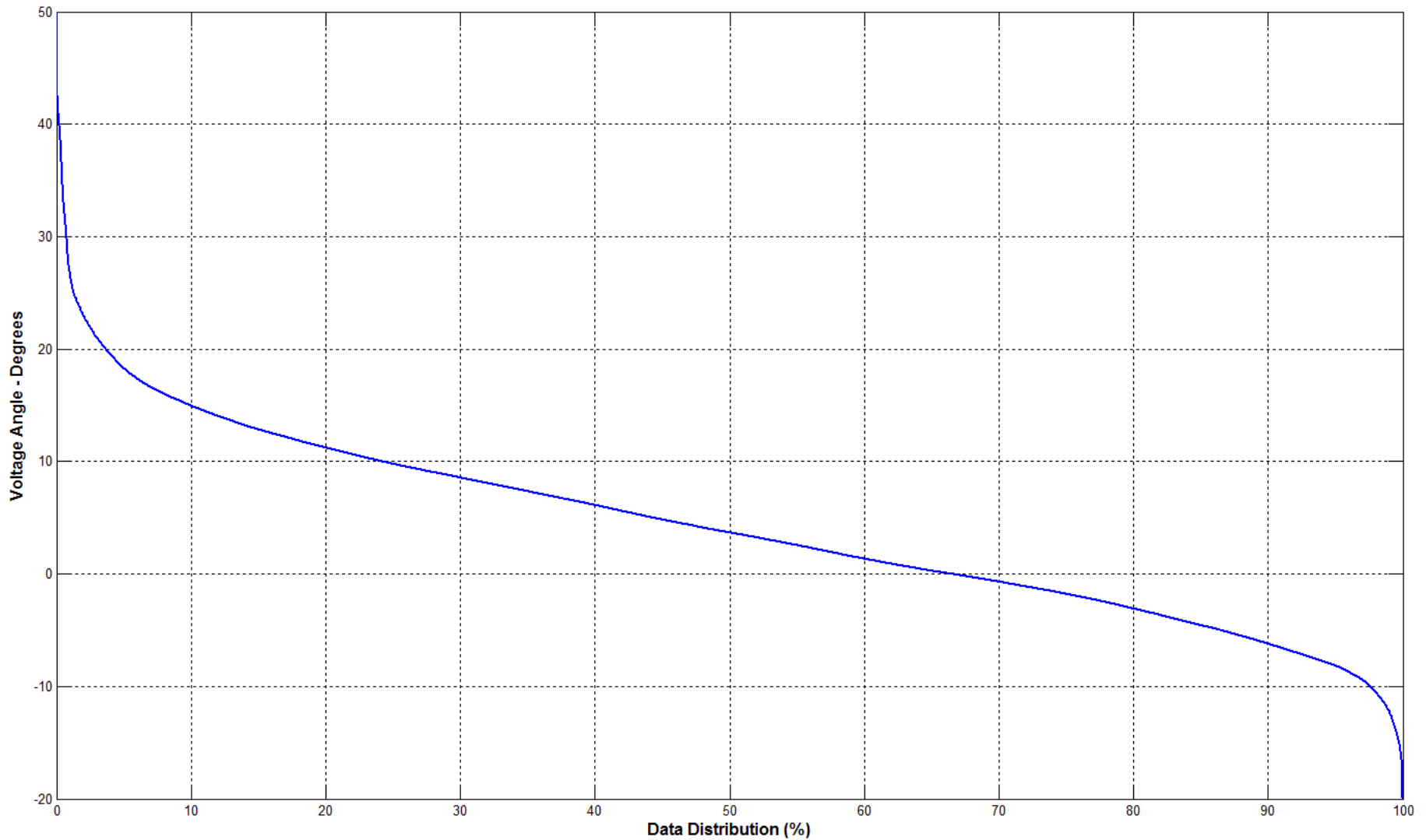
External Version



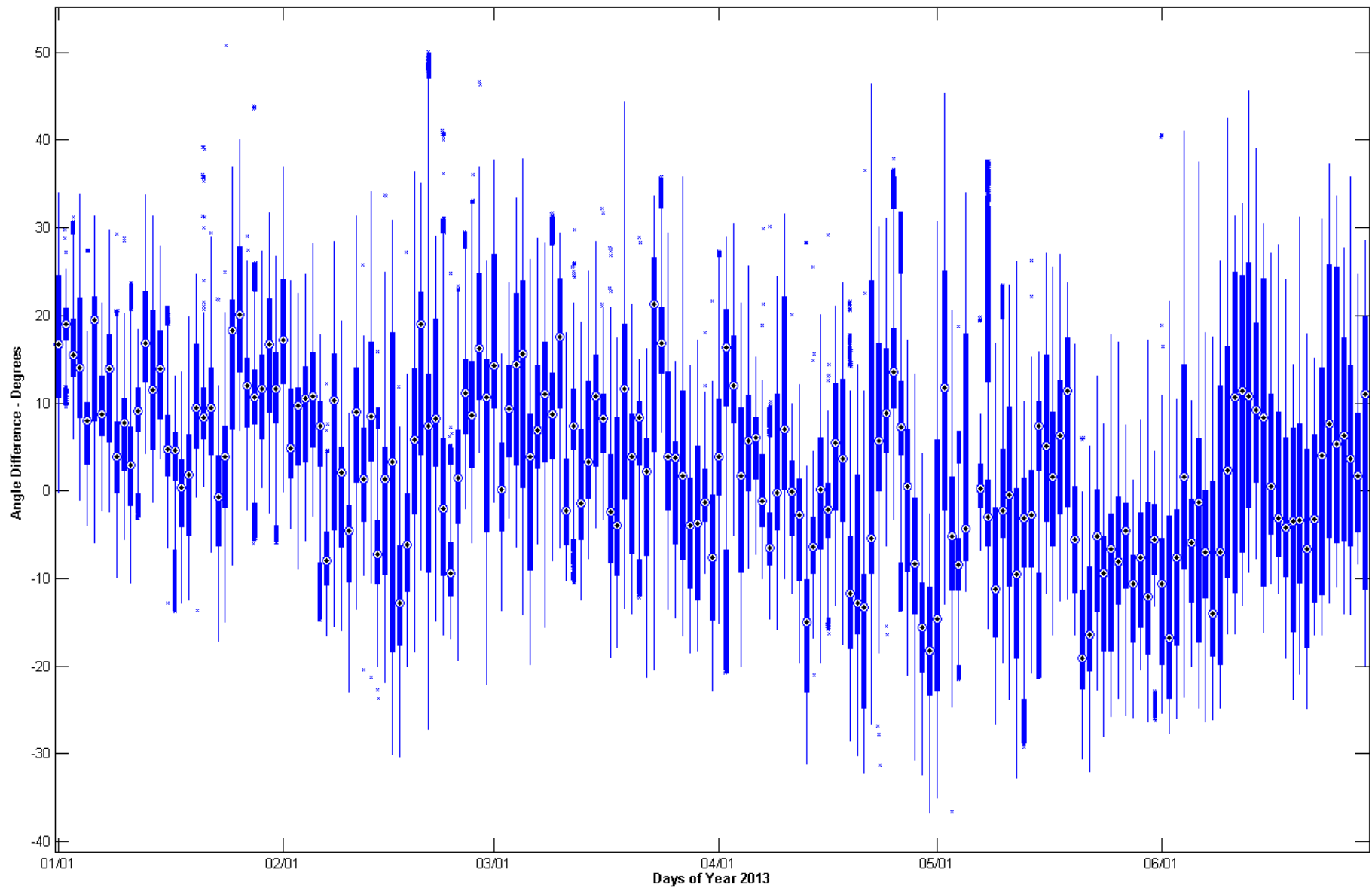
Coast 1 – South 13



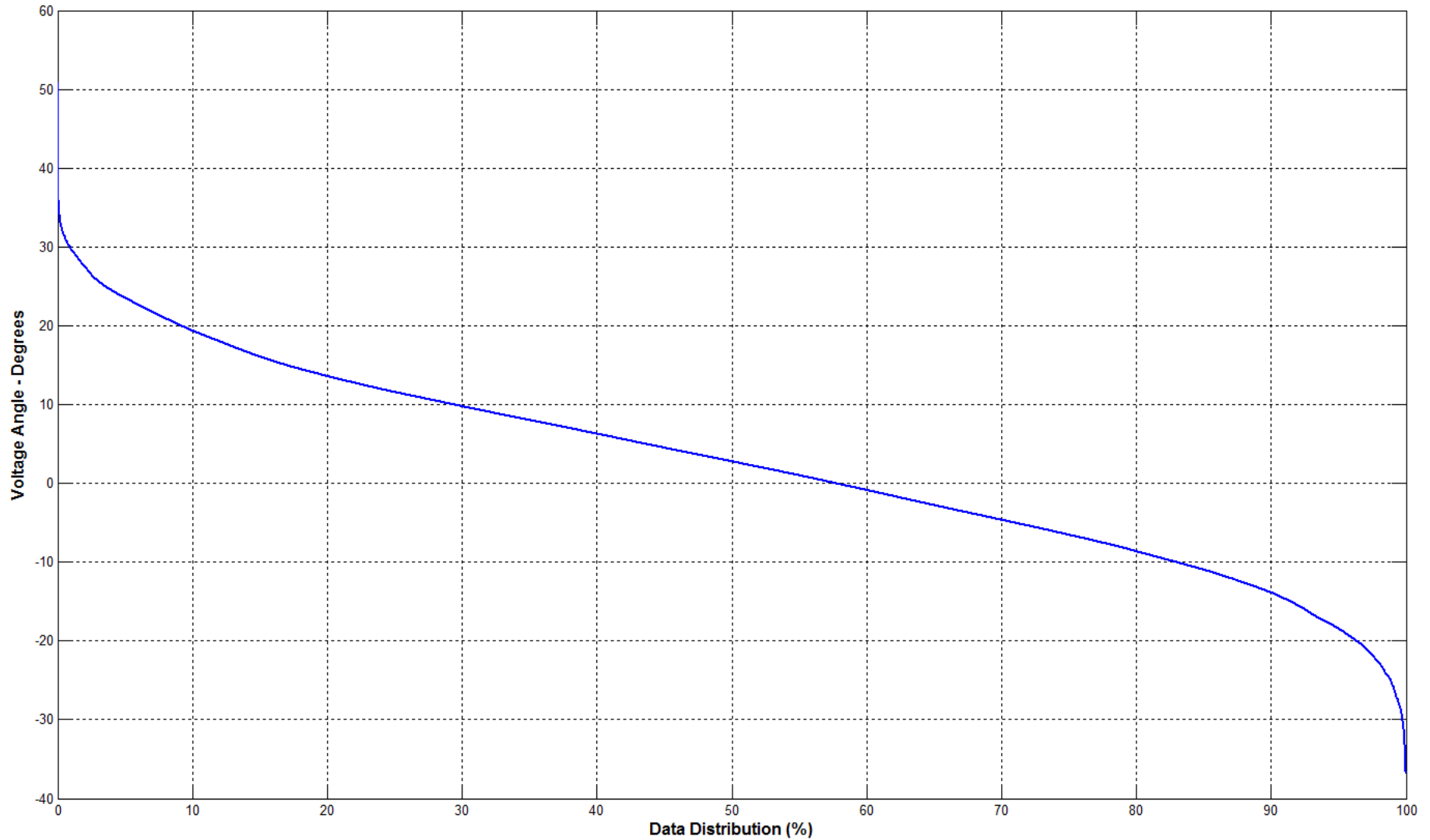
Coast 1 – South 13



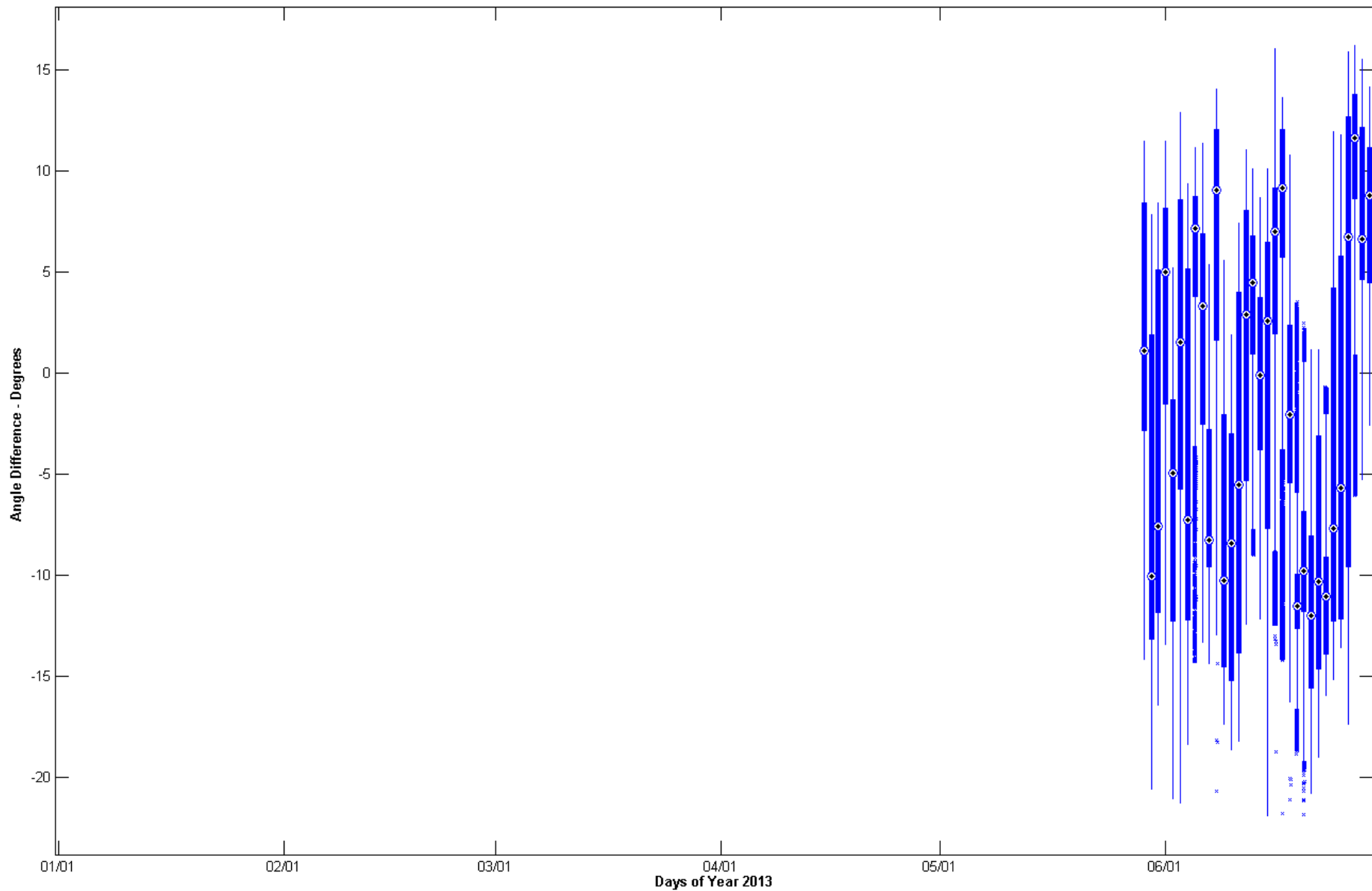
Coast 1 – North 7



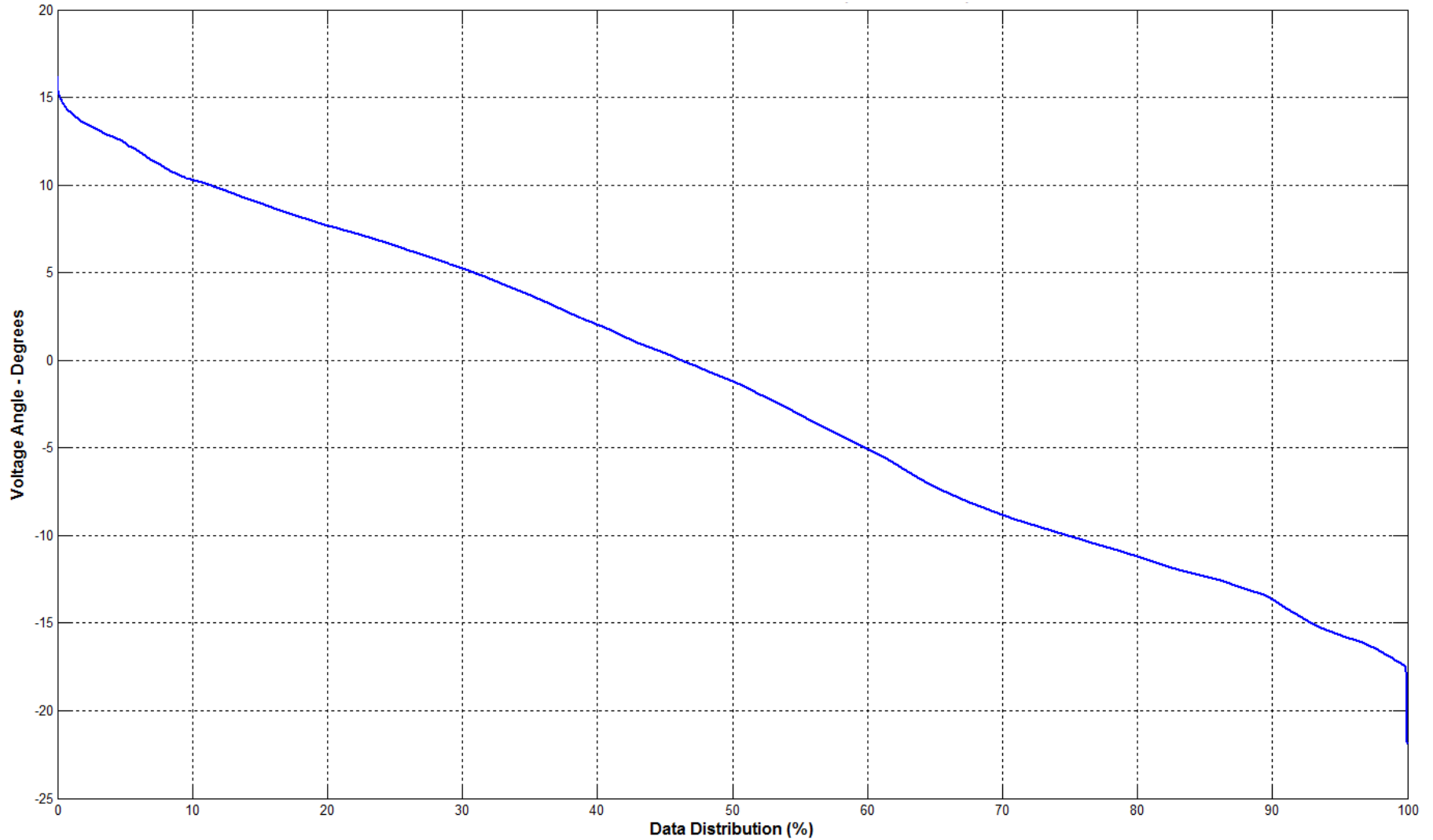
Coast 1 – North 7



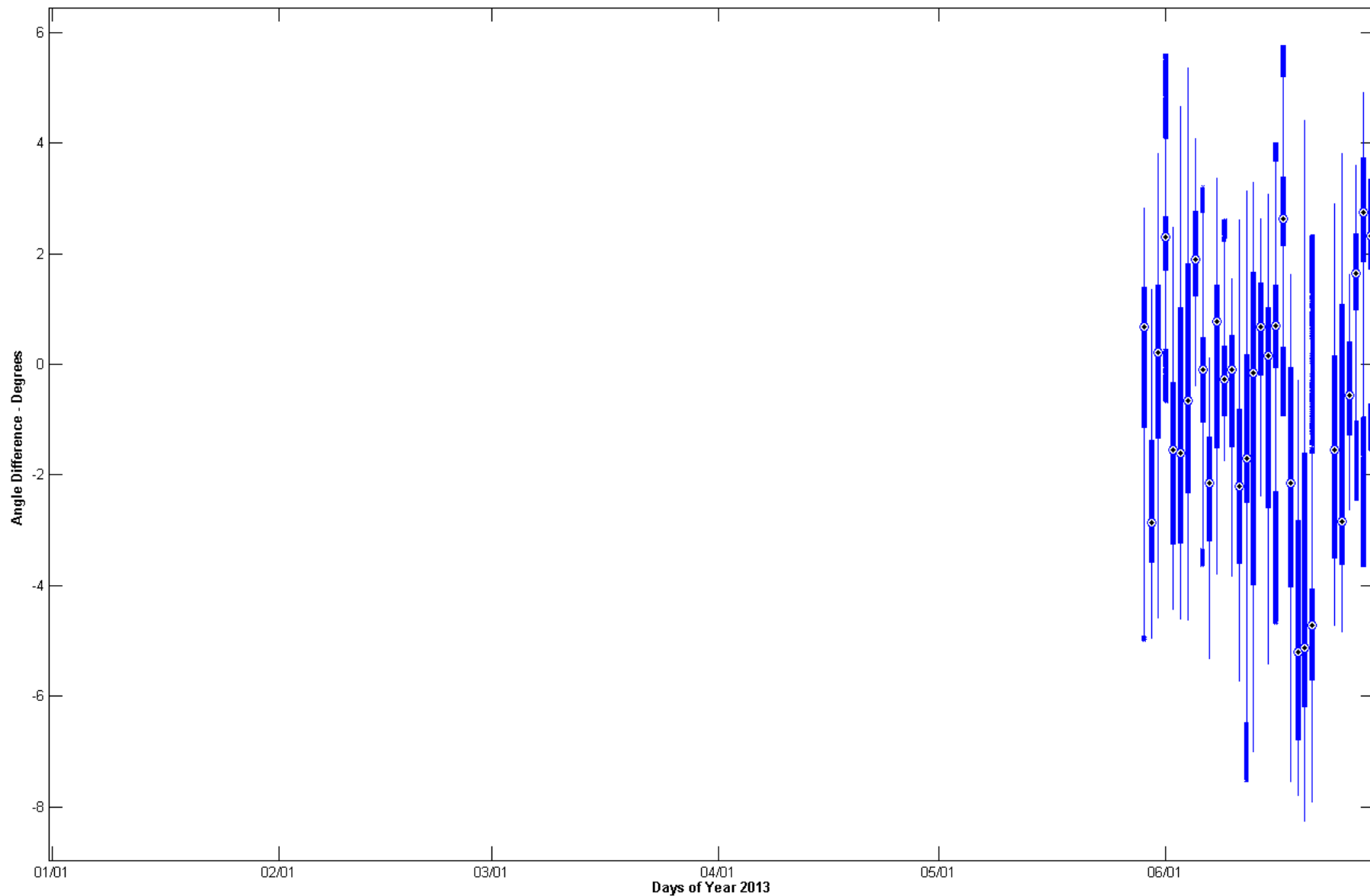
West 5 – West 10



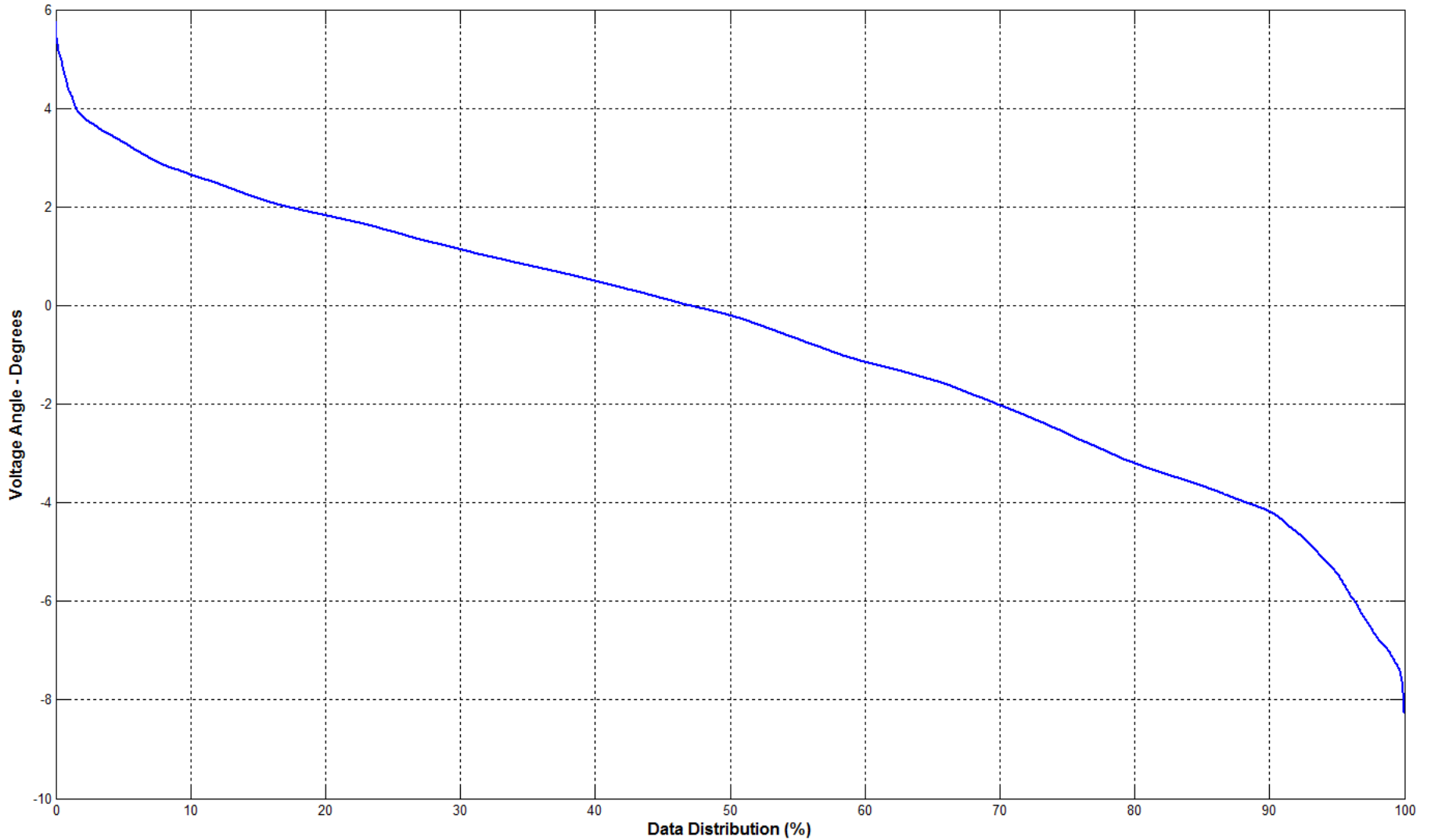
West 5 – West 10



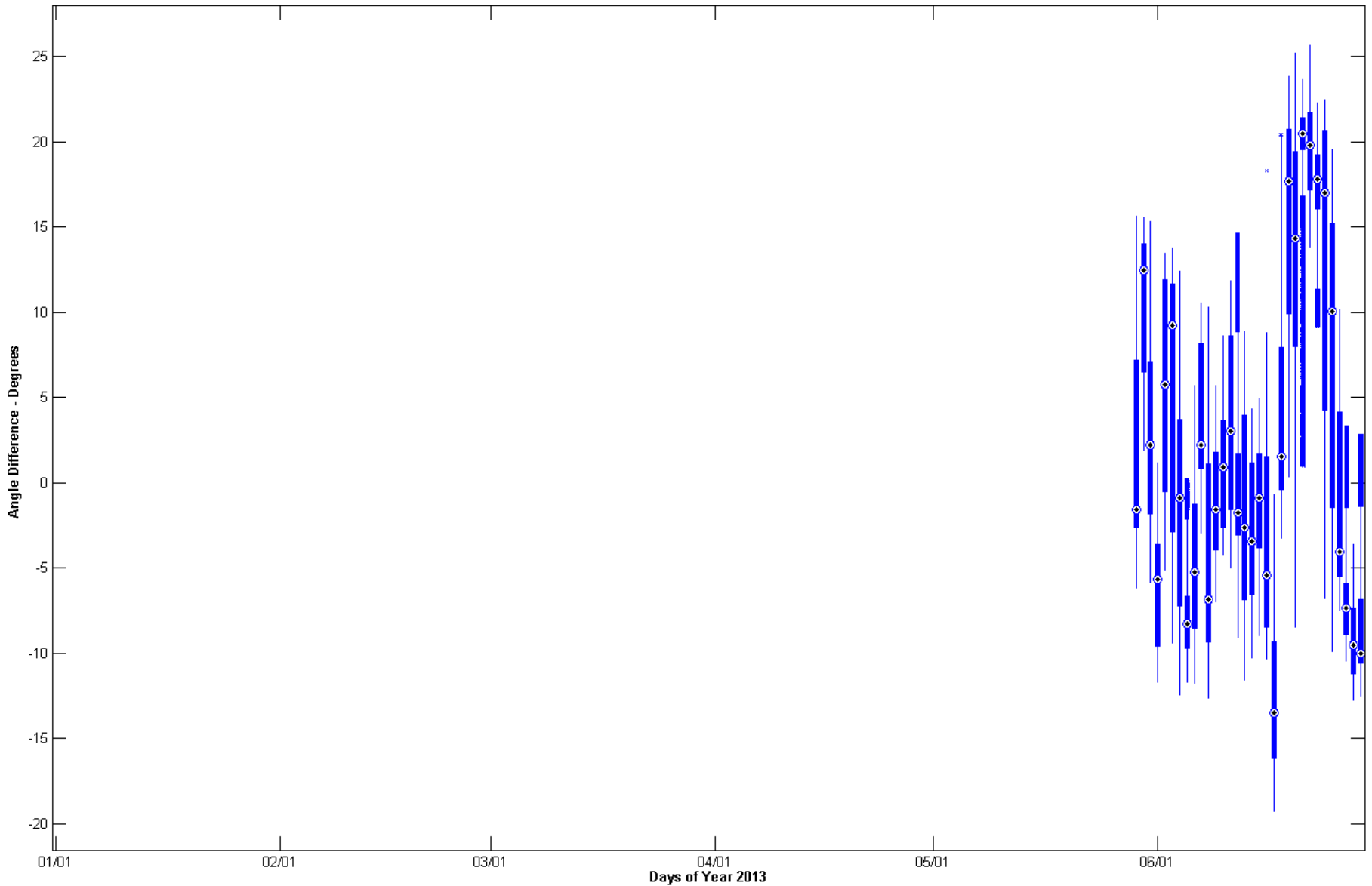
West 5 – FarWest 4



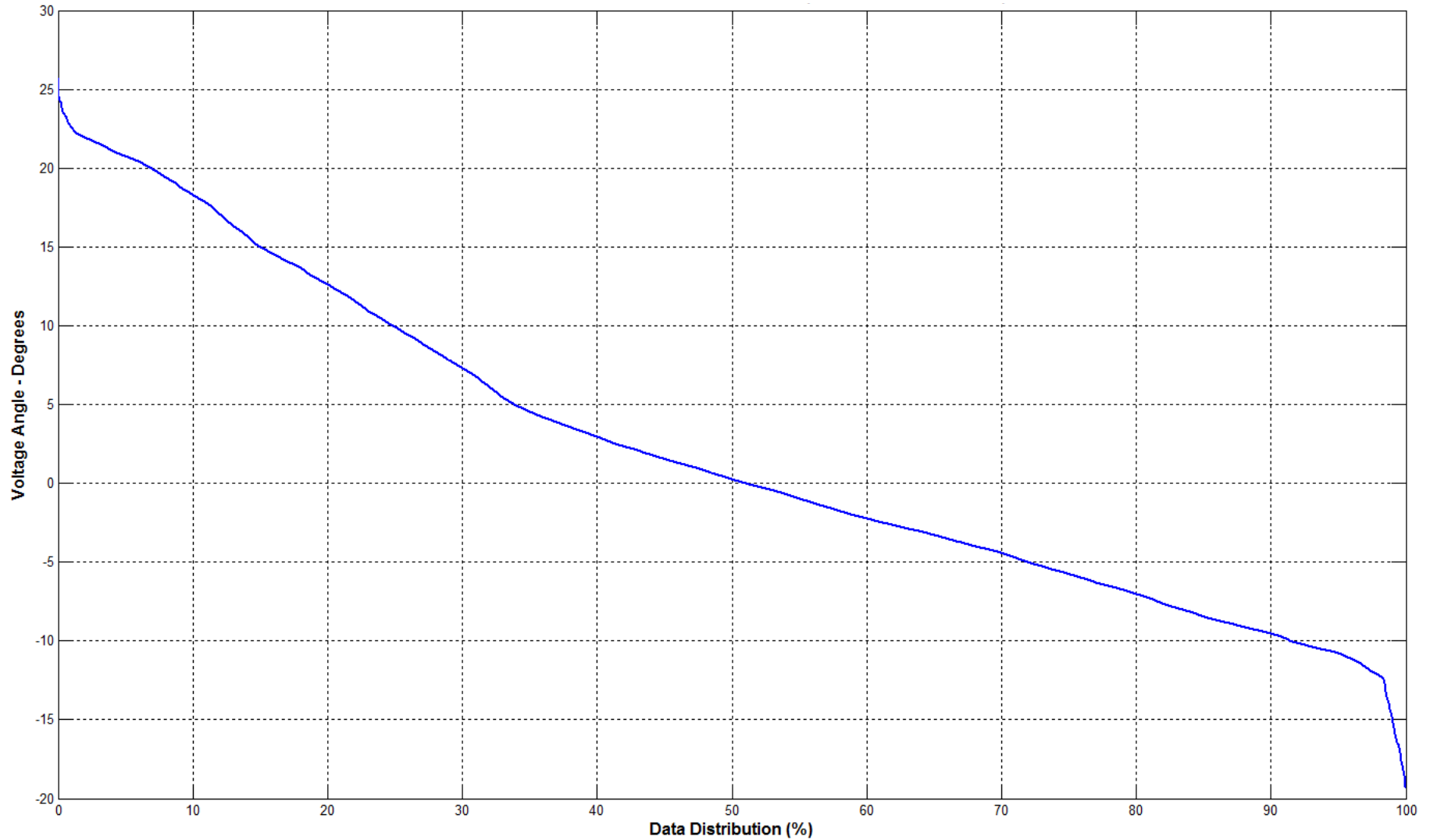
West 5 – FarWest 4



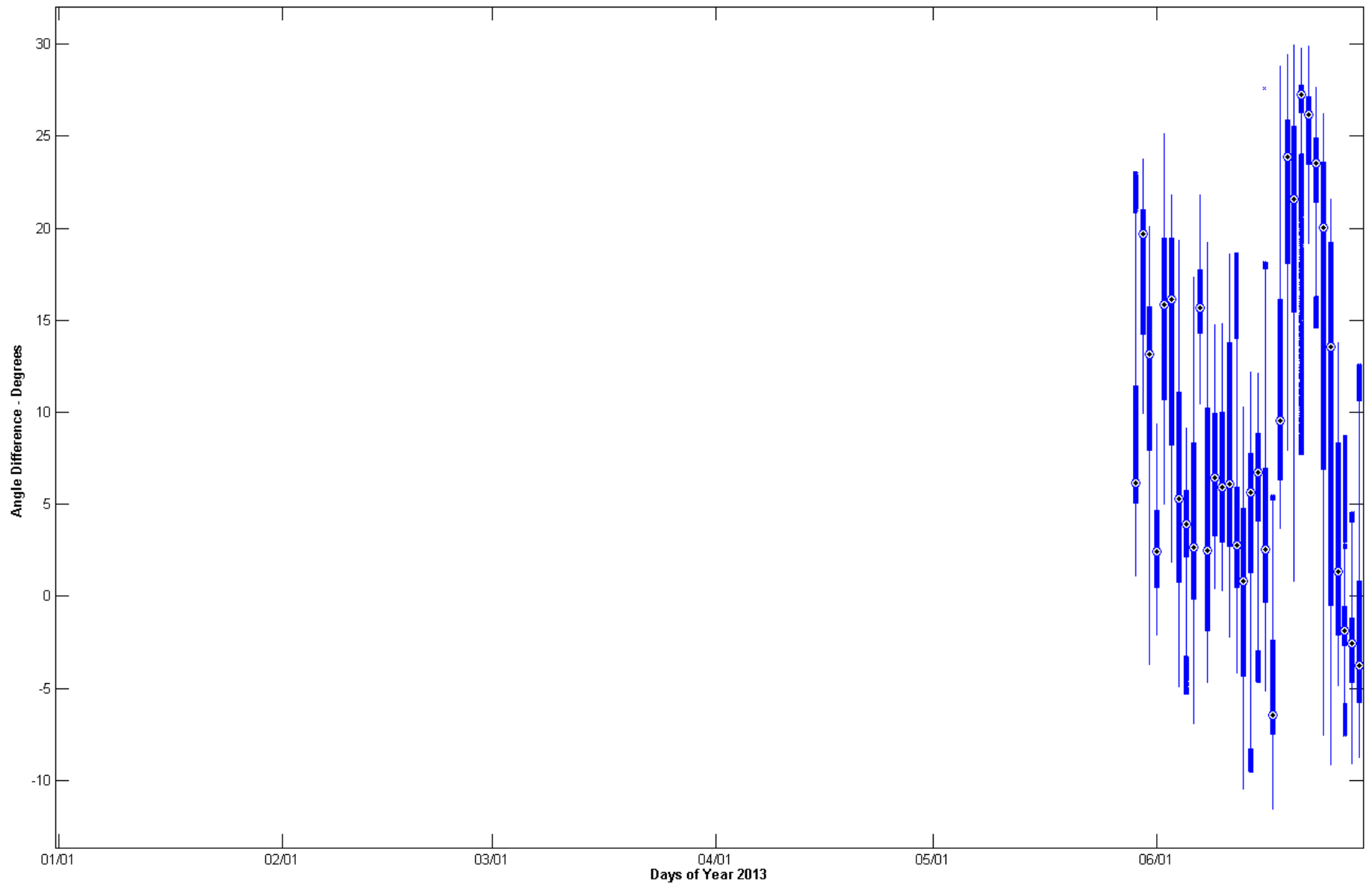
West 5 – North 1



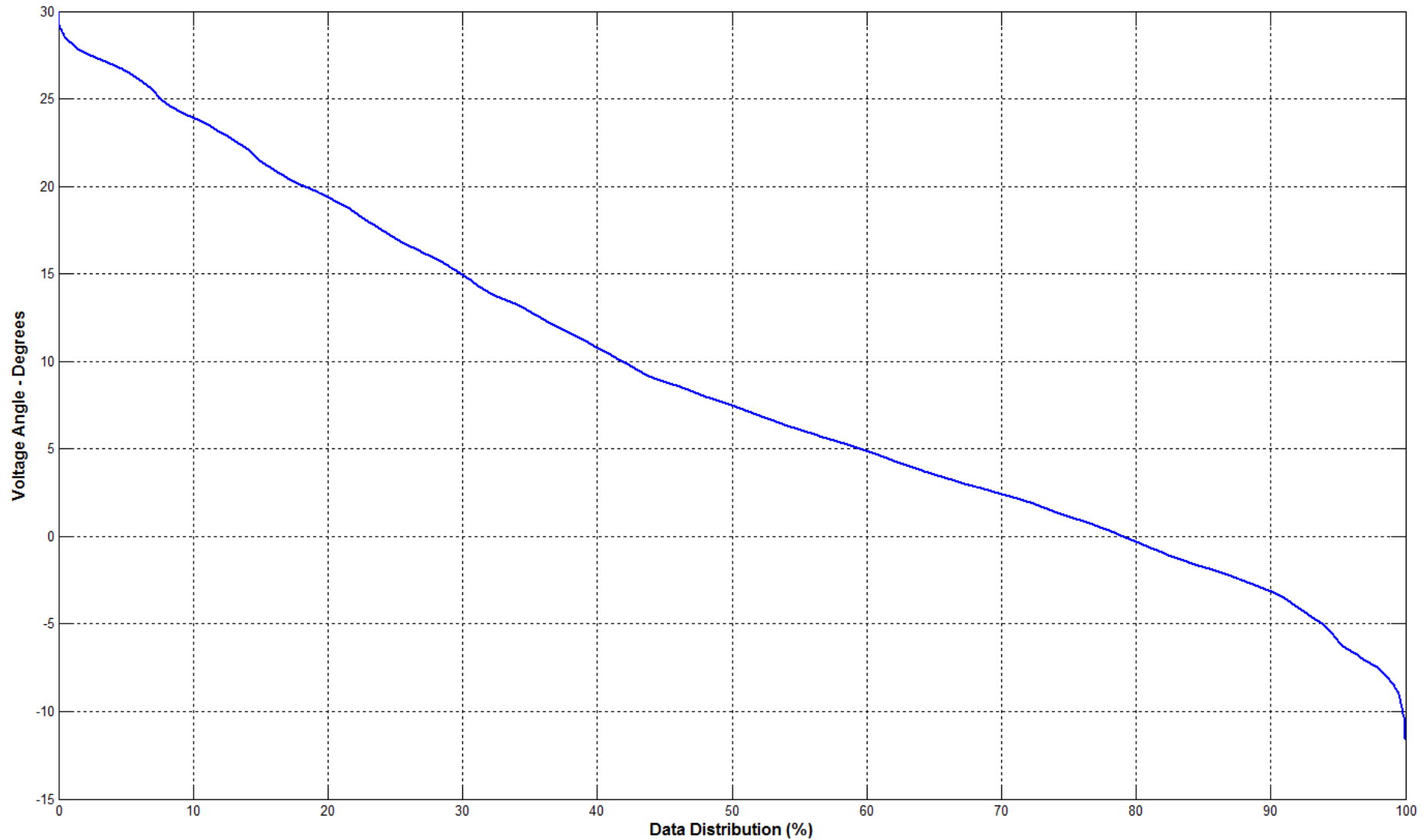
West 5 – North 1



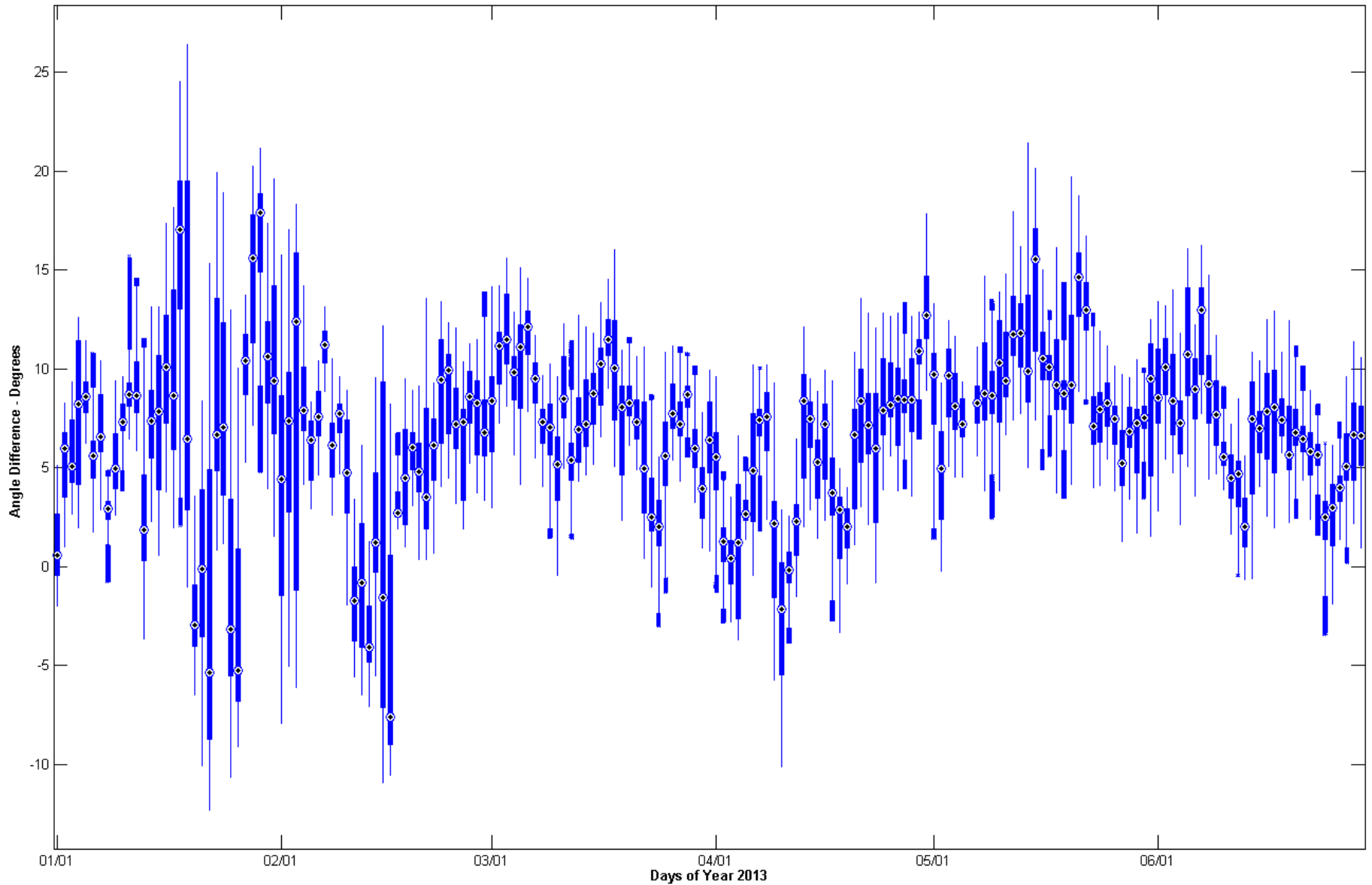
West 5 – North 7



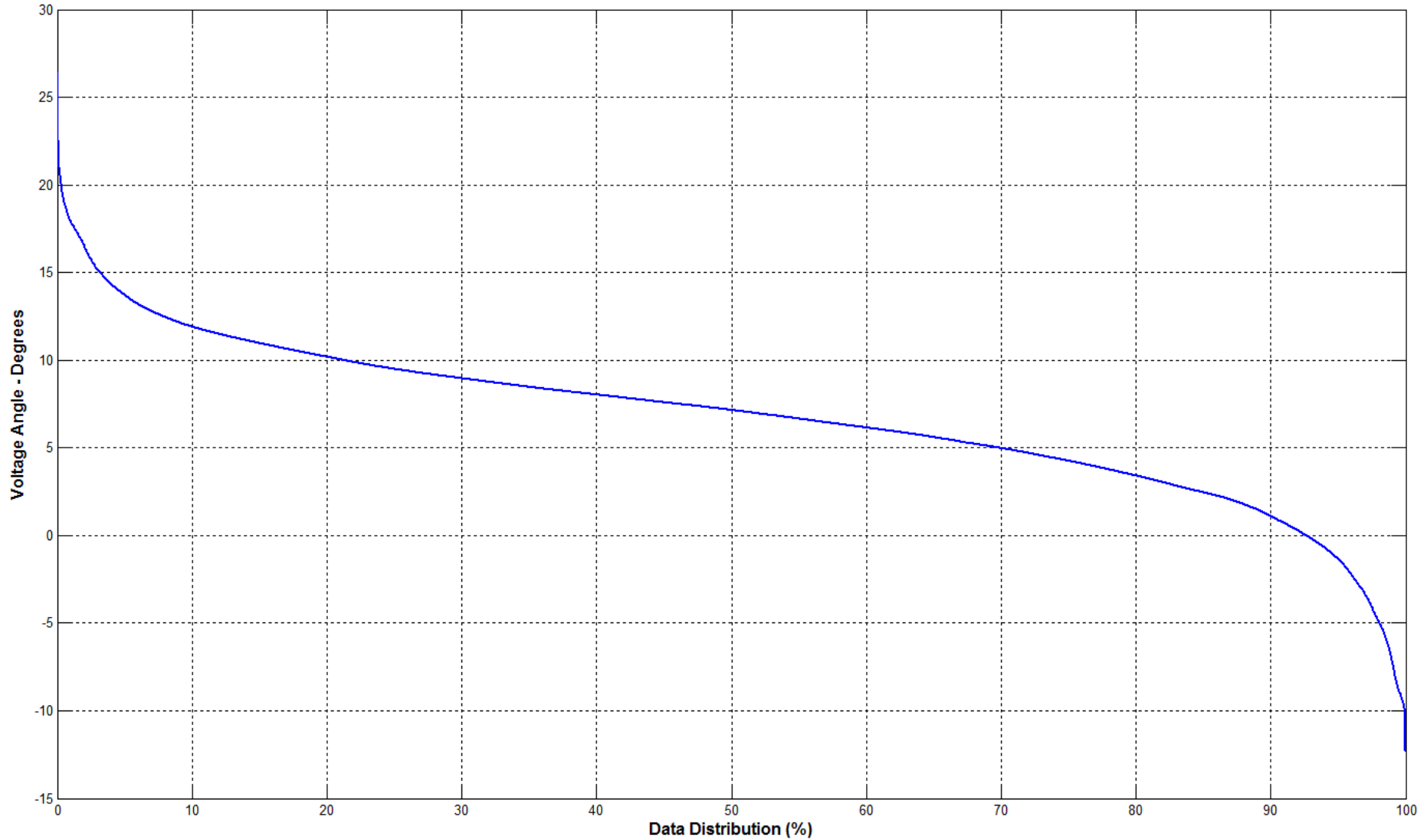
West 5 – North 7



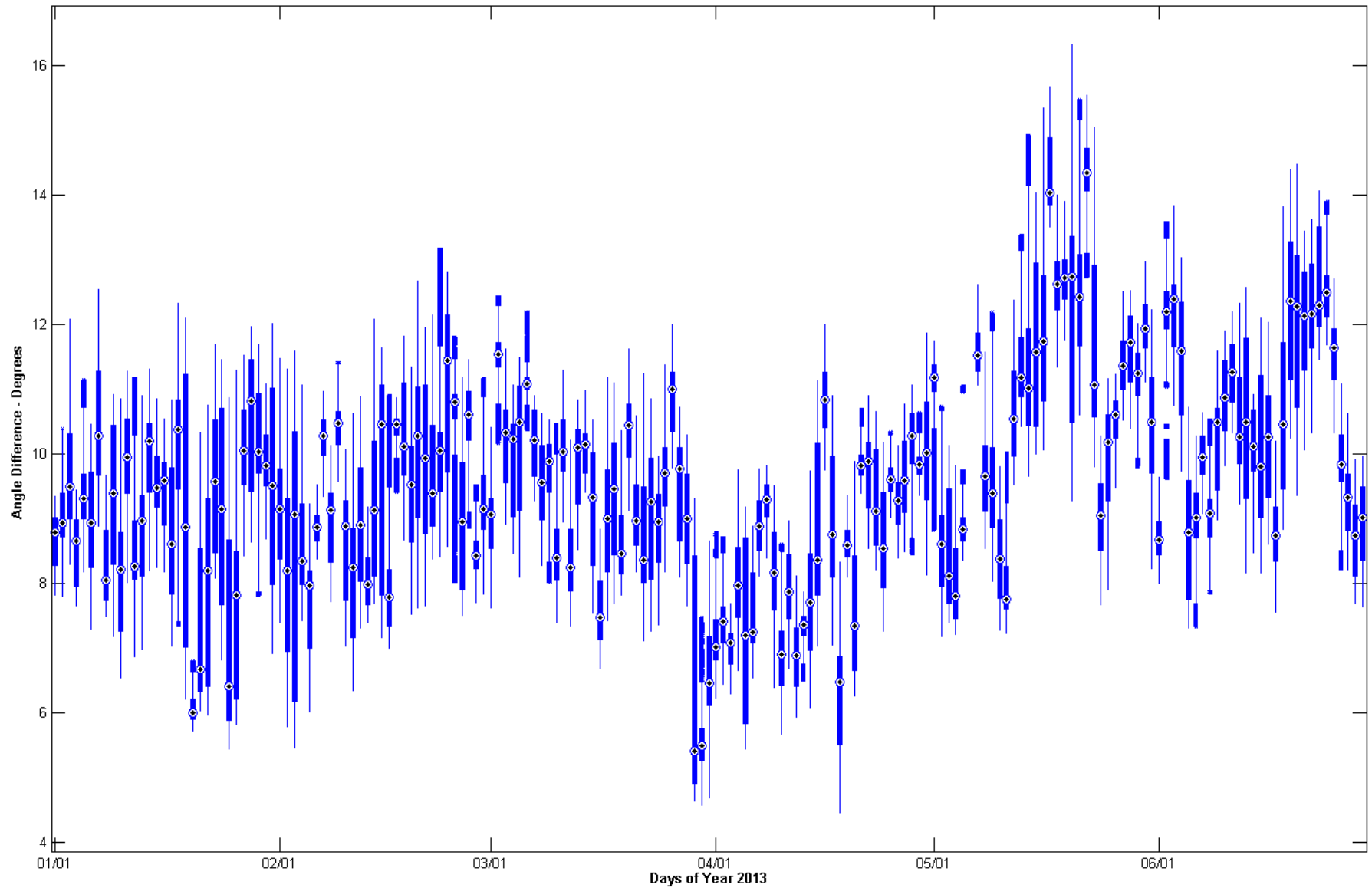
North 1 – North 7



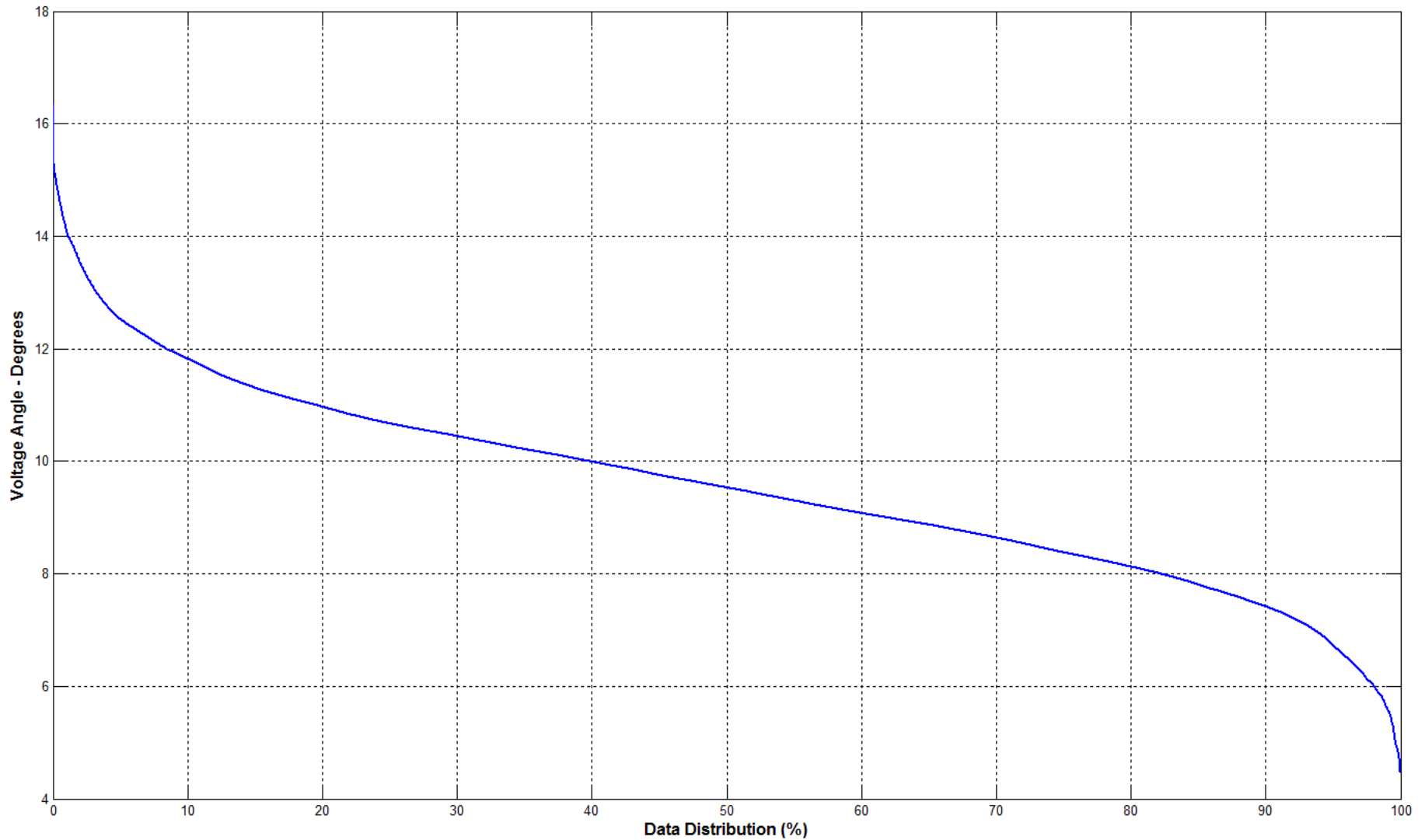
North 1 – North 7



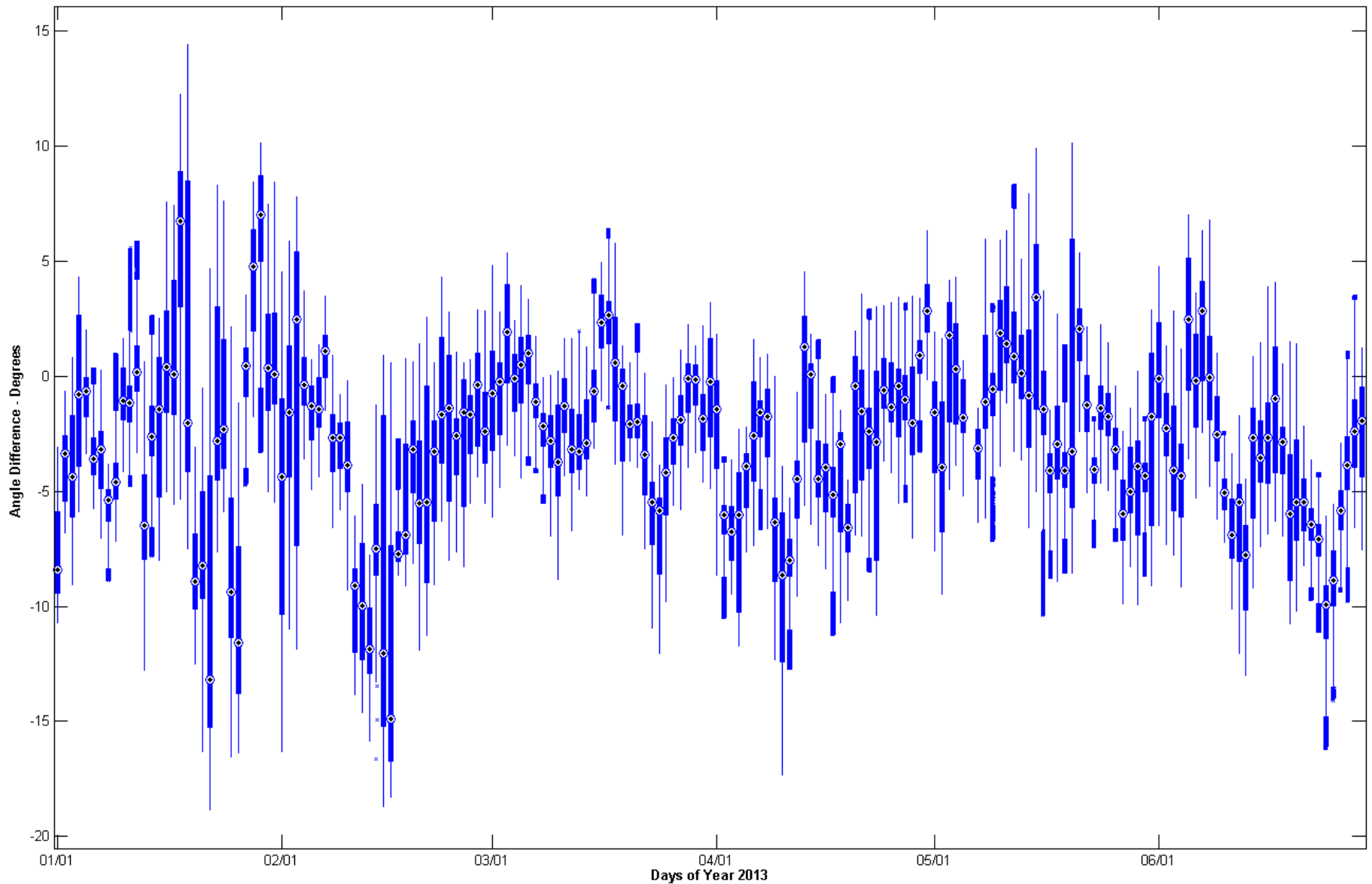
North 1 – North 4



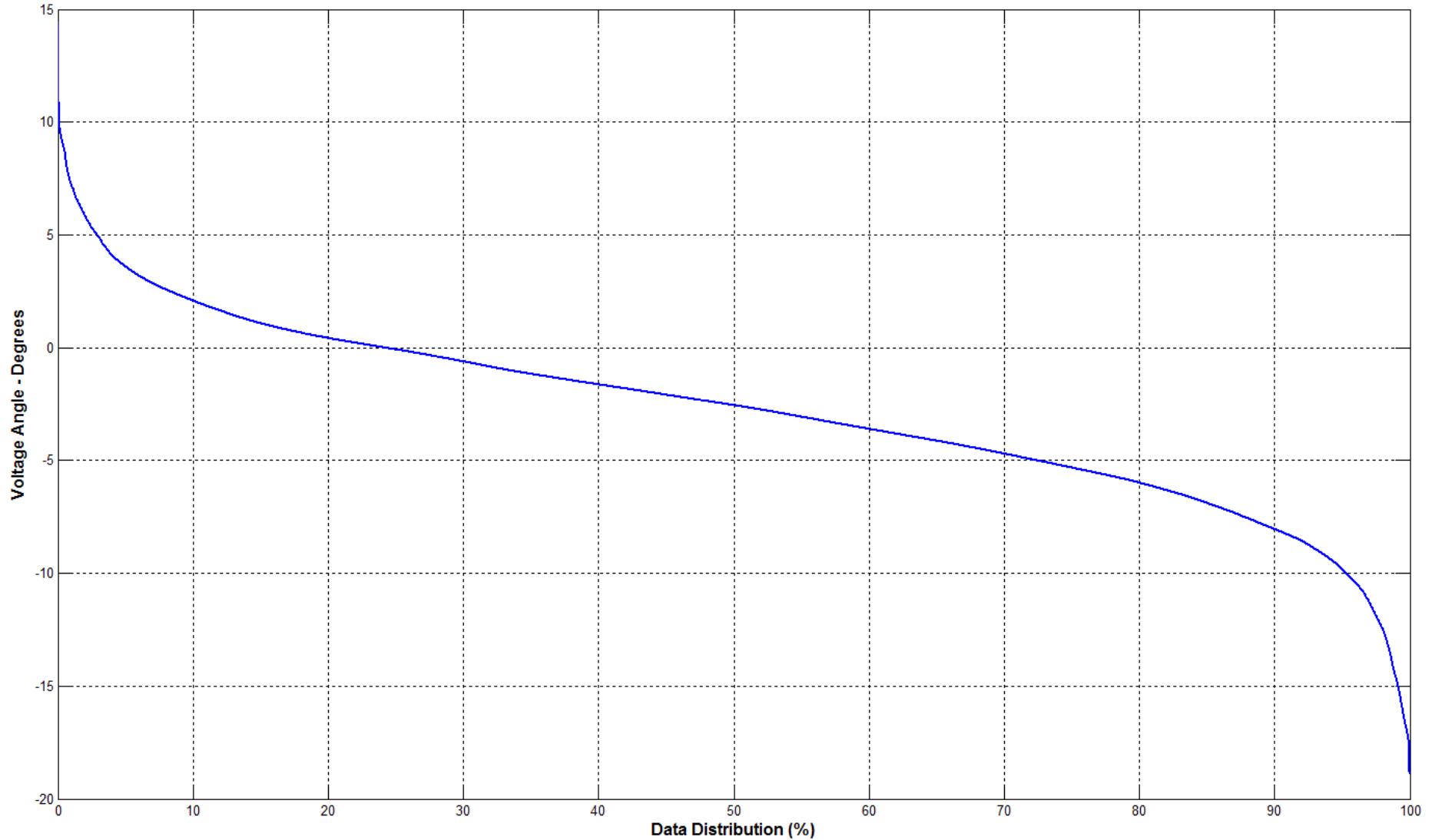
North 1 – North 4



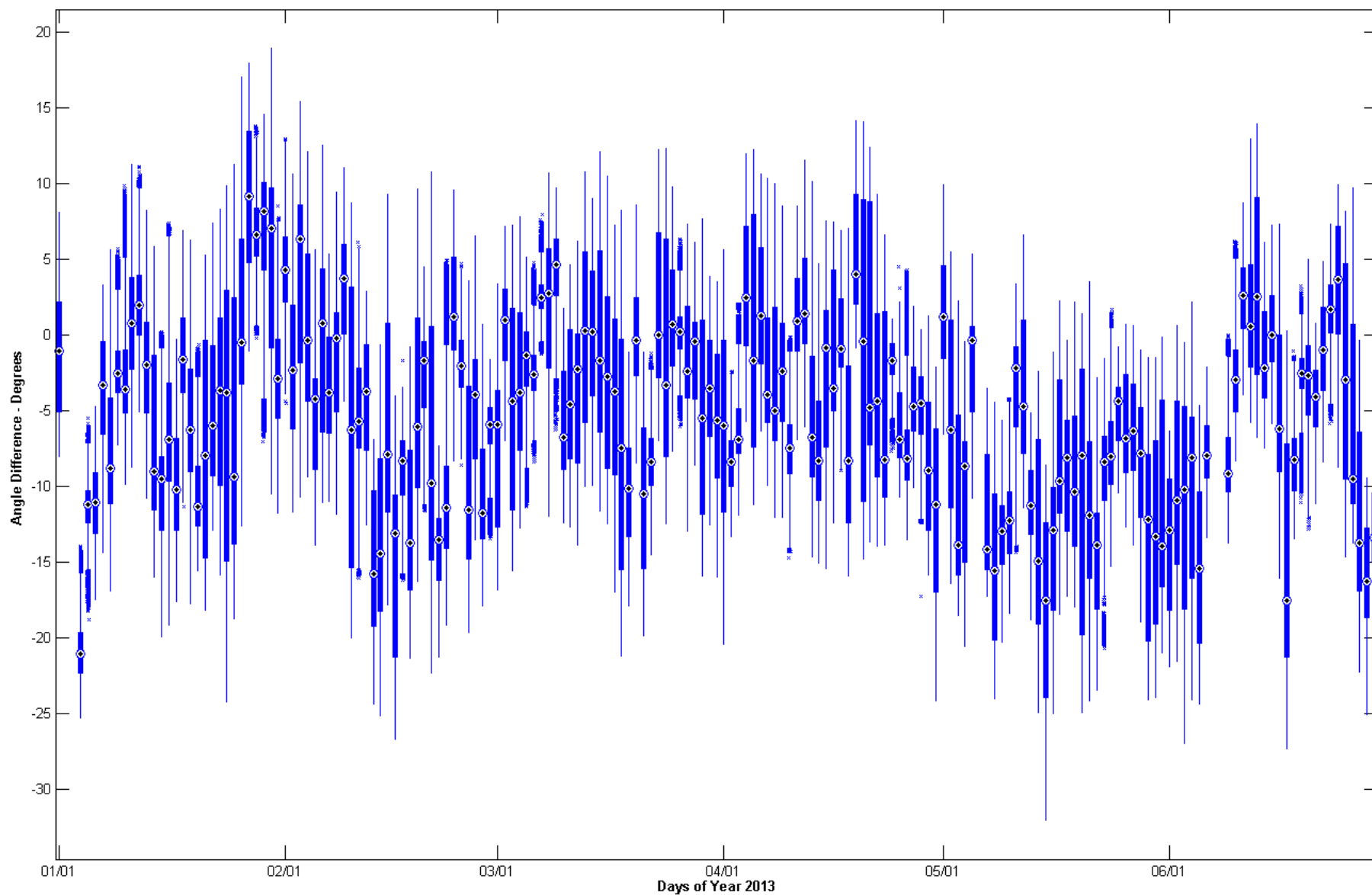
North 4 – North 7



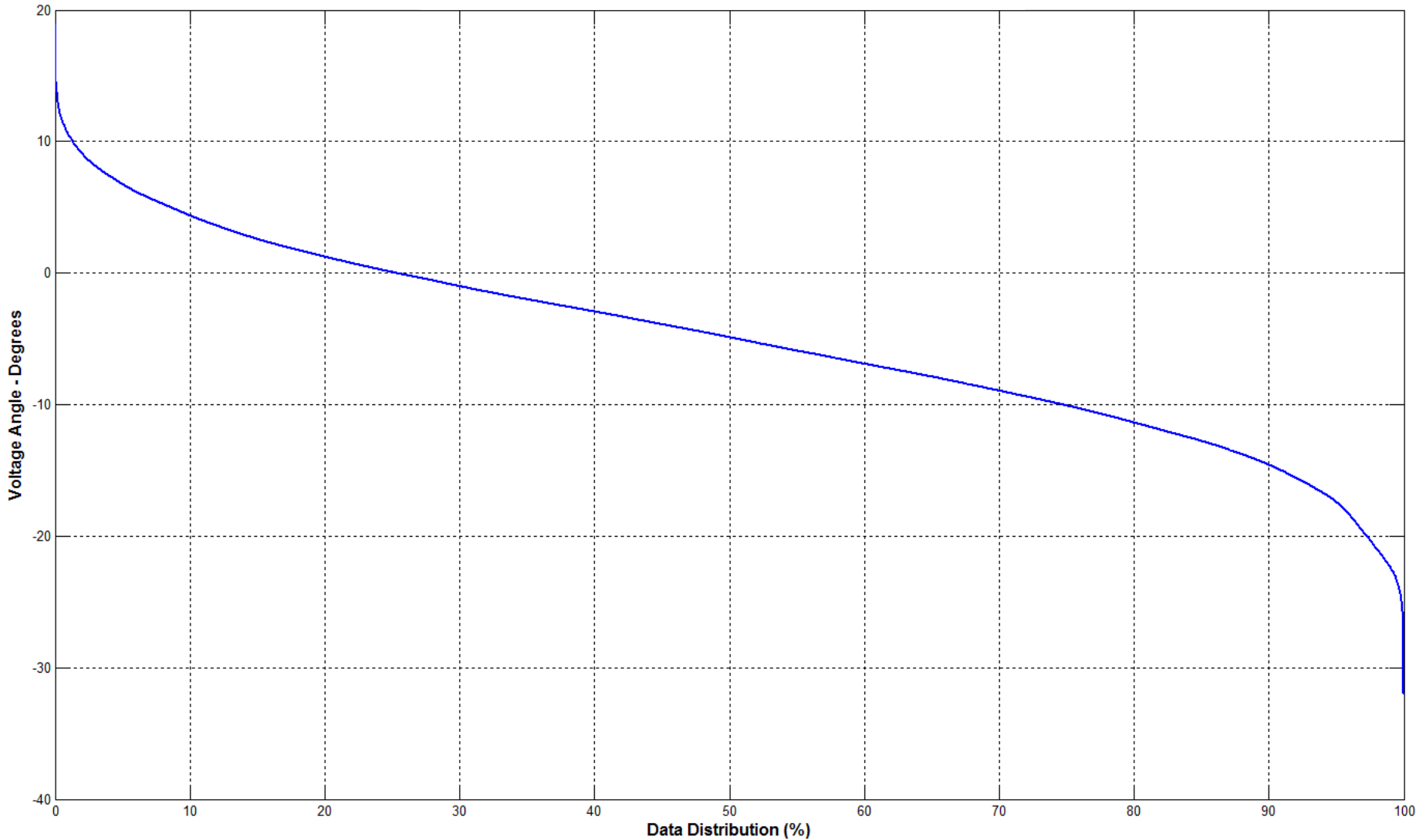
North 4 – North 7



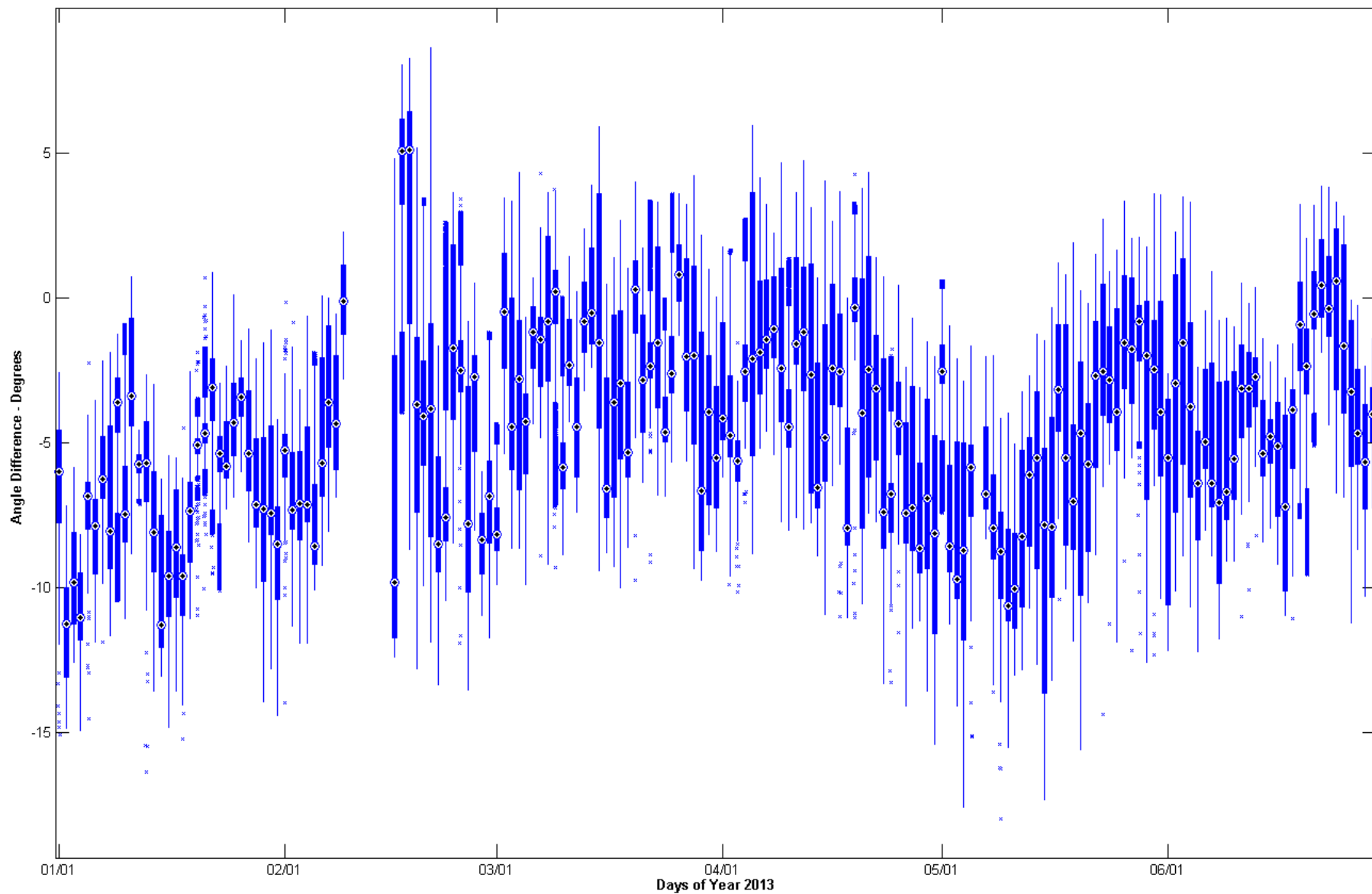
West 4 – North 7



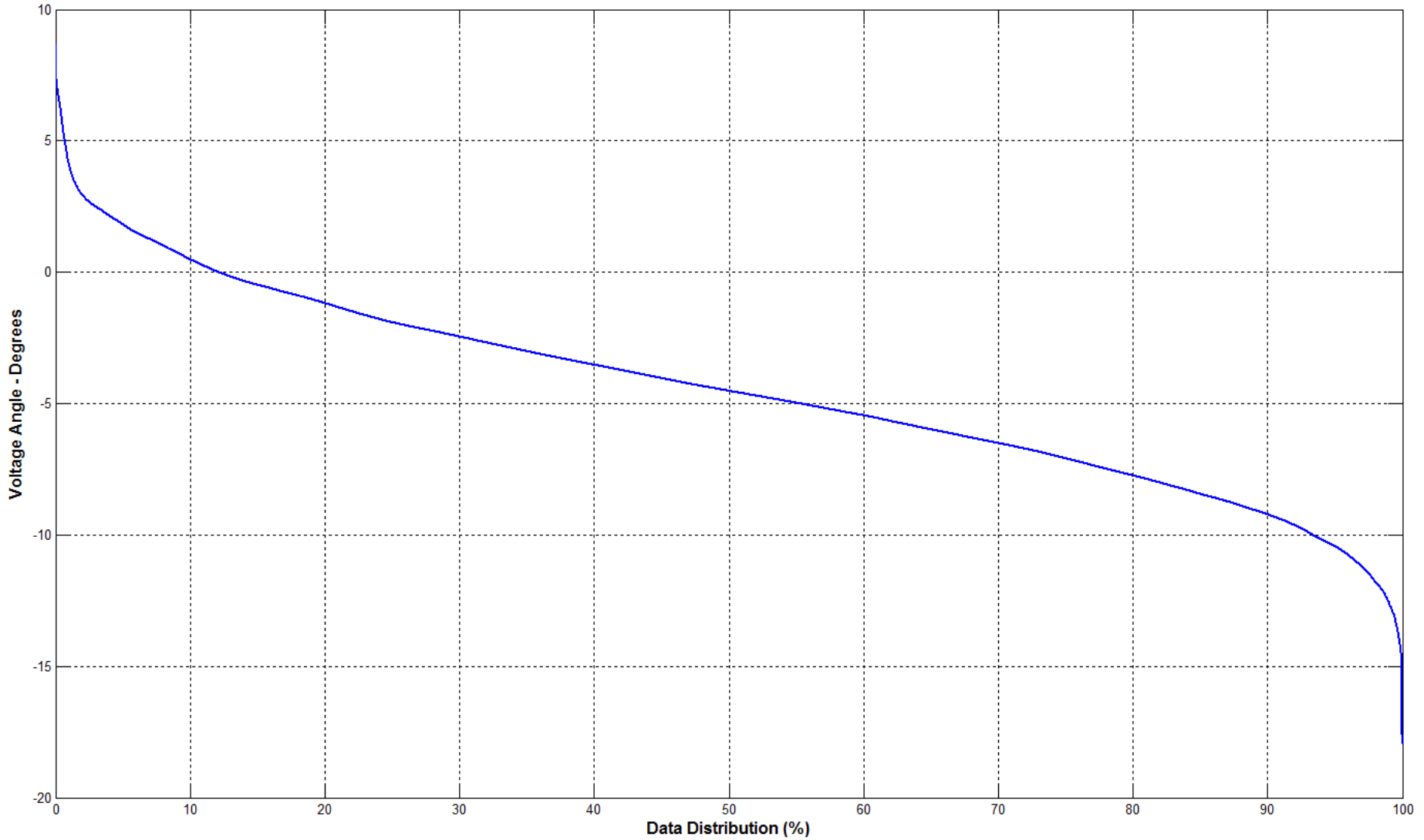
West 4 – North 7



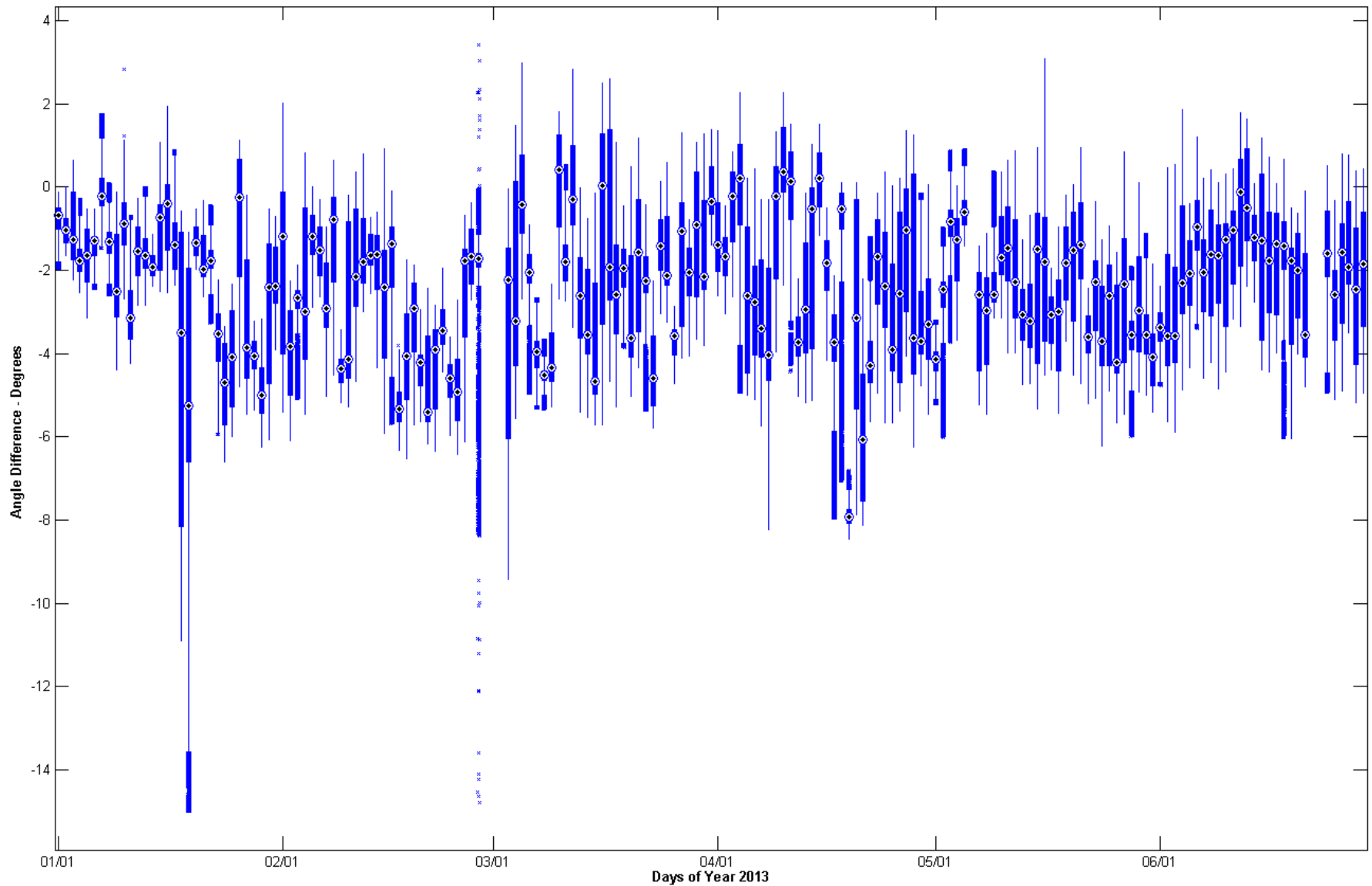
North 7 – North 6



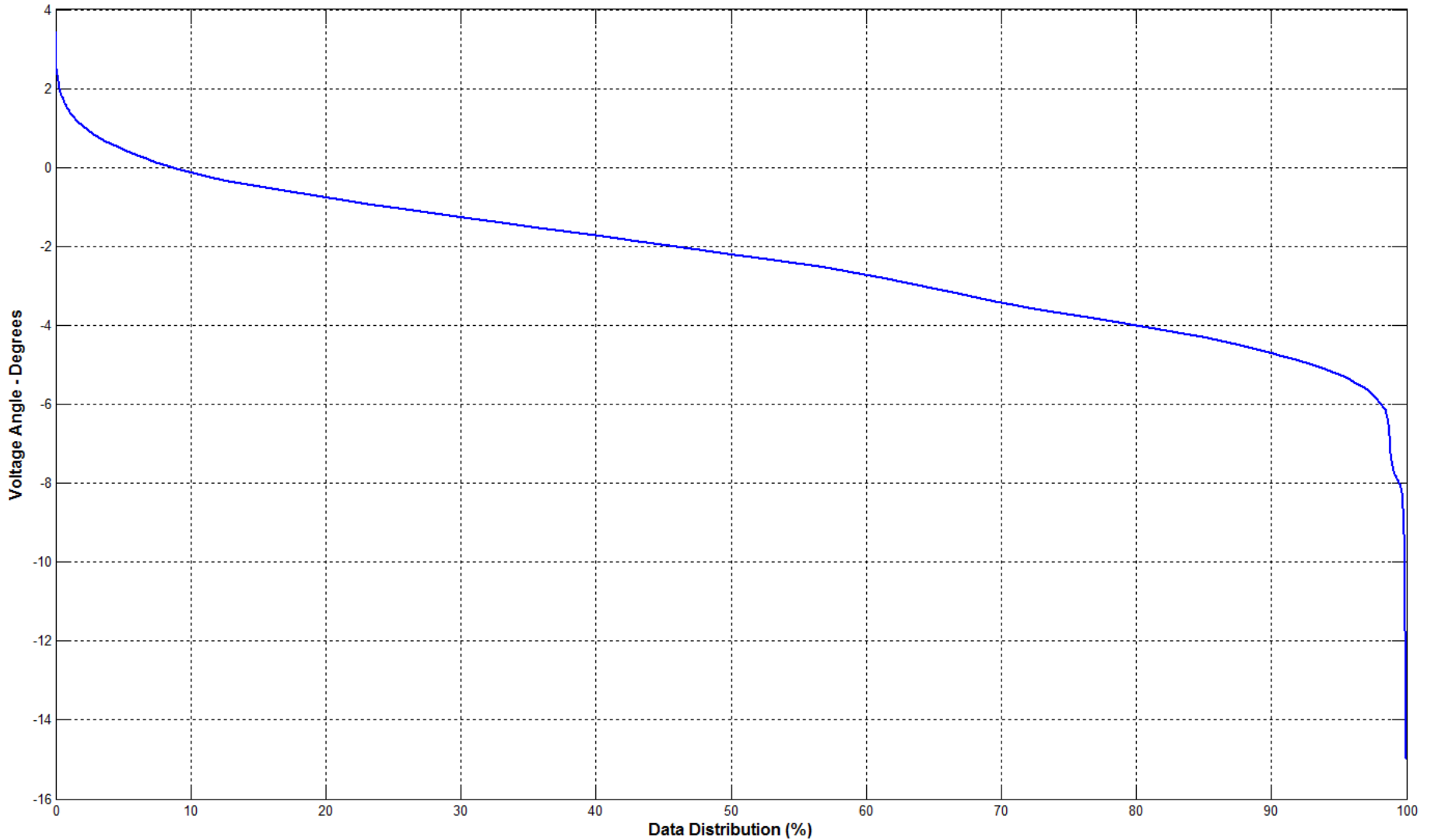
North 7 – North 6



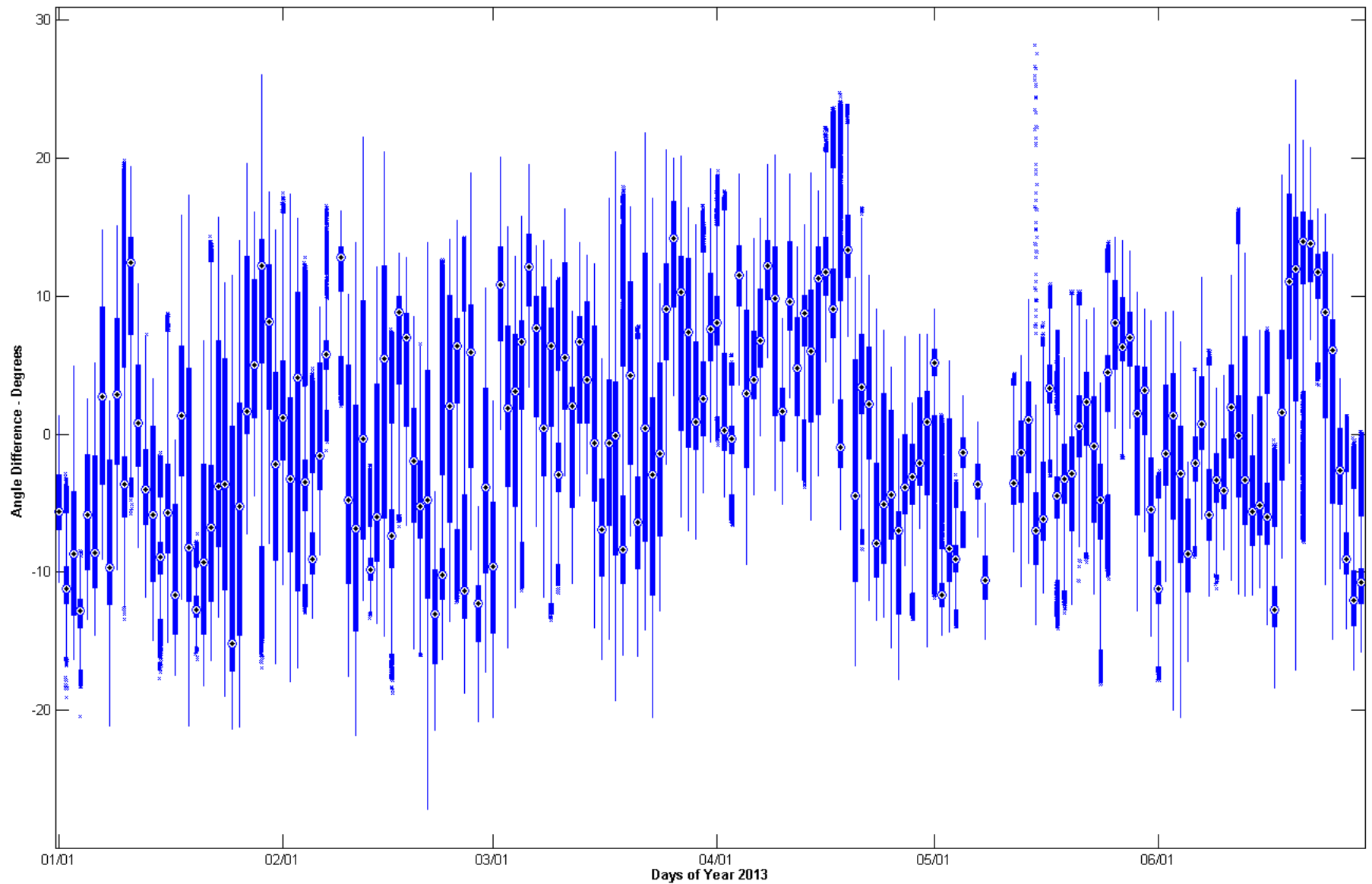
FarWest 7 – FarWest 4



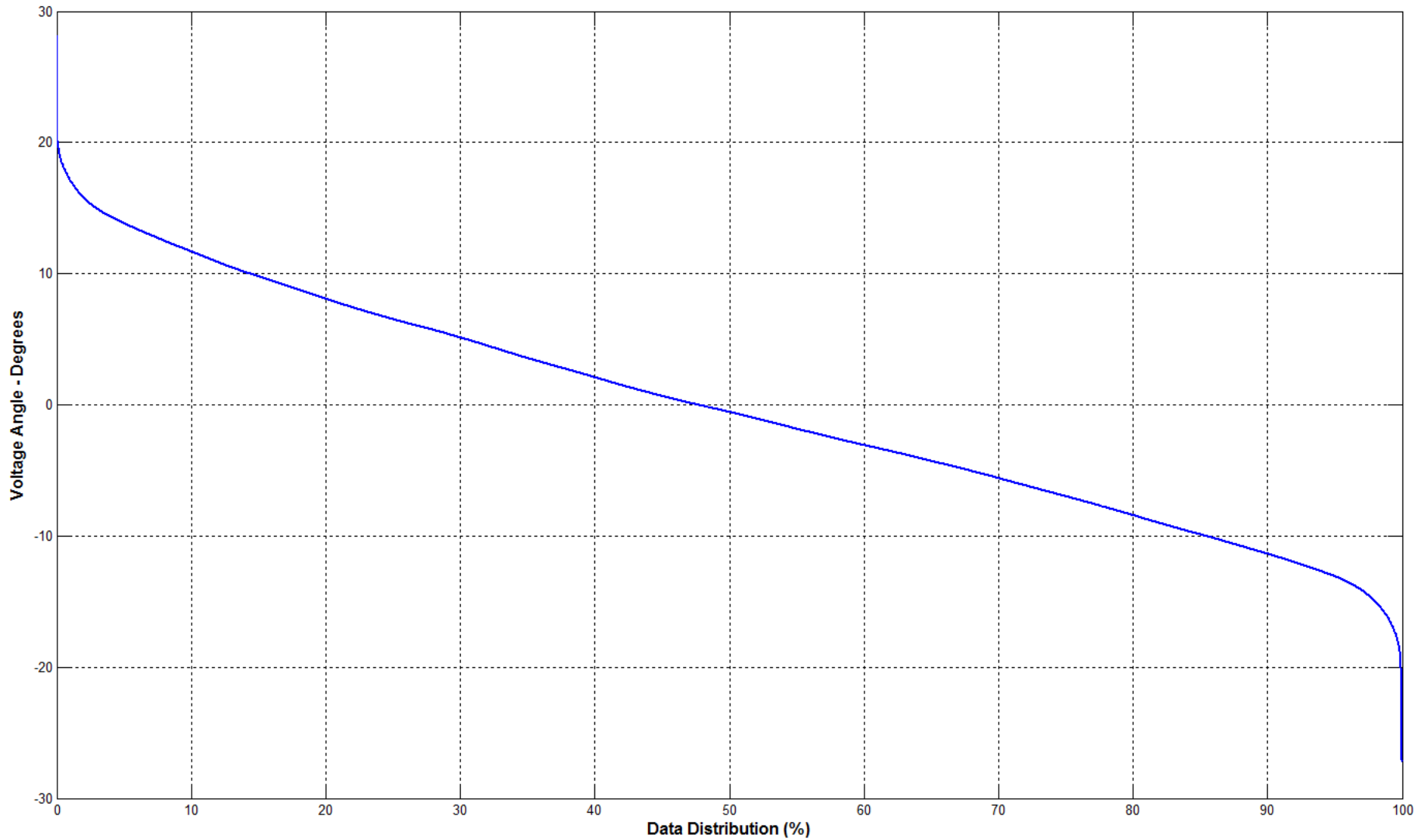
FarWest 7 – FarWest 4



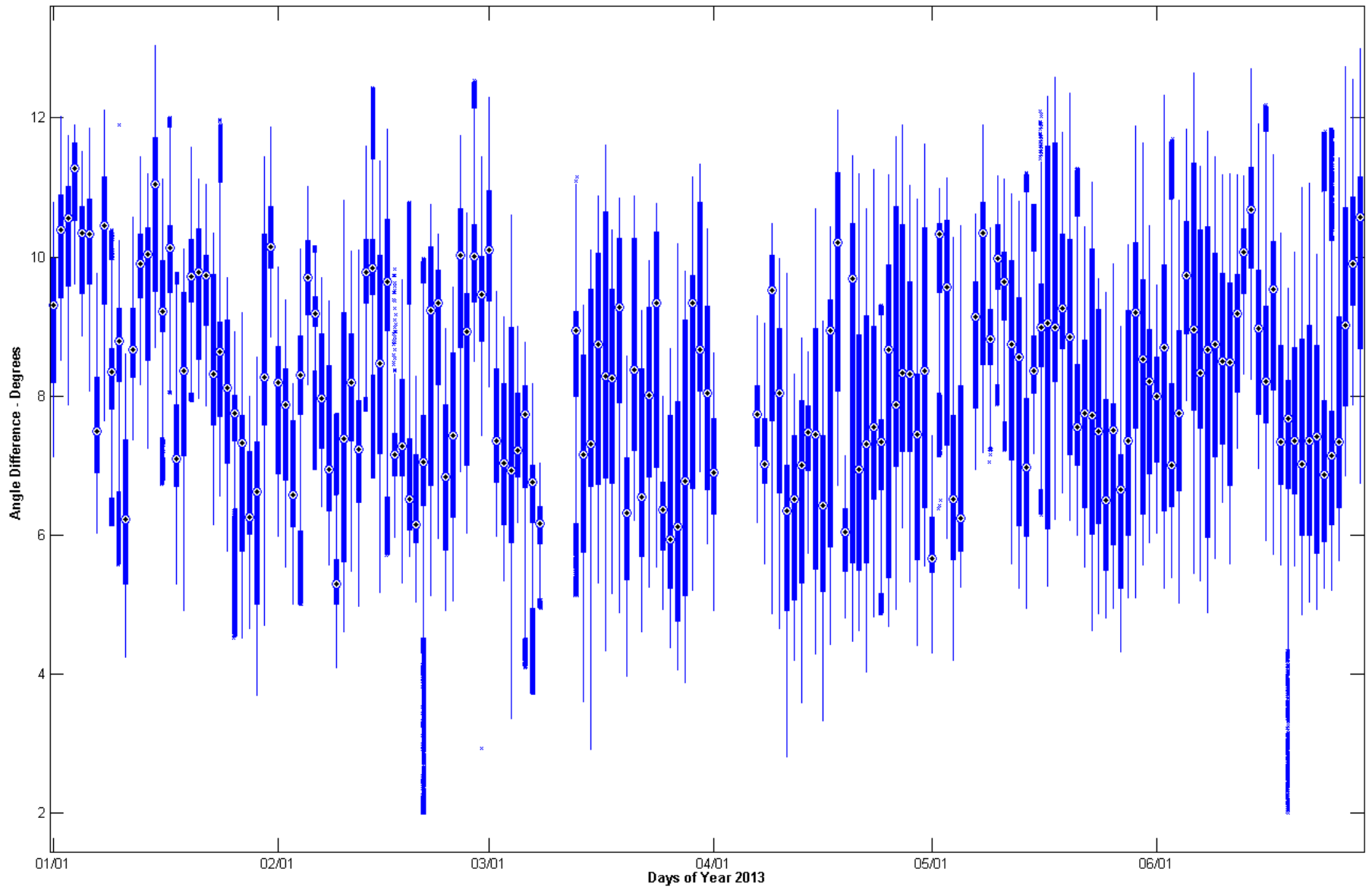
FarWest 7 – West 14



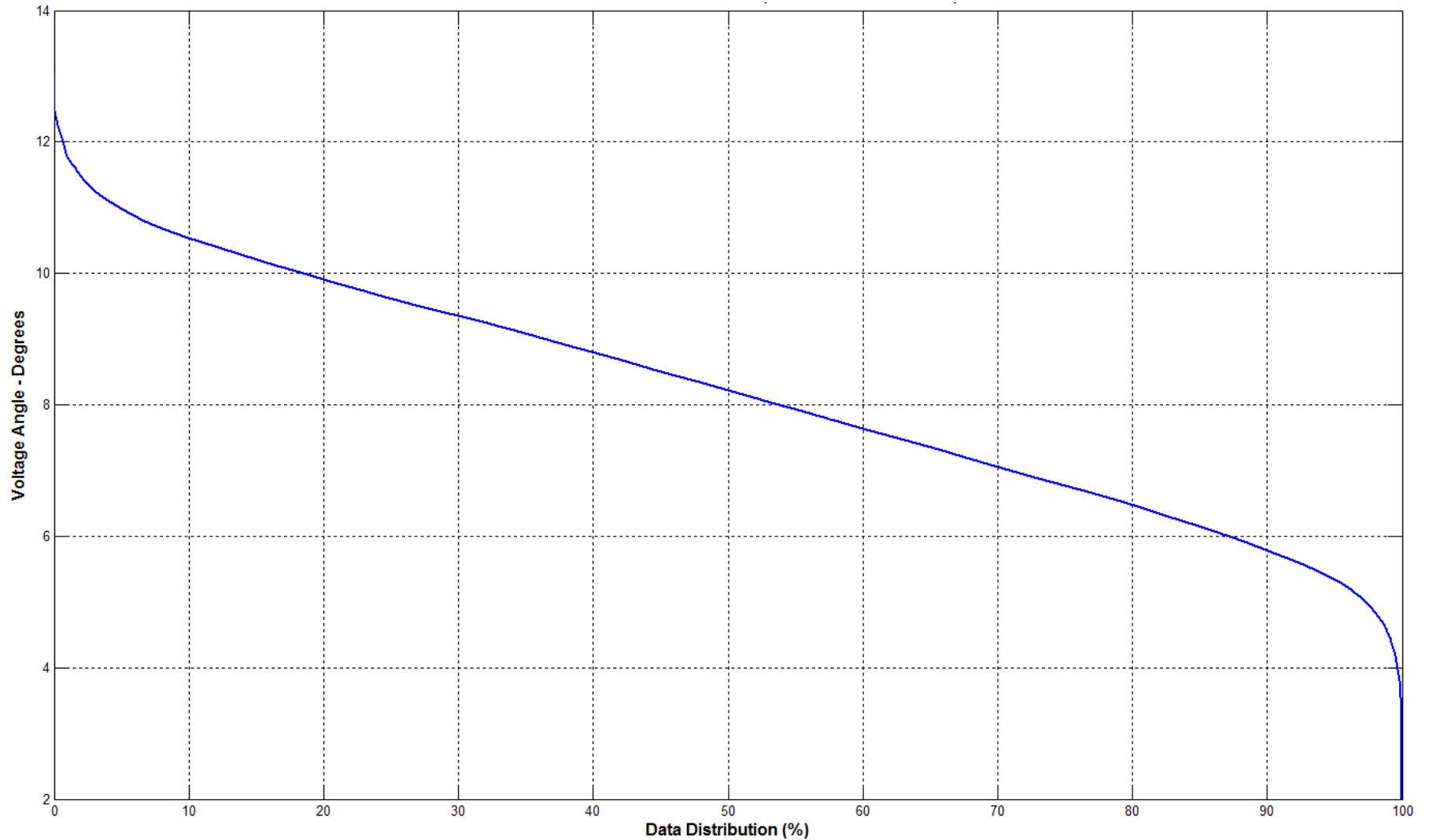
FarWest 7 – West 14



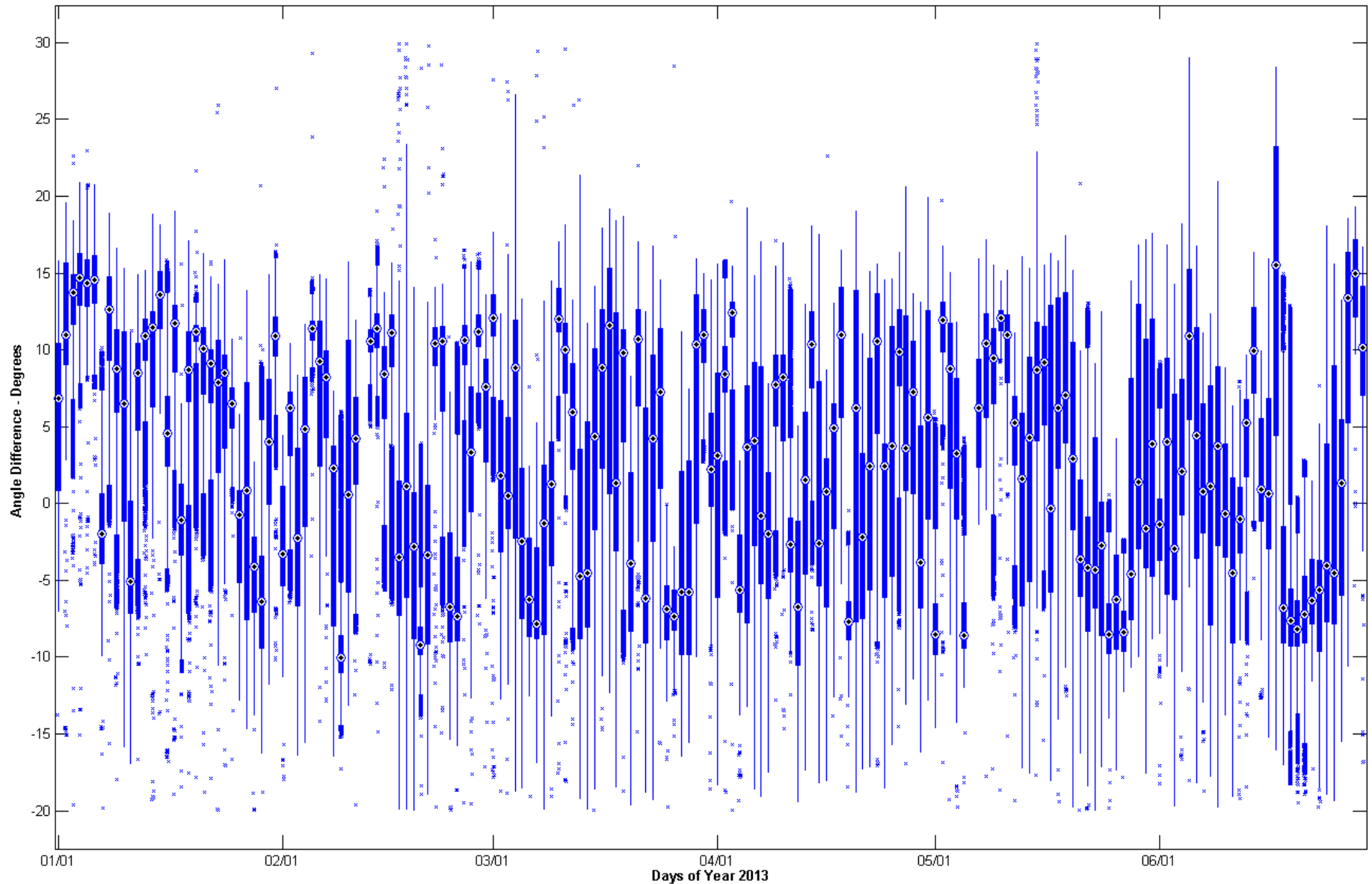
FarWest 7 – FarWest 8



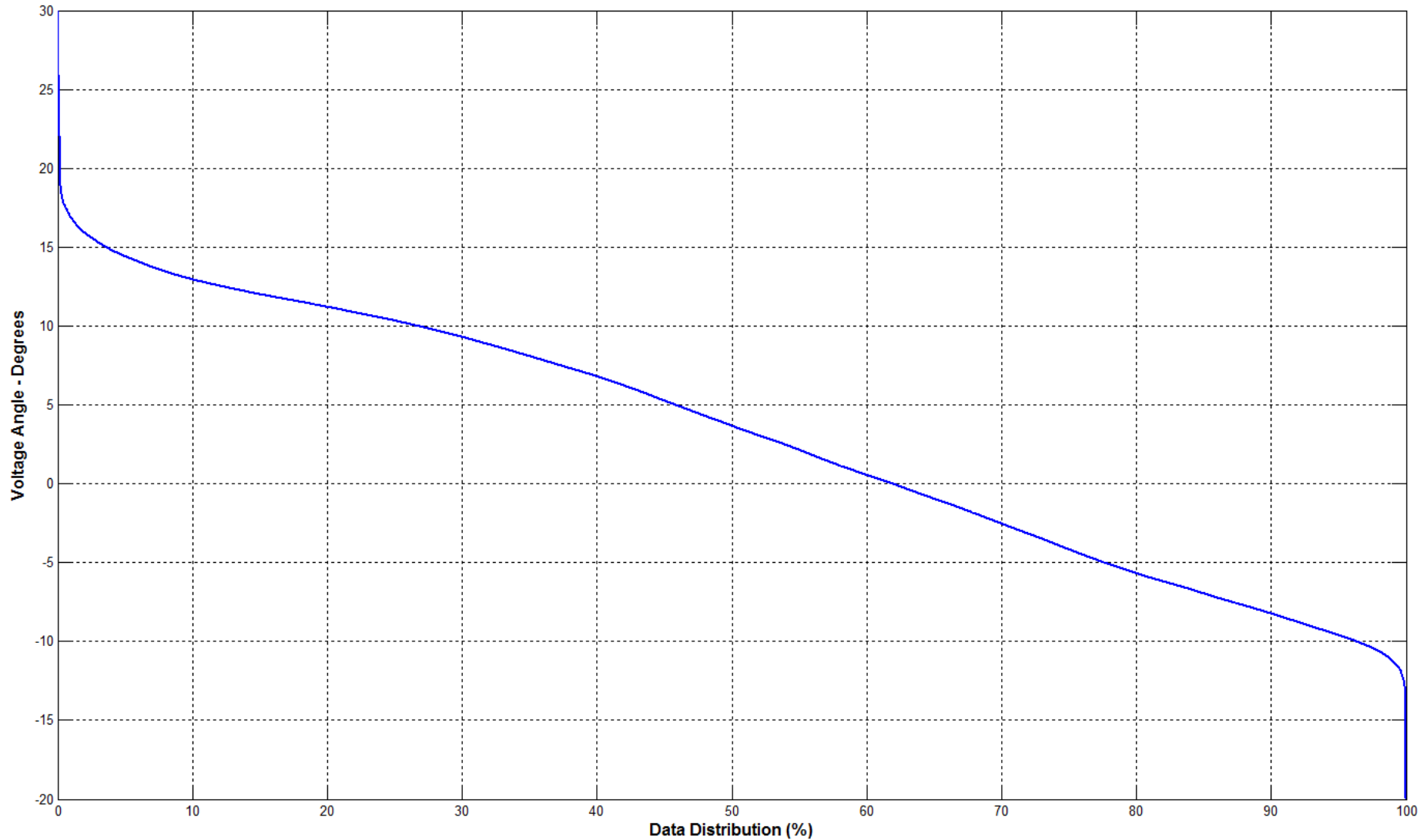
FarWest 7 – FarWest 8



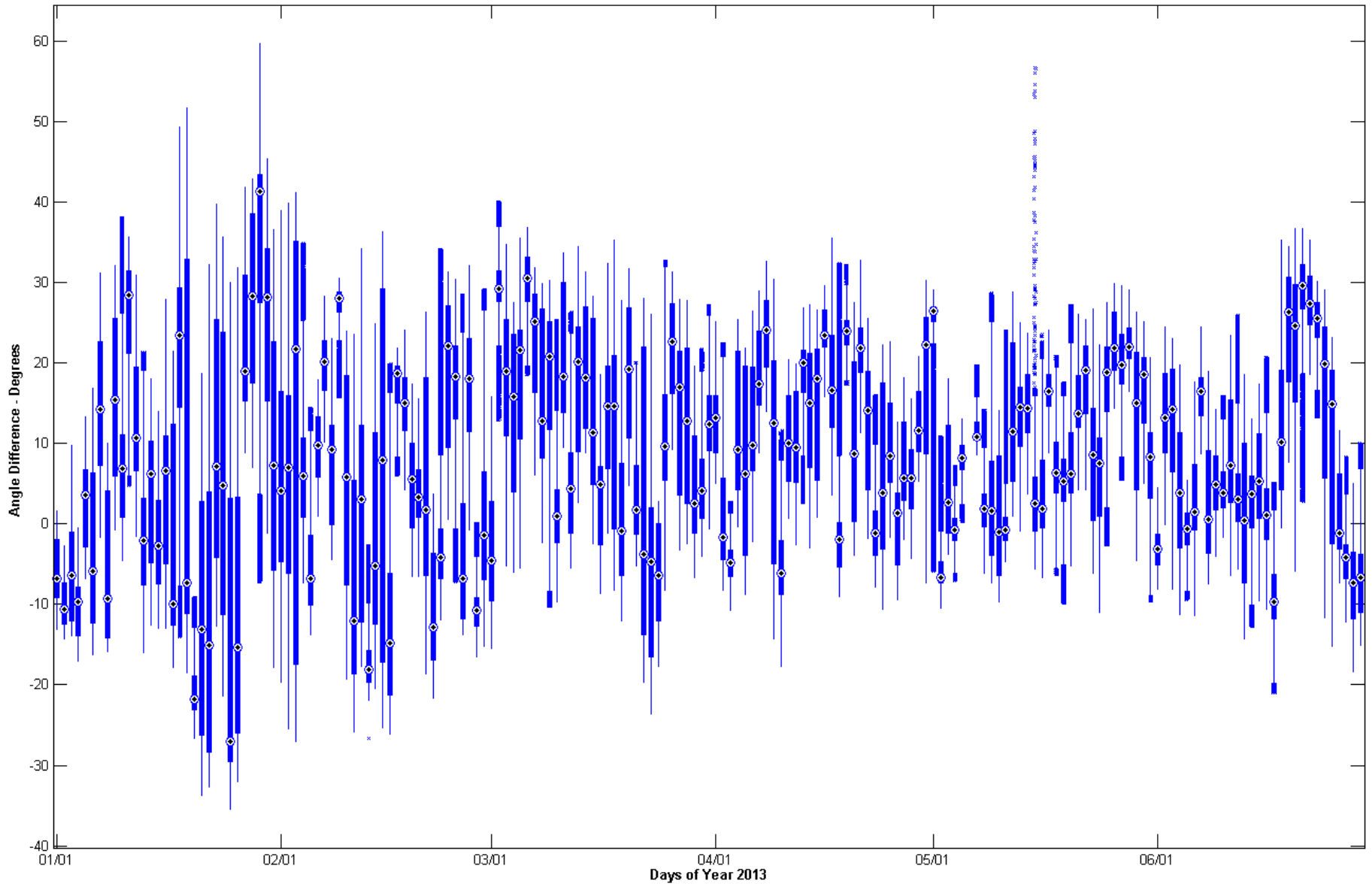
FarWest 7 – FarWest 9



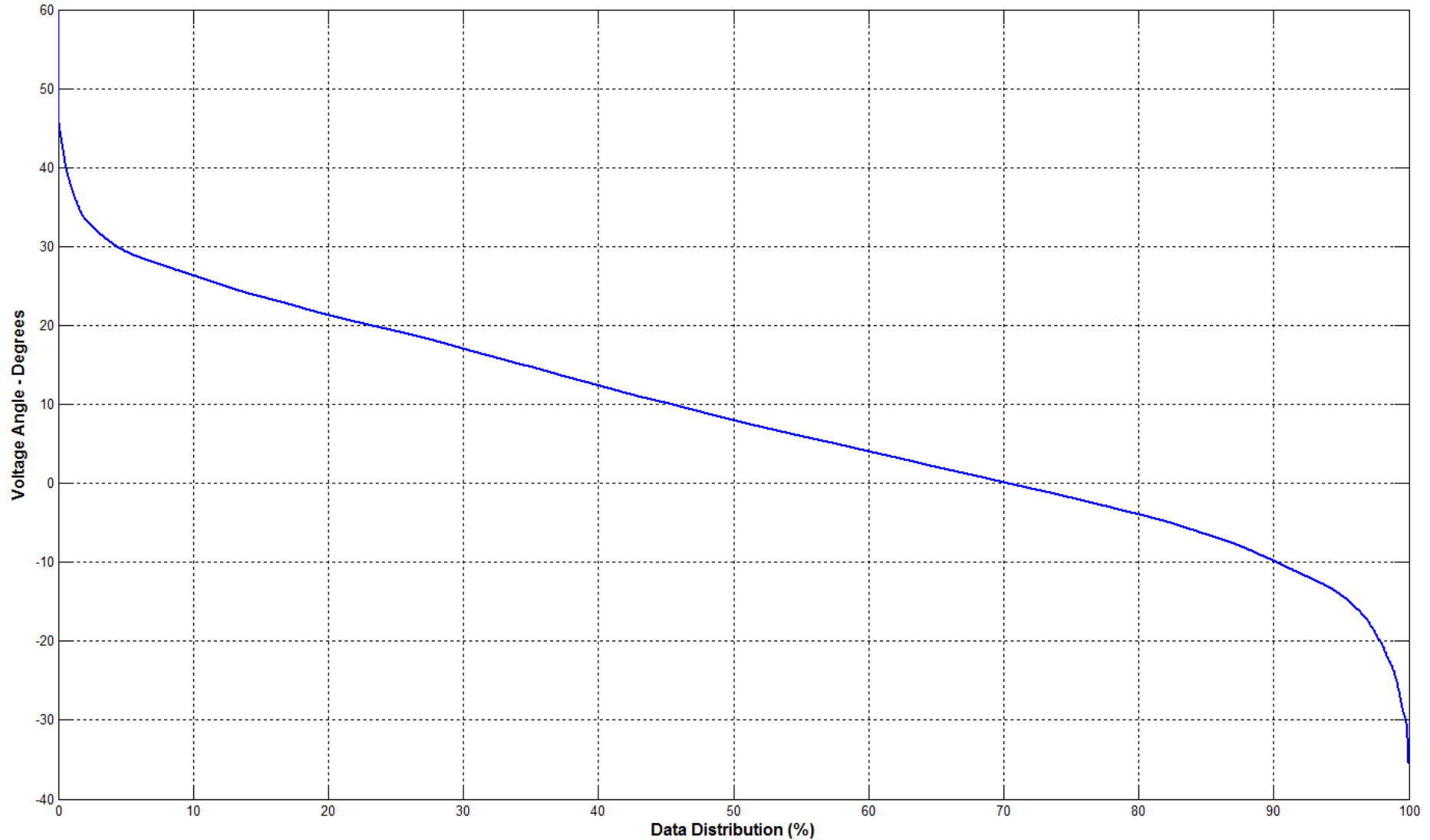
FarWest 7 – FarWest 9



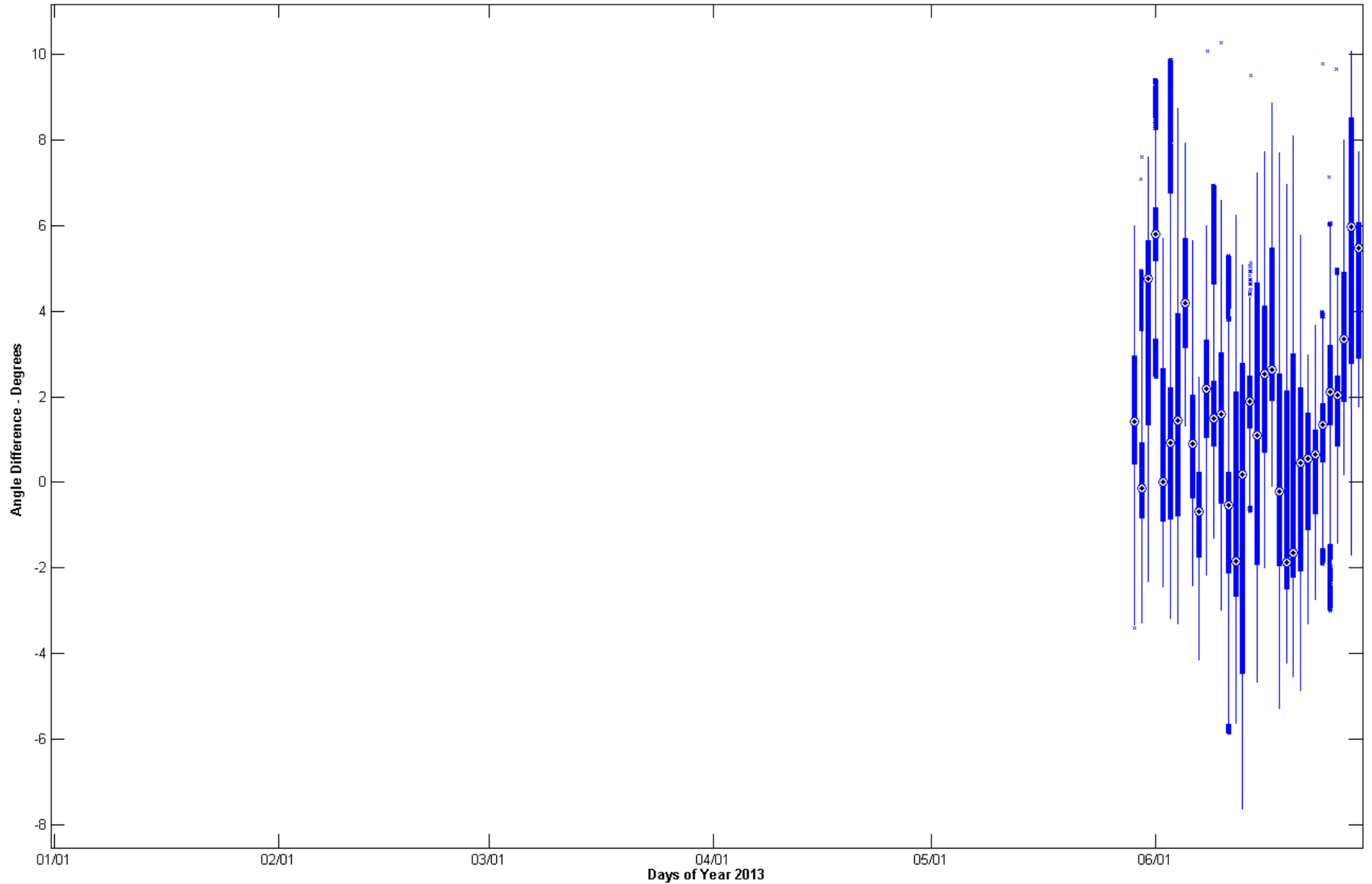
FarWest 7 – North 7



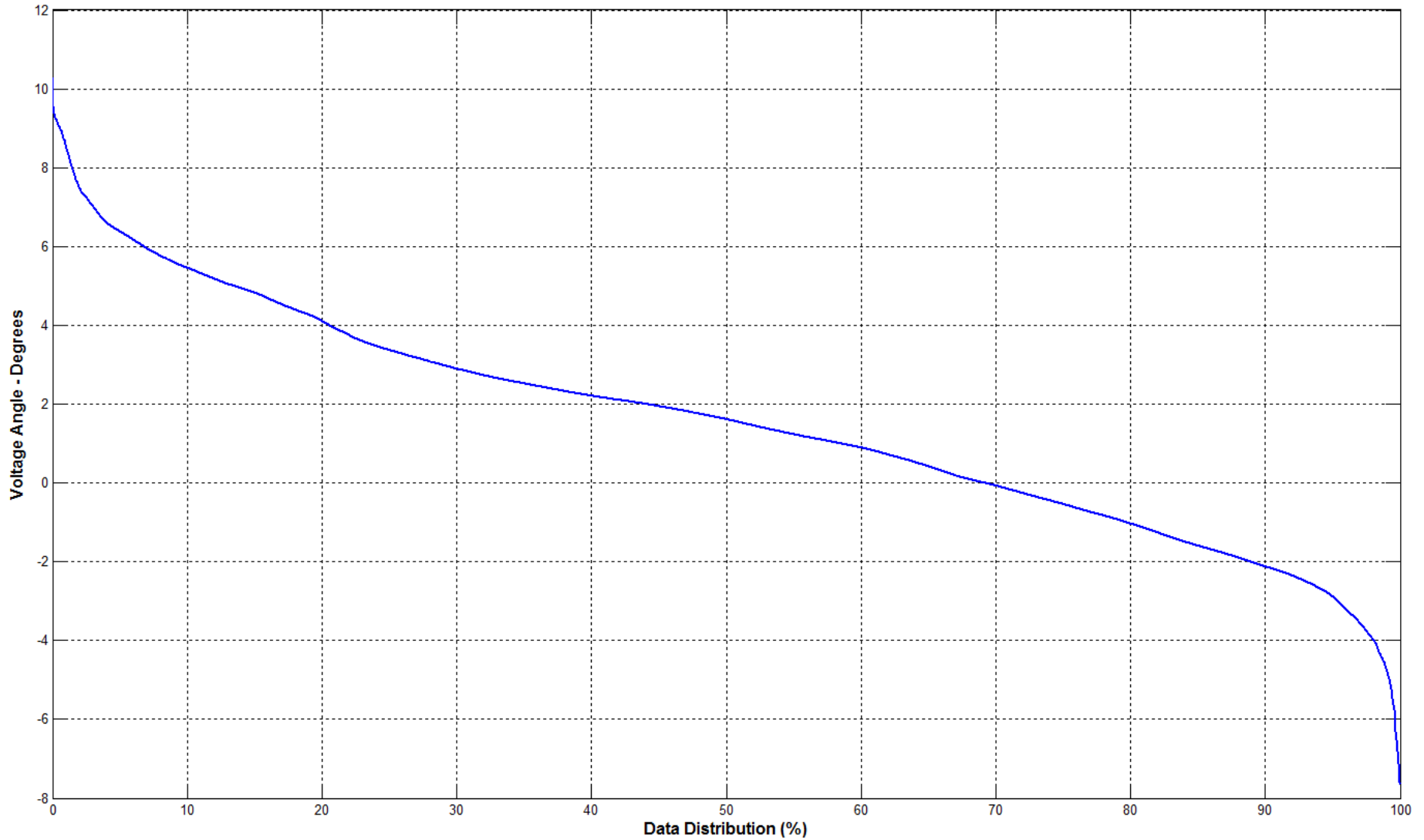
FarWest 7 – North 7



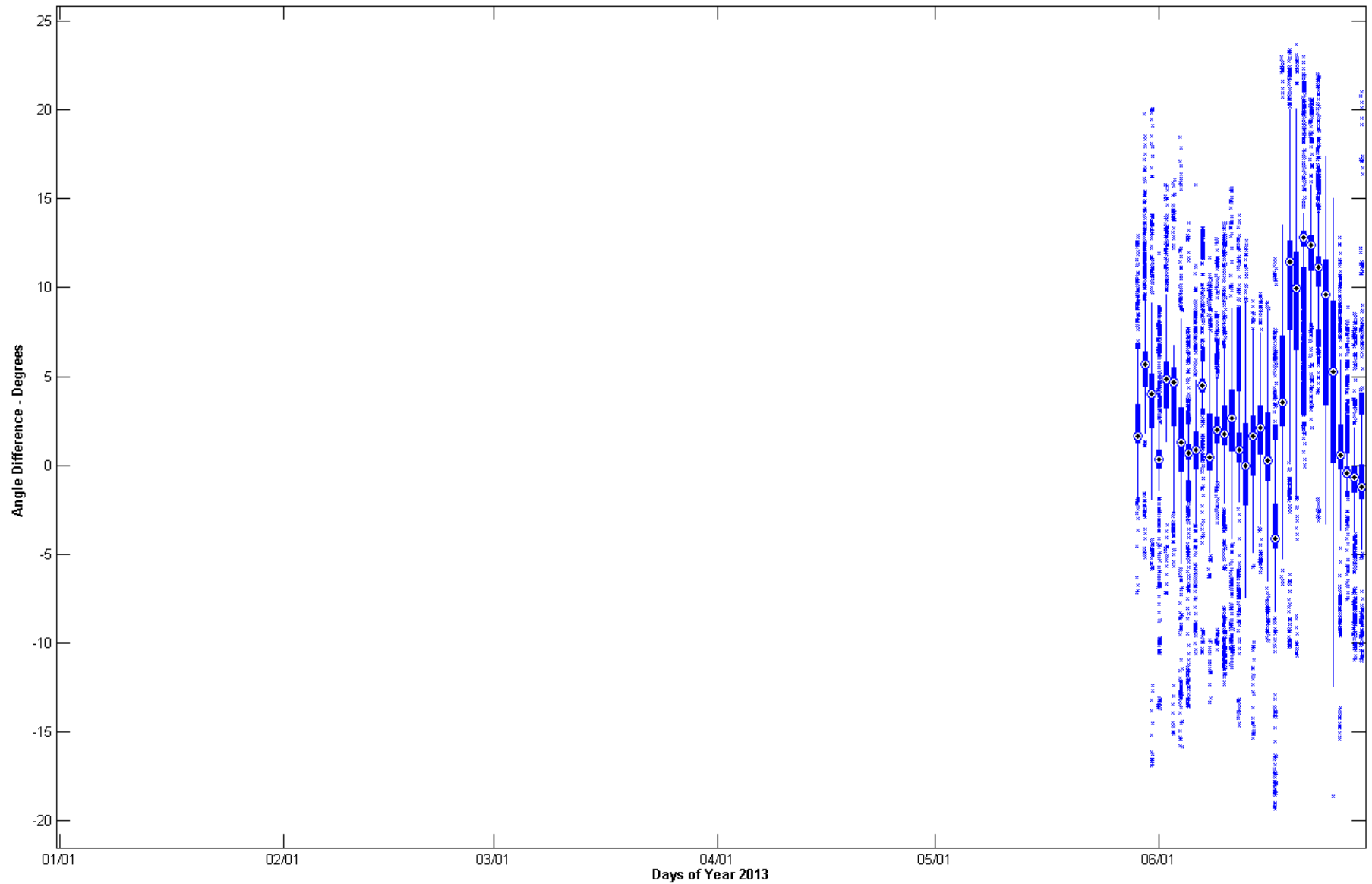
West 9 – FarWest 7



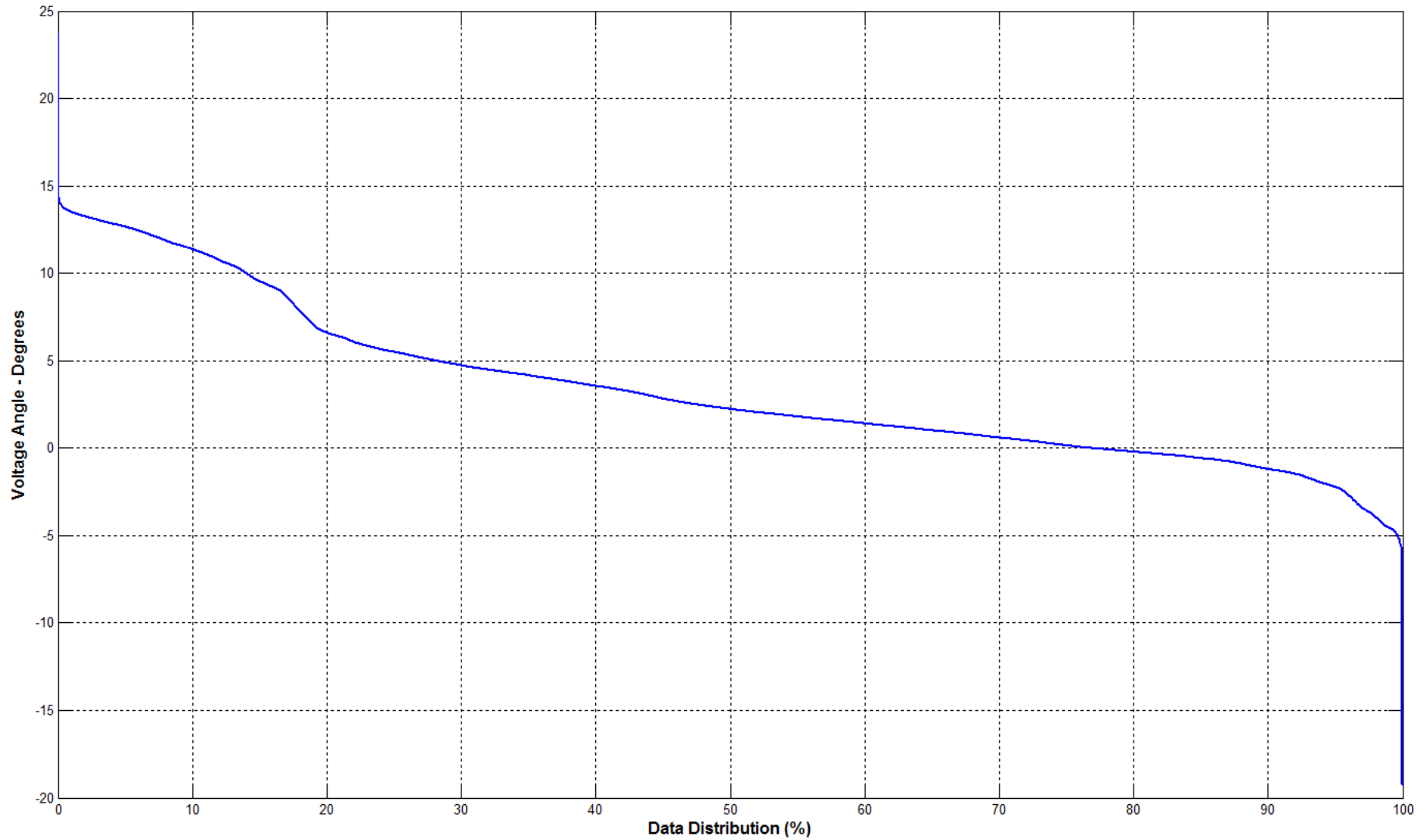
West 9 – FarWest 7



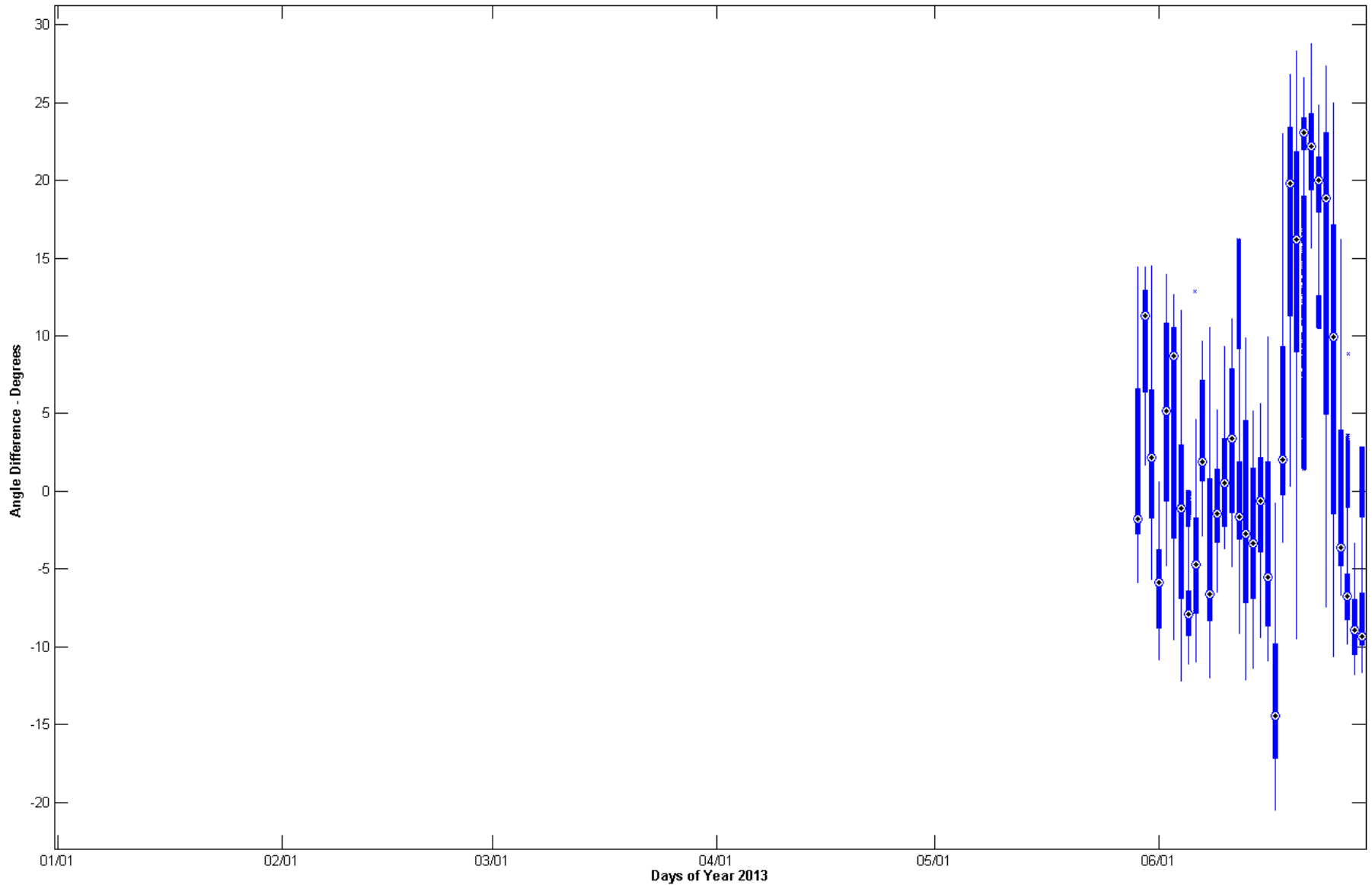
West 9 – West 1



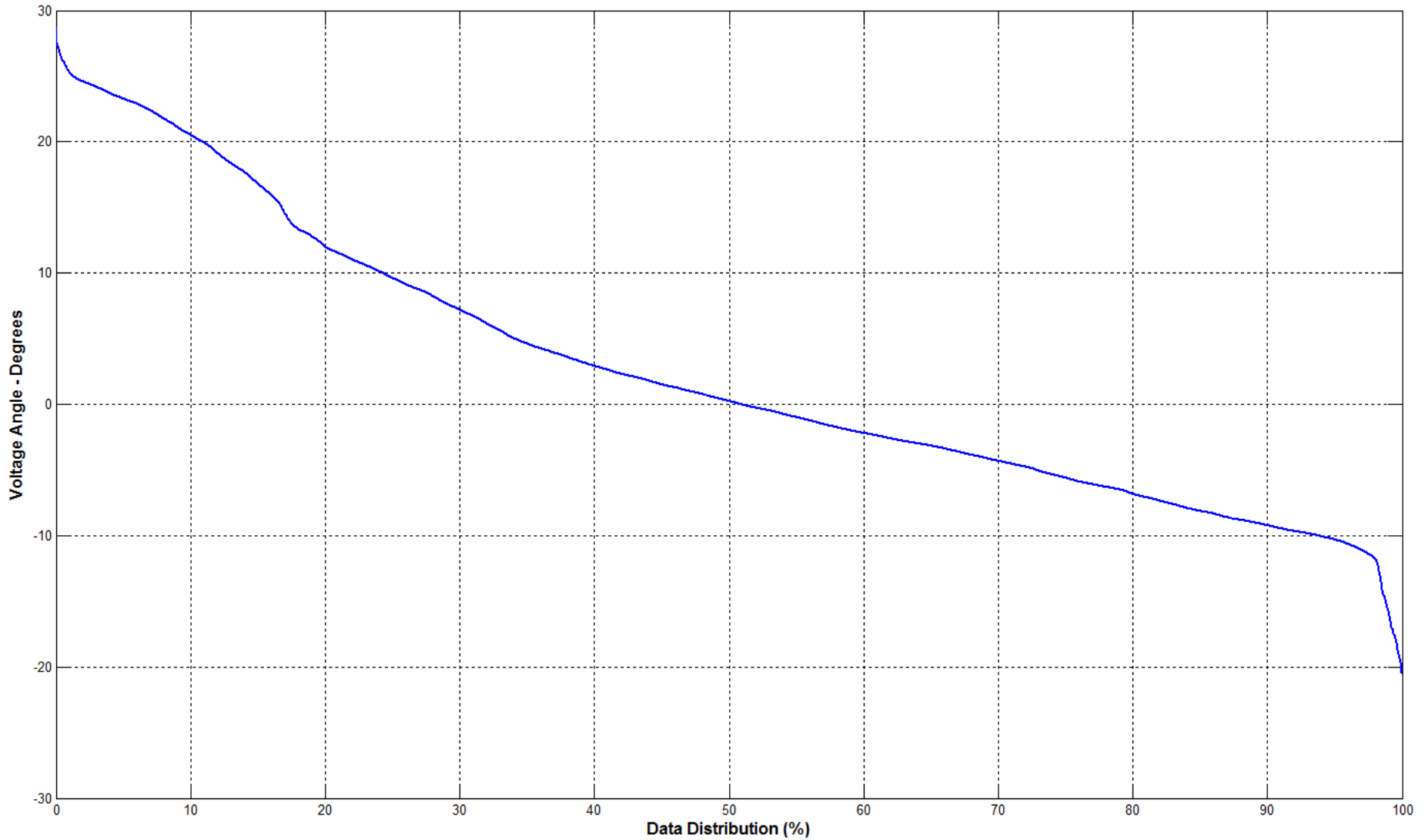
West 9 – West 1



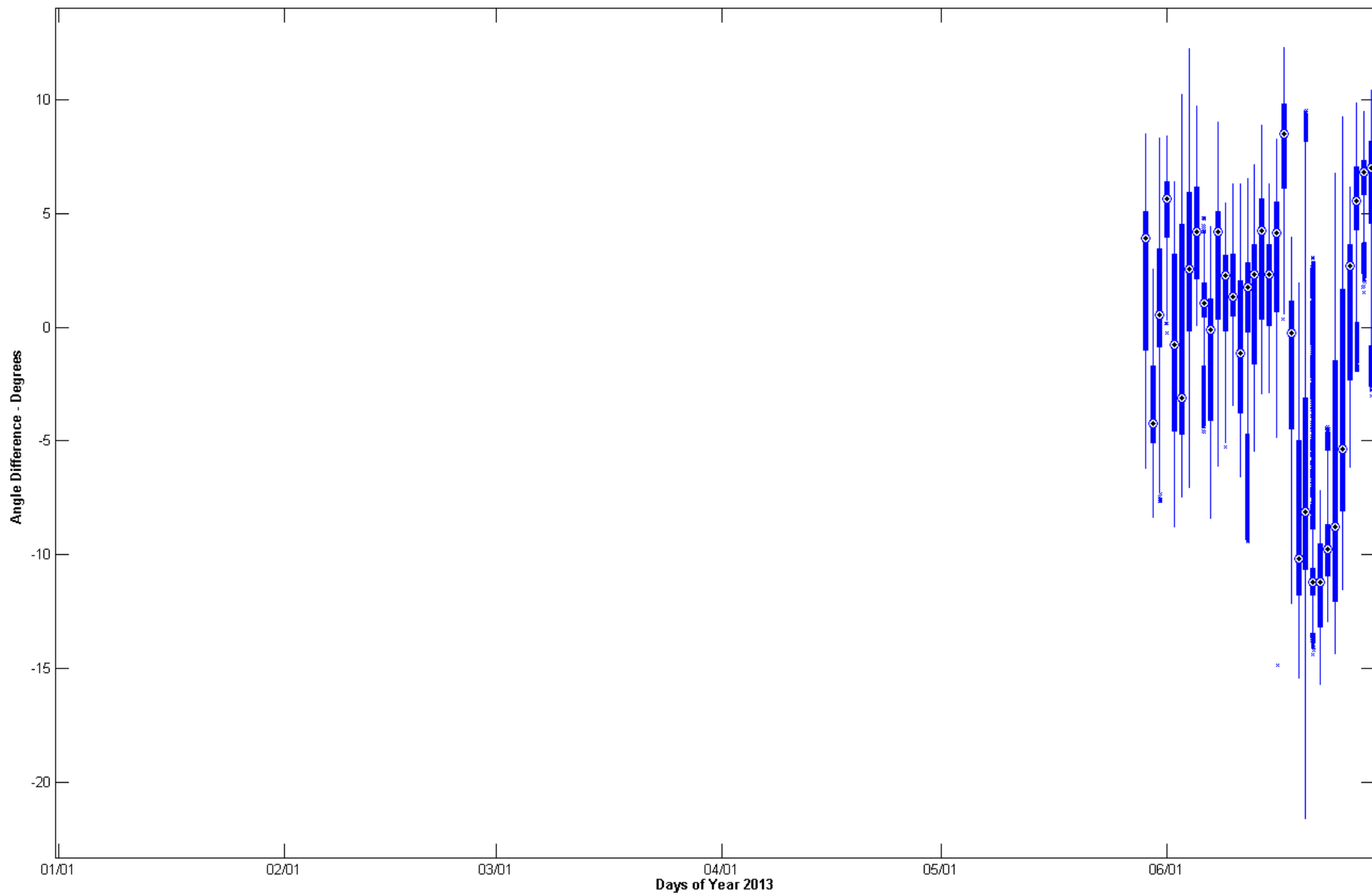
West 9 – North 1



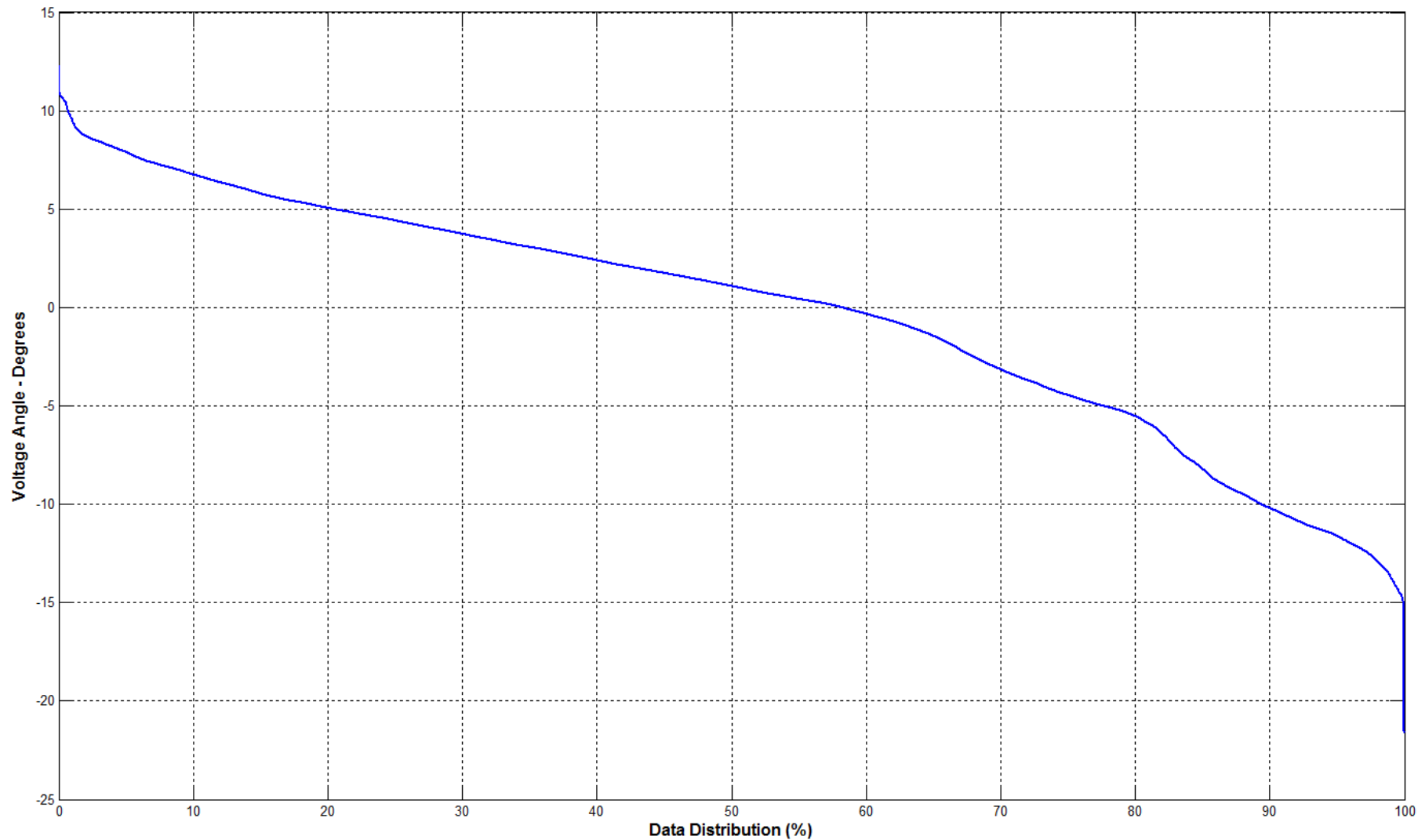
West 9 – North 1



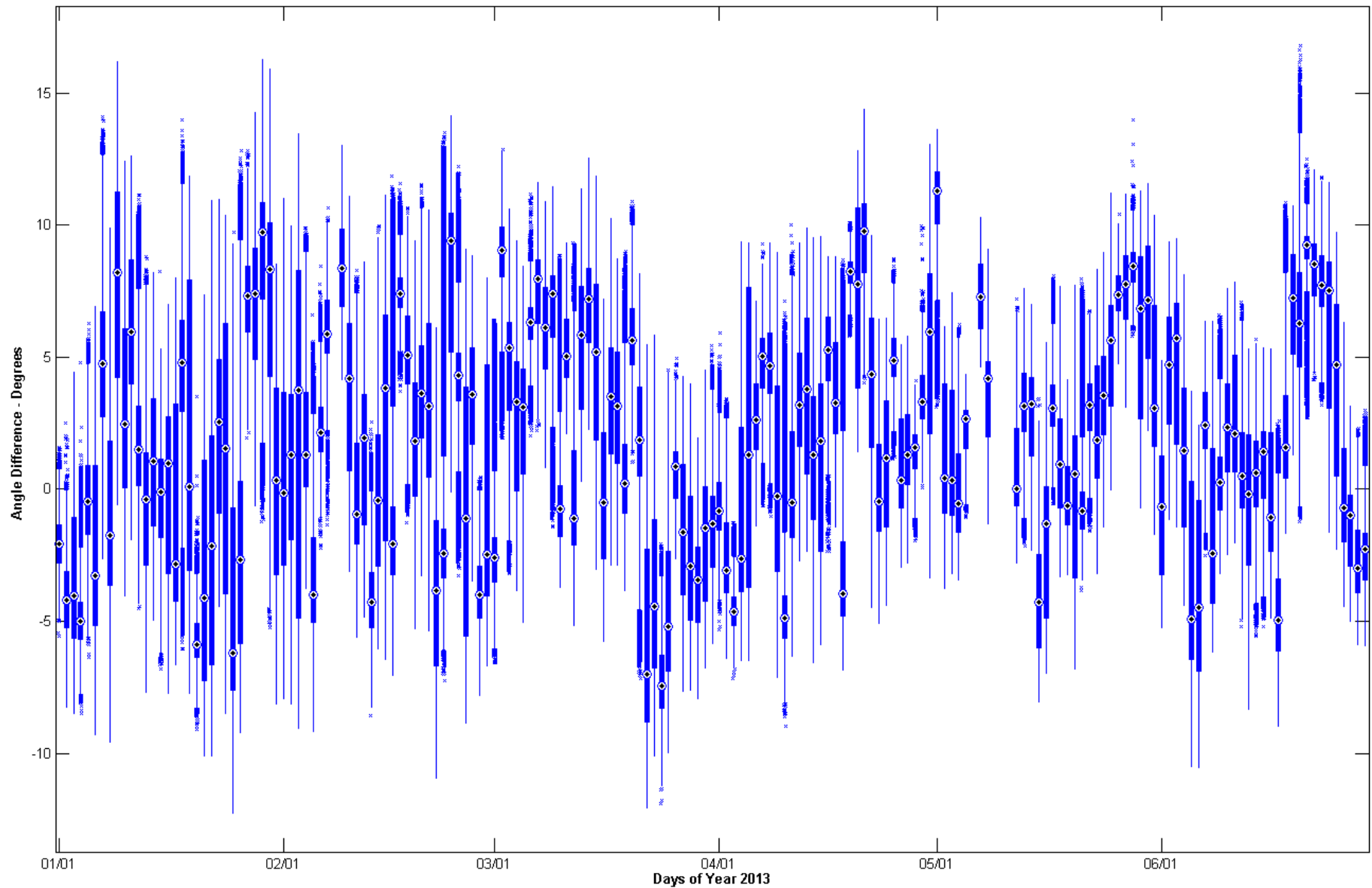
West 14 – West 5



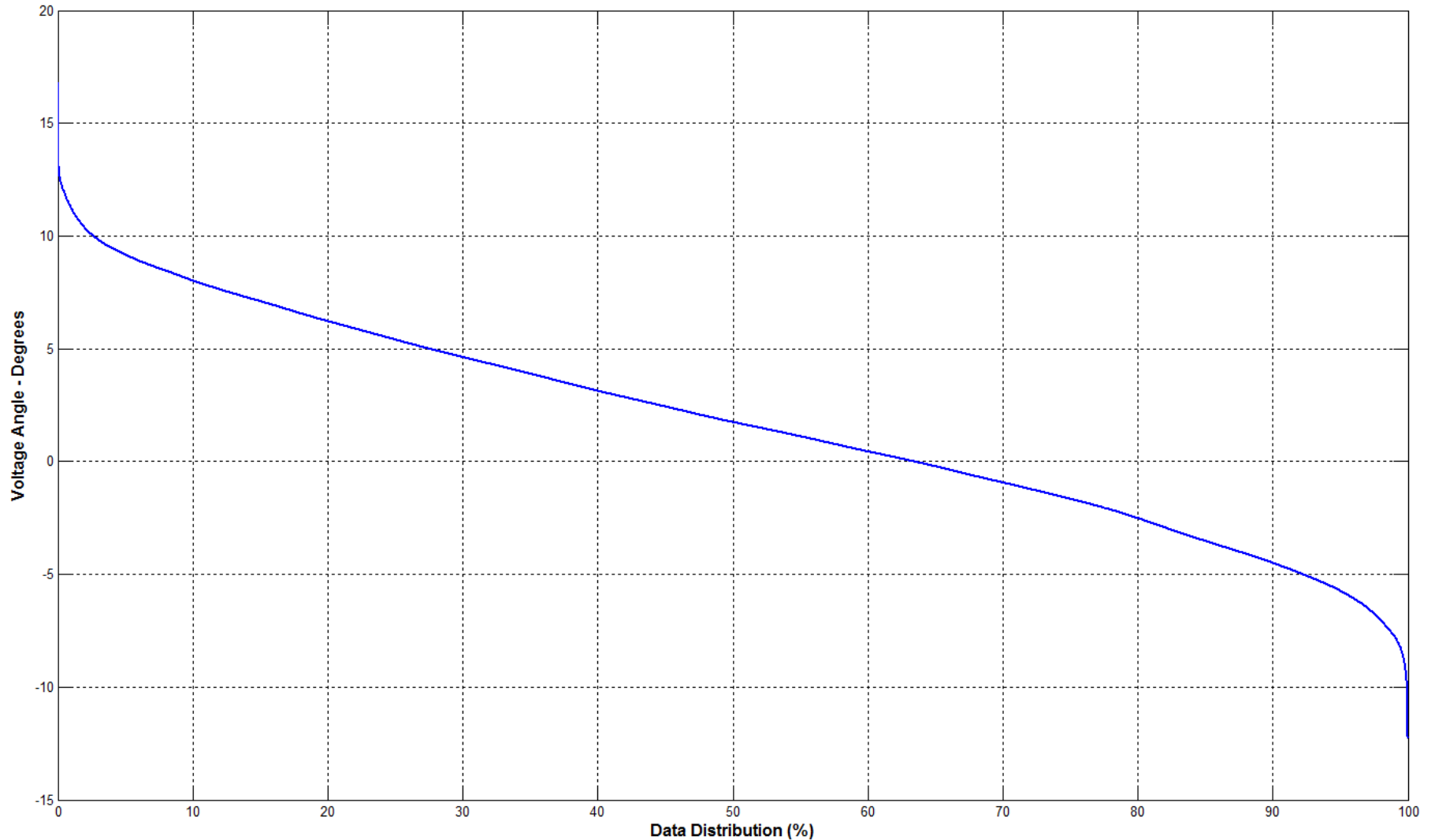
West 14 – West 5



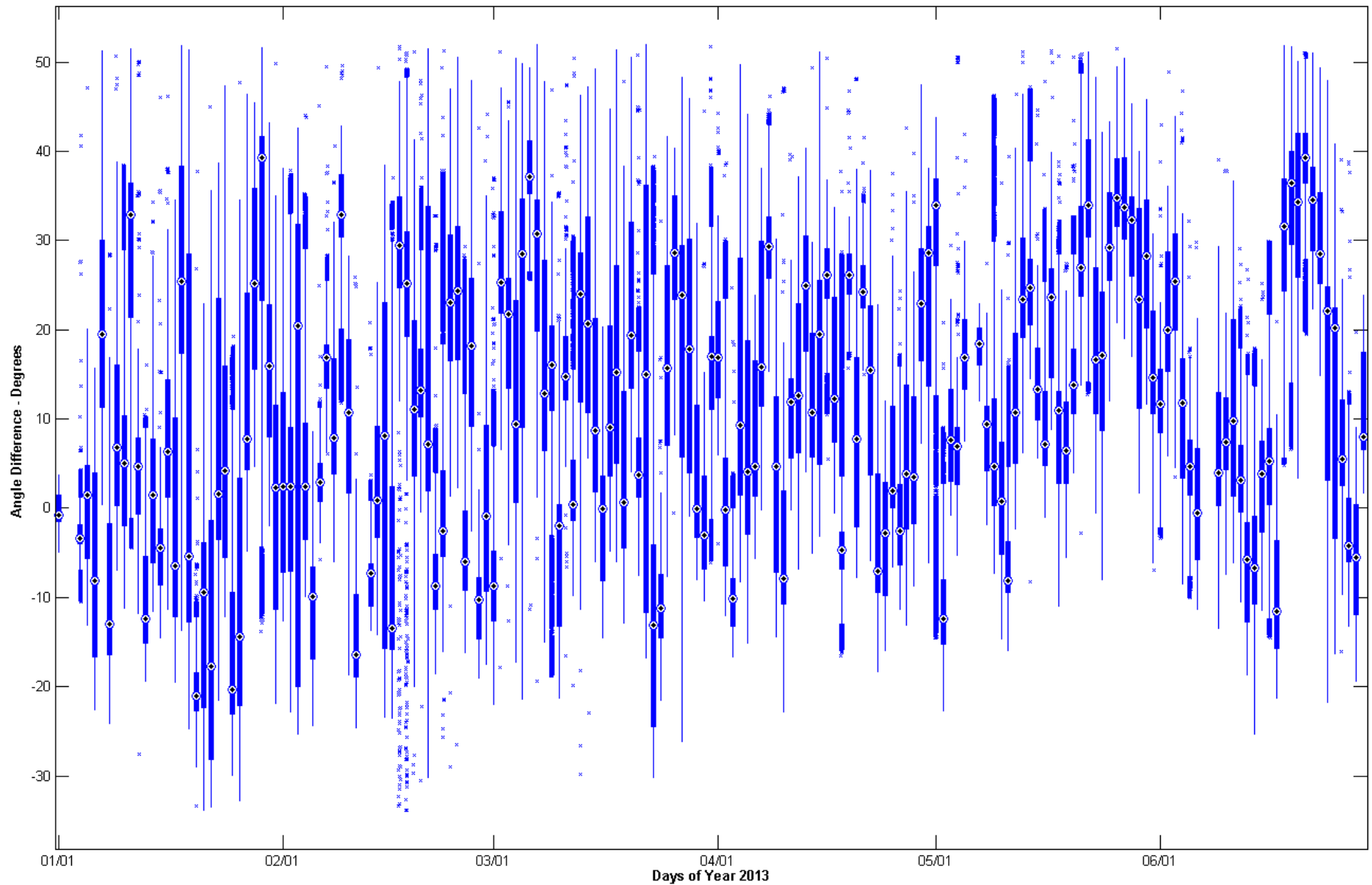
West 14 – North 1



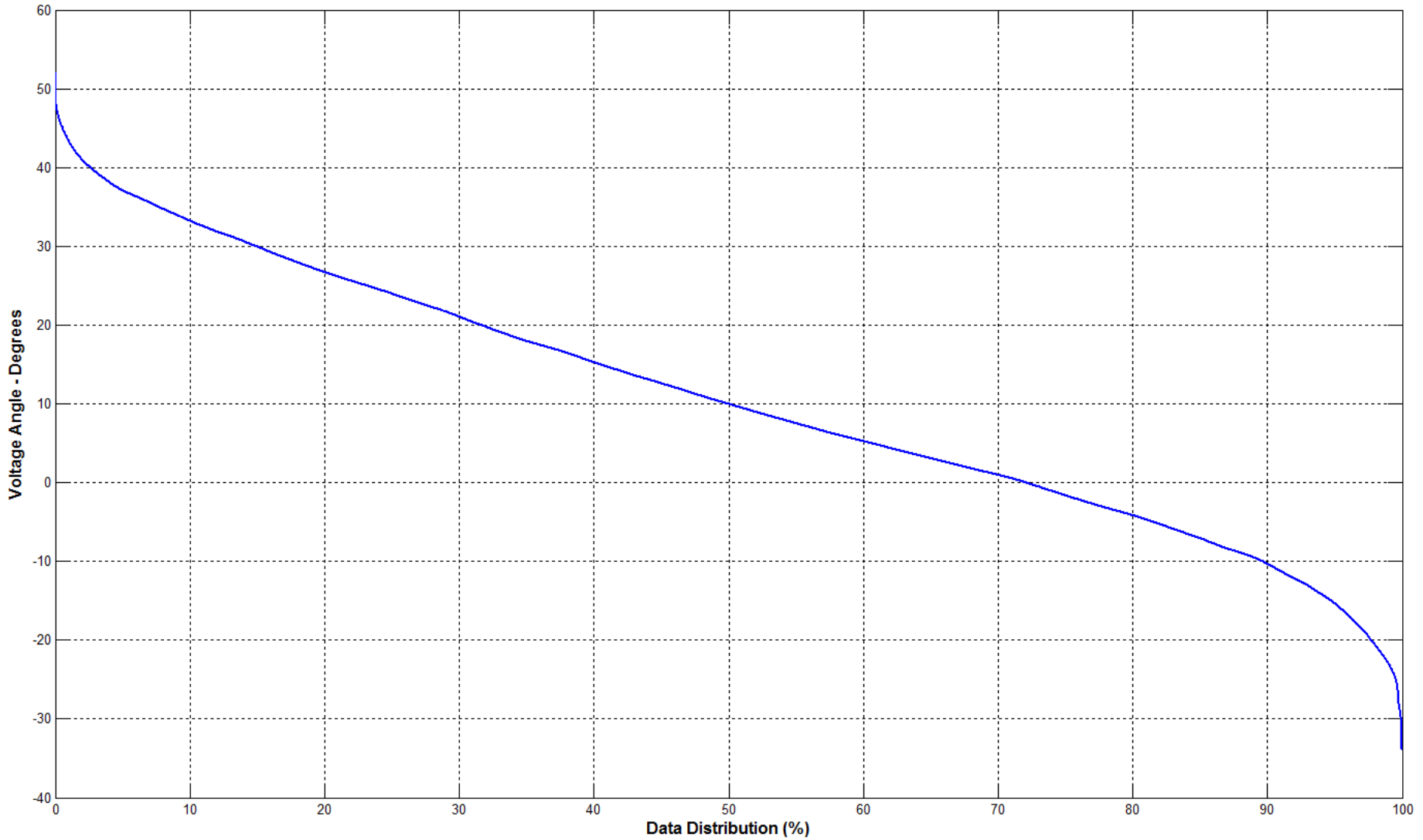
West 14 – North 1



FarWest 9 – West 4



FarWest 9 – West 4



**Attachment 4. Updated Baseline Study #2
for 2013**

Baselining Analysis Update 2:
2013, 12-Months Data
Discovery Across Texas Project

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External Version

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APPENDICES (attached as separate documents)

- A, Voltage Magnitude Box Whiskers& Time Duration
- B, Voltage Angles, Ref: North 7- Box Whiskers & Time Duration
- C, Angles Differences Box Whiskers & Time Duration

1. INTRODUCTION

The Center for Commercialization of Electric Technologies (CCET) was awarded contract DE-OE0000194 by the Department of Energy to perform the Discovery Across Texas demonstration project. Electric Power Group, LLC (EPG) received a sub award from CCET to provide professional services to perform, among other things, a substation cluster analysis, comparison of phasor data versus state estimator data, and voltage and angle difference baselining. In October 2013, EPG completed a Baselining Study update (Update 1) using 2012 and January-June 2013 data that included the following: (1) grouped substations having Phasor Measurement Units (PMUs), which are geographically close to each other and performed a voltage and angle difference analysis for each group (cluster analysis); (2) performed a comparison of voltage and angle differences obtained using phasor measurements versus similar results using state estimator data (phasor vs. state estimator comparison); and, (3) performed a baseline analysis for voltages and angle differences for selected pairs of substations. Alarm limits were established and documented based on the baseline analysis.

Thirty new Competitive Renewable Energy Zone (CREZ) 345 kV lines were added to the Electric Reliability Council of Texas (ERCOT) system in 2013, which will change the results obtained with the 2012 data, particularly in what is related to angle differences. Results shown in the Baselining Study Update 1 indicated that phasor data and state estimator data track very well and, therefore, EPG did not repeat that comparison study in this Baselining Update 2. Updated analysis was completed for the Baselining Analysis. The Cluster Analysis update will be completed as soon as EPG obtains peak load data and wind data from ERCOT.

Baselining Analysis Update 2 report provides results from the update analysis to track the changes in voltage magnitudes and in voltage angles caused by the new 345 kV lines added to the ERCOT system in the year 2013.

2. PROJECT SCOPE

A. Baseline Analysis for Voltage and Angle Differences

This study update analyzed historical performance of ERCOT grid, using State Estimator data plus phasor data for the January 2012 to December 2013 data to identify normal and abnormal voltages and angle limits across the grid. In this analysis, EPG compared the results obtained using 2013 data with those obtained using 2012 data and summarized the differences, if any, due to addition of the 345 kV lines added in 2013. Activities performed as part of this item:

1. Extract key metric information (i.e., voltage, angles and angle differences).
2. Analyze extracted data and develop baseline understanding of voltage, phase angle, and angle difference patterns for key substations and key pairs of substations. Substations were selected based on current or projected availability of PMUs at those substations.
3. Monitor voltages and angle differences (pairs) and develop patterns and statistics in the form of box-whisker plots and load duration curves. Substations selected for analysis of voltages are listed in Table 1 below and pairs of substations selected for analysis of angle differences are listed in Table 2 below.
4. Prepare baselining analysis results for the selected substations and pair of substations as Excel spreadsheet and charts, including:
 - a. Voltage statistics (mean, maximum and minimum).
 - b. Voltage phase angle difference statistics (mean, maximum and minimum).

- c. Voltage and phase angle distribution functions.
5. Develop a comparison table to show the differences in results for voltages and angle differences using 2012 and 2013 data.
6. Prepare baselining analysis summary for discussion with ERCOT and the Synchrophasor Team.

B. Establishing Alarm Limits for Use in Operations

Based on the baselining analysis, EPG will prepare a preliminary recommendation of key substations and angle pairs for monitoring in Real Time Dynamics Monitoring System¹ (RTDMS®), and voltage and angle difference alarm settings for use in RTDMS® to alert operators when grid stress is approaching limits.

This section will be completed in this report on a preliminary status. Nineteen new 345 kV lines were added to the ERCOT system in the second half of 2013 as part of the CREZ project, changing significantly the distribution of power among the existing and new transmission lines. This will result in changes in limits for voltages, voltage angles, and particularly angle differences. Recommending alarm limits based on 2013 data will only be preliminary. As requested by ERCOT, EPG plans to conduct a baselining analysis Update 3 using data for the first five months of 2014. Please note that a few kV lines were added in late March 2014, which may change the alarm limits for a few pairs near those new lines. Final voltage and angle difference limits for use by operators should be reviewed with data collected from the months of April to September 2014; the ERCOT system will have no new CREZ lines added to it during this period, and the angle difference ranges base of alarm limits should be stable. Also, the data availability should be similar during this period for all the angle pairs under analysis resulting in a more current and accurate alarm limits.

3. DATA SOURCES

Two sources of data were utilized to perform the study update analysis of voltage and angle differences in the ERCOT network: phasor data and state estimator cases. A description of these sources of data is provided below.

A. Phasor Data

ERCOT provided EPG phasor data for the entire year 2013 with a resolution of 30-samples per second (SPS). EPG performed the following actions on the phasor data provided by ERCOT prior to using it for statistical analysis:

1. Download the ERCOT data provided in MySQL format.
2. Convert ERCOT binary format data into alphanumeric format.
3. Convert MySQL data to comma-separated value (CSV) data files for use in MatLab data analysis programs.
4. Link ERCOT data through the MySQL server to the EPG local *enhanced* Phasor Data Concentrator (ePDC™) database tool to allow downloading as CSV files to the local computer.

¹ Electric Power Group. Built upon GRID-3P platform, US Patent 7,233,843, US Patent 8,060,259, and US Patent 8,401,710. All rights reserved.

5. Down sample phasor data from 30 SPS to 1 SPS, and download it to the local computer for analysis.
6. Apply status flag filtering to perform the first step in data cleaning.
7. Develop data filtering algorithms and write code in MatLab to perform the second step of data filtering.
8. Address small data dropouts by interpolation techniques or fill dropouts with blanks.

This process of data setup, downloading, cleaning, and data dropout fixing has now been automated to reduce the time taken to process the data from the time received to the time when the data is suitable for analysis. However, further manual cleaning is necessary to weed out remaining outliers. In some cases, the phasor data was simply not of good quality, in those cases this report will point out those PMUs with bad data for review by their owners.

After the data was extracted and processed, another program, developed by EPG, was used to extract the information and compile it into a summary table, and two series of graphs. One graph (box -whisker) shows daily summaries of data, and the other, time duration curves, shows values versus percent time for each study variable. The time duration curves were used to obtain the metric values corresponding to 1% and 99% exceedance (the value which was less than 1% plus inflection or greater than 99% minus inflection).

Phasor Measurement Units (PMUs) Installed and Planned in ERCOT

As of December, 2013 there were 69 PMUs installed in 31 locations across the ERCOT service area. Table 1 below shows the 31 substation equipped with PMUs.

The baselining study update 2 was completed using data from the twelve months of 2013 that included state estimator data analysis for locations for which PMUs are installed and for which PMUs are planned.

Table 1 – List of Substations with PMUs Currently Connected to the ERCOT Grid, as of March 10, 2014

| TABLE 1 - List of Substations with PMUs Currently Connected to the ERCOT Grid As of March 10, 2014 | | | | | | | |
|---------------------------------------------------------------------------------------------------------------|-----------|-----------------|---------------------|------------------------------------------|-------------------------------------|---------|---------|
| # | Company | PMU Name | PMU Name in D. Base | Name of the Station where PMU is located | Date-data stream connected to ERCOT | Enabled | Base kV |
| 1 | AEP | Line_1 | Line_1@ West 14 | West 14 | 7/25/2012 | Yes | 345 |
| 2 | AEP | Line_3 | Line_3@West_4 | West 4 | 7/2/2012 | Yes | 138 |
| 3 | AEP | Coast 3 TR1-345 | Coast_3 TR1-345 | Coast 3 | 4/30/2012 | Yes | 345 |
| 4 | AEP | Coast 4 TR1-345 | Coast_4 TR1-345 | Coast 4 | 3/26/2012 | Yes | 345 |
| 5 | AEP | Line_1 | Line_1@Coast_1 | Coast 1 | 1/23/2012 | Yes | 138 |
| 6 | AEP | Line_1 | Line_1@FarWest_9 | FarWest 9 | 3/26/2012 | Yes | 138 |
| 7 | AEP | West_10 | West_10 | West 10 | 8/1/2008. | Yes | 69 |
| 8 | AEP | Line_1* | Line_1@West 15 | West 15 | 9/16/2013 | Yes | 345 |
| 9 | AEP | Line_1* | Line_1@West16 | West 16 | 12/19/2013 | Yes | 345 |
| 10 | AEP | Line_1* | Line_1@West_3 | West 3 | 12/19/2013 | Yes | 345 |
| 11 | AEP | Line_1 | Line_1 | Coast 2 | ?/2012 | Yes | 69 |
| 12 | AEP | Line_1 | Line_1@FarWest 2 | FarWest 2 | 6/21/2013 | Yes | 69 |
| 13 | AEP | Line_1 | Line_1@South_3 | South 3 | 6/21/2013 | Yes | 138 |
| 14 | AEP | Line_1 | Line_1@South_3 | South 5 | 6/21/2013 | Yes | 69 |
| 15 | AEP | Line_1 | Line_1@West_7 | West 7 | 6/21/2013 | Yes | 138 |
| 16 | ONCOR | North_4 | North_4 | North 4 | 10/20/2010 | Yes | 138 |
| 17 | ONCOR | North_5 | North_5 | North 5 | 10/20/2010 | Yes | 138 |
| 18 | ONCOR | North_6 | North_6 | North 6 | 10/20/2010 | Yes | 138 |
| 19 | ONCOR | North_7 | North_7 | North 7 | 10/20/2010 | Yes | 138 |
| 20 | ONCOR | FarWest_4 | FarWest_4 | FarWest 4 | 10/20/2010 | Yes | 345 |
| 21 | ONCOR | West_11 | West_11 | West 11 | 3/9/2012 | Yes | 345 |
| 22 | ONCOR | FarWest_7 | FarWest_7 | FarWest 7 | 10/20/2010 | Yes | 345 |
| 23 | ONCOR | FarWest_8 | FarWest_8 | FarWest 8 | 3/9/2012 | Yes | 138 |
| 24 | ONCOR | West_6 | West_6 | West 6. | 10/20/2010 | Yes | 345 |
| 25 | ONCOR | North_1 | North_1 | North 1 | 11/28/2012 | Yes | 345 |
| 26 | ONCOR | West_9 | West_9 | West 9 | 6/21/2013 | Yes | 345 |
| 27 | ONCOR | West12 | West12 | West 12 | 6/21/2013 | Yes | 345 |
| 28 | ONCOR | West_5 | West_5 | West 5 | 6/21/2013 | Yes | 345 |
| 29 | ONCOR | West_2 | West_2 | West 2 | 6/21/2013 | Yes | 345 |
| 30 | ONCOR | West_1 | West_1 | West 1 | 6/21/2013 | Yes | 345 |
| 31 | SHARYLAND | South13 | South13 | South 13 | 8/10/2012 | Yes | 138 |

Note: * Means new substations with PMU connected to ERCOT grid

B. State Estimator (SE) Data

ERCOT provided EPG with SE data for the 12-months of 2013. EPG used the PowerWorld simulator provided by ERCOT via PowerWorld, to extract approximately 23,708 SE cases. There were 126-days for which SE data was not available, as shown below:

| Dates for Which SE data was not available (12-months of 2013) | |
|--------------------------------------------------------------------------|------------|
| Dates | Days |
| All of January | 31 |
| 03/23 to 03/26/2013, 03/28 to 03/31/2013 | 8 |
| 07/22 | 1 |
| 08/02-08/05, 08/20-08/31 | 16 |
| 09/01-09/28 | 28 |
| 11/06-11/11, 11/1-11/19, 11/22-11/30 | 22 |
| 12/03-12/10, 12/12-12/17, 12/26-12/31 | 19 |
| Total | 126 |

C. Data Availability

Data availability for the phasor data sources varied from substation to substation; the summary table of phasor-based results shows the percent availability for each substation or each pair analyzed. As shown in Table A-1, availability varies from substation to substation and ranges from less than 20% for West 16, West 3 and West 15 (which were installed in late 2013), to greater than 90% for nine PMUs. No phasor data was reported for North 2 and South 6. Box-whisker plots in Appendix A provide a view of data availability on a day-by-day basis.

For state estimator (SE) data availability, ERCOT produces state estimator cases every 5-minutes for a total of 105,120 possible cases per year. EPG received approximately 23,708 cases, which means the availability of SE data for the 12-months of 2013 was approximately 22.6 % data availability. SE data availability for 2013 improved to almost double that of the 2012 SE data. However, as shown above, SE data availability can improve further by reducing to a minimum the number of days SE data is not available.

Below a summary of phasor data availability from Table A-1 for 2012 and for 2013:

| <u><20%</u> | <u>20% to 60%</u> | <u>61% to 80%</u> | <u>>80%</u> |
|--------------------|-------------------|-------------------|----------------|
| <u>2013</u> | | | |
| West 16 | West 1 | West 14 | West 10 |
| West 3 | West 2 | West 4 | West 11 |
| West 15 | West 9 | Coast 4 | West 6 |
| | West 12 | Coast 3 | North 1 |
| | West 5 | | North 4 |
| | FarWest 2 | | North 5 |
| | South 3 | | North 6 |
| | South 5 | | North 7 |
| | | | Coast 2 |
| | | | Coast 1 |
| | | | South 13 |
| | | | FarWest 4 |
| | | | FarWest 7 |
| | | | FarWest 8 |
| | | | FarWest 9 |
| <u>2012</u> | | | |
| <u><40%</u> | <u>41% to 60%</u> | <u>61% to 80%</u> | <u>>80%</u> |
| West 14 | West 4 | West 11 | West 10 |
| North 1 | Coast 4 | Coast 1 | North 7 |
| Coast 2 | Coast 3 | FarWest 8 | North 2 |
| South 6 | South 13 | | North 4 |
| FarWest 7 | FarWest 9 | | North 5 |
| | | | West 6 |
| | | | North 6 |
| | | | FarWest 4 |

4. BASELINE ANALYSIS FOR VOLTAGE MAGNITUDE AND VOLTAGE ANGLE (Ref: North 7)

This baseline analysis update for voltages magnitude and voltage angle was performed using the phasor data and state estimator data obtained from ERCOT for the 12-months of 2013. This data was processed to extract voltage magnitude and voltage angles. Minimum and maximum values for these variables were documented in summary tables; box-whiskers plots and time duration curves were developed for each variable and for each type of data used. Below is an analysis of voltage magnitudes and voltage angles.

A. Methodology

For the pairs selected for study, the following work was performed:

1. Obtain and process phasor data and state estimator data.
2. Extract information to identify max, min and average values from these data sources. Prepare summary tables showing results of all data, including data saved during events.
3. Use phasor and SE data to develop weekly box-whisker graphs and time duration curves for angle differences.
4. Identify limits corresponding to normal operation; excluding events and outages. To exclude extreme values corresponding to outliers and to events, values corresponding to the metrics within the 1% to 99% percent of the time range were identified for the entire study period, to be identified as normal operating limits. A summary showing these normal operation limits were obtained using phasor and SE data and tabulated in the same table for comparison.
5. Analyze results, identify limits, and report results for each pair selected.

B. Study Approach

Electric Power Group used the following approach:

1. Obtain available phasor data and state estimator data from ERCOT.
2. Extract phasor data and condition it for processing.
3. Solve state estimator cases and save solved cases.
4. Select substations and angle pairs of interest to ERCOT and the synchrophasor team members by choosing substations that have or soon will have PMUs installed.
5. Identify the substations and subsets of substations and pairs for which phasor data is available.
6. Develop statistical charts including time duration curve and box-whisker graphs for voltage magnitudes and angles and for angle pairs.
7. Perform statistical analyses to identify angle differences limits for the selected pairs under all conditions. Summarize angle difference limits.
 - Establish limits for normal operation based on the criteria described in the corresponding methodology. Summarize angle difference limits.
 - The limits for angle differences identified in this report shall be compared with ERCOT's criteria, if any, that apply to angle differences for the paths selected for this study.

5. BASELINE ANALYSIS FOR VOLTAGES MAGNITUDES

A. Substations Identified For Voltage Monitoring

Table 2 below shows the substations identified for monitoring.

Table 2 – Substations for Voltage Monitoring

| Table 2 - SUBSTATIONS FOR VOLTAGE MONITORING | | | |
|-----------------------------------------------------------|-------------------|-----------|---------------|
| # | SUBSTATION | kV | REGION |
| 1 | West 10 | 69 | Panhandle |
| 2 | West 14 | 345 | Panhandle |
| 3 | West 1 | 345 | Central |
| 4 | West 2 | 345 | Central |
| 5 | West 9 | 345 | Central |
| 6 | West 11 | 345 | Central |
| 7 | West 12 | 345 | Central |
| 8 | West 5 | 345 | Central |
| 9 | West 6 | 345 | Central |
| 10 | North 1 | 345 | Dallas |
| 11 | North 4 | 138 | Dallas |
| 12 | North 5 | 138 | Dallas |
| 13 | North 6 | 138 | East |
| 14 | FarWest 2 | 69 | West Texas |
| 15 | North 7 | 138 | Central-East |
| 16 | West 4 | 138 | SouthWest |
| 17 | Coast 2 | 69 | Valley |
| 18 | Coast 1 | 138 | Valley |
| 19 | South 3 | 138 | Valley |
| 20 | South 5 | 138 | Valley |
| 21 | Coast 4 | 345 | Valley |
| 22 | Coast 3 | 345 | Valley |
| 23 | South 13 | 138 | Valley |
| 24 | FarWest 4 | 345 | West Texas |
| 25 | FarWest 7 | 345 | West Texas |
| 26 | FarWest 8 | 138 | West Texas |
| 27 | FarWest 9 | 138 | West Texas |
| 28 | West 16 | 345 | Panhandle |
| 29 | West 3 | 345 | Central |
| 30 | West 15 | 345 | Panhandle |
| 31 | West 8* | 345 | Central |
| 32 | South 15* | 345 | Central |
| 33 | South 2* | 345 | Central-East |
| 34 | South 4* | 345 | Central-East |
| 35 | South 7* | 345 | Central-East |
| 36 | South 9* | 345 | Central-East |
| 37 | South 11* | 345 | Central-East |
| 38 | South 10* | 138 | Valley |
| 39 | West 17* | 345 | Panhandle |
| 40 | West 13* | 345 | Panhandle |
| NOTE: * Means substations without PMUs connected to ERCOT | | | |

B. Analysis of Data and Results

All Data Conditions: Data availability of SE data for the 12-months of 2013 was approximately 22.6%. SE data availability for these 12-months improved to 174% that of the 2012 SE data. Data availability was approximately 13% for all SE cases in 2012. Phasor data availability varies from bus to bus. Twelve PMUs were connected to the ERCOT system in 2013: nine in June, one in September and two in December. As a result, data availability for these substations ranges from less than 10% to less than 60%. On the other hand, PMUs that have been connected to the ERCOT system during the entire year 2013 have availability ranging from 66% to 93%. Two PMUs have no data available for 2013: North 2 and South 6.

Table A- 1 below summarizes the Min, Max and average values for voltage magnitude for the selected substations. The largest max-min voltage spreads observed were 23.3 kV at the Coast 4 345 bus and 10.1 kV for West 4 138 kV bus. The maximum voltages observed were: 367.11 kV at West 14 345 kV and 147.67 kV at South 3 138 kV. The highest average voltages observed were: 356.8 kV at West 14 and 142.7 kV at South 3.

The summary shown in Table A- 1 below shows the results for all data, including events and outages.

Normal Conditions: Voltage magnitudes which could be expected during normal conditions were obtained by excluding values corresponding to events and outages by isolating the values that lie in the lowest one percent and in the highest one percent at the point of inflection in the time duration curve. The values of the remaining voltages obtained this way are considered to be the “normal points of operation” and are summarized in Table A- 2 below.

Table A- 1 –Summary of Voltage Magnitudes – All Data, Jan 1 to Dec 31, 2013

| Table A-1 ERCOT DISCOVERY ACROSS TEXAS PROJECT - SUMMARY OF VOLTAGE MAGNITUDES - ALL DATA | | | | | | | | | | | | |
|-------------------------------------------------------------------------------------------|------------|---------|--------------|-----------------------------------------------------------------------------------------------------------|--------|---------|----------------|------------------------|-------------------------------------|--------|---------|----------------|
| JANUARY 1 TO DECEMBER 31, 2013 | | | | | | | | | | | | |
| | | | | PHASOR DATA | | | | | STATE ESTIMATOR DATA | | | |
| No | Substation | Base kV | Region | Min | Max | Average | Max-Min Spread | Percent Data Available | Min | Max | Average | Max-Min Spread |
| 1 | West 10 | 69 | Panhandle | 68.36 | 72.99 | 70.86 | 4.63 | 92.11 | 68.00 | 74.15 | 71.57 | 6.2 |
| 2 | West 14 | 345 | Panhandle | 345.33 | 364.95 | 355.64 | 19.62 | 79.82 | 350.73 | 363.56 | 356.76 | 12.8 |
| 3 | West 1 | 345 | Central | 346.05 | 362.77 | 355.76 | 16.72 | 52.90 | 345.17 | 362.80 | 354.57 | 17.6 |
| 4 | West 2 | 345 | Central | 346.92 | 363.34 | 356.28 | 16.42 | 53.12 | 349.97 | 361.28 | 356.49 | 11.3 |
| 5 | West 9 | 345 | Central | 345.34 | 362.27 | 354.34 | 16.93 | 52.43 | 345.52 | 362.84 | 353.92 | 17.3 |
| 6 | West 11 | 345 | Central | 346.23 | 360.09 | 353.12 | 13.86 | 92.06 | 350.00 | 357.87 | 353.95 | 7.9 |
| 7 | West 12 | 345 | Central | 346.40 | 362.85 | 355.39 | 16.45 | 53.09 | 347.62 | 361.28 | 354.48 | 13.7 |
| 8 | West 5 | 345 | Central | 346.13 | 362.56 | 355.71 | 16.43 | 53.10 | 349.97 | 360.56 | 355.71 | 10.6 |
| 9 | West 6 | 345 | Central | 347.74 | 360.56 | 354.30 | 12.82 | 88.08 | 349.14 | 360.35 | 354.82 | 11.2 |
| 10 | North 1 | 345 | Dallas | 343.10 | 354.96 | 349.13 | 11.86 | 93.08 | 344.31 | 356.76 | 350.10 | 12.5 |
| 11 | North 4 | 138 | Dallas | 138.73 | 144.31 | 142.04 | 5.58 | 93.20 | 138.39 | 143.44 | 141.28 | 5.1 |
| 12 | North 5 | 138 | Dallas | 138.11 | 143.93 | 141.19 | 5.81 | 93.10 | 137.34 | 142.21 | 139.78 | 4.9 |
| 13 | North 6 | 138 | East | 138.19 | 145.08 | 141.85 | 6.89 | 93.00 | 138.33 | 145.60 | 141.97 | 7.3 |
| 14 | FarWest 2 | 69 | Central-East | 65.97 | 73.41 | 69.64 | 7.44 | 55.18 | 66.28 | 72.12 | 69.48 | 5.8 |
| 15 | North 7 | 138 | Central-East | 138.24 | 145.04 | 142.55 | 6.80 | 91.95 | 137.85 | 144.86 | 141.37 | 7.0 |
| 16 | West 4 | 138 | SouthWest | 134.09 | 148.22 | 142.00 | 14.13 | 73.35 | 136.68 | 146.75 | 141.78 | 10.1 |
| 17 | Coast 2 | 69 | Valley | 66.70 | 73.10 | 70.24 | 6.40 | 84.74 | 66.01 | 73.24 | 69.91 | 7.2 |
| 18 | Coast 1 | 138 | Valley | 139.75 | 144.25 | 142.40 | 4.50 | 87.30 | 138.40 | 145.18 | 142.00 | 6.8 |
| 19 | South 3 | 138 | Valley | 141.44 | 142.90 | 142.24 | 1.46 | 56.38 | 137.70 | 147.67 | 142.68 | 10.0 |
| 20 | South 5 | 69 | Valley | 68.58 | 71.77 | 70.38 | 3.20 | 46.02 | 67.84 | 73.46 | 70.65 | 5.6 |
| 21 | Coast 4 | 345 | Valley | 343.83 | 364.41 | 354.05 | 20.57 | 66.23 | 342.86 | 366.15 | 354.49 | 23.3 |
| 22 | Coast 3 | 345 | Valley | 343.24 | 363.58 | 353.34 | 20.34 | 79.42 | 342.79 | 365.60 | 354.19 | 22.8 |
| 23 | South 13 | 138 | Valley | 137.04 | 146.80 | 141.85 | 9.76 | 83.75 | 137.70 | 146.27 | 142.00 | 8.6 |
| 24 | FarWest 4 | 345 | West Texas | 348.58 | 360.23 | 354.18 | 11.65 | 90.74 | 350.52 | 358.83 | 354.65 | 8.3 |
| 25 | FarWest 7 | 345 | West Texas | 342.31 | 355.88 | 350.65 | 13.57 | 92.96 | 344.86 | 356.04 | 351.20 | 11.2 |
| 26 | FarWest 8 | 138 | West Texas | 137.35 | 145.47 | 142.13 | 8.12 | 82.33 | 137.24 | 143.52 | 140.59 | 6.3 |
| 27 | FarWest 9 | 138 | West Texas | 136.77 | 144.39 | 141.25 | 7.62 | 86.16 | 137.37 | 144.47 | 140.95 | 7.1 |
| 28 | West 16 | 345 | Panhandle | PMUs installed in mid December: not enough phasor data for analysis | | | | | 346.38 | 360.08 | 353.31 | 13.7 |
| 29 | West 3 | 345 | Panhandle | | | | | | Not enough phasor data | | | |
| 30 | West 15 | 345 | Panhandle | 345.88 | 360.50 | 353.34 | 14.62 | 19.14 | 349.45 | 360.04 | 353.73 | 10.6 |
| 31 | West 8* | 345 | Central | No PMUs installed at these substations. No phasor data available for the January to December 2013 period. | | | | | 345.90 | 367.11 | 356.63 | 21.2 |
| 32 | South 15* | 345 | Central | | | | | | 349.14 | 361.73 | 355.77 | 12.6 |
| 33 | South 2* | 345 | Central-East | | | | | | 347.73 | 362.39 | 354.81 | 14.7 |
| 34 | South 4* | 345 | Central-East | | | | | | 349.66 | 361.53 | 356.11 | 11.9 |
| 35 | South 7* | 345 | Central-East | | | | | | 348.93 | 362.35 | 355.59 | 13.4 |
| 36 | South 9* | 345 | Central-East | | | | | | 343.34 | 365.32 | 354.51 | 22.0 |
| 37 | South 11* | 345 | Central-East | | | | | | 349.69 | 361.22 | 355.86 | 11.5 |
| 38 | South 10* | 138 | Valley | | | | | | 139.05 | 144.83 | 141.81 | 5.8 |
| 39 | West 17* | 345 | Panhandle | | | | | | Not enough phasor data for analysis | | | |
| 40 | West 13* | 345 | Panhandle | | | | | | | | | |

Note: Substations marked with * did not have PMU data for the January 1 to December 31, 2013 period.

Table A-2 –Limits for Voltages – Normal Conditions

| TABLE A-2 CCET DISCOVERY ACROSS TEXAS - LIMITS FOR VOLTAGES - NORMAL CONDITIONS | | | | | | | | | | | | | | | | |
|---------------------------------------------------------------------------------|-----------|---------|--------------------------------------------------------------------------------------|------------|----------------|------------------------------------------------------------------------------------------------------------------------|-------------|---------|-----------|--------|----------|---------------|-----------|----------------------------------------|------------|----------------|
| | | | Phasor Data | | | State Estimator Data - January 1 To December 31, 2013 | | | | | | | | SE Data | | |
| No. | Bus Names | Base kV | Normal Min | Normal Max | Max-Min Spread | Normal Min-100% | 100% or POI | 99% Min | 99% - POI | 1% Max | 1% + POI | Normal Max-0% | 0% or POI | Normal Min | Normal Max | Max-Min Spread |
| 1 | West 10 | 69 | 69.08 | 72.33 | 3.25 | 68.36 | 99.97% | 69.60 | 98.97% | 73.56 | 1.07% | 74.01 | 0.07% | 68.36 | 74.01 | 5.65 |
| 2 | West 14 | 345 | 349.40 | 360.90 | 11.50 | 351.54 | 99.98% | 352.94 | 98.98% | 361.54 | 1.04% | 363.33 | 0.04% | 351.54 | 363.33 | 11.79 |
| 3 | West 1 | 345 | 346.70 | 362.00 | 15.30 | 345.42 | 99.98% | 347.63 | 98.98% | 358.97 | 1.02% | 361.53 | 0.02% | 345.42 | 361.53 | 16.10 |
| 4 | West 2 | 345 | 349.80 | 360.00 | 10.20 | 350.50 | 99.91% | 352.04 | 98.91% | 359.46 | 1.05% | 360.33 | 0.05% | 350.50 | 360.33 | 9.83 |
| 5 | West 9 | 345 | 348.00 | 360.30 | 12.30 | 346.84 | 99.90% | 348.64 | 98.90% | 359.48 | 1.04% | 362.08 | 0.04% | 346.84 | 362.08 | 15.24 |
| 6 | West 11 | 345 | 349.10 | 357.20 | 8.10 | 350.23 | 99.95% | 351.28 | 98.95% | 356.24 | 1.07% | 357.41 | 0.07% | 350.23 | 357.41 | 7.19 |
| 7 | West 12 | 345 | 349.50 | 359.90 | 10.40 | 348.02 | 99.93% | 349.95 | 98.93% | 358.65 | 1.03% | 361.03 | 0.03% | 348.02 | 361.03 | 13.01 |
| 8 | West 5 | 345 | 349.20 | 359.30 | 10.10 | 350.22 | 99.97% | 351.97 | 98.97% | 358.80 | 1.02% | 360.07 | 0.02% | 350.22 | 360.07 | 9.85 |
| 9 | West 6 | 345 | 348.80 | 358.30 | 9.50 | 349.42 | 99.96% | 351.05 | 98.96% | 358.34 | 1.03% | 359.70 | 0.03% | 349.42 | 359.70 | 10.28 |
| 10 | North 1 | 345 | 344.30 | 354.40 | 10.10 | 344.59 | 99.99% | 345.79 | 98.99% | 355.14 | 1.05% | 356.24 | 0.05% | 344.59 | 356.24 | 11.65 |
| 11 | North 4 | 138 | 139.10 | 143.70 | 4.60 | 138.42 | 99.94% | 139.09 | 98.94% | 142.65 | 1.03% | 143.35 | 0.03% | 138.42 | 143.35 | 4.93 |
| 12 | North 5 | 138 | 138.50 | 143.20 | 4.70 | 137.43 | 99.97% | 138.10 | 98.97% | 141.26 | 1.05% | 141.89 | 0.05% | 137.43 | 141.89 | 4.46 |
| 13 | North 6 | 138 | 139.50 | 144.50 | 5.00 | 138.61 | 99.98% | 139.87 | 98.98% | 144.62 | 1.02% | 145.51 | 0.02% | 138.61 | 145.51 | 6.90 |
| 14 | FarWest 2 | 69 | 66.90 | 72.46 | 5.56 | 66.73 | 99.96% | 67.51 | 98.96% | 71.13 | 1.02% | 71.80 | 0.02% | 66.73 | 71.80 | 5.07 |
| 15 | North 7 | 138 | 139.90 | 144.30 | 4.40 | 138.06 | 99.94% | 139.29 | 98.94% | 143.69 | 1.03% | 144.72 | 0.03% | 138.06 | 144.72 | 6.66 |
| 16 | West 4 | 138 | 137.60 | 146.20 | 8.60 | 136.84 | 99.97% | 138.41 | 98.97% | 144.79 | 1.03% | 146.33 | 0.03% | 136.84 | 146.33 | 9.49 |
| 17 | Coast 2 | 69 | 67.61 | 72.33 | 4.72 | 66.17 | 99.95% | 67.19 | 98.95% | 71.94 | 1.02% | 72.75 | 0.02% | 66.17 | 72.75 | 6.58 |
| 18 | Coast 1 | 138 | 139.90 | 143.70 | 3.80 | 138.89 | 99.97% | 139.61 | 98.97% | 144.32 | 1.03% | 145.07 | 0.03% | 138.89 | 145.07 | 6.18 |
| 19 | South 3 | 138 | 141.60 | 142.50 | 0.90 | 137.78 | 99.98% | 139.94 | 98.98% | 146.20 | 1.02% | 147.57 | 0.02% | 137.78 | 147.57 | 9.79 |
| 20 | South 5 | 69 | 68.99 | 71.64 | 2.65 | 67.92 | 99.88% | 69.09 | 98.88% | 72.37 | 1.01% | 73.40 | 0.01% | 67.92 | 73.40 | 5.48 |
| 21 | Coast 4 | 345 | 345.00 | 361.70 | 16.70 | 343.12 | 99.97% | 346.63 | 98.97% | 361.91 | 1.02% | 366.10 | 0.02% | 343.12 | 366.10 | 22.98 |
| 22 | Coast 3 | 345 | 345.70 | 361.10 | 15.40 | 343.13 | 99.98% | 346.62 | 98.98% | 361.47 | 1.07% | 365.37 | 0.07% | 343.13 | 365.37 | 22.24 |
| 23 | South 13 | 138 | 138.60 | 144.40 | 5.80 | 138.06 | 99.95% | 139.24 | 98.95% | 144.41 | 1.01% | 146.03 | 0.01% | 138.06 | 146.03 | 7.97 |
| 24 | FarWest 4 | 345 | 350.30 | 356.70 | 6.40 | 350.62 | 99.95% | 351.79 | 98.95% | 356.87 | 1.08% | 358.31 | 0.08% | 350.62 | 358.31 | 7.70 |
| 25 | FarWest 7 | 345 | 343.60 | 354.60 | 11.00 | 345.30 | 99.95% | 347.02 | 98.95% | 354.44 | 1.02% | 355.66 | 0.02% | 345.30 | 355.66 | 10.36 |
| 26 | FarWest 8 | 138 | 139.50 | 144.60 | 5.10 | 137.41 | 99.96% | 138.50 | 98.96% | 142.41 | 1.02% | 143.26 | 0.02% | 137.41 | 143.26 | 5.85 |
| 27 | FarWest 9 | 138 | 137.80 | 143.60 | 5.80 | 137.76 | 99.94% | 138.67 | 98.94% | 143.11 | 1.04% | 144.03 | 0.04% | 137.76 | 144.03 | 6.27 |
| 28 | West 16 | 345 | Not enough phasor data available for analysis | | | 346.45 | 99.95% | 346.95 | 98.95% | 358.00 | 1.03% | 360.05 | 0.03% | 346.45 | 360.05 | 13.60 |
| 29 | West 3 | 345 | | | | No PSSE data available for this period | | | | | | | | | | |
| 30 | West 15 | 345 | 348.50 | 359.50 | 11.00 | 349.59 | 99.95% | 350.05 | 98.95% | 358.40 | 1.03% | 360.00 | 0.03% | 349.59 | 360.00 | 10.41 |
| 31 | West 8* | 345 | PMUs not installed at these substations. No phasor data available for the year 2013. | | | 346.03 | 99.96% | 347.16 | 98.96% | 360.48 | 1.04% | 366.77 | 0.04% | 346.03 | 366.77 | 20.74 |
| 32 | South 15* | 345 | | | | 349.64 | 99.99% | 351.11 | 98.99% | 359.71 | 1.01% | 361.48 | 0.01% | 349.64 | 361.48 | 11.84 |
| 33 | South 2* | 345 | | | | 347.92 | 99.94% | 349.70 | 98.94% | 359.14 | 1.01% | 362.27 | 0.01% | 347.92 | 362.27 | 14.35 |
| 34 | South 4* | 345 | | | | 350.01 | 99.98% | 351.48 | 98.98% | 359.94 | 1.02% | 361.41 | 0.02% | 350.01 | 361.41 | 11.40 |
| 35 | South 7* | 345 | | | | 349.71 | 99.98% | 351.76 | 98.98% | 359.08 | 1.08% | 361.84 | 0.08% | 349.71 | 361.84 | 12.13 |
| 36 | South 9* | 345 | | | | 343.80 | 99.98% | 346.41 | 98.98% | 361.41 | 1.03% | 364.66 | 0.03% | 343.80 | 364.66 | 20.86 |
| 37 | South 11* | 345 | | | | 350.04 | 99.97% | 351.39 | 98.97% | 359.47 | 1.01% | 360.90 | 0.01% | 350.04 | 360.90 | 10.86 |
| 38 | South 10* | 138 | | | | 139.20 | 99.97% | 140.00 | 98.97% | 143.88 | 1.02% | 144.73 | 0.02% | 139.20 | 144.73 | 5.53 |
| 39 | West 17* | 345 | | | | These substations were not in service during the July to December 2013 period. No PSSE data available for this period. | | | | | | | | No PSSE data available for this period | | |
| 40 | West 13* | 345 | | | | | | | | | | | | | | |

NOTE: The substations marked with * did not have PMUs installed in 2013; no phasor data available.

Note that the greater Max-Min voltage spreads occurred at Coast 4 345 kV and South 3 138 kV buses with 22.98 kV and 9.79 kV, respectively.

For both the SE data and the phasor data, box-whisker plots and time duration curves were developed for each of the substations listed above and were used to obtain the values in the Table A-2 above. Summaries of SE-based voltage pairs with their corresponding box-whisker and time duration curves, as well as summaries of phasor-based voltage pairs with their corresponding box-whisker and time duration curves are presented in Appendix A, Parts 1 and 2.

C. Observations

1. Data availability: the availability for state estimator data was approximately 22.7%; the availability for phasor data was greater overall but varied from 19.1% at West 15 to 93.20% at North 4. Eighteen PMUs show data availability greater than 70%.

2. State estimator data points to South 3 and West 8 as having the highest voltages in their class. The highest voltage spreads are found at Coast 4 345 kV and West 4 138 kV substations. Voltages at these substations are more volatile than at the other substations; the Max-Min ranges for these substations are 23.3 and 10.1 respectively. Note that Coast 3 345 kV also has a high voltage spread (22.8).
3. The lowest voltage spreads of 7.9 kV and 4.9 kV occurred at West 11 345 kV and North 5 138 kV substations respectively.
4. Twenty-one substations show voltage spreads greater than 10 kV under all conditions.
5. Eighteen substations show voltage spreads greater than 10 kV under normal conditions. Voltage spreads under normal conditions are lower than those under all conditions as expected.

D. Comparison of Alarm Limits for Voltages – 2012 vs. 2013 Data

The limits summarized in the two tables above reflect system performance after the addition of the CREZ lines in the 12-months of 2013. EPG has prepared a comparison table to identify the changes in voltages due to the addition of the new 345 kV lines. Table 3 shows a comparison of voltage magnitude averages as well as Max-Min spreads for 2012 and 2013.

Table 3 – Voltage Magnitudes – All Data Comparison 2012 vs. 2013 (Jan 1 – Dec 31)

| Table 3 - ERCOT DISCOVERY ACROSS TEXAS PROJECT - VOLTAGE MAGNITUDES - ALL DATA | | | | | | | | | | | |
|--------------------------------------------------------------------------------|------------|---------|--------------|-----------------------------|--------|---------|----------------|-------------------------------------|--------|---------|----------------|
| COMPARISON 2012 vs. 2013 (January 1 to December 31) | | | | | | | | | | | |
| No | Substation | Base kV | Region | STATE ESTIMATOR DATA - 2012 | | | | STATE ESTIMATOR DATA - 2013 | | | |
| | | | | Min | Max | Average | Max-Min Spread | Min | Max | Average | Max-Min Spread |
| 1 | West 10 | 69 | Panhandle | 68.03 | 73.13 | 71.03 | 5.1 | 68.00 | 74.15 | 71.57 | 6.2 |
| 2 | West 14 | 345 | Panhandle | 348.07 | 362.15 | 355.89 | 14.1 | 350.73 | 363.56 | 356.76 | 12.8 |
| 3 | West 1 | 345 | Central | No data available | | | | 345.17 | 362.80 | 354.57 | 17.6 |
| 4 | West 2 | 345 | Central | 348.17 | 366.11 | 357.56 | 17.9 | 349.97 | 361.28 | 356.49 | 11.3 |
| 5 | West 9 | 345 | Central | 346.93 | 365.53 | 357.31 | 18.6 | 345.52 | 362.84 | 353.92 | 17.3 |
| 6 | West 11 | 345 | Central | 347.73 | 361.28 | 355.14 | 13.6 | 350.00 | 357.87 | 353.95 | 7.9 |
| 7 | West 12 | 345 | Central | 346.17 | 364.70 | 356.50 | 18.5 | 347.62 | 361.28 | 354.48 | 13.7 |
| 8 | West 5 | 345 | Central | 347.83 | 365.77 | 356.95 | 17.9 | 349.97 | 360.56 | 355.71 | 10.6 |
| 9 | West 6 | 345 | Central | 346.73 | 364.08 | 356.45 | 17.4 | 349.14 | 360.35 | 354.82 | 11.2 |
| 10 | North 1 | 345 | Dallas | 340.69 | 353.14 | 347.70 | 12.5 | 344.31 | 356.76 | 350.10 | 12.5 |
| 11 | North 4 | 138 | Dallas | 138.55 | 144.07 | 142.13 | 5.5 | 138.39 | 143.44 | 141.28 | 5.1 |
| 12 | North 5 | 138 | Dallas | 137.34 | 141.75 | 139.80 | 4.4 | 137.34 | 142.21 | 139.78 | 4.9 |
| 13 | North 6 | 138 | East | 138.88 | 143.53 | 141.59 | 4.7 | 138.33 | 145.60 | 141.97 | 7.3 |
| 14 | FarWest 2 | 69 | Central-East | 67.32 | 71.53 | 69.27 | 4.2 | 66.28 | 72.12 | 69.48 | 5.8 |
| 15 | North 7 | 138 | Central-East | 139.23 | 144.46 | 142.21 | 5.2 | 137.85 | 144.86 | 141.37 | 7.0 |
| 16 | West 4 | 138 | SouthWest | 132.52 | 151.74 | 141.17 | 19.2 | 136.68 | 146.75 | 141.78 | 10.1 |
| 17 | Coast 2 | 69 | Valley | 66.58 | 71.94 | 69.61 | 5.4 | 66.01 | 73.24 | 69.91 | 7.2 |
| 18 | Coast 1 | 138 | Valley | 138.69 | 143.18 | 141.20 | 4.5 | 138.40 | 145.18 | 142.00 | 6.8 |
| 19 | South 3 | 138 | Valley | 138.25 | 146.38 | 142.11 | 8.1 | 137.70 | 147.67 | 142.68 | 10.0 |
| 20 | South 5 | 69 | Valley | 67.14 | 72.67 | 70.56 | 5.5 | 67.84 | 73.46 | 70.65 | 5.6 |
| 21 | Coast 4 | 345 | Valley | 341.96 | 363.32 | 353.39 | 21.4 | 342.86 | 366.15 | 354.49 | 23.3 |
| 22 | Coast 3 | 345 | Valley | 341.62 | 363.39 | 353.27 | 21.8 | 342.79 | 365.60 | 354.19 | 22.8 |
| 23 | South 13 | 138 | Valley | 137.74 | 145.48 | 141.72 | 7.7 | 137.70 | 146.27 | 142.00 | 8.6 |
| 24 | FarWest 4 | 345 | West Texas | 349.45 | 360.63 | 355.81 | 11.2 | 350.52 | 358.83 | 354.65 | 8.3 |
| 25 | FarWest 7 | 345 | West Texas | 345.38 | 360.59 | 352.86 | 15.2 | 344.86 | 356.04 | 351.20 | 11.2 |
| 26 | FarWest 8 | 138 | West Texas | 135.41 | 142.35 | 139.39 | 6.9 | 137.24 | 143.52 | 140.59 | 6.3 |
| 27 | FarWest 9 | 138 | West Texas | 136.10 | 146.85 | 141.20 | 10.8 | 137.37 | 144.47 | 140.95 | 7.1 |
| 28 | West 16 | 345 | Panhandle | Not in service in 2012 | | | | 346.38 | 360.08 | 353.31 | 13.7 |
| 29 | West 3 | 345 | Central | | | | | Not enough phasor data | | | |
| 30 | West 15 | 345 | Panhandle | | | | | 349.45 | 360.04 | 353.73 | 10.6 |
| 31 | West 8* | 345 | Central | No data available | | | | 345.90 | 367.11 | 356.63 | 21.2 |
| 32 | South 15* | 345 | Central | 349.49 | 359.46 | 354.82 | 10.0 | 349.14 | 361.73 | 355.77 | 12.6 |
| 33 | South 2* | 345 | Central-East | 348.80 | 358.52 | 354.07 | 9.7 | 347.73 | 362.39 | 354.81 | 14.7 |
| 34 | South 4* | 345 | Central-East | 349.17 | 359.83 | 354.80 | 10.7 | 349.66 | 361.53 | 356.11 | 11.9 |
| 35 | South 7* | 345 | Central-East | 348.59 | 359.04 | 354.33 | 10.5 | 348.93 | 362.35 | 355.59 | 13.4 |
| 36 | South 9* | 345 | Central-East | 343.17 | 358.90 | 352.20 | 15.7 | 343.34 | 365.32 | 354.51 | 22.0 |
| 37 | South 11* | 345 | Central-East | 348.52 | 358.46 | 354.22 | 9.9 | 349.69 | 361.22 | 355.86 | 11.5 |
| 38 | South 10* | 138 | Valley | 138.59 | 144.49 | 141.46 | 5.9 | 139.05 | 144.83 | 141.81 | 5.8 |
| 39 | West 17* | 345 | Panhandle | No data available | | | | Not enough phasor data for analysis | | | |
| 40 | West 13* | 345 | Panhandle | | | | | | | | |

Note: The substations with * did not have PMUs installed in 2013.

Observation of Table 3 shows that voltages in the West Texas and Central areas were lower in 2013 than in 2012, probably due to the higher transfer of power from those areas to the rest of the ERCOT system. Voltages in the Central East, Valley and Dallas areas increased in 2013 compared with 2012 possibly due to the relief the wind power provided to these areas.

Voltage spreads went higher in the areas where the voltage increased and lower where the voltages decreased.

E. Analysis of the Box-whisker Voltage Plots - 2013 Data

1. No state estimator (SE) data was available for the last third of March, for mid-August to late September and for most of November and December 2013 for just about every substation included in Appendix A, Part 1.
2. Two voltage spikes at West 14: for one day, January 10, the voltage went up by about 3.5 kV and again in mid-March by about 3.5 kV.
3. The voltage at West 1 fluctuated between 345 and 362 kV (17 kV range) during the first seven-months of 2013.
4. The voltage at West 9 fluctuated within a 16 kV range (346 and 362 kV); the voltages at this substation spiked up by up to 4 kV during the first four-months of 2013.
5. West 12 substation also experienced voltages operating within a wide-range of 15 kV (347 to 361 kV). Voltage spiked several times during the first six-months of 2013, by up to 3 kV.
6. The voltage at North 1 varied somewhat erratically between 344 and 357 kV during the 12-months of 2013. During the month of April, the voltage jumped up 4 kV and operated in the neighborhood of 354 kV for most of the month. By the end of May, the voltage came down drastically to approximately 347 kV, and then day-by-day went up and ended up operating around 354 kV by the end of June.
7. The voltage at North 5 was operated tightly between the 137.5 and 142 kV range.
8. The voltage at North 6 operated about 2 kV higher during May and part of June compared to the rest of 2013.
9. The voltage at West 4 fluctuated within a 10 kV bandwidth (136 to 146 kV) during the twelve months of 2013.
10. The voltage at Coast 1 operated at high levels during October 2013, around 144 kV.
11. Large fluctuations are seen at South 3 during the first five months of 2013: within a 139.5 to 147.5 kV bandwidth.
12. The voltage at Coast 4 operated within a 23 kV range: several voltage spikes were observed throughout the year.
13. Similarly, the voltage at Coast 3 operated with a 23 kV range with several voltage spikes occurring throughout the year.
14. FarWest 4: one spike in April (358.5 kV) and four dips (340.5 kV)
15. FarWest 7: operated within a 10 kV range (345 to 355 kV) with large daily swings.
16. Not enough data for West 16, West 15 and West 8. No meaningful conclusions can be reached from these plots.
17. South 2: operated within a 13 kV range (348 to 361 kV)
18. South 9: voltage fluctuated within a wide range from 344 to 365 kV (21 kV range) with a spike up around March 2.
19. South 10: the median voltage changes constantly with the few spikes occurring during May to August 2013.
20. The box-whisker plots for North 4, North 5, FarWest 8, Coast 1, FarWest 9 and FarWest 4 exhibit what appear to be a large number of outlier points.

6. BASELINE ANALYSIS FOR VOLTAGE ANGLES(REFERENCE: North 7 Bus)

A. Substations Identified for Voltage Angle Analysis

The following substations were selected for voltage angle analysis; the substation selected as reference was North 7.

Table 4 – Substations for Voltage Angle Difference Monitoring

| Table 4 - SUBSTATIONS FOR VOLTAGE ANGLE DIFFERENCE MONITORING (Ref.: North 7) | | | |
|------------------------------------------------------------------------------------------|-------------------|-----------|---------------|
| # | SUBSTATION | kV | REGION |
| 1 | West 10 | 69 | Panhandle |
| 2 | West 14 | 345 | Panhandle |
| 3 | West 1 | 345 | Central |
| 4 | West 2 | 345 | Central |
| 5 | West 9 | 345 | Central |
| 6 | West 11 | 345 | Central |
| 7 | West 12 | 345 | Central |
| 8 | West 5 | 345 | Central |
| 9 | West 6 | 345 | Central |
| 10 | North 1 | 345 | Dallas |
| 11 | North 2 | 138 | Dallas |
| 12 | North 4 | 138 | Dallas |
| 13 | North 5 | 138 | Dallas |
| 14 | North 6 | 138 | East |
| 15 | FarWest 2 | 69 | West Texas |
| 16 | West 4 | 138 | SouthWest |
| 17 | Coast 2 | 69 | Valley |
| 18 | Coast 1 | 138 | Valley |
| 19 | South 3 | 138 | Valley |
| 20 | South 5 | 138 | Valley |
| 21 | Coast 4 | 345 | Valley |
| 22 | Coast 3 | 345 | Valley |
| 23 | South 6 | 138 | Valley |
| 24 | South 13 | 138 | Valley |
| 25 | FarWest 4 | 345 | West Texas |
| 26 | FarWest 7 | 345 | West Texas |
| 27 | FarWest 8 | 138 | West Texas |
| 28 | FarWest 9 | 138 | West Texas |
| 29 | West 16 | 345 | Panhandle |
| 30 | West 15 | 345 | Panhandle |
| 31 | West 3 | 345 | Central |
| 32 | West 8* | 345 | Central |
| 33 | South 15* | 345 | Central |
| 34 | South 2* | 345 | Central-East |
| 35 | South 4* | 345 | Central-East |
| 36 | South 7* | 345 | Central-East |
| 37 | South 9* | 345 | Central-East |
| 38 | South 11* | 345 | Central-East |
| 39 | South 10* | 138 | Valley |
| 40 | West 17* | 345 | Panhandle |
| 41 | West 13* | 345 | Panhandle |

NOTE: * Means substations without PMUs connected to ERCOT

B. Summary of Results - All data included

The voltage angle results obtained from all data available: all solved SE cases, and all phasor data, are summarized in Table B- 1 below.

These results were obtained using all data available including event and outage conditions; under these conditions, voltage angles would be expected to be larger than under normal conditions because during event and outages conditions the angles tend to increase in absolute magnitude to reflect the changes in system conditions or changes in system configuration. The maximum Max-Min spreads observed were 104.1 degrees for FarWest 9 138 kV substation and 90.8 degrees for FarWest 4 345 kV substation. Note also that the substations close to the wind farms in groups 1 and 2 shown in yellow have over 73 degrees Max-Min spreads and the angles for these substations are positive more than 71% of the time; that is, the power flows from these substations towards North 7 most of the time. These spreads are lower than those maximum spreads found in the 2012 baselining study; this is expected since the grid is now tighter with the addition of most CREZ 345 kV lines. The lowest spread of 28 degrees was seen at North 6. The phasor data for FarWest 2 appears to be unreliable given the inconsistent results (average of -127.5 degrees).

Table B- 1 – Baselining Analysis – Voltage Angles – ALL Conditions

| Table B-1: CCET DISCOVERY ACROSS TEXAS- BASELINING ANALYSIS - VOLTAGE ANGLES - ALL CONDITIONS (Reference- North 7). | | | | | | | | | | | | | | |
|----------------------------------------------------------------------------------------------------------------------------|-------------------------|---------|----------------------------------------------------------------------------------------|--------|---------|------------|------------|-----------|------------------------------------------------------------------------|-------|---------|------------------|------------|-----|
| No | Angle Pair FROM - TO | Base kV | Phasor Data - 1/1/13 to 12/31/13 | | | | | | State Estimator Data - 1/1/13 to 12/31/13 | | | | | |
| | | | Min | Max | Average | % Positive | Min Spread | Available | Min | Max | Average | Percent Positive | Min Spread | Max |
| 1 | West 10 | 69 | -40.45 | 70.08 | 6.70 | 57.58 | 110.53 | 91.62 | -37.25 | 66.38 | 8.40 | 62.13% | 103.6 | |
| 2 | West 14 | 345 | -21.43 | 37.65 | 6.73 | 82.71 | 59.08 | 78.79 | -18.97 | 32.46 | 5.63 | 81.63% | 51.4 | |
| 3 | West 1 | 345 | -19.92 | 33.07 | 3.25 | 66.43 | 52.99 | 52.88 | -24.06 | 38.14 | 5.41 | 74.43% | 62.2 | |
| 4 | West 2 | 345 | -15.05 | 28.80 | 3.98 | 61.75 | 43.85 | 53.07 | -26.31 | 46.74 | 7.10 | 71.62% | 73.1 | |
| 5 | West 9 | 345 | -16.94 | 33.07 | 4.43 | 65.36 | 50.01 | 52.40 | -27.52 | 49.71 | 7.76 | 73.28% | 77.2 | |
| 6 | West 11 | 345 | -30.72 | 62.04 | 6.49 | 65.08 | 92.76 | 91.79 | -29.63 | 58.64 | 7.45 | 68.41% | 88.3 | |
| 7 | West 12 | 345 | -16.89 | 33.07 | 4.48 | 64.45 | 49.96 | 53.06 | -27.52 | 49.71 | 7.78 | 72.76% | 77.2 | |
| 8 | West 5 | 345 | -16.47 | 30.23 | 4.43 | 62.61 | 46.70 | 53.07 | -26.90 | 48.06 | 7.42 | 71.00% | 75.0 | |
| 9 | West 6 | 345 | -28.43 | 60.40 | 7.17 | 69.42 | 88.83 | 87.84 | -27.52 | 49.71 | 7.68 | 71.45% | 77.2 | |
| 10 | North 1 | 345 | -12.33 | 26.41 | 6.53 | 93.29 | 38.74 | 92.78 | -11.20 | 24.01 | 6.49 | 93.78% | 35.2 | |
| 11 | North 4 | 138 | -18.85 | 14.43 | -2.88 | 23.27 | 33.28 | 92.91 | -17.84 | 13.60 | -2.47 | 25.23% | 31.4 | |
| 12 | North 5 | 138 | -20.35 | 14.99 | -4.67 | 14.60 | 35.34 | 92.81 | -19.99 | 11.56 | -4.73 | 13.69% | 31.6 | |
| 13 | North 6 | 138 | -8.67 | 17.99 | 5.15 | 91.50 | 26.65 | 90.77 | -10.70 | 17.25 | 3.82 | 85.15% | 28.0 | |
| 14 | FarWest 2 | 69 | -160.79 | -78.92 | -127.46 | 0.00 | -81.88 | 54.90 | -26.50 | 10.39 | -7.46 | 5.97% | 36.9 | |
| 15 | West 4 | 138 | -35.00 | 18.95 | -6.24 | 19.98 | 53.95 | 72.70 | -32.46 | 16.94 | -6.18 | 20.45% | 49.4 | |
| 16 | Coast 2 | 69 | -31.96 | 29.99 | -5.62 | 25.14 | 61.95 | 84.14 | -31.46 | 24.56 | -5.80 | 23.39% | 56.0 | |
| 17 | Coast 1 | 138 | -36.75 | 50.83 | 3.92 | 59.74 | 87.58 | 86.45 | -35.89 | 44.81 | 3.28 | 59.30% | 80.7 | |
| 18 | South 3 | 138 | -32.04 | 34.44 | -0.27 | 46.37 | 66.47 | 56.00 | -31.00 | 32.95 | 0.32 | 51.22% | 64.0 | |
| 19 | South 5 | 138 | -28.71 | 15.31 | -8.39 | 9.96 | 44.02 | 45.72 | -29.57 | 14.61 | -7.20 | 10.56% | 44.2 | |
| 20 | Coast 4 | 345 | -34.98 | 60.00 | 5.23 | 63.91 | 94.97 | 62.59 | -33.40 | 53.07 | 5.82 | 65.99% | 86.5 | |
| 21 | Coast 3 | 345 | -39.98 | 59.99 | 5.45 | 63.16 | 99.97 | 78.43 | -33.40 | 52.41 | 5.53 | 65.55% | 85.8 | |
| 22 | South 13 | 138 | -53.93 | 54.99 | 0.27 | 50.77 | 108.92 | 83.26 | -51.34 | 46.50 | -0.24 | 50.62% | 97.8 | |
| 23 | FarWest 4 | 345 | -32.57 | 60.00 | 7.04 | 65.46 | 92.57 | 90.49 | -30.54 | 60.24 | 7.82 | 68.15% | 90.8 | |
| 24 | FarWest 7 | 345 | -35.49 | 59.79 | 5.30 | 61.92 | 95.28 | 92.78 | -34.04 | 55.59 | 5.80 | 63.63% | 89.6 | |
| 25 | FarWest 8 | 138 | -44.79 | 54.96 | -3.09 | 38.49 | 99.75 | 82.09 | -42.34 | 51.30 | -2.11 | 42.58% | 93.6 | |
| 26 | FarWest 9 | 138 | -44.80 | 59.98 | 2.21 | 50.40 | 104.77 | 85.43 | -40.92 | 63.14 | 2.80 | 52.74% | 104.1 | |
| 27 | West 16 | 345 | PMUs installed in mid December; not enough phasor data for analysis | | | | | | New substations; Not enough data available for analysis. | | | | | |
| 28 | West 3 | 345 | | | | | | | | | | | | |
| 29 | West 15 | 345 | -13.74 | 22.74 | 3.82 | 72.24 | 36.47 | 19.07 | | | | | | |
| 30 | West 8* | 345/138 | No phasor data available for these substations for the year 2013. PMUs not in service. | | | | | | -13.09 | 27.27 | 4.15 | 61.04% | 40.4 | |
| 31 | South 15* | 345/138 | | | | | | | -18.62 | 16.09 | 0.31 | 50.90% | 34.7 | |
| 32 | South 2* | 345/138 | | | | | | | -14.44 | 18.32 | 2.48 | 74.48% | 32.8 | |
| 33 | South 4* | 345/138 | | | | | | | -19.22 | 17.53 | 0.31 | 50.35% | 36.8 | |
| 34 | South 7* | 345/138 | | | | | | | -16.09 | 21.19 | 3.85 | 78.73% | 37.3 | |
| 35 | South 9* | 345/138 | | | | | | | -18.41 | 16.37 | -0.13 | 46.84% | 34.8 | |
| 36 | South 11* | 345/138 | | | | | | | -21.08 | 18.56 | 0.06 | 48.18% | 39.6 | |
| 37 | South 10* | 138 | | | | | | | -35.17 | 24.79 | -6.64 | 18.13% | 60.0 | |
| 38 | West 17* | 345/138 | | | | | | | Substations not in service during the January to December 2013 period. | | | | | |
| 39 | West 13* | 345/138 | | | | | | | | | | | | |

NOTE: * Means substations without PMUs connected to FRCOT; no phasor data available

C. Summary of Results – Normal Conditions (events and outages excluded)

The voltage angle results obtained from excluding extreme values based on analysis of the box-whiskers plots and time duration curves are shown in Table B-2 below.

Table B- 2 – Baselining Analysis Update – Voltage Angles – Normal Conditions (Ref: 138 kV North 7)

| Table B-2: CCET DISCOVERY ACROSS TEXAS- BASELINING ANALYSIS UPDATE- VOLTAGE ANGLES - NORMAL CONDITIONS (Reference: 138 kV North 7) | | | | | | | | | | | | | | | | | | |
|---------------------------------------------------------------------------------------------------------------------------------------|-------------------------|---------|-----------------------------------------------------|--------------|-----------------------|------------------------------------------------------------------------|--------------------------------|-----------------------------|------------------------------------|---------------------------------|----------------------------------|-------------------------------|------------------------------|---------------------------|--|--------------------------------------|--------------|-------------------|
| No | Angle Pair FROM - TO | Base kV | DATA ANALYSIS RESULTS | | | | | | | | | | | | | | | |
| | | | Phasor-Normal | | | State Estimator Data - 1/1/13 to 12/31/13 | | | | | | | | | | SE Data-Normal | | |
| | | | Min Angle | Max Angle | Max- Min Spread | Percent Positive | Min Angle at POI or 100% | Percent (POI or 100%) | Min Angle at 99% or POI - 1% | Percent (99% or POI - 1%) | Max Angle at 1% or POI +1% | Percent (1% or POI +1%) | Max Angle at POI or 0% | Percent (POI or 0%) | | Min Angle | Max Angle | Max-Min Spread |
| 1 | West 10 | 69 | -36.64 | 52.43 | 89.1 | 62.13% | -32.08 | 99.78% | -23.12 | 98.78% | 44.57 | 1.02% | 59.73 | 0.02% | | -32.08 | 59.73 | 91.8 |
| 2 | West 14 | 345 | -17.69 | 29.69 | 47.4 | 81.63% | -16.66 | 99.95% | -10.85 | 98.95% | 20.66 | 1.09% | 27.62 | 0.09% | | -16.66 | 27.62 | 44.3 |
| 3 | West 1 | 345 | -9.48 | 24.51 | 34.0 | 74.43% | -20.62 | 99.85% | -12.39 | 98.85% | 26.79 | 1.07% | 37.02 | 0.07% | | -20.62 | 37.02 | 57.6 |
| 4 | West 2 | 345 | -12.78 | 26.80 | 39.6 | 71.62% | -23.76 | 99.94% | -14.85 | 98.94% | 31.45 | 1.07% | 44.10 | 0.07% | | -23.76 | 44.10 | 67.9 |
| 5 | West 9 | 345 | -12.71 | 31.40 | 44.1 | 73.28% | -24.51 | 99.93% | -15.57 | 98.93% | 33.08 | 1.10% | 45.22 | 0.10% | | -24.51 | 45.22 | 69.7 |
| 6 | West 11 | 345 | -27.33 | 49.82 | 77.2 | 68.41% | -26.61 | 99.94% | -17.84 | 98.94% | 34.46 | 1.02% | 47.50 | 0.02% | | -26.61 | 47.50 | 74.1 |
| 7 | West 12 | 345 | -13.86 | 31.47 | 45.3 | 72.76% | -24.06 | 99.89% | -15.46 | 98.89% | 32.93 | 1.10% | 45.07 | 0.10% | | -24.06 | 45.07 | 69.1 |
| 8 | West 5 | 345 | -13.74 | 29.25 | 43.0 | 71.00% | -23.57 | 99.89% | -14.85 | 98.89% | 31.54 | 1.09% | 44.00 | 0.09% | | -23.57 | 44.00 | 67.6 |
| 9 | West 6 | 345 | -21.94 | 49.22 | 71.2 | 71.45% | -24.14 | 99.90% | -15.28 | 98.90% | 32.66 | 1.09% | 45.22 | 0.09% | | -24.14 | 45.22 | 69.4 |
| 10 | North 1 | 345 | -9.99 | 20.95 | 30.9 | 93.78% | -9.23 | 99.94% | -5.26 | 98.94% | 16.42 | 1.08% | 20.83 | 0.08% | | -9.23 | 20.83 | 30.1 |
| 11 | North 4 | 138 | -17.60 | 9.86 | 27.5 | 25.23% | -16.06 | 99.95% | -12.42 | 98.95% | 6.49 | 1.02% | 11.33 | 0.02% | | -16.06 | 11.33 | 27.4 |
| 12 | North 5 | 138 | -18.02 | 9.39 | 27.4 | 13.69% | -19.03 | 99.92% | -14.79 | 98.92% | 5.52 | 1.05% | 9.47 | 0.05% | | -19.03 | 9.47 | 28.5 |
| 13 | North 6 | 138 | -4.34 | 14.90 | 19.2 | 85.15% | -7.77 | 99.89% | -4.09 | 98.89% | 11.59 | 1.06% | 15.68 | 0.06% | | -7.77 | 15.68 | 23.5 |
| 14 | FarWest 2 | 69 | -155.10 | -89.68 | 65.4 | 5.97% | -23.99 | 99.84% | -17.58 | 98.84% | 3.54 | 1.05% | 8.25 | 0.05% | | -23.99 | 8.25 | 32.2 |
| 15 | West 4 | 138 | -25.20 | 12.92 | 38.1 | 20.45% | -31.32 | 99.97% | -22.92 | 98.97% | 10.04 | 1.05% | 14.66 | 0.05% | | -31.32 | 14.66 | 46.0 |
| 16 | Coast 2 | 69 | -26.54 | 22.13 | 48.7 | 23.39% | -28.89 | 99.91% | -24.35 | 98.91% | 15.49 | 1.06% | 21.42 | 0.06% | | -28.89 | 21.42 | 50.3 |
| 17 | Coast 1 | 138 | -28.49 | 38.43 | 66.9 | 59.30% | -33.45 | 99.95% | -24.68 | 98.95% | 32.72 | 1.01% | 42.06 | 0.01% | | -33.45 | 42.06 | 75.5 |
| 18 | South 3 | 138 | -26.25 | 29.59 | 55.8 | 51.22% | -27.01 | 99.95% | -21.13 | 98.95% | 22.85 | 1.01% | 31.16 | 0.01% | | -27.01 | 31.16 | 58.2 |
| 19 | South 5 | 138 | -23.63 | 13.35 | 37.0 | 10.56% | -27.71 | 99.95% | -21.02 | 98.95% | 9.19 | 1.05% | 13.81 | 0.05% | | -27.71 | 13.81 | 41.5 |
| 20 | Coast 4 | 345 | -30.53 | 49.53 | 80.1 | 65.99% | -30.80 | 99.95% | -24.15 | 98.95% | 37.38 | 1.06% | 47.52 | 0.06% | | -30.80 | 47.52 | 78.3 |
| 21 | Coast 3 | 345 | -29.75 | 47.56 | 77.3 | 65.55% | -31.05 | 99.96% | -24.24 | 98.96% | 36.71 | 1.03% | 48.11 | 0.03% | | -31.05 | 48.11 | 79.2 |
| 22 | South 13 | 138 | -41.02 | 43.43 | 84.5 | 50.62% | -41.43 | 99.83% | -33.33 | 98.83% | 31.74 | 1.06% | 42.97 | 0.06% | | -41.43 | 42.97 | 84.4 |
| 23 | FarWest 4 | 345 | -28.73 | 50.97 | 79.7 | 68.15% | -27.47 | 99.94% | -19.69 | 98.94% | 35.81 | 1.07% | 47.69 | 0.07% | | -27.47 | 47.69 | 75.2 |
| 24 | FarWest 7 | 345 | -30.47 | 45.89 | 76.4 | 63.63% | -29.21 | 99.89% | -22.39 | 98.89% | 33.08 | 1.04% | 43.20 | 0.04% | | -29.21 | 43.20 | 72.4 |
| 25 | FarWest 8 | 138 | -39.07 | 41.67 | 80.7 | 42.58% | -39.09 | 99.92% | -31.70 | 98.92% | 27.01 | 1.02% | 40.23 | 0.02% | | -39.09 | 40.23 | 79.3 |
| 26 | FarWest 9 | 138 | -40.15 | 49.82 | 90.0 | 52.74% | -37.81 | 99.89% | -31.60 | 98.89% | 39.71 | 1.06% | 50.63 | 0.06% | | -37.81 | 50.63 | 88.4 |
| 27 | West 16 | 345 | Not enough phasor data available for analysis | | | 81.45% | -11.53 | 99.93% | -9.00 | 98.93% | 16.80 | 1.08% | 19.41 | 0.08% | | -11.53 | 19.41 | 30.9 |
| 28 | West 3 | 345 | | | | | | | | | | | | | | | | |
| 29 | West 15 | 345 | | | | 81.97% | -11.49 | 99.92% | -9.13 | 98.92% | 17.18 | 1.06% | 19.36 | 0.06% | | -11.49 | 19.36 | 30.8 |
| 30 | West 8* | 345 | No Phasor Data Available the first half of 2013 | | | 61.04% | -12.44 | 99.92% | -9.67 | 98.92% | 25.28 | 1.04% | 27.03 | 0.04% | | -12.44 | 27.03 | 39.5 |
| 31 | South 15* | 345 | | | | 50.90% | -17.35 | 99.92% | -10.37 | 98.92% | 12.13 | 1.11% | 14.70 | 0.11% | | -17.35 | 14.70 | 32.0 |
| 32 | South 2* | 345 | | | | 74.48% | -12.64 | 99.83% | -6.67 | 98.83% | 12.31 | 1.17% | 15.76 | 0.17% | | -12.64 | 15.76 | 28.4 |
| 33 | South 4* | 345 | | | | 50.35% | -17.69 | 99.89% | -10.95 | 98.89% | 12.87 | 1.08% | 15.84 | 0.08% | | -17.69 | 15.84 | 33.5 |
| 34 | South 7* | 345 | | | | 78.73% | -15.05 | 99.94% | -7.70 | 98.94% | 15.38 | 1.08% | 19.62 | 0.08% | | -15.05 | 19.62 | 34.7 |
| 35 | South 9* | 345 | | | | 46.84% | -15.74 | 99.84% | -10.40 | 98.84% | 11.64 | 1.12% | 13.93 | 0.12% | | -15.74 | 13.93 | 29.7 |
| 36 | South 11* | 345 | | | | 48.18% | -19.39 | 99.96% | -12.27 | 98.96% | 12.80 | 1.20% | 15.70 | 0.20% | | -19.39 | 15.70 | 35.1 |
| 37 | South 10* | 138 | | | | 18.13% | -29.58 | 99.77% | -25.06 | 98.77% | 14.27 | 1.09% | 18.42 | 0.09% | | -29.58 | 18.42 | 48.0 |
| 38 | West 17* | 345 | | | | Substations not in service during the January to December 2013 period. | | | | | | | | | | PSSE data not available for 2013. | | |
| 39 | West 13* | 345 | | | | | | | | | | | | | | | | |

Note: The substations market with * did not have PMUs installed in 2013; no phasor data available.

NOTE: the substations noted with a * have no phasor data available for 2013.

Summaries of voltage angle pairs with their corresponding box-whisker and time duration curves based on state estimator data and based on phasor data are presented in Appendix B, Parts 1 and 2.

D. Observations

1. Voltage angles vary over a wide-range for several substations. The largest variation of 88.4 degrees (-37.8 to 50.6 degrees) occurred at FarWest 9 138 kV substation. Among the 345 kV substations, the largest angle variation over the 12-months of 2013 occurred at Coast 3 with a range of 79.2 (-31.05 to 48.11) degrees. The lowest angle variation occurred at North 6 (23.5 degrees).

2. The largest angle variations occurred among the substations in the southern part of the state namely: South 13, Coast 3, Coast 4 and Coast 1.
3. The next largest angle variations occurred in the Central and Western part of the state namely: FarWest 7, West 11, West 6, FarWest 8, FarWest 9, FarWest 4, West 2, West 9 and West 5.
4. The two largest normal angles observed were at Coast 3 345 kV and FarWest 9 138 kV substations with 48.11 and 50.63 degrees respectively.
5. The minimum angles occurred at Coast 3 345 and South 13 138 kV substations with 31.05 and 41.43 degrees respectively.
6. Angle spreads were lower for normal conditions than for all conditions, as expected.

7. COMPARISON OF VOLTAGE ANGLES (Ref.: North 7) – 2012 vs. 2013

A. Goal:

EPG performed a comparison of voltage angles for a number of pairs to determine the effect the new CREZ lines had on the performance of the ERCOT grid. Following are the results of that comparison.

B. Pairs Selected For Comparison

Twelve pairs were selected to compare voltage angles between 2012 and 2013 conditions. They listed in Table 5 below.

Table 5 – Angle Pairs for Voltage Angle Comparison (Monthly Median for 2012 and 2013)

| TABLE 5: ANGLE PAIRS FOR VOLTAGE ANGLE COMPARISON (Monthly Median for 2012 and 2013) | | | | |
|-------------------------------------------------------------------------------------------------|--------------|--------------|-------------|--------------|
| # | Substation A | Substation B | From Region | To Region |
| 1 | West 10 | North 7 | Panhandle | Central-East |
| 2 | West 14 | North 7 | Panhandle | Central-East |
| 3 | West 9 | North 7 | Panhandle | Central-East |
| 4 | West 5 | North 7 | Panhandle | Central-East |
| 5 | FarWest 7 | North 7 | West Texas | Central-East |
| 6 | FarWest 7 | South 9 | West Texas | Central-East |
| 7 | West 11 | North 7 | West Texas | Central-East |
| 8 | North 5 | North 7 | Dallas | Central-East |
| 9 | North 6 | North 7 | East | Central-East |
| 10 | Coast 1 | North 7 | Valley | Central-East |
| 11 | South 13 | South 11 | Valley | Valley |
| 12 | West 4 | South 11 | Valley | Valley |
| 13 | FarWest 9 | South 11 | West Texas | Valley |
| 14 | South 11 | North 7 | Valley | Central-East |

C. Procedure

This monthly median comparison was completed using median values to avoid as much as possible distortions in the comparison. State Estimator data was collected for the 12-months of 2012 and 2013, and analyzed to produce monthly median comparison values shown in Table 6 below.

In addition to these daily median graphs, Box-whisker plots were developed for each pair using median values. These Box-whisker plots produced a new median for 2012 and for 2013.

D. Results

The results of the comparison are shown in Table 6 below. Observation of these results shows that for most of the angle pairs analyzed, the 2013 median voltage angle differences (relative to North 7) were lower than the 2012 monthly median values. Two angle pairs show an increase in monthly median values. More details in the section below.

Table 6 – Voltage Angle Comparison (Monthly Median), 2012 vs. 2013

| Table 6 - VOLTAGE ANGLE COMPARISON (MONTHLY MEDIAN) | | | | |
|------------------------------------------------------------|--------------------|----------------------|-------------|------------|
| 2012 vs. 2013 | | | | |
| # | Angle Pair | VOLTAGE ANGLE MEDIAN | | |
| | | 2012 Median | 2013 Median | Difference |
| 1 | West 10-North 7 | 14.1 | 7.3 | 6.8 |
| 2 | West 14-North 7 | 9.4 | 9.7 | -0.3 |
| 3 | West 9-North 7 | 10.8 | 6.6 | 4.2 |
| 4 | West 5-North 7 | 10.5 | 6.4 | 4.1 |
| 5 | FarWest 7-North 7 | 8.6 | 5.1 | 3.6 |
| 6 | FarWest 7-South 9 | 7.3 | 5.4 | 1.9 |
| 7 | West 11-North 7 | 10.4 | 6.3 | 4.2 |
| 8 | North 5-North 7 | -2.7 | -4.7 | 2.0 |
| 9 | North 6-North 7 | 5.4 | 4.0 | 1.4 |
| 10 | Coast 1-North 7 | 8.8 | 3.4 | 5.4 |
| 11 | South 13-South 11 | 2.3 | 0.2 | 2.1 |
| 12 | West 4-South 11 | -8.4 | -6.3 | -2.0 |
| 13 | FarWest 9-South 11 | 4.7 | 1.5 | 3.2 |
| 14 | South 11-North 7 | 2.2 | -0.2 | 2.4 |

E. Review of Table 6 Shows the Following:

- i. All pairs in the list, except the West 14 and North 5 to North 7 pairs, had a decrease in angle median.
- ii. The largest difference occurred on the West 10, West 9, West 5, West 11 and Coast 1 to North 7 pairs. All these substations are located in West Texas except for Coast 1.
- iii. The FarWest 7 and North 6 to North 7 pairs had the lowest reduction: 1.9 and 1.4 degrees respectively.
- iv. The West 14 and North 5 to North 7 pairs had an increase in angle median of 0.3 and 2.0 degrees respectively.
- v. Coast 1 to North 7 pair had a reduction of 5.4 degrees. This reduction is significant though EPG is not aware of new lines added between the Valley and the North 7 area in 2013. This could be explained by an increase in wind power from the northwest part of Texas resulting in lower power transfer (lower angles) from the south.

F. Conclusions

- i. The new transmission lines added since July, 2012, have tightened the ERCOT system, which is reflected in the reduced voltage angle differences for twelve pairs being lower in 2013 than in 2012.
- ii. These voltage angles may change again with the addition of wind resources in West Texas and the Panhandle.
- iii. Some angle pairs are expected to change with the addition of a few more CREZ lines added in January and March of 2014. This analysis will be revised using data for the first six-months of 2014.

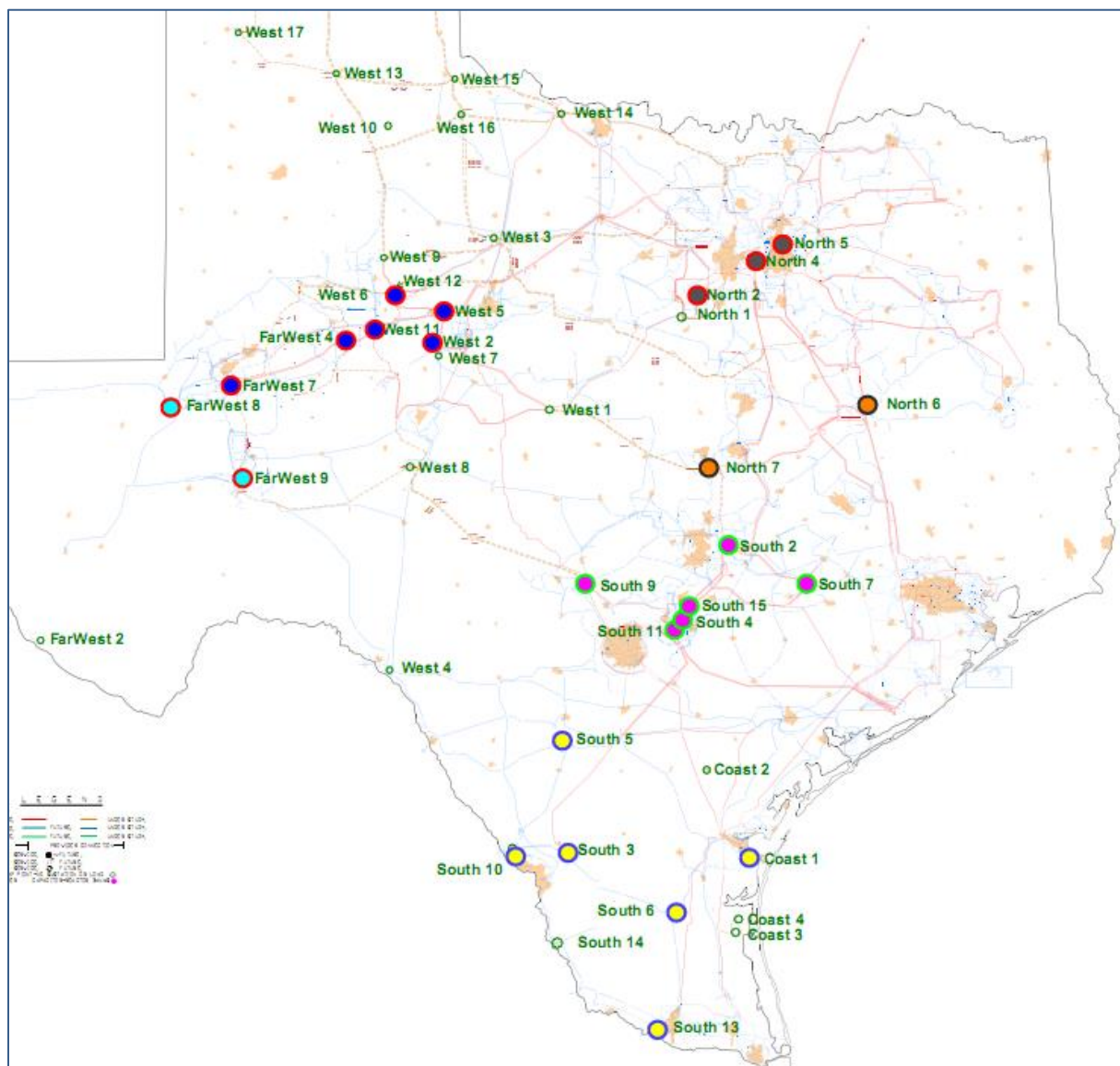
8. BASELINE ANALYSIS FOR ANGLE DIFFERENCES

A. Pairs of Substations Identified for Angle Difference Analysis

The following pairs of substations were selected to perform the angle difference analysis (also see map below):

Table 7 – Angle Pairs for Angle Differences Analysis Update 2

| TABLE 7: ANGLE PAIRS FOR ANGLE DIFFERENCES ANALYSIS UPDATE #2 | | | | |
|-----------------------------------------------------------------------|--------------|--------------|--------------|--------------|
| PAIRS WITH PHASOR DATA AVAILABLE | | | | |
| # | Substation A | Substation B | From Region | To Region |
| 1 | Coast 1 | South 13 | Valley | Valley |
| 2 | Coast 1 | North 7 | Valley | Central-East |
| 3 | West 5 | West 10 | Central | Panhandle |
| 4 | West 5 | FarWest 4 | Central | West Texas |
| 5 | West 5 | North 1 | Central | Central |
| 6 | West 5 | North 7 | Central | Central-East |
| 7 | North 1 | North 7 | Dallas | Central-East |
| 8 | North 1 | North 4 | Dallas | Central |
| 9 | North 4 | North 7 | Central | Central-East |
| 10 | North 7 | North 6 | Central-East | East |
| 11 | North 4 | North 6 | Central | East |
| 12 | FarWest 7 | FarWest 4 | West Texas | West Texas |
| 13 | FarWest 7 | West 14 | West Texas | Panhandle |
| 14 | FarWest 7 | FarWest 8 | West Texas | West Texas |
| 15 | FarWest 7 | FarWest 9 | West Texas | West Texas |
| 16 | FarWest 7 | North 7 | West Texas | Central-East |
| 17 | West 12 | FarWest 7 | Central | West Texas |
| 18 | West 12 | West 1 | Central | Central-East |
| 19 | West 12 | North 1 | Central | Dallas |
| 20 | West 14 | West 5 | Panhandle | Central |
| 21 | West 14 | North 1 | Panhandle | Dallas |
| 22 | FarWest 9 | West 4 | West Texas | Southwest |
| 23 | West 4 | North 7 | SouthWest | Central-East |
| 24 | West 16 | West 3 | Panhandle | Panhandle |
| 25 | West 16 | West 14 | Panhandle | Panhandle |
| 26 | West 15 | West 14 | Panhandle | Panhandle |
| PAIRS WITHOUT PHASOR DATA AVAILABLE | | | | |
| 27 | Coast 1 | South 10* | Valley | Valley |
| 28 | South 3 | South 11* | Valley | Central-East |
| 29 | South 11* | North 7 | Valley | Central-East |
| 30 | North 7 | South 7* | Central-East | Central-East |
| 31 | North 7 | South 9* | Central-East | Central-East |
| 32 | West 11 | West 8* | Central | Central |
| 33 | West 8 | South 9* | Central | Central-East |
| 34 | FarWest 7 | South 9* | West Texas | Central-East |
| 35 | FarWest 9 | South 9* | West Texas | Central-East |
| 36 | West 19* | West 9 | Panhandle | Panhandle |
| * Denotes substations without existing PMUs or w/o phasor data stream | | | | |



B. Summary of Results – All Data Included

Table C- 1 below contains angle difference results for all those angle pairs selected for study. Several PMUs were connected to the ERCOT grid during the year 2013 and were streaming phasor data. As a result, 26 pairs with phasor data were included in the analysis (total of 36). Table C- 1 shows min, max and average values for angle differences obtained from all data received for the 12-months of 2013 (all solved SE cases and all phasor data, normal and contingency conditions). Phasor data was not available for some of the pairs selected for study; no phasor results are provided for those pairs.

Data availability for those pairs which had at least one PMU recently added, shows low values because the availability is calculated based on the entire 12-months.

Observation of Table C- 1 results shows the following:

- Five pairs show Max-Min angle spreads greater than 80 degrees: Coast 1-North 7, FarWest 7-North 7, FarWest 9-West 4, FarWest 7-South 9 and FarWest 9-South 9.
- Max-Min angle spread of less than 15 degrees occurred on the following pairs: Comanche to North 4, FarWest 7 to FarWest 8 and West 11 to West 8.
- Sixteen pairs have spread between 15 and 40 degrees and nine pairs have Max-Min spreads of between 40 to 80 degrees.
- Four pairs have maximum angles greater than 50 degrees: FarWest 7-North 7, FarWest 9-West 4, FarWest 7-South 9 and FarWest 9-South 9.
- Six pairs have minimum angles lower than -30 degrees: Coast 1-North 7, FarWest 7-North 7, FarWest 9-West 4, West 4-North 7, FarWest 7-South 9 and FarWest 9-South 9.

Table C- 1 – Baselining Analysis – Summary of Angle Differences – All Data

| Table C-1 - CCET DISCOVERY ACROSS TEXAS- BASELINING ANALYSIS- SUMMARY OF ANGLE DIFFERENCES - ALL DATA | | | | | | | | | | | | |
|-------------------------------------------------------------------------------------------------------|---------------------|------------|--------------------------------------------------------------------------------------------------------|-------|---------|------------------|------------------|-------------------------------------------|-------|---------|------------------|----------------|
| | | | Phasor Data - 1/1/13 to 12/31/13 | | | | | State Estimator Data - 1/1/13 to 12/31/13 | | | | |
| | Angle Pair | Base kV | Min | Max | Max-Min | Percent Positive | % Data Available | Min | Max | Max-Min | Percent Positive | Max-Min Spread |
| 1 | Coast 1-South 13 | 138kV | -20.00 | 49.99 | 69.99 | 66.01 | 77.74 | -19.37 | 31.69 | 3.19 | 65.4% | 51.1 |
| 2 | Coast 1-North 7 | 138kV | -36.75 | 50.83 | 87.58 | 59.74 | 86.45 | -35.89 | 44.81 | 3.28 | 59.3% | 80.7 |
| 3 | West 5-West 10 | 345/69kV | -24.97 | 24.99 | 49.96 | 57.71 | 52.23 | -23.88 | 15.88 | -0.72 | 51.7% | 39.8 |
| 4 | West 5-FarWest 4 | 345kV | -11.49 | 9.39 | 20.88 | 51.47 | 51.99 | -10.50 | 9.15 | -0.32 | 48.4% | 19.7 |
| 5 | West 5-North 1 | 345kV | -19.30 | 25.72 | 45.01 | 33.51 | 53.04 | -18.64 | 36.19 | 0.93 | 48.5% | 54.8 |
| 6 | West 5-North 7 | 345/138kV | -16.47 | 30.23 | 46.70 | 62.61 | 53.07 | -26.90 | 48.06 | 7.42 | 71.0% | 75.0 |
| 7 | North 1-North 7 | 345/138 kV | -12.33 | 26.41 | 38.74 | 93.29 | 92.78 | -11.20 | 24.01 | 6.49 | 93.8% | 35.2 |
| 8 | North 1-North 4 | 345/138kV | 4.33 | 16.34 | 12.01 | 100.00 | 92.77 | 4.05 | 15.49 | 8.96 | 100.0% | 11.4 |
| 9 | North 4-North 7 | 138kV | -18.85 | 14.43 | 33.28 | 23.27 | 92.91 | -17.84 | 13.60 | -2.47 | 25.2% | 31.4 |
| 10 | North 7-North 6 | 138kV | -17.31 | 8.29 | 25.60 | 8.50 | 90.77 | -17.25 | 10.70 | -3.82 | 14.8% | 28.0 |
| 11 | North 4-North 6 | 138kV | -27.48 | 4.69 | 32.18 | 2.41 | 90.77 | -20.43 | 5.04 | -6.30 | 4.9% | 25.5 |
| 12 | FarWest 7-FarWest 4 | 345kV | -9.99 | 3.99 | 13.98 | 13.13 | 89.95 | -10.51 | 4.60 | -2.27 | 10.9% | 15.1 |
| 13 | FarWest 7-West 14 | 345kV | -27.18 | 26.65 | 53.82 | 43.63 | 78.67 | -25.16 | 21.19 | -1.17 | 43.4% | 46.4 |
| 14 | FarWest 7-FarWest 8 | 345/138kV | 2.00 | 13.83 | 11.83 | 100.00 | 81.95 | 2.84 | 13.58 | 7.91 | 100.0% | 10.7 |
| 15 | FarWest 7-FarWest 9 | 345/138kV | -19.98 | 29.94 | 49.92 | 68.20 | 85.31 | -17.09 | 26.89 | 3.01 | 64.7% | 44.0 |
| 16 | FarWest 7-North 7 | 345/138kV | -35.49 | 59.79 | 95.28 | 61.92 | 92.78 | -34.04 | 55.59 | 5.80 | 63.6% | 89.6 |
| 17 | West 12-FarWest 7 | 345kV | -12.82 | 14.12 | 26.95 | 67.85 | 52.93 | -9.64 | 13.59 | 1.99 | 74.5% | 23.2 |
| 18 | West 12-West 1 | 345kV | -15.99 | 20.96 | 36.95 | 61.02 | 52.85 | -7.01 | 14.62 | 2.28 | 69.9% | 21.6 |
| 19 | West 12-North 1 | 345kV | -20.51 | 28.79 | 49.30 | 33.05 | 53.02 | -19.59 | 37.65 | 1.09 | 48.3% | 57.2 |
| 20 | West 14-West 5 | 345kV | -21.62 | 12.90 | 34.52 | 59.60 | 41.69 | -21.33 | 12.24 | -0.64 | 50.1% | 33.6 |
| 21 | West 14-North 1 | 345kV | -13.00 | 16.81 | 29.81 | 45.93 | 78.58 | -10.03 | 14.86 | 1.99 | 65.6% | 24.9 |
| 22 | FarWest 9-West 4 | 138kV | -34.84 | 54.94 | 89.79 | 70.66 | 70.41 | -30.09 | 60.11 | 8.89 | 71.6% | 90.2 |
| 23 | West 4-North 7 | 138kV | -35.00 | 18.95 | 53.95 | 19.98 | 72.70 | -32.46 | 16.94 | -6.18 | 20.5% | 49.4 |
| 24 | West 16-West 3 | 345kV | PMUs at new West 16, West 3 and West 15 substations had less than 16% data available; not enough data. | | | | | Not enough data available | | | | |
| 25 | West 16-West 14 | 345kV | | | | | | | | | | |
| 26 | West 15-West 14 | 345kV | | | | | | | | | | |
| 27 | Coast 1-South 10* | 138kV | PMUs at the stations market with * are not available. Phasor data is not available for these pairs | | | | | -10.38 | 33.67 | 9.92 | 84.6% | 44.1 |
| 28 | South 3-South 11* | 138kV | | | | | | -21.35 | 21.54 | 0.26 | 50.4% | 42.9 |
| 29 | South 11*-North 7 | 345/69kV | | | | | | -21.08 | 18.56 | 0.06 | 48.2% | 39.6 |
| 30 | North 7-South 7* | 138/345kV | | | | | | -21.19 | 16.09 | -3.85 | 21.2% | 37.3 |
| 31 | North 7-South 9* | 138/345kV | | | | | | -16.37 | 18.41 | 0.13 | 53.1% | 34.8 |
| 32 | West 11-West 8* | 345kV | | | | | | -2.84 | 5.75 | 0.68 | 64.8% | 8.6 |
| 33 | West 8-South 9* | 345kV | | | | | | -24.69 | 30.69 | 3.26 | 57.8% | 55.4 |
| 34 | FarWest 7-South 9* | 345kV | | | | | | -37.01 | 56.88 | 6.05 | 64.1% | 93.9 |
| 35 | FarWest 9-South 9* | 138/345kV | | | | | | -44.29 | 64.43 | 3.04 | 53.0% | 108.7 |
| 36 | West 19*- West 9 | 345kV | | | | | | | | | | |
| * Denotes substations without existing PMUs or w/o data stream | | | | | | | | | | | | |

* Denotes substations without existing PMUs or w/o data stream

C. Criteria to Identify Normal Operations Limits for Angle Differences

The data received, both phasor and state estimator, provide information for all conditions during the study period including those conditions where the system experienced outages of lines or generators. This study is intended to provide angle difference limits that can be expected during normal operations; that is, when all facilities are in service. The following criteria were used to determine the angle difference limits expected during normal operations for the selected substation pairs.

- i. If the angle difference time duration curves show only positive angles, then two limits will be identified: one corresponding to the angle difference that occurred at about one percent of the time, and the other corresponding to the maximum value observed.
- ii. If the angle difference time duration curves show positive as well as negative angles, then four limits will be identified, two for one direction of flow and two for the opposite direction of flow, based on the criteria below:
 - The first limit in either direction will be set using state estimator results by selecting the maximum (or minimum) angle difference observed on the corresponding time duration curves if the box-whisker and time duration plots show no extreme values (outliers or extreme values due to events in the system). If extreme values or outliers are present, a point of inflection will be determined and the maximum or minimum angle will be set at the angle corresponding to the point of inflection.
 - The second max limit will be set at the angle difference which occurred 1% more time than the time corresponding to the selected maximum limit, based on the time duration curve. The second minimum limit will be set at the angle difference corresponding to 1% less time than the time corresponding to the selected minimum limit.
- iii. In some cases such as when there was an extended outage, EPG reproduced the time duration curve excluding those days when the extended outage occurred to determine the angle differences corresponding to normal conditions.
- iv. The 1% values can be used to set alarms for the operators to be notified of impending maximum angle differences. The maximum and minimum values can be used to set alarms notifying the operator that expected maximum or minimum values have been reached.
- v. The alarms so determined should be monitored for a year against actual values observed during operation. If maximum values are exceeded, the observed values should be logged and documented for further analysis.
- vi. Maximum and minimum angle differences will change as major changes occur in the system, such as the addition of the 345 kV CREZ lines to the ERCOT system. This analysis should be revised based on at least six-months of historical data obtained with all the new transmission lines in place. Maximum and minimum values can also be estimated from many power flow cases representing different system conditions of the year. After all the CREZ lines are added to the ERCOT system, March 22, 2014, this study and conclusions should be updated to reflect the impact of those significant additions.

D. Summary of Results – Normal Conditions

The angle difference results for normal conditions are summarized in Table C- 2 below, which was developed based on the criteria described above.

Box-whisker and time duration curves were developed for each of the pairs analyzed. Angle differences that may be the results of contingencies were excluded by reviewing points of inflection; that is, points that significantly deviated from the normal operation trend observed in the box-whisker plots. The value of angle difference at the point of inflection was considered to be the maximum angle during normal conditions. If no outlier points were identified, then the angle corresponding to the 0% or 100% time points will represent the maximum and minimum angles reached during normal operations in either direction of flow. SE-based voltage angle pairs with their corresponding box-whisker and time duration curves as well as phasor-based voltage angle pairs with their corresponding box-whisker and time duration curves are presented in Appendix C.

Table C- 2 – Baselining Analysis – Summary of Angle Differences – Normal Data

| Table C-2 BASELINING ANALYSIS- SUMMARY OF ANGLE DIFFERENCES - NORMAL CONDITIONS | | | | | | | | | | | | | | | | | |
|---------------------------------------------------------------------------------|-------------------------|-----------|---------|------------------------------------------|-----------|------------------------------------------------------|--------------------------|-----------------------|------------------------------|---------------------------|----------------------------|-------------------------|------------------------|---------------------|-----------------|-----------|----------------|
| | | | | DATA RESULTS | | | | | | | | | | | | | |
| | | | | Phasor Data | | State Estimator Data - 1/1/13 to 12/31/13 | | | | | | | | | SE Data-Normal | | |
| No | Angle Pair FROM - TO | | Base kV | Min Angle | Max Angle | Percent Positive | Min Angle at POI or 100% | Percent (POI or 100%) | Min Angle at 99% or POI - 1% | Percent (99% or POI - 1%) | Max Angle at 1% or POI +1% | Percent (1% or POI +1%) | Max Angle at POI or 0% | Percent (POI or 0%) | Min Angle | Max Angle | Max-Min Spread |
| 1 | Coast 1 | South 13 | 138 | -15.49 | 42.6 | 65.43% | -16.65 | 99.91% | -12.21 | 98.91% | 20.56 | 1.03% | 23.50 | 0.03% | -16.65 | 23.50 | 40.1 |
| 2 | Coast 1 | North 7 | 138 | -28.49 | 38.43 | 59.30% | -30.03 | 99.89% | -24.50 | 98.89% | 32.61 | 1.08% | 38.83 | 0.08% | -30.03 | 38.83 | 68.9 |
| 3 | West 5 | West 10 | 345/69 | -19.73 | 18.44 | 51.65% | -21.03 | 99.91% | -17.86 | 98.91% | 13.70 | 1.17% | 15.00 | 0.17% | -21.03 | 15.00 | 36.0 |
| 4 | West 5 | FarWest 4 | 345 | -9.51 | 5.83 | 48.44% | -9.39 | 99.89% | -5.23 | 98.89% | 4.67 | 1.13% | 5.10 | 0.13% | -9.39 | 5.1 | 14.5 |
| 5 | West 5 | North 1 | 345 | 17.00 | 23.53 | 48.46% | -16.93 | 99.87% | -15.73 | 98.87% | 21.53 | 1.04% | 26.96 | 0.04% | -16.93 | 26.96 | 43.9 |
| 6 | West 5 | North 7 | 345/138 | -13.74 | 29.25 | 71.00% | -22.79 | 99.84% | -14.51 | 98.84% | 31.53 | 1.09% | 43.95 | 0.09% | -22.79 | 43.95 | 66.7 |
| 7 | North 1 | North 7 | 345/138 | -9.99 | 20.95 | 93.78% | -8.02 | 99.77% | -4.82 | 98.77% | 16.32 | 1.14% | 19.85 | 0.14% | -8.02 | 19.85 | 27.9 |
| 8 | North 1 | North 4 | 345/138 | 4.47 | 15.32 | 100.00% | 4.23 | 99.82% | 5.42 | 98.82% | 13.05 | 1.17% | 14.76 | 0.17% | 4.23 | 14.76 | 10.5 |
| 9 | North 4 | North 7 | 138 | -17.60 | 9.86 | 25.23% | -15.52 | 99.88% | -12.32 | 98.88% | 6.35 | 1.12% | 9.50 | 0.12% | -15.52 | 9.50 | 25.0 |
| 10 | North 7 | North 6 | 138 | -14.73 | 7.64 | 14.79% | -15.74 | 99.94% | -11.59 | 98.94% | 4.09 | 1.11% | 7.90 | 0.11% | -15.74 | 7.90 | 23.6 |
| 11 | North 4 | North 6 | 138 | -22.75 | 3.43 | 4.88% | -19.16 | 99.90% | -16.56 | 98.90% | 2.16 | 1.03% | 4.33 | 0.03% | -19.16 | 4.33 | 23.5 |
| 12 | FarWest 7 | FarWest 4 | 345 | -8.34 | 3.11 | 10.90% | -10.16 | 99.86% | -7.15 | 98.86% | 1.96 | 1.06% | 3.90 | 0.06% | -10.16 | 3.90 | 14.1 |
| 13 | FarWest 7 | West 14 | 345 | -21.62 | 20.34 | 43.37% | -19.65 | 99.90% | -16.97 | 98.90% | 15.62 | 1.08% | 19.05 | 0.08% | -19.65 | 19.05 | 38.7 |
| 14 | FarWest 7 | FarWest 8 | 345/138 | 3.75 | 13.52 | 100.00% | 3.25 | 99.94% | 4.30 | 98.94% | 11.51 | 1.11% | 13.04 | 0.11% | 3.25 | 13.04 | 9.8 |
| 15 | FarWest 7 | FarWest 9 | 345/138 | -12.85 | 18.66 | 64.70% | -13.50 | 99.96% | -11.41 | 98.96% | 16.25 | 1.07% | 17.50 | 0.07% | -13.50 | 17.50 | 31.0 |
| 16 | FarWest 7 | North 7 | 345/138 | -30.47 | 45.89 | 63.63% | -29.05 | 99.87% | -22.30 | 98.87% | 33.11 | 1.03% | 40.70 | 0.03% | -29.05 | 40.70 | 69.7 |
| 17 | West 12 | FarWest 7 | 345 | -7.70 | 9.66 | 74.53% | -7.03 | 99.87% | -5.06 | 98.87% | 8.79 | 1.23% | 10.20 | 0.23% | -7.03 | 10.20 | 17.2 |
| 18 | West 12 | West 1 | 345 | -7.27 | 14.26 | 69.91% | -5.86 | 99.78% | -4.62 | 98.78% | 12.27 | 1.11% | 13.58 | 0.11% | -5.86 | 13.58 | 19.4 |
| 19 | West 12 | North 1 | 345 | -17.25 | 26.48 | 48.32% | -17.95 | 99.92% | -15.86 | 98.92% | 23.24 | 1.14% | 26.64 | 0.14% | -17.95 | 26.64 | 44.6 |
| 20 | West 14 | West 5 | 345 | -16.75 | 11.37 | 50.06% | -15.54 | 99.87% | -13.62 | 98.87% | 9.62 | 1.03% | 11.90 | 0.03% | -15.54 | 11.90 | 27.4 |
| 21 | West 14 | North 1 | 345 | -10.24 | 13.22 | 65.58% | -9.36 | 99.83% | -7.23 | 98.83% | 10.90 | 1.21% | 12.47 | 0.21% | -9.36 | 12.47 | 21.8 |
| 22 | FarWest 9 | West 4 | 138 | -29.80 | 48.48 | 71.57% | -26.48 | 99.89% | -19.65 | 98.89% | 39.74 | 1.07% | 46.01 | 0.07% | -26.48 | 46.01 | 72.5 |
| 23 | West 4 | North 7 | 138 | -25.20 | 12.92 | 20.45% | -29.03 | 99.88% | -22.77 | 98.88% | 9.92 | 1.13% | 13.97 | 0.13% | -29.03 | 13.97 | 43.0 |
| 24 | West 16 | West 3 | 345 | Not enough data | | One or more substations are new with not enough data | | | | | | | | | Not enough data | | |
| 25 | West 16 | West 14 | 345 | | | | | | | | | | | | | | |
| 26 | West 15 | West 14 | 345 | | | | | | | | | | | | | | |
| 27 | Coast 1 | South 10* | 138 | NO PHASOR DATA AVAILABLE FOR THESE PAIRS | | 84.56% | -8.68 | 99.82% | -6.82 | 98.82% | 26.65 | 1.06% | 30.76 | 0.06% | -8.68 | 30.76 | 39.4 |
| 28 | South 3 | South 11* | 138/345 | | | 50.43% | -18.22 | 99.86% | -14.79 | 98.86% | 15.32 | 1.11% | 18.88 | 0.11% | -18.22 | 18.88 | 37.1 |
| 29 | South 11* | North 7 | 138/345 | | | 48.18% | -16.54 | 99.63% | -11.21 | 98.63% | 12.89 | 1.15% | 16.02 | 0.15% | -16.54 | 16.02 | 32.6 |
| 30 | North 7 | South 7* | 138/345 | | | 21.21% | -18.05 | 99.83% | -15.22 | 98.83% | 7.38 | 1.14% | 14.37 | 0.14% | -18.05 | 14.37 | 32.4 |
| 31 | North 7 | South 9* | 138/345 | | | 53.07% | -13.80 | 99.88% | -11.63 | 98.88% | 10.55 | 1.10% | 16.39 | 0.10% | -13.80 | 16.39 | 30.2 |
| 32 | West 11 | West 8* | 345 | | | 64.80% | -2.31 | 99.85% | -1.71 | 98.85% | 4.88 | 1.11% | 5.47 | 0.11% | -2.31 | 5.47 | 7.8 |
| 33 | West 8 | South 9* | 345 | | | 57.84% | -23.88 | 99.91% | -19.73 | 98.91% | 27.17 | 1.19% | 29.36 | 0.19% | -23.88 | 29.36 | 53.2 |
| 34 | FarWest 7 | South 9* | 345 | | | 64.13% | -31.48 | 99.88% | -23.21 | 98.88% | 36.74 | 1.13% | 42.77 | 0.13% | -31.48 | 42.77 | 74.3 |
| 35 | FarWest 9 | South 9* | 138/345 | | | 52.96% | -39.57 | 99.87% | -32.87 | 98.87% | 42.59 | 1.12% | 49.40 | 0.12% | -39.57 | 49.40 | 89.0 |
| 36 | West 19* | West 9 | 345 | | | One or more substations are new with not enough data | | | | | | | | | Not enough data | | |
| NOTE: These results were obtained with 2013 data. | | | | | | | | | | | | | | | | | |

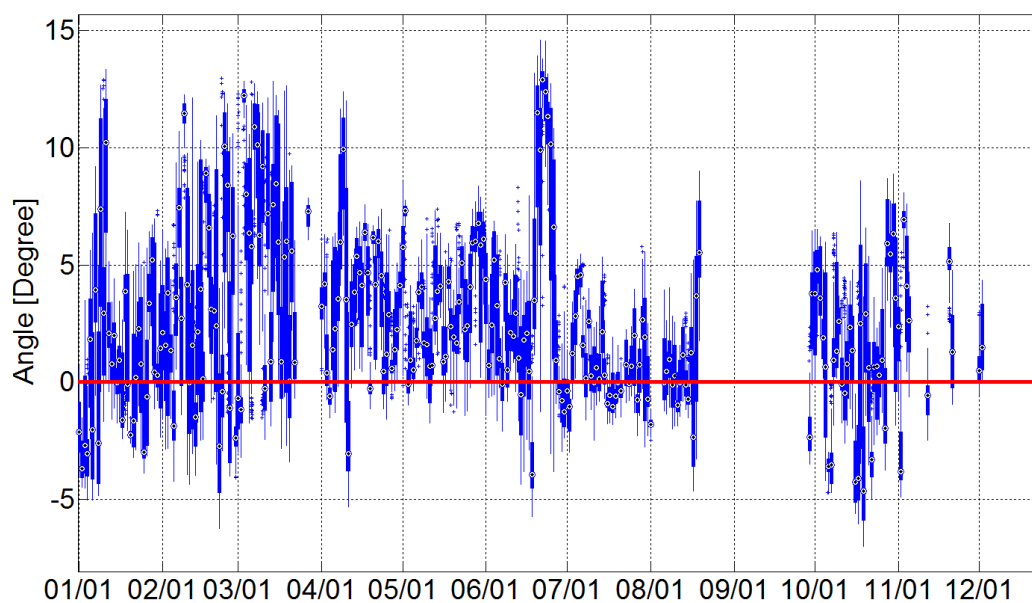
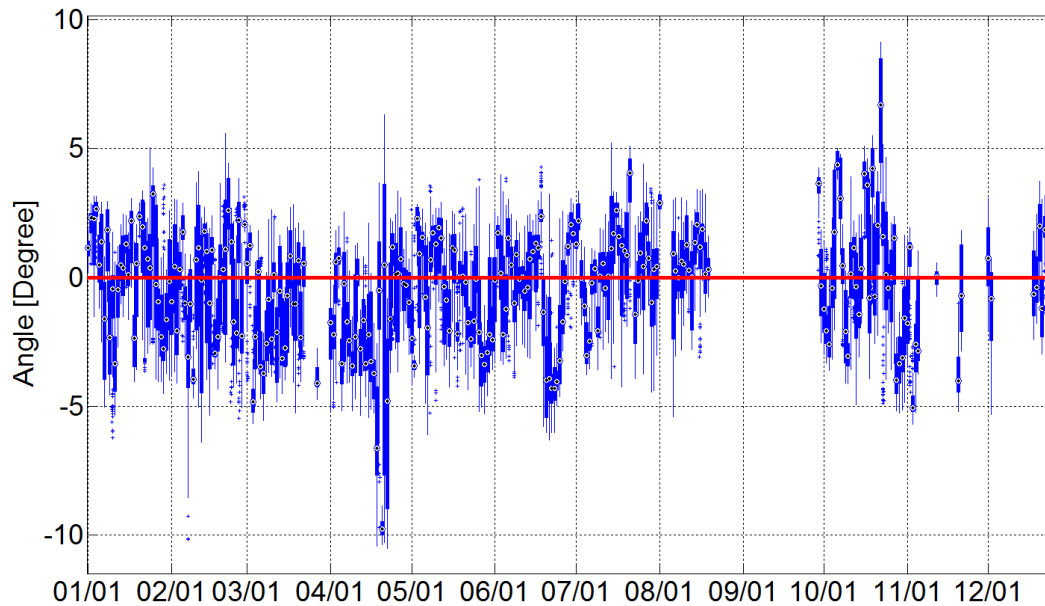
NOTE: These results were obtained with 2013 data.

E. Observations from Table C-2

1. The maximum Max-Min angle spreads under normal conditions occurred at FarWest 9-Hamilton (72.5), FarWest 7-South 9 (74.5), and FarWest 9-South 9 (89).
2. The angle pairs with Max-Min spreads less than 10 degrees are: FarWest 7-FarWest 8 (9.8) and West 11-West 8 (7.8).
3. The maximum voltage angles under normal conditions occurred at FarWest 9-West 4 (46.01) and FarWest 9-South 9 (49.4). Minimum angles occurred at Coast 1-North 7 (-30.03), FarWest 7-South 9 (-31.48), and FarWest 9-South 9 (-39.57).
4. Fourteen pairs had maximum angles of less than 15 degrees and the rest had angles between 15 and 49.4 degrees. Nine substations had minimum angles lower than -20 degrees.

F. Observations from Box-whisker Plots (Appendix C-Part 1)

1. State Estimator (SE) data is missing for the last 10-days of March, mid-August to late September and for most of November and December for most substations.
2. SE data for FarWest 7-West 14, West 14-West 5 and West 14-North 1 is missing for the great majority of July through December period. Since West 14 is the common substations for these three pairs, it is reasonable to suspect that the EMS data at West 14 needs checking.
3. SE data for West 16-West 14 and West 15-West 14 is available for only a few days at the beginning of October 2013; not enough data for analysis.
4. SE data for West 11-West 8 and West 8-South 9 is available only for June, July and part of August; SE data is missing for the rest of the year 2013.
5. Several angle pairs exhibit abrupt changes in angle that may be due to outages or construction work. Some of these changes last several days before returning to the original values. If the abrupt changes are due to construction/maintenance work, then the “normal operations” angles differences may need to be revisited with feedback from ERCOT operation personnel. Examples: Coast 1-South 13, West 5-FarWest 4, West 5-North 1, West 5-North 7, North 1-North 7, North 1-North 4, North 4-North 7, North 7-North 6, FarWest 7-FarWest 4, FarWest 7-West 14, FarWest 7-North 7, West 12-West 1, West 12-North 1, West 4-North 7, South 11-North 7, North 7-South 7, North 7-South 9 and FarWest 7-South 9.
6. If there were extended outages, the angles corresponding to the outage time should be excluded from the data used to establish normal operation alarm limits.
7. Examples of these abrupt angle changes are shown for West 5-FarWest 4 and West 12-West 1 below:



9. PAIRS FOR REAL TIME MONITORING

A. Criteria for Selection of Angle Pairs for Real-time Monitoring

1. Choose a few transmission paths (pairs) from the wind areas to monitor wind power delivery.
2. Choose a load center such as North 1 and select transmission paths serving such loads.
3. Choose transmission paths delivering power from the Valley.

4. Choose transmission paths connecting the load centers such as Dallas, Austin, San Antonio and Houston areas (no PMUs in the Houston area at this time).

NOTE: Because there are not enough PMUs installed in the system, EPG chose pairs that meet the criteria as closely as possible.

B. Transmission Paths (PAIRS) Selected for Real Time Monitoring

The transmission paths selected for monitoring are shown in Table 8 below:

Table 8 – Angle Pairs Selected for Real-time Monitoring (Based on PMU Availability)

| TABLE 8: ANGLE PAIRS SELECTED FOR REAL TIME MONITORING (Based on PMU Availability) | | | | |
|-----------------------------------------------------------------------------------------------|-----------------------------------------------------------------------|--------------|-------------|--------------|
| PAIRS WITH PHASOR DATA AVAILABLE | | | | |
| # | Substation A | Substation B | From Region | To Region |
| 1 | Coast 1 | South 13 | Valley | Valley |
| 2 | Coast 1 | North 7 | Valley | Central-East |
| 3 | Coast 4 | North 7 | Valley | Central-East |
| 4 | South 3 | South 11* | Valley | Valley |
| 5 | South 11* | North 7 | Valley | Central-East |
| 6 | North 6 | North 7 | East | Central-East |
| 7 | North 4 | North 7 | Dallas | Central-East |
| 8 | West 14 | North 1 | Panhandle | Dallas |
| 9 | West 5 | North 1 | Central | Dallas |
| 10 | North 1 | North 7 | Dallas | Central-East |
| 11 | West 3 | North 7 | Central | Central-East |
| 12 | West 14 | West 5 | Panhandle | Central |
| 13 | West 5 | North 7 | Central | Central-East |
| 14 | West 12 | FarWest 7 | Central | West Texas |
| 15 | West 12 | West 1 | Central | Central |
| 16 | West 1 | North 7 | Central | Central-East |
| 17 | FarWest 7 | North 7 | West Texas | Central-East |
| 18 | FarWest 7 | South 9* | West Texas | Valley |
| 19 | FarWest 7 | FarWest 9 | West Texas | West Texas |
| 20 | FarWest 9 | West 4 | West Texas | Southwest |
| 21 | West 4 | North 7 | Southwest | Central-East |
| 22 | West 15 | West 14 | Panhandle | Panhandle |
| 23 | West 16 | West 14 | Panhandle | Panhandle |
| 24 | West 16 | West 3 | Panhandle | Central |
| 25 | West 19* | West 9 | Panhandle | Central |
| * | Means PMU planned for this substation but not available at this time. | | | |

C. Proposed Alarm Limits

Table 9 below shows the proposed angle limits for the paths (pairs) selected for real-time monitoring. These proposed limits were selected from the results for normal conditions shown in Table B- 2 and Table C- 2 of this report. These results are based on the data for the 12-months of 2013 provided by ERCOT. Most of the planned CREZ 345 kV lines were added by the end of 2013. Additional 345 kV lines were added to the ERCOT system in January and March 2014, which will further tighten electrically the ERCOT system. EPG expects the alarm limits proposed in this section based on 2013 data to tighten once the ERCOT system operates for several months with all the CREZ lines in service. Alarm limits will be revised using data obtained for a period of time (about six-months) when all CREZ transmission lines are in service.

By monitoring these angle pairs, the ERCOT grid operators should have a good overview of power flow from generation centers to the load centers and between load centers. It will provide them with a good idea of ongoing power flows among the different regions of the ERCOT grid.

EPG suggests that operators document anytime these limits are exceeded, noting the reason, if known, for the deviations such as line or generation outages.

Table 9 – Baselining Analysis – Alarm Limits for Real-time Monitoring

| Table 9 - BASELINING ANALYSIS - ALARM LIMITS FOR REAL TIME MONITORING | | | | | | | | | | | | |
|------------------------------------------------------------------------------|-------------------------|-----------|---------|---------------------|-----------|--------------------------------------------------------|---------------------|---------------------|---------------------|-----------------|-----------|----------------|
| ALARM LIMITS - NORMAL CONDITIONS | | | | | | | | | | | | |
| No | Angle Pair FROM - TO | | Base kV | Phasor Data | | RECOMMENDED ALARM LIMITS | | | | SE Data-Normal | | |
| | | | | Min Angle | Max Angle | MINIMUM ALARM LIMIT | MINIMUM ALARM ALERT | MAXIMUM ALARM ALERT | MAXIMUM ALARM LIMIT | Min Angle | Max Angle | Max-Min Spread |
| 1 | Coast 1 | South 13 | 138 | -15.49 | 42.6 | -16.65 | -12.21 | 20.56 | 27.19 | -16.65 | 23.50 | 40.1 |
| 2 | Coast 1 | North 7 | 138 | -28.49 | 38.43 | -33.45 | -24.68 | 32.72 | 42.06 | -33.45 | 42.06 | 75.5 |
| 3 | Coast 4 | North 7 | 345 | -30.53 | 49.53 | -30.80 | -24.15 | 37.38 | 47.52 | -30.80 | 47.52 | 78.3 |
| 4 | South 3 | South 11* | 138/345 | No PMUs at South 11 | | -18.22 | -14.79 | 15.32 | 18.88 | -18.22 | 18.88 | 37.1 |
| 5 | South 11* | North 7 | 345 | | | -19.39 | -12.27 | 12.80 | 15.70 | -19.39 | 15.70 | 35.1 |
| 6 | North 6 | North 7 | 138 | -4.34 | 14.90 | -7.77 | -4.09 | 11.59 | 15.68 | -7.77 | 15.68 | 23.5 |
| 7 | North 4 | North 7 | 138/345 | -17.60 | 9.86 | -16.06 | -12.42 | 6.49 | 11.33 | -16.06 | 11.33 | 27.4 |
| 8 | West 14 | North 1 | 345 | -10.24 | 13.22 | -9.36 | -7.23 | 10.90 | 12.47 | -9.36 | 12.47 | 21.8 |
| 9 | West 5 | North 1 | 345 | 17.00 | 23.53 | -16.93 | -15.73 | 21.53 | 26.96 | -16.93 | 26.96 | 43.9 |
| 10 | North 1 | North 7 | 345 | -9.99 | 20.95 | -9.23 | -5.26 | 16.42 | 20.83 | -9.23 | 20.83 | 30.1 |
| 11 | West 3 | North 7 | 345 | No data | | Not enough data | | | | Not enough data | | |
| 12 | West 14 | West 5 | 345 | -16.75 | 11.37 | -15.54 | -13.62 | 9.62 | 11.90 | -15.54 | 11.90 | 27.4 |
| 13 | West 5 | North 7 | 345 | -13.74 | 29.25 | -23.57 | -14.85 | 31.54 | 44.00 | -23.57 | 44.00 | 67.6 |
| 14 | West 12 | West 1 | 345 | -7.27 | 14.26 | -5.86 | -4.62 | 12.27 | 13.58 | -5.86 | 13.58 | 19.4 |
| 15 | West 12 | FarWest 7 | 345 | -7.70 | 9.66 | -7.03 | -5.06 | 8.79 | 12.86 | -7.03 | 10.20 | 17.2 |
| 16 | West 1 | North 7 | 345 | -9.48 | 24.51 | -20.62 | -12.39 | 26.79 | 37.02 | -20.62 | 37.02 | 57.6 |
| 17 | FarWest 7 | North 7 | 345 | -30.47 | 45.89 | -29.21 | -22.39 | 33.08 | 43.20 | -29.21 | 43.20 | 72.4 |
| 18 | FarWest 7 | South 9* | 345 | No PMUs at Ken | | -31.48 | -23.21 | 36.74 | 42.77 | -31.48 | 42.77 | 74.3 |
| 19 | FarWest 7 | FarWest 9 | 345/138 | -12.85 | 18.66 | -13.50 | -11.41 | 16.25 | 25.04 | -13.50 | 17.50 | 31.0 |
| 20 | FarWest 9 | West 4 | 138 | -29.80 | 48.48 | -26.48 | -19.65 | 39.74 | 46.01 | -26.48 | 46.01 | 72.5 |
| 21 | West 4 | North 7 | 138/345 | -25.20 | 12.92 | -31.32 | -22.92 | 10.04 | 14.66 | -31.32 | 14.66 | 46.0 |
| 22 | West 15 | West 14 | 345 | Not enough data | | New substations - Not enough data - No PMUs at West 19 | | | | Not enough data | | |
| 23 | West 16 | West 14 | 345 | | | | | | | | | |
| 24 | West 16 | West 3 | 345 | | | | | | | | | |
| 25 | West 19* | West 9 | 345 | | | | | | | | | |

NOTE: These alarm limits were developed based on 2013 data.

Note that all the pairs in Table 9 have two negative alarm limit values and two positive alarm limit values. The negative values apply in the TO to FROM direction and the positive values apply in the FROM to TO direction.

10. CONCLUSIONS

a. Data Availability was Improved in 2013

State estimator data provided by ERCOT for 2013 had availability of 22.6% which was significantly higher than the 13% availability rate for 2012. Phasor data availability ranged from 19.1% to 93.2%. Those substations with the lower availability rates were those that began transmitting data to ERCOT at the end of the twelve months study period.

b. Phasor Data Availability for 2013

Several PMUs were installed in 2013, some of them late in 2013. As a result, the phasor data availability for pairs involving these new PMUs was incomplete. This resulted in some discrepancies in results obtained with phasor data versus results obtained with the more complete SE data.

c. Highest Voltage Spreads at 138 and 345 kV Locations

State estimator data points to West 4 - 138 kV and Coast 4 - 345 kV as having the greatest voltage spreads in their class.

d. Substations with High Voltage Spreads

Six substations have voltage spreads of higher than 15 kV: West 1, West 9, Coast 4, Coast 3, West 8 and South 9.

e. Voltage Angle Variability at 345kV and 138kV Substations (Ref.: North 7)

Voltage angles vary over a wide range for several substations. The greatest variation of 104.1 degrees (-40.9 to 63.2) occurred at FarWest 9 - 138 kV substation. Among the 345 kV substations, the greatest angle variation over the twelve months of 2013 occurred at FarWest 4 with a spread of 90.8 (-30.6 to 60.2) degrees.

- i. The greatest variations occurred among the substations in the western part of the state namely: FarWest 7, West 11, West 6, FarWest 8, FarWest 9, FarWest 4, West 2, West 9, West 12 and West 5.
- ii. The next greatest angle variation occurred in the south part of the state namely: South 13, Coast 3, Coast 4 and Coast 1.
- iii. The two greatest angles under normal conditions (Ref: North 7) observed were at West 10 and FarWest 9 with 59.73 and 50.63 degrees respectively.

- iv. The maximum Max-Min angle spreads under normal conditions occurred at West 10-North 7, FarWest 9-South 9 and Coast 3-North 7 with 91.8, 89.0 and 79.2 degrees respectively.

f. Maximum Voltage Angles under Normal Conditions

The maximum voltage angles under normal conditions occurred at West 10-North 7, FarWest 9-North 7, FarWest 4-North 7 and Coast 4-North 7 with 59.73, 50.63, 47.69 and 47.52 degrees respectively.

g. Voltage spreads are smaller in 2013

The voltage spreads obtained with 2013 data are smaller than those obtained with 2012 data. This is an indication of the ERCOT system's increased tightness due to the addition of the many new 345 kV CREZ lines.

h. Alarm Limits for Voltage Angles

CREZ lines have been added during several months of 2013 changing the angle values as lines were added to the ERCOT system. The alarm limits obtained with 2013 data will change once all CREZ lines are added and the ERCOT system gets a chance to normalize. A few additional CREZ lines were added in January and March of 2014, which will contribute to change in angle differences among pairs near those lines. ERCOT operators can use the alarm limits established in this report to monitor real-time operations keeping in mind that these limits will be conservative until the alarm limits are revised with 2014 data.

11. RECOMMENDATIONS

a. Data Monitoring and Data Integrity

Many gaps in data were observed during this analysis. EPG recommends that ERCOT and PMU owners monitor the state estimator and phasor data to find and fix problems associated with missing data. Alarm limits will be a true reflection of system performance if the data upon which they are based is as complete as possible.

b. Monitoring Locations

EPG has produced alarm limits for 25-pairs for real-time monitoring shown in Section 9 of this report. EPG will propose, after this report is completed, a number of pairs to be shown in the RTDMS daily reports.

c. Panhandle Wind Output Monitoring

There are four new CREZ lines connecting the panhandle new 345 kV system with the rest of the ERCOT system: West 15-West 14, West 16-West 14, West 16-West 3 and West 19-West 9. The flow and angle on these four lines should provide a tool to monitor the wind output from that area. EPG recommends that ERCOT monitor this interface by including these four pairs in the RTDMS daily report. Note, however, that there are no PMUs installed at the West 19 substation; all the other substations in the interface are equipped with PMUs.

d. PMU at West 19

The Panhandle-North ERCOT interface mentioned above has PMUs installed at all the substations except for West 19. EPG recommends that PMUs be installed at this substation to be able to monitor voltage angle and power on all four lines comprising the interface.

e. Need for an Alarm Limits Update

The CREZ project was completed in March 2014. The alarm limits proposed in this report should be updated with phasor data and state estimator data for the first six-months of 2014. EPG will perform this update. However, an annual update should be performed with all 2014 data to obtain a more accurate set of alarm limits to be used during real-time normal conditions.

Appendix A – Part 1
CCET Discovery Across Texas project

Baseline Analysis Update - Voltage Magnitudes

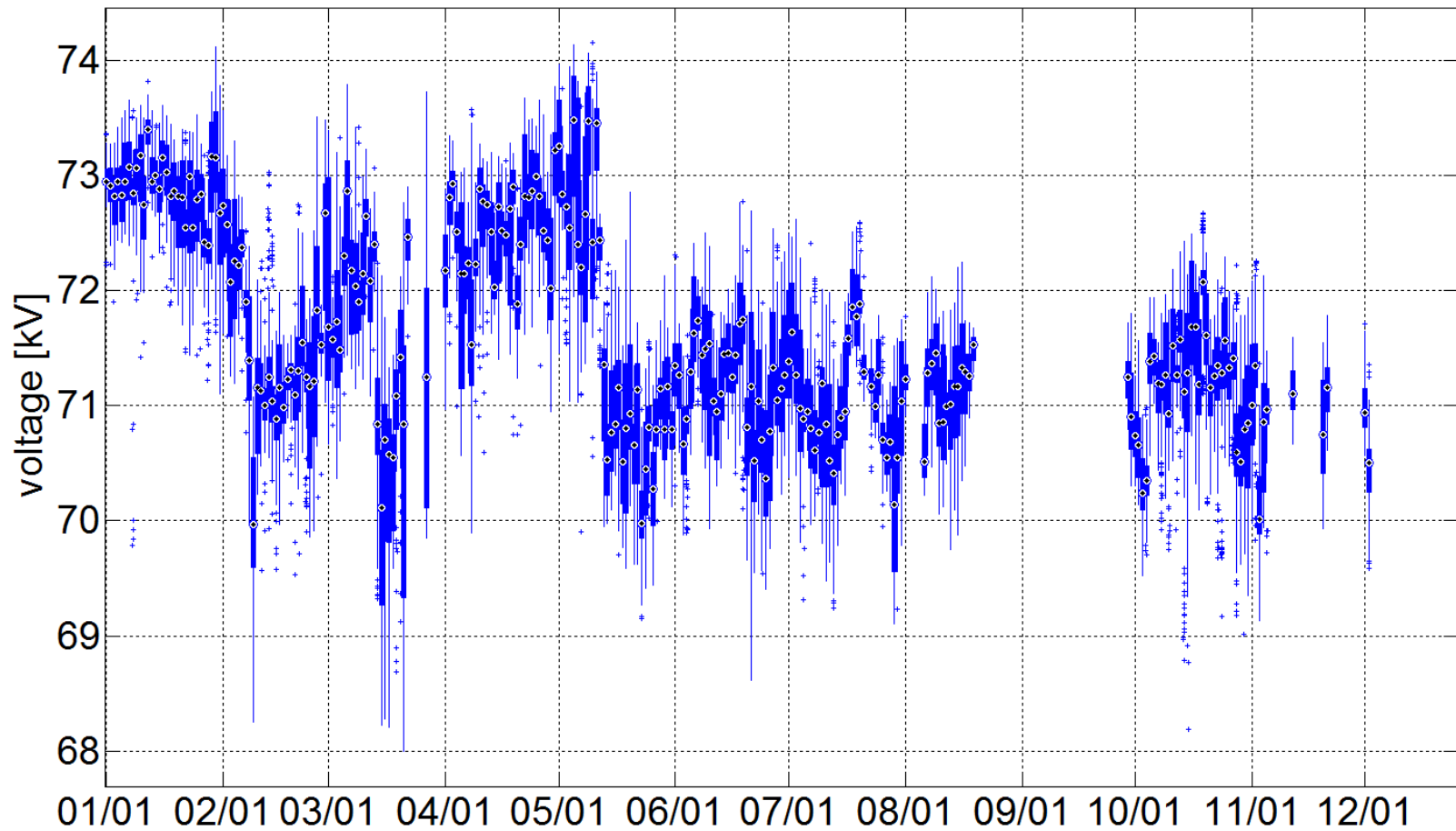
State Estimator Data: January to December 2013
Box Whiskers Plots and Time Duration Curves



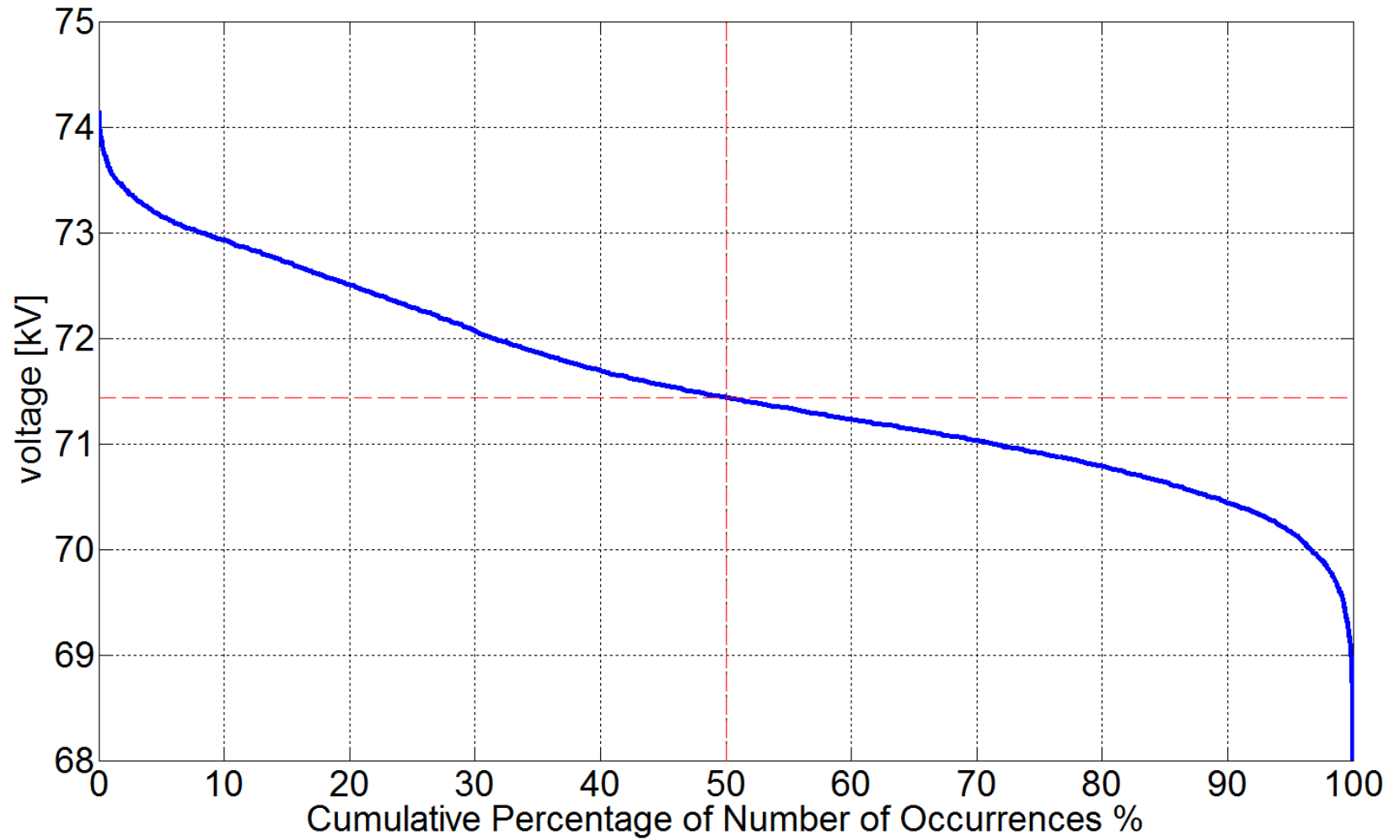
Electric Power Group



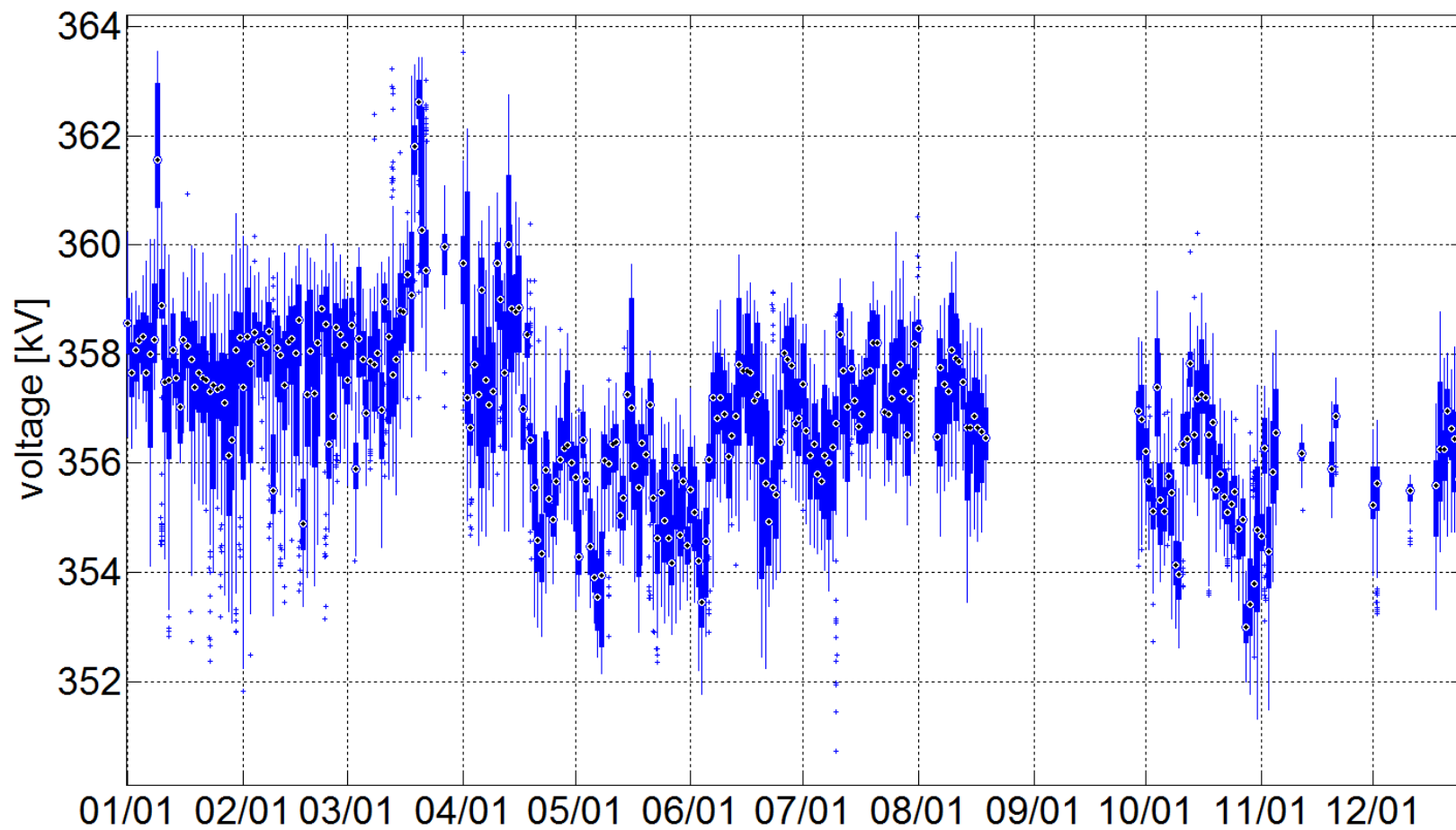
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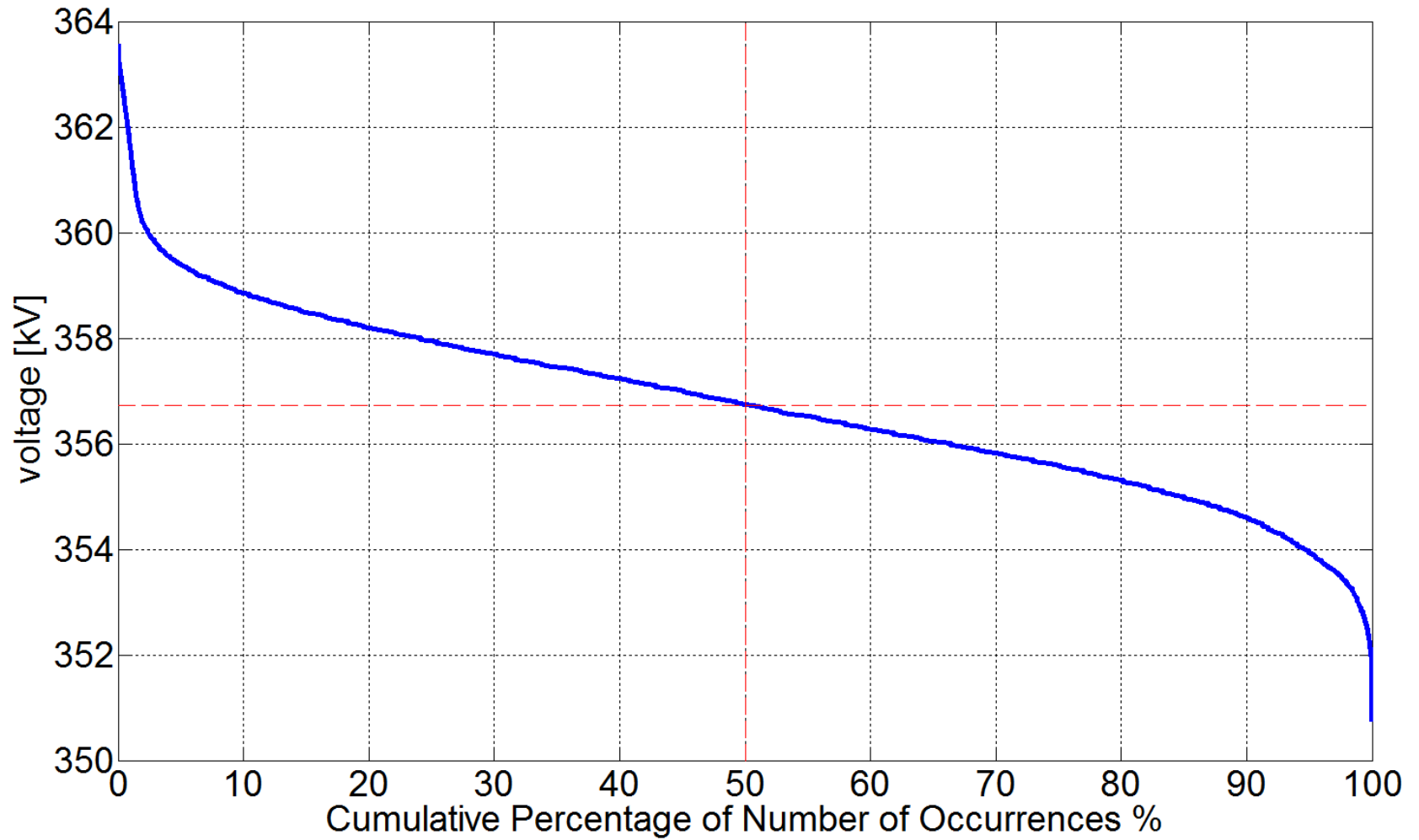
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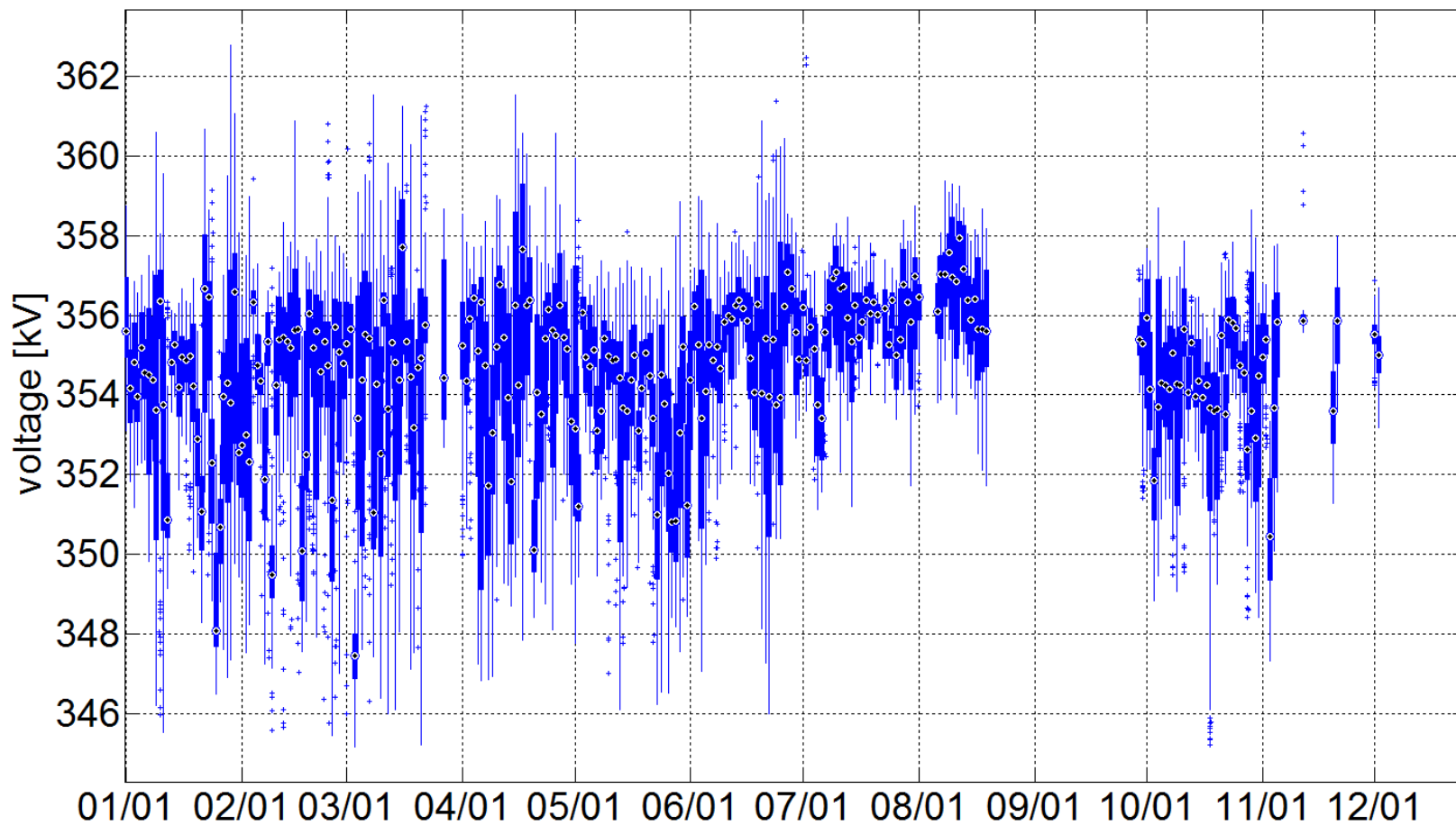
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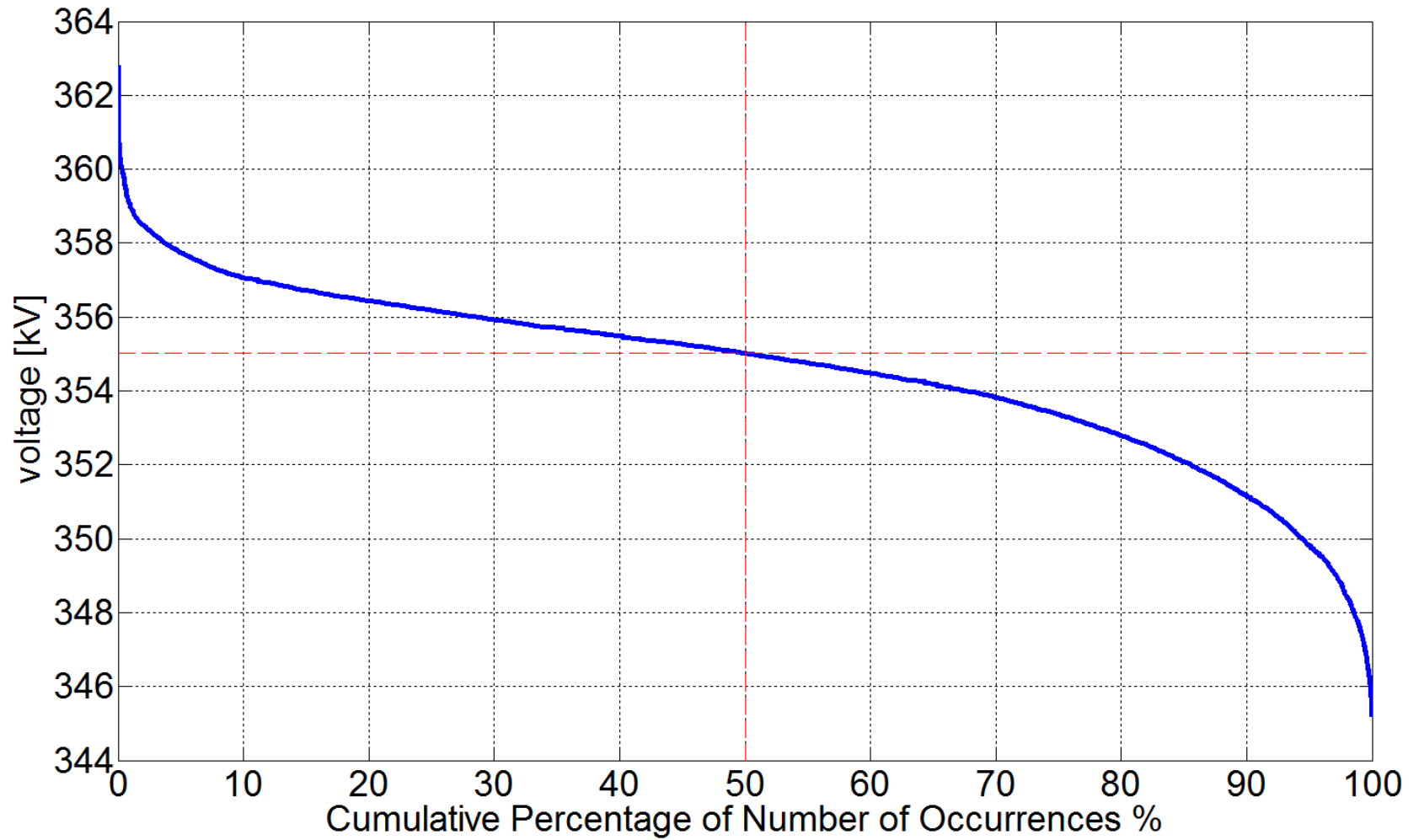
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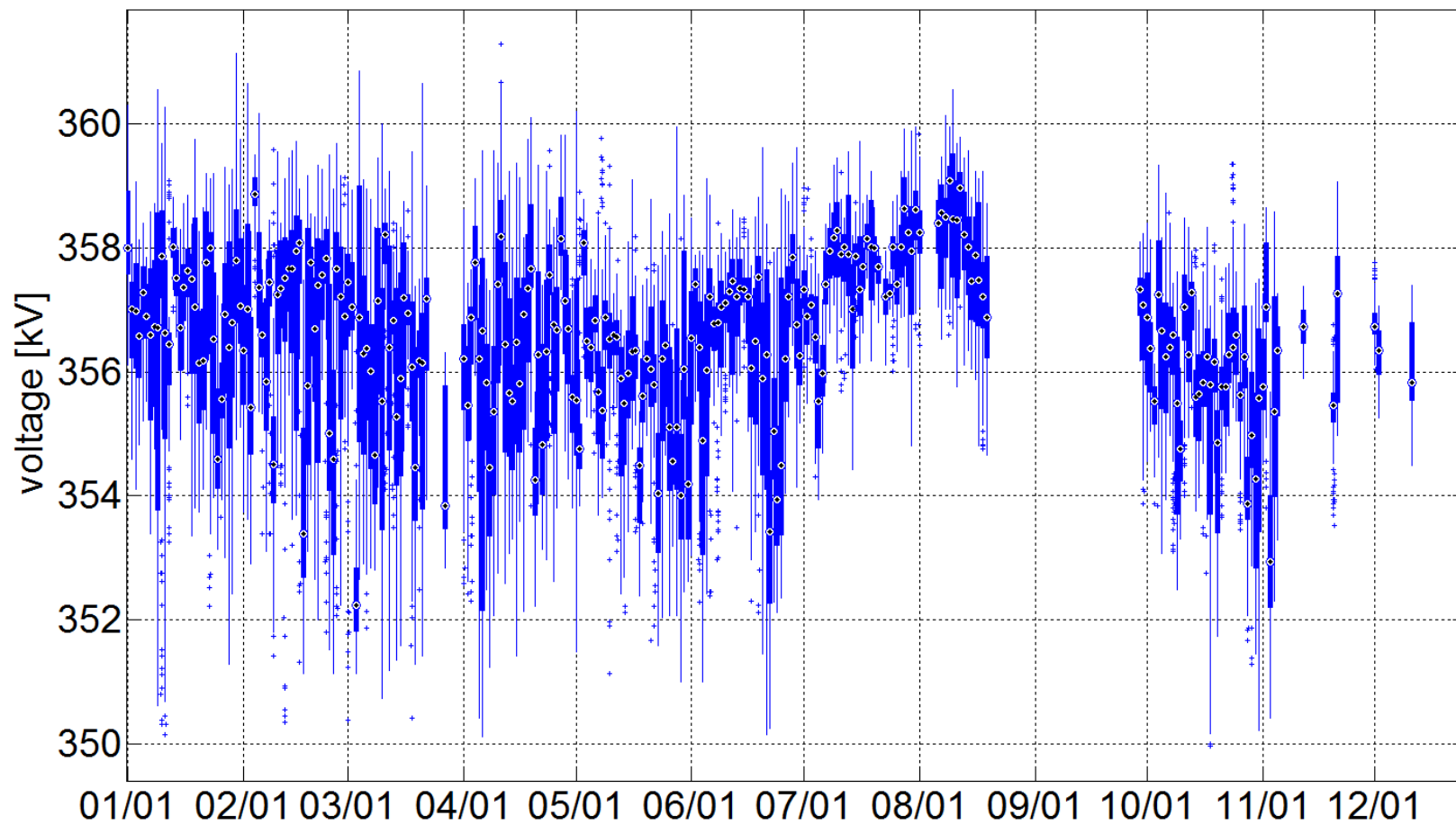
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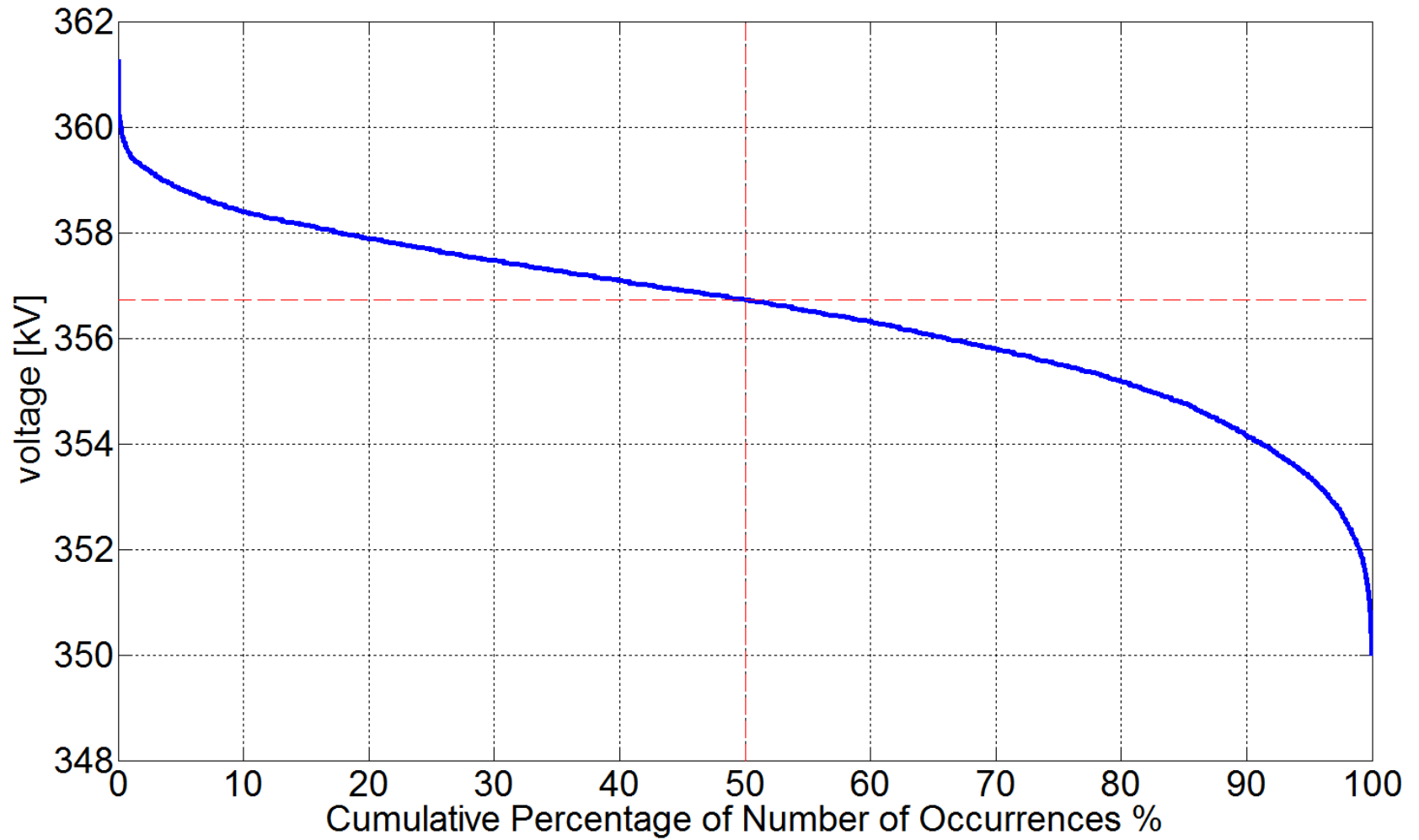
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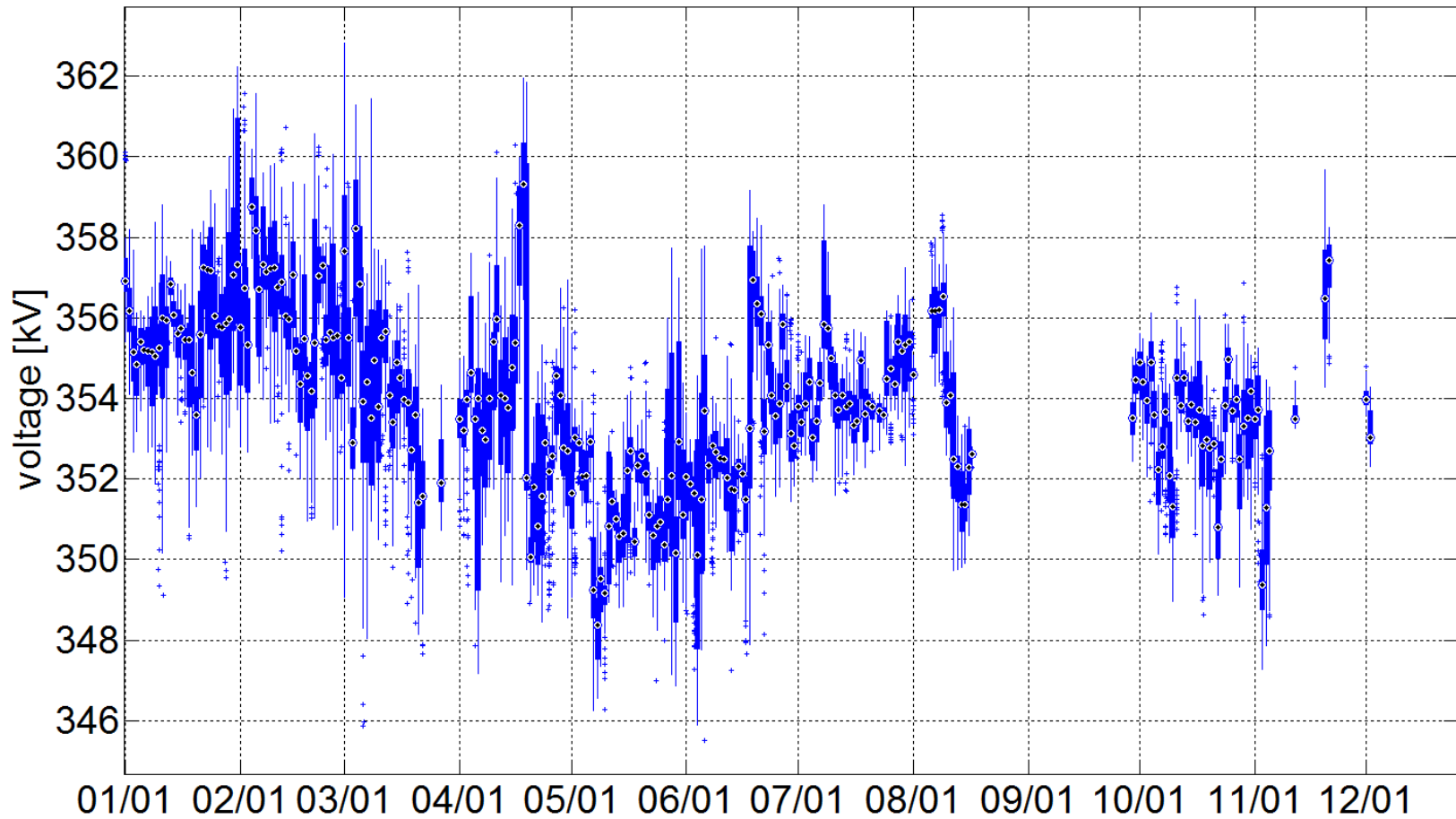
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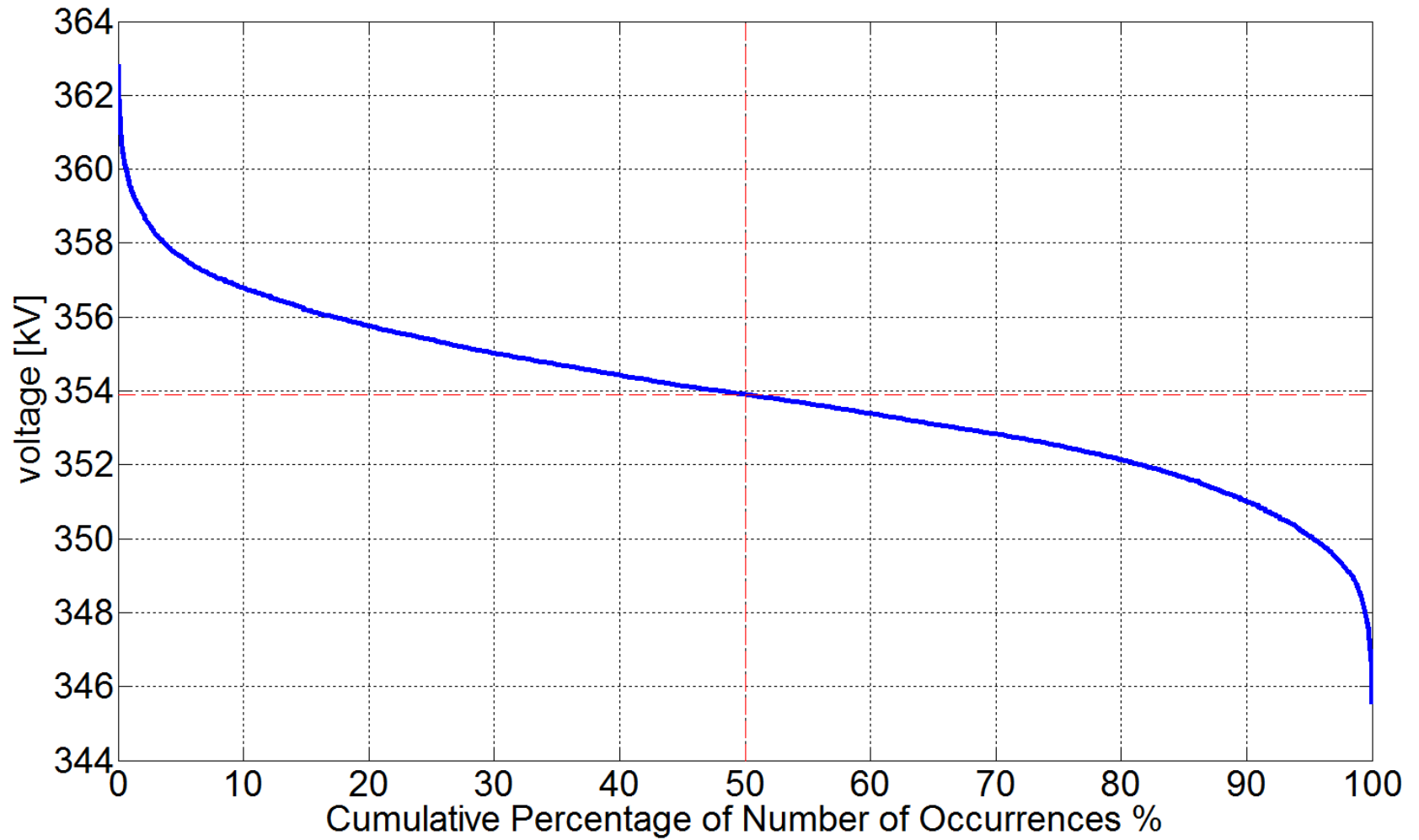
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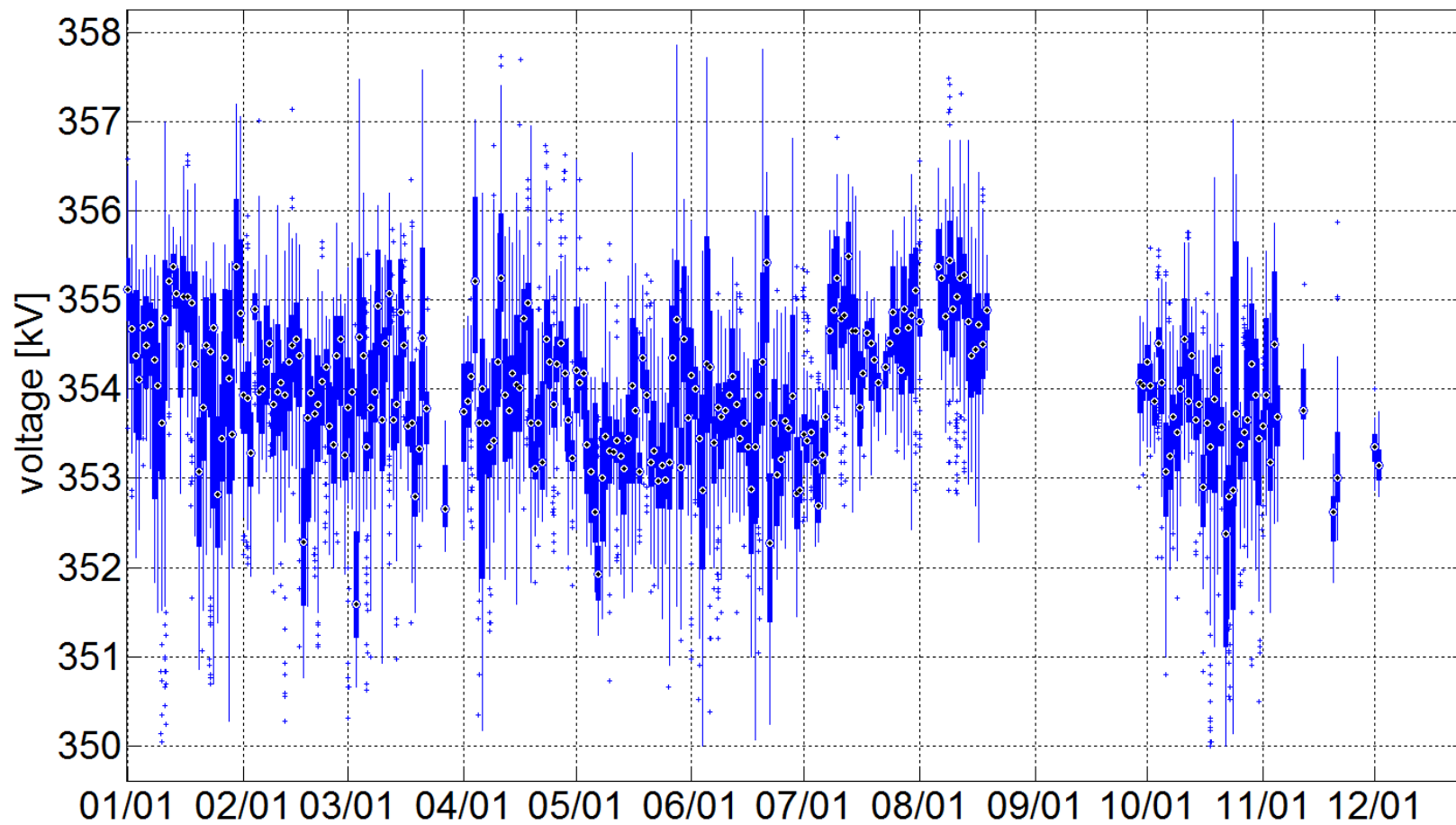
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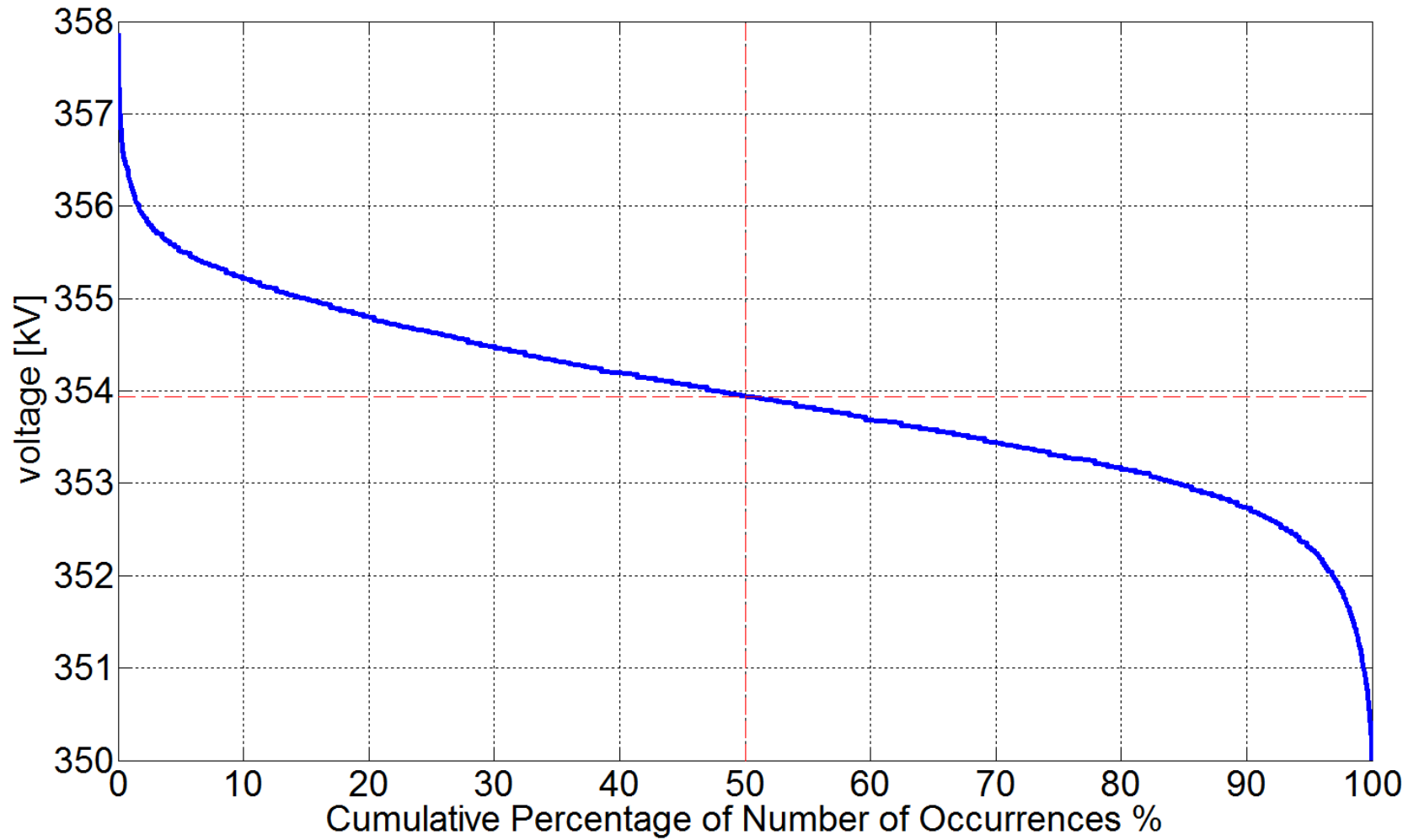
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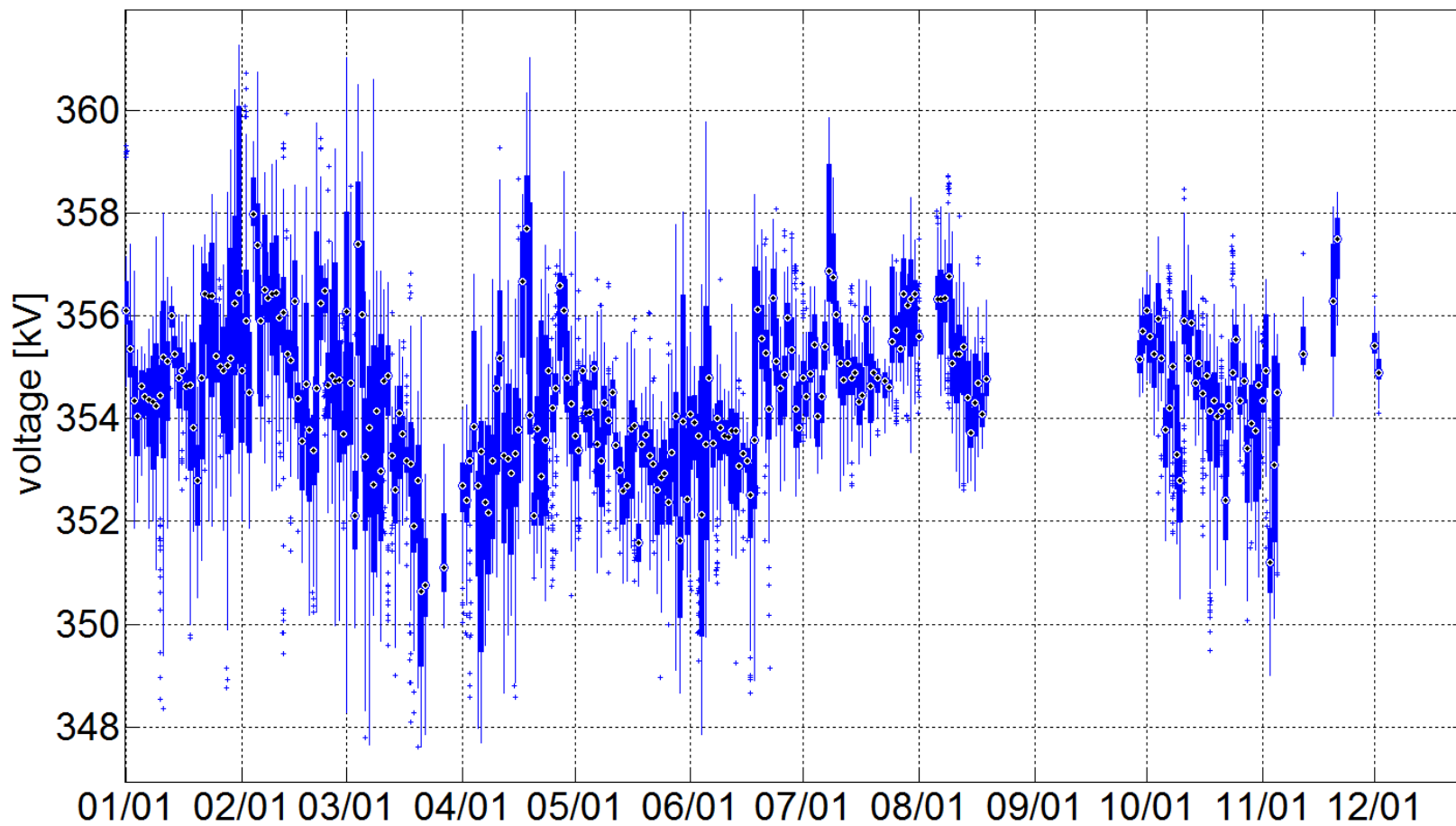
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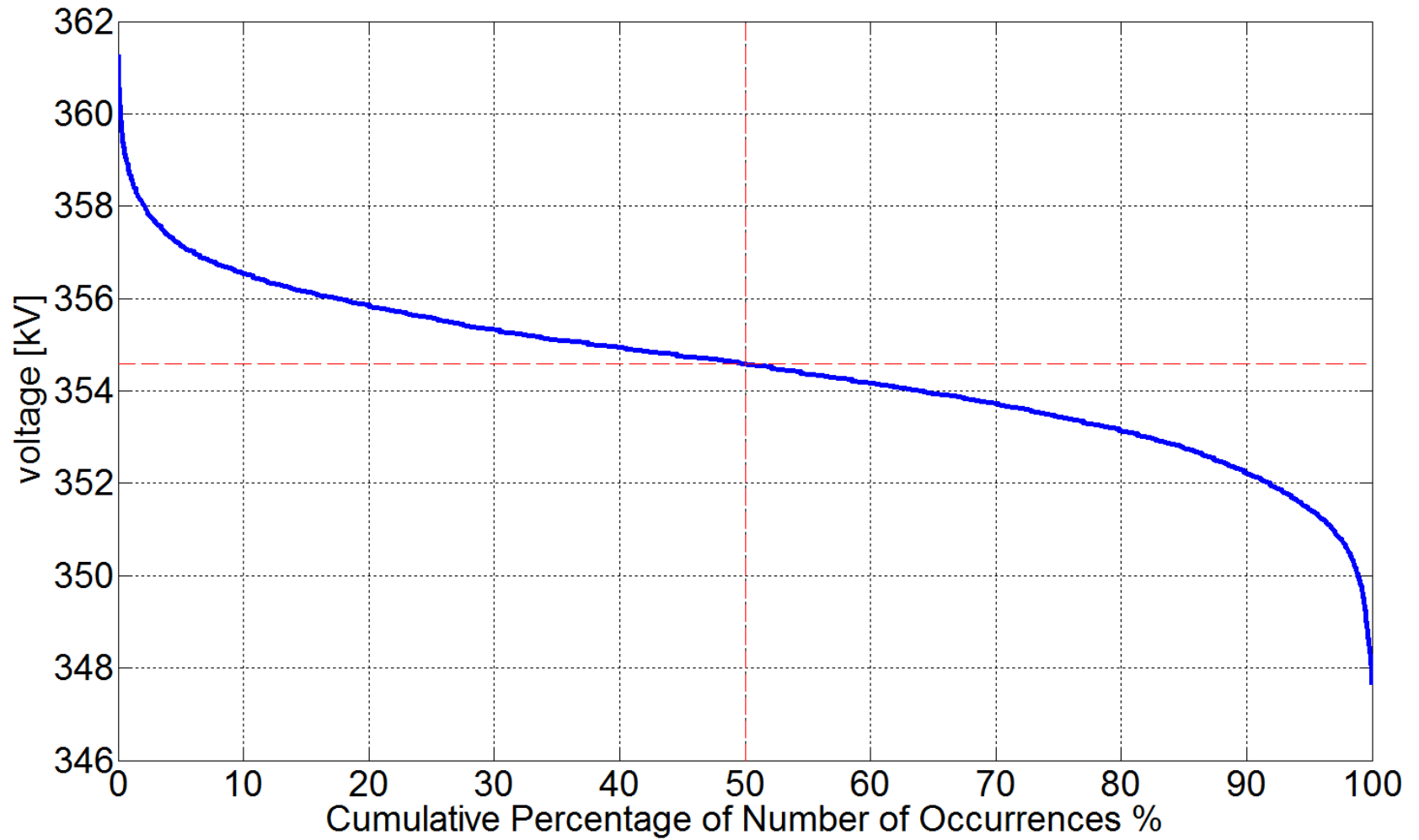
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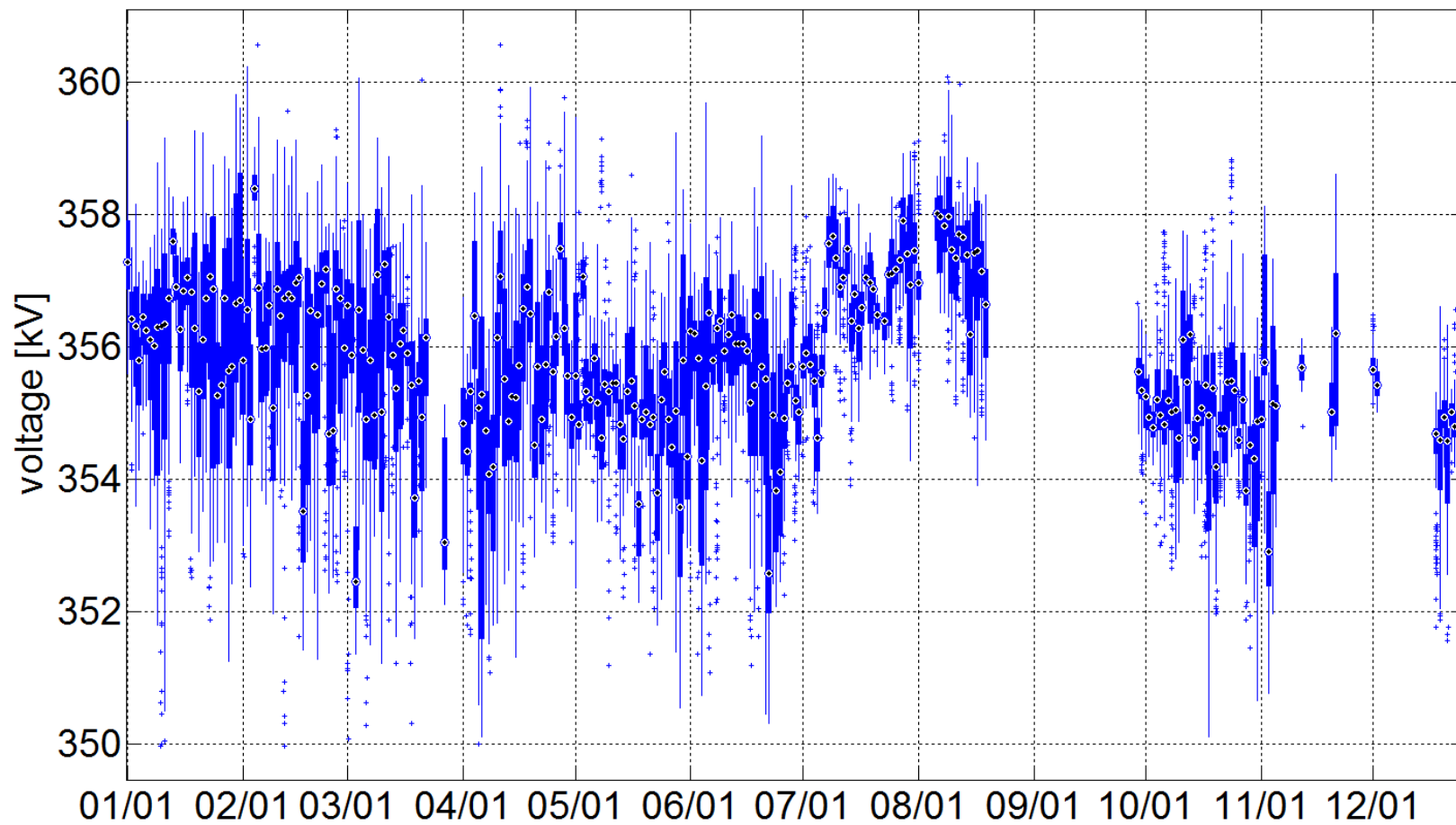
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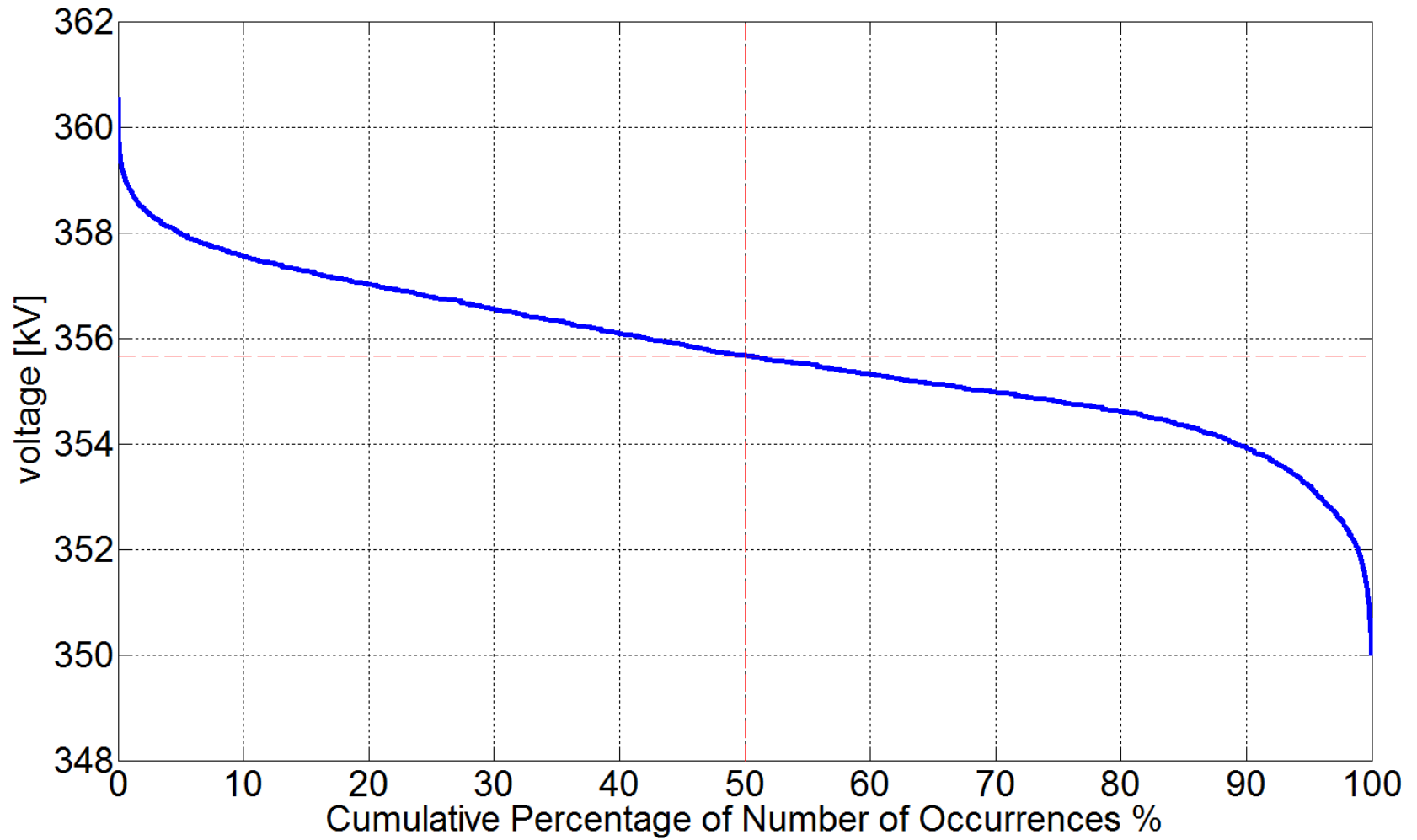
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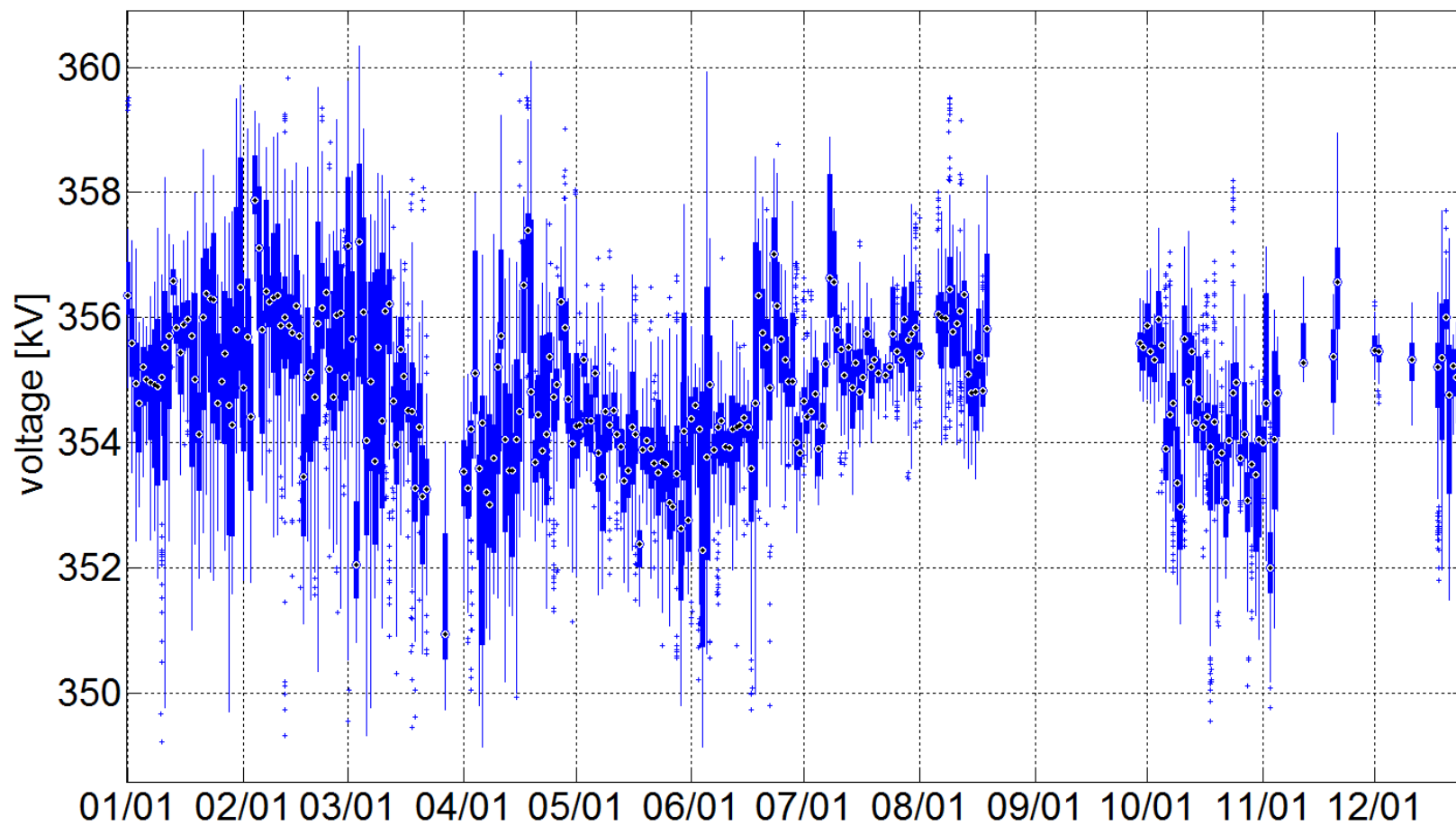
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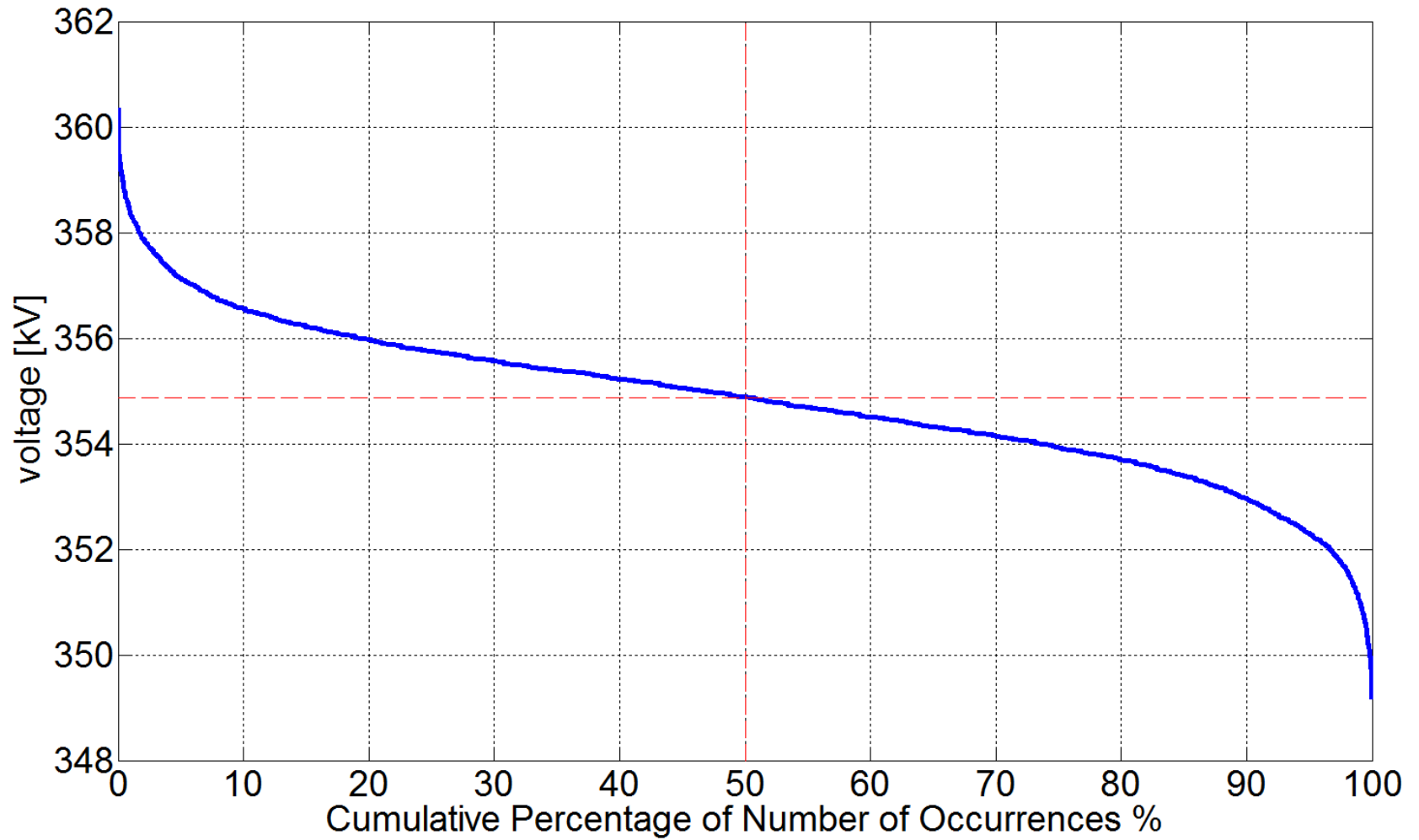
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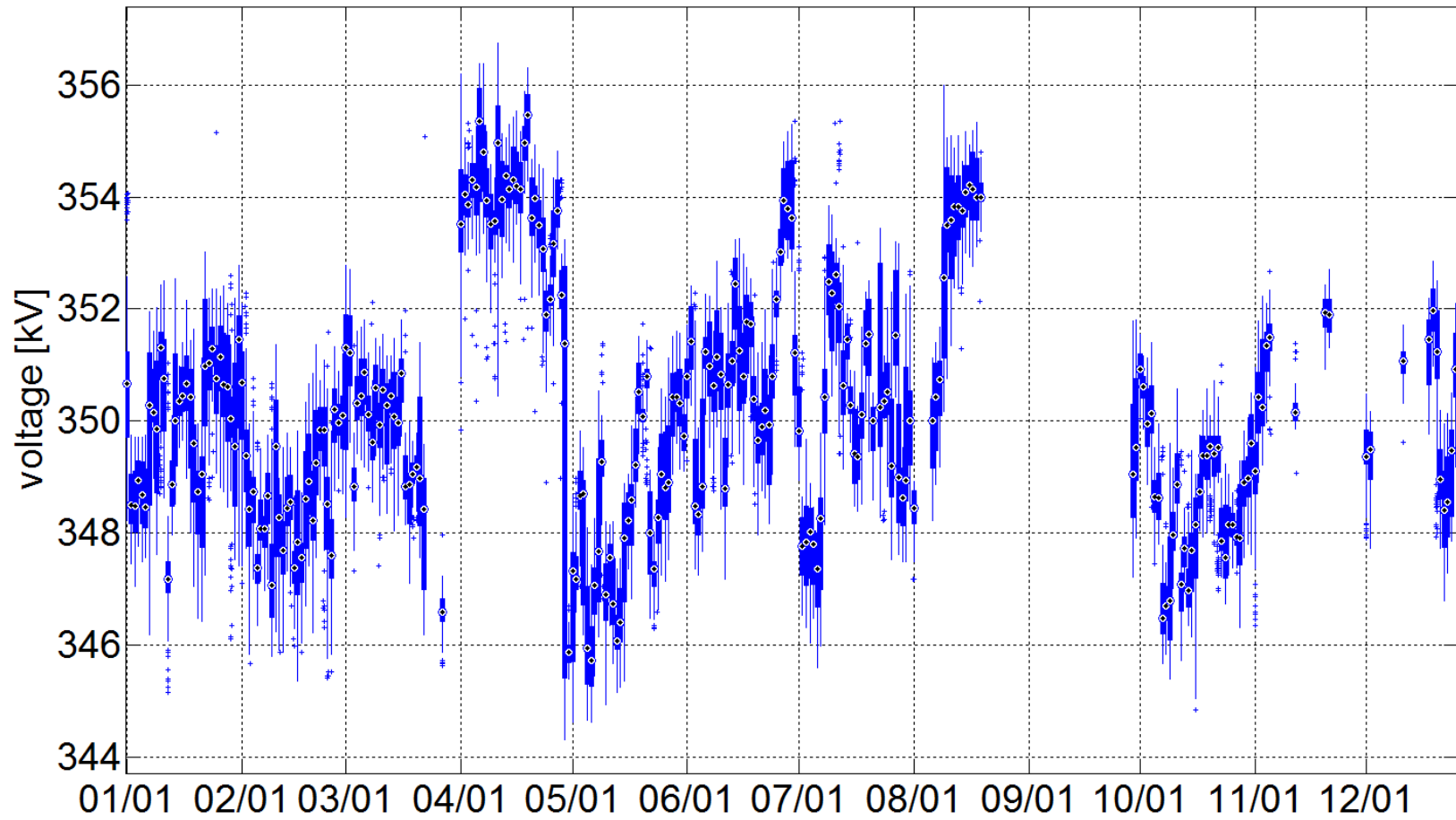
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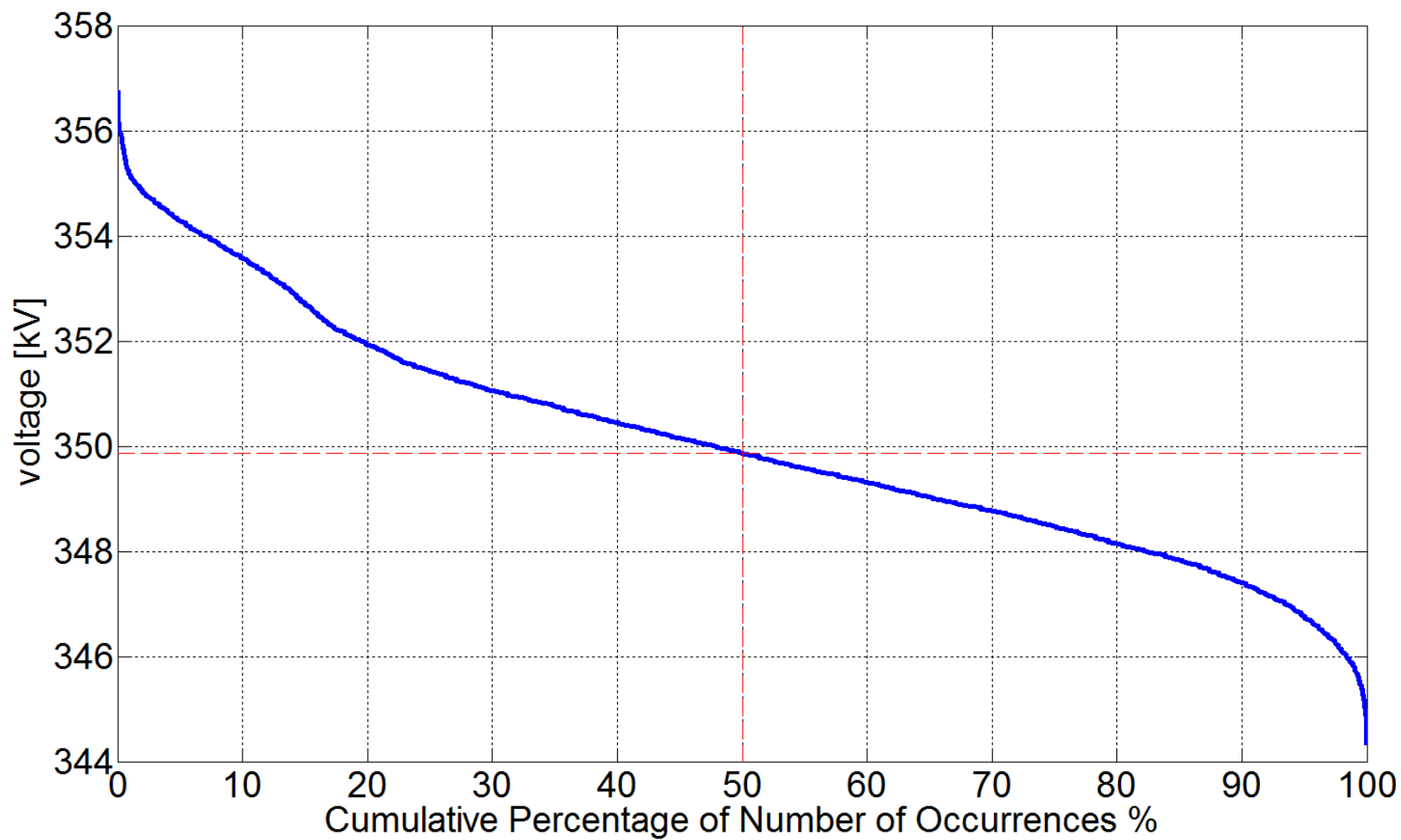
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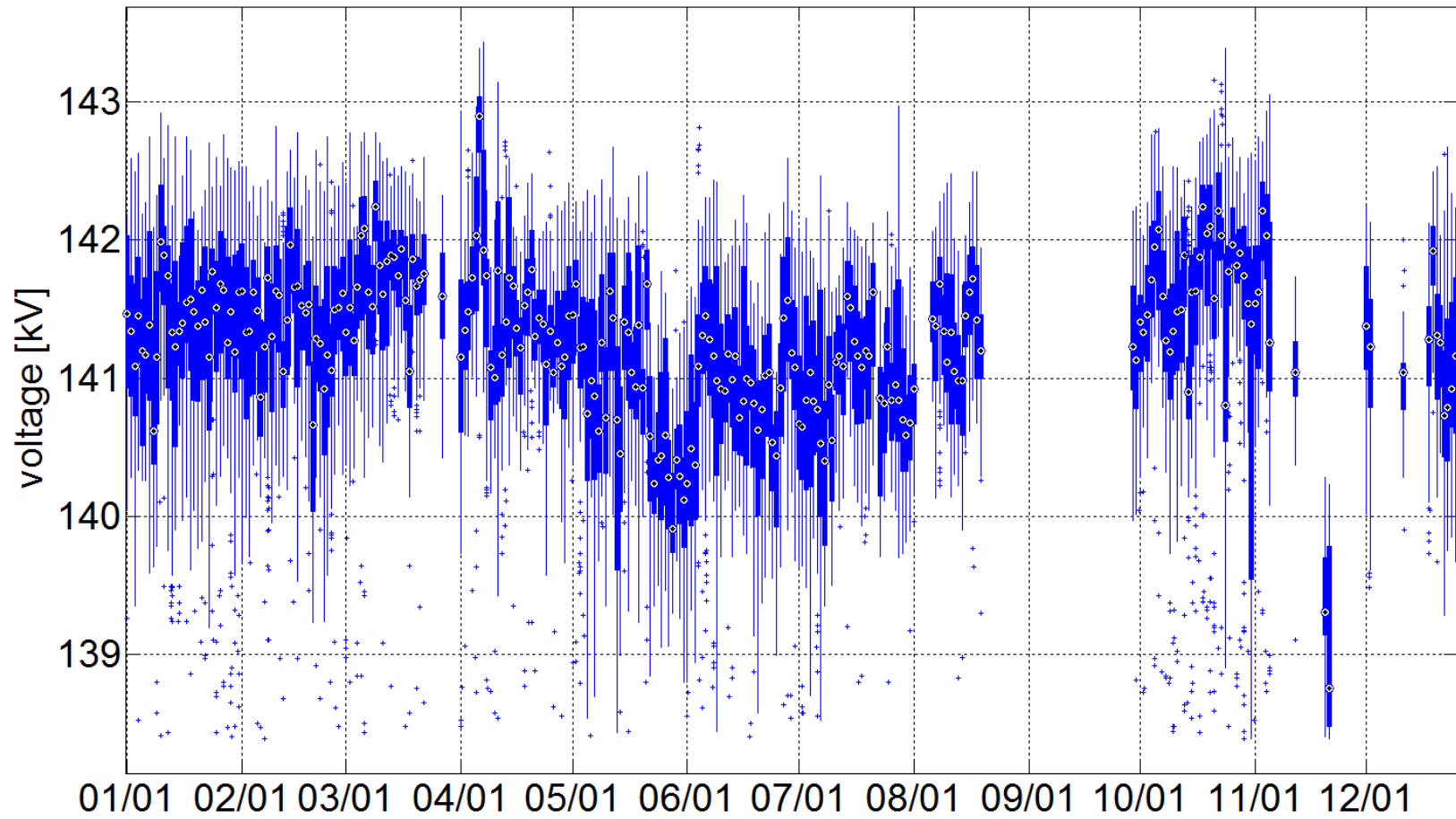
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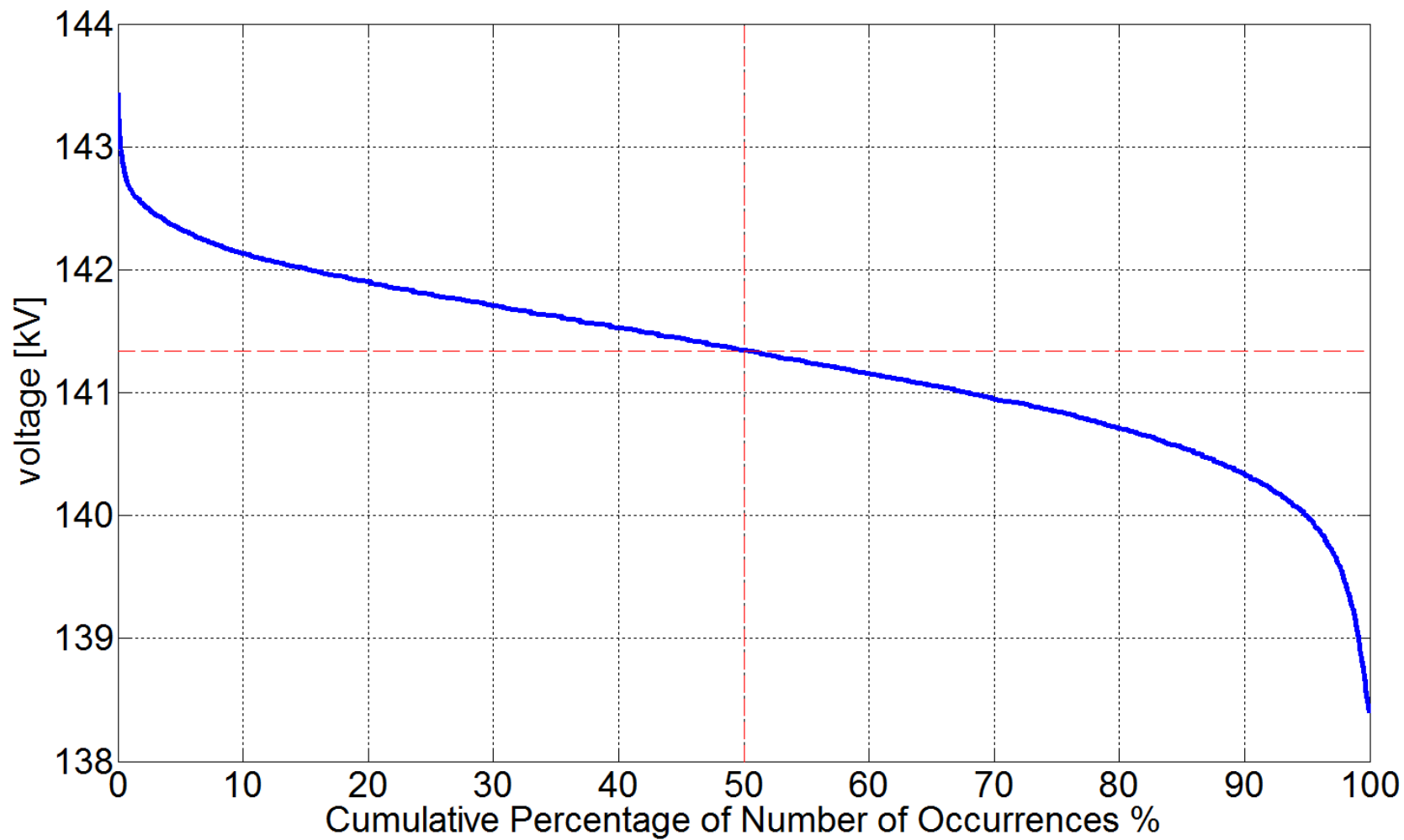
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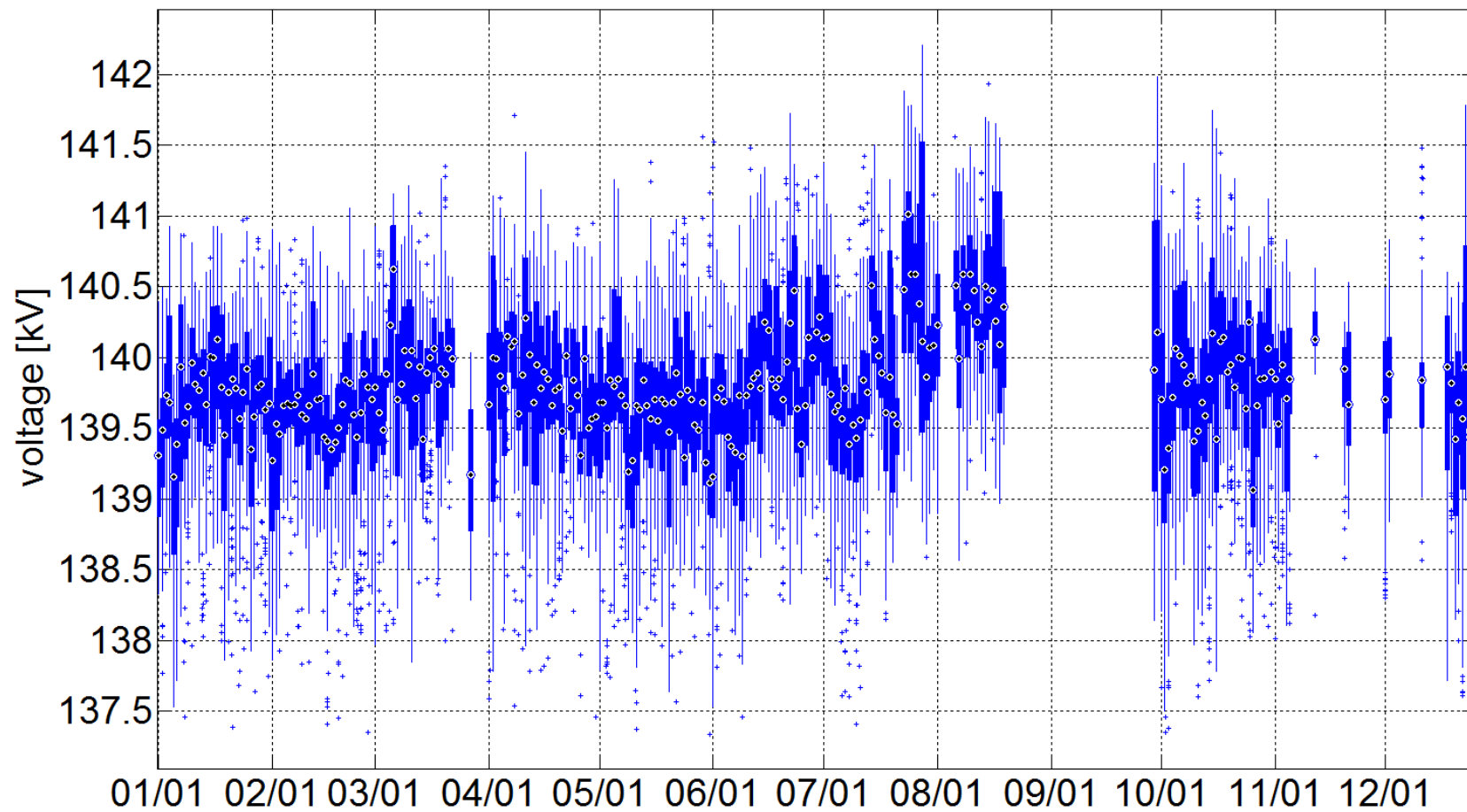
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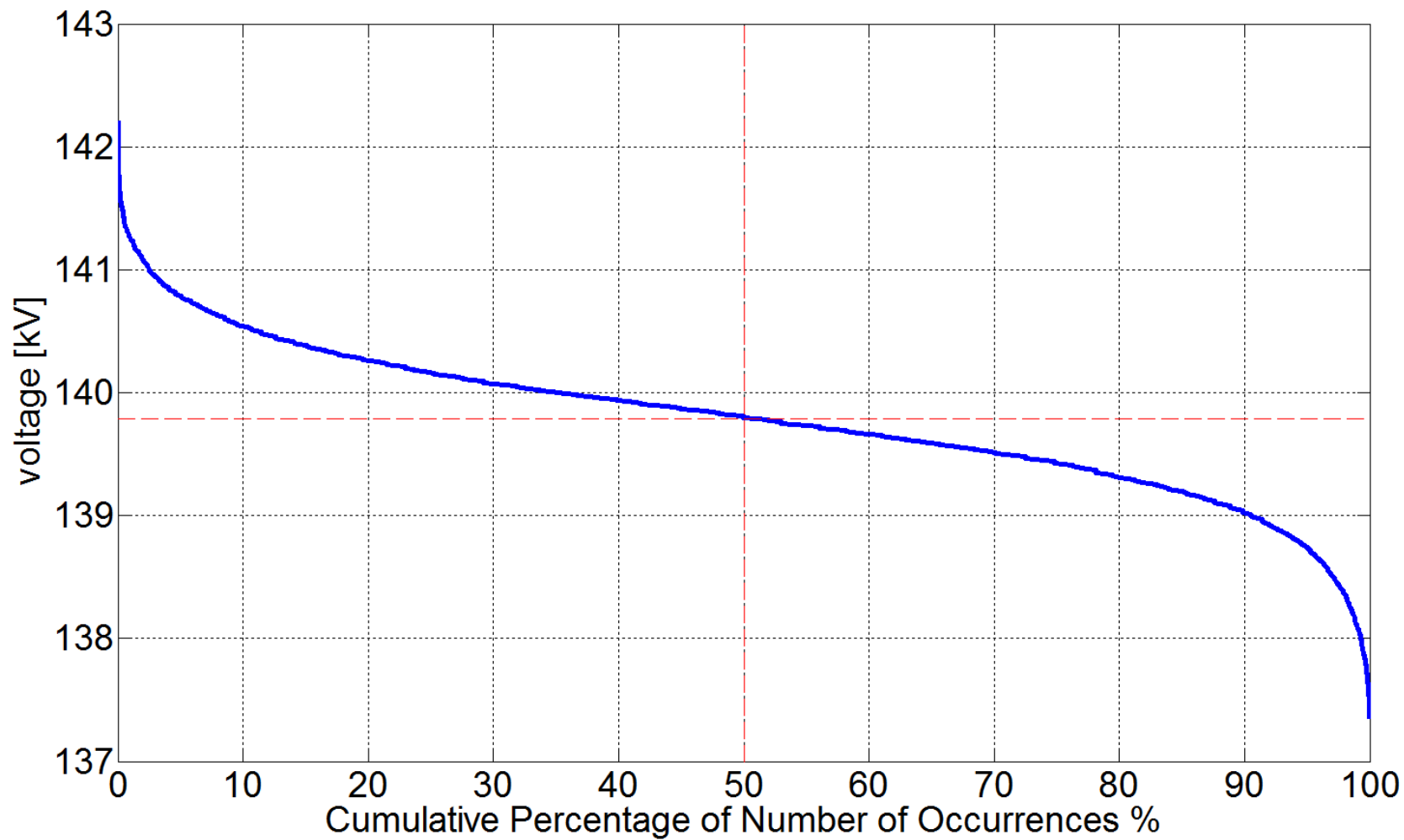
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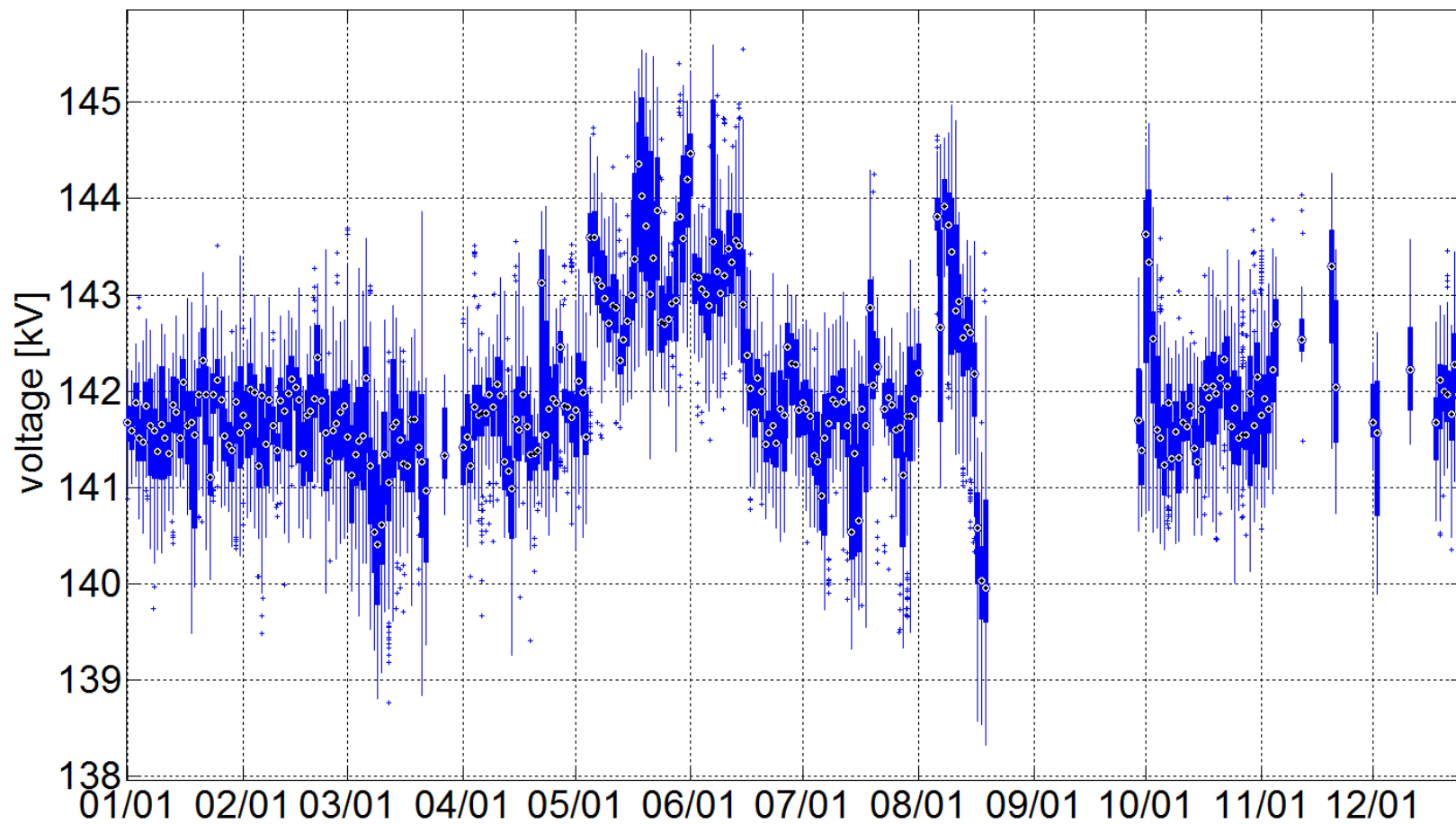
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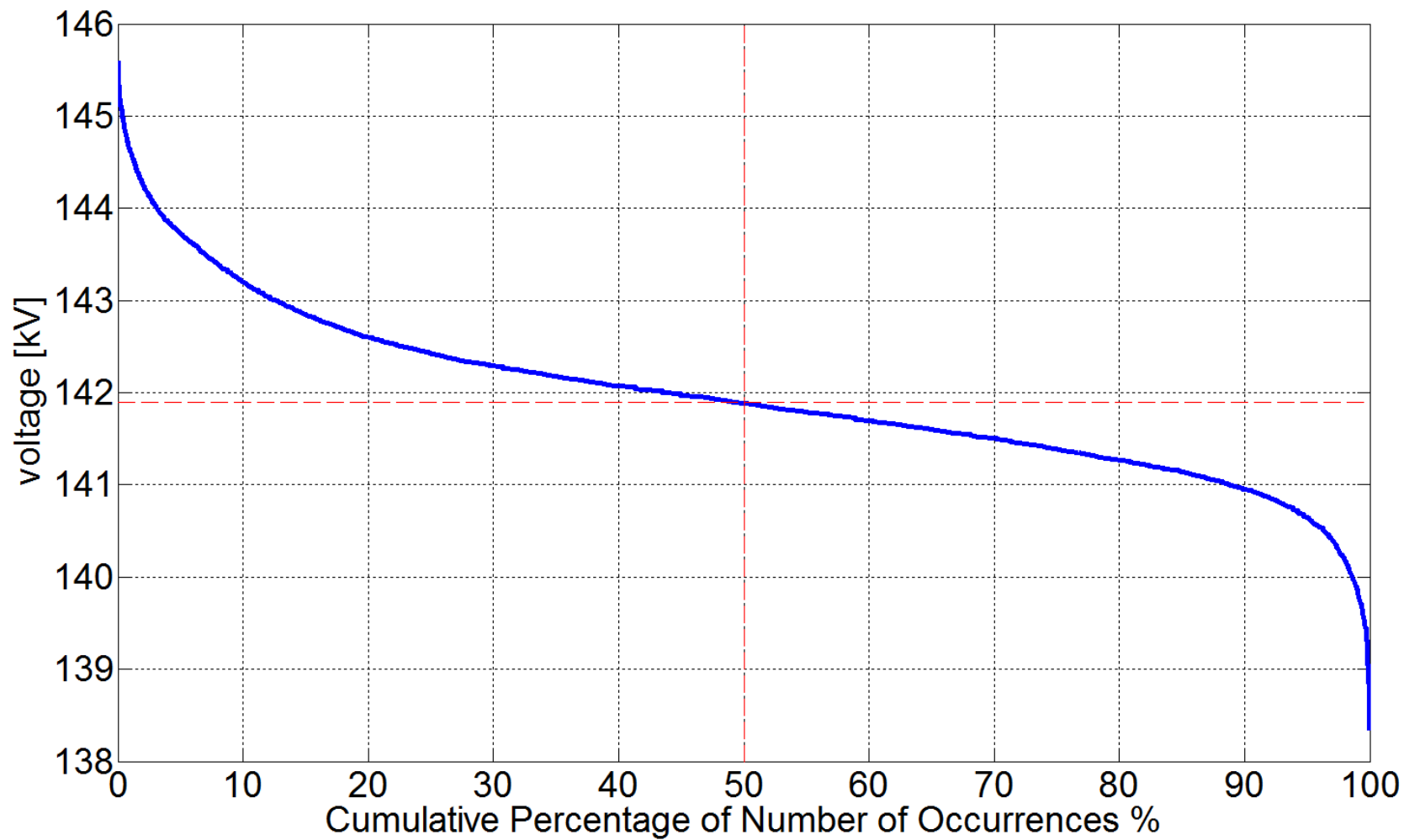
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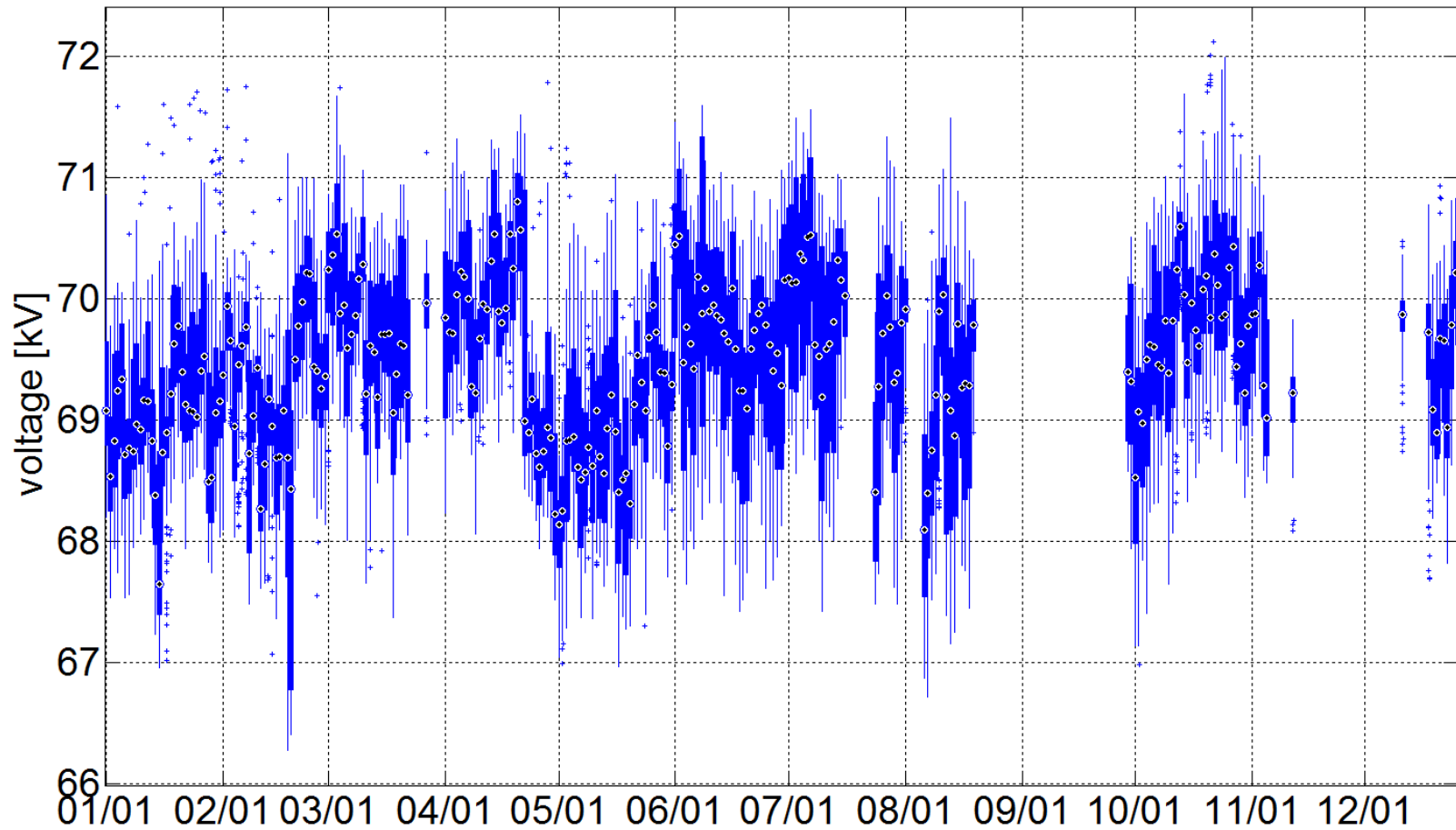
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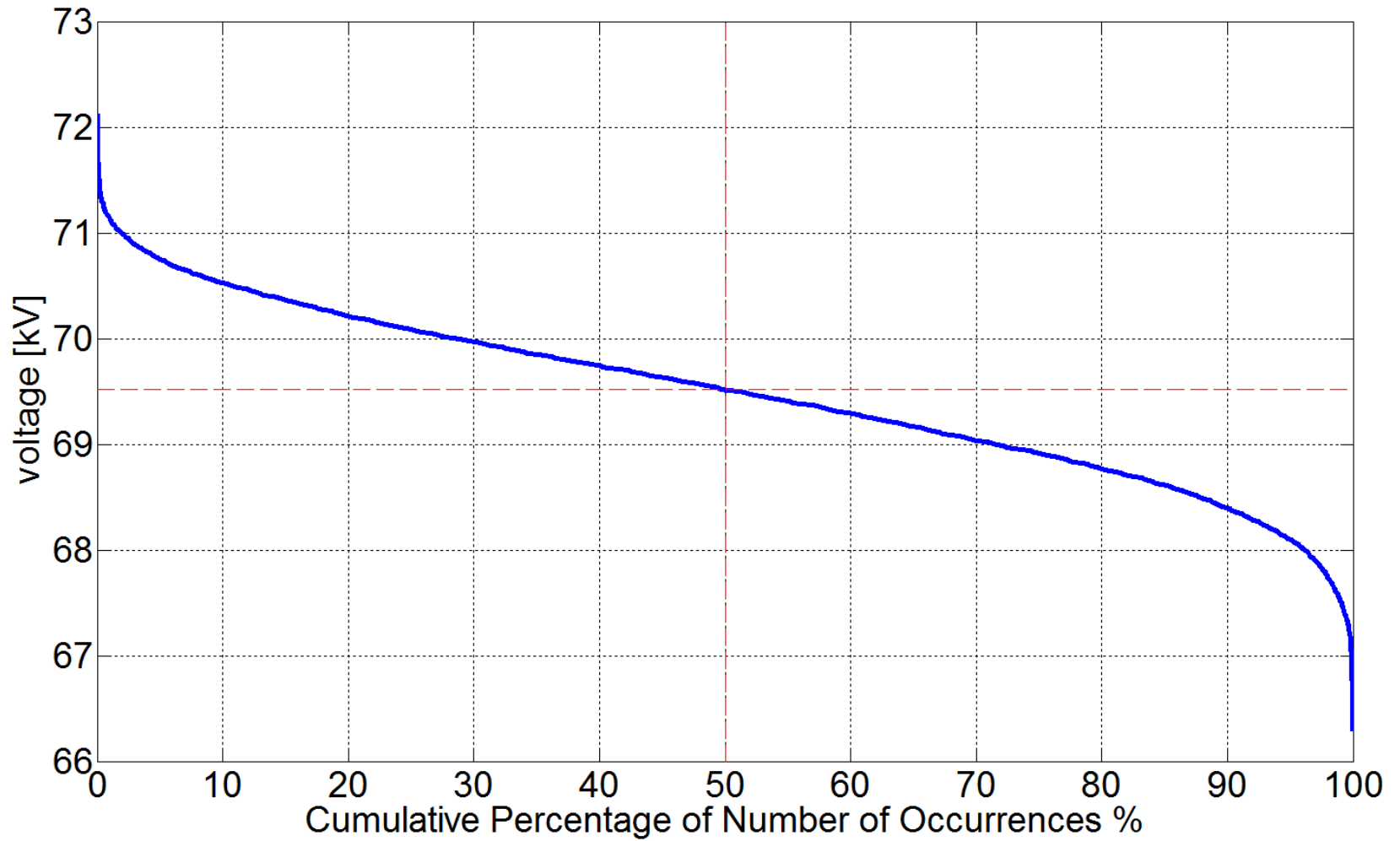
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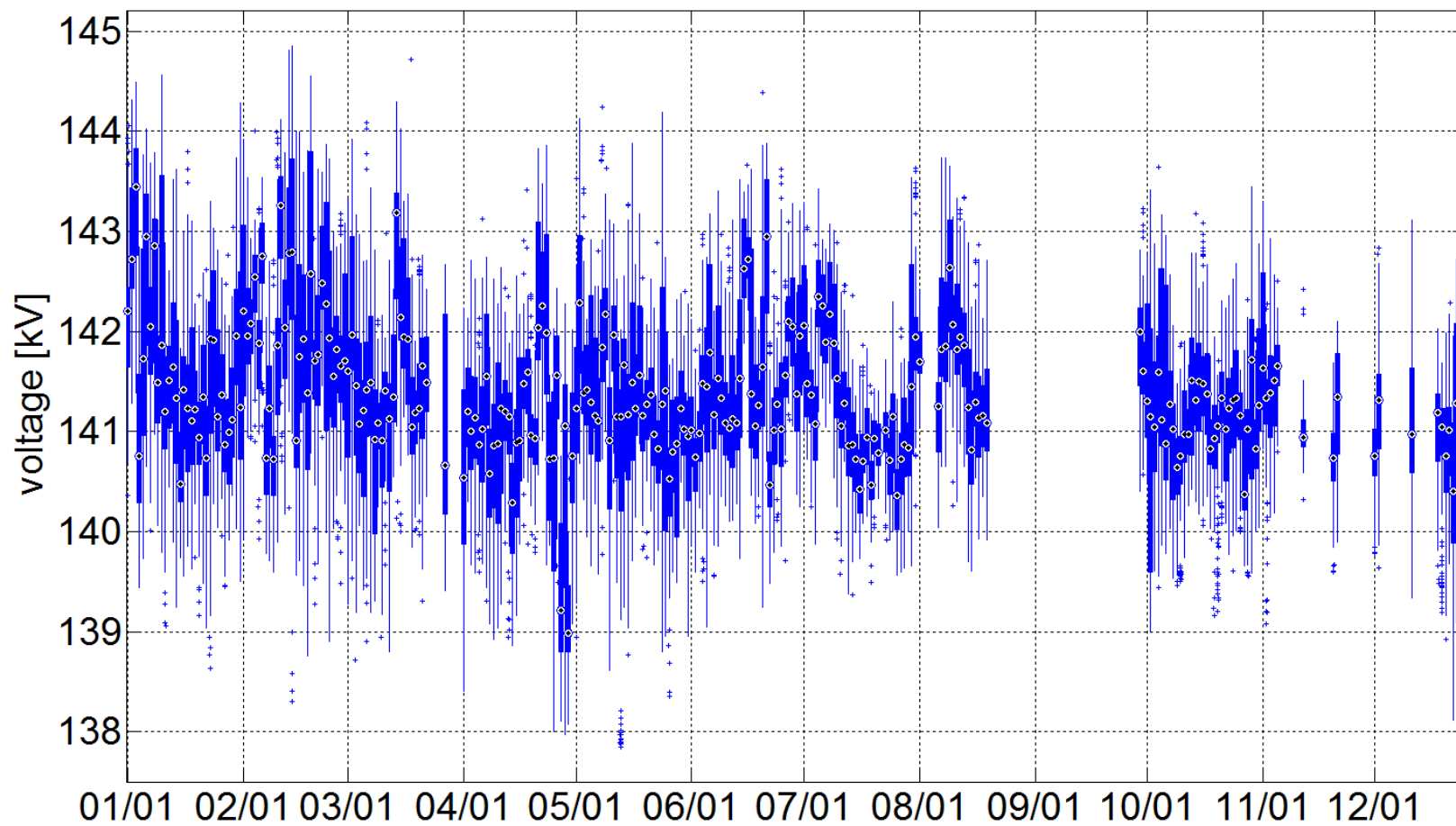
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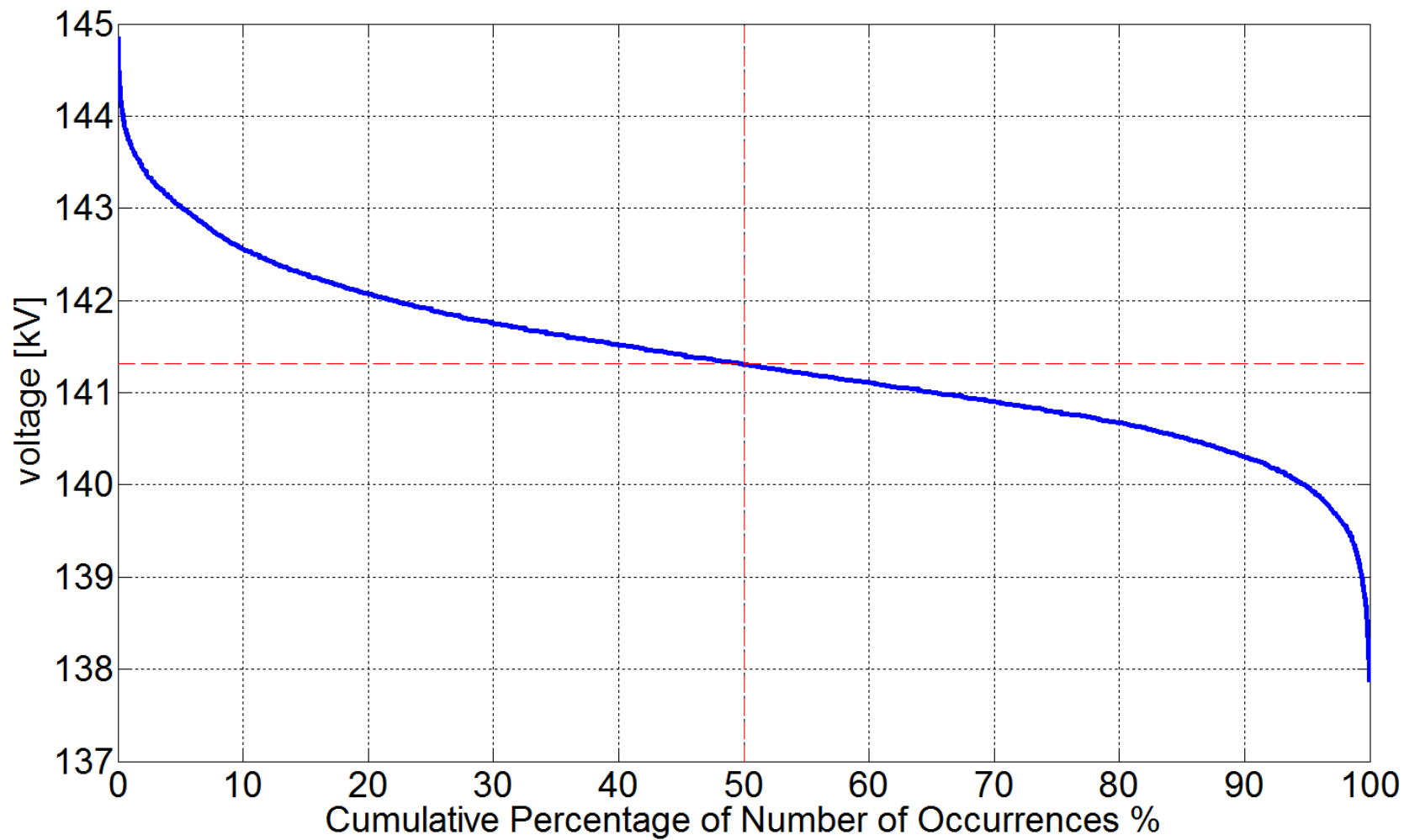
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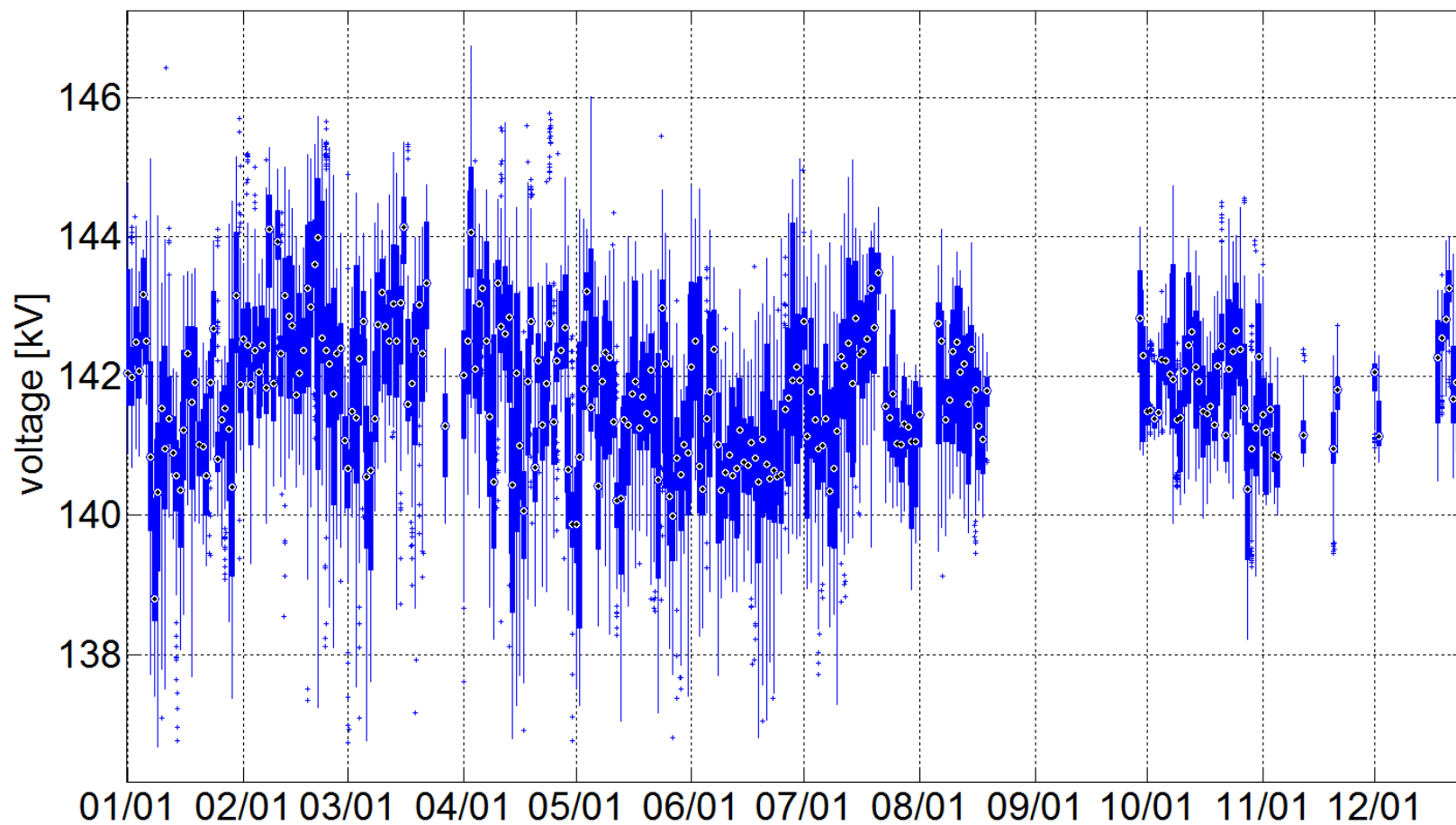
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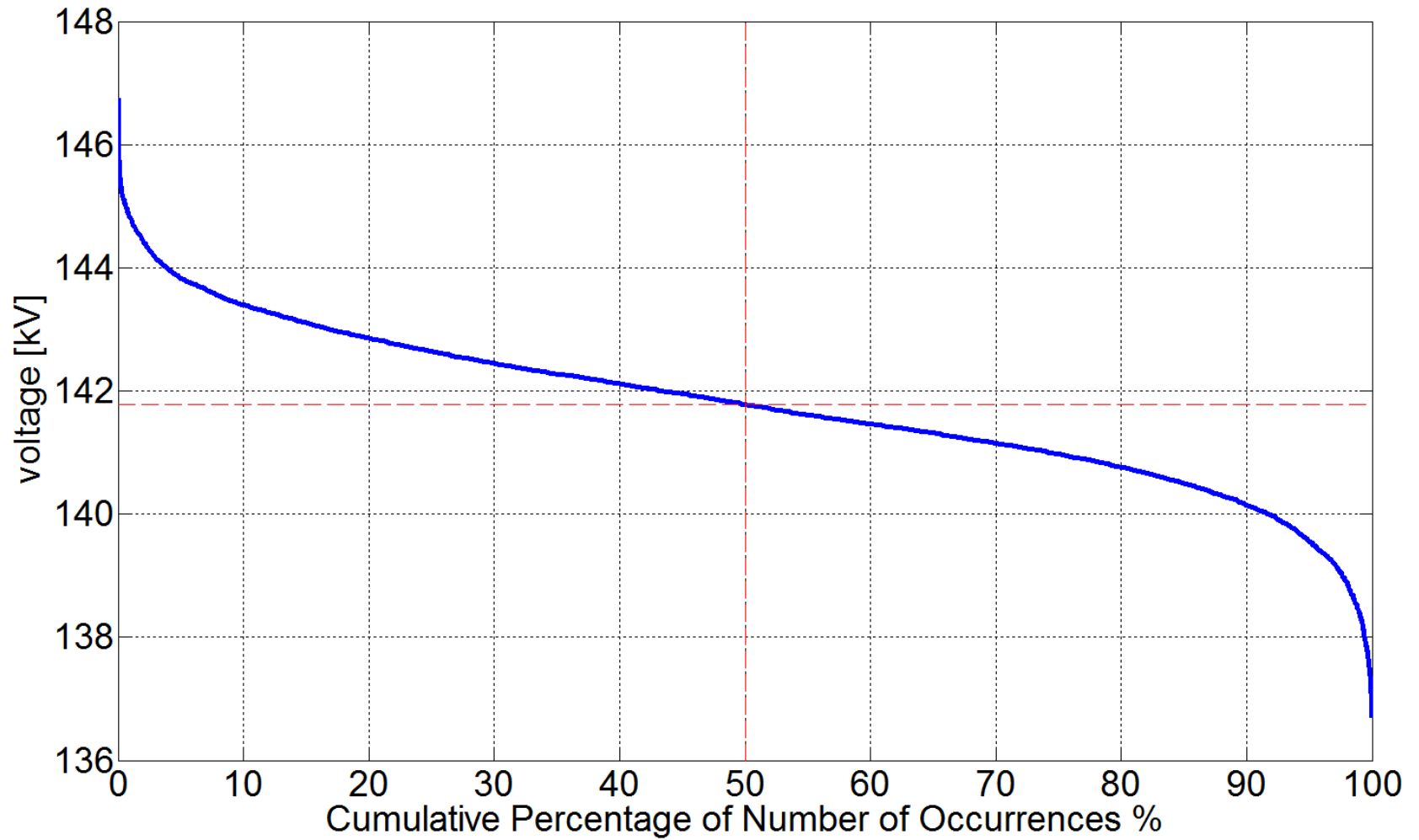
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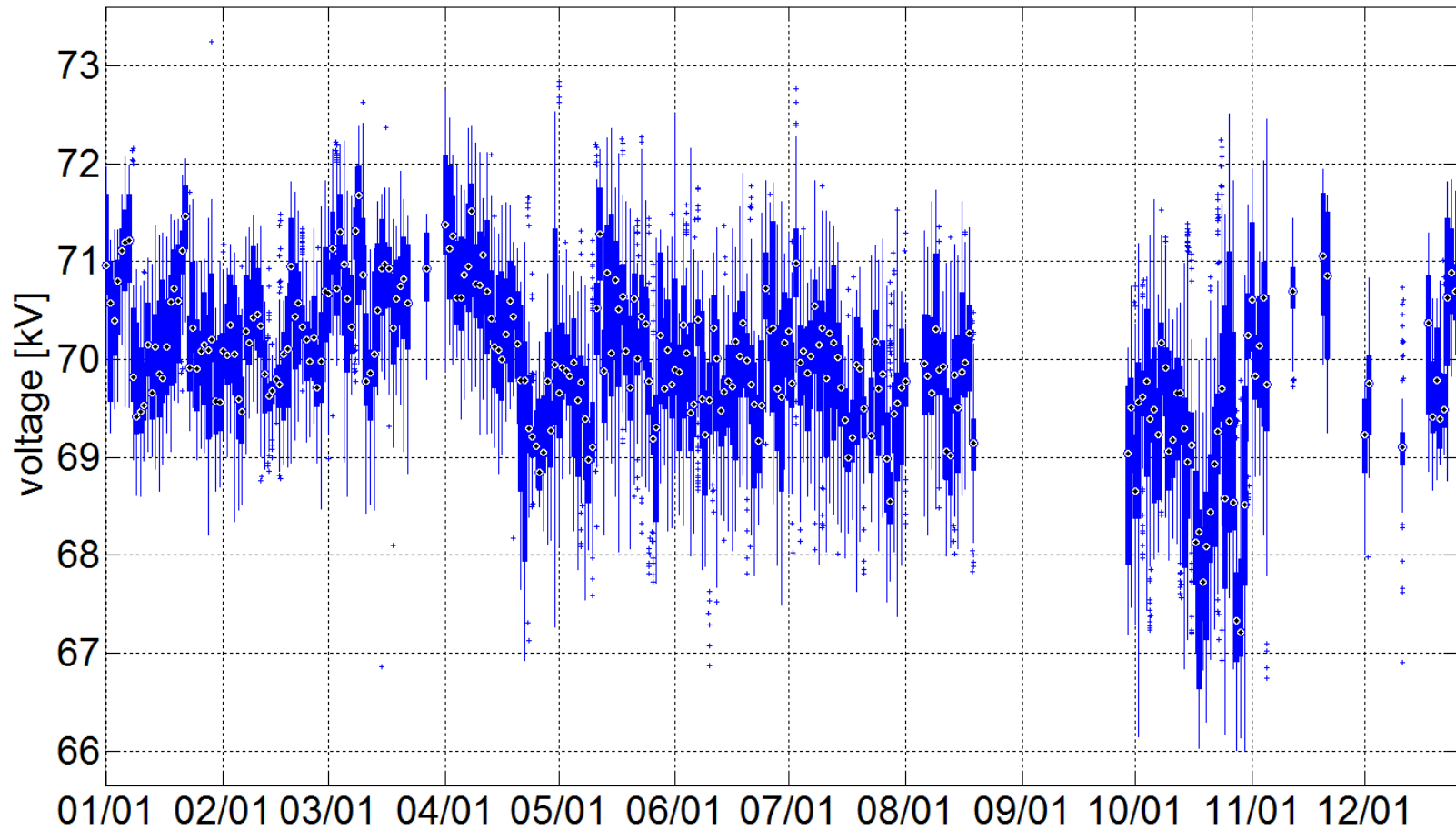
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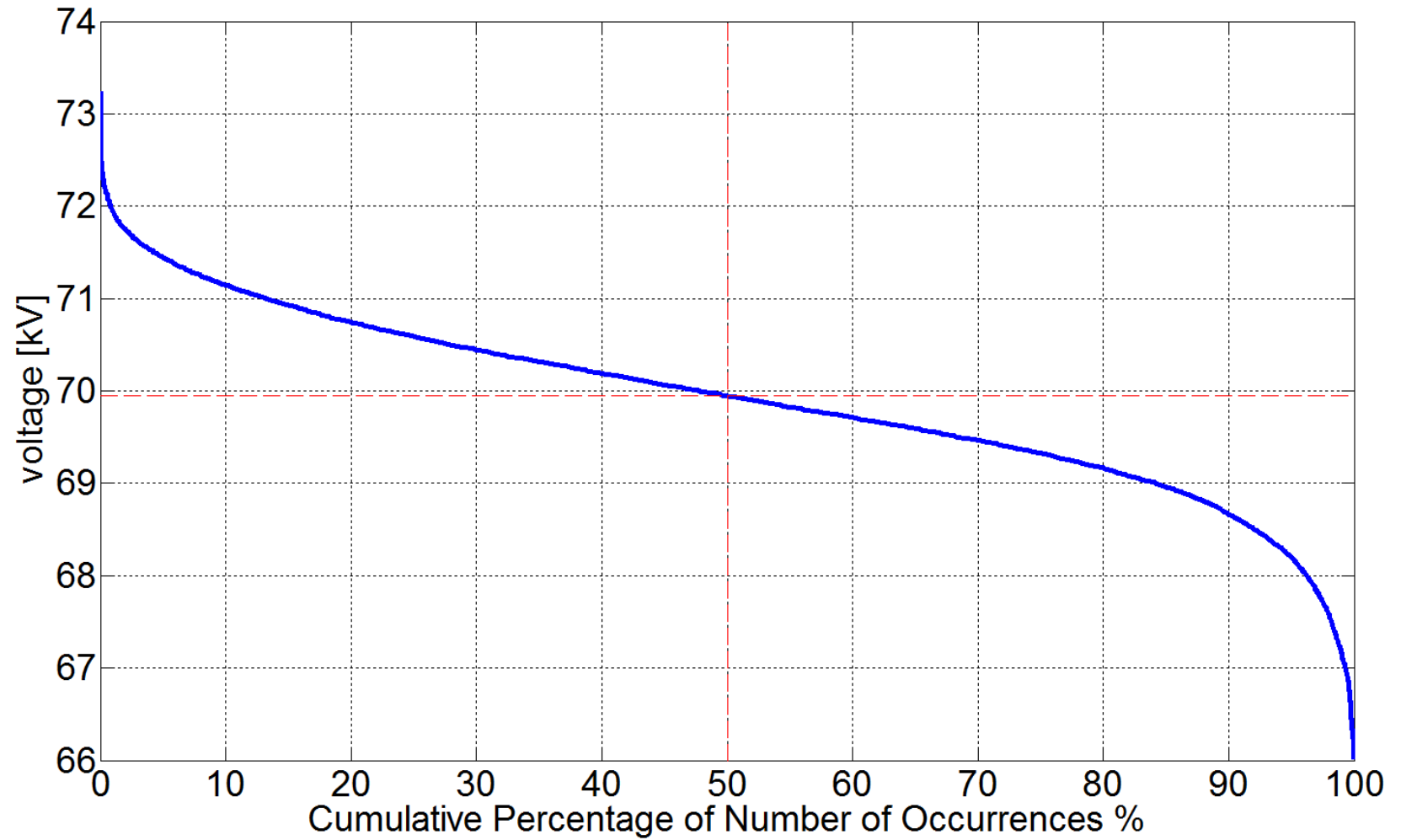
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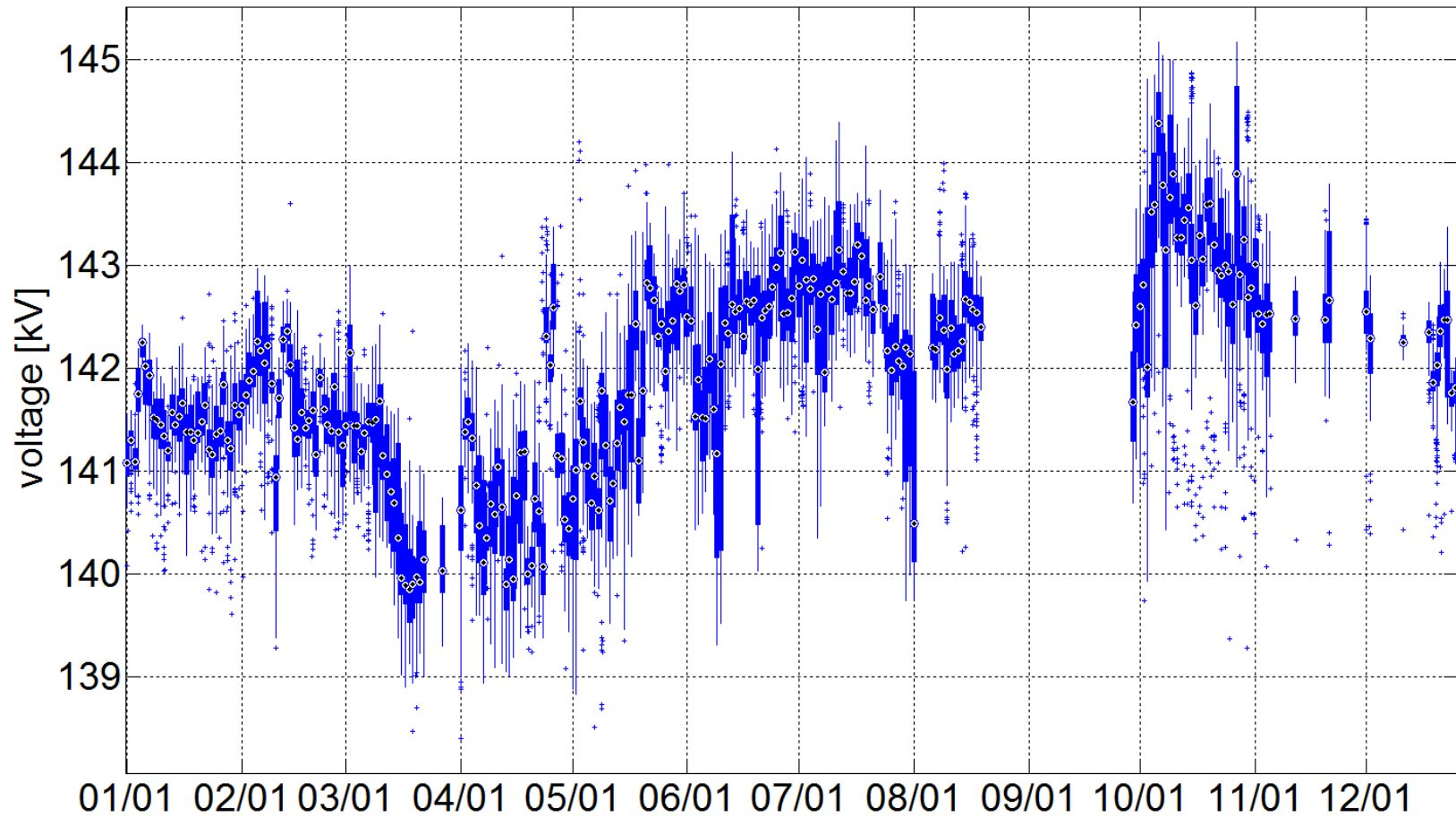
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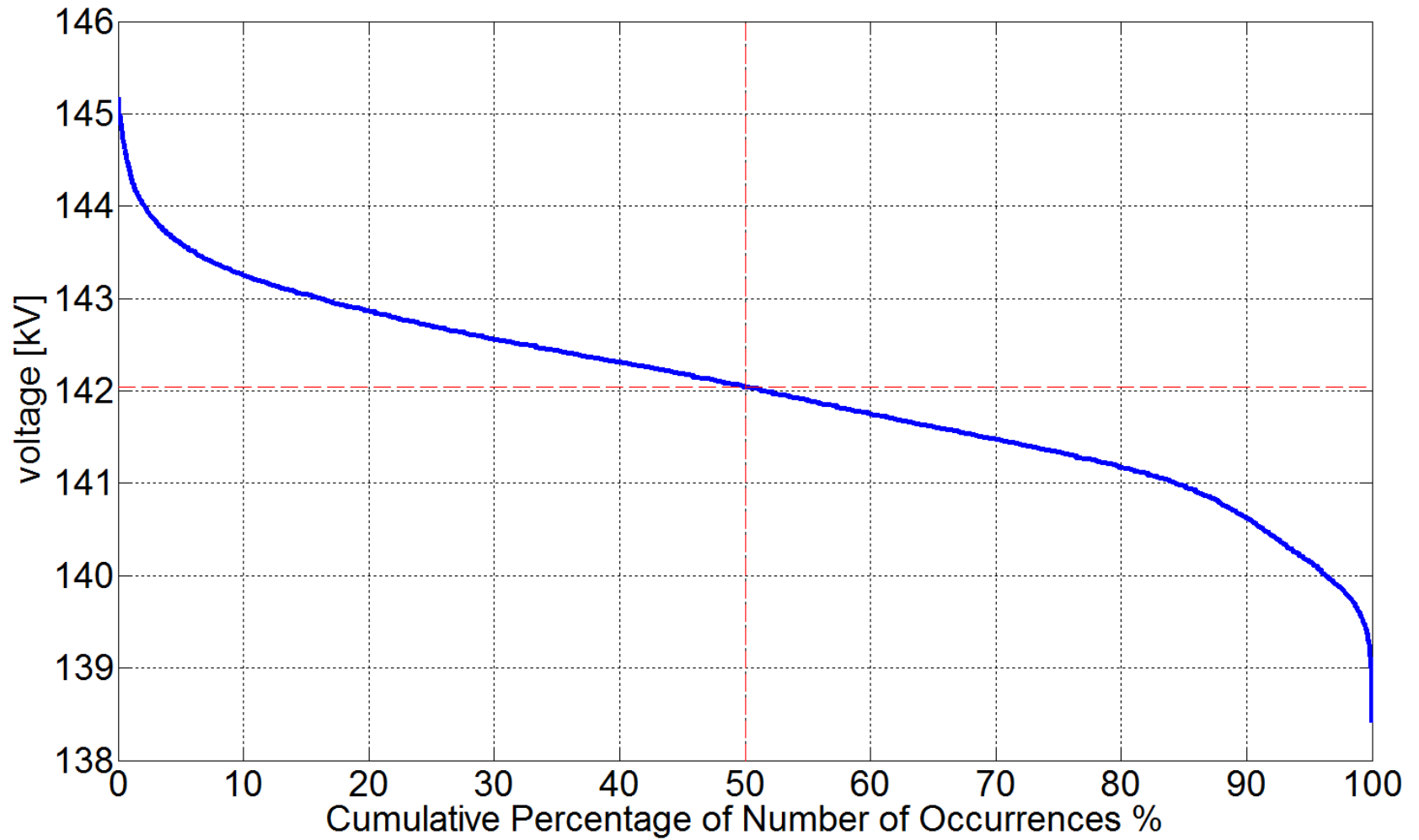
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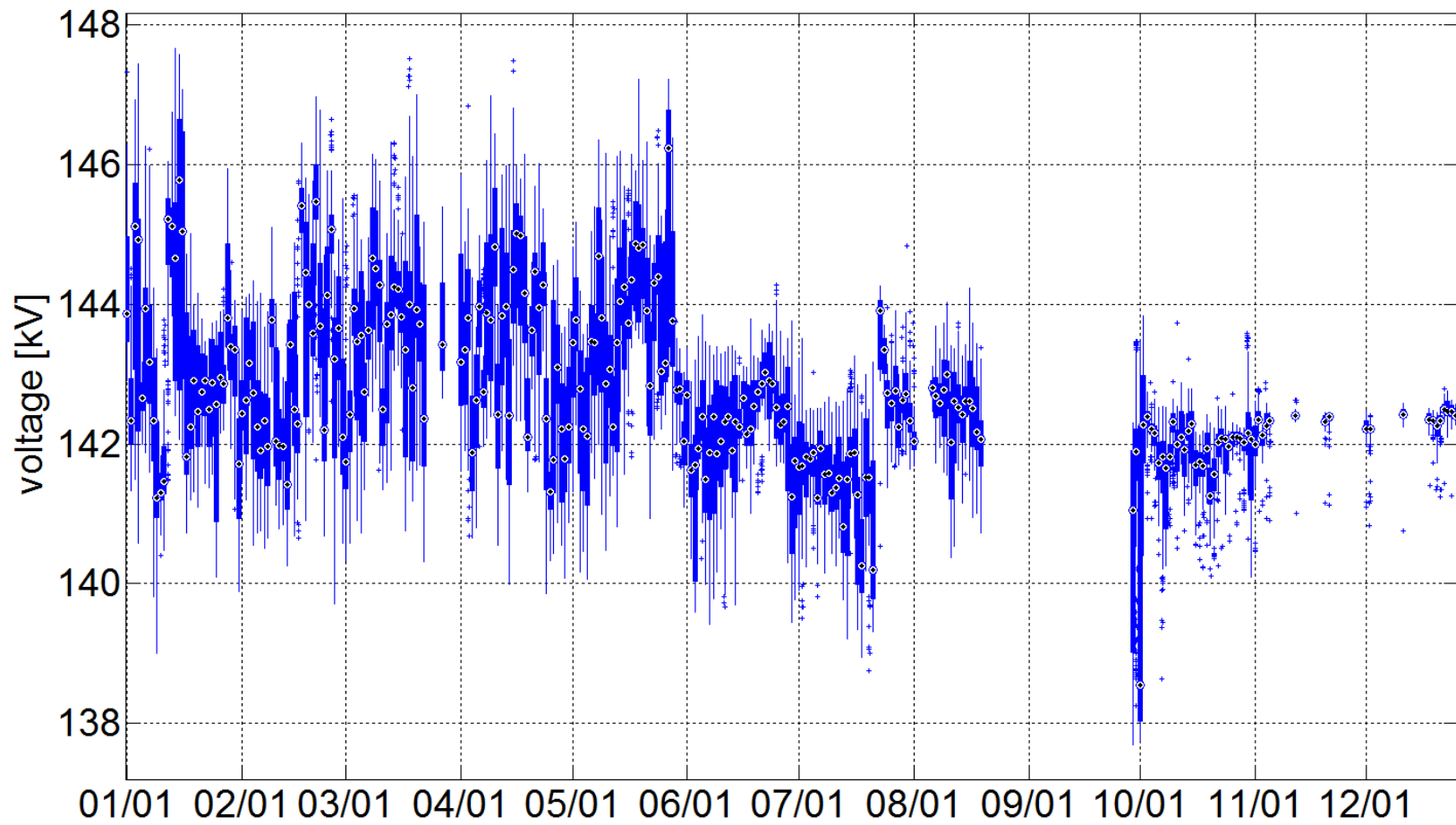
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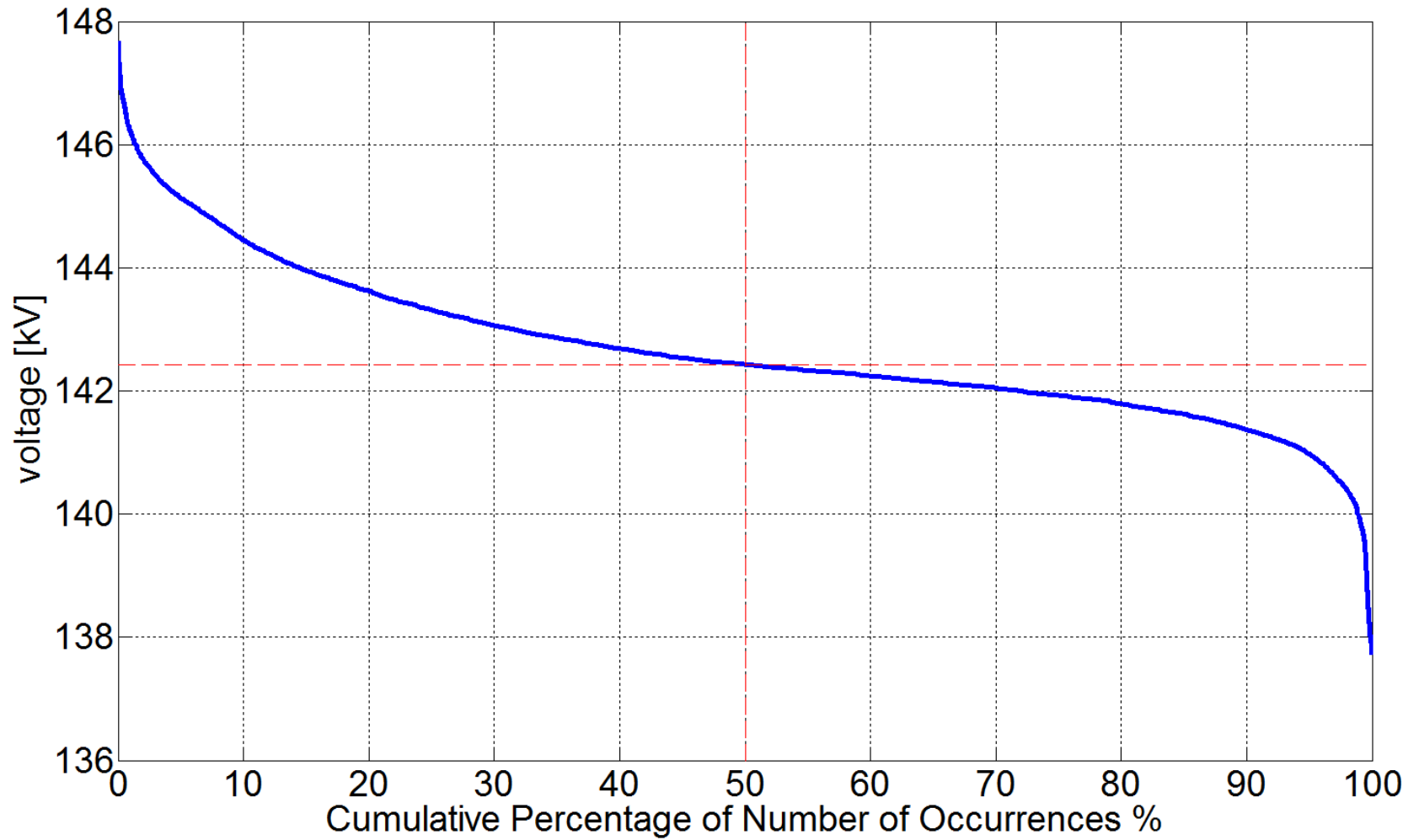
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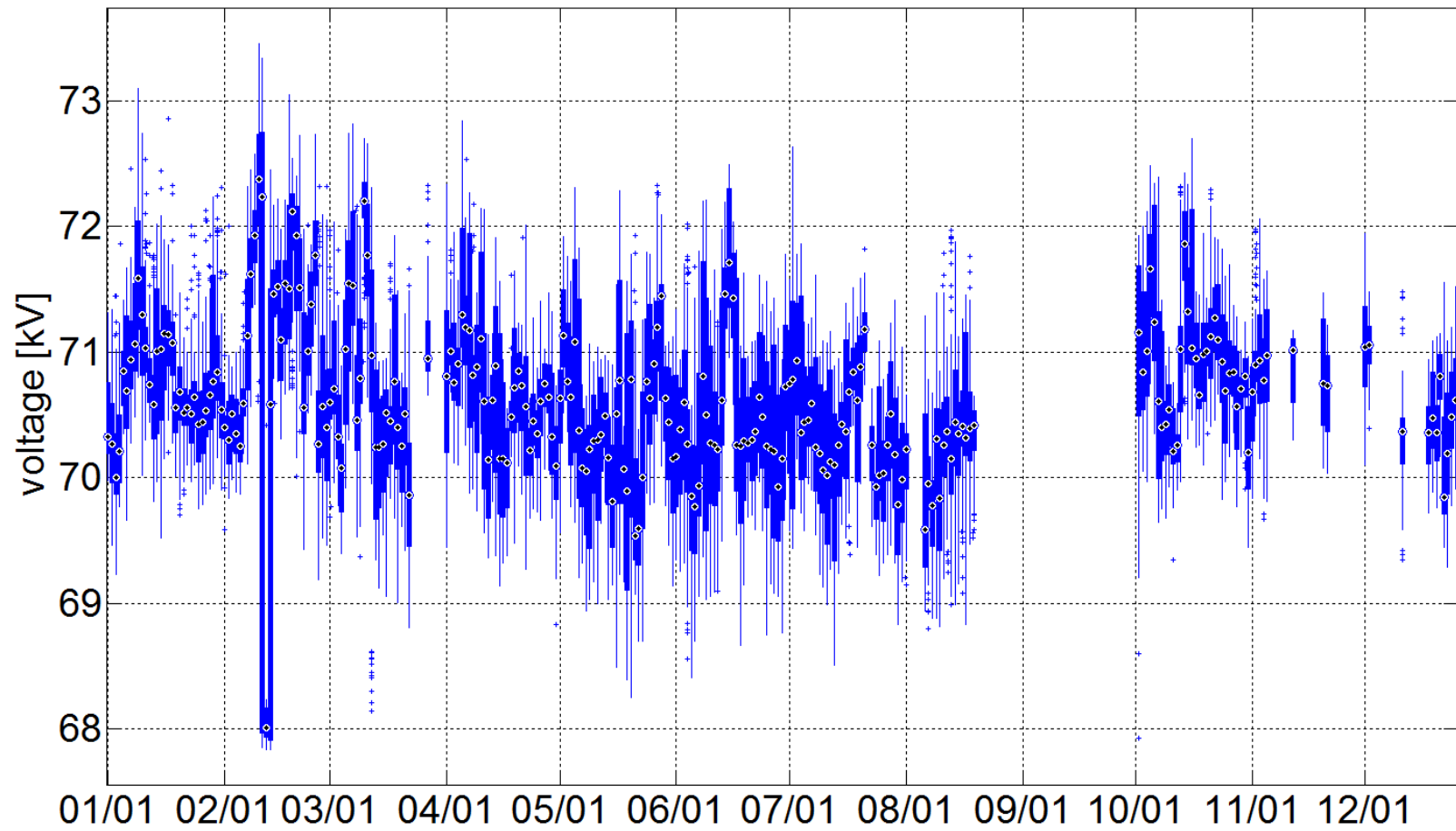
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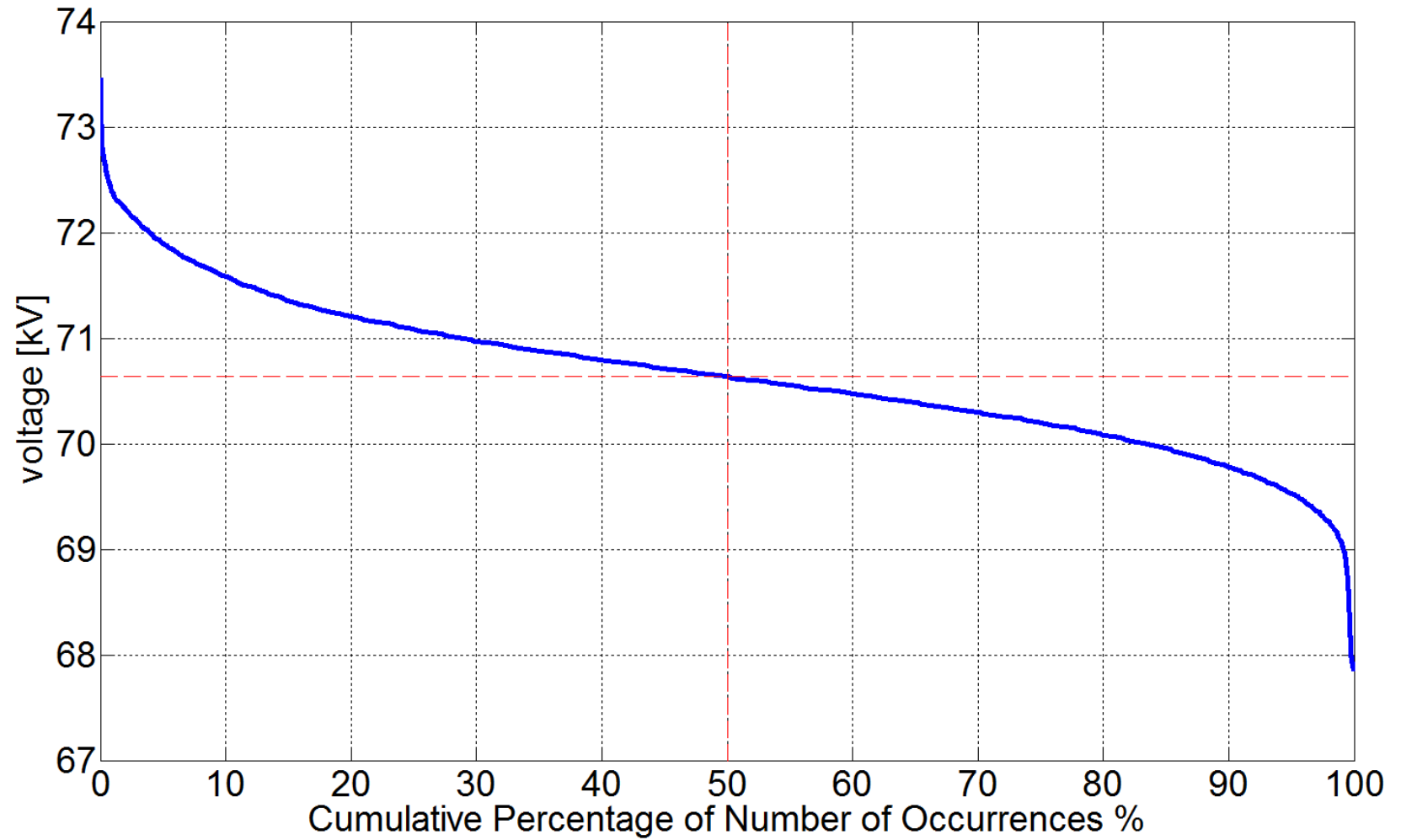
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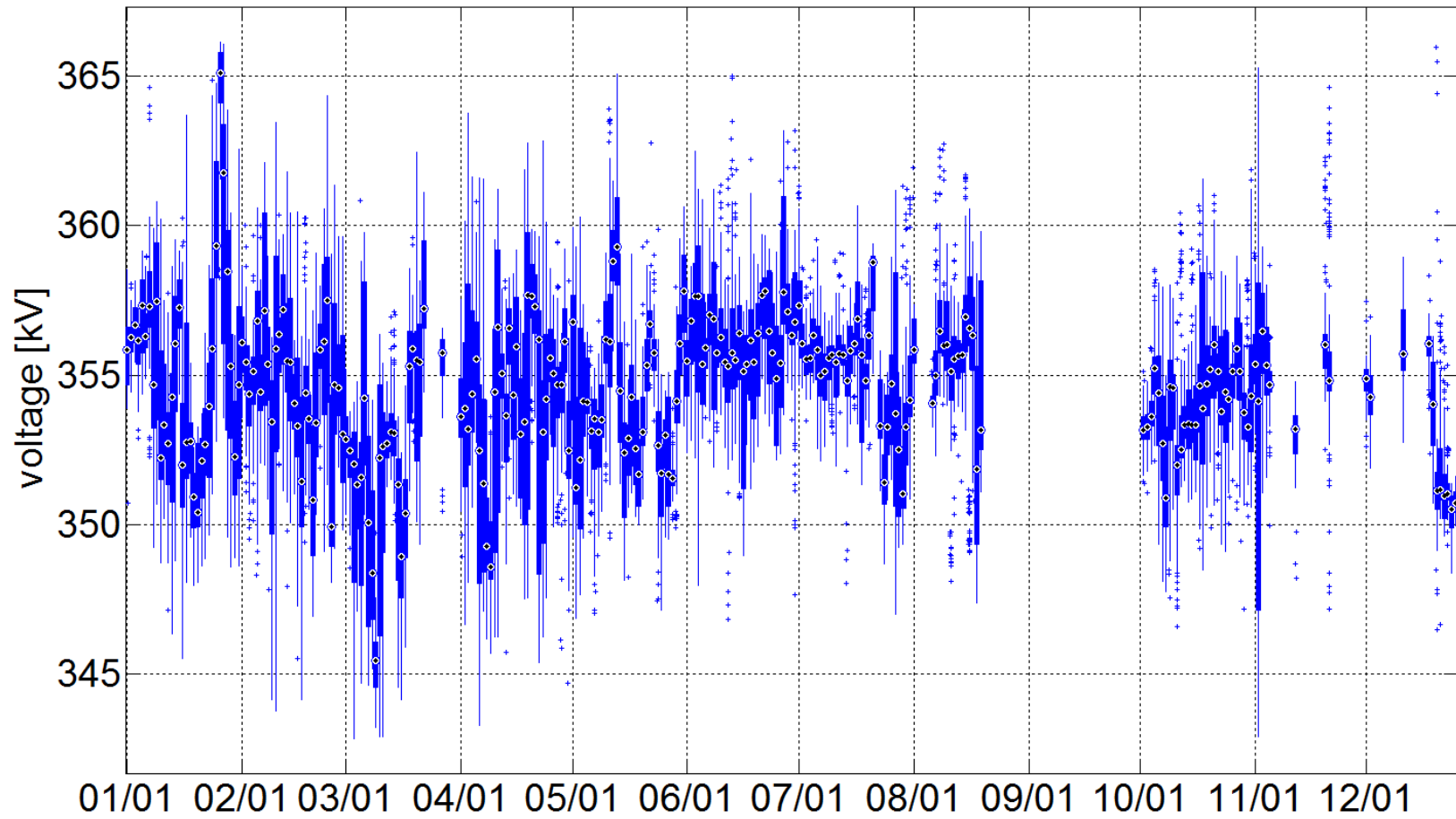
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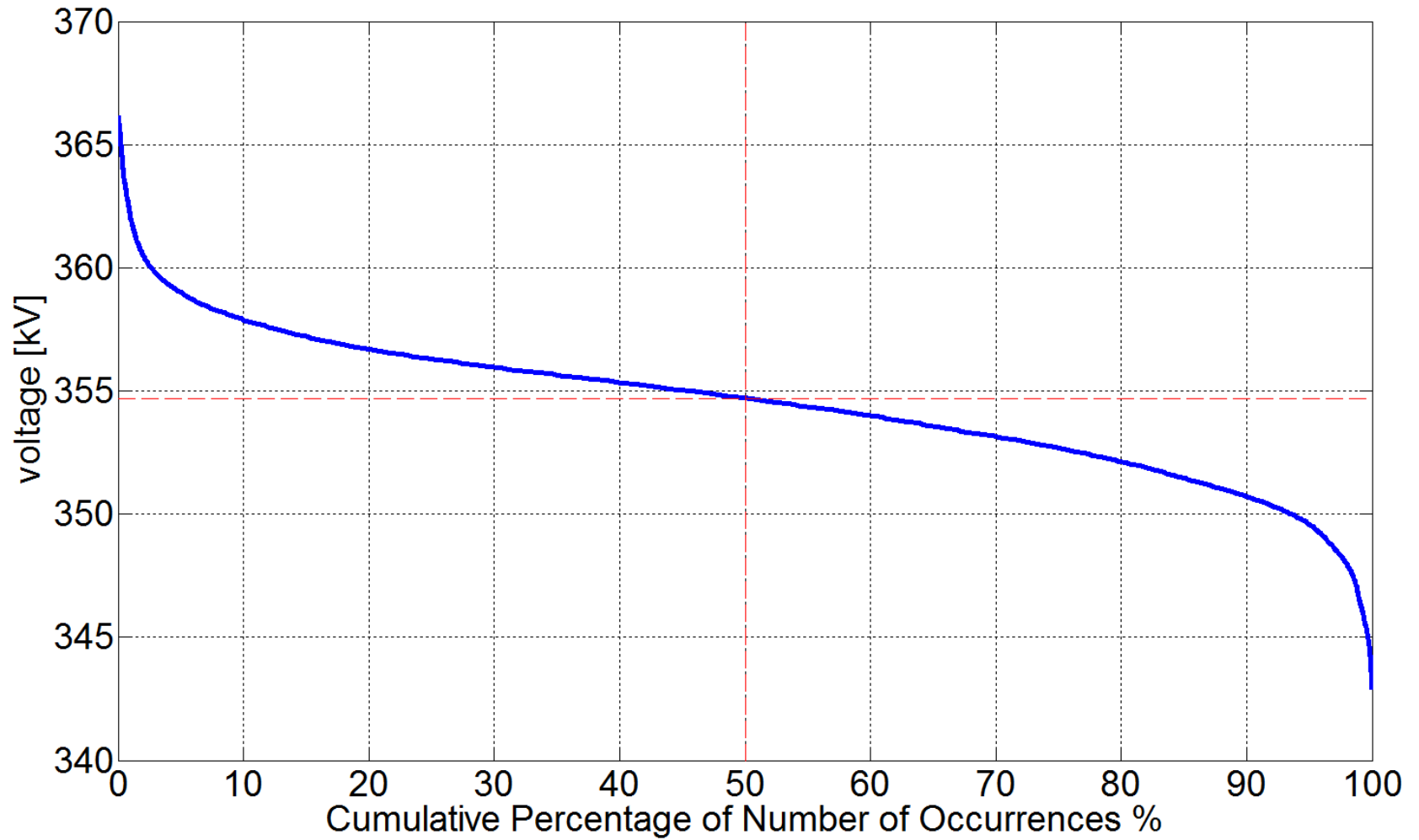
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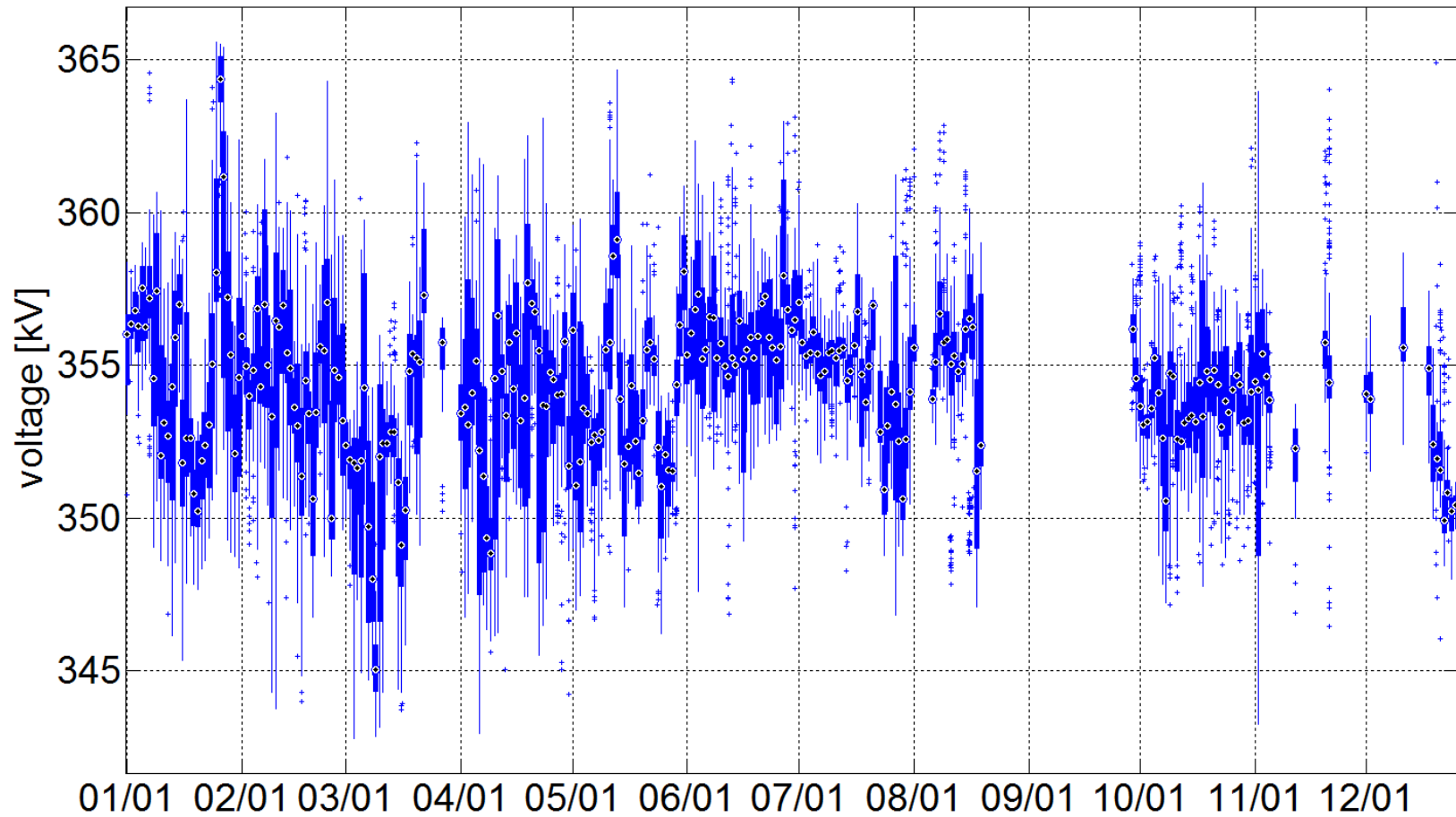
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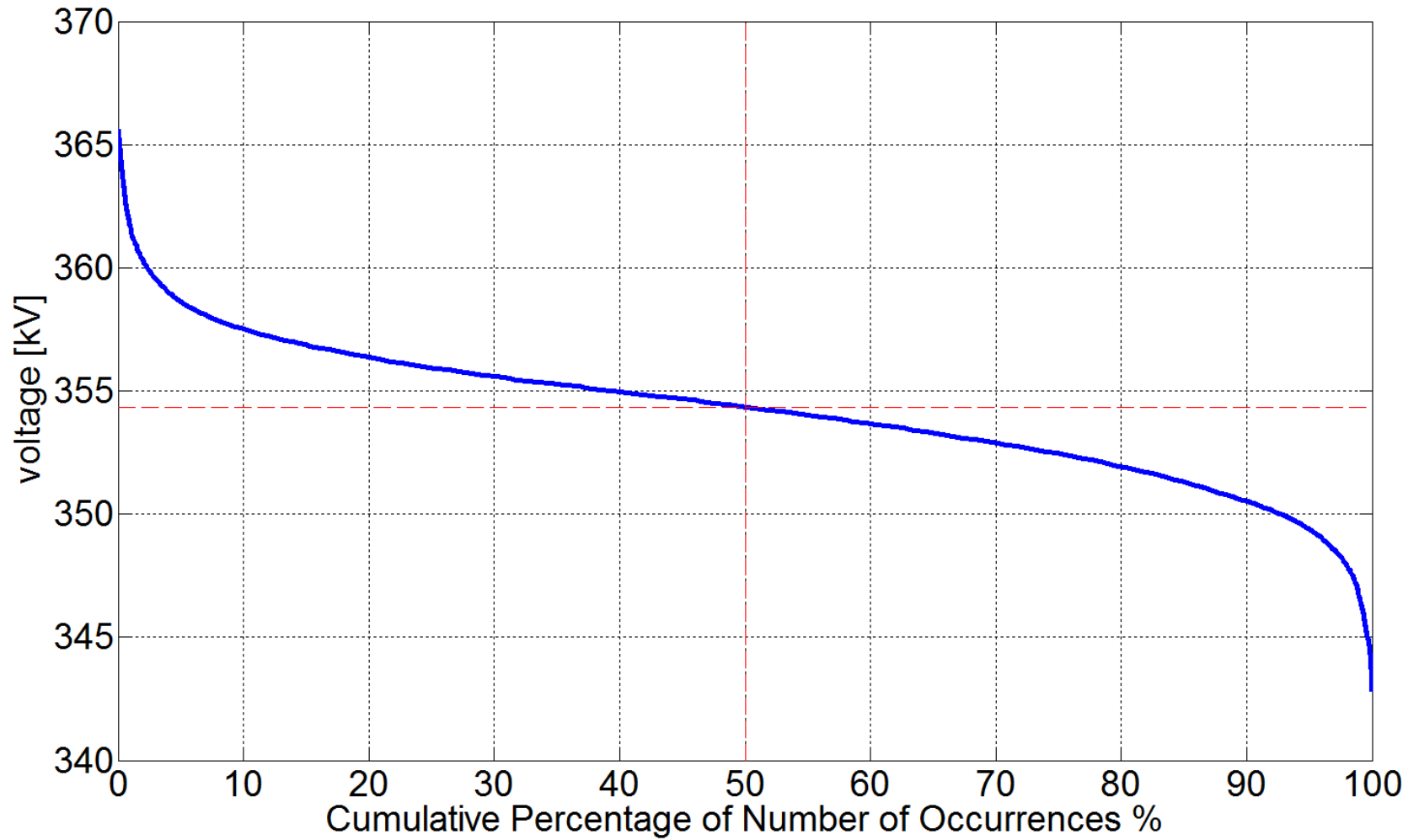
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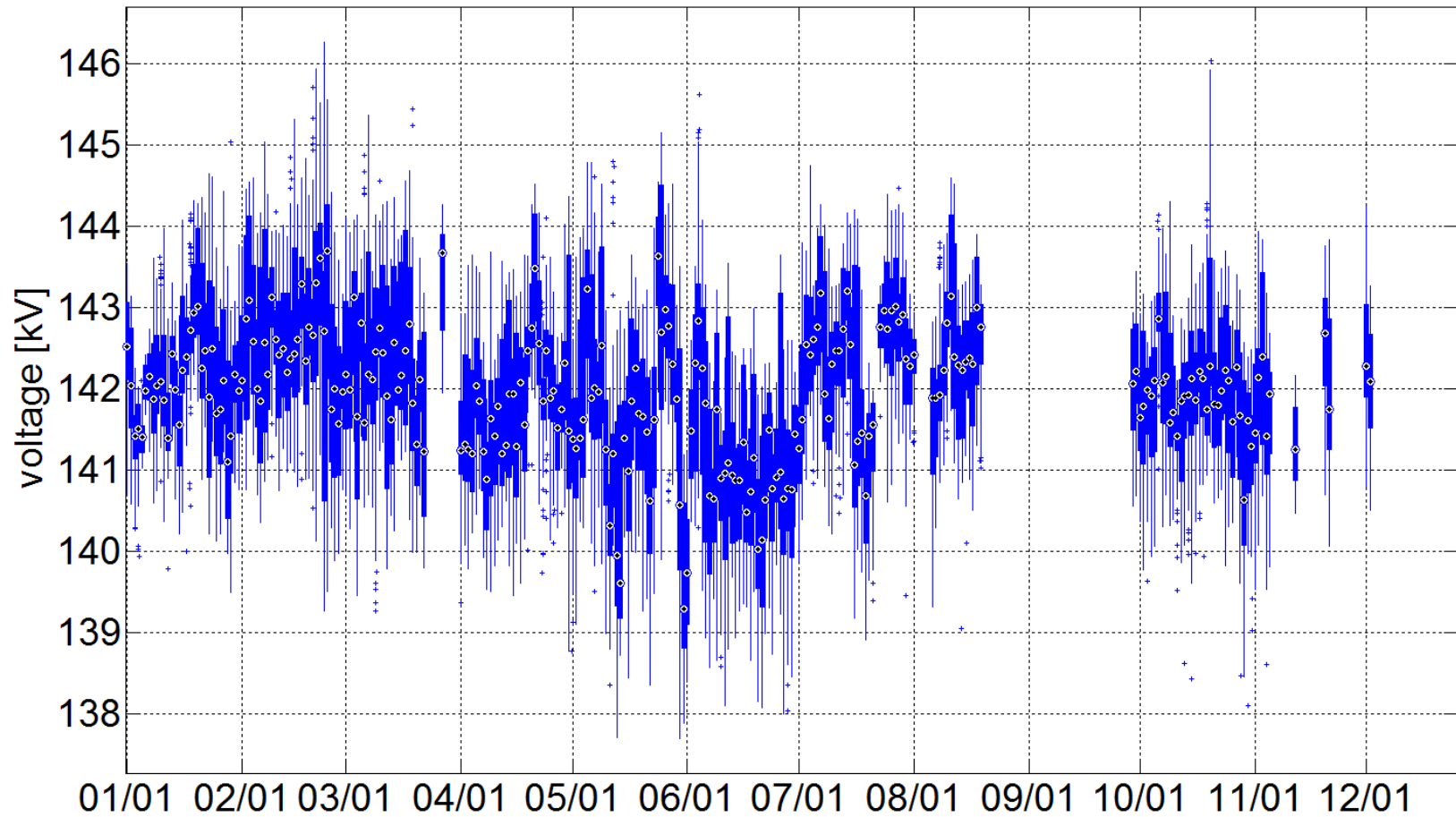
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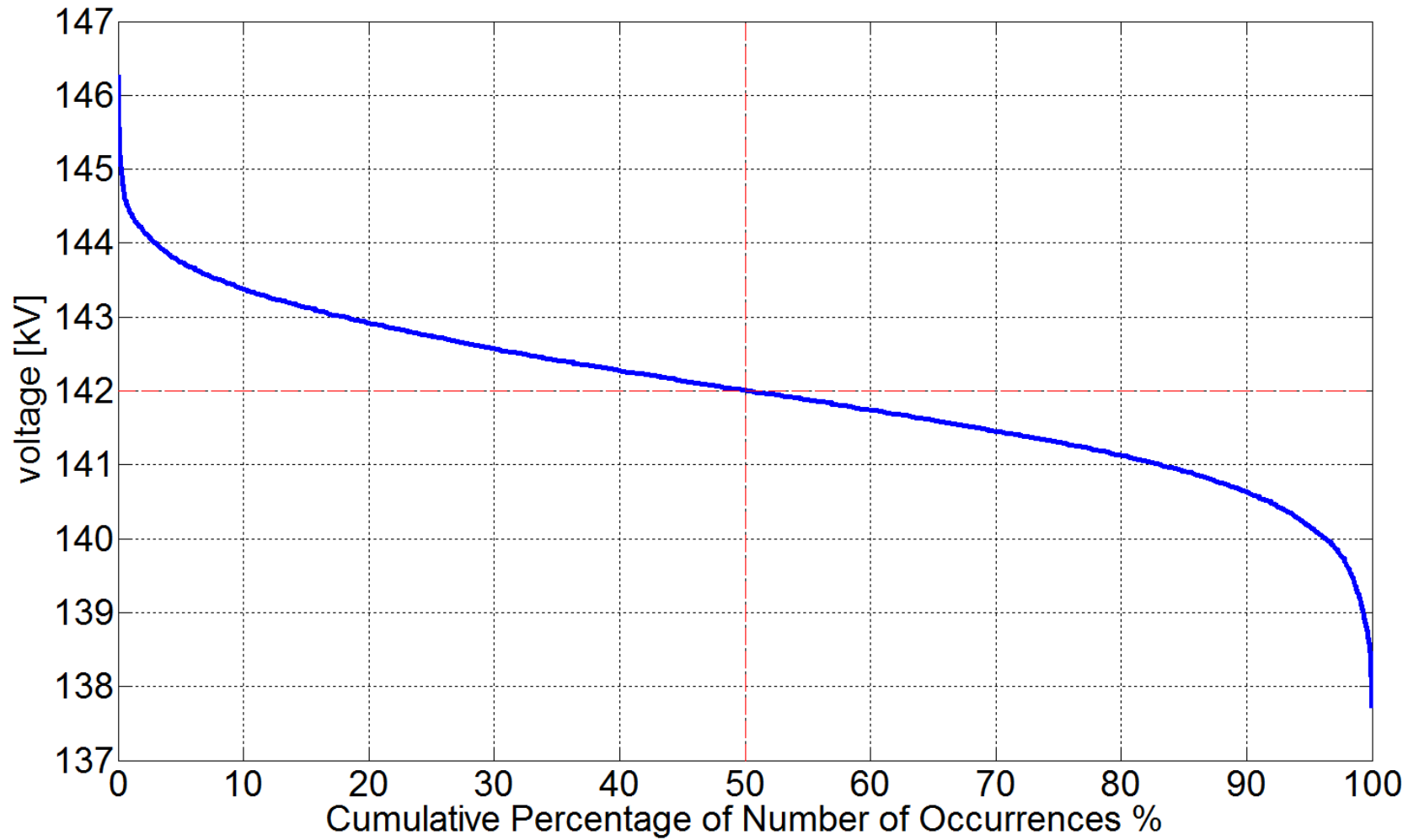
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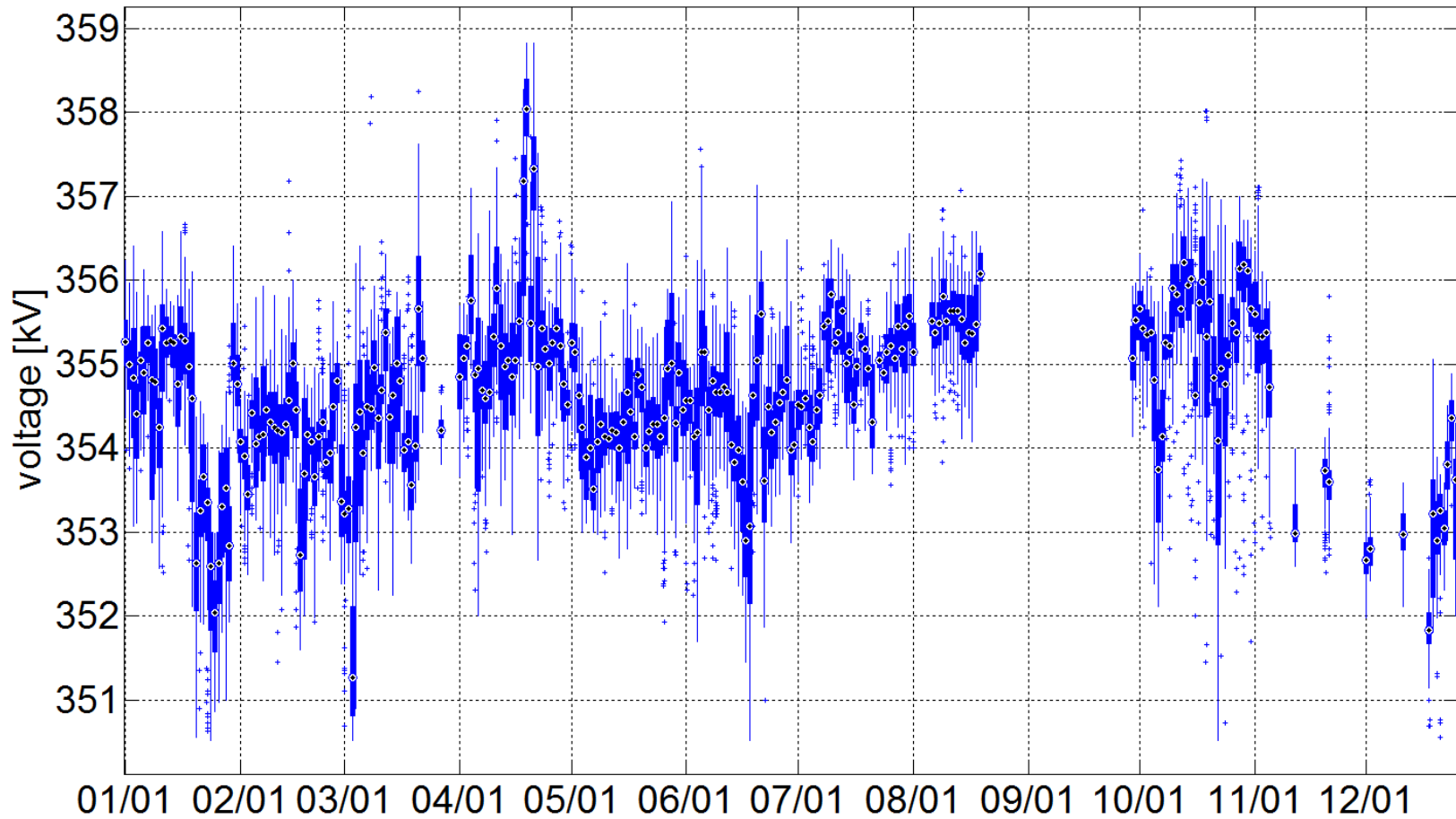
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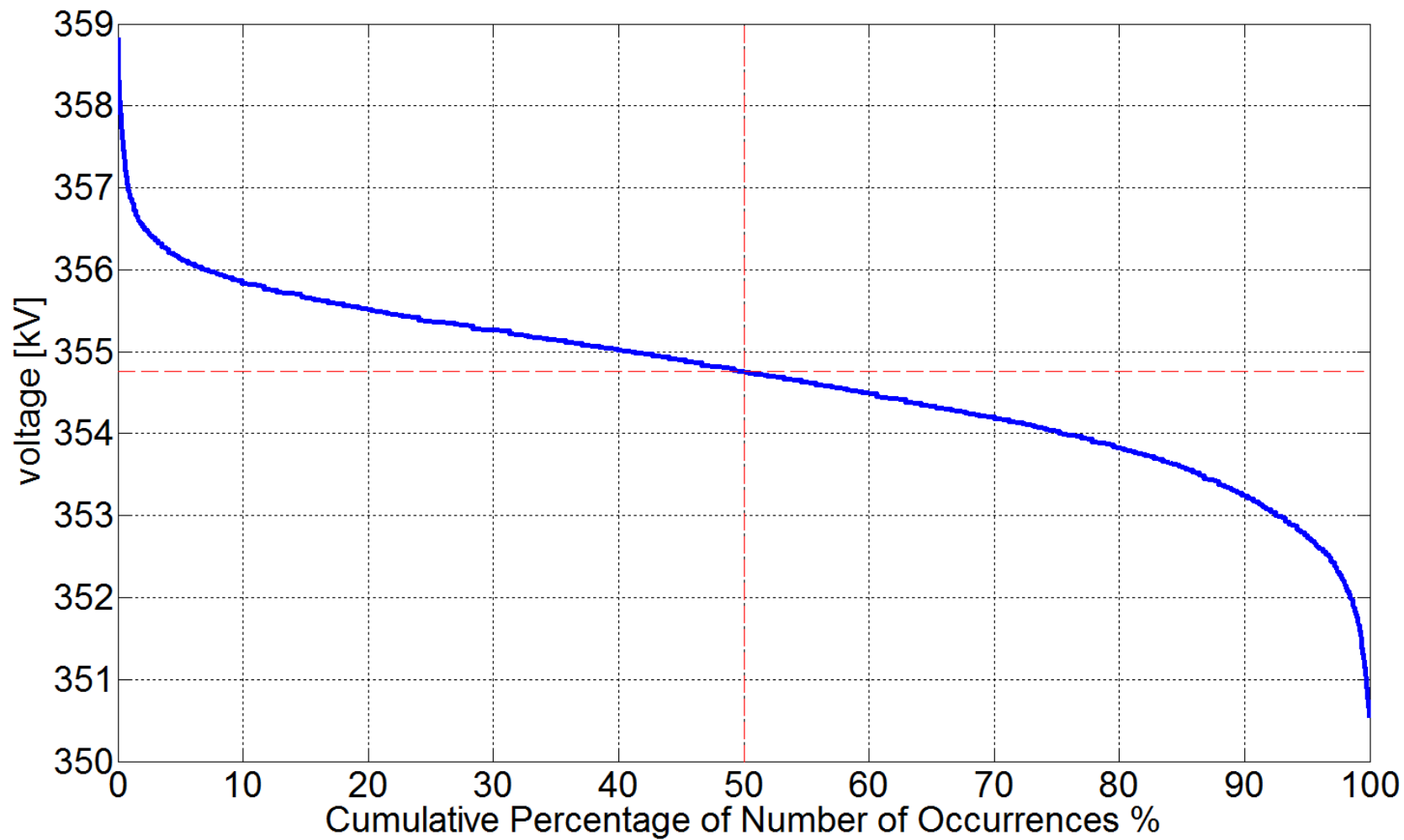
South 13



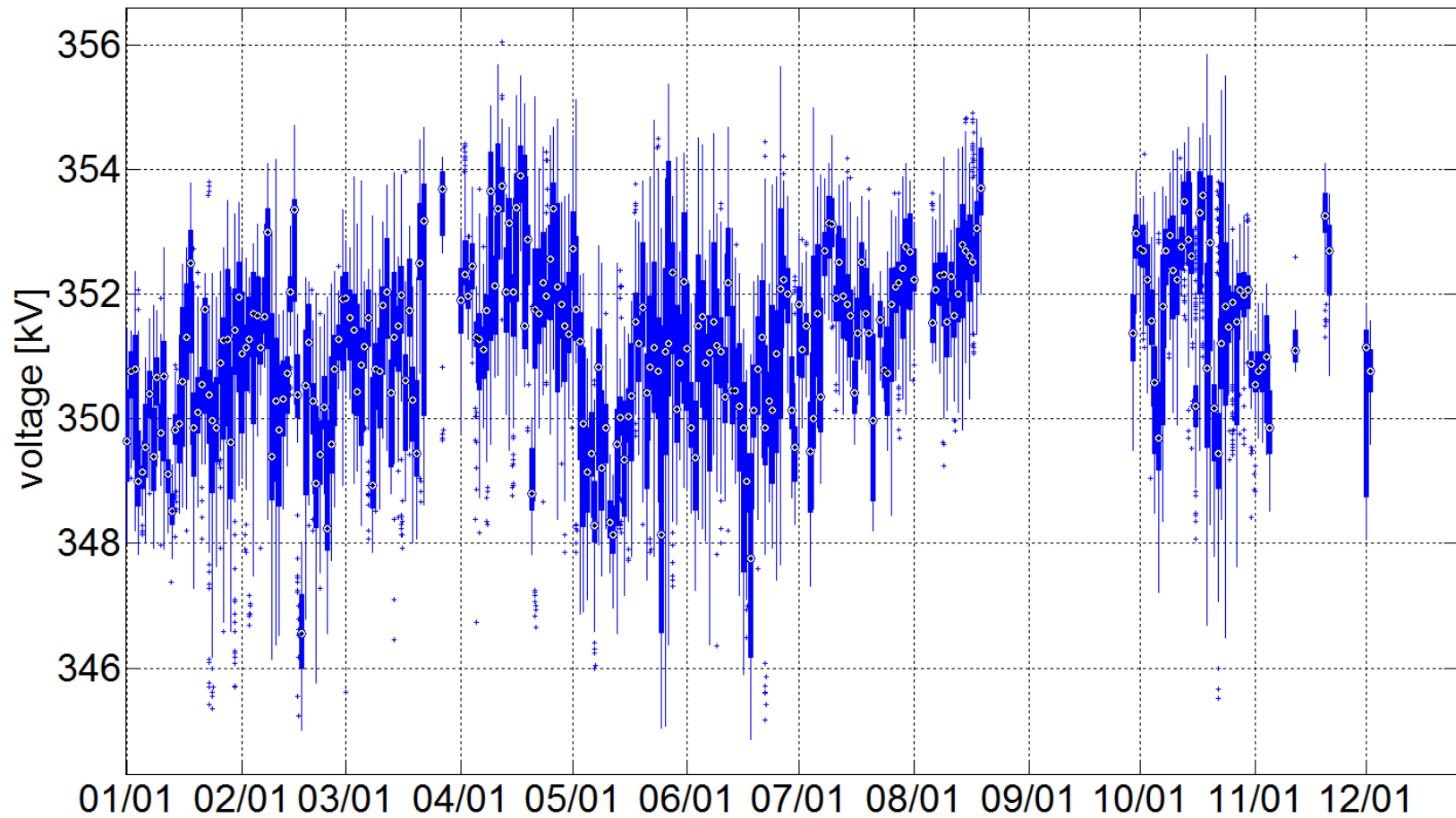
FarWest 4



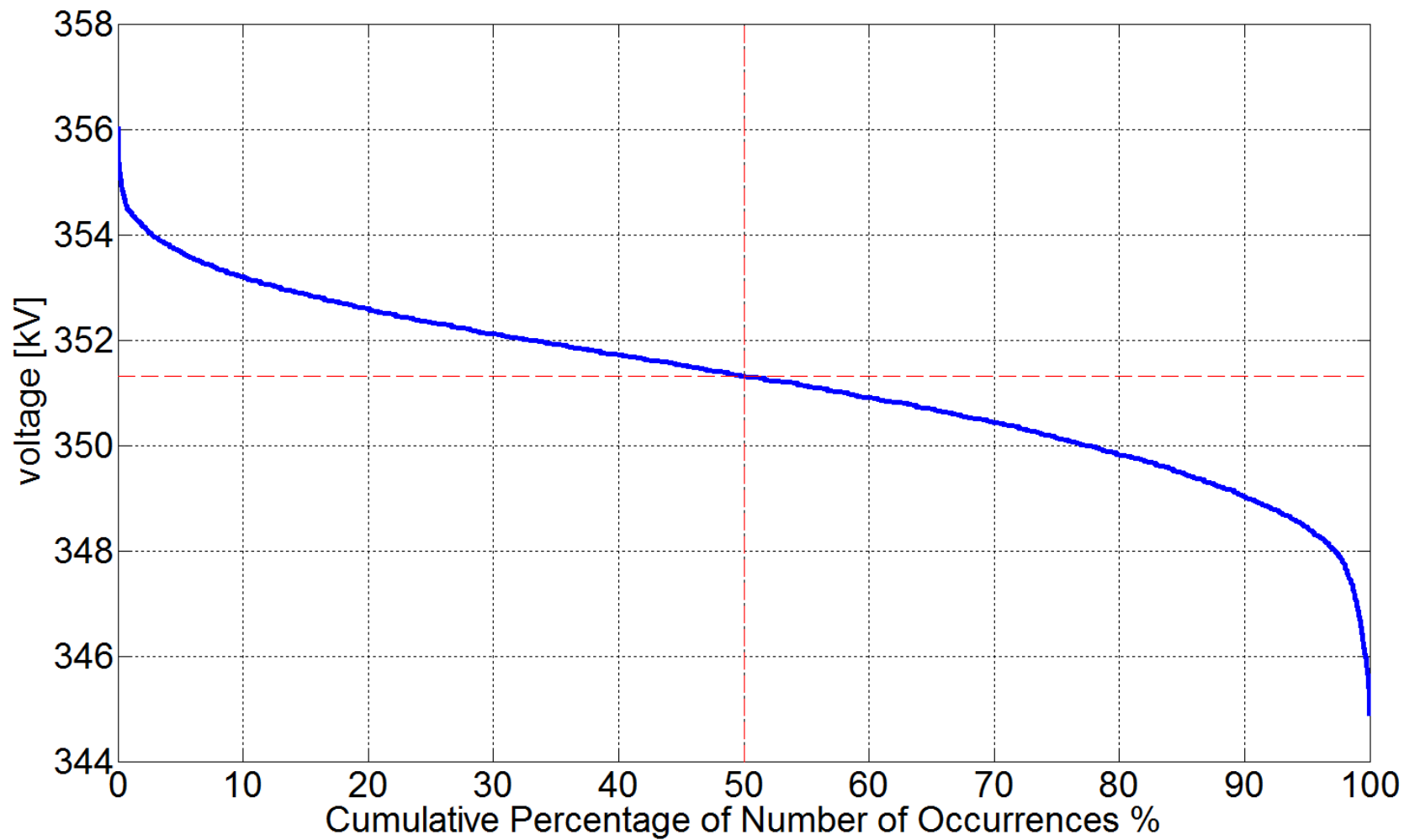
FarWest 4



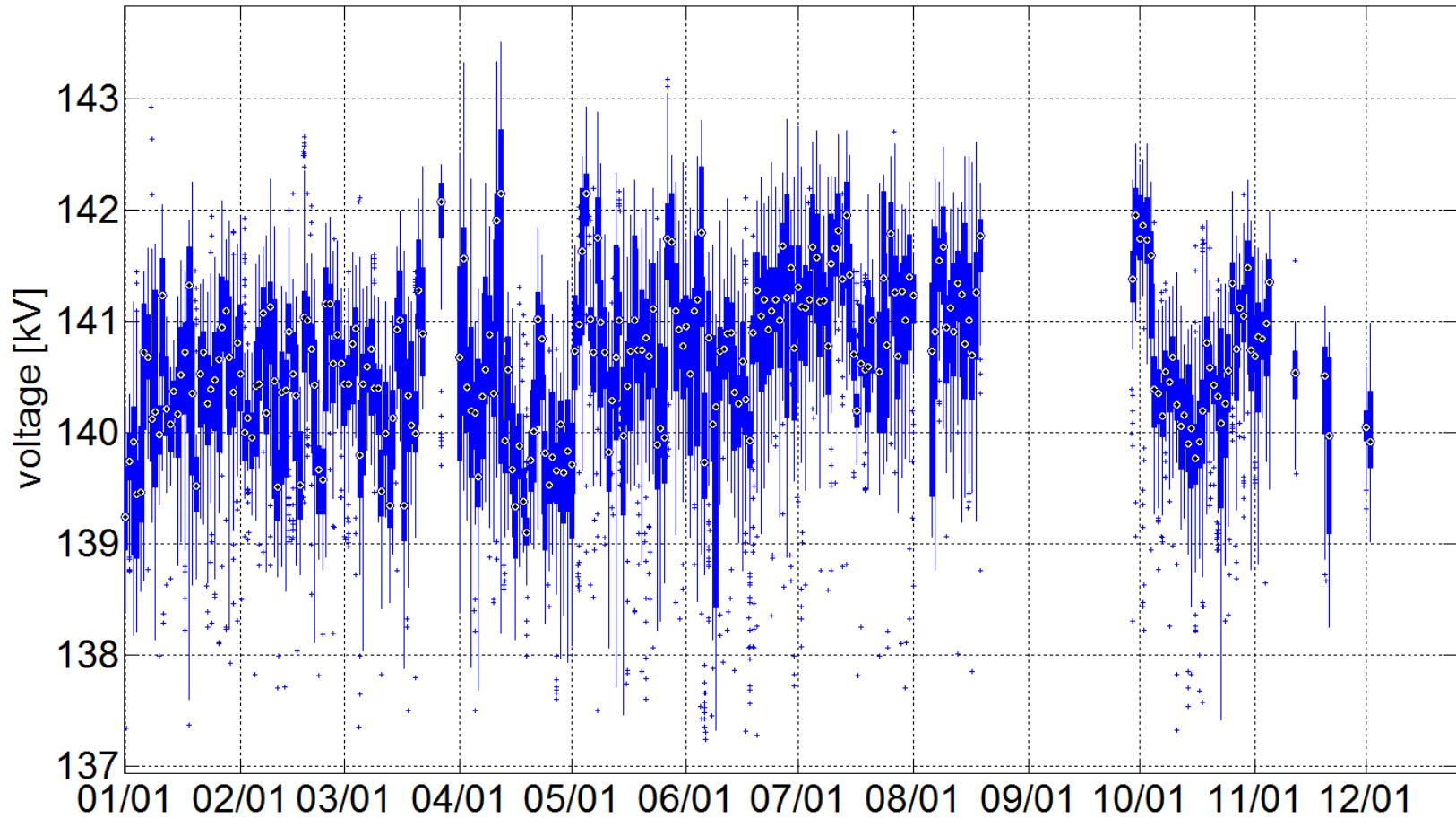
FarWest 7



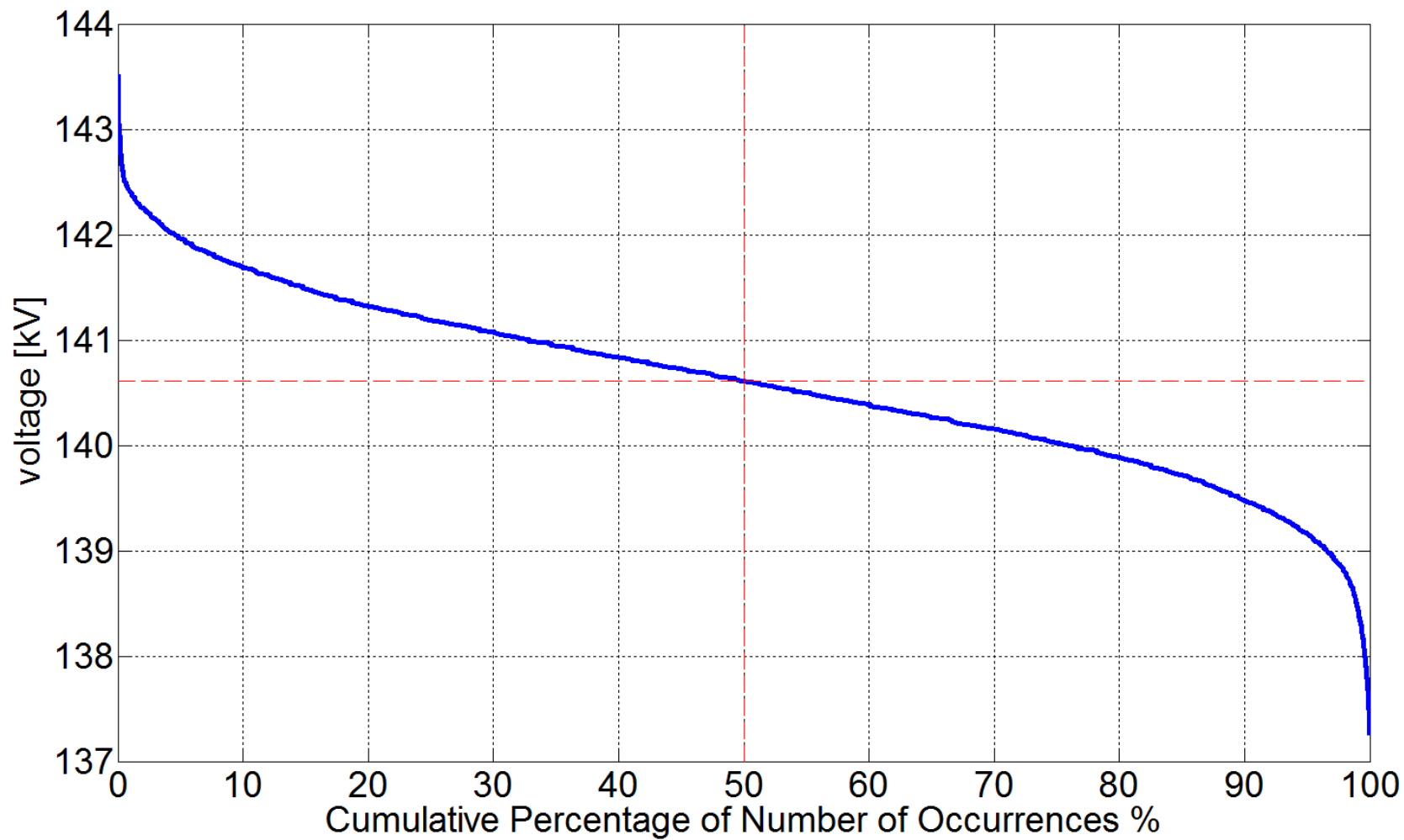
FarWest 7



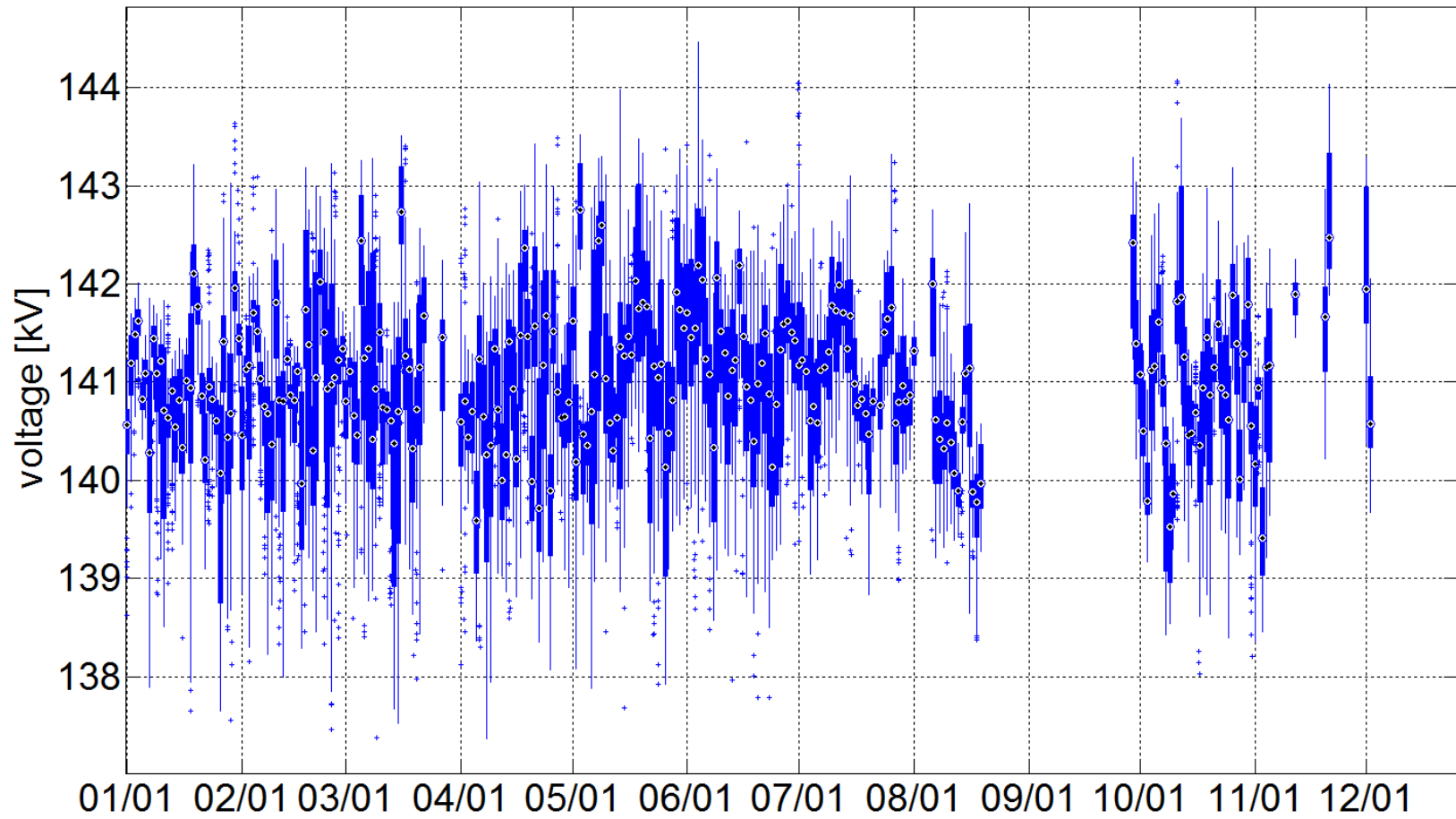
FarWest 8



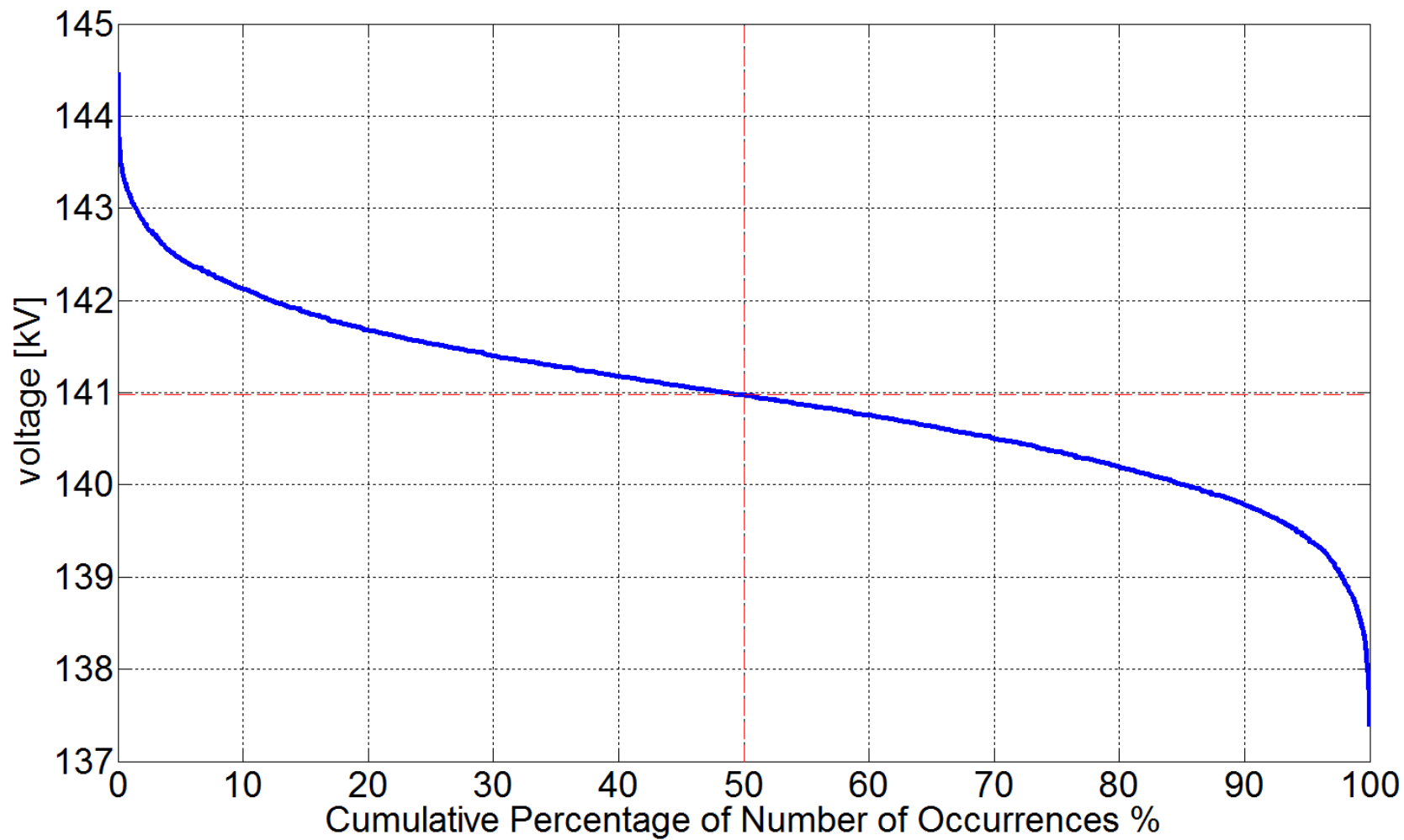
FarWest 8



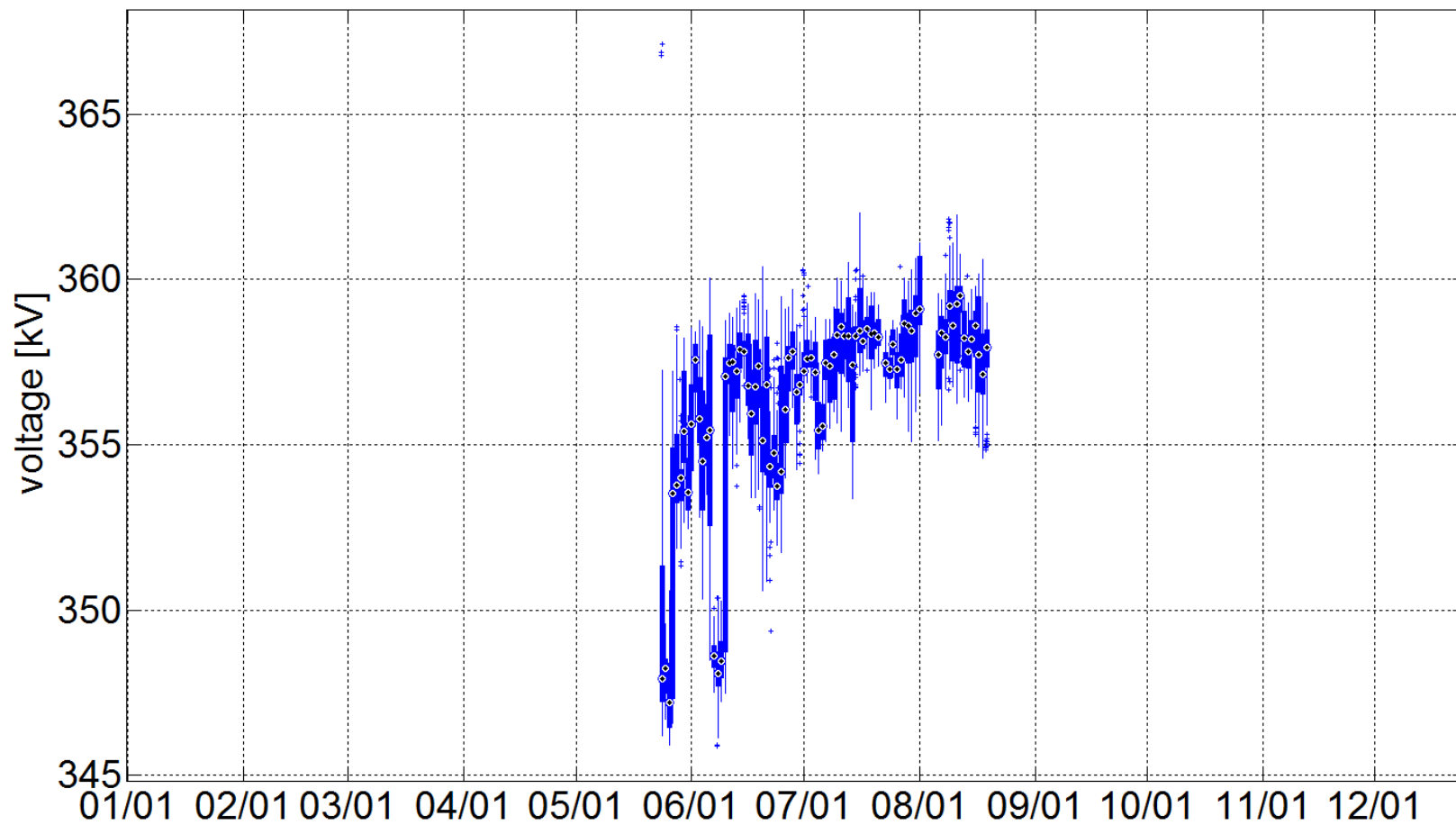
FarWest 9



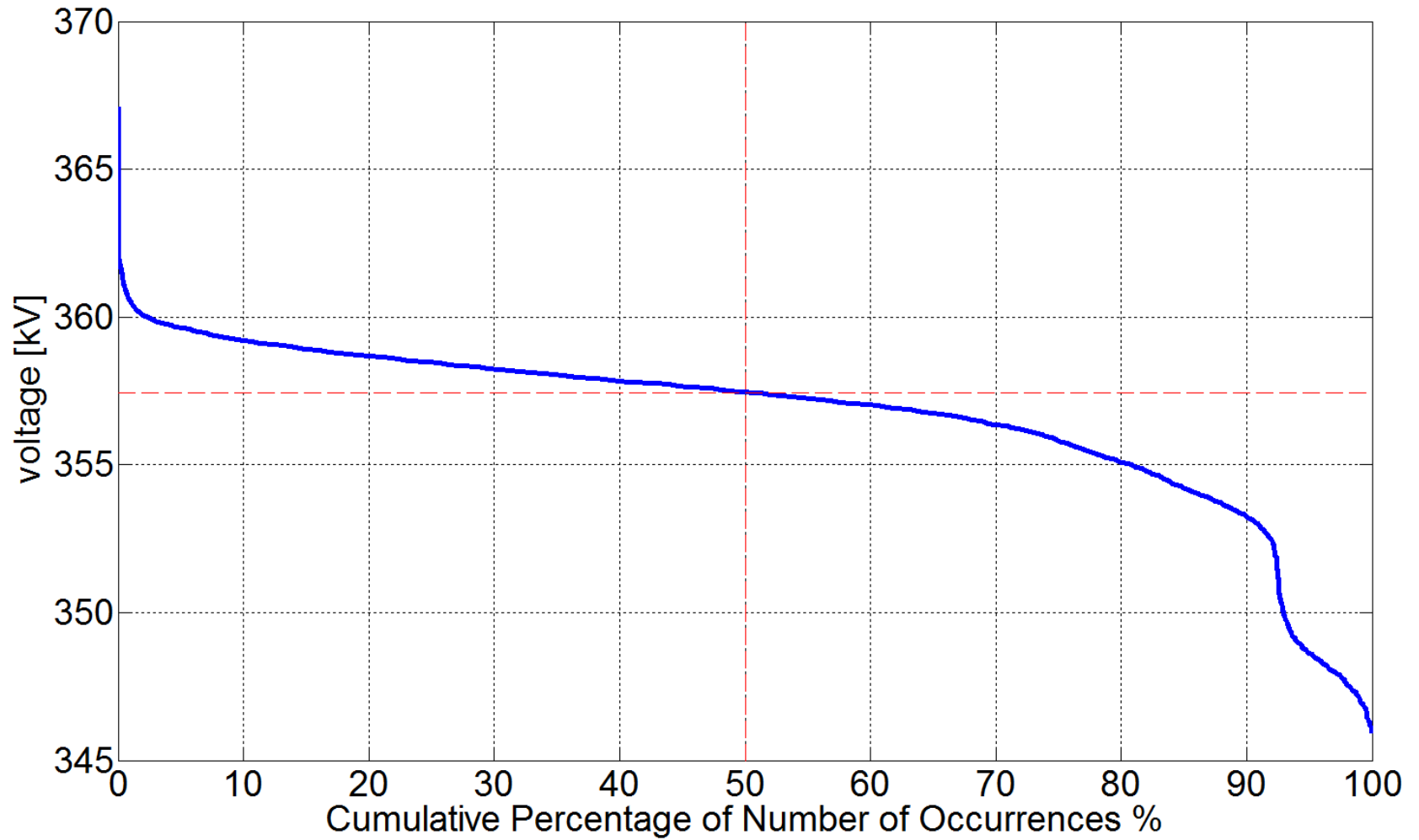
FarWest 9



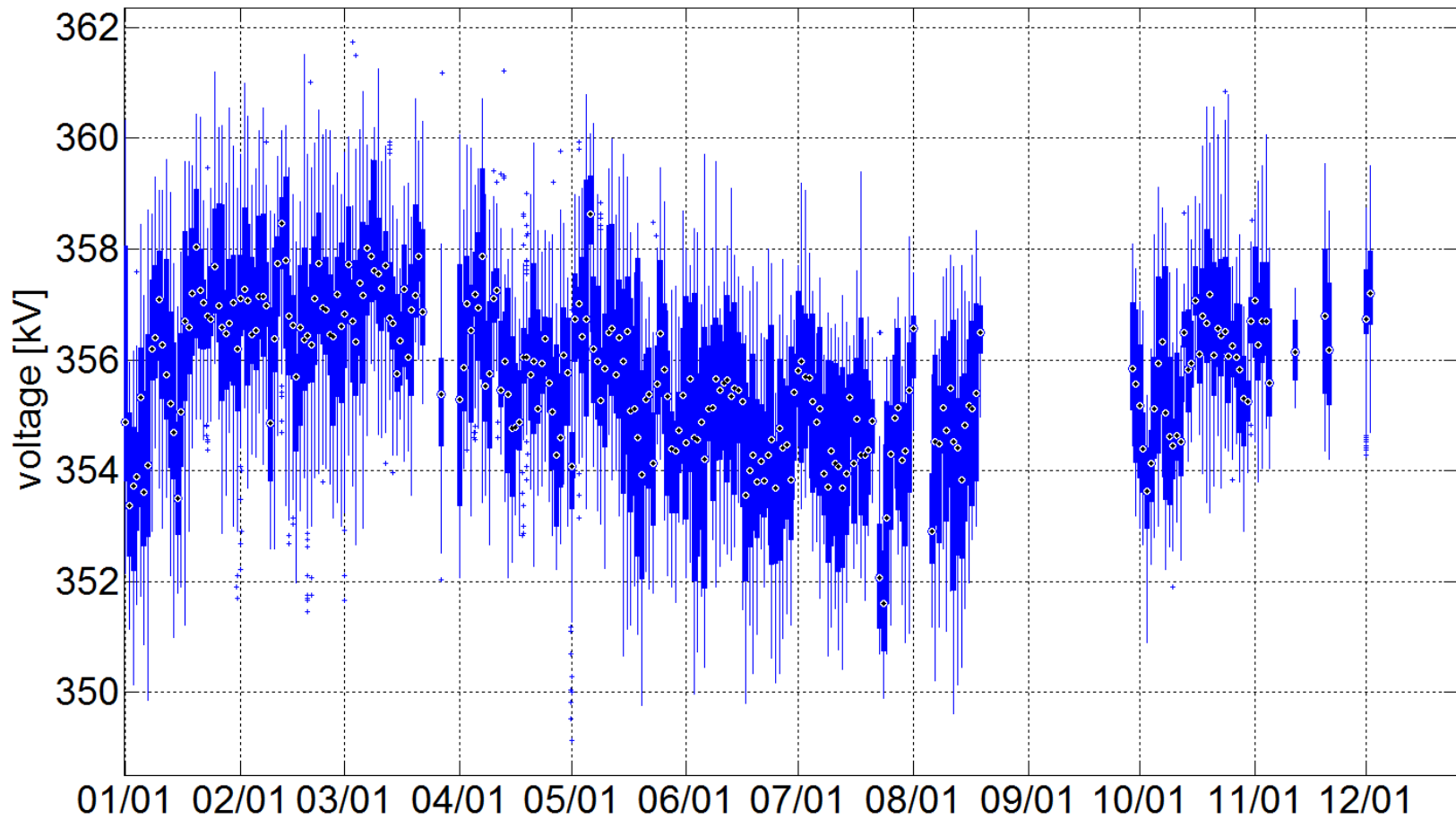
West 8



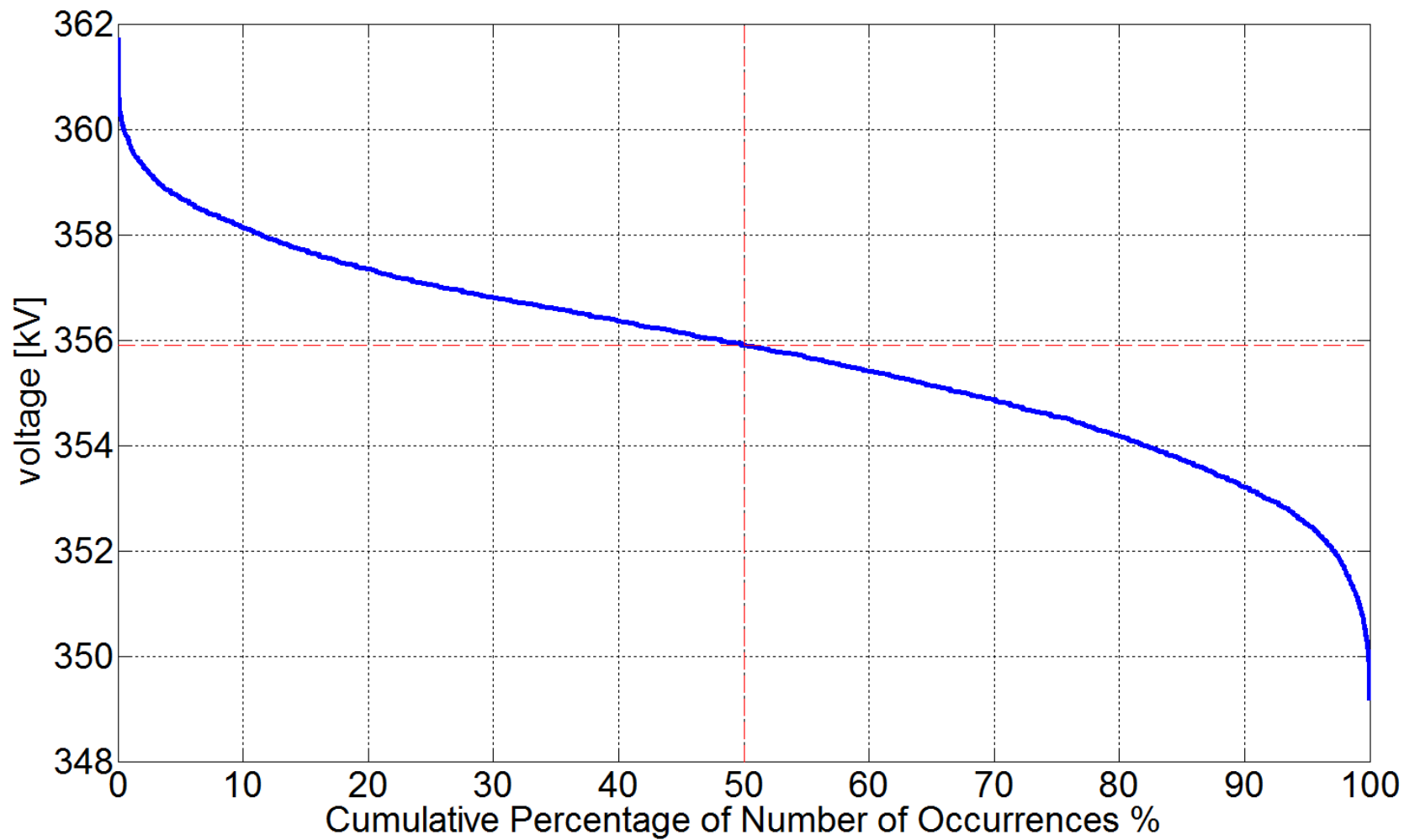
West 8



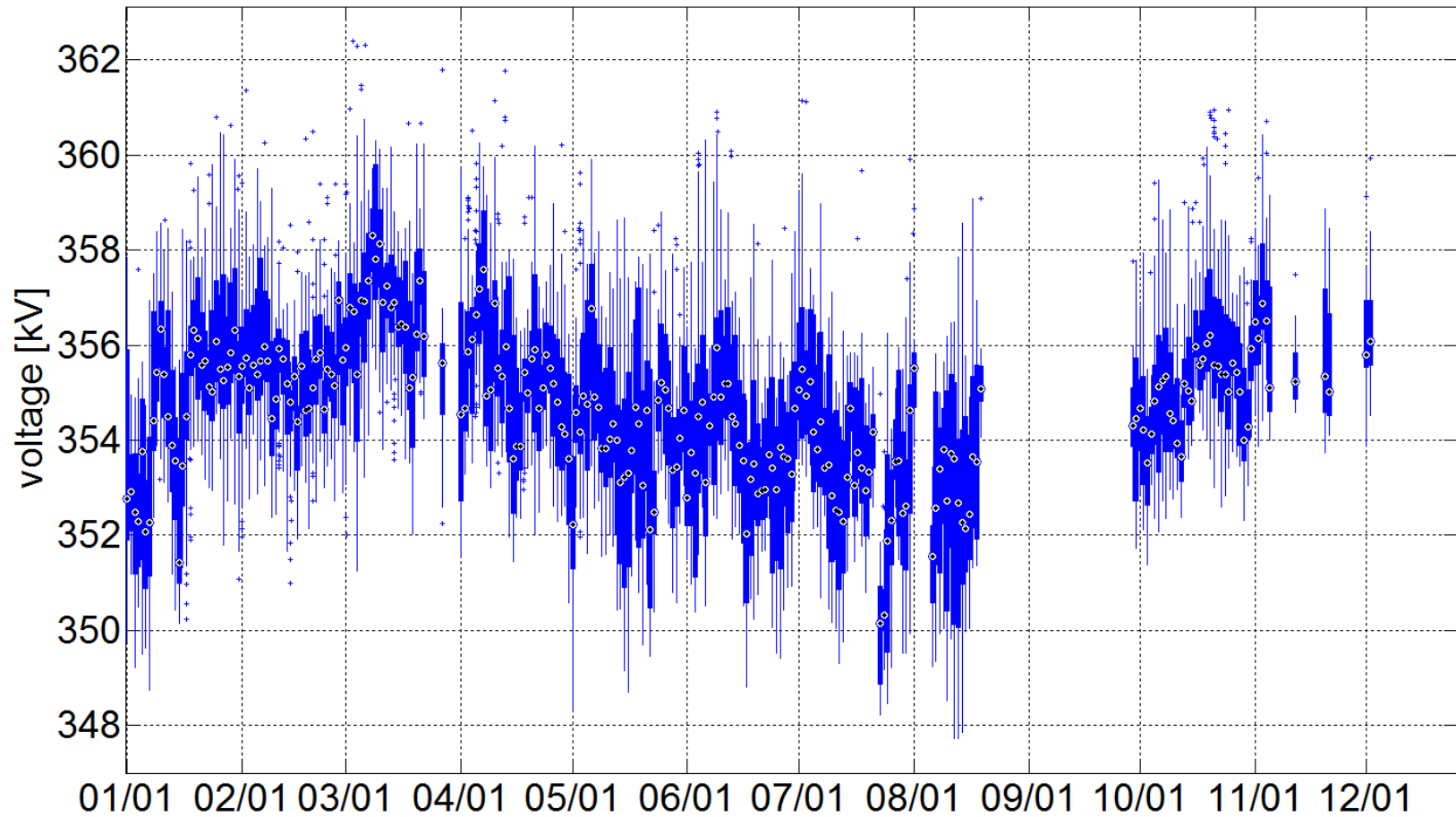
South 15*



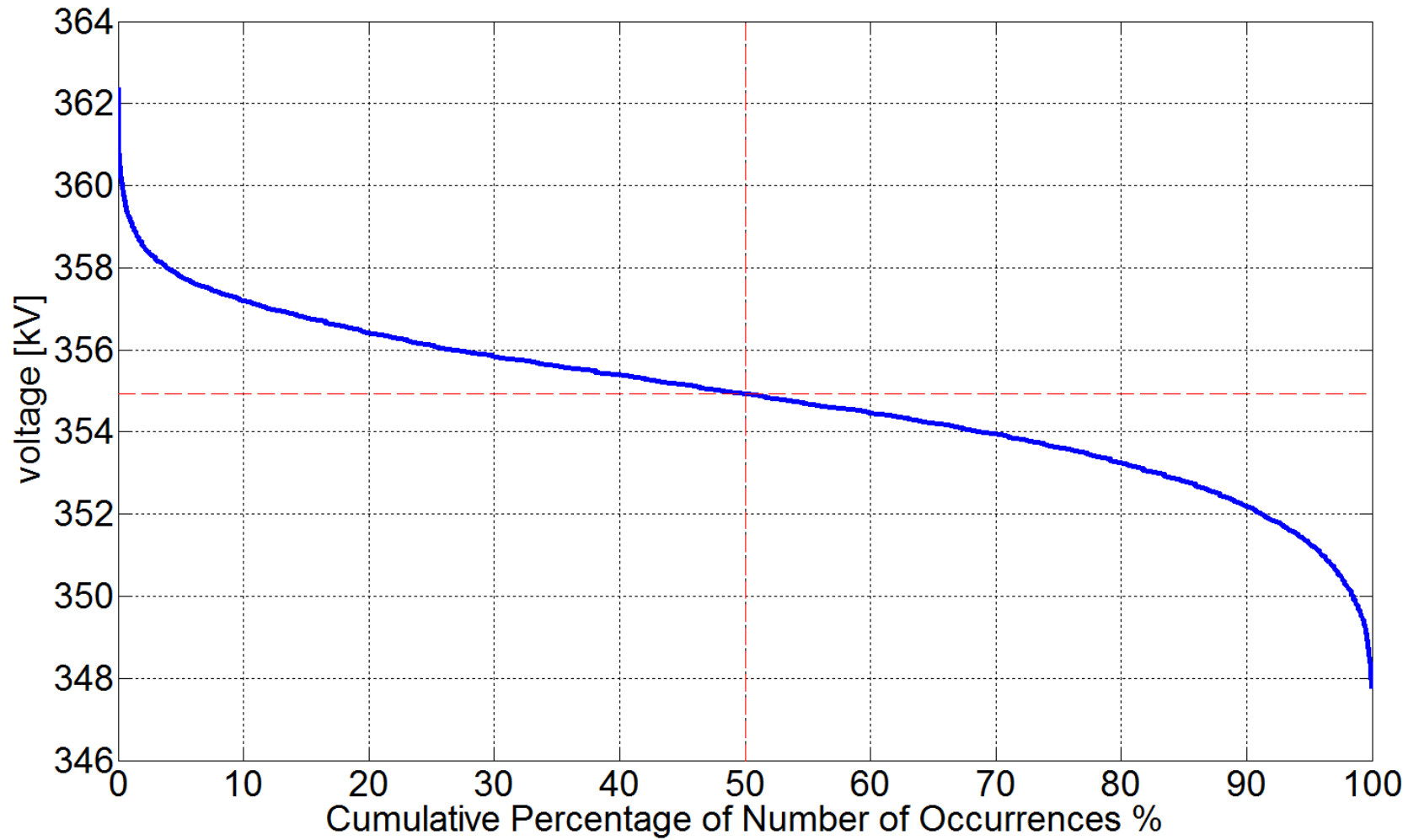
South 15*



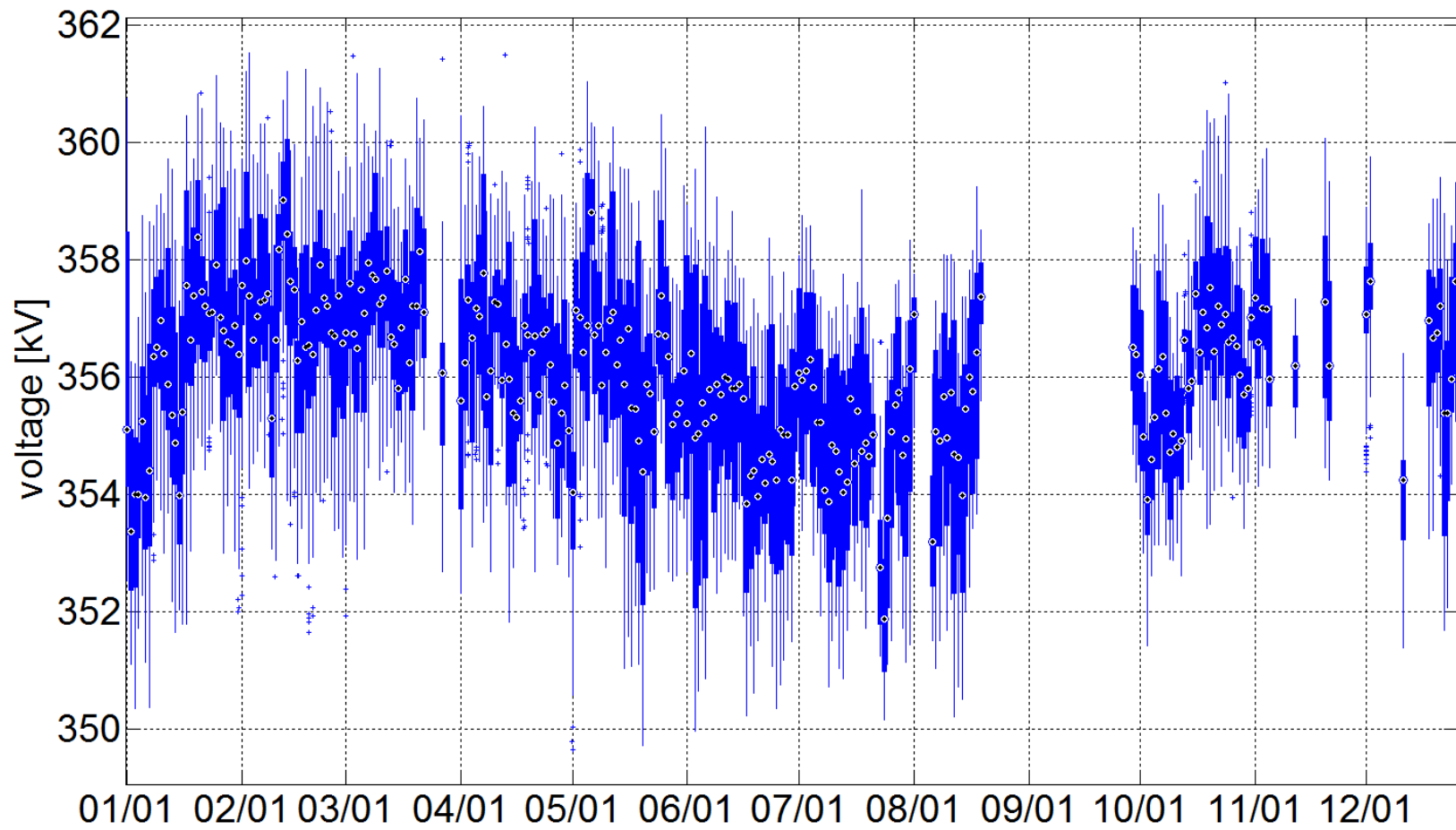
South 2*



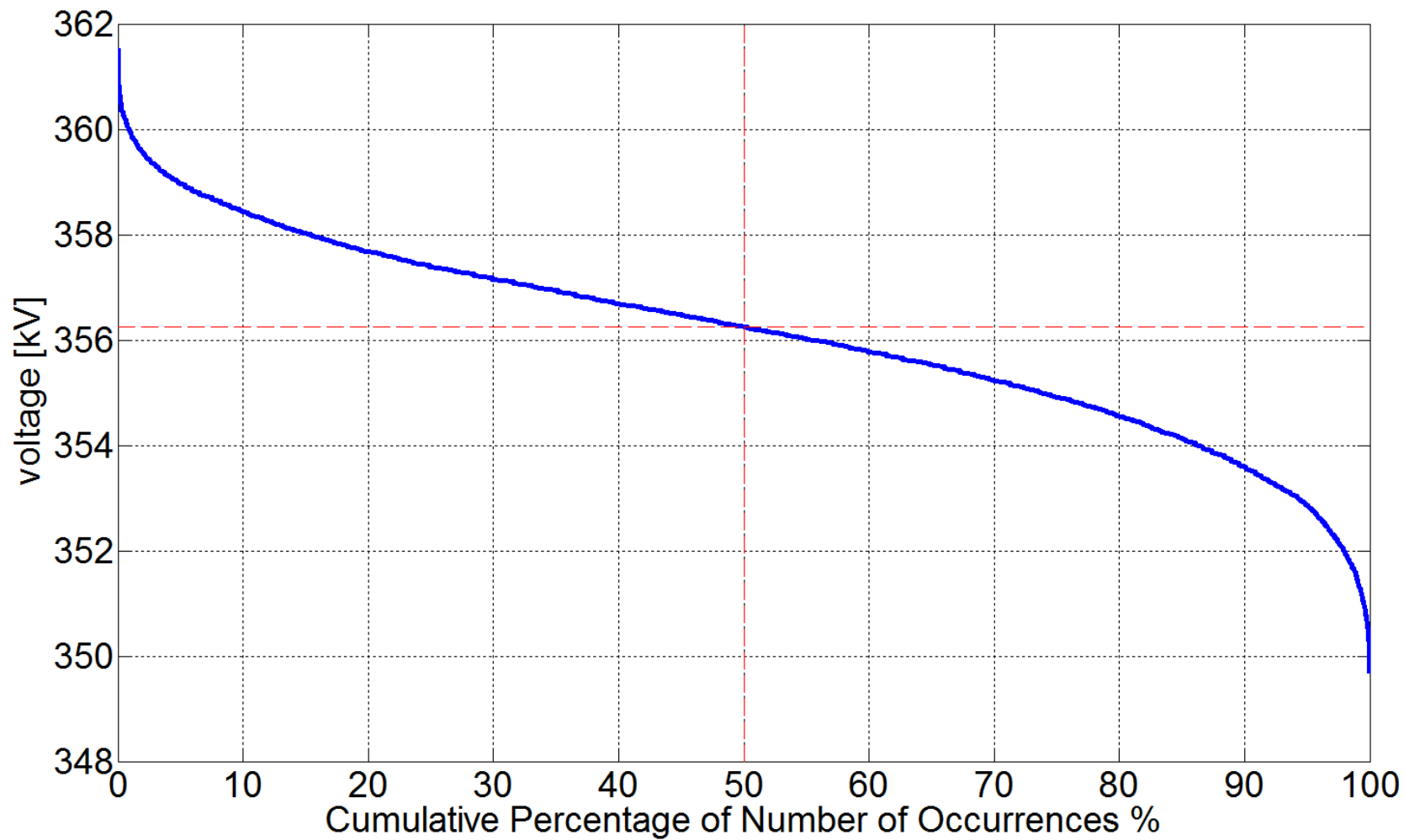
South 2*



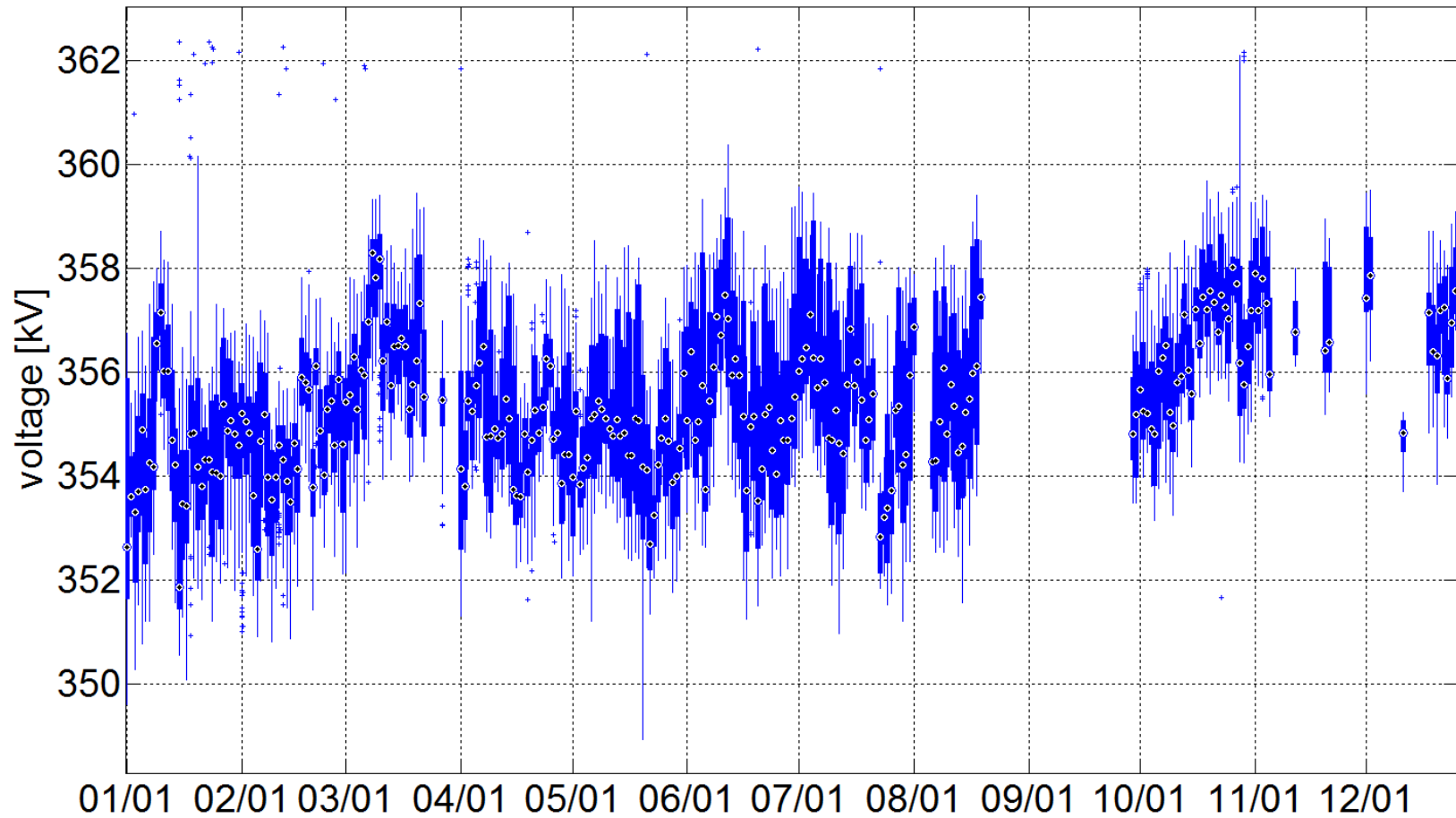
South 4*



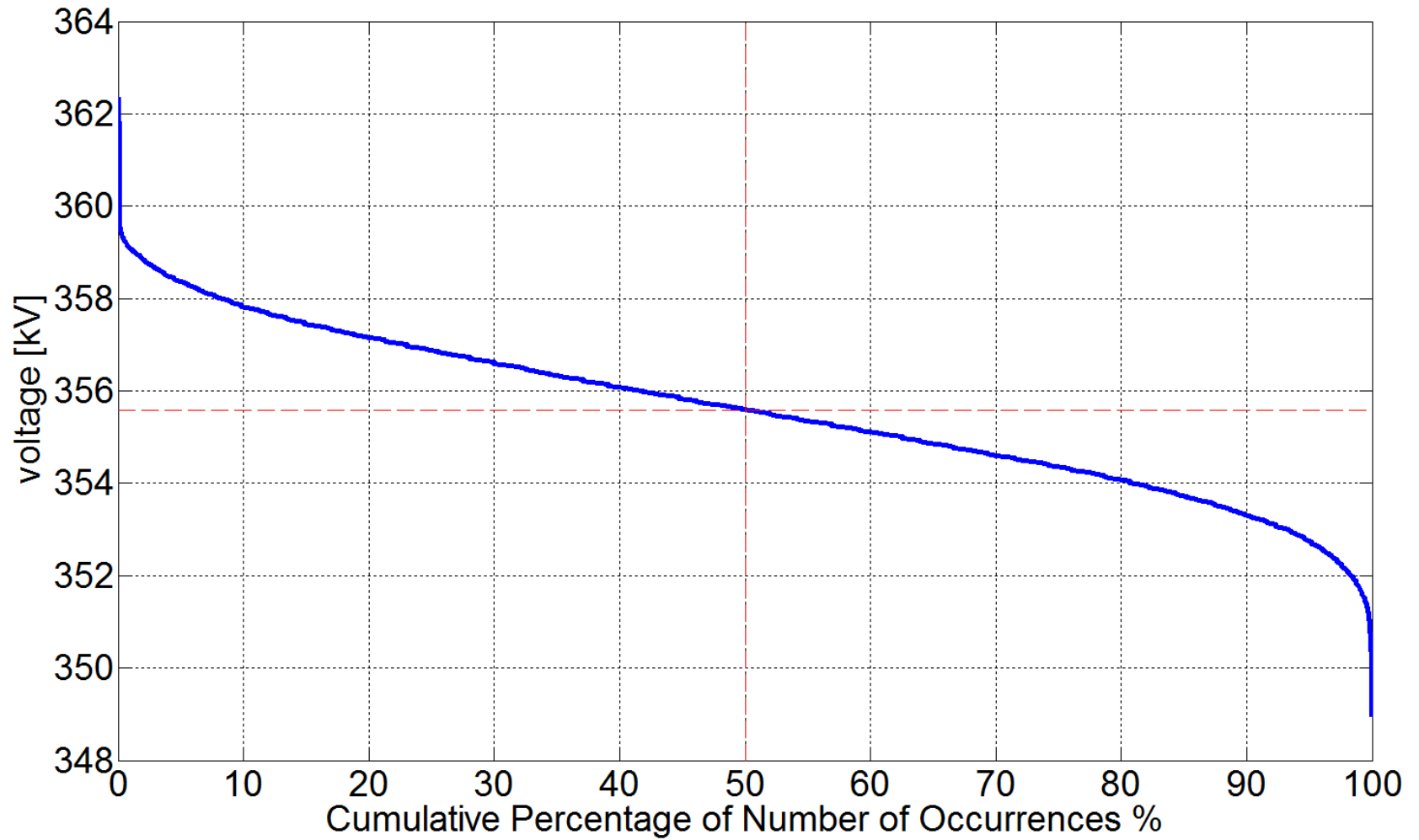
South 4*



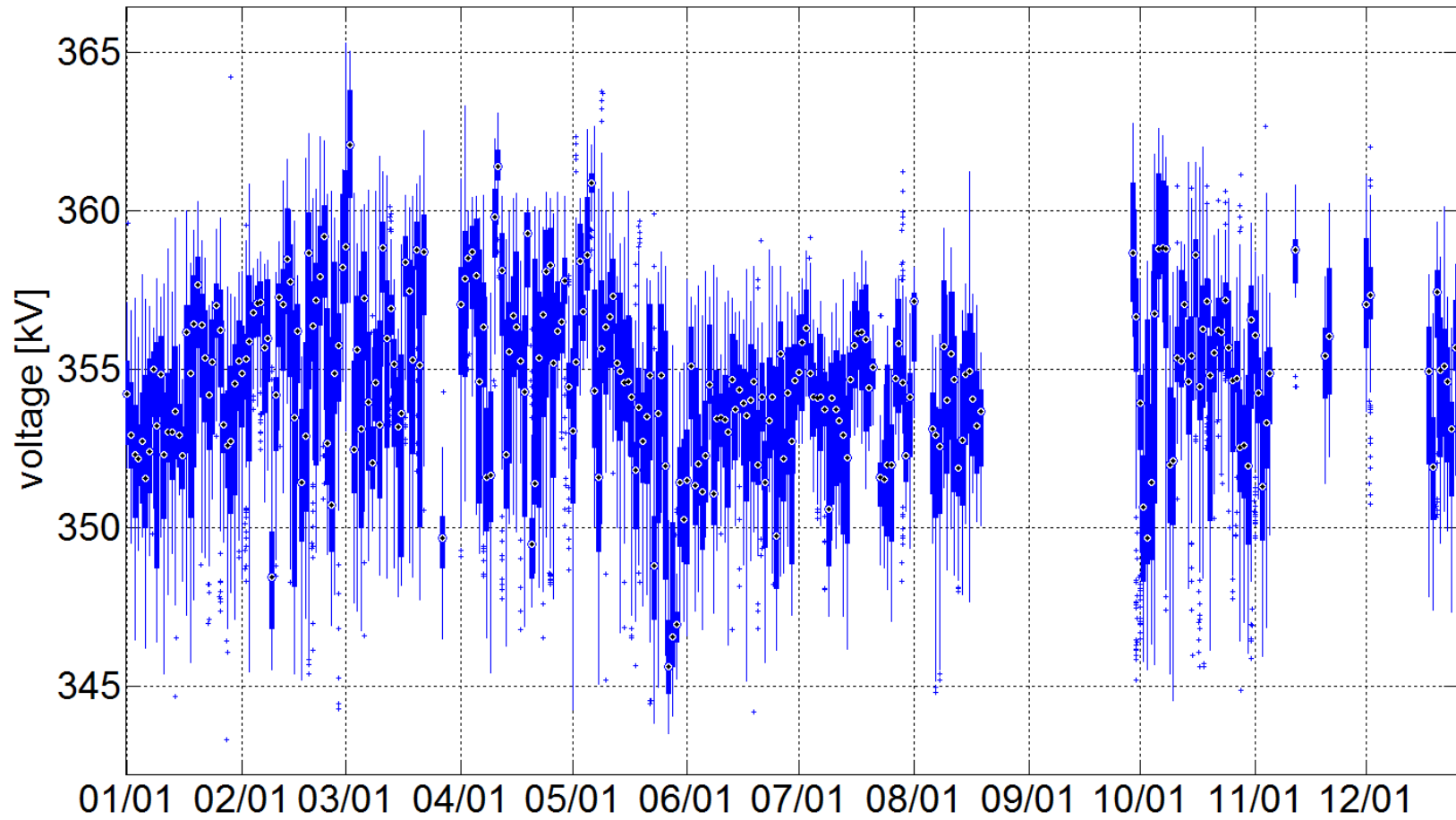
South 7*



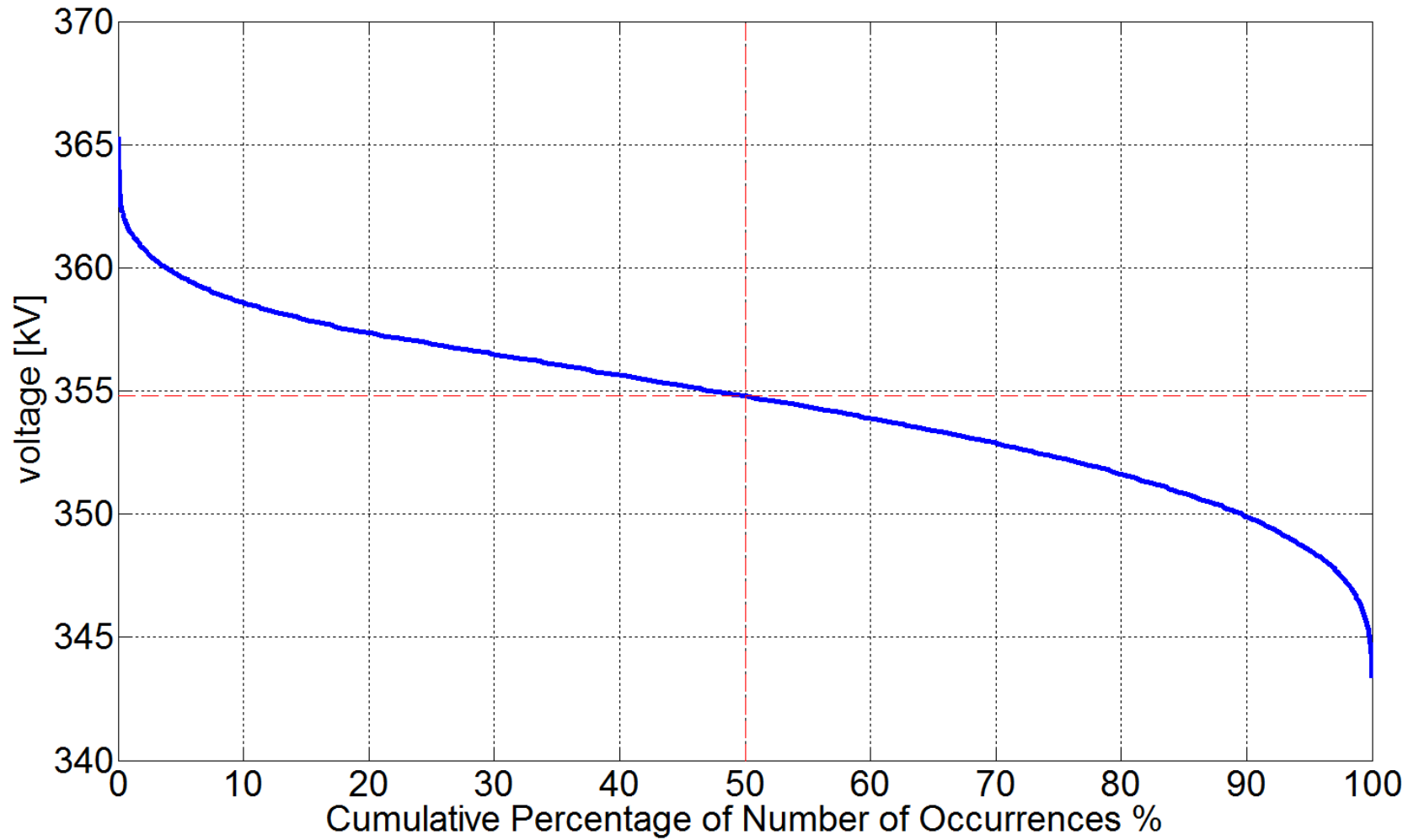
South 7*



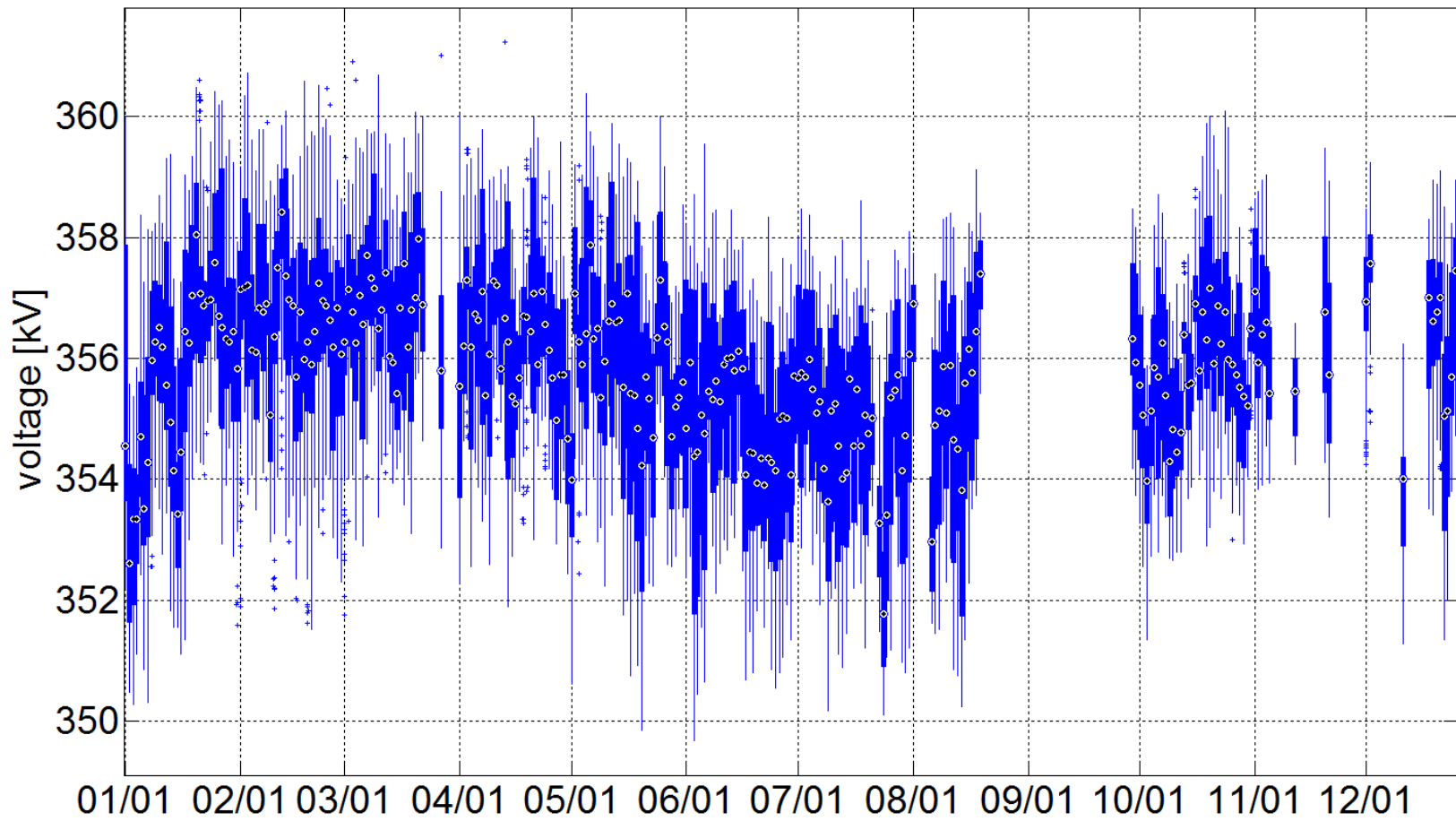
South 9*



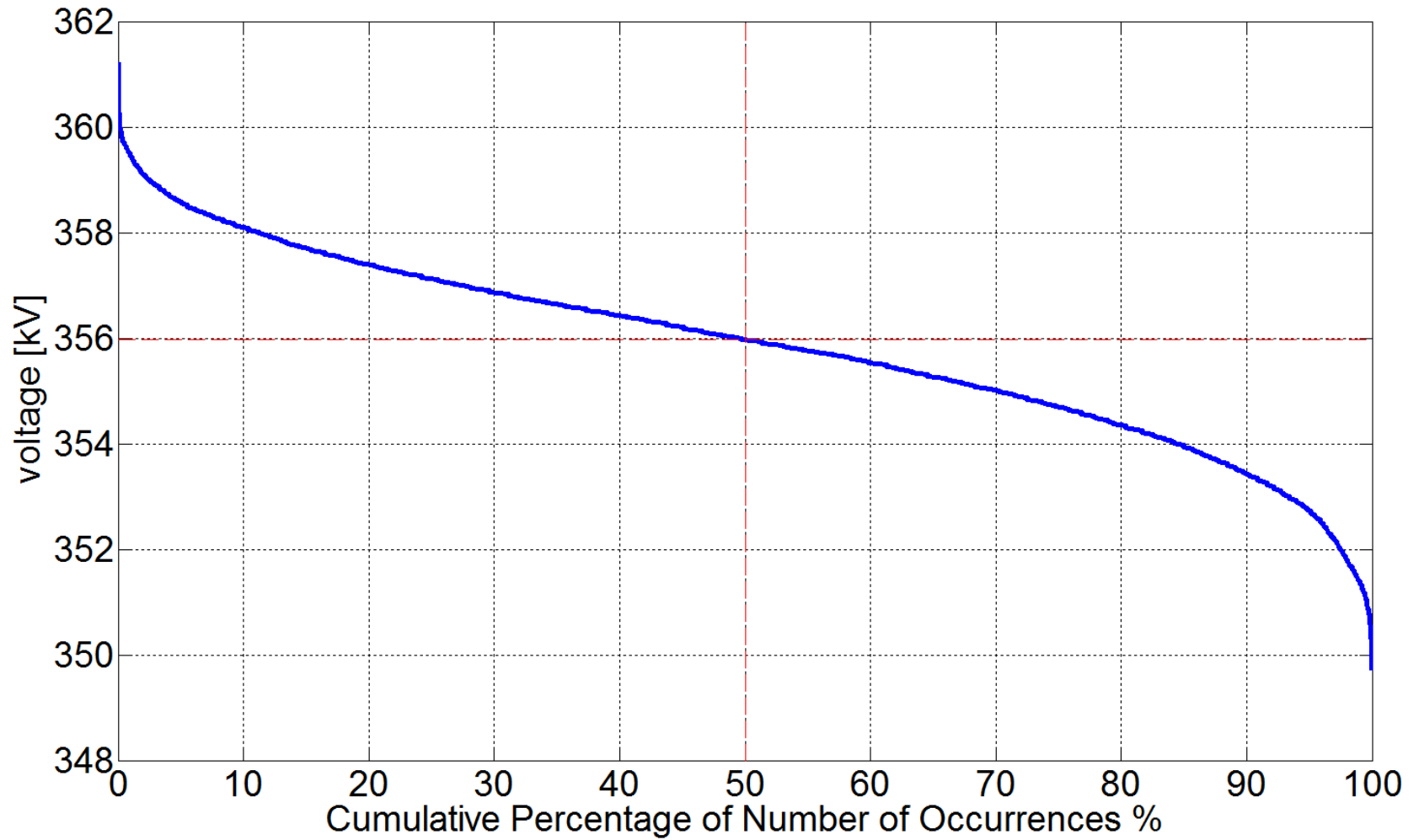
South 9*



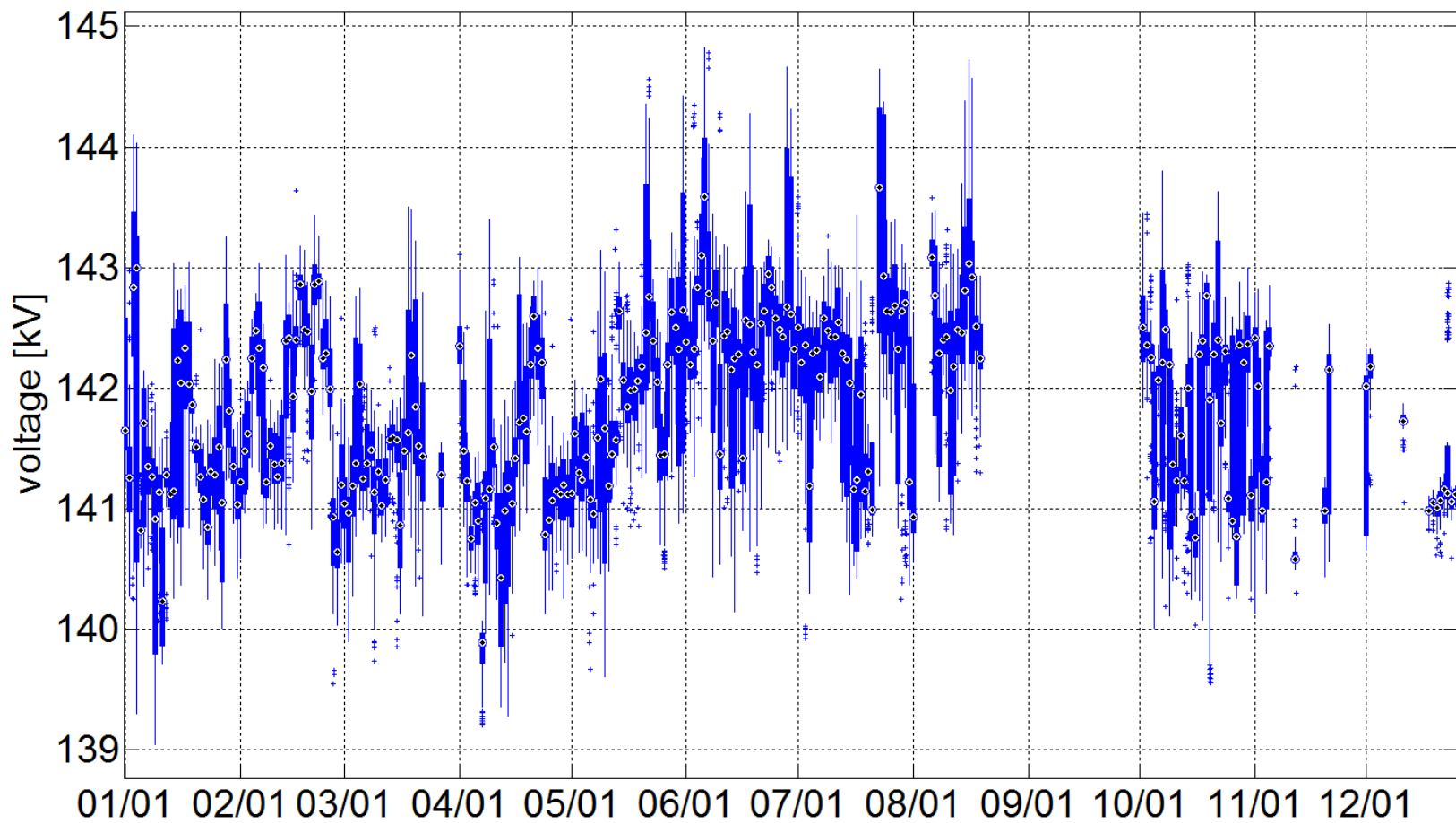
South 11*



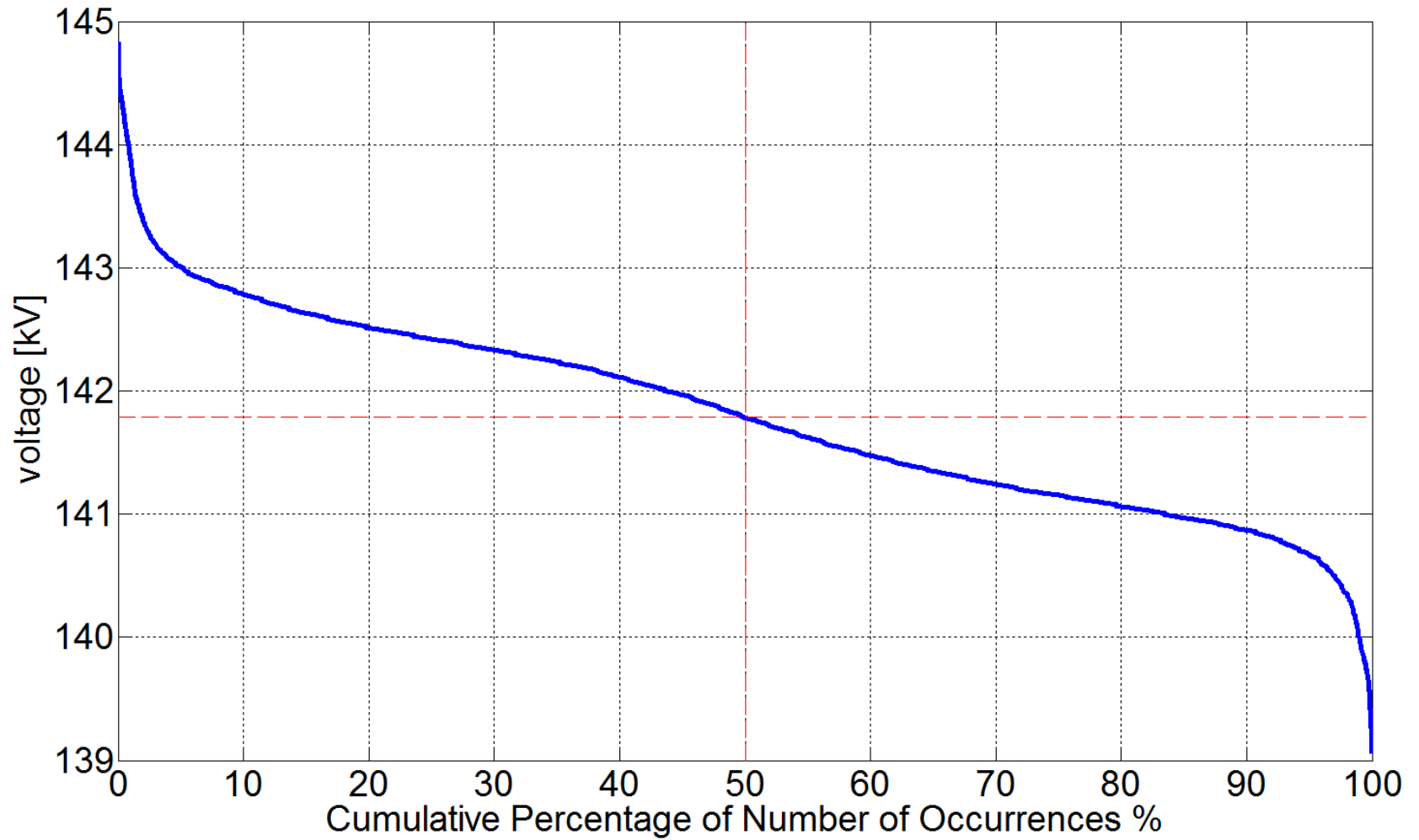
South 11*



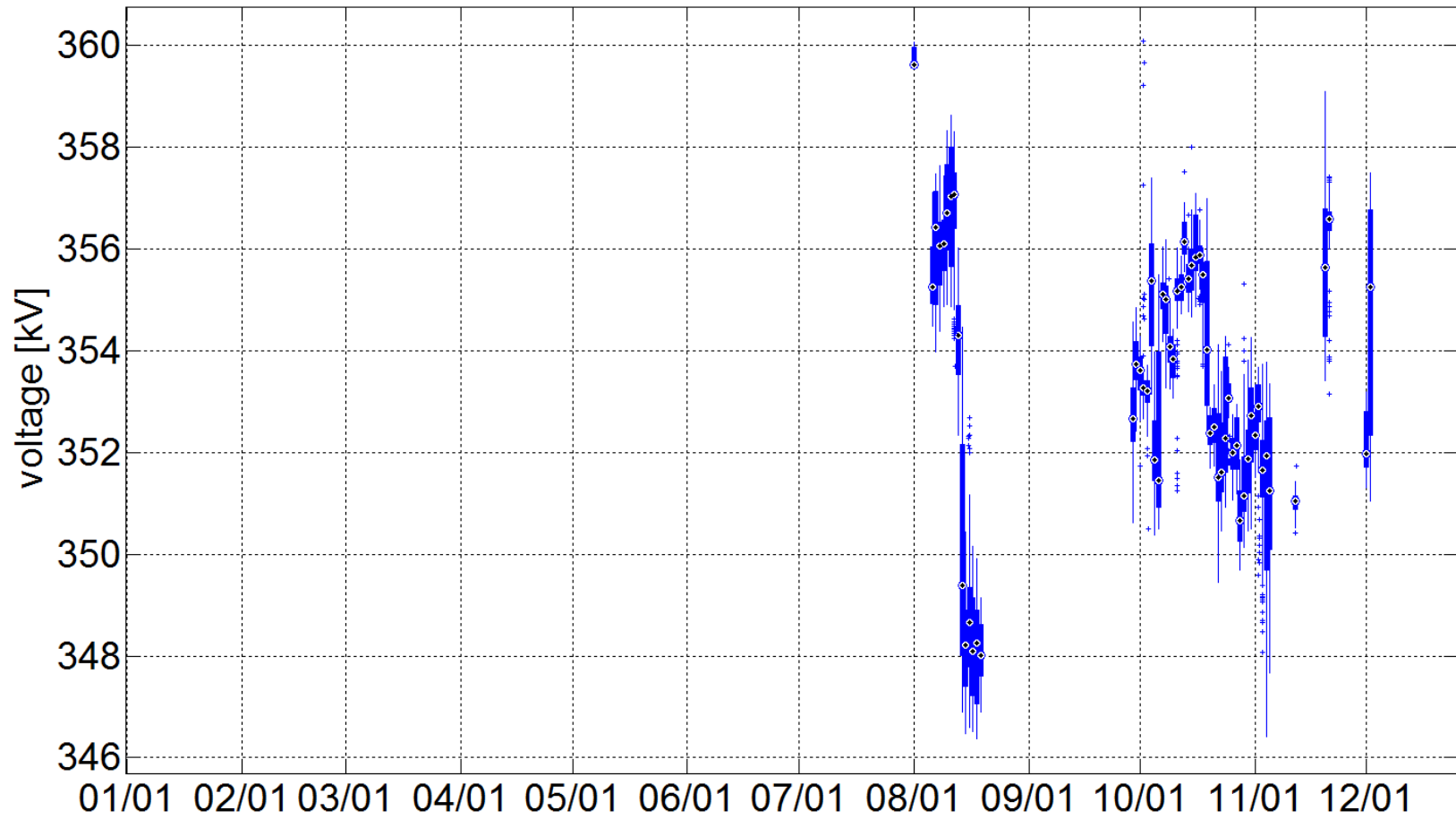
South 10*



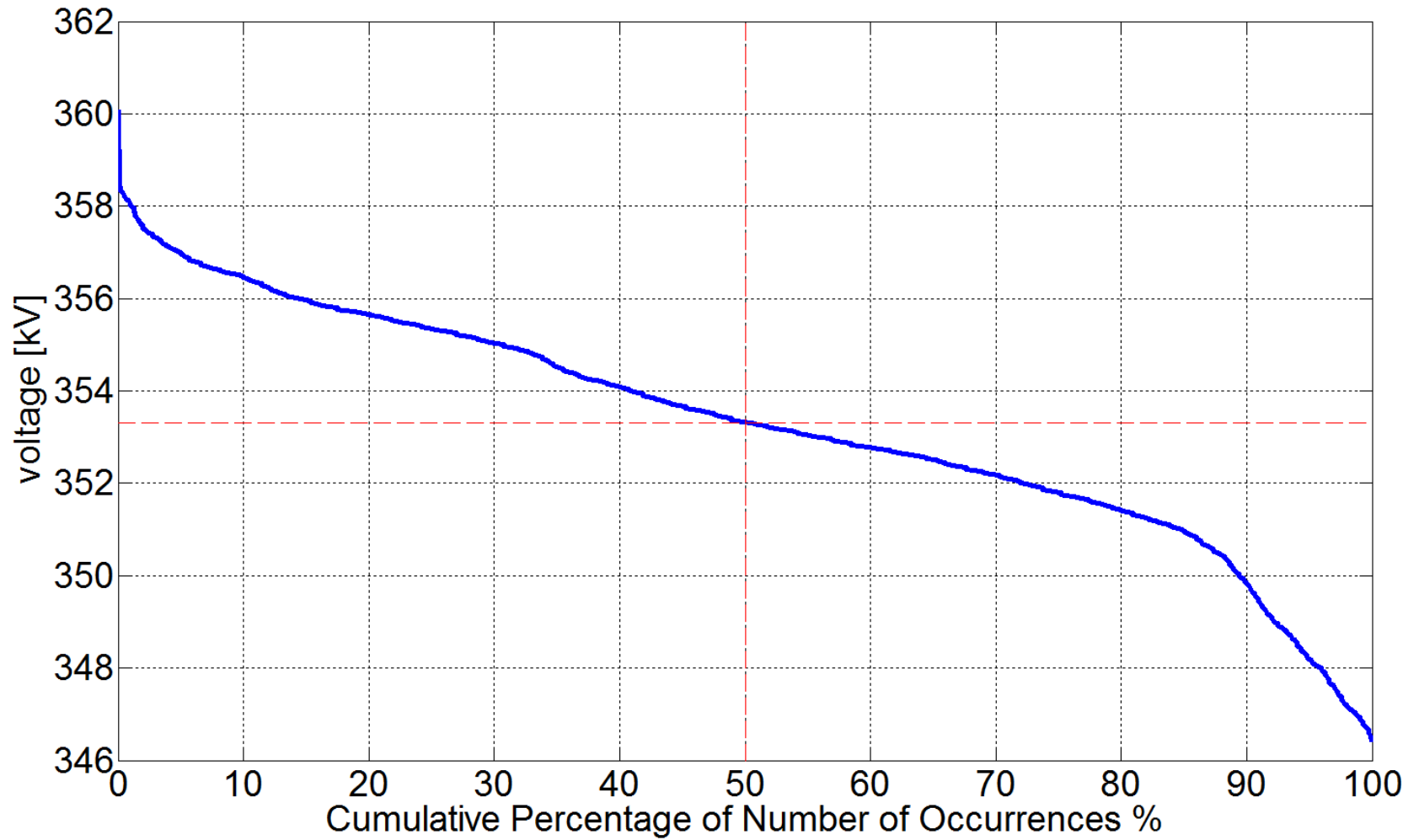
South 10*



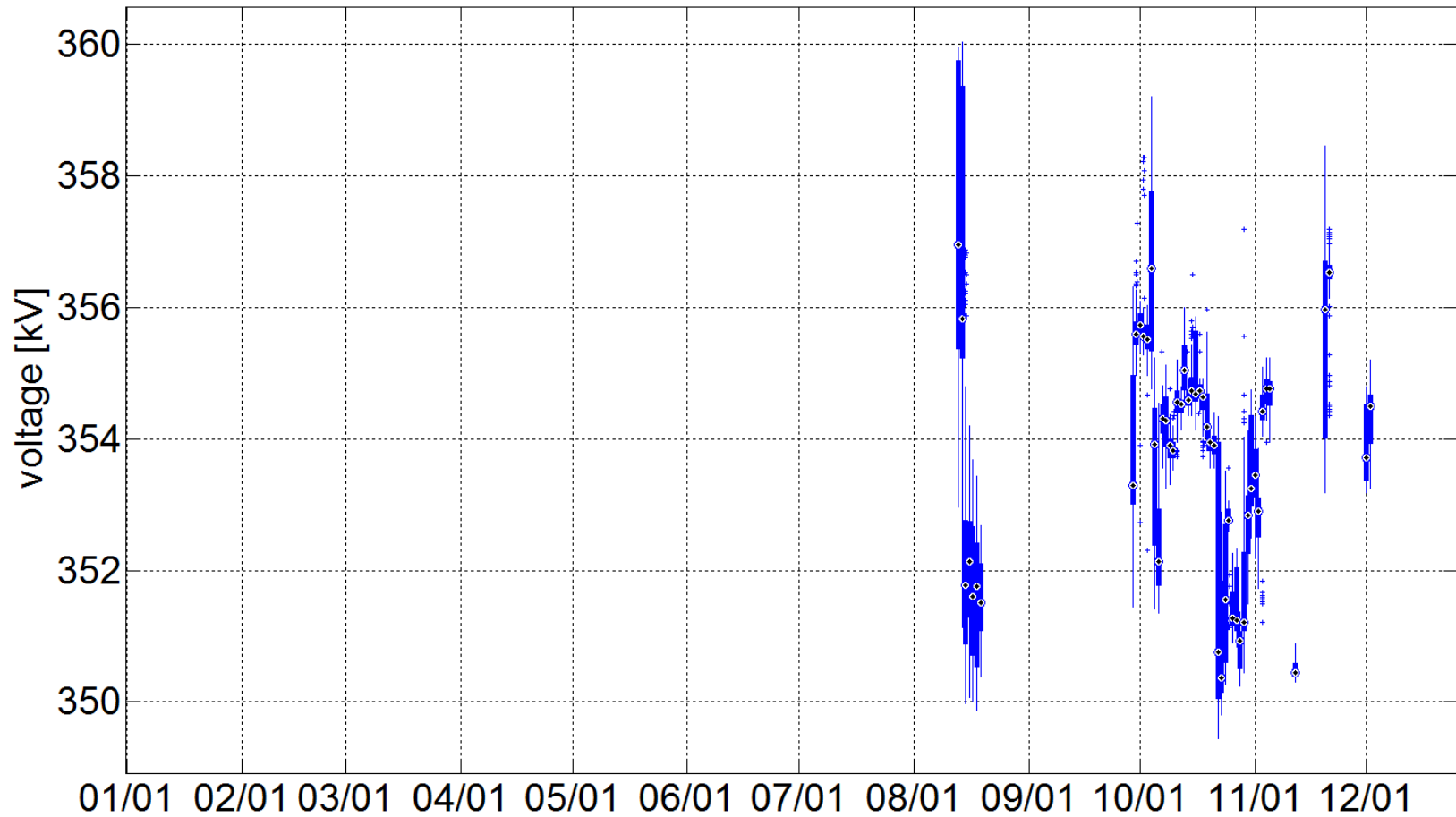
West 16*



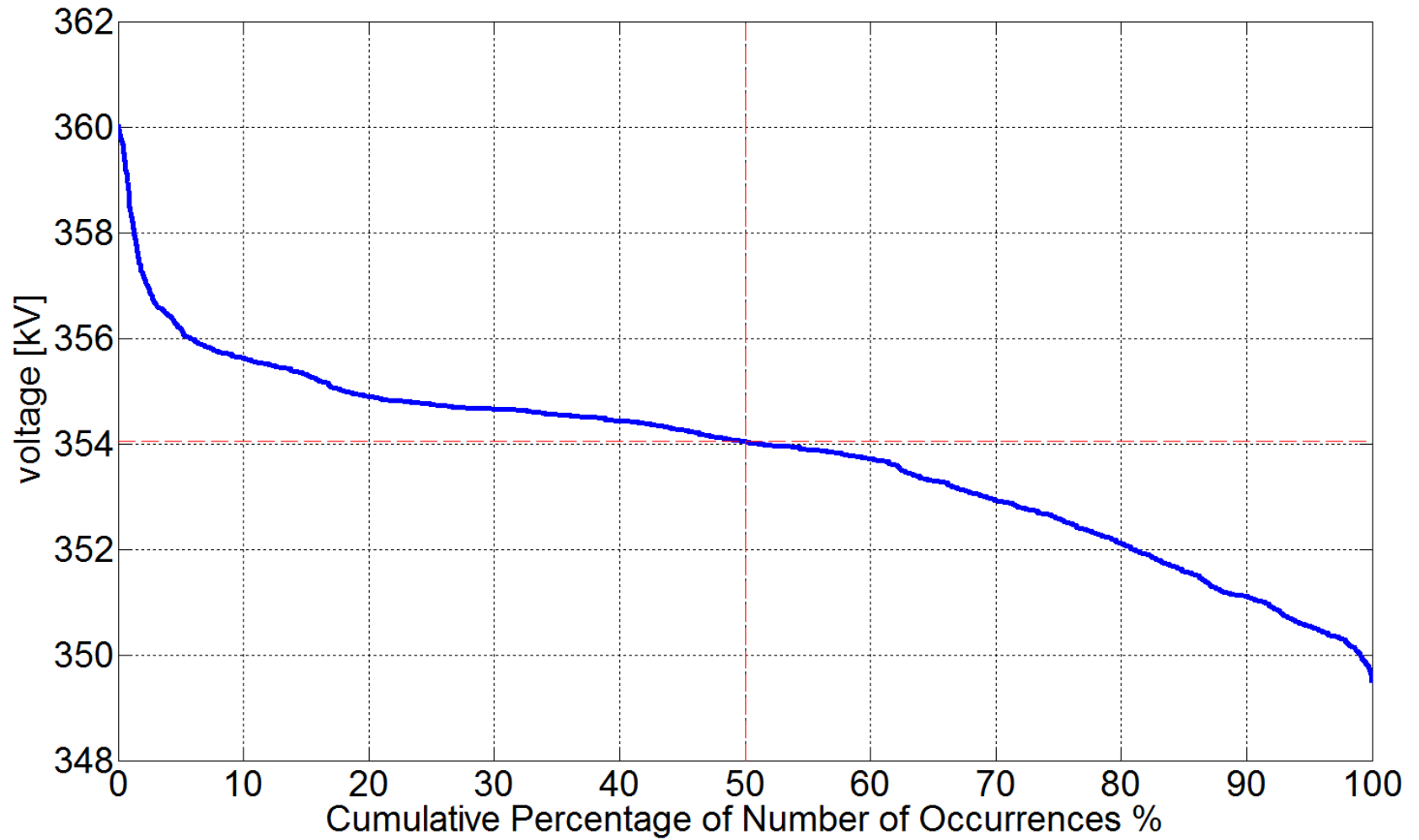
West 16*



West 15*



West 15*



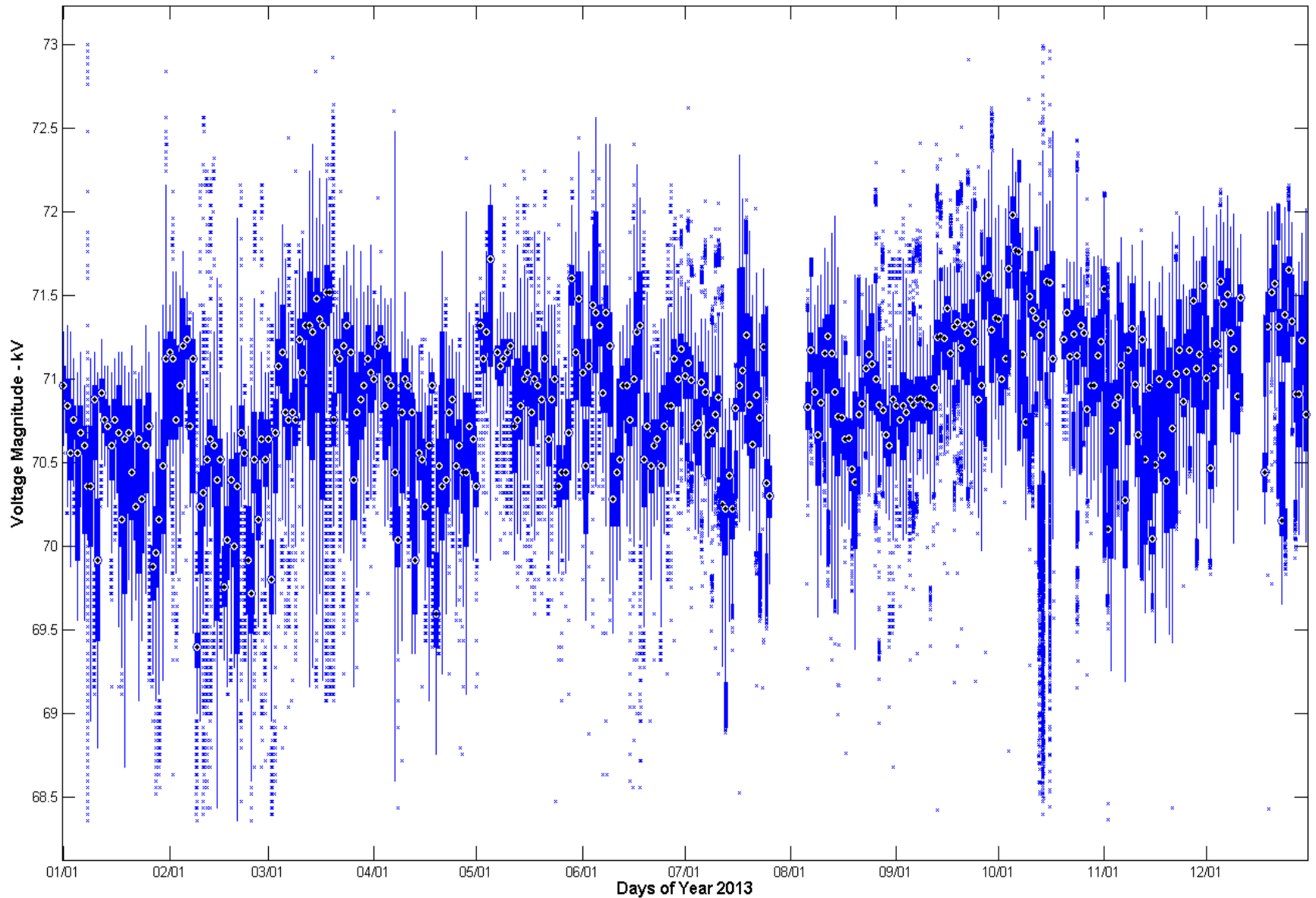
Appendix A – Part 2
CCET Discovery Across Texas project

Baseline Analysis Update #2
Voltage Magnitudes

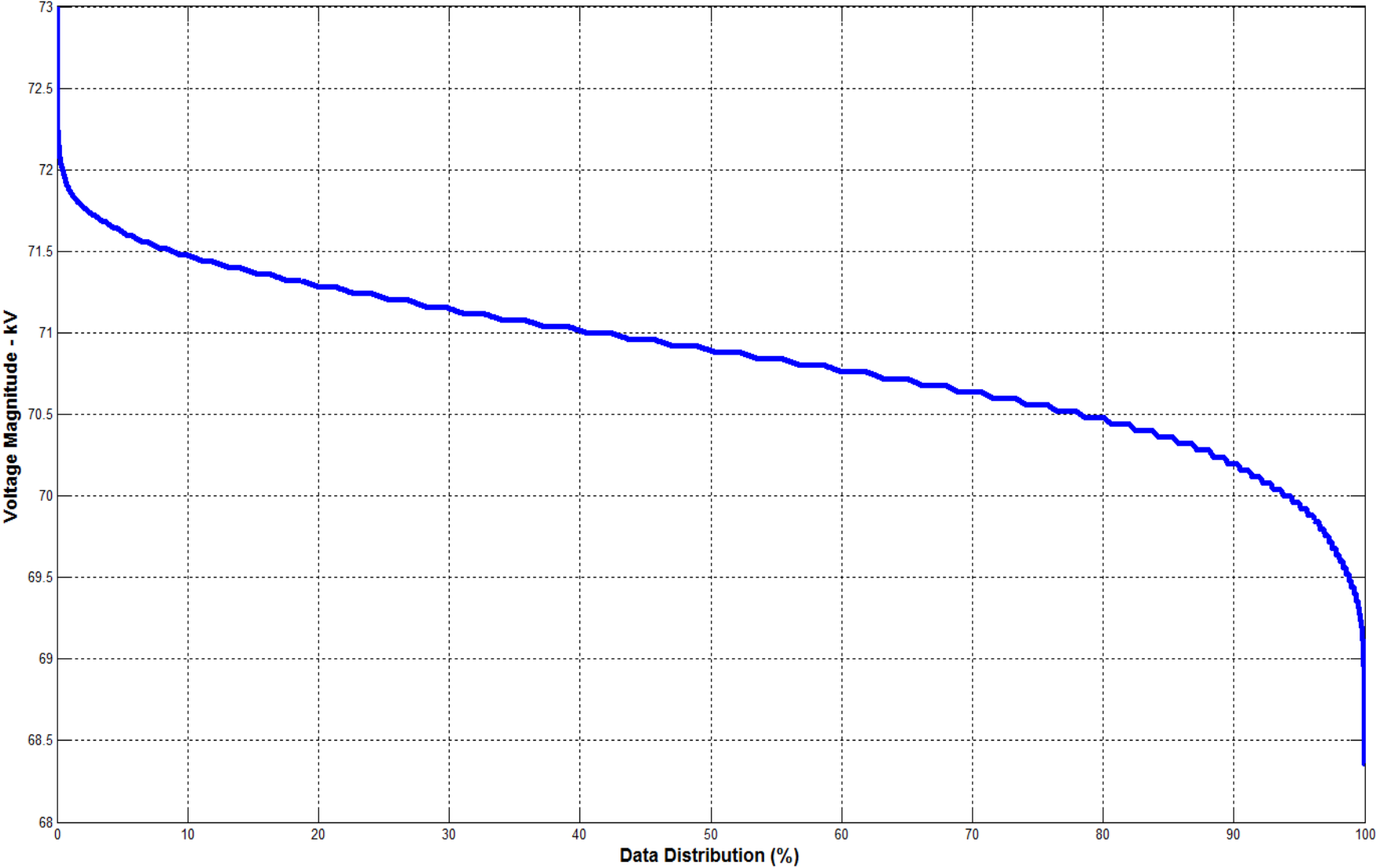
Phasor Data: January to December 2013
Box Whiskers Plots and Time Duration Curves

West 10

Daily Box-Whisker Chart:

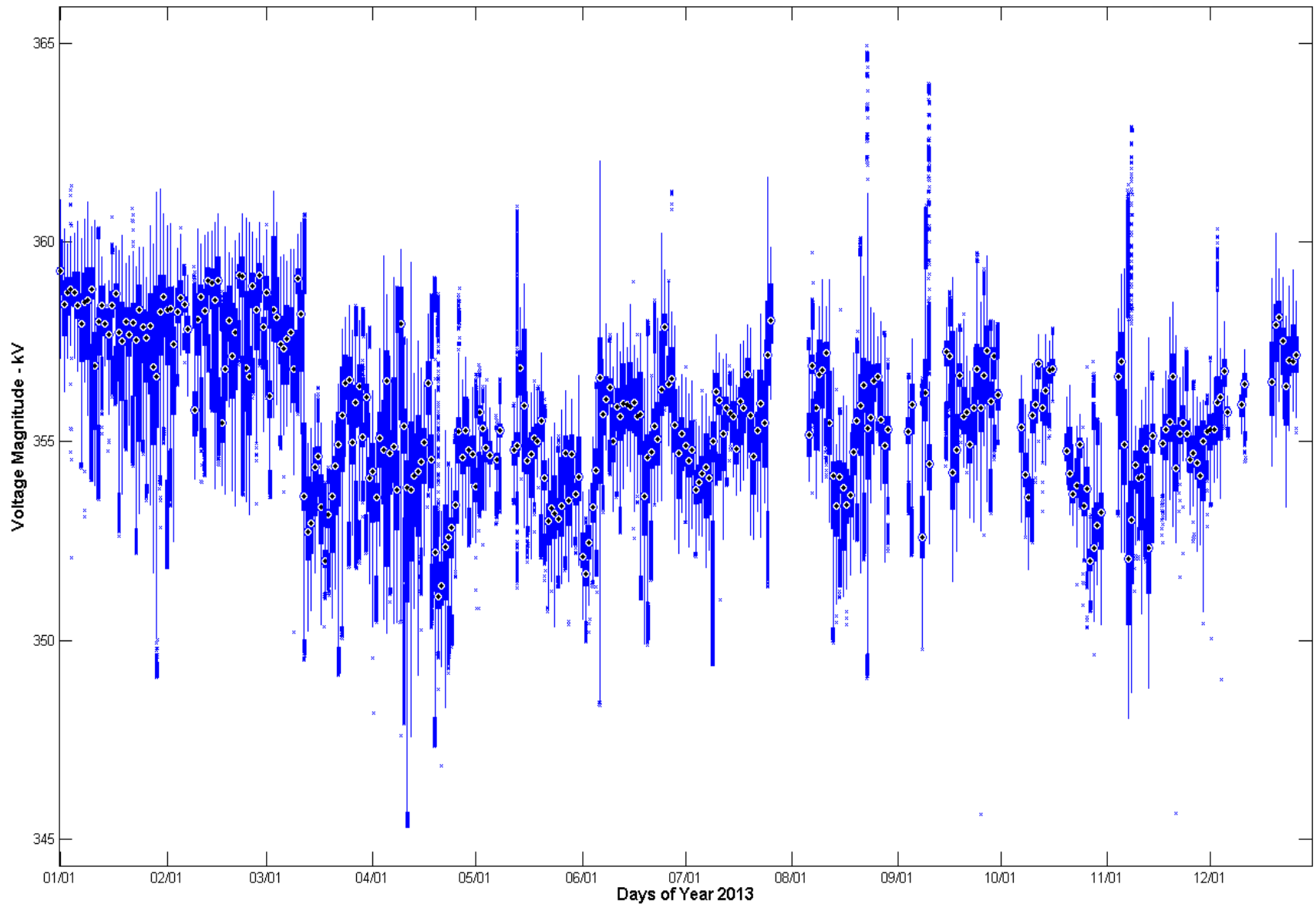


Time Duration Chart:



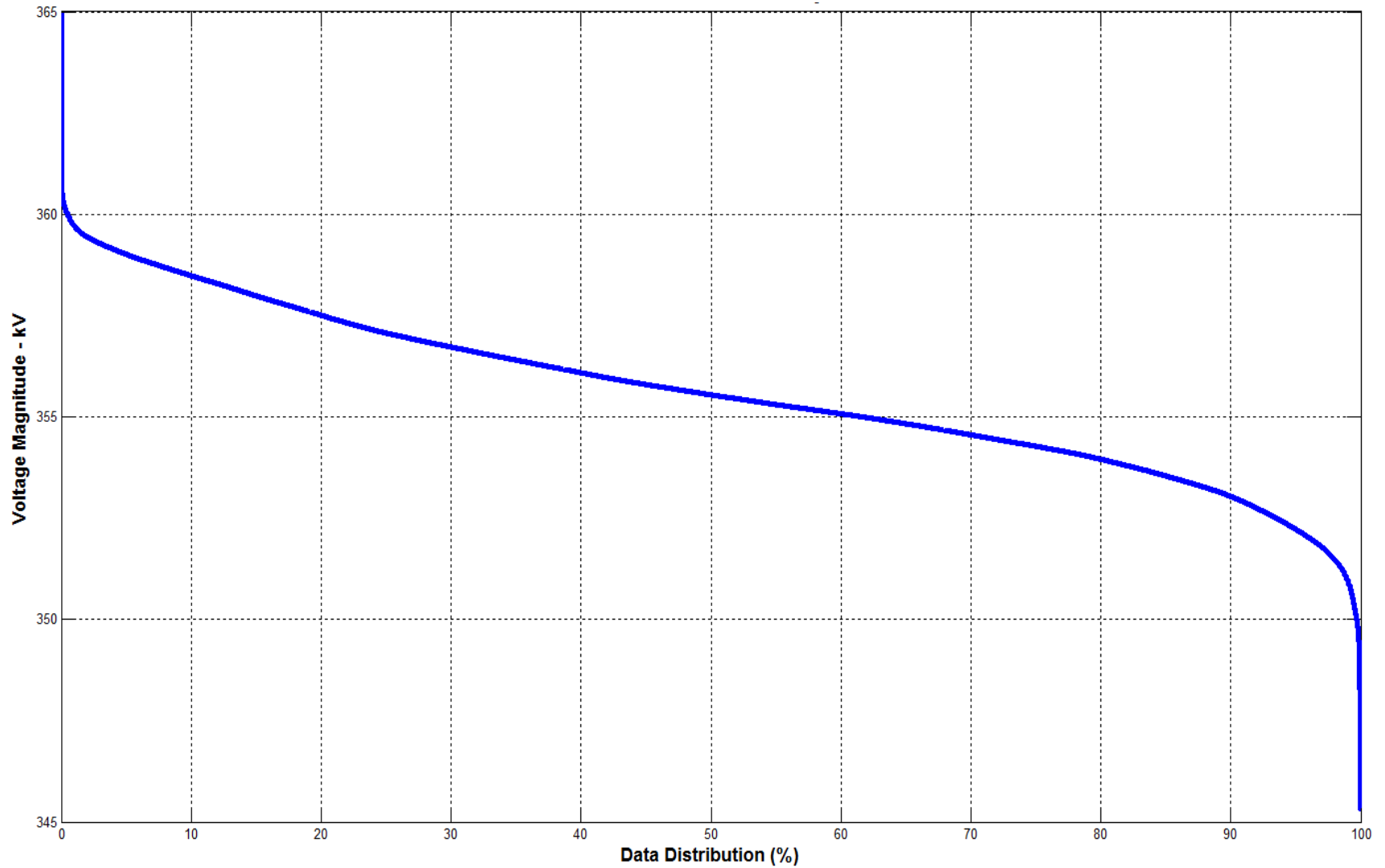
West 14

Daily Box-Whisker Chart:



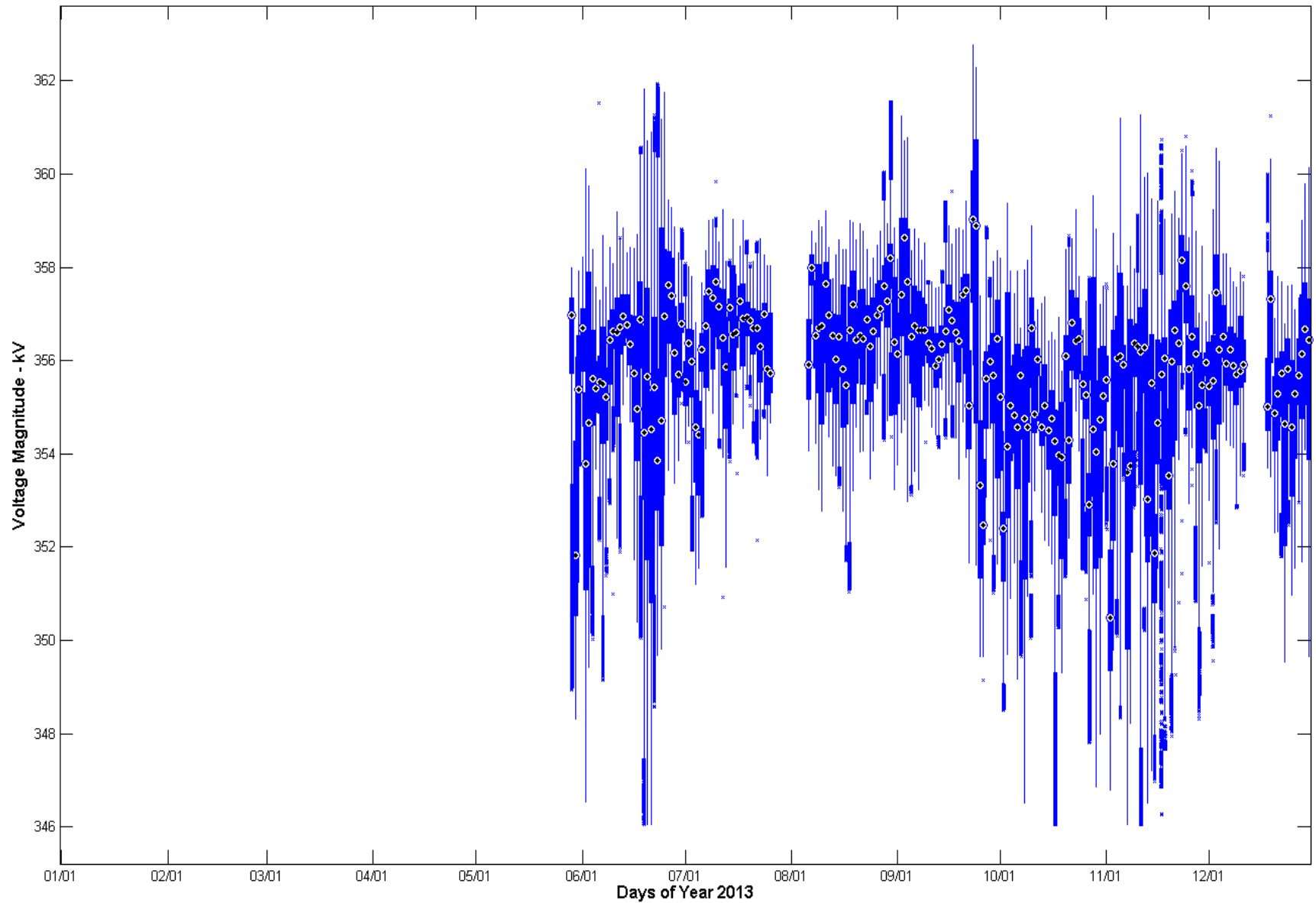
West 14

Time Duration Chart:



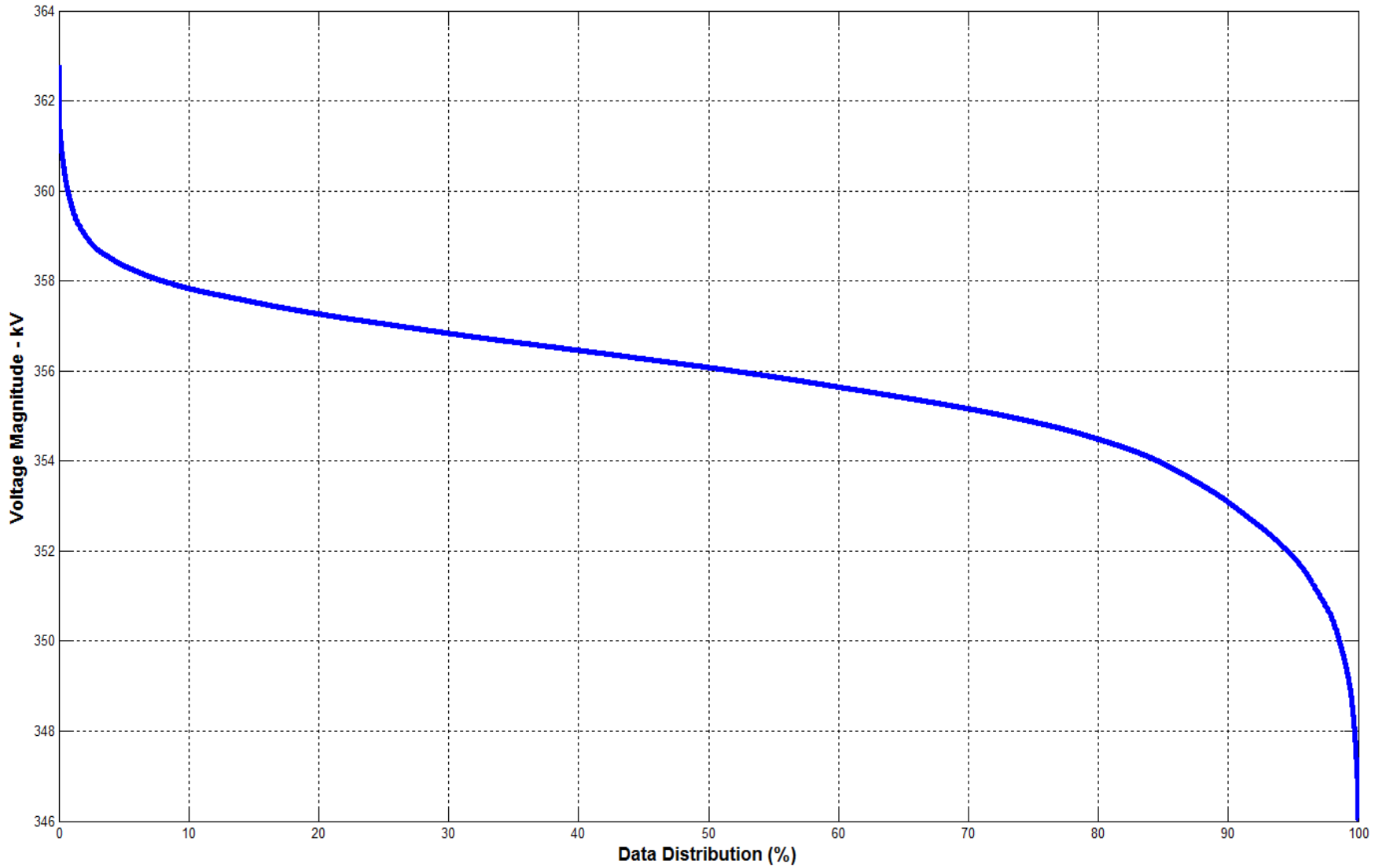
West 1

Daily Box-Whisker Chart:



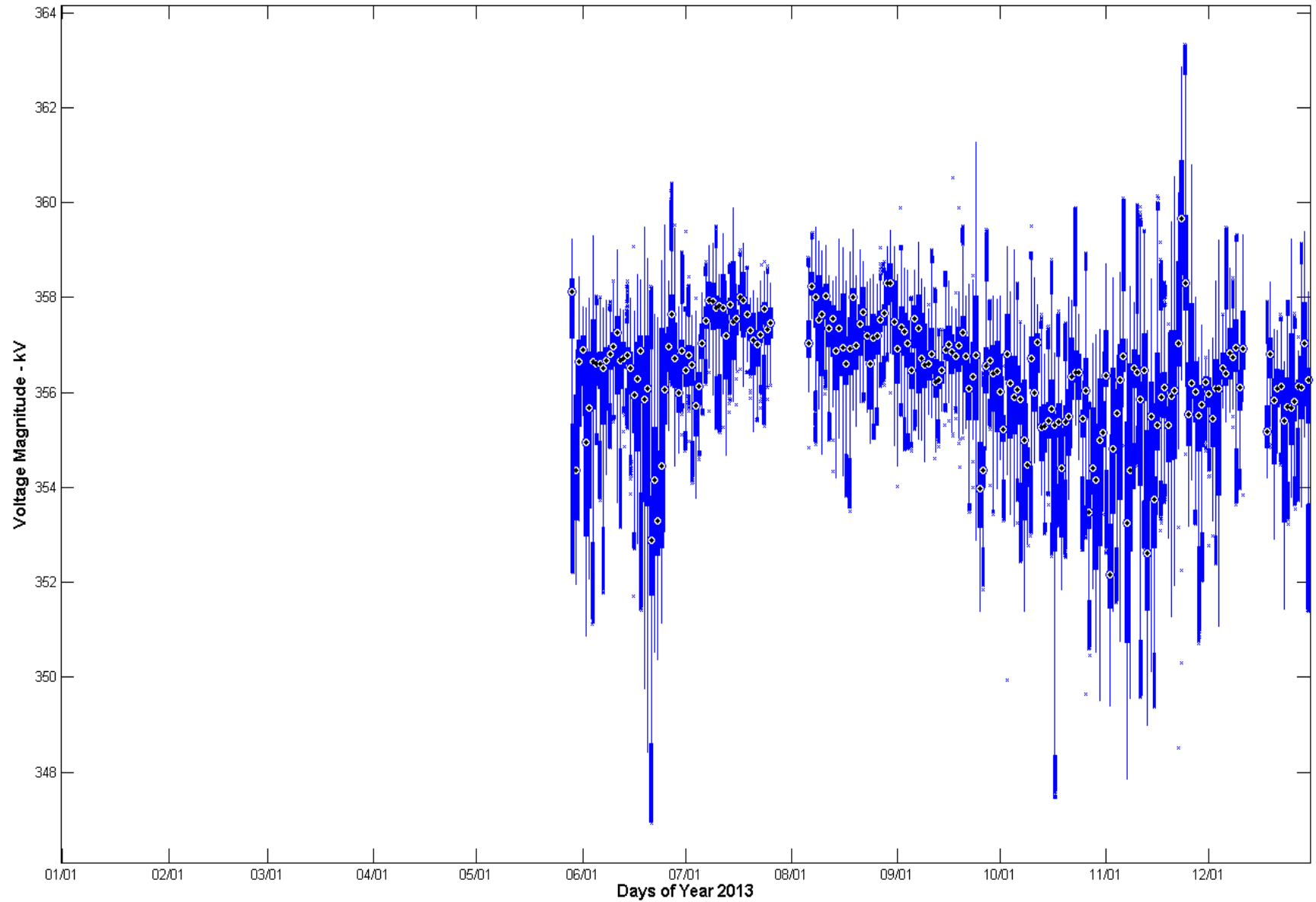
West 1

Time Duration Chart



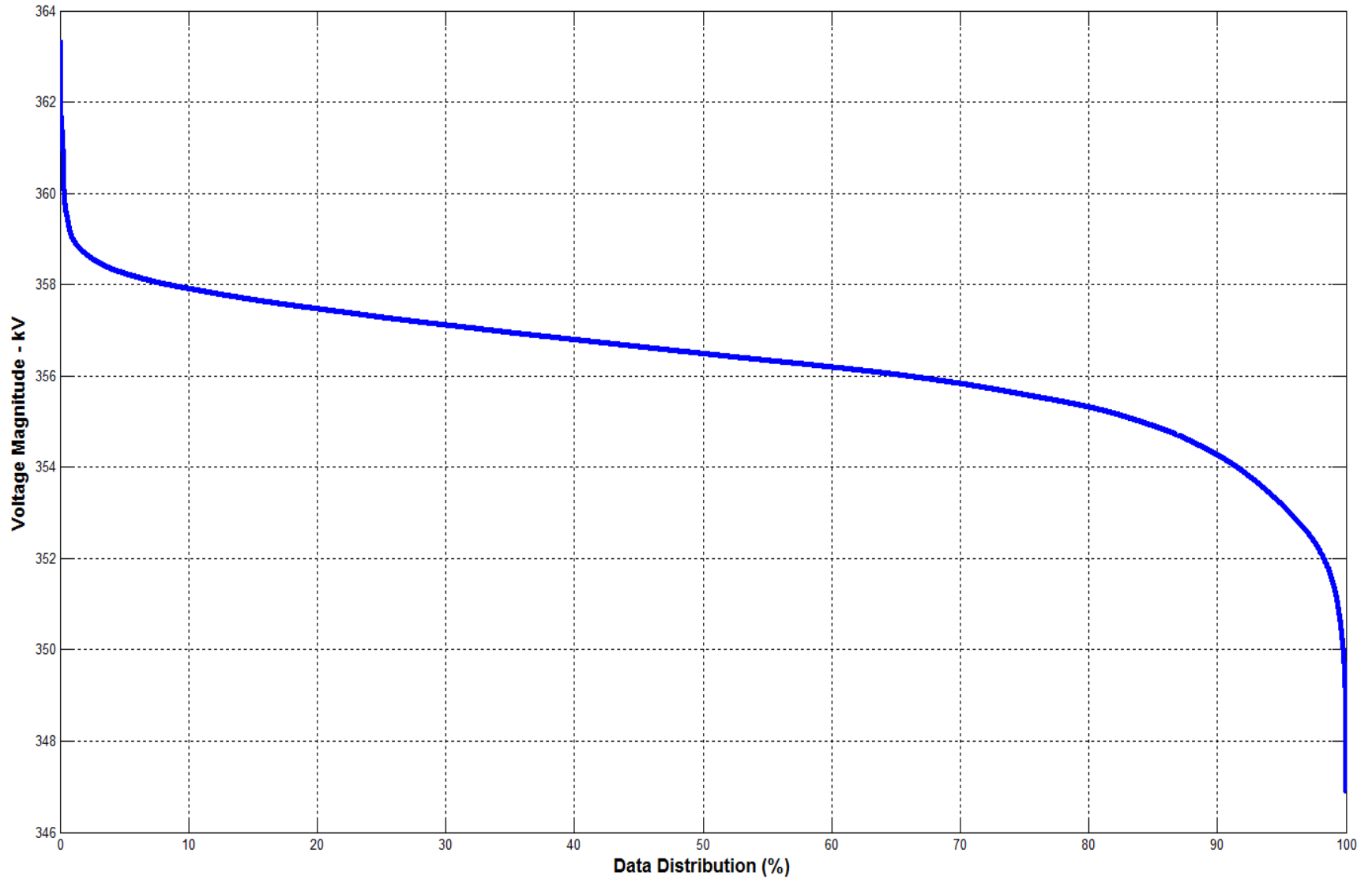
West 2

Daily Box-Whisker Chart:



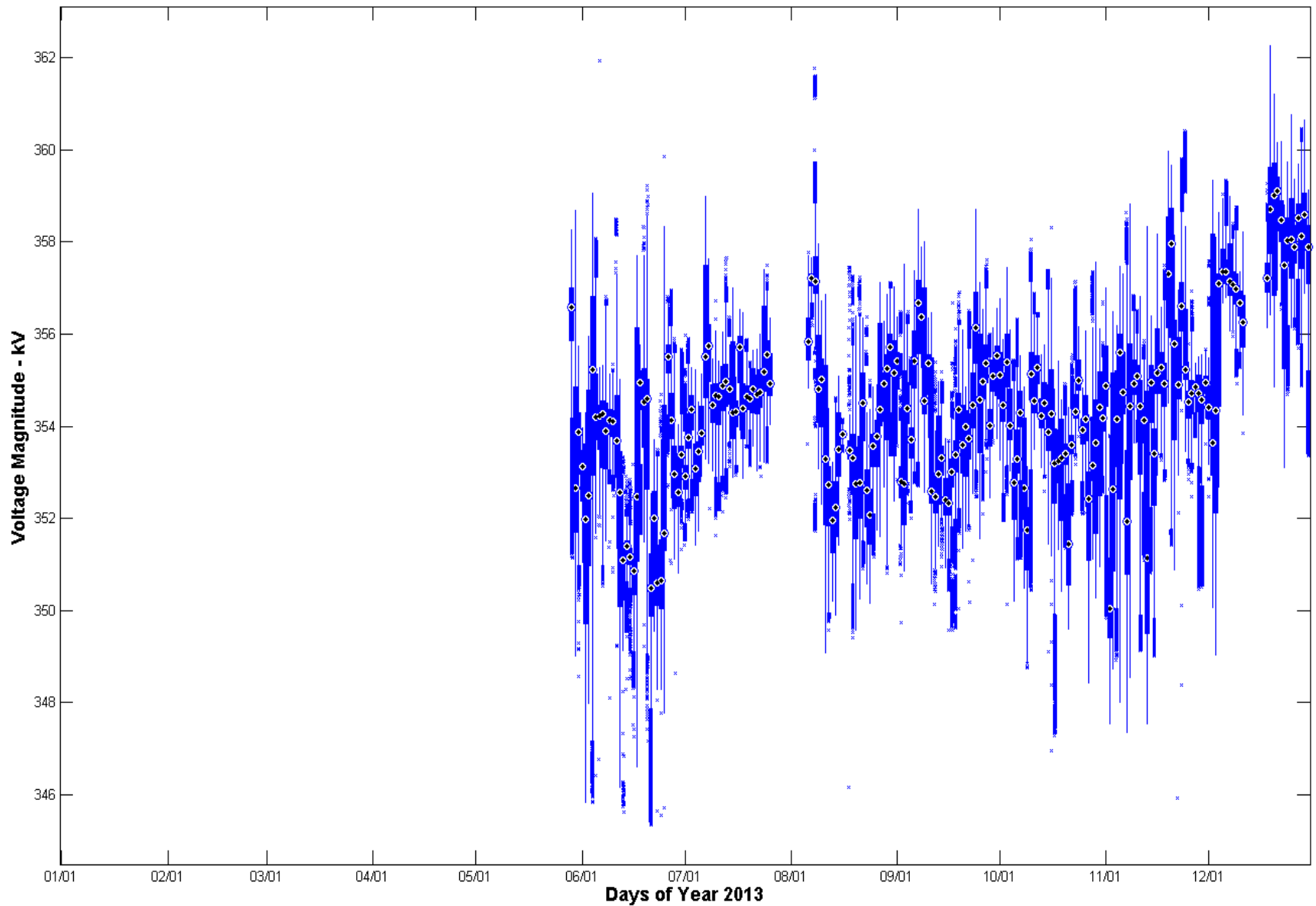
West 2

Time Duration Chart:



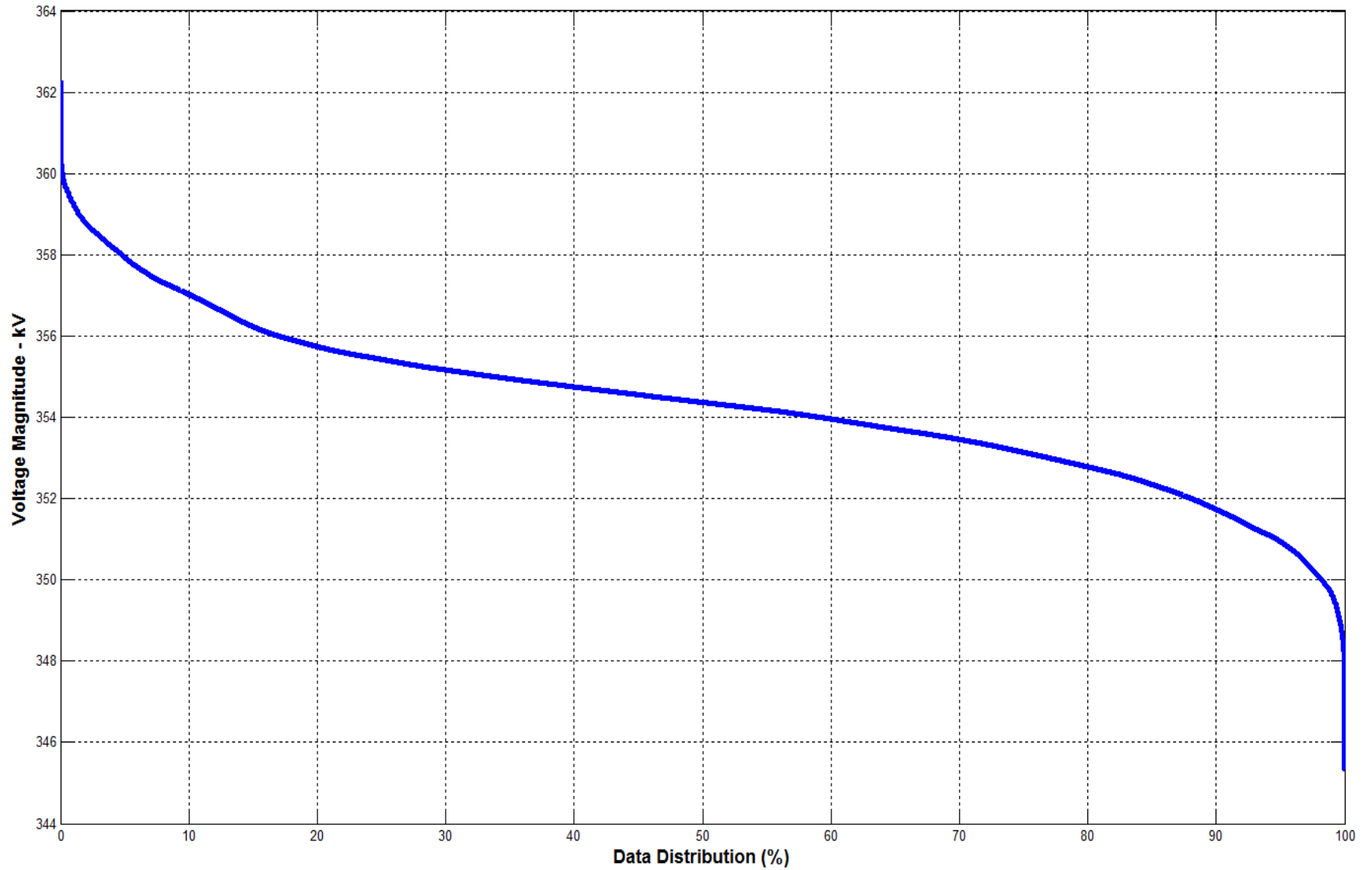
West 9

Daily Box-Whisker Chart:



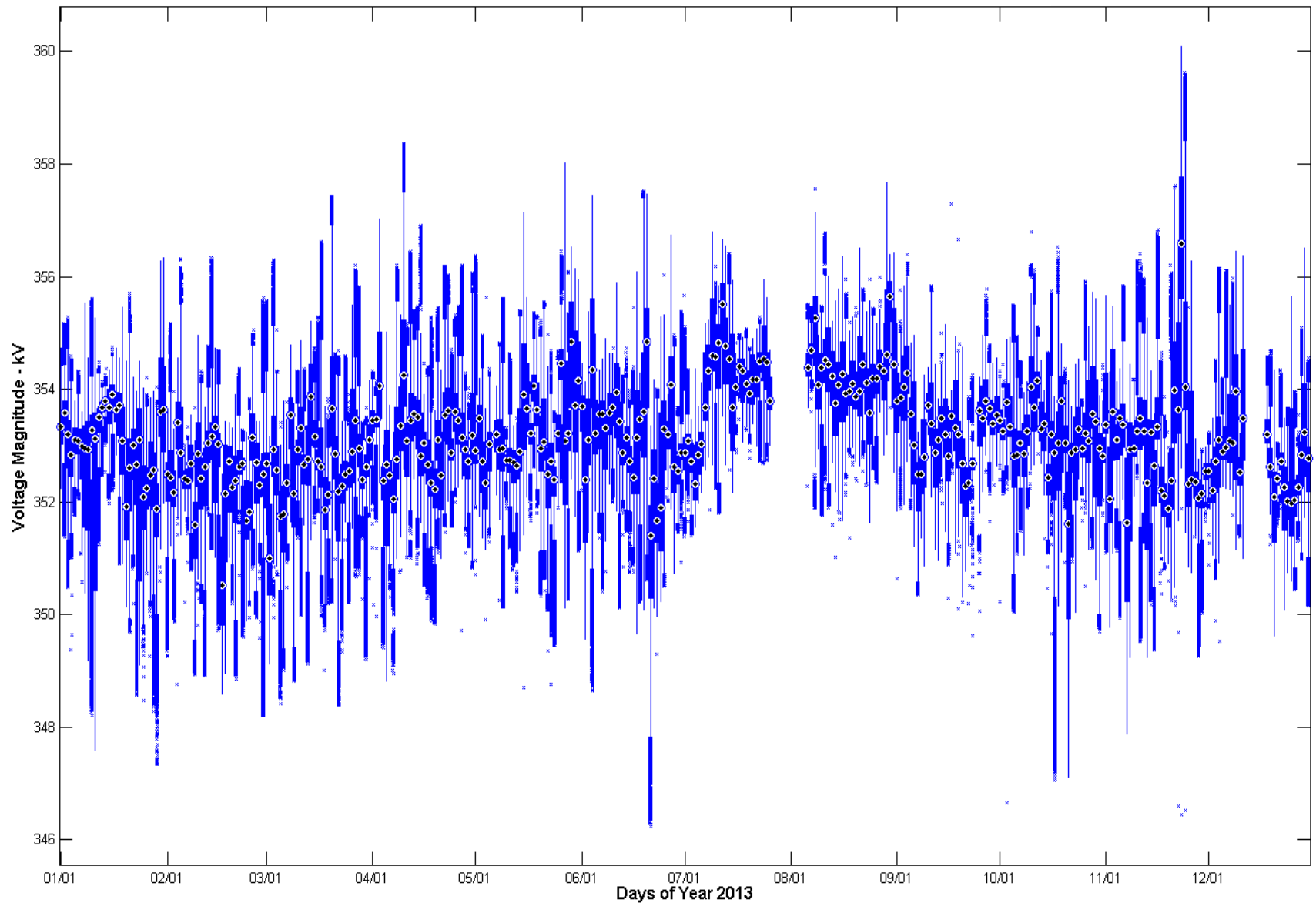
West 9

Time Duration Chart:



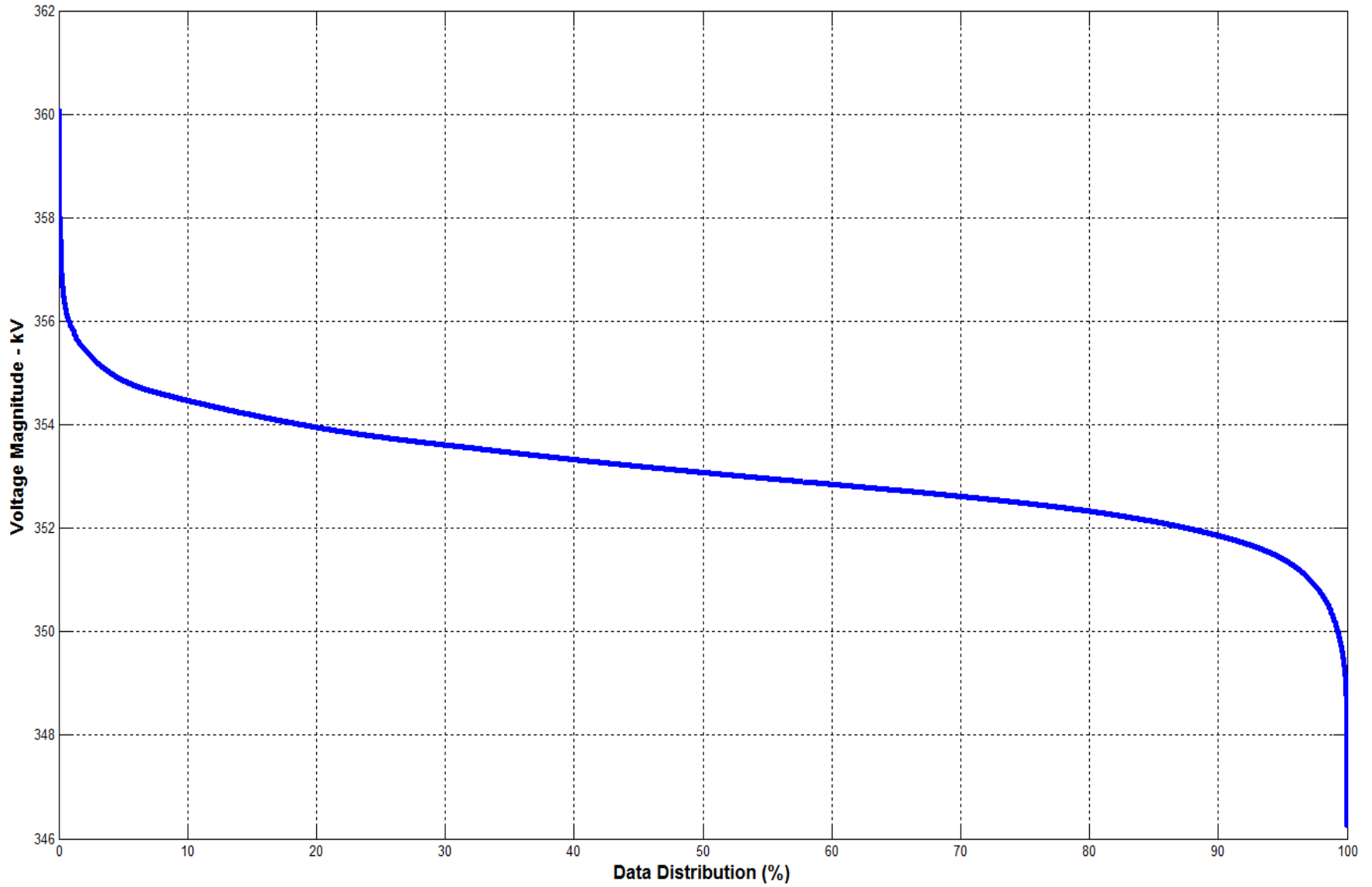
West 11

Daily Box-Whisker Chart:



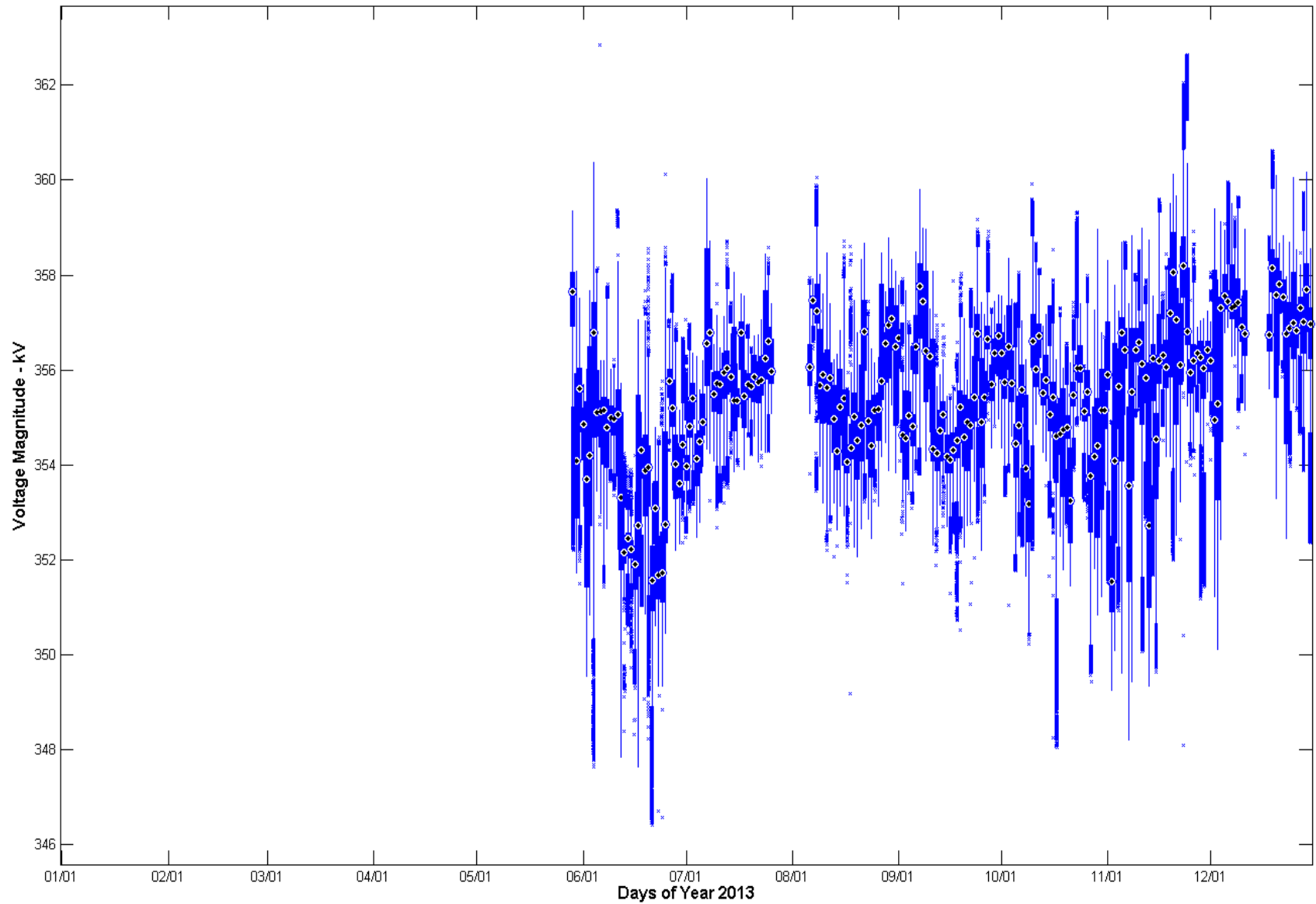
West 11

Time Duration Chart:

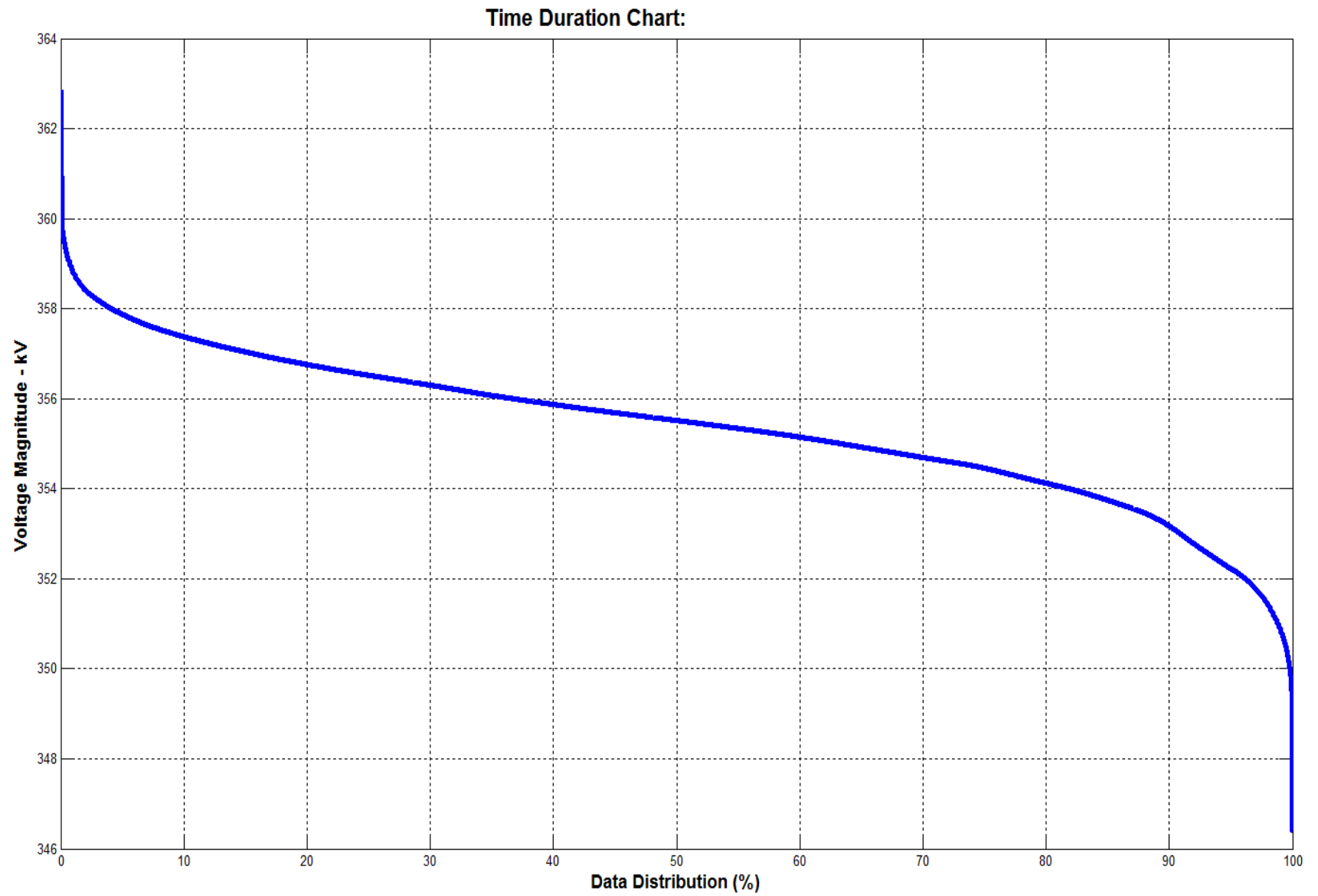


West 12

Daily Box-Whisker Chart:

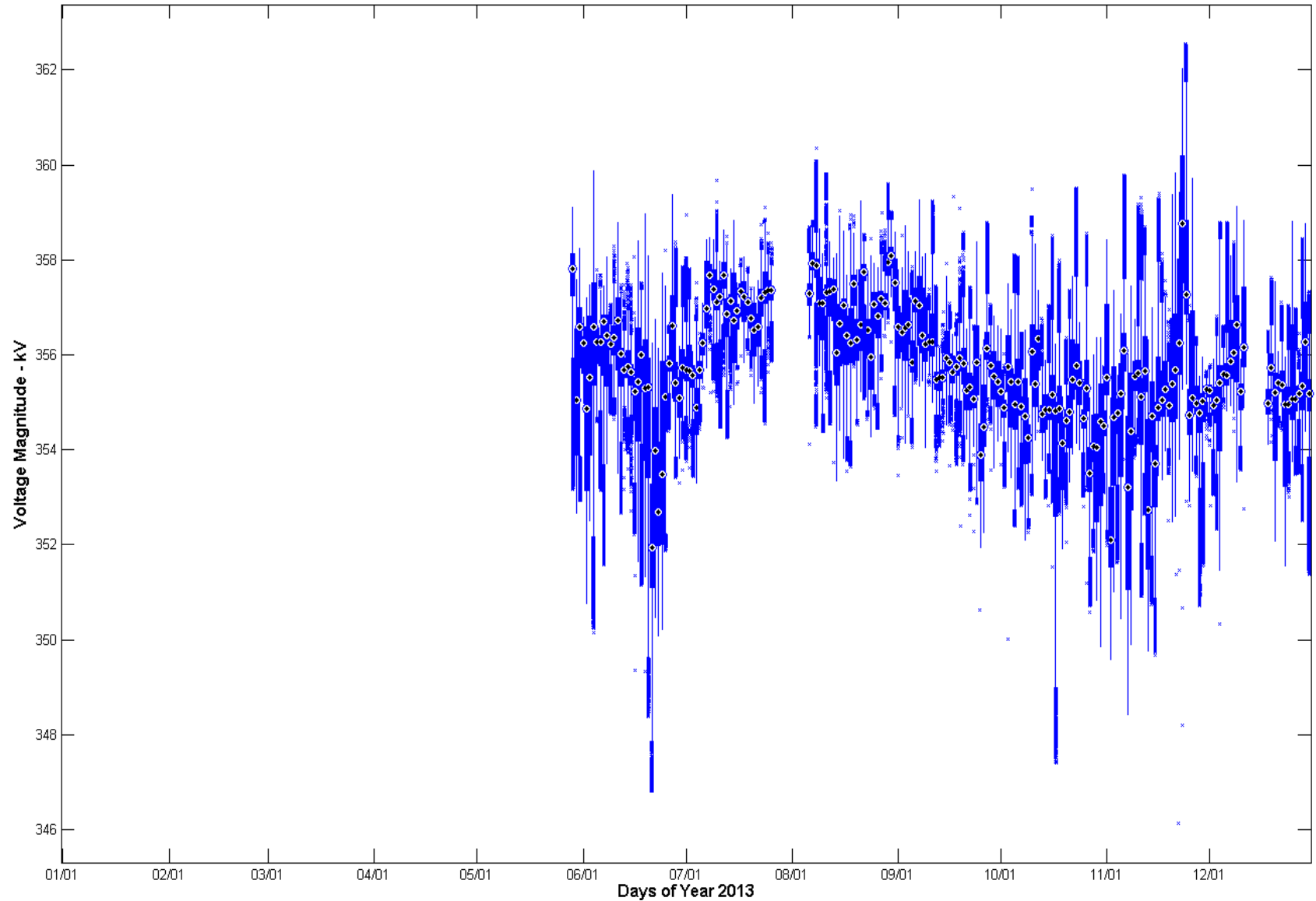


West 12



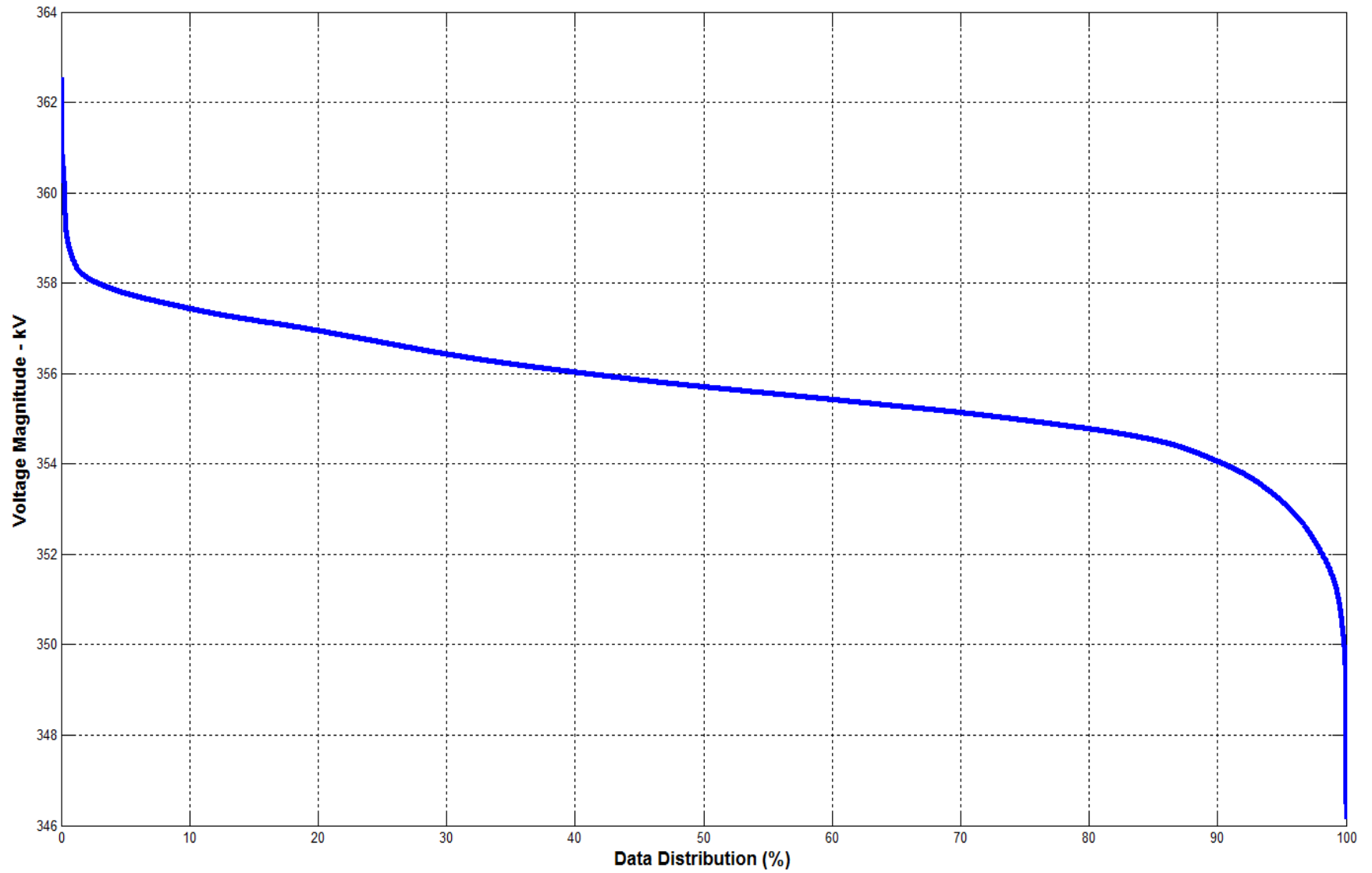
West 5

Daily Box-Whisker Chart:



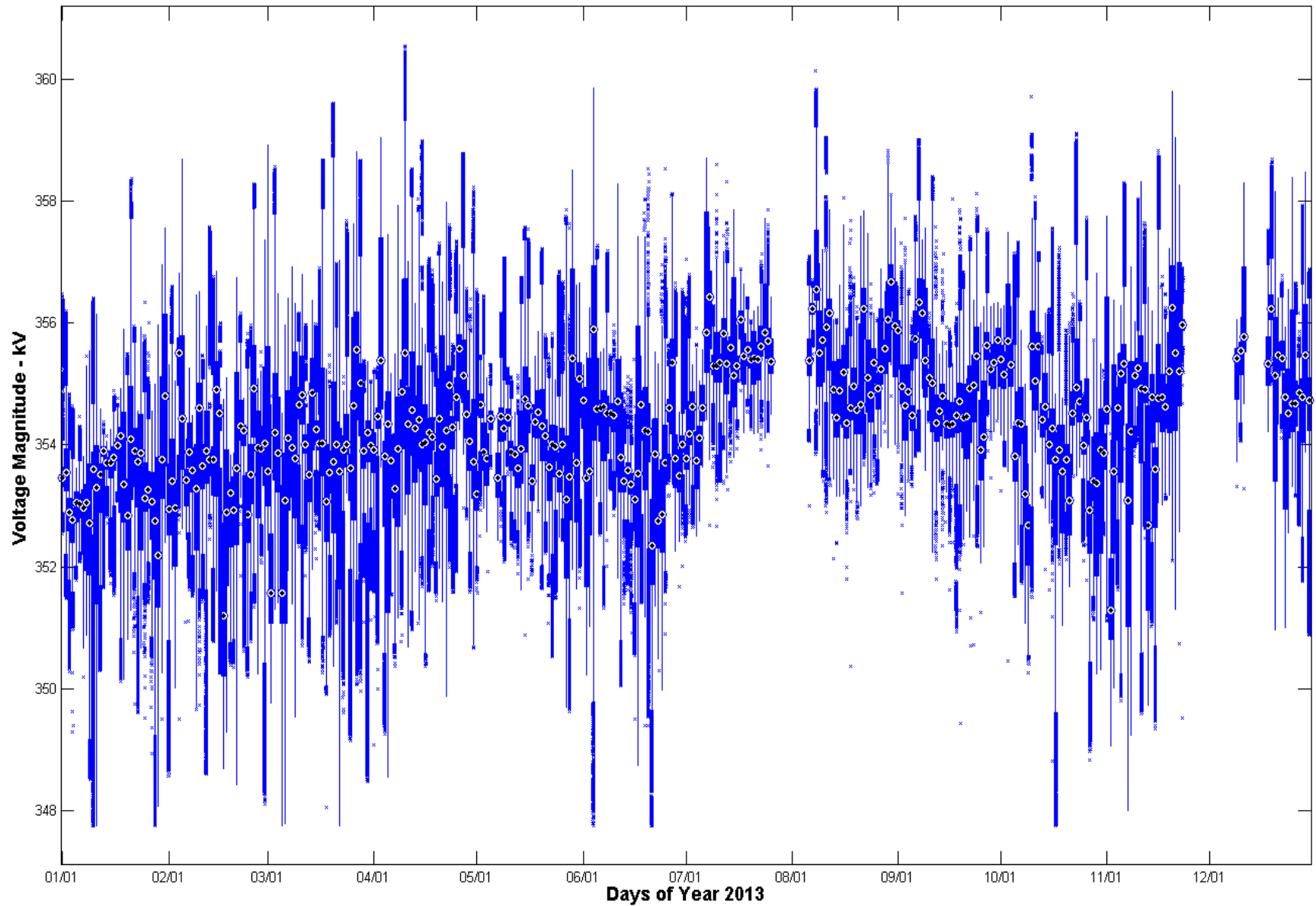
West 5

Time Duration Chart:



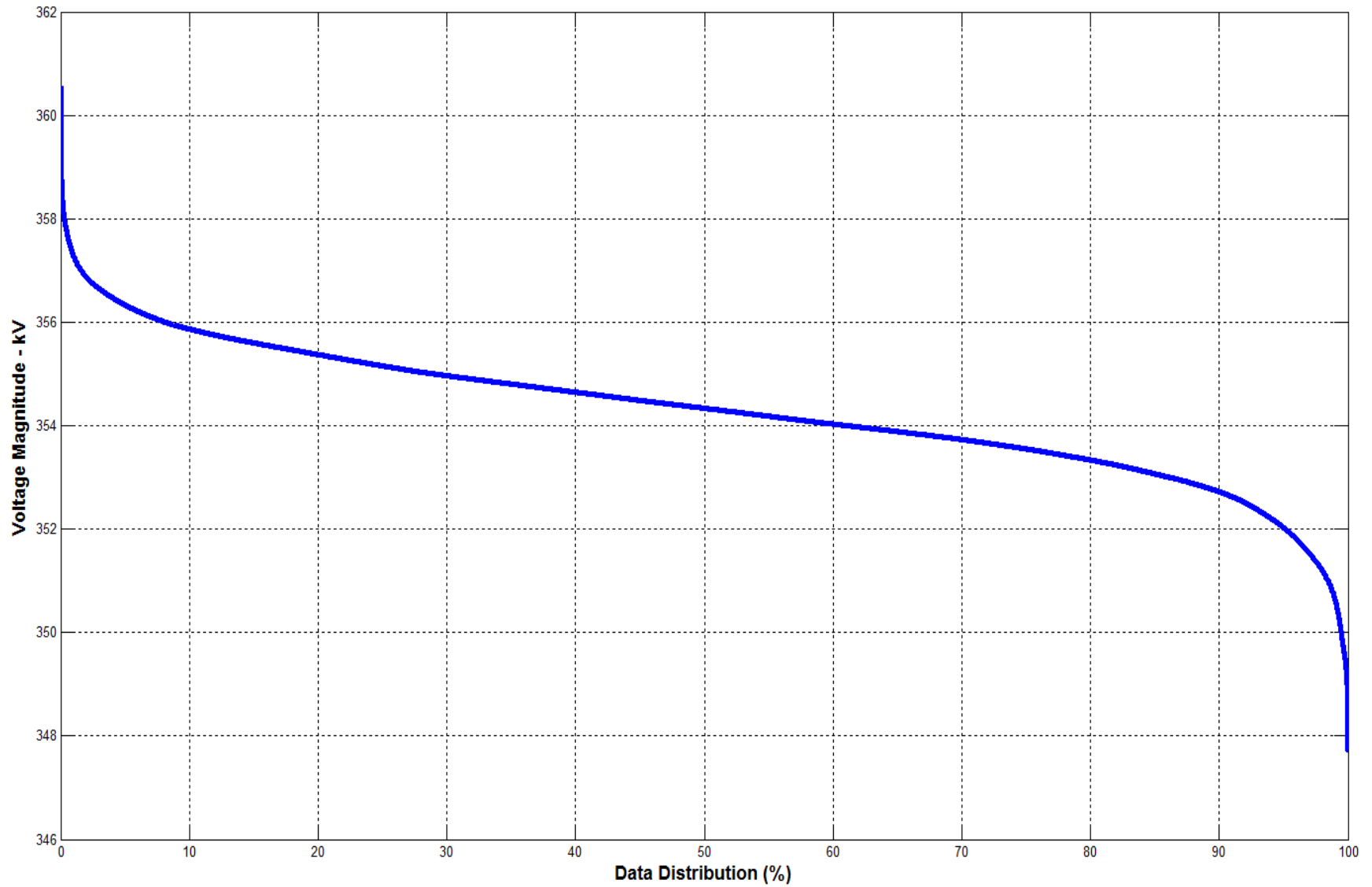
West 6

Daily Box-Whisker Chart:



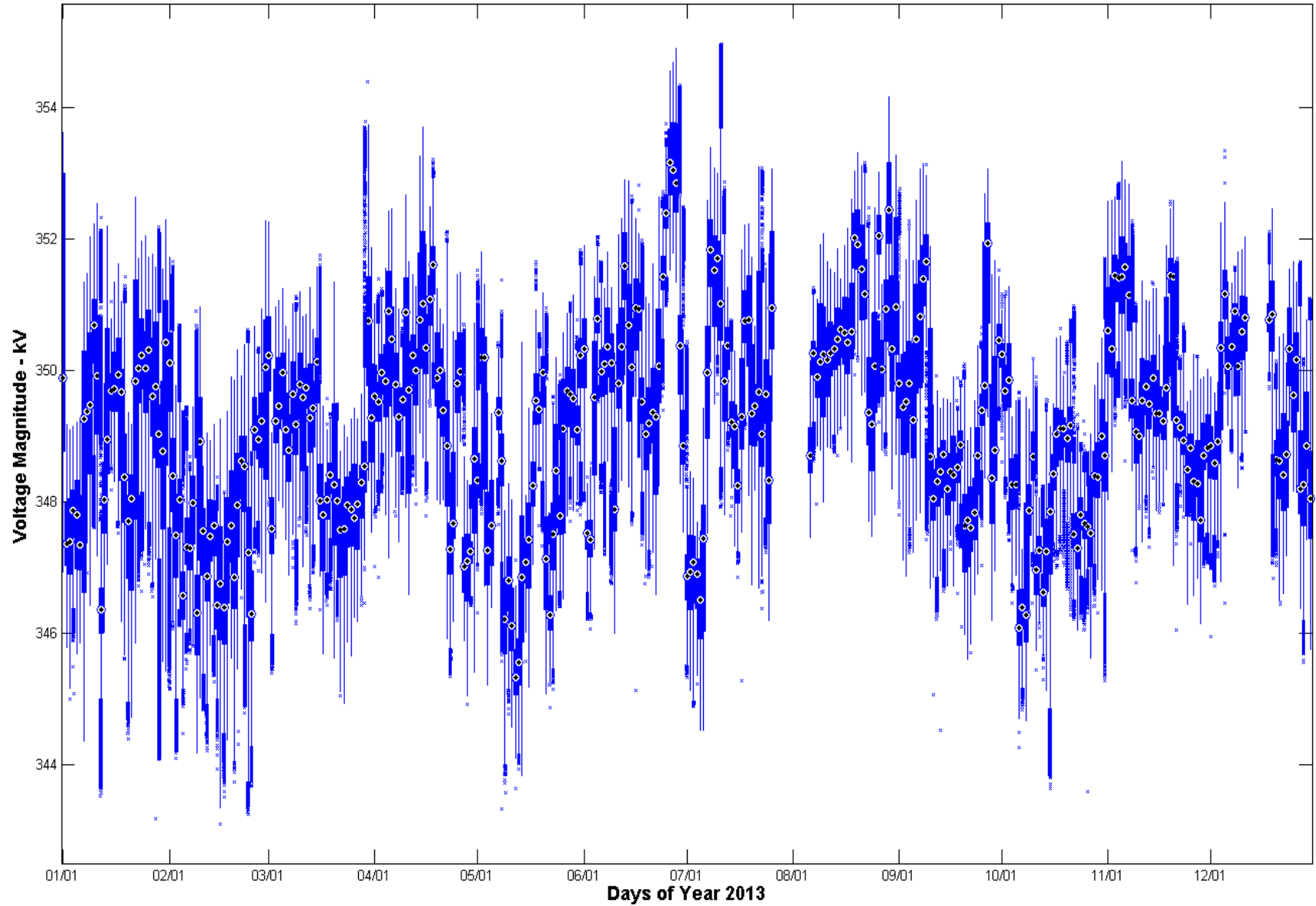
West 6

Time Duration Chart:



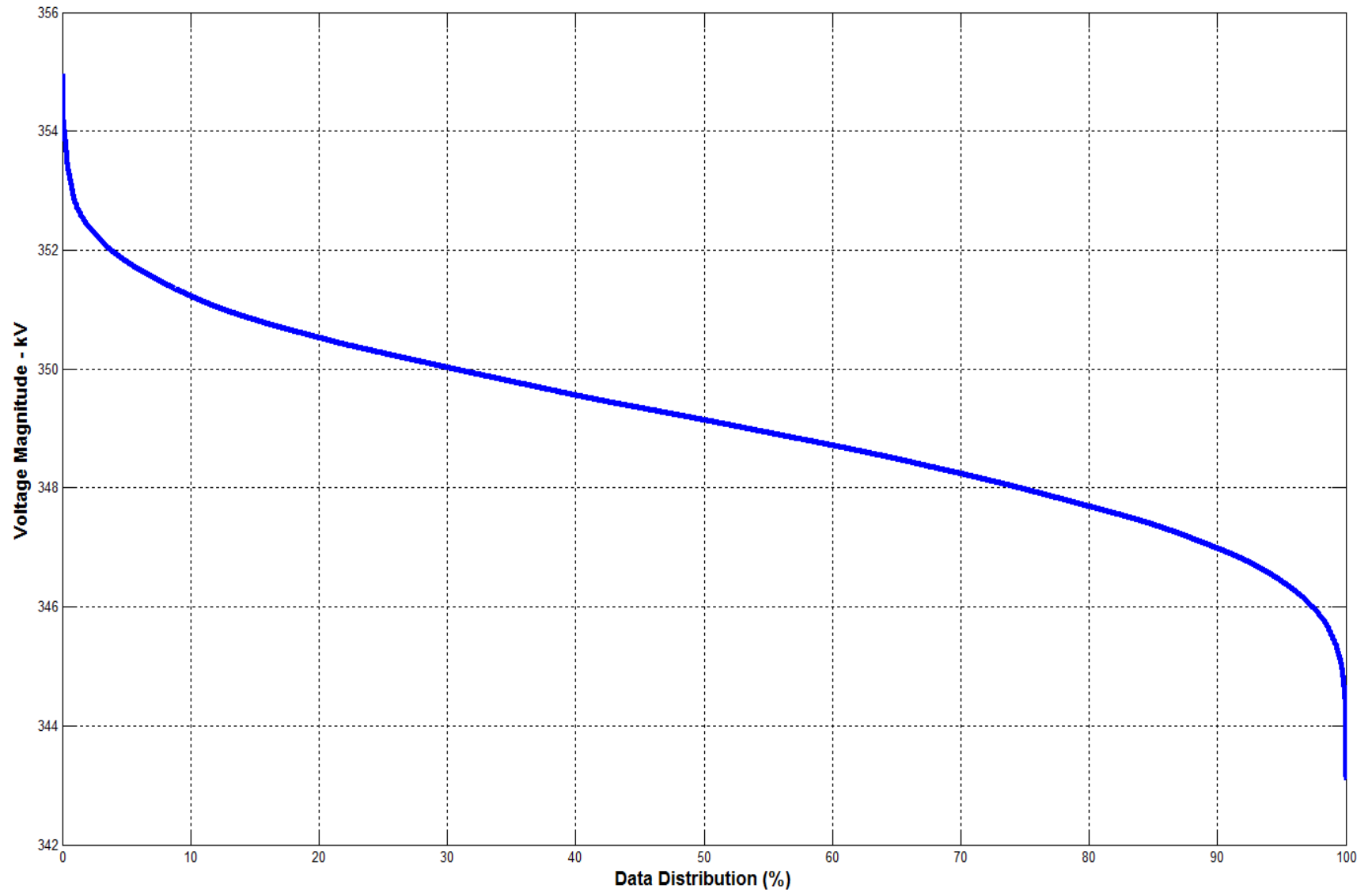
North 1

Daily Box-Whisker Chart:



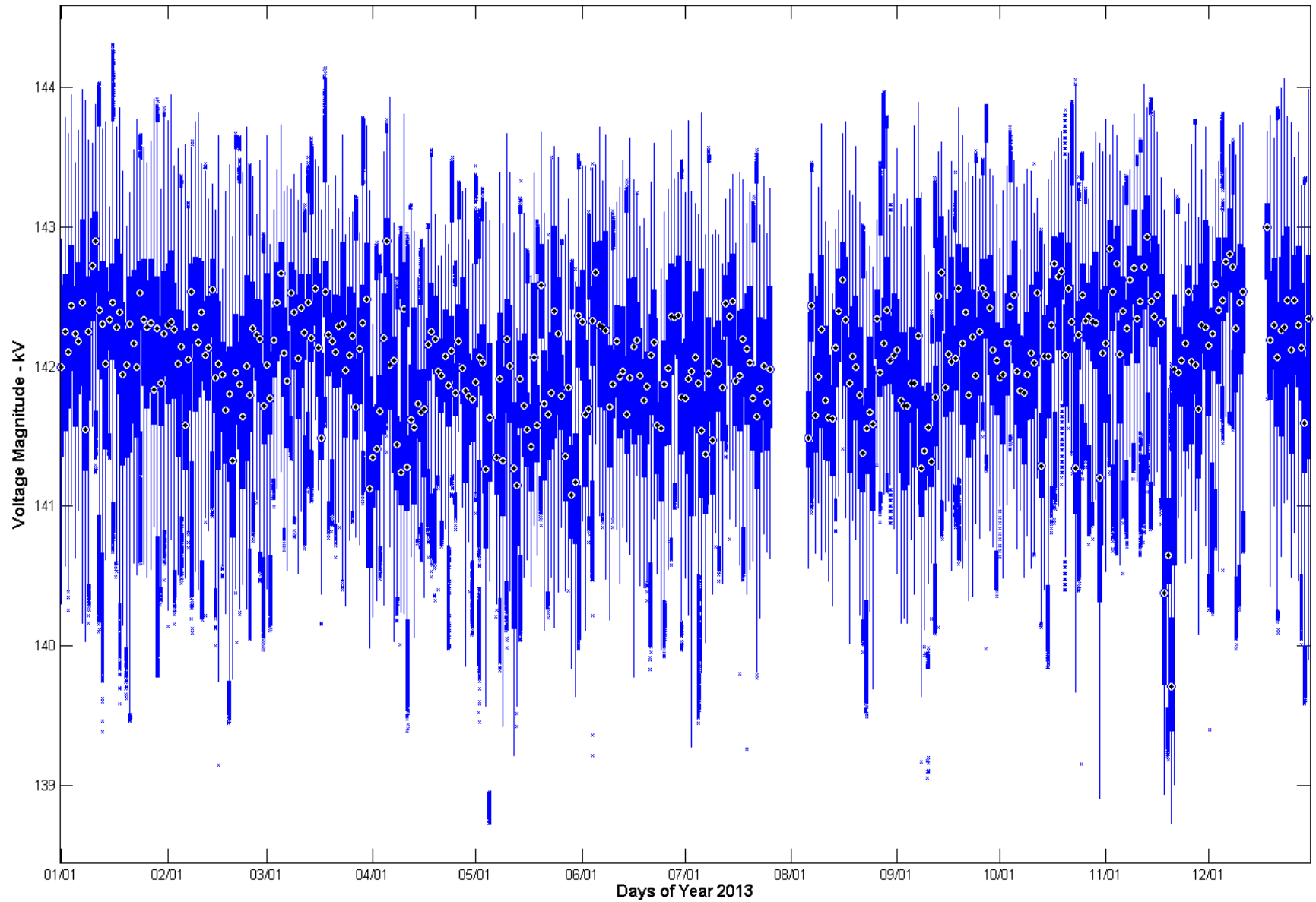
North 1

Time Duration Chart:



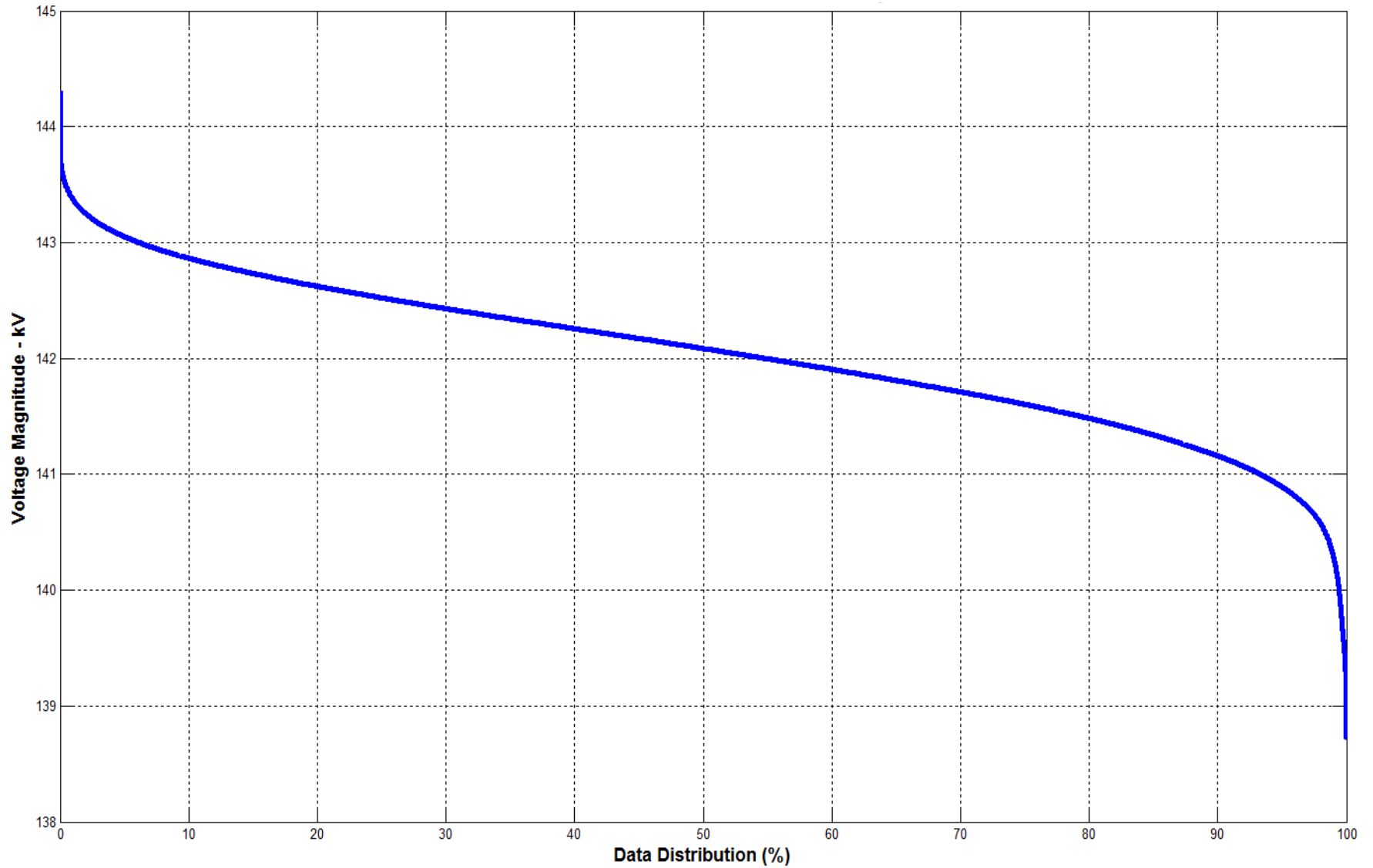
North 4

Daily Box-Whisker Chart:



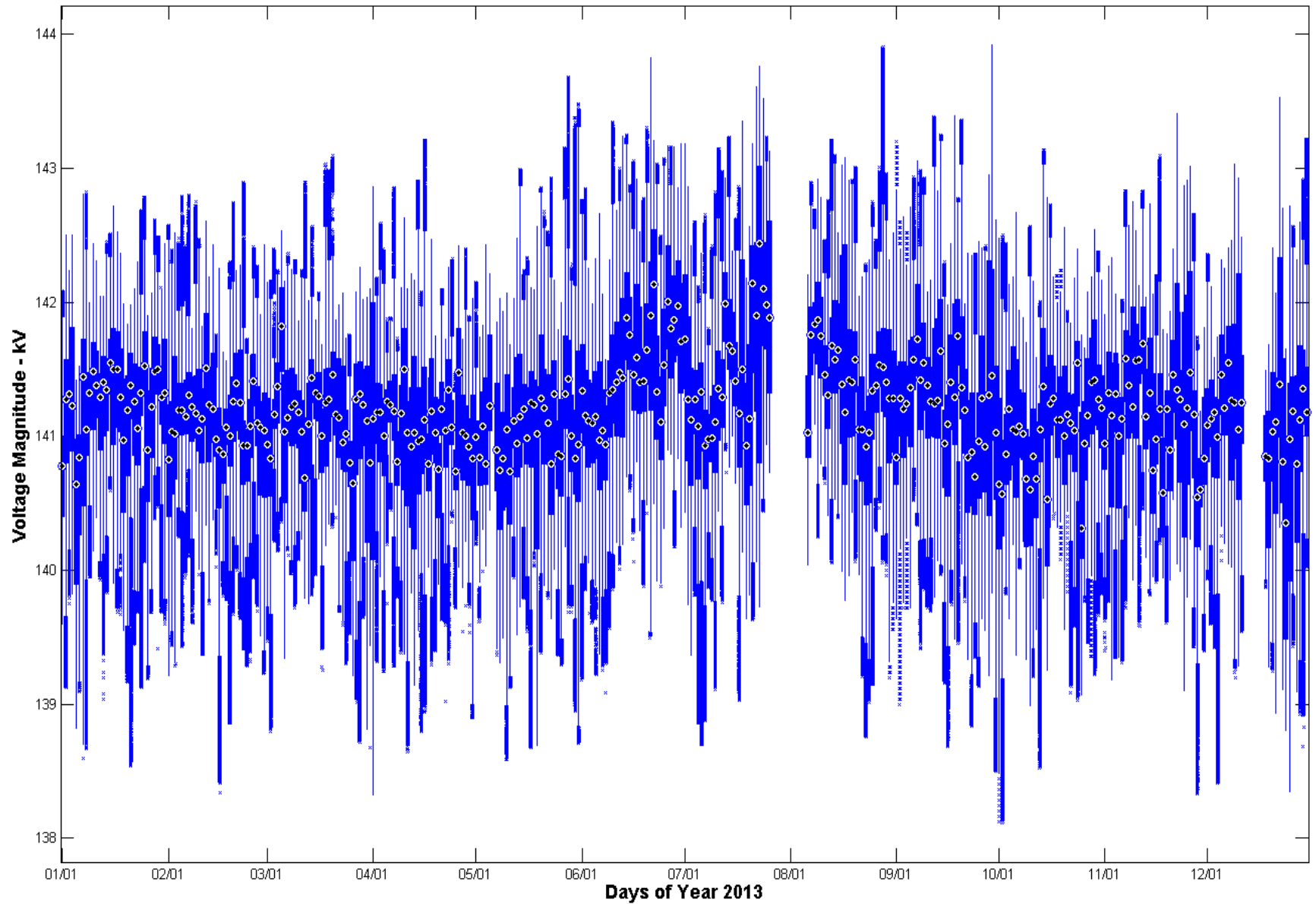
North 4

Time Duration Chart:



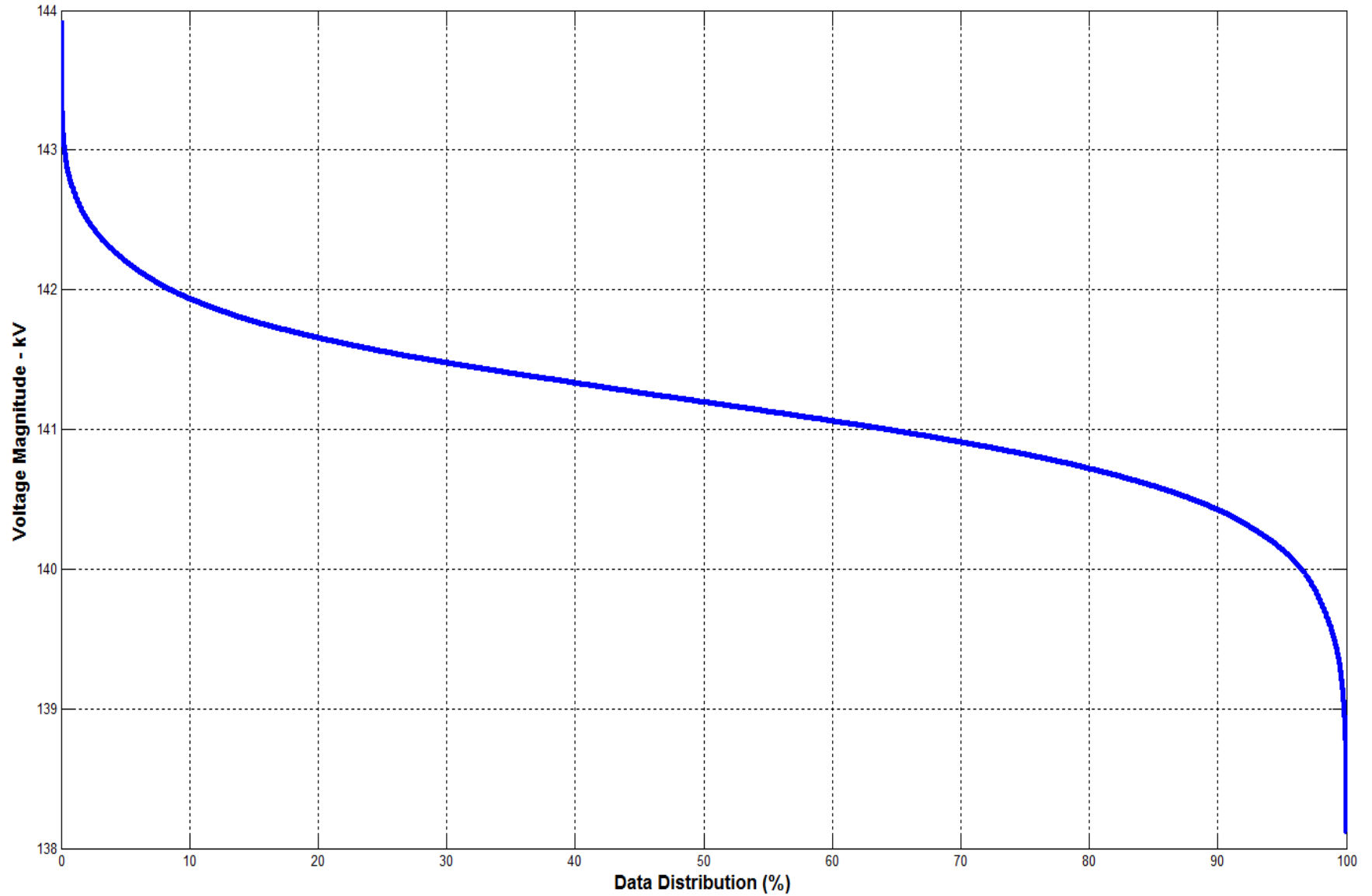
North 5

Daily Box-Whisker Chart:



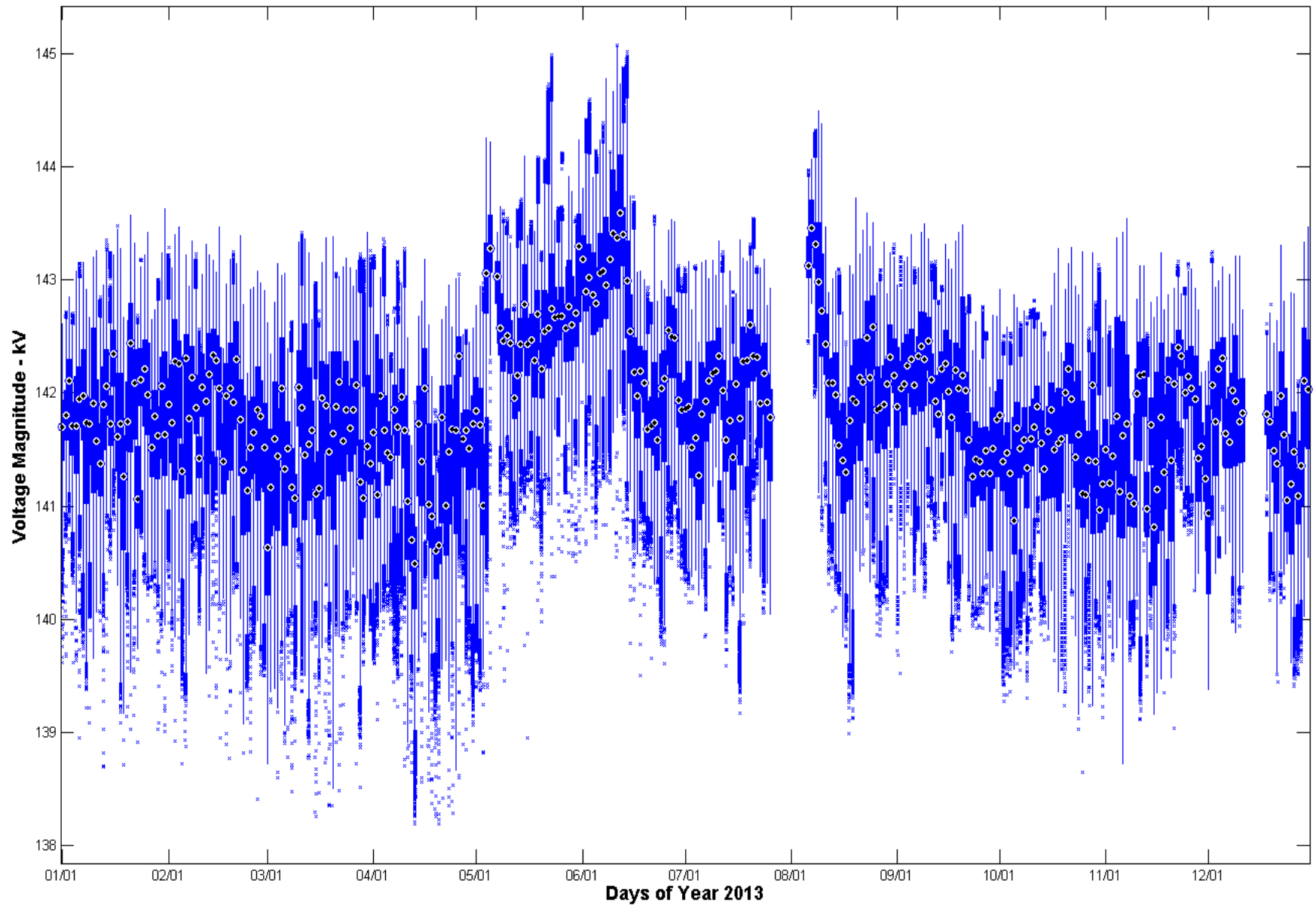
North 5

Time Duration Chart:



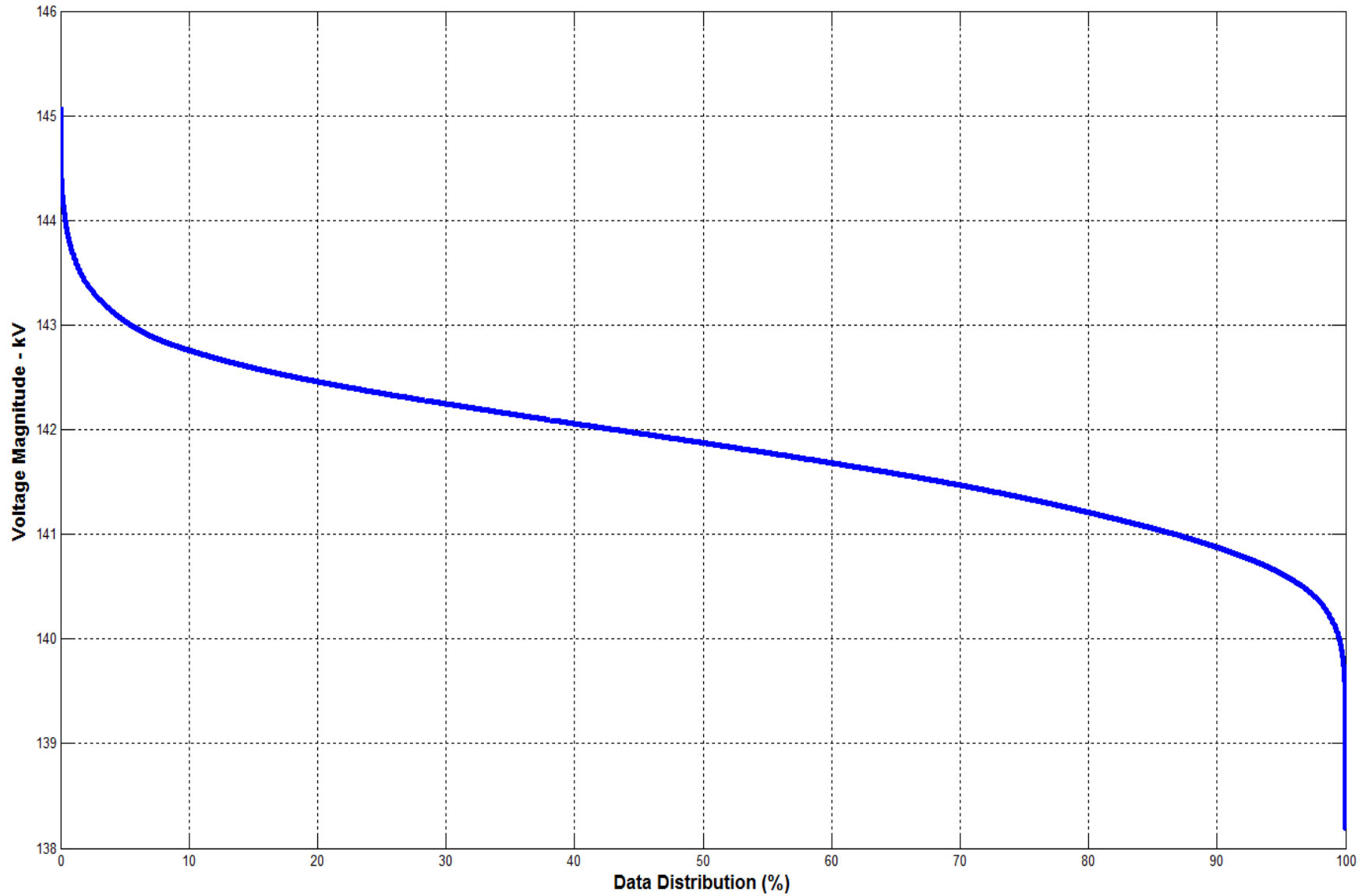
North 6

Daily Box-Whisker Chart:



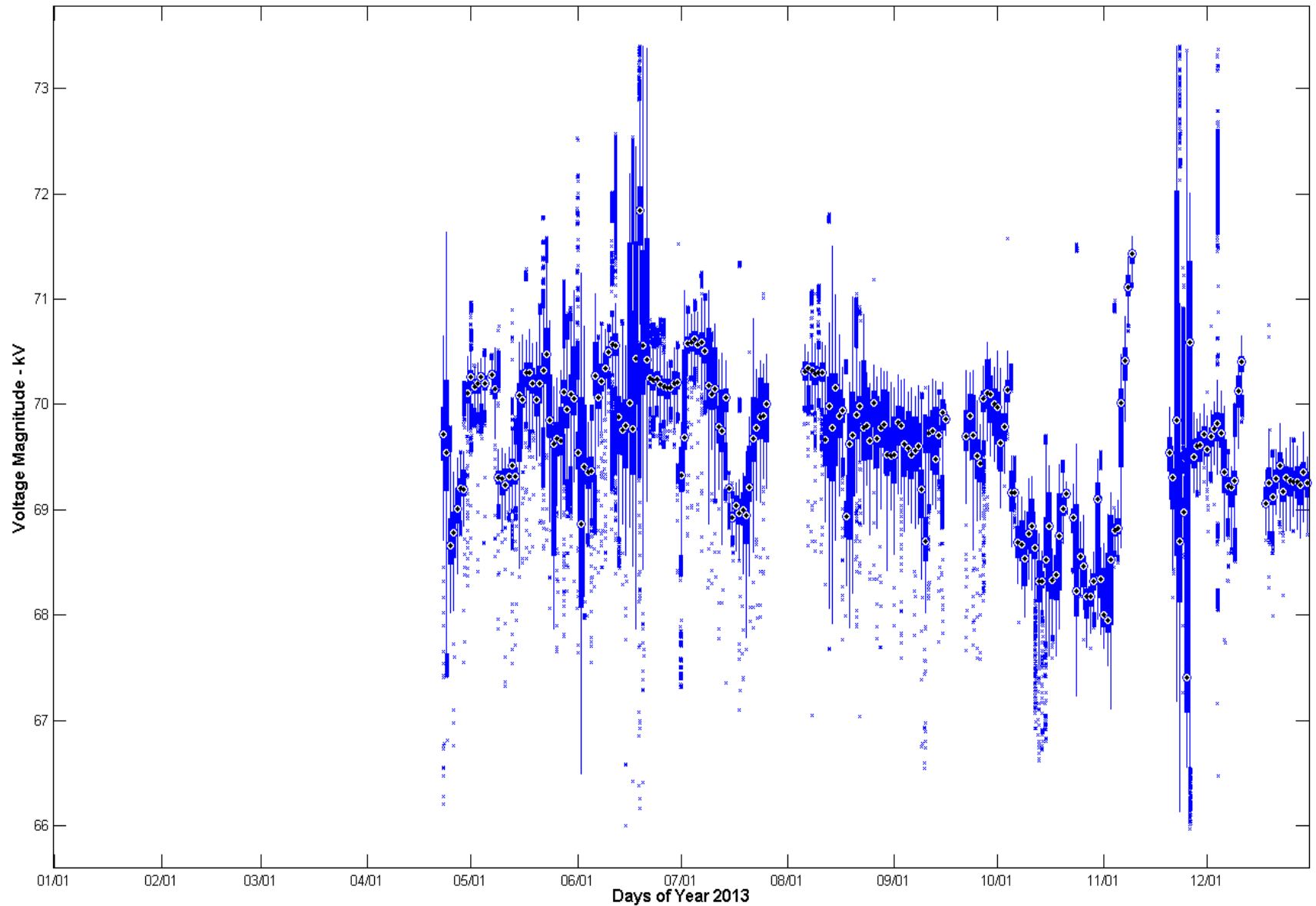
North 6

Time Duration Chart:



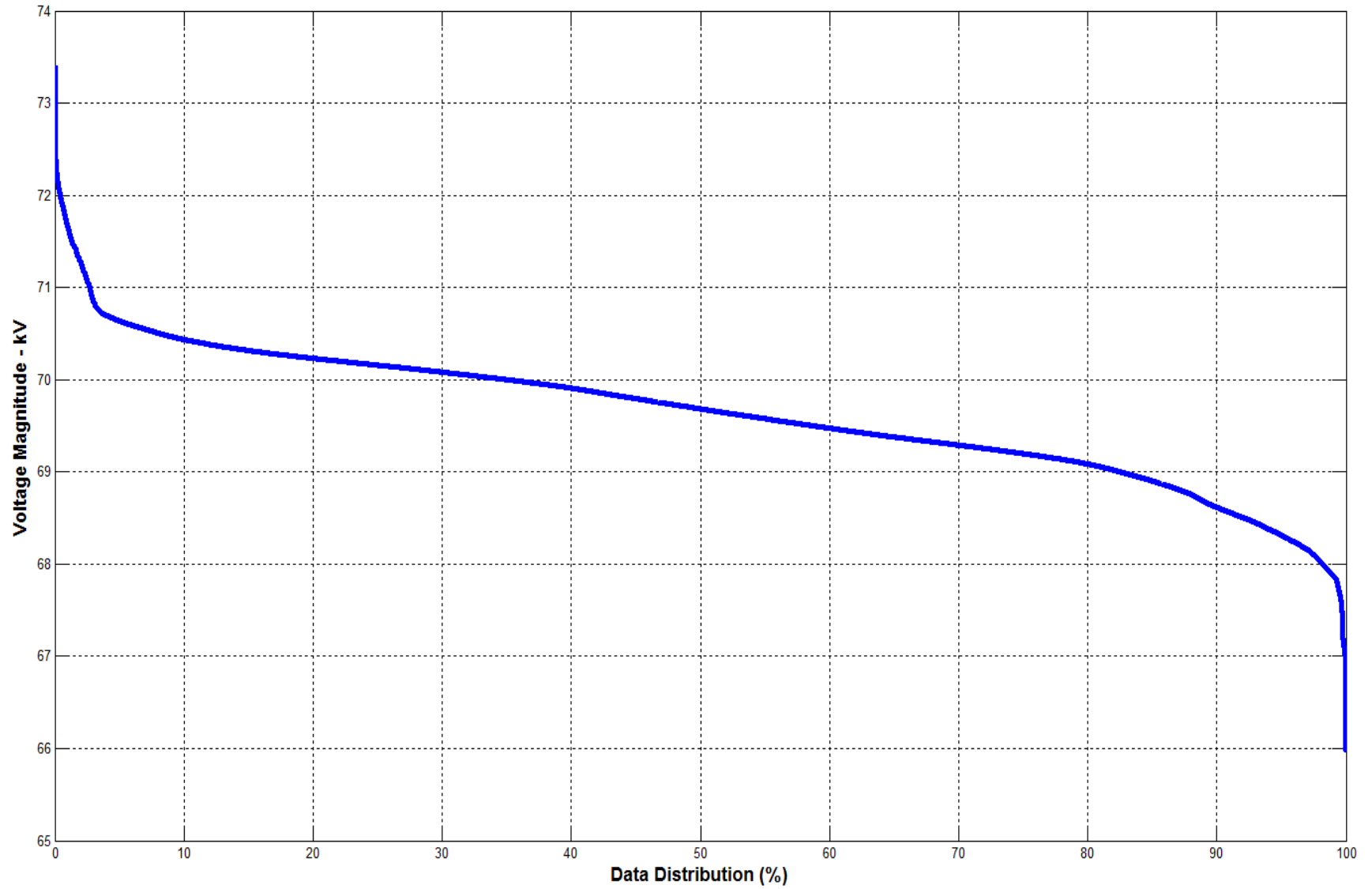
FarWest 2

Daily Box-Whisker Chart:



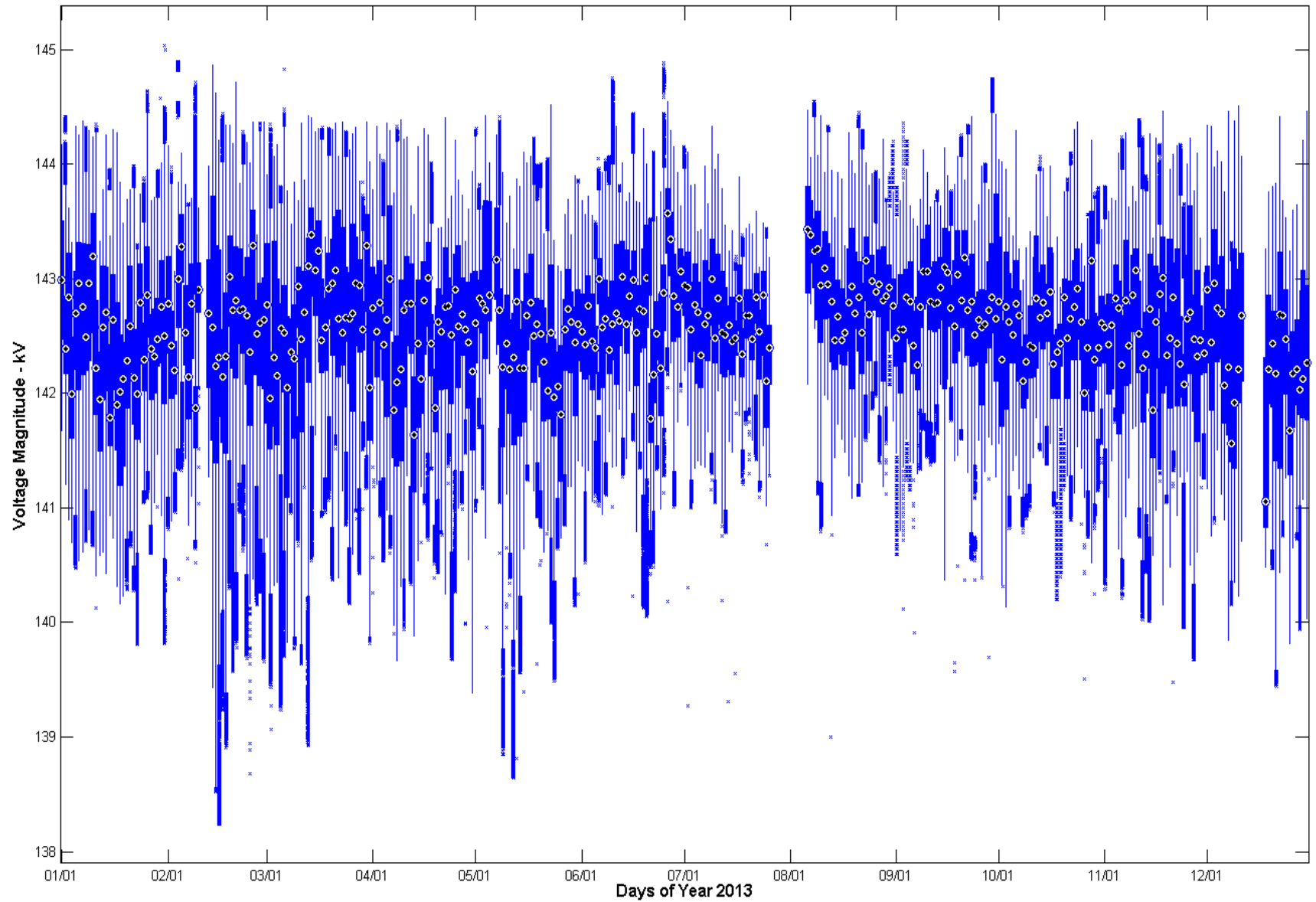
FarWest 2

Time Duration Chart:



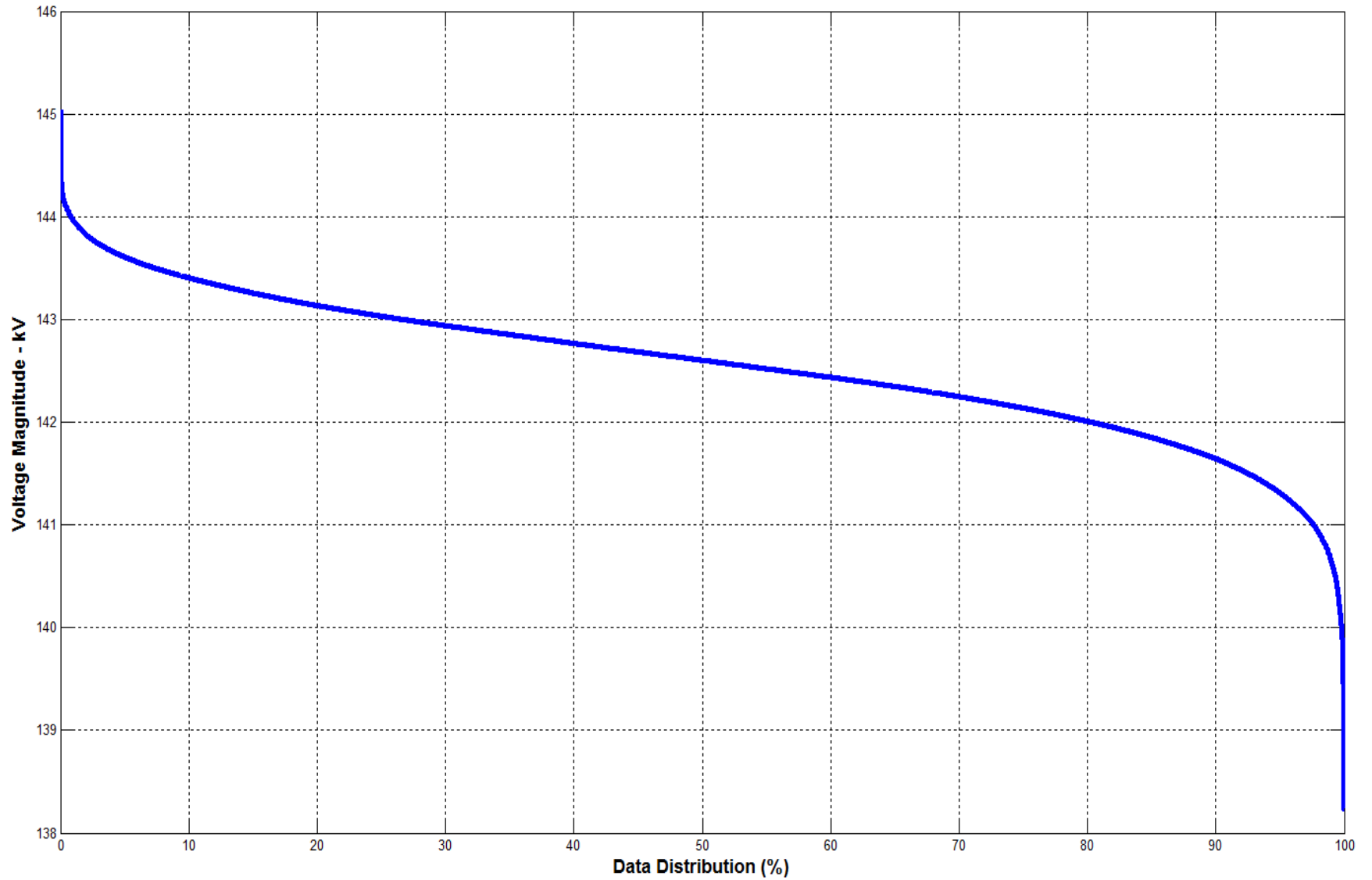
North 7

Daily Box-Whisker Chart:



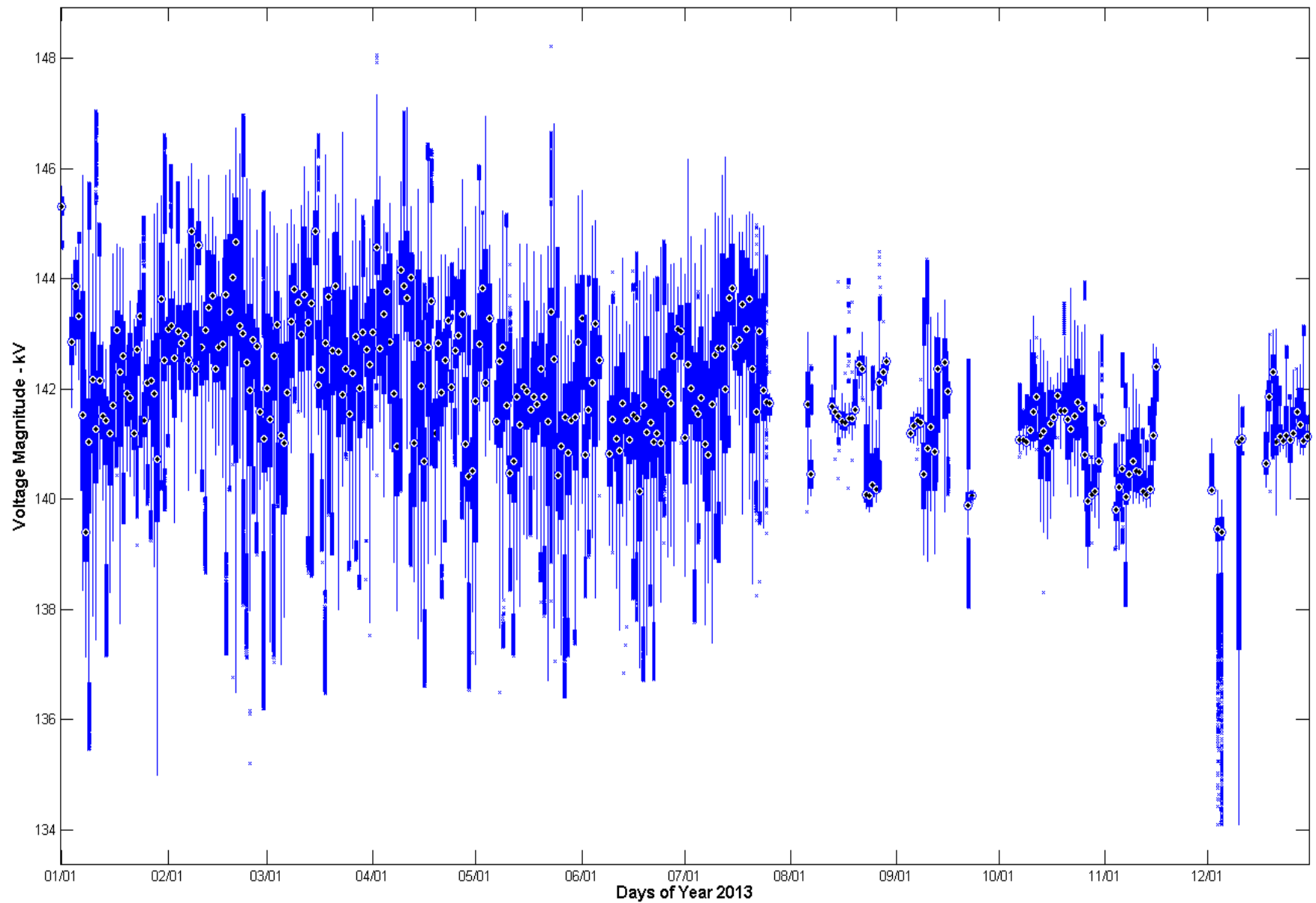
North 7

Time Duration Chart:



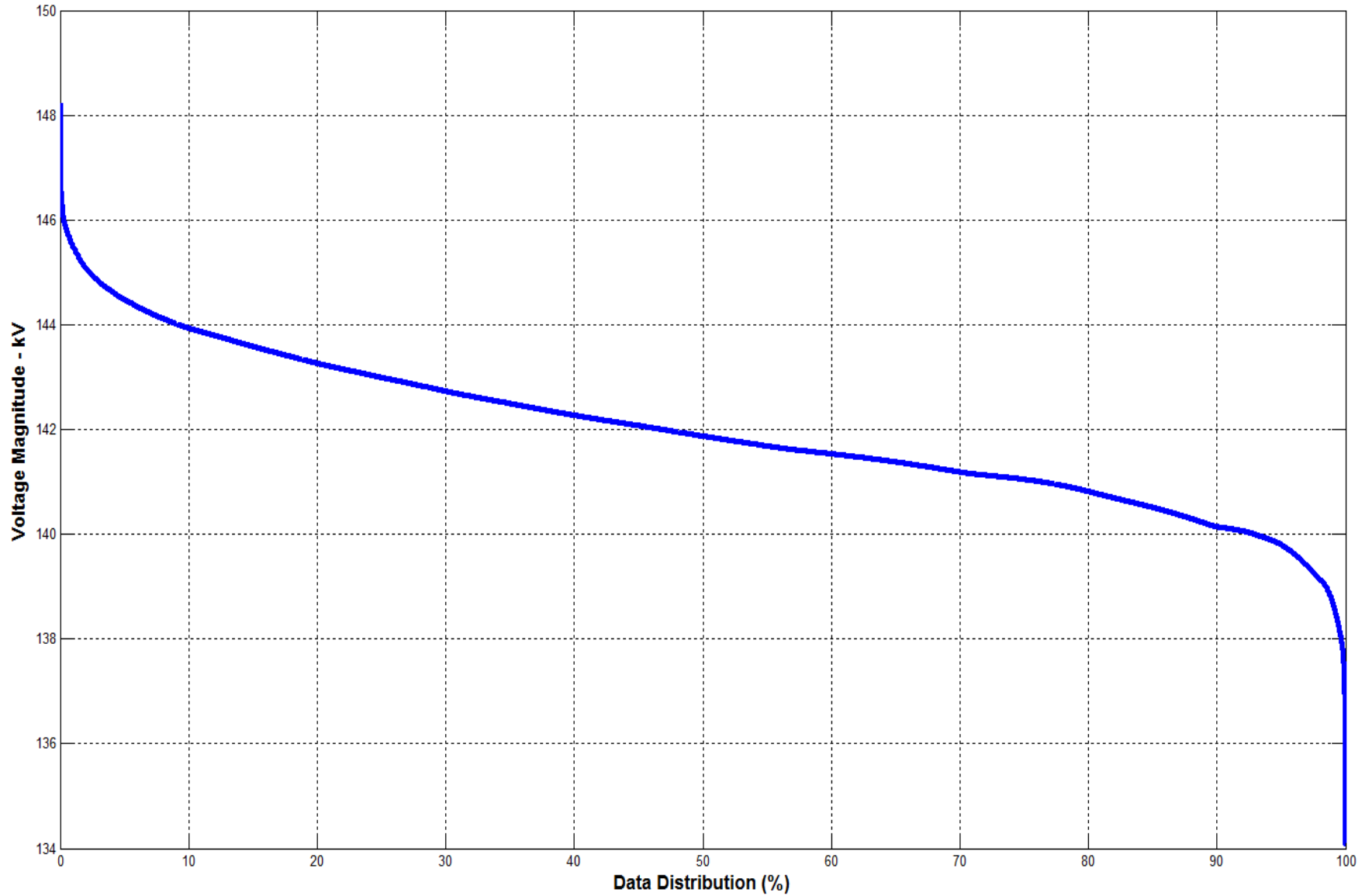
West 4

Daily Box-Whisker Chart:

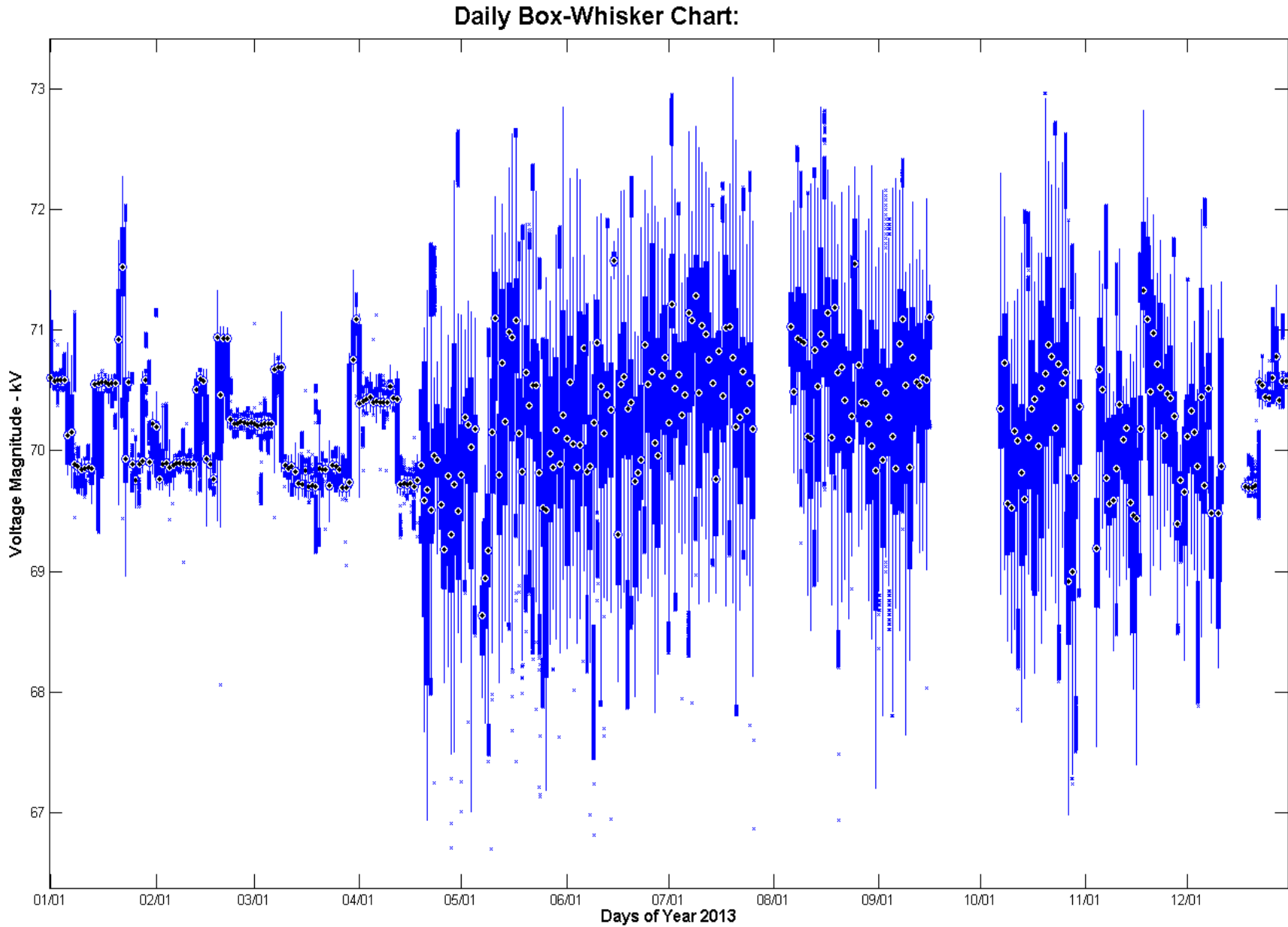


West 4

Time Duration Chart:

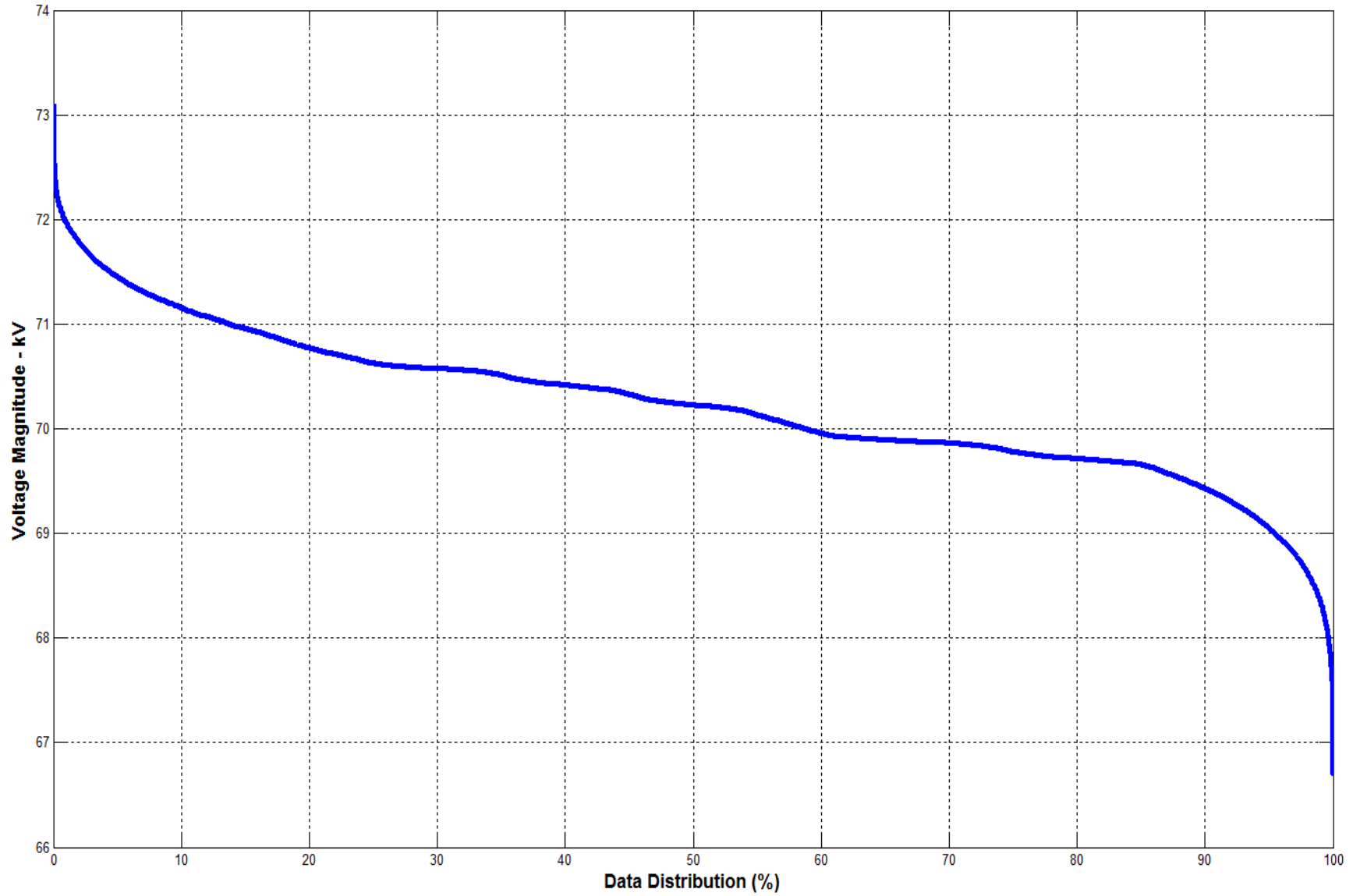


Coast 2



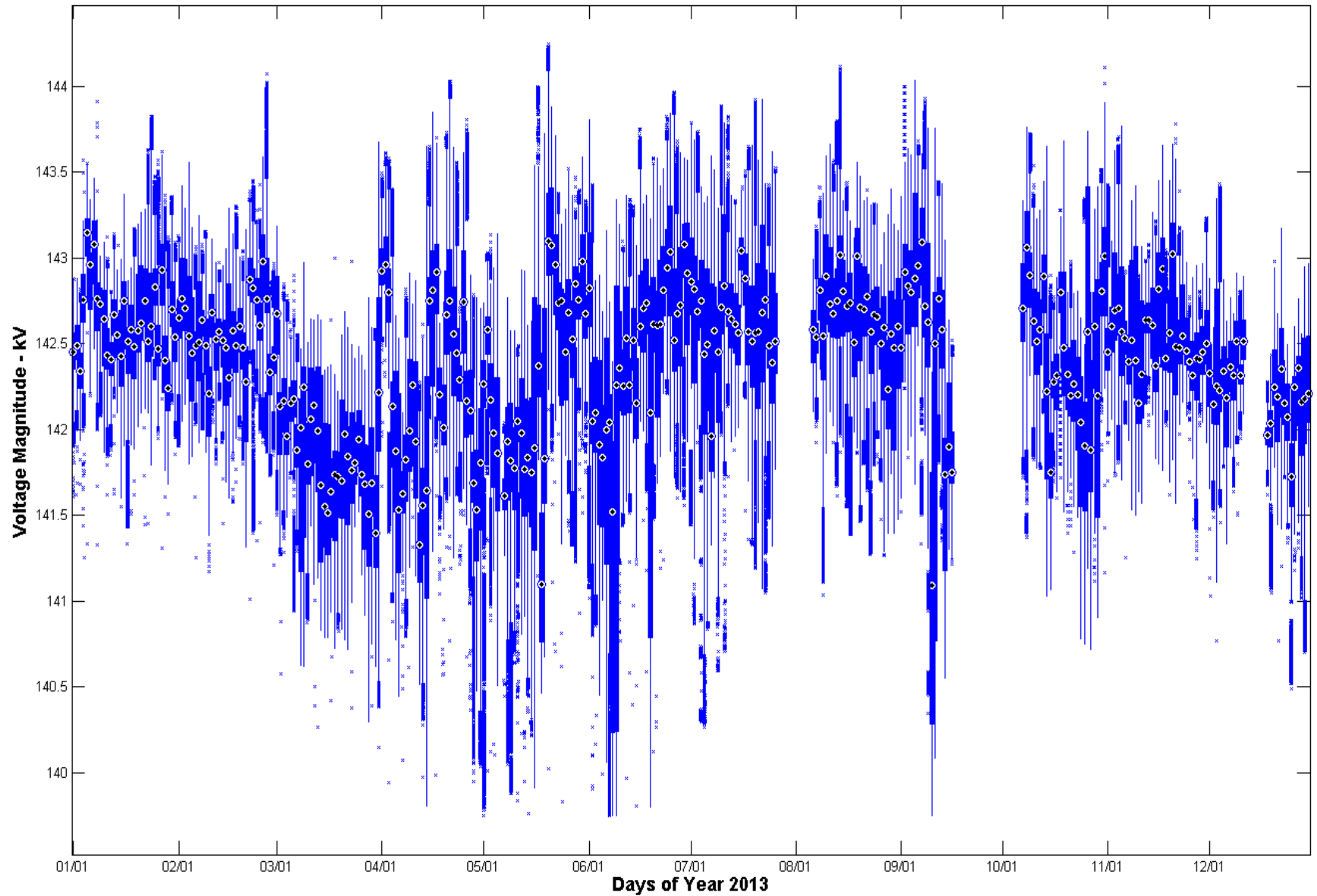
Coast 2

Time Duration Chart:



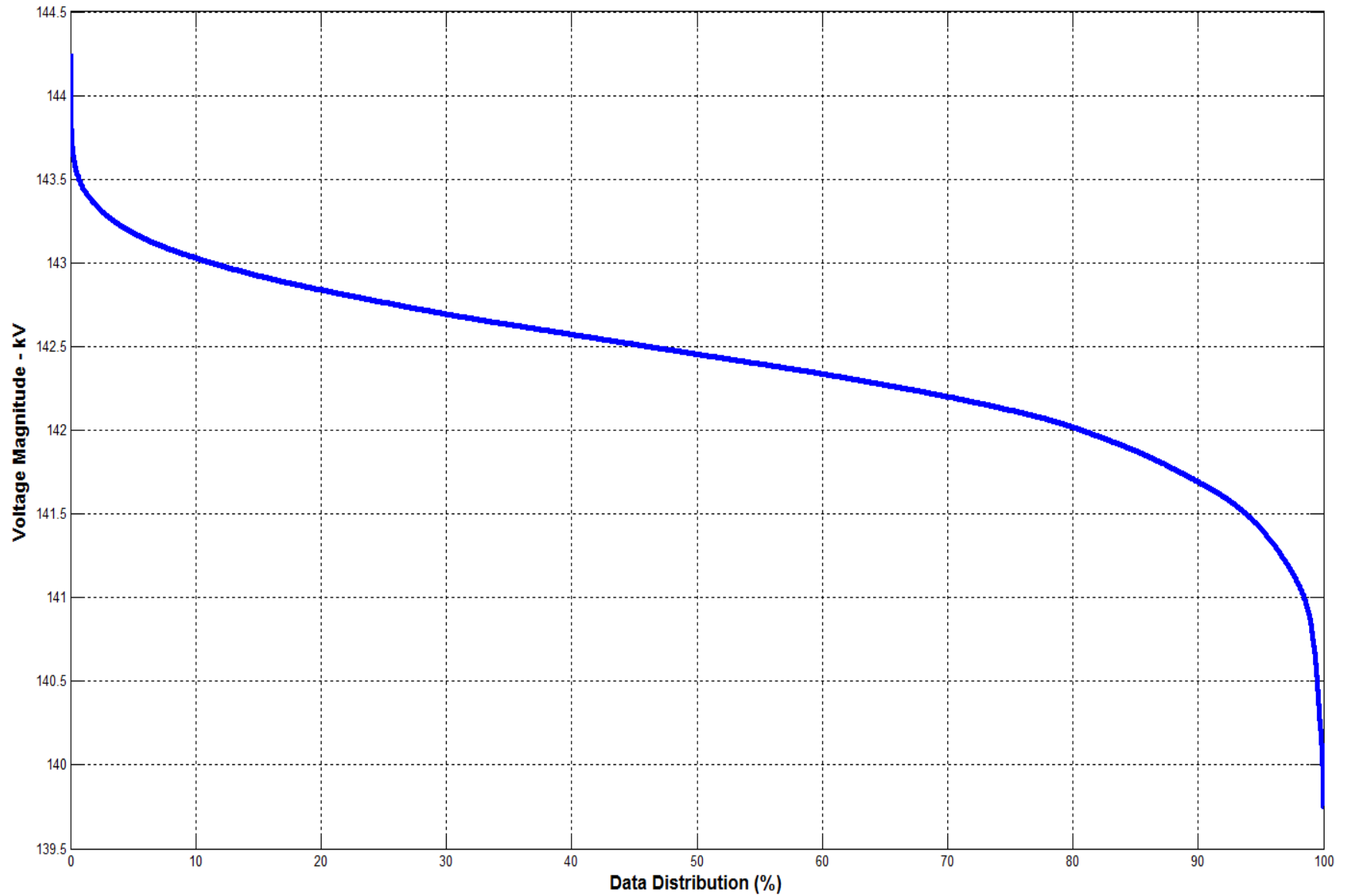
Coast 1

Daily Box-Whisker Chart:



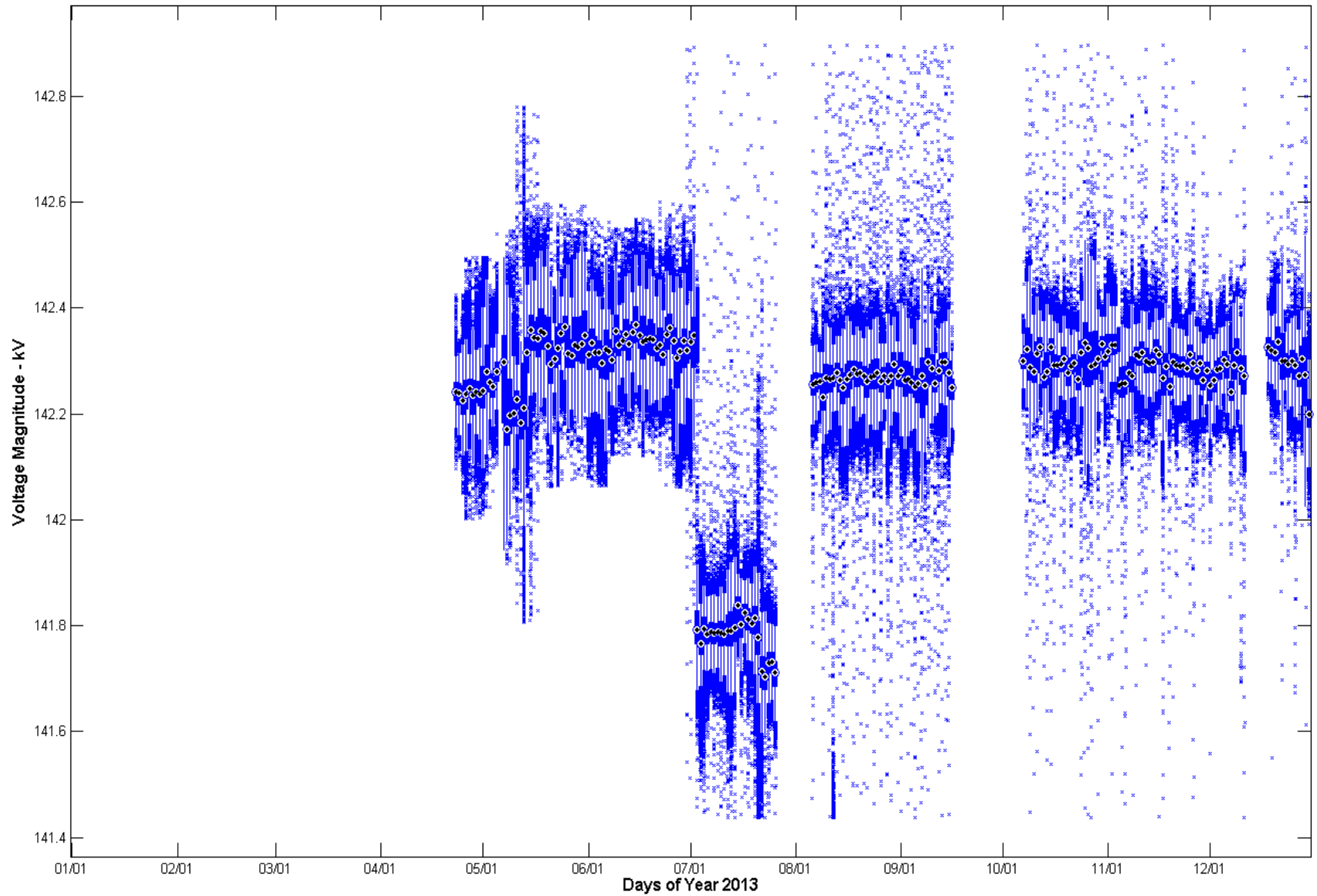
Coast 1

Time Duration Chart:

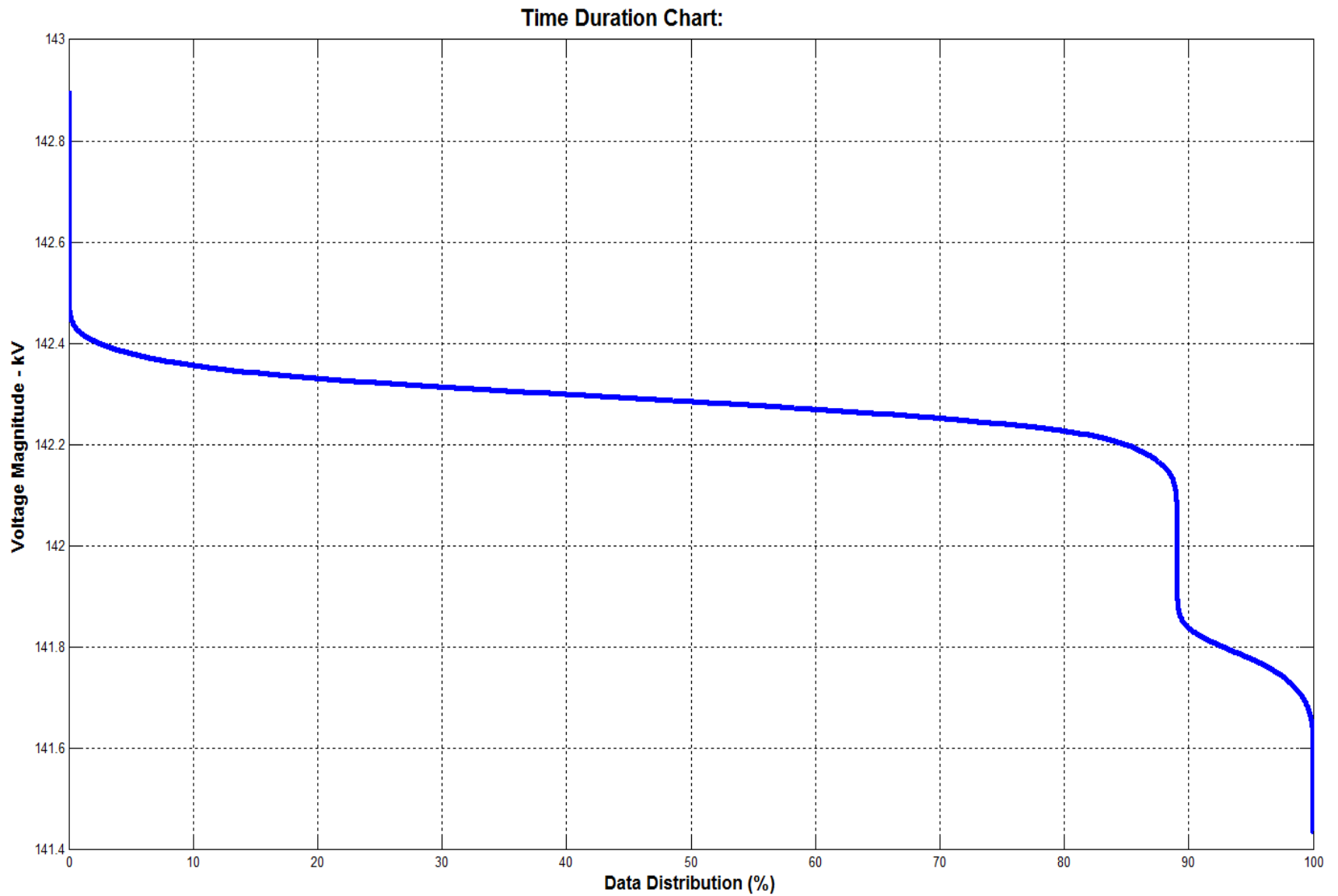


South 3

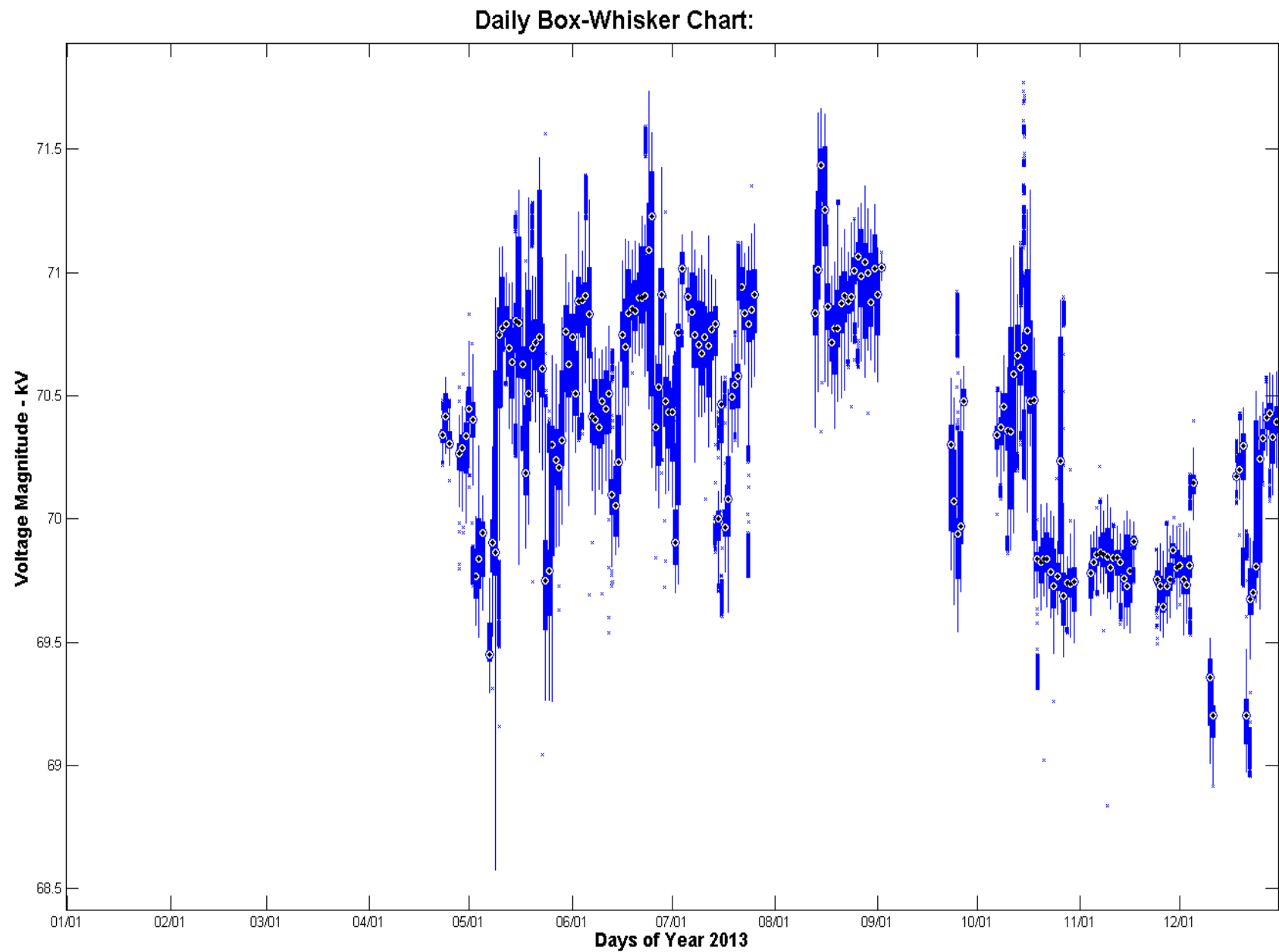
Daily Box-Whisker Chart:



South 3

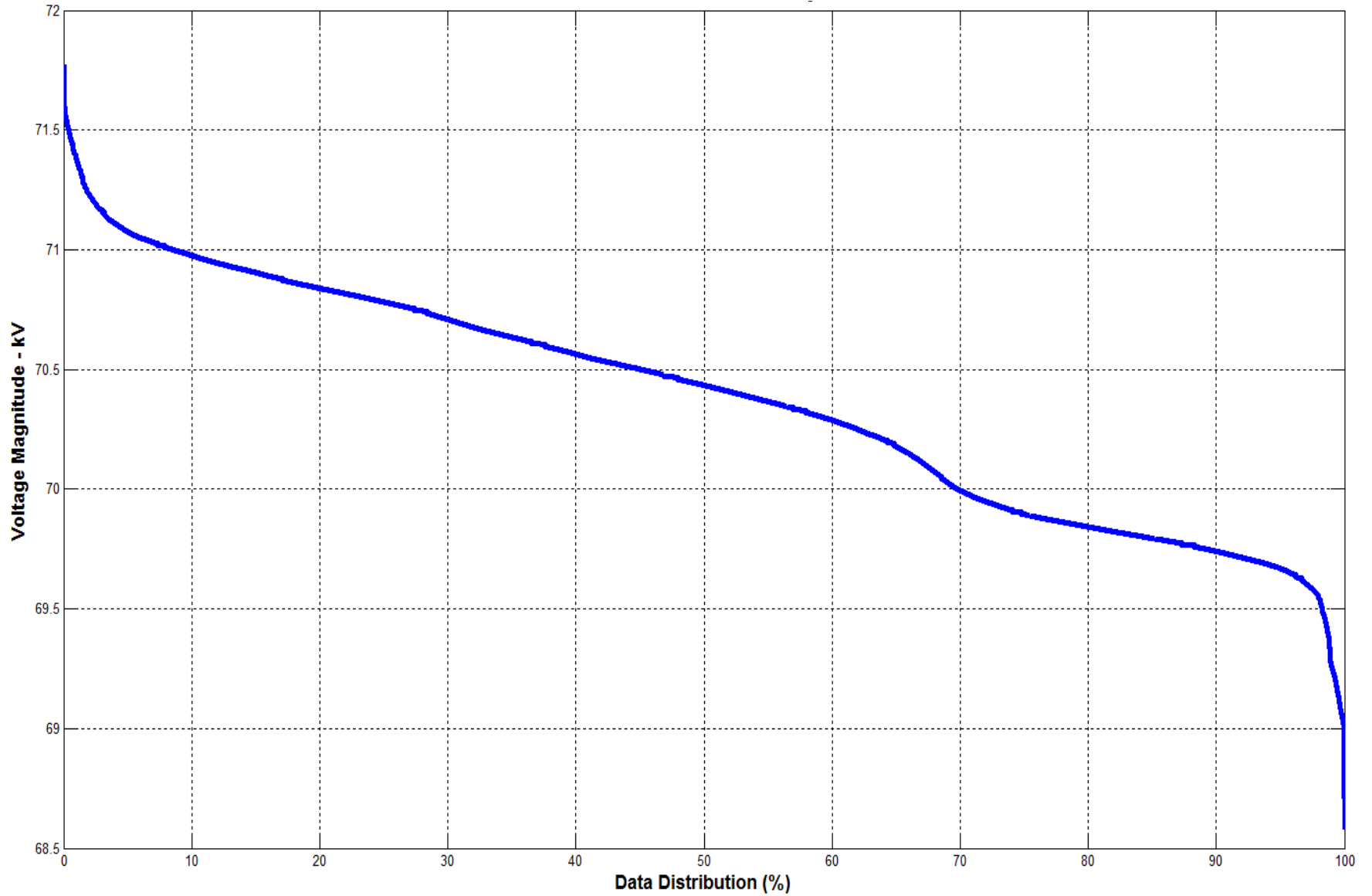


South 5



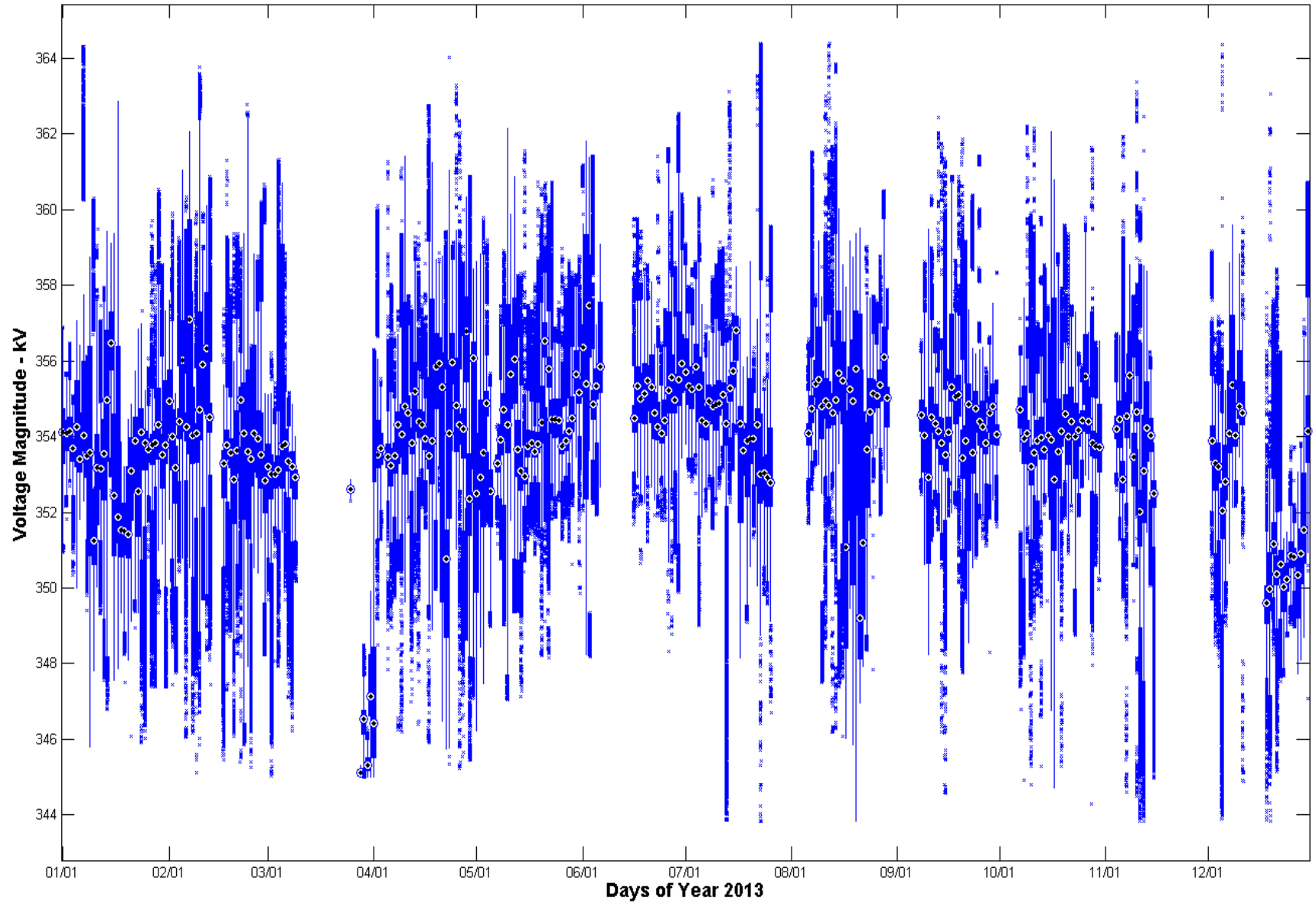
South 5

Time Duration Chart:

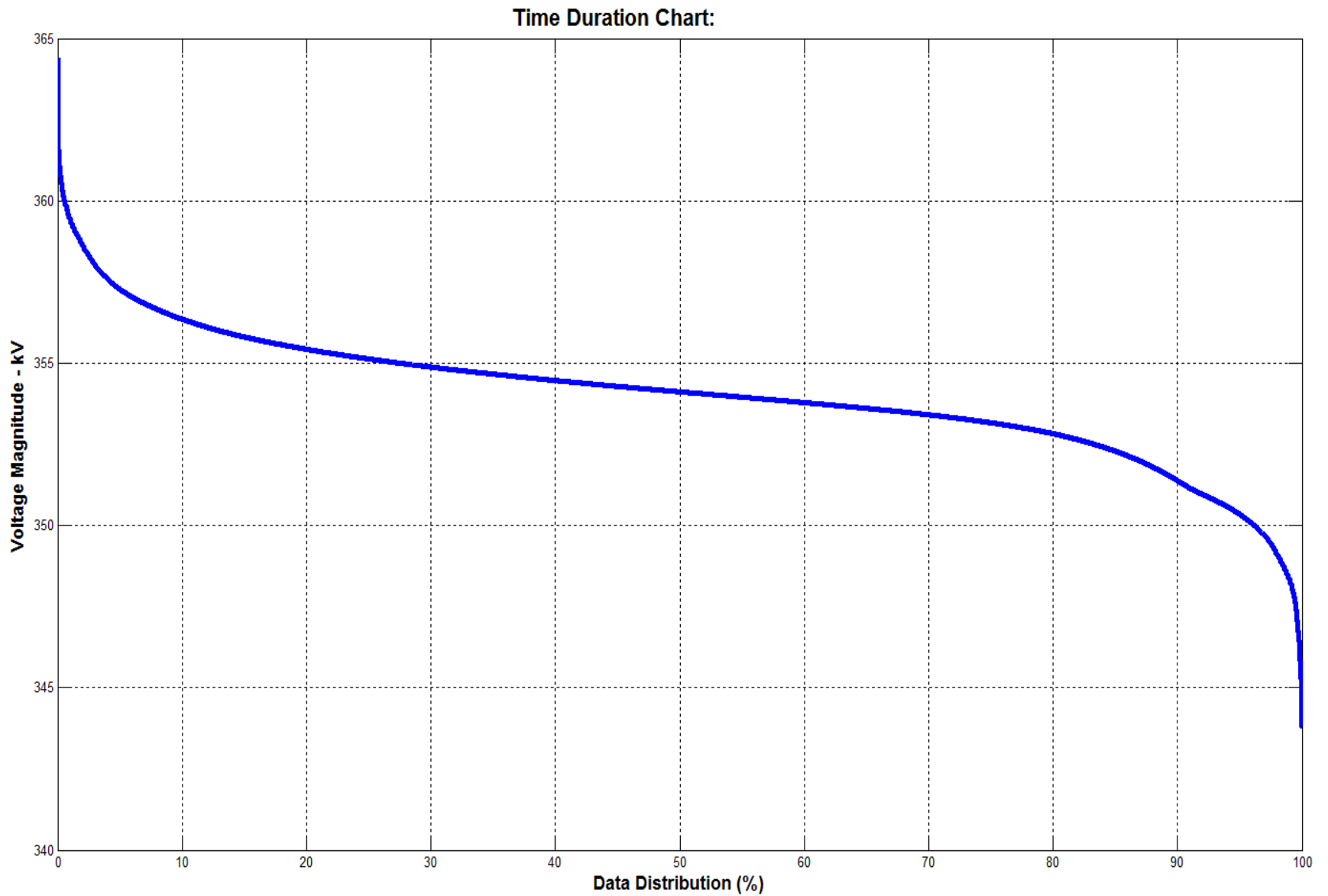


Coast 4

Daily Box-Whisker Chart:

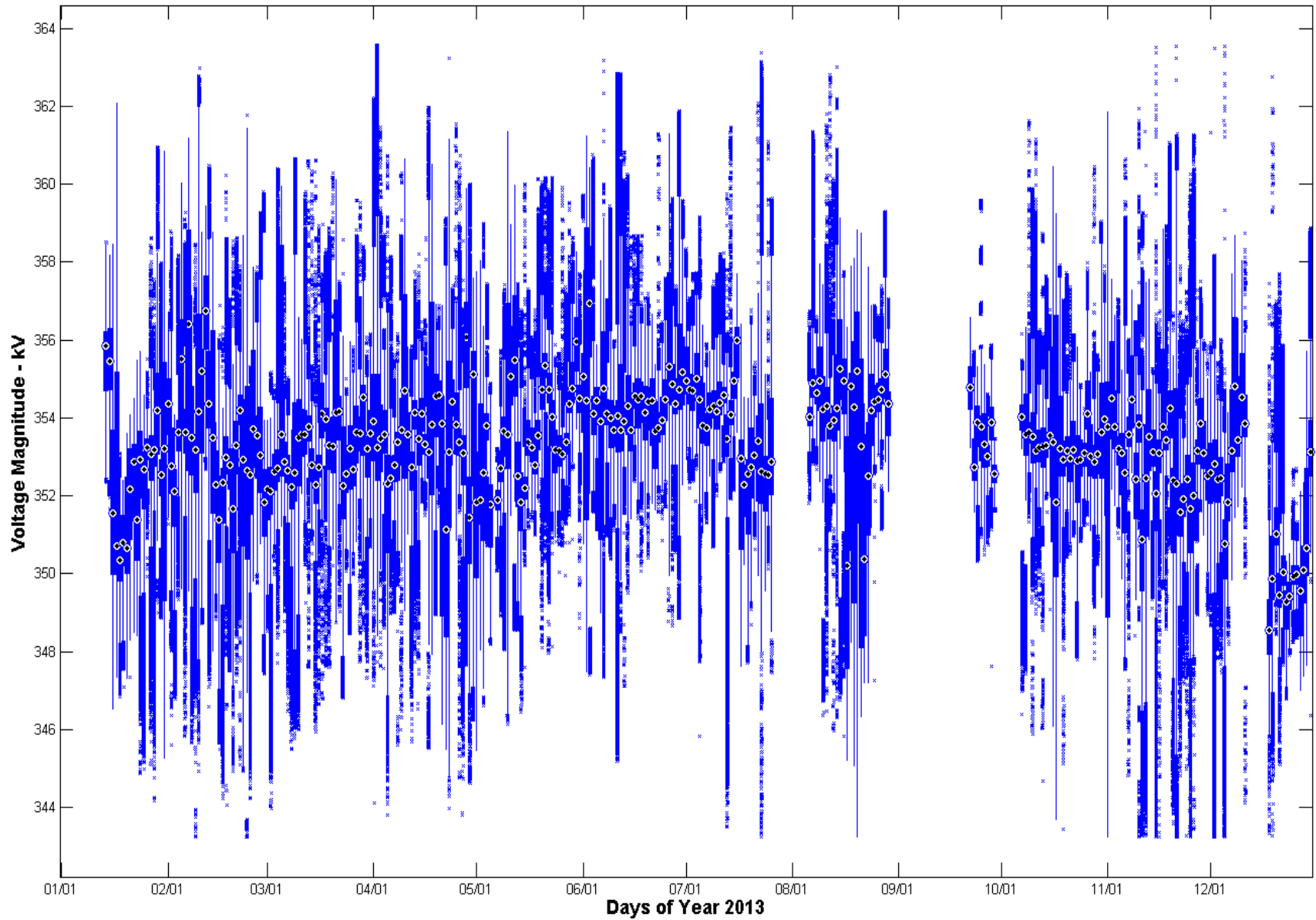


Coast 4



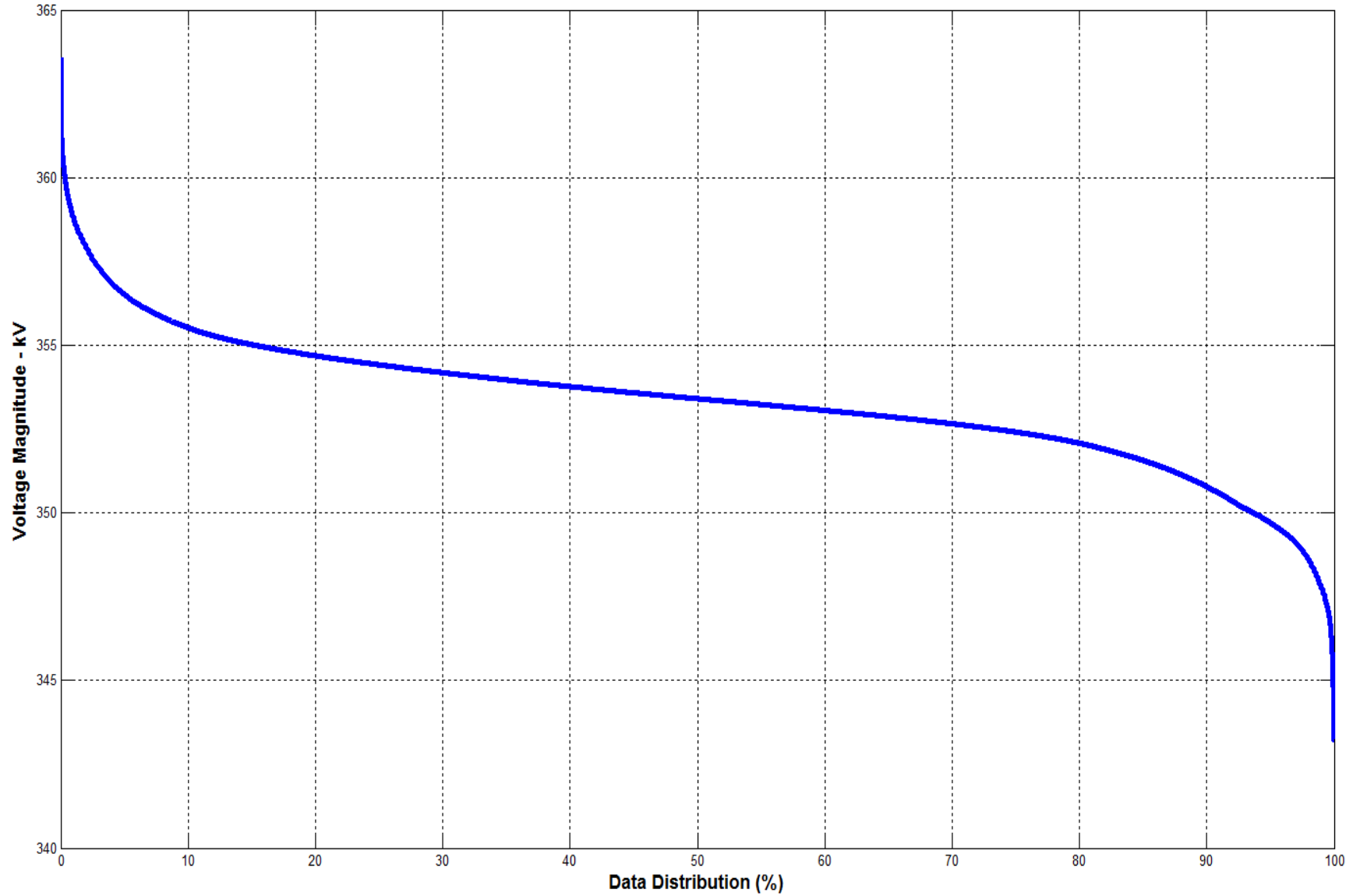
Coast 3

Daily Box-Whisker Chart:



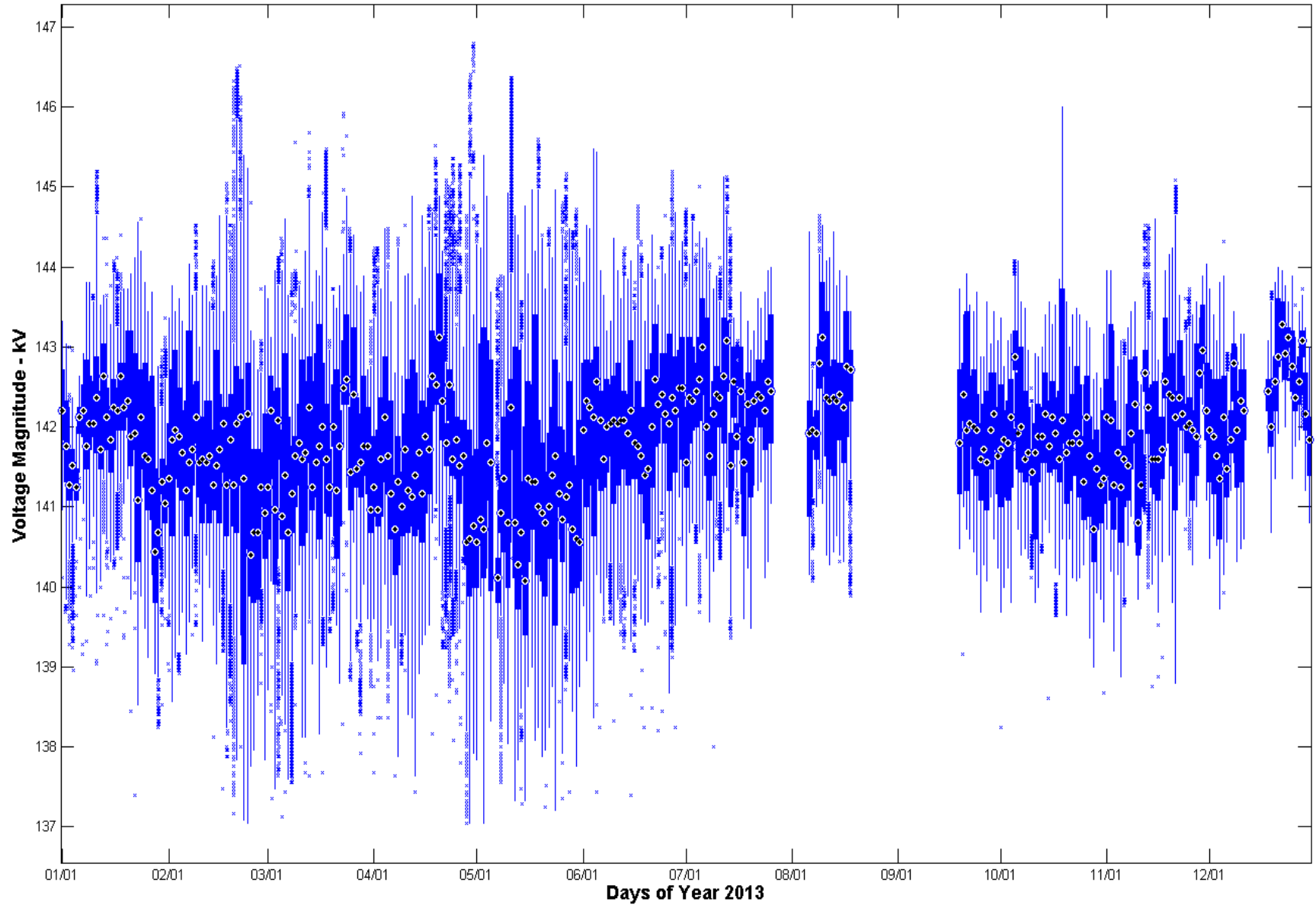
Coast 3

Time Duration Chart:



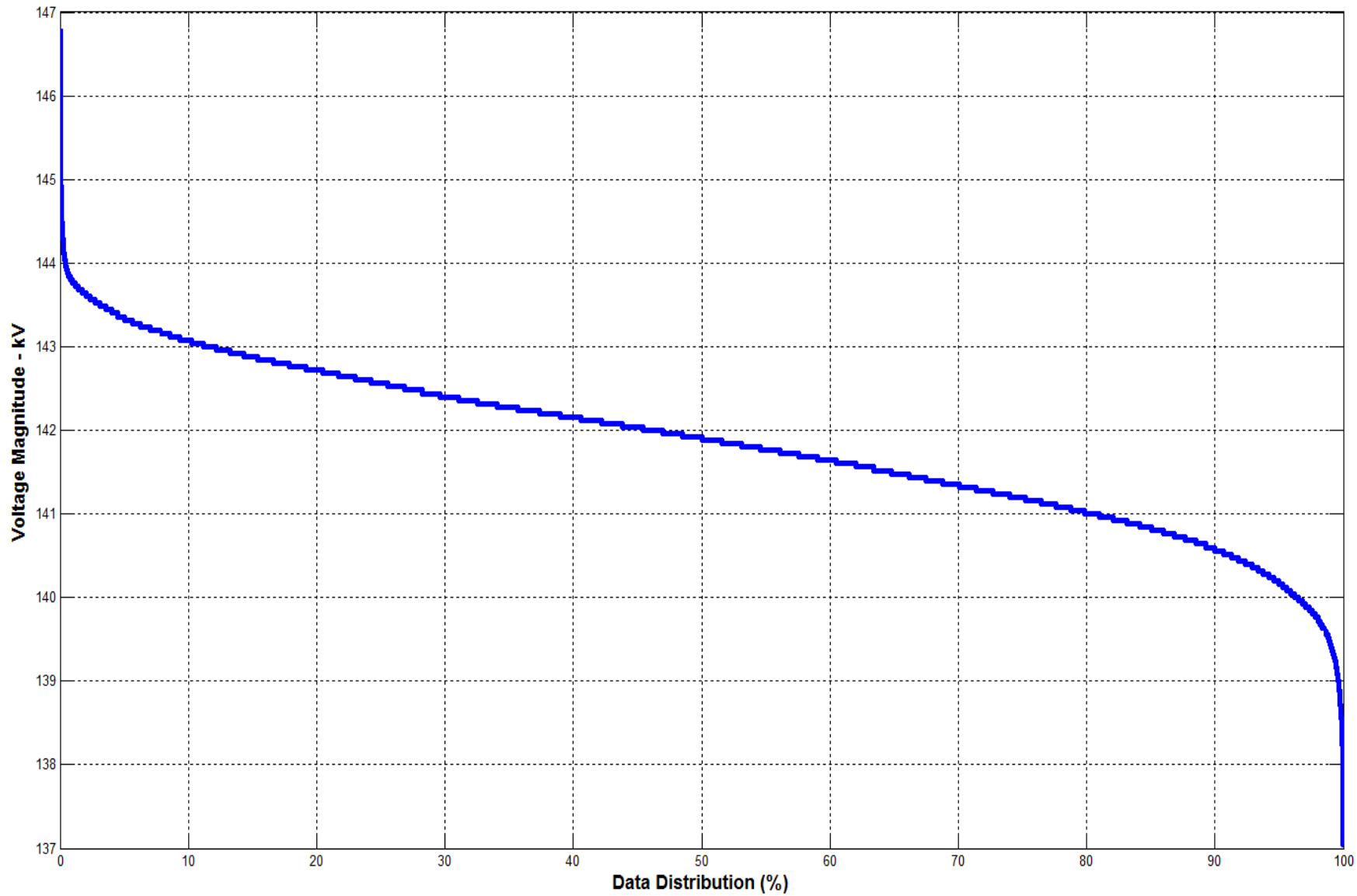
South 13

Daily Box-Whisker Chart:



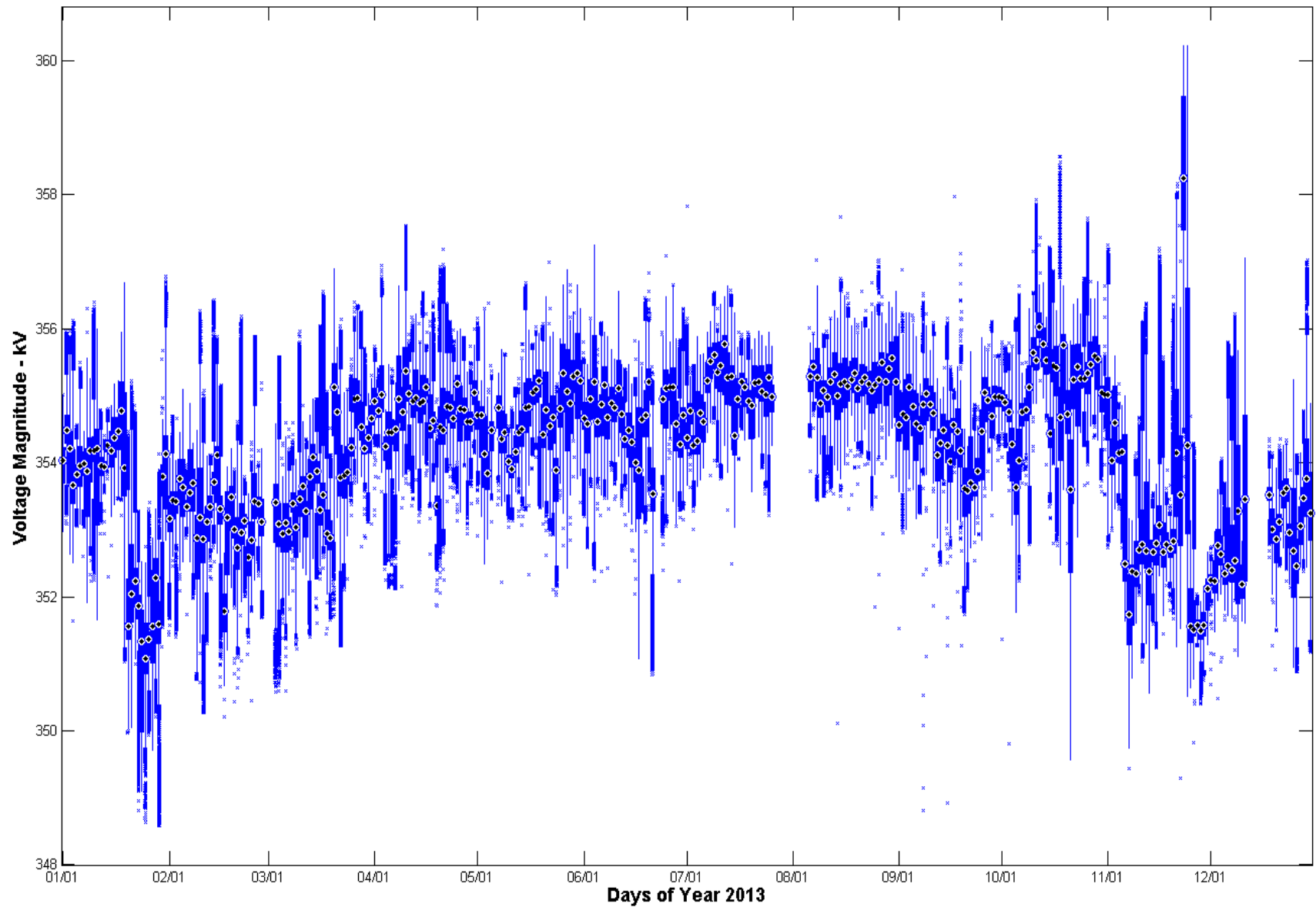
South 13

Time Duration Chart:



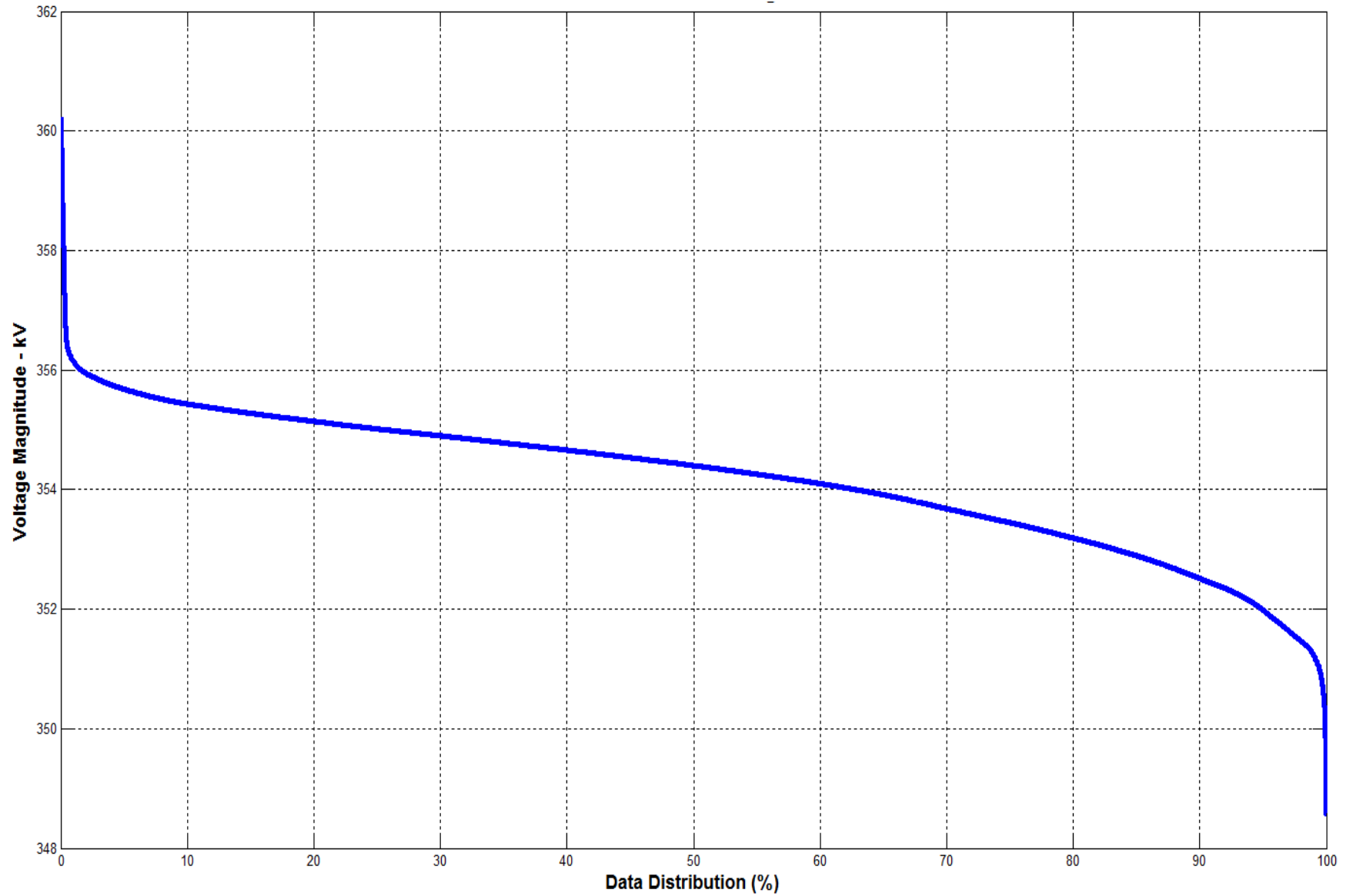
FarWest 4

Daily Box-Whisker Chart:



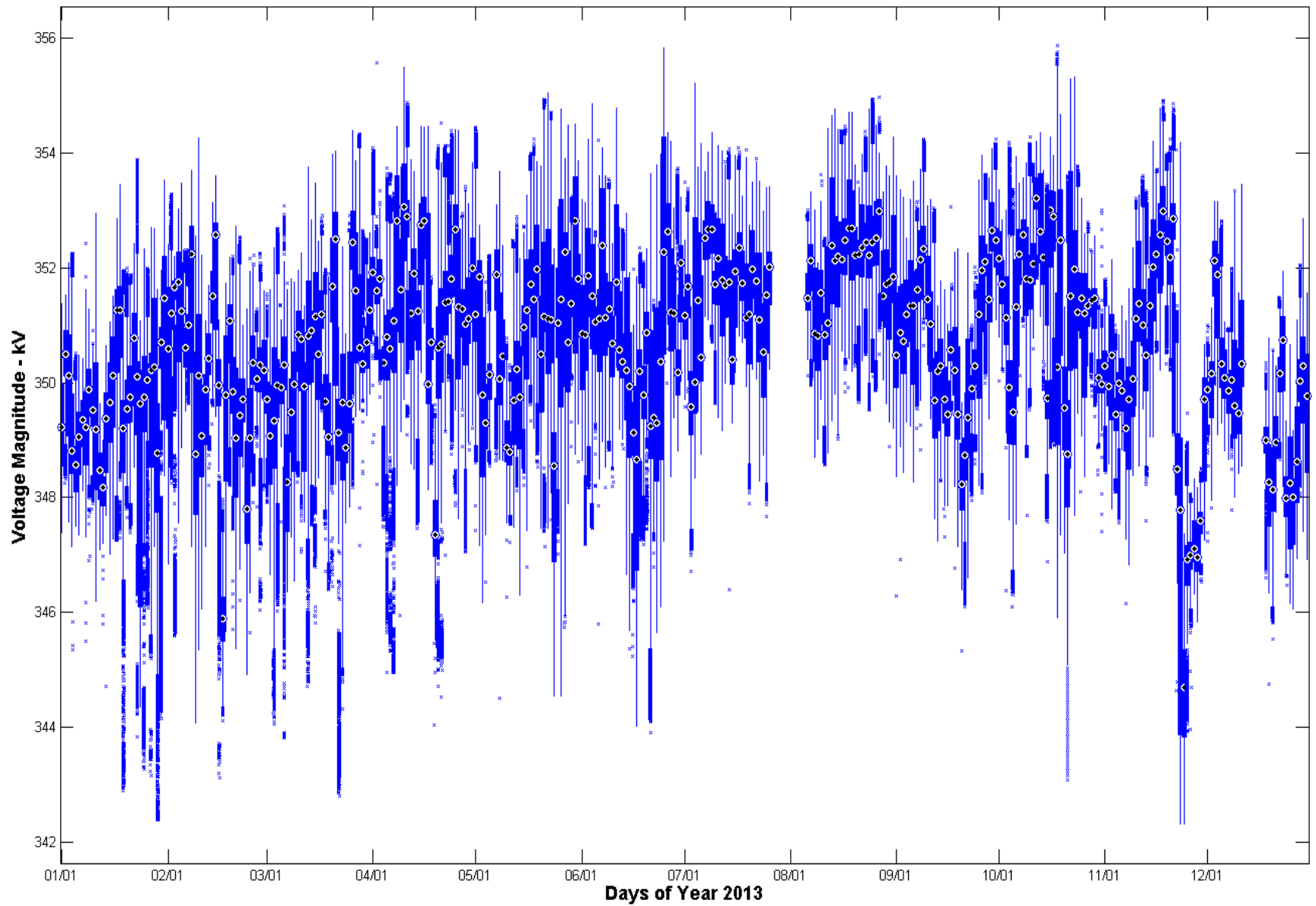
FarWest 4

Time Duration Chart:

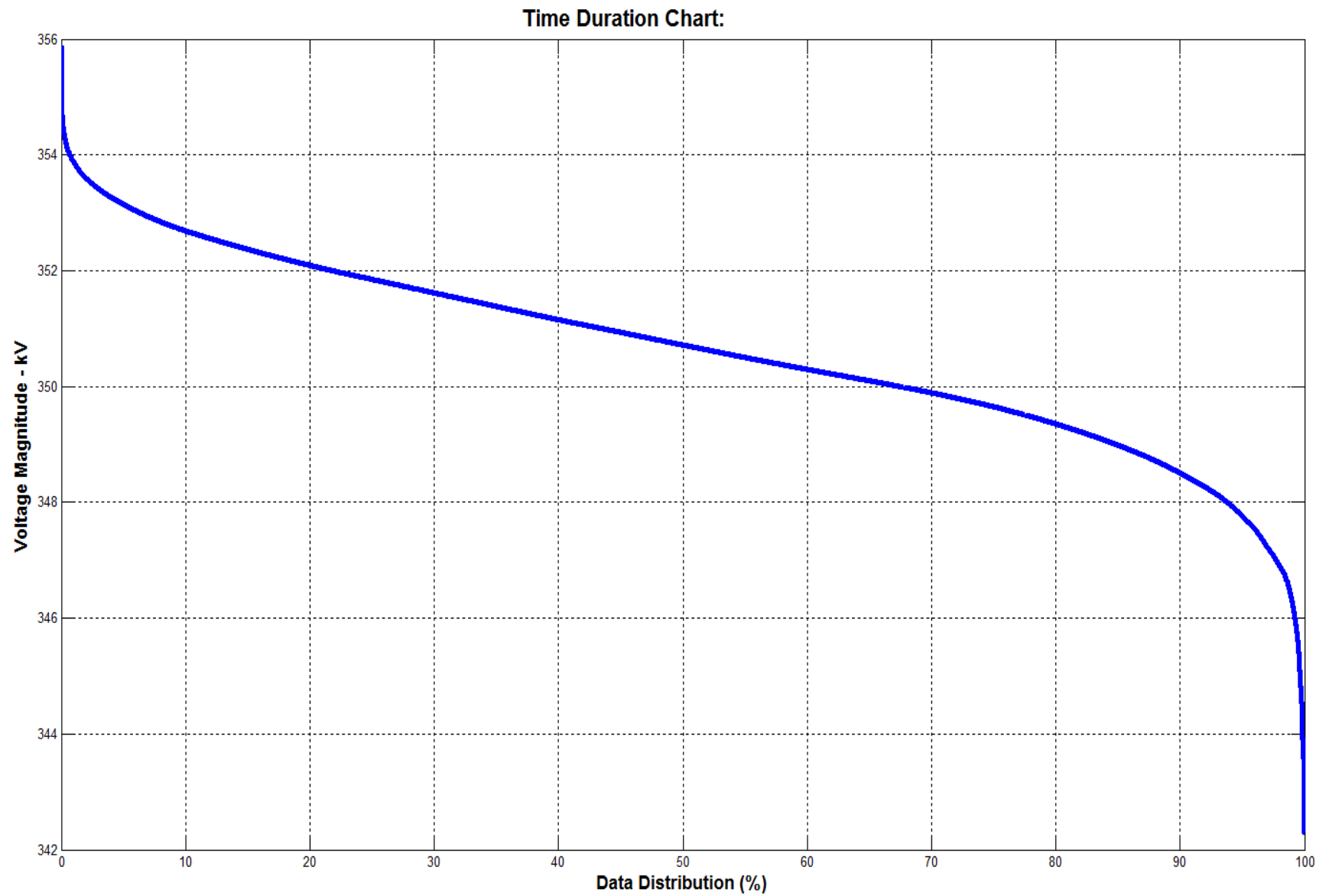


FarWest 7

Daily Box-Whisker Chart:

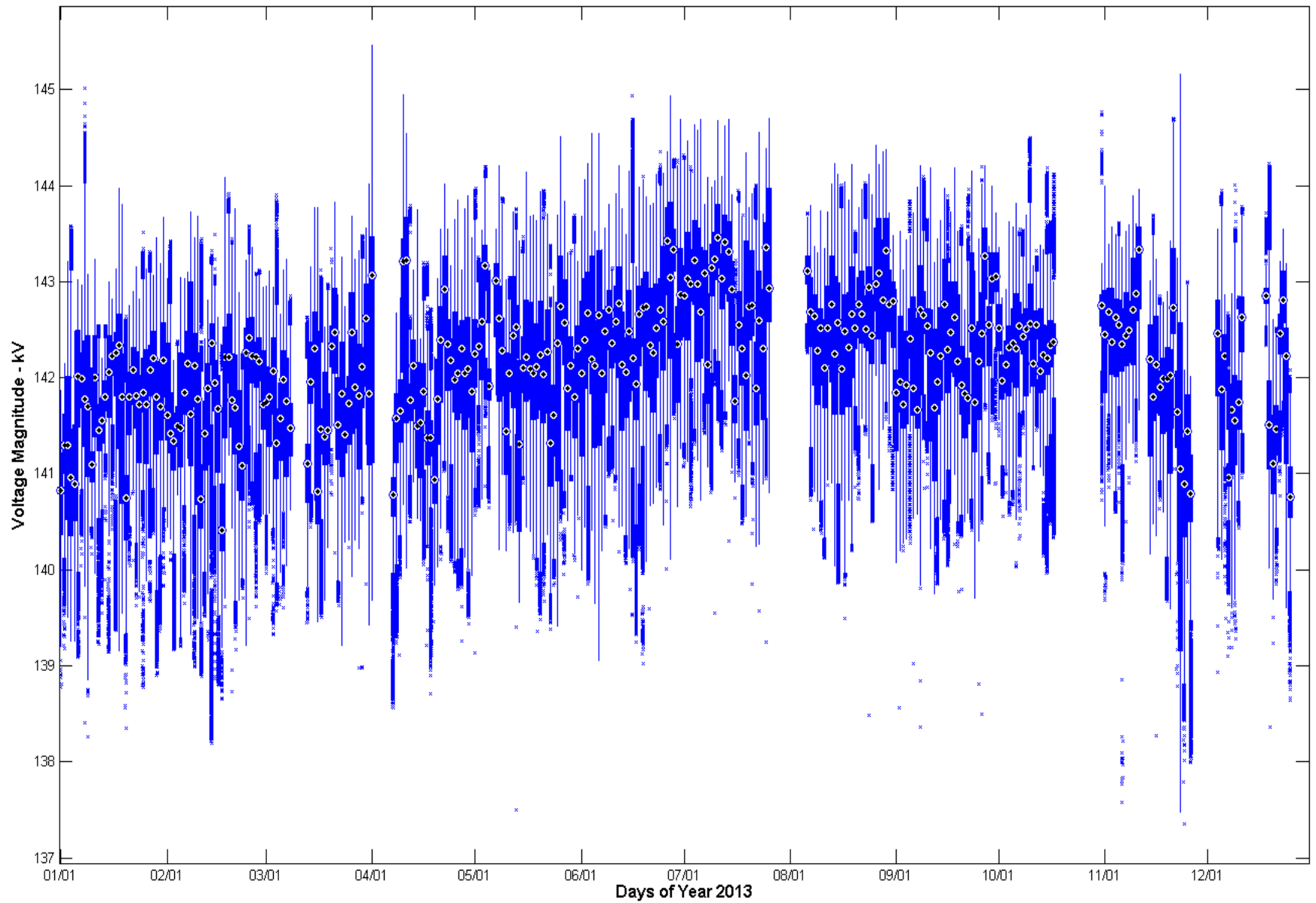


FarWest 7



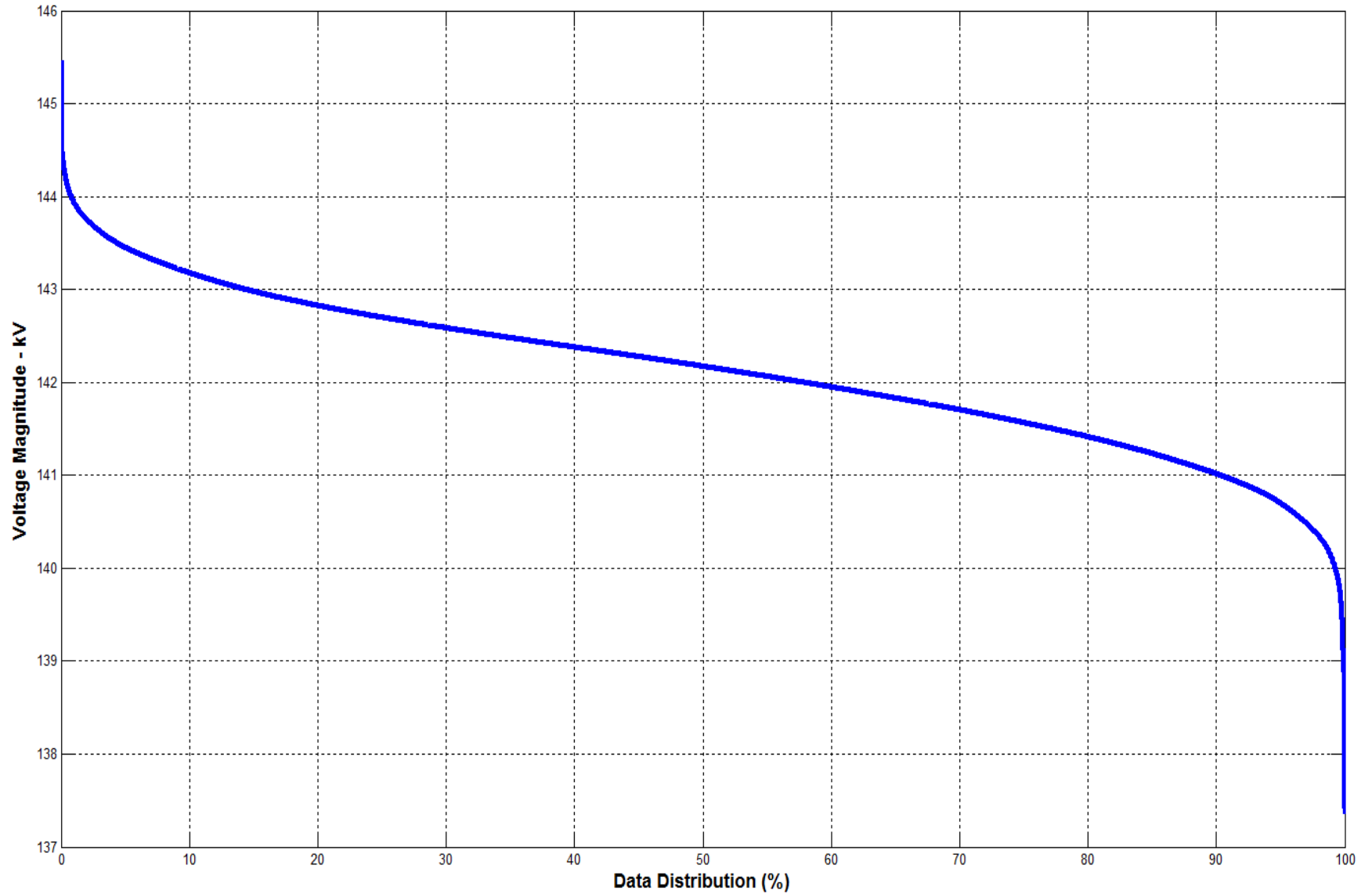
FarWest 8

Daily Box-Whisker Chart:



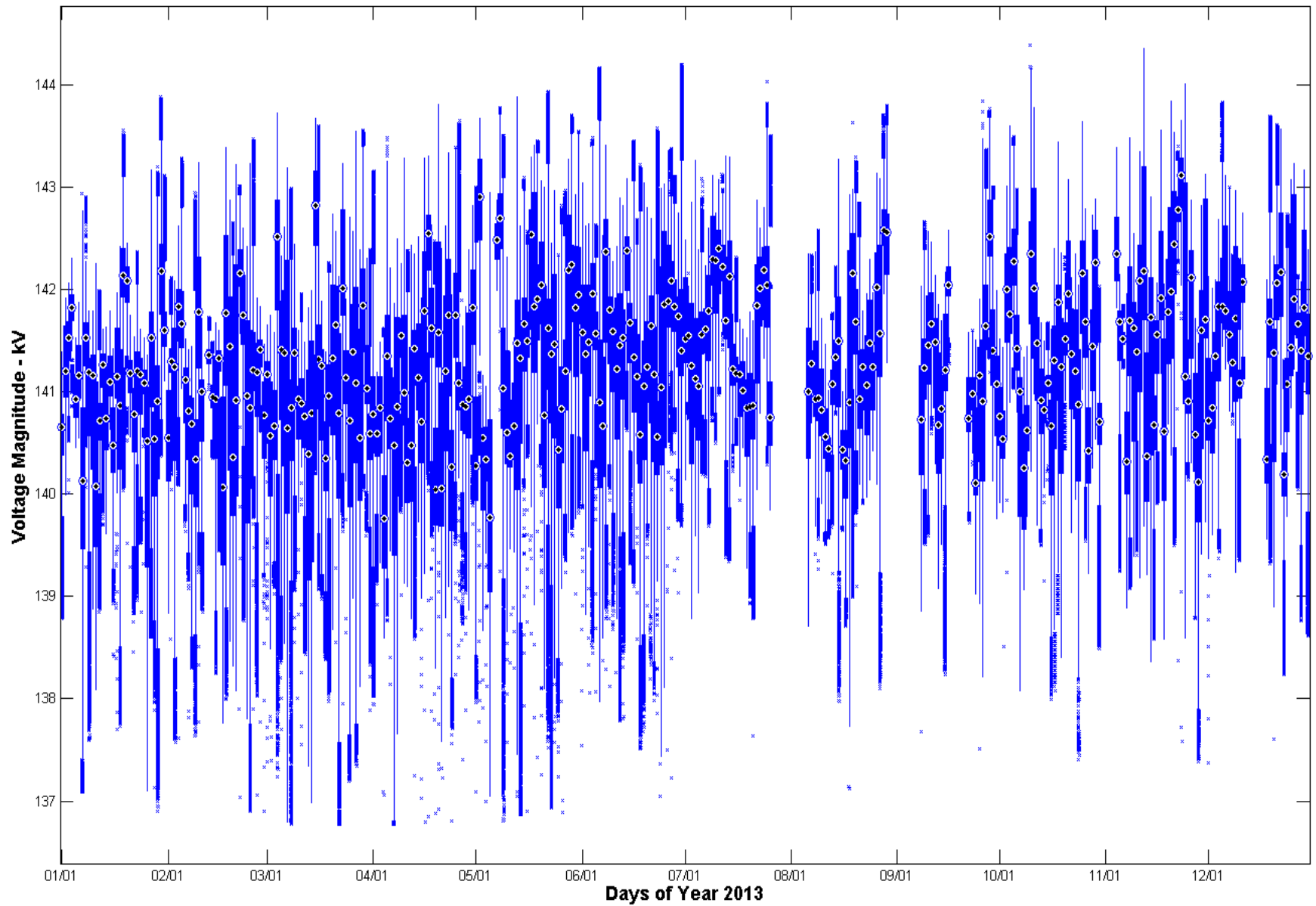
FarWest 8

Time Duration Chart:



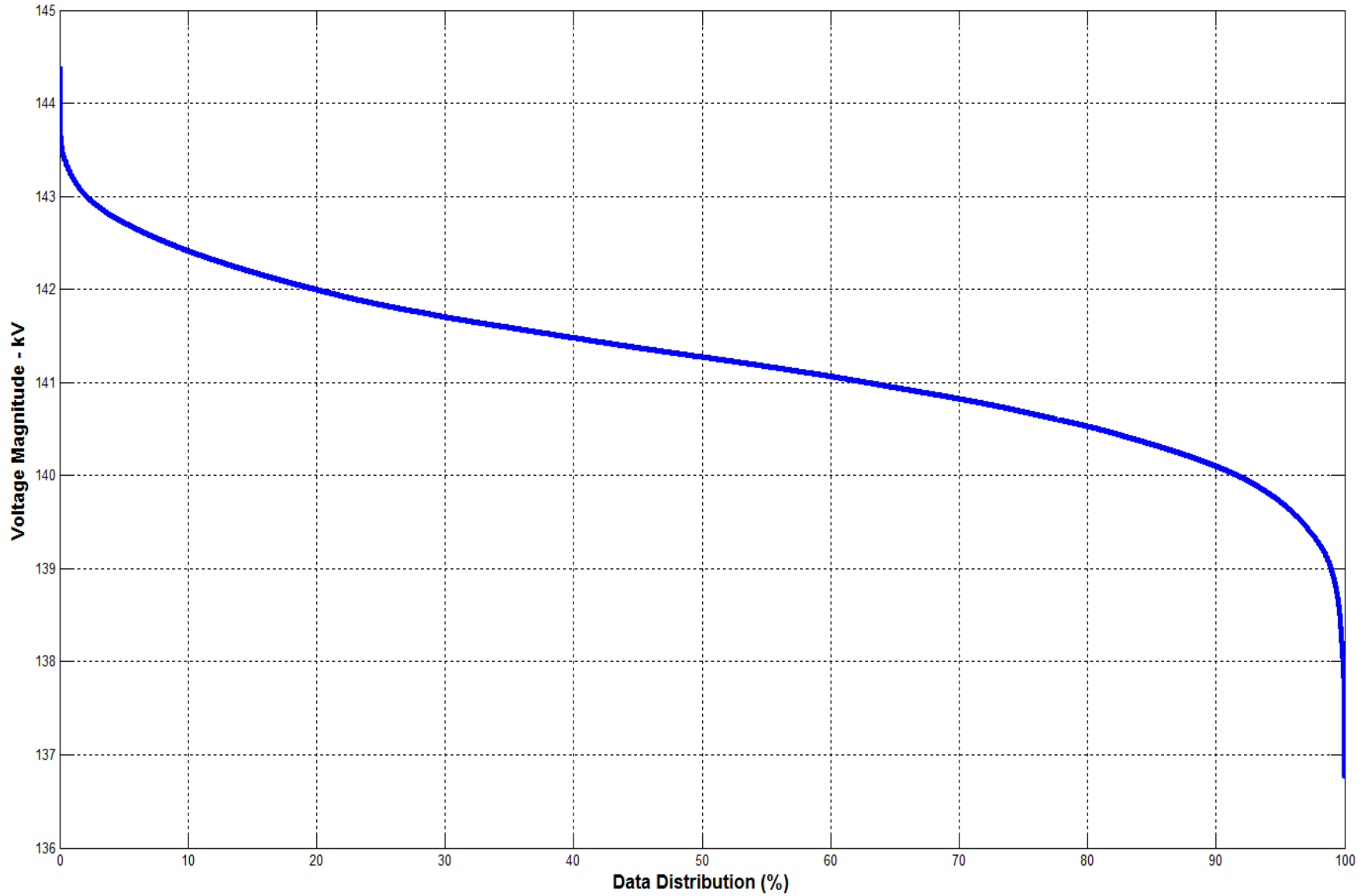
FarWest 9

Daily Box-Whisker Chart:



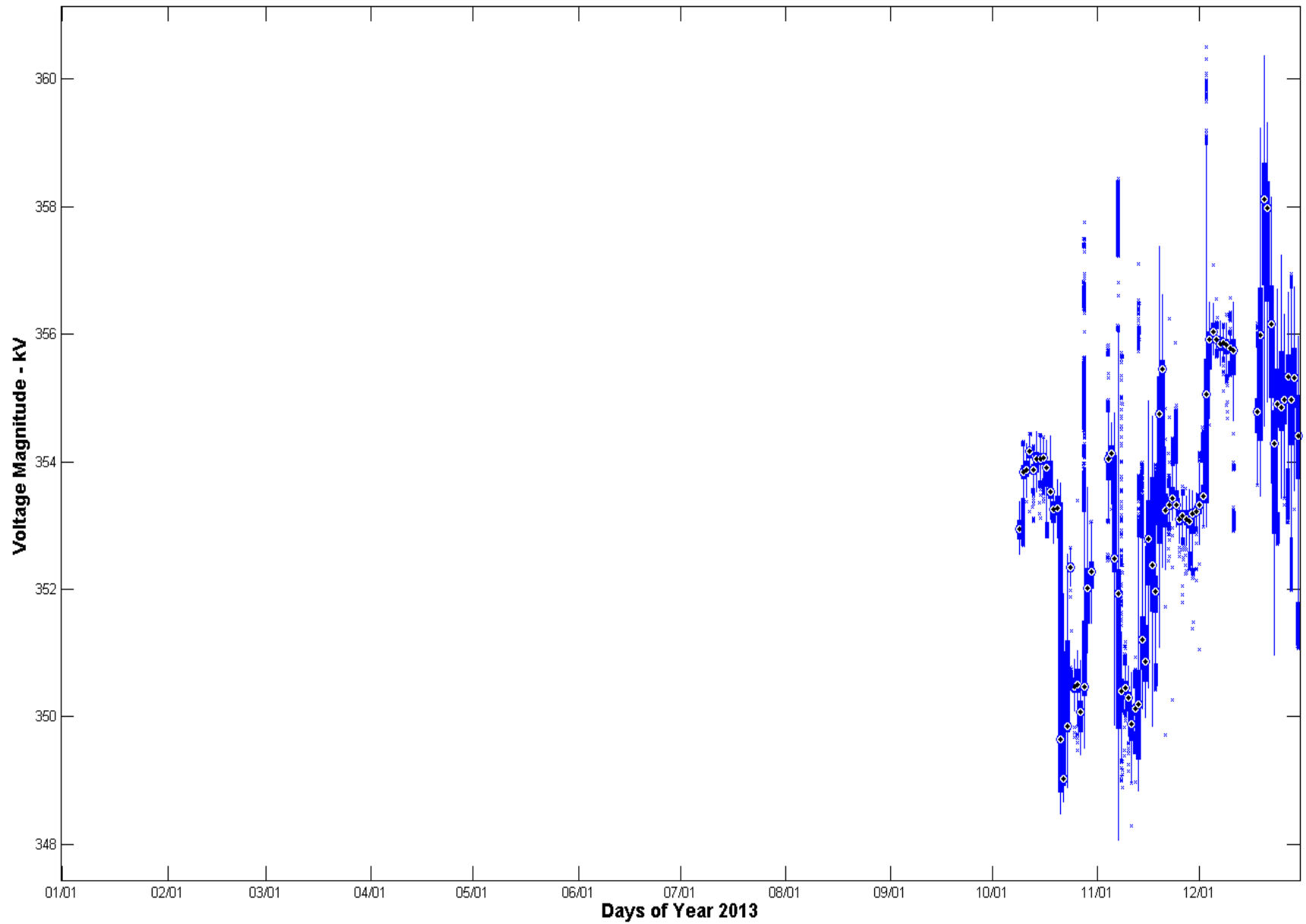
FarWest 9

Time Duration Chart:



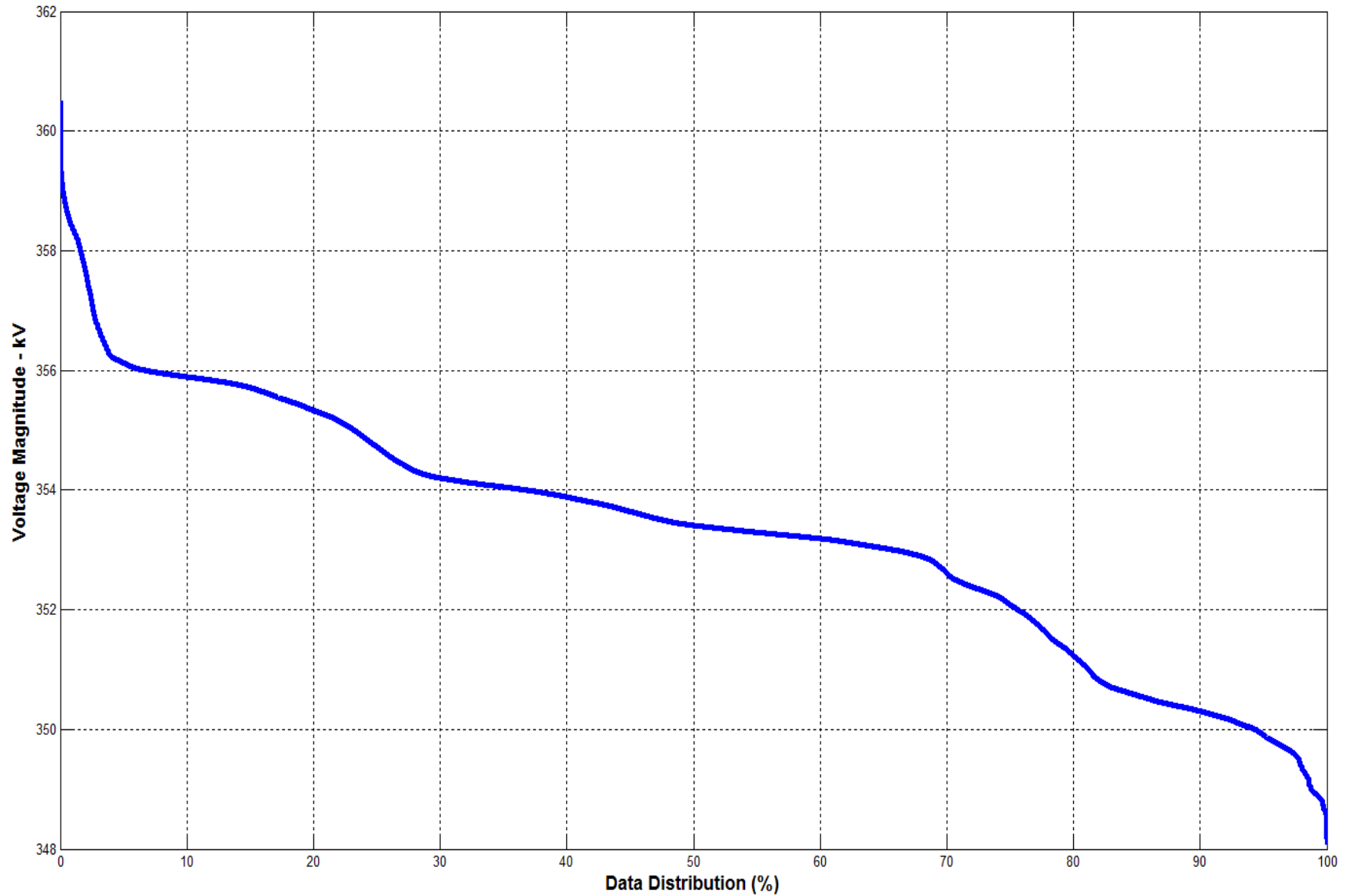
West 15

Daily Box-Whisker Chart:



West 15

Time Duration Chart:

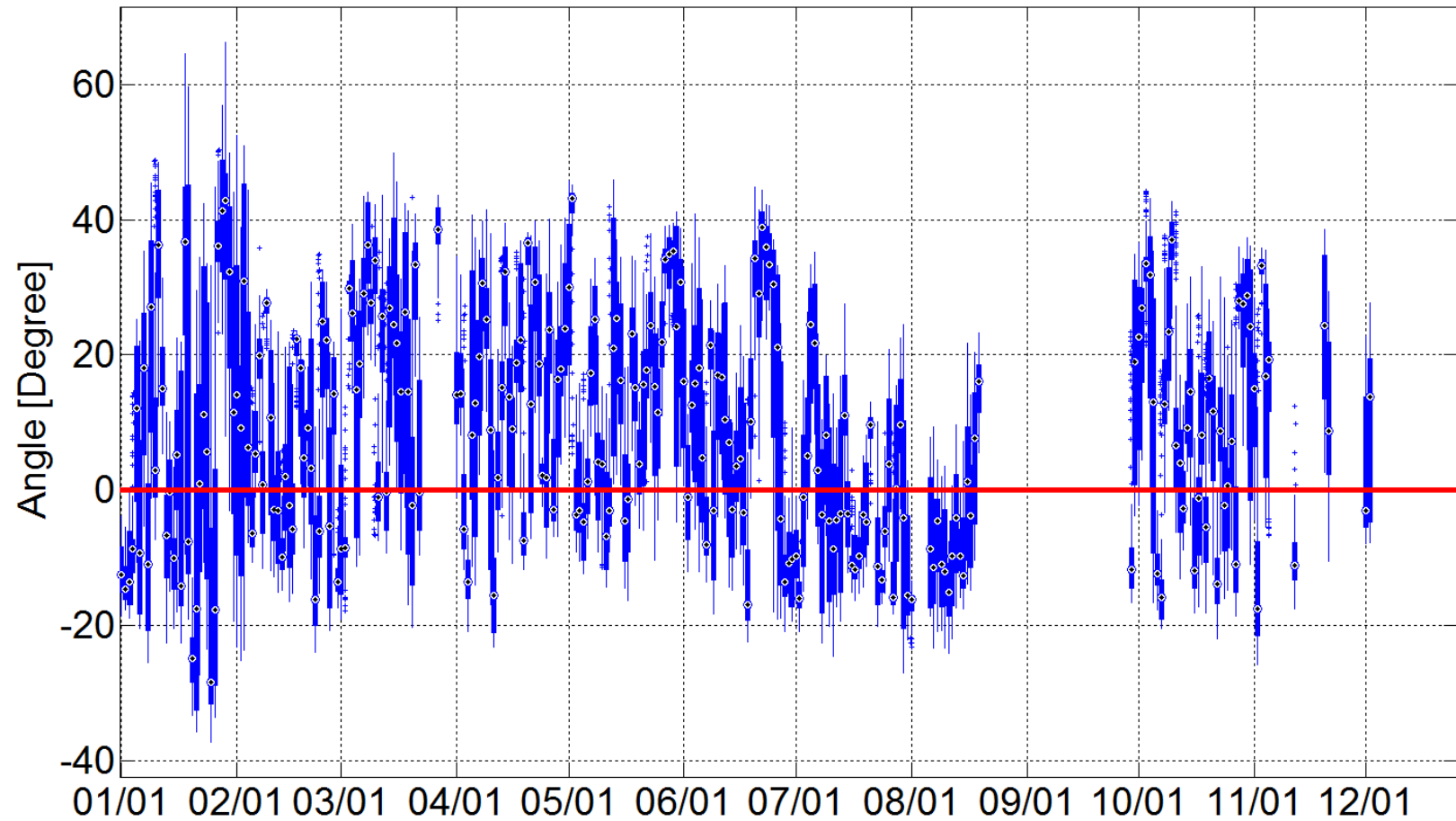


Appendix B – Part 1
CCET Discovery Across Texas project

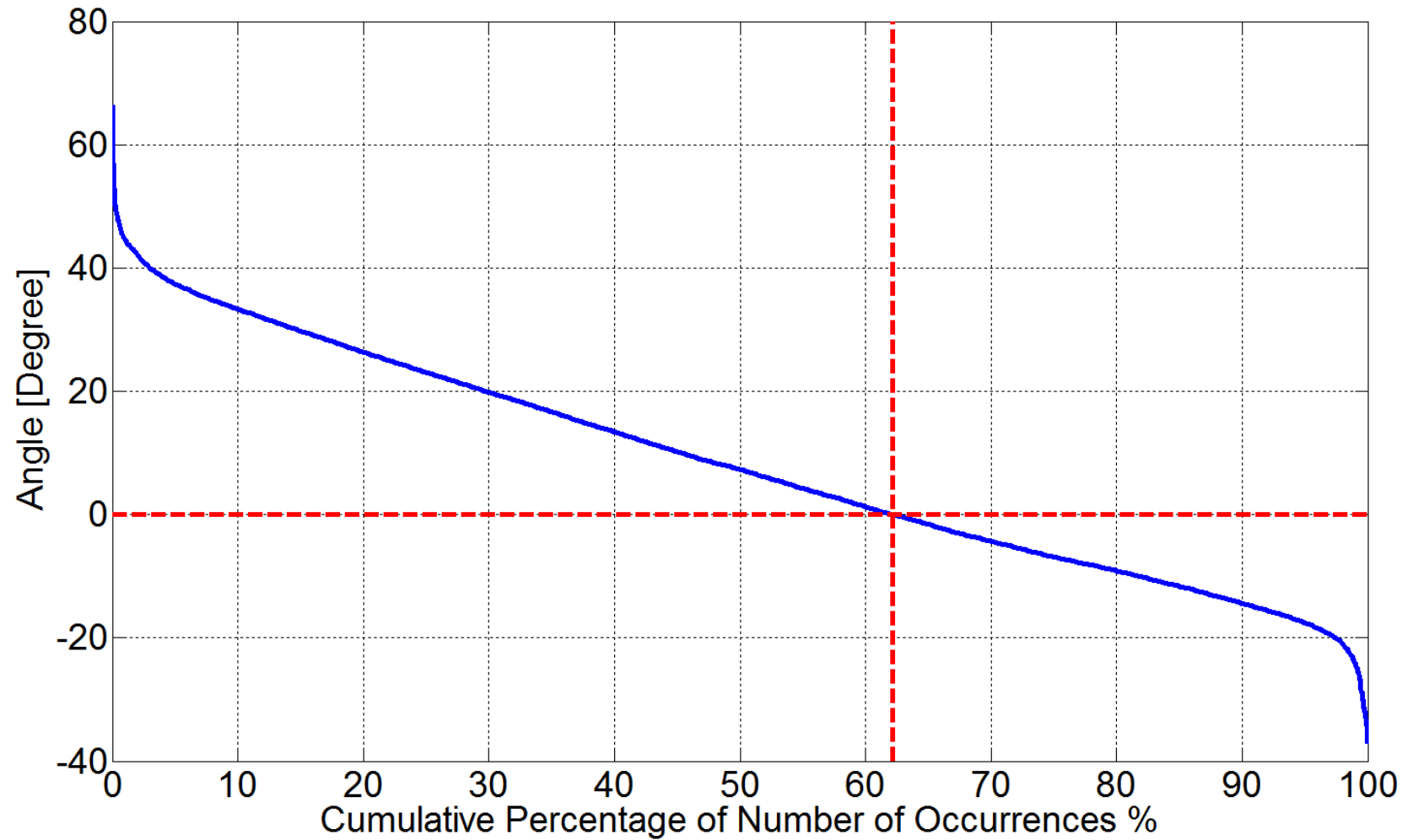
**Baseline Analysis Update - Voltage Angles
(Ref.: North 7)**

State Estimator Data: January to December 2013
Box Whiskers Plots and Time Duration Curves

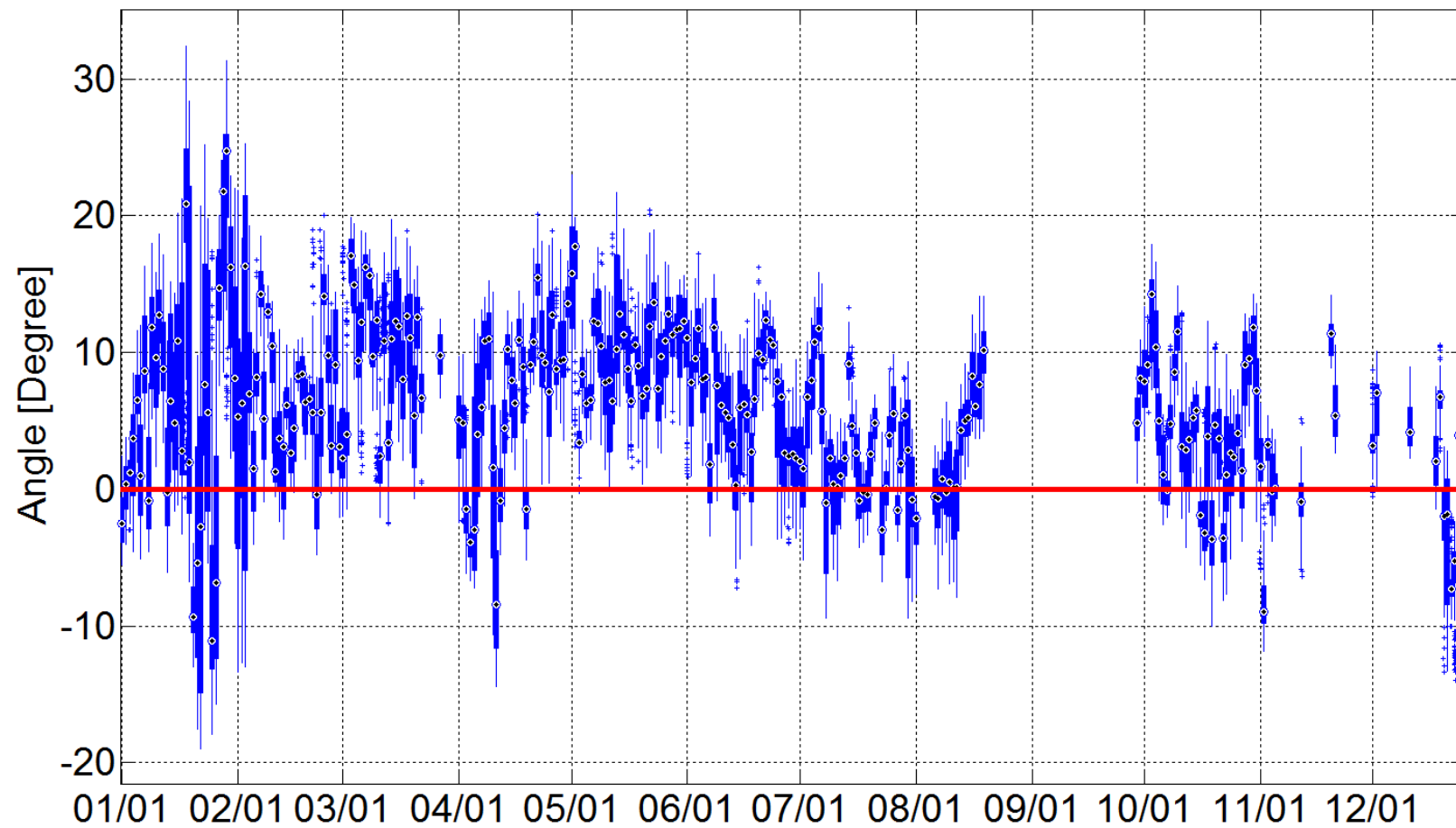
West 10-North 7



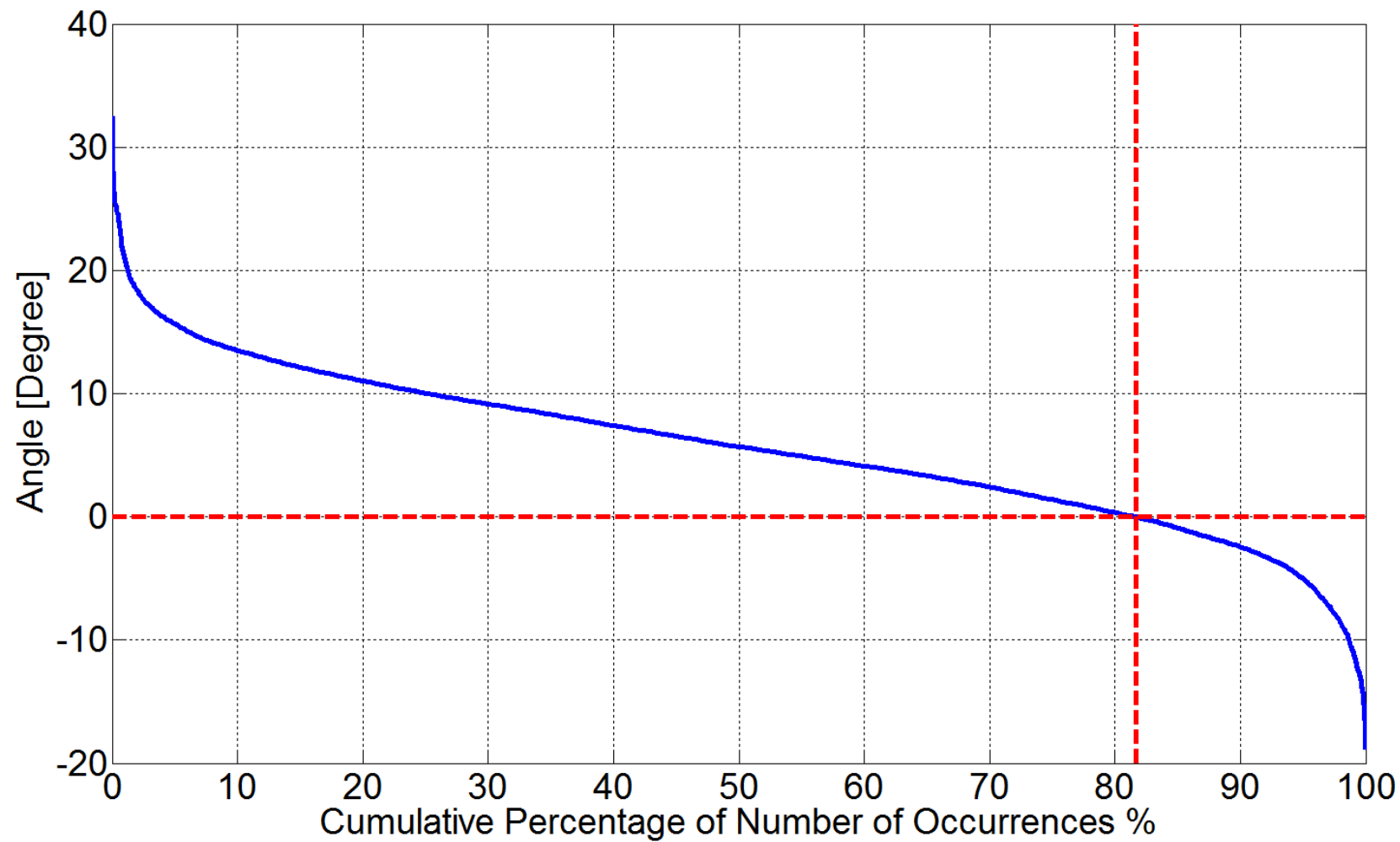
West 10-North 7



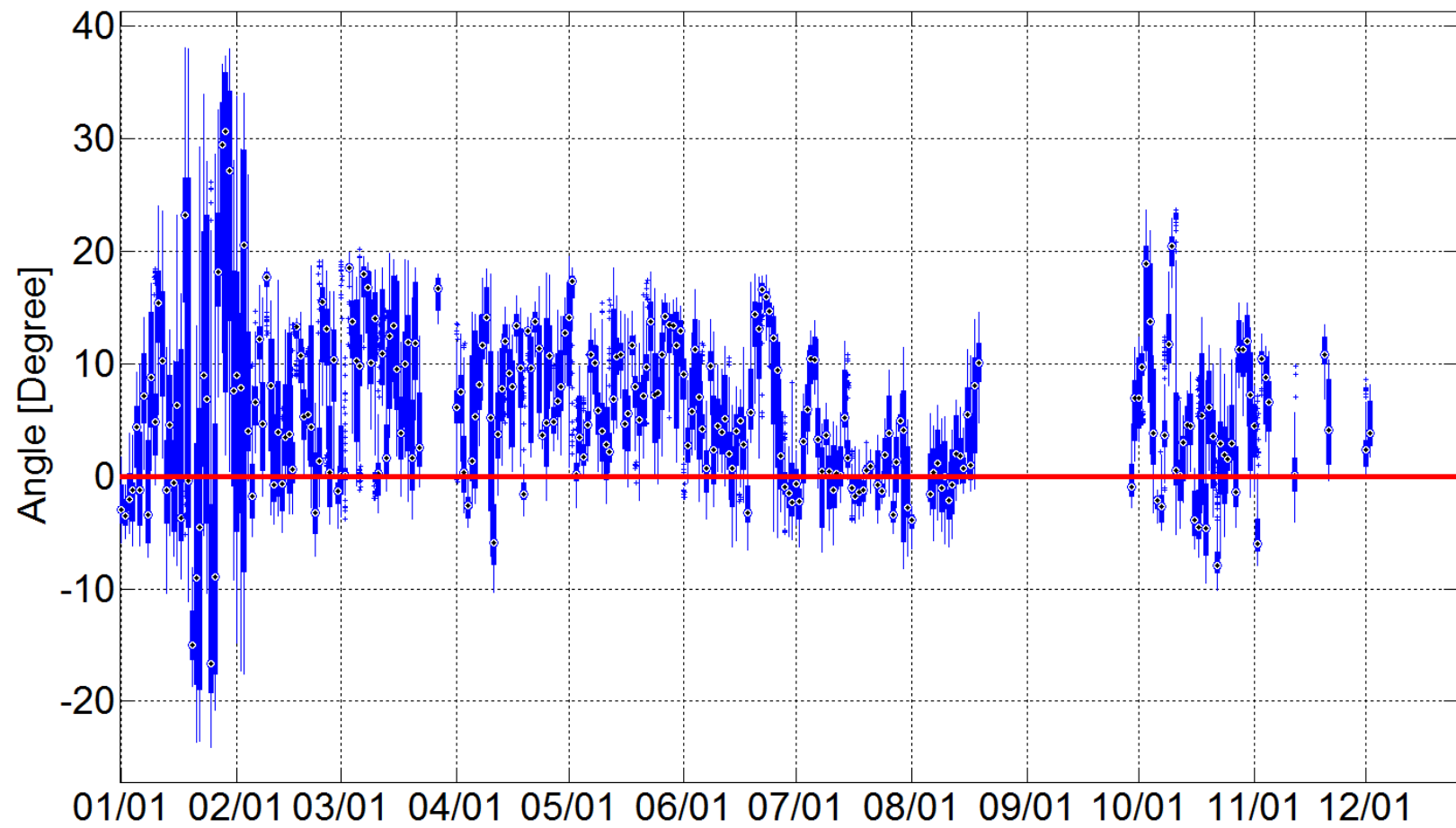
West 14-North 7



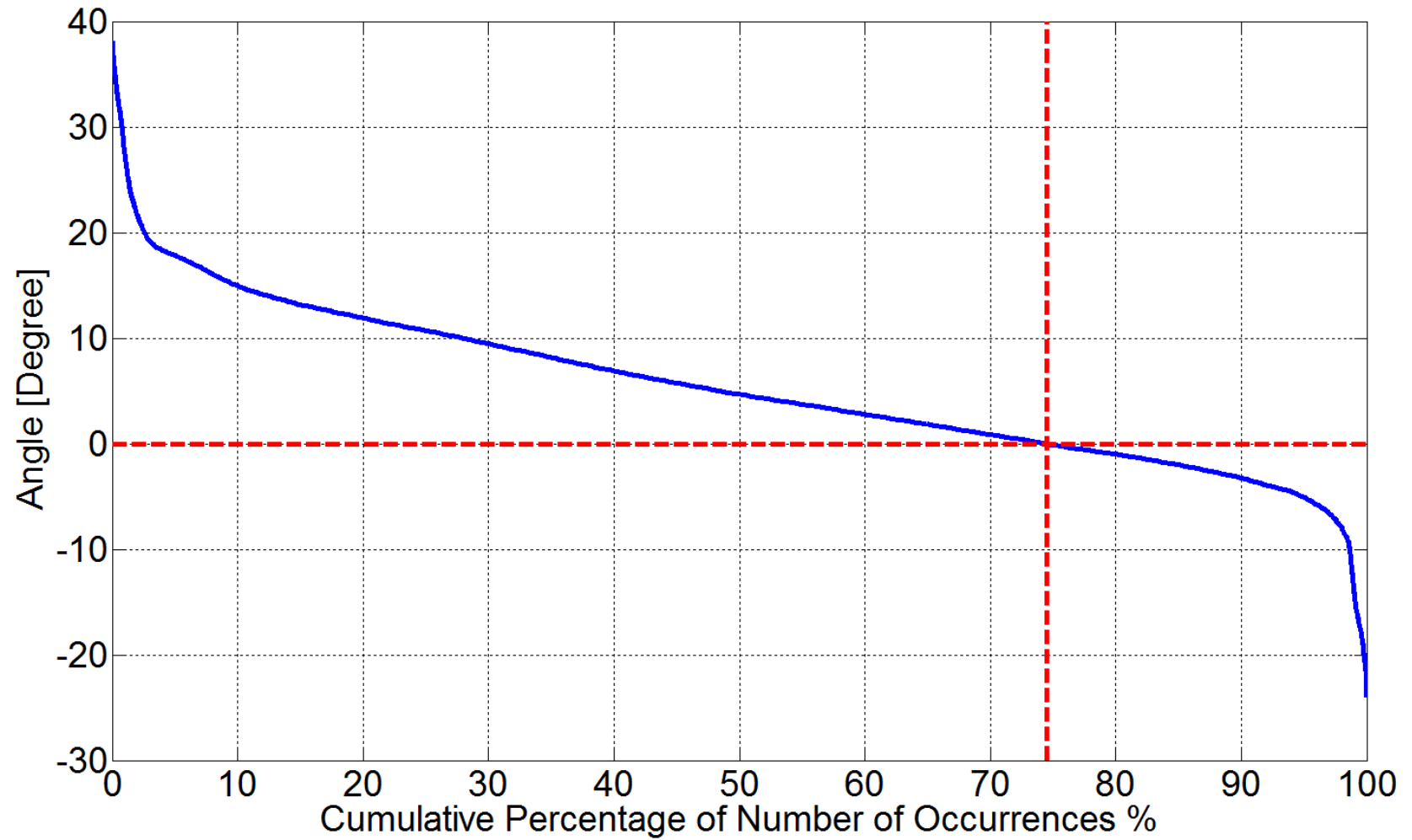
West 14-North 7



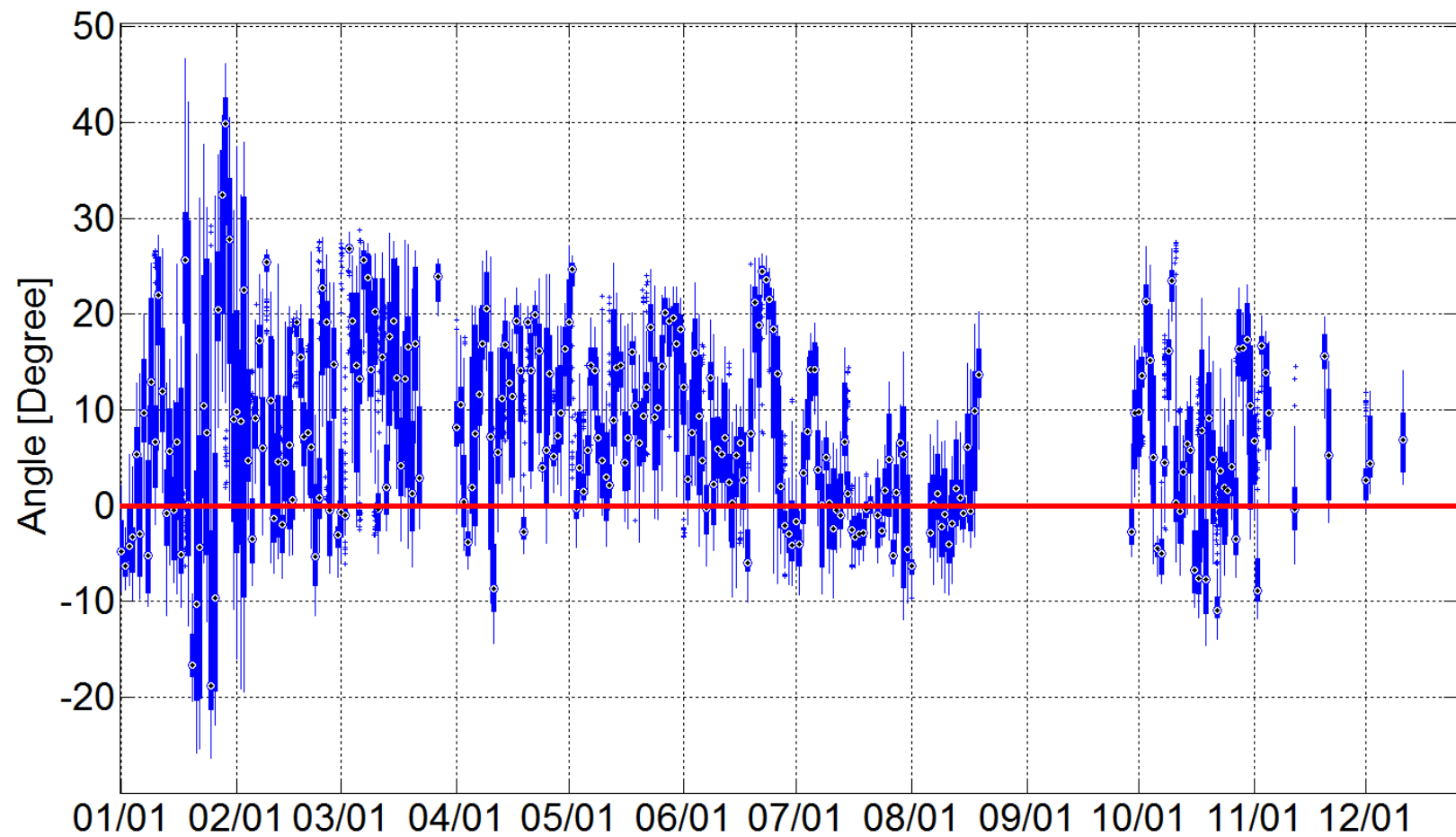
West 1-North 7



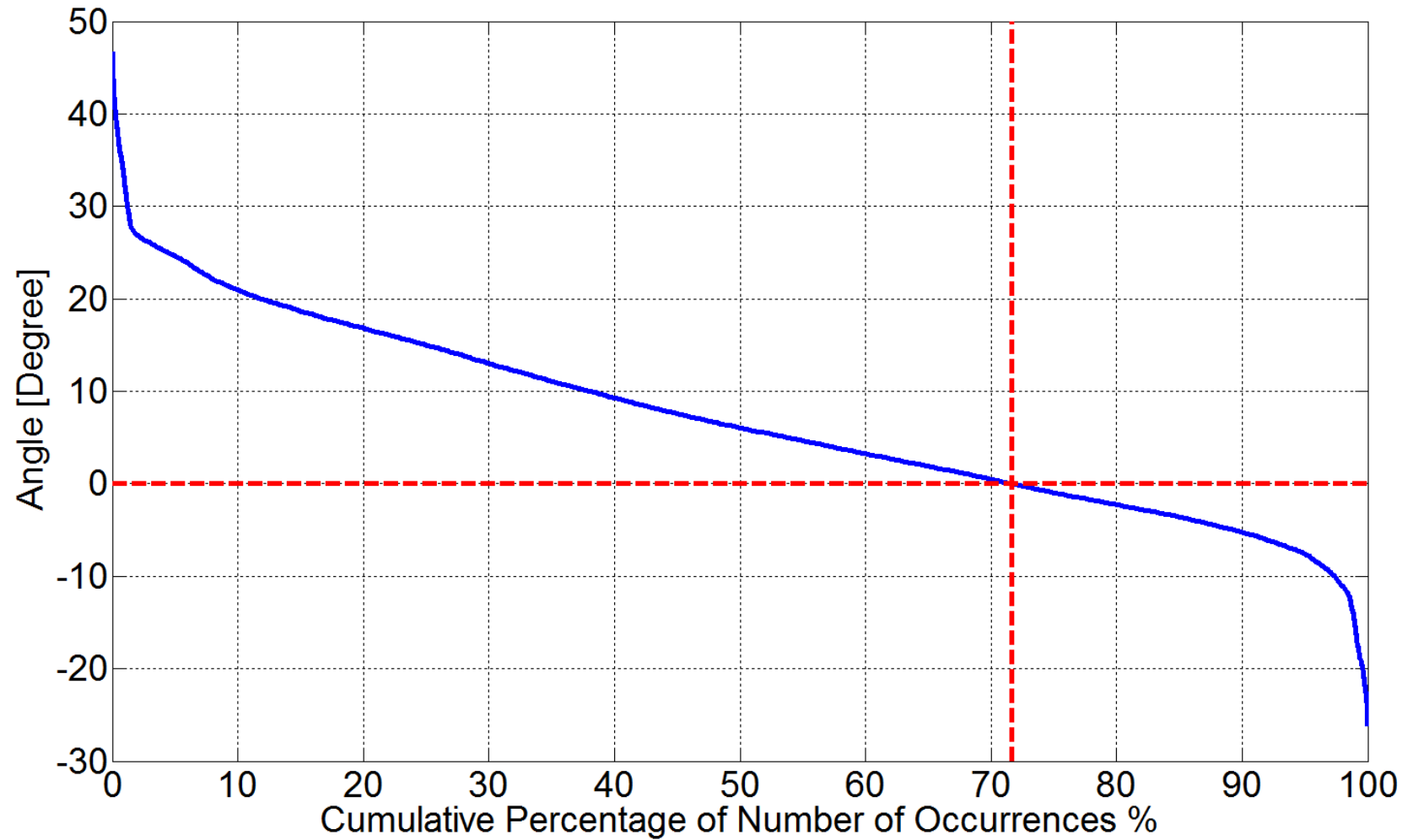
West 1-North 7



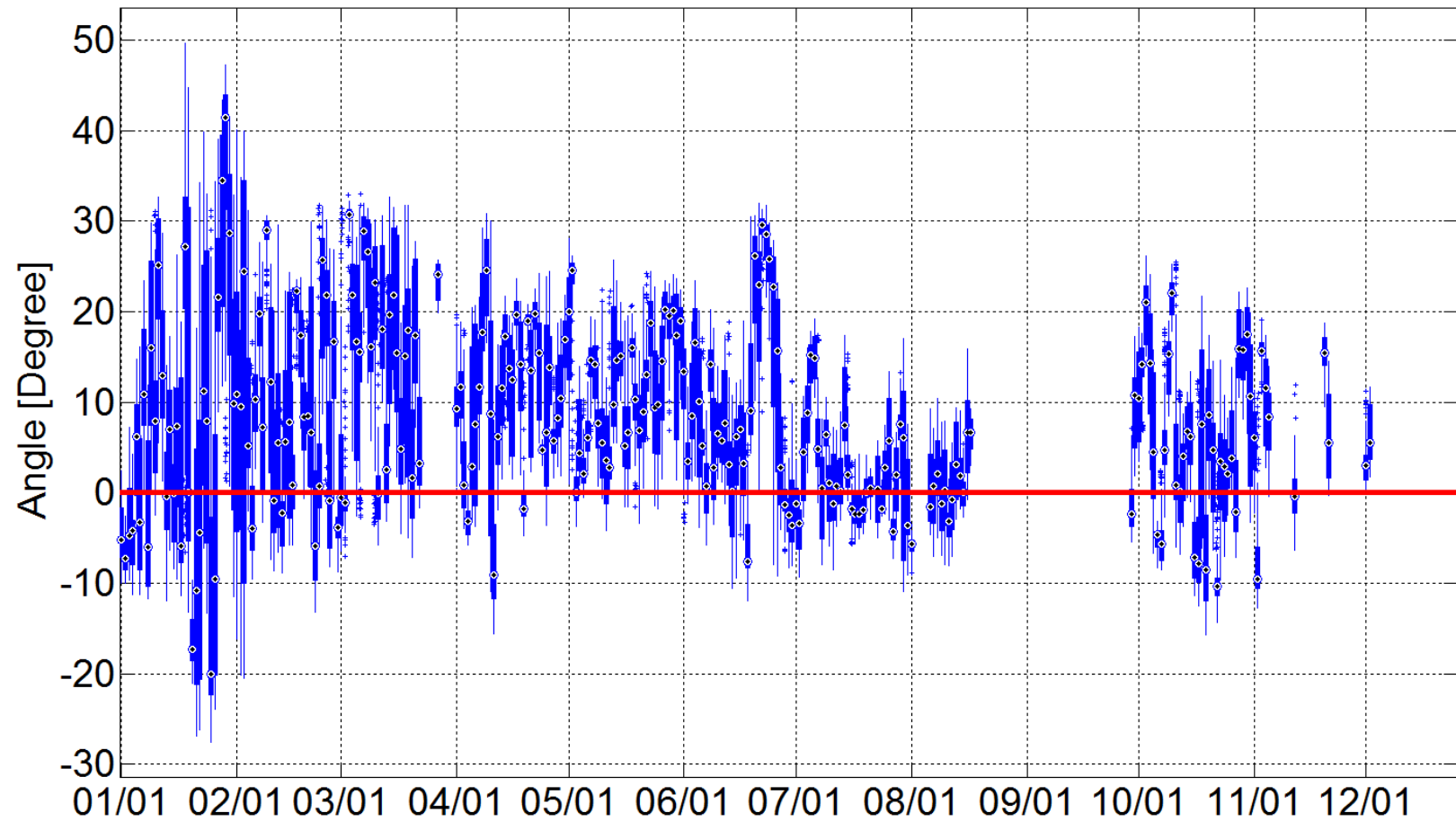
West 2-North 7



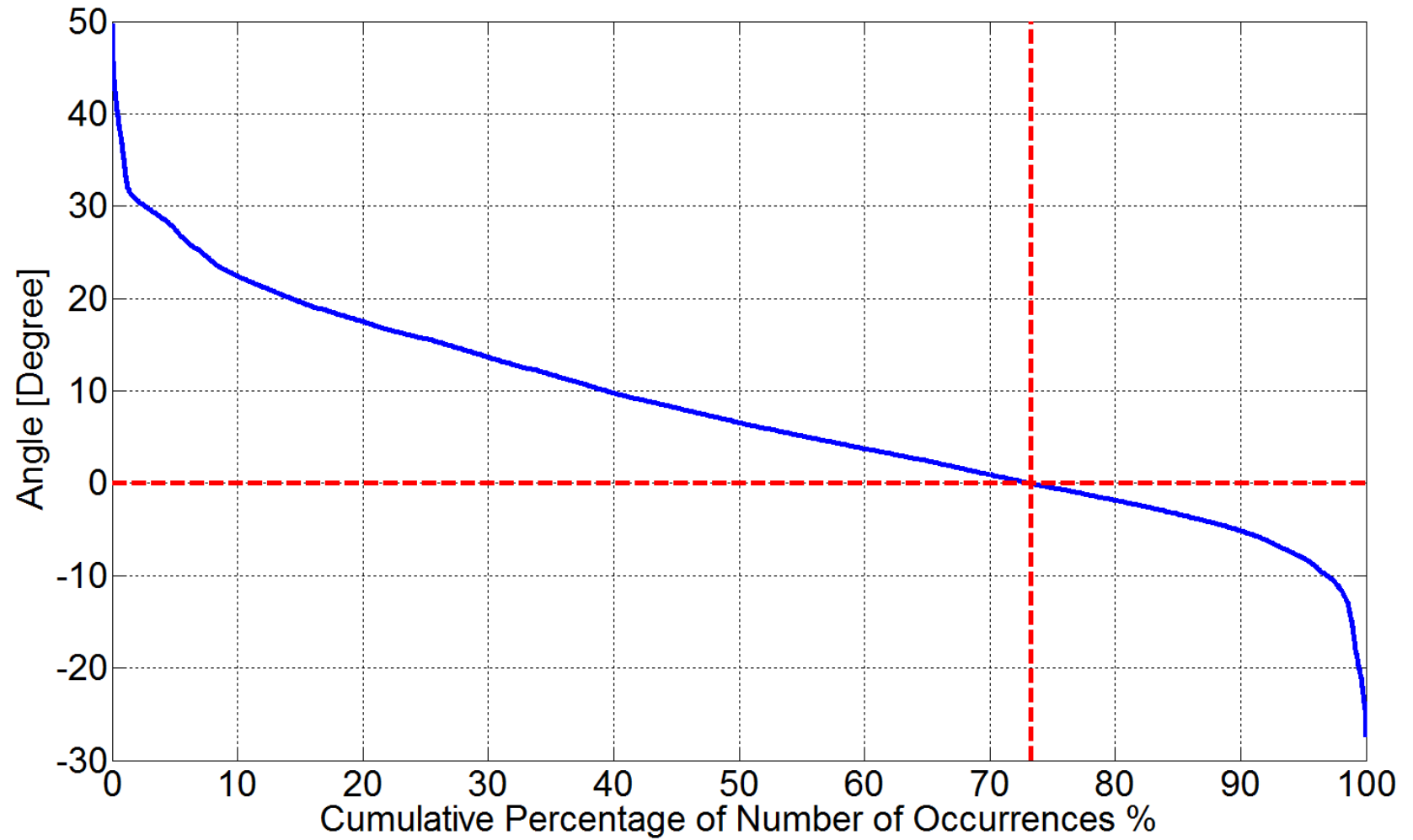
West 2-North 7



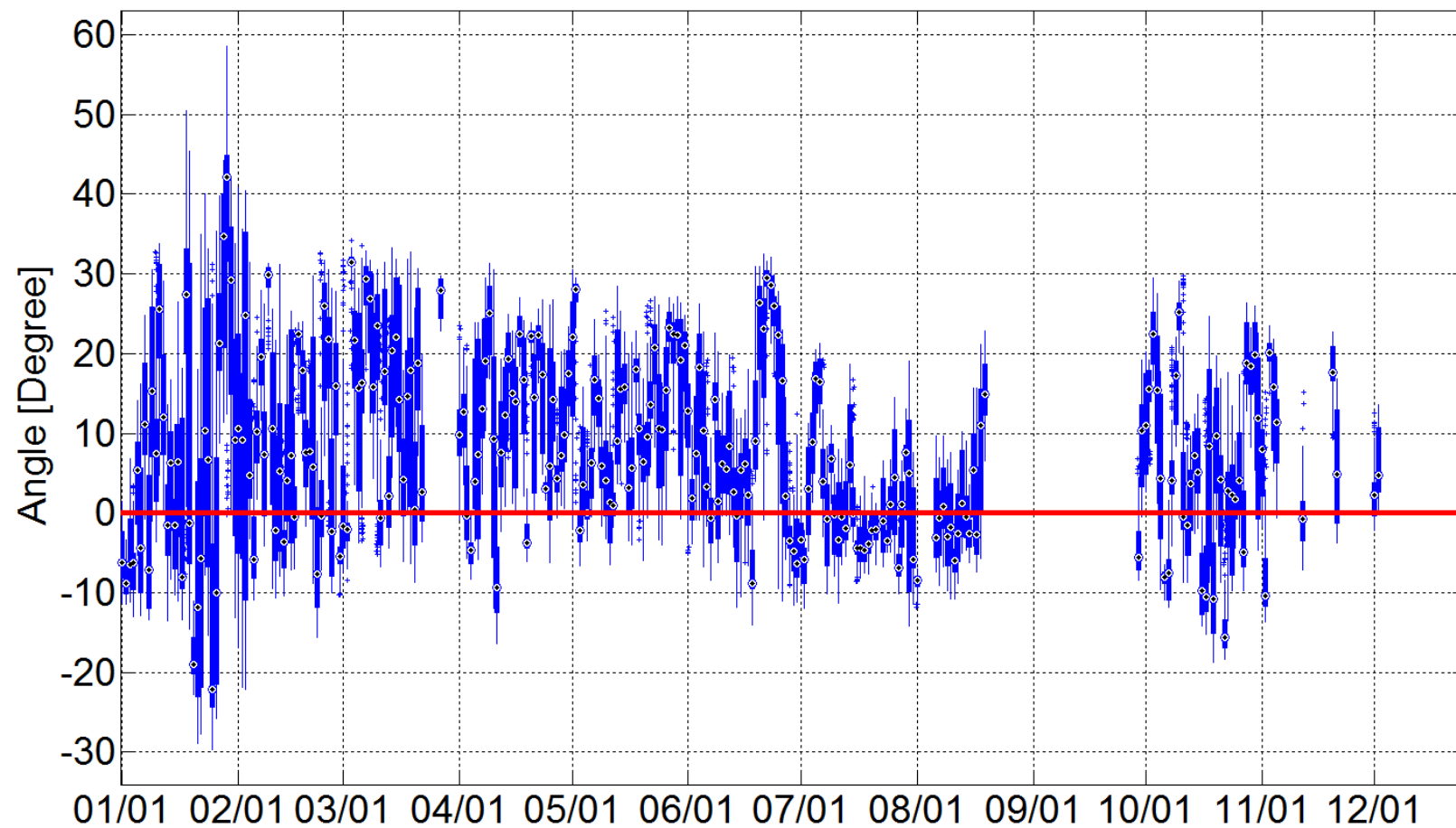
West 9-North 7



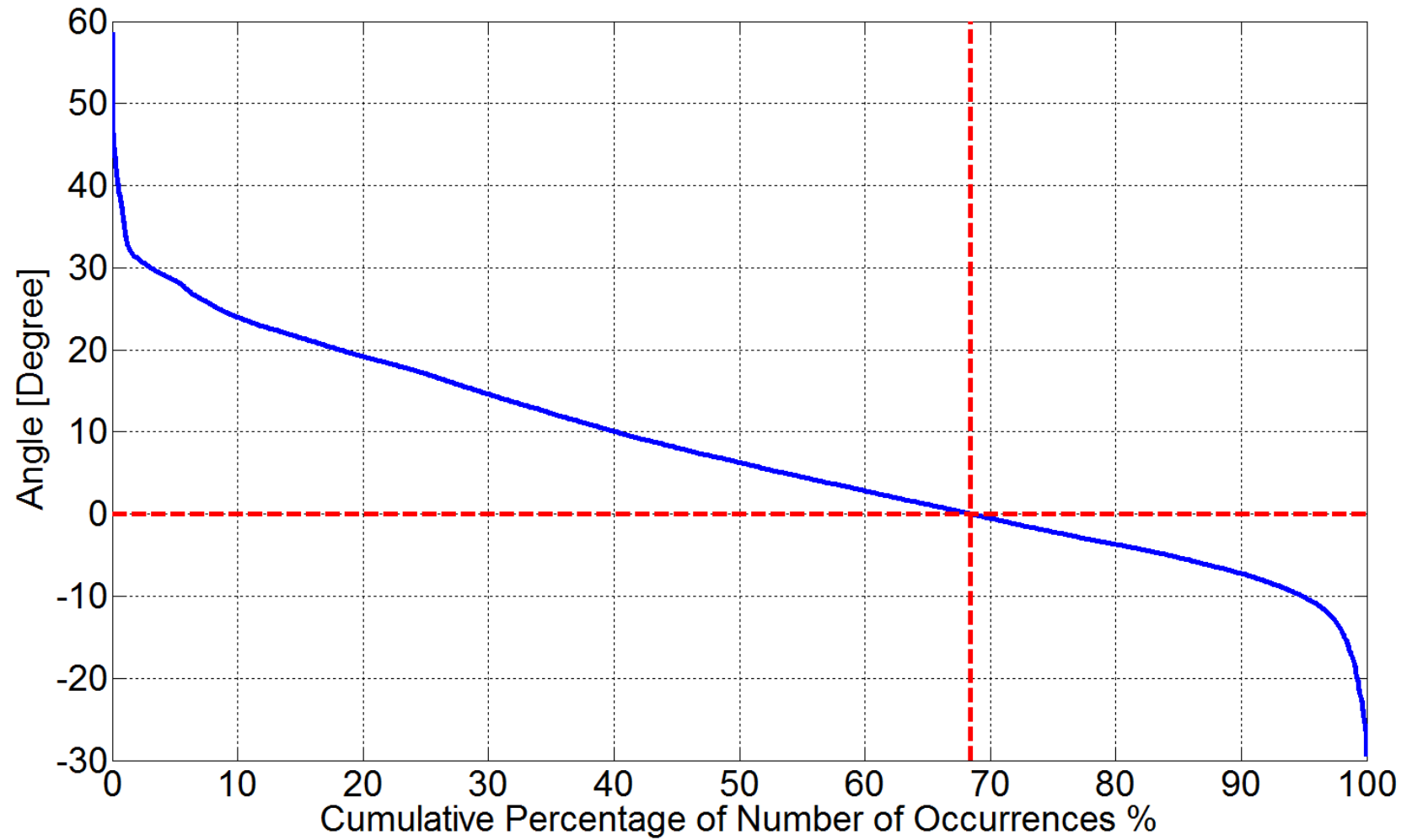
West 9-North 7



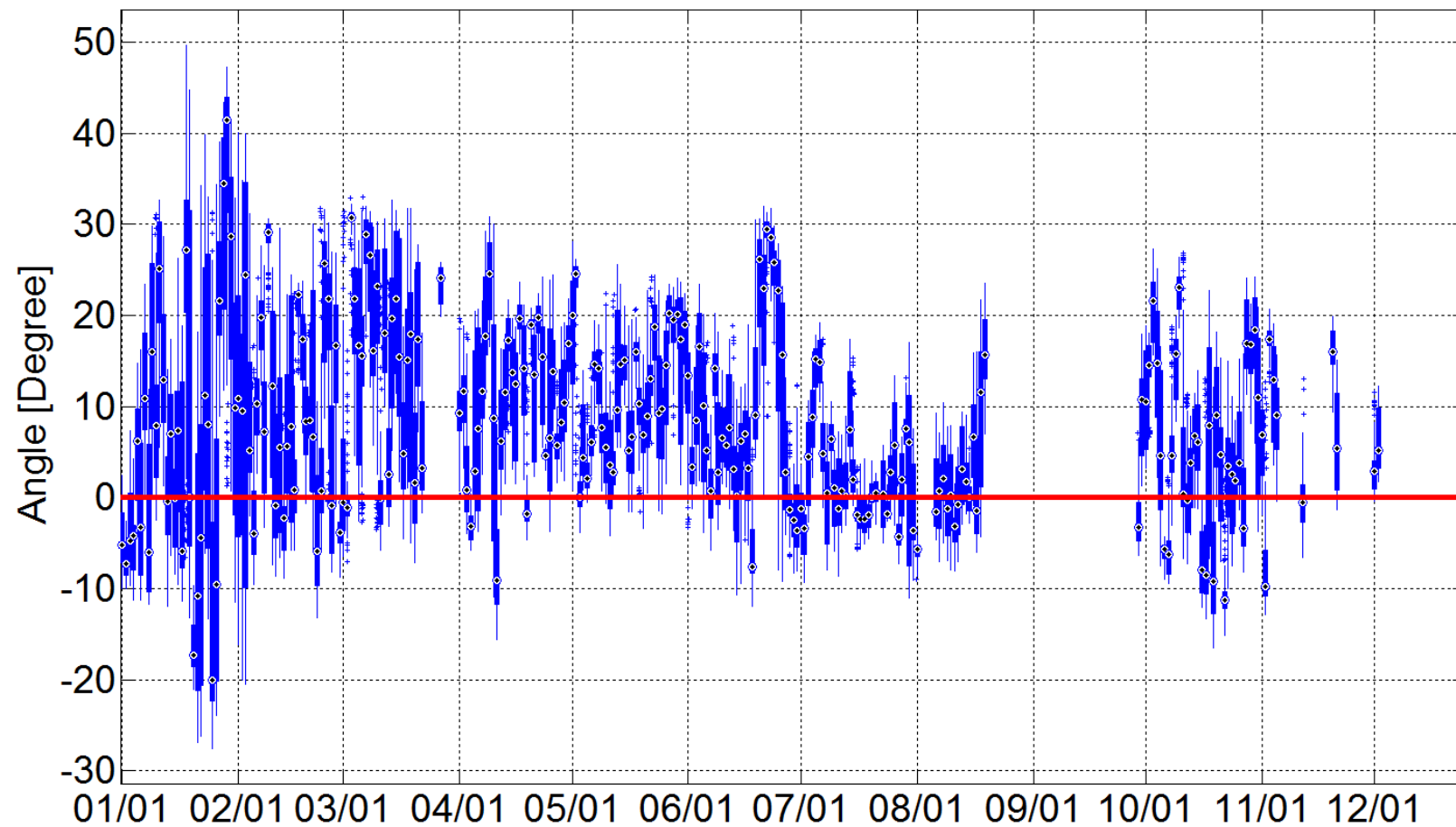
West 11-North 7



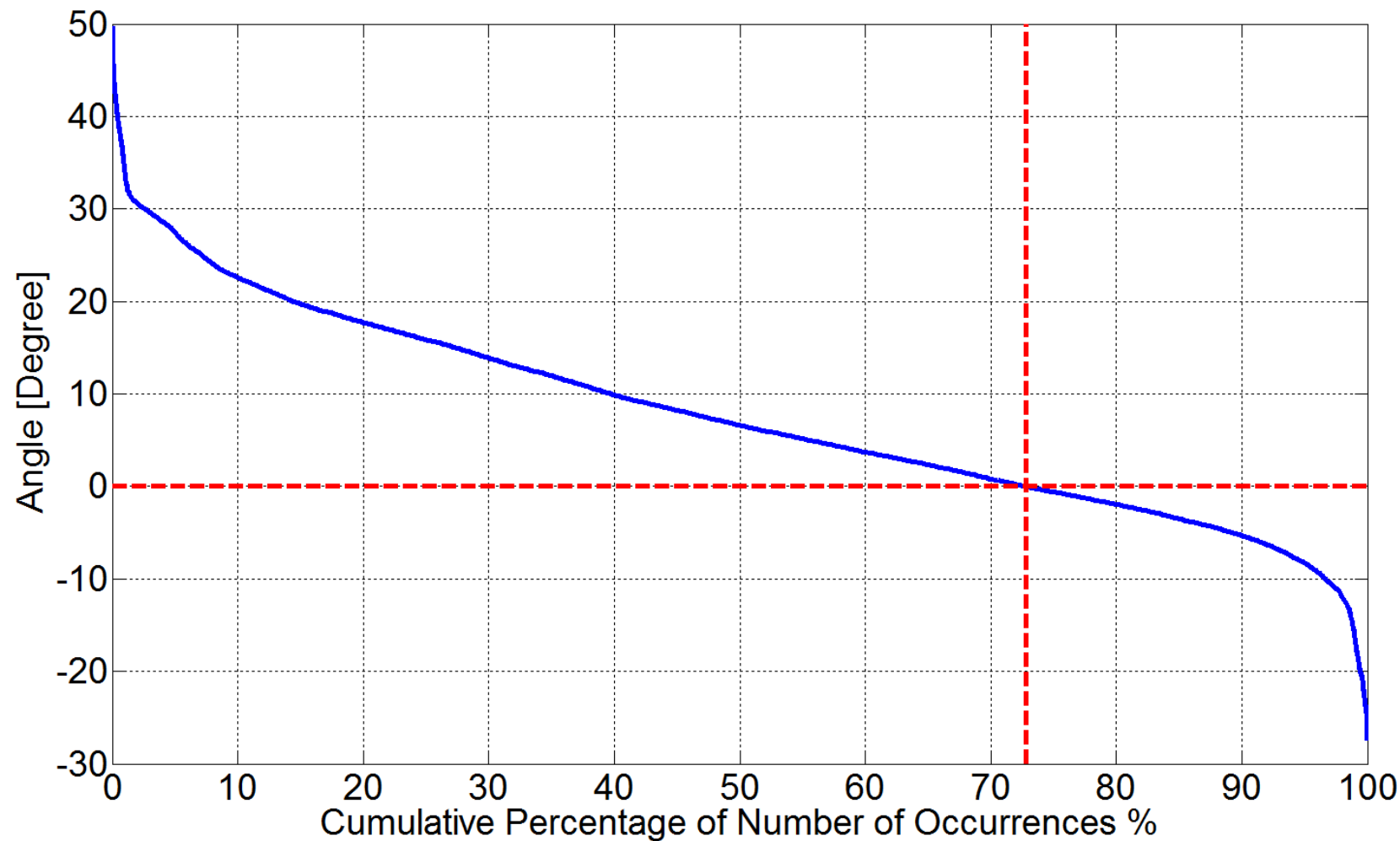
West 11-North 7



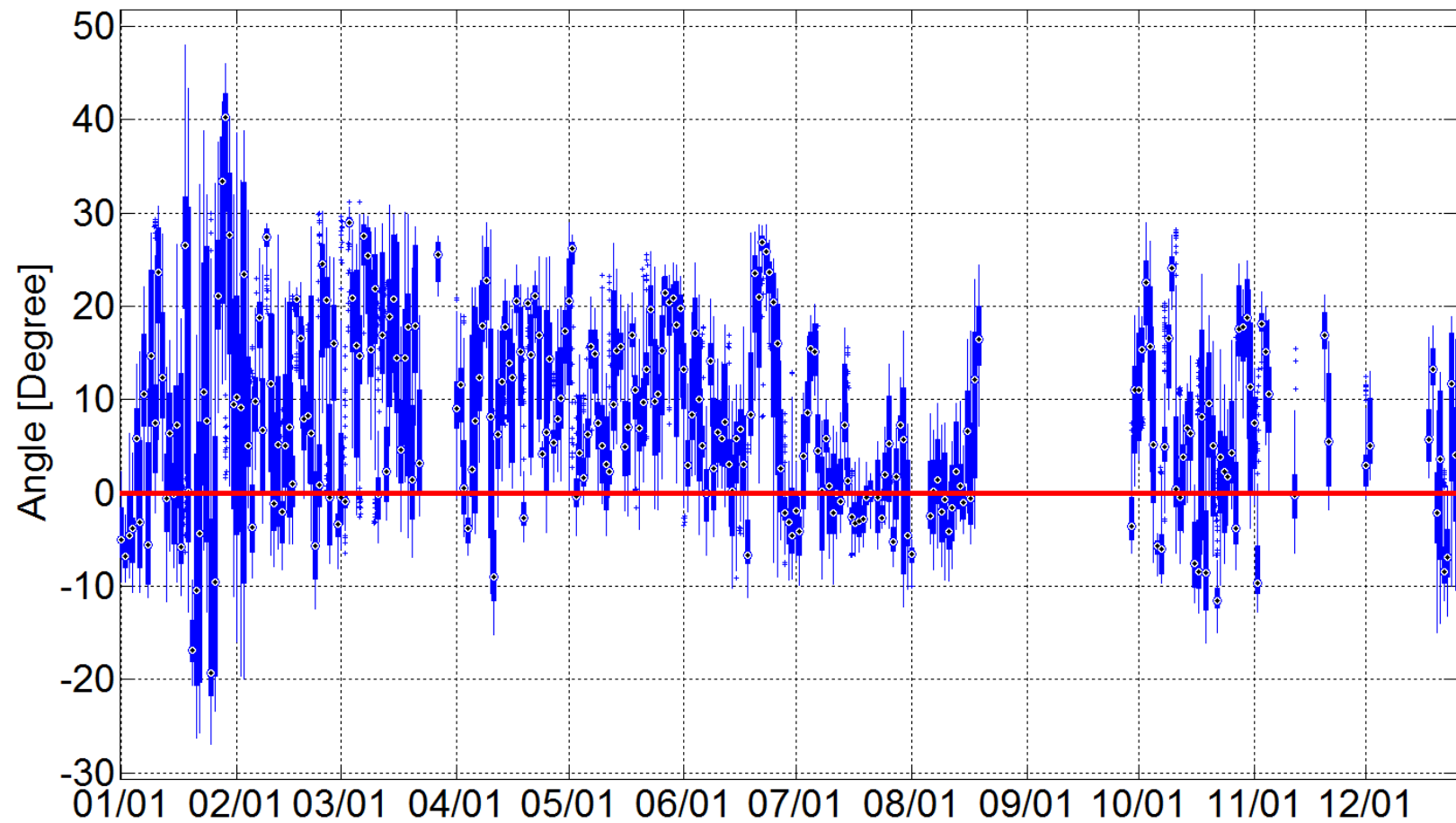
West 12-North 7



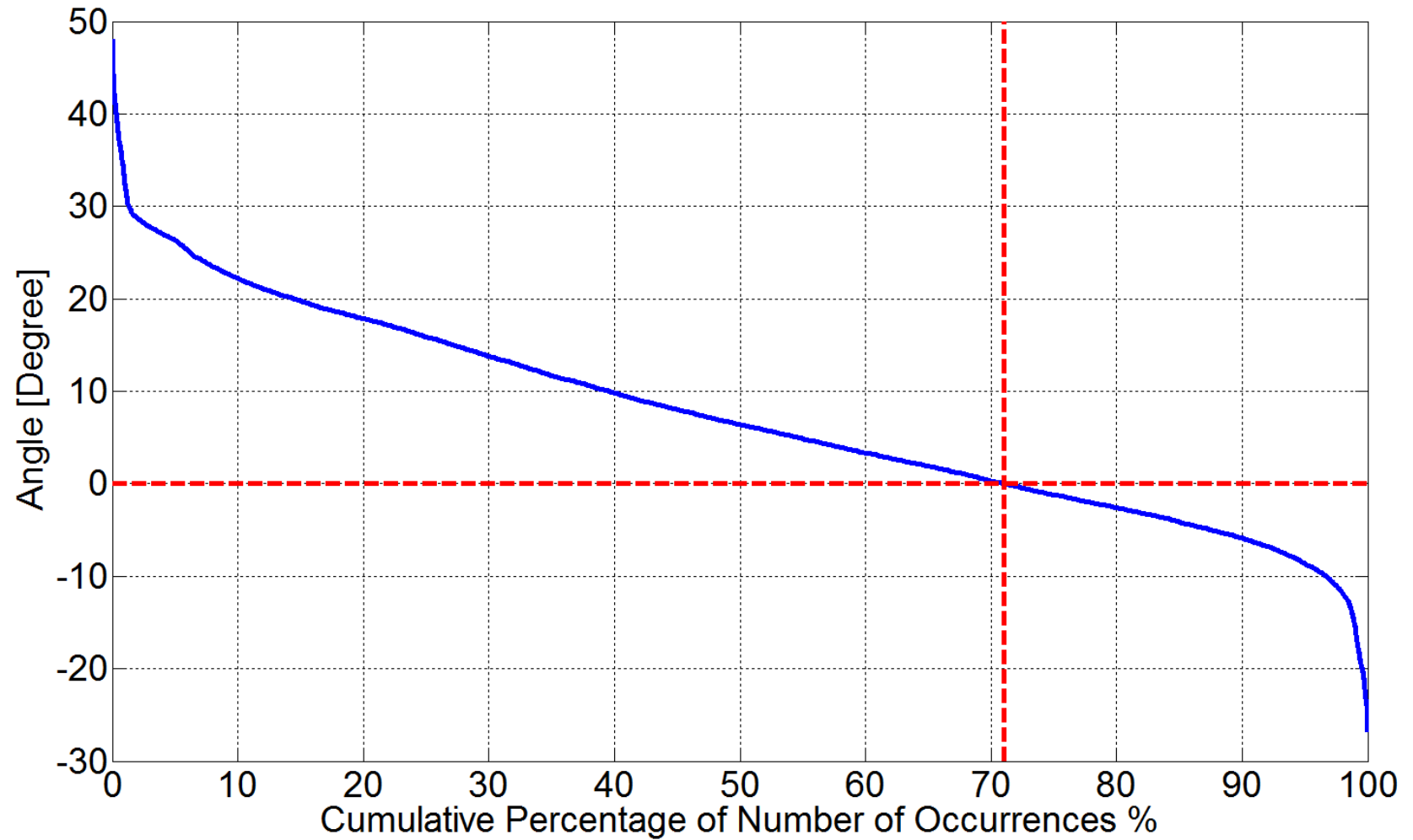
West 12-North 7



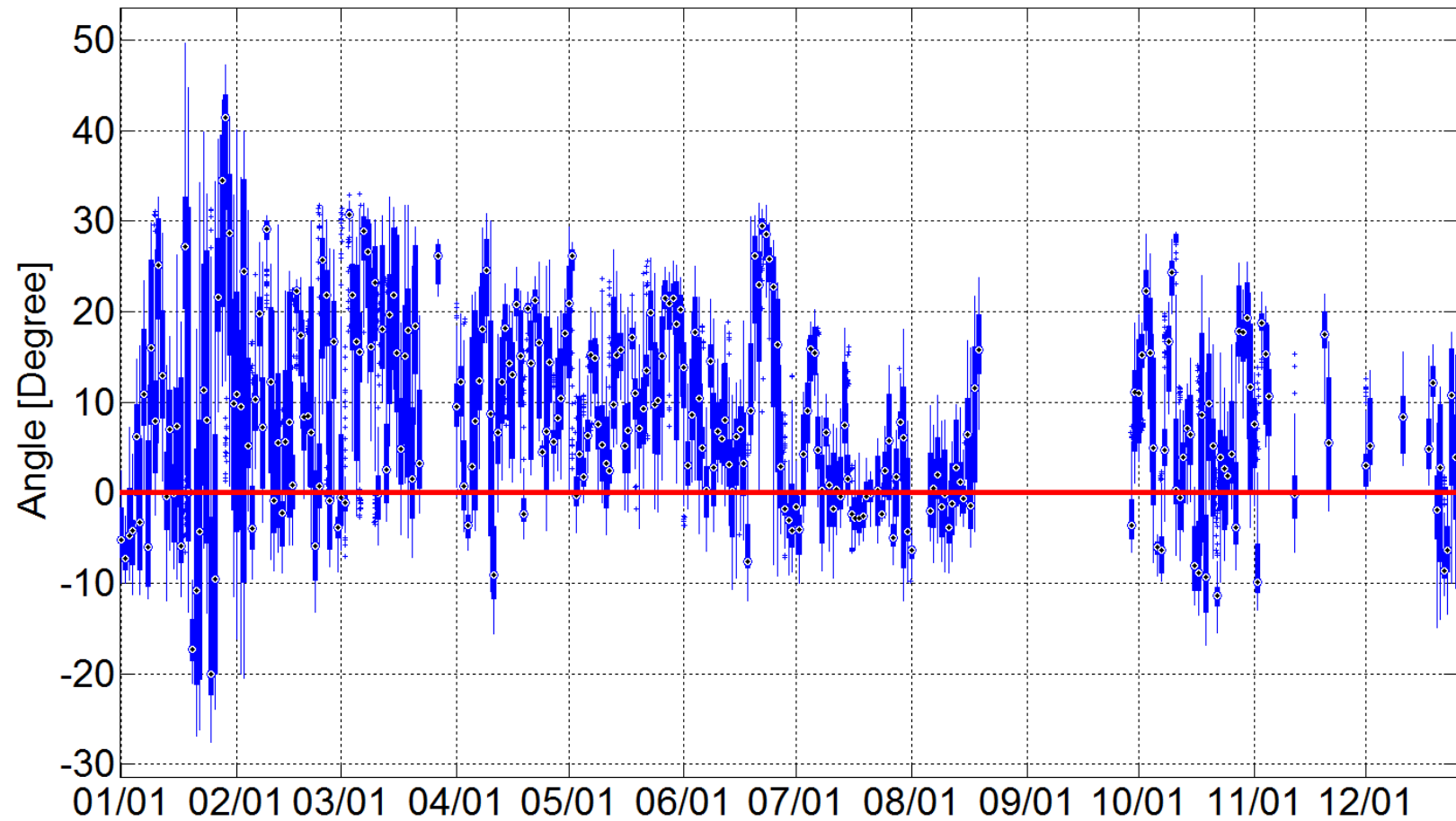
West 5-North 7



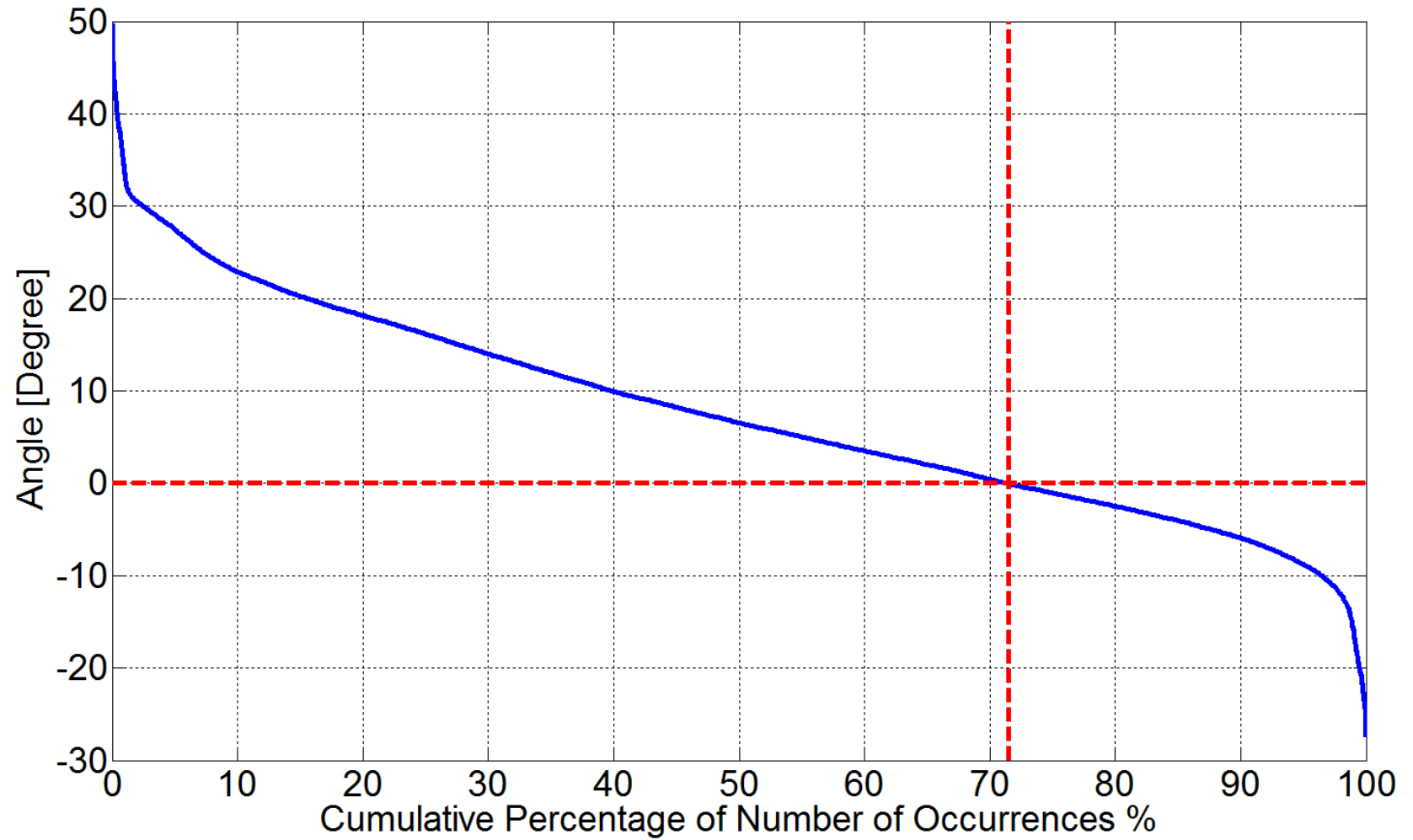
West 5-North 7



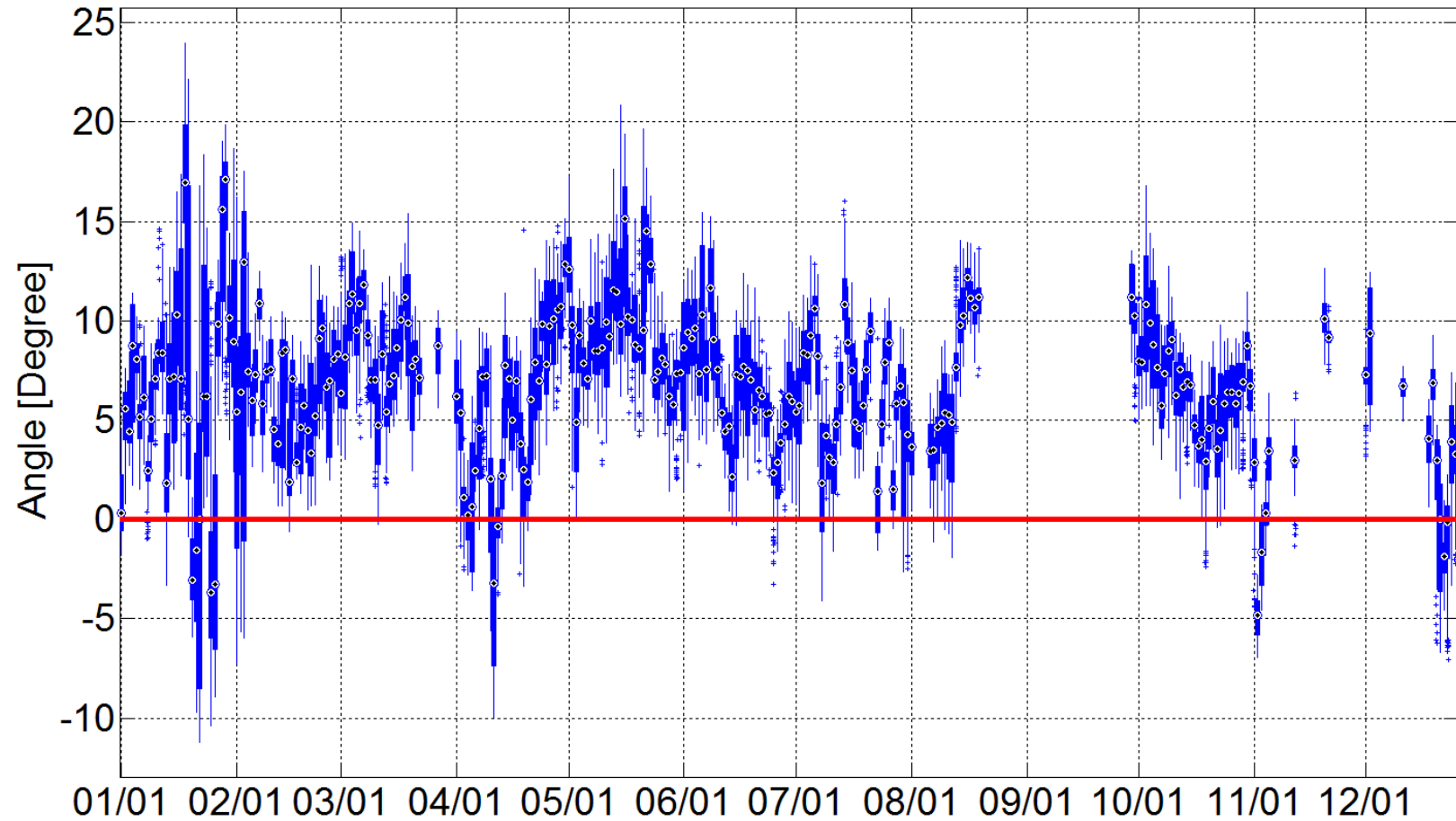
West 6-North 7



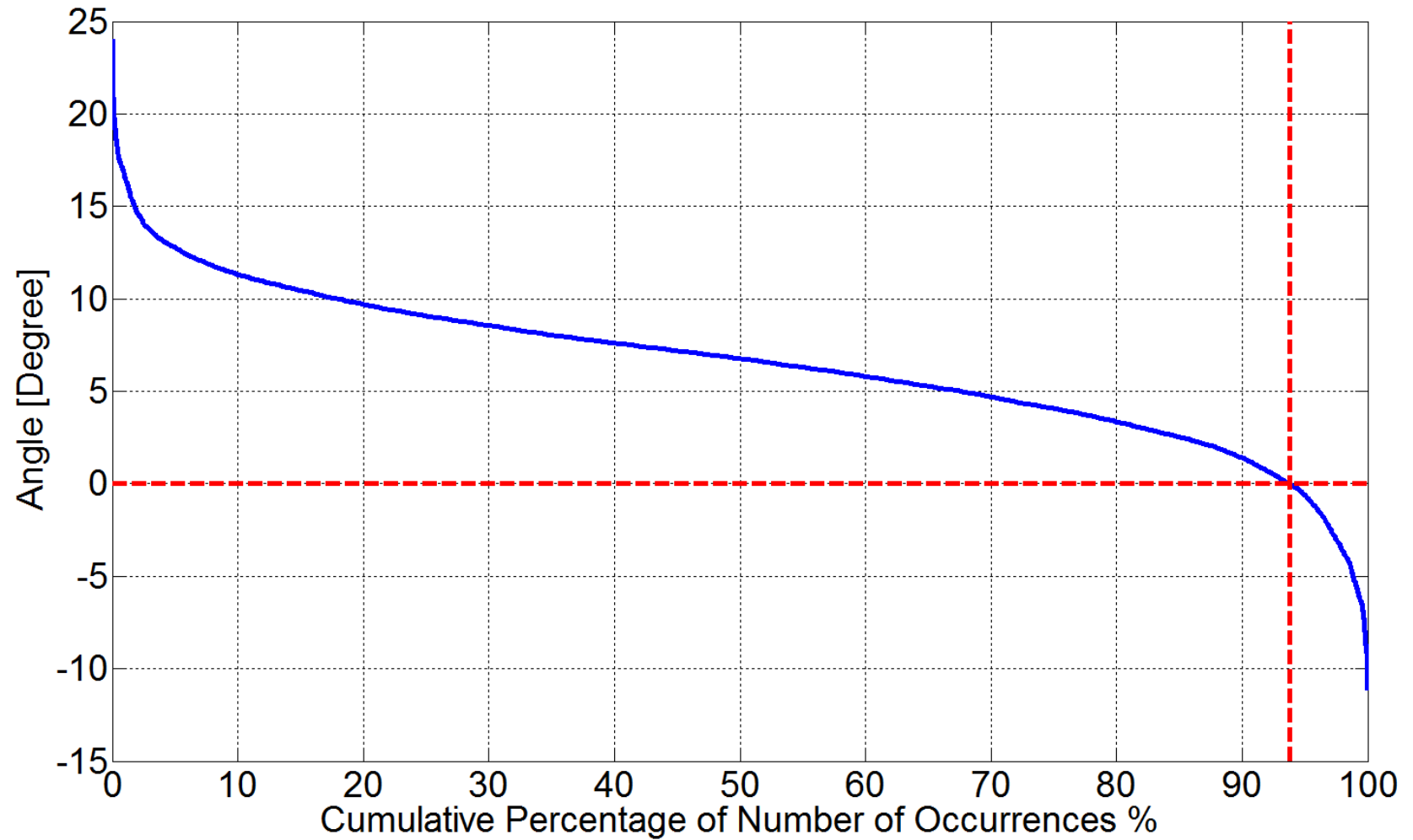
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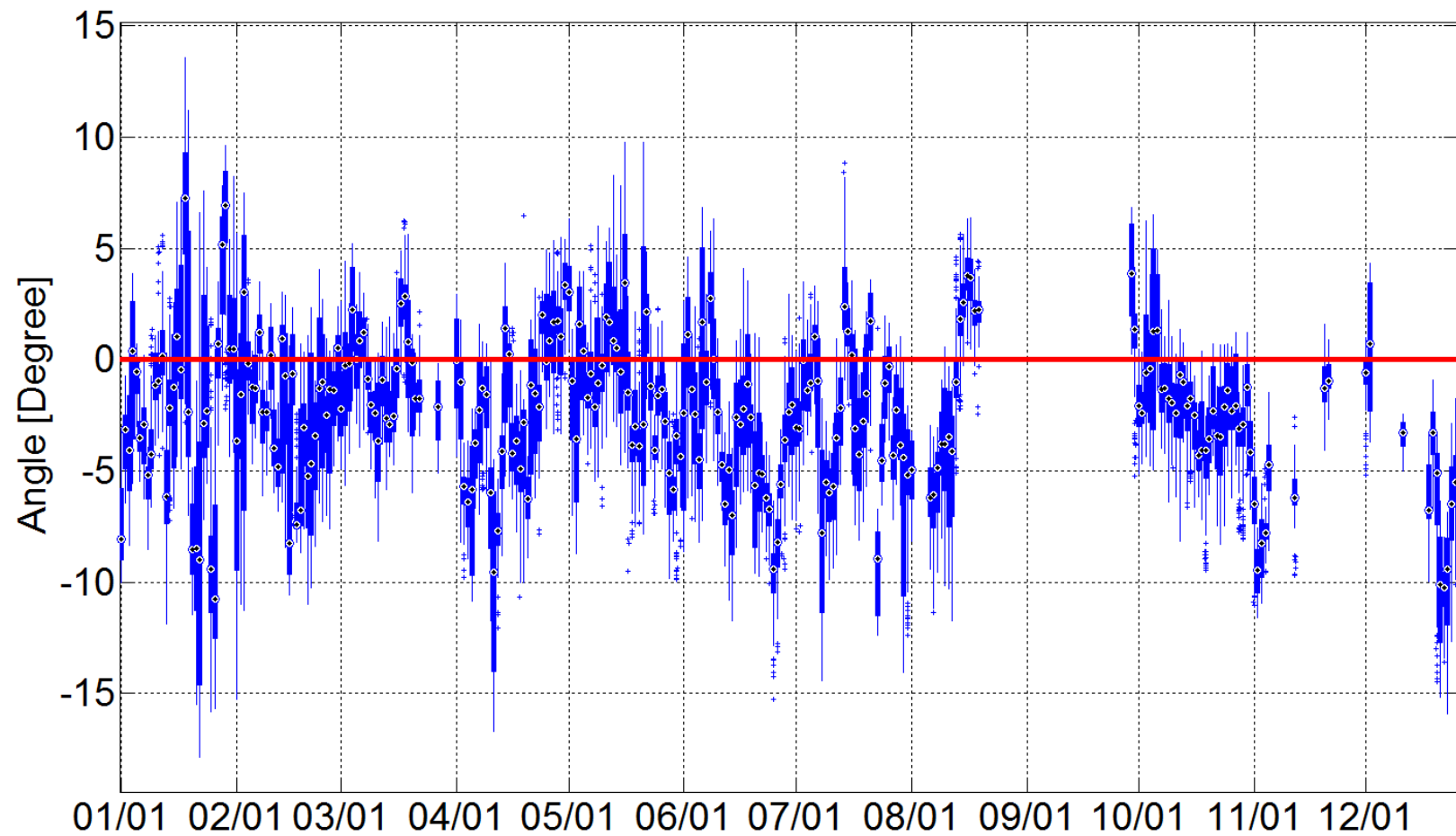
North 1-North 7



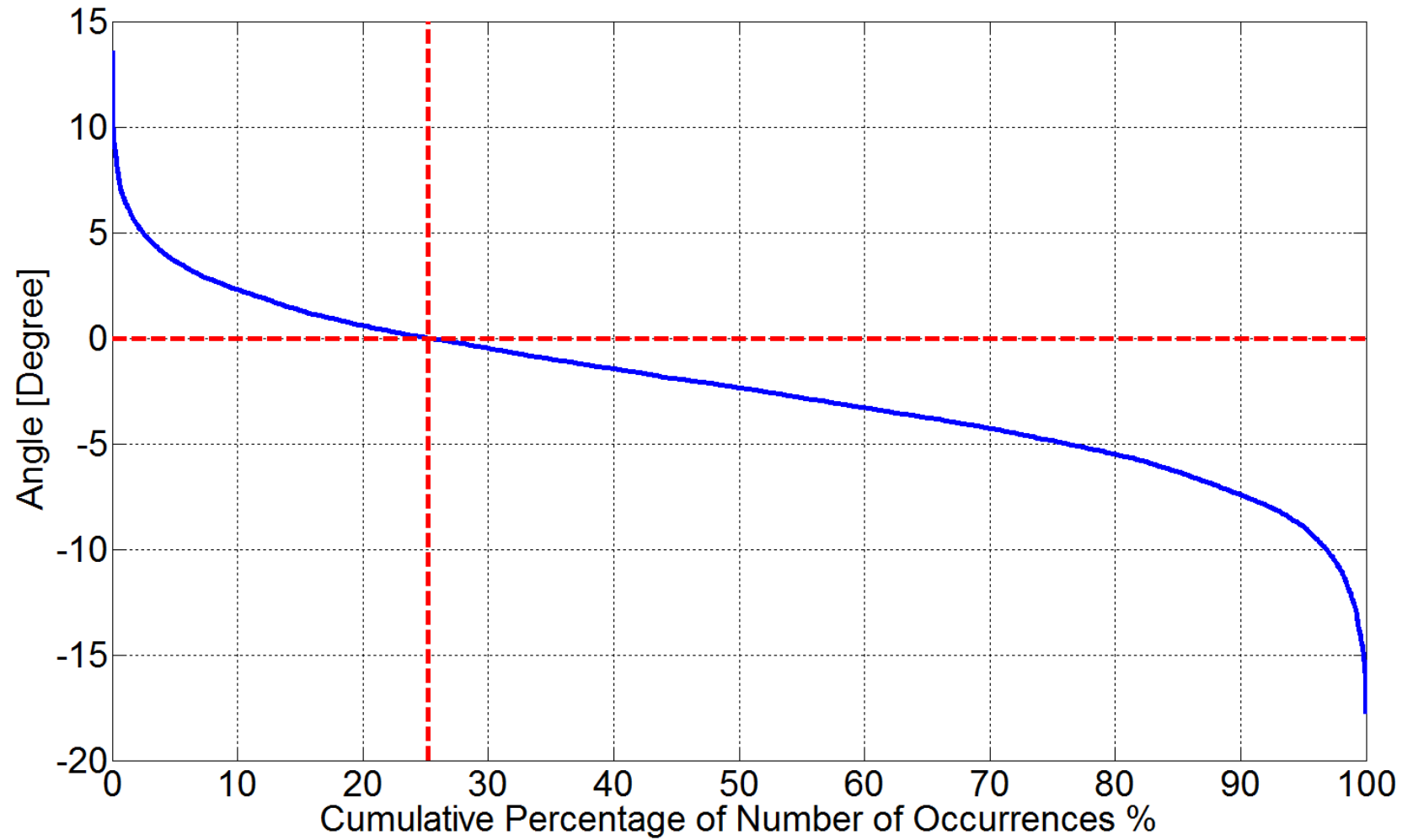
North 1-North 7



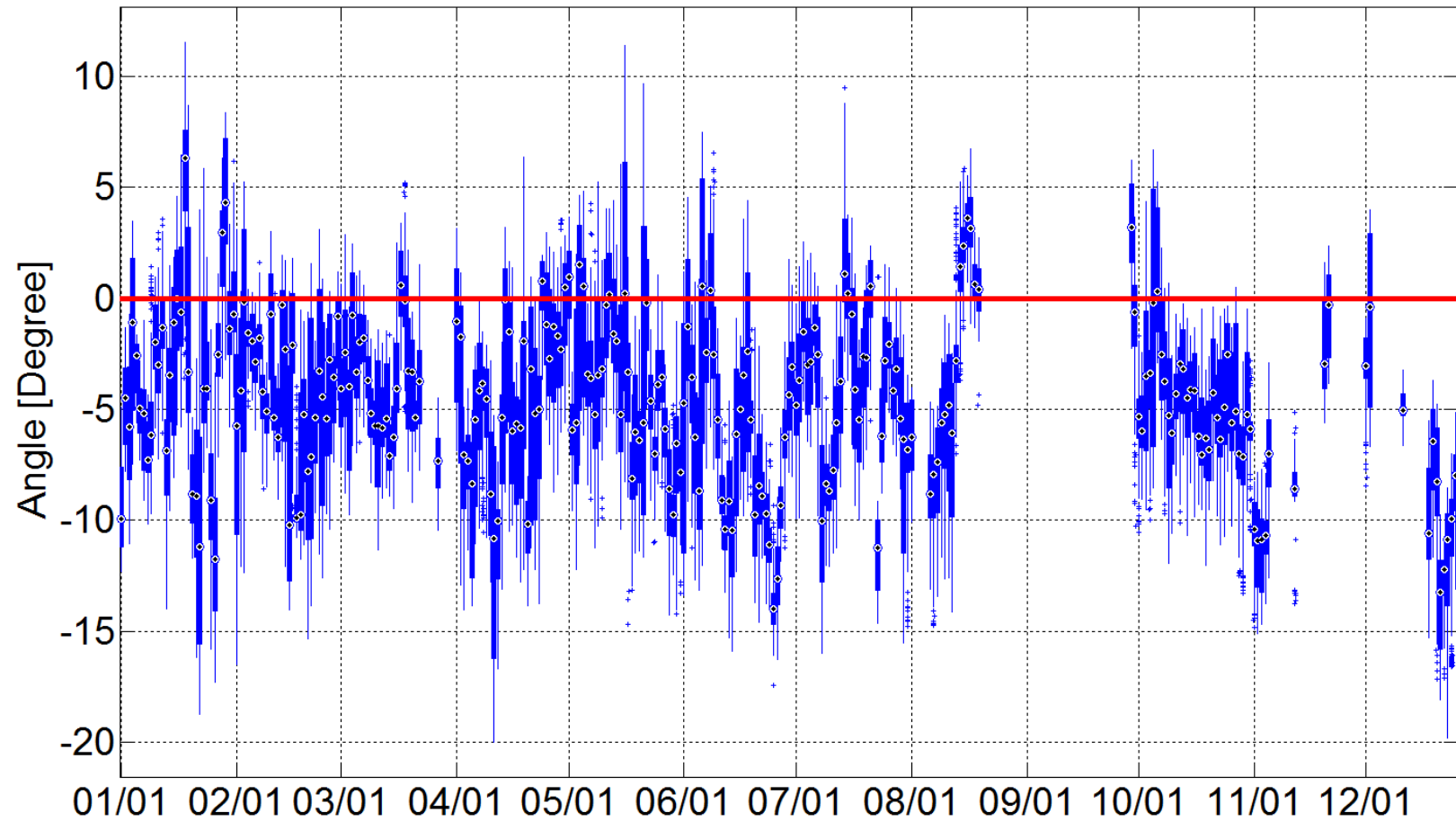
North 4-North 7



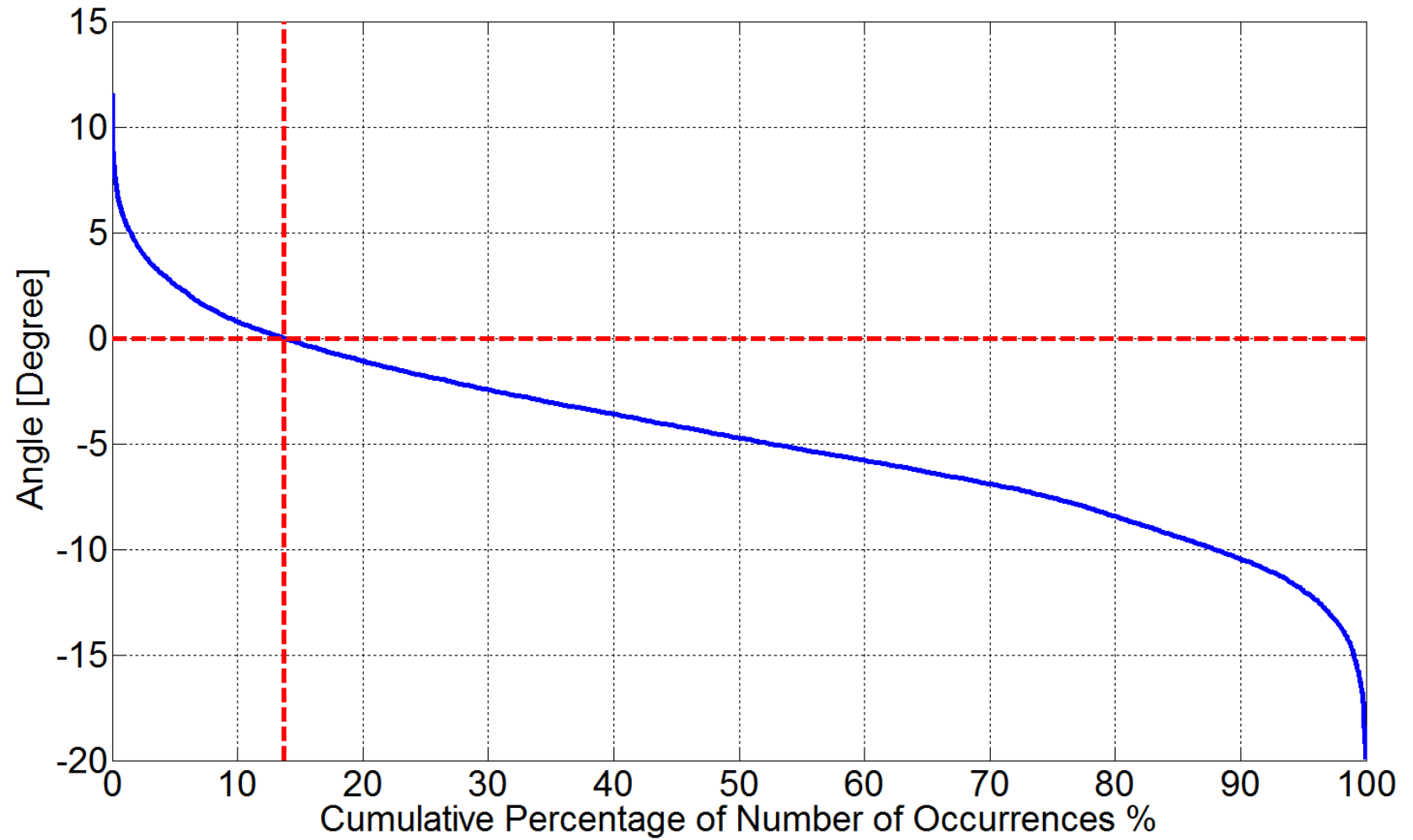
North 4-North 7



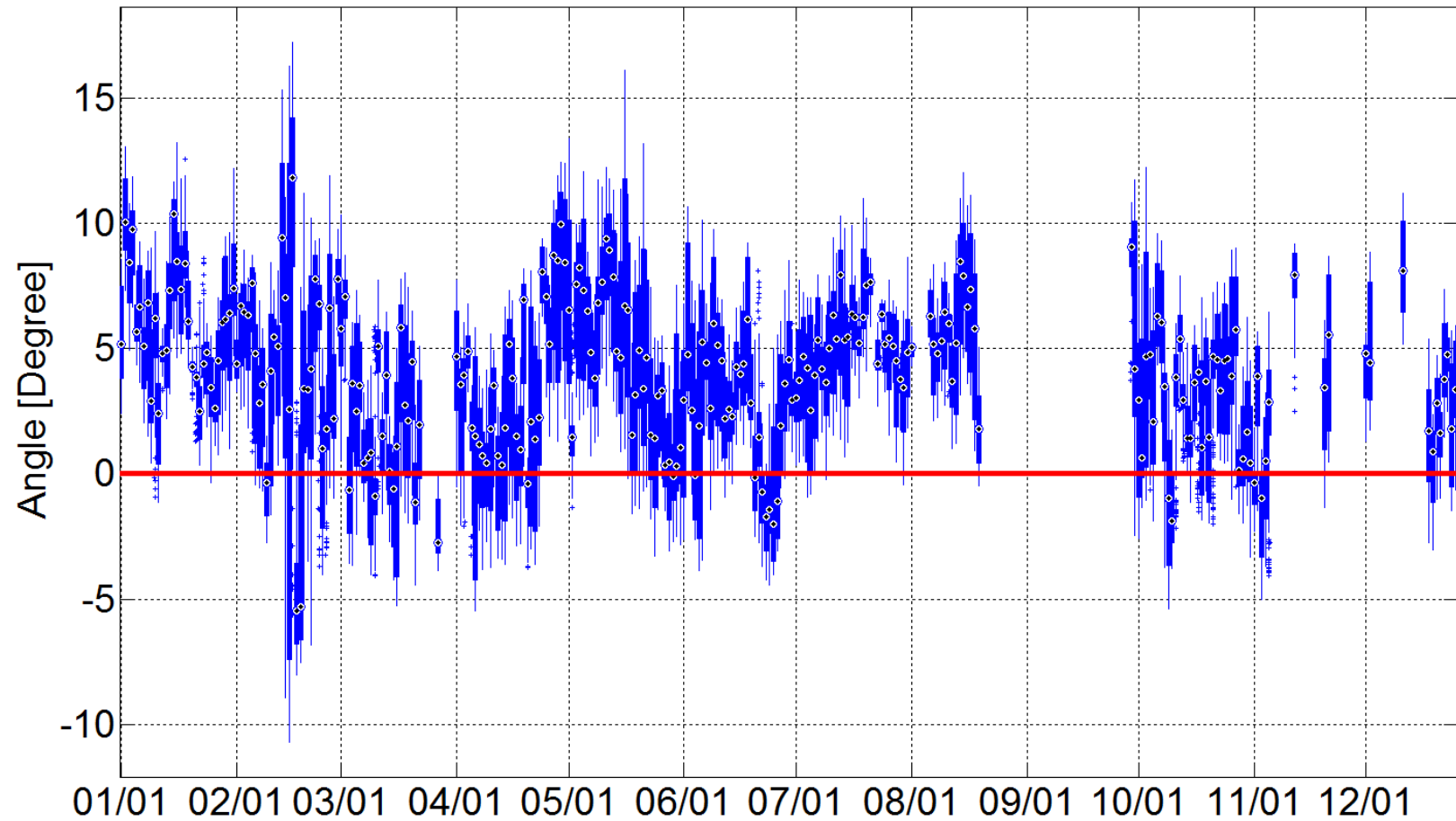
North 5-North 7



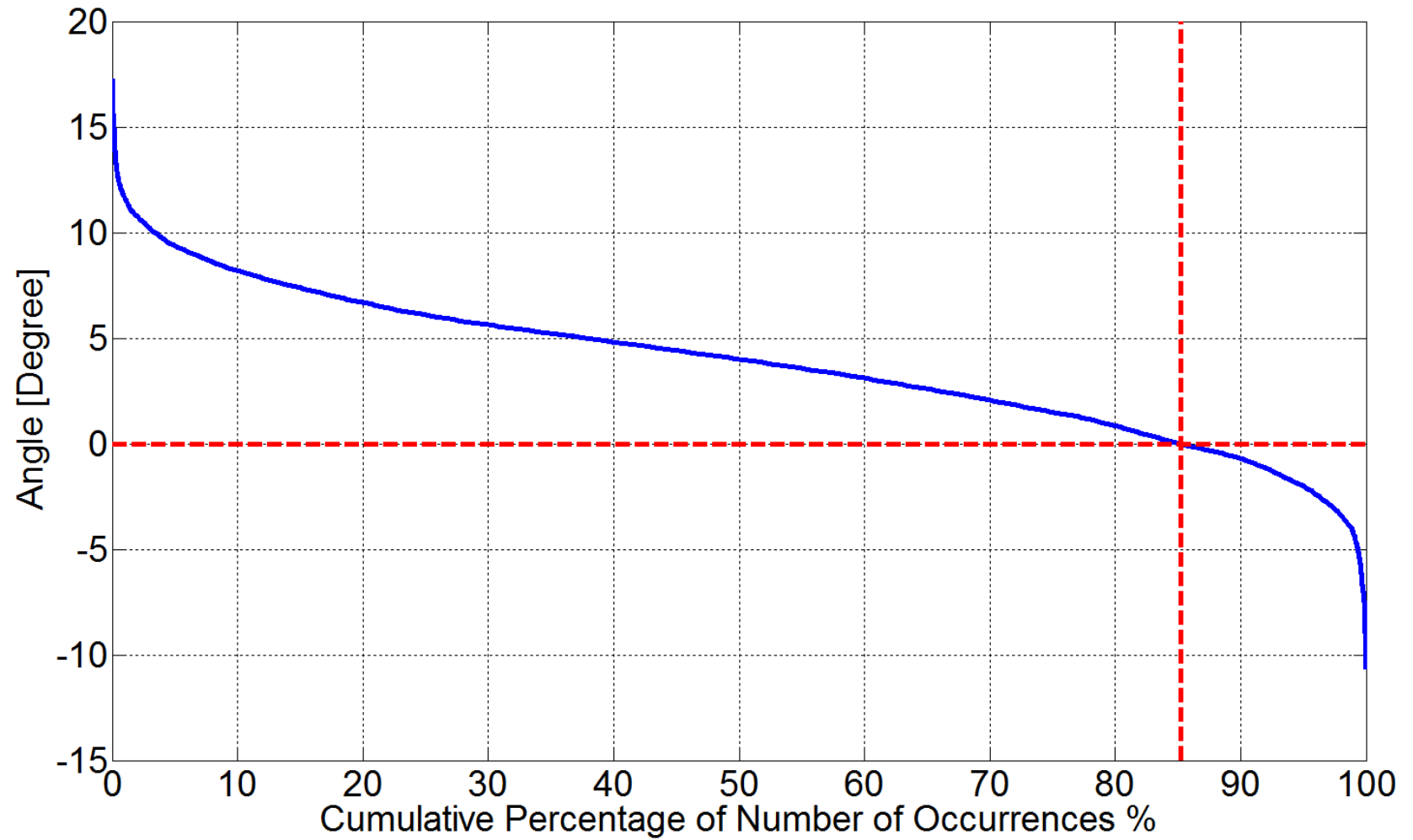
North 5-North 7



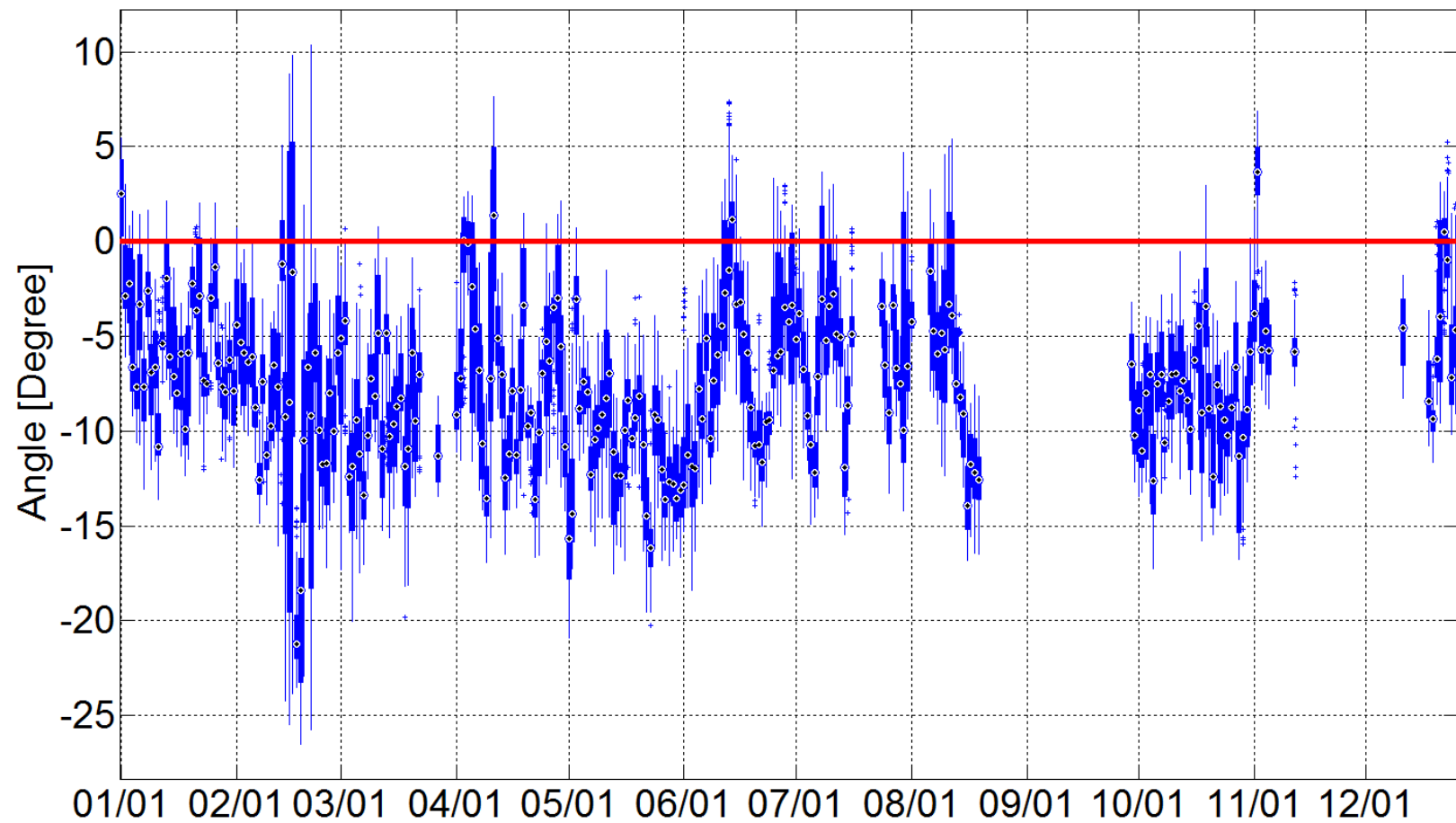
North 6-North 7



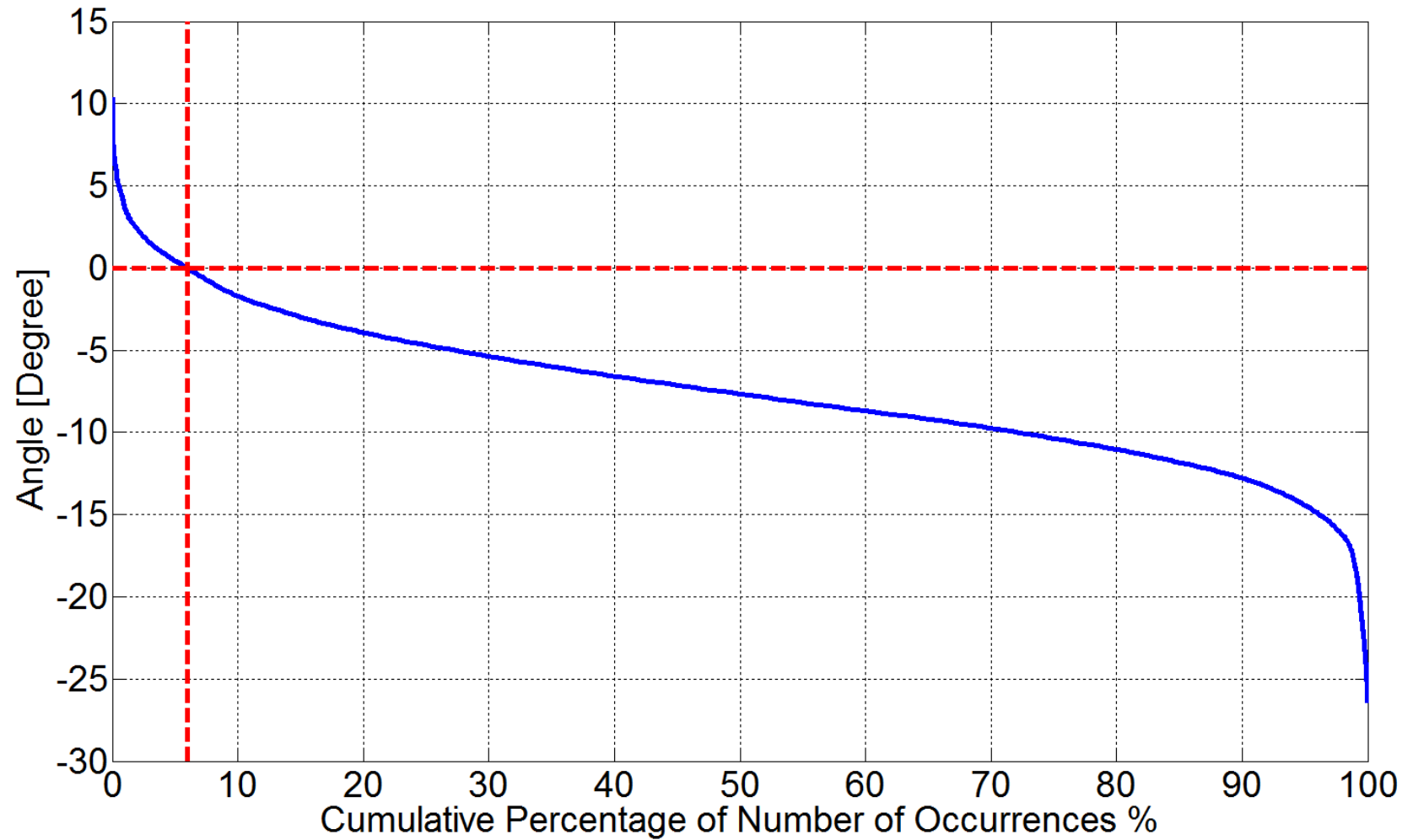
North 6-North 7



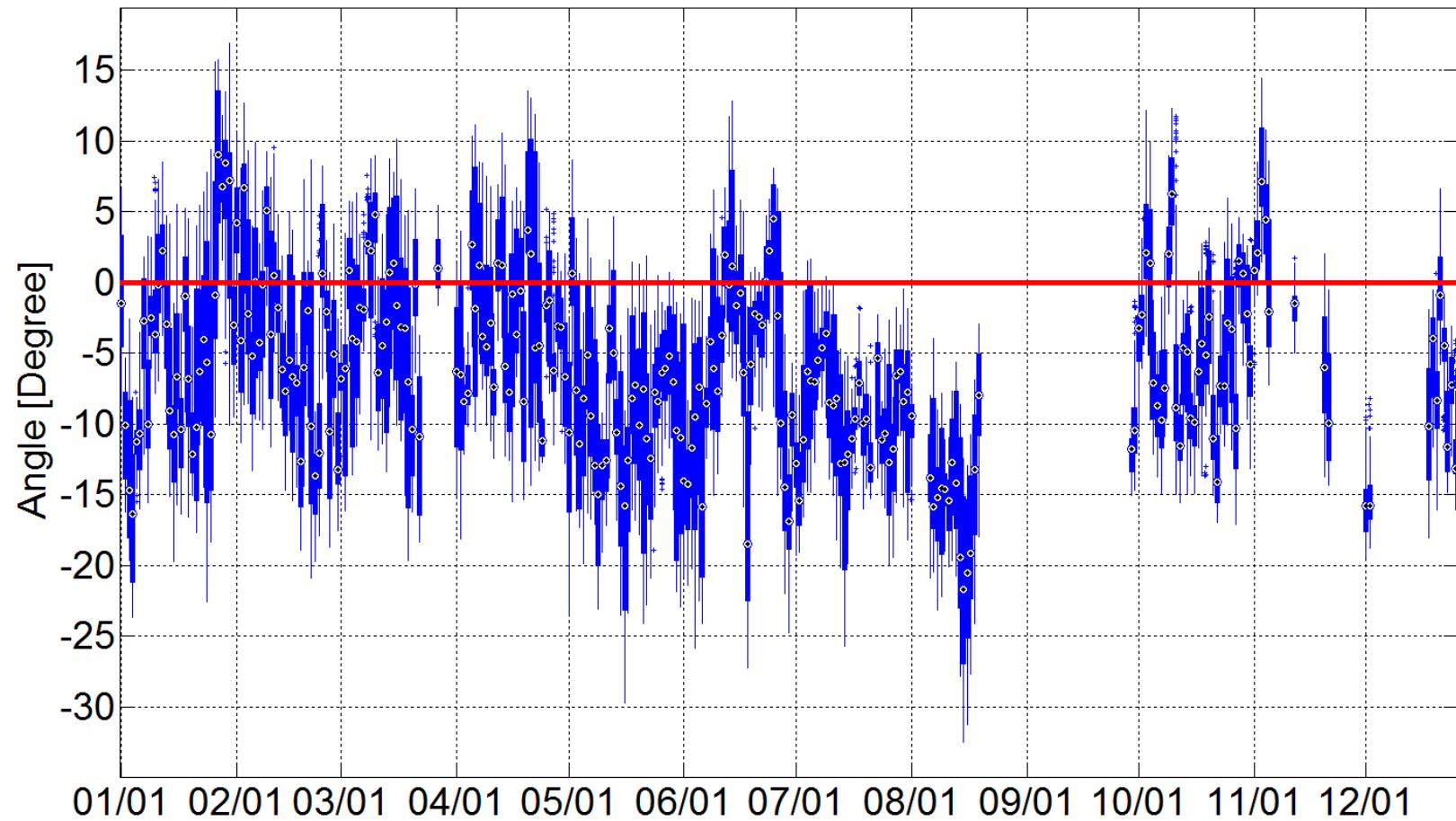
FarWest 2-North 7



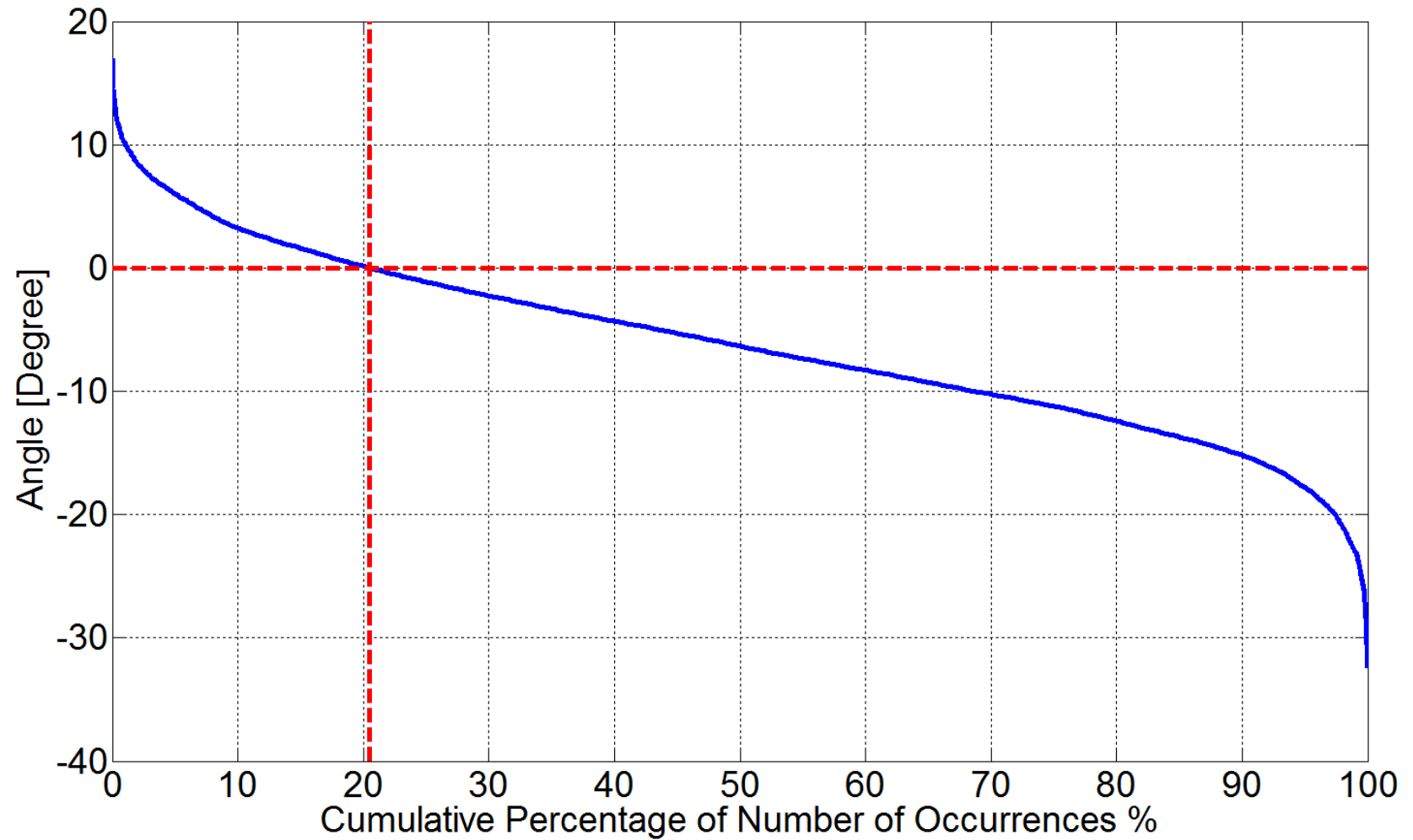
FarWest 2-North 7



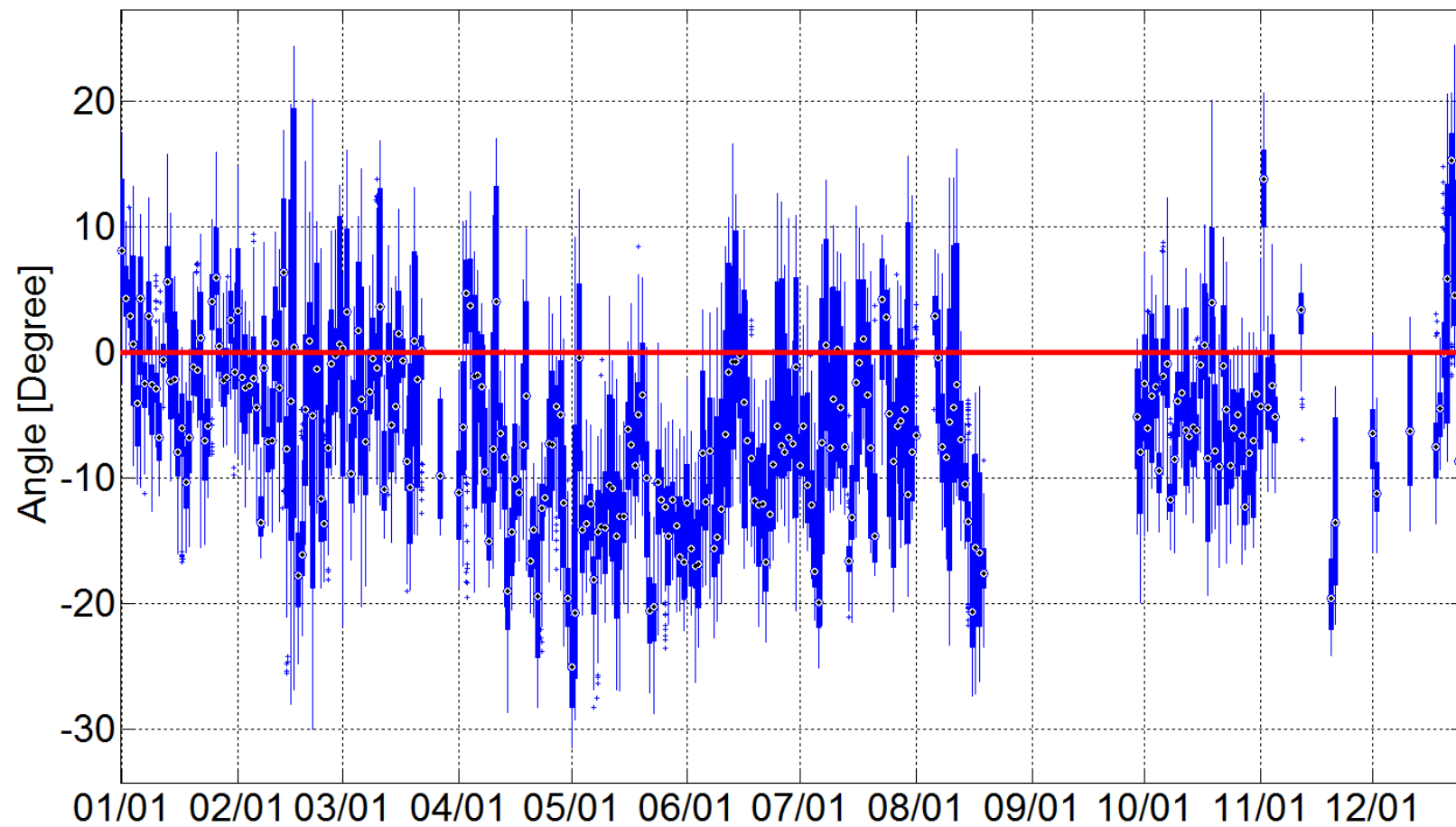
West 4-North 7



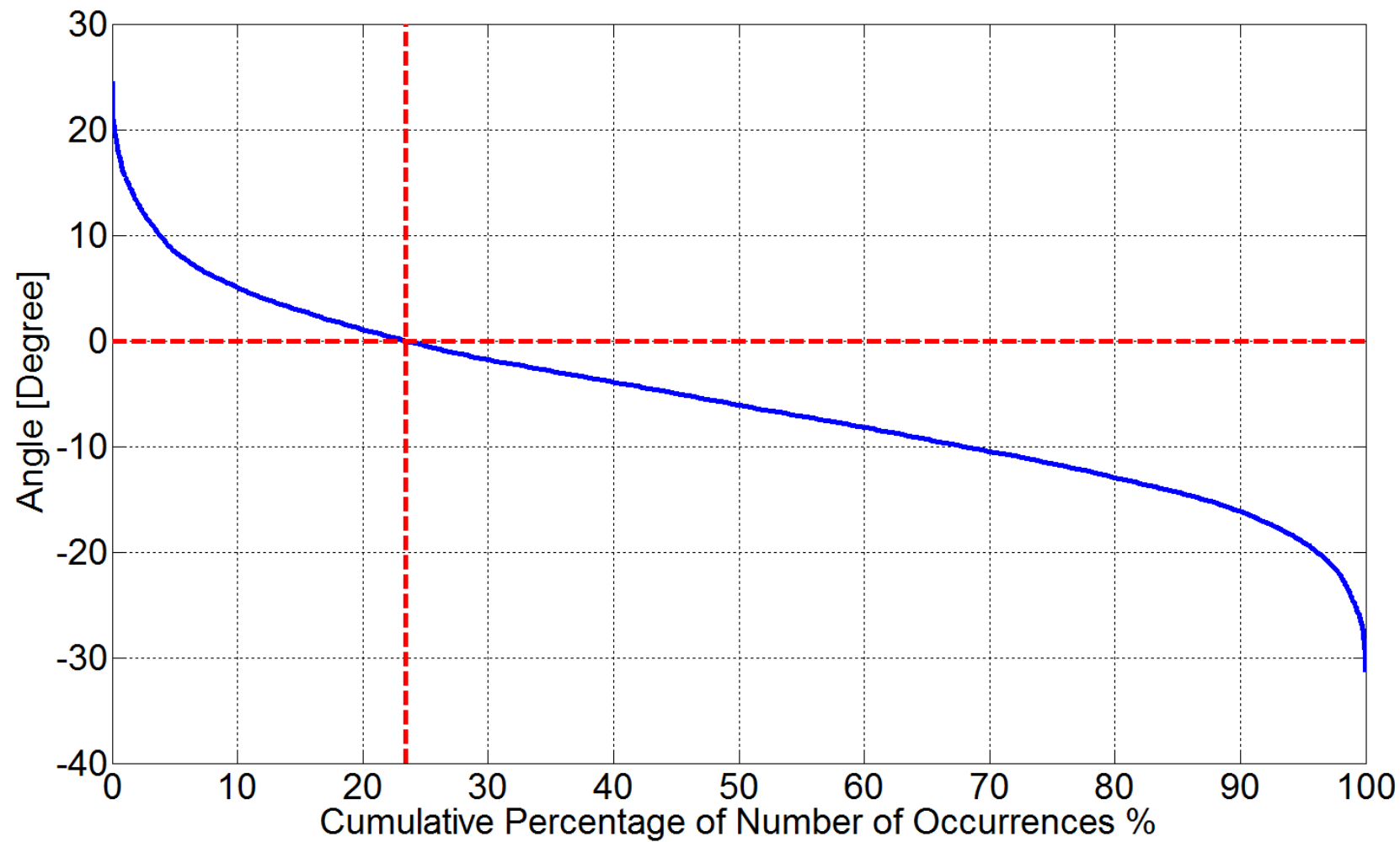
West 4-North 7



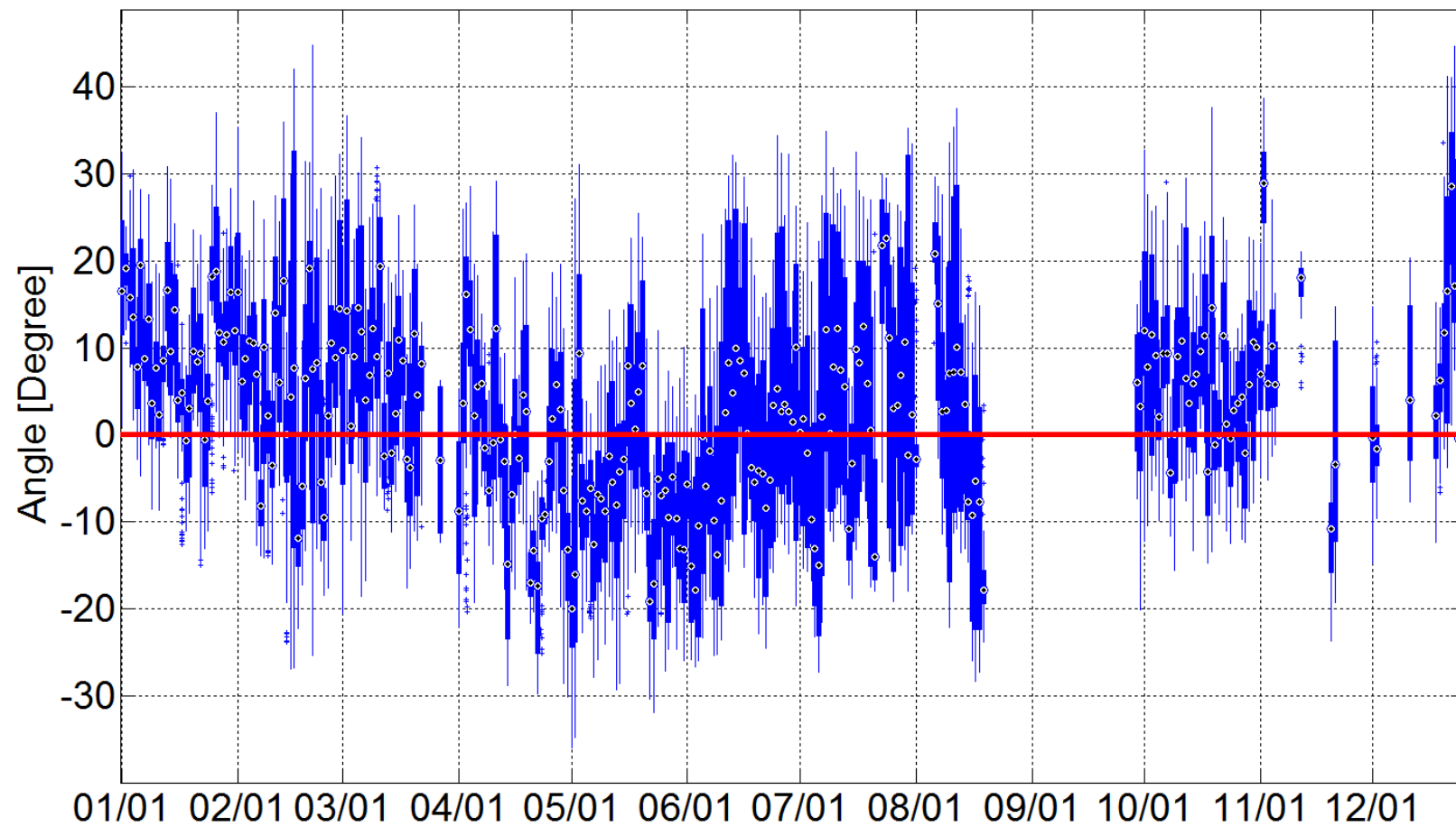
Coast 2-North 7



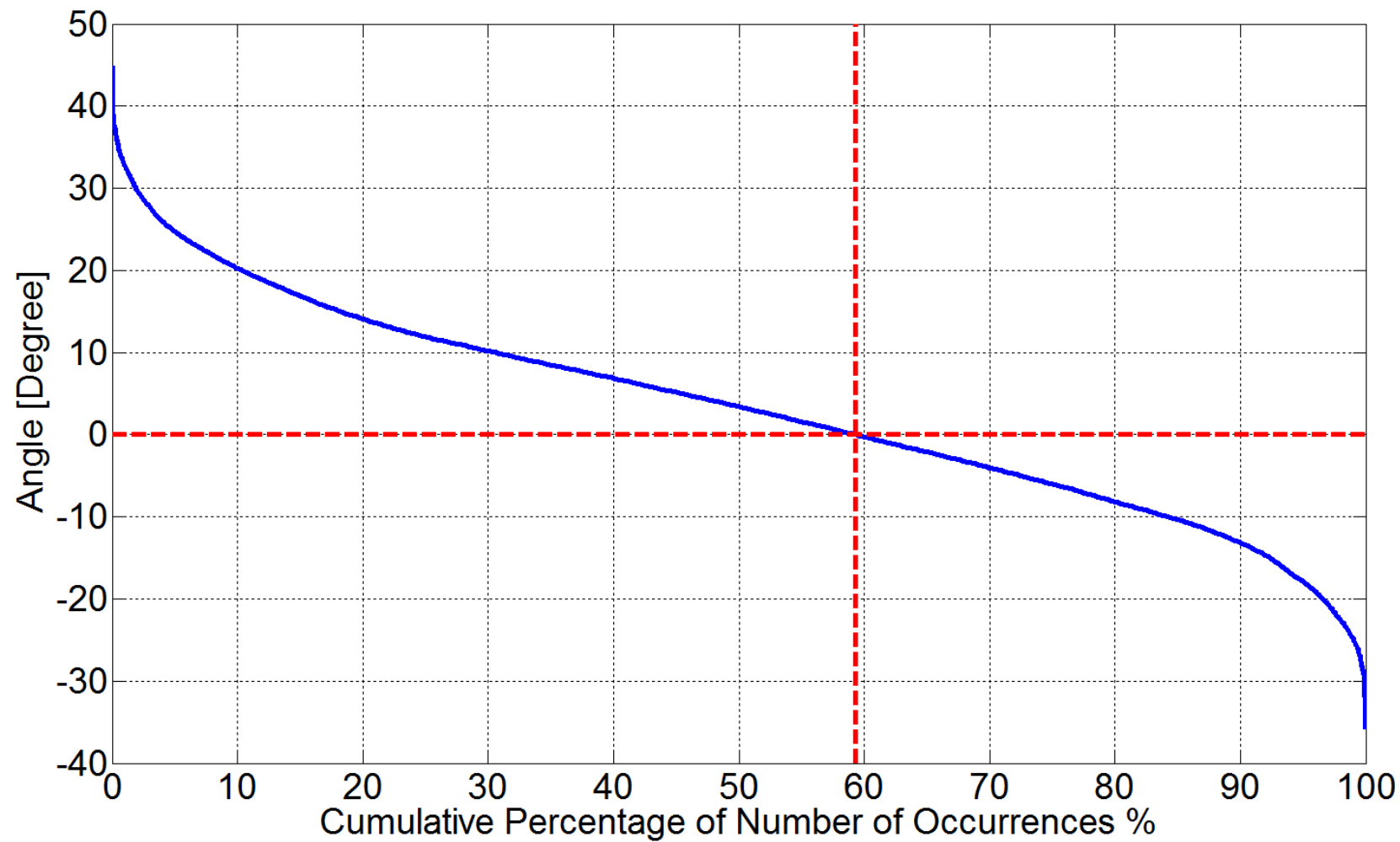
Coast 2-North 7



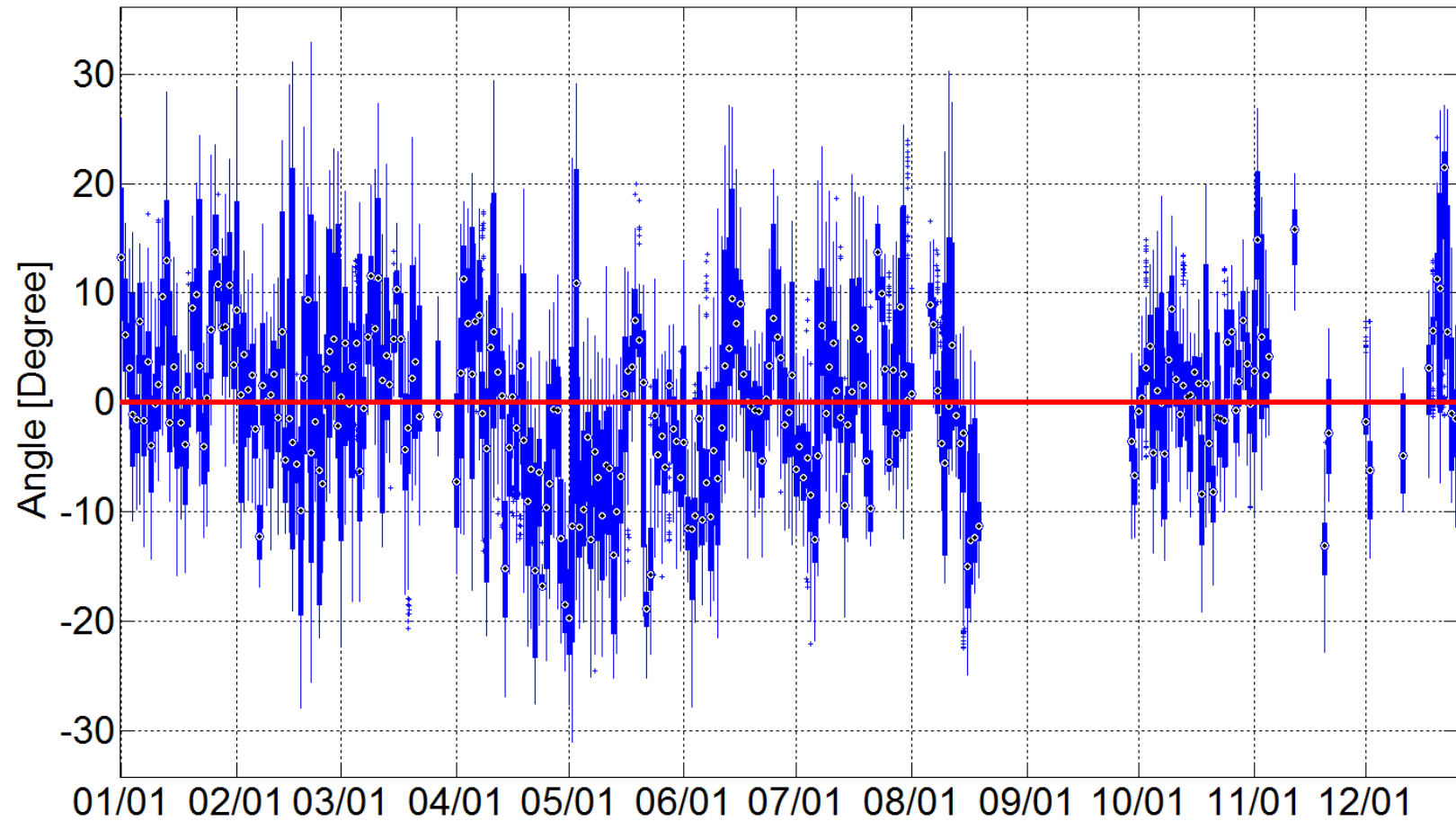
Coast 1-North 7



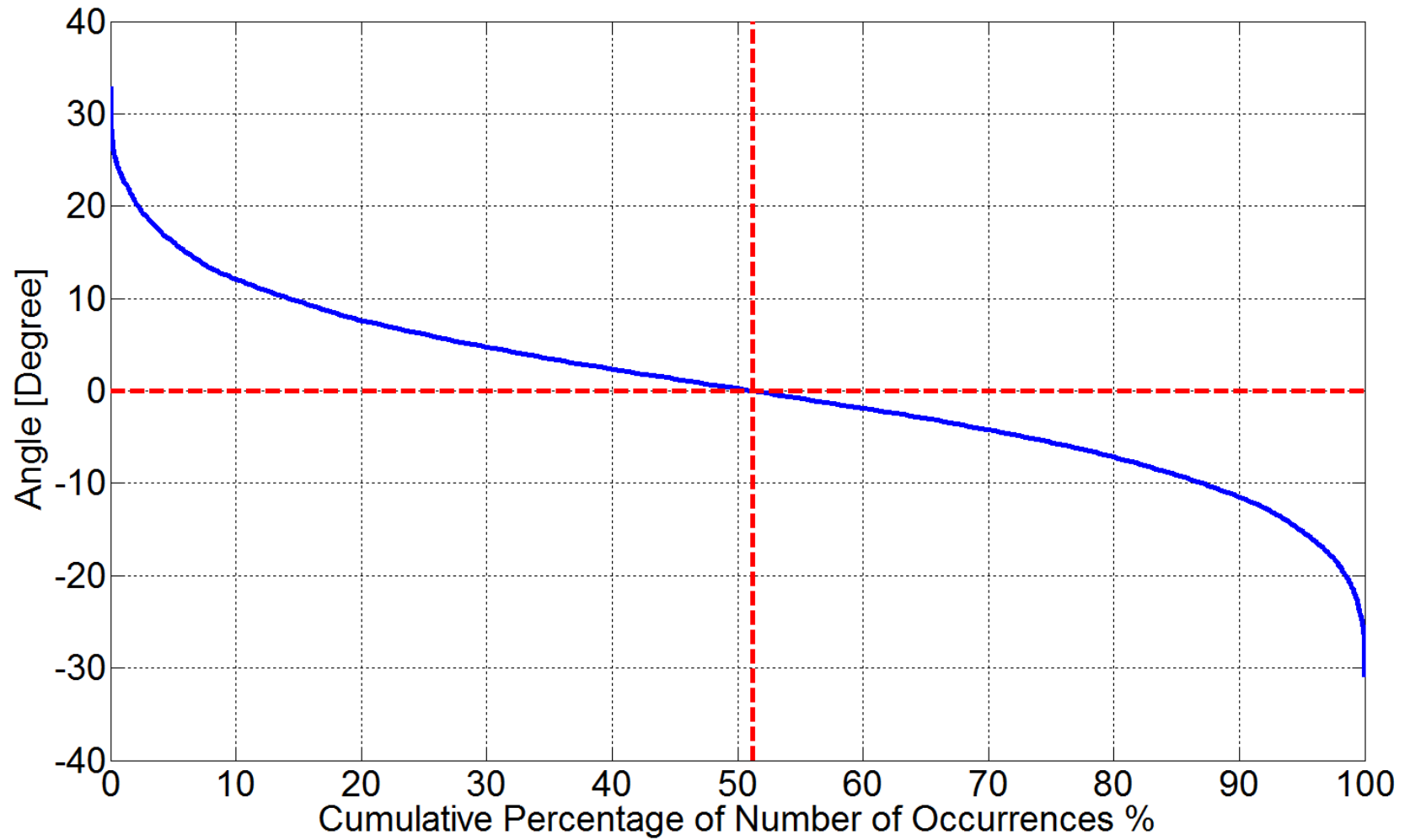
Coast 1-North 7



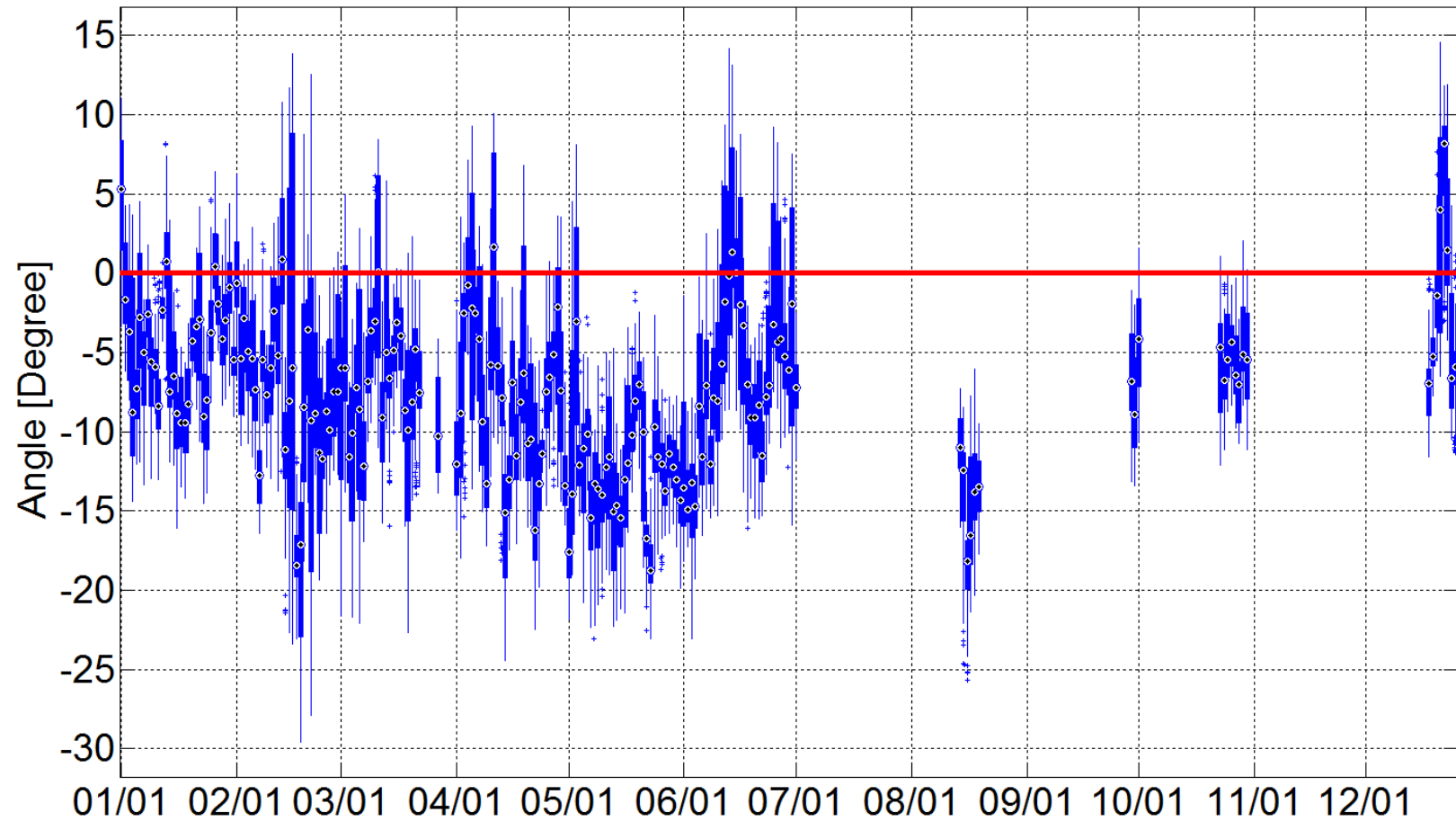
South 3-North 7



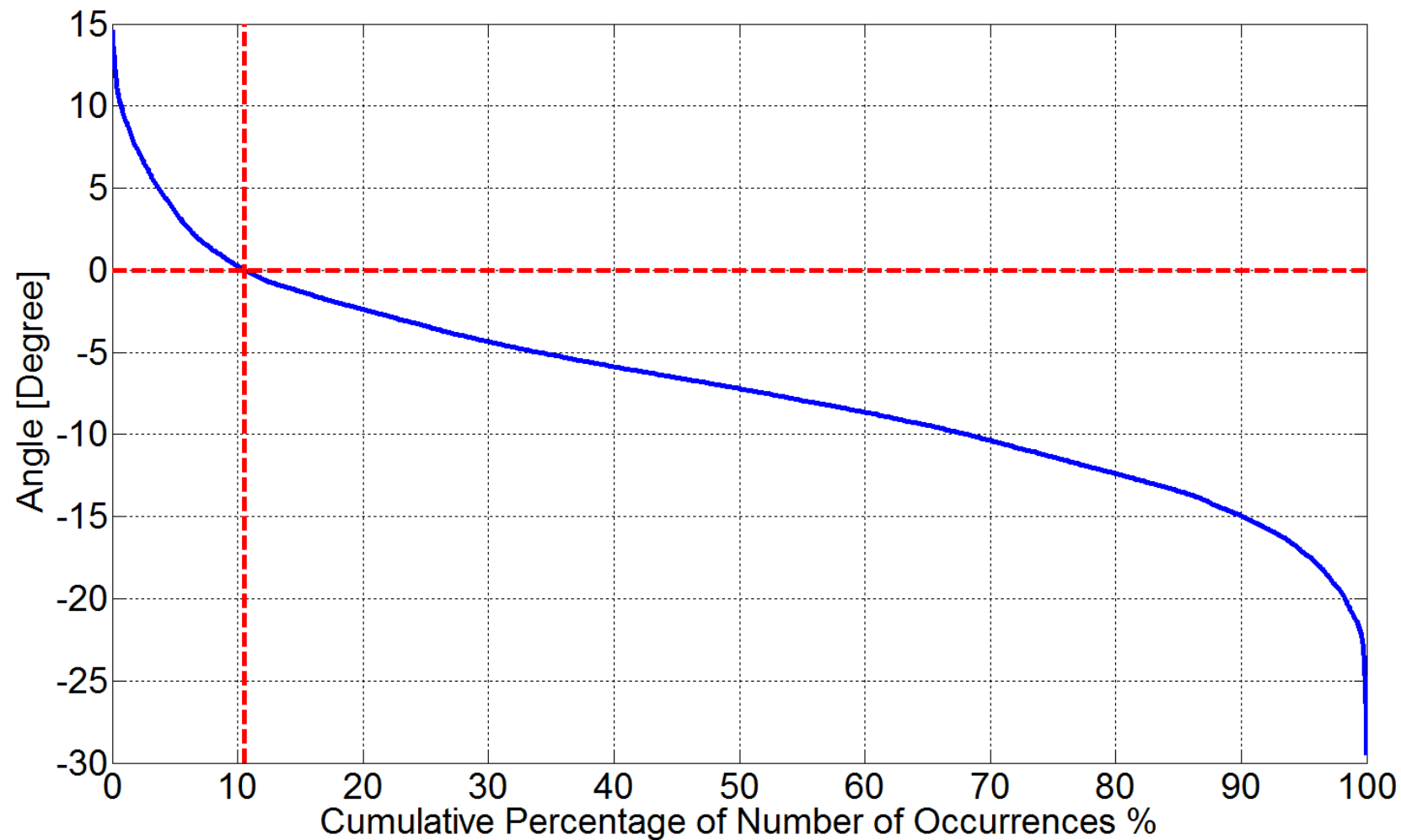
South 3-North 7



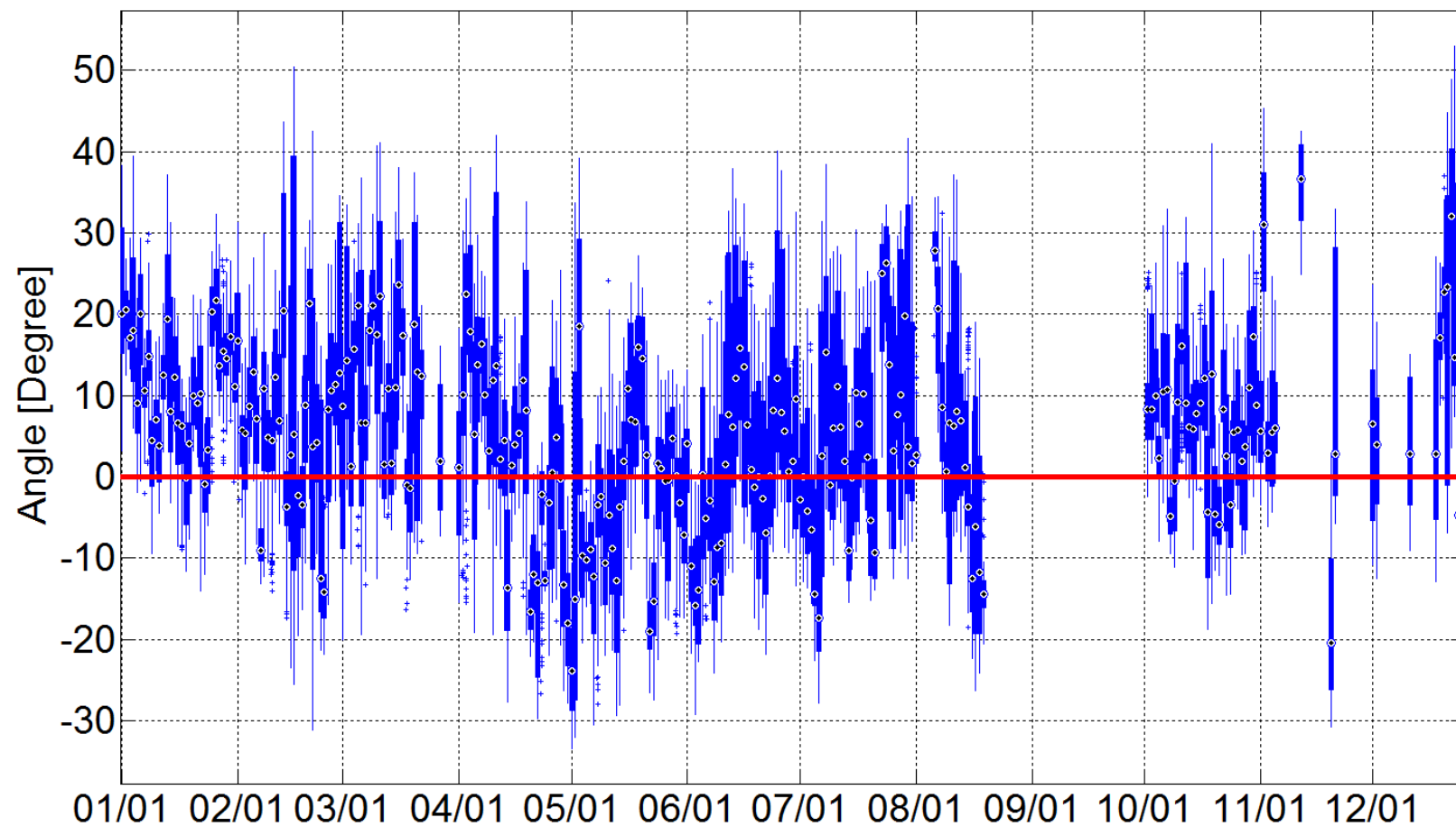
South 5-North 7



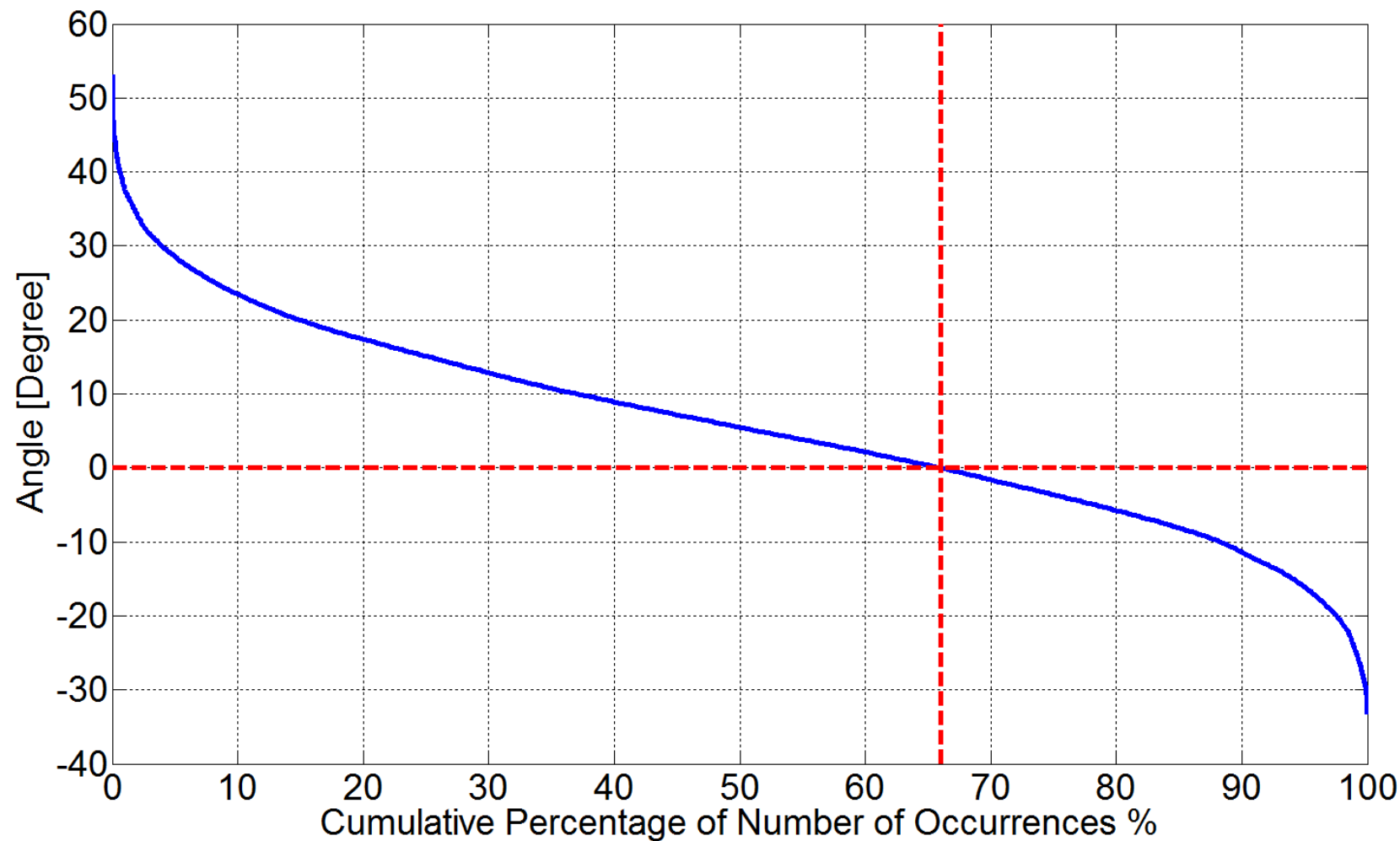
South 5-North 7



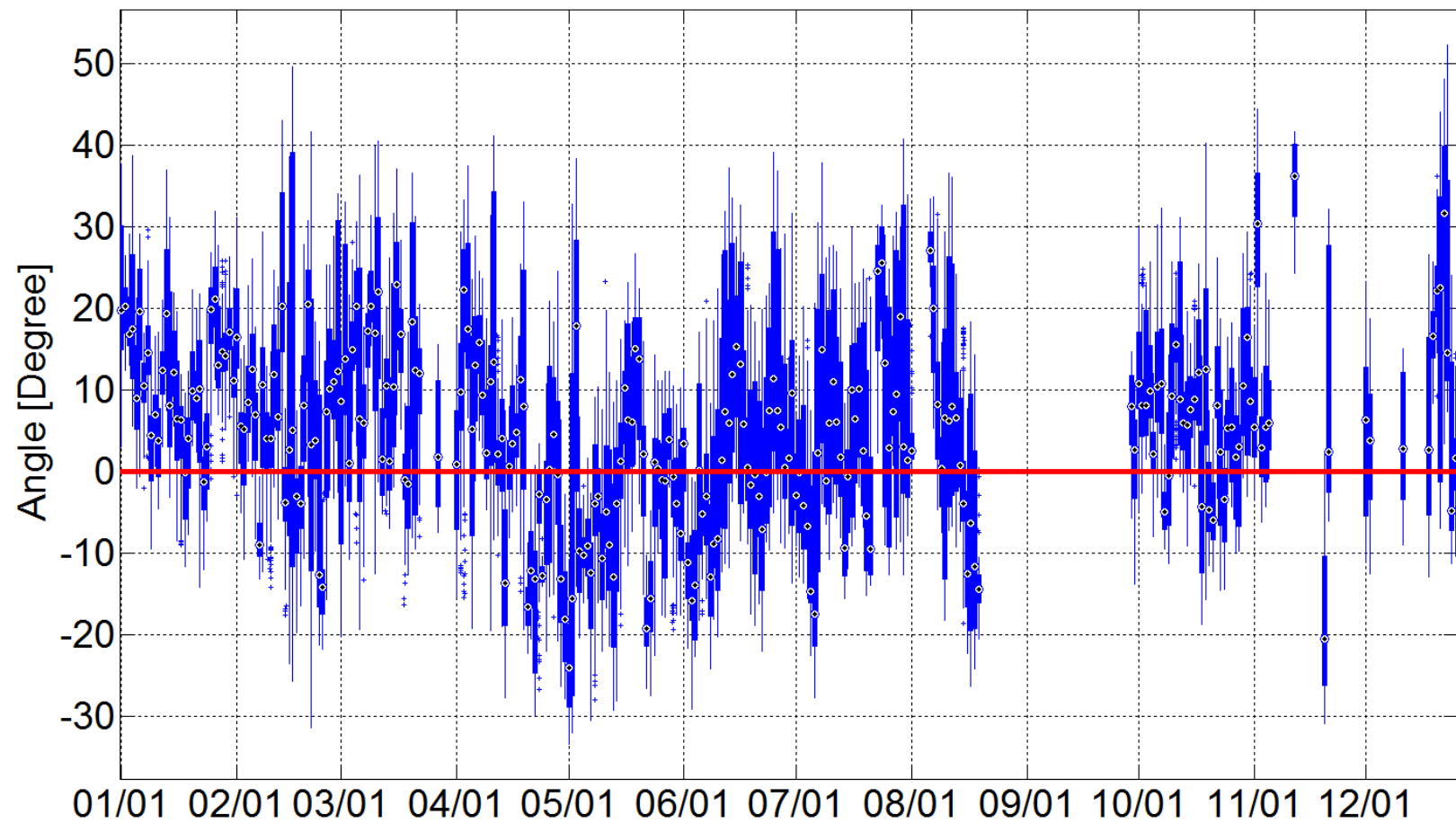
Coast 4-North 7



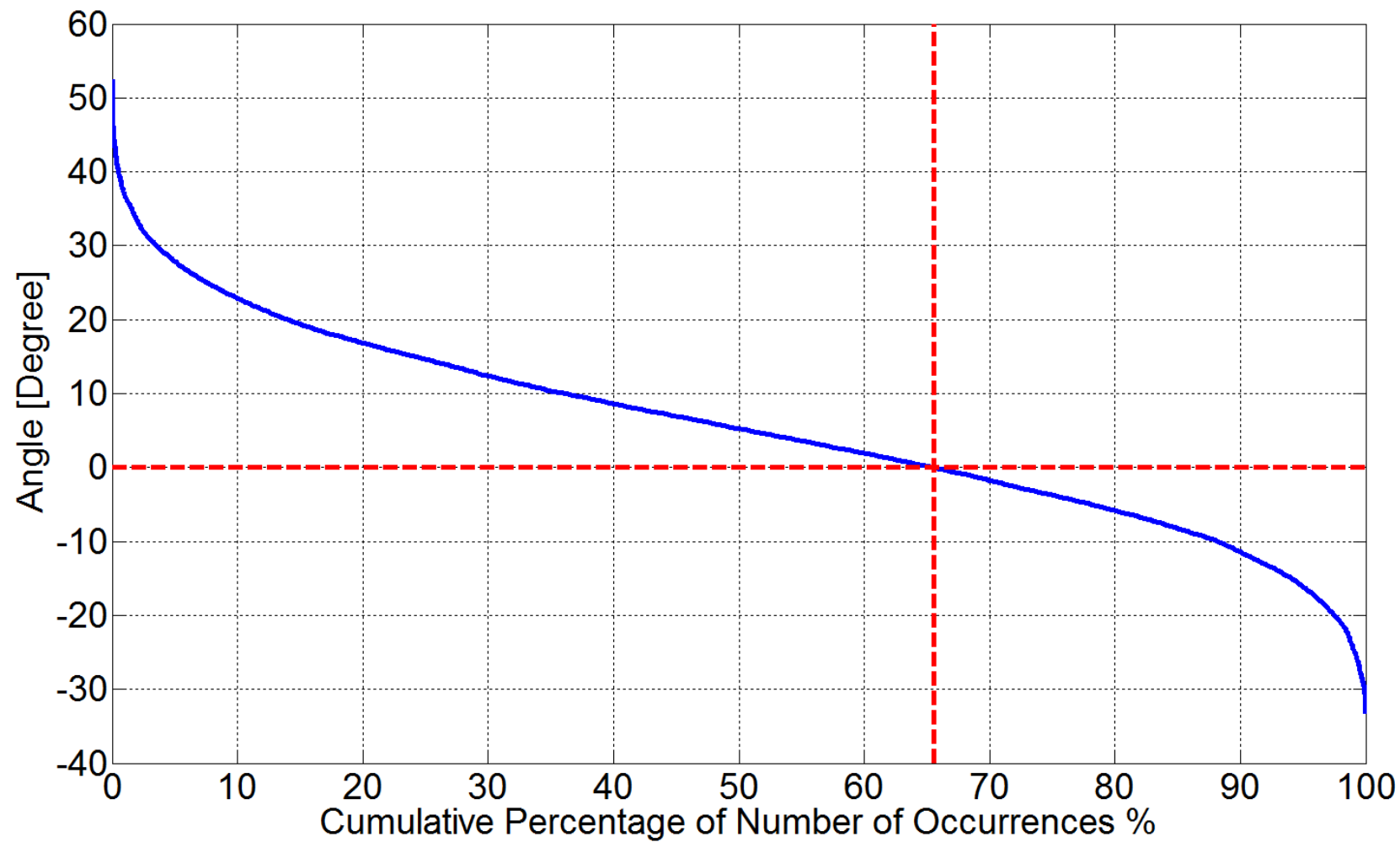
Coast 4-North 7



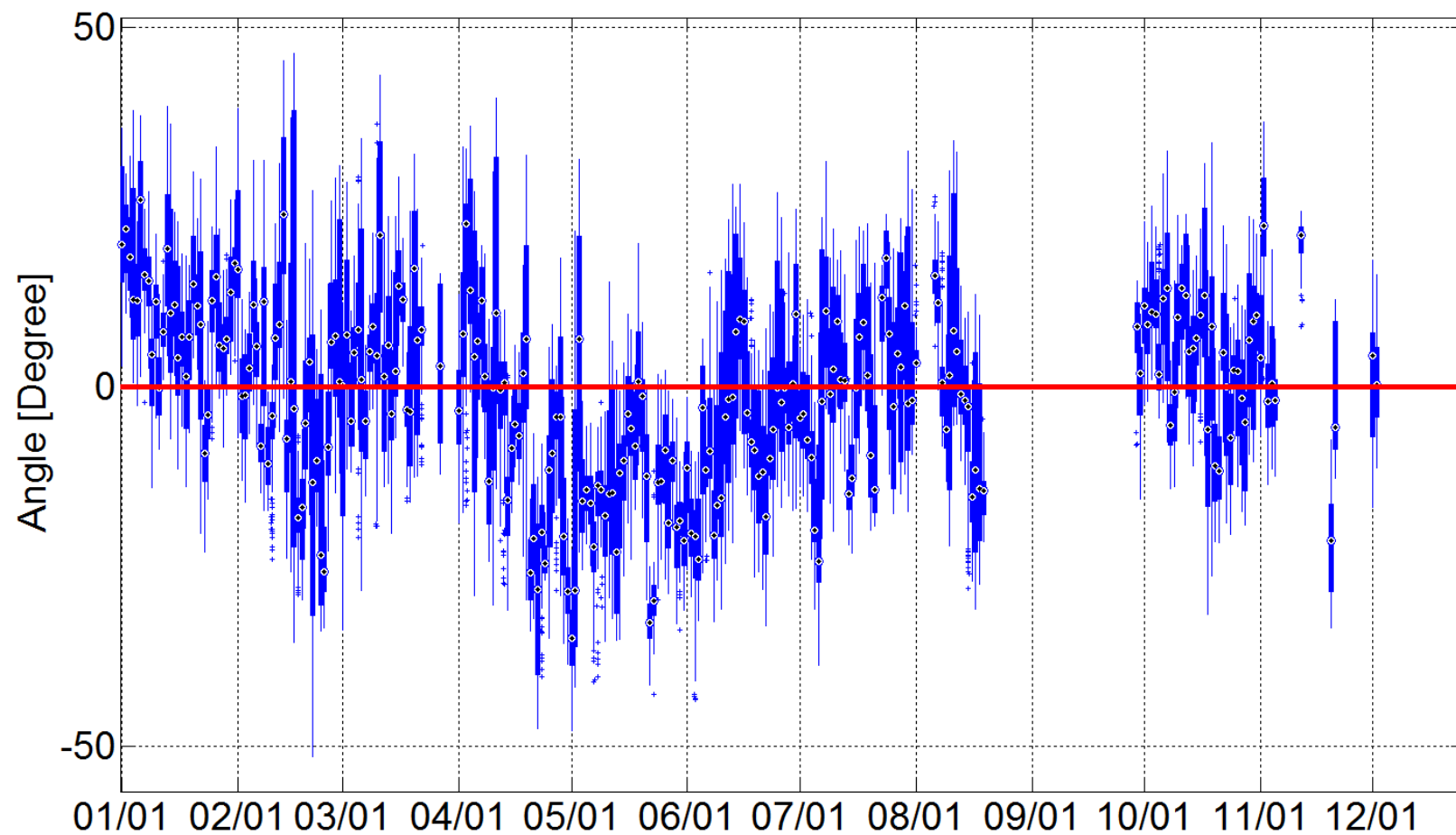
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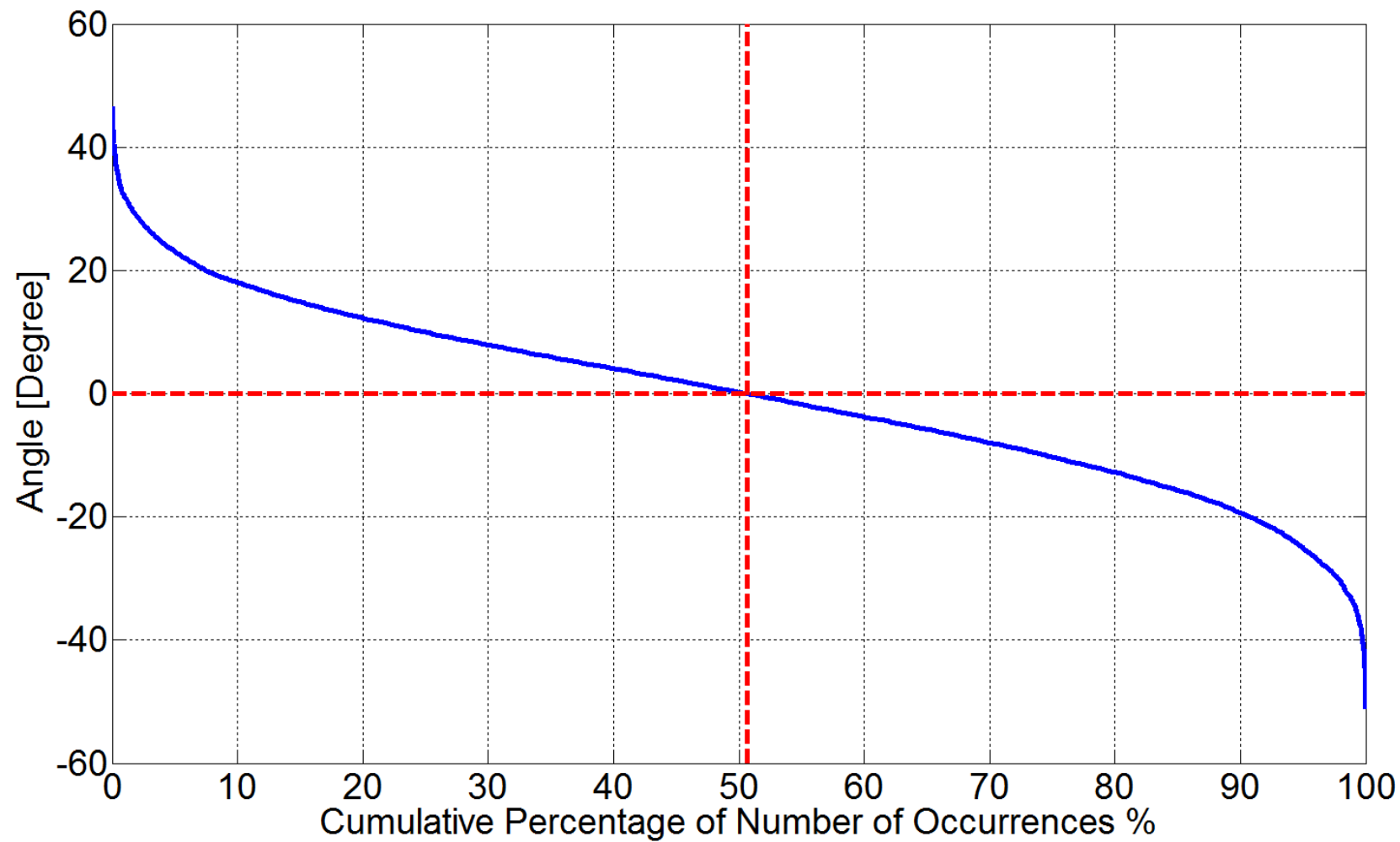
Coast 3-North 7



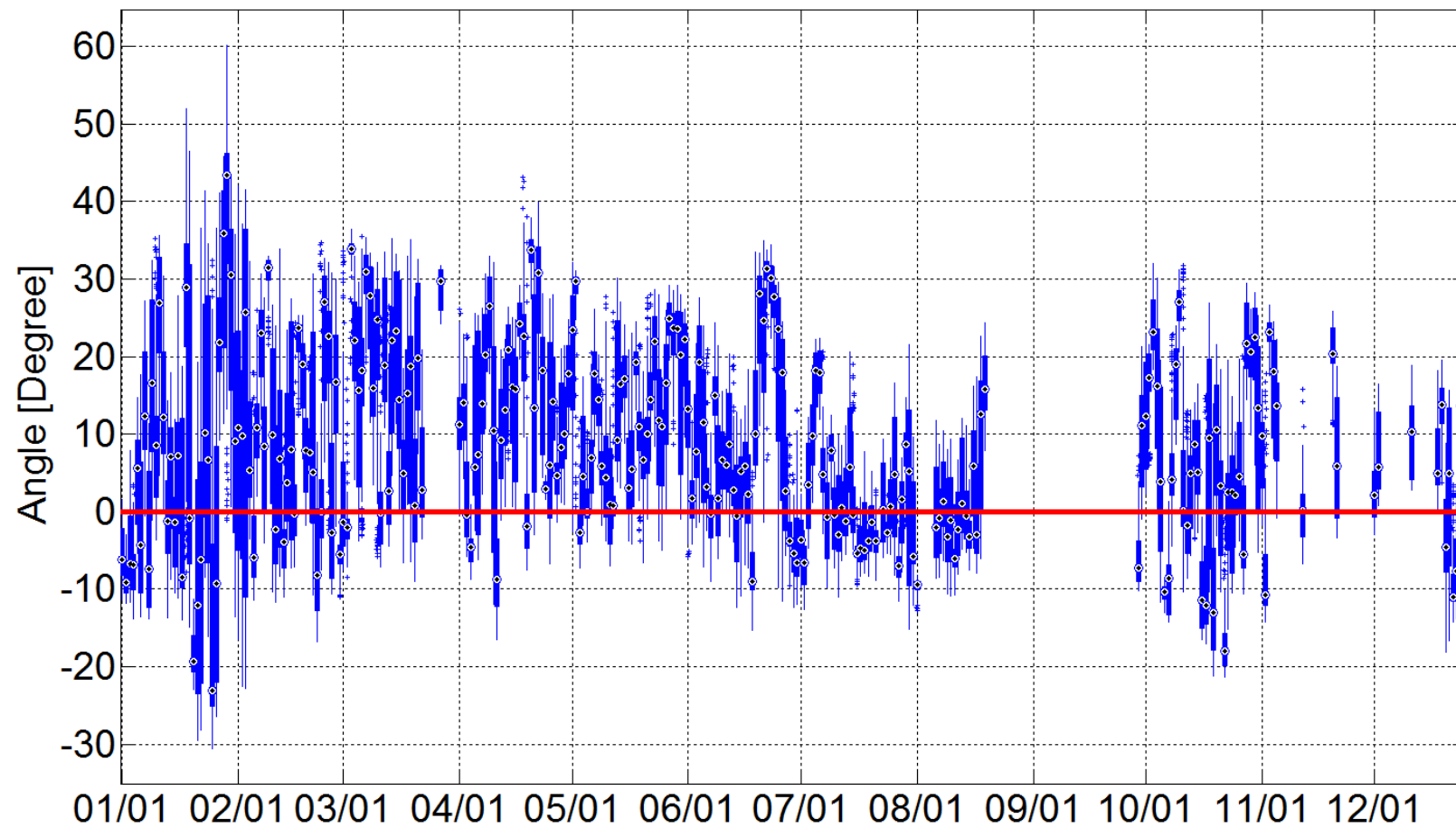
South 13-North 7



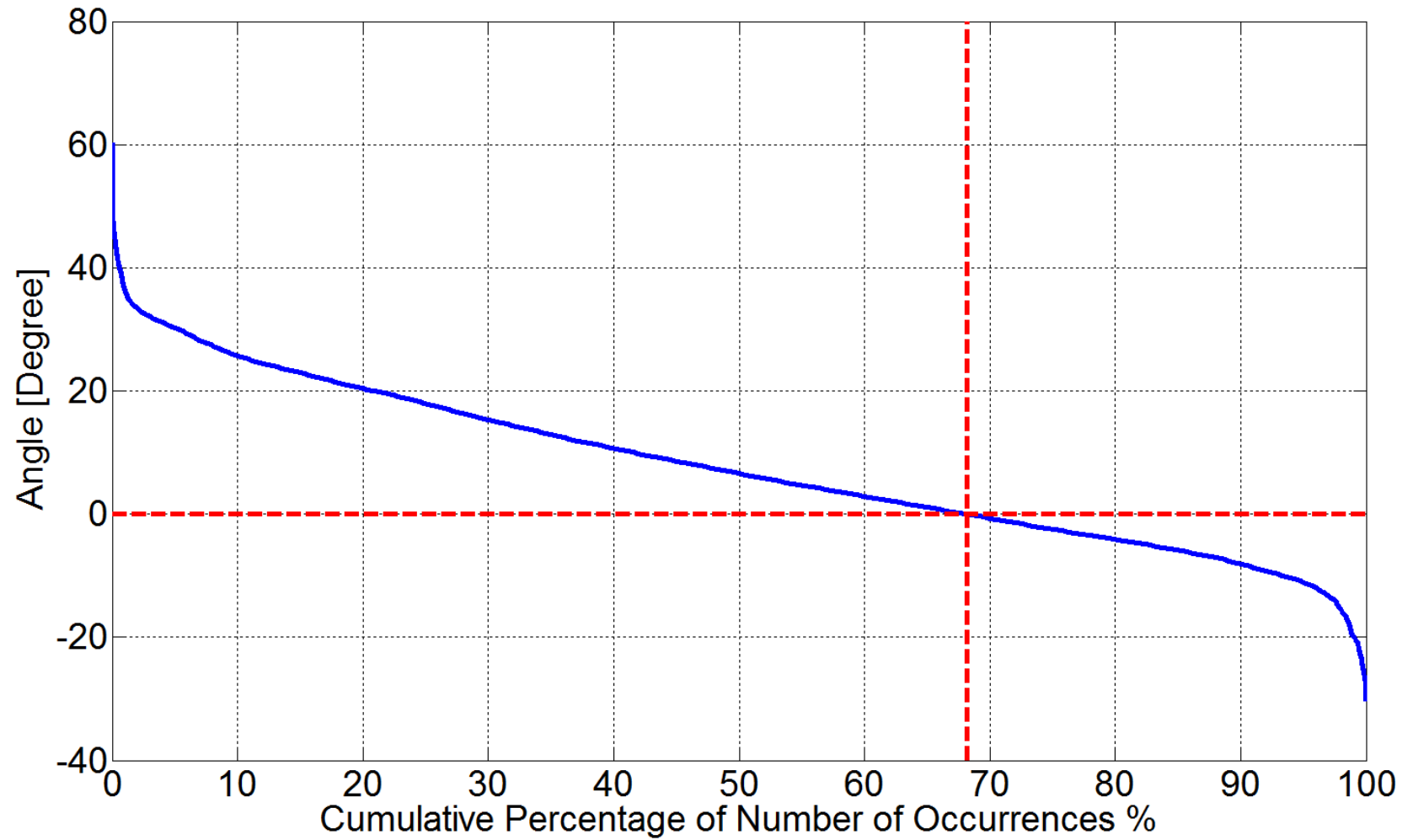
South 13-North 7



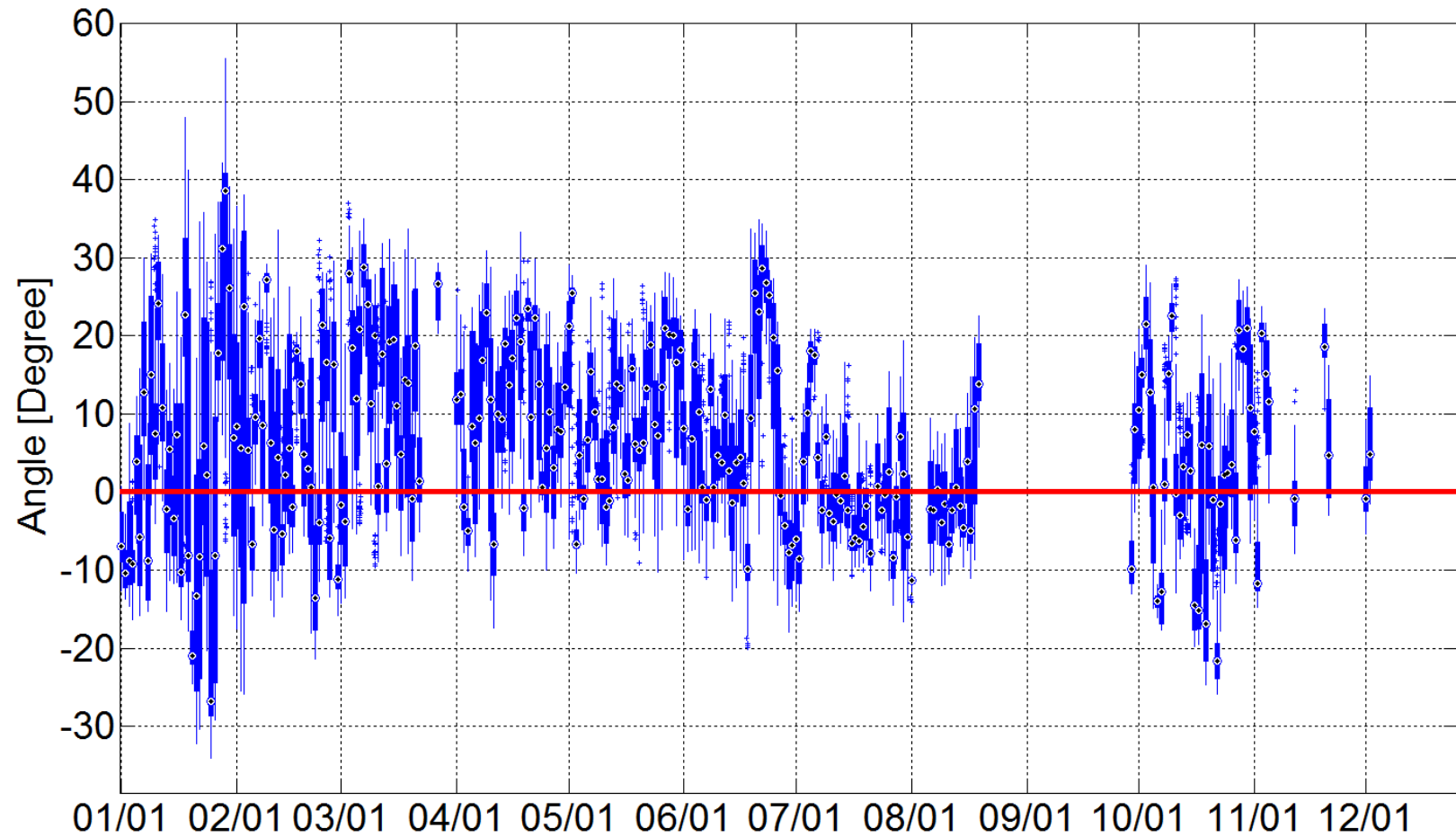
FarWest 4-North 7



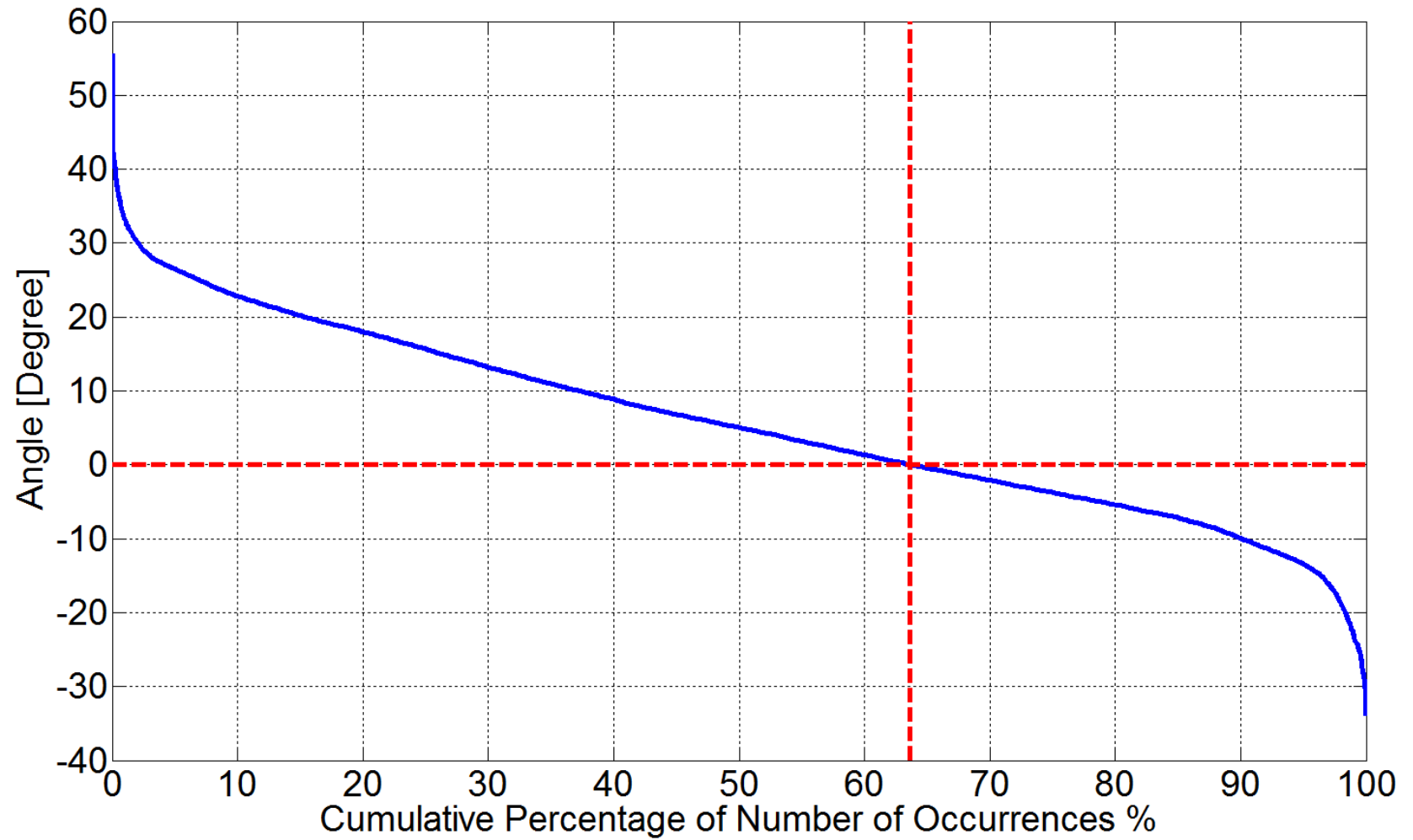
FarWest 4-North 7



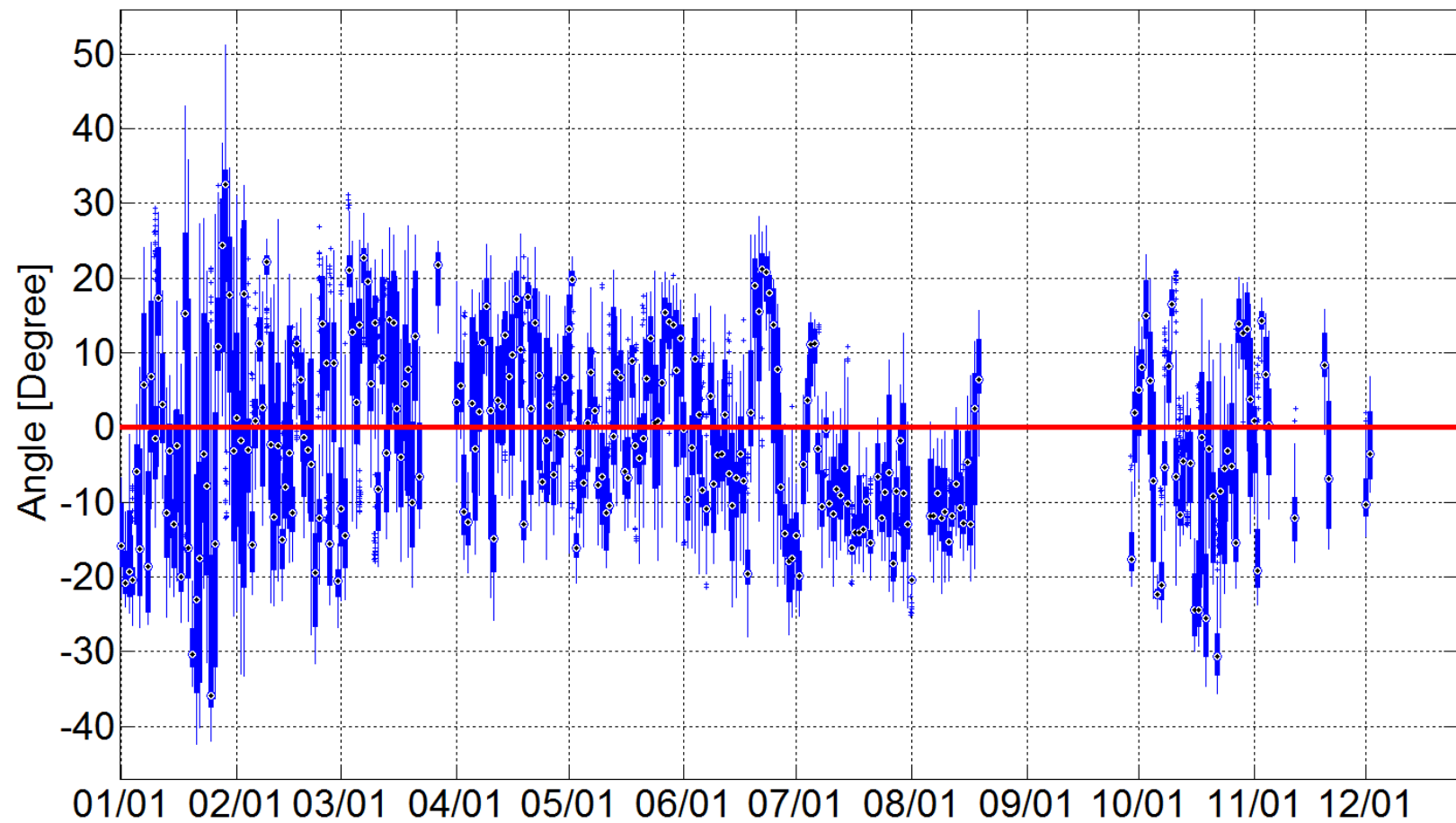
FarWest 7-North 7



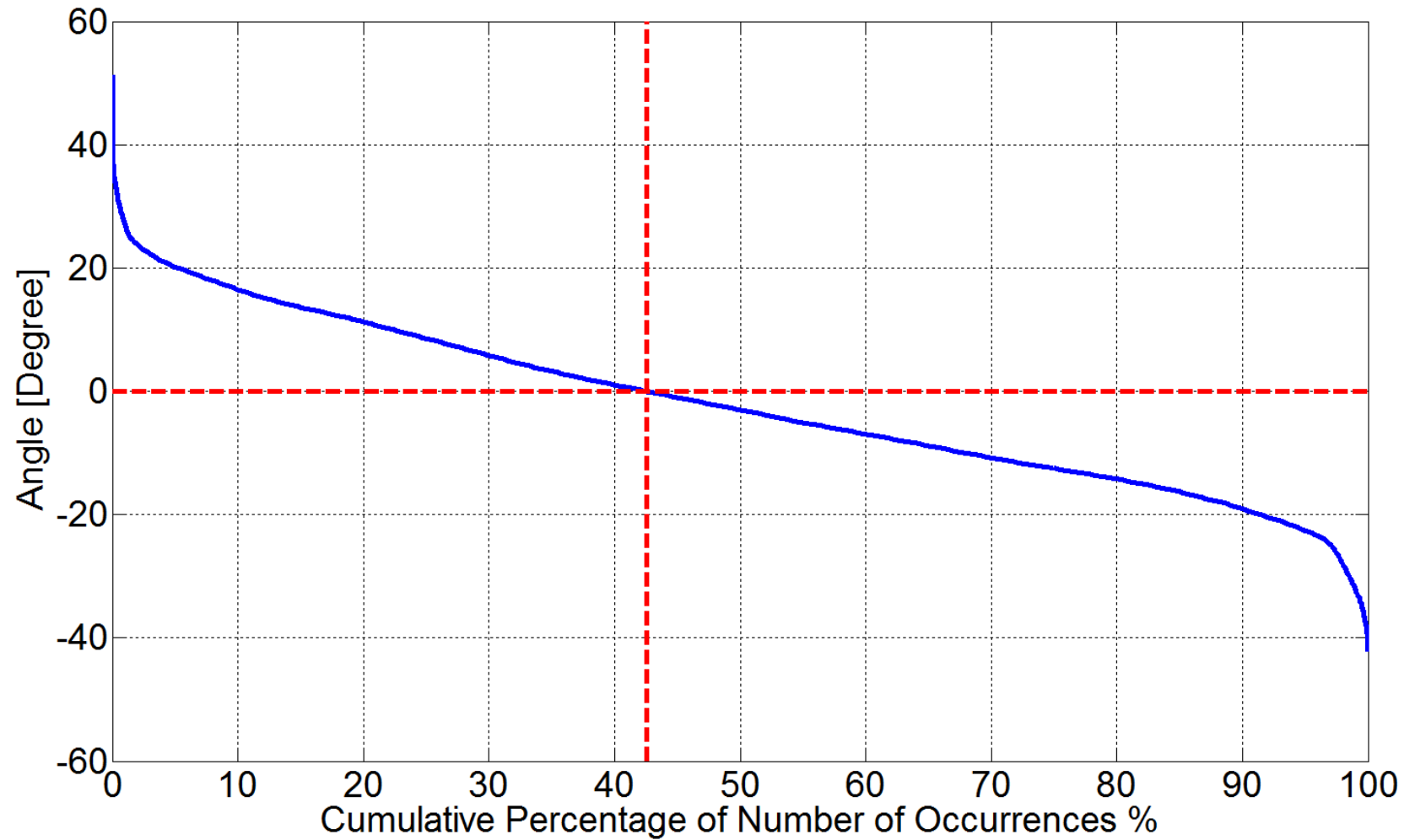
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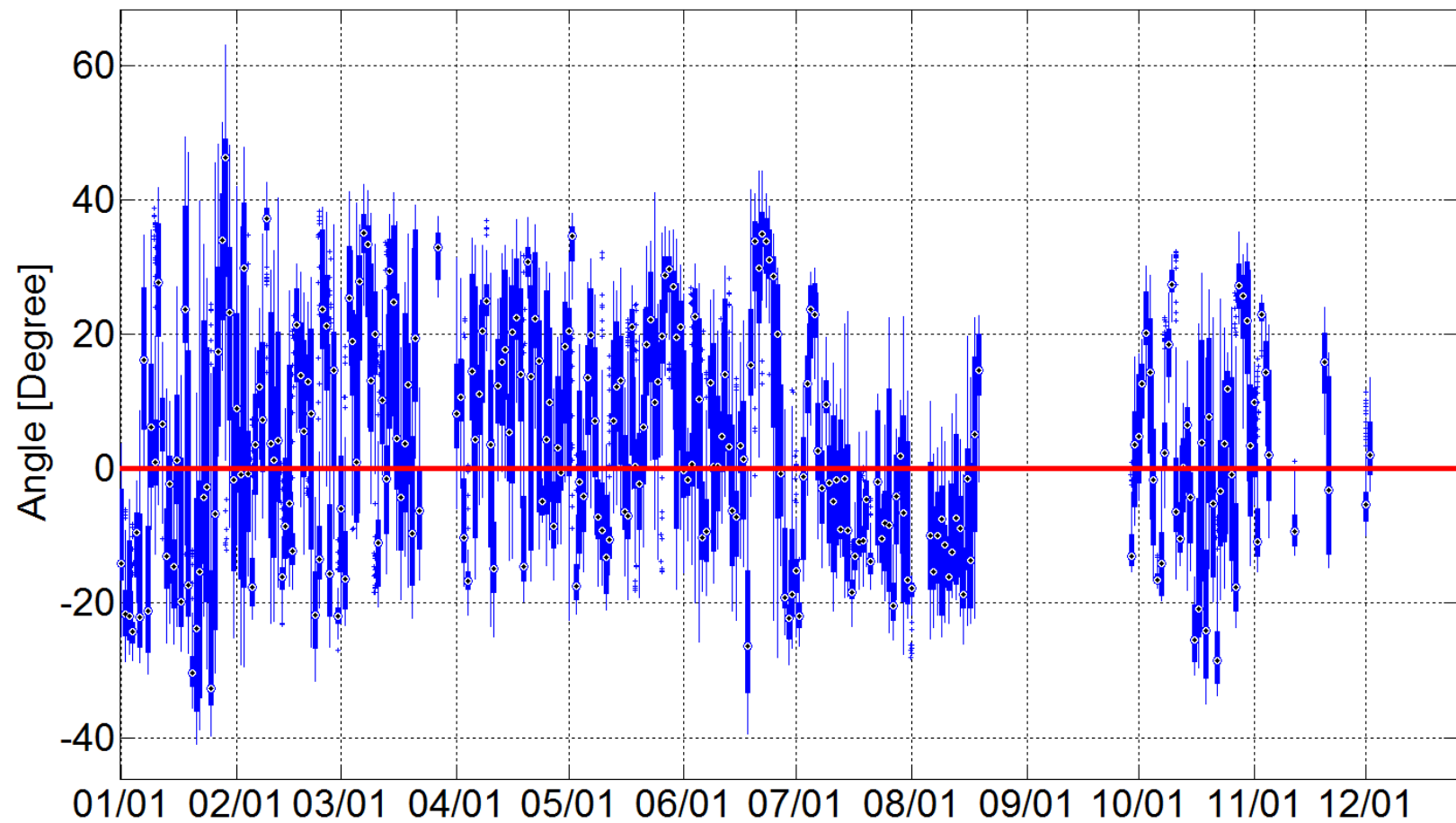
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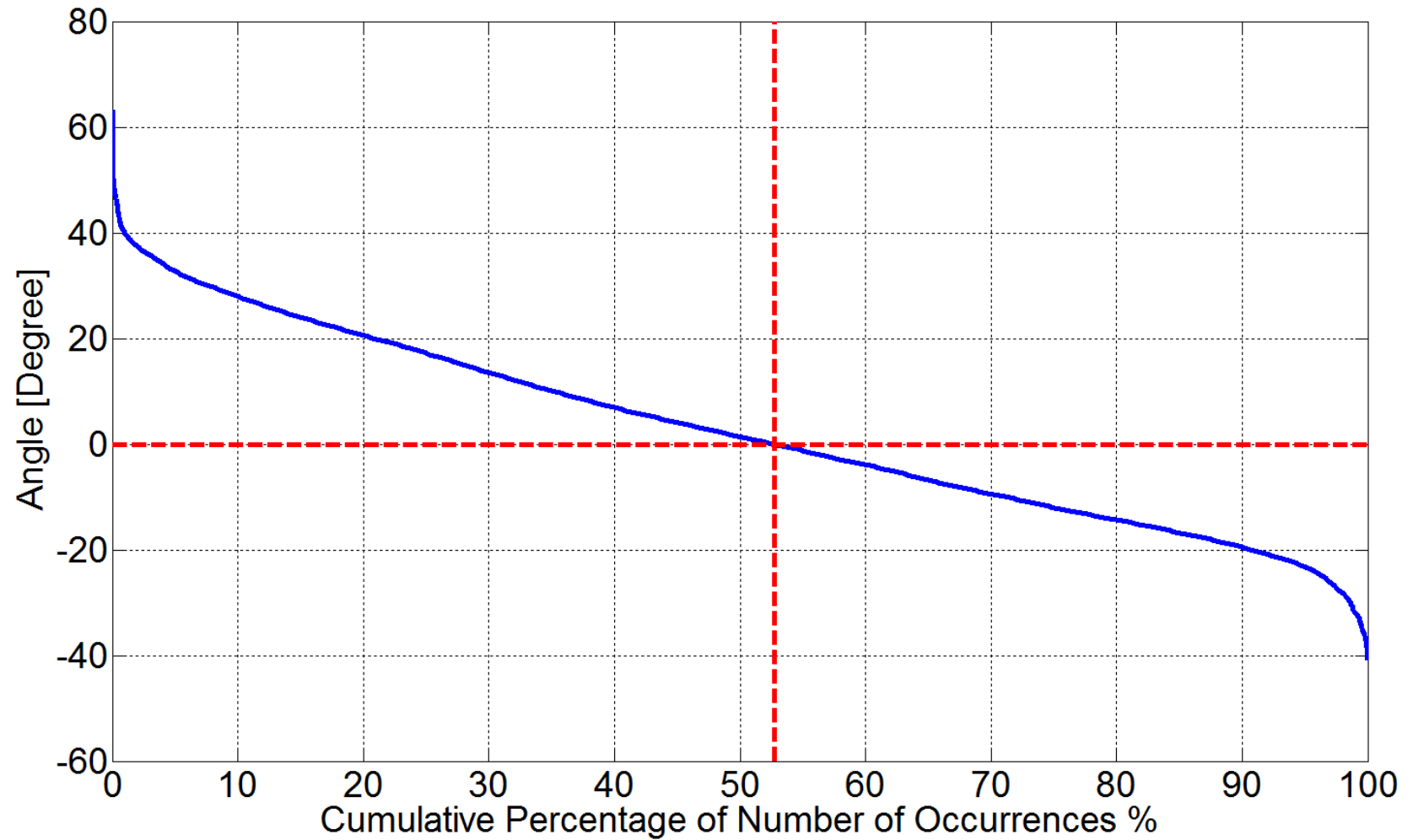
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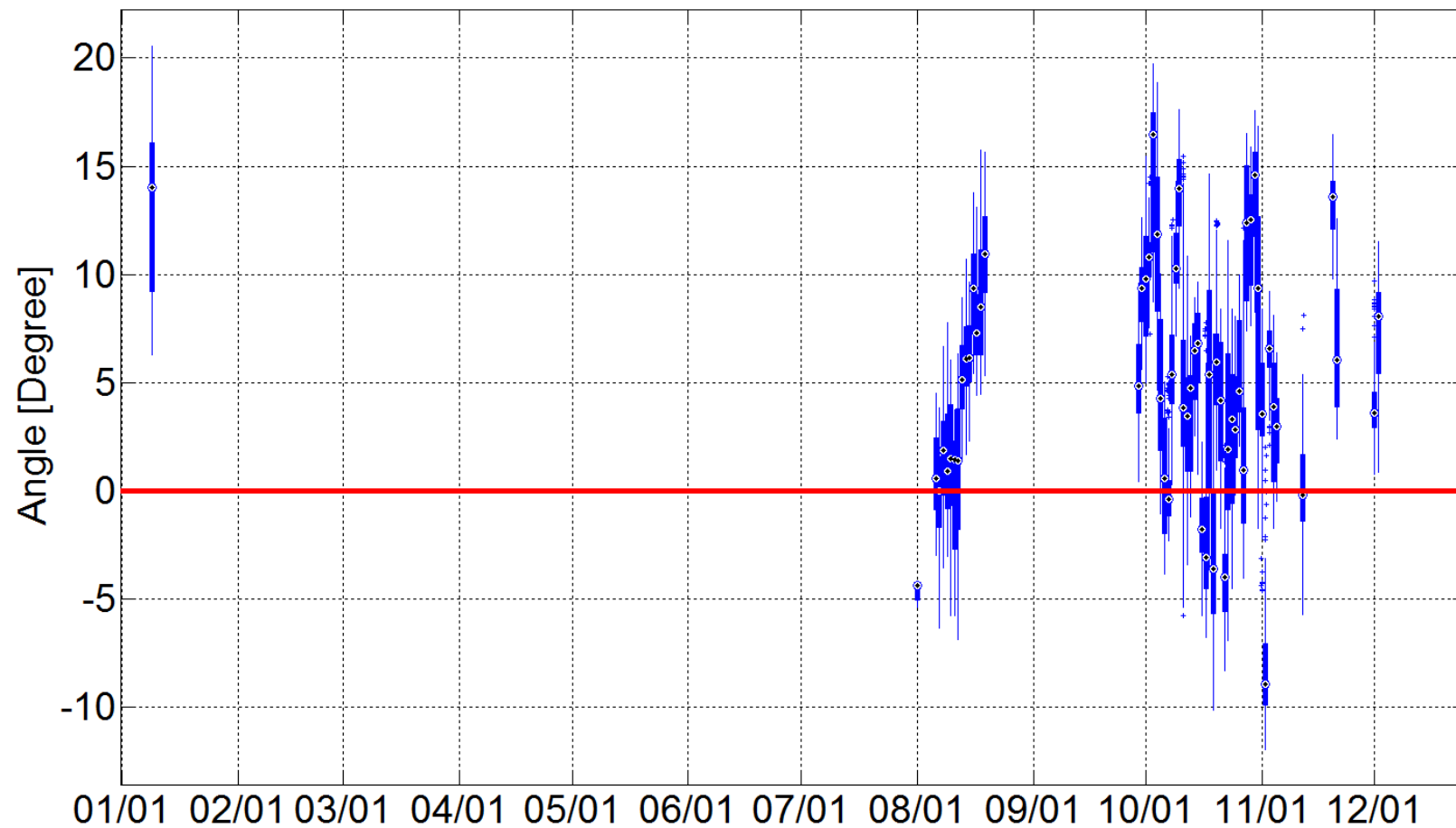
FarWest 9-North 7



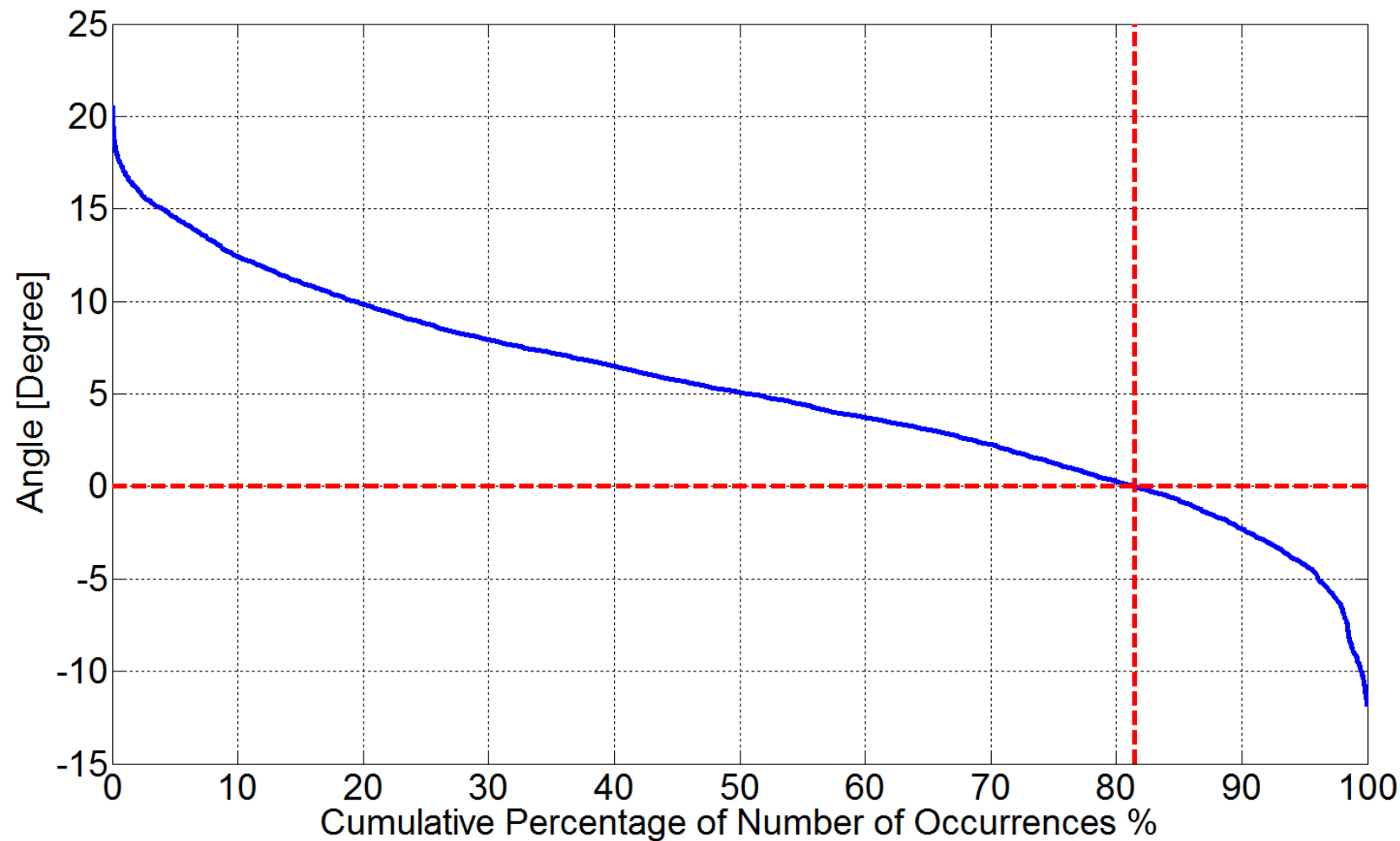
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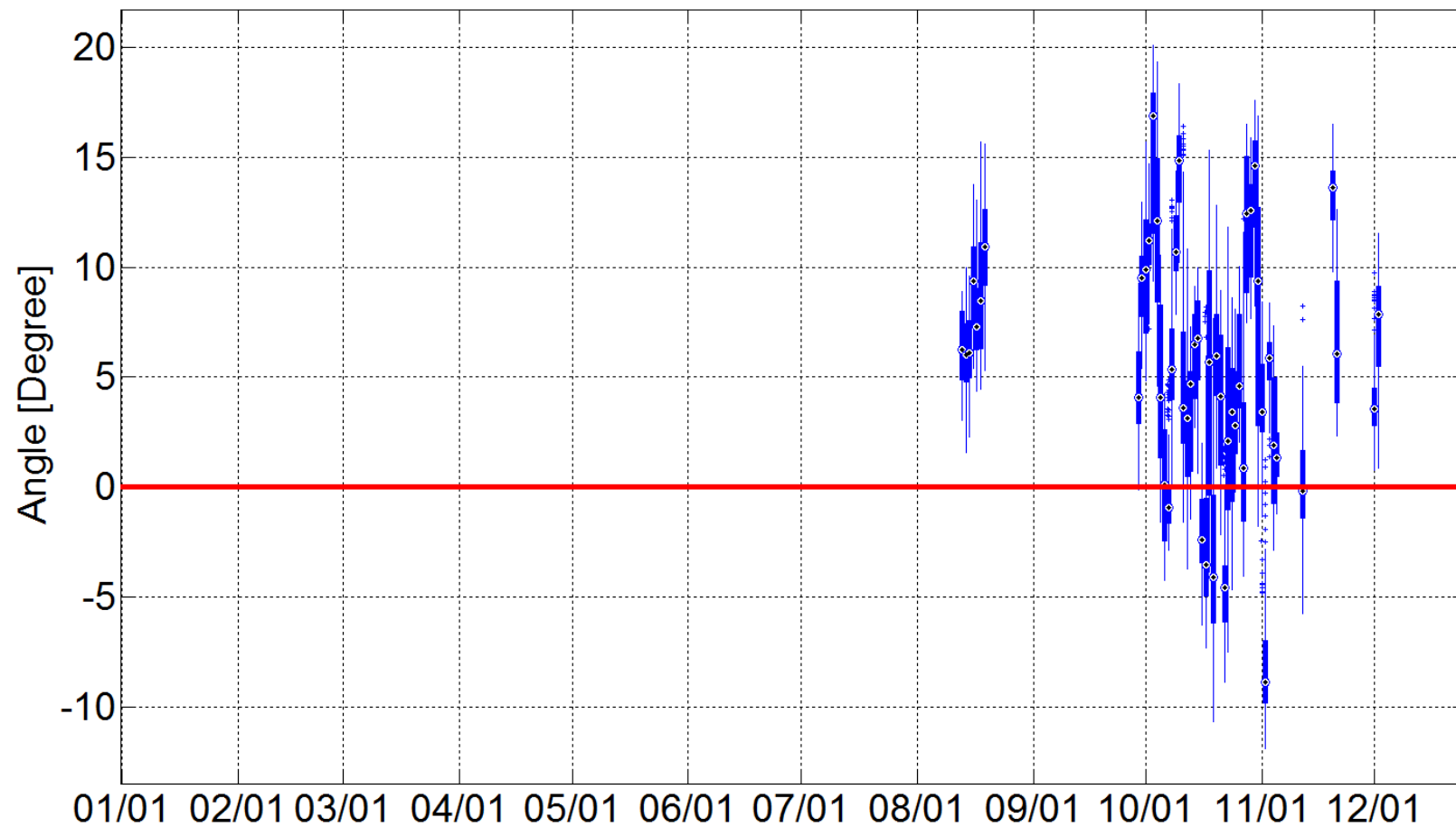
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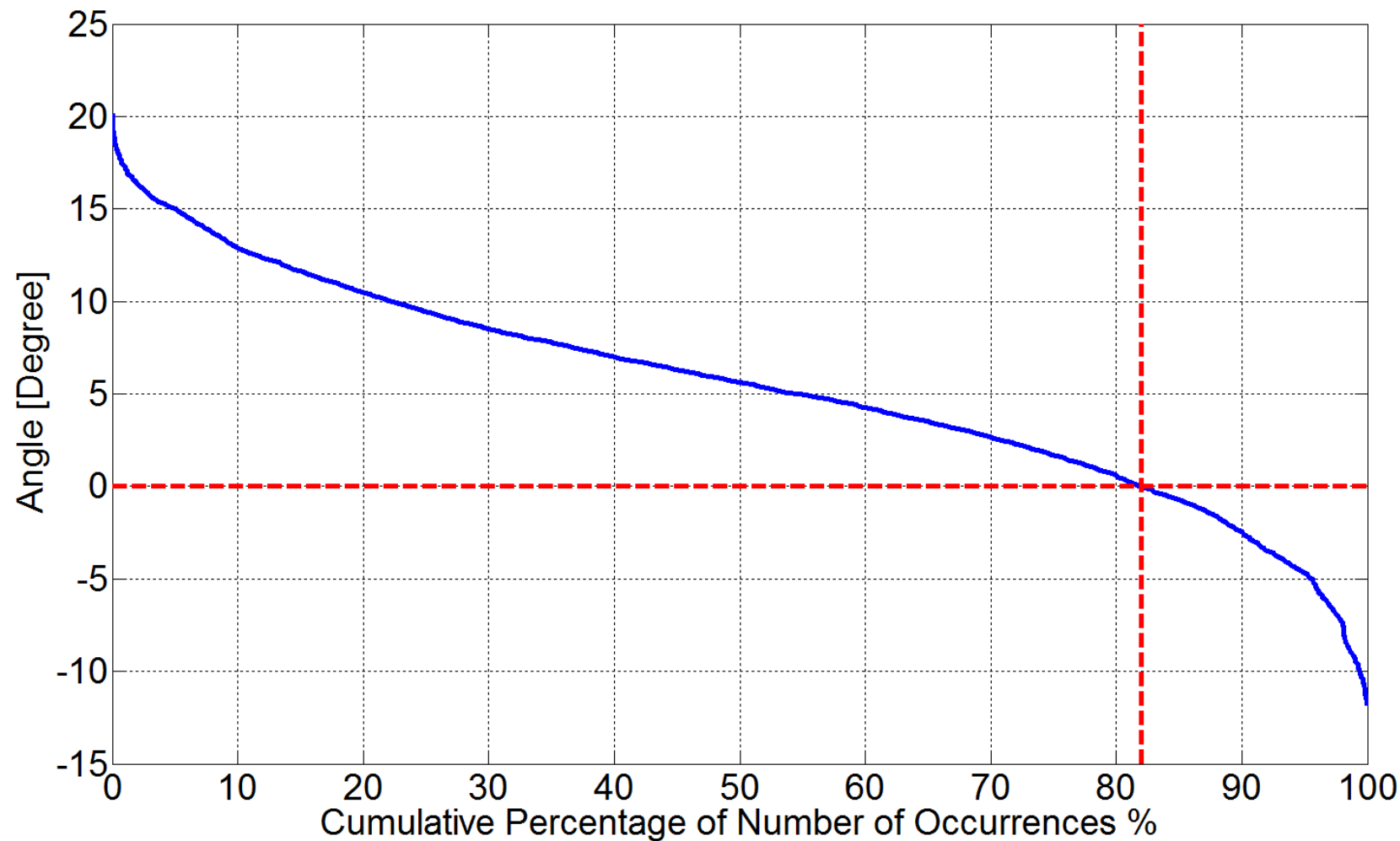
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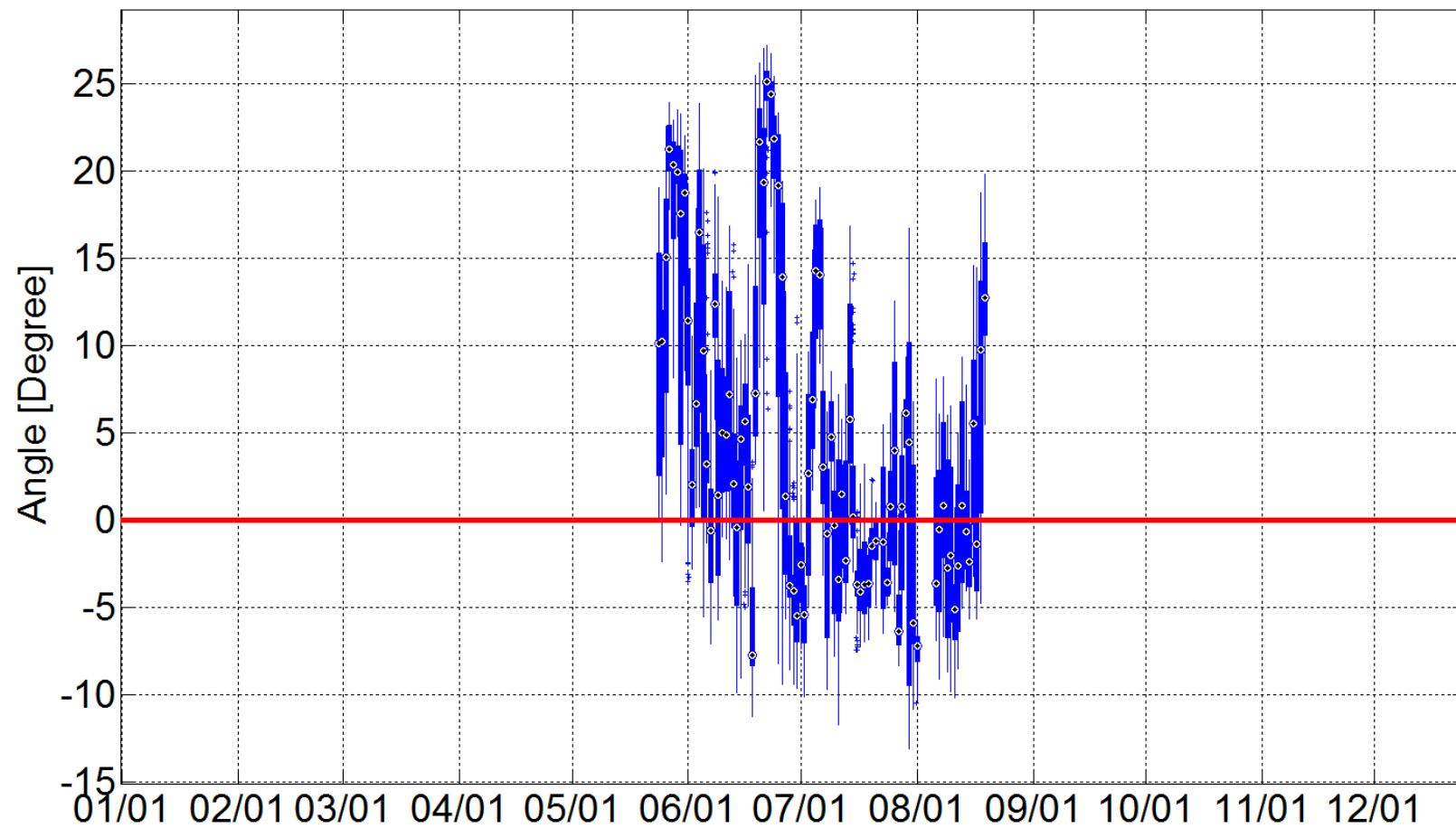
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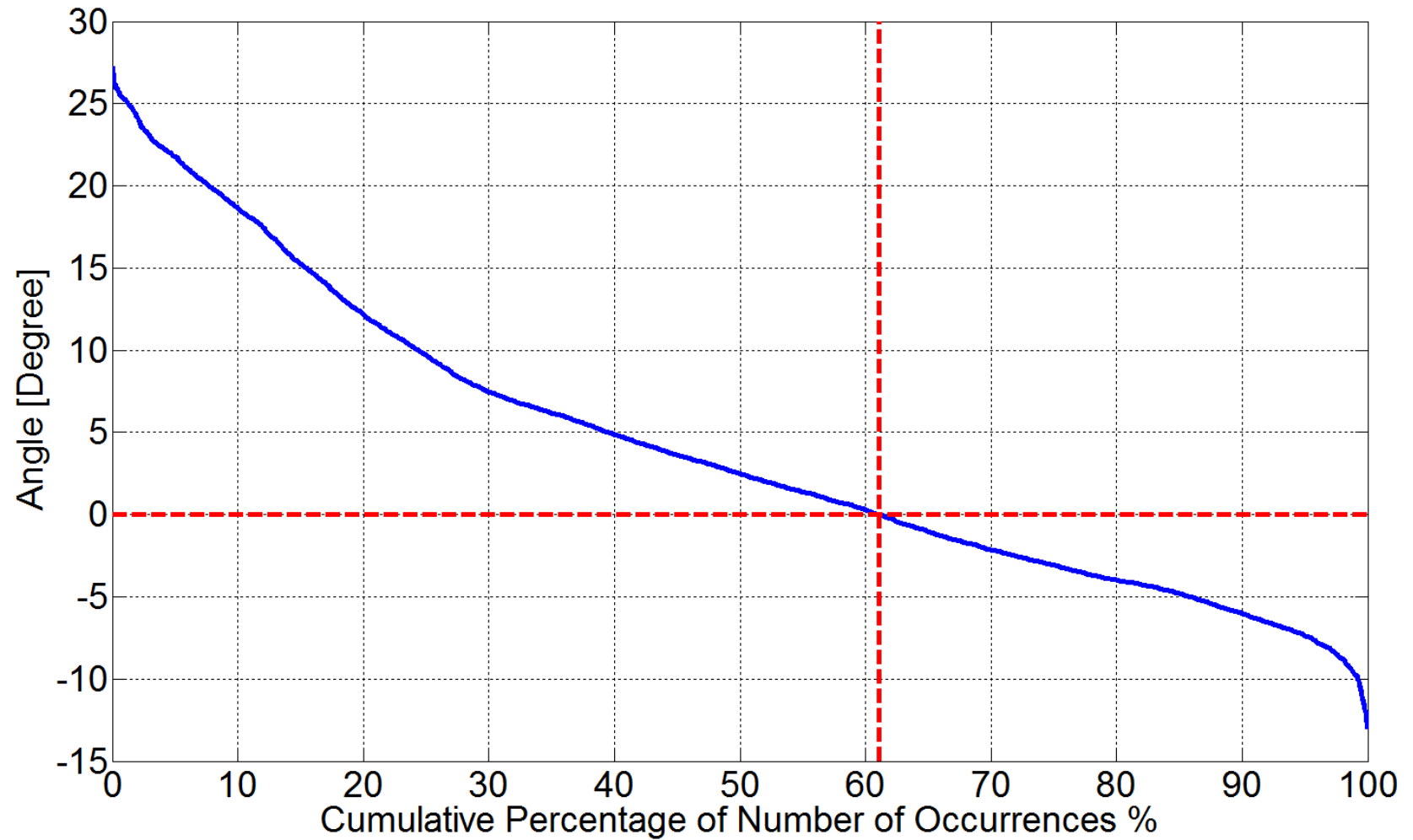
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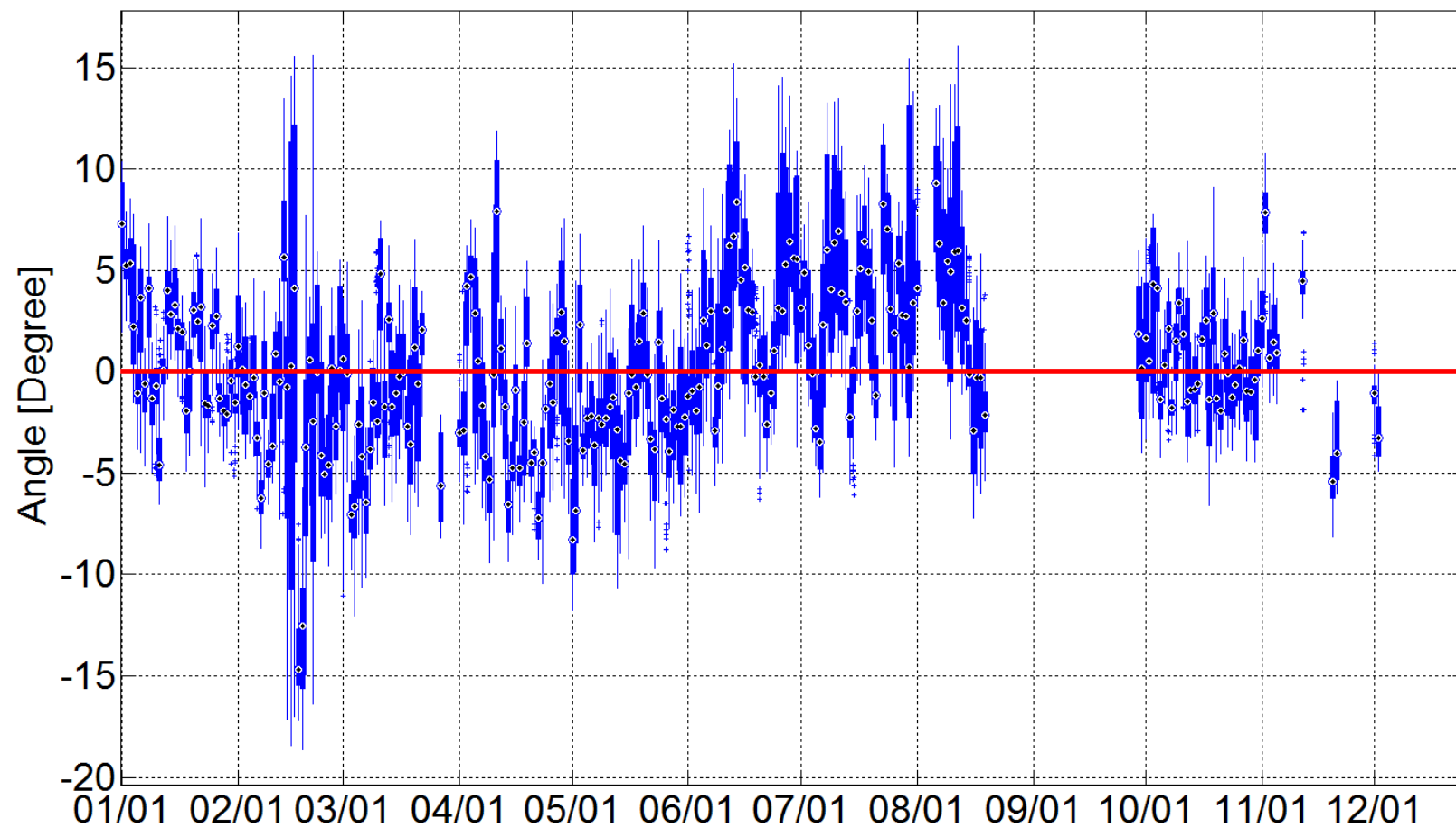
West 8-North 7



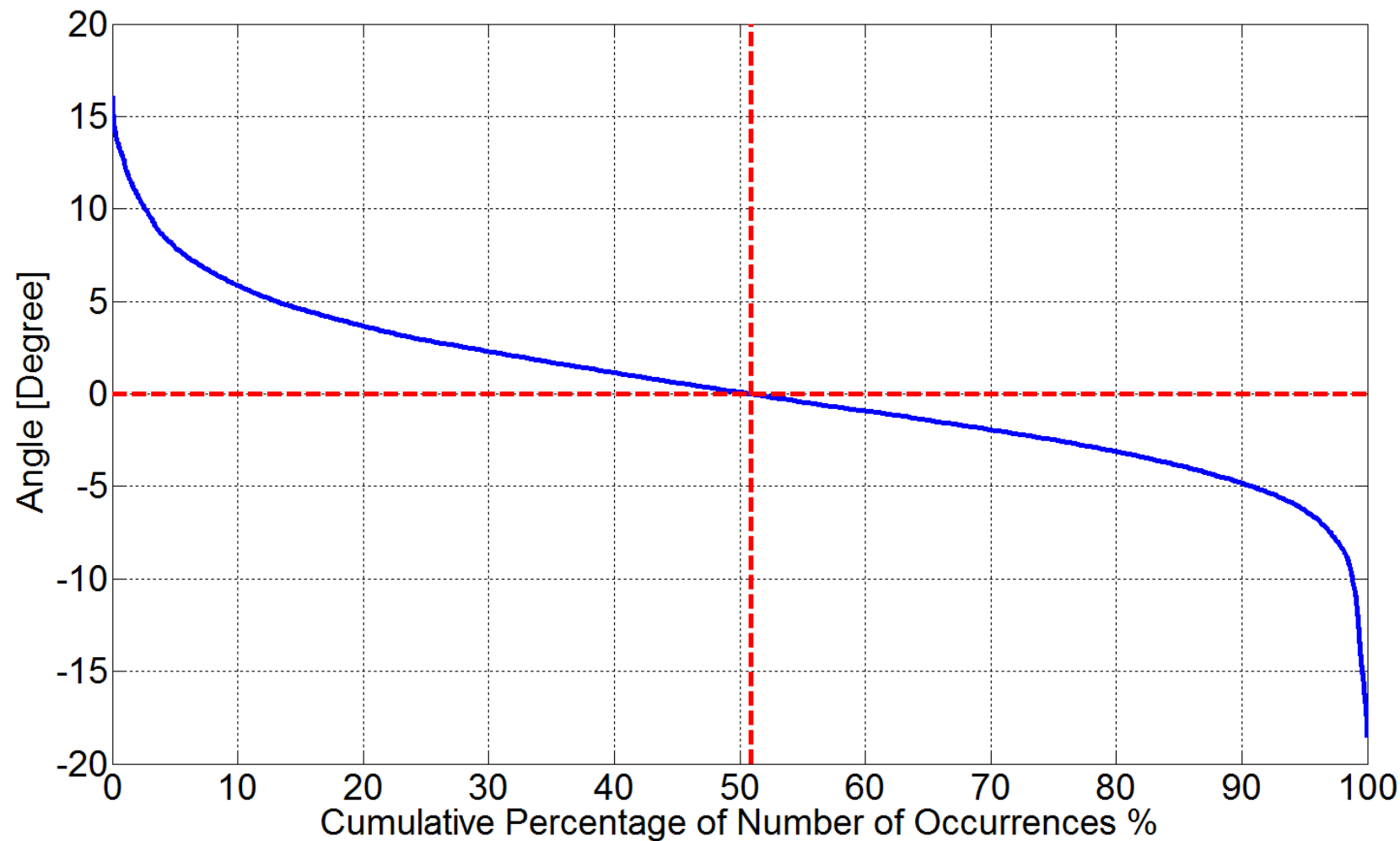
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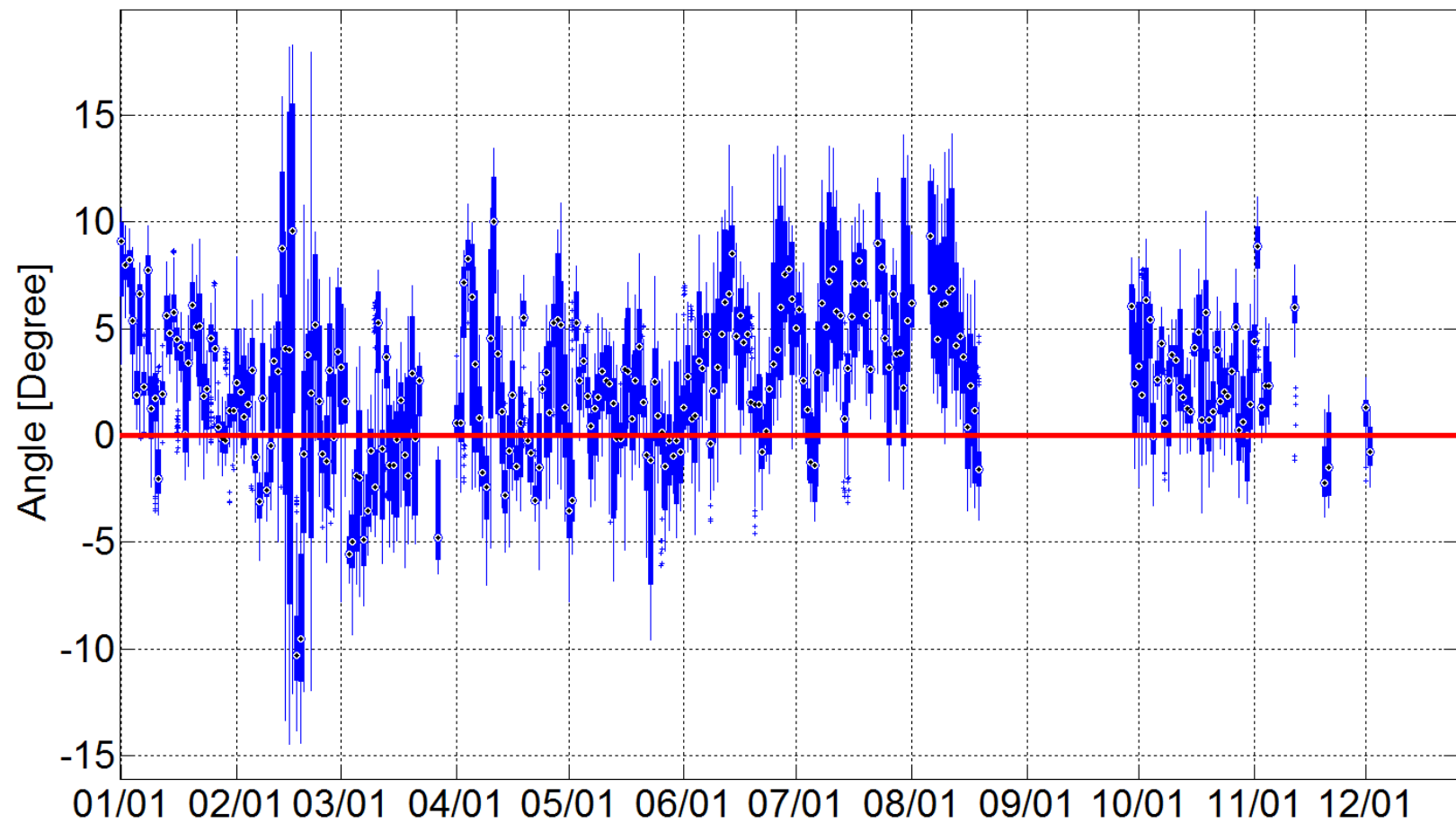
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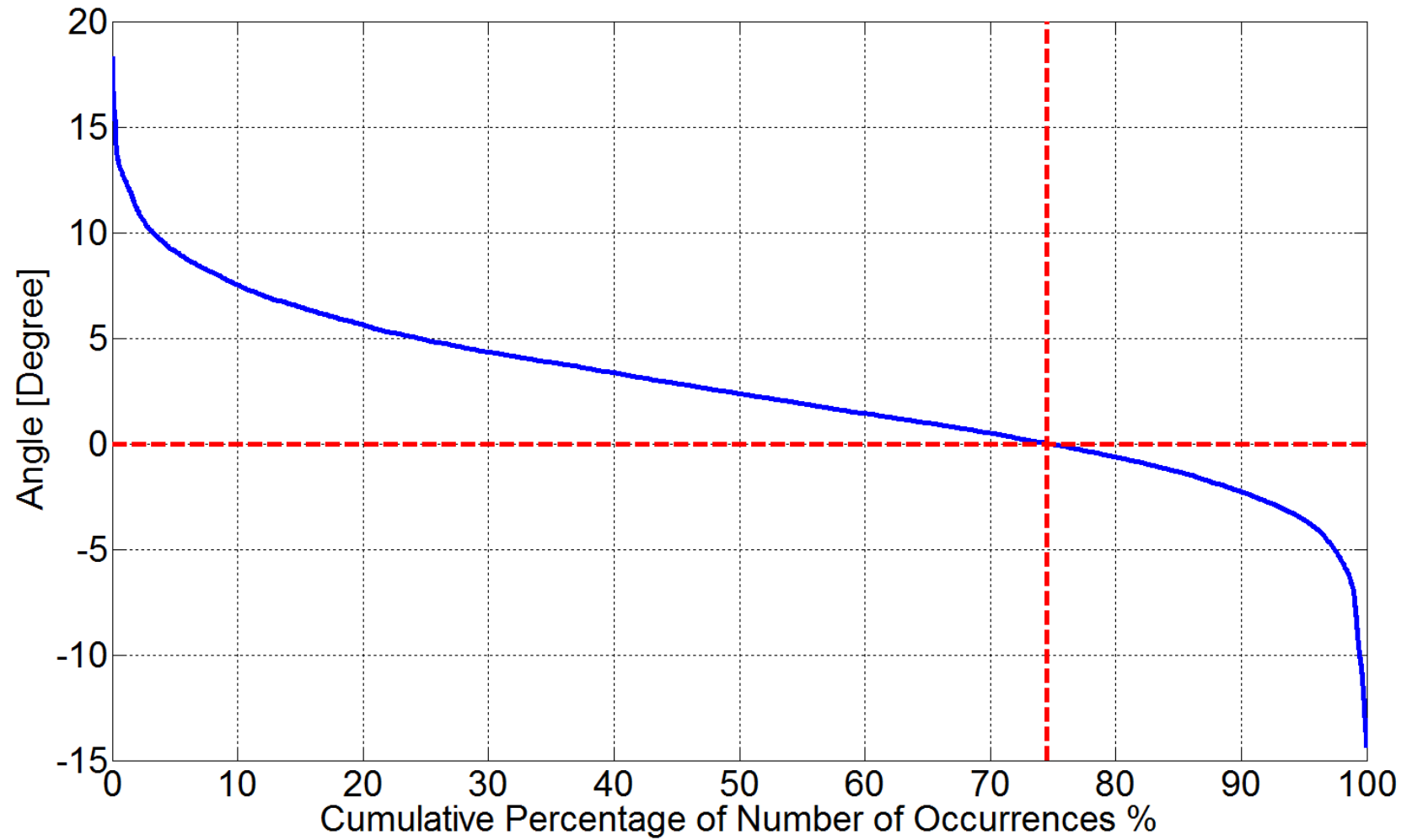
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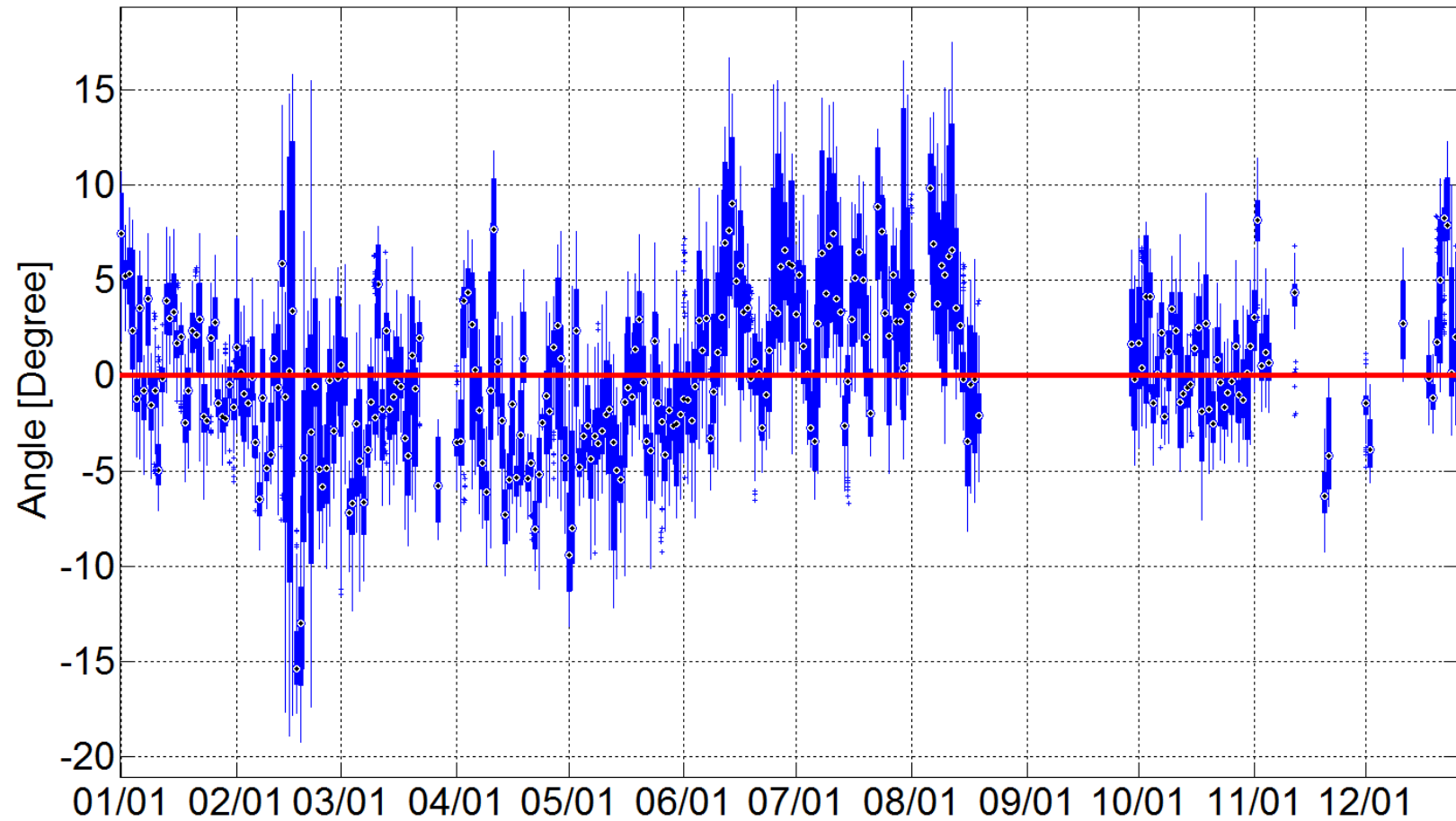
South 2-North 7



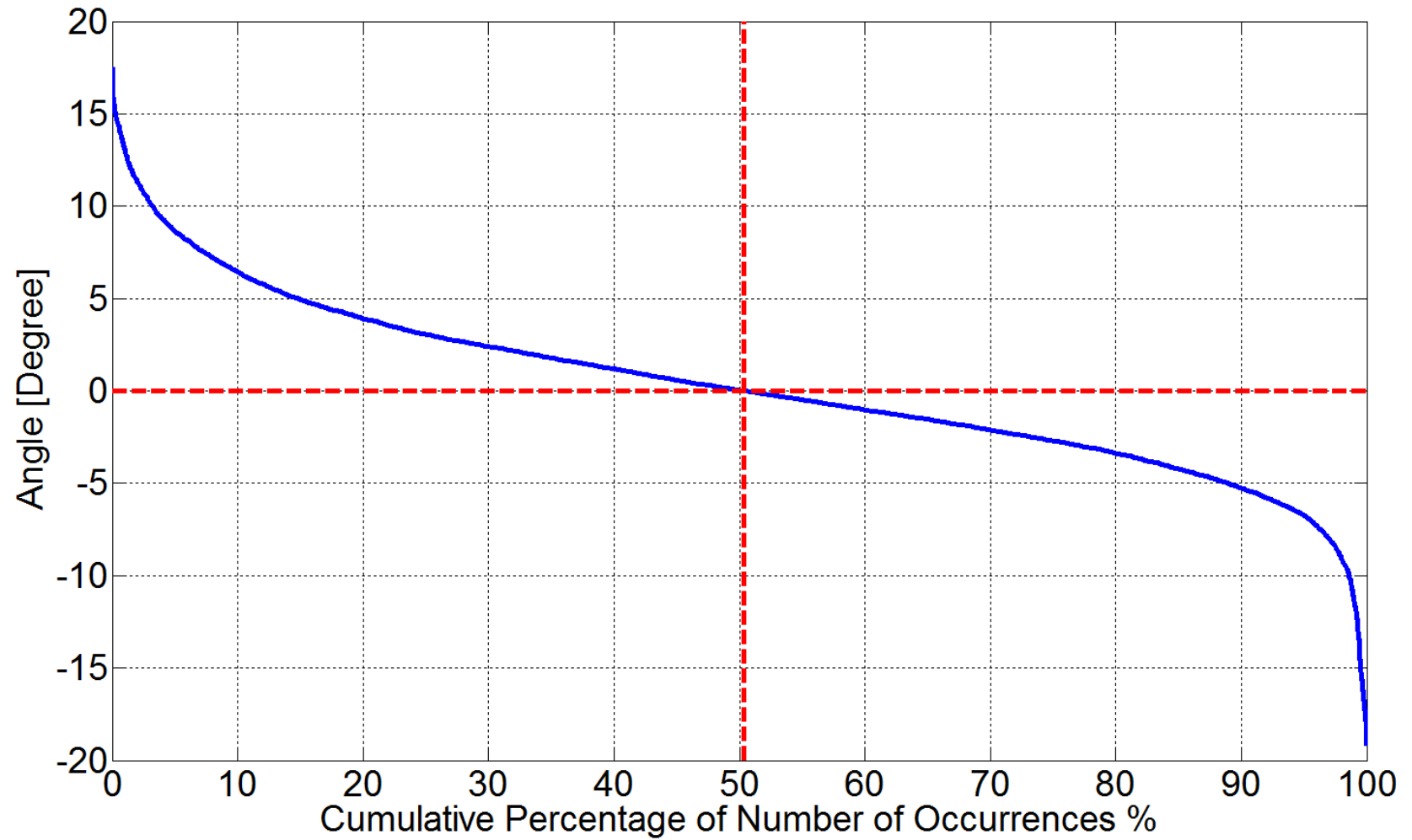
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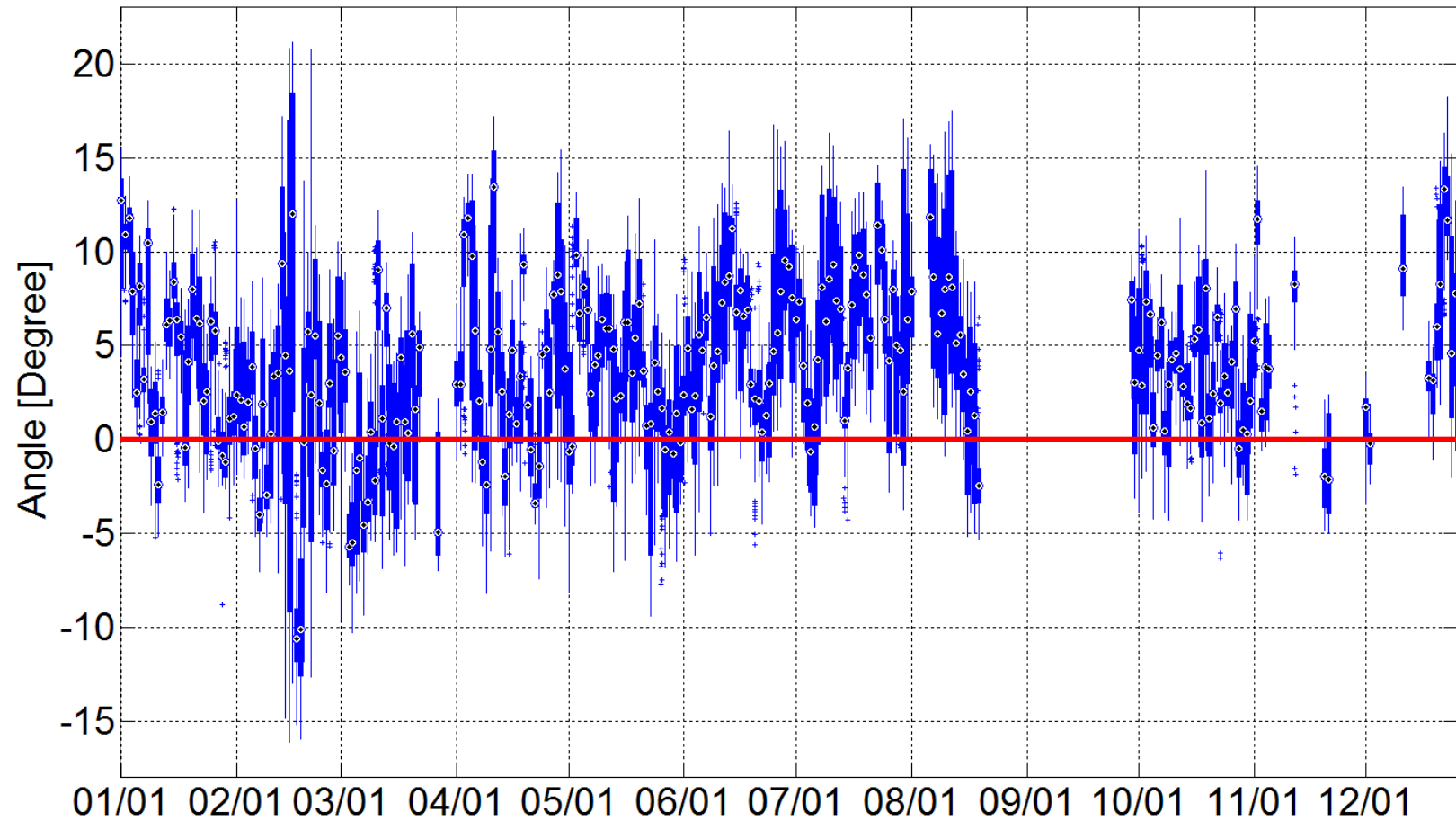
South 4-North 7



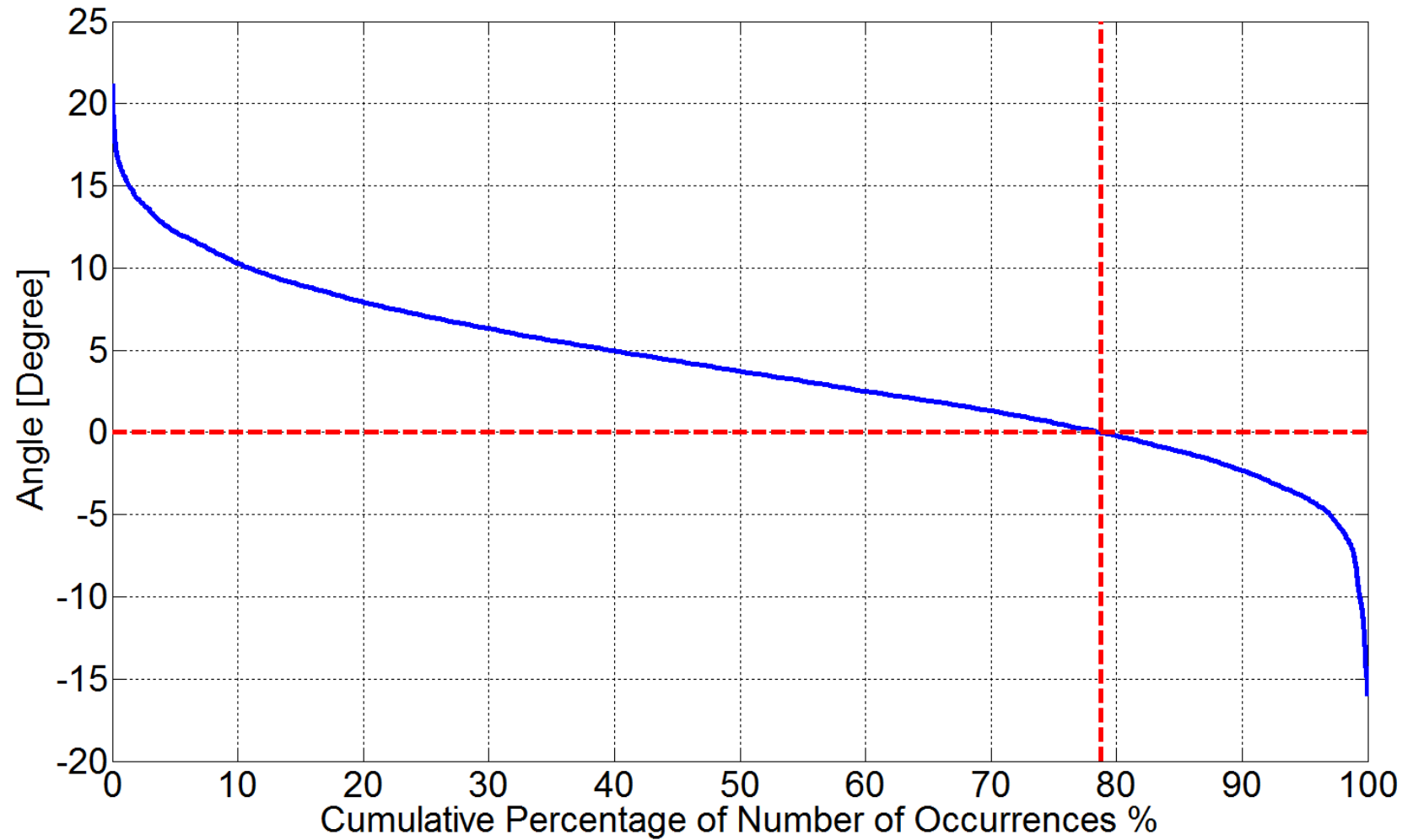
South 4-North 7



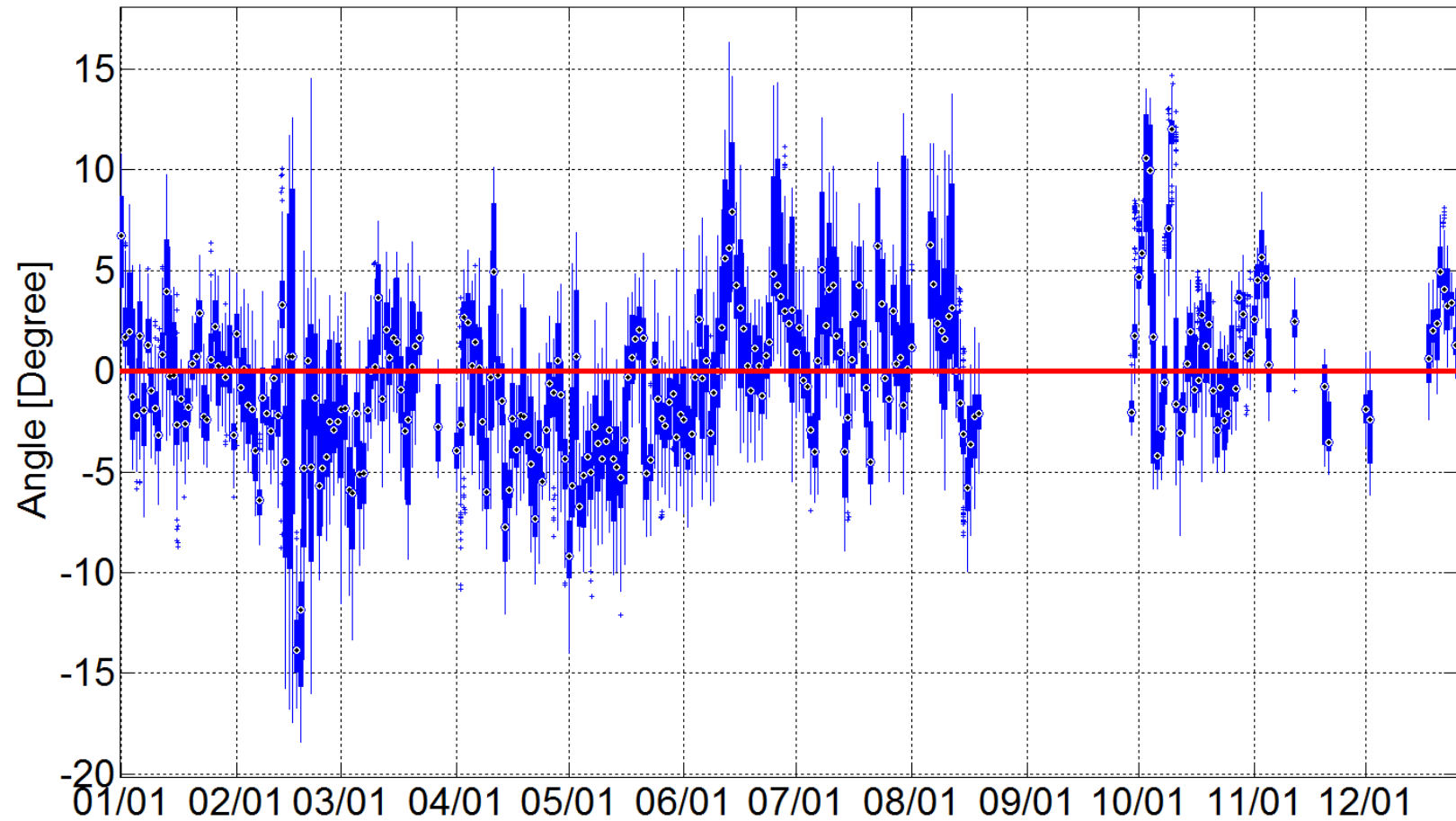
South 7-North 7



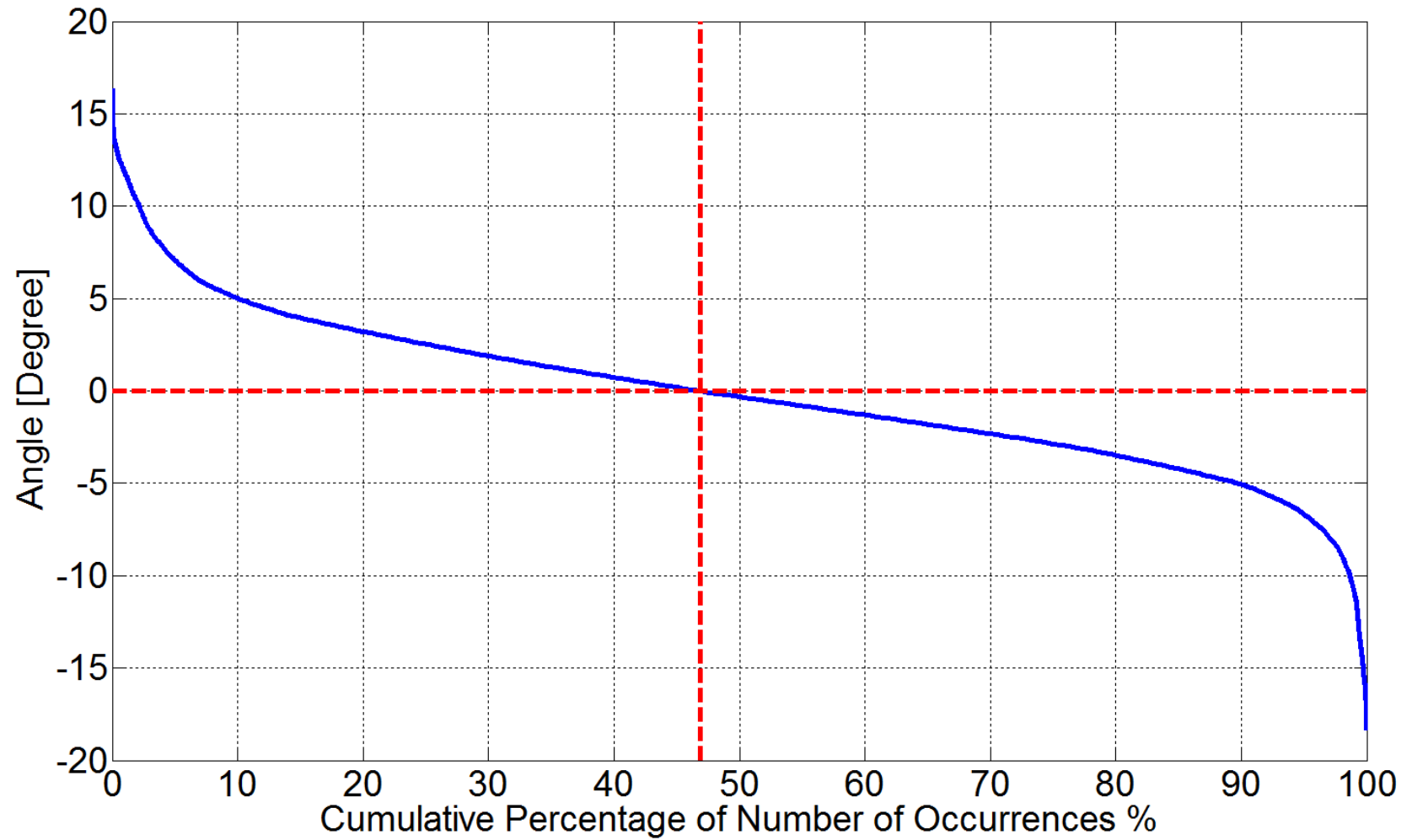
South 7-North 7



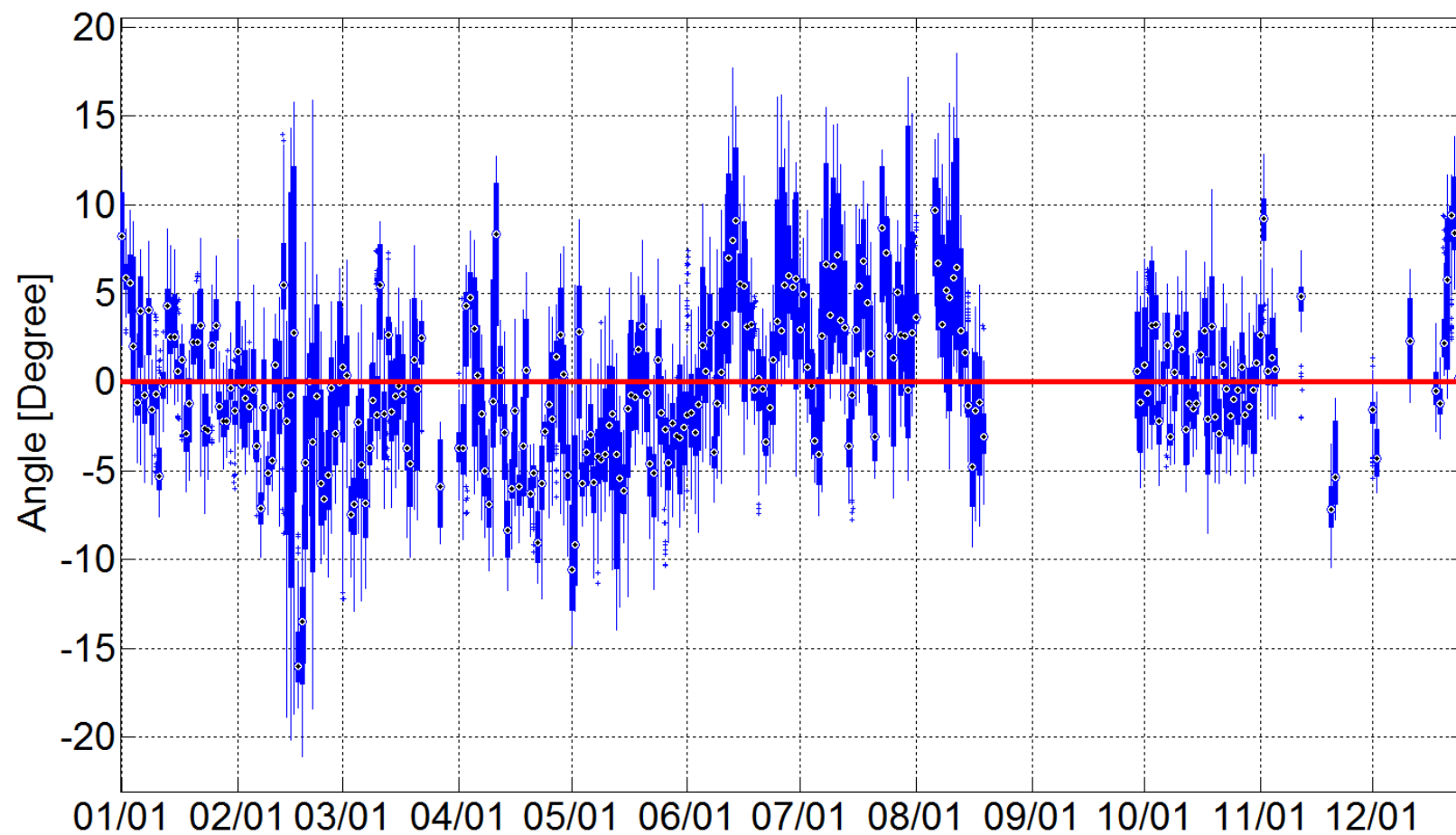
South 9-North 7



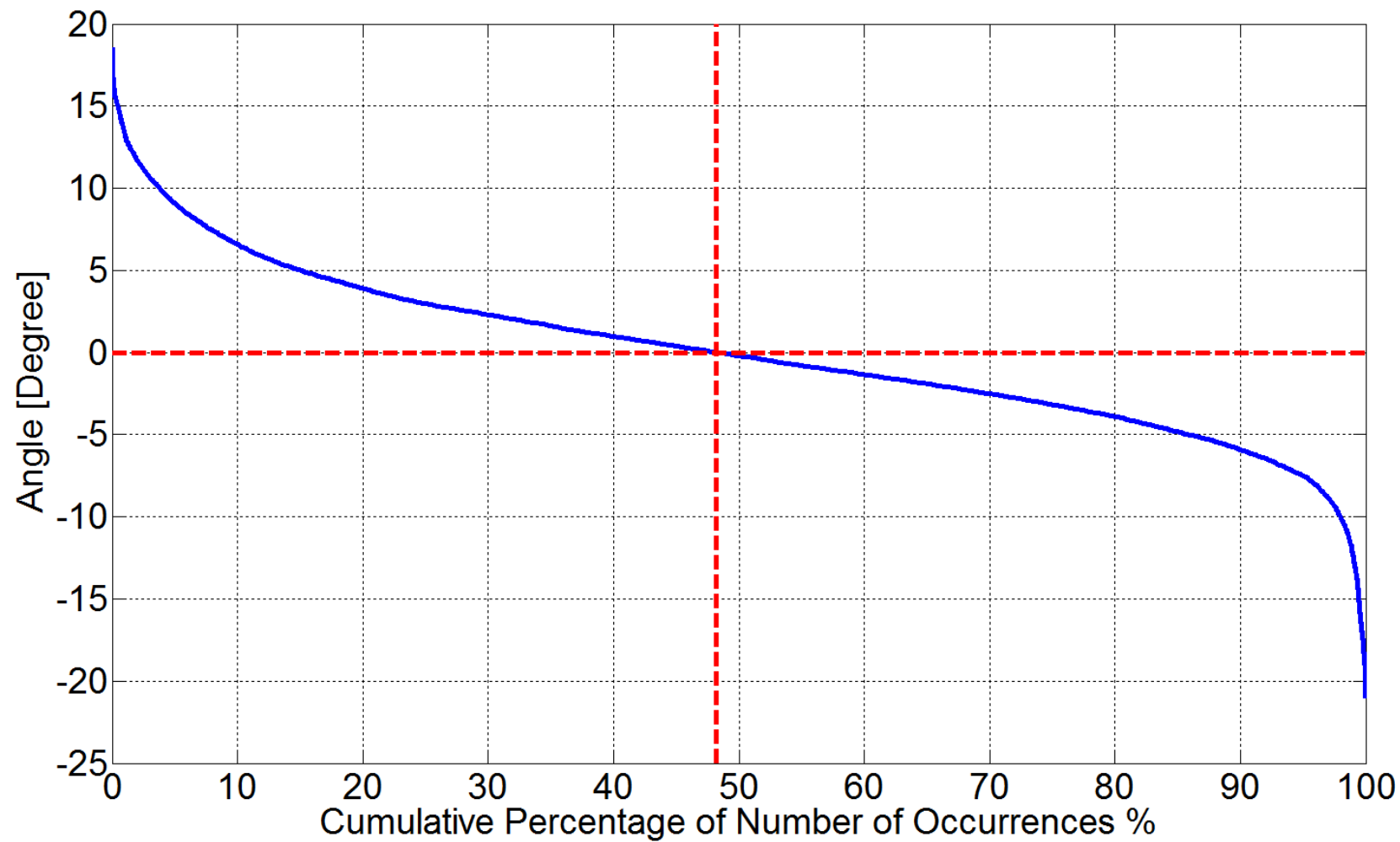
South 9-North 7



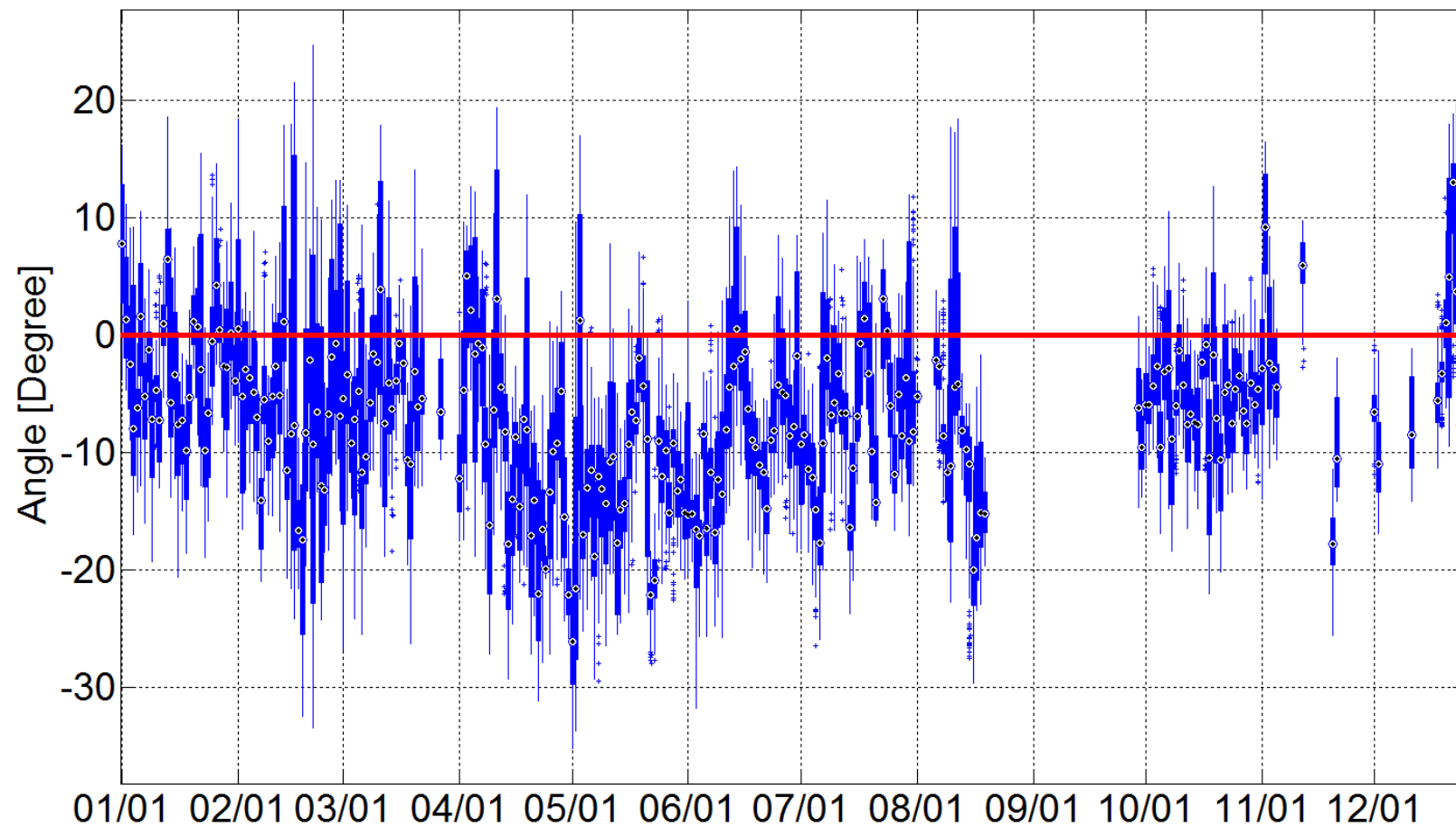
South 11-North 7



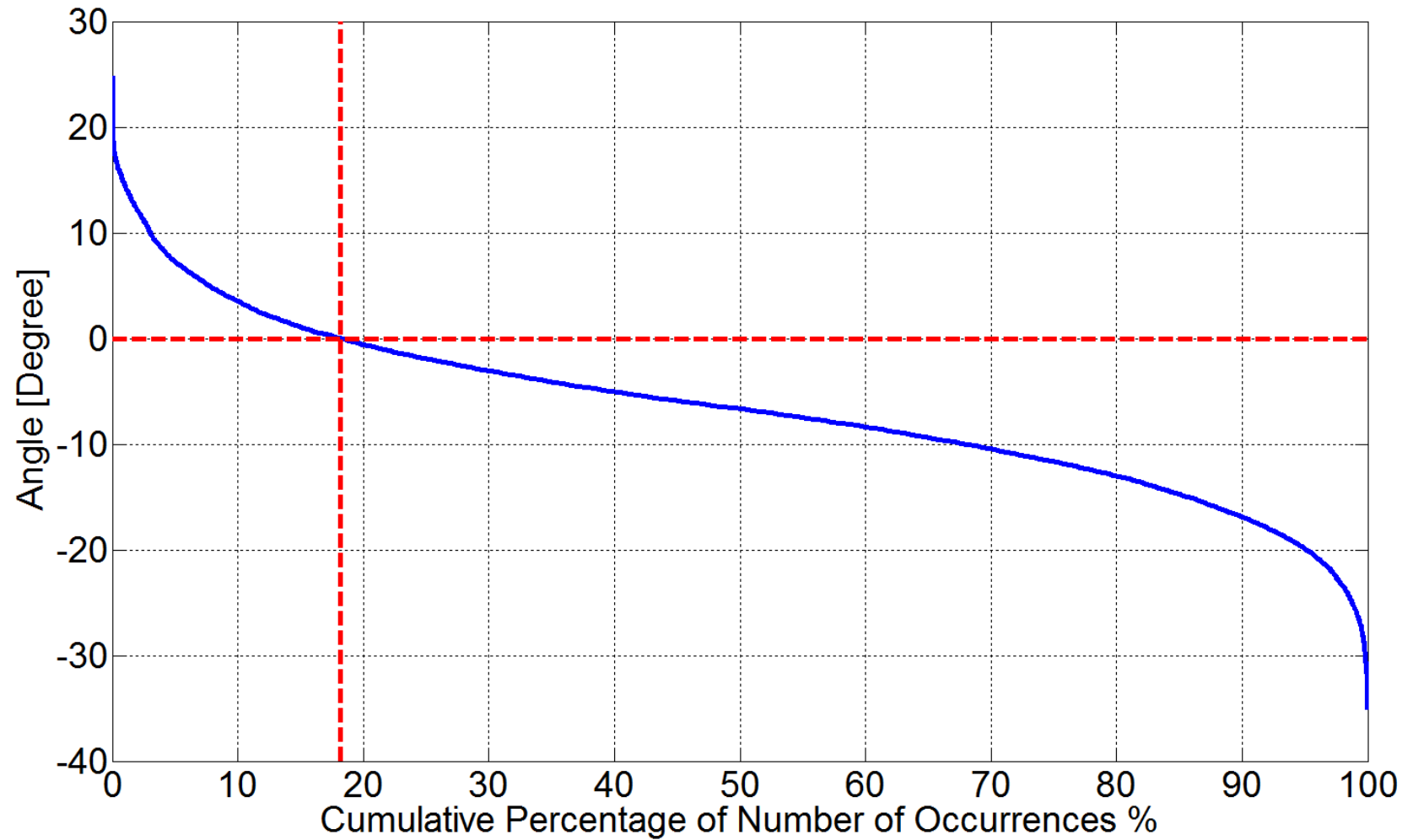
South 11-North 7



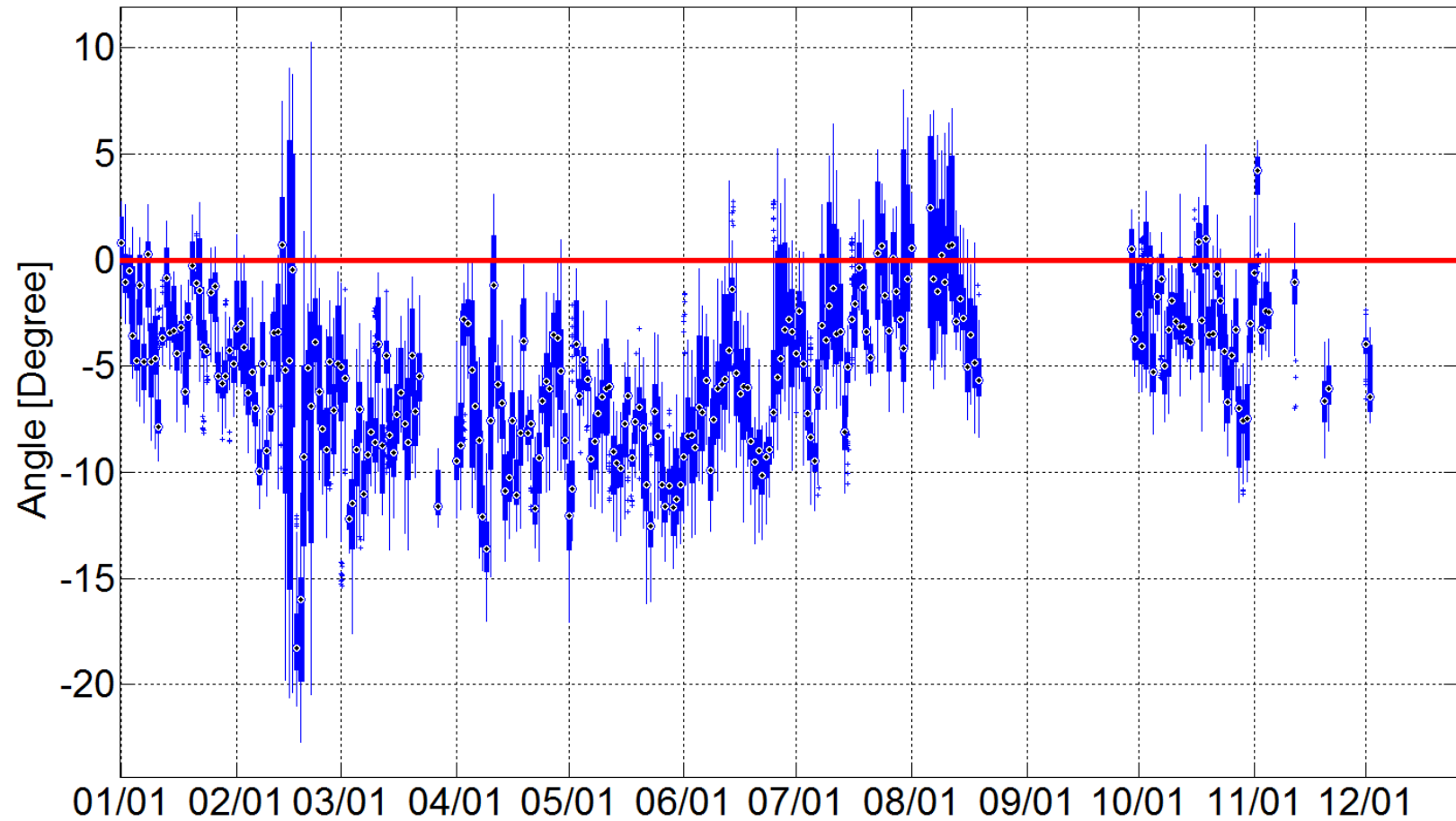
South 10-North 7



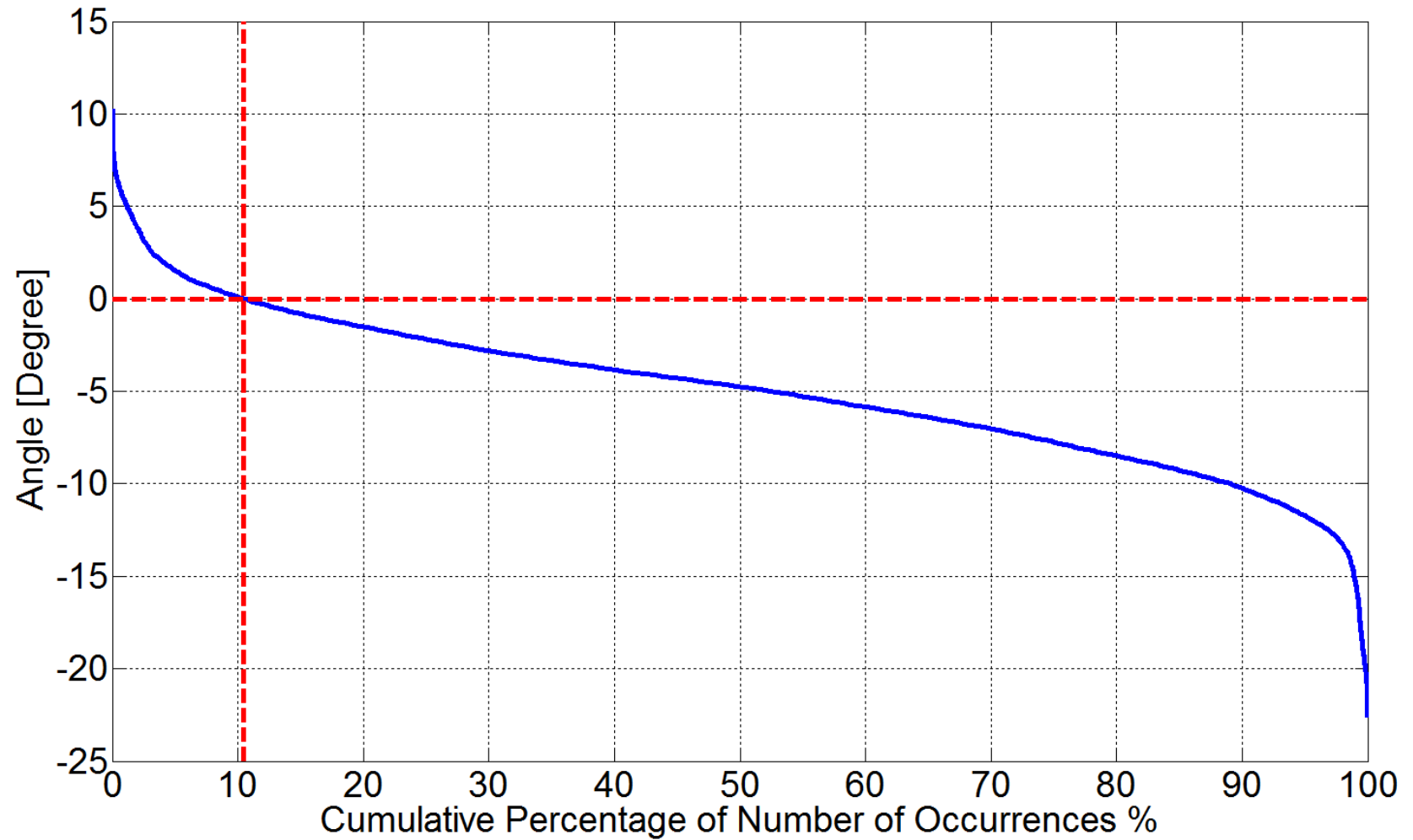
South 10-North 7



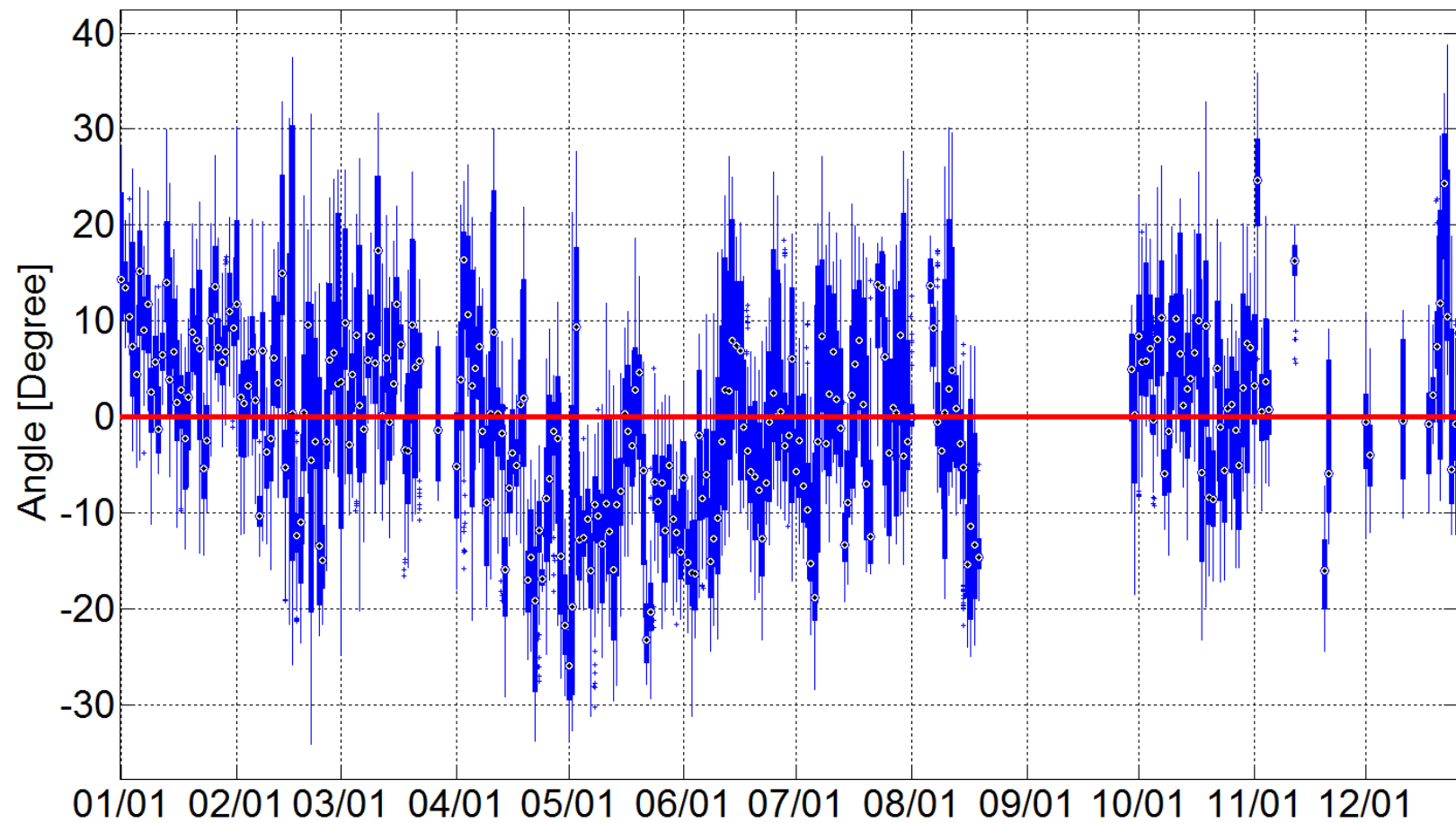
North 2-North 7



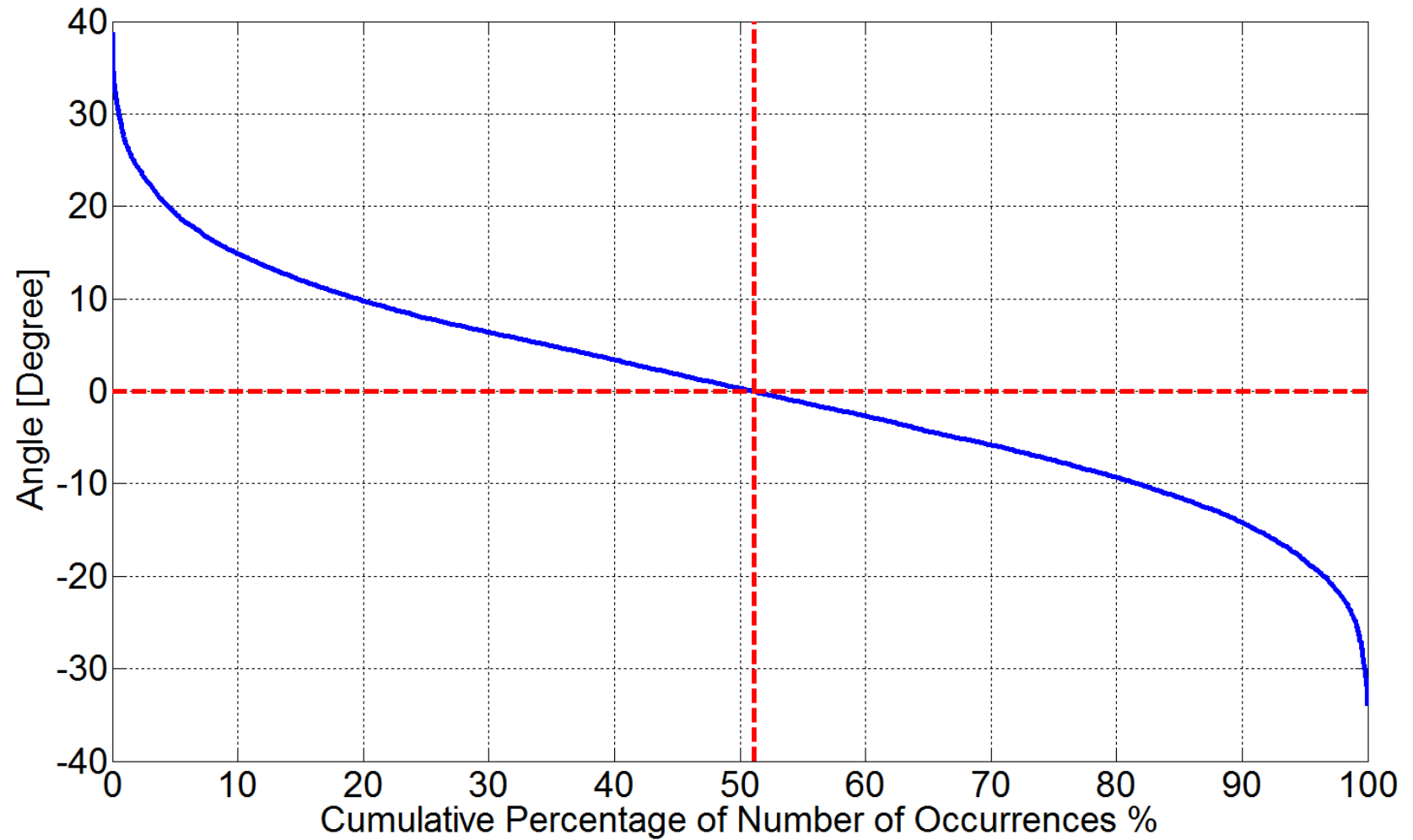
North 2-North 7



South 6-North 7



South 6-North 7

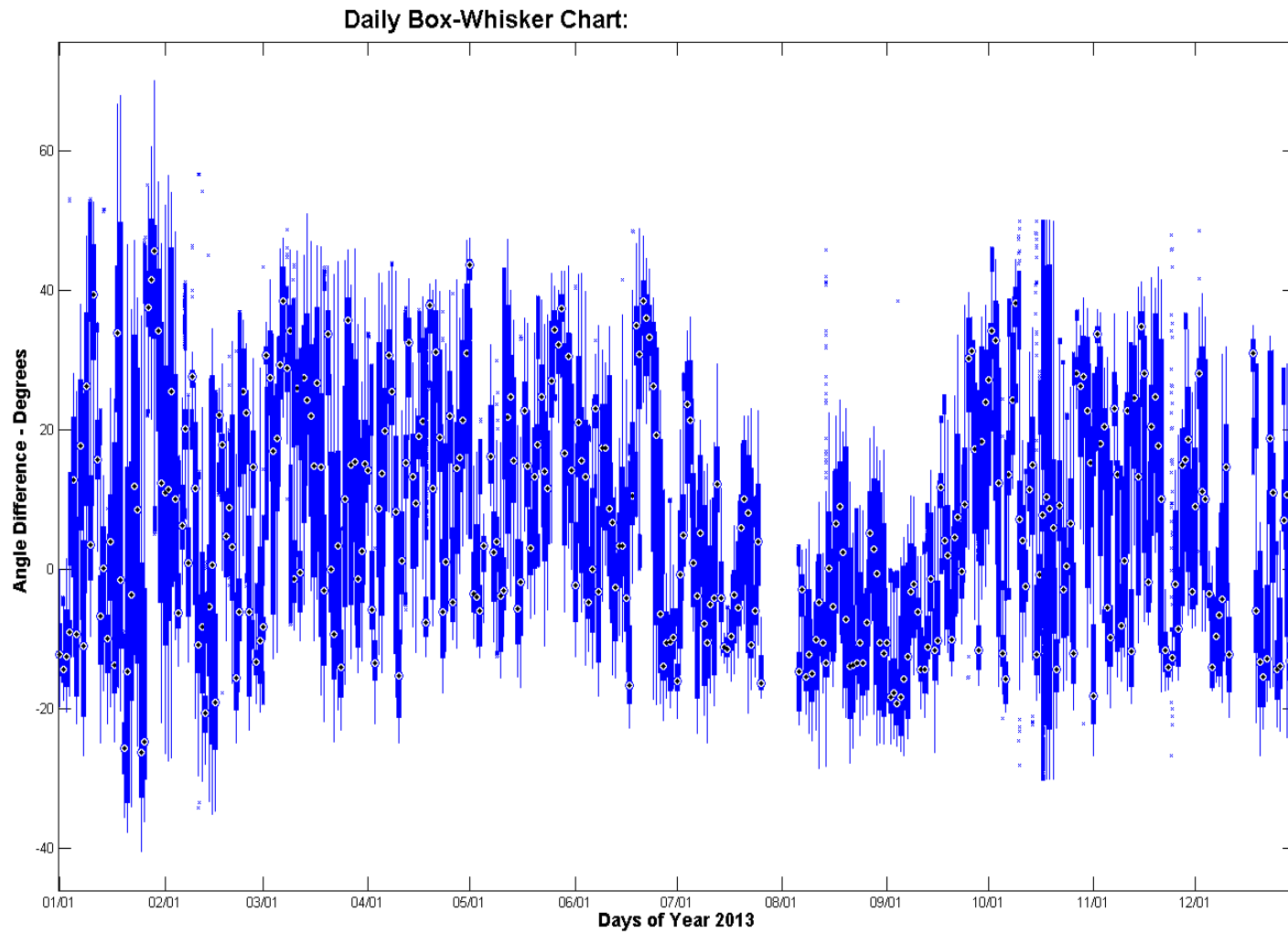


Appendix B – Part 2
CCET Discovery Across Texas project

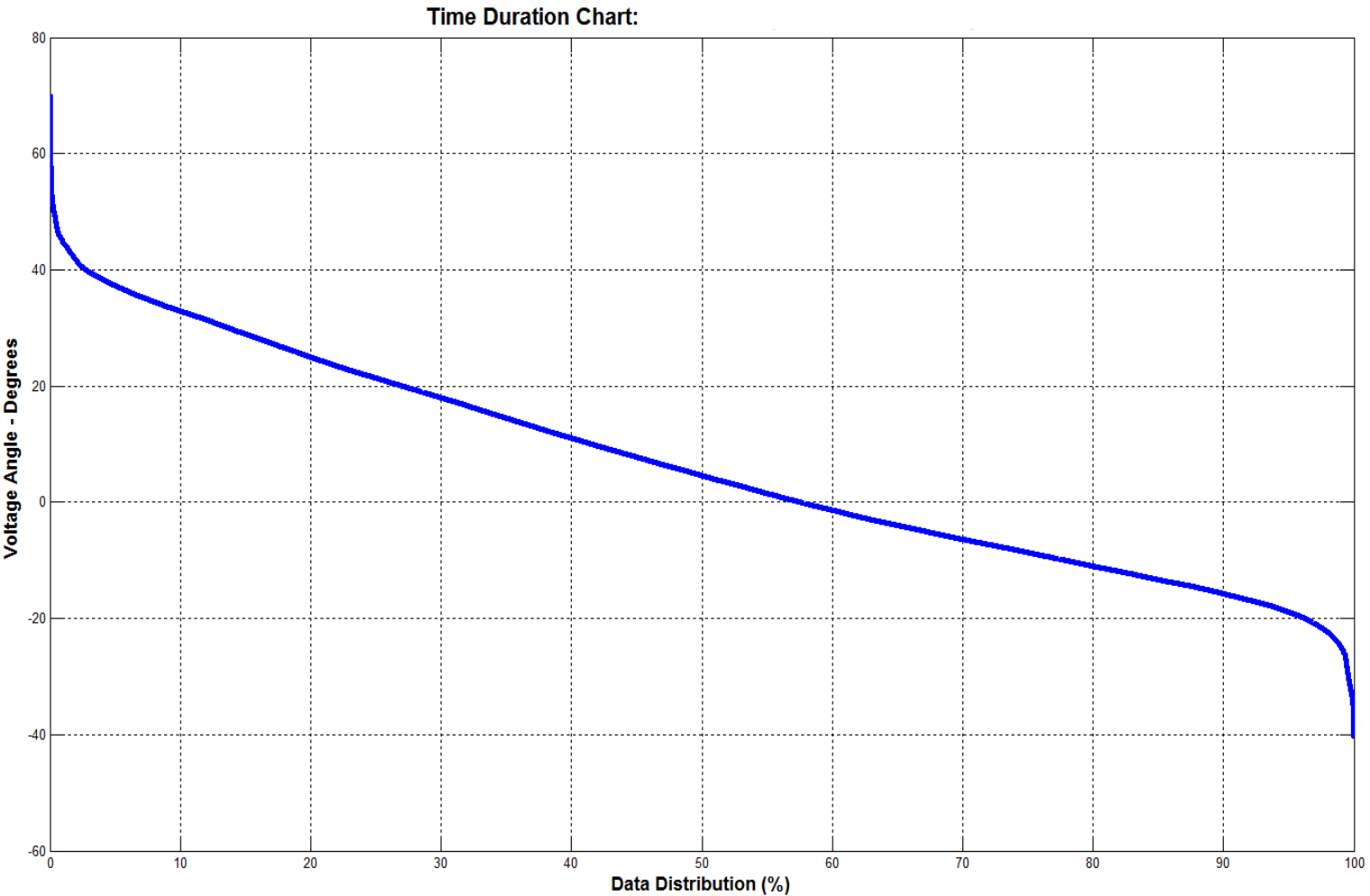
**Baseline Analysis Update - Voltage Angles
(Ref.: North 7)**

Phasor Data: January to December 2013
Box Whiskers Plots and Time Duration Curves

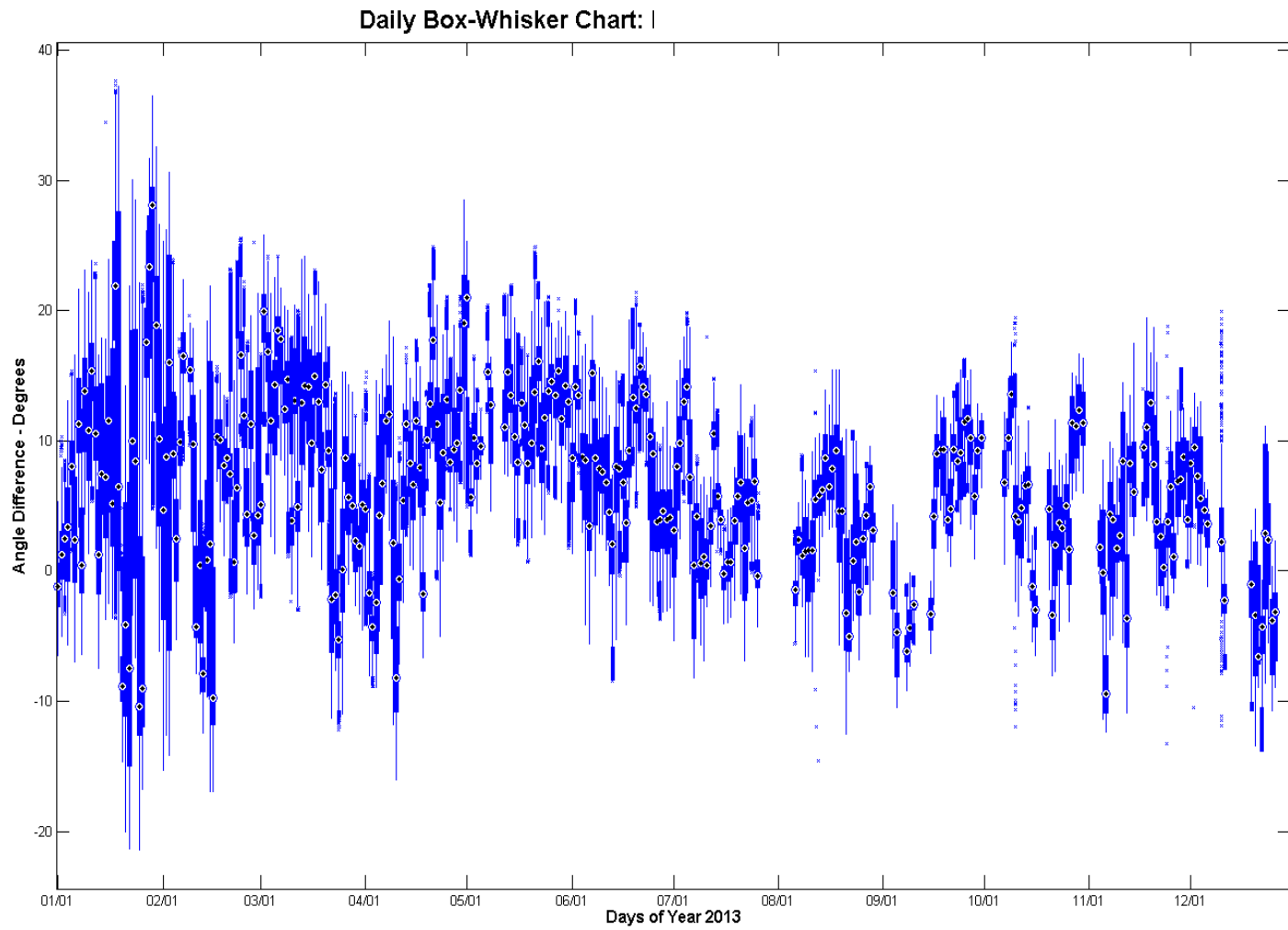
West 10



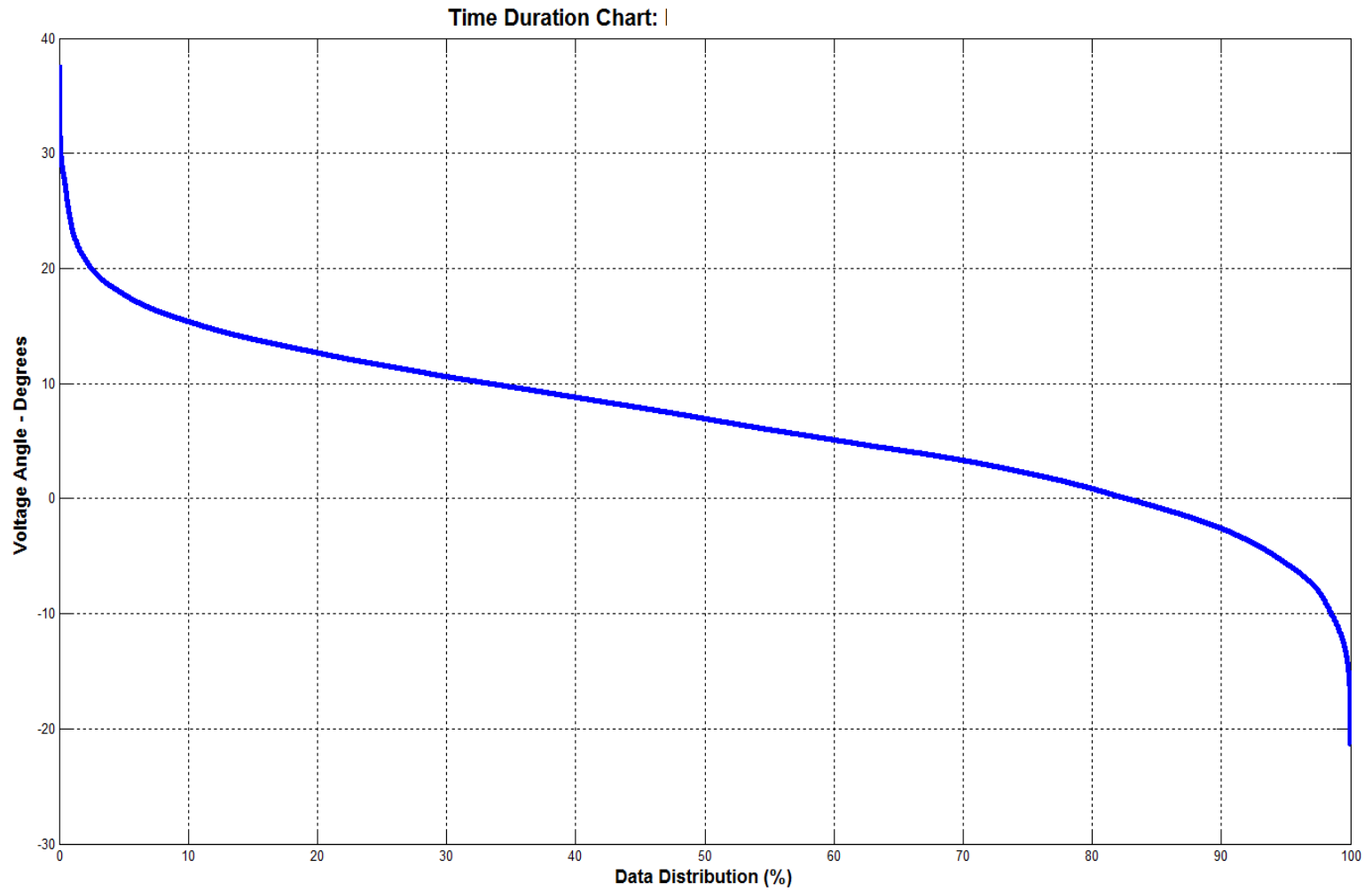
West 10



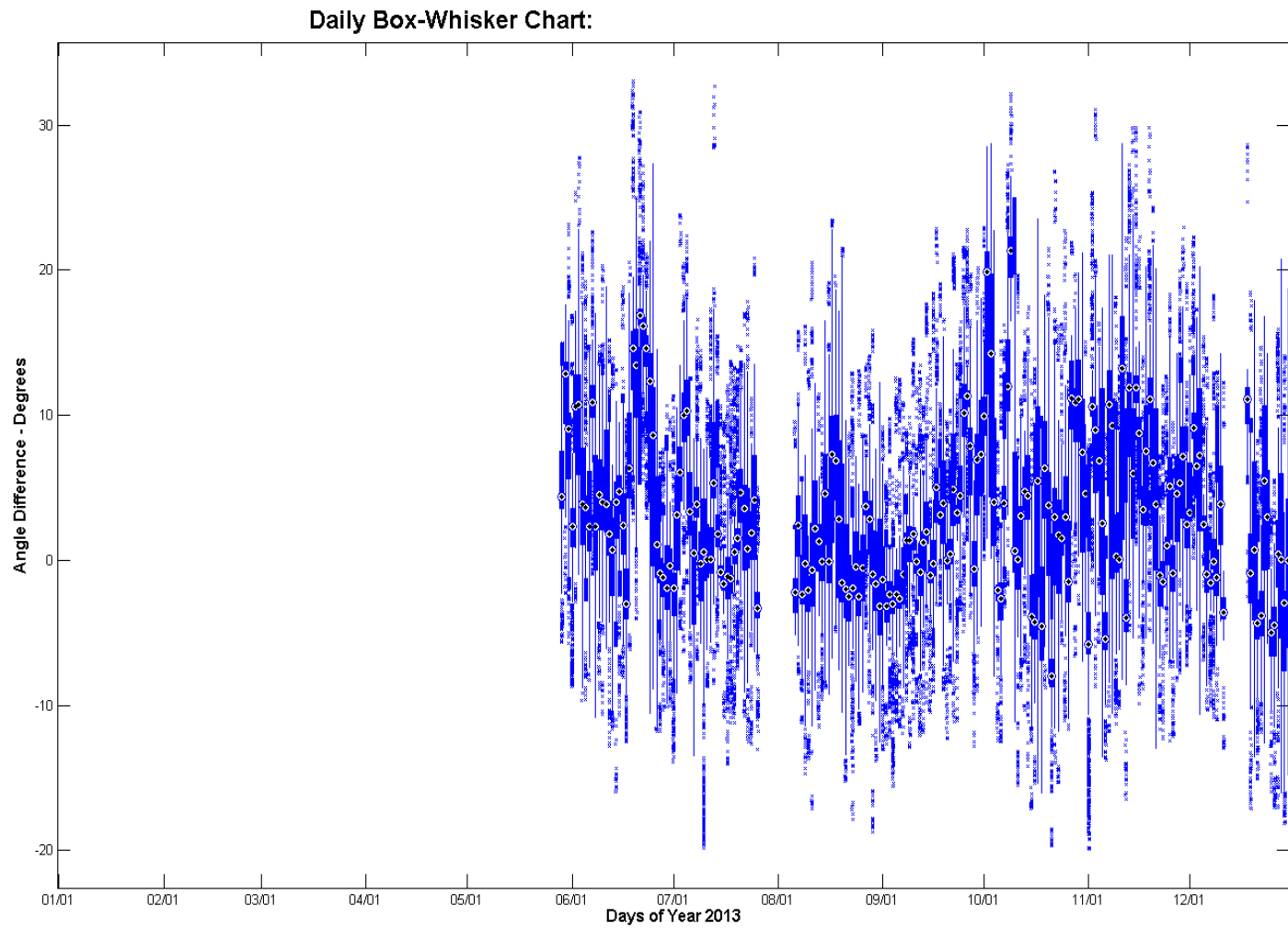
West 14



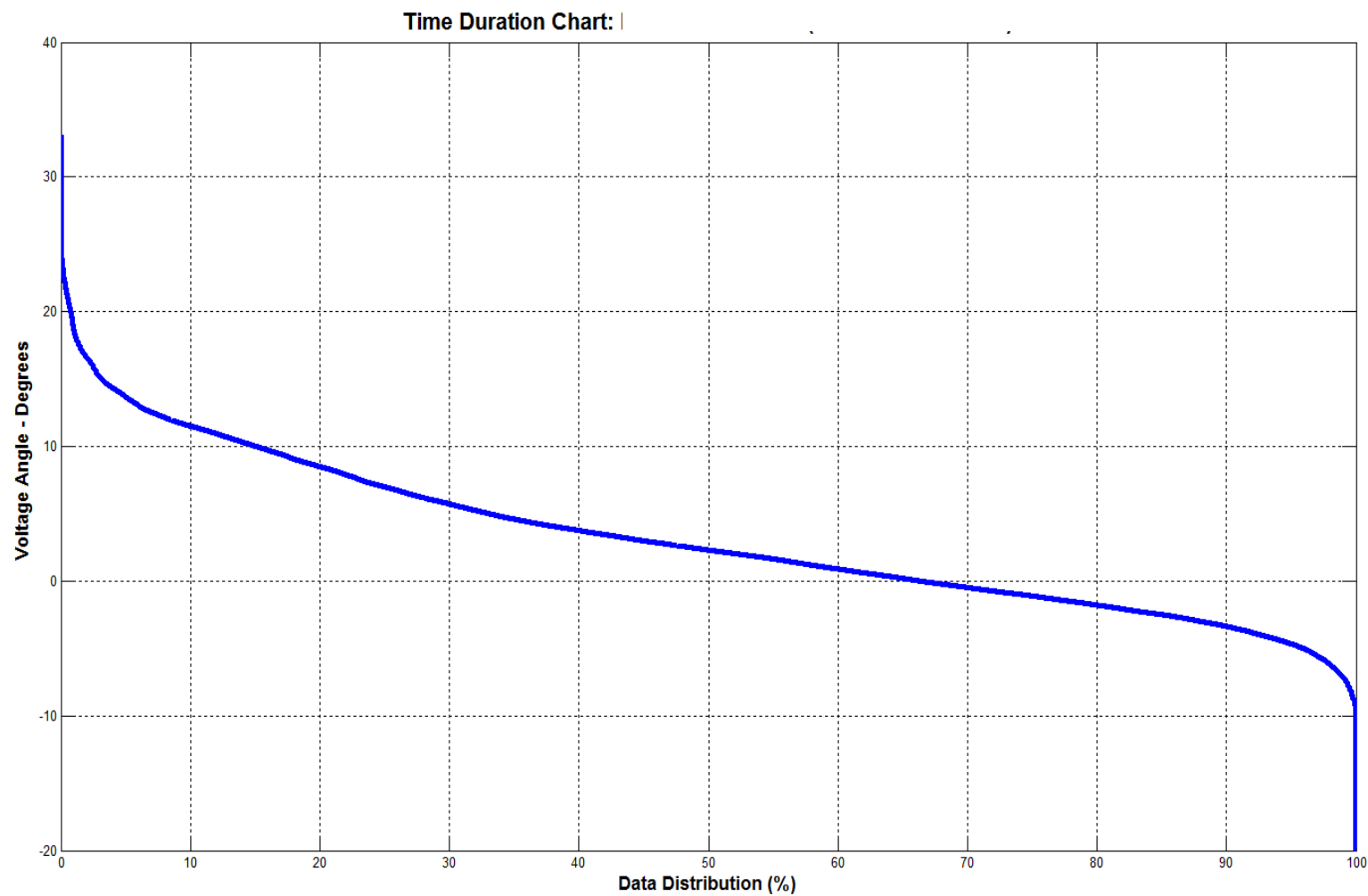
West 14



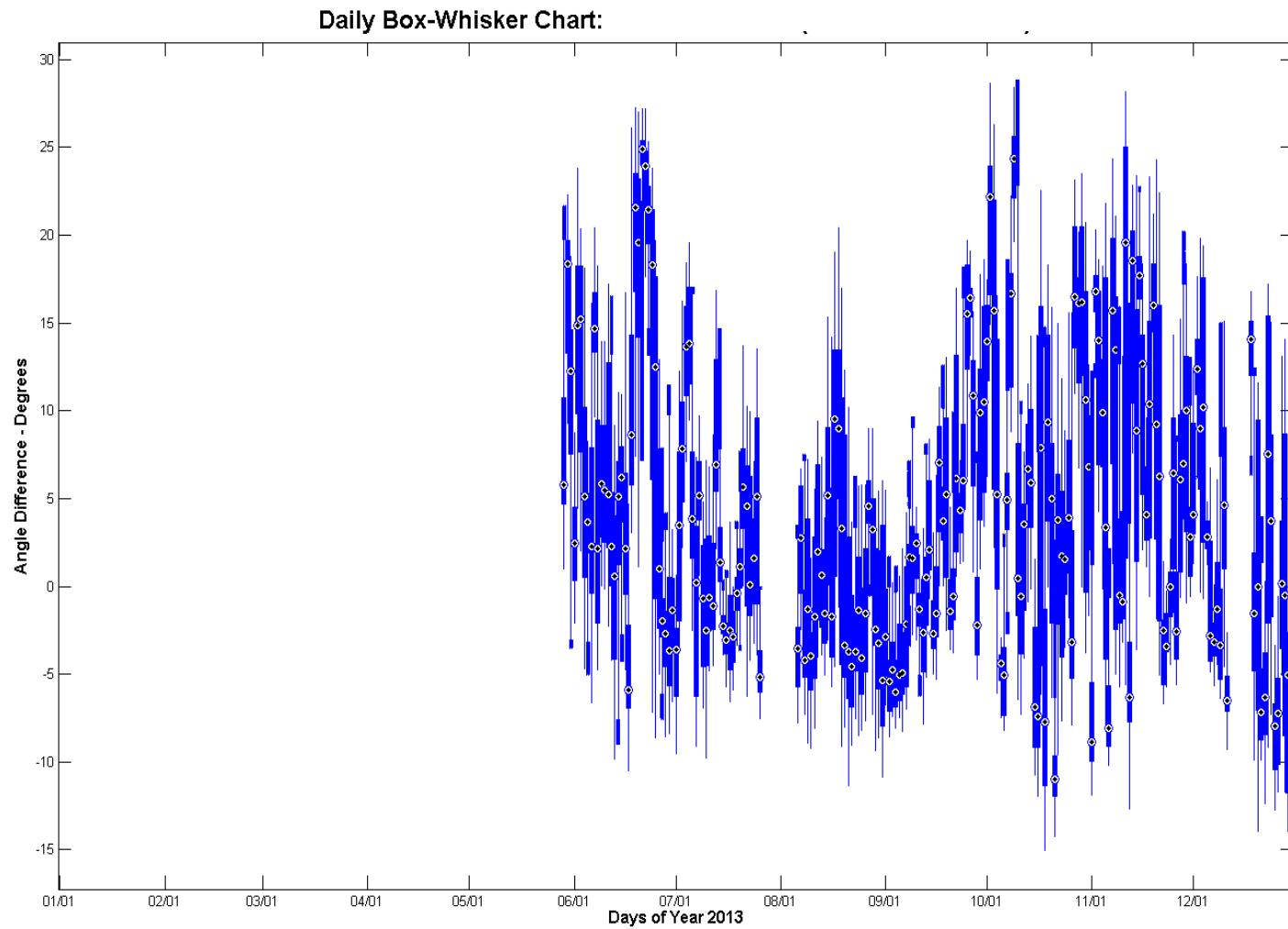
West 1



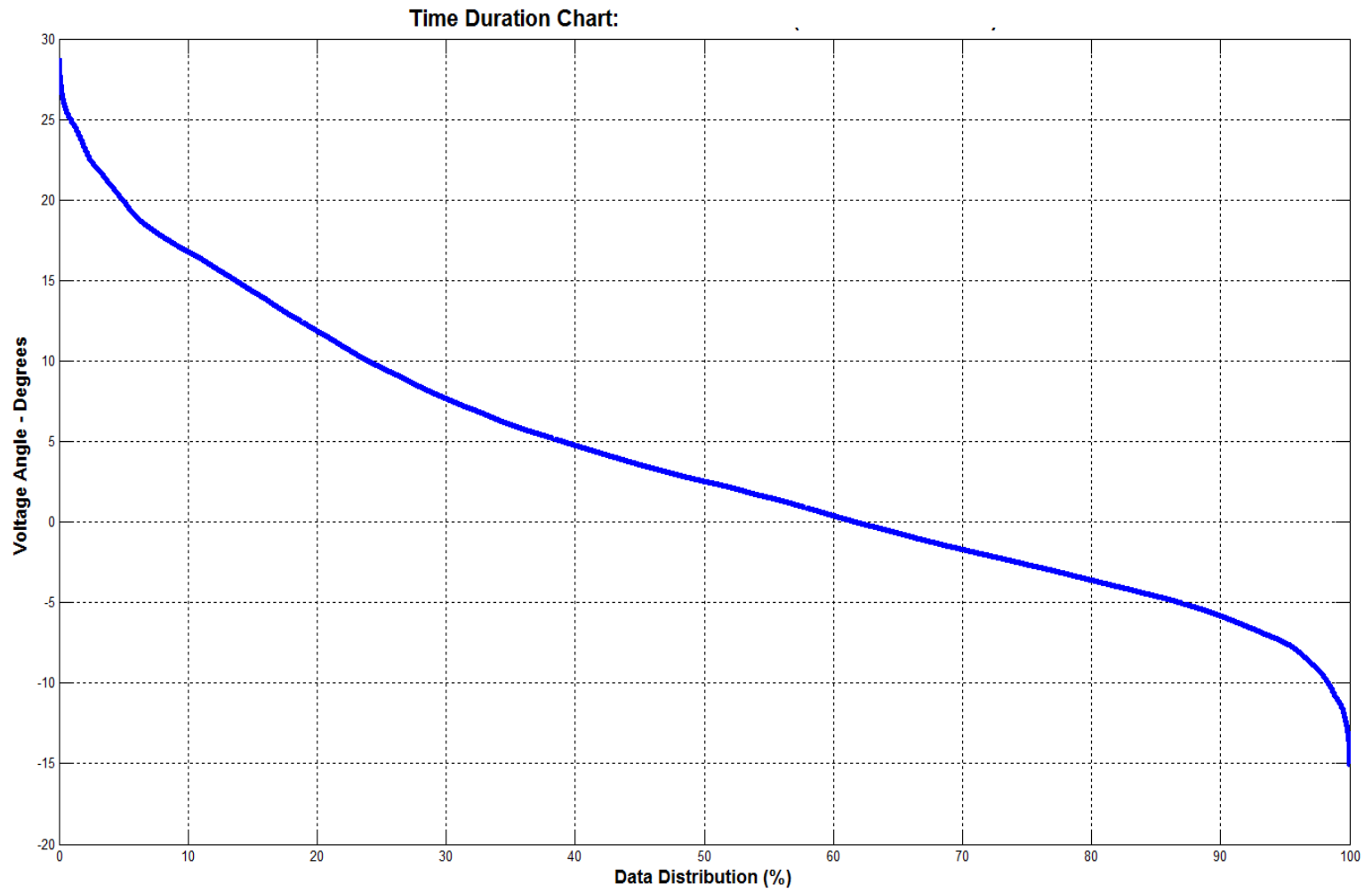
West 1



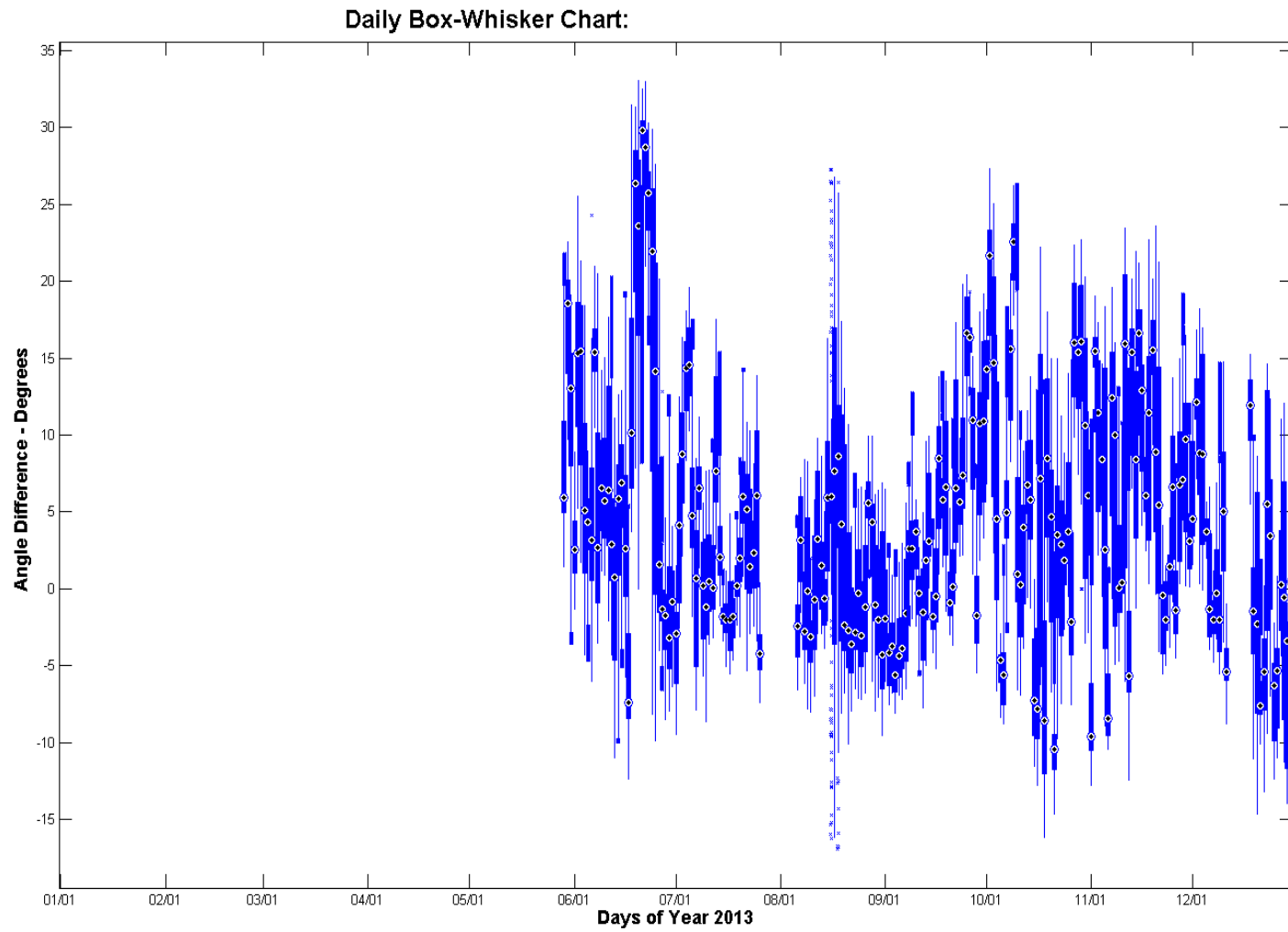
West 2



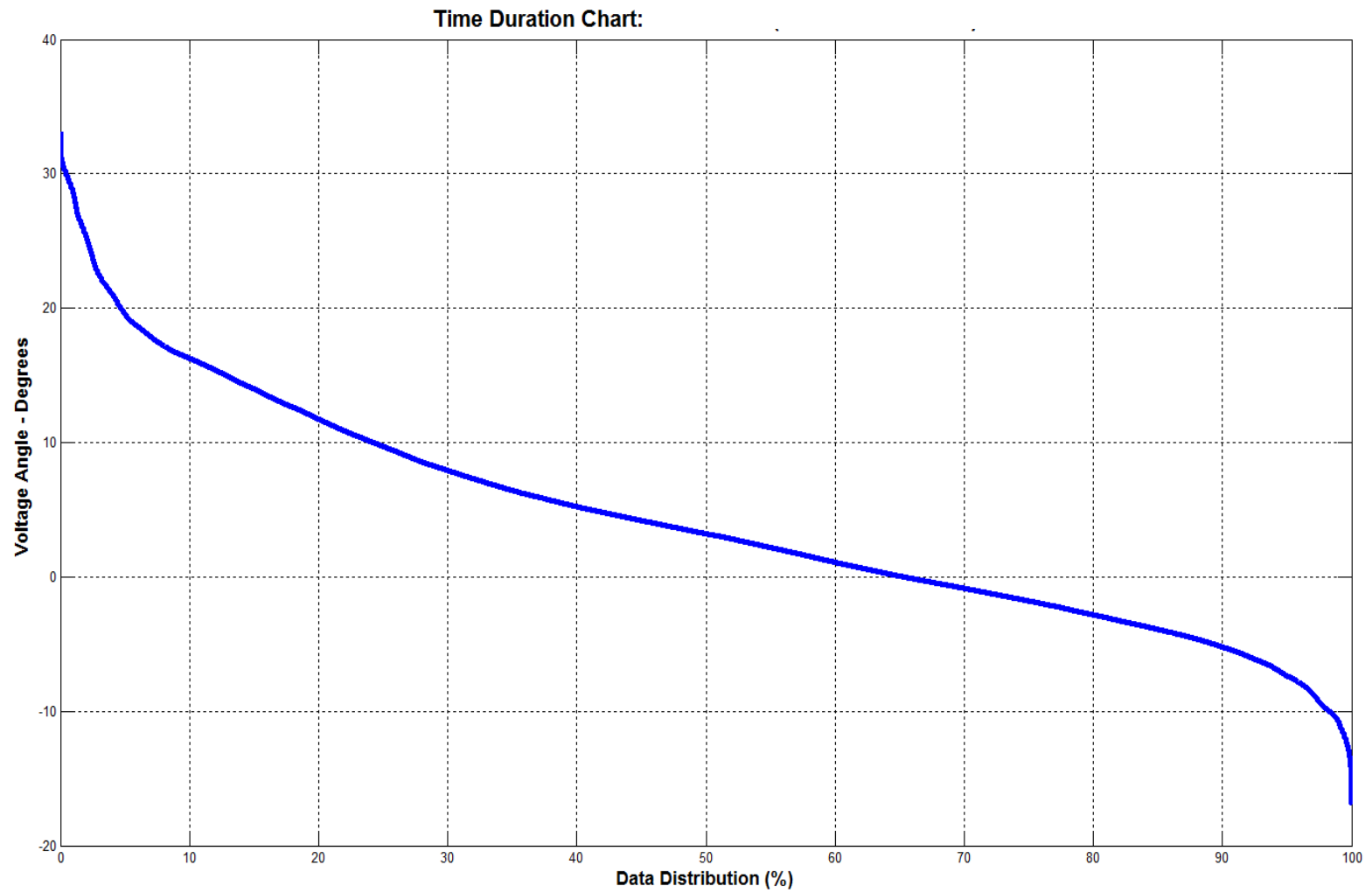
West 2



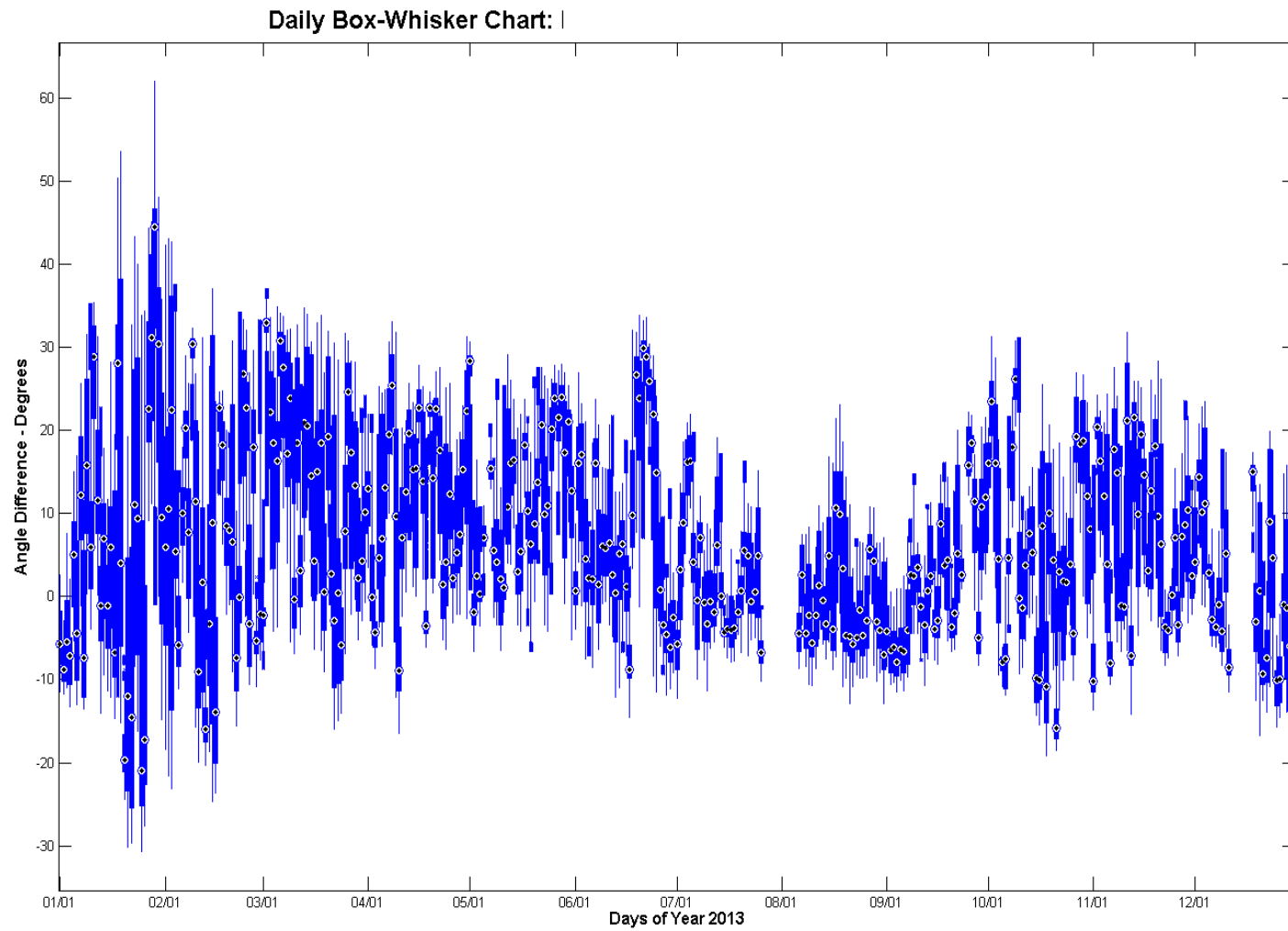
West 9



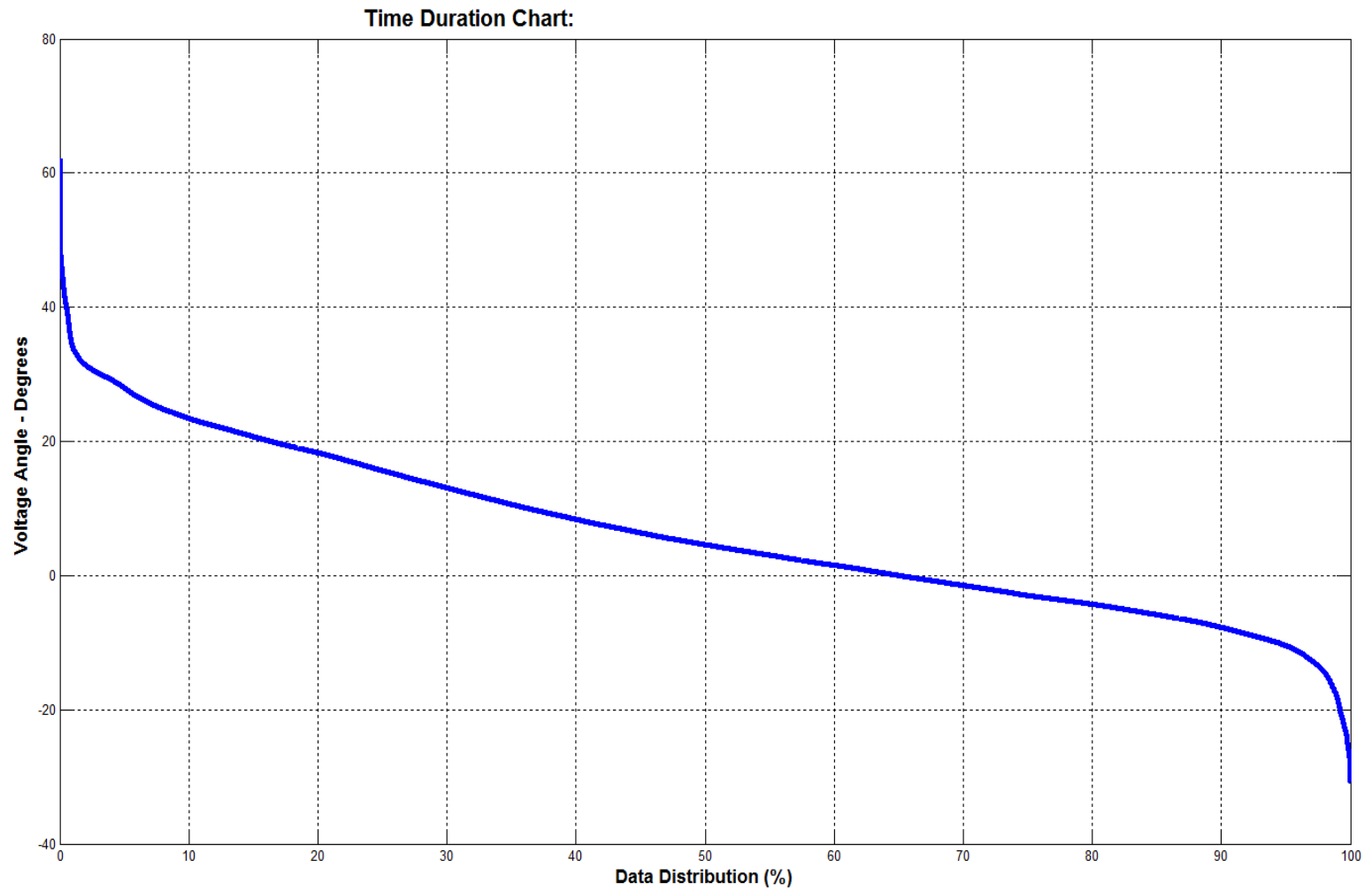
West 9



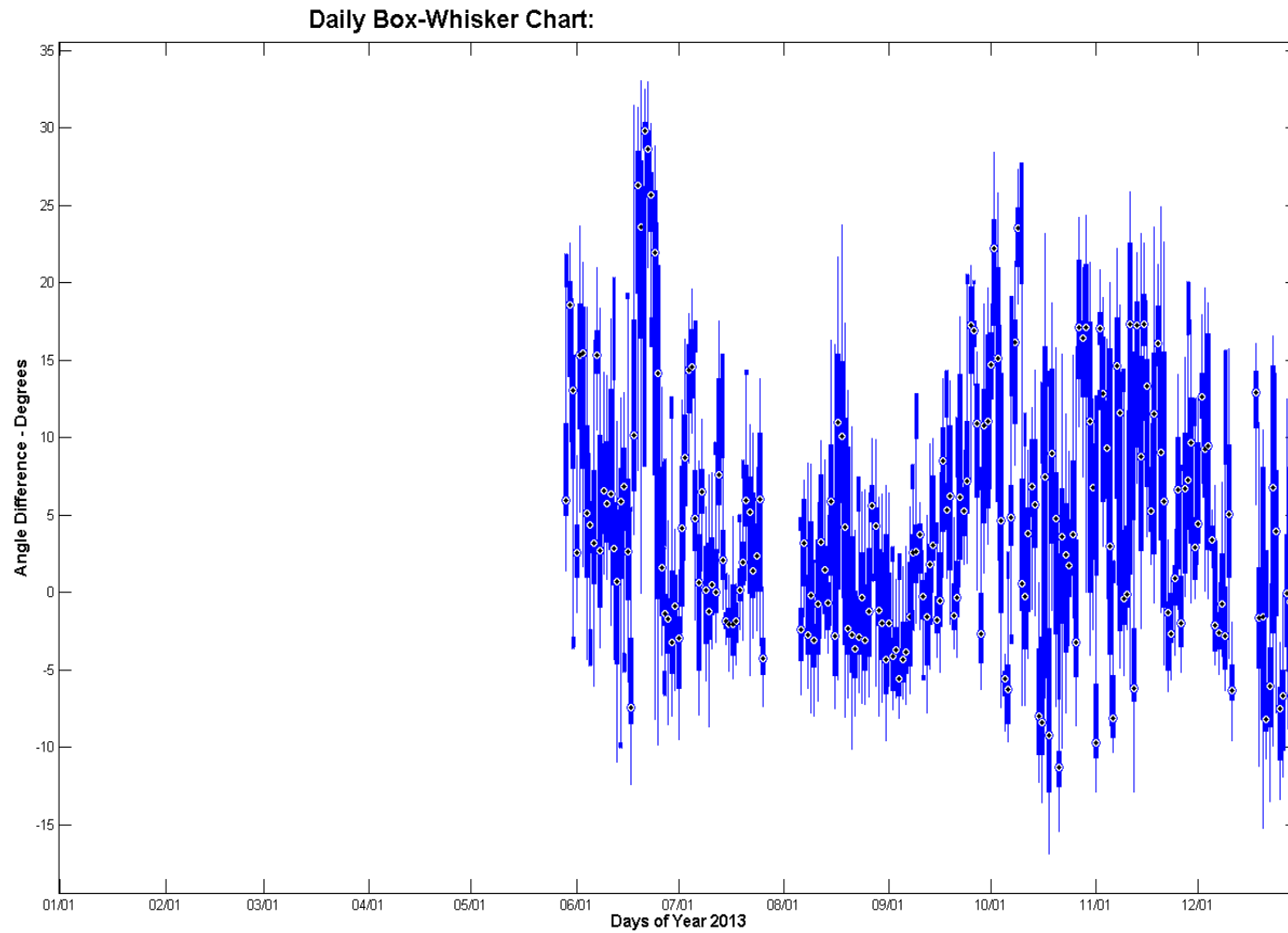
West 11



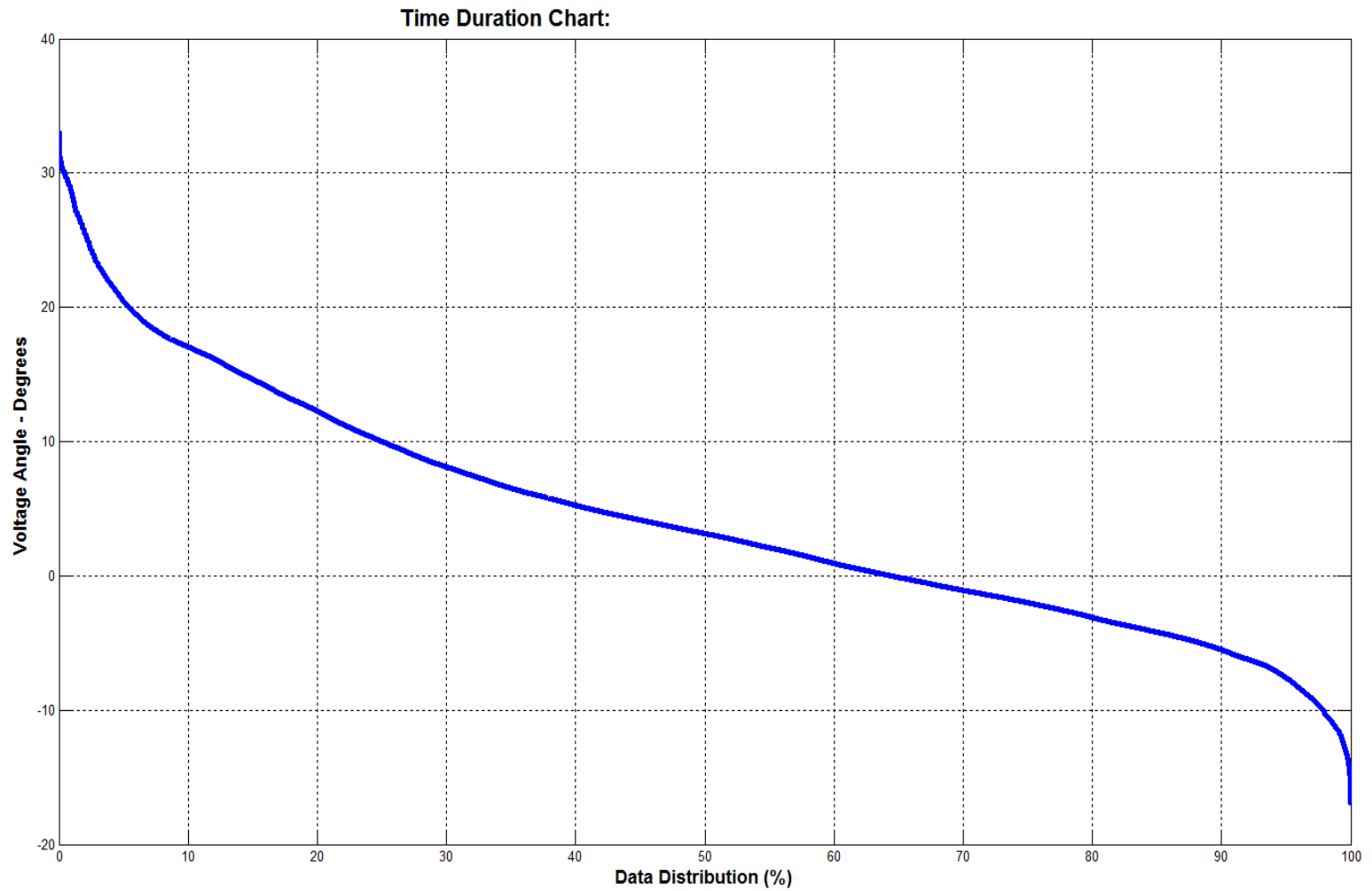
West 11



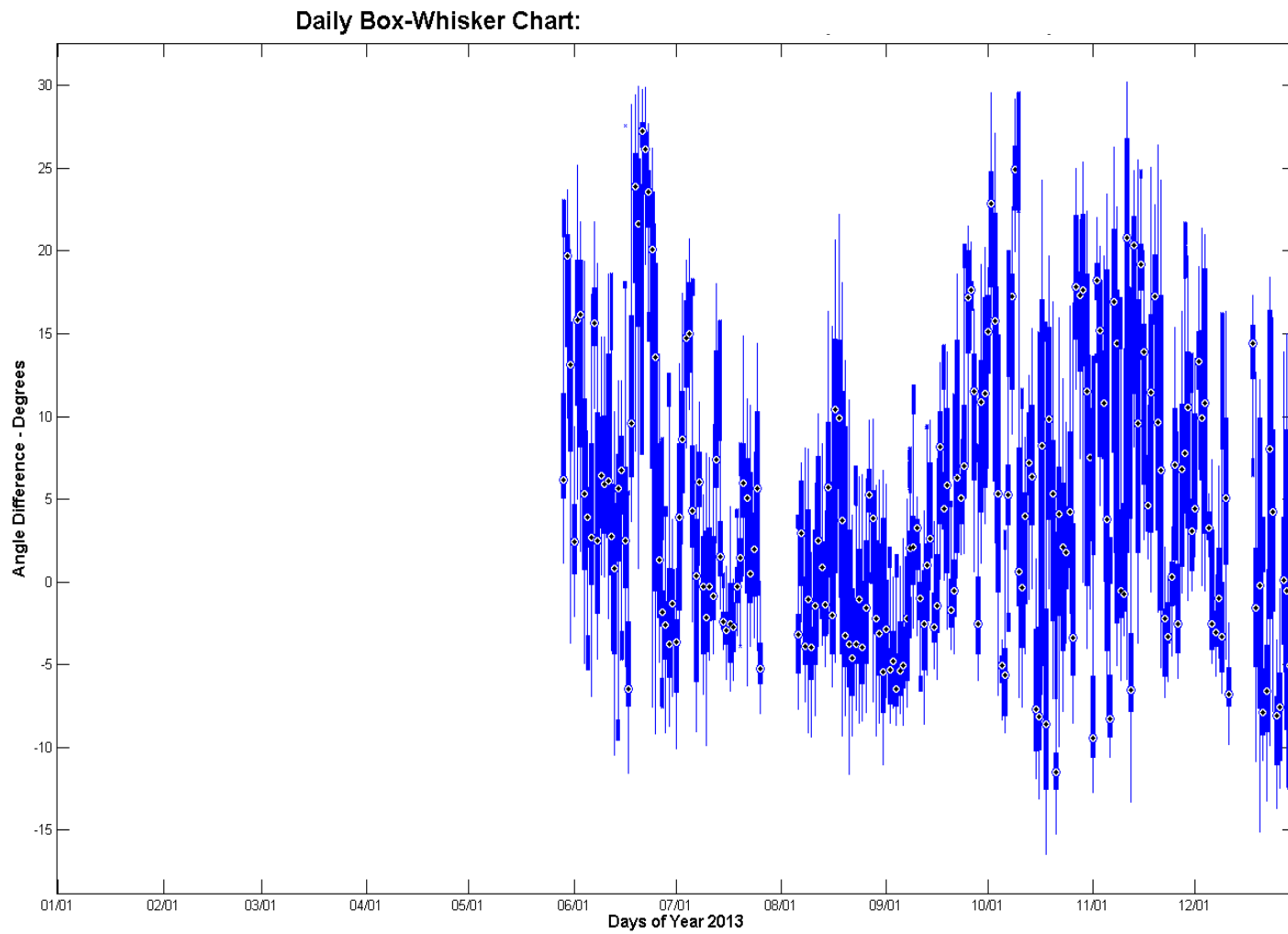
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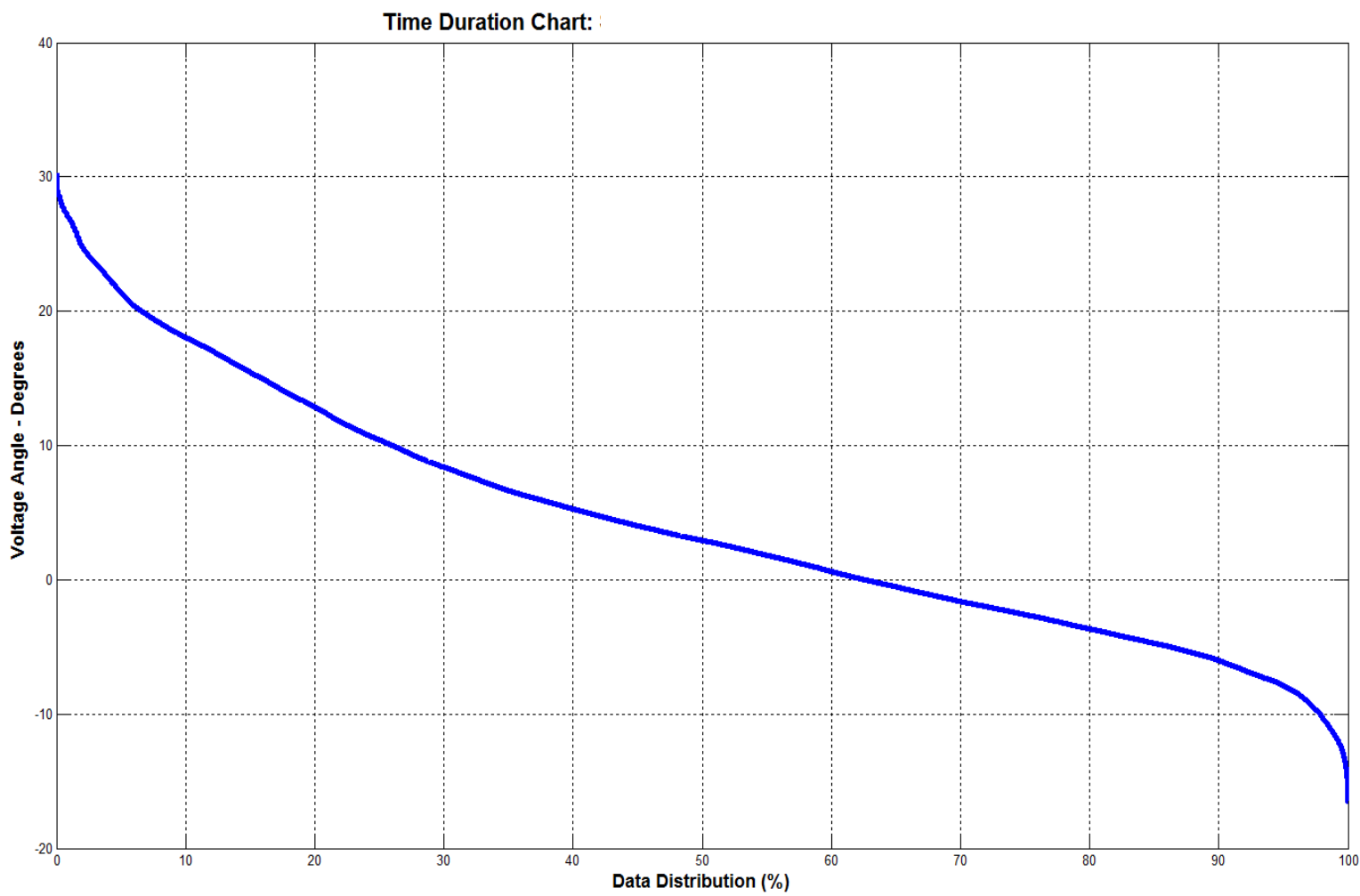
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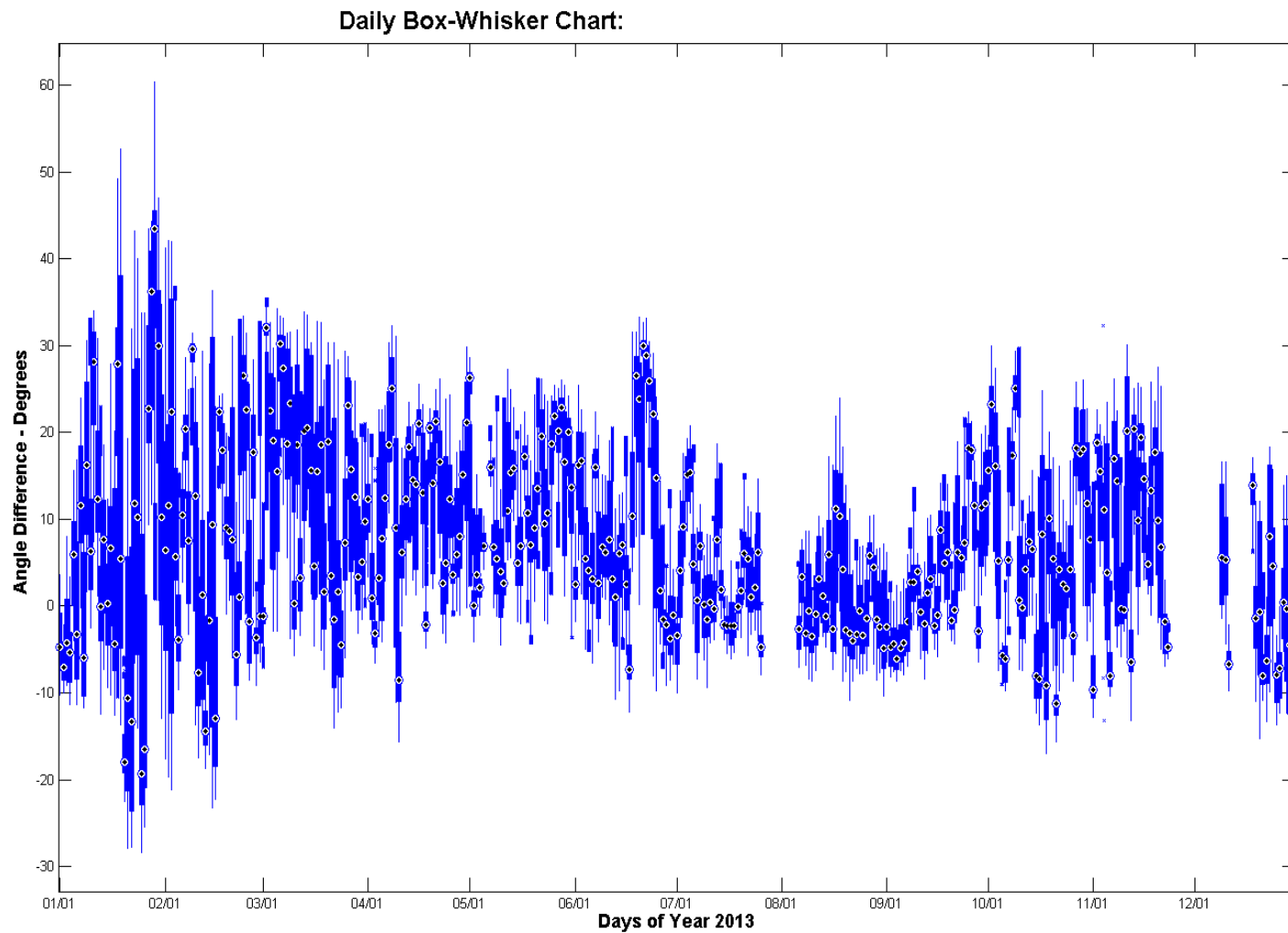
West 5



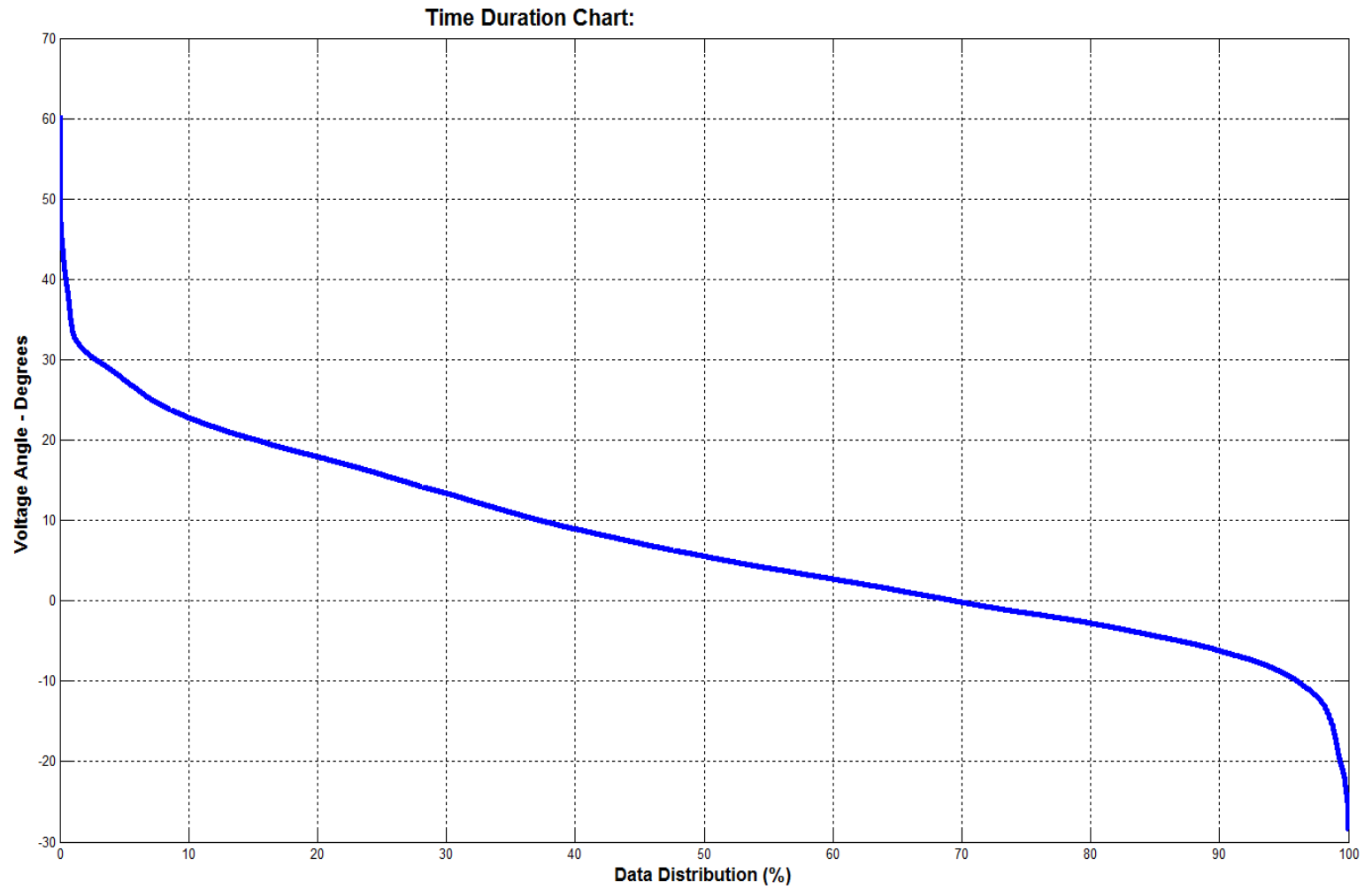
West 5



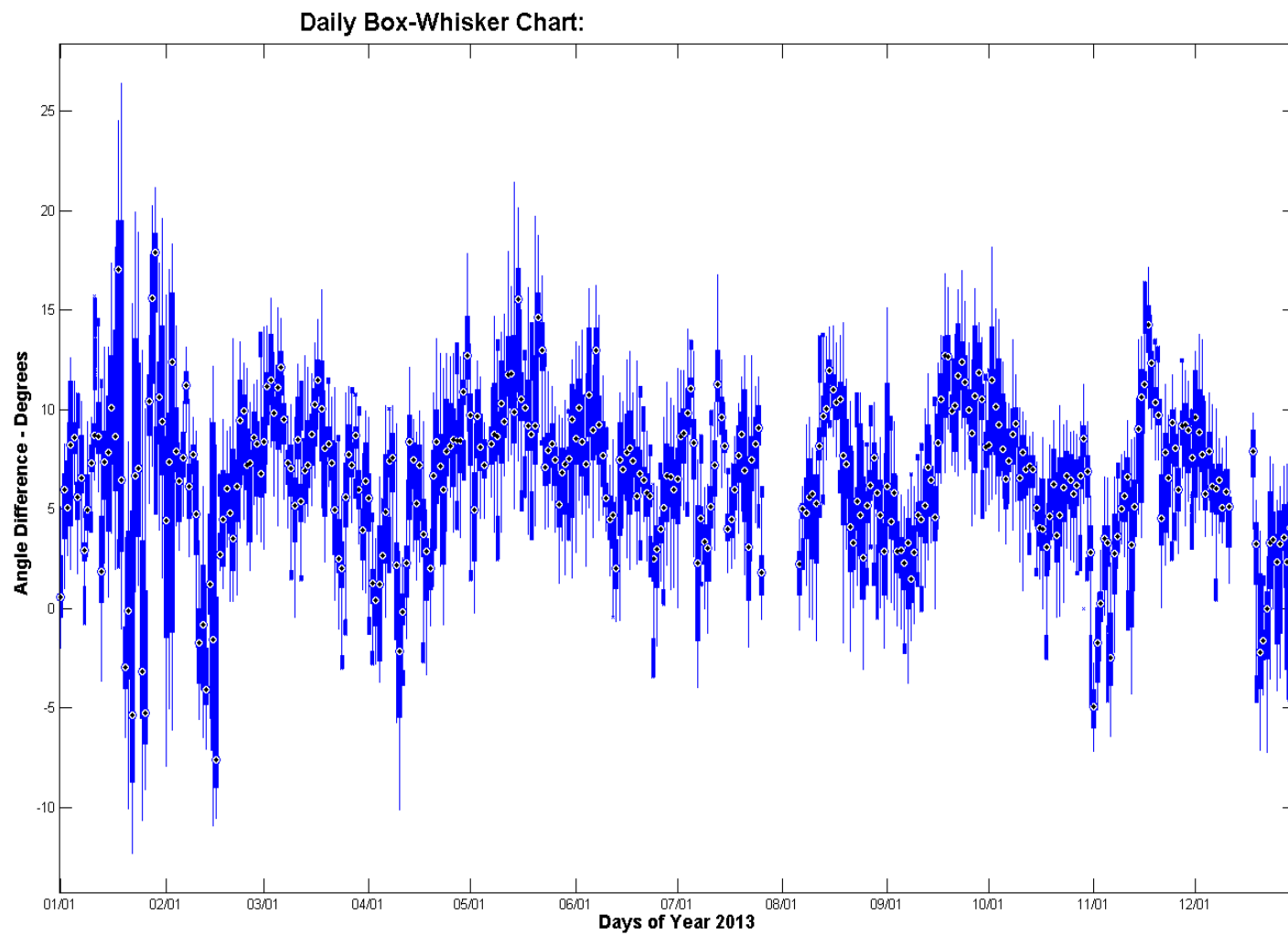
West 6



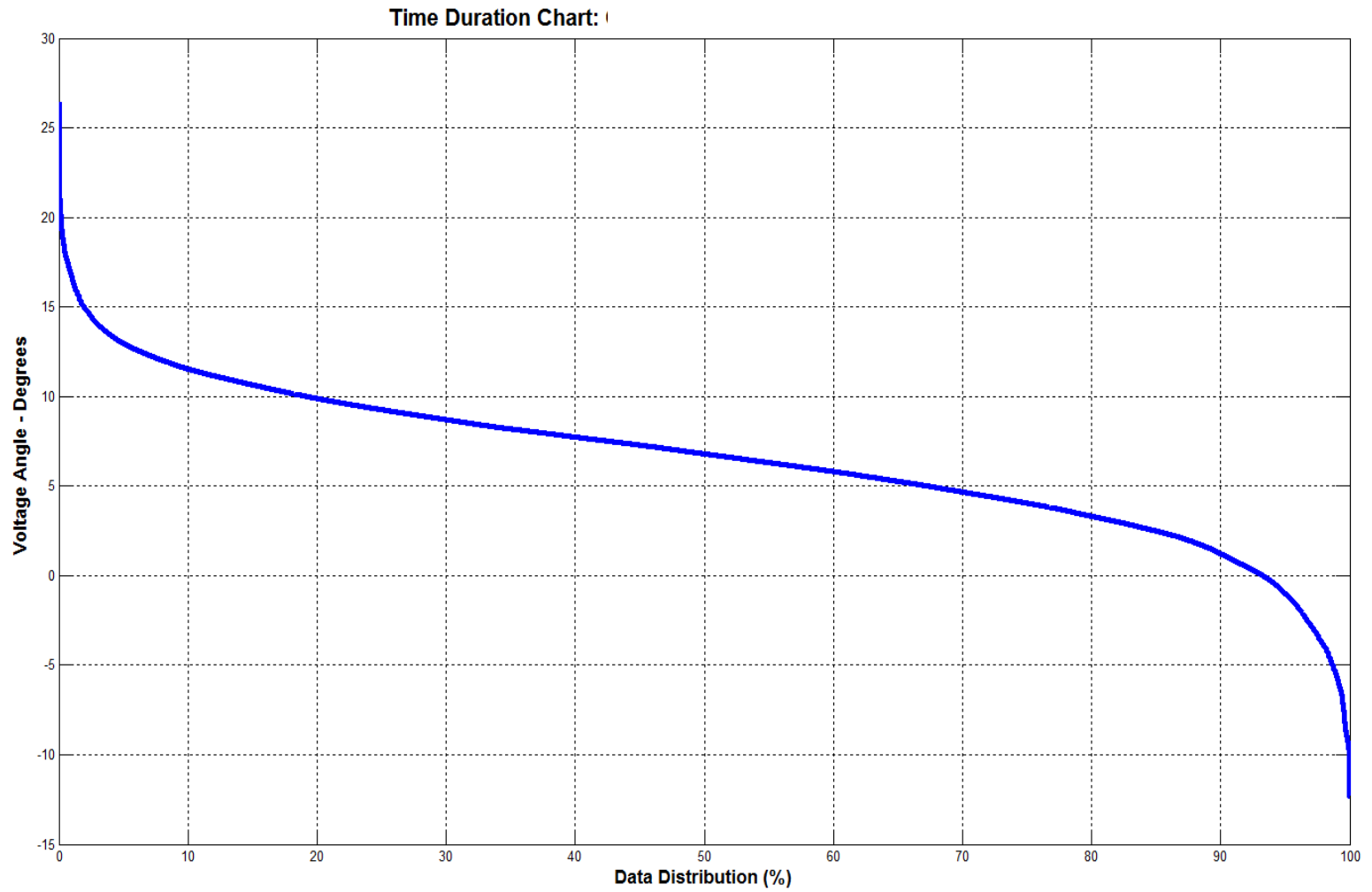
West 6



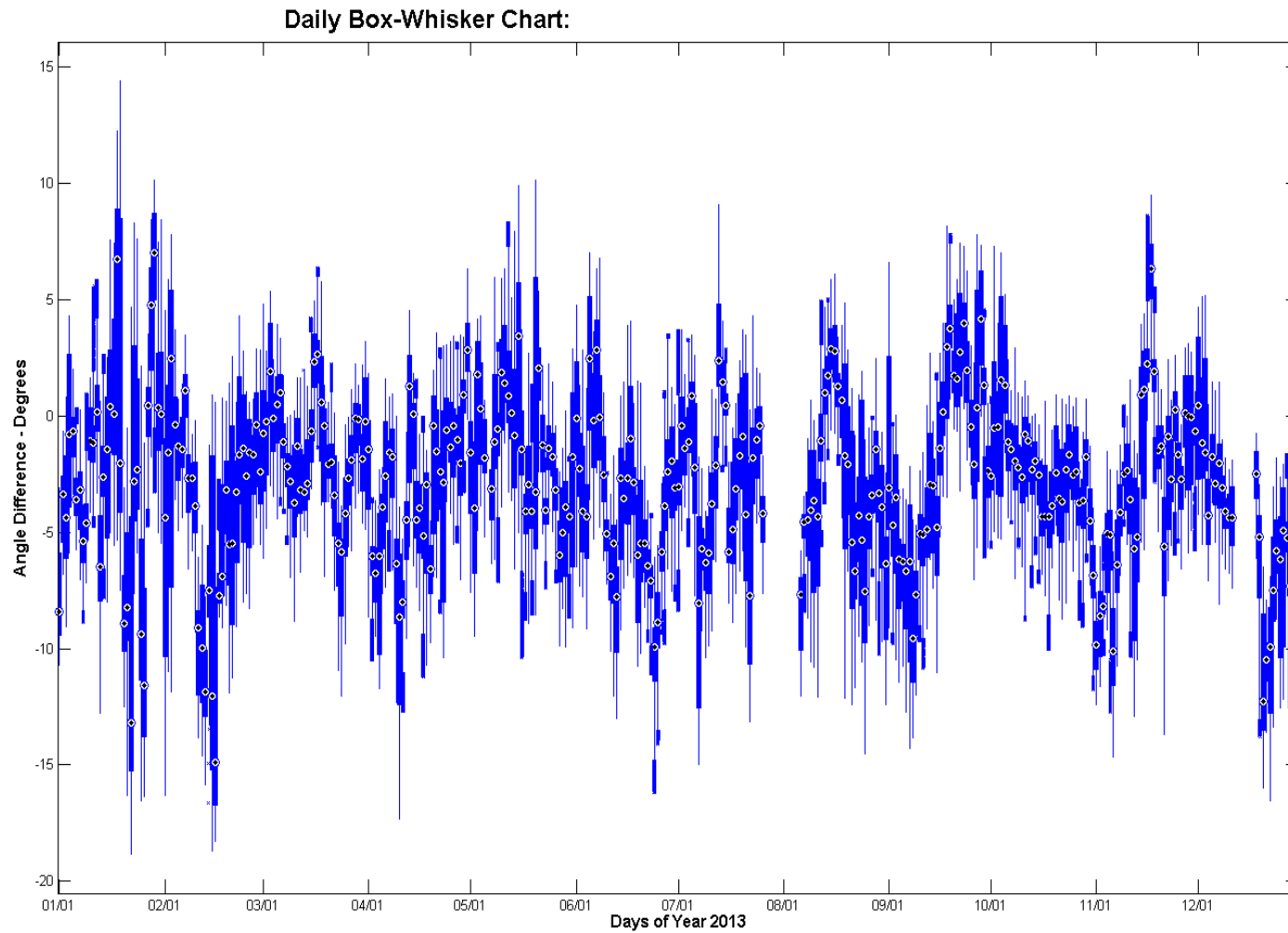
North 1



North 1

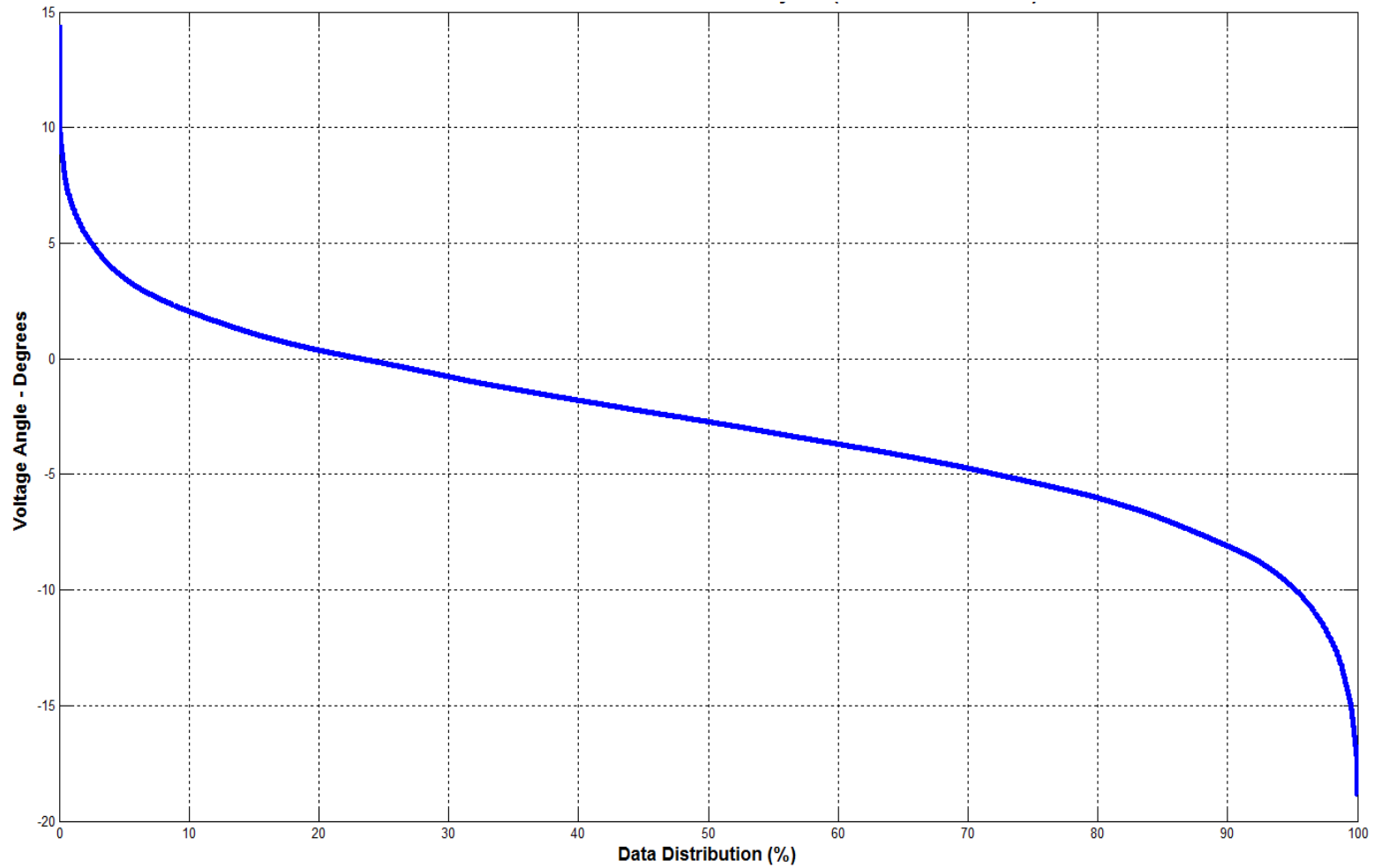


North 4

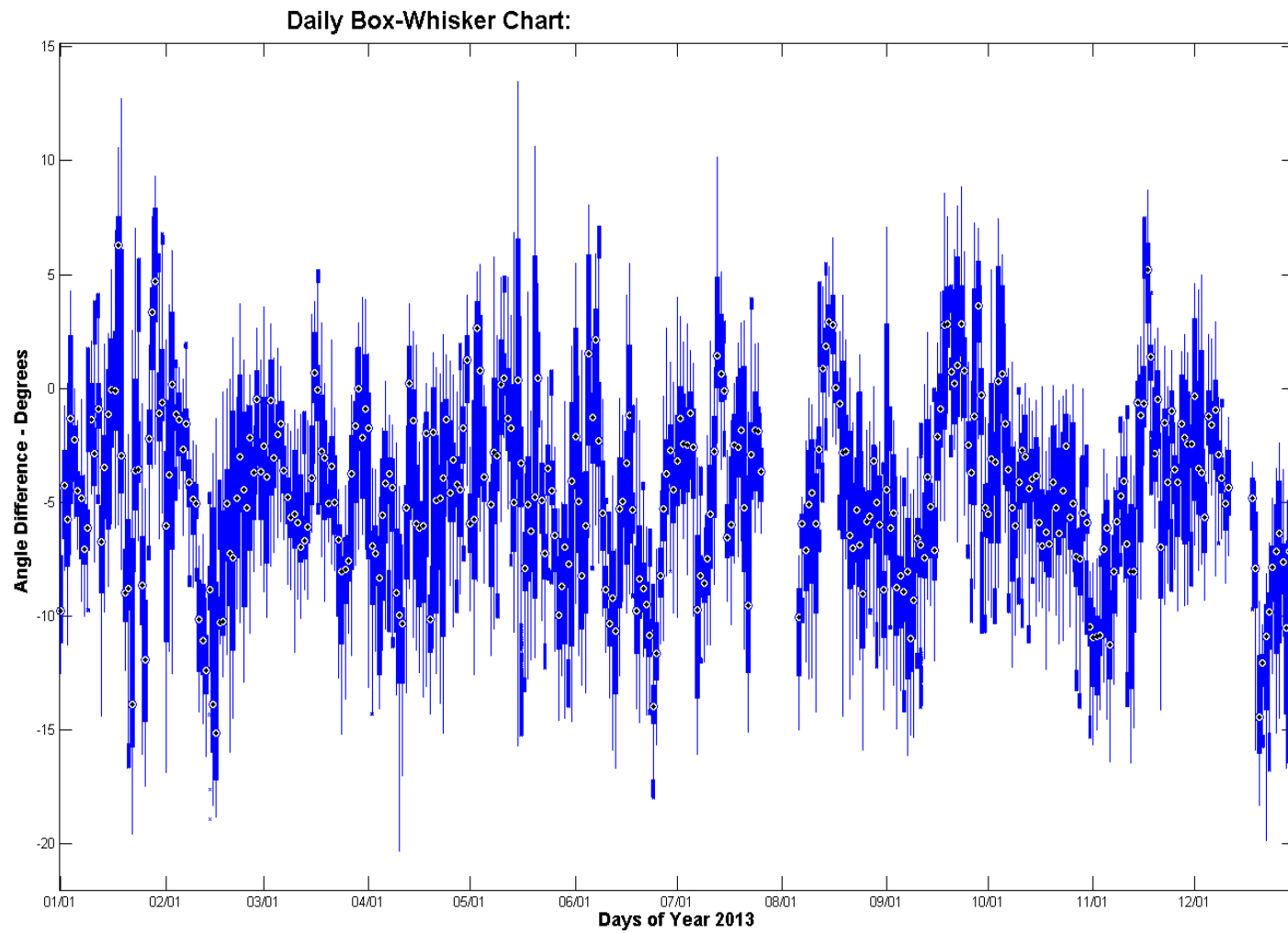


North 4

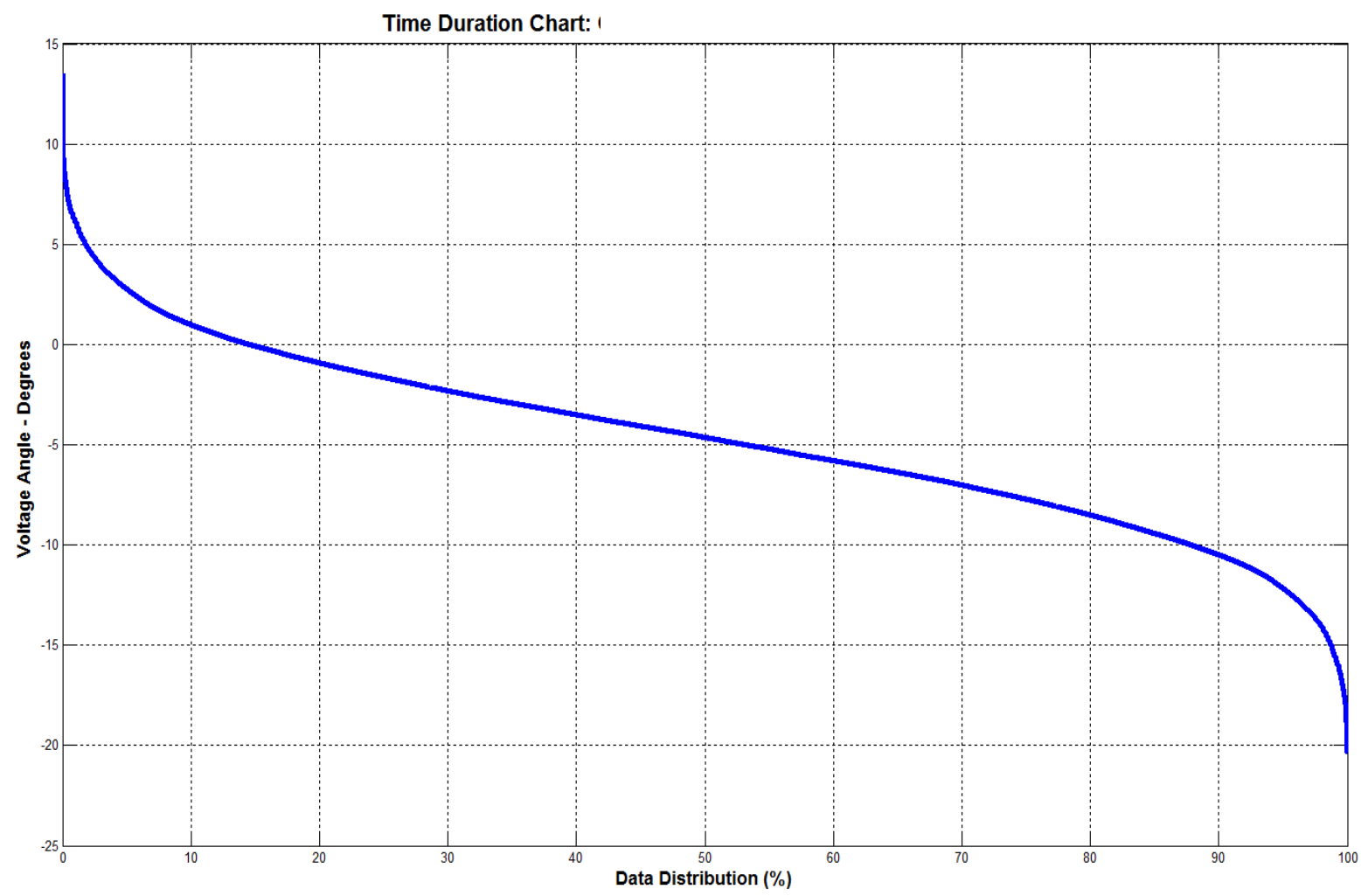
Time Duration Chart:



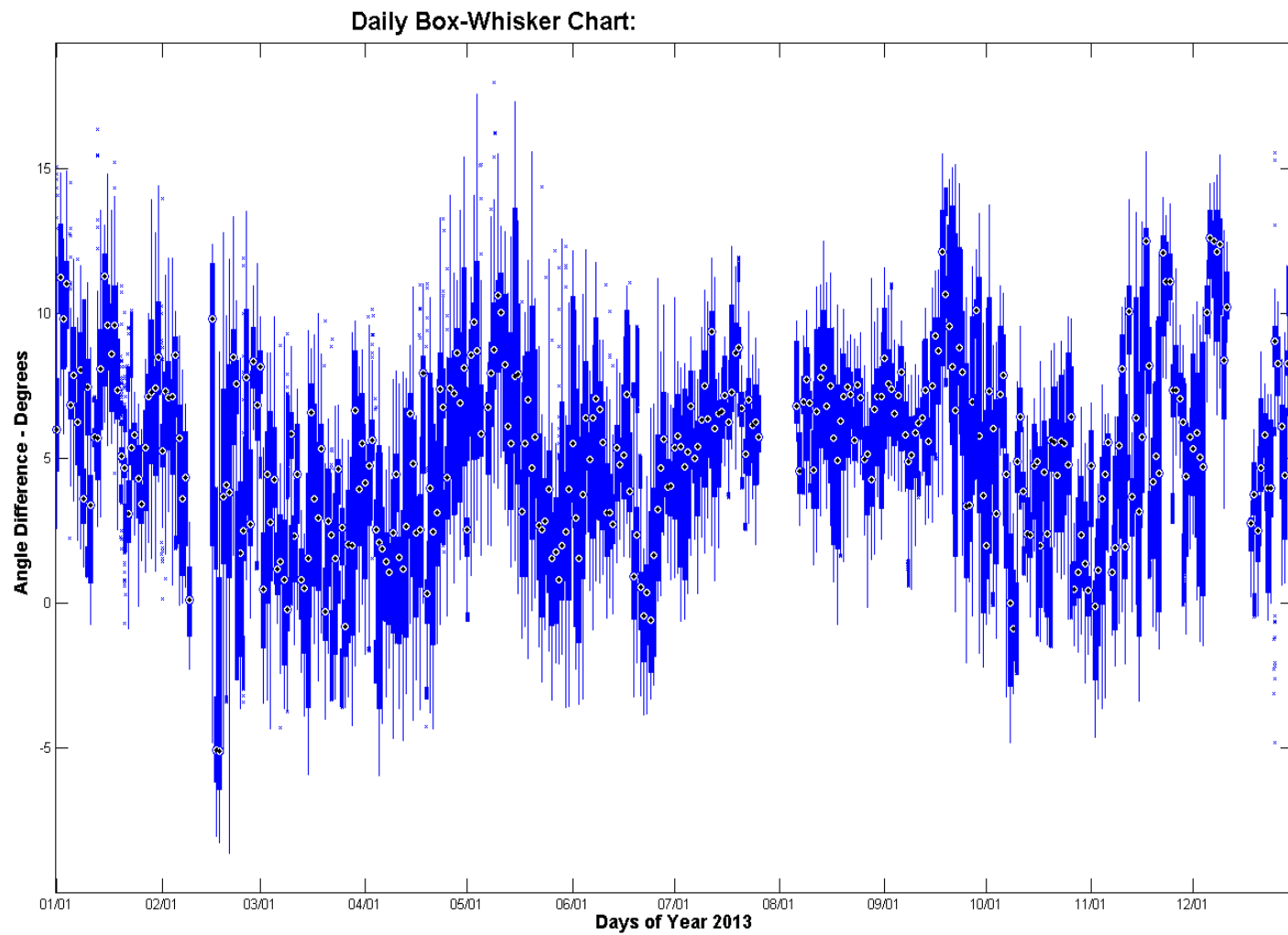
North 5



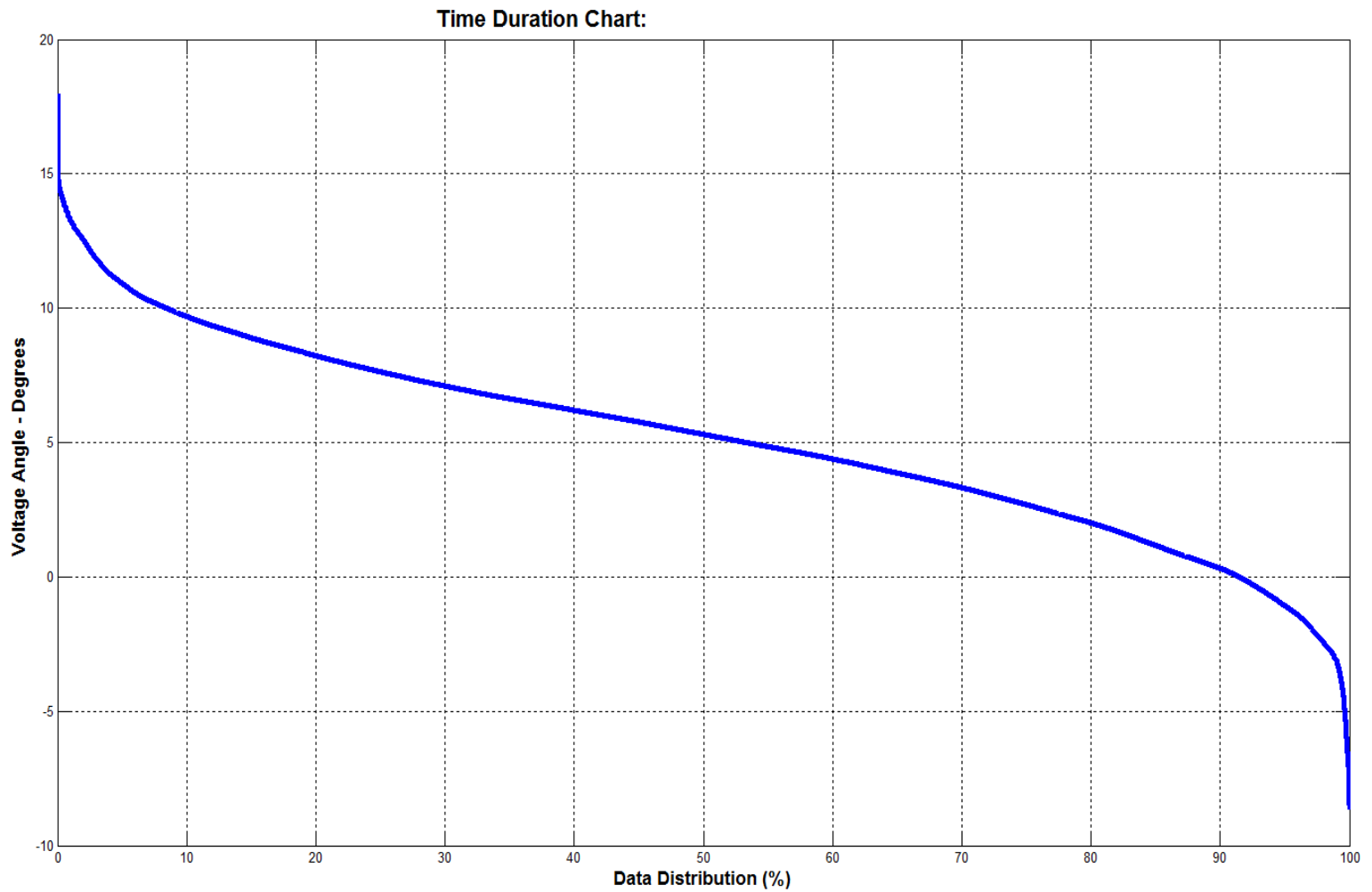
North 5



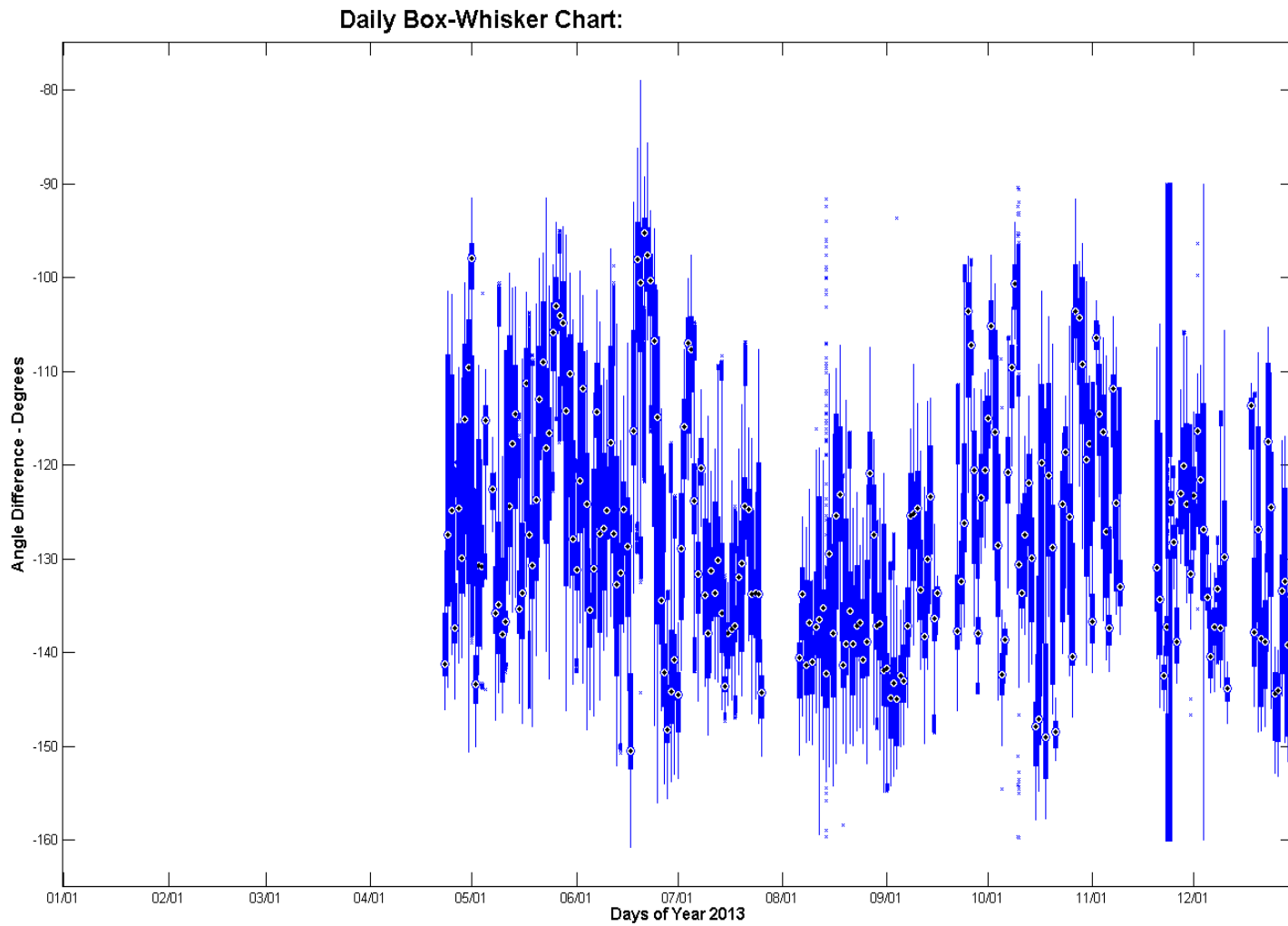
North 6



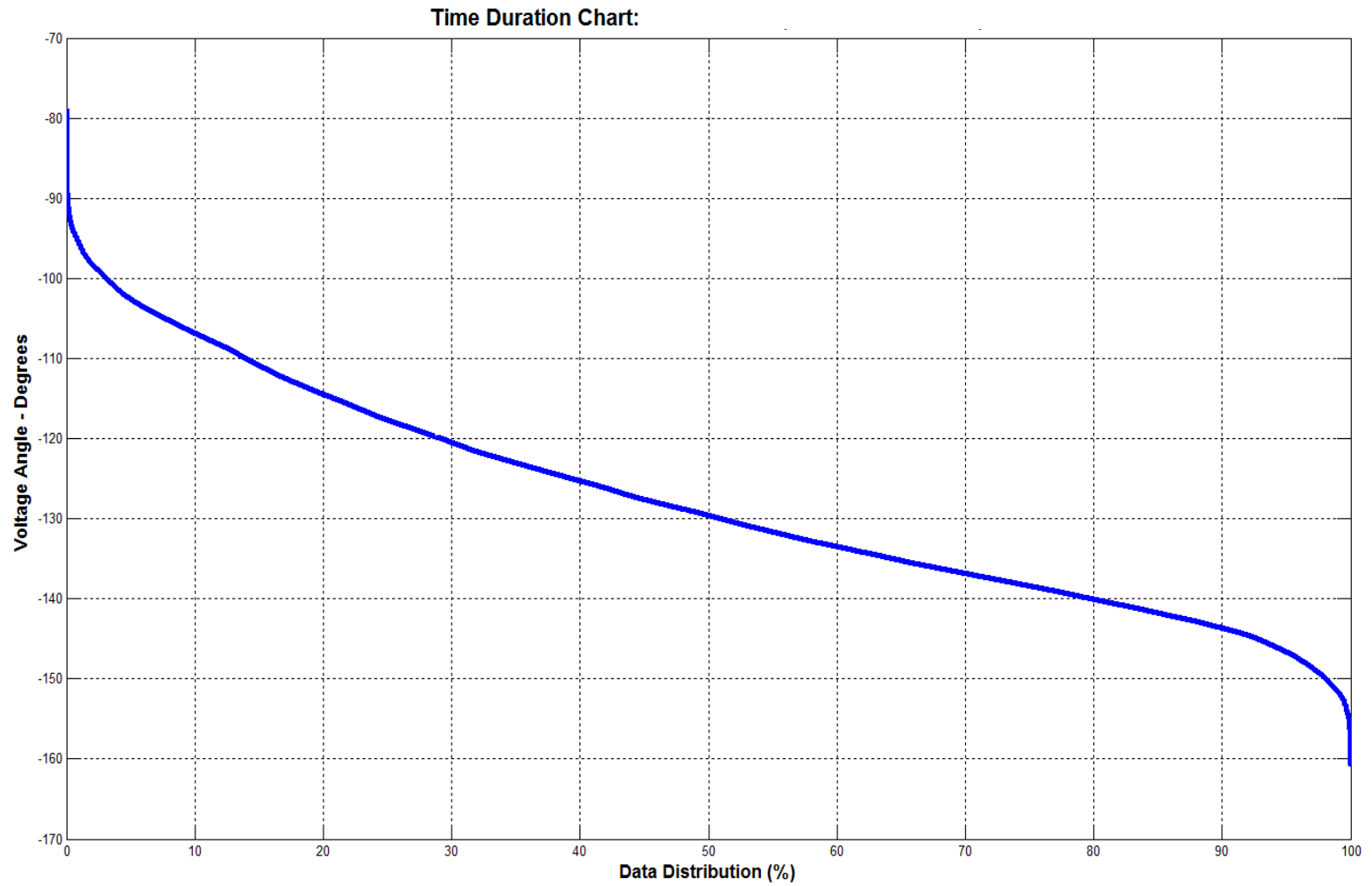
North 6



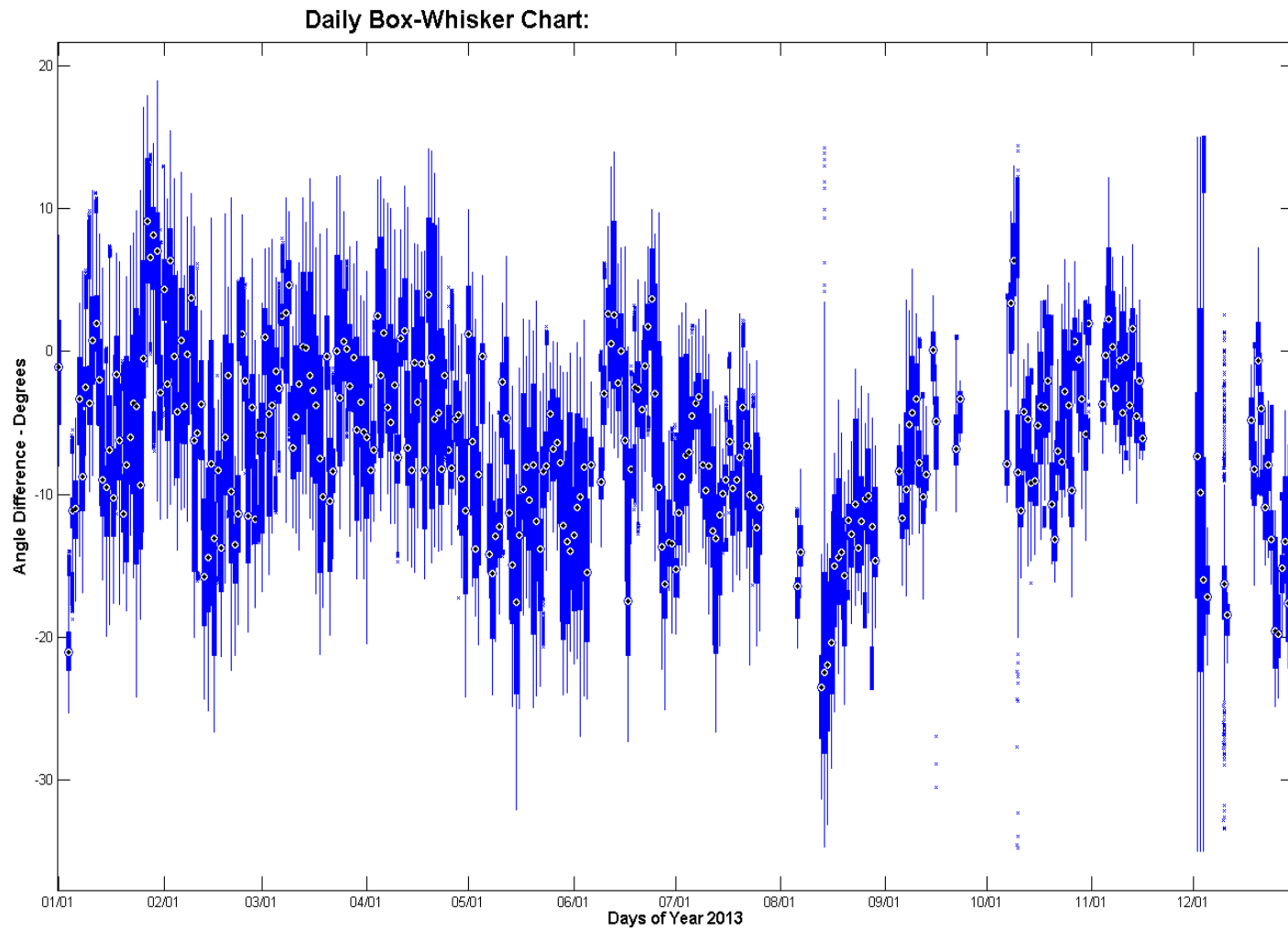
FarWest 2



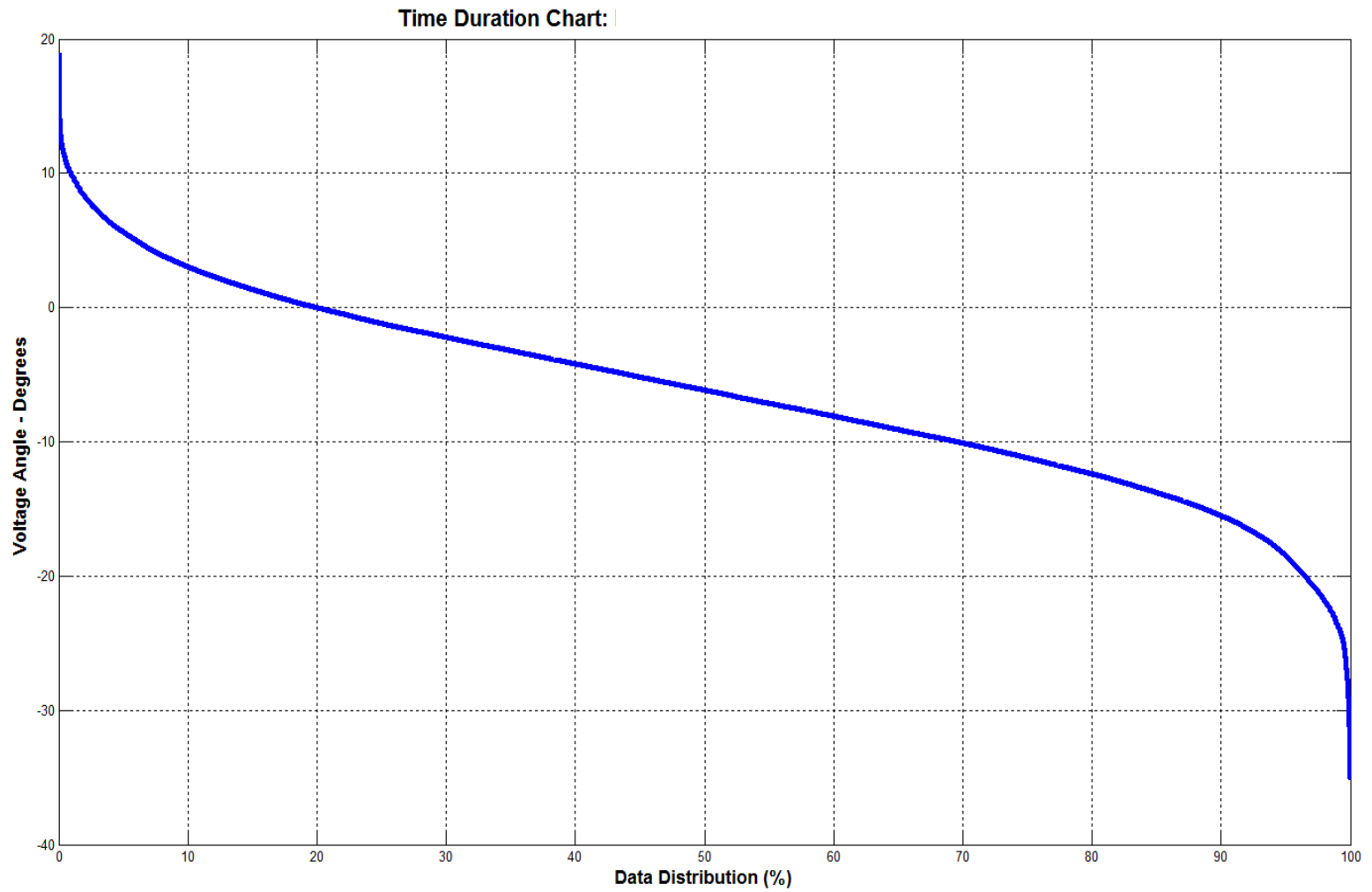
FarWest 2



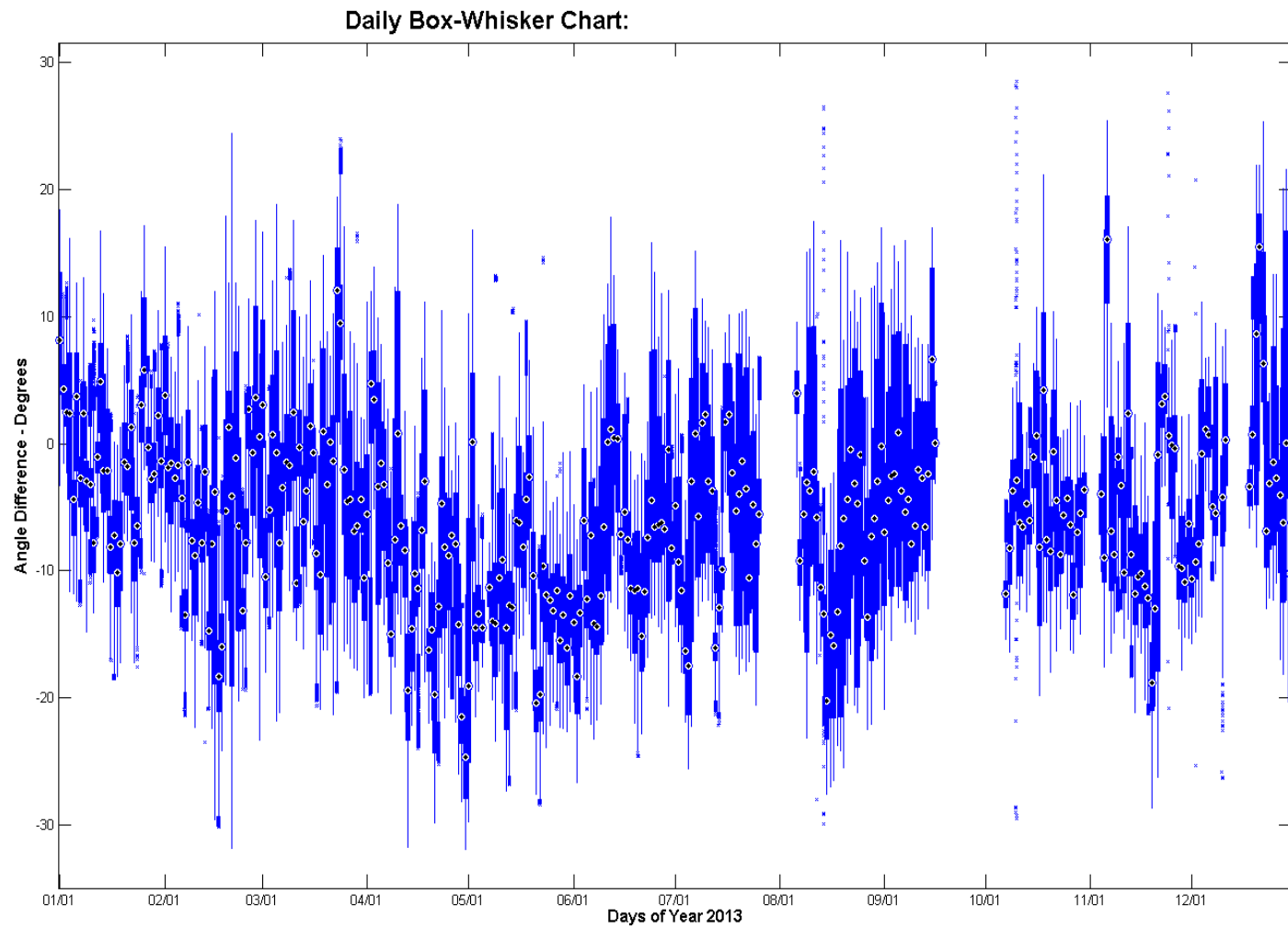
West 4



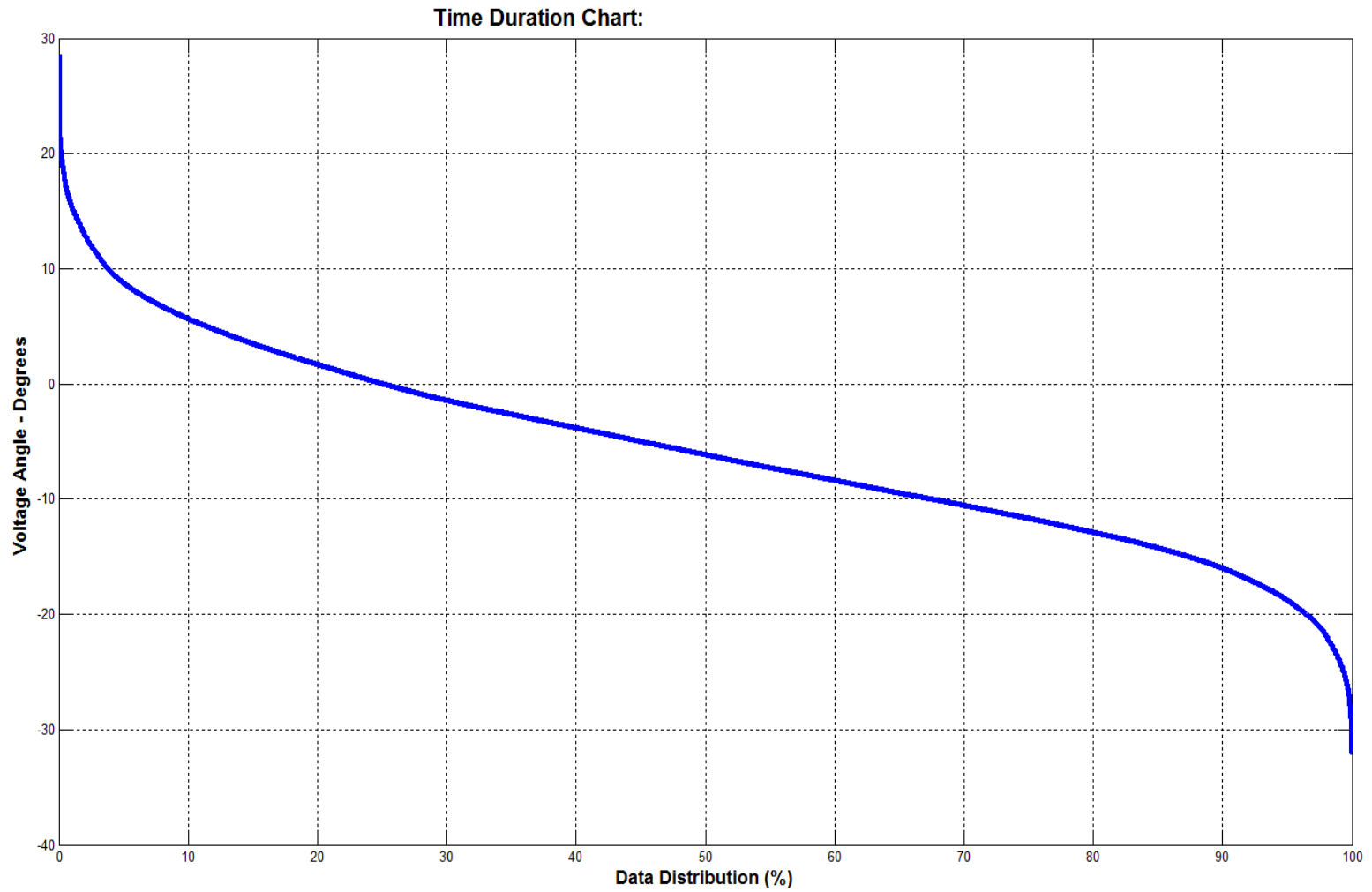
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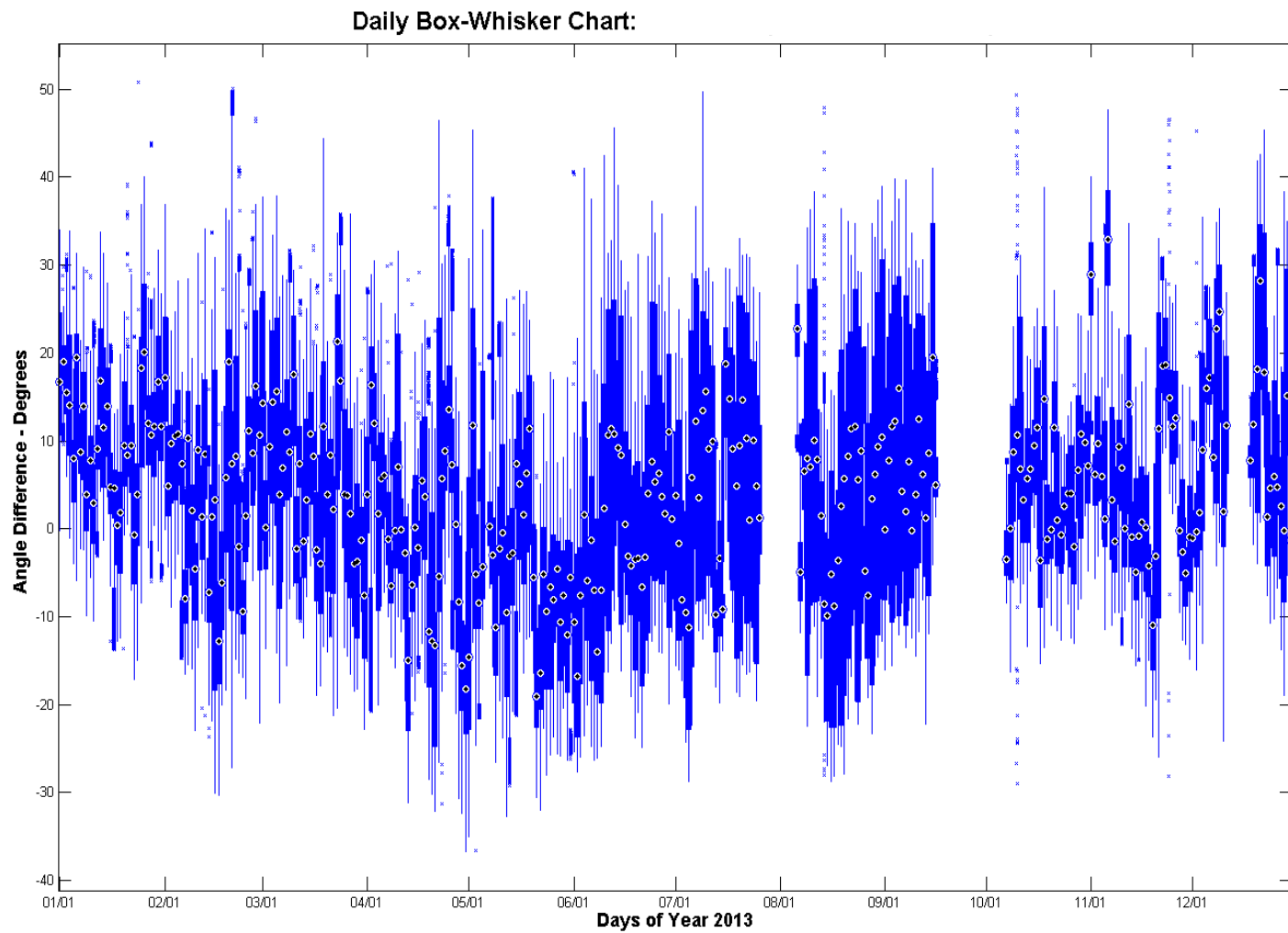
Coast 2



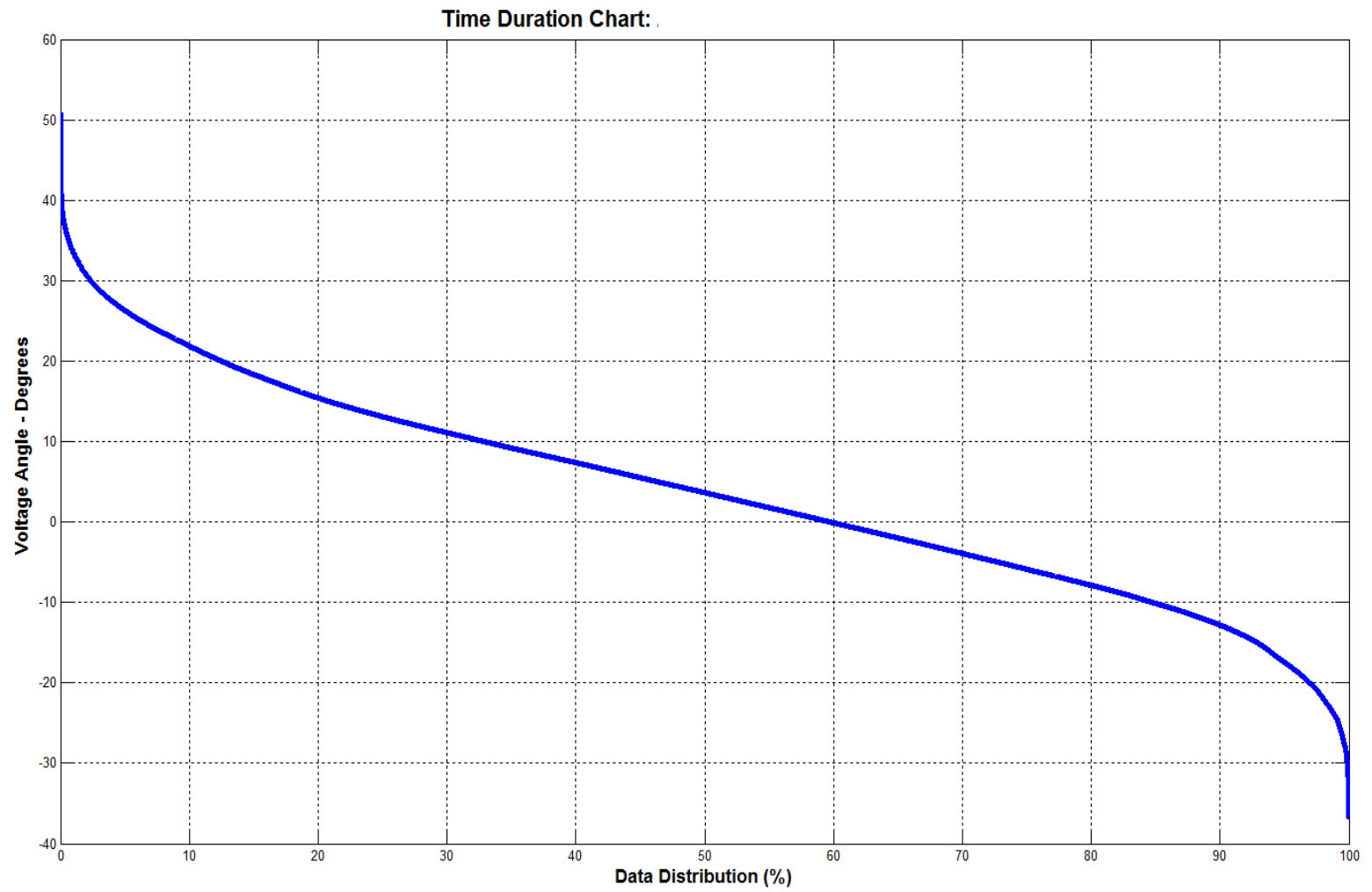
Coast 2



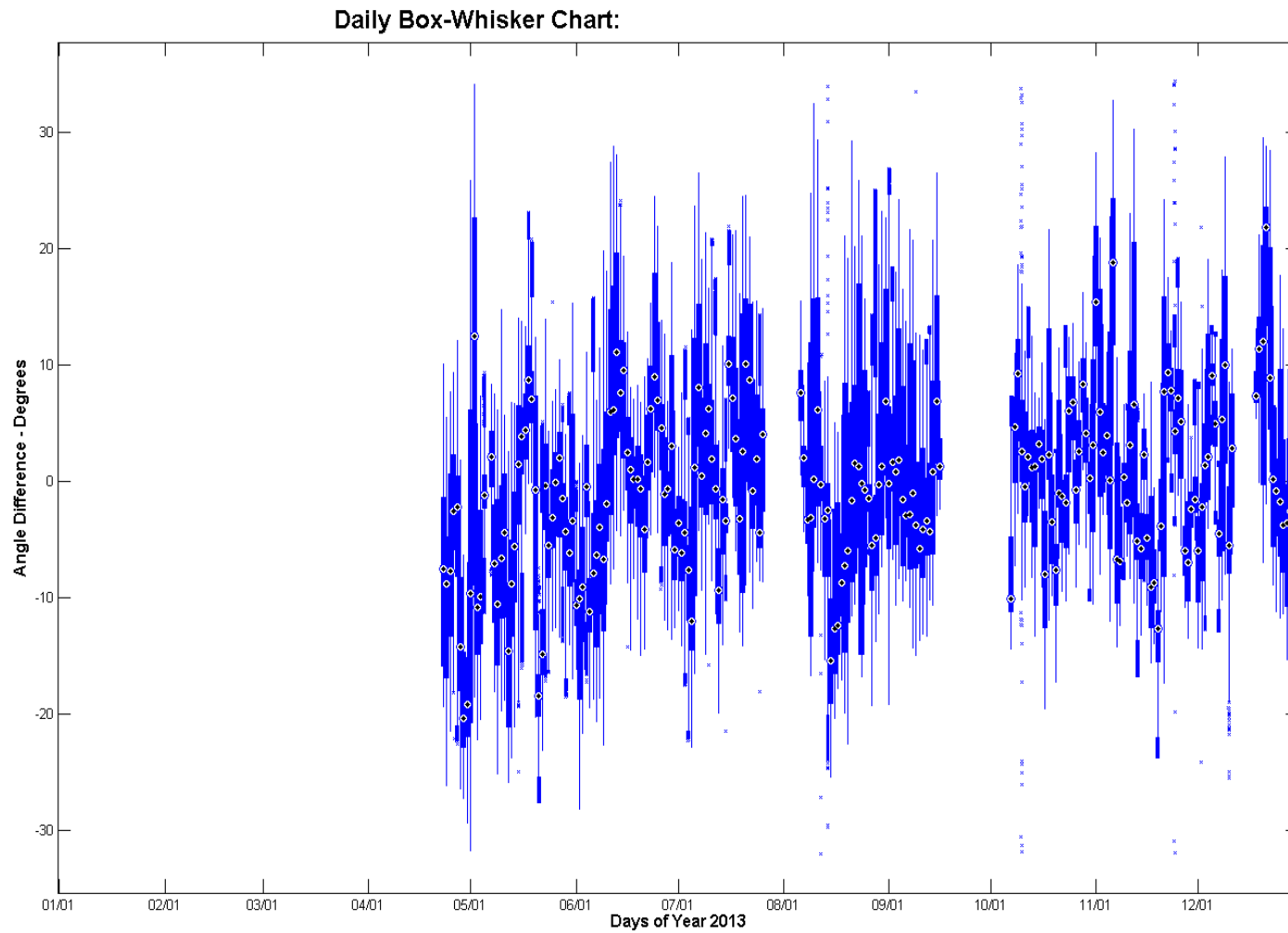
Coast 1



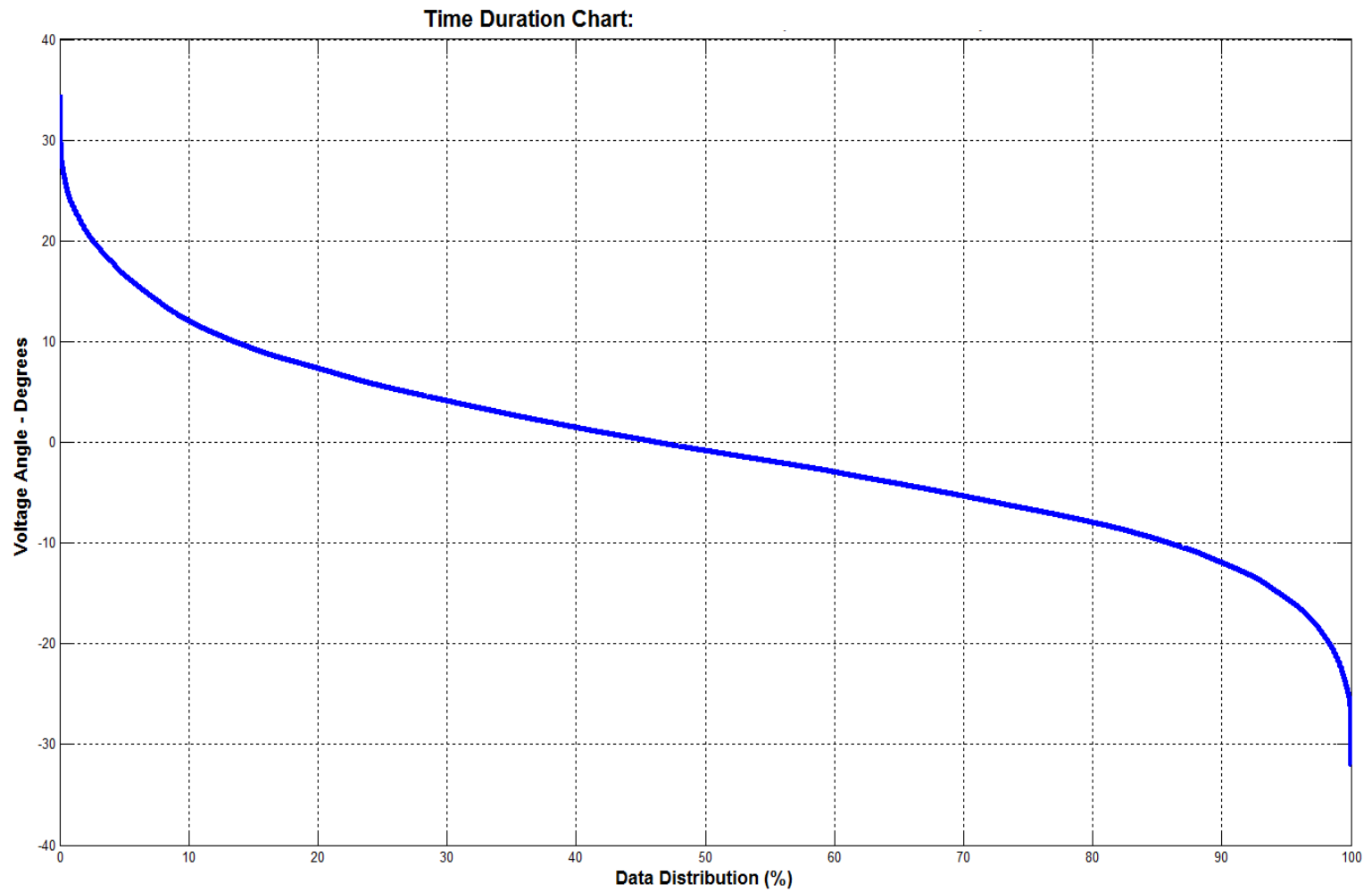
Coast 1



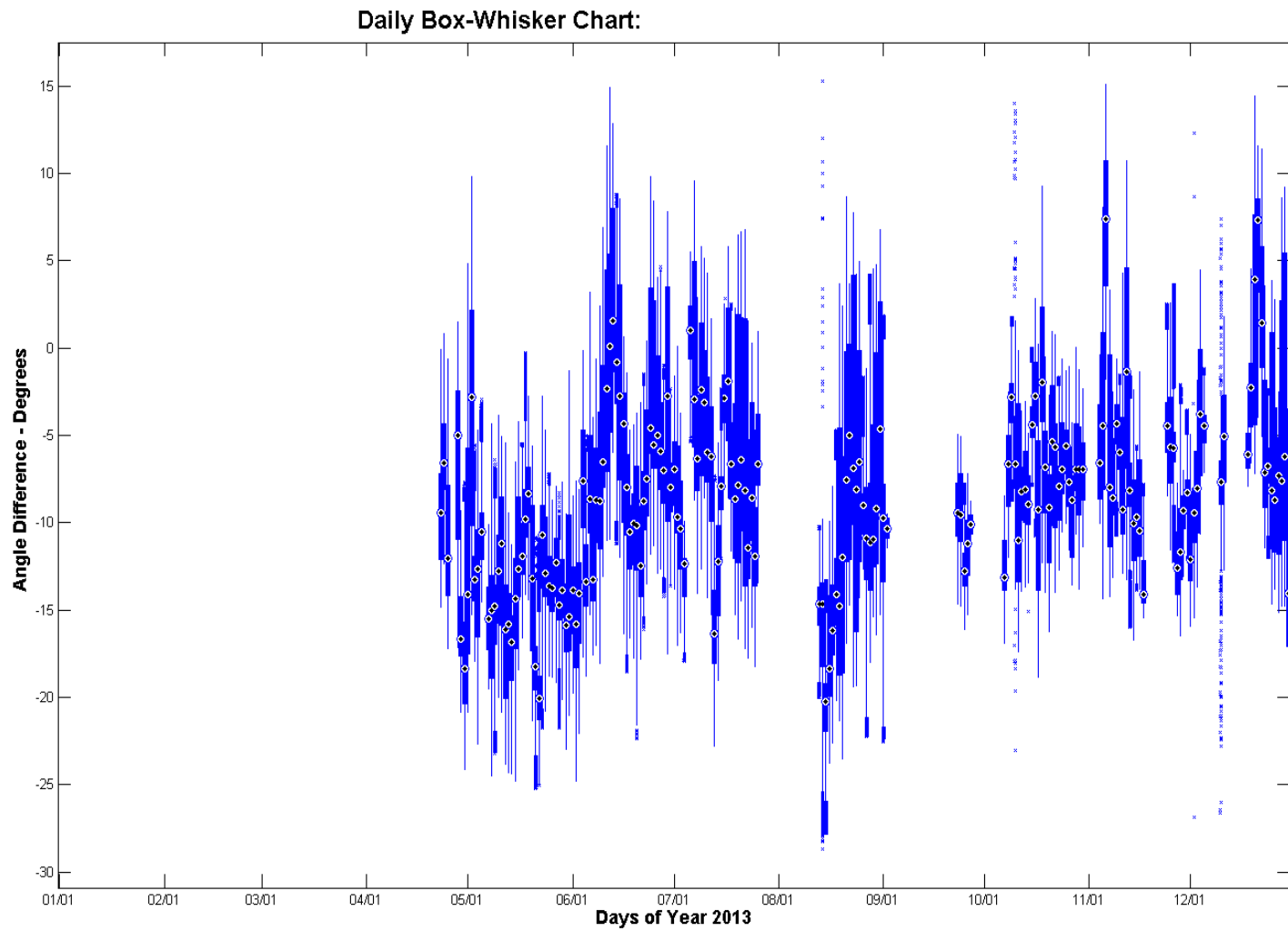
South 3



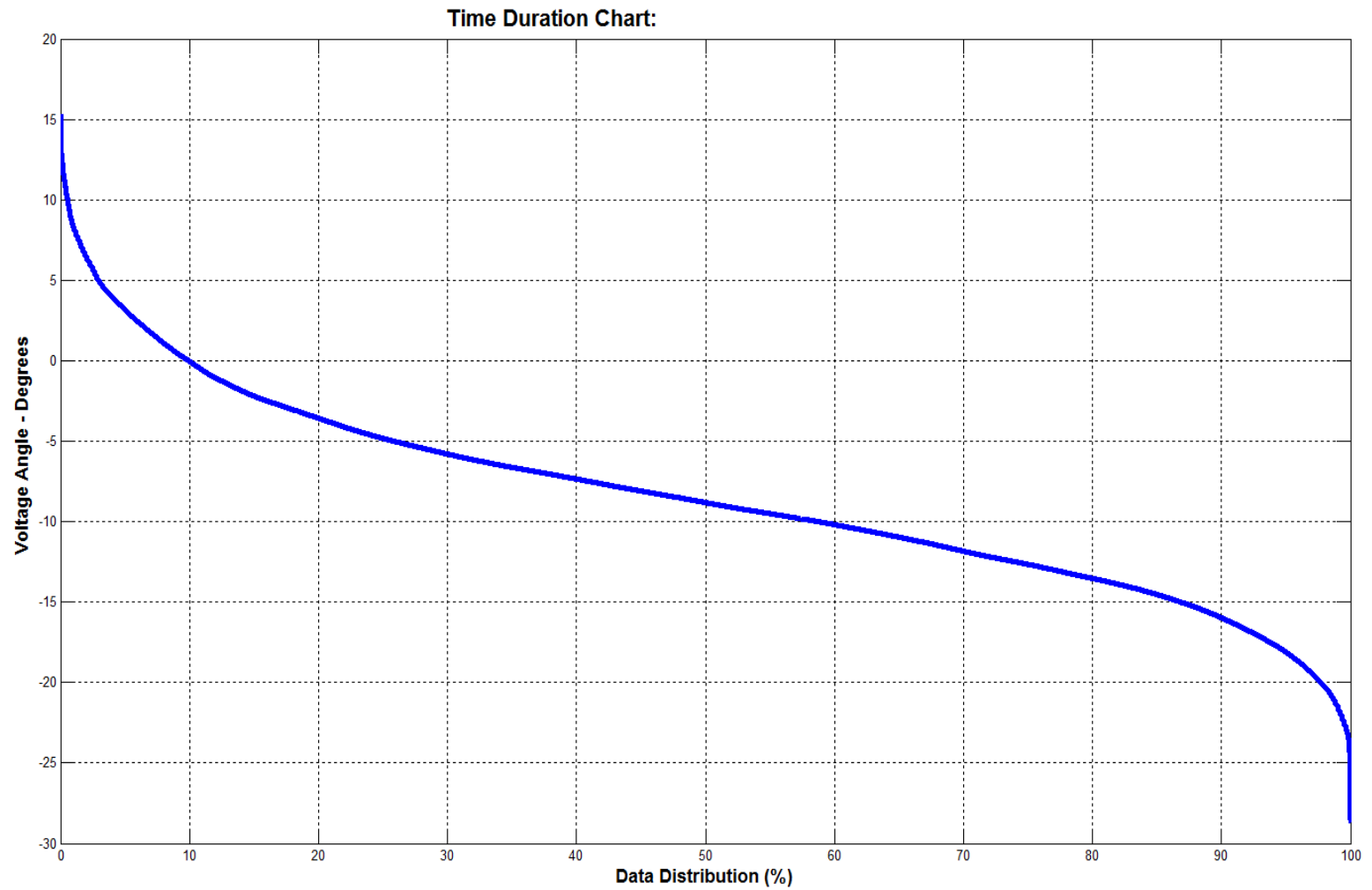
South 3



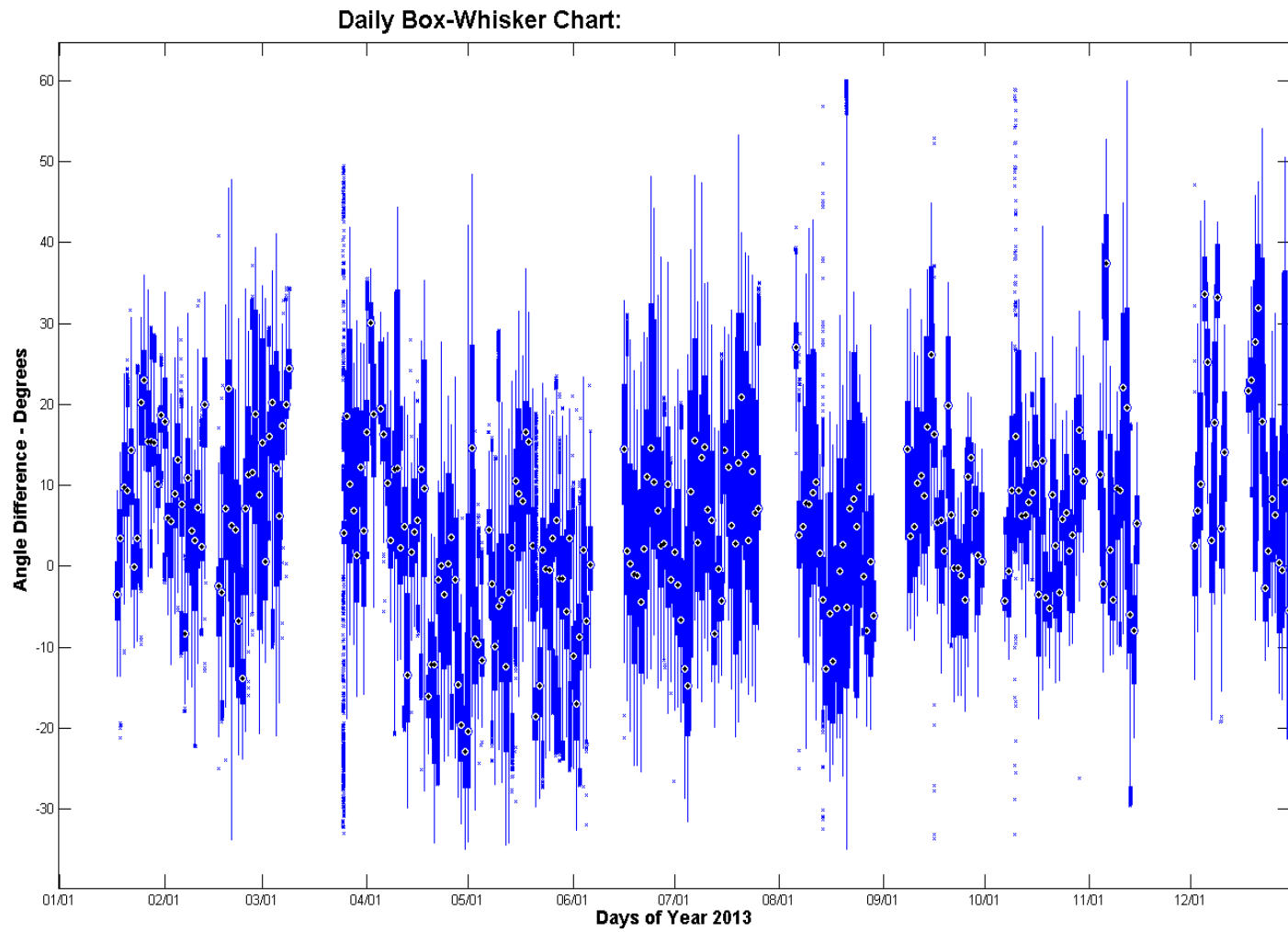
South 5



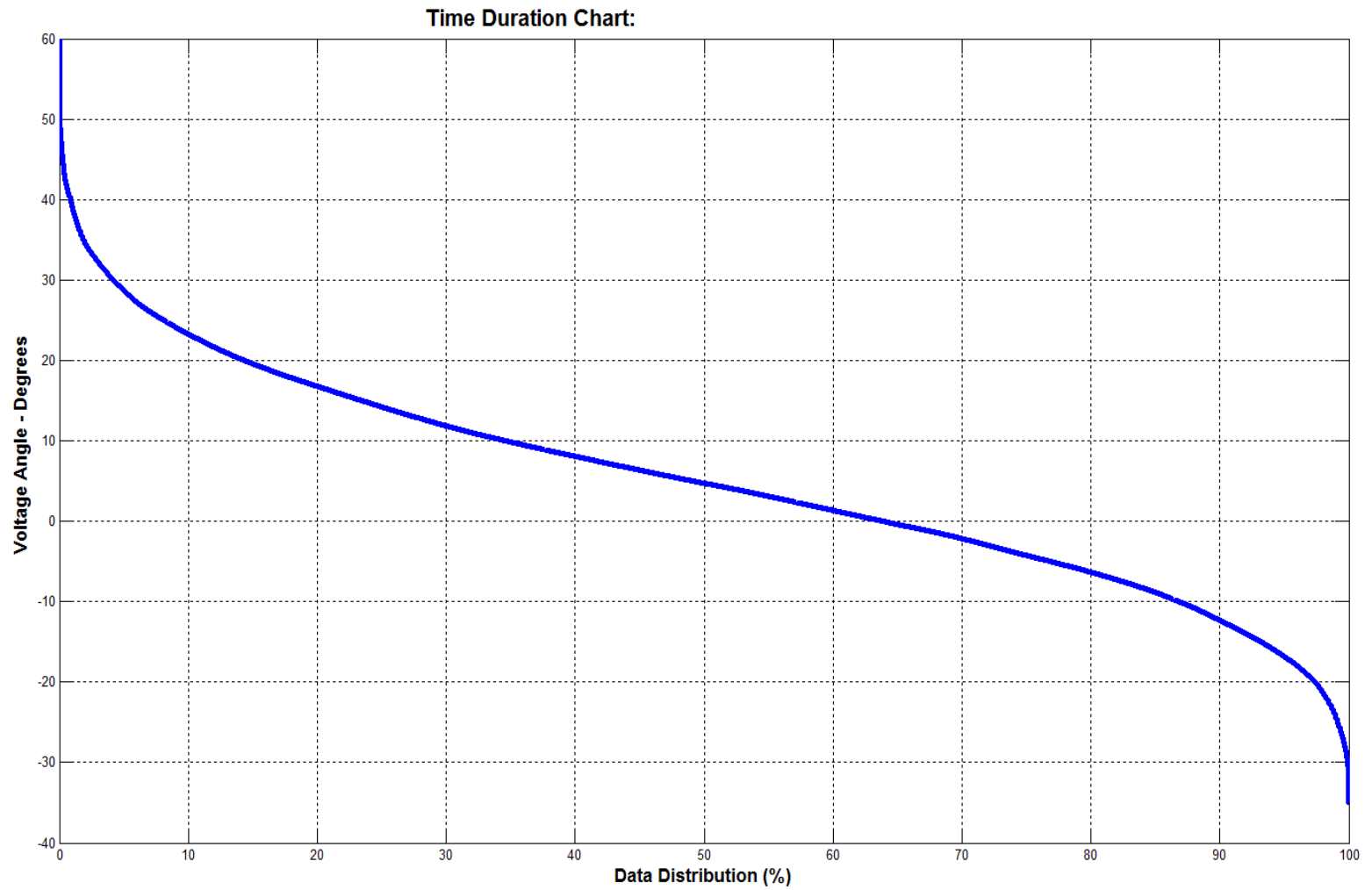
South 5



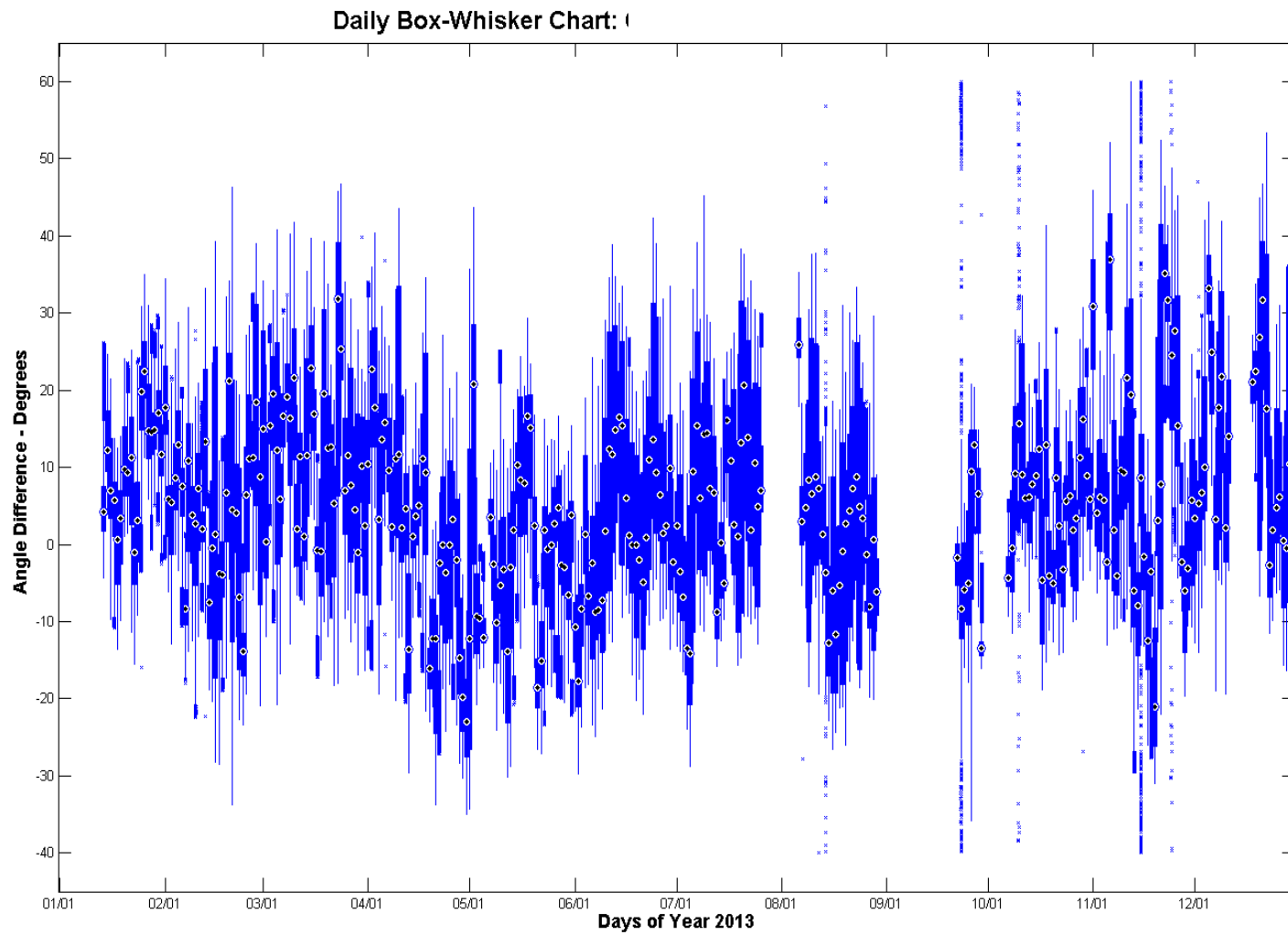
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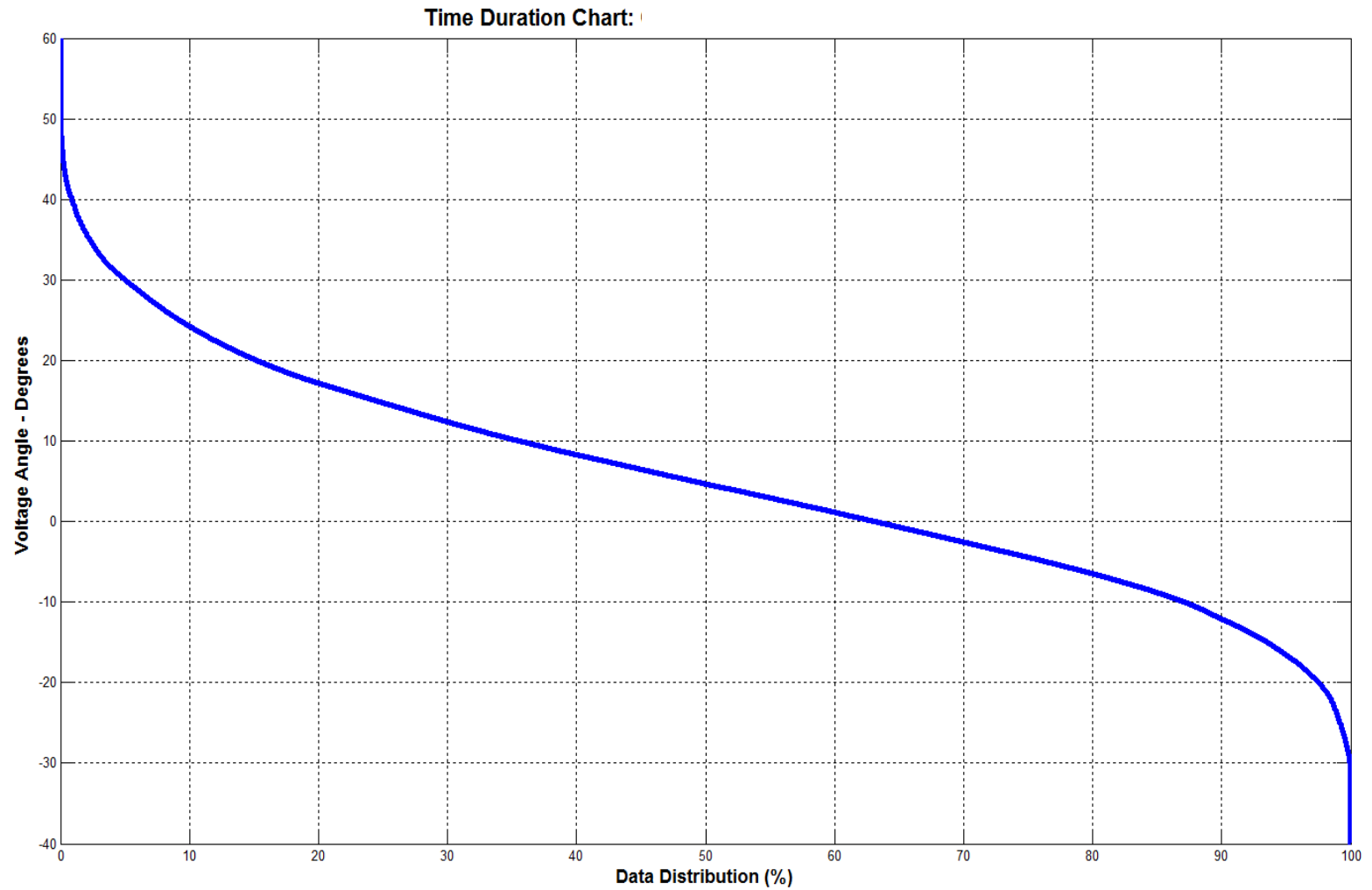
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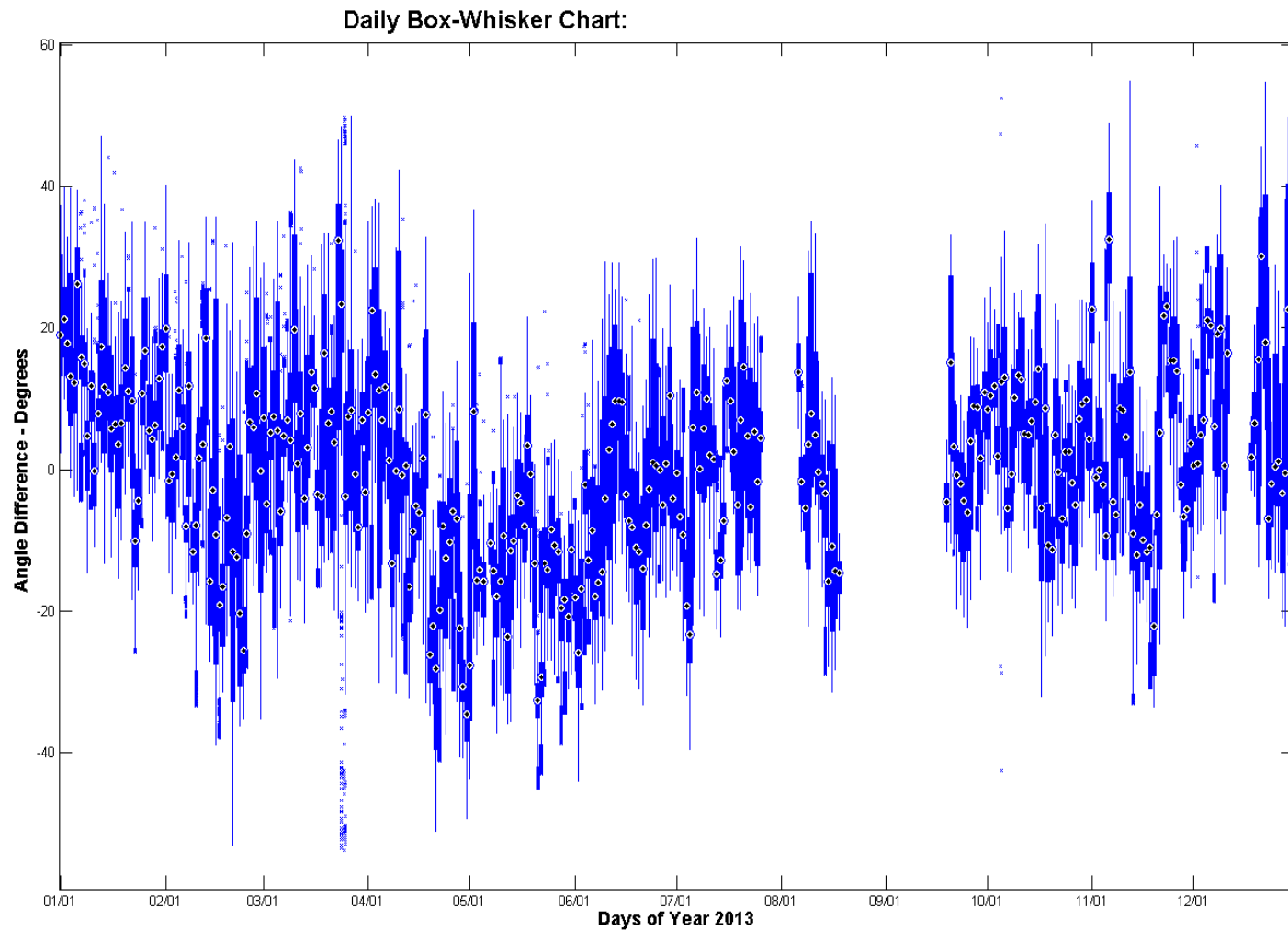
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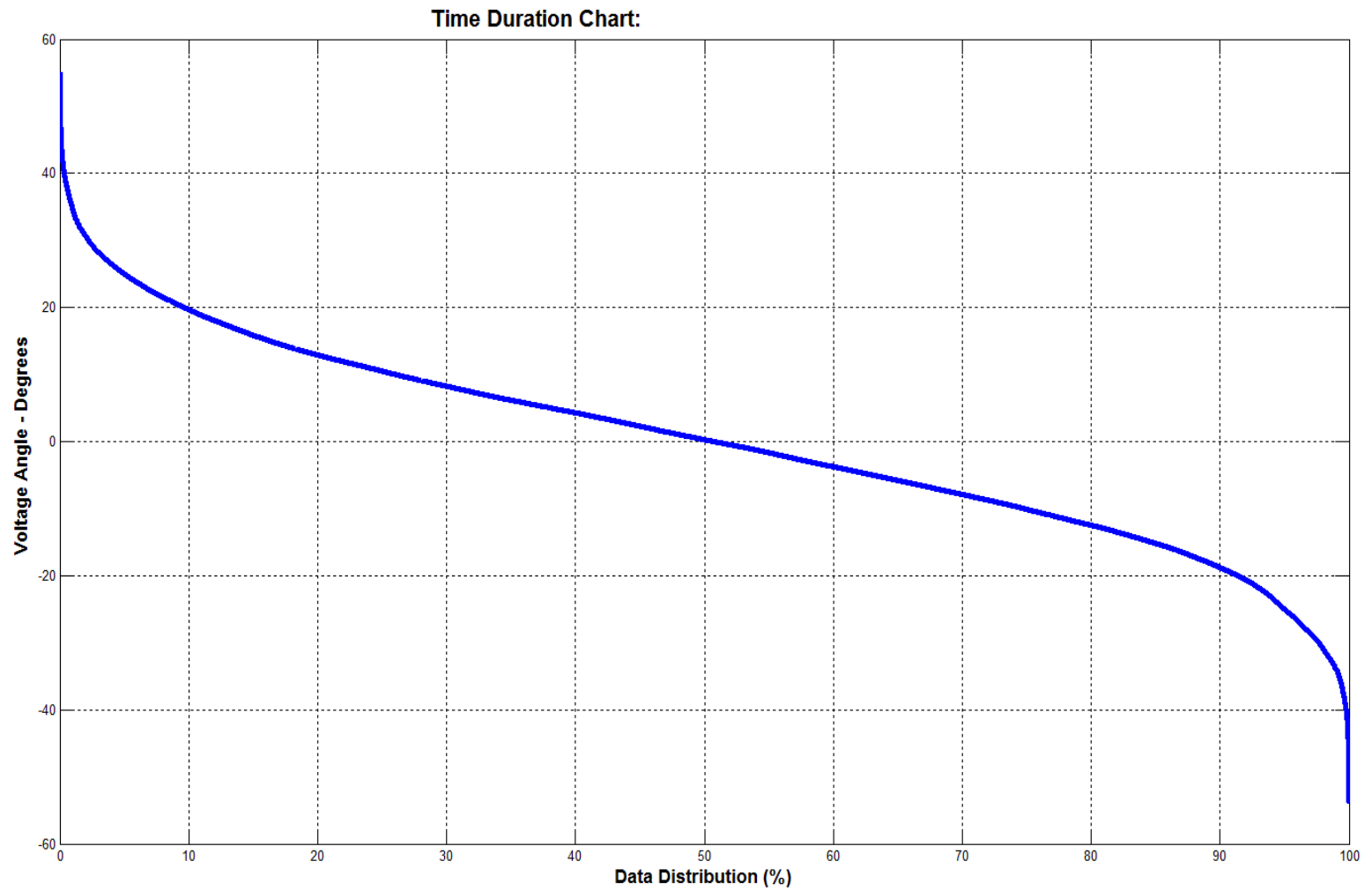
Coast 3



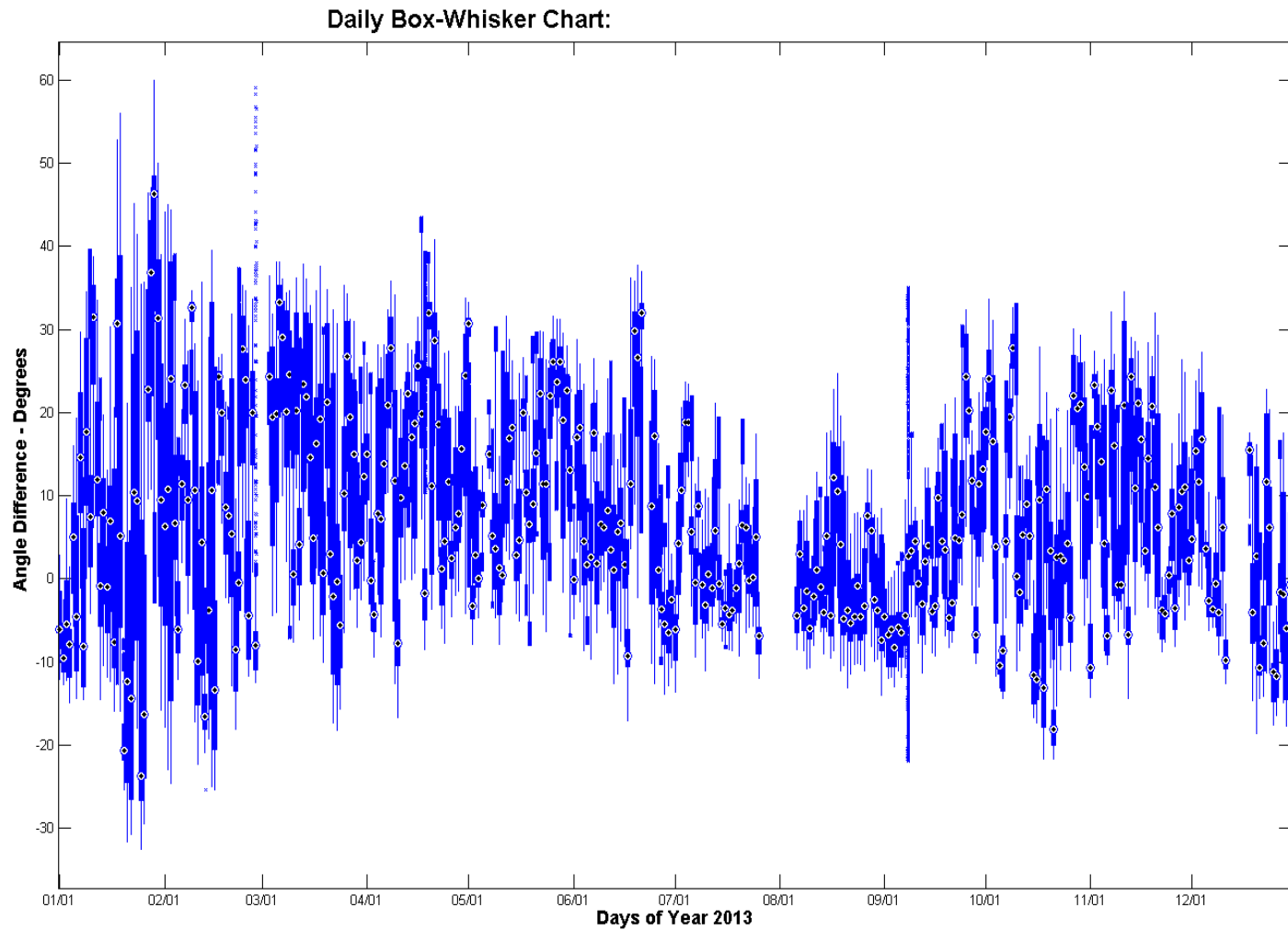
South 13



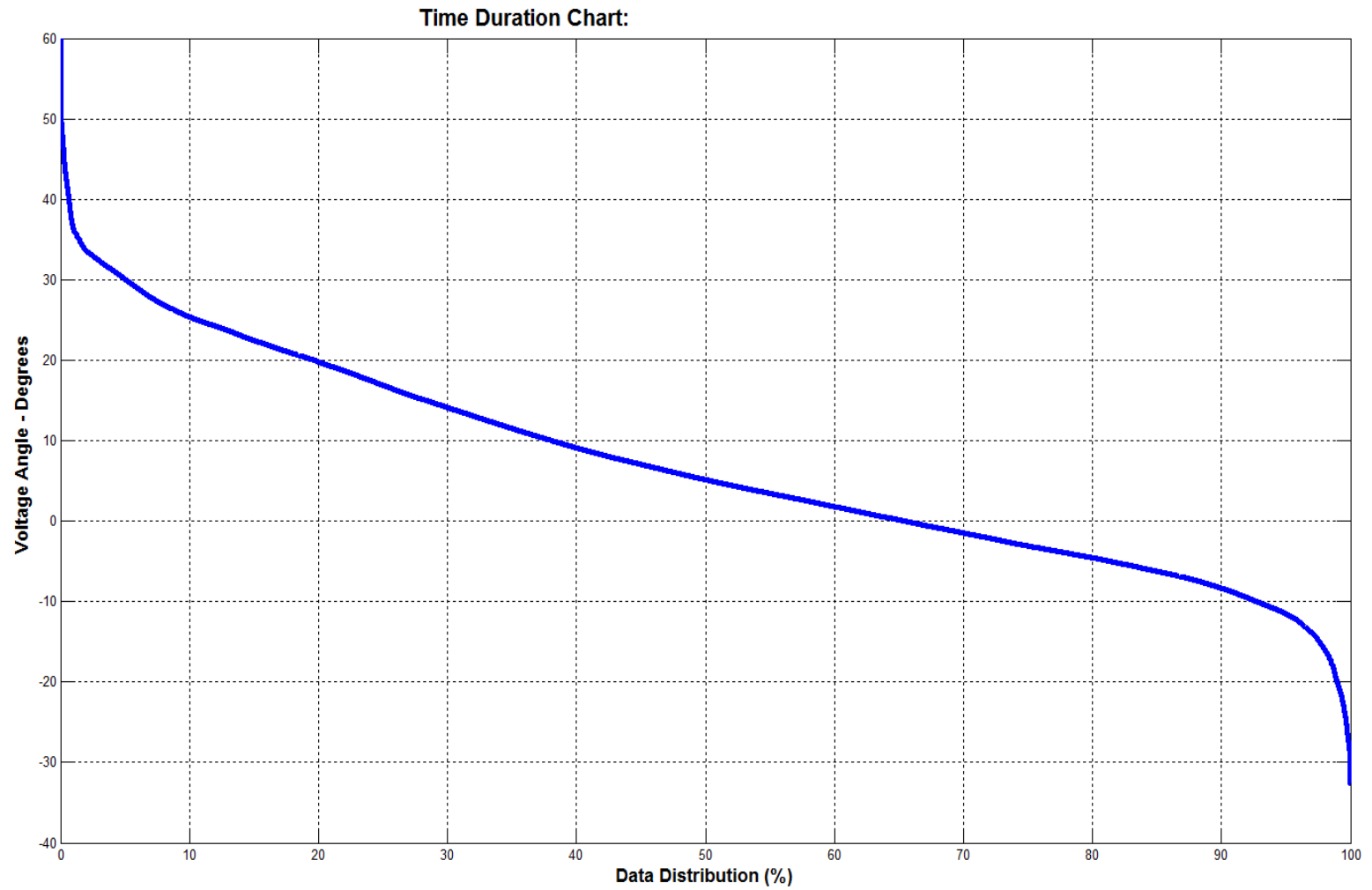
South 13



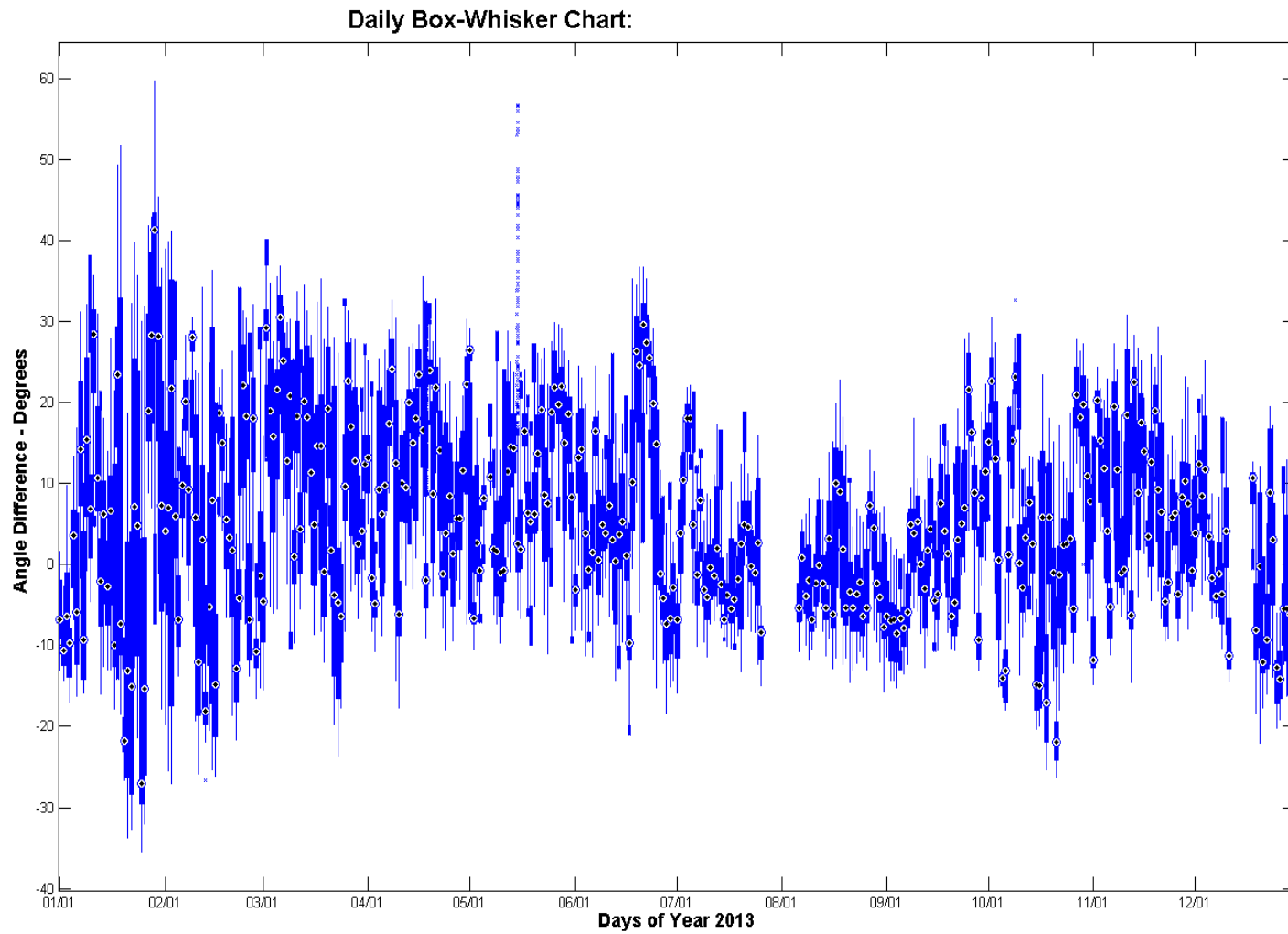
FarWest 4



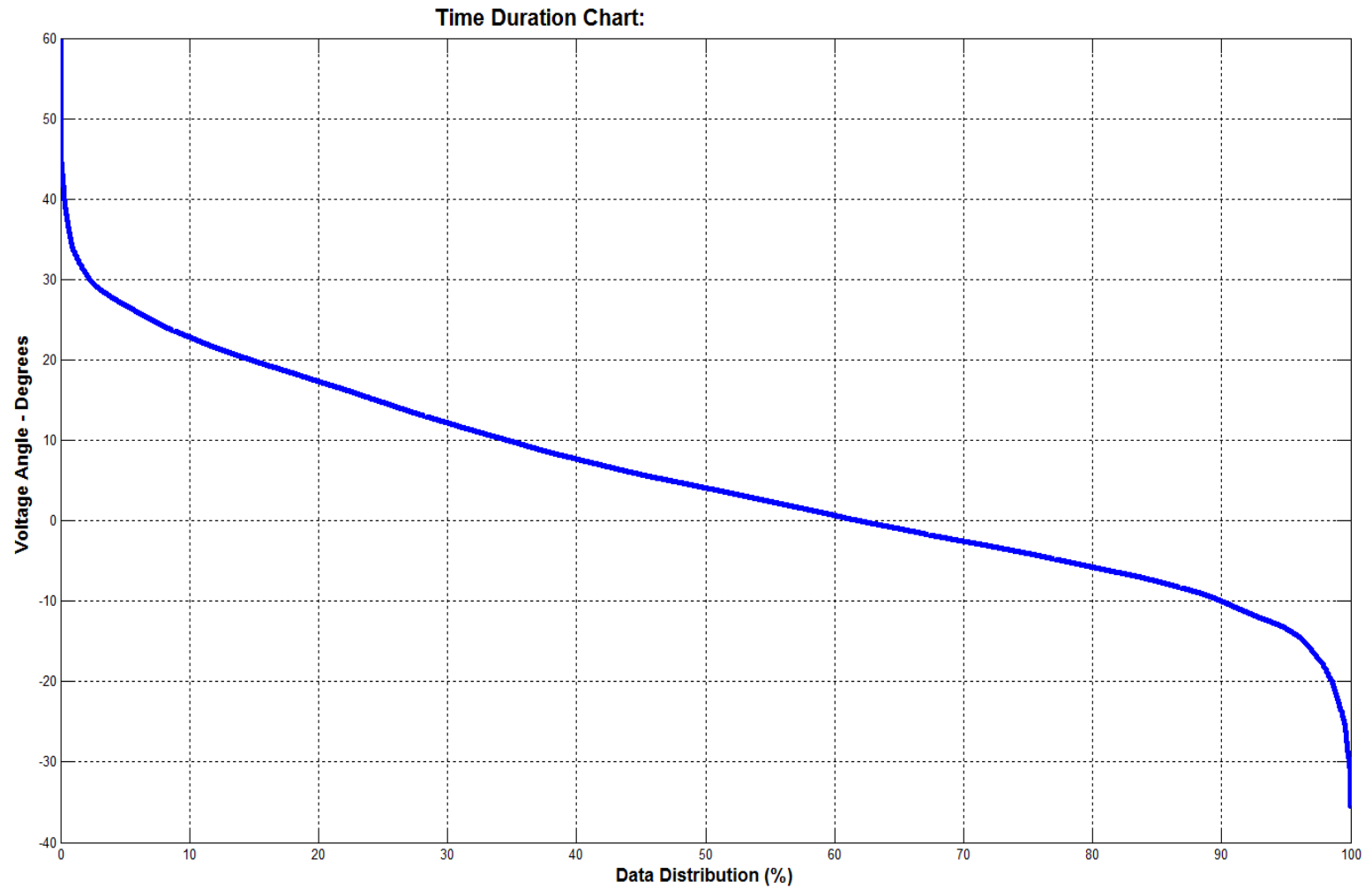
FarWest 4



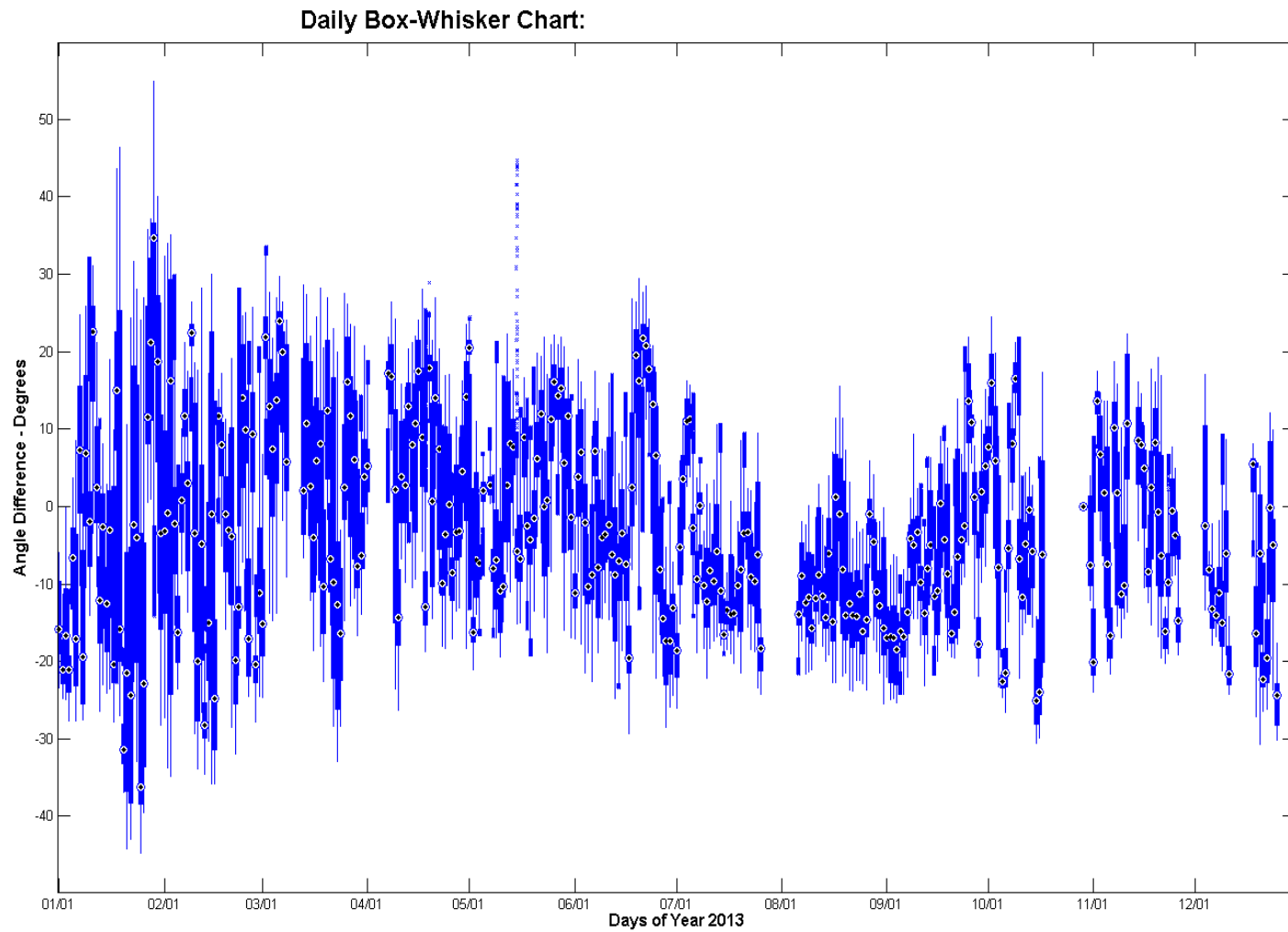
FarWest 7



FarWest 7

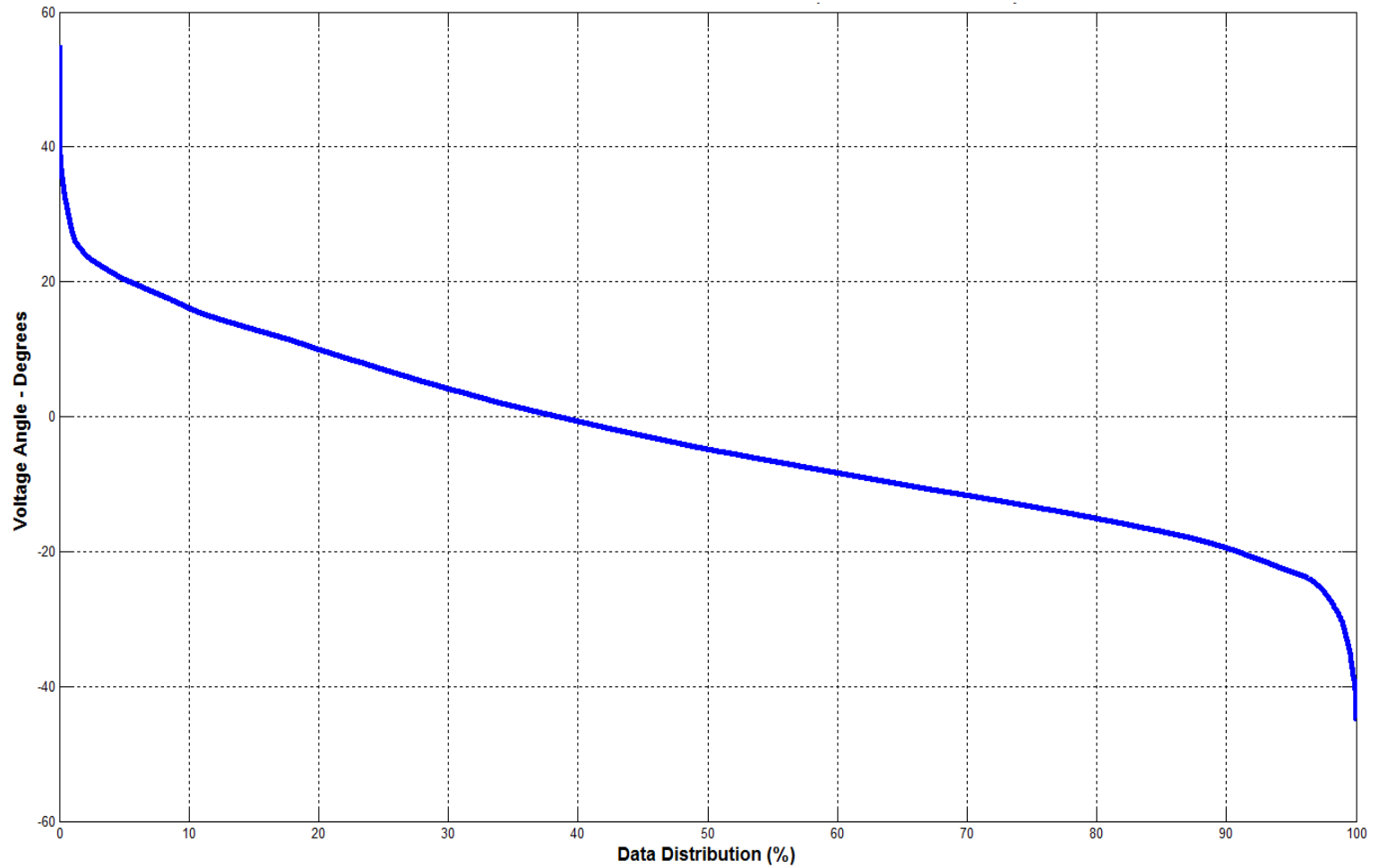


FarWest 8

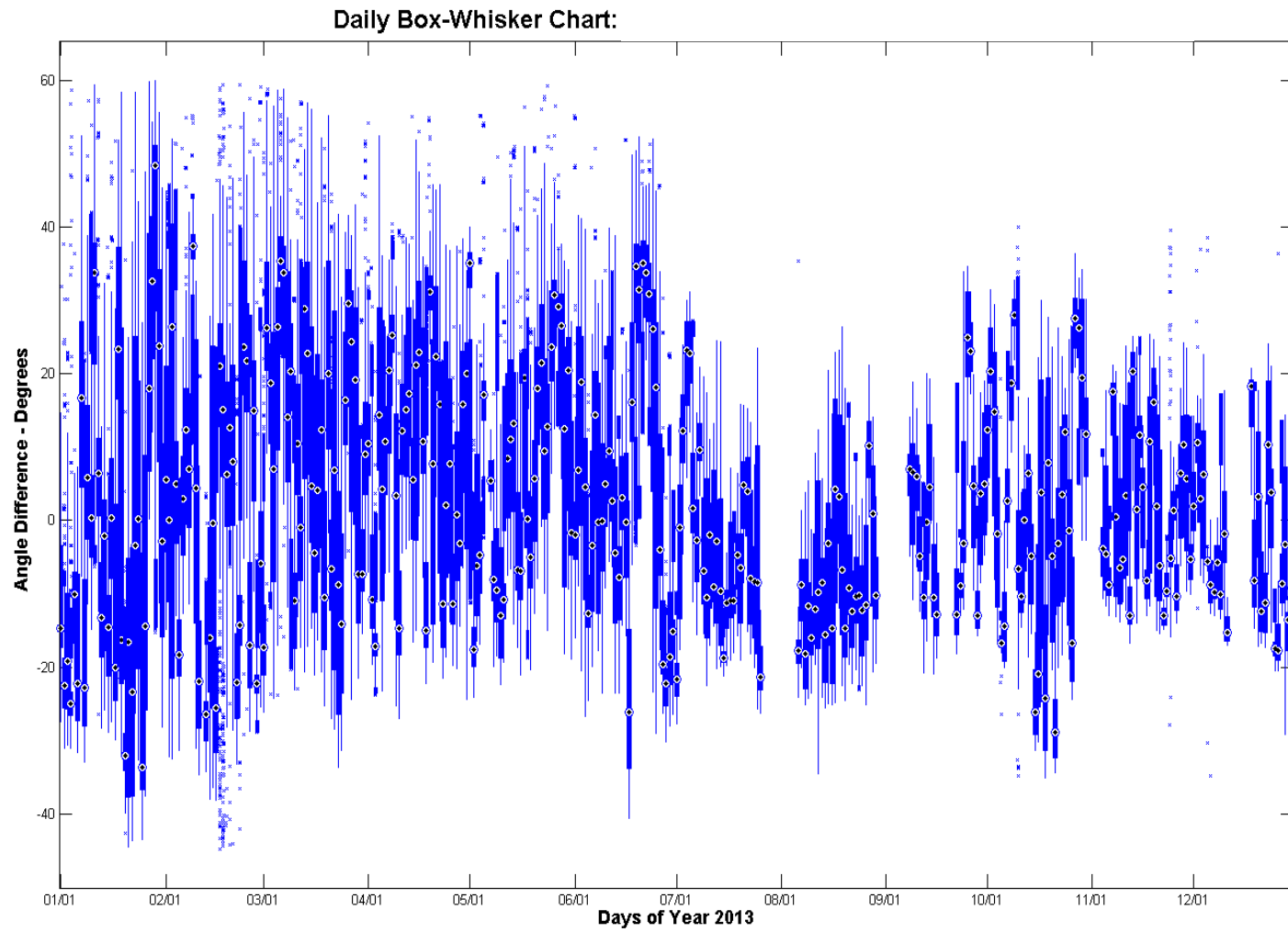


FarWest 8

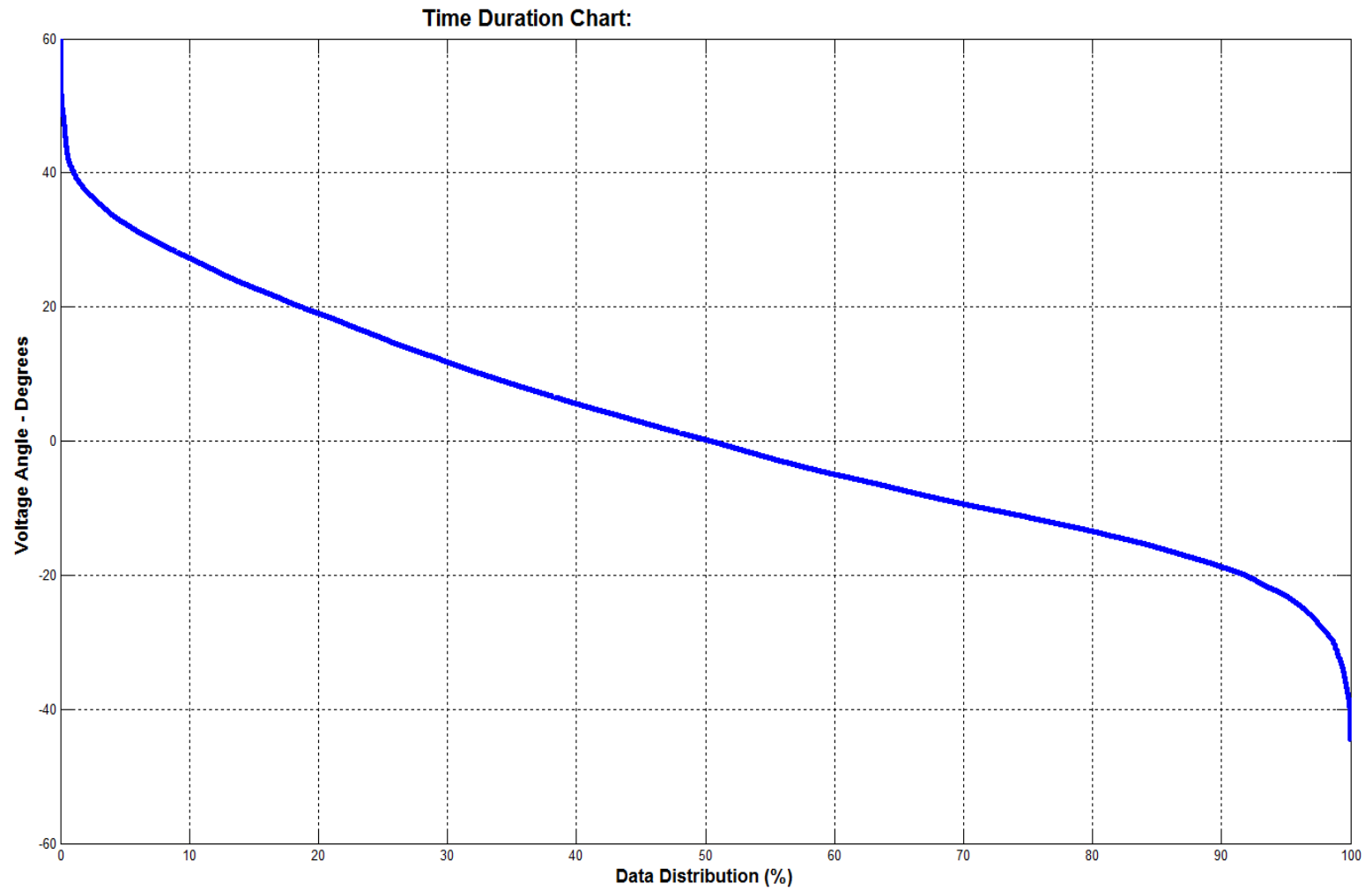
Time Duration Chart:



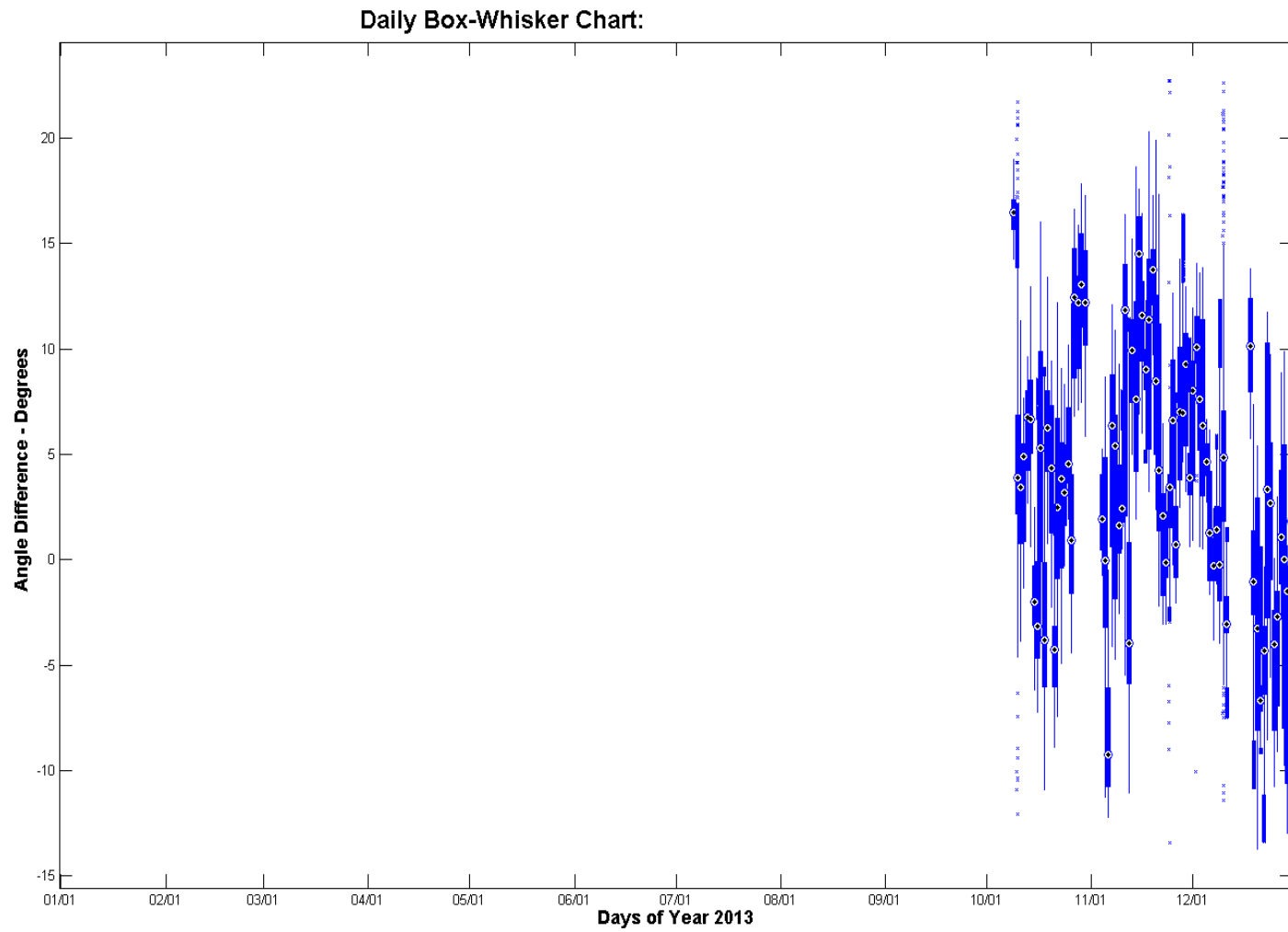
FarWest 9



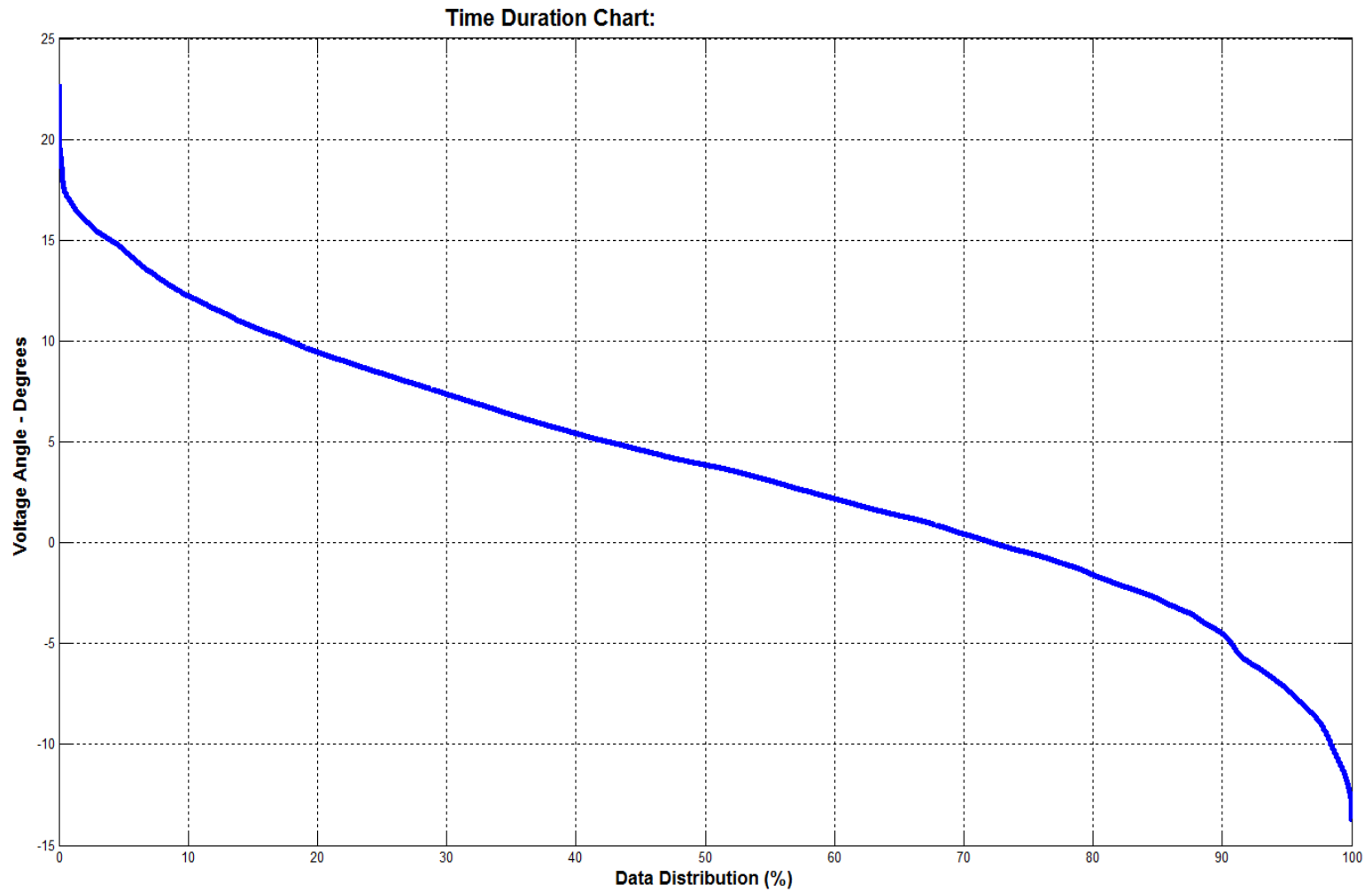
FarWest 9



West 15



West 15



Appendix C – Part 1

CCET Discovery Across Texas project

Baseline Analysis Update – Angle Differences

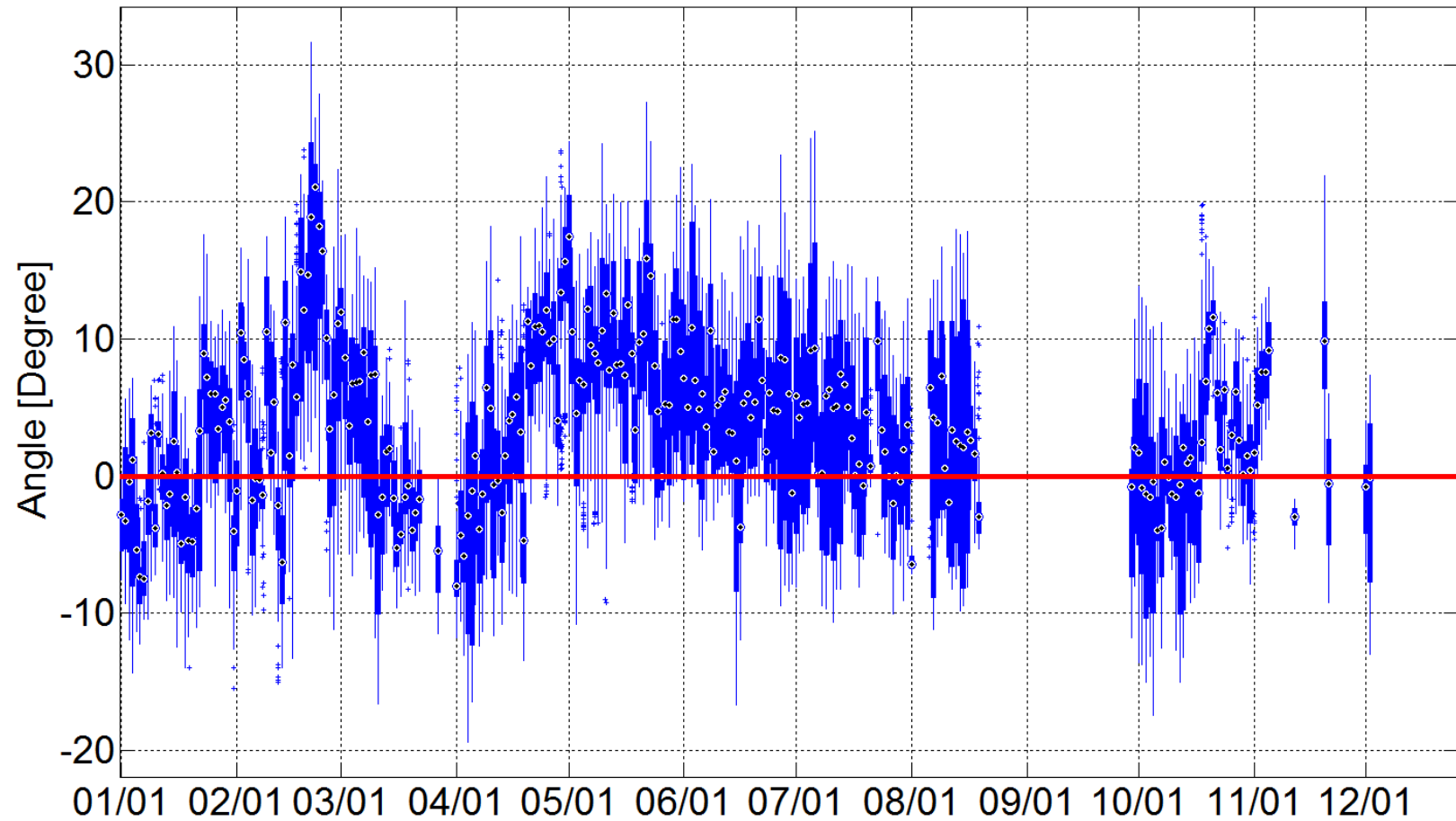
State Estimator Data: January to December 2013
Box Whiskers Plots and Time Duration Curves



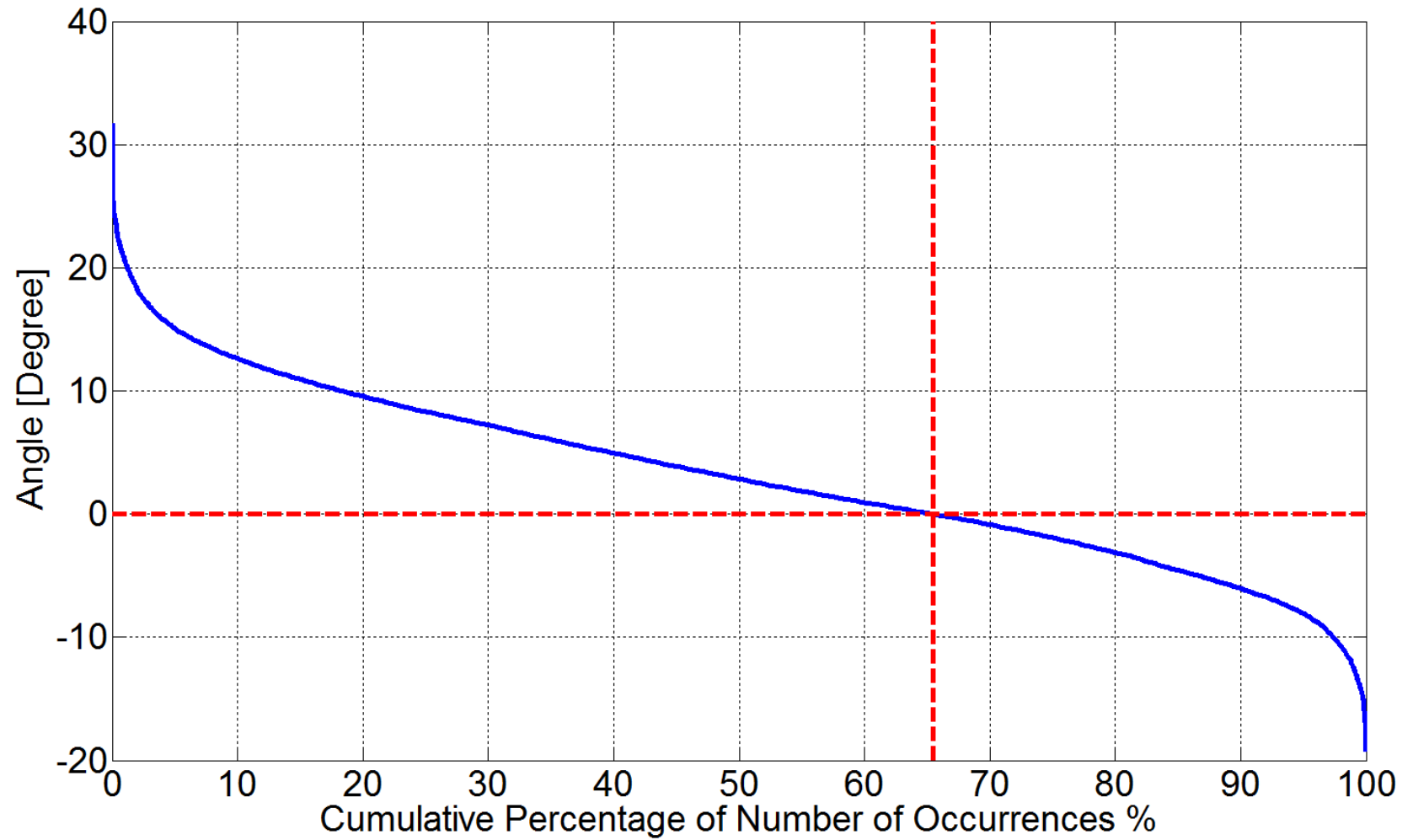
Electric Power Group



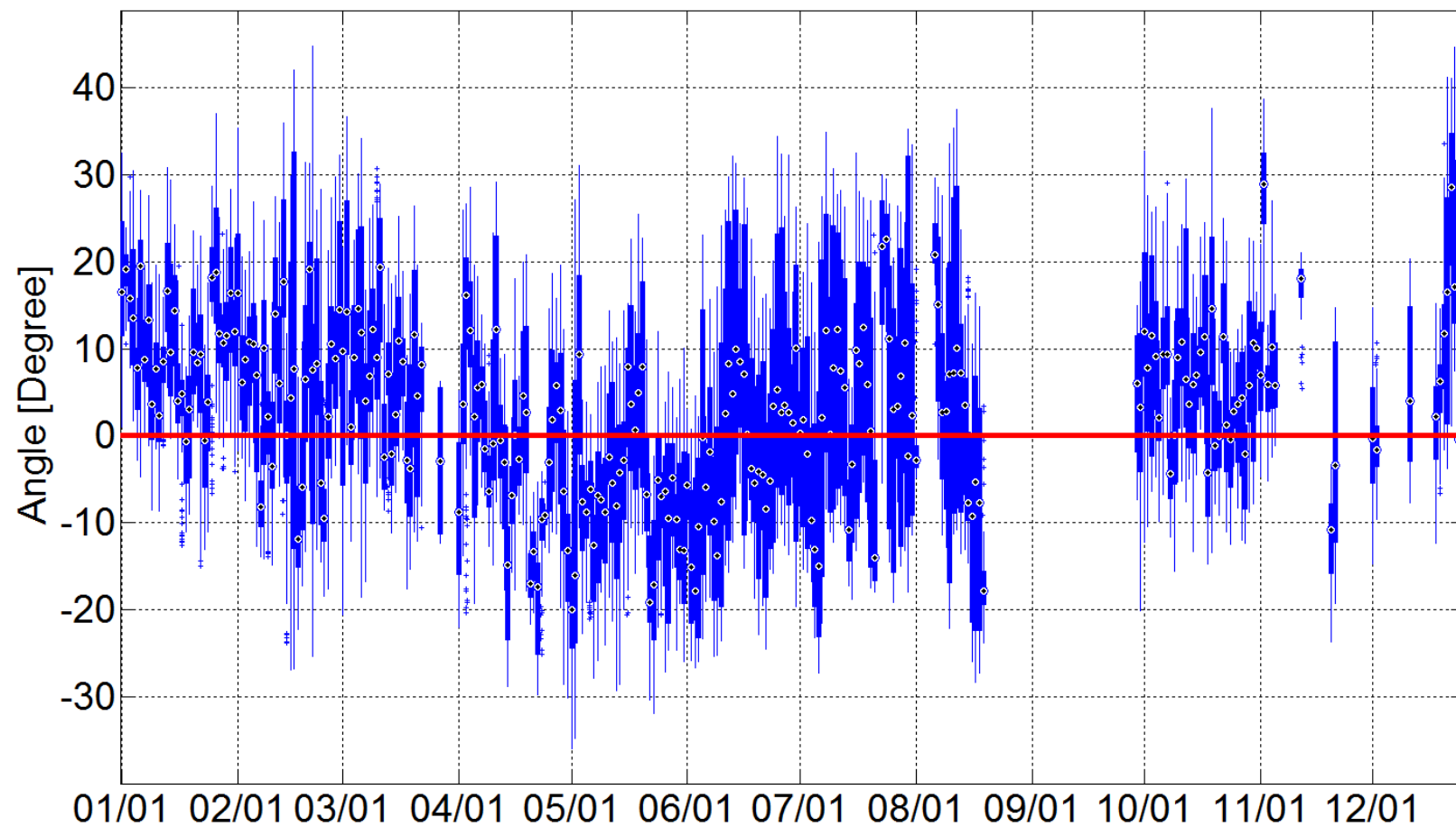
Coast 1-South 13



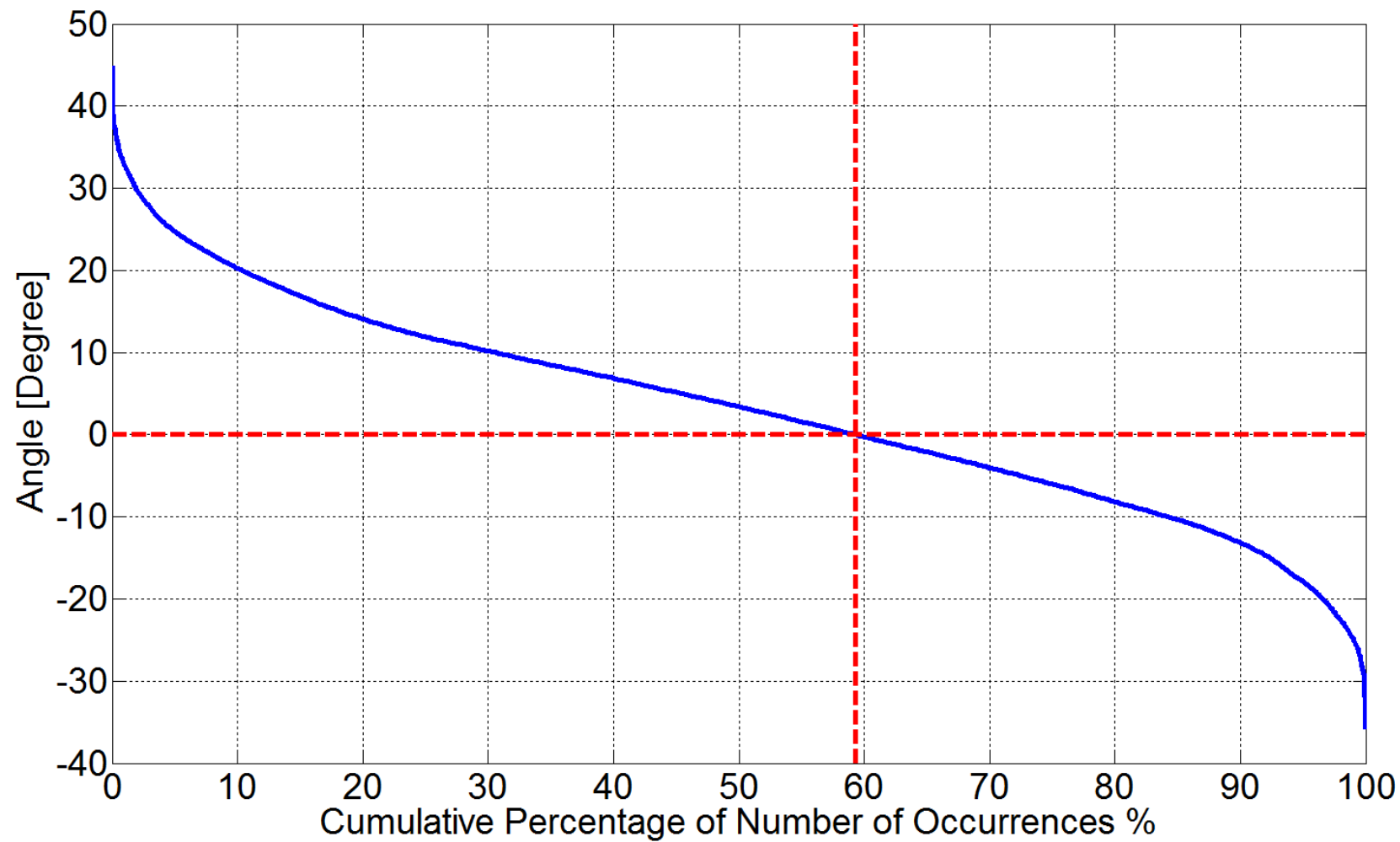
Coast 1-South 13



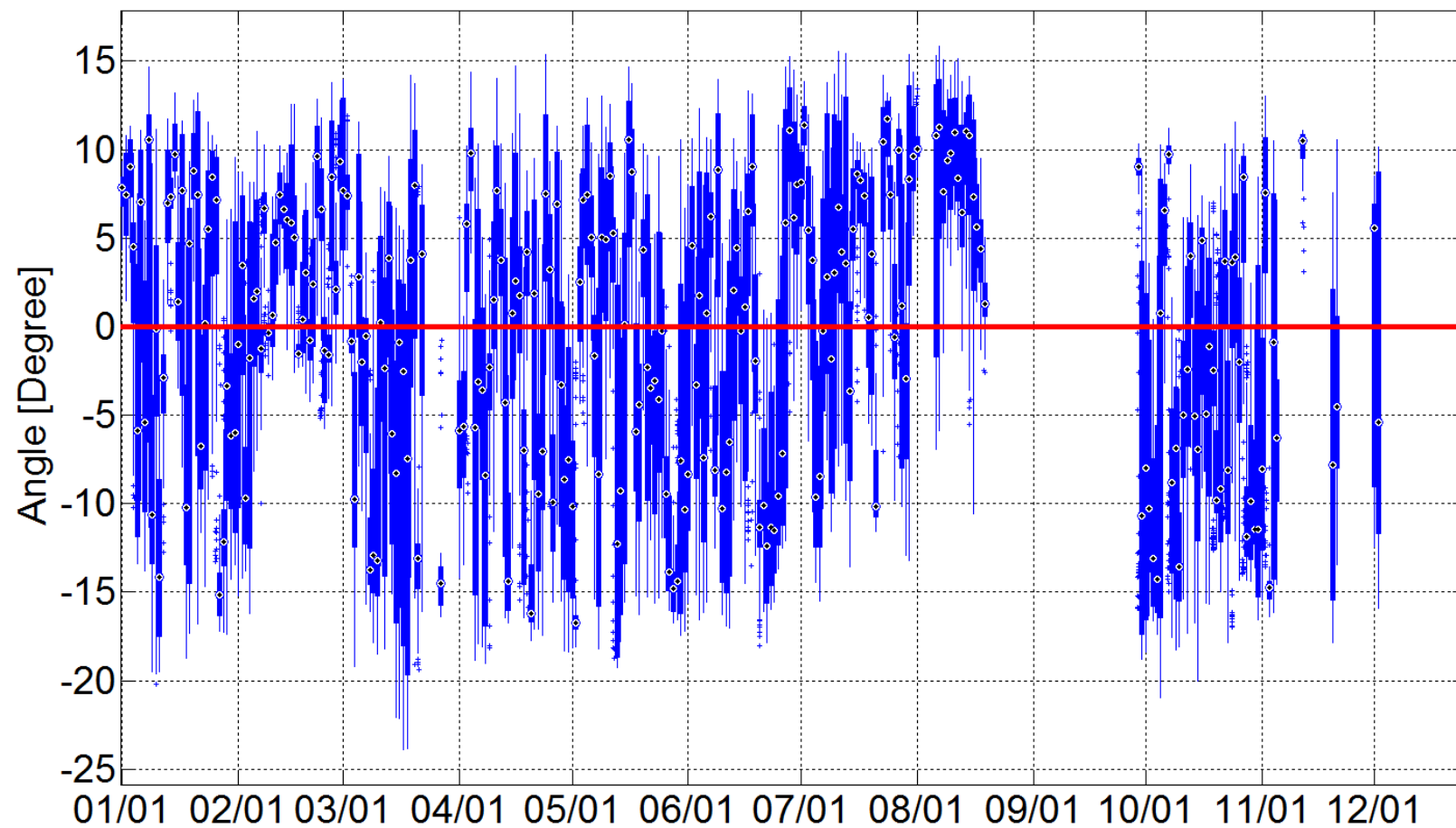
Coast 1-North 7



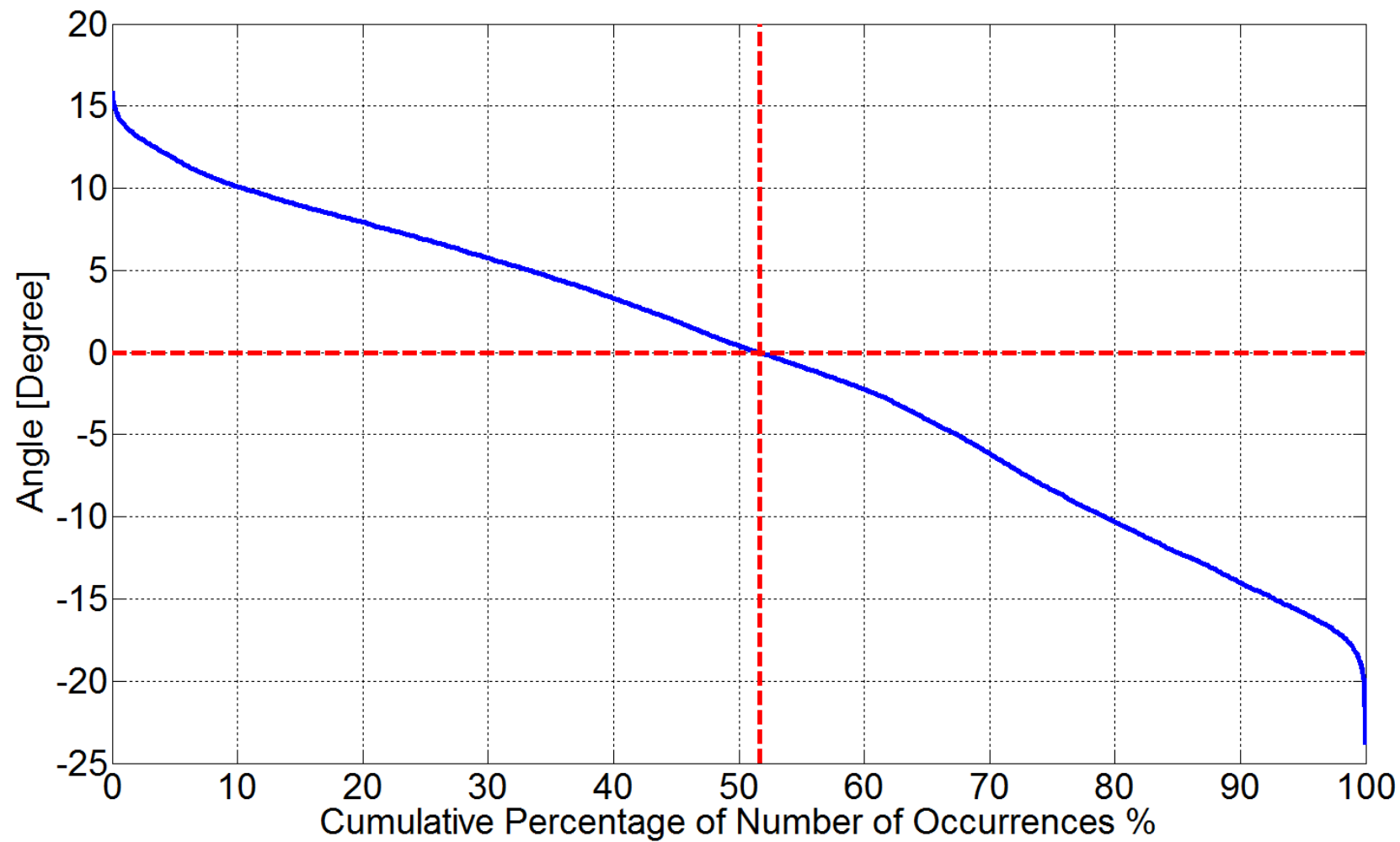
Coast 1-North 7



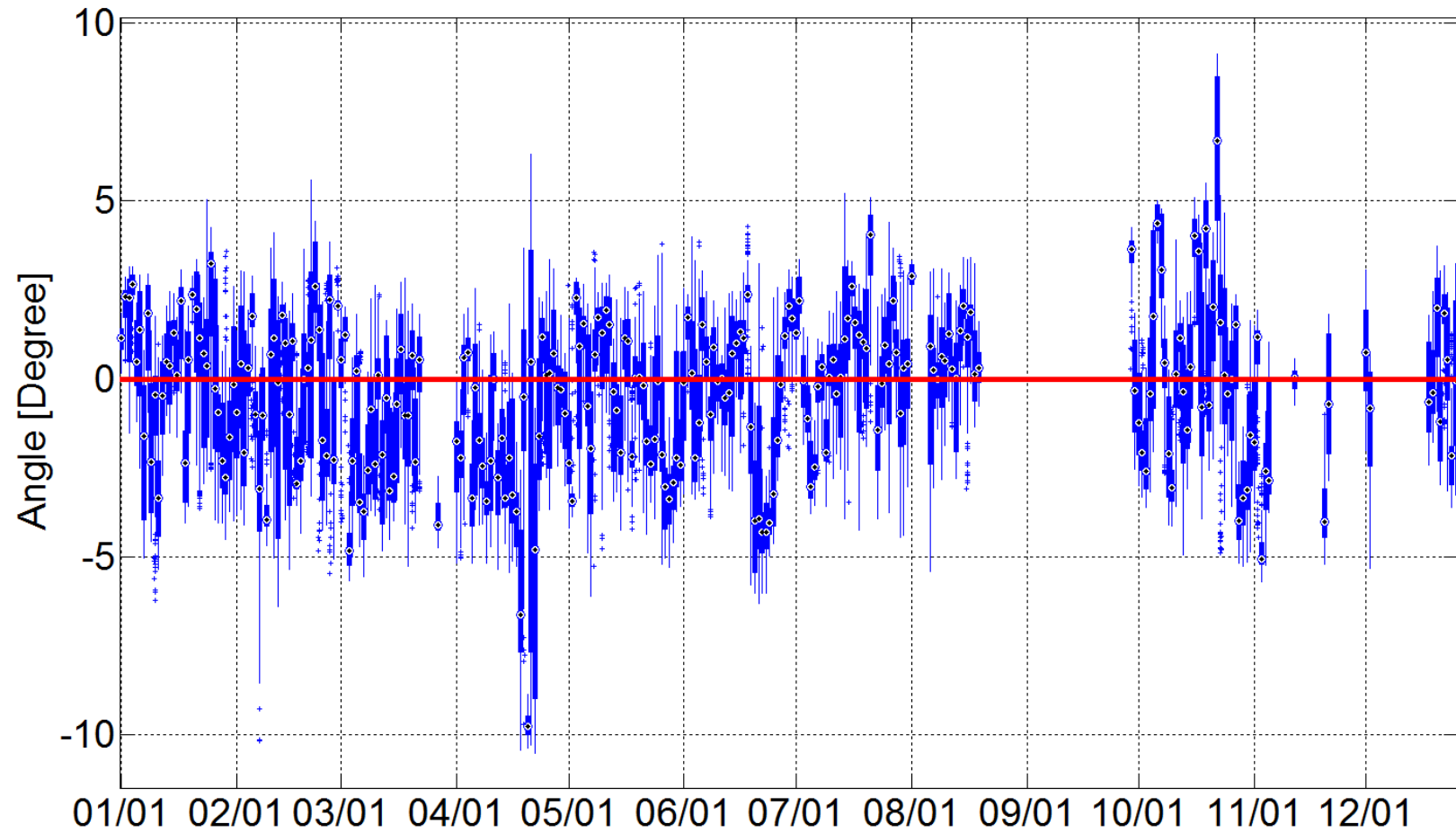
West 5-West 10



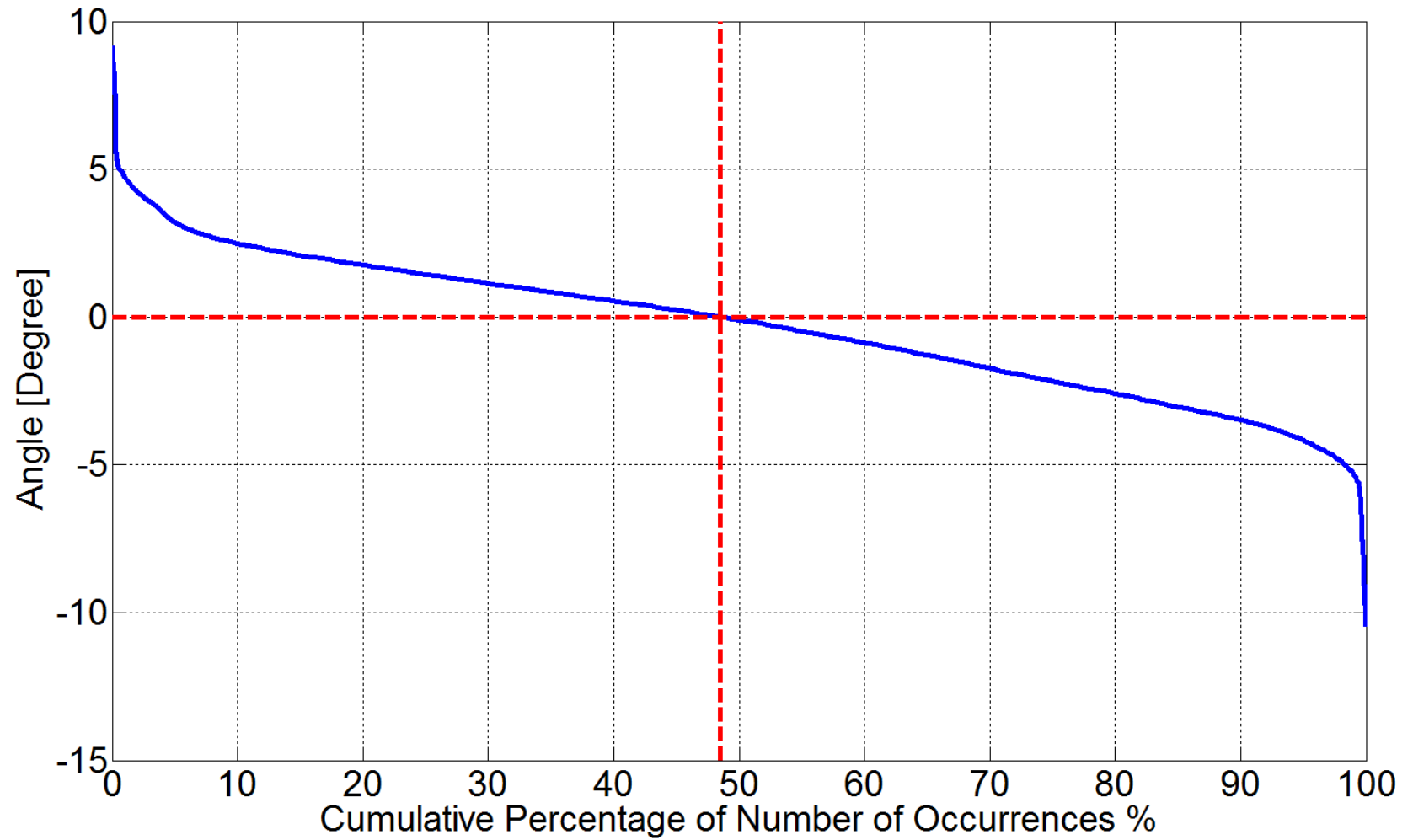
West 5-West 10



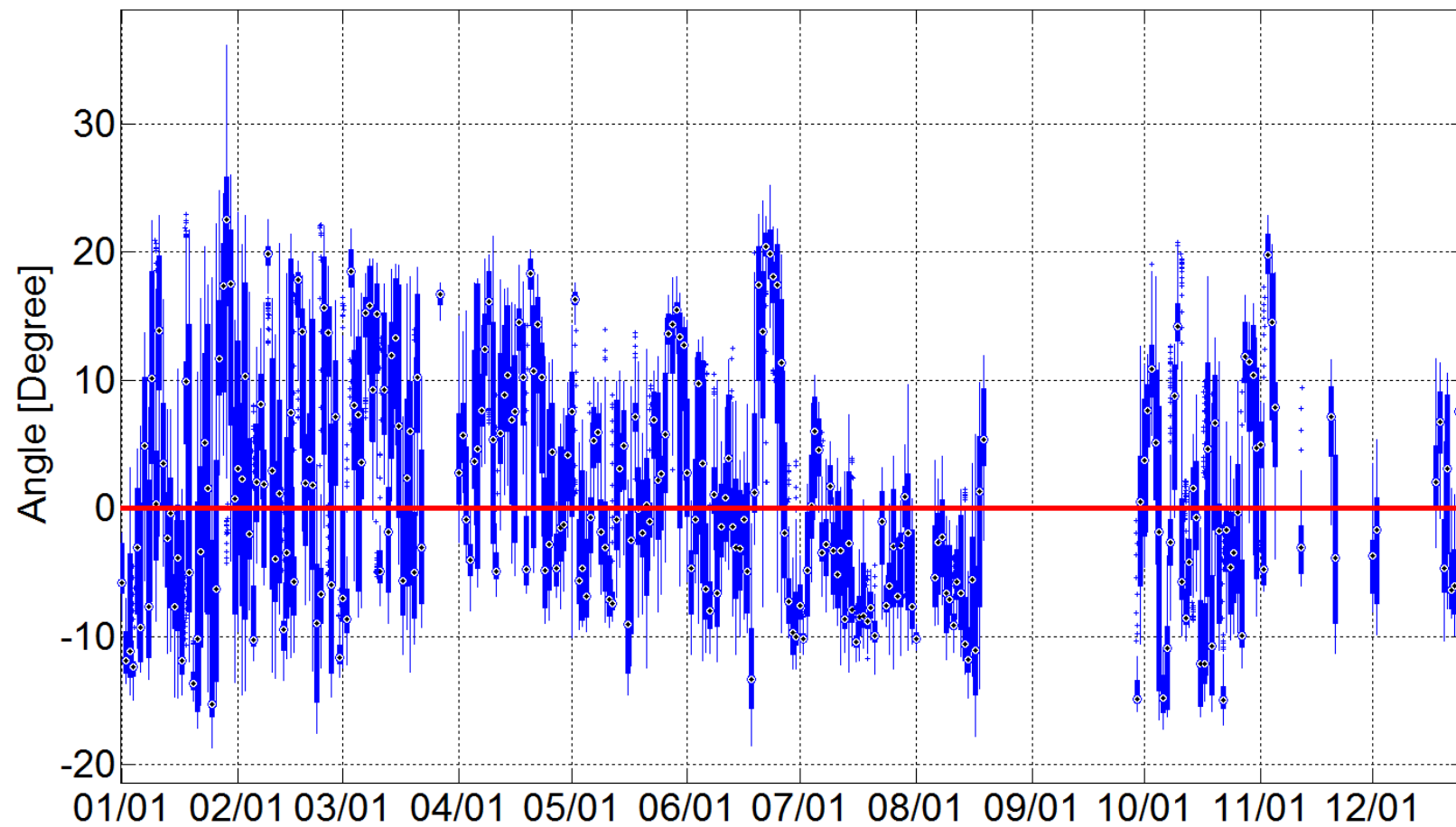
West 5-FarWest 4



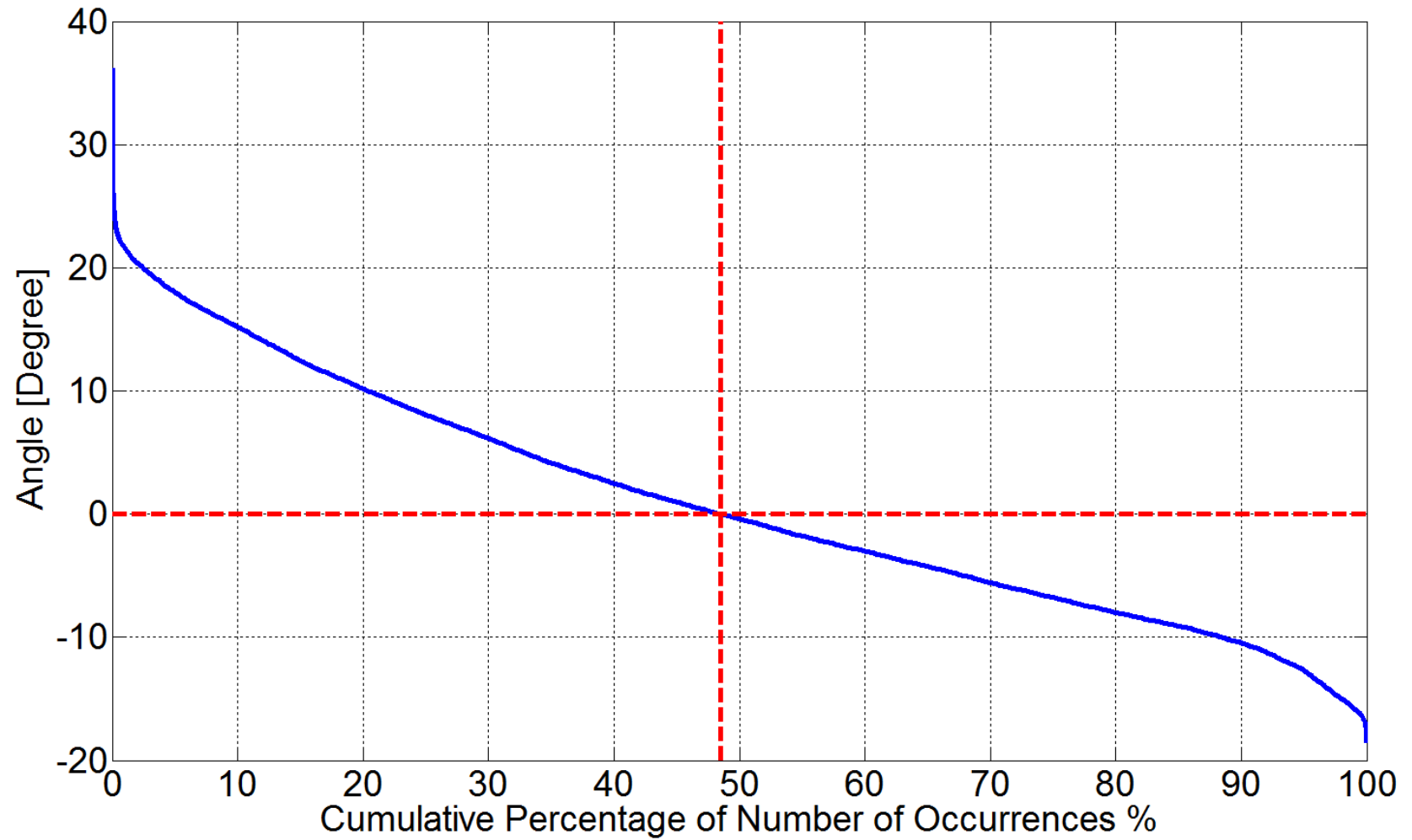
West 5-FarWest 4



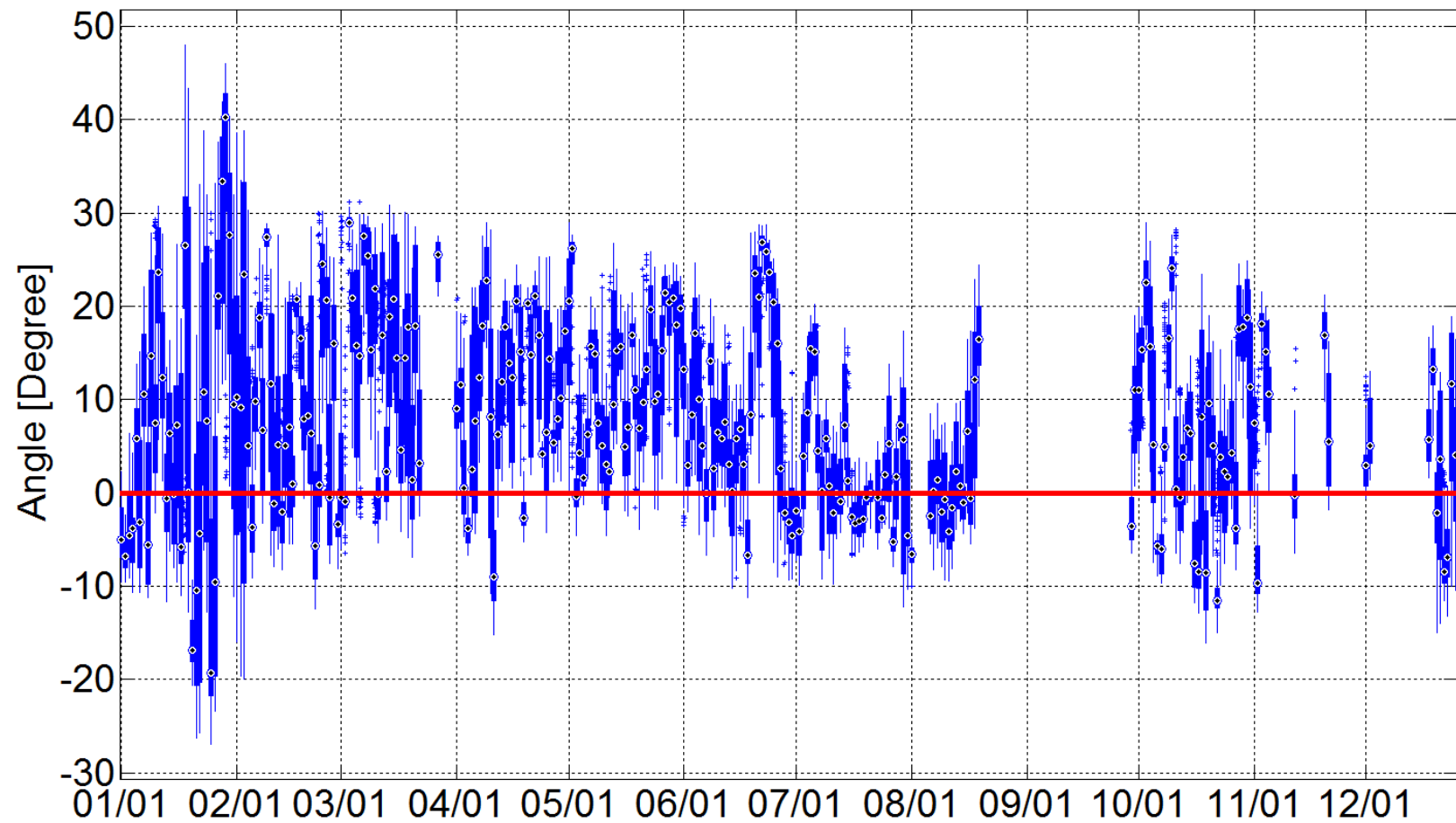
West 5-North 1



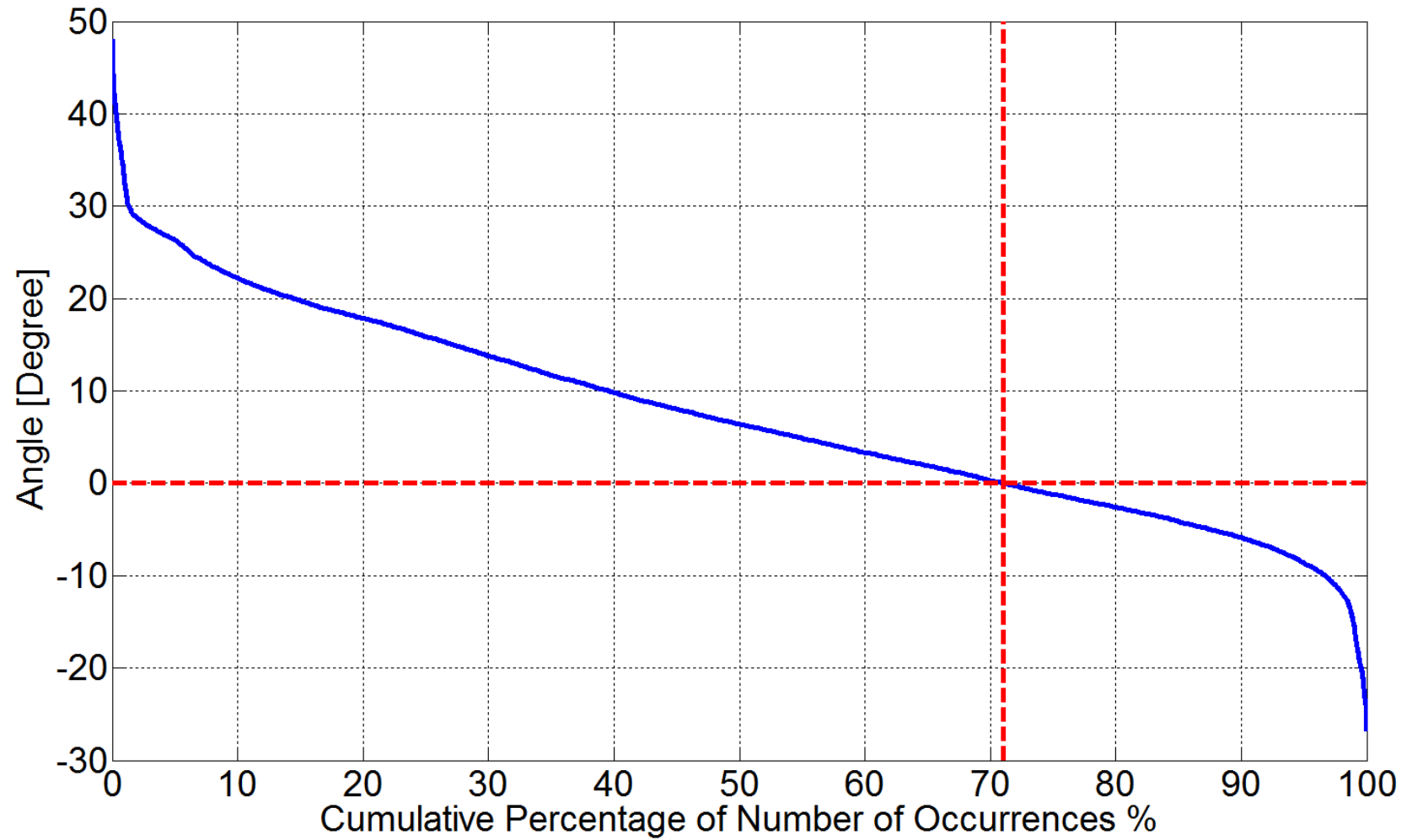
West 5-North 1



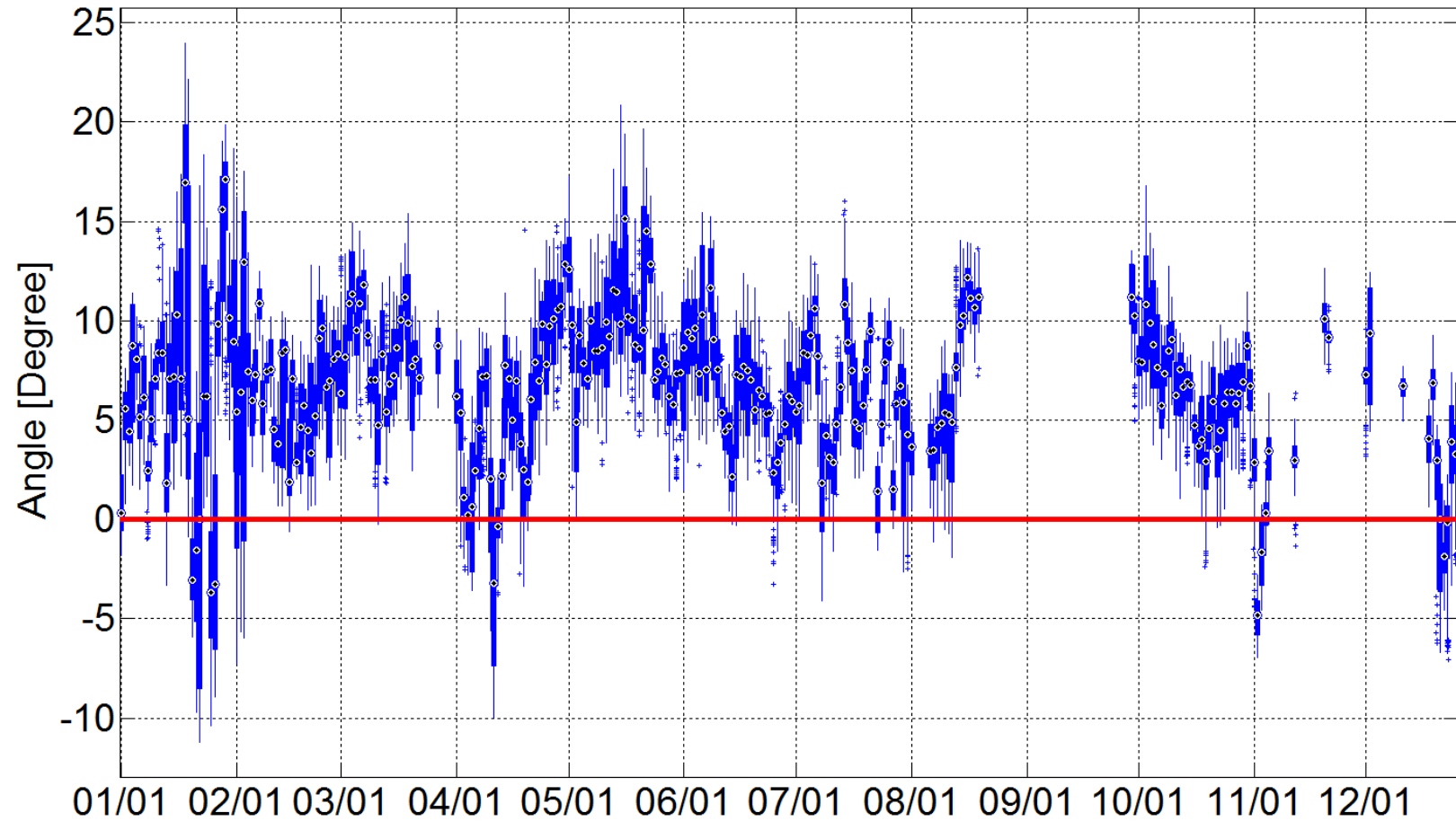
West 5-North 7



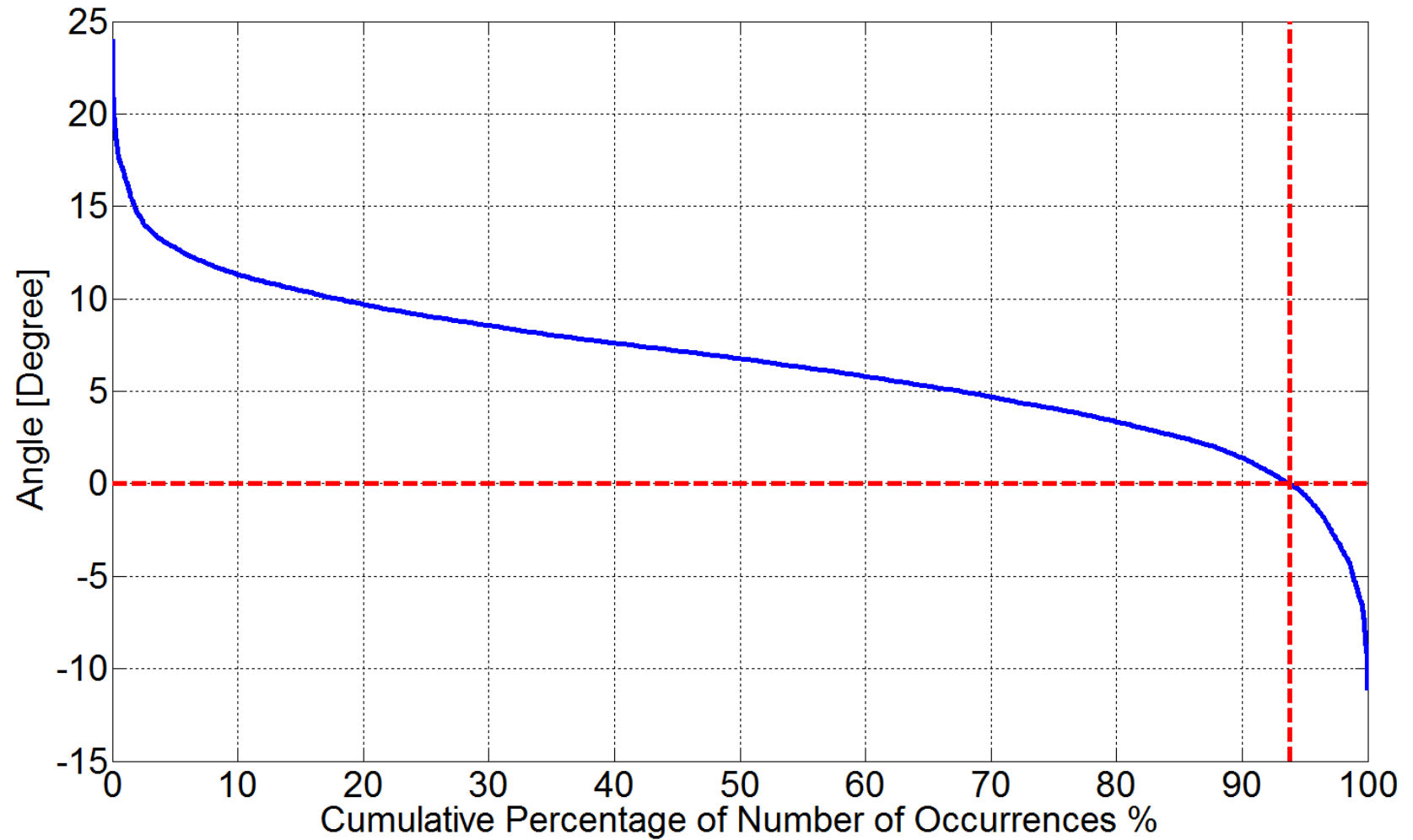
West 5-North 7



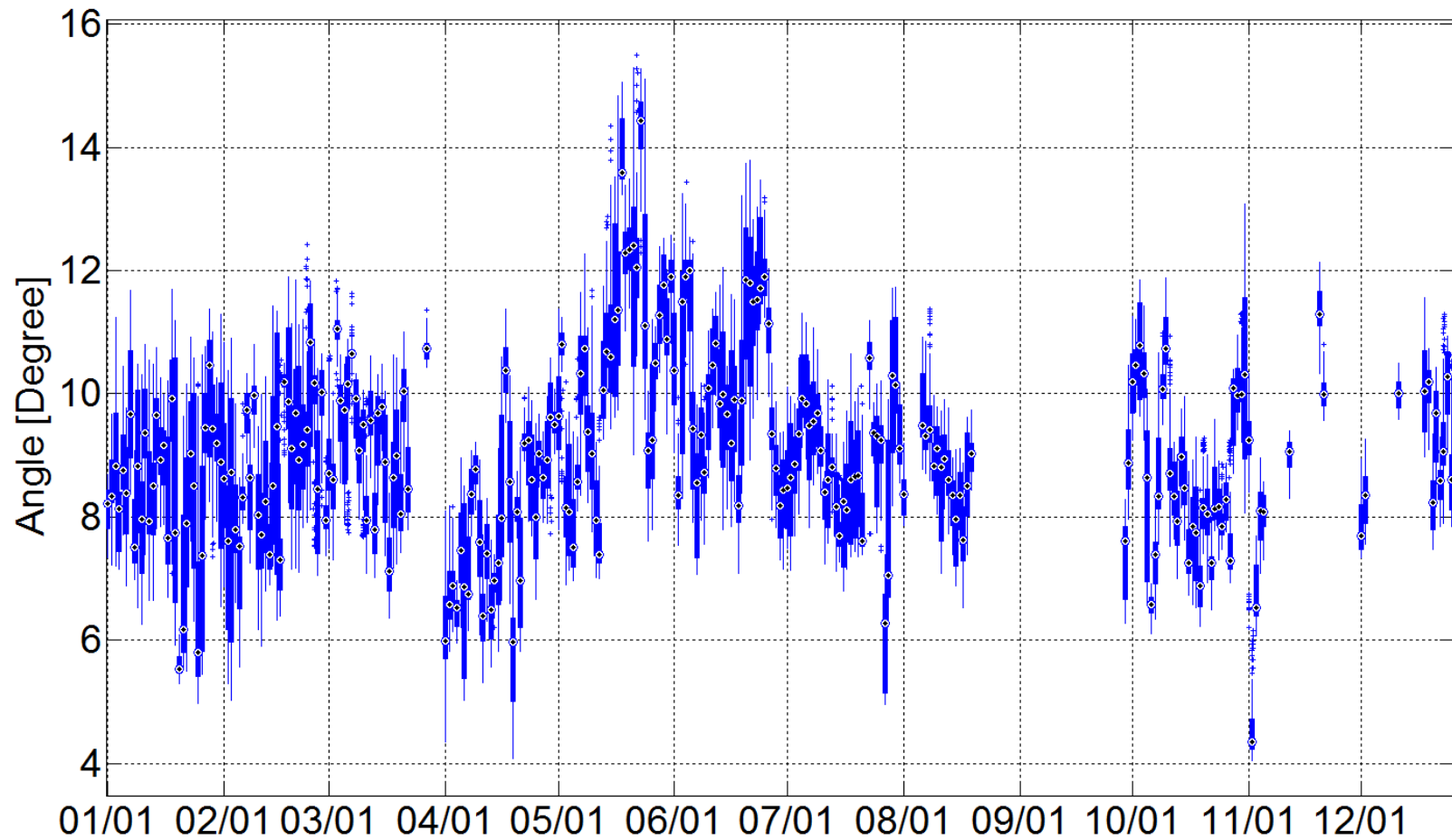
North 1-North 7



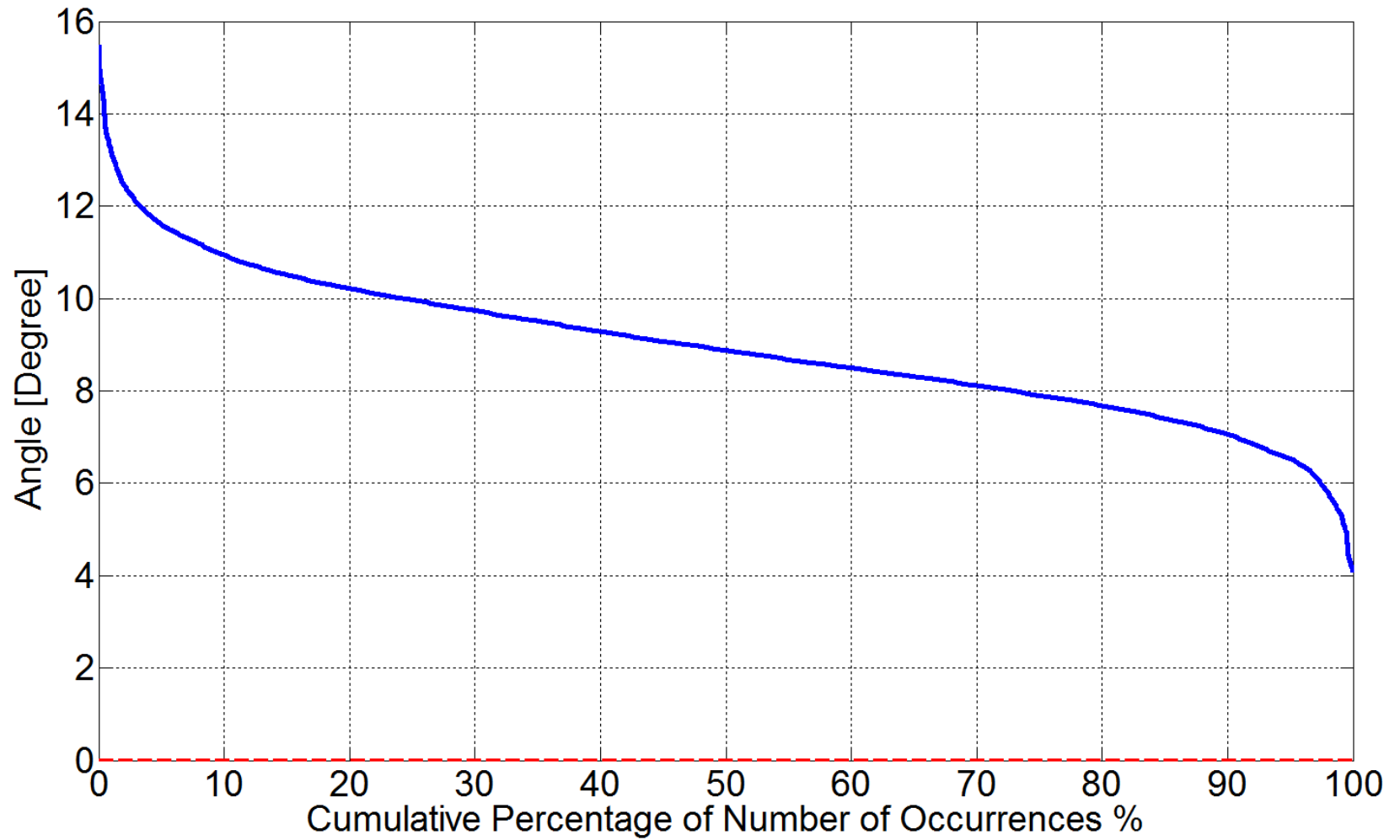
North 1-North 7



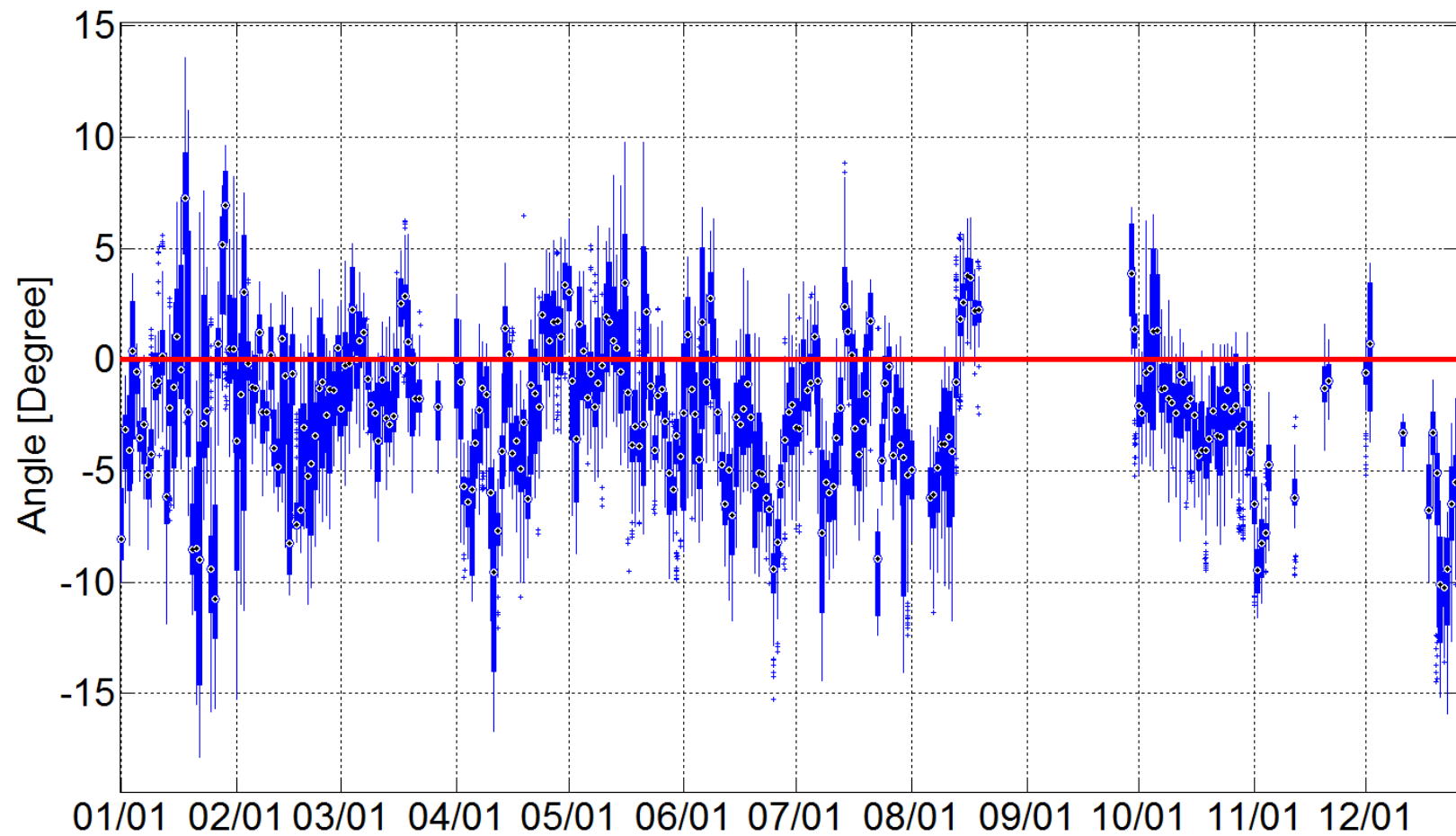
North 1-North 4



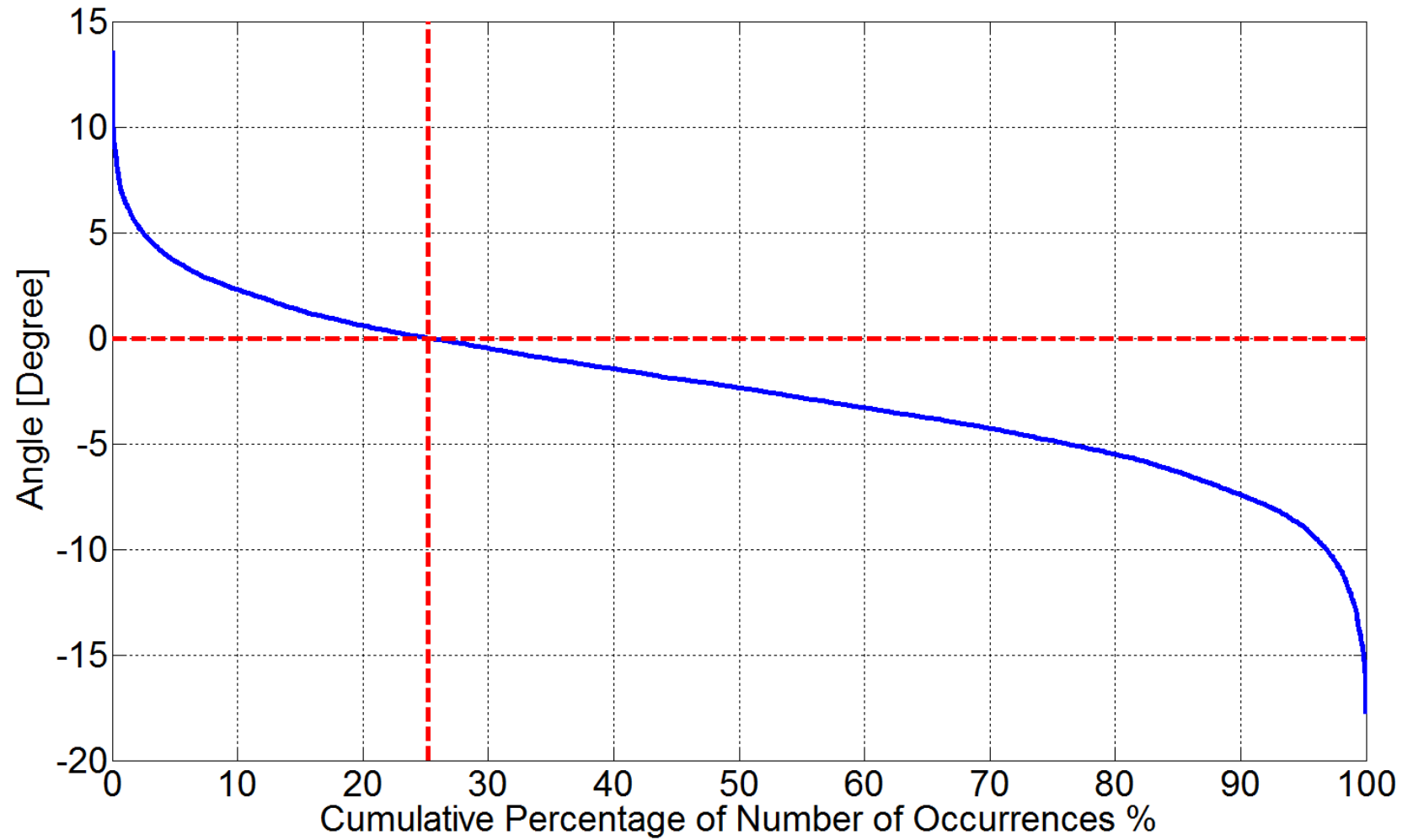
North 1-North 4



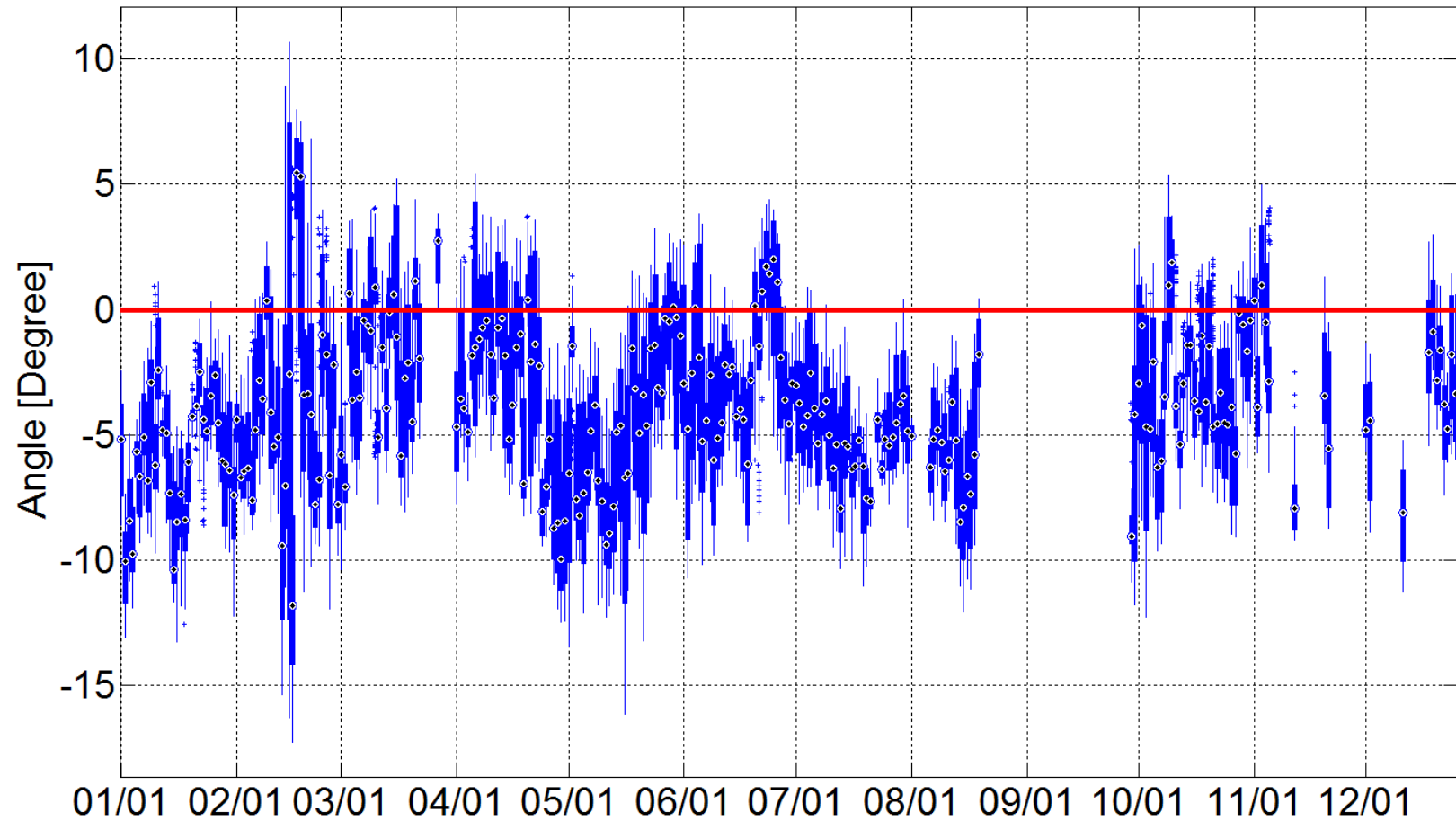
North 4-North 7



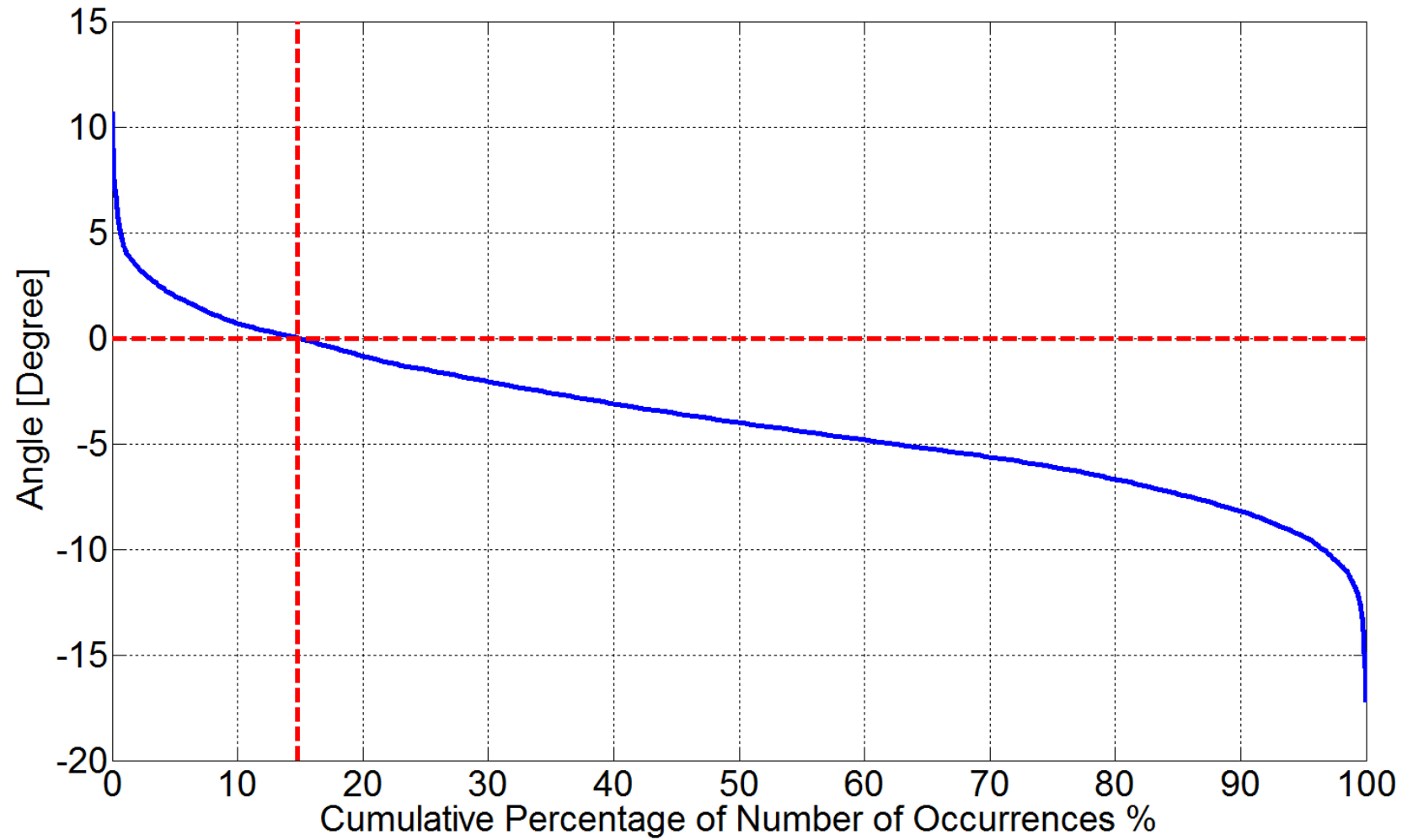
North 4-North 7



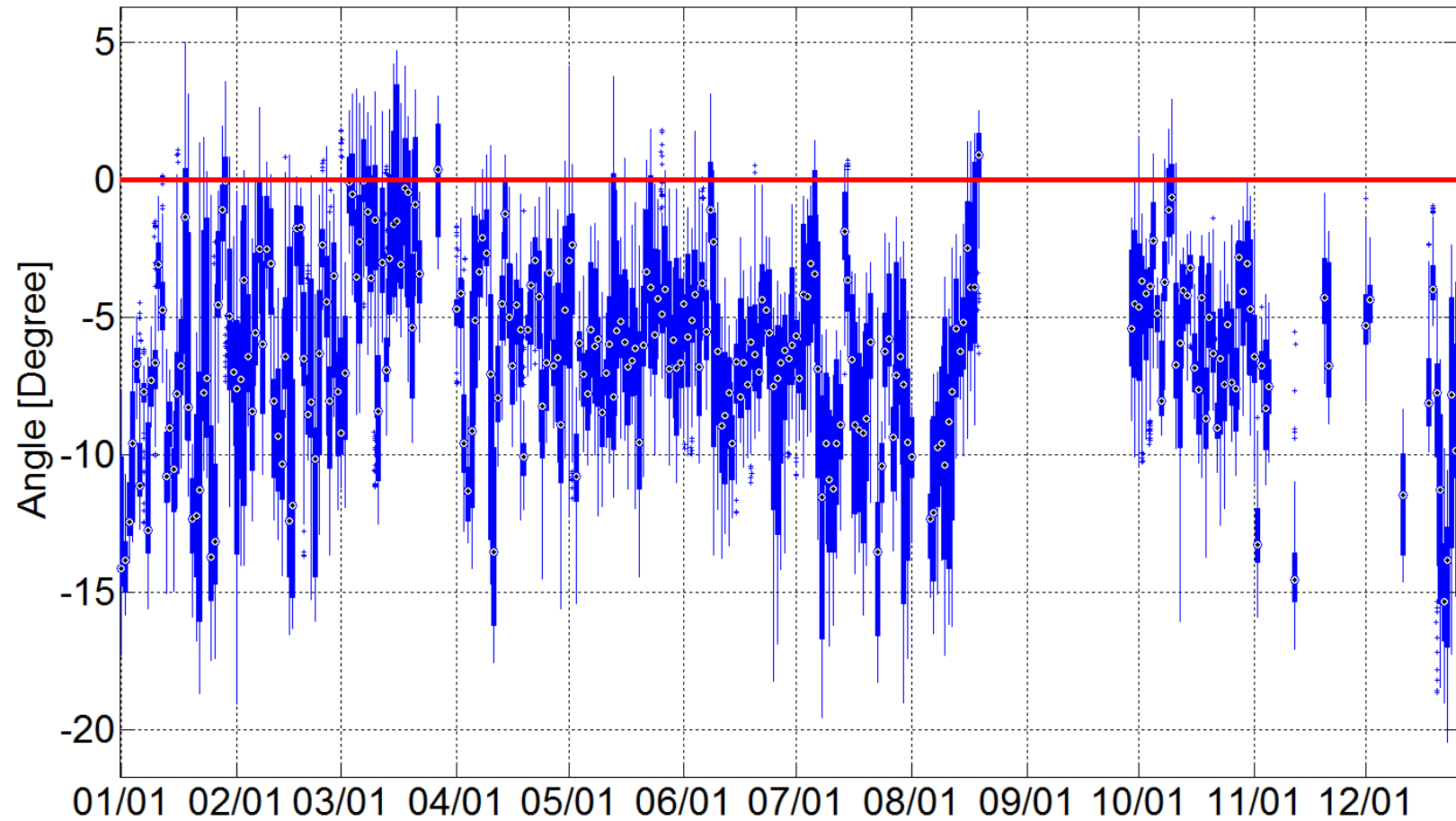
North 7-North 6



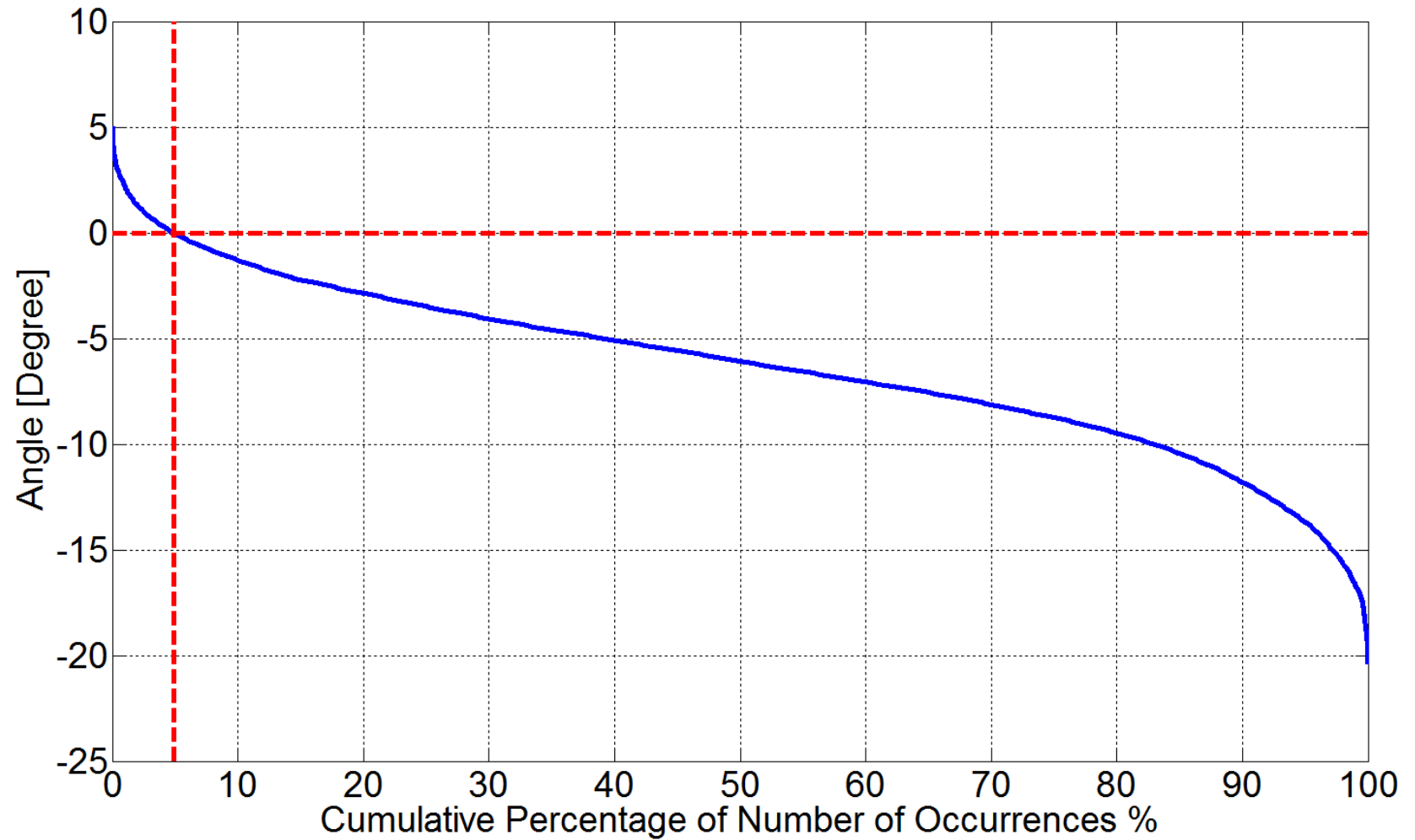
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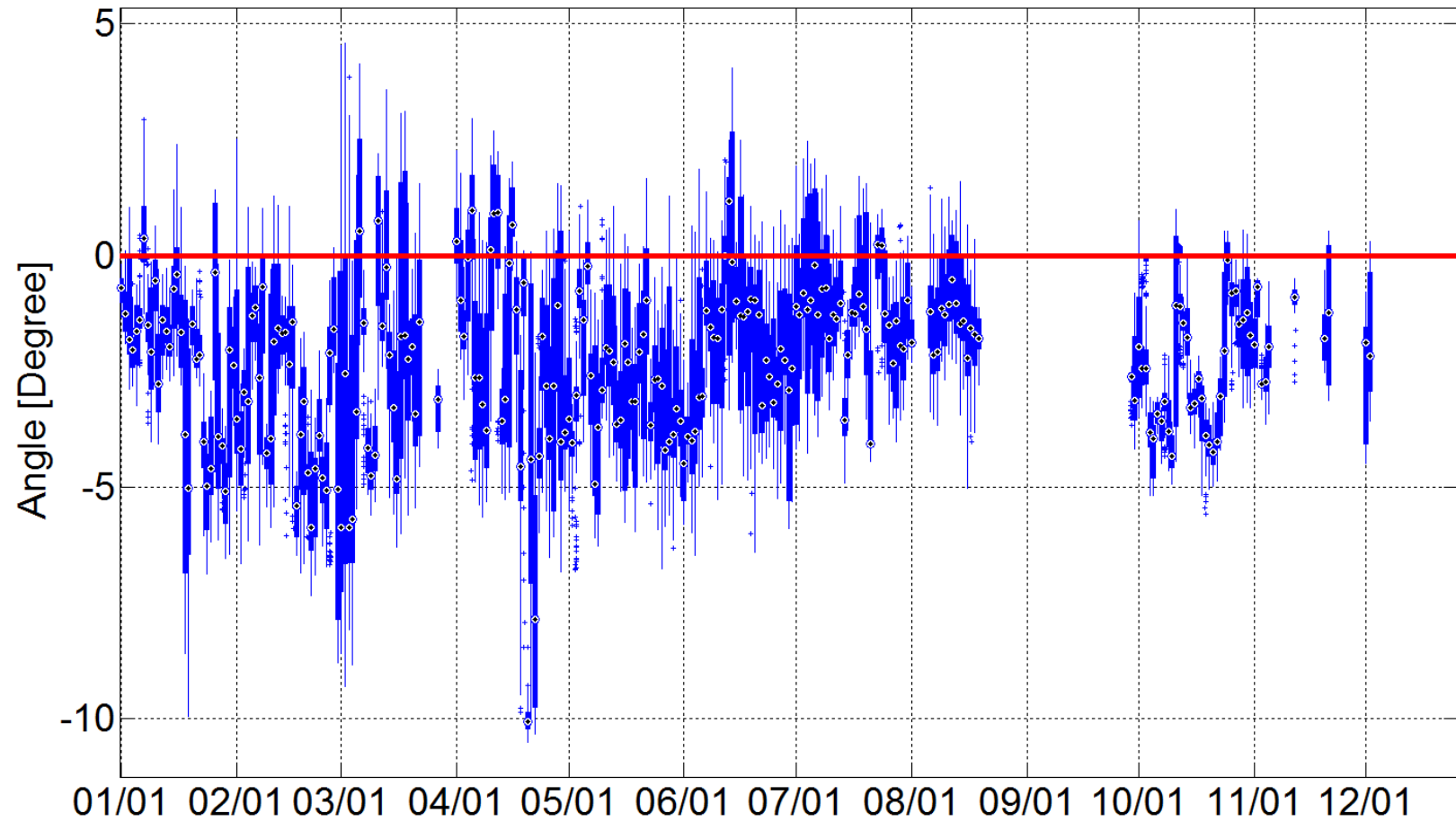
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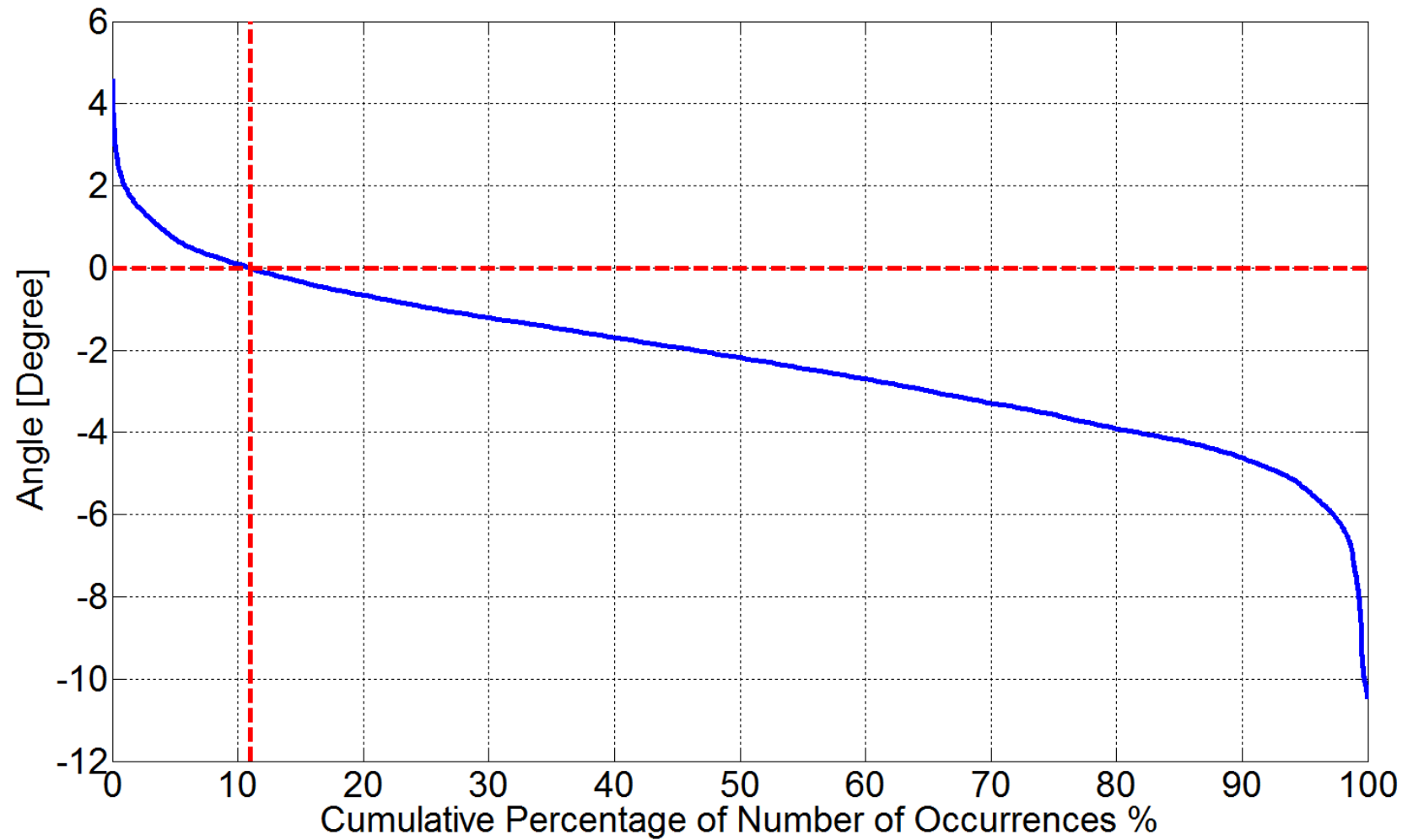
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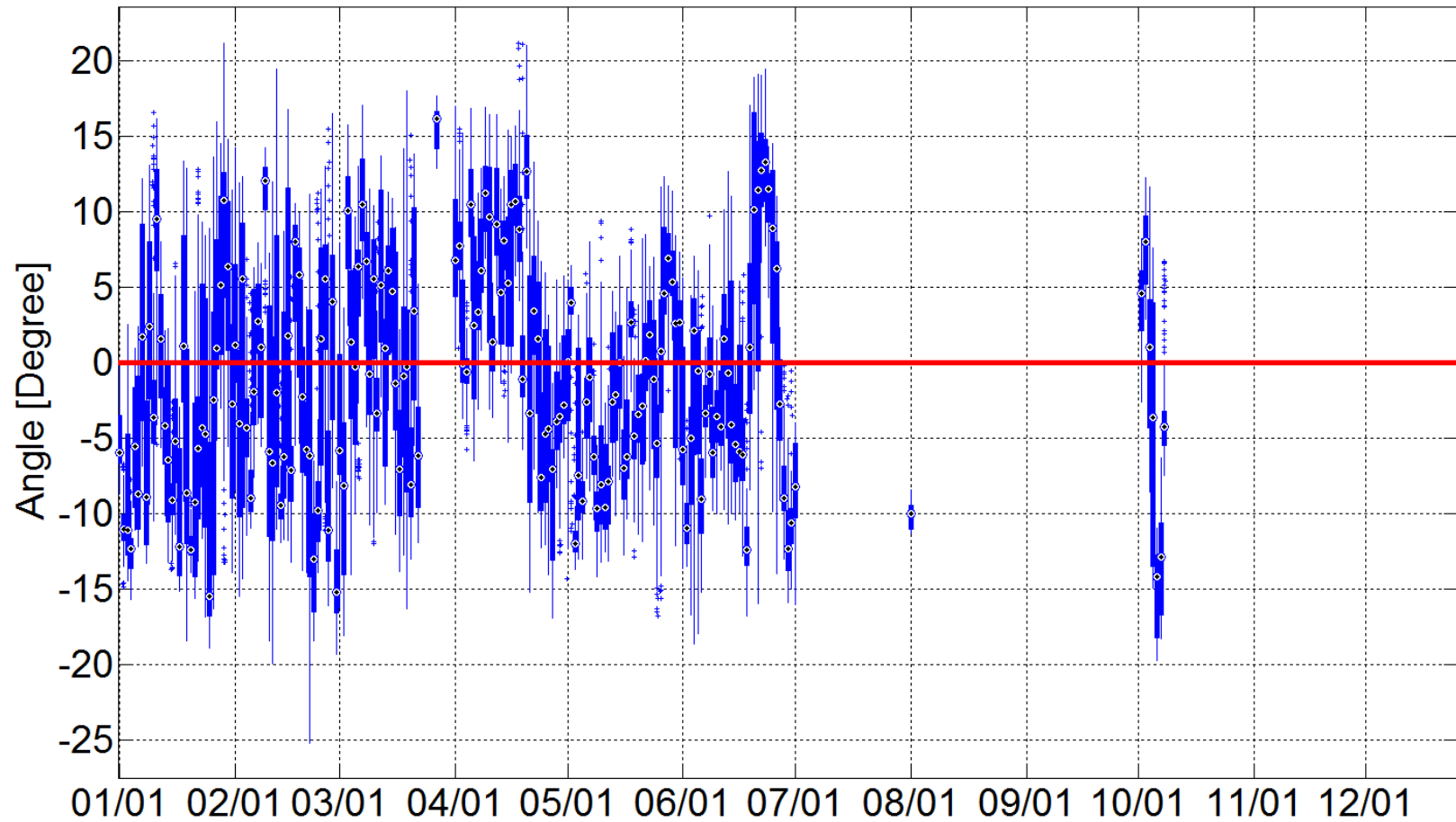
FarWest 7-FarWest 4



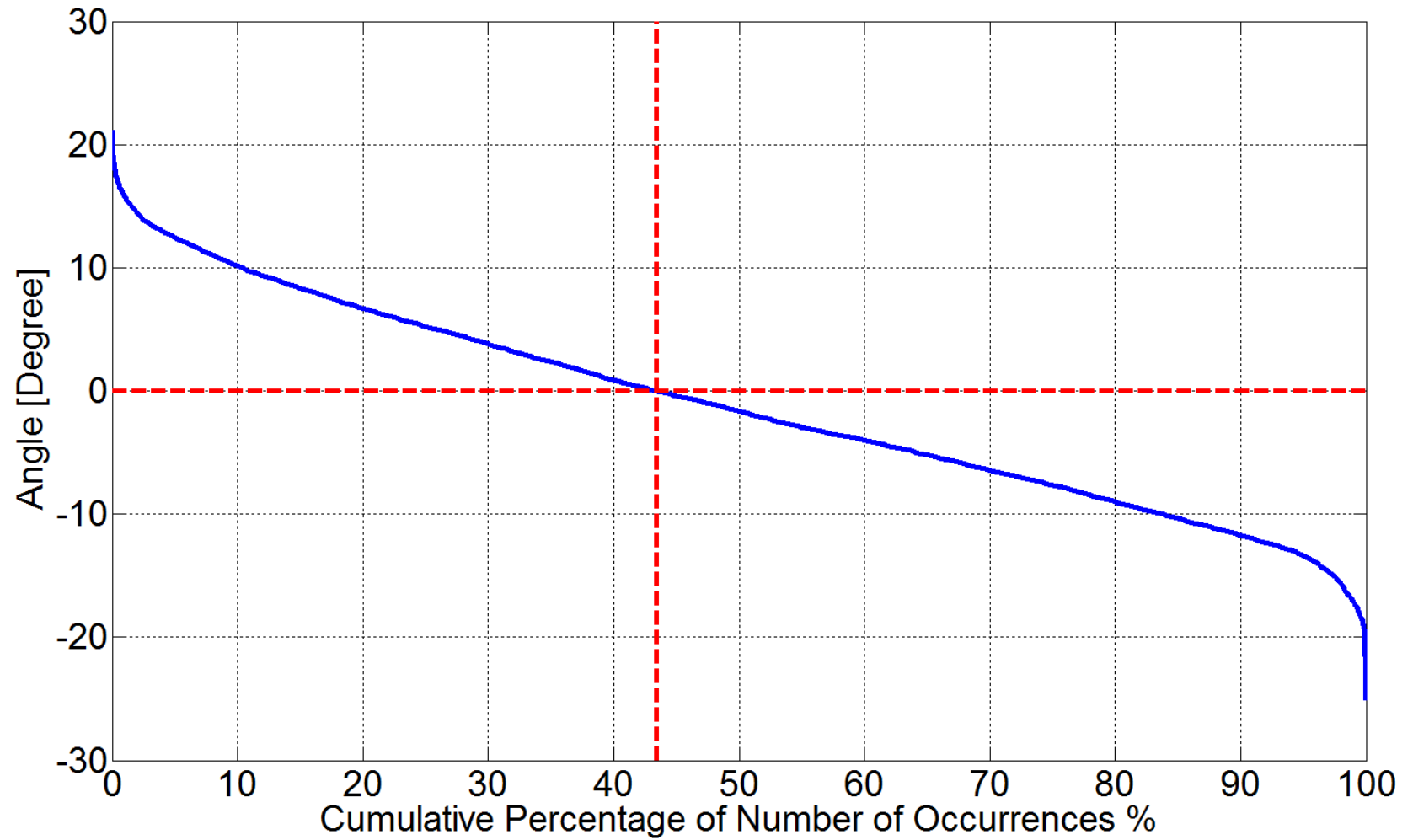
FarWest 7-FarWest 4



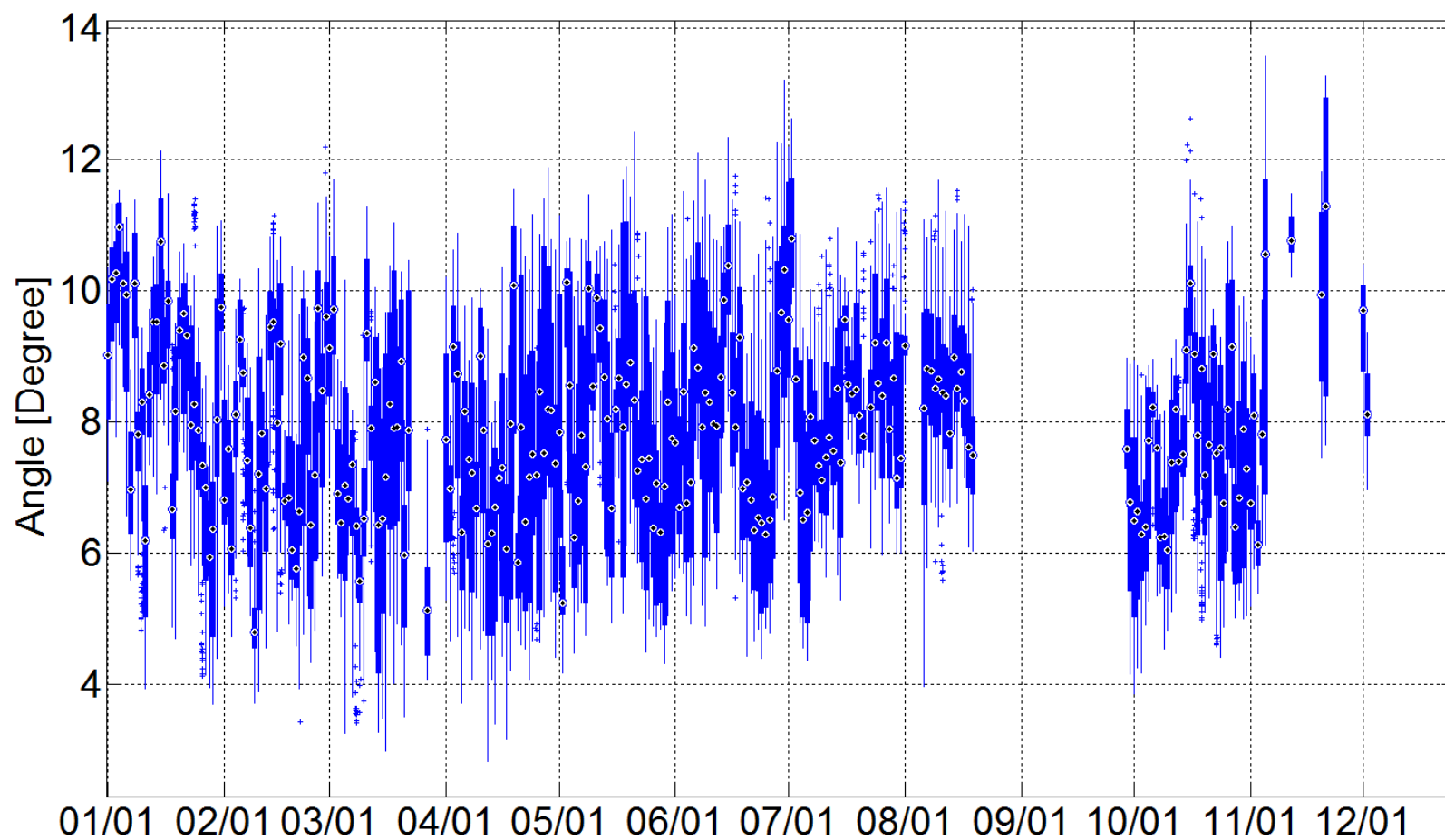
FarWest 7-West 14



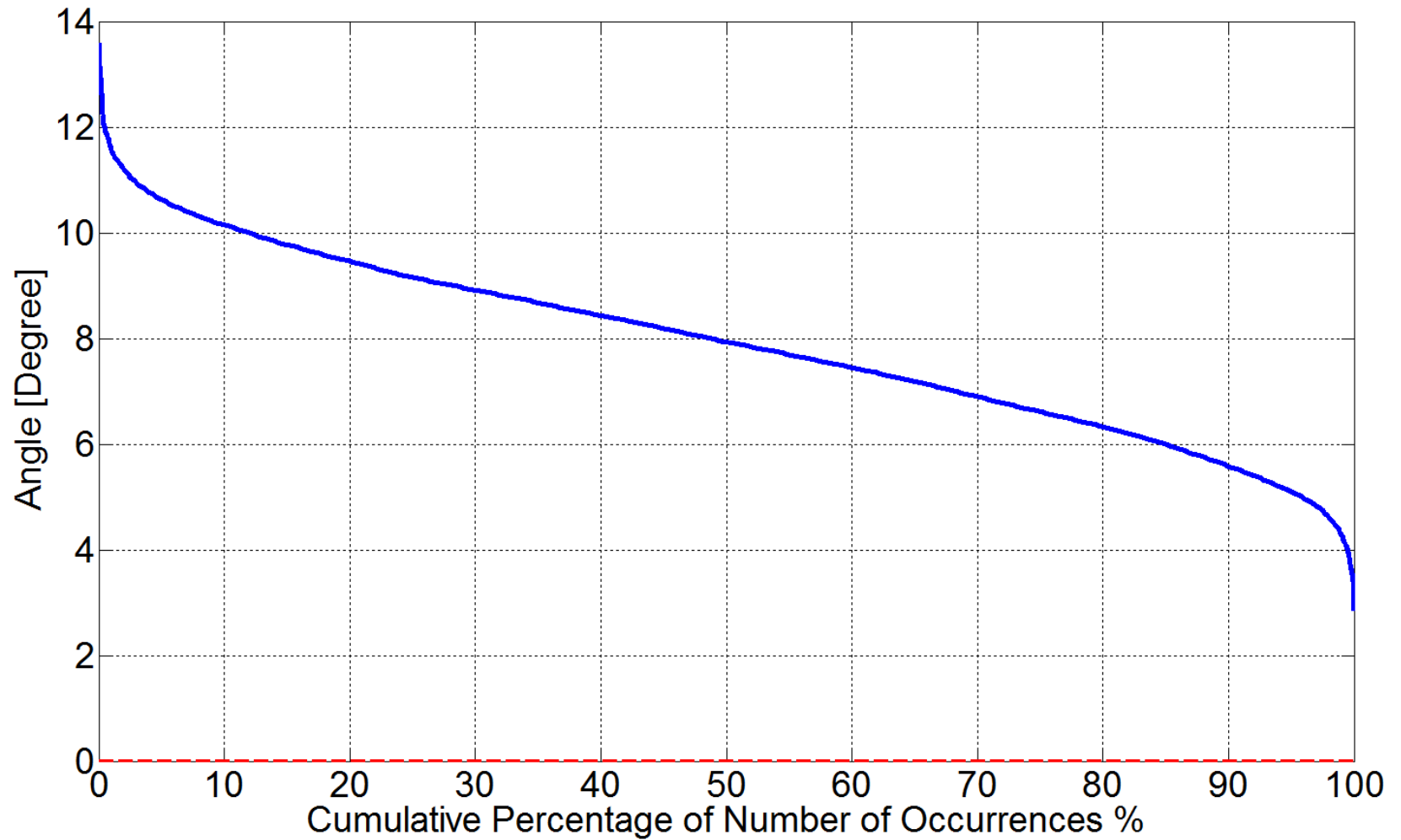
FarWest 7-West 14



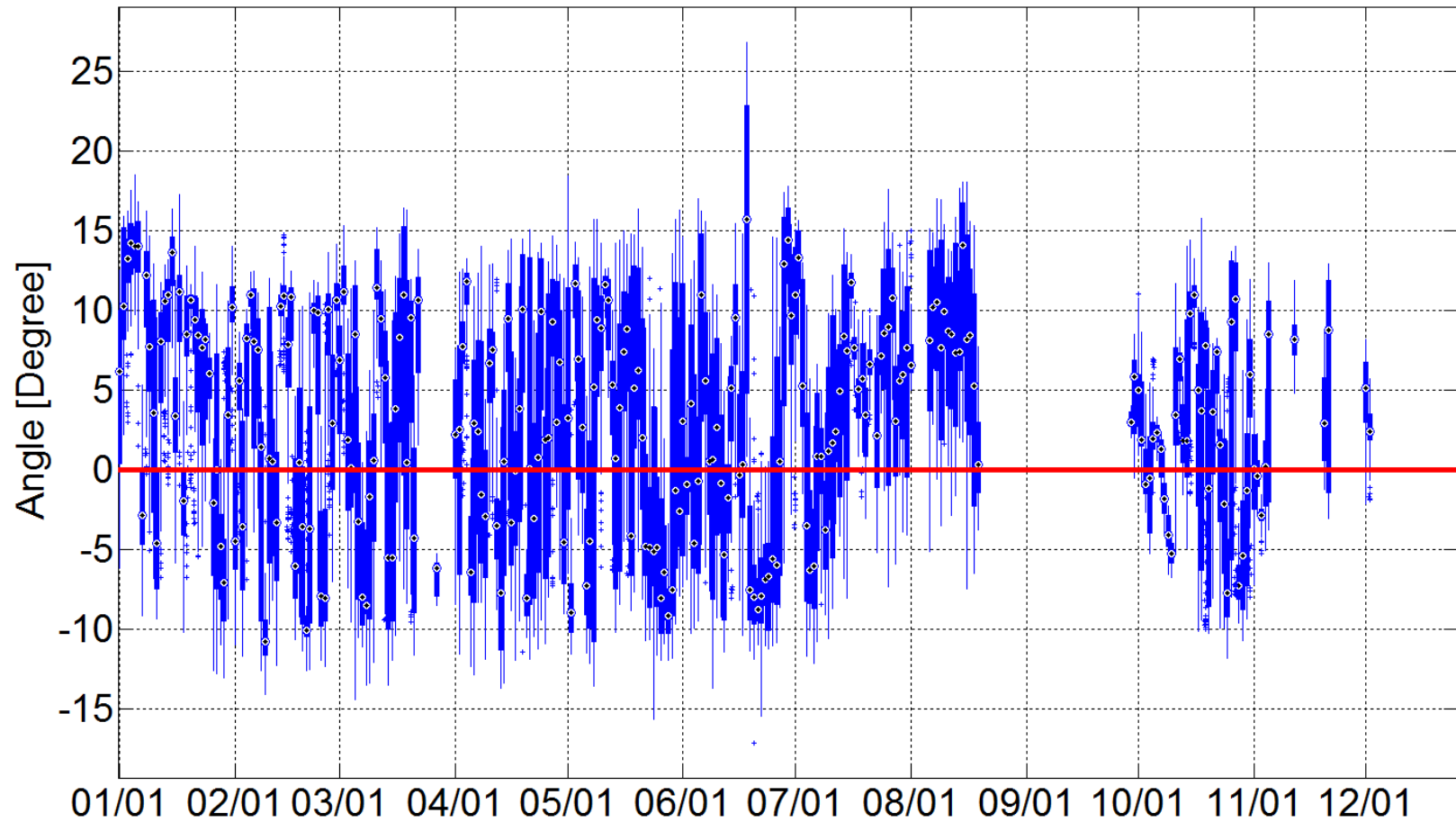
FarWest 7-FarWest 8



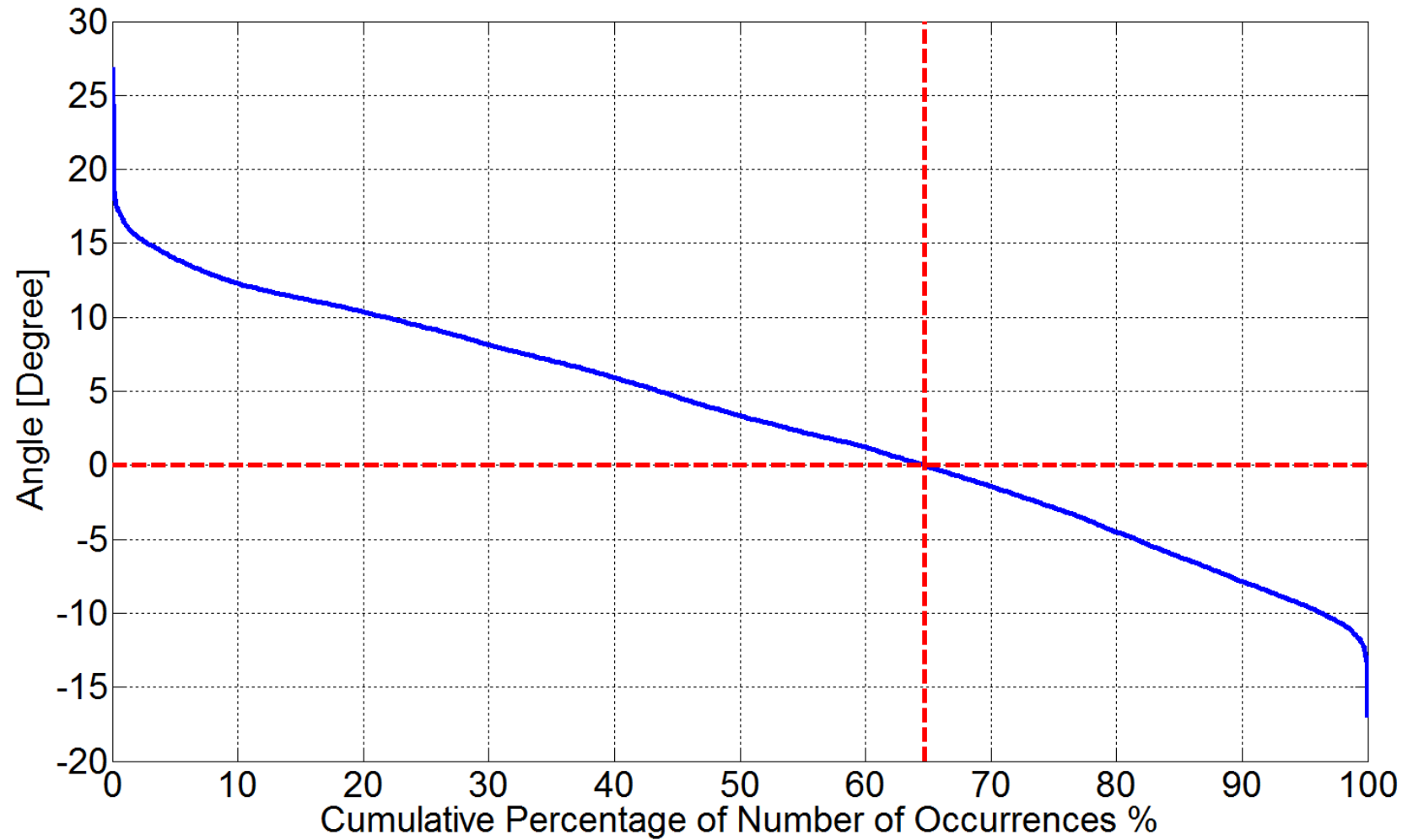
FarWest 7-FarWest 8



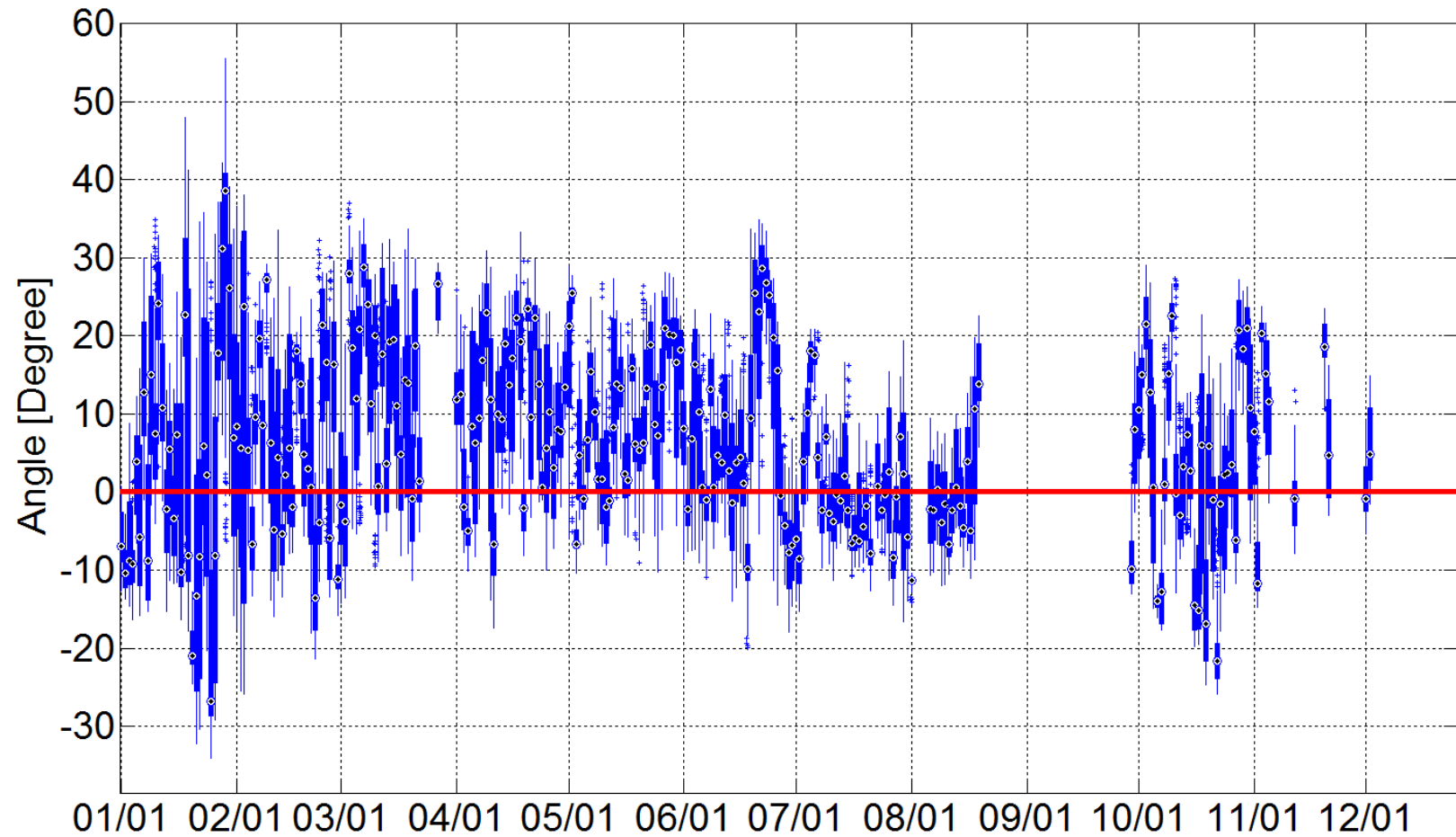
FarWest 7-FarWest 9



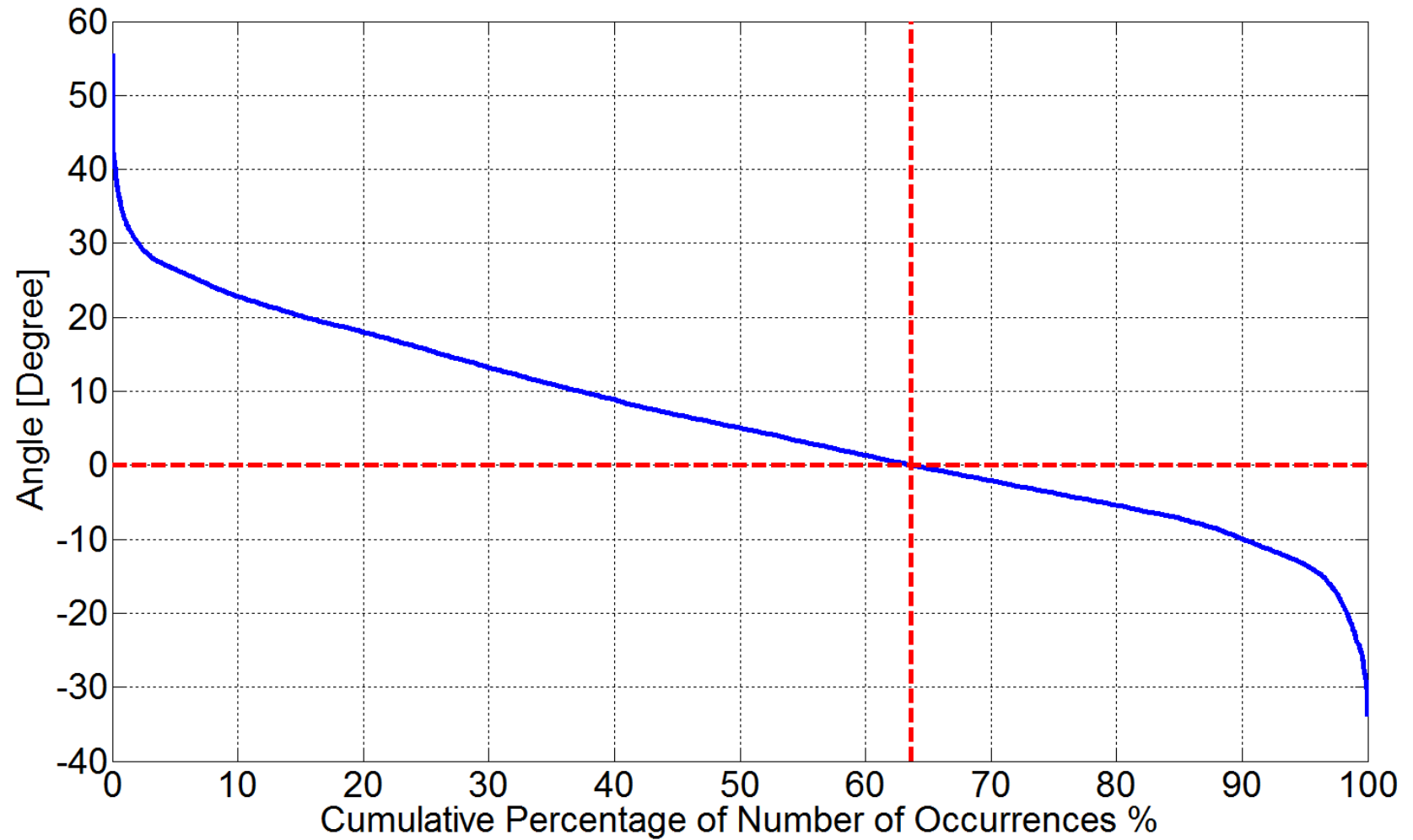
FarWest 7-FarWest 9



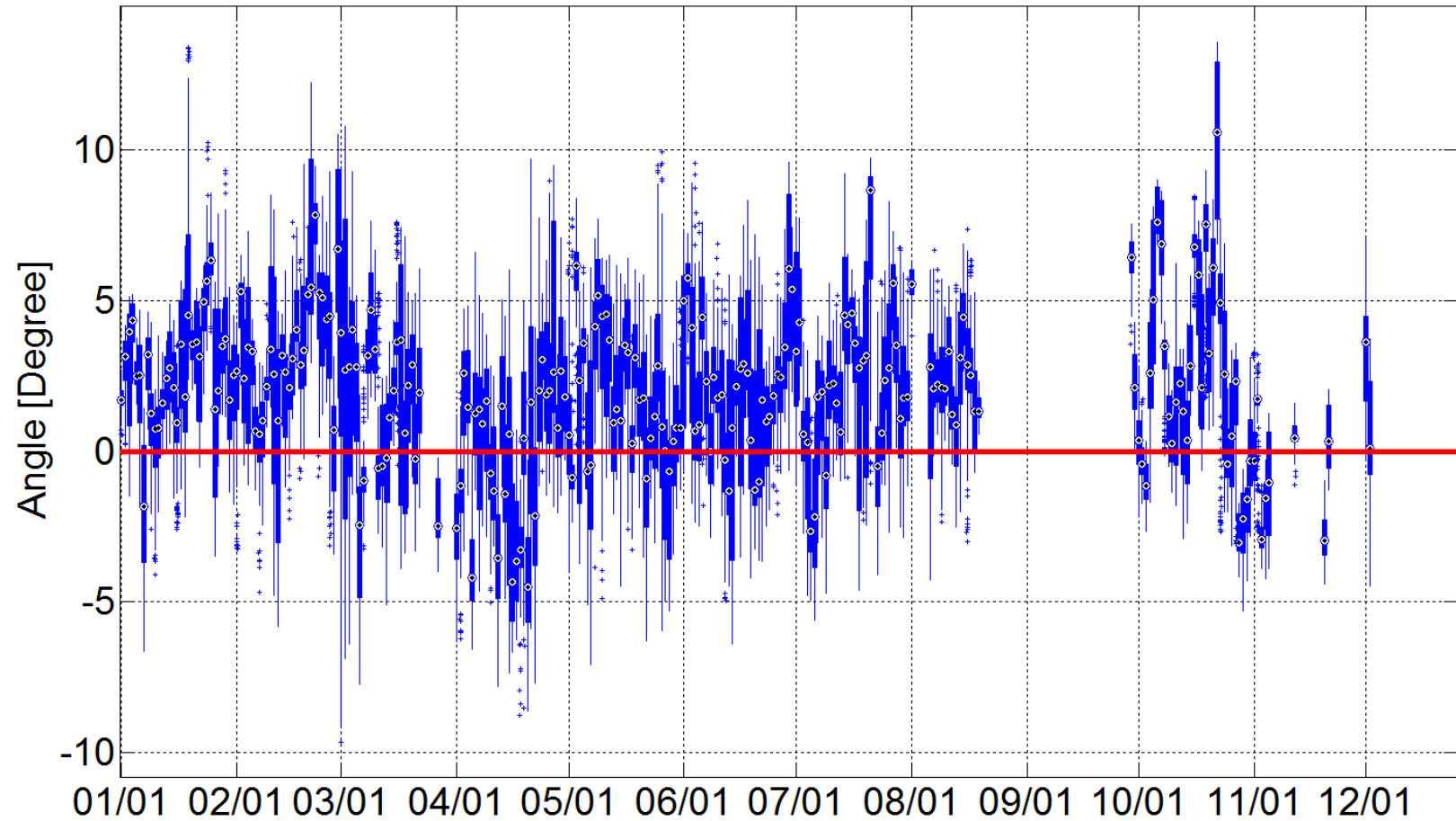
FarWest 7-North 7



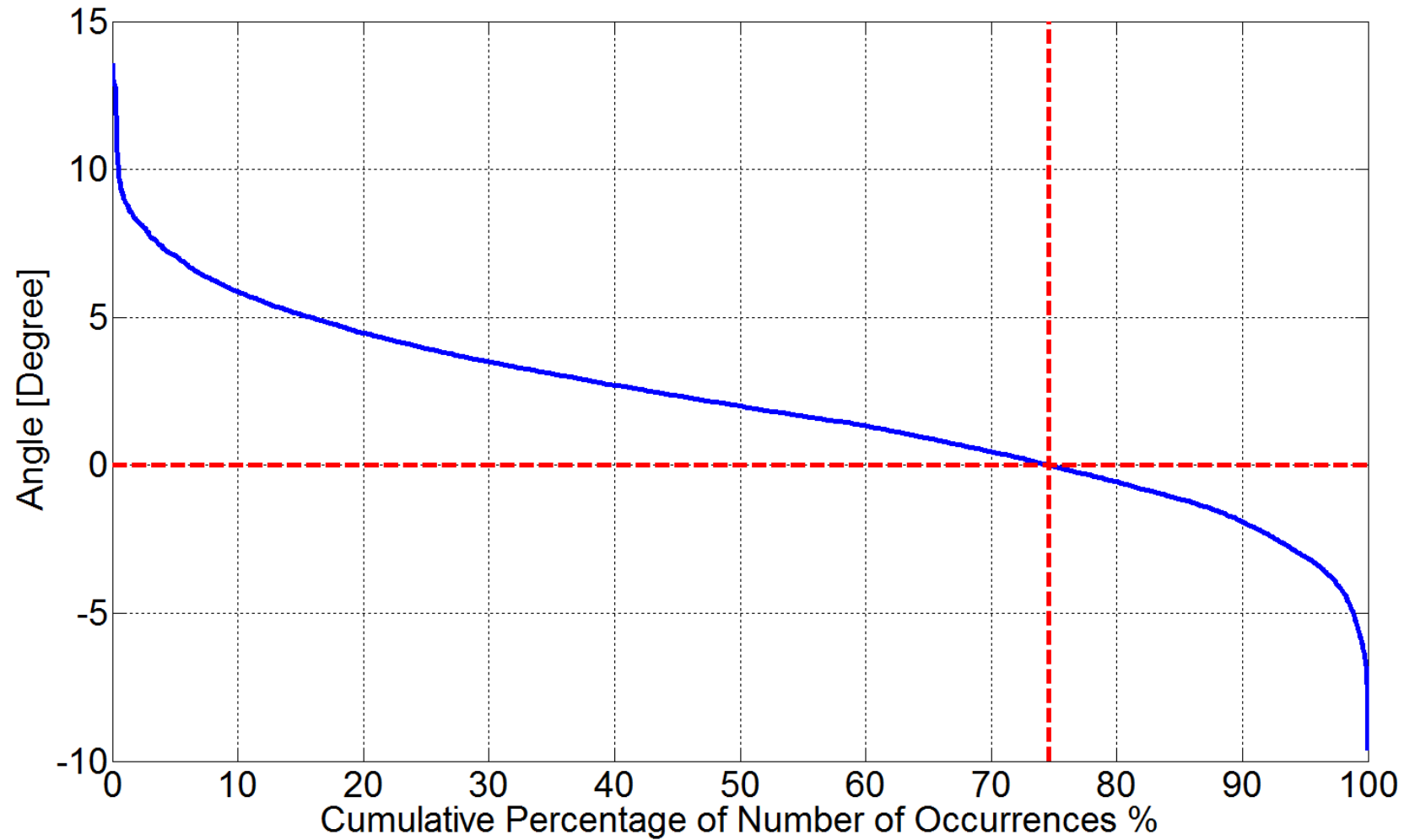
FarWest 7-North 7



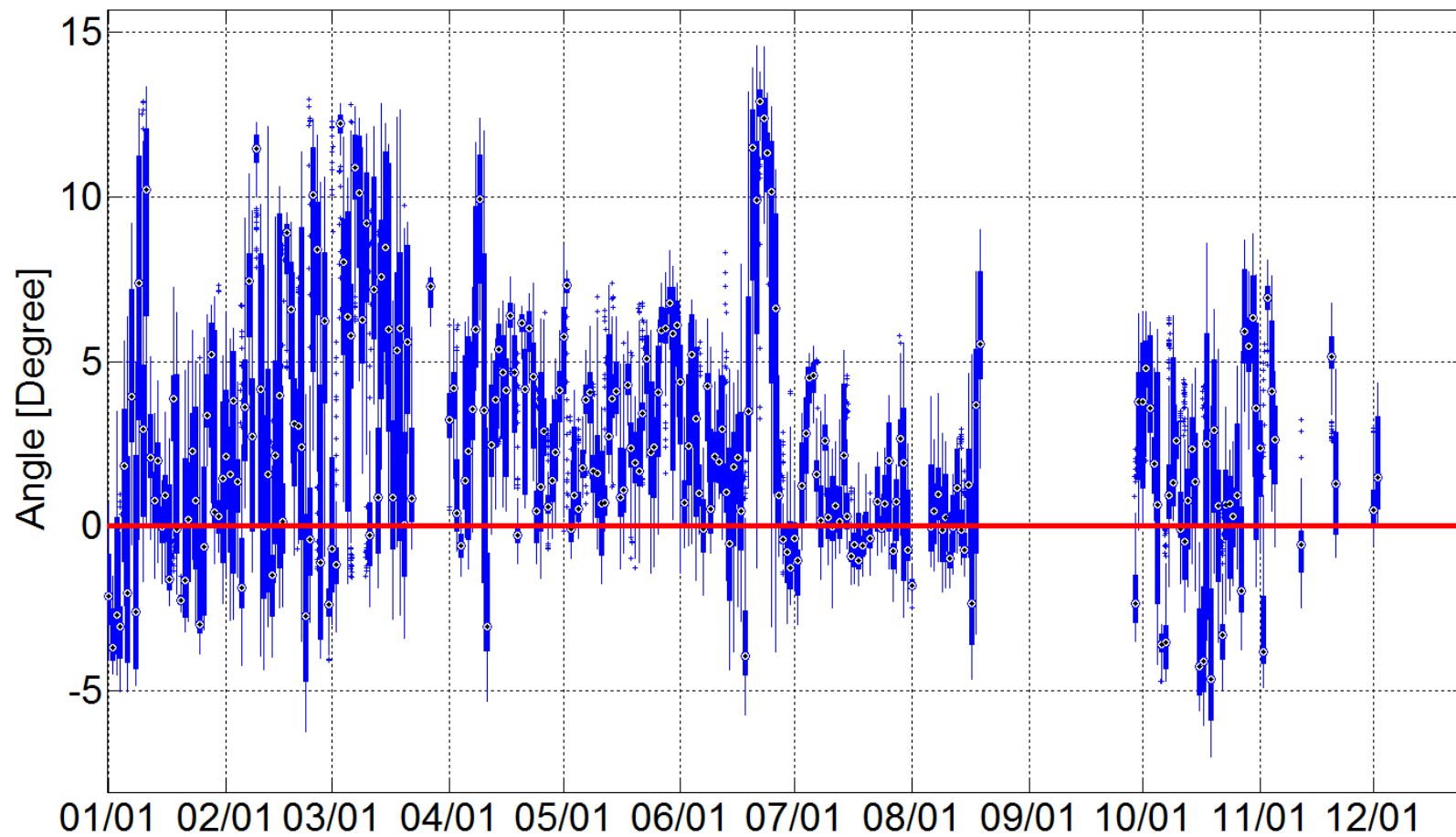
West 12-FarWest 7



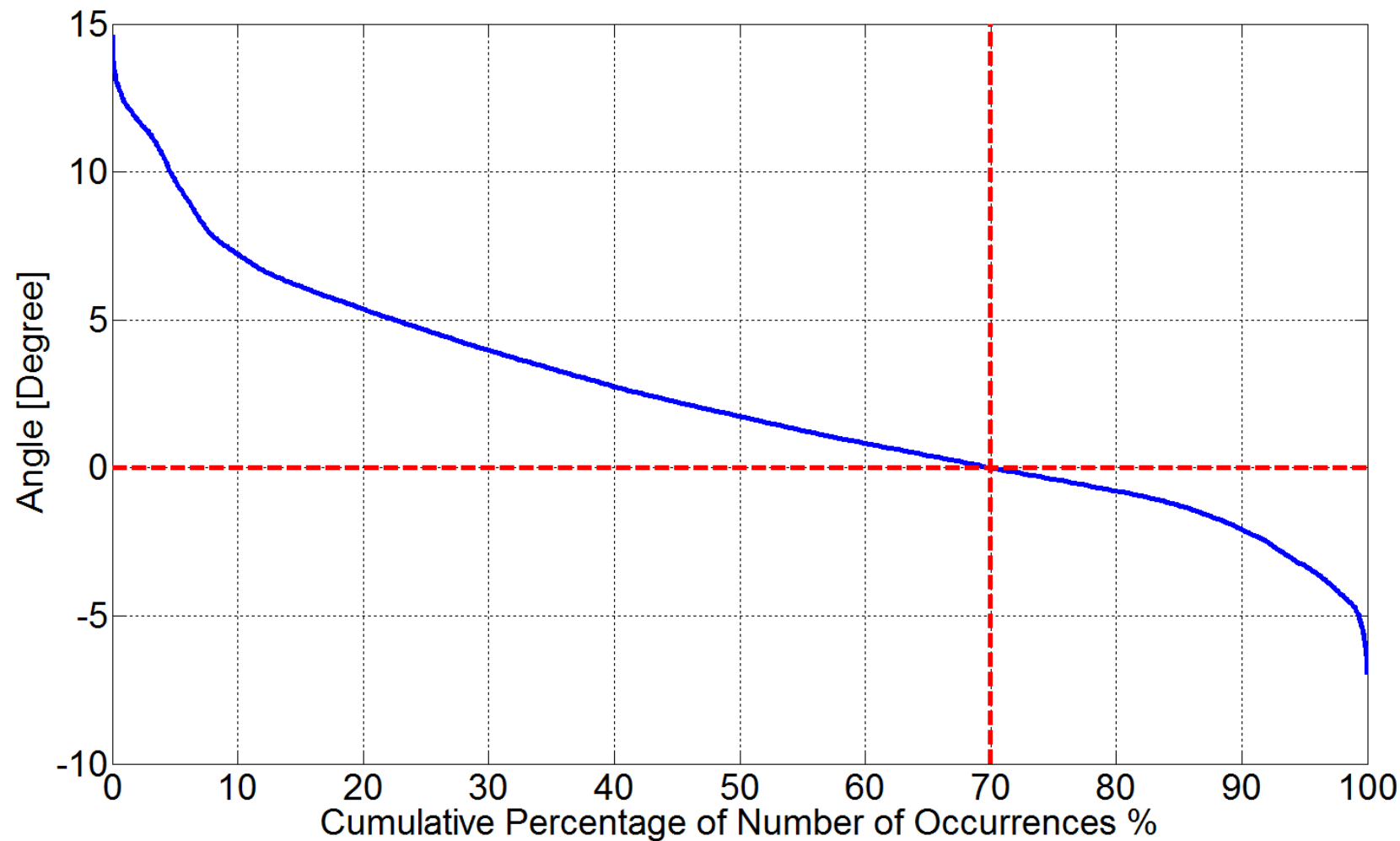
West 12-FarWest 7



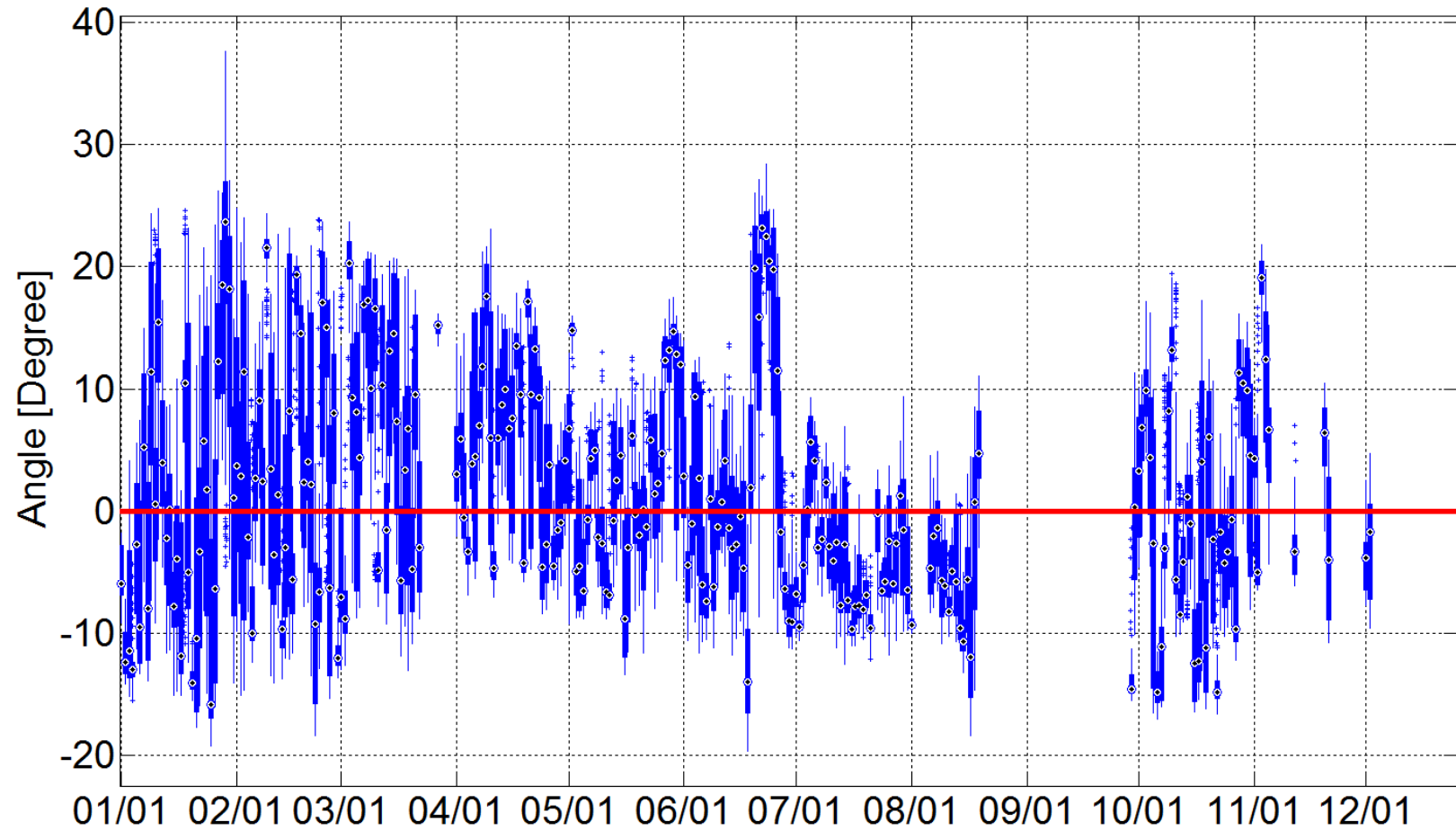
West 12-West 1



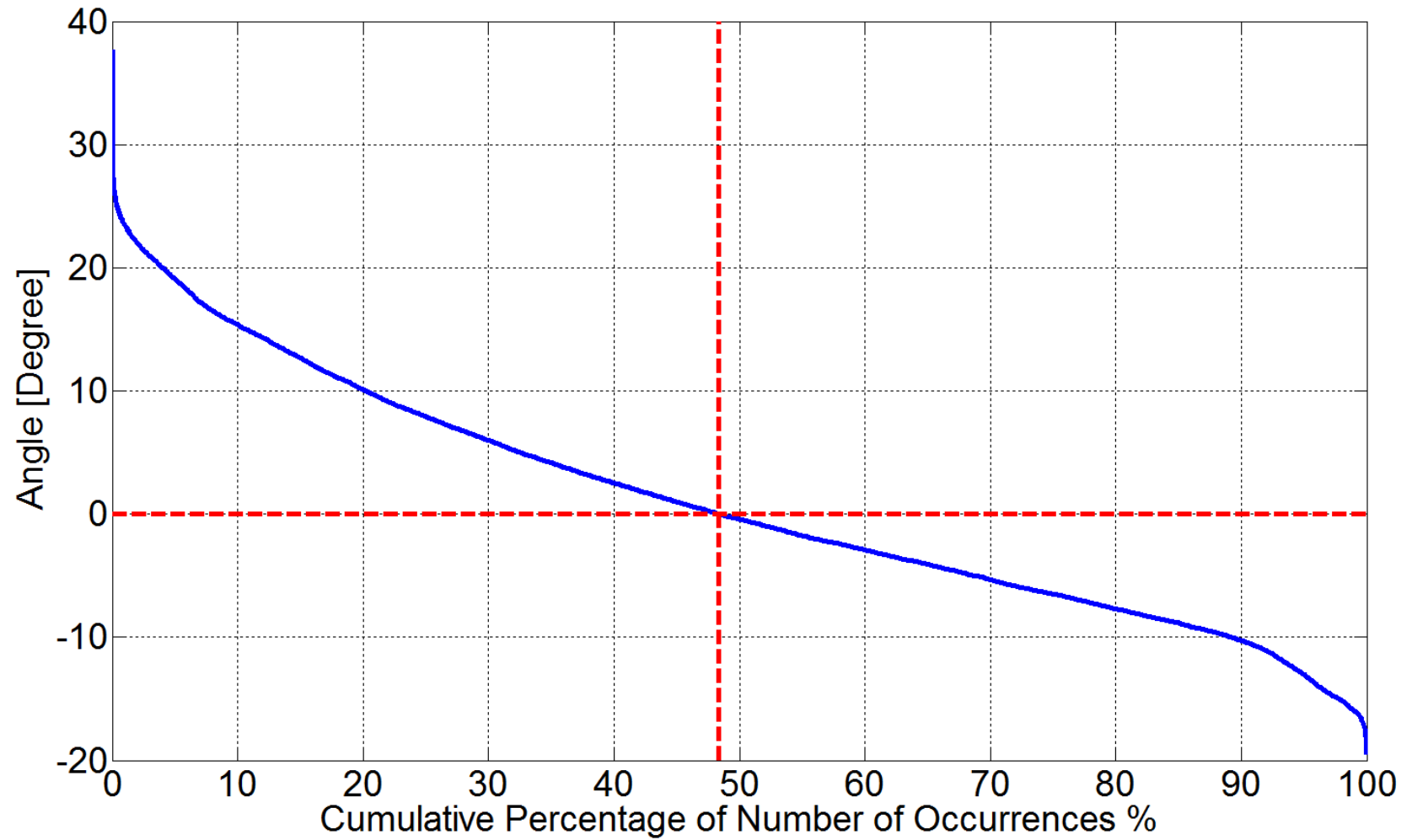
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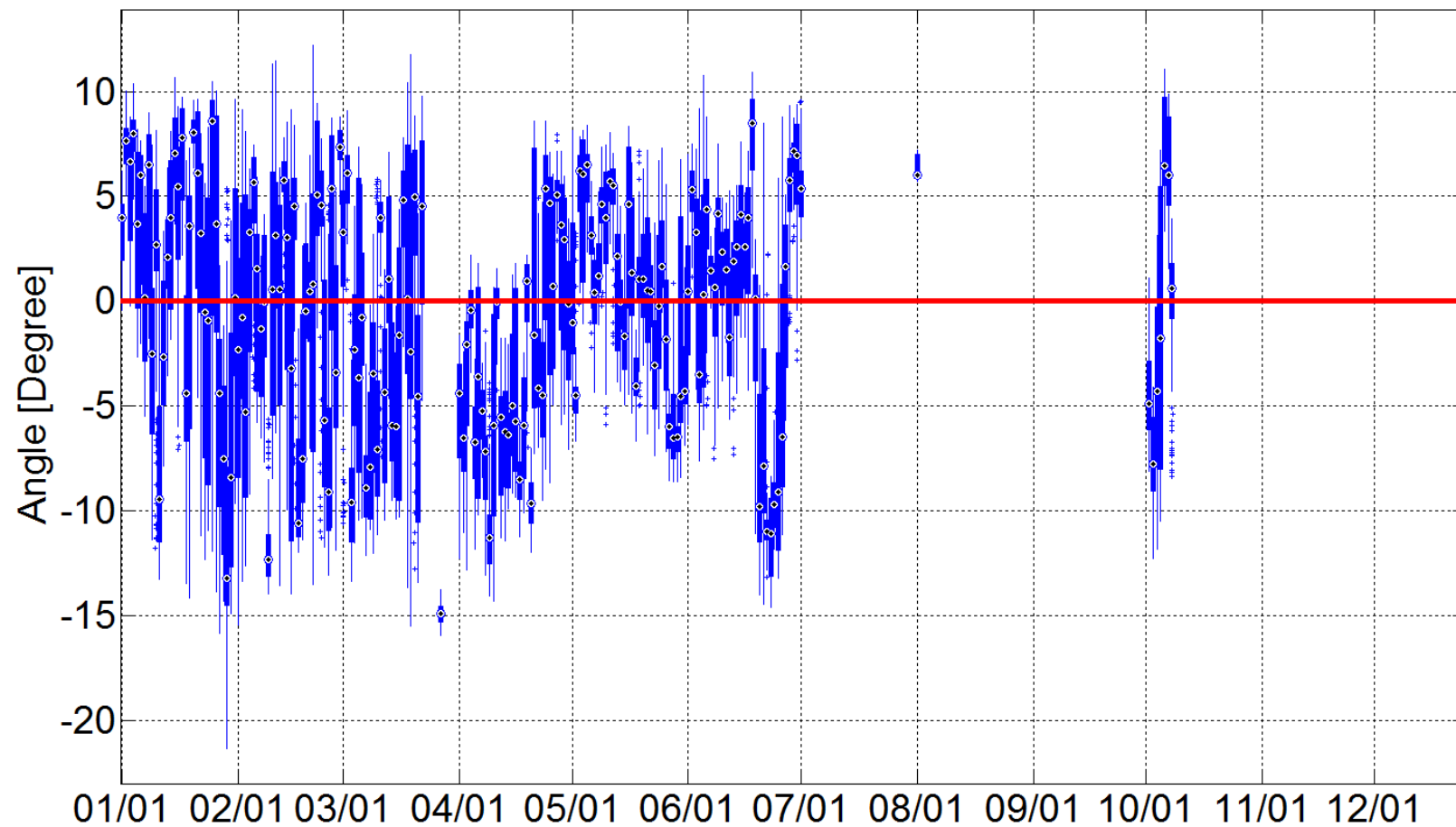
West 12-North 1



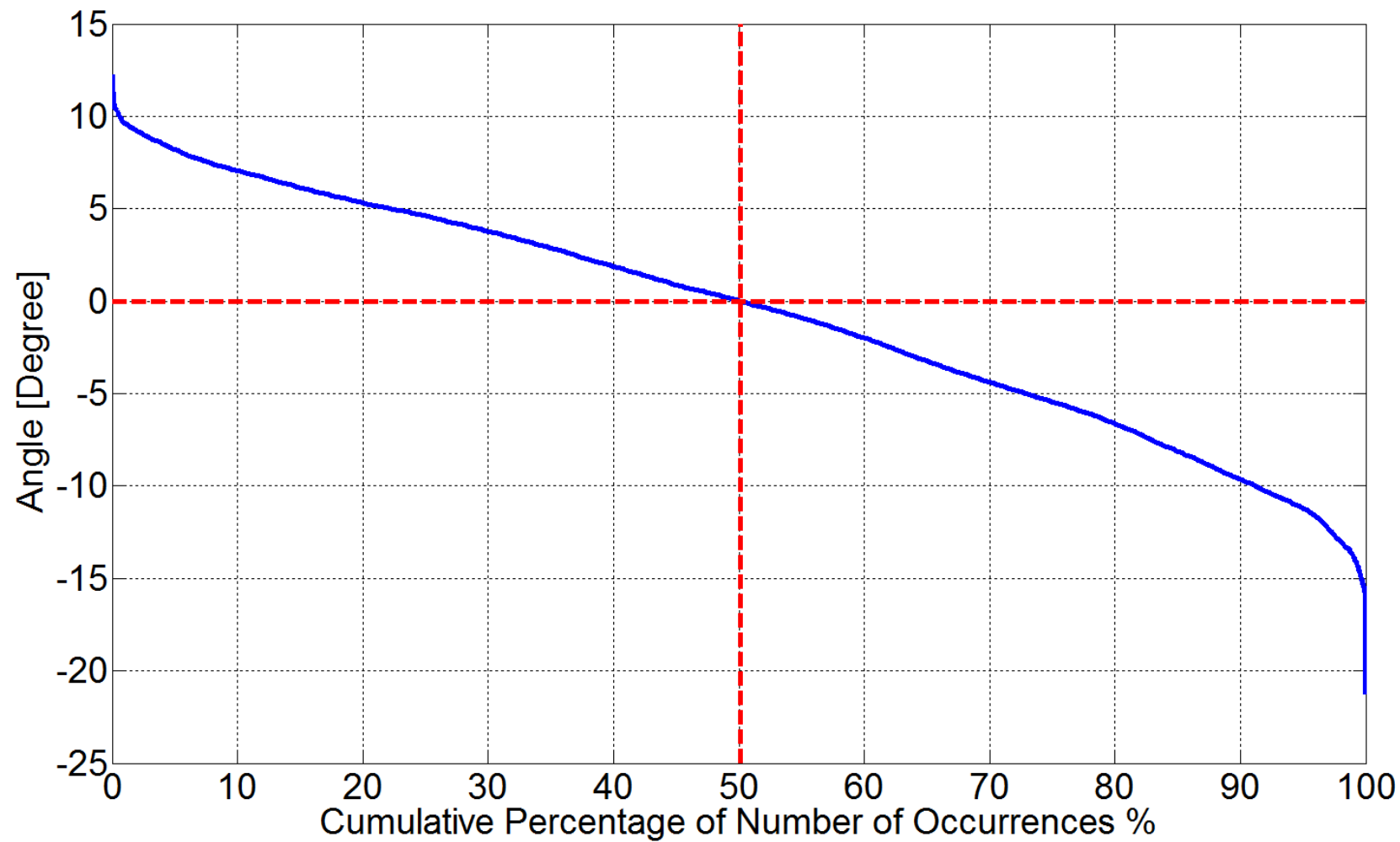
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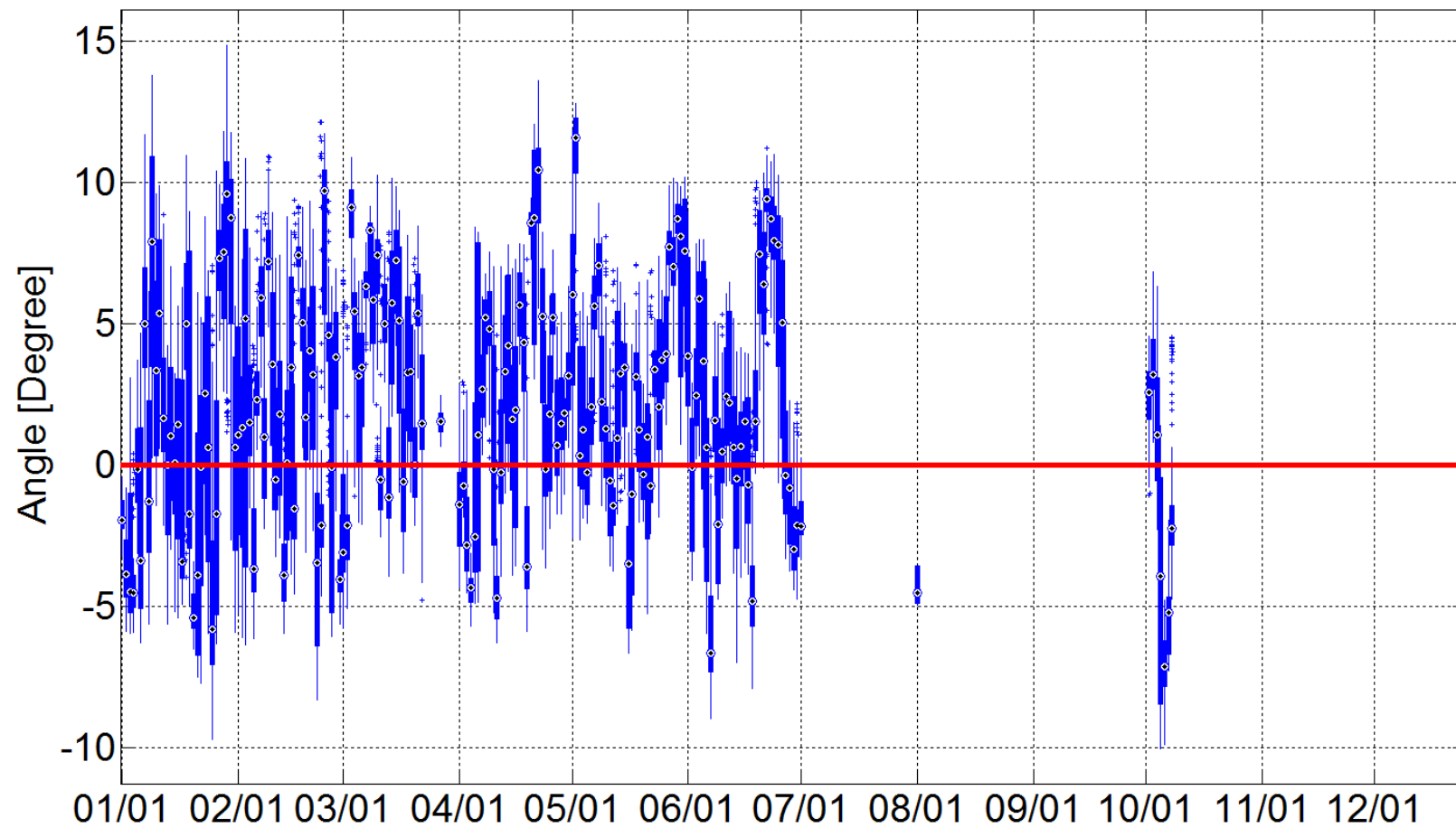
West 14-West 5



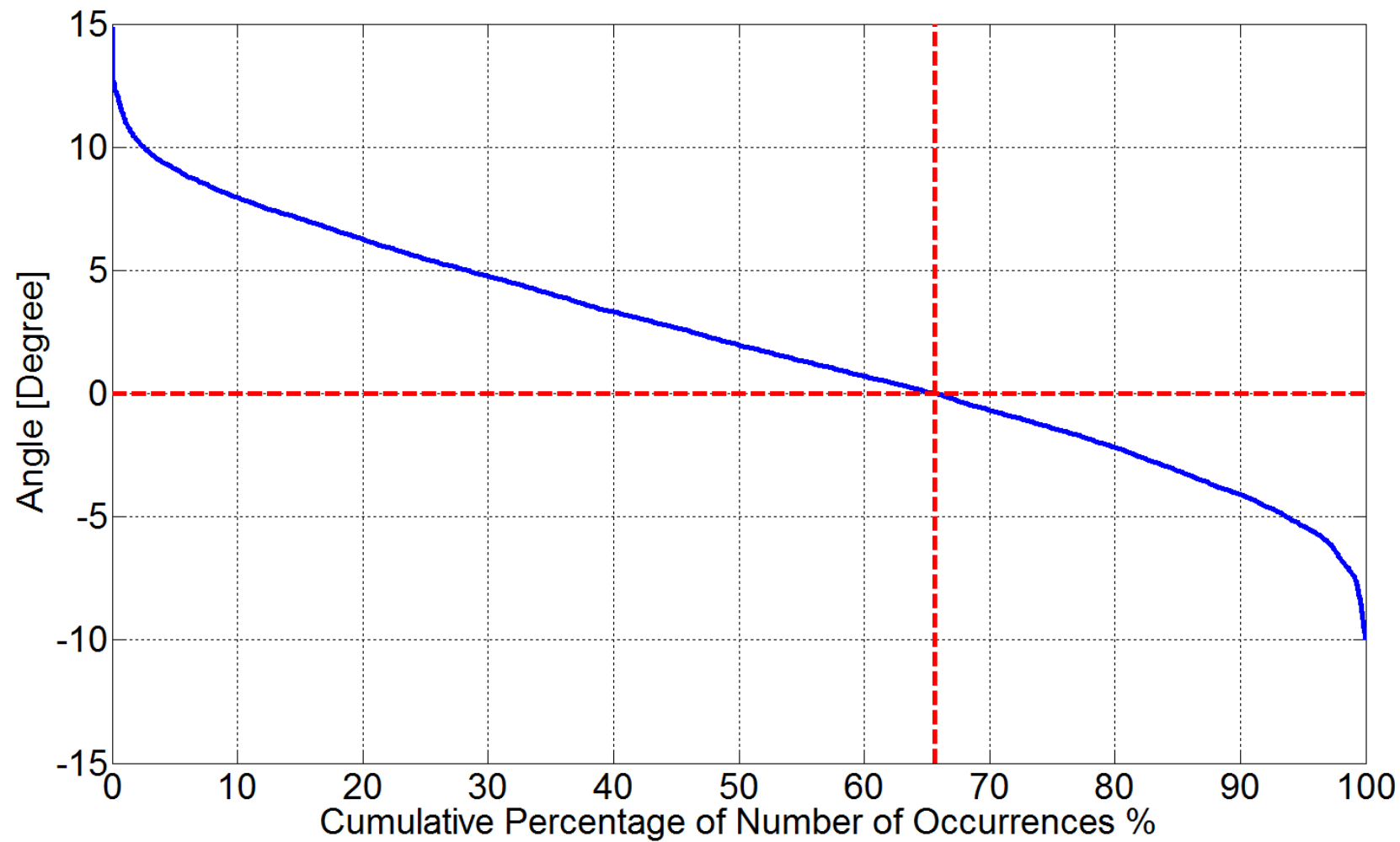
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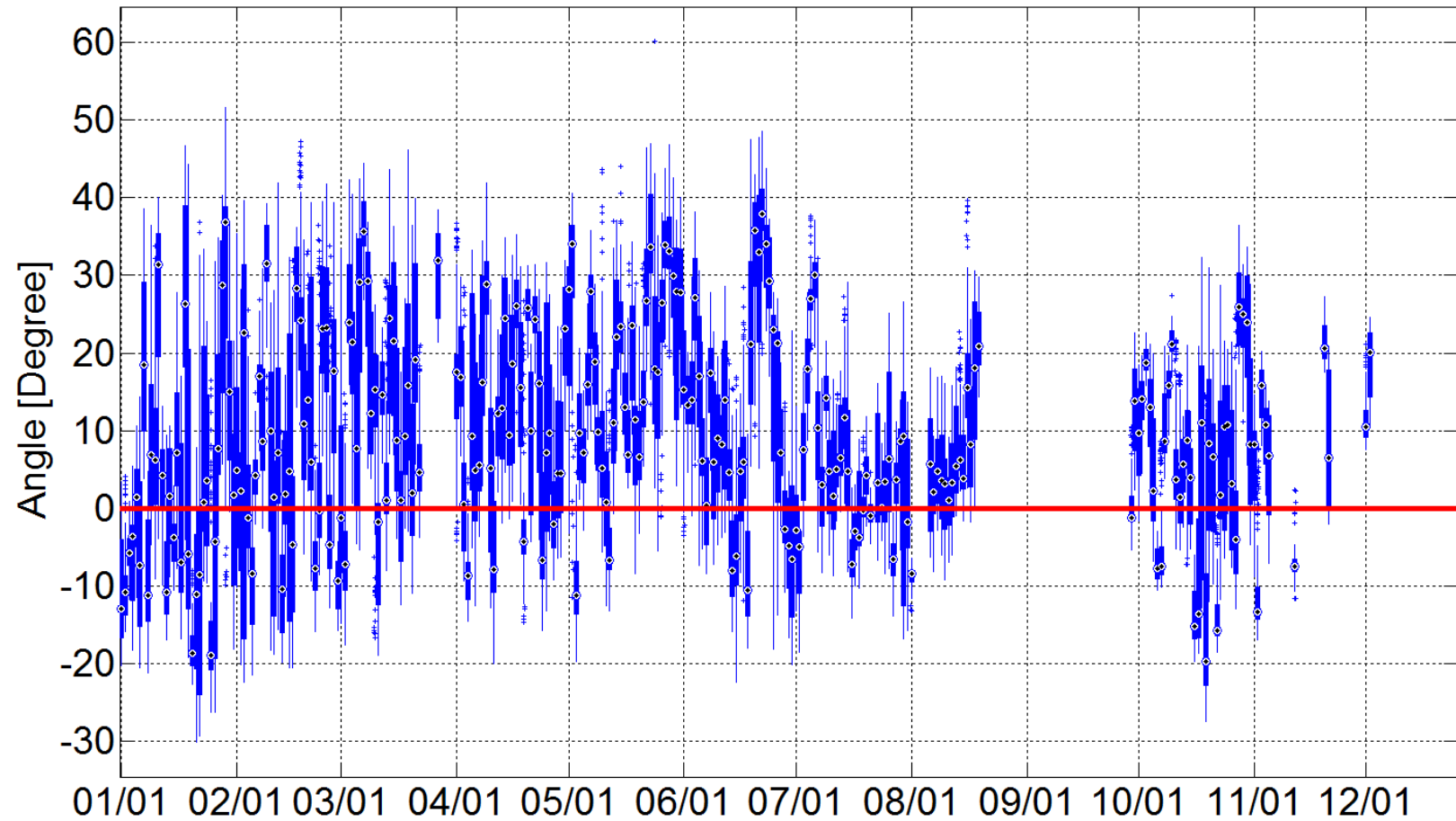
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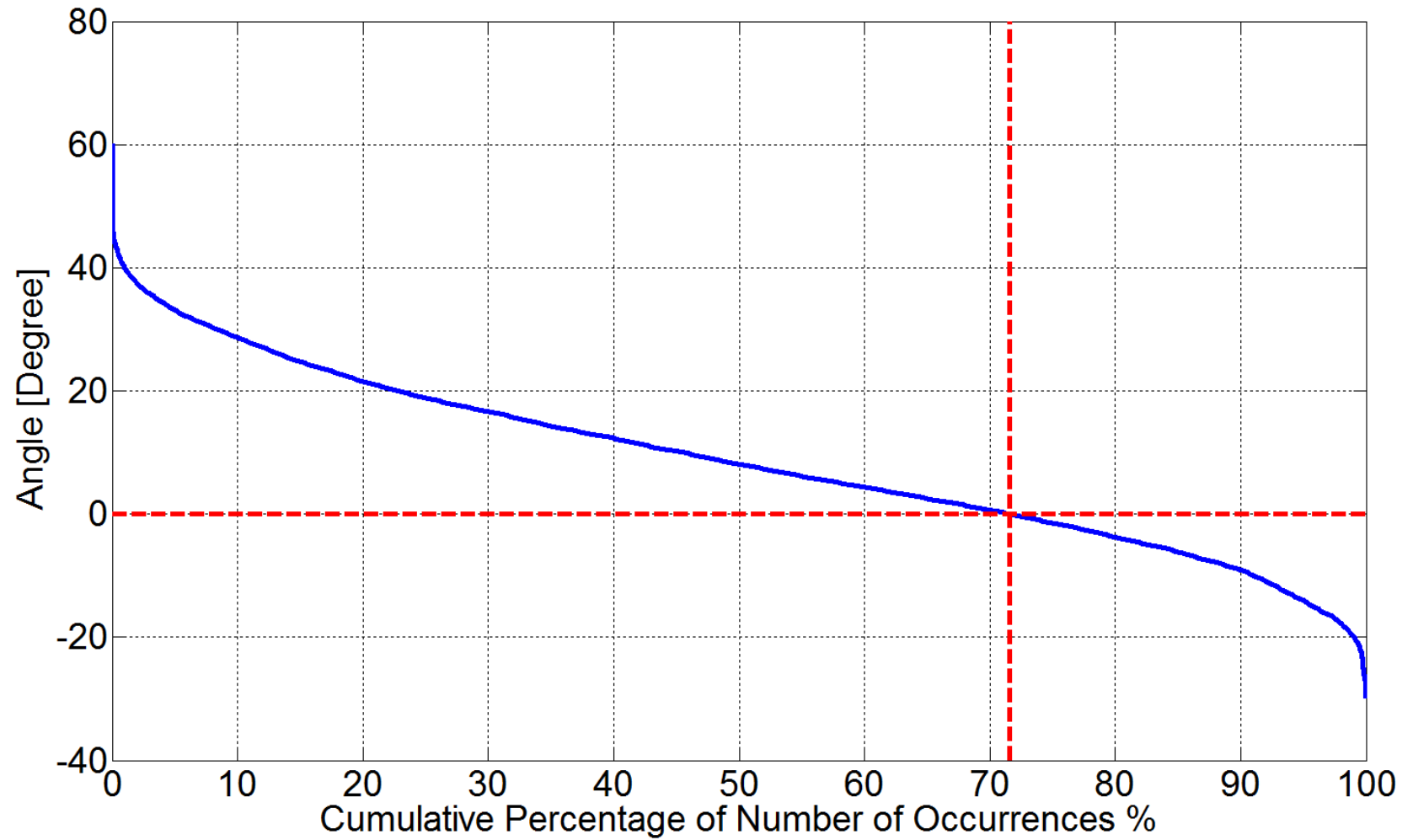
West 14-North 1



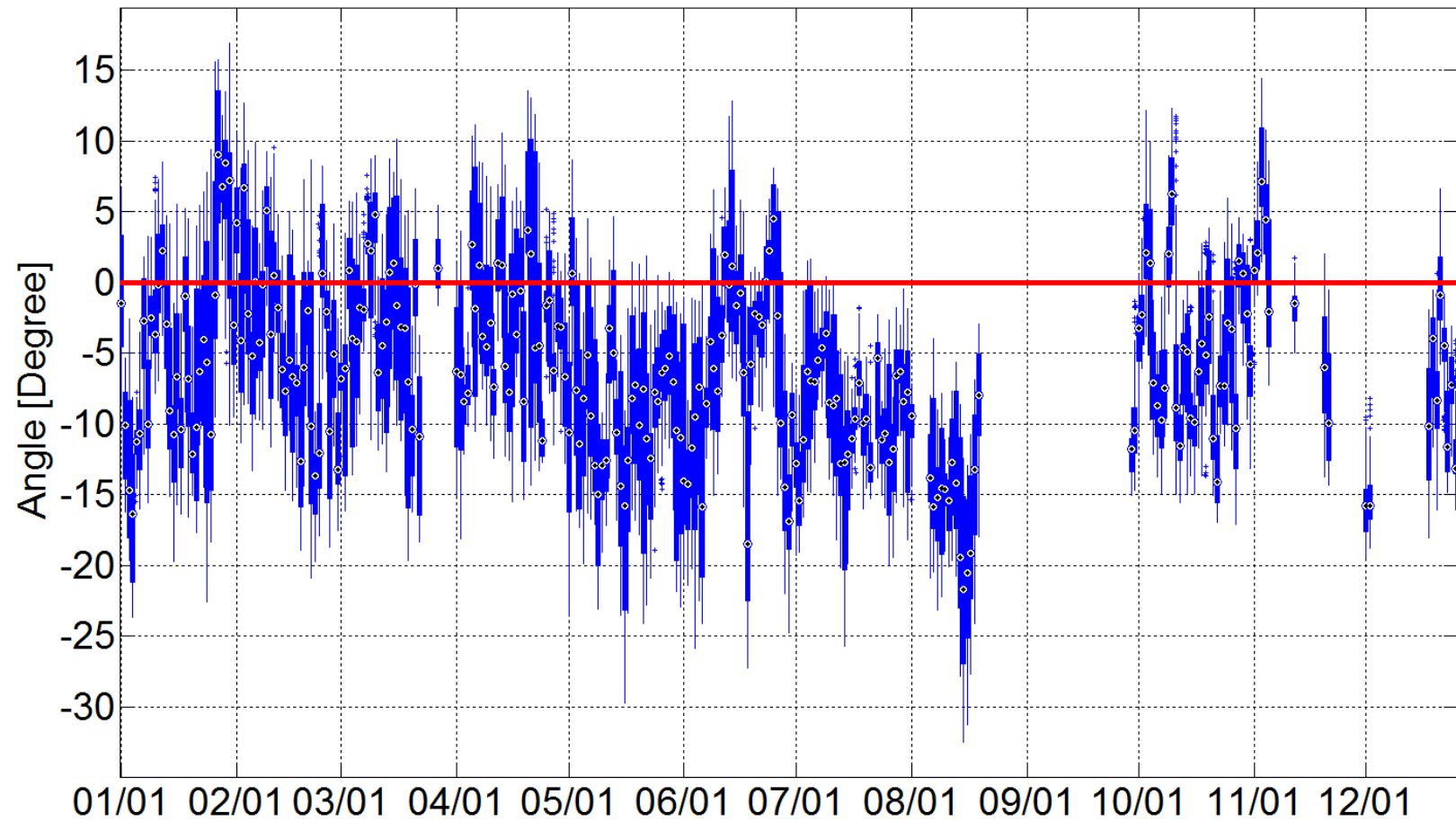
FarWest 9-West 4



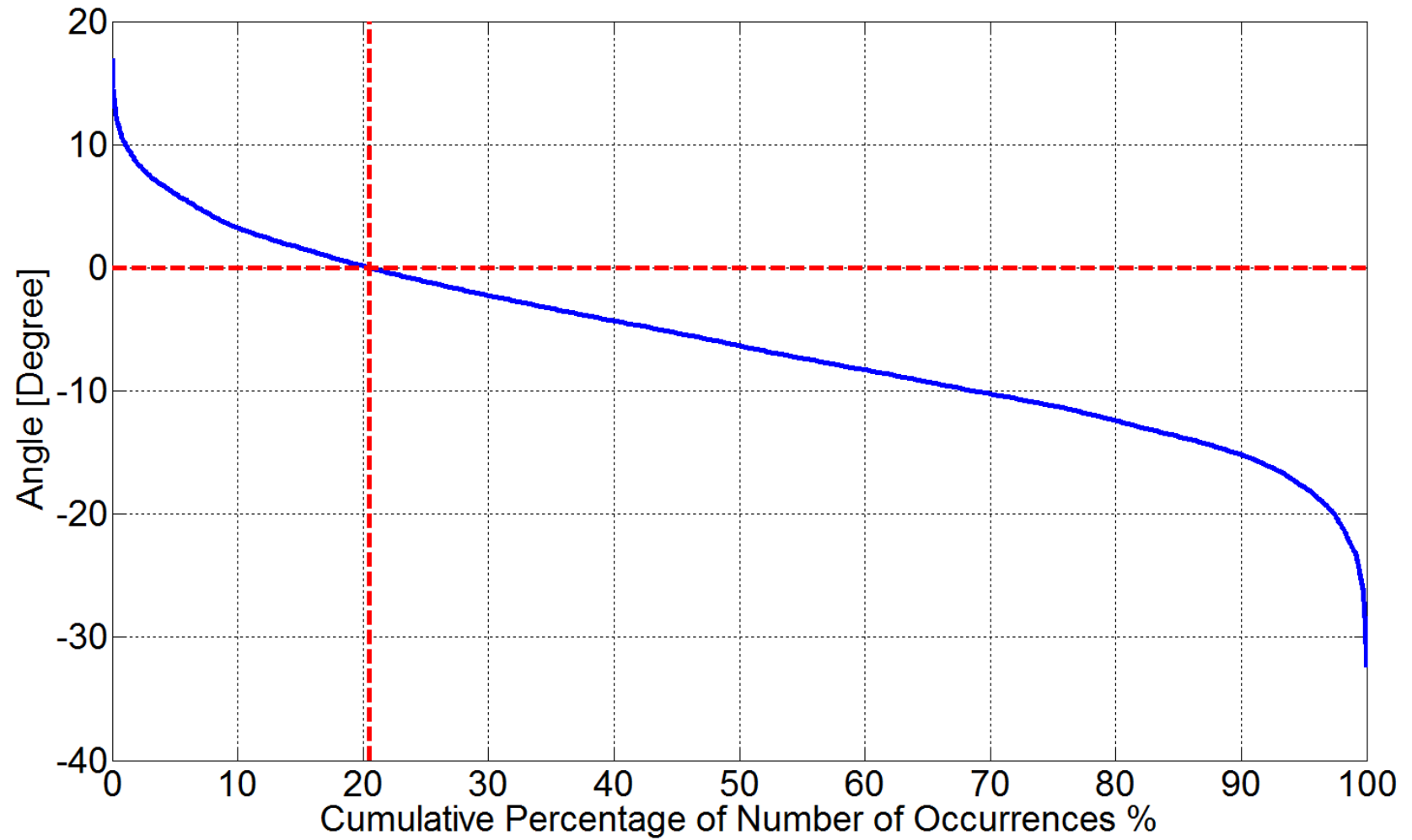
FarWest 9-West 4



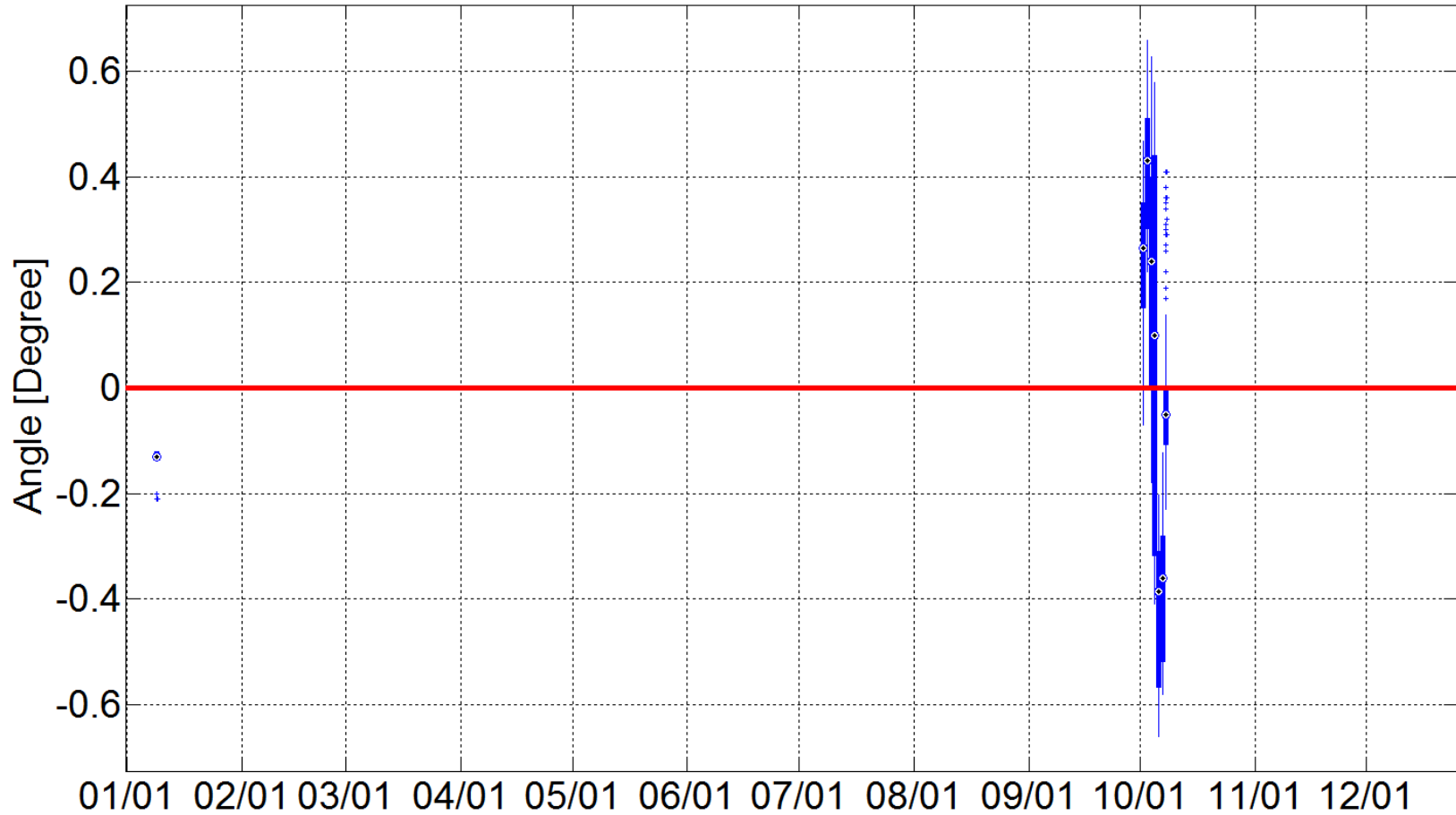
West 4-North 7



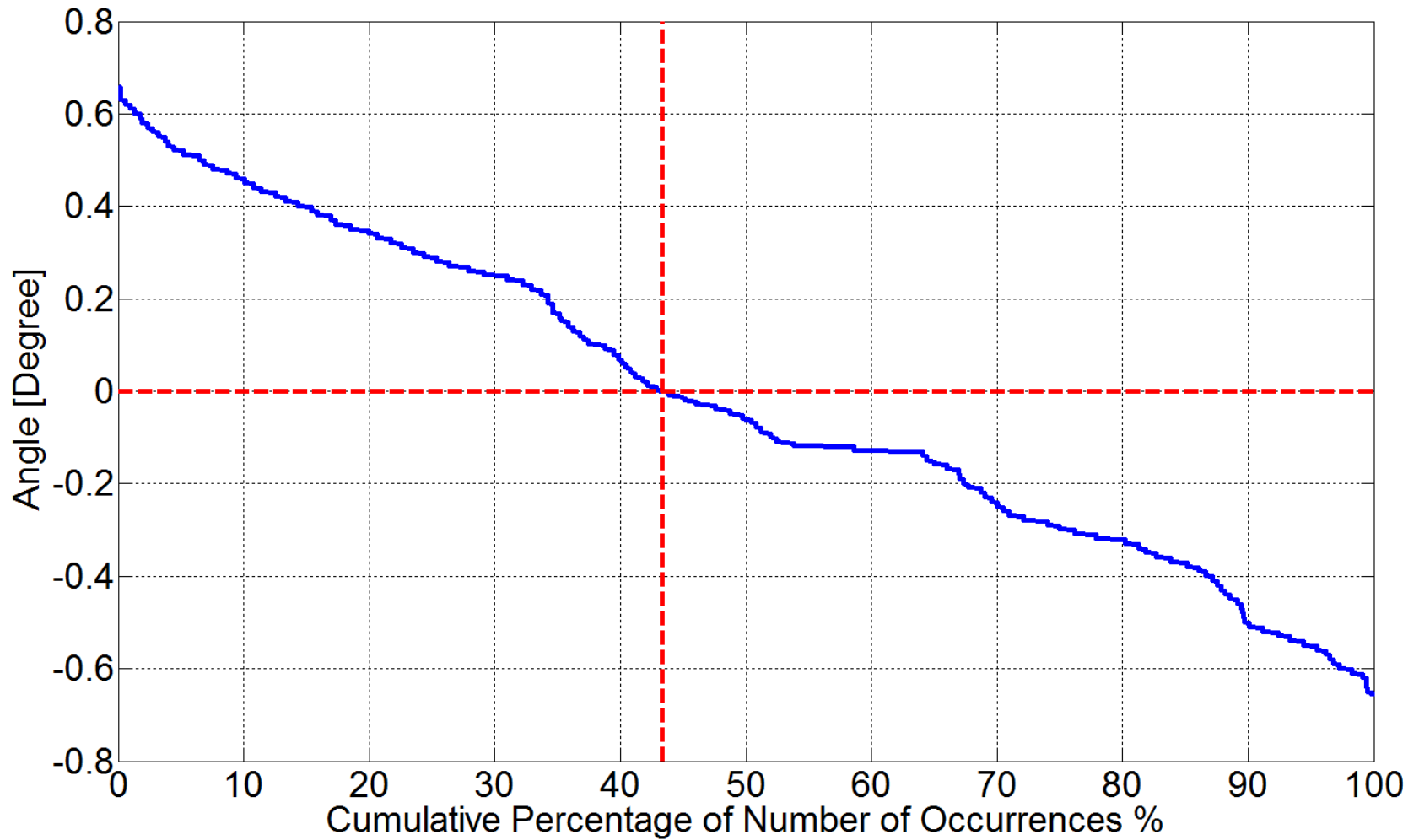
West 4-North 7



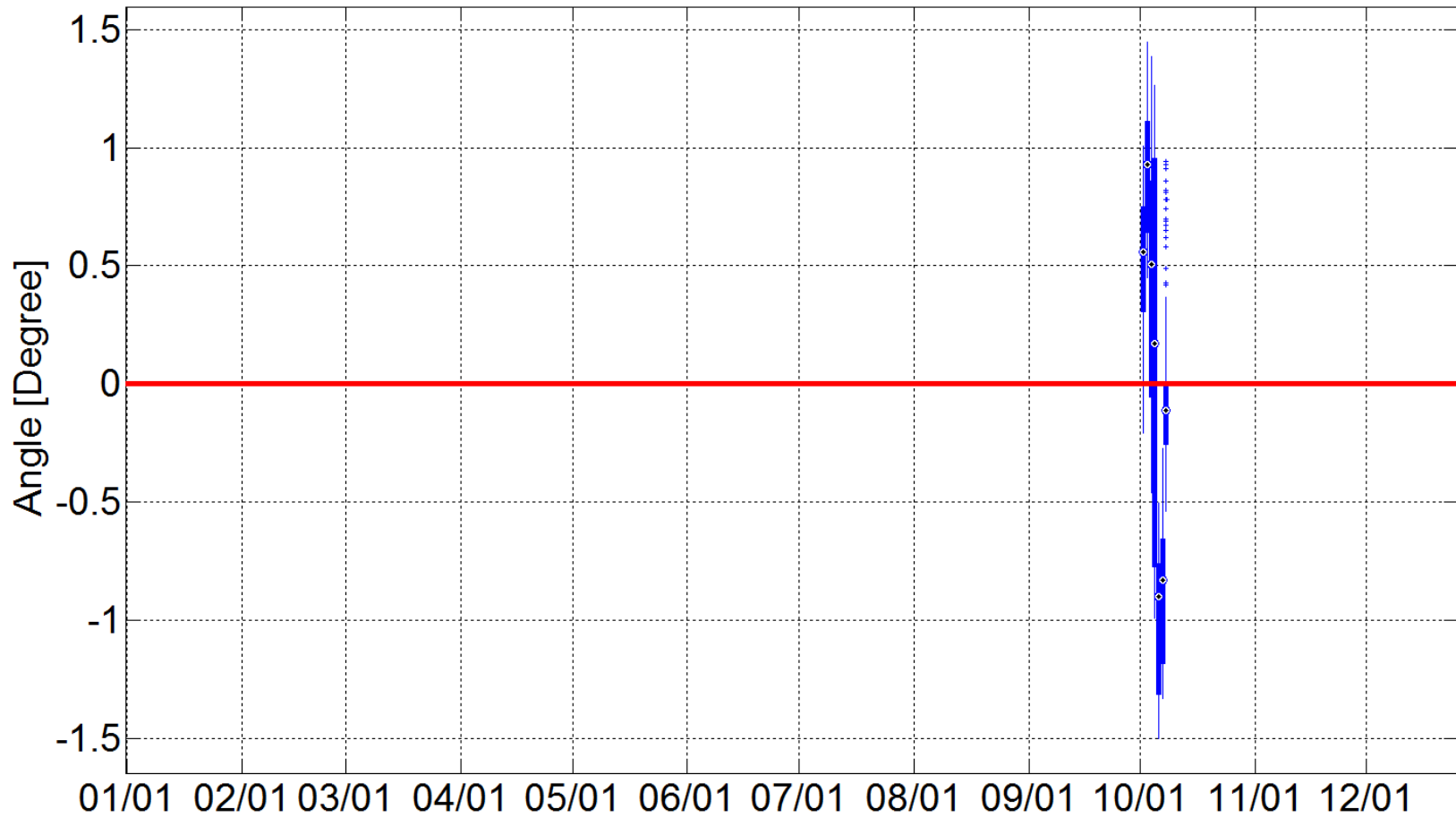
West 16-West 14



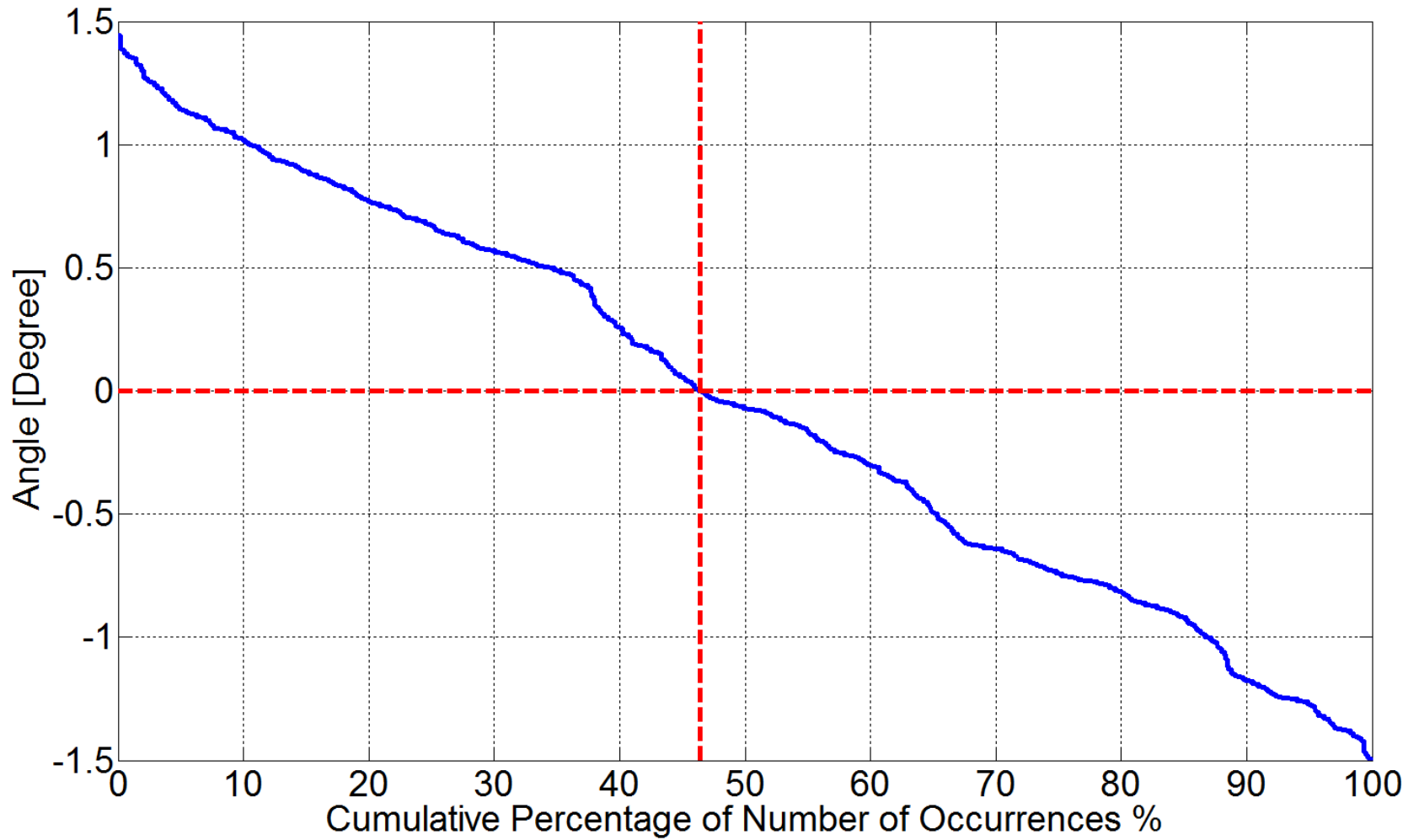
West 16-West 14



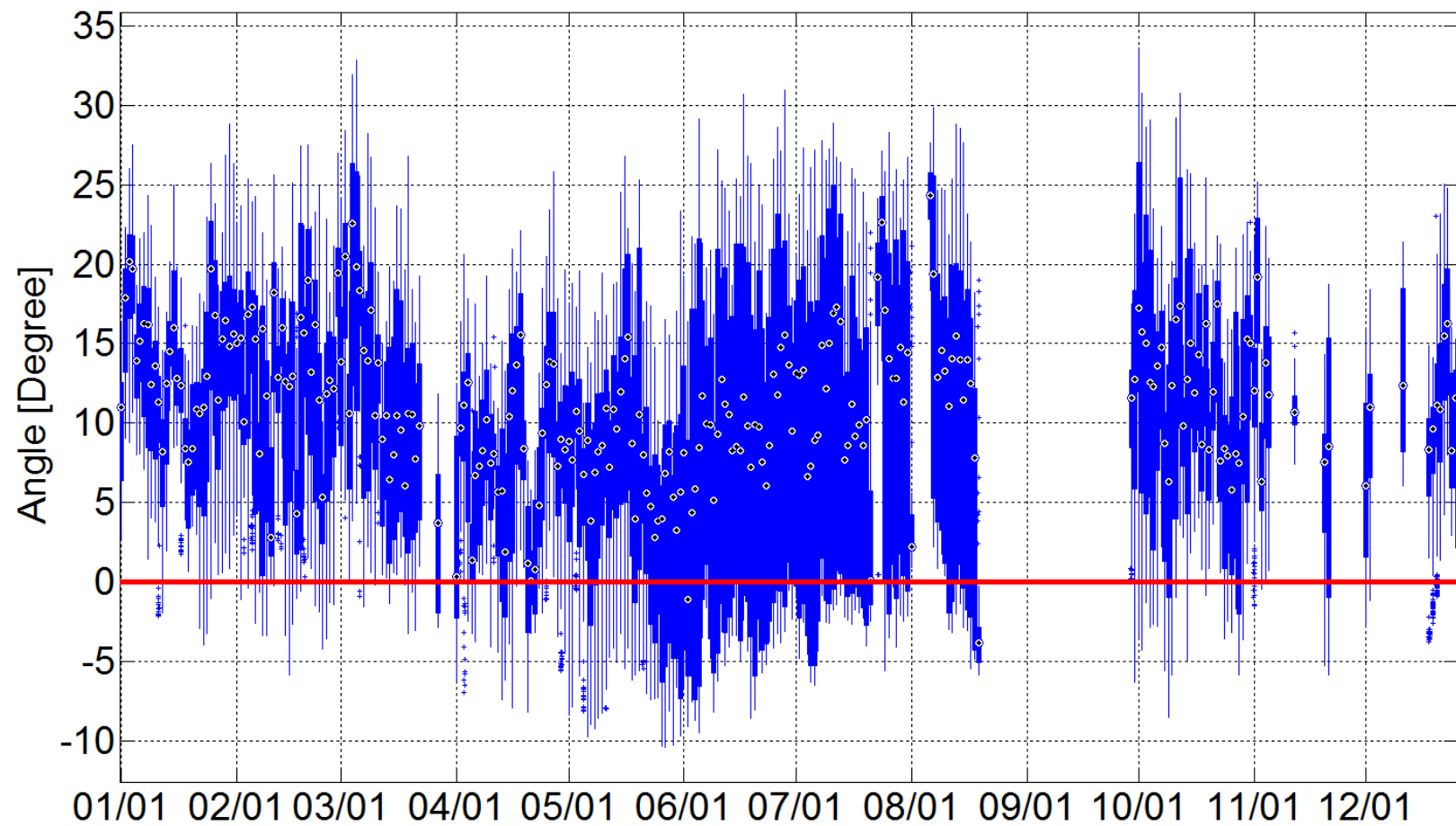
West 15-West 14



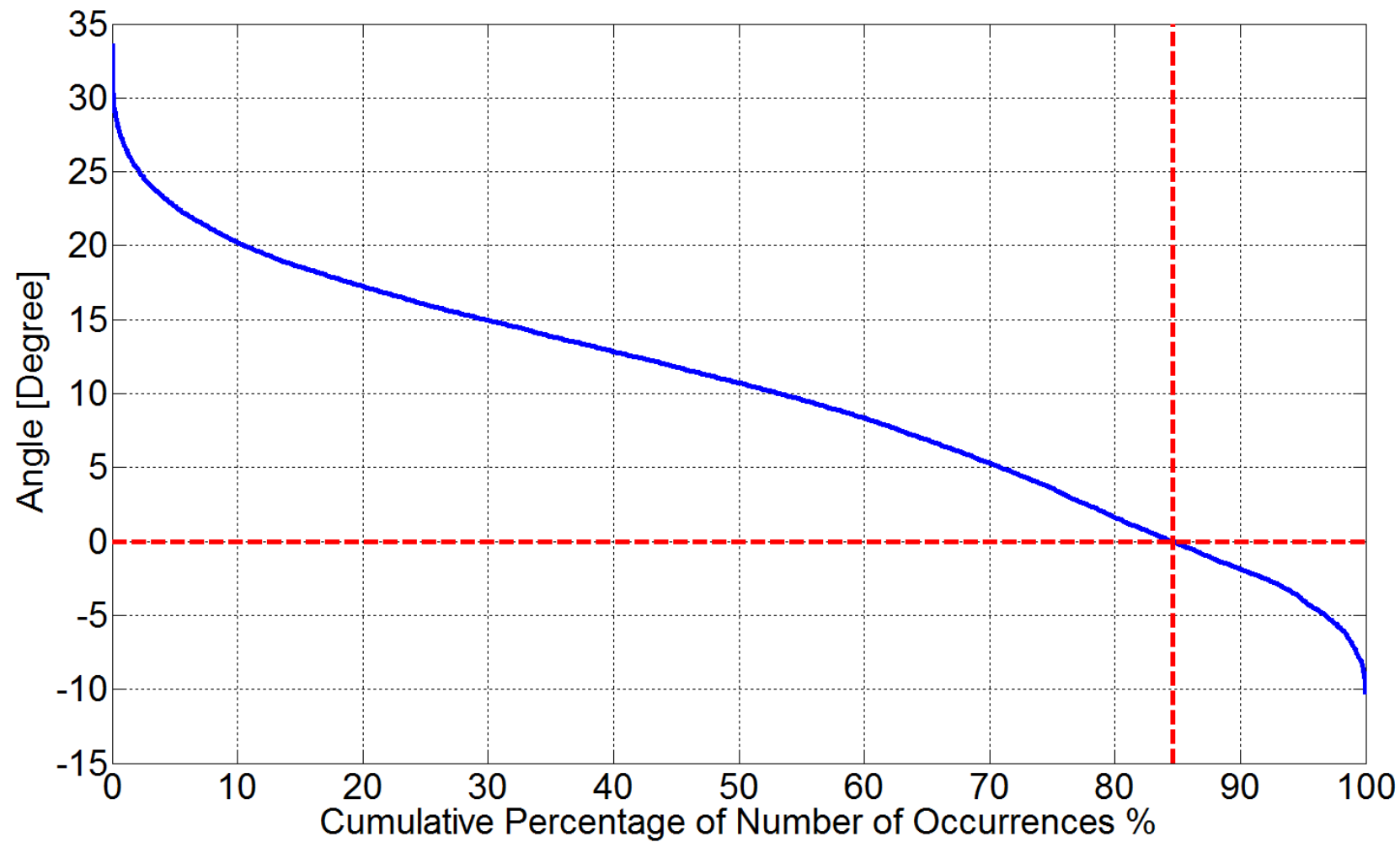
West 15-West 14



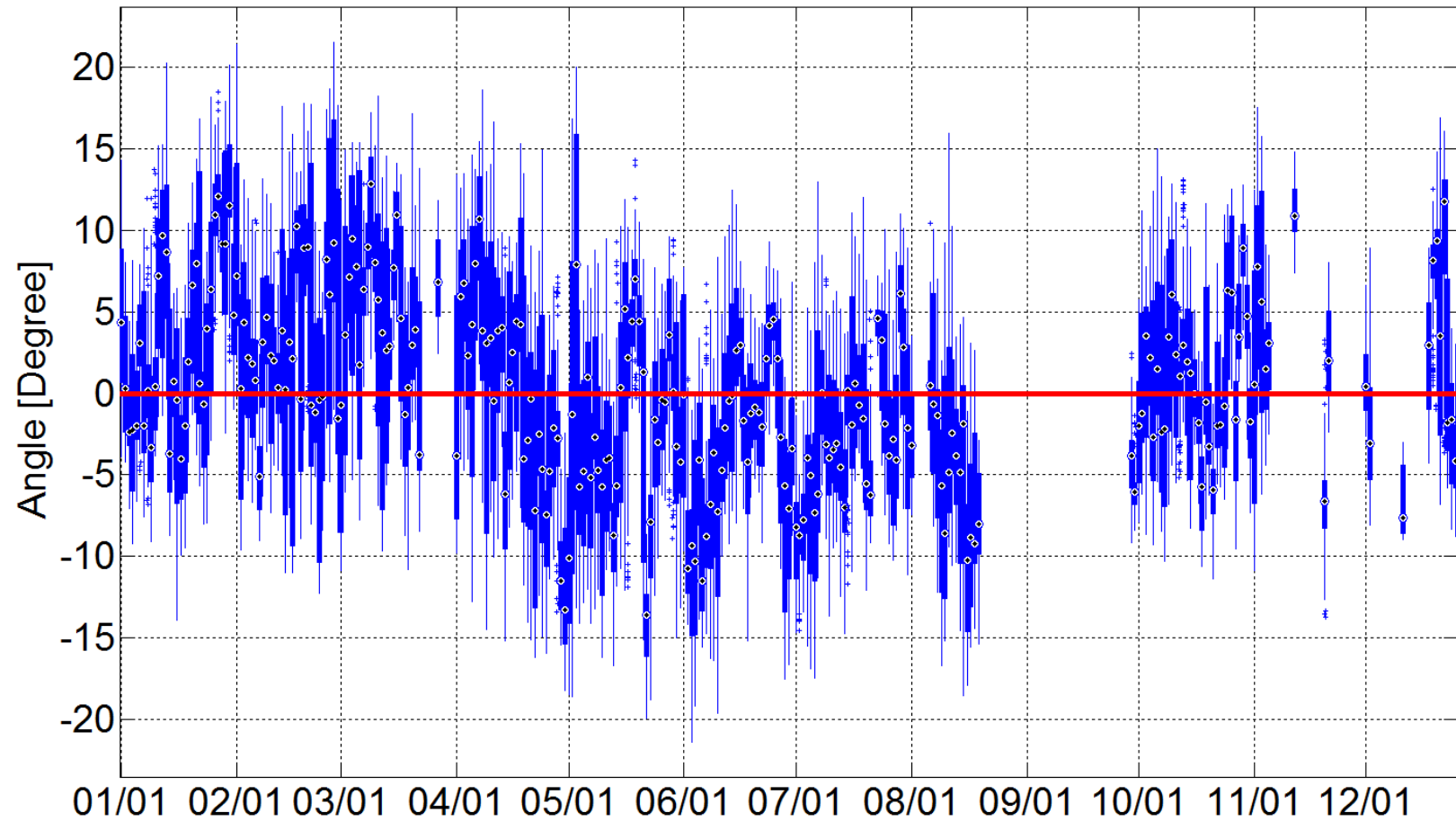
Coast 1-South 10*



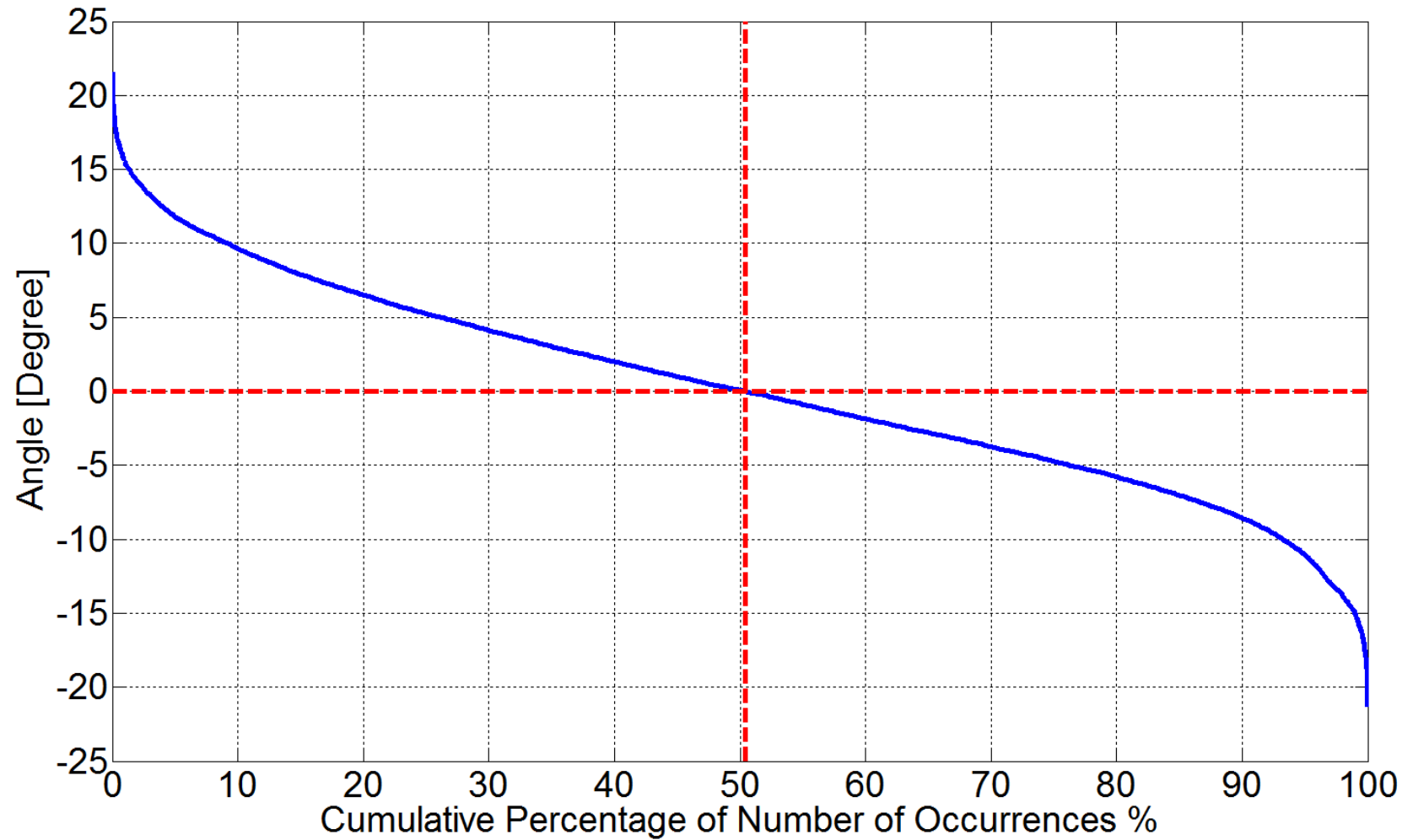
Coast 1-South 10*



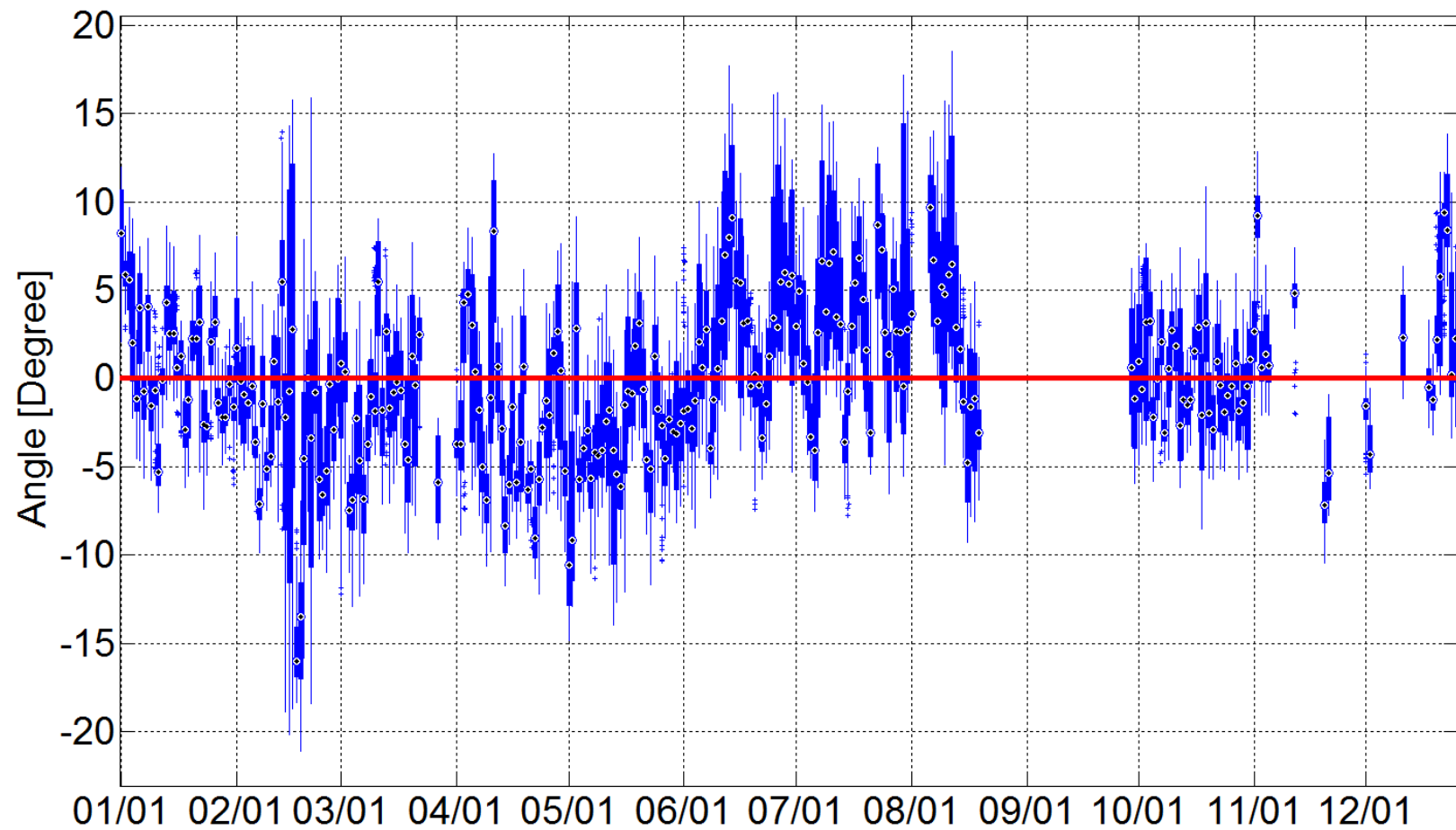
South 3*-South 11*



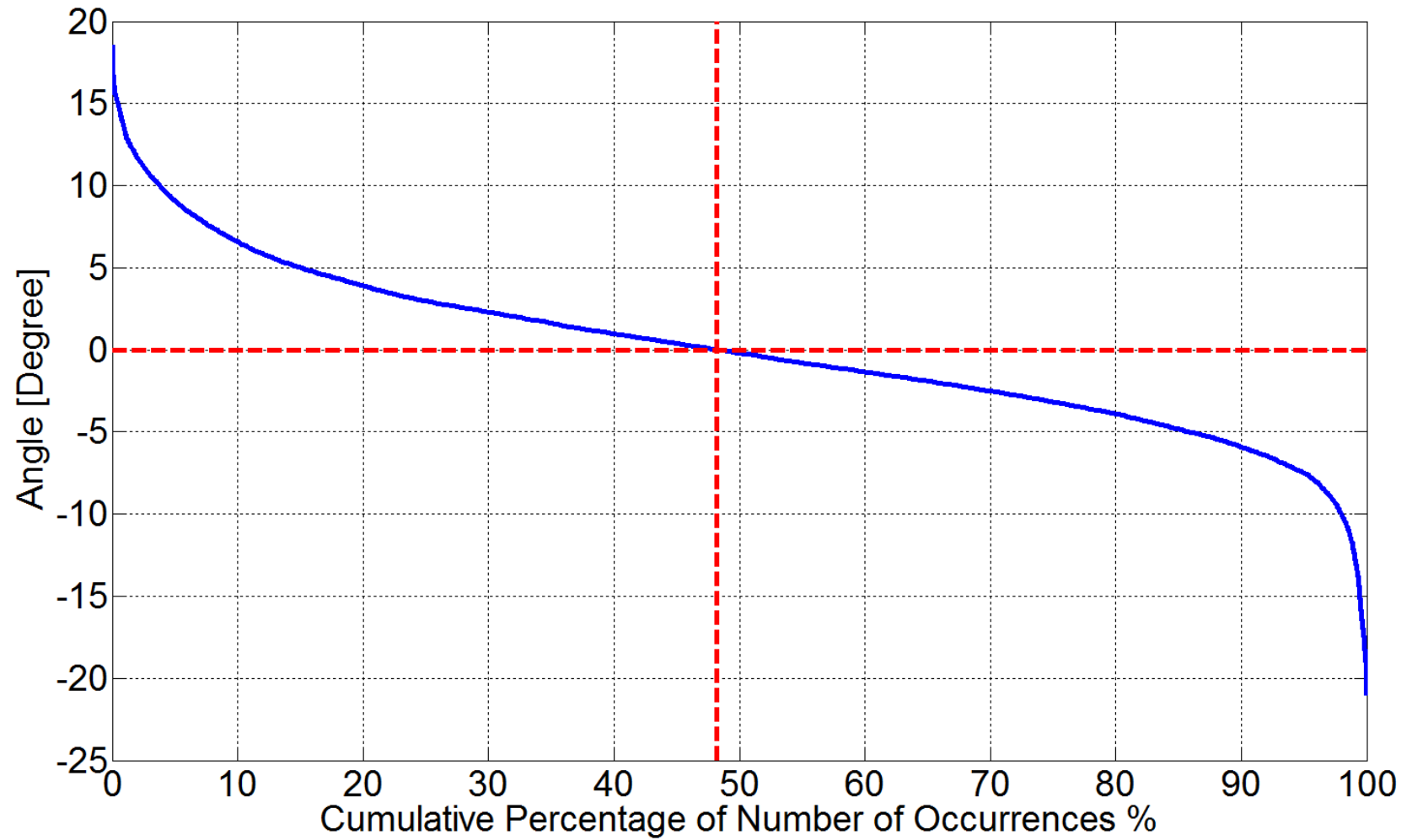
South 3*-South 11*



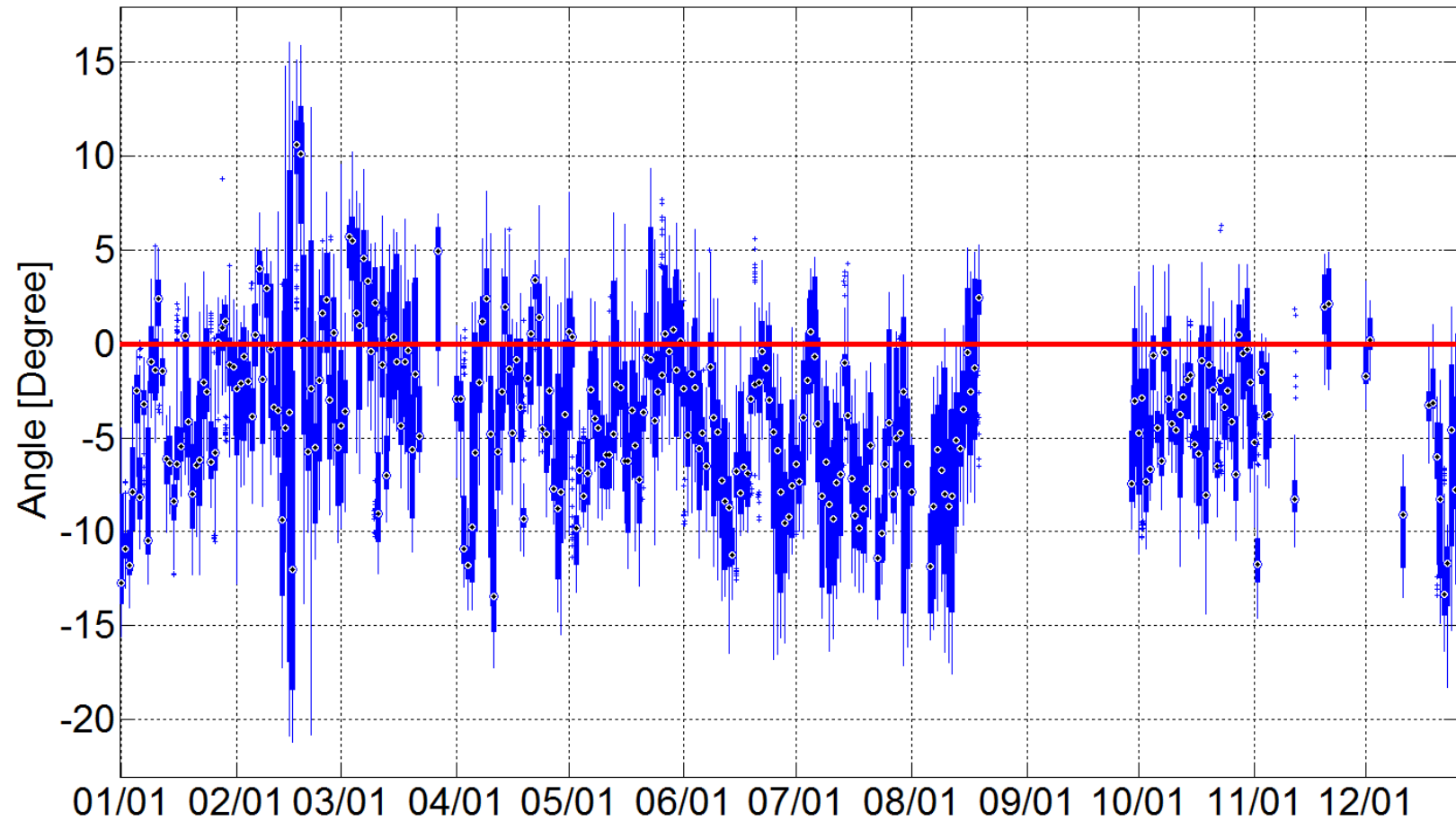
South 11*-North 7



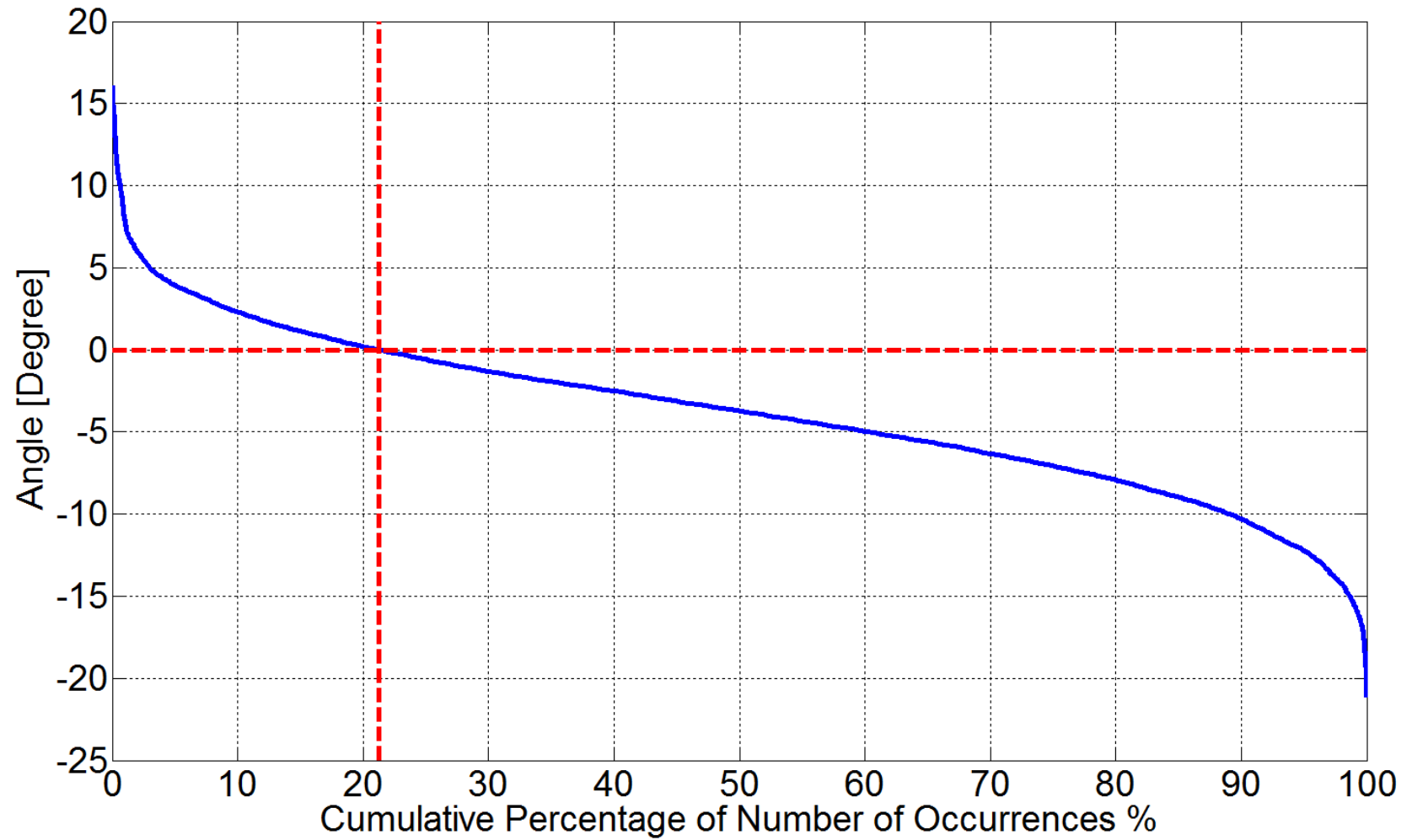
South 11*-North 7



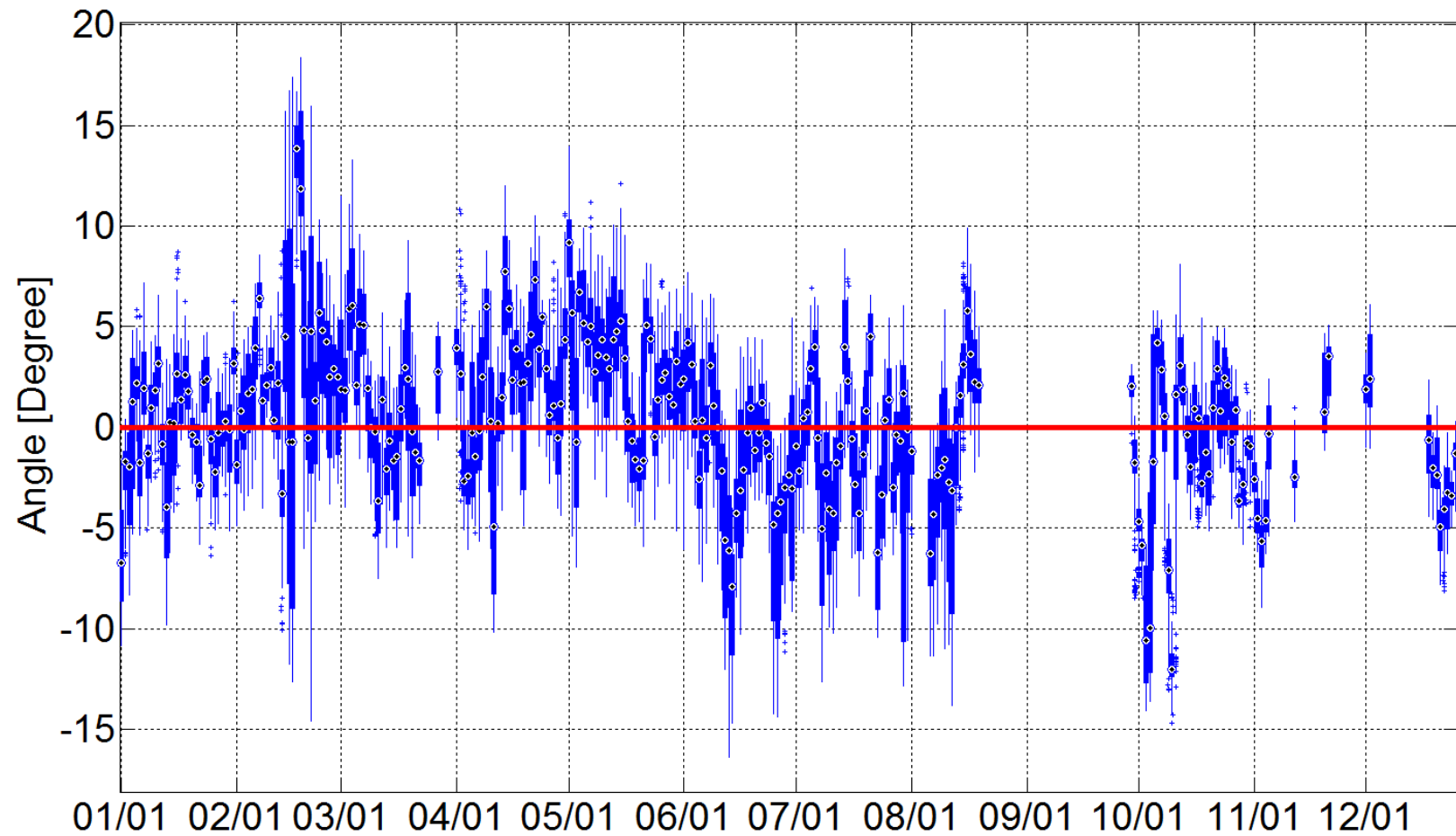
North 7-South 7*



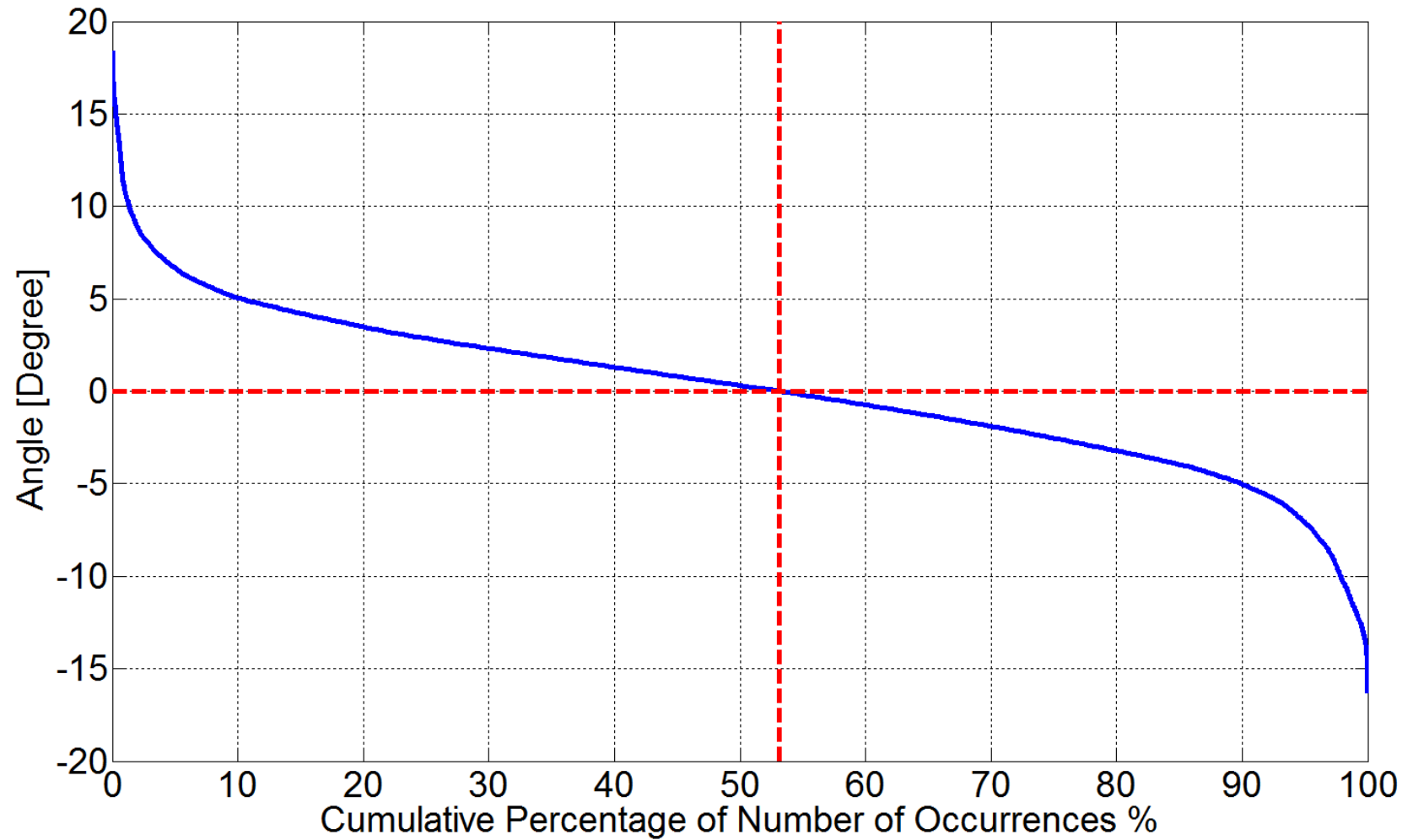
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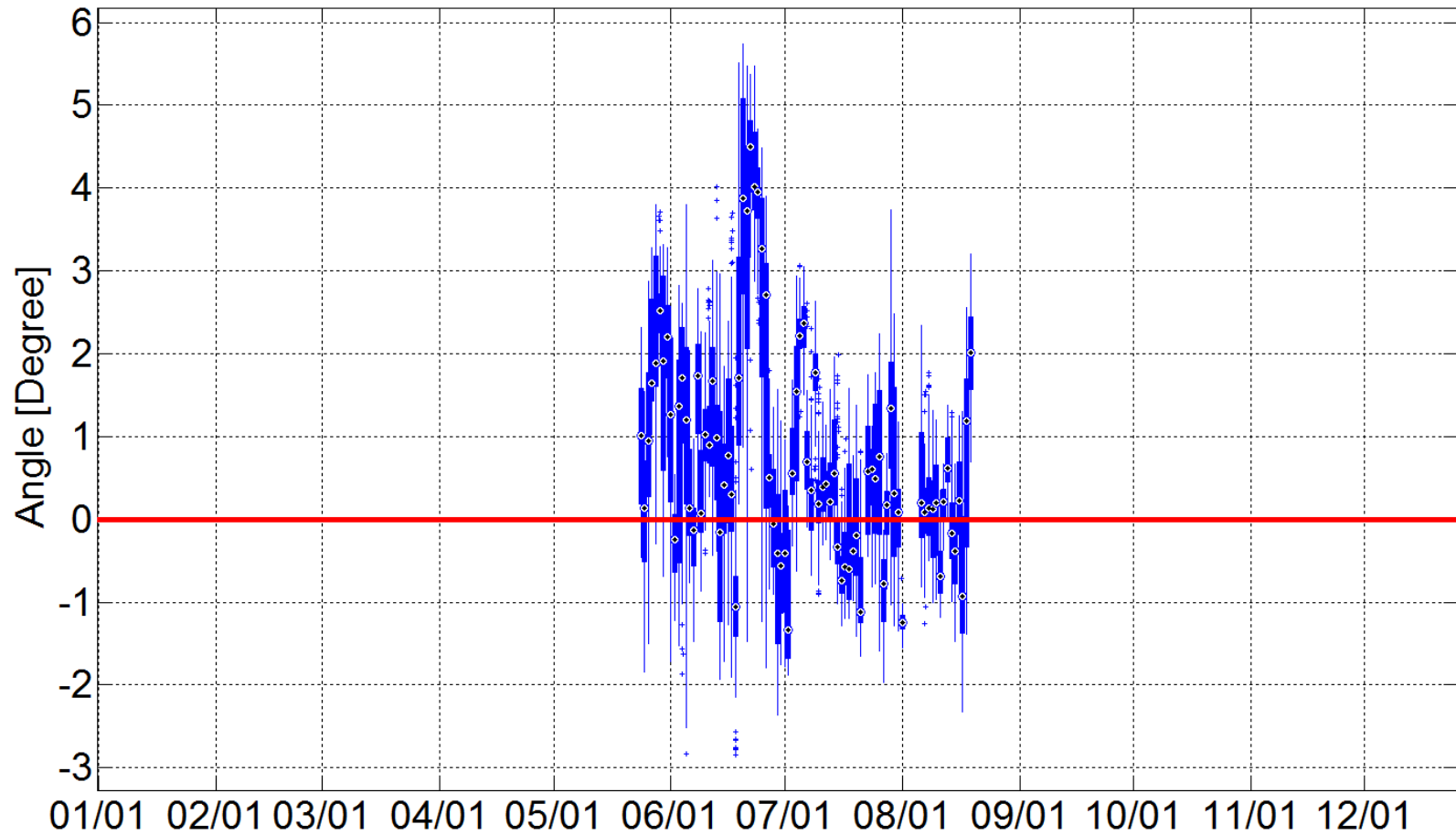
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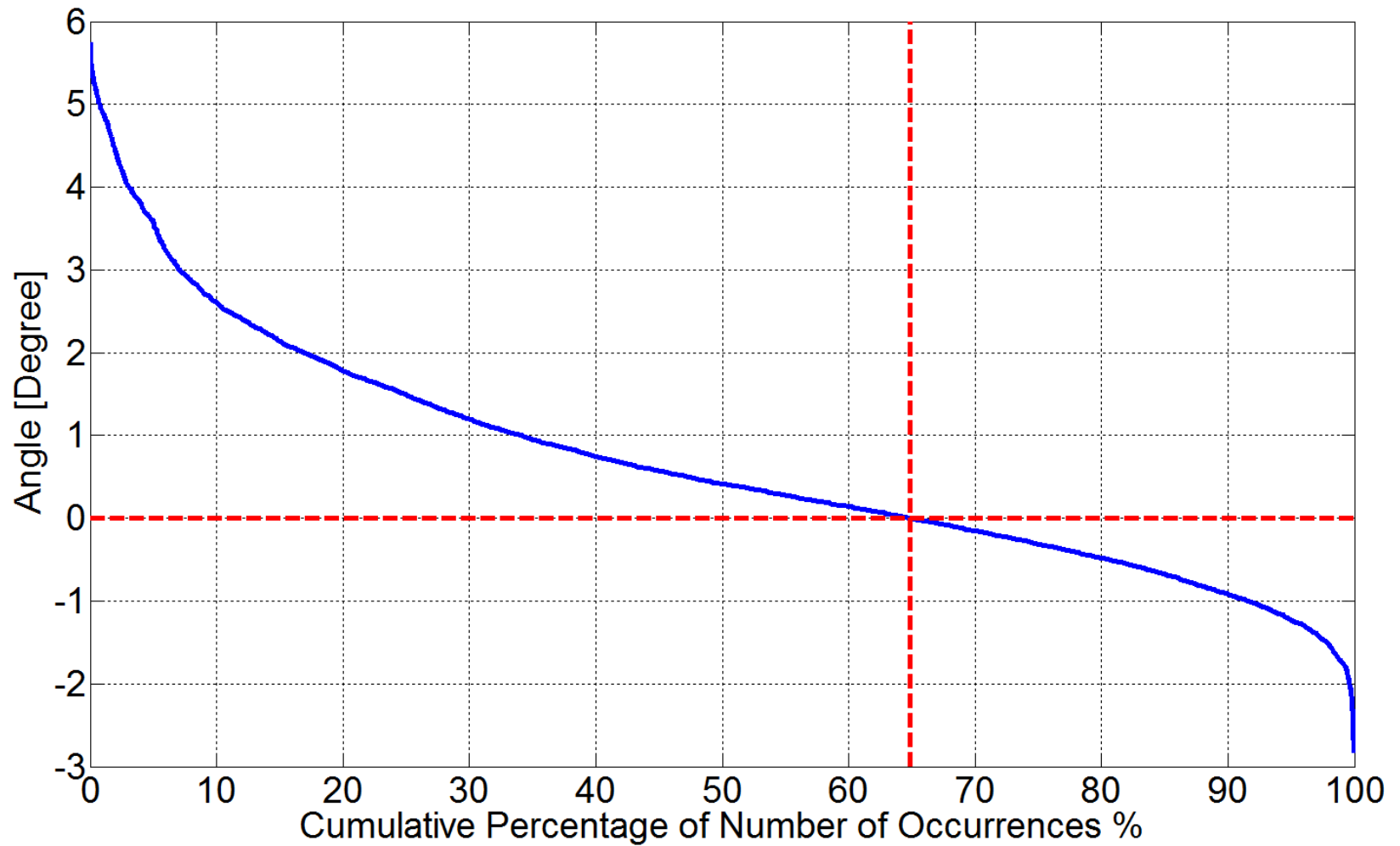
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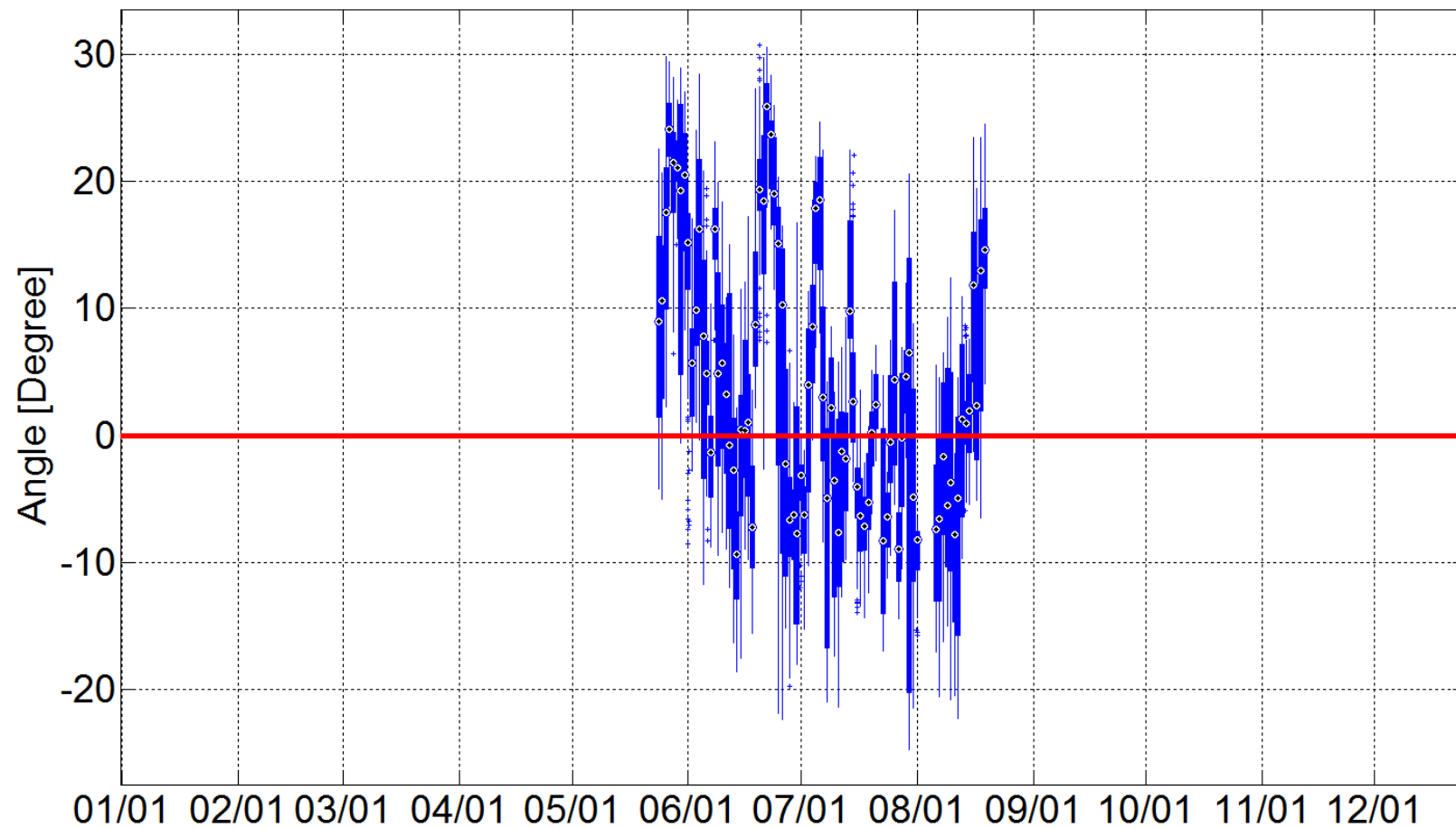
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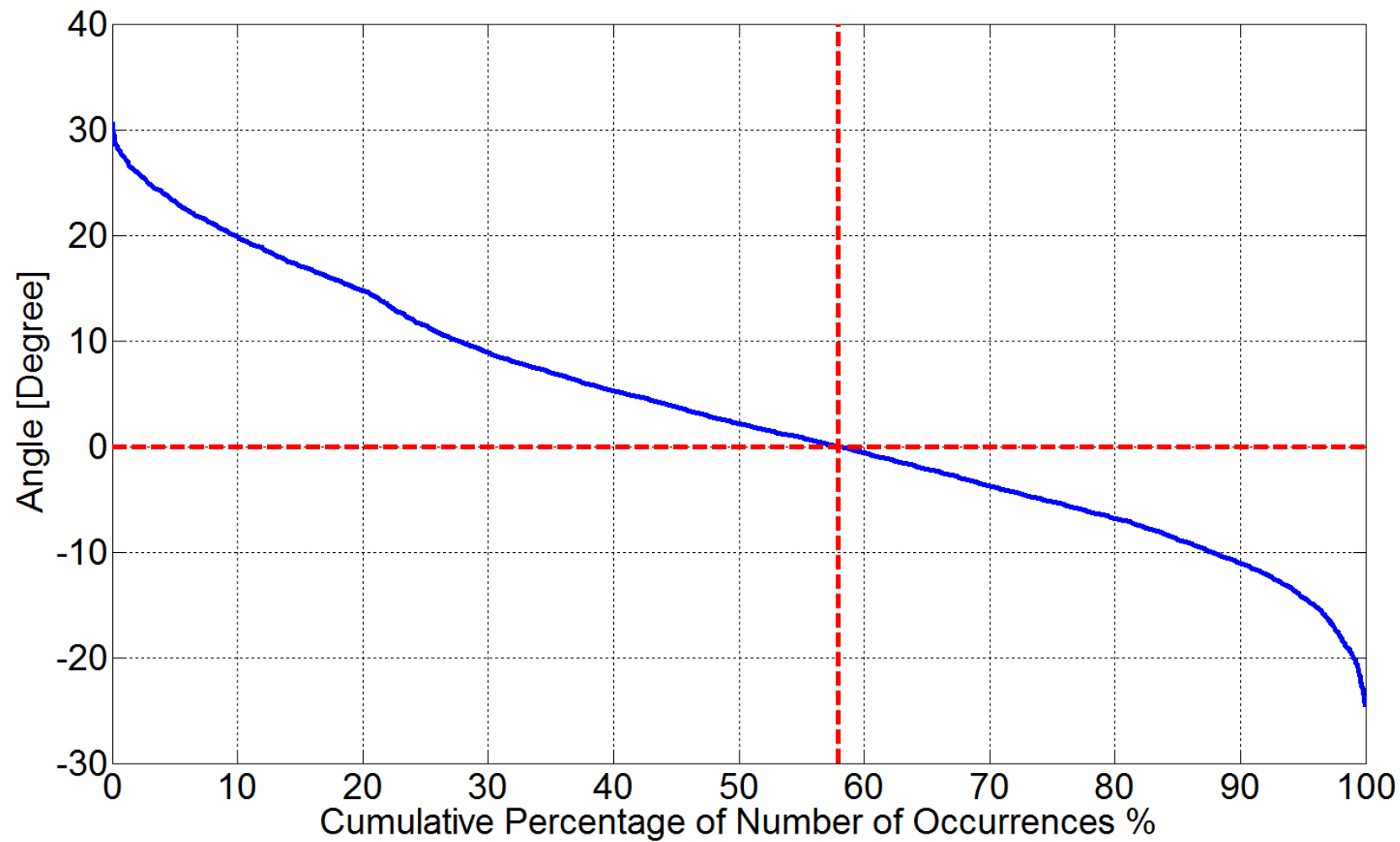
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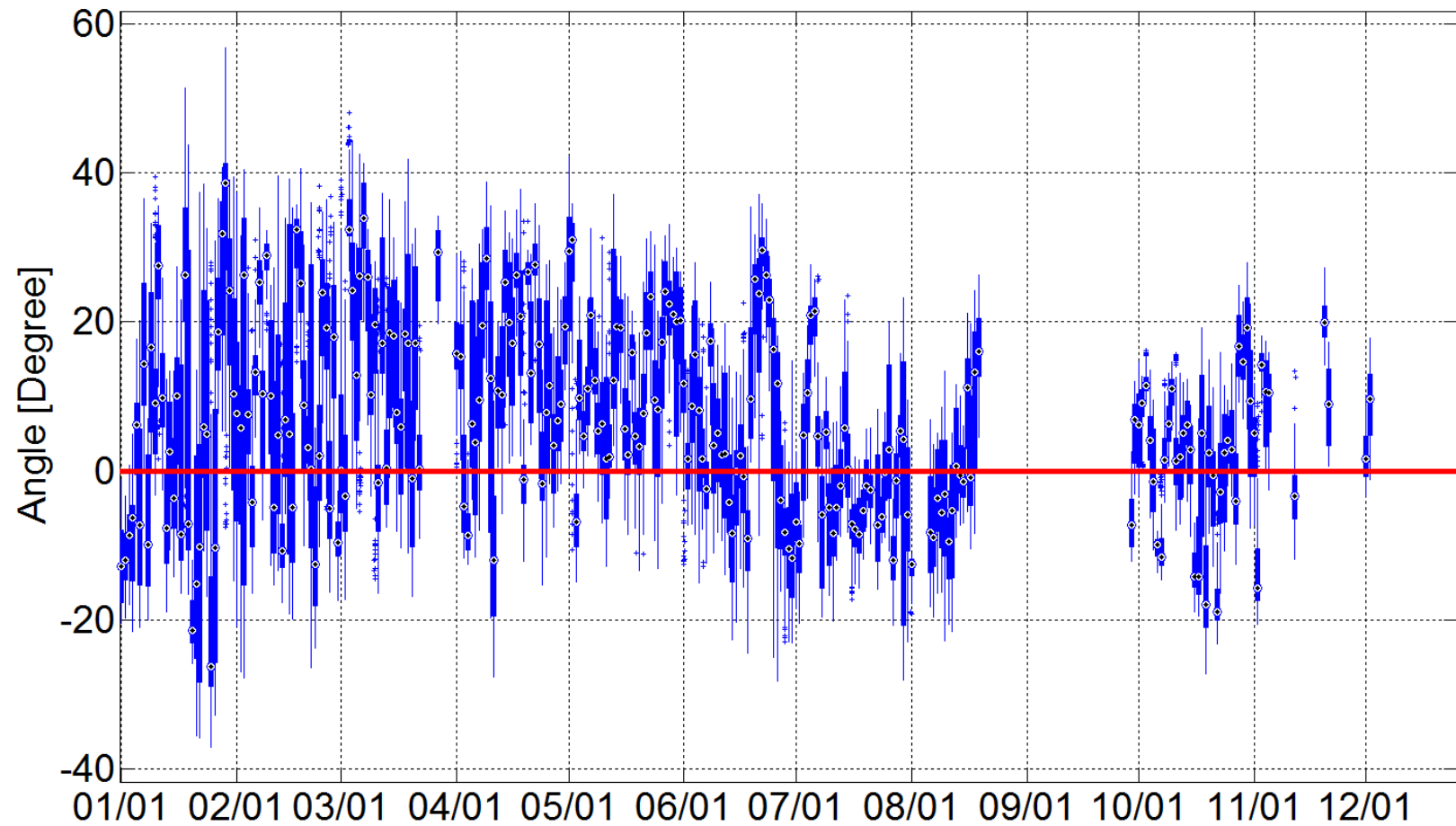
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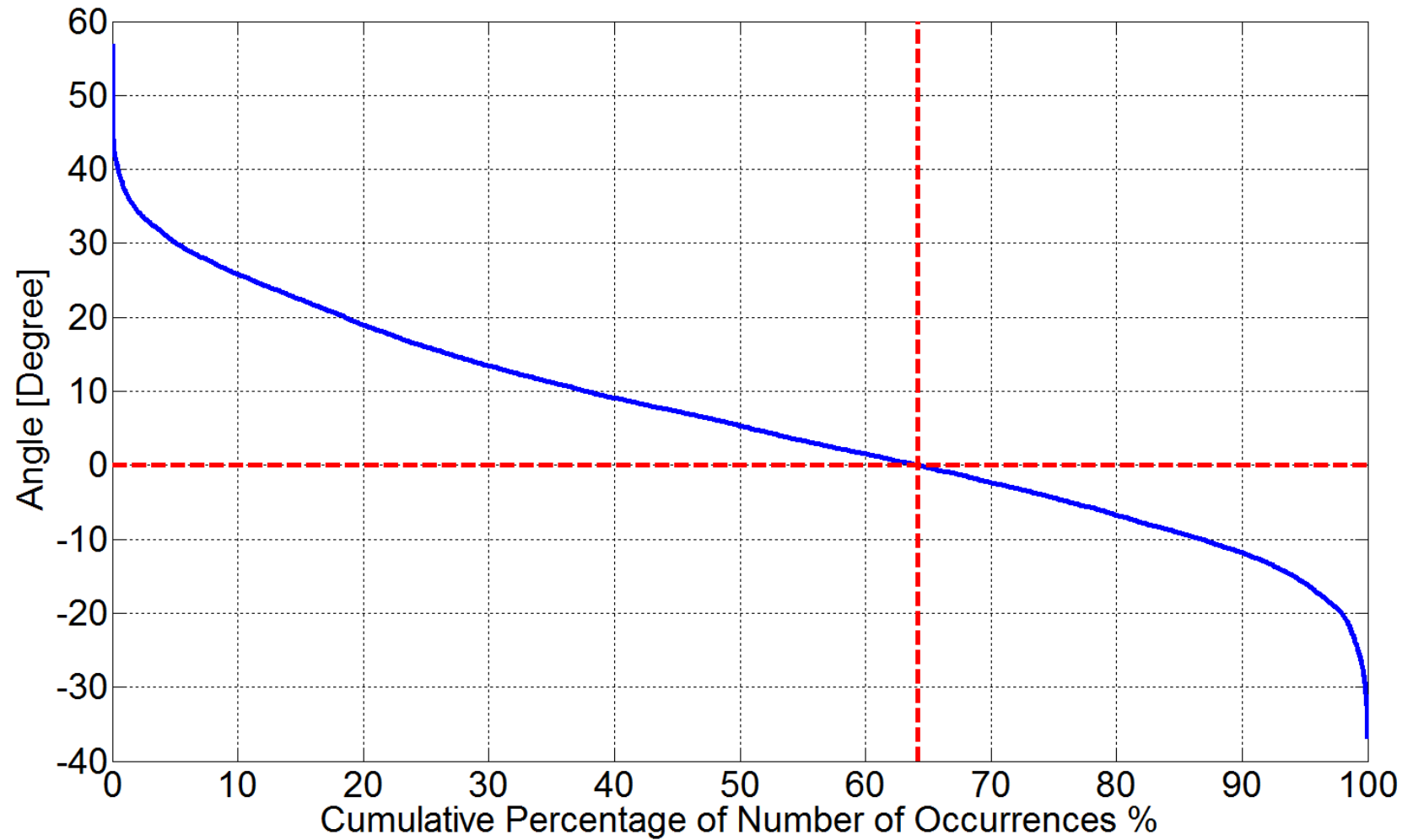
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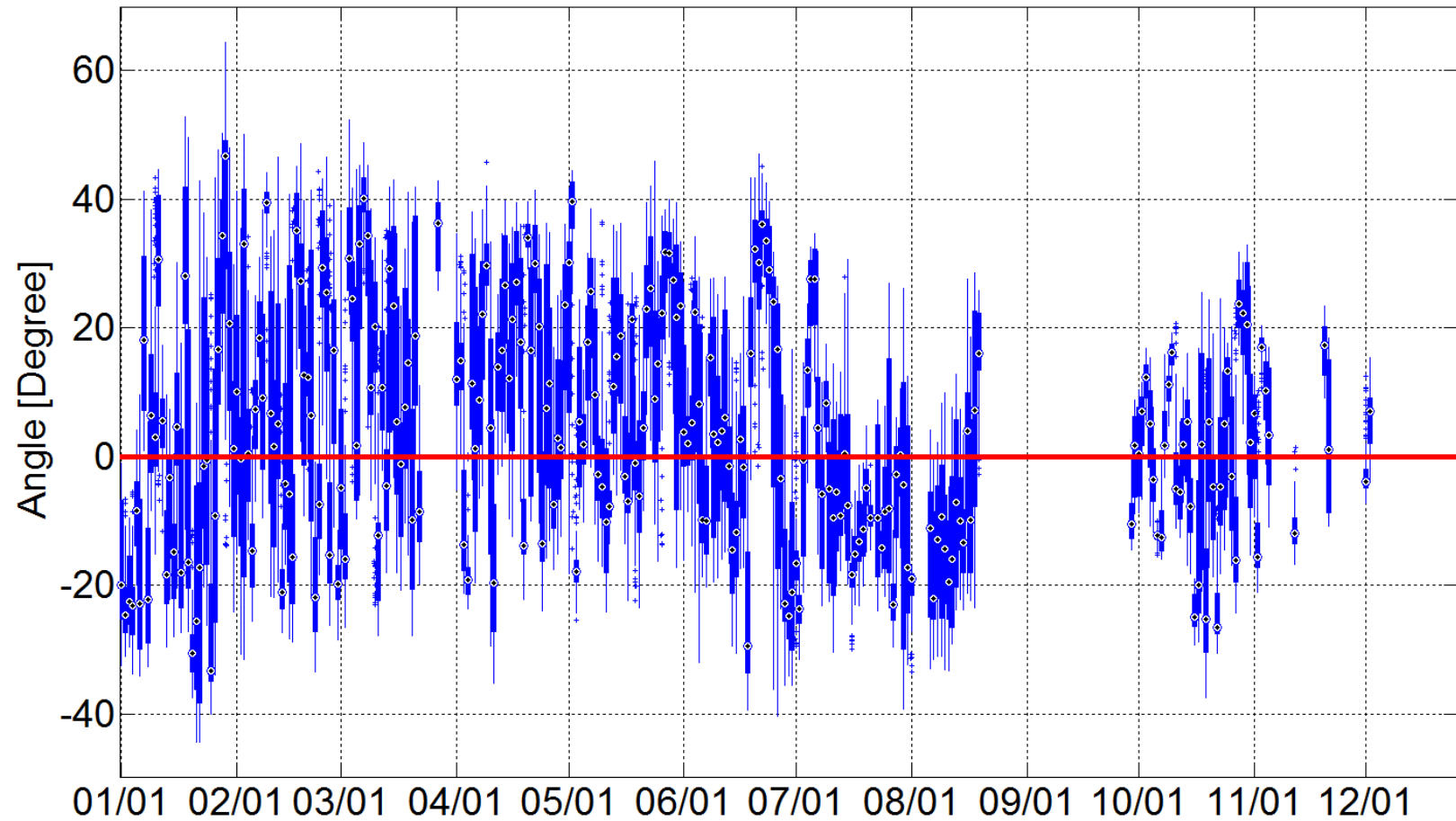
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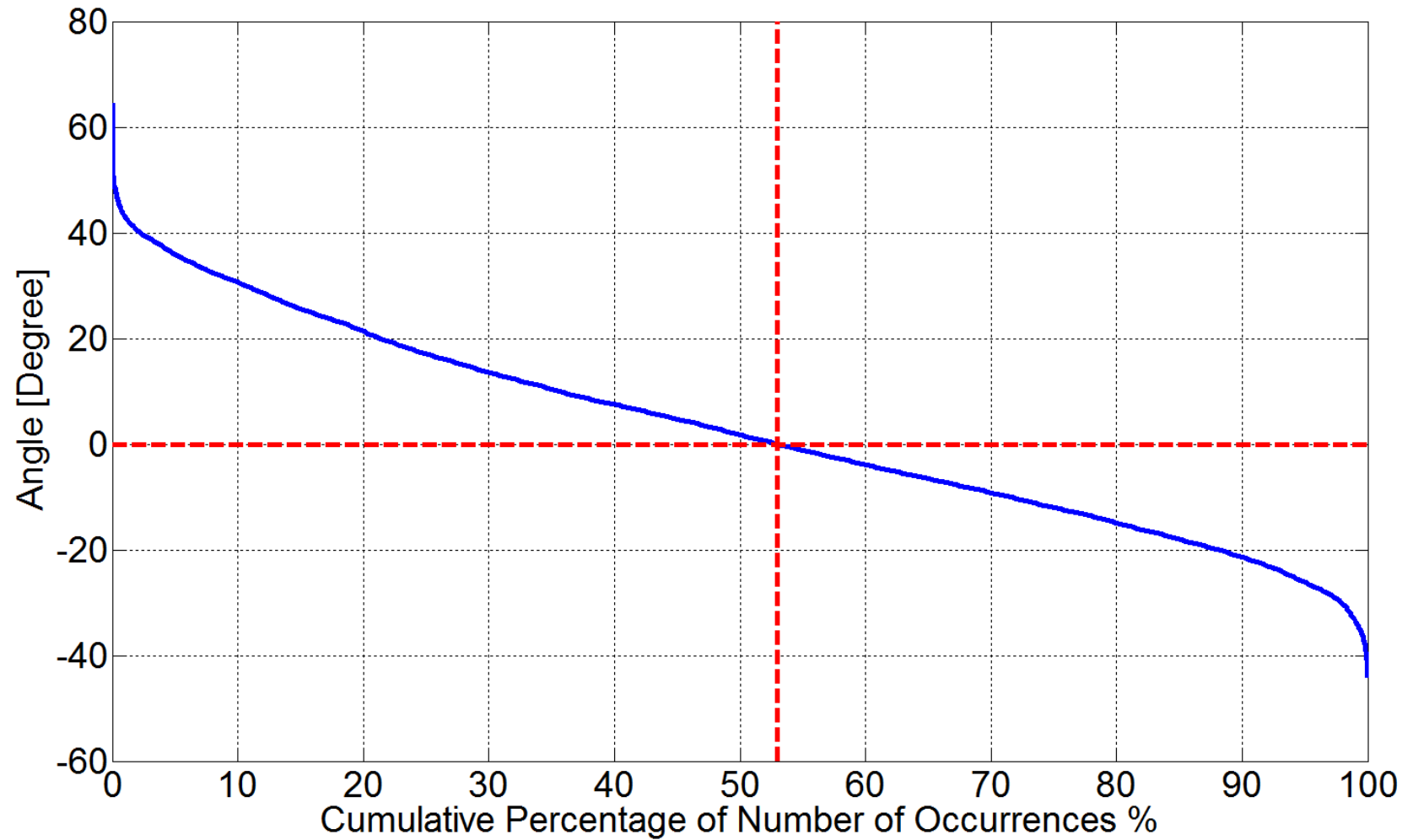
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FarWest 9-South 9*



FarWest 9-South 9*



Appendix C – Part 2

CCET Discovery Across Texas project

Baseline Analysis Update – Angle Differences

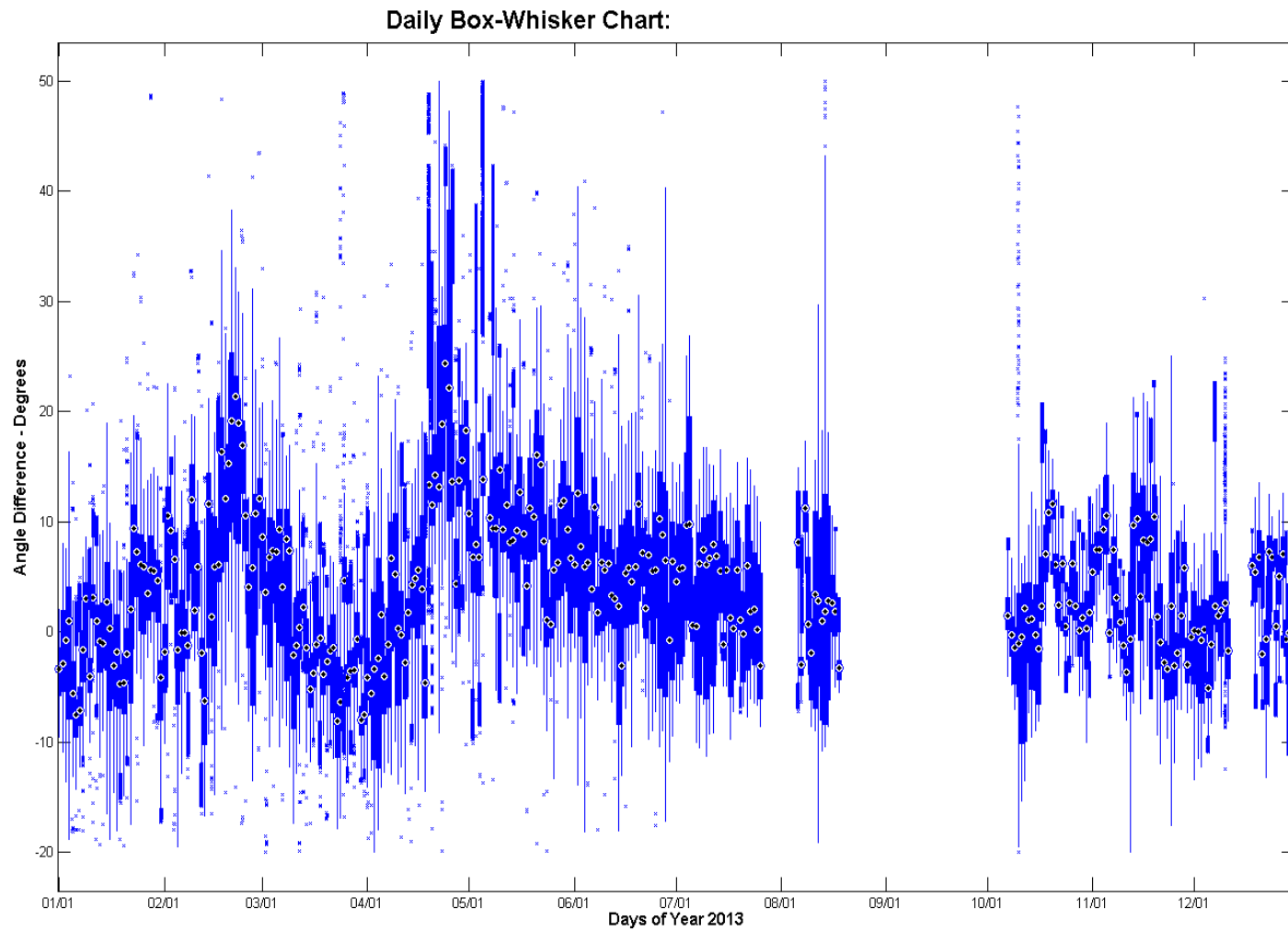
Phasor Data: January to December 2013
Box Whiskers Plots and Time Duration Curves



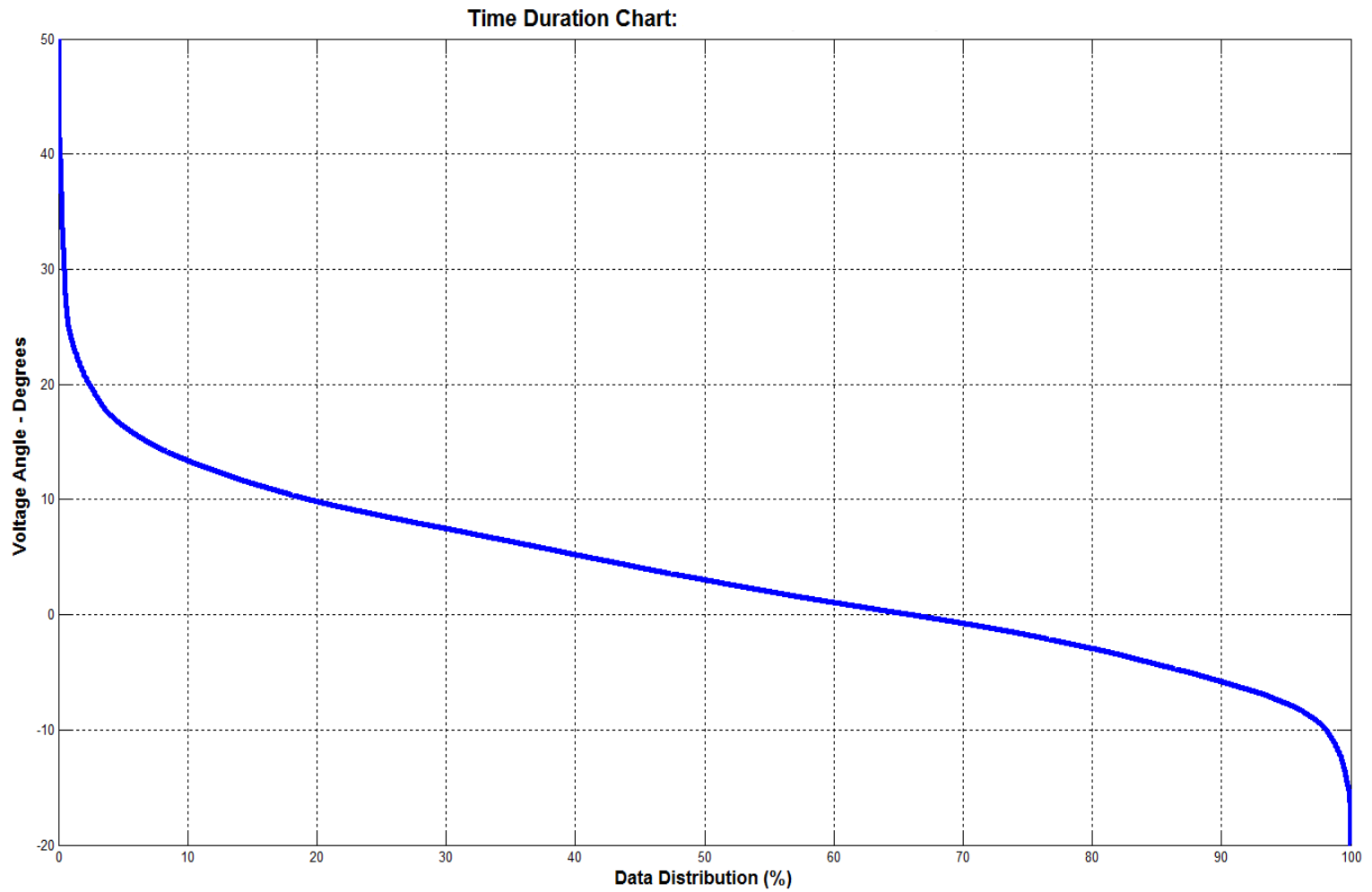
Electric Power Group



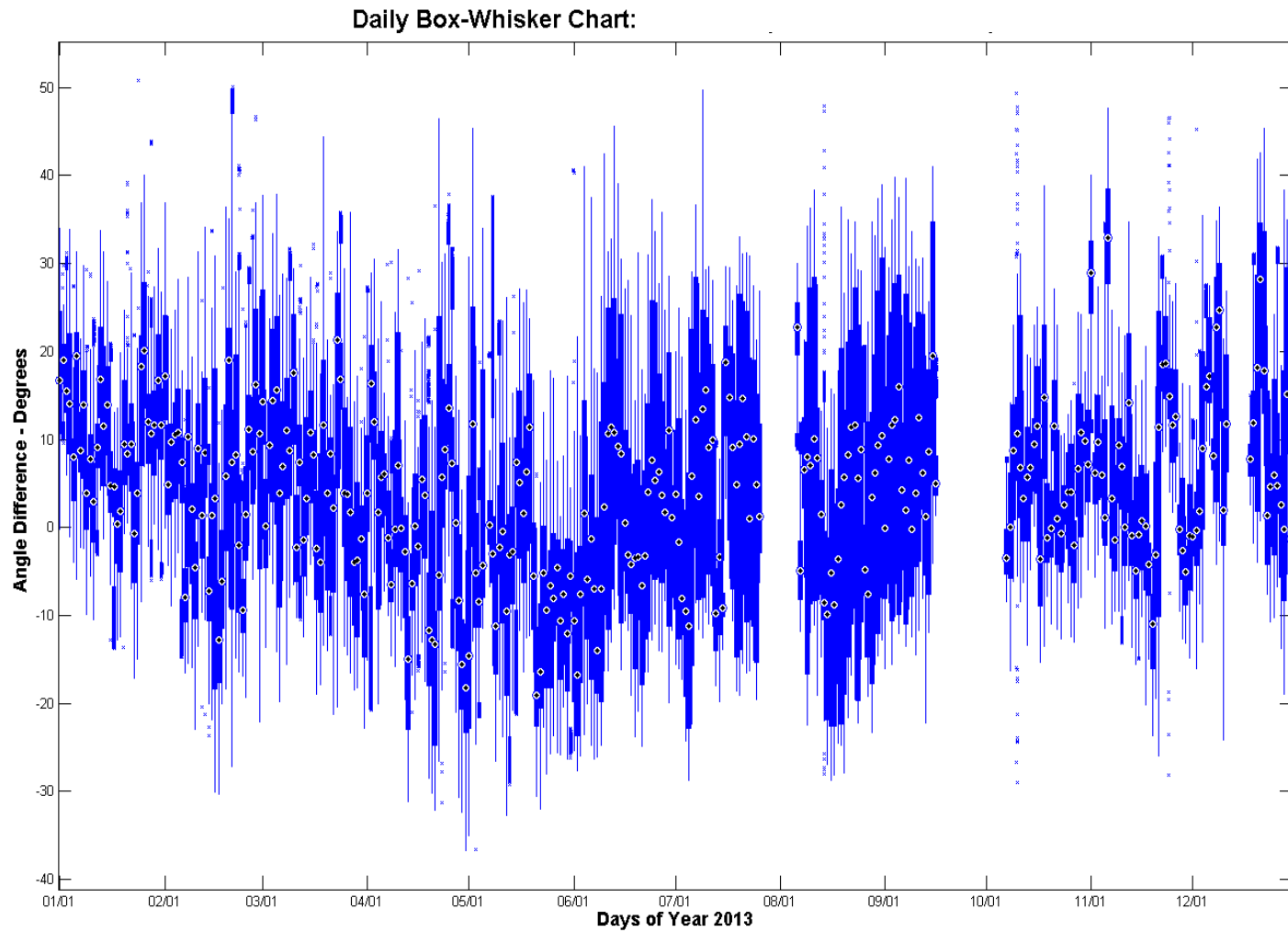
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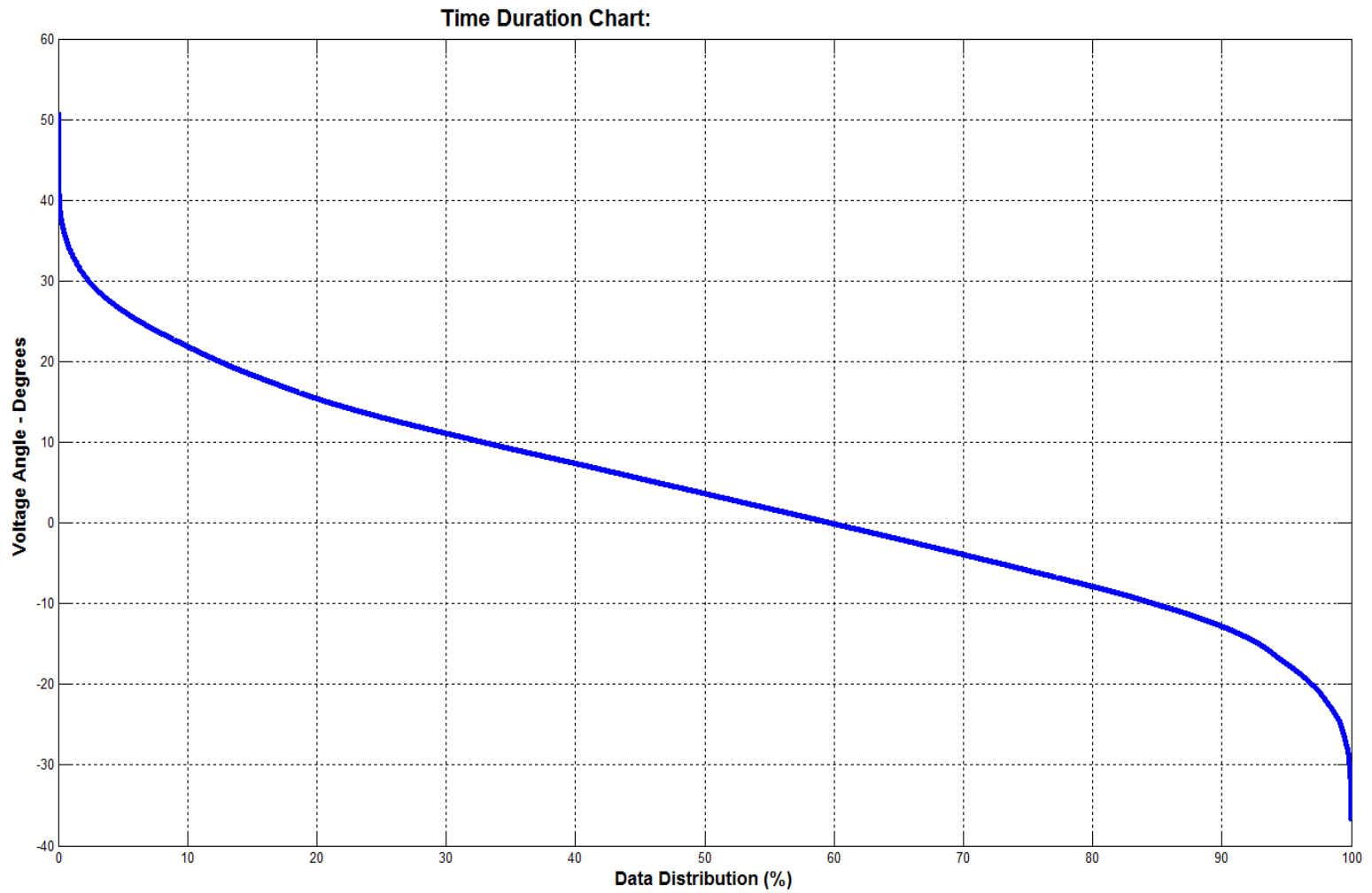
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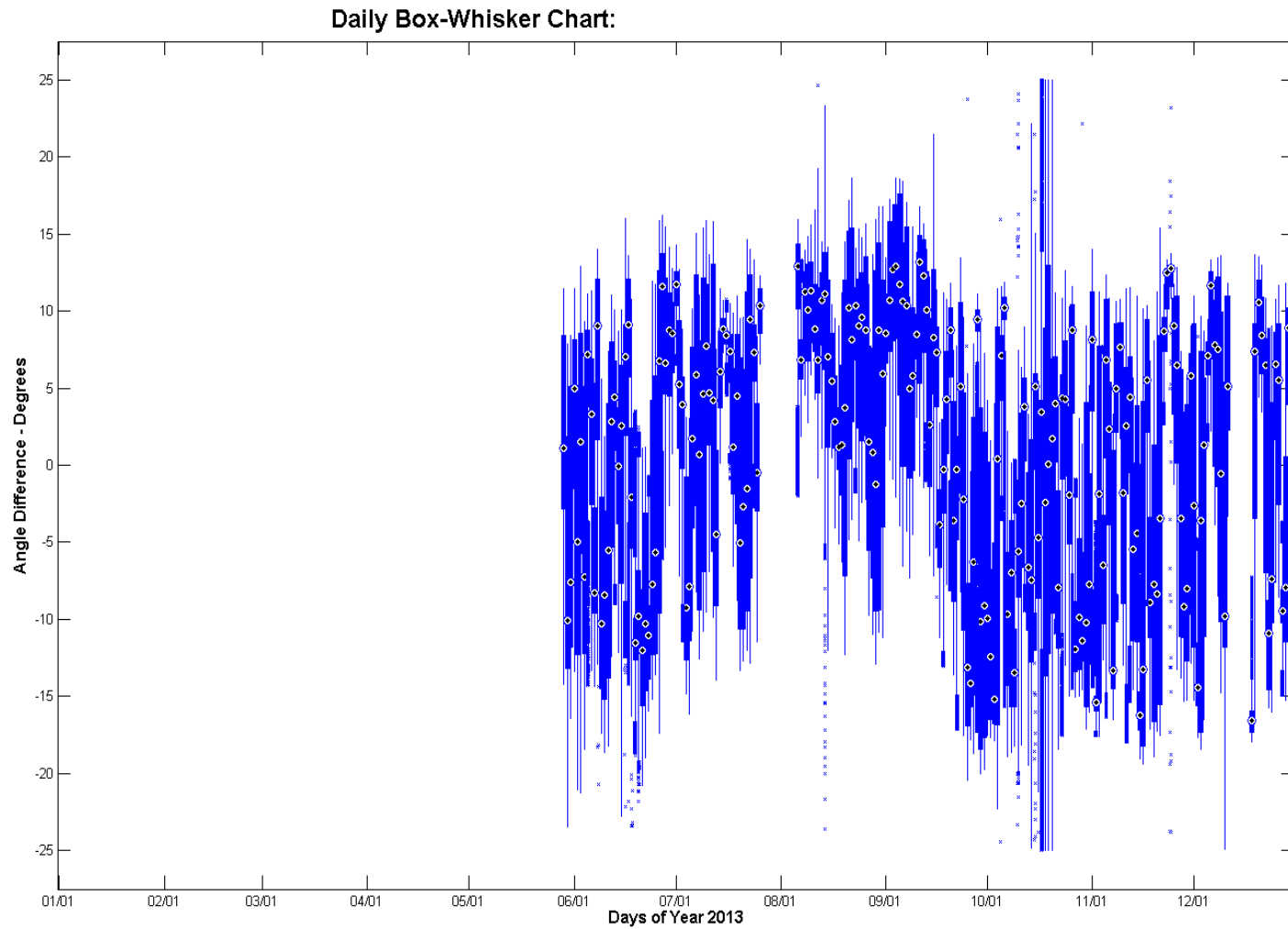
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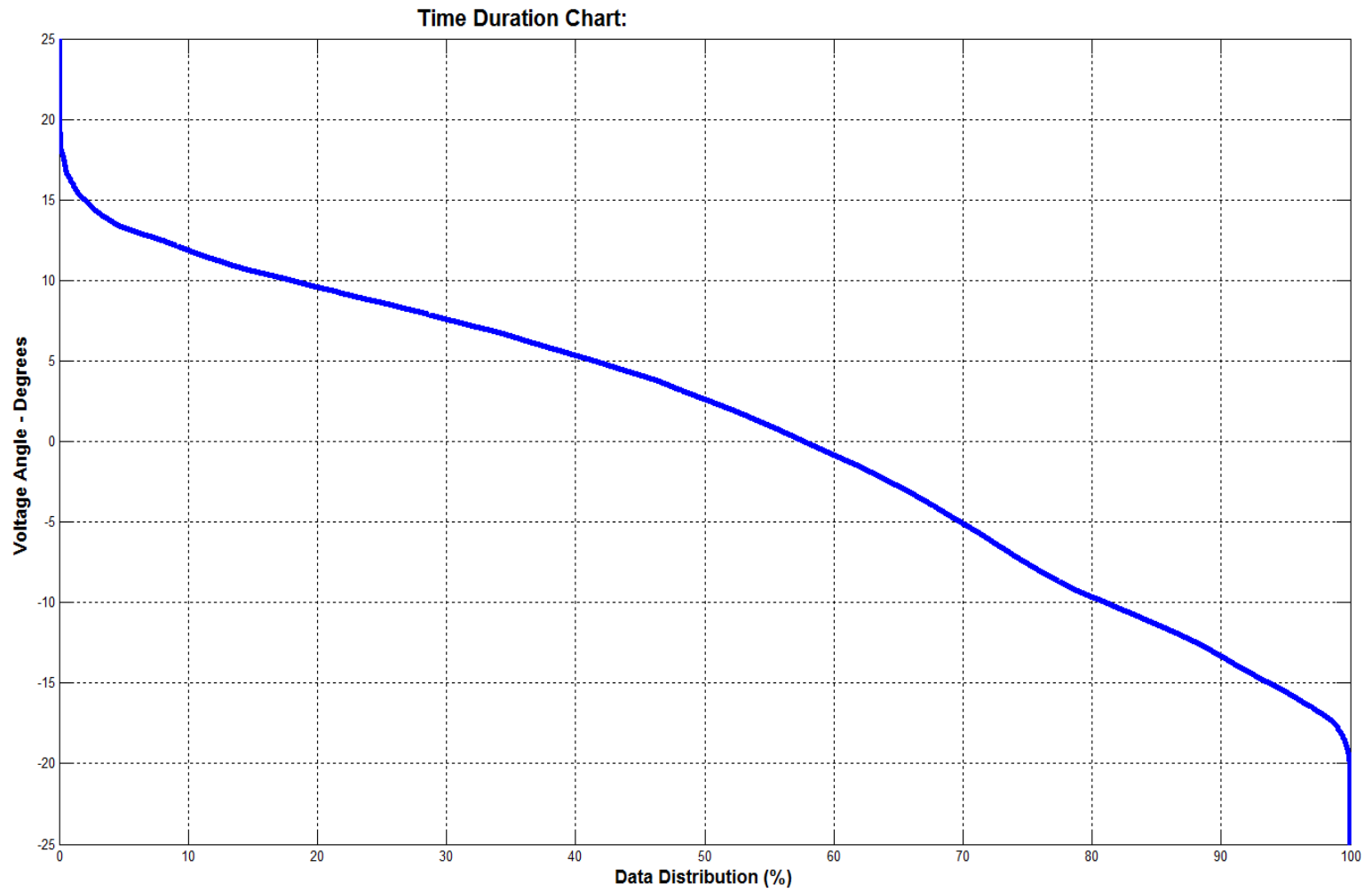
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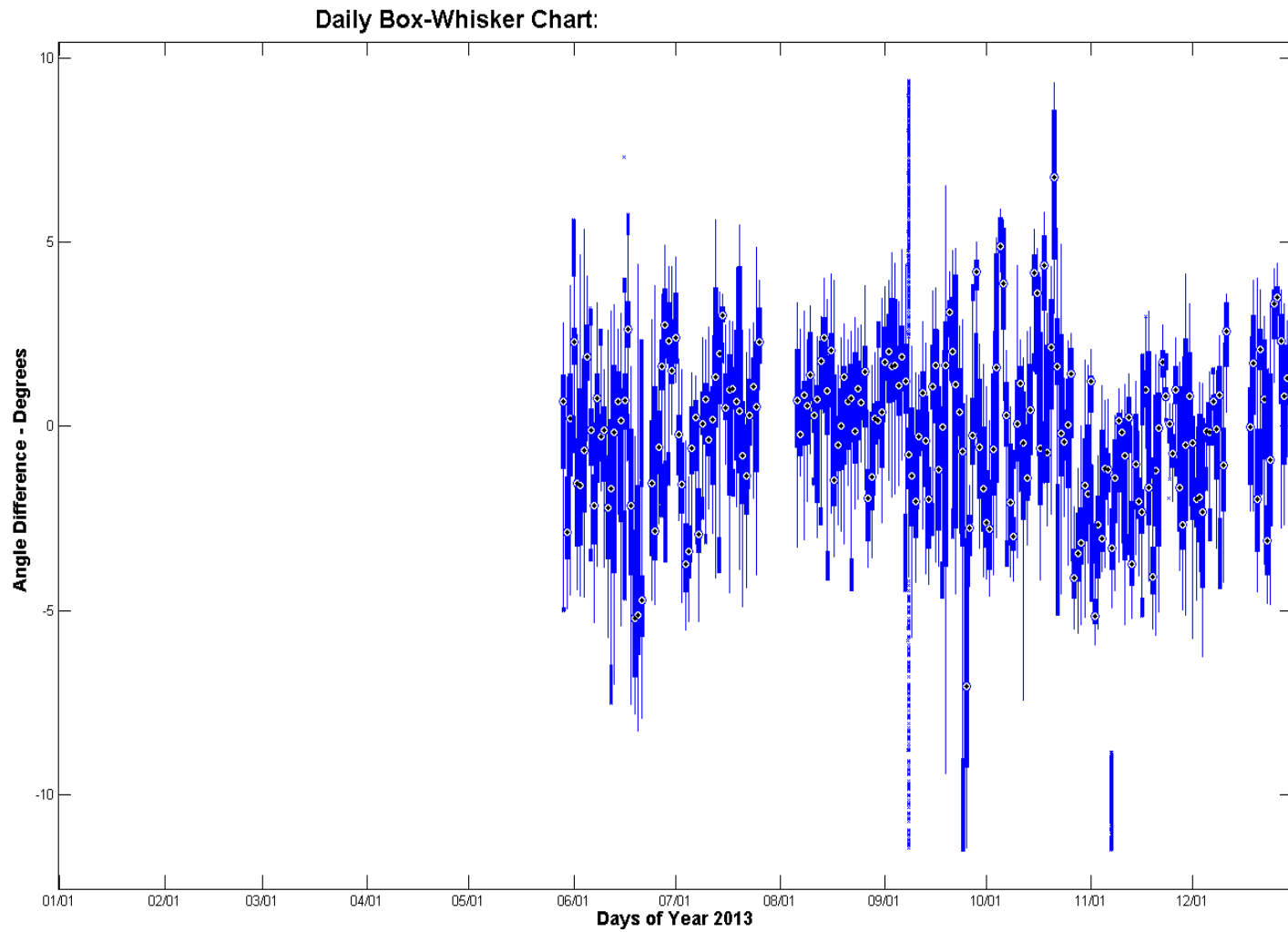
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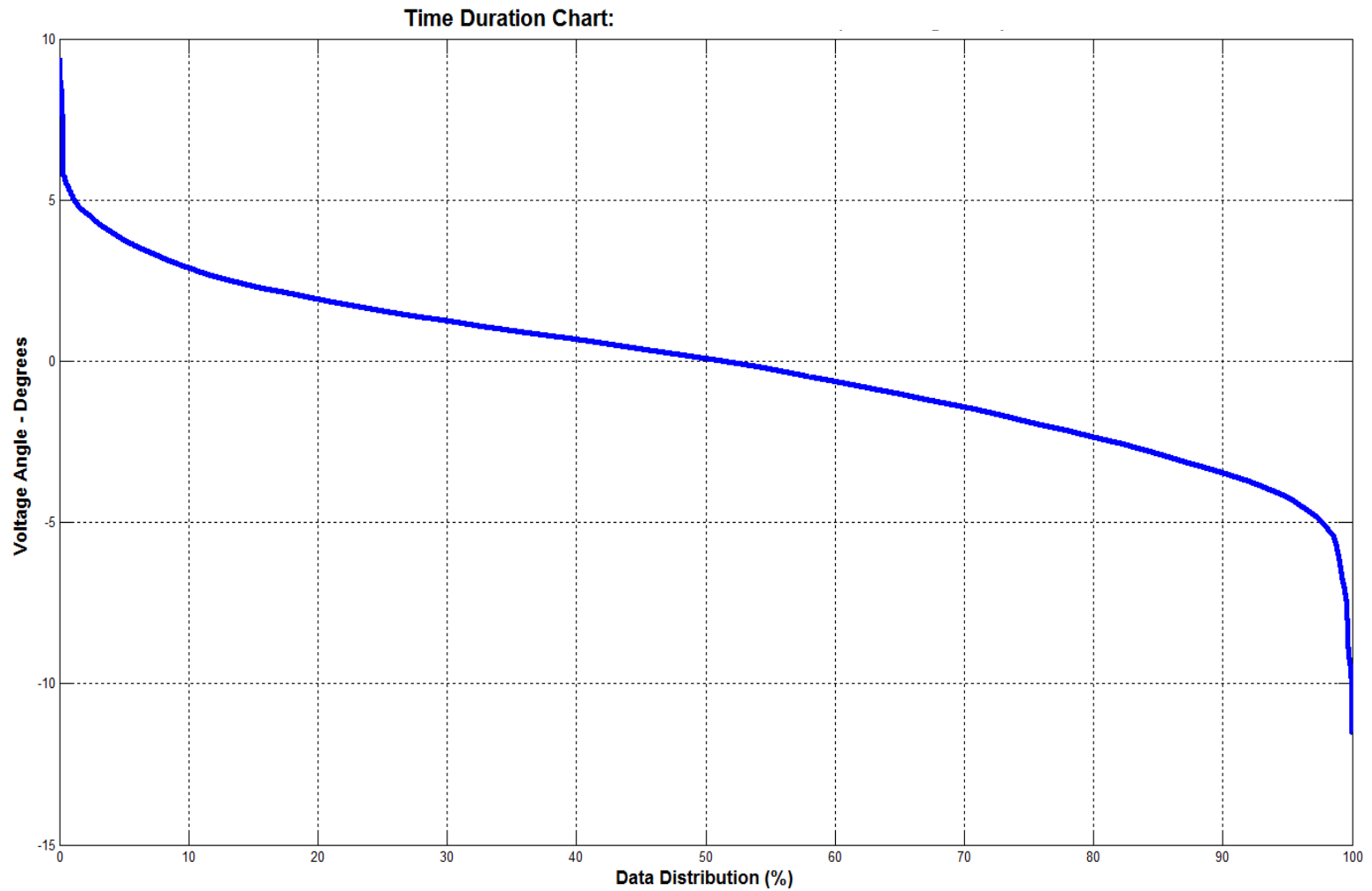
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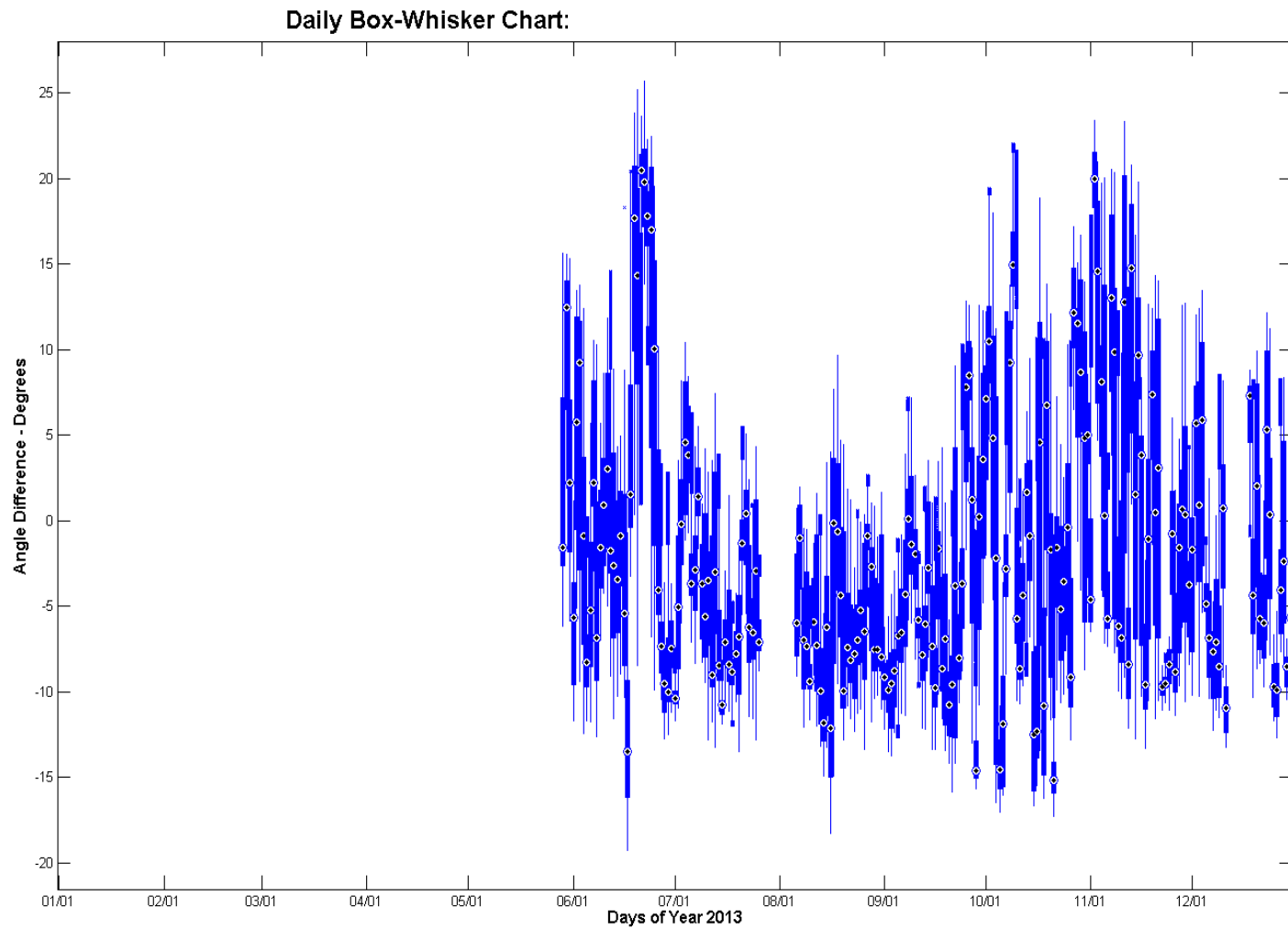
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West 5-FarWest 4

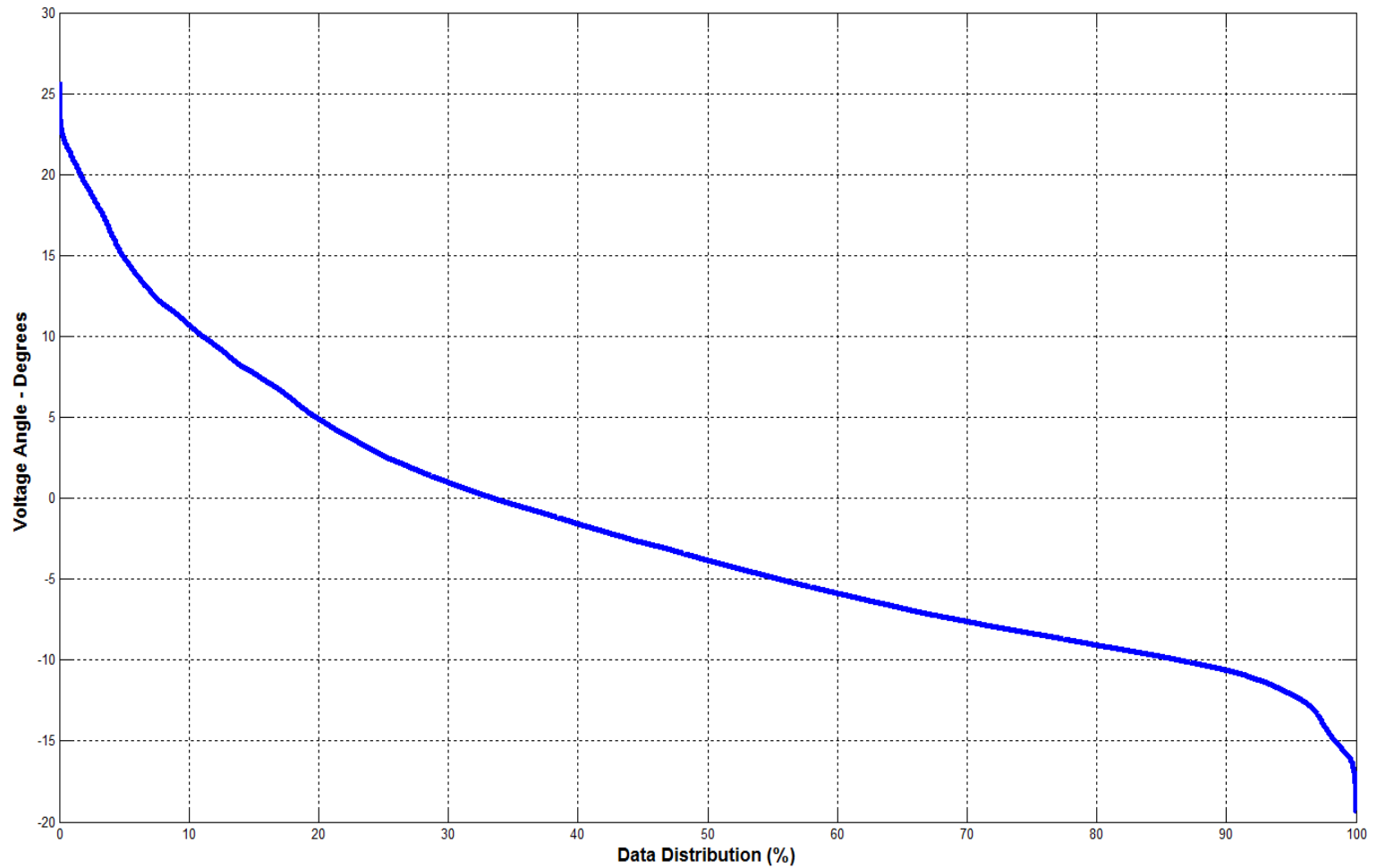


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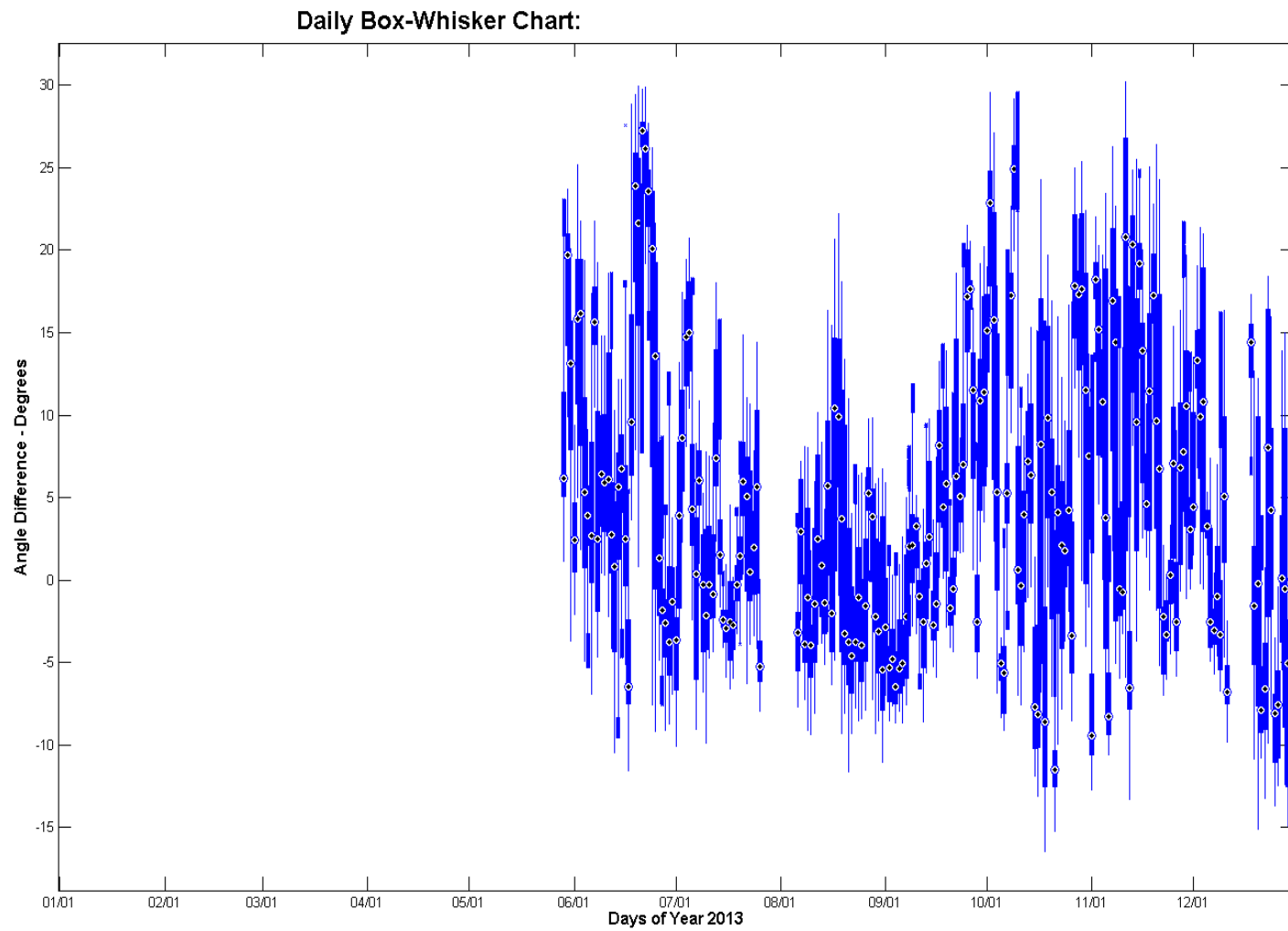


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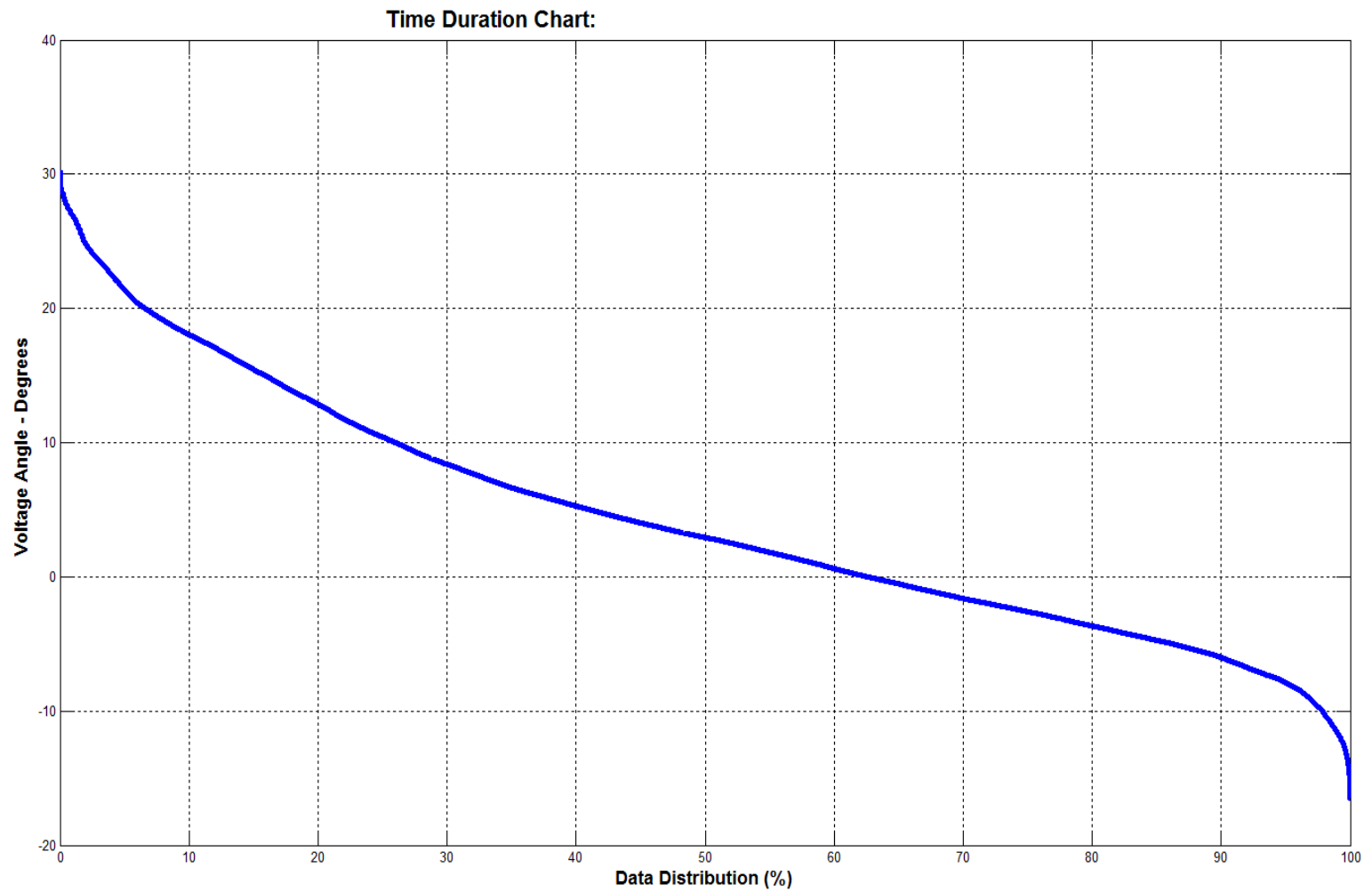
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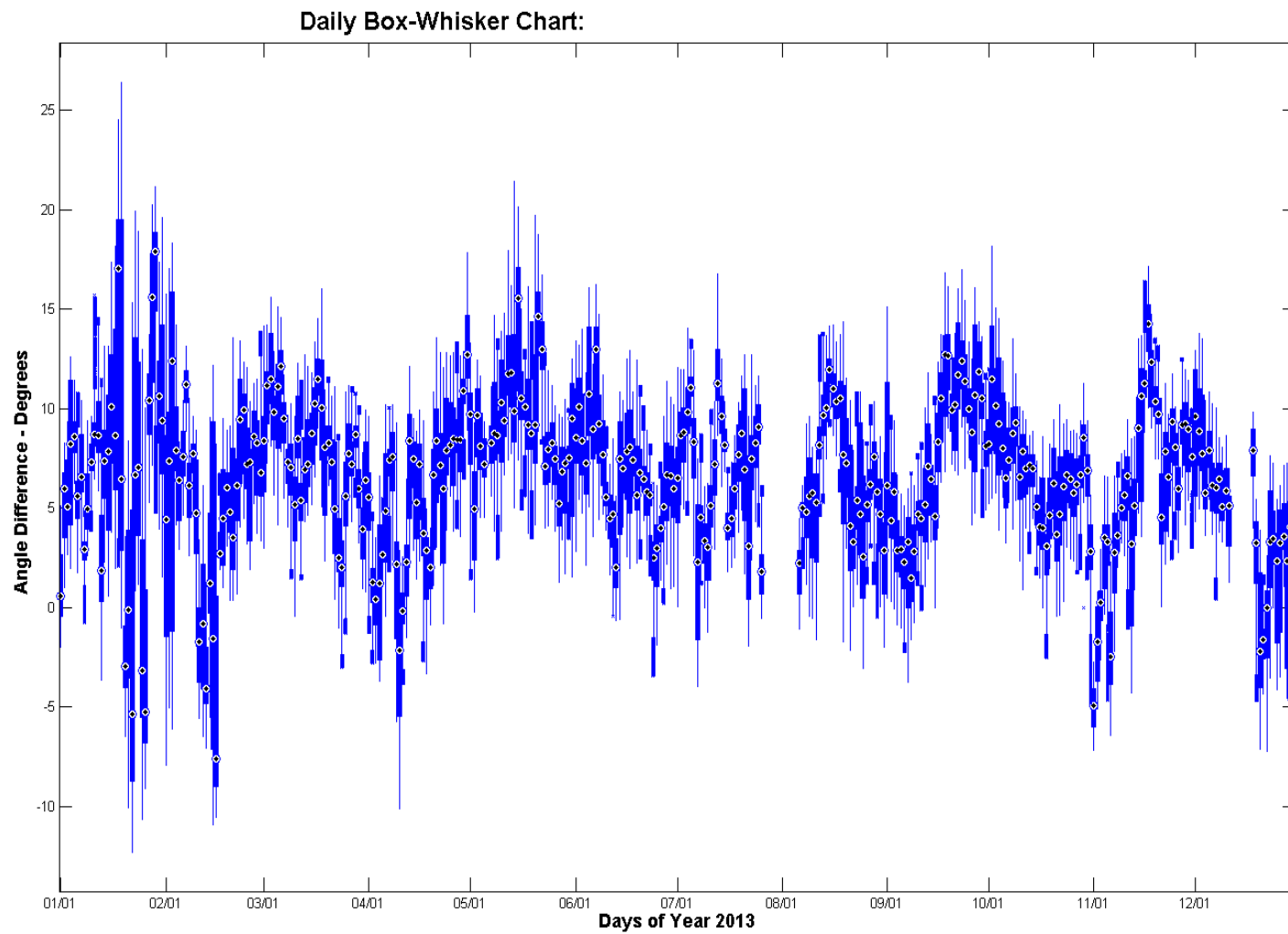
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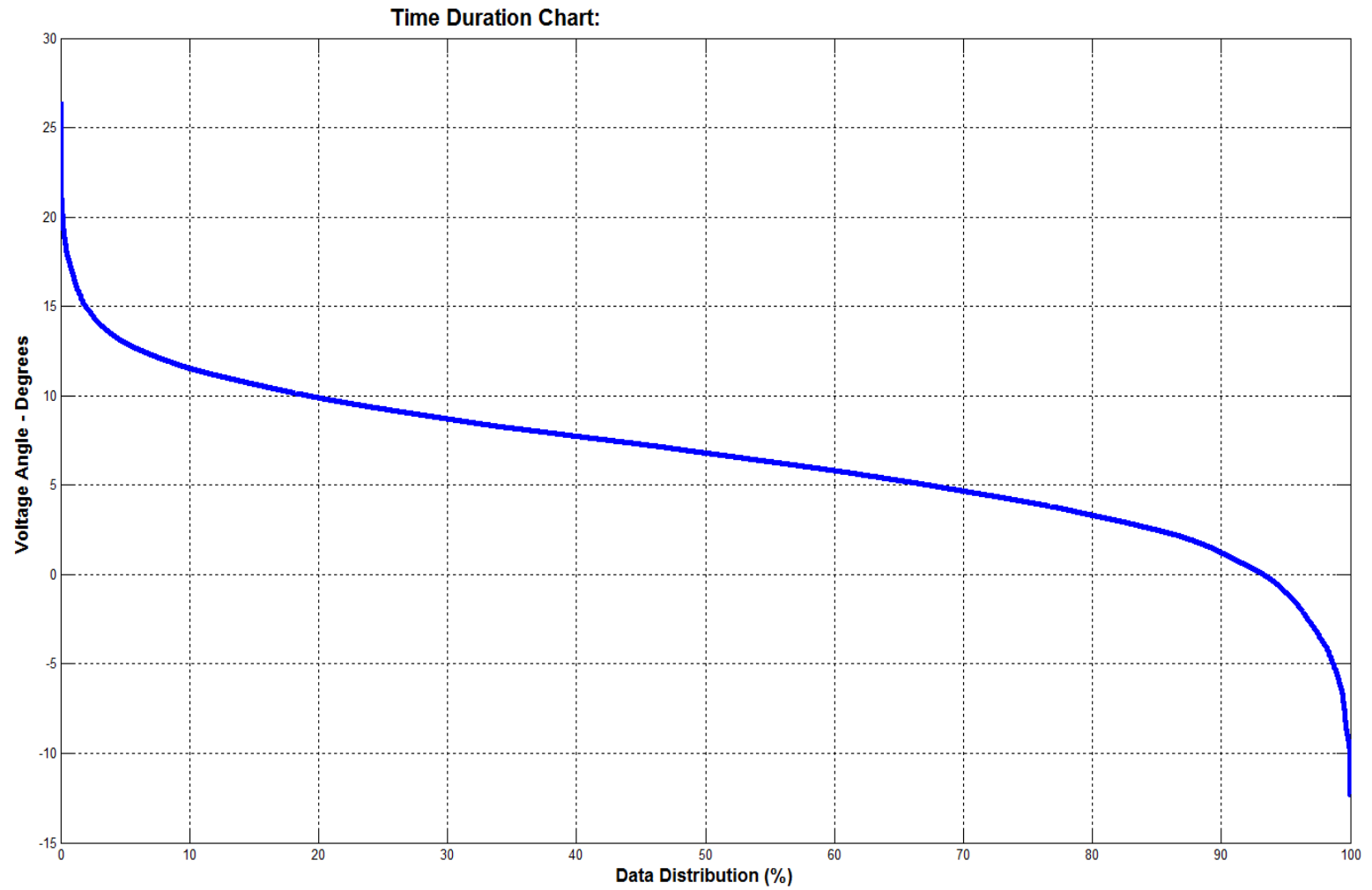
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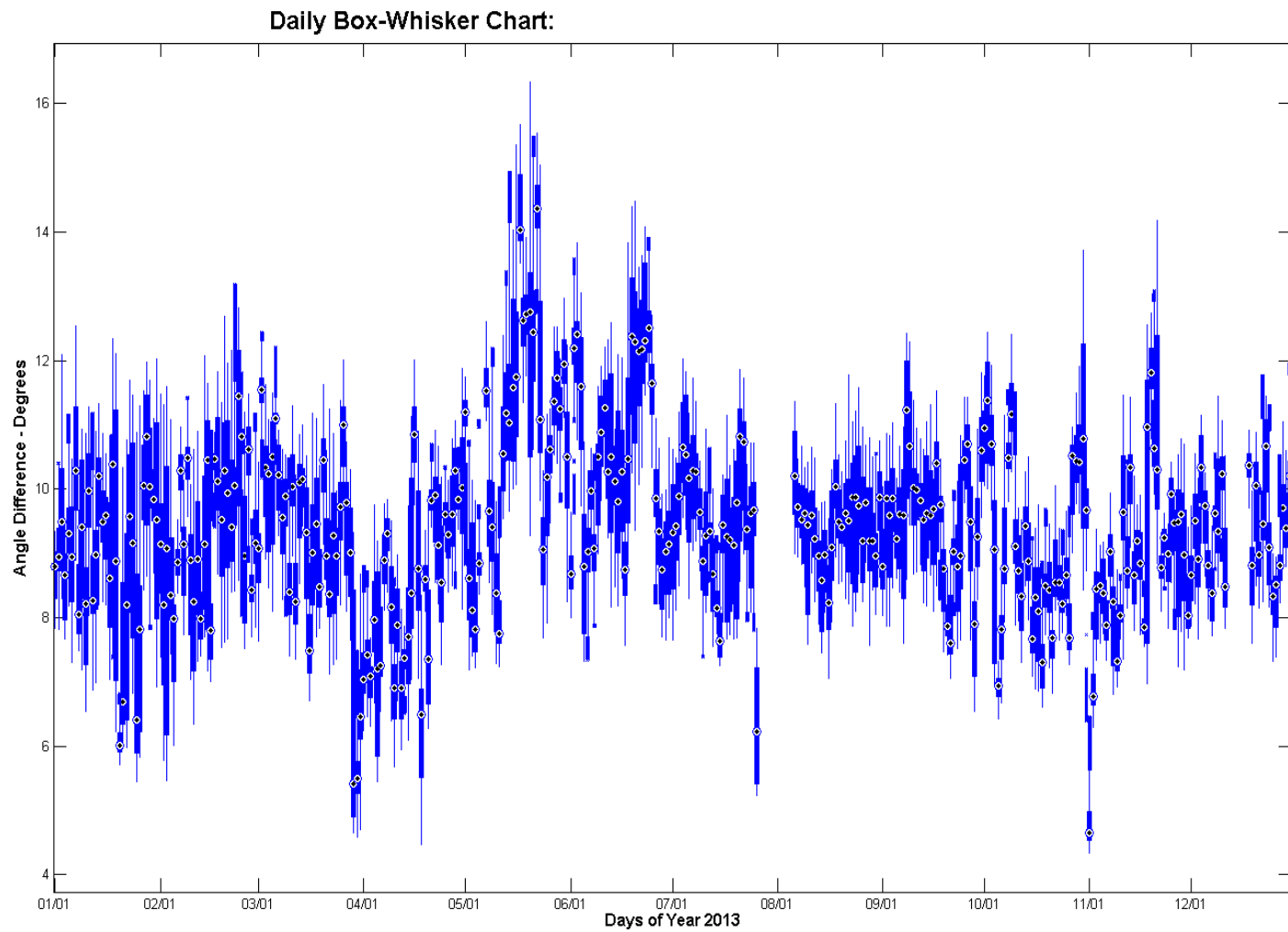
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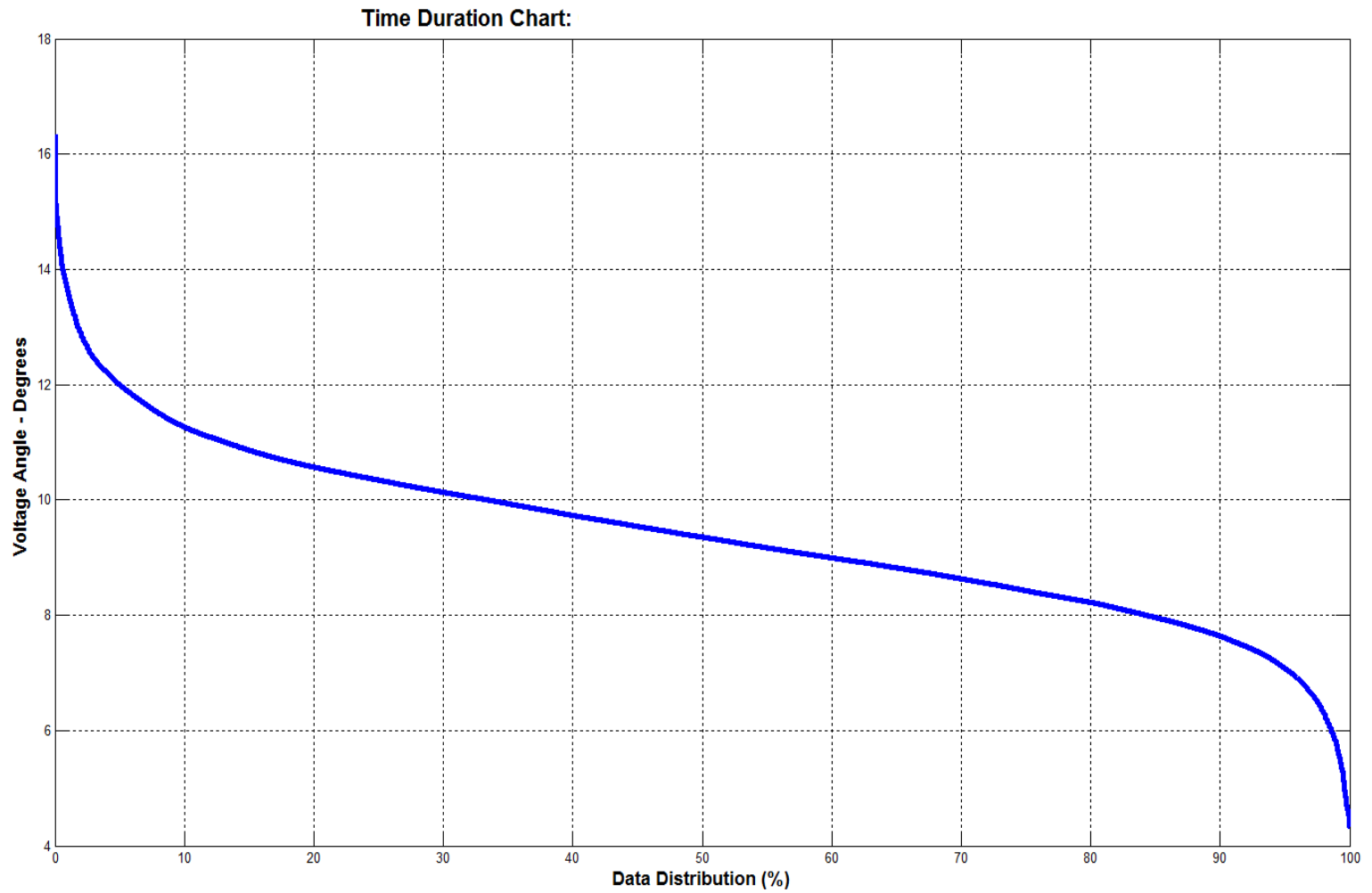
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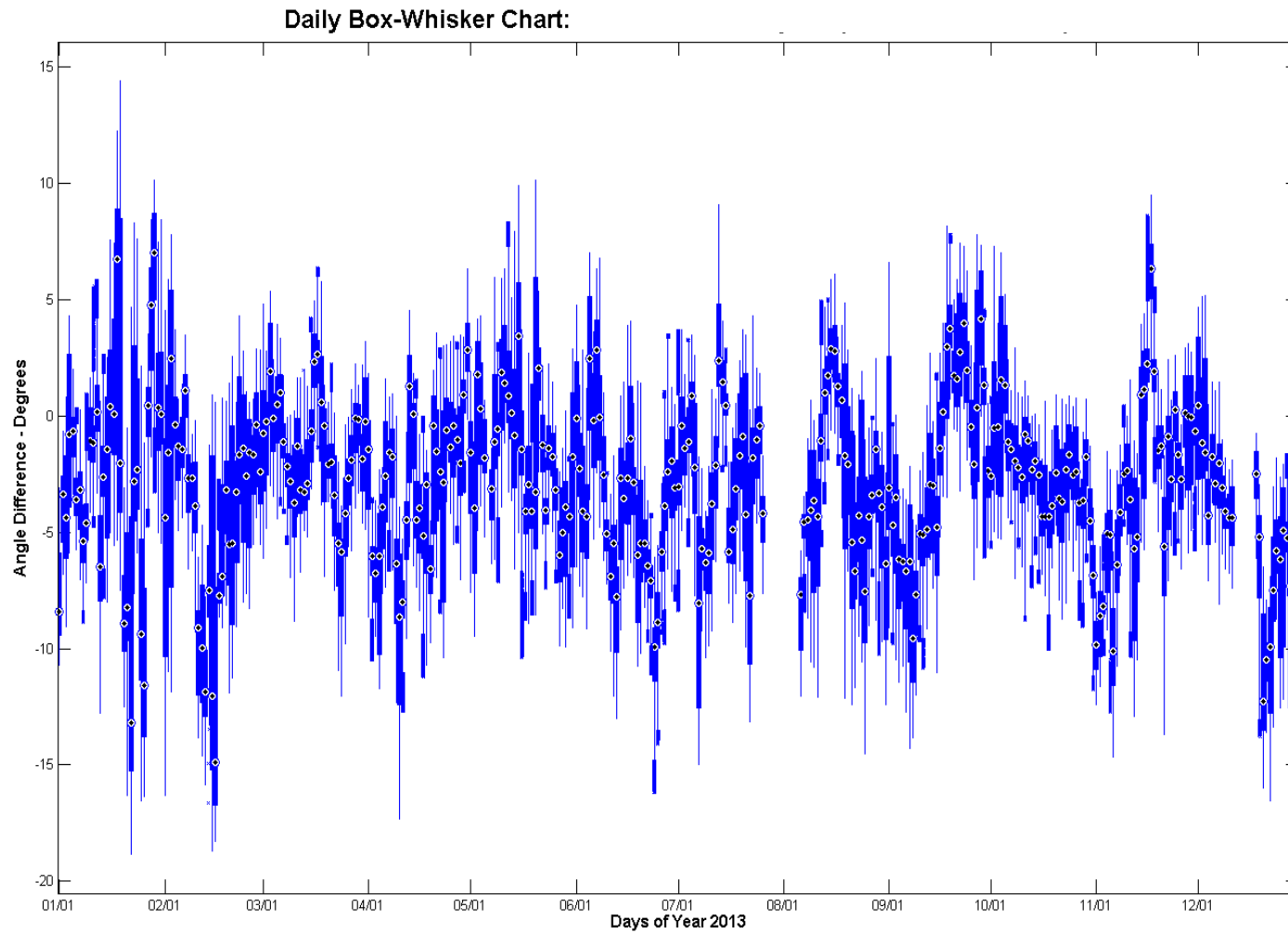
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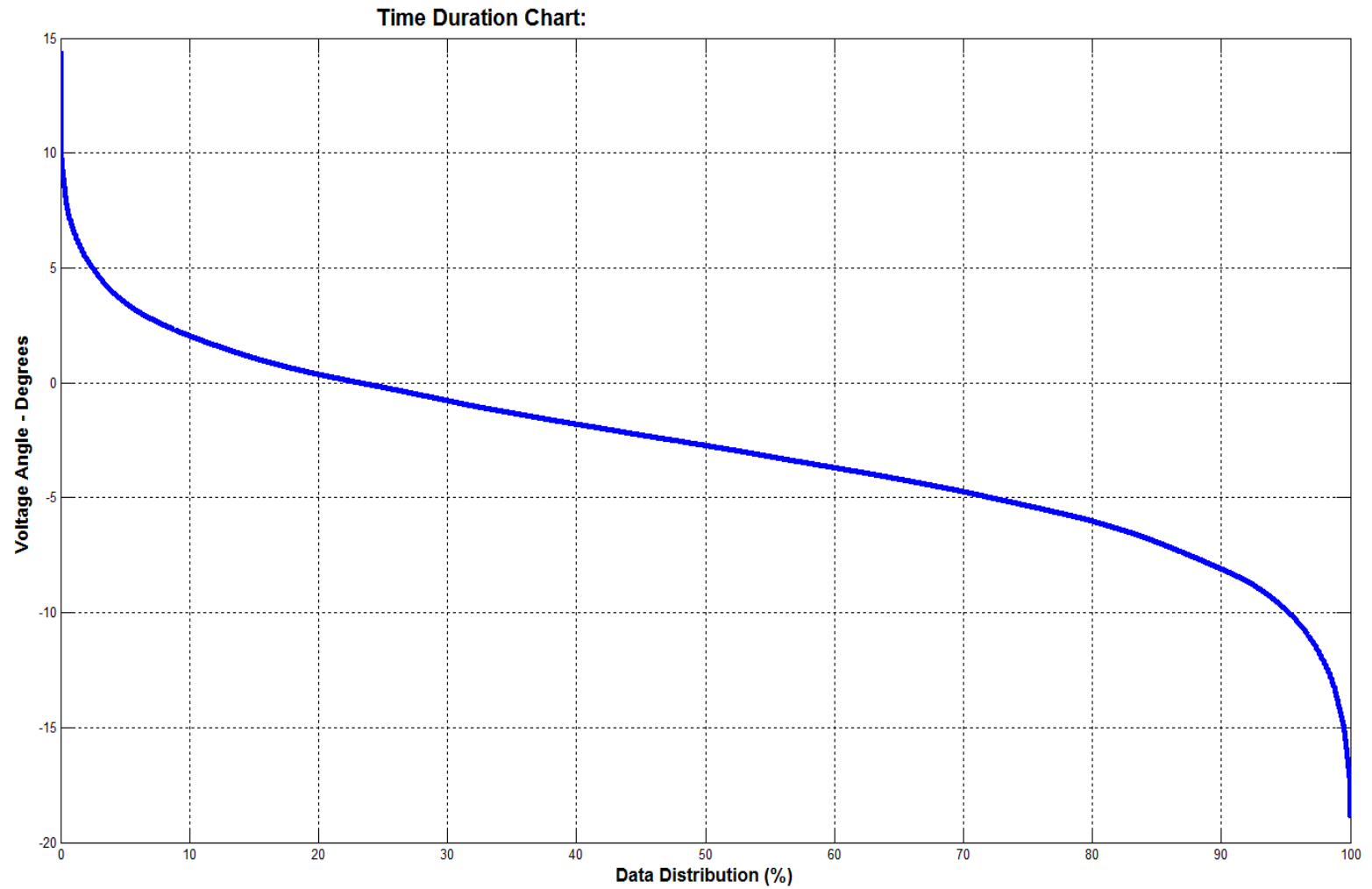
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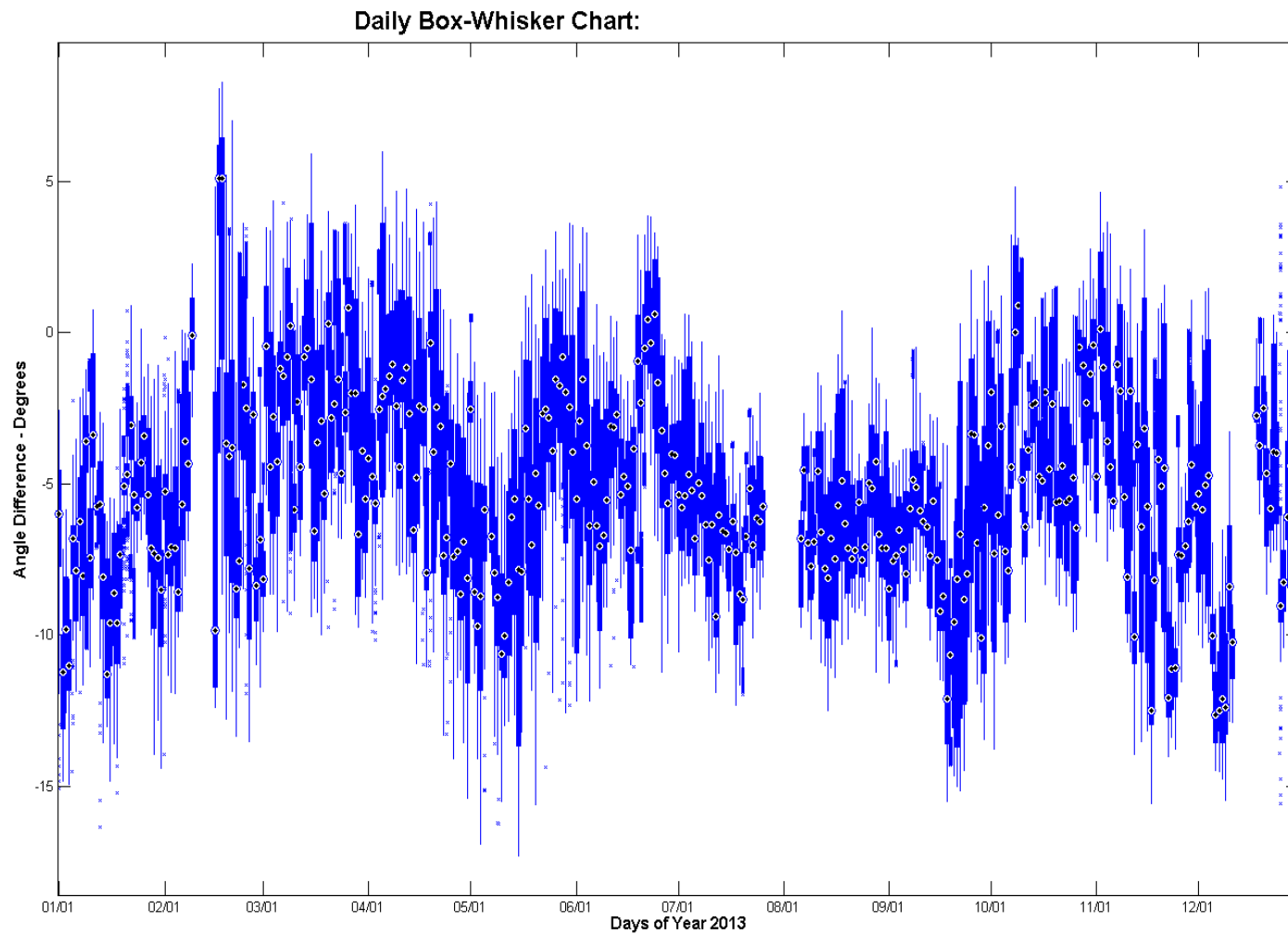
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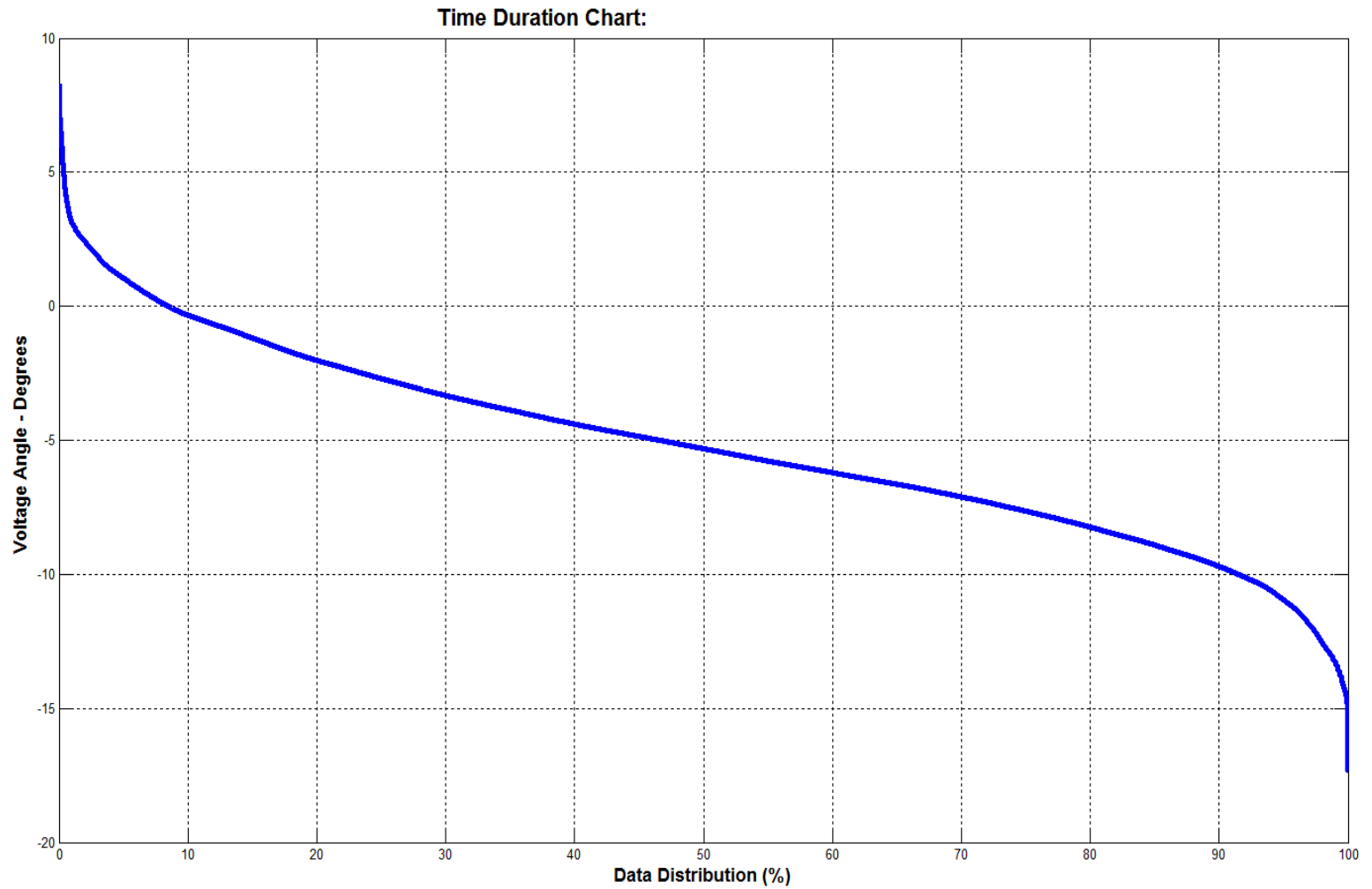
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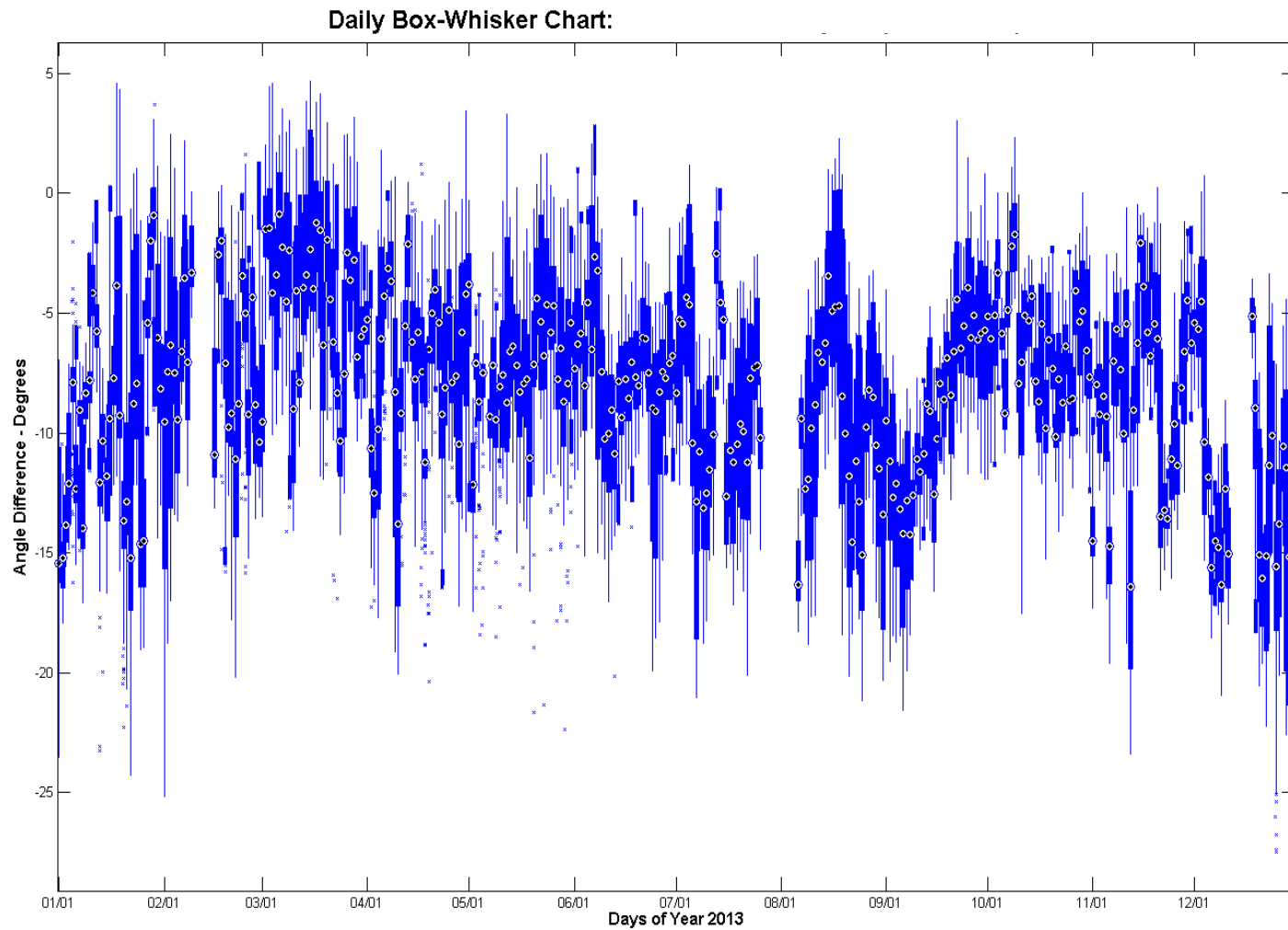
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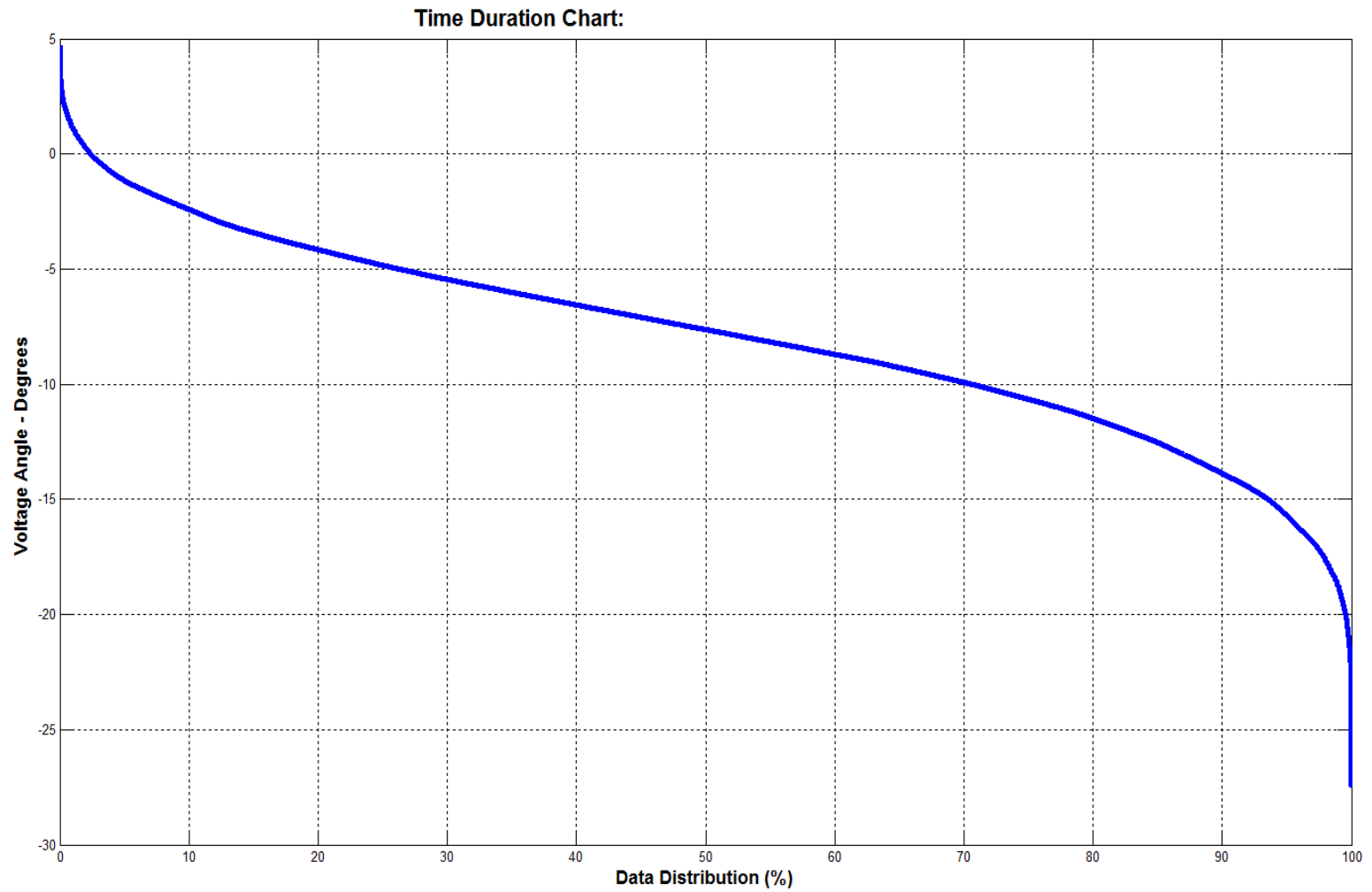
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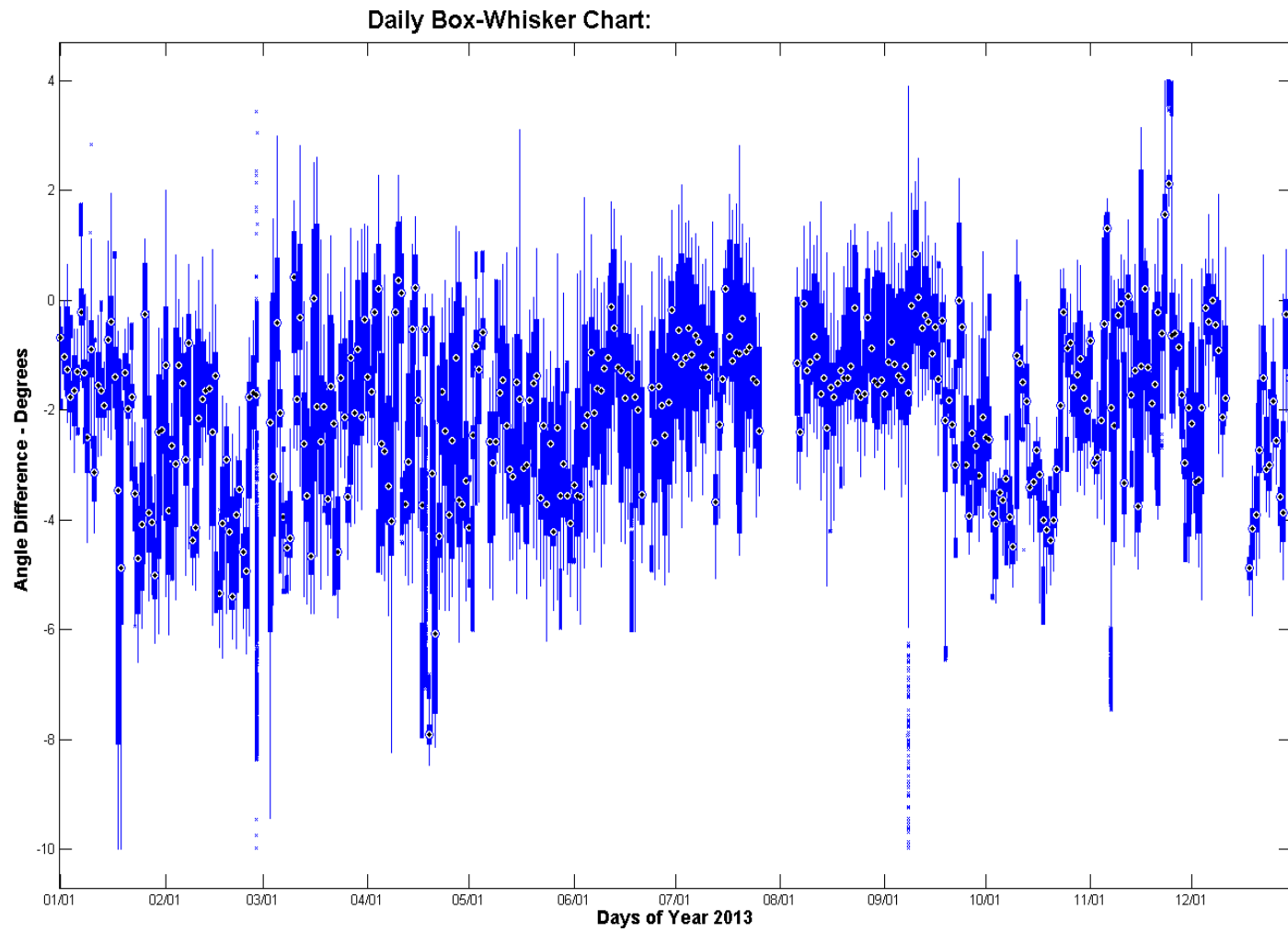
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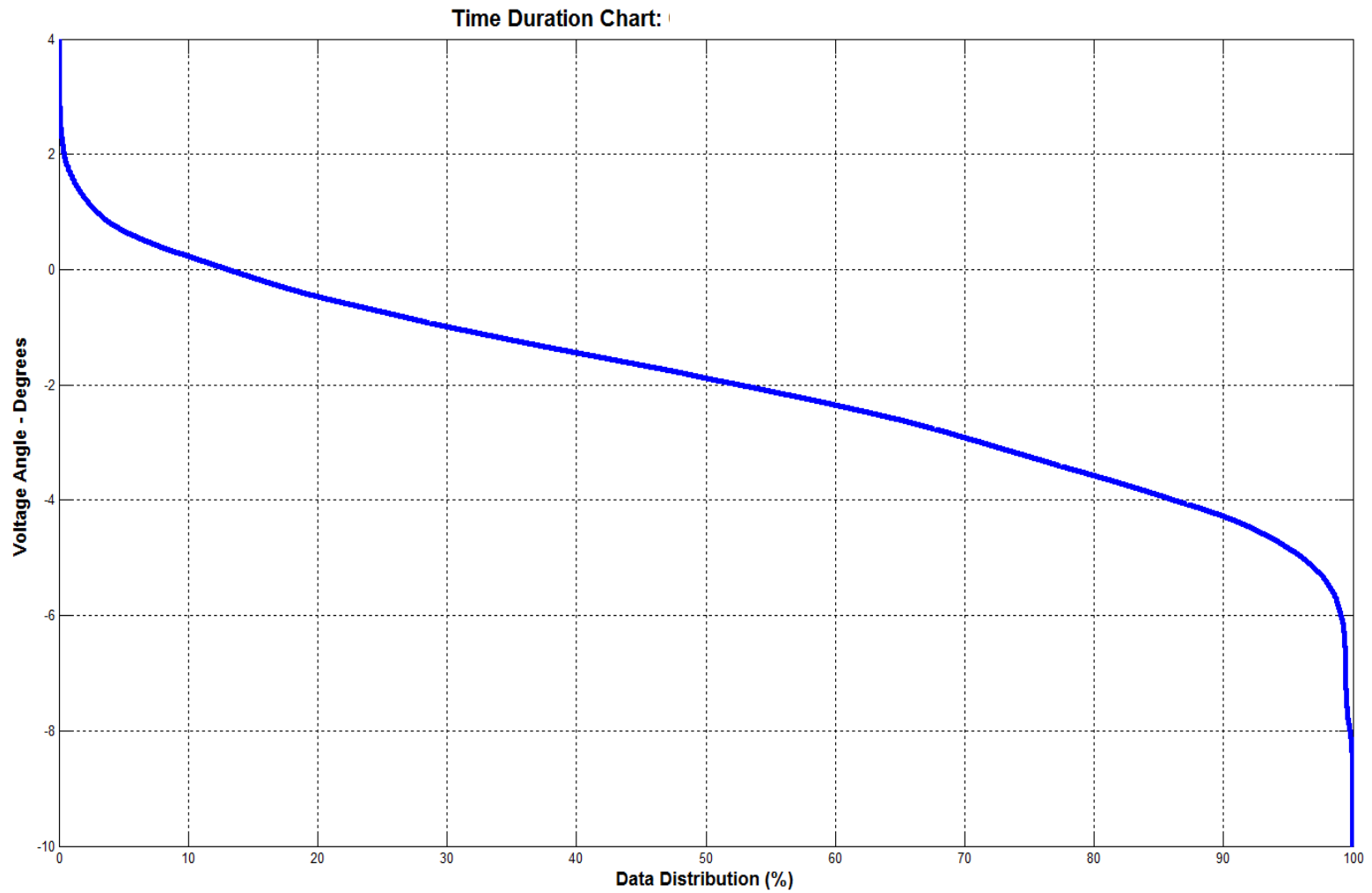
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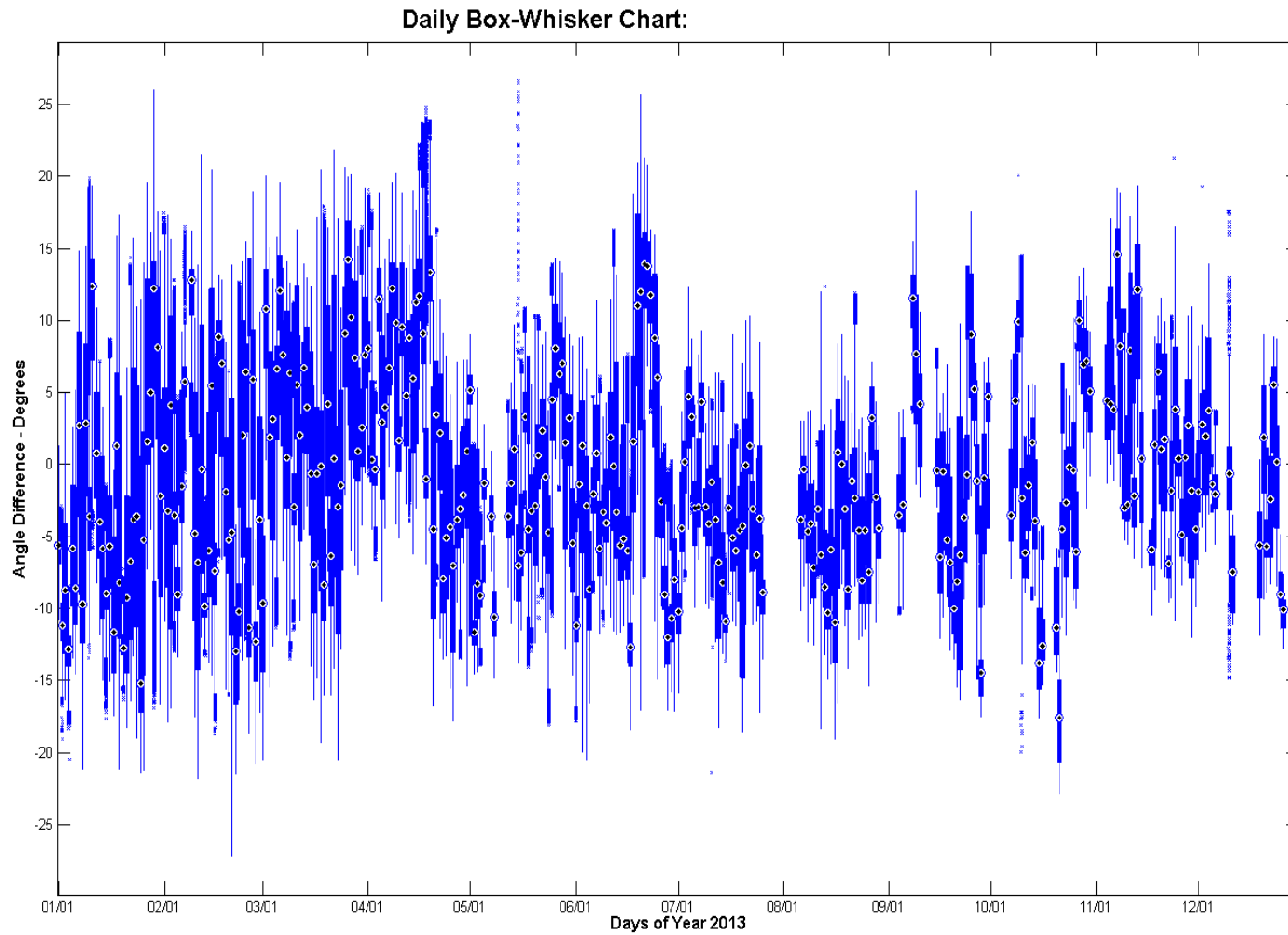
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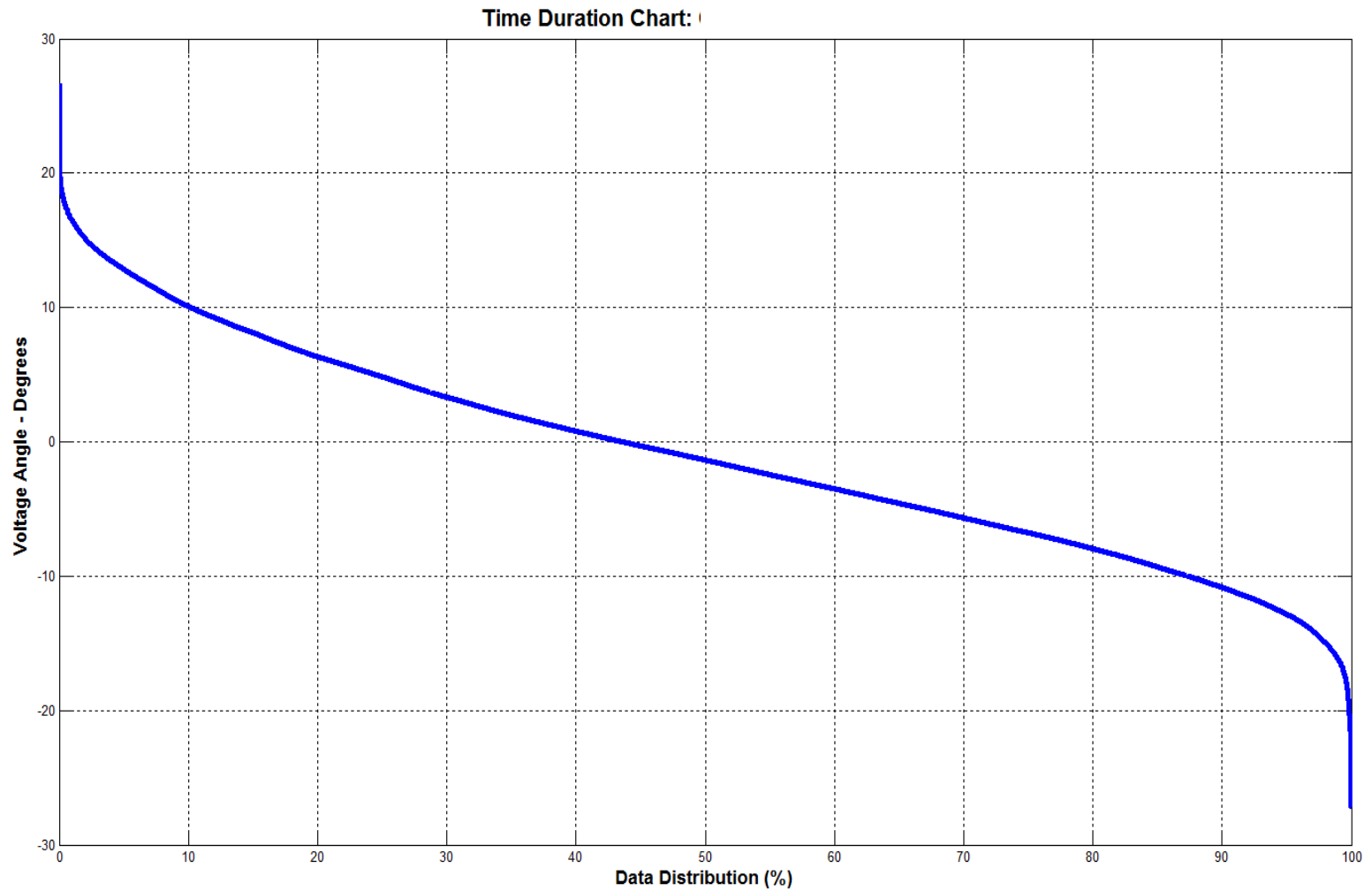
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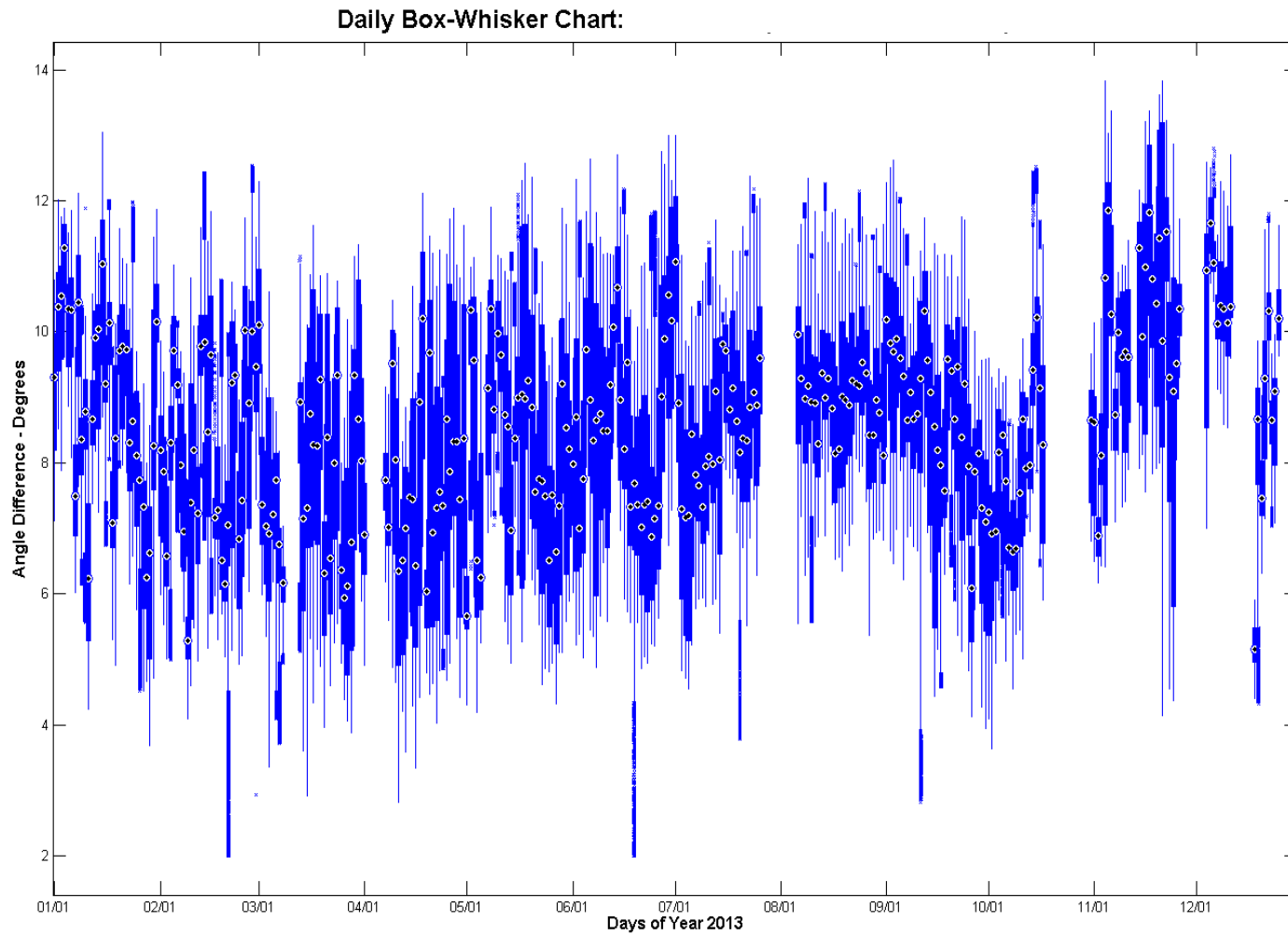
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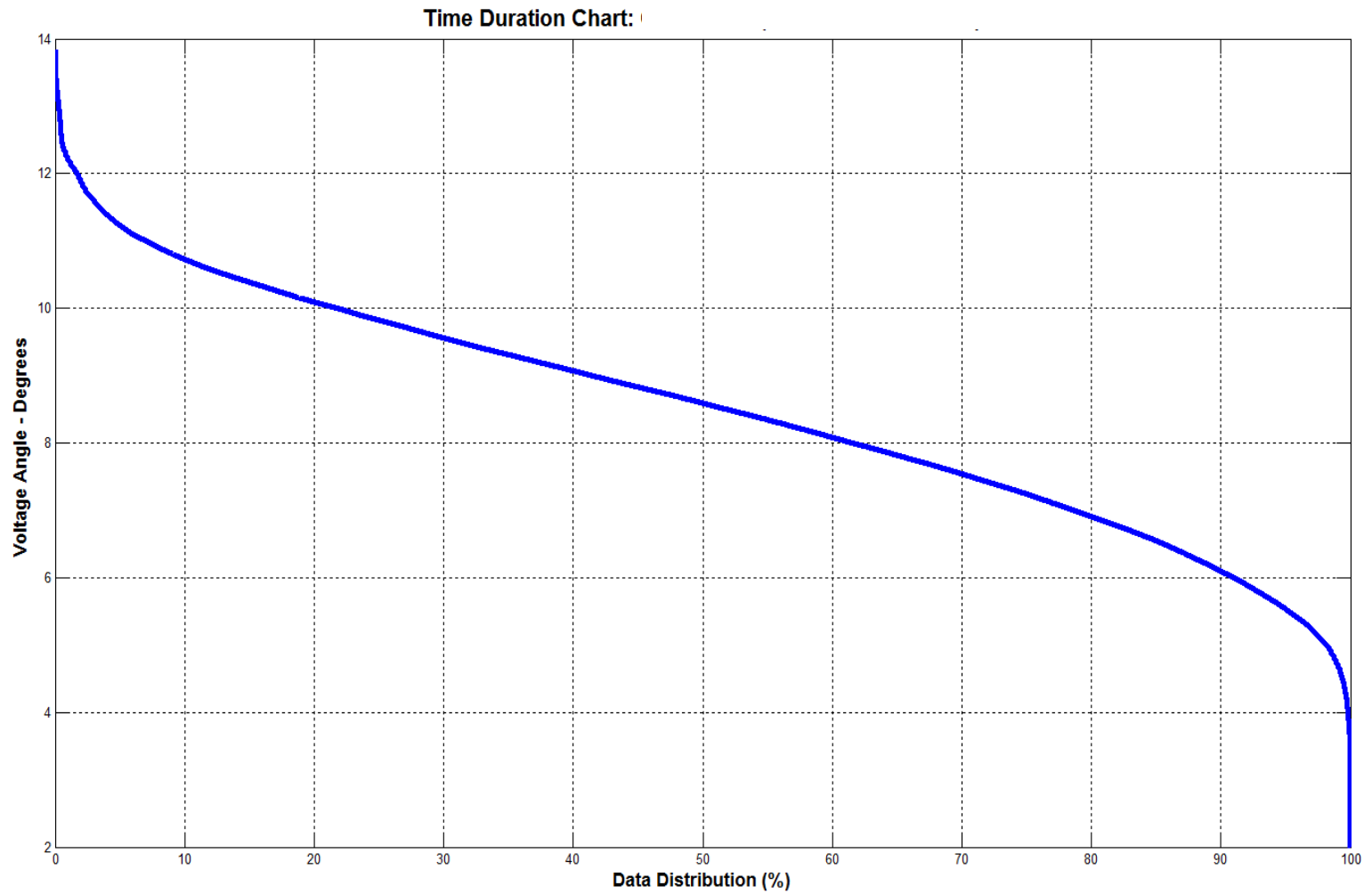
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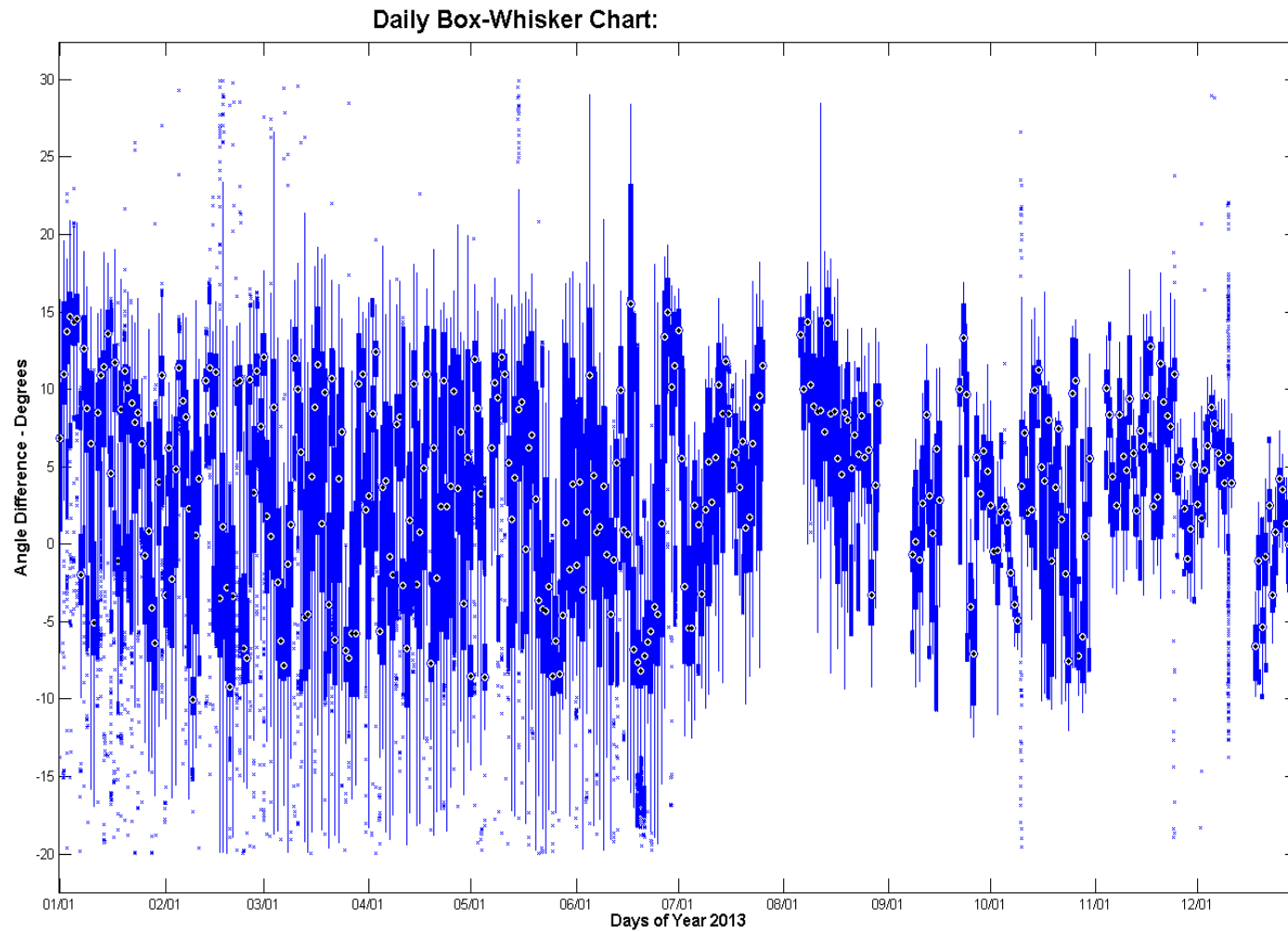
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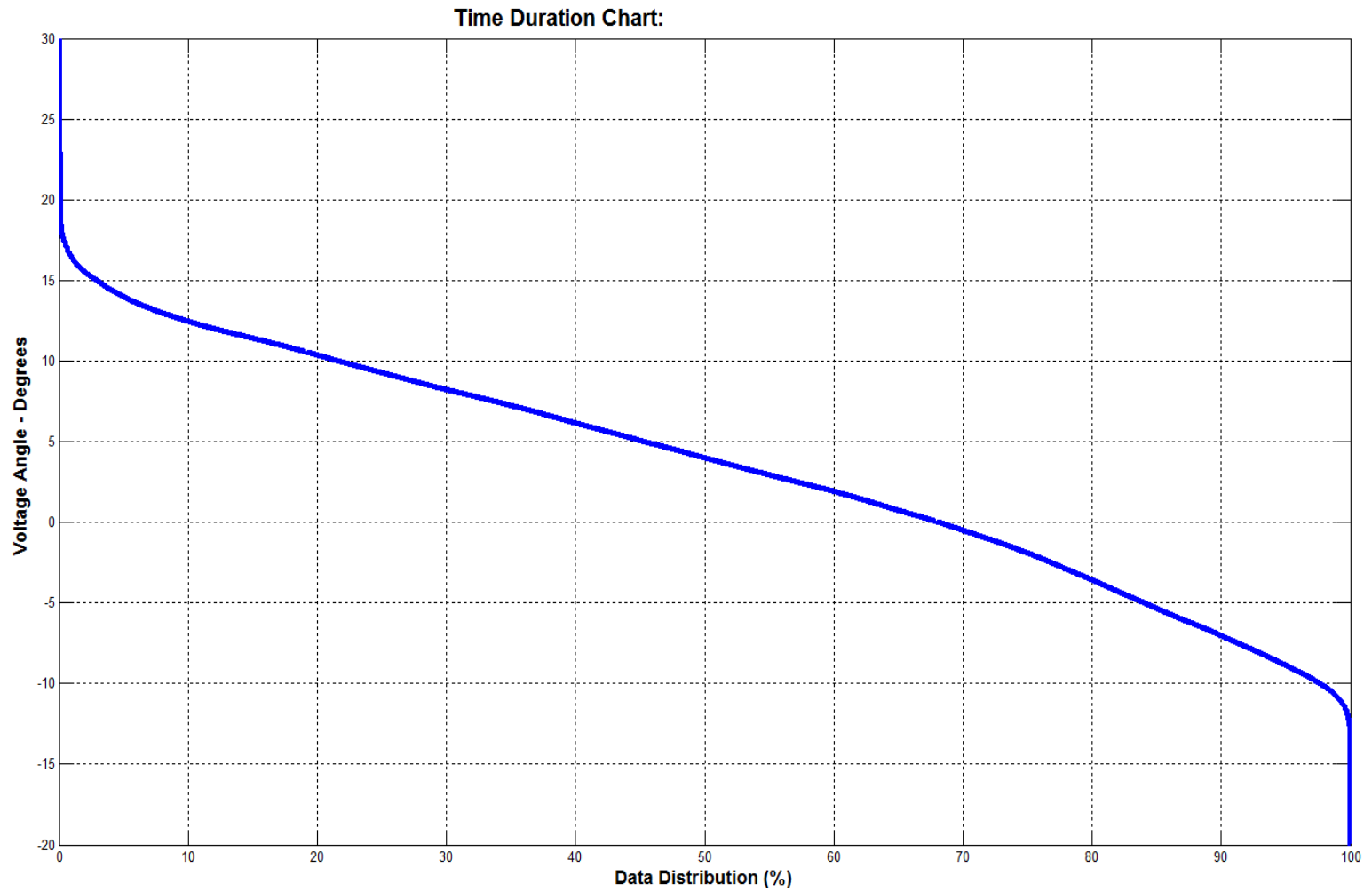
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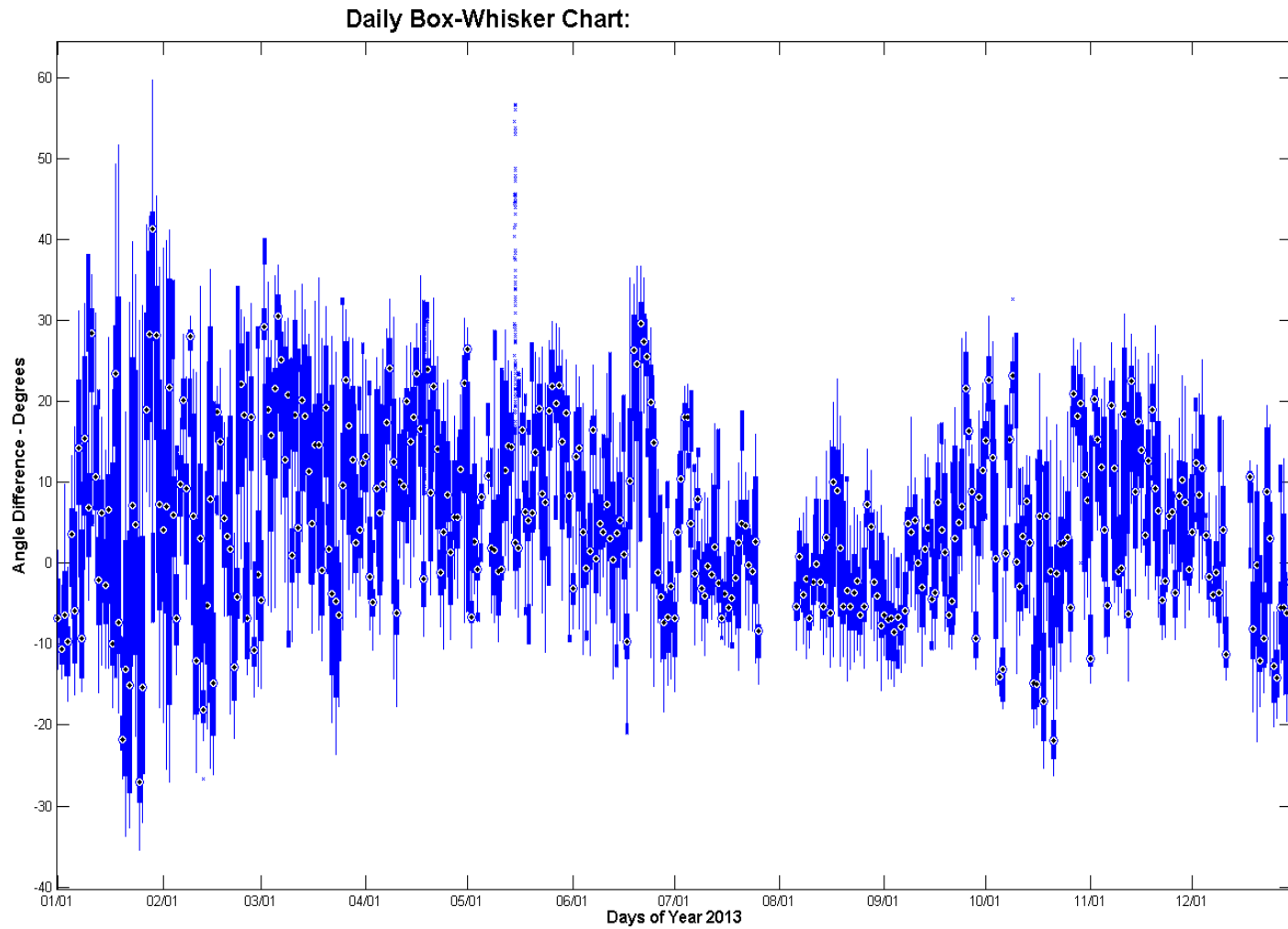
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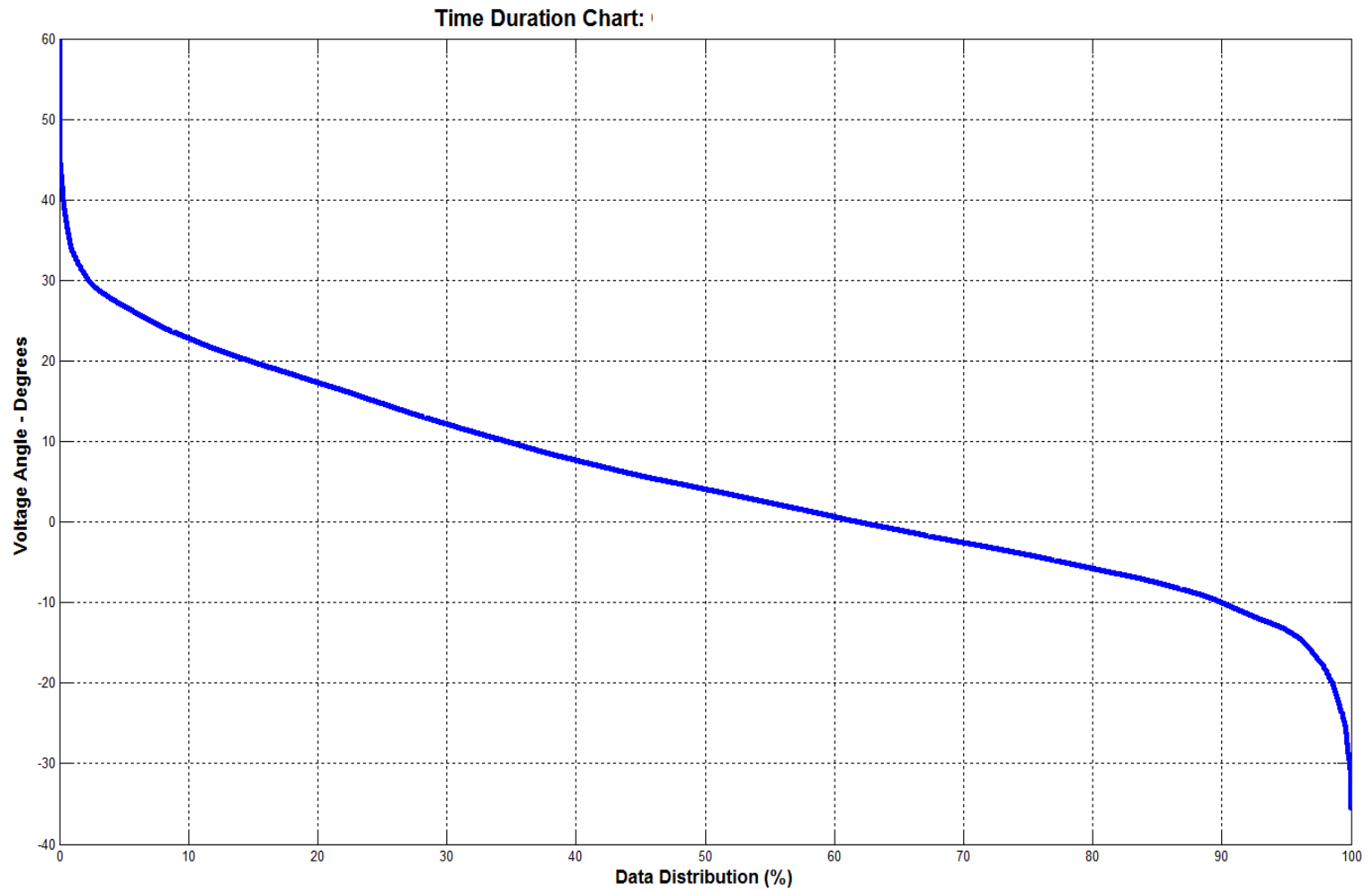
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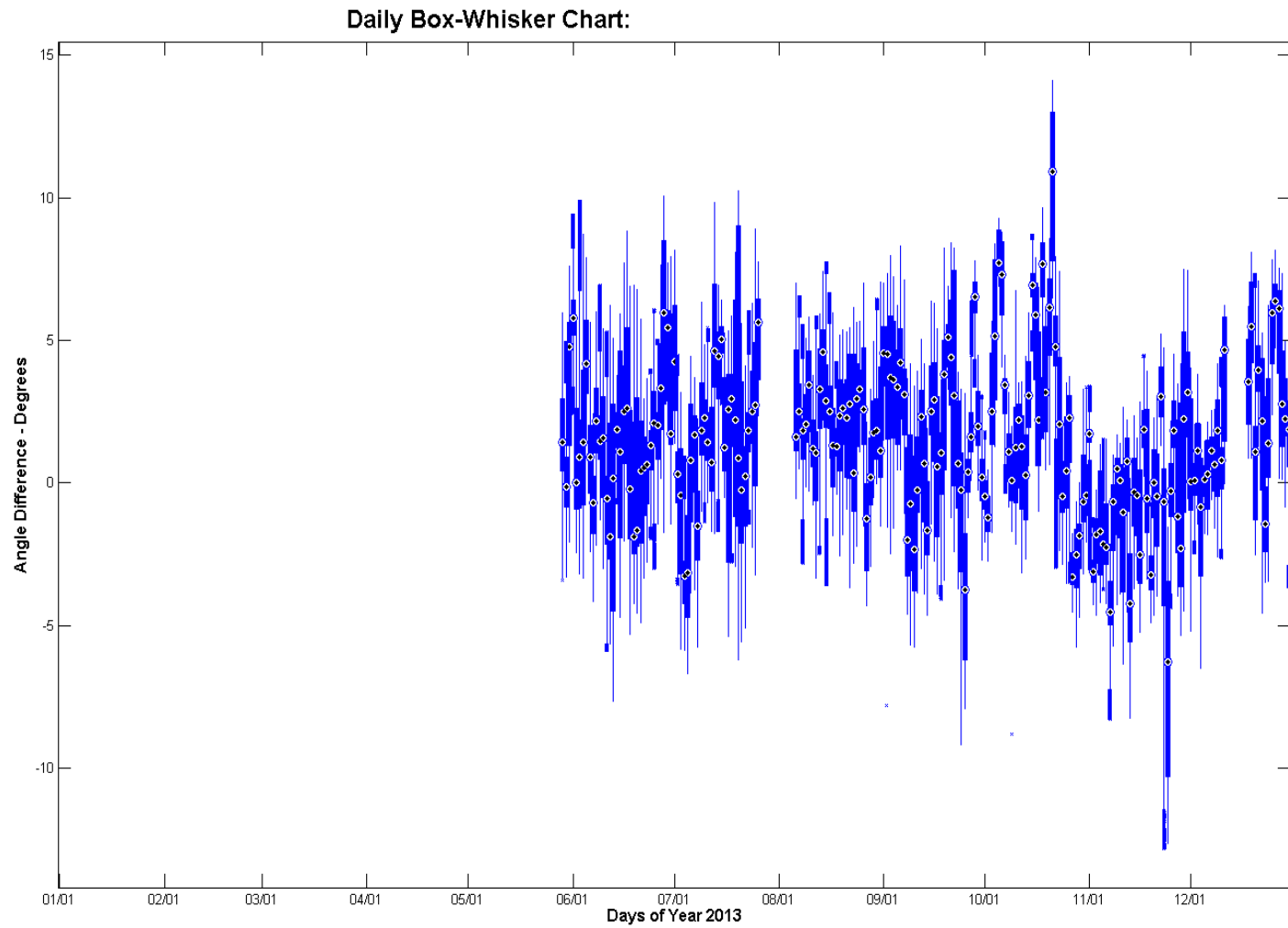
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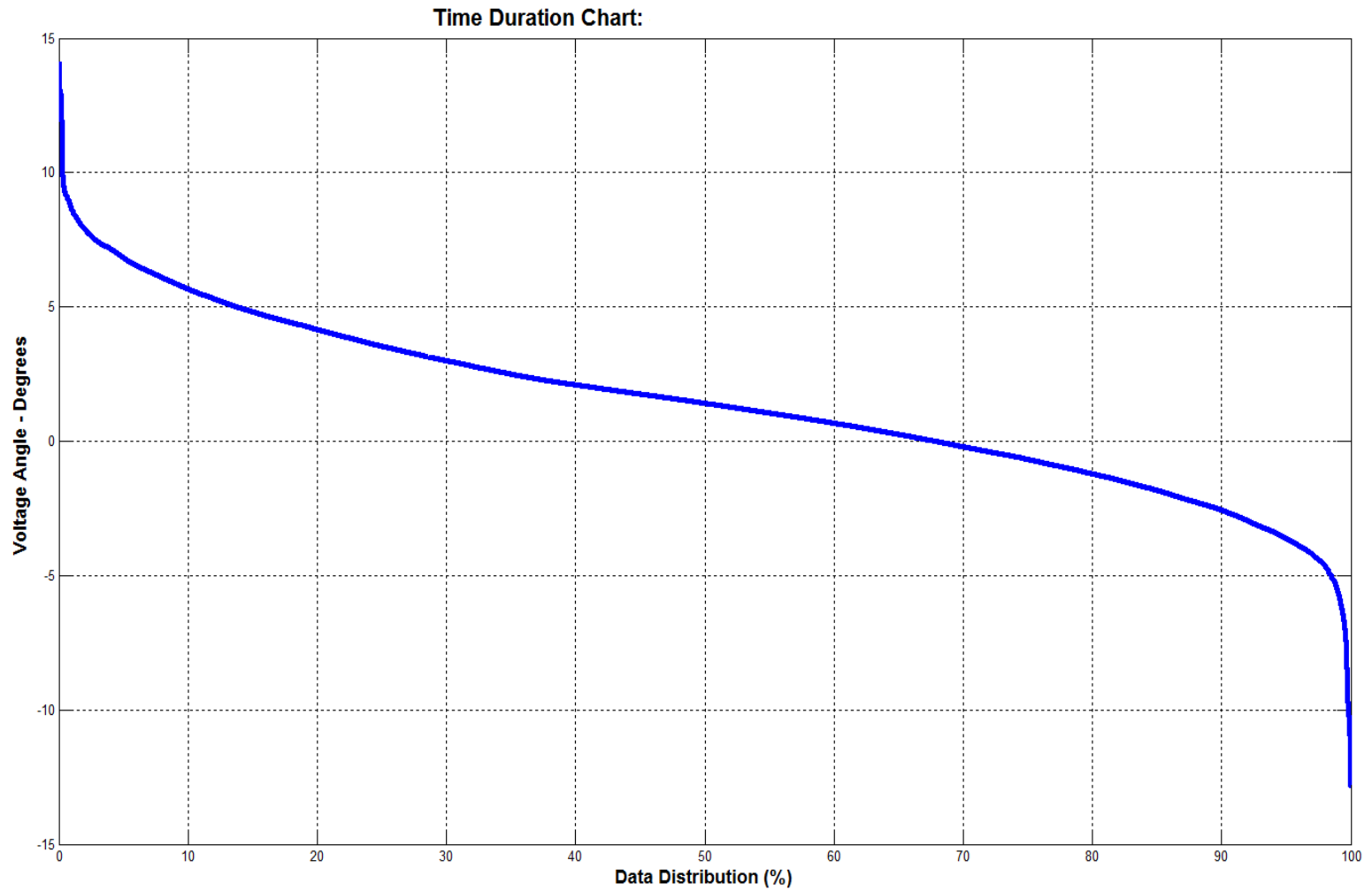
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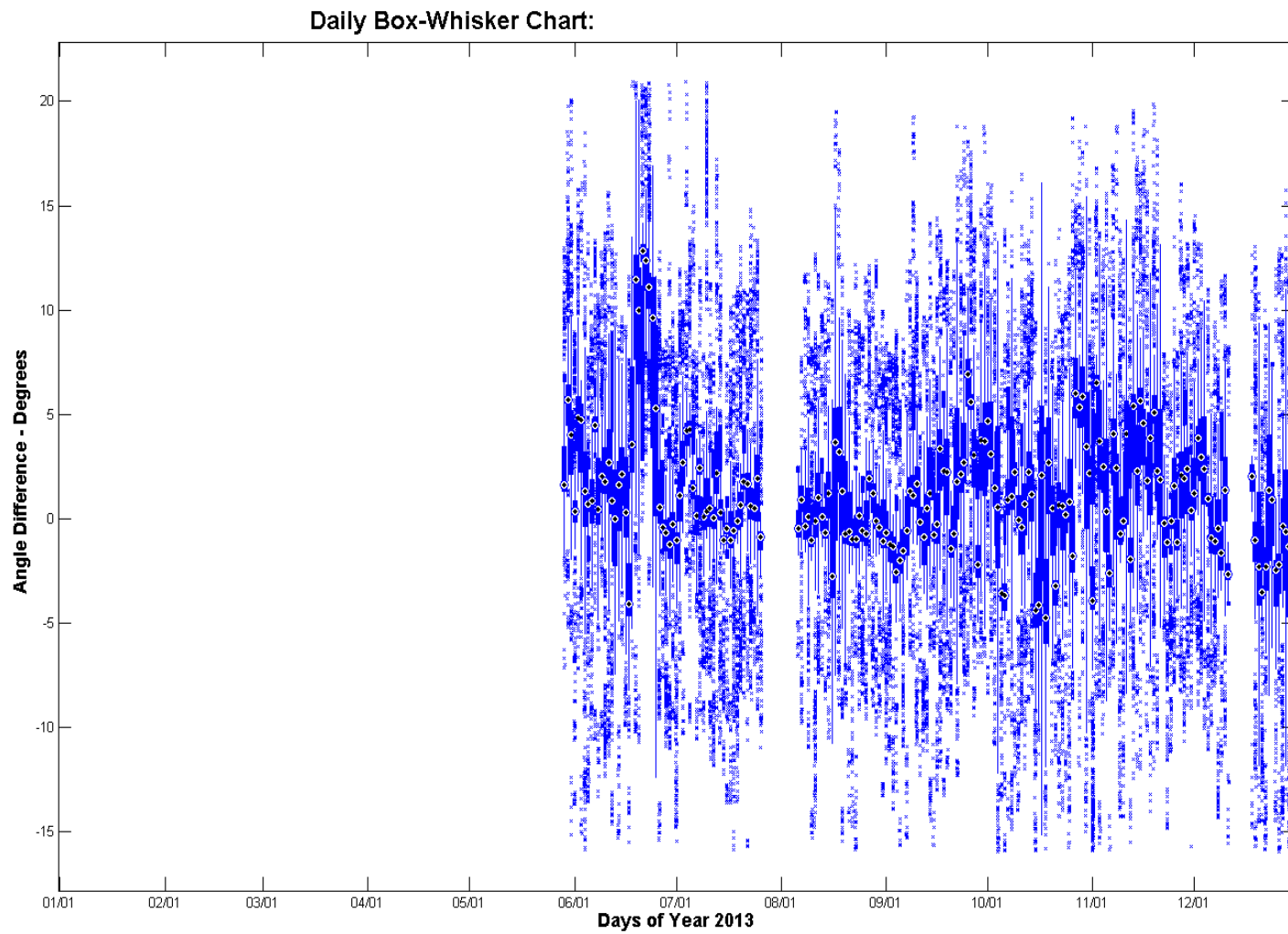
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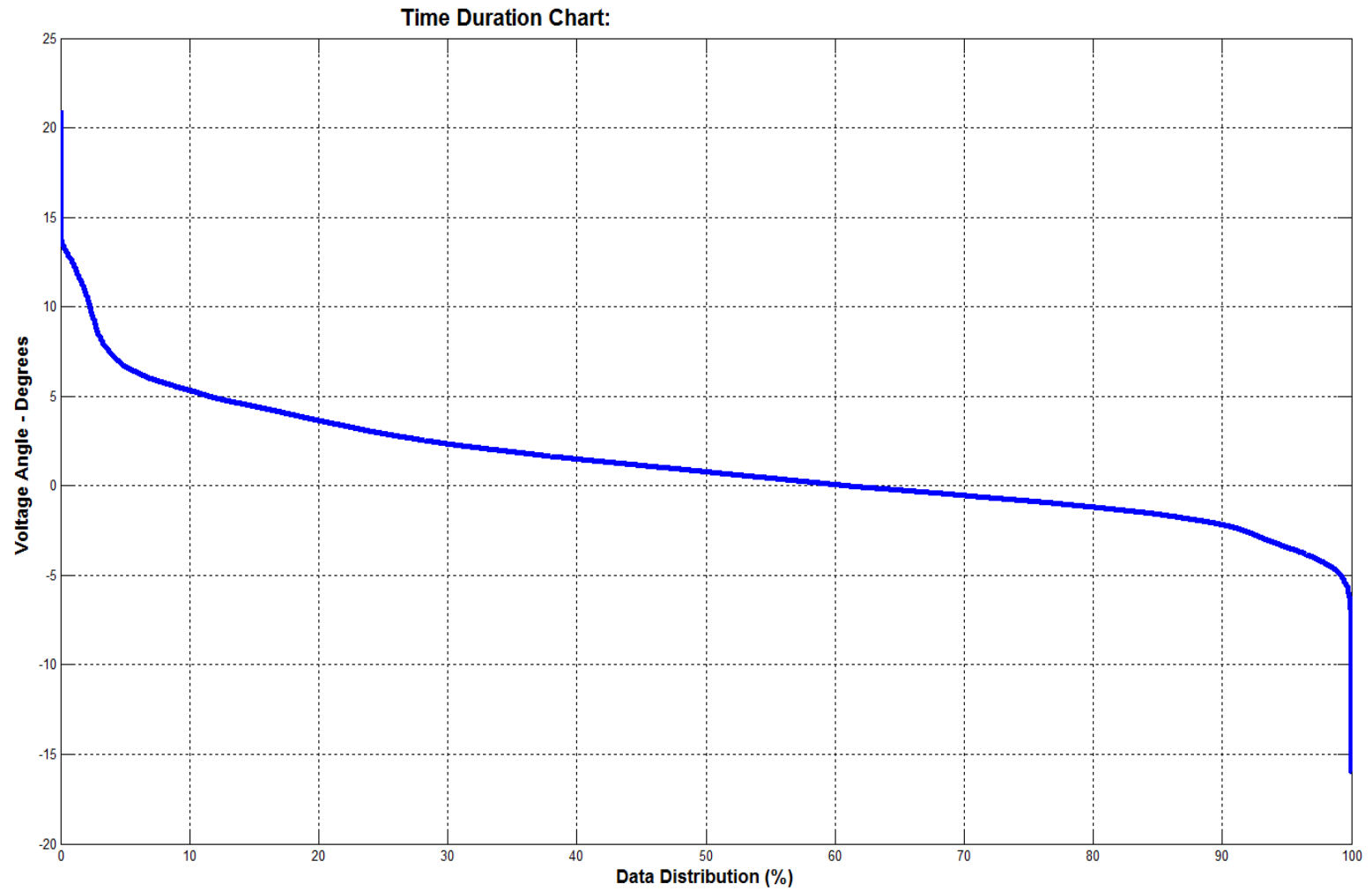
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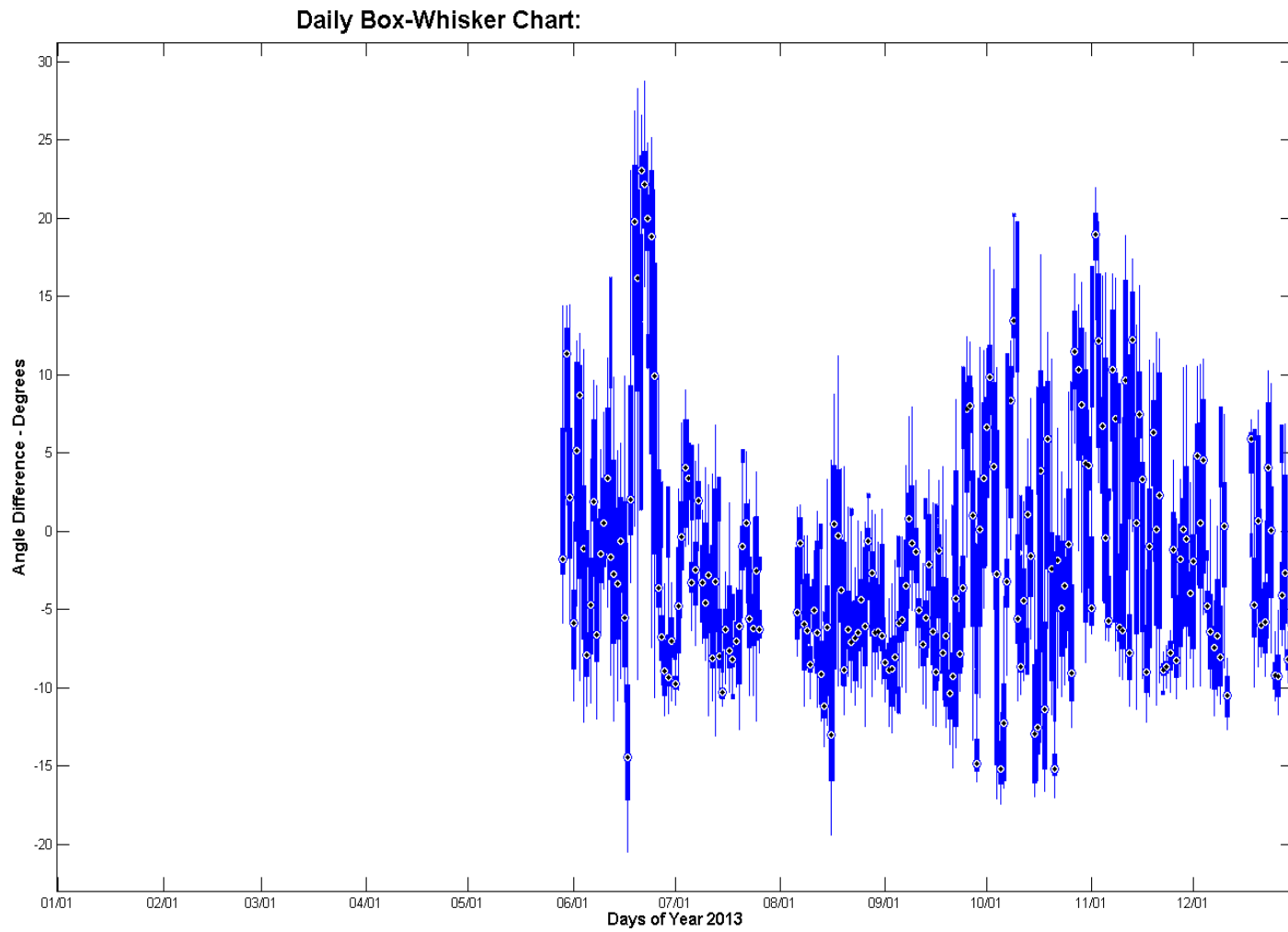
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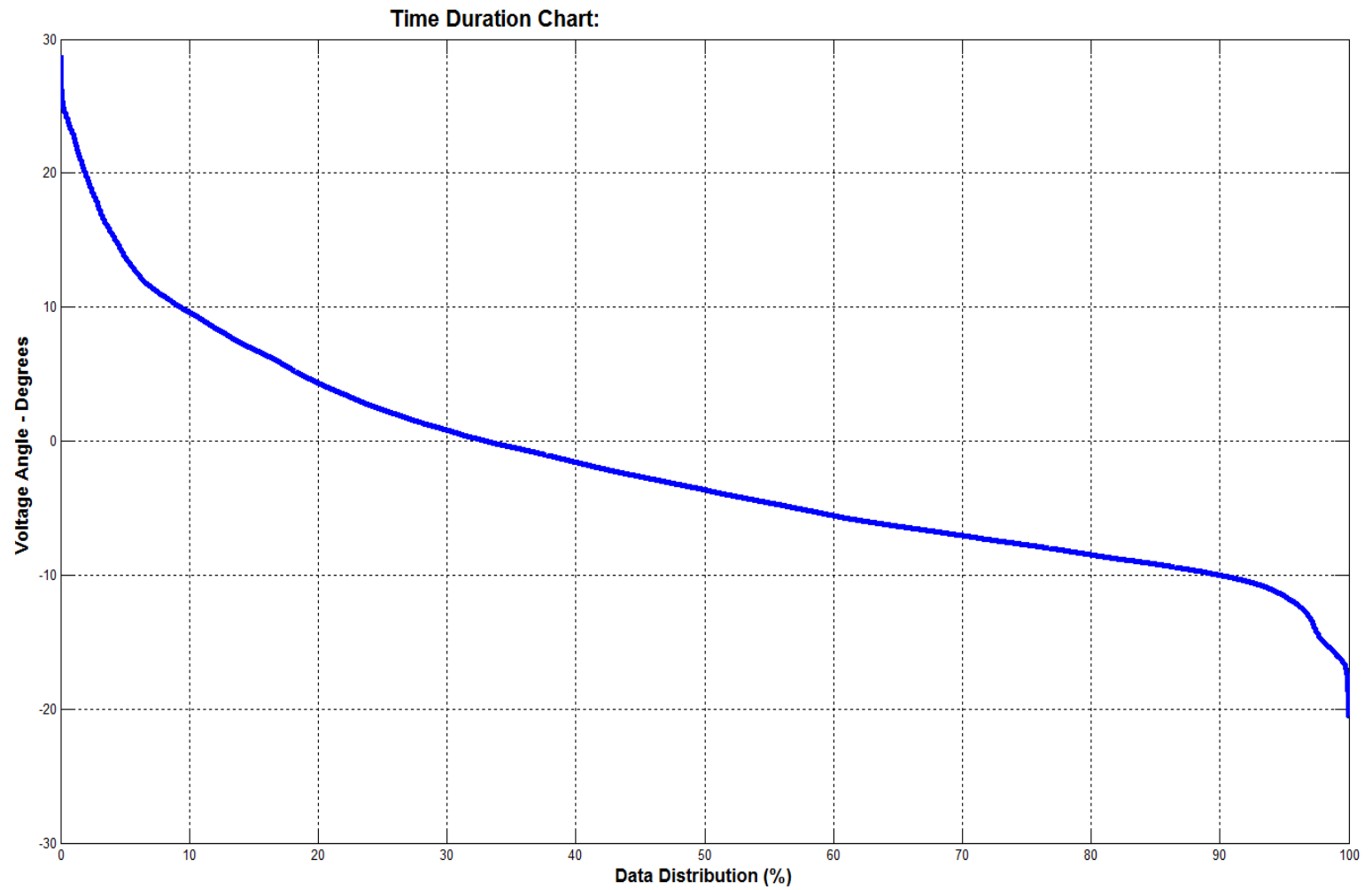
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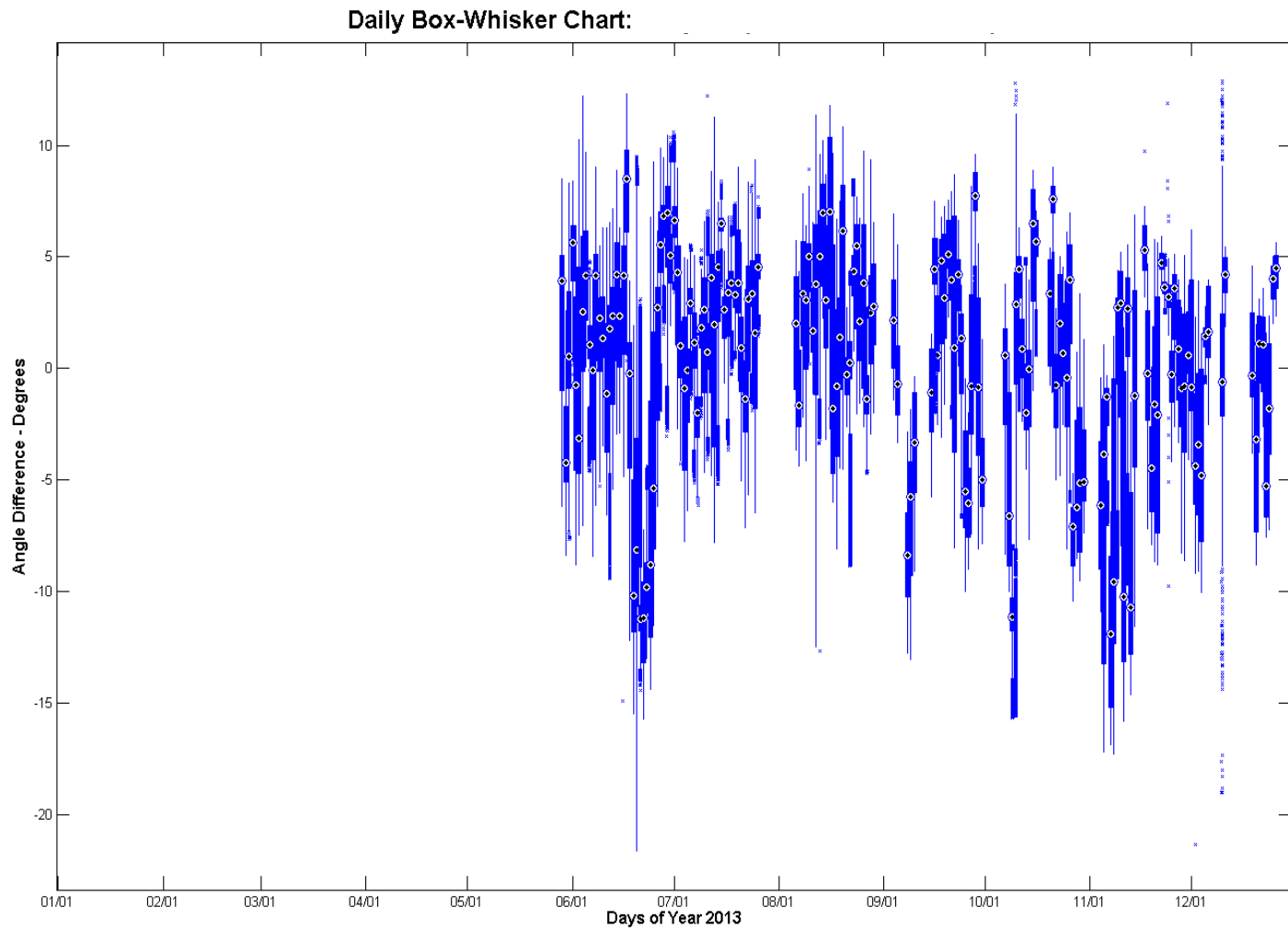
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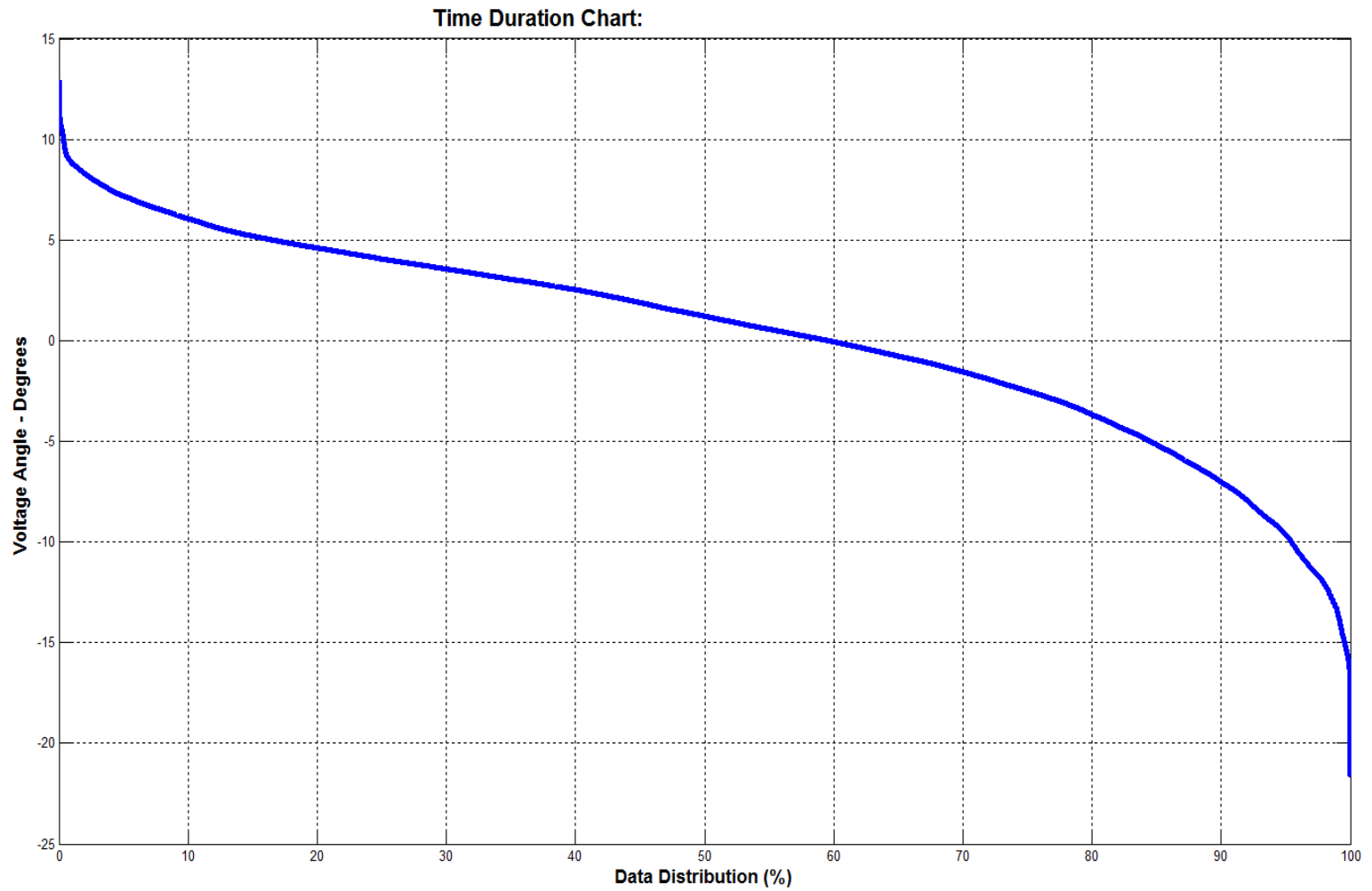
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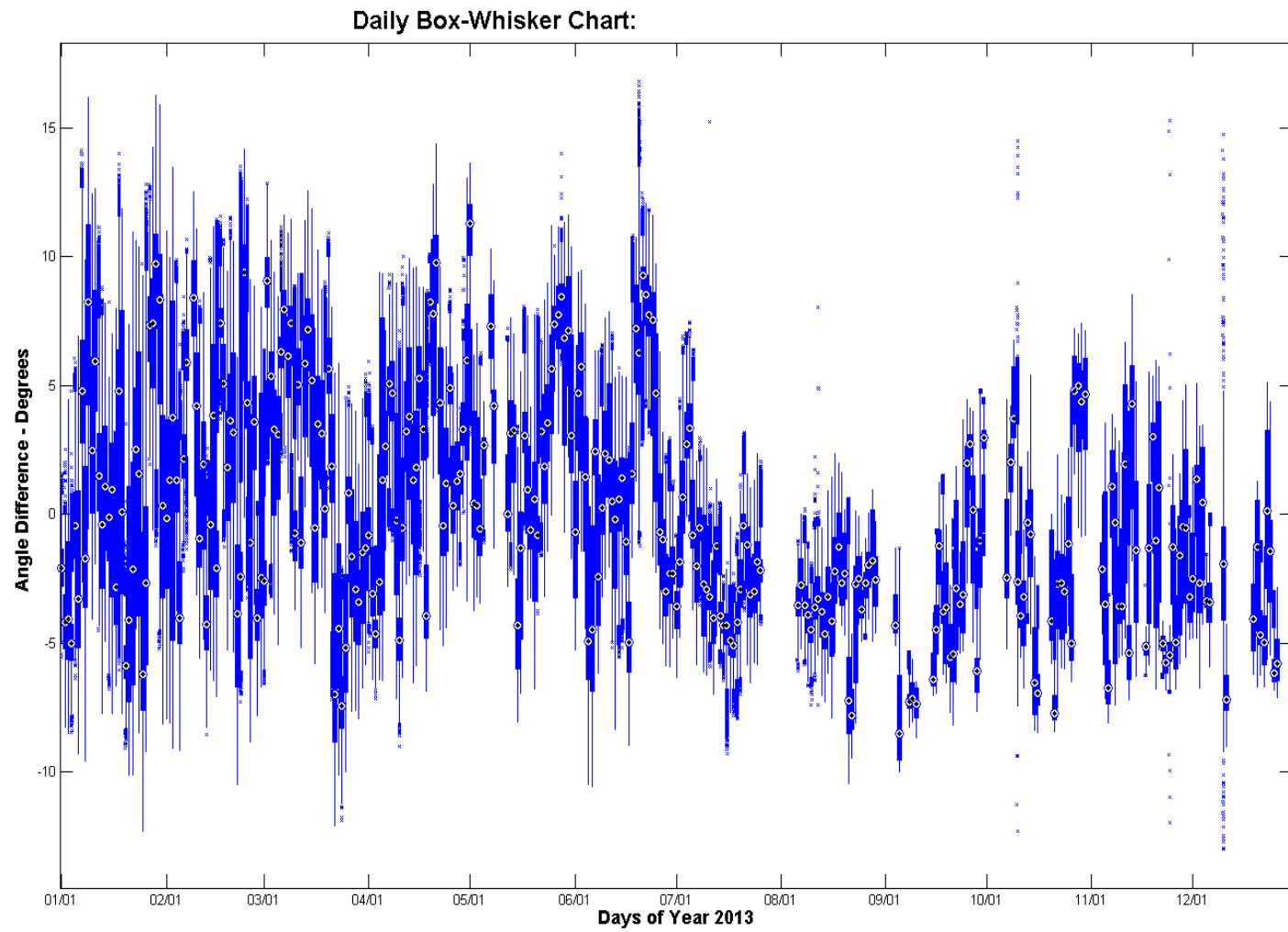
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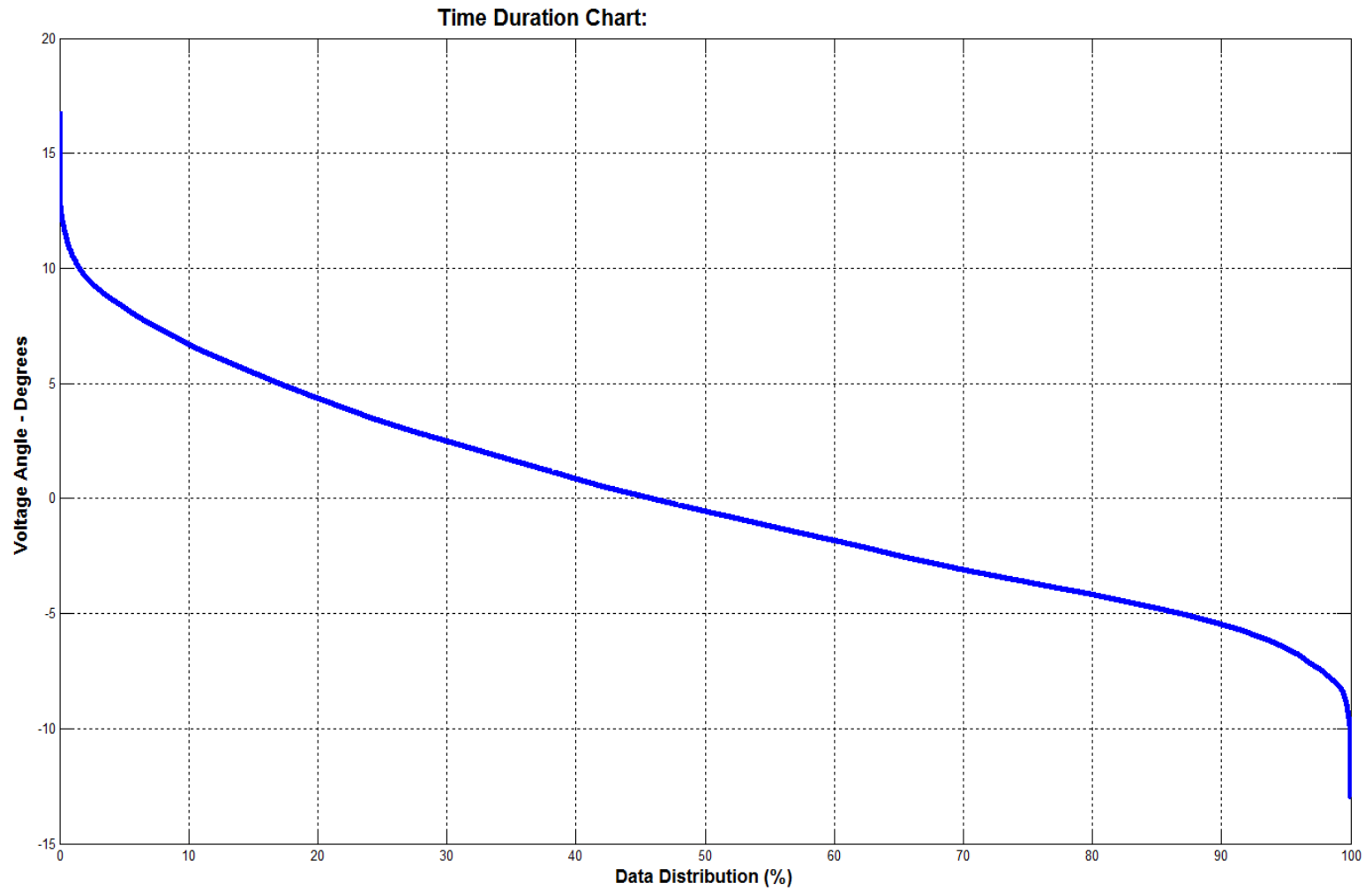
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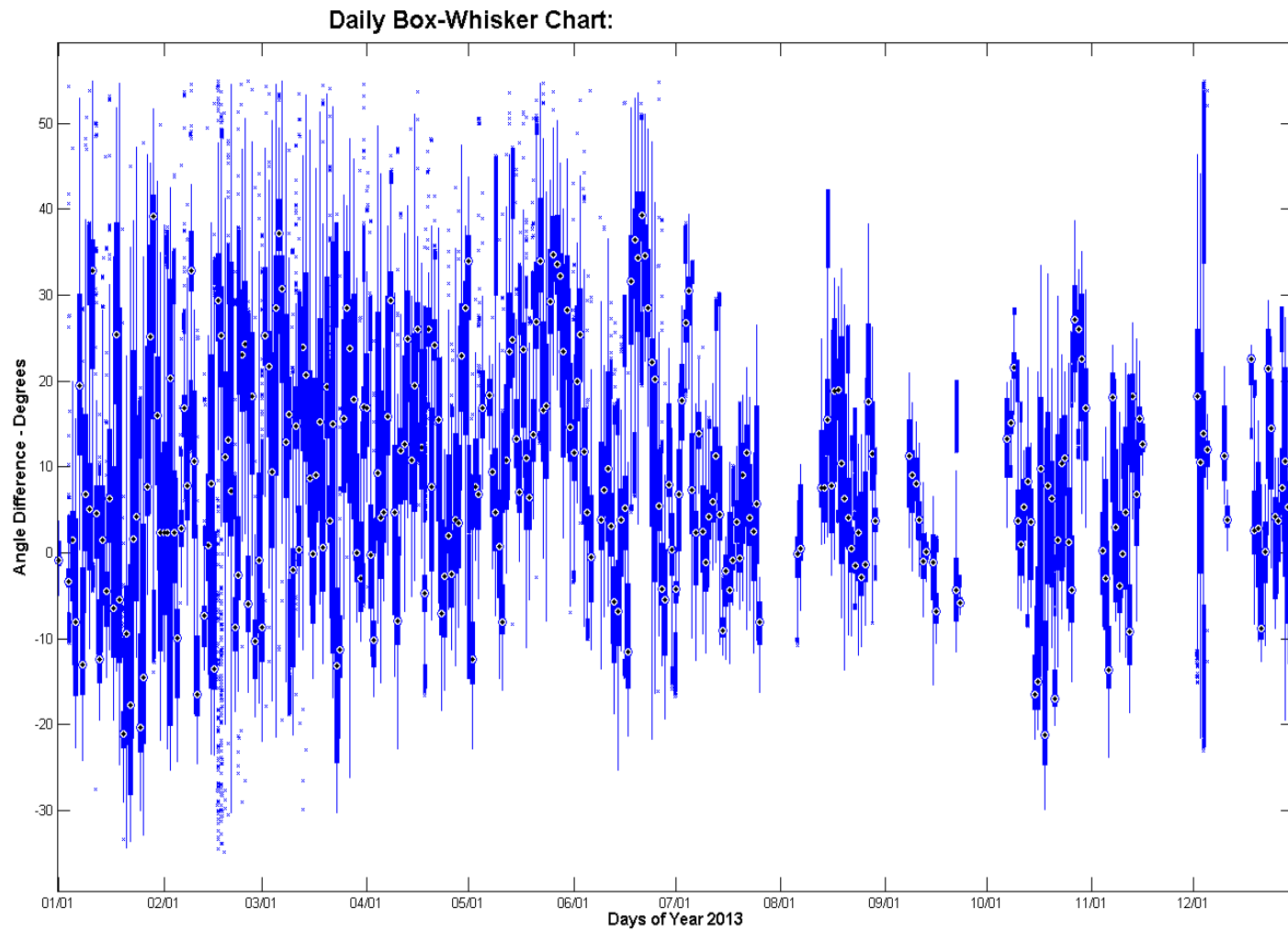
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West 14-North 1

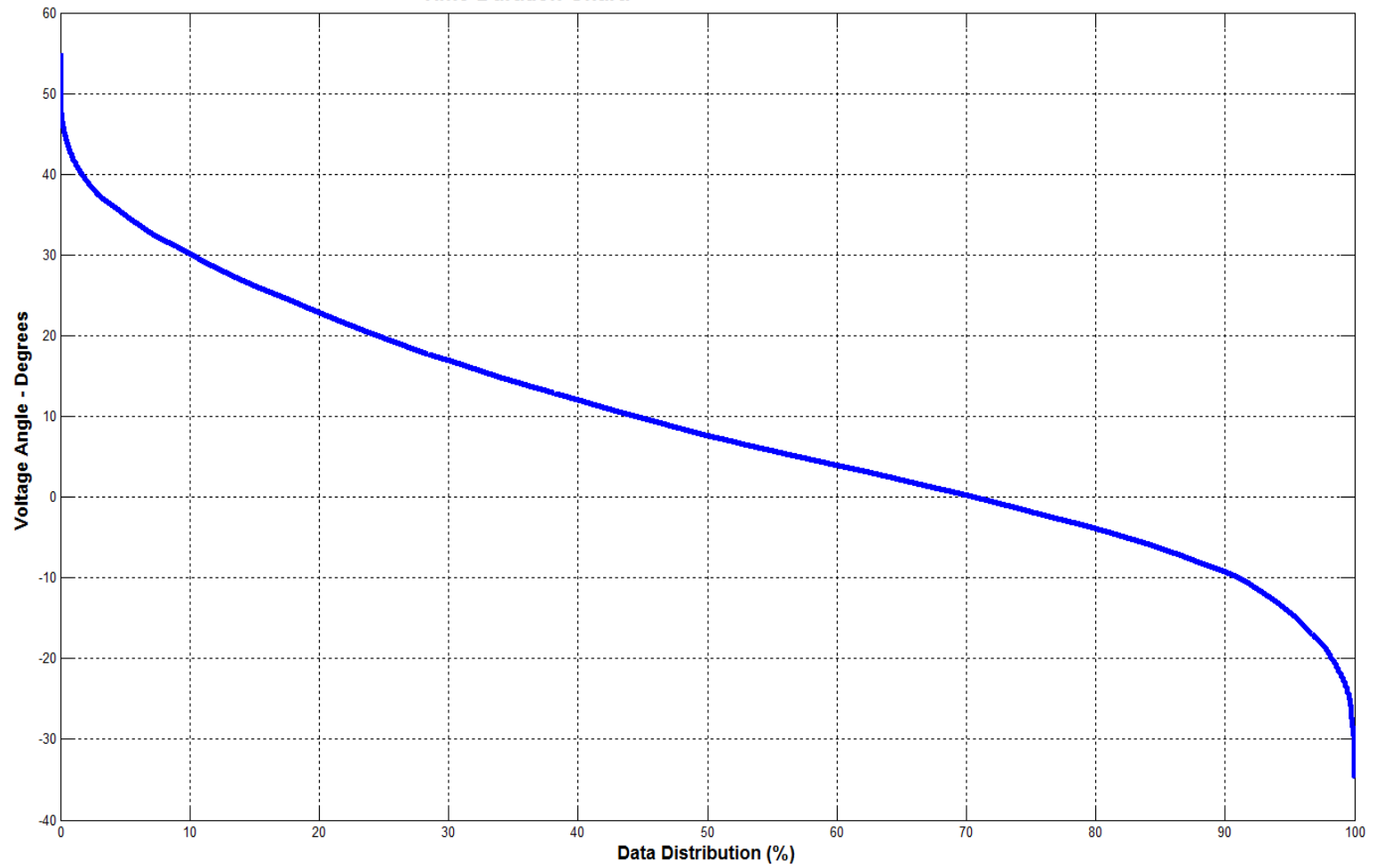


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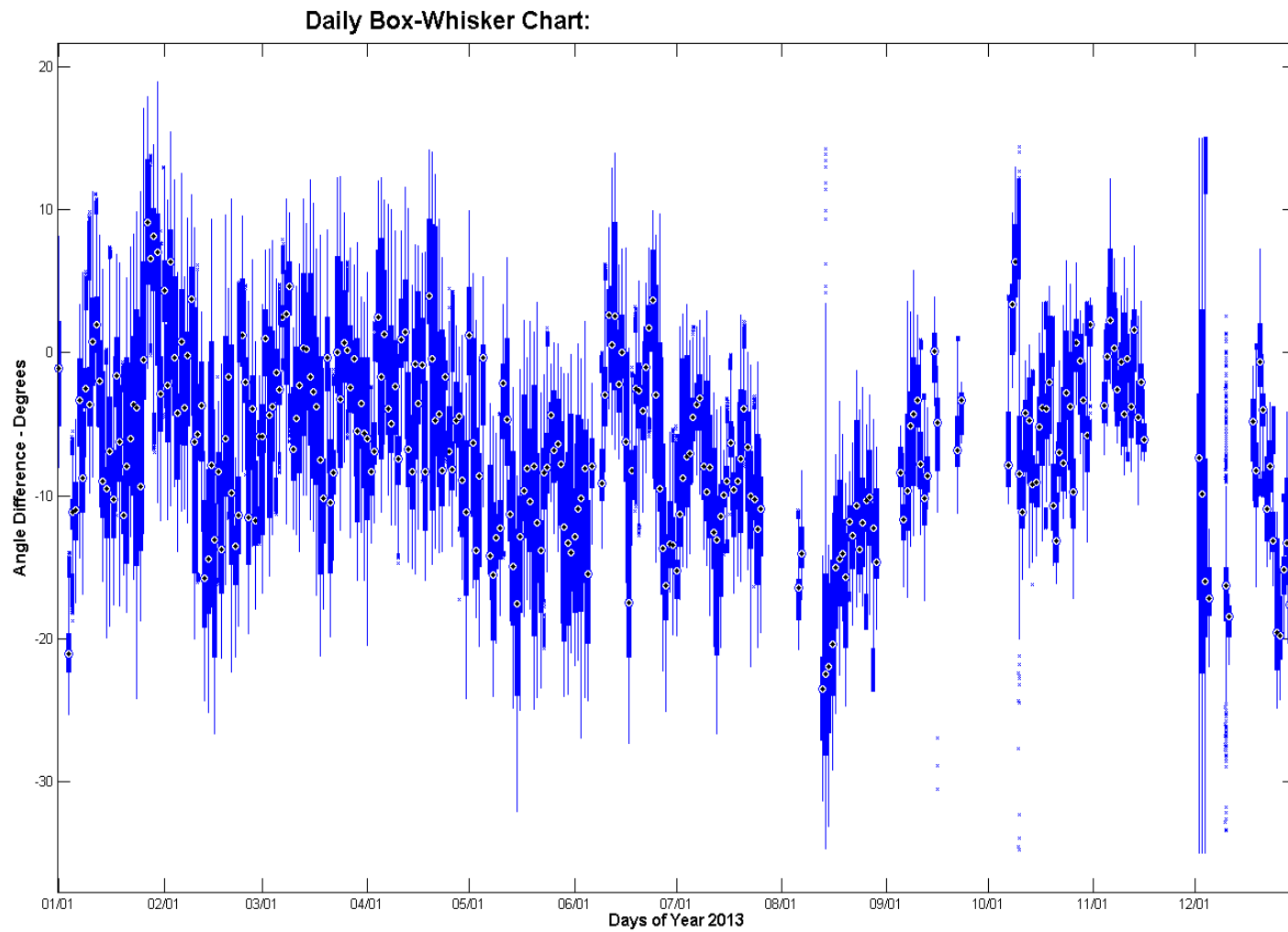


FarWest 9-West 4

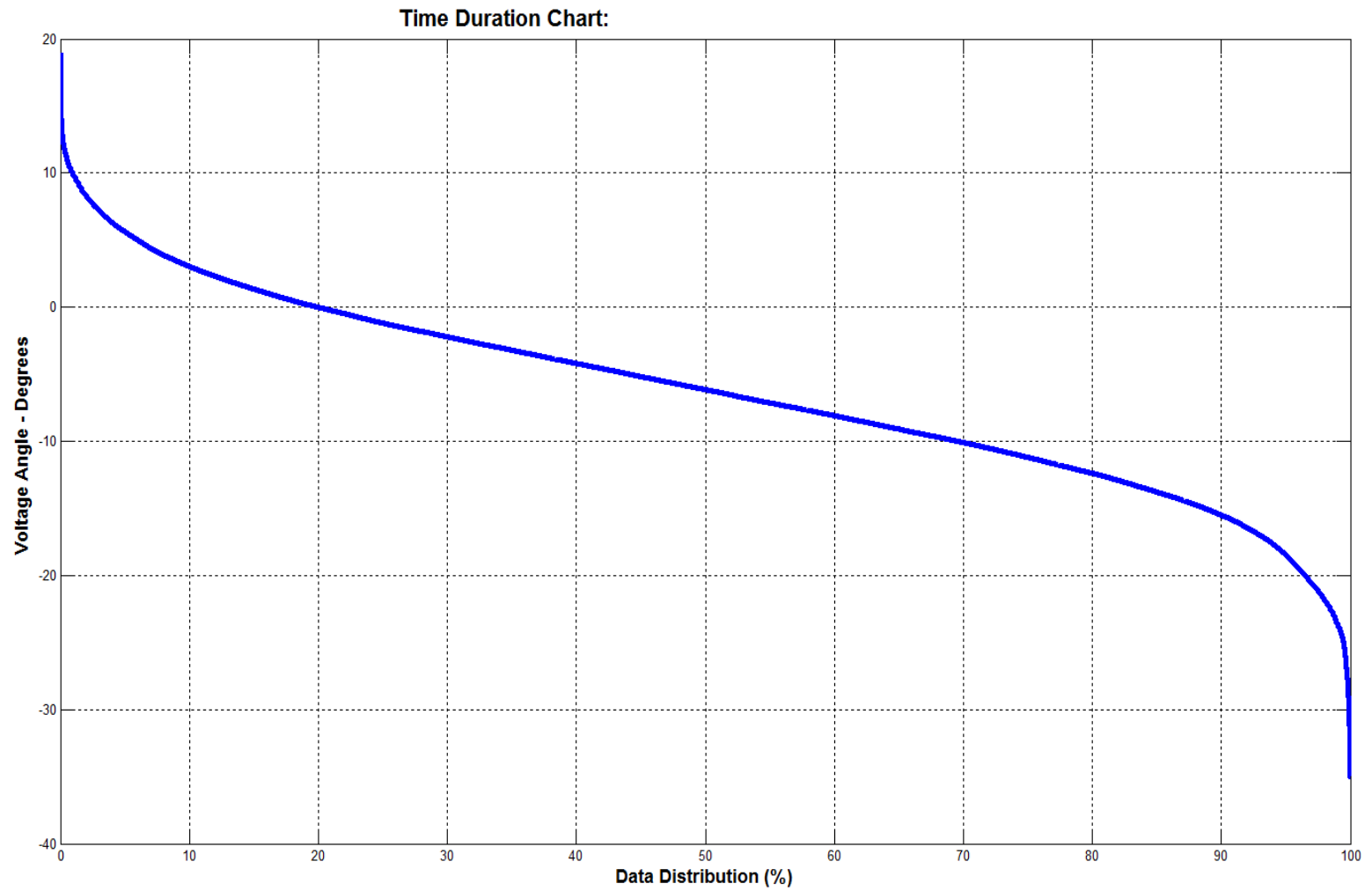
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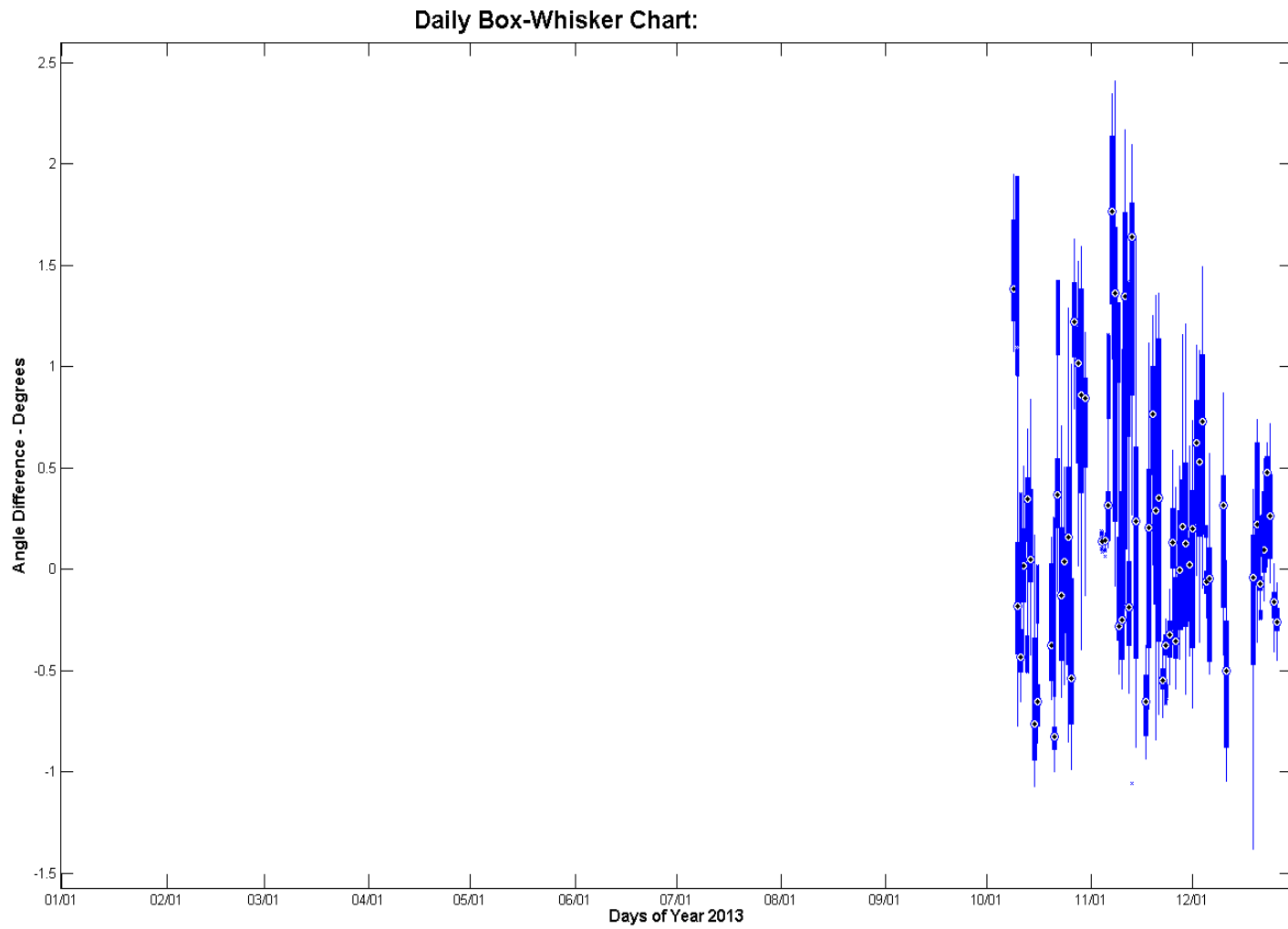
West 4-North 7



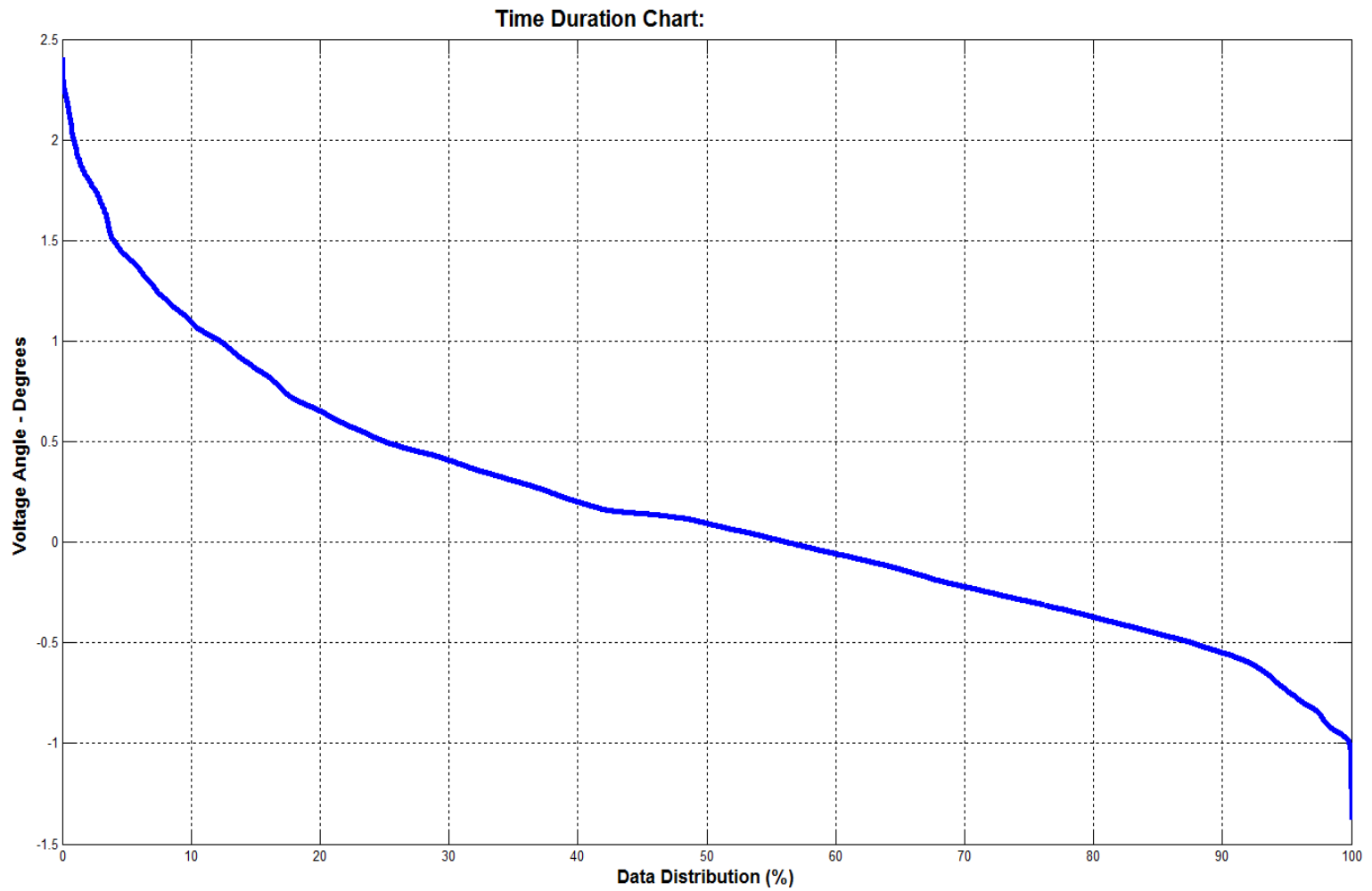
West 4-North 7



West 15-West 14



West 15-West 14



**Attachment 5. Updated Baseline Study #3
for 2013 and First Half of 2014**

Baselining Analysis Update 3
Six Months Data (February to July 2014)
Discovery Across Texas Project

Submitted to:

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External Report

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APPENDICES (attached as separate documents)

A, Voltage Angles, Ref: North 7- Box Whiskers & Time Duration

B, Angles Differences Box Whiskers & Time Duration

C, Comparison of Median Values, 2012 to 2014

D, RTDMS DAILY REPORT Recommendations

1. INTRODUCTION

The Center for Commercialization of Electric Technologies (CCET) was awarded contract DE-OE0000194 by the Department of Energy to perform the Discovery Across Texas demonstration project. Electric Power Group, LLC (EPG) received a sub award from CCET to provide professional services to perform, among other things, a substation cluster analysis, comparison of phasor data versus state estimator data, and voltage and angle difference baselining. In October 2013, EPG completed a Baselining Study update (Update 1) using 2012 and January-June 2013 data that included the following: (1) substations having Phasor Measurement Units (PMUs) which are geographically close to each other were grouped, and a voltage and angle difference analysis for each group (cluster analysis) was performed; (2) performed a comparison of voltage and angle differences obtained using phasor measurements versus similar results using state estimator data (phasor vs. state estimator comparison); and, (3) performed a baseline analysis for voltages and angle differences for selected pairs of substations. Alarm limits were established and documented based on the baseline analysis.

Twenty eight new Competitive Renewable Energy Zone (CREZ) 345 kV lines were added to the Electric Reliability Council of Texas (ERCOT) system in 2013, which will change the results obtained with the 2012 data and the first six-months of 2013 data, particularly in angle differences between locations. Nineteen of these lines were added in the second half of 2013. Since many CREZ lines were added in late 2013, the analysis results were still subject to change since the system configuration continued changing and so did the voltage angles and angle differences.

In June 2014, Baselining Update 2 was completed using data for the full 12-months of 2013. Update 2 report provided results that tracked the changes in voltage magnitudes and in voltage angle differences caused by the twenty eight new 345 kV lines added to the ERCOT system throughout 2013. The Update 2 report shows how the angle differences were changing as CREZ lines were being added to the ERCOT system. In general, results shown in the Baselining Study Update 2 report indicated that the angle differences for 2013 were smaller (representing a tighter electrical grid) than those found with 2012 state estimator and phasor data. Alarm limits were developed and proposed in this report. However those alarm limits were expected to change because they were obtained with data obtained under continued changing system conditions, since new CREZ lines were being added month-by-month all the way to December 2013.

An additional seven CREZ lines were added during the first quarter of 2014. By the end of March 2014, all planned CREZ lines had been added to the ERCOT system and by the end of July 2014 the ERCOT system has been operating with all these lines in service for 4-months. This Baselining Analysis Update 3, performed using data for the February to July, 2014 period, provides results that capture the effect of all the CREZ lines added to the ERCOT system. This Update was performed only for angle differences. Alarm limits for angle differences obtained in this Update 3 will reflect conditions that are not expected to change significantly in the foreseeable future since all the CREZ lines have been in service for several months and, therefore, can be used by operators in real-time monitoring of the ERCOT system. These alarm limits may need to be revised if major changes in transmission infrastructure or major shifts in generation patterns occur.

2. PROJECT SCOPE

A. Baseline Analysis for Voltage and Angle Differences

This study update analyzed the performance of ERCOT grid, using State Estimator data plus phasor data for the February to July 2014 period to identify normal and abnormal voltages angle limits across the grid. In this analysis, EPG also compared the results obtained using 7-months of 2014 data with those obtained using 2013 and 2012 data and summarized the differences, if any, due to addition of the 345 kV lines added in 2013. Activities performed as part of this update 3:

1. Extract key metric information (i.e., angles and angle differences).
2. Analyze extracted data and develop baseline understanding of voltage phase angle, and angle difference patterns for key pairs of substations similar to those used in Update 2.
3. Monitor angle differences (pairs) and develop patterns and statistics in the form of box-whisker plots and load duration curves. Substations selected for analysis of angle differences are listed in Table 3 below.
4. Prepare baselining analysis results for the selected pair of substations as Excel spreadsheet and charts, including:
 - a. Voltage phase angle difference statistics (mean, maximum and minimum).
 - b. Voltage and phase angle distribution functions.
5. Develop a comparison table to show the differences in results for voltages and angle differences using 2012, 2013, and the 6-months of 2014 data.
6. Prepare baselining analysis summary for discussion with ERCOT and the Synchrophasor Team.

B. Establishing Alarm Limits for Use in Operations

Based on this baselining analysis Update 3, EPG prepared a list of key angle pairs for monitoring in Real Time Dynamics Monitoring System¹ (RTDMS®), and voltage angle and angle difference alarm settings for use in RTDMS® to alert operators when grid critical variables are approaching limits.

As requested by ERCOT, EPG has conducted a baselining analysis Update 3 using data for the months of February to July 2014. No SE data was available for the month of January. Please note that a few CREZ 345 kV lines were added in January 2014 and a few more in late March 2014.

Final voltage and angle difference limits for use by operators should be reviewed with data collected for all 12-months of 2014; the ERCOT system will have no new CREZ lines added to it beyond March 22, 2014, and the angle difference ranges should be more stable resulting in a more current and accurate alarm limits.

^{1*} Electric Power Group. Built upon GRID-3P platform, US Patent 7,233,843, US Patent 8,060,259, and US Patent 8,401,710. All rights reserved.

3. DATA SOURCES

Two sources of data were utilized to perform the study update analysis of voltage and angle differences in the ERCOT network: phasor data and state estimator cases. A description of these sources of data is provided below. In-service dates for the new CREZ lines were also obtained from transmission owners and from ERCOT.

A. CREZ Lines Added to the ERCOT System

Table 1 below shows all the CREZ lines added to the ERCOT system during 2012, 2013, and 2014.

B. Phasor Data

ERCOT provided EPG phasor data for the February to July 2014 period with a resolution of 30-samples per second (SPS). Through an automated process, EPG downloaded, cleaned, and filtered data dropout to make it suitable for analysis. Further manual cleaning was necessary to weed out remaining outliers.

After the data was extracted and pre-processed, another program, developed by EPG, was used to extract the information and compiled it into a summary table, and two series of graphs. One graph (box -whisker) shows daily summaries of data, and the other, time duration curves, shows values versus percent time for each study variable. The time duration curves were used to obtain the metric values corresponding to 1% and 99% exceedance (the value which was less than 1% plus inflection or greater than 99% minus inflection).

Phasor Measurement Units (PMUs) Installed in the ERCOT System

As of May 27, 2014 there were 69 PMUs installed in 31 locations across the ERCOT service area. Table 2 below shows the 31 substation equipped with PMUs.

The baselining study Update 3 was completed using February to July, 2014 data, which included state estimator data for locations for which PMUs are installed or for which PMUs are planned.

Table 1 - CREZ 345 kV lines added to the ERCOT system as of April 14, 2014

Table 1: CREZ 345 Lines added to the ERCOT system as of April 14, 2014

| (Subject to Confirmation by ERCOT) | | | | |
|------------------------------------|-------------|------------|----------------|-------------------------|
| | <u>FROM</u> | <u>TO</u> | <u>VOLTAGE</u> | <u>IN-SERVICE DATES</u> |
| Year 2012 | | | | |
| 1 | West 2 | West 23 | 345 | February 10, 2012. |
| 2 | West 18 | West 1 | 345 | June 15, 2012. |
| 3 | West 23 | West 1 | 345 | June 16, 2012. |
| 4 | West 1 | West 24 | 345 | December 31, 2012. |
| 5 | West 24 | North 7 | 345 | December 31, 2012. |
| Year 2013 | | | | |
| 1 | South 9 | South 16 | 345 | February 27, 2013. |
| 2 | West 12 | West 21 | 345 | March 6, 2013. |
| 3 | North 9 | North 8 | 345 | March 21, 2013. |
| 4 | West 21 | North 8 | 345 | March 24, 2013. |
| 5 | West 19 | West 9 | 345 | April 15, 2013. |
| 6 | West 13 | West 19 | 345 | April 29, 2013. |
| 7 | West 18 | West 8 | 345 | May 23, 2013. |
| 8 | West 22 | North 11 | 345 | June 30, 2013. |
| 9 | West 14 | North 10 | 345 | June 30, 2013. |
| 10 | West 14 | West 16 | 345 | July 31, 2013. |
| 11 | West 15 | West 14 | 345 | August 13, 2013. |
| 12 | West 25 | West 15 | 345 | August 15, 2013. |
| 13 | West 15 | West 16 | 345 | August 15, 2013. |
| 14 | West 13 | West 19 | 345 | August 19, 2013. |
| 15 | West 26 | West 13 | 345 | August 21, 2013. |
| 16 | West 26 | West 17 | 345 | August 21, 2013. |
| 17 | West 17 | West 27 | 345 | August 21, 2013. |
| 18 | FarWest 10 | West 8 | 345 | August 31, 2013. |
| 19 | West 8 | South 9 | 345 | September 5, 2013. |
| 20 | West 13 | West 15 | 345 | September 18, 2013. |
| 21 | West 25 | West 27 | 345 | September 25, 2013. |
| 22 | West 12 | FarWest 11 | 345 | September 30, 2013. |
| 23 | West 3 | West 9 | 345 | November 6, 2013. |
| 24 | West 16 | West 3 | 345 | November 7, 2013. |
| 25 | West 27 | West 13 | 345 | November 15, 2013. |
| 26 | North 10 | North 11 | 345 | December 5, 2013. |
| 27 | West 3 | West 21 | 345 | December 18, 2013. |
| 28 | West 3 | West 22 | 345 | December 19, 2013. |
| Year 2014 | | | | |
| 1 | FarWest 12 | FarWest 7 | 345 | January 3, 2014. |
| 2 | FarWest 10 | FarWest 12 | 345 | January 3, 2014. |
| 3 | West 16 | West 19 | 345 | January 18, 2014. |
| 4 | FarWest 11 | FarWest 13 | 345 | March 22, 2014. |
| 5 | FarWest 13 | FarWest 7 | 345 | March 22, 2014. |
| 6 | FarWest 11 | FarWest 14 | 345 | March 22, 2014. |
| 7 | FarWest 14 | West 28 | 345 | March 22, 2014. |

Table 2 - List of Substations with PMUs Currently Connected to the ERCOT Grid, as of May27, 2014

| TABLE 2 - List of Substations with PMUs Currently Connected to the ERCOT Grid As of May 27, 2014 | | | | | | | |
|-----------------------------------------------------------------------------------------------------|-----------|----------|---------------------|------------------------------------------|--------------------------------------------------------|---------|---------|
| # | Company | PMU Name | PMU Name in D. Base | Name of the Station where PMU is located | Date-data stream connected to ERCOT | Enabled | Base kV |
| 1 | AEP | Line_1 | Line_1@ West 14 | West 14 | 7/25/2012 | Yes | 345 |
| 2 | AEP | Line_3 | Line_3@West_4 | West 4 | 7/2/2012 | Yes | 138 |
| 3 | AEP | Line_1 | Line_1 | Coast 3 | 4/30/2012 | Yes | 345 |
| 4 | AEP | Line_1 | Line_1 | Coast 4 | 3/26/2012 | Yes | 345 |
| 5 | AEP | Line_1 | Line_1@Coast_1 | Coast 1 | 1/23/2012 | Yes | 138 |
| 6 | AEP | Line_1 | Line_1@FarWest_9 | FarWest 9 | 3/26/2012 | Yes | 138 |
| 7 | AEP | Line_1 | Line_1 | West 10 | 8/1/2008. | Yes | 69 |
| 8 | AEP | Line_1 | Line_1 | West 15 | 9/16/2013 | Yes | 345 |
| 9 | AEP | Line_1 | Line_1 | West 16 | 12/19/2013 | Yes | 345 |
| 10 | AEP | Line_1* | Line_2@West_3 | West 3 | 12/19/2013 | Yes | 345 |
| 11 | AEP | Line_1 | Line_1 | Coast 2 | ?/2012 | Yes | 69 |
| 12 | AEP | Line_1 | Line_1@FarWest 2 | FarWest 2 | 6/21/2013 | Yes | 69 |
| 13 | AEP | Line_1 | Line_1@South_3 | South 3 | 6/21/2013 | Yes | 138 |
| 14 | AEP | Line_1 | Line_1@South_5 | South 5 | 6/21/2013 | Yes | 69 |
| 15 | AEP | Line_1 | Line_1@West_7 | West 7 | 6/21/2013 | Yes | 138 |
| 16 | ONCOR | Line_1 | Line_1 | North 4 | 10/20/2010 | Yes | 138 |
| 17 | ONCOR | Line_1 | Line_1 | North 5 | 10/20/2010 | Yes | 138 |
| 18 | ONCOR | Line_1 | Line_1 | North 6 | 10/20/2010 | Yes | 138 |
| 19 | ONCOR | Line_1 | Line_1 | North 7 | 10/20/2010 | Yes | 138 |
| 20 | ONCOR | Line_1 | Line_1 | FarWest 4 | 10/20/2010 | Yes | 345 |
| 21 | ONCOR | Line_1 | Line_1 | West 11 | 3/9/2012 | Yes | 345 |
| 22 | ONCOR | Line_1 | Line_1 | FarWest 7 | 10/20/2010 | Yes | 345 |
| 23 | ONCOR | Line_1 | Line_1 | FarWest 8 | 3/9/2012 | Yes | 138 |
| 24 | ONCOR | Line_1 | Line_1 | West 6 | 10/20/2010 | Yes | 345 |
| 25 | ONCOR | Line_1 | Line_1 | North 1 | 11/28/2012 | Yes | 345 |
| 26 | ONCOR | Line_1 | Line_1 | West 9 | 6/21/2013 | Yes | 345 |
| 27 | ONCOR | Line_1 | Line_1 | West 12 | 6/21/2013 | Yes | 345 |
| 28 | ONCOR | Line_1 | Line_1 | West 5 | 6/21/2013 | Yes | 345 |
| 29 | ONCOR | Line_1 | Line_1 | West 2 | 6/21/2013 | Yes | 345 |
| 30 | ONCOR | Line_1 | Line_1 | West 1 | 6/21/2013 | Yes | 345 |
| 31 | SHARYLAND | Line_3 | Line_3@South 13 | South 13 | 8/10/2012 | Yes | 138 |
| Note: * | | | | | Means new substations with PMU connected to ERCOT grid | | |

C. State Estimator (SE) Data

ERCOT provided EPG with SE data for the February to July months of 2014. EPG used the PowerWorld simulator provided by ERCOT via PowerWorld to extract approximately 25,419 SE cases. There was only one day, May 6, for which SE data was not available. This high-level of SE data availability in 2014 was a significant improvement from 2013.

D. Data Availability

Data availability for the phasor data sources varied from substation to substation; the summary table of phasor-based results shows the percent availability for each substation or each pair analyzed. As shown in Table A-1, availability ranges from less than 20% for FarWest 2 and Coast 2 to greater than 90% for eighteen PMUs. The remaining ten PMUs have availability ranging from

62.08% (Coast 4) to 89.06% (Coast 1). Box-whisker plots in Appendix A provide a view of data availability on a day-by-day basis.

Below is a summary of phasor data availability from Table A-1 for 2012, for 2013 and for 2014 (six months):

2014

<20%

Coast 2
FarWest 2

20% to 60%

None

61% to 90%

Coast 1
West 4
West 14
Coast 4
Coast 3
South 13
FarWest 9
West 16
West 3
West 15

>90%

West 10
West 11
South 3
South 5
West 1
West 2
West 9
West 12
West 5
West 6
North 1
North 4
North 5
North 6
FarWest 4
FarWest 7
FarWest 8
North 7

2013

<20%

West 16
West 3
West 15

20% to 60%

West 1
West 2
West 9
West 12
West 5
FarWest 2
South 3
South 5

61% to 80%

West 14
West 4
Coast 4
Coast 3

>80%

West 10
West 11
West 6
North 1
North 4
North 5
North 6
North 7
Coast 2
Coast 1
South 13
FarWest 4
FarWest 7
FarWest 8
FarWest 9

2012

<40%

West 14
North 1
Coast 2
South 6
FarWest 7

41% to 60%

West 4
Coast 4
Coast 3
South 13
FarWest 9

61% to 80%

West 11
Coast 1
FarWest 8

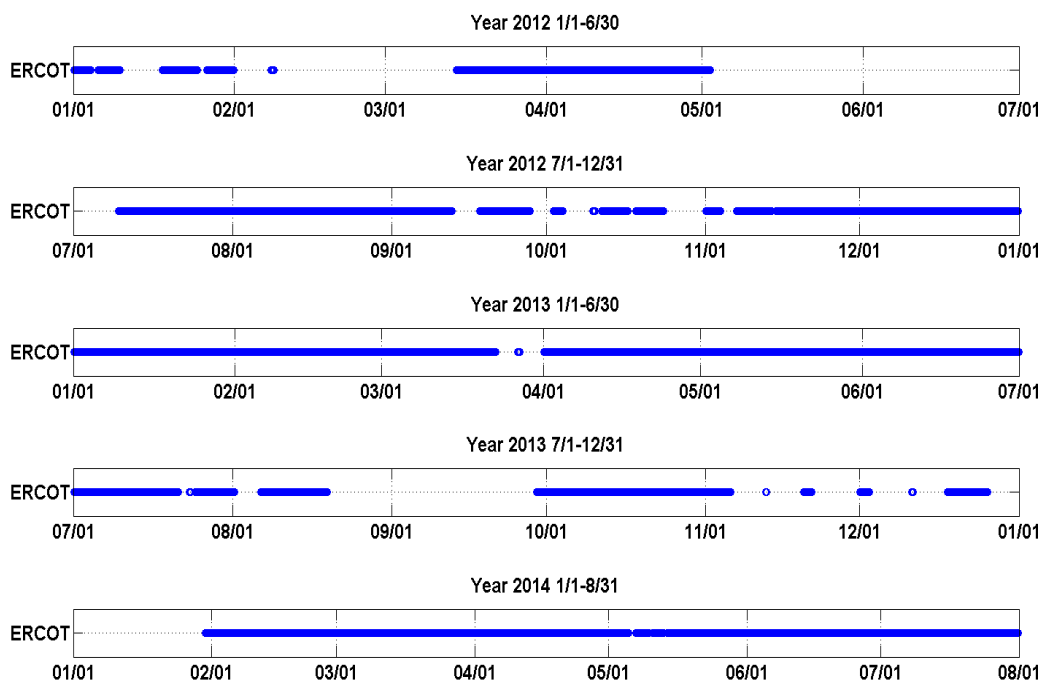
>80%

West 10
North 7
North 2
North 4
North 5
West 6
North 6
FarWest 4

For SE data availability, ERCOT produces state estimator cases every 5-minutes for a total of 52,218 possible cases for the February to July months. ERCOT provided SE data at a rate of six cases per hour. The total possible number of cases at this rate for the February to July period is 26,064. EPG received 25,419 cases, which means the availability of SE data for these 6-months was approximately 97.5 %. State Estimator data availability has significantly improved during this six-month period.

The graph below shows ERCOT SE data availability since January 1, 2012 until July 31, 2014.

ERCOT SE Data Availability



4. METHODOLOGY FOR BASELINE ANALYSIS FOR VOLTAGE ANGLES

This baseline analysis update for voltage angle was performed using the phasor data and state estimator data obtained from ERCOT for six-months of 2014 (February to July). This data was processed to extract voltage angles. Minimum and maximum values for these variables were documented in summary tables; box-whiskers plots and time duration curves were developed for each variable and for each type of data used. Below is an analysis of voltage angles.

For the substation pairs selected for study, the following work was performed:

1. Obtain and process phasor data and state estimator data.
2. Identify the substations for which phasor data is available and for which PMUs are planned.
3. Select angle pairs of interest to ERCOT and the synchrophasor team members by choosing substations that have or soon will have PMUs installed.
4. Extract information to identify max, min and average values from these data sources. Prepare summary tables for the selected pairs showing results of all data, including data saved during events.
5. Develop statistical charts including time duration curve and box-whisker graphs for voltage angles pairs.
6. Identify limits corresponding to normal operation; excluding events and outages. To exclude extreme values corresponding to outliers and to events, values corresponding to the metrics within the 1% to 99% percent of the time range were identified for the entire study period, to be identified as normal operating limits.
7. Perform statistical analyses to identify angle differences limits for the selected pairs under all conditions. Summarize angle difference limits.
 - Establish limits for normal operation based on the criteria described in the corresponding methodology. Summarize angle difference limits.
 - The limits for angle differences identified in this report shall be compared with ERCOT's criteria, if any, that apply to angle differences for the paths selected for this study.
8. Analyze results, identify limits, and report results for each pair selected.

5. BASELINE ANALYSIS FOR VOLTAGE ANGLES (REFERENCE: NORTH 7)

A. Substations Identified for Voltage Angle Analysis

The following substations were selected for voltage angle analysis; the North 7 substation was selected as a common reference.

Table 3 - Substations for Voltage Angle Difference Monitoring

| Table 3 - SUBSTATIONS FOR VOLTAGE ANGLE DIFFERENCE MONITORING (Ref.: North 7) | | | |
|--------------------------------------------------------------------------------------|-------------------|-----------------------------------------------------|---------------|
| # | SUBSTATION | kV | REGION |
| 1 | West 10 | 69 | Panhandle |
| 2 | West 14 | 345 | Panhandle |
| 3 | West 1 | 345 | Central |
| 4 | West 2 | 345 | Central |
| 5 | West 9 | 345 | Central |
| 6 | West 11 | 345 | Central |
| 7 | West 12 | 345 | Central |
| 8 | West 5 | 345 | Central |
| 9 | West 6 | 345 | Central |
| 10 | North 1 | 345 | Dallas |
| 11 | North 4 | 138 | Dallas |
| 12 | North 5 | 138 | Dallas |
| 13 | North 6 | 138 | East |
| 14 | FarWest 2 | 69 | West Texas |
| 15 | West 4 | 138 | SouthWest |
| 16 | Coast 2 | 69 | Valley |
| 17 | Coast 1 | 138 | Valley |
| 18 | South 3 | 138 | Valley |
| 19 | South 5 | 138 | Valley |
| 20 | Coast 4 | 345 | Valley |
| 21 | Coast 3 | 345 | Valley |
| 22 | South 13 | 138 | Valley |
| 23 | FarWest 4 | 345 | West Texas |
| 24 | FarWest 7 | 345 | West Texas |
| 25 | FarWest 8 | 138 | West Texas |
| 26 | FarWest 9 | 138 | West Texas |
| 27 | West 16 | 345 | Panhandle |
| 28 | West 3 | 345 | Central |
| 29 | West 15 | 345 | Panhandle |
| 30 | West 8* | 345 | Central |
| 31 | South 15 | 345 | Central |
| 32 | South 2* | 345 | Central-East |
| 33 | South 4* | 345 | Central-East |
| 34 | South 7* | 345 | Central-East |
| 35 | South 9* | 345 | Central-East |
| 36 | South 11* | 345 | Central-East |
| 37 | South 10* | 138 | Valley |
| 38 | West 17* | 345 | Panhandle |
| 39 | West 13* | 345 | Panhandle |
| NOTE: | | * Means substations without PMUs connected to ERCOT | |

Summary of Results - All data included

The voltage angle results obtained from all data available: all solved SE cases, and all phasor data, are summarized in Table A-1 below.

These results were obtained using all data available, including event and outage conditions; under these conditions, voltage angles would be expected to be larger than under normal conditions because during event and outage conditions the angle spreads tend to increase in absolute magnitude to reflect the changes in system conditions or changes in system configuration. The maximum Max-Min spreads observed were 91.4 degrees for South 13 - 138 kV substation and 81.5 degrees for Coast 4 - 345 kV substation. The lowest spread of 19.5 degrees was seen at North 6. The angles for North 1 and North 6 were positive most of the time (93.5 and 78.8% respectively) whereas North 4, North 5, West 4 and South 5 substations are positive less than 20% of the time; that is, the power flows from North 7 to these substations most of the time.

As expected, the Max-Min spreads from this update are smaller than those Max-Min spreads found in the 2013 baselining study; particularly for those substations in the Western and Panhandle areas of Texas.

The phasor data for FarWest 2 appears to be unreliable given the inconsistent results (average of -130.2 degrees). The SE data for this substation seems reasonable.

Table A- 1 - Baselining Analysis – Voltage Angles – ALL Conditions

| Table A-1: CCET DISCOVERY ACROSS TEXAS- BASELINING ANALYSIS- VOLTAGE ANGLES- ALL CONDITIONS | | | | | | | | | | | | | | |
|---------------------------------------------------------------------------------------------|-------------------------|---------|---------------------------------------------------------------------------------------|--------|---------|------------------|----------------|-----------|----------------------------------|-------|---------|------------------|----------------|--|
| (Reference: North 7) | | | | | | | | | | | | | | |
| No | Angle Pair FROM - TO | Base kV | Phasor Data 2/1/2014 to 7/31/2014 % Data | | | | | | State Estimator Data 2/1/2014 to | | | | | |
| | | | Min | Max | Average | Percent Positive | Max-Min Spread | Available | Min | Max | Average | Percent Positive | Max-Min Spread | |
| 1 | West 10 | 69 | -27.17 | 38.37 | 5.05 | 57.90 | 65.54 | 94.42 | -26.56 | 37.13 | 4.63 | 56.53% | 63.7 | |
| 2 | West 14 | 345 | -18.62 | 19.39 | 3.32 | 72.36 | 38.01 | 75.78 | -17.29 | 16.95 | 3.13 | 71.31% | 34.2 | |
| 3 | West 1 | 345 | -27.01 | 33.17 | 2.98 | 67.87 | 60.17 | 95.27 | -10.60 | 16.71 | 2.88 | 67.11% | 27.3 | |
| 4 | West 2 | 345 | -15.54 | 22.72 | 3.70 | 64.06 | 38.25 | 96.31 | -15.43 | 22.63 | 3.59 | 63.29% | 38.1 | |
| 5 | West 9 | 345 | -16.46 | 21.38 | 3.49 | 66.30 | 37.84 | 96.24 | -16.34 | 21.45 | 3.49 | 65.66% | 37.8 | |
| 6 | West 11 | 345 | -18.16 | 26.39 | 3.59 | 60.44 | 44.55 | 92.55 | -18.18 | 26.06 | 3.26 | 58.77% | 44.2 | |
| 7 | West 12 | 345 | -16.91 | 22.19 | 3.57 | 64.33 | 39.10 | 96.26 | -16.83 | 22.41 | 3.56 | 63.63% | 39.2 | |
| 8 | West 5 | 345 | -16.73 | 23.95 | 3.97 | 64.32 | 40.67 | 96.16 | -16.71 | 25.08 | 3.95 | 63.35% | 41.8 | |
| 9 | West 6 | 345 | -16.91 | 23.88 | 4.08 | 64.88 | 40.79 | 96.07 | -17.02 | 23.82 | 3.86 | 63.41% | 40.8 | |
| 10 | North 1 | 345 | -11.21 | 16.64 | 5.56 | 93.32 | 27.85 | 96.14 | -8.17 | 16.09 | 5.47 | 93.52% | 24.3 | |
| 11 | North 4 | 138 | -17.64 | 8.28 | -3.88 | 11.70 | 25.92 | 96.21 | -16.45 | 7.56 | -3.50 | 13.06% | 24.0 | |
| 12 | North 5 | 138 | -21.82 | 10.06 | -5.54 | 8.78 | 31.87 | 95.74 | -20.90 | 8.89 | -5.70 | 7.95% | 29.8 | |
| 13 | North 6 | 138 | -6.82 | 14.70 | 3.65 | 84.01 | 21.52 | 96.26 | -6.15 | 13.30 | 2.82 | 78.81% | 19.5 | |
| 14 | FarWest 2 | 69 | -162.27 | -90.41 | -130.15 | 0.00 | 71.86 | 14.32 | -21.25 | 9.01 | -9.14 | 4.44% | 30.3 | |
| 15 | West 4 | 138 | -31.82 | 16.98 | -6.27 | 17.11 | 48.80 | 88.34 | -31.28 | 14.83 | -6.70 | 14.97% | 46.1 | |
| 16 | Coast 2 | 69 | -24.78 | 20.95 | -3.25 | 30.05 | 45.73 | 11.58 | -31.62 | 24.32 | -7.12 | 17.68% | 55.9 | |
| 17 | Coast 1 | 138 | -32.87 | 59.15 | 1.64 | 54.51 | 92.02 | 89.06 | -31.69 | 45.22 | 1.08 | 52.67% | 76.9 | |
| 18 | South 3 | 138 | -44.24 | 44.77 | 0.58 | 51.79 | 89.01 | 90.82 | -26.06 | 34.32 | 0.36 | 50.96% | 60.4 | |
| 19 | South 5 | 138 | -29.91 | 16.90 | -7.46 | 10.45 | 46.80 | 92.41 | -24.51 | 11.25 | -7.31 | 12.83% | 35.8 | |
| 20 | Coast 4 | 345 | -33.74 | 51.82 | 5.15 | 63.02 | 85.55 | 62.08 | -32.03 | 49.50 | 4.91 | 62.89% | 81.5 | |
| 21 | Coast 3 | 345 | -33.02 | 55.99 | 5.09 | 63.40 | 89.01 | 86.18 | -32.03 | 49.03 | 4.58 | 62.21% | 81.1 | |
| 22 | South 13 | 138 | -42.85 | 48.42 | -0.16 | 47.27 | 91.27 | 69.34 | -44.63 | 47.00 | -0.70 | 46.41% | 91.6 | |
| 23 | FarWest 4 | 345 | -19.45 | 29.63 | 3.87 | 59.46 | 49.08 | 96.06 | -19.36 | 29.19 | 3.64 | 58.50% | 48.6 | |
| 24 | FarWest 7 | 345 | -24.48 | 28.17 | 1.05 | 51.98 | 52.65 | 95.91 | -24.59 | 27.81 | 0.91 | 51.01% | 52.4 | |
| 25 | FarWest 8 | 138 | -35.13 | 20.96 | -8.52 | 22.22 | 56.08 | 91.49 | -34.23 | 21.16 | -7.71 | 25.13% | 55.4 | |
| 26 | FarWest 9 | 138 | -25.35 | 31.81 | 1.19 | 51.54 | 57.16 | 75.44 | -23.43 | 31.27 | 0.45 | 49.30% | 54.7 | |
| 27 | West 16 | 345 | -17.80 | 20.70 | 3.29 | 71.38 | 38.50 | 72.64 | -17.01 | 17.50 | 3.36 | 70.95% | 34.5 | |
| 28 | West 3 | 345 | -14.90 | 16.41 | 3.45 | 73.71 | 31.31 | 83.88 | -14.46 | 16.13 | 3.14 | 71.38% | 30.6 | |
| 29 | West 15 | 345 | -17.06 | 19.70 | 3.61 | 73.17 | 36.76 | 72.06 | -16.92 | 18.22 | 3.55 | 71.36% | 35.1 | |
| 30 | West 8* | 345/138 | No phasor data available for these substations for the study period (2/1 to 7/1/2014) | | | | | | -13.59 | 25.61 | 2.05 | 57.60% | 39.2 | |
| 31 | South 15 | 345/138 | | | | | | | -7.71 | 15.46 | 1.43 | 62.28% | 23.2 | |
| 32 | South 2* | 345/138 | | | | | | | -5.59 | 16.26 | 2.91 | 79.51% | 21.9 | |
| 33 | South 4* | 345/138 | | | | | | | -8.57 | 16.91 | 1.54 | 61.77% | 25.5 | |
| 34 | South 7* | 345/138 | | | | | | | -14.89 | 22.14 | 3.93 | 78.18% | 37.0 | |
| 35 | South 9* | 345/138 | | | | | | | -10.29 | 11.74 | 1.06 | 63.08% | 22.0 | |
| 36 | South 11* | 345/138 | | | | | | | -9.77 | 18.16 | 1.41 | 59.32% | 27.9 | |
| 37 | South 10* | 138 | | | | | | | -34.29 | 24.01 | -7.19 | 16.84% | 58.3 | |
| 38 | West 17* | 345/138 | | | | | | | -16.73 | 19.66 | 4.04 | 71.99% | 36.4 | |
| 39 | West 13* | 345/138 | | | | | | | -16.81 | 18.80 | 3.71 | 70.67% | 35.6 | |

NOTE: * Means substations without PMUs connected to ERCOT by July 31, 2014; no phasor data available

B. Summary of Results – Normal Conditions (events and outages excluded)

The voltage angle results obtained from excluding extreme values based on analysis of the box-whiskers plots and time duration curves are shown in Table A- 2 below.

Summaries of voltage angle pairs with their corresponding box-whisker and time duration curves based on state estimator data and based on phasor data are presented in Appendix A, Parts 1 and 2.

NOTE: Phasor data availability for FarWest 2 and Coast 2 was less than 15% for the study period; all other substations had data availability greater than 60%.

Table A- 2 - Baselining Analysis Update – Voltage Angles – Normal Conditions (Ref: 138 kV North 7)

| | | | Phasor Data | | | State Estimator Data - 2/1/14 to 7/31/14 | | | | | | | | | | SE Data-Normal | | |
|-------------------------------------------------------------------------------------------------------------|-------------------------|---------|---------------------------------------------------|--------------|-----------------------|------------------------------------------|-----------------------------------|-----------------------------|---------------------------------------|---------------------------------|-------------------------------------|-------------------------------|---------------------------------|---------------------------|--------------|----------------|-----------------------|--|
| No | Angle Pair FROM - TO | Base kV | Min Angle | Max Angle | Max- Min Spread | Percent Positive | Min Angle at POI or 100% | Percent (POI or 100%) | Min Angle at 99% or POI - 1% | Percent (99% or POI - 1%) | Max Angle at 1% or POI +1% | Percent (1% or POI +1%) | Max Angle at POI or 0% | Percent (POI or 0%) | Min Angle | Max Angle | Max- Min Spread | |
| 1 | West 10 | 69/138 | -26.42 | 35.08 | 61.50 | 56.53% | -26.33 | 99.98% | -22.65 | 98.98% | 33.15 | 1.05% | 35.22 | 0.05% | -26.33 | 35.22 | 61.6 | |
| 2 | West 14 | 345/138 | -13.28 | 16.14 | 29.42 | 71.31% | -16.60 | 99.97% | -9.48 | 98.97% | 13.90 | 1.02% | 16.61 | 0.02% | -16.60 | 16.61 | 33.2 | |
| 3 | West 1 | 345/138 | -10.38 | 16.58 | 26.96 | 67.11% | -9.26 | 99.94% | -7.01 | 98.94% | 13.04 | 1.03% | 15.89 | 0.03% | -9.26 | 15.89 | 25.1 | |
| 4 | West 2 | 345/138 | -13.48 | 20.88 | 34.36 | 63.29% | -13.63 | 99.94% | -10.84 | 98.94% | 18.60 | 1.06% | 21.03 | 0.06% | -13.63 | 21.03 | 34.7 | |
| 5 | West 9 | 345/138 | -13.47 | 19.41 | 32.88 | 65.66% | -13.06 | 99.81% | -10.71 | 98.81% | 17.48 | 1.03% | 20.77 | 0.03% | -13.06 | 20.77 | 33.8 | |
| 6 | West 11 | 345/138 | -15.79 | 24.26 | 40.05 | 58.77% | -16.19 | 99.93% | -13.50 | 98.93% | 21.03 | 1.03% | 24.20 | 0.03% | -16.19 | 24.20 | 40.4 | |
| 7 | West 12 | 345/138 | -14.21 | 20.33 | 34.54 | 63.63% | -14.63 | 99.93% | -11.36 | 98.93% | 18.74 | 1.02% | 21.86 | 0.02% | -14.63 | 21.86 | 36.5 | |
| 8 | West 5 | 345/138 | -14.28 | 21.52 | 35.80 | 63.35% | -14.50 | 99.92% | -11.59 | 98.92% | 21.26 | 1.02% | 24.66 | 0.02% | -14.50 | 24.66 | 39.2 | |
| 9 | West 6 | 345/138 | -14.34 | 21.84 | 36.18 | 63.41% | -14.92 | 99.94% | -11.68 | 98.94% | 19.90 | 1.06% | 22.51 | 0.06% | -14.92 | 22.51 | 37.4 | |
| 10 | North 1 | 345/138 | -6.67 | 14.71 | 21.38 | 93.52% | -6.78 | 99.95% | -3.75 | 98.95% | 12.45 | 1.02% | 15.75 | 0.02% | -6.78 | 15.75 | 22.5 | |
| 11 | North 4 | 138 | -15.94 | 6.11 | 22.05 | 13.06% | -16.15 | 99.98% | -12.88 | 98.98% | 4.41 | 1.04% | 6.79 | 0.04% | -16.15 | 6.79 | 22.9 | |
| 12 | North 5 | 138 | -18.85 | 8.17 | 27.02 | 7.95% | -18.87 | 99.93% | -15.29 | 98.93% | 4.33 | 1.04% | 7.64 | 0.04% | -18.87 | 7.64 | 26.5 | |
| 13 | North 6 | 138 | -4.95 | 12.50 | 17.45 | 78.81% | -5.91 | 99.99% | -3.81 | 98.99% | 9.93 | 1.05% | 12.56 | 0.05% | -5.91 | 12.56 | 18.5 | |
| 14 | FarWest 2 | 69/138 | -151.20 | -101.40 | 49.80 | 4.44% | -21.06 | 99.98% | -18.19 | 98.98% | 3.80 | 1.05% | 7.55 | 0.05% | -21.06 | 7.55 | 28.6 | |
| 15 | West 4 | 138 | -31.12 | 13.81 | 44.93 | 14.97% | -29.59 | 99.91% | -23.63 | 98.91% | 9.00 | 1.08% | 12.89 | 0.08% | -29.59 | 12.89 | 42.5 | |
| 16 | Coast 2 | 69/138 | -23.69 | 19.29 | 42.98 | 17.68% | -28.60 | 99.93% | -23.17 | 98.93% | 14.15 | 1.05% | 23.20 | 0.05% | -28.60 | 23.20 | 51.8 | |
| 17 | Coast 1 | 138 | -28.38 | 40.80 | 69.18 | 52.67% | -29.94 | 99.98% | -24.09 | 98.98% | 30.94 | 1.07% | 41.21 | 0.07% | -29.94 | 41.21 | 71.2 | |
| 18 | South 3 | 138 | -24.78 | 27.99 | 52.77 | 50.96% | -25.01 | 99.97% | -19.46 | 98.97% | 22.40 | 1.08% | 31.17 | 0.08% | -25.01 | 31.17 | 56.2 | |
| 19 | South 5 | 138 | -24.90 | 13.04 | 37.94 | 12.83% | -21.72 | 99.78% | -19.16 | 98.78% | 7.26 | 1.06% | 10.82 | 0.06% | -21.72 | 10.82 | 32.5 | |
| 20 | Coast 4 | 345/138 | -28.96 | 47.63 | 76.59 | 62.89% | -29.09 | 99.94% | -20.87 | 98.94% | 34.65 | 1.04% | 47.54 | 0.04% | -29.09 | 47.54 | 76.6 | |
| 21 | Coast 3 | 345/138 | -26.38 | 46.84 | 73.22 | 62.21% | -29.06 | 99.94% | -20.89 | 98.94% | 34.22 | 1.02% | 47.73 | 0.02% | -29.06 | 47.73 | 76.8 | |
| 22 | South 13 | 138 | -31.17 | 45.74 | 76.91 | 46.41% | -40.30 | 99.94% | -27.59 | 98.94% | 30.63 | 1.02% | 45.16 | 0.02% | -40.30 | 45.16 | 85.5 | |
| 23 | FarWest 4 | 345/138 | -18.25 | 26.24 | 44.49 | 58.50% | -18.25 | 99.97% | -15.03 | 98.97% | 23.91 | 1.02% | 28.22 | 0.02% | -18.25 | 28.22 | 46.5 | |
| 24 | FarWest 7 | 345/138 | -22.45 | 23.62 | 46.07 | 51.01% | -22.50 | 99.93% | -18.51 | 98.93% | 20.71 | 1.05% | 24.87 | 0.05% | -22.50 | 24.87 | 47.4 | |
| 25 | FarWest 8 | 138 | -31.51 | 15.85 | 47.36 | 25.13% | -33.09 | 99.98% | -27.22 | 98.98% | 13.62 | 1.02% | 20.05 | 0.02% | -33.09 | 20.05 | 53.1 | |
| 26 | FarWest 9 | 138 | -22.92 | 26.28 | 49.20 | 49.30% | -22.76 | 99.98% | -19.42 | 98.98% | 23.22 | 1.04% | 27.32 | 0.04% | -22.76 | 27.32 | 50.1 | |
| 27 | West 16 | 345 | -13.41 | 16.31 | 29.72 | 70.95% | -15.72 | 99.95% | -9.17 | 98.95% | 14.80 | 1.02% | 17.22 | 0.02% | -15.72 | 17.22 | 32.9 | |
| 28 | West 3 | 345 | -11.29 | 15.25 | 26.54 | 71.38% | -13.80 | 99.97% | -8.18 | 98.97% | 13.36 | 1.02% | 15.82 | 0.02% | -13.80 | 15.82 | 29.6 | |
| 29 | West 15 | 345 | -13.38 | 17.43 | 30.81 | 71.36% | -13.37 | 99.88% | -9.12 | 98.88% | 15.60 | 1.03% | 17.87 | 0.03% | -13.37 | 17.87 | 31.2 | |
| 30 | West 8* | 345 | No phasor data available for these substations | | | 57.60% | -12.53 | 99.88% | -8.30 | 98.88% | 15.40 | 1.02% | 24.59 | 0.02% | -12.53 | 24.59 | 37.1 | |
| 31 | South 15 | 345 | | | | 62.28% | -6.84 | 99.95% | -5.03 | 98.95% | 12.29 | 1.02% | 15.18 | 0.02% | -6.84 | 15.18 | 22.0 | |
| 32 | South 2* | 345 | | | | 79.51% | -5.17 | 99.95% | -3.25 | 98.95% | 12.95 | 1.04% | 15.60 | 0.04% | -5.17 | 15.60 | 20.8 | |
| 33 | South 4* | 345 | | | | 61.77% | -6.73 | 99.84% | -5.45 | 98.84% | 13.29 | 1.03% | 16.40 | 0.03% | -6.73 | 16.40 | 23.1 | |
| 34 | South 7* | 345 | | | | 78.18% | -7.72 | 99.93% | -4.84 | 98.93% | 17.58 | 1.06% | 21.40 | 0.06% | -7.72 | 21.40 | 29.1 | |
| 35 | South 9* | 345 | | | | 63.08% | -8.06 | 99.92% | -6.00 | 98.92% | 8.65 | 1.04% | 11.25 | 0.04% | -8.06 | 11.25 | 19.3 | |
| 36 | South 11* | 345 | | | | 59.32% | -8.54 | 99.95% | -6.36 | 98.95% | 14.18 | 1.02% | 17.66 | 0.02% | -8.54 | 17.66 | 26.2 | |
| 37 | South 10* | 138 | | | | 16.84% | -33.46 | 99.98% | -24.81 | 98.98% | 13.81 | 1.02% | 23.43 | 0.02% | -33.46 | 23.43 | 56.9 | |
| 38 | West 17* | 345 | | | | 71.99% | -16.10 | 99.97% | -9.41 | 98.97% | 16.84 | 1.09% | 18.71 | 0.09% | -16.10 | 18.71 | 34.8 | |
| 39 | West 13* | 345 | | | | 70.67% | -14.68 | 99.92% | -9.42 | 98.92% | 16.21 | 1.09% | 18.09 | 0.09% | -14.68 | 18.09 | 32.8 | |
| Note: The substations market with * did not have PMUs installed by July 31, 2014; no phasor data available. | | | | | | | | | | | | | | | | | | |

Note: The substations marked with * did not have PMUs installed by July 31, 2014; no phasor data available.

NOTE: the substations noted with a * have no phasor data available.

C. Observations – Normal Conditions

- Angles and angle spreads from State Estimator data track well with those obtained with phasor data except for FarWest 2 and Coast 2. Phasor data for these two substations is incomplete or unreliable.

2. Voltage angle fluctuations have been reduced and now they vary over a smaller range. There are only five substations with Max-Min angle spread of more than 60 degrees. The largest angle variations occurred among the substations in the southern part of the state: South 13 with 85.5 degrees (-40.3 to 45.2 degrees), Coast 3 with 76.8 degrees (-29.1 to 47.7 degrees), Coast 4 with 76.6 degrees (-29.1 to 47.5 degrees) and Coast 1 with 71.2 degrees (-29.9 to 41.2 degrees).
3. Only two substations had a Max-Min angle spread of less than 20 degrees: North 6 (18.5 degrees) and South 9 (19.3 degrees). All other substations have Max-Min spreads in the 21 to 61 degrees range.
4. With the addition of the CREZ lines the voltage angles in the Central and Western part of the state (FarWest 7, West 11, West 6, FarWest 8, FarWest 9, FarWest 4, West 2, West 9 and West 5) varied within a range significantly smaller than in 2013.
5. The four largest normal condition angles in degrees observed were at Coast 3 (47.73), Coast 4 (47.74), South 13 (45.16) and Coast 1 (41.21).
6. The smallest normal condition angles in degrees occurred at South 13 (-40.30) and South 10 (-33.46).

6. COMPARISON OF VOLTAGE ANGLE PAIRS (Ref.: North 7) – 2012 vs. 2013 vs. 2014

A. Goal:

EPG performed a comparison of voltage angle pairs for a number of pairs to determine the effect the new CREZ lines had on the performance of the ERCOT grid. The covered period includes the months of February to July for a fair comparison. Following are the results of that comparison.

B. Pairs Selected For Comparison

Sixteen pairs were selected to compare voltage angles between 2012, 2013 and 2014 conditions. They are listed in Table 4 below.

Table 4 - Angle Pairs for Voltage Angle Comparison (Monthly Median for 2012, 2013 and 2014)

**TABLE 4: ANGLE PAIRS FOR VOLTAGE ANGLE COMPARISON
(Monthly Median for 2012, 2013 and 2014)**

| # | Substation A | Substation B | From Region | To Region |
|----|--------------|--------------|-------------|--------------|
| 1 | West 10 | North 7 | Panhandle | Central-East |
| 2 | West 14 | North 7 | Panhandle | Central-East |
| 3 | West 16 | North 7 | Panhandle | Central-East |
| 4 | West 19 | North 7 | Panhandle | Central-East |
| 5 | West 9 | North 7 | Panhandle | Central-East |
| 6 | West 5 | North 7 | Panhandle | Central-East |
| 7 | FarWest 7 | North 7 | West Texas | Central-East |
| 8 | FarWest 7 | South 9 | West Texas | Central-East |
| 9 | West 11 | North 7 | West Texas | Central-East |
| 10 | North 5 | North 7 | Dallas | Central-East |
| 11 | North 6 | North 7 | East | Central-East |
| 12 | Coast 1 | North 7 | Valley | Central-East |
| 13 | South 13 | South 11 | Valley | Valley |
| 14 | West 4 | South 11 | Valley | Valley |
| 15 | FarWest 9 | South 11 | West Texas | Valley |
| 16 | South 11 | North 7 | Valley | Central-East |

C. Procedure

This monthly median comparison was completed using median values to avoid as much as possible distortions in the comparison. State Estimator data was collected for the February to July months of 2012, 2013, and 2014 and analyzed to produce monthly median comparison values shown in Table 5below.

Monthly median graphs for each of the 16-pairs are shown in Appendix C for the years 2012, 2013 and the six months of 2014. Box-whisker plots were also developed for each pair using median values and are also shown in Appendix C.

D. Results

The results of the comparison are shown in Table 5below.

Table 5 - Voltage Angle Comparison (Monthly Median), 2012, 2013 and 2014

| Table 5 - BASELINING ANALYSIS UPDATE #3 - VOLTAGE ANGLE COMPARISON | | | | | |
|---------------------------------------------------------------------------|--------------------|-------------|-------------|-------------|----------------------|
| (February to July months) - 2012, 2013 and 2014 | | | | | |
| # | Angle Pair | 2012 Median | 2013 Median | 2014 Median | 2014-2013 Difference |
| 1 | West 10-North 7 | 13.12 | 9.42 | 3.29 | -6.13 |
| 2 | West 14-North 7 | 7.84 | 8.99 | 3.36 | -5.63 |
| 3 | West 16-North 7 | N/A | N/A | 3.51 | N/A |
| 4 | West 19-North 7 | N/A | 10.38 | 3.31 | -7.07 |
| 5 | West 9-North 7 | 9.90 | 8.46 | 3.03 | -5.43 |
| 6 | West 5-North 7 | 9.45 | 8.34 | 3.04 | -5.30 |
| 7 | FarWest 7-North 7 | 7.61 | 6.84 | 0.27 | -6.57 |
| 8 | FarWest 7-South 9 | 4.18 | 7.98 | -0.08 | -8.06 |
| 9 | West 11-North 7 | 9.68 | 8.20 | 2.33 | -5.87 |
| 10 | North 5-North 7 | -1.38 | -4.56 | -5.96 | -1.40 |
| 11 | North 6-North 7 | 5.31 | 3.71 | 2.84 | -0.87 |
| 12 | Coast 1-North 7 | 11.21 | -0.36 | 0.90 | 1.26 |
| 13 | South 13-South 11 | 0.62 | -3.08 | -2.55 | 0.53 |
| 14 | West 4-South 11 | -9.84 | -5.08 | -7.95 | -2.87 |
| 15 | FarWest 9-South 11 | 3.53 | 5.00 | -1.32 | -6.32 |
| 16 | South 11-North 7 | 3.83 | -1.04 | 0.93 | 1.97 |

E. Review of Results in Table 5 Shows the Following:

- All pairs in the list, except Coast 1 and North 5 to North 7, West 4 to South 11 and South 11 to North 7, had a decrease in angle monthly median.
- Nine pairs all located in either the West Texas or the Panhandle area had a decrease in angle from 2013 to 2014 between 5.30 to 8.06 degrees. The largest difference of 8.06 degrees occurred on the FarWest 7 to South 9 pair. NOTE: 22 new CREZ lines were added to the ERCOT system between July 31, 2013 and January 18, 2014. All these lines were added in the Central, Western, and Panhandle areas of Texas.
- North 6 seems to be delivering less power to North 7 in 2014 than in 2013 since the median voltage angle went down 0.87 degrees.
- The North 5 and West 4 to North 7 pairs had their voltage angle going more negative; North 5 and West 4 appear to be drawing power from North 7 more often.
- On the other hand, the voltage angle median for the Coast 1 to North 7 increased by 1.26 degrees and it seems Coast 1 delivered power to North 7 in 2014 more days than it received.
- The South 13 to North 7 pair had their voltage angle going less negative; South 13 appears to be drawing less power from North 7.

F. Conclusions

- i. The voltage angles for substations in the West Texas and Panhandle areas have tightened (smaller angles referenced to North 7) significantly due to the addition during the second half of 2013 and January of 2014 of 22 new CREZ lines between these substations and the central area of Texas.
- ii. A re-distribution of power has occurred among the several transmission lines in the Valley area of Texas.
- iii. These voltage angle monthly medians are likely to change less in the future unless a significant amount of wind power is added in the western area and the Panhandle areas of Texas displacing generation in other areas such as the Valley area.
- iv. The new CREZ lines added in March 2014 are not expected to result in any major changes in voltage angle monthly medians.

7. BASELINE ANALYSIS FOR ANGLE DIFFERENCES

A. Pairs of Substations Identified for Angle Difference Analysis

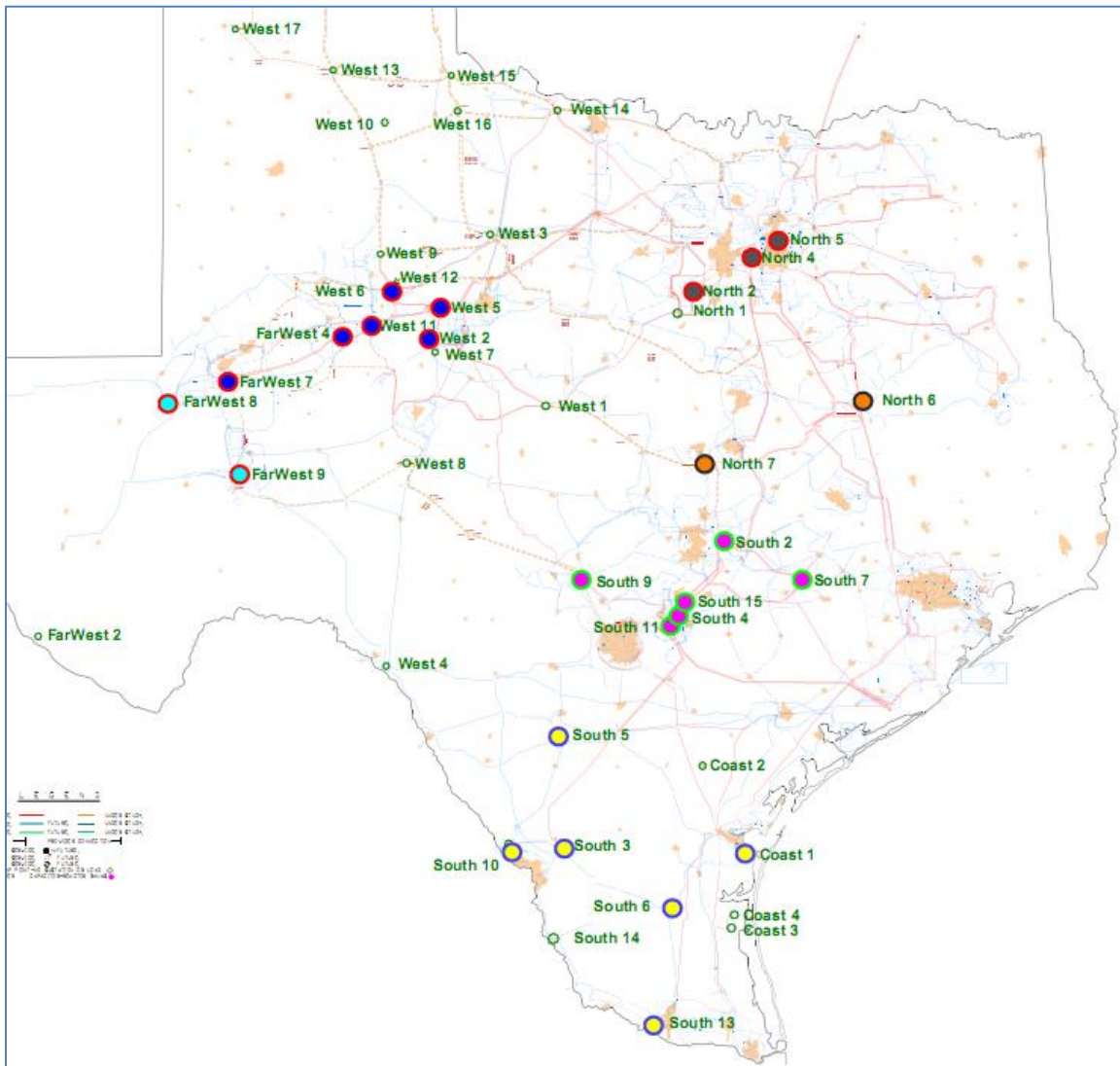
The following pairs of substations were selected to perform analysis of angle difference (also see map below):

Table 6 - Angle Pairs for Angle Differences Analysis Update 3

| TABLE 6: ANGLE PAIRS FOR ANGLE DIFFERENCES ANALYSIS UPDATE #3 | | | | |
|---------------------------------------------------------------|--------------|--------------|-------------|--------------|
| PAIRS WITH PHASOR DATA AVAILABLE | | | | |
| # | Substation A | Substation B | From Region | To Region |
| 1 | Coast 1 | South 13 | Valley | Valley |
| 2 | West 5 | West 10 | Central | Panhandle |
| 3 | West 5 | FarWest 4 | Central | West Texas |
| 4 | West 5 | North 1 | Central | Central |
| 5 | North 1 | North 4 | Dallas | Central |
| 6 | North 4 | North 6 | Central | East |
| 7 | FarWest 7 | FarWest 4 | West Texas | West Texas |
| 8 | FarWest 7 | West 14 | West Texas | Panhandle |
| 9 | FarWest 7 | FarWest 8 | West Texas | West Texas |
| 10 | FarWest 7 | FarWest 9 | West Texas | West Texas |
| 11 | West 12 | FarWest 7 | Central | West Texas |
| 12 | West 12 | West 1 | Central | Central-East |
| 13 | West 12 | North 1 | Central | Dallas |
| 14 | West 14 | West 5 | Panhandle | Central |
| 15 | West 14 | North 1 | Panhandle | Dallas |
| 16 | FarWest 9 | West 4 | West Texas | Southwest |
| 17 | West 16 | West 3 | Panhandle | Panhandle |

| | | | | |
|--------------------------------------------|-----------|-----------|--------------|--------------|
| 18 | West 16 | West 14 | Panhandle | Panhandle |
| 19 | West 15 | West 14 | Panhandle | Panhandle |
| PAIRS WITHOUT PHASOR DATA AVAILABLE | | | | |
| 20 | Coast 1 | South 10* | Valley | Valley |
| 21 | South 3 | South 11* | Valley | Central-East |
| 22 | South 11* | North 7 | Valley | Central-East |
| 23 | North 7 | South 7* | Central-East | Central-East |
| 24 | North 7 | South 9* | Central-East | Central-East |
| 25 | West 11 | West 8* | Central | Central |
| 26 | West 8 | South 9* | Central | Central-East |
| 27 | FarWest 7 | South 9* | West Texas | Central-East |
| 28 | FarWest 9 | South 9* | West Texas | Central-East |
| 29 | West 19* | West 9 | Panhandle | Panhandle |

* Denotes substations without existing PMUs or w/o phasor data stream



B. Summary of Results – All Data Included

Table B-1 below contains angle difference results for all those angle pairs selected for study. Nineteen pairs with phasor data were included in the analysis (total of 29). Table B-1 shows min, max and average values for angle differences obtained from all data received for the period February to July, 2014 (all solved SE cases and all phasor data, normal and contingency conditions). Phasor data was not available for seven of the pairs selected for study; no phasor results are provided for those pairs.

NOTE: Phasor data availability for FarWest 2 and Coast 2 was less than 15% for the study period, all other had data availability greater than 60%. State Estimator data availability was very good for this period with only one day of data missing.

Observation of Table B-1 results shows the following:

1. The highest Max-Min angle spread occurred at FarWest 9- South 9 (63.0 degrees).

2. Five pairs have spreads between 40 and 60 degrees: Coast 1-South 13, FarWest 9-West 4, Coast 1-South 10, West 8-South 9 and FarWest 7-South 9.
3. Max-Min angle spread of less than 10 degrees occurred on four pairs: West 16-West 3, West 16-West 14, West 15-West 14, and West 19-West 9.
4. The remaining nineteen pairs have angle spreads between 11.2 and 39.9 degrees.
5. Angle spreads for the February-July, 2014 period are lower than those found for the same period in 2013 due to the addition of the CREZ lines to the ERCOT system.
6. The maximum voltage angle found in this update was 39.8 degrees on the Coast 1-South 10 pair.
7. Only two pairs have minimum voltage angles lower than -25 degrees: FarWest 7-South 9 (-28.73 degrees) and FarWest 9 South 9 (-29.98 degrees).

Table B- 1 - Baselining Analysis – Summary of Angle Differences – All Data

| Table B-1 -CCET DISCOVERY ACROSS TEXAS- BASELINING ANALYSIS- SUMMARY OF ANGLE DIFFERENCES | | | | | | | | | | | | |
|-------------------------------------------------------------------------------------------------------------------------|---------------------|-----------|----------------------------------------------|-------|---------|------------------|------------------|------------------------------------|-------|---------|------------------|---------|
| ALL DATA | | | | | | | | | | | | |
| | | | Phasor Data - 2/1/2014 to 7/31/2014 | | | | | State Estimator Data - 2/1/2014 to | | | | |
| | Angle Pair | Base kV | Min | Max | Max-Min | Percent Positive | % Data Available | Min | Max | Average | Percent Positive | Max-Min |
| 1 | Coast 1-South 13 | 138kV | -19.61 | 29.53 | 49.13 | 57.18 | 64.41 | -18.05 | 25.38 | 1.95 | 58.7% | 43.4 |
| 2 | West 5-West 10 | 345/69kV | -18.11 | 17.25 | 35.36 | 49.13 | 94.22 | -17.37 | 16.79 | -0.69 | 50.2% | 34.2 |
| 3 | West 5-FarWest 4 | 345kV | -7.53 | 6.34 | 13.88 | 53.04 | 95.86 | -7.19 | 6.01 | 0.32 | 57.5% | 13.2 |
| 4 | West 5-North 1 | 345kV | -15.49 | 16.48 | 31.97 | 39.25 | 95.94 | -15.59 | 18.94 | -1.53 | 39.0% | 34.5 |
| 5 | North 1-North 4 | 345/138kV | 4.15 | 15.96 | 11.81 | 100.00 | 95.98 | 3.91 | 15.87 | 8.95 | 100.0% | 12.0 |
| 6 | North 4-North 6 | 138kV | -23.96 | 4.47 | 28.44 | 2.52 | 96.12 | -22.28 | 4.89 | -6.32 | 4.5% | 27.2 |
| 7 | FarWest 7-FarWest 4 | 345kV | -13.78 | 2.72 | 16.50 | 3.65 | 95.60 | -8.55 | 2.60 | -2.66 | 3.7% | 11.2 |
| 8 | FarWest 7-West 14 | 345kV | -18.00 | 15.72 | 33.72 | 39.11 | 75.41 | -17.93 | 15.29 | -2.22 | 36.4% | 33.2 |
| 9 | FarWest 7-FarWest 8 | 345/138kV | 3.77 | 15.21 | 11.44 | 100.00 | 91.44 | 2.91 | 14.13 | 8.63 | 100.0% | 11.2 |
| 10 | FarWest 7-FarWest 9 | 345/138kV | -6.99 | 8.39 | 15.38 | 57.22 | 74.99 | -7.61 | 7.98 | 0.46 | 56.7% | 15.6 |
| 11 | West 12-FarWest 7 | 345kV | -6.25 | 11.71 | 17.96 | 80.26 | 95.80 | -5.73 | 11.15 | 2.63 | 81.7% | 16.9 |
| 12 | West 12-West 1 | 345kV | -19.99 | 23.53 | 43.52 | 55.78 | 95.18 | -6.23 | 7.08 | 0.67 | 55.9% | 13.3 |
| 13 | West 12-North 1 | 345kV | -14.56 | 14.66 | 29.22 | 36.87 | 96.03 | -14.38 | 14.51 | -1.92 | 36.6% | 28.9 |
| 14 | West 14-West 5 | 345kV | -12.42 | 9.52 | 21.94 | 45.55 | 75.57 | -14.74 | 9.36 | -0.80 | 47.3% | 24.1 |
| 15 | West 14-North 1 | 345kV | -10.83 | 8.19 | 19.02 | 27.56 | 75.56 | -10.51 | 8.08 | -2.33 | 25.4% | 18.6 |
| 16 | FarWest 9-West 4 | 138kV | -25.83 | 35.38 | 61.21 | 76.95 | 73.49 | -24.30 | 34.76 | 7.17 | 77.2% | 59.1 |
| 17 | West 16-West 3 | 345kV | -2.56 | 4.60 | 7.17 | 64.42 | 66.21 | -3.40 | 4.34 | 0.20 | 65.2% | 7.7 |
| 18 | West 16-West 14 | 345kV | -1.46 | 1.60 | 3.06 | 61.37 | 58.57 | -2.11 | 2.21 | 0.05 | 52.3% | 4.3 |
| 19 | West 15-West 14 | 345kV | -4.57 | 9.44 | 14.01 | 68.45 | 61.22 | -2.41 | 2.95 | 0.27 | 65.2% | 5.4 |
| 20 | Coast 1-South 10* | 138kV | Phasor data is not available for these pairs | | | | | -12.27 | 39.84 | 8.22 | 79.1% | 52.1 |
| 21 | South 3-South 11* | 138kV | | | | | | -20.61 | 19.30 | -1.12 | 46.9% | 39.9 |
| 22 | South 11*-North 7 | 345/69kV | | | | | | -9.77 | 18.16 | 1.41 | 59.3% | 27.9 |
| 23 | North 7-South 7* | 138/345kV | | | | | | -22.14 | 14.89 | -3.92 | 21.9% | 37.0 |
| 24 | North 7-South 9* | 138/345kV | | | | | | -11.74 | 10.29 | -1.04 | 37.1% | 22.0 |
| 25 | West 11-West 8* | 345kV | | | | | | -9.83 | 10.00 | 1.21 | 62.9% | 19.8 |
| 26 | West 8-South 9* | 345kV | | | | | | -20.58 | 22.57 | 0.98 | 56.6% | 43.2 |
| 27 | FarWest 7-South 9* | 345kV | | | | | | -28.73 | 30.91 | -0.14 | 49.6% | 59.6 |
| 28 | FarWest 9-South 9* | 138/345kV | | | | | | -29.98 | 32.99 | -0.60 | 46.8% | 63.0 |
| 29 | West 19*-West 9 | 345kV | | | | | | -6.13 | 3.78 | -0.07 | 50.4% | 9.9 |
| * Denotes substations without existing PMUs or w/o data stream; no phasor data available for the Feb-July, 2014 period. | | | | | | | | | | | | |

C. Criteria to Identify Normal Operations Limits for Angle Differences

The data received, both phasor and state estimator, provide information for all conditions during the study period including those conditions where the system experienced outages of lines or generators. This study is intended to provide angle difference limits that can be expected during normal operations; that is, when all facilities are in service. The following criteria were used to determine the angle difference limits expected during normal operations for the selected substation pairs.

- i. If the angle difference time duration curves show only positive angles, then two limits will be identified: one corresponding to the angle difference that occurred at about one percent of the time, and the other corresponding to the maximum value observed.
- ii. If the angle difference time duration curves show positive as well as negative angles, then four limits will be identified, two for one direction of flow and two for the opposite direction of flow, based on the criteria below:
 - The first limit in either direction will be set using state estimator results by selecting the maximum (or minimum) angle difference observed on the corresponding time duration curves if the box-whisker and time duration plots show no extreme values (outliers or extreme values due to events in the system). If extreme values or outliers are present, a point of inflection will be determined and the maximum or minimum angle will be set at the angle corresponding to the point of inflection.
 - The second max limit will be set at the angle difference which occurred 1% more time than the time corresponding to the selected first maximum limit, based on the time duration curve. The second minimum limit will be set at the angle difference corresponding to 1% less time than the time corresponding to the selected first minimum limit.
- iii. In some cases such as when there was an extended outage, EPG reproduced the time duration curve excluding those days when the extended outage occurred to determine the angle differences corresponding to normal conditions.
- iv. The 1% values can be used to set alarms for the operators to be notified of impending maximum angle differences. The maximum and minimum values can be used to set alarms notifying the operator that expected maximum or minimum values have been reached.
- v. The alarms so determined should be monitored for a year against actual values observed during operation. If maximum values are exceeded, the observed values should be logged and documented for further analysis and updates.
- vi. Maximum and minimum voltage angles and their differences obtained for the pair analyzed in this update are not expected to change significantly unless major changes occur in generation output such as a large increase in wind power production or additional major transmission lines are added to the ERCOT system in addition to those CREZ lines already in service.
- vii. This analysis should be revised based on the entire 12-months of 2014 historical data obtained with all the new CREZ transmission lines in service.

D. Summary of Results – Normal Conditions

The angle difference results for normal conditions are summarized in Table B- 2below, which was developed based on the criteria described above.

Box-whisker and time duration curves were developed for each of the pairs analyzed. Angle differences that may be the results of contingencies were excluded by reviewing points of inflection; that is, points that significantly deviated from the normal operation trend observed in the box-whisker plots. The value of angle difference at the point of inflection was considered to be the maximum angle during normal conditions. If no outlier points were identified, then the angle corresponding to the 0% or 100% time points will represent the maximum and minimum angles reached during normal operations in either direction of flow. SE-based voltage angle pairs with their corresponding box-whisker and time duration curves as well as phasor-based voltage angle pairs with their corresponding box-whisker and time duration curves are presented in Appendix B.

Table B- 2 - Baselining Analysis – Summary of Angle Differences – Normal Data

| Table B-2 - CCET DISCOVERY ACCROSS TEXAS- BASELINING ANALYSIS- SUMMARY OF ANGLE DIFFERENCES - NORMAL CONDITIONS | | | | | | | | | | | | | | | | | | |
|------------------------------------------------------------------------------------------------------------------------|-------------------------|-----------|---------|------------------------------------------------|--------------|-----------------------|----------------------|-----------------------------------|-----------------------------|---------------------------------------|---------------------------------|-------------------------------------|-------------------------------|---------------------------------|---------------------------|--------------|--------------|-----------------------|
| DATA RESULTS (Study Period: February 1 to July 31, 2014) | | | | | | | | | | | | | | | | | | |
| No | Angle Pair FROM - TO | | Base kV | Phasor Data | | | State Estimator Data | | | | | | | | | SE Data | | |
| | | | | Min Angle | Max Angle | Max- Min Spread | Percent Positive | Min Angle at 99% or 100% | Percent (POI or 100%) | Min Angle at 99% or POI - 1% | Percent (99% or POI - 1%) | Max Angle at 1% or POI +1% | Percent (1% or POI +1%) | Max Angle at POI or 0% | Percent (POI or 0%) | Min Angle | Max Angle | Max- Min Spread |
| 1 | Coast 1 | South 13 | 138 | -16.41 | 20.79 | 37.20 | 58.74% | -17.09 | 99.97% | -12.22 | 98.97% | 17.08 | 1.03% | 24.77 | 0.03% | -17.09 | 24.77 | 41.9 |
| 2 | West 5 | West 10 | 345/69 | -16.88 | 17.05 | 33.93 | 50.21% | -16.81 | 99.98% | -15.09 | 98.98% | 13.40 | 1.12% | 16.31 | 0.12% | -16.81 | 16.31 | 33.1 |
| 3 | West 5 | FarWest 4 | 345 | -5.99 | 6.08 | 12.07 | 57.47% | -5.93 | 99.94% | -4.44 | 98.94% | 5.03 | 1.02% | 5.85 | 0.02% | -5.93 | 5.85 | 11.8 |
| 4 | West 5 | North 1 | 345 | -14.46 | 15.72 | 30.18 | 39.02% | -14.83 | 99.96% | -13.34 | 98.96% | 15.15 | 1.04% | 18.39 | 0.04% | -14.83 | 18.39 | 33.2 |
| 5 | North 1 | North 4 | 345/138 | 4.41 | 15.84 | 11.43 | 100.00% | 3.98 | 99.98% | 4.50 | 98.98% | 13.64 | 1.03% | 15.29 | 0.03% | 3.98 | 15.29 | 11.3 |
| 6 | North 4 | North 6 | 138 | -23.62 | 3.56 | 27.18 | 4.47% | -21.73 | 99.88% | -19.88 | 98.88% | 2.27 | 1.02% | 4.73 | 0.02% | -21.73 | 4.73 | 26.5 |
| 7 | FarWest 7 | FarWest 4 | 345 | -9.66 | 1.48 | 11.14 | 3.67% | -8.00 | 99.93% | -5.98 | 98.93% | 0.69 | 1.06% | 2.13 | 0.06% | -8.00 | 2.13 | 10.1 |
| 8 | FarWest 7 | West 14 | 345 | -16.58 | 14.59 | 31.17 | 36.42% | -16.19 | 99.90% | -14.80 | 98.90% | 11.79 | 1.01% | 15.02 | 0.01% | -16.19 | 15.02 | 31.2 |
| 9 | FarWest 7 | FarWest 8 | 345/138 | 6.08 | 14.66 | 8.58 | 100.00% | 4.82 | 99.98% | 5.80 | 98.98% | 12.04 | 1.02% | 13.79 | 0.02% | 4.82 | 13.79 | 9.0 |
| 10 | FarWest 7 | FarWest 9 | 345/138 | -6.88 | 6.73 | 13.61 | 56.69% | -7.10 | 99.97% | -5.83 | 98.97% | 5.69 | 1.05% | 7.20 | 0.05% | -7.10 | 7.20 | 14.3 |
| 11 | West 12 | FarWest 7 | 345 | -5.36 | 11.47 | 16.83 | 81.73% | -5.40 | 99.97% | -3.53 | 98.97% | 9.60 | 1.06% | 10.95 | 0.06% | -5.40 | 10.95 | 16.4 |
| 12 | West 12 | West 1 | 345 | -6.47 | 6.70 | 13.17 | 55.89% | -5.93 | 99.97% | -4.50 | 98.97% | 5.85 | 1.01% | 6.73 | 0.01% | -5.93 | 6.73 | 12.7 |
| 13 | West 12 | North 1 | 345 | -13.86 | 14.03 | 27.89 | 36.62% | -14.14 | 99.96% | -12.59 | 98.96% | 12.20 | 1.01% | 14.39 | 0.01% | -14.14 | 14.39 | 28.5 |
| 14 | West 14 | West 5 | 345 | -11.55 | 8.71 | 20.26 | 47.27% | -14.27 | 99.94% | -12.10 | 98.94% | 7.31 | 1.04% | 9.17 | 0.04% | -14.27 | 9.17 | 23.4 |
| 15 | West 14 | North 1 | 345 | -10.53 | 7.86 | 18.39 | 25.43% | -10.32 | 99.98% | -8.84 | 98.98% | 4.82 | 1.02% | 8.01 | 0.02% | -10.32 | 8.01 | 18.3 |
| 16 | FarWest 9 | West 4 | 138 | -24.16 | 33.55 | 57.71 | 77.17% | -23.42 | 99.95% | -14.49 | 98.95% | 27.60 | 1.02% | 34.29 | 0.02% | -23.42 | 34.29 | 57.7 |
| 17 | West 16 | West 3 | 345 | -2.38 | 3.49 | 5.87 | 65.21% | -3.29 | 99.98% | -2.31 | 98.98% | 3.58 | 1.04% | 4.25 | 0.04% | -3.29 | 4.25 | 7.5 |
| 18 | West 16 | West 14 | 345 | -1.32 | 1.51 | 2.83 | 52.35% | -2.04 | 99.95% | -1.38 | 98.95% | 1.65 | 1.11% | 2.15 | 0.11% | -2.04 | 2.15 | 4.2 |
| 19 | West 15 | West 14 | 345 | -3.86 | 7.92 | 11.78 | 65.17% | -2.33 | 99.96% | -1.38 | 98.96% | 2.13 | 1.02% | 2.93 | 0.02% | -2.33 | 2.93 | 5.3 |
| 20 | Coast 1 | South 10* | 138 | NO PHASOR DATA AVAILABLE FOR THESE PAIRS | | | 79.11% | -11.38 | 99.93% | -6.93 | 98.93% | 25.86 | 1.02% | 38.17 | 0.02% | -11.38 | 38.17 | 49.5 |
| 21 | South 3 | South 11* | 138/345 | | | | 46.89% | -20.36 | 99.99% | -16.23 | 98.99% | 12.12 | 1.02% | 18.02 | 0.02% | -20.36 | 18.02 | 38.4 |
| 22 | South 11* | North 7 | 138/345 | | | | 59.32% | -9.24 | 99.99% | -6.41 | 98.99% | 14.21 | 1.01% | 18.05 | 0.01% | -9.24 | 18.05 | 27.3 |
| 23 | North 7 | South 7* | 138/345 | | | | 21.92% | -21.56 | 99.95% | -17.62 | 98.95% | 4.89 | 1.06% | 13.70 | 0.06% | -21.56 | 13.70 | 35.3 |
| 24 | North 7 | South 9* | 138/345 | | | | 37.10% | -11.16 | 99.96% | -8.65 | 98.96% | 6.06 | 1.02% | 9.89 | 0.02% | -11.16 | 9.89 | 21.1 |
| 25 | West 11 | West 8* | 345 | | | | 62.92% | -9.19 | 99.96% | -6.74 | 98.96% | 8.05 | 1.02% | 9.88 | 0.02% | -9.19 | 9.88 | 19.1 |
| 26 | West 8 | South 9* | 345 | | | | 56.63% | -18.44 | 99.92% | -11.31 | 98.92% | 12.69 | 1.05% | 21.88 | 0.05% | -18.44 | 21.88 | 40.3 |
| 27 | FarWest 7 | South 9 | 345 | | | | 49.58% | -27.44 | 99.94% | -21.70 | 98.94% | 20.10 | 1.02% | 29.95 | 0.02% | -27.44 | 29.95 | 57.4 |
| 28 | FarWest 9 | South 9* | 138/345 | | | | 46.80% | -29.16 | 99.97% | -22.63 | 98.97% | 20.92 | 1.03% | 31.73 | 0.03% | -29.16 | 31.73 | 60.9 |
| 29 | West 19* | West 9 | 345 | | | | 50.40% | -5.79 | 99.94% | -4.59 | 98.94% | 2.81 | 1.01% | 3.50 | 0.01% | -5.79 | 3.50 | 9.3 |

Note: The substations market with * did not have PMUs installed by July 31, 2014; no phasor data available.

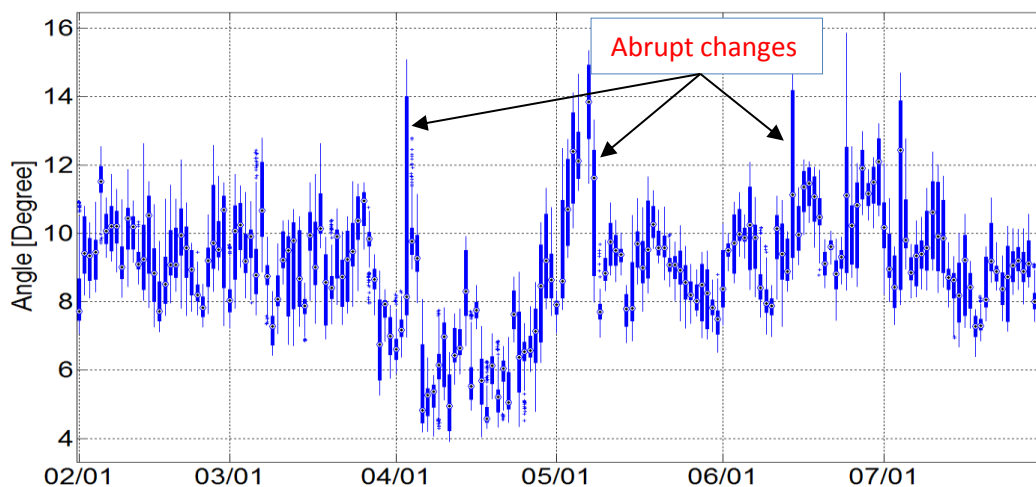
E. Observations from Table B-2:

- I. The maximum Max-Min angle spreads under normal conditions occurred at FarWest 9-South 9 with 60.9 degrees.
- II. Two pairs had Max-Min spreads between 57 and 60 degrees: FarWest 9-West 4 (57.7 degrees) and FarWest 7-South 9 (57.4 degrees).
- III. Five pairs had minimum Max-Min voltage spreads of less than 10 degrees: West 16-West 14 (4.2), West 15-West 14 (5.3), West 16-West 3 (7.5), FarWest 7-FarWest 8 (9.0) and West 19-West 9 (9.3).
- IV. The maximum voltage angles in degrees under normal conditions occurred at Coast 1-South 10 (38.2), FarWest 9-West 4 (34.3) and FarWest 9-South 9 (31.7).
- V. Minimum angles occurred at FarWest 9-South 9 (-29.2) and FarWest 7-South 9 (-27.4).
- VI. Four additional substations had minimum angles lower than -20 degrees.
- VII. Four pairs had positive flows greater than 90% of the time: North 1-North 4 (100%), FarWest 7-FarWest 8 (100%), FarWest 4-FarWest 7 (96.3%) and North 6-North 4 (95.6%).

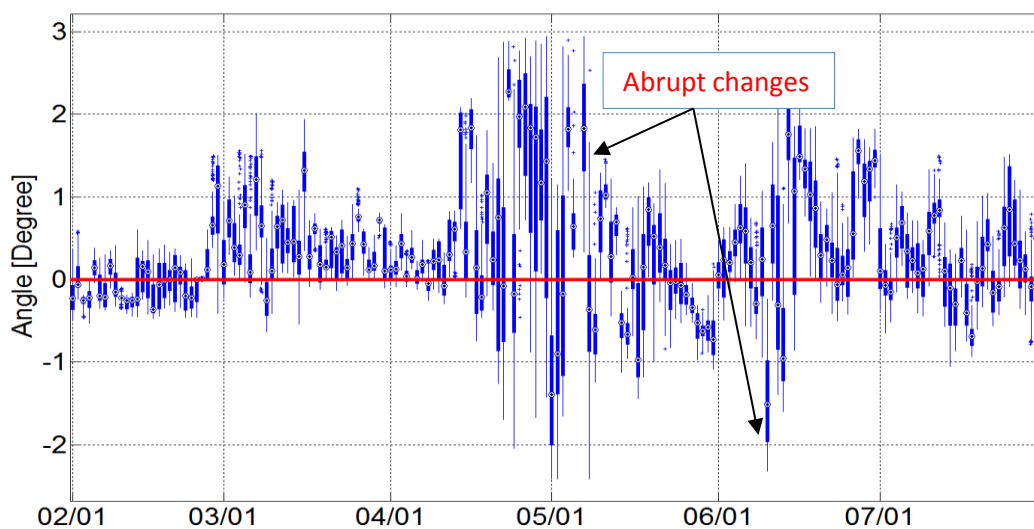
F. Observations from State Estimator Box-whisker Plots (Appendix B-Part 1)

1. State Estimator data availability for this update was the best EPG has received so far. Only one day of data was missing (May 6). Aside from this missing day, two pairs show a gap in data: Coast 1 South 13 (second half of February) and West 19-West 9 (between April and May).
2. In general, the box-whisker plots show less variability than in 2013.
3. A few pairs show some variability: North 1-North 4, FarWest 7-West 14, West 12-FarWest 7, West 12-North 1, West 14-North 1, FarWest 9-West 4, Coast 1-South 10, South 3-South 11, South 11-North 7 and FarWest 9-South 9.
4. Box-whisker plots for four pairs show data that may be suspect: West 16-West 3, West 16-West 14, West 15-West 14 and West 19-West 9.
5. If there were extended outages, the angles corresponding to the outage times should be excluded from the data used to establish normal operation alarm limits. Outage data should be documented and taken into account for any future updates.
6. Examples of abrupt angle changes that may be due to outages are shown below:

North 1 – North 4



West 15 – West 14



8. PAIRS FOR REAL TIME MONITORING

A. Criteria for Selection of Angle Pairs for Real-time Monitoring

1. Choose a few transmission paths (pairs) from the wind areas to monitor wind power delivery.
2. Choose a load center such as North 1 and select transmission paths serving such loads.
3. Choose transmission paths delivering power from the Valley.
4. Choose transmission paths connecting the load centers such as Dallas, Austin, San Antonio and Houston areas (no PMUs in the Houston area at this time).

NOTE: Because there are not enough PMUs installed in the system, EPG chose pairs that meet this criteria as closely as possible.

B. Transmission Paths (PAIRS) Selected for Real Time Monitoring

The transmission paths selected for monitoring are shown in Table 7 below:

Table 7 - Angle Pairs Selected for Real-time Monitoring (Based on PMU Availability)

| TABLE 7: ANGLE PAIRS SELECTED FOR REAL TIME MONITORING (Based on PMU Availability) | | | | |
|-----------------------------------------------------------------------------------------------|-----------------------------------------------------------------------|--------------|-------------|--------------|
| PAIRS WITH PHASOR DATA AVAILABLE | | | | |
| # | Substation A | Substation B | From Region | To Region |
| 1 | Coast 1 | South 13 | Valley | Valley |
| 2 | Coast 1 | North 7 | Valley | Central-East |
| 3 | Coast 4 | North 7 | Valley | Central-East |
| 4 | South 3 | South 11* | Valley | Valley |
| 5 | South 11* | North 7 | Valley | Central-East |
| 6 | North 6 | North 7 | East | Central-East |
| 7 | North 4 | North 7 | Dallas | Central-East |
| 8 | West 14 | North 1 | Panhandle | Dallas |
| 9 | West 5 | North 1 | Central | Dallas |
| 10 | North 1 | North 7 | Dallas | Central-East |
| 11 | West 3 | North 7 | Central | Central-East |
| 12 | West 14 | West 5 | Panhandle | Central |
| 13 | West 5 | North 7 | Central | Central-East |
| 14 | West 12 | West 1 | Central | Central |
| 15 | West 12 | FarWest 7 | Central | West Texas |
| 16 | FarWest 7 | North 7 | West Texas | Central-East |
| 17 | FarWest 7 | South 9* | West Texas | Valley |
| 18 | FarWest 7 | FarWest 9 | West Texas | West Texas |
| 19 | West 1 | North 7 | Central | Central-East |
| 20 | FarWest 9 | West 4 | West Texas | Southwest |
| 21 | West 4 | North 7 | Southwest | Central-East |
| 22 | West 15 | West 14 | Panhandle | Panhandle |
| 23 | West 16 | West 14 | Panhandle | Panhandle |
| 24 | West 16 | West 3 | Panhandle | Central |
| 25 | West 19* | West 9 | Panhandle | Central |
| * | Means PMU planned for this substation but not available at this time. | | | |

C. Proposed Alarm Limits

Table 8 below shows the proposed angle limits for the paths (pairs) selected for real-time monitoring. These proposed limits were selected from the results for normal conditions shown in Table A- 2 and Table B- 2 of this report. These results are based on the data for the February to July months of 2014 provided by ERCOT. Whereas in 2013 CREZ lines were being added almost on a monthly basis, causing an ongoing change in angle differences, during this most recent 6-month period all, except four CREZ lines have been in-service. As a result the angle differences are now more stable. The four additional 345 kV CREZ lines added to the ERCOT system in March 2014, are not expected to significantly change the angle differences under analysis. However, the alarm limits proposed in this section may change to some degree if generation is redistributed due to the addition of significant amounts of wind power or significant decommissioning of old generation. EPG suggest that an alarm limits update be conducted in 2015 when the ERCOT system has had the opportunity to adjust to its new significantly expanded transmission infrastructure.

By monitoring these angle pairs, the ERCOT grid operators should have a good overview of power flow from generation centers to the load centers and between load centers. It will provide them with a good idea of ongoing power flows among the different regions of the ERCOT grid.

EPG suggests that the ERCOT system operators document anytime these limits are exceeded noting the possible reason, if known, for the deviations such as line or generation outages.

Note that all the pairs in Table 8 below have two negative alarm limit values and two positive alarm limit values. The negative values apply in the TO to the FROM (inbound power flow) direction and the positive values apply in the FROM to the TO (outbound power flow) direction.

Table 8 - Baselining Analysis – Recommended Alarm Limits for Real-time Monitoring

| Table 8 - BASELINING UPDATE 3 - RECOMMENDED ALARM LIMITS FOR REAL TIME MONITORING | | | | | | | | | | |
|------------------------------------------------------------------------------------------|---------------------------------|-----------|----------------|---------------------------------------------------------------------------------------|----------------------|--------------------------------|------------------------------------|------------------------------------|------------------------------------|------------------------------------|
| | | | | ALARM LIMITS UNDER NORMAL CONDITIONS (Based on February to July, 2014 Data) | | | | | | |
| | | | | SE Data-Normal | | | RECOMMENDED ALARM LIMITS | | | |
| No | Angle Pair FROM - TO | | Base kV | Min Angle | Max Angle | Max- Min Spread | MINIMUM ALARM LIMIT | MINIMUM ALARM ALERT | MAXIMUM ALARM ALERT | MAXIMUM ALARM LIMIT |
| 1 | Coast 1 | South 13 | 138 | -17.09 | 24.77 | 41.86 | -17.09 | -12.22 | 17.08 | 24.77 |
| 2 | Coast 1 | North 7 | 138 | -29.94 | 41.21 | 71.2 | -29.94 | -24.09 | 30.94 | 41.21 |
| 3 | Coast 4 | North 7 | 345 | -29.09 | 47.54 | 76.6 | -29.09 | -20.87 | 34.65 | 47.54 |
| 4 | South 3 | South 11* | 138/345 | -20.36 | 18.02 | 38.4 | -20.36 | -16.23 | 12.12 | 18.02 |
| 5 | South 11* | North 7 | 345 | -8.54 | 17.66 | 41.9 | -8.54 | -6.36 | 14.18 | 17.66 |
| 6 | North 6 | North 7 | 138 | -5.91 | 12.56 | 18.5 | -5.91 | -3.81 | 9.93 | 12.56 |
| 7 | North 4 | North 7 | 138/345 | -16.15 | 6.79 | 22.9 | -16.15 | -12.88 | 4.41 | 6.79 |
| 8 | West 14 | North 1 | 345 | -10.32 | 8.01 | 18.3 | -10.32 | -8.84 | 4.82 | 8.01 |
| 9 | West 5 | North 1 | 345 | -14.83 | 18.39 | 33.2 | -14.83 | -13.34 | 15.15 | 18.39 |
| 10 | North 1 | North 7 | 345 | -6.78 | 15.75 | 22.5 | -6.78 | -3.75 | 12.45 | 15.75 |
| 11 | West 3 | North 7 | 345 | -13.80 | 15.82 | 29.6 | -13.80 | -8.18 | 13.36 | 15.82 |
| 12 | West 14 | West 5 | 345 | -14.27 | 9.17 | 23.4 | -14.27 | -12.10 | 7.31 | 9.17 |
| 13 | West 5 | North 7 | 345 | -14.50 | 24.66 | 39.2 | -14.50 | -11.59 | 21.26 | 24.66 |
| 14 | West 12 | West 1 | 345 | -5.93 | 6.73 | 12.7 | -5.93 | -4.50 | 5.85 | 6.73 |
| 15 | West 12 | FarWest 7 | 345 | -5.40 | 10.95 | 16.4 | -5.40 | -3.53 | 9.60 | 10.95 |
| 16 | FarWest 7 | North 7 | 345 | -22.50 | 24.87 | 47.4 | -22.50 | -18.51 | 20.71 | 24.87 |
| 17 | FarWest 7 | South 9* | 345 | -27.44 | 29.95 | 57.4 | -27.44 | -21.70 | 20.10 | 29.95 |
| 18 | FarWest 7 | FarWest 9 | 345/138 | -7.10 | 7.20 | 14.3 | -7.10 | -5.83 | 5.69 | 7.20 |
| 19 | West 1 | North 7 | 345 | -9.26 | 15.89 | 25.1 | -9.26 | -7.01 | 13.04 | 15.89 |
| 20 | FarWest 9 | West 4 | 138 | -23.42 | 34.29 | 57.7 | -23.42 | -14.49 | 27.60 | 34.29 |
| 21 | West 4 | North 7 | 138/345 | -29.59 | 12.89 | 42.5 | -29.59 | -23.63 | 9.00 | 12.89 |
| 22 | West 15 | West 14 | 345 | -2.33 | 2.93 | 5.3 | -2.33 | -1.38 | 2.13 | 2.93 |
| 23 | West 16 | West 14 | 345 | -2.04 | 2.15 | 4.2 | -2.04 | -1.38 | 1.65 | 2.15 |
| 24 | West 16 | West 3 | 345 | -3.29 | 4.25 | 7.5 | -3.29 | -2.31 | 3.58 | 4.25 |
| 25 | West 19* | West 9 | 345 | -5.79 | 3.50 | 9.3 | -5.79 | -4.59 | 2.81 | 3.50 |
| NOTE: These alarm limits were developed based on February to July, 2014 data. | | | | | | | | | | |

9. CONCLUSIONS

a. State Estimator (SE) Data Availability was best in 2014

State estimator data provided by ERCOT for the February to July, 2013 period was the most complete EPG received in the Baselining process. Of the six months of data provided by ERCOT there was only one day of data missing (May 6, 2014). The state estimator collects data at a rate of 12-samples per hour. Overall SE availability was 48.7% of the total SE data collected, which was much better than the 29.6% availability for 2013 and the 13% availability for 2012. ERCOT provided SE data at a rate of six samples per hour. The SE data provided by ERCOT was 97.5% of all possible data at this rate.

b. Phasor Data Availability for 2014

All the PMUs providing data for this Baselining Update³ were already in service by February 2014 which resulted in much improved phasor data availability compared to prior study periods. However data availability was not uniformly high in all PMUs. Eighteen PMUs had availability greater than 90%, two PMUs had less than 20% availability (FarWest 2 and Coast 2), and the remaining ten PMUs had availability ranging from 62.08% (Coast 4) to 89.06% (Coast 1). Phasor data availability for all PMUs should be in the greater than 90% range for most accurate results.

c. Voltage Angle Variability (Ref.: North 7)

Voltage angles with reference to North 7 have tightened considerably due to the completion of the CREZ project.

ALL DATA RESULTS:

- i. The largest voltage angle variations occurred in the Valley. The maximum Max-Min spreads observed were 91.4 degrees for South 13 - 138 kV substation, 81.5 degrees for Coast 4 - 345 kV, and 81.1 degrees for Coast 3 substation.
- ii. The lowest spread of 19.5 degrees was seen at North 6.
- iii. The angles for North 1 and North 6 were positive most of the time (93.5 and 78.8% respectively) whereas North 4, North 5, West 4 and South 5 substations are positive less than 20% of the time; that is, the power flows from North 7 to these substations most of the time.

NORMAL CONDITIONS: Due to the higher level of data availability for SE and Phasor data, the voltage angle spreads for normal conditions obtained from SE data were very similar to those voltage angle spreads obtained from phasor data.

- i. Voltage angles fluctuations have been reduced and now vary over a smaller range. There are only five substations with Max-Min angle spreads of more than 60 degrees.
- ii. The largest angle variations occurred among the substations in the southern part of the state: South 13, Coast 3, Coast 4 and Coast 1. South 13 with 85.5 degrees (-40.3 to 45.2

- degrees), Coast 3 with 76.8 degrees (-29.1 to 47.7 degrees), Coast 4 with 76.6 degrees (-29.1 to 47.5 degrees) and Coast 1 with 71.2 degrees (-29.9 to 41.2 degrees).
- iii. Only two substations had a Max-Min angle spreads of less than twenty degrees: North 6 (18.5 degrees) and South 9 (19.3 degrees). All other substations have Max-Min spreads in the 21 to 61 degrees range.
- iv. The smallest normal condition angles in degrees occurred at South 13 (-40.30) and South 10 (-33.46).

d. Maximum Voltage Angles Under Normal Conditions

The four largest normal condition angles in degrees observed were at Coast 3 (47.73), Coast 4 (47.74), South 13 (45.16) and Coast 1 (41.21).

e. Voltage Angle Variability (Angle Differences)

Voltage angles differences have also tightened (smaller angle differences) considerably due to the completion of the CREZ projects.

ALL DATA RESULTS:

- i. The highest Max-Min angle spread occurred at FarWest 9 South 9 (63.0 degrees).
- ii. Five pairs have spreads between 40 and 60 degrees: Coast 1-South 13, FarWest 9-West 4, Coast 1-South 10, West 8-South 9 and FarWest 7-South 9.
- iii. Max-Min angle spread of less than 10 degrees occurred on four pairs: West 16-West 3, West 16-West 14, West 15-West 14, and West 19-West 9.
- iv. The remaining nineteen pairs have angle spreads between 11.2 and 39.9 degrees.
- v. Angle spreads for the February-July, 2014 period are smaller than those found for the same period in 2012 due to the addition of the CREZ lines to the ERCOT system.
- vi. The maximum voltage angle found in this update was 39.8 degrees on the Coast 1-South 10 pair.
- vii. Only two pairs have minimum voltage angles lower than -25 degrees: FarWest 7-South 9 (-28.73 degrees) and FarWest 9-South 9 (-29.98 degrees).

NORMAL CONDITIONS: Due to the higher level of data availability for SE and Phasor data, the voltage angle spreads for normal conditions obtained from SE data were very similar to those voltage angle spreads obtained from phasor data.

- i. The maximum Max-Min angle spreads under normal conditions occurred at FarWest 9-South 9 with 60.9 degrees.
- ii. Three pairs had Max-Min spreads between 57 and 60 degrees: FarWest 9-West 4 (57.7 degrees) and FarWest 7-South 9 (57.4 degrees).
- iii. Five pairs had minimum Max-Min voltage spreads of less than 10 degrees: West 16-West 14 (4.2), West 15-West 14 (5.3), West 16-West 3 (7.5), FarWest 7-FarWest 8 (9.0) and West 19-West 9 (9.3).

- iv. The maximum voltage angles in degrees under normal conditions occurred at Coast 1-South 10 (38.2), FarWest 9-West 4 (34.3) and FarWest 9-South 9 (31.7).
- v. Minimum angles occurred at FarWest 9-South 9 (-29.2) and FarWest 7-South 9 (-27.4).
- vi. Three additional substations had minimum angles lower than -20 degrees.
- vii. Four pairs had percent positive flows greater than 90%: North 1-North 4 (100%), FarWest 7-FarWest 8 (100%), FarWest 4-FarWest 7 (96.3%) and North 6-North 4 (95.5).

f. Maximum Voltage Angles Under Normal Conditions

The four largest normal condition angles in degrees for angle differences were observed were at Coast 1-South 10 (38.17), FarWest 9-West 4 (34.29) and FarWest 9-South 9 (31.73).

g. Voltage Spreads are Smaller in 2014

Voltage angle spreads for the substations in the western part of Texas including the Panhandle were much smaller in this update than in prior periods because many of the new CREZ transmission lines added between these regions and the rest of the ERCOT system. For example: 2014 voltage angle spreads for West 2, West 9, West 11, West 12, West 5 and West 6 referenced to North 7 experienced a reduction of more than 30-degrees from 2013.

h. Alarm Limits for Voltage Angles

All but four of the new CREZ lines were connected to the ERCOT system by January 2014. The remaining four lines were connected to the ERCOT system in March 2014. The ERCOT system has been operating with all the planned CREZ lines in-service since April 2014. The alarm limits obtained with the February to July 2014 data will be very stable unless major generation changes occur, such as major addition of wind power.

These alarm limits are not likely to change significantly in the near future unless a significant amount of wind power is added in the western area and the Panhandle areas of Texas displacing generation in other areas such as the Valley area. ERCOT operators can use the alarm limits established in this report to monitor real-time operations keeping in mind that if major changes/shifts occur in generation production these alarm limits should be revised as appropriate.

Also, it is suggested that the ERCOT operators validate these limits by keeping track of the times when the limits are exceeded indicating possible causes such as transmission or generation changes. A full year history of this validation tracking should be used to update alarm limits.

10. RECOMMENDATIONS

a. Data Monitoring and Data Integrity

State Estimator Data: The SE data provided by ERCOT for the February to July 2014 period was very good. However data for January was not available. EPG recommends that SE data be fully preserved on a continuous basis for use in future alarm limits updates and for calibrating phasor data.

Phasor Data: Of the 30 PMUs used in this update, eight PMUs show availability of less than 76% of which two PMUs, FarWest 2 and Coast 2, show availability of less than 15%. EPG recommends that ERCOT and the PMU owners monitor phasor data for these eight PMUs to find and fix problems associated with missing data. PMUs signals, when available and producing accurate data, will allow system operators to accurately monitor the real-time conditions of the ERCOT system.

b. Alarm Limits for Real Time Monitoring

EPG has produced alarm limits for 25-pairs for real-time monitoring; the recommended alarm limits for use by ERCOT system operators are shown in Section 8, Table 8 of this report. Each set of alarm limits includes two pairs, one pair of alarms to be used in the positive direction of flow (From-To) and the other pair of alarms to be used in the negative direction of flow (To –From). These recommended alarms can be implemented immediately.

c. Panhandle Wind Output Monitoring

There are four new CREZ lines connecting the Panhandle new 345 kV system with the Central ERCOT system: West 15-West 14, West 16-West 14, West 16-West 3 and West 19-West 9. The flows and angles on these four lines should provide a tool to monitor the wind output from that area. EPG recommends that ERCOT monitor this interface by including these four pairs in the RTDMS® daily report or a separate report if necessary.

d. PMU at West 19

The Panhandle-North ERCOT interface recommended above has PMUs installed at all the substations except for West 19. EPG recommends that, in order to monitor wind power flow from the Panhandle area to the Central area of the ERCOT system, PMUs be installed at this substation to be able to monitor voltage angle and power on all four lines comprising the interface.

e. RTDMS® Daily Report

The RTDMS® daily report should be simple, clear, meaningful and easy to read quickly. EPG has produced some recommendations to accomplish these objectives. These recommendations are presented in Appendix D attached to this report.

f. Need for an Alarm Limits Update

The last four CREZ lines were placed in service in March 2014, completing the CREZ Project. The alarm limits proposed in this report are considered a good representation of present ERCOT conditions since during most of the February to July 2014 period base of this update, all CREZ lines were already in-service.

With the new transmission infrastructure now in place, it is expected that in future months and years wind output will increase considerably, causing a re-distribution of power among the different generating areas of the ERCOT system. As a result, some angle differences may change, necessitating a periodic update of alarm limits. EPG recommends an annual update of alarm limits to reflect these changes. If major or sudden changes in these patterns occur, updates to the alarm limits should be performed.

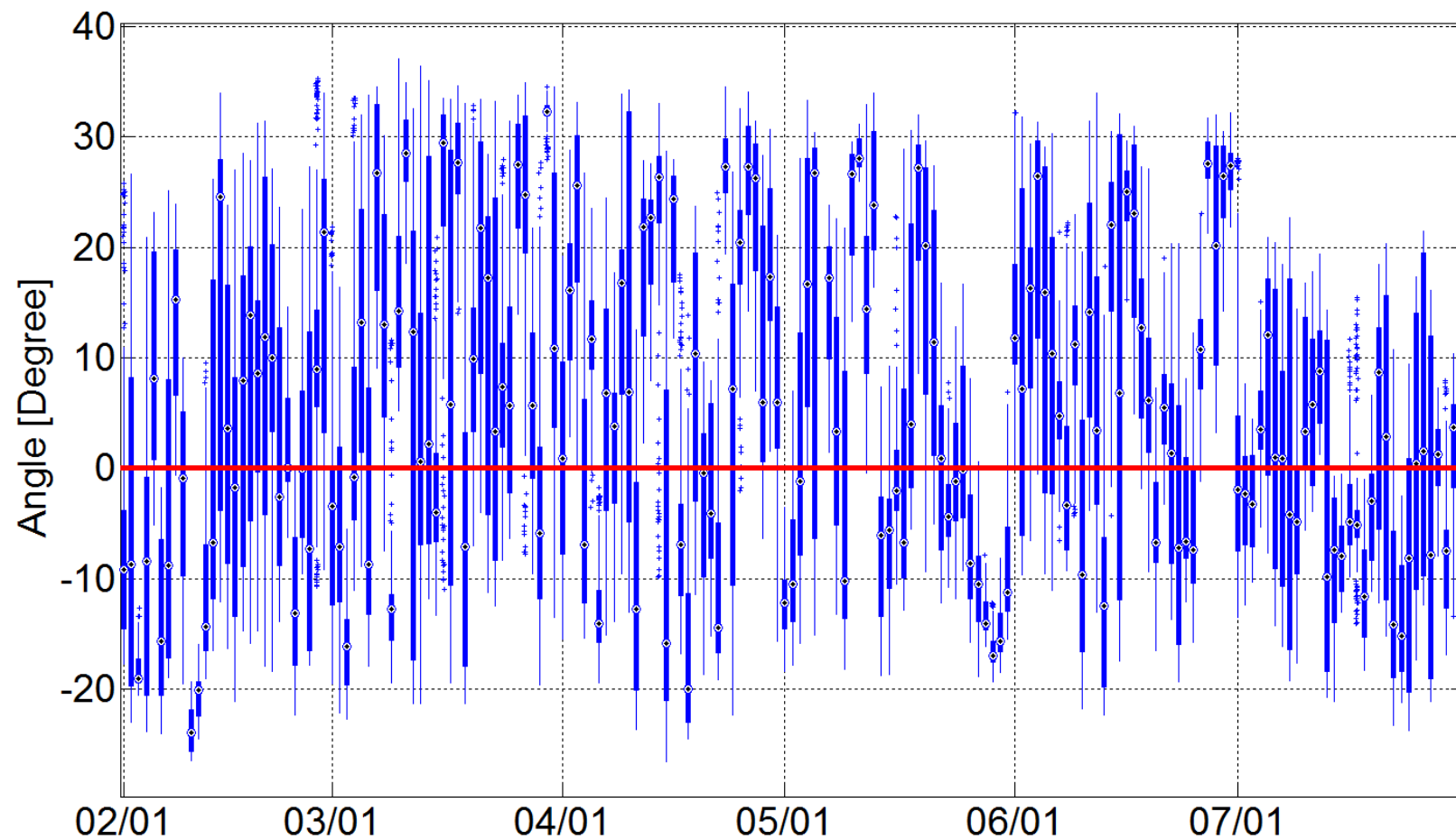
Appendix A – Part 1

CCET Discovery Across Texas project

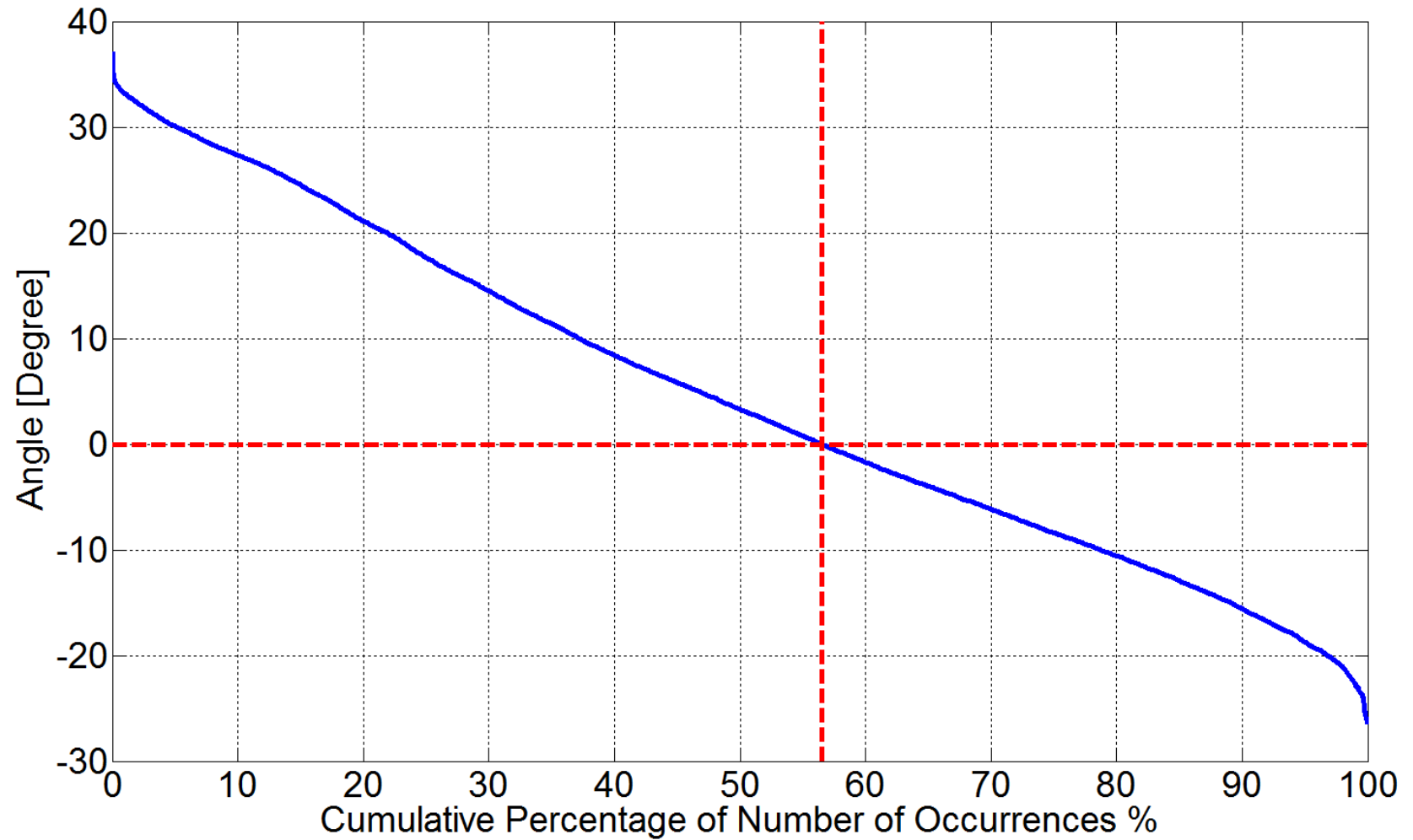
Baseline Analysis Update - Voltage Angles (Ref.: North 7)

State Estimator Data: February to July 2014
Box Whiskers Plots and Time Duration Curves

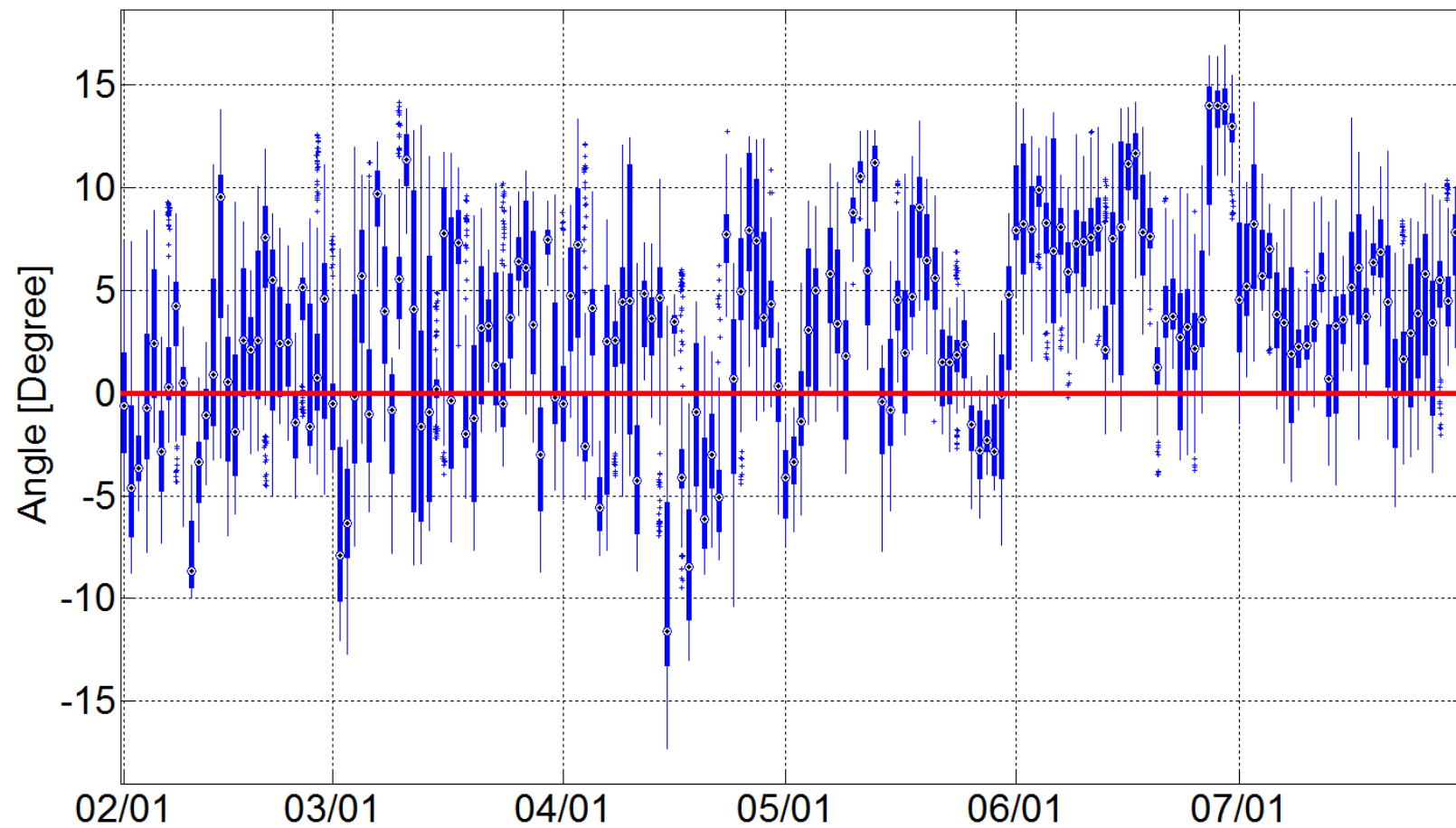
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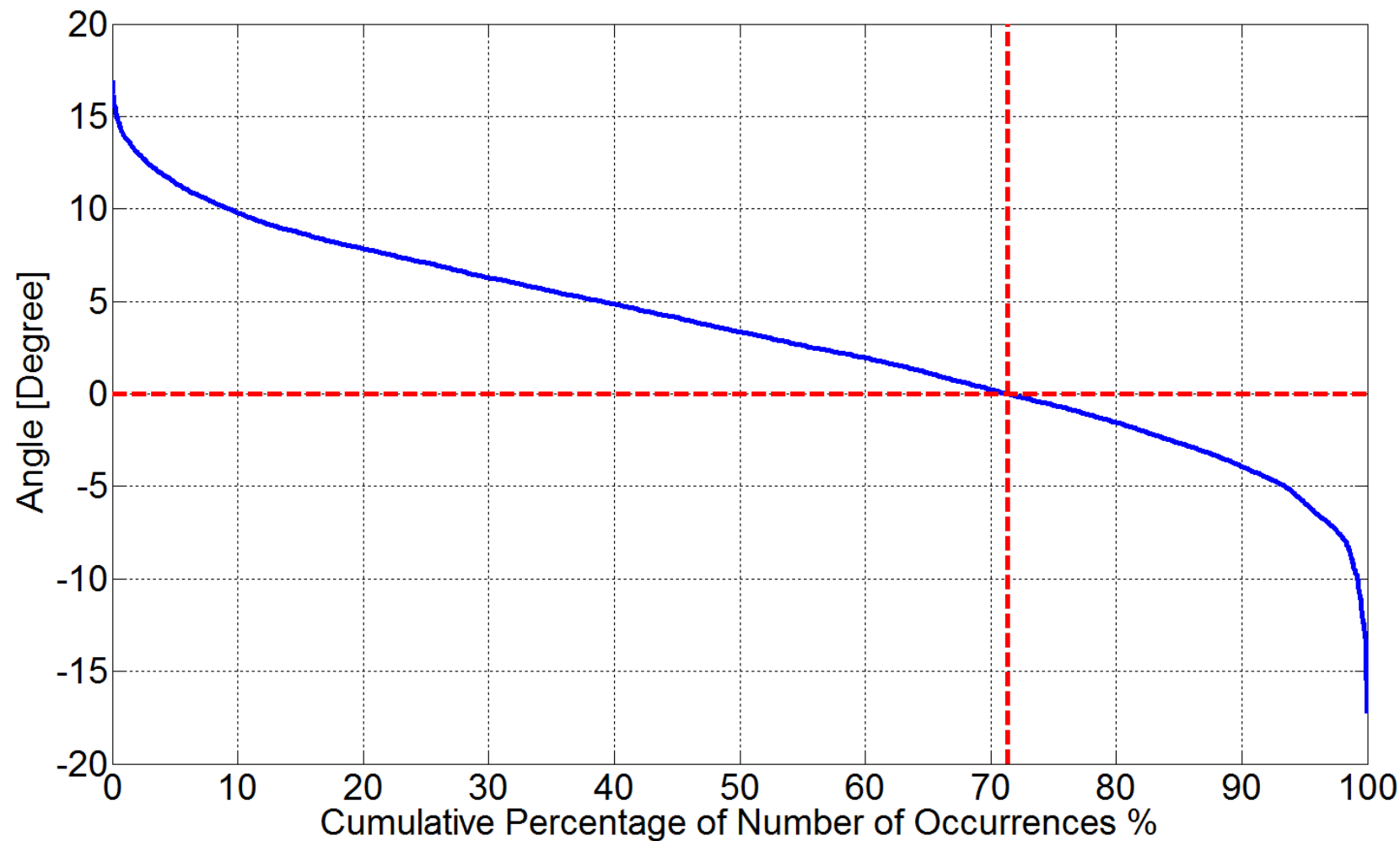
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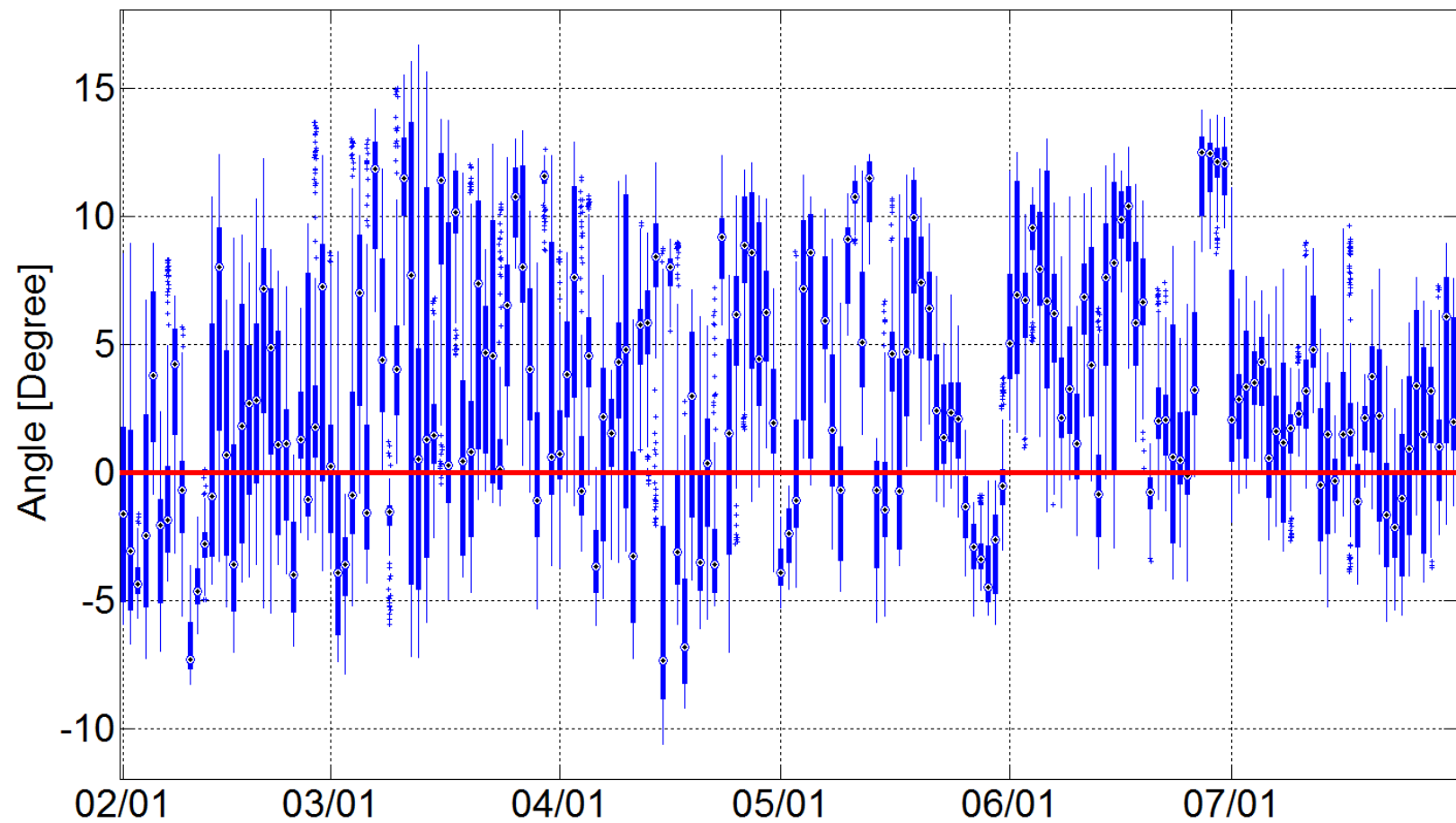
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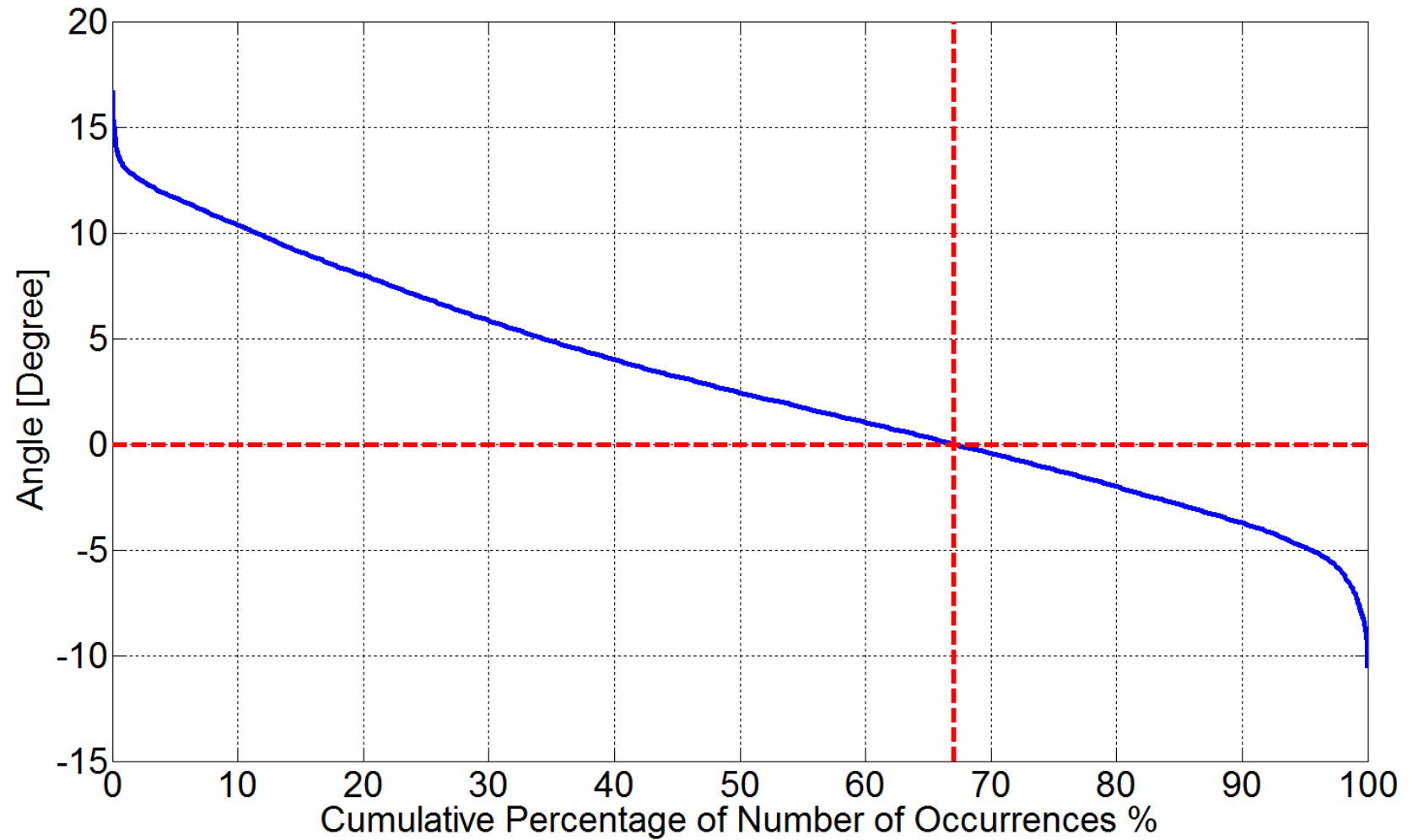
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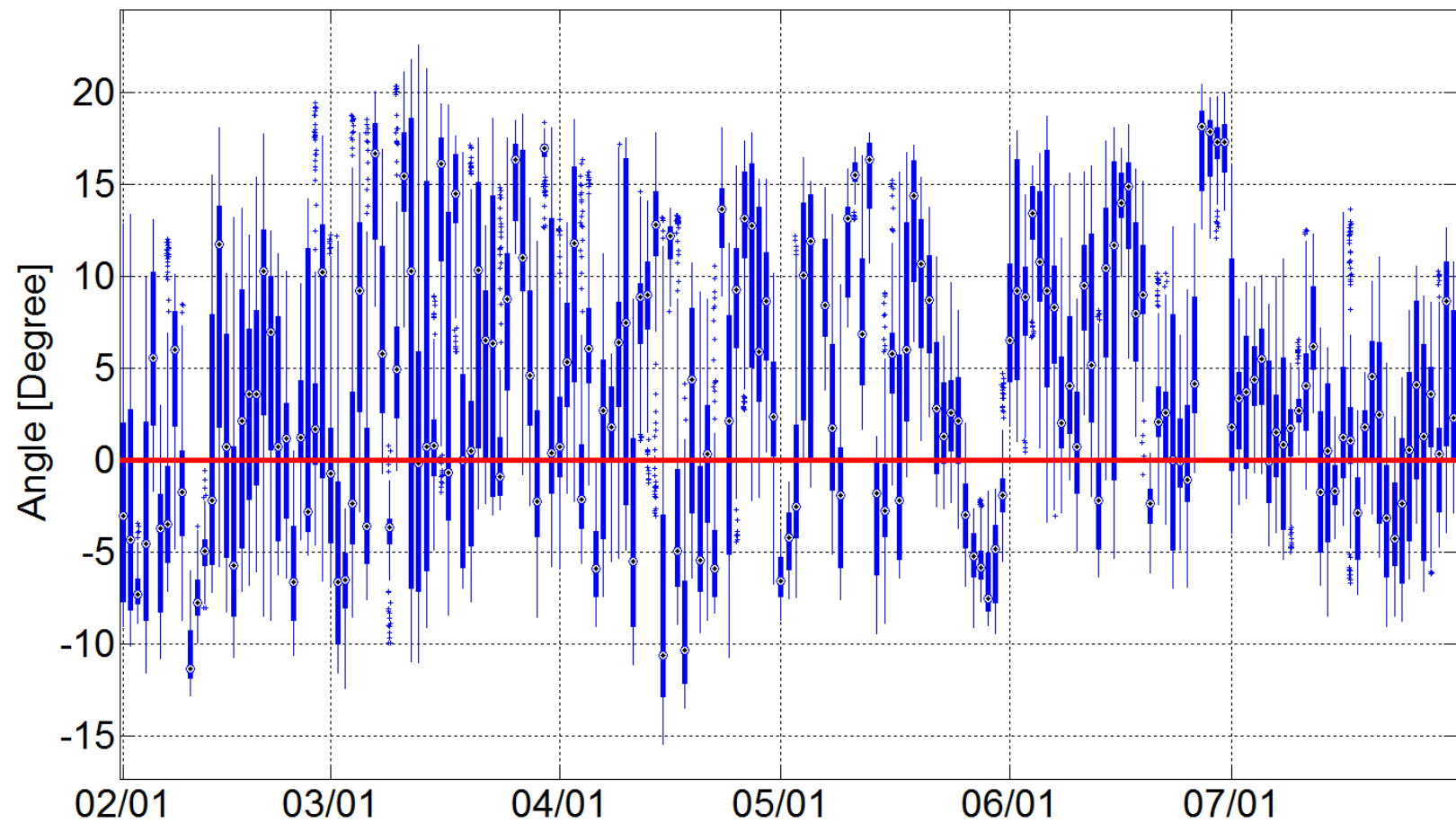
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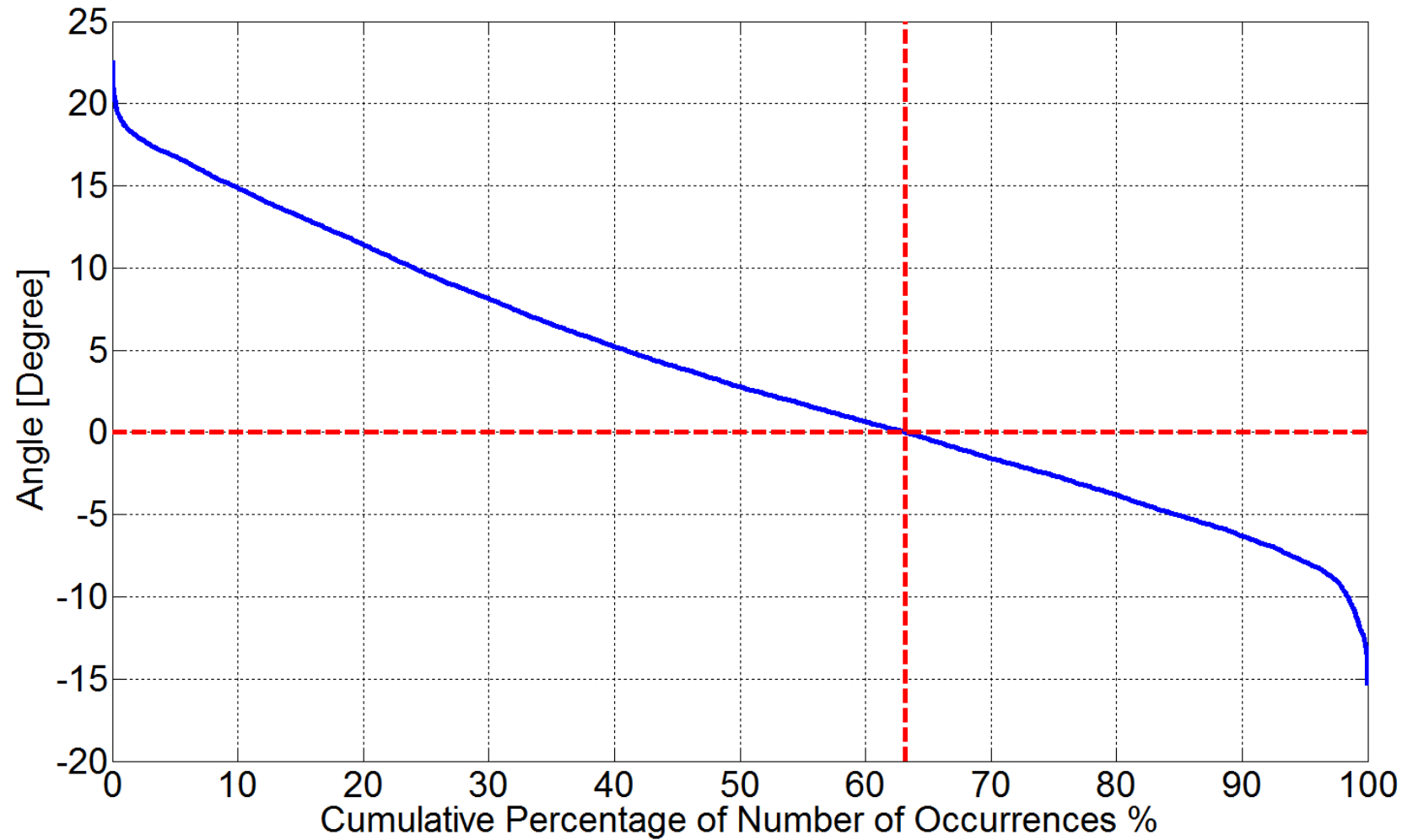
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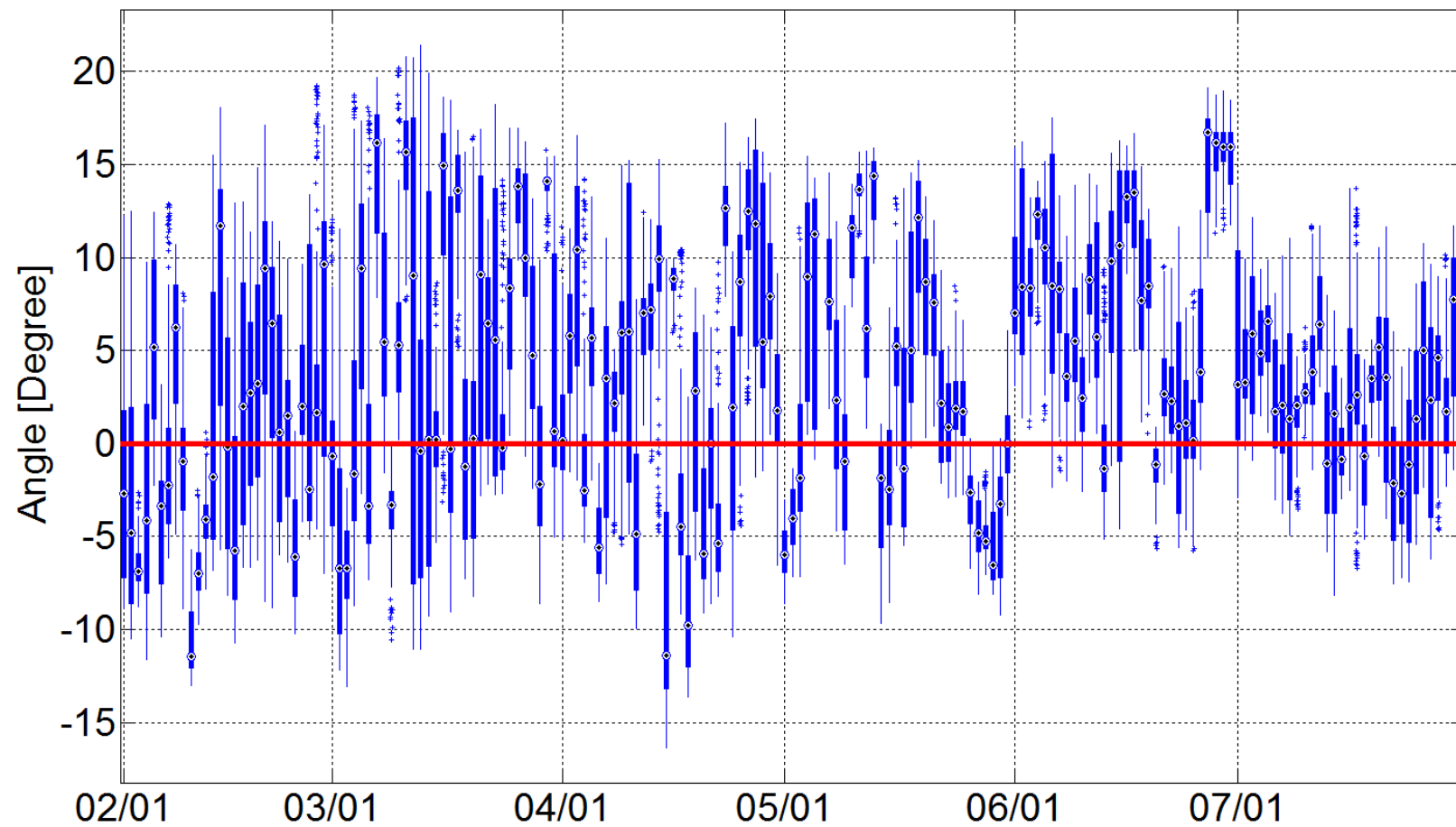
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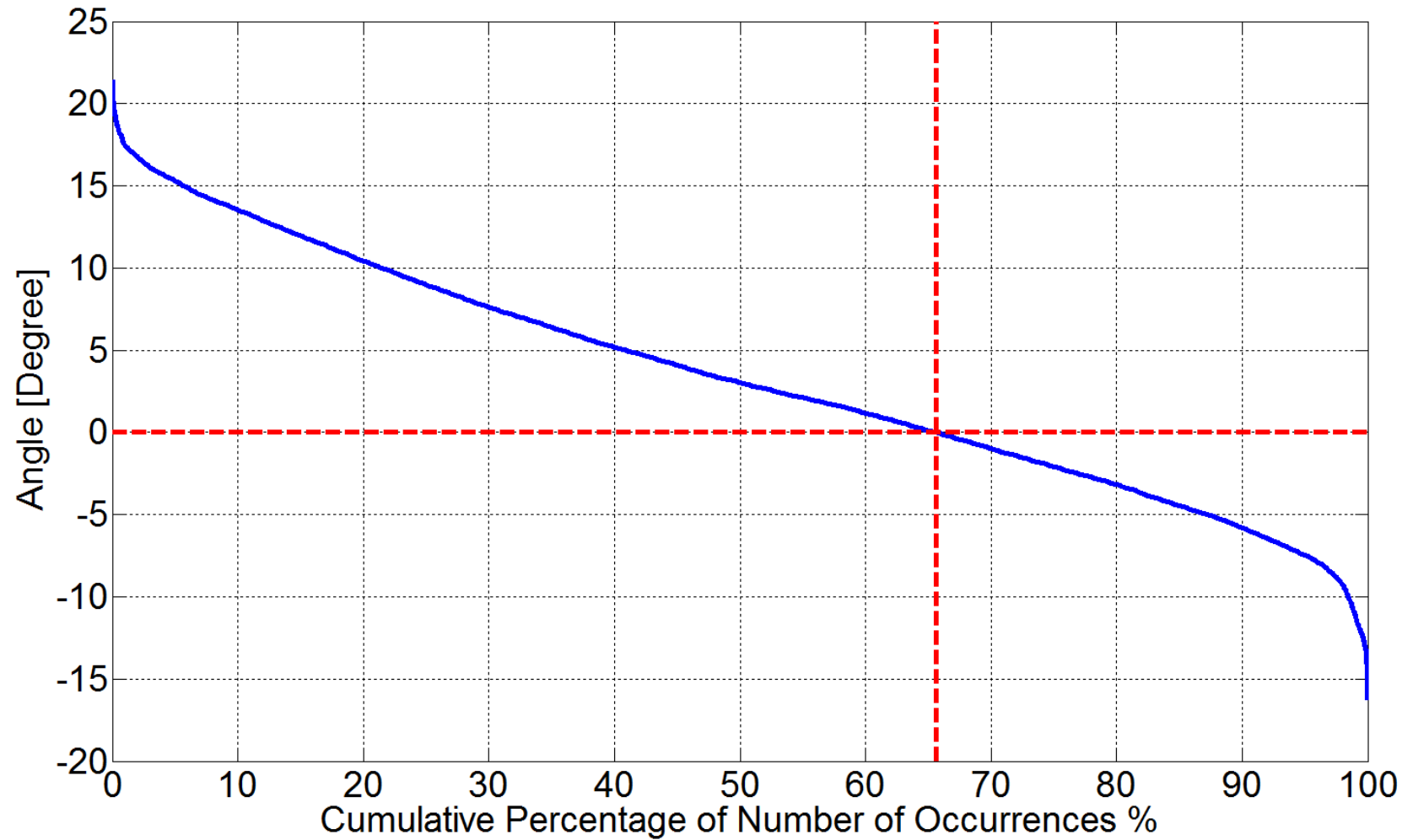
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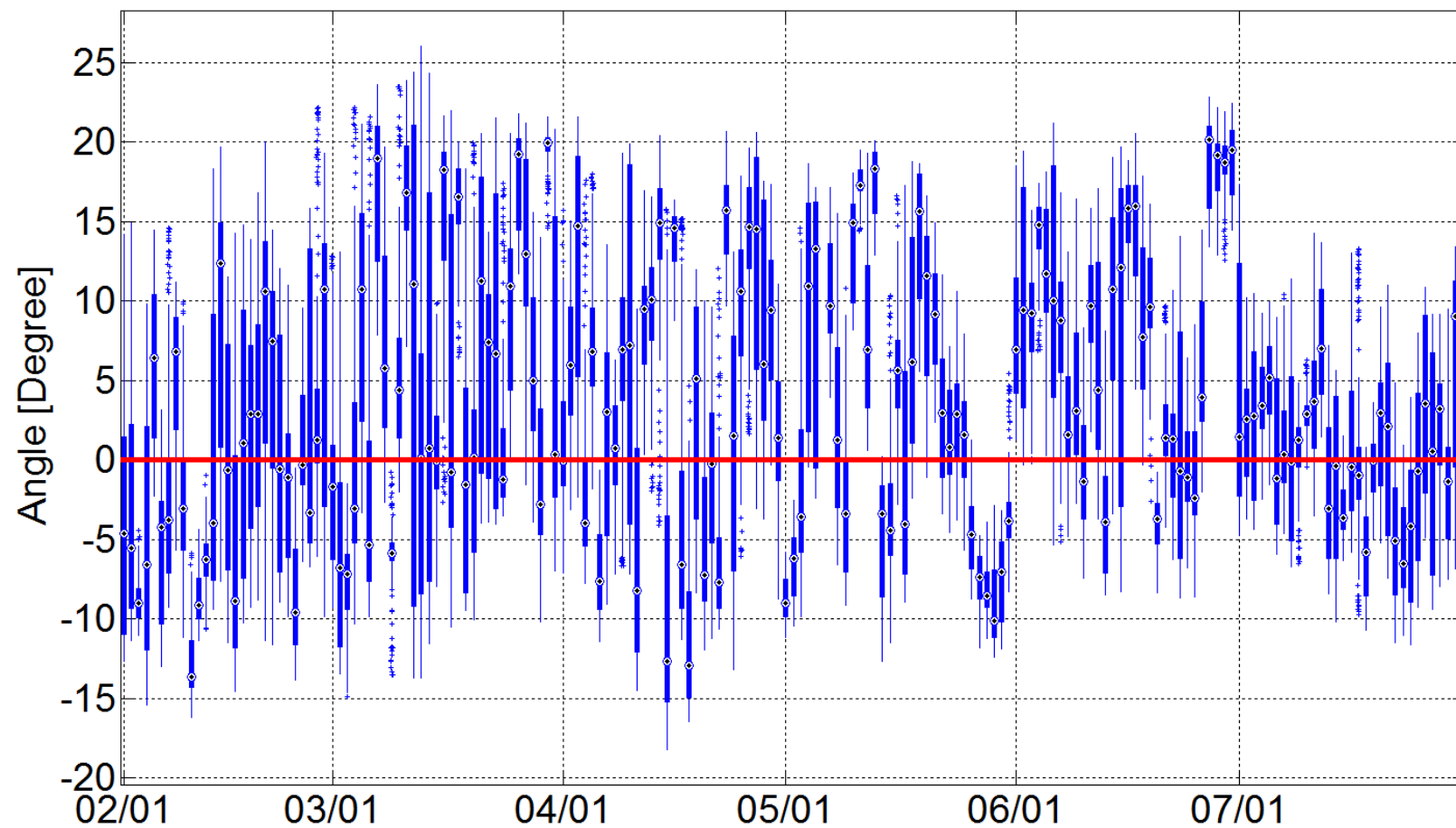
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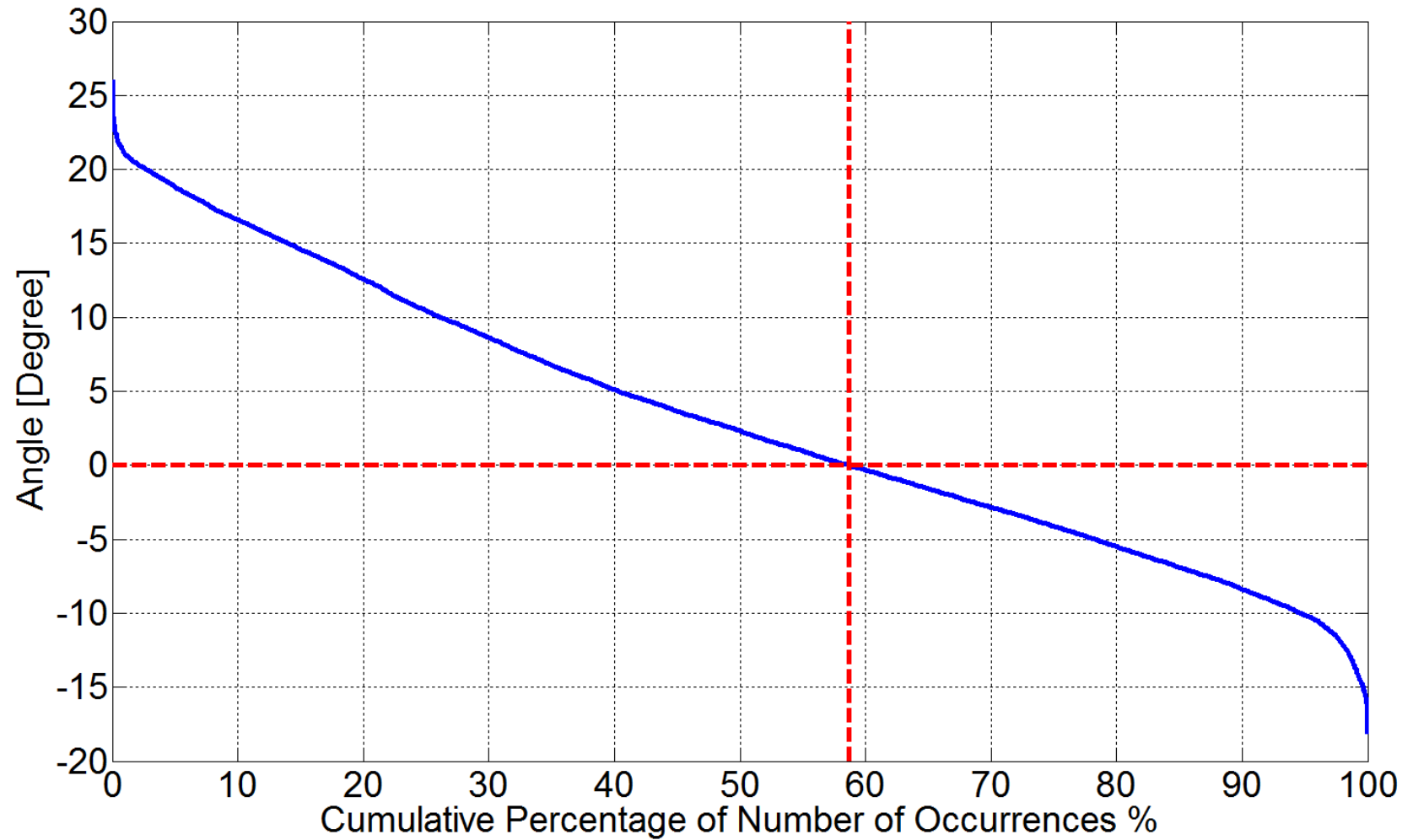
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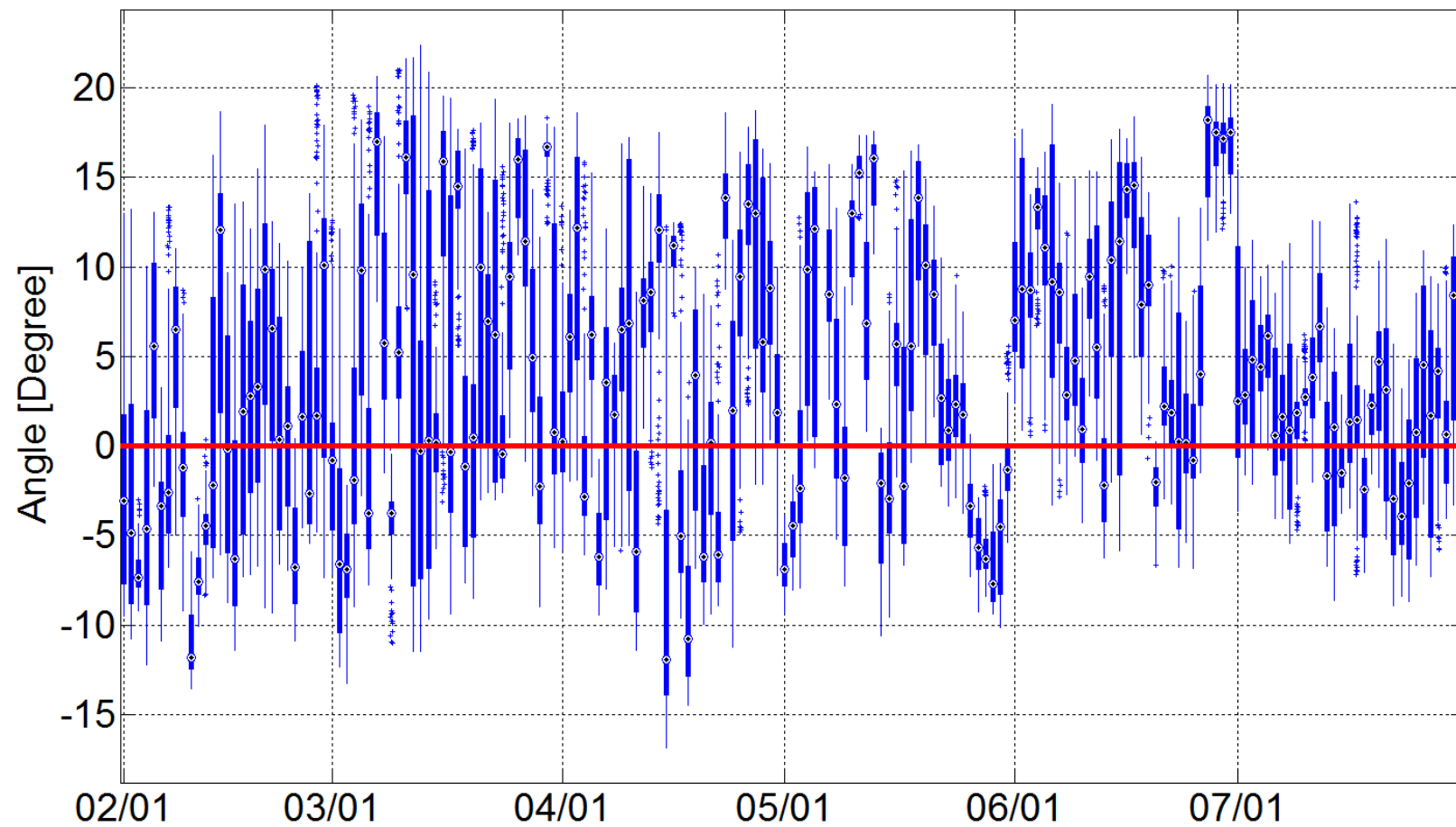
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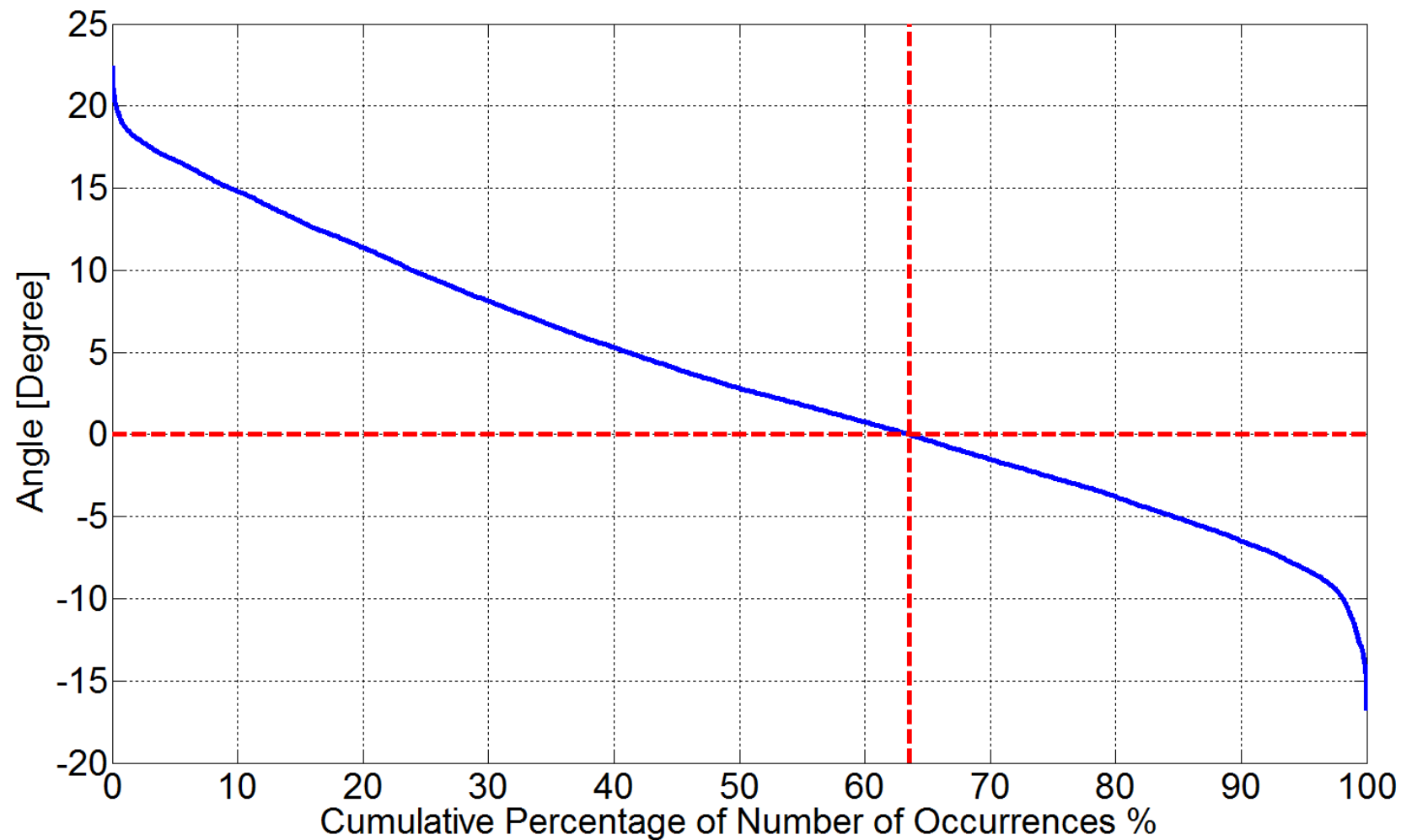
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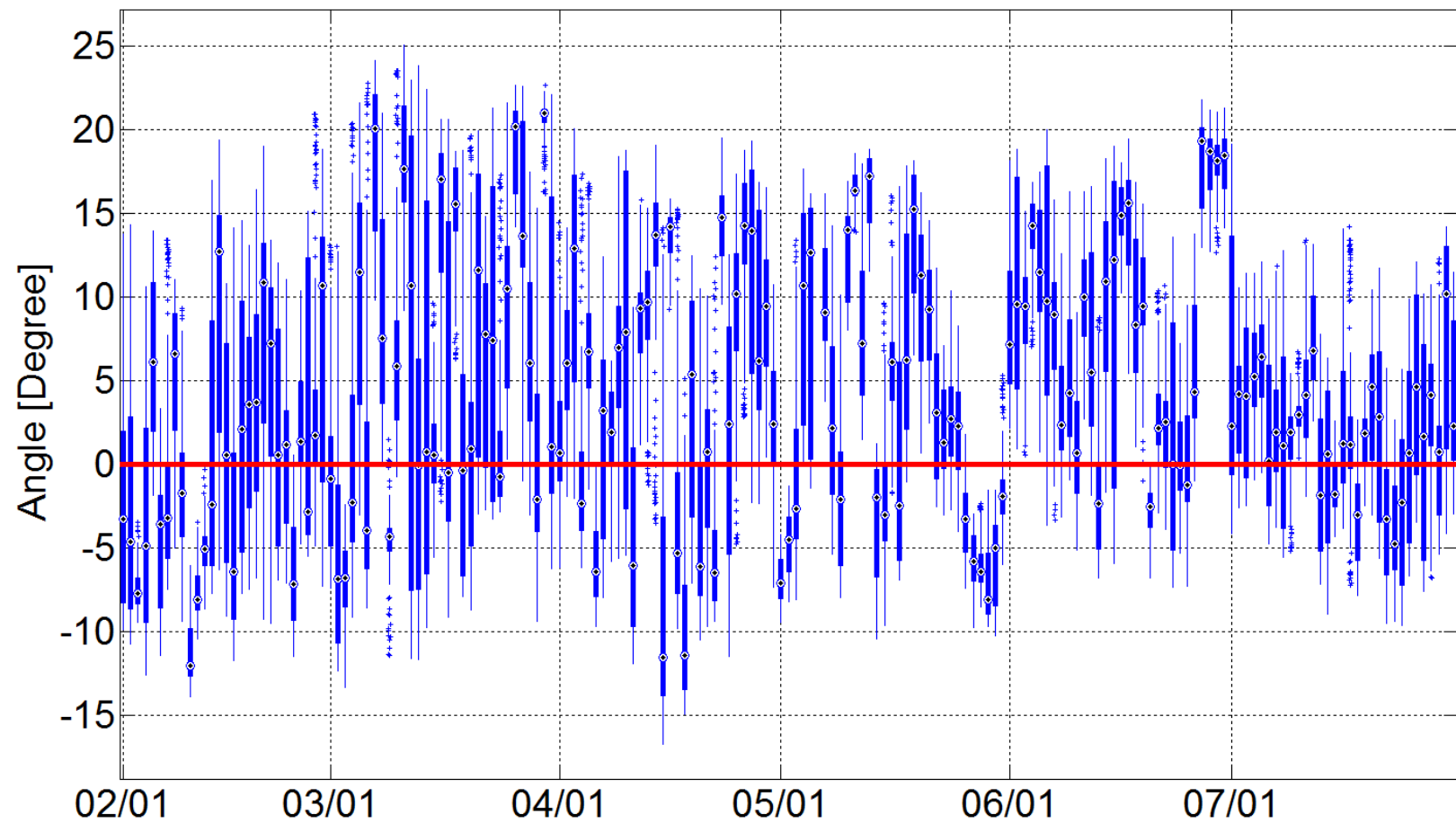
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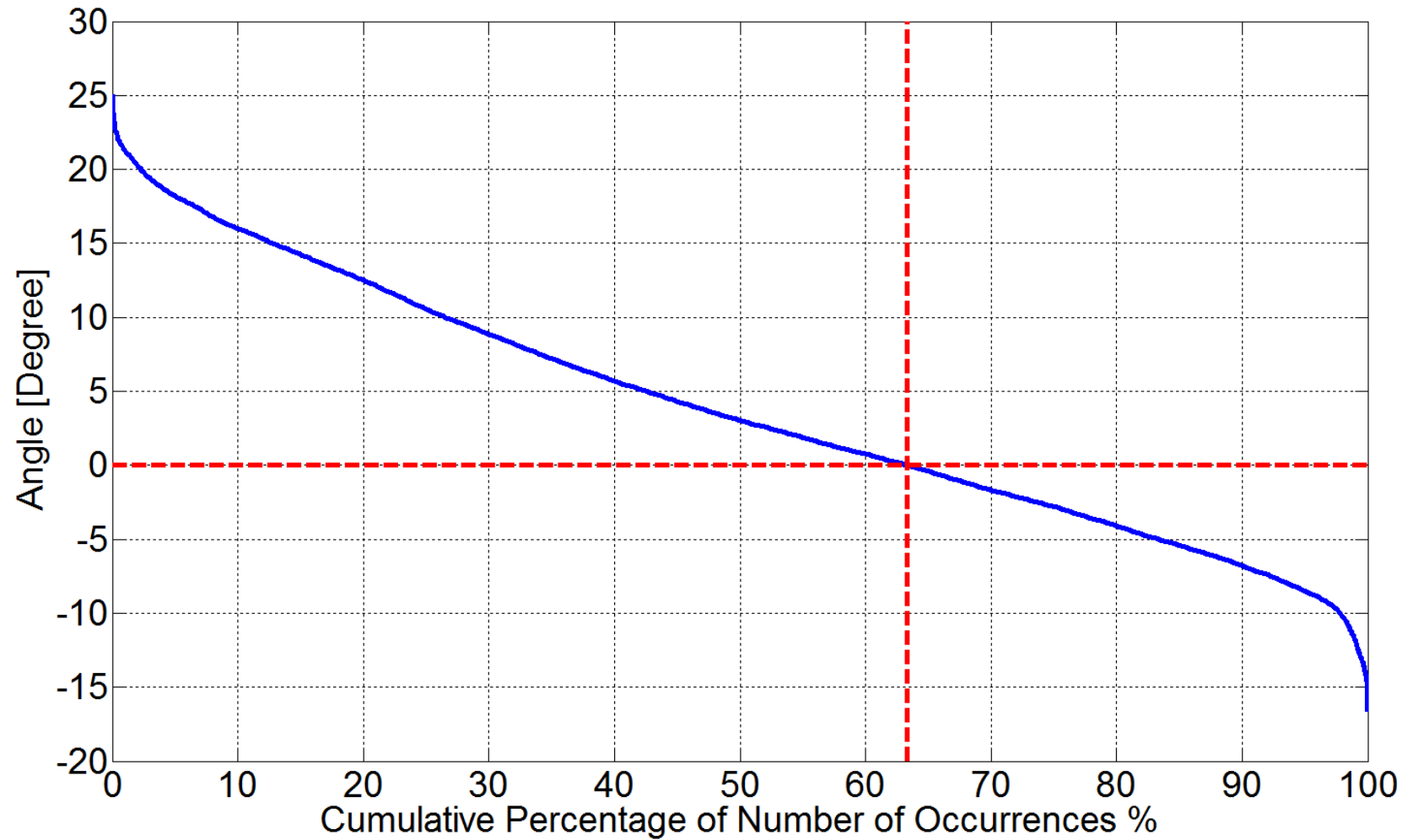
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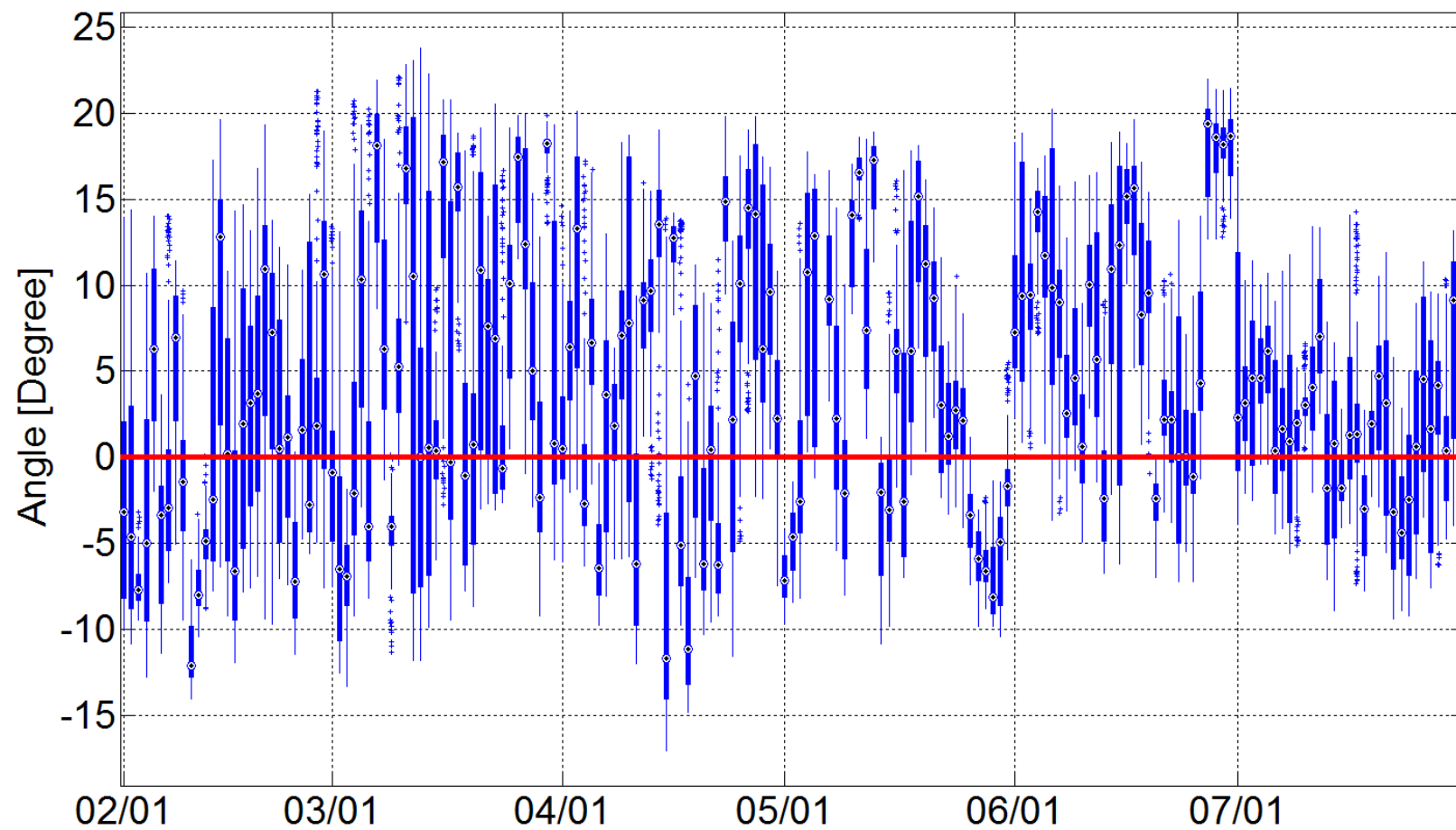
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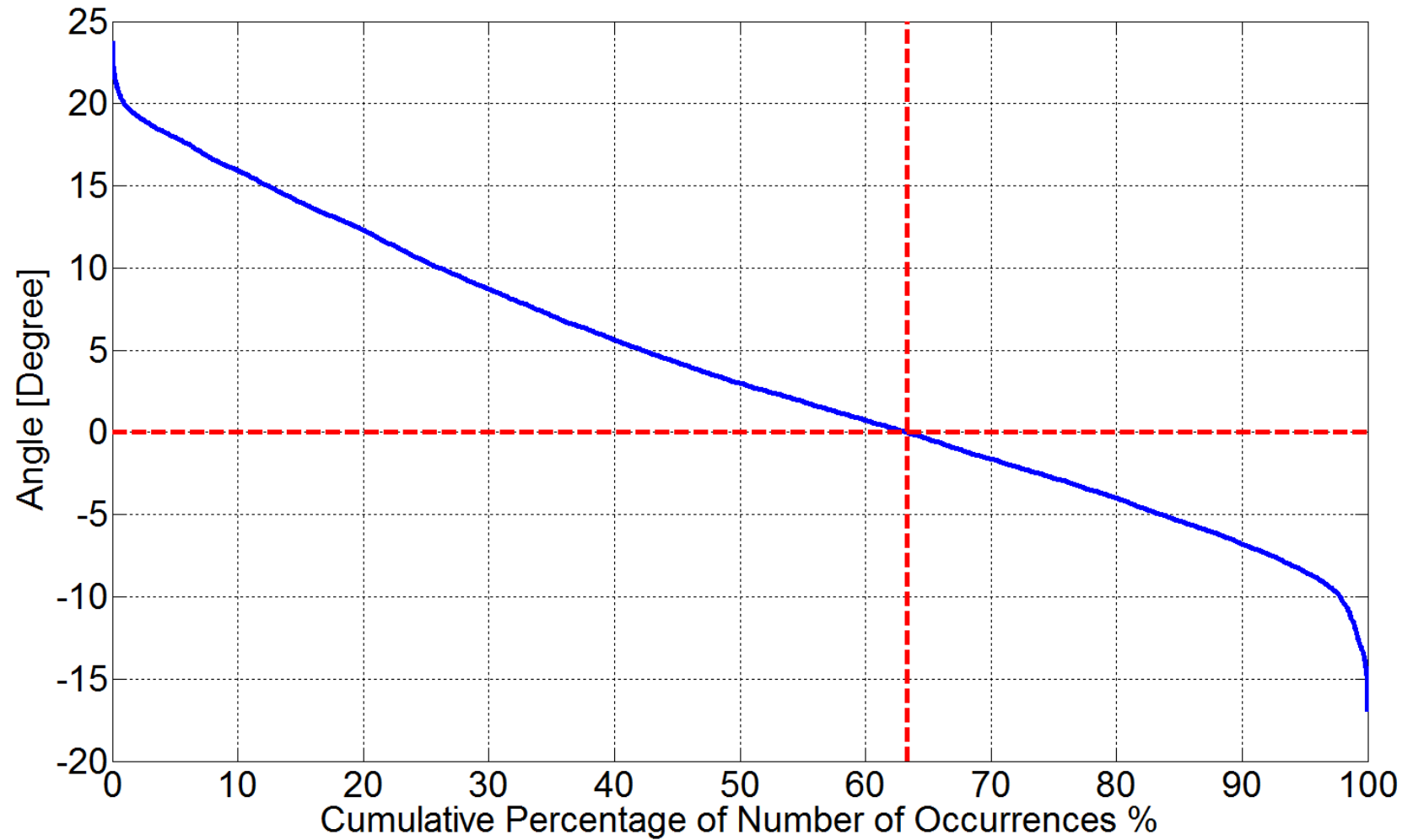
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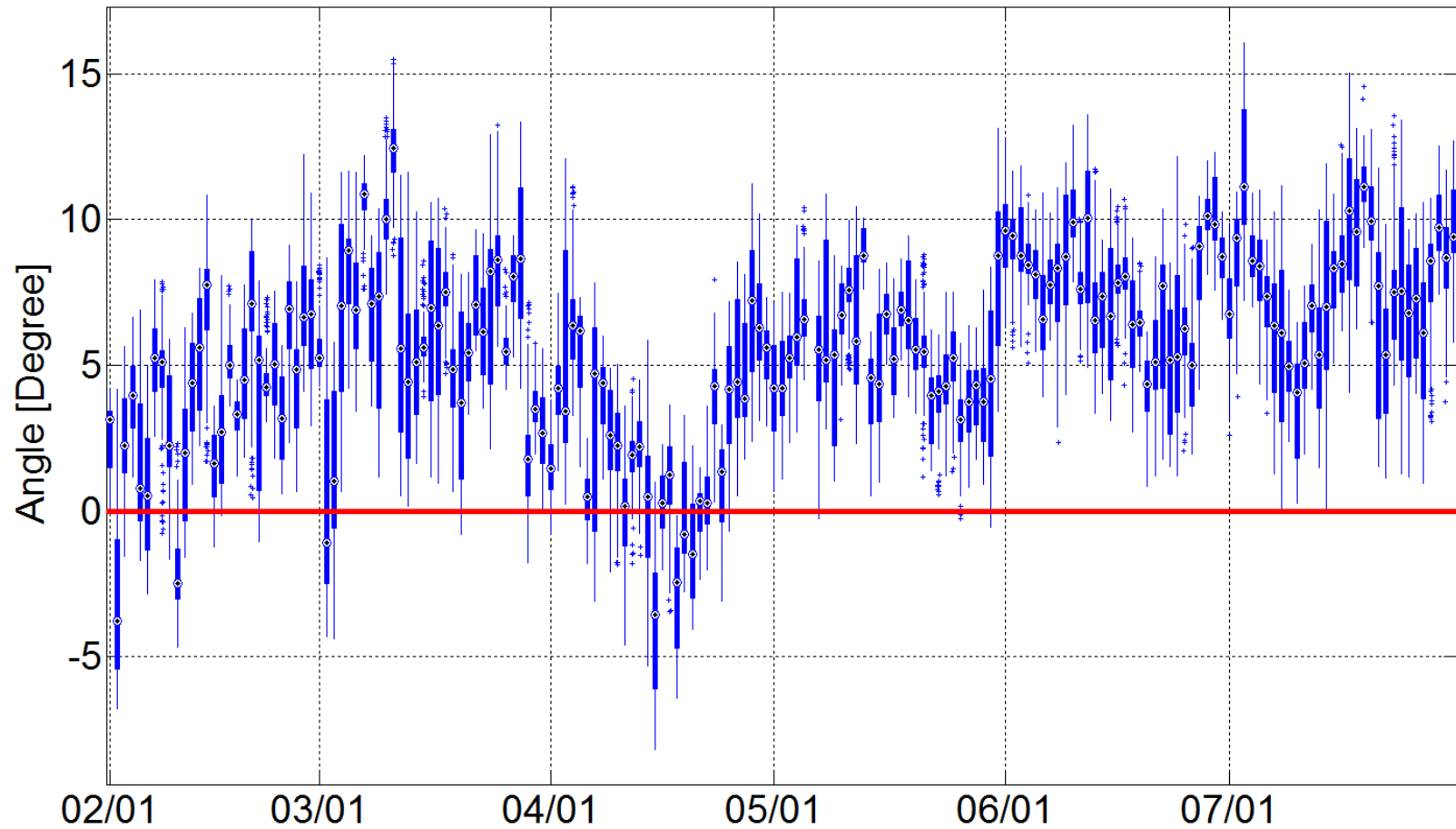
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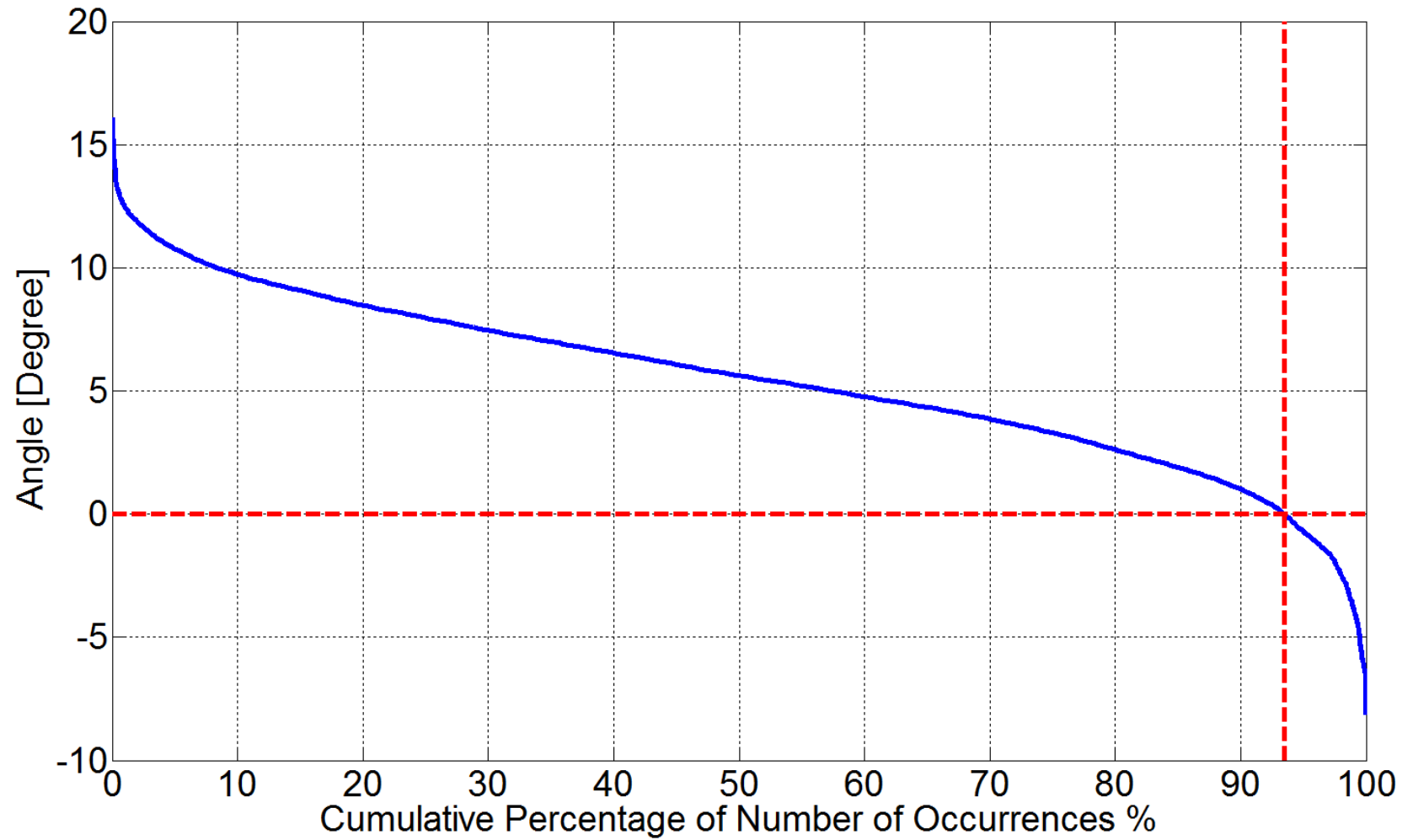
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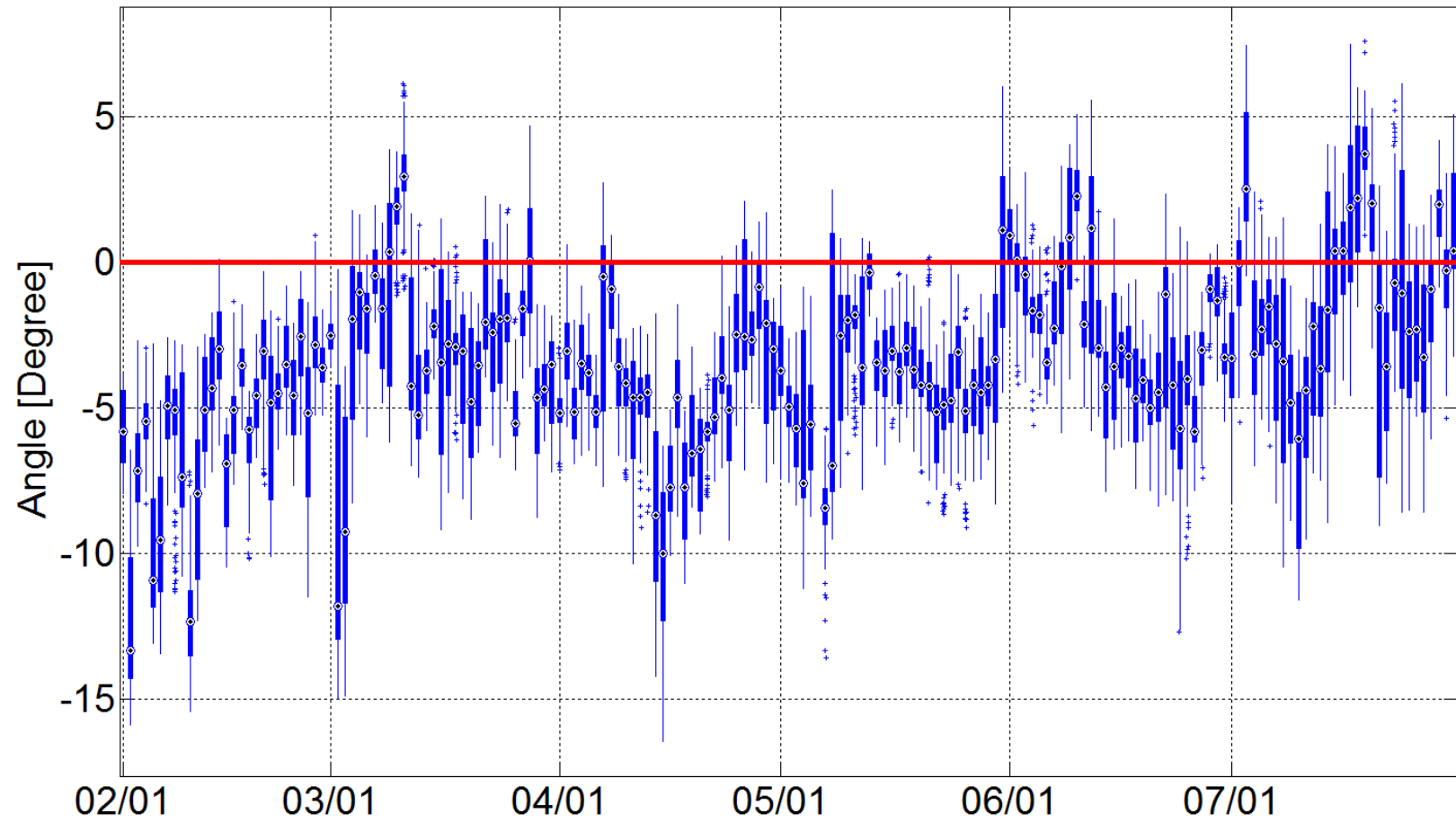
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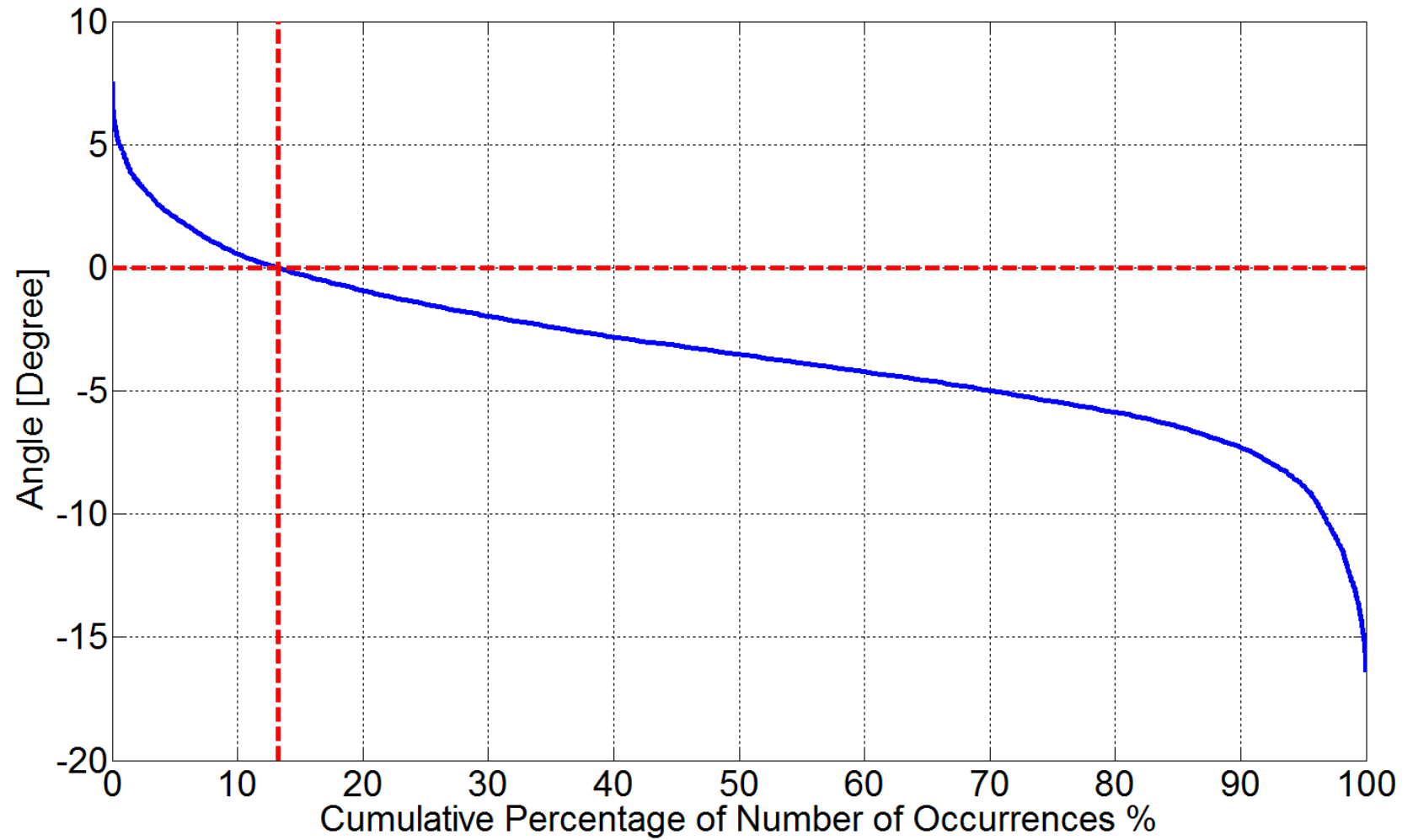
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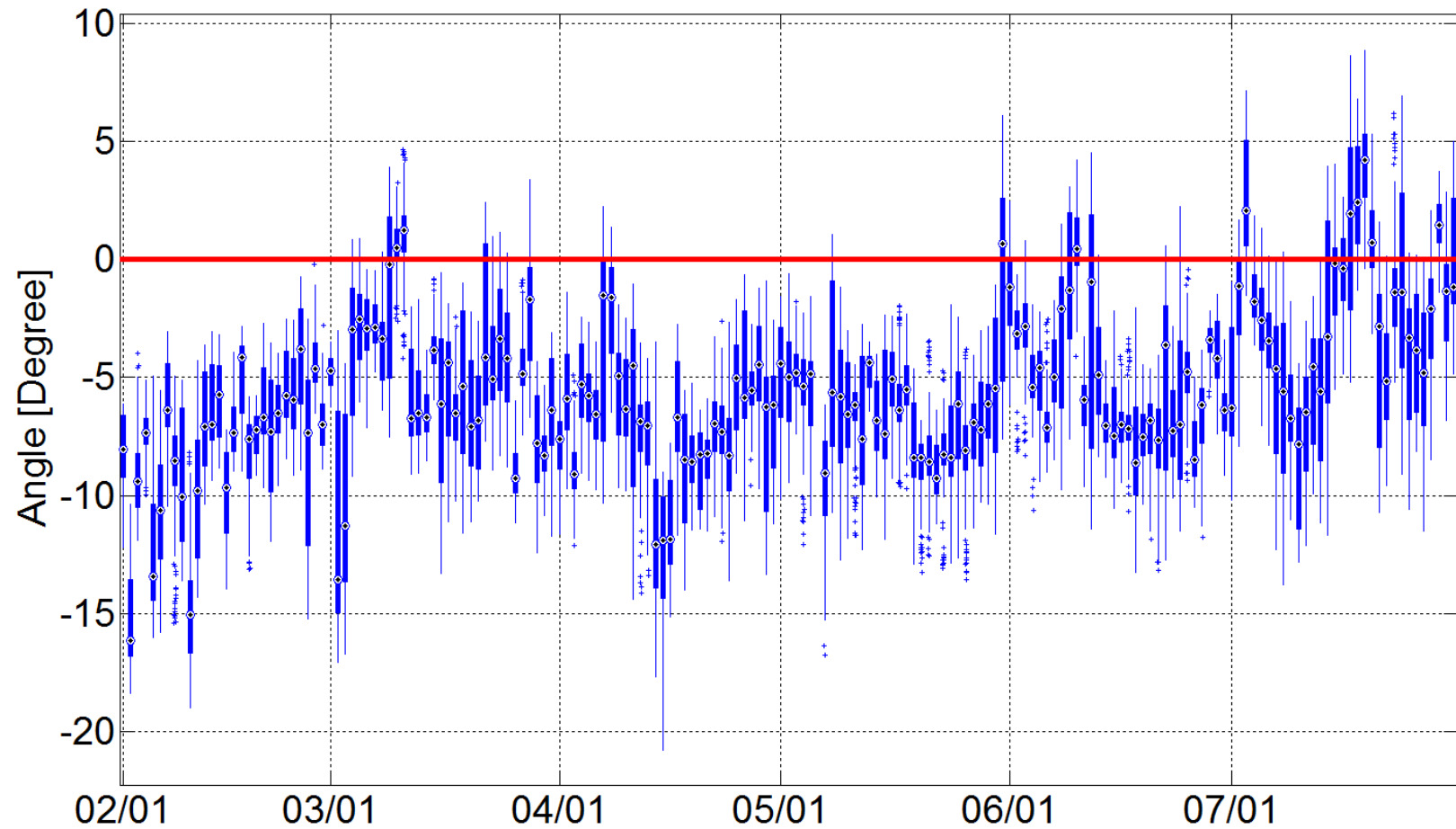
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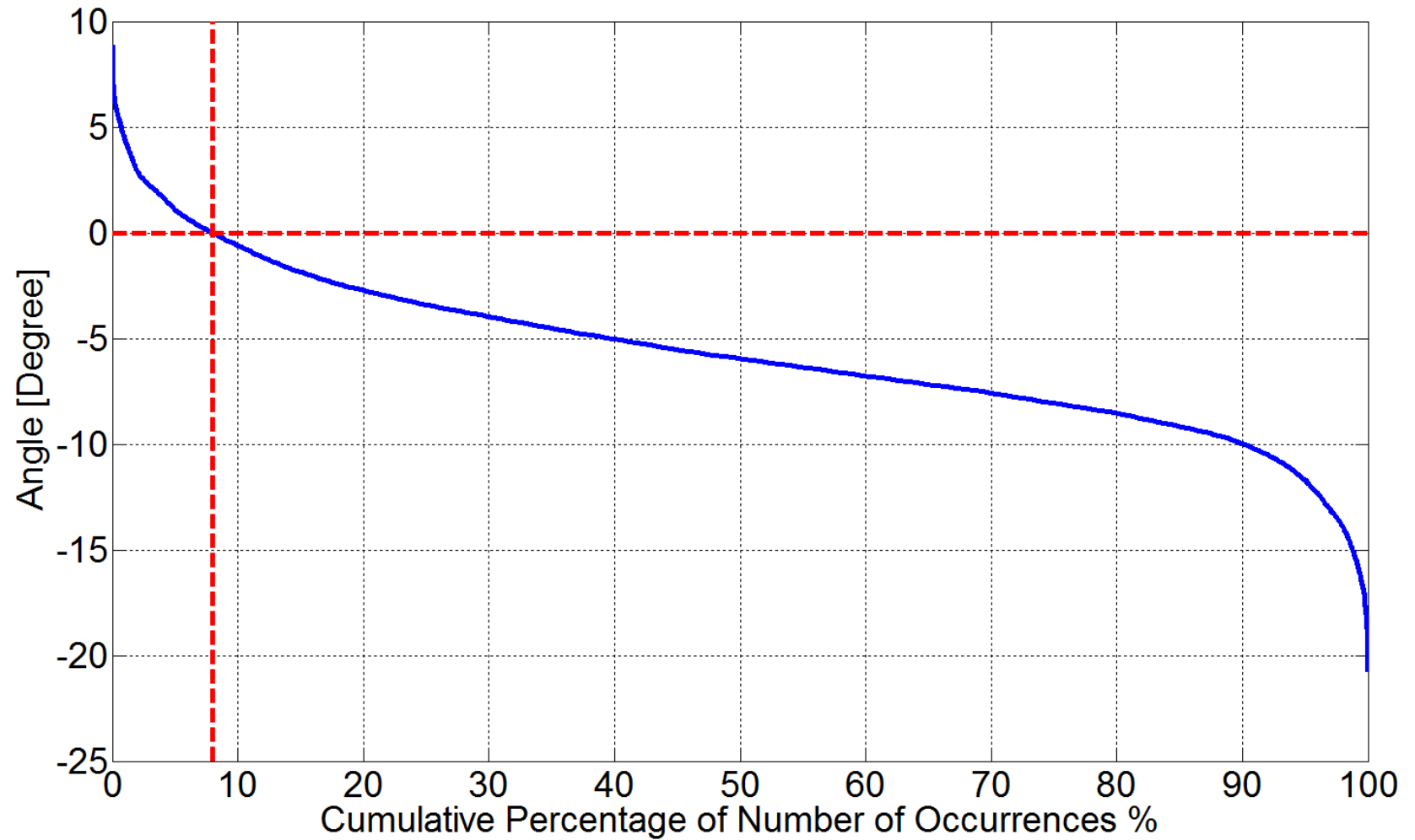
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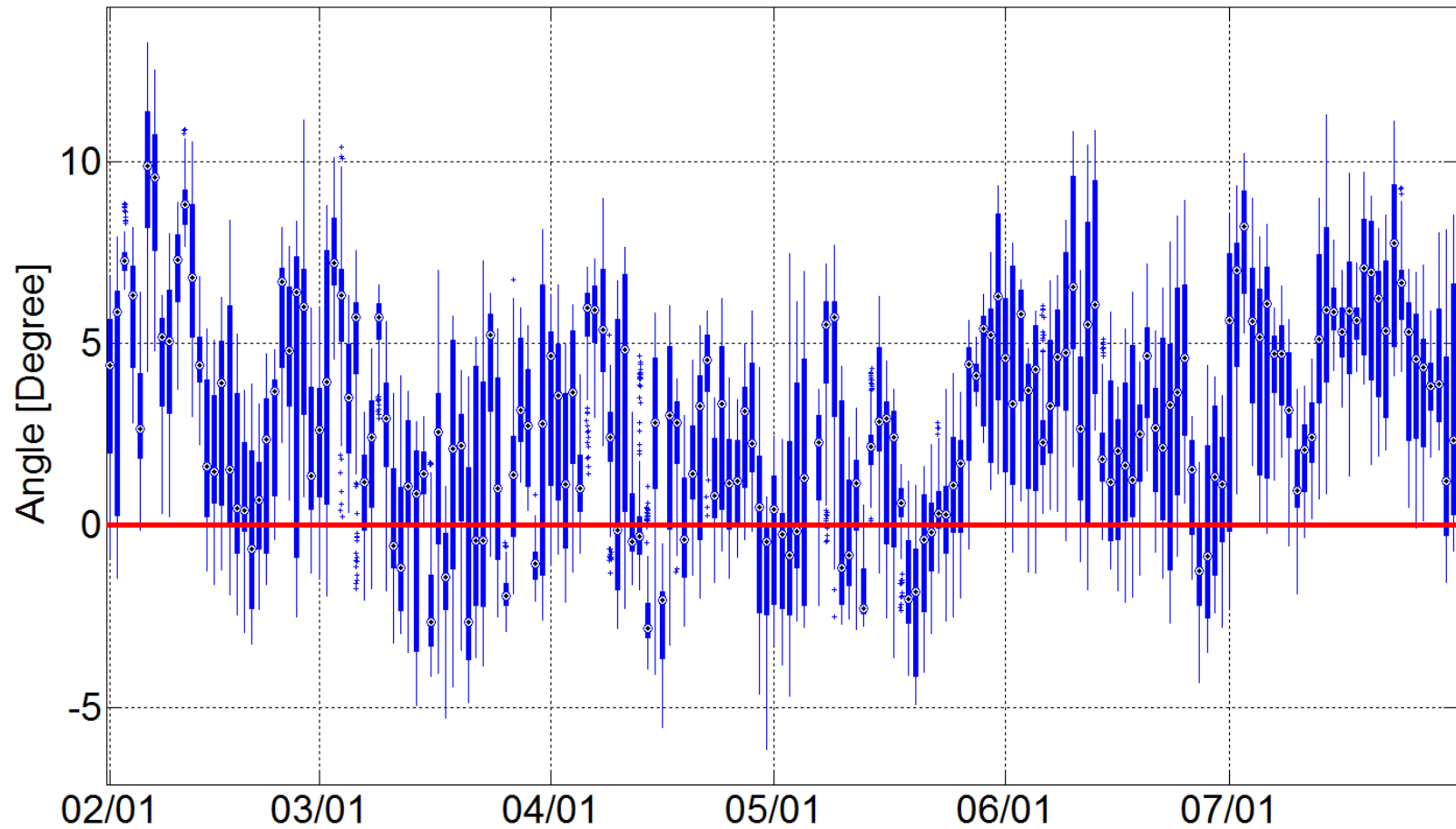
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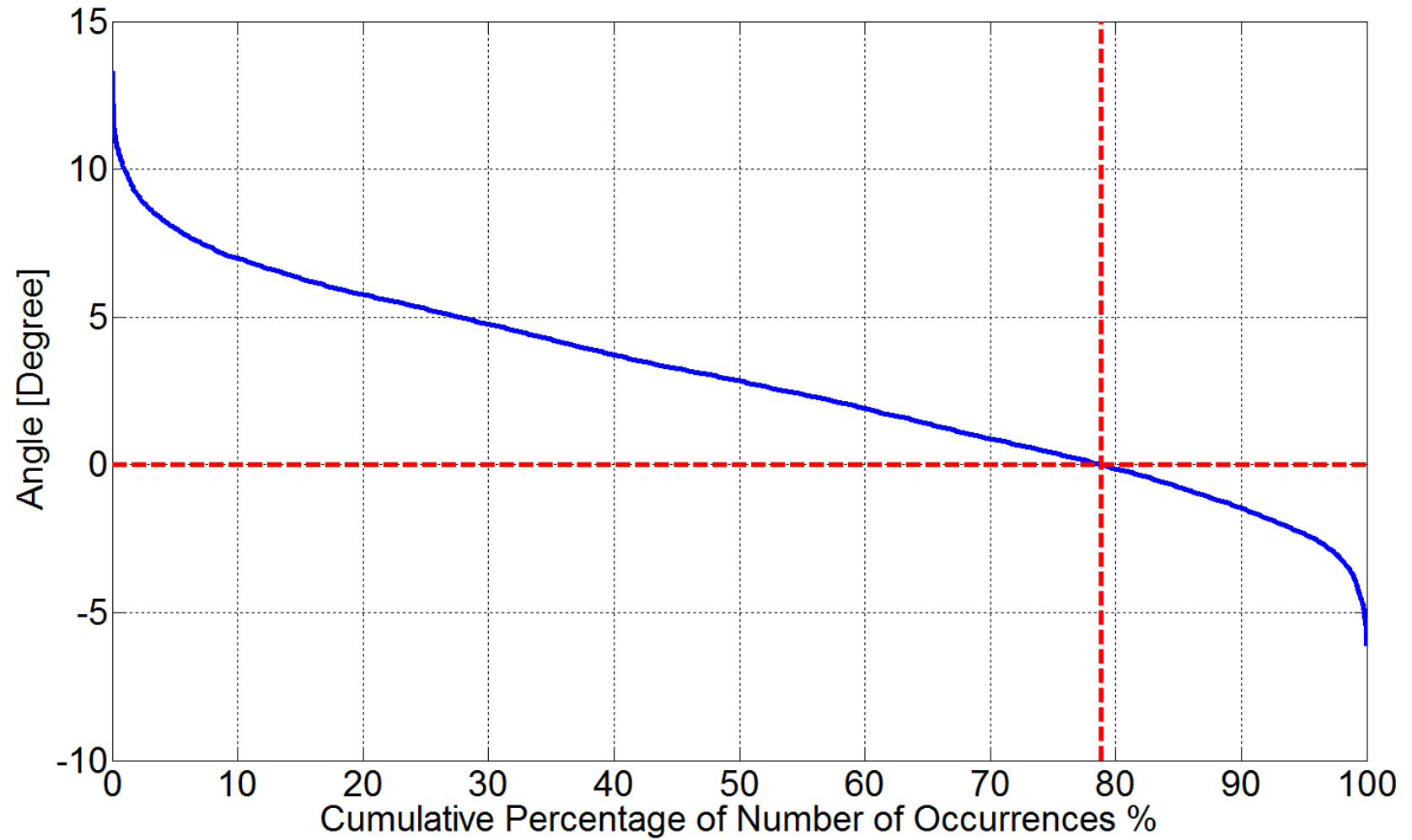
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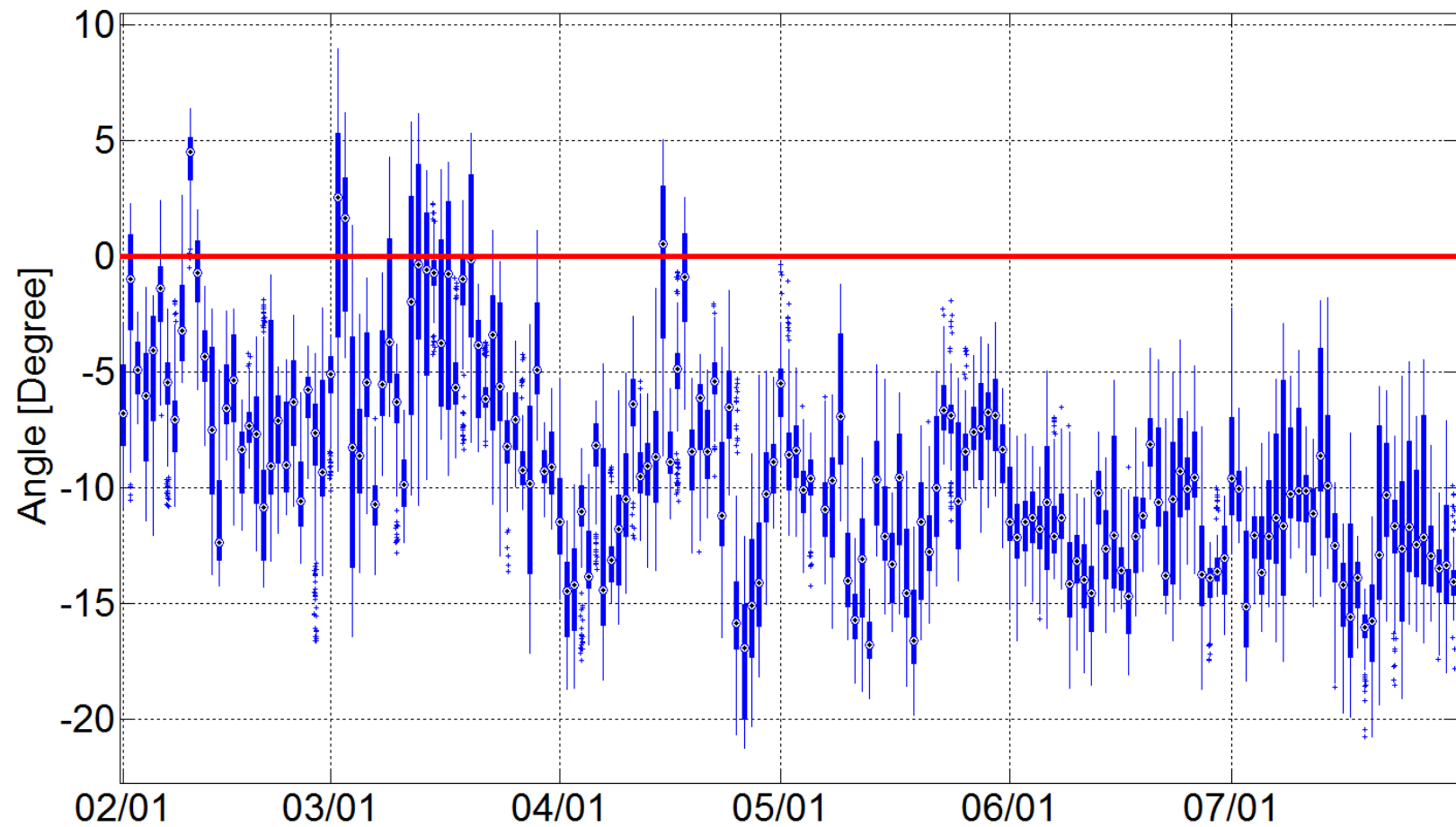
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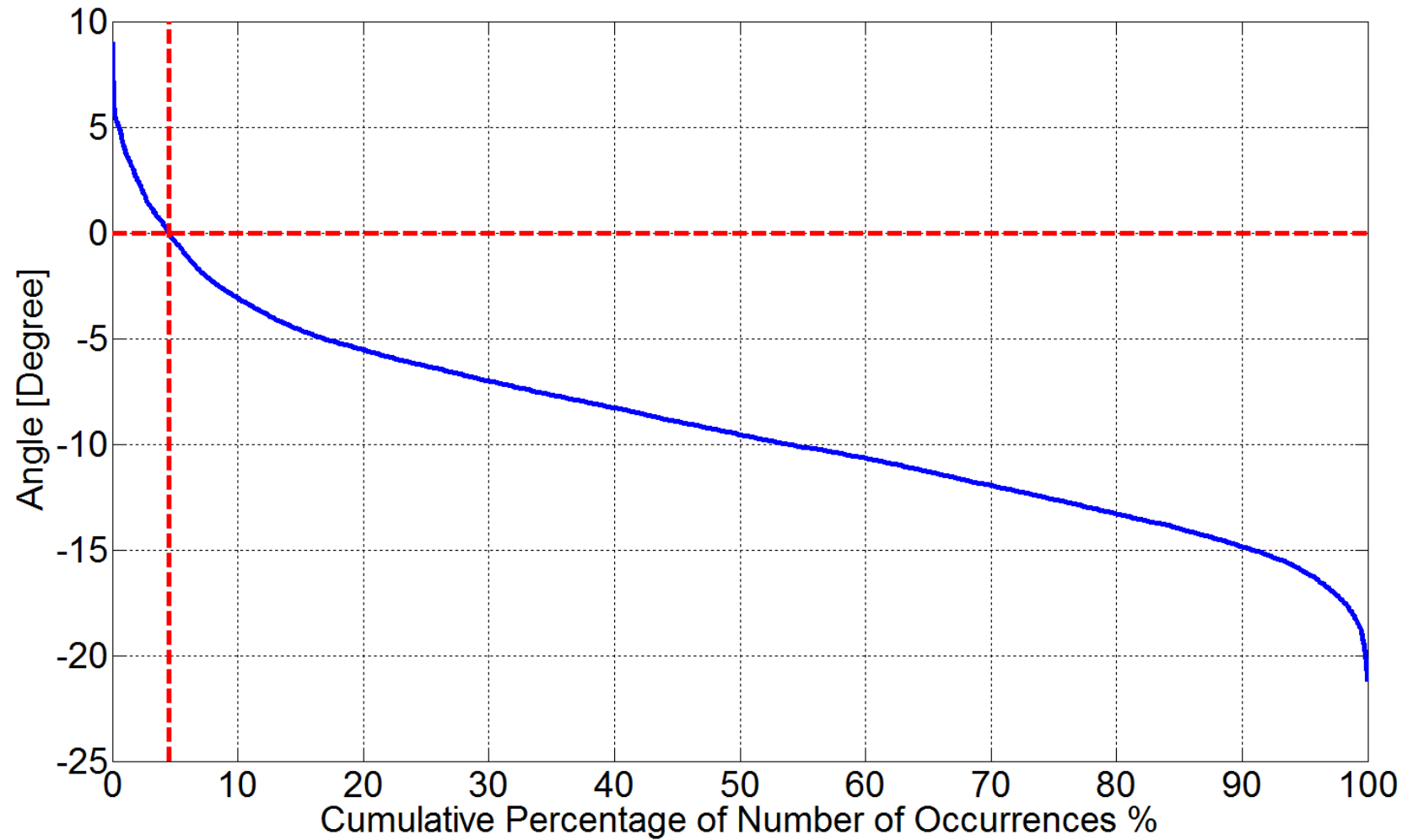
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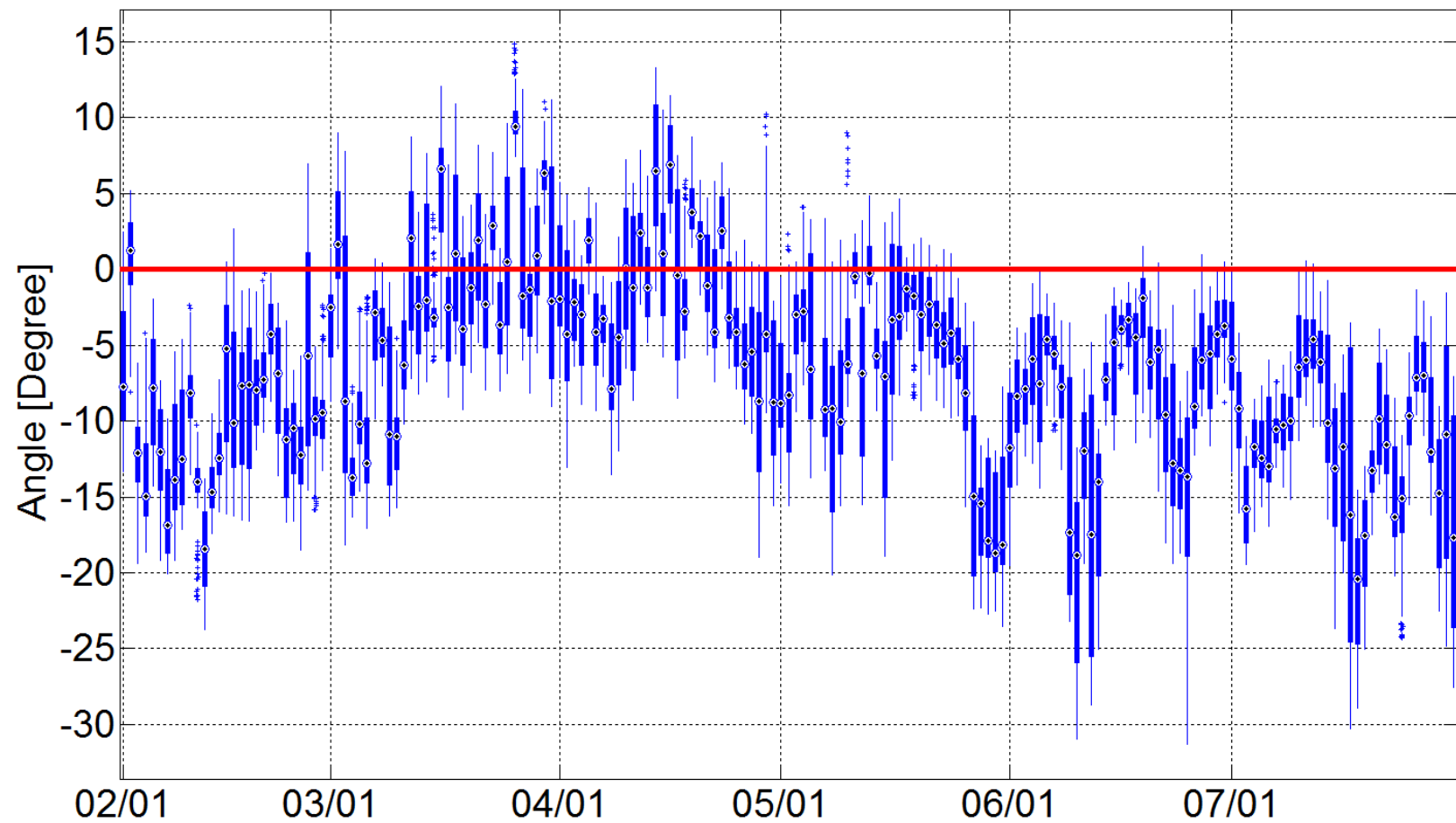
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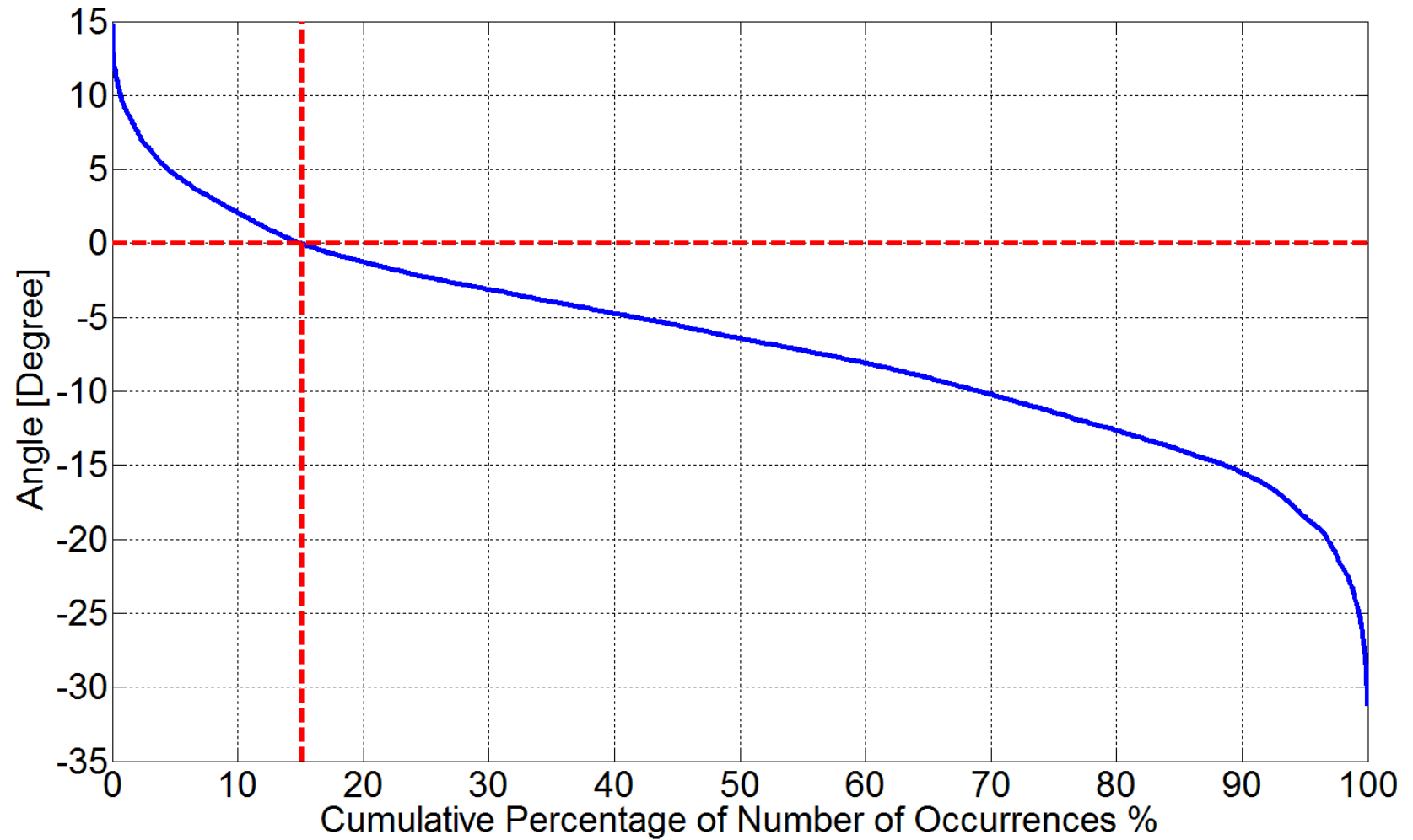
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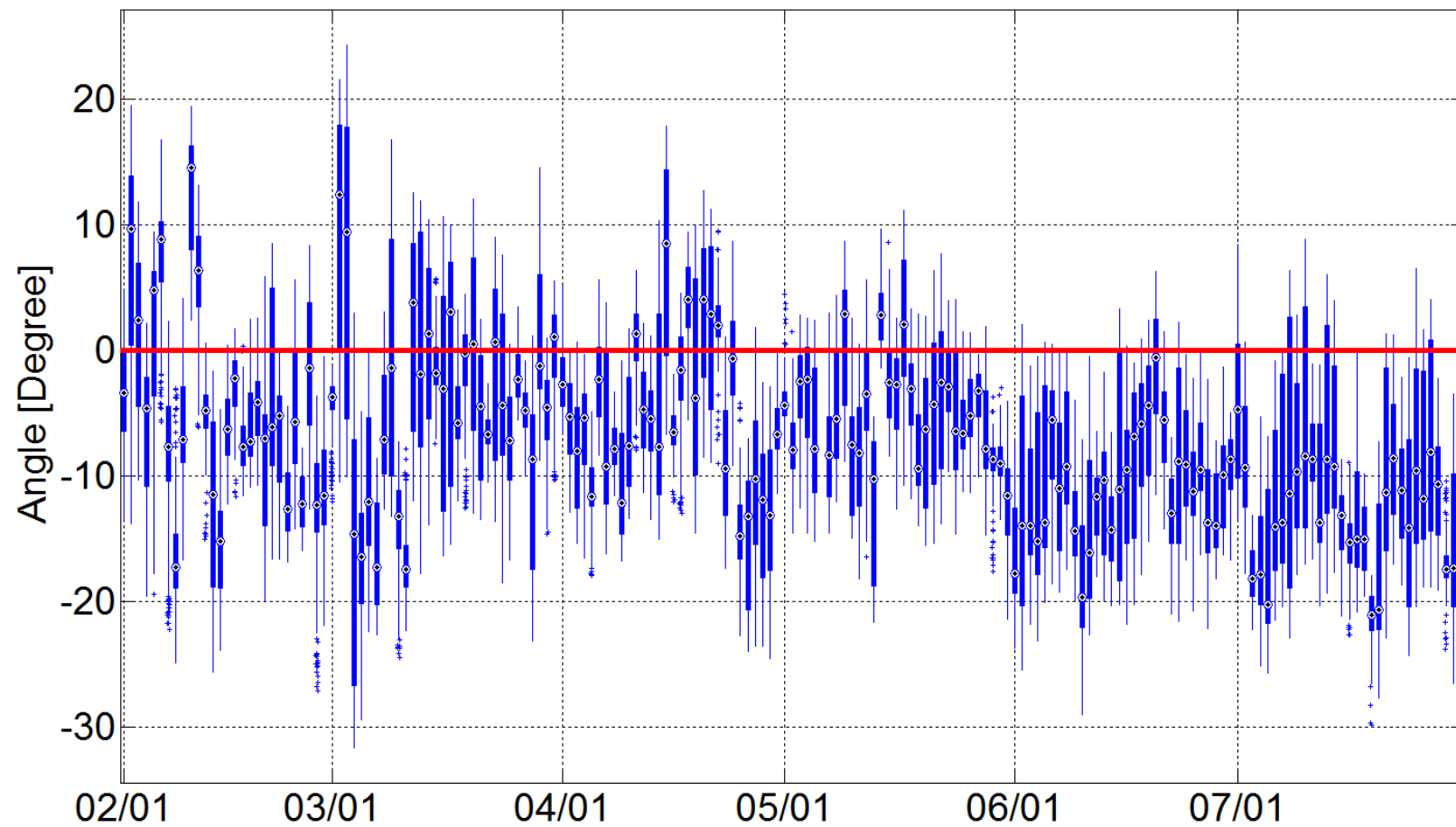
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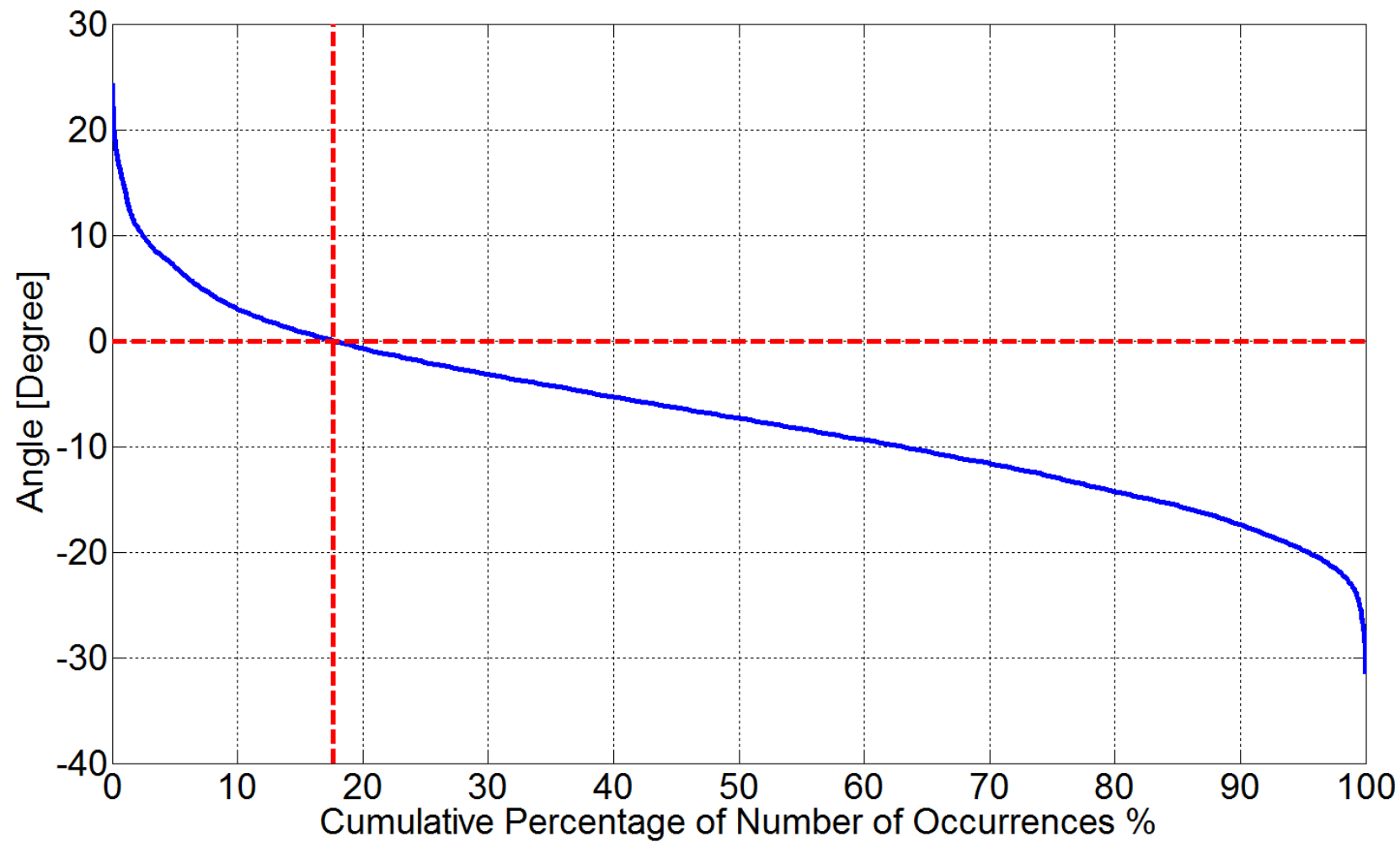
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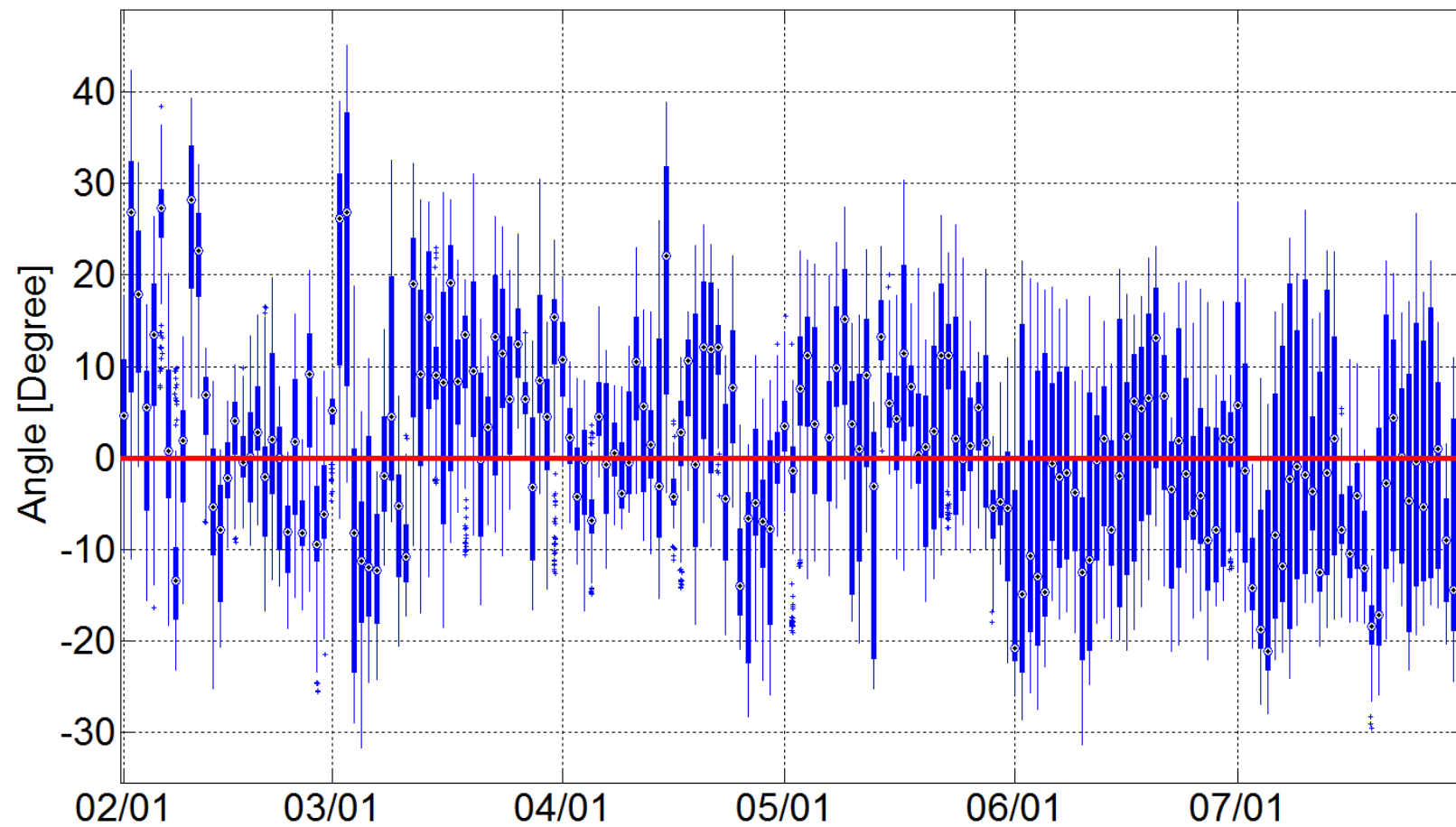
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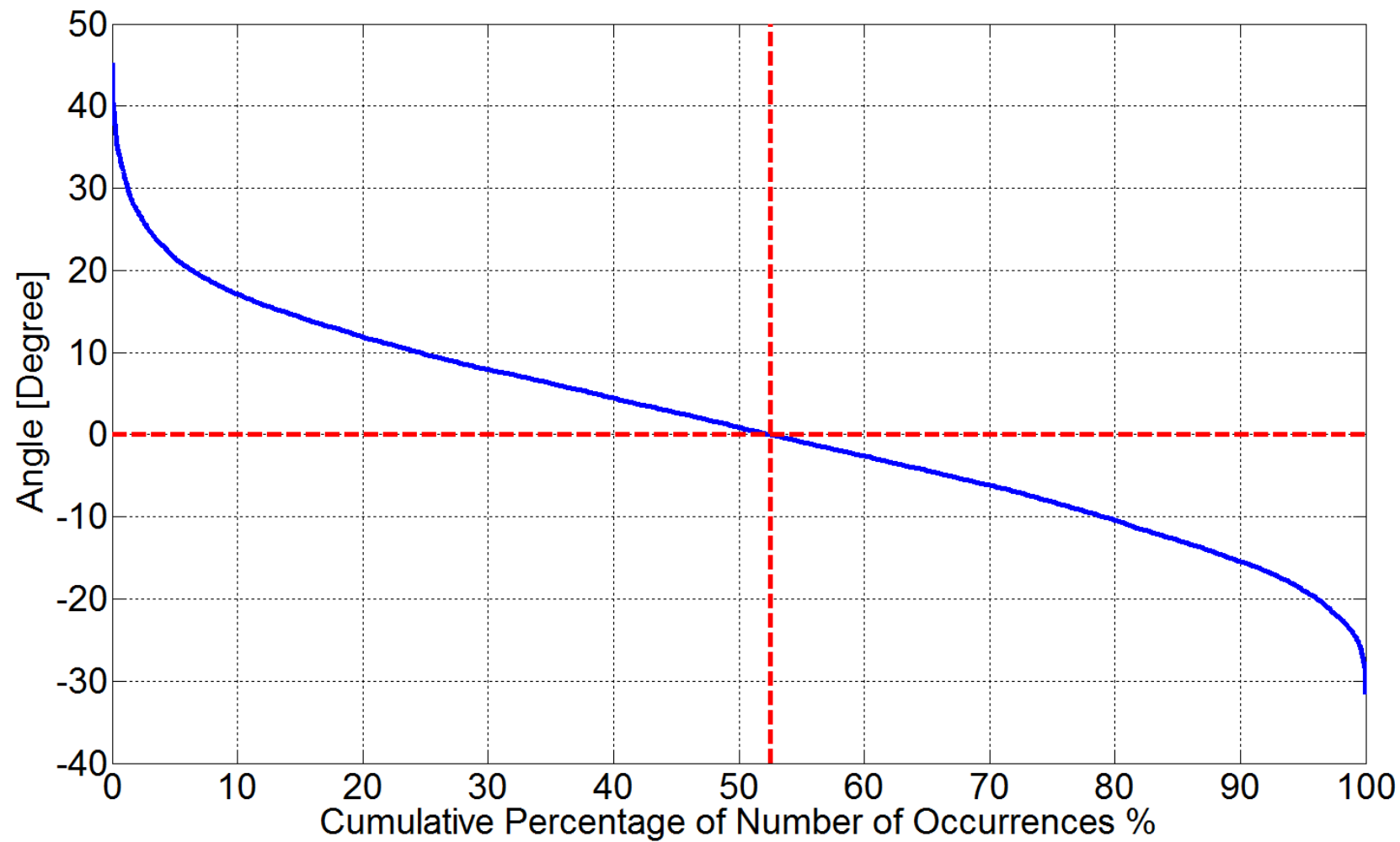
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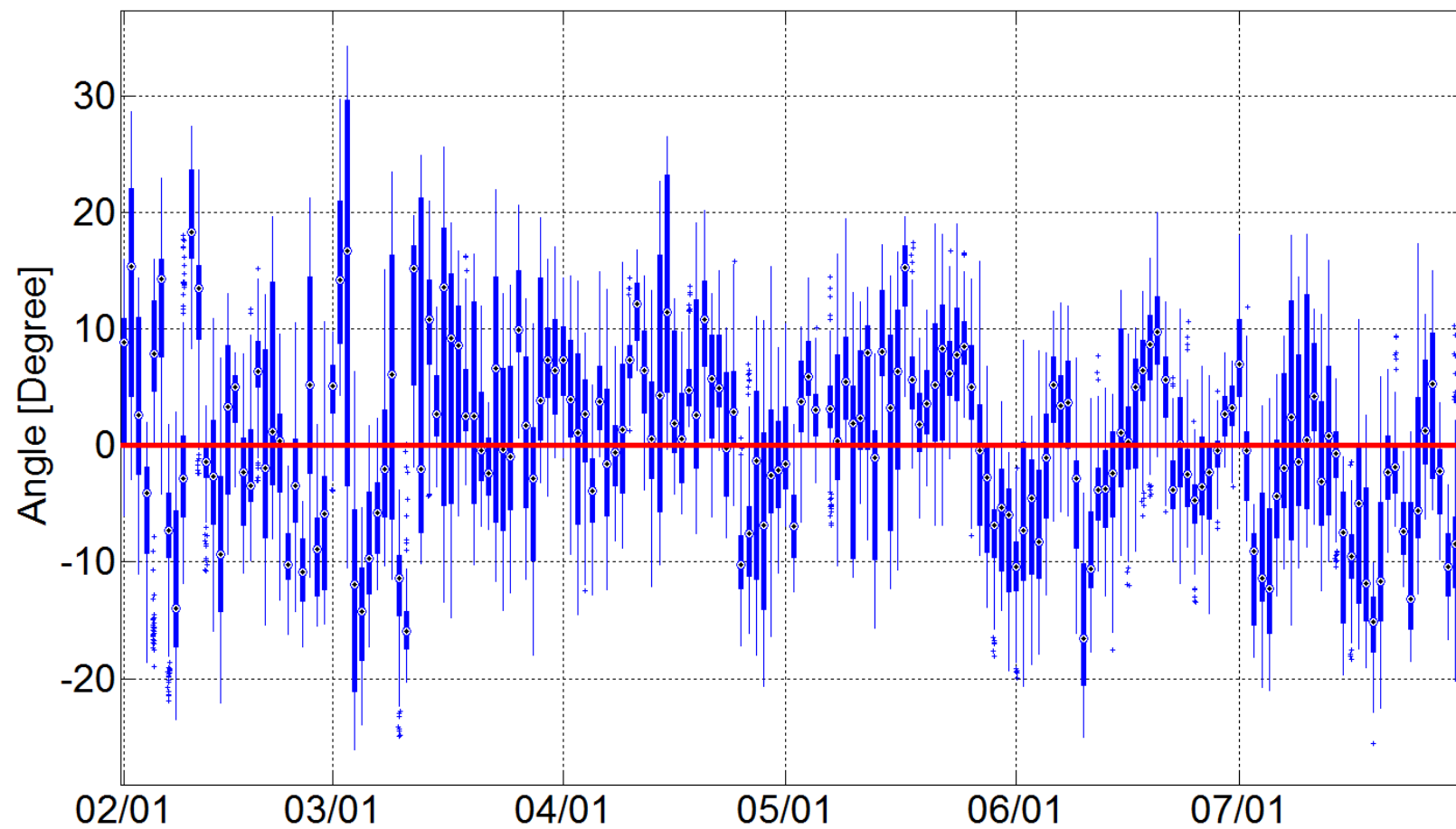
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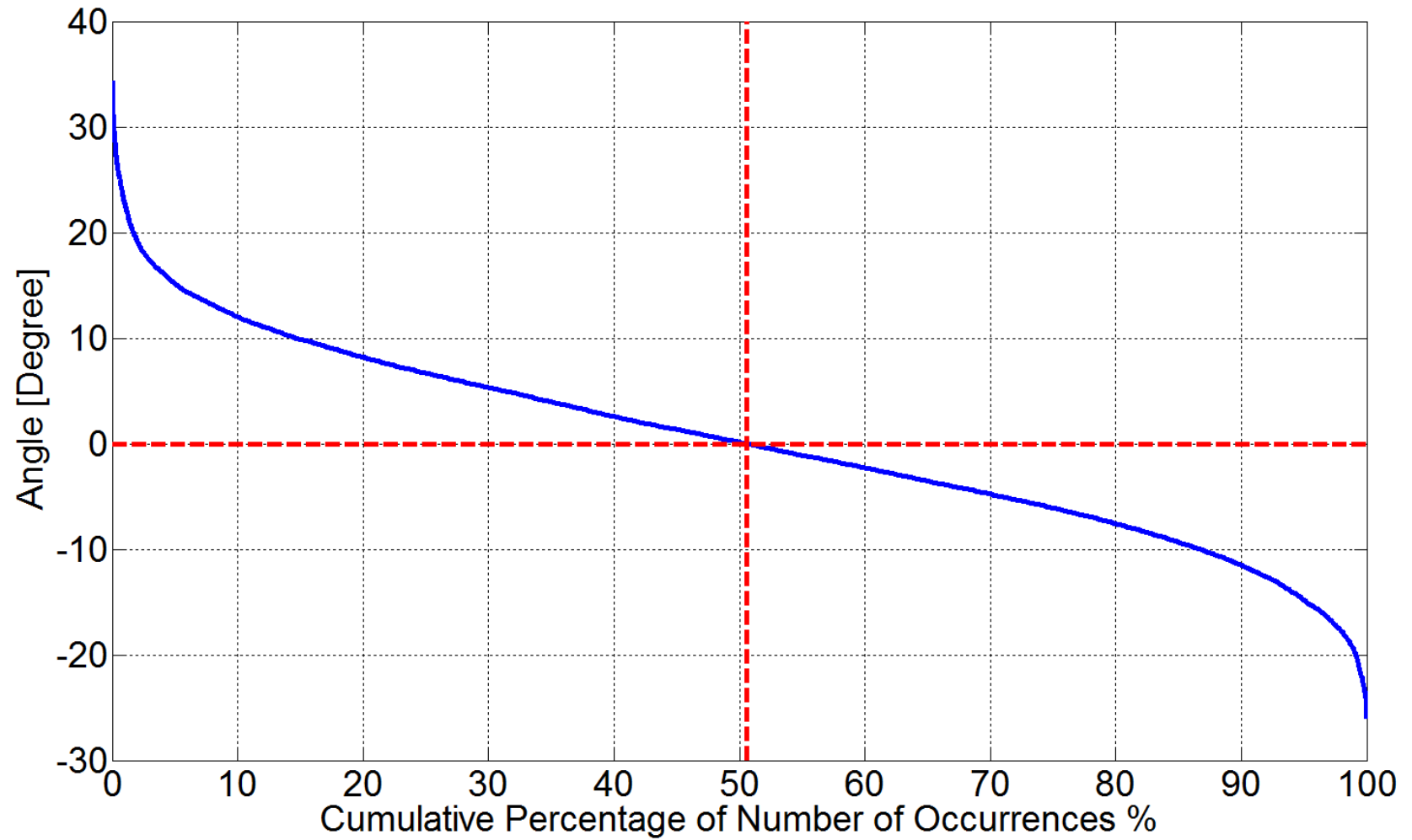
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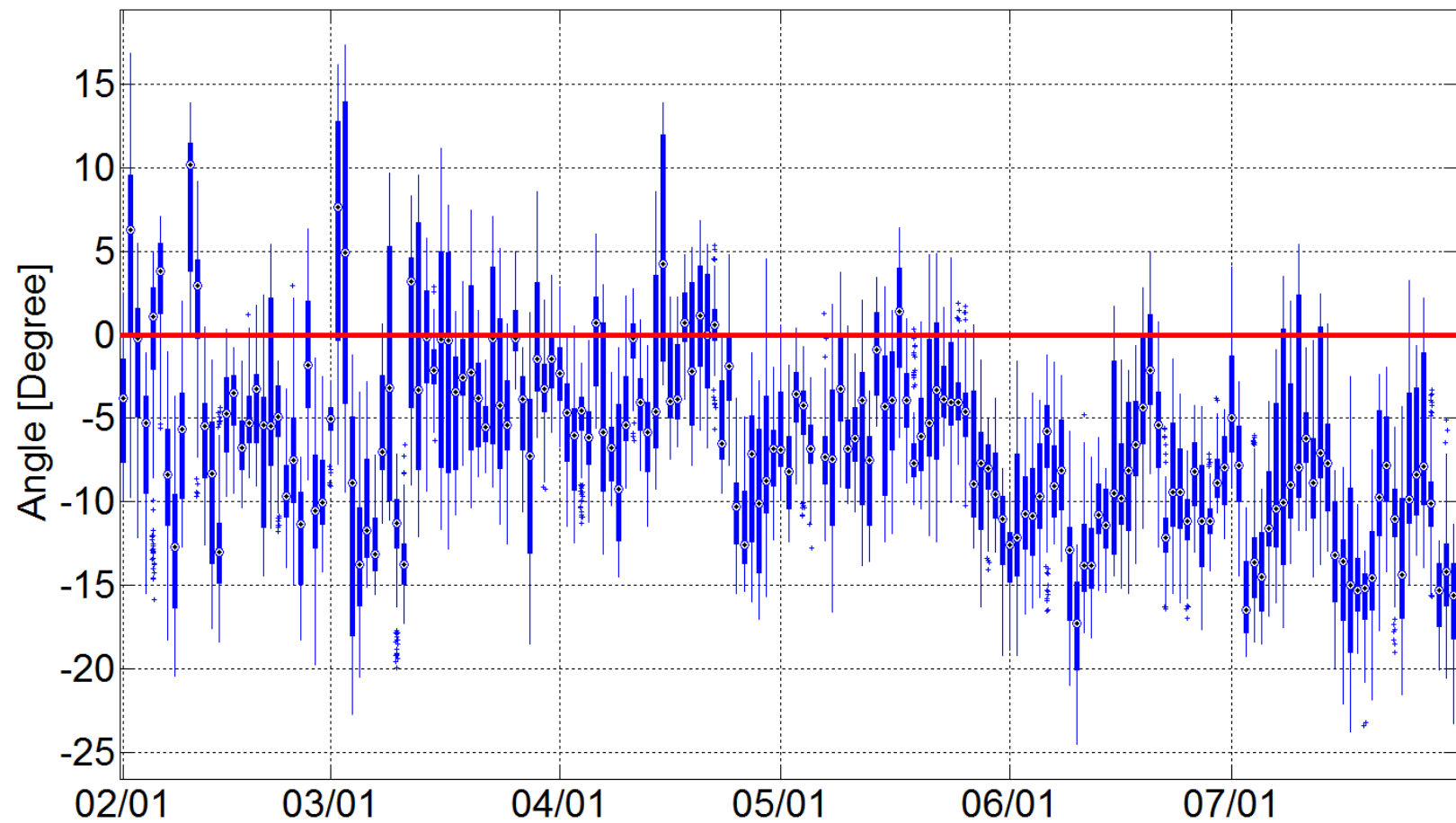
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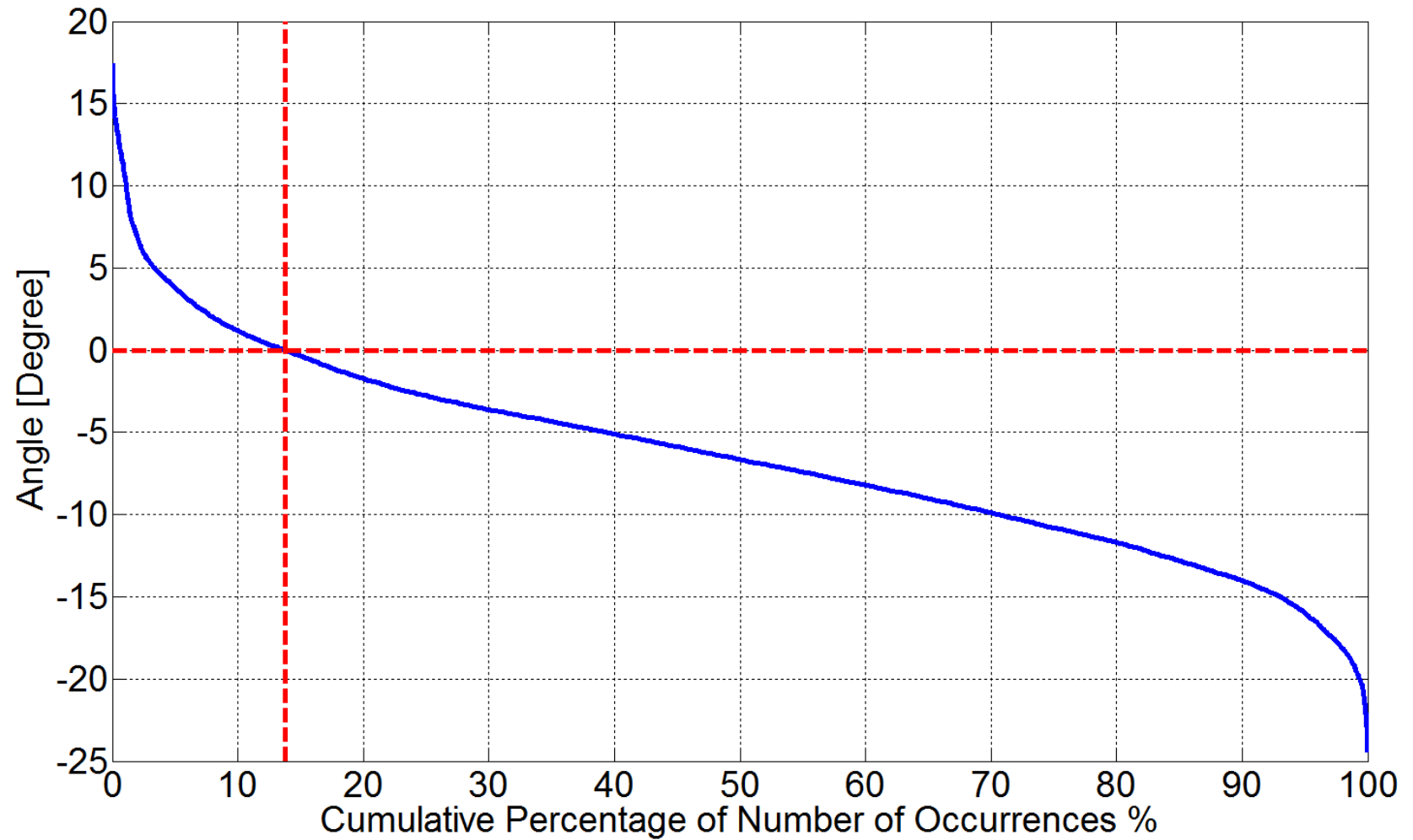
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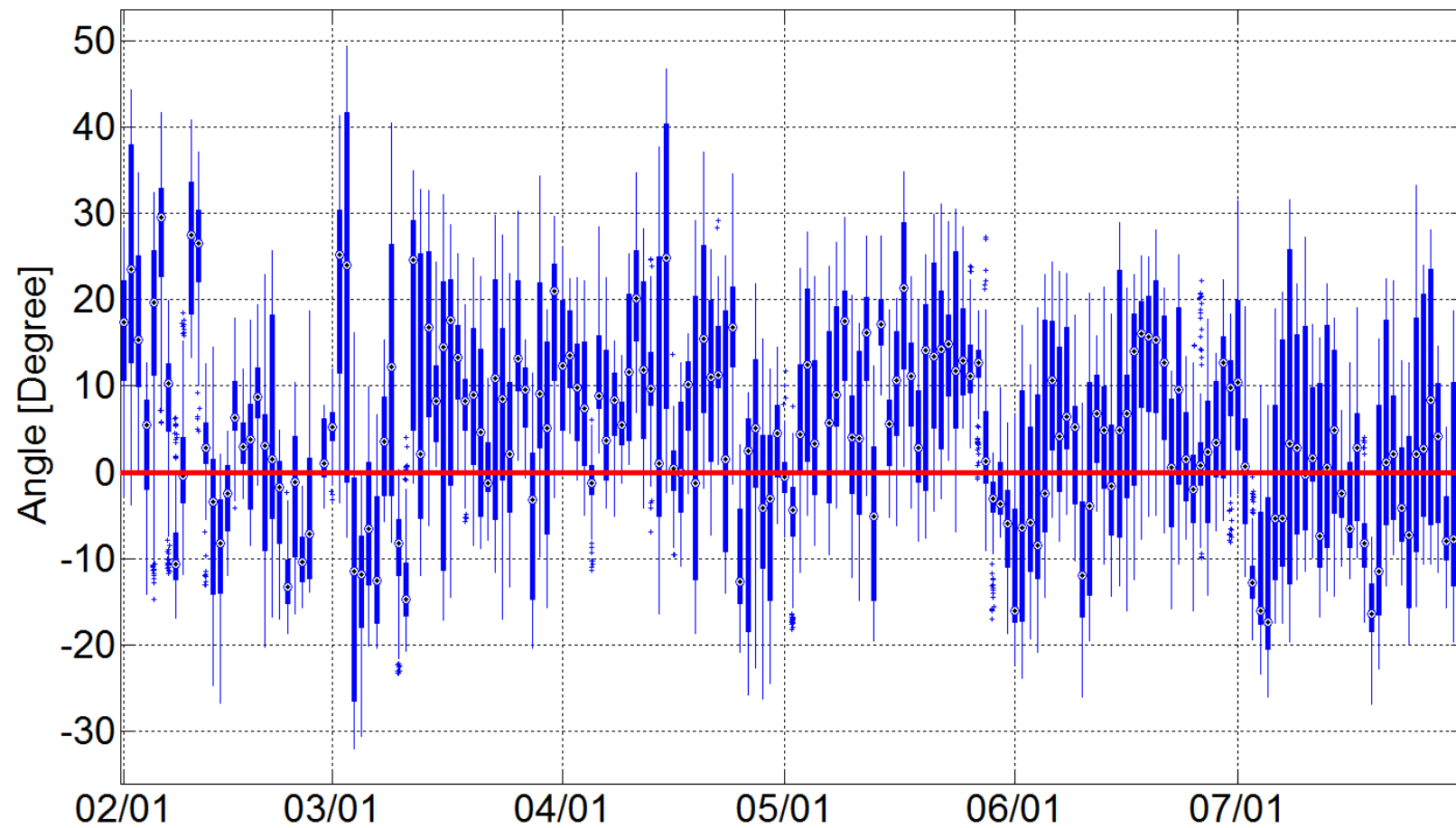
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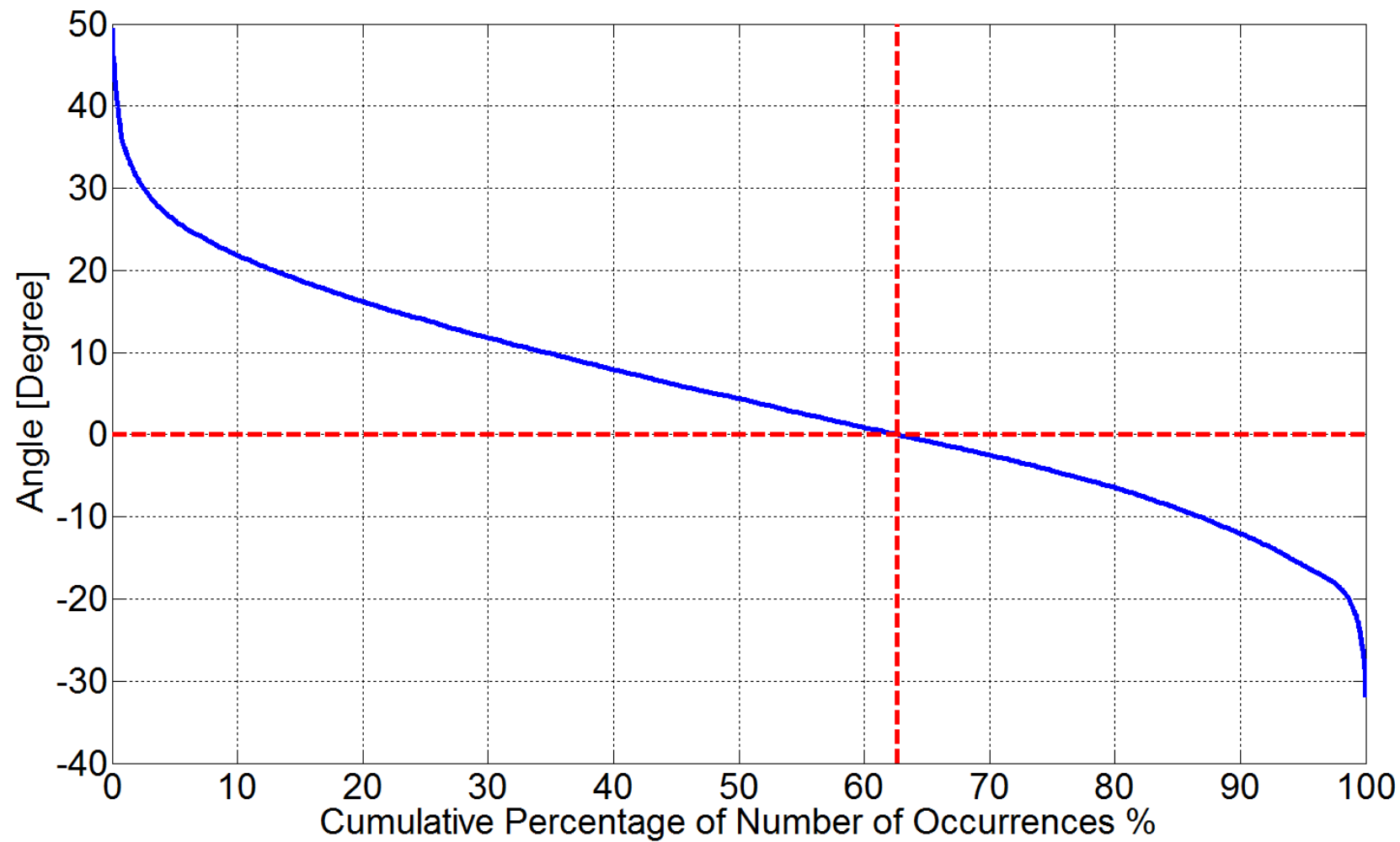
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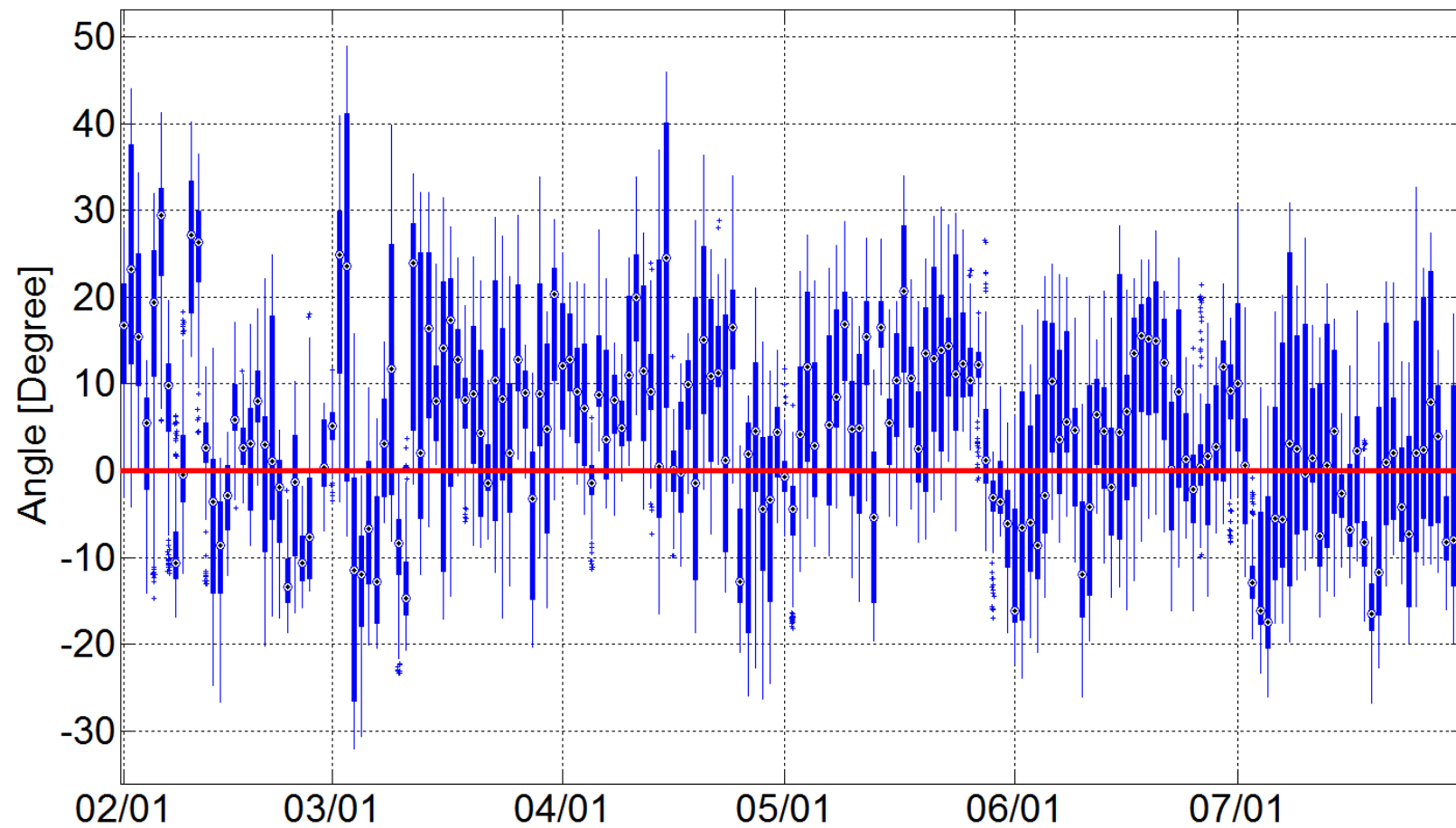
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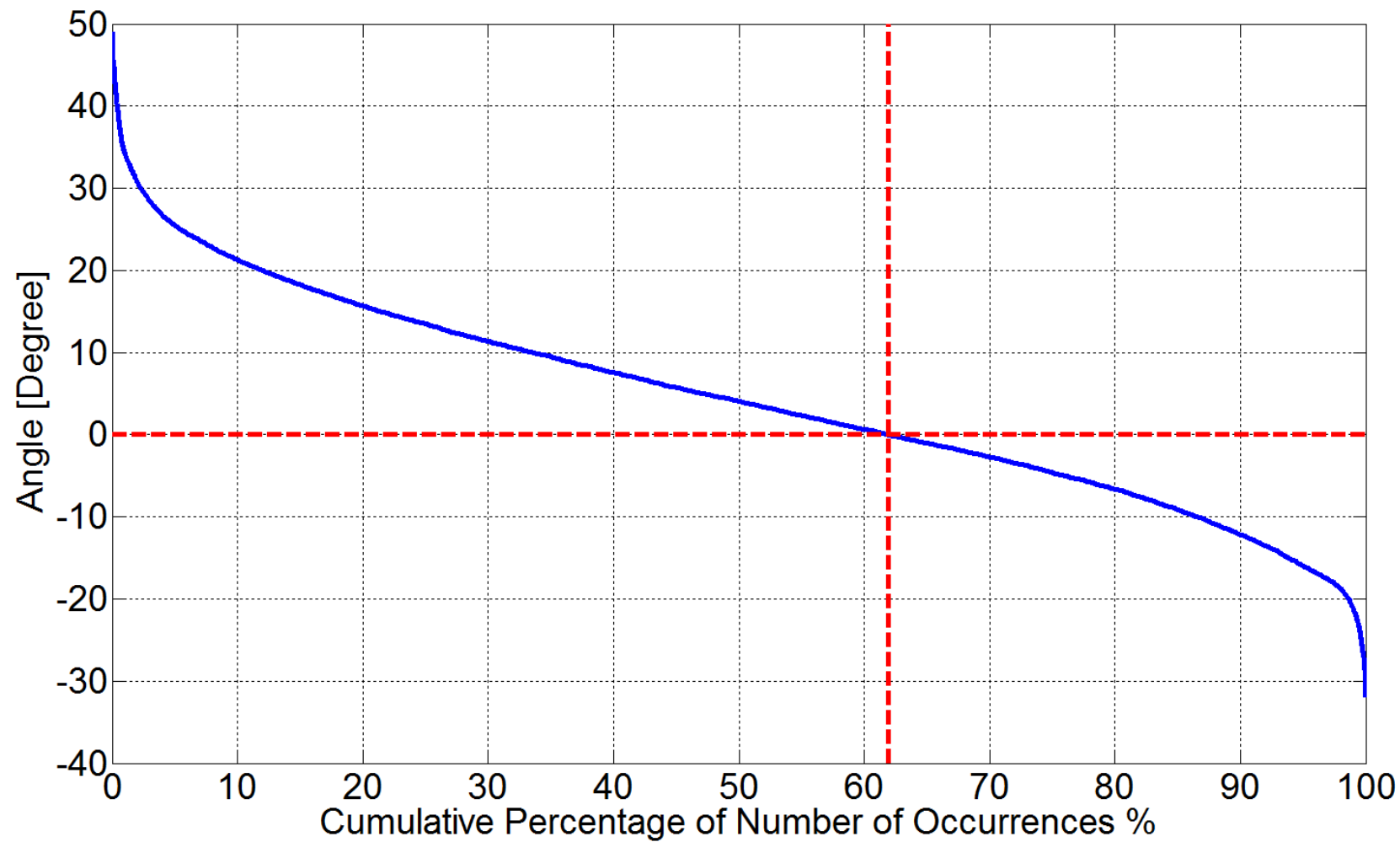
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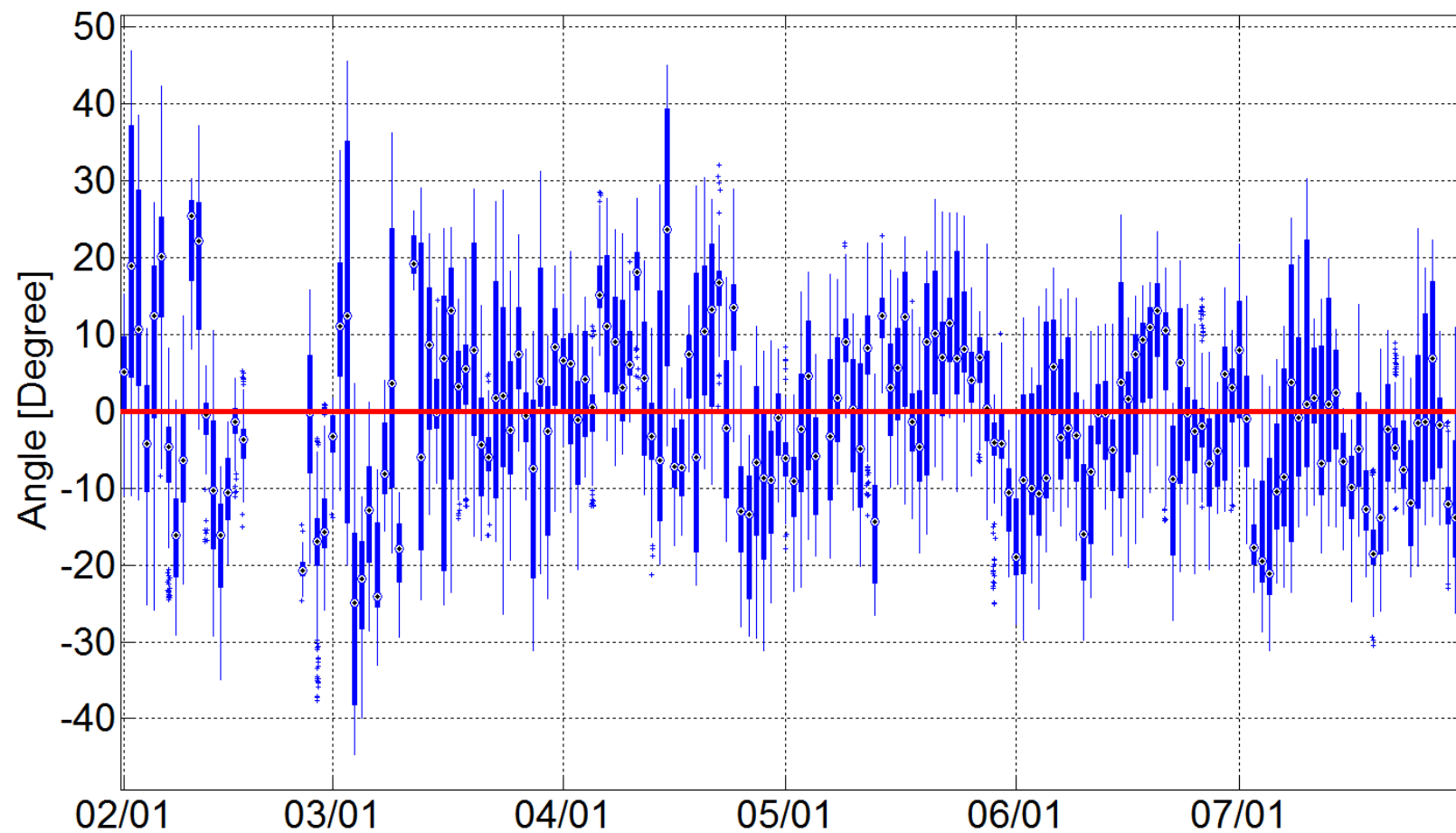
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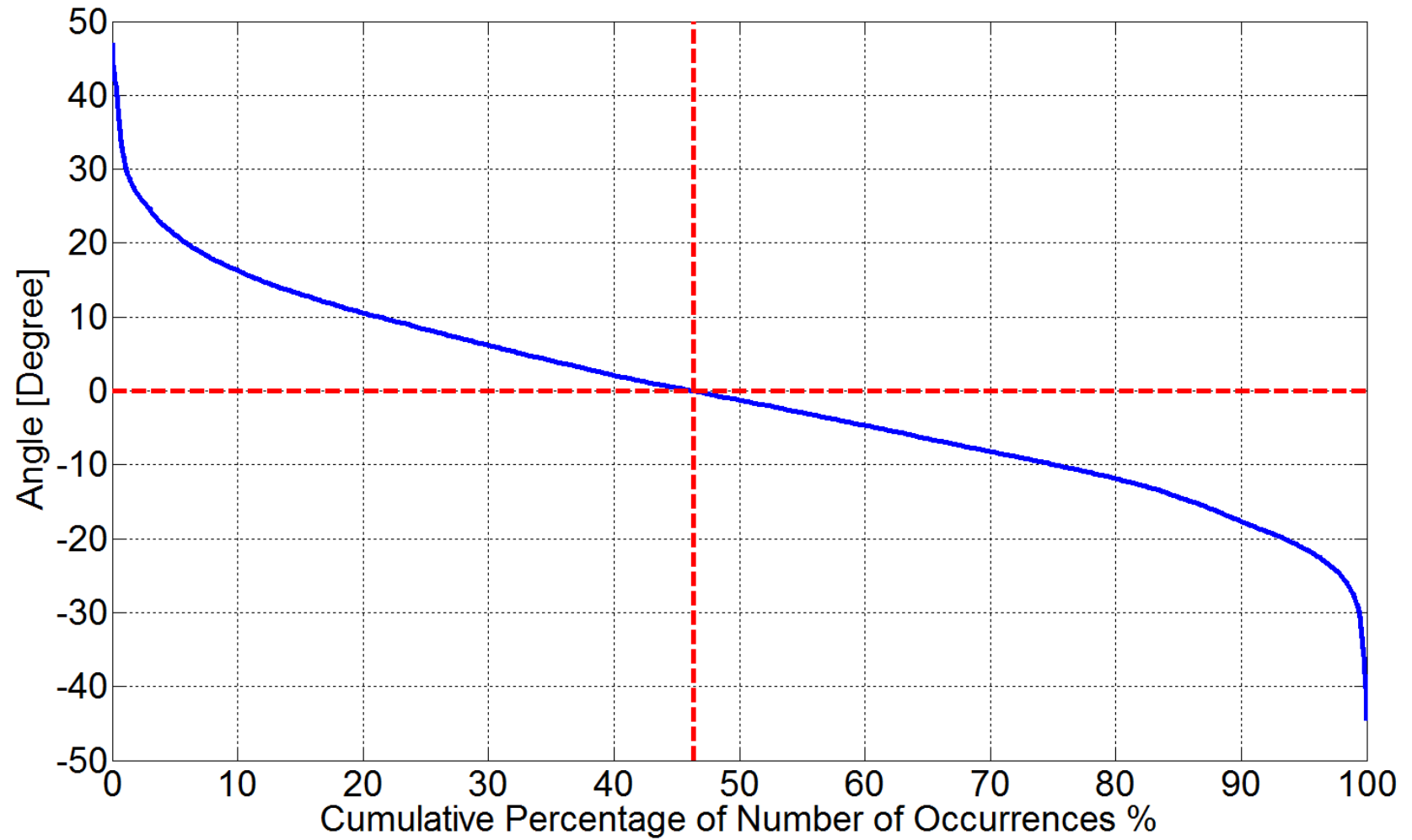
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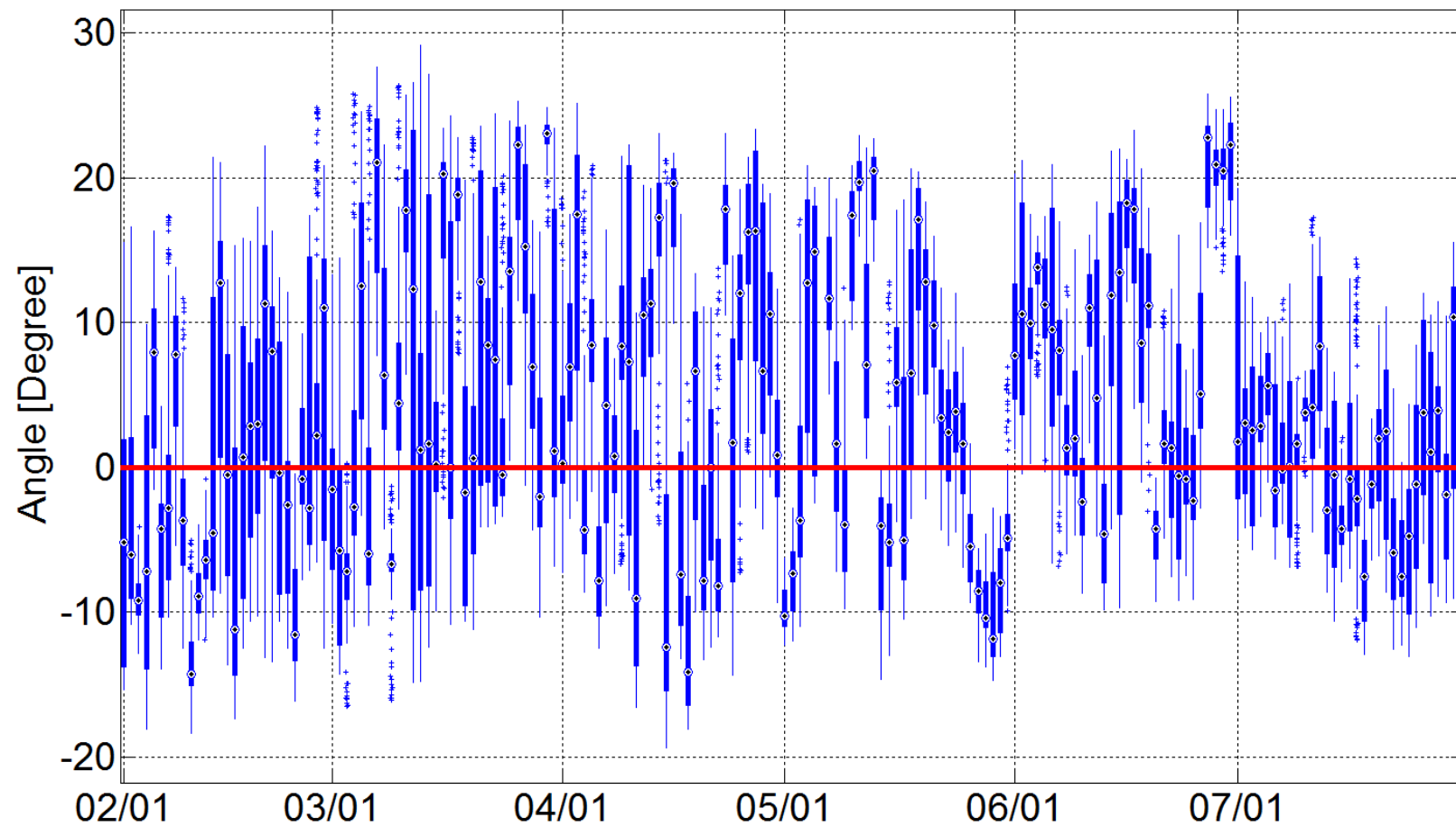
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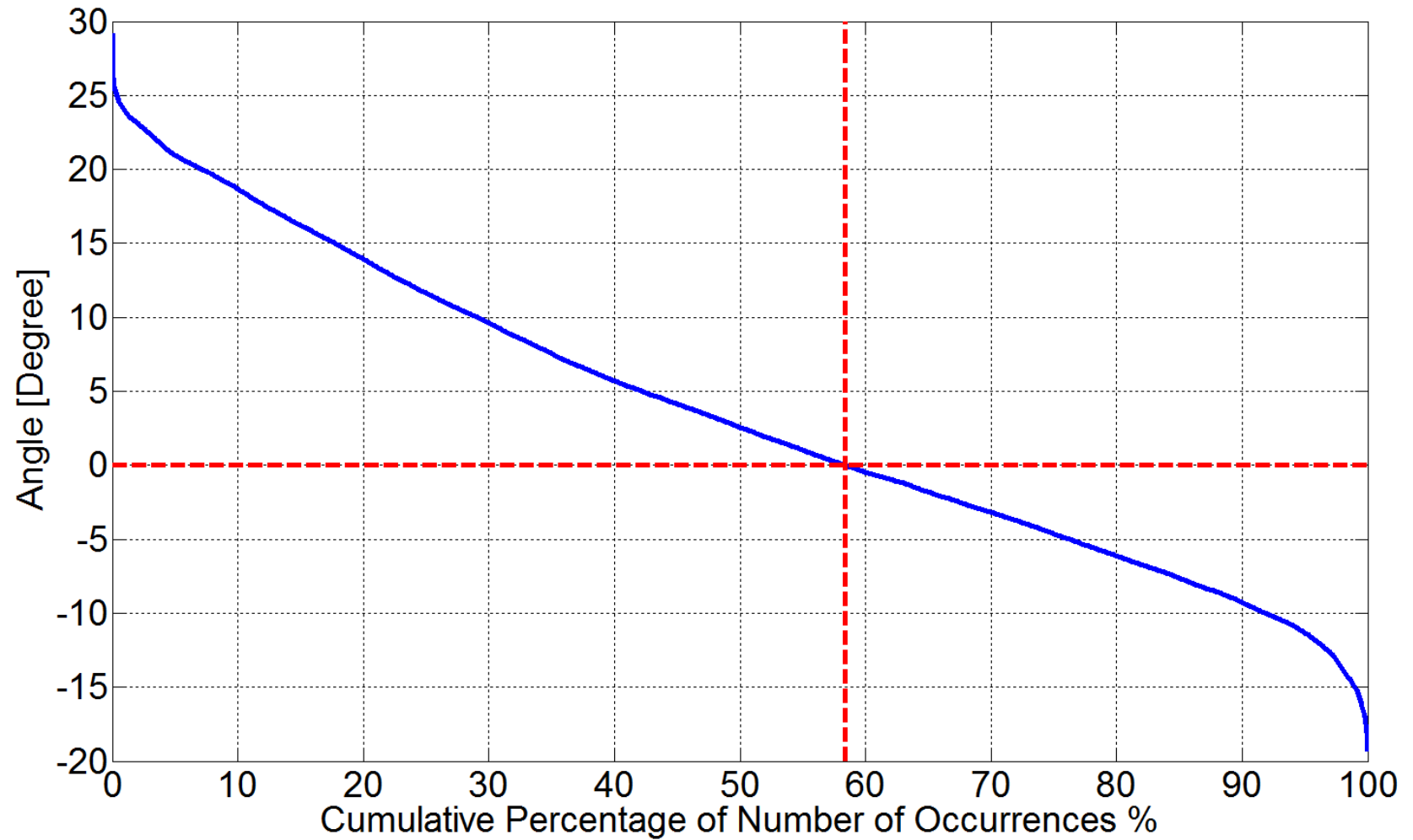
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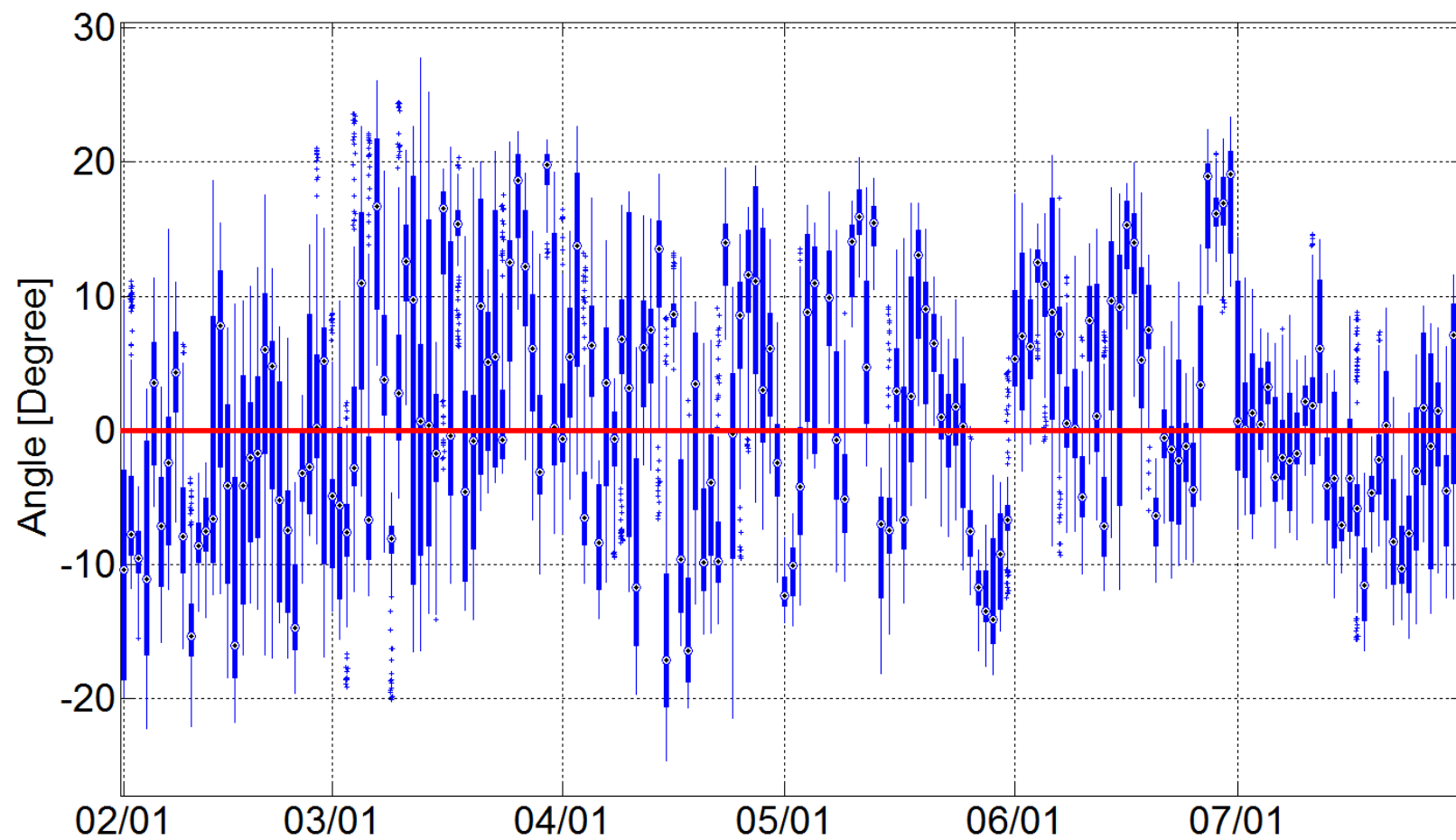
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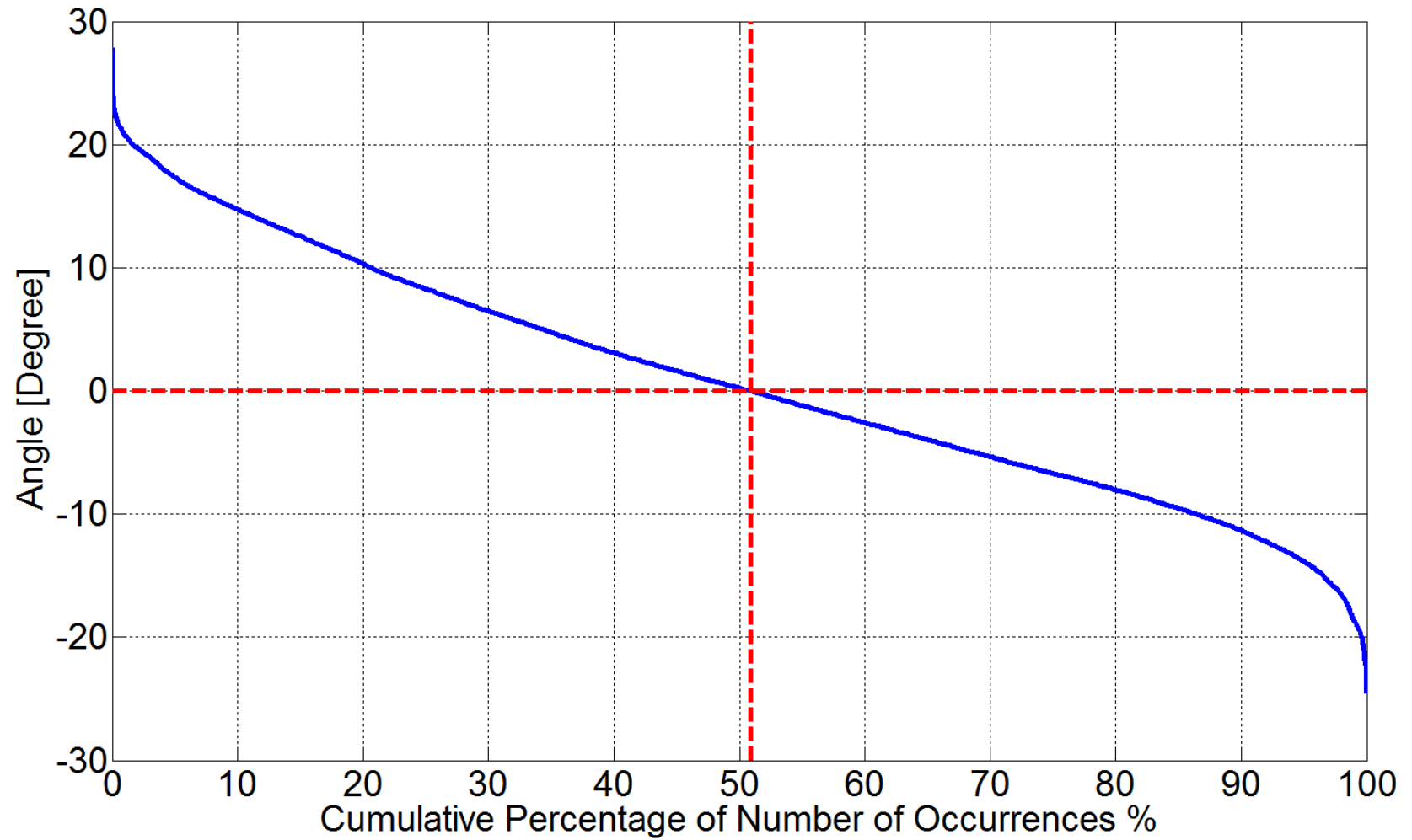
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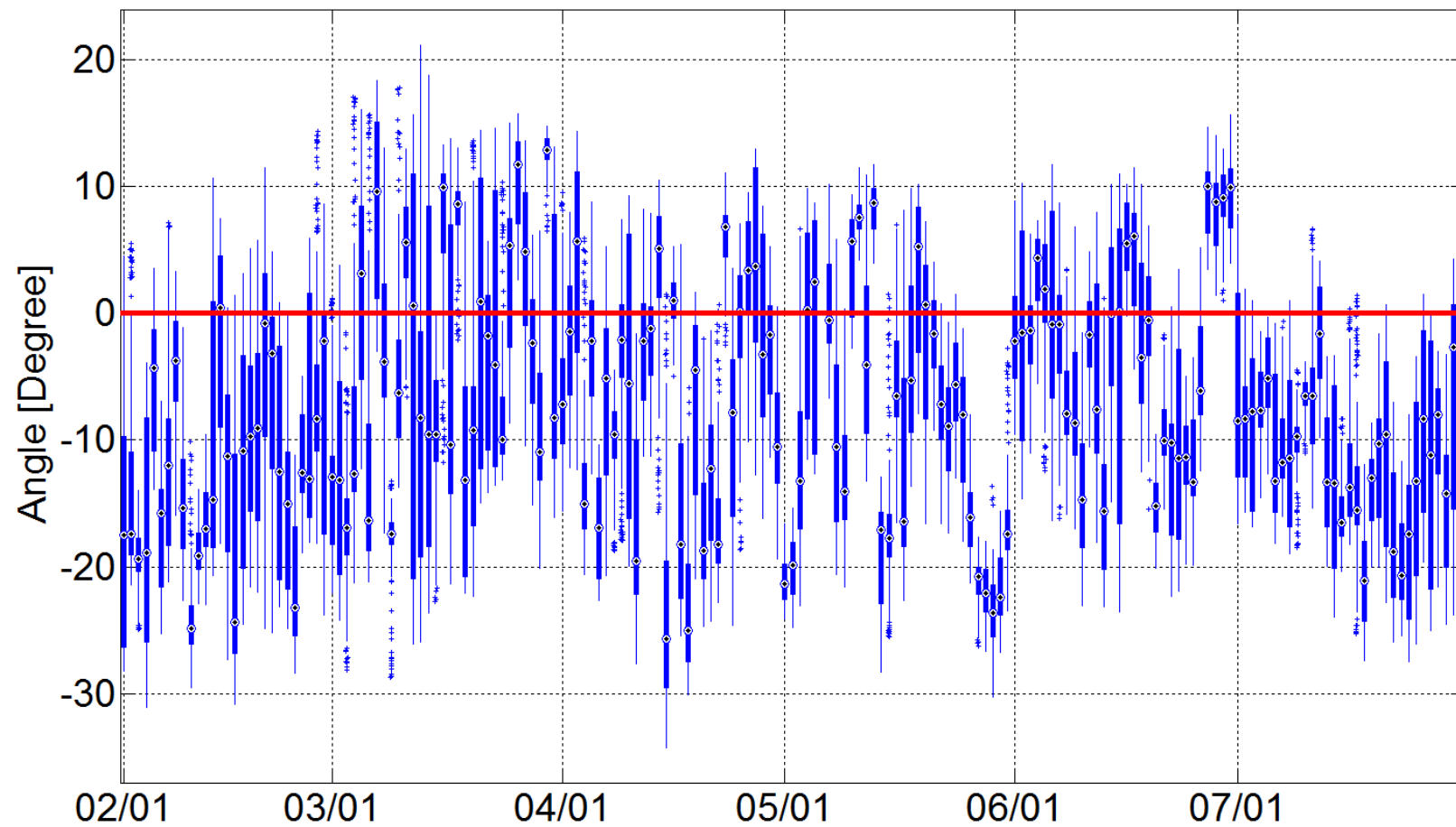
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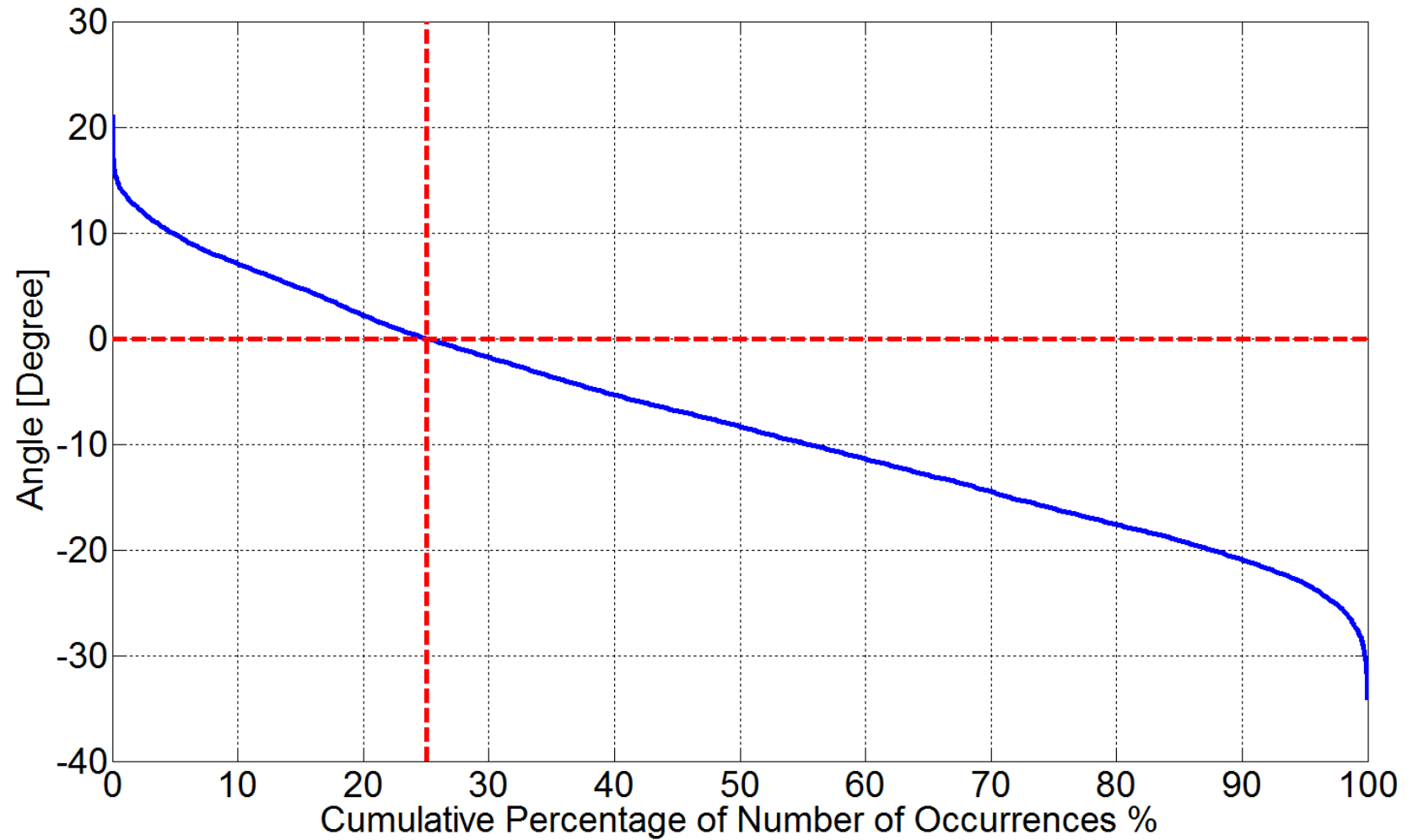
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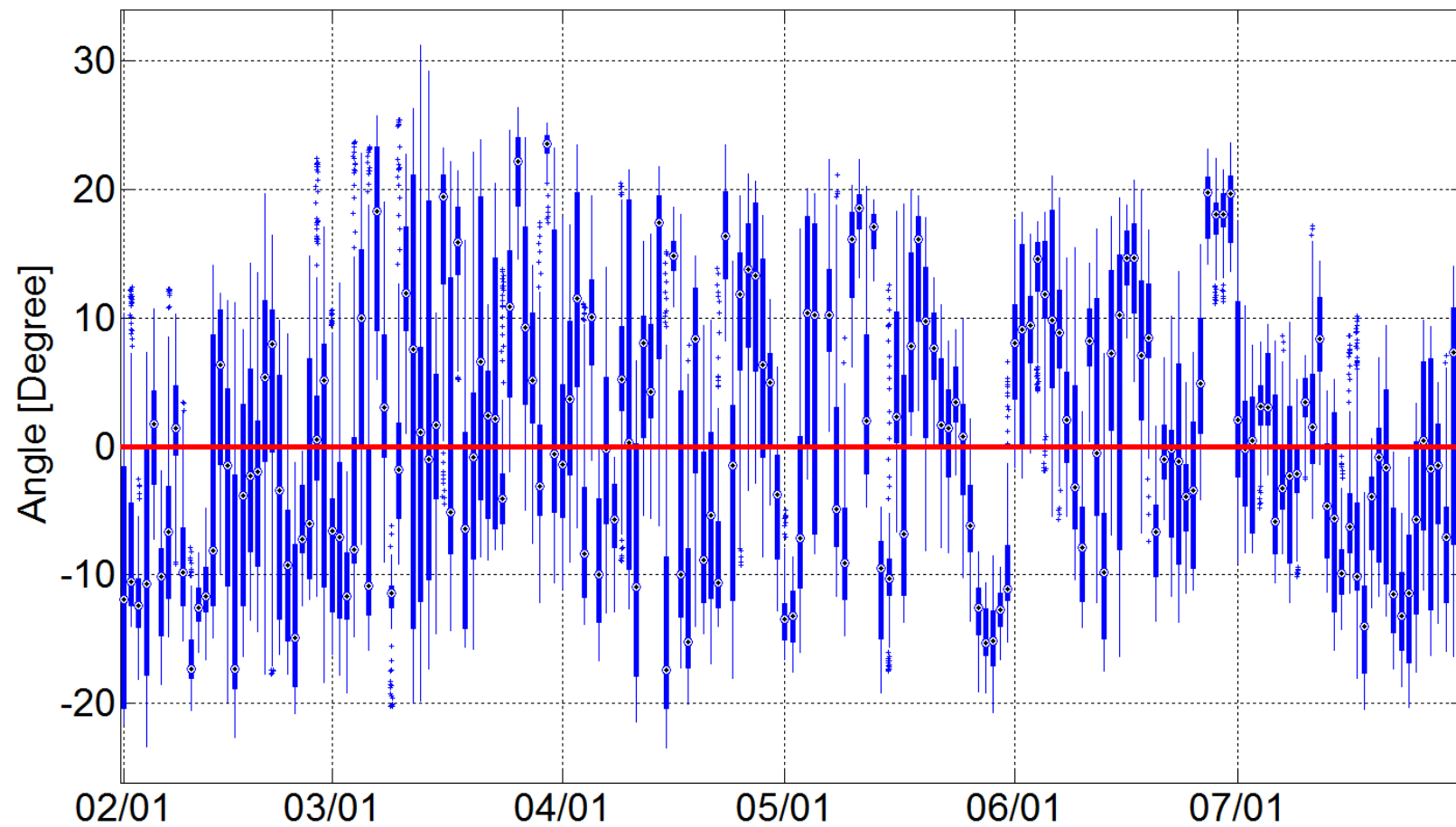
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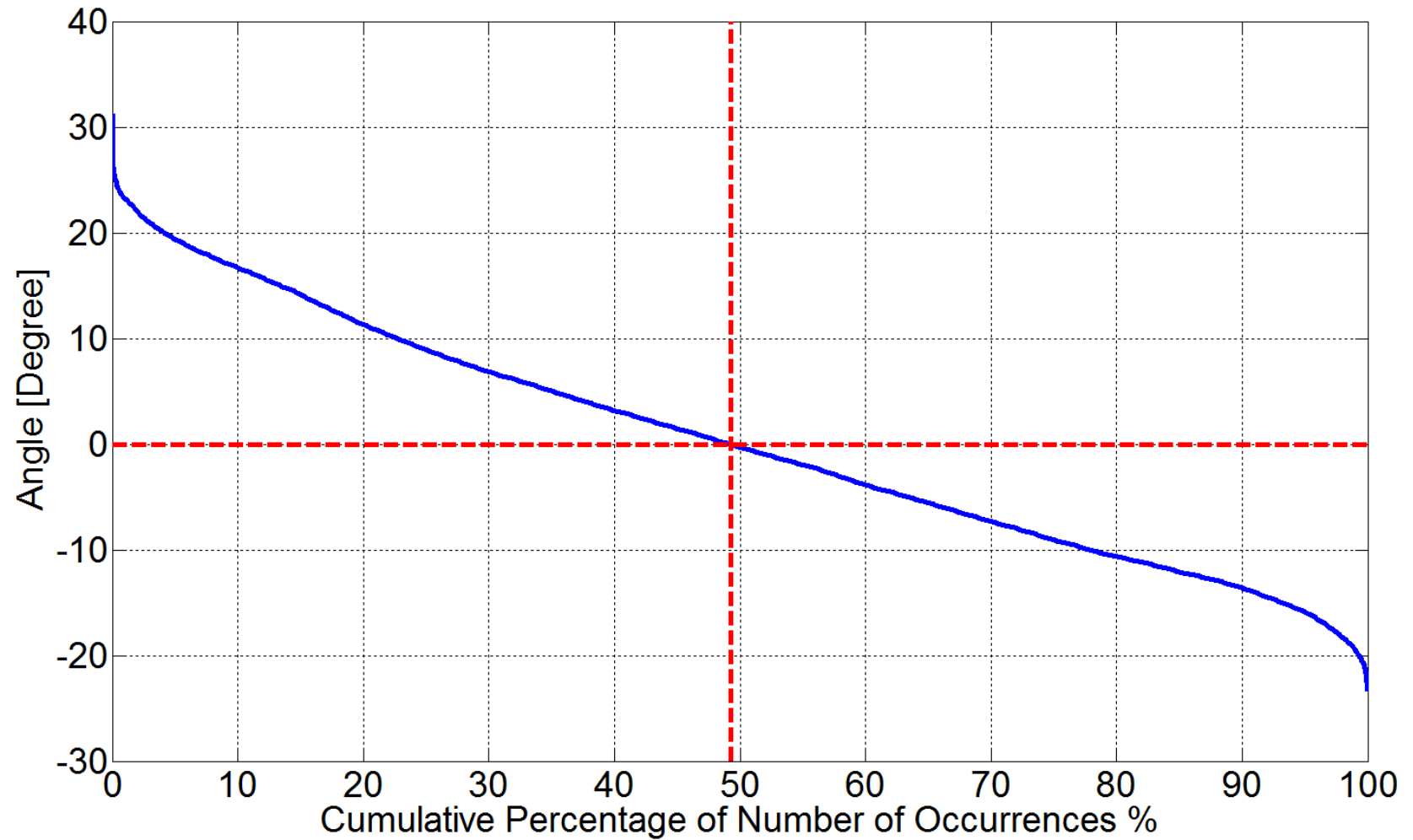
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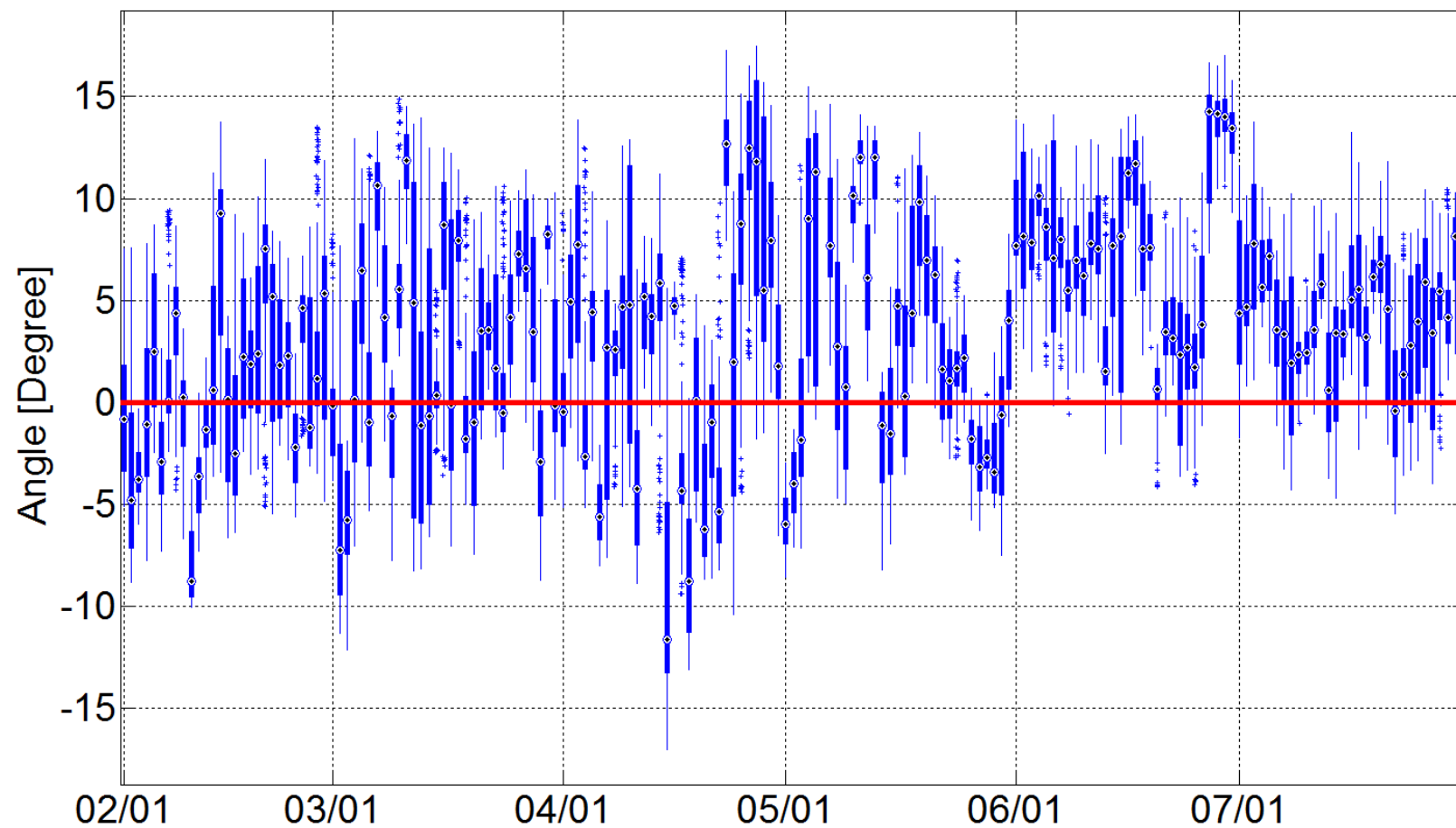
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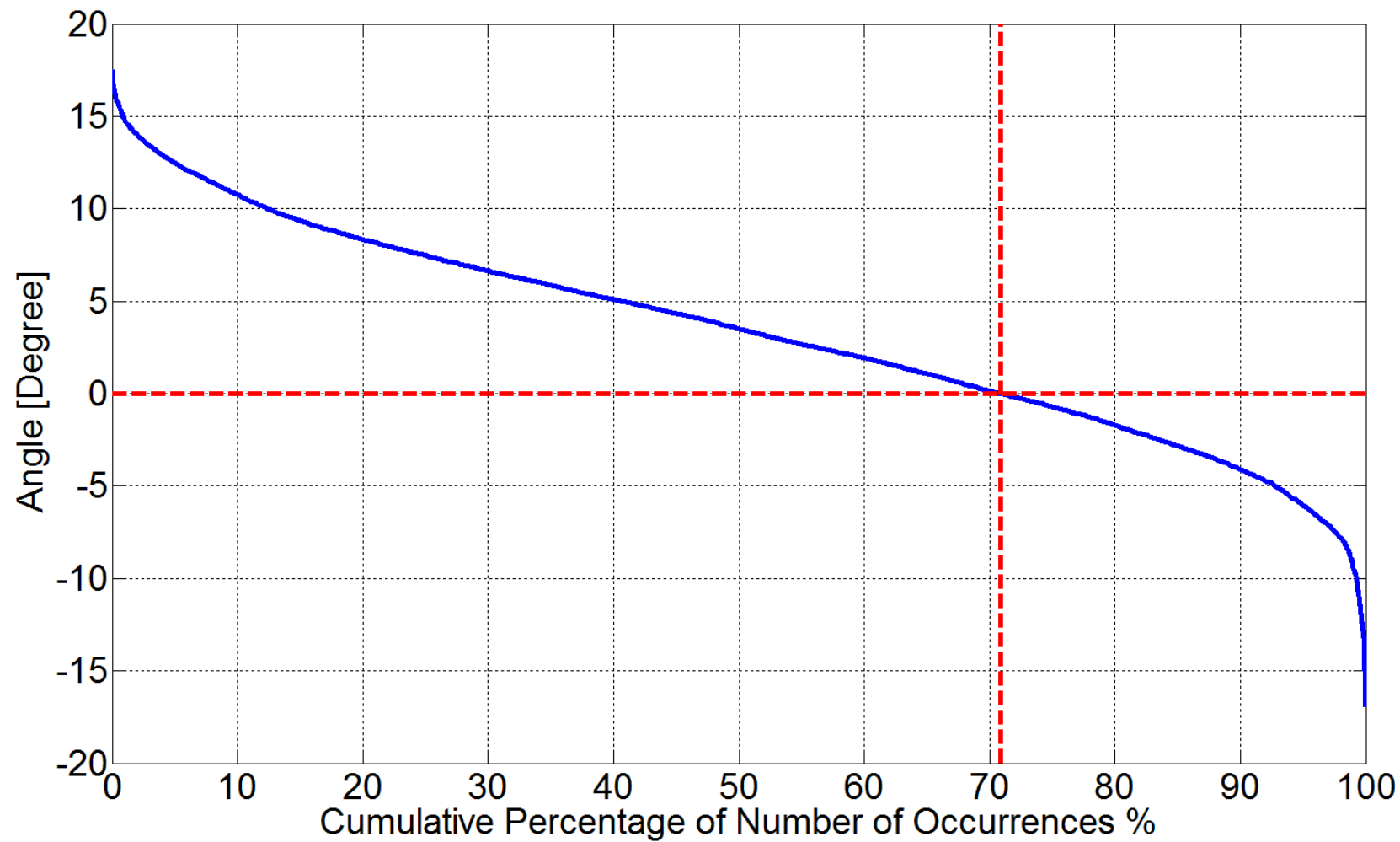
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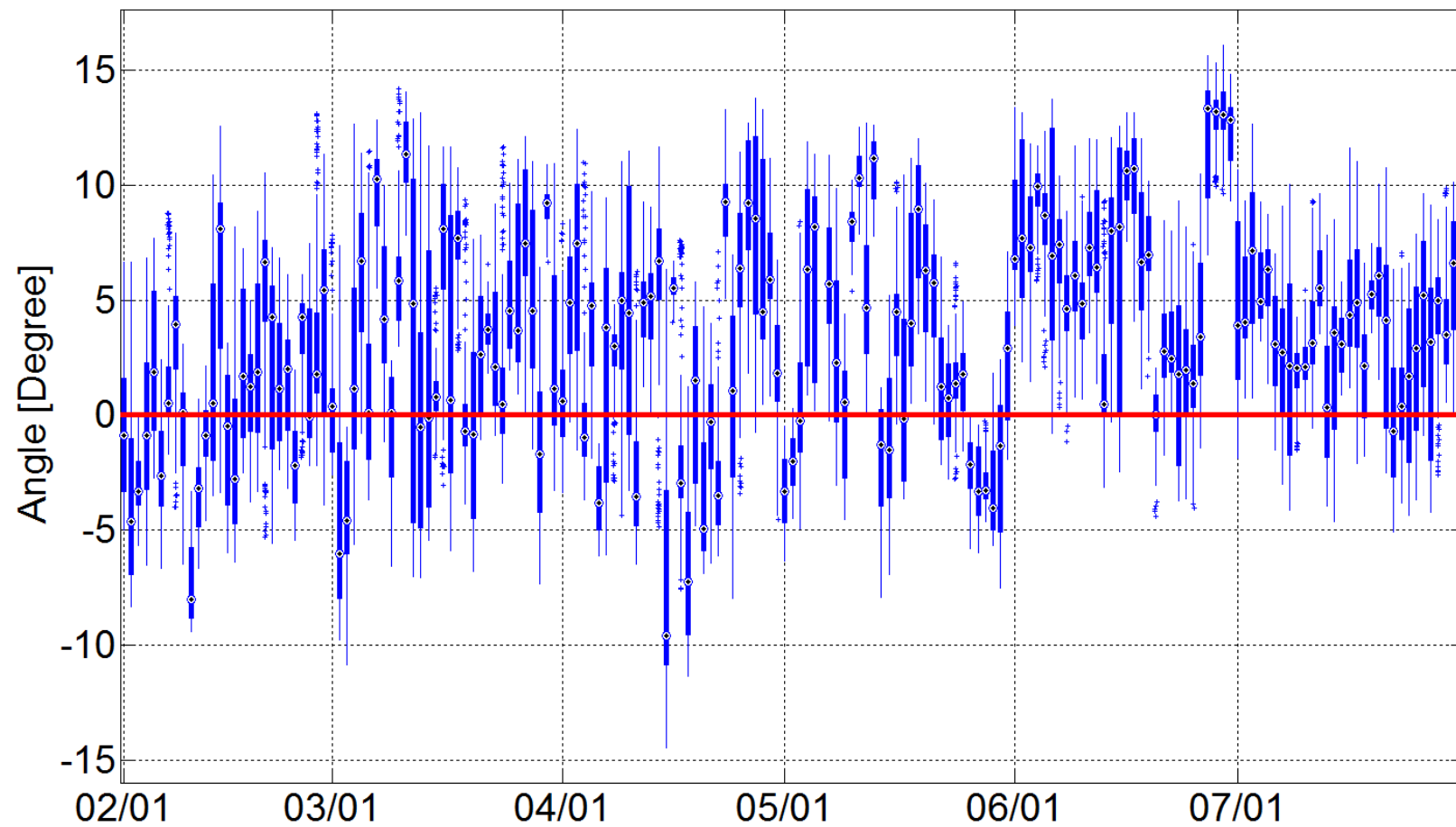
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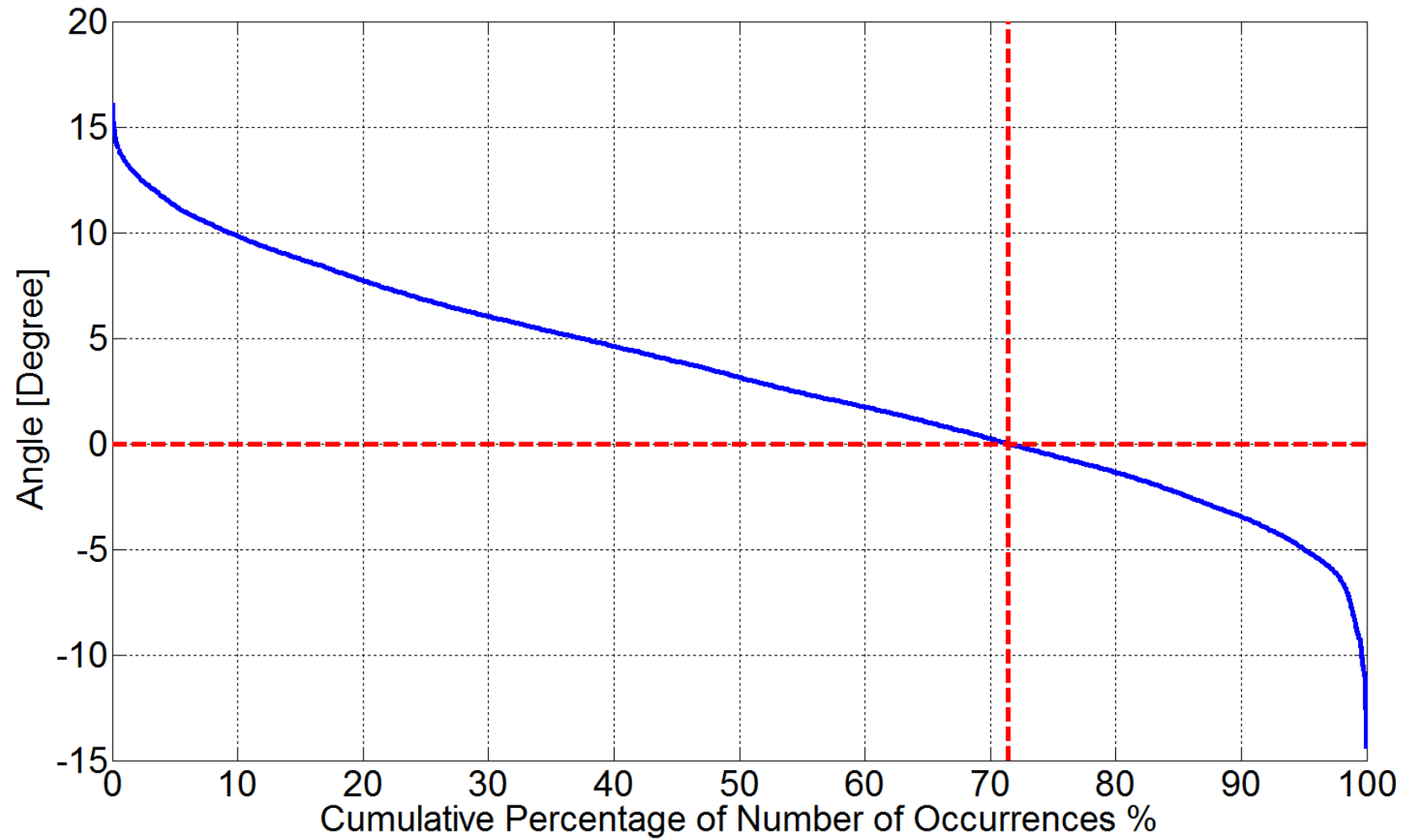
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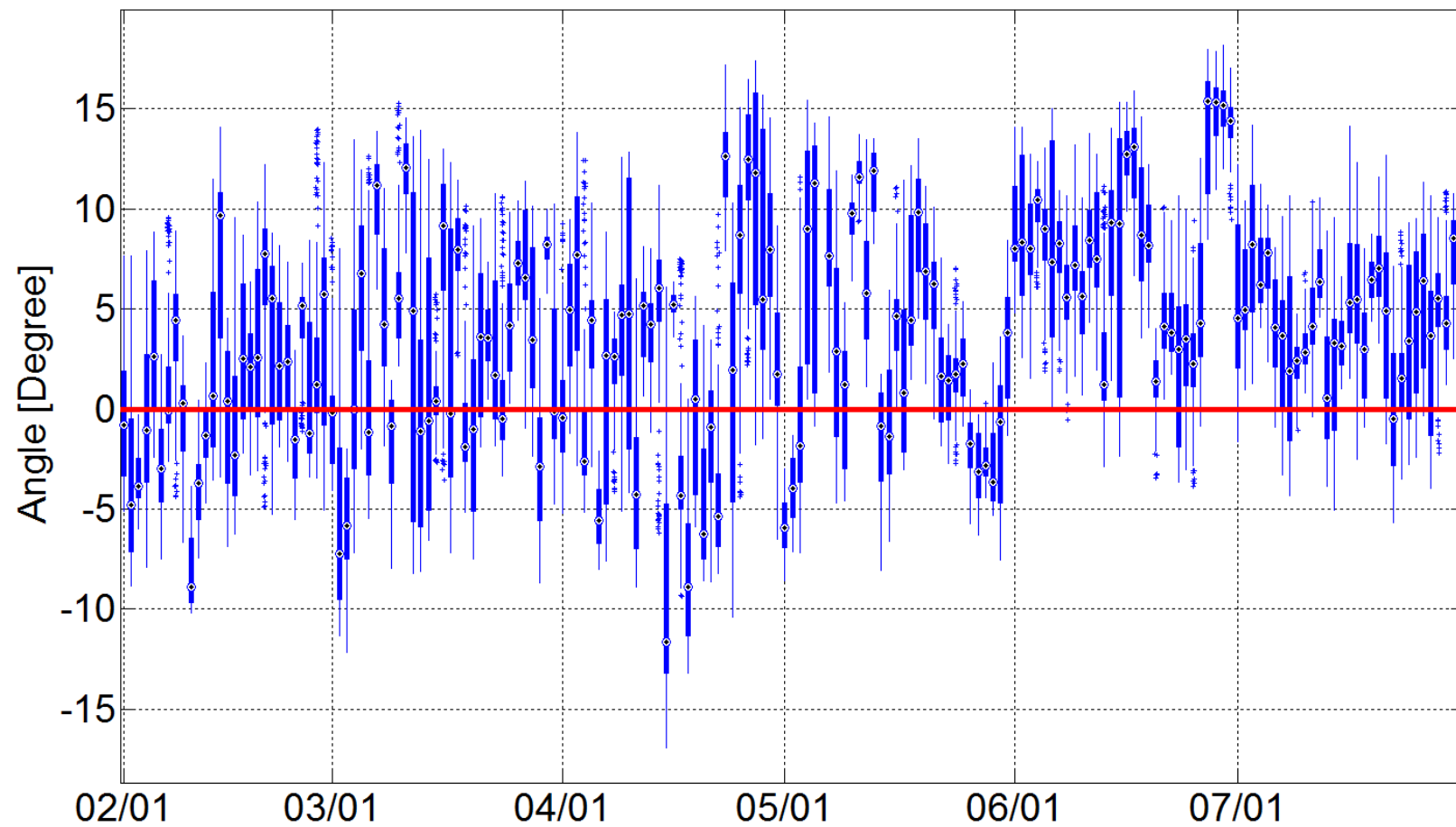
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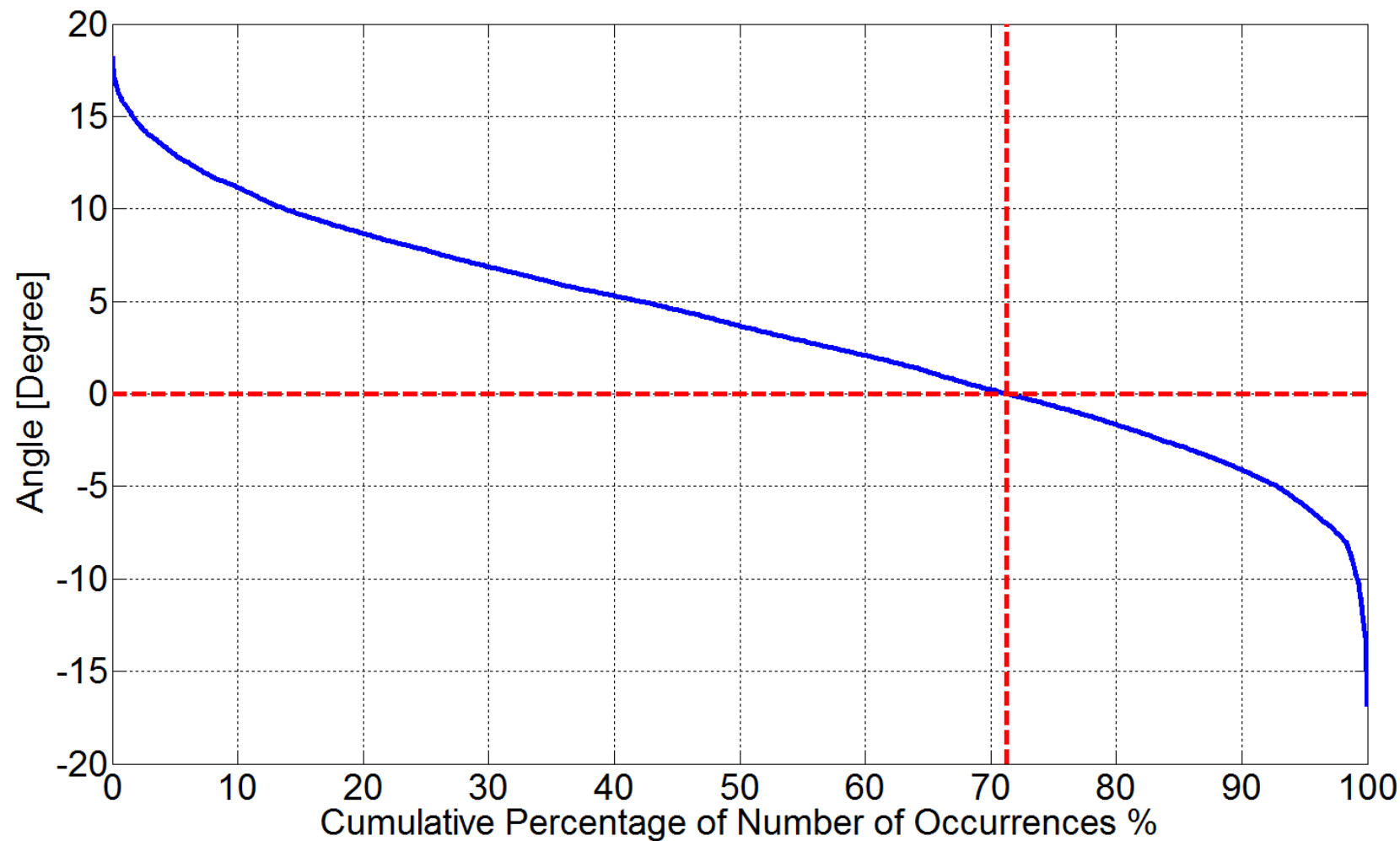
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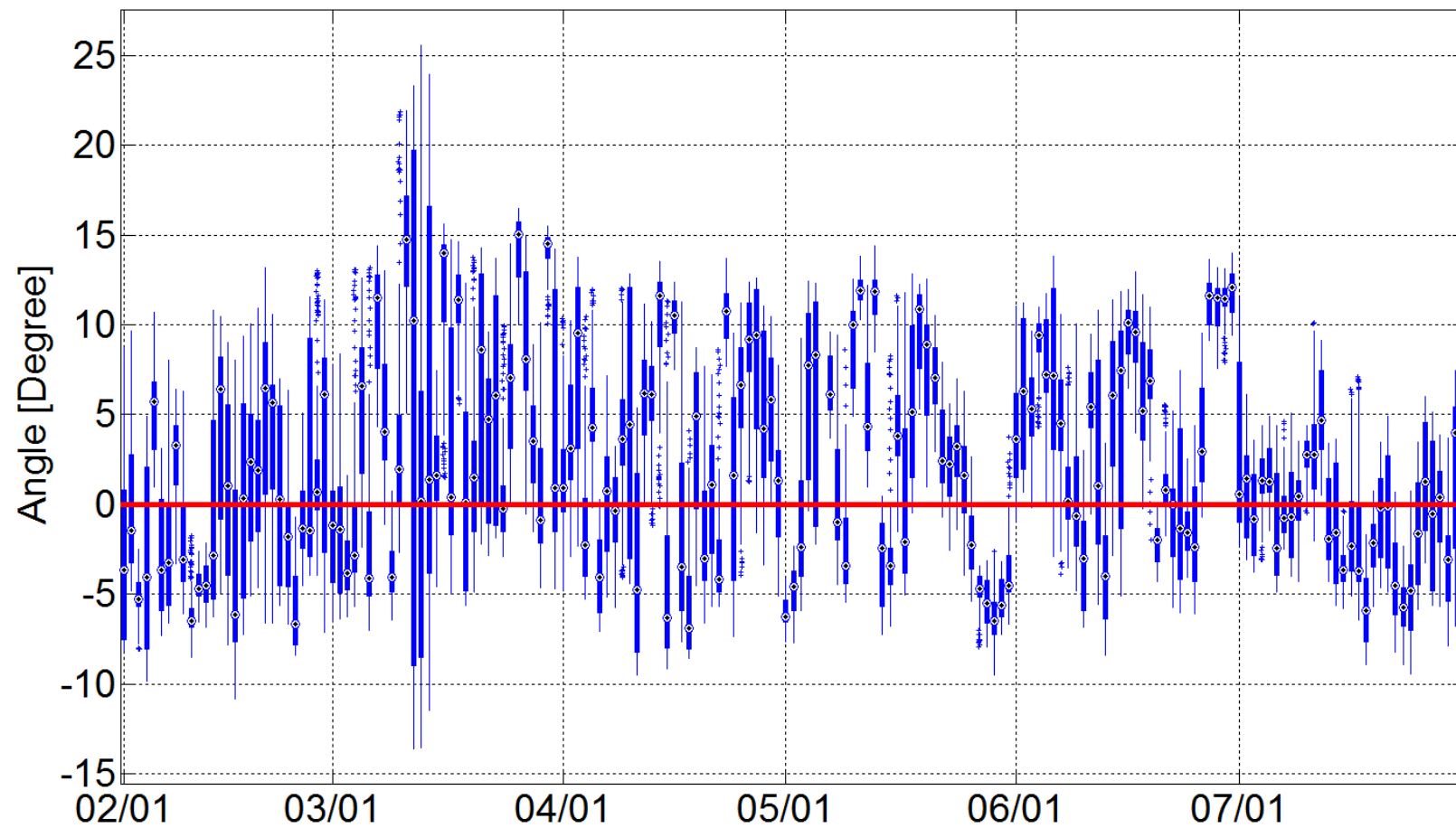
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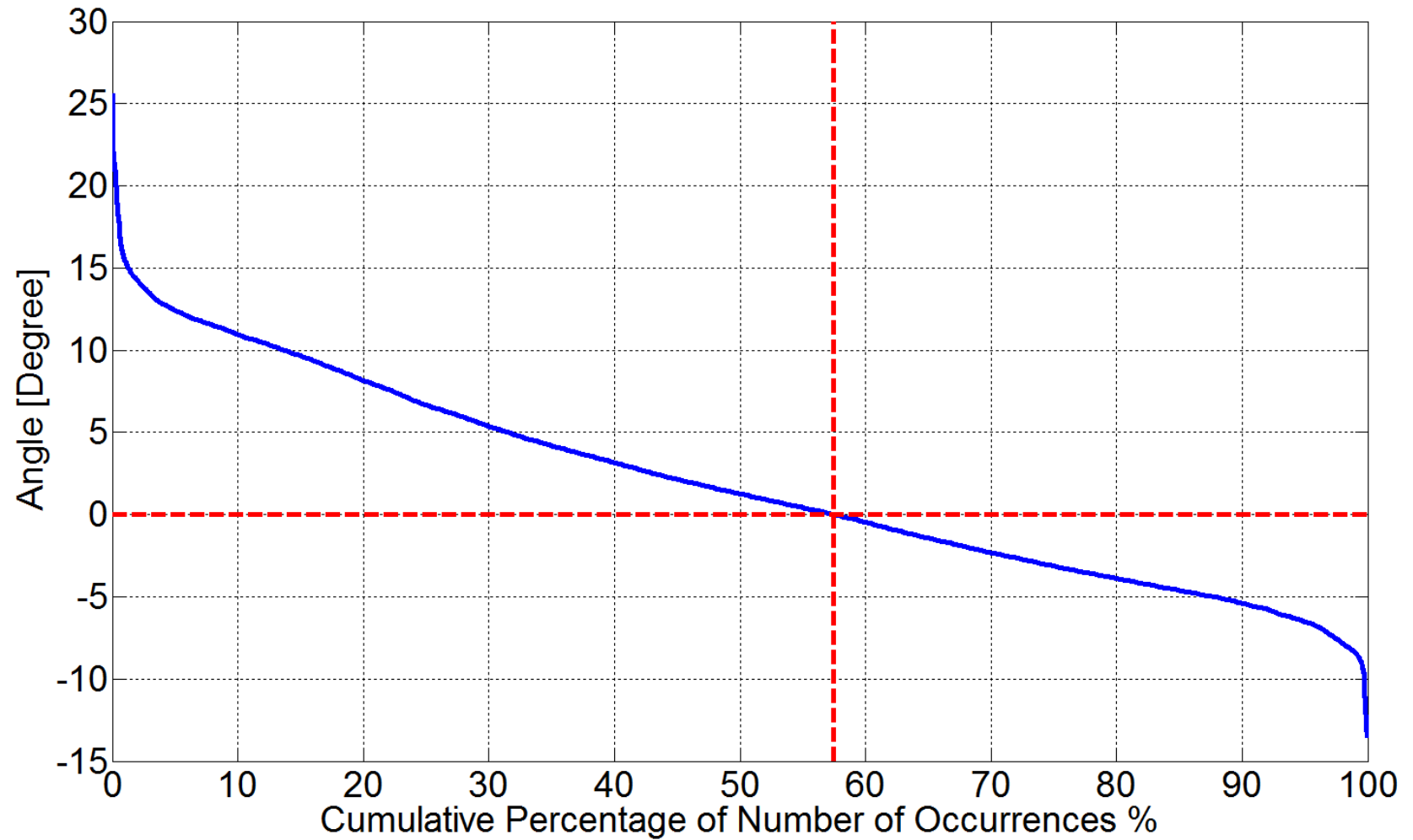
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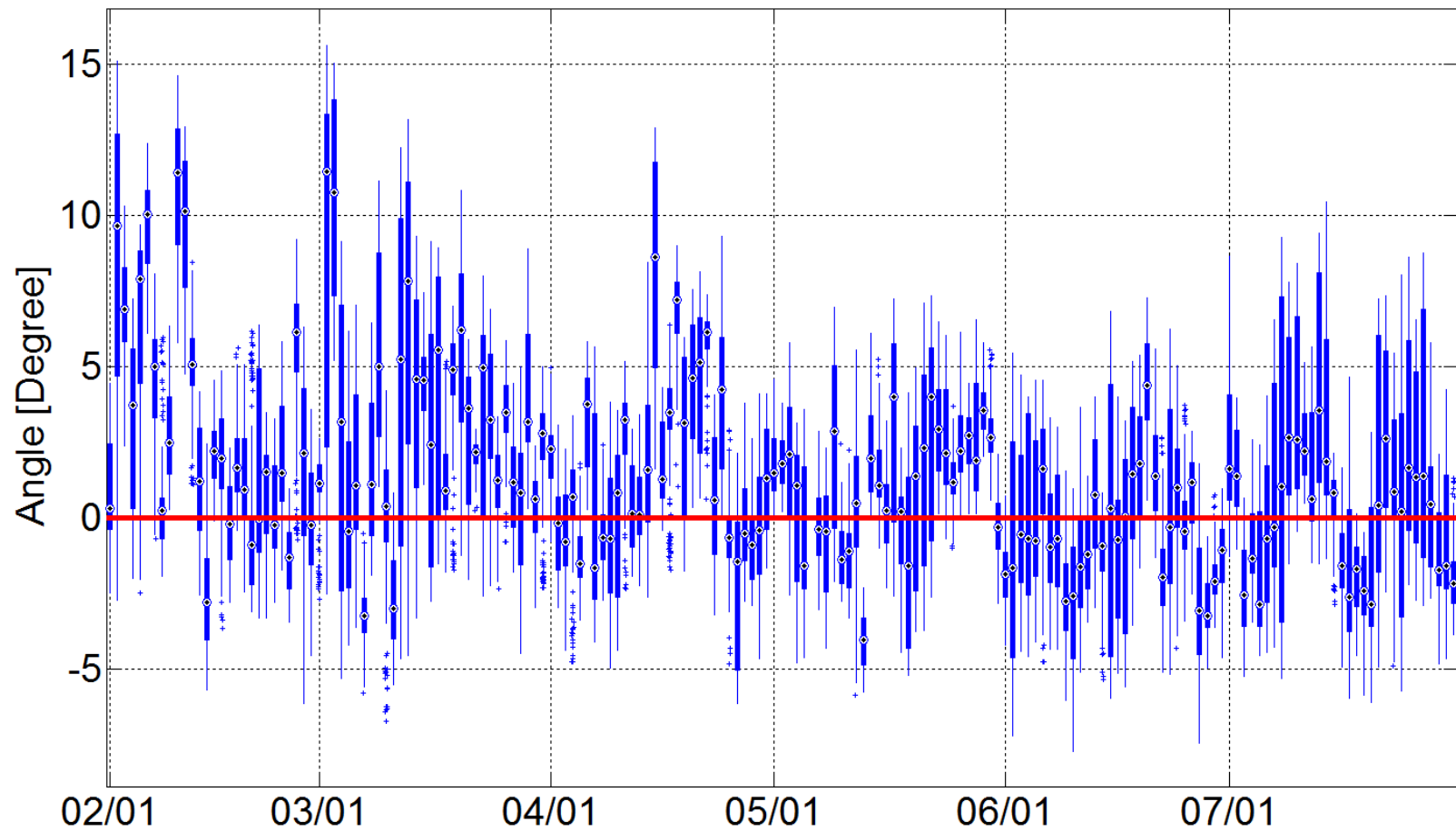
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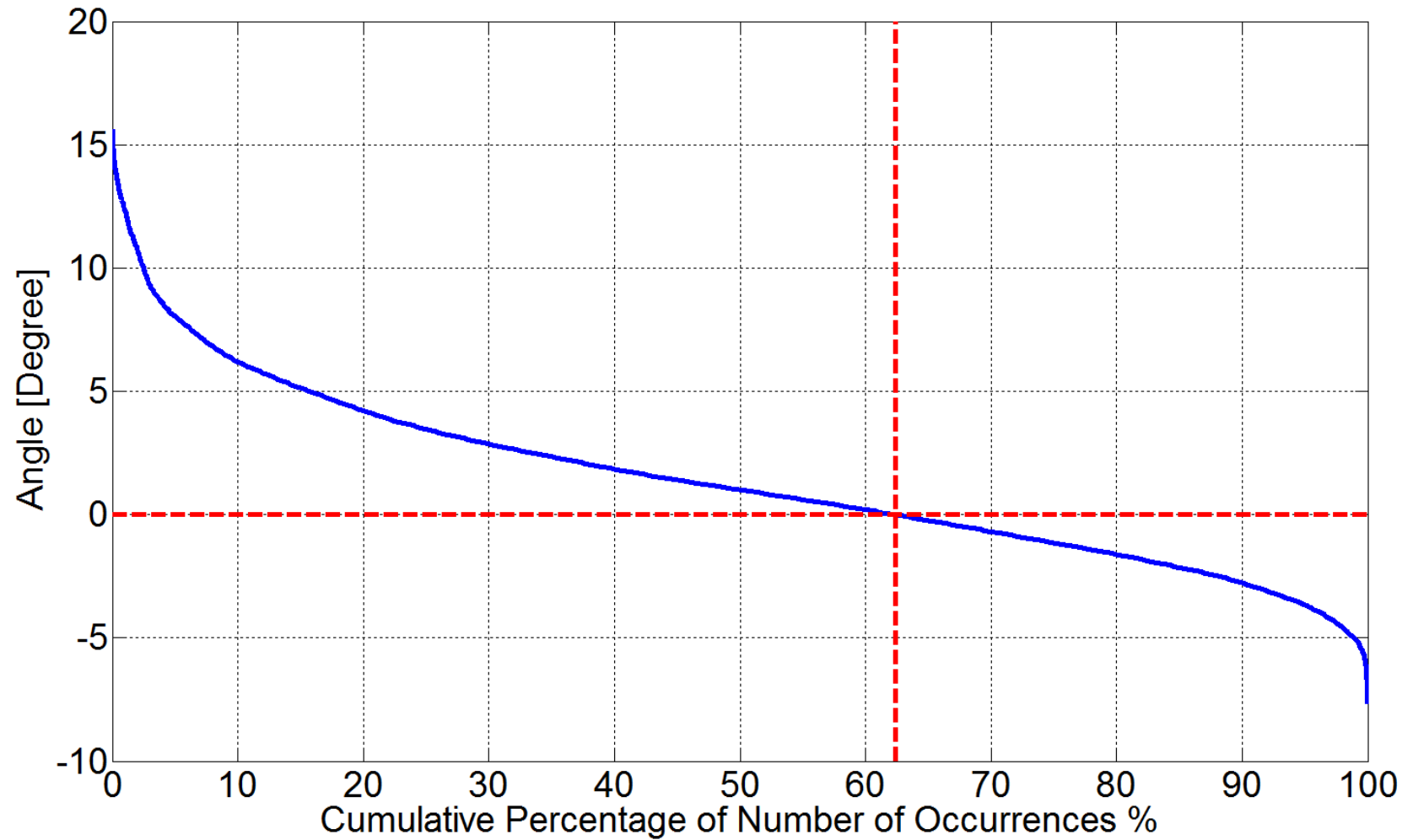
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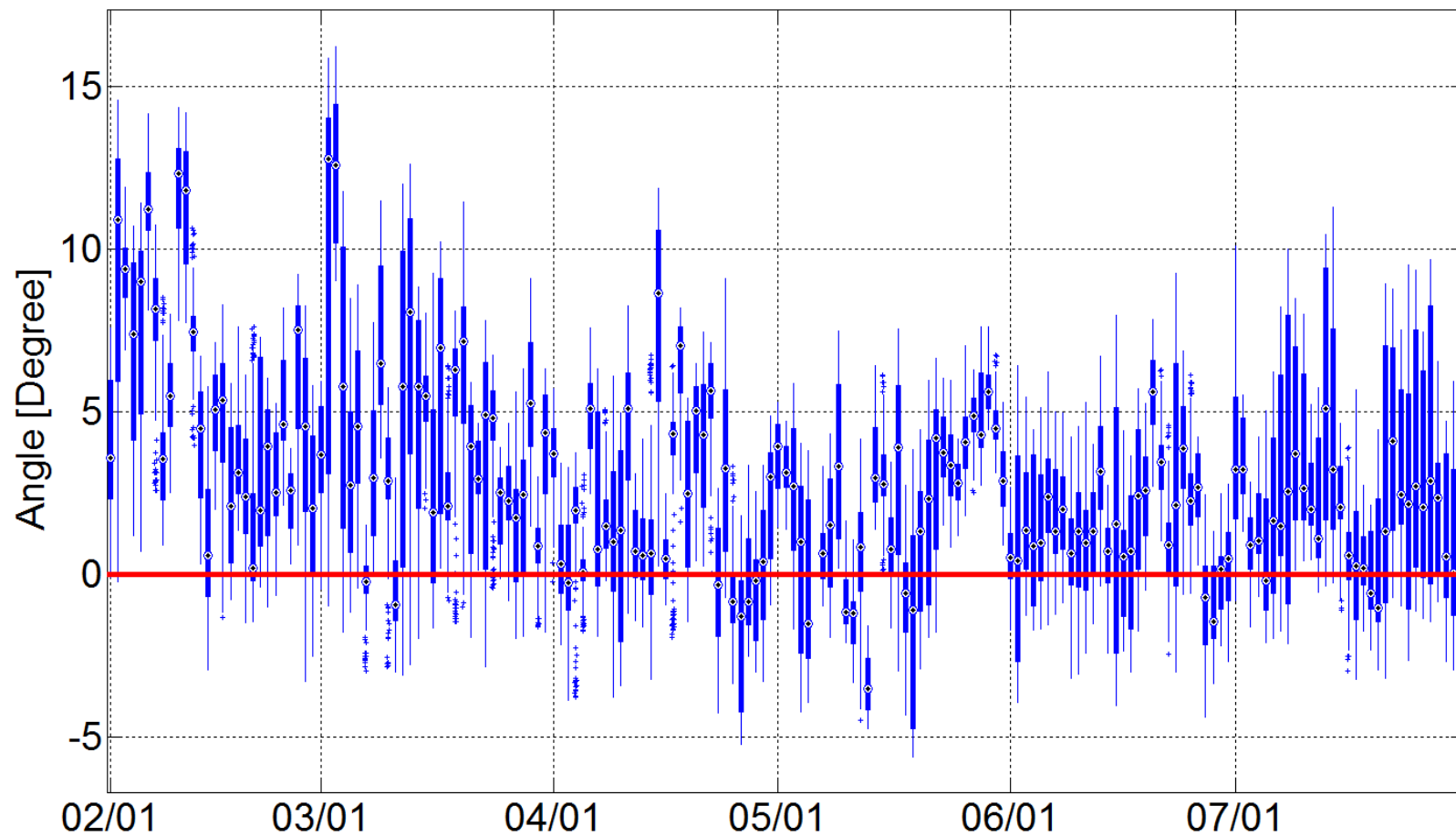
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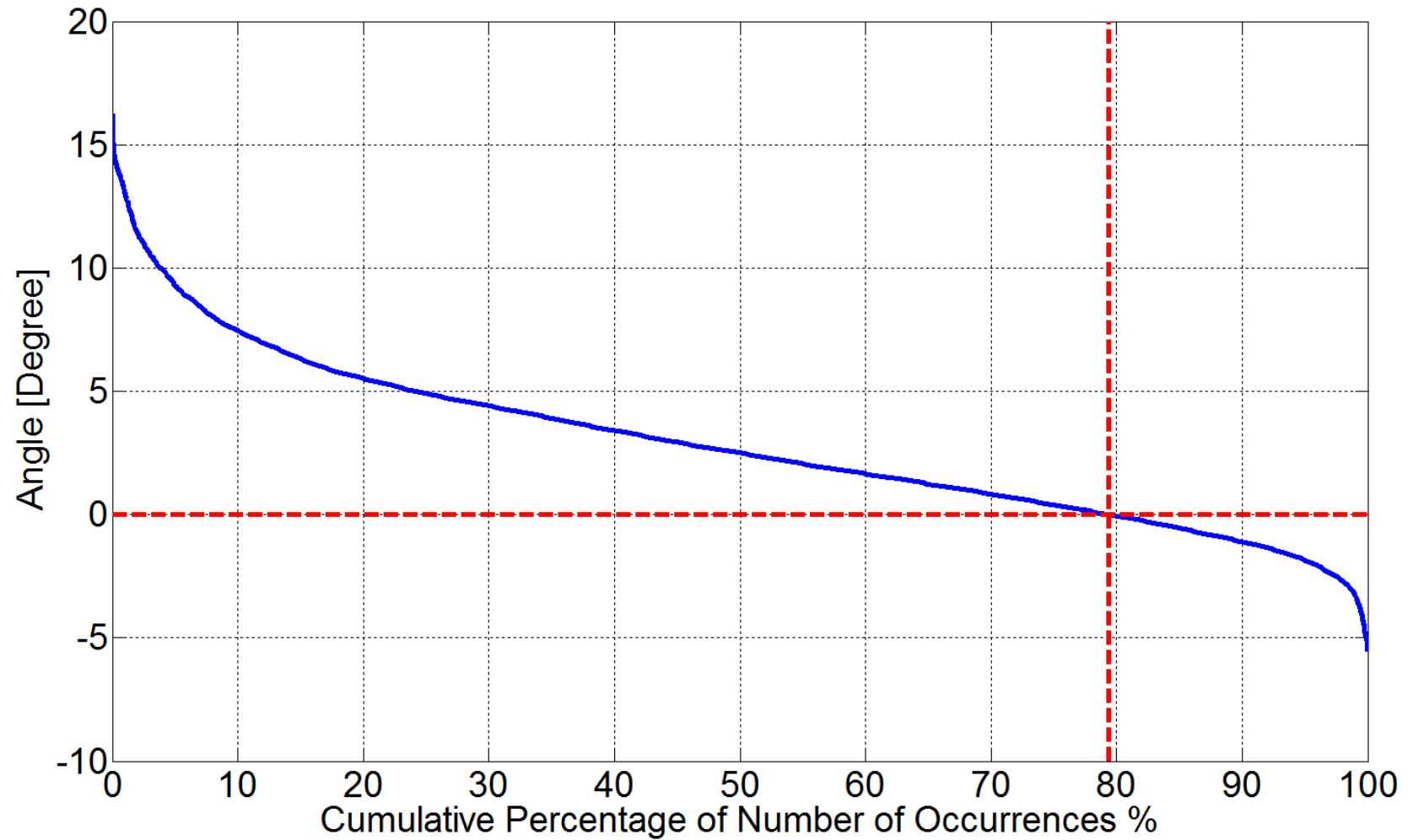
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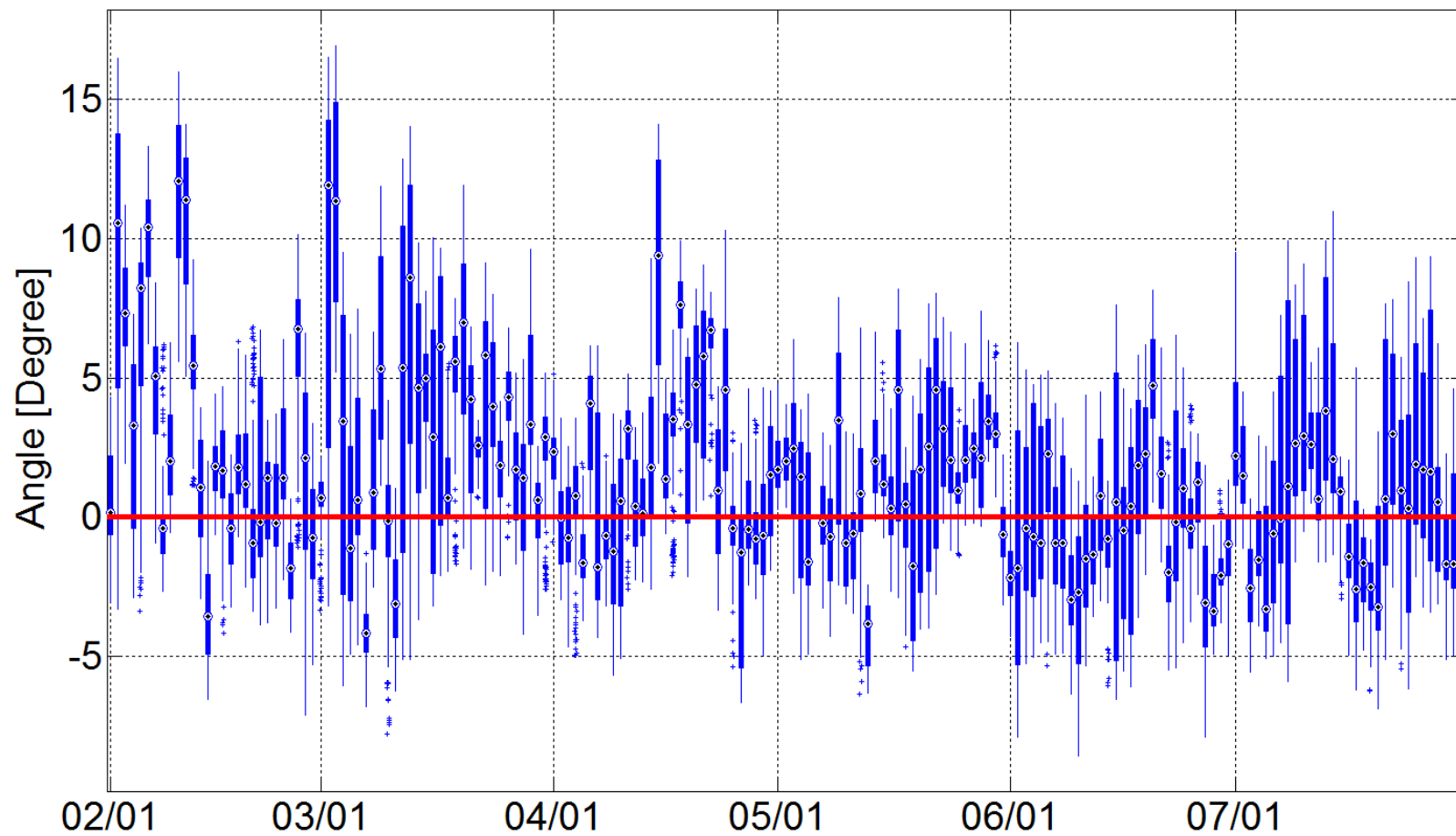
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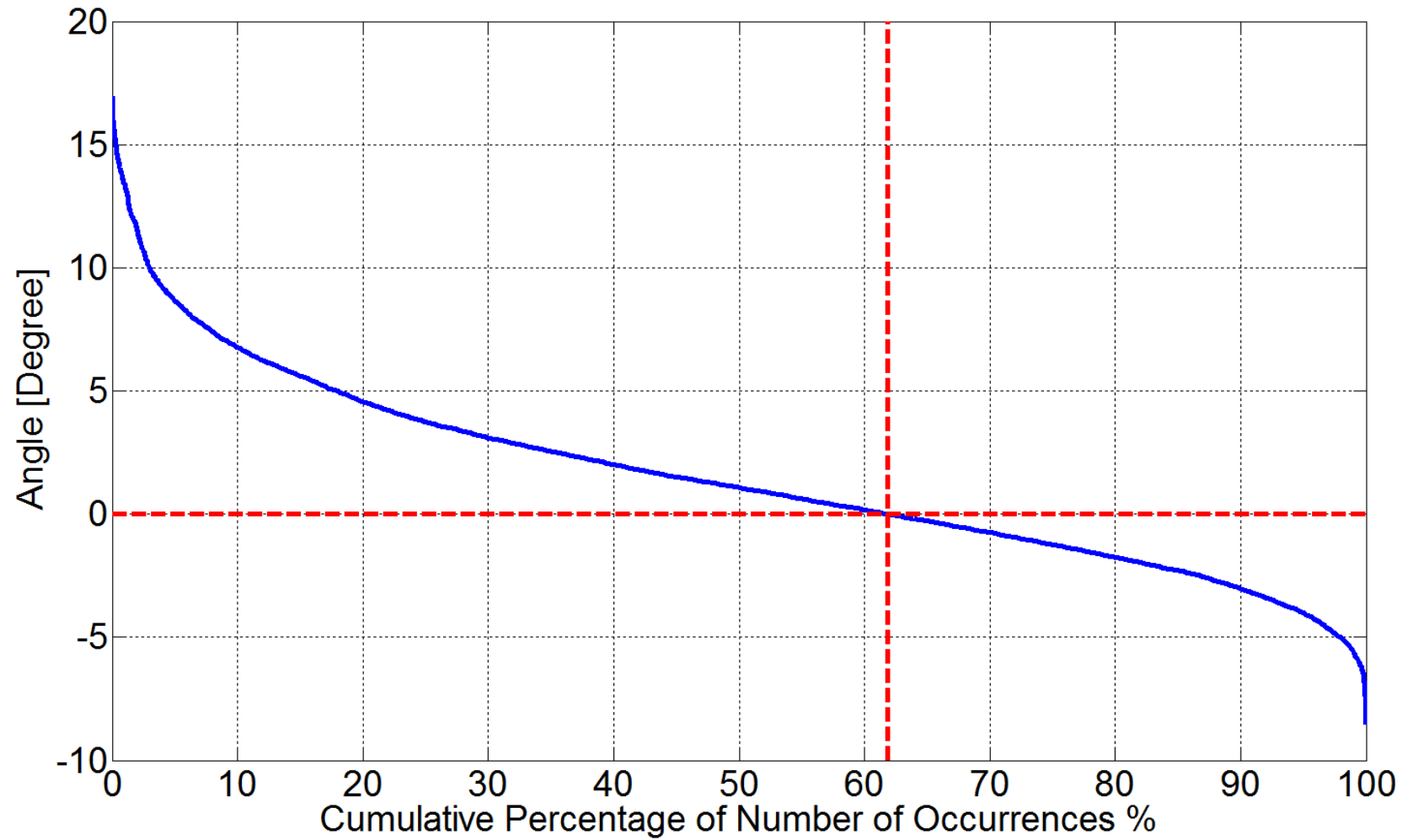
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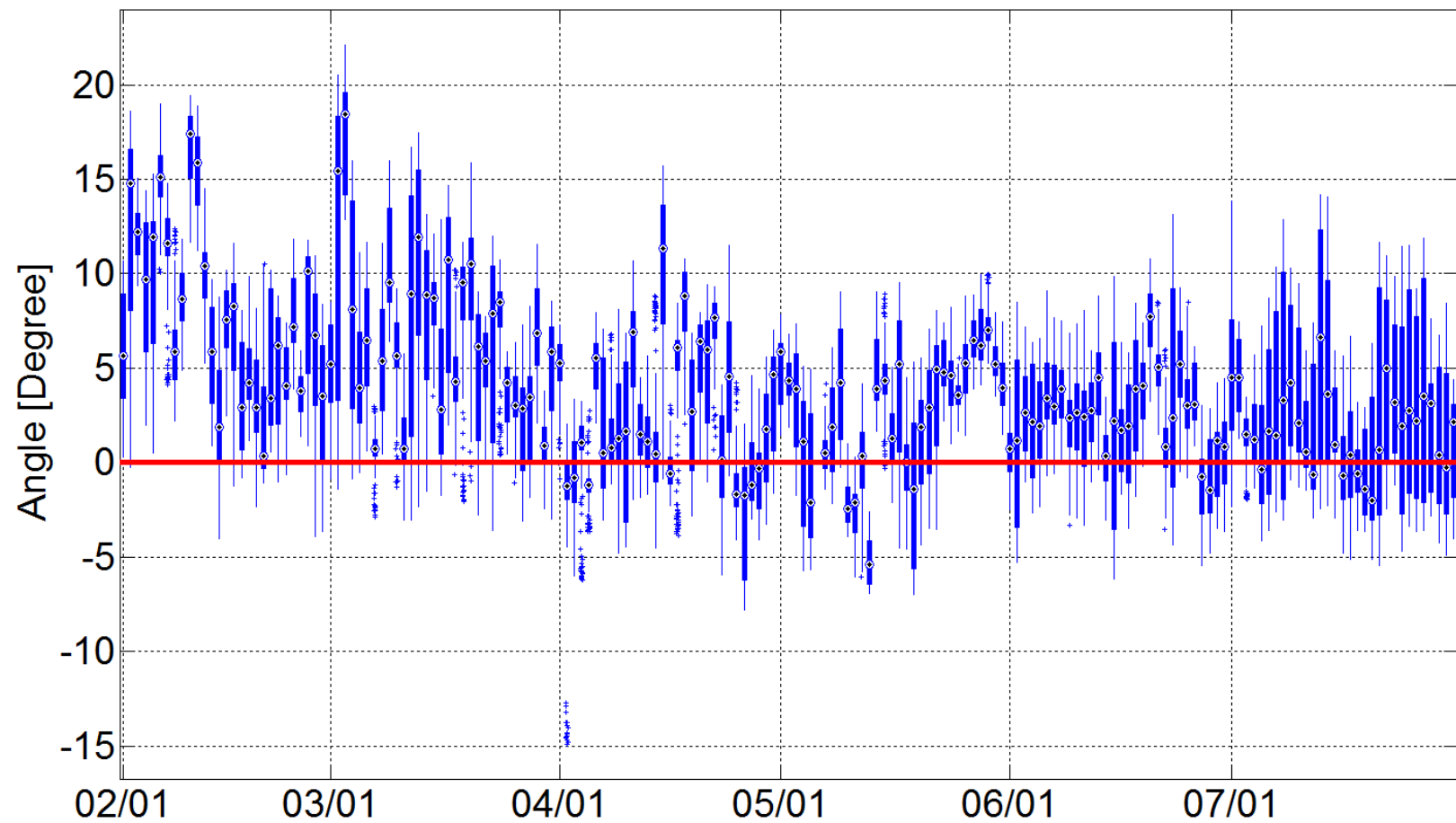
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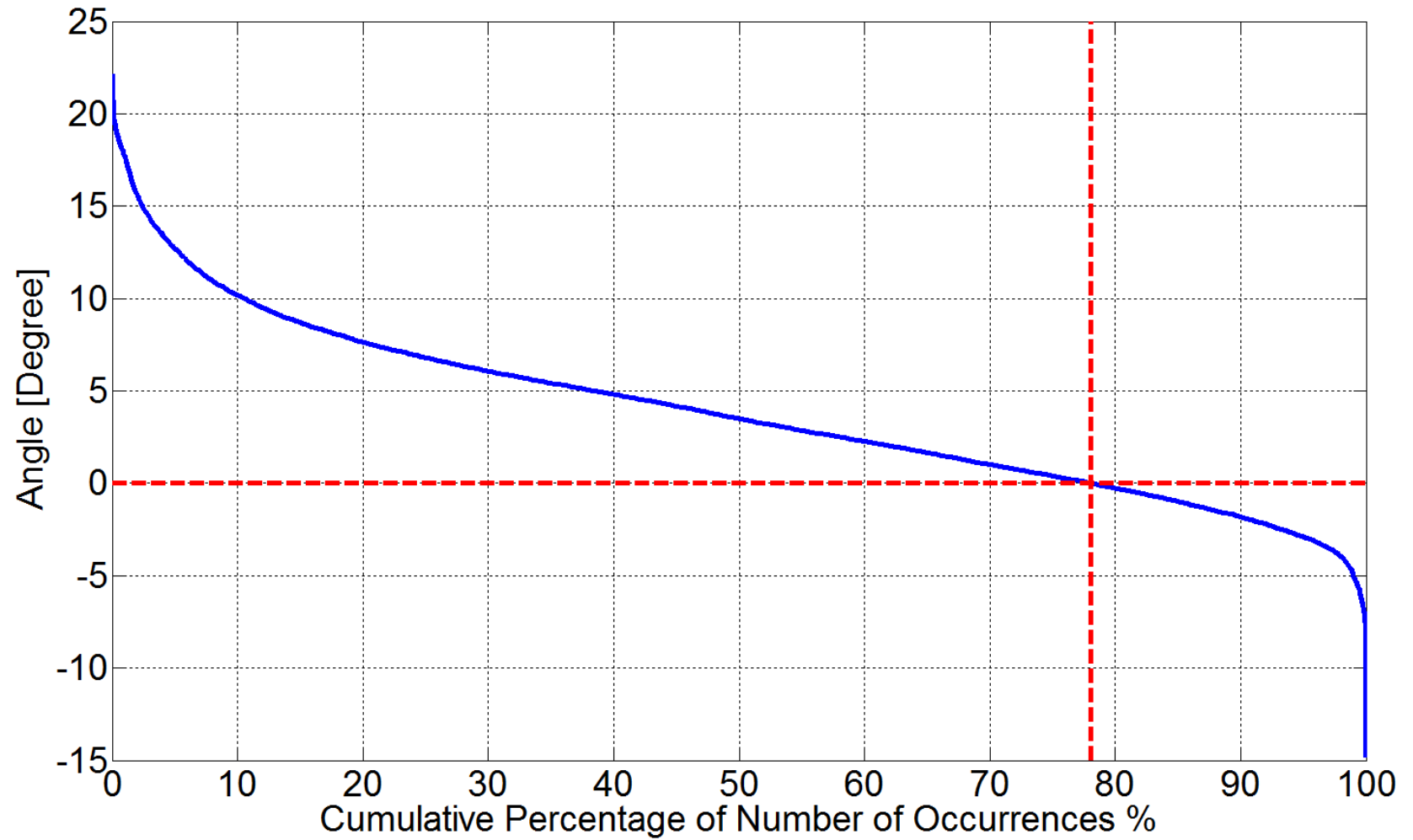
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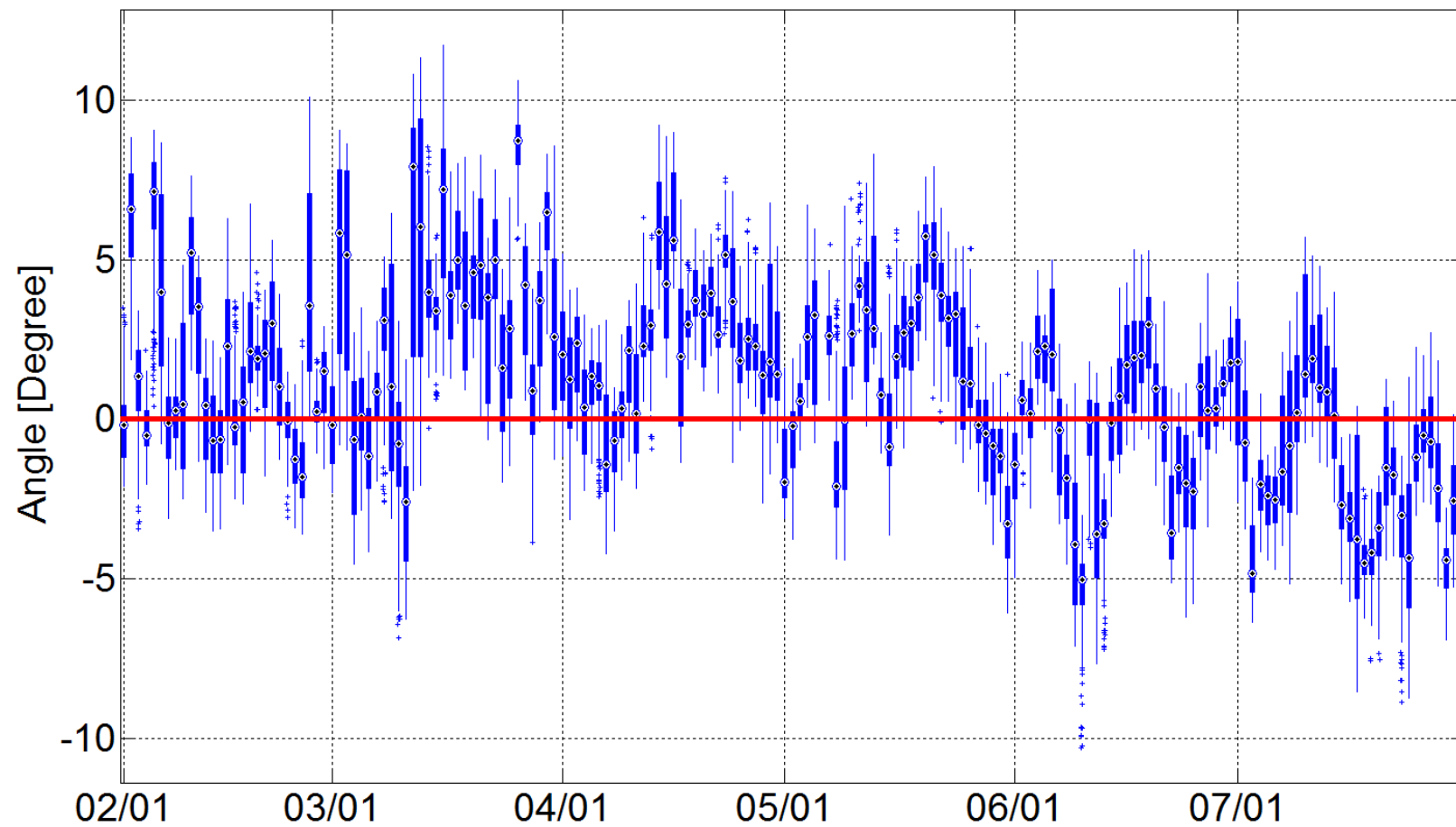
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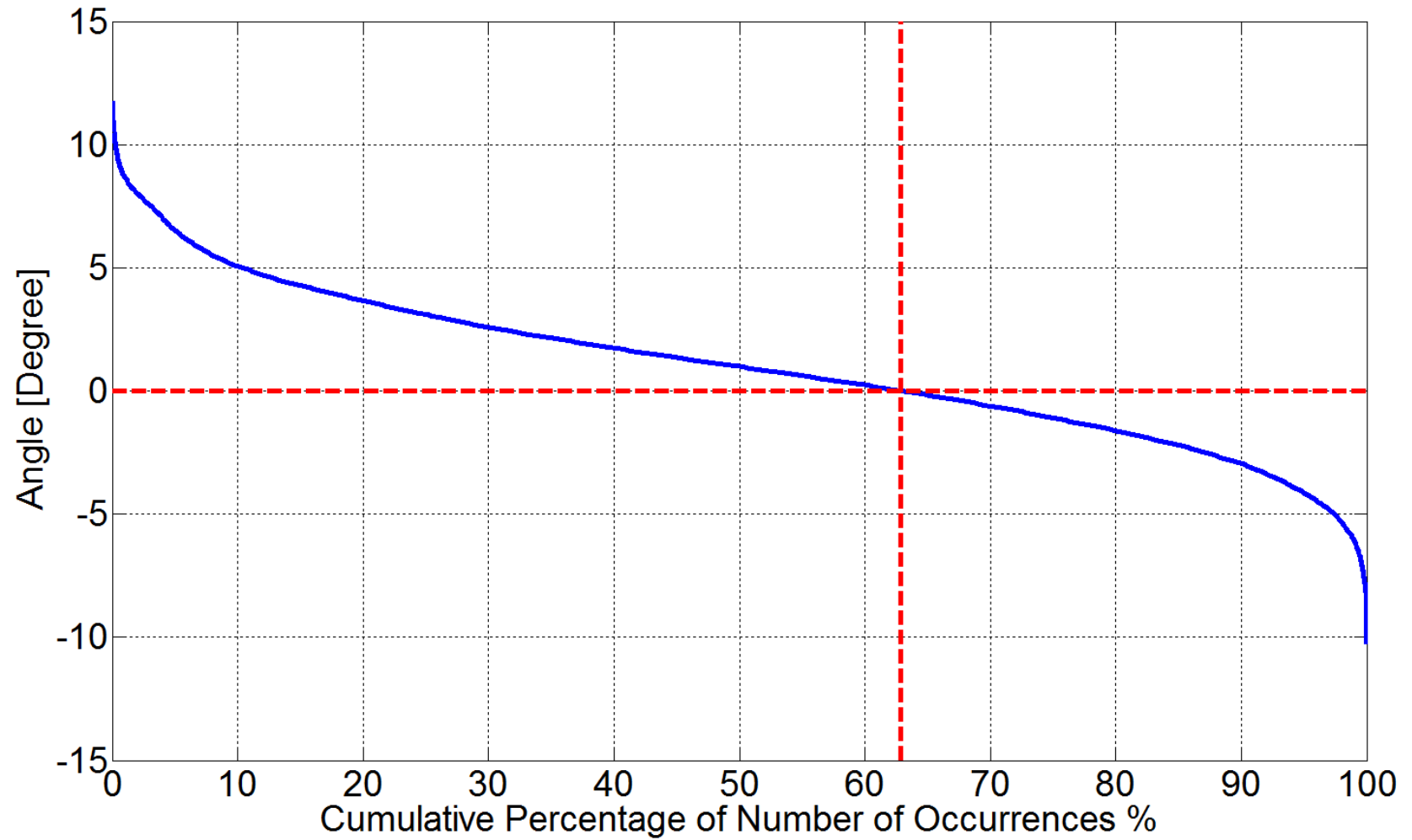
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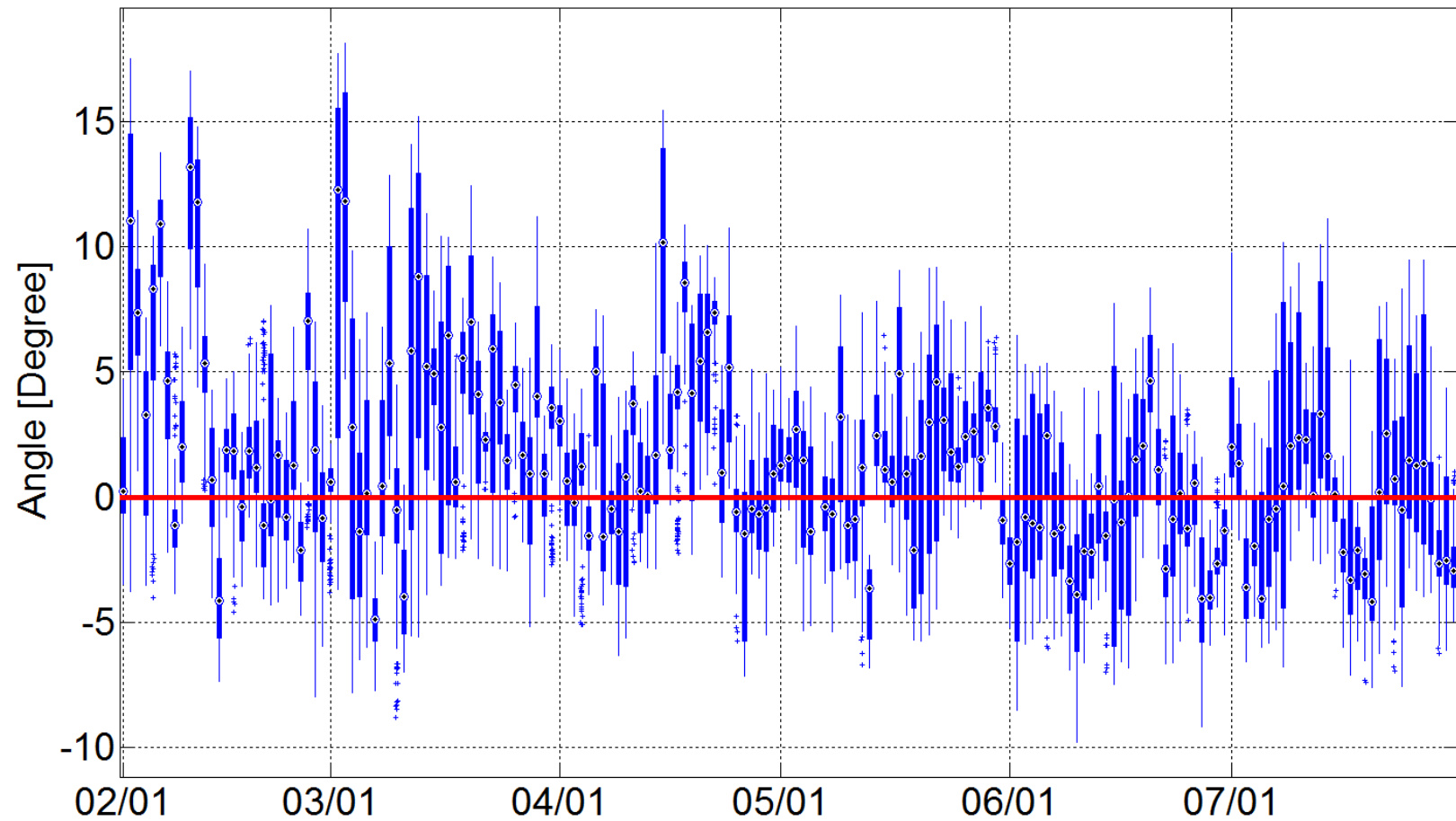
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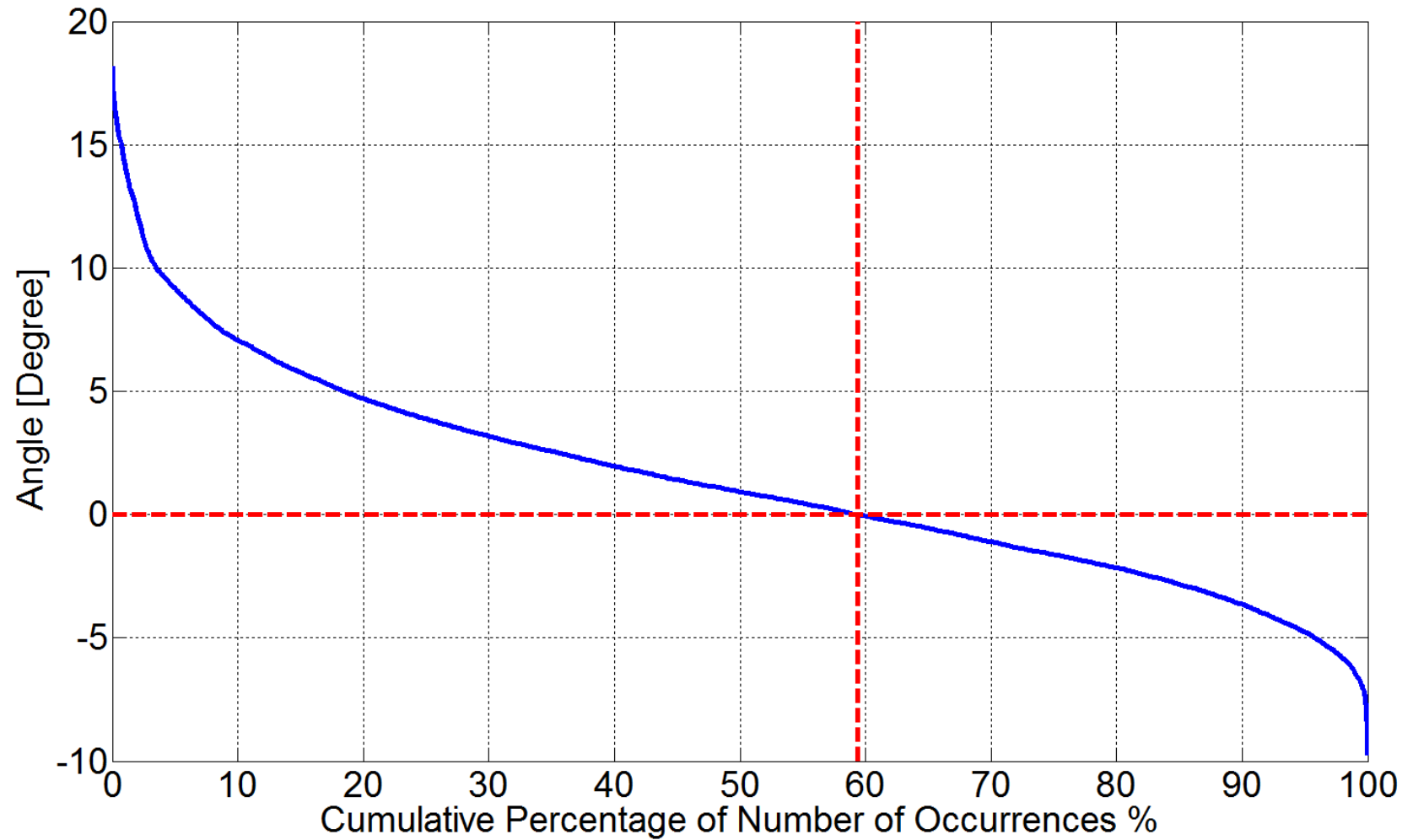
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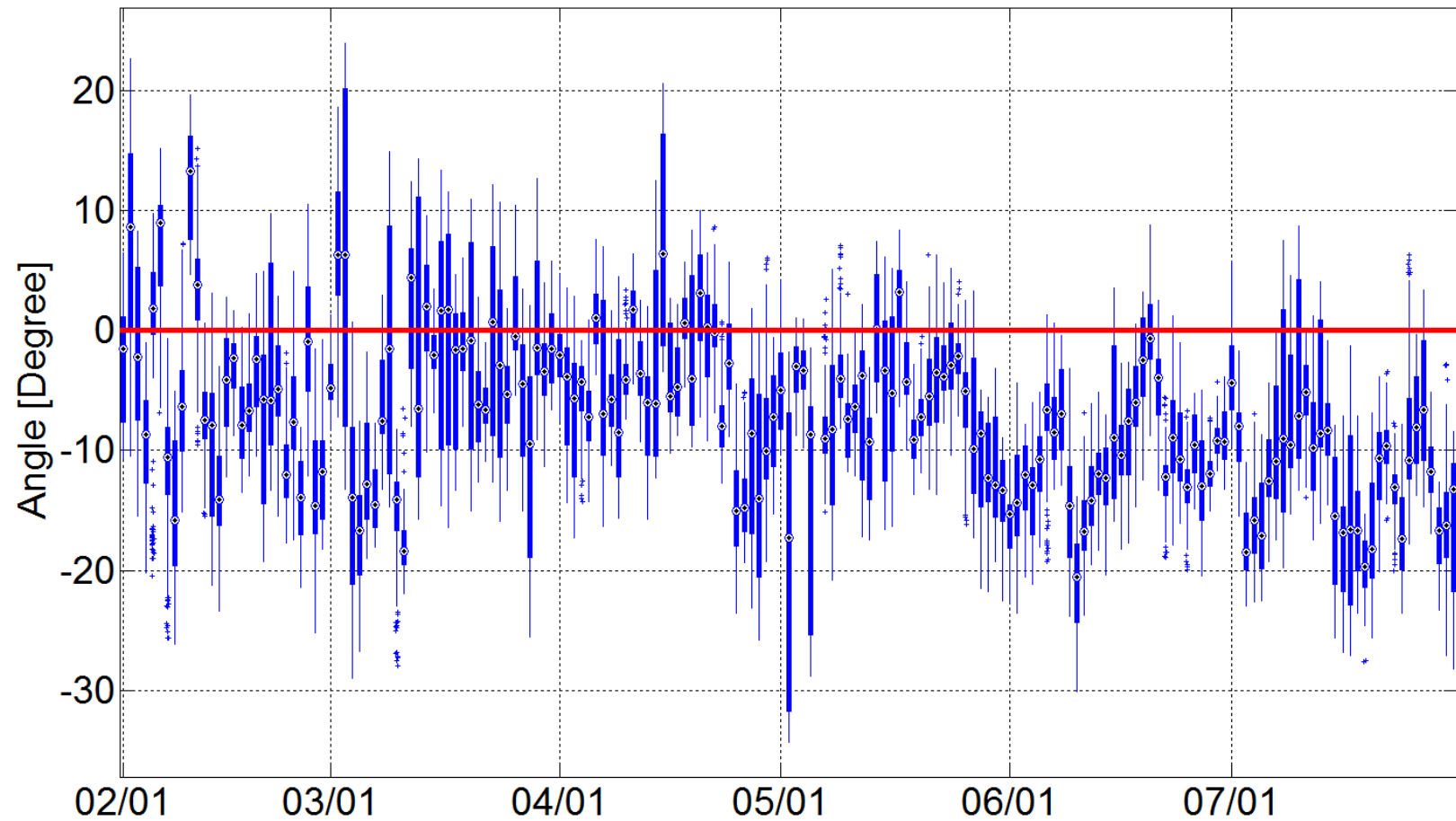
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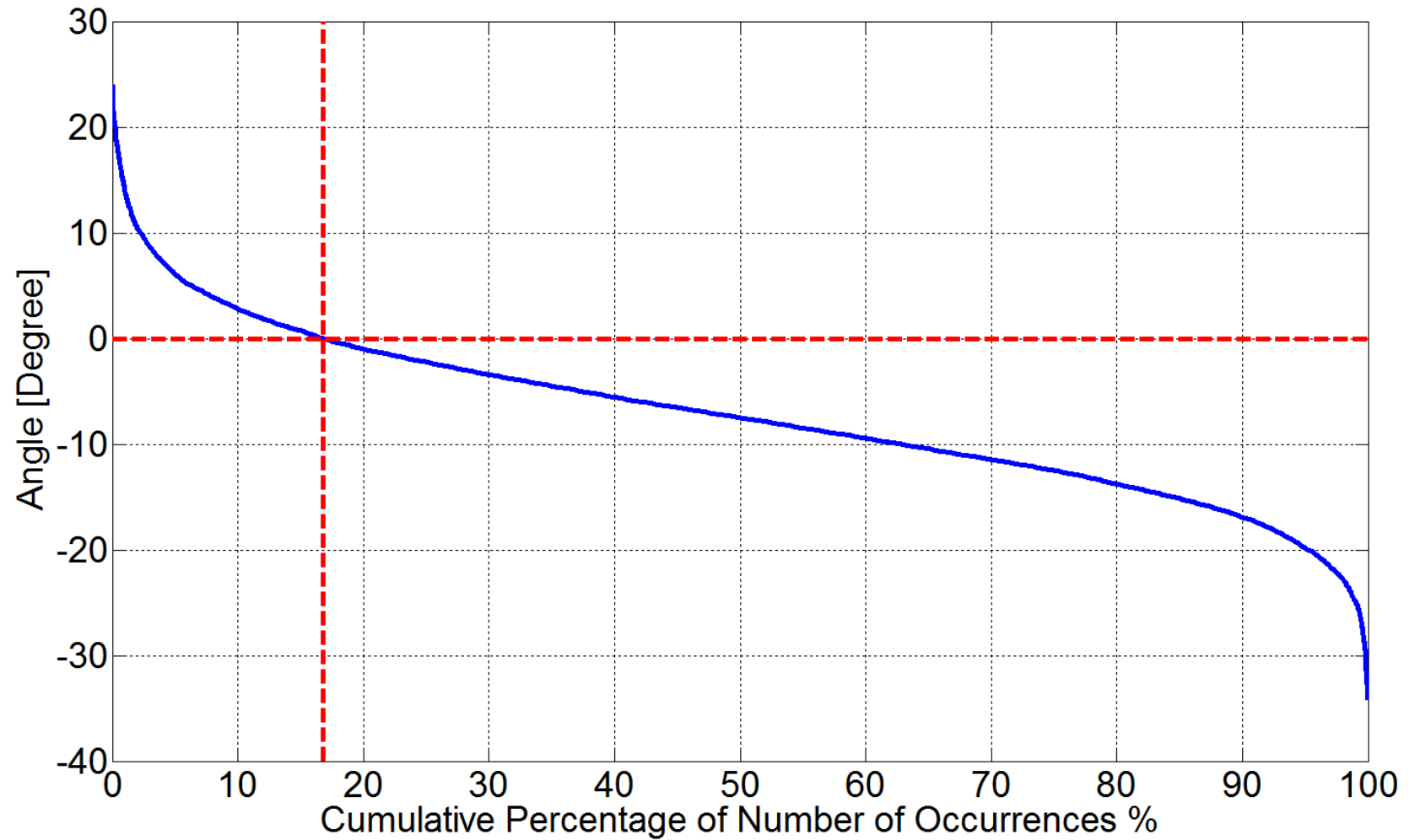
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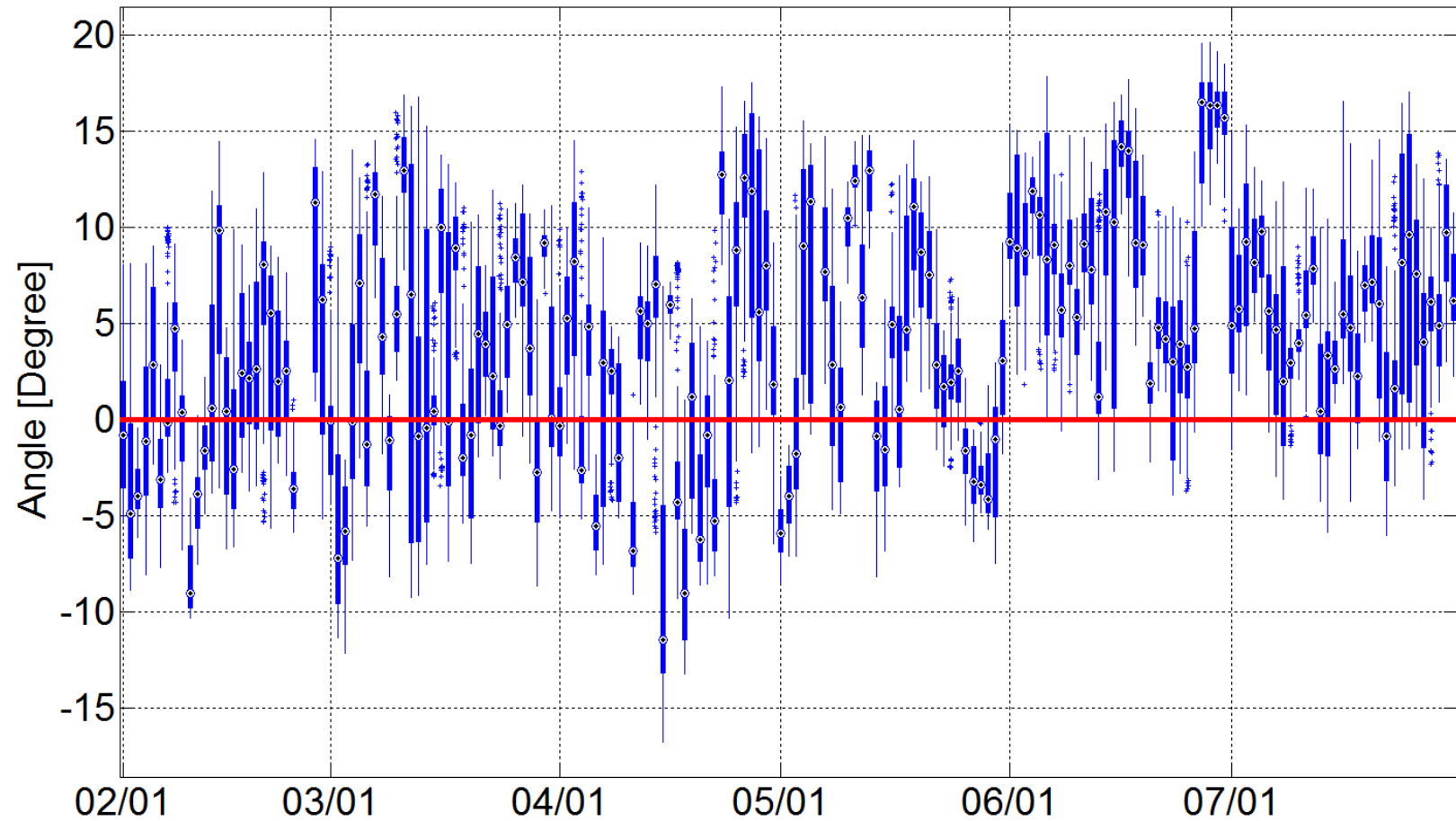
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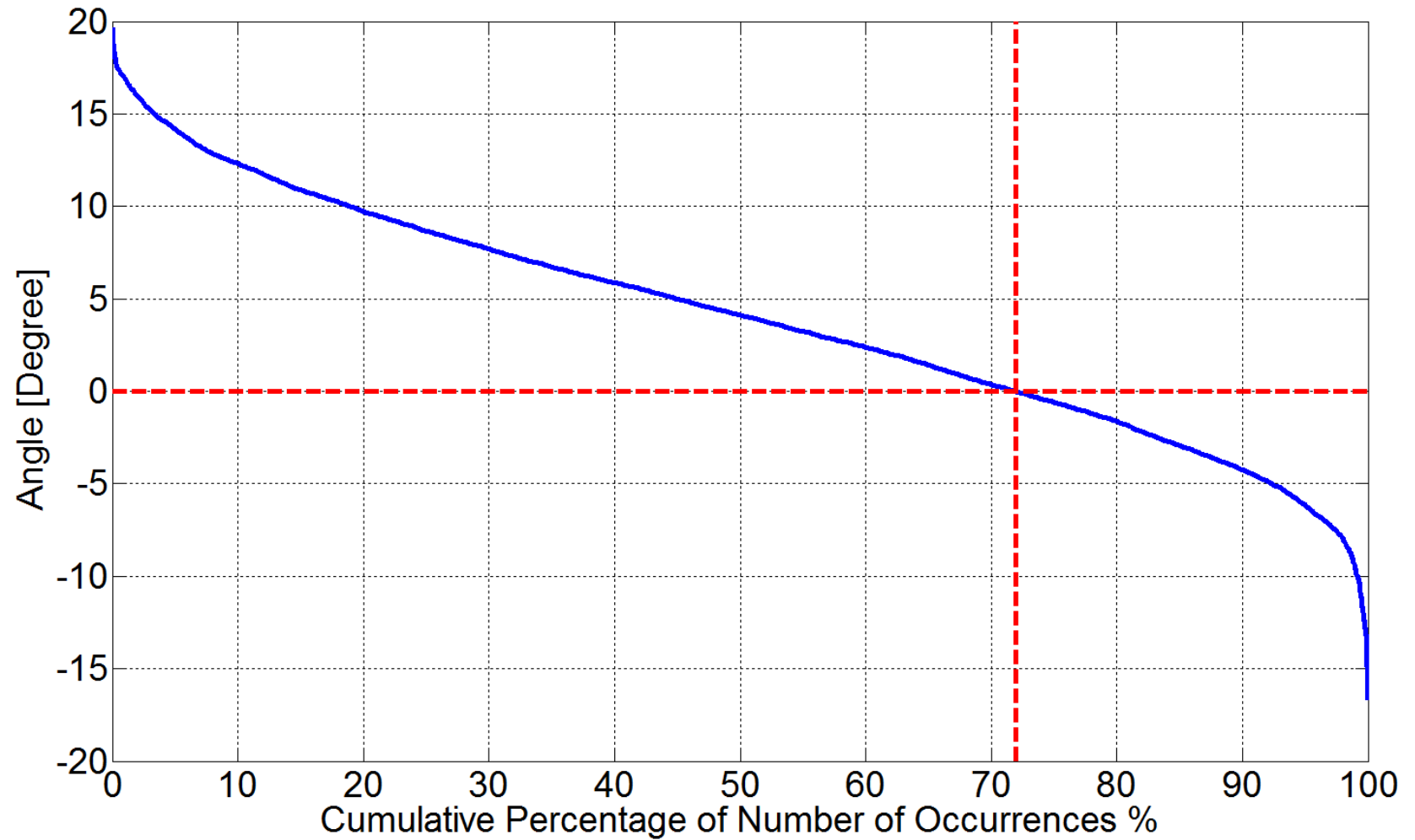
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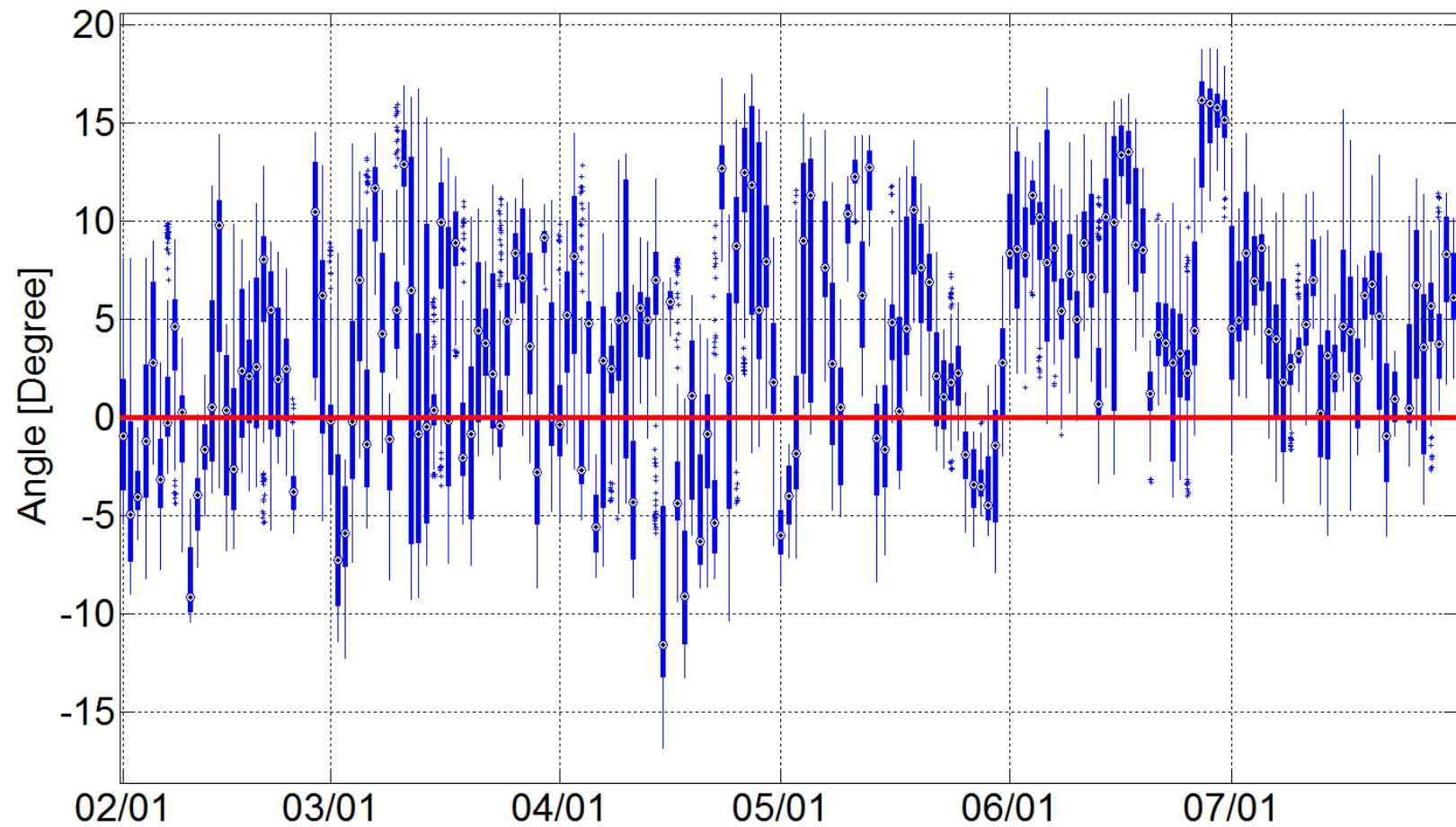
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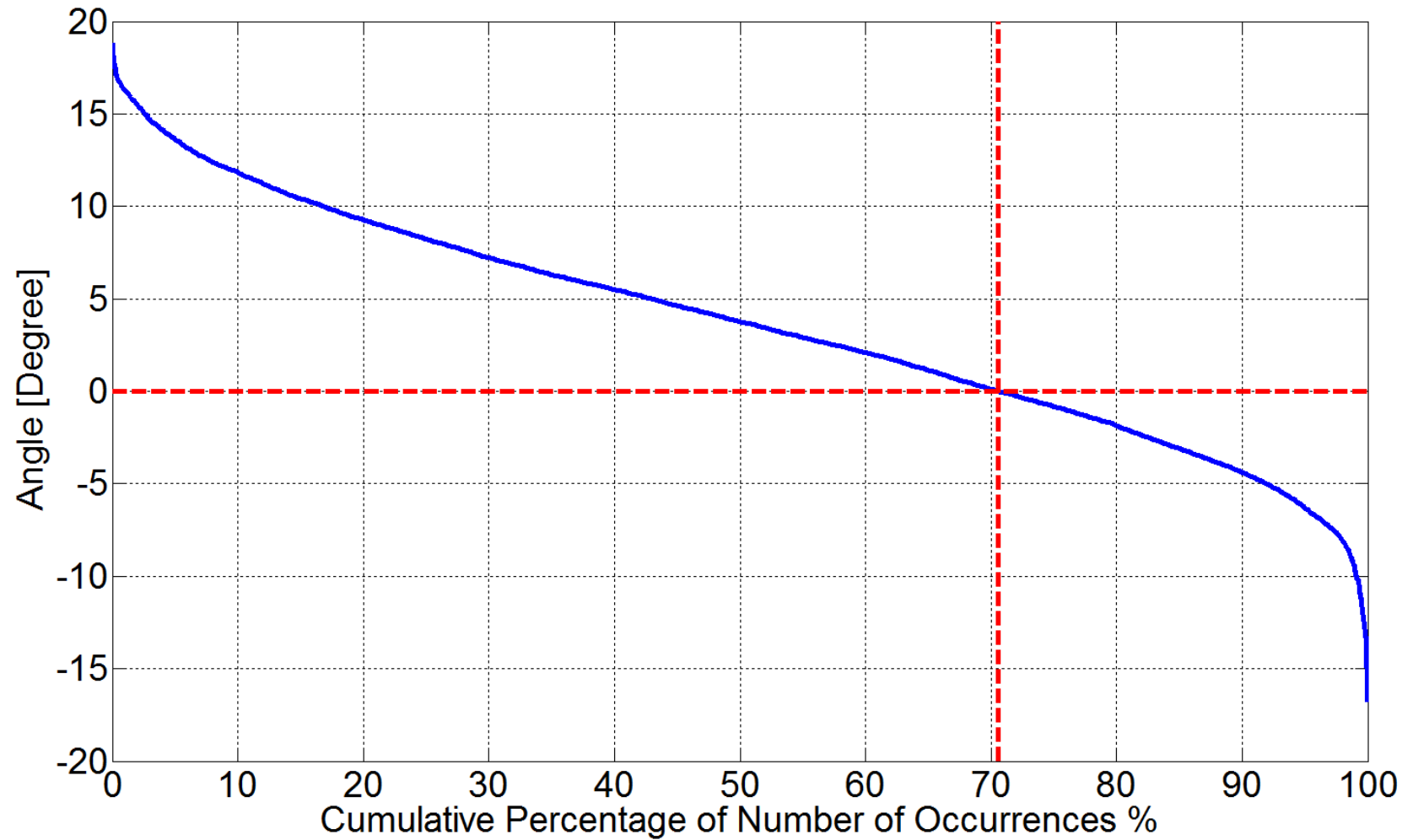
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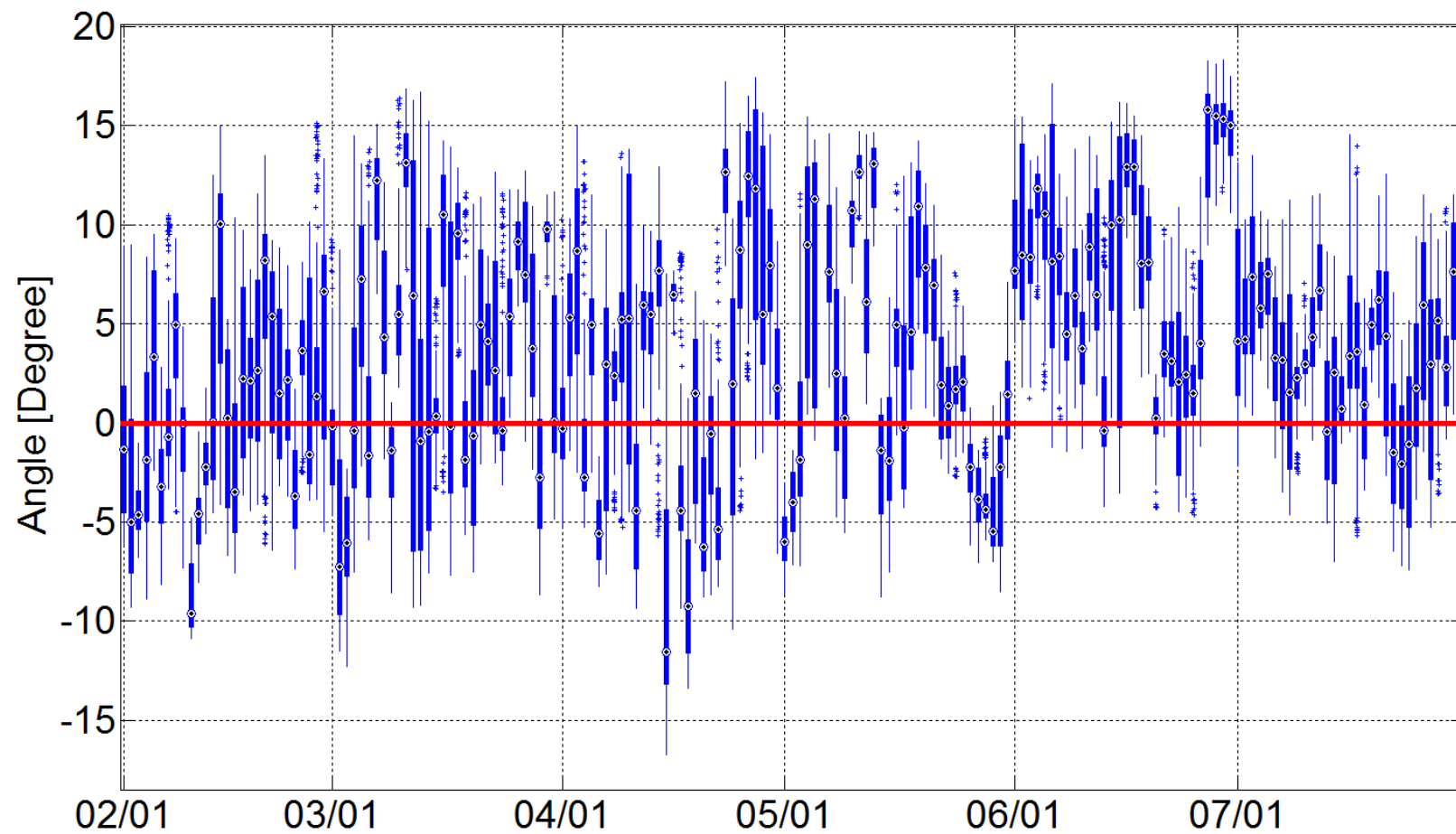
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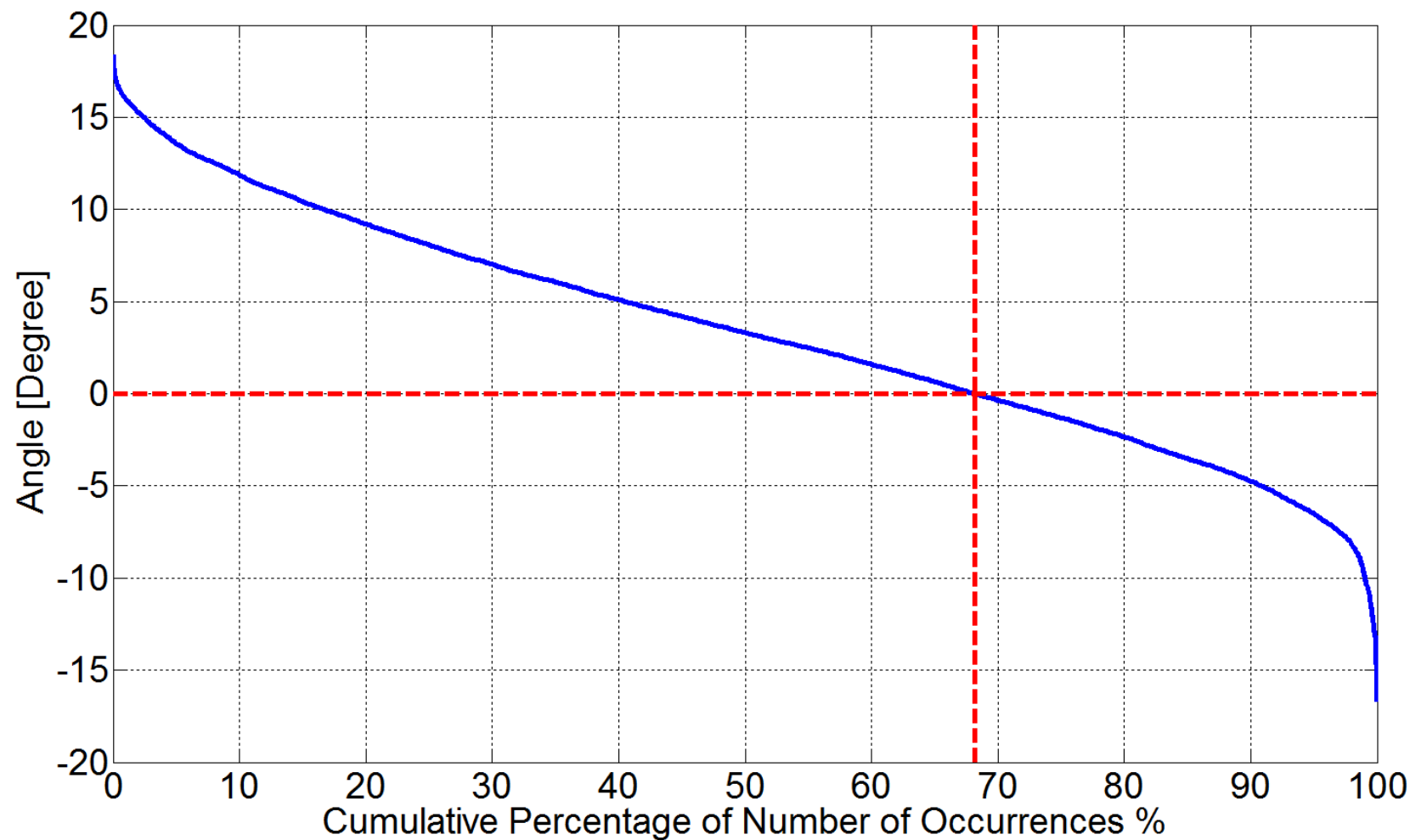
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West 19-North 7



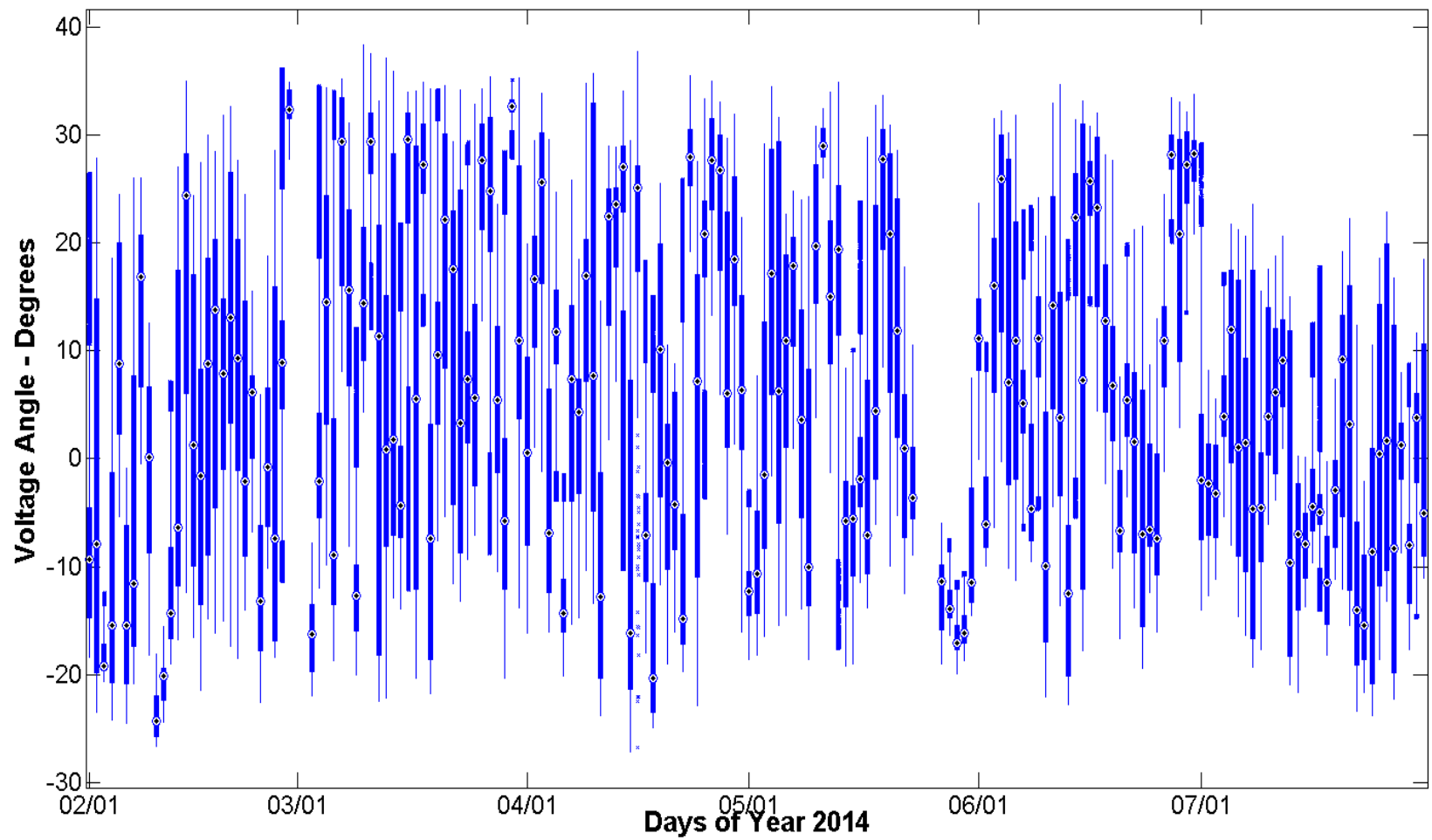
Appendix A – Part 2
CCET Discovery Across Texas project

**Baseline Analysis Update - Voltage Angles
(Ref.: North 7)**

Phasor Data: February to July 2014
Box Whiskers Plots and Time Duration Curves

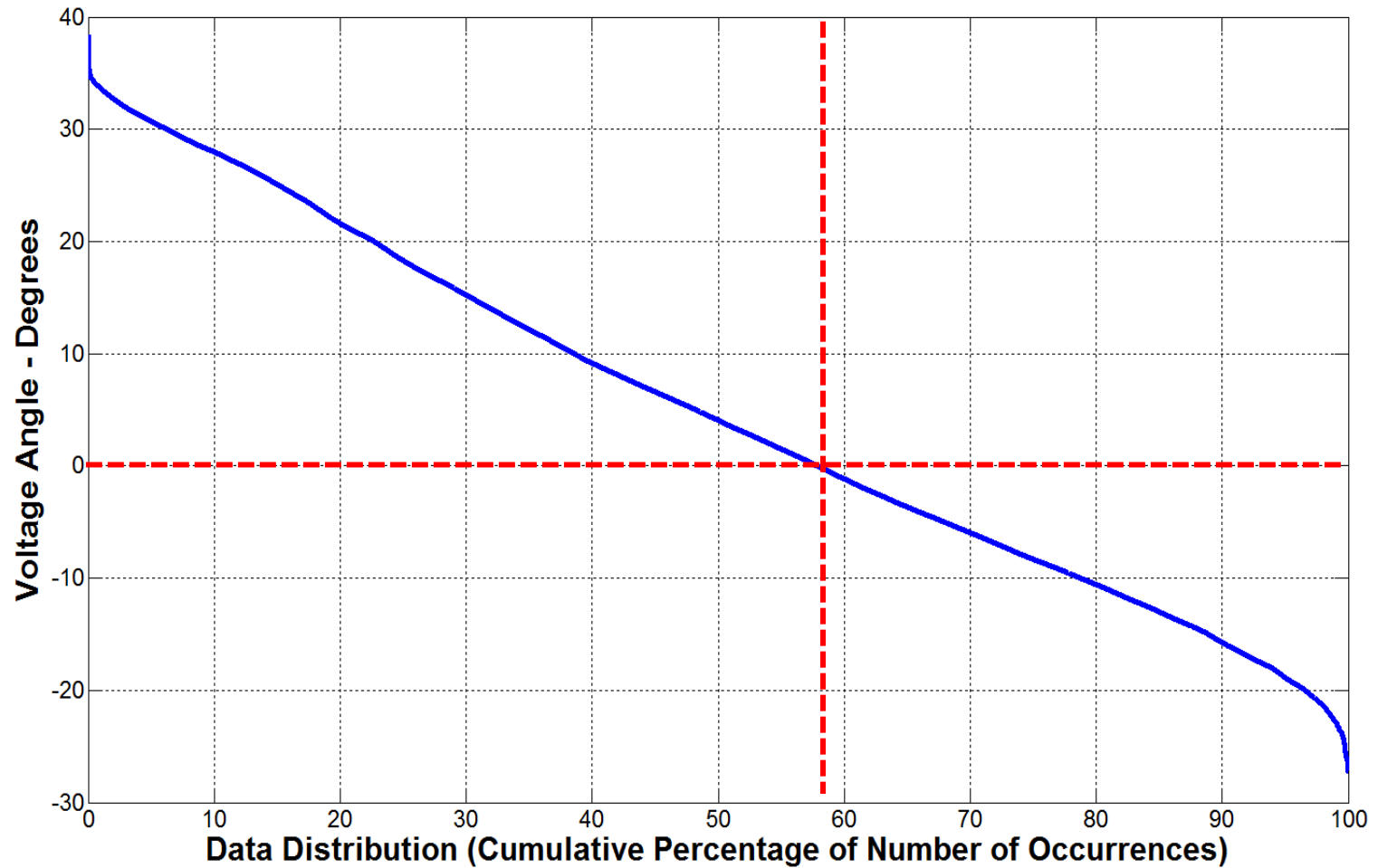
West 10

Daily Box-Whisker Chart:



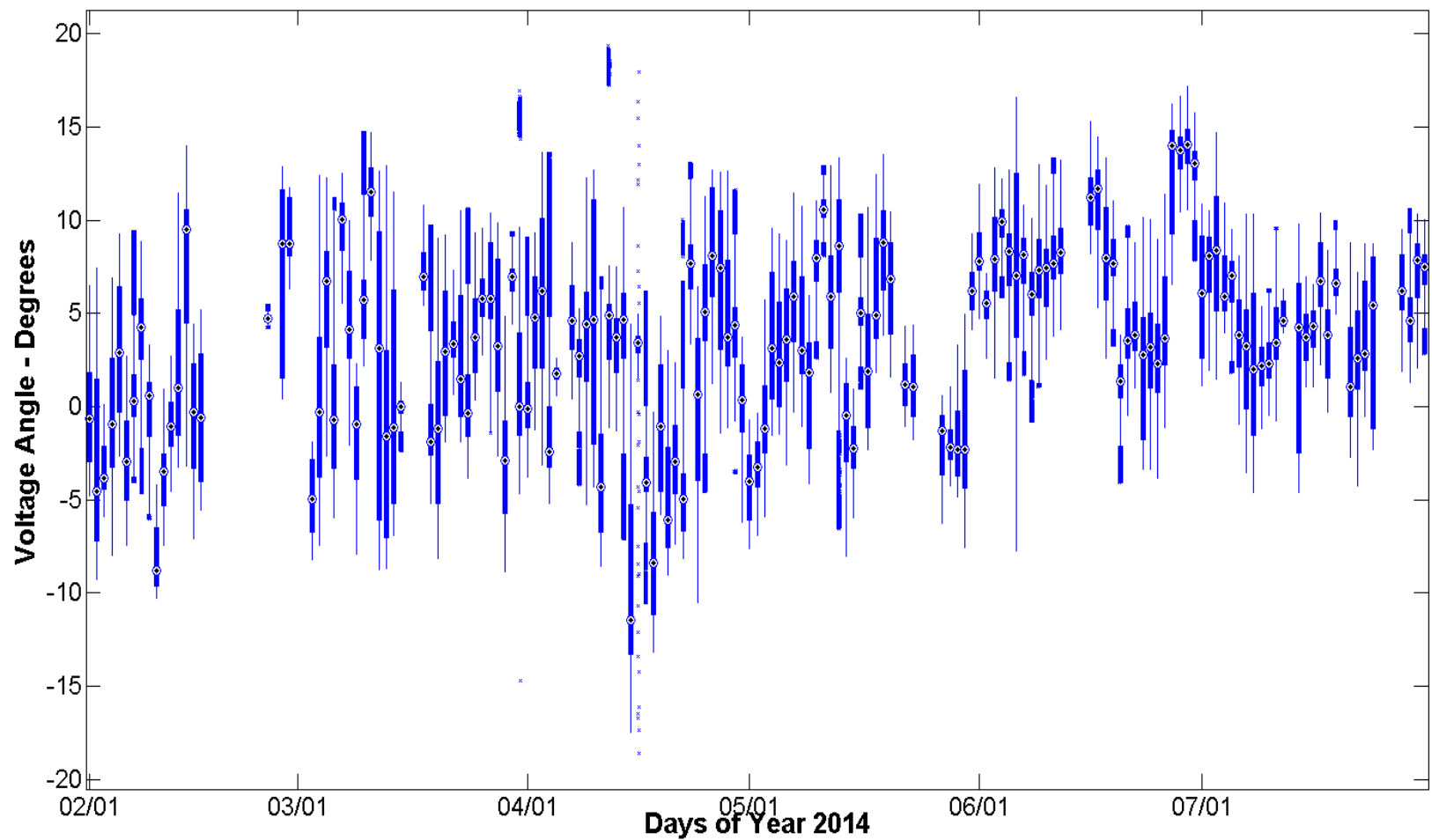
West 10

Time Duration Chart:

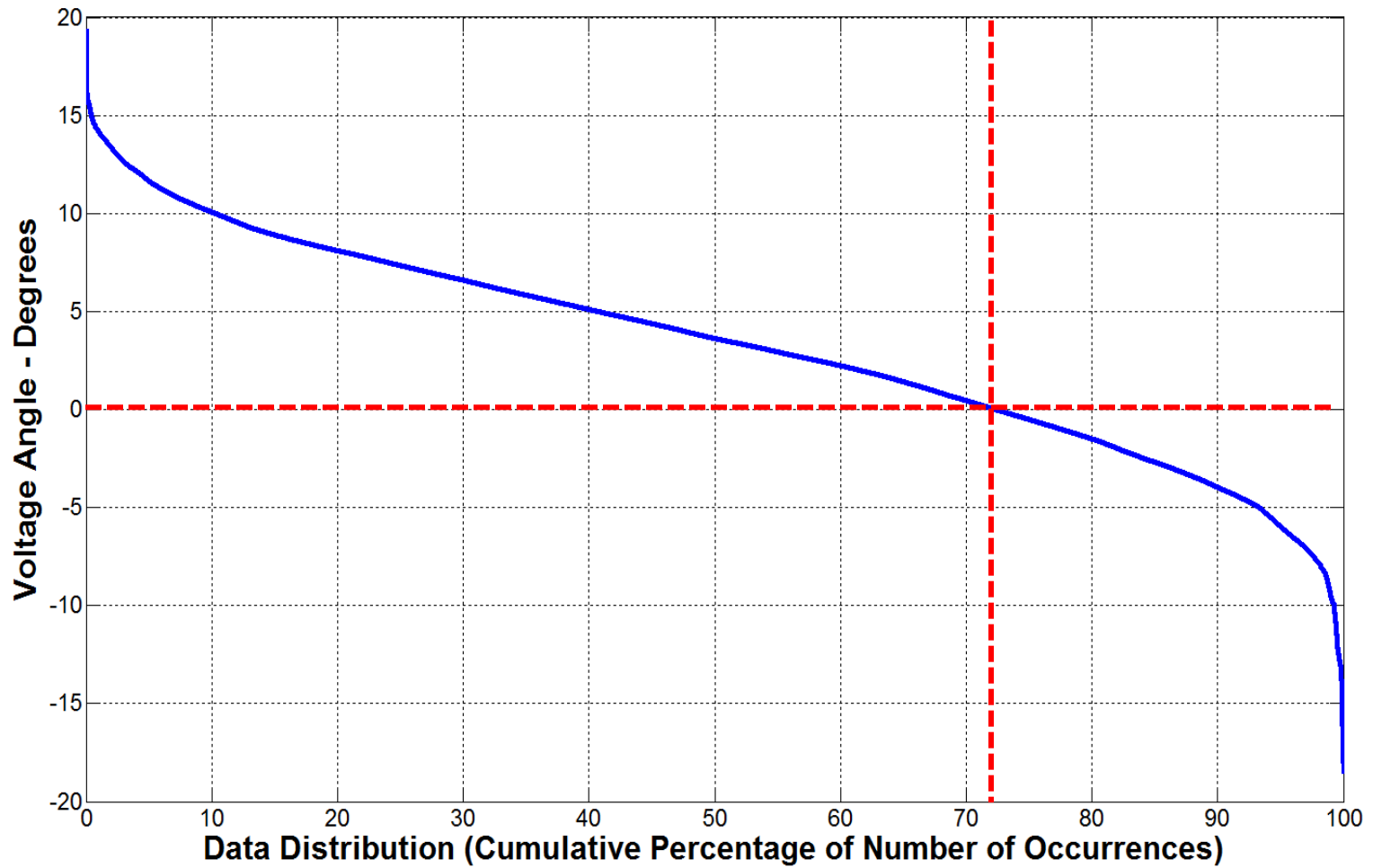


West 14

Daily Box-Whisker Chart:

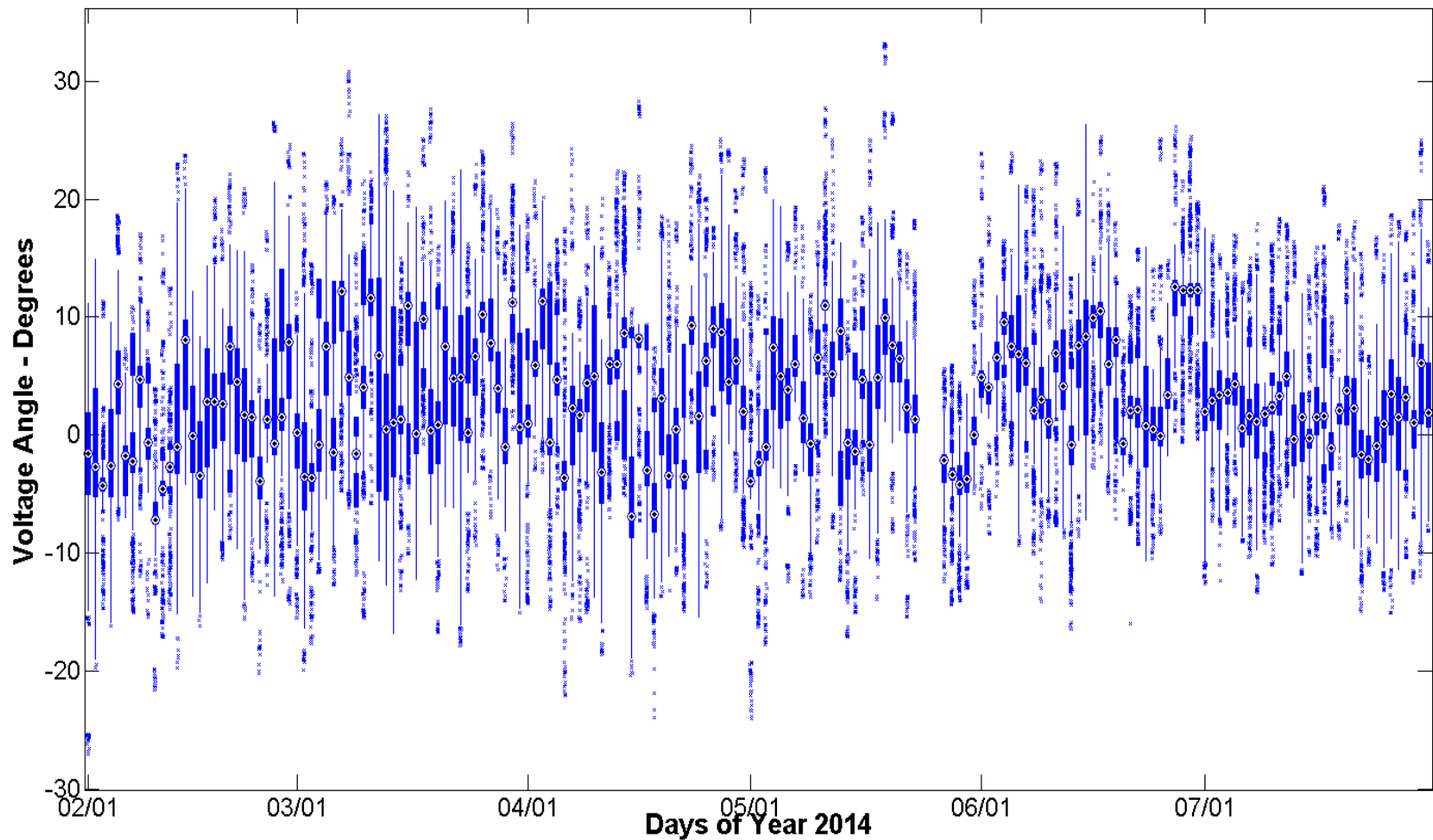


Time Duration Chart:



West 1*

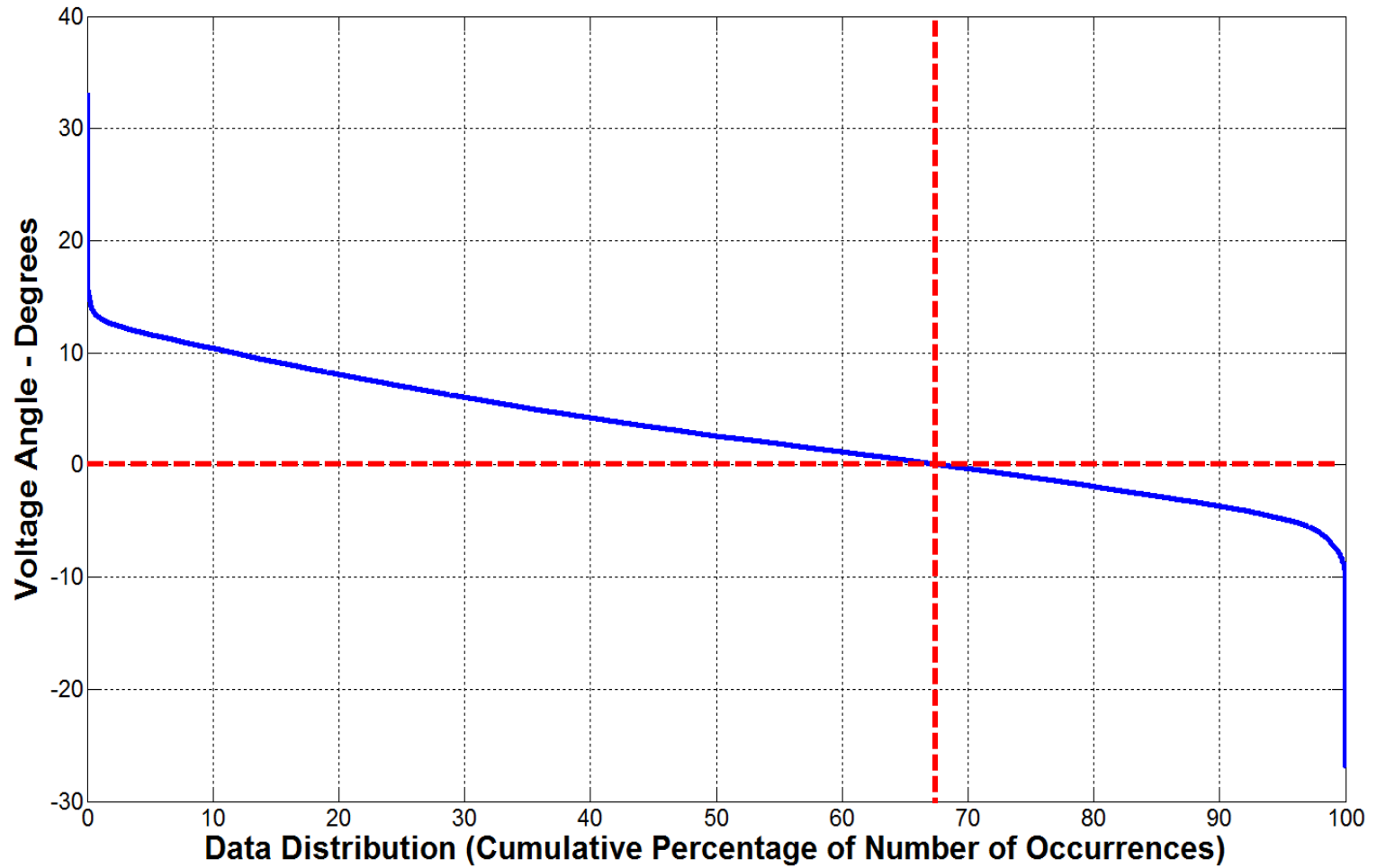
Daily Box-Whisker Chart:



* West 1 PMU has noisy signal

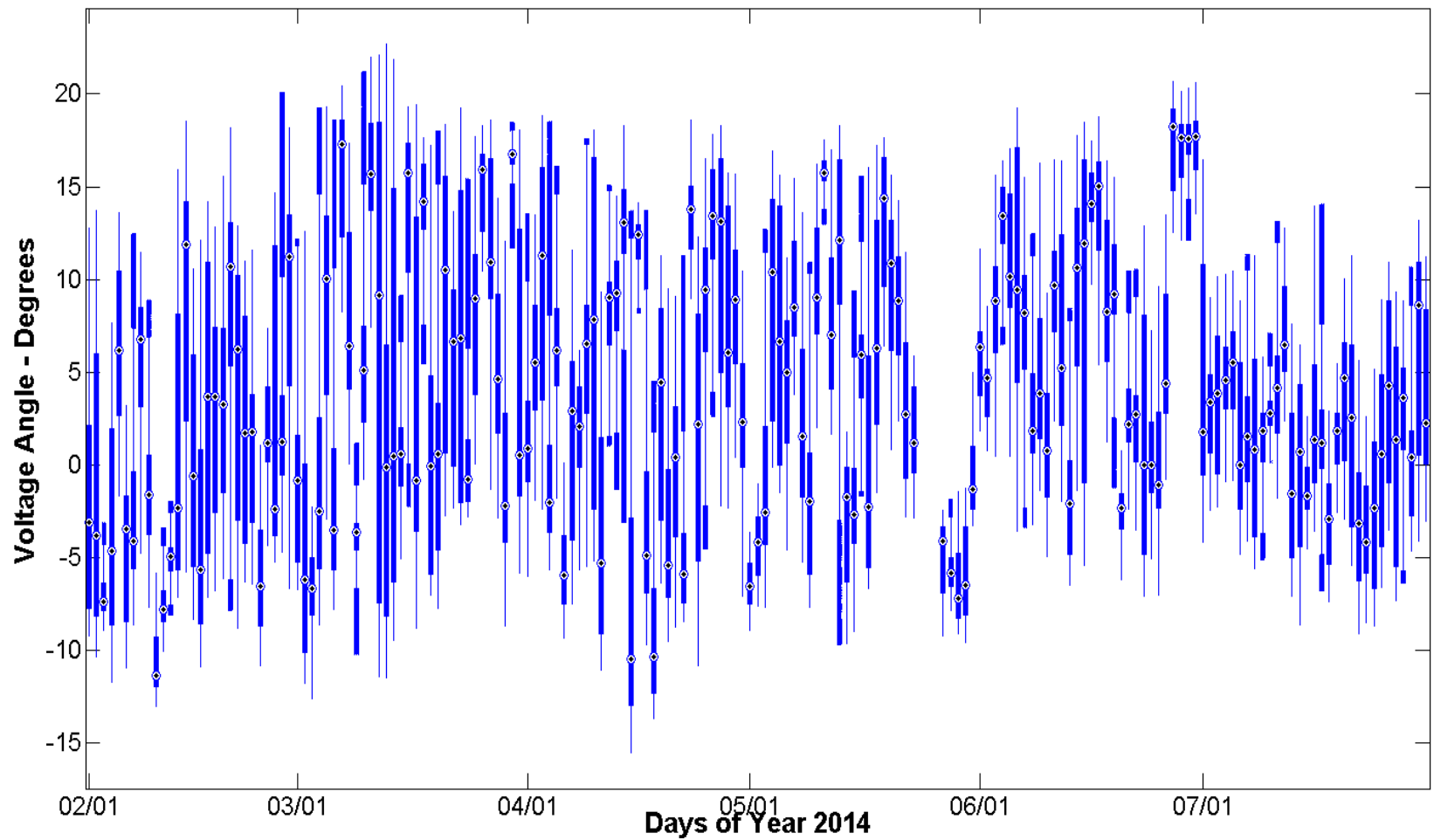
West 1

Time Duration Chart:



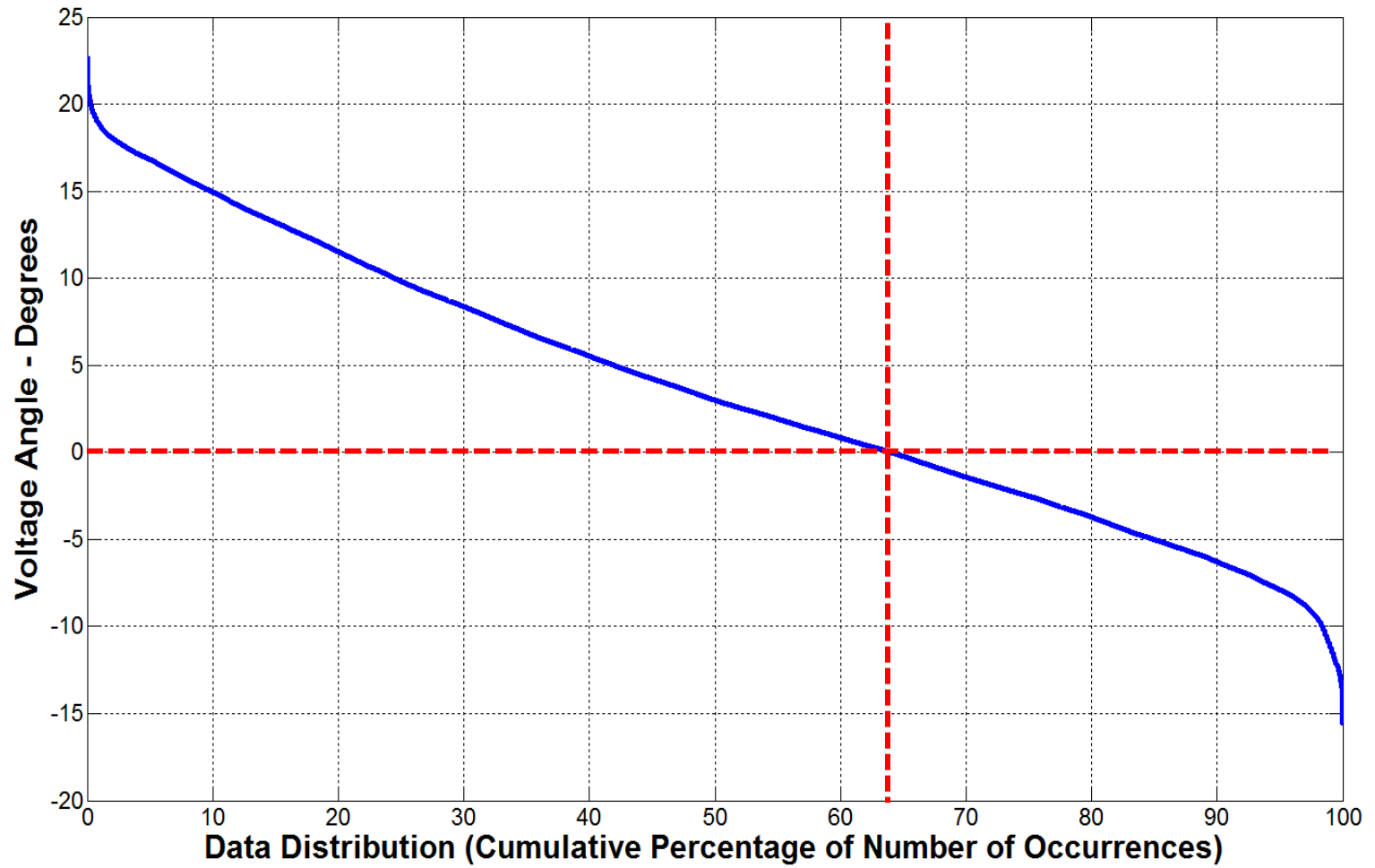
West 2

Daily Box-Whisker Chart:



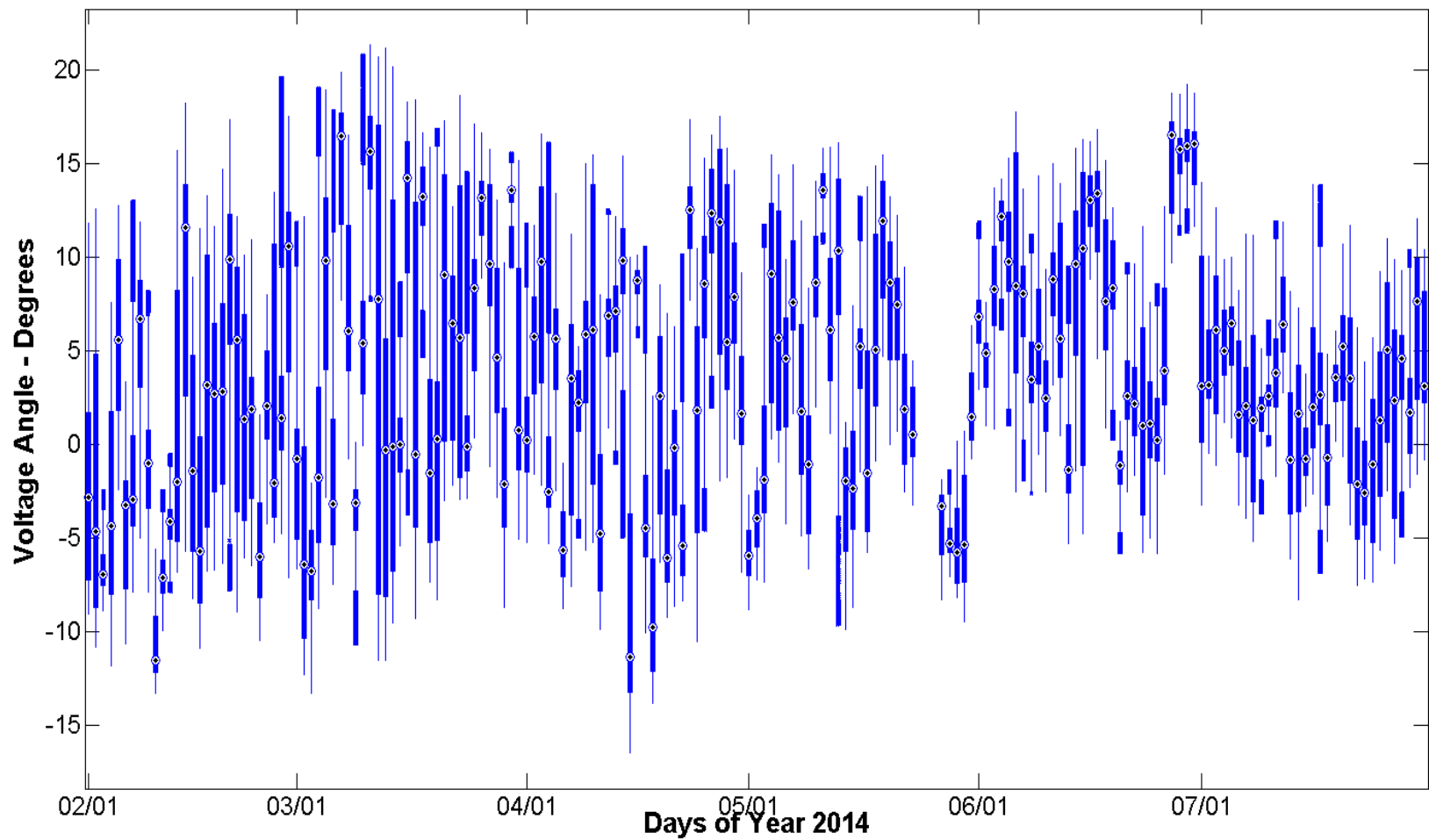
West 2

Time Duration Chart:

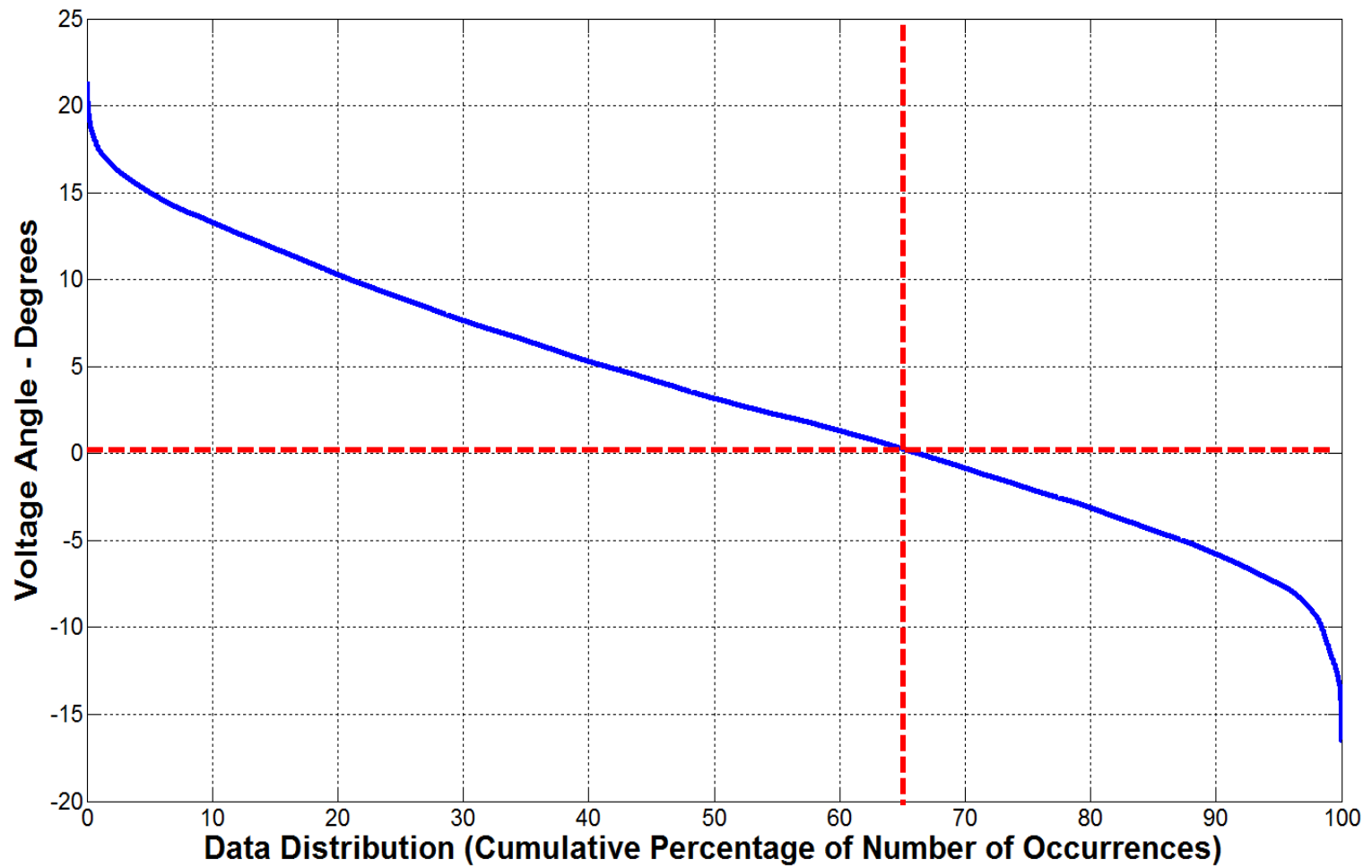


West 9

Daily Box-Whisker Chart:

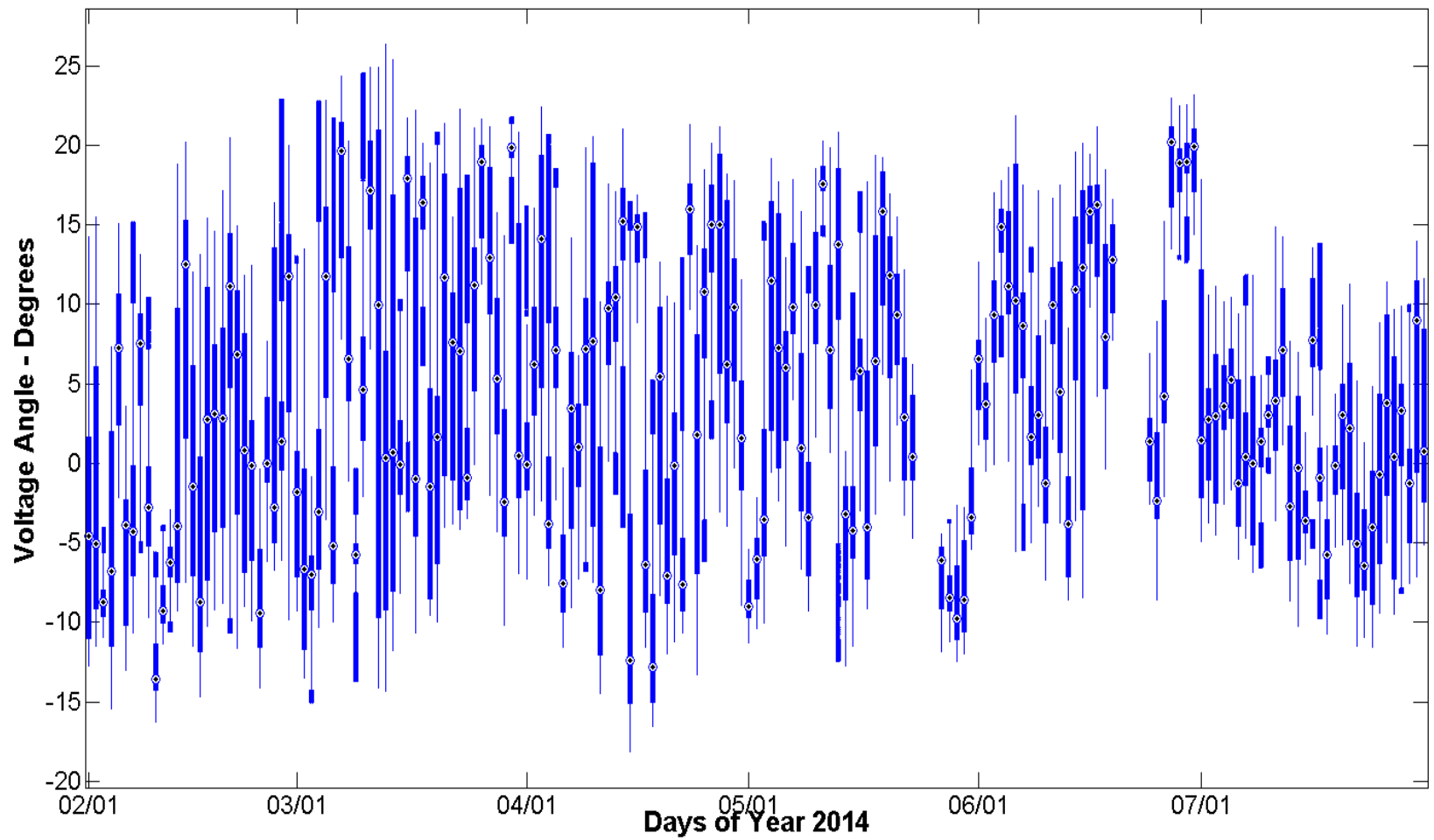


Time Duration Chart:

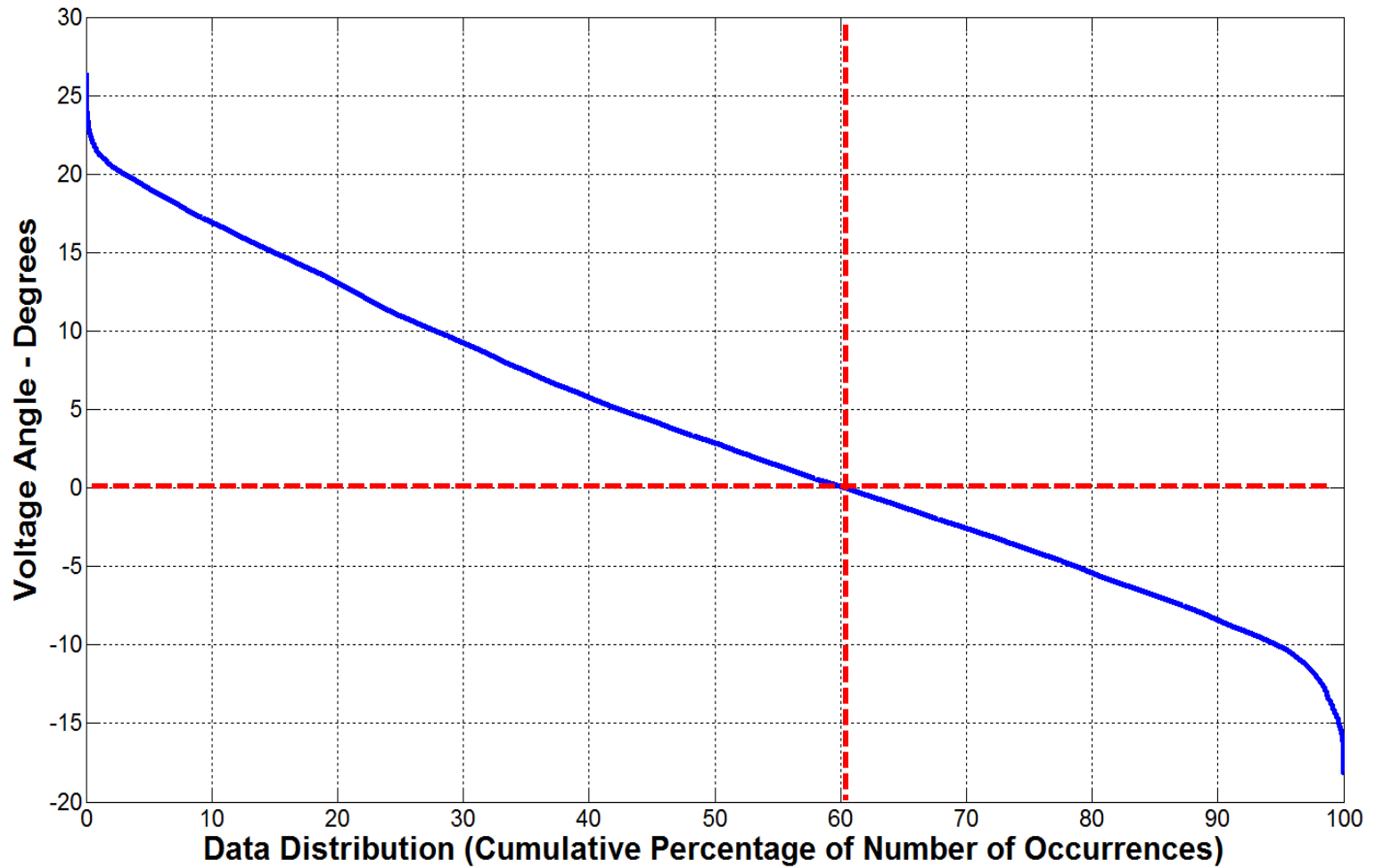


West 11

Daily Box-Whisker Chart:

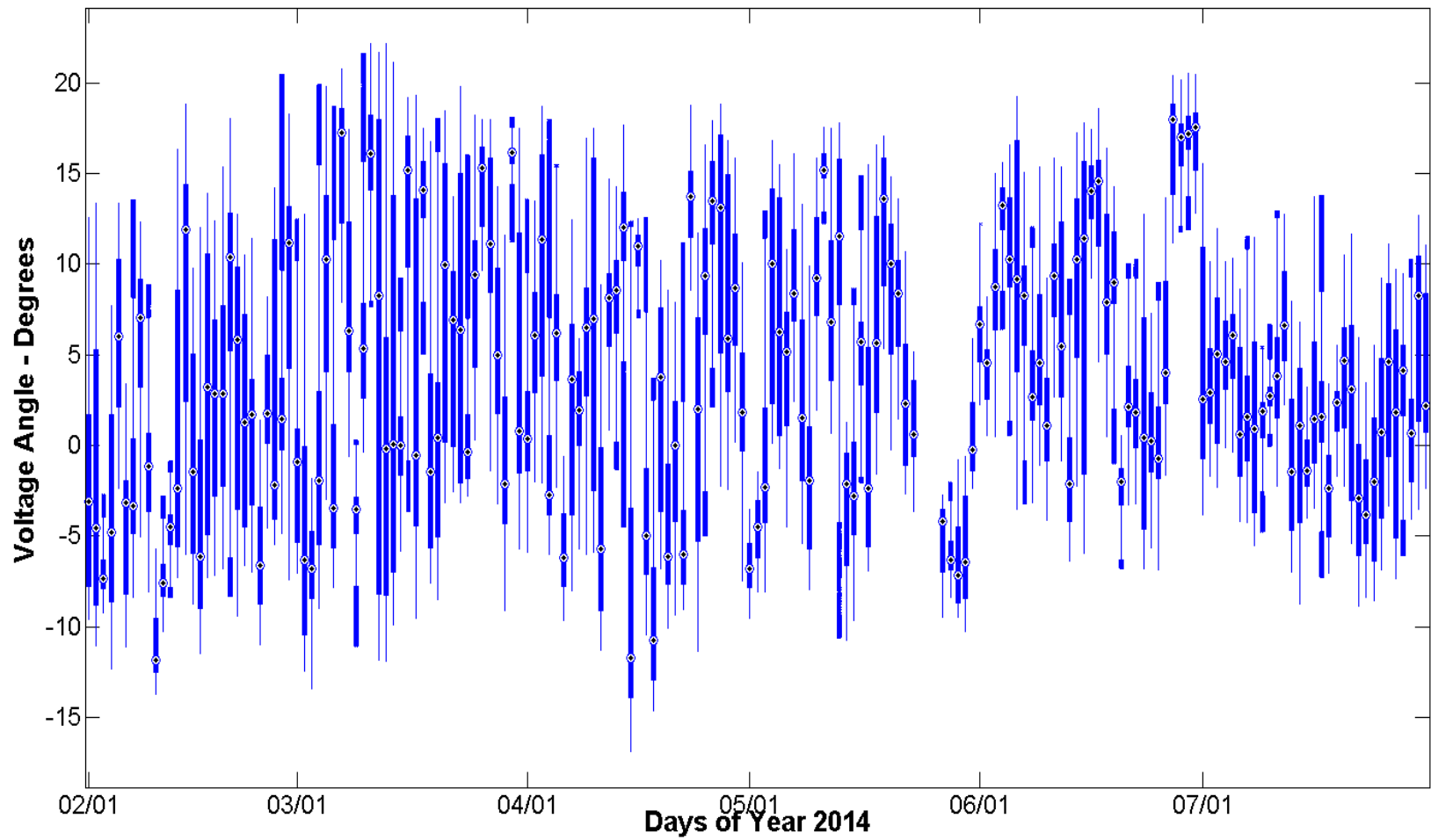


Time Duration Chart:

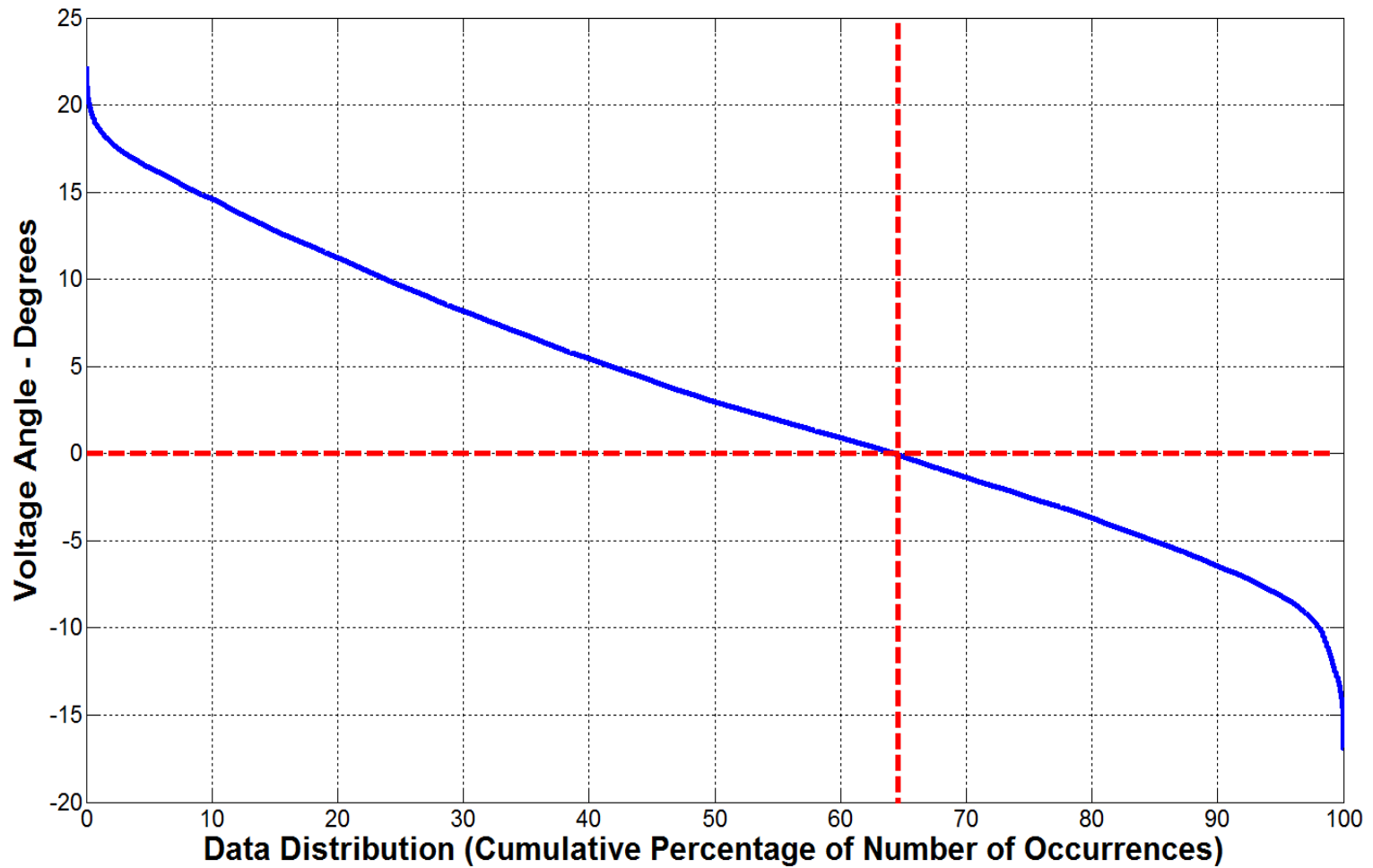


West 12

Daily Box-Whisker Chart:

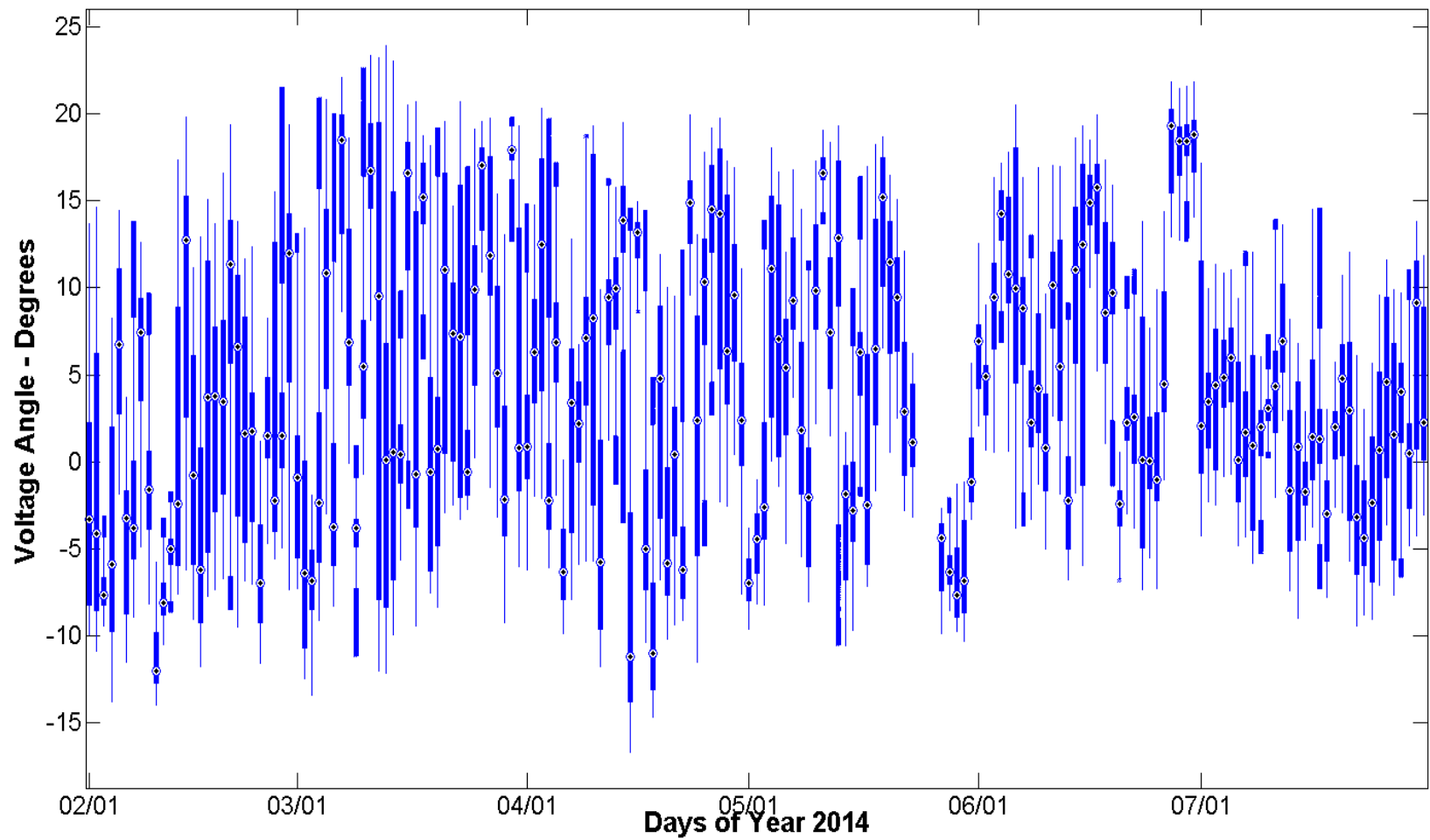


Time Duration Chart:



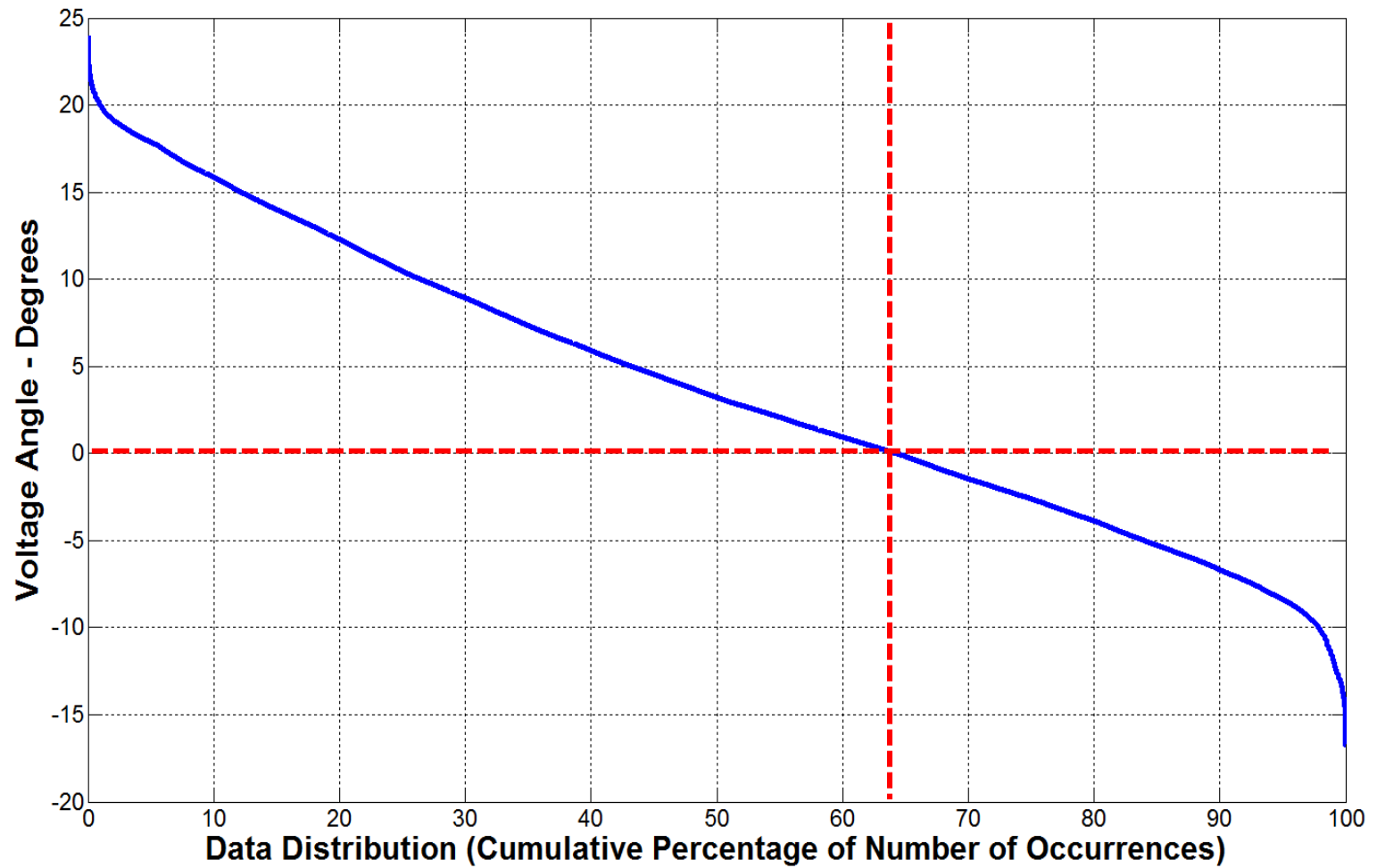
West 5

Daily Box-Whisker Chart:



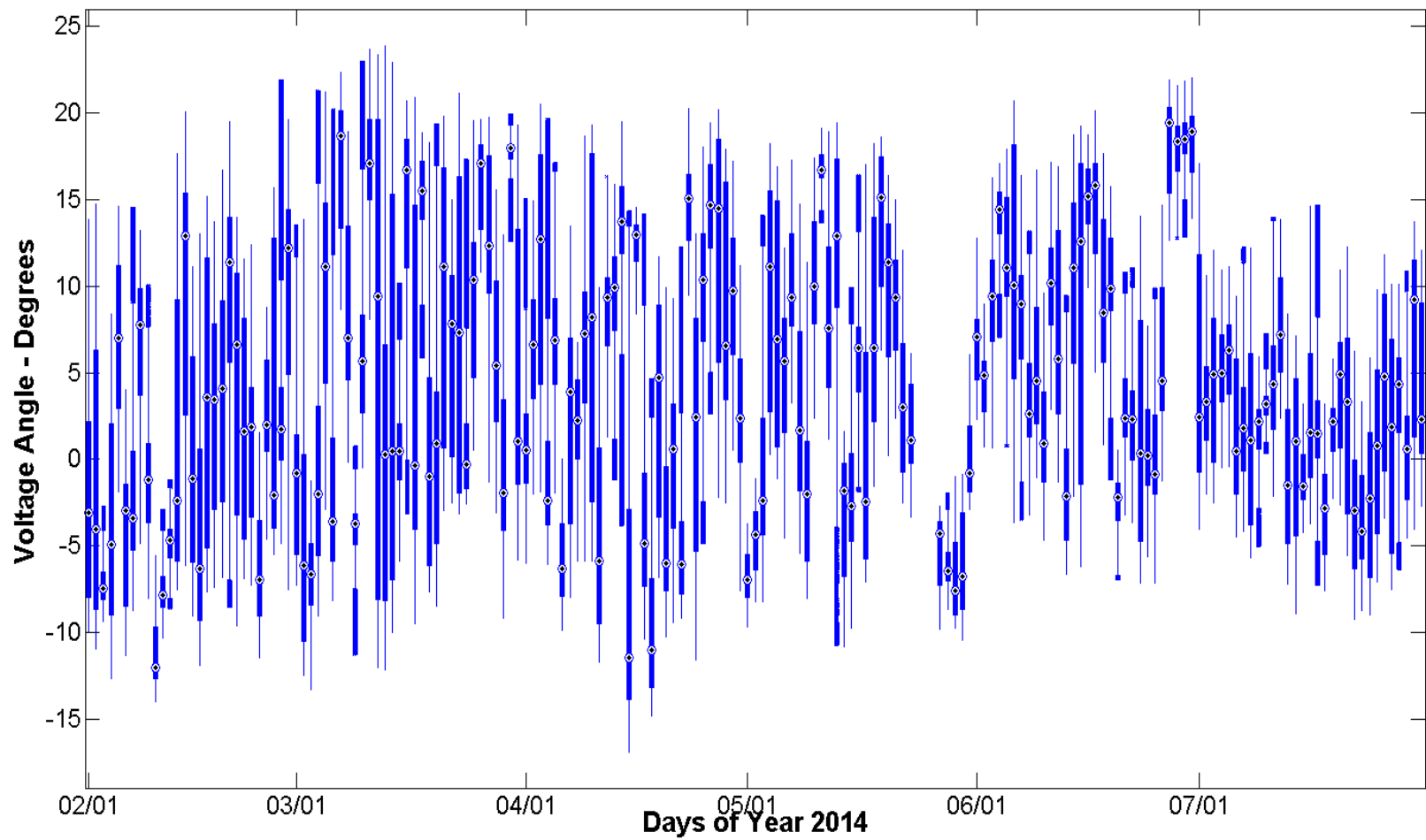
West 5

Time Duration Chart:



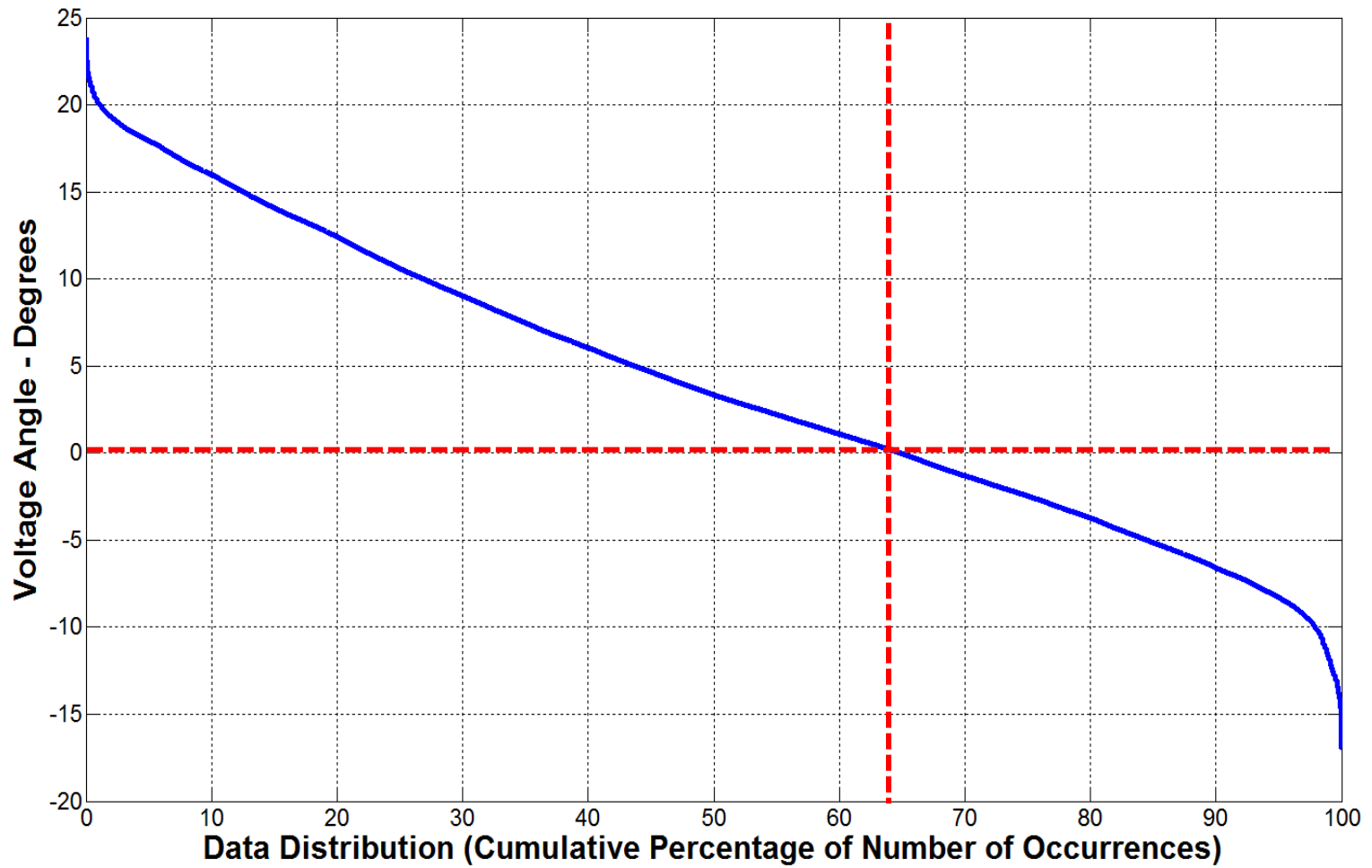
West 6

Daily Box-Whisker Chart:



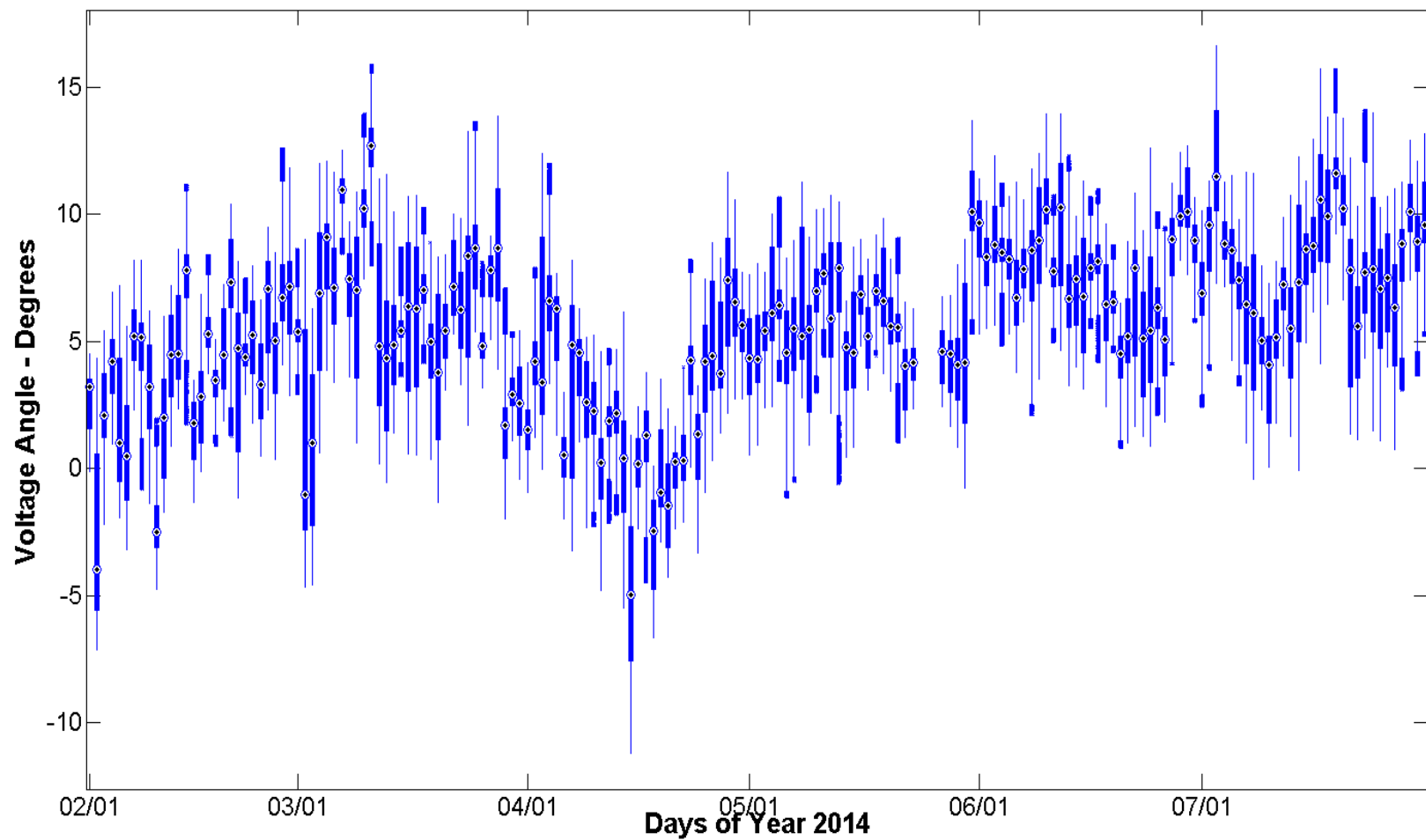
West 6

Time Duration Chart:

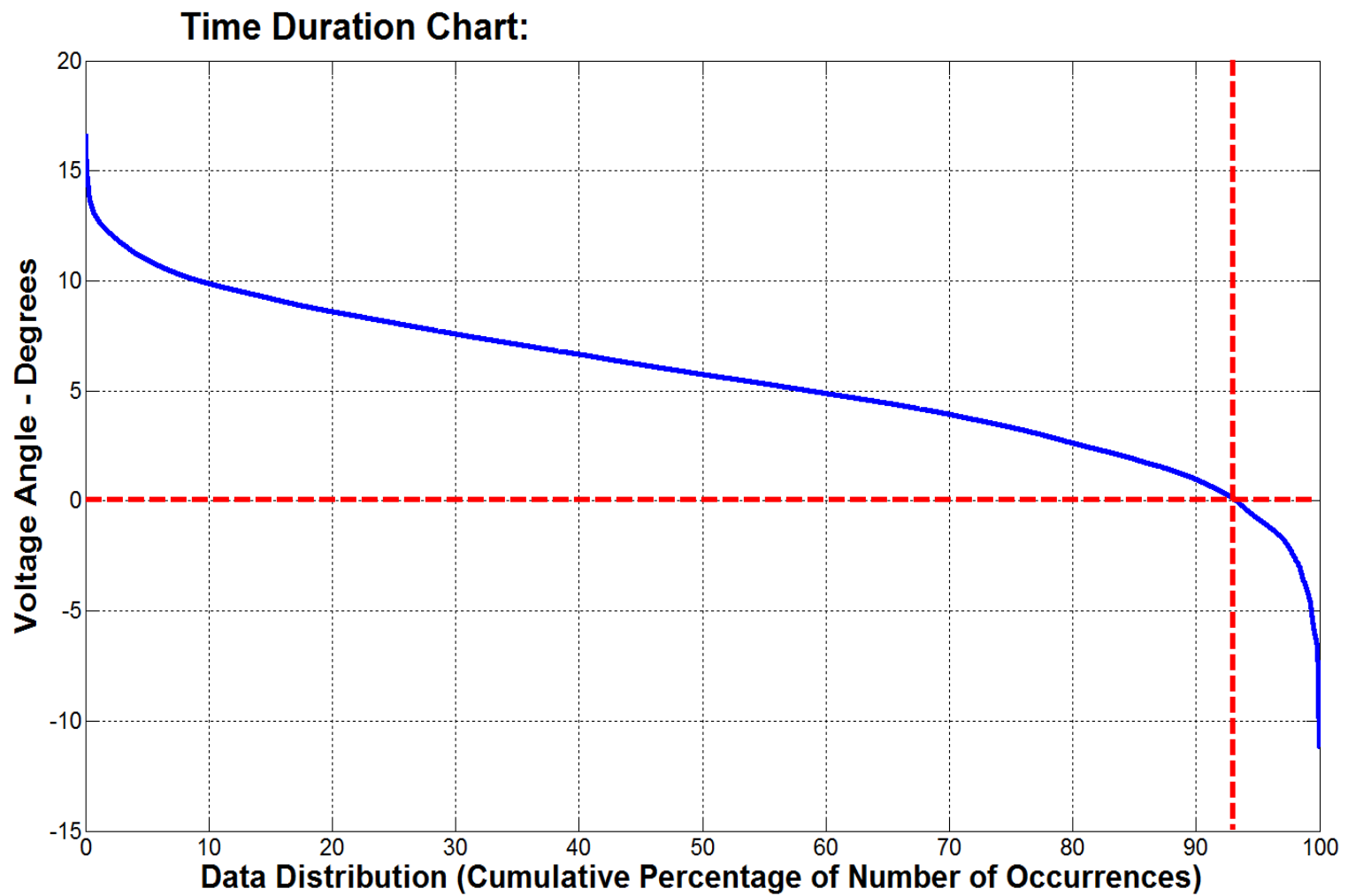


North 1

Daily Box-Whisker Chart:

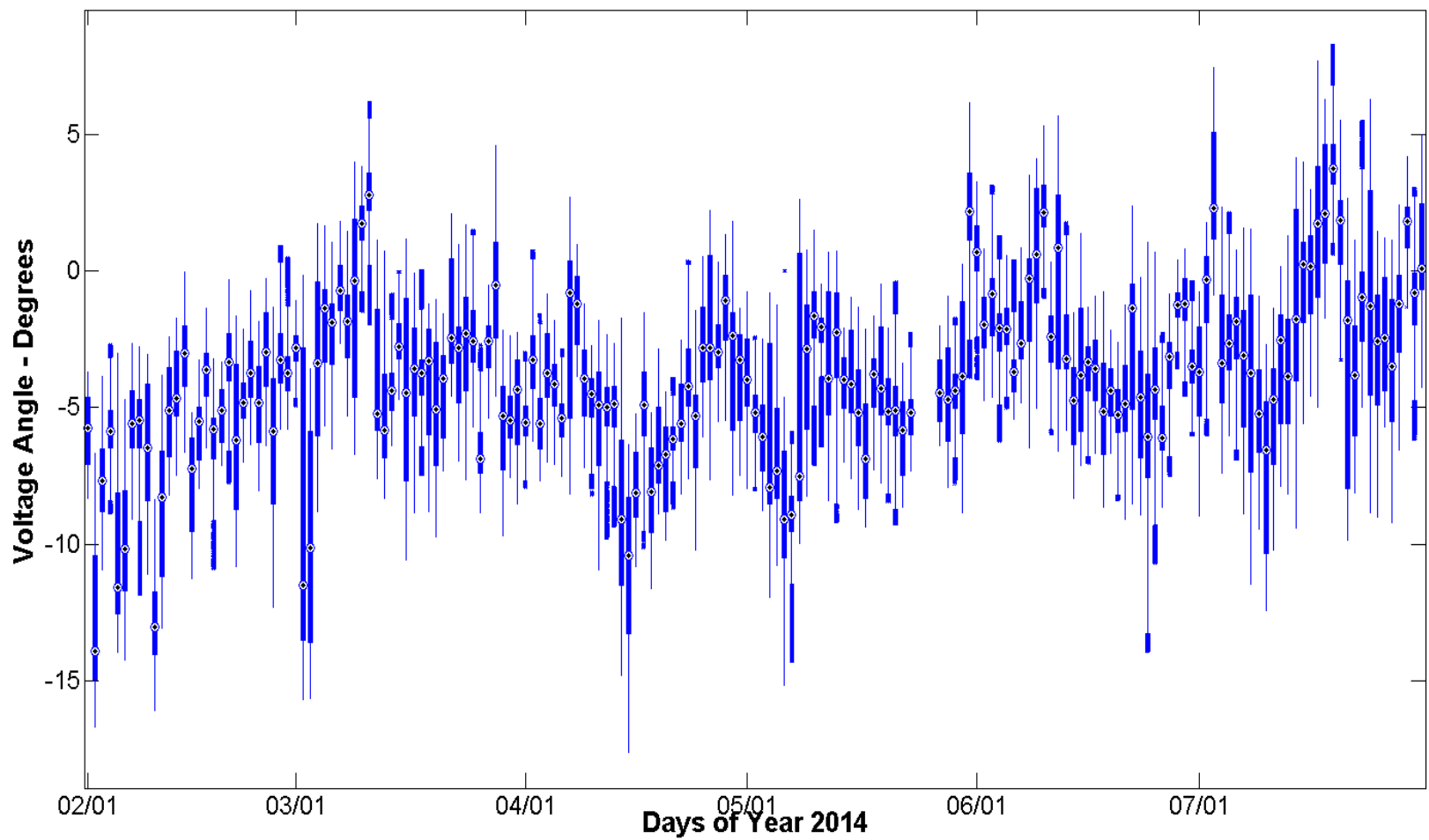


North 1



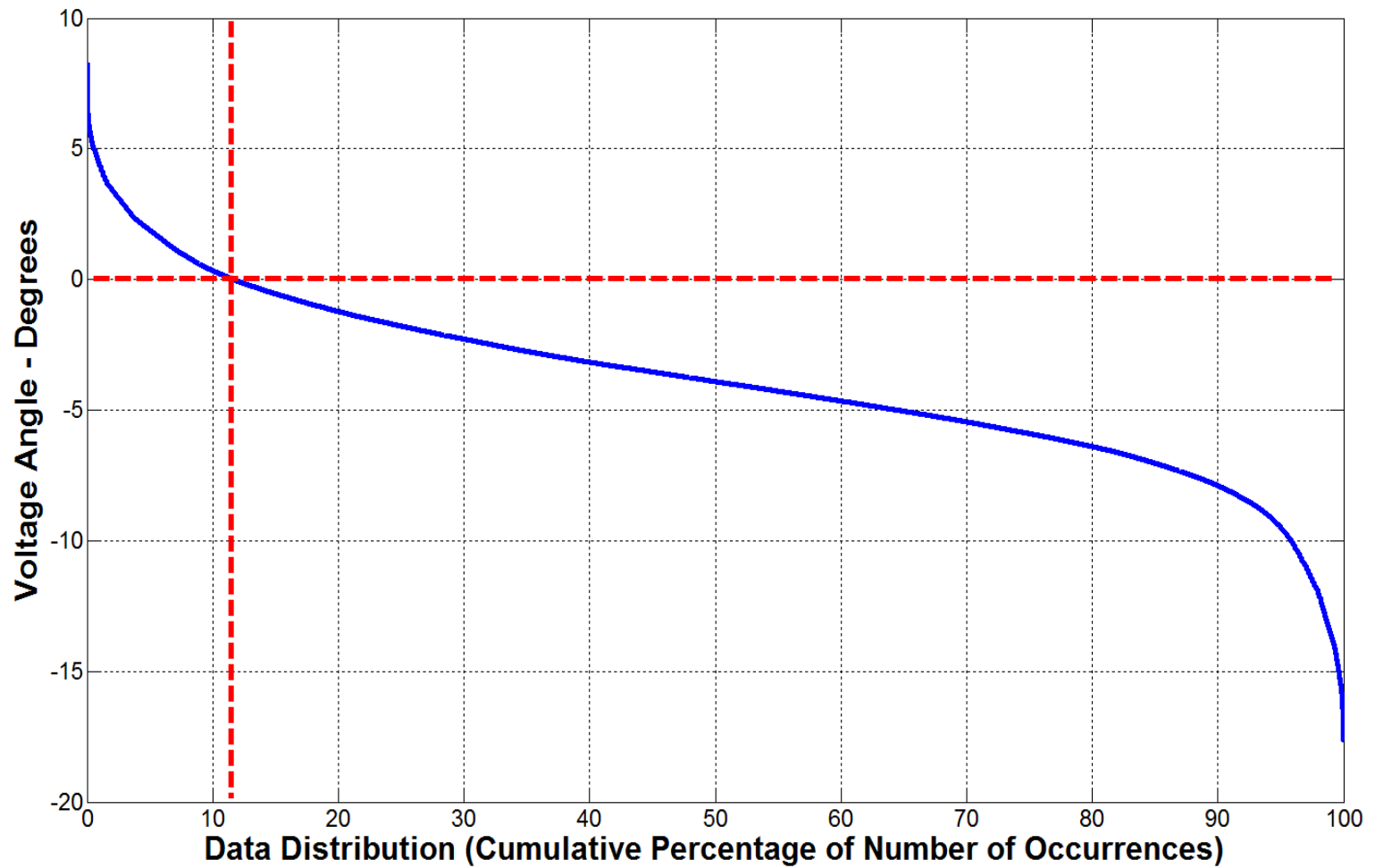
North 4

Daily Box-Whisker Chart:



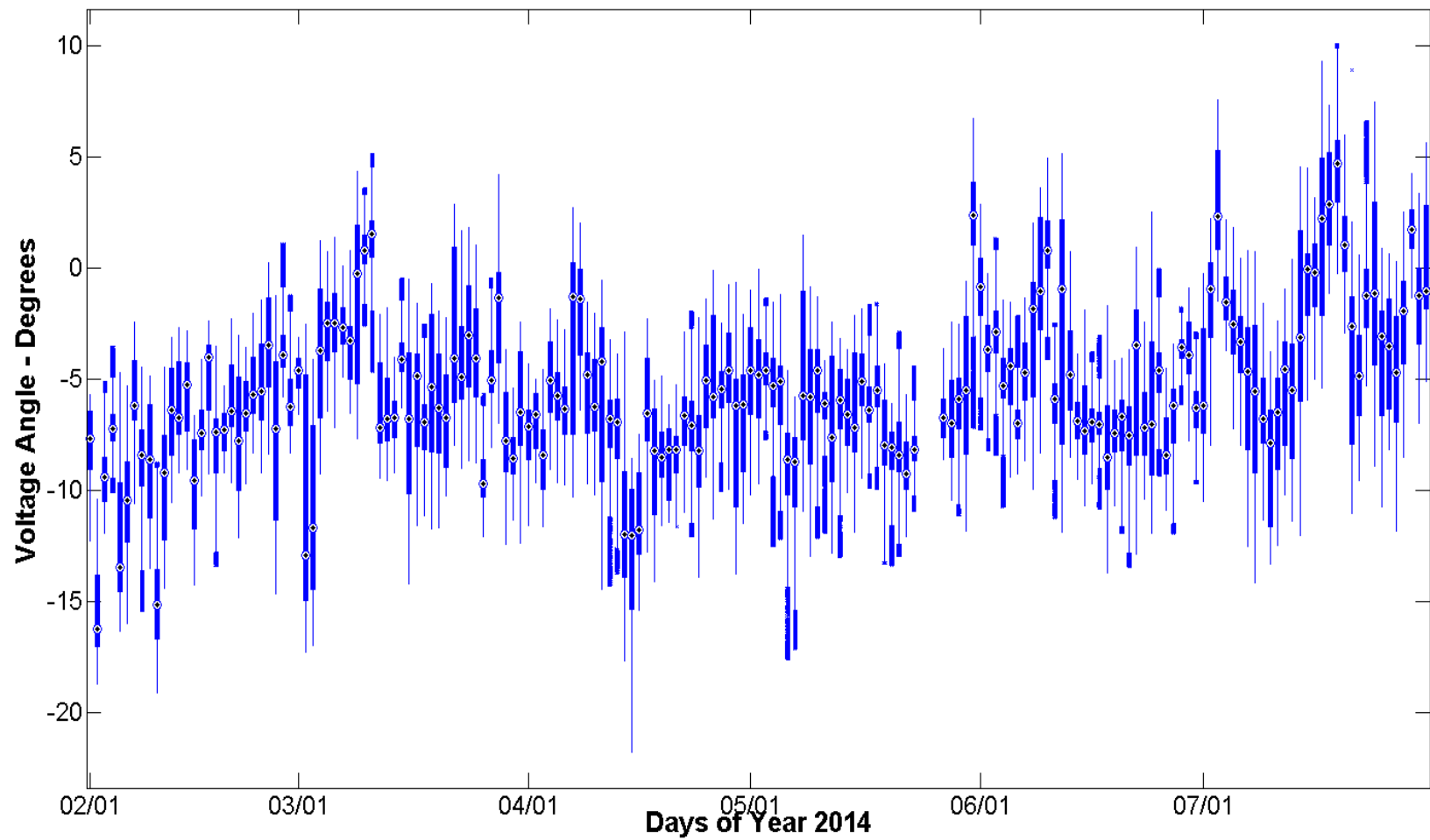
North 4

Time Duration Chart: I

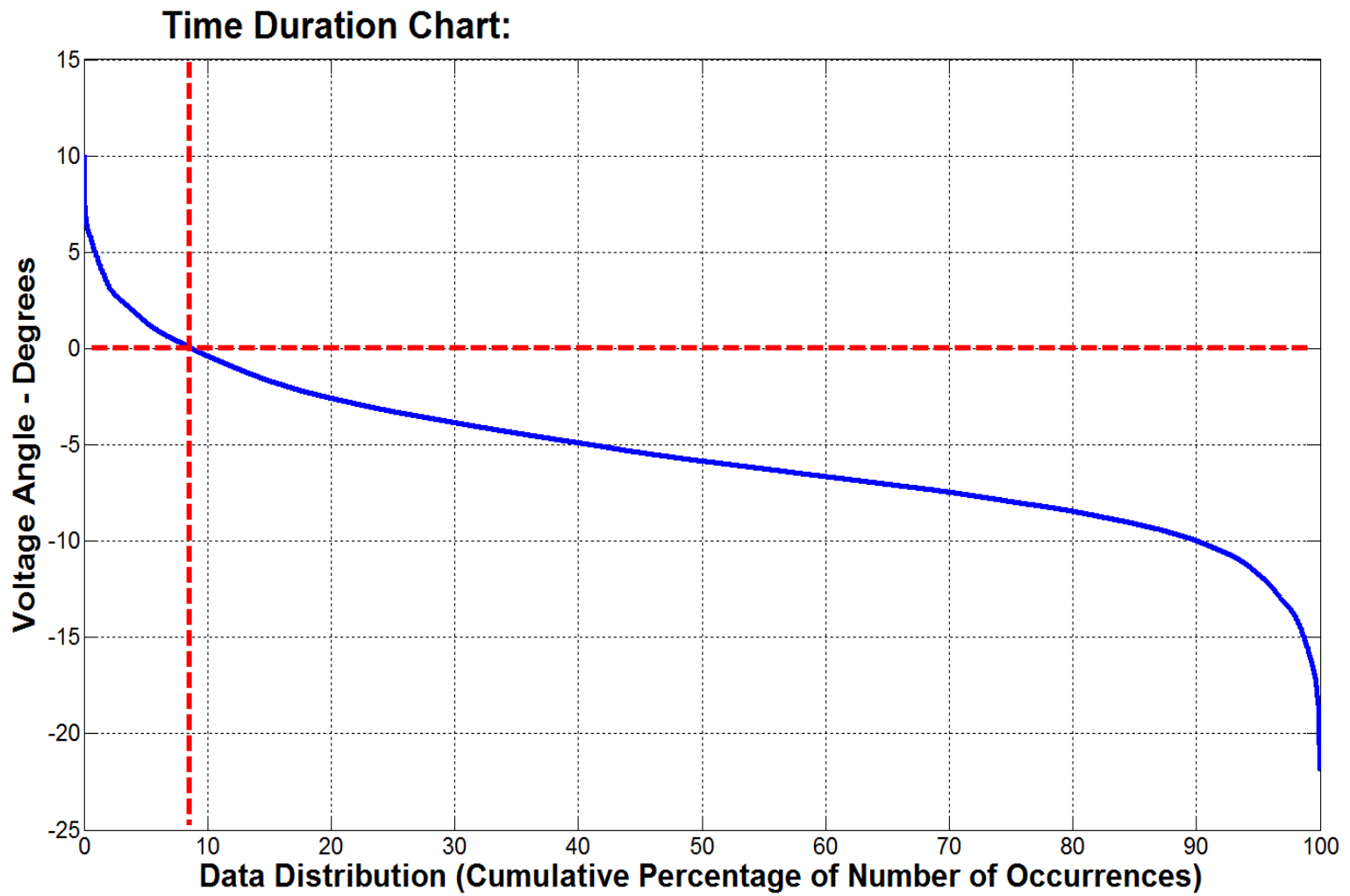


North 5

Daily Box-Whisker Chart:

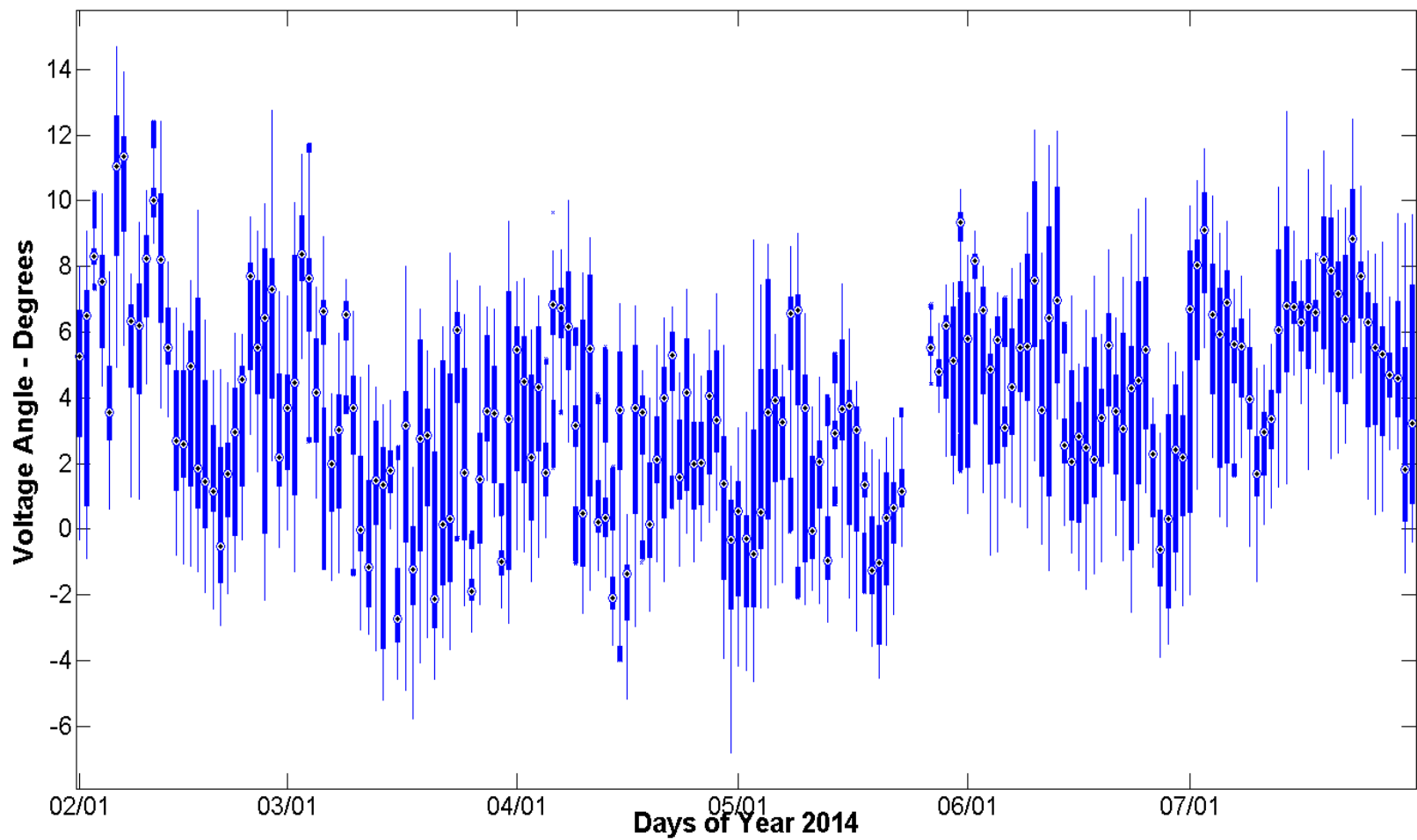


North 5



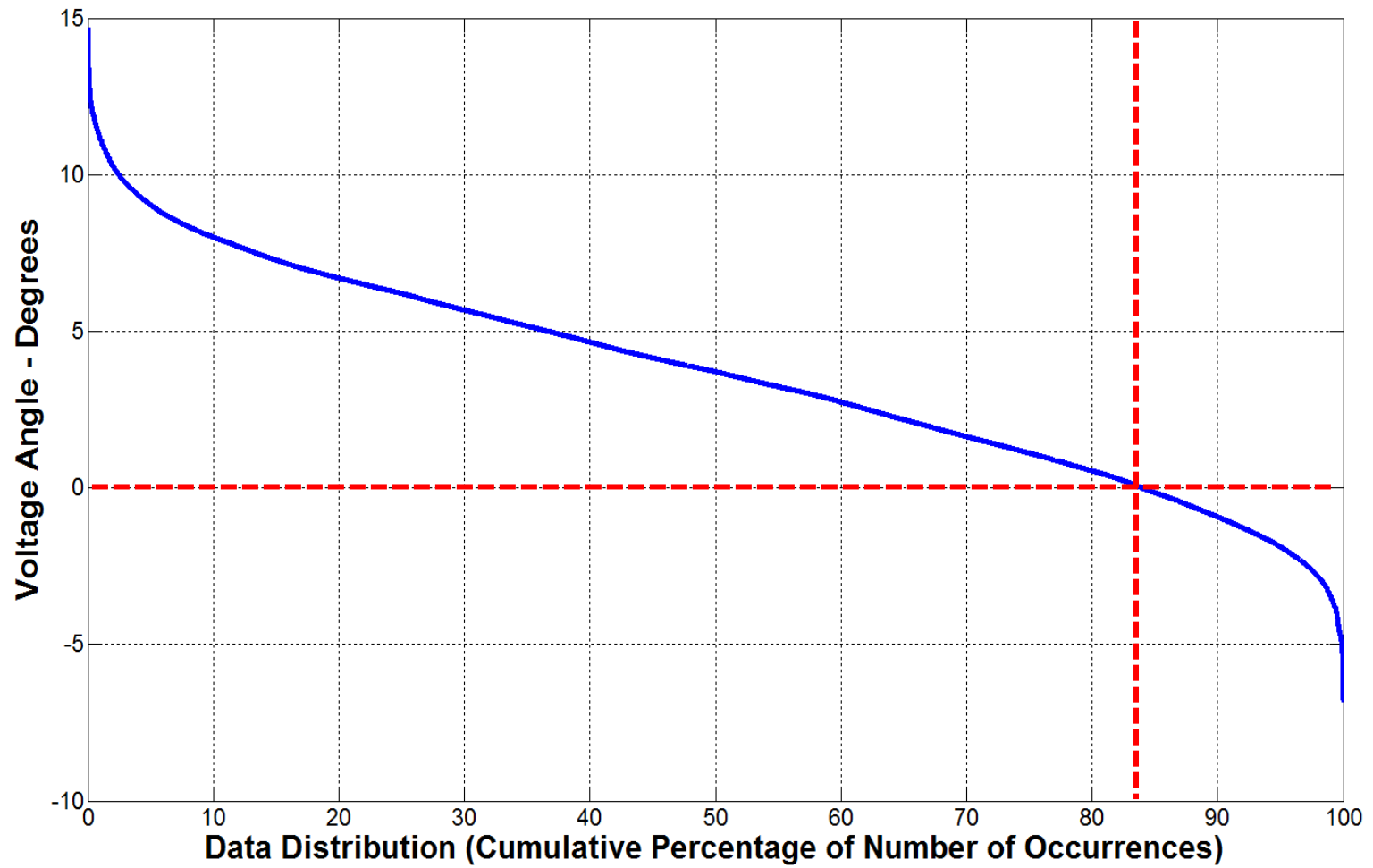
North 6

Daily Box-Whisker Chart:



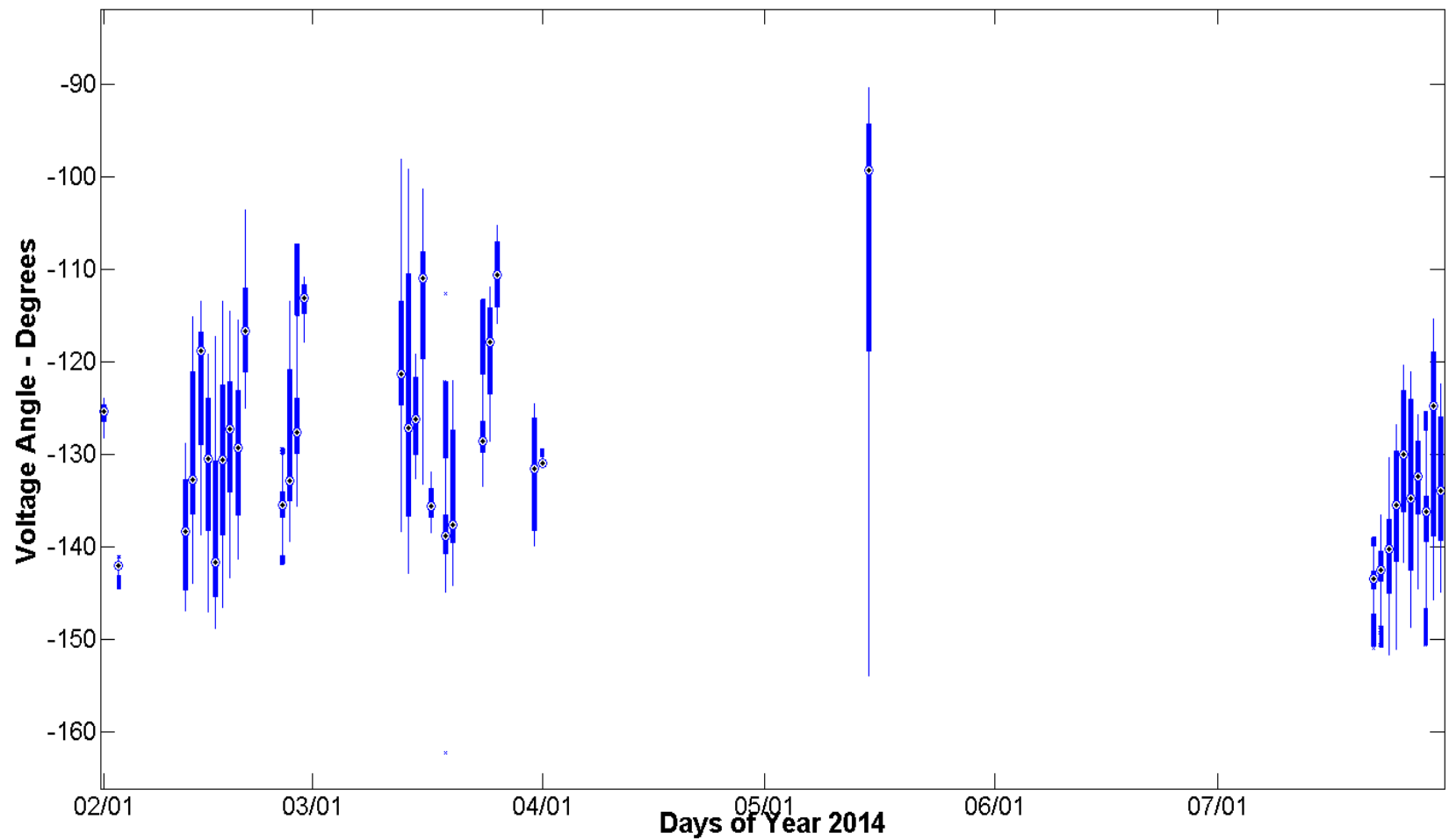
North 6

Time Duration Chart:



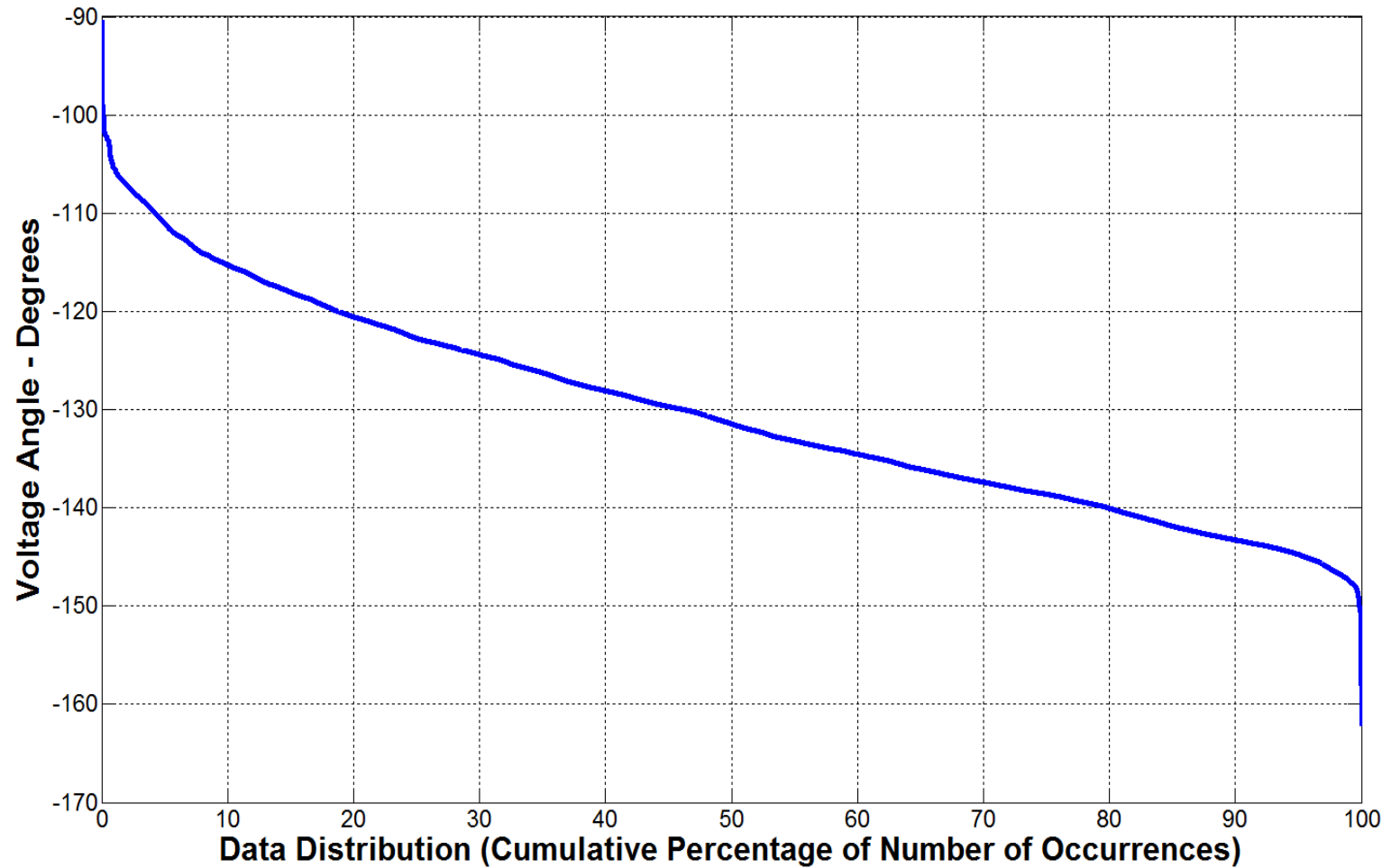
FarWest 2

Daily Box-Whisker Chart:



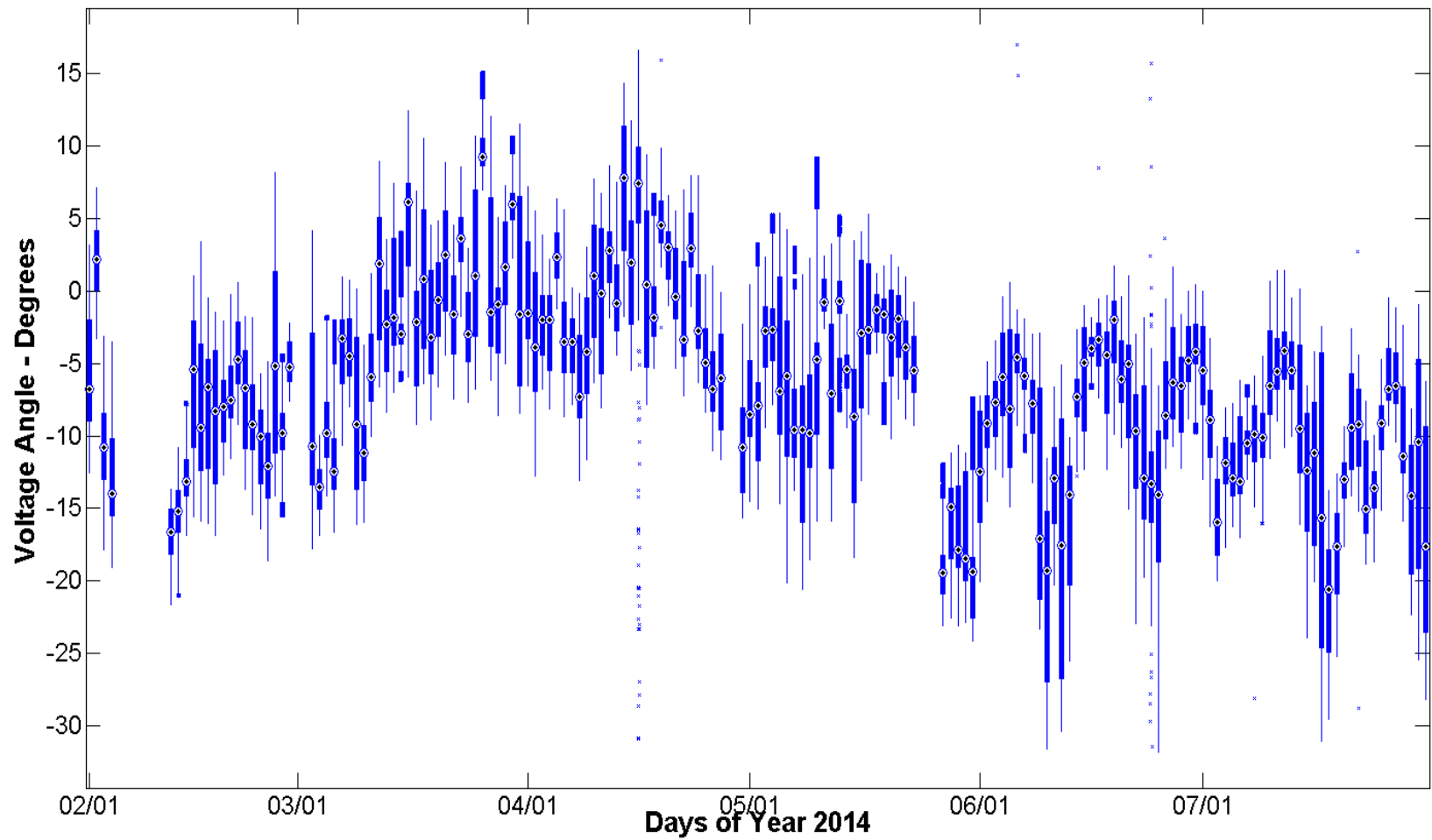
FarWest 2

Time Duration Chart:



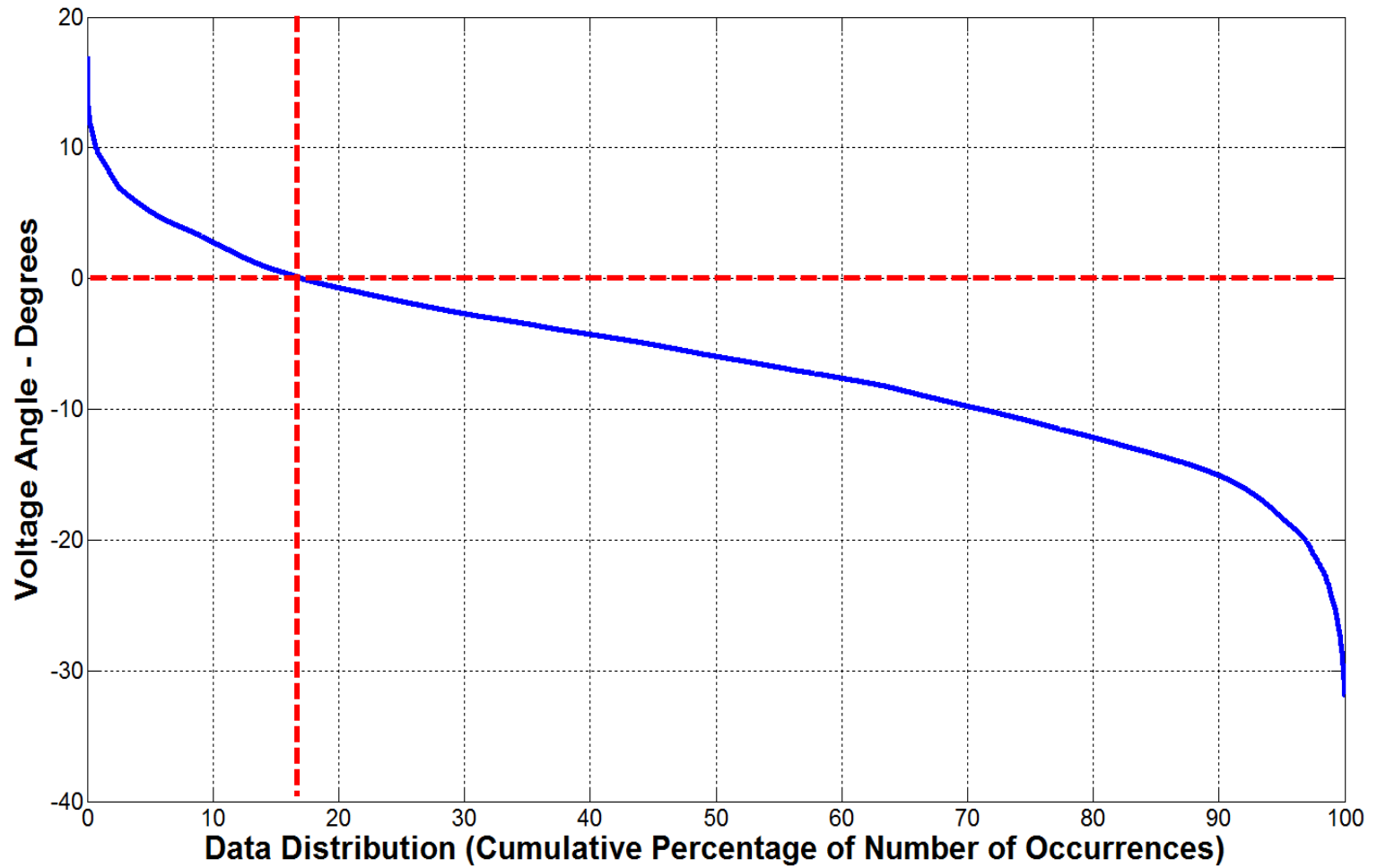
West 4

Daily Box-Whisker Chart:



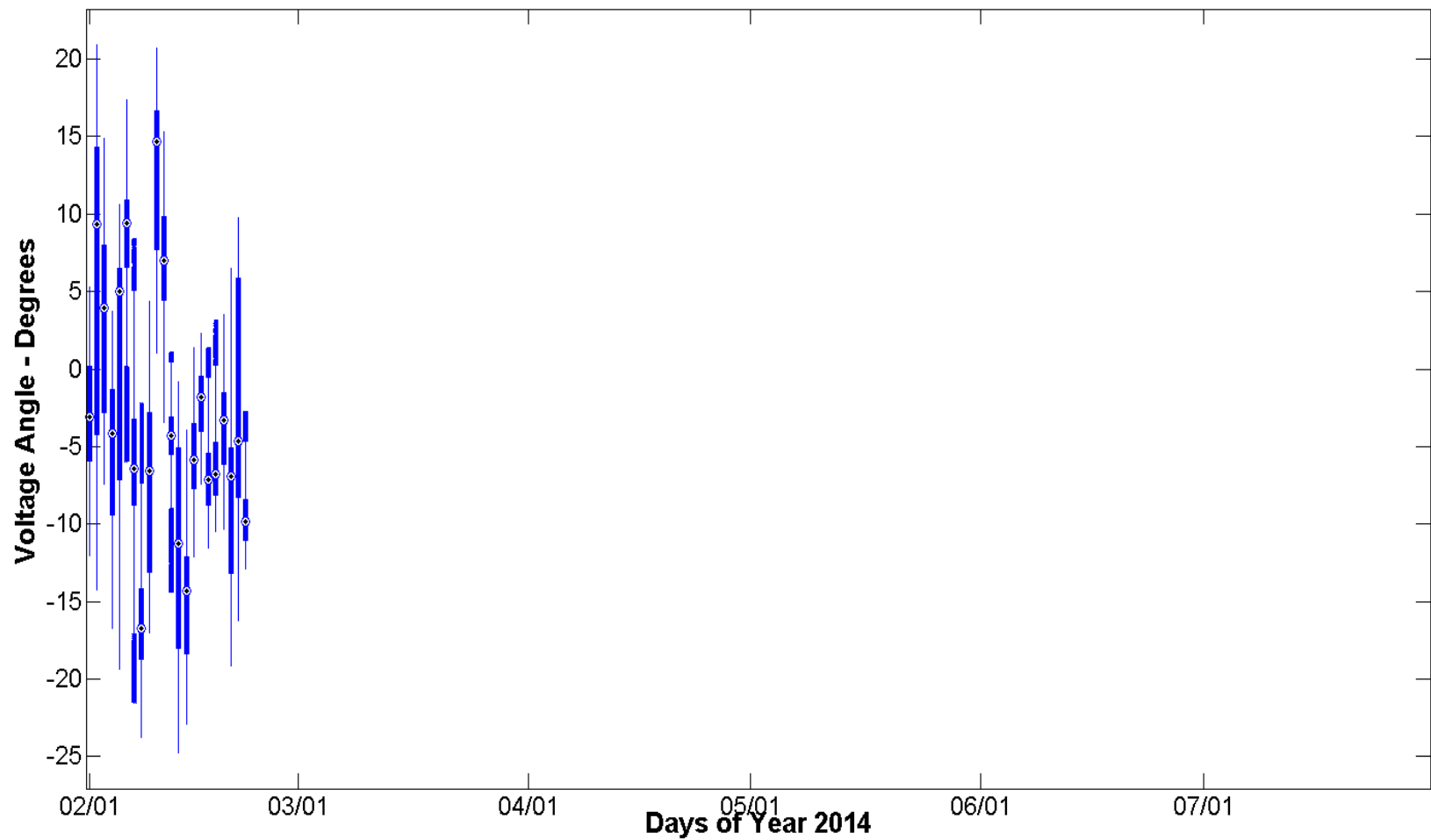
West 4

Time Duration Chart:



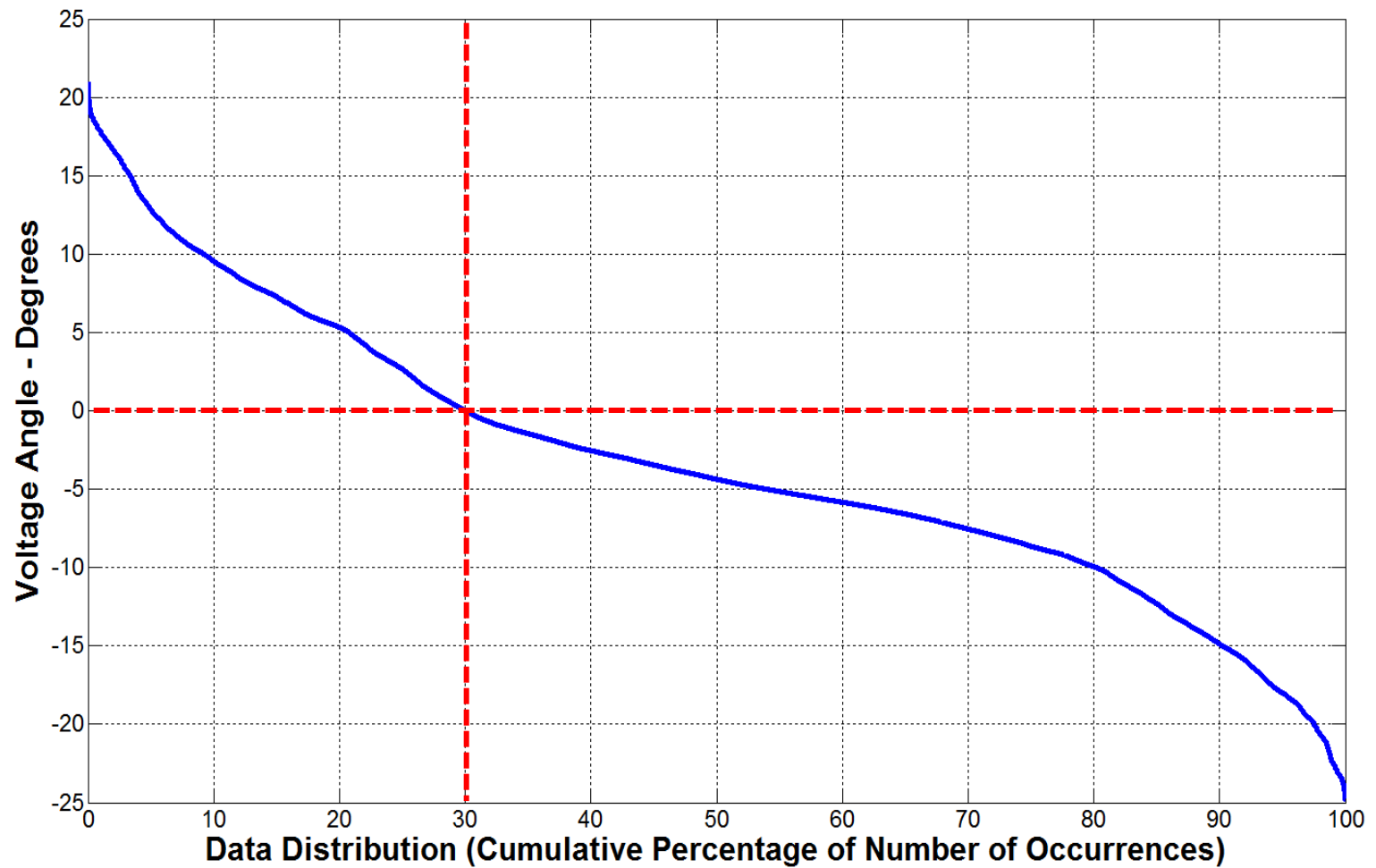
Coast 2

Daily Box-Whisker Chart:



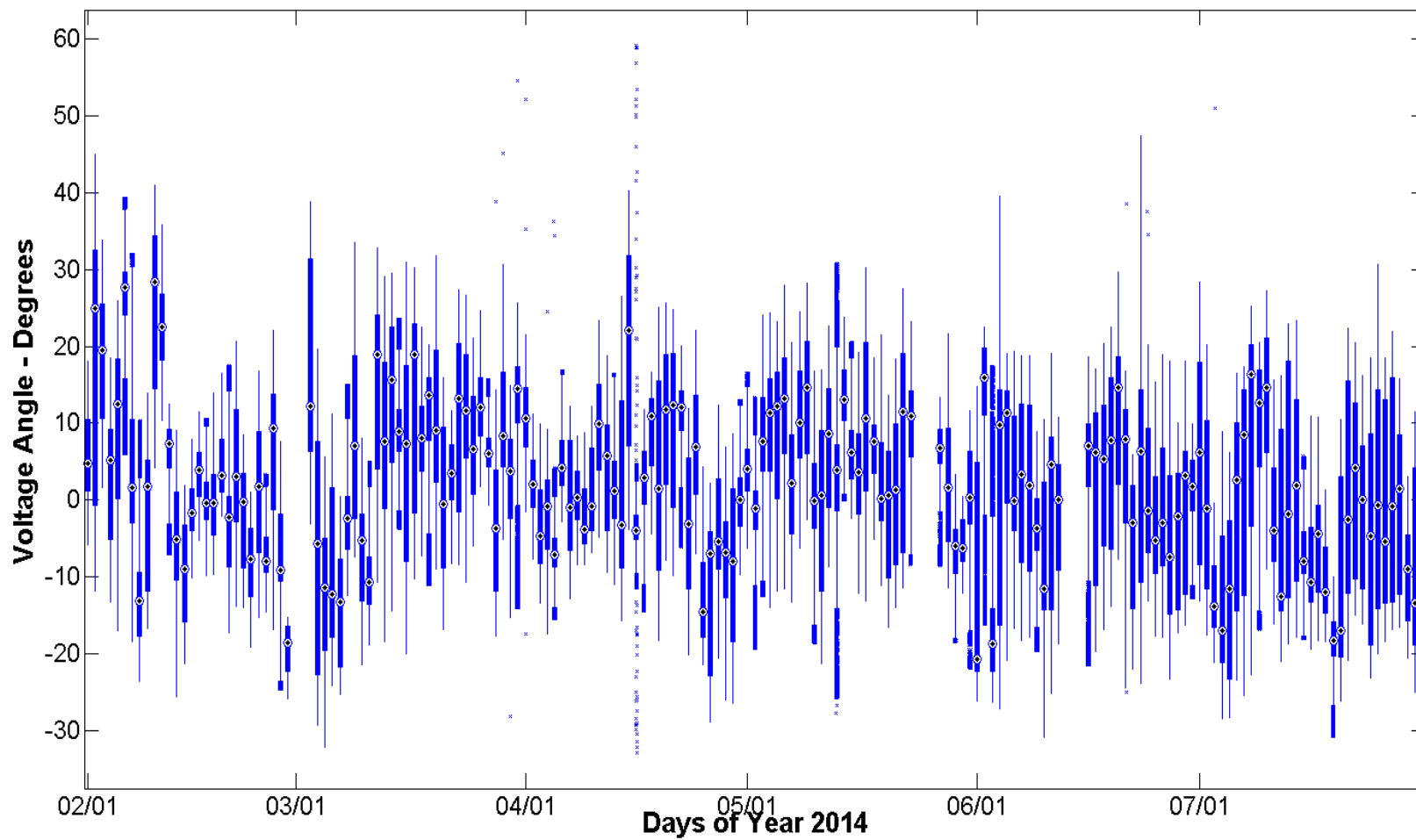
Coast 2

Time Duration Chart:



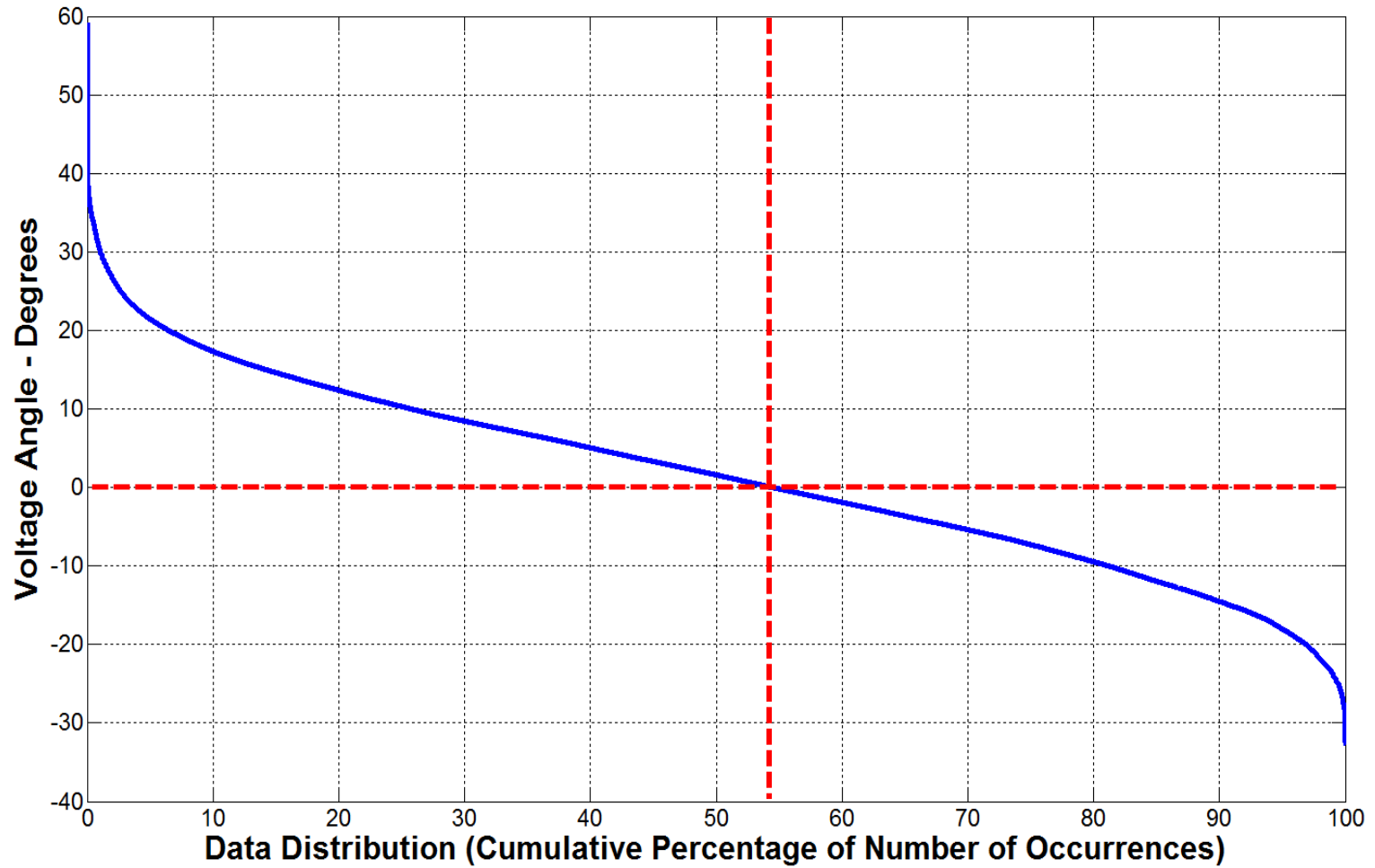
Coast 1

Daily Box-Whisker Chart:



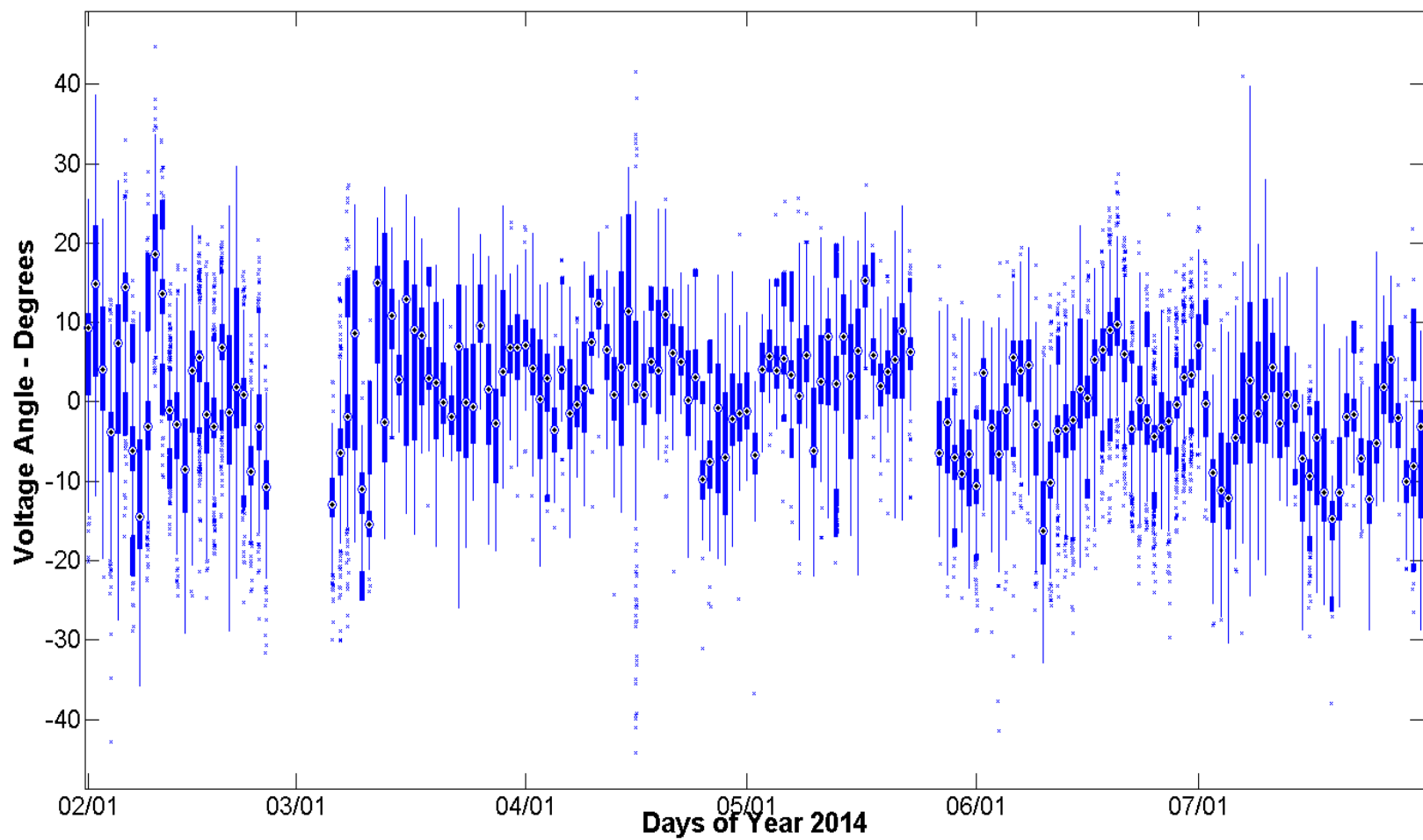
Coast 1

Time Duration Chart:



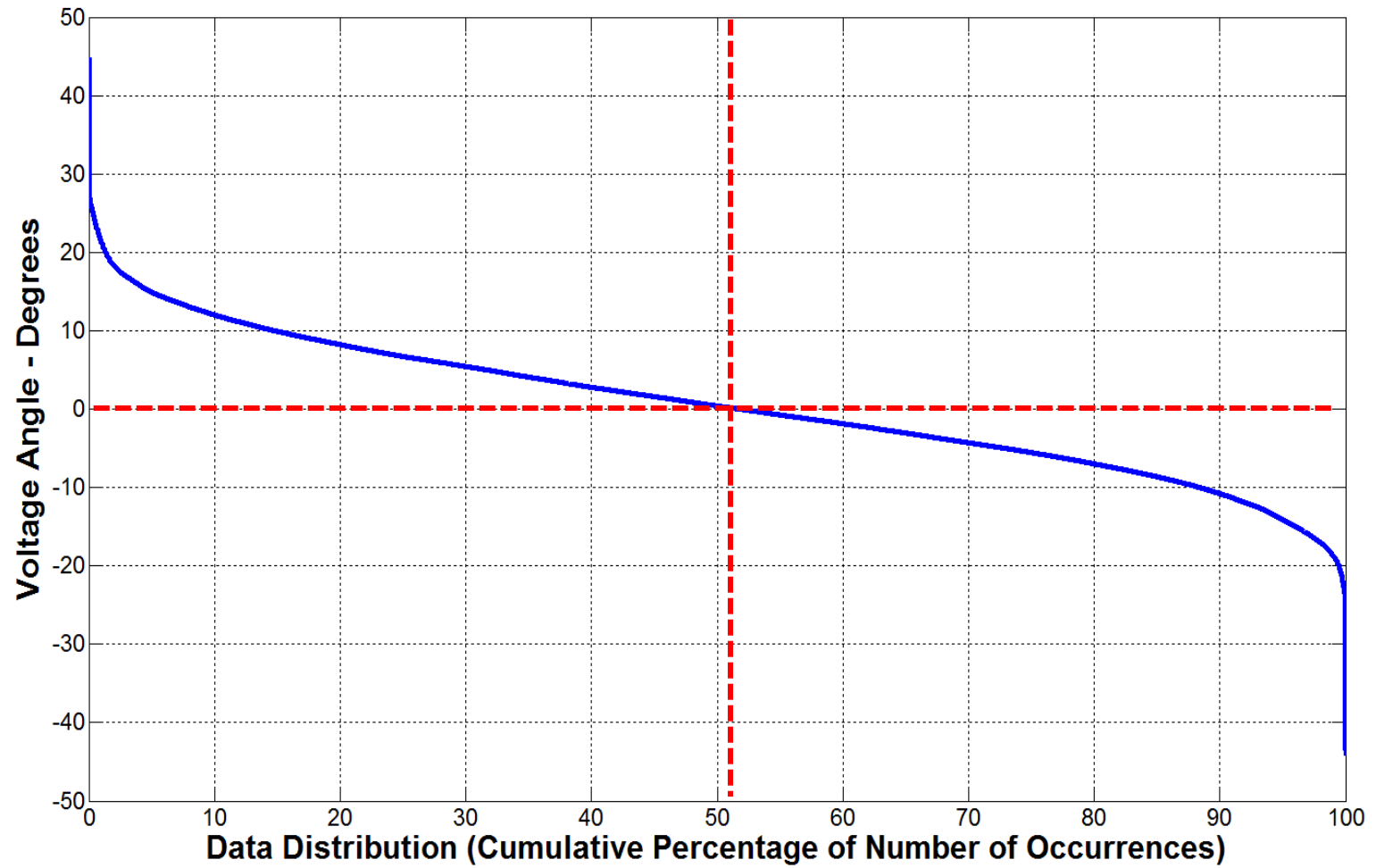
South 3

Daily Box-Whisker Chart:



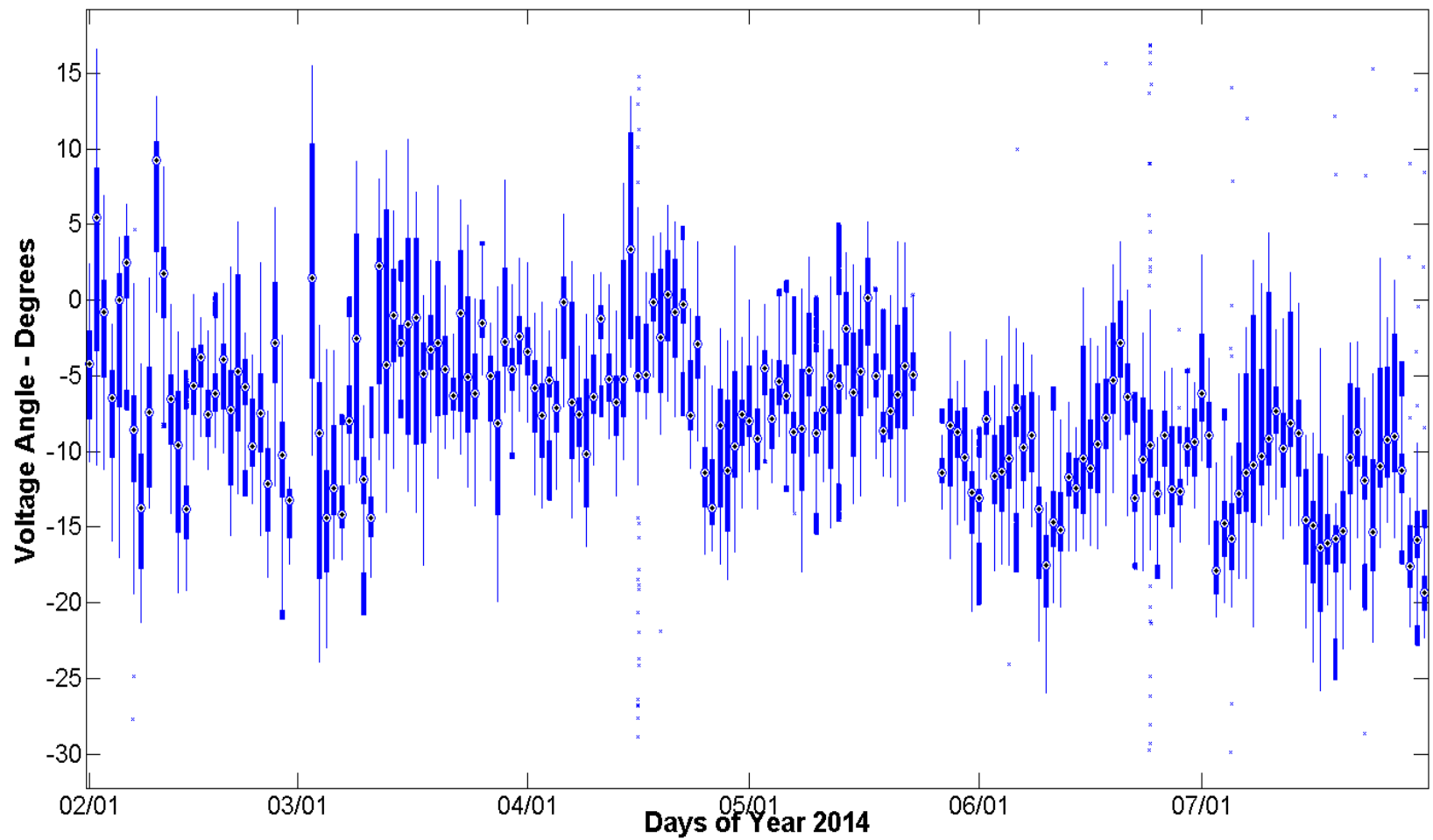
South 3

Time Duration Chart:



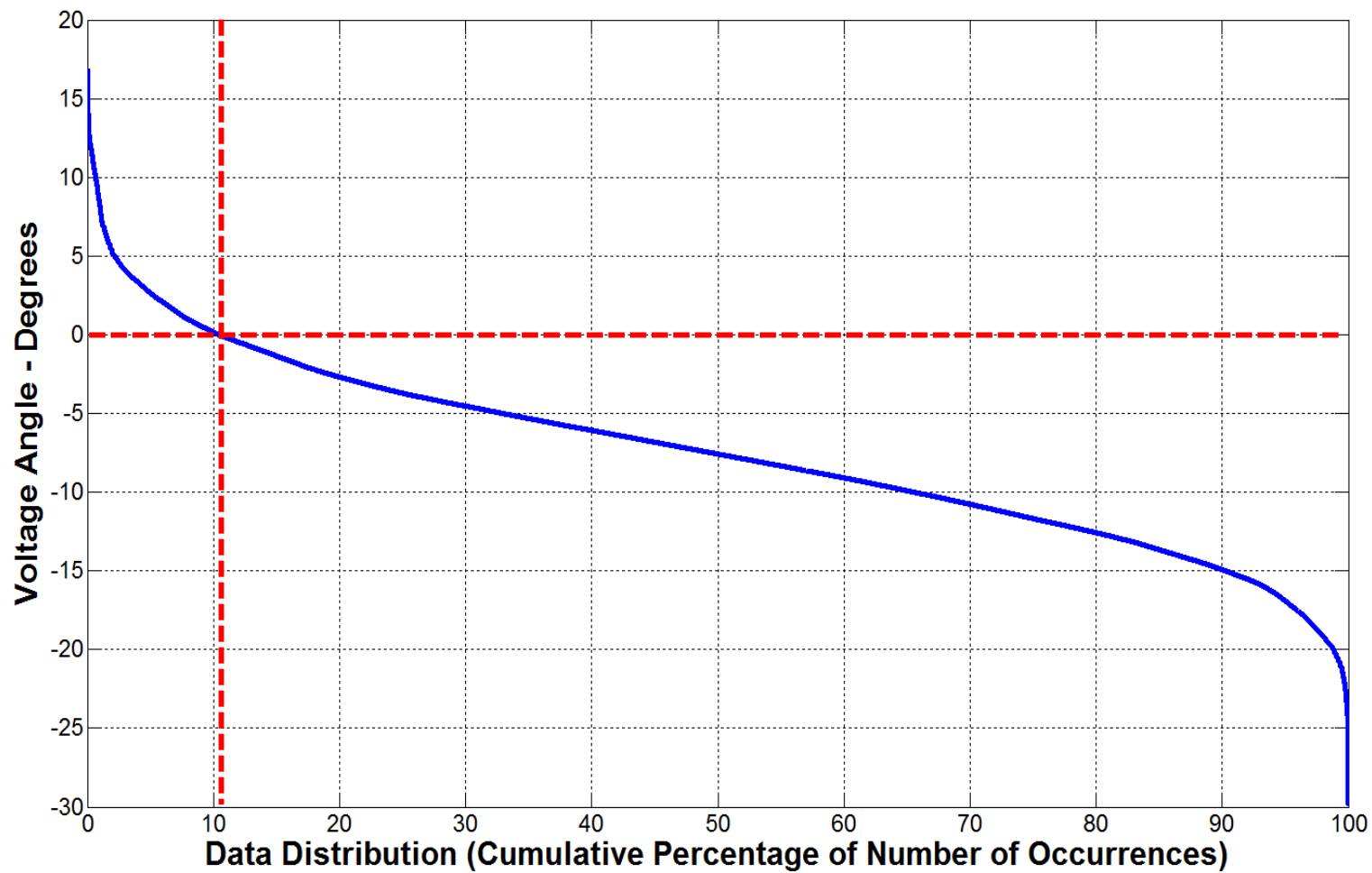
South 5

Daily Box-Whisker Chart:



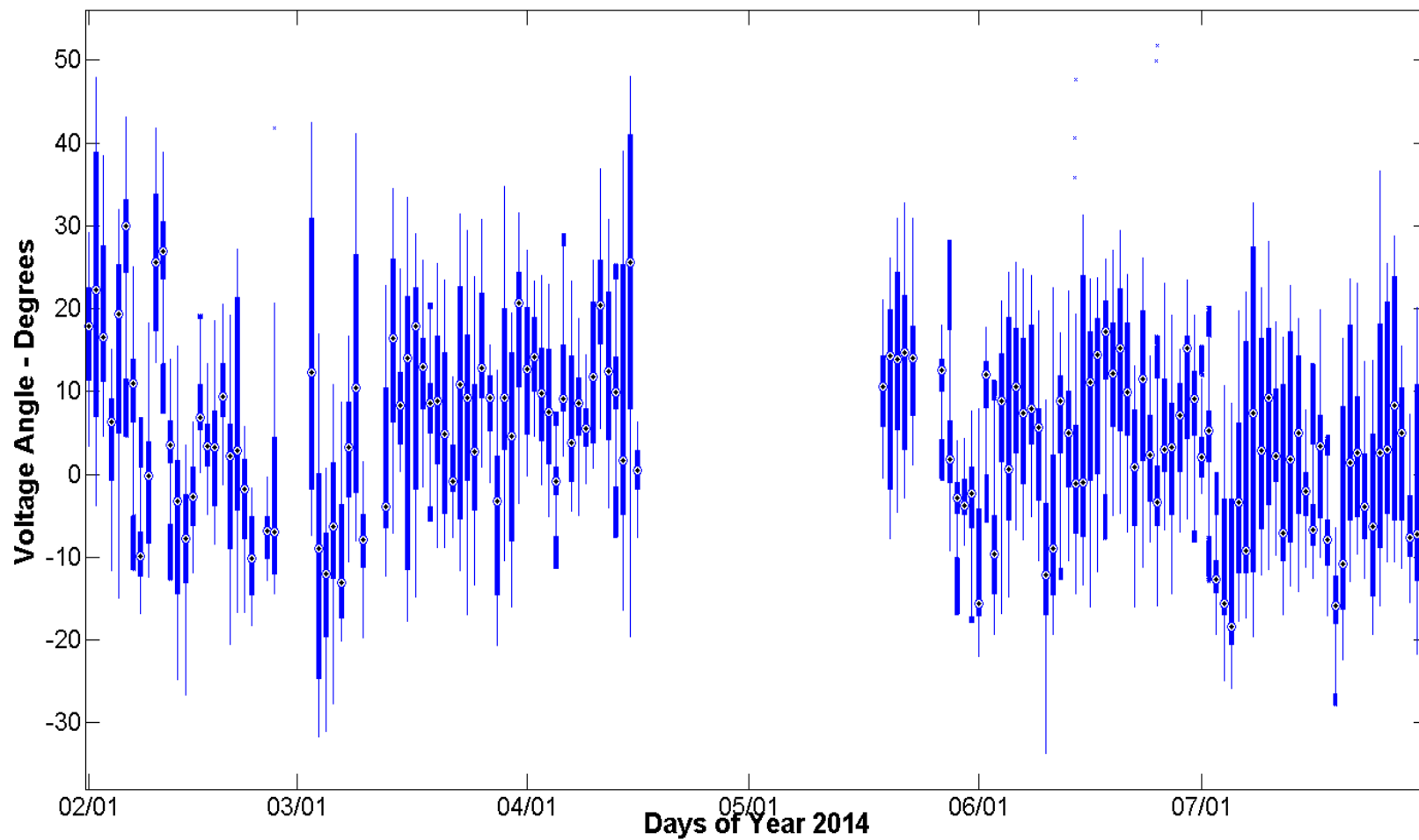
South 5

Time Duration Chart:



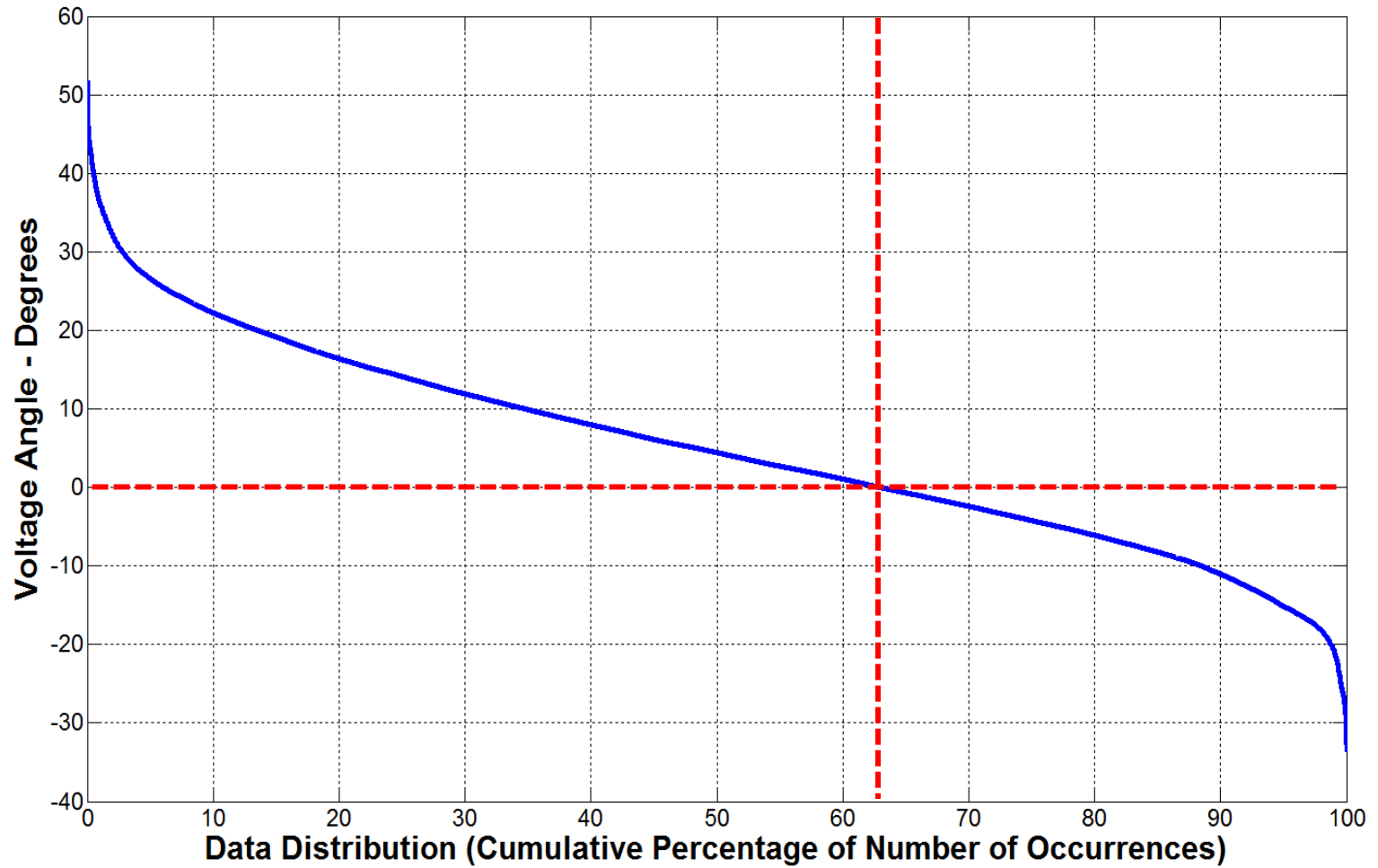
Coast 4

Daily Box-Whisker Chart:



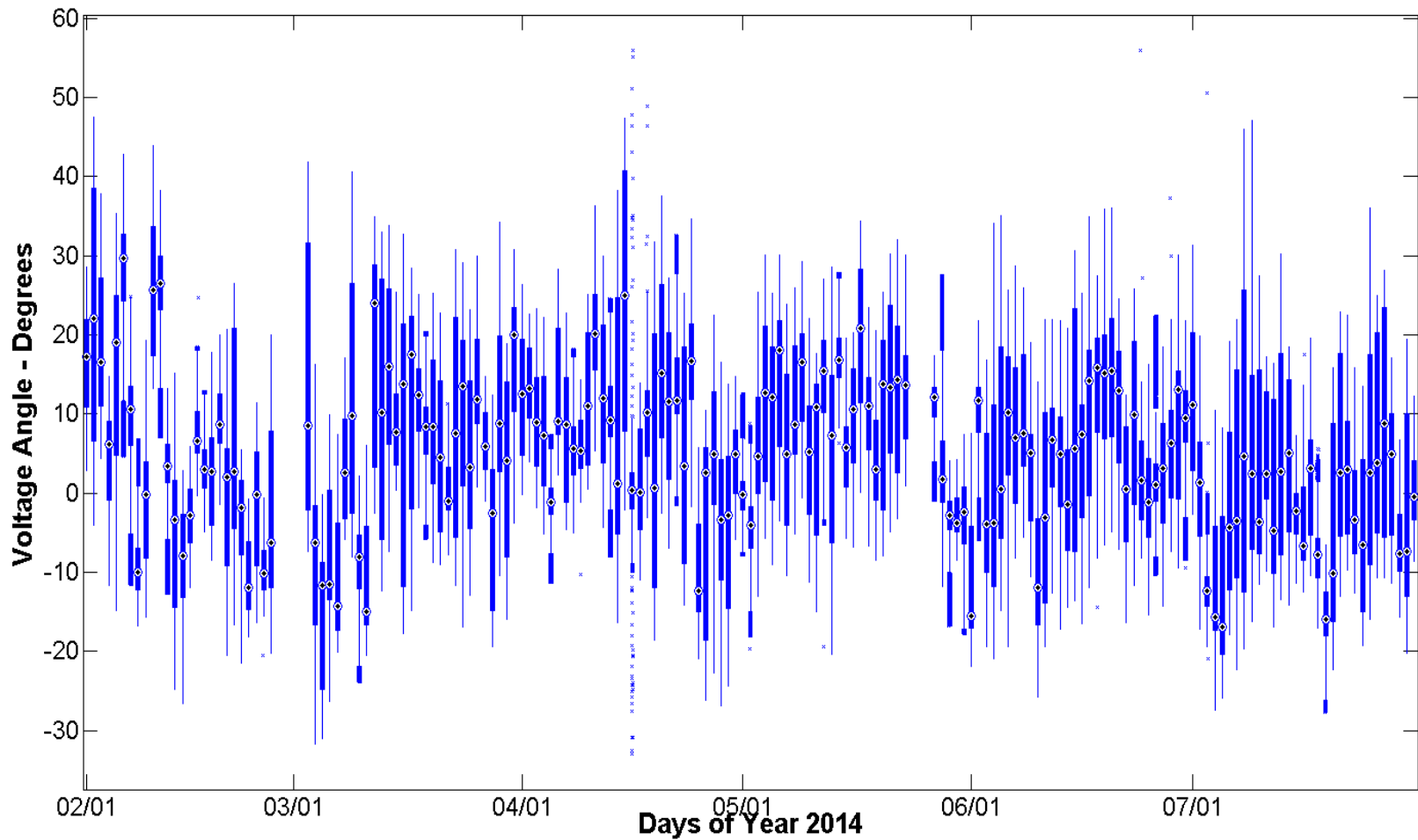
Coast 4

Time Duration Chart:



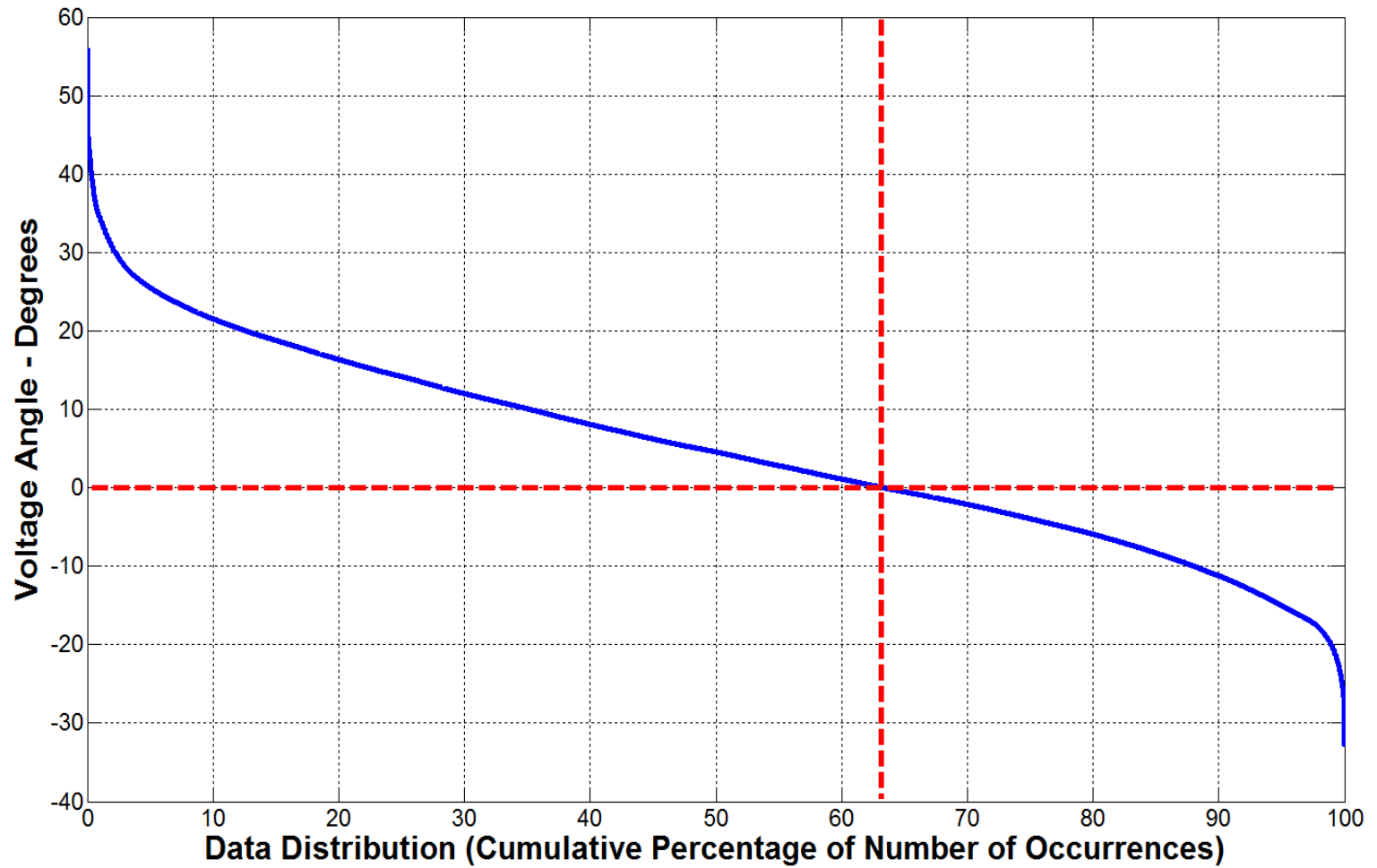
Coast 3

Daily Box-Whisker Chart:



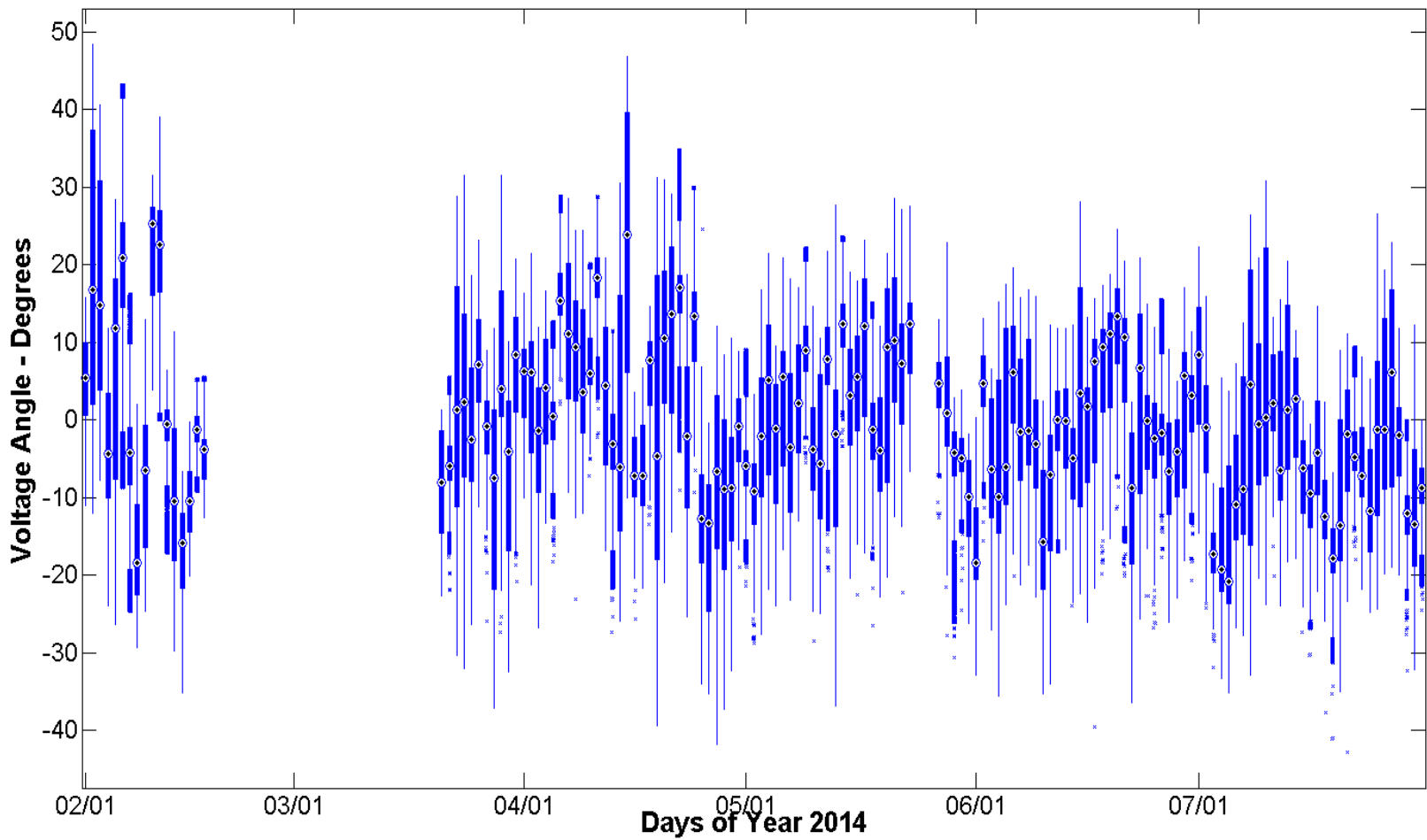
Coast 3

Time Duration Chart:

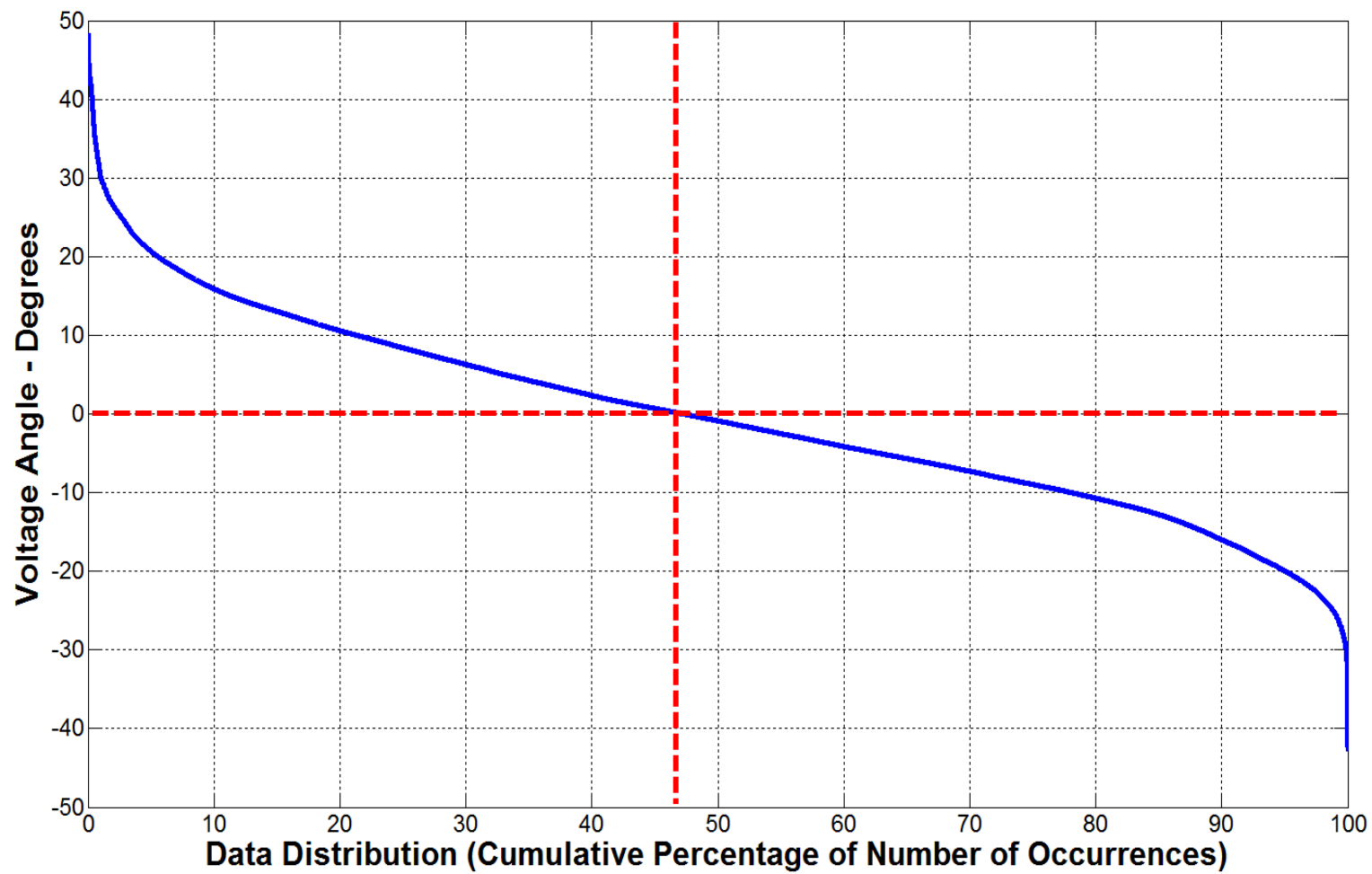


South 13

Daily Box-Whisker Chart:

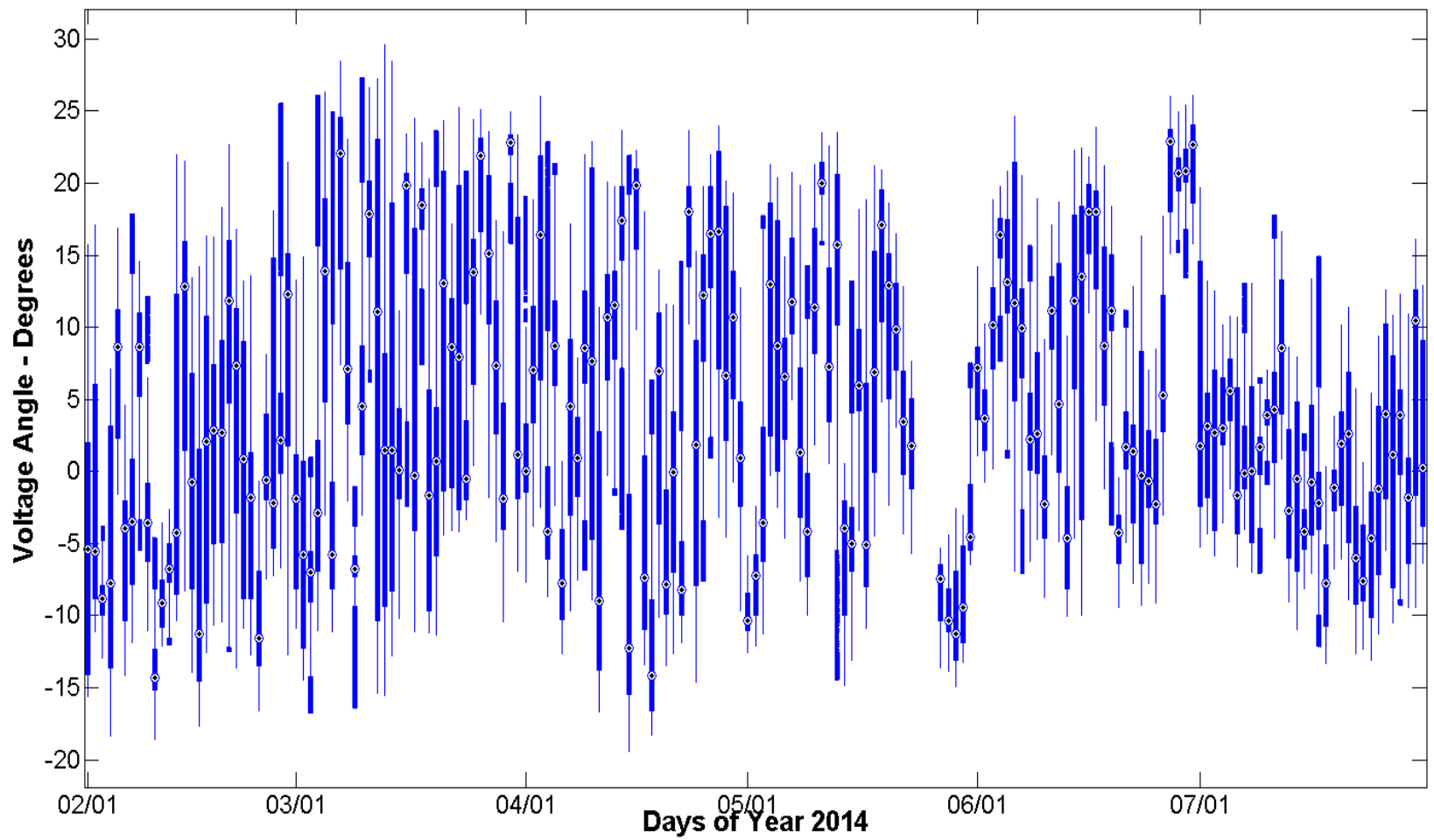


Time Duration Chart:



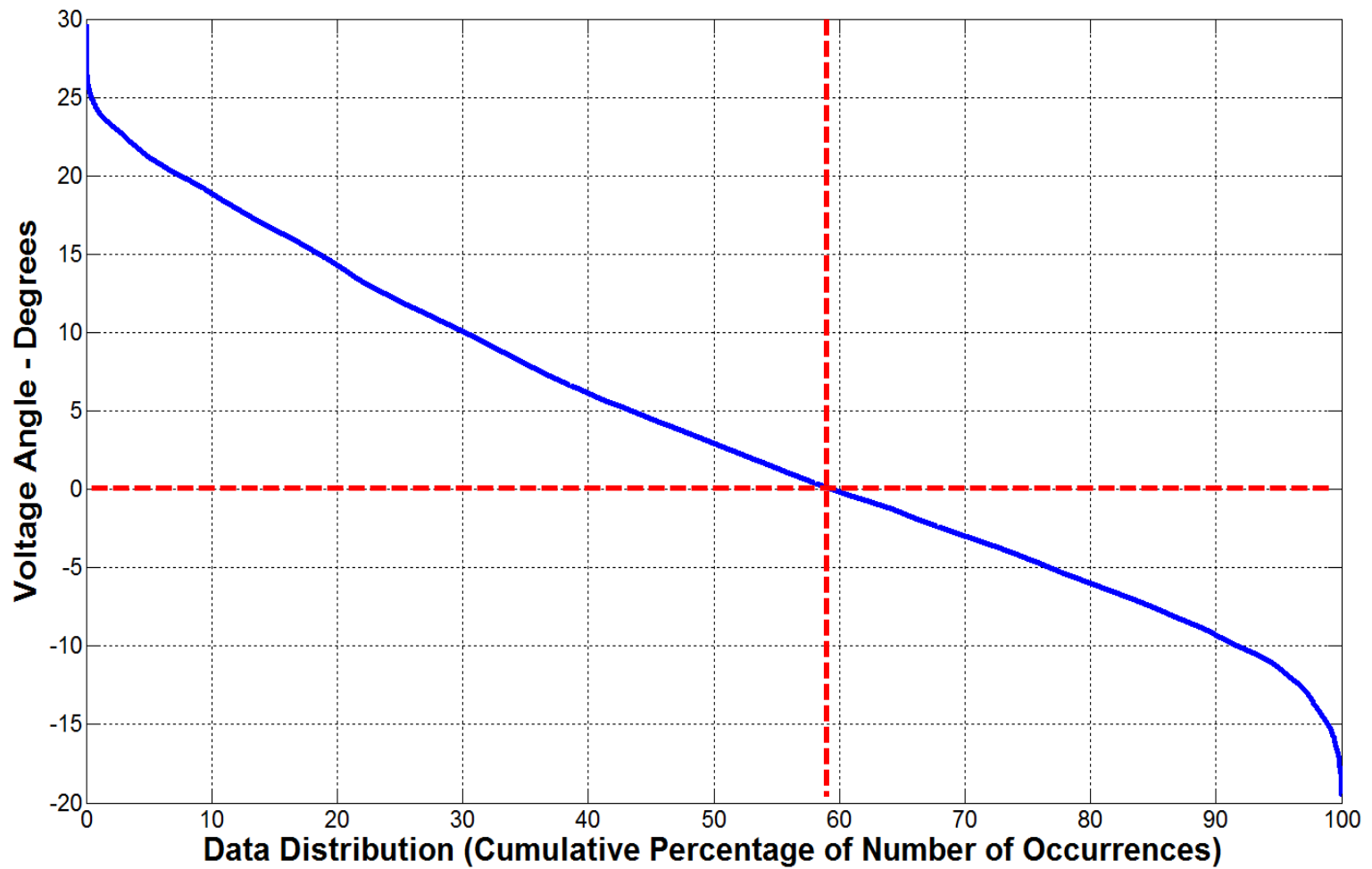
FarWest 4

Daily Box-Whisker Chart:

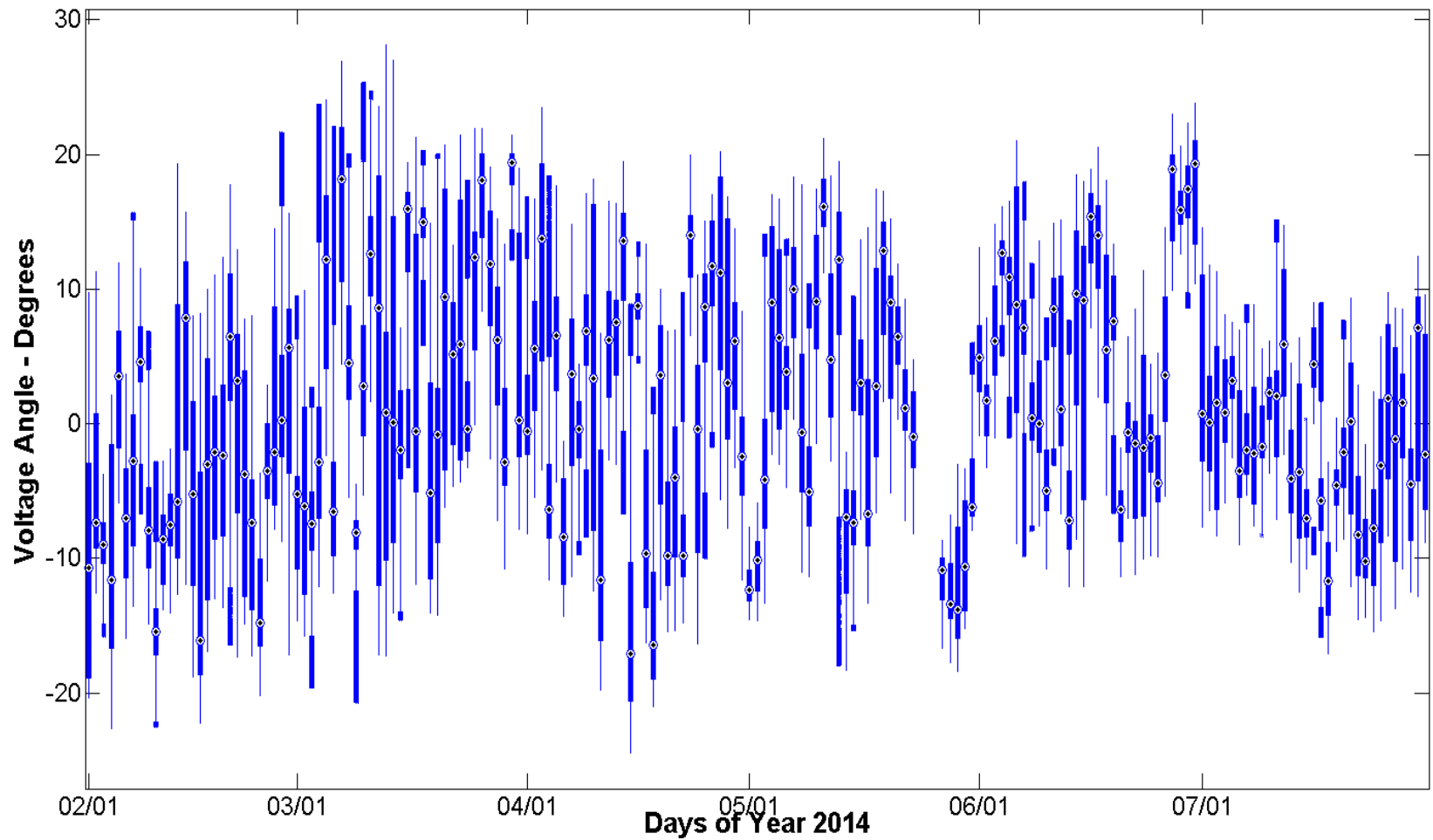


FarWest 4

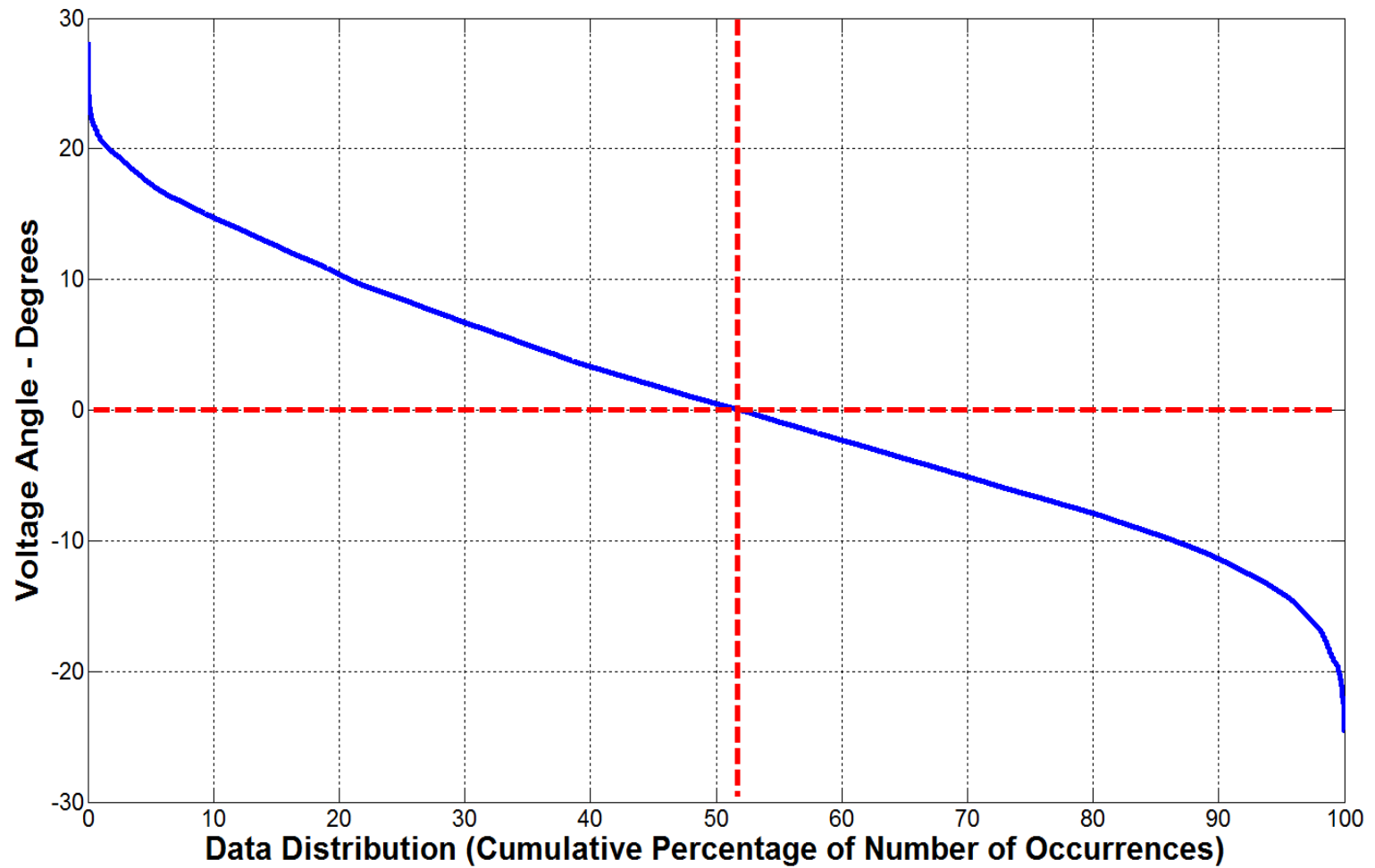
Time Duration Chart:



Daily Box-Whisker Chart:

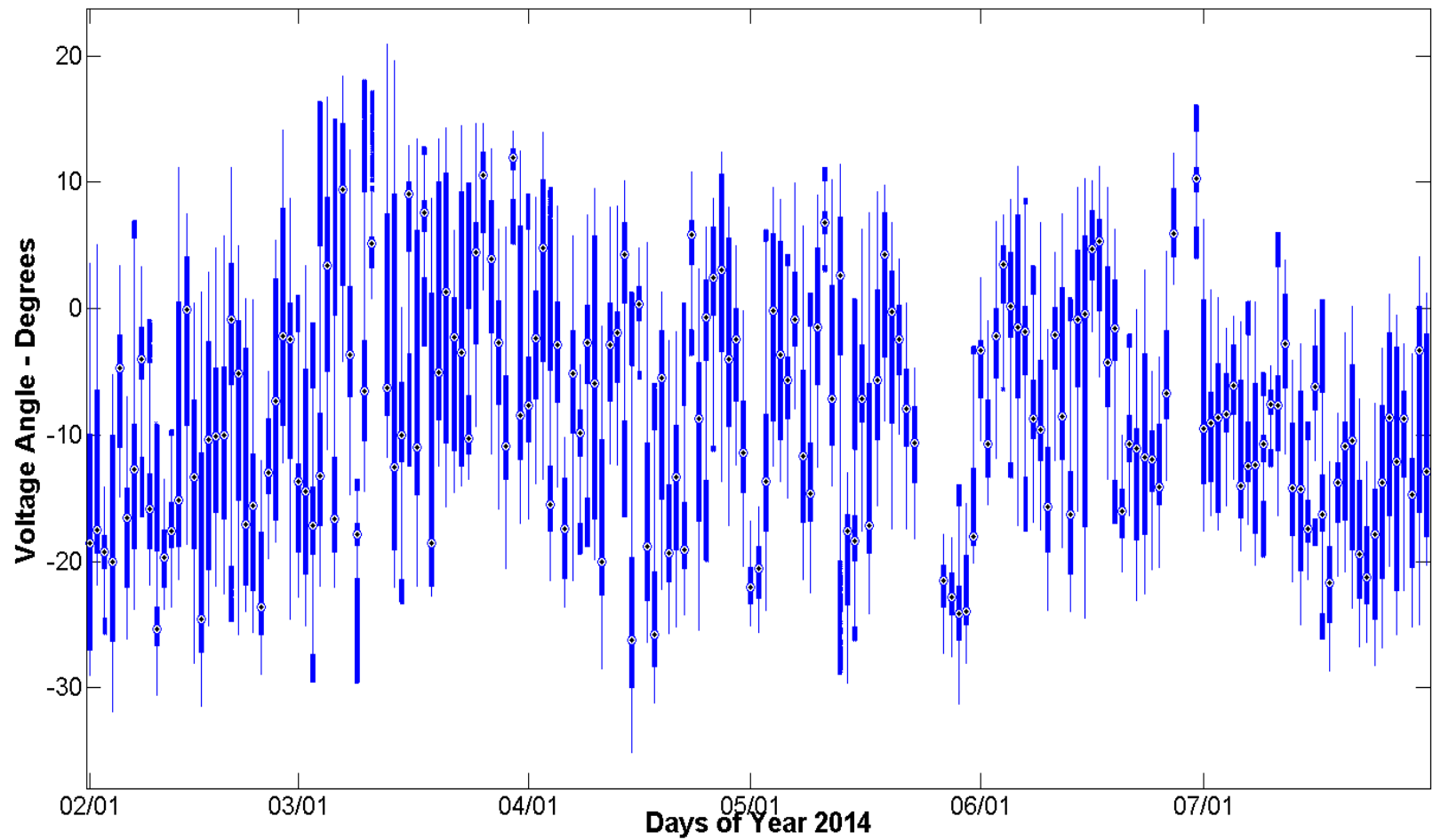


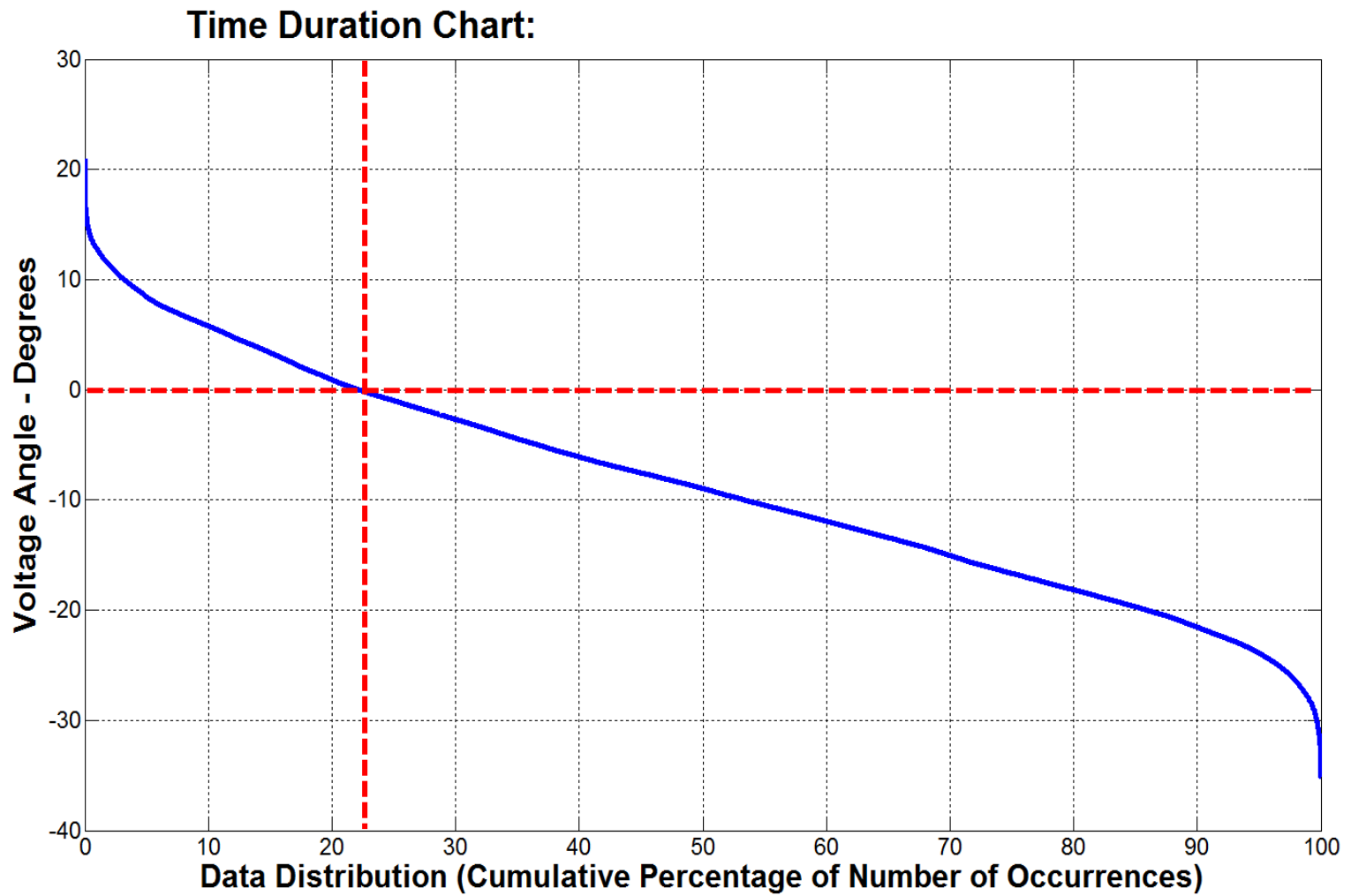
Time Duration Chart:



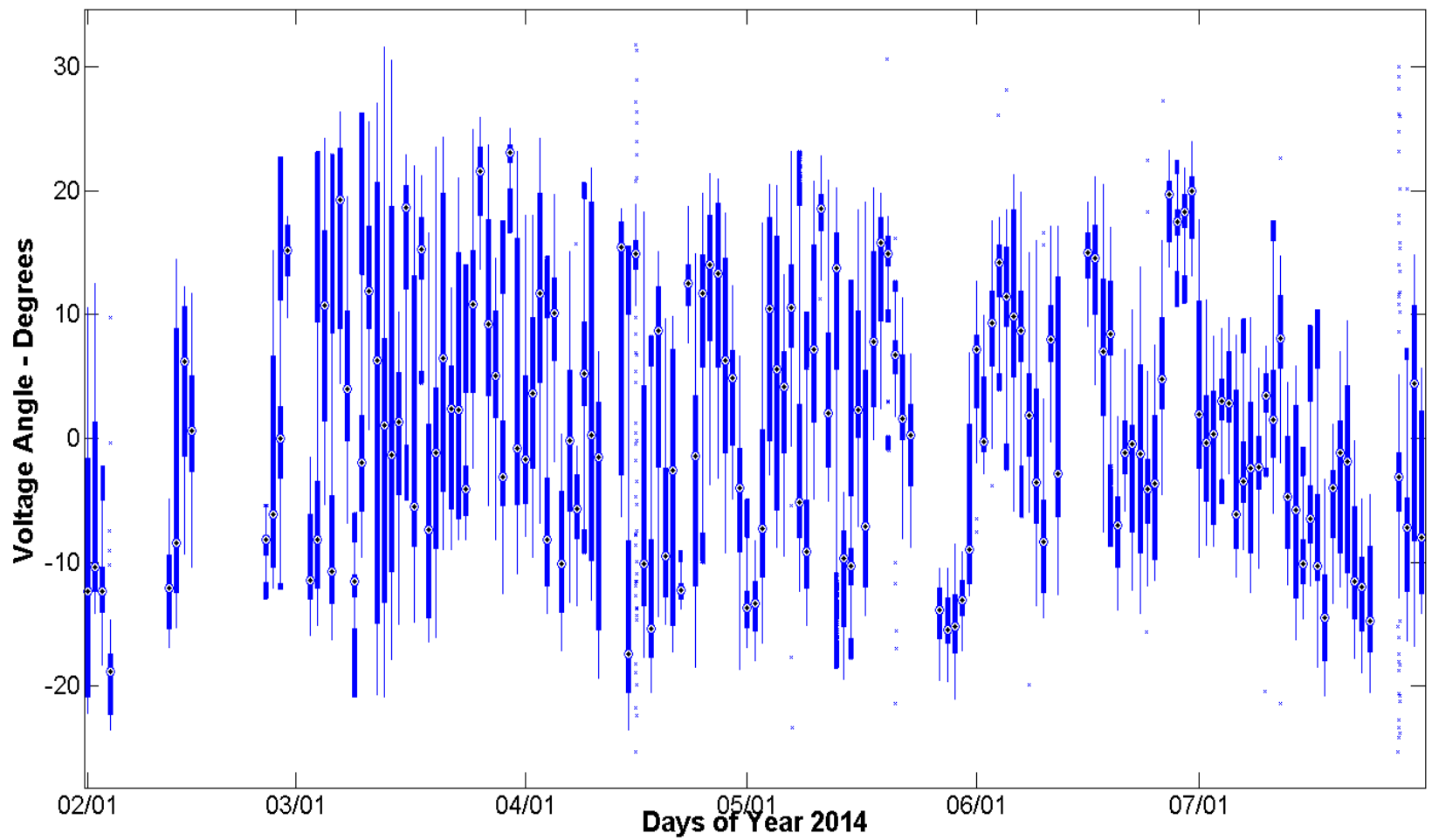
FarWest 8

Daily Box-Whisker Chart:

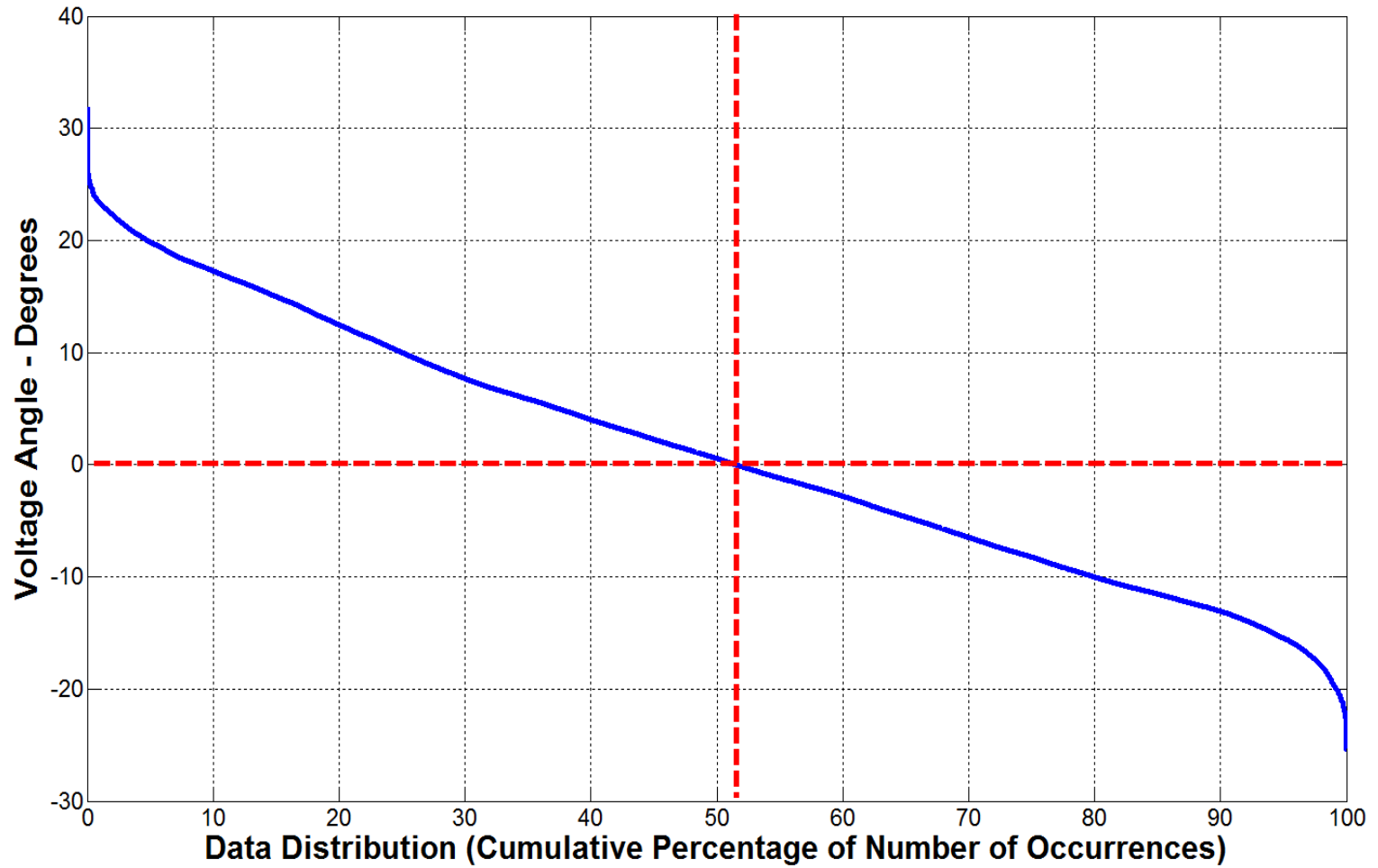




Daily Box-Whisker Chart:

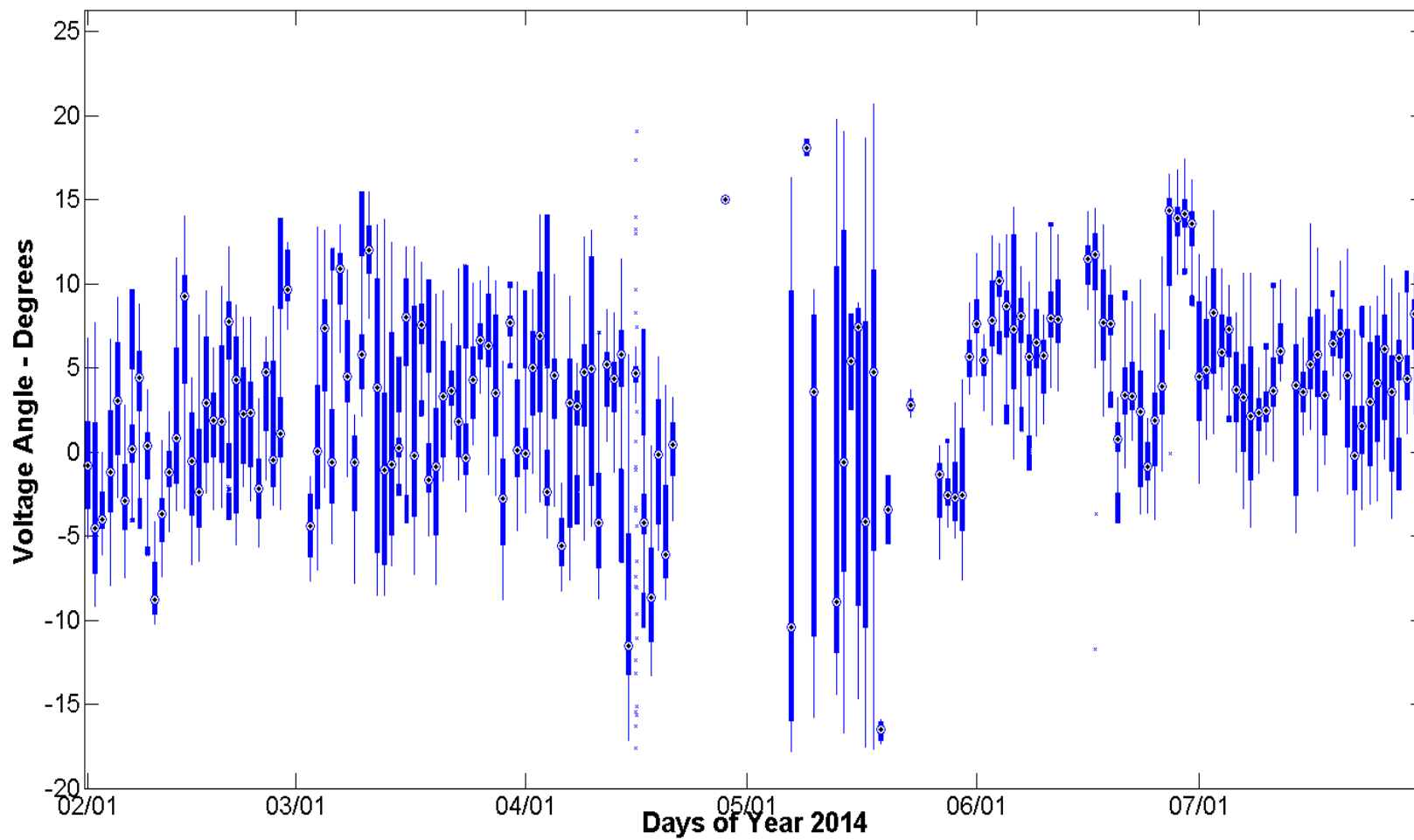


Time Duration Chart:

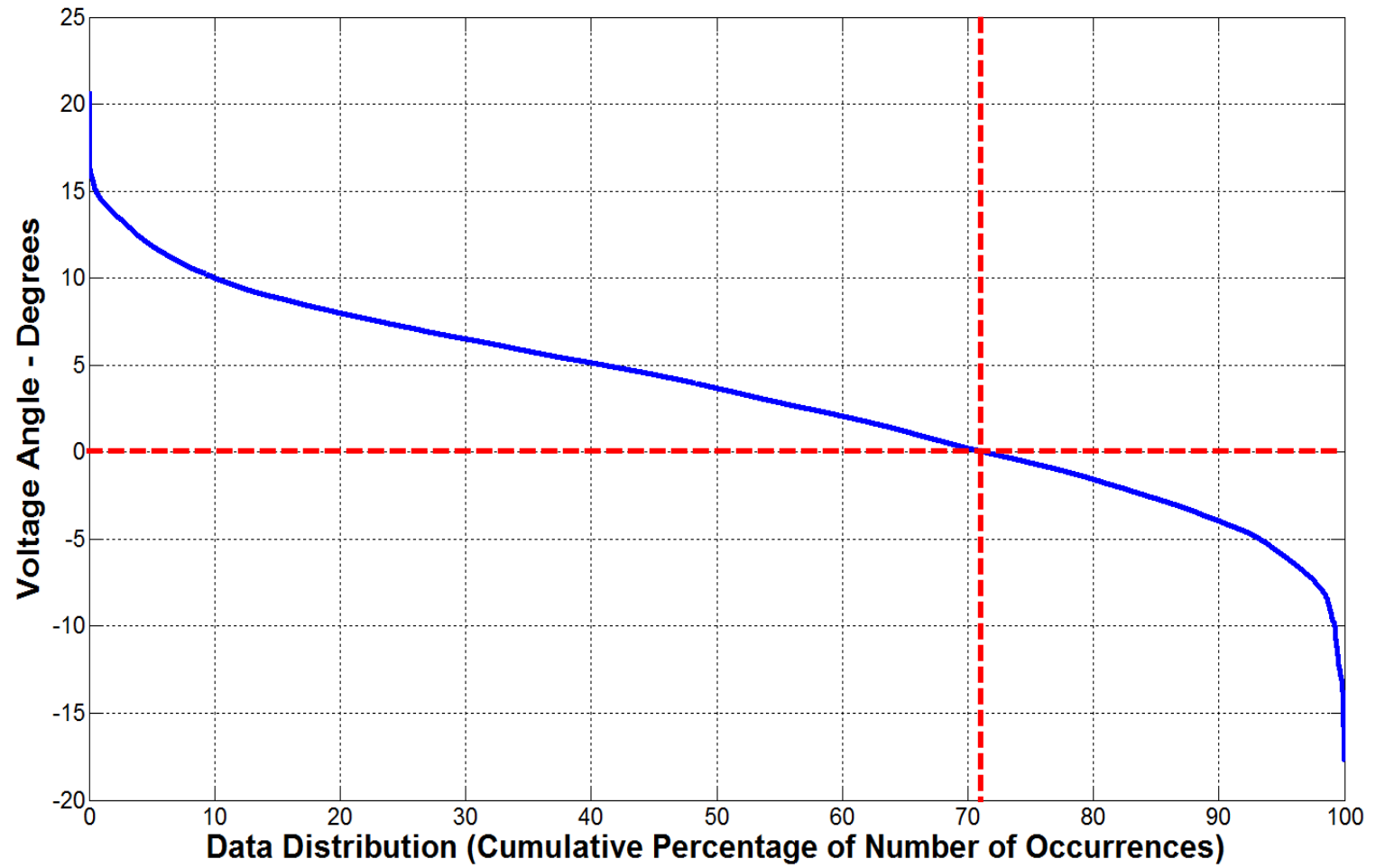


West 16

Daily Box-Whisker Chart:

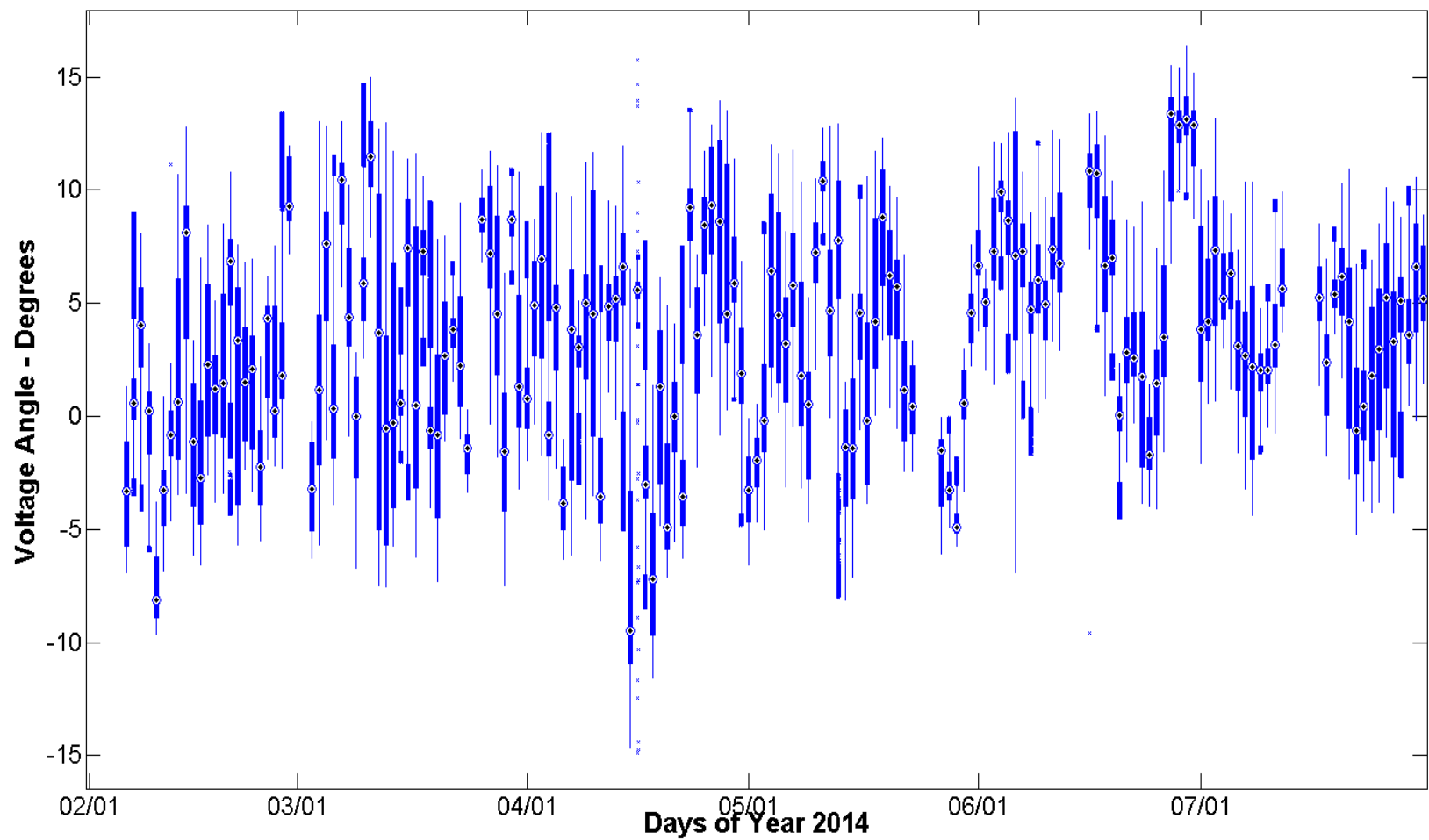


Time Duration Chart:



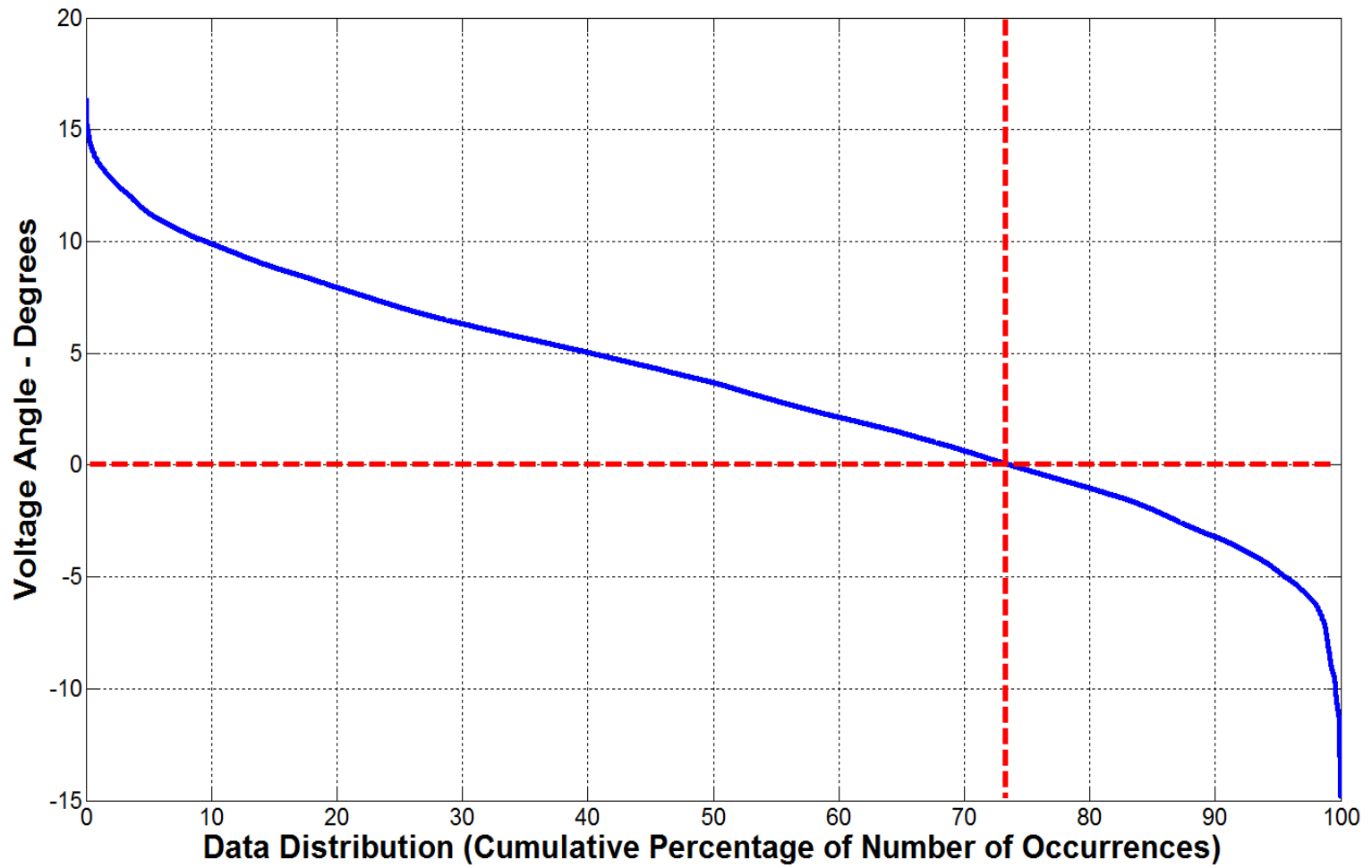
West 3

Daily Box-Whisker Chart:



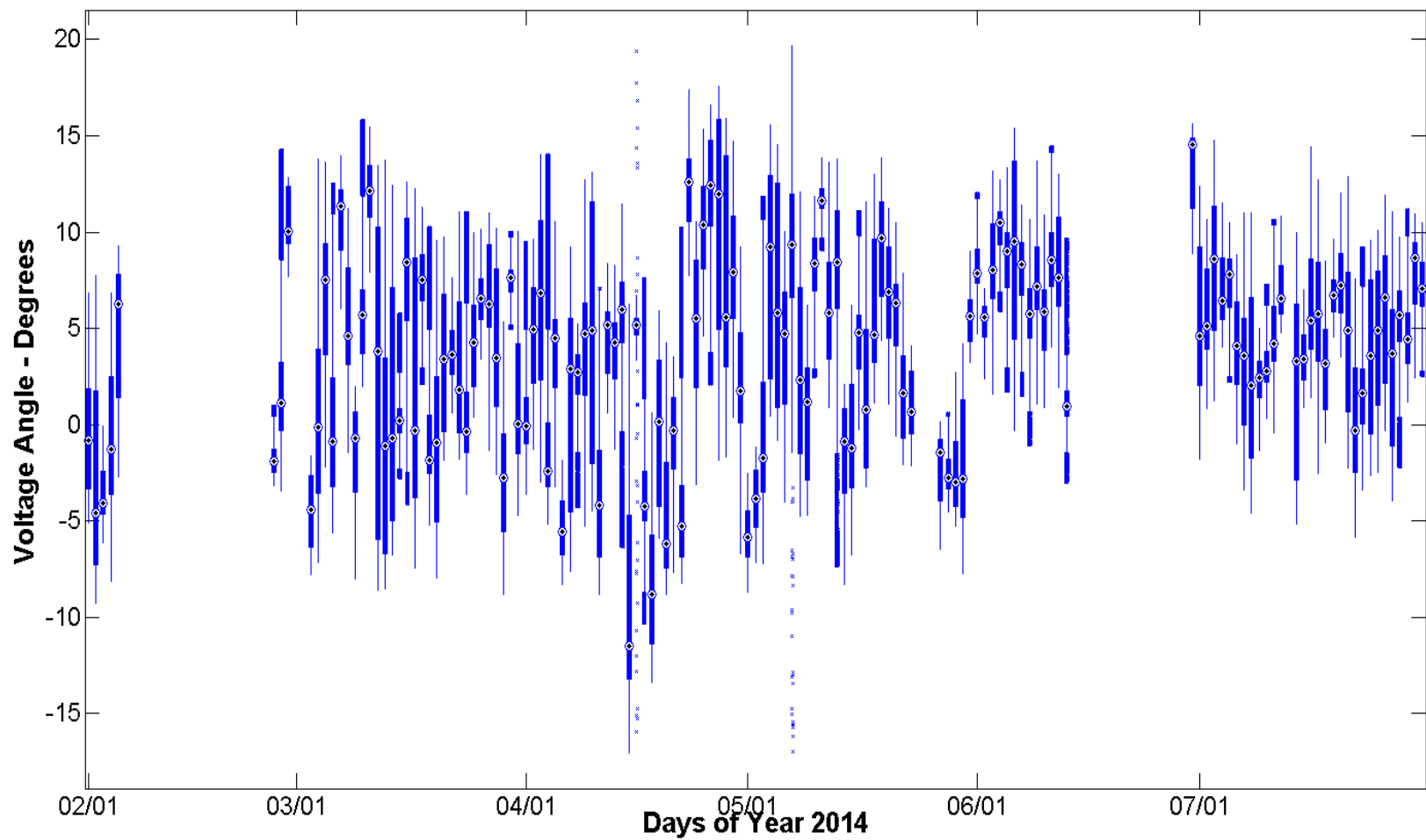
West 3

Time Duration Chart:



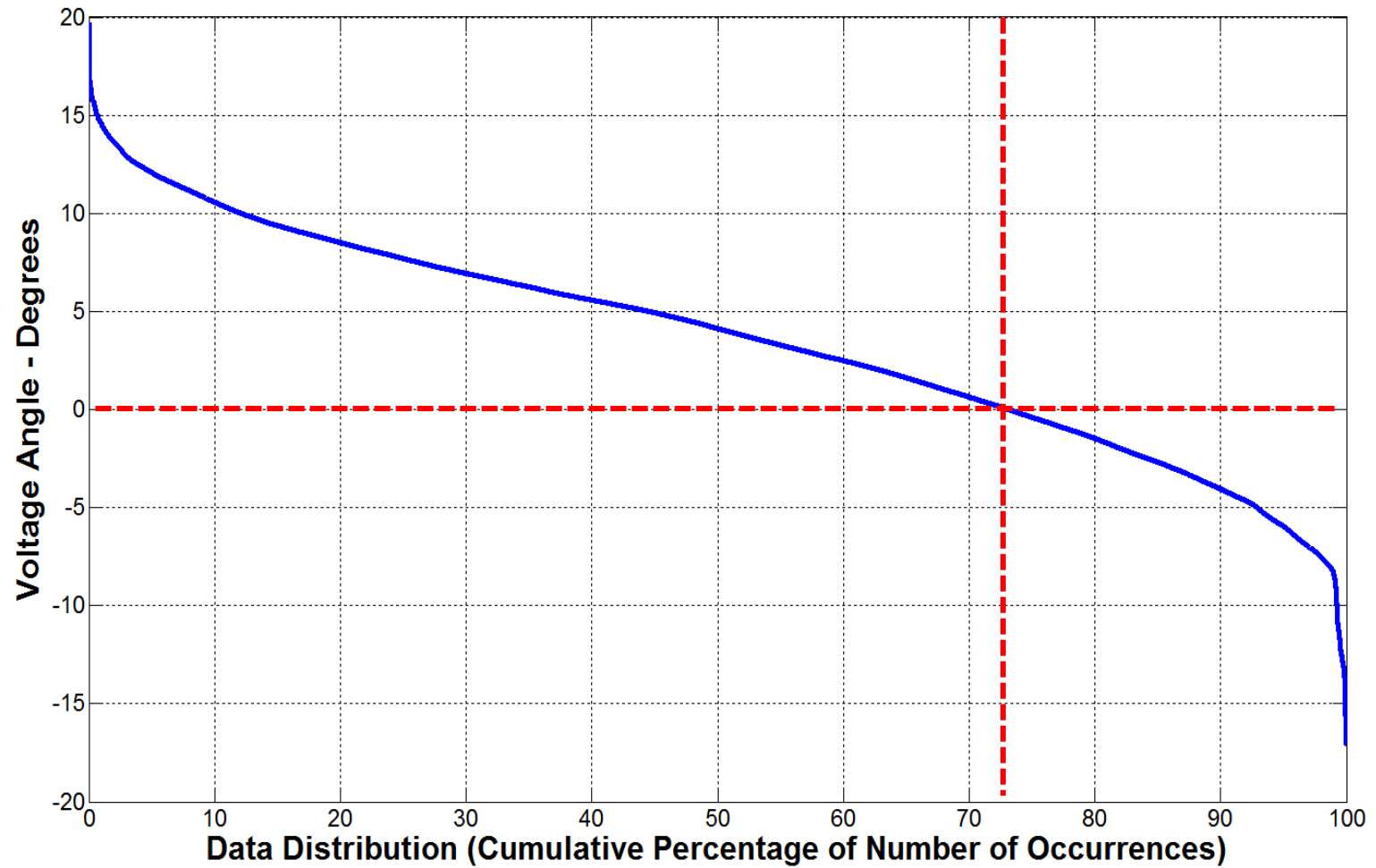
West 15

Daily Box-Whisker Chart:



West 15

Time Duration Chart:



Appendix B – Part 1

CCET Discovery Across Texas project

Baseline Analysis Update – Angle Differences

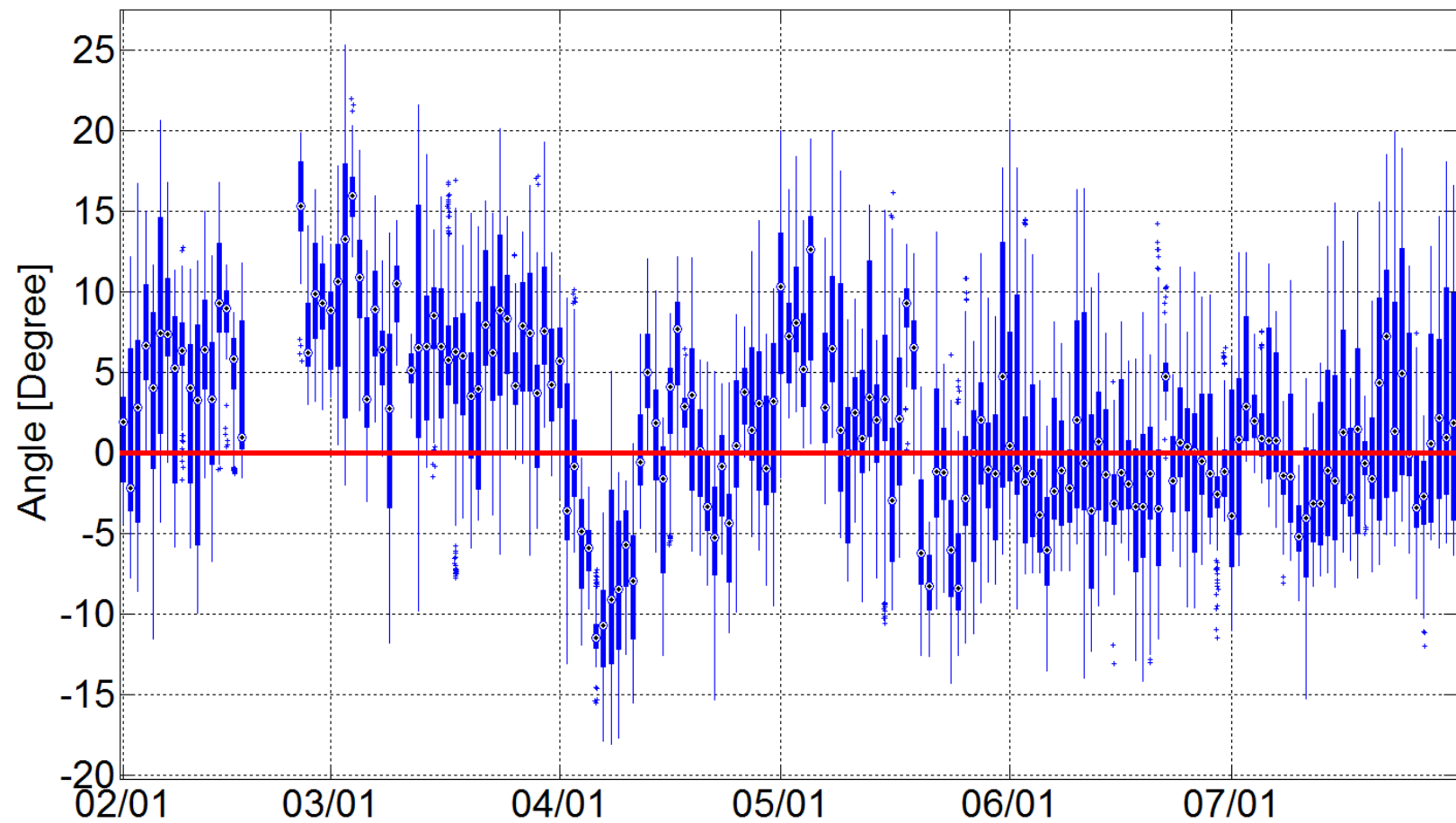
State Estimator Data: February to July 2014
Box Whiskers Plots and Time Duration Curves



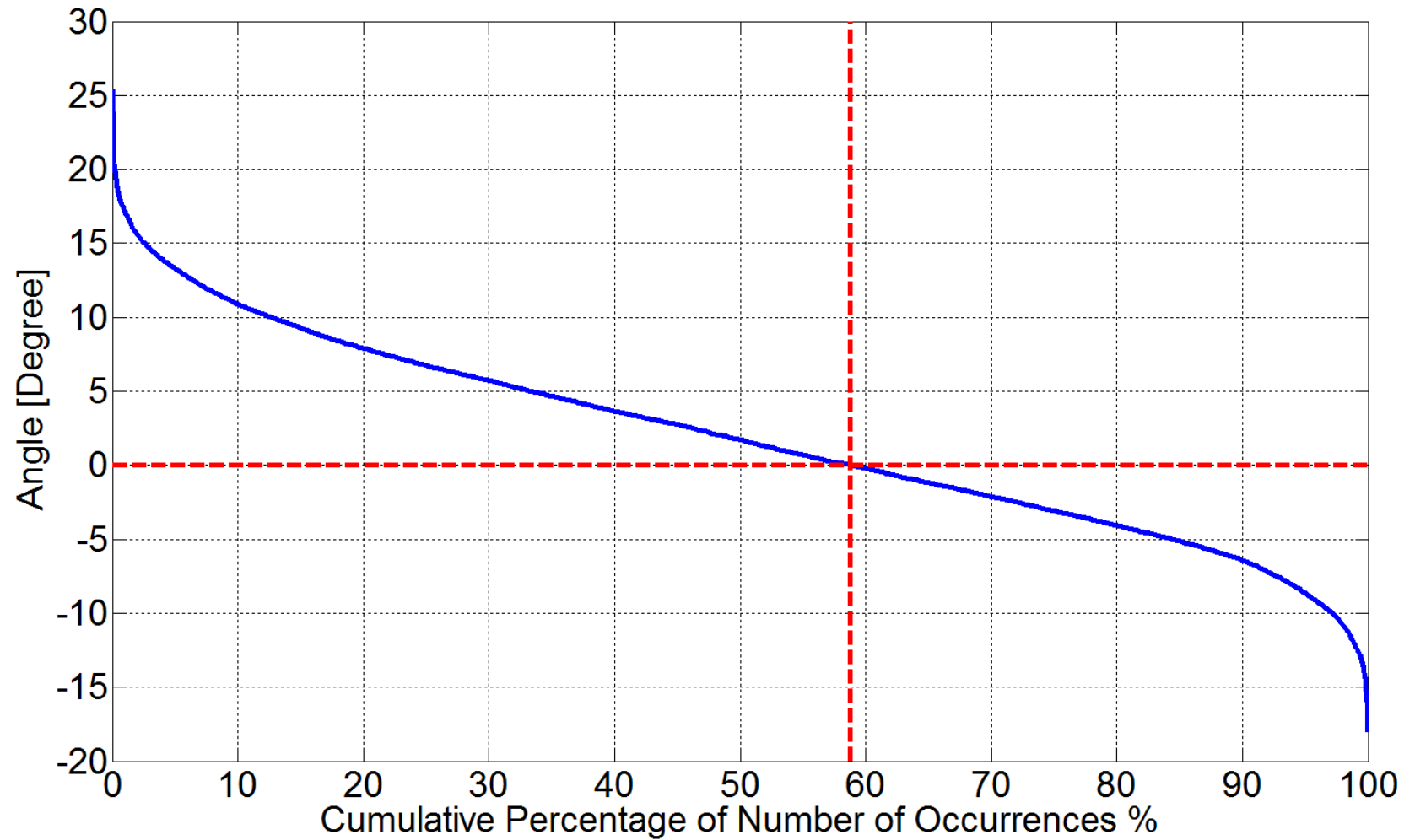
Electric Power Group



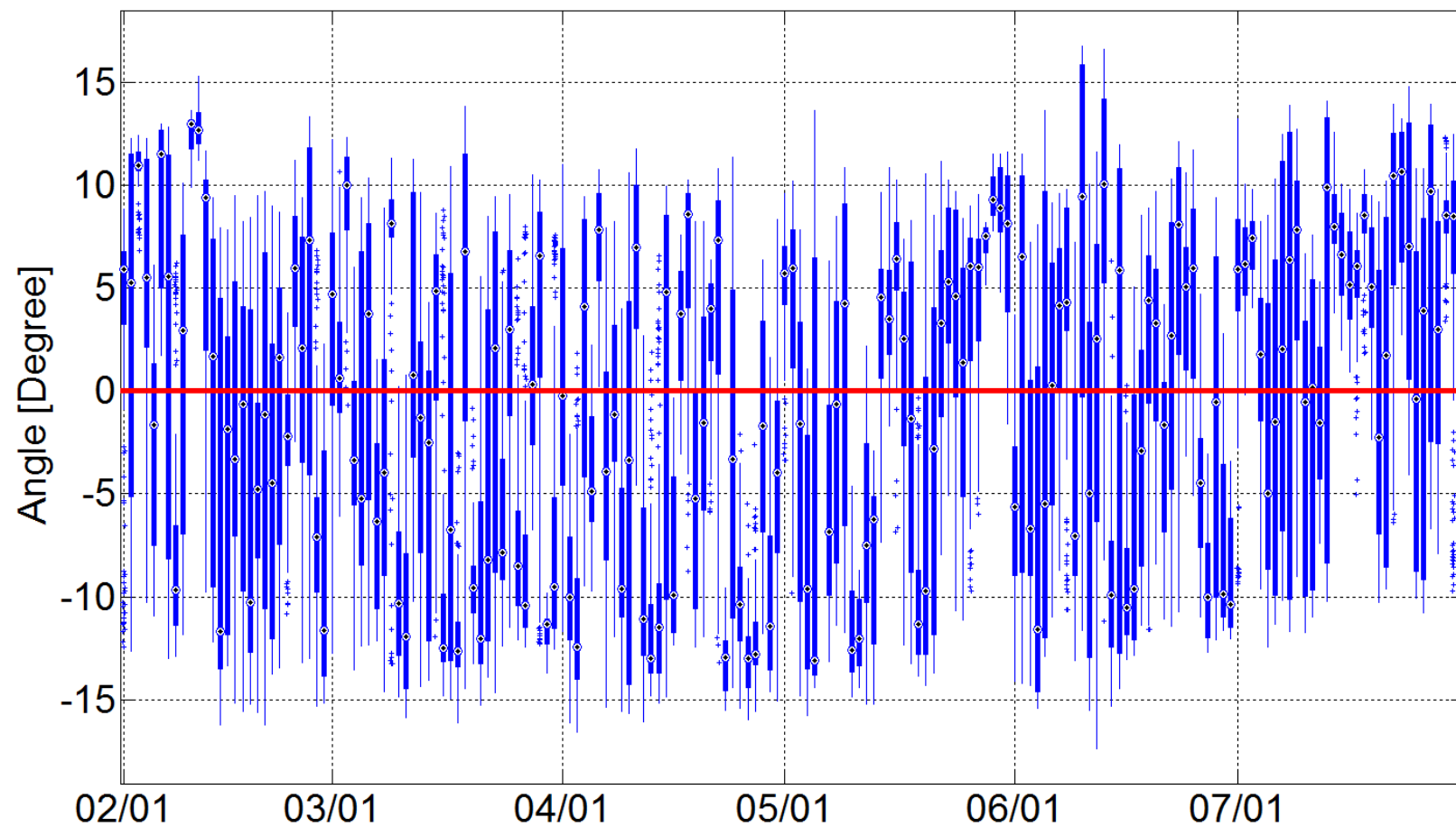
Coast 1-South 13



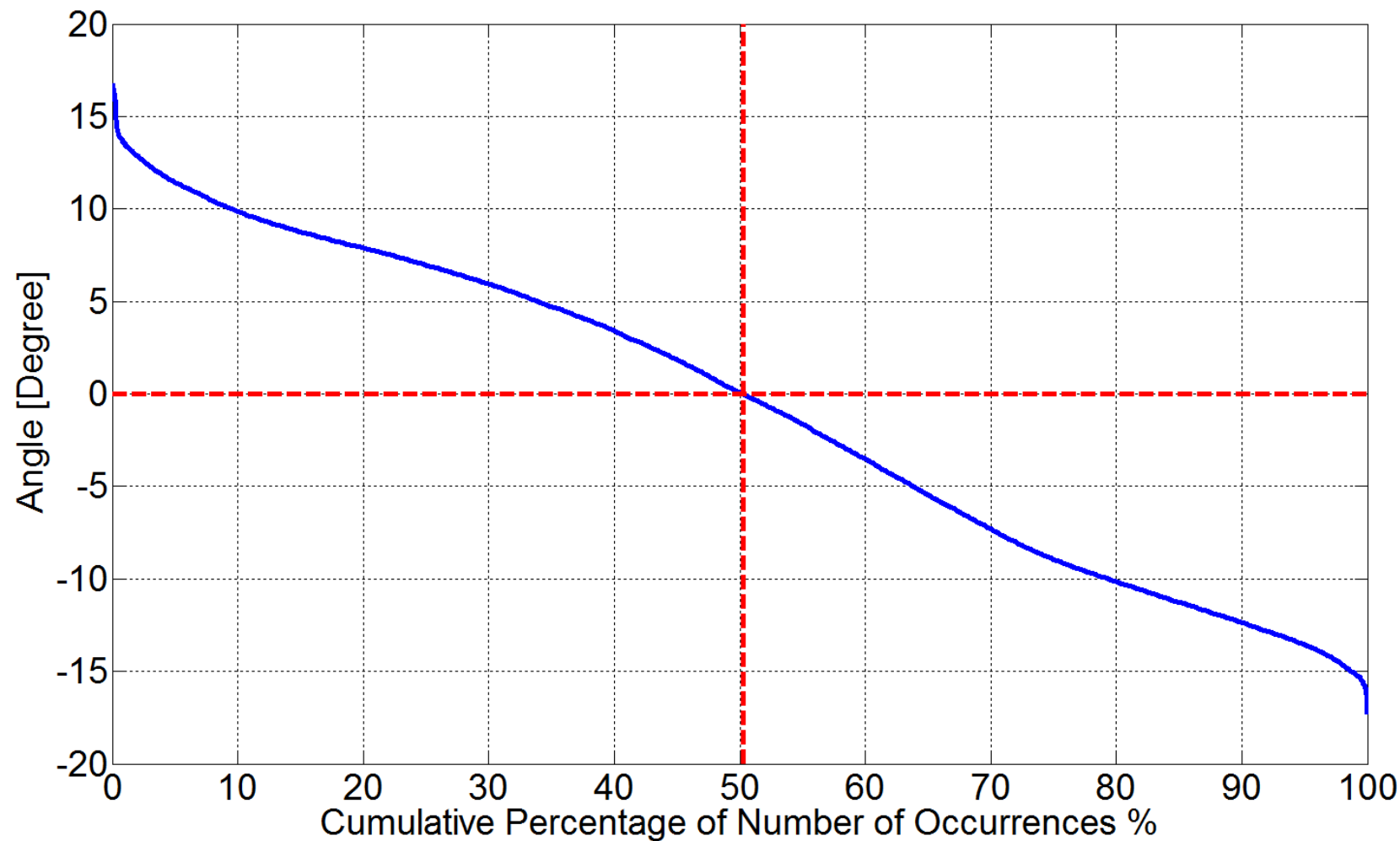
Coast 1-South 13



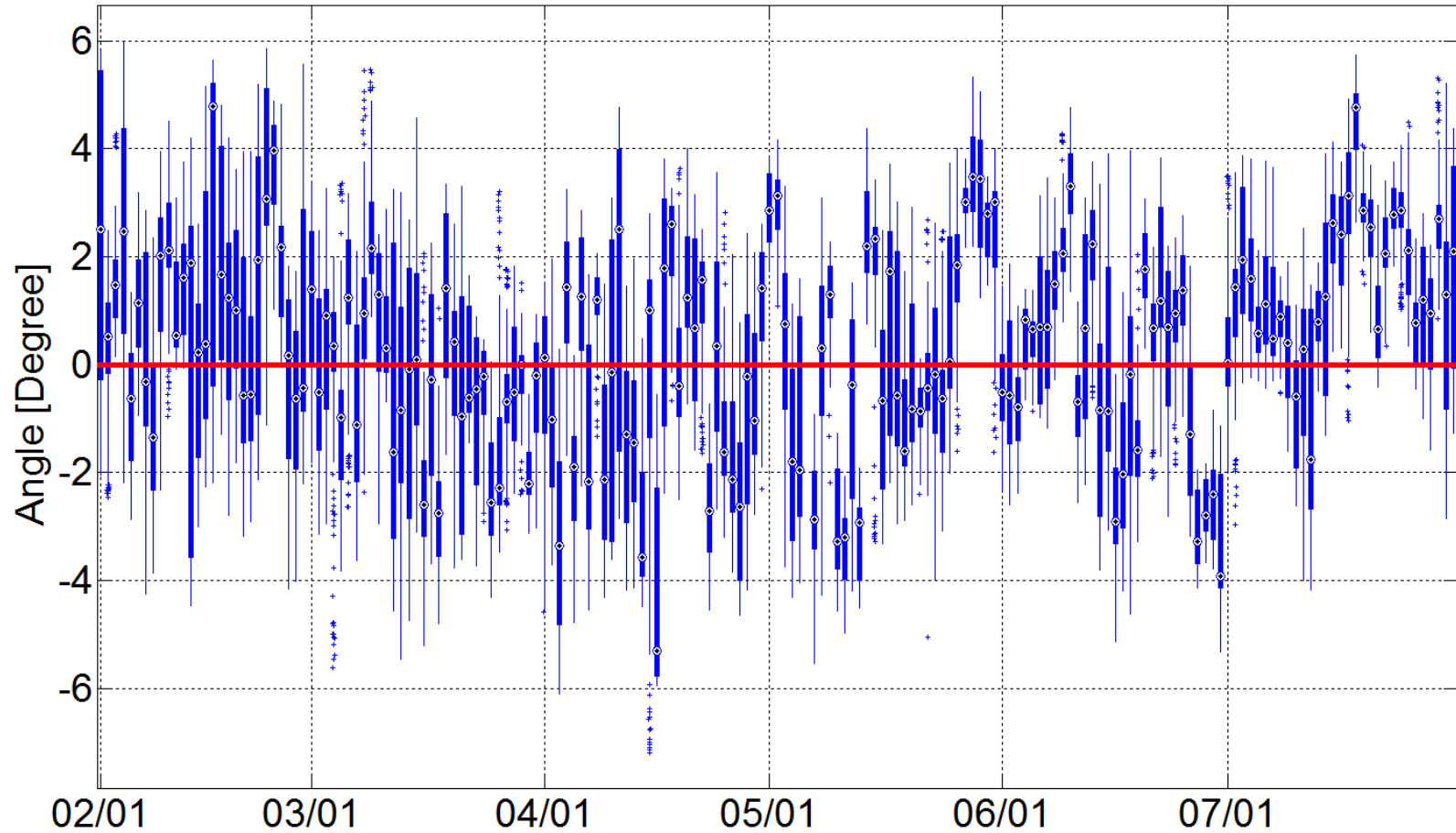
West 5-West 10



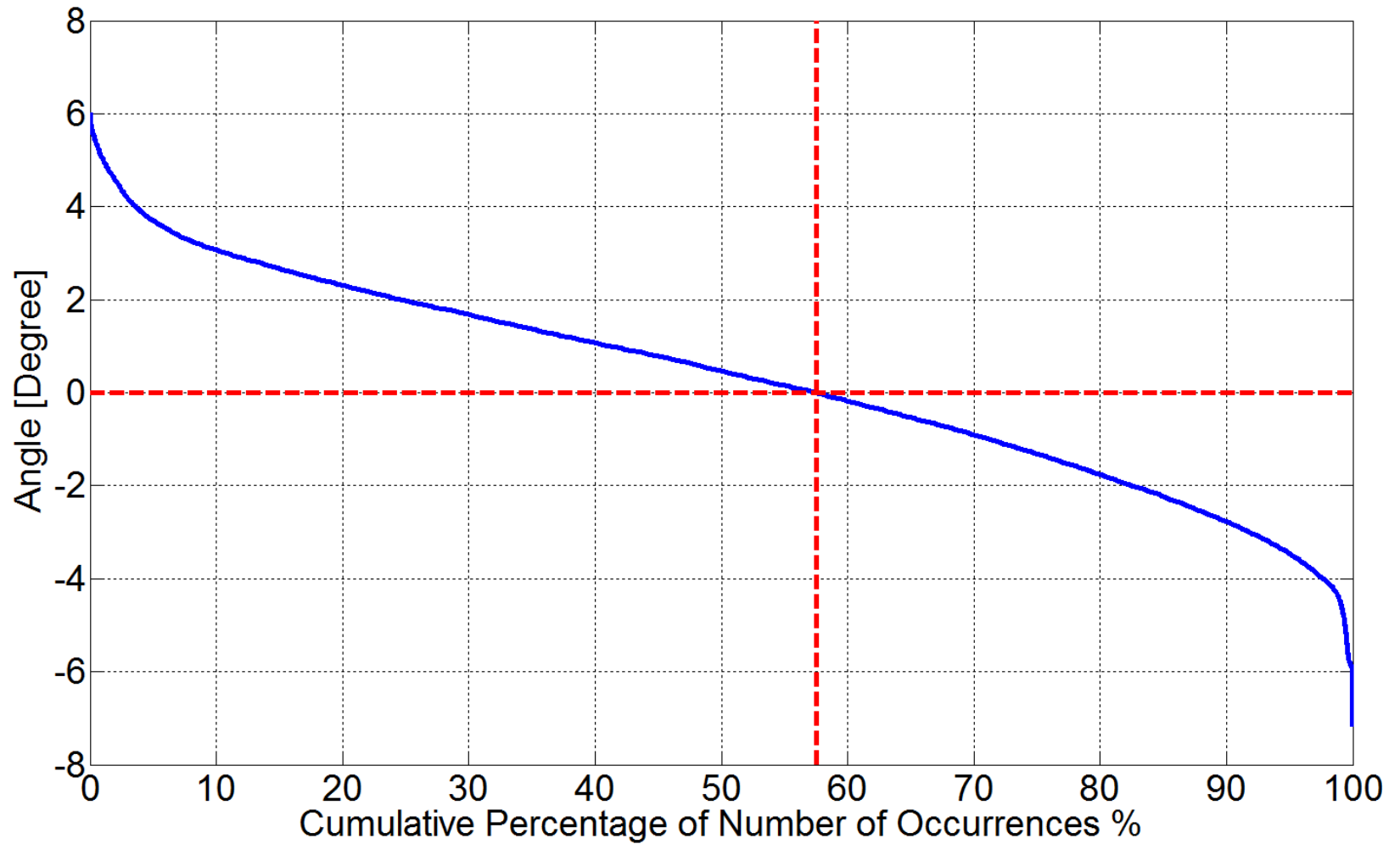
West 5-West 10



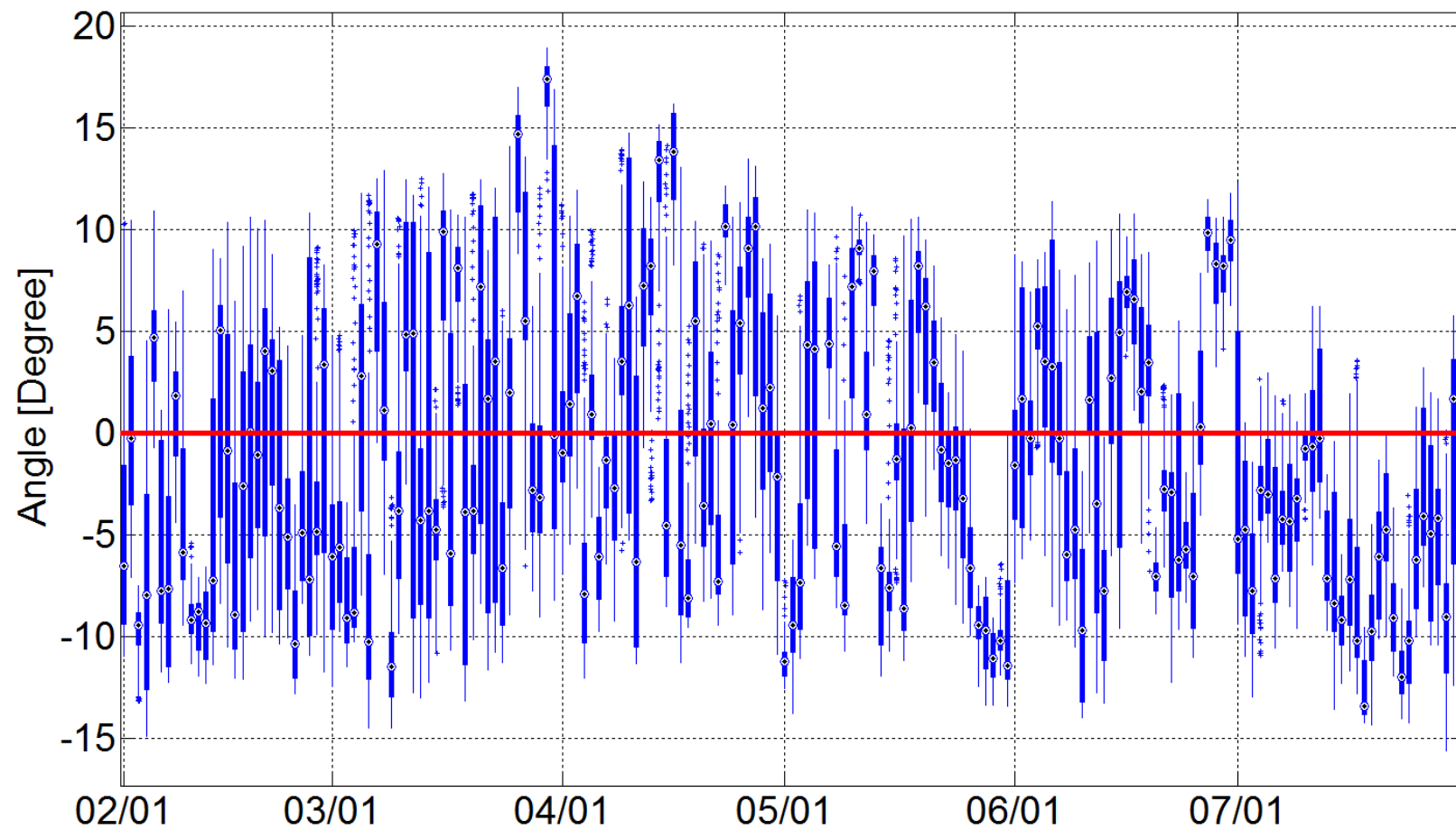
West 5-FarWest 4



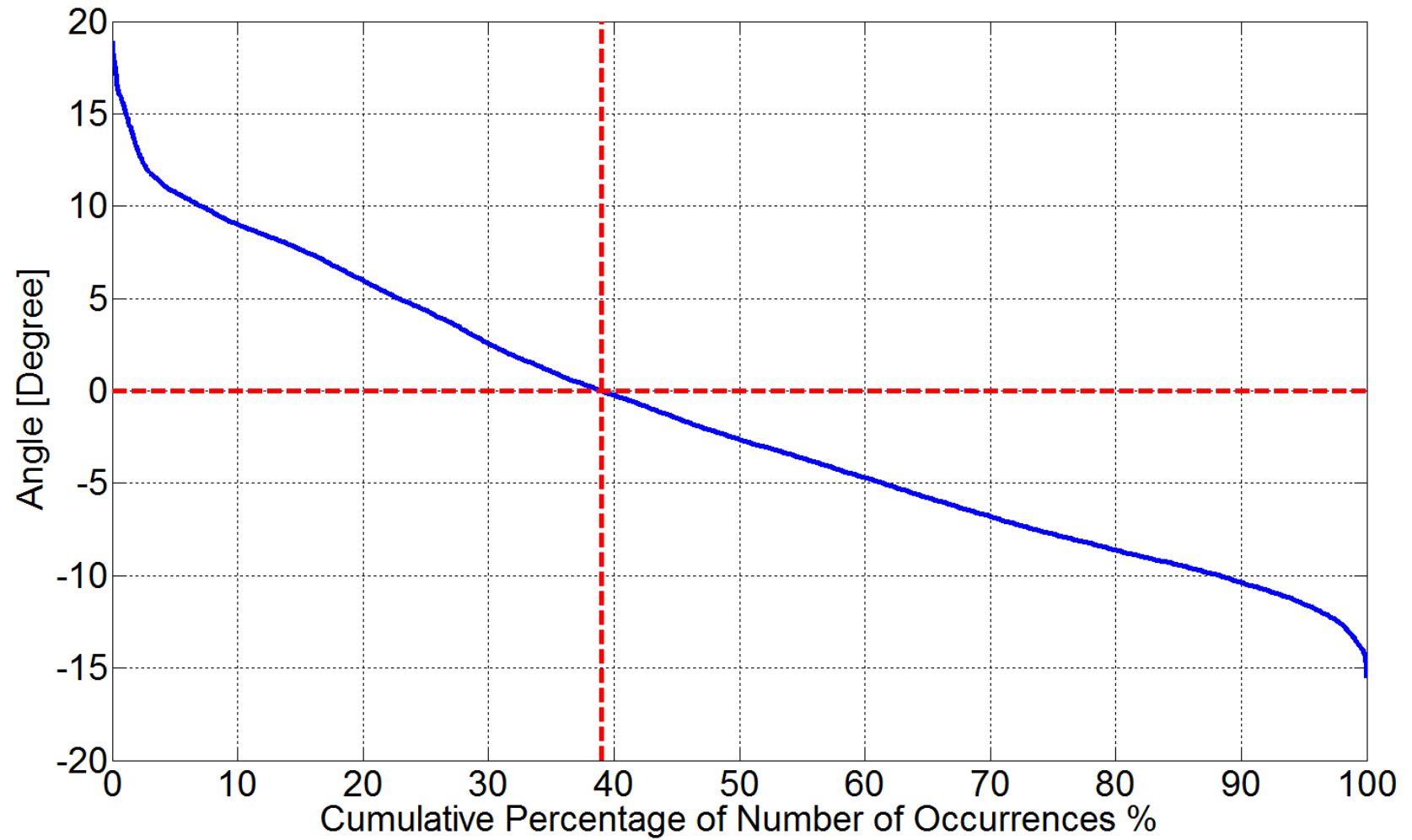
West 5-FarWest 4



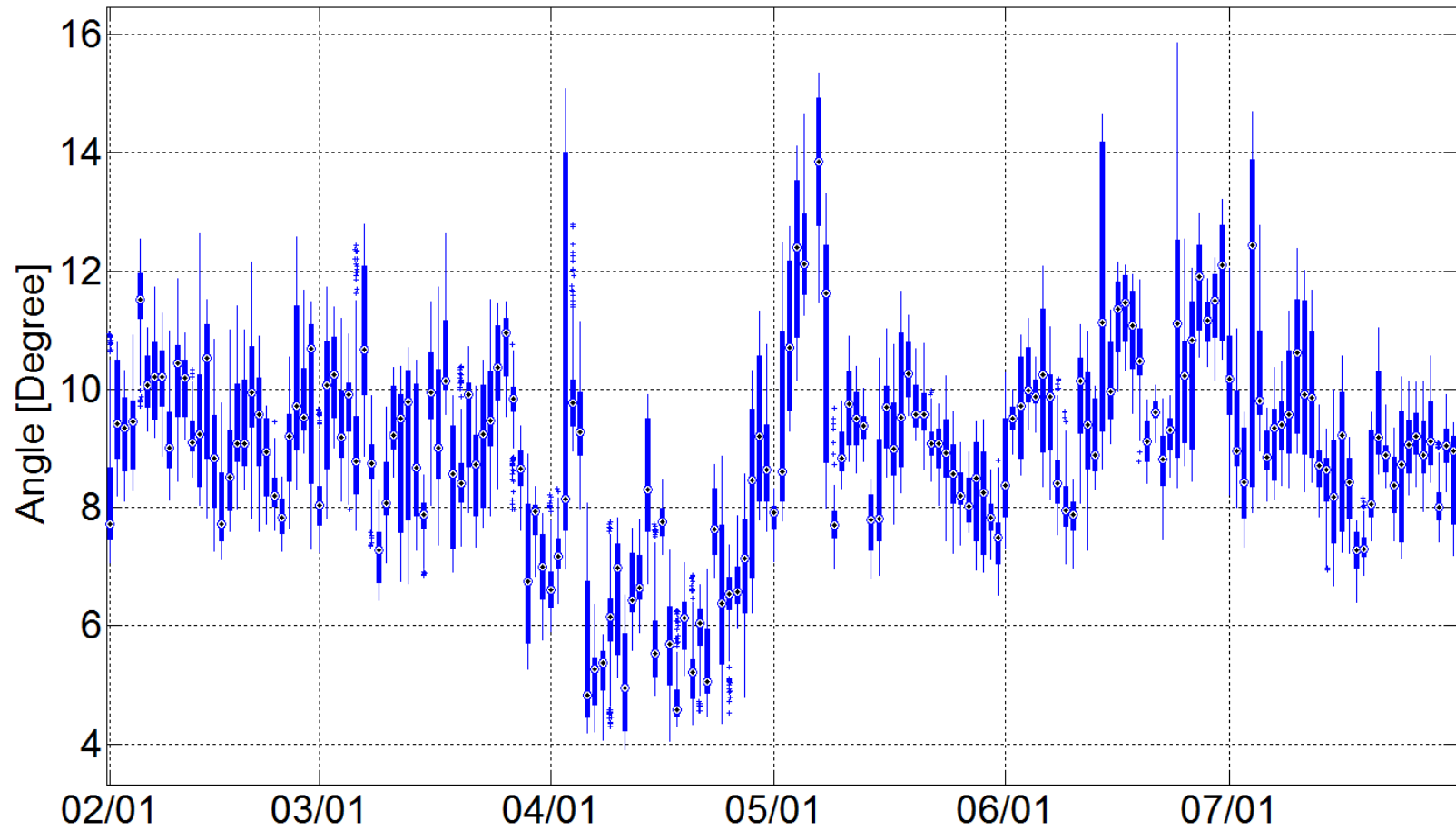
West 5-North 1



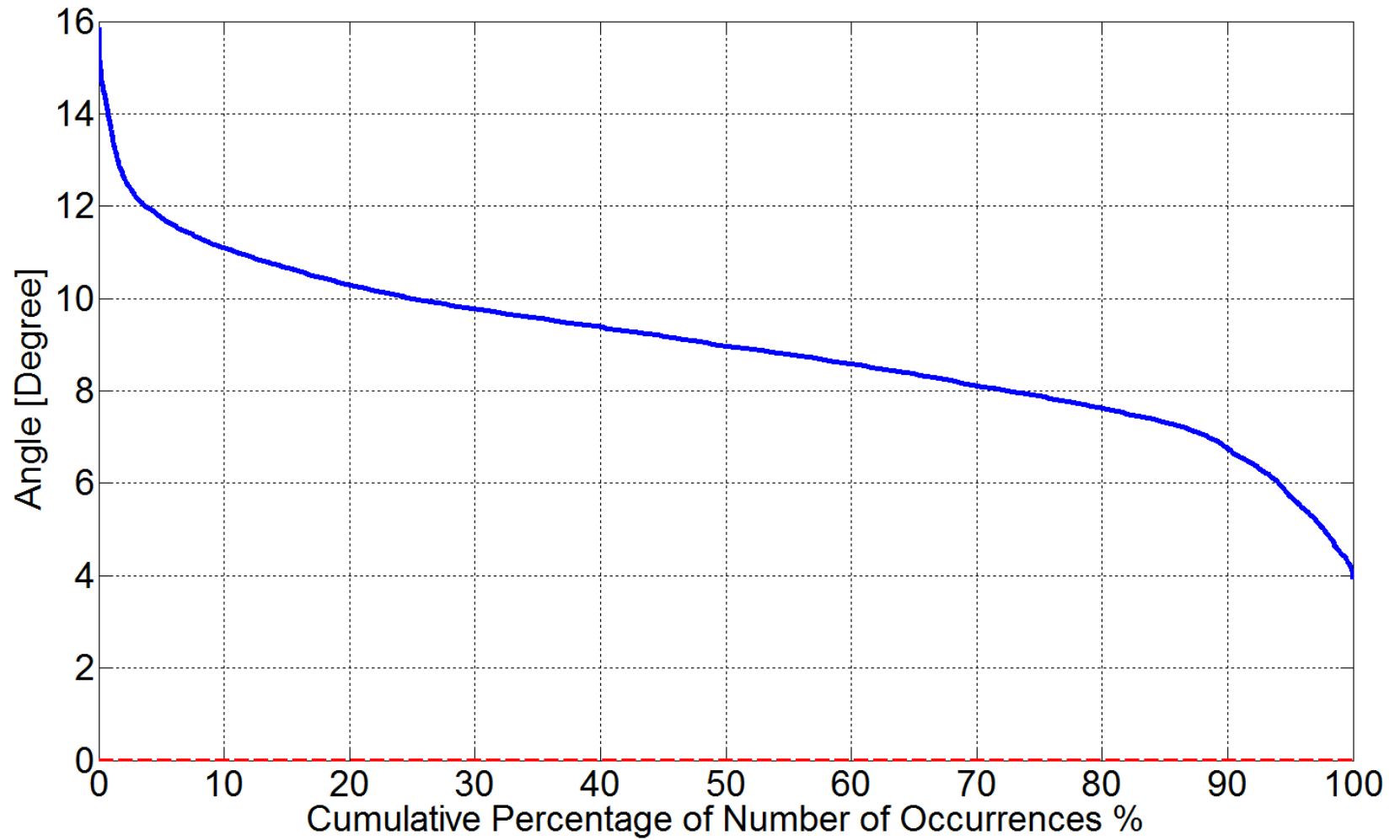
West 5-North 1



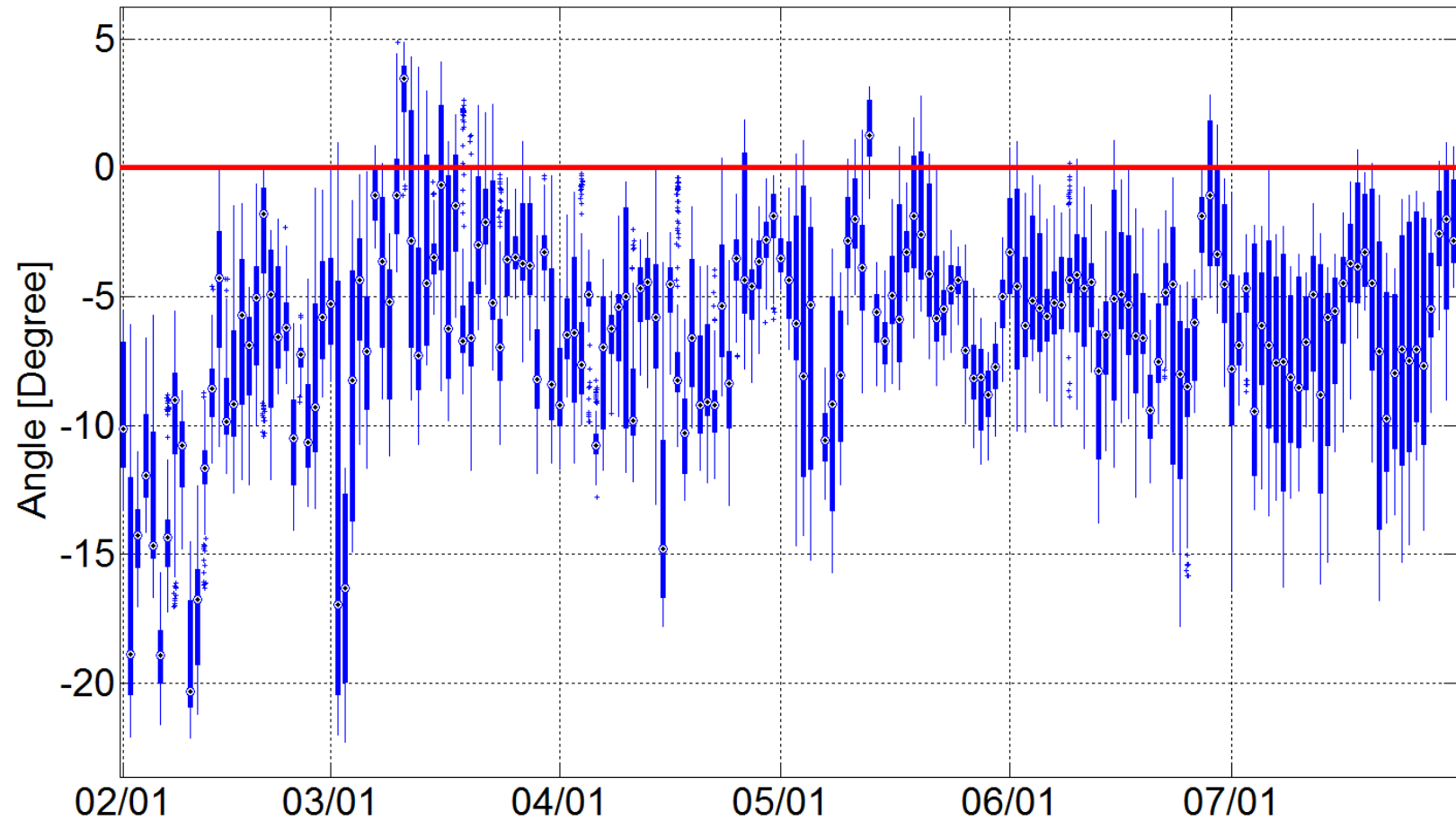
North 1-North 4



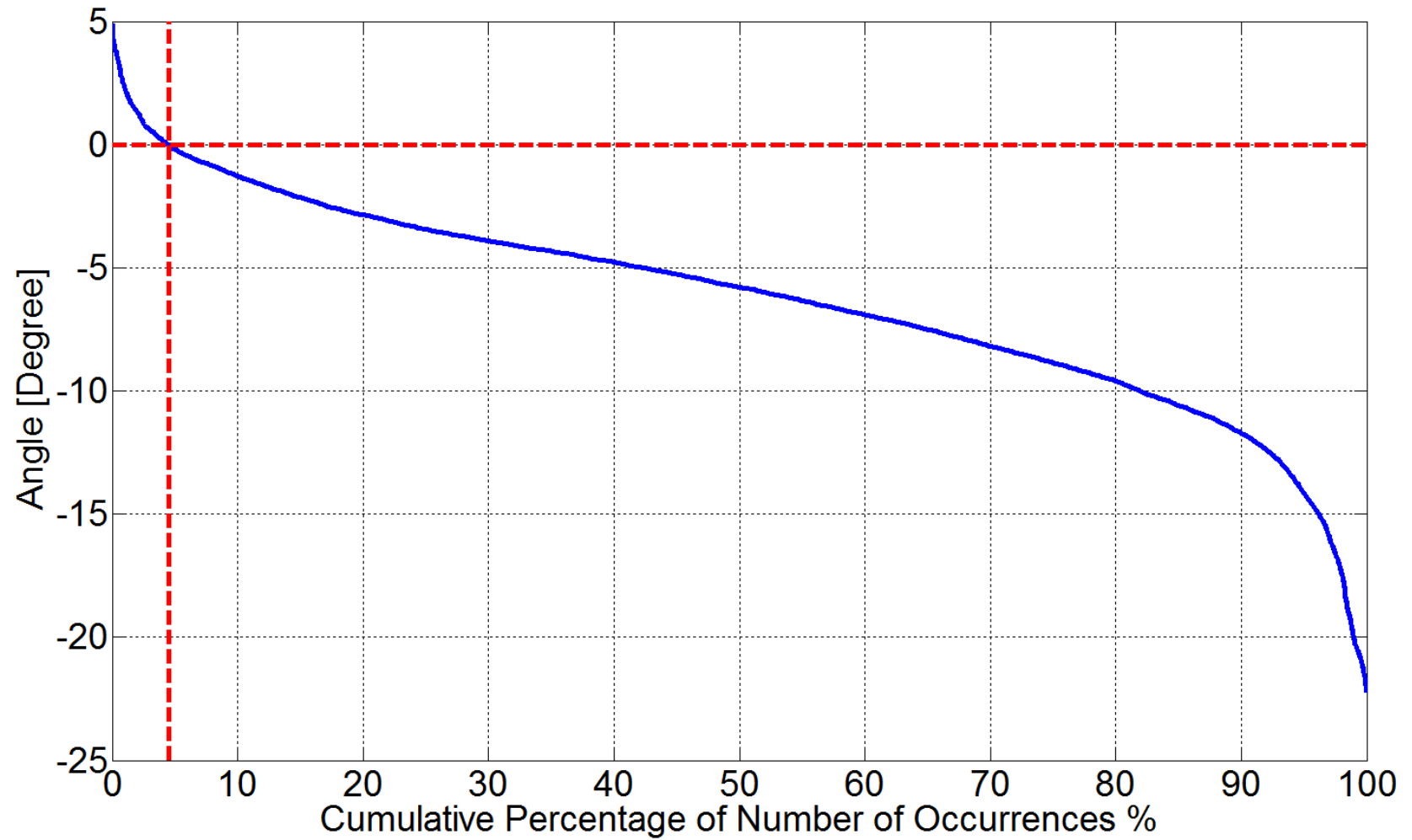
North 1-North 4



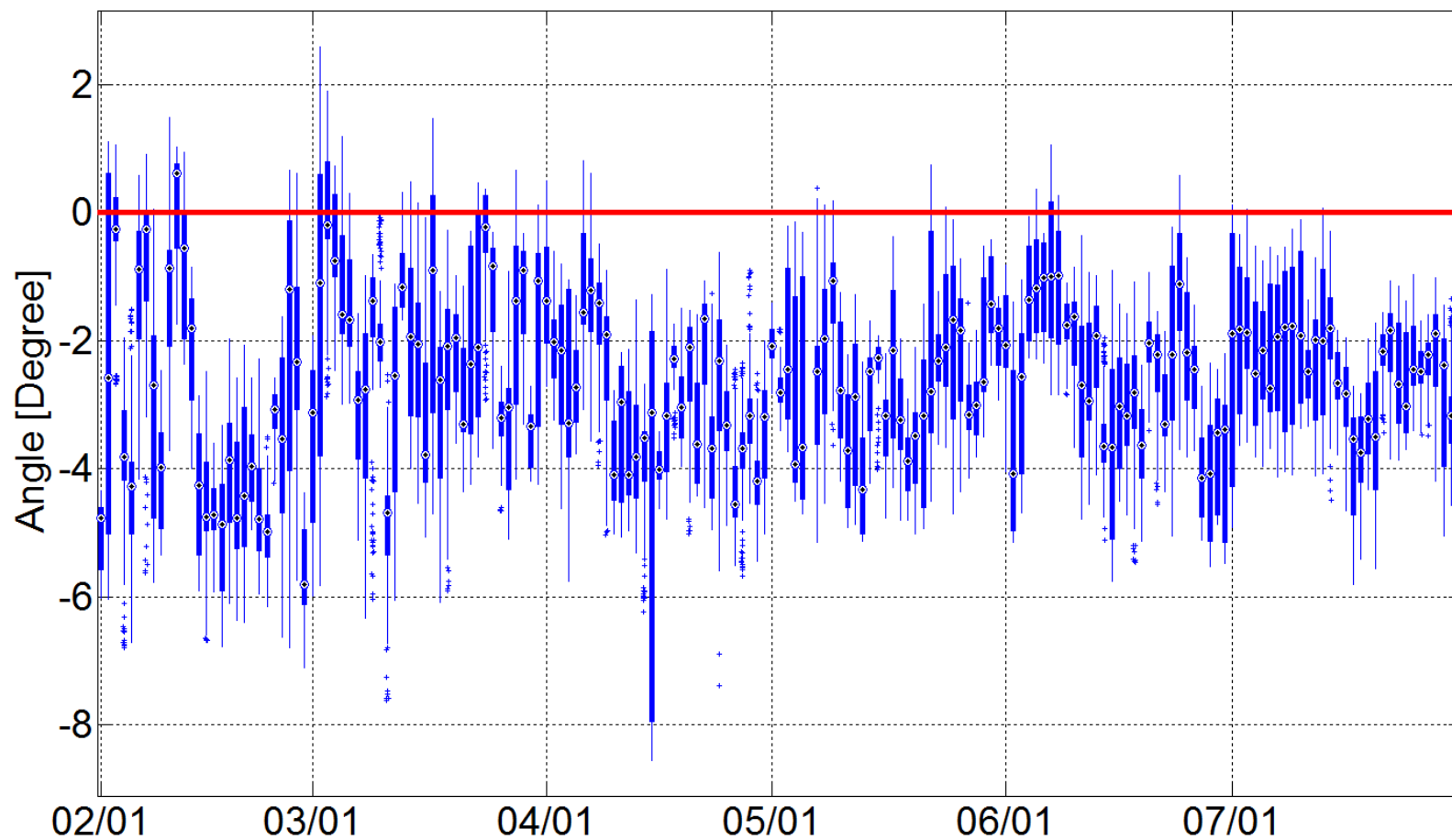
North 4-North 6



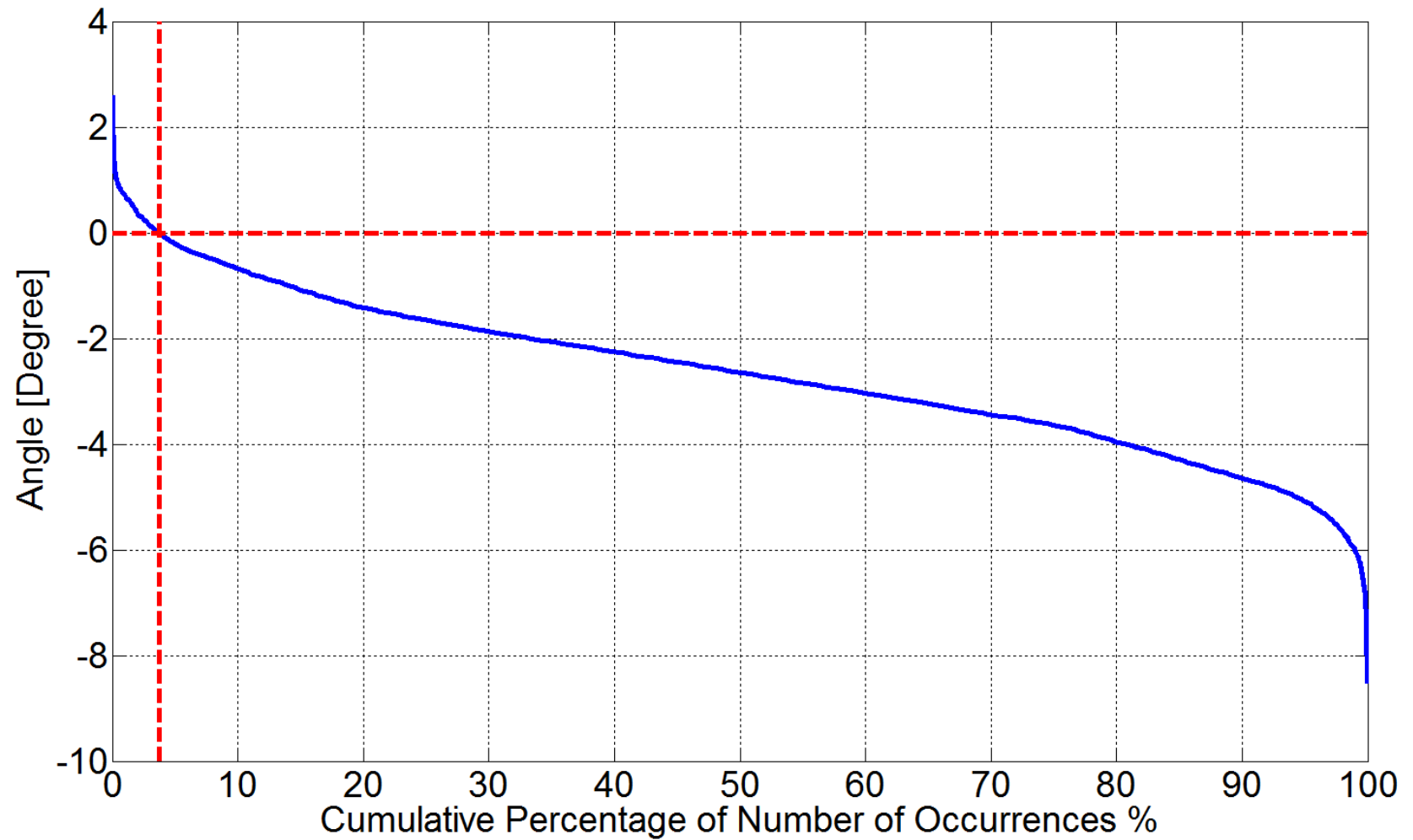
North 4-North 6



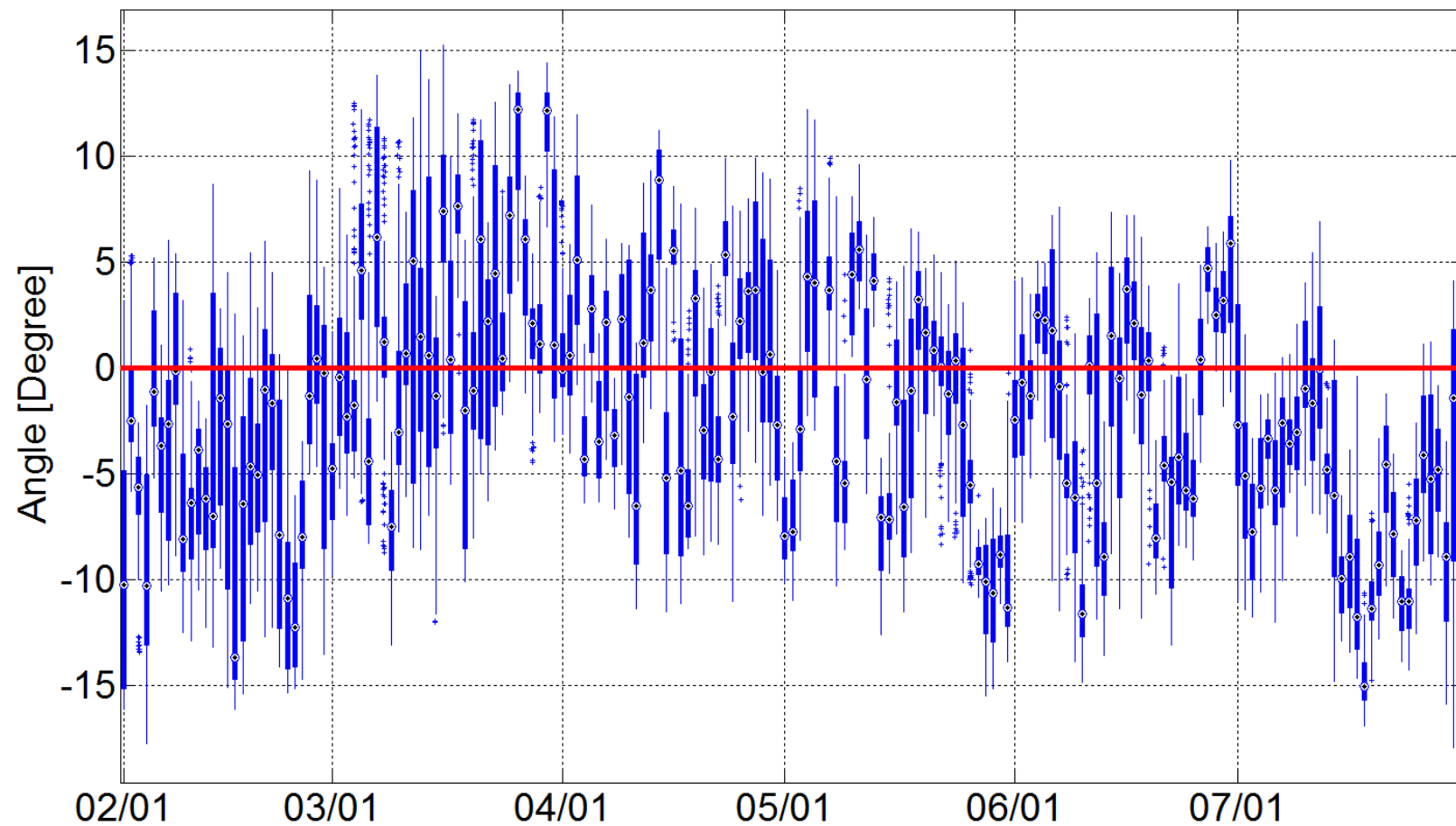
FarWest 7-FarWest 4



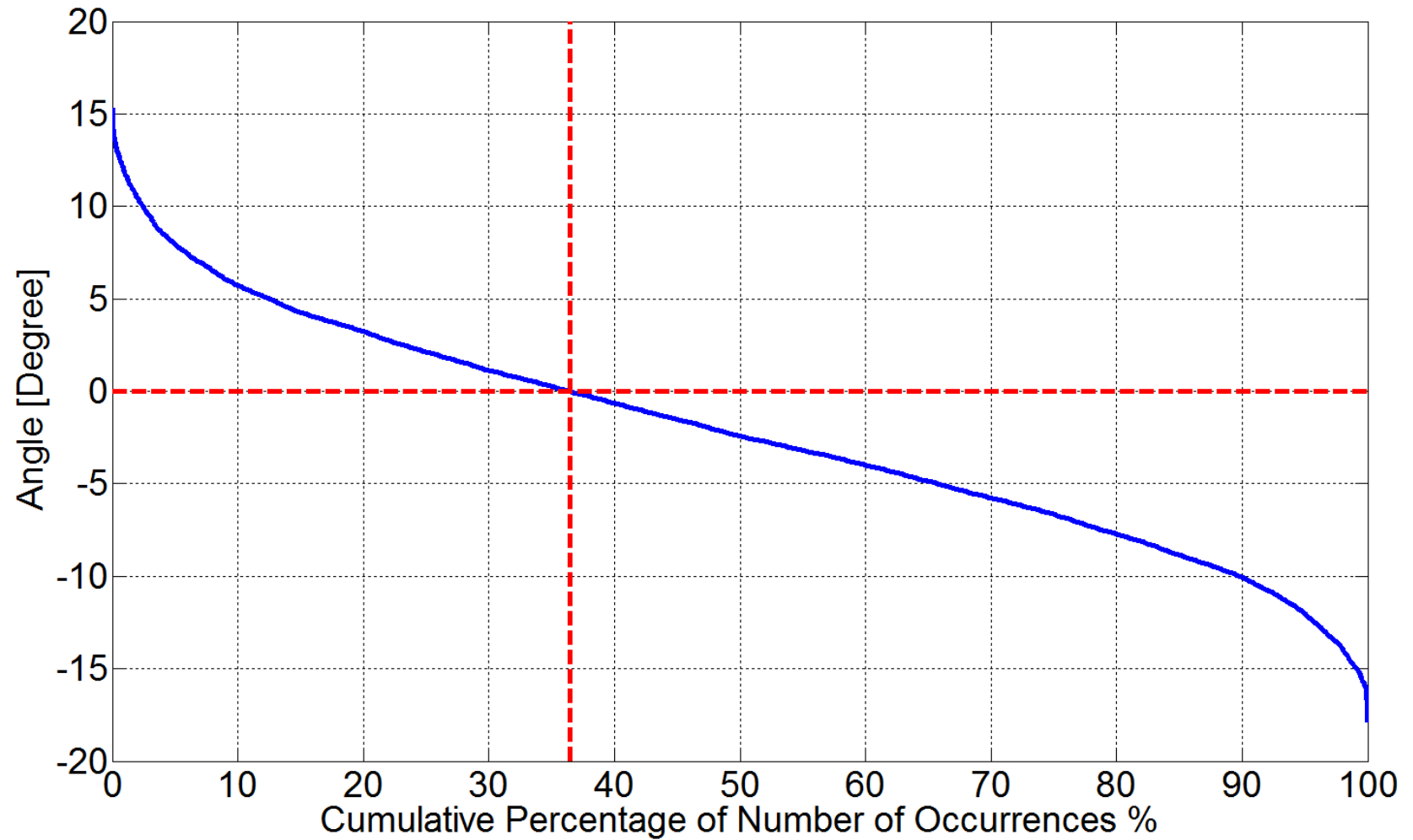
FarWest 7-FarWest 4



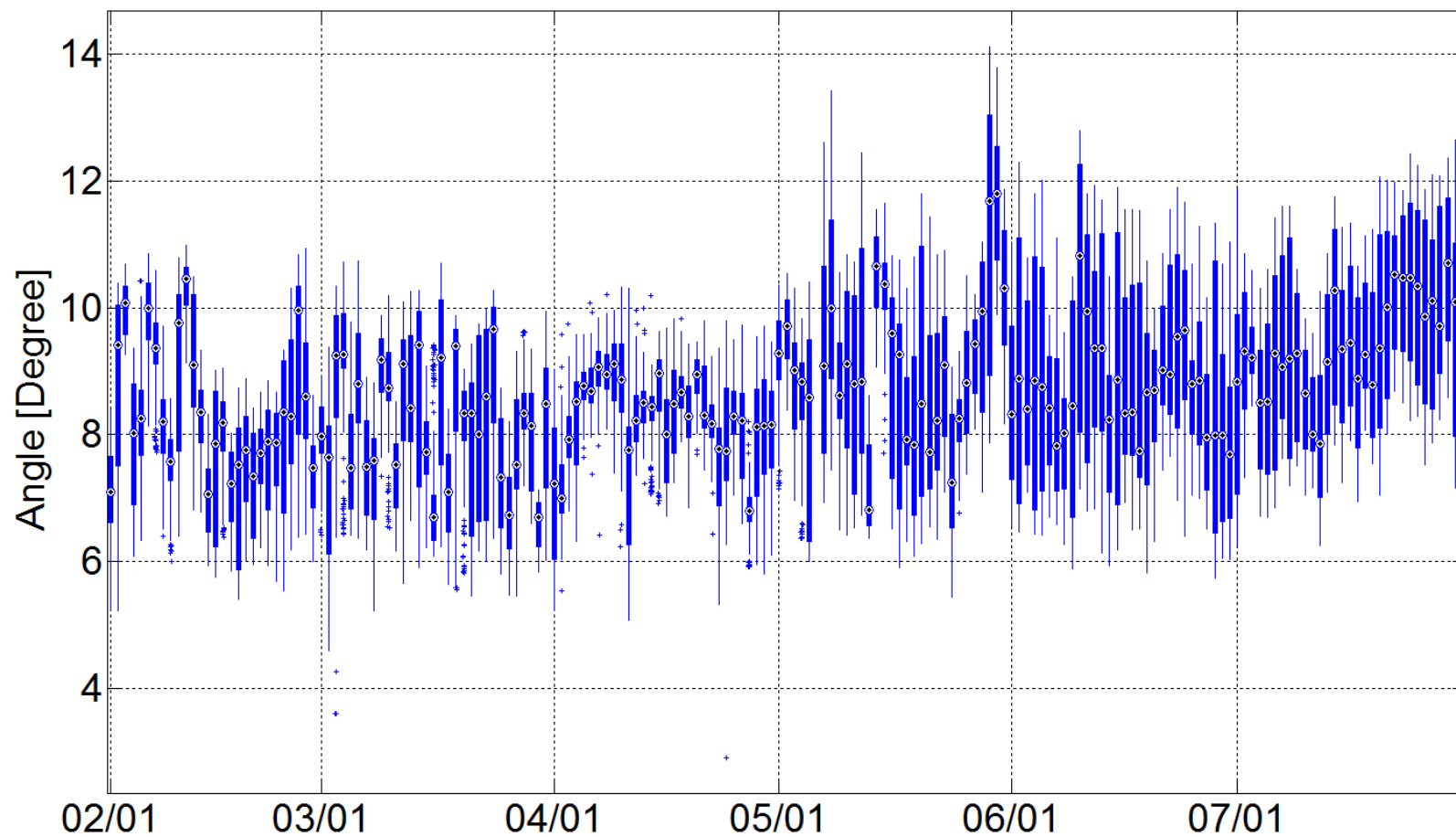
FarWest 7-West 14



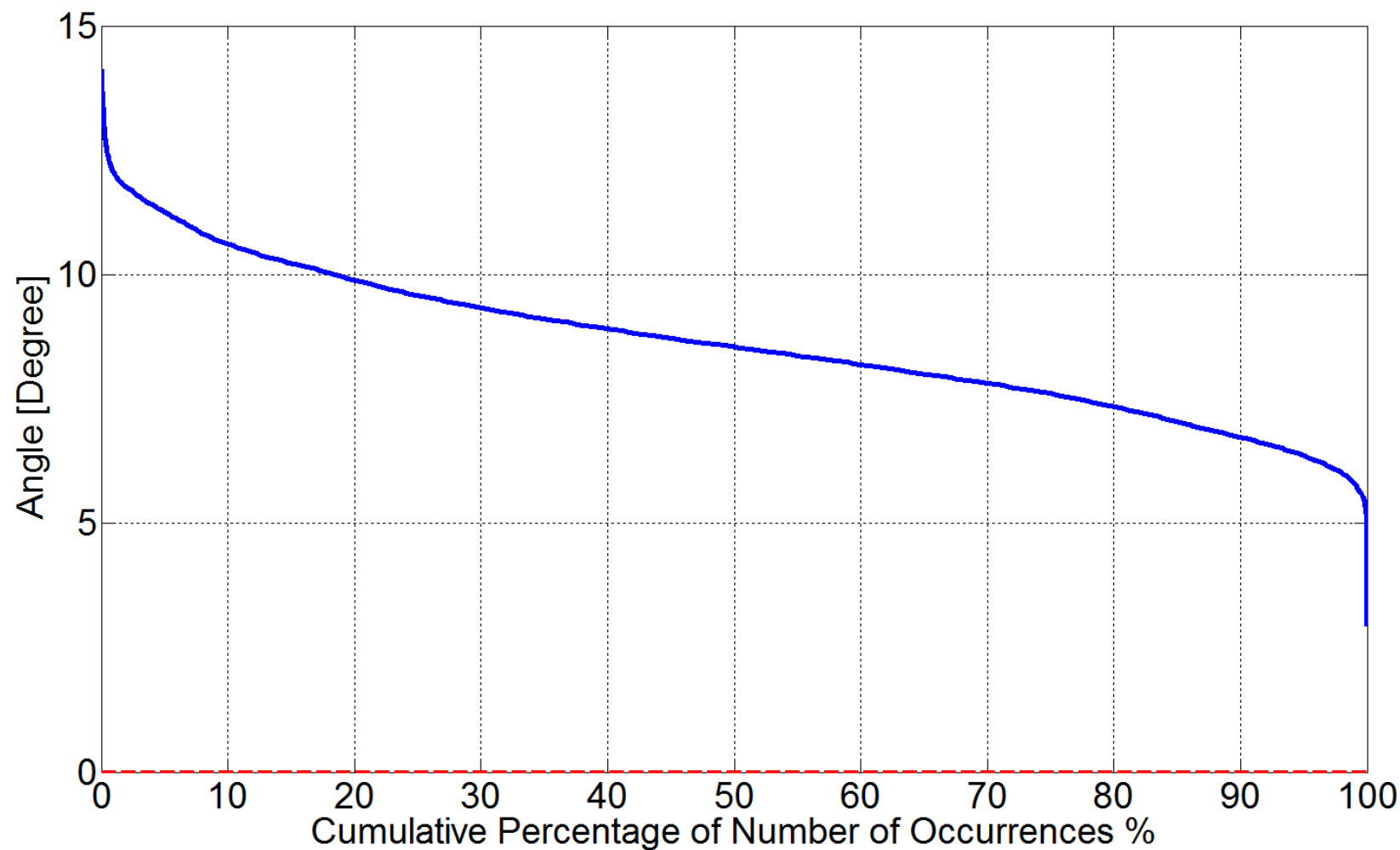
FarWest 7-West 14



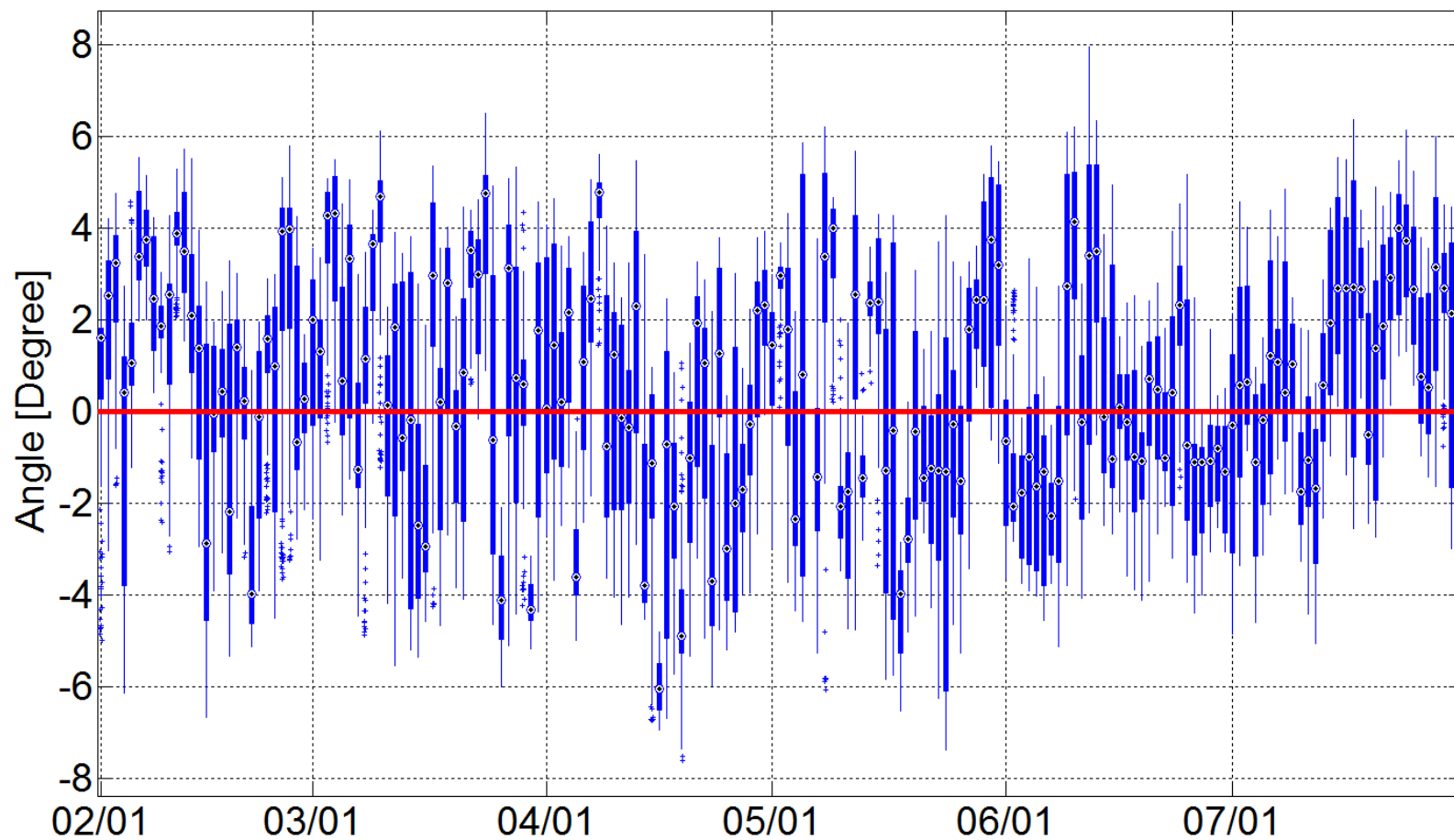
FarWest 7-FarWest 8



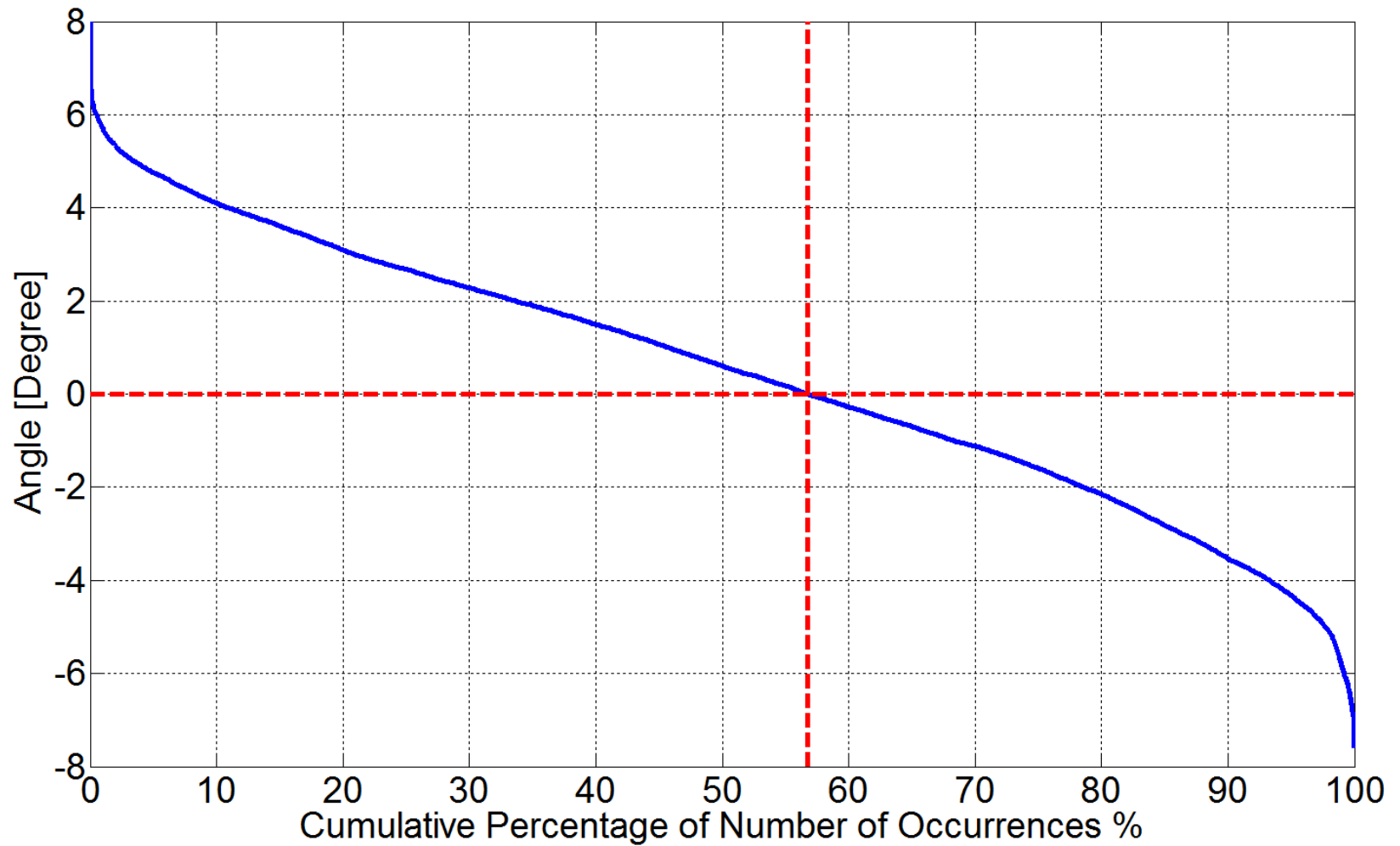
FarWest 7-FarWest 8



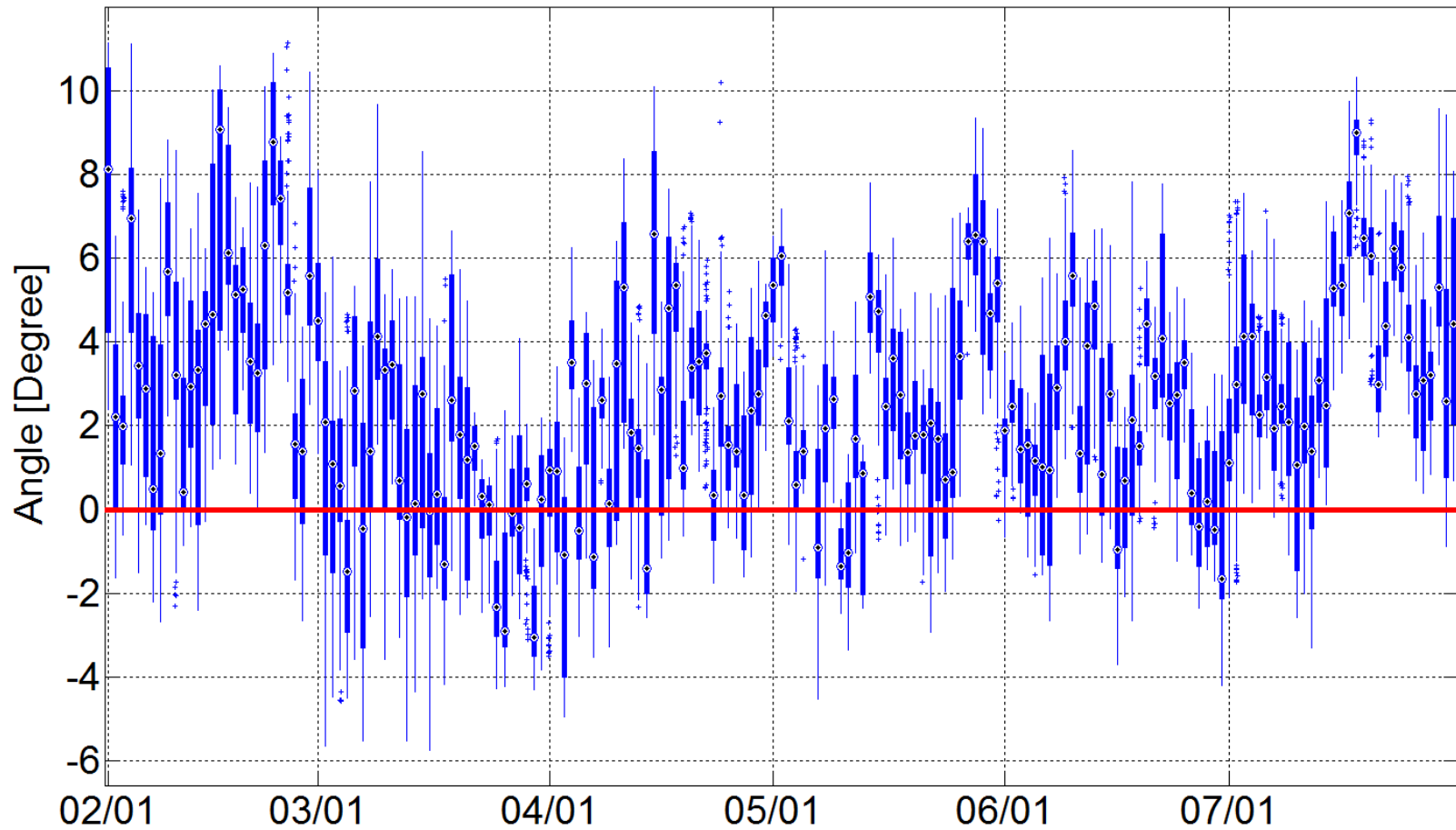
FarWest 7-FarWest 9



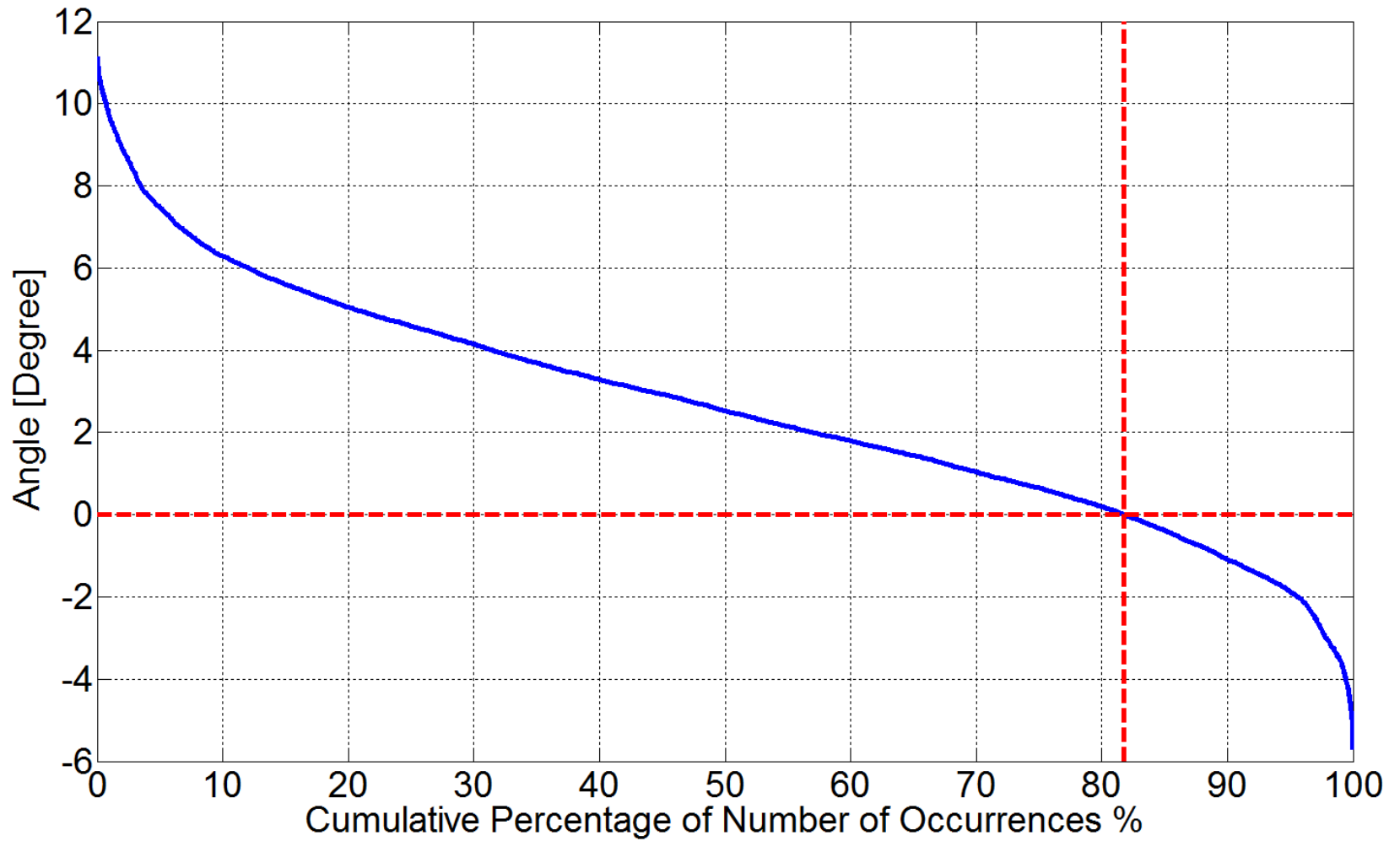
FarWest 7-FarWest 9



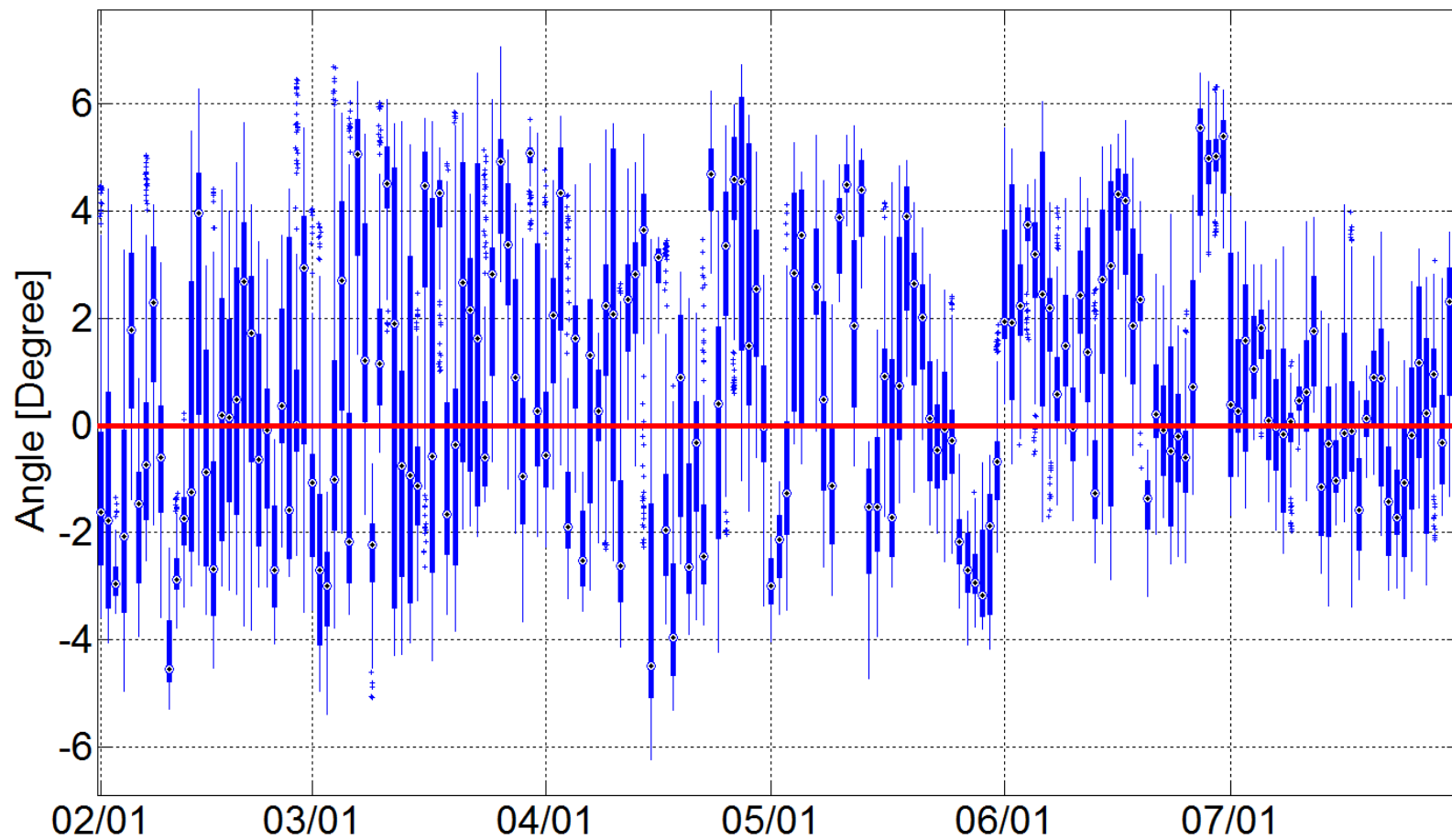
West 12-FarWest 7



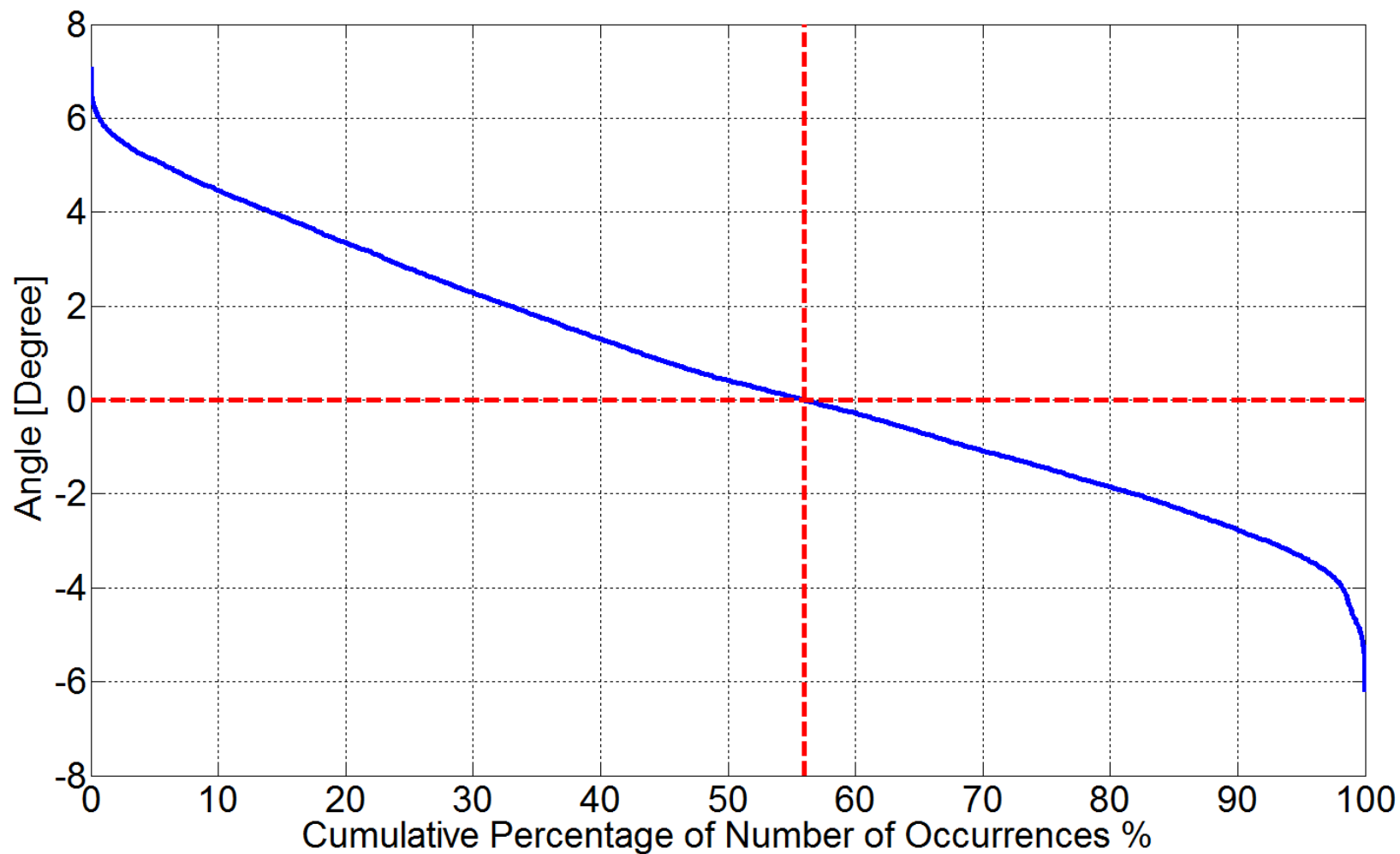
West 12-FarWest 7



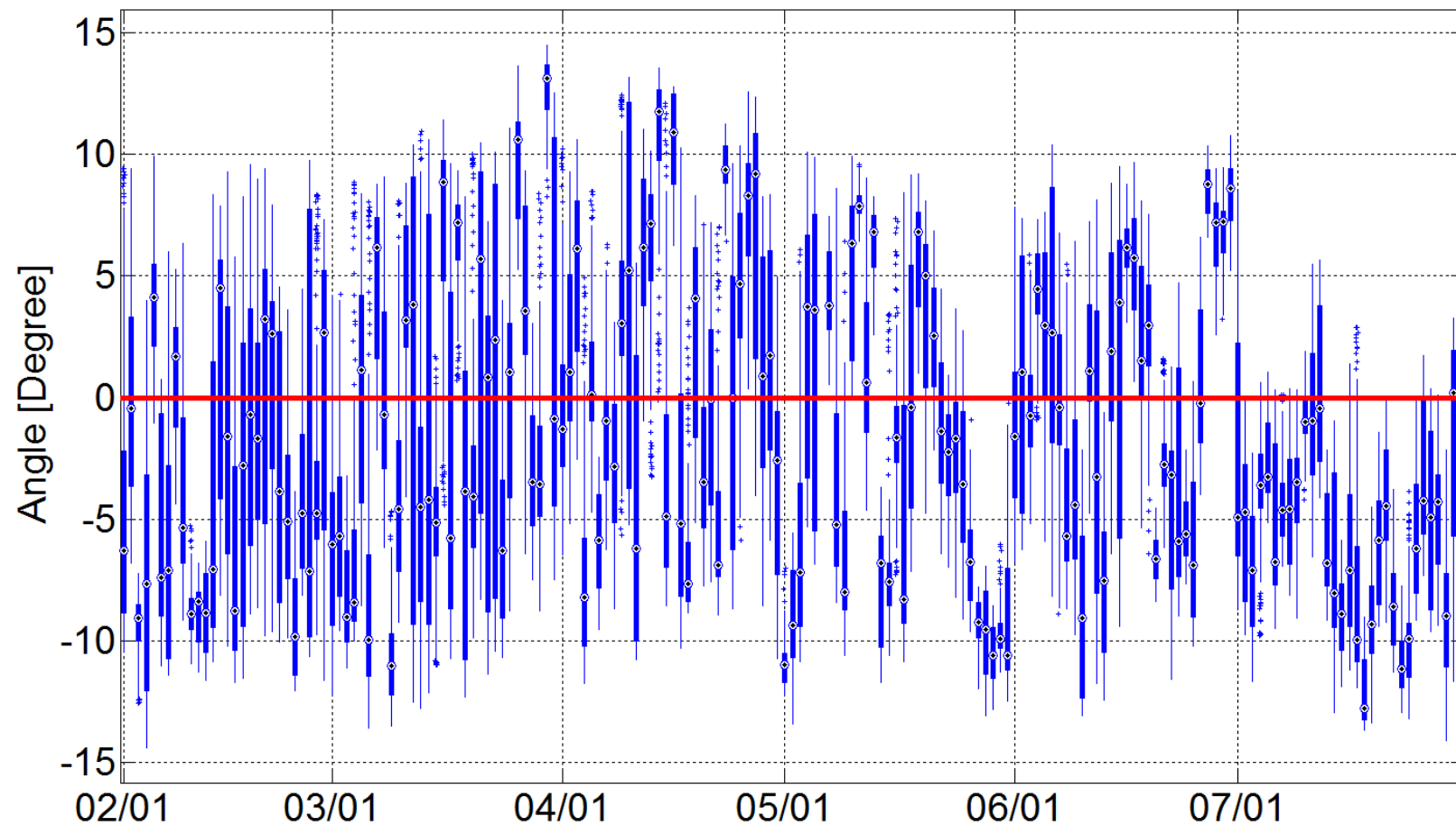
West 12-West 1



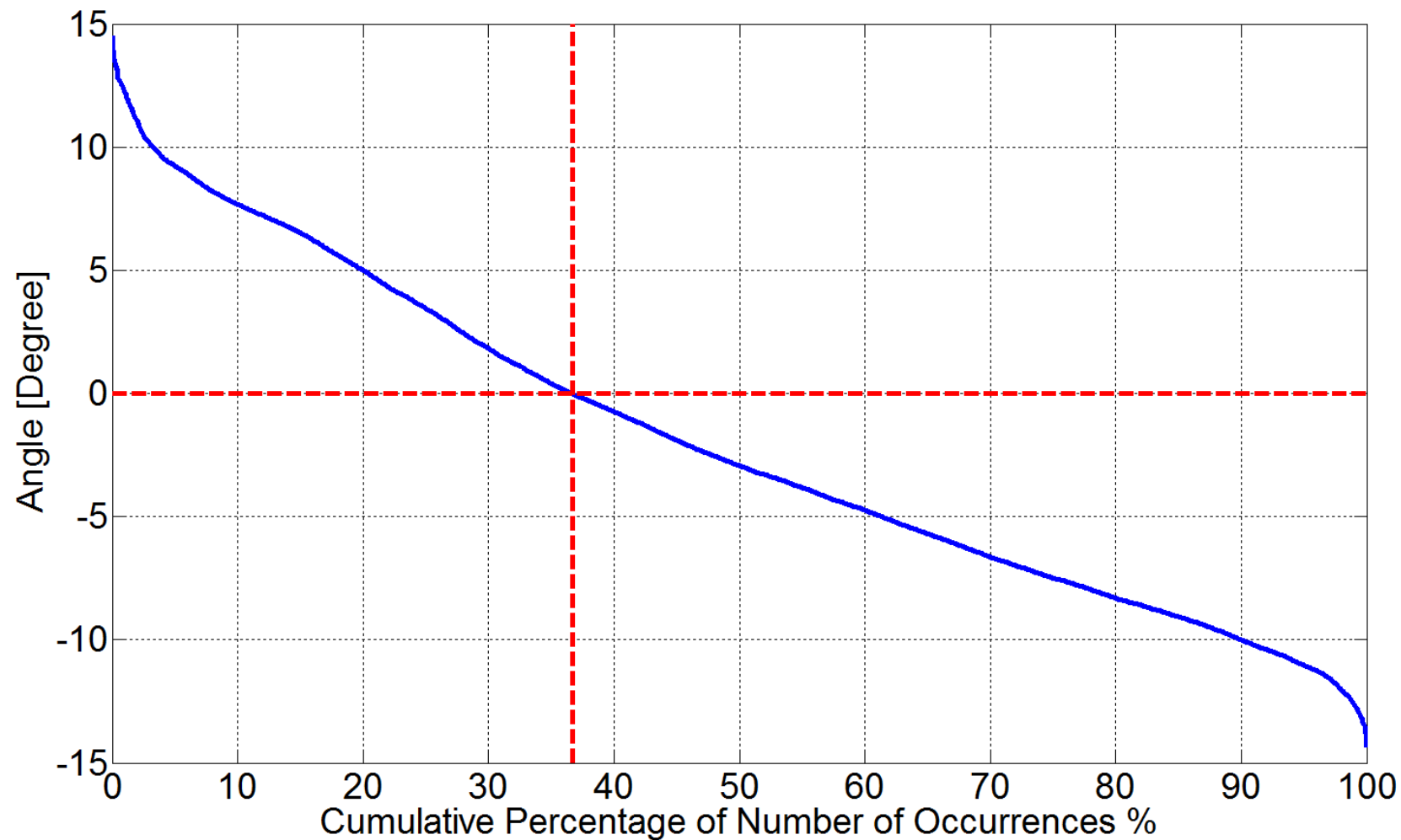
West 12-West 1



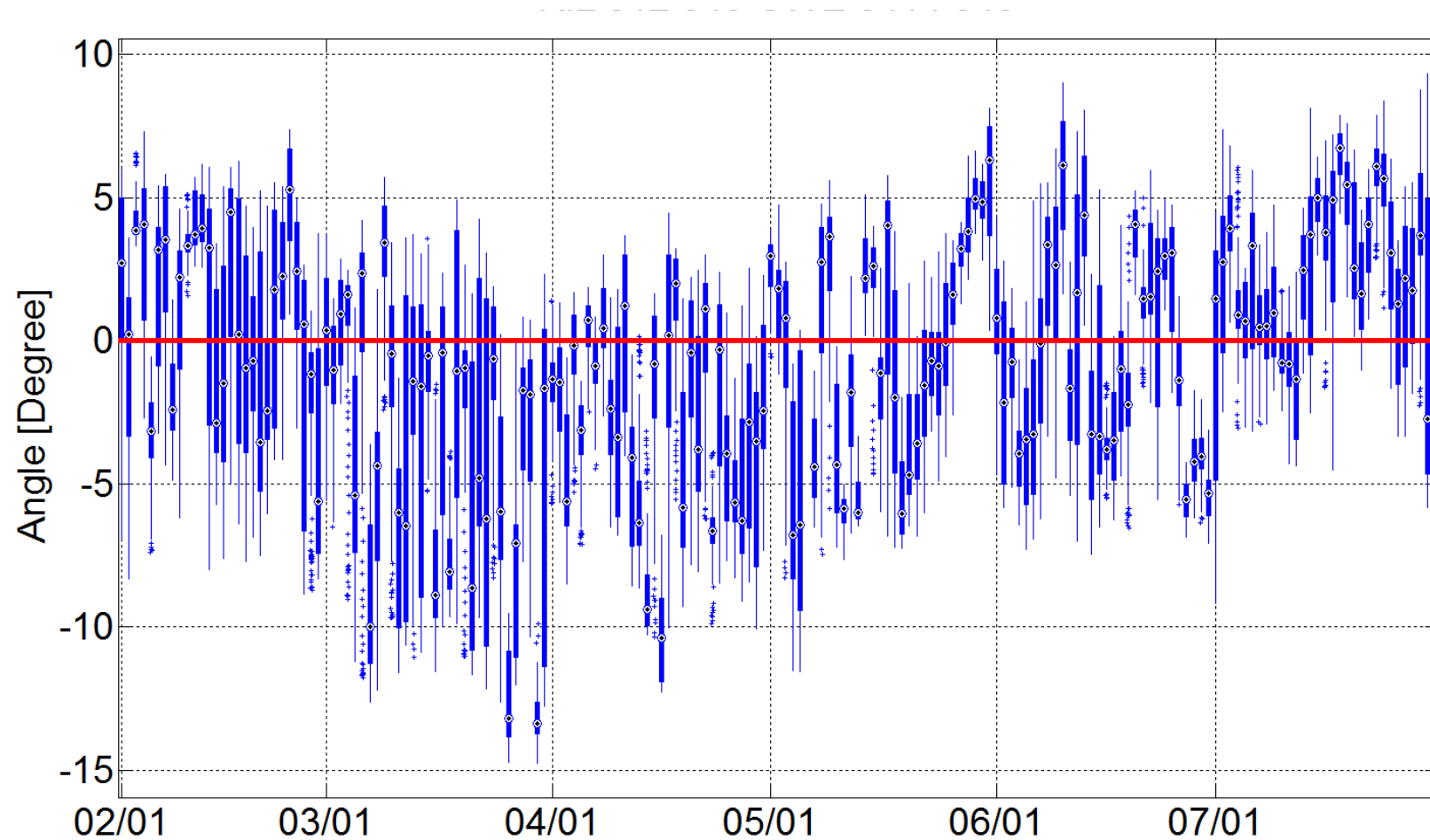
West 12-North 1



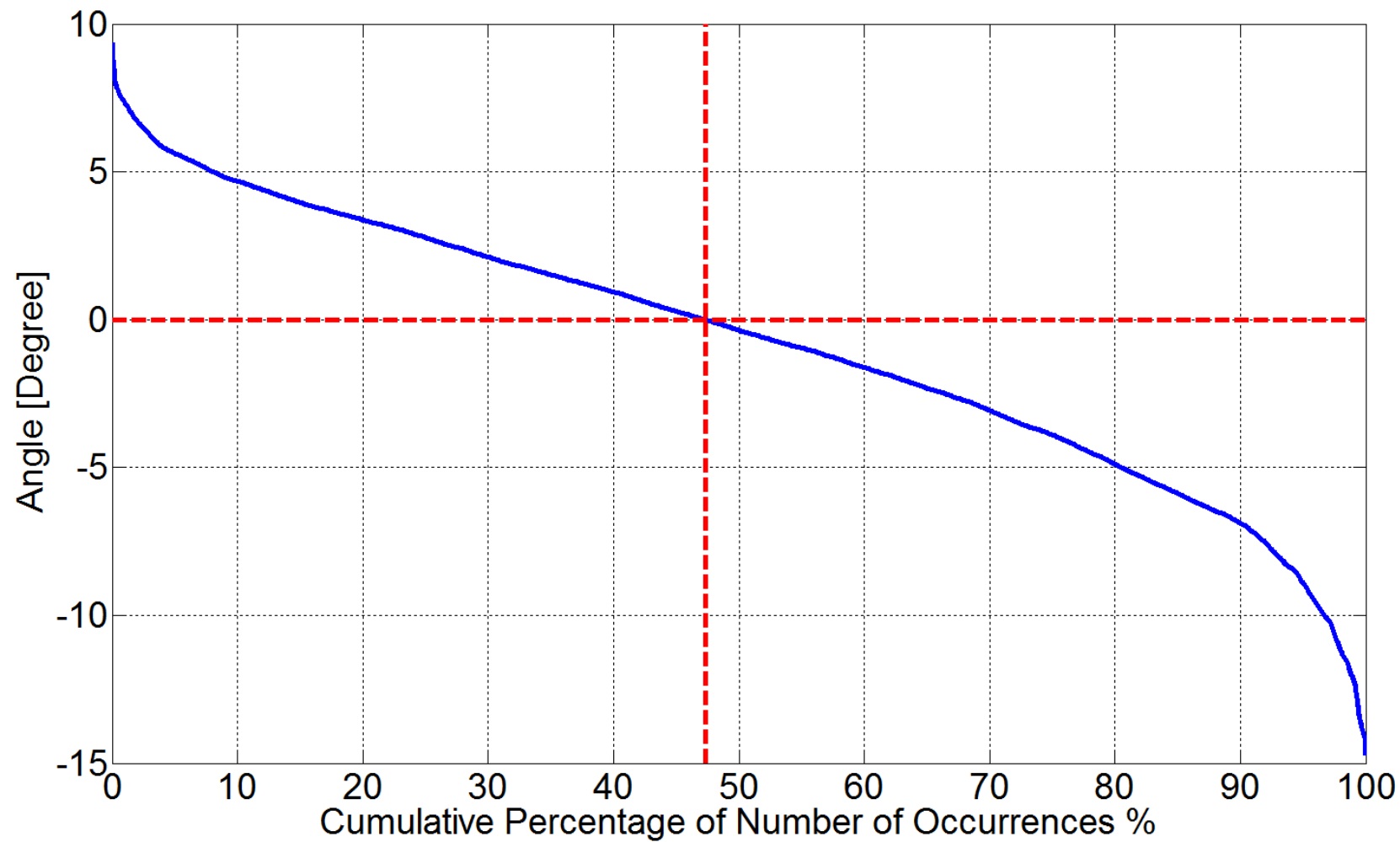
West 12-North 1



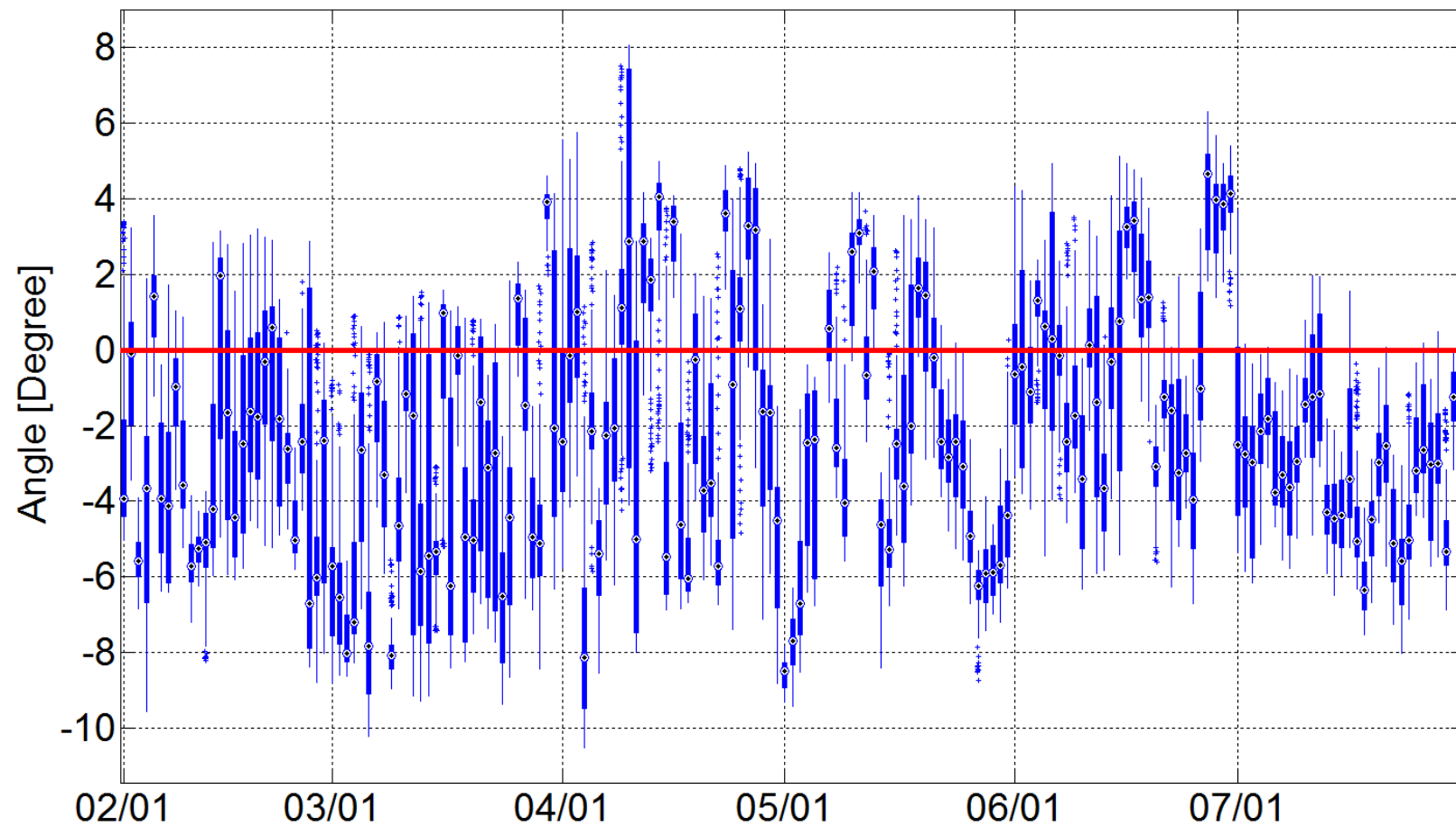
West 14-West 5



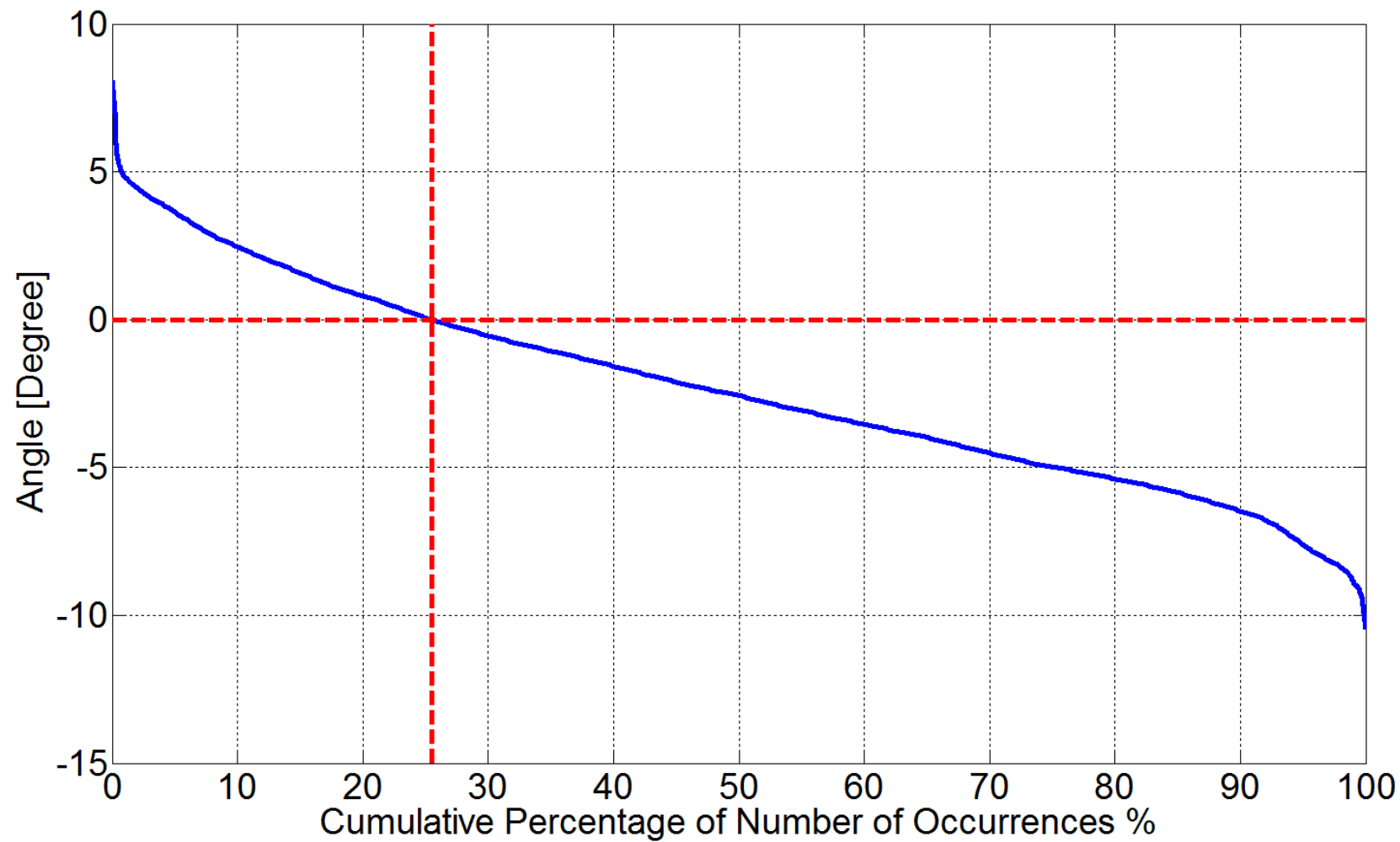
West 14-West 5



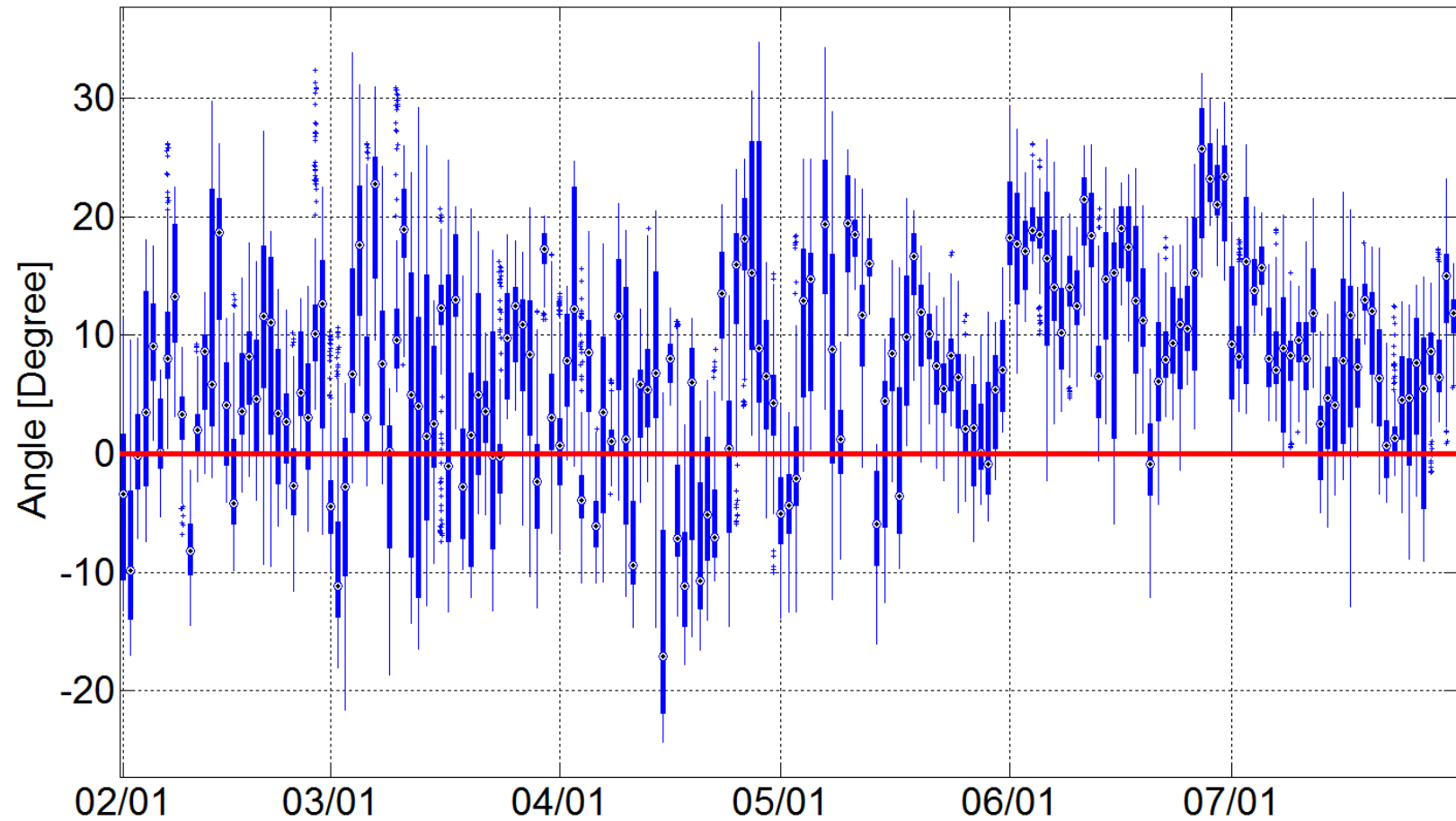
West 14-North 1



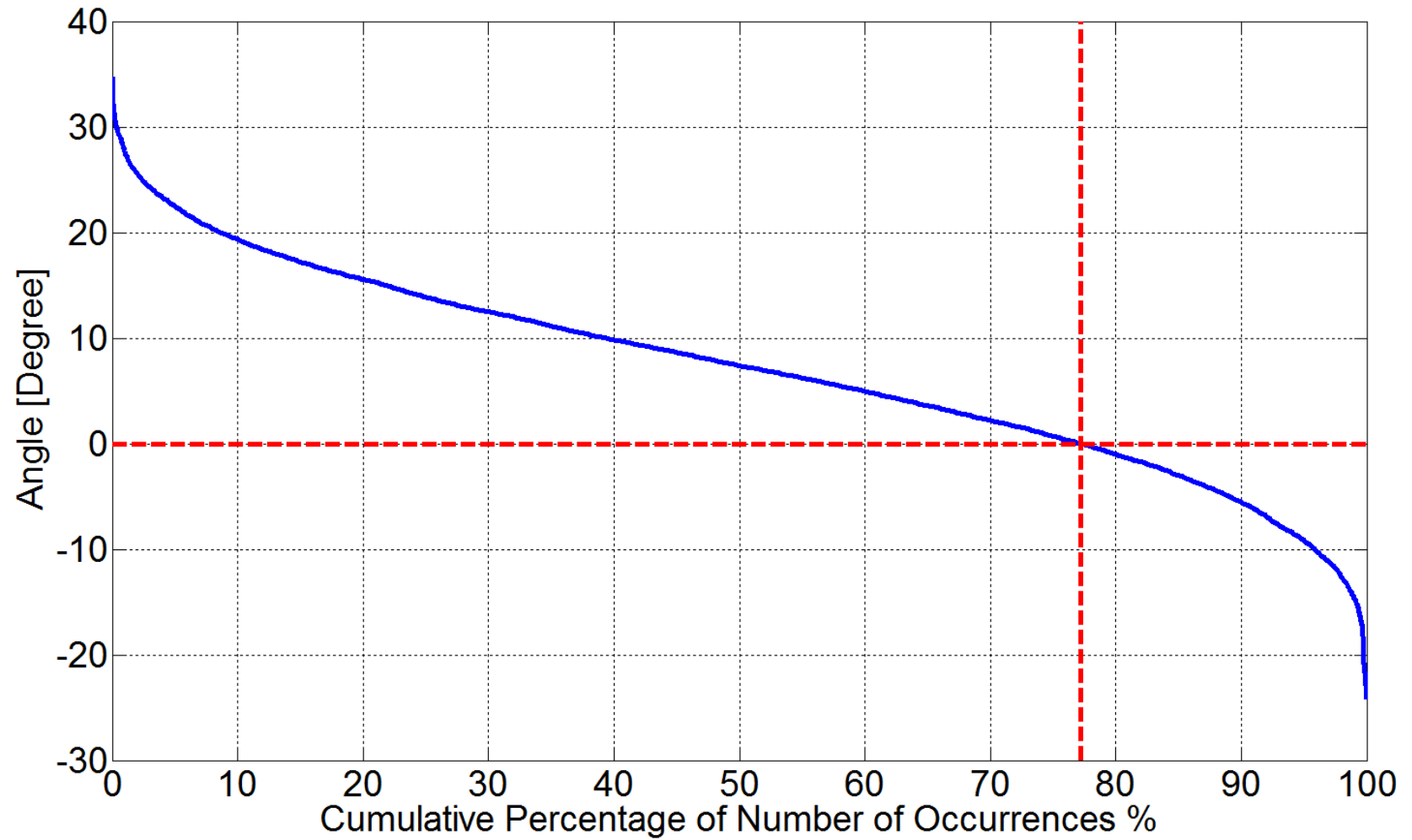
West 14-North 1



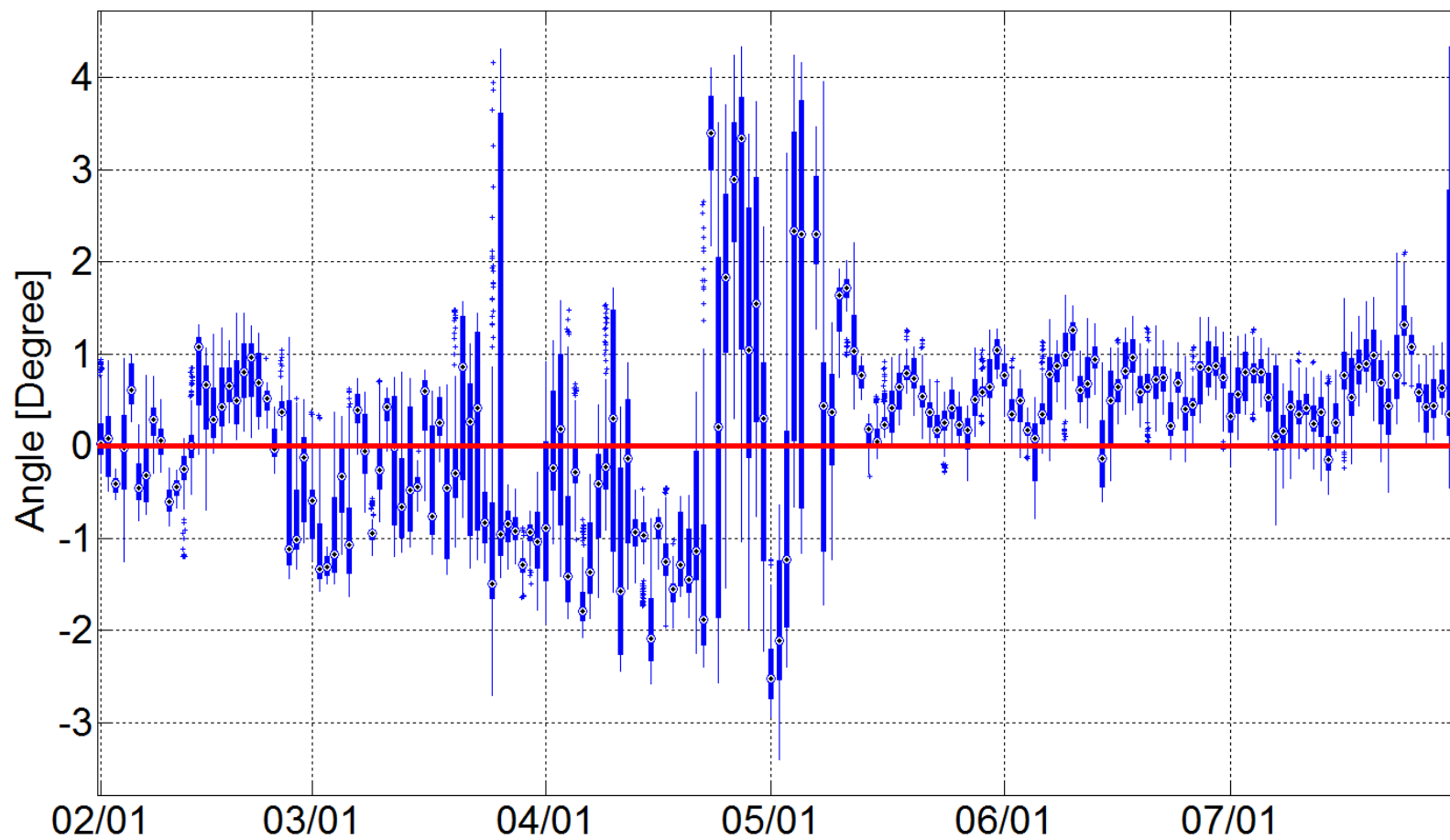
FarWest 9-West 4



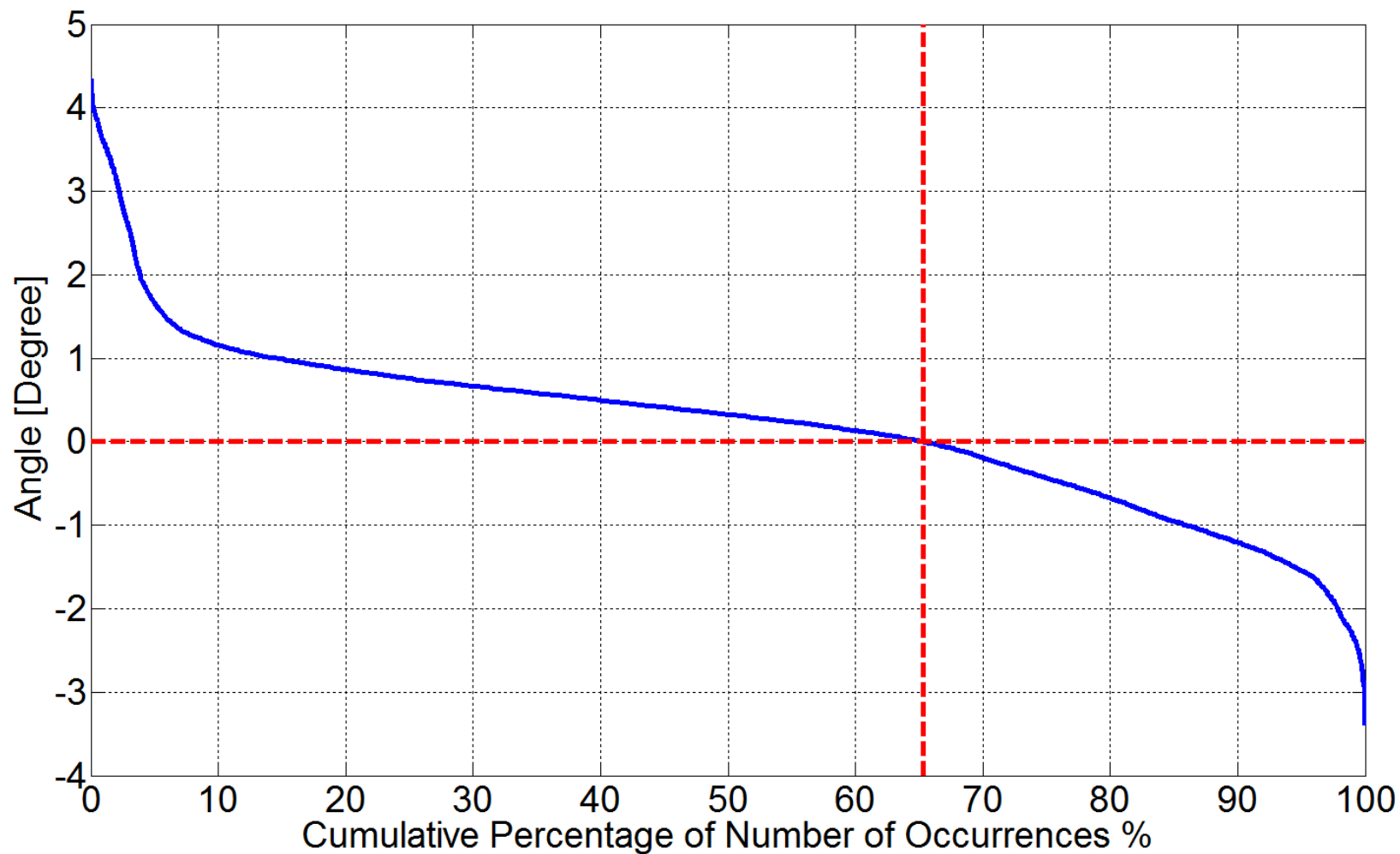
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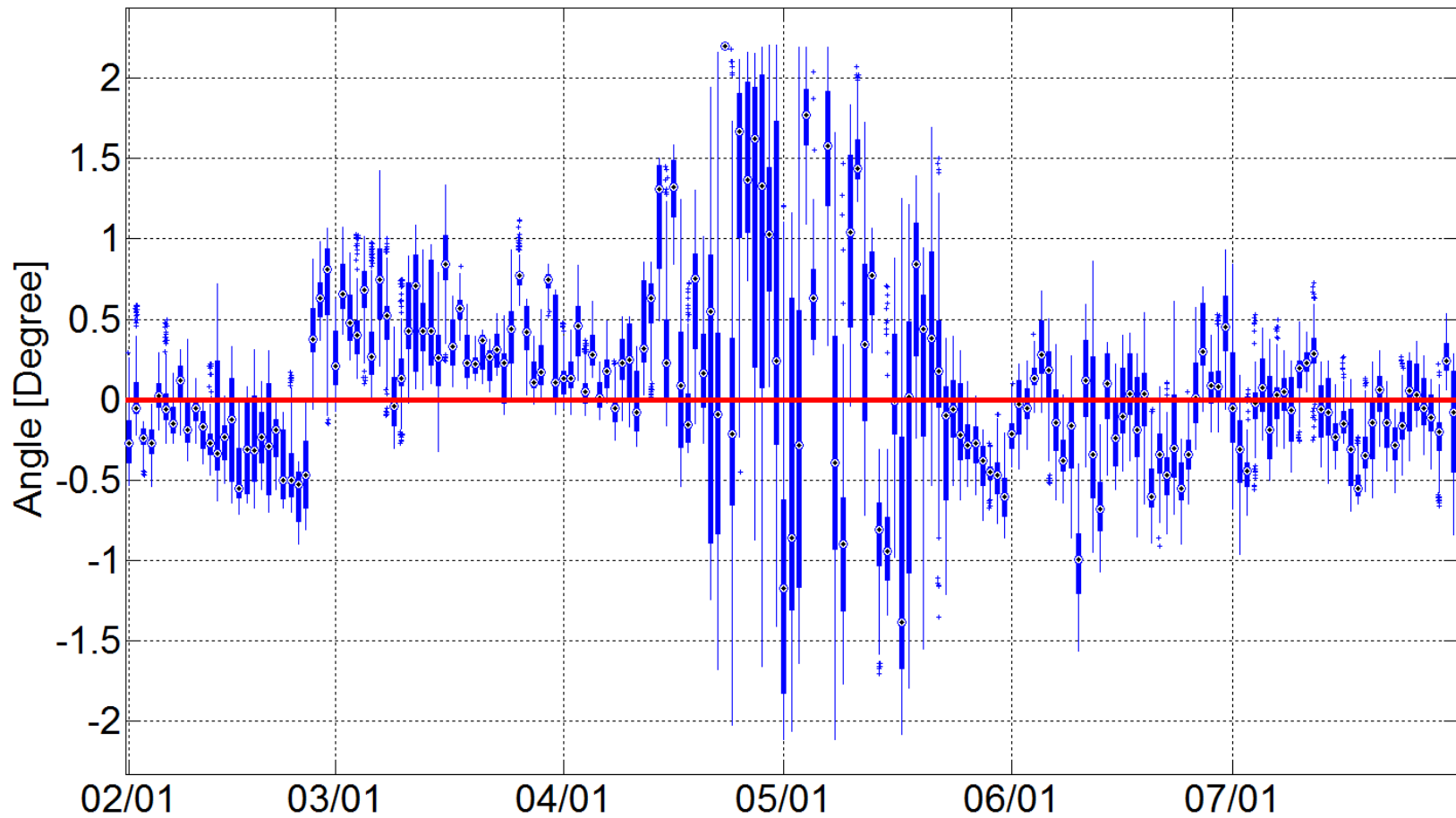
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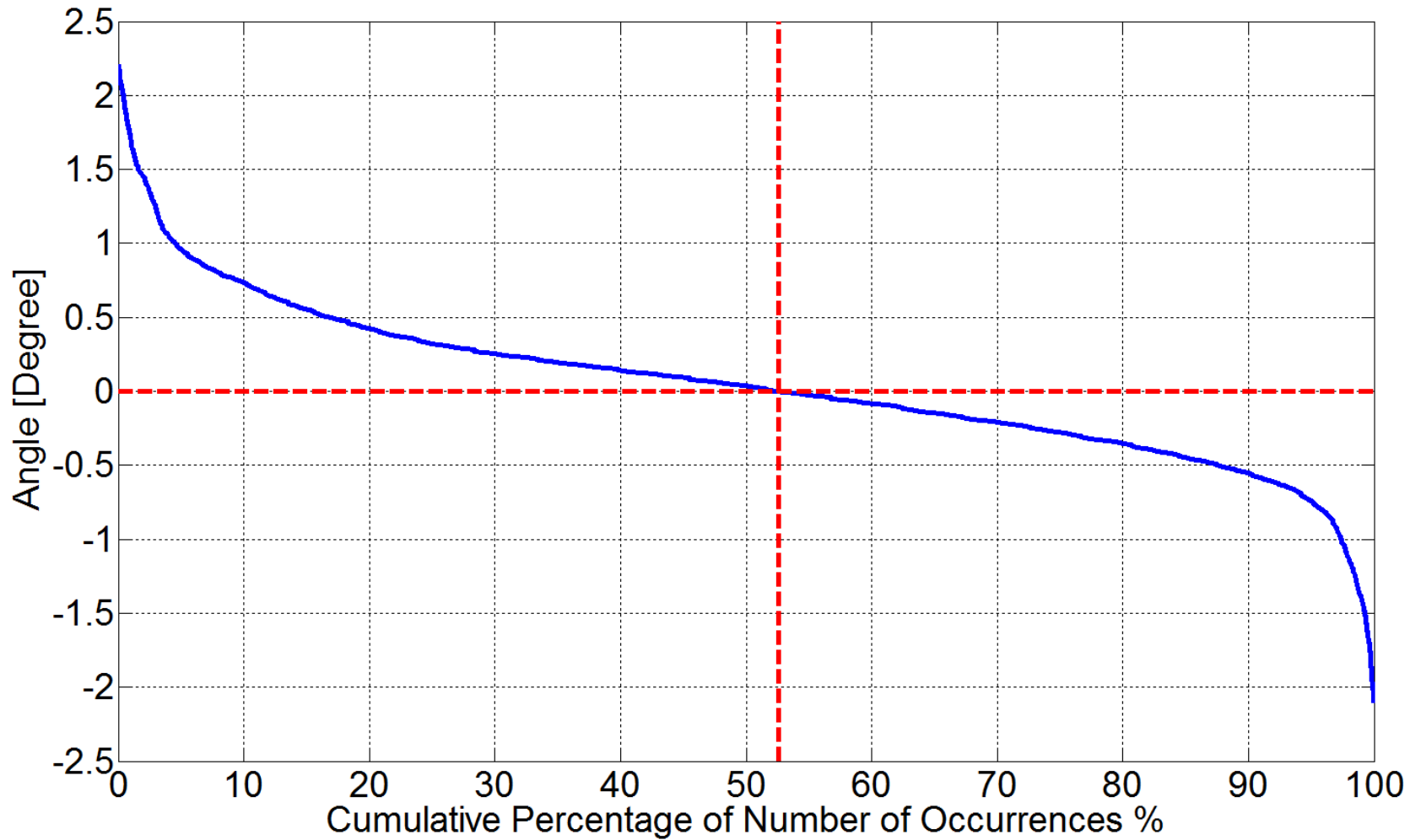
West 16-West 3



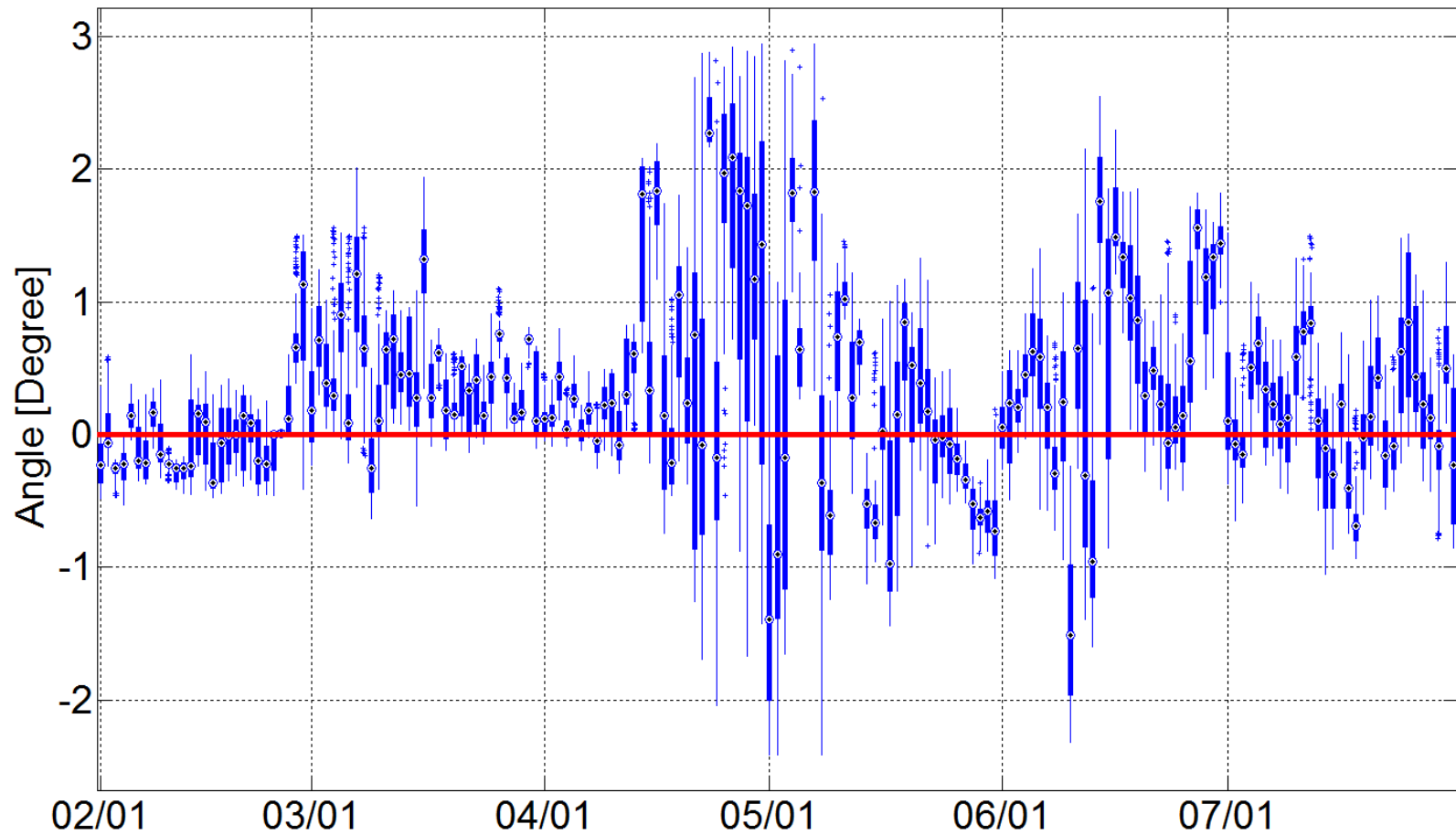
West 16-West 14



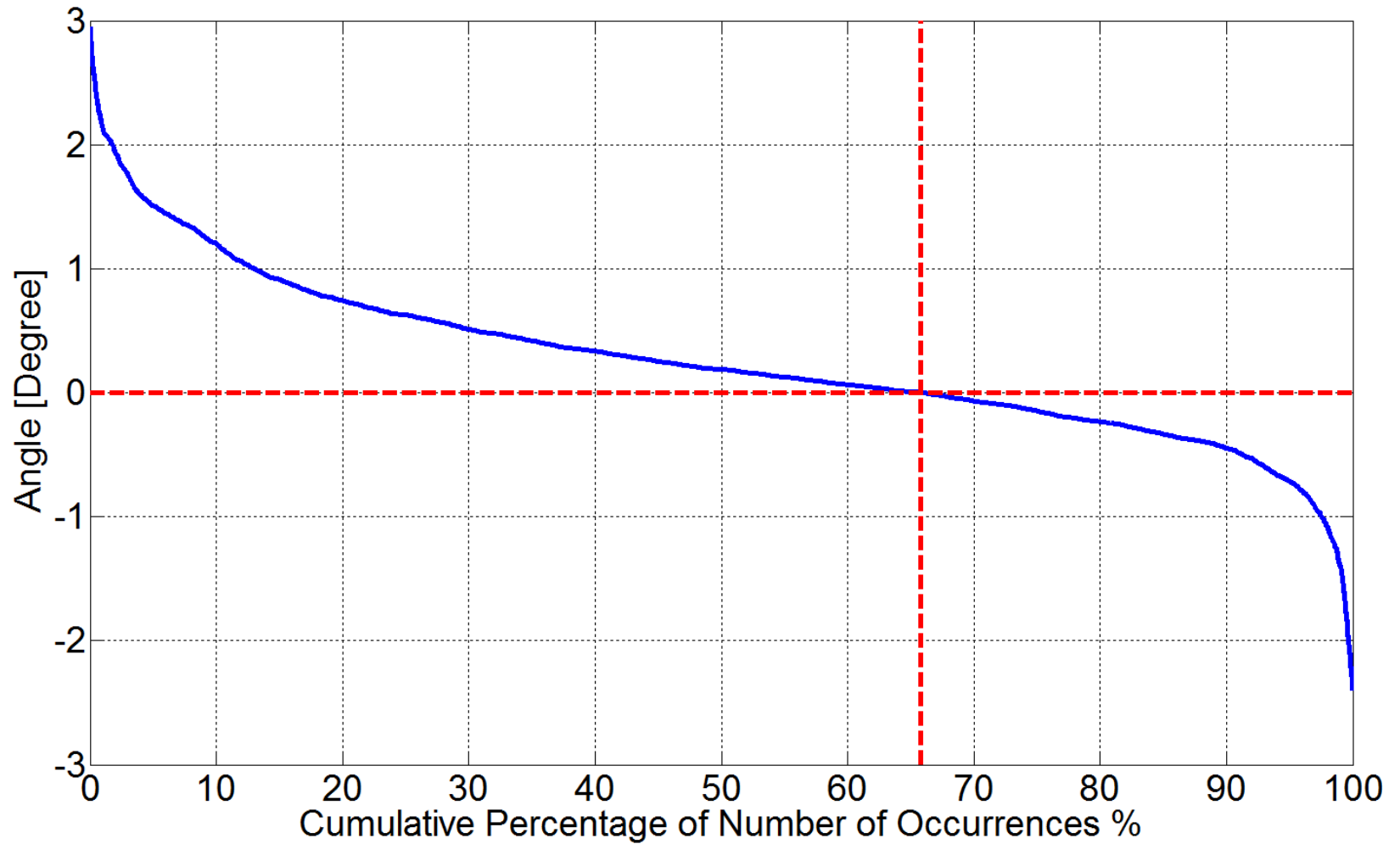
West 16-West 14



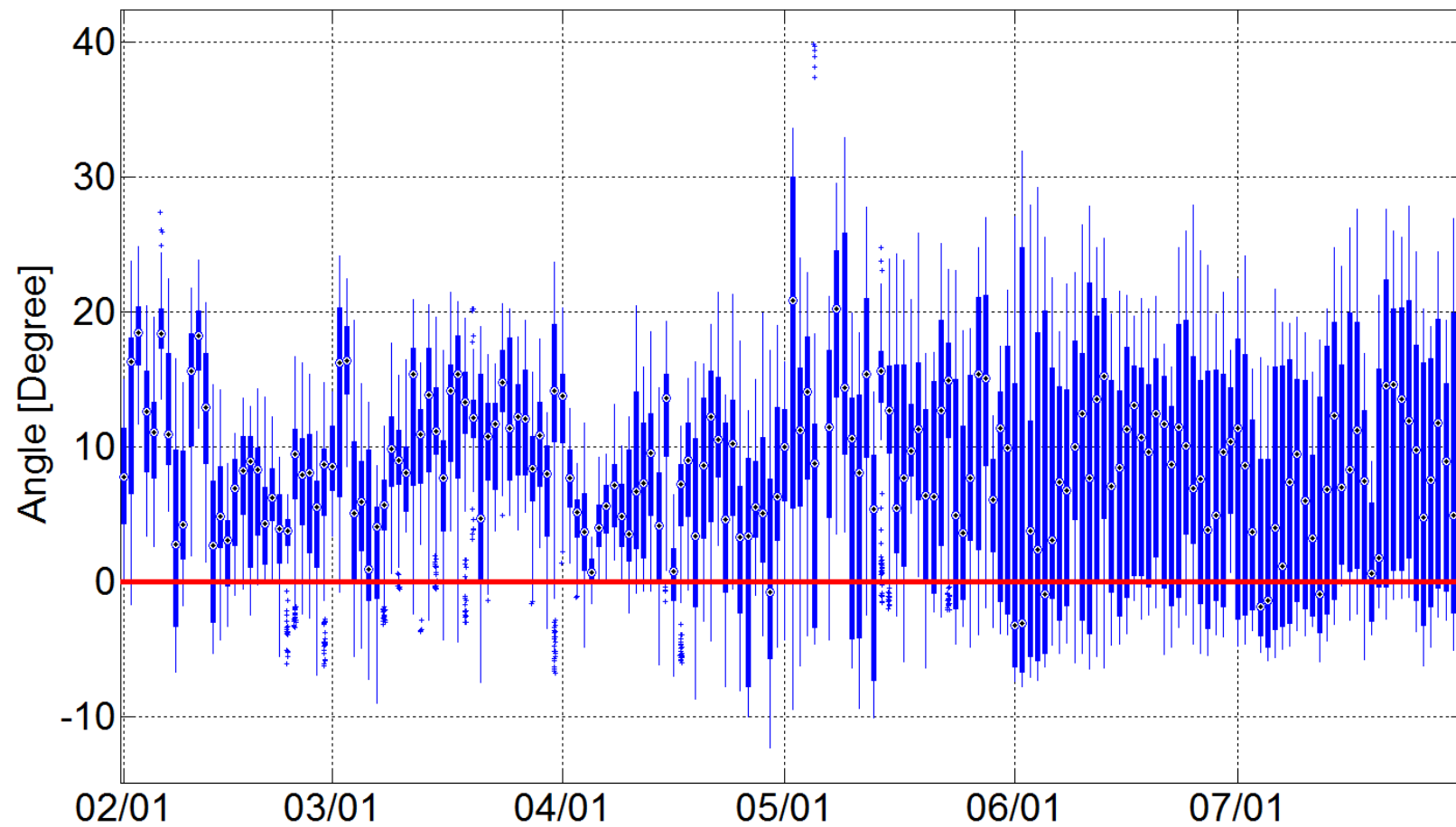
West 15-West 14



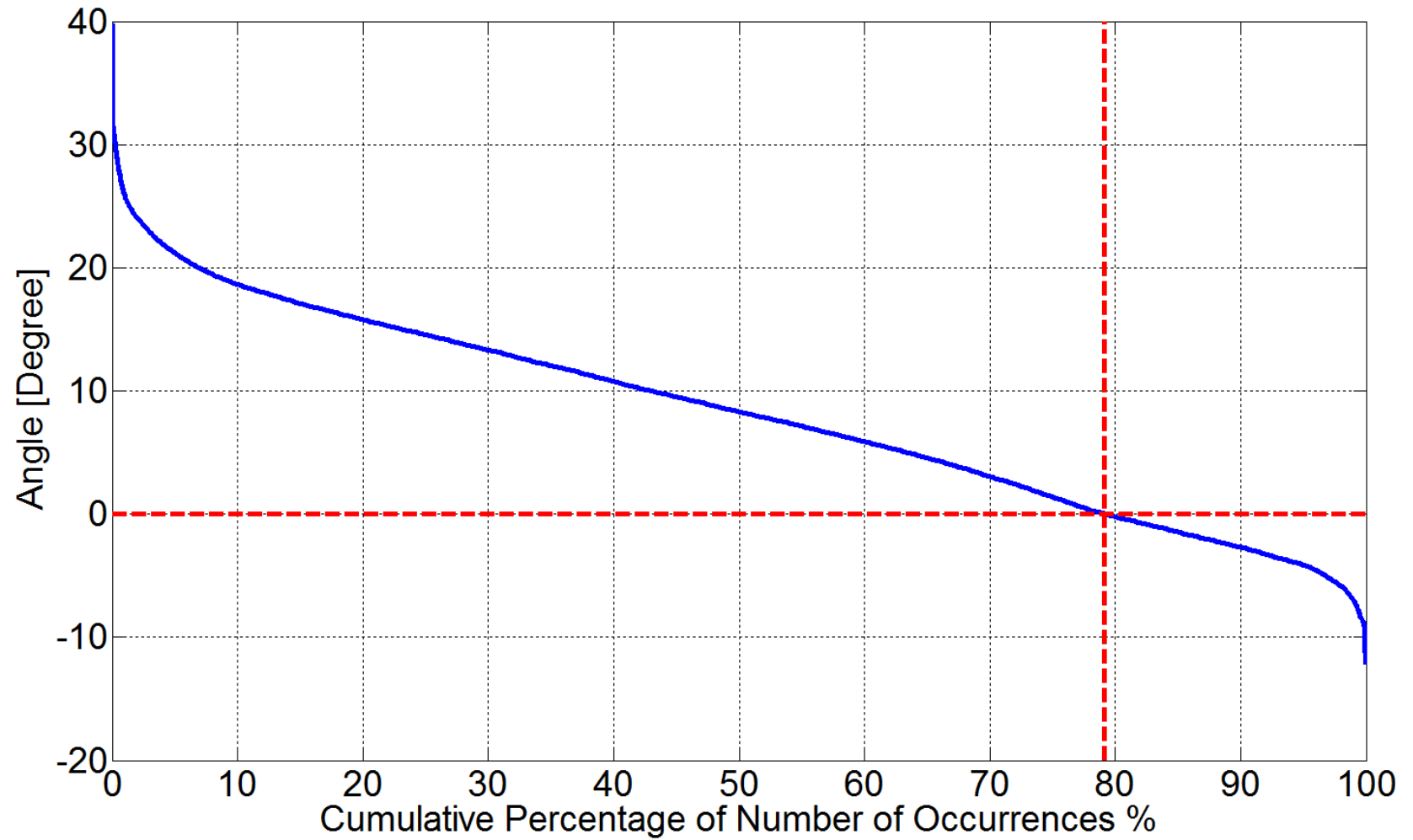
West 15-West 14



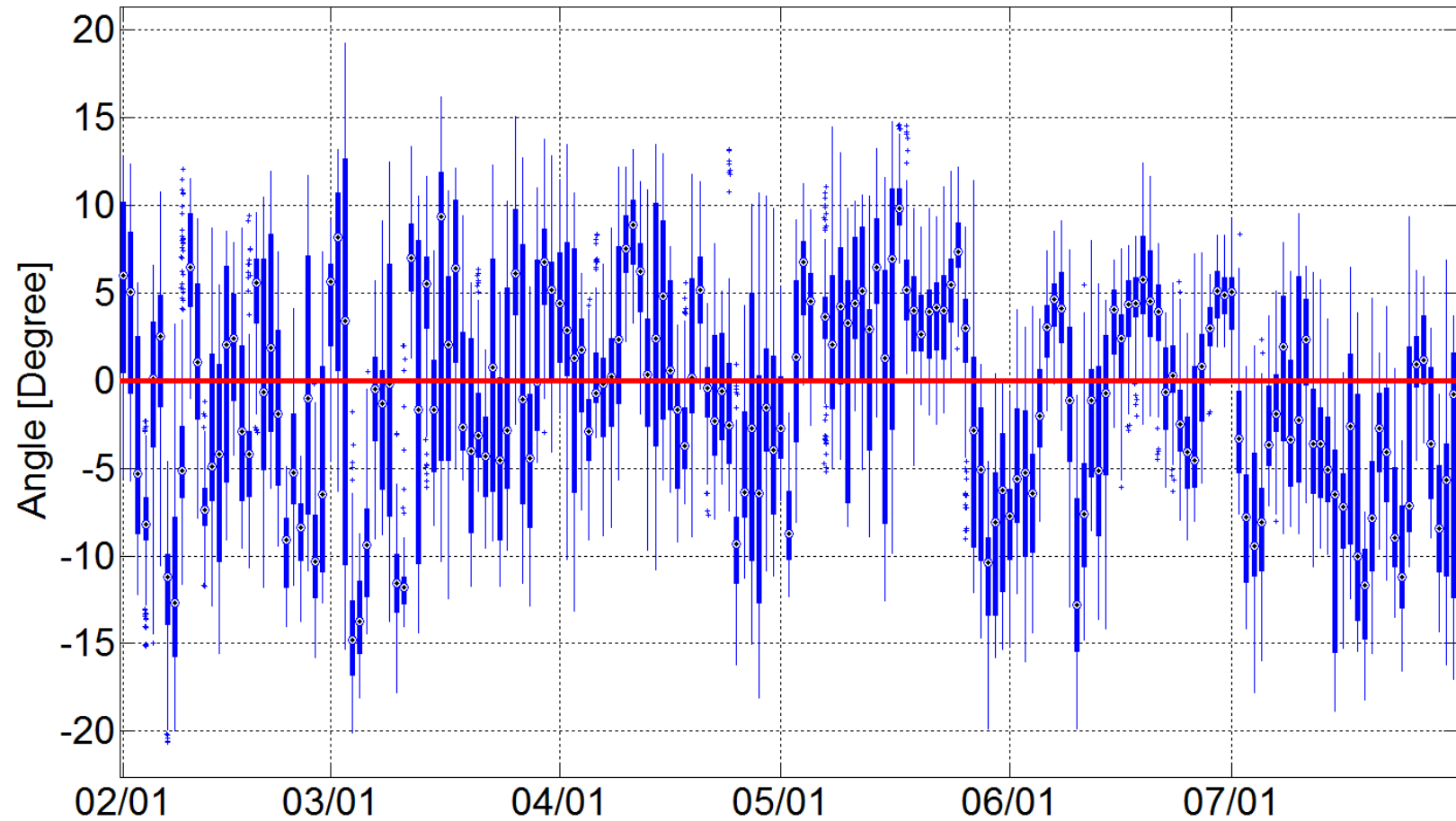
Coast 1-South 10*



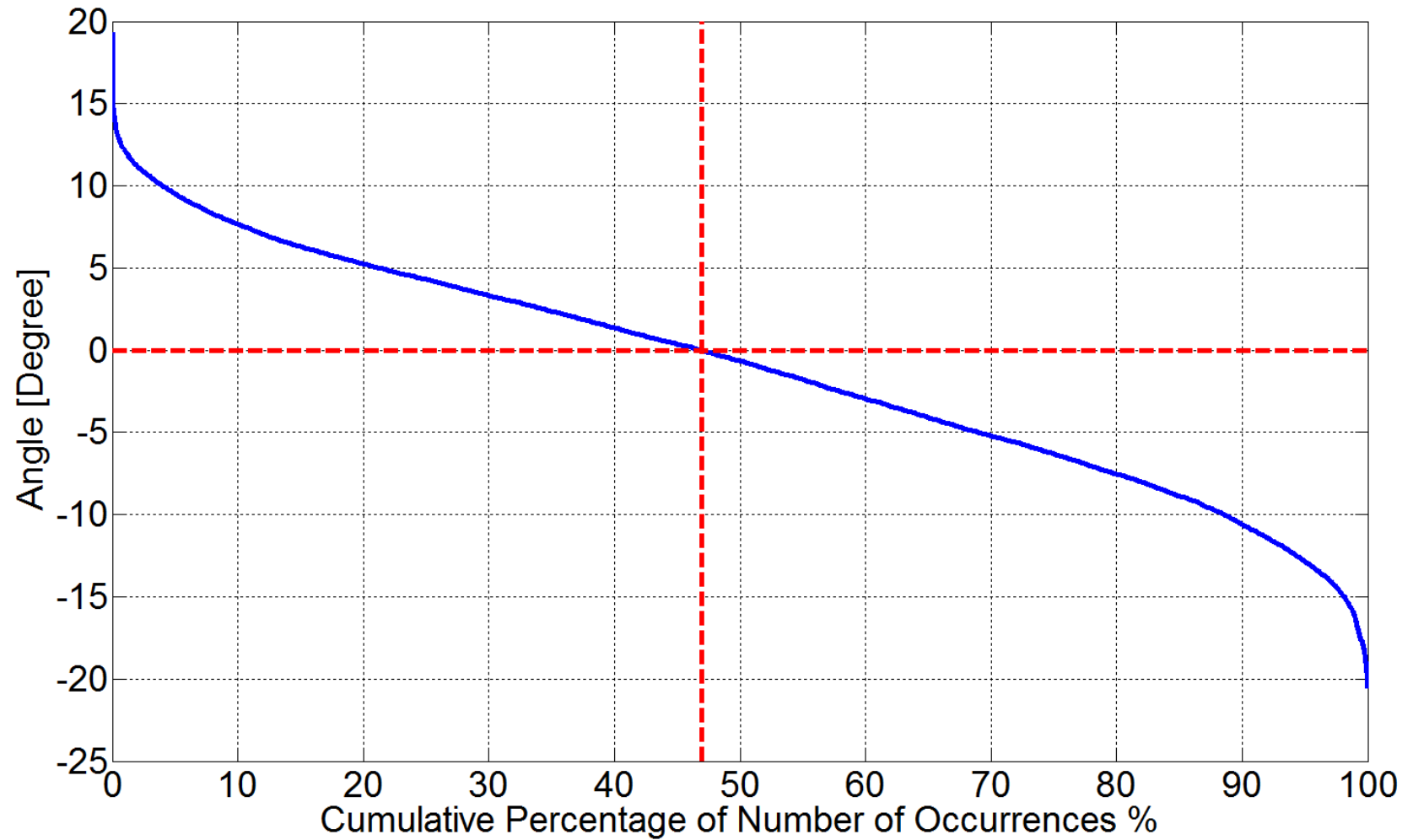
Coast 1-South 10*



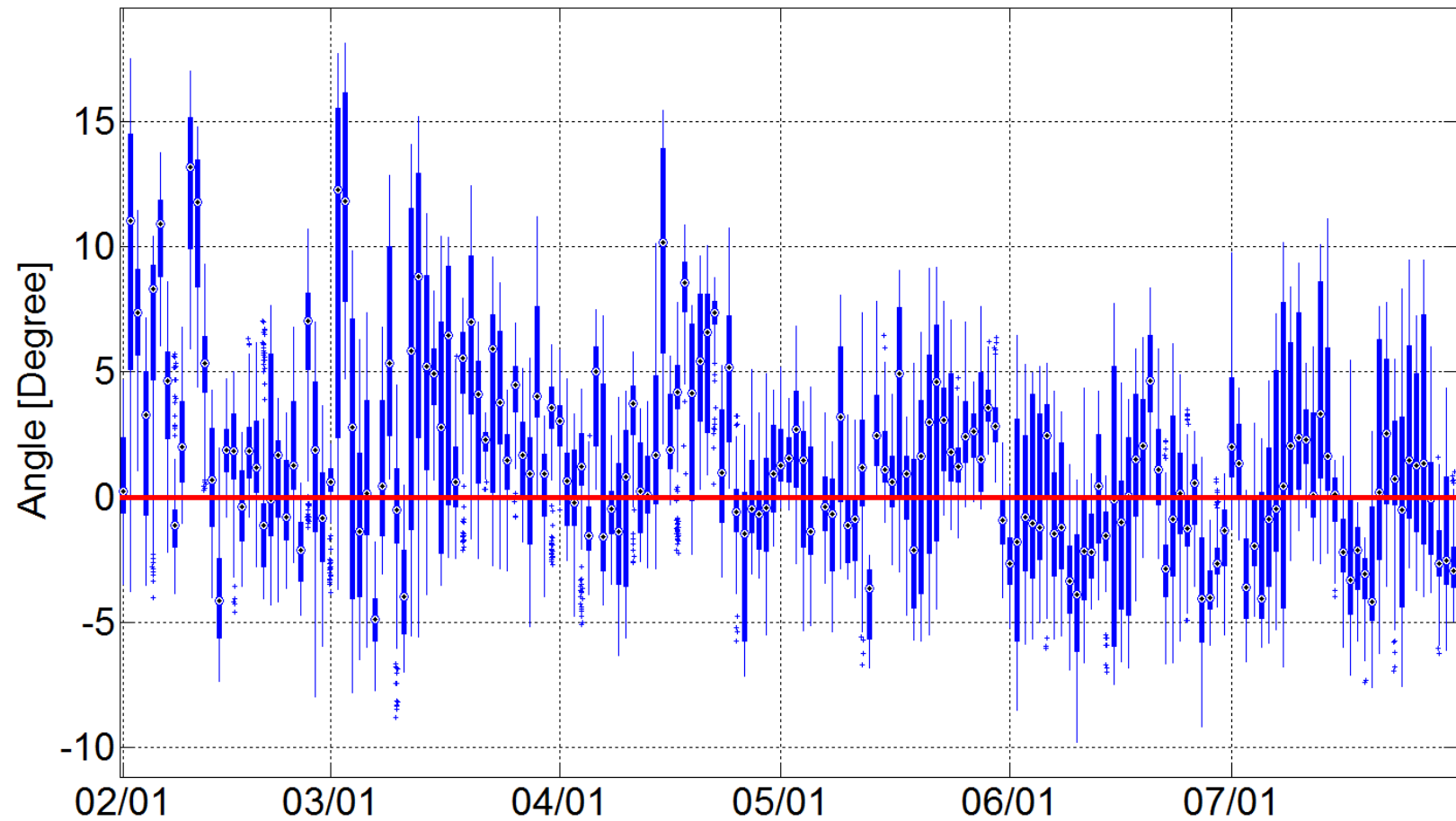
South 3*-South 11*



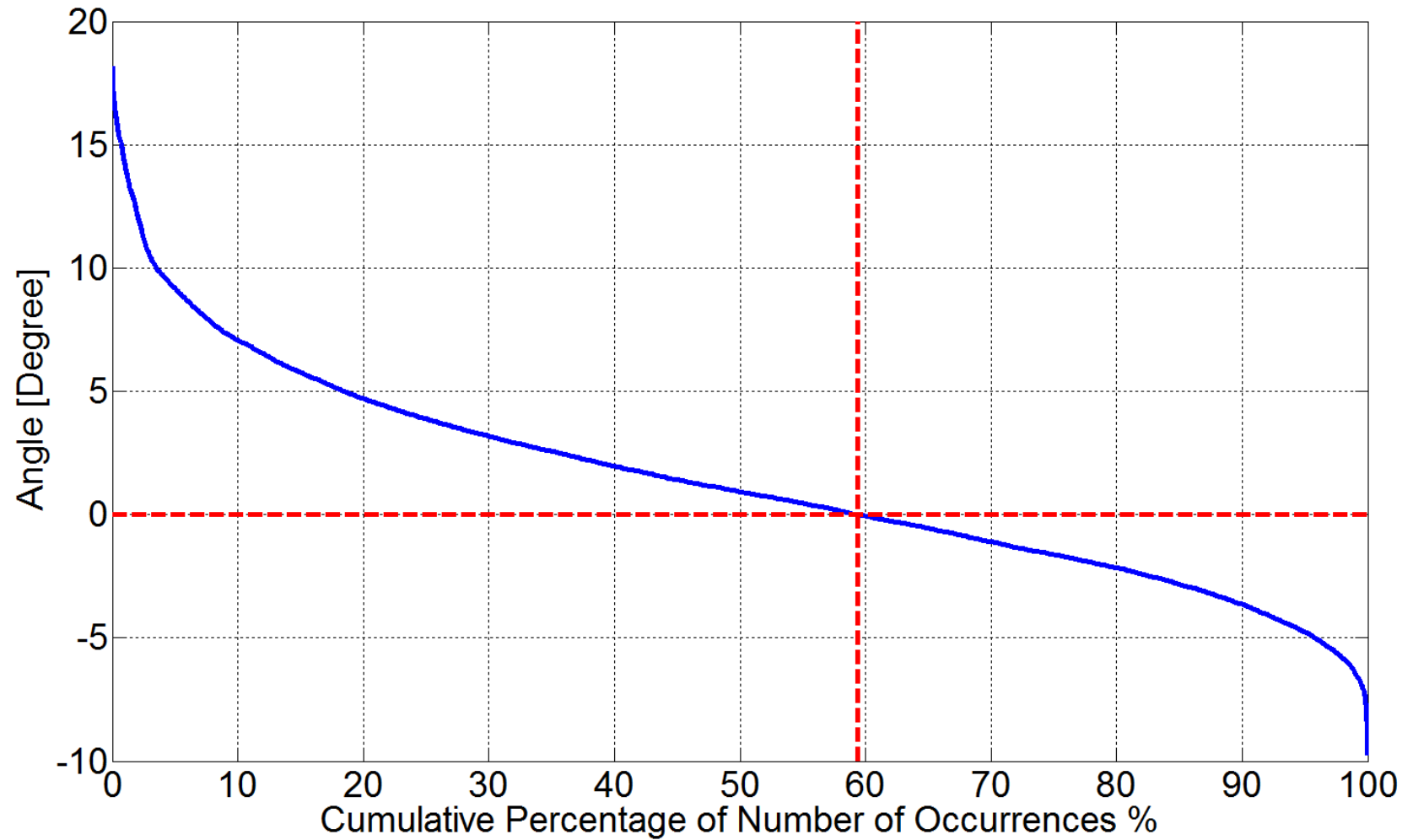
South 3*-South 11*



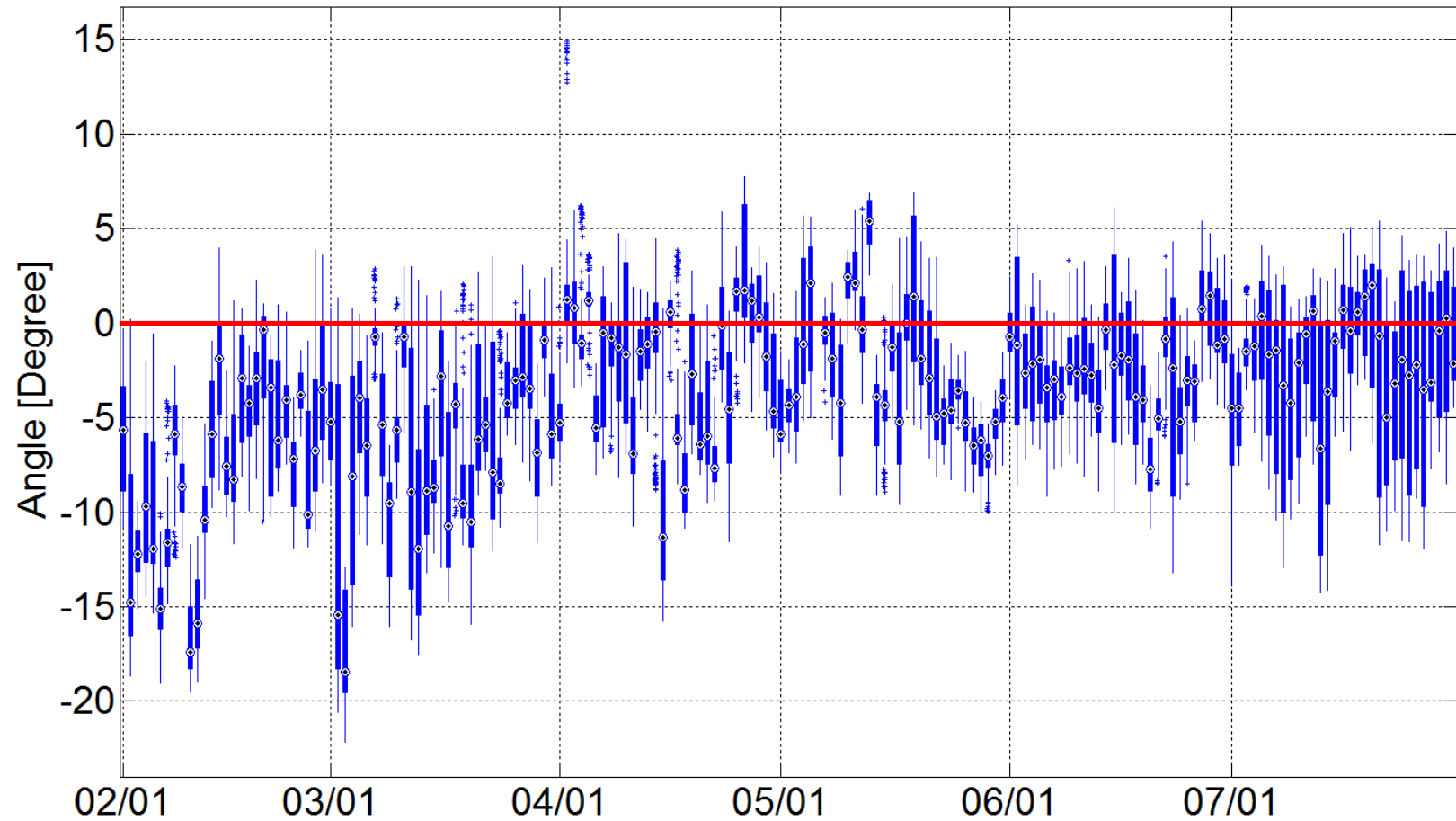
South 11*-North 7



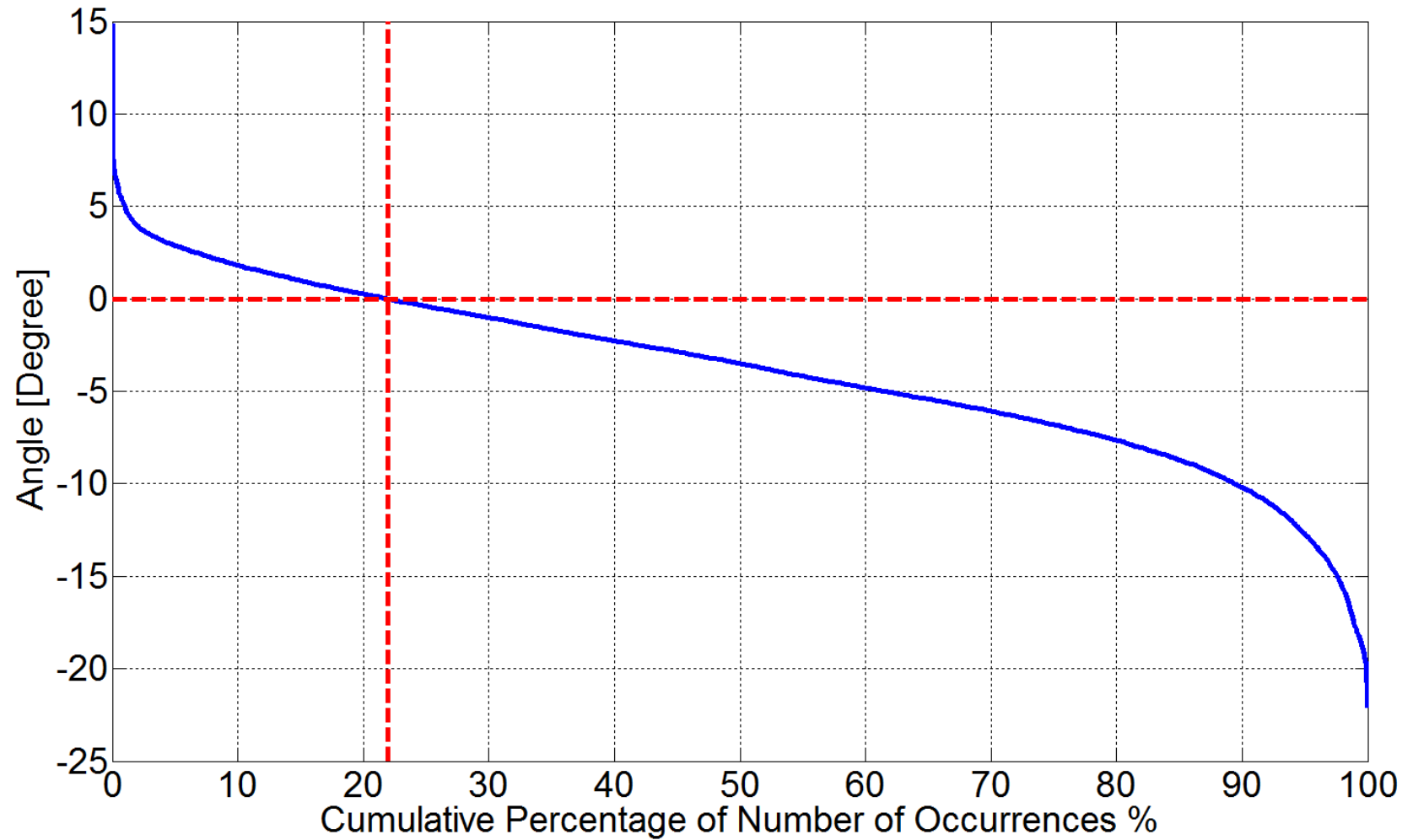
South 11*-North 7



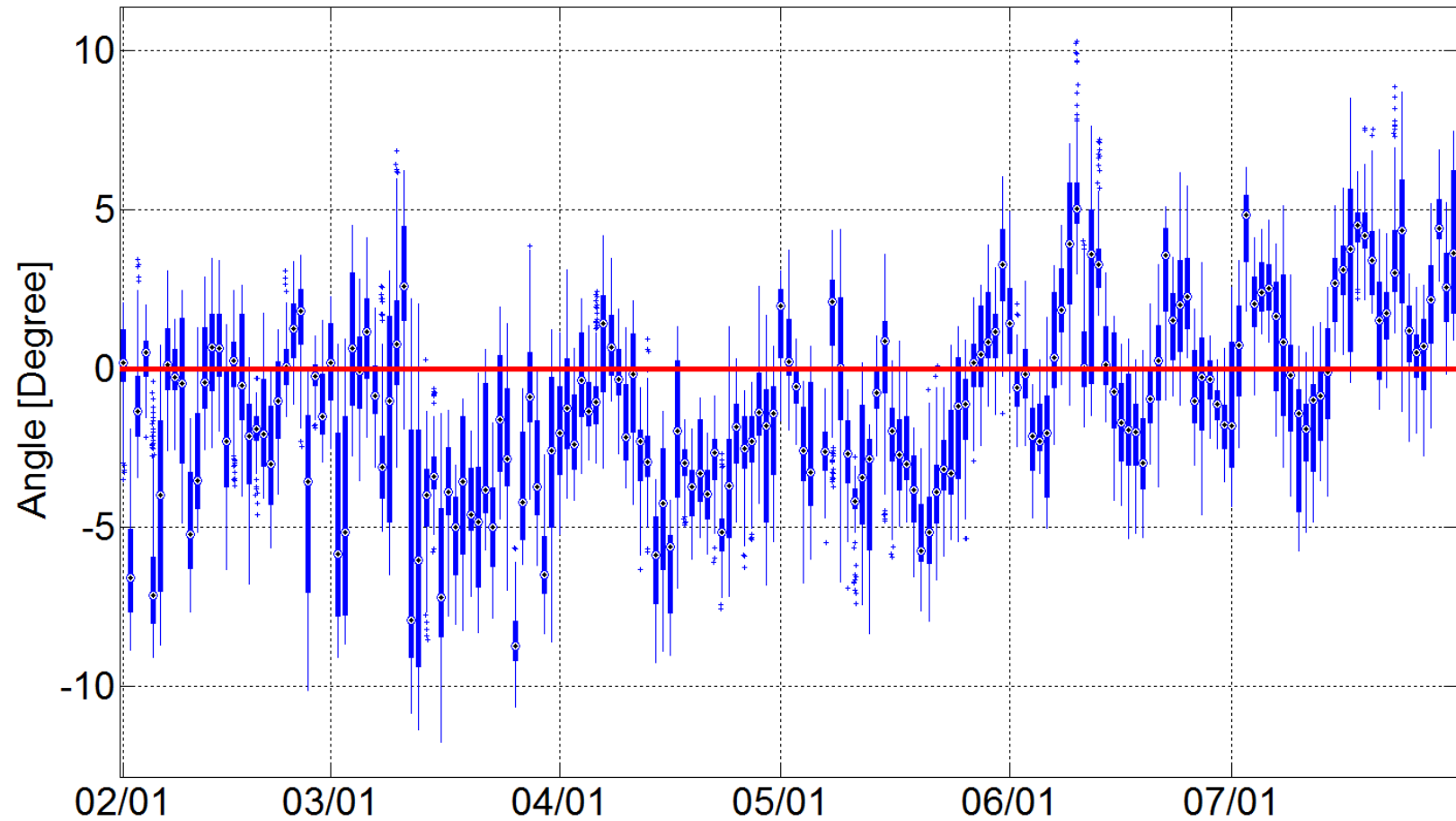
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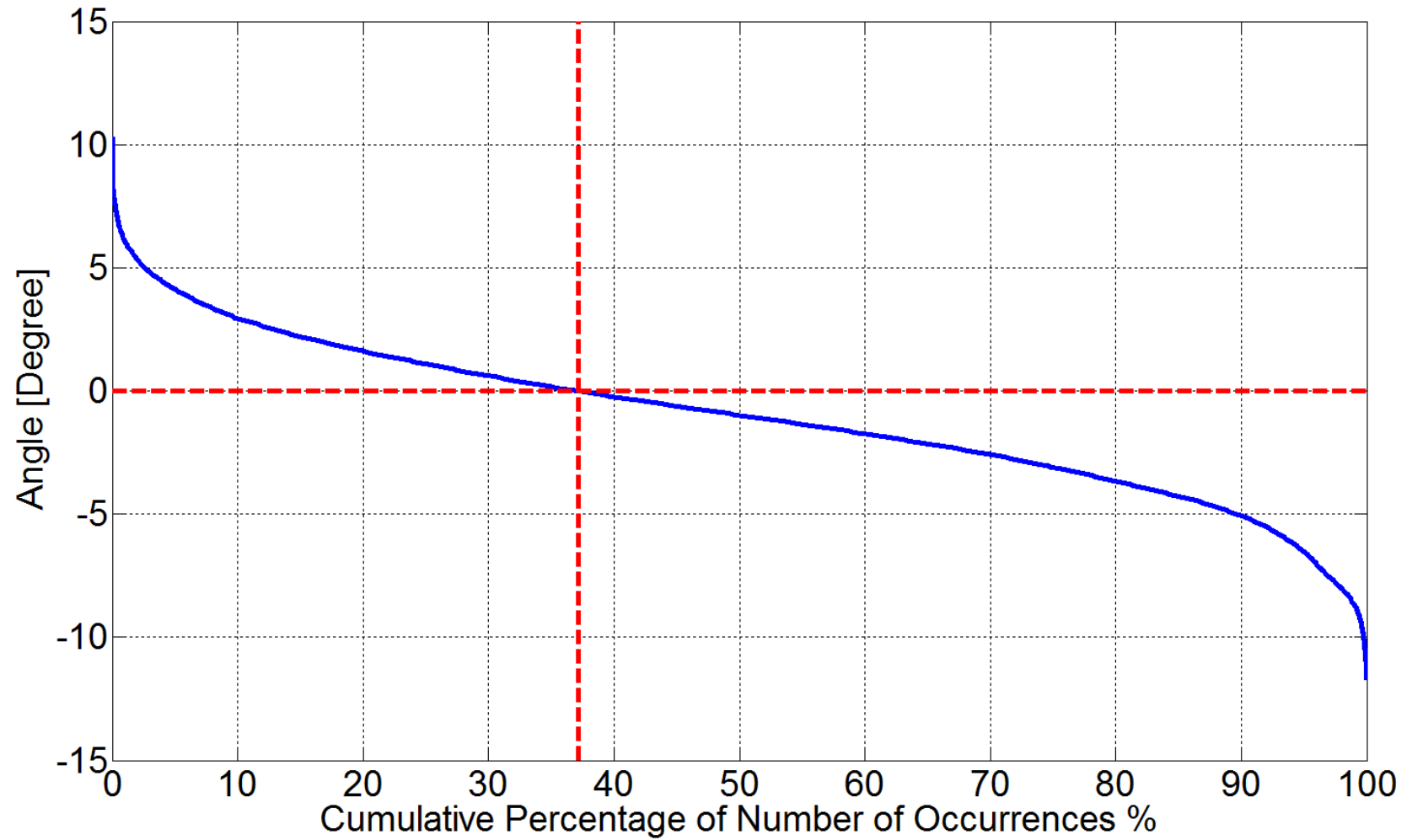
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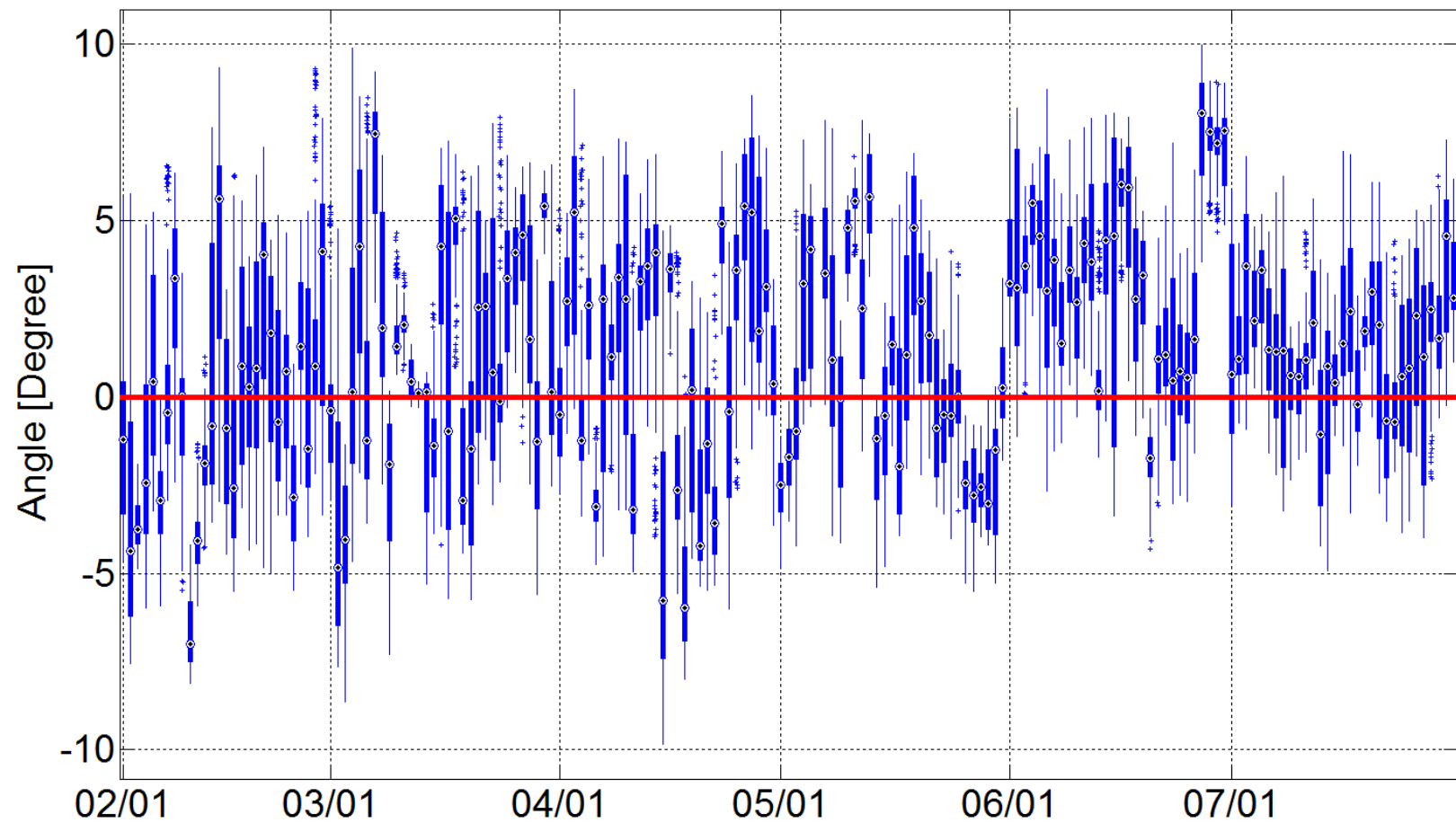
North 7-South 9*



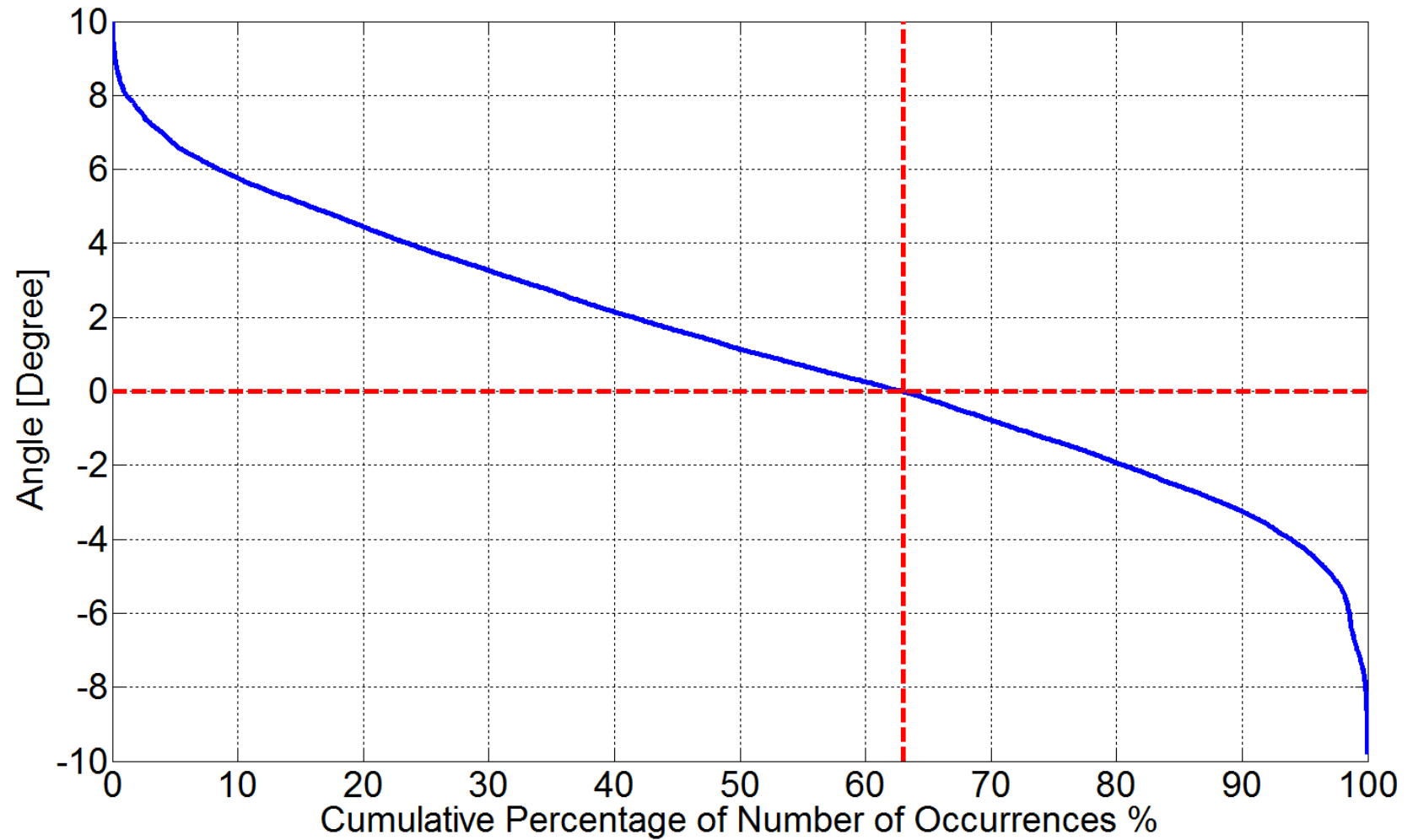
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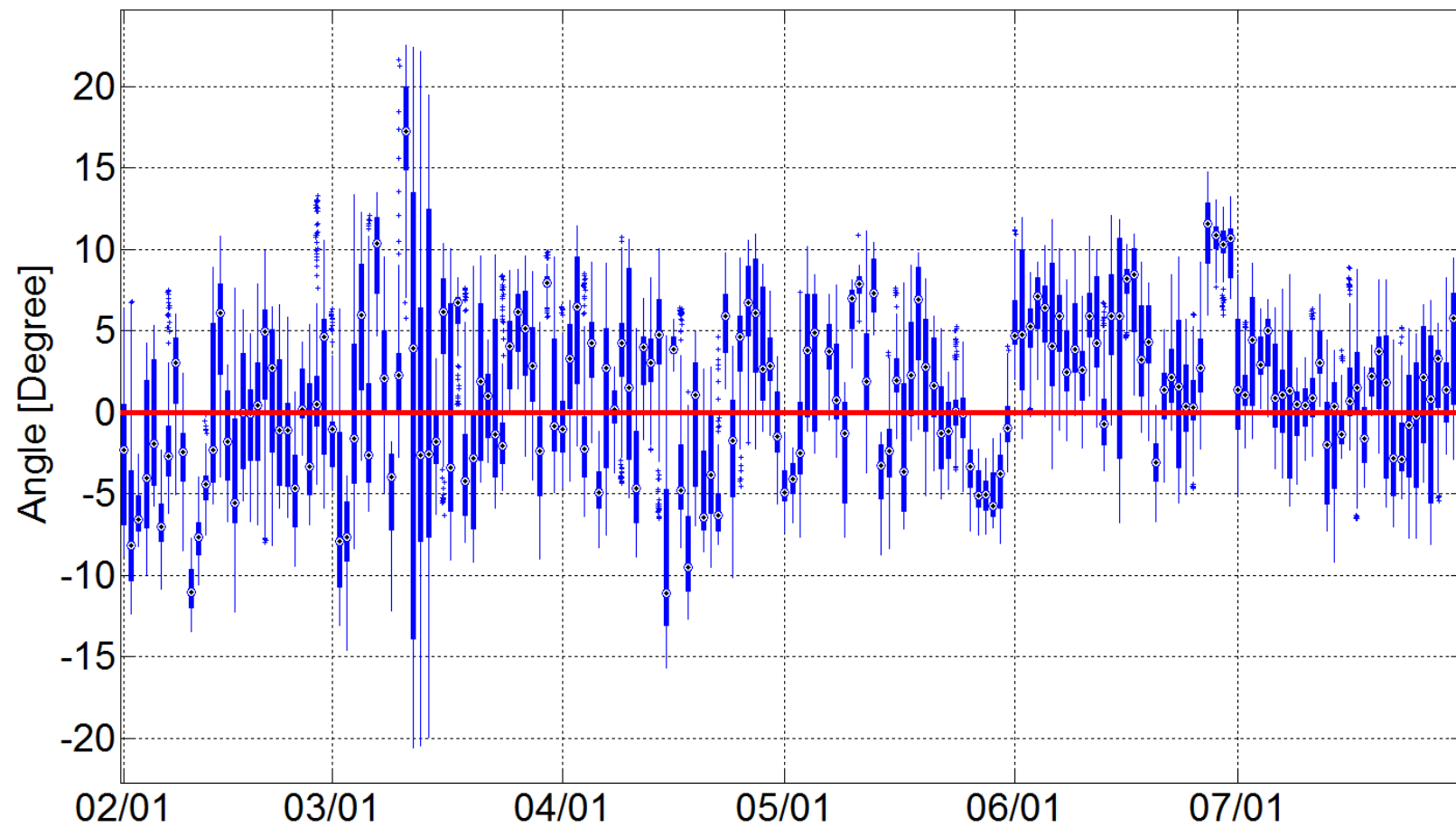
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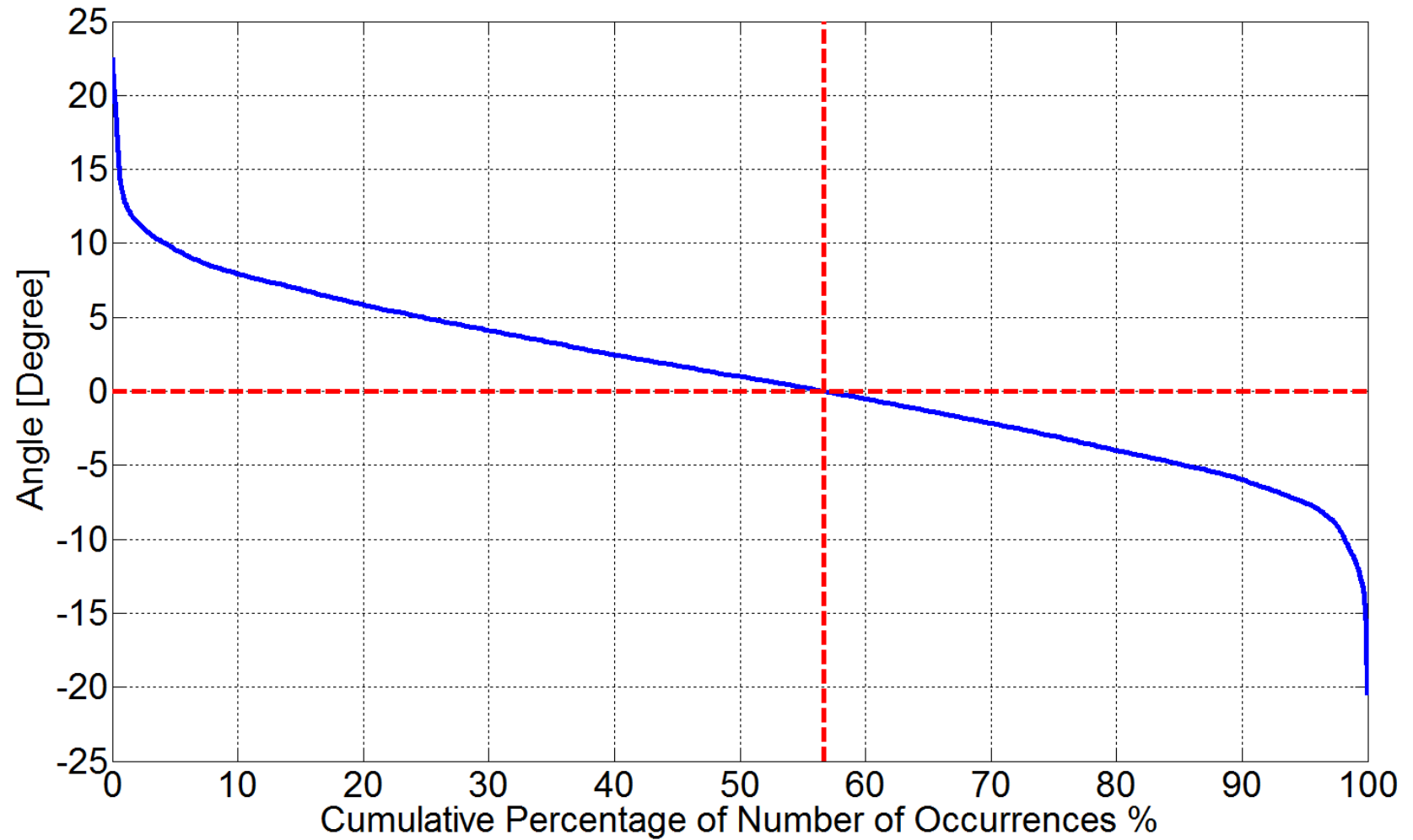
West 11-West 8*



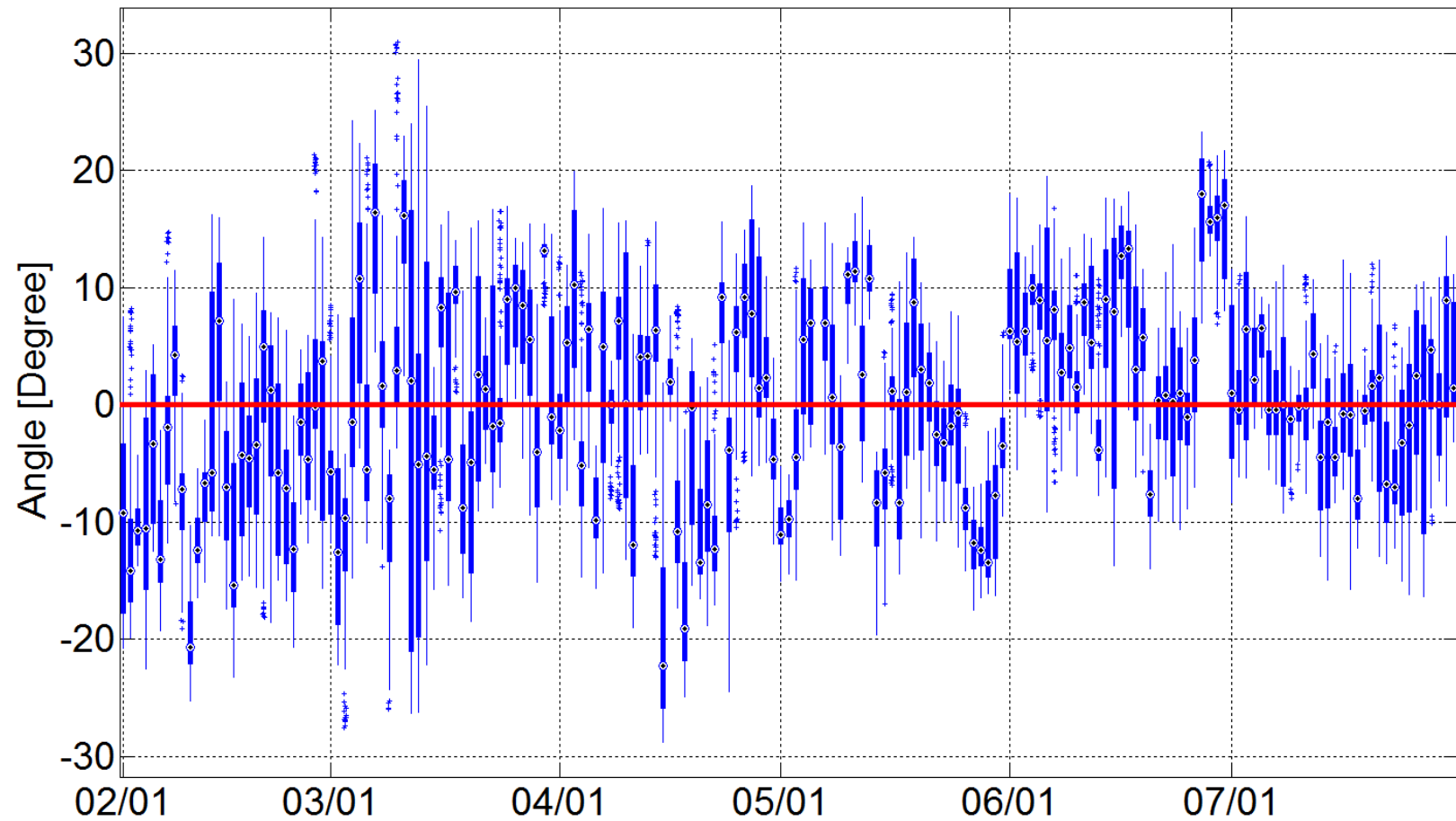
West 8*-South 9*



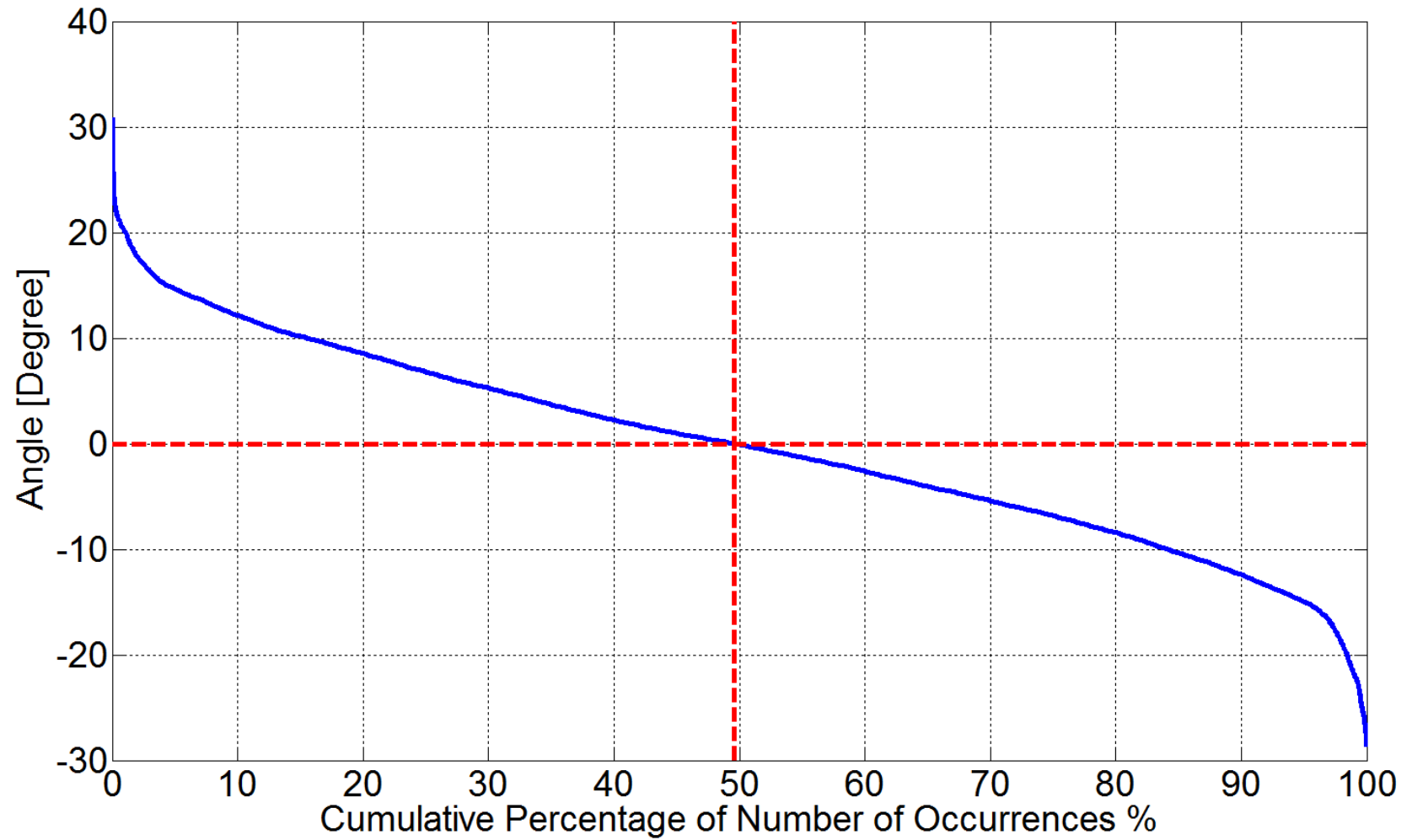
West 8*-South 9*



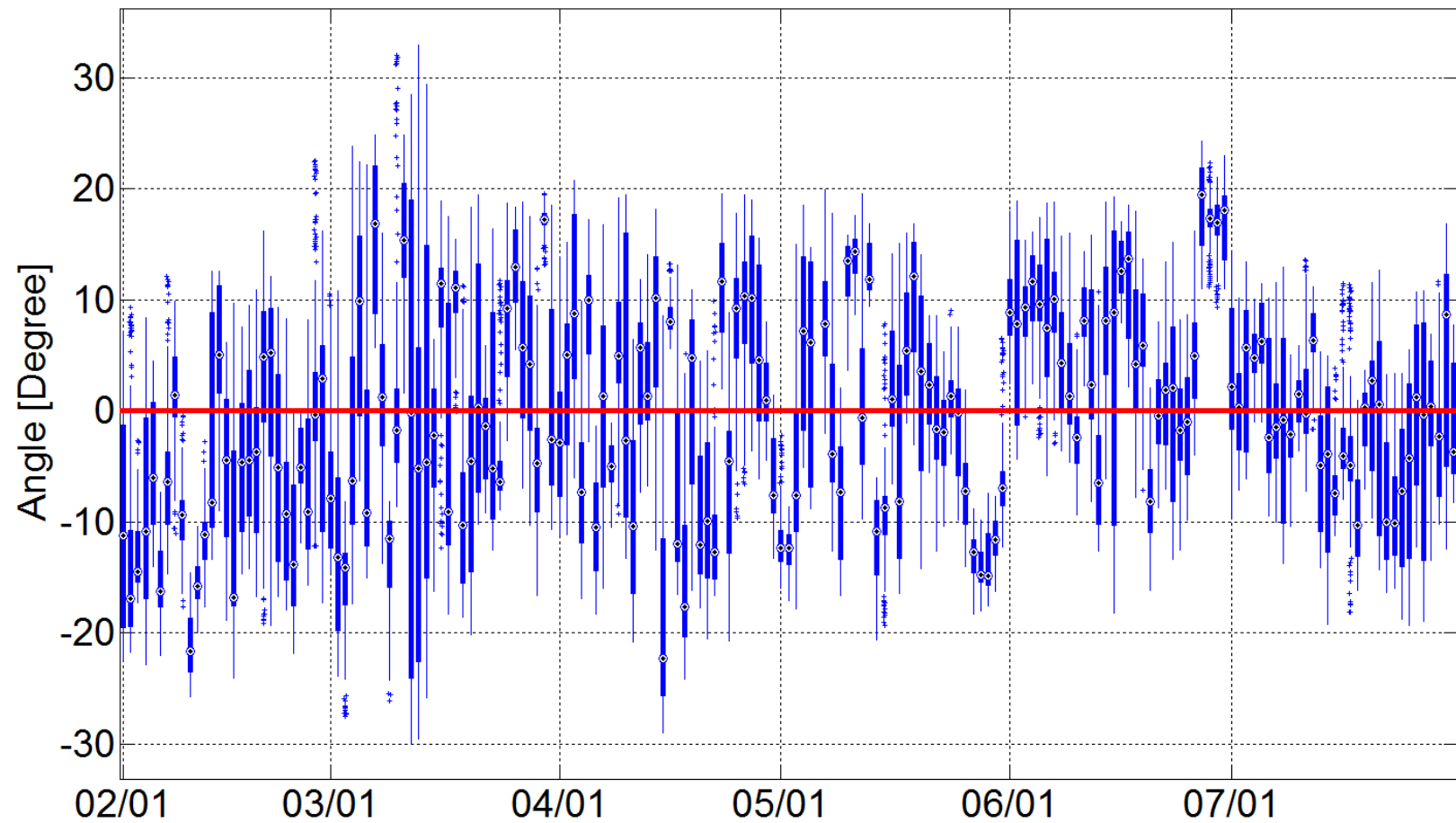
FarWest 7-South 9*



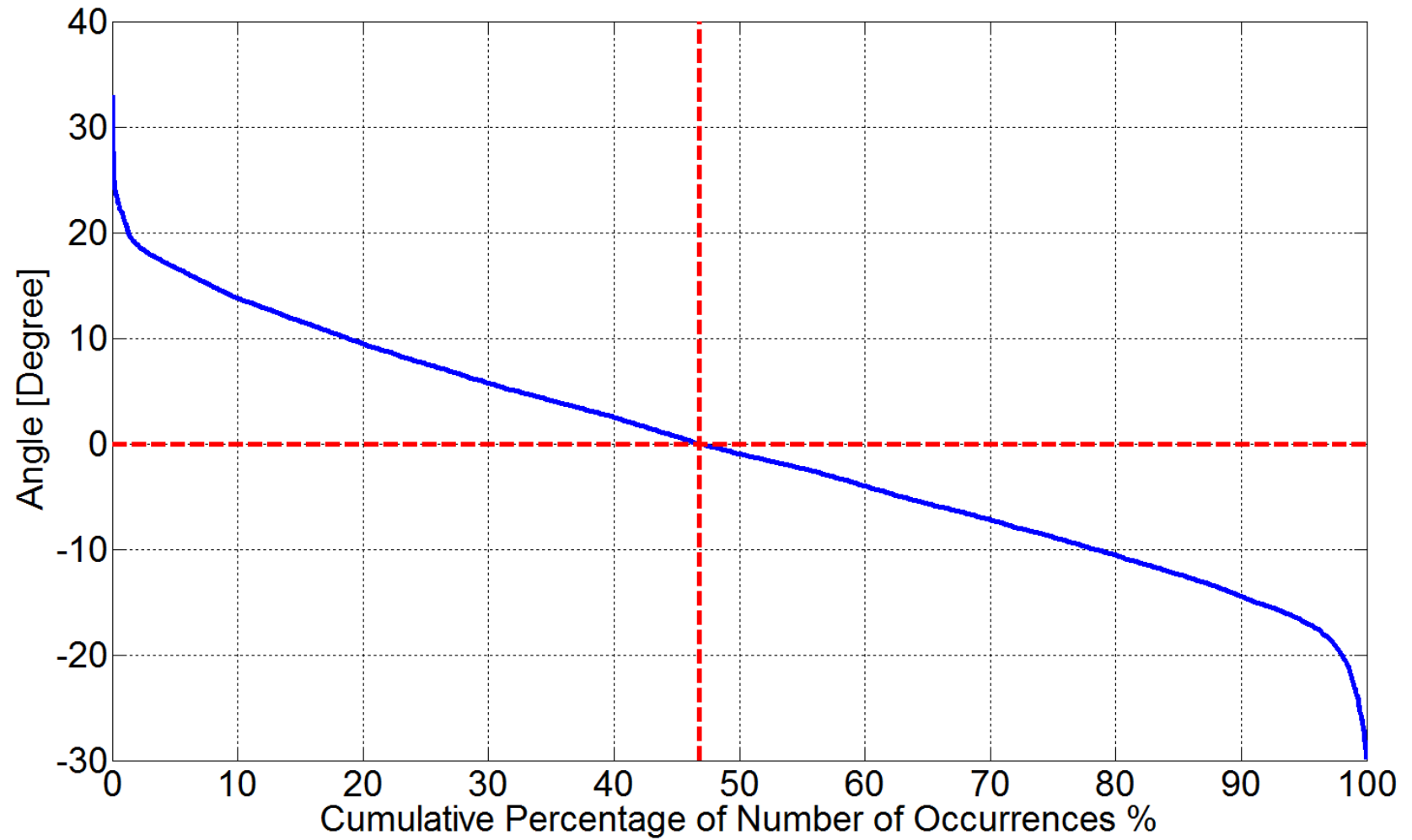
FarWest 7-South 9*



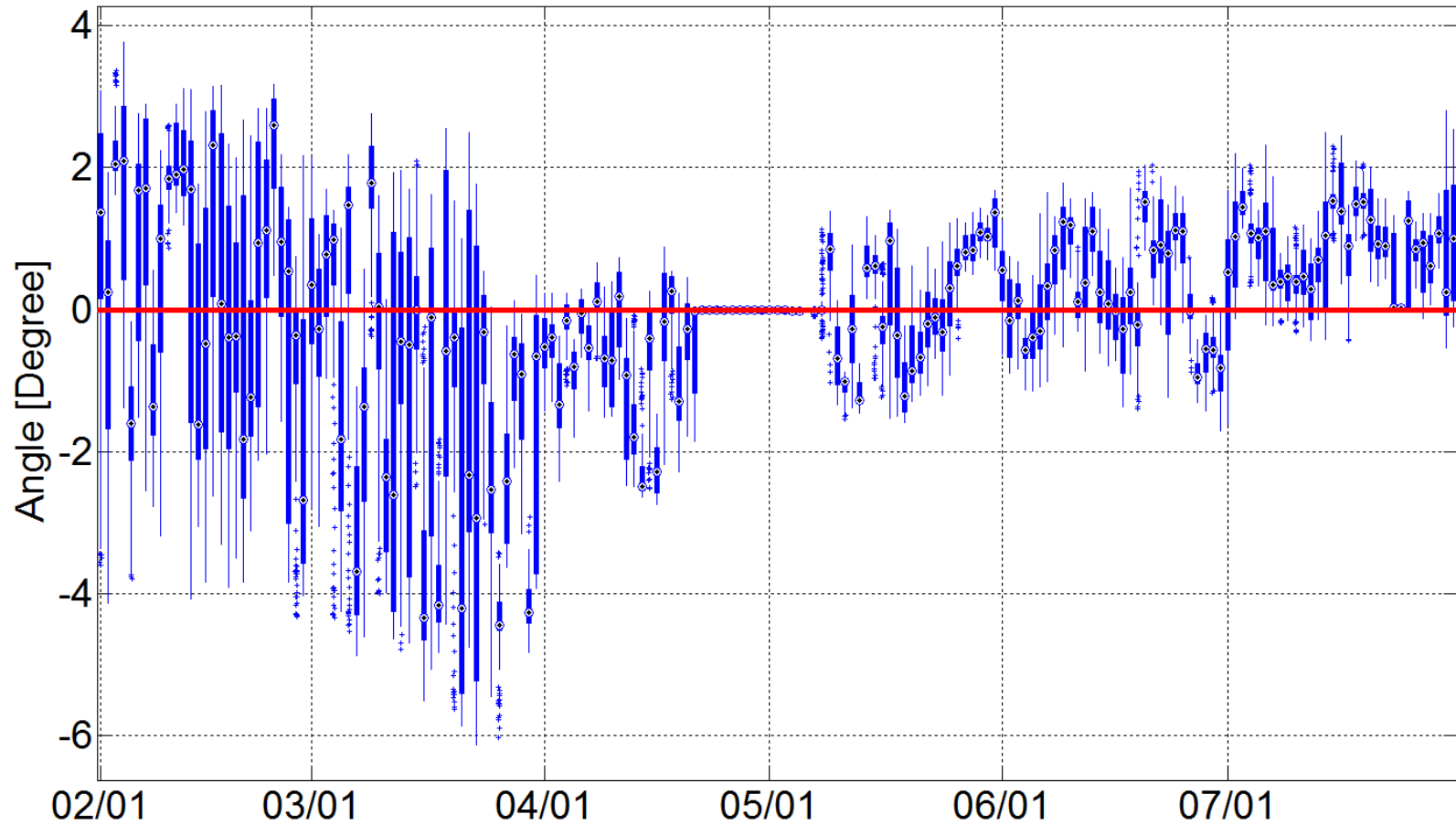
FarWest 9-South 9*



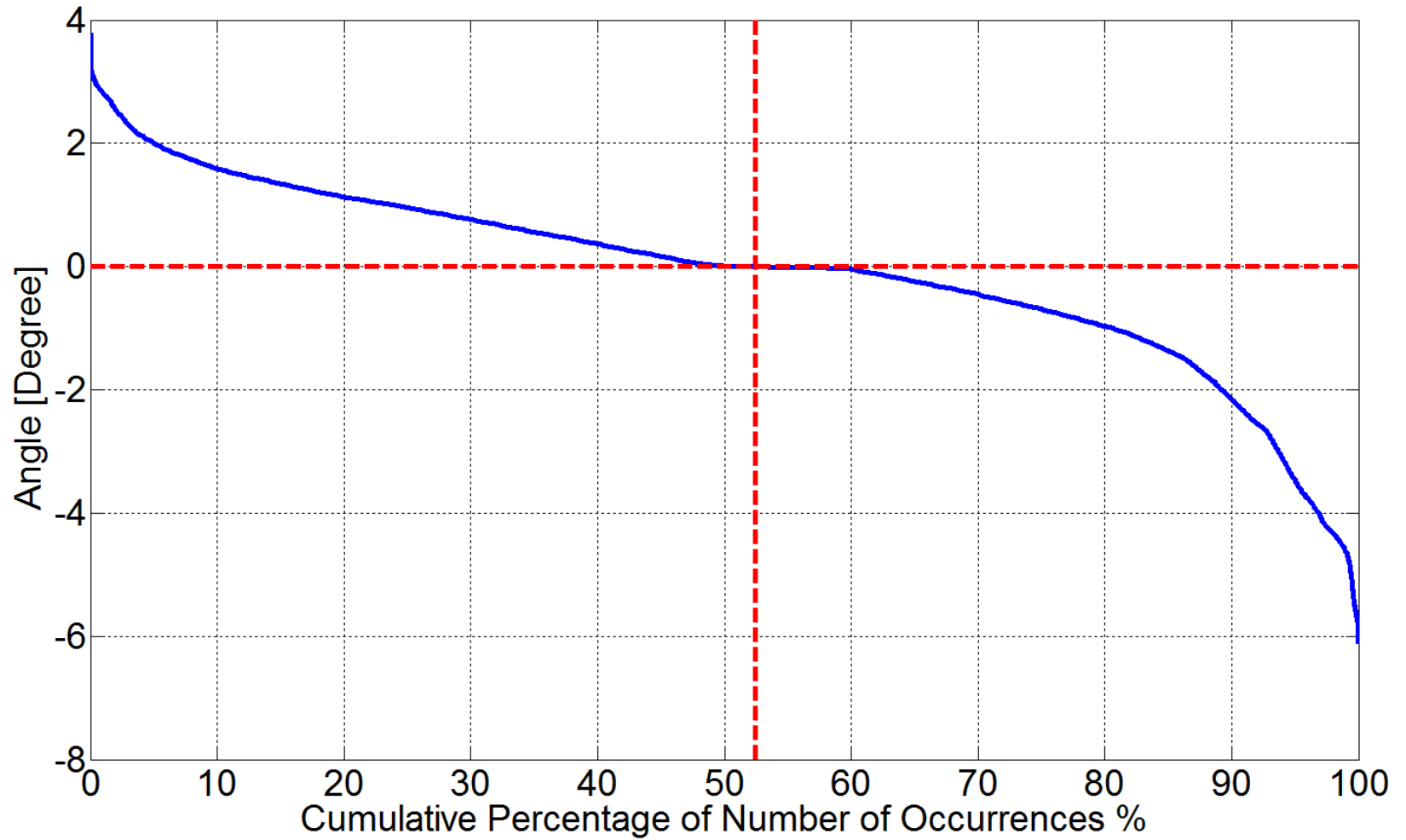
FarWest 9-South 9*



West 19*-West 9



West 19*-West 9



Appendix B – Part 2

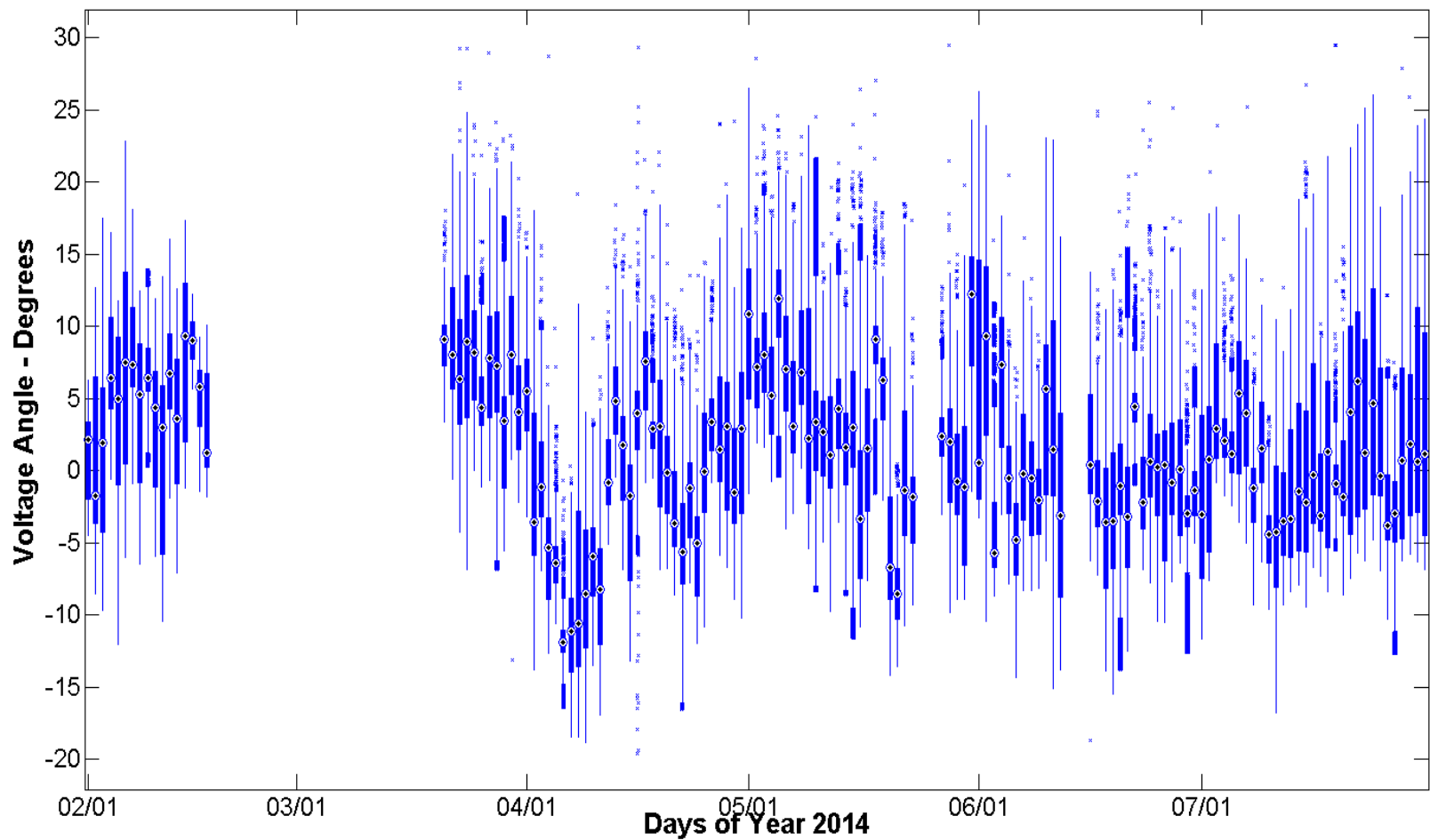
CCET Discovery Across Texas project

Baseline Analysis Update – Angle Differences

Phasor Data: February to July 2014
Box Whiskers Plots and Time Duration Curves

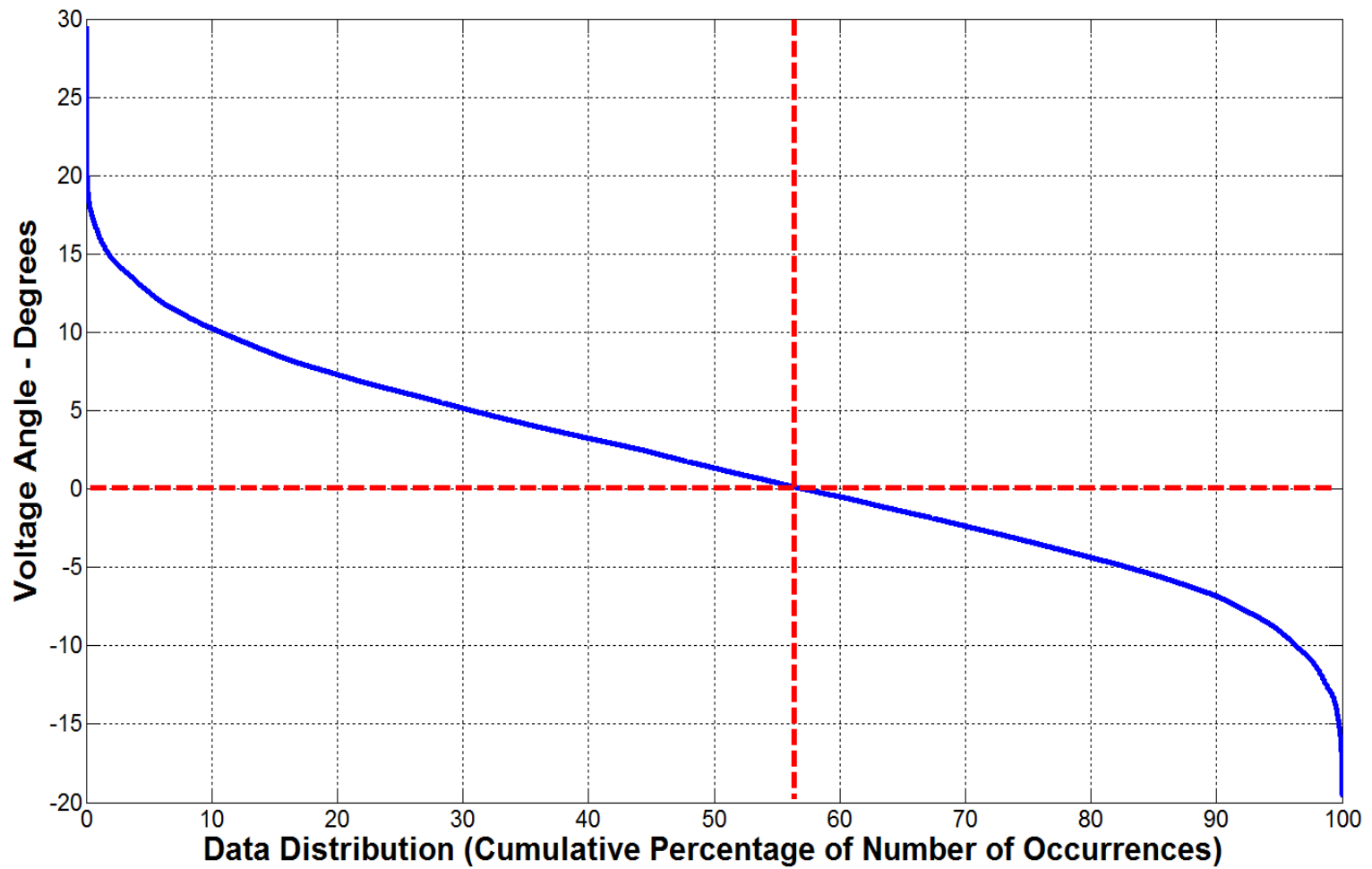
Coast 1 - South 13

Daily Box-Whisker Chart:



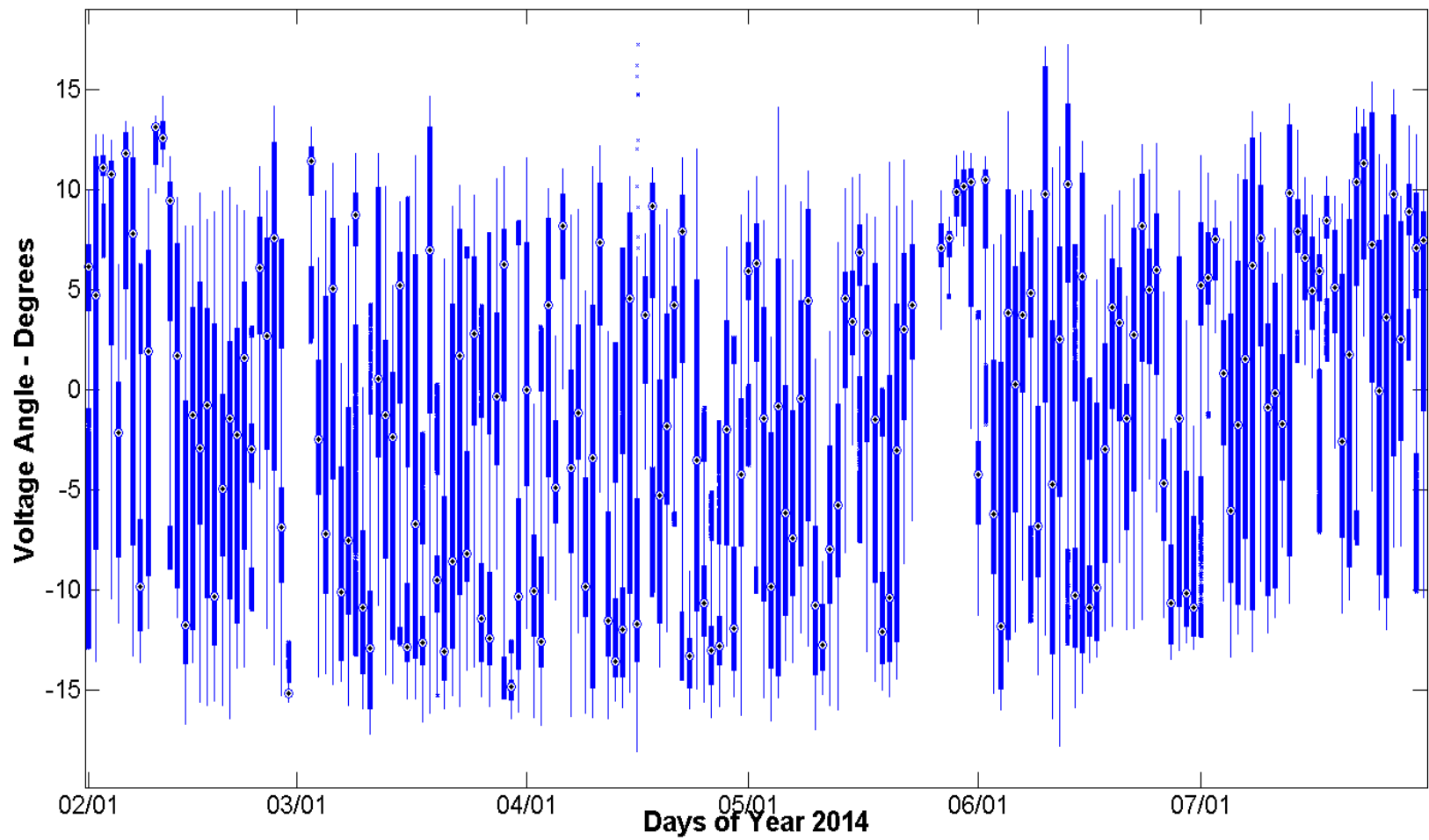
Coast 1 - South 13

Time Duration Chart:



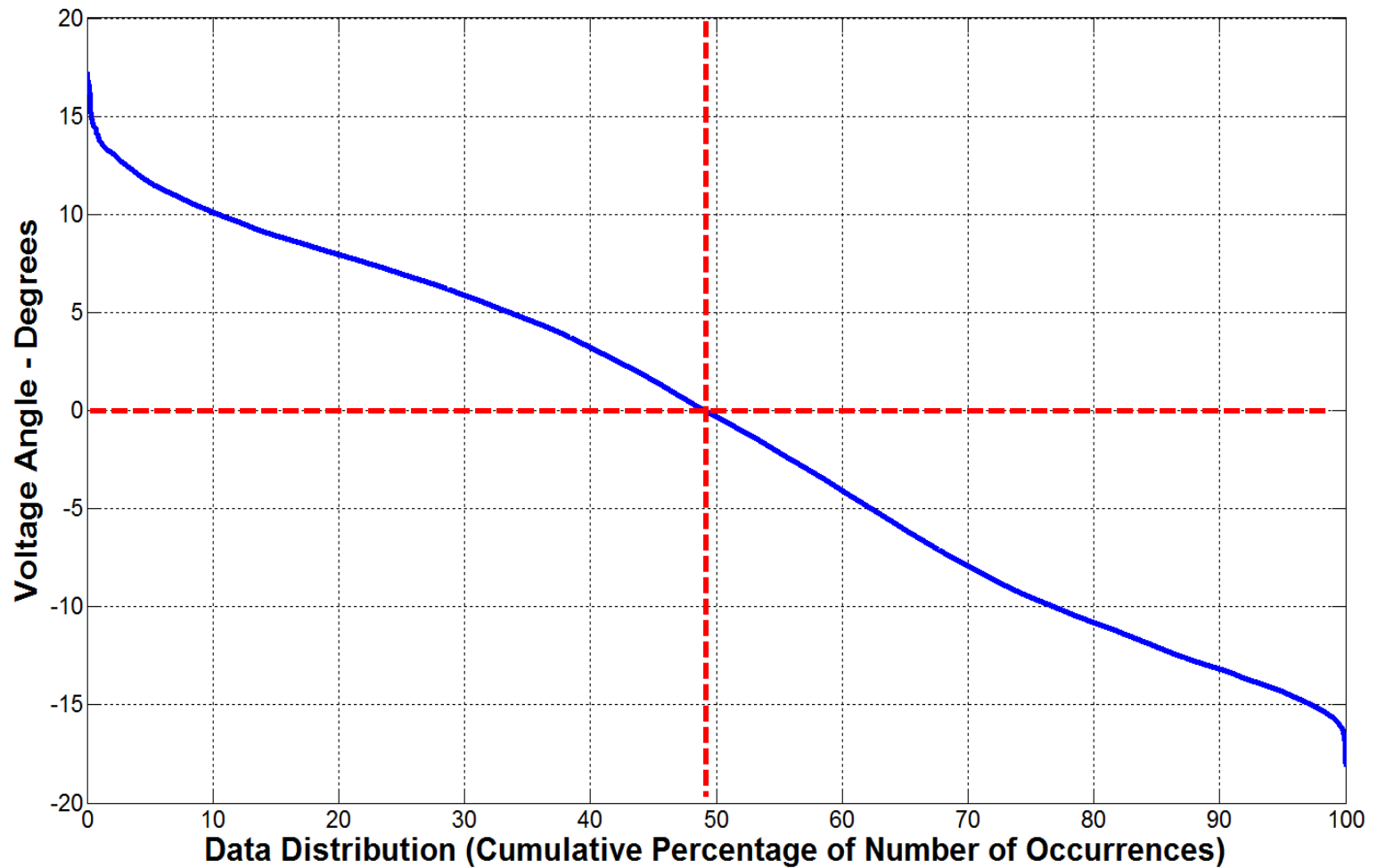
West 5 – West 10

Daily Box-Whisker Chart:



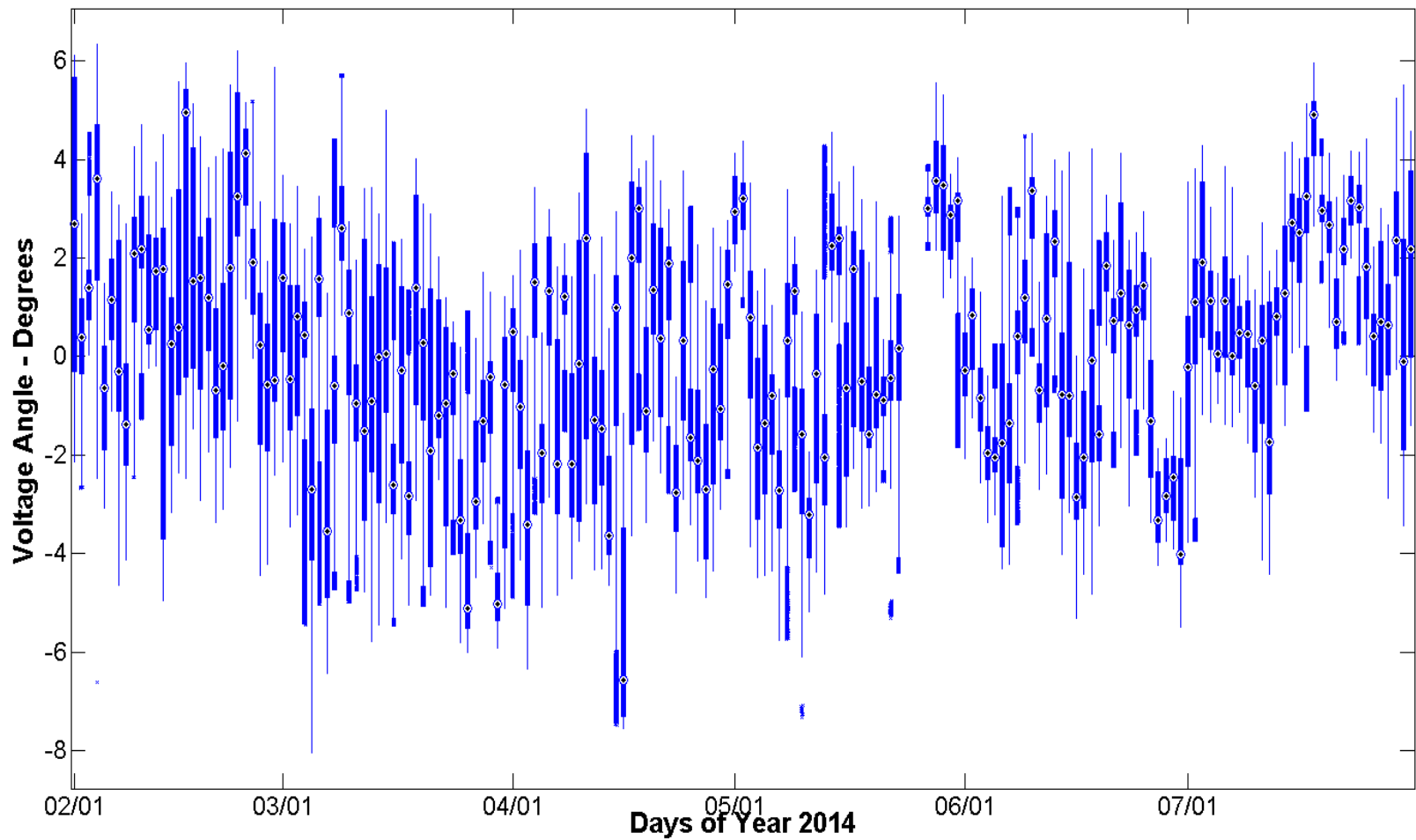
West 5 – West 10

Time Duration Chart:



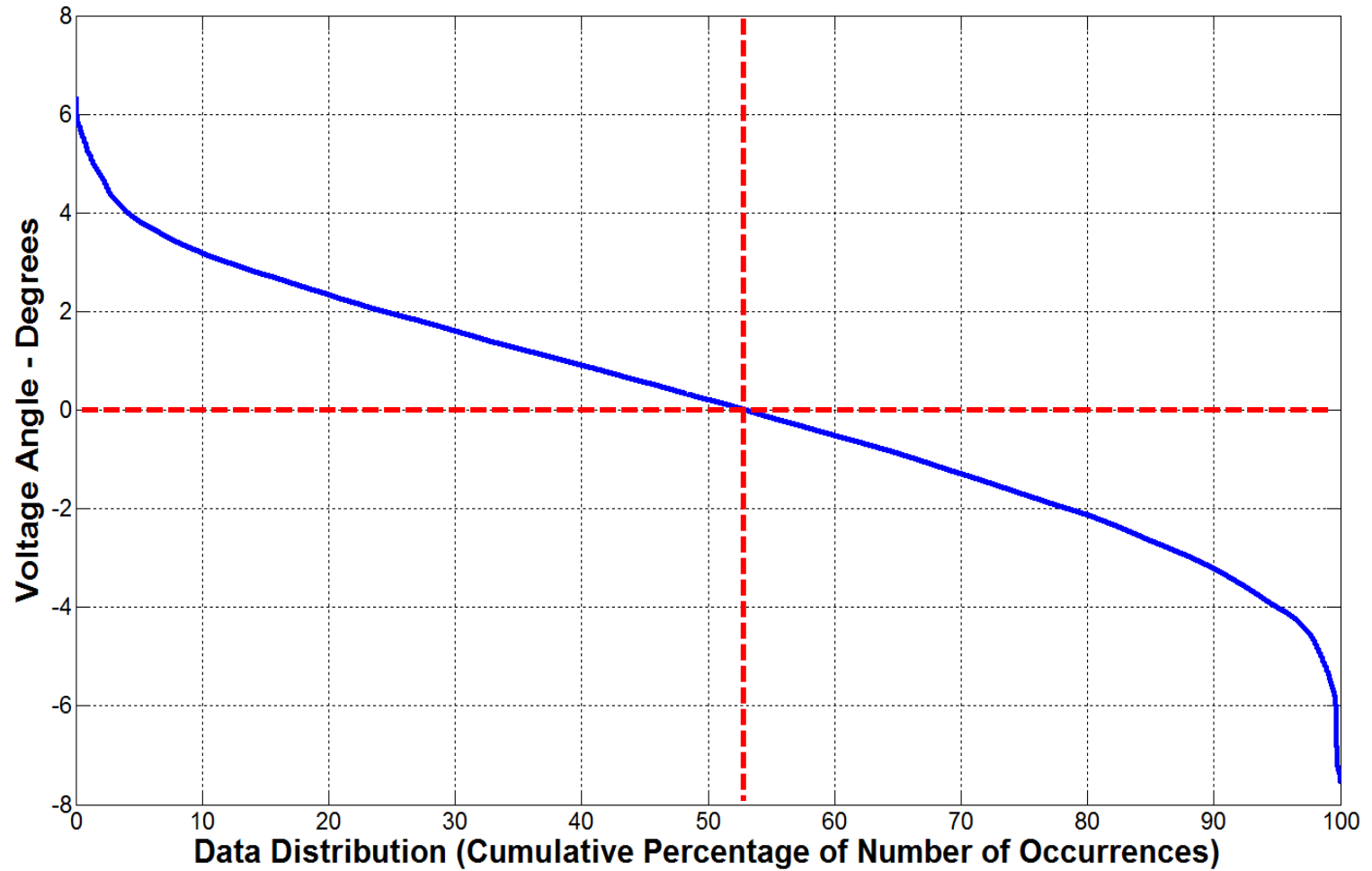
West 5 – FarWest 4

Daily Box-Whisker Chart:



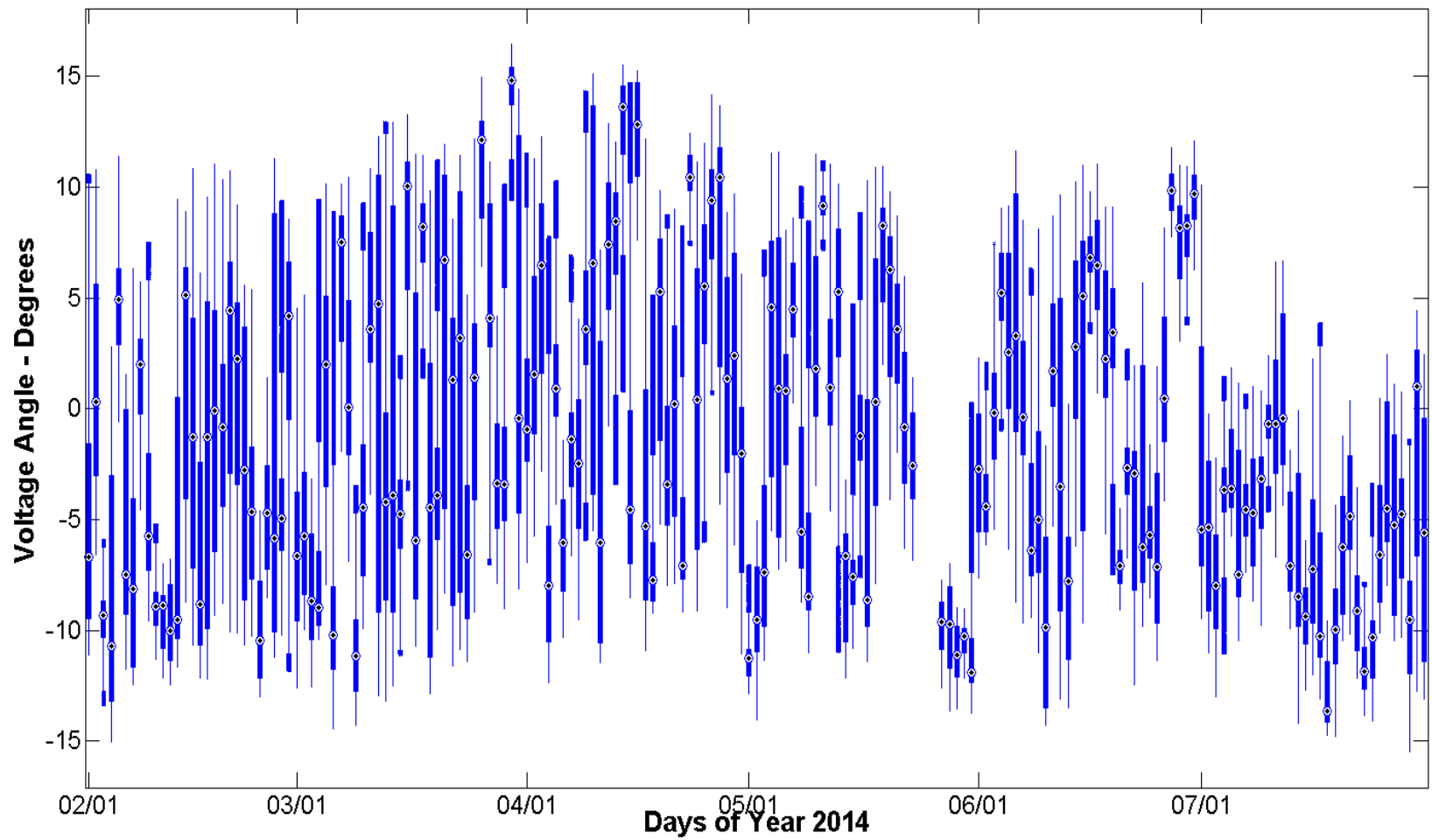
West 5 – FarWest 4

Time Duration Chart:



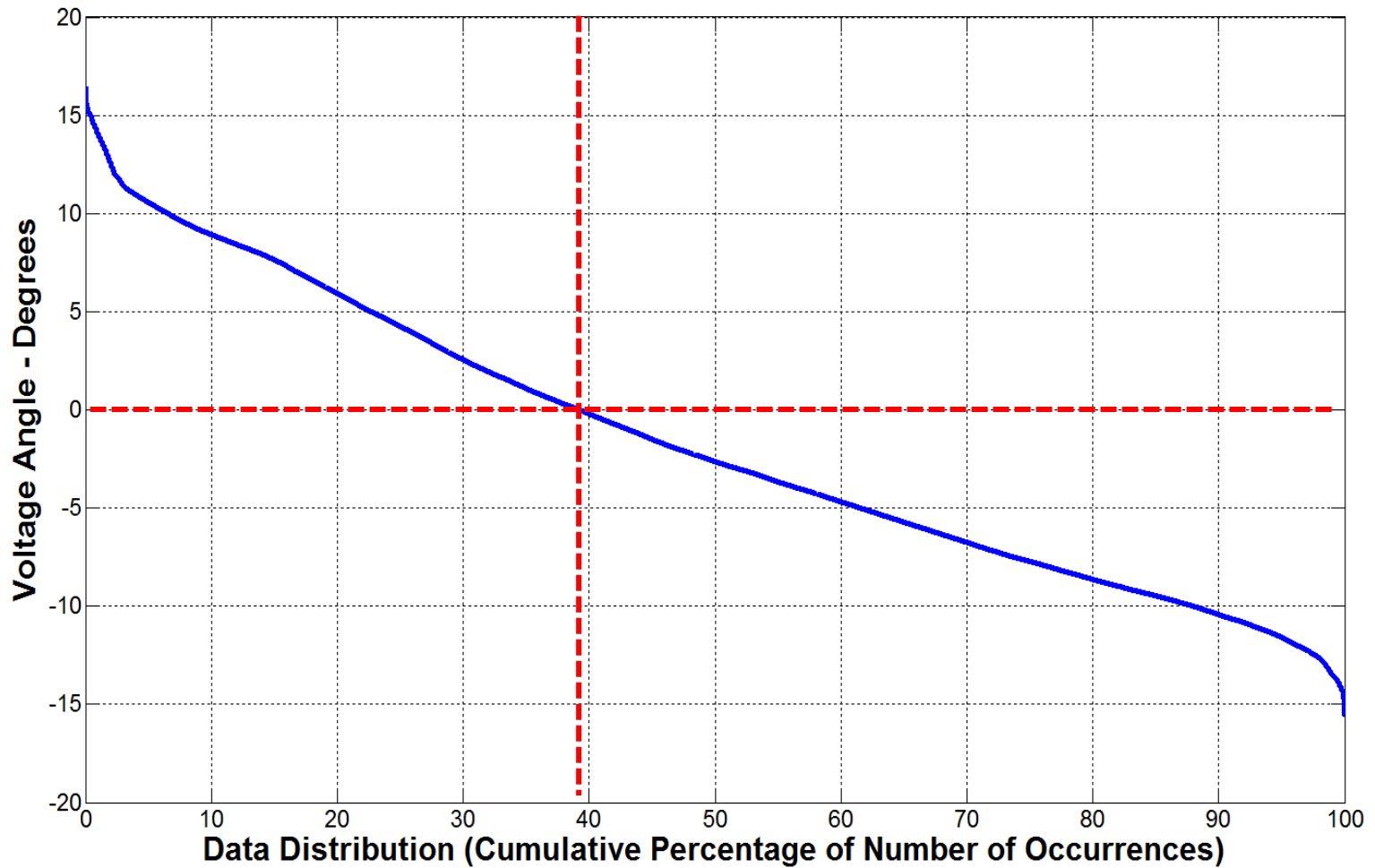
West 5 – North 1

Daily Box-Whisker Chart:



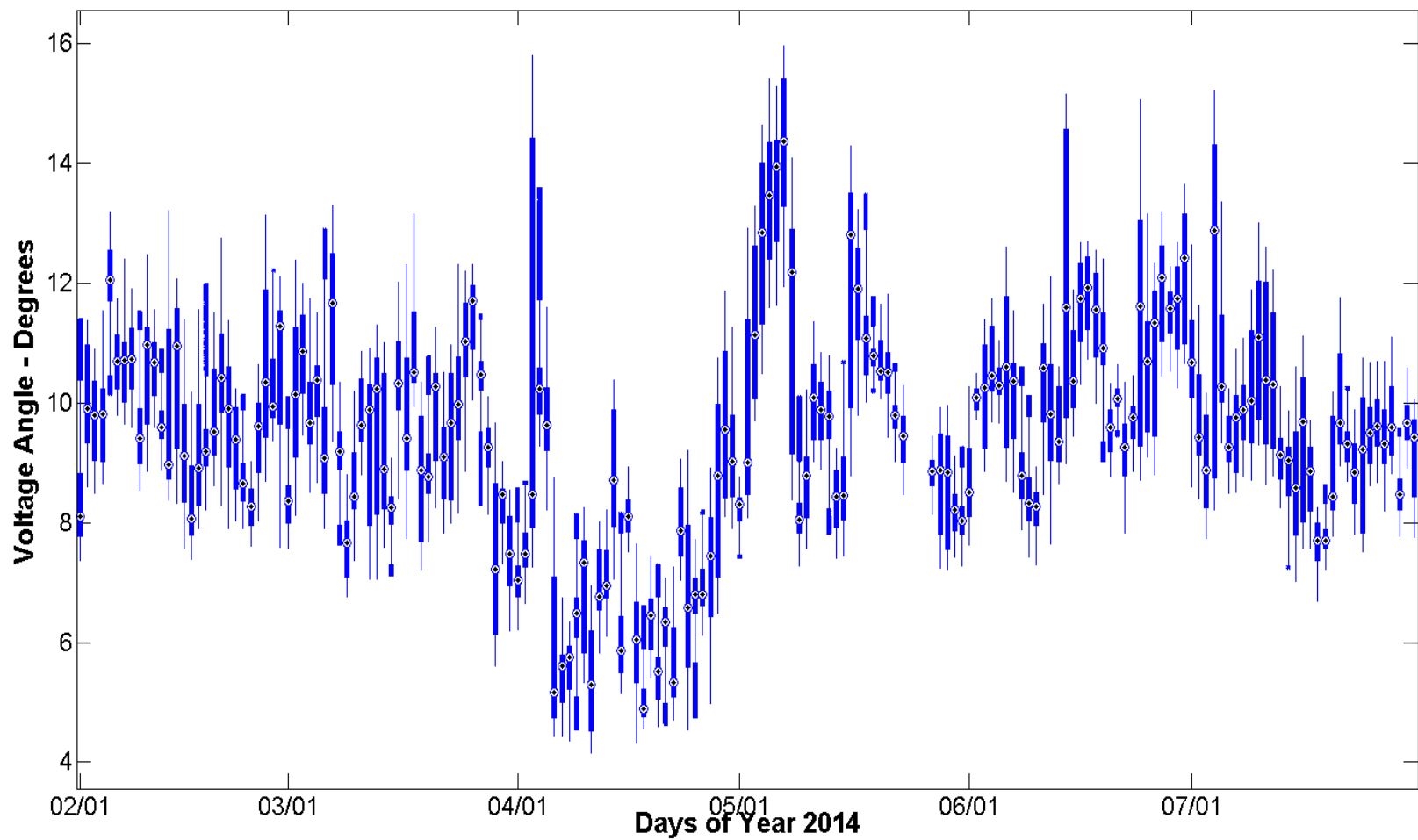
West 5 – North 1

Time Duration Chart:

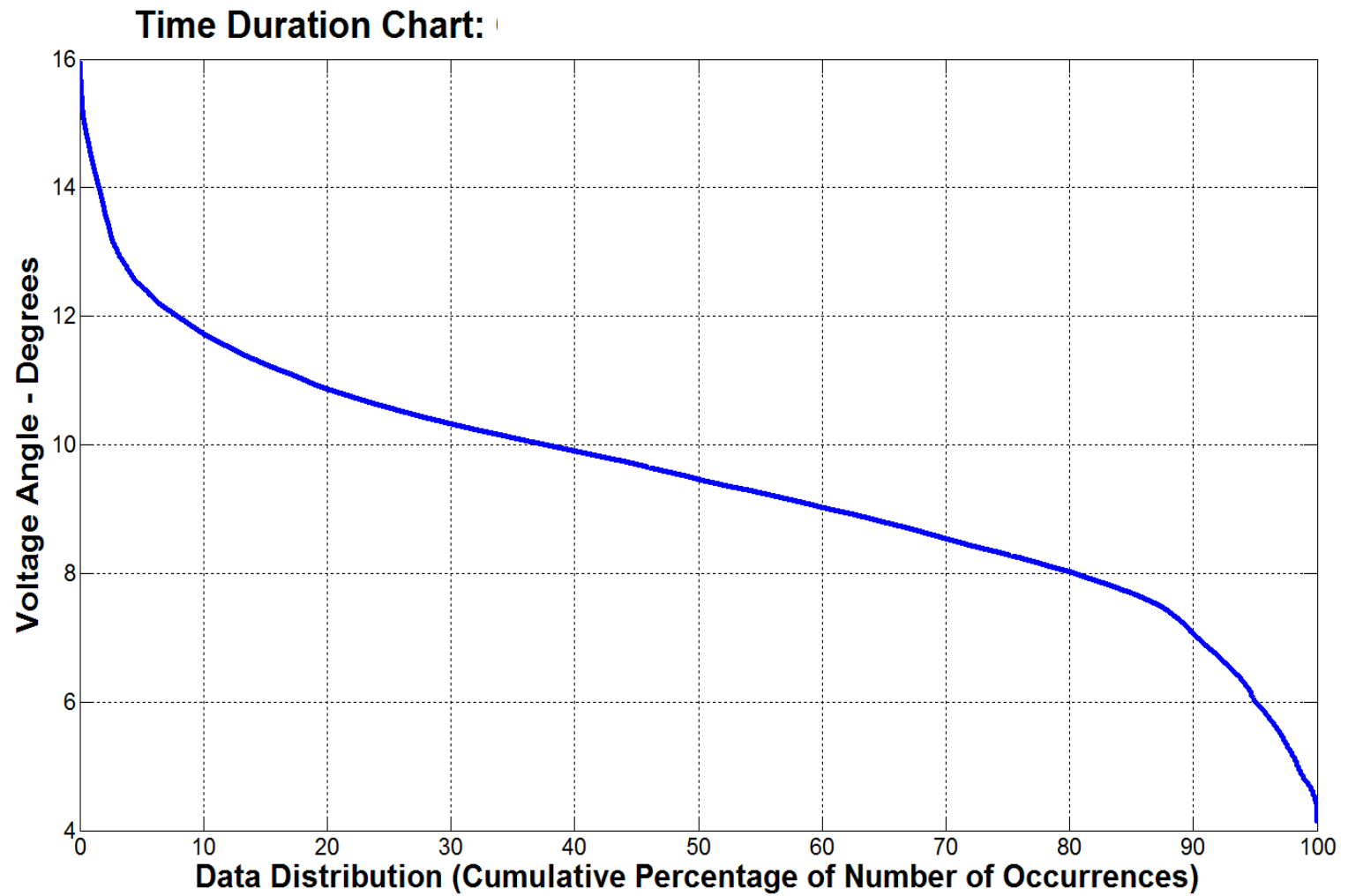


North 1 – North 4

Daily Box-Whisker Chart:

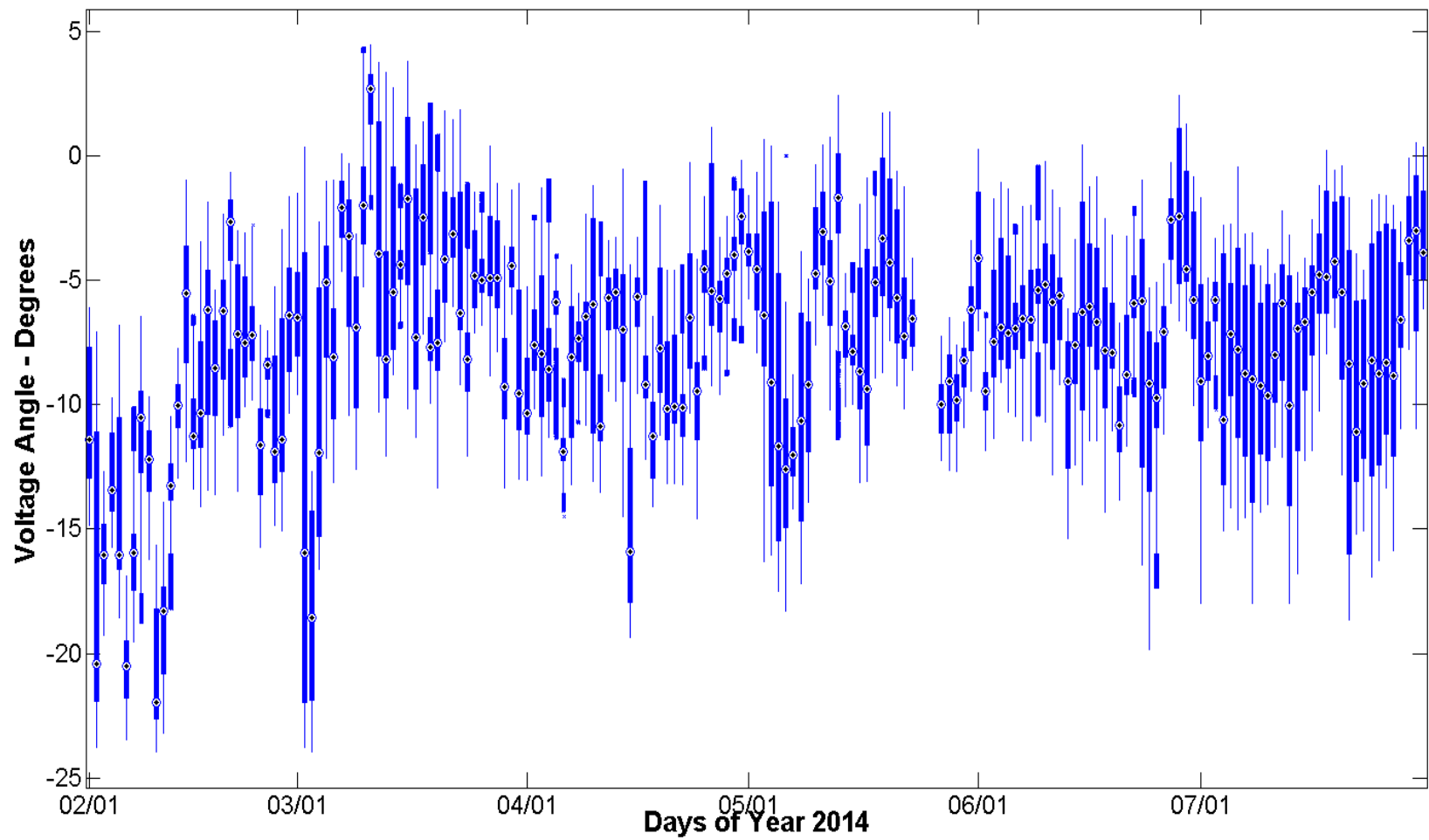


North 1 – North 4



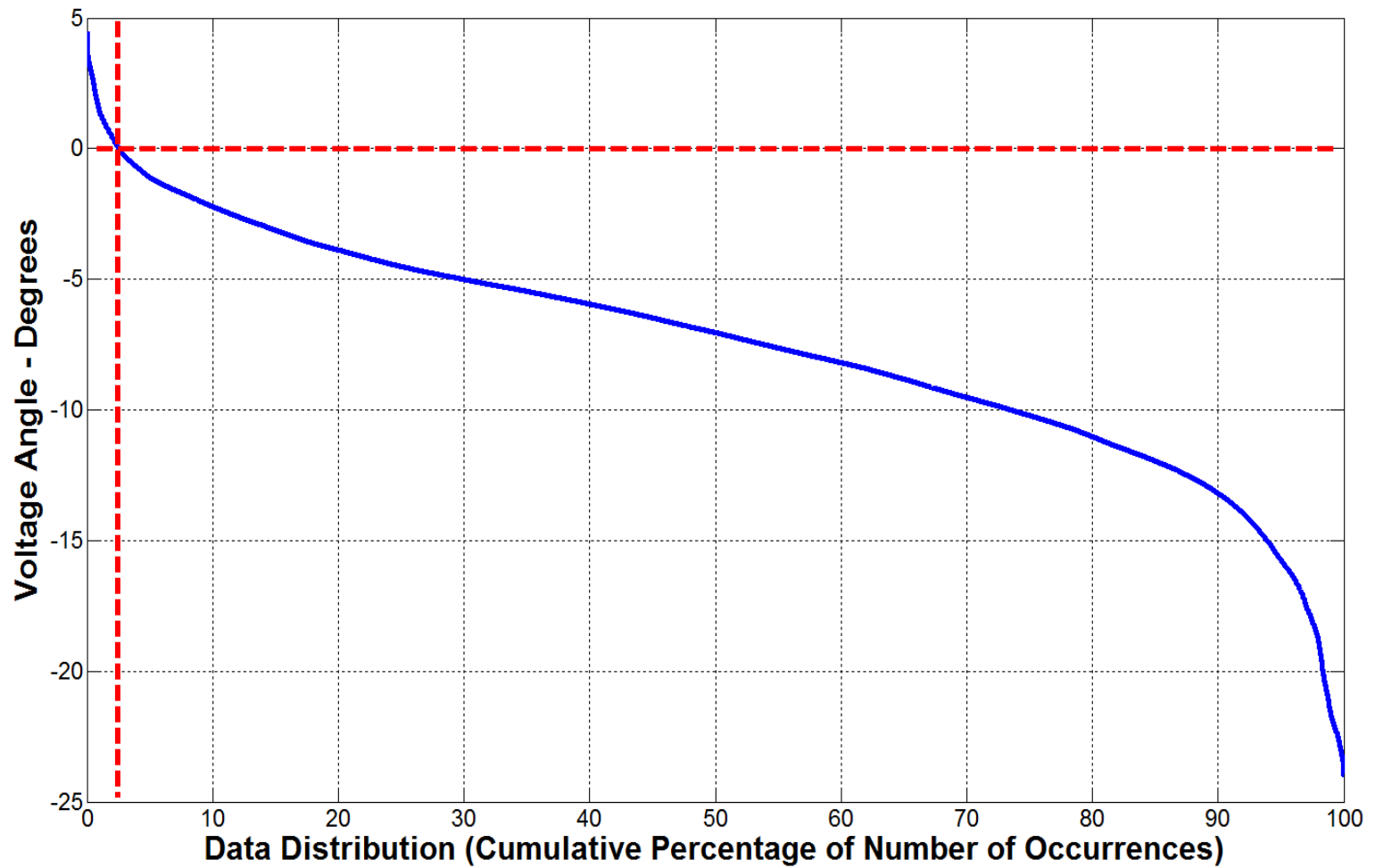
North 4 – North 6

Daily Box-Whisker Chart:



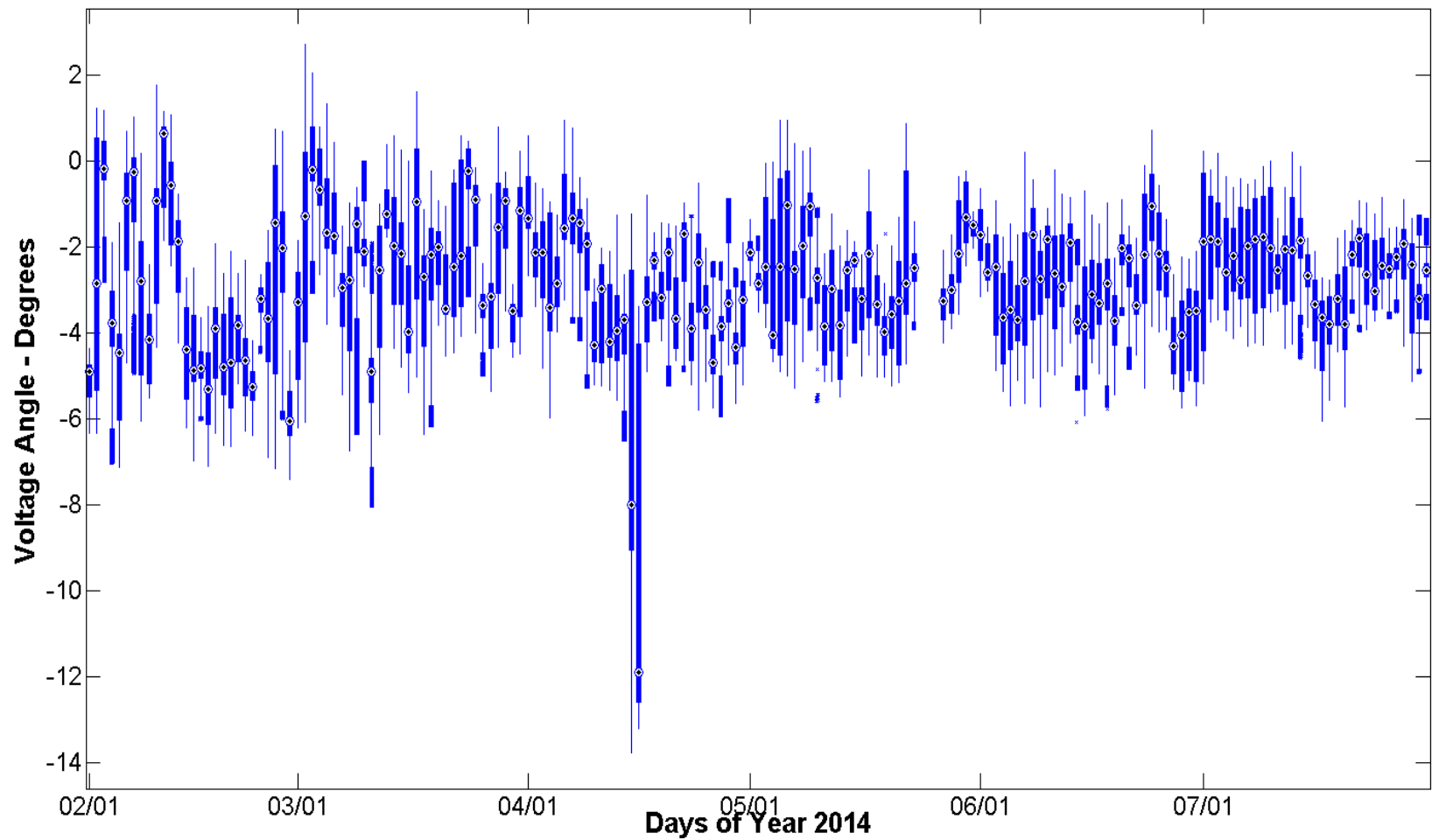
North 4 – North 6

Time Duration Chart:



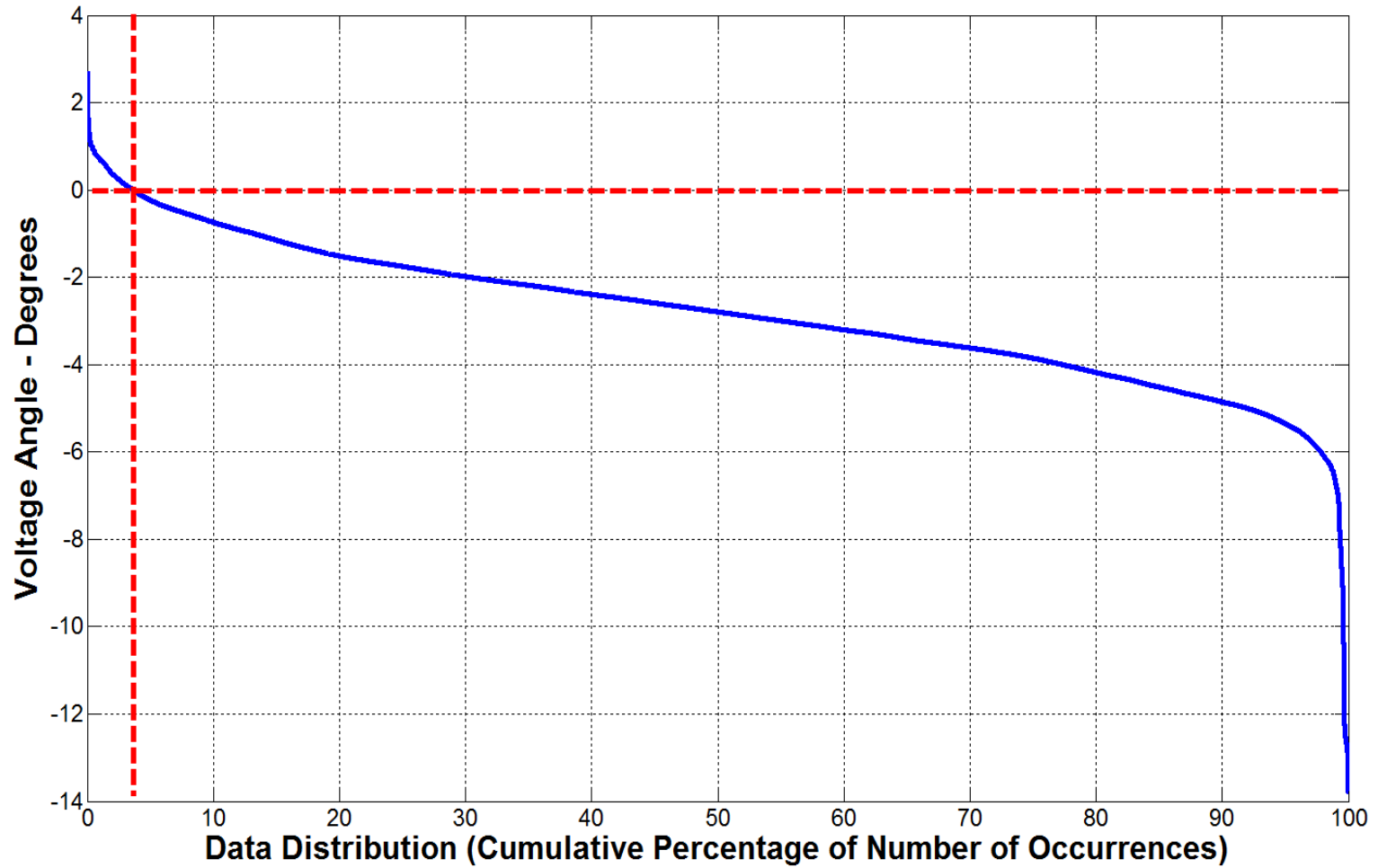
FarWest 7 – FarWest 4

Daily Box-Whisker Chart:



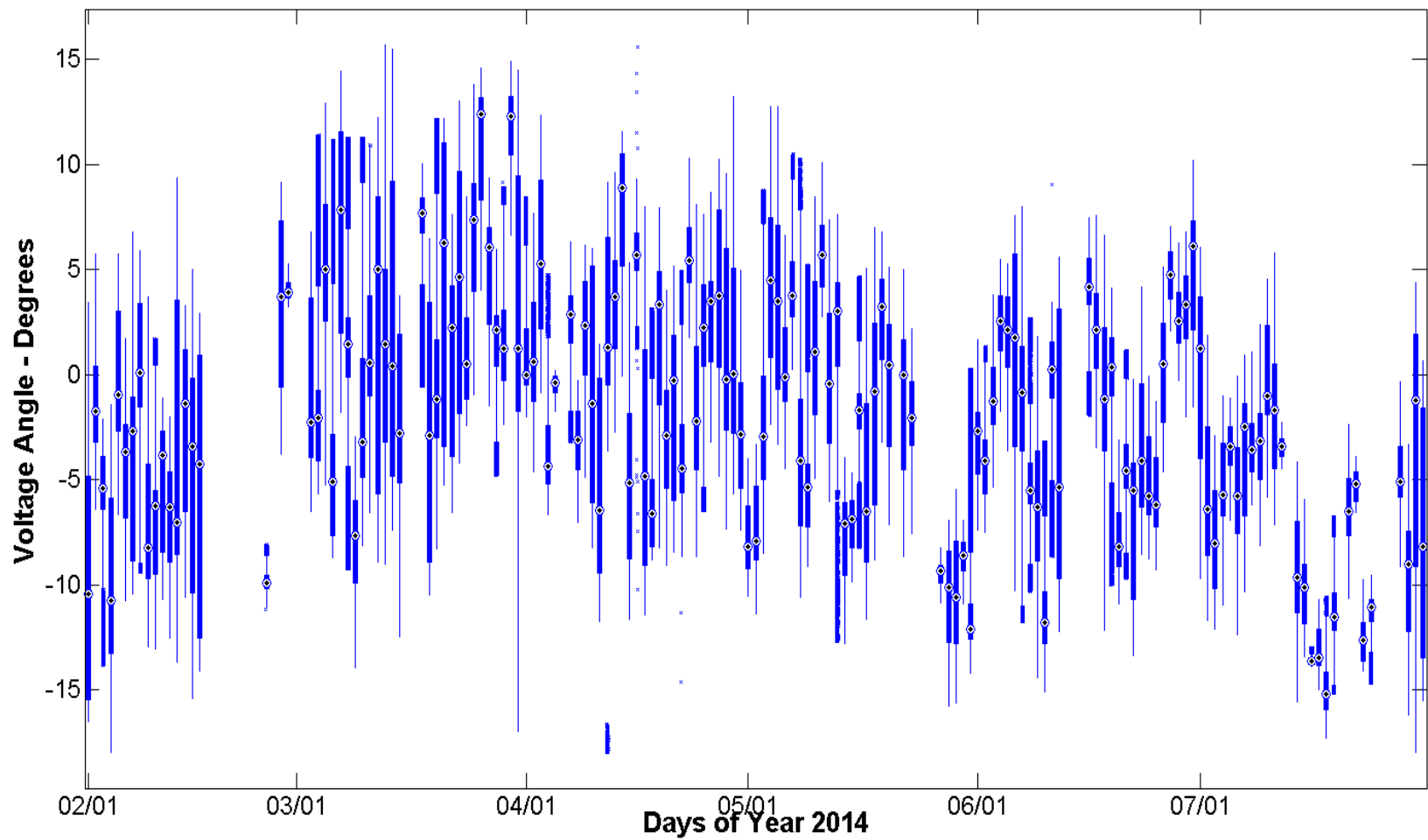
FarWest 7 – FarWest 4

Time Duration Chart:



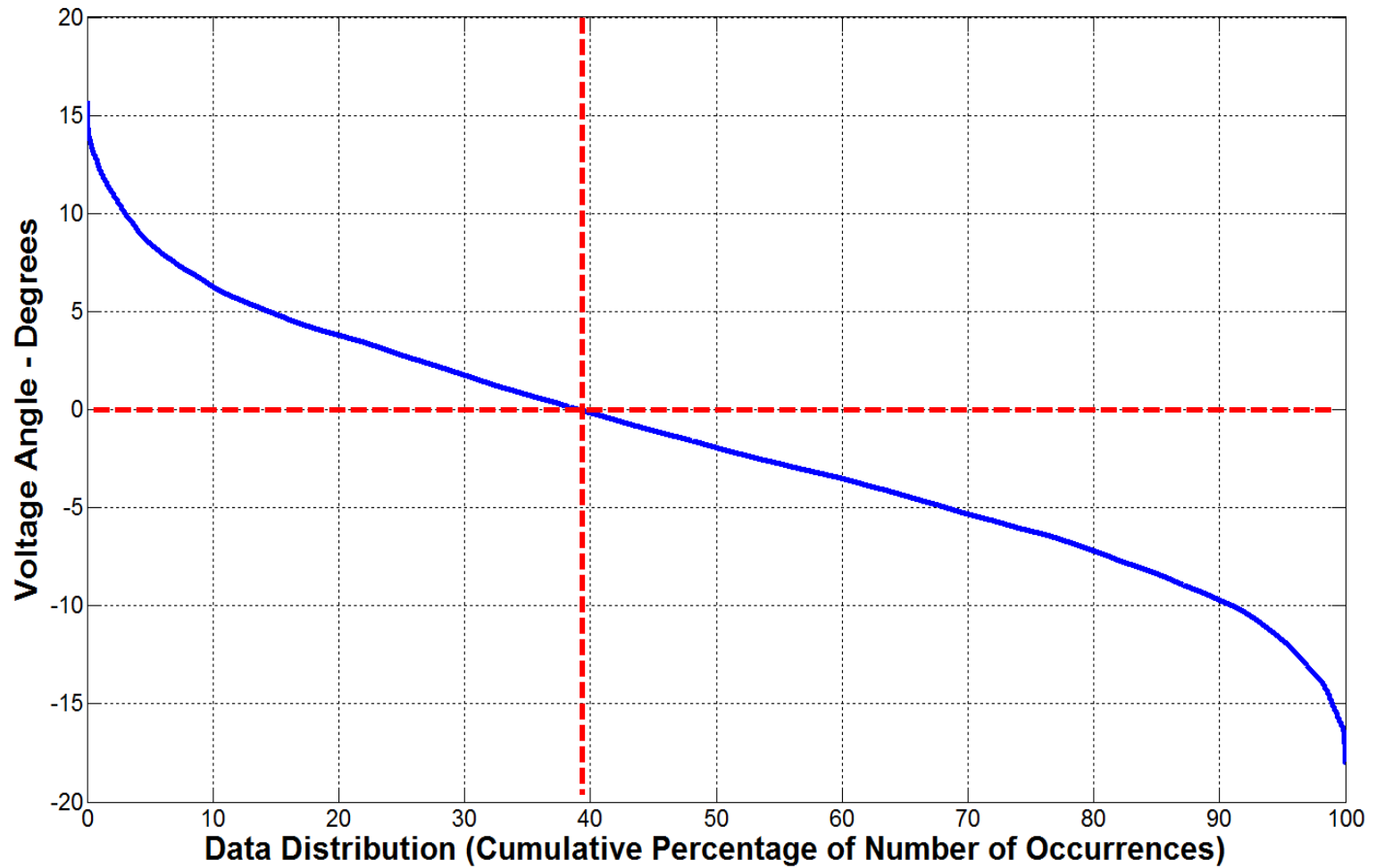
FarWest 7 – West 14

Daily Box-Whisker Chart:



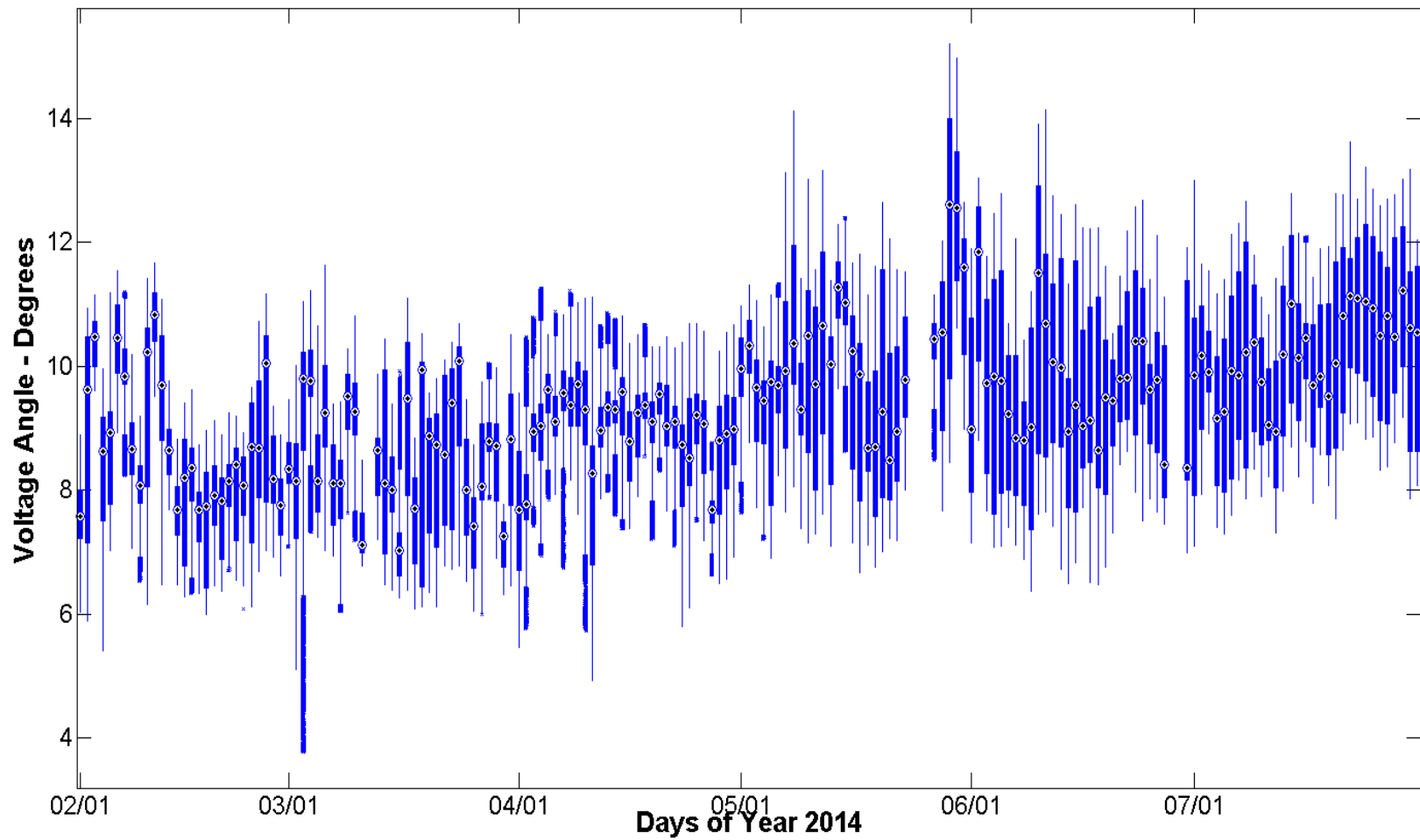
FarWest 7 – West 14

Time Duration Chart:



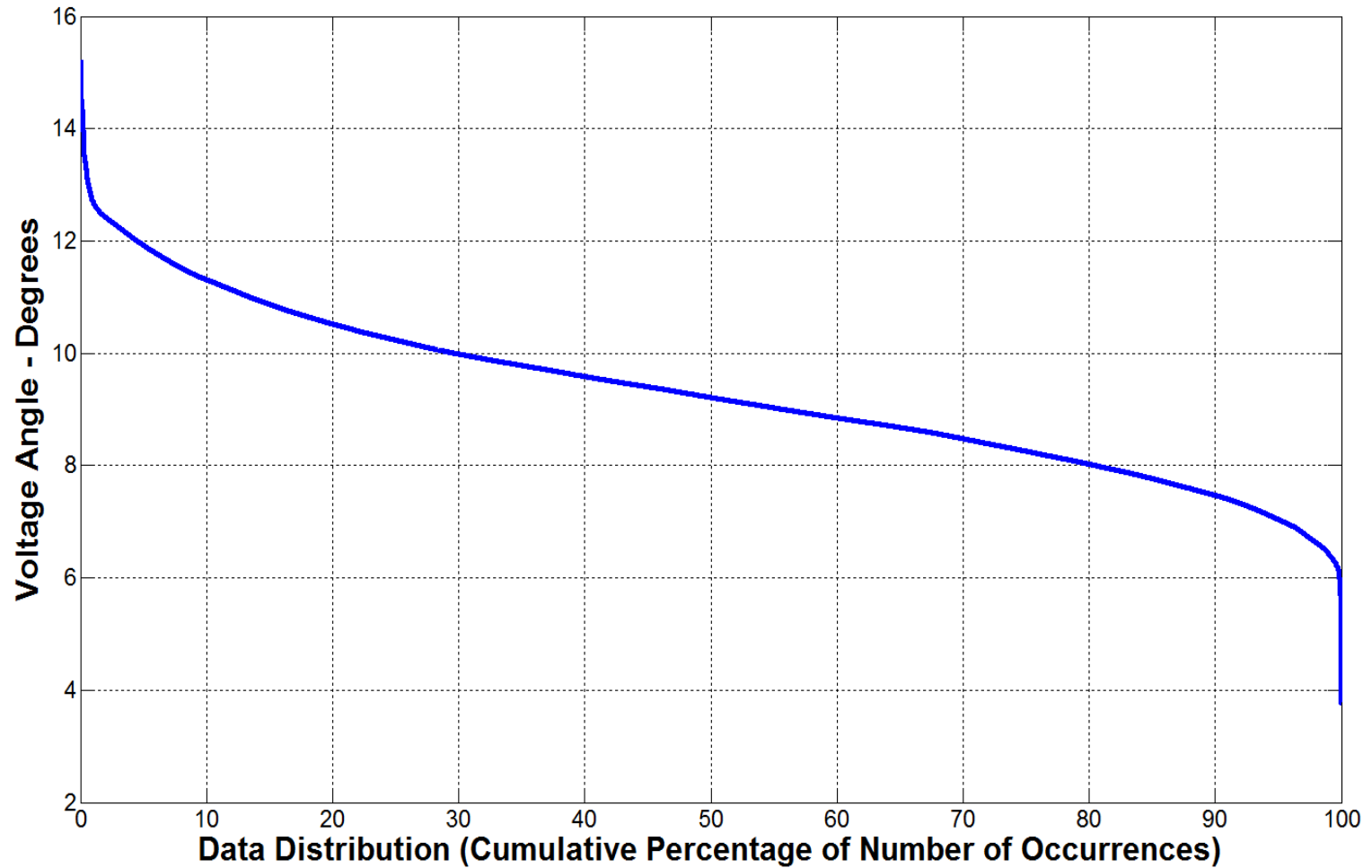
FarWest 7 – FarWest 8

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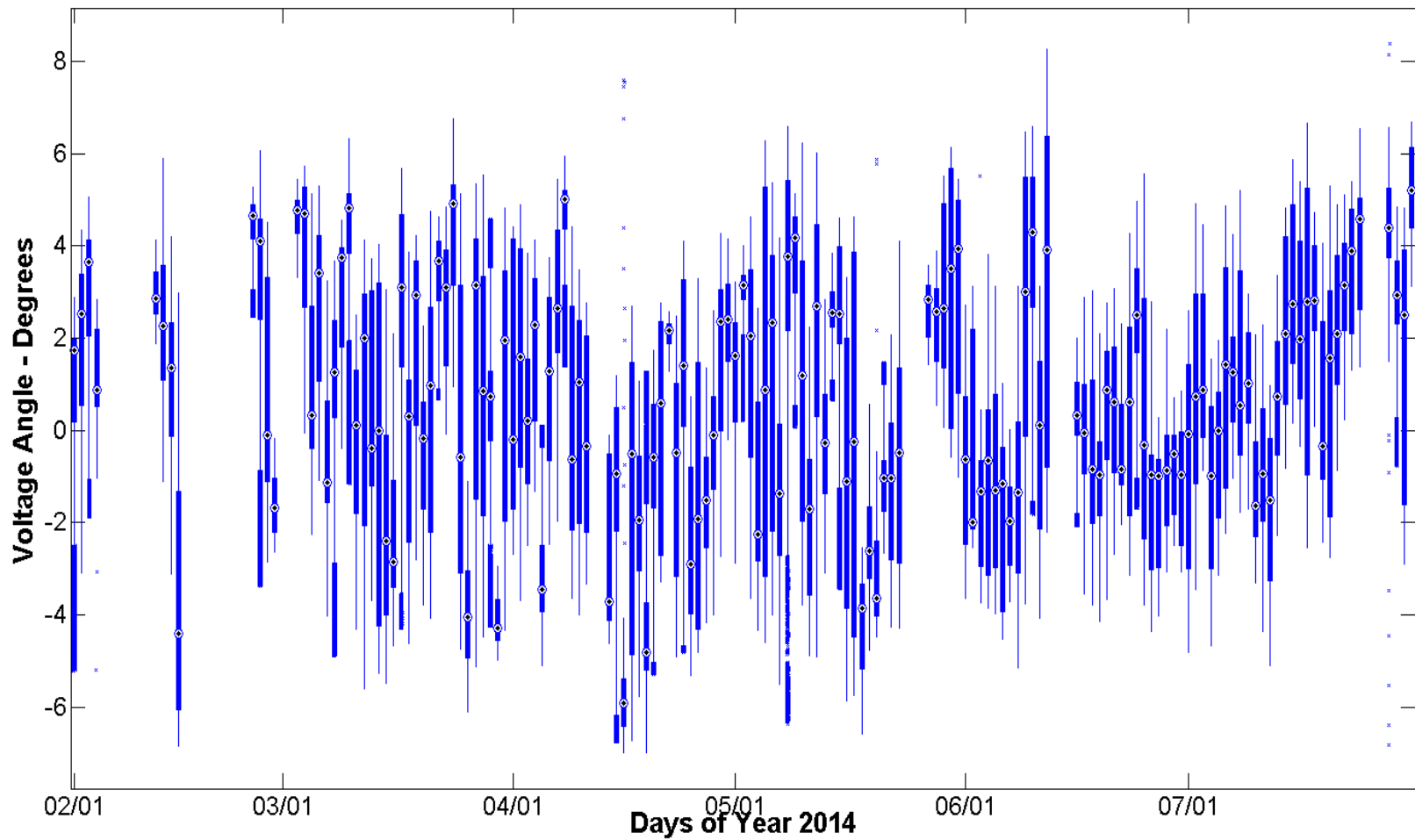
FarWest 7 – FarWest 8

Time Duration Chart:



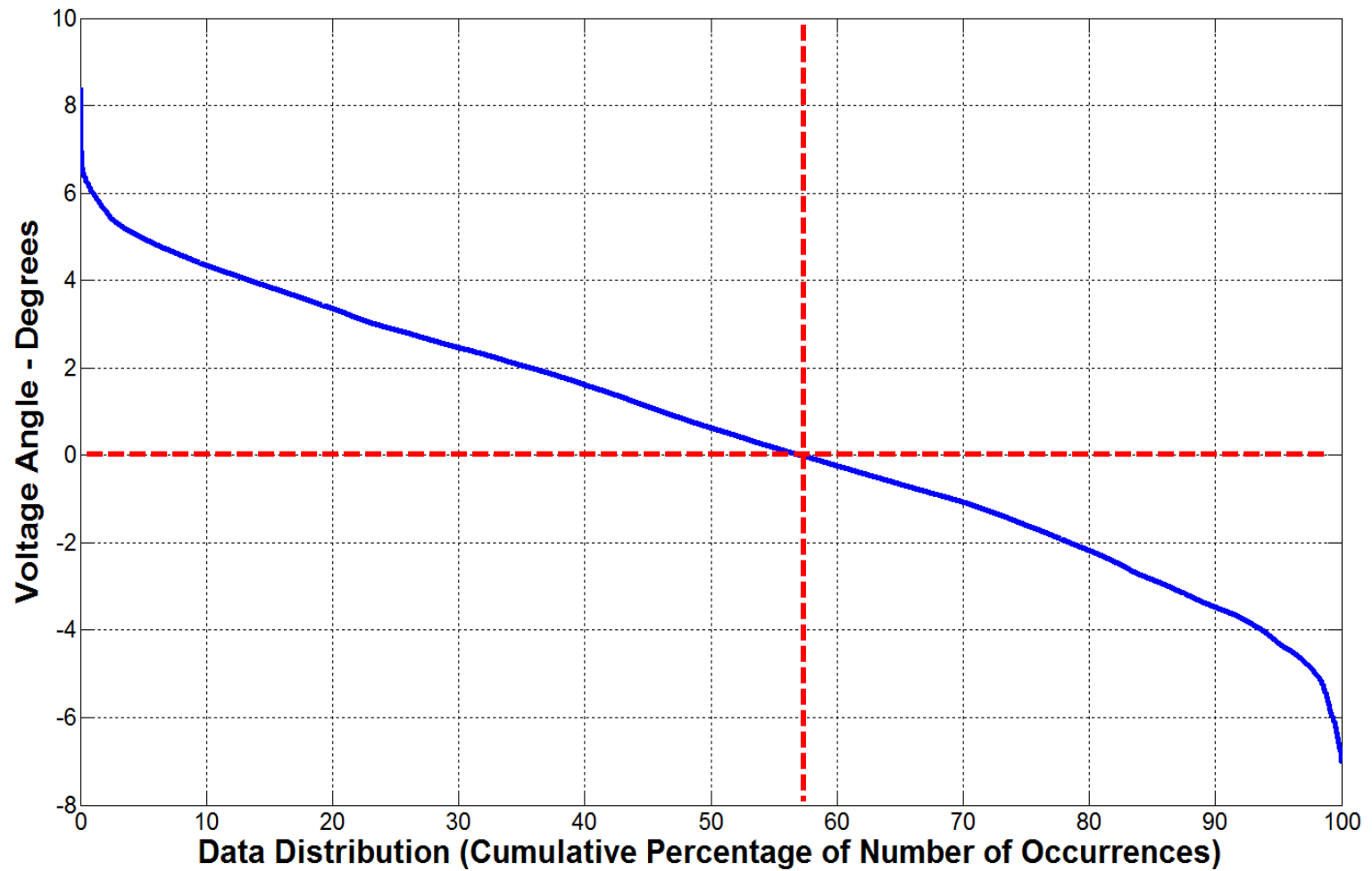
FarWest 7 – FarWest 9

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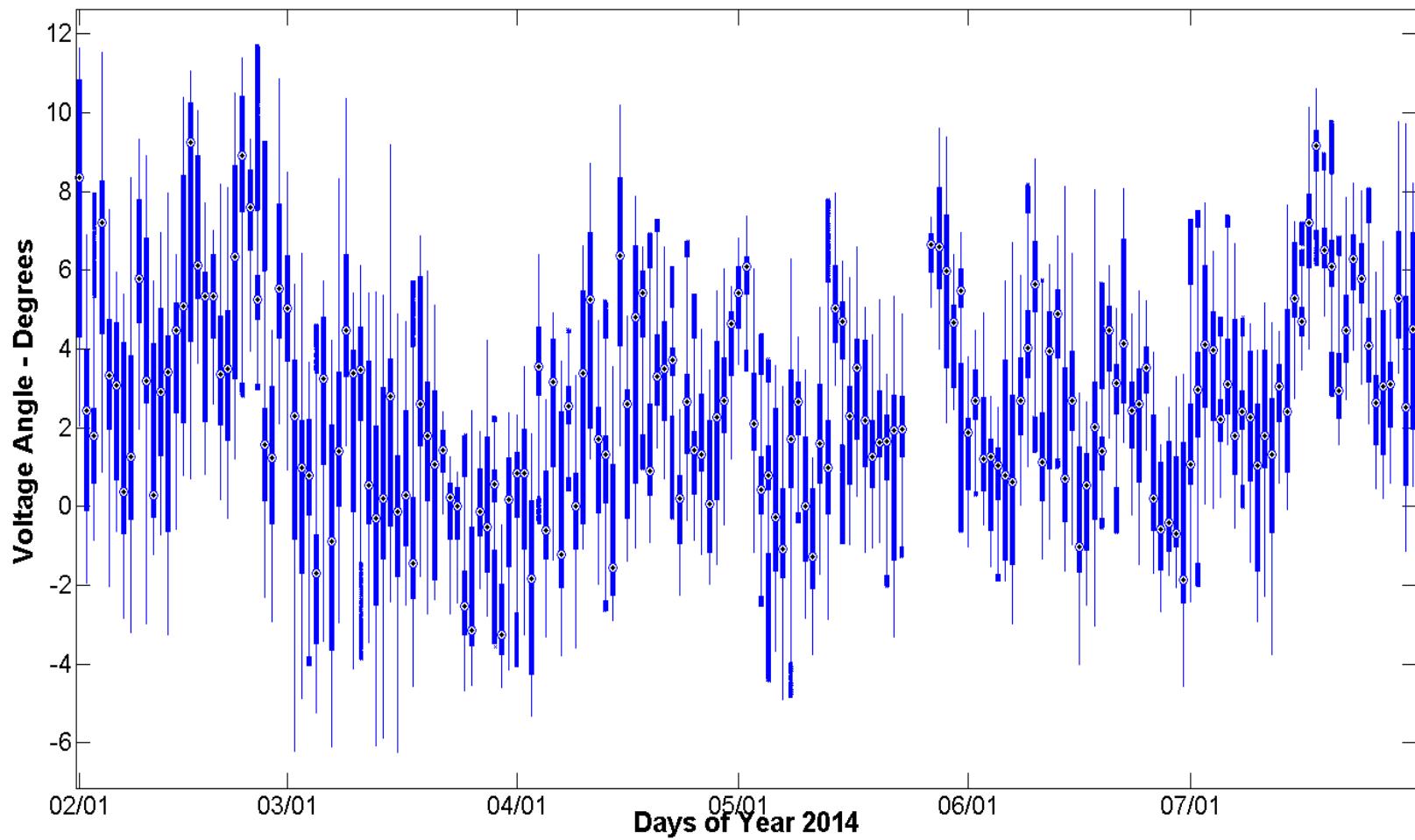
FarWest 7 – FarWest 9

Time Duration Chart:



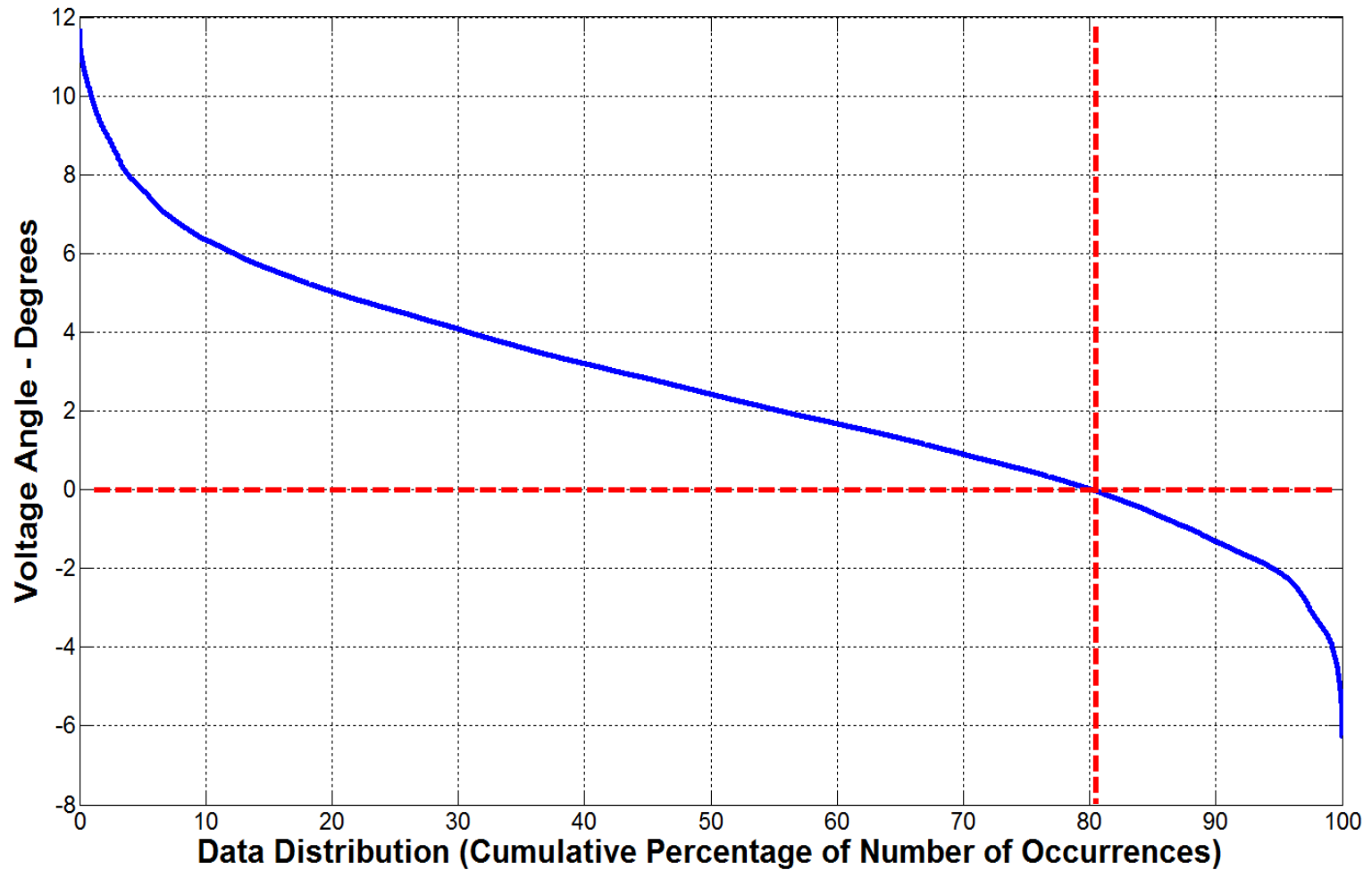
West 12 – FarWest 7

Daily Box-Whisker Chart:



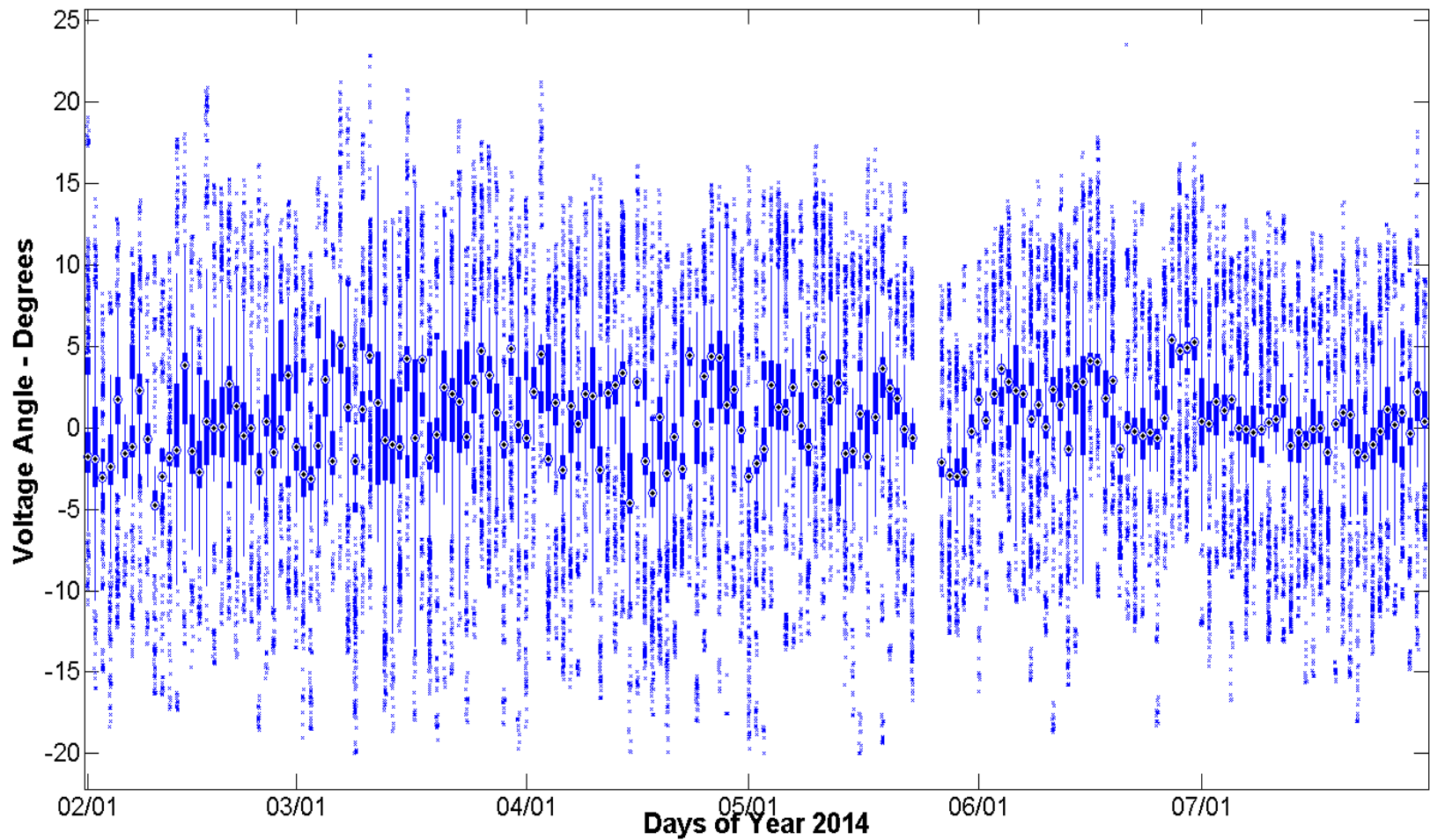
West 12 – FarWest 7

Time Duration Chart:



West 12 – West 1*

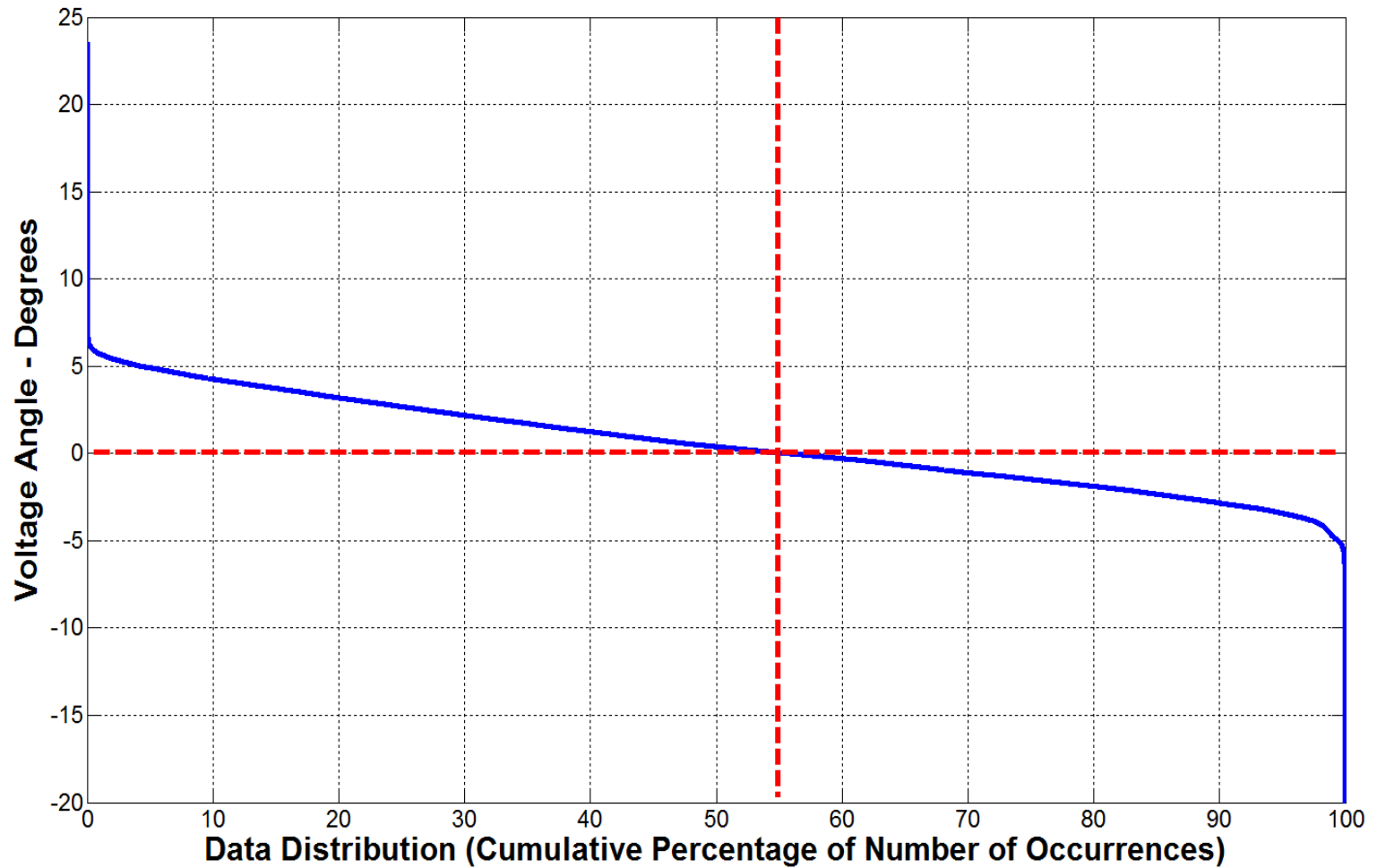
Daily Box-Whisker Chart:



* West 1 PMU has noisy signal

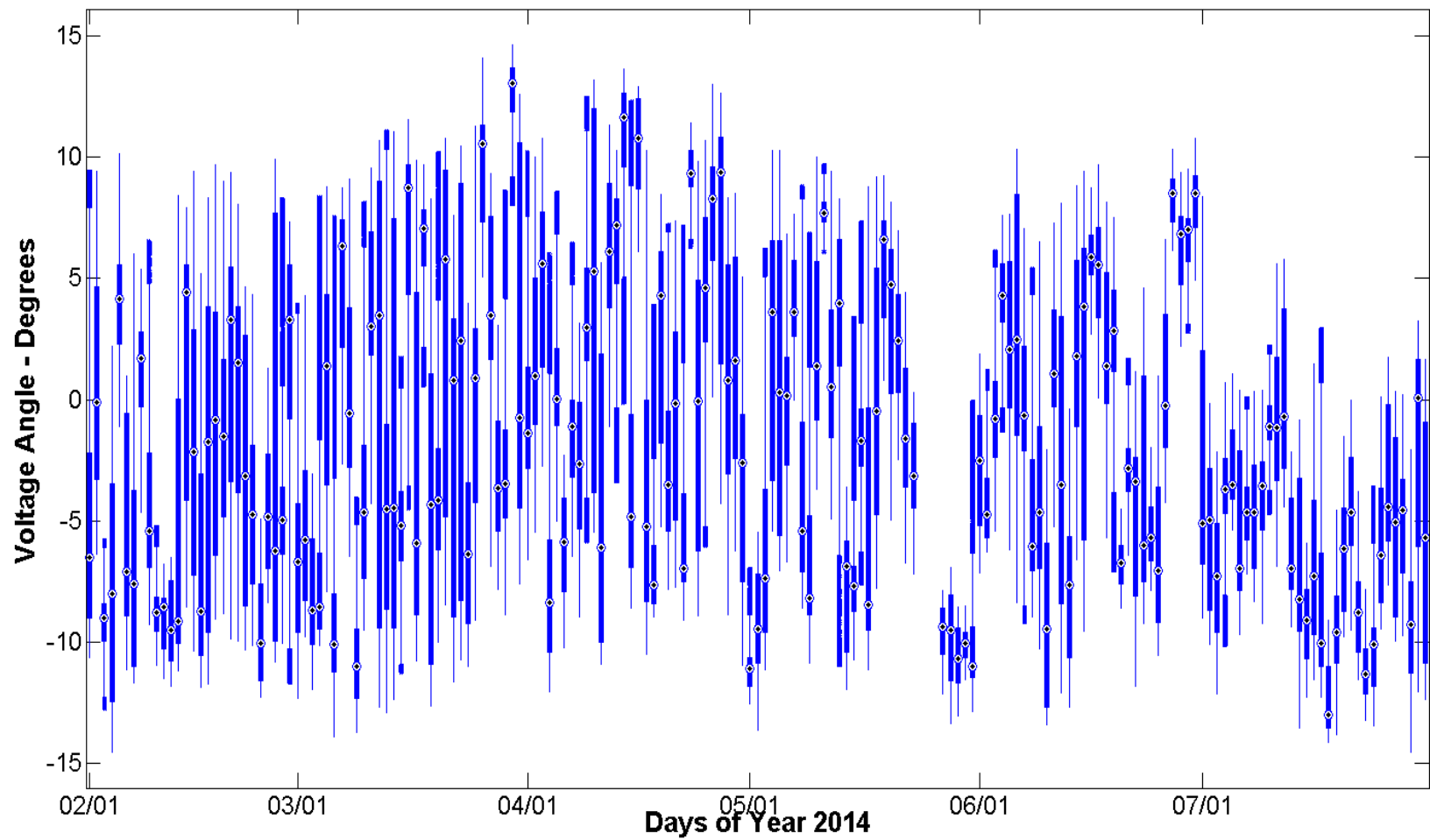
West 12 – West 1

Time Duration Chart:



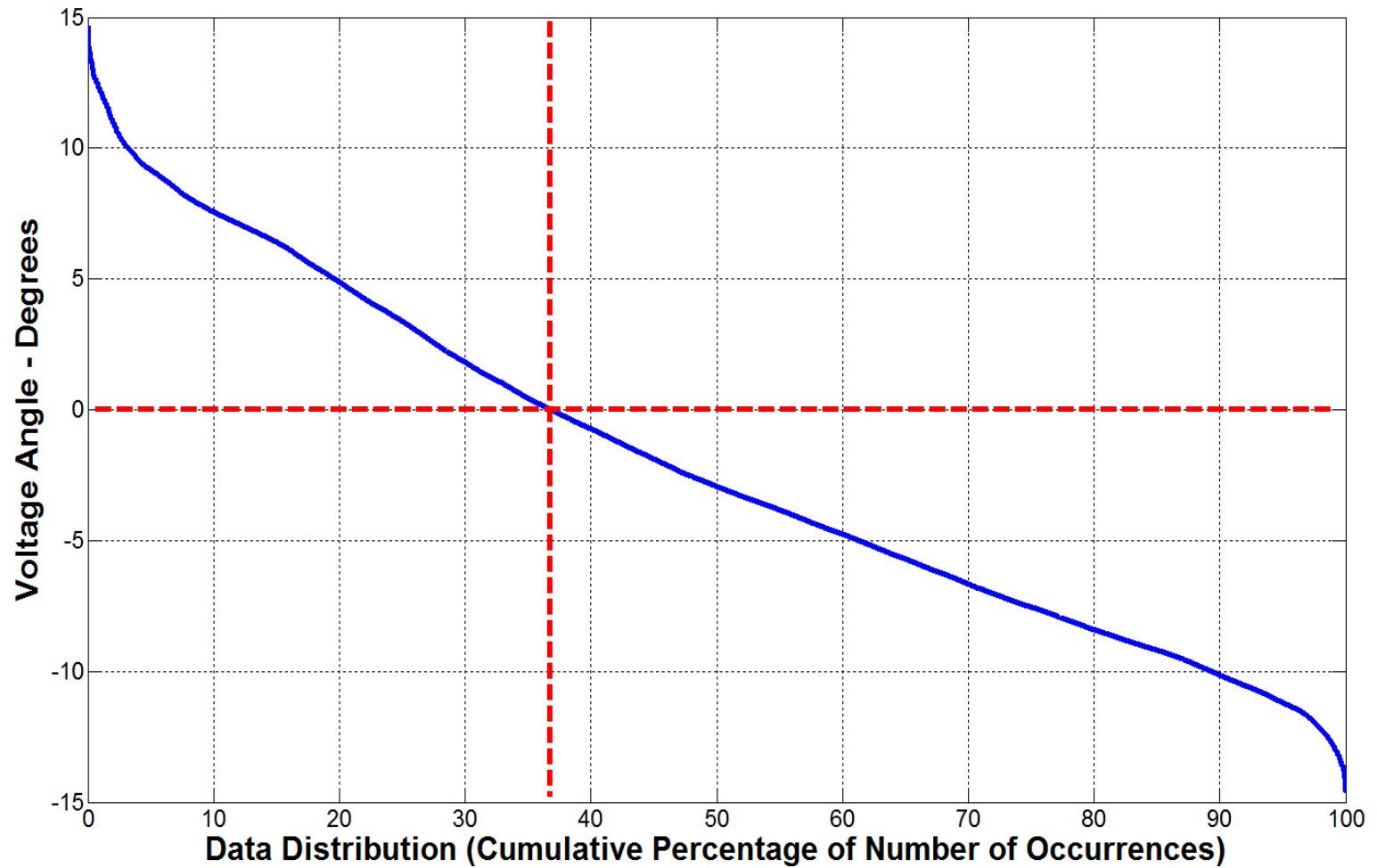
West 12 – North 1

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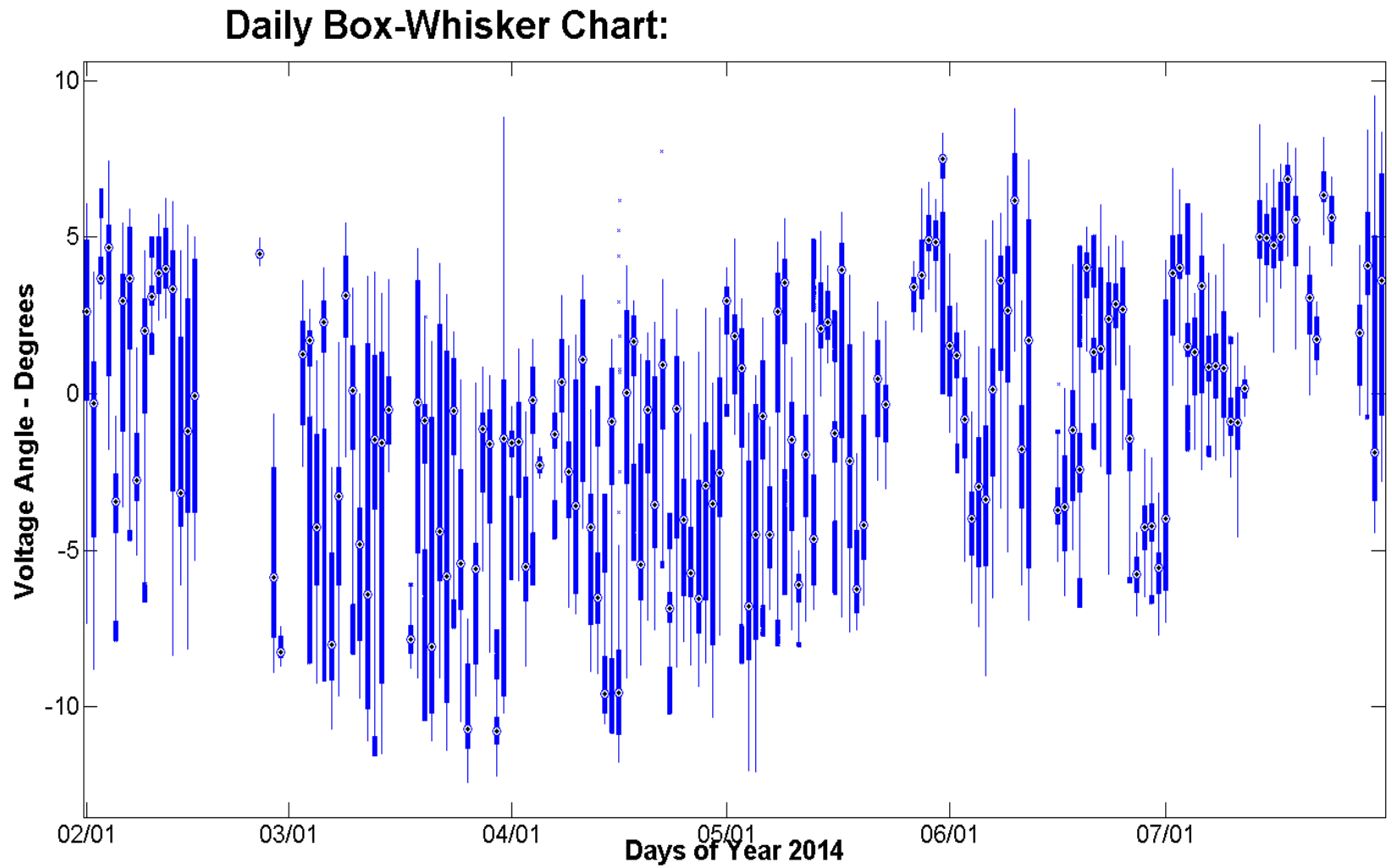


West 12 – North 1

Time Duration Chart:

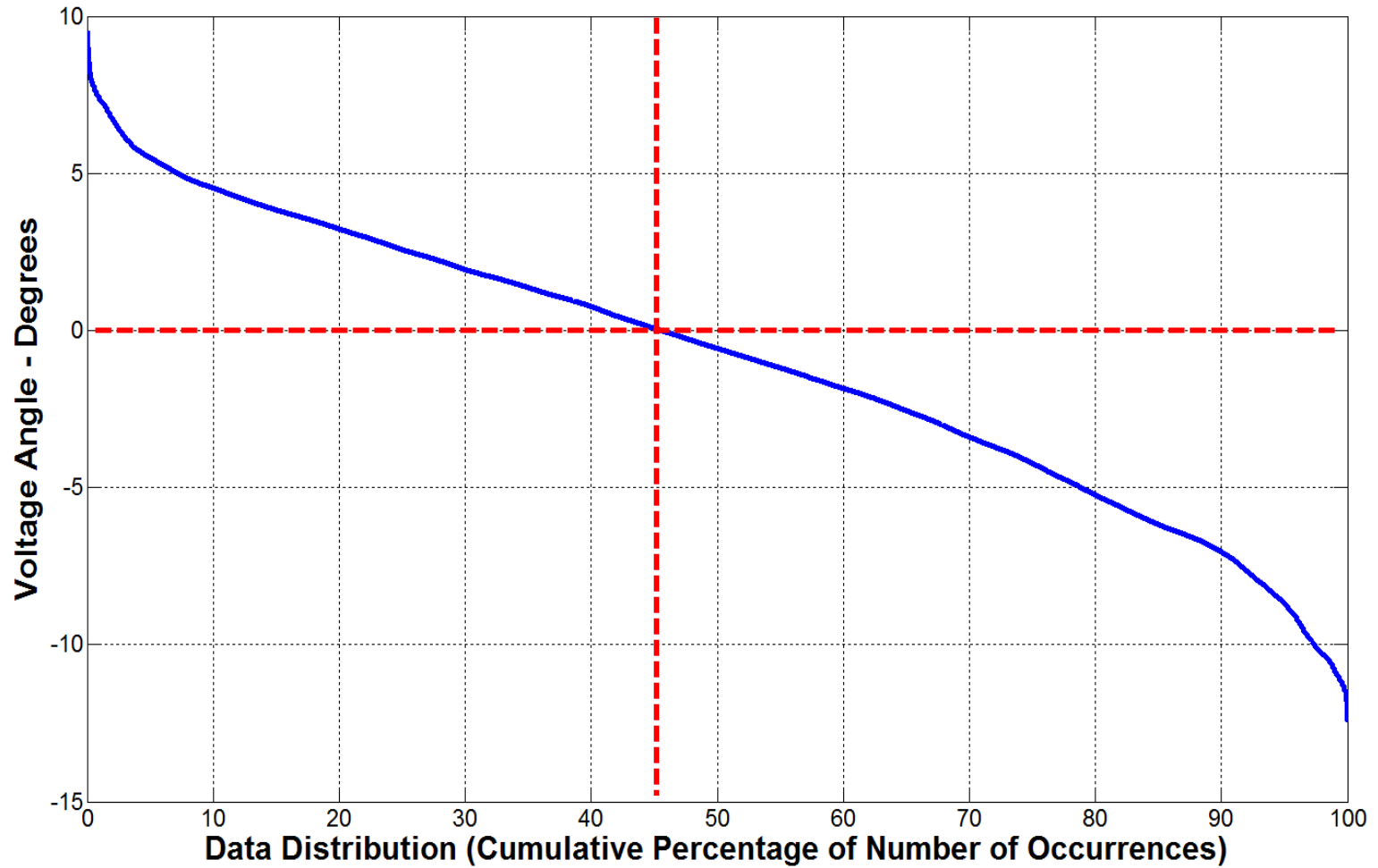


West 14 – West 5



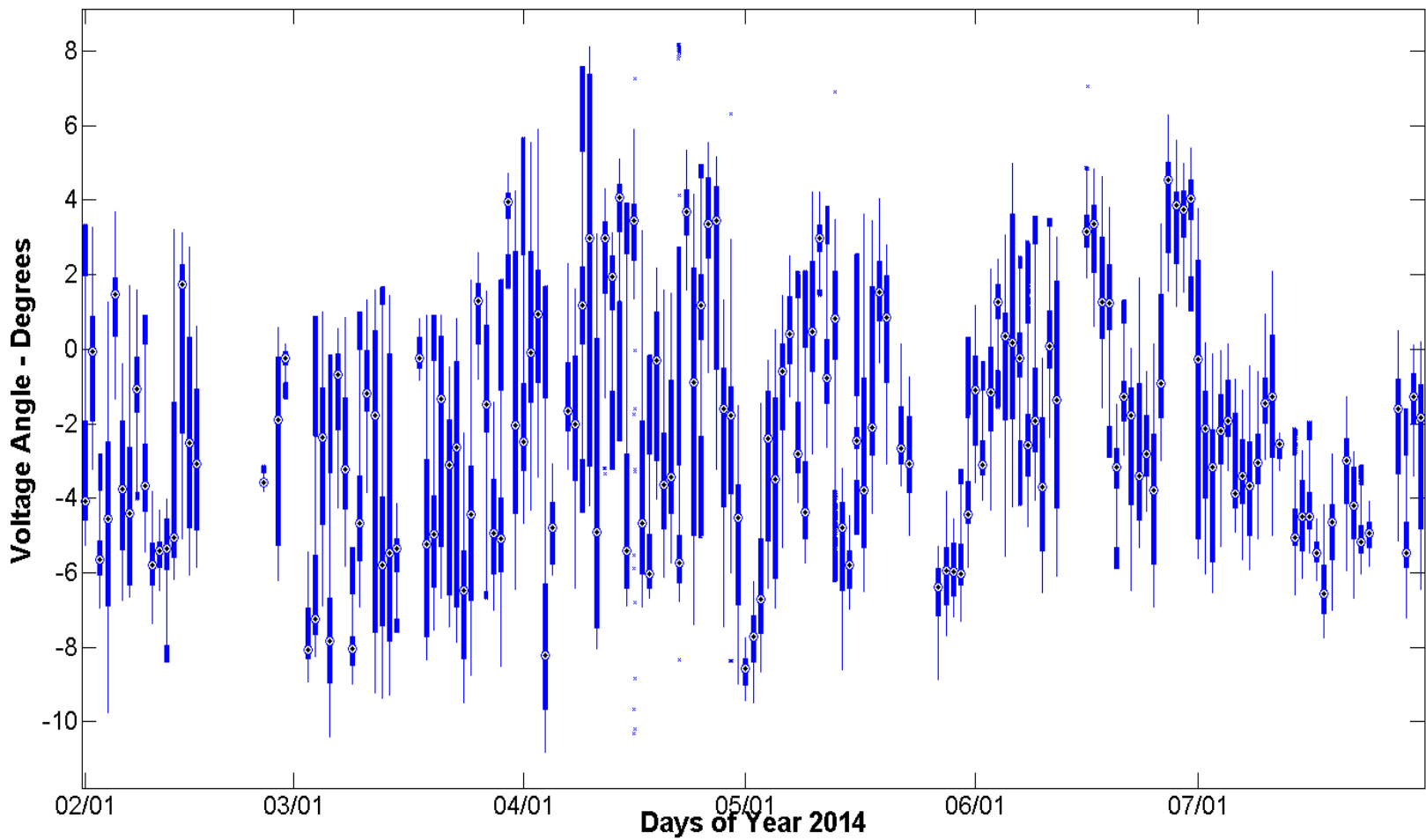
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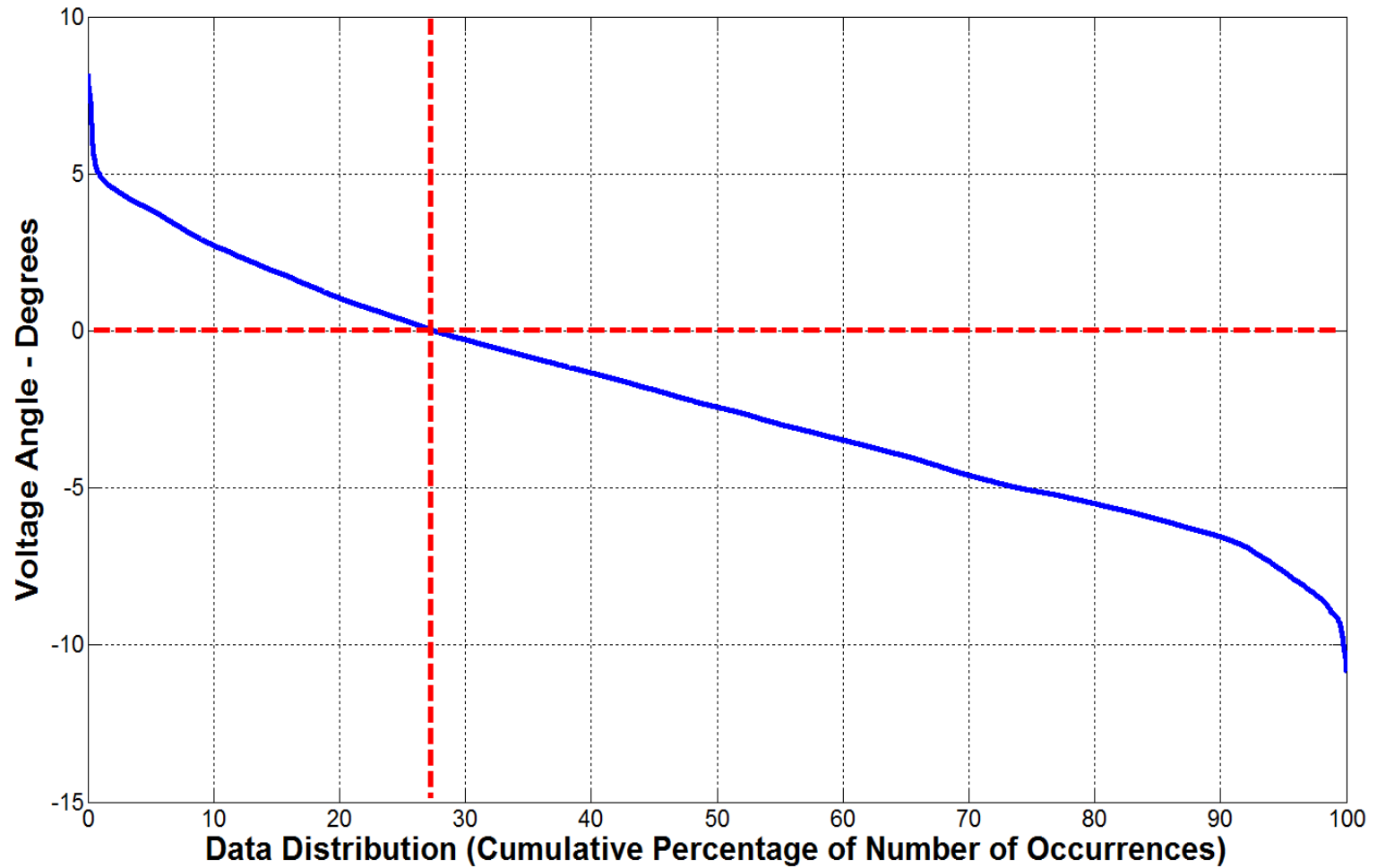
West 14 – North 1

Daily Box-Whisker Chart:



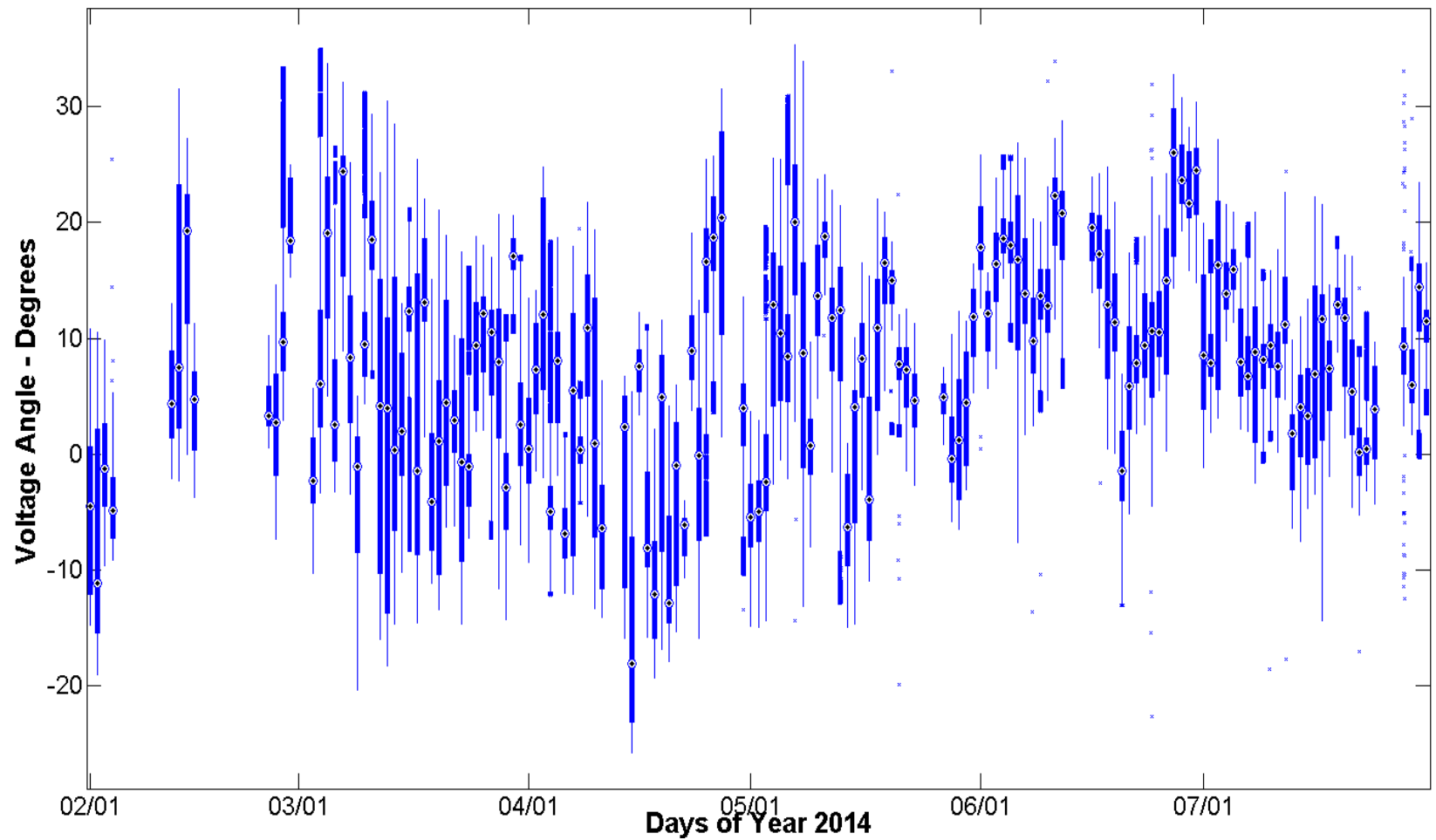
West 14 – North 1

Time Duration Chart:



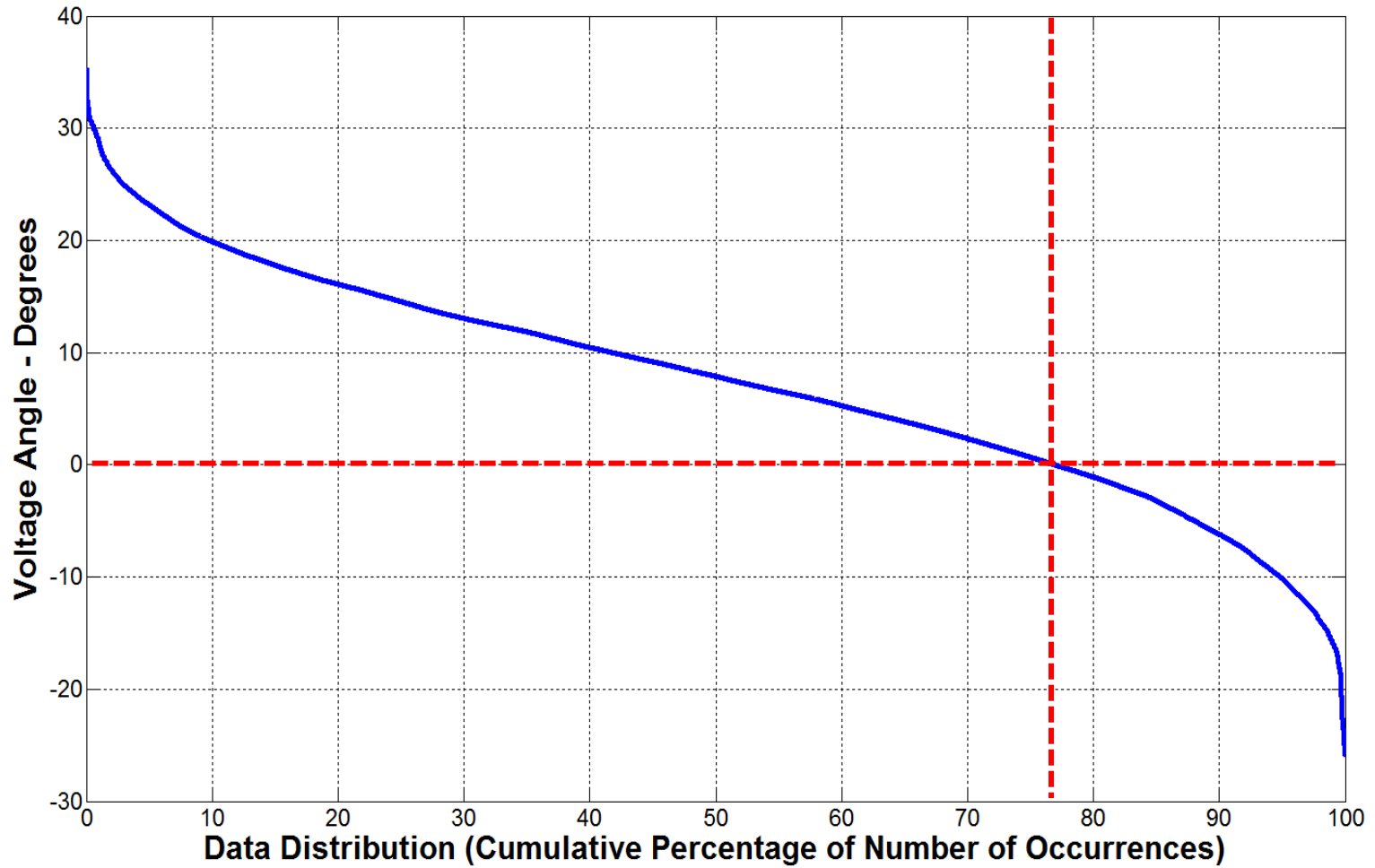
FarWest 9 – West 4

Daily Box-Whisker Chart:



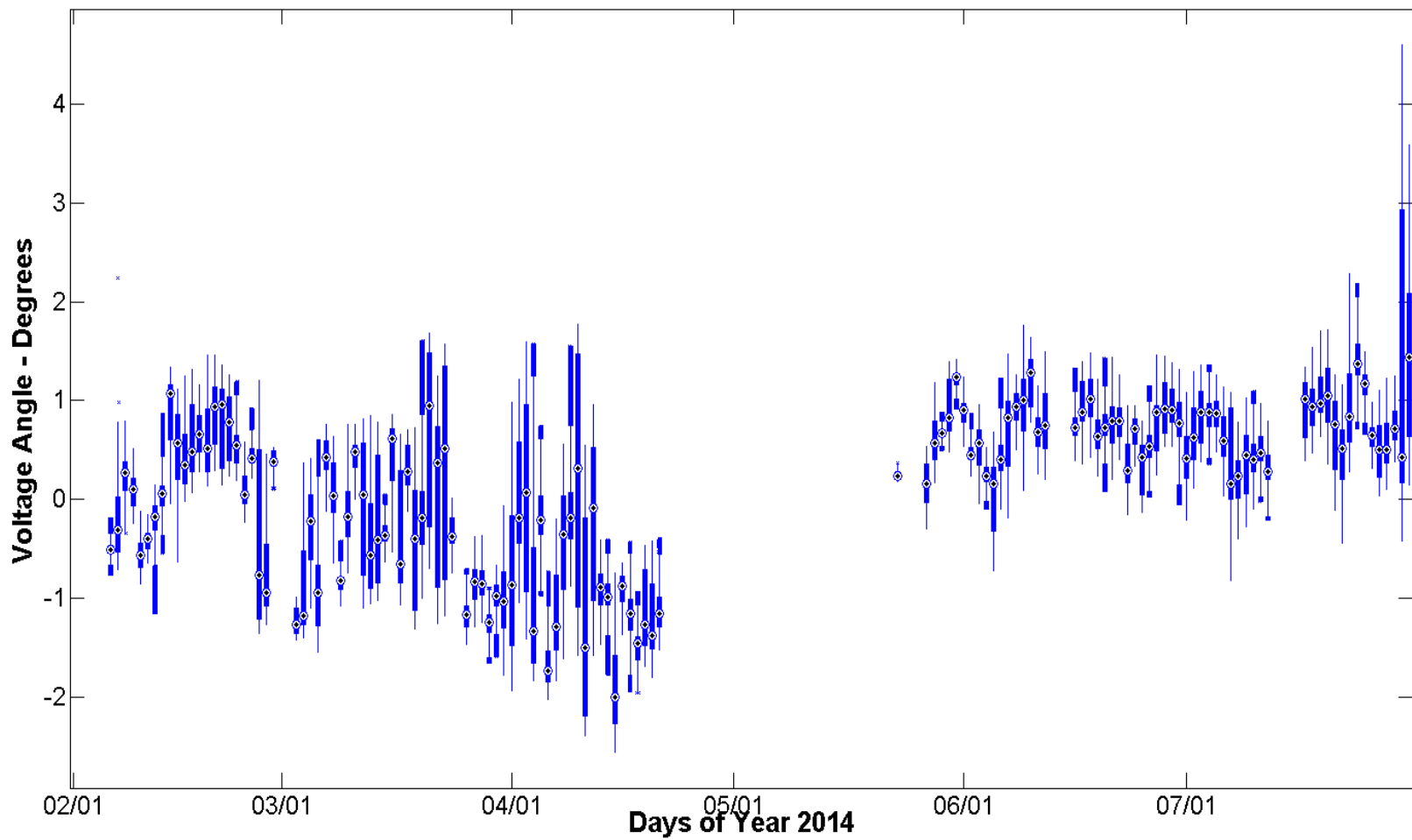
FarWest 9 – West 4

Time Duration Chart:



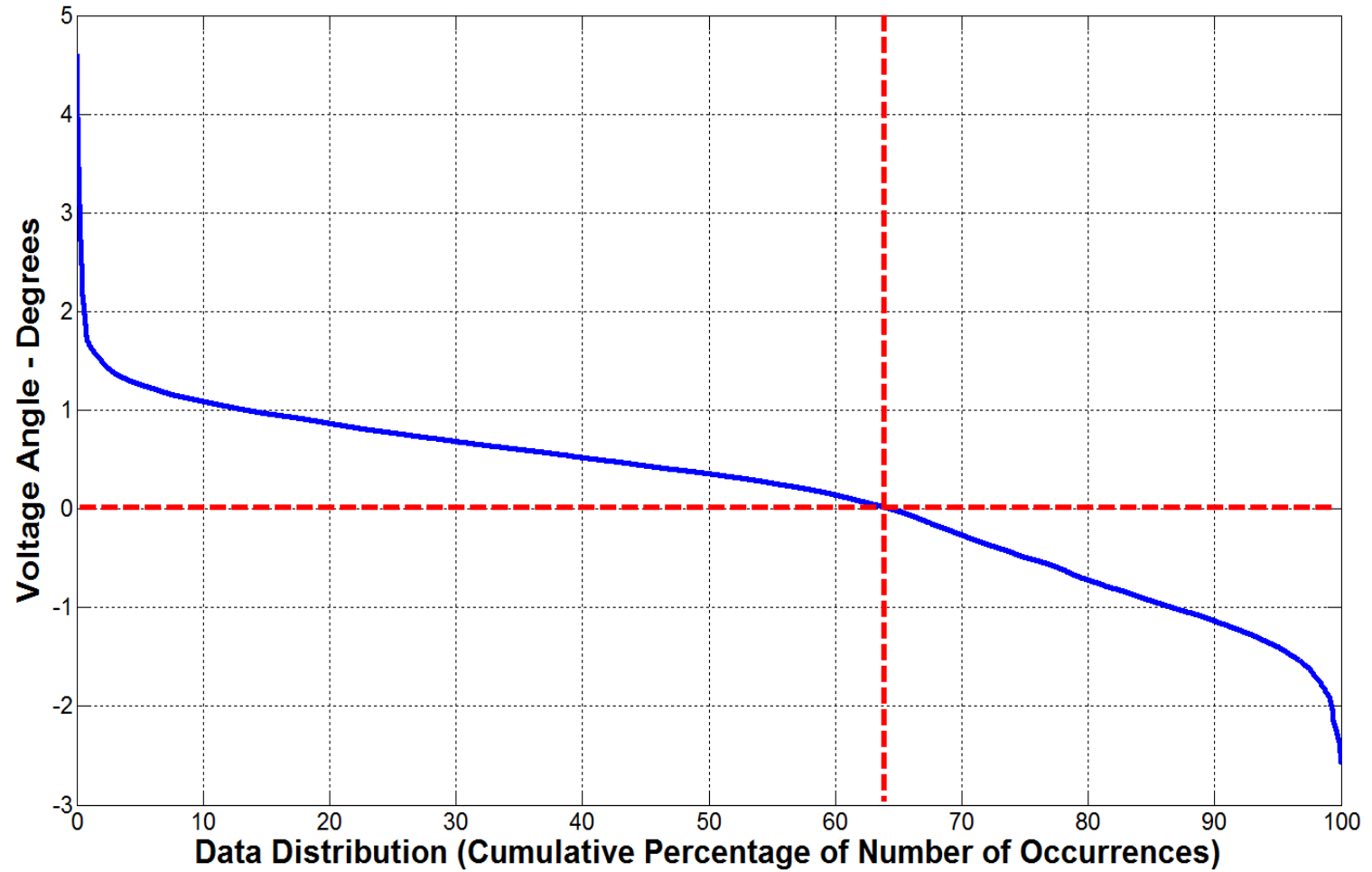
West 16 – West 3

Daily Box-Whisker Chart:



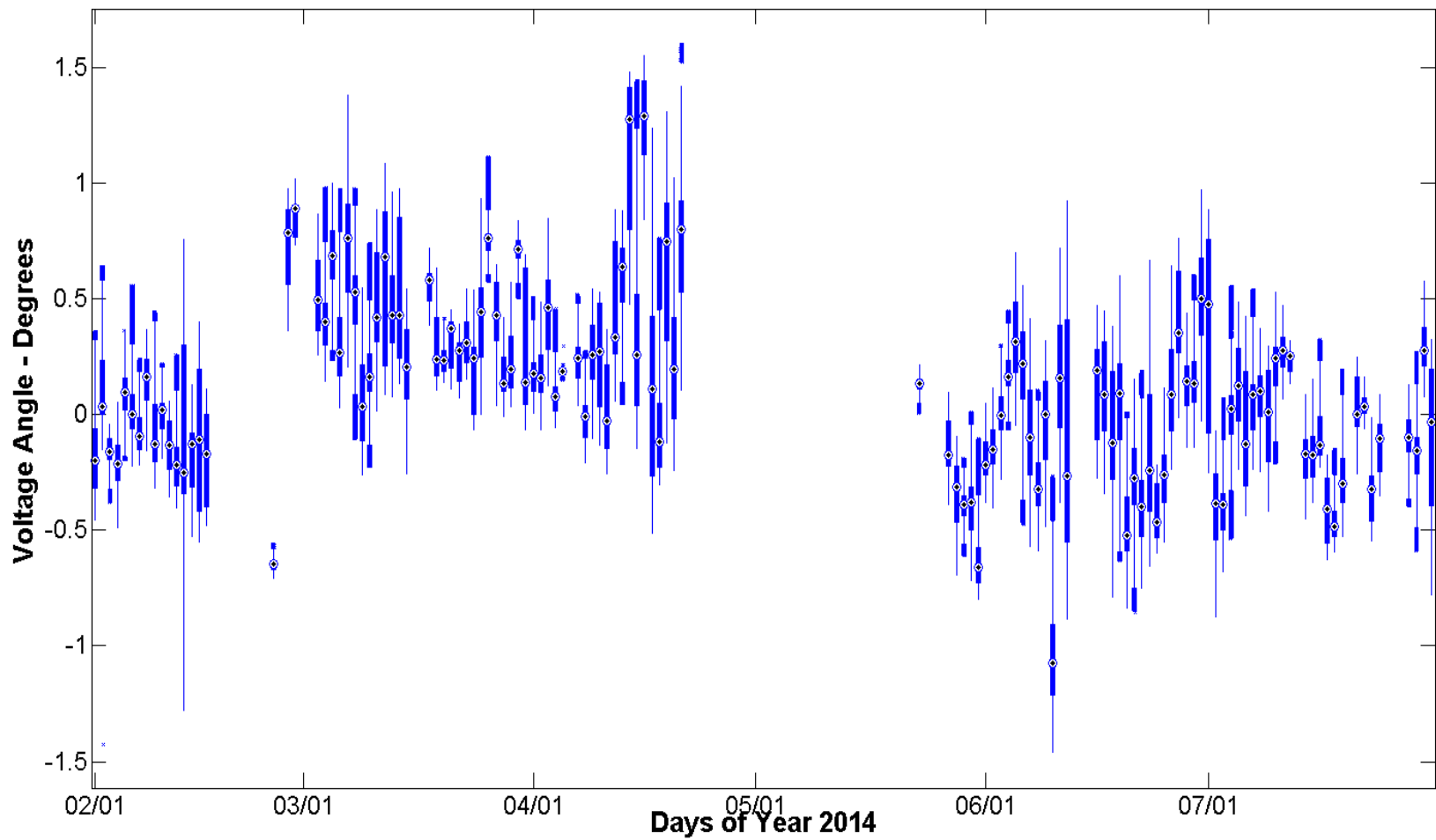
West 16 – West 3

Time Duration Chart:



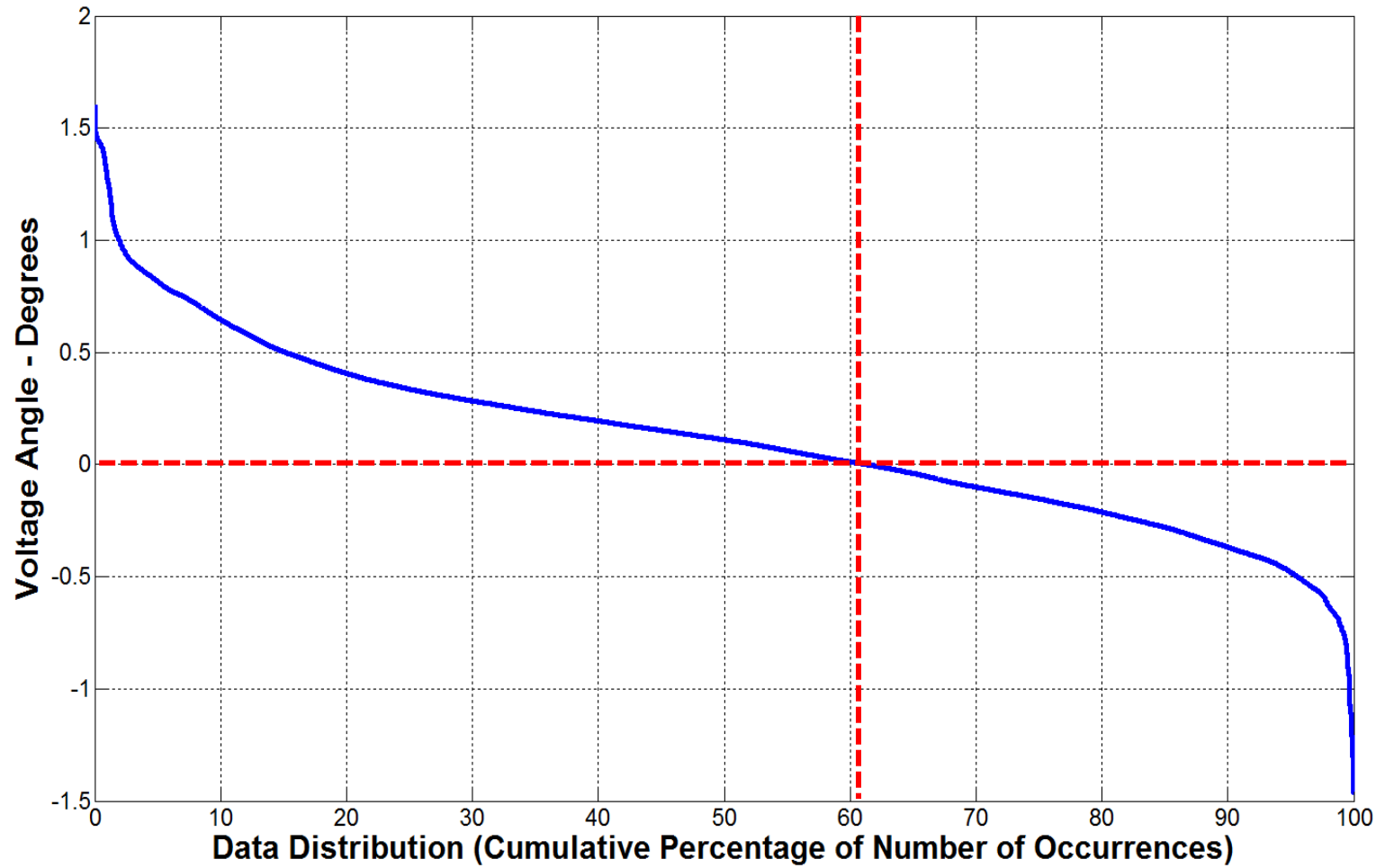
West 16 – West 14

Daily Box-Whisker Chart:



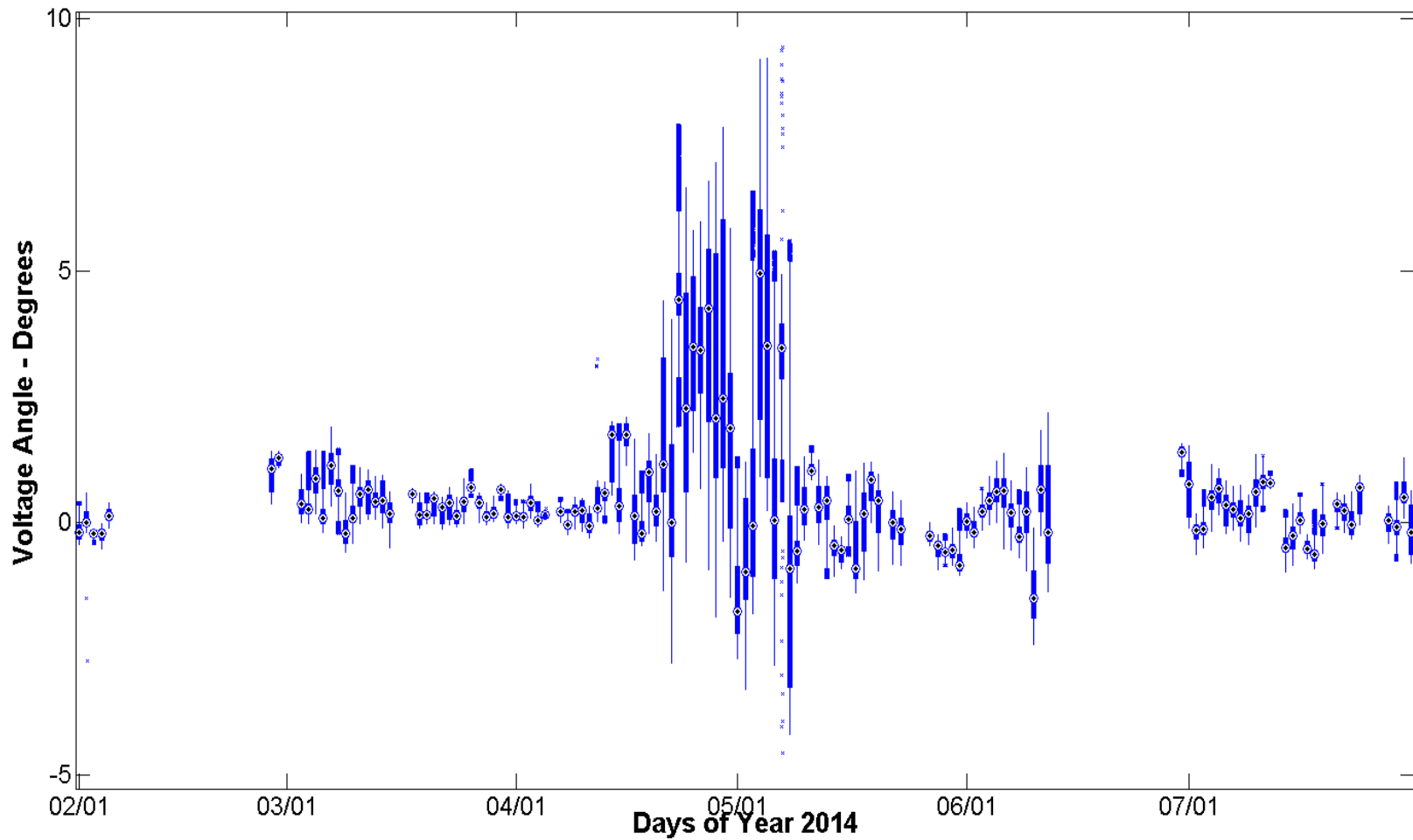
West 16 – West 14

Time Duration Chart:

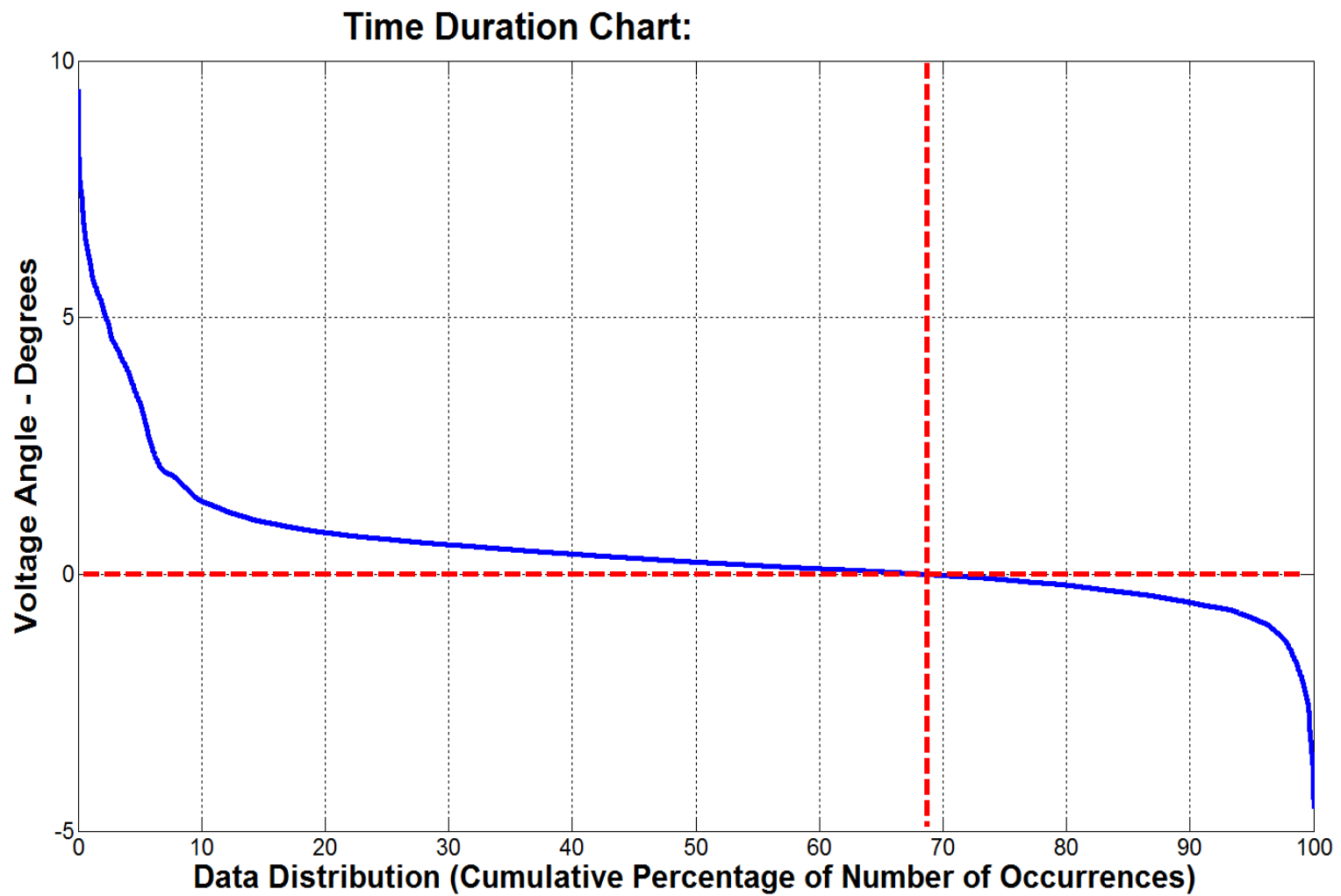


West 15 – West 14

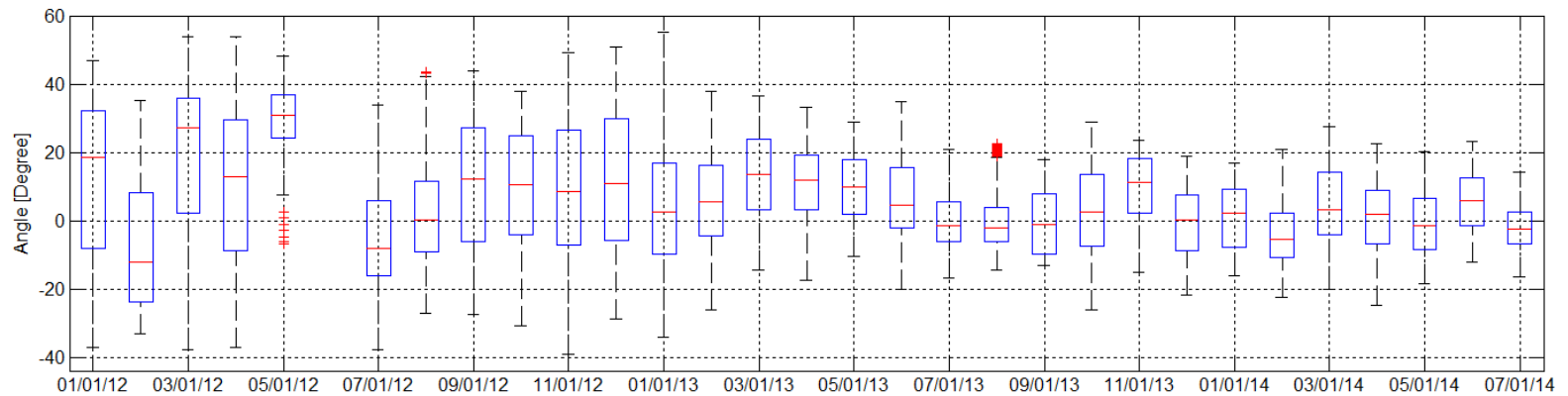
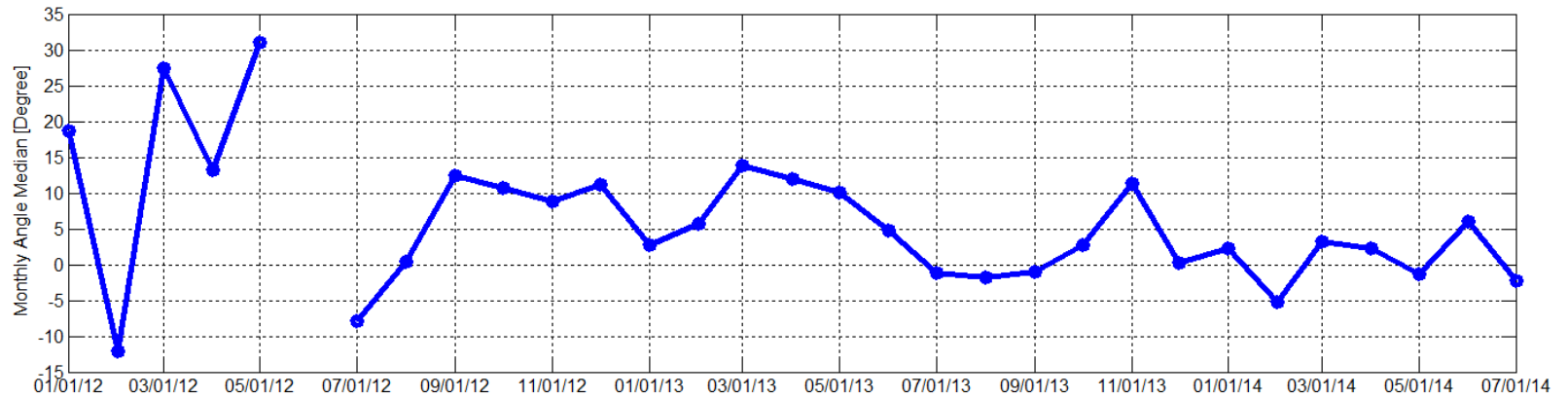
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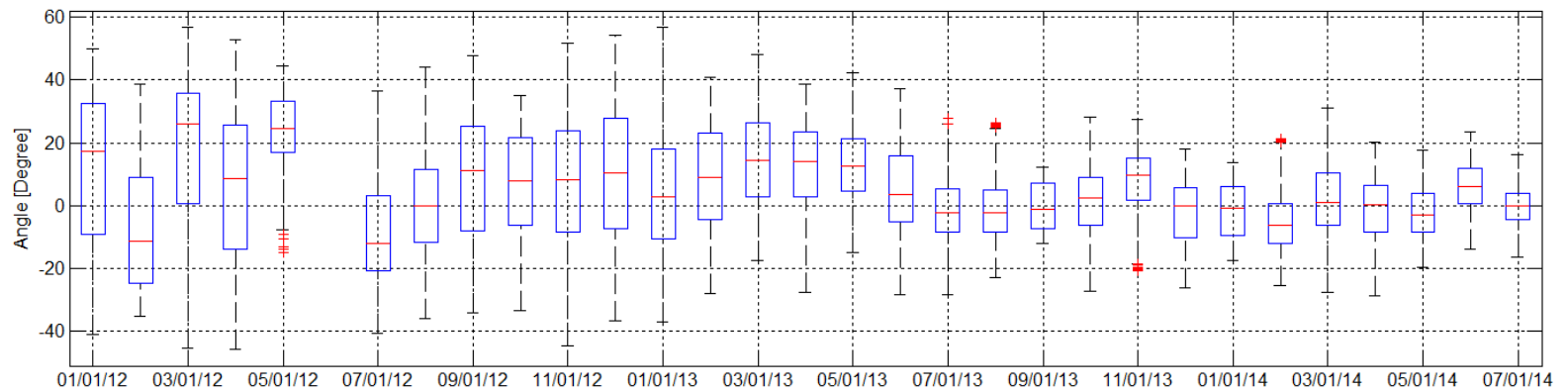
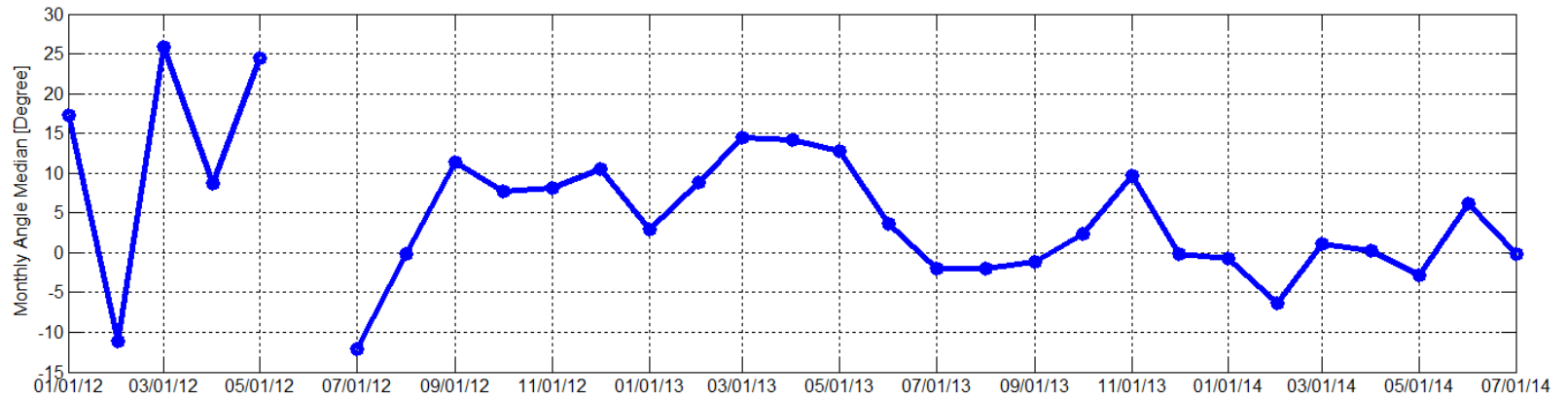
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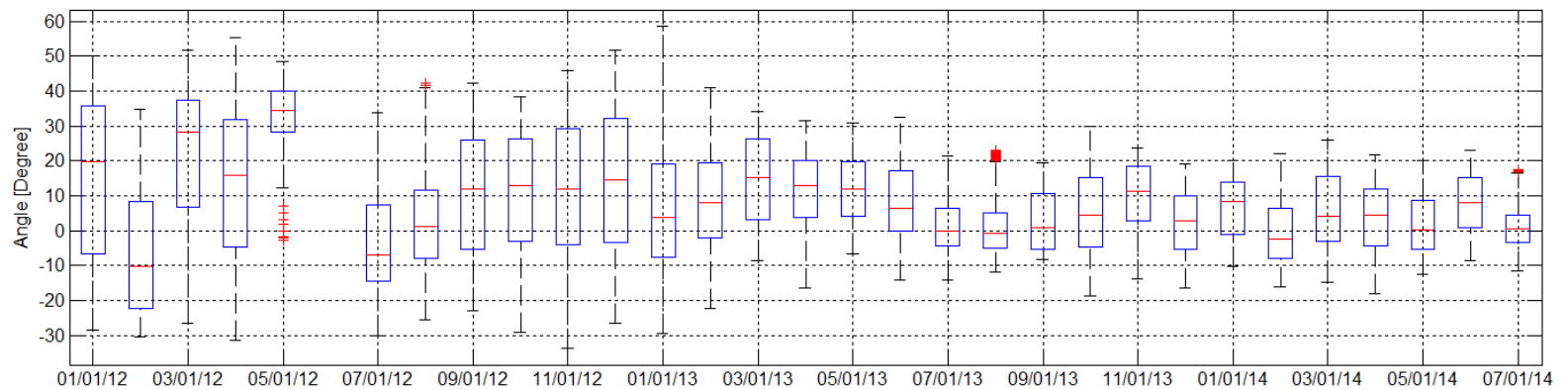
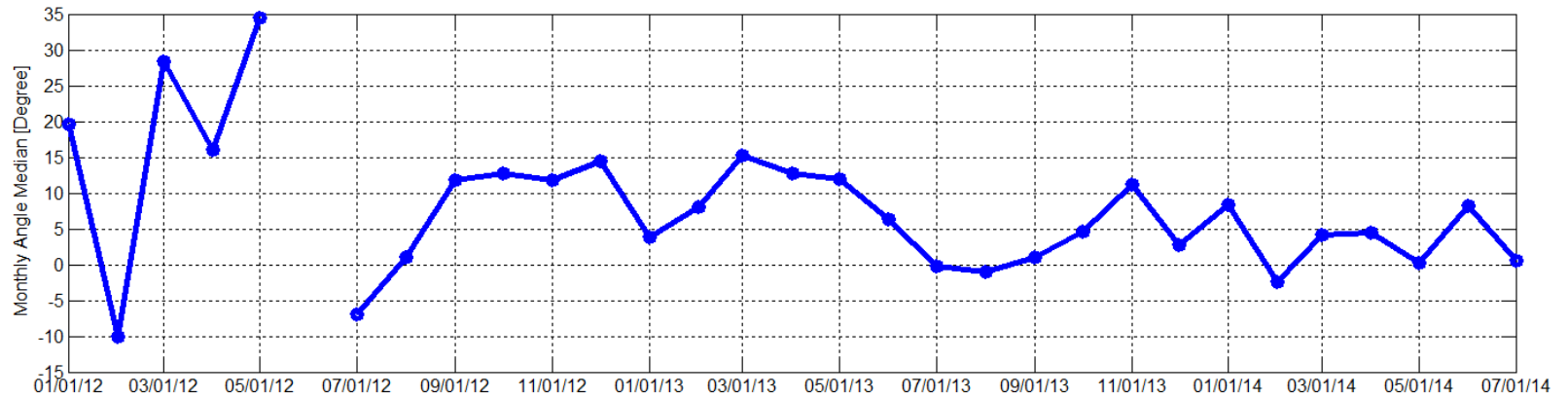
FarWest 7-North 7



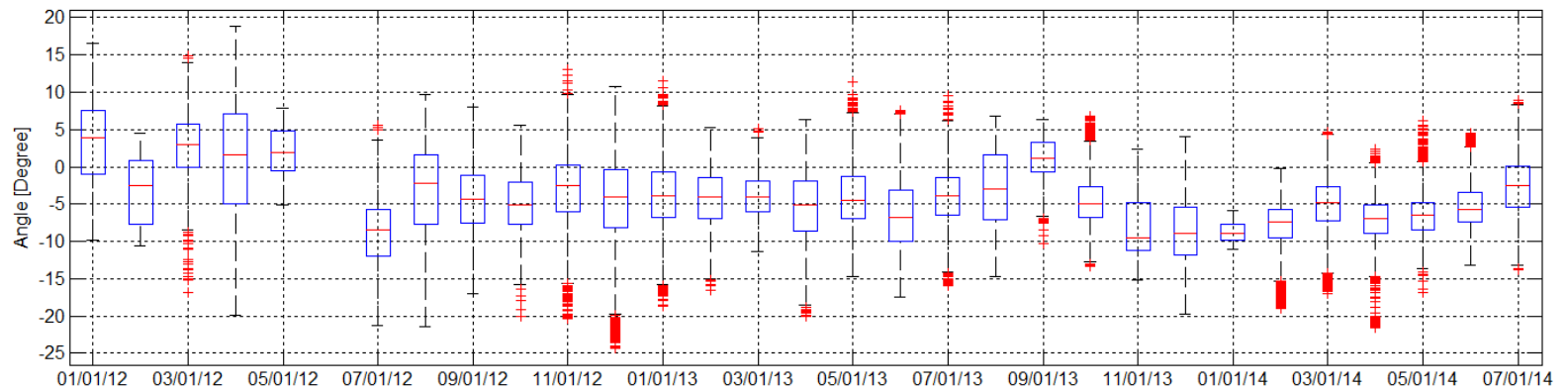
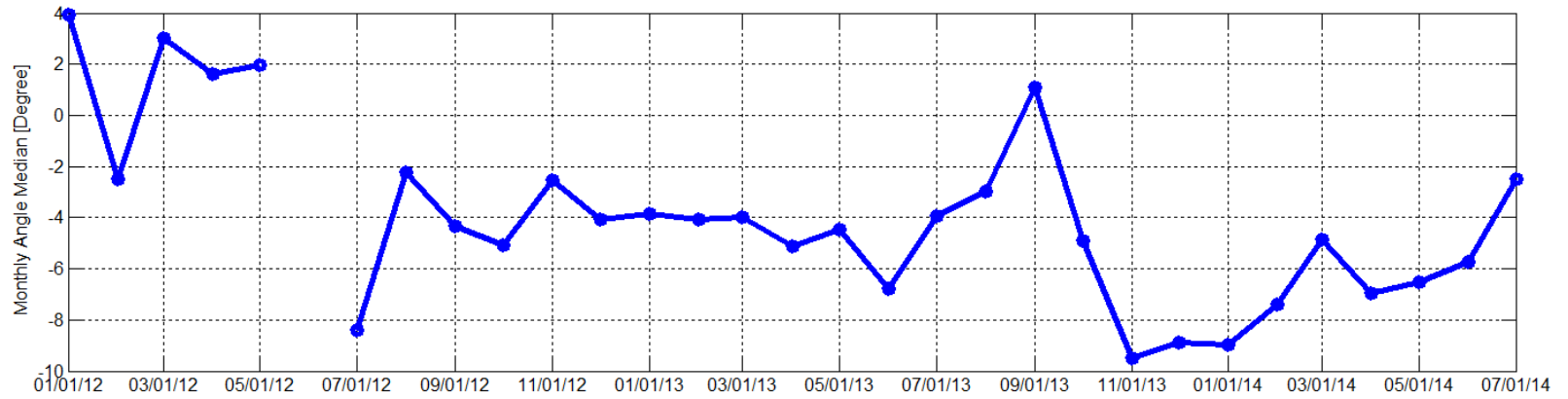
FarWest 7-South 9*



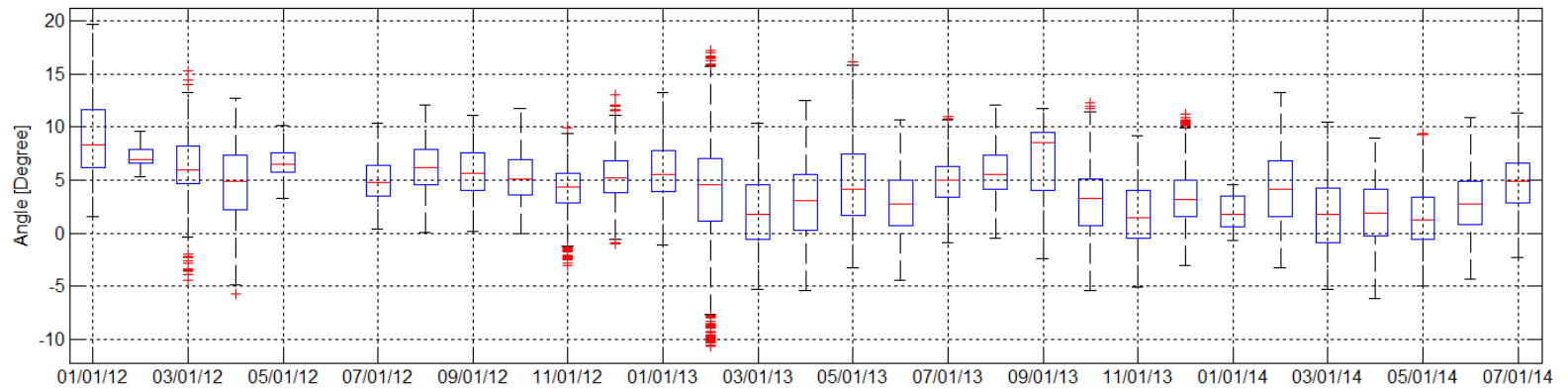
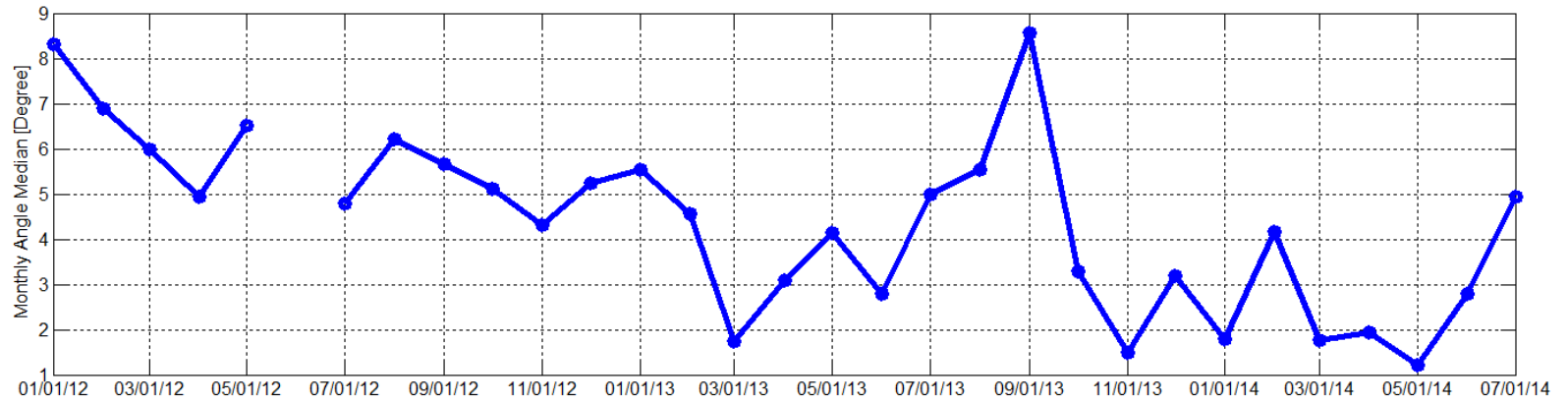
West 11-North 7



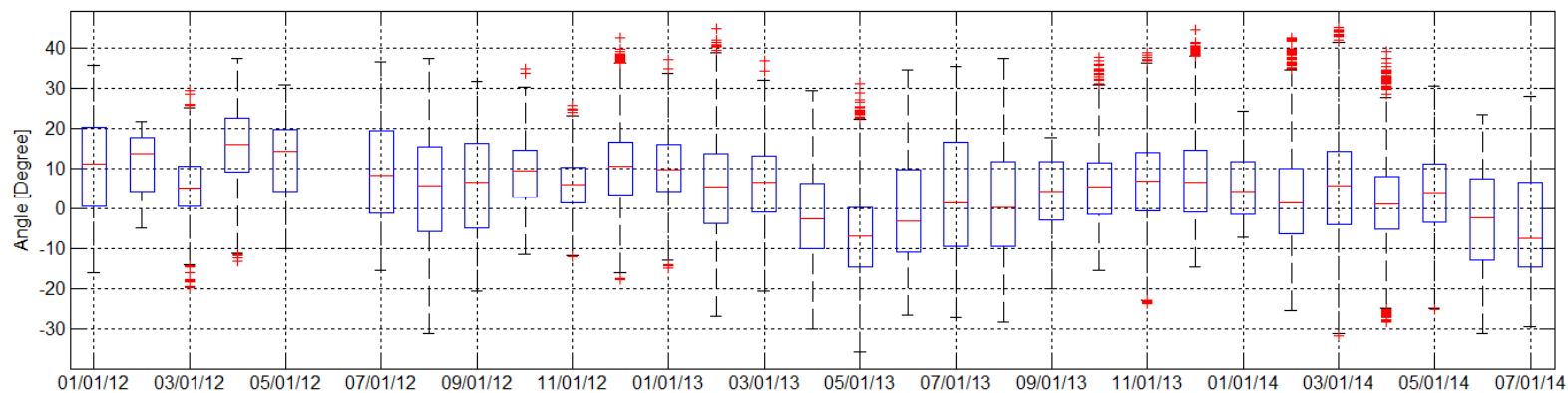
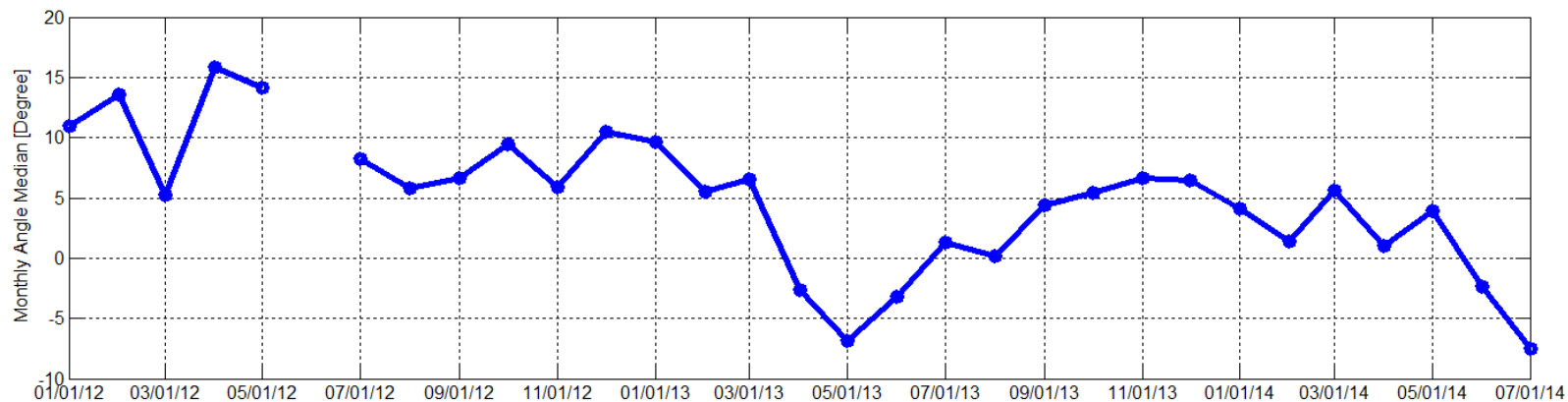
North 5-North 7



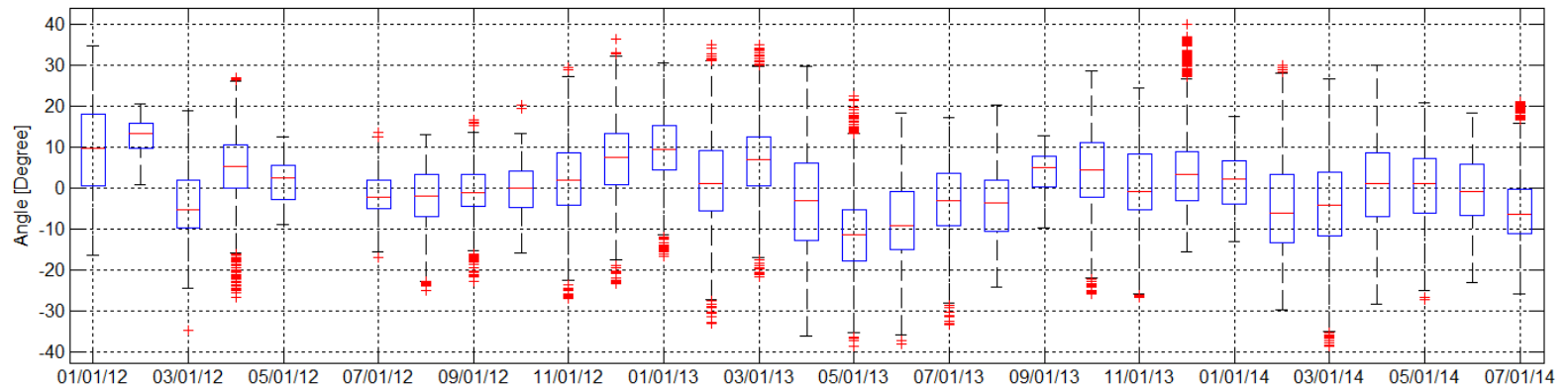
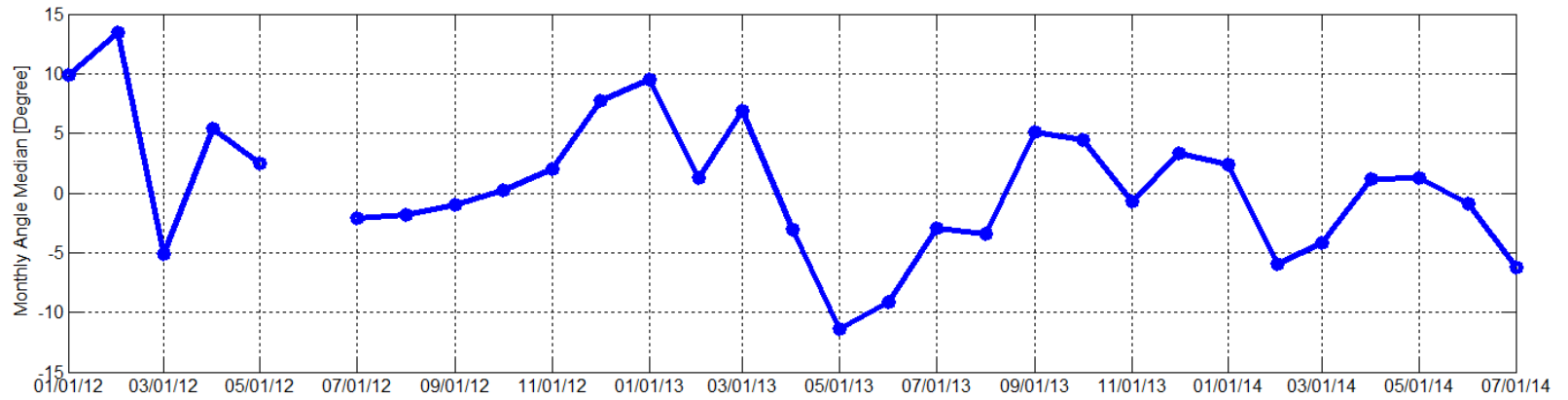
North 6-North 7



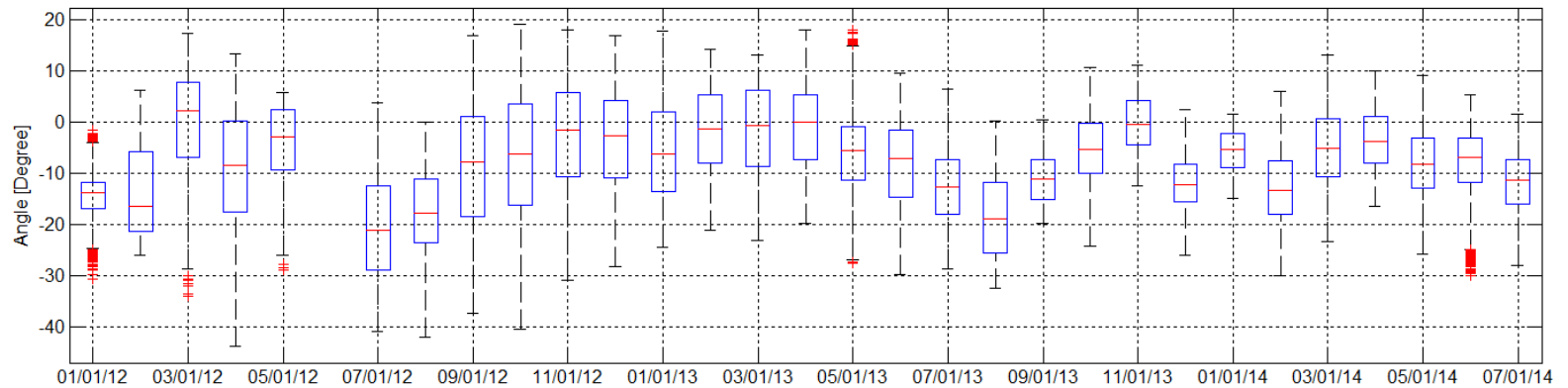
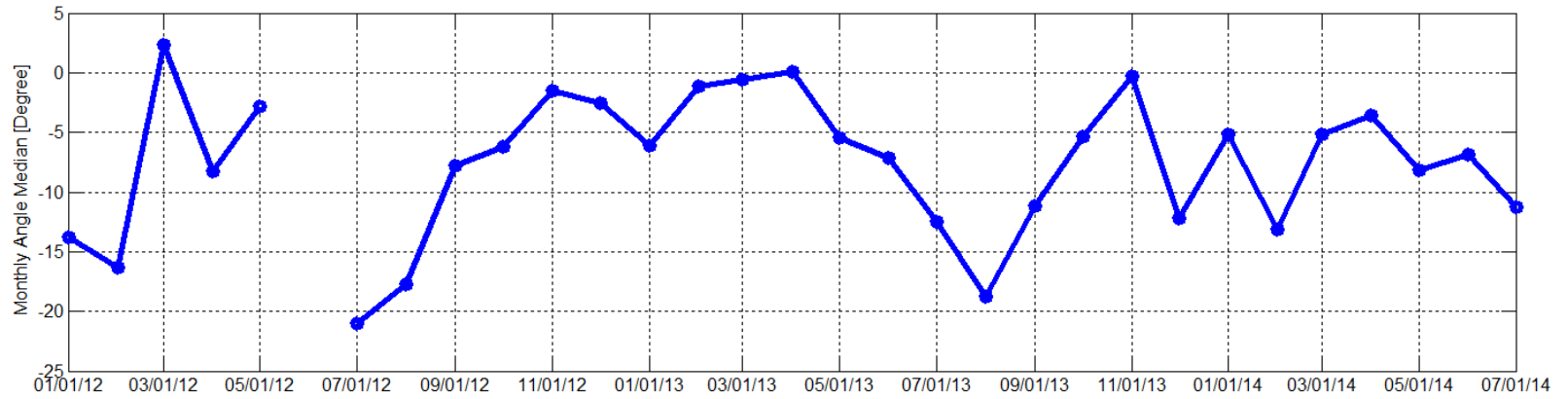
Coast 1-North 7



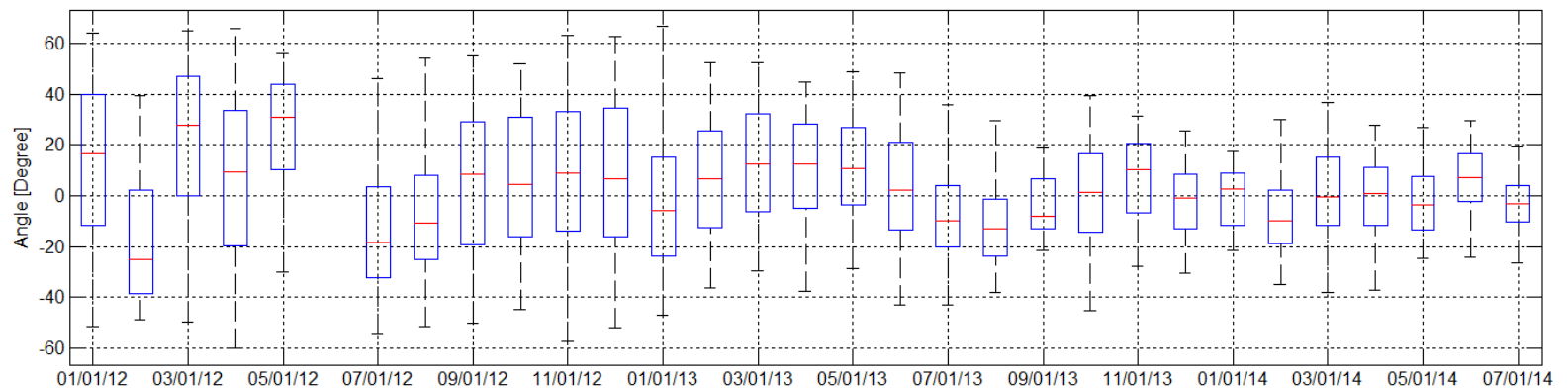
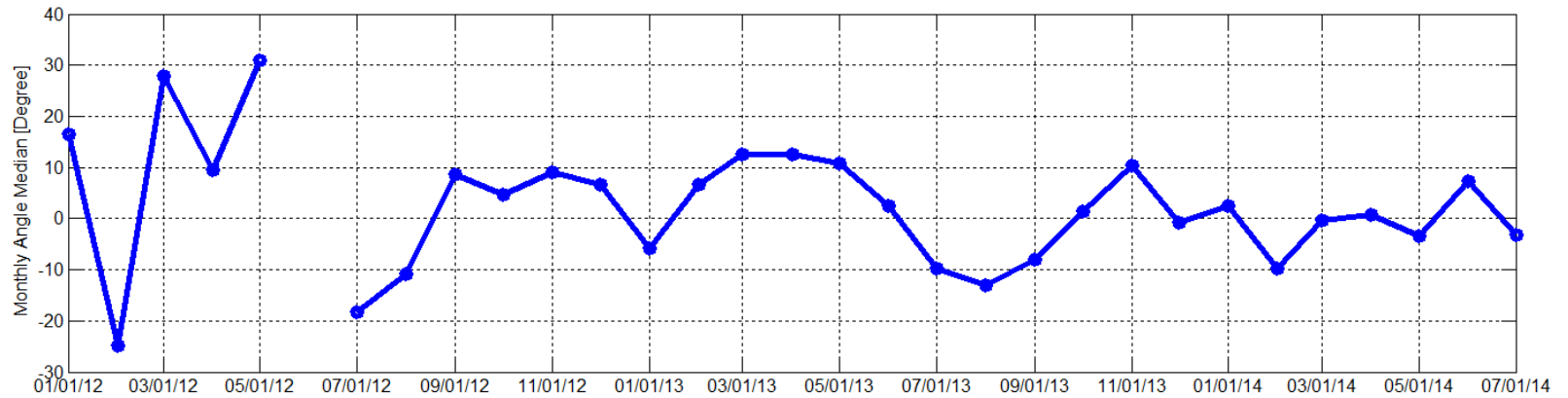
South 13-South 11*



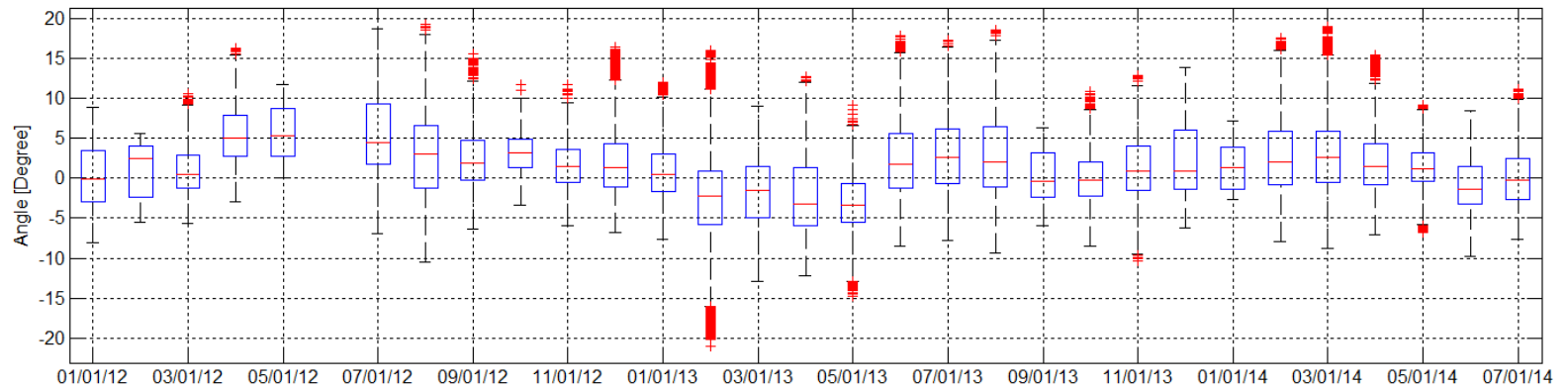
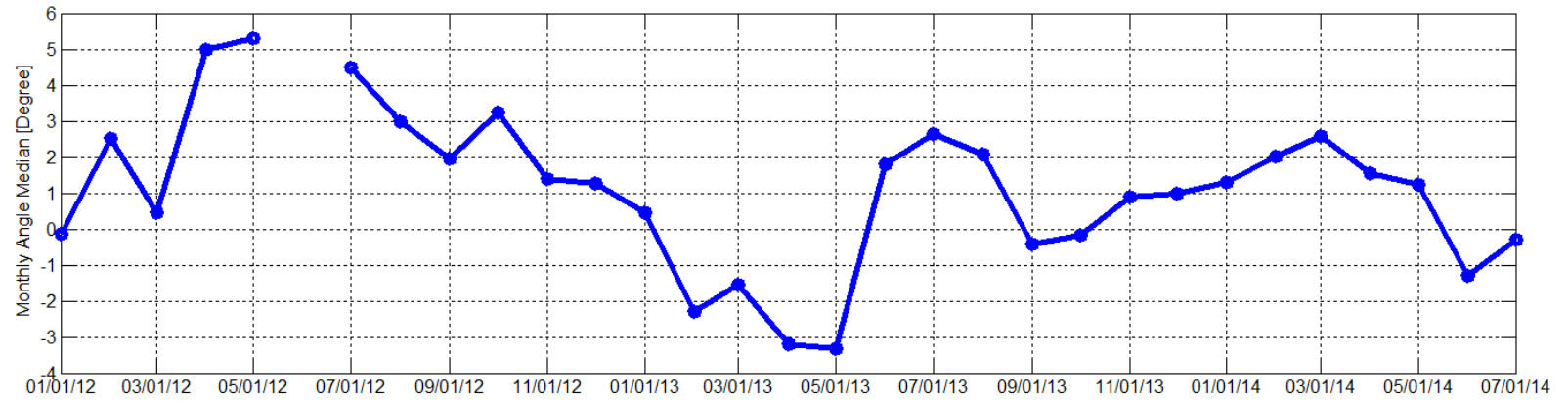
West 4-South 11*



FarWest 9-South 11*



South 11*-North 7



Attachment 6. Data Quality Study

**Center for Commercialization
Of Electric Technologies
Discovery Across Texas Project**

**ERCOT Synchrophasor Network
Data Quality Analysis**

Final Report

Submitted to:

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Submitted by:

John Ballance
Prashant Palayam



October 27, 2014

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1. INTRODUCTION

The Center for Commercialization of Electric Technologies (CCET) was awarded contract DE-OE0000194 by the Department of Energy to perform the Discovery Across Texas demonstration project. Electric Power Group, LLC (EPG) received a sub-award from CCET to provide professional services to perform, among other things, an analysis of the accuracy and continuity of synchrophasor data delivery from the Transmission Owners' phasor data concentrators, through the various communications systems and computer networks, and into the Real Time Dynamics Monitoring System¹ (RTDMS[®]) server and data base. The goal of this particular analysis was to validate that data was flowing continuously through the communications and computer systems, and was being accurately recorded and archived in the ERCOT enhanced Phasor Data Concentrator (ePDC) and RTDMS[®] data base systems.

This Data Quality Study analyzed the data streams from the three participating Transmission Owners: American Electric Power (AEP), Oncor Electric Delivery (Oncor) and Sharyland Utilities. This analysis was initially performed using the AEP data stream. Following completion of the initial analysis, examinations of the Oncor and Sharyland data streams were completed.

2. PROJECT SCOPE

In order for the Electric Reliability Council of Texas (ERCOT) to achieve a production quality phasor monitoring that can be relied upon in real-time operations, three conditions must be met:

1. The data must be flowing reliably from the phasor measurement unit (PMU) to the operator's console (data availability);
2. The data must be valid; and,
3. The data must be monitoring the critical locations (right places).

This report reflects the study being done on the first portion of this Data Quality assessment, data availability, and is focused on identifying any portion of the synchrophasor data network where data is being lost. The approaches include:

1. Identify nodes in the phasor network affecting data availability (i.e., data dropouts).
2. Classify identified dropout issues by severity and frequency.
3. Determine likely causes of data dropouts at identified locations.
4. Propose solutions to help eliminate identified data availability problems.

The 2012 and 2013 Baseline Studies have addressed the validity of the synchrophasor data compared to state estimator data for the ERCOT system, satisfying condition number 2.

The third condition, monitoring at the critical locations, is being addressed by working groups within ERCOT, as expansion of the synchrophasor monitoring system is being planned.

¹ ©Electric Power Group. Built upon GRID-3P platform, US Patent 7,233,843, US Patent 8,060,259, and US Patent 8,401,710. All rights reserved.

3. PHASOR DATA NETWORK

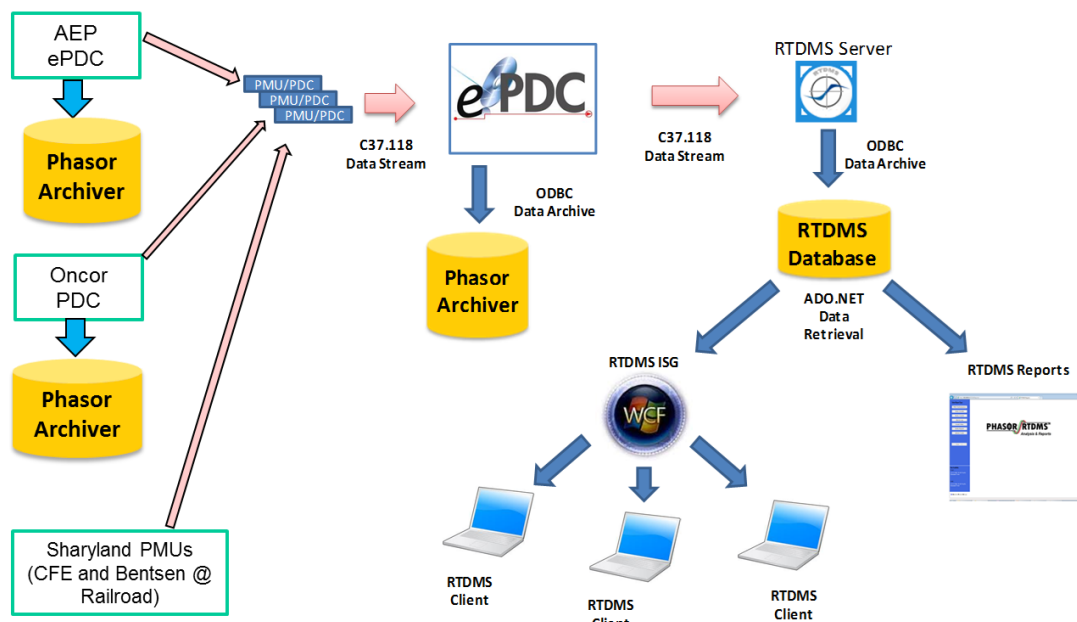
The ERCOT Synchrophasor Network was originally implemented beginning in 2006. With the development of the CCET Discovery Across Texas Regional Demonstration Project, the three participating Transmission Owners, AEP, Oncor, and Sharyland, committed to install PMUs in their respective transmission networks, and to provide their synchrophasor data signals to ERCOT, as a means of improving the overall operation of the ERCOT grid while accommodating a large increase in remote wind generation.

In 2012 and 2013, dozens of new PMUs were activated and connected to the data collection system. With the inherent complexity of the data collection and communications systems, it quickly became apparent that there were many opportunities for data to be lost or compromised. Available monitoring systems indicated that the network was not successfully delivering all the data that was expected.

3.1 Observable Dropouts

- RTDMS Daily Reports showed significant dropout data on some signals (60-99%).
- Observation of ePDC Management Tool showed major dropouts (60-99%) in real-time data streams.
- Observation of ePDC and RTDMS performance log showed the presence of missing samples as dropouts for past streams.
- Data availability check performed on the RTDMS® and ePDC Database confirmed the presence of data dropouts.
- Examination of one-second and one-minute tables in RTDMS® database confirmed down sampled data was missing on signals as well.

3.2 Phasor Data Network



3.3 Possible Locations of Data Dropout

- RTDMS® Reports (and/or RTDMS® Intelligent Synchrophasor Gateway) to RTDMS® database interface.
- RTDMS® Server to RTDMS® Database interface.
- ePDC to RTDMS® Server interface problems.
- ePDC input and/or output configuration problems.
- Problems on the outbound ePDC stream to ePDC database.
- Problems on the inbound ePDC stream (e.g., T.O. PDC/PMU problems, PMU installation problems, etc.).

4. DATA PROCESSING

Data extracts from the respective PDCs were provided in *.csv file formats in full resolution (30-samples per second) for pre-determined time periods. For the AEP analysis, 26-hours of data for two different days were analyzed. For the Oncor analysis, three hours of data were analyzed, and for the Sharyland analysis, one-hour of data was analyzed. These data extracts were loaded into MATLAB to conduct a performance test on all the available status signals for the identified dates. A MATLAB script was written to scan through the database and populate performance metrics such as data dropouts, data invalid, GPS sync error, time error, received samples, good samples and missing samples using the status flag information embedded in the PMU status signals. These performance metrics provided an hourly statistics of the database for all the available signals.

The performance metrics such as data dropouts, data invalid, GPS sync error, time error were derived and data availability statistics such as received samples, good samples and missing samples were calculated on periodic intervals (hourly).

The performance metrics and data availability were calculated to:

- Identify the data dropouts
 - Recurring and Non-recurring missing samples
- Compare with the ePDC and RTDMS[®] performance log
 - Identify Difference in missing samples

A comparative check on the signal headers was also performed between the ERCOT ePDC and RTDMS[®] databases to validate that all data was being properly forwarded.

A comparative check on the data values (accuracy and time alignment) was also performed between the ePDC and RTDMS[®] databases at ERCOT, and between the ePDC databases at AEP, Oncor, Sharyland and ERCOT.

Analysis was conducted separately for each of the three companies into the ERCOT databases (ePDC & RTDMS):

1. Phase 1 – AEP.
2. Phase 2 – Oncor.
3. Phase 3 – Sharyland.

5. DATA AVAILABILITY FOR STUDY

The study approach for this “data availability” phase was to compare the phasor data that was being sent from the AEP, Oncor and Sharyland PDCs to ERCOT, to the data reported as received in the ERCOT PDC, and to the data reported as received in the ERCOT RTDMS[®] data base. The study initially (for the AEP data) focused on two recent days (26-hours of data will be used for each day to avoid any time synchronization issues).

The two identified study dates were:

1. Friday, January 25, 2013 – The day with highest number of PMU dropouts.
2. Sunday, January 28, 2013 – The day with lowest total data availability in RTDMS[®] data base.

Extracts from the following sources for a 26-hour period were used to analyze data quality:

1. ERCOT RTDMS[®] Data Base (Central Time).
2. ERCOT ePDC Phasor Archiver Data Base (Central Time).

3. AEP ePDC Phasor Archiver Data Base (Eastern Time) – the stream is currently sent to ERCOT.

Oncor's database was unavailable for the sample dates selected above, so it was determined to complete the analysis using the AEP data, and to follow up an analysis of Oncor's data stream using a different set of study dates/hours:

1. January 9, 2014 (10-11 AM UTC).
2. January 17, 2014 (00-01 AM UTC), (01-02 AM UTC).

Extracts from the following sources were used to analyze data quality:

1. ERCOT ePDC Phasor Archiver Data Base (UTC) – Collected at EPG.
2. Oncor PDC Data Base (UTC) – the stream is currently sent to ERCOT.

The identified study date for Sharyland was:

1. June 19, 2014 (5-6 PM UTC)

The data provided includes PMU2 & PMU3 from South13 substation without status flag information.

Extracts from the following sources for a 1-hour period were used to analyze data quality:

1. ERCOT ePDC Phasor Archiver Data Base (UTC) – Collected at EPG.
2. Sharyland PDC Data Base (UTC) – the stream is currently sent to ERCOT.

6. OBSERVATIONS

6.1 Phase 1 – Investigation of ERCOT and AEP

6.1.1 AEP ePDC Database Recurring and Non-Recurring Missing Samples

During the study, it was found that there were missing samples in local AEP ePDC database, both recurring and non-recurring, which are shown in the table below.

| Missing samples - Frequency Type | Jan 25, 2013 - AEP Stream | ERCOT ePDC Performance Log | Jan 28, 2013 – AEP Stream | ERCOT ePDC Performance Log |
|--------------------------------------|---------------------------------------------------------------------------------|-------------------------------|---------------------------------------------------------------------------------------------------------------|---------------------------------------------|
| Recurring – 1800 per hour | Second 59 of every minute is missing entire 30 samples | Received most of the samples. | Second 59 of every minute is missing entire 30 samples | Received most of the samples. |
| Non-recurring – 1800 plus additional | 14 th Hour missing additional 336 samples at 5 th minute | Received most of the samples. | 3 rd Hour missing additional 412 samples at 54 th minute | Log shows missing 469 samples at same hour. |
| Non-recurring – 1800 plus additional | 15 th Hour missing additional 332 samples at 30 th minute | Received most of the samples. | 16 th Hour missing additional 307 samples at 32 th and 33 rd minute combined | Received most of the samples. |

A confirmation was performed by scanning through another day - Jan 24 , 2013. The likely cause for samples being received by the ERCOT performance log but not found in the local AEP database could be a problem on the outbound side of the AEP ePDC stream to its local database. And the likely cause for samples missing in both ERCOT performance log and AEP database could be a problem on the inbound stream of the AEP ePDC receiving the data from the PMUs.

Resolution:

The AEP ePDC was upgraded to ePDC v3.0.3 from v2.3.2 which corrected the recurring data loss of missing the entire 30 samples at 59th second of every minute plus the additional non-recurring samples. A confirmation was done on scanning through another day - May 20, 2013. The problem was identified on the outbound stream of the ePDC to the local ePDC database. The ePDC was corrected to send data to ePDC database without missing samples.

The table below shows the result. All AEP data is being received successfully in the local database. No further dropouts were observed in the AEP Database.

| From | Date/Time 2013-05-20 | PMU Signal | Data Dropout | Data Invalid | GPS Usync | Time Error | Good Samples | Received Samples | Missing Samples |
|------------------------------------|-------------------------|-------------------------|-----------------|-----------------|--------------|---------------|-----------------|---------------------|--------------------|
| AEP ePDC database extract | Hour 11 | Line_1@FarWest_9.Status | 0 | 0 | 0 | 0 | 108000 | 108000 | 0 |
| | Hour 11 | Line_1@West14.Status | 0 | 0 | 0 | 0 | 108000 | 108000 | 0 |
| | Hour 11 | Line_2@West14.Status | 0 | 0 | 0 | 0 | 108000 | 108000 | 0 |
| | Hour 11 | Line_3@West_4.Status | 70 | 0 | 0 | 0 | 107930 | 108000 | 0 |
| | Hour 12 | Line_1@FarWest_9.Status | 0 | 0 | 0 | 0 | 108000 | 108000 | 0 |
| | Hour 12 | Line_1@West14.Status | 0 | 0 | 0 | 0 | 108000 | 108000 | 0 |
| | Hour 12 | Line_2@West14.Status | 0 | 0 | 0 | 0 | 108000 | 108000 | 0 |
| | Hour 12 | Line_3@West_4.Status | 61 | 0 | 0 | 0 | 107939 | 108000 | 0 |
| | Hour 13 | Line_1@FarWest_9.Status | 0 | 0 | 0 | 0 | 108000 | 108000 | 0 |
| | Hour 13 | Line_1@West14.Status | 0 | 0 | 811 | 0 | 107189 | 108000 | 0 |
| | Hour 13 | Line_2@West14.Status | 0 | 0 | 1197 | 0 | 106803 | 108000 | 0 |
| | Hour 13 | Line_3@West_4.Status | 1002 | 0 | 0 | 0 | 106998 | 108000 | 0 |

6.1.2 RTDMS Database Missing Samples

6.1.2.1 ERCOT RTDMS Database Missing Samples at Specific Hour on January 25, 2013

| Missing samples - Frequency Type | Jan 25, 2013 - RTDMS Database | ERCOT RTDMS Performance Log | ERCOT RTDMS Operations Log | ePDC Database Tool |
|----------------------------------|-------------------------------------------------------------------------|-------------------------------------------|--------------------------------------------------------------------------------------------|---------------------------------------------------|
| Non-recurring | 9 th Hour missing 93600 samples after 8 th minute | Reported 37 missing samples for that Hour | Watch dog message - heart beat message sent out successfully for application for that hour | Error message while retrieving data from database |

The RTDMS[®] database for Jan 25, 2013 had data available only for the first 8-minutes of hour 9. The database extractor reported an error message by the ePDC database tool while retrieving data for that hour. The error could not be reproduced because the data archive causing the problem was no longer available. The RTDMS[®] database storage capacity is approximately 30-days.

The likely cause for samples not found in the ERCOT database could be:

- Time out problem to query data from the database by the ePDC database client tool.
- Batch size duration issue in the ePDC database tool specific for that hour.
- Database *.ini configuration problem like table_cache (default values are limited to few rows).

6.1.2.2 ERCOT RTDMS database missing samples at specific hour on January 28, 2013

For Jan 28, 2013 hour 10, the entire 30-samples started dropping from the 10th second of 6th minute until the 10th second of 15th minute, equivalent to 16230 missing samples. The likely cause for samples not found in the ERCOT database can be a problem on:

- RTDMS[®] Server to RTDMS Database interface (the RTDMS Server log reported a connection problem with the database).

Another observation during the investigation was that the missing samples reported in the RTDMS[®] daily report and the missing samples in the RTDMS[®] database did not match.

- RTDMS[®] 2012 Daily Report shows that the RTDMS[®] database was filled with 23.83 hours of data availability. ($24 - 23.83 = 0.17$ missing hours) or ($0.17 * 60 = 10.2$ missing minutes) or ($10.2 * 60 = 612$ missing seconds) or samples ($612 * 30 = 18360$ samples).
- The Daily Report shows loss of about 72 seconds more than the RTDMS[®] Database.

| Missing samples - Frequency Type | Jan 28, 2013 - RTDMS Database | ERCOT RTDMS Performance Log | ERCOT RTDMS Operations Log | RTDMS Daily Report 2012 |
|----------------------------------|----------------------------------------------|-----------------------------------------|----------------------------------------------------------------------------------------------------------------|--------------------------------------------------------|
| Non-recurring | 10 th Hour missing 16230 samples. | Reported missing 1 sample for that Hour | Watch dog message – database error during batch table insertion and connection failed for that period of time. | 23.83 hours of data availability. (Missing 0.17 hours) |

Resolution:

On Monday, July 08, 2013 – the ERCOT System was upgraded to:

| System Component | Version |
|------------------------------------------------------------------|-----------|
| ePDC | 3.1.1 |
| ePDC Phasor Archiver (MySQL) | 3.1.1 |
| ePDC Database Tool | 3.1.1 |
| RTDMS [®] Server | 2.4.0 |
| RTDMS [®] Database | 2.1.6 |
| Intelligent Synchrophasor Gateway (ISG) | 3.3.1 |
| RTDMS [®] Clients (on the sever and single user laptop) | 2.0.0.350 |

Starting July 9, 2013 till present, the data availability is 24-hours. No Dropouts in ERCOT RTDMS[®] Database. The data dropout problem was identified on the outbound stream of the RTDMS[®] Server to the RTDMS[®] database, which was resulting in a database insertion error. RTDMS[®] Server was corrected to send raw data, second average and minute average data without any database insertion errors, leaving no room for dropouts in RTDMS[®] database.

6.1.2.3 Mismatch in signal headers between ERCOT ePDC and RTDMS database

The RTDMS® Server calculates the pseudo signals such as Real Power (*.PP) and Reactive Power (*.PQ), together with virtual signals such as System frequency and angle difference pairs. The pseudo signal names account for some of the mismatch of signals available in the RTDMS® database but not found in the ePDC database. Additionally, there were 56 additional RTDMS® non-pseudo signal headers which were not found in the ePDC database.

| # | Possible Reason | RTDMS Signal Header Example | ePDC Signal Header Example | Additional Examples |
|---|---------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------|------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------|
| 1 | Signal Name Change | WEST10.V1LPM.VM WEST10.I1WPM.IM | WEST10.AEP_WEST10 +SV.VM WEST10.AEP_WEST10 +SI.IM | |
| 2 | Signal Name Duplicates (Good data vs Bad data) | WEST10.V1LPM.VM (Good data) WEST10.V1LPM.VM (Bad data – zeros) WEST10.V1LPM.VA (Good data) WEST10.V1LPM.VA (Bad data – zeros) | | FARWEST_7, WEST11, NORTH_1, FARWEST_8, NORTH_4, NORTH_5, WEST_6, NORTH_6, NORTH_7, FARWEST_4 |
| 3 | Bad Data Dropouts | Line_3@South13.VALPM.IA Line_3@South13.VALPM.IA Line_3@South13.VALPM.IM Line_3@South13.VALPM.IM | | SOUTH13 |
| 4 | Signal Name Change – Current Magnitude Phase Name | FARWEST7HV11425/11420.VALPM.IM FARWEST7HV11425/11420.VALPM.IA | FARWEST7HV11425/11420.I1SPM.IM FARWEST7HV11425/11420.I1SPM.IA | WEST11, NORTH_1, FARWEST_8, NORTH_4, NORTH_5, WEST_6, NORTH_6, NORTH_7, FARWEST_4 |

Conclusion: The RTDMS® database had both old and new signal headers in the data base.

On the other hand, there were 58 ePDC signal headers not found in the RTDMS® database.

| # | Possible Reason | RTDMS Signal Header Example | ePDC Signal Header Example | Additional Examples |
|---|---------------------------------------------|-----------------------------|----------------------------------------------|------------------------------------|
| 1 | Missing Phase A Signals – Voltage Magnitude | Missing | NORTH_1 8070.VAPM.VA NORTH_1 8070.VAPM.VM | WEST11, FARWEST_7, FARWEST_8 |

| | | | | |
|---|-----------------------------|--------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------------|
| 2 | Complete Missing PMU stream | Missing | Coast2_11/1690/8530.Frequency.DF Coast2_11/1690/8530.Frequency.FR Coast2_11/1690/8530.I1XPM.IA Coast2_11/1690/8530.I1XPM.IM Coast2_11/1690/8530.Status Coast2_11/1690/8530.V1LPM.VA Coast2_11/1690/8530.V1LPM.VM | Coast_4, West_4, Coast_2 |
| 3 | Others - Digitals | | North_2 138KV.PSV49,PSV50,PSV51,PSV52,PSV53,PSV54, PSV55,PSV56,PSV57,PSV58,PSV59,PSV60,PSV61, PSV62,PSV63,PSV64 | |
| 4 | PMU Name Change | Line_2@West14.F requency.FR | Line_3@West14.Frequency.FR | DF, IM, IA, Status |
| 5 | Bad Data Dropouts | | Line_1@South13.VALPM.VM Line_1@South13.VALPM.VA | South13 |

Conclusion: the ePDC database also had both old and new headers.

Resolution:

The signal name changes and duplicate names between the ePDC and RTDMS[®] database can be corrected.

- ePDC can be corrected to set the output configuration for the phasor identification method to be same as the input name for a input stream.
- So for each PMU under an input stream, the PMU output system configuration can be set same as the input system configuration.
- ePDC sends data to RTDMS[®] Server and ePDC database – The above two steps can be corrected to both output streams from the ePDC.

The missing signals, legacy signal names and incorrect channel names in the RTDMS[®] database can be corrected.

- RTDMS[®] Server output to RTDMS[®] database can be configured to output same as the ePDC output to ePDC database.
- After ePDC gets corrected, the RTDMS[®] Server output and input channel name can be mapped to the correct signal type.

6.1.2.4 Difference in missing samples between ERCOT ePDC performance log and database

6.1.2.4.1 January 25, 2013

Until mid-2014, two PMUs from Sharyland were streaming their data directly to the ERCOT ePDC and were logged as separate streams in the ERCOT ePDC performance log. In the table

below, for the Line_3@South13 PMU, the “Difference” column shows the number of samples that were not reported in the log but were available in the ERCOT ePDC database. The possible reason behind the positive difference in missing samples is progressive forward padding.

The current version of ePDC Padding feature does not flag the associated padded data sample timestamp as “data dropout,” which causes the difference between the missing samples in the performance log and the data dropout in the ERCOT ePDC database. The occurrence of progressive forward padding and the count of occurrence are not logged. But the difference could give the plausible number of padded samples. A similar difference was also found in Line_1@South13 PMU stream.

| Input Name | Hour | Checksum Error | Format Error | Time Error | GPS UnSync | Good | Received | Missing | Data Dropout - ERCOT ePDC Database | Difference |
|------------|-----------------|----------------|--------------|------------|------------|--------|----------|---------|------------------------------------|------------|
| SHARYLAND2 | 1/25/2013 3:00 | 0 | 0 | 0 | 0 | 105481 | 105481 | 2519 | 2507 | 12 |
| SHARYLAND2 | 1/25/2013 1:00 | 0 | 0 | 0 | 0 | 107172 | 107172 | 828 | 822 | 6 |
| SHARYLAND2 | 1/25/2013 2:00 | 0 | 0 | 0 | 0 | 105479 | 105479 | 2521 | 2515 | 6 |
| SHARYLAND2 | 1/25/2013 4:00 | 0 | 0 | 0 | 0 | 105456 | 105456 | 2544 | 2538 | 6 |
| SHARYLAND2 | 1/25/2013 5:00 | 0 | 0 | 0 | 391 | 107164 | 107164 | 836 | 830 | 6 |
| SHARYLAND2 | 1/25/2013 6:00 | 0 | 0 | 0 | 0 | 105465 | 105465 | 2535 | 2529 | 6 |
| SHARYLAND2 | 1/25/2013 13:00 | 0 | 0 | 0 | 0 | 107192 | 107192 | 808 | 802 | 6 |
| SHARYLAND2 | 1/25/2013 19:00 | 0 | 0 | 0 | 0 | 105480 | 105480 | 2520 | 2514 | 6 |
| SHARYLAND2 | 1/25/2013 21:00 | 0 | 0 | 0 | 0 | 107204 | 107204 | 796 | 790 | 6 |
| SHARYLAND2 | 1/25/2013 23:00 | 0 | 0 | 0 | 0 | 105372 | 105372 | 2628 | 2622 | 6 |

6.1.2.4.2 January 28, 2013

In the table below for Line_1@South13, the “Difference” column shows the number of samples that were considered available in the ERCOT ePDC database. The possible reason behind the positive difference in missing samples is progressive forward padding. The occurrence of progressive forward padding and the count of occurrence is not logged. A similar, not identical, difference was also found in Line_3@South13 PMU stream. There was a noticeable huge negative difference in missing samples between the ERCOT ePDC performance log and the database.

It was likely that ePDC marked them as data dropouts due to:

- Error in timestamps.
- Duplicate timestamps.

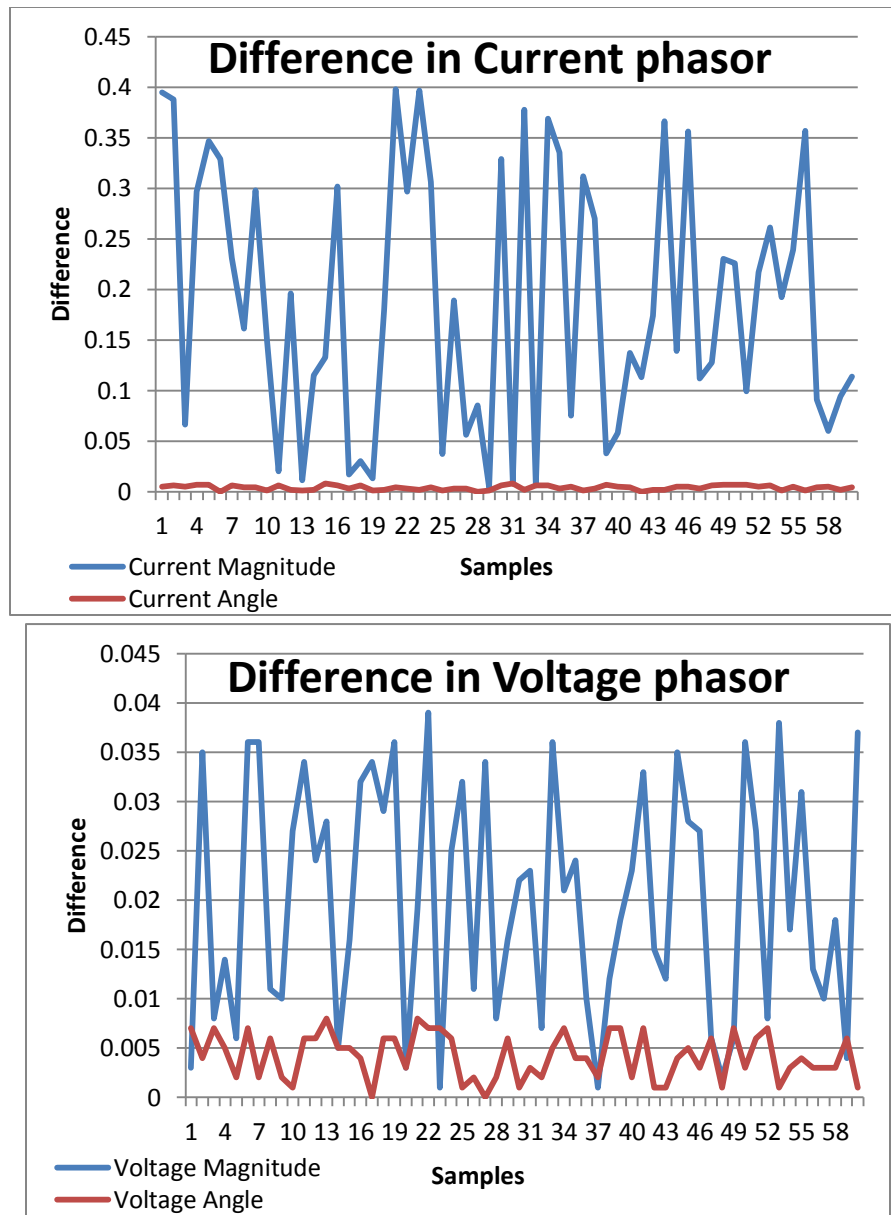
| Input Name | Hour | Checksum Error | Format Error | Time Error | GPS UnSync | Good | Received | Missing | Data Dropout - ERCOT ePDC Database | Difference |
|------------|-----------------|----------------|--------------|------------|------------|--------|----------|---------|------------------------------------|------------|
| SHARYLAND1 | 1/28/2013 7:00 | 0 | 0 | 0 | 0 | 107375 | 107375 | 625 | 0 | 625 |
| SHARYLAND1 | 1/28/2013 16:00 | 0 | 0 | 0 | 0 | 105447 | 105447 | 2553 | 2547 | 6 |
| SHARYLAND1 | 1/28/2013 19:00 | 0 | 0 | 0 | 0 | 107154 | 107154 | 846 | 840 | 6 |
| SHARYLAND1 | 1/28/2013 20:00 | 0 | 0 | 0 | 0 | 107203 | 107203 | 797 | 791 | 6 |
| SHARYLAND1 | 1/28/2013 8:00 | 0 | 0 | 0 | 0 | 107901 | 107901 | 99 | 2548 | -2449 |

No Difference in missing samples between ERCOT ePDC performance log and database.

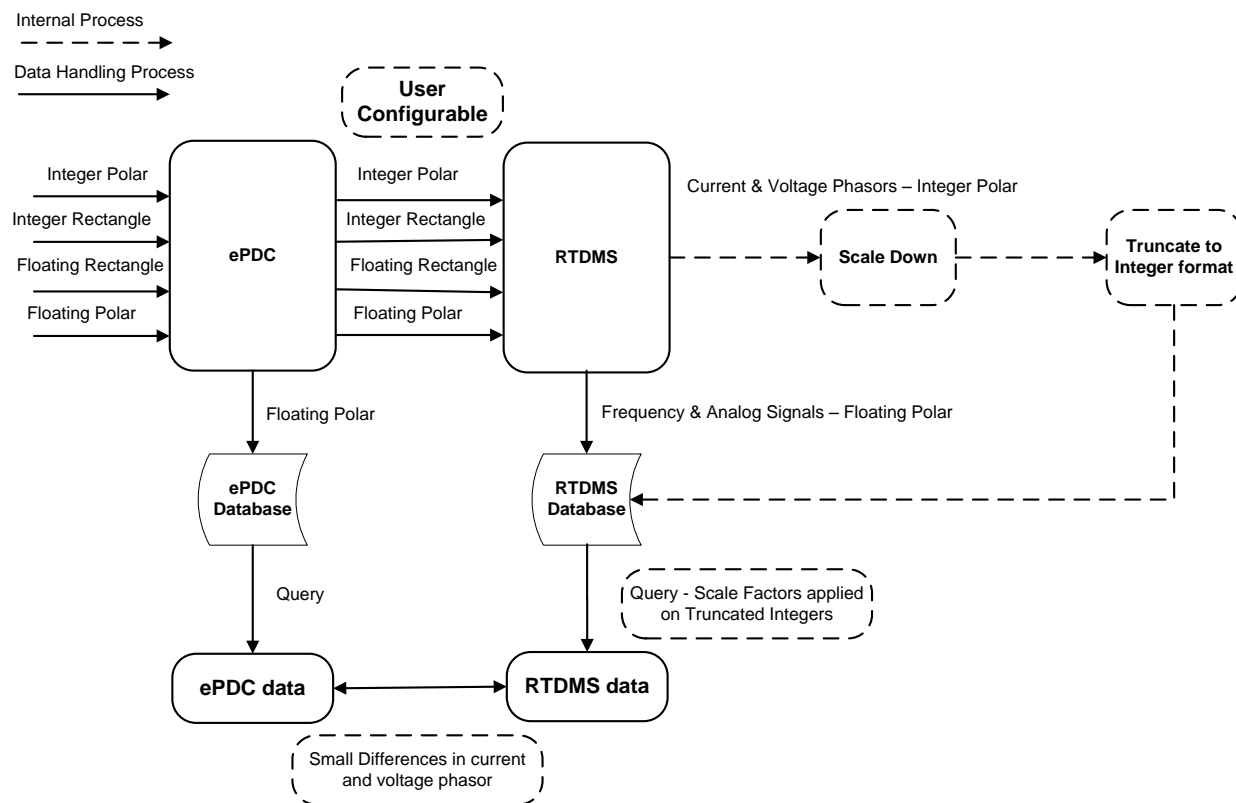
The possible reason behind the positive difference in missing samples is progressive forward padding. The occurrence of progressive forward padding and count of occurrence are not logged, but the latest version of ePDC v3.1.1 is enhanced to flag the associated data sample padded timestamp as data dropout. The data dropout is indicated when all the four STAT bits from bit 15 – bit 12 are set to 1. The padded sample will have PMU STAT word set as 0xF200.

6.1.3 Accuracy of Decimal Digits Between ERCOT ePDC and RTDMS® Database – Jan 24, 2013, 23rd Hour

RTDMS® data was observed to be stored and extracted at a slightly lower accuracy than ePDC. It was observed that the accuracy of decimal digits is more noticeable in the voltage magnitude phasor than in the current magnitude phasor, in terms of significant digits after the decimal. The Voltage and Current angle phasors show matching decimal digits up to the second significant digit after the decimal (the hundredths digit). In contrast, the Frequency phasor matches identically between the ePDC and RTDMS® Database. The graphs below show differences in current phasor and voltage phasor. (Difference = ePDC data – RTDMS® data).



These small differences in accuracy between ePDC and RTDMS[®] Database can be explained.



The diagram above illustrates the data handling process. The ePDC database always stores the received phasor data in Floating point Polar format in the database and outputs the received phasor data in whatever format the user chooses (often with the same format as was received) to other applications such as RTDMS[®]. RTDMS[®] converts phasor data to a scaled integer format for database storage in order to save storage space in the database (floating point data storage requires approximately twice as much space as does scaled integer format).

RTDMS[®] stores the phasor data (voltage and current) in scaled Integer polar format, while frequency and analog signals are stored in floating point format. Since integers are whole numbers, preservation of the accuracy requires scaling the value so an integer representation will retain most of the accuracy. For example, if 15.4 amperes is converted to an integer 15, the resolution has been reduced from .65% to 7%. If the value is first scaled (divided) by 0.1, the stored value is 154. When retrieved and rescaled, it has its full pre-storage accuracy. However, if we have a current of 8,477.34 amperes and scale by 0.1, the integer representation will be 84773 which will overflow the integer storage range (-32,767 to 32,767) and will corrupt the value.

The following fixed scale factors are used currently in RTDMS[®] to handle the trade-off between reducing storage space and limiting the 2-byte 2's complement range (-32,767 to +32,767)

| Phasor | Current Magnitude | Voltage Magnitude | Angle |
|--------|-------------------|-------------------|-------|
|--------|-------------------|-------------------|-------|

| | | | |
|-------------------------|---------------|--------------------|---------------|
| Scale Factor | 0.4 | 0.04 | 0.008 |
| Resolution limit | 0.4 amps | 0.04 kV (40 volts) | 0.008 degrees |
| Maximum range | ± 13,106 amps | ± 1311 kV | 262 degrees |

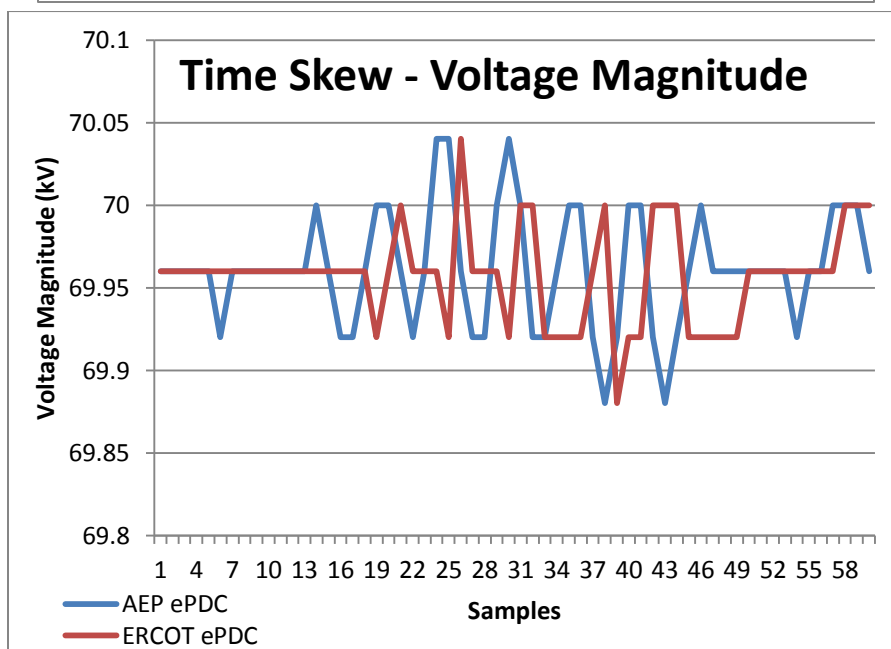
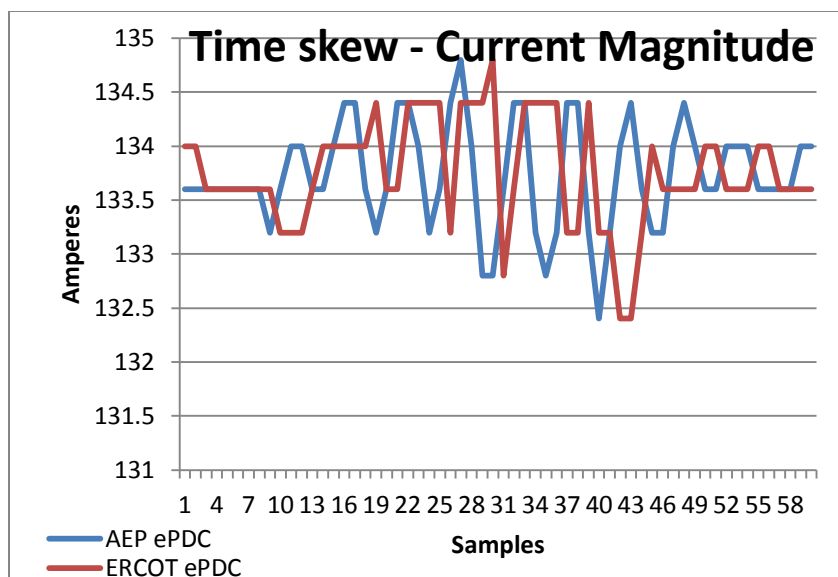
The following describes how the data is scaled down and stored in the RTDMS[®] database:

- Scale Up - For those metrics that require a conversion and need to be stored as Integer/Polar data format, the value of each part of the phasor (Magnitude and Angle) with the entire resolution (all fractional part of the mantissa) is divided by its corresponding scale factor.
- The scaled up value of each part of the phasor is truncated to an integer and stored in the database.
- When the data is queried directly from the database, scale factors are used (to multiply) to rescale the received phasor data from the ePDC.
- Hence the following was be observed
 - The accuracy of the mantissa was more noticeable in voltage magnitude compared to current magnitude.
 - The Frequency phasor had a very good match between the ePDC and RTDMS[®] Database as the values are stored in floating point.
 - The Order of resolution is Current magnitude < Voltage magnitude < Angle < Frequency.
- Resolution: RTDMS[®] Enhancement: The option to store data as floating point will be made available in RTDMS[®] Server v2.7 for Voltage and Current Phasors.

6.1.4 Time Skew Between AEP and ERCOT ePDC database – Jan 24, 2013, 23rd Hour (Central Time)

ERCOT ePDC data extracted appears to be time skewed from the AEP ePDC data. When the ERCOT ePDC data is shifted forward by 2 time samples (2/30 of a second), then the voltage and current angles nearly coincide. Voltage and current magnitude are close enough, but not as close as angles.

It appears that ERCOT data is time shifted (delayed) by 0.067 seconds compared to the AEP ePDC data. The plots below show comparison between AEP ePDC data and ERCOT ePDC data for current magnitude and voltage magnitude.

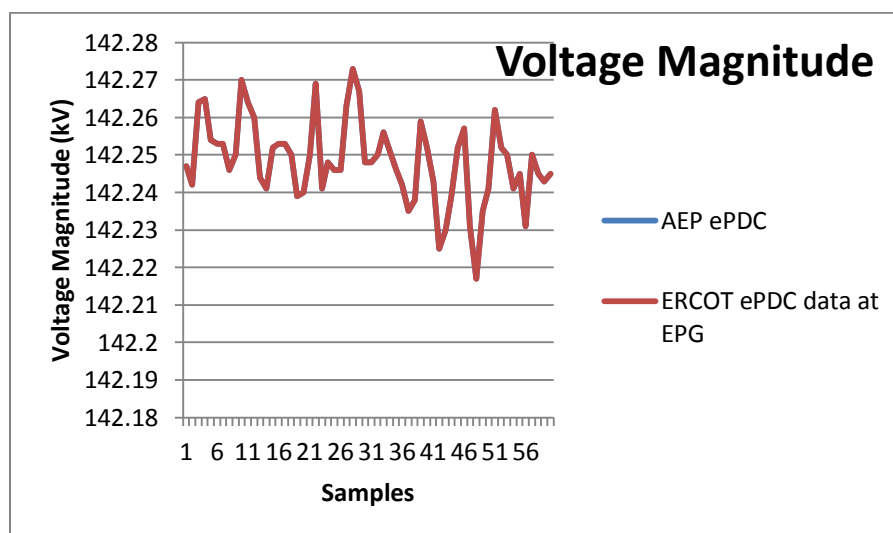
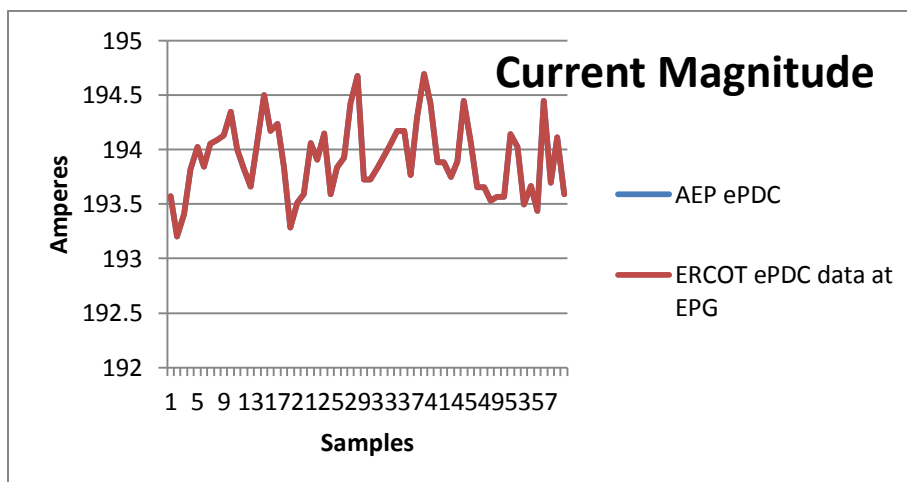


Resolution:

The time skew issue was related to user-defined ePDC minimum output latency and the use of progressive forward padding. To resolve this issue, the ePDC at AEP was corrected to wait longer (Increase the minimum output latency to 100 ms) or to disable the progressive forward padding. Currently AEP is running ePDC v3.1.1 with missing data padding disabled.

Following a configuration change to the AEP ePDC, an extract was obtained for 30-minutes starting 27th August 2013 11AM UTC and compared with ERCOT data for the same time collected at the EPG database. An investigation was performed on the voltage phasor, current

phasor and frequency for two PMUs namely – West 10 and Coast 1. It was found that there were no longer any differences between the two databases and that they now overlay on top of each other as shown below.



6.2 Analysis of ERCOT and Oncor Data Streams

To analyze the Oncor-ERCOT data stream, three hours of data was extracted from the Oncor PDC local database:

1. January 9, 2014 (10-11 AM UTC).
2. January 17, 2014 (00-01 AM UTC), (01-02 AM UTC).

A matching set of data was extracted from the ERCOT ePDC Phasor Archiver Data Base (which is replicated at EPG for this project).

6.2.1 Dropouts in Oncor Database Extracts

| Missing samples - Frequency Type | Jan 9, 2014 (10-11AM UTC) – Oncor DB | ERCOT DB | Observation |
|----------------------------------|---------------------------------------------------------------------------------------|-------------------------------|----------------------------------------|
| Non-recurring – 1716 | 59 th Minute Start to miss from 3 rd second till last second | Received most of the samples. | Local Archiving between Oncor PDC & DB |

Missing samples means no record of the data was found in the Oncor dataset. However, there were no missing samples for any other dates. It is recommended that Oncor check their PDC logs for possible data insertion errors in case the dropout was due to maintenance or network issues. It is also recommended to verify querying the database directly in case it was data extraction issue.

6.2.2 ERCOT Receiving a Higher Count of Flagged Data

| PMU Name | Oncor - Number of Flagged Data | ERCOT - Number of Flagged Data | Observation |
|-------------------|--------------------------------|--------------------------------|-------------------------------------------------------------------------------|
| WEST1_10840/10835 | 0 | 197 | Flagged bad as '0xe' (0xe meaning data invalid, PMU Error and GPS Sync Error) |
| WEST2_11130/11135 | 0 | 234 | |
| WEST2_11140/11135 | 0 | 234 | |
| WEST1_10845/10850 | 0 | 197 | |

The study of the data from January 17, 2014 (00-01 AM UTC) reveals that there is a higher count of bad data flags in the ERCOT ePDC DB than in the Oncor DB. There are only four PMUs in Oncor single stream to ERCOT that are flagged bad. As a rule of thumb, dropouts from a single stream such as Oncor to ERCOT will be flagged '0xF'. It is more likely a communication issue between Oncor and ERCOT, not at the Oncor PDC. On the other hand, the above table shows only four PMUs flagged bad (not likely a communication issue since they belong to the same stream) as '0xe'. '0xe' seems to be marked by the PDC at Oncor while sending to ERCOT.

Possible Explanation: The Oncor PDC flagged the data bad when it was sent to ERCOT, but waited longer to archive the data samples locally in the database, at which time the data was valid (perhaps there is more latency in these four signals than the PDC would accept).

6.2.3 Missing Signals in ERCOT Database

Oncor confirmed that these signals are being archived in their local database, and not being sent to ERCOT (at ERCOT's request):

- NORTH_5 025
- WEST2_11125/11120
- WEST2_11145/11150
- WEST1_11540/11545
- WEST1_11550/11545
- WEST1_10855/10850
- WEST1_10860/10865
- WEST1_10885/10880

6.3 Analysis of ERCOT and Sharyland Data Streams

For the analysis of the Sharyland-ERCOT data stream one-hour of data was extracted from the Sharyland PDC local storage:

1. June 19, 2014 (5-6 PM UTC).

The data provided includes PMU2 & PMU3 from South13 substation without status flag information.

A matching set of data was extracted from the ERCOT ePDC Phasor Archiver Data Base (which is replicated at EPG for this project).

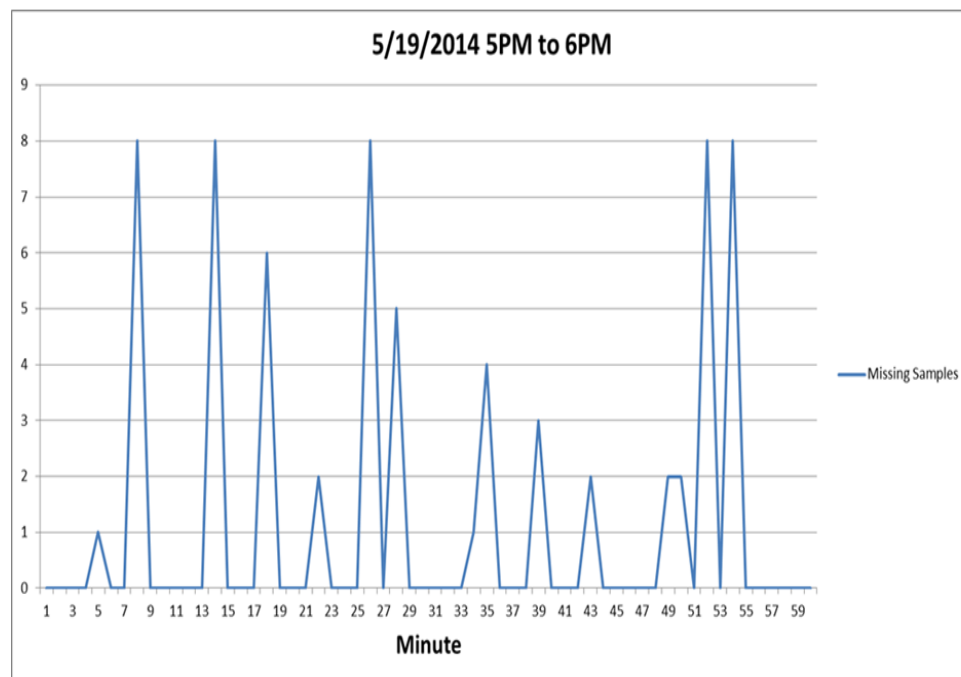
6.3.1 Dropouts in Sharyland Database Extracts

| Missing Samples - Frequency Type | June 19, 2014 (5-6PM UTC) – Sharyland | ERCOT DB | Observation |
|----------------------------------|---------------------------------------|-------------------------------|--------------------------------------------|
| Non-recurring – 68 | Scattered | Received most of the samples. | Local Archiving between Sharyland PDC & DB |

Missing samples means no record of data found in Sharyland dataset. It is recommended that Sharyland check their PDC logs for data insertion error in case the missing data was due to maintenance or a network issue. It is also recommended to verify querying the database directly in case it was data extraction issue. The missing samples did not have evident pattern and they were scattered over different minutes in that hour.

The plot and table below shows that:

- Maximum number of Missing Samples – **8 per minute**.
- Missing either at beginning of a second or towards end of factors of 10 second.



| Minute ? | Second? | Missing Samples |
|----------|-------------------------------------|-----------------|
| 7 | 9 th & 10 th | 8 |
| 13 | 49 th & 50 th | 8 |
| 25 | 19 th & 20 th | 8 |
| 51 | 10 th | 8 |
| 53 | 9 th & 10 th | 8 |
| 4 | 10 th | 1 |
| 21 | 0 th | 2 |
| 42 | 0 th | 2 |
| 48 | 40 th | 2 |
| 49 | 20 th | 2 |
| 34 | 10 th | 4 |

6.3.2 ERCOT Receiving More Count of Flagged Data

| PMU Name | Sharyland - Number of Flagged Data | ERCOT - Number of Flagged Data | Observation |
|--------------|------------------------------------|--------------------------------|----------------------|
| PMU2-South13 | Cannot Determine | 2406 | Flagged bad as '0xe' |
| PMU3-South13 | Cannot Determine | 0 | |

| Date/Time | PMU Signal | Data Dropout | Data Invalid | GPS Usync | Time Error | Data Invalid + GPS Unsyn + PMU Error (0xe) | GPS Unsyn + Time Error (0x3) | Flagged Good Samples (0x0) | Good Samples | Received Samples | Missing Samples |
|---------------------------|--------------------------|--------------|--------------|-----------|------------|--------------------------------------------|------------------------------|----------------------------|--------------|------------------|-----------------|
| 2014-05-19T170000_60m.csv | "PMU2-South13.Status.ST" | 6759 | 0 | 0 | 0 | 2406 | 0 | 98835 | 98835 | 108000 | 0 |
| 2014-05-19T170000_60m.csv | "PMU3-South13.Status.ST" | 108000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 108000 | 0 |

This issue appears to be similar to the Oncor PDC. There were higher counts of bad data in the ERCOT DB than in the Sharyland DB. '0xe' seems to be marked by the Sharyland PDC while sending the data to ERCOT and not while archiving. The signal values looks good in the Sharyland Database even without knowing status flag information.

7. SUGGESTIONS AND RECOMMENDATIONS

Any Utility/ISO with a phasor network should:

- Validate the data quality and data flow – don't assume it is good.
- Validate data storage on received data samples.
- Check for missing samples – Received Vs. Reported.
- Verify data time alignment between databases.
- Verify data accuracy and sufficient resolution between databases.
- Verify signal name consistency between databases.
- Fix data quality issues in a timely manner.
- Conduct periodic validation of data quality.
- Also plan to validate the data measurements.
- Continuously monitor data being received.

**Attachment 7. Data Quality Inputs
to ERCOT Communications Handbook**



Excerpt from Draft

ERCOT Synchrophasor Communication Handbook

V1.0

August 11, 2014

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5 SYNCHROPHASOR NETWORK DATA QUALITY

In order for ERCOT and their Market Participants to achieve a production quality phasor network system that can be relied upon in real-time operations, it is important to check whether the data link that is established between a market participant and ERCOT carries data flow reliably to ERCOT. The Data Quality Test will address the prior condition and will certify whether data sent from Market Participants is received and archived same at ERCOT.

Once a reliable synchrophasor network is established, it is also important to check the performance of each PMU on a continuous basis. The reliable synchrophasor network ensures high data availability but may not have high PMU performance. A highly reliable synchrophasor network may still have PMUs reporting with flagged data which cannot be used in real time operations. The occurrence of flagged data from the PMUs (or PDC) can be recurring or non-recurring (repeating or non-periodic respectively). It is important to check and correct the occurrence of flagged data in order to establish a reliable synchrophasor network with high PMU performance.

The good practices on the two phasor data test on the synchrophasor network are briefly explained below. The Data quality test ensures reliable synchrophasor network between the Market Participant and ERCOT. The PMU Performance Test will improve the occurrence of good data and reporting from PMU & PDCs itself.

The testing method listed here is specific for EPG RTDMS product.

5.1 RTDMS Data Quality Test

The Data Quality Test is an end-to-end analysis between the Market Participant (or any data sender) and ERCOT. This end-to-end analysis is a direct comparison between the data sent by Market Participant and the data received and archived at ERCOT. In order to conduct the study, it is most important that Market Participant (MP) and ERCOT archive data at both ends.

It is recommended to capture one hour of data (minimum) or more from both ends for two different days (minimum) or more. The data collected at both ends for the same time duration will help to conduct the data quality test. Some of the common findings on data quality issues between data collected at both ends are as follows:

1. Missing Samples
2. Missing PMUs & Signals
3. Mismatch in PMU & Signal Headers/Names
4. Data Shift in time (Time Skewed)
5. Difference in Data Resolution
6. Difference in Count of Flagged Data

Missing Samples

1. Verify the count of samples reported matches the received rate

For example – If the phasor data reporting rate is 30samples per second, then the count of samples expected for duration of 1 hour is equal to 108000 samples.

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2. Compare the results at both ends to verify
 - a. There are no local archiving issues
 - b. There are no communication issues between MPs and ERCOT

Missing PMUs

1. Verify the count of PMUs sent matches the received PMUs
For example – If the MP is sending 10 PMUs to ERCOT, then ERCOT should be receiving data for all the 10 PMUs.
2. Verify the count of signals sent under each PMU matches the reported received signals under that PMU
3. Compare the results at both ends to verify
There are no lost PMUs/Signals during the communication

Mismatch in PMU & Signal Headers/Names

1. Verify whether PMU headers/names sent matches the received PMU headers/names
2. Verify whether Signal headers/names sent matches the received Signal headers/names under each PMU
3. Compare the results at both ends to verify
 - a. There is no mismatch due to configuration changes
 - b. There is consistent PMU naming convention
 - c. There is consistent name for a PMU and its signal for common displays and analysis

Data Shift in time (Time Skewed)

1. Verify whether PMU signal data reported for a timestamp matches exactly at both ends
For Example: Plot and Compare same PMU signal data from both ends for a duration of time
2. Compare the results at both ends to verify
 - a. There is Time alignment – PMU Signal data at both ends should be identical (they will lie on top of each other when plotted)
 - b. There is no Time Skew – PMU Signal data from one end will be time shifted from other and will not lie on top of each other when plotted
 - c. If there is time skew, it could possibly be latency issue related to the PDC

Difference in Data Resolution

1. Verify whether the PMU signal data value matches (magnitude and phase angle) at both ends for a duration of time
For Example: Calculate the Difference between PMU signal data from both ends for a duration of time (Assuming there is no time skew)

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2. Compare the results to verify
 - a. There is no difference in resolution at both ends
 - b. There are no data conversion issues at the PDC
 - c. There is no mismatch in scaling factors used at the PDC

Difference in Count of Flagged Data

1. Verify the count of flagged data matches at both ends

For Example: If the count of data samples, flagged good, sent by MP were 108000 in an hour, then ERCOT should receive the same count of good data samples during the same hour

3. Compare the results to verify
 - a. There are no communication issues causing data dropouts
 - b. The count of flagged data at the receiving end matches the count at the sending end
 - c. There is consistency of flagged data samples at both ends (data is flagged identically for the same time interval)
 - d. There is no communication delay between both ends

Flagged Data Samples

The C37.118 data stream includes quality information for all the signals for each PMU in a Status flag. The Status flag is represented by hexadecimal integer 0x0000. The left most hexadecimal integer carries the quality information for the PMU data (0x0). Below table shows the findings on different types of observed flags on data samples.

| # | Types of Flags | Description – The data is flagged bad due to |
|---|----------------|---------------------------------------------------------------|
| 1 | '0x0' | Good Quality data |
| 2 | '0xF' | Dropouts (set by the ePDC) |
| 3 | '0x8' | Data Invalid |
| 4 | '0x1' | Time Alignment Error (Sorted by Arrival and not by Timestamp) |
| 5 | '0x2' | GPS Sync Error |
| 6 | '0x3' | GPS Sync Error + Time Error |
| 7 | '0xE' | Data Invalid + GPS Sync Error + PMU Error |

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The data quality test is needed to be expanded to the following

1. Within ERCOT Synchrophasor Network – Between ePDC and RTDMS
2. Between PMU and MP, if there are local archives at PMU level

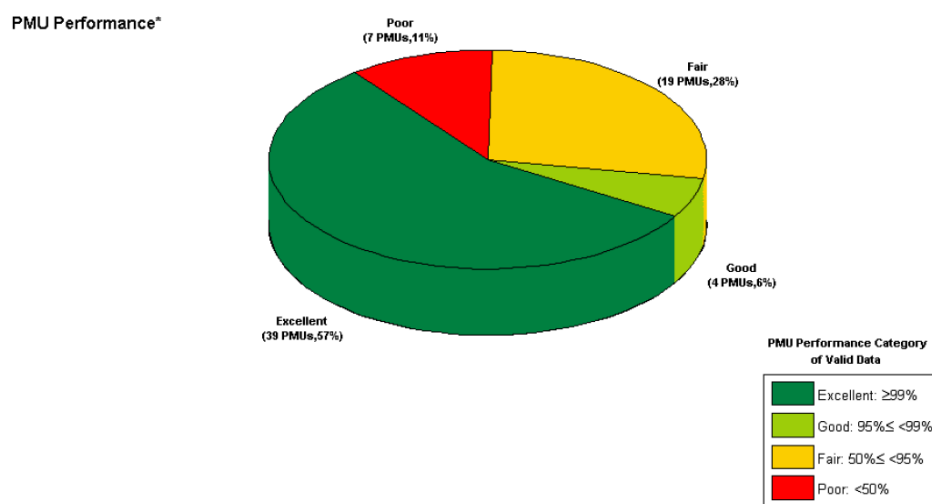
5.2 RTDMS PMU Performance Test

A highly reliable synchrophasor network may still have PMUs reporting with flagged data which cannot be used in real time operations. The occurrence of flagged data from the PMUs or PDC can be recurring or non-recurring (repeating or non-periodic respectively). It is important to check and prevent the occurrence of flagged data to establish a reliable synchrophasor network with high PMU performance.

PMU Performance Chart shown below is a pie chat from the RTDMS Daily Report showing the performance of PMUs under different performance categories. The objective of the PMU Performance analysis is to

1. Make all PMUs perform excellently
2. Identify plausible reasons for those PMUs that don't have excellent data quality
3. Find consistent patterns that affect PMU Performance
4. Identify any other inconsistent data quality issues affecting PMU Performance on a continuous basis

This study may identify issues with PMU devices and their supporting instruments, network issues transporting data within the synchrophasor network and many more.



*PMU Performance is based on Archived Data only. (PMU Performance(%) = Valid Data / Total Archived Data * 100%)

PMU Performance Chart – RTDMS Daily Report

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The PMU Performance analysis is done at the ERCOT level to identify the PMUs that are not performing well (as reported in the data delivered to ERCOT) and report to MPs on consistent data quality issues for improved performance. It is recommended to

1. Use one month of data collected at ERCOT
2. Count occurrence of flagged data (see above list of flagged data types), good samples, received samples and missing samples on a daily basis for all PMUs
3. Find patterns of data quality issues over the month

Some of the common findings on data quality issues affecting PMU Performance are as follows:

1. Daily Dropouts between MPs and ERCOT
2. Daily Dropouts between Specific PMUs and MPs
3. Specific PMUs showing GPS Sync Error
4. Specific PMUs reporting more count of flagged data

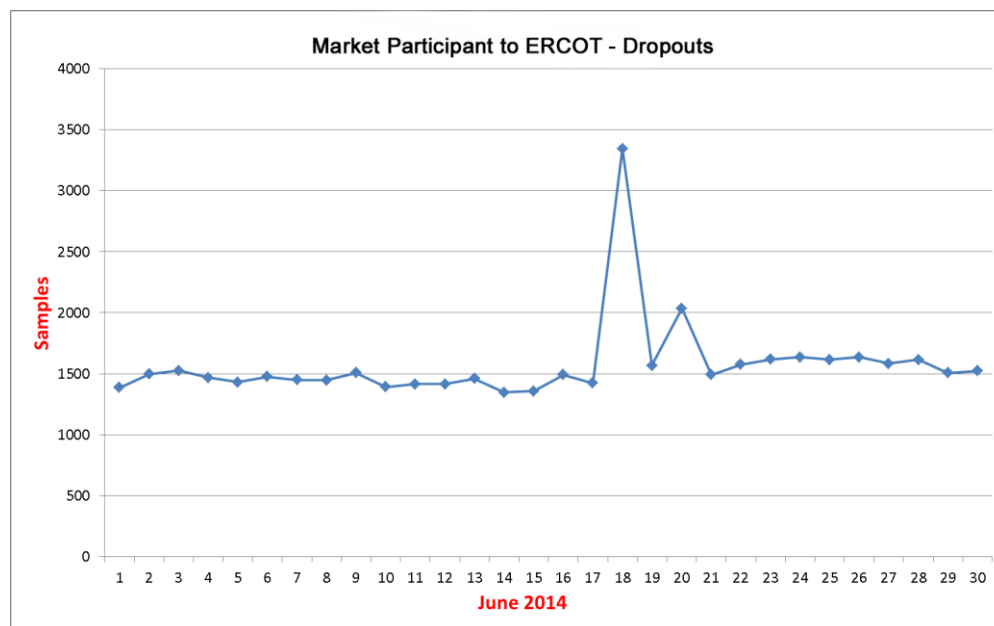
Daily Dropouts between MPs and ERCOT

The data samples are flagged bad as dropouts when they don't reach the destination due to communication issues. It is likely that the PDC sets the flag. Some of the common patterns of dropouts are

1. Daily Consistent Dropouts for entire stream from MP
2. Daily Irregular Dropouts for entire stream from MP

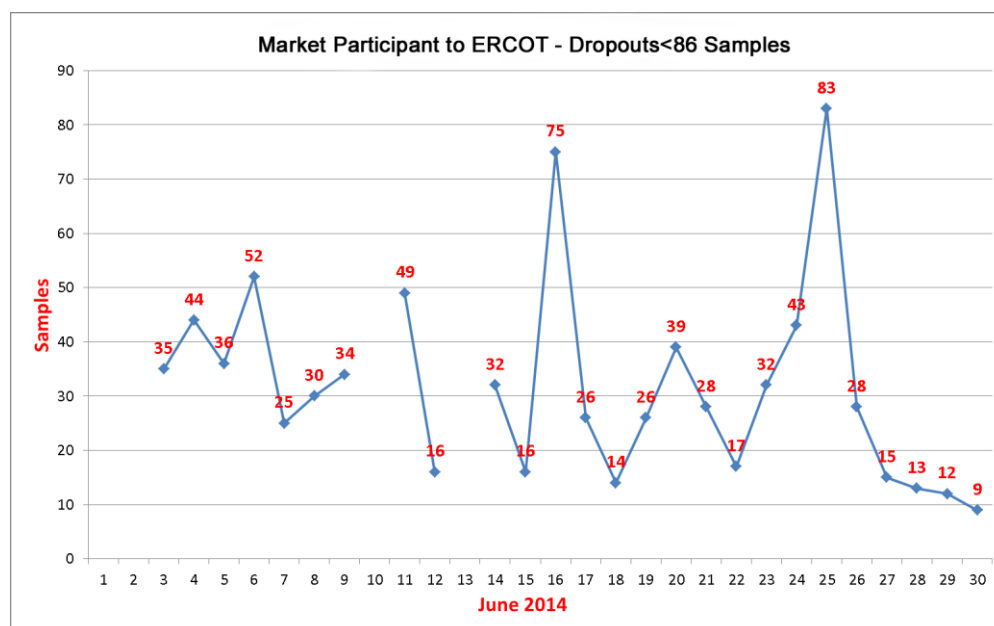
Daily Consistent Dropouts for entire stream from MP

1. If all the PMUs in the stream from MP shows same dropouts, it is more likely that there is communication issues between the MP and ERCOT
2. If the dropouts are consistent over the entire month, then there is most likely there are communication issues between MP and ERCOT on a daily basis.
3. For Example: Below figure illustrates the scenario that a certain Market Participant is having consistent daily dropouts for their entire data stream to ERCOT.



Daily Irregular Dropouts for entire stream from MP

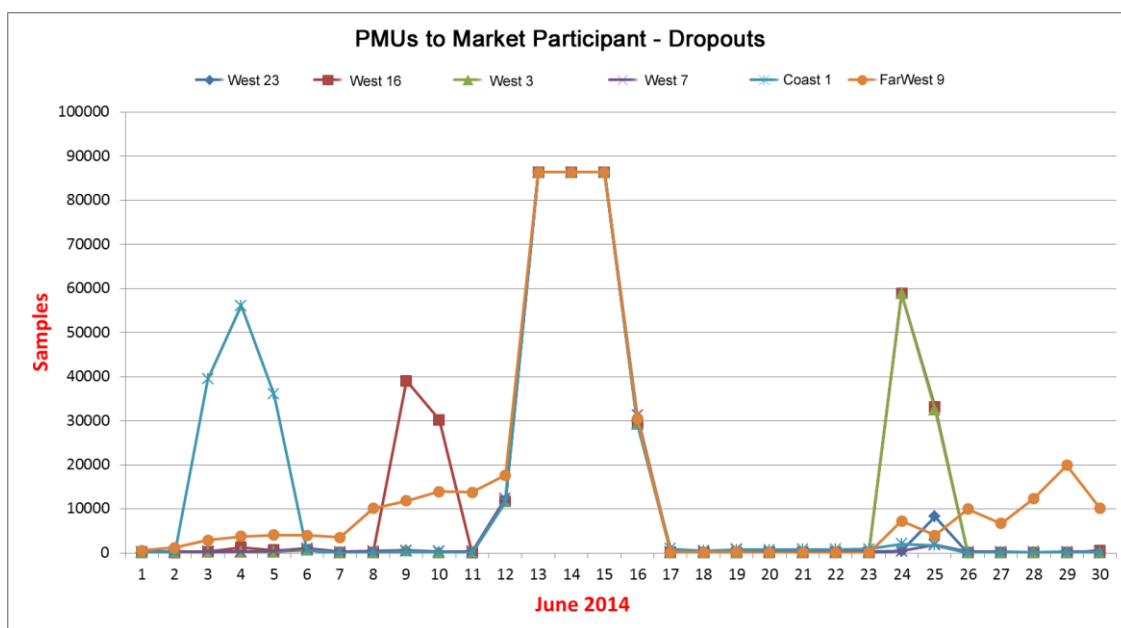
1. If all the PMUs in the stream from MP shows same dropouts, it is more likely that there is communication issues between the MP and ERCOT
2. Sometimes the dropouts are not consistent over the entire month and are found to be irregular over the entire month
3. For Example: Below figure illustrates the scenario where a certain Market Participant is having inconsistent daily dropouts for entire stream to ERCOT



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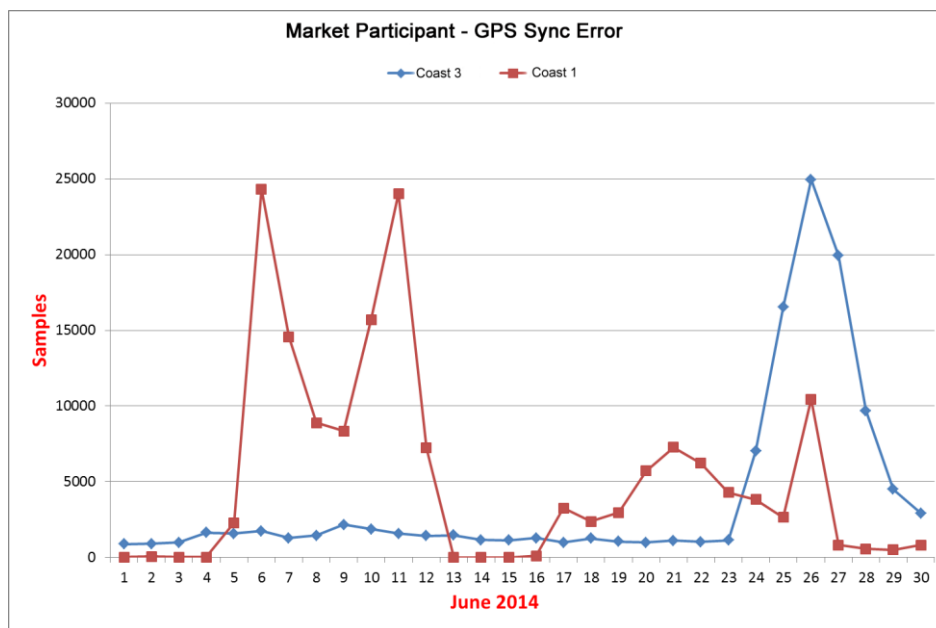
Daily Dropouts between Specific PMUs and MPs

1. MP sent PMU data stream as a single stream to ERCOT. So when there is a communication link failure, then all the PMUs are subject to be flagged as dropouts.
2. If specific PMUs in the stream from MP show dropouts, it is more likely that there are communication issues between the specific PMUs and MP PDC
3. It is most likely the dropouts are not the same for all PMUs as they represent dropouts from specific PMUs and are found to be irregular over the entire month.
4. Sometimes dropouts are the same for specific group of PMUs, if they are sent from a substation PDC or on a common communications path
5. For Example: Below figure illustrates the scenario where a certain Market Participant is having inconsistent daily dropouts for specific PMUs to their PDC



Specific PMUs showing GPS Sync Error

1. PMU data samples are flagged bad as GPS Sync Error if the PMU loses synchronization with its GPS clock.
2. The occurrence of flagged data samples under this category may be consistent or non-periodic over the entire month for each PMU.
3. Identifying the PMUs which frequently lose synchronization with the GPS clock can enable the MP to correct the GPS clock in order to improve the PMU performance.
4. For Example: Below figure illustrates the scenario where two PMUs from a Market Participant were showing frequent counts of flagged data samples. The plot below illustrates that Coast 3 (in blue) had a consistent count of samples flagged bad every day of the month and Coast 1 (in red) was irregular over the month.



Specific PMUs reporting higher count of flagged data

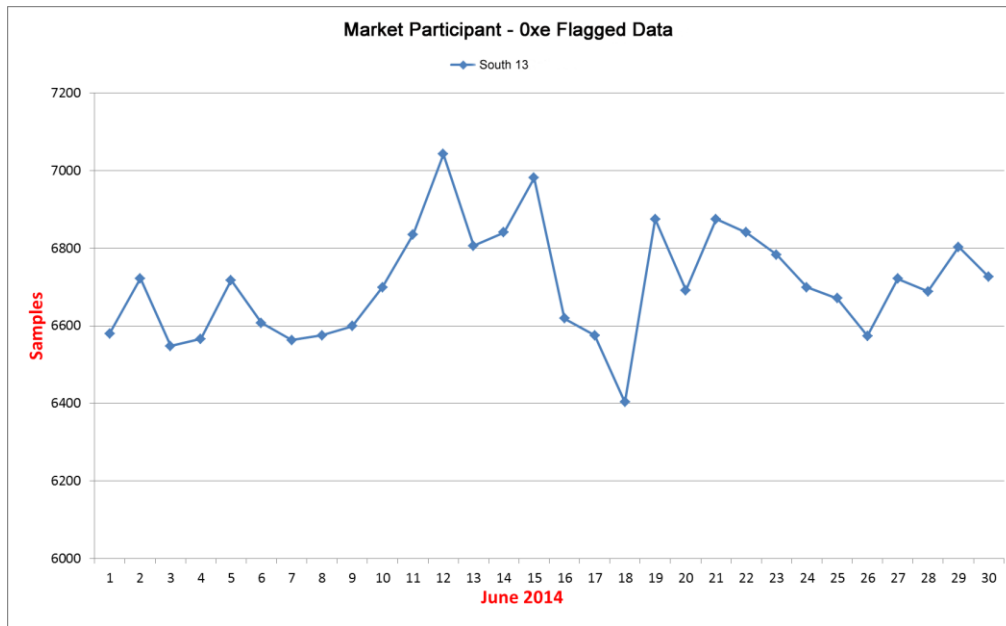
ERCOT might notice data samples from specific PMUs that are flagged bad as '0xE', most likely set by the MP's PDC and sent to ERCOT. It was found that those flagged data samples were flagged and archived as good at the MP database. It was observed that ERCOT was receiving a greater count of flagged data samples under this category, and this condition needs to be monitored.

It is likely that the PDC sets the flag. Some of the common patterns of '0xE' are

1. Daily Consistent Pattern from specific group of PMUs
2. Daily Irregular Pattern from specific group of PMUs

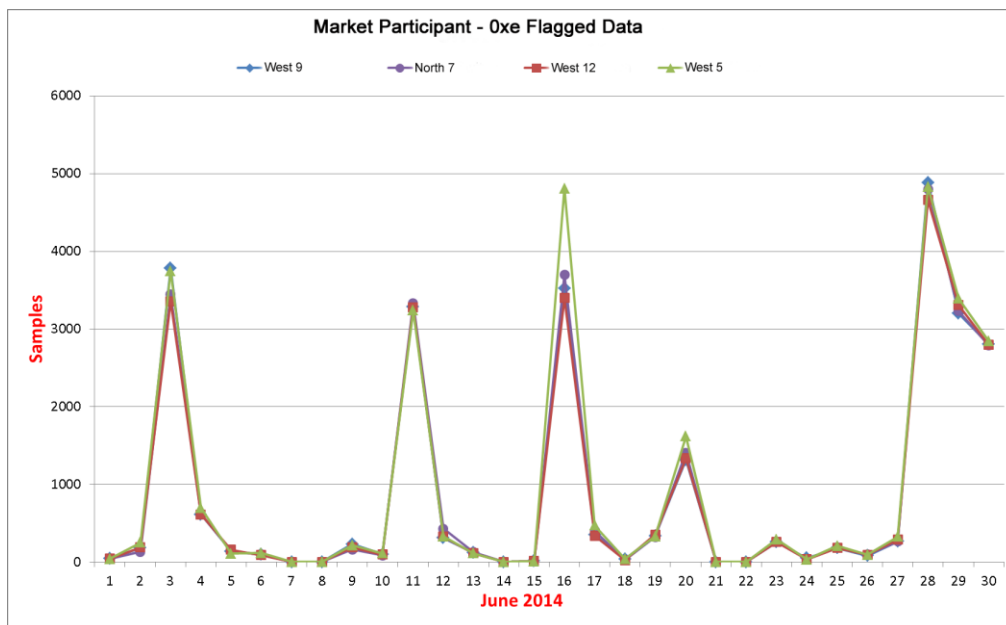
Daily Consistent Pattern from specific group of PMUs

1. Identifying the PMUs which frequently have flagged data samples can be notified and corrected to improve the PMU performance.
2. For Example: Below figure illustrates the scenario where a PMU from a Transmission Owner was showing a consistently high count of flagged data samples over the entire month.



Daily Irregular Pattern from specific group of PMUs

1. Identifying the PMUs which frequently have flagged data samples can be notified and corrected to improve the PMU performance.
2. For Example: Below figure illustrates the scenario where a specific group of PMUs from a Transmission Owner were showing irregular counts of flagged data samples over the entire month, but the irregular patterns were very similar for the entire group over the entire month.



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The PMU Performance analysis can be expanded to other types of flagged data samples as tabulated in the previous section. This analysis can pinpoint which PMUs are the “bad actors” sinking the overall PMU performance. The data quality test and PMU performance test on a continuing basis can drive to a reliable and high performance synchrophasor network. It is also a good practice to include other non-duplicative findings that are of concern based on future observations.

**Attachment 8. PMU Event Analysis Report
for 10 January 2014**

EVENT DETAILS

On January 10th, 2014, at about 8:30 a.m., after logging on into RTDMS system, ERCOT Operations Engineers noticed oscillations on the RTDMS displays. Since the oscillations were showing up only at the Wind Farm PMU as shown in Fig1, ERCOT looked at the generation at the Wind Farm unit close to Wind Farm PMU. It was generating about 56 MW (Fig2). These oscillations were showing up even though there was no line outage at the substation. (In October 2013, ERCOT had observed oscillations due to a line outage at the Wind Farm substation).

In order to reduce the oscillations, ERCOT advised the Wind Farm unit to turn OFF their AVR. This did not help to reduce the oscillations. In order to reduce oscillations, they were curtailed to 45 MW output. This reduced the oscillations to some extent. Since the oscillations did not go away completely, they were further constrained to 40 MW and the oscillations finally went away as shown in Fig3 and Fig4. It was found that oscillations were present in the system since 6:15 p.m. of January 9th, 2014. Analysis of these oscillations using Phasor Grid Dynamics Analyzer (PGDA) tool indicated that the dominant mode that was present was 3.3 Hz as shown in Fig 5 and 6. The voltage oscillations were having magnitude of about 1kV as shown in Fig 7. The oscillations were present till the next morning. Fig 7 and 8 show the oscillations present in the morning of January 10th, 2014 until the unit had been curtailed to less than 40 MWs. ERCOT Operations contacted the plant operator at the Wind Farm to determine the cause of oscillations. It was discovered that some updates were made to the settings for the system controller on January 9th, which matched the time of initial observation of the oscillations. After ERCOT informed the Wind Farm Operators about the oscillations, they pulled back the updates which finally stopped the oscillations. After that, no oscillations were observed even when the plant was generating at greater than 50 MWs.

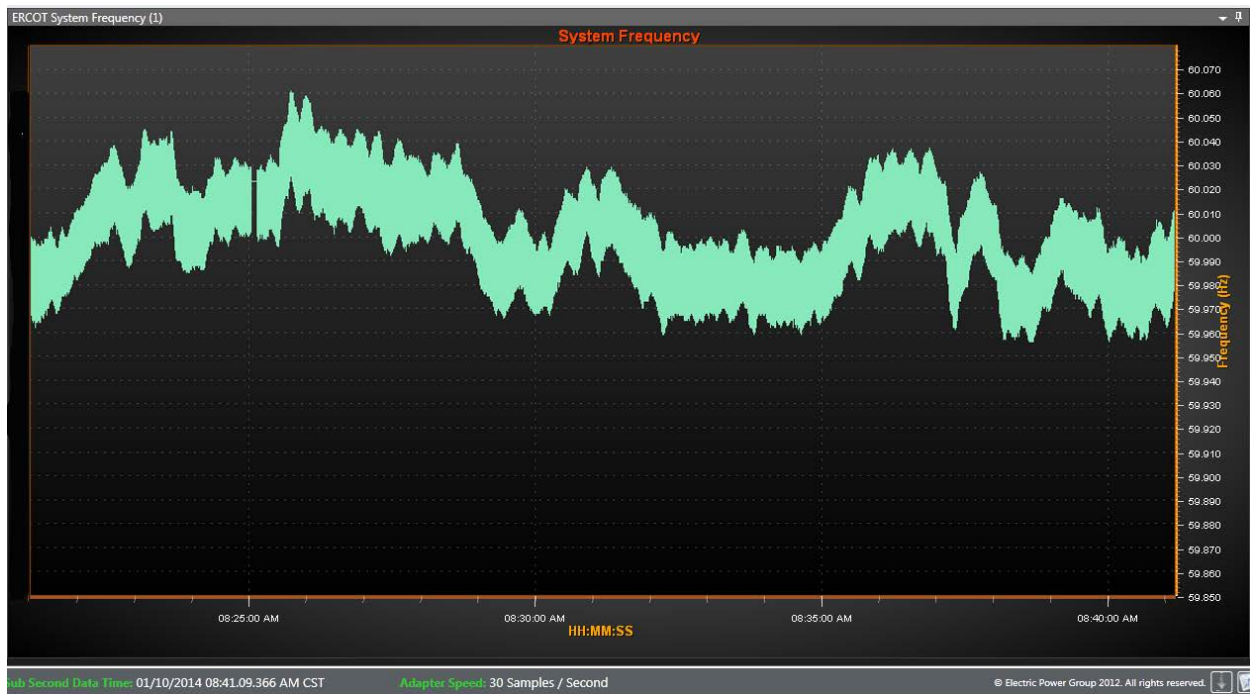


Fig1. Frequency at Wind Farm PMU on RTDMS System on 10th Jan 2014.

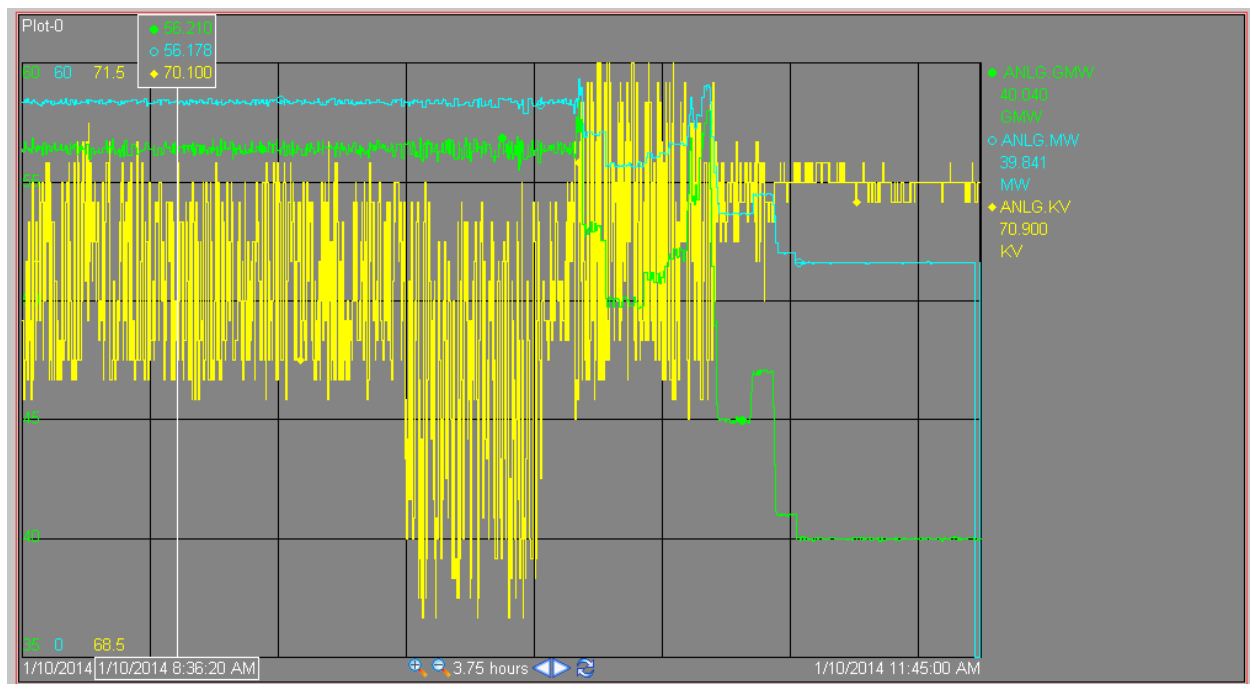
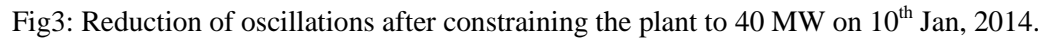


Fig2: EMS trend for Generation at the Wind Farm on 10th Jan, 2014.



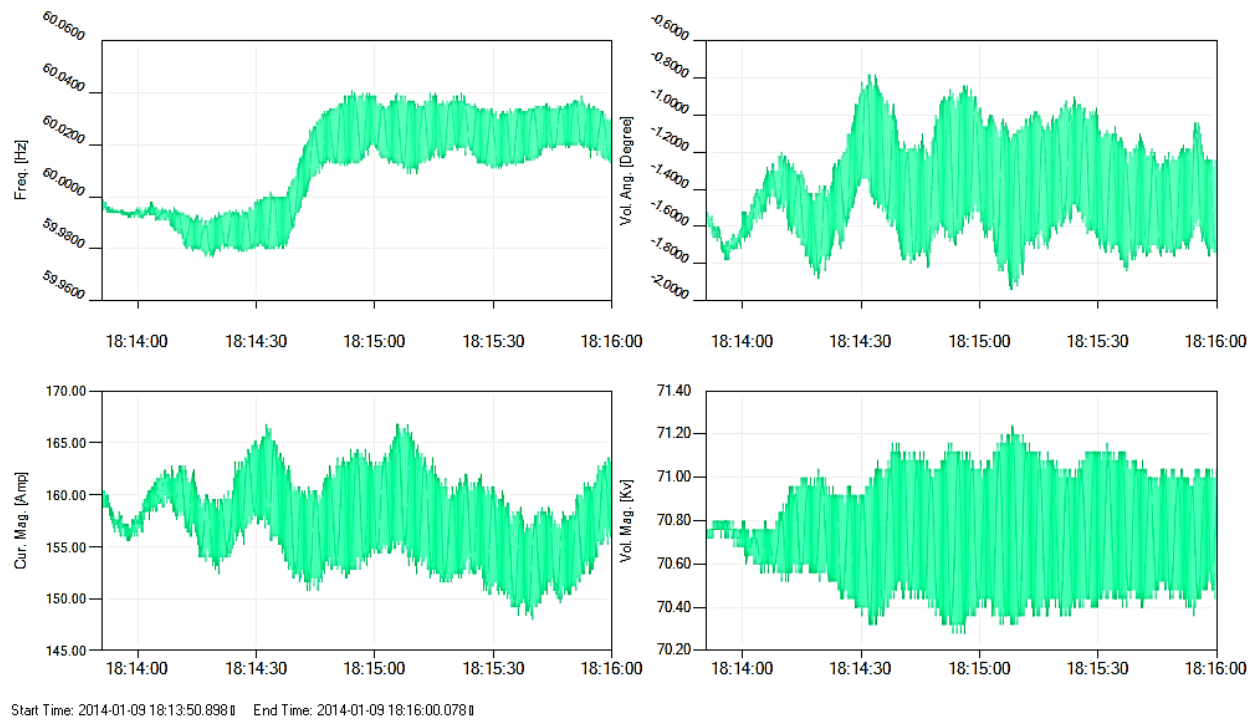


Fig 5: The frequency, voltage and currents captured by the Wind Farm PMU on 9th January, 2014

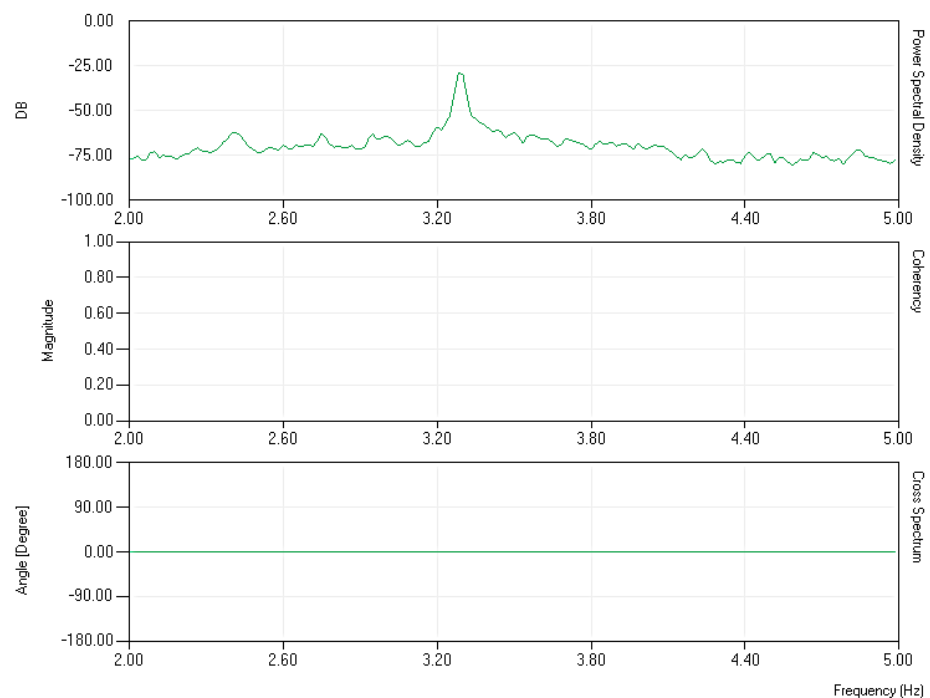
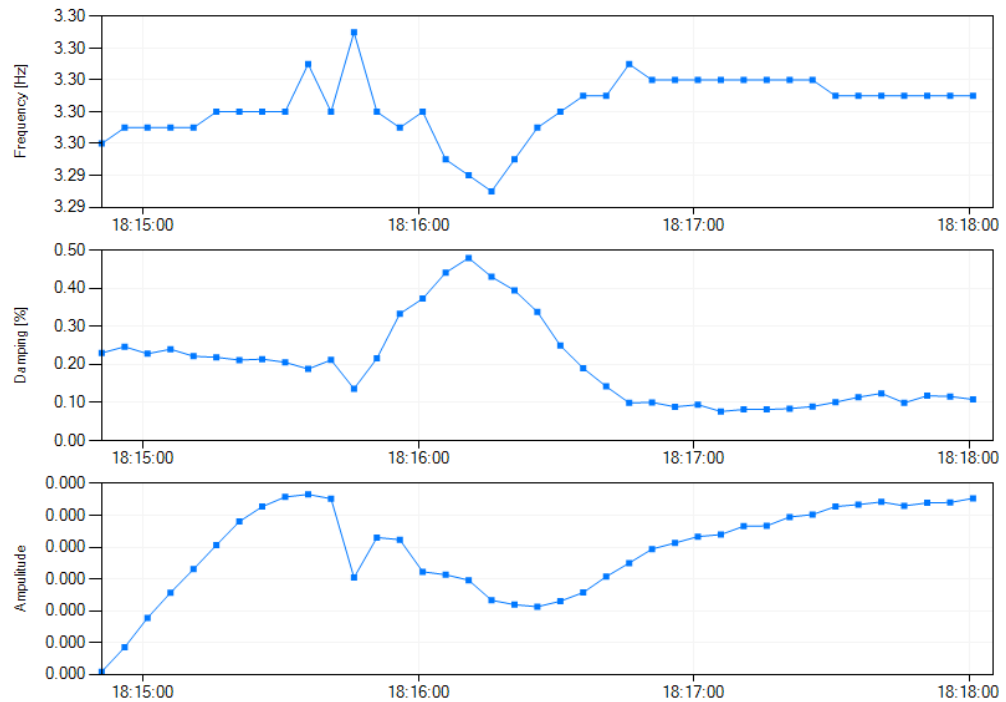
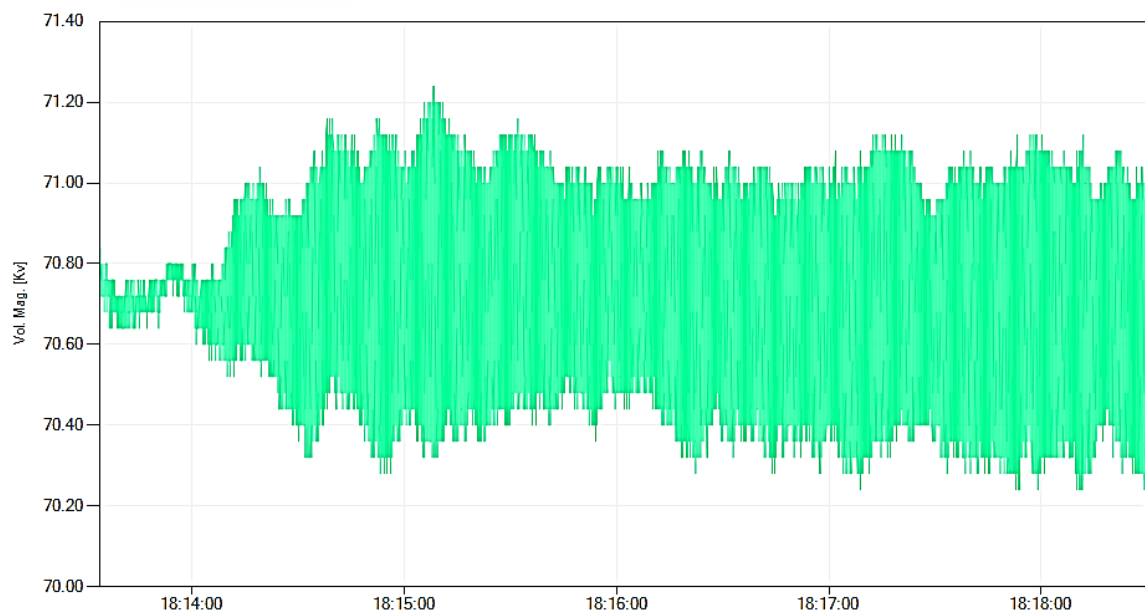


Fig 6a: Modal Analysis of the Frequency data using PGDA on 9th January, 2014.



Start Time: 2014-01-09 18:13:50.898 End Time: 2014-01-09 18:18:05.255

Fig 6b: Modal Analysis of the Frequency data using PGDA on 9th Jan 2014.



Start Time: 2014-01-09 18:13:34.000 End Time: 2014-01-09 18:18:32.230

Fig7: Voltage Oscillations at Wind Farm

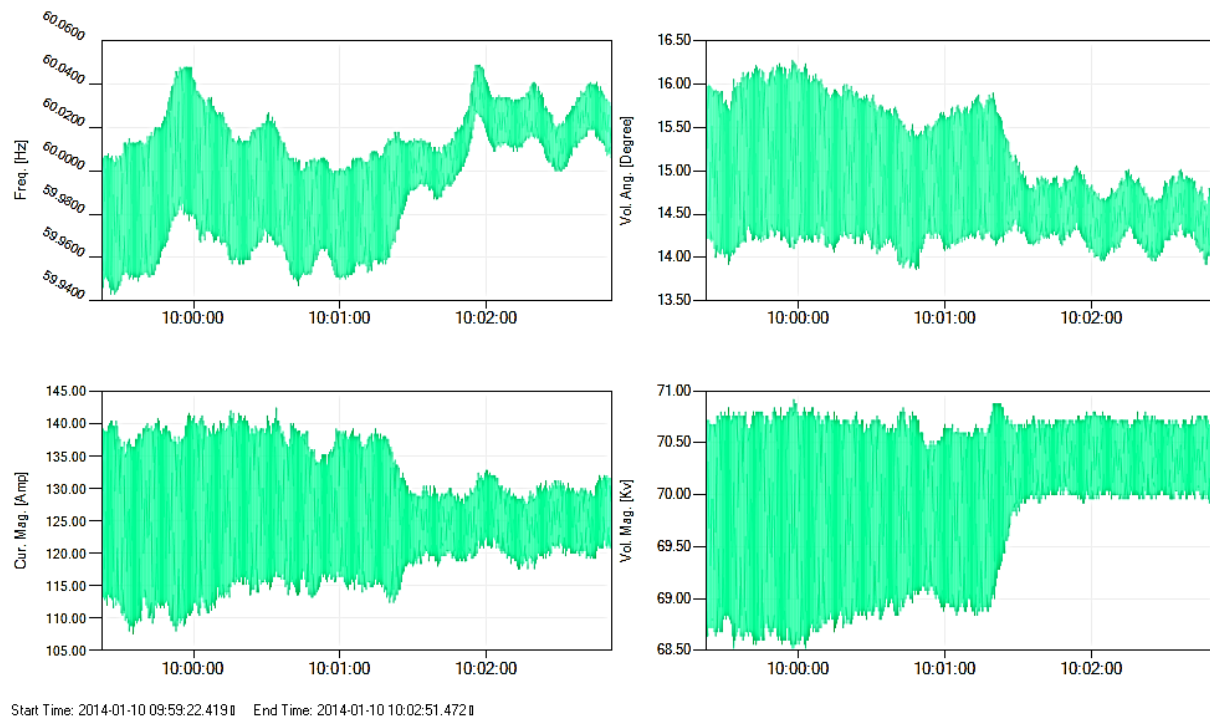


Fig.8: The frequency, voltage and Currents captured by the Wind Farm PMU on 10th January, 2014

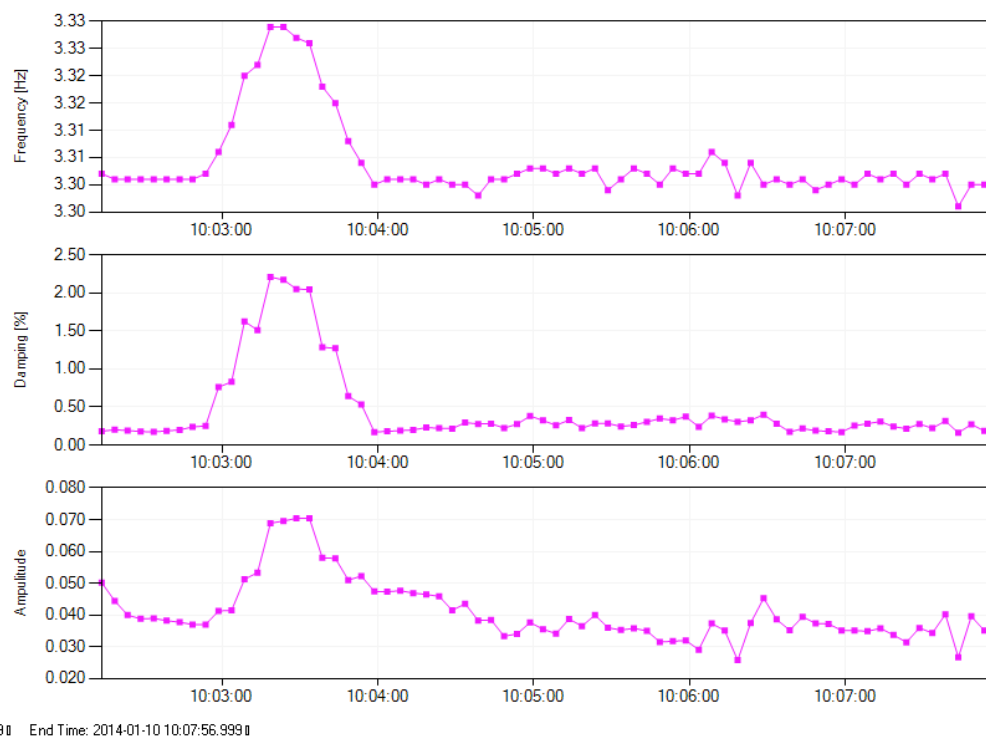


Fig 9: Modal Analysis of the Frequency data using PGDA on 10th January, 2014.

**Attachment 9. PMU Event Analysis Report
for 18 & 27 February 2014**

EVENT DETAILS

On February 18th, 2014, at about 8:30 am, after logging on into RTDMS system, ERCOT Operations Engineers noticed oscillations on the RTDMS displays as shown in Figure 1. On analysis, it was found that the oscillations were showing up only at Line 1@West 4 PMU as shown in Figure 2a and Figure 2b. ERCOT looked at the generation at the Hydro Unit close to West 4 PMU. It was generating about 25 MW (Figure 3). It was found that when the unit went offline at about 10:00 am, the oscillations died down as shown in Figure 4. It was noticed that, when the second unit at the same plant was running there were no oscillations observed. Oscillations showed up again on February 27th, 2014 when Unit 1 came online, as shown in Figure 5a and Figure 5b. Analysis of these oscillations using Phasor Grid Dynamics Analyzer (PGDA) tool indicated that the dominant mode that was present was 1.8 Hz as shown in Figure 6a and 6b. ERCOT discussed with the power plant operators to find the root cause of these oscillations with one of the units of the plant. It was confirmed that they could also see the oscillations for that unit. It was then decided that the plant operators would change some of the control cards for the problematic unit and test to see if it would solve the problem. Usually they operate the units alternatively. Since ERCOT was going through some severe weather conditions, the plant operators decided to operate only the good unit until ERCOT passed through this severe weather conditions. On March 5th, when weather conditions were good, Unit 1 (for which some of the control cards had been replaced) was brought online at about 4:00 pm (Figure 7). It was found that the oscillations were significantly reduced, as shown in Figure 7a, Figure 7b and Figure 7c after the control cards were replaced.

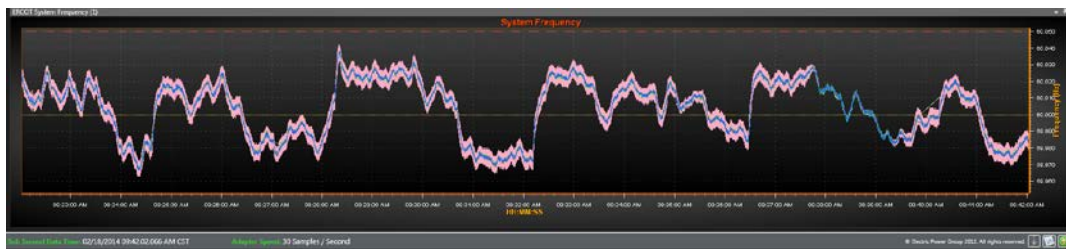


Figure 1: Frequency oscillations on RTDMS System on February 18th, 2014.

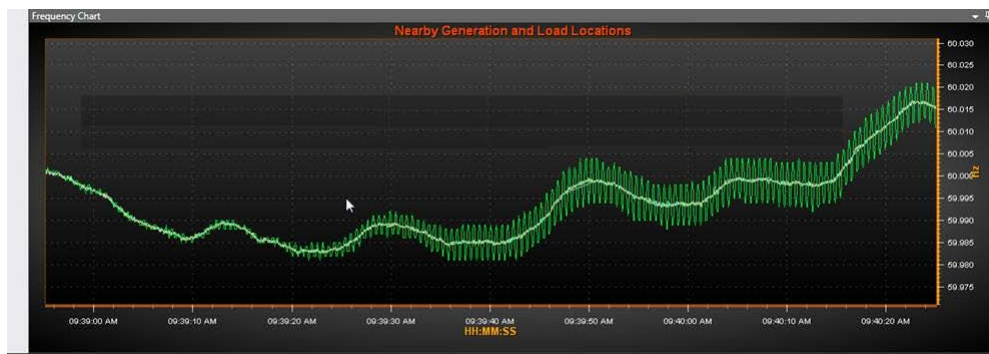


Figure 2a: Frequency Oscillations in West 4 PMU on February 18th, 2014.

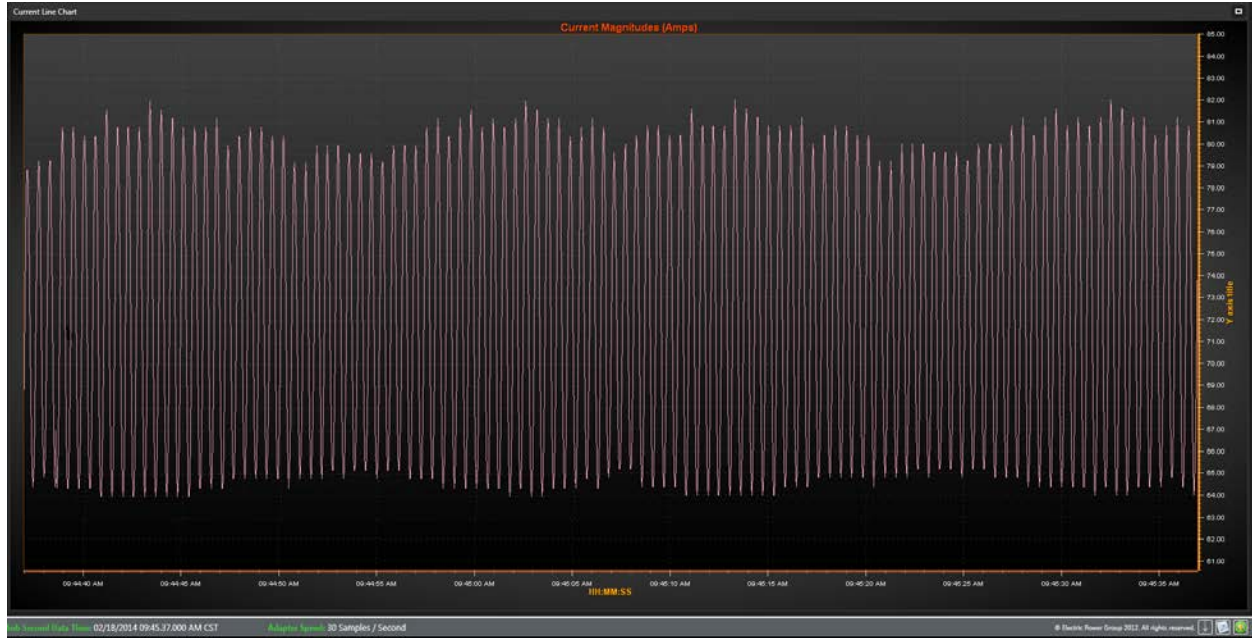


Figure 2b: Current oscillations on West 4 PMU on February 18th, 2014.

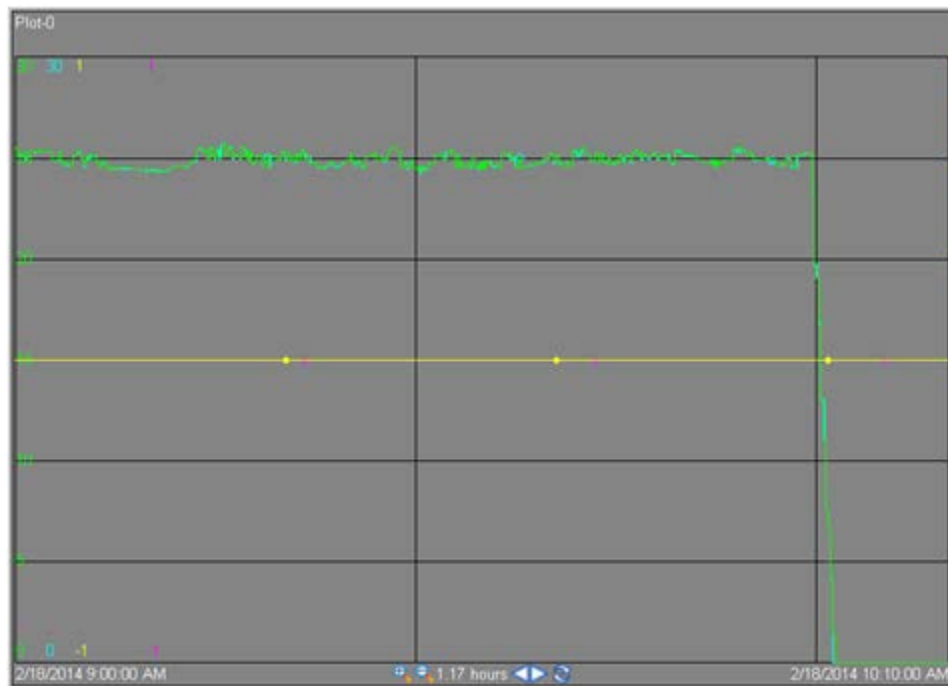


Figure 3: EMS trend for generation at the power plant on February 18th, 2014 at 10:00 am

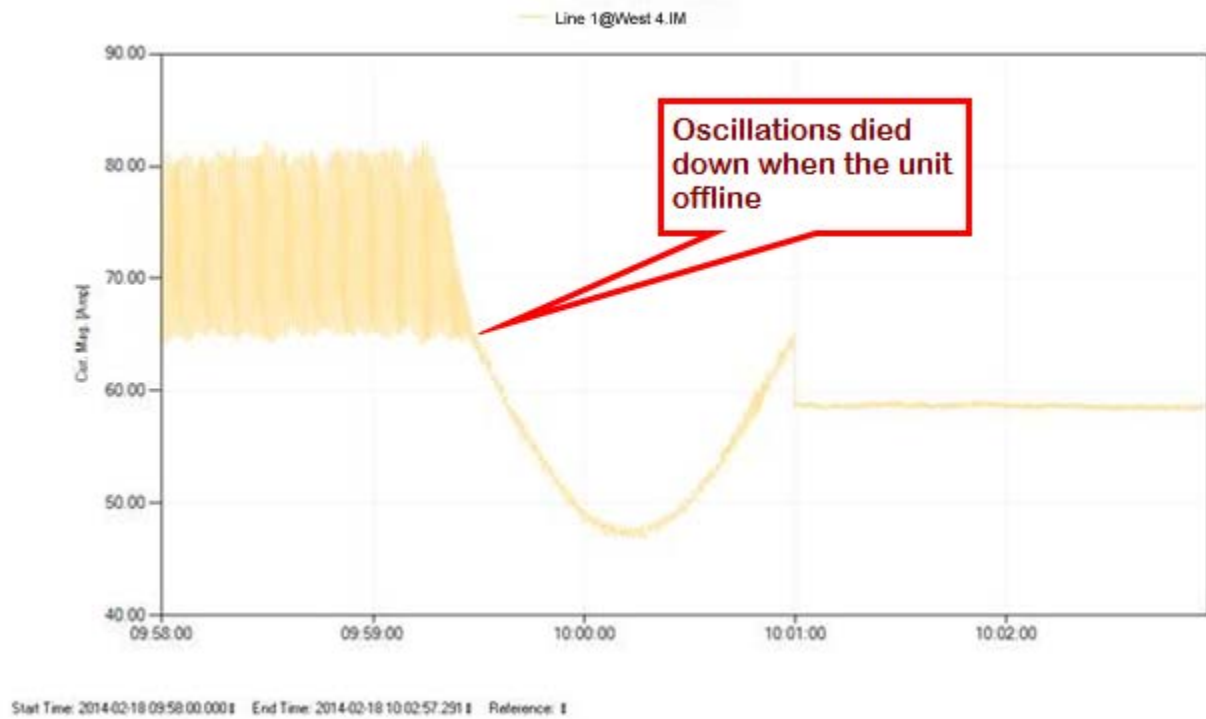


Figure 4: Current Oscillations when the unit went off line on February 18th, 2014 at 10:00 am

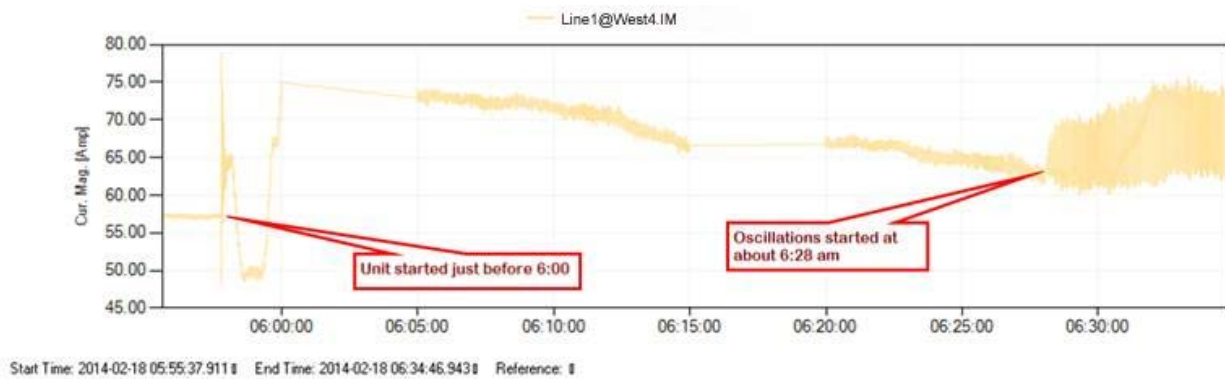


Figure 5a: Oscillations on February 27th, 2014

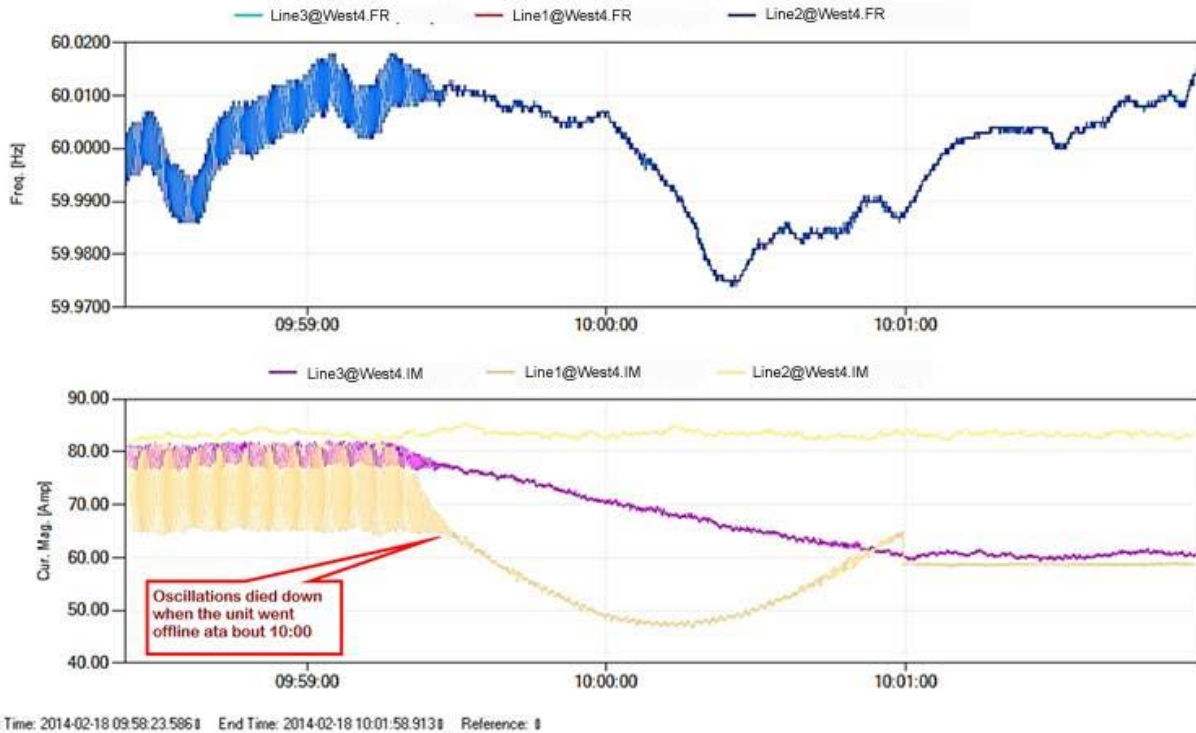


Figure 5b: Oscillations when the unit went off line on February 27th, 2014 at 9:59 am

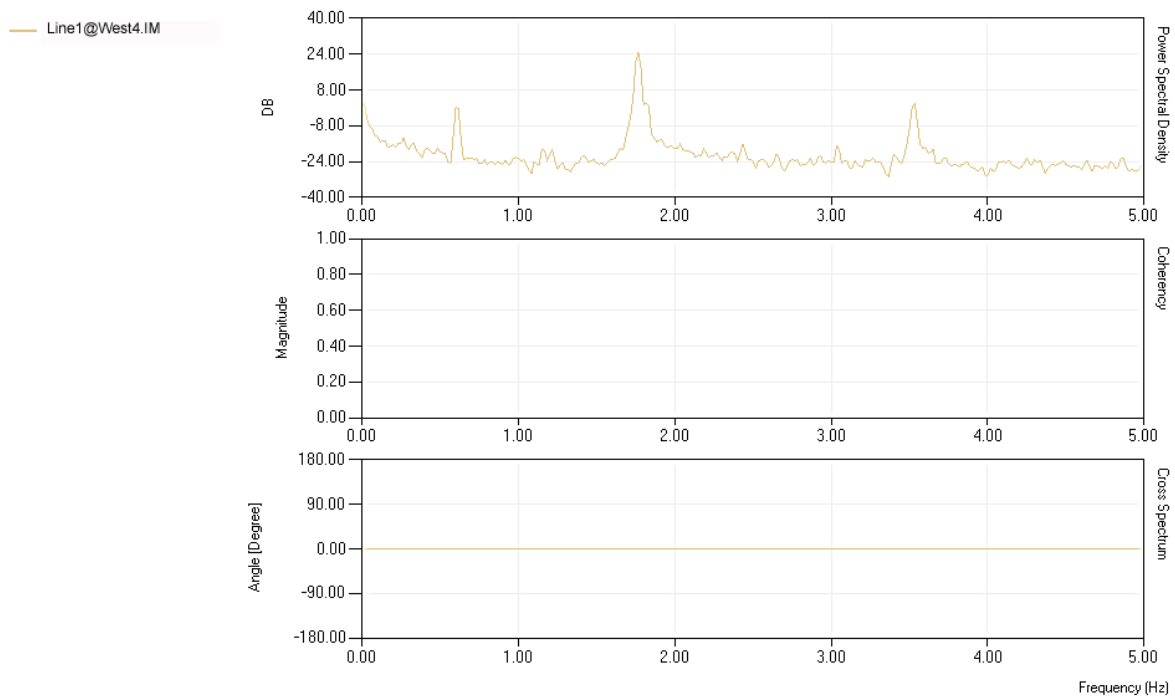


Figure 6a: Modal Analysis of the current data using PGDA on February 27th, 2014.

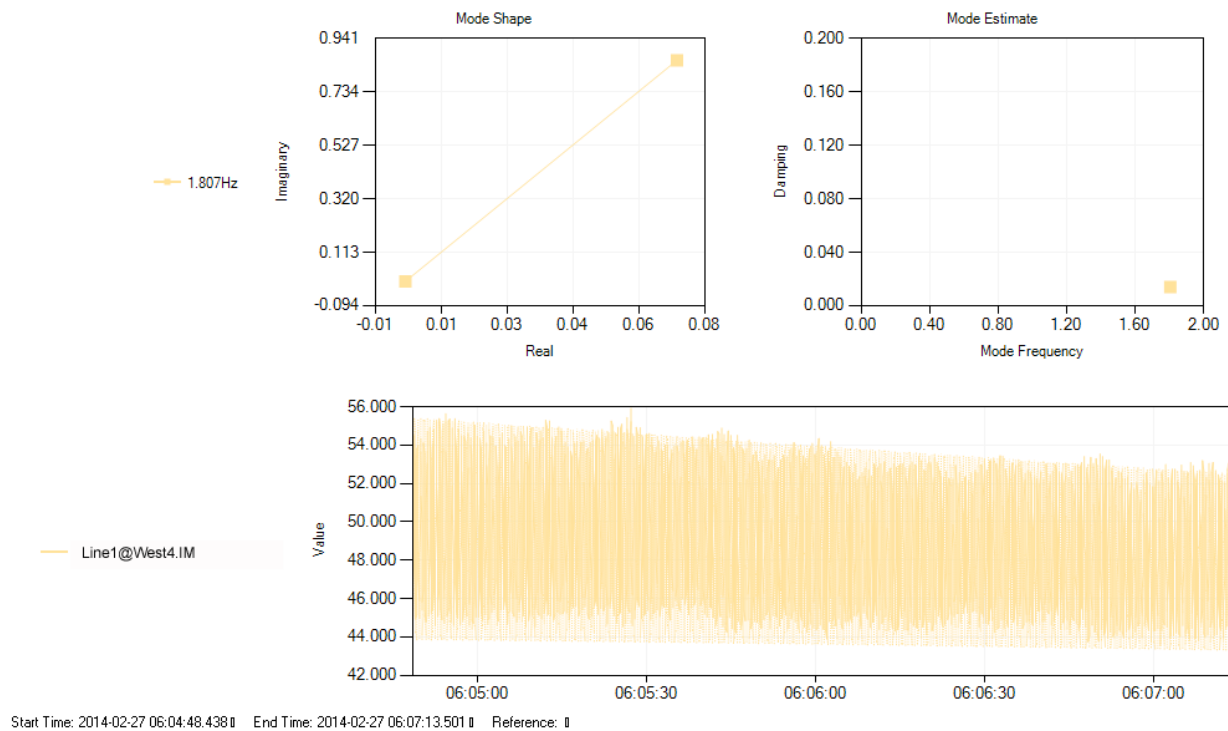


Figure 6b: Modal Analysis of the current data using PGDA on February 27th, 2014.

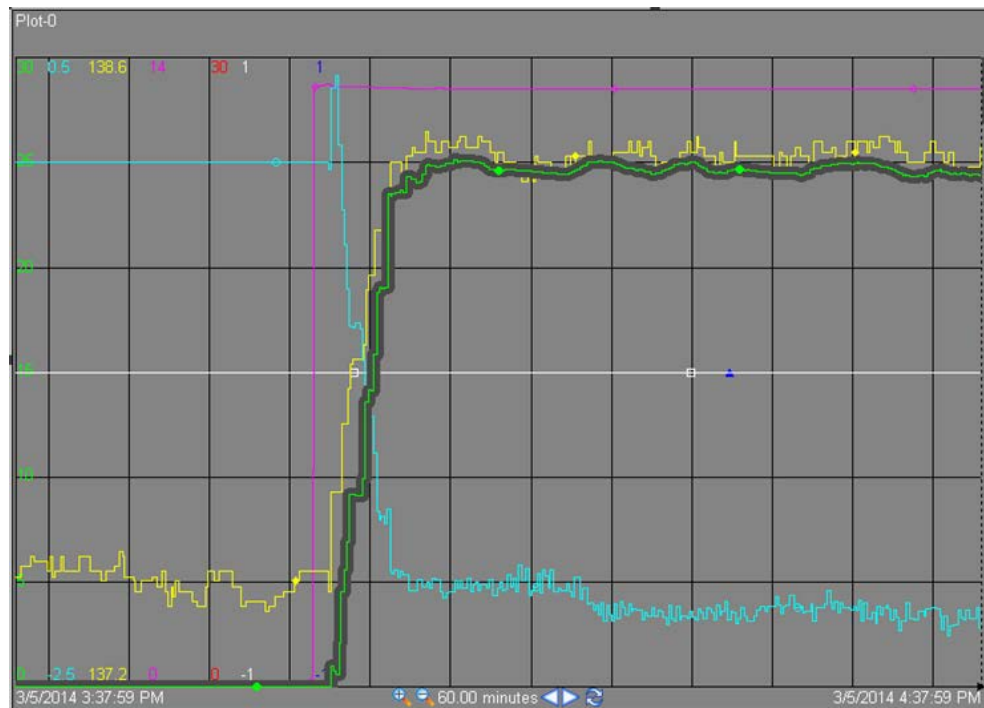


Figure 7: EMS display showing Unit 1 coming online at 4 pm on March 5th, 2014

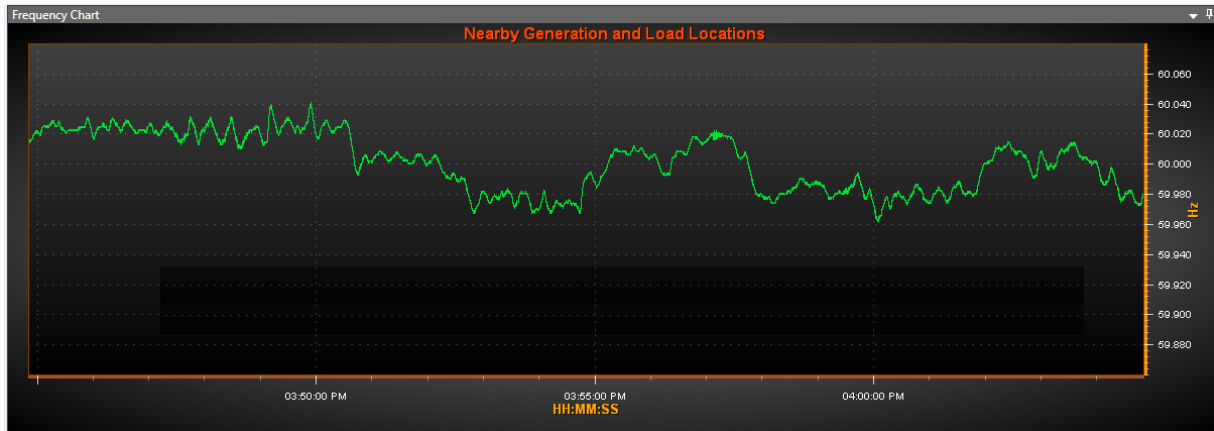


Figure 8a : Frequency display on RTDMS on March 5th, 2014

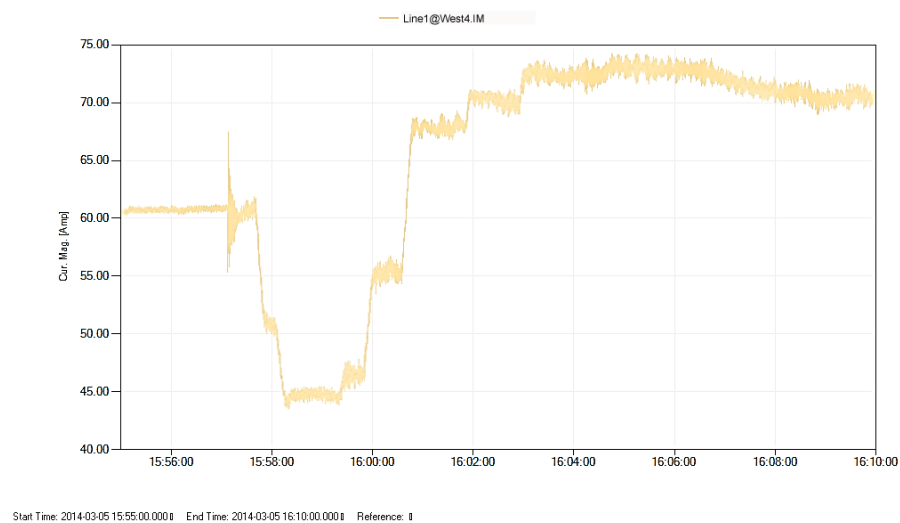


Figure 7b: Current display on PGDA on March 5th, 2014

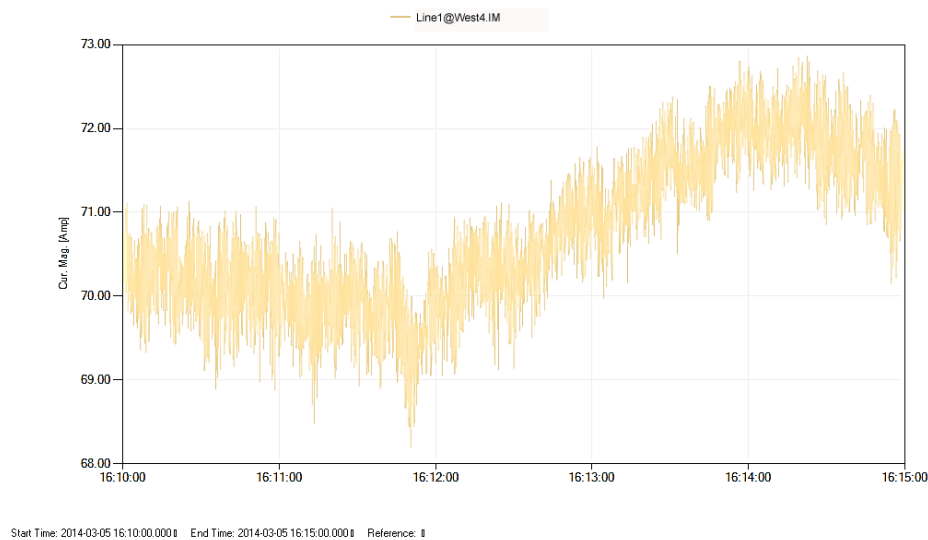


Figure 7c: Current display on PGDA on March 5th, 2014

Attachment 10. Inertial Frequency Response Study

Center for Commercialization of Electric Technologies (CCET)

Discovery Across Texas Project

Final Report on Wind Characteristics Inertial Frequency Response Study

Submitted to
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Prepared by:



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Prashant C. Palayam

October 30, 2014

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CCET Discovery Across Texas

Wind Characteristics – Inertial Frequency Response Study

CCET 3.1.3, Task c

1. Introduction

The Center for Commercialization of Electric Technologies (CCET) was awarded contract DE-OE0000194 by the Department of Energy to perform the Discovery Across Texas demonstration project. Electric Power Group, LLC (EPG) received a sub-award from CCET to provide professional services to perform, among other things, an analysis of the impact of increasing levels of wind generation on the inertial frequency response of the Electric Reliability Council of Texas (ERCOT) grid. Texas has the greatest amount of wind generation on-line in the nation and attains a new wind production record every year. Increasing wind production and penetration (percentage of total energy production) into the grid under different operating conditions poses operating challenges for ERCOT. One of the challenges with high wind penetration is to maintain an adequate level of Inertial Frequency Response that is crucial to ensure reliable operation of grid. Inertial Frequency Response represents the inherent resistance of the grid to frequency decline following a sudden loss of generation. It is measured by the amount of generation loss (in MW) required to cause a first swing frequency decline of 0.1 Hz, and a larger value corresponds to increased grid resilience. This study was initiated to investigate the contribution of wind generation to the ERCOT grid Inertial Frequency Response based on a starting hypothesis that a decline in Inertial Frequency Response with respect to increasing levels of wind generation was being observed in the ERCOT Interconnection.

This analysis summarizes four illustrative scenarios that collectively conclude that Wind Generation provides no significant contribution to Inertial Frequency Response. Rather, Inertial Frequency Response appears to be primarily dependent upon the total amount of Non-Wind Generation available online, including non-wind generation that is unloaded but on-line to provide spinning reserve. This report provides insights on the minimum amount of Non-Wind Generation needed to maintain adequate levels of Inertial Frequency Response under all conditions for the ERCOT Interconnection.

2. Executive Summary

Texas has the greatest amount of wind generation on-line in the nation and attains a new wind production every year. With increasing amount of wind production and penetration into the grid under different operating conditions, there are challenges and observations faced by ERCOT. One of the challenges with high wind penetration is to maintain an adequate level of Inertial Frequency Response that is crucial to ensure reliable operation of grid.

A generator unit trip or sudden loss of generation will result in a frequency drop due to the imbalance between generation and load. The frequency drop gets arrested by the inertial frequency response. Inertial Frequency Response represents the inherent resistance of the grid to frequency decline following a sudden loss of generation. It is measured by the amount of generation loss (in MW) required to cause a first swing frequency decline of 0.1 Hz, and a larger index corresponds to increased grid security. Inertial Frequency Response is illustrated in Figure 2.

Inertial Frequency Response is a measure of how far the frequency will drop following loss of a generator. Primary and secondary frequency response (including automatic governor and load response actions together with operator-dispatched generating reserves) will eventually restore the frequency back to a nominal system frequency value. This study was proposed to investigate the contribution of wind generation on Inertial Frequency Response based on a starting hypothesis that a decline in Inertial Frequency Response with respect to increasing wind generation was being observed in ERCOT Interconnection. The performance of inertial frequency response was investigated at different levels of wind generation as part of this analysis.

This analysis was based on 183 generator trip frequency events, collected over three years (2012-2014) to investigate the contribution of wind generation on the inertial frequency response of the ERCOT grid. Inertial Frequency Response was calculated for each individual event using Electric Power Group's Phasor Grid Dynamics Analyzer (PDGA) and correlated with different operating conditions using an assumed linear relationship between the amount of generation loss and the corresponding frequency drop. For the analysis, ERCOT Load, ERCOT Generation, ERCOT Wind Generation, ERCOT Spinning Reserves and Phasor Measurement Unit (PMU) data collected from substations located nearby wind units were collected and analyzed to quantify the variation and trend in inertial frequency response. There was empirical evidence from operating performance of a general decline in inertia with increasing levels of wind generation. This analysis identified four different illustrative scenarios which collectively lead to a conclusion that Wind generation does not contribute to inertial frequency response.

The key findings that suggest there is no contribution from wind generation to inertial frequency response are:

1. The Seasonal Trend of inertial frequency response remained the same even at different levels of wind penetration, indicating no relationship between response and penetration.
2. Inertial Frequency Response and the total level of Non-Wind Generation on-line had a strong positive correlation, suggesting inertia is proportional to Non-Wind Generation.

3. The generation trip events which show a decline in inertial frequency response with higher wind generation were found to have lower Non-Wind Generation online.
4. There was no significant increase in the power output from the wind plants (as measured by the nearby PMUs) coincident with frequency drop for each of the frequency events, indicating no inertia contribution from the wind plants. In contrast, the power flows from locations near non-wind generation showed coincident power flow changes.

This study concludes that inertial frequency response of the ERCOT interconnection is directly correlated to the amount of Non-Wind Generation available online, and finds that the level of wind generation has no impact on the inertial frequency response. The report also provides insights on the minimum amount of Non-Wind Generation that would need to be maintained online in order to maintain minimum levels of inertial frequency response under all operating conditions.

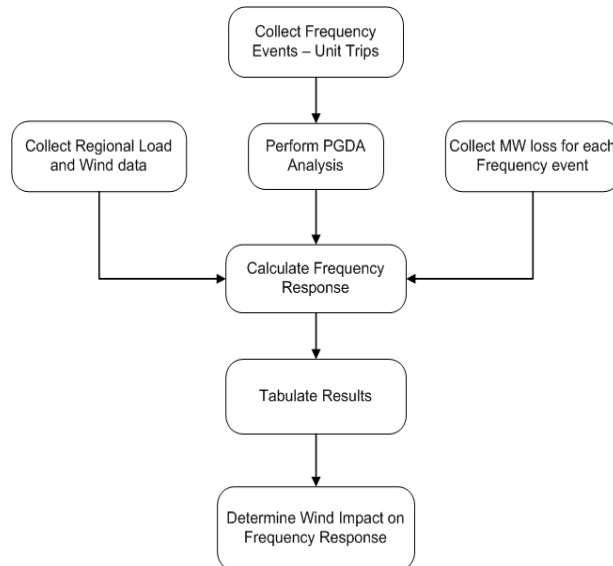
3. Goals & Methodology

The objective of this analysis was to identify if wind generation contributed to inertial frequency response. Utilizing 183 different generator trip events during the period of 2012-2014, the study set four goals:

1. Calculate the Inertial Frequency Response for each event.
2. Estimate the typical Inertial Frequency Response under different operating conditions (e.g., high wind/low load, high wind /high load, low wind/high load, etc.).
3. Find any identifiable trends in Inertial Frequency Response with respect to increasing levels of Wind Generation under different conditions of ERCOT:
 - a. Load
 - b. Total Generation
 - c. Wind Generation
 - d. Spinning Reserves
4. Identify the causes of different levels of inertia.

Figure 1 shows the flowchart that describes the workflow of the analysis study. The different steps in the analysis study were:

- Step 1** Identify & Collect PMU data containing frequency events (Generator trips) for three years.
- Step 2** Gather ERCOT EMS data associated with each event.
- Step 3** Gather amount of generation loss in MW from the EMS logs associated with each event.
- Step 4** Using PGDA, calculate the Inertial Frequency Response associated with each event.
- Step 5** Tabulate each event and its associated EMS data & calculated Inertial Frequency Response.
- Step 6** Calculate Variables & Derive Metrics needed for the study.

Step 7 Conduct analysis to achieve the goals for this study.**Figure 1. Analysis Work flow****4. Derived Metrics & Calculated Variables**

The following data associated with each event was collected from the ERCOT EMS:

1. Regional Wind data.
2. Regional Load data.
3. Total Generation.
4. Spinning Reserve data.
5. Total amount of Generation loss.

The variables calculated for this study are:

1. Total Online Generation = Total Generation + Spinning Reserves (MW).
2. Wind Generation = Summation of regional wind data (3 regions)
 - a. ERCOT Wind = West + North + South (MW)
3. Non-Wind Generation = Total Online Generation – Wind Generation (MW).
4. ERCOT Load = Summation of Regional load data (8 regions)

$$\text{ERCOT Load} = \text{Coast} + \text{East} + \text{Far West} + \text{North} + \text{North Central} + \text{Southern} + \text{Southern Central} + \text{West (MW)}$$

The metrics derived for this study are:

1. Percentage of Wind Generation (%) = (Wind Generation / Total Online Generation) * 100.
2. Inertial Frequency Response (MW/0.1Hz) = (Amount of Generation loss) / (F_A - F_C) * 0.1
 - a. F_A – Represents value of frequency in Hz immediately before the disturbance.
 - b. F_C – Represents the lowest value of frequency in Hz, which occurred within 12 seconds of initial disturbance.
 - c. (F_A - F_C) – Represents the Frequency Drop (Hz).

5. Inertial Frequency Response Calculation – Using PGDA

The Inertial Frequency Response Calculation for each event is calculated based on the amount of generation loss and change in frequency during the frequency event. The unit for inertial frequency response is MW/0.1 Hz.

Inertial Frequency Response = (Amount of Generation loss) / (F_A - F_C) * 0.1 (MW/0.1Hz).

- a. F_A – Represents value of frequency in Hz immediately before the disturbance.
- b. F_C – Represents the lowest value of frequency in Hz.
- c. (F_A - F_C) – Represents the Frequency change (Hz).

The frequency change calculation is automated in PGDA by identifying the start of disturbance and lowest value of frequency during the disturbance using the North American Electric Reliability Corporation (NERC) methodology. For a given period of time containing frequency event data, the event start time T(0) is determined and then F_A & F_C are calculated. The algorithm used to calculate the:

F_A – Average frequency value between T (-16) and T (-1)

F_C – Lowest frequency value within 12 seconds after T (0)

The Inertial Frequency Response is calculated for each event to study its seasonal trend over three years and its correlation with the amount of wind generation on-line during each event.

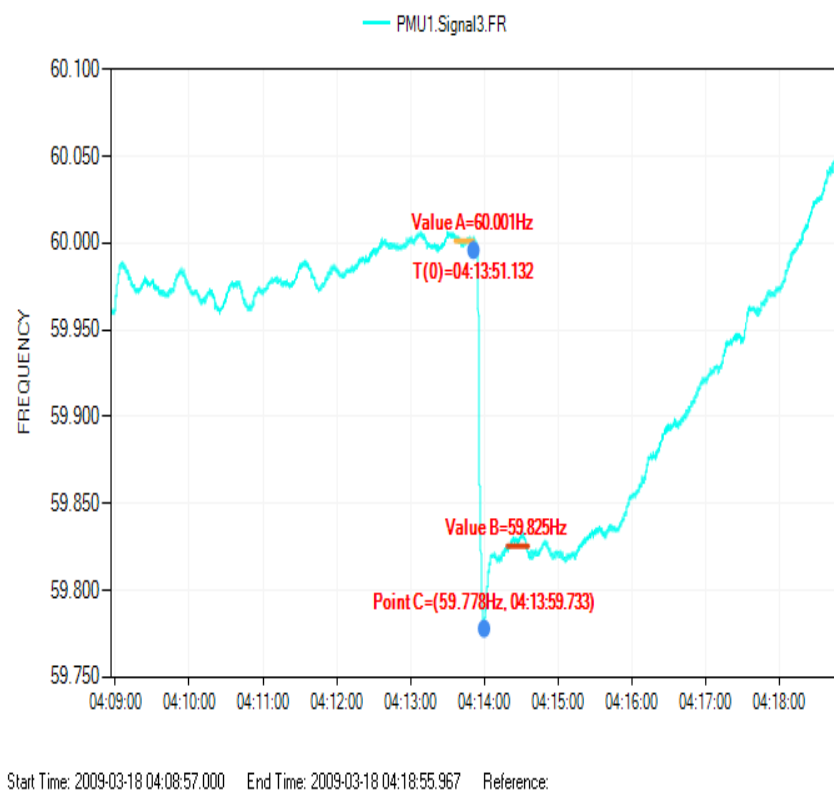


Figure 2. PGDA Event Analysis Plot

6. Inertial Frequency Response Estimation – Using Linear Relationship

The Inertial Frequency Response estimation for a group of events is done based on an assumed linear relationship between the amount of Generation Loss (MW) and the associated Frequency change (Hz). The Inertial Frequency Response is estimated from the slope of the linear regression model between the generation loss and frequency change. The linear regression model is intercepted at zero based on the assumption that there will be no change in frequency change (0 Hz) for no loss of generation (0 MW). Figure 3 shows the estimation of inertial frequency response for 2014 by grouping all 27 events. The Inertial Frequency Response for 2014 is estimated at approximately 444 MW/0.1Hz. Figures A-1 & A-2 in the Appendix shows the estimation of Inertial Frequency Response for 2012 & 2013 respectively.

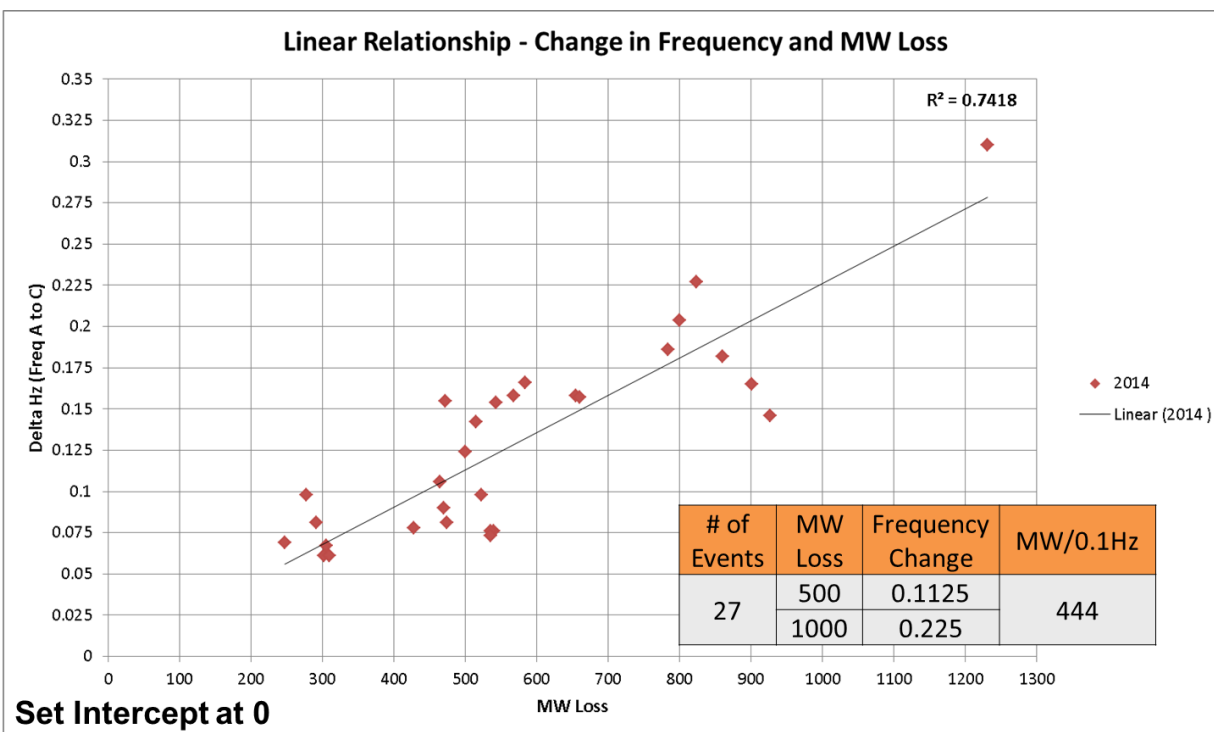


Figure 3. Estimation of Inertial Frequency Response – 2014

The above technique was used to estimate the inertial frequency response at:

1. Different levels of wind generation.
2. Different levels of load.

And to assess:

1. If there is any decline in inertial frequency response with increasing levels of wind.
2. If the above statement is true, is the decline the same or different at High load and Low Load conditions.

7. Decline in Inertial Frequency Response During High Wind Generation

The estimation of inertial frequency response using a linear relationship was applied to different levels of wind generation. Figure 4 shows the estimation of inertial frequency response for 2014 under two levels of wind penetration (percentage of wind generation to total on-line generation) without filtering on different load conditions. The two levels of wind penetration chosen were:

1. $\leq 10\%$
2. $> 10\%$

There appears to be clear evidence of a decline in inertial frequency response by 40 MW/0.1Hz as the wind penetration increases. But there can be other variables in the grid reducing the inertial frequency response such as load conditions, or the amount of Non-Wind Generation. Hence the hypothesis that there is a decline in inertial frequency response when wind penetration increases needs to be validated against different loading conditions in the grid.

The next section identifies different loading conditions and examines the relationship between inertial frequency response and various levels of wind generation.

Figures A-3 and A-4 in the Appendix show the estimation of inertial frequency response for 2012 and 2013.

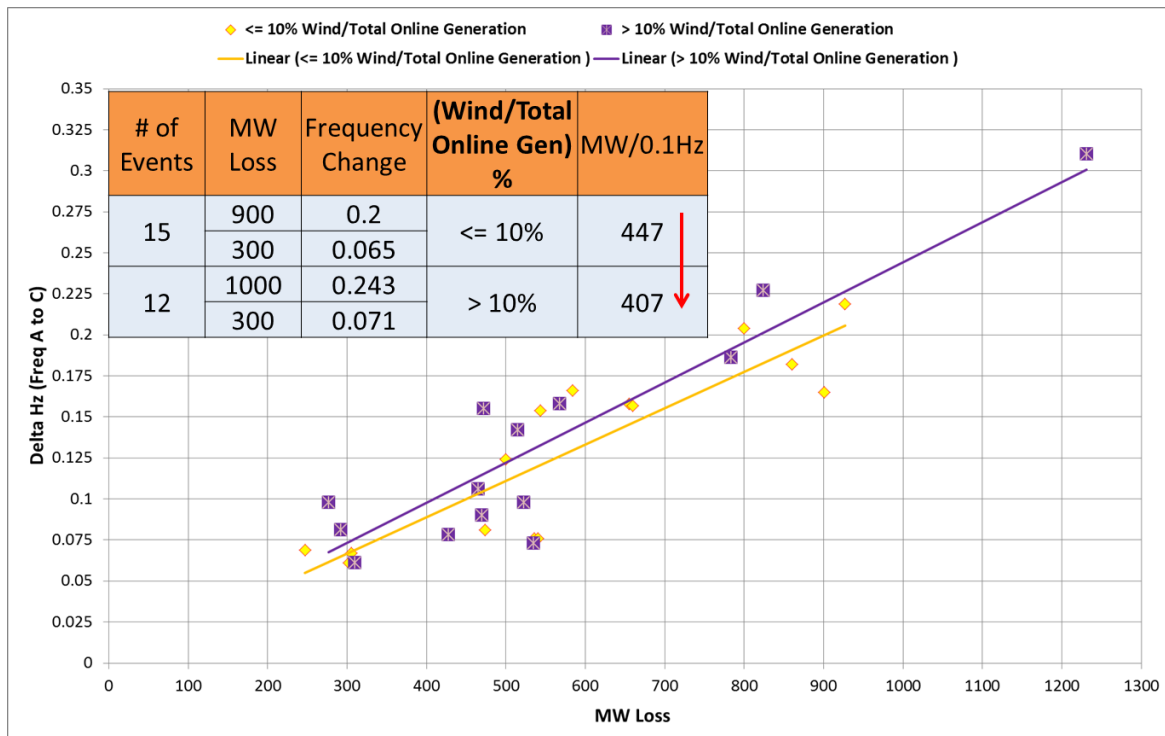


Figure 4. Estimation of Inertial Frequency Response (Two Wind Levels & No Load Levels) – 2014

8. Inertial Frequency Response Estimation – Under Operating Conditions

The load duration curve for 2012 was used to identify the loading conditions which would reasonably divide high vs. low load. Figure 5a shows the ERCOT load duration curve for 2012, and identifies the median load at 50% of the year to be approximately 35,000 MW. The load duration curve was leveraged to identify other loading conditions such as:

1. Load < 30,000 MW.

2. Load > 35,000 MW.
3. Load > 40,000 MW.

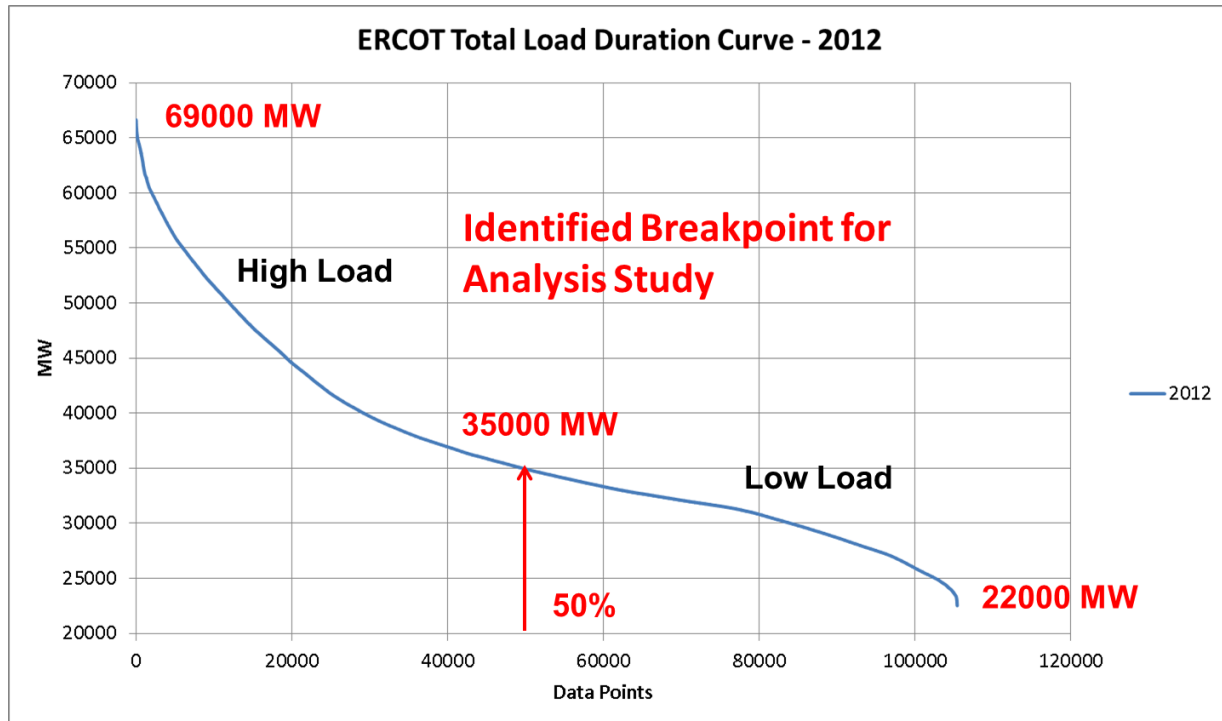


Figure 5a. Load Duration Curve – 2012

Figure 5b shows an example of estimating inertial frequency response for 2014 with load less than 35 GW using four different levels of wind generation. The events for this case were divided into four different levels of wind generation, and using the linear relationship between generation and frequency change, inertial frequency response was estimated under each level of wind. It is interesting to note that even though inertial frequency response showed an overall decline with increasing wind generation, it was relatively insensitive to changes in wind generation below 15%, and to changes in wind generation greater than 15% (the inertial response dropped above 15%, but remained constant as generation exceeded 20%). This suggests that the percentage of wind generation without consideration of different loading conditions may not be the most useful metric.

Similarly inertial frequency response was estimated for several loading conditions with different levels of wind generation as shown in Figure 6. Figure 6 suggests that at high levels of load (e.g., above 40 GW), increasing wind generation above 10% has little impact on inertial frequency response, while the same increase in wind generation seems to reduce inertial response at lower load levels. The inertial frequency response remained unchanged under:

1. Different levels of wind generation when load > 40 GW.

2. When Load > 35 GW and wind penetration is less than 10%.
3. When load < 35GW and wind penetration is less than 16%.

Figures A-5 to A-17 in the Appendix contains estimations of inertial frequency response under different loading conditions and different levels of wind generation for 2012, 2013 & 2014.

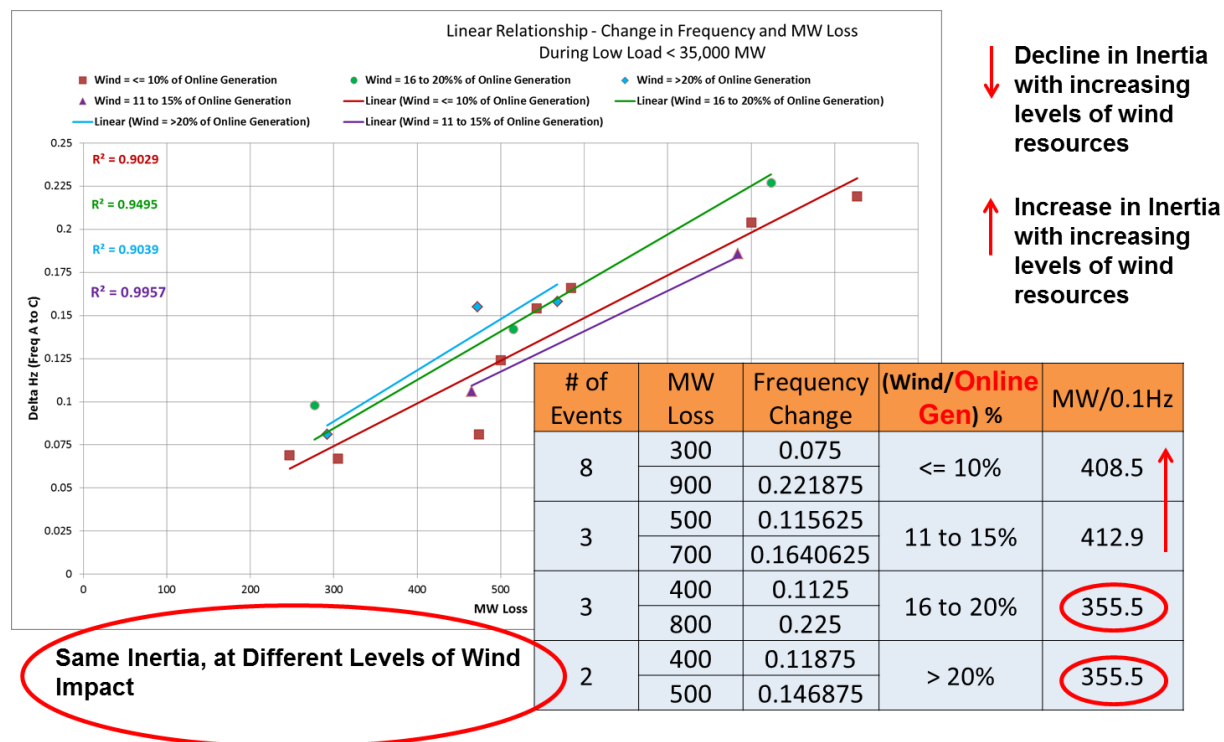


Figure 5b. Estimation of Inertial Frequency Response (Four Wind Levels & Load < 35GW) – 2014

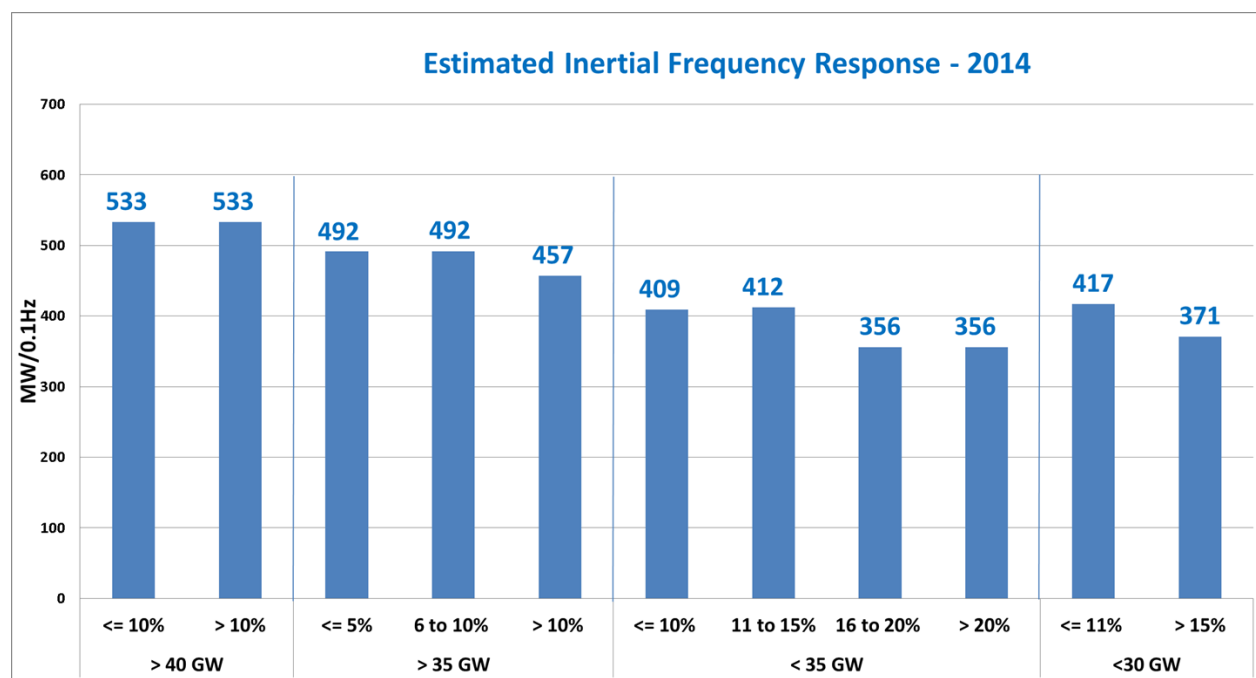


Figure 6. Estimation of Inertial Frequency Response (Different Wind Levels & Load Levels) – 2014

9. Wind Generation – No Contribution to Inertial Frequency Response

This section of the report provides four illustrative scenarios to support a conclusion that wind generation does not contribute to inertial frequency response. The four scenarios are:

1. Inertial Frequency Response vs. Wind Pattern.
2. Inertial Frequency Response vs. Non-Wind Generation On-Line.
3. Inertial Frequency Response vs. Different Operating Conditions.
4. Wind Output vs. Frequency change (PMU Data).

1. Inertial Frequency Response Vs. Wind Pattern:

The calculated inertial frequency response for each event and the percentage of wind generation was compared to examine the relationship between them. Figures 7, 8 & 9 show the seasonal trends of inertial frequency response and percentage of wind generation for each generator loss event in all three years. The seasonal trend of inertial frequency response remained the same in all three years. The pattern of inertial frequency response was high in summer, low in winter, rising and falling during spring and fall, respectively in all three years. The Pattern of Inertial Frequency Response remained the same even at different levels of wind penetration in all seasons, illustrating no relationship between them. The relationship between inertial frequency

response and wind generation was inverse in 2012, linear in 2013 and close to inverse in 2014 (first six months of 2014). The generation loss events occurred at different times during the day, and that had different levels of wind generation from year to year. Collectively, this illustrates that there is no simple relationship between inertial frequency response and the level of wind generation.

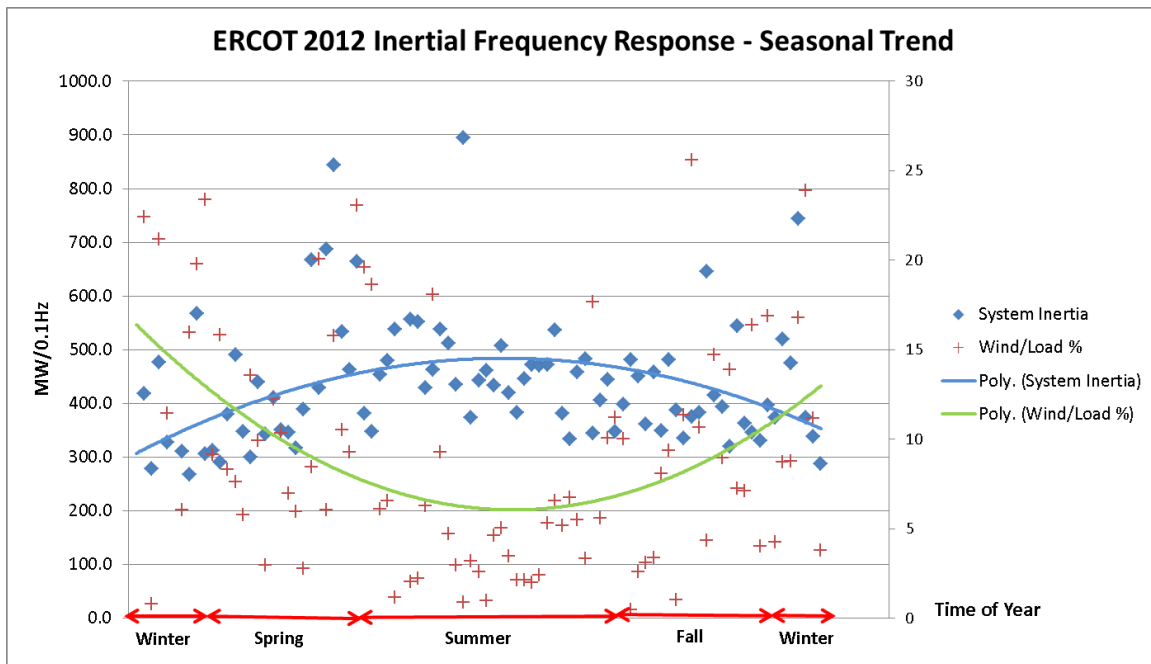


Figure 7. Seasonal Trend of ERCOT Inertial Frequency Response & Percentage of Wind Generation – 2012

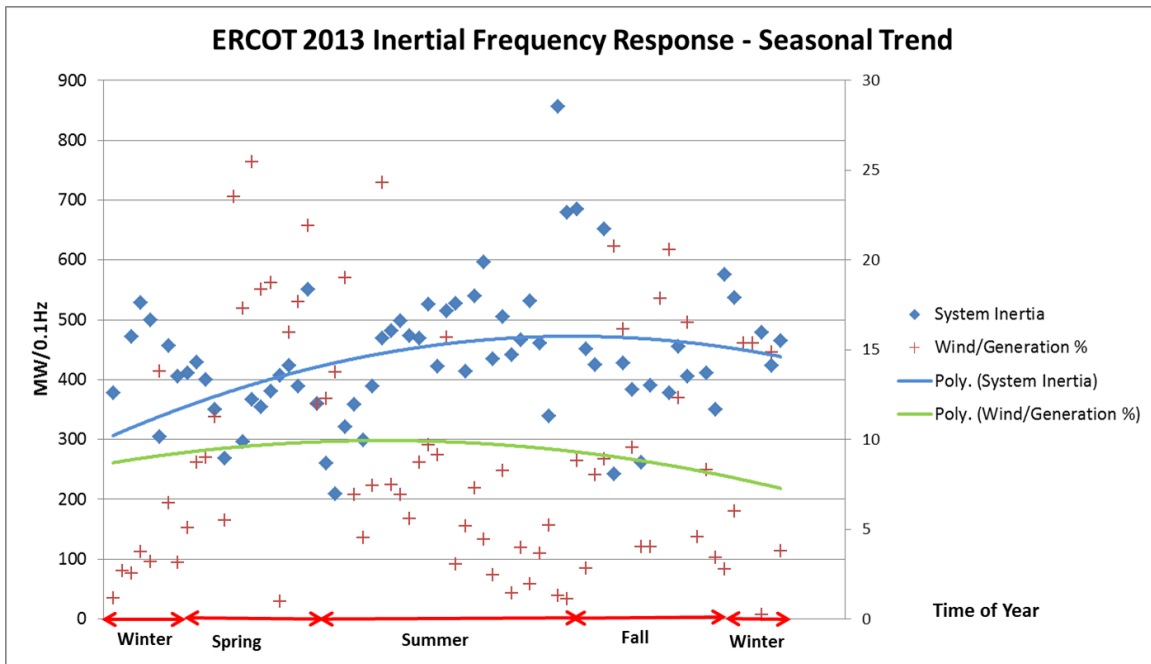


Figure 8. Seasonal Trend of ERCOT Inertial Frequency Response & Percentage of Wind Generation – 2013

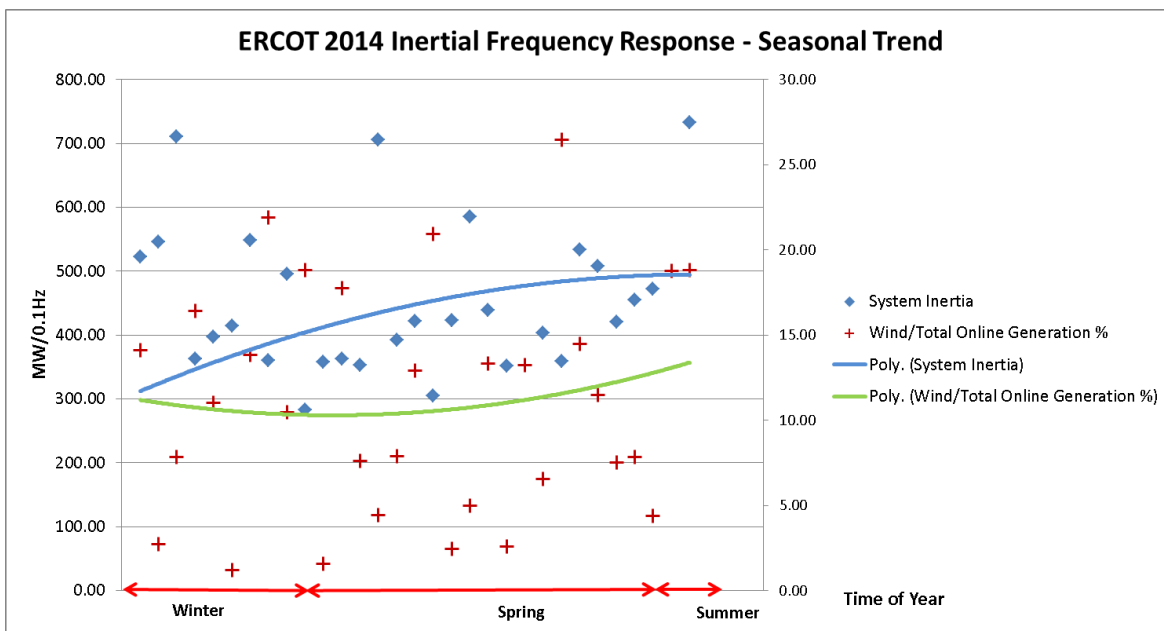


Figure 9. Seasonal Trend of ERCOT Inertial Frequency Response & Percentage of Wind Generation – 2014

2. Inertial Frequency Response Vs. Non-Wind Generation On-Line

The relationship between the calculated inertial frequency response for each event and the Non-Wind generation was then examined. Figure 10 shows that the relationship between Inertial Frequency Response and Non-Wind Generation on-line is both linear and positively correlated, suggesting a strong relationship. The Non-Wind Generation on-line is the sum of Total ERCOT Generation plus Spinning Reserves minus Wind Generation. Because the recorded level of spinning reserve was only available for 2014, this analysis could not be completed on 2012 and 2013 data.

The relationship between Inertial Frequency Response and Wind Generation as shown in Figure 11 is relatively flat illustrating no significant contribution from wind generation and no impact with different levels of wind penetration.

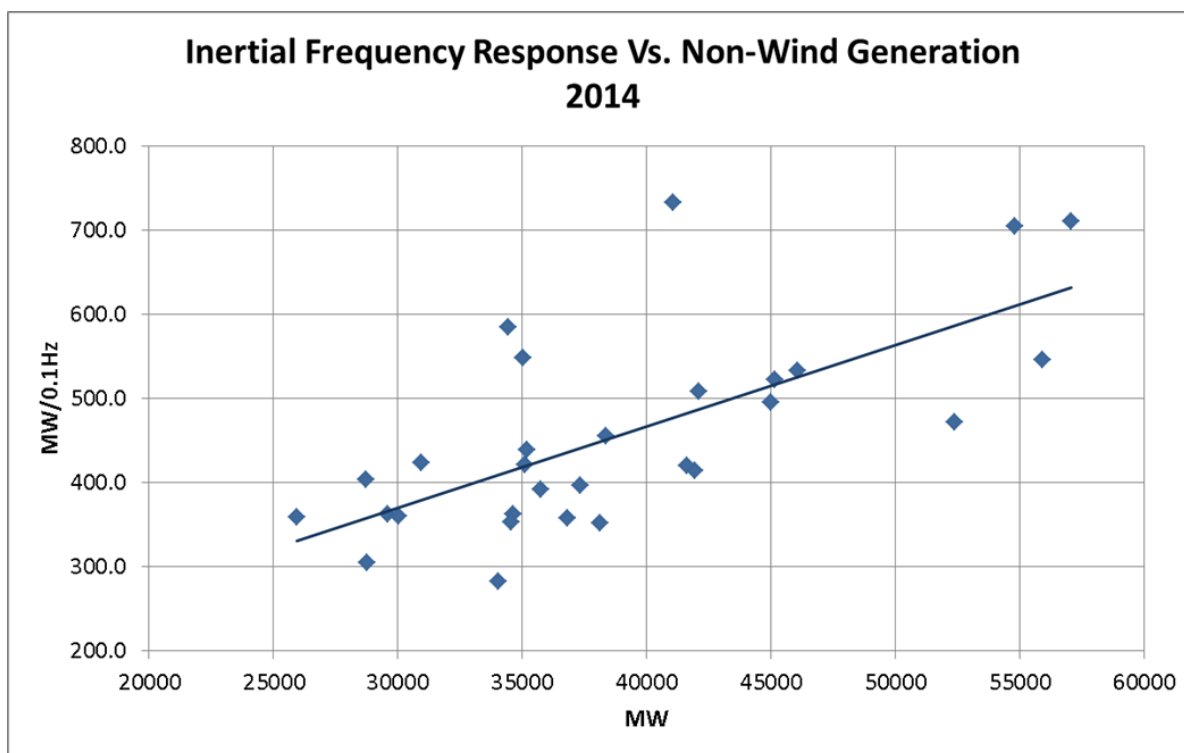


Figure 10. Linear Relationship (Inertia Proportional to Non-Wind Generation) – 2014

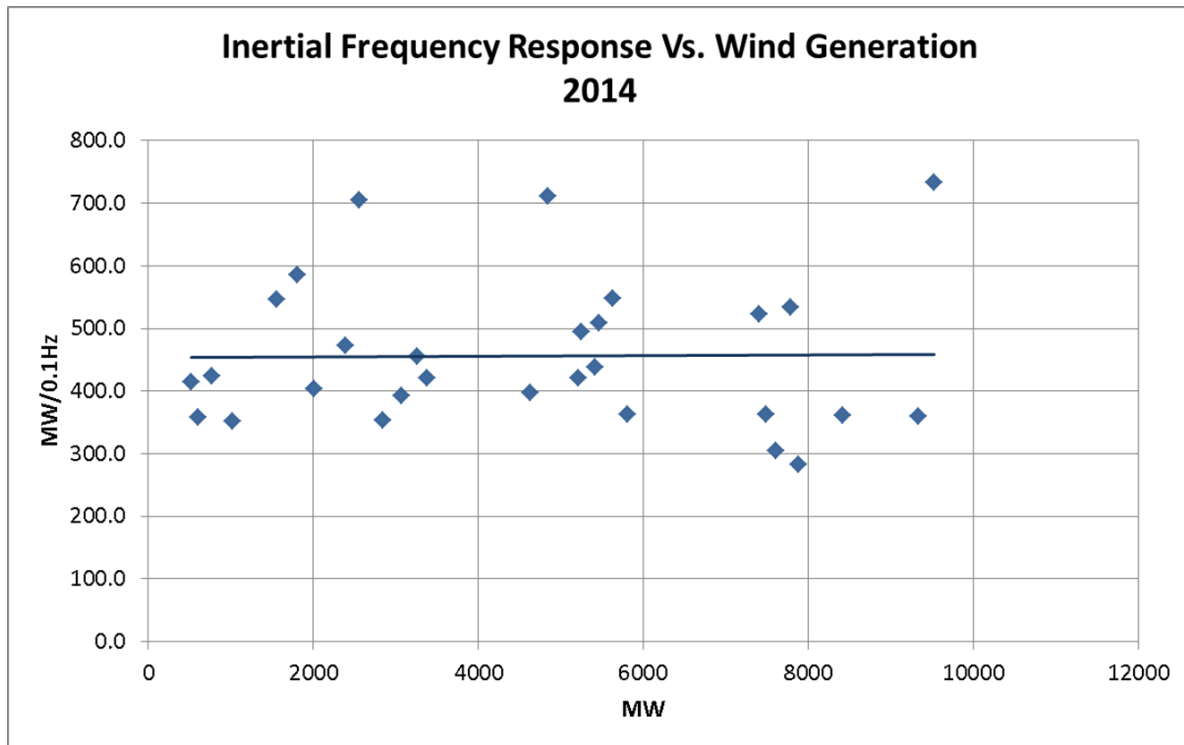


Figure 11. Wind Generation showing no contribution to Inertial Frequency Response – 2014

3. Inertial Frequency Response Vs. Different Operating Conditions

The Inertial Frequency Response for a group of events was estimated based on a linear regression between the amount of Generation loss and the associated Frequency drop. The Inertial Frequency Response was estimated for different conditions of ERCOT Load and levels of wind generation for 2014 as show in Figure 6. The different levels of wind generation were determined based on the availability and occurrence of actual generator loss events.

There is partly clear evidence of no change in inertial frequency response with increasing levels of wind generation as explained in the previous section. There is also evidence of a decline in inertia with increasing wind generation which is likely due to wind generation displacing Non-Wind Generation.

The inertial frequency response declined with increasing levels of wind generation under the following conditions:

1. When load < 30 GW and wind penetration is greater than 15%.
2. When load < 35GW and wind penetration is greater than 15%.
3. When Load > 35GW and wind penetration is greater than 10%.

Figure 12 illustrates the first two cases, showing the Minimum, Maximum and Average Non-Wind Generation for different levels of wind generation for both low and high load conditions. The Average Non-wind generation is the mean for the grouped events. As there is a decline in inertial frequency response with increasing wind generation, there is also a decline or decrease in Average Non-wind generation, reducing the rotating mass available to sustain the level of inertial response.

This suggests that as the penetration (percent of total energy production) of wind generation increases, non-wind generation is displaced off-line, thus reducing the rotating inertia available to support the grid during frequency events (such as loss of a generator). When the non-wind generation is retained on-line (e.g., as spinning reserve), the inertial frequency response remains higher.

The decline in inertial frequency response may not be exactly proportional to the level of non-wind generation because different types of generation have different levels of inertia contribution. Steam and gas turbines have much higher inertia constants (MWs-seconds per MW) than do hydro units. The mix of non-wind generation on-line during an event will have an impact on the inertial frequency response, and affect the linearity of the relationship between the level of non-wind generation and inertial response. Unfortunately, the data needed to estimate the connected inertia was not available to test the linearity of the relationship.

| # of Events | MW Loss | Frequency Change | (Wind/Online Gen) % | MW/0.1Hz | Min Non-Wind Gen (MW) | Max Non-Wind Gen (MW) | Average Non-Wind Gen (MW) |
|-------------|---------|------------------|---------------------|----------|-----------------------|-----------------------|---------------------------|
| 8 | 300 | 0.075 | <= 10% | 408.5 | 28708 | 38364 | 34712 |
| | 900 | 0.221875 | | | | | |
| 3 | 500 | 0.115625 | 11 to 15% | 412.9 | 35062 | 35173 | 35116 |
| | 700 | 0.1640625 | | | | | |
| 3 | 400 | 0.1125 | 16 to 20% | 355.5 | 29585 | 34648 | 32752 |
| | 800 | 0.225 | | | | | |
| 2 | 400 | 0.11875 | > 20% | 355.5 | 25924 | 30018 | 28232 |
| | 500 | 0.146875 | | | | | |

| # of Events | MW Loss | Frequency Change | (Wind/Online Gen) % | MW/0.1Hz | Min Non-Wind Gen (MW) | Max Non-Wind Gen (MW) | Average Non-Wind Gen (MW) |
|-------------|---------|------------------|---------------------|----------|-----------------------|-----------------------|---------------------------|
| 2 | 600 | 0.14375 | <= 10% | 417.3 | 28708 | 30936 | 29822 |
| | 900 | 0.215625 | | | | | |
| 2 | 568 | 0.158 | > 20 % | 371 | 25924 | 29585 | 27754 |
| | 824 | 0.227 | | | | | |

Figure 12. Decline in Inertia at Low Load & High Wind (For the Reason that Non-Wind Generation is Lower) – 2014

4. Wind Output vs. Frequency Change (PMU Data)

The existing PMUs located nearby wind and non-wind generators were used to check if there was any observable inertial contribution during the frequency events. Inertial contribution from generators would be indicated, by an increase in power output coincident, with the frequency drop caused by a generator trip event. An analysis of the synchrophasor data from selected PMUs was performed to study, if there is any **change in power output** from different types of generators **coincidental with drop in frequency** following a generation trip.

The analysis was completed for several events under different scenarios as shown in Figure 13. Twenty seven (27) events spanning two years (2012-2013) were selected to examine different event scenarios and different system conditions to identify whether wind generation was observed to contribute to inertial frequency response. Events were categorized into four different scenarios:

1. Generation loss of more than 1000 MW.
2. Generation loss when load was low and wind production was high.
3. Generation loss when load was high and wind was high.
4. Generation loss during the months of October-December.

Examining the 27 different events, it was observed that there was **“no significant”** increase in power change coincidental with the frequency drop for each of the events from the **wind plants**, indicating no inertia contribution to the grid. However, an **“increase in power change”** was observed, coincidental during the frequency drop, from **non-wind units** indicating inertial response from rotating mass. The changing levels of inertial frequency response appear to be driven primarily by the amount of Non-Wind Generation online.

| Year | Event Scenarios | Conditions | Count of Events |
|------|-----------------------|----------------|-----------------|
| 2012 | Generation Loss | > 1000 MW | 4 |
| | Low Load & High Wind | <35 GW & > 16% | 4 |
| 2013 | Generation Loss | > 1000 MW | 3 |
| | Low Load & High Wind | <35 GW & > 10% | 11 |
| | High Load & High Wind | >35 GW & > 16% | 2 |
| | October – December | > 35GW & > 6% | 3 |
| 2 | 4 | 5 | 27 |

Figure 13. Event Scenarios & Count of Events – Wind Output vs. Frequency Range (PMU data)

Figure 14 shows an example of PMU data, located close to wind units and non-wind units, during a frequency event. Using the PGDA tool, the Real Power was calculated from Voltage and Current phasors from each of the selected PMUs and De-trended by first value to more clearly illustrate the change in power output during the frequency drop. The lower plot illustrates the grid frequency drop following the loss of generation. The upper plot illustrates:

1. A change in power flow (increase) is very clear in Non-Wind units at **West 11**, **FarWest 7** and **North 1**.
2. No significant change in power flow in the transmission lines near Wind Generation at **FarWest 4**, **West 10**, **West 6**.

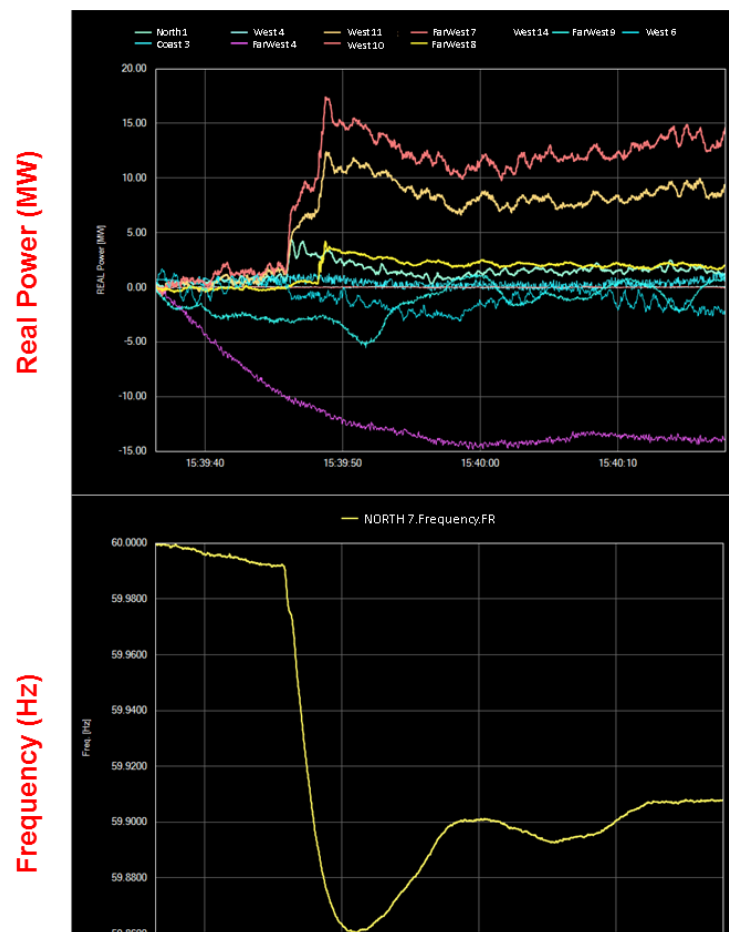


Figure 14. Example of No Inertia from Wind Plants Using PGDA – Wind Output Vs. Frequency Range (PMU data)

Taken together, the four different analysis scenarios presented above provide sufficient evidence to conclude that wind generation does not contribute to inertial frequency response.

10. Conclusion

The analysis study used 183 generator trip frequency events, collected on the ERCOT grid over three years (2012-2014) to investigate the impact of wind generation on inertial frequency response. Inertial Frequency Response was calculated for each individual event using PGDA and estimated for different operating conditions using a linear relationship between the amount of generation loss and the corresponding first swing frequency drop. For this analysis study, ERCOT Load, ERCOT Generation, ERCOT Wind Generation, ERCOT Spinning Reserves and Phasor Measurement Units (PMU) data located nearby wind units were collected and analyzed to understand the variation and trend in inertial frequency response. The analysis examined four different illustrative scenarios to evaluate whether Wind generation contributes to inertial frequency response.

Some of the key highlights of the findings from the illustrative scenarios that reflect no contribution of wind generation to inertial frequency response are:

1. **Inertial Frequency Response Vs. Wind Pattern** - The Seasonal Trend of inertial frequency response remained the same even at different levels of wind penetration indicating no relationship between inertial response and wind penetration.
2. **Inertial Frequency Response Vs. Non-Wind Generation** - Inertial Frequency Response and Non-Wind Generation had a strong positive correlation suggesting inertia is proportional to Non-Wind Generation.
3. **Inertial Frequency Response Vs. Different Operating Conditions** - The instances of decline in inertial frequency response with higher wind generation were found to have lower Non-Wind Generation.
4. **Wind Output Vs. Frequency Change (PMU Data)** - There was no significant increase in power output coincidental with frequency drop for each of the frequency events from the wind plants under different conditions, indicating no inertia contribution from the wind plants.

The four different analyses provided evidence that wind generation provides no contribution to inertial frequency response. The inertial frequency response is driven (primarily) by the amount of non-wind generation available online.

To maintain a minimum level of Inertial Frequency Response on the grid, ERCOT operations will need to commit a minimum level of non-wind generation online under all conditions.

Example: Maintaining an adequate level of Inertial Frequency Response (450MW/0.1Hz) for reliable operation of grid would require ERCOT to commit Minimum Non-Wind Generation (35,000 MW) under all conditions (e.g., under frequency load shedding coordination).

11. Appendix

Inertial Frequency Response Estimation – Using Linear Relationship

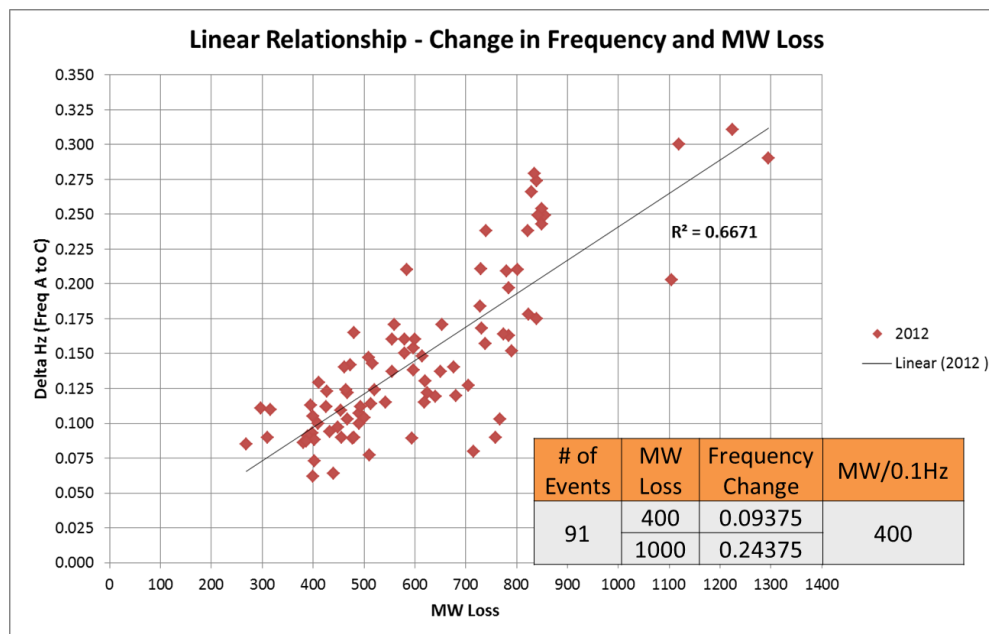


Figure A-1. Estimation of Inertial Frequency Response – 2012

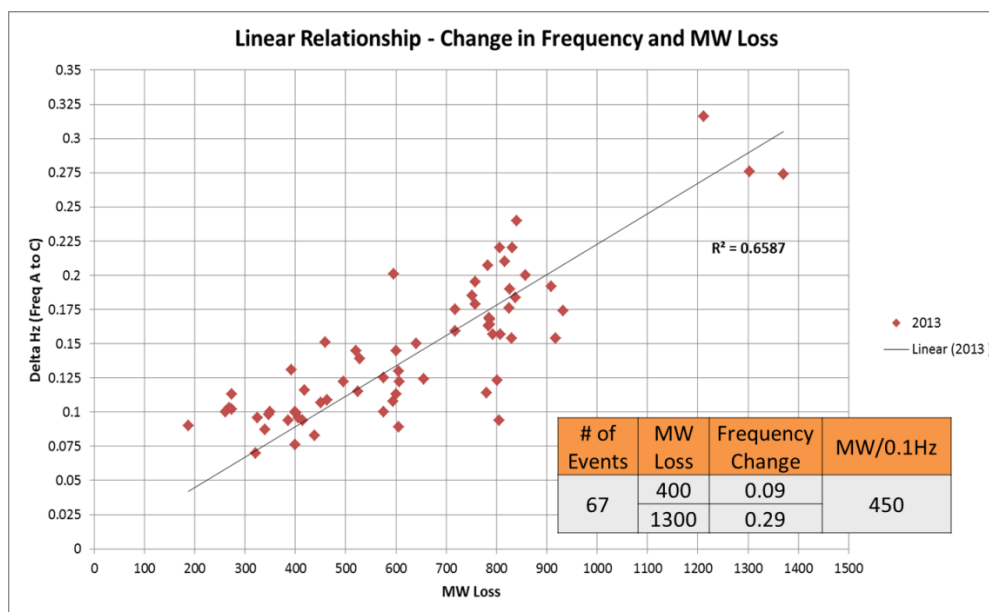


Figure A-2. Estimation of Inertial Frequency Response – 2013

Hypothesis – Decline in Inertial Frequency Response

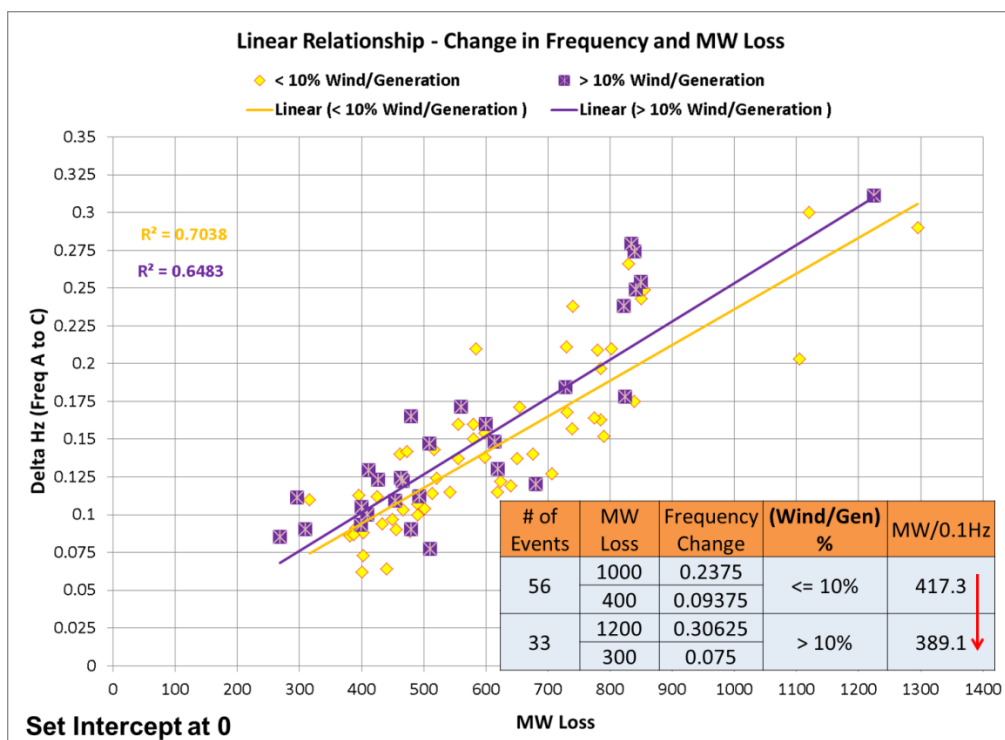


Figure A-3. Estimation of Inertial Frequency Response (Two Wind Levels & No Load Levels) – 2012

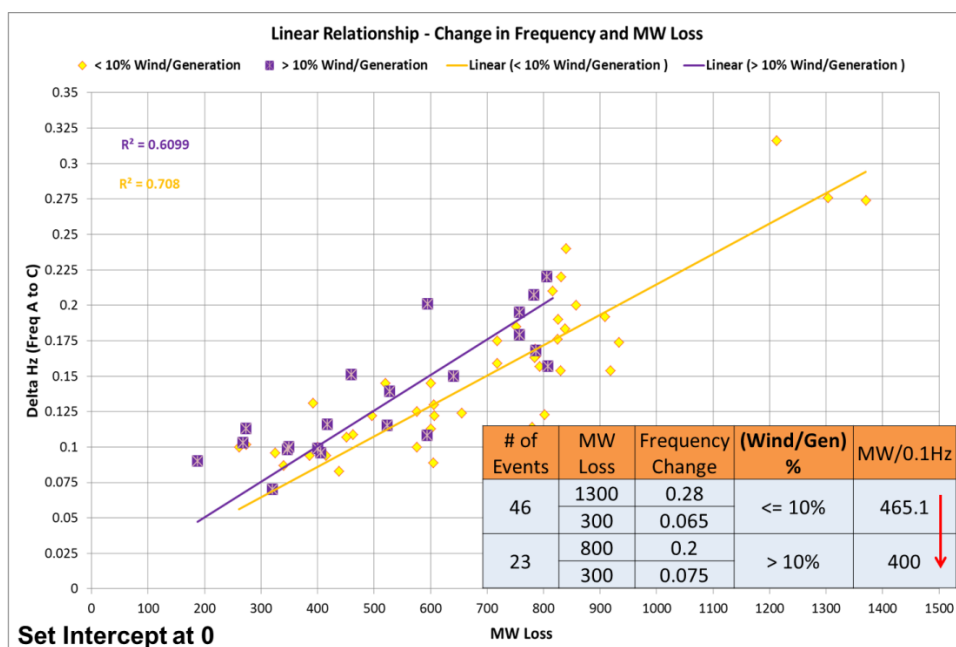


Figure A-4. Estimation of Inertial Frequency Response (Two Wind Levels & No Load Levels) – 2013

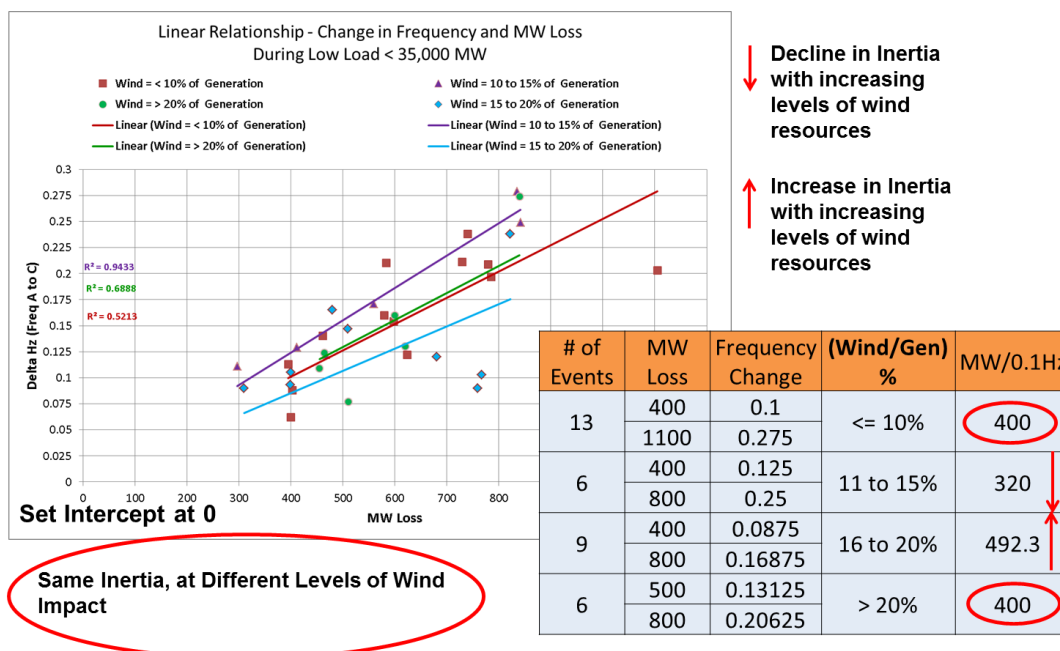


Figure A-5. Estimation of Inertial Frequency Response (Four Wind Levels & Load <35 GW) – 2012

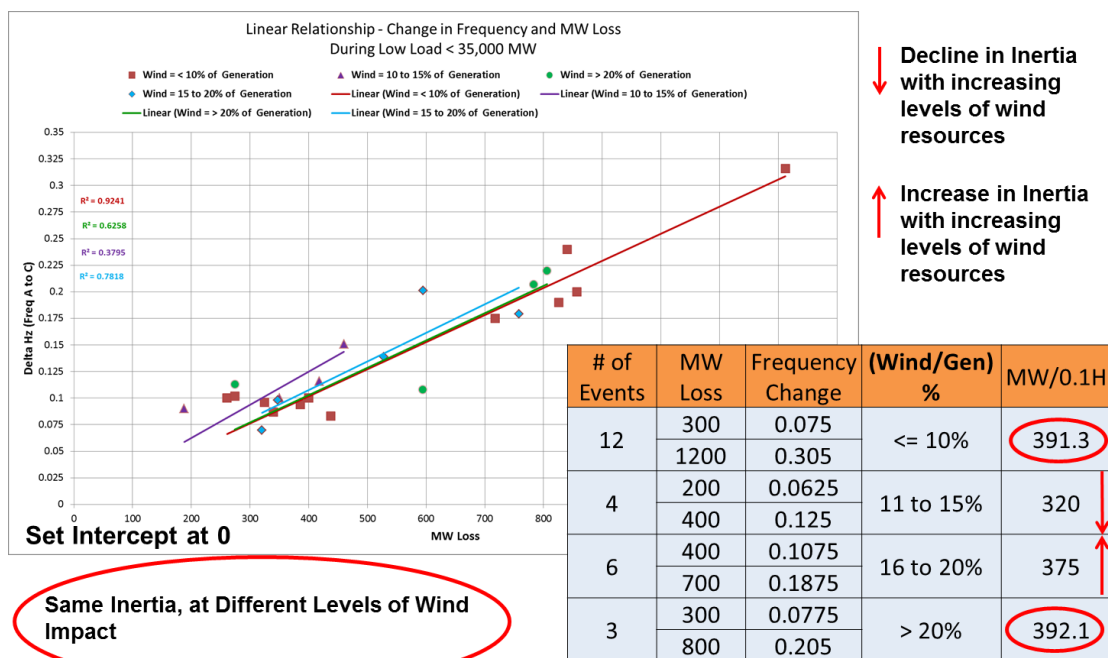


Figure A-6. Estimation of Inertial Frequency Response (Four Wind Levels & Load <35 GW) – 2013

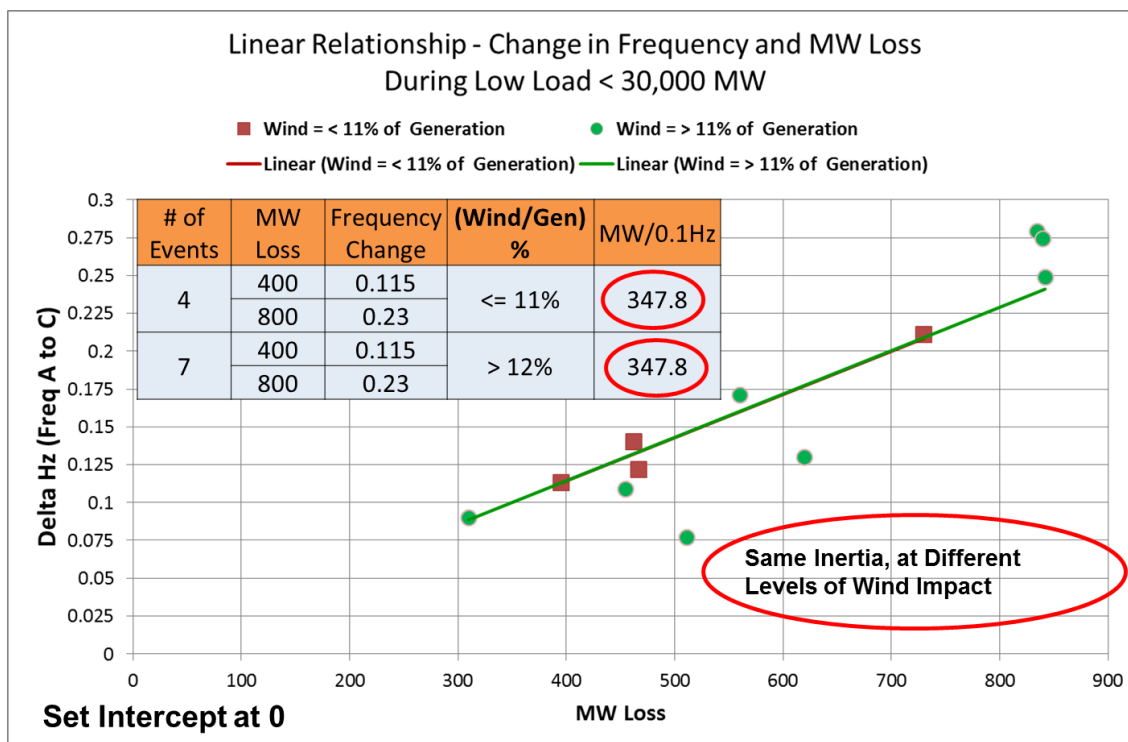


Figure A-7. Estimation of Inertial Frequency Response (Two Wind Levels & Load <30 GW) – 2012

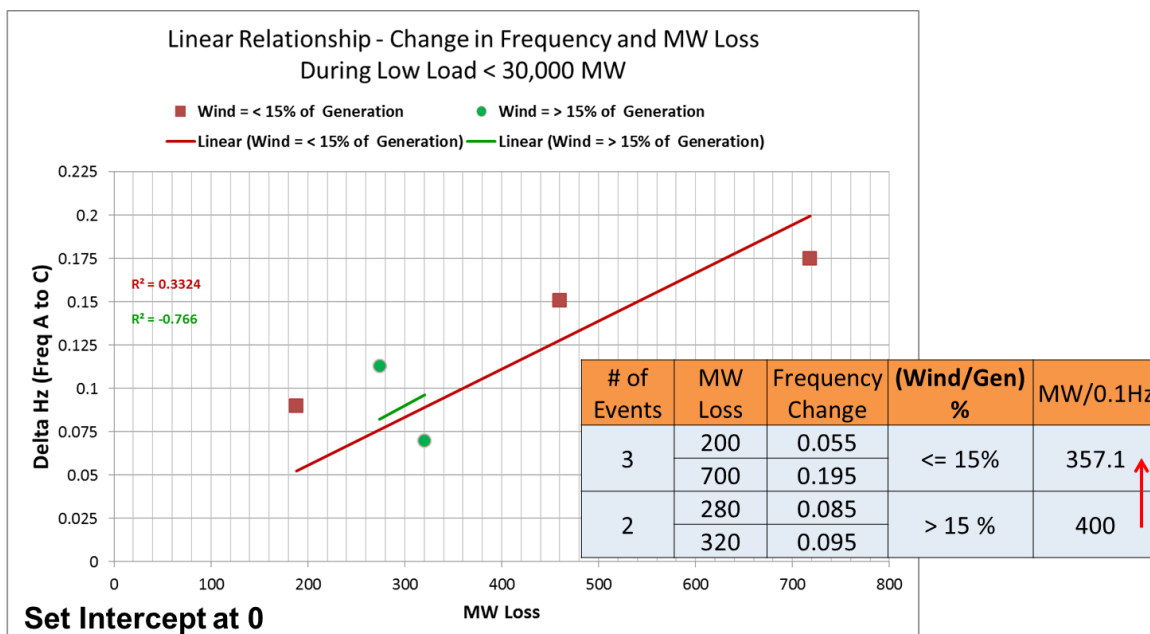


Figure A-8. Estimation of Inertial Frequency Response (Two Wind Levels & Load <30 GW) – 2013

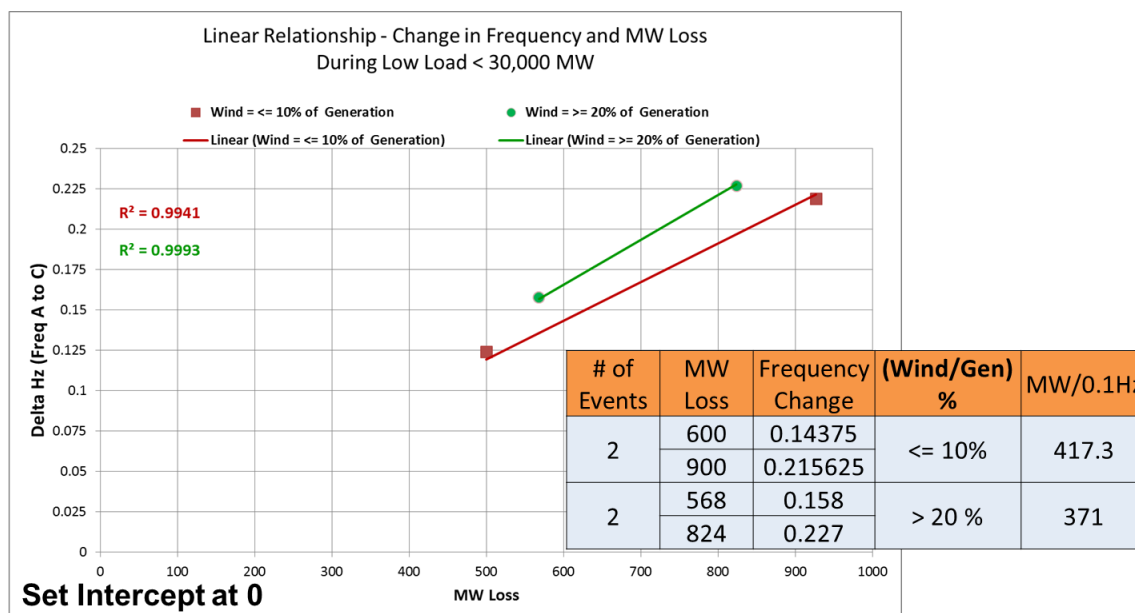


Figure A-9. Estimation of Inertial Frequency Response (Two Wind Levels & Load <30 GW) – 2014

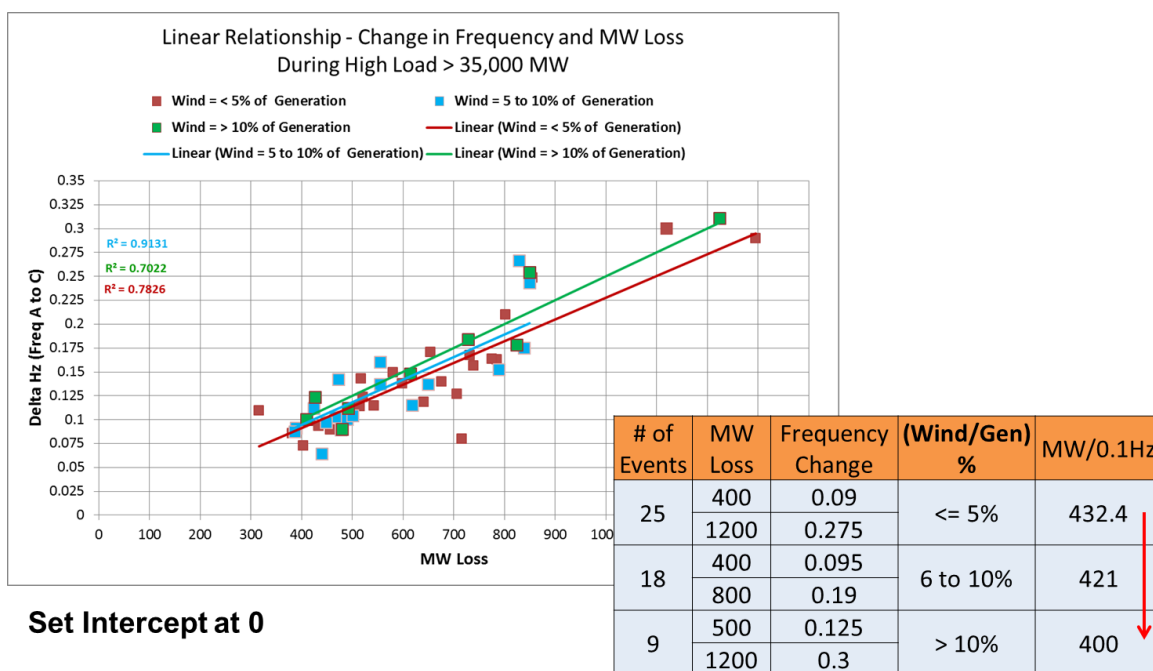


Figure A-10. Estimation of Inertial Frequency Response (Three Wind Levels & Load >35 GW) – 2012

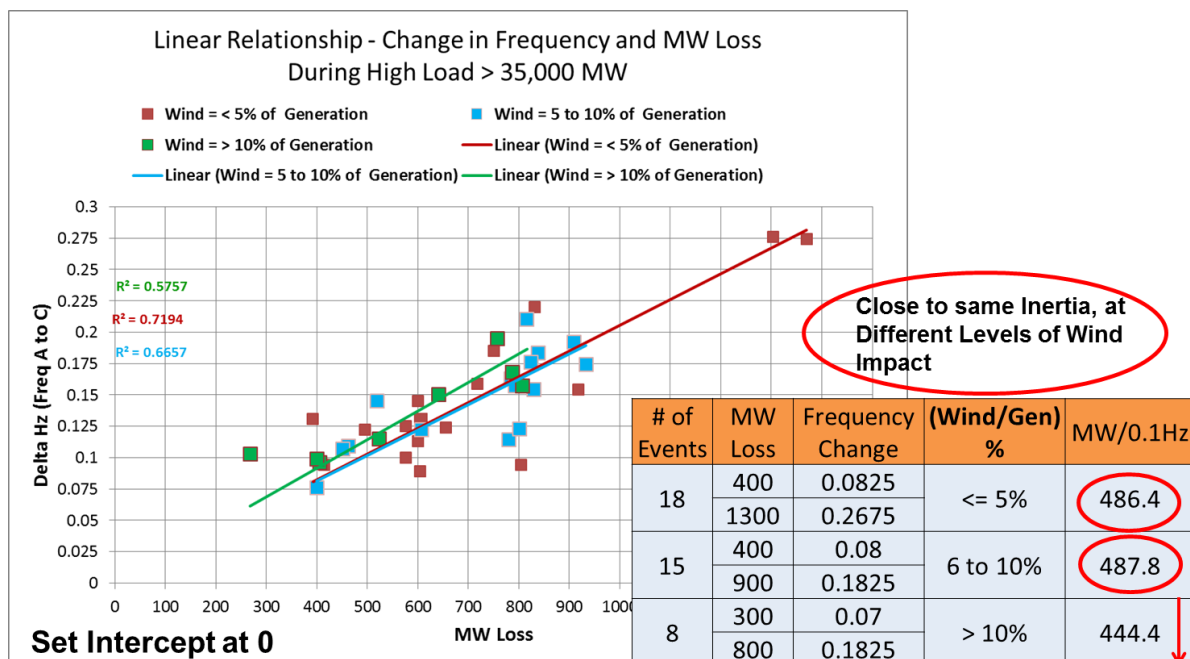


Figure A-11. Estimation of Inertial Frequency Response (Three Wind Levels & Load >35 GW) – 2013

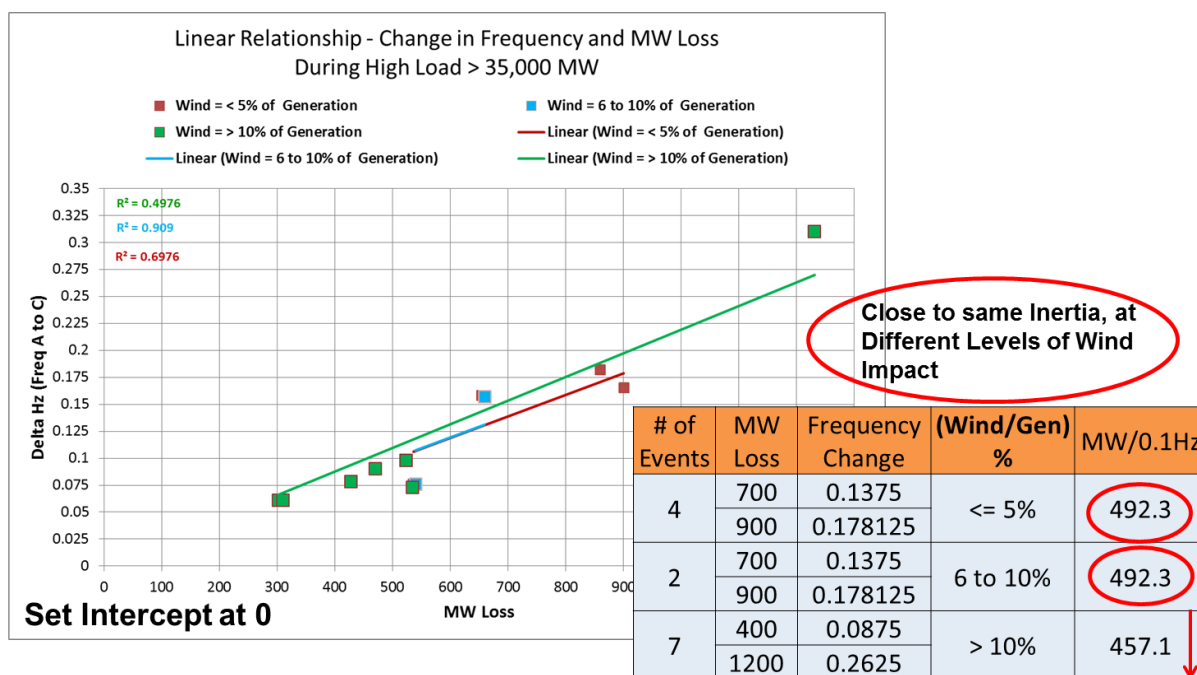


Figure A-12. Estimation of Inertial Frequency Response (Three Wind Levels & Load >35 GW) – 2014

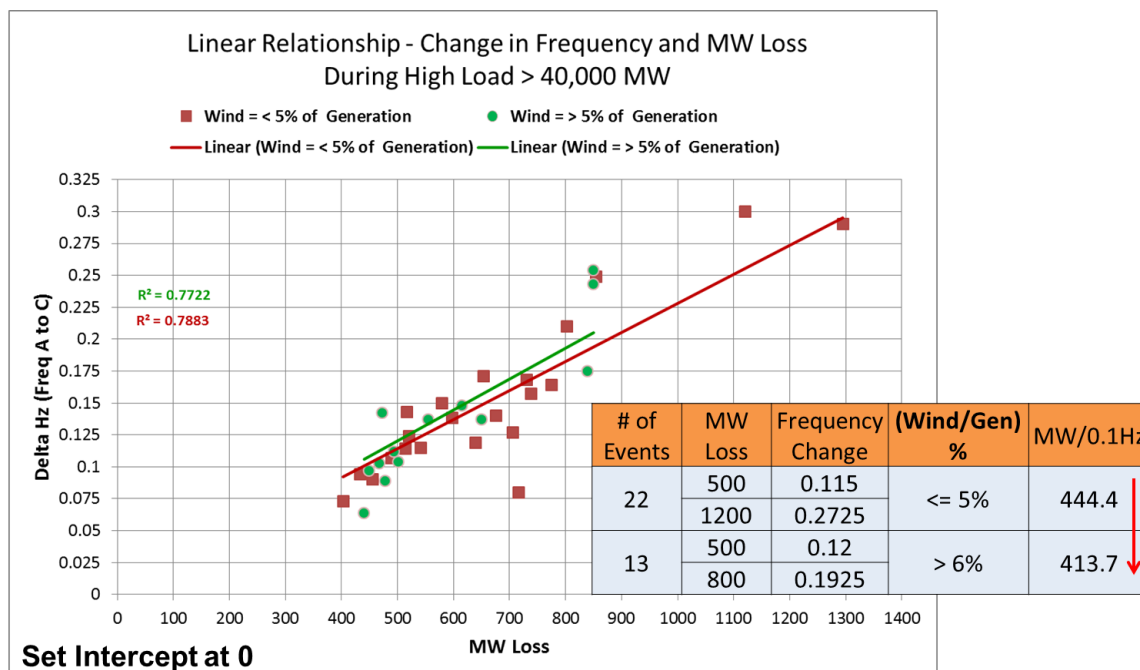


Figure A-13. Estimation of Inertial Frequency Response (Two Wind Levels & Load >40 GW) – 2012

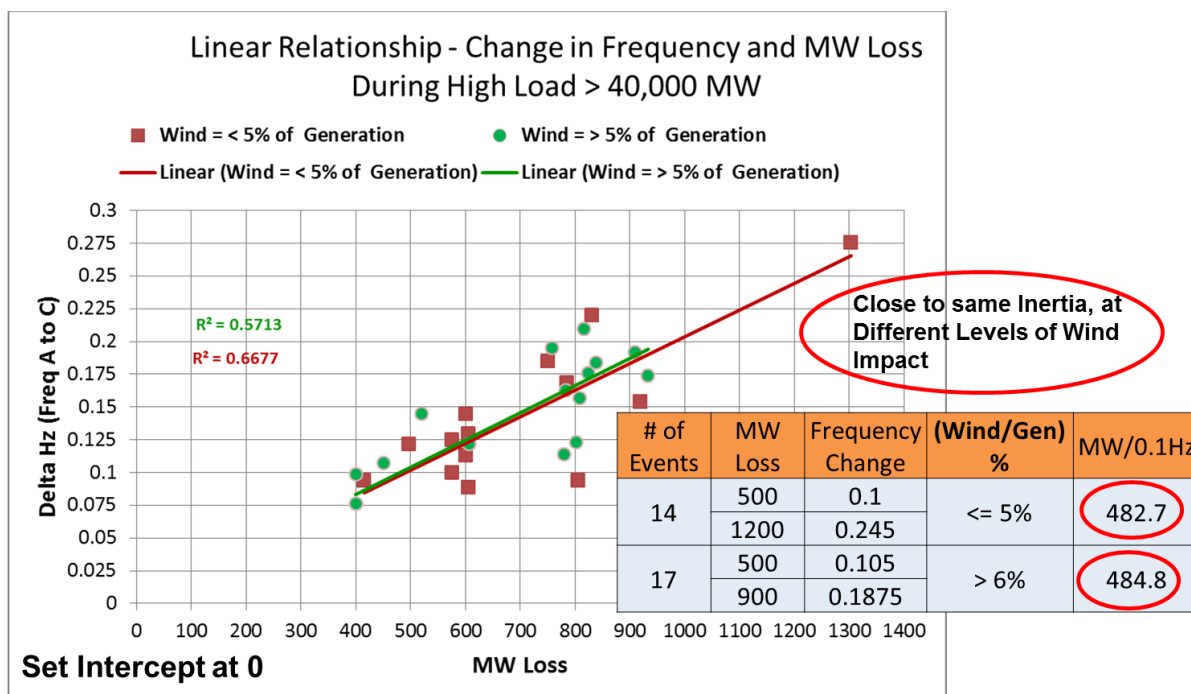


Figure A-14. Estimation of Inertial Frequency Response (Two Wind Levels & Load >40 GW) – 2013

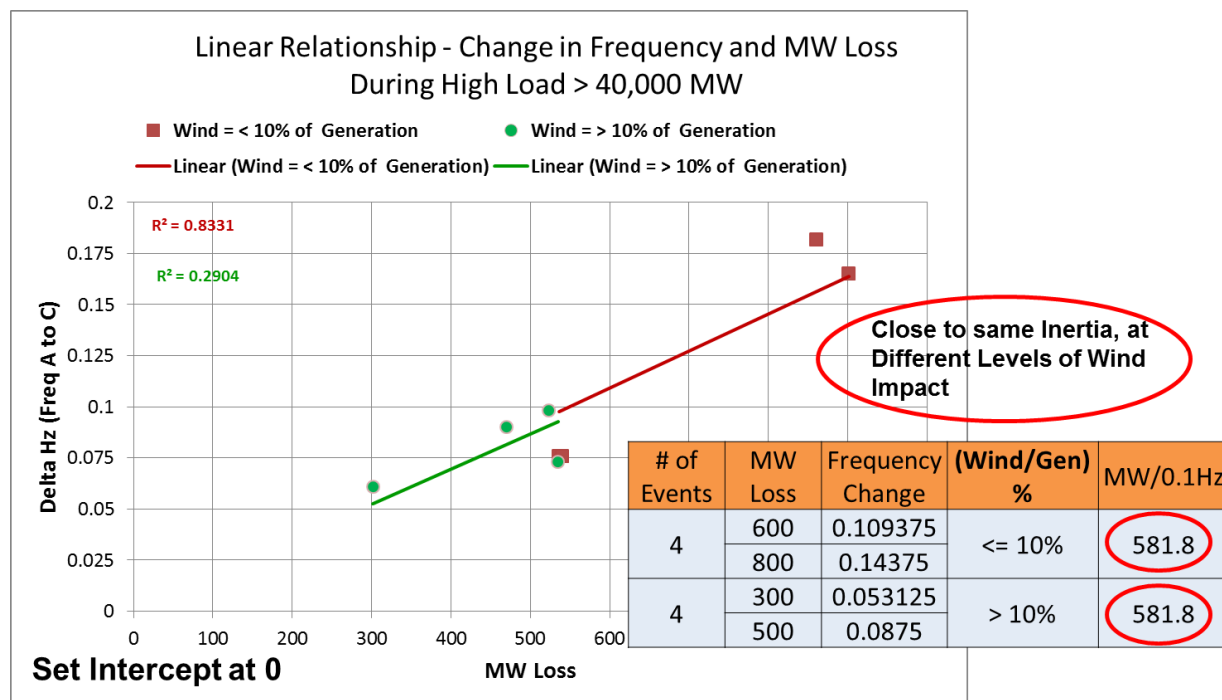


Figure A-15. Estimation of Inertial Frequency Response (Two Wind Levels & Load >40 GW) – 2014

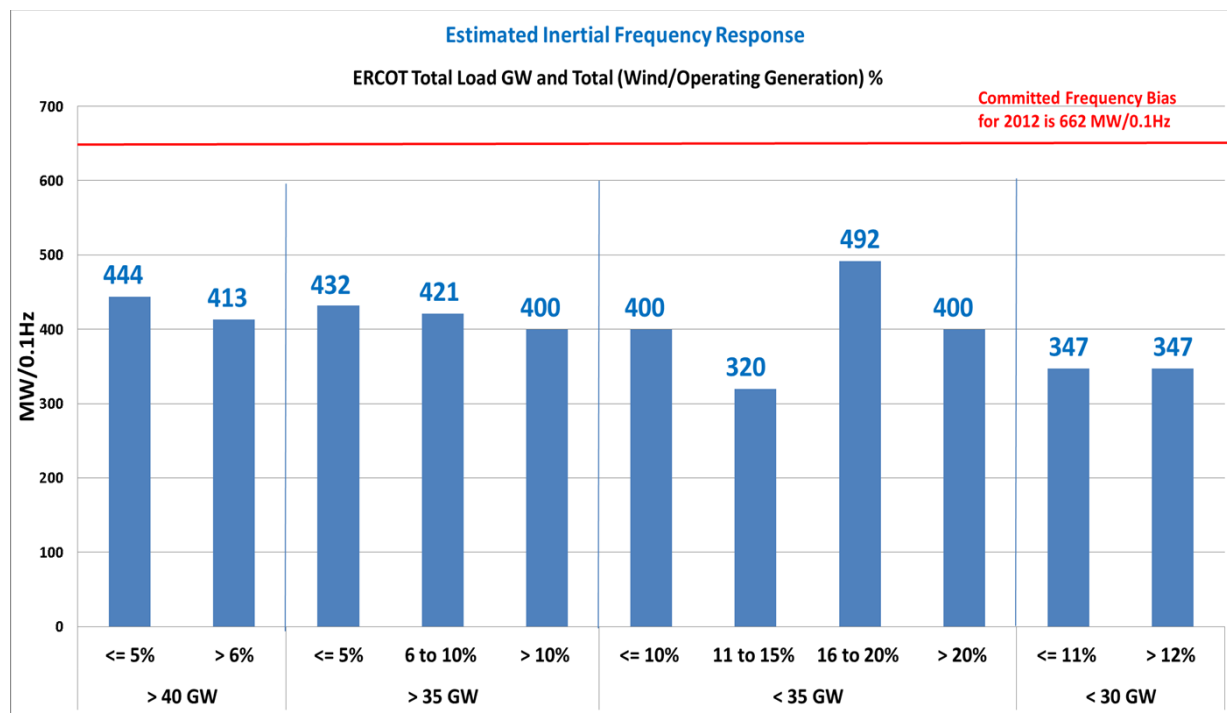


Figure A-16. Estimation of Inertial Frequency Response (Different Wind Levels & Load Levels) – 2012

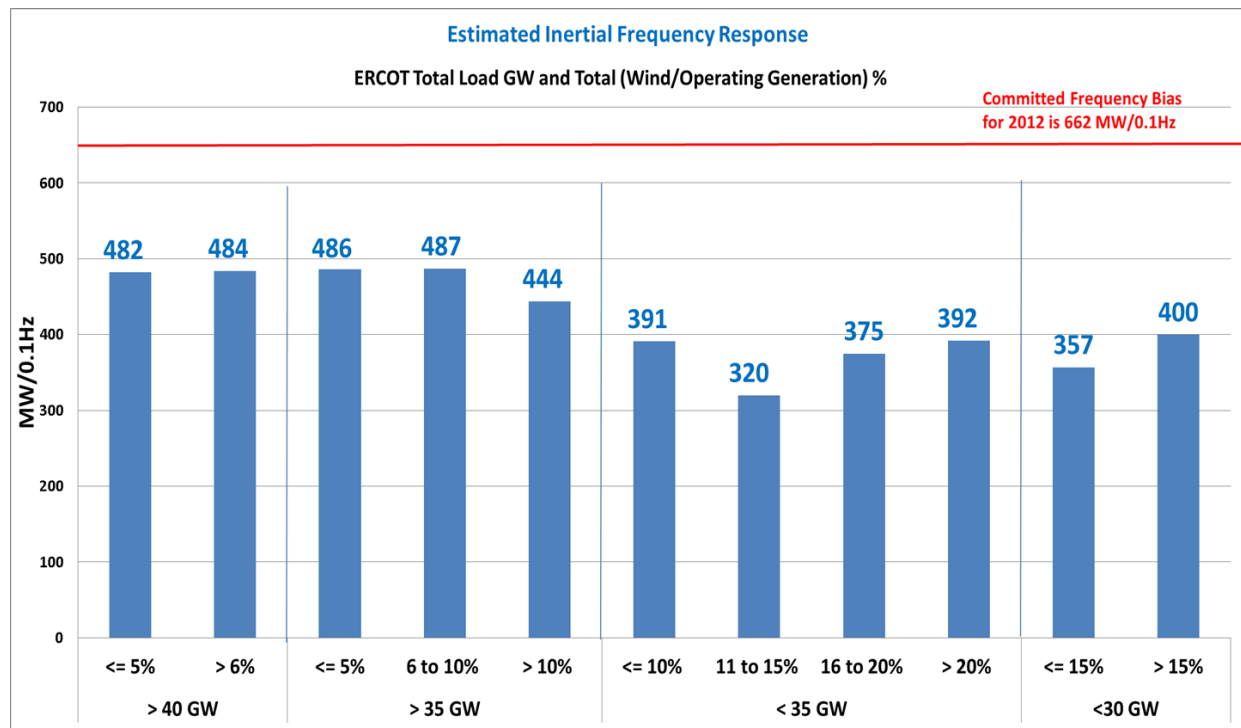


Figure A-17. Estimation of Inertial Frequency Response (Different Wind Levels & Load Levels) – 2013

12. References

1. Sandip Sharma, Shun-Hsien Huang and NDR Sarma, “System Inertial Frequency Response Estimation and Impact of Renewable Resources in ERCOT Interconnection”.

Attachment 11. Oscillation Data Mining Study

Center for Commercialization of Electric Technologies (CCET)

Discovery Across Texas Project

Final Report on Wind Characteristics Oscillation Data Mining Study

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November 17, 2014

EXTERNAL VERSION

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CCET Discovery Across Texas

Wind Characteristics – Oscillation Data Mining Study

CCET 3.1.3, Task C

1. Introduction

The Center for Commercialization of Electric Technologies (CCET) was awarded contract DE-OE0000194 by the Department of Energy to perform the Discovery Across Texas demonstration project. Electric Power Group, LLC (EPG) received a sub-award from CCET to provide professional services to perform, among other things, an analysis to identify unknown oscillations from existing connected wind generators in the Electric Reliability Council of Texas (ERCOT) grid to prevent system vulnerability and customer complaints. Texas has the greatest amount of wind generation on-line in the nation and attains a new wind production record every year. Increasing wind production with installation of wind controllers poses operating challenges for ERCOT. One of the challenges faced by ERCOT is presence of high/low frequency oscillations from wind generators driven by control systems with a bad setting. The wind farms are embedded with electronic controllers to monitor wind output and manage voltage. These fast responding wind controllers with a bad setting or bad design introduce high/low frequency control system oscillations either intermittently with high energy or consistently with low energy which can plausibly cause the following:

1. Voltage fluctuations at the distribution level power systems.
2. Damage to motor and pumps at homes and residential circuits.
3. To drive nearby wind farms to oscillate at the same frequency and damage nearby wind farm turbine blades and shafts.
4. Interact with other conventional generation units such as coal, natural gas etc., in the grid to oscillate at the same frequency and cause significant forced damage to mechanical parts such as generator shafts.

This analysis summarizes the investigation on examining the Phasor data from nearby wind generators for three years and identification of unknown oscillations. The nearby location with the highest occurrence of those oscillations are identified and labeled as critical locations to monitor in real-time for early detection and mitigation. Based on the occurrence of each mode pattern and its associated energy level spanning over three years, the report groups the

oscillations and provides guidelines for ERCOT to help prevent grid vulnerability and customer complaints.

2. Executive Summary

Texas has the greatest amount of wind generation on-line in the nation and attains a new wind production record every year. Increasing wind production with installation of wind controllers poses operating challenges for ERCOT. One of the challenges faced by ERCOT is presence of high/low frequency oscillations from wind generators driven by control systems with a bad setting. The wind farms are embedded with electronic controllers to monitor wind output and manage voltage. These fast responding wind controllers with a bad setting or bad design introduce high/low frequency control system oscillations either intermittently with high energy or consistently with low energy. The early detection and mitigation of emerging oscillations in real-time is crucial to ensuring reliable operation of grid. This sets the stage for baselining the oscillations from nearby wind generators leveraging the existing and installed Phasor Measurement Unit (PMU) locations measuring grid metrics sampling at 30 frames per second.

Hence this study was proposed to investigate:

1. Other unknown oscillations from wind generators.
2. Identify the locations with highest occurrence of those oscillatory modes.
3. Precursors (if any) for such occurrences and the associated energy output.
4. Frequency band and Minimum Energy for additional monitoring.

The detection of unknown oscillations from phasor data was done spanning three years using EPG's Phasor Data Mining Tool. The Tool enabled automatic scanning through the data in periodic intervals, and records the incidents of detected oscillations with damping and energy levels time-stamped for each PMU location.

This analysis was based on six PMUs located nearby wind farms in the ERCOT Interconnection. The Phasor Data Mining Tool was configured with needed algorithm settings to scan through six PMU locations for different frequency bands ranging from 0.1Hz to 15Hz. The measurements including Frequency, Voltage Phasor and Current Magnitude under each PMU were examined to record detected modes every minute and calculated damping and energy associated with each mode. The results were time-stamped and tagged to the PMU locations to identify the source of the oscillations. The Tool was asked to discard modes with damping greater than 8%, regardless of the detected energy level. The Tool leveraged the PMU status information to clean bad data to avoid false detections. The detection results from the tool were parsed and post processed through MATLAB scripts to rank the oscillatory modes with the highest occurrence and highest energy. These results were then examined to identify any relationship between each Mode Occurrence and the corresponding Regional wind data. The highest energy of a mode was extracted and compared with the Mode Occurrence to baseline the minimum energy required to monitor in real-time and also to differentiate modes related to wind production versus modes driven by control systems or setting change in control systems.

Some of the key findings are as follows:

1. The study identified 10 different ERCOT Oscillatory Modes.
2. The occurrence of 2 modes appears to be related to wind production – 0.9Hz (West 6) & 2.7Hz (FarWest 4).
3. The occurrence of 4 modes appear to be related to control system settings changes – 1.5Hz (Coast 3), 1.7Hz (FarWest 7), 2Hz (Coast 3), 3.2Hz (West 10).
4. The occurrence of 3 modes appear to be related to the presence of wind generation and control systems - 5.0Hz (Coast 3), 5.4Hz (West 10 & FarWest 4), 6.0Hz (West 10).
5. The occurrence of 1 mode appears to be a local oscillation caused by topology change or mis-tuning of the wind generator control system – 0.6Hz (West 10).

This study concludes that four modes appear consistently for three years and are still present. There are four other modes that appear intermittently with high energy. There are other two modes that appeared consistently for the first two years, but were not detected in 2014. The report provides insights on the Real Time Dynamics Monitoring System¹ (RTDMS[®]) configuration for monitoring certain modes in real-time to detect and mitigate the oscillations. The modes which appear only sporadically may need additional review by ERCOT with the plant owners to determine the root cause and evaluate the need for additional monitoring.

3. Goals & Methodology

The objective of this analysis was to identify unknown oscillations from existing connected wind generators in the Electric Reliability Council of Texas (ERCOT) grid to prevent system vulnerability and customer complaints. Utilizing six different PMUs located nearby wind generators during the period of 2012-2014, the study set five goals:

1. Build a Phasor Data Mining Tool that can scan through the phasor data, detect low damped oscillatory modes and record the associated damping & energy value.
2. Using the results from the mining tool, calculate following monthly statistics for each mode
 - a. Mode Occurrence (in percent of time)
 - b. Highest Energy Value
 - c. Timestamp and PMU measurement with the Highest Energy Value
3. Identify the nearby PMU location that had highest mode occurrence.
4. Correlate Mode Occurrences with Regional Wind data to determine the type of oscillation – Related to Wind Production or Driven by Control Systems.

¹ Built upon GRID-3P[®] platform. US Patent 7,233,843, US Patent 8,060,259, and US Patent 8,401,710.
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5. Baseline Oscillation characteristics – Minimum Energy Level and Frequency Band for additional monitoring in real-time.

Figure 1 shows the flowchart that describes the workflow of the analysis study. The different steps in the analysis study were:

- Step 1** Gather phasor data from six different PMU locations for three years in a database.
- Step 2** Setup Jobs in the Phasor Data Mining Tool to connect to the database and scan through the data with user-defined configuration.
- Step 3** Export the Mining Tool results from the results database into a CSV file.
- Step 4** The CSV file containing results for all PMU measurements was then parsed for post processing in MATLAB.
- Step 5** MATLAB script was written to calculate monthly statistics on mode occurrence and filter oscillatory modes with low occurrence and low energy.
- Step 6** Export post processed results for each PMU measurement
 - 1. Mode Occurrence of each mode
 - 2. Highest Energy for each mode
 - 3. Timestamp of the mode with highest energy
- Step 7** Conduct analysis to achieve the goals for this study.

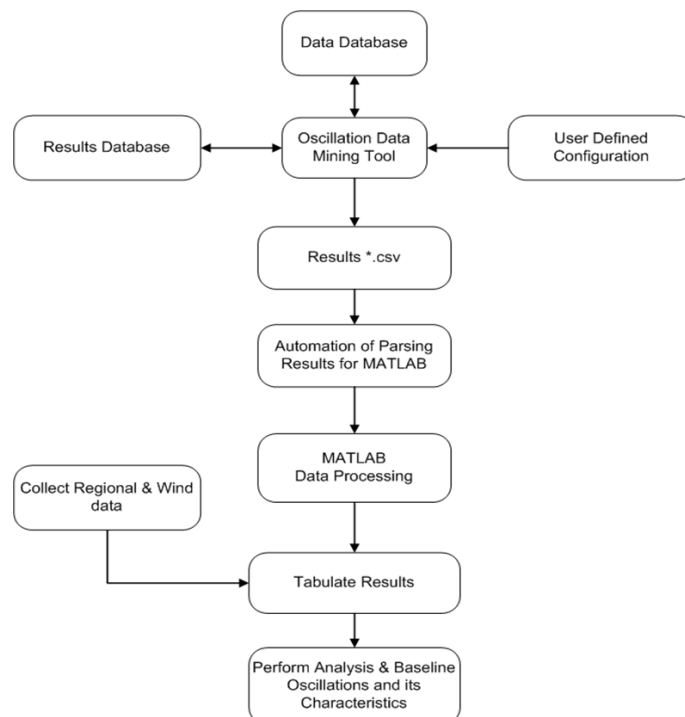


Figure 1. Analysis Work flow

4. Derived Metrics & Calculated Variables

The following results associated with oscillations were collected from the Phasor Data Mining Tool after scanning through the phasor data:

1. Oscillatory Mode (Frequency Value in Hz).
2. Damping associated with Oscillatory Mode (Percentage).
3. Energy level associated with Oscillatory Mode (no unit, Magnitude).

The above sets of results were time-stamped and tagged with the associated PMU measurement. The Tool was configured to output results every minute (sampling of successive 60 second intervals of phasor data).

The variables calculated for this study are:

1. Monthly Average Regional Wind Generation (3 regions)
 - a. Wind North = Aggregation (North)
 - b. Wind West = Aggregation (Far West, West)
 - c. Wind South = Aggregation (South, Coastal Wind)

The metrics derived for this study are:

1. Monthly Mode Occurrence (%) = (Count of minutes having mode/total number of reported minutes) * 100 (e.g. 0.9Hz appeared 42% of time in April 2012)
2. Monthly Highest Energy = Maximum Energy of an oscillatory mode each month

Other information extracted along with monthly statistics is:

1. Timestamp associated with the highest energy
2. PMU measurement associated with mode

5. Phasor Data Mining Tool – Oscillation Candidates

The six different PMU locations that were used in the study were located nearby wind generators, but do not directly monitor the output of individual wind farms, include the following:

1. FarWest 7
2. West 10
3. FarWest 4
4. West 6
5. Coast 4
6. Coast 3

The PMU at substation North 7 was used in the study as a reference for PMU Voltage angle measurements. The signal types from PMU measurements used in the study are as follows:

1. Frequency.
2. Voltage Phasor (Voltage Magnitude & Voltage Angle).
3. Current Magnitude.

The Mining Tool is configured to look for oscillatory modes within one frequency band from 0.1Hz to 15Hz. Bad data in the phasor measurements are removed before scanning for oscillations using the flags set in the Status Signal embedded with PMU measurements C37.118 format. The algorithm settings to scan for oscillations are set in such a way that the output results are reported:

1. Every Minute – The output result for each (study) minute is the algorithm output for the phasor data available in that minute.
2. Modes are discarded with Damping greater than 8%.
3. Energy for each Mode is computed.
4. Minimum Frequency – 0.1Hz.
5. Maximum Frequency – 15Hz.

6. Oscillation Data Mining Tool Performance & Processing

The Phasor Data Mining Tool performs several functions such as data extraction, data cleaning, data calculation and data storage into the results database. The approximate time taken to completely process one minute of phasor data (for multiple PMUs) is approximately 4 seconds. Using this average processing timing, the processing of a full month of phasor data would take approximately 2 days. Figure 2 shows the Tool performance for an operation, 1 Hour, 1 day & 1 Month.

| Task | Time |
|-------------------------------------------------------------|------------------|
| Data Loading (1 minute of data, All PMU signals) | 3 sec |
| Data Filtering Mode Solving Result Exporting | 1 sec |
| Total (All Frequency Bands) | 4 sec |
| | |
| Ideal Example | |
| 1 Hour | 4 Min |
| 1 Day | 1.6 Hours |
| 1 Week | 11.2 Hours |
| 1 Month (31 days) | 2.06 Days |

Figure 2. Phasor Data Mining Tool Performance

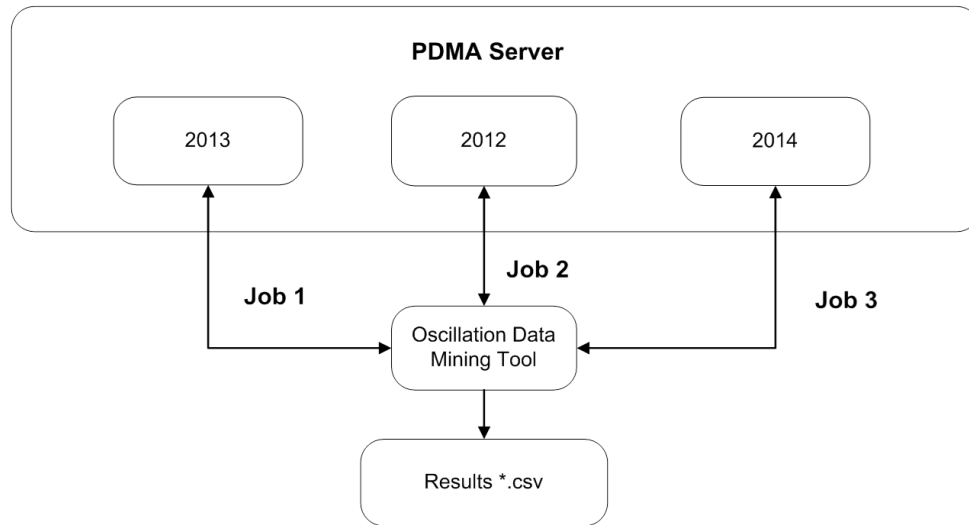


Figure 3. Analysis Work flow

In order to expedite the scanning process to successfully scan a full 3-years' worth of data, three simultaneous processing jobs were established to scan each of the three different years in parallel. The same performance that took two days for 1 Month was achieved for each job if they were setup in different servers. This parallel processing helped expedite the completion of oscillation scanning process in a more effective way instead of scanning one year after another.

7. Oscillation Data Mining Results – Post Processing

The Phasor Data Mining Tool reports results for each study minute which has a detectable oscillatory mode, including its associated damping and energy value time-stamped with PMU measurements. The MATLAB script was written to read the output results of the Phasor Data Mining tool and scan through to populate monthly statistics for each detected mode in each of the PMU measurements. The statistics and metrics are explained briefly in Section 4. It is important for planners and operators to focus on those oscillatory modes that occur most of the time and those modes that occur with high energy. Hence, those oscillatory modes with a monthly occurrence which was less than 20% of the highest occurrence among all the modes observed in all PMU measurements were discarded. Similarly oscillatory modes were discarded where the highest mode energy was less than 20% of the highest energy among all the modes observed in all PMU measurements. The output results from MATLAB post processing include PMU metric identification (name and signal type), oscillatory modes detected, Mode Occurrence, and Highest Energy and associated Timestamps for further analysis studies to accomplish the goals of the project.

The output results for three years from MATLAB post processing are attached to this report as an Excel workbook, “Wind Oscillation Study – Monthly Statistics,” The Excel workbook

consists of two sheets. The first sheet, “Modes_Aval” contains the modes filtered by highest occurrence, and the second sheet, “Modes_Ene” contains the modes filtered by highest energy. Both sheets include the following information in different columns in the following order: Year-Month, PMU Name, Signal Name, Signal Type, Frequency Range, Monthly Occurrence, Highest Energy, Mode (Associated Oscillatory Frequency value in Hz), and Timestamp (Associated time in UTC). The Highest Energy, Mode & Timestamp are associated with each other.

8. Summary of Identified ERCOT Oscillatory Modes

Figure 4 shows a quick summary of the ten identified oscillatory modes in the ERCOT interconnection, as measured by PMUs located at nearby wind generators. All the modes appeared due to the presence of wind generators, but differed in terms of energy levels and mode occurrence. The Mode occurrence and energy levels provided clues to differentiate between those modes related to wind production and those which appear to be driven by control systems. There appear to be four modes (0.9Hz, 5.0Hz, 5.4Hz & 6.0Hz) that are consistent in occurrence spanning three years and continue to be present. The rest of the modes appear to fall into two categories of intermittency. The 0.6Hz & 2.7Hz modes appeared constantly for a period of time (four months and twenty four months, respectively), but then they disappeared, and have not reoccurred. Their disappearance may indicate a relationship between the oscillation and a topology change or a change in the tuning of the generator controls. These modes need further investigation to review their disappearance for additional monitoring. The second category of oscillations appears to be intermittent and shows high energy when they occurred. These modes need additional monitoring to identify their nature and initiating factors. The 1.7Hz, 1.5Hz, 3.2Hz & 2Hz belong to this second category and appear to be driven by temporary changes in the control systems settings of the nearby generators.

Figure 5 shows the list of ten oscillatory modes with the nearby location of wind generators that saw the highest occurrence of each mode. The 0.9Hz and 2.7Hz mode occurrences followed the regional wind pattern and appeared to be related to wind production. The monthly highest energy levels gathered across three years tracked the level of occurrence, providing further indication that the respective modes were related to wind production. The monthly highest energy levels of the 5.0Hz, 5.4Hz & 6.0Hz modes remained flat and didn’t appear to vary in relationship with changing levels of regional wind production, except for the 6.0Hz mode, which had relatively high energy during certain periods of time. This mode deserves additional monitoring. The highest energy levels of these modes appear to be driven by settings change in control systems provided, and the baseline energy levels can be used as a reference for the minimum energy to set for additional monitoring (alarming) in real-time. It is also evident that there are several modes observed from a PMU location nearby to wind generators.

| # | Mode (Hz) | 2012 | 2013 | 2014 | Oscillation Type |
|----|------------|---------------|---------|-------------|-------------------------|
| 1 | 0.6 | Till March | Absent | Absent | Local |
| 2 | 0.9 | Present | Present | Present | Wind Production Related |
| 3 | 1.5 | Only in April | Absent | Absent | Control Systems |
| 4 | 1.7 | 4 Months | Absent | Absent | Control Systems |
| 5 | 2.0 | Absent | April | Absent | Control Systems |
| 6 | 2.7 | Present | Present | Absent | Wind Production Related |
| 7 | 3.2 | 4 Months | Absent | Only in Jan | Control Systems |
| 8 | 5.0 | Present | Present | Present | Control Systems |
| 9 | 5.4 | Present | Present | Present | Control Systems |
| 10 | 6.0 | Present | Present | Present | Control Systems |

Figure 4. Presence/Absence of 10 Oscillatory Modes over 3-years

| # | Mode (Hz) | Nearest PMU | Related to Wind Production | Highest Energy Level |
|----|------------|--------------------|----------------------------|-----------------------------------|
| 1 | 0.6 | West 10 | No | Low Energy & Flat |
| 2 | 0.9 | West 6 | Yes | High Energy & Tracking Occurrence |
| 3 | 1.5 | Coast 3 | No | Low Energy |
| 4 | 1.7 | FarWest 7 | No | High Energy |
| 5 | 2.0 | Coast 3 | No | Low Energy |
| 6 | 2.7 | FarWest 4 | Yes | High Energy & Tracking Occurrence |
| 7 | 3.2 | West 10 | No | High Energy |
| 8 | 5.0 | Coast 3 | No | Low Energy & Remained Flat |
| 9 | 5.4 | West 10, FarWest 4 | No | Low Energy & Remained Flat |
| 10 | 6.0 | West 10 | No | Intermittent High Energy |

Figure 5. Ten Oscillatory Modes – Location, Type, and Energy Level Pattern

9. Detailed Description of 10 Identified Modes

This section of the report describes the four types of oscillatory modes identified in the ERCOT interconnection associated with nearby wind generators. The four types of oscillatory modes are:

1. The Occurrence of 2 modes appears to be related to wind production – 0.9Hz (West 6) & 2.7Hz (FarWest 4).
2. The Occurrence of 4 modes appear to be related to control system settings changes – 1.5Hz (Coast 3), 1.7Hz (FarWest 7), 2Hz (Coast 3), 3.2Hz (West 10).
3. The Occurrence of 3 modes appear to be related to the presence of wind generation and related to wind generation control systems - 5.0Hz (Coast 3), 5.4Hz (West 10 & FarWest 4), 6.0Hz (West 10).
4. The Occurrence of 1 mode appears to be a local oscillation due to a topology change or tuning of wind generators – 0.6Hz (West 10).

Mode 2: 0.9Hz

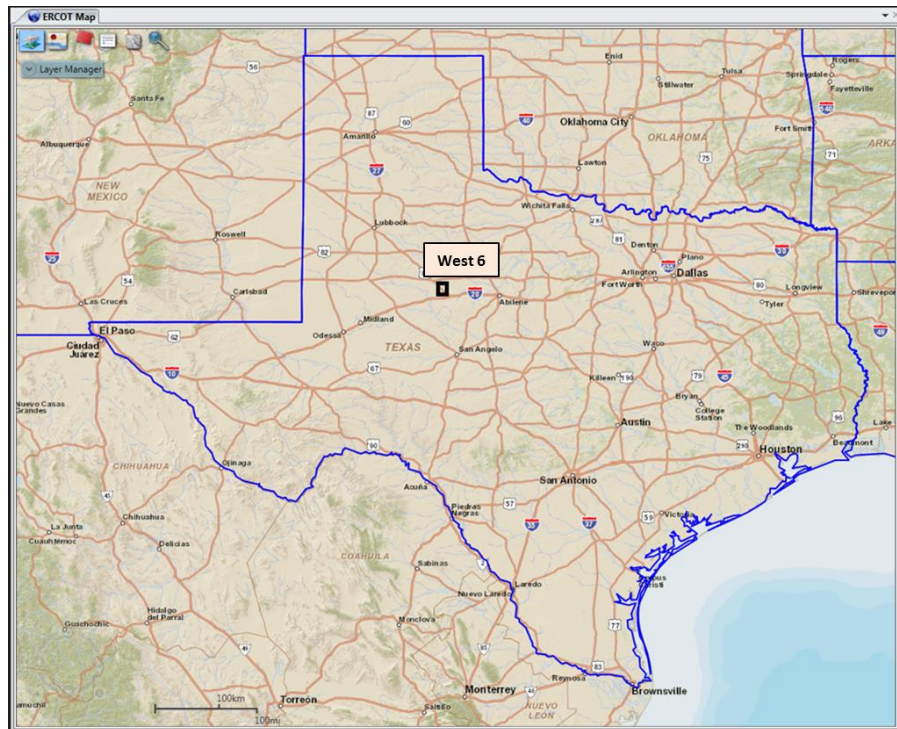


Figure 6. Mode 2 – PMU location

Figure 6 shows the PMU location in the ERCOT interconnection that had consistent occurrence of the 0.9Hz mode spanning 3-years and continues to be present. The Mode showed up in the current magnitude signal measurement in the West 6 substation located nearby wind generators

including WestGen1, WestGen2, WestGen3, and WestGen4. Figure 8 shows the trend of the 0.9Hz mode occurrence in the West 6 current magnitude signal over 3-years. The maximum occurrence of 0.9Hz mode appeared for 53% of time in June 2014, and minimum occurrence of the same mode appeared 22% of time in December 2013. The average occurrence over all 3-years is approximately 42% of the time each month. Figure 7 shows the comparison between the mode occurrence of 0.9Hz and the monthly average west wind production in MW from January 2012 to April 2013. The trend of Mode Occurrence & Average West Wind have similar patterns and provides a first indication that 0.9Hz is likely related to wind production. The mode occurrence reduced from 40% to 30% when the average wind production showed reduction from 3000MW to 1600MW in August 2012, suggesting that Mode 0.9Hz is related to wind production. This relationship is based on west wind generation (an aggregation of wind production) - wind production solely at West 6 was not available for comparison. Similarly, the mode occurrence increased to 48% in April 2013 when the average wind production increased to 3500MW in the same month.

This mode appears to be wind production related and occurs consistently every month. It is noted that the energy level of the mode closely tracks wind production (e.g., increases with increasing levels of wind production, etc.). Figure 8 shows the comparison of the mode occurrence to the highest energy of the mode during each month spanning 3-years. The mode obtained its maximum highest monthly energy of approximately 12 in February 2013 and the minimum highest monthly energy in September 2013 of approximately 0.5. It is recommended that ERCOT monitor this mode in real-time with the following mode meter configuration to detect increasing energy levels during high wind production.

- PMU Signal: West 6 Current Magnitude.
- Minimum Frequency = 0.85Hz.
- Maximum Frequency = 1.2Hz.
- Minimum Energy = 2.
- Damping = 8%.

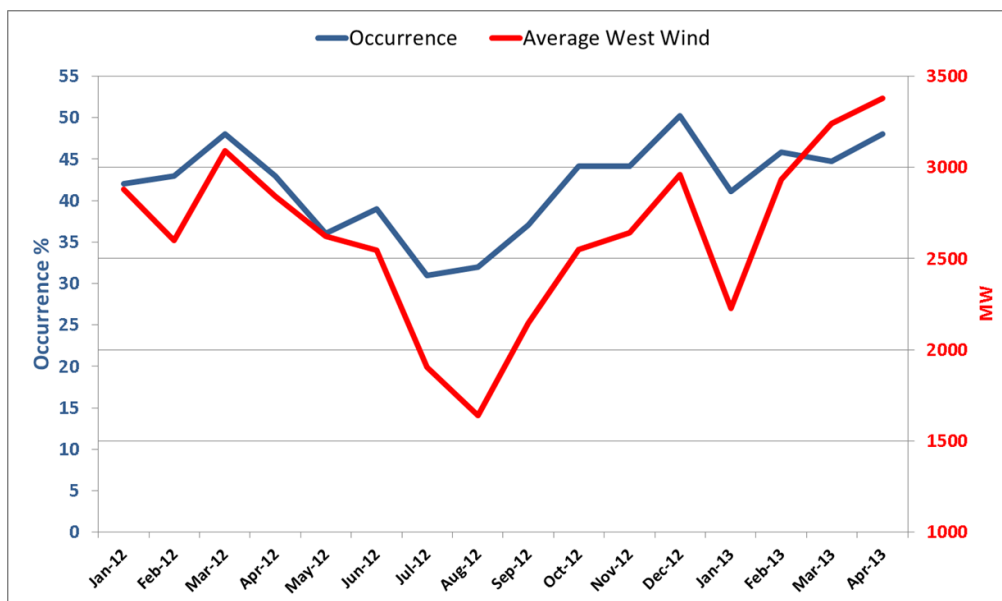


Figure 7. Mode 2 – Mode Occurrence vs. Regional West Wind

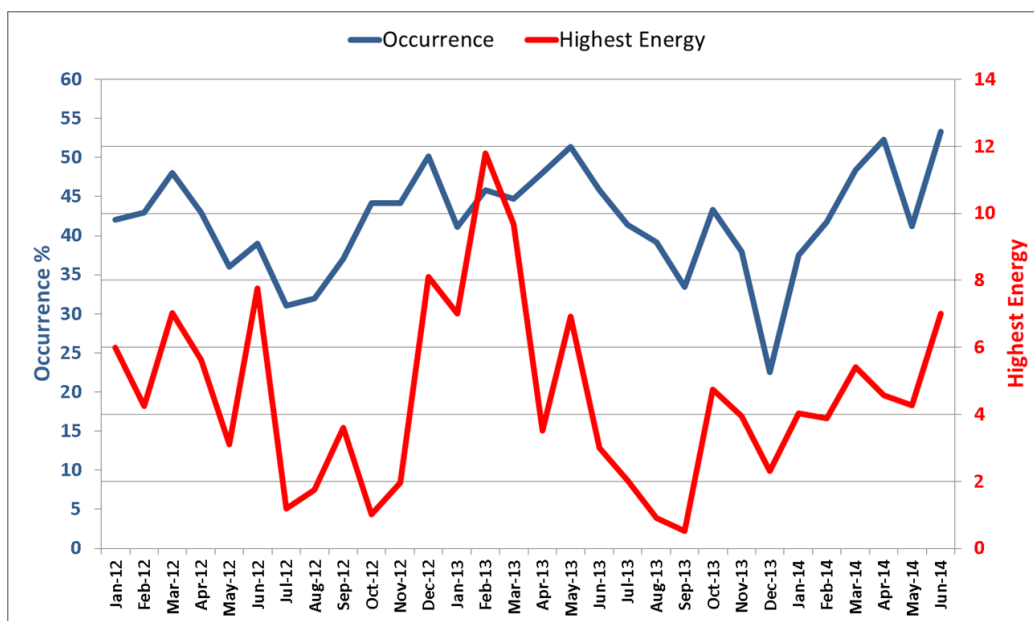


Figure 8. Mode 2 – Mode Occurrence vs. Highest Energy

Mode 6: 2.7Hz

Similar to 0.9Hz, the study discovered another mode at 2.7Hz related to wind production. Figure 9 shows the PMU location in the ERCOT interconnection that had the most consistent occurrence of the 2.7Hz mode. The mode showed up in the current magnitude signal measurement in the FarWest 4 substation located nearby generators including FarWestGen4.

Figure 11 shows the trend of this 2.7Hz mode occurrence in the FarWest 4 current magnitude signal over 2-years, and then suddenly disappearing starting January of 2014. The maximum occurrence of 2.7Hz mode appeared for 34% of the time in May 2013, and minimum occurrence of the same mode appeared 9% of the time in July 2013. The average occurrence in first 2-years is approximately 20% of the time each month. Figure 10 shows the comparison between mode occurrence of 2.7Hz and monthly average west wind production in MW from January 2012 to April 2013. The trends of mode Occurrence & Average West Wind have similar patterns and provide a first indication that the 2.7Hz mode is likely related to wind production.

This mode is no longer present and its disappearance may be related to the addition of new CREZ transmission lines near FarWest 4 or the re-tuning of machines at FarWestGen4. Figure 11 shows the comparison of the mode occurrence to the highest energy of the mode during each month spanning the first 2-years. During the mode occurrence, the highest energy was not relatively high as compared to 0.9Hz. It is recommended that ERCOT review the disappearance of the mode with wind owners and determine the root cause to evaluate the need for additional monitoring.

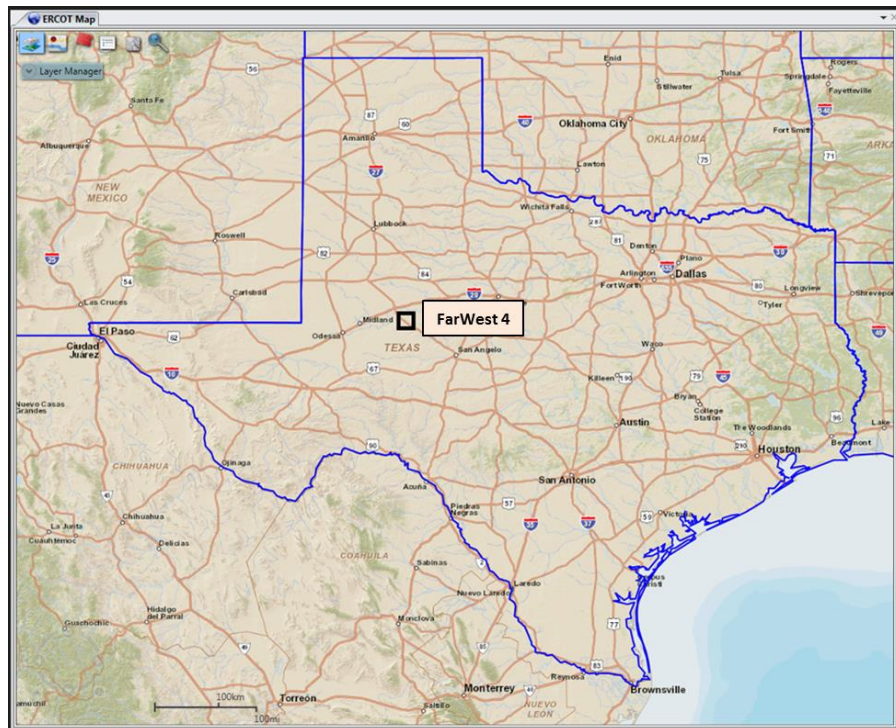


Figure 9. Mode 6 – PMU Location

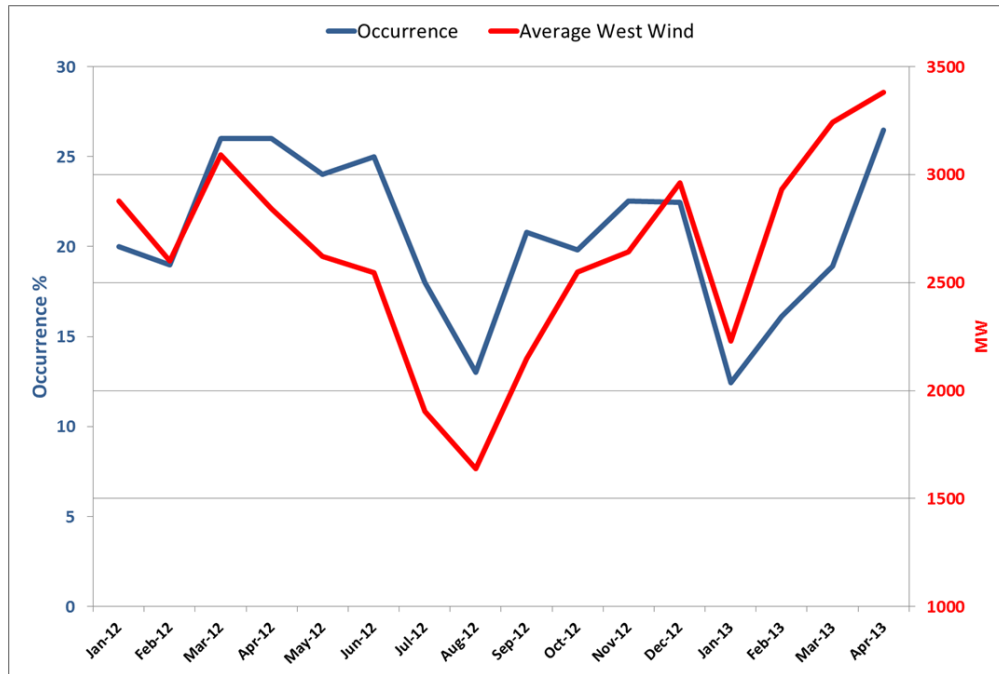


Figure 10. Mode 6 – Mode Occurrence vs. Regional West Wind

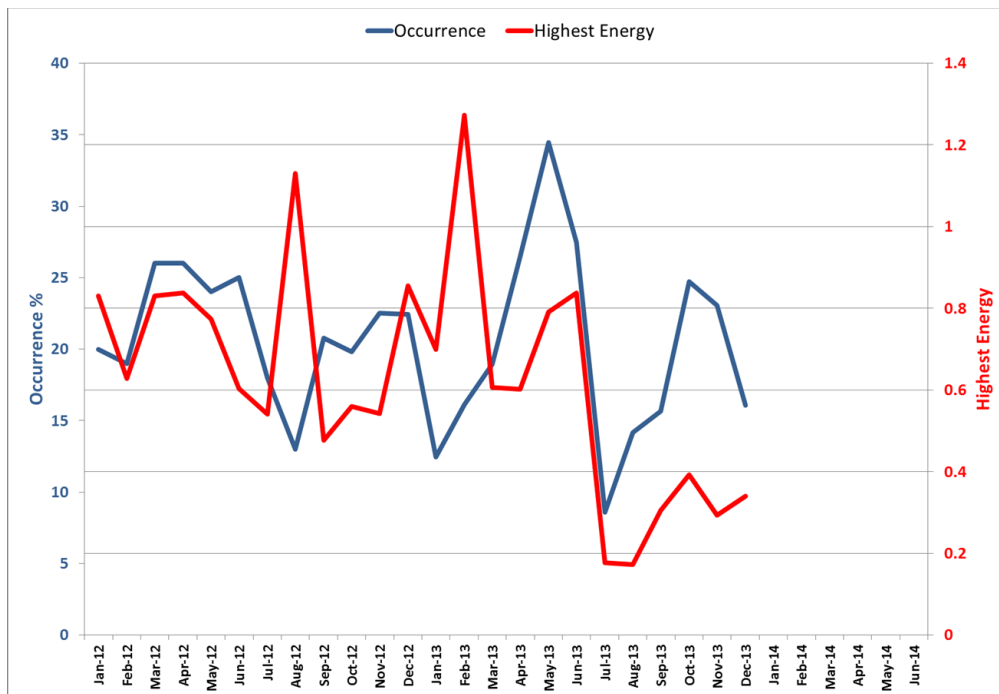


Figure 11. Mode 6 – Mode Occurrence vs. Highest Energy

Mode 8: 5.0Hz

Figure 12 shows the six different PMU locations in the ERCOT interconnection that showed the occurrence of the 5.0Hz mode. Of these six locations, Coast 3 & Coast 4 in the Valley saw the highest and most consistent occurrence of this mode. This mode showed up in the Voltage Magnitude, Voltage Angle & Frequency signal measurements in the Coast 3 & Coast 4 substations, both of which are located at nearby wind generators including Coast 3 & Coast 4. Figure 14 shows the trend of the 5.0Hz mode occurrence in the Coast 3 Voltage magnitude signal over 3-years. The mode appeared every month in all three years except first three months of 2012 and the month of March 2013. The maximum occurrence of the 5.0Hz mode was 57% of the month in May 2014, and the minimum occurrence was 0.1% of the month in December 2012.

Figure 13 shows the comparison between the mode occurrence of 5.0Hz from all signal measurements of Coast 3 and the monthly average south wind production in MW from January 2012 to April 2013. The trend of mode Occurrence from all signal measurements does not have pattern similar to the Average South Wind MW, and thus it appears that this mode is likely not related to wind production. Figure 14 shows the comparison between mode Occurrence and monthly highest energy of the 5.0Hz mode. The highest energy level remained flat and low; not changing with different levels of south wind production, suggesting that the mode is likely driven by the control systems of the nearby wind generators. The mode appears to be related to the operation (simply being on-line) of the wind generation and not to the level wind production. During the span of 3-years, the energy level of this mode remains consistently low. The mode obtained its maximum highest monthly energy of approximately 0.09 in May 2013, and minimum highest monthly energy in December 2012 was approximately 0.00015. It is recommended that ERCOT review this 5.0Hz oscillation with wind owners to determine the root cause, and to evaluate need for additional monitoring and possible mitigation.

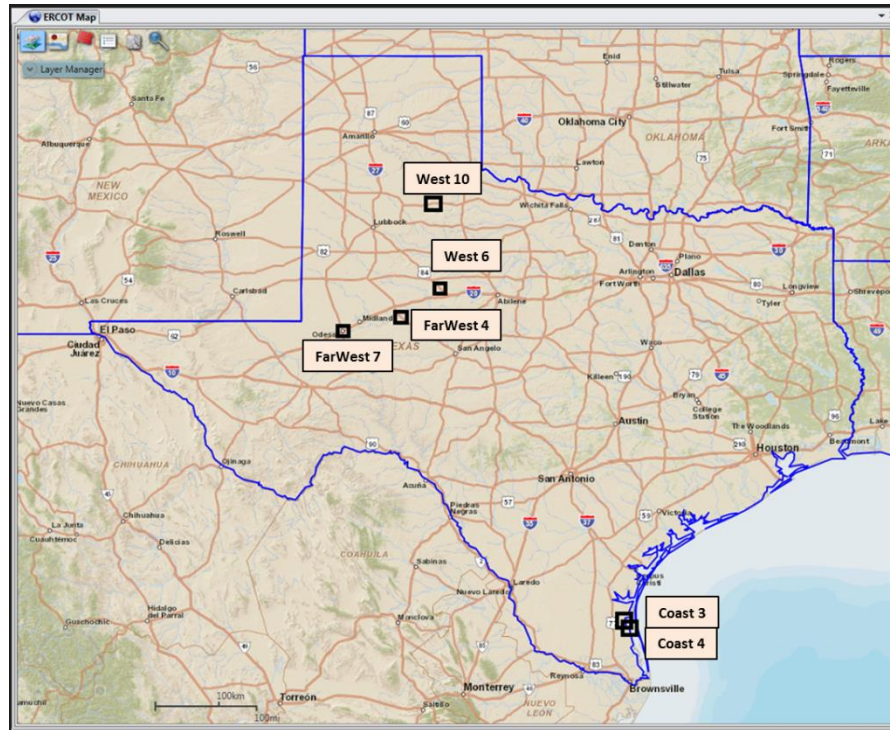


Figure 12. Mode 8 – PMU locations

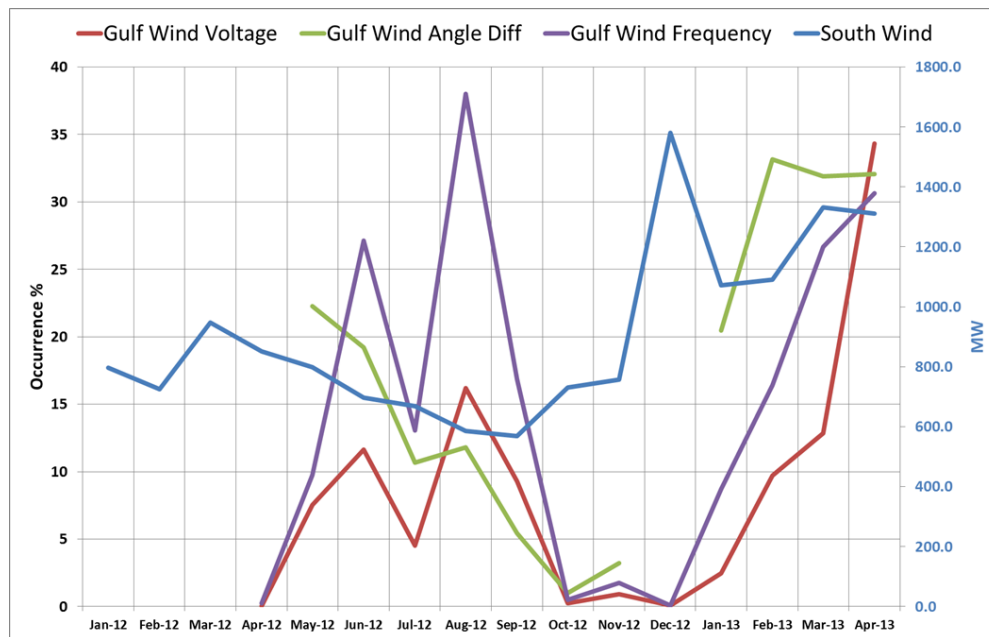


Figure 13. Mode 8 – Mode Occurrence vs. Regional South Wind

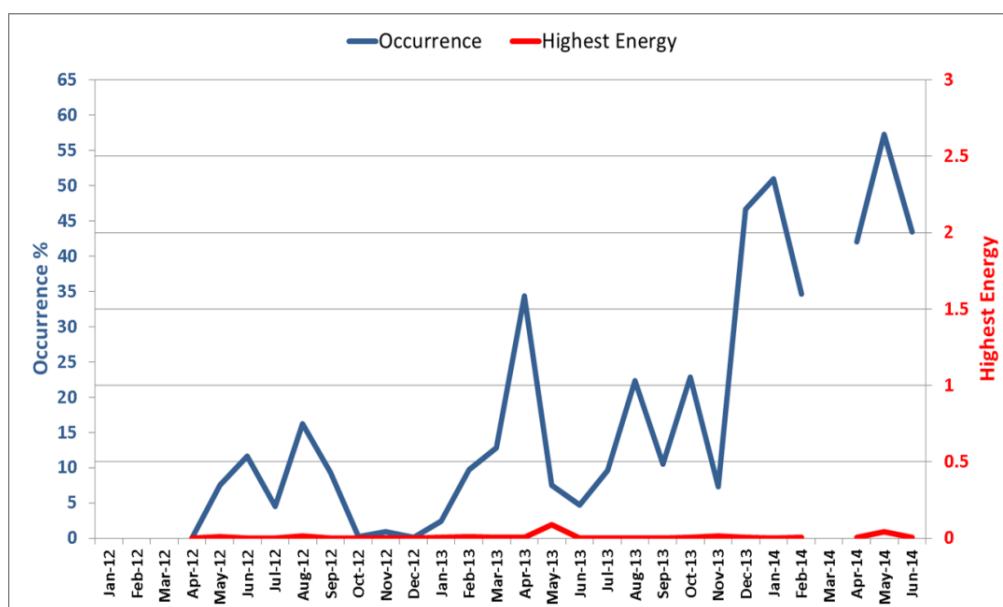


Figure 14. Mode 8 – Mode Occurrence vs. Highest Energy

Mode 9: 5.4Hz

Similar to the 5.0Hz mode, the study discovered another mode at 5.4Hz at six different locations as shown in Figure 15. The highest occurrence of the mode showed up in both West Texas and the Panhandle regions of the ERCOT interconnection. This mode exhibits patterns similar to the 5.4Hz mode occurrence. The Voltage Magnitude signal measurement at FarWest 4 substation in the West Texas region showed the highest occurrence of the mode in West Texas (FarWest 7 and West 6 also showed the mode, but at lower energy levels). Figure 20 shows the mode occurrence of 5.4Hz at West 10 and FarWest 4 indicating that the 5.4Hz mode has different drivers in the two regions. Hence, FarWest 4 at West Texas and West 10 at Panhandle were identified as critical locations to monitor 5.4Hz mode.

Similar to the 5.0Hz mode at Coast 3 and Coast 4, the 5.4Hz mode at West 10 appears to be driven by the control systems of the nearby wind generators, and not by the level of wind production. The same forensics for mode 5.0Hz was obtained using the Figures 16 & 17. Figure 16 shows the comparison between the mode occurrence of 5.4Hz and the monthly average north wind production in MW from January 2012 to April 2013. Figure 17 shows the comparison between the mode Occurrence and the monthly highest energy of the 5.4Hz mode. The same relationship appears to be true for this 5.4Hz mode at FarWest 4 as shown in figures 18 & 19. The highest energy level trend of the 5.4Hz mode at FarWest 4 remained flat and low; not changing with different levels of wind production, even though the mode occurrence interestingly tracked the west wind production. It is recommended that ERCOT review the 5.4Hz

oscillation with wind owners to determine the root cause, and to evaluate the need for additional monitoring and possible mitigation.

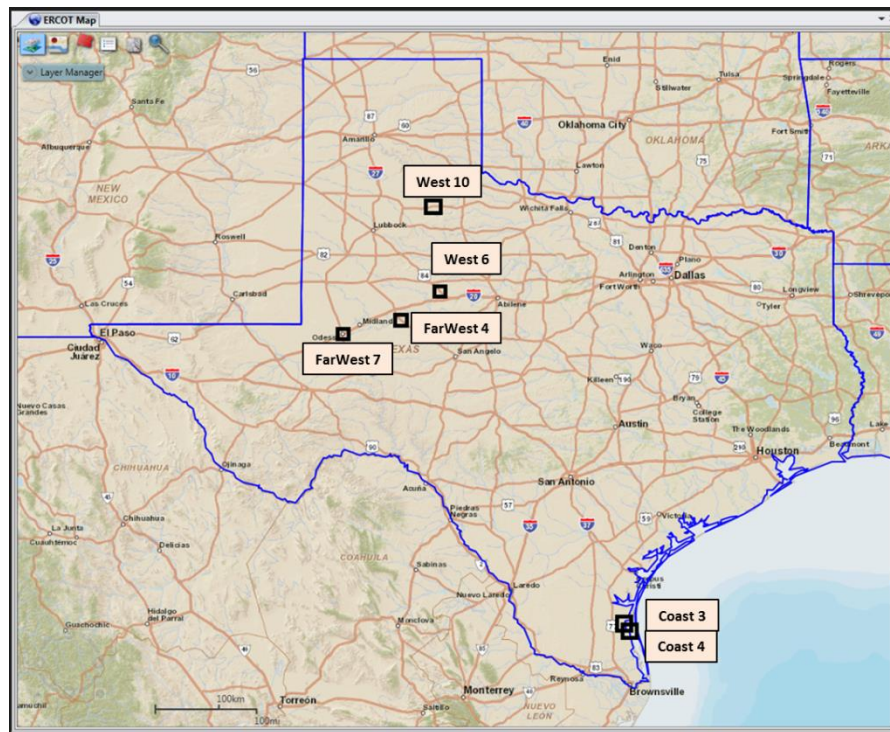


Figure 15. Mode 9 – PMU Locations

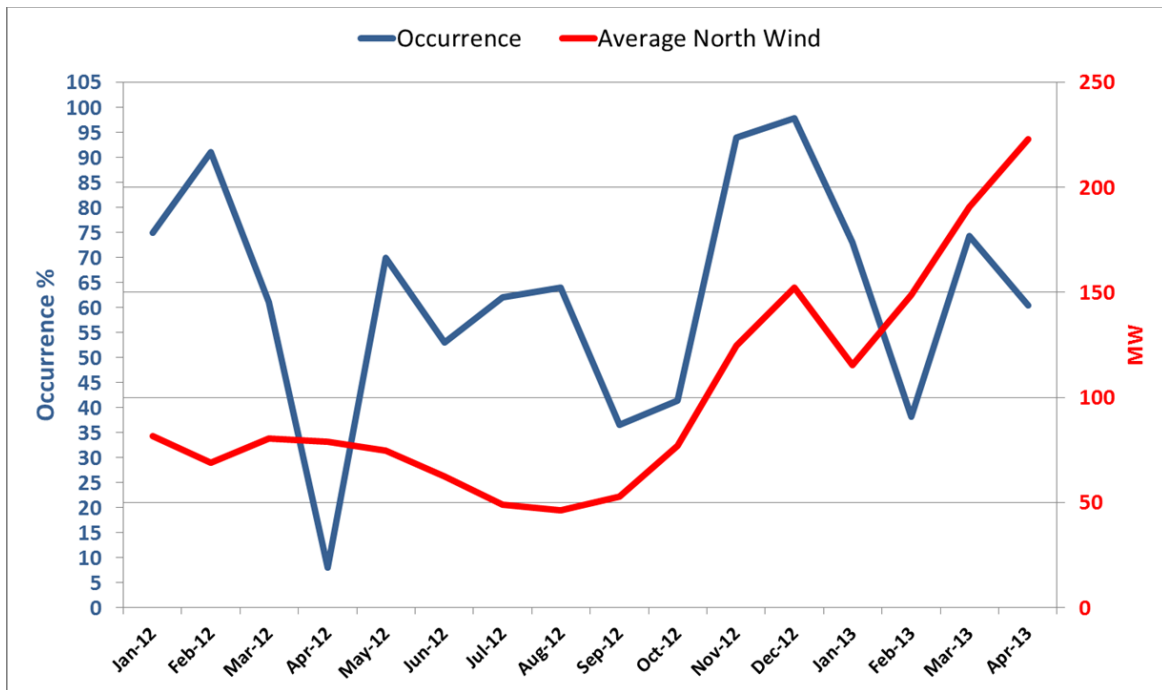


Figure 16. Mode 9 @ West 10 – Mode Occurrence vs. Regional North Wind

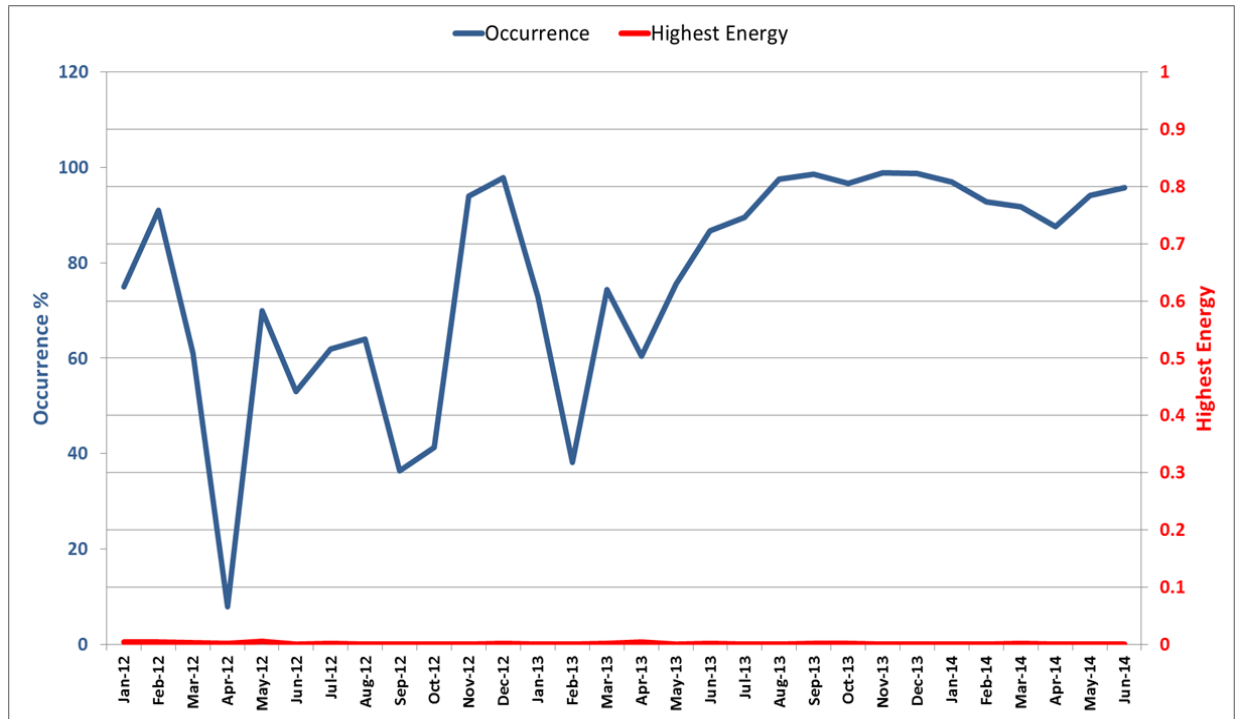


Figure 17. Mode 9 @ West 10 – Mode Occurrence vs. Highest Energy

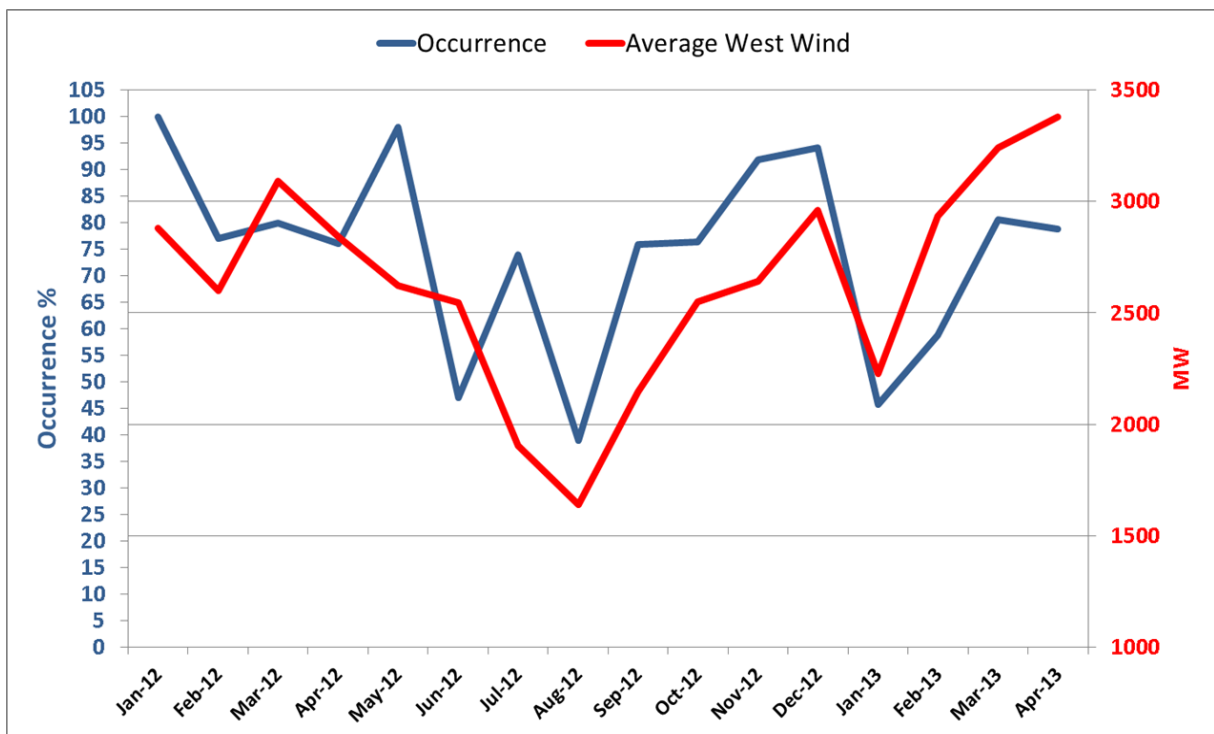


Figure 18. Mode 9 @ FarWest 4 – Mode Occurrence vs. Regional West Wind

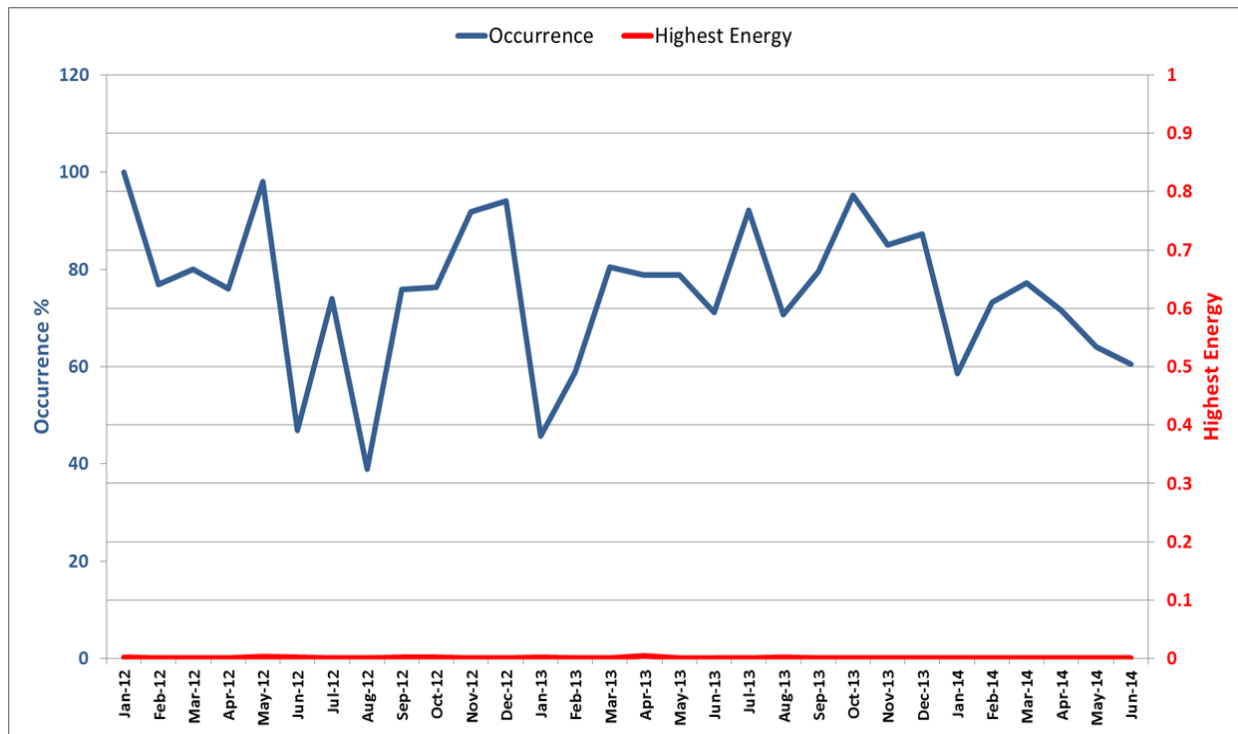


Figure 19. Mode 9 @ FarWest 4 – Mode Occurrence vs. Highest Energy

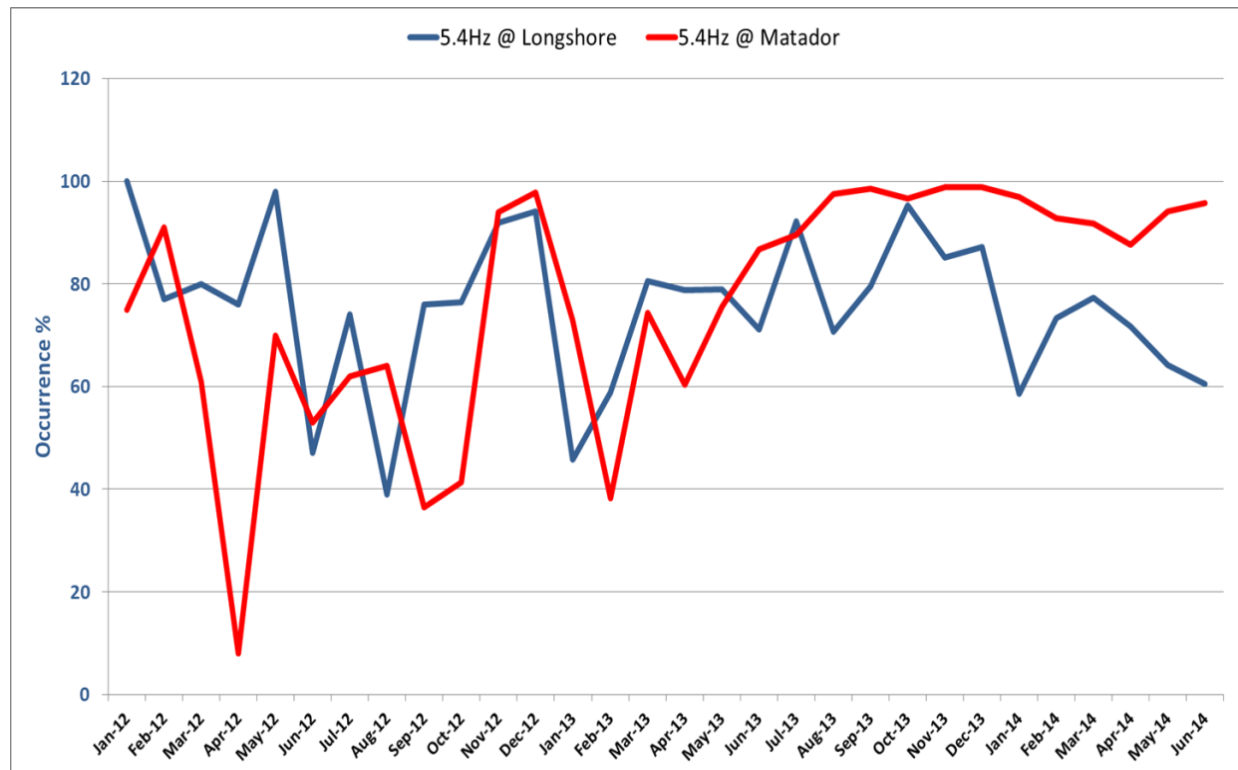


Figure 20. Mode 9 – West 10 vs. FarWest 4

Mode 10: 6.0Hz

Similar to the 5.0Hz & 5.4Hz modes, the study discovered another mode at 6.0Hz, and which was present at six locations, as shown in Figure 21. The mode was strongest at West 10. Figure 22 shows the first indication that the mode at 6.0Hz appears not to be related to average monthly north wind production. But these oscillations are detected more strongly near wind generators. Figure 23 shows the comparison of the mode occurrence with the highest energy level of the current magnitude signal measurement at West 10. The monthly highest energy trend remained fairly flat at low levels (< 0.01) except in Jan-March & August 2012, suggesting that these oscillations are driven by control systems at the local wind generators and can reach high energy levels. This also suggests the need for additional monitoring. The West 10 current magnitude signal was selected as the critical location to monitor in real-time.

It is recommended that ERCOT review the 6.0Hz oscillation with wind owners for possible mitigation and also monitor this mode in real time with the following configuration to detect increasing energy levels during high wind production.

- PMU Signal: West 10 Current Magnitude.
- Minimum Frequency = 5.5Hz.
- Maximum Frequency = 6.5Hz.
- Minimum Energy = 5.
- Damping = 8%.

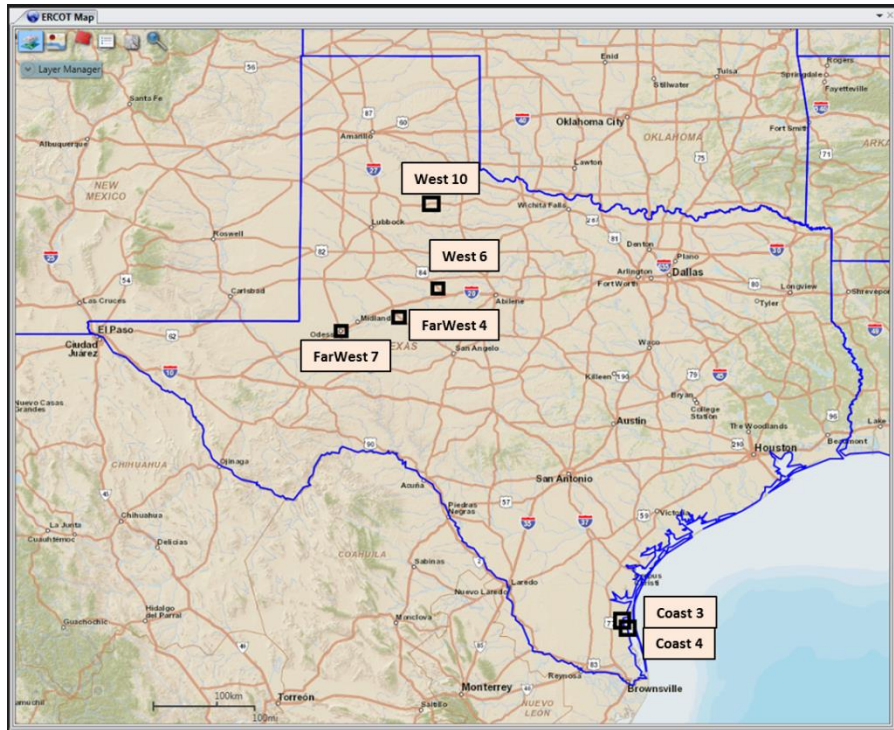


Figure 21. Mode 10 – PMU Location

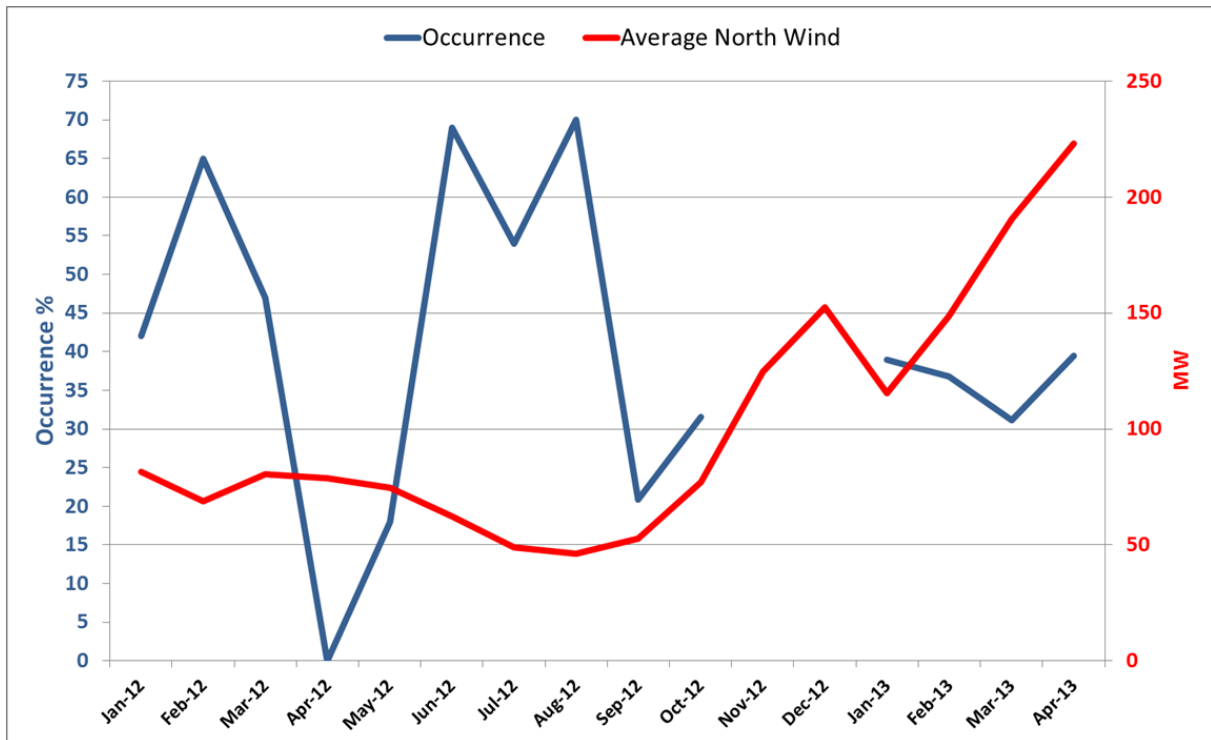


Figure 22. Mode 10 – Mode Occurrence vs. Regional North Wind

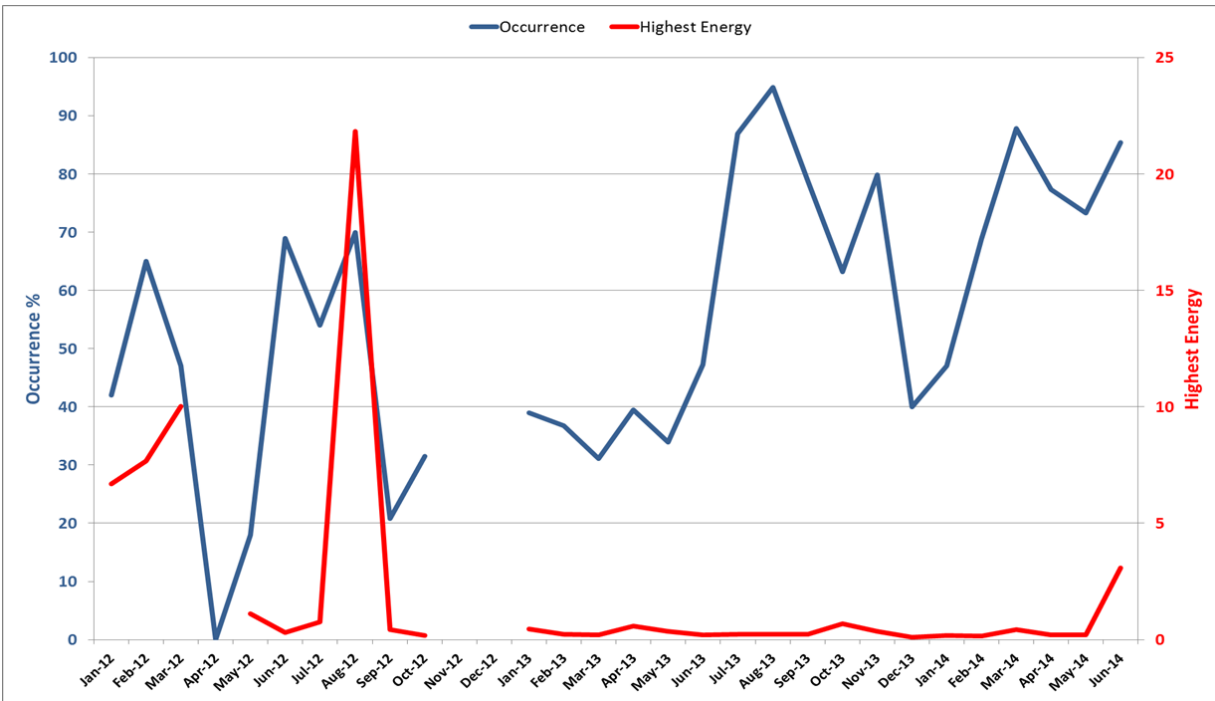


Figure 23. Mode 10 – Mode Occurrence vs. Highest Energy

West 10 appears to have two strong modes at 6.0Hz & 5.4Hz driven by the control systems of the nearby wind generators. Figure 24 shows the mode occurrence of 5.4Hz at West 10 measured from current magnitude signal spanning 3-years. The mode occurrence at 5.4Hz shows consistently higher persistence than the 6.0Hz trend, but never showed the high energy levels which were recorded for the 6.0Hz mode.

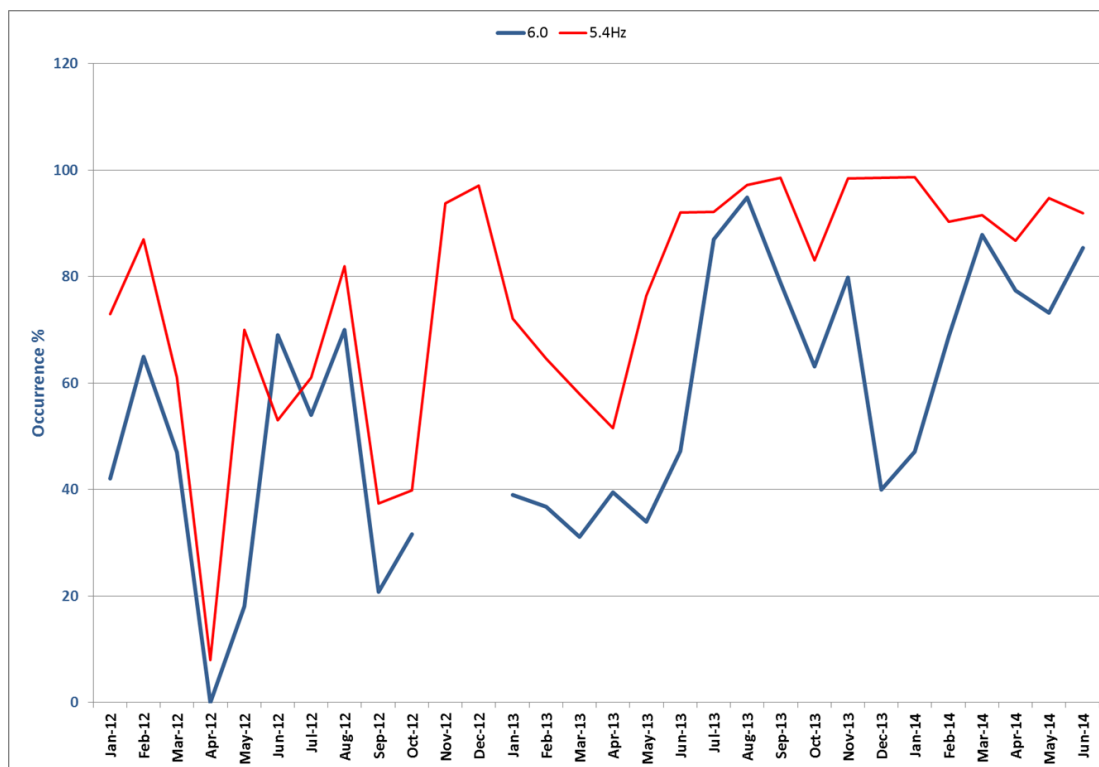


Figure 24. Mode 10 @ West 10 – 5.4Hz vs. 6.0Hz

Mode 7: 3.2Hz

Figure 25 shows the PMU location in the ERCOT interconnection that had observed 3.2Hz mode. This mode showed up in the current magnitude signal measurement in the West 10 substation. Figure 27 shows the trend of the 3.2Hz mode occurrence in the West 10 current magnitude signal over 3-years. The mode does not appear to be consistent such as 5.0Hz, 5.4Hz & 6.0Hz, but rather intermittent. The mode appeared in January, February, March, and June of 2012, then disappeared until January 2014, when it reappeared. The maximum occurrence of 3.2Hz mode appeared for 20% of time in January 2014 and minimum occurrence of the same mode appeared 10% of time in March 2013. Figure 26 shows the comparison between Mode occurrence of 3.2Hz and the monthly average north wind production in MW from January 2012 to April 2013, suggesting no causal relationship

Figure 27 also shows the comparison of the monthly mode occurrence and the highest energy levels, suggesting that the energy of the mode is relatively high when it occurs. This mode appears to be driven by control system setting changes and not to the level of wind production. This mode does not appear all the time with low energy, but rather occurs sporadically with high energy, which requires additional monitoring to detect and mitigate oscillations.

It is recommended that ERCOT do additional monitoring in real-time with the following configuration to detect increasing energy levels during high wind production.

- PMU Signal: West 10 Current Magnitude.
- Minimum Frequency = 2.6Hz.
- Maximum Frequency = 3.8Hz.
- Minimum Energy = 50.
- Damping = 8%.

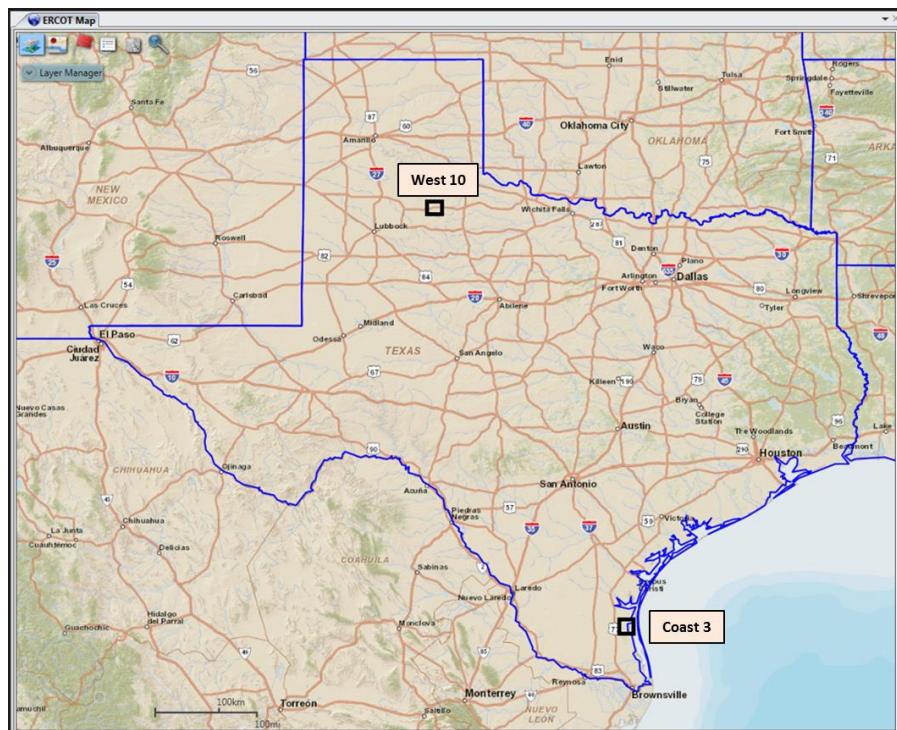


Figure 25. Mode 7 – PMU Locations

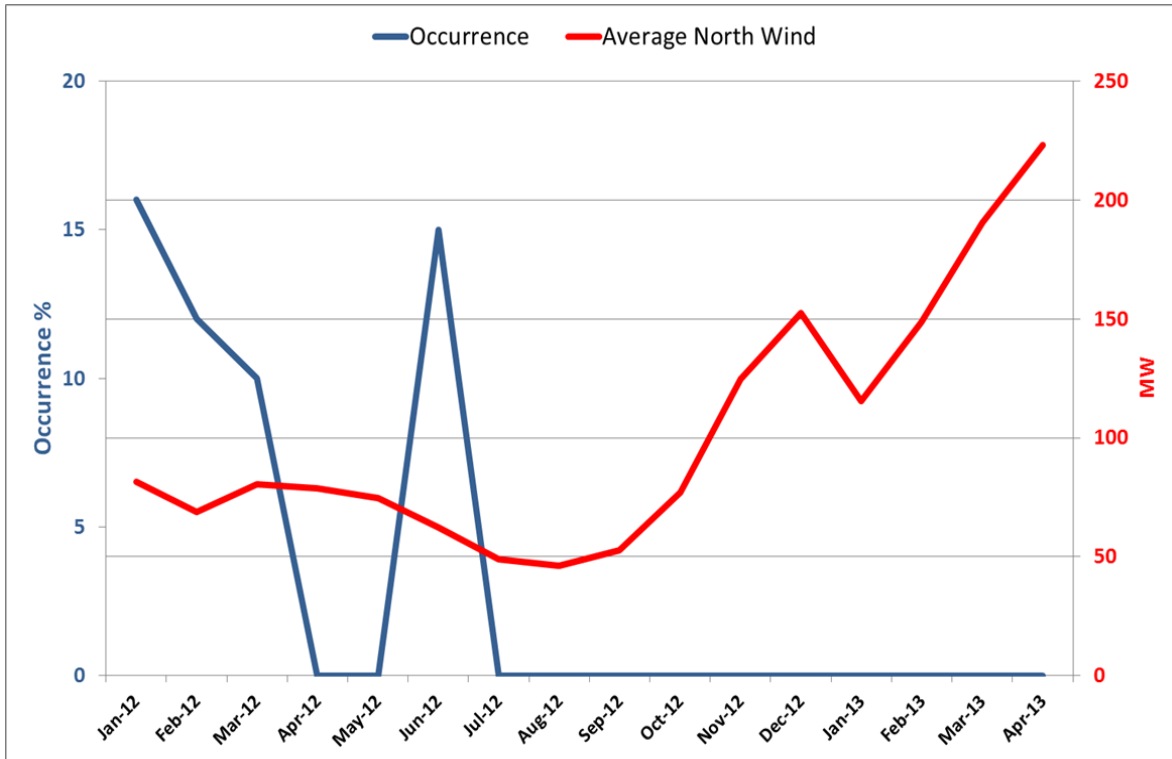


Figure 26. Mode 7 – Mode Occurrence vs. Regional North Wind

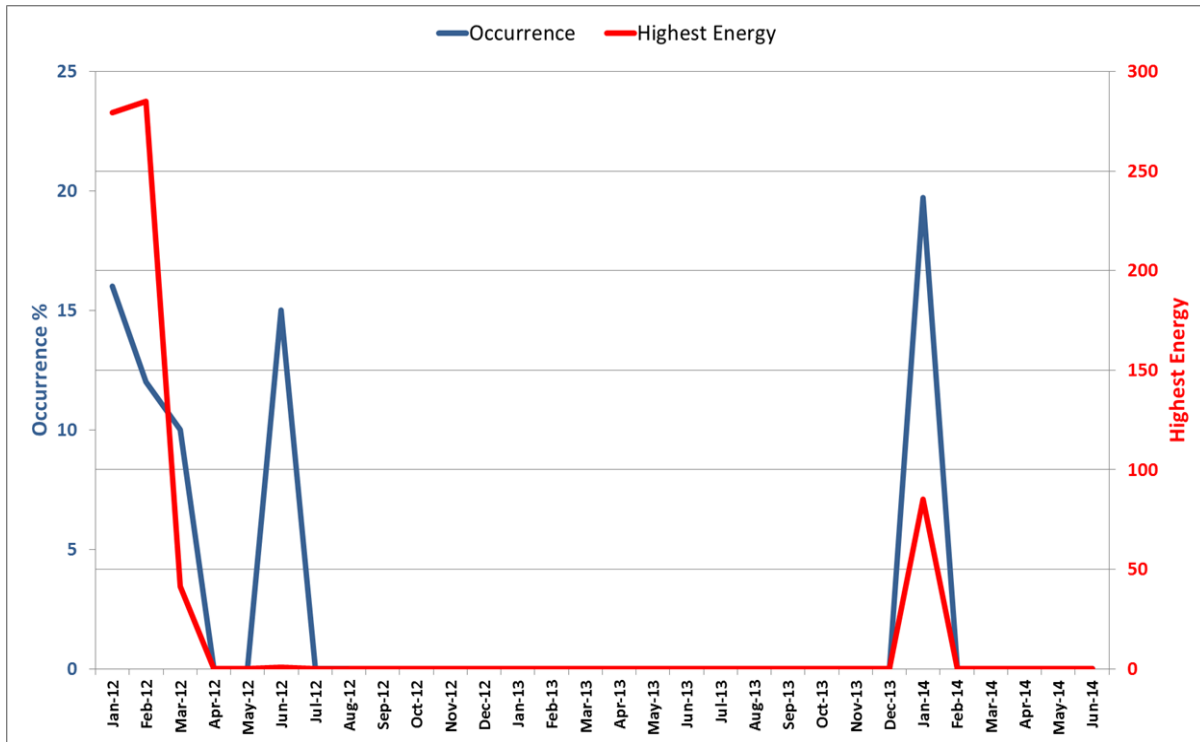


Figure 27. Mode 7 – Mode Occurrence vs. Highest Energy Level

The study also discovered other modes (1.5Hz, 1.7Hz & 2Hz) similar to 3.2Hz which are apparently driven by setting changes in the control systems of the nearby wind generators. The sources and energy levels of those modes are explained below.

Mode 3: 1.5Hz

The study discovered a mode at 1.5Hz at Coast 3 in the Valley region as shown in Figure 28. This mode occurred only in April 2012 for 0.04% of time, and with a small energy of approximately 0.02. Figure 29 shows the comparison of the mode occurrence at Coast 3 current magnitude signal with the average south wind production, suggesting that this mode occurs intermittently and is driven by settings change in the wind generation control systems. It is recommended that ERCOT do additional monitoring of this mode with the following configuration.

- Minimum Frequency = 1.0Hz.
- Maximum Frequency = 2.0Hz.
- Minimum Energy = 0.1.

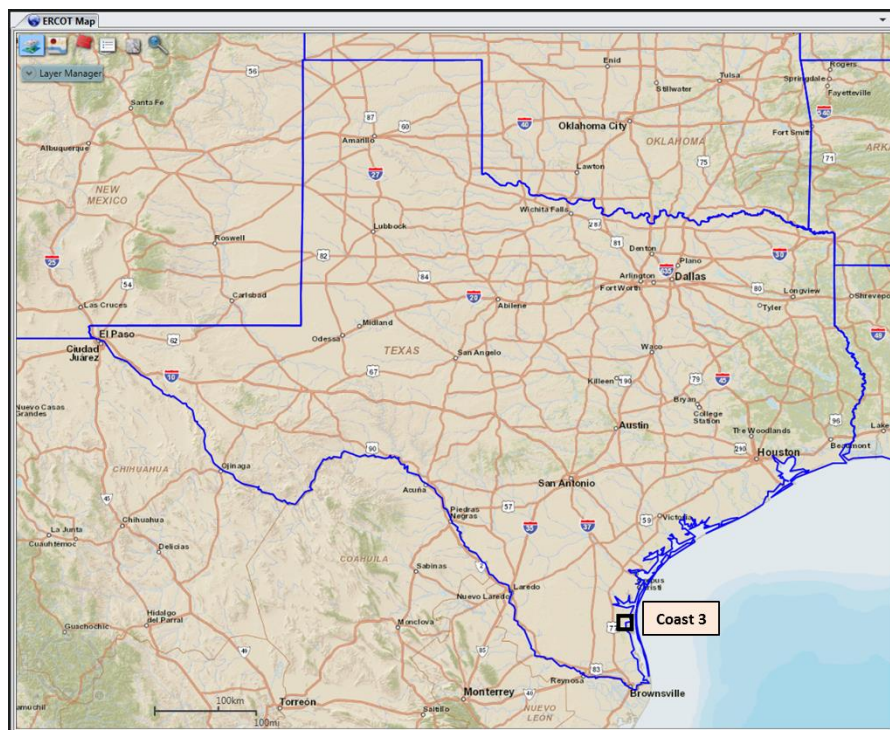


Figure 28. Mode 3 – PMU Location

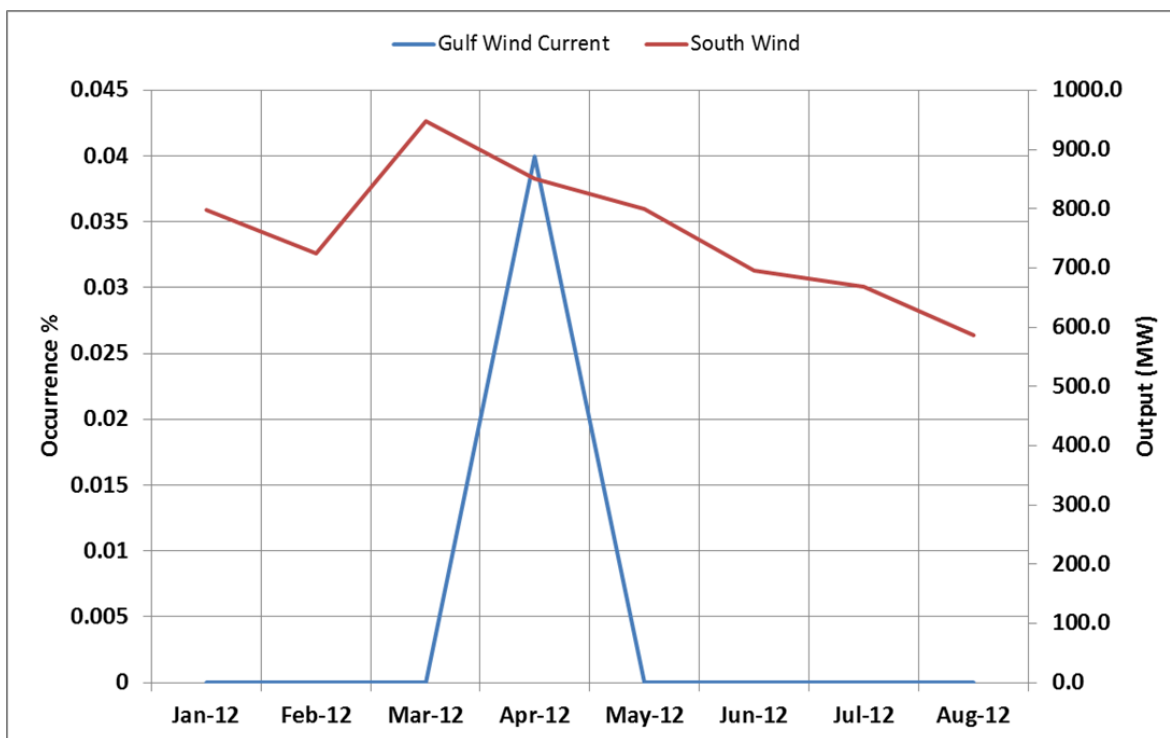


Figure 29. Mode 3 – Mode Occurrence vs. Regional South Wind

Mode 4: 1.7Hz

The study also discovered a mode at 1.7Hz at FarWest 7 in West Texas region as shown in Figure 30. This mode occurred only in January 2012 for 4% of time with high energy of approximately 36. Figure 31 shows the comparison of the mode occurrence at FarWest 7 in the current magnitude signal with the average west wind production, suggesting this is an intermittent occurrence. The oscillation was observed more strongly near FarWest 7, which has nearby Combined Cycle Units. This appears to be a local issue & ERCOT needs to review the appearance of this mode with the local generation plant owners to determine the root cause, and to evaluate the need for additional monitoring.

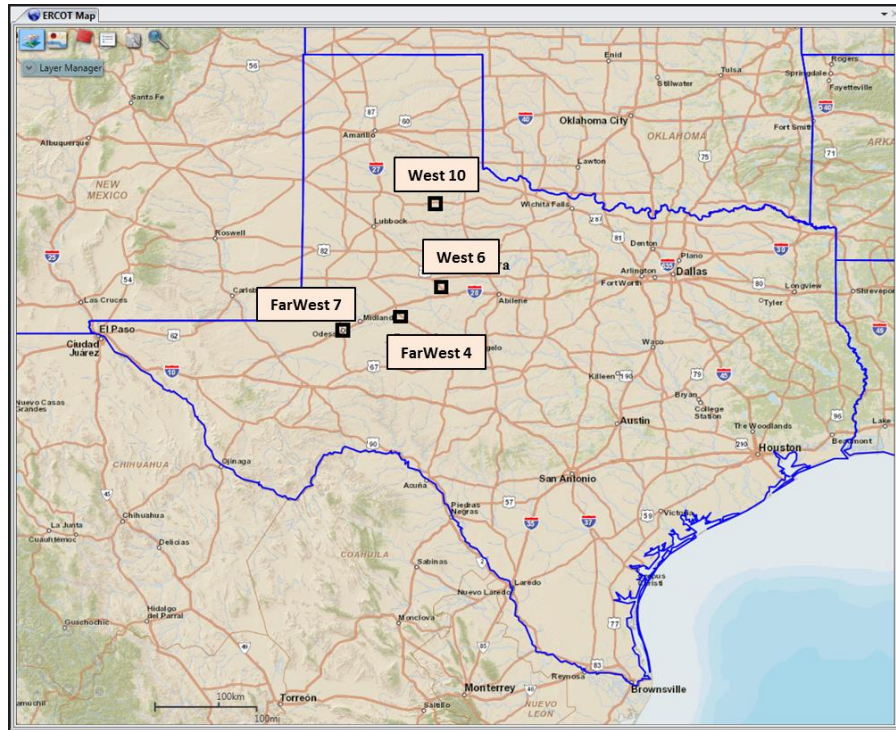


Figure 30. Mode 4 – PMU Location

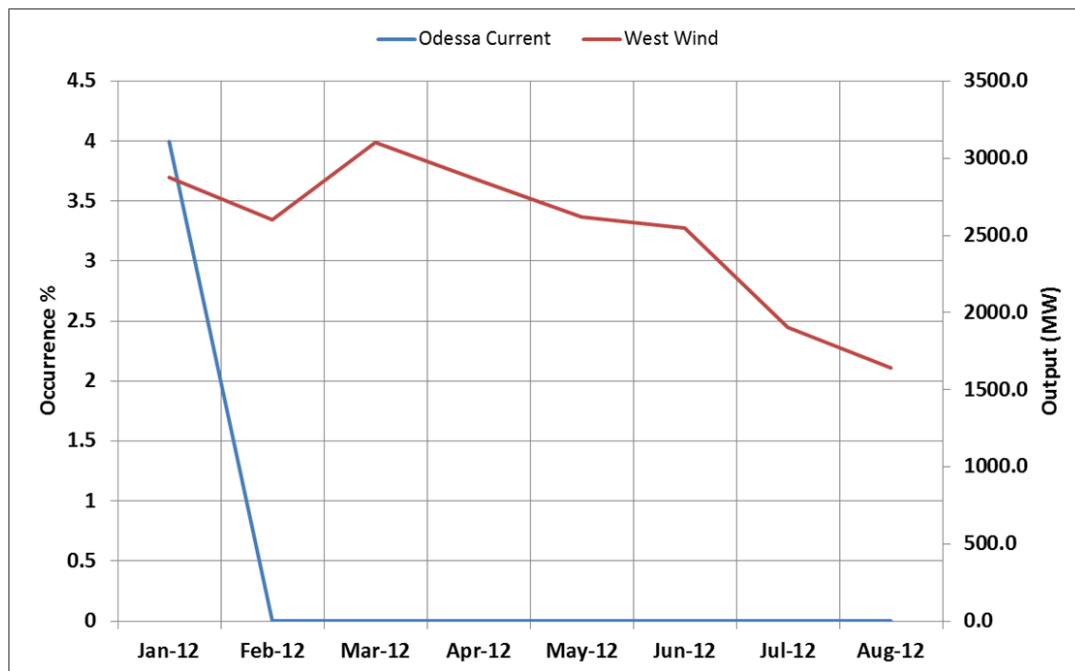


Figure 31. Mode 4 – Mode Occurrence vs. Regional West Wind

Mode 5: 2.0Hz

The study also discovered another mode at 2.0Hz at Coast 3 (Voltage Magnitude Signal measurement) in Valley region as shown in Figure 32. This mode occurred only in April 2013 for 0.8% of time with high energy approximately 0.5. The oscillation was observed more strongly near Coast 3, having nearby wind generators such as CoastGen3, CoastGen4 & CoastGen5. It is recommended that ERCOT do additional monitoring of the mode with the following configuration.

- Minimum Frequency = 1.5Hz.
- Maximum Frequency = 2.5Hz.
- Minimum Energy = 0.1.

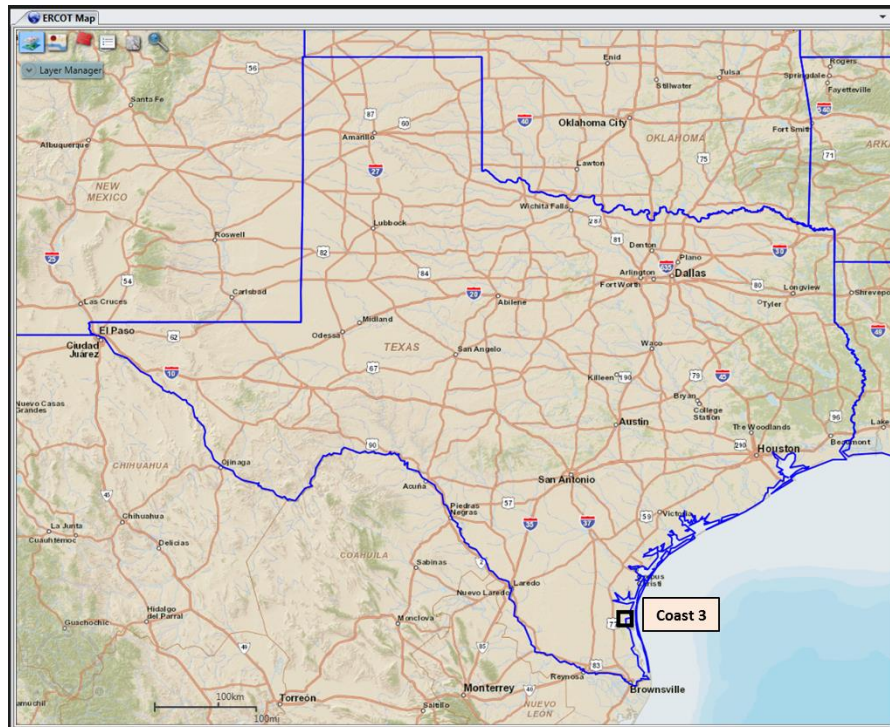


Figure 32. Mode 5 – PMU Location

Mode 1: 0.6Hz

The study discovered a mode at 0.6Hz, showing most strongly in the West 10 current magnitude signal, and which appeared for the first three months of 2012 and was never detected again. This mode occurrence at West 10 did not follow the average north wind production but was observed at nearby wind generators including WestGen10 at West 10. This appears to be a local issue and may be related to a local oscillation triggered by a transmission network topology change. The maximum highest energy of the mode was approximately 2 and minimum highest energy was about 1.6. It is recommended that ERCOT review the appearance of this mode with plant owners in order to determine the root cause, and to evaluate the need for additional monitoring. Figure

33 shows the PMU locations that observed the 0.6Hz mode, but more strongly at West 10. Figure 34 shows the comparison of the mode occurrence with the average monthly north wind production and indicates that it is likely not related to the level of wind production.

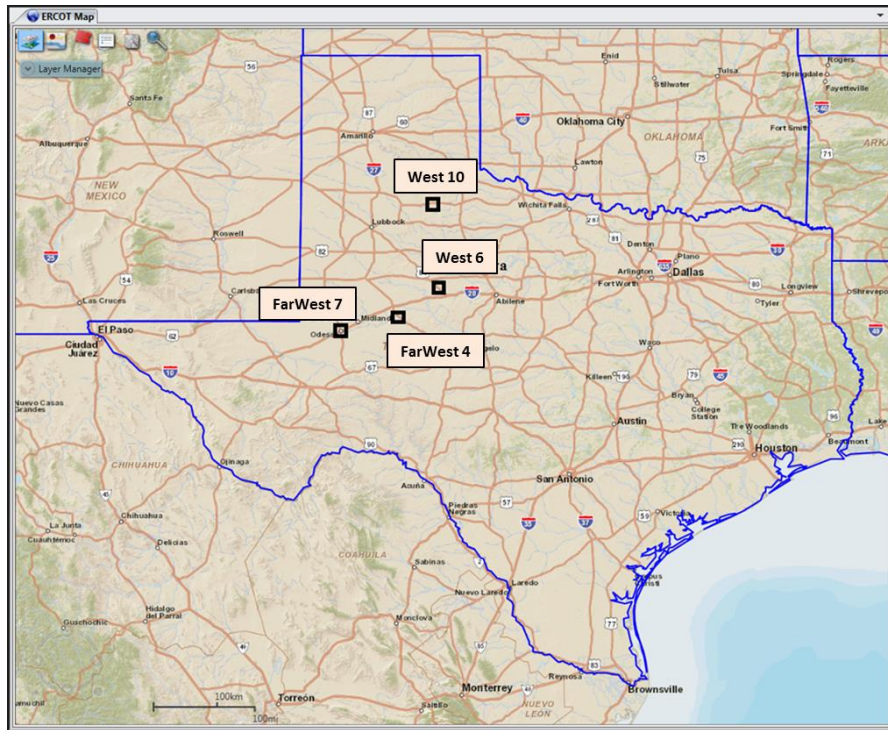


Figure 33. Mode 1 – PMU Location

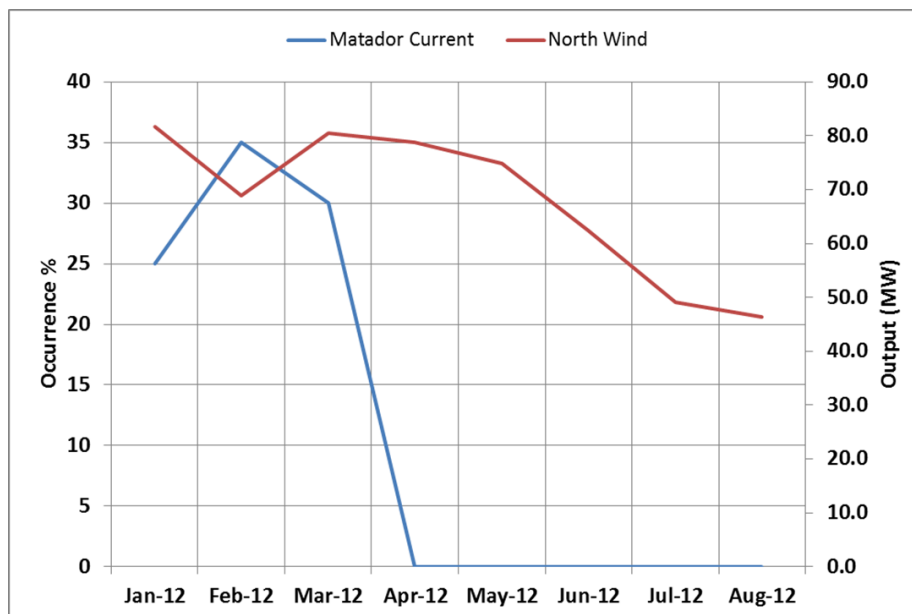


Figure 34. Mode 1 – Mode Occurrence vs. Regional North Wind

10. Conclusion

The detection of unknown oscillations from phasor data spanned 3-years of ERCOT synchrophasor data, and was performed using the Phasor Data Mining Tool. The tool enabled the automatic scanning of the data in periodic intervals, and produced a results summary, including detected oscillations, percentage of occurrence (time), and energy level time-stamped with the PMU location.

This analysis was based on six PMUs located at nearby wind farms in the ERCOT Interconnection. The Phasor Data Mining Tool was configured with the needed algorithm settings to scan for oscillations within the frequency band from 0.1Hz to 15Hz. The measurements including Frequency, Voltage Phasor and Current Magnitude for each PMU were used to scan through the input data for oscillation modes using 60-second blocks of data, and when oscillations were detected, the calculated damping and energy of each mode was recorded. The results were time-stamped and tagged to the PMU measurements to identify the source of the oscillations. The tool was asked to discard modes with damping greater than 8%. The tool leveraged the PMU status information to clean bad data in order to avoid false detections. The output results from the tool were parsed and post processed through MATLAB scripts to rank the oscillatory modes according to high occurrence and high energy. Then the results were studied to identify any relationships between Mode Occurrence and Regional wind data. The highest energy of each mode was extracted and compared with the Mode Occurrence to baseline the minimum energy required to monitor the mode in real-time, and also to differentiate modes related to wind production versus modes driven by control systems or setting change in control systems.

Some of the key findings are as follows:

1. The Study identified 10 different ERCOT Oscillatory Modes.
2. The Occurrence of 2 modes appear to be related to wind production – 0.9Hz (West 6) & 2.7Hz (FarWest 4).
3. The Occurrence of 4 modes appear to be related to control system settings changes – 1.5Hz (Coast 3), 1.7Hz (FarWest 7), 2Hz (Coast 3), 3.2Hz (West 10).
4. The Occurrence of 3 modes appear to be related to the presence of wind generation and control systems - 5.0Hz (Coast 3), 5.4Hz (West 10 & FarWest 4), 6.0Hz (West 10).
5. The Occurrence of 1 mode appears to be a local oscillation due to a topology change or tuning of wind generators – 0.6Hz (West 10).

This study concludes that four modes appear consistently for 3-years and are still present. There are four other modes that appear intermittently with high energy. There are two other modes that appeared consistently at the beginning of the study, and then were never detected again. The report provides insights on the configuration for monitoring certain modes in real-time to detect these oscillations. The modes which disappeared after some duration of time may need additional

review by ERCOT with plant owners to determine the root cause and to evaluate the need for additional monitoring.

11. Appendix

1. Final Report Presentation Material -
“CCET_Data_Mining_Oscillation_Study_313b_110414_ppt_external.pdf”.

CCET Discovery Across Texas

Wind Characteristics – Oscillations Data Mining

Presented to CCET
November 5, 2014

John W. Ballance

Prashant C. Palayam



Electric **P**ower **G**roup

PUBLIC VERSION



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Oscillations Data Mining - Outline

- Background & Purpose
- Goals
- Methodology
- Oscillations Data Mining Candidates
- MATLAB – Post Processing
- Oscillations Data Mining Performance
- Oscillations Mining Results – 3 years, 10 Modes
- Conclusion



Background & Purpose

- Texas has the greatest amount of wind generation on-line in the nation and attains a new wind production every year
- Early Detection & Mitigation of Oscillations prevents system vulnerability and customer complaints
- These Oscillations can possibly grow at high energy with increasing level of Wind Generation
- Baselining the Grid Oscillations and Monitoring in real-time is crucial to ensuring reliable operation of grid
- Purpose – Perform Phasor Data Mining Analytics to Investigate Oscillations in ERCOT Interconnection and study its impact with increasing levels of Wind Generation



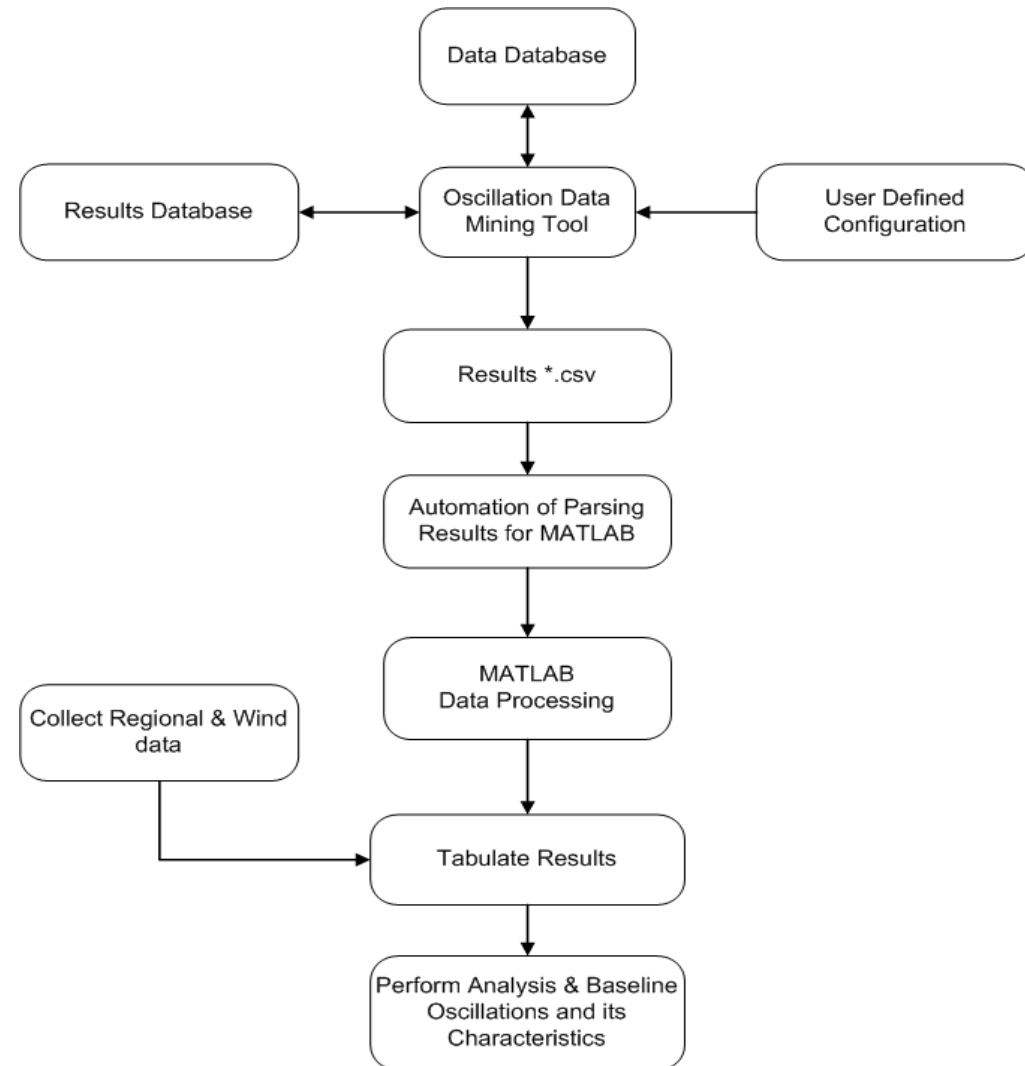
Goals

- Determine Other Unknown Oscillations
- Determine Source of Unknown Oscillations
- Determine the type of Identified Oscillations – Wind Related or driven by Control System
- Baseline Oscillations Characteristics – Mode Damping & Energy for Real-time Monitoring



Methodology

- Phasor Data (2012-2014)
- Regional Load/Wind – EMS Data
- User Configuration – *.xml file
- Identify Significant Oscillations – Using MATLAB
- Map different sources of data
- Perform Study



Oscillations Data Mining Candidates

- **PMUs near Wind Farms** – FarWest 7, West 10, FarWest 4, West 6, Coast 4, Coast 3, North 7 (Voltage Angle Reference)
- **Signal Types** – Frequency, Voltage Phasor, Current
- **1 Frequency Band** - Captures all modes
- **Use C37.118 Status bits**– Clean Data
- **Mining Tool – Reports**
 - Every Minute
 - Modes with Damping $< 8\%$
 - Minimum Energy = 0



Identification of Significant Oscillations – MATLAB Post Processing

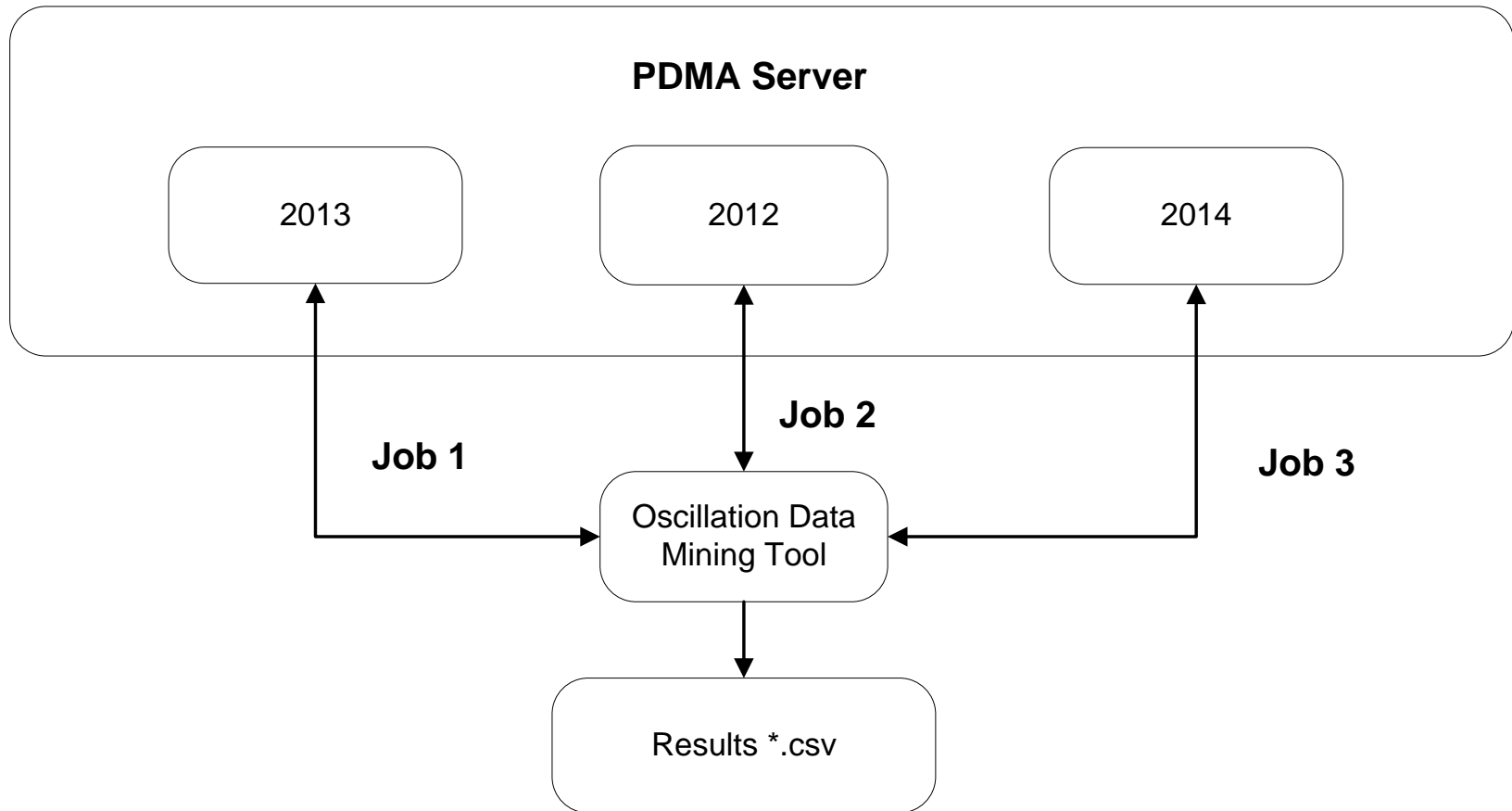
- Oscillation Data Mining Tool outputs **all calculated modes** every minute for all configured signals
- Planners and Operators need to focus on “Modes” that:
 - Occurs most of time (High Occurrence)
 - Occurs with high energy (High Magnitude)
- MATLAB Code was written to identify such critical “Modes” whose:
 - Existence is “ \geq ” 20% of Highest Occurrence
 - Magnitude is “ \geq ” 20% of Highest Energy
- Intelligence is included in code to count only distinct modes



Oscillations Data Mining Performance

| Task | Time |
|-----------------------------------------------------|--------------|
| Data Loading (1 minute of data, All PMU signals) | 3 sec |
| Data Filtering Mode Solving Result Exporting | 1 sec |
| Total (All Frequency Bands) | 4 sec |
| | |
| Ideal Example | |
| 1 Hour | 4 Min |
| 1 Day | 1.6 Hours |
| 1 Week | 11.2 Hours |
| 1 Month (31 days) | 2.06 Days |

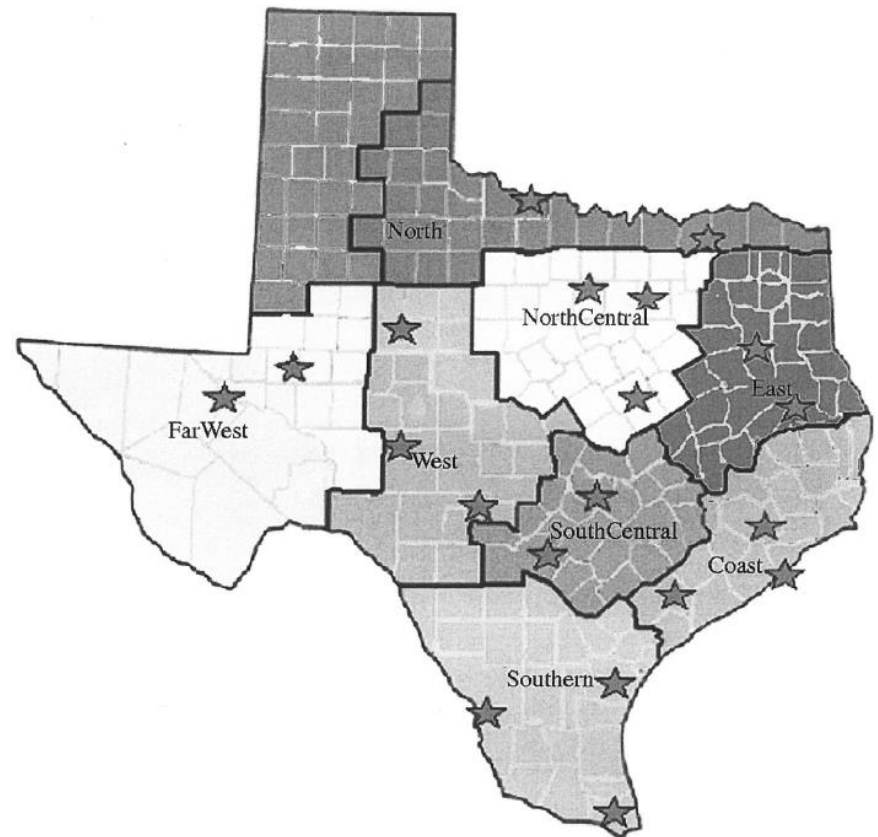
Oscillation Data Mining - Parallel Job Processing



Regional Wind Data

■ Wind Variables

- Wind North = Aggregation (North)
- Wind West = Aggregation (Far West, West)
- Wind South = Aggregation (South, Coastal Wind)



Source: ERCOT



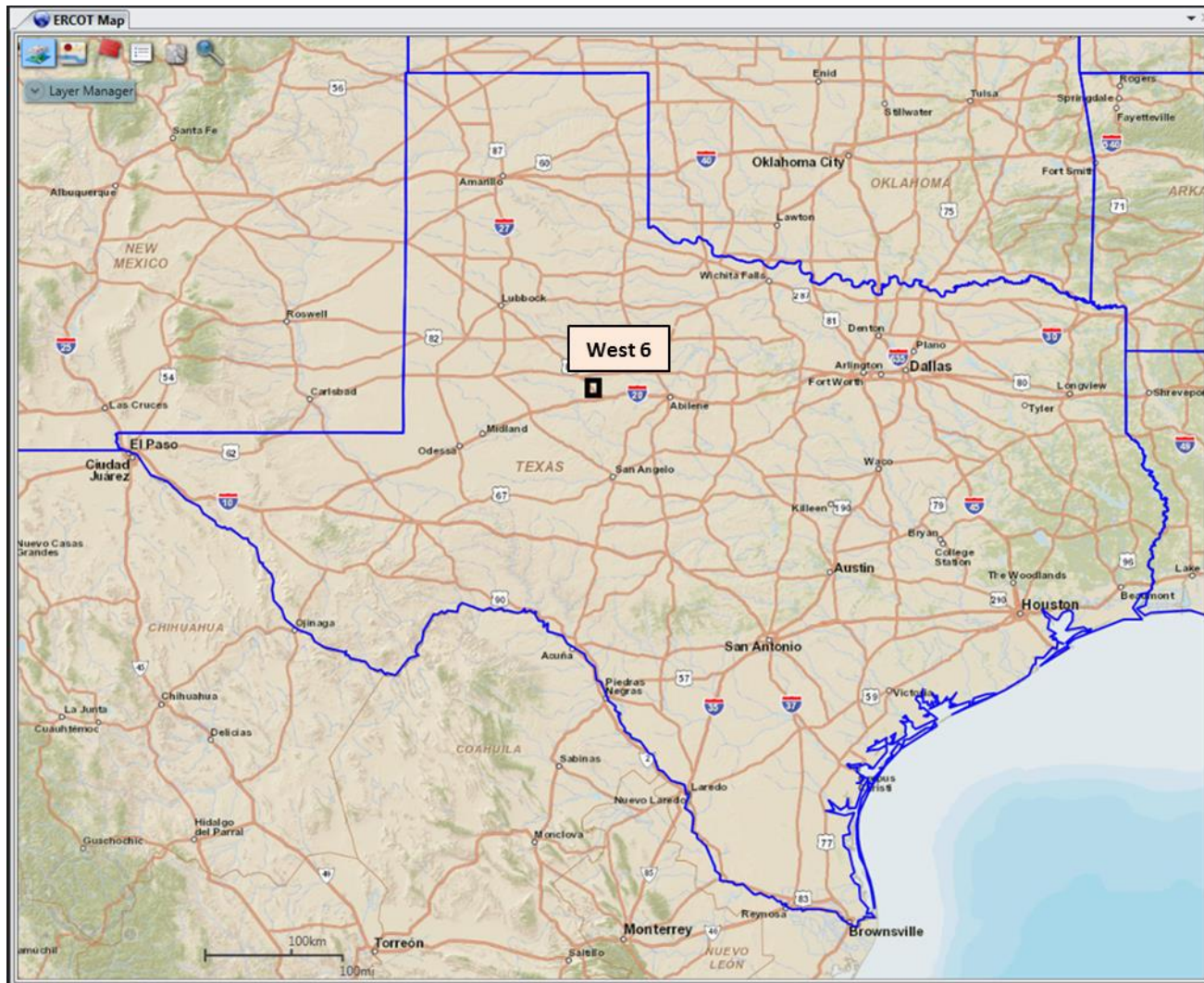
Identified 10 ERCOT Oscillatory Modes

| # | Mode (Hz) | 2012 | 2013 | 2014 | Oscillation Type |
|----|------------|---------------|---------|-------------|-------------------------|
| 1 | 0.6 | Till March | Absent | Absent | Local |
| 2 | 0.9 | Present | Present | Present | Wind Production Related |
| 3 | 1.5 | Only in April | Absent | Absent | Control Systems |
| 4 | 1.7 | 4 Months | Absent | Absent | Control Systems |
| 5 | 2.0 | Absent | April | Absent | Control Systems |
| 6 | 2.7 | Present | Present | Absent | Wind Production Related |
| 7 | 3.2 | 4 Months | Absent | Only in Jan | Control Systems |
| 8 | 5.0 | Present | Present | Present | Control Systems |
| 9 | 5.4 | Present | Present | Present | Control Systems |
| 10 | 6.0 | Present | Present | Present | Control Systems |

Identified 10 ERCOT Oscillatory Modes

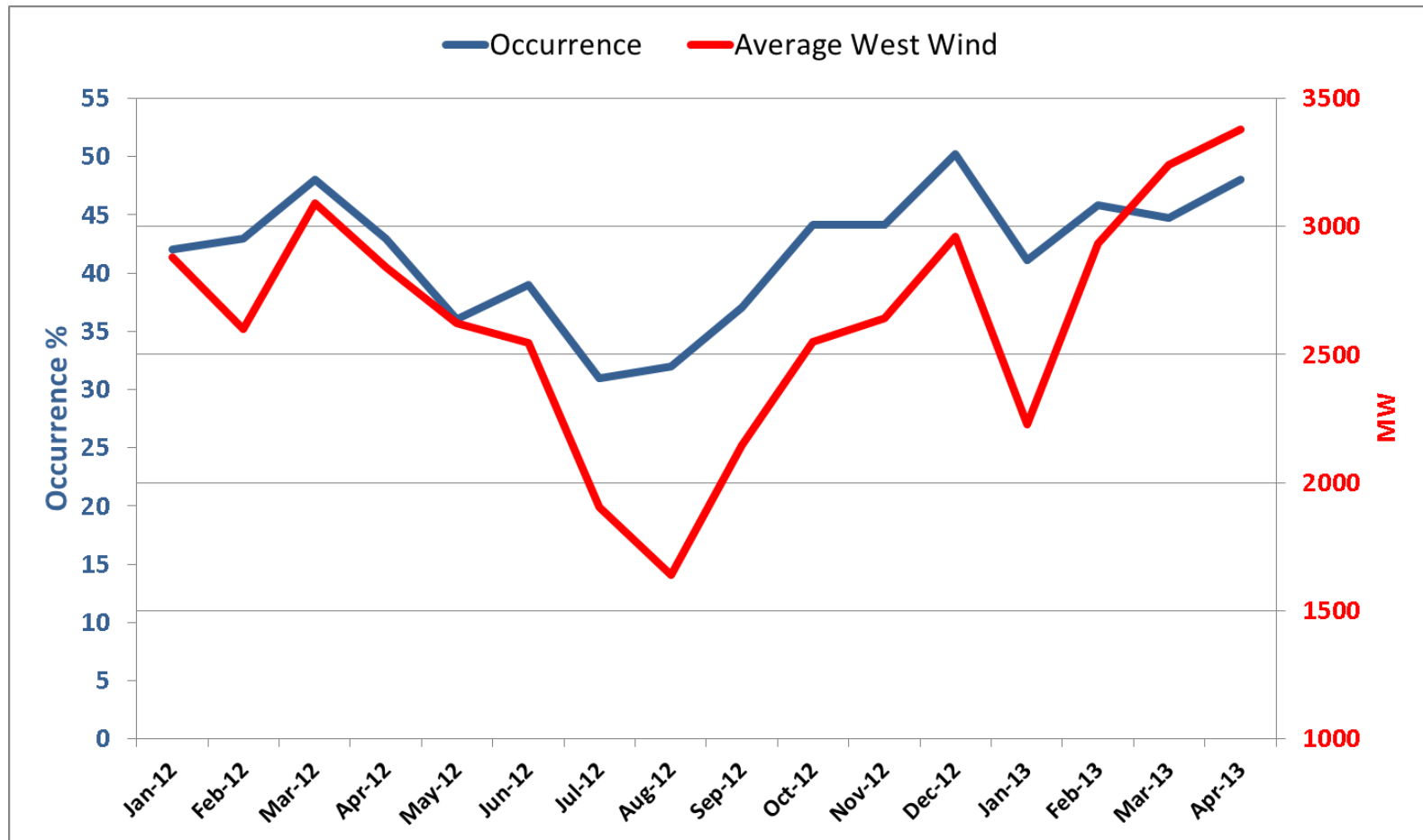
| # | Mode (Hz) | Nearest PMU | Related to Wind Production | Highest Energy Level |
|----|------------|--------------------|----------------------------|-----------------------------------|
| 1 | 0.6 | West 10 | No | Low Energy & Flat |
| 2 | 0.9 | West 6 | Yes | High Energy & Tracking Occurrence |
| 3 | 1.5 | Coast 3 | No | Low Energy |
| 4 | 1.7 | FarWest 7 | No | High Energy |
| 5 | 2.0 | Coast 3 | No | Low Energy |
| 6 | 2.7 | FarWest 4 | Yes | High Energy & Tracking Occurrence |
| 7 | 3.2 | West 10 | No | High Energy |
| 8 | 5.0 | Coast 3 | No | Low Energy & Remained Flat |
| 9 | 5.4 | West 10, FarWest 4 | No | Low Energy & Remained Flat |
| 10 | 6.0 | West 10 | No | Intermittent High Energy |

Mode #2 – 0.9Hz @ West 6



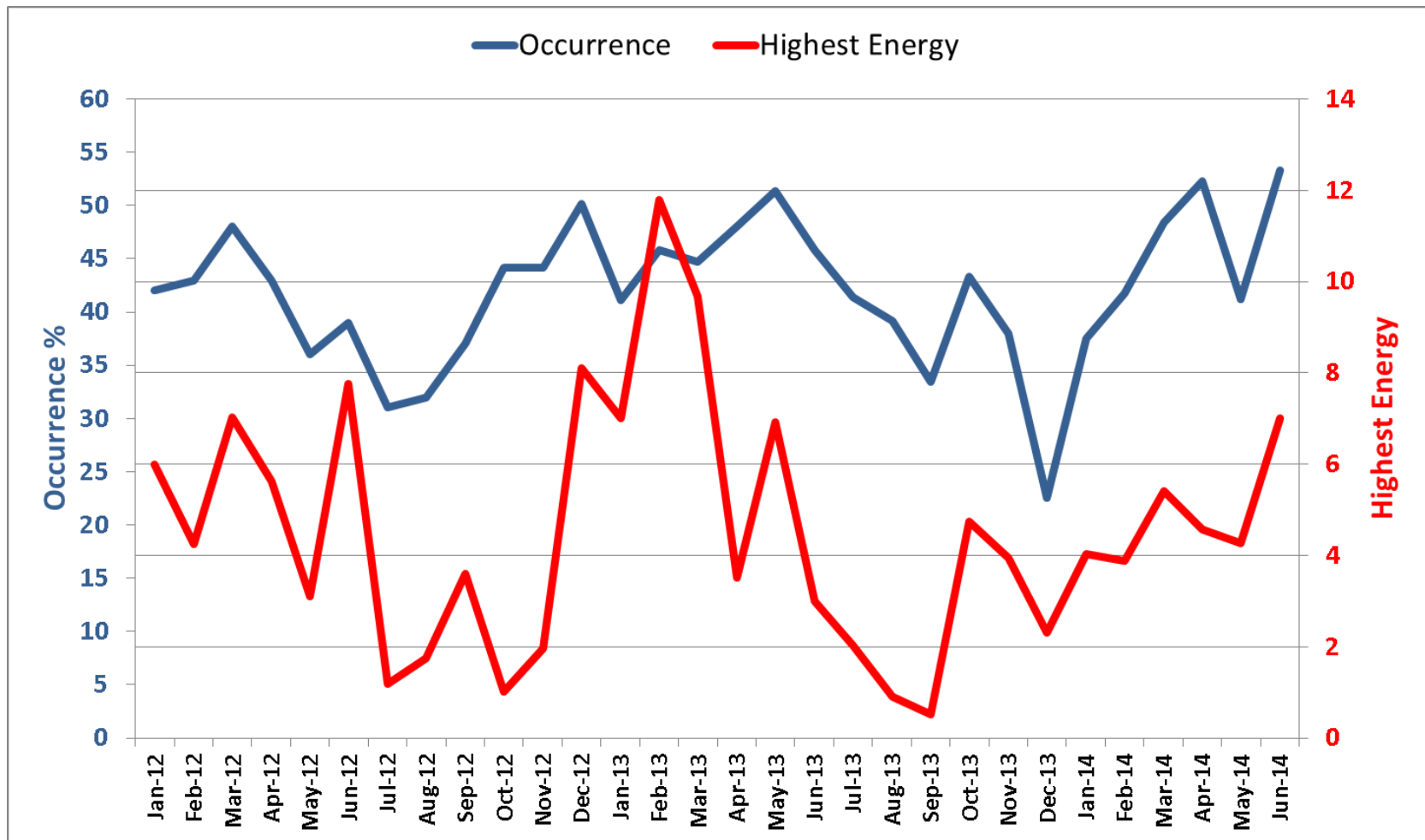
Mode #2 – 0.9Hz @ West 6

The Trend of Mode Occurrence & Average West Wind have similar pattern and provides first indication that 0.9Hz is more likely related to wind production



Mode #2 – 0.9Hz @ West 6

The peaks & valleys of Mode Occurrence & Highest Energy matched very well to provide second indication that 0.9Hz is more likely related to wind production near West 6



Mode #2 – 0.9Hz @ West 6

- Source: West 6
- Signal Type: Current Magnitude
- Oscillation Type: Wind Related
- Wind Generators Nearby: WestGen1, WestGen2, WestGen3, WestGen4
- Occurrence: Appeared every month in all three years
 - Minimum Occurrence in Dec 2013 and appeared for 22% of time
 - Maximum Occurrence in June 2014 and appeared for 53% of time
 - Average Occurrence in all three years is about 42% of time during the month

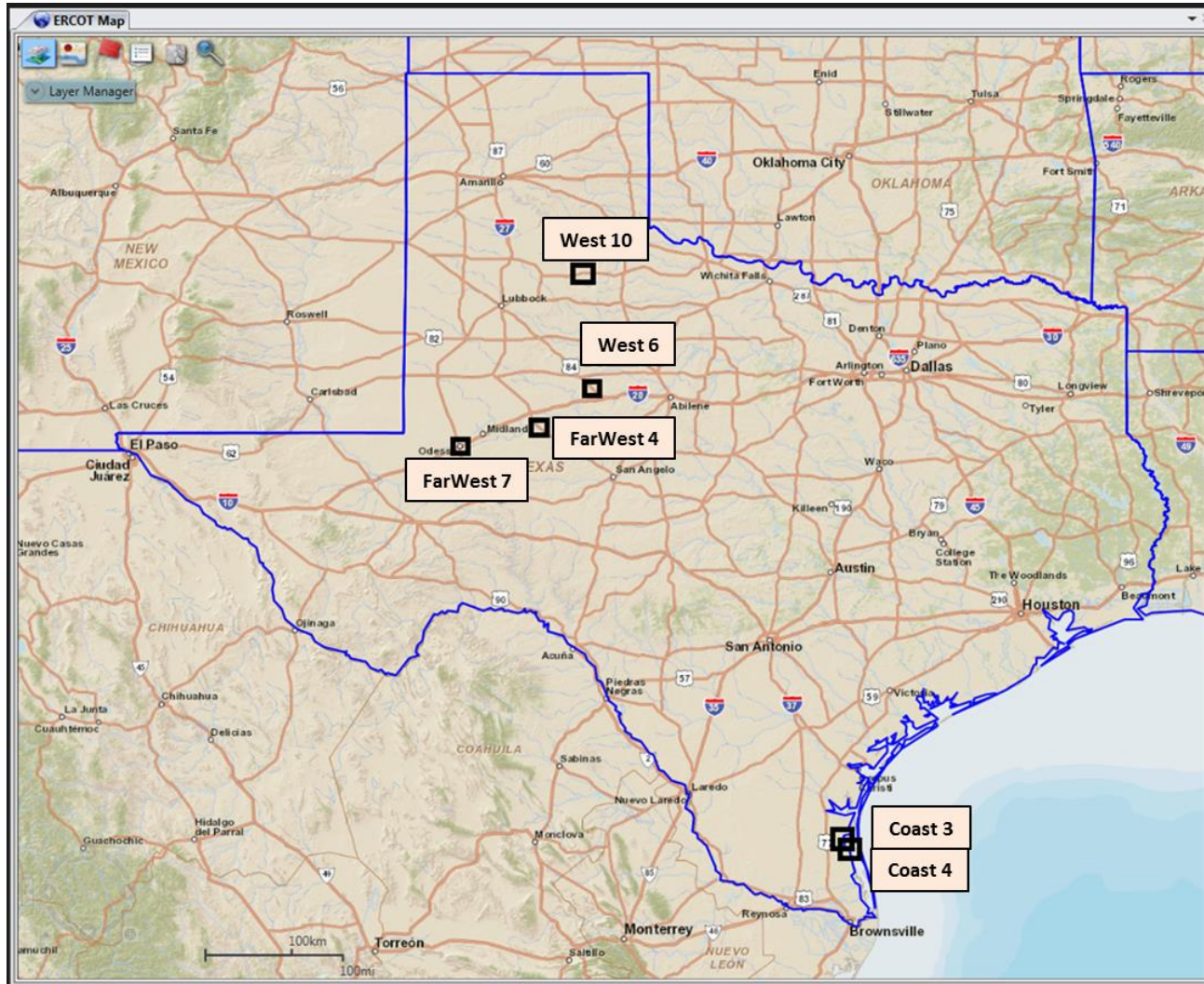


Mode #2 – 0.9Hz @ West 6

- Highest Energy: Represents the highest energy of the mode during each month
 - Maximum Highest Energy in Feb 2013 and Energy was 12
 - Minimum Highest Energy in Sep 2013 and Energy was 0.5
- **ERCOT should monitor in Real Time with the following Configuration**
 - West 6 Current Magnitude
 - Minimum Frequency = 0.85Hz
 - Maximum Frequency = 1.2Hz
 - Minimum Energy = 2
 - Damping = 8%

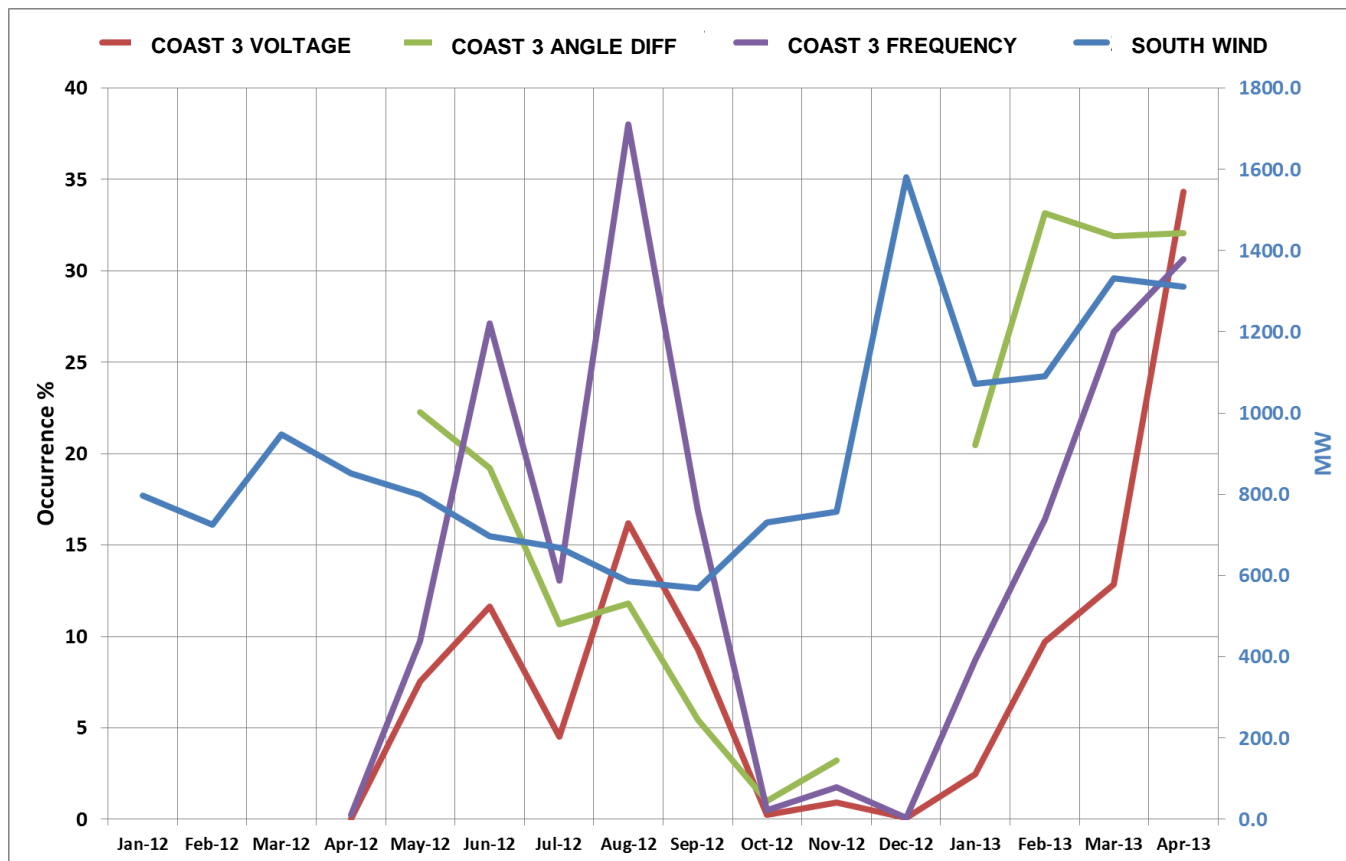


Mode #8 – 5.0Hz @ 6 Locations



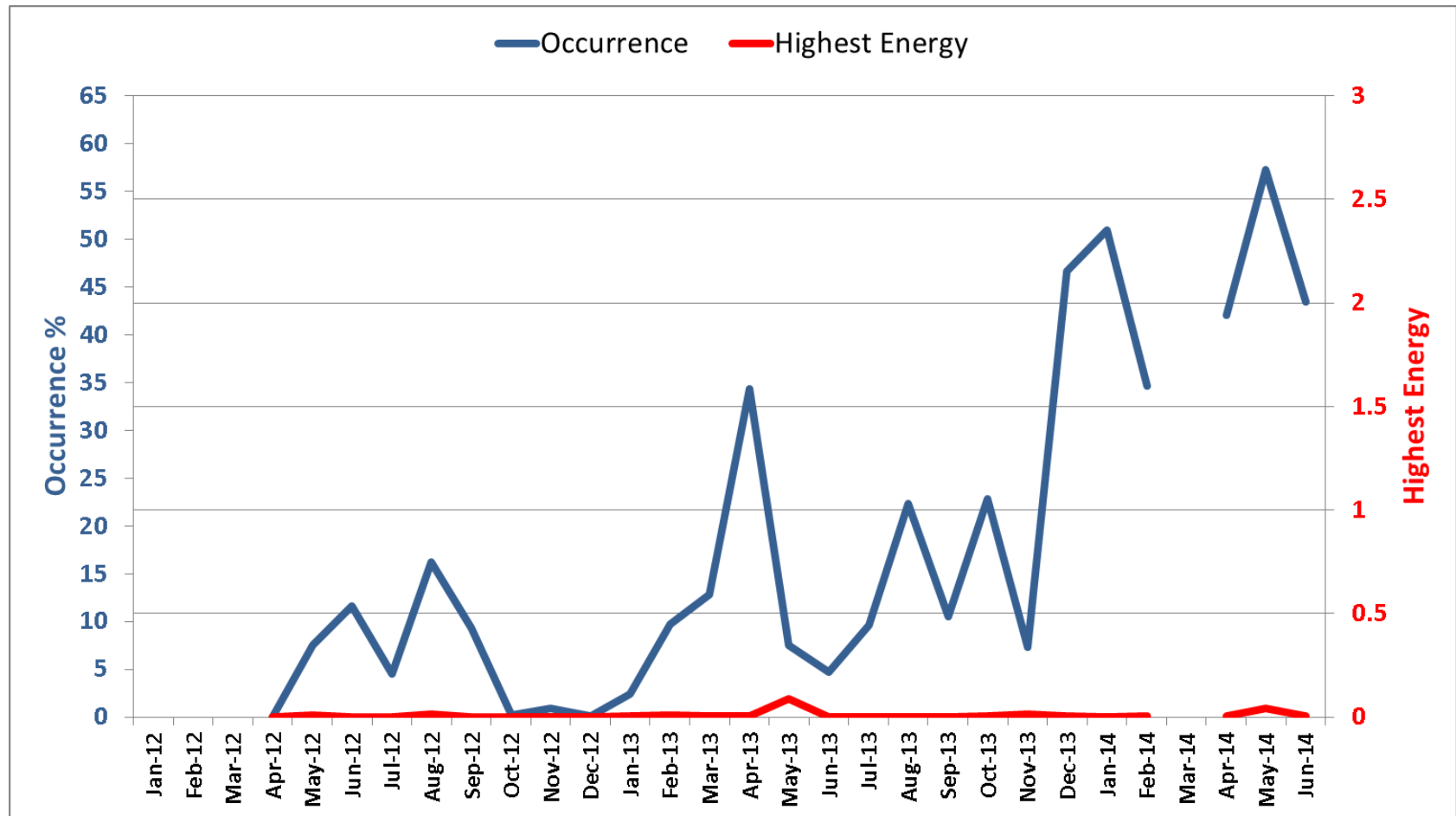
Mode #8 – 5.0Hz (May Not be Wind Production Related)

- Mode Occurrence @ Coast 3 does not follow South Wind Pattern & may need local wind production data to confirm any relationship
- But these oscillations are observed more strongly near wind generators



Mode #8 – 5.0Hz (Local Control Systems)

- The energy of the mode remained fairly flat at low levels (< 0.01) indicating no relationship with changing wind production
- But these oscillations are more likely driven by control systems at the local wind generators



Mode #8 – 5.0Hz @ Coast 3

- Source: Valley (Coast 3 & Coast 4 – Most Occurrence)
- Signal Type: Voltage Magnitude
- Oscillation Type: Wind Generator Control System
- Generators Nearby: CoastGen3 & CoastGen4
- Occurrence: Appeared every month in all three years except first 3 months of 2012 & March 2013
 - Minimum Occurrence in Dec 2012 and appeared for 0.1% of time
 - Maximum Occurrence in May 2014 and appeared for 57% of time

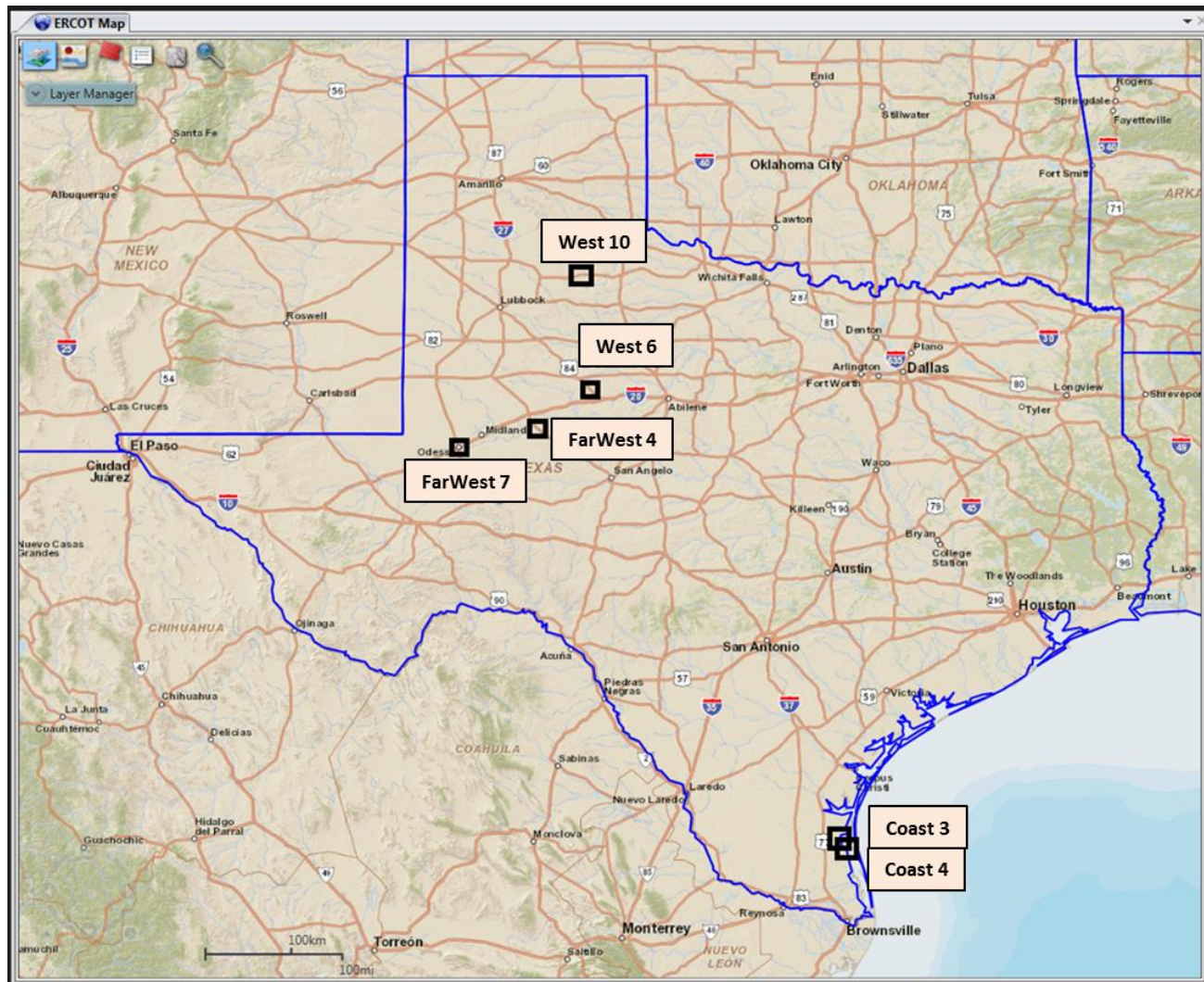


Mode #8 – 5.0Hz @ Coast 3

- Highest Energy: Represents the highest energy of the mode during each month (No Significant Event with High Energy)
 - Maximum Highest Energy in May 2013 and Energy was 0.09 (low)
 - Minimum Highest Energy in Dec 2012 and Energy was 0.00015 (very low)
- **ERCOT should review 5.0Hz oscillation with wind owners for possible mitigation and determine root cause to evaluate need for additional monitoring**

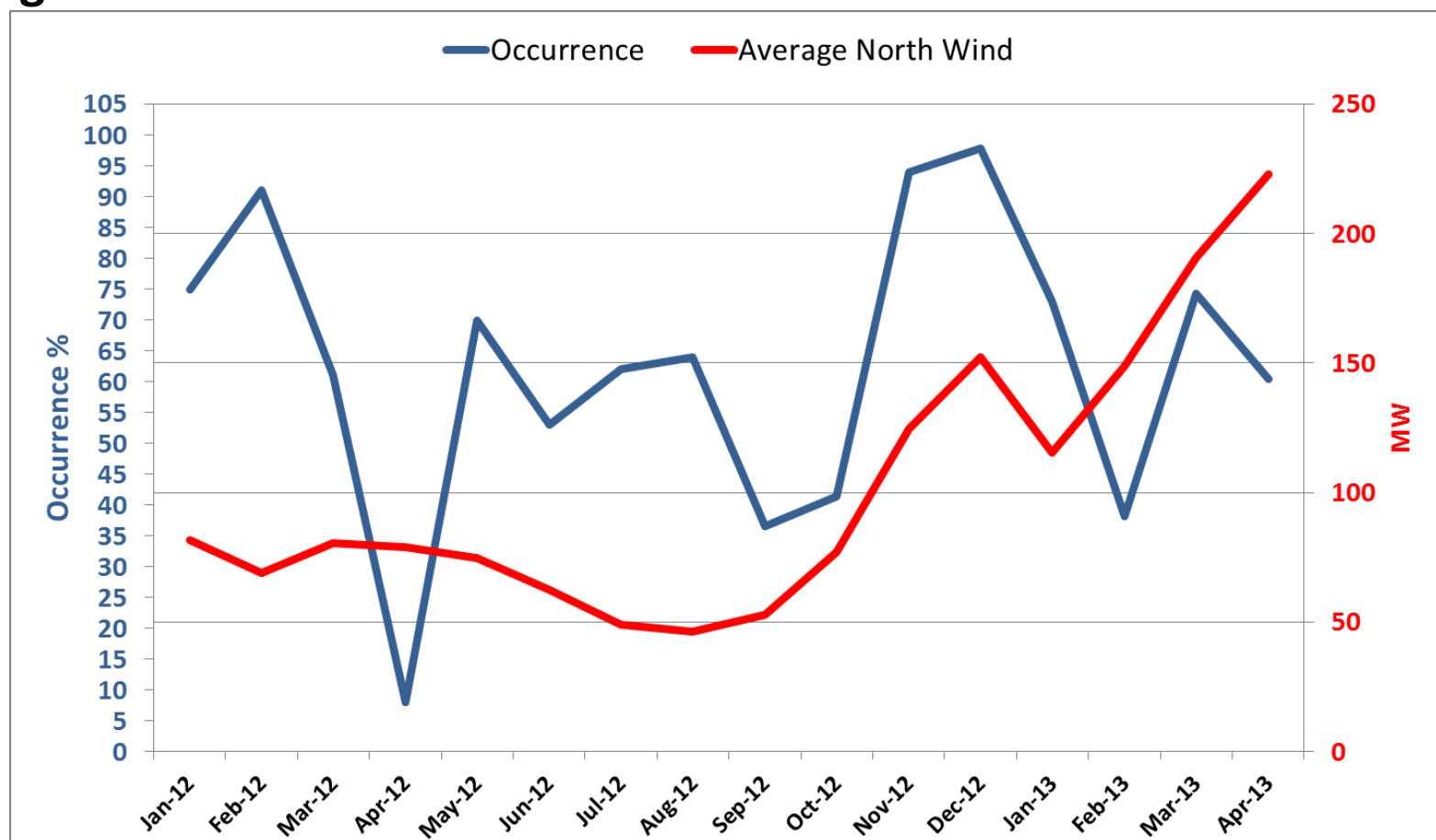


Mode #9 – 5.4Hz @ 6 Locations



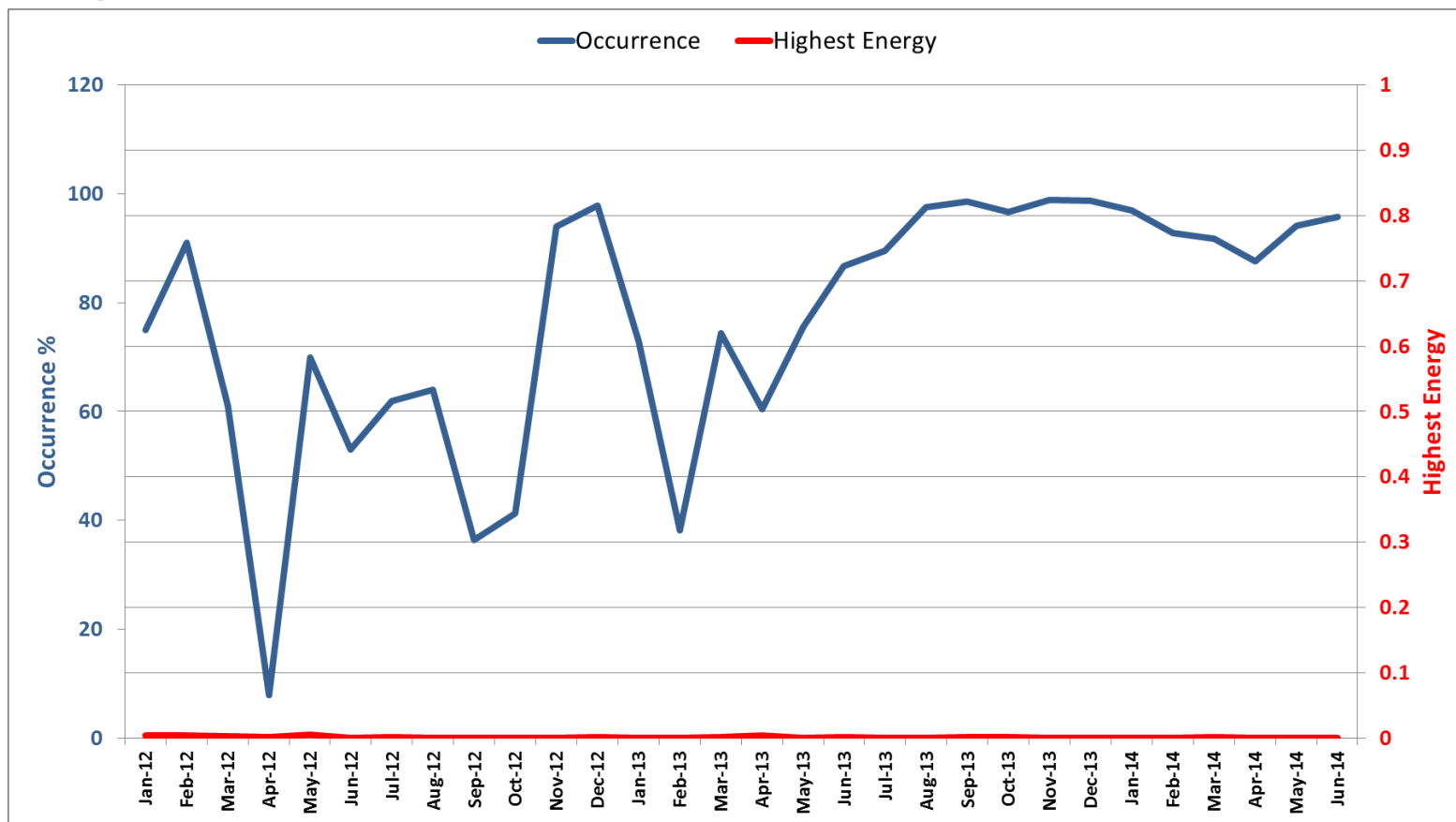
Mode #9 – 5.4Hz @ West 10

- Mode Occurrence @ West 10 does not follow North Wind Pattern & may need local wind production data to confirm any relationship
- But these oscillations are observed more strongly near wind generators



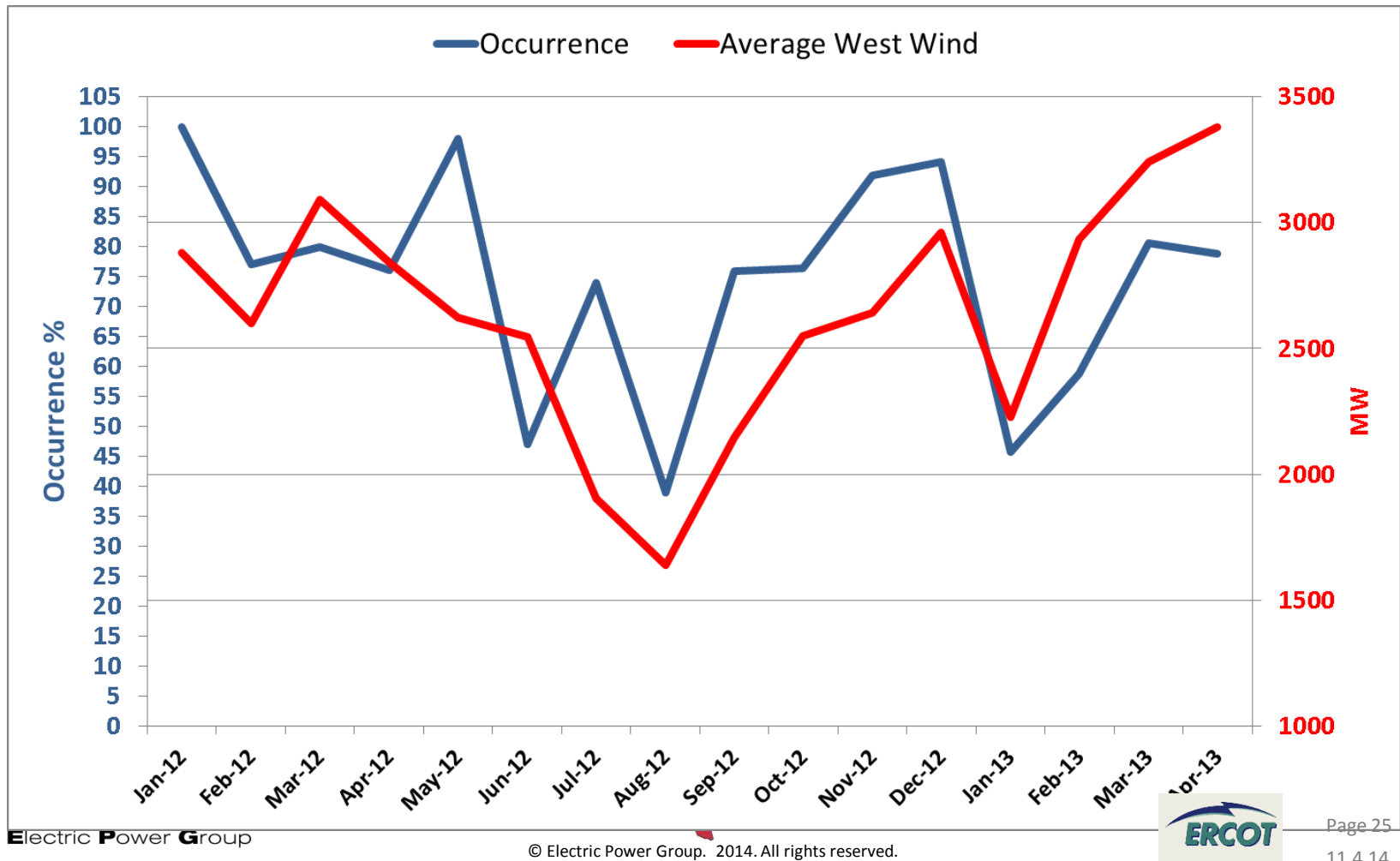
Mode #9 – 5.4Hz @ West 10 (Local Control Systems)

- The energy of the mode remained fairly flat at low levels (< 0.01) indicating no relationship with changing wind production
- But these oscillations are more likely driven by control systems at the local wind generators



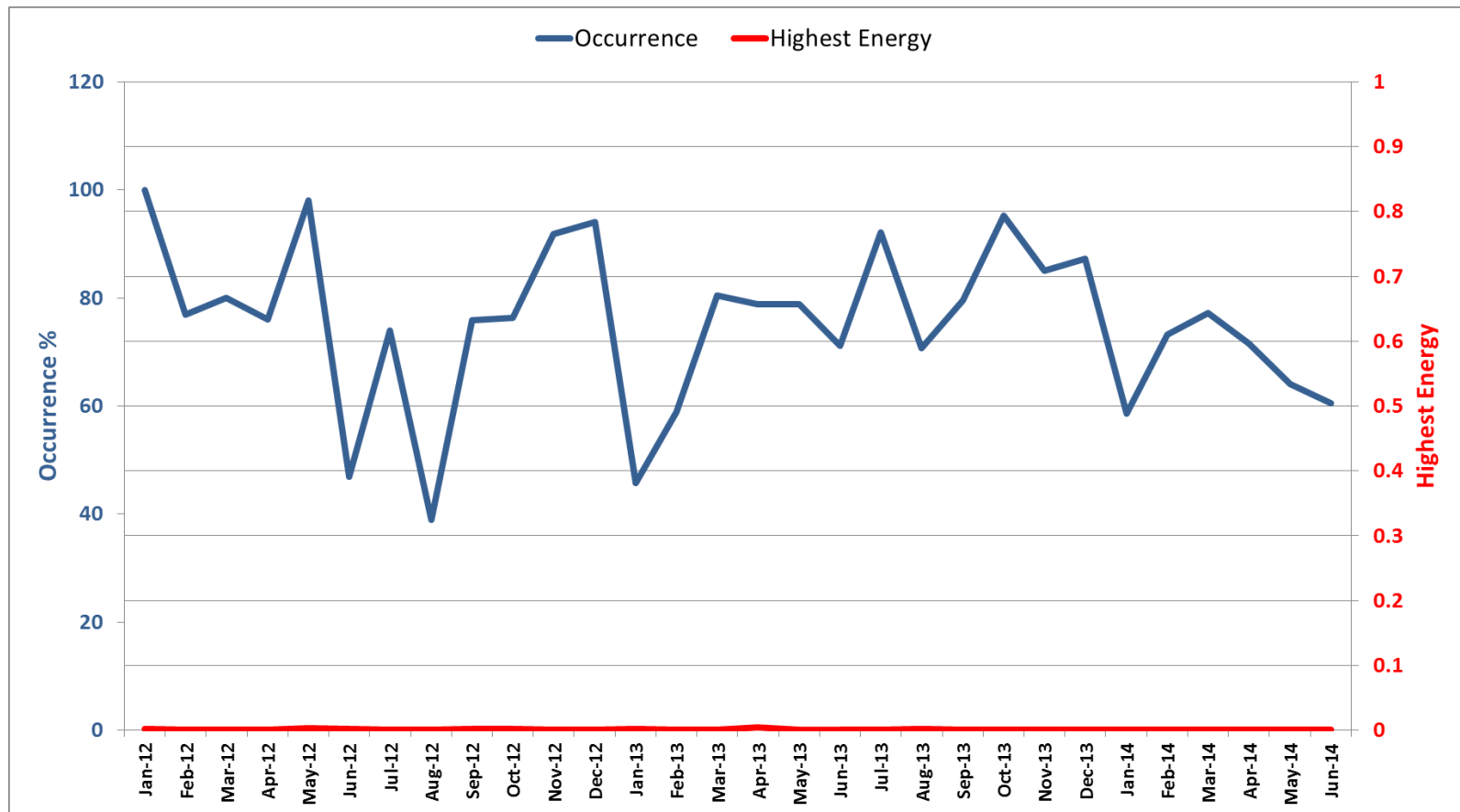
Mode #9 – 5.4Hz @ FarWest 4

The Trend of Mode Occurrence & Average West Wind have similar pattern and provides first indication that 5.4Hz may be related to wind production

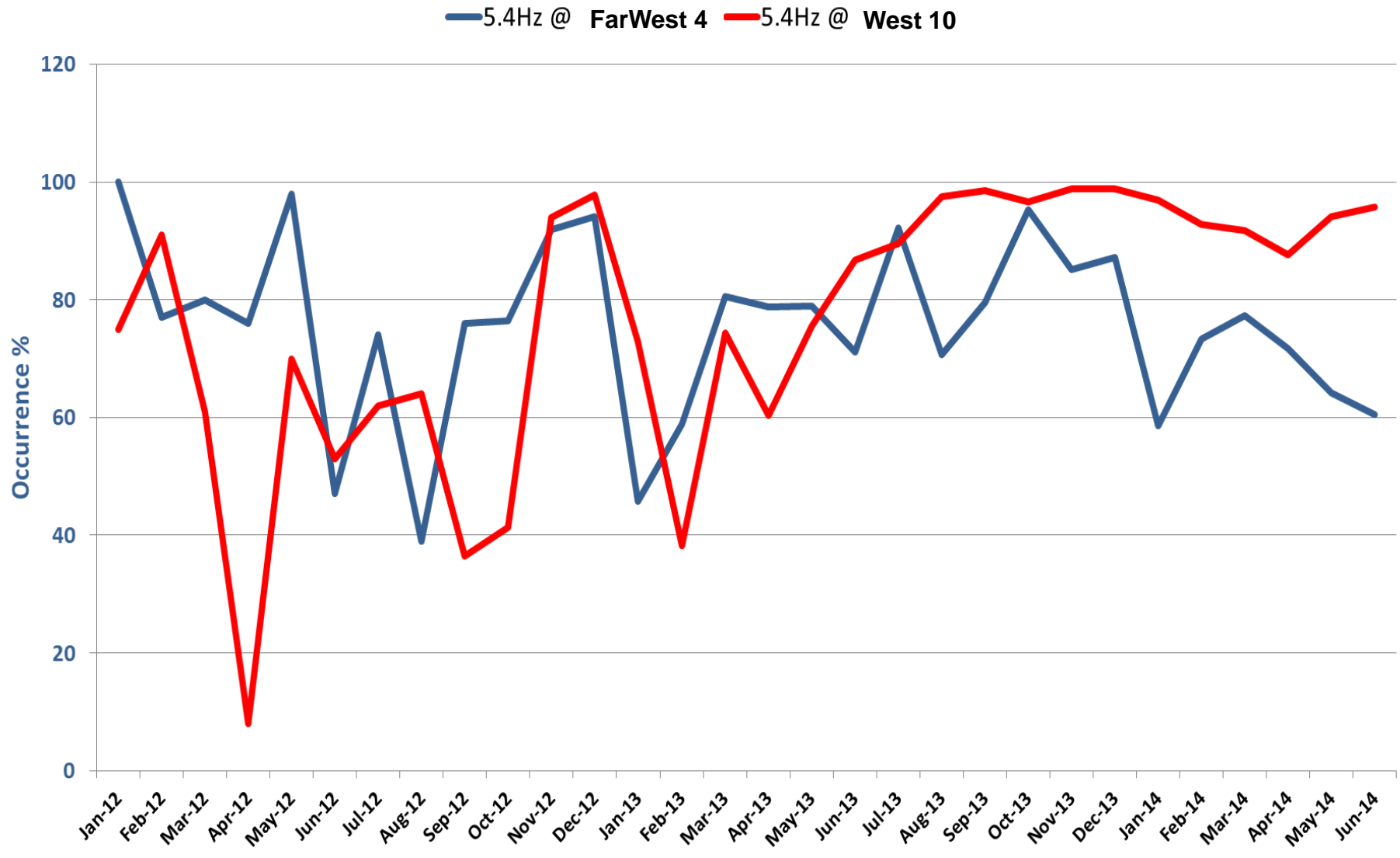


Mode #9 – 5.4Hz @ FarWest 4 (Local Control Systems)

- The energy of the mode remained fairly flat at low levels (< 0.01) indicating no relationship with changing wind production
- But these oscillations are more likely driven by control systems at the local wind generators



5.4Hz Mode Pattern – FarWest 4 Vs. West 10



Mode #9 – 5.4Hz @ West Texas & Panhandle

- Source: Panhandle (West 10), West (FarWest 4, FarWest 7, West 6) – Most Occurrence
- PMU: West 10 & FarWest 4
 - West 10 was selected to monitor mode in the panhandle region
 - FarWest 4 was selected since it had the highest Mode Occurrence among FarWest 7 & West 6 in West Texas
- Signal Type: Voltage Magnitude
 - Voltage Magnitude was selected since it had the highest Occurrence in each PMU
- Oscillation Type: Wind Generator Control System
- Wind Generators Nearby: WestGen10 & FarWestGen4

Mode #9 – 5.4Hz @ West 10

- Occurrence: Appeared every month in all three years
 - Minimum Occurrence in April 2012 and appeared for 8% of time (2.5 Days)
 - Maximum Occurrence in Sep, Nov & Dec 2013 and appeared for 99% of time (All the time)
- **ERCOT should review 5.4Hz oscillation with wind owners for possible mitigation and determine the root cause to evaluate need for additional monitoring**

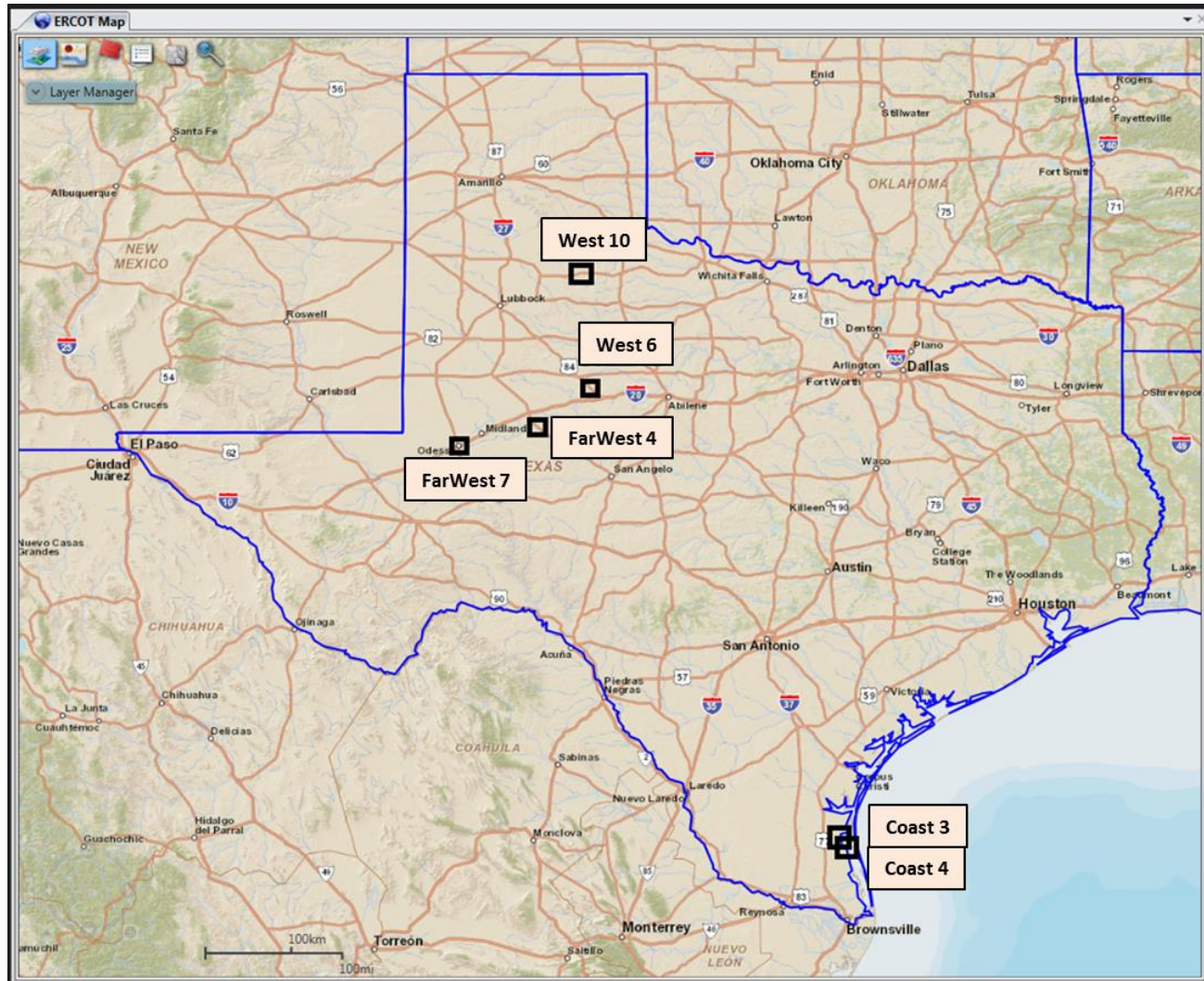


Mode #9 – 5.4Hz @ FarWest 4

- Occurrence: Appeared every month in all three years
 - Minimum Occurrence in August 2012 and appeared for 39% of time (12 Days)
 - Maximum Occurrence in Jan 2012 and appeared All the time
- **ERCOT should review 5.4Hz oscillation with wind owners for possible mitigation and determine the root cause to evaluate need for additional monitoring**

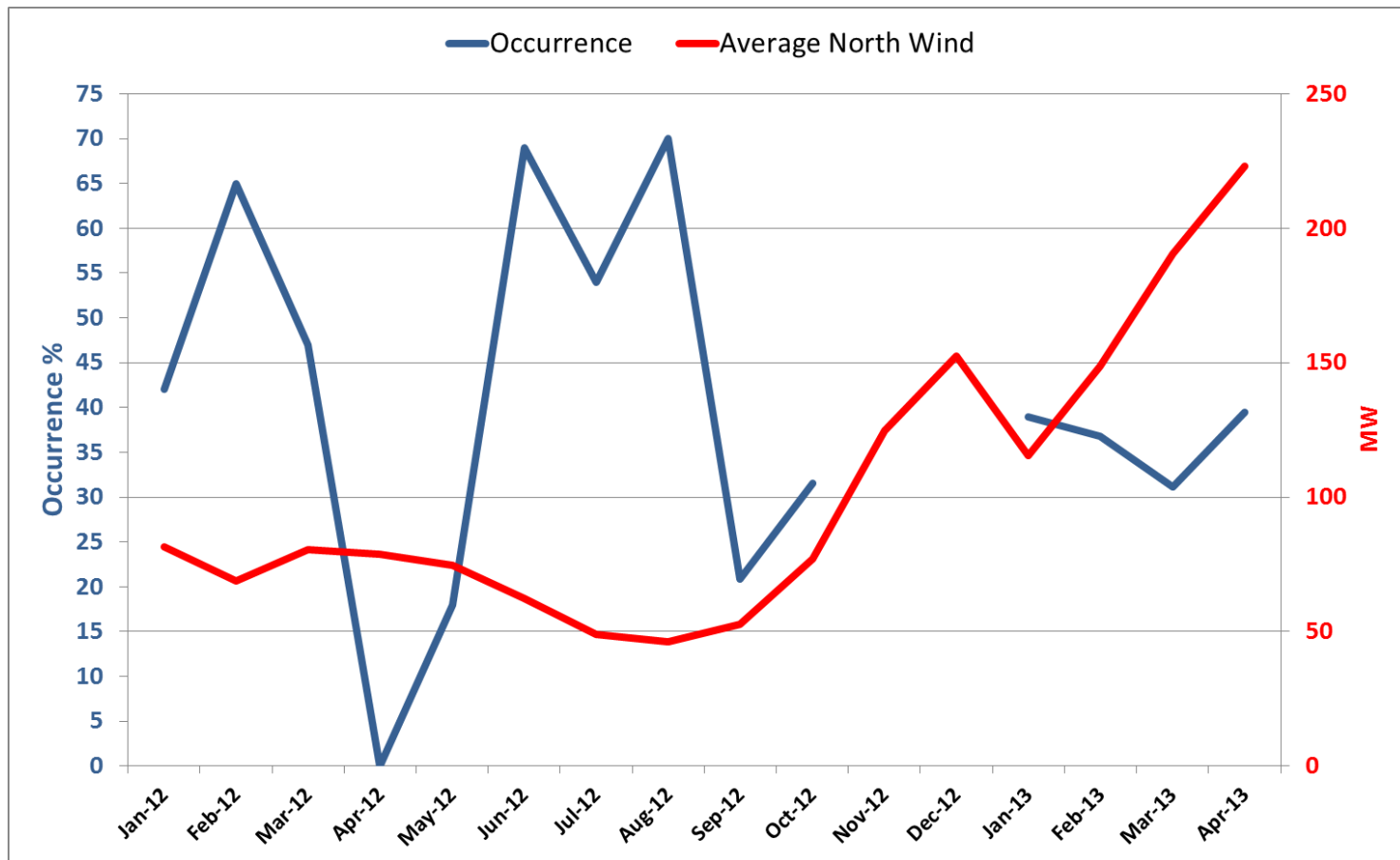


Mode #10 – 6.0Hz @ 6 Locations



Mode #10 – 6.0Hz @ West 10

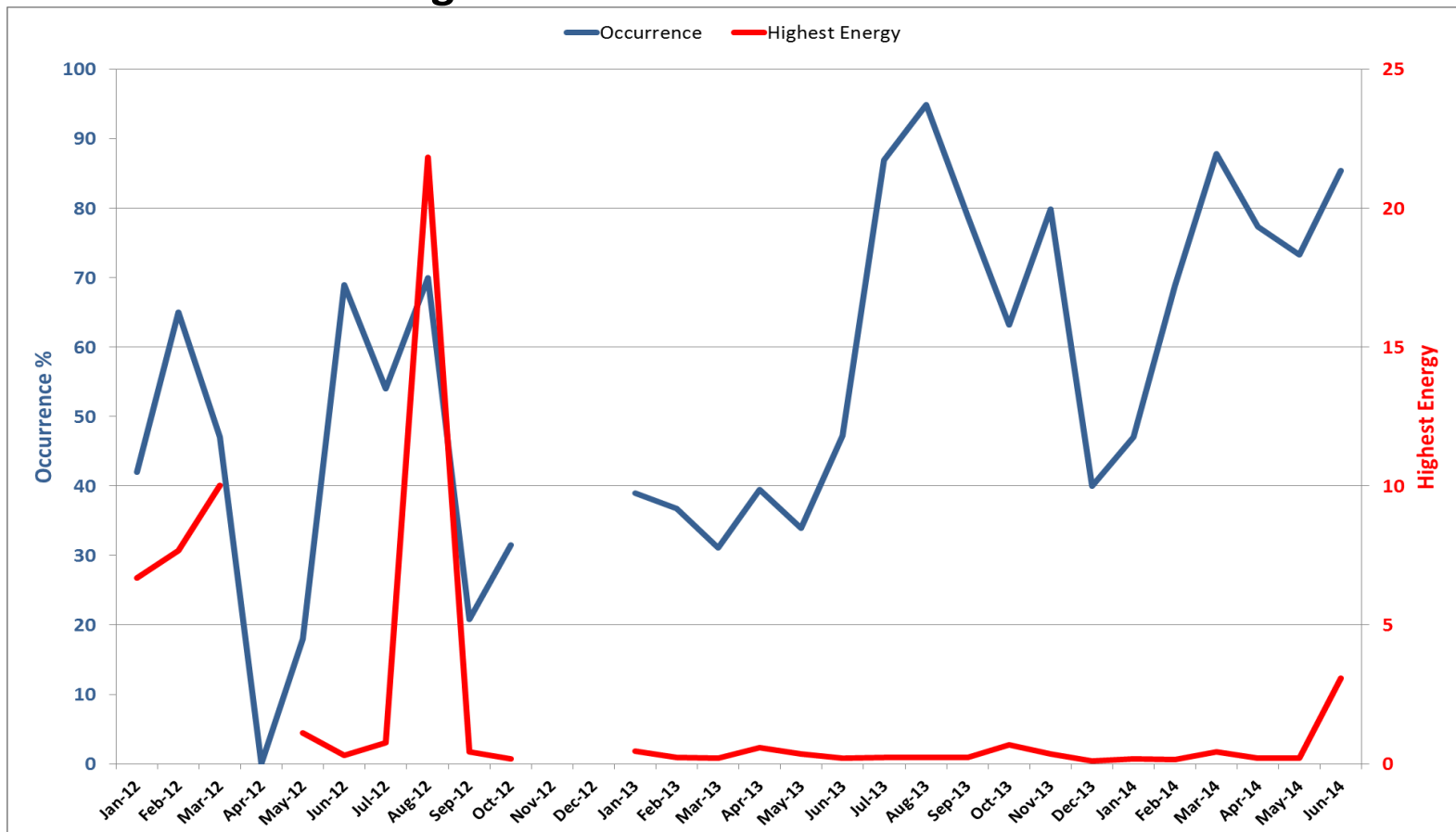
- Mode Occurrence @ West 10 does not follow North Wind Pattern & may need local wind production data to confirm any relationship
- But these oscillations are observed more strongly near wind generators



Mode #10 – 6.0Hz @ West 10

(Local Control Systems)

- The energy of the mode remained fairly flat at low levels (< 0.01) except in Jan-March & August 2012, indicating oscillations driven by control systems at the local wind generators can also reach high energy levels and needs additional monitoring



Mode #10 – 6.0Hz @ West Texas & Panhandle

- Source: Panhandle (West 10) – Most Occurrence
- PMU: West 10
 - West 10 was selected to monitor mode in the panhandle region since it had the most & consistent Mode Occurrence
- Signal Type: Current Magnitude
 - Current Magnitude was selected since it had the highest Occurrence among other signal types
- Oscillation Type: Wind Generator Control Systems
- Generators Nearby: WestGen10

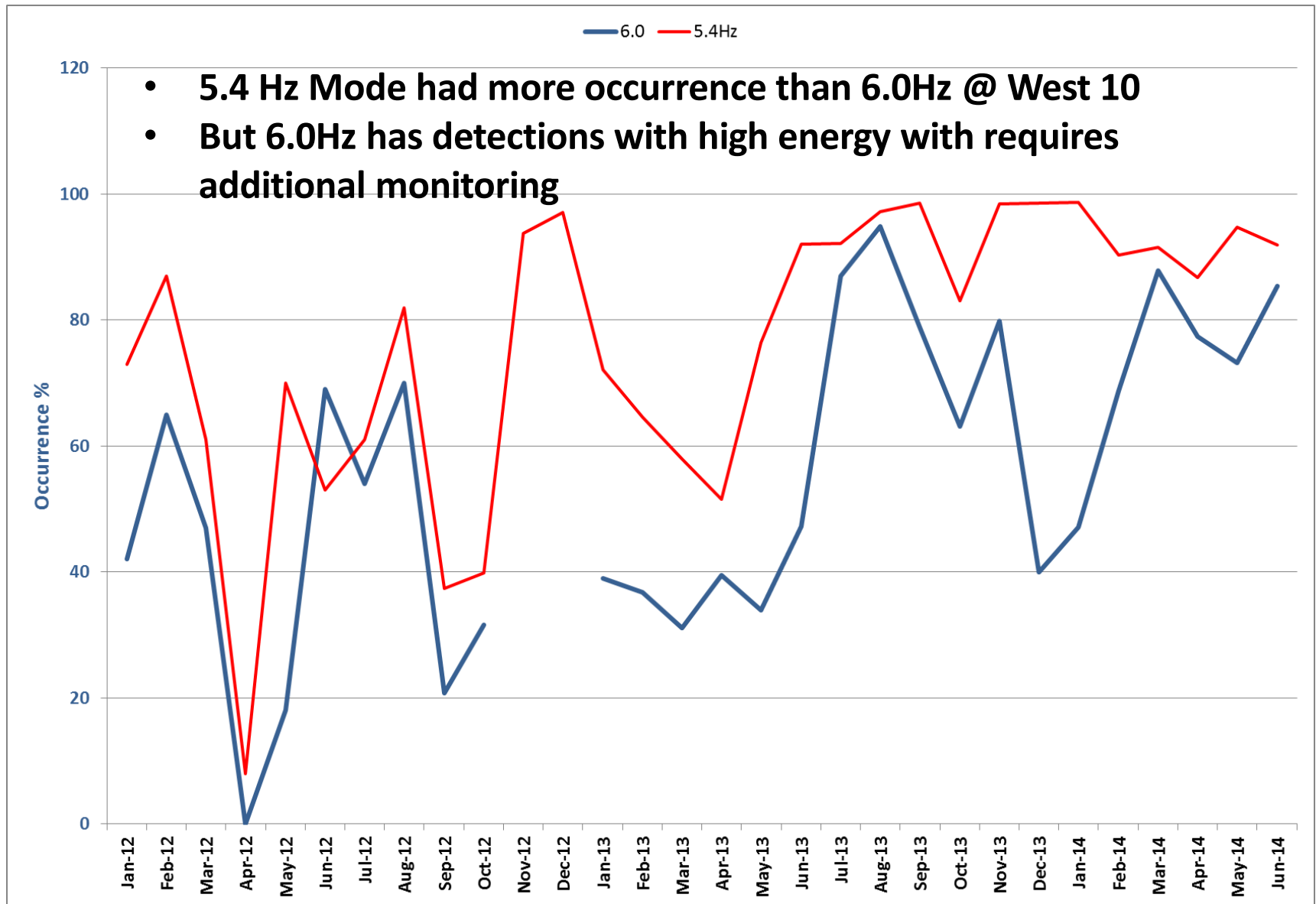


Mode #10 – 6.0Hz @ West 10

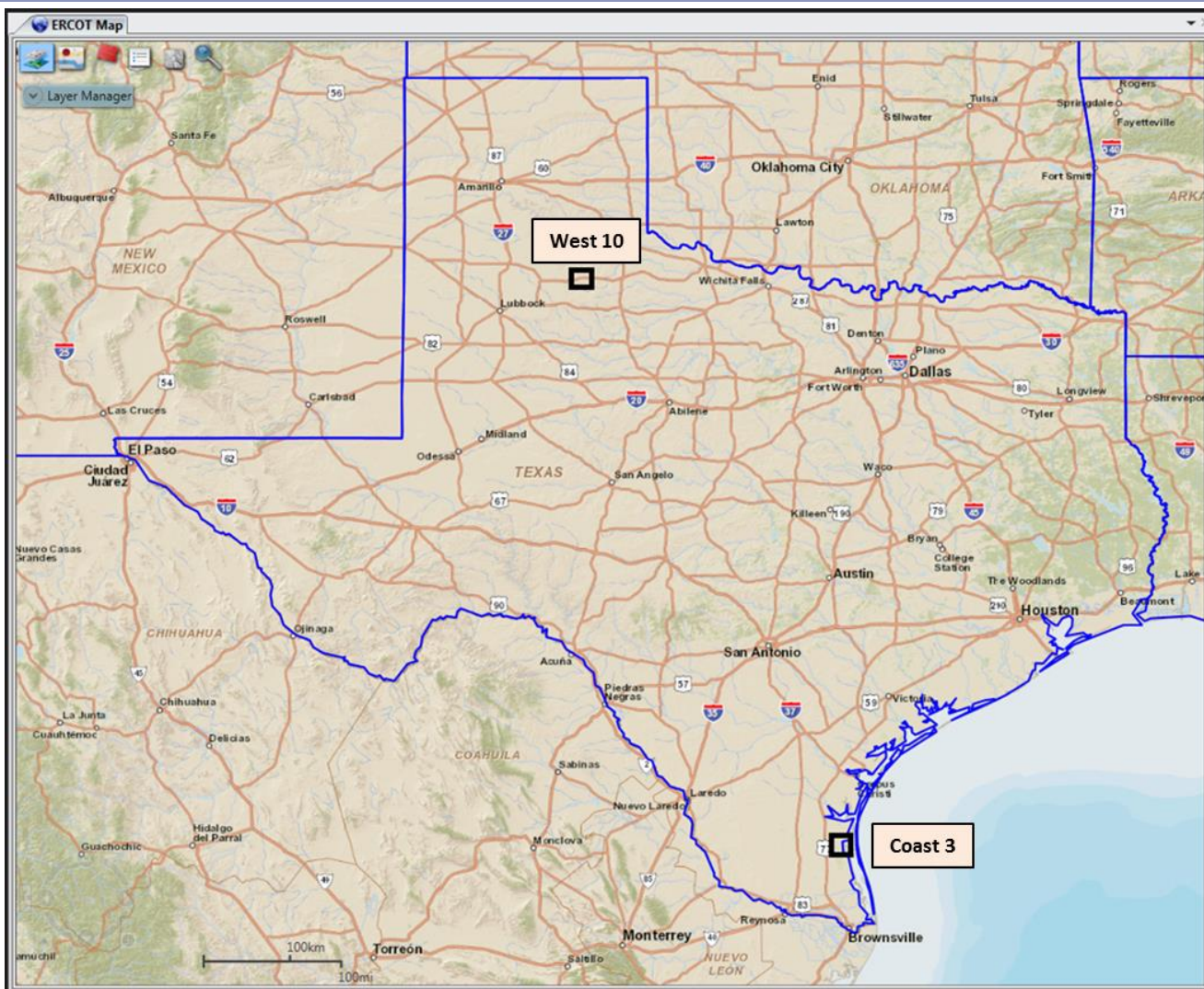
- Occurrence: Appeared every month in all three years except April 2012
 - Minimum Occurrence in May 2012 and appeared for 18% of time
 - Maximum Occurrence in Aug 2013 and appeared 95% of time
- **ERCOT should review 6.0Hz oscillation with wind owners for possible mitigation and also monitor with following configuration**
 - West 10 Current Magnitude
 - Minimum Frequency = 5.5Hz
 - Maximum Frequency = 6.5Hz
 - Minimum Energy = 5
 - Damping = 8%



West 10 – 5.4Hz Vs. 6.0Hz

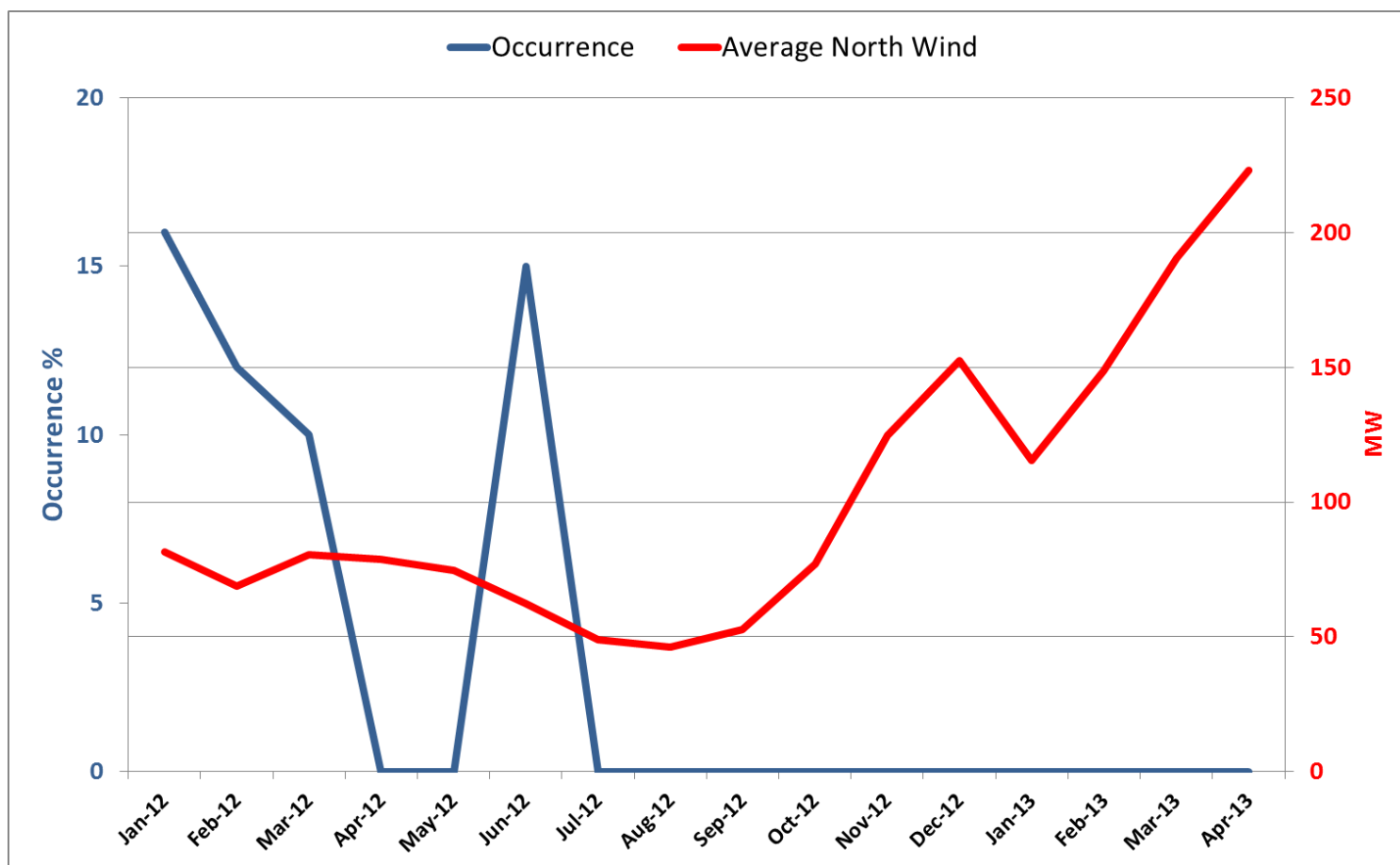


Mode #7 – 3.2Hz @ West 10



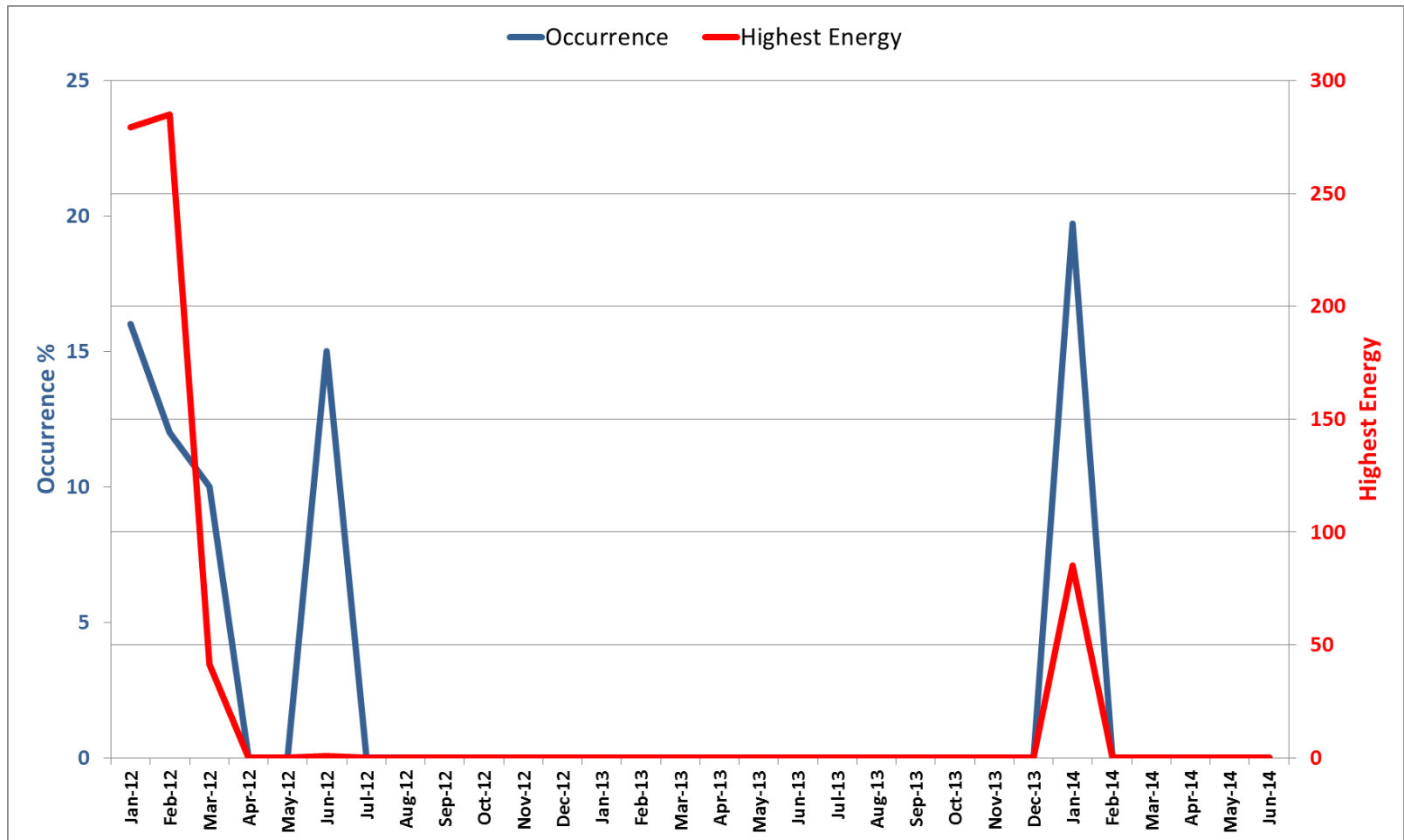
Mode #7 – 3.2Hz @ West 10

- Mode Occurrence @ West 10 does not follow North Wind Pattern & does not appear to be consistent as 5.4Hz or 6.0Hz, rather intermittent
- But these oscillations are observed more strongly near wind generators and appear to be driven by “settings change in the control systems”



Mode #7 – 3.2Hz @ West 10

- The occurrence of 3.2Hz Mode appears to be intermittent and energy is high during the occurrence and would require additional monitoring to detect occurrence of same mode at West 10



Mode #7 – 3.2Hz @ West 10

- Source: West 10
- Signal Type: Current Magnitude
- Oscillation Type: Wind Generator Control Systems Setting Change
- Generators Nearby: WestGen10
- Occurrence:
 - Appeared in First 3 months & June of 2012, Jan of 2014
 - Minimum Occurrence in Mar 2013 and appeared for 10% of time
 - Maximum Occurrence in Jan 2014 and appeared for 20% of time

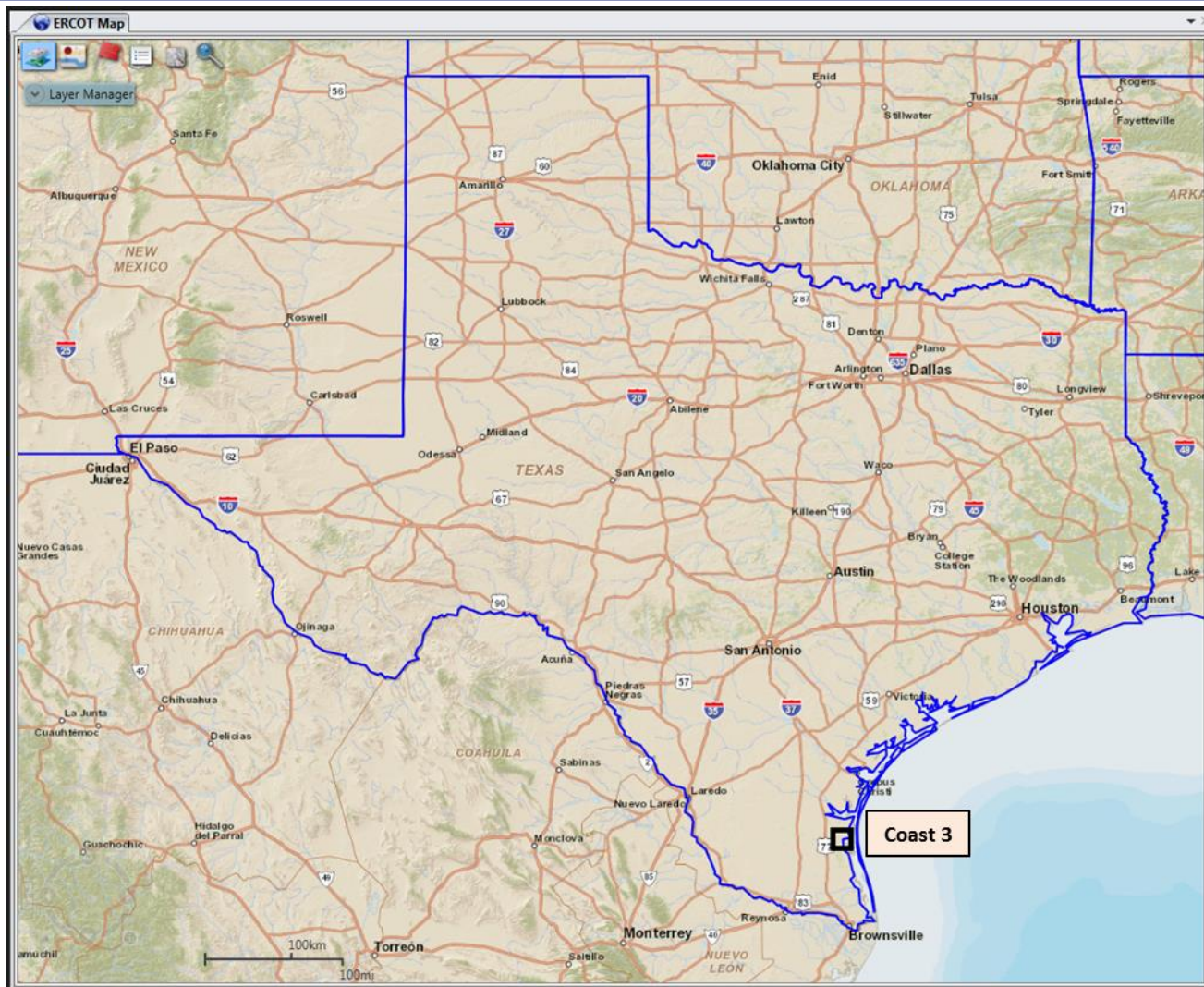


Mode #7 – 3.2Hz @ West 10

- The Mode 3.2Hz is driven by control systems settings change and needs additional monitoring at West 10 with following configuration
- **ERCOT should do additional monitoring of the mode with the following configuration**
 - Signal: West 10 Current Magnitude
 - Minimum Frequency = 2.6Hz
 - Maximum Frequency = 3.8Hz
 - Minimum Energy = 50
 - Damping = 8%

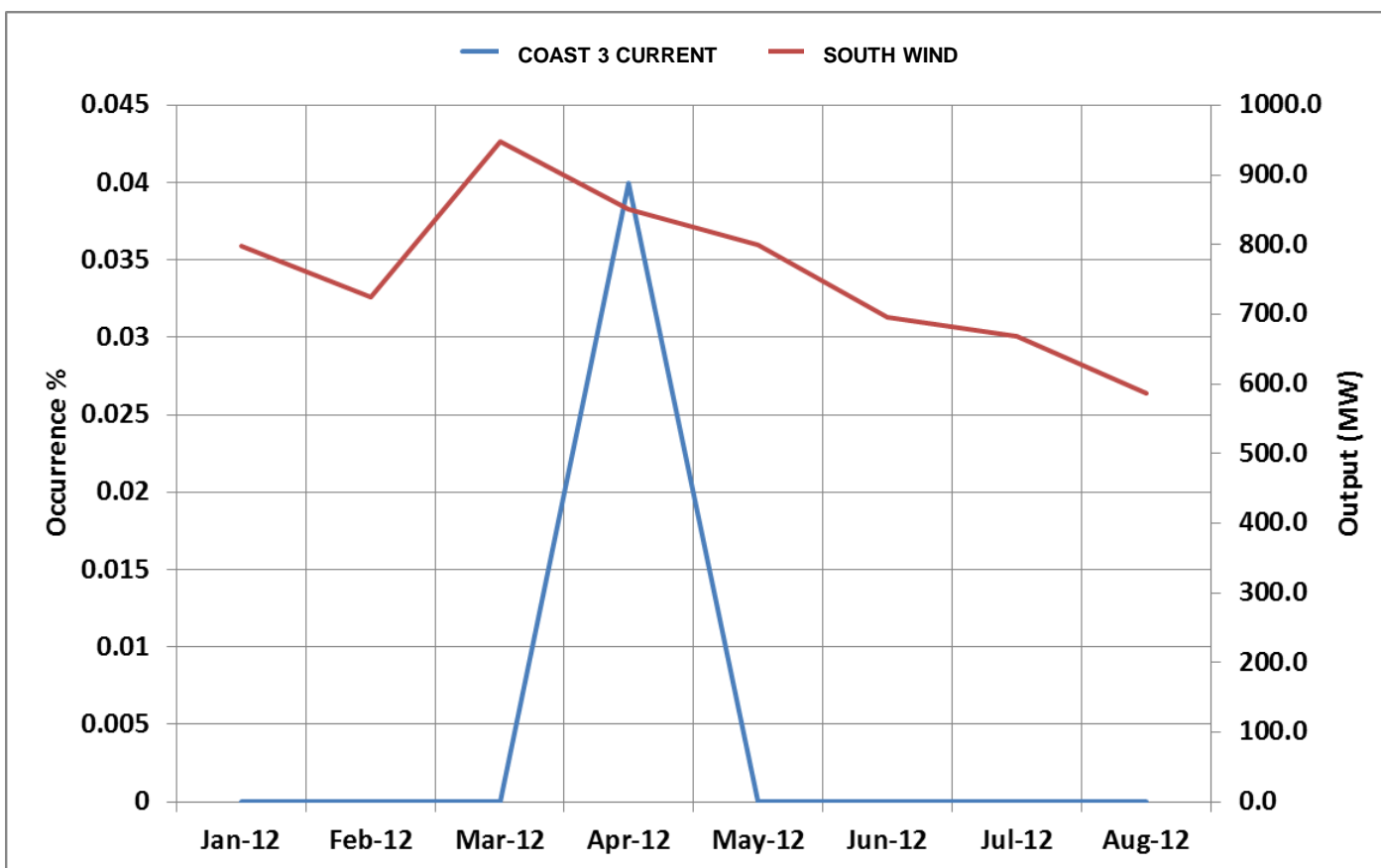


Mode #3 – 1.5Hz @ Coast 3



Mode #3 – 1.5Hz @ Coast 3

- Mode Occurrence @ Coast 3 does not follow South Wind Pattern & does not appear to be consistent as 5.4Hz or 6.0Hz, rather occurred once
- But these oscillations are observed more strongly near wind generators and appear to be driven by “settings change in the control systems”

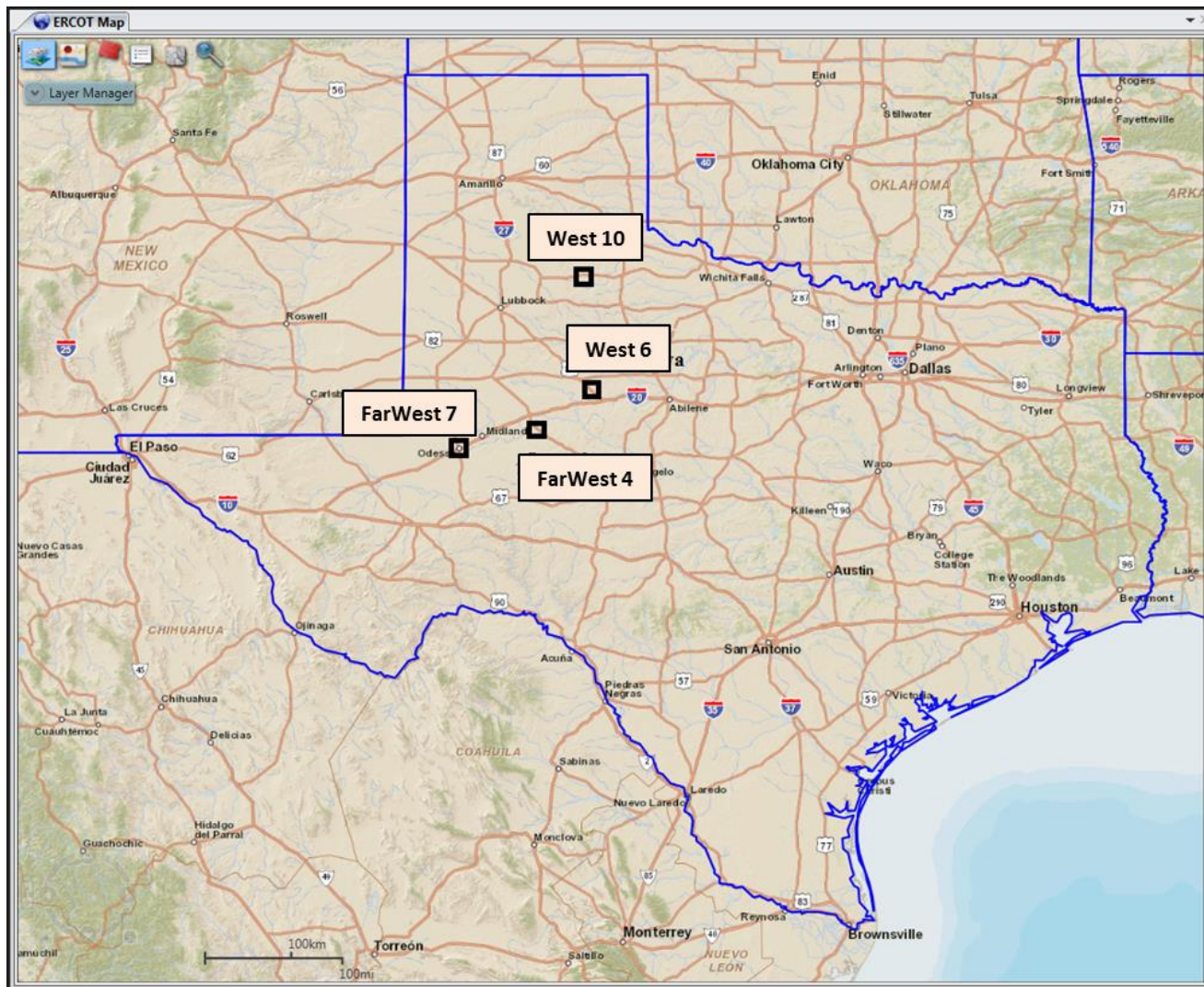


Mode #3 – 1.5Hz @ Coast 3

- Source: Valley (Coast 3)
- Oscillation Type: Wind Generator Control Systems Setting Change
- Wind Generators Nearby: CoastGen3 & CoastGen4
- Occurrence:
 - Appeared only in April 2012 for 0.04% of time
- Energy – Within the period of Occurrence
 - Highest Energy was about 0.02
- Occurred for a short period of time with low energy

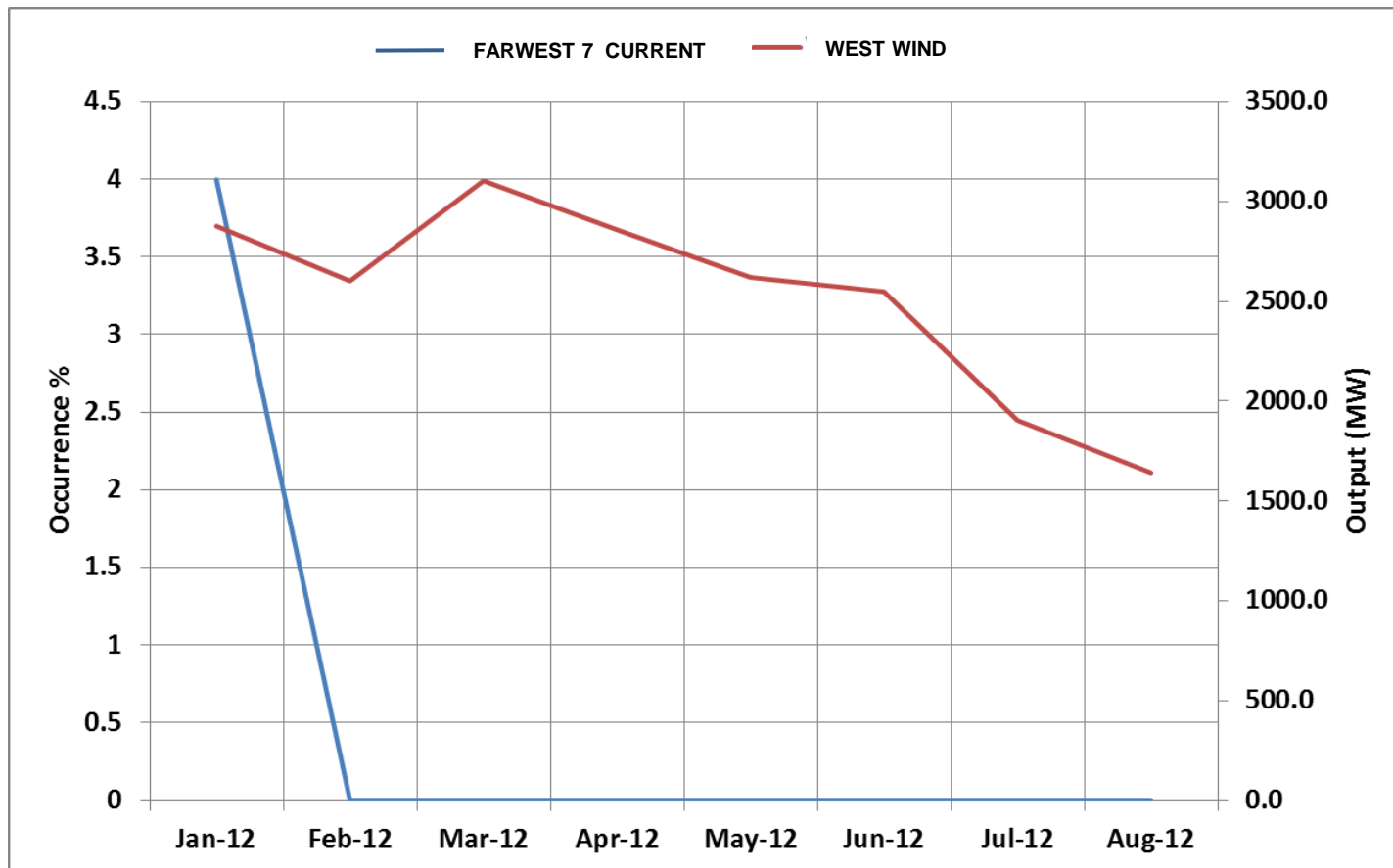


Mode #4 – 1.7Hz @ 4 Locations



Mode #4 – 1.7Hz Mode Occurrence

- Mode Occurrence @ FarWest 7 does not follow West Wind Pattern & does not appear to be consistent as 5.4Hz or 6.0Hz, rather occurred once
- But these oscillations were observed more strongly near Combined Cycle Unit with total capacity of 1135MW (6 Units)

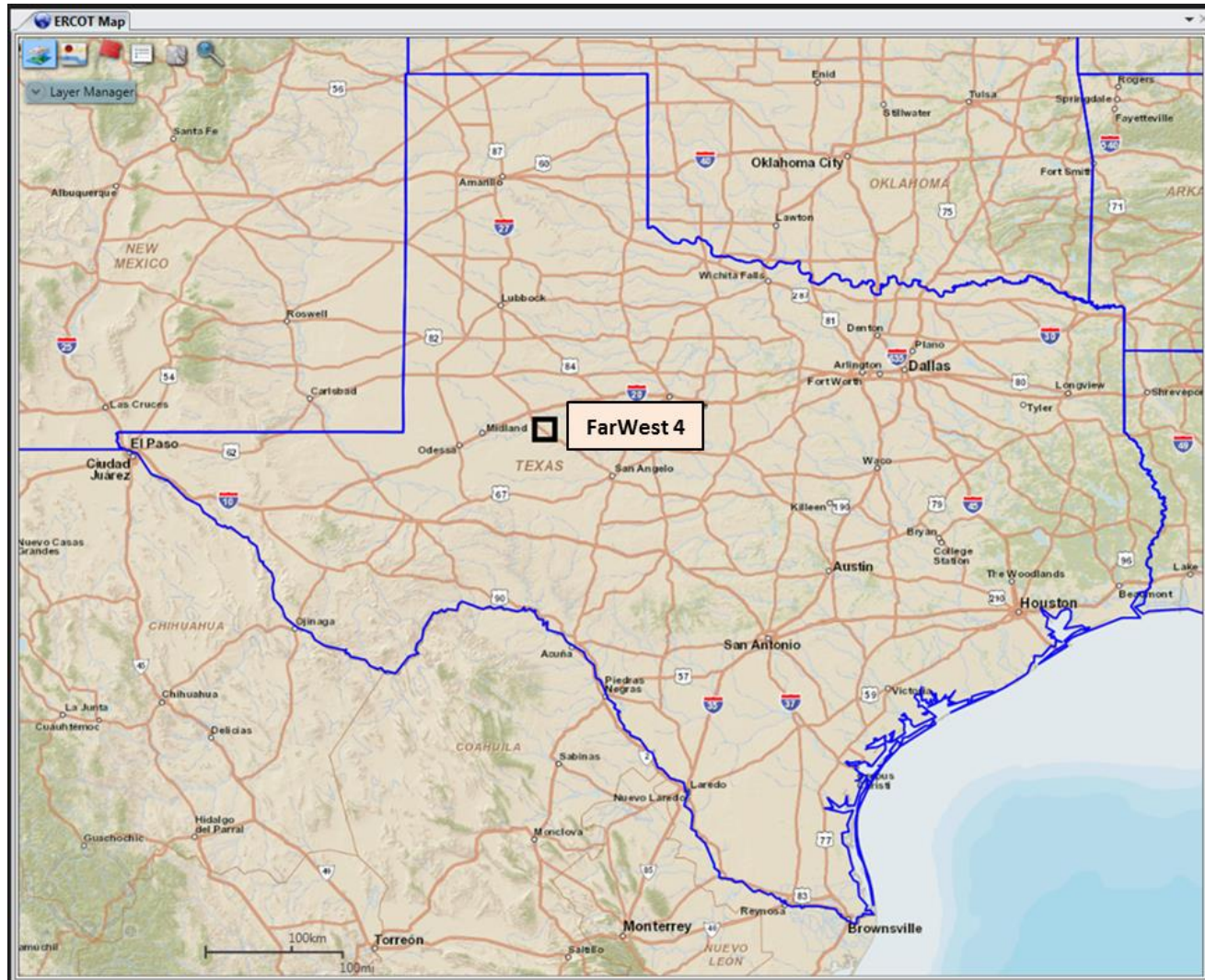


Mode #4 – 1.7Hz @ FarWest 7

- Source: West Texas (FarWest 7)
- Oscillation Type: Local
- Other Generators Nearby: FarWestGen7 & FarWestGen8
- Occurrence:
 - Appeared only in Jan of 2012
- Highest Energy – Within the period of Occurrence
 - Highest Value was about 36
- **Appears to be a local issue & ERCOT needs to review the appearance of the mode with plant owners & determine the root cause to evaluate the need for additional monitoring**

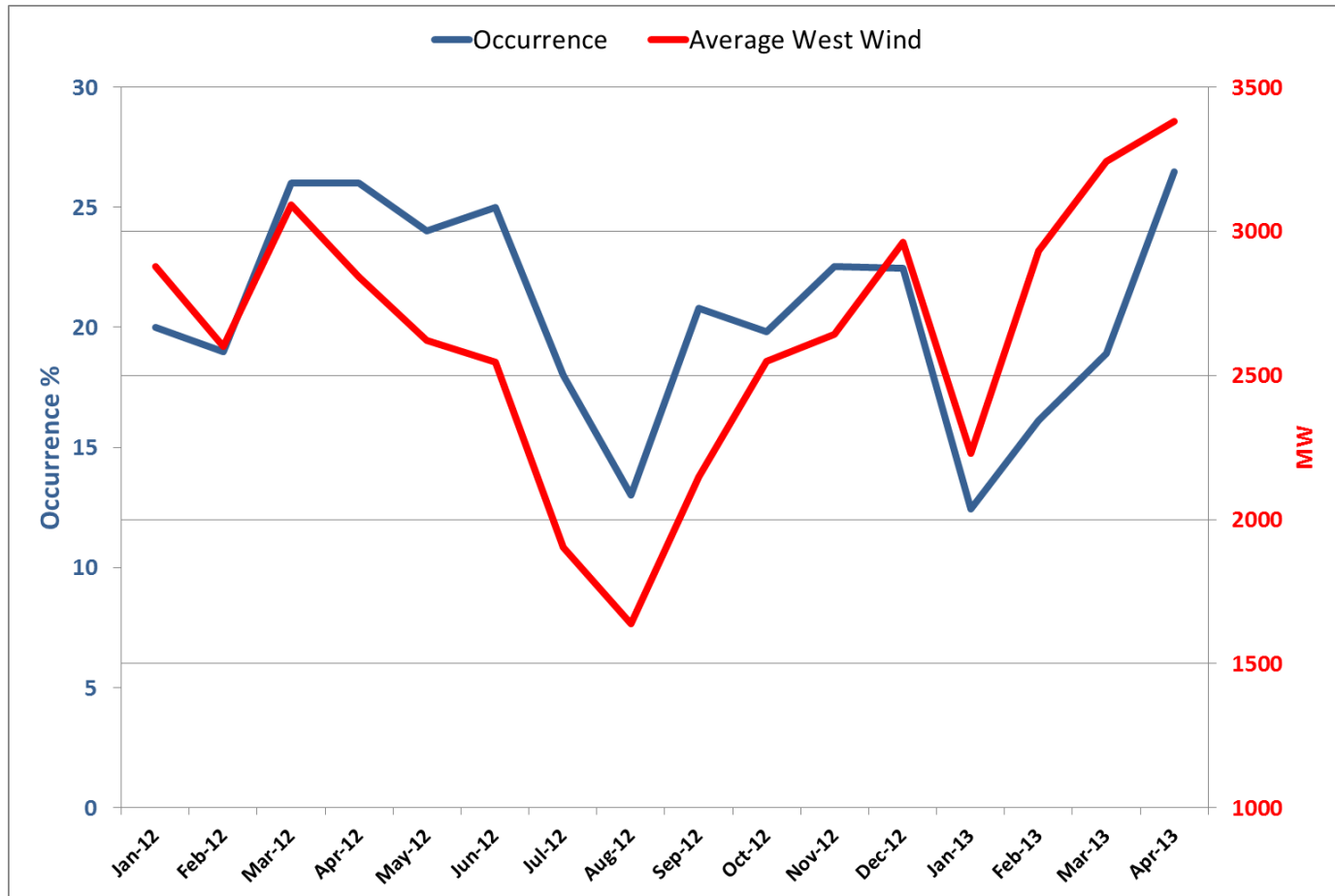


Mode #6 – 2.7Hz @ FarWest 4

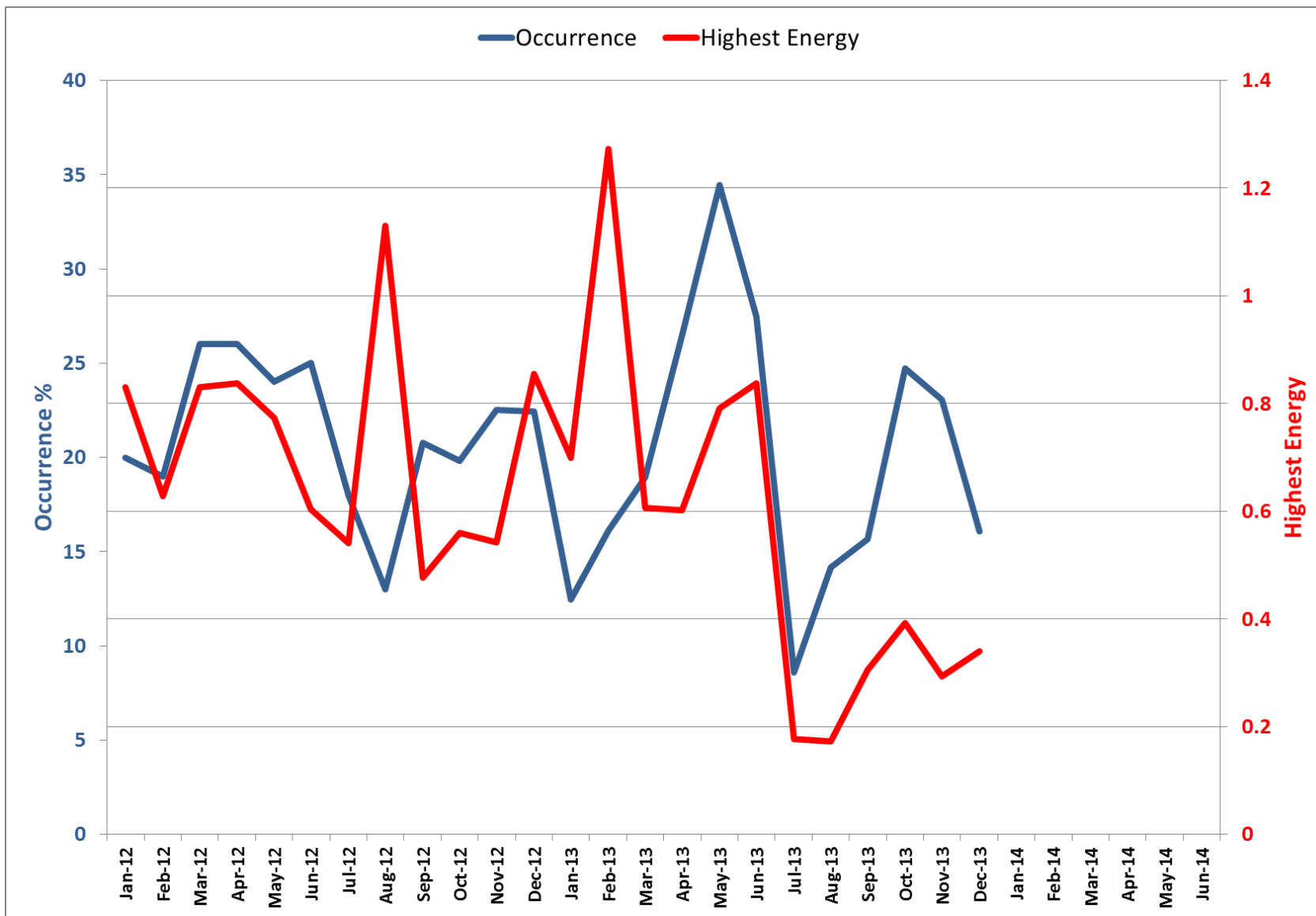


Mode #6 – 2.7Hz @ FarWest 4

The Trend of Mode Occurrence & Average West Wind have similar pattern and provides first indication that 2.7Hz is more likely related to wind production



Mode #6 – 2.7Hz @ FarWest 4



Mode #6 – 2.7Hz @ FarWest 4

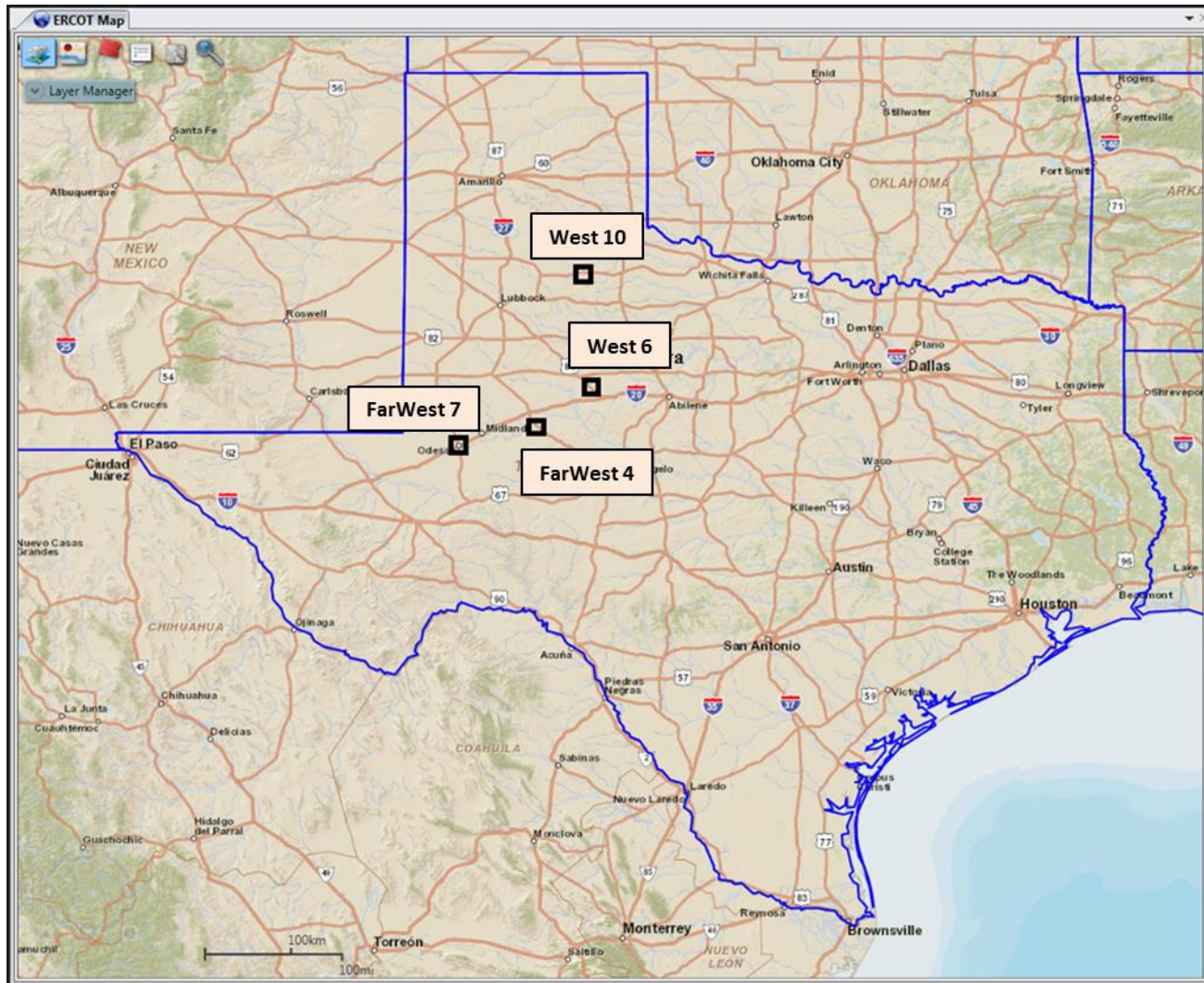
- Source: FarWest 4
- Signal Type: Current Magnitude
- Oscillation Type: Wind Generation Related
- Wind Generators Nearby: FarWestGen4
- Occurrence:
 - Appeared every month in all three years
 - Minimum Occurrence in July 2013 and appeared for 9% of time
 - Maximum Occurrence in May 2013 and appeared for 34% of time
 - Average Occurrence in all three years is about 20% of time during the month



Mode #6 – 2.7Hz @ FarWest 4

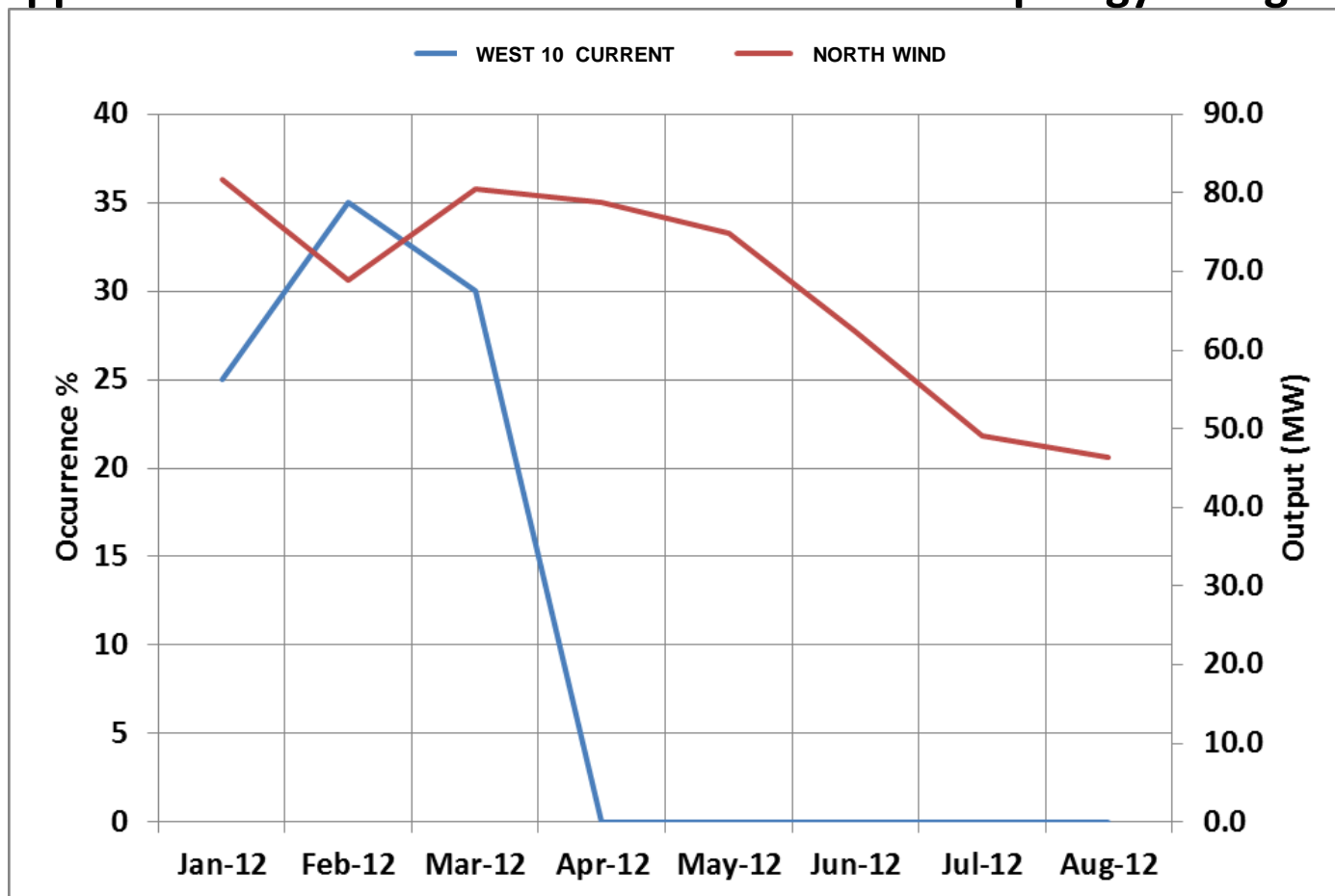
- Occurrence:
 - Mode Disappears beginning of 2014
- Disappearance of 2.7Hz Mode may be related to addition of new CREZ transmission lines near FarWest 7 running down to West 29 and West 8 on Jan 3, 2014 or any tuning of control systems @ FarWestGen4
- **ERCOT should review the disappearance of the mode with wind owners and determine the root cause to evaluate the need for additional monitoring**

Mode #1 – 0.6Hz @ 4 Locations



Mode #1 – 0.6Hz @ West 10

- Mode Occurrence @ West 10 does not follow North Wind Pattern & does not appear to be consistent as 3.2Hz, rather disappeared after March 2012
- But these oscillations were observed more strongly near wind generators and appear to be related to local oscillation due to topology change

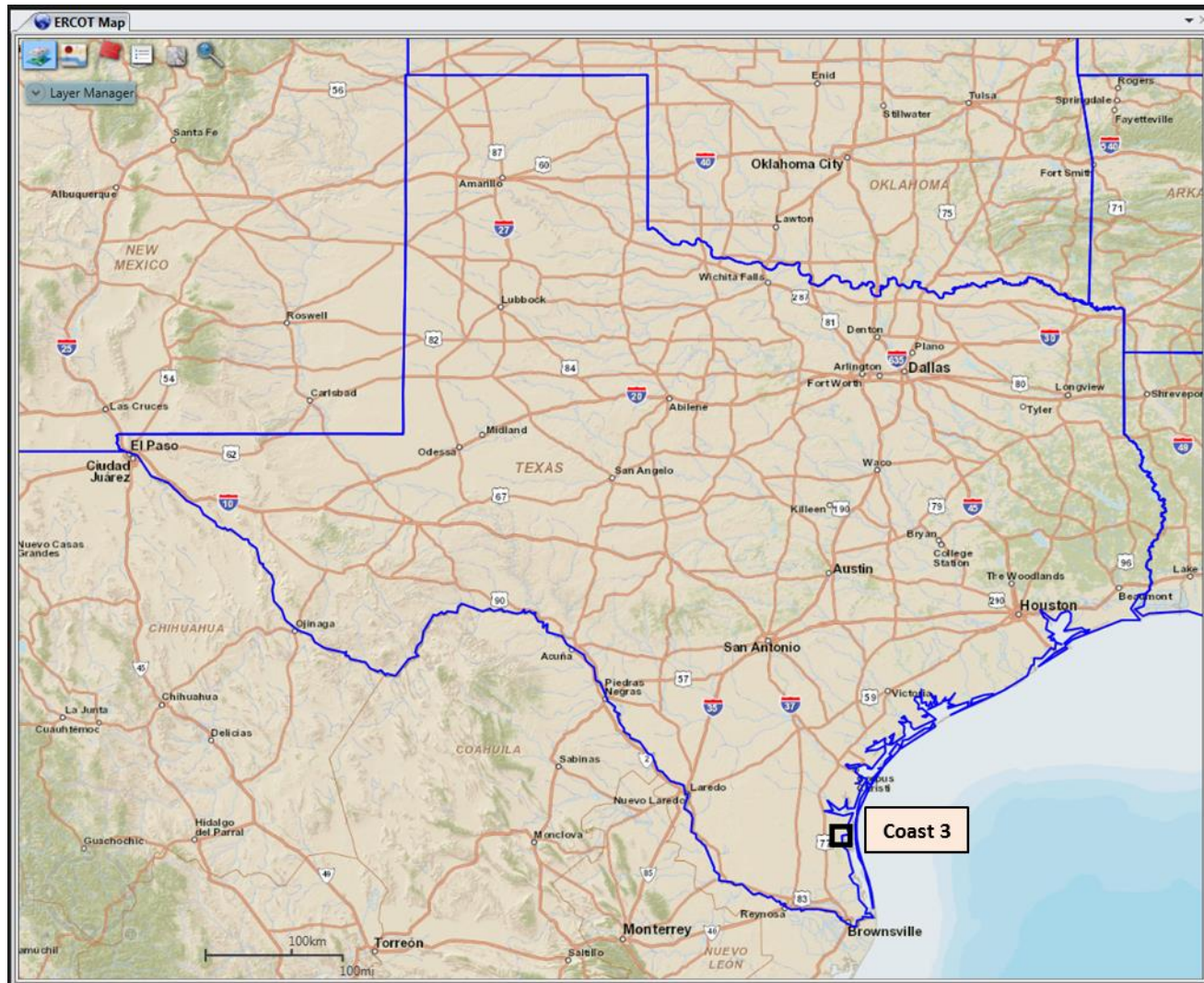


Mode #1 – 0.6Hz @ West 10

- Source: Panhandle (West 10)
- Oscillation Type: Local
- Generators Nearby: WestGen10
- Occurrence:
 - Appeared only in first three months in 2012
- Energy – Within the period of Occurrence
 - Maximum Highest energy was about 2
 - Minimum Highest energy was about 1.6
- **Appears to be a Local Issue & ERCOT needs to review the appearance of the mode with plant owners & determine the root cause to evaluate the need for additional monitoring**



Mode #5 – 2Hz @ Coast 3



Mode # – 2Hz @ Coast 3

- Source: Valley (Coast 3)
- Signal Type: Voltage Magnitude
- Oscillation Type: Local Control Systems from Nearby Wind Generators
- Wind Generators Nearby: CoastGen3, CoastGen4, CoastGen5
- Occurrence:
 - Appeared only in April 2013 for 0.8% of time
- Energy – Within the period of Occurrence
 - Highest Energy value was about 0.5
- Occurred for a short period of time with low energy



Conclusion – Identified 9 Oscillatory Modes

- Occurrence of some modes appear to be related to wind production – 0.9Hz (On going) & 2.7Hz (No Longer Present)
- Occurrence of some modes appear to be related to control system changes – 1.5Hz (Coast 3), 1.7Hz (FarWest 7), 2Hz (Coast 3), 3.2Hz (West 10)
 - Appear with significant energy for a short period of time and disappear
- Occurrence of some modes (5.0Hz ,5.4Hz & 6.0Hz) appear to be related to the presence of wind generation but not to production
- 0.6Hz from West 10 – Local Oscillation (No Longer Present)
- 0.9Hz from West 6 (Ongoing)
- 5.0Hz from Coast 3 (Ongoing)
- 5.4Hz from West Wind & Panhandle (Ongoing)
- 6.0Hz from Panhandle (Ongoing)



Thank You.

Any questions ?

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**Attachment 12. 2014 RTDMS and PGDA
Training Comments**

ERCOT RTDMS User Training Evaluation Form/Responses

September 16, 2014

44 responses received

1. Did the training meet your expectations?

- 39 - Yes
- 2 - Yes and more than expected
- Yes. But 2 days not enough to go through a lot of new information
- First exposure to material but provided good introduction to analysis tool

2. What was the most effective part of this training?

- 13 - Case study
- 13 - Hands on use
- 2 - Tools and slides
- 2 - Understanding navigation tools, GUI features, understanding what types of raw data is available
- Understanding voltage phase angle and stress on transmission system; case studies interesting and improved understanding
- Reviewing the various tab in order to analyze trends
- Learning how to use the dashboard and responding to alarms
- Display interaction
- Monitoring grid stability in real time
- Event recognition and diagnosis
- How much data is analyzed
- Phasor grid dynamics
- Interaction of personal with Q&A sessions
- Synchrophasors is a very new topic for me and I think every part of this training was very effective in terms of giving me a good overview of it and the tools
- Lots of computers

3. What was the least effective part of this training?

- 16 - NA
- 6 - Too much info in a short period of time
- 3 - Slides
- 4 - Laptop/Server was slow and could not be used most of the time
- 2 - Need written material to follow presentation as part of presentation may be missed while trying to follow on computer and slides presentation
- 2 - How to customize displays
- 2 - Basic navigation and settings
- Navigating through screen so quick
- At times it got too technical to the engineer level we will never use
- Sharing laptop limited hands on, so gained less experience
- Using just the RTDMS to analyze an event

- Nothing on setting alarm thresholds
- Real-time dynamics monitoring presenter
- Need more hands on
- Hard to understand
- Understanding dialects. It's rude to tear down while the last 2 are presenting. Shorten other talks, give them their time, then tear down your laptops after we leave

4. What suggestions do you have to improvement the training?

- 14 - NA
- 5 - More Hands on and use cases training on ERCOT examples
- 4 - More training days with less time per each day, with more hands on
- 3 - Break down in smaller groups
- 3 - More breaks
- 2 - Have screenshots of step by step for the solutions, sort of a visual manual of how past analysis was done to determine what happened
- 2 - Speakers need more improvement on crowd involvement
- Make it longer and more technical (not for operators). For operators, cover more on damping. Cover algorism for location of unit trip and first responders
- Add some more power system dynamics analysis knowledge. Help students review some concepts first
- Develop web based training modules, that can be used later to reinforce the presented material
- Try to have people hold questions about specifics until after the "big picture" presentations are over
- Show examples how the RTDMS will be integrated using SCADA, SE, and RTCA
- Make more displays/profiles
- Follow a separate of observation to learn how to analyze a system problem
- Follow up once it is available to the user
- Power points

5. Are you comfortable with your level of proficiency to use the RTDMS application?

- 25 – Yes
- 13 - Need more practices
- 3 - Somewhat
- Limited to moderate. We do not have this application at my company
- No, but not just because of presenter but the software is new to me
- No

ERCOT PGDA User Training Evaluation Form/Responses

September 17, 2014

42 responses received

1. Did the training meet your expectations?

- 37 – Yes
- 2 - Yes and beyond
- Training was short and fast, but fairly straight forward system
- Not quite, information was presented very rapidly
- For the most part. I was more looking for analytics behind the scene stuff, not how to change colors, names, and titles. It has been touched upon over the course of training but wasn't the main focus.

2. What was the most effective part of this training?

- 11 - Use cases studies
- 8 - Hands on
- 3 - Demos
- 3 - Navigation views, displays and tools
- 2 - Walking through step-by-step
- 2 - Using the computer to figure out the scenario
- 2 – Analysis/Frequency response analysis
- The base lining. How different events in the system change the system response, how frequency phase angle changes, how to learn and categorize typical system events
- Phasor grid dynamics analyzer
- Knowledge of the instructors
- User interaction
- Data collected
- Lots of computers
- 5 - Not answered

3. What was the least effective part of this training?

- 21 - NA
- 4 - Too much info in a short period of time
- 3 - Slides
- 2 - Some are hard to understand
- 2 - Need more hands on

- A lot of options/settings that weren't explained perhaps due to highlighting most useful/important features
- How and when to start taking actions? You have all the data streaming through, lots of data, lots of information, alarms. For the operator having to take action within minutes, it is not helpful to initiate the proper action process
- The last case, more in depth analysis
- Introduction to user interface but necessary
- Overall intuitiveness of locating info in the GUI
- Multiple view and analysis was confusing
- Zoom-in function didn't always work properly
- How to customize displays
- Server could not keep up

4. What suggestions do you have to improvement the training?

- 17 - NA
- 7- More event cases
- 2 - More hands on
- 2 - More training days with less time per each day, with more hands on
- 2 - Break down in smaller groups based on audience needs
- 2 - More breaks
- Develop web based training modules, that can be used later to reinforce the presented material
- Need more time to explain how to get access and when it will be available
- More time spent on frequency response and more in depth on modal analysis
- Discuss NERC A,B,C points
- Get through exercise for New-Load-Save-Open process
- Good to have written outline, that easy to follow
- Less days
- Better server
- Speaker
- More snacks

5. Are you comfortable with your level of proficiency to use the RTDMS application?

- 30 - Yes
- 8 - Need more practices
- 4 - Somewhat

Attachment 13. Generator Model Validation Tool

Center for Commercialization of Electric Technologies (CCET)

Discovery Across Texas Project

Generator Parameter Validation

Submitted to

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Prepared by:



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November 20, 2014

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CCET Discovery Across Texas

Generator Parameter Validation

CCET 3.1.1

1. Introduction

The Center for Commercialization of Electric Technologies (CCET) was awarded contract DE-OE0000194 by the Department of Energy to perform the Discovery Across Texas demonstration project. Electric Power Group, LLC (EPG) received a sub-award from CCET to provide professional services to perform, among other things, development of the Generator Parameter Validation (GPV) tool for Electric Reliability Council of Texas (ERCOT) use. The Generator Parameter Validation (GPV) tool is based on the research work done by Dr. Wei-Jen Lee et al from the University of Texas at Arlington [1][2]. EPG appreciates their contribution to the generator parameter validation process and for providing the program code which was used for the development of the GPV tool.

Power systems are complex networks with thousands of components. Computer simulations are used as the basis to simulate and study the power system's response to a variety of contingencies. Generators, loads, transmission lines and other power system components are represented as mathematical models in the computer simulation programs to predict network responses. Simulations, based on models of the network components, are used widely in both power system planning and operation, and play an important role in predicting the grid response and preparing for contingencies. Hence, having correct models is very essential. Checking and validating models is a must for maintaining grid reliability. Also, periodic validation of the models would be required to comply with North American Electric Reliability Corporation (NERC) reliability standards [3].

Generators are one of the most important components of the power systems. Having correct generator models is highly important. The traditional testing method of performing staged tests on generators, taking detailed recordings of the generator's response, and then comparing the measured and predicted responses, is very expensive, time-consuming and may risk damage to the equipment. Also, the units typically have to be taken out of service for testing.

GPV is the process of validating generator model parameters using Phasor Measurement Units (PMU) measured data. GPV uses recorded disturbance data measured at the output of a generator to validate and calibrate generator model parameters. Disturbances occur frequently on the network, and afford the opportunity to measure the response of the generator, if appropriate data

recording capability is in place and operational. PMU data collected at the output of the generator provides the continuous high-speed monitoring capability needed to perform model validation. The GPV tool provides a means of validating the simulated results with the measured generator response from these occasional grid disturbances. If the model simulation results don't match the recorded data, the model parameters are likely to be incorrect and the model needs to be corrected. The correct model parameters are identified by the optimization process using advanced algorithms. The types of models that can be validated are generators, governors, exciters and stabilizers. This validation process can be done frequently, using data from normally occurring grid disturbances, without taking the generators offline. The GPV tool allows the user to perform the validation process with a user interface.

2. Executive Summary

Power systems are complex networks with thousands of components. Models are required to understand system behavior and are used widely in power system studies, planning and operation. They play an important role in predicting the grid response and planning for contingencies. Hence, having correct models is very essential. Checking and validating models is a must for maintaining grid reliability. Also, periodic validation of the models would be required to comply with North American Electric Reliability Corporation (NERC) reliability standards.

Generators are one of the most important components of the power system. Having correct generator models is highly important. The traditional testing method of performing staged tests on generators is very expensive, time-consuming and may damage the equipment. The units have to be taken out of service for testing. GPV is a process of validating the generator model parameters using synchrophasor data. Using synchrophasor data, the models can be periodically validated without taking the generators offline. The GPV tool uses measured disturbance data captured by Phasor Measurement Units (PMUs) to validate the generator models. The types of models that can be validated are generator models, exciter models, governor models and stabilizer models.

The generator parameter validation consists of three processes: validation, sensitivity analysis and optimization. In the validation process, the model simulation output waveform is compared to the PMU measured waveform. If the validation results indicate a poor match between the simulated and measured waveforms, sensitivity analysis should be performed. Sensitivity analysis identifies the model parameters which have the greatest effect on the output of the simulation. Thus, sensitivity analysis helps to identify the key parameters that need to be selected for the final step, which is the optimization process. Sensitivity analysis also enables plotting of trajectories of the change in active and reactive power for every parameter. Optimization is the process of finding the set of parameter values for which the simulation output best matches the PMU recorded measurements. Advanced algorithms are used for the optimization process. Also,

the variation of parameters can be restricted by specifying a maximum and minimum value for individual parameters. This enables fine-tuning of the identified parameters and helps to converge on the most representative parameter values. The newly identified parameter values can then be used for calibrating the models. The GPV tool provides a user interface for all three steps in the generator parameter validation process.

This report includes a brief description of the generator parameter validation process. It includes the work done towards the development of the GPV tool and also includes some results obtained by using the tool.

3. Process and Methodology

The steps involved in the generator parameter validation process are shown in Figure 1 below:

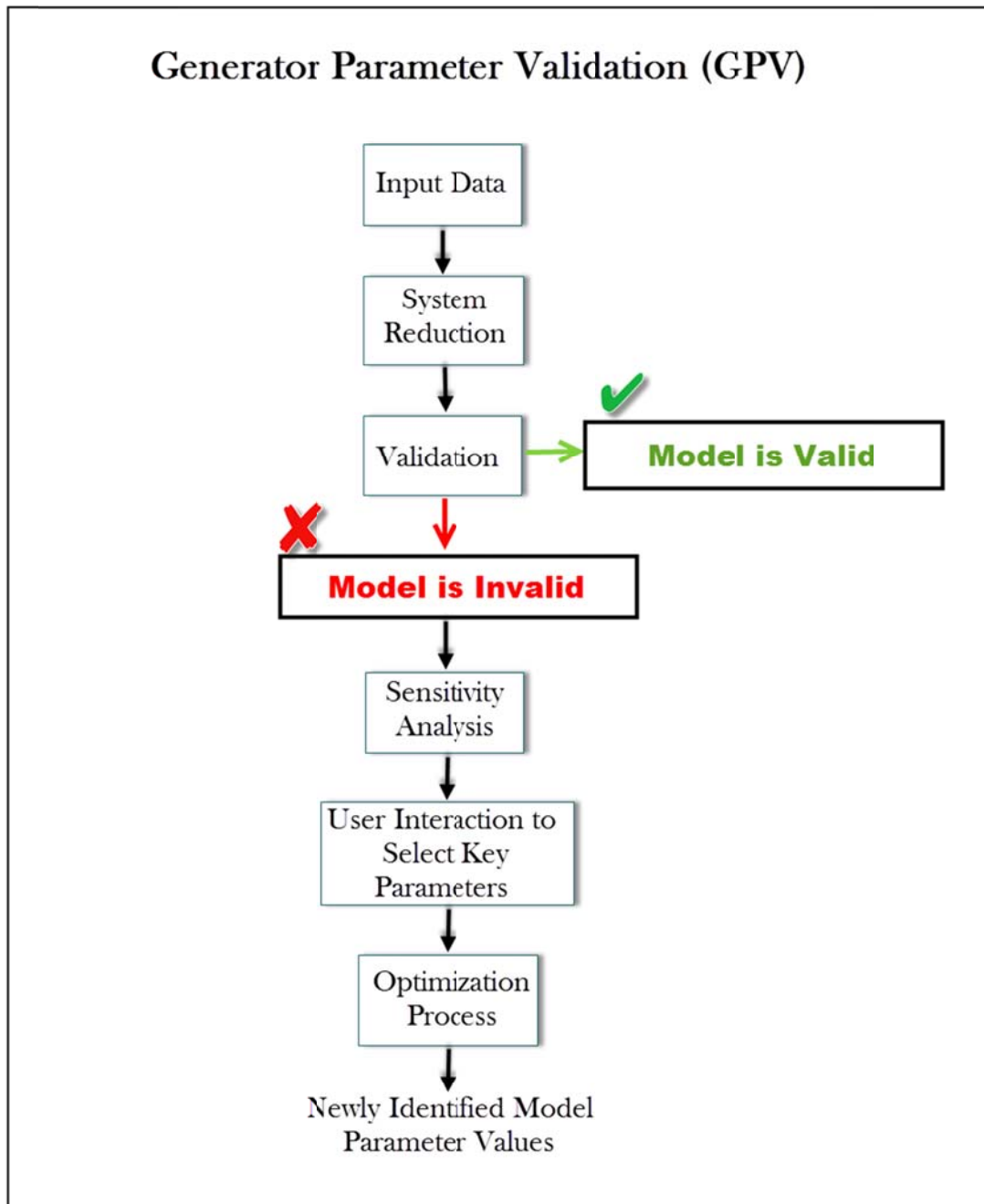


Figure 1. Generator Parameter Validation Process Workflow

- Step 1** Obtain PMU measured data (Voltage, Voltage angle, Active Power and Reactive power) at the output of the individual generator unit as input data in the format required by the tool.
- Step 2** Using a system reduction approach, reduce the entire system to a smaller system at the output of the generator.

- Step 3** Perform the validation process by comparing model simulation results with the measured data and evaluate the need for calibration.
- Step 4** Run sensitivity analysis to display sensitivity of power flows to each parameter.
- Step 5** Select key parameters for the optimization process based on the sensitivity analysis results. Optionally specify range (minimum, maximum) limits for parameter variation.
- Step 6** Run the optimization process to identify correct parameter values.

The generator parameter validation process requires three input data files: an Excel file with PMU measured data in the required format; a PSS\E saved case file, and PSS\E dynamics file corresponding to the electrical network at the time of the recorded disturbance. A system reduction approach is used whereby the entire power system is reduced to a smaller system at the output of the generator, and the simulations are then performed using a concept called as hybrid dynamic simulation [1][2]. Hybrid dynamic simulation uses measured data as well as the simulation model to perform dynamic simulations. The GPV tool runs the PSS\E simulation engine in the background using the python programming language.

The system reduction process is followed by three processes: validation, sensitivity analysis, and optimization. In the validation process, the model simulation output waveform is compared to the PMU measured waveform. If the validation results indicate a poor match between the simulated and measured waveforms, sensitivity analysis should be performed. Sensitivity analysis identifies those model parameters which have the greatest effect on the output of the simulation. Thus, sensitivity analysis helps to identify the key parameters that need to be selected for the next step, which is the optimization process. Sensitivity analysis also enables plotting of trajectories of the change in active and reactive power for every parameter. These trajectory plots provide an additional visualization of the sensitivities of the power flows to each parameter change.

When there is a mismatch in the simulation results and measured results, it is important to identify the parameters that caused the mismatch. Optimization is the process of finding the set of parameter values for which the simulation output best matches the PMU recorded measurements. Two advanced algorithms, namely Particle Swarm Optimization (PSO) and Simultaneous Perturbation Stochastic Approximation - Particle Swarm Optimization (SPSA-PSO) Cooperative Method may be used for the optimization process [1][2]. For the optimization process, the variation of parameters can be restricted by specifying maximum and minimum values for individual parameters. This enables fine-tuning of the identified parameters and helps to narrow down on the correct parameter values. The newly identified parameter values will be useful for calibrating the models.

4. User Interface

A user interface was built for the GPV process.

The interface allows users to:

1. Select input data files.
2. Specify case and model information.
3. Run the validation process and view results and plots.
4. Perform sensitivity analysis and view results.
5. Select key parameters.
6. Select algorithm for optimization process.
7. Run the optimization process and view results and plots.

The GPV tool interface is shown in Figure 2 below.

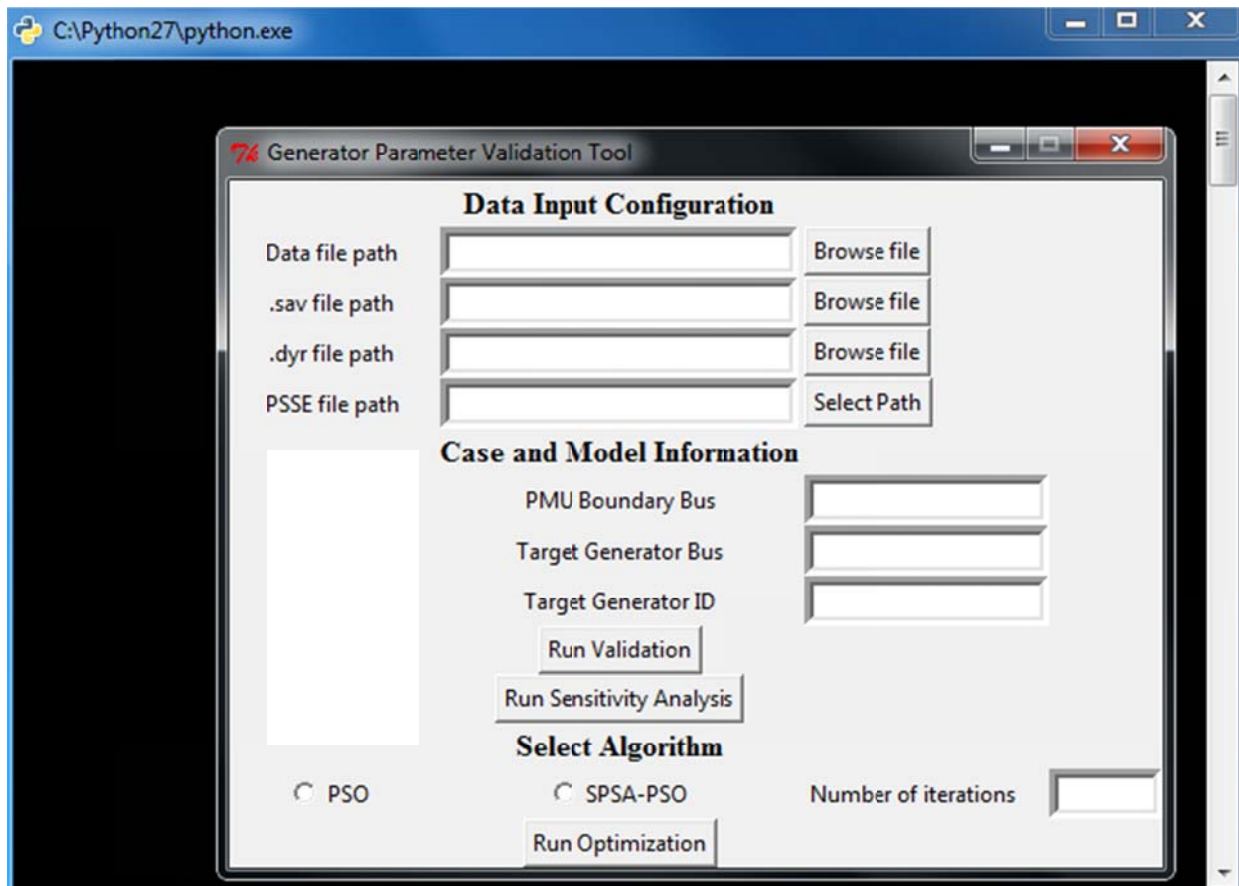


Figure 2. GPV tool user interface

5. Tool Features

Some of the key features of the GPV tool are listed below:

1. Automation of the system reduction process.
2. Sensitivity analysis results with ranked and color coded parameter values.
3. Comparison plots for validation – simulation output vs. measured data.
4. User interaction to select key parameters and optionally specify range for each parameter.
5. Plot trajectories for sensitivity of active and reactive power flows to each parameter.
6. Optimization process with two advanced algorithms.
7. Plots comparing measured data, actual model simulation output and new identified model simulation output .

6. Test Case Results

The GPV tool was tested on PSS\E example case files using simulated data as input measured data. Input data for 10 seconds was obtained by simulating a bus fault event and obtaining P, Q, V, and Angle measurements at the PMU boundary bus (201) in order to validate a hydro generator at bus number 211. The one-line diagram view of the generator is shown in Figure 3 below. This generator is a part of a 23 bus example system provided by PSS/E. The models associated with this generator are generator model - GENSAL, governor model – HYGOV and exciter model - SCRX. One of the dynamic model parameters was manually changed to create a mismatch between the simulated and measured results. Parameter number 3 (H-Inertia) from the GENSAL model was changed from 5 to 4 per unit on machine MVA base. In other words, simulation data that was used as measured data input to the tool was obtained with the parameter value of 5 but the input dynamic data for running simulations with the tool had parameter value set to 4.

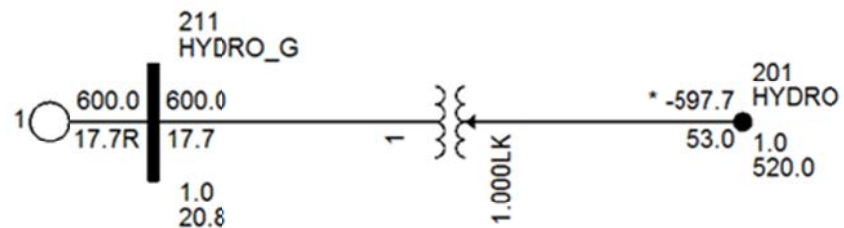


Figure 3. One-line diagram view of the target generator

The results from the validation process are shown in figures 4 and 5 below.

Active Power (P)

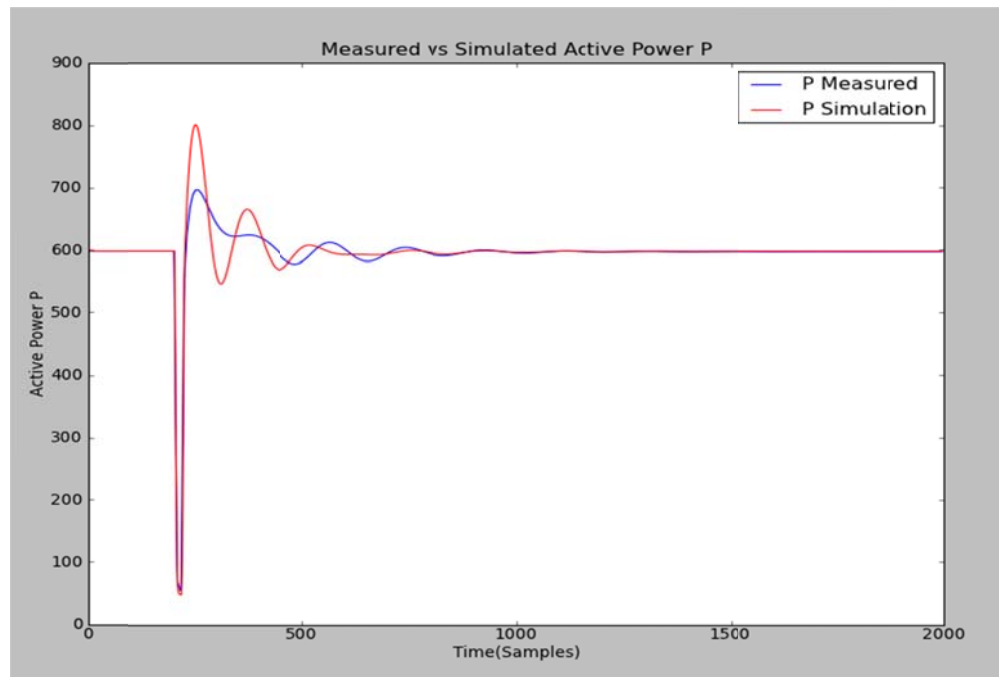


Figure 4. Validation Plots for active power (P)

Reactive Power (Q)

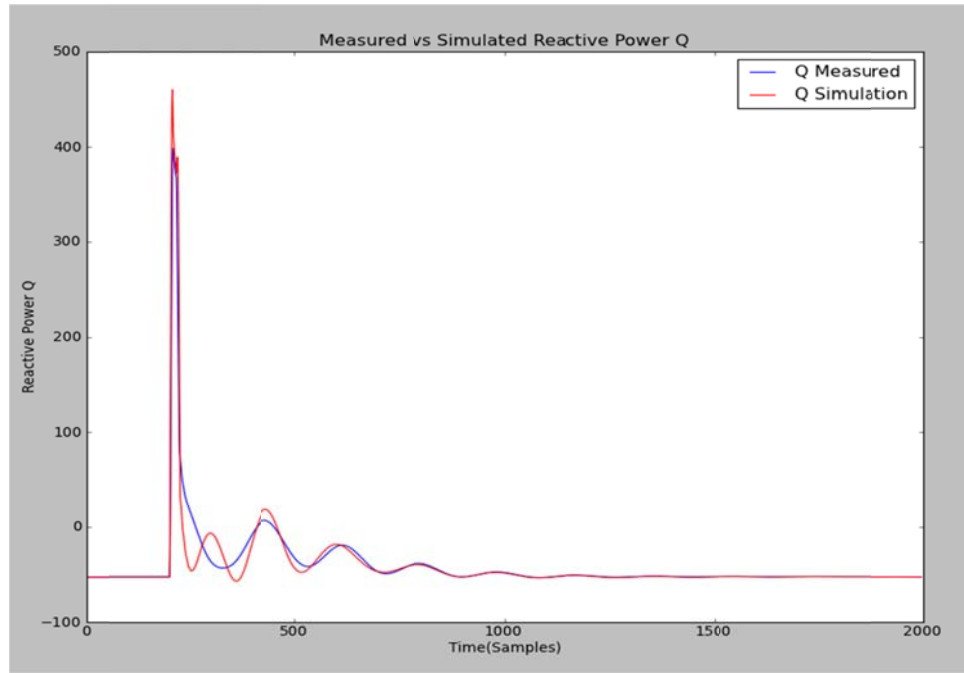


Figure 5. Validation plots for reactive power (Q)

A mismatch in the measured and simulation results is observed in the validation plots. Sensitivity analysis was then performed to identify the key parameters that have highest impact on the simulation response. The sensitivity analysis results are shown in figure 6 below.

| Parameter | MSE-P | MSE-Q | Ranks | | Min | Max |
|----------------|----------|---------|-------|-------------------------------------|-----|-----|
| GENSAL- Par 0 | 0.35171 | 1.18298 | 7 | <input type="checkbox"/> | | |
| GENSAL- Par 1 | 0.05296 | 0.07701 | 14 | <input type="checkbox"/> | | |
| GENSAL- Par 2 | 1.43549 | 0.39824 | 6 | <input type="checkbox"/> | | |
| GENSAL- Par 3 | 19.03361 | 3.87913 | 1 | <input checked="" type="checkbox"/> | | |
| GENSAL- Par 4 | 0.0 | 0.0 | | <input type="checkbox"/> | | |
| GENSAL- Par 5 | 0.02876 | 0.13491 | 12 | <input type="checkbox"/> | | |
| GENSAL- Par 6 | 3.0208 | 1.10109 | 4 | <input type="checkbox"/> | | |
| GENSAL- Par 7 | 1.7801 | 3.23206 | 3 | <input type="checkbox"/> | | |
| GENSAL- Par 8 | 1.10012 | 4.82334 | 2 | <input type="checkbox"/> | | |
| GENSAL- Par 9 | 0.00126 | 0.00175 | 22 | <input type="checkbox"/> | | |
| GENSAL- Par 10 | 0.00029 | 0.00273 | 21 | <input type="checkbox"/> | | |
| GENSAL- Par 11 | 0.00433 | 0.1711 | 11 | <input type="checkbox"/> | | |
| HYGOV- Par 0 | 0.00022 | 3e-05 | 25 | <input type="checkbox"/> | | |
| HYGOV- Par 1 | 0.01574 | 0.00143 | 17 | <input type="checkbox"/> | | |
| HYGOV- Par 2 | 0.00126 | 7e-05 | 23 | <input type="checkbox"/> | | |
| HYGOV- Par 3 | 0.00439 | 0.00031 | 20 | <input type="checkbox"/> | | |
| HYGOV- Par 4 | 0.00796 | 0.00123 | 19 | <input type="checkbox"/> | | |
| HYGOV- Par 5 | 0.02005 | 0.00101 | 16 | <input type="checkbox"/> | | |
| HYGOV- Par 6 | 0.0 | 0.0 | | <input type="checkbox"/> | | |
| HYGOV- Par 7 | 0.0 | 0.0 | | <input type="checkbox"/> | | |
| HYGOV- Par 8 | 0.00872 | 0.00102 | 18 | <input type="checkbox"/> | | |
| HYGOV- Par 9 | 0.0216 | 0.00277 | 15 | <input type="checkbox"/> | | |
| HYGOV- Par 10 | 0.00075 | 0.00015 | 24 | <input type="checkbox"/> | | |
| HYGOV- Par 11 | 0.00013 | 2e-05 | 26 | <input type="checkbox"/> | | |
| SCRX- Par 0 | 0.10718 | 1.12362 | 8 | <input type="checkbox"/> | | |
| SCRX- Par 1 | 0.00672 | 0.49471 | 9 | <input type="checkbox"/> | | |
| SCRX- Par 2 | 0.11912 | 0.39971 | 10 | <input type="checkbox"/> | | |
| SCRX- Par 3 | 0.01846 | 0.12846 | 13 | <input type="checkbox"/> | | |
| SCRX- Par 4 | 0.0 | 0.0 | | <input type="checkbox"/> | | |
| SCRX- Par 5 | 0.4519 | 1.62349 | 5 | <input type="checkbox"/> | | |
| SCRX- Par 6 | 0.0 | 0.0 | | <input type="checkbox"/> | | |
| SCRX- Par 7 | 0.0 | 0.0 | | <input type="checkbox"/> | | |

Figure 6. Sensitivity Analysis Results

Note that the top five highest sensitivity parameters are color-coded in red. Parameter 3 (Inertia-H) from the GENSAL model was ranked 1 in the sensitivity analysis results. This parameter was selected for the optimization process.

Results from the optimization process for one iteration using the SPSA-PSO [1][2] algorithm are shown below.

Active Power (P)

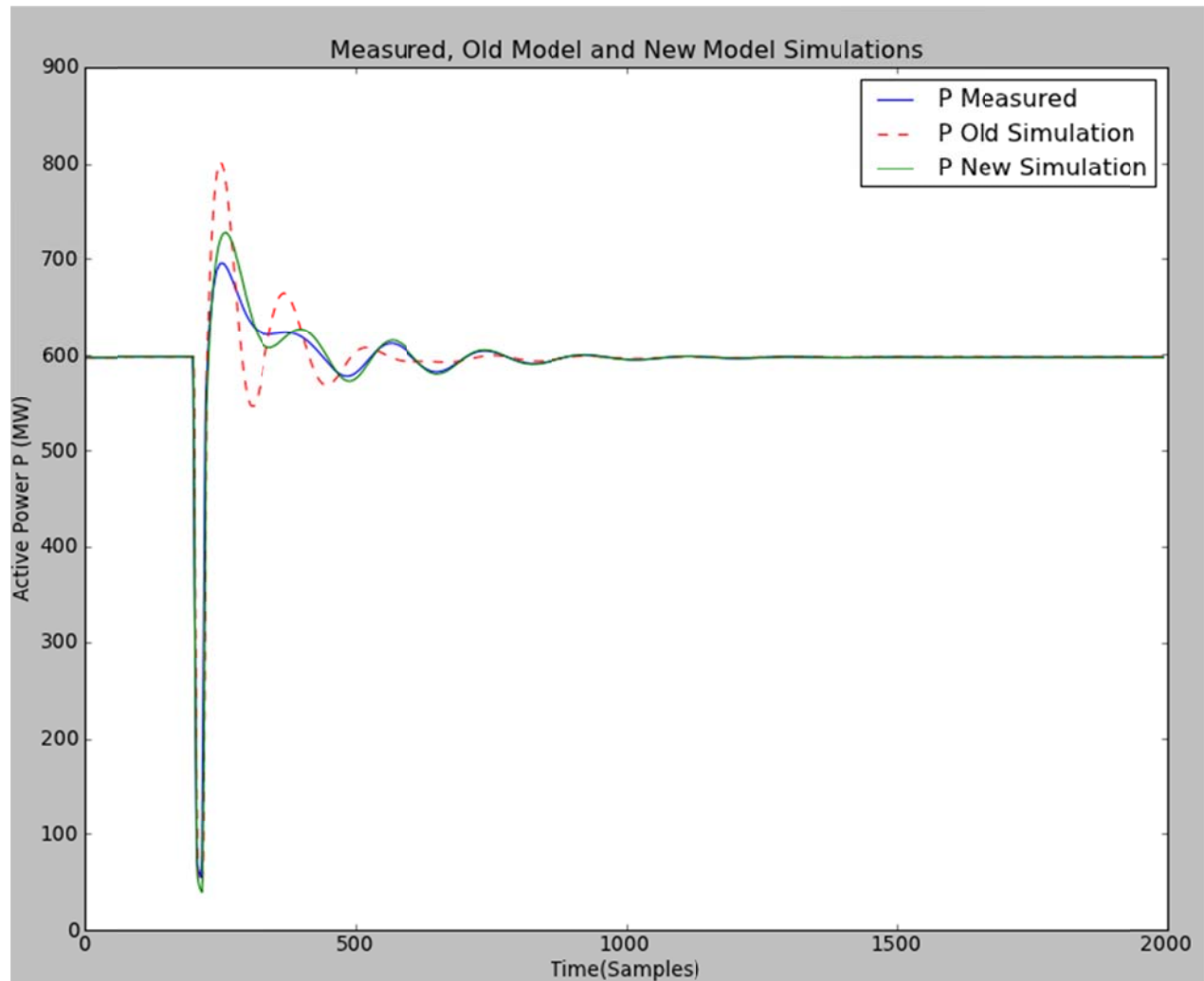


Figure 7. Active power plots after the optimization process

Reactive Power (Q)

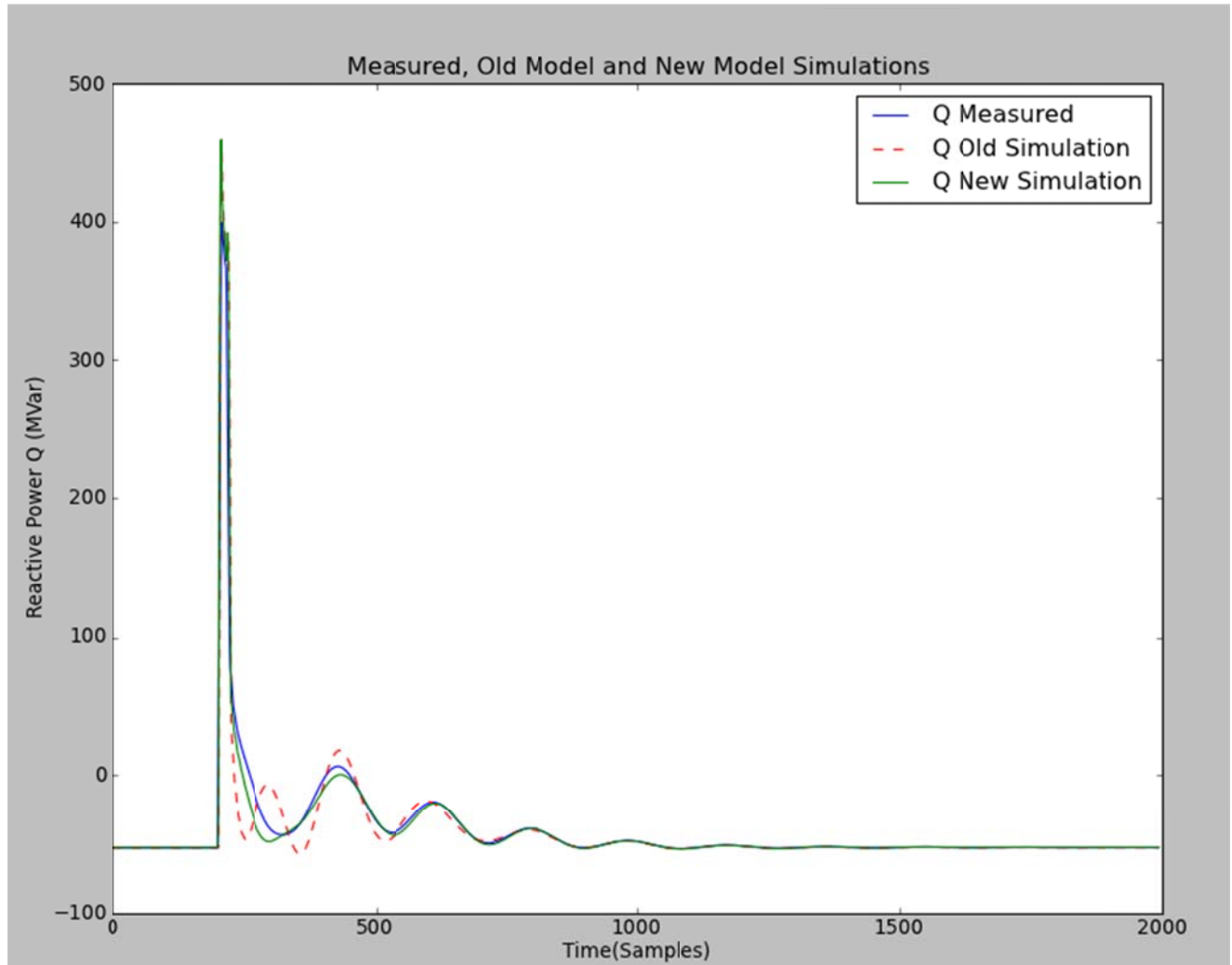


Figure 8. Reactive power plots after the optimization process

| Model | Parameter | Old Value | New Value |
|--------------|-----------|-----------|---------------|
| Model-GENSAL | Par- 3 | 4.0 | 5.05573574144 |

Figure 9. Parameter validation results – new identified parameter values

It can be seen from the figures 7 and 8 that the P and Q response with the new identified parameter value (green line) is much closer to the measured input value (blue line) than the original model simulation (red line). Note that some error due to the use of a reduced system is inevitable. The newly identified parameter value for GENSAL parameter 3 is 5.056 as shown in figure 9 above. This value is very close to the actual value (5) of the parameter in the model.

Some information with regards to the tool run time is provided below:

For the input data corresponding to 10 second duration:

1. Validation Process took about 15 seconds.
2. Sensitivity Analysis took about 7 minutes.
3. Optimization process with one iteration took about 8 minutes.

It was observed that with simulation data as input, one or two iterations were sufficient to identify the parameter change and reduce the mismatch. However, the optimization process for two iterations and five iterations takes approximately 11 minutes and 23 minutes, respectively on the test machine.

7. Testing with Real Data

The GPV tool was recently tested with real data obtained from an electric utility. The following data was obtained for the testing purpose.

1. PMU recorded Voltage and Current Phasors at the output of a generator corresponding to an event – Excel file (.xlsx).
2. PSS\E Model data – Case file (.sav) and Dynamic file (.dyr).

Validation was performed on generator, exciter, governor and stabilizer models. The results are shown in figures 10 and 11 below.

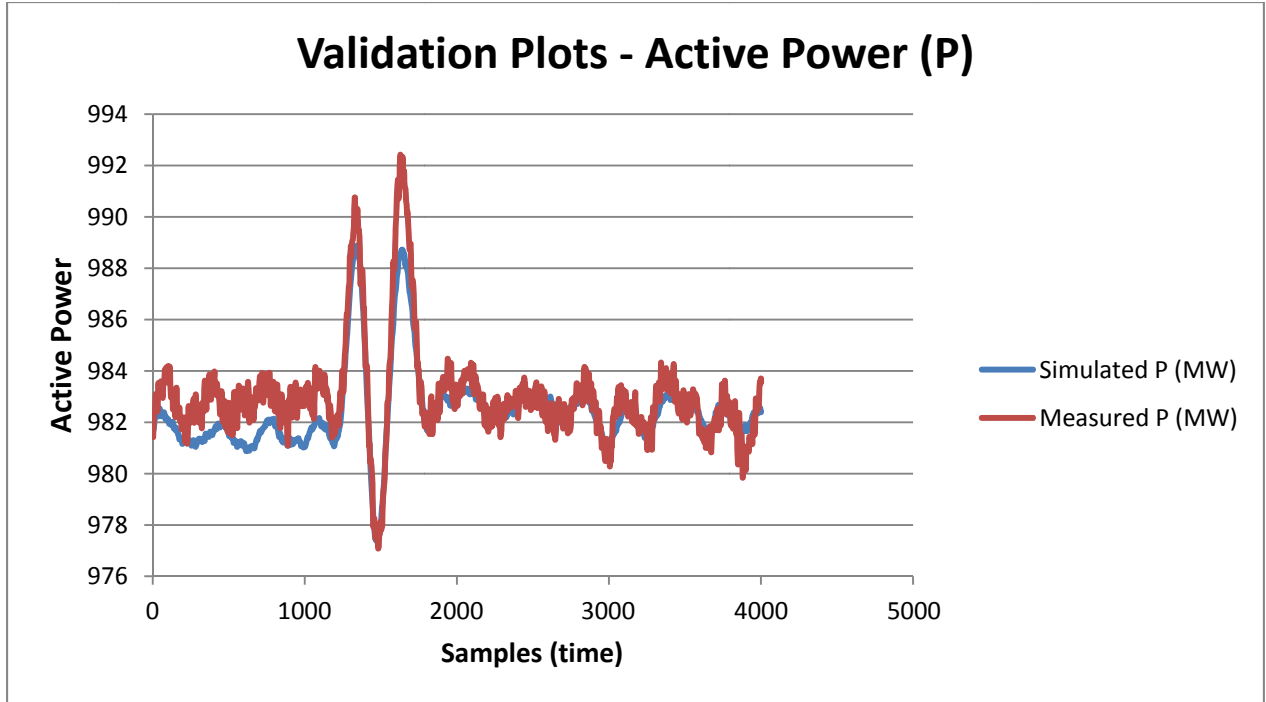


Figure 10. Validation plots for active power (P)

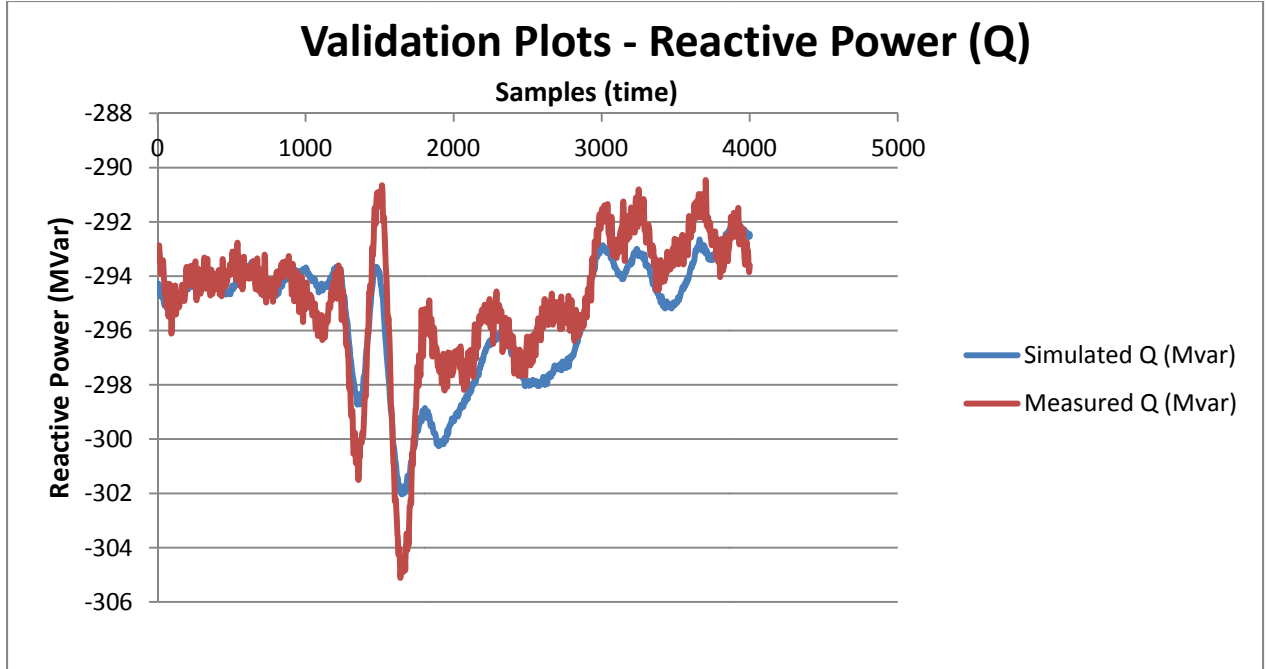


Figure 11. Validation plots for reactive power (Q)

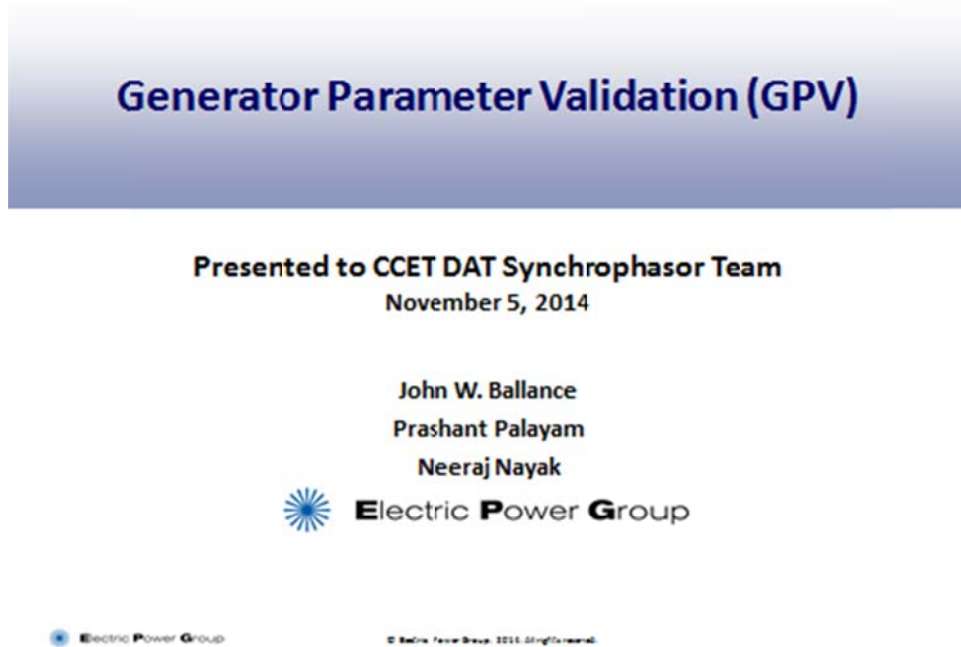
We can see from the plots above that the model simulation results reasonably match that of the measured data. It is important to remember that models are an approximation of the real system and some error due to the use of a reduced system is inevitable.

8. Conclusion

A tool was built for use by Electric Reliability Council of Texas (ERCOT) to perform the generator parameter validation process. The tool, Generator Parameter Validation, uses synchrophasor data from Phasor Measurement Units. The PMUs must be located at the output of the individual generator unit and measure the individual generator branch for validating the generator. The system reduction approach used for this methodology has been automated and is –built-in to the tool. The entire process is split into three steps in sequence - Validation, Sensitivity Analysis, and Optimization. Validation results show comparison plots between simulation and measured data. Sensitivity analysis shows sensitivity of the power flows to each parameter and identifies the key parameters. User interaction is enabled for key parameter selection and for fine-tuning parameter values by specifying a range for the parameters. The optimization process identifies new parameter values for which the model simulation results best match the measured data. The results from the optimization process produces plots comparing the measured, actual model and new model parameter simulation results. The entire validation process for a 10-second input data record takes approximately 20-minutes with one iteration of the optimization algorithm.

9. Appendix

Generator Parameter Validation Presentation



10. References

- [1] Chin-Chu Tsai; Wei-Jen Lee; Nashawati, E.; Chin-Chung Wu; Hong-Wei Lan, "PMU based generator parameter identification to improve the system planning and operation.
- [2] Chin-Chu Tsai, "PMU based parameter identification for the synchronous generator dynamic model", December 2011
- [3] <http://www.nerc.net/standardsreports/standardssummary.aspx>

Generator Parameter Validation (GPV)

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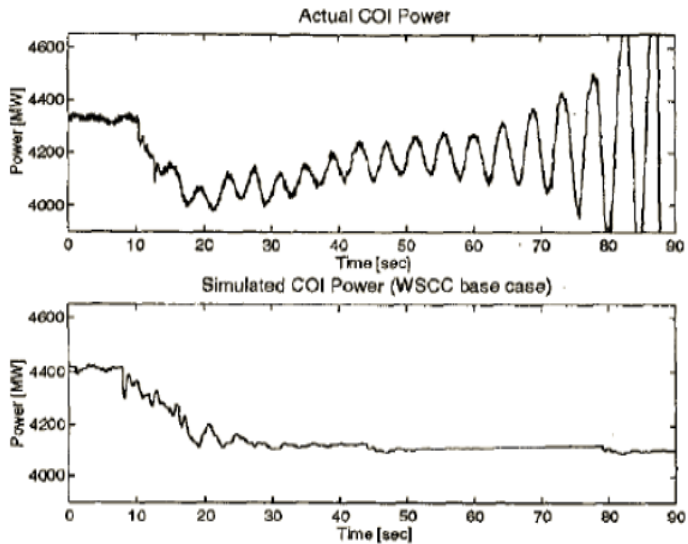
Electric **P**ower **G**roup

November 5, 2014
Presented to CCET DAT Synchrophasor Team

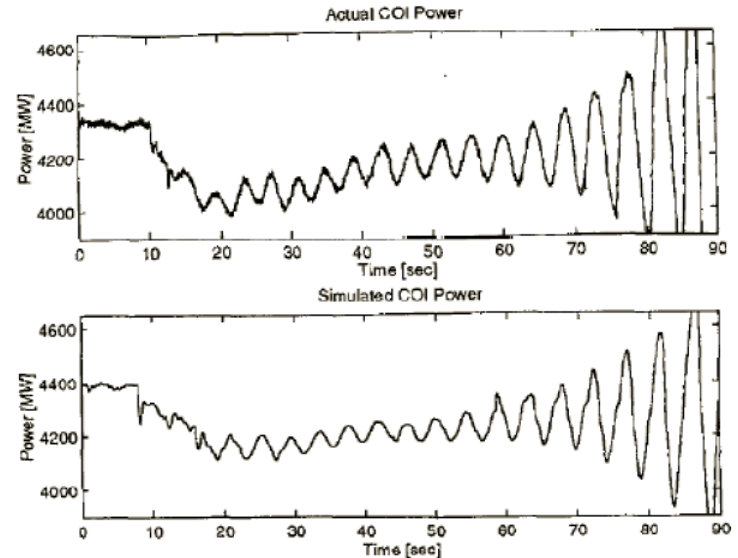
Outline

- Background and Purpose
- Introduction
- Generator Parameter Validation Process
- Example
- Testing on Real Data
- Best Practices
- Limitations and Area of Improvement
- Summary

Background and Purpose



After
Tuning
Models



August, 1996 WSCC

Importance of Correct Models

- Match dynamic grid response
- Establish Operation limits and guidelines
- Study Contingencies and Analyze Events
- System planning

Background and Purpose

- Staged Tests
 - Online testing is expensive , time consuming and can damage the equipment
 - Unit has to be taken out of service.
 - Periodic validation is needed - Parameters may change over time with aging of equipment
- NERC recommended a process for validating power system models and data including generator dynamic models to address the shortcomings that contributed to August 14th 2003 blackout
- NERC Standards
 - MOD-012 requires power plant owners to provide power plant data for dynamic simulations
 - MOD-026 requires power plant owners to verify that the provided dynamic models of excitation controls are accurate and up to date
 - MOD-027 requires power plant owners to verify that the provided dynamic models of governors and turbine controls are accurate and up to date

Background and Purpose

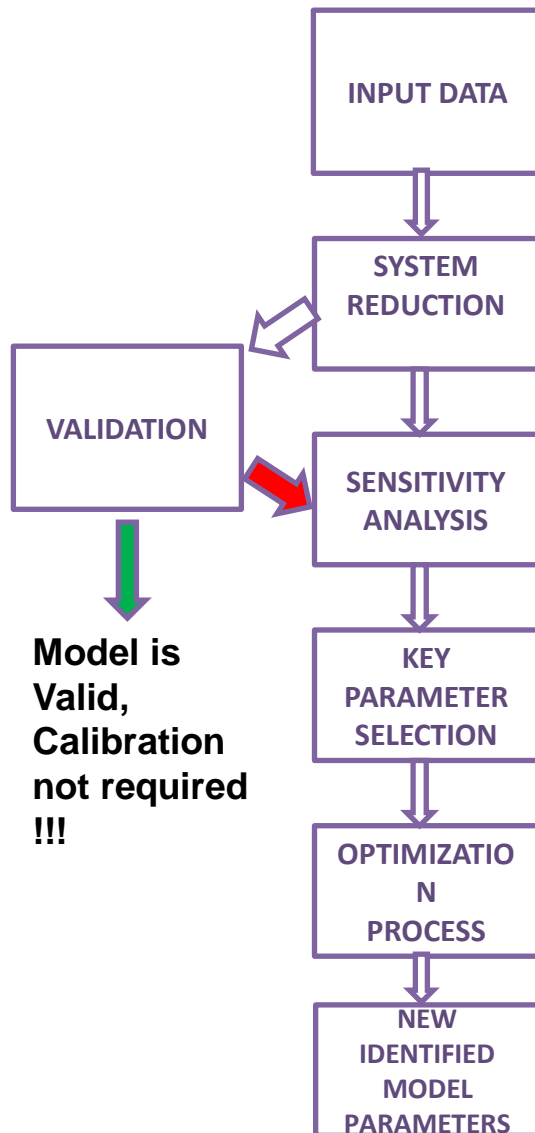
- Dr. Wei-Jen Lee (UT Arlington) et. al proposed and developed a PMU based parameter identification method
- The purpose of the GPV tool is to validate generator models and calibrate the models to identify correct parameter values
- An initial first phase development of GPV method as a tool that was planned is completed
- The algorithm was implemented and tested using 8 different case studies via simulation data that mimics the phasor data
- Lately the tool was also tested with PMU data

Introduction

Methodology:

- Use PMU measured event data to validate the Generator model parameters
- Develop a model parameter validation process based on the following constraints:
 - PMU measured event data (P,Q,V,Angle) is available
 - System operation conditions corresponding to the disturbance are available
 - PSS/E case file (.sav) and dynamics file (.dyr) are available (Only applicable to PSSE models)
- Types of Models that can be validated:
 - Generators
 - Governors
 - Exciters
 - Stabilizers
- Software Used : PSS/E Version 33.4.0, Python 2.7

Generator Parameter Validation Process

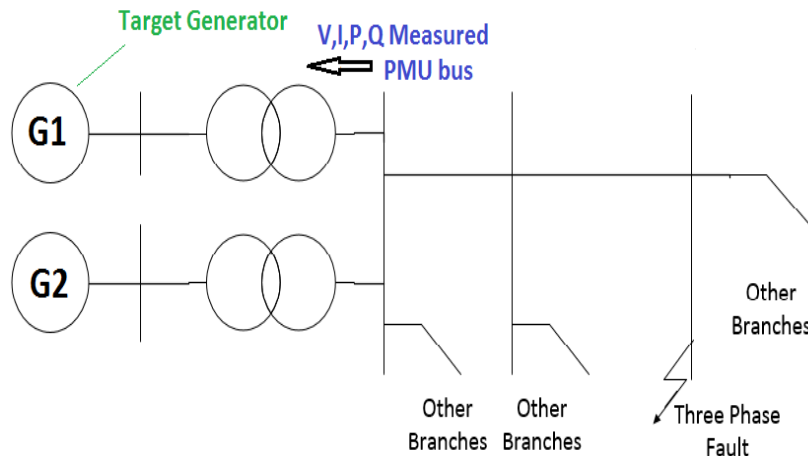


Steps :

1. Input Data – Obtain PMU event data and convert it into Excel file format (P,Q,V,Angle). Obtain the PSS E case file(.sav) and dynamics file(.dyr)
2. System Reduction- Reduce the system beyond the boundary bus (PMU bus) keeping the Target Generator bus and the Boundary bus in the reduced system
3. Validate the measured response with model simulation
4. Trajectory Sensitivity Analysis – Compute Sensitivities of P and Q flows to parameter change
 - Tabulate results
 - Plot results
5. Key Parameter Selection
 - User Interaction to select key parameters from the Sensitivity Analysis for the Optimization Process
6. Optimization Process – Run the optimization process with the selected key parameters to identify the new model parameters
 - Tabulate results
 - Plot results

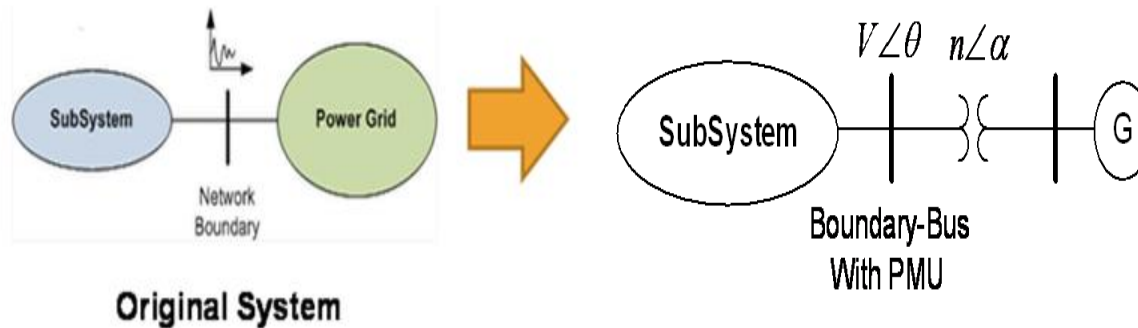
Input Data

- Obtain PMU data (V,I,P,Q) at the generator point of interconnection for an **event** as shown below
- Individual generator data is required , For example : For validating G1 , data for the branch PMU bus – G1 should be obtained
- Extract the PMU data into the Excel file format as shown



| T | V | Angle | P | Q |
|----------|----------|----------|----------|----------|
| 0 | 1.026683 | 24.728 | -149.704 | -109.731 |
| 0.026666 | 1.026683 | 24.728 | -149.704 | -109.731 |
| 0.059999 | 1.026683 | 24.728 | -149.704 | -109.731 |
| 0.093332 | 1.026682 | 24.72764 | -149.708 | -109.731 |
| 0.126665 | 1.02668 | 24.72699 | -149.714 | -109.731 |
| 0.159998 | 1.026678 | 24.72595 | -149.722 | -109.731 |
| 0.193331 | 1.026675 | 24.72445 | -149.732 | -109.732 |
| 0.226664 | 1.026671 | 24.72244 | -149.741 | -109.732 |
| 0.259997 | 1.026667 | 24.71987 | -149.75 | -109.733 |
| 0.29333 | 1.026662 | 24.71669 | -149.757 | -109.735 |
| 0.326663 | 1.026657 | 24.71289 | -149.762 | -109.738 |
| 0.359996 | 1.026652 | 24.70847 | -149.763 | -109.74 |
| 0.393329 | 1.026646 | 24.70344 | -149.762 | -109.743 |
| 0.426662 | 1.026644 | 24.69784 | -149.758 | -109.744 |
| 0.459995 | 1.026638 | 24.69175 | -149.751 | -109.749 |
| 0.493328 | 1.026637 | 24.6852 | -149.743 | -109.749 |
| 0.526661 | 1.026632 | 24.67833 | -149.732 | -109.753 |
| 0.559994 | 1.02663 | 24.67121 | -149.721 | -109.755 |
| 0.593327 | 1.02663 | 24.66394 | -149.71 | -109.756 |
| 0.626659 | 1.02663 | 24.65664 | -149.7 | -109.757 |
| 0.659992 | 1.026631 | 24.64941 | -149.69 | -109.757 |
| 0.693325 | 1.026632 | 24.64234 | -149.682 | -109.757 |
| 0.726657 | 1.026635 | 24.63551 | -149.675 | -109.756 |
| 0.75999 | 1.026637 | 24.62899 | -149.671 | -109.755 |
| 0.793323 | 1.026641 | 24.62283 | -149.668 | -109.754 |
| 0.826656 | 1.026647 | 24.61705 | -149.667 | -109.75 |

System Reduction



- An artificial generator and an ideal transformer are added at the boundary bus
- The turns ratio and the phase shift of the added transformer are adjusted to inject the measured Voltage and angle signals at the boundary.
- The model of the generator is a classical generator model with zero internal reactance, very high inertia constant, and zero damping ratio.
- The transformer is a near zero impedance ideal transformer.
- This method allows for the dynamic simulation of a subsystem with measured signals injected at its boundary without introducing errors caused by the external system model.

Validation

- Use the reduced system for event playback by injecting Voltage and Angle
- Compare measured P and Q with the simulated P and Q
- No calibration required if the models match
- Mismatch indicates calibration is required

Sensitivity Analysis

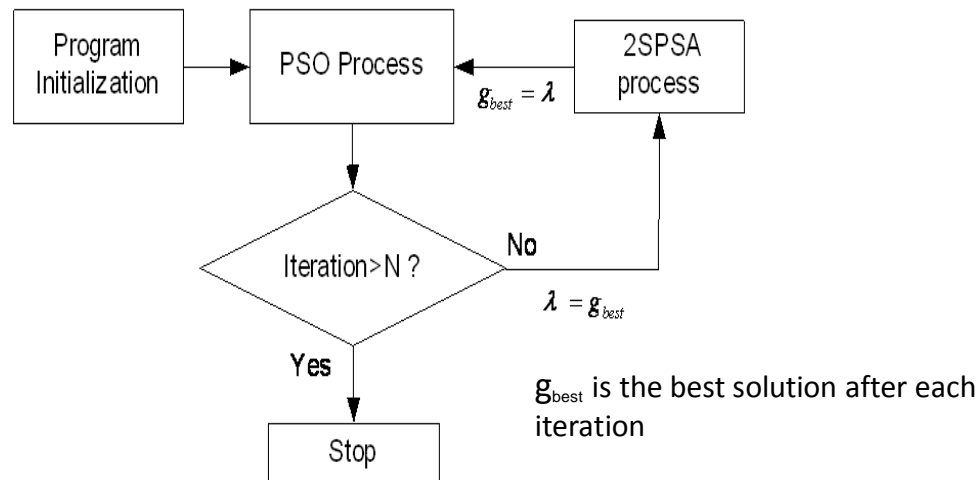
- The objective of sensitivity analysis is to identify the key parameters to be chosen for the validation process
- There are several parameters in generator unit's models, each parameter has a different influence on system response.
- The trajectory sensitivity analysis is carried out to understand the effect of each parameter on the simulation results.
- Sensitivity Analysis computes the sensitivity of P (active power) and Q (reactive power) flows by changing each parameter by a certain value(5%)
- Mean square error (MSE) of P and Q is used as an index for the sensitivities and the analysis identifies parameters having sensitivity above a threshold value

$$\Delta P(t) = \frac{\partial P(t)}{\partial X_0} \Delta X_0 = P_{X_0}(t) \Delta X_0$$

$$\Delta Q(t) = \frac{\partial Q(t)}{\partial X_0} \Delta X_0 = Q_{X_0}(t) \Delta X_0$$

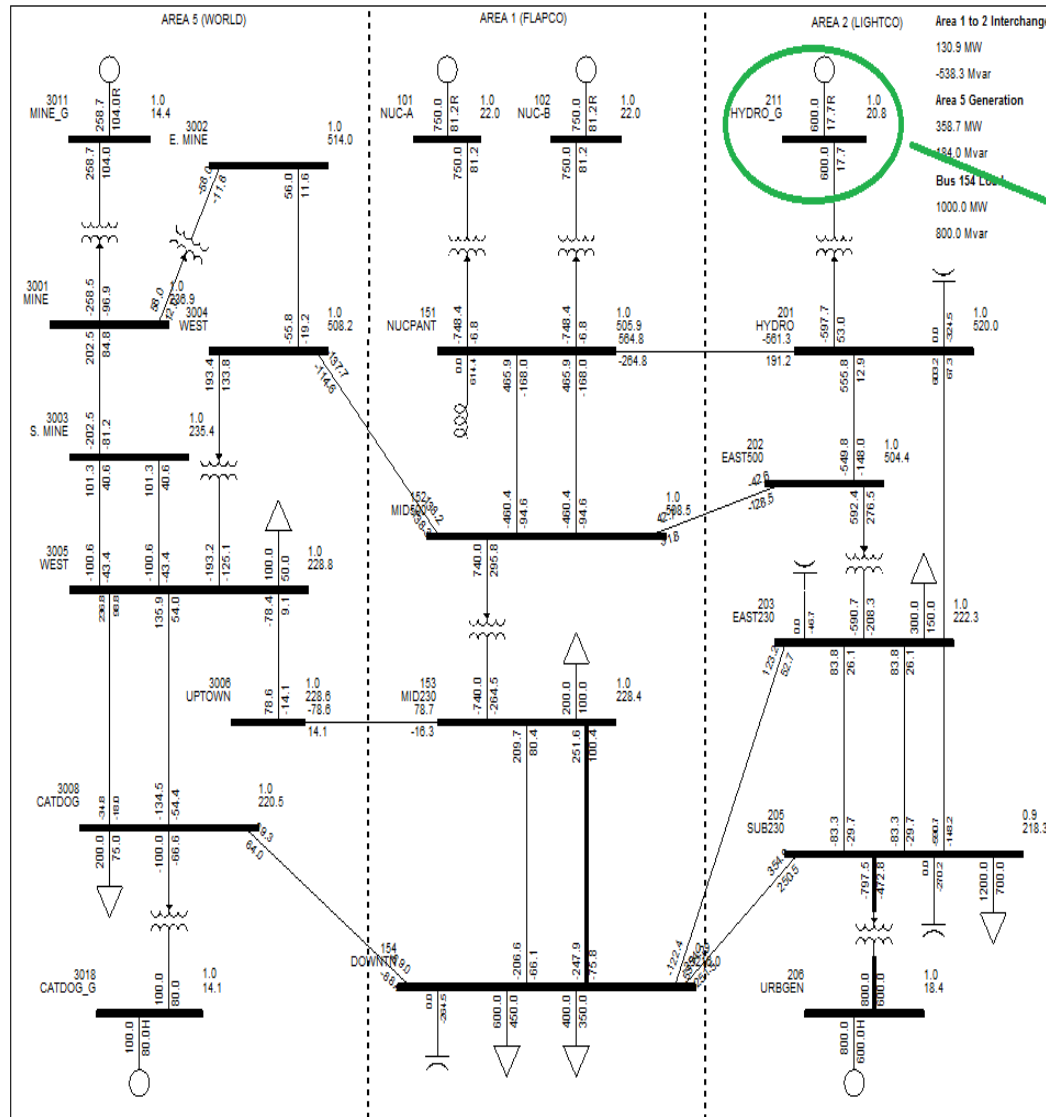
Optimization Process

- Optimization objective is to fit the simulation curves with the measured curves by adjusting the model parameters and identify the new model parameter values
- Two algorithms are used for the optimization process:
 - Particle Swarm Optimization (PSO)
 - Simultaneous Perturbation Stochastic Approximation (SPSA)–PSO
- PSO is not affected by initial guess and has global search ability but the convergence rate is slow
- SPSA is a gradient based algorithm which steers the particle to the right direction and has better convergence
- A new intelligent optimization method SPSA-PSO cooperative method is used to obtain a combination of global search ability and better convergence. SPSA drives the results of PSO for faster convergence.



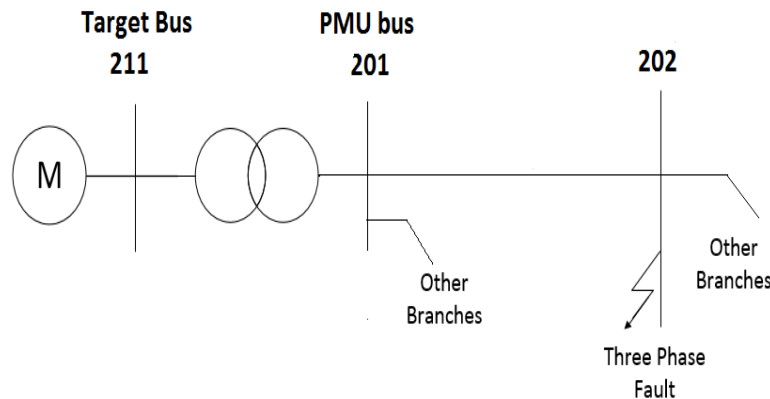
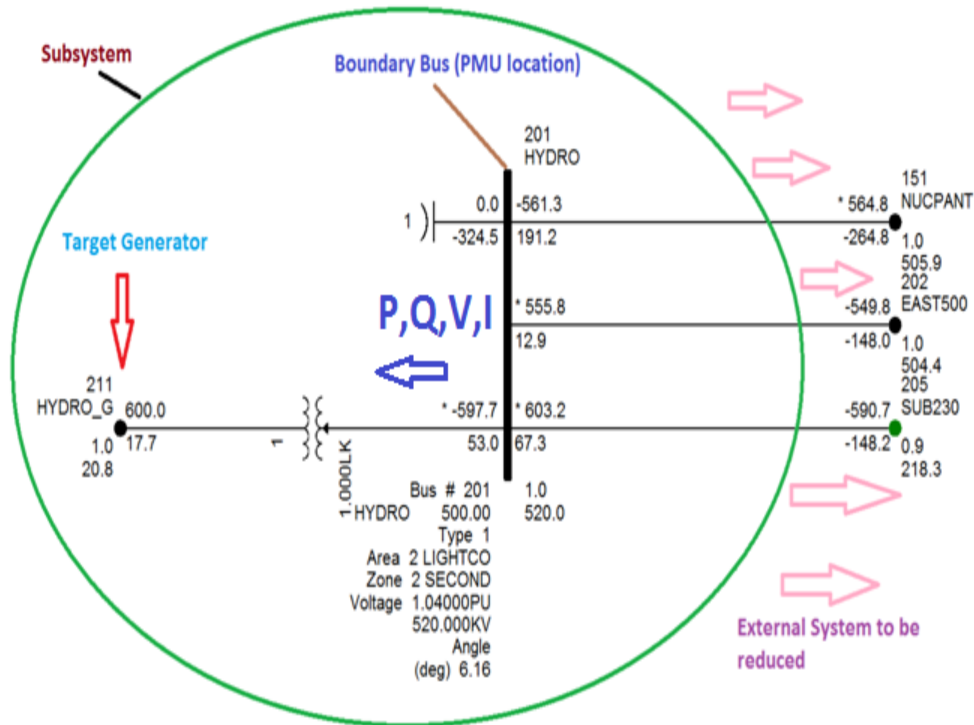
EXAMPLE

PSSE Example Case savnw.sav



Target Generator

Bus Display View



Event description : 3 phase bus fault at bus no: 202 at t=1 sec , fault cleared at t =1.08 sec and system is run to 5 sec

Run GPV Tool

Input data file (.xlsx)

PSSE case file
(.sav)

PSSE dynamics
file(.dyr)

Path to PSSE PSSBIN
folder containing python
modules

Generator Parameter Validation Tool

Data Input Configuration

| | | |
|----------------|----------------------------------|-------------|
| Data file path | GenMatched/Test1/InputData.xlsx | Browse file |
| .sav file path | fterGenMatched/Test1/savnw.sav | Browse file |
| .dyr file path | ched/Test1/savnwchanged_H.dyr | Browse file |
| PSSE file path | am Files (x86)\PTI\PSSE33\PSSBIN | Select Path |

Case and Model Information

| | |
|----------------------|-----|
| PMU Boundary Bus | 201 |
| Target Generator Bus | 211 |
| Target Generator ID | 1 |

Run Validation

Run Sensitivity Analysis

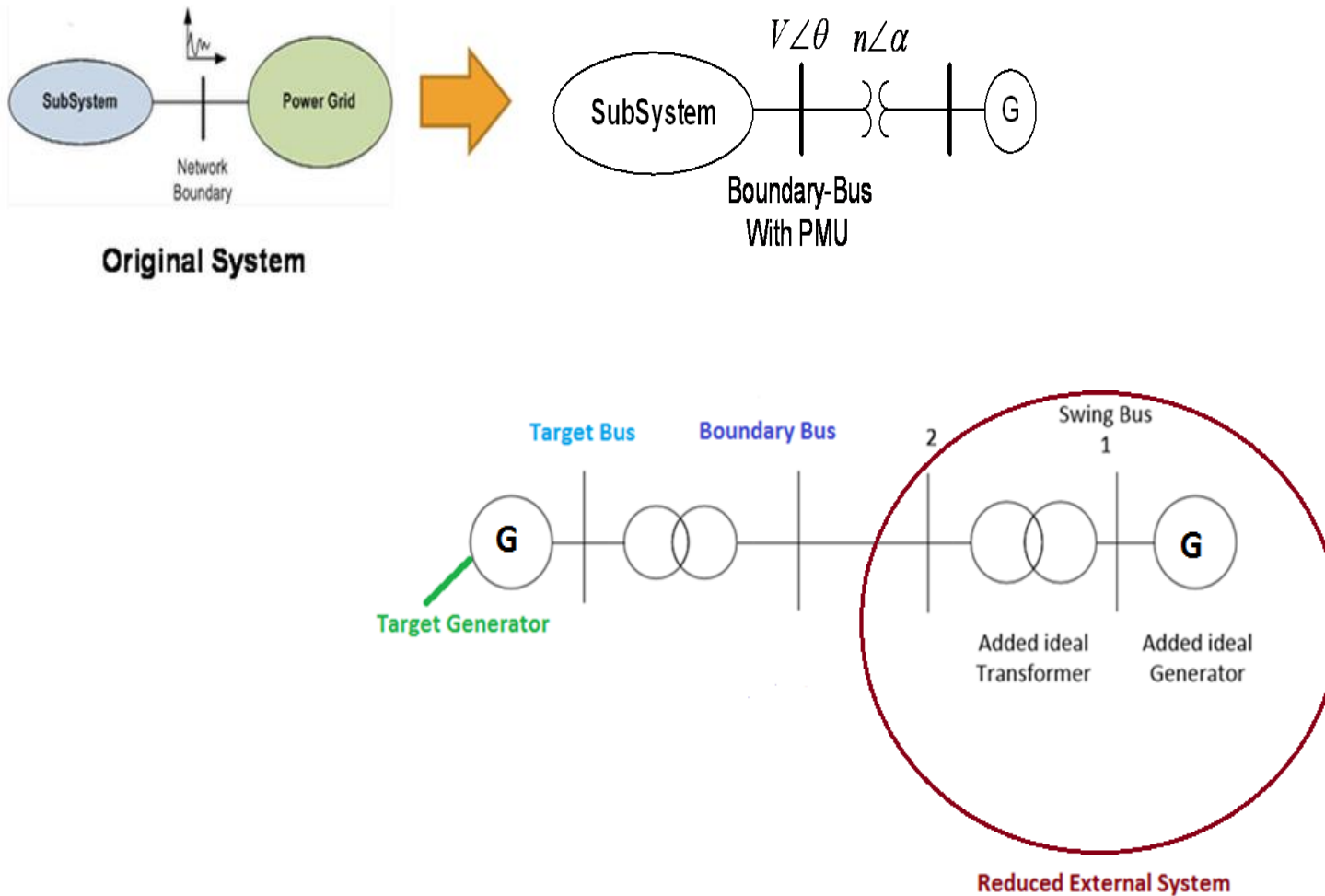
Select Algorithm

☐ PSO ☐ SPSA-PSO

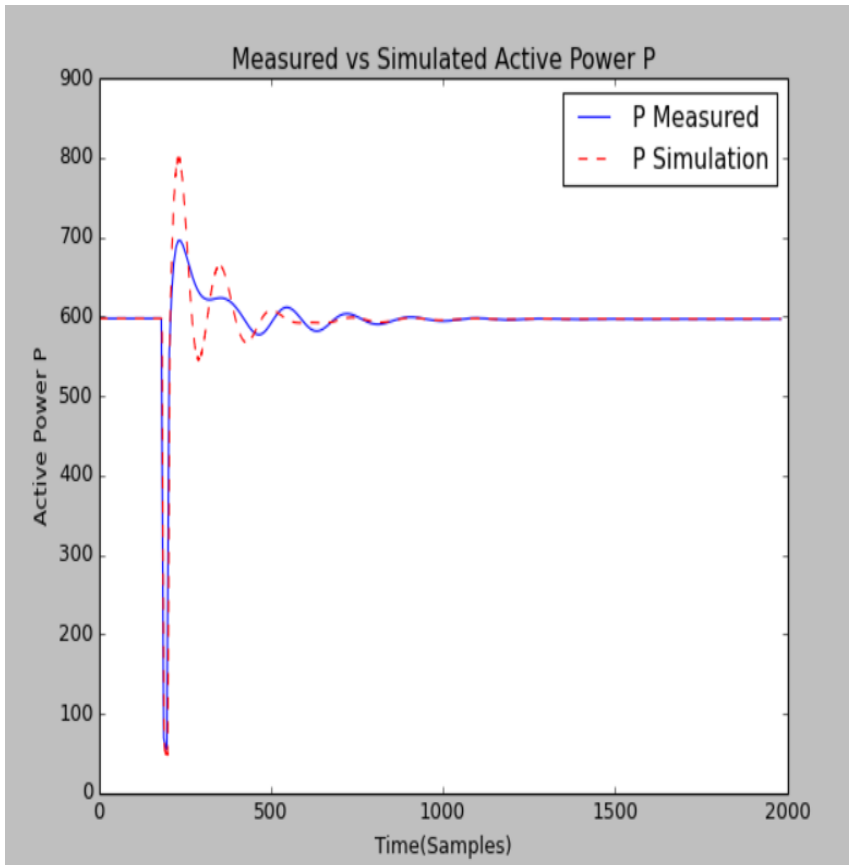
Run Optimization

Number of iterations

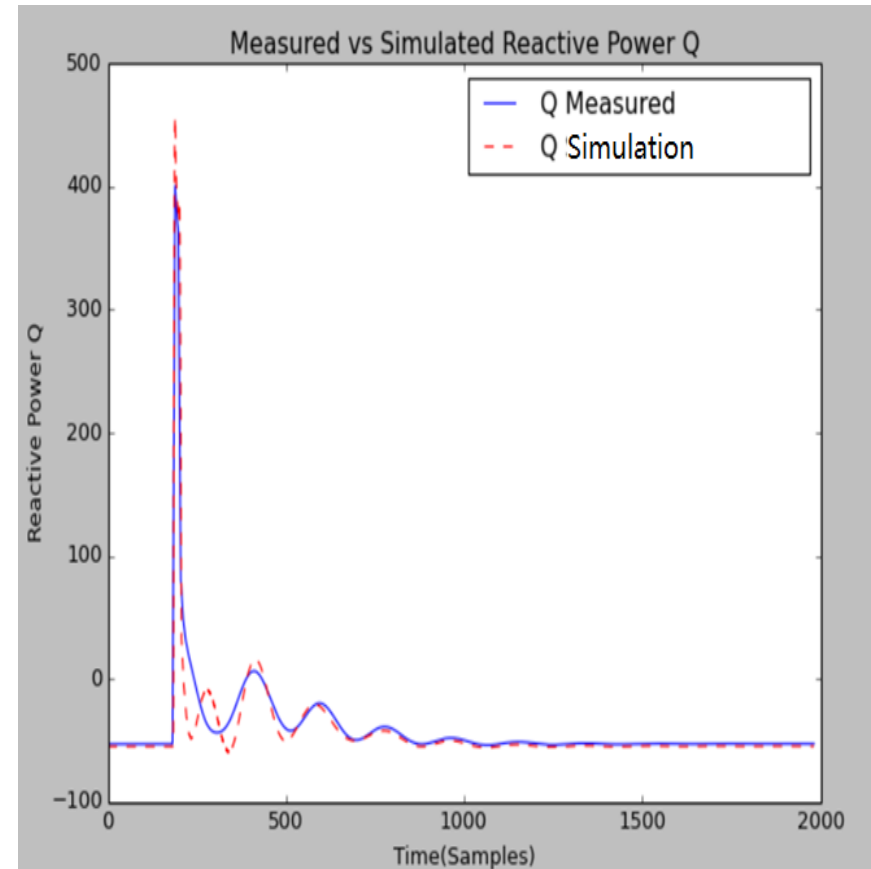
Automated System Reduction



Validation Plots



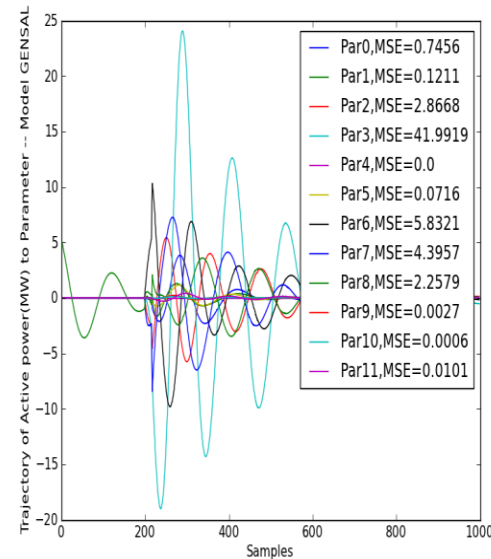
Active Power (P)



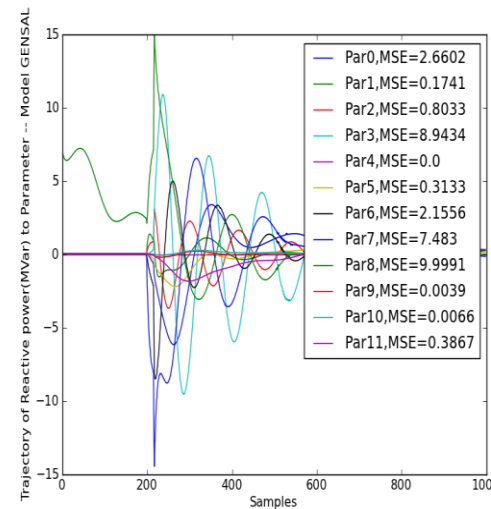
Reactive Power (Q)

Sensitivity Analysis- Identify Key Parameters

| Parameter | MSE-P | MSE-Q | Ranks | Min | Max |
|----------------|----------|---------|-------|-----|-----|
| GENSAL- Par 0 | 0.3562 | 1.19294 | 7 | | |
| GENSAL- Par 1 | 0.05373 | 0.07745 | 14 | | |
| GENSAL- Par 2 | 1.4388 | 0.39999 | 6 | | |
| GENSAL- Par 3 | 19.13134 | 3.89948 | 1 | | |
| GENSAL- Par 4 | 0.0 | 0.0 | | | |
| GENSAL- Par 5 | 0.02824 | 0.13205 | 12 | | |
| GENSAL- Par 6 | 3.02644 | 1.10927 | 4 | | |
| GENSAL- Par 7 | 1.79128 | 3.23443 | 3 | | |
| GENSAL- Par 8 | 0.95289 | 4.44052 | 2 | | |
| GENSAL- Par 9 | 0.00129 | 0.00177 | 22 | | |
| GENSAL- Par 10 | 0.00028 | 0.00267 | 21 | | |
| GENSAL- Par 11 | 0.00419 | 0.16833 | 11 | | |
| HYGOV- Par 0 | 0.00021 | 3e-05 | 25 | | |
| HYGOV- Par 1 | 0.01525 | 0.00142 | 17 | | |
| HYGOV- Par 2 | 0.0012 | 6e-05 | 23 | | |
| HYGOV- Par 3 | 0.00402 | 0.00028 | 20 | | |
| HYGOV- Par 4 | 0.00805 | 0.00125 | 19 | | |
| HYGOV- Par 5 | 0.01905 | 0.00096 | 16 | | |
| HYGOV- Par 6 | 0.0 | 0.0 | | | |
| HYGOV- Par 7 | 0.0 | 0.0 | | | |
| HYGOV- Par 8 | 0.0088 | 0.00104 | 18 | | |
| HYGOV- Par 9 | 0.02207 | 0.00282 | 15 | | |
| HYGOV- Par 10 | 0.00074 | 0.00016 | 24 | | |
| HYGOV- Par 11 | 0.00012 | 2e-05 | 26 | | |
| SCRX- Par 0 | 0.11311 | 1.13153 | 8 | | |
| SCRX- Par 1 | 0.00683 | 0.49723 | 9 | | |
| SCRX- Par 2 | 0.12592 | 0.42198 | 10 | | |
| SCRX- Par 3 | 0.01961 | 0.12695 | 13 | | |
| SCRX- Par 4 | 0.0 | 0.0 | | | |
| SCRX- Par 5 | 0.44422 | 1.58719 | 5 | | |
| SCRX- Par 6 | 0.0 | 0.0 | | | |
| SCRX- Par 7 | 0.0 | 0.0 | | | |



Trajectory of Pnew-Pold for GENSAL model parameters



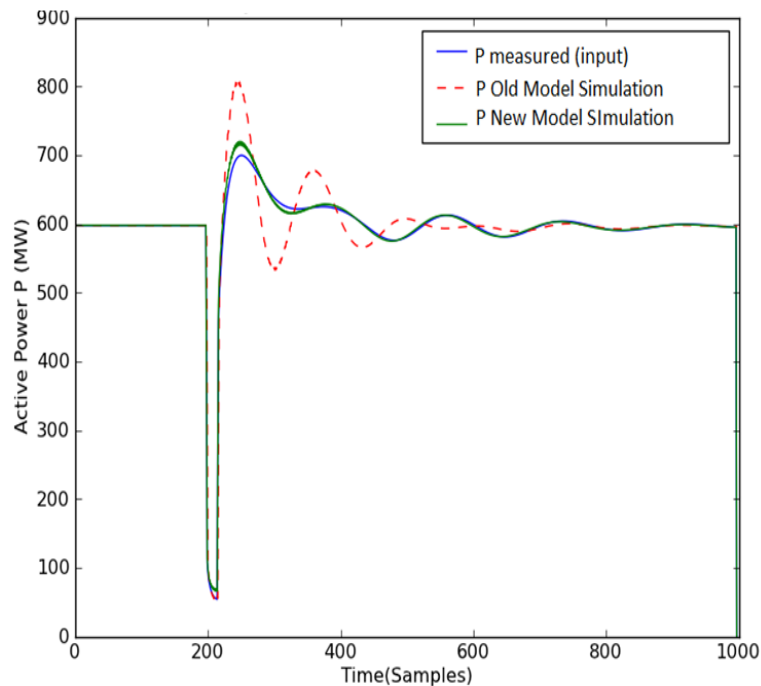
Trajectory of Qnew-Qold for GENSAL model parameters

Note:

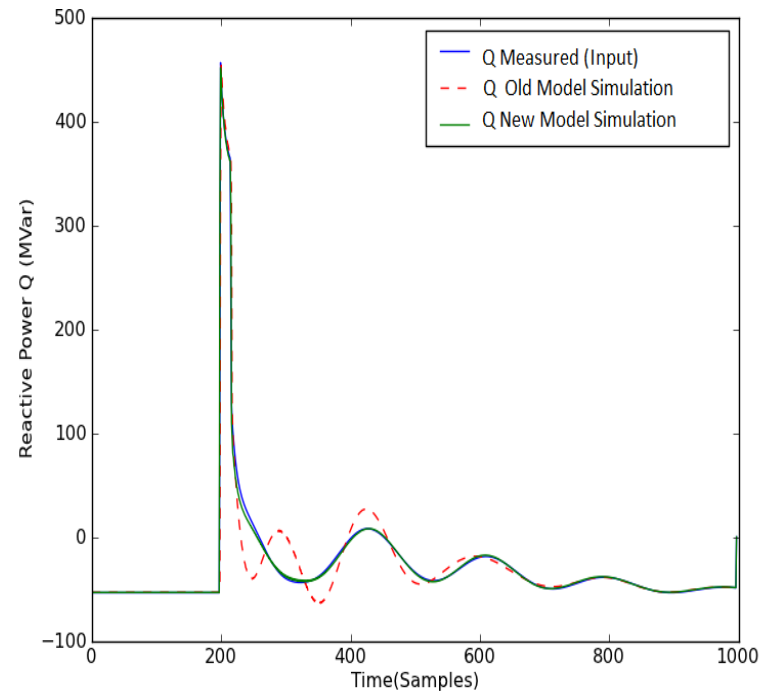
Pnew = Active Power flow for original model parameter value
 Qnew = Reactive Power flow for original model parameter value
 Pold/Qold = Active Power/Reactive Power flow for a 5% increase in the corresponding parameter value
 *Key Parameter column based on a sensitivity threshold of 0.01

Optimization Results - Identified Parameter Values

| 7% Parameter Validation Results | | | |
|---------------------------------|-----------|----------------|----------------|
| Model | Parameter | Old Value | New Value |
| Model-GENSAL | Par- 2 | 0.239999994636 | 0.168001055427 |
| Model-GENSAL | Par- 3 | 4.0 | 4.6727793482 |



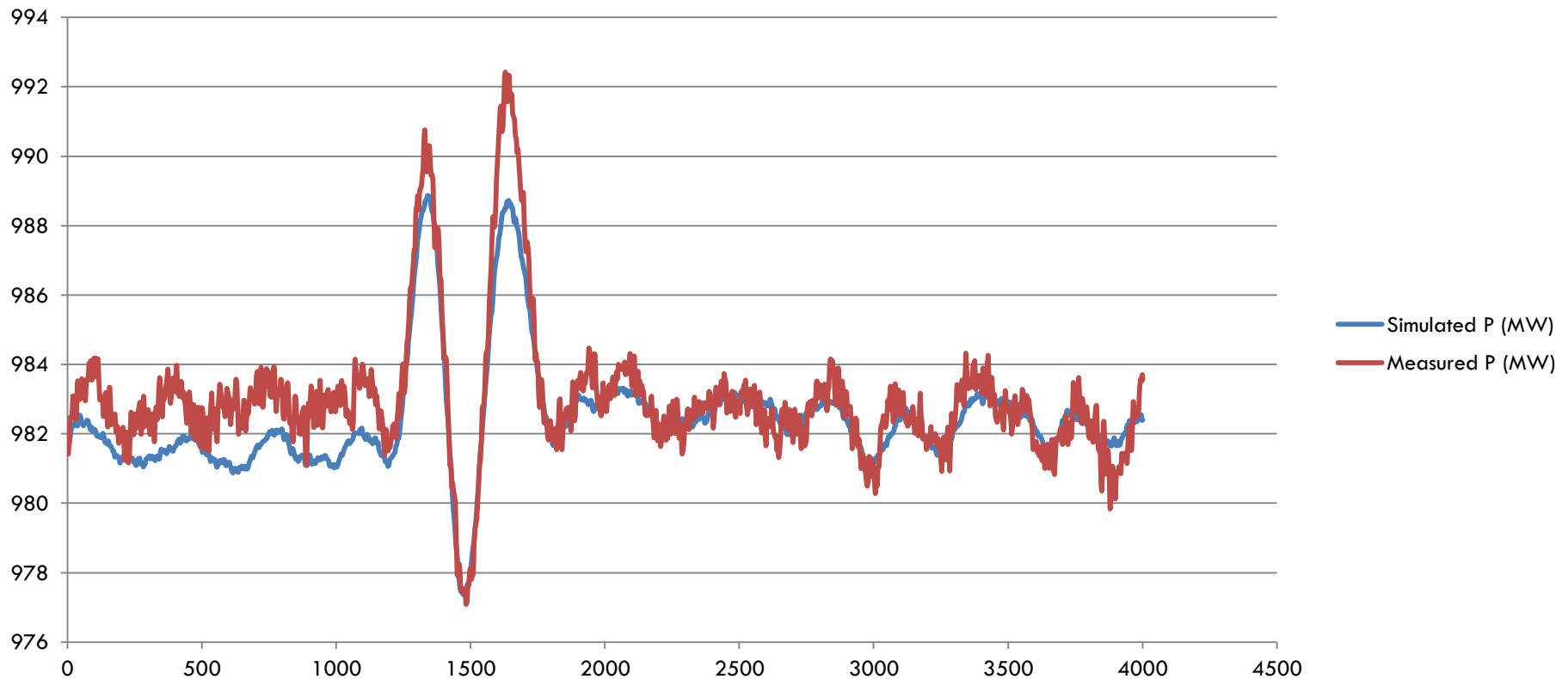
| Parameter | Constant Description |
|--------------------|----------------------|
| GENSAL Parameter 2 | $T''q_0$ (sec) |
| GENSAL Parameter 3 | H, Inertia |



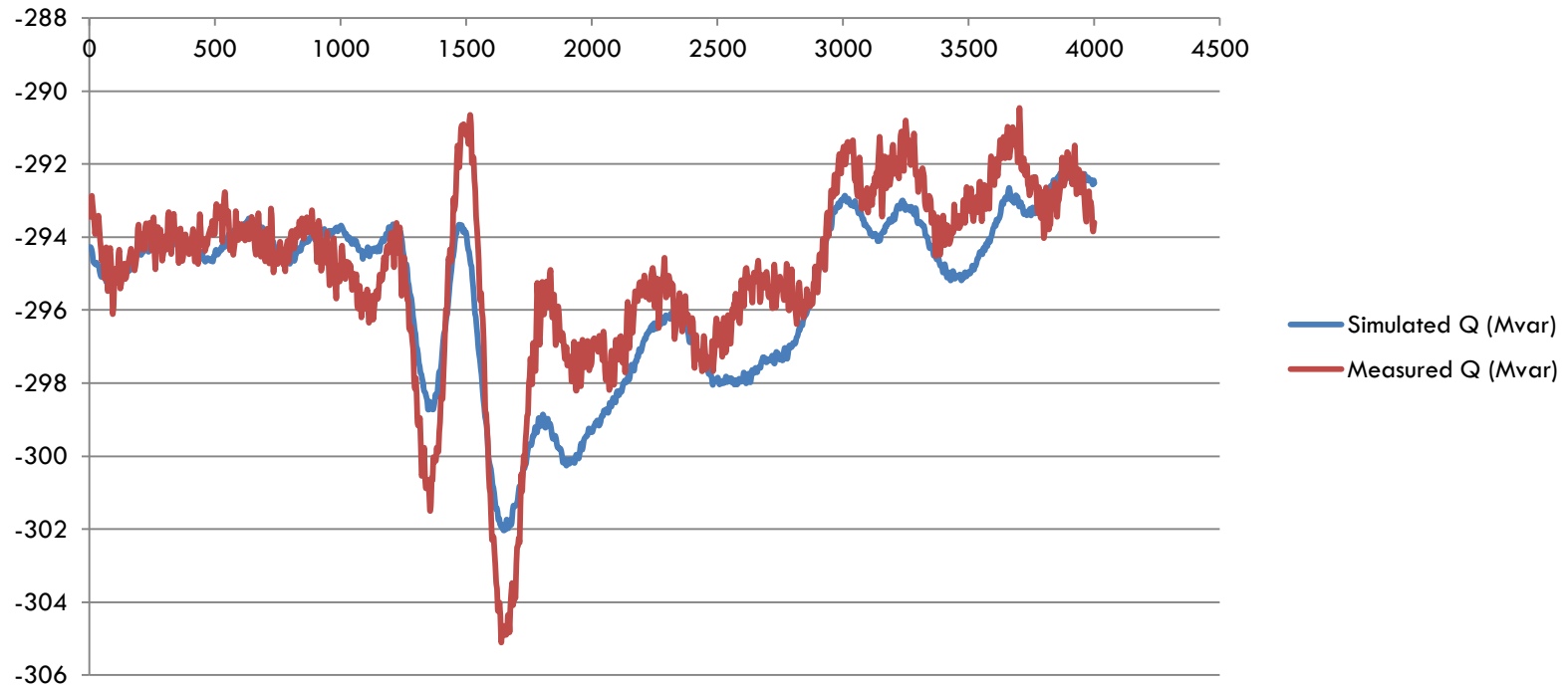
Testing on Real Data

- The tool was tested on data sets obtained from an electric utility
- Data obtained:
 - PMU recorded Voltage and Current Phasors at the output of a generator corresponding to an event
 - PSS\E Model data – Case file and Dynamic file
- Performed Validation on generator, exciter, governor and stabilizer models

Validation - Real Power (P)



Validation – Reactive Power (Q)



Best Practices

- Use individual branch data to validate and calibrate individual generators
- Obtain input data covering the dynamics during the event
- Select key parameters that have highest P,Q sensitivity (Example:top 5)→ Check the results→ Change key parameters selection→ Check Results→ Narrow down on key parameters and fine tune parameter values
- Specify maximum and minimum range for the parameters to restrict their variation (based on knowledge about the parameters)
- Use multiple runs for the same generator-event case and multiple events for the same generator to tune results

Limitation and Area of Improvement

- Limitation:
 - Applicable for PSS\E models
 - Processing time increases with length of input data and number of iterations
- Area of Improvement:
 - Update code to correct for offset due to system reduction
 - Update code to correct for any initial transient
 - Update code to unwrap angles before interpolation to avoid periodic transients

Summary

- Built the user interface to
 - Accept Input Data
 - Automate System Reduction Process
 - Perform Validation to evaluate the need for calibration
 - Perform Sensitivity Analysis to identify key parameters
 - Restrict parameter variation by adding upper and lower bounds on the parameter values
 - Calibrate the models using an Optimization Process and display identified parameter values
- Next Steps
 - Obtain recorded event data at the output of individual generators
 - Obtain model data for the generators
 - Test the tool to validate and calibrate on additional data sets

Thank You.

Any questions ?

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nayak@electricpowergroup.com



Electric **P**ower **G**roup

Attachment 14. Use Cases with Sample Events

Synchrophasor Technology – PMU Use Case Examples

John W Ballance - EPG

Prashant C Palayam – EPG

Sarma (NDR) Nuthapalati - ERCOT

November 5, 2014

Prepared for CCET DAT Synchrophasor Team



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Use Case Overview

| Use Case | Grid Scope | Streaming 30 samples/sec | Slow Speed 3 samples/min | Local Event Capture | Example of Application on ERCOT Grid |
|----------------------------------------------------------------------------------------|---------------------|-----------------------------|-----------------------------|------------------------|---------------------------------------------------------------------------------------------------------|
| High Stress Across System (High Phase Angle) Observed | Wide Area | Yes | Yes | | High Phase Angle from Valley - November 13, 2013 |
| Small Signal Stability – Damping is Low | Wide Area | Yes | | | Control system oscillations from wind plant - January 9, 2014 |
| Small Signal Stability – Emerging Oscillation Observed | Wide Area and Local | Yes | | | Slow System Oscillation Detected October 12, 2014 |
| Voltage Oscillation Observed | Regional | Yes | | | Wind Control System Oscillations in Valley - April 12-13, 2013 |
| Voltage Instability Monitoring (real-time P-V or Q-V curve) | Regional | Yes | | | High Phase Angle in Valley - November 13, 2013 |
| Detection of Subsynchronous Interactions (Not necessarily resonance, just below 60 Hz) | Local Regional | Yes | | | |
| Integrate PMU Data Into State Estimator | Wide Area | Yes | Yes | | Baselining Study confirmed correlation between PMU and State Estimator data |
| System Disturbance – Capture and Interpretation | Regional | Yes | Yes, not high resolution | Yes | Enhanced Event Analysis Capabilities - including control system performance diagnostics |
| Generator Parameter Determination | Local | Yes | | Yes | Wind plant oscillation and trip following line outage - September 2011, reported in 2012 IEEE PES paper |
| Major Load Parameter Determination | Local | Yes | | Yes | |
| PMU-Based Fault Location | Local Regional | Yes | | Yes | |
| Phase Angle Across Breaker for Reclosing Action | | Yes | Yes | | ERCOT operating studies identify need for monitoring phase angles |
| Subsynchronous Resonance Identification and Mitigation (PGRR027) | Regional | Yes | | | |
| Transmission Characteristics Determination | Regional | Yes | | Yes | |
| Dynamic Transmission Line Ratings using PMU monitoring | Regional | Yes | | | |
| Validation of Control Devices (e.g. SVC) performance | Regional | Yes | | Yes | |

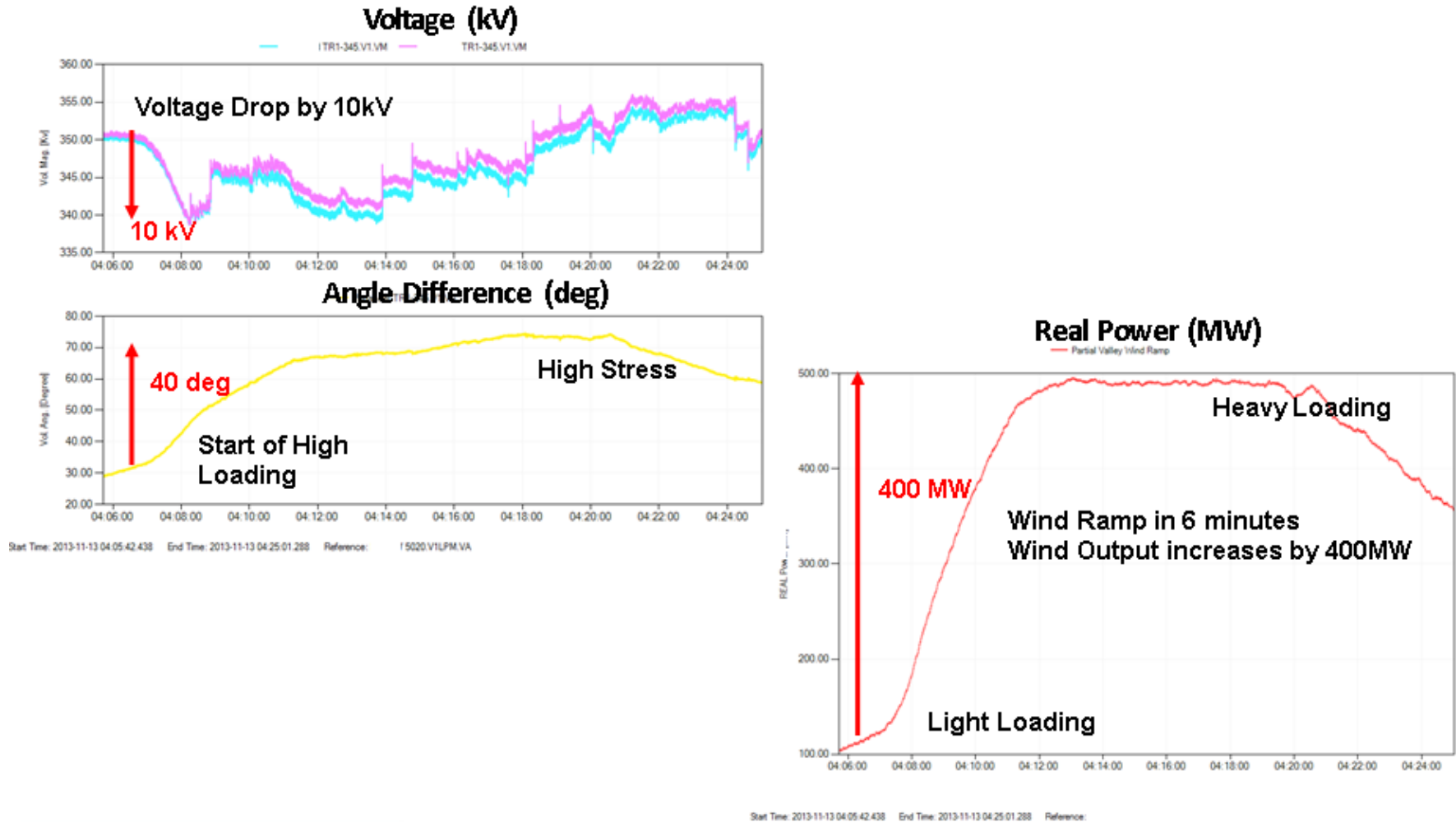


Use Case - High Stress Across System (High Phase Angle) Observed

- **Need:** PMU Phase Angle data can advise the Shift Engineer about the measured angle across wide area to provide early warnings on high power flow (high grid stress)
- **EXAMPLE: HIGH PHASE ANGLE AT COAST 3 (VALLEY) – NOV 13, 2013**
- **Possible Action:**
 - Shift Engineer reviews high phase angle, and examines possible consequences if an event aggravates this.
 - Online TSAT Study
 - Online VSAT study
 - Online Power flow study
 - Shift Engineer may recommend action to shift supervisor
 - Impose Transfer limit
 - Adjust generation pattern



Event Analysis – Impact of High Wind on System Performance Following Wind Ramp



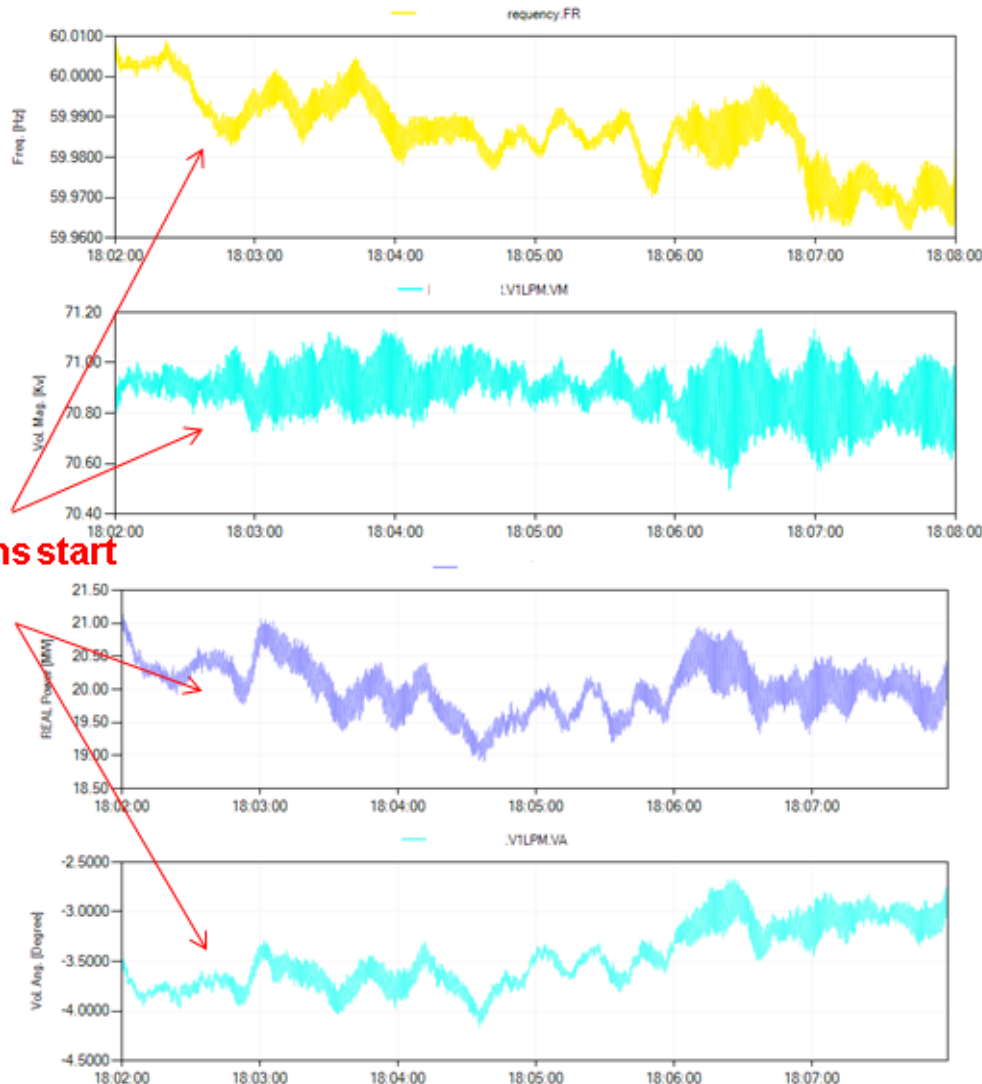
Reference Angle: North 7

Use Case - Small Signal Stability – Low Damping

- **Need:** PMU data can advise the Shift Engineer about both known & unknown oscillations at location/s
- **EXAMPLE: CONTROL SYSTEM OSCILLATIONS FROM WIND PLANT – JANUARY 9, 2014**
- **Possible Action:**
- Shift engineer should review
 - Oscillatory frequency & damping
 - Determine type of oscillation (inter-area such as 0.6Hz North-South Mode, Local Control system such as 3.2Hz at West 10)
- Shift Engineer may recommend action to shift supervisor
 - Reduce Transfer out of area
 - Reduce generation output
 - Revert control system settings to original value & restore output



PMU Data Illustrates Oscillation With Low Damping



Oscillations start
sharply

Frequency (Hz)

Voltage (kV)

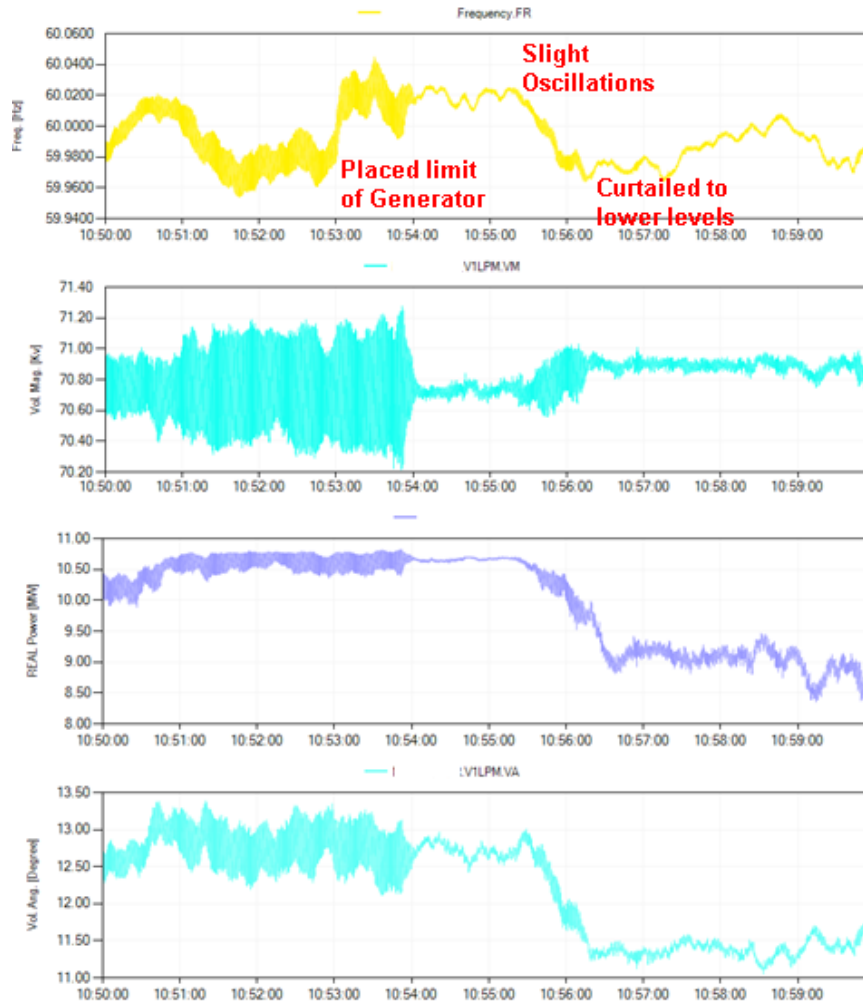
Real Power (MW)

Angle Difference (deg)

Reference Angle: North 7

Phasor Grid Dynamic Analyzer (PGDA) plots

PMU Data Illustrates Oscillation With Low Damping



Frequency (Hz)

Voltage (kV)

Real Power (MW)

Angle Difference (deg)

Reference Angle: North 7

Phasor Grid Dynamic Analyzer (PGDA) plots

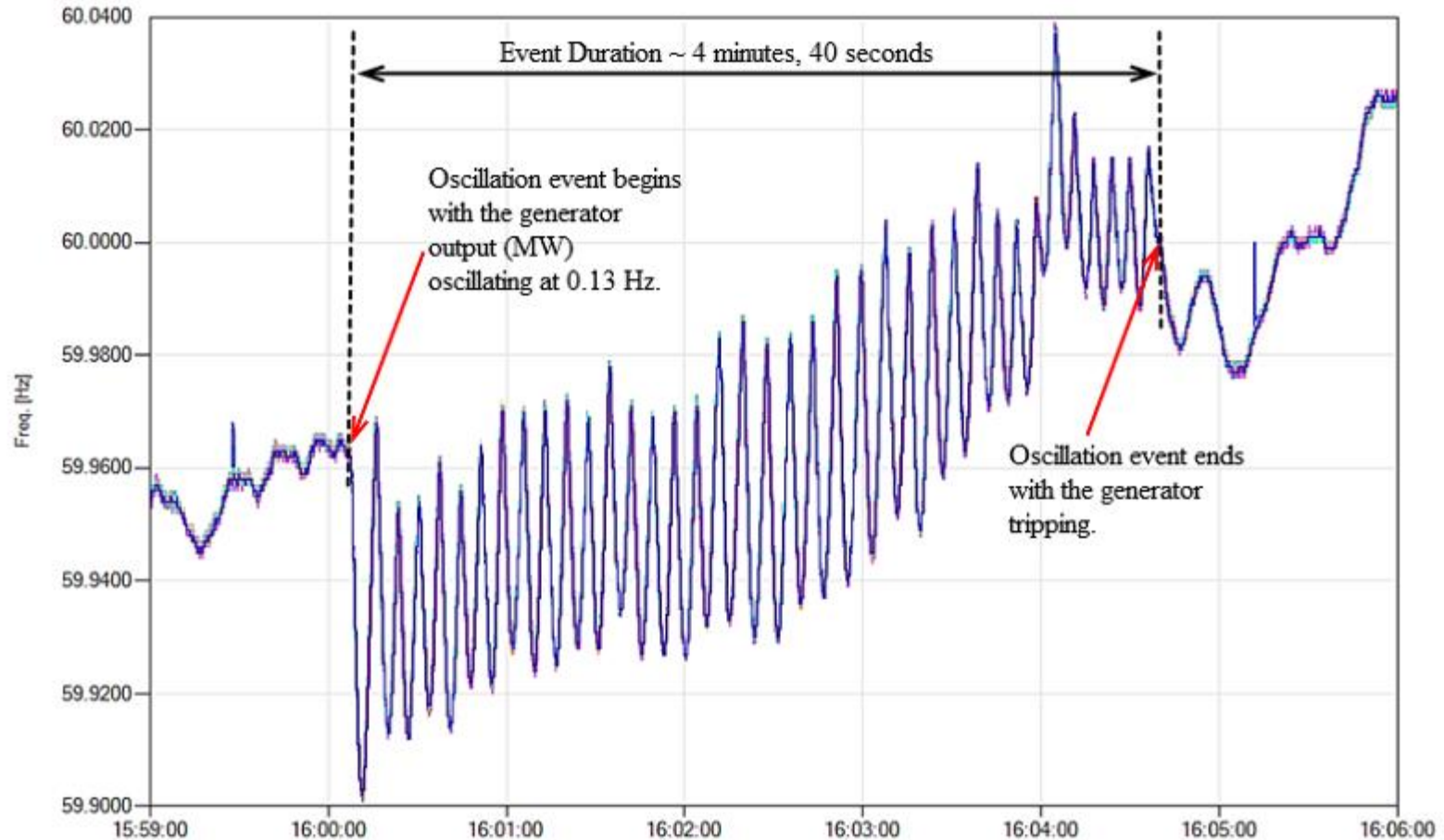


Use Case - Small Signal Stability – Emerging Oscillation Observed

- **Need:** PMU data can advise the Shift Engineer about both known & unknown oscillations at location/s
- **EXAMPLE: SYSTEM-WIDE OSCILLATIONS FOLLOWING LOSS OF GENERATION – OCTOBER 12, 2014**
- **Possible Action:**
- Shift engineer should review
 - Oscillatory frequency & damping
 - Determine type of oscillation (e.g. inter-area such as 0.6Hz North-South Mode or Local Control system such as 3.2Hz at West 10)
- Shift Engineer may recommend action to shift supervisor
 - Reduce Transfer out of area
 - Reduce generation output
 - Block control system (to eliminate control system-driven oscillations)



PMU Data Illustrates Emerging Oscillation

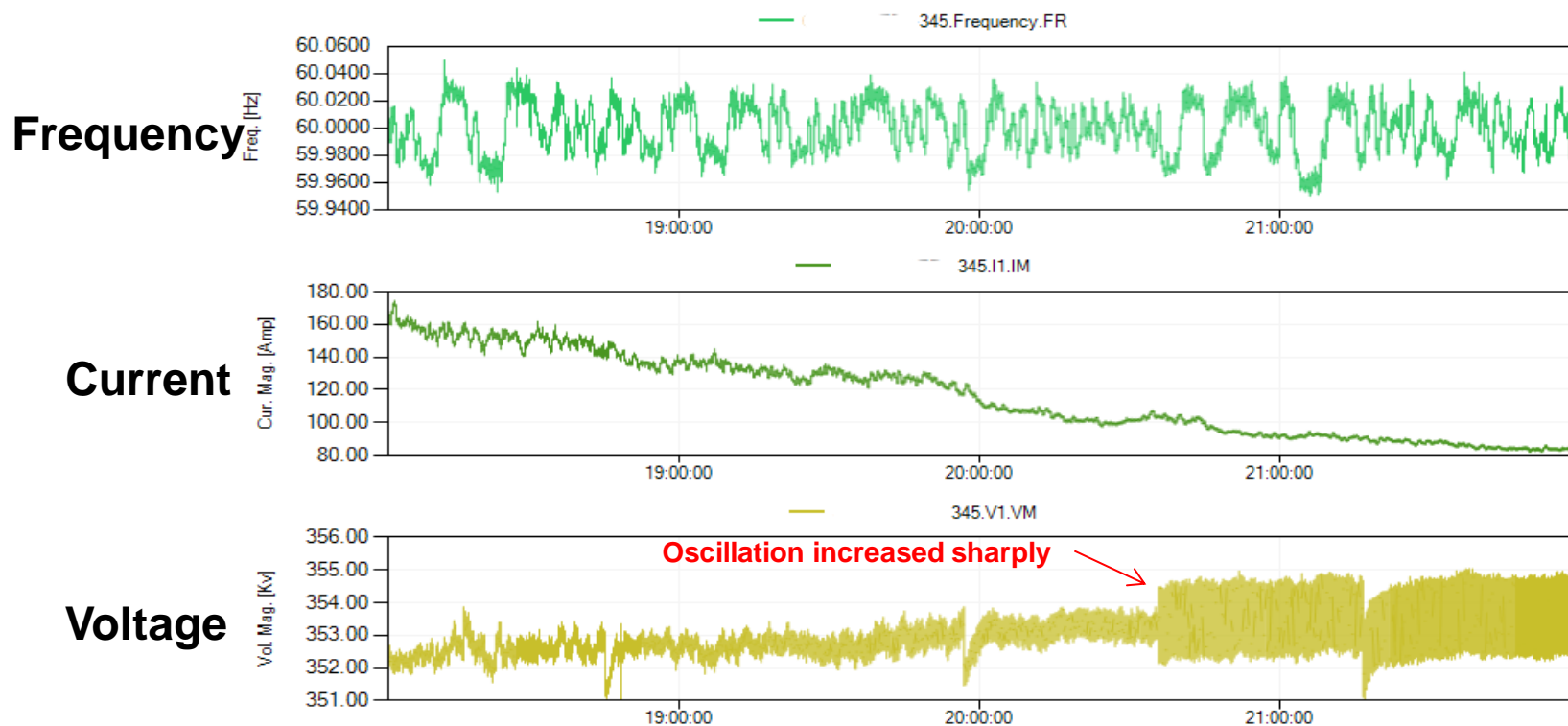


Use Case - Voltage Oscillation Observed

- **Need:** PMU Voltage Phasor can advise the Shift Engineer about the voltage oscillations at location/s due to fast voltage controllers at wind generators and other control devices in the grid
- **EXAMPLE: VOLTAGE CONTROL OSCILLATIONS FROM NEARBY WIND PLANT – APRIL 12-13, 2013**
- **Possible Action:**
 - Shift engineer should review location for possible causes
 - Low strength area (weak grid or low circuit ratio)
 - Incorrect settings on voltage controllers/voltage regulators
 - Shift Engineer may recommend action to shift supervisor
 - Reduce Transfer out of area
 - Reduce generation output
 - Restore outages

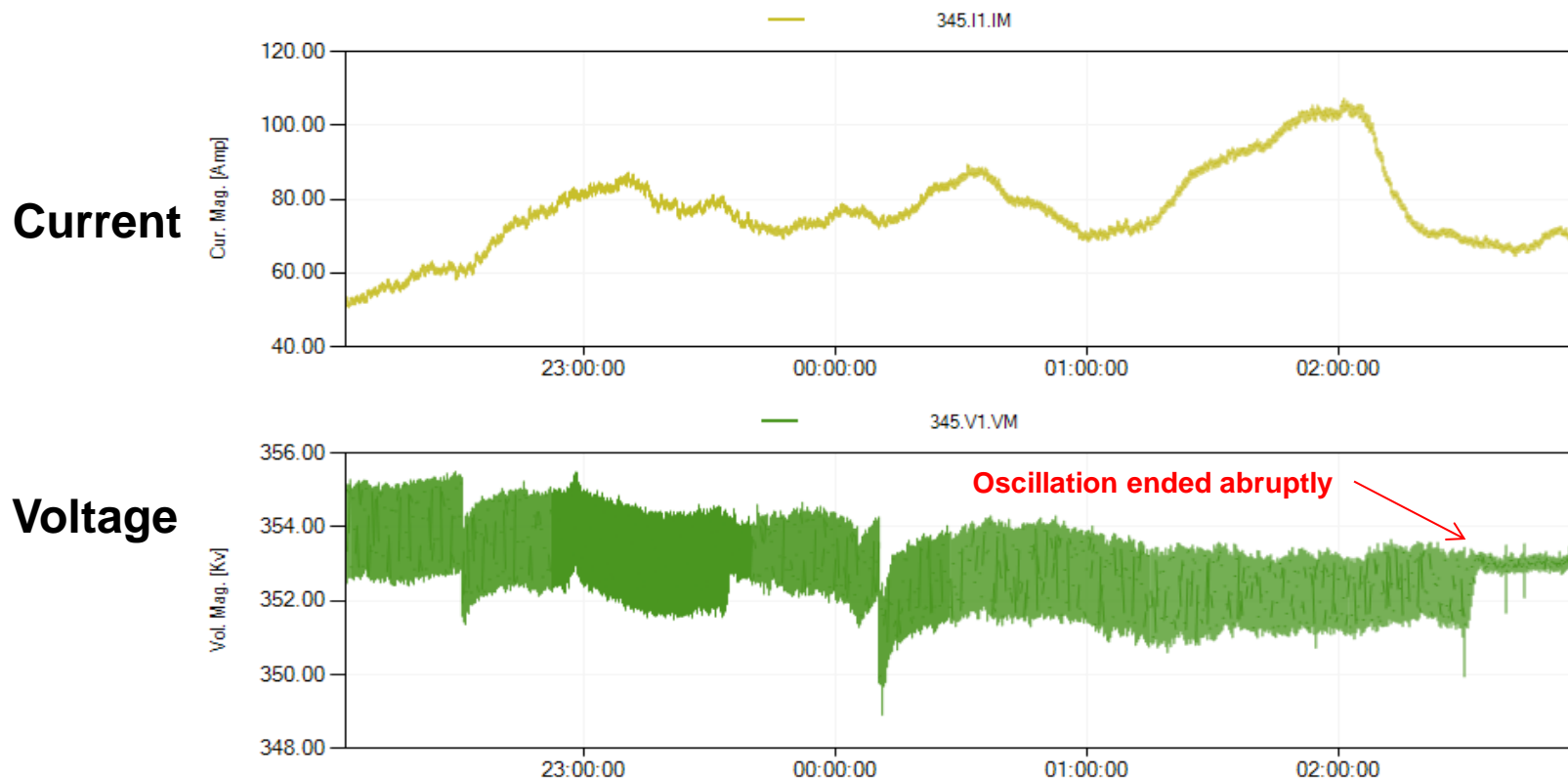


Nearby PMU Detects Voltage Oscillation



Screenshot of PGDA (Phasor Grid Dynamics Analyzer)

Nearby PMU Detects Voltage Oscillation



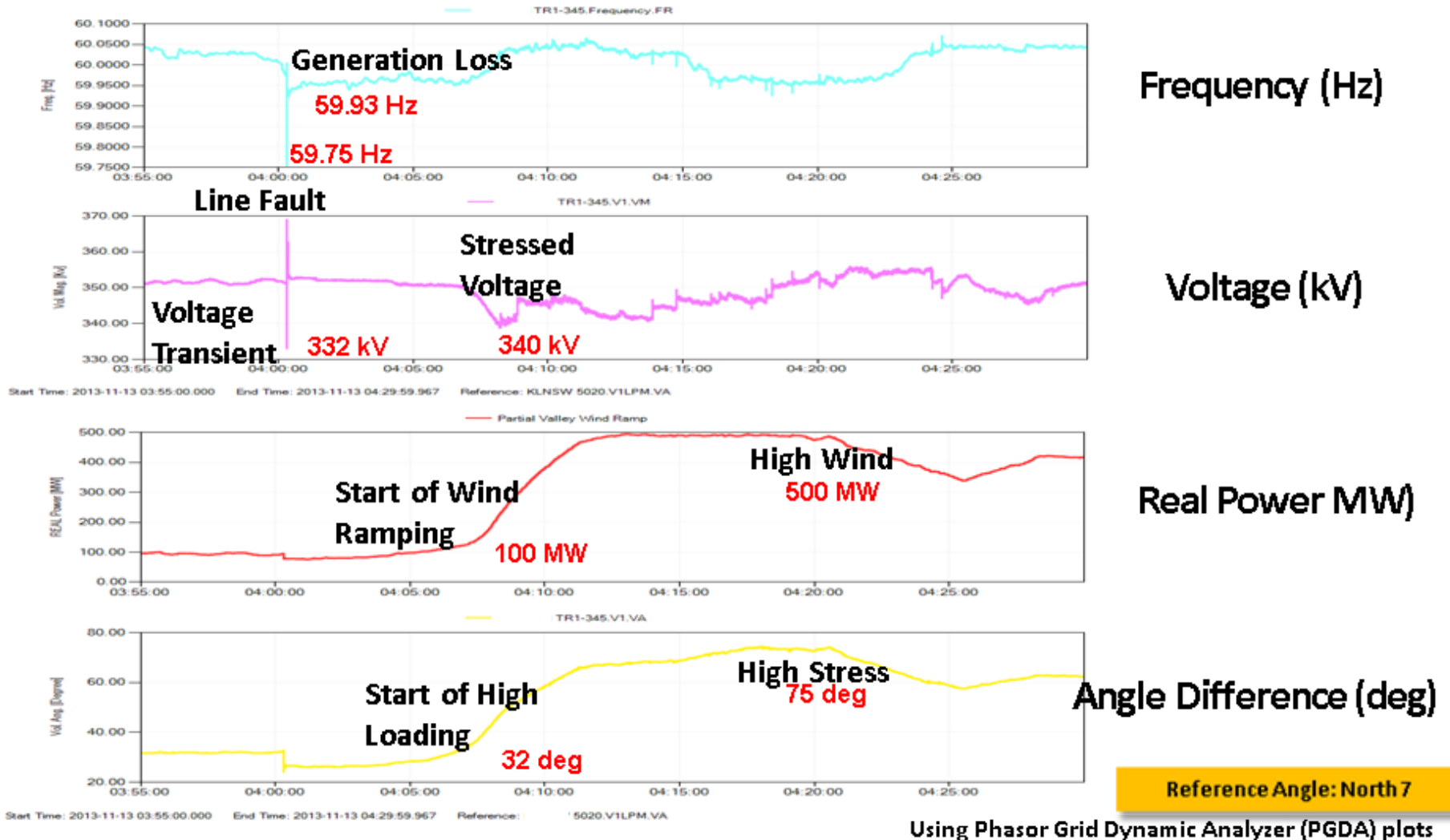
Screenshot of PGDA (Phasor Grid Dynamics Analyzer)

Use Case - Voltage Instability Monitoring (P-V, Q-V)

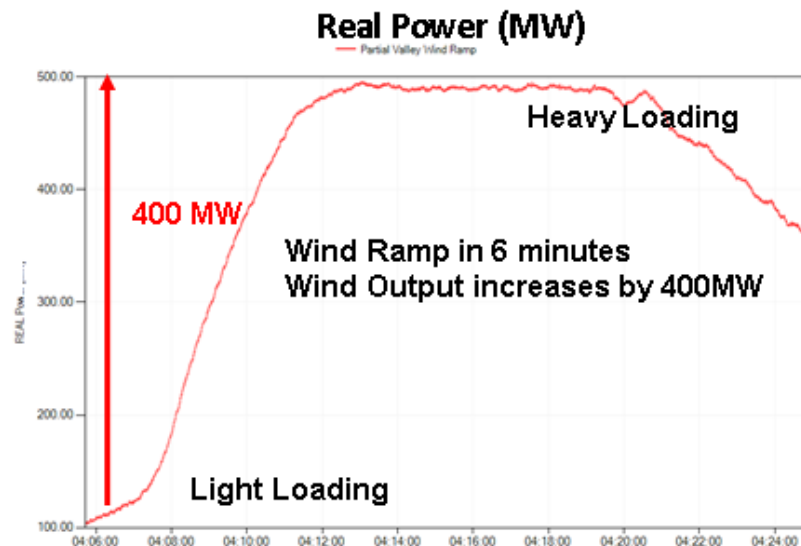
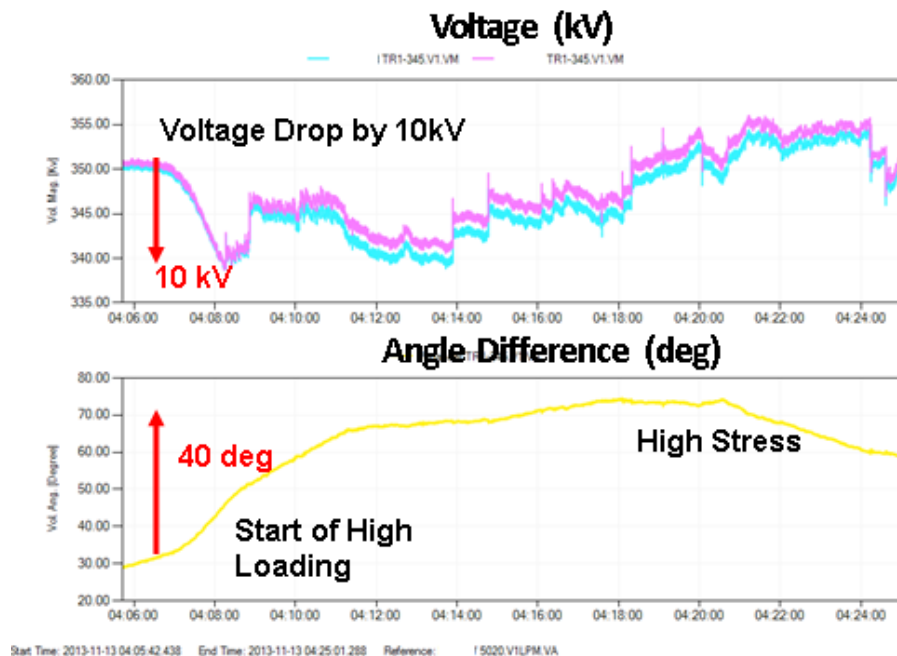
- **Need:** PMU data (Real, Reactive Power & Voltage) can advise the Shift Engineer indirectly on high grid stress under low voltage deteriorating conditions
- **EXAMPLE: HIGH PHASE ANGLE AT COAST 3 (VALLEY) – NOV 13, 2013**
- **Possible Action:**
 - Shift Engineer reviews P-V performance, compares to online VSAT study
 - Shift Engineer may recommend action to shift supervisor
 - Impose Transfer limit
 - Adjust generation pattern
- Operations planning studies and benchmarking will be required to identify critical substations for voltage instability monitoring



PMU Data Illustrates Voltage Stress During Power Ramp



PMU Data Illustrates Voltage Stress During Power Ramp



Reference Angle: North 7

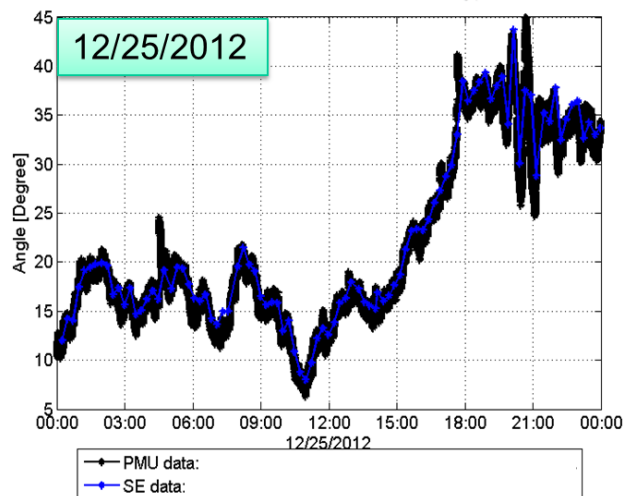
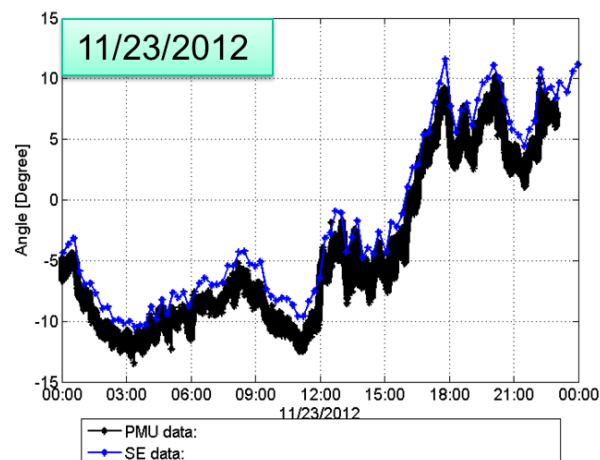
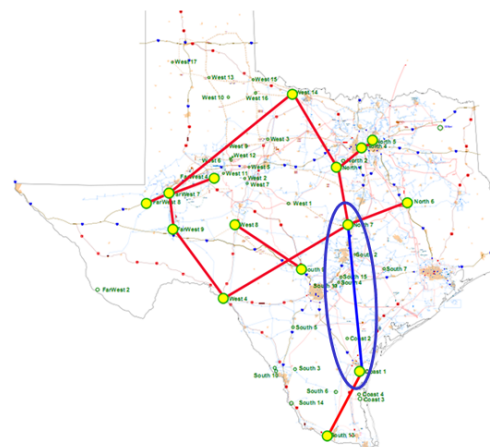
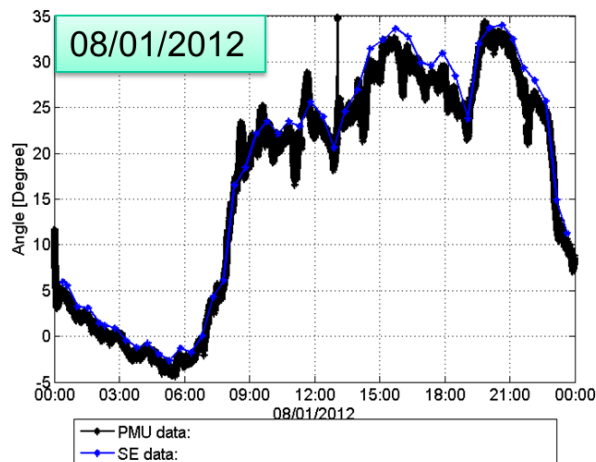
Use Case - Validate State Estimator Results Used in Control Rooms

- **Need:** PMU Phase Angles can be used to validate the state estimator results used in control rooms (locates differences which reflect anomalies in models used for state estimation)
- **EXAMPLE: BASELINING STUDIES**
- Possible Action:
 - Identify the root cause for the mismatch and update models



PMU Data vs SE Data Comparison

Coast 1-North 7



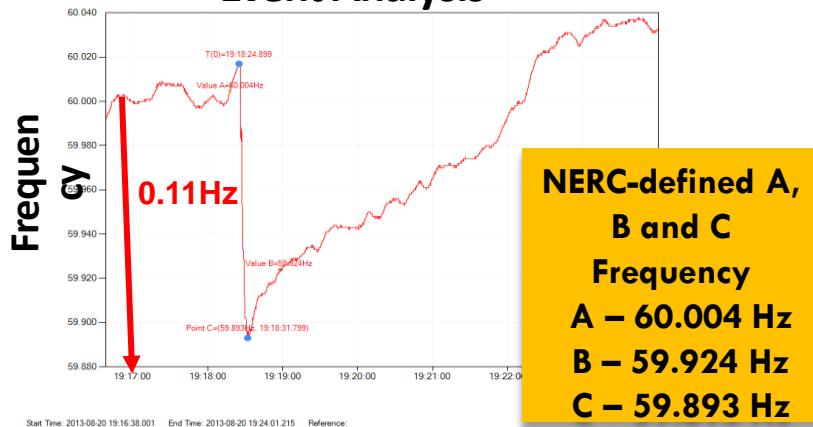
Use Case - System Disturbance – Cause & Interpretation

- **Need:** PMU data is useful for event analysis and determine root cause of the event and its location.
- **EXAMPLE: EVENT SIGNATURES OF GENERATION TRIP, LINE TRIP & OSCILLATIONS**
- **Possible Action:**
 - Shift Engineer reviews network performance, including frequency dip and recovery, voltage dip and recovery, power dip (and phase angle) and recovery, and any transient oscillations and the associated ring-down characteristics
 - If recovery looks slow, refers to Advanced Network Applications expert or System Planning dynamics expert to determine if some action is recommended or for further review
 - If frequency, voltage, or power (and phase angle) dip looks too large or too small, or does not return to expected levels, refer to Advanced Network Applications expert or System Planning dynamics expert to investigate the reasons for abnormal grid responsiveness
 - Frequency response and/or transient voltage response of generation (including wind, solar, and conventional generation) should be monitored for compliance with standards
 - Should include an automatic reporting capability, providing a high-level review of the network performance

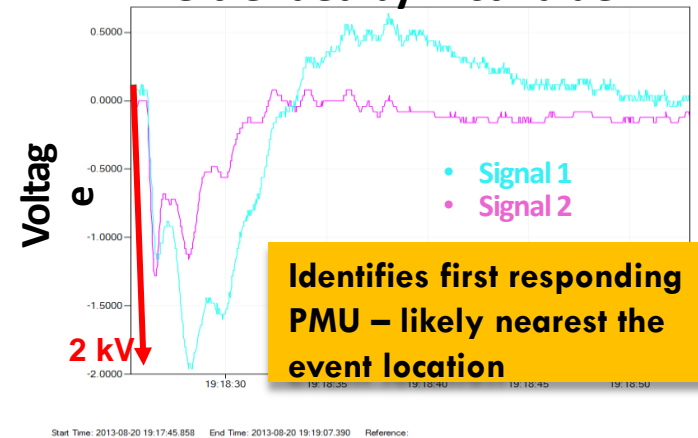


PMU Data Enables Effective Post-Event Analysis

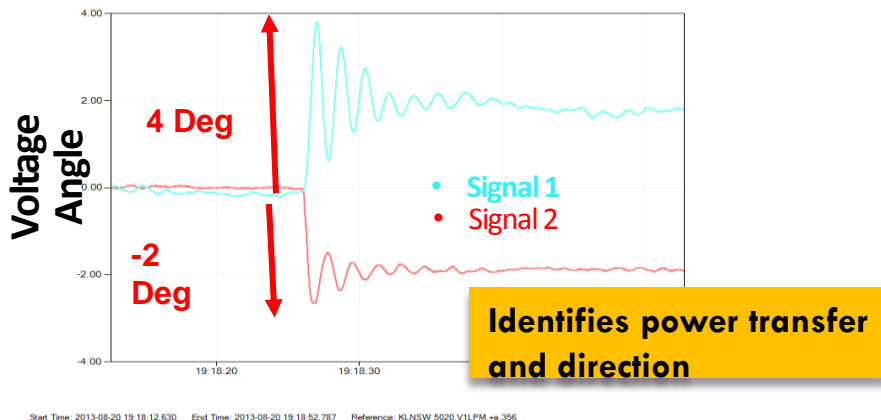
Event Analysis



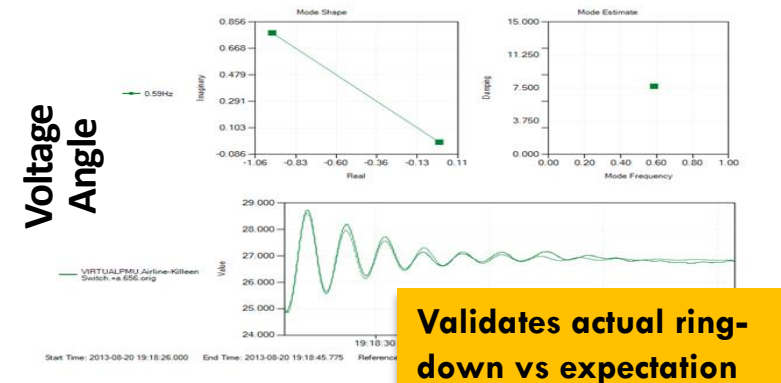
De-trended by First Value



De-trended by First Value



Ringdown Analysis



PGDA used for analysis

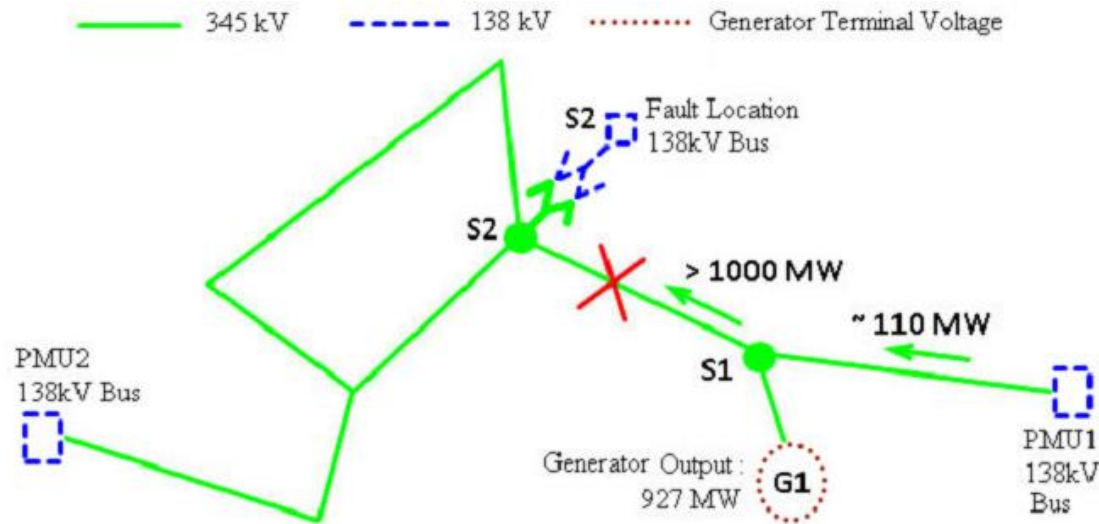


PMU Data Enables Effective Post-Event Analysis – Power Load Unbalance Circuit Example

- **Predictive relaying**
 - Protection against possible over-speed of generator/turbine
- **Designed to rapidly close control/intercept valves under load imbalance conditions**
- **Relay checks for two conditions –**
 - Difference in mechanical and electrical loading
 - operates if the difference is greater than 40% (typically)
 - Rate of decrease of electrical load
- **After clearing of unbalanced condition –**
 - Wait for pre-set time delay
 - Reset PLU relay
 - Allow intercept valves to open again



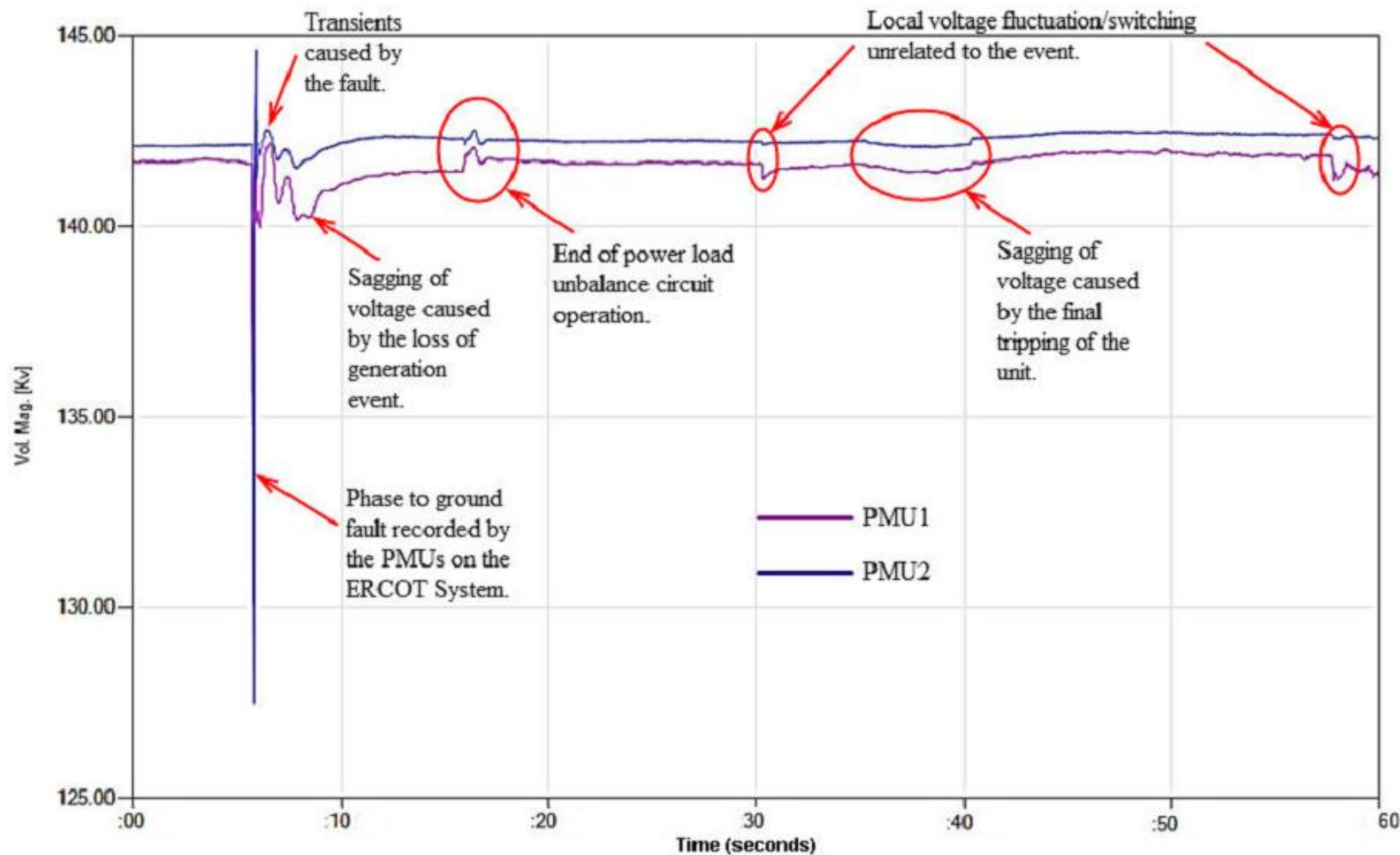
Event Analysis - System Condition



- **Generator 'G1' close to full output.**
- **Fault on 138kV bus section at sub-station 'S2'**
 - Fault cleared in ~5 cycles
 - Three 138kV circuits tripped as part of the fault clearing.
- **Fault detection and mis-operation of relay at substation 'S1'**
 - Line from 'S1' to 'S2' tripped due to mis-operation

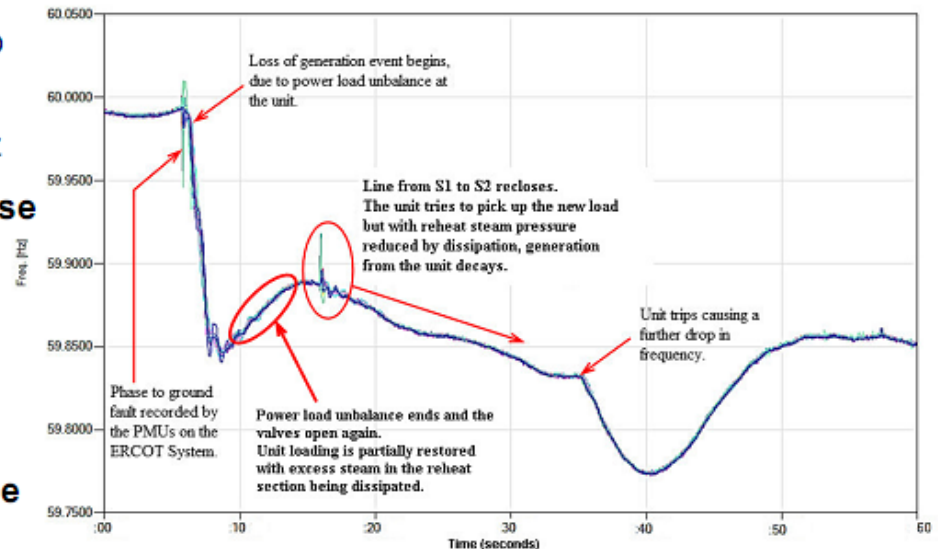


Event Analysis - Fault



Event Analysis - Description

- **Following the fault and clearing –**
 - Due to loss of the 'S1' – 'S2' circuit, PLU initiated at unit 'G1'
 - Closing of control/intercept valves leading to ~575 MW loss
 - Frequency drop from 59.99 Hz to 59.846 Hz
- **Frequency decline arrested by inertial response**
 - PLU condition cleared
 - Intercept valves allowed to open again
 - Loading restored partially to ~500 MW
 - Excess steam in reheat dissipated
- **'S1' – 'S2' circuit reclosed 10 seconds after the fault**
 - Unit 'G1' loading increased after reclosing
 - Lack of sufficient pressure in reheat to sustain increased load
 - Generation decay – run back
- **Trip of Unit 'G1'**



Event Analysis - Lessons Learned

- **New use-case for synchrophasor technology from ISO viewpoint**
 - Correction of incorrect design/operation of protection systems
- **Sequence of Events established by collaboration with Transmission Owner and Plant Operator**
 - Mis-operation of transmission relay leading to line trip
 - No mis-operation in PLU circuit, relay operated as designed
- **Unit tripping not the objective of PLU circuit**
- **Plant Operator in discussion with vendor to determine –**
 - whether unit trip was necessary
 - whether PLU circuit parameters need to be changed
- **Accurate representation of PLU relaying effects in modeling of contingencies in planning studies**
 - Investigate the possibility of other generators on the system having similar characteristics
 - Possible detailed dynamic studies to investigate improved modeling of this type of event.
 - Consider when these type studies would be appropriate.
 - Possibly as part of interconnection process.

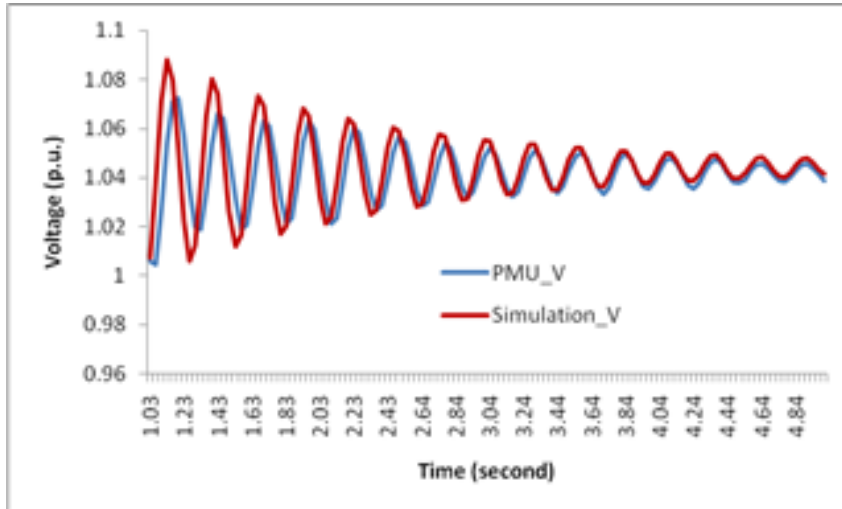


Use Case - Generator Parameter Determination

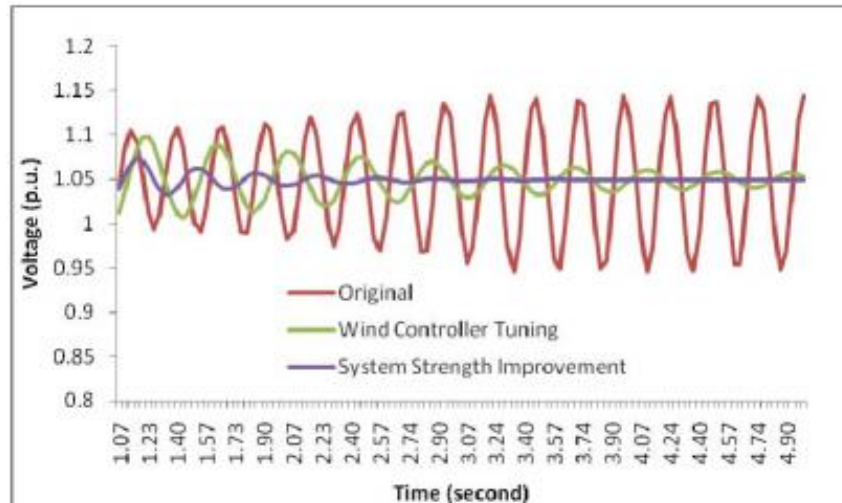
- **Need:** PMU data (Voltage Phasor, P & Q) can advise generator dynamic response following a nearby transient, compares results to simulated response (based on system planning models), and alerts if differences are significant (meaning that the generator response to the transient event was different from what was expected)
- **EXAMPLE: PMU DATA USED TO VALIDATE AND CALIBRATE GENERATOR MODELS**
- **Possible Action:**
 - Advance Network Applications expert or System Planning dynamics expert reviews the event and the generator response differences, and if necessary, triggers the capture of the current grid state for further study
 - System Planning dynamics expert coordinates with generator owner to investigate the reasons for unexpected generator response
 - System Planning – Dynamics Working Group utilizes the apparent unit parameters and system response data to tune/benchmark the dynamic model associated with the unit in the ERCOT DWG dynamic dataset



Generator Parameter Validation



Recorded vs Simulated Voltage Response at Wind Power Plant – Low power output



Recorded vs Simulated Voltage Response at Wind Power Plant – High power output – Improved performance after tuning wind controller settings

Source: Jian Chen, Prakash Shrestha, Shun-Hsien Huang, N.D.R. Sarma, John Adams, Diran Obadina, John Balance, "Use of Synchronized Phasor Measurements for Dynamic Stability Monitoring and Model Validation in ERCOT", Proceedings of the 2012 IEEE PES General Meeting, San Diego, July 2012.

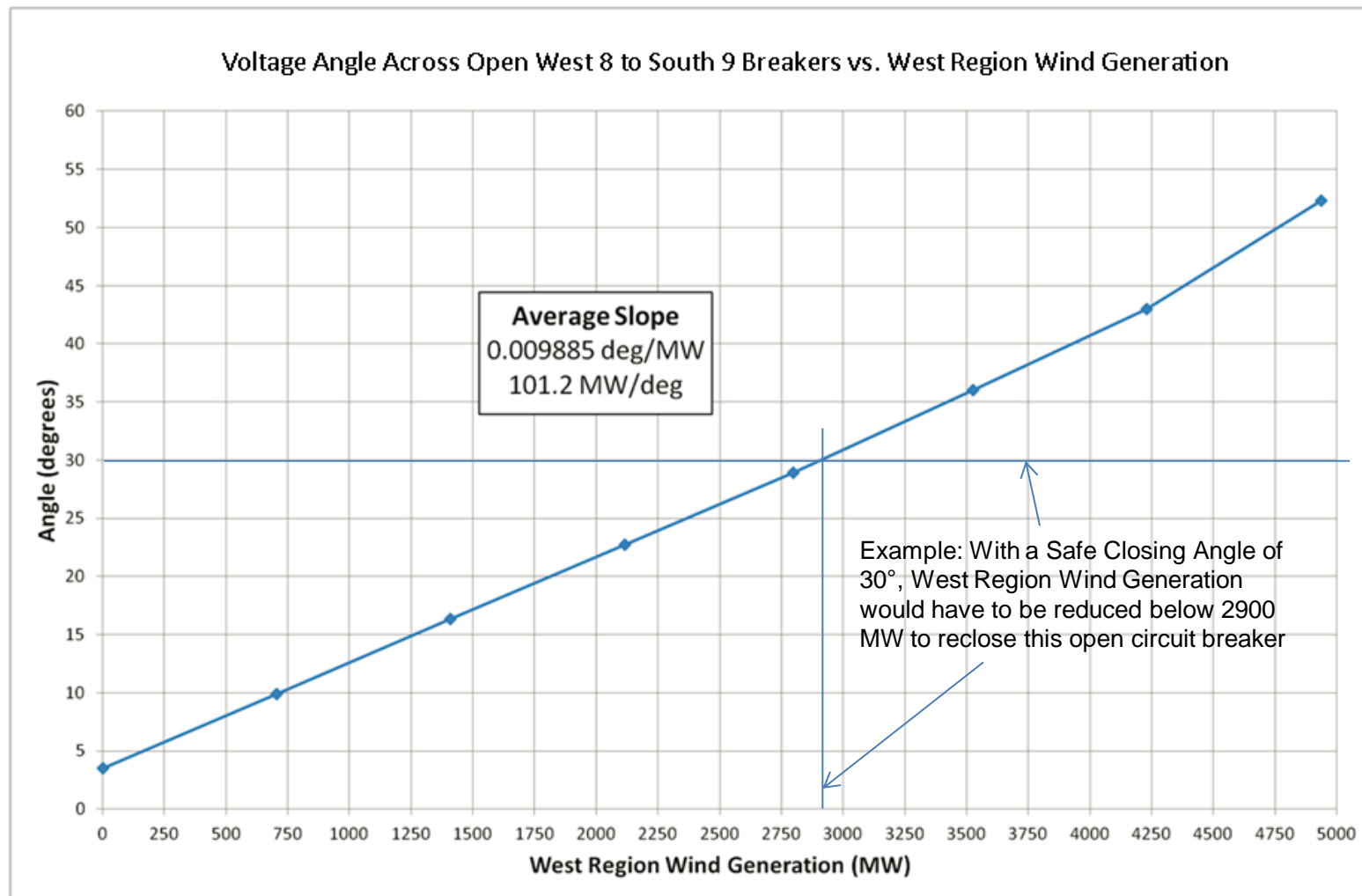


Use Case - Phase Angle Across Breaker for Reclosing Action

- **Need:** PMU data is useful during an event to identify stress across system, and validate safe restoration actions
- **EXAMPLE: HIGH PHASE ANGLE ACROSS BREAKER**
- **Possible Action:**
 - Shift Engineer reviews PMU voltage phase angle differences between substations (with breaker open between them)
 - If voltage phase angle difference is within safe breaker reclosing limits, proceed with planned restoration of lines
 - If voltage phase angle difference looks too large, refer to Advanced Network Applications expert or System Planning dynamics expert to identify mitigation actions needed to reduce phase angle to within limits for restoration



Phase Angle Across Open Breaker - Example



Thank You.

Any questions ?

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Attachment 15. TTU Network Forensics Report

Texas Tech University Network Forensics Report

Security Connected for Critical Infrastructure (SC4CI)

Demonstration for Cyber Security Protection of Synchrophasor Network

Executive Overview

A cooperative effort between the Center for Commercialization of Energy Technologies (CCET), Electric Power Group (EPG), and Intel Corp. (including Intel subsidiaries McAfee and Wind River) has resulted in the demonstration installation of a set of security controls for the Synchrophasor *enhanced* Phasor Data Concentrator ePDC devices deployed in the Texas Tech University (TTU) campus Electric Smart Grid and Real Time Dynamics Monitoring Platform (RTDMS) for analytics and visualization. The Intel solution, known as Security Connected for Critical Infrastructure (SC4CI), is comprised of an embedded security system that provides network and endpoint hardening technologies for each EPG synchrophasor application/device – ePDC, RTDMS, and RTDMS Client. In addition, the solution includes Security Management and Monitoring capabilities to understand and react to the threats and security status of the devices in the environment.

Upon installing the SC4CI devices on the TTU network in December, 2013, significant traffic originating from China and Eastern Europe was identified as attempting to access the resources of the SC4CI protected devices. The nature of this traffic was mainly relegated to attempts to access the exposed SSH port (Secure Shell port 22) on the Management Instance protecting the EPG applications on the device. Additional controls are being put into place to increase the sensitivity of the security awareness to provide new data points to help understand the quantity, quality, and nature of the threats.

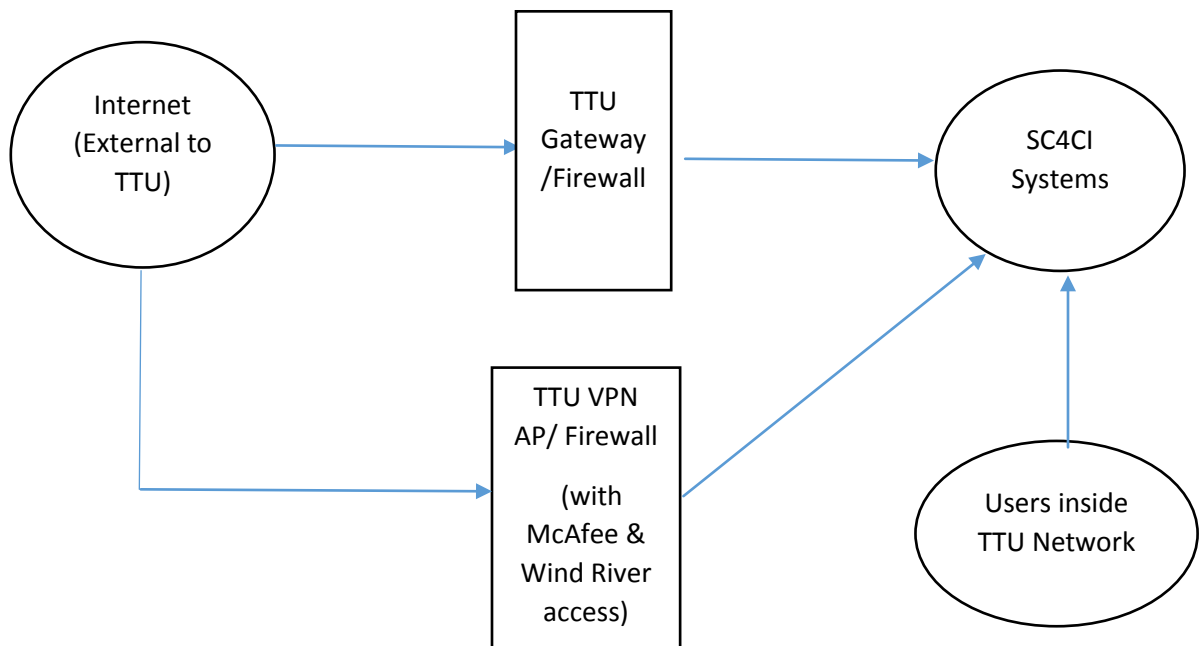
This forensics report describes the analysis of unauthorized attempts to access the SC4CI devices installed at TTU during the time period December 2013 through February 2014. The variety of intrusion attempts demonstrates the need to provide active protection and monitoring of critical infrastructure computer systems. It is expected that additional forensics analyses will be performed over the next several months of this demonstration, to document the performance of the SC4CI systems.

Conclusions

Almost immediately upon connecting the SC4SI systems to the TTU network in December, 2013, significant traffic originating from China and Eastern Europe was identified as attempting to access the resources of the SC4CI protected devices. In general, the attacks observed consisted of generic SSH Brute Force exploit attempts. These are common on the Internet and are generally automated. Sifting through the logs indicated that all the brute force attempts failed to authenticate and only whitelist IP addresses have been successful thus far in accessing the systems. There has been evidence in the logs that something is trying to access one of the protected services, but again, the systems have been successful (so far) in rejecting those attempts. Continued monitoring and analysis of intrusion attempts will be needed to validate the security performance of the systems.

Technical Background

The setup at TTU is deployed roughly as shown in the network topology diagram below,



The above network connectivity layout represents the network environment at the TTU campus within which the devices protected by the SC4CI have been deployed. The majority of the other network topology details are not specified as they are out of scope for this document. The above representation depicts three network connection sources found to be accessing the SC4CI systems and are explained in more detail below.

It is important to note that there exists an SSH listener on the SC4CI device(s) that accepts network connections from any network source with correct credentials, and is a potential vulnerability to the system. This SSH listener service is a desirable feature in order to allow ease of management when unexpected modifications are required to the system from support personnel accessing the device from arbitrary network source locations (within the TTU network, over the VPN, etc.). The SSH listener is not expected to be a feature available in future versions of the platform, but it is being leveraged as a good proof point for the security capabilities of the platform to demonstrate the security response capabilities when new vulnerabilities are discovered. At the conclusion of this investigation on the malicious traffic coming from China and Eastern Europe, passive countermeasures shall be implemented, using the tools provided by the SC4CI platform, to mitigate the threat to the SSH listener. The countermeasure will leverage the SC4CI Console to remotely configure the embedded firewall to block all traffic originating outside of the TTU network from reaching the SSH listener service. This creates Tailored Trustworthy Space within the TTU network consisting of a select set of nodes, both endpoint device and security server, that comprise the SC4CI protection platform.

Internet Connection Source

Connections from the open Internet, external to the TTU network, apparently have network connectivity to the SC4CI systems directly. Currently the firewall rules on the perimeter TTU Gateway do not appear to restrict, or at least not to successfully prevent, this traffic. There is presently no influence to be exerted over the TTU Gateway from the members of this project, so the network connectivity issue must be dealt with using the SC4CI controls we have at our disposal. Again, these connections will be blocked in the future to prevent access to the system by non-legitimate sources of network traffic.

TTU Connection Sources

Connections originating from the internal TTU network address space also have the ability to access the SC4CI device(s). It is not desirable to block these connections as they include the support and operations personnel that leverage the EPG applications, and therefore are assumed to be legitimate sources of traffic. However, there is concern related to the threat from insider attacks as well as compromised devices within the TTU perimeter, so additional controls may need to be put into place to restrict access down to a known set of hosts within the network.

The connections traversing the TTU VPN network address space have the ability to access the SC4CI device(s). It is not desirable to block these connections as they have been authenticated and authorized by the TTU VPN, and therefore are assumed to be legitimate sources of traffic. However, there is concern related to the threat from insider attacks as well as from compromised devices within the TTU perimeter, so additional controls may need to be put into place to restrict access down to a known set of hosts within the network.

There is currently no known differentiation scheme to segregate the TTU VPN traffic originating from outside of the TTU network from the TTU internal (local) TTU network traffic.

Threat Observations

Assumptions

- There is no management control over the TTU Gateway or VPN access point by project personnel.
- There are no allowable changes to firewall rules for any of the TTU Gateways and Firewalls.

The appropriate process to manage the access to the SC4CI devices is by implementing the embedded security controls on each of them. This is managed from the SC4CI console, the McAfee ePO product (ePolicy Orchestrator), by modifying the embedded Firewall policy configuration and the Secure Tunnel VPN policy definitions for the endpoint Nodes protecting the EPG software. There are additional policies that define the monitoring of log files on the endpoint Nodes to collect data points to be evaluated on the McAfee ePolicy Orchestrator (ePO) product, as well as the McAfee Enterprise Security Manager (ESM) product.

Any violations of the policies triggers an alarm to be generated and an update to the security visualization dashboards within the ePO product. The ePO product defines the policies and automates the provisioning of the policies to the endpoint Nodes. The ESM product doesn't exert operational

control on these systems but is merely an observer. The ESP performs security audit operations such as data aggregation, data correlation, analysis (risk algorithm for each node and the network communication between the nodes), and generates alarms in response to rule violations, which are forwarded to the ePO system for automated response (for example, notifying appropriate response personnel, or updating policy on devices which are under attack).

Since all data points pass through the ESM analytics, it is the logical point to perform both audit operations and any needed forensics duties. Therefore, the ESM product is the best source of evidence relating to the security posture of the endpoint node devices. The security metrics presented in this document are derived from the raw data collected by the ESM.

Within the ESM, we are expecting to see two categories of network addresses,

- External connection sources attempting to directly access the SSH listener on the SC4CI system via the port 22. These users must have proper credentials to gain access.
- Connection sources with TTU internal network address space attempting to access the SSH listener on the SC4CI system via the port 22. These sources could be either from users that have authenticated to the TTU VPN or users already authenticated on one of the systems within TTU network. At present, these two classifications of users and network locations cannot be differentiated within the ESM.

Network Forensics

The network forensics process model followed in this document has a phased approach wherein each stage feeds data to the following. The phases are described below in detail.

Detection

All events from all devices are logged remotely in the ESM. The ESM leverages the consolidated view of the logs collected to uncover behavioral anomalies. The logs currently available in the ESM date back to the time when the platform went live in mid-December, 2013.

Forensics performed using the ESM data illustrates that unwanted network traffic has been occurring since the SC4CI devices have been connected to the TTU network. Examples of this activity are listed below.

Direct Internet Connections to SSH Listener Trace Data

```
12/13/2013 02:26:06, ,Local ESM
(144115188075855872),Informational,Authentication,User Device Failed
Login. Dec 13 08:26:05 McAfee sshd[4422]: input_userauth_request:
invalid user app [preauth]
```

```
12/13/2013 02:26:06, ,Local ESM
(144115188075855872),Informational,Authentication,User Device Failed
Login. Dec 13 08:26:06 McAfee sshd[4422]: Failed password for invalid
user app from 112.91.240.230 port 33701 ssh2
```

```
12/13/2013 02:26:06, ,Local ESM
(144115188075855872),Informational,Authentication,User Device Logout.
```

Dec 13 08:26:06 McAfee sshd[4422]: Received disconnect from
112.91.240.230: 11: Bye Bye [preauth]

12/13/2013 02:26:08, ,Local ESM
(144115188075855872),Informational,Authentication,User Device Failed
Login. Dec 13 08:26:08 McAfee sshd[4458]: input_userauth_request:
invalid user bin [preauth]

12/13/2013 02:26:08, ,Local ESM
(144115188075855872),Informational,Authentication,User Device Failed
Login. Dec 13 08:26:08 McAfee sshd[4458]: Failed password for invalid
user bin from 112.91.240.230 port 35242 ssh2

12/13/2013 02:27:40, ,Local ESM
(144115188075855872),Informational,Authentication,User Device Logout.
Dec 13 08:27:40 McAfee sshd[5063]: Received disconnect from
112.91.240.230: 11: Bye Bye [preauth]

...<snip>..... The brute force search for username continues until the attacker finds "root"<snip>...

12/13/2013 02:27:42, ,Local ESM
(144115188075855872),Informational,Authentication,User Device Failed
Login. Dec 13 08:27:42 McAfee sshd[5077]: Failed password for root
from 112.91.240.230 port 60346 ssh2

12/13/2013 02:27:43, ,Local ESM
(144115188075855872),Informational,Authentication,User Device Logout.
Dec 13 08:27:43 McAfee sshd[5077]: Received disconnect from
112.91.240.230: 11: Bye Bye [preauth]

Internal Connections to SSH Listener Trace Data

12/02/2013 17:11:14, ,Local ESM
(144115188075855872),Informational,Authentication,User Device Failed
Login. Dec 2 23:11:14 McAfee sshd[6997]: Failed password for root
from 129.118.26.37 port 62563 ssh2

12/02/2013 17:11:23, ,Local ESM
(144115188075855872),Informational,Authentication,User Device Login.
Dec 2 23:11:23 McAfee sshd[6997]: Accepted password for root from
129.118.26.37 port 62563 ssh2

Examination

A methodical search has been performed on the collected logs to identify data sets which contain least information and highest possible evidence. Python scripts matched the attack patterns (data sets) seen in the logs to malicious activities. After running the python scripts on the copy of logs, it segregates the below data sets into separate text files.

Data Sets:

Example of Failed Login Attempts:

```
12/02/2013 17:11:14, ,Local ESM  
(144115188075855872),Informational,Authentication,User Device Failed  
Login. Dec 2 23:11:14 McAfee sshd[6997]: Failed password for root  
from 129.118.26.37 port 62563 ssh2
```

Example of Accepted Password Messages:

```
12/02/2013 17:11:23, ,Local ESM  
(144115188075855872),Informational,Authentication,User Device Login.  
Dec 2 23:11:23 McAfee sshd[6997]: Accepted password for root from  
129.118.26.37 port 62563 ssh2
```

Example of Username Brute Force

```
12/13/2013 02:26:08, ,Local ESM  
(144115188075855872),Informational,Authentication,User Device Failed  
Login. Dec 13 08:26:08 McAfee sshd[4458]: input_userauth_request:  
invalid user bin [preauth]
```

```
12/13/2013 02:26:08, ,Local ESM  
(144115188075855872),Informational,Authentication,User Device Failed  
Login. Dec 13 08:26:08 McAfee sshd[4458]: Failed password for invalid  
user bin from 112.91.240.230 port 35242 ssh2
```

Other Example Traces

```
12/15/2013 05:13:51, ,Local ESM (144115188075855872),,,yqj6j9gjlyo_8v  
log-in failed - incorrect username or password
```

```
12/15/2013 05:13:52, ,Local ESM (144115188075855872),,,v13oi8o3zyi  
log-in failed - incorrect username or password
```

Analysis

The attacks are replayed in a controlled Lab environment to understand the nature of the attacks, to ensure that the logs in the replay generate identical output, and also to validate the methodology of the attacker.

Failed Login Attempt Logs

In general, the attacks observed consisted of generic SSH Brute Force exploit attempts. These are common on the Internet and are generally automated such that they are set to run on a regular basis looking for new target systems with open SSH port (22). The brute force attack initially attempts to determine a legitimate username and once that has been accomplished, a brute force attack on the password is attempted. This type of automated attack is designed to identify systems on the network that have either default passwords, or weak passwords, and if any are found, to notify the Threat Source of the compromise and the availability of a new beachhead device on that particular network.

All evidence indicates that these Internet crawlers repeatedly tried brute force tactics to guess the username even though they had already found a username in the past. Therefore, it is reasonable to assume that the level of sophistication of the attacker is not high.

Sifting through the names list used for brute forcing the usernames indicates that they were commonly used usernames on the Internet. It appears that the password guessing was random in nature. It is interesting to observe that the automated attacks perform a limited number of brute force attempts at any one time in order to avoid detection and limit the amount of evidence in the local logs. But every set of attempts being made definitely tried a different set of passwords. A medium to strong password would require an average of millions of years to compromise with a daily attack schedule such as is being observed in this situation. However, with billions of devices on the Internet, these attacks are likely to be both statistically successful, and also potentially lucrative as a foundation for generating more automated attacks, thereby increasing the odds of finding more victims to exploit.

Accepted Logins

One objective of the forensics work is to ensure that none of the malicious connections were able to successfully authenticate to the SSH listener. An implicit whitelist of acceptable, and therefore currently not considered hostile, network addresses has been compiled, consisting of the internal and VPN TTU network address space. Sifting through these logs indicated that all the brute force attempts failed to authenticate and only whitelist IP addresses have been successful thus far. Therefore, it can be assumed that the automated threats have not yet compromised any of the SC4CI devices.

Other Login Attempts

It should be noted that there have been evidence in the logs of other activity that appears suspicious, for example:

```
12/15/2013 05:13:51, ,Local ESM (144115188075855872),,,yqj6j9gjlyo_8v  
log-in failed - incorrect username or password
```

```
12/15/2013 05:13:52, ,Local ESM (144115188075855872),,,v13oi8o3zyi  
log-in failed - incorrect username or password
```

These two traces indicate that something is trying to access one of the protected services. The two logs appear to show random passwords used in brute forcing the credentials. Following good secure programming techniques, the generic web service error message consisting of “incorrect username and password” message makes it difficult for the attackers to guess the credentials because it is not clear whether it is the password or the username that is incorrect.

NOTE: upon discovery of potentially nefarious network activity, all passwords in all systems are reviewed for their strength, and where necessary, the password strength is increased. Also, a password rotation policy has been put into place to regularly change the passwords.

Investigation

In general, the Investigation phase of forensics involves tracing the attackers back to their source. The data for this phase is iterative provided by the analysis and examination phases. In this report, we do not try to trace back to the attacker for prosecution and hence this phase is limited to identifying either the source country or that the source was within the TTU environment or on the TTU VPN.

Reporting

In order to understand the nature of the attacks and to match the log entries with the actual attack operations, one must replay the attack and confirm that the forensics match what was seen during the actual attack. This is an iterative process. Once the attacks have been replayed and the log patterns have been reverse engineered, the patterns are correlated in the database and the attacks can be quickly identified and collated. Below are the initial attacks that were found soon after installation of the secured platform.

Please note that the data points are correlated based on information from the network packets themselves. Therefore, the data could be “spoofed” or “faked”. In addition, the simplistic nature of the attack and the fact that there seemed to be little variability between the attacks from day to day indicates that the attacks are automated, therefore, it is entirely possible that the source of the attacks has no knowledge of the activity, and therefore is not itself the active threat actor.

| IP Address | Type of Network | Failure Attempts | Successful Attempts | Number of Attempts | Region | Type of Attempt |
|-----------------|-----------------|------------------|---------------------|--------------------|--------------------------------|-----------------|
| 113.240.248.18 | External | 7824 | 0 | 7824 | China Telecom | Brute Force |
| 121.96.56.11 | External | 1425 | 0 | 1425 | Bayan Telecommunications, Inc. | Brute Force |
| 222.186.15.153 | External | 1825 | 0 | 1825 | China Telecom | Brute Force |
| 222.211.85.150 | External | 436 | 0 | 436 | China Telecom | Brute Force |
| 58.215.173.114 | External | 410 | 0 | 410 | China Telecom | Brute Force |
| 61.147.113.93 | External | 768 | 0 | 768 | China Telecom | Brute Force |
| 114.80.202.30 | External | 275 | 0 | 275 | China Telecom | Brute Force |
| 114.80.226.94 | External | 408 | 0 | 408 | China Telecom | Brute Force |
| 61.147.116.20 | External | 400 | 0 | 400 | China Telecom | Brute Force |
| 61.147.116.24 | External | 276 | 0 | 276 | China Telecom | Brute Force |
| 61.147.119.106 | External | 264 | 0 | 264 | China Telecom | Brute Force |
| 60.191.45.248 | External | 228 | 0 | 228 | China | Brute Force |
| 112.91.240.230 | External | 109 | 0 | 109 | China Unicom Jieyang Branch | Brute Force |
| 195.93.180.125 | External | 105 | 0 | 105 | Russia | Brute Force |
| 112.216.82.130 | External | 99 | 0 | 99 | Korea | Brute Force |
| 222.88.154.79 | External | 87 | 0 | 87 | Russia | Brute Force |
| 92.63.96.106 | External | 86 | 0 | 86 | Russia | Brute Force |
| 85.232.244.50 | External | 84 | 0 | 84 | Poland | Brute Force |
| 61.235.70.231 | External | 68 | 0 | 68 | China | Brute Force |
| 222.186.59.42 | External | 95 | 0 | 95 | China | Brute Force |
| 222.189.239.10 | External | 126 | 0 | 126 | China | Brute Force |
| 208.115.201.251 | External | 61 | 0 | 61 | Limestone Networks, Brazil | Brute Force |
| 103.23.244.22 | External | 48 | 0 | 48 | Indonesia | Brute Force |
| 106.186.116.117 | External | 45 | 0 | 45 | Tokyo | Brute Force |
| 221.234.231.190 | External | 37 | 0 | 37 | China | Brute Force |
| 198.172.23.11 | External | 36 | 0 | 36 | Orem, Utah, US | Brute Force |
| 116.213.79.220 | External | 35 | 0 | 35 | China | Brute Force |
| 212.116.159.146 | External | 34 | 0 | 34 | Bulgaria | Brute Force |
| 61.160.251.141 | External | 48 | 0 | 48 | China | Brute Force |
| 114.80.246.146 | External | 24 | 0 | 24 | China | Brute Force |
| 61.147.116.5 | External | 44 | 0 | 44 | China | Brute Force |

| | | | | | | |
|-----------------|----------|----|---|----|------------------------------|----------------------|
| 2.139.155.90 | External | 18 | 0 | 18 | Madrid | Brute Force |
| 32.65.252.65 | External | 15 | 0 | 15 | AT&T Global Network Services | Brute Force |
| 77.81.50.113 | External | 15 | 0 | 15 | Romania | Brute Force |
| 61.136.208.23 | External | 21 | 0 | 21 | China | Brute Force |
| 222.186.57.67 | External | 24 | 0 | 24 | China | Brute Force |
| 221.230.54.115 | External | 10 | 0 | 10 | China | Brute Force |
| 183.86.221.244 | External | 7 | 0 | 7 | South Korea | Brute Force |
| 183.61.164.202 | External | 9 | 0 | 9 | China | Brute Force |
| 61.147.103.157 | External | 10 | 0 | 10 | China | Brute Force |
| 61.182.227.182 | External | 5 | 0 | 5 | China | Brute Force |
| 211.202.2.135 | External | 3 | 0 | 3 | South Korea | Unknown /Brute Force |
| 207.210.192.36 | External | 3 | 0 | 3 | Unknown | Unknown /Brute Force |
| 37.247.103.107 | External | 2 | 0 | 2 | Turkey | Unknown |
| 113.108.211.131 | External | 2 | 0 | 2 | China | Unknown |
| 115.236.79.98 | External | 2 | 0 | 2 | China | Unknown |
| 123.232.122.162 | External | 1 | 0 | 1 | China | Unknown |
| 183.224.249.22 | External | 1 | 0 | 1 | China | Unknown |
| 209.255.116.35 | External | 1 | 0 | 1 | New York | Unknown |
| 183.247.177.35 | External | 1 | 0 | 1 | China | Unknown |
| 67.207.180.163 | External | 1 | 0 | 1 | Las Vegas, NV | Unknown |
| 128.226.31.97 | External | 1 | 0 | 1 | Binghamton University, NY | Unknown |

Attachment 16. Security Fabric Compliance and Penetration Testing

Appendix A: TTU Security Testing Part 1

Verification of Security Fabric Requirement Specifications

This appendix provides details of testing against given security requirement specifications summarized in Section 4.5.1.1 of the Final Technical Report. Each section groups a set of test specifications by the NIST's requirement category. Each subsection gives details of a specific test including the description of NIST requirement along with its corresponding specification developed by Intel/McAfee, and verification results. If the specification is satisfactorily verified, evidence will be provided when appropriate. Otherwise, the explanation to why the specification is not satisfied will be described. In the latter case, the explanation should clarify how the issue can be resolved. It is noted that all of the issues identified can be fixed to meet the requirements by defining the specifications more thoroughly, eliminating some inappropriate requirements, providing additional information for testing, or by incorporating additional existing Intel/McAfee tools or applications.

A.1 Access Control (SG.AC)

The focus of access control is ensuring that resources are accessed only by the appropriate personnel, and that personnel are correctly identified. Mechanisms need to be in place to monitor access activities for inappropriate activity.

A.1.1 Remote Access Policy and Procedures (SG.AC-2)

Requirement

The organization—

1. Documents allowed methods of remote access to the Smart Grid information system;
2. Establishes usage restrictions and implementation guidance for each allowed remote access method;
3. Authorizes remote access to the Smart Grid information system prior to connection; and
4. Enforces requirements for remote connections to the Smart Grid information system.

Supplemental Guidance

Remote access is any access to an organizational Smart Grid information system by a user (or process acting on behalf of a user) communicating through an external, non-organization-controlled network (e.g., the Internet).

Category

Common Governance, Risk, and Compliance (GRC) Requirement

Specification

The development of the machine policy, based on the corporate or regulatory Policy, defining how the machines communicate is managed by the platform. So, instead of managing policy via Word Document, PDF, etc. (in prose), the platform provides the ability to digitally define policy, distribute to appropriate endpoints, enforce the policy, and monitor for policy violations.

- 1) Manage policy on ePO to define allowed system behavior: describe server components and endpoint components, defining how the system can communicate to other (remote) systems.
- 2) Define policy specifically to restrict access to platform services which have not been explicitly allowed.
- 3) Authorizes that each communication is allowed based on policy.
- 4) Non-allowed communications are blocked.

Verification Results

Satisfactory. The proposed system provides remote access policy via ePO policy management system to control communication among the components (including outside of SF system). The following gives an example of Security Fabric IPTFW configuration from the ePO policy management system:

```
# S2-Layer2 Note this comment is used by the script to detect the policy type is L2

in tcp 129.118.26.8 1113

out tcp 129.118.26.8 1113

in tcp 129.118.105.50 1113

out tcp 129.118.105.50 1113

in tcp 0.0.0.0 3389

out tcp 0.0.0.0 3389

out udp 129.118.26.8 123

out udp 129.118.105.50 123

in tcp 129.118.26.8 1433

out tcp 129.118.19.210 1433

in tcp 129.118.105.44 6688

out tcp 129.118.105.44 6688
```

A.1.2 Account Management (SG.AC-3)

Requirement

The organization manages Smart Grid information system accounts, including:

1. Authorizing, establishing, activating, modifying, disabling, and removing accounts;
2. Specifying account types, access rights, and privileges (e.g., individual, group, system, guest, anonymous and temporary);
3. Reviewing accounts on an organization-defined frequency; and
4. Notifying account managers when Smart Grid information system users are terminated, transferred, or Smart Grid information system usage changes.

Management approval is required prior to establishing accounts.

Additional Considerations

1. The organization reviews currently active Smart Grid information system accounts on an organization-defined frequency to verify that temporary accounts and accounts of terminated or transferred users have been deactivated in accordance with organizational policy.
2. The organization authorizes and monitors the use of guest/anonymous accounts.
3. The organization employs automated mechanisms to support the management of Smart Grid information system accounts.
4. The Smart Grid information system automatically terminates temporary and emergency accounts after an organization-defined time period for each type of account.
5. The Smart Grid information system automatically disables inactive accounts after an organization-defined time period.
6. The Smart Grid information system automatically audits account creation, modification, disabling, and termination actions and notifies, as required, appropriate individuals.

Category

Common Governance, Risk, and Compliance (GRC) Requirement

Specification

Inherit from Org Policy. ePO is dependent upon HR & other systems for the user information. The Active Directory server is configured to authorize the target systems to use defined system resources in Security Fabric. Active directory acts as Authentication system as it uses Kerberos as the authentication mechanism. The provisioning of the AD system with Machine principals is automated. The import of User Principals from AD into ePO is automated.

1. We leverage the Org Policy. We do not introduce new User Principals, but use Machine Principals. All Kerberos principals are Machine Principals, therefore, there are no user principals required. By default, there are no other accounts (guest, anonymous or individual user account)

to be monitored or managed by the Security Fabric devices. This simplifies the management activities. Any existing User Principals in AD can be imported into ePO to simplify the management of the users, and therefore keep the system more secure.

2. Accounts/principals should be reviewed on an organization-defined frequency in ePO. Scheduled Tasks may be created to remind personnel to review the User accounts.
3. Since User Accounts are not leveraged in the Security Fabric, there is less impact from termination of employees and such. In ePO and ESM, the accounts may need to be manually synchronized.

A heightened level of access is required to establish Machine Principals in Active Directory.

Verification Results

Issue Identified – specification needs more information. The specification does not describe account type, access rights, and privileges (e.g., the users of the proposed system and their individual responsibility). Based on system account information, the specification should state how to authorize, establish, activate, modify, disable, and remove accounts (i.e., functions of account management system) in the proposed system.

A.1.3 Access Enforcement (SG.AC-4)

Requirement

The Smart Grid information system enforces assigned authorizations for controlling access to the Smart Grid information system in accordance with organization-defined policy.

Additional Considerations

1. The organization considers the implementation of a controlled, audited, and manual override of automated mechanisms in the event of emergencies.

Category

Common Governance, Risk, and Compliance (GRC) Requirement

Specification

The control/monitor systems (AD, ePO and ESM) are part of the back-end systems that manage the security fabric. Password authentication is necessary to access these devices/instances.

Verification Results

Satisfactory. The control/monitor systems are protected by secured authentication (authentication with encrypted channel) as shown below.

| System | Protocol | Location | Password | Encrypted |
|--------|----------|-------------------------------------------------------|----------|-----------|
| ePO | HTTPS | https://129.118.19.210:8443/core/orionSplashScreen.do | Yes | Yes |
| ePO | RDP | 129.118.19.210:3389 | Yes | Yes |
| ESM | SSH | 129.118.26.40:22 | Yes | Yes |
| ESM | SSH | 129.118.26.40:23 | Yes | Yes |
| ESM | HTTPS | http://129.118.26.40/Application.html | Yes | Yes |
| AD | RDP | 129.118.26.37:3389 | Yes | Yes |

Table 1. Verification results from checking authentication with secured channel in SF Components.

A.1.4 Information Flow Enforcement (SG.AC-5)

Requirement

The Smart Grid information system enforces assigned authorizations for controlling the flow of information within the Smart Grid information system and between interconnected Smart Grid information systems in accordance with applicable policy.

Supplemental Guidance

Information flow control regulates where information is allowed to travel within a Smart Grid information system and between Smart Grid information systems. Specific examples of flow control enforcement can be found in boundary protection devices (e.g., proxies, gateways, guards, encrypted tunnels, firewalls, and routers) that employ rule sets or establish configuration settings that restrict Smart Grid information system services or provide a packet-filtering capability.

Additional Considerations

1. The Smart Grid information system enforces information flow control using explicit labels on information, source, and destination objects as a basis for flow control decisions.
2. The Smart Grid information system enforces dynamic information flow control allowing or disallowing information flows based on changing conditions or operational considerations.
3. The Smart Grid information system enforces information flow control using organization-defined security policy filters as a basis for flow control decisions.
4. The Smart Grid information system enforces the use of human review for organization-defined security policy filters when the Smart Grid information system is not capable of making an information flow control decision.
5. The Smart Grid information system provides the capability for a privileged administrator to configure, enable, and disable the organization-defined security policy filters.

Category

Unique

Specification

The flow of information is enforced in the Management Instance. There are no connections allowed to the internal Operational Instance that have not been explicitly pre-allowed. This is configured via policy in the remote console (ePO server instance) which inherits from the Org Policy.

The device has multiple layers of security:

- a) external firewall to reject incoming (and outgoing) connections to non-allowed systems
- b) mutual authentication of connections to ensure the identity of the remote endpoint
- c) secure tunnel implementation upon successful mutual authentication to ensure the data cannot be intercepted or disclosed enroute

Therefore, all flow control decisions are made "below the Operational OS" in the Management instance. In addition, the flow control rules are defined by policy provided by ePO so that it is quite dynamic in nature and can be modified as required based on situation.

Violations of the flow-control policy are remotely logged and can be reviewed by a human if the automated controls prove to be insufficient.

A privileged user on the remote ePO console can change the organization-defined security policy filters if needed. During an emergency, increased access can be assigned to one or more users on the ePO system.

The information flow regulation policies are created in firewall on Windows, iptables on WR Linux and also the secure communications EPO policy where the create string defines the flow of the data between the WRL boxes.

Verification Results

Satisfactory. The proposed system regulates the flow of information using ePO policy. The following example is the proxy configuration from policy titled "Security Fabric CORE Configuration" from ePO policy configuration:

```
delete
lport=tcp:192.168.250.3:8712;tport=ssl:129.118.26.8:129.118.105.50:1113;rport=tcp:192.168.250.3:8712;tlskey=kerberos;servicehost=Reese-SF;maxdatarate=1;mdreventperiod=10

create
lport=tcp:192.168.250.3:8712;tport=ssl:129.118.26.8:129.118.105.50:1113;rport=tcp:192.168.250.3:8712;tlskey=kerberos;servicehost=Reese-SF;maxdatarate=1000;mdreventperiod=10

create lport=tcp:192.168.250.3:1433;tport=tcp:129.118.26.8:129.118.19.210:1433

create lport=tcp:192.168.250.3:8443;tport=tcp:129.118.26.8:eposerver:8443

create lport=tcp:192.168.250.3:6688;tport=tcp:129.118.105.50:129.118.105.44:6688

create tport=tcp:0.0.0.0:129.118.105.50:3389;rport=tcp:192.168.250.3:3389
```

```
create tport=tcp:0.0.0.0:129.118.26.8:3389;rport=tcp:192.168.250.3:3389

create lport=udp:192.168.250.3:123;tport=udp:129.118.26.8:129.118.26.37:123

create lport=udp:192.168.250.3:123;tport=udp:129.118.105.50:129.118.26.37:123
```

A.1.5 Separation of Duties (SG.AC-6)

Requirement

The organization—

1. Establishes and documents divisions of responsibility and separates functions as needed to eliminate conflicts of interest and to ensure independence in the responsibilities and functions of individuals/roles;
2. Enforces separation of Smart Grid information system functions through assigned access authorizations; and
3. Restricts security functions to the least amount of users necessary to ensure the security of the Smart Grid information system.

Category

Integrity

Specification

- 1) the organization partitions the responsibilities into buckets as needed to eliminate any conflicts of interest and to ensure independence in the responsibilities of users and roles
- 2) the ePO system (as well as AD and ESM) enforce the separation of system functions based on the roles and permission defined.
- 3) The users assigned to the roles that have permission to specific resources are kept to a minimum.

ePO facilitates separation of duties on the server side. Different accounts can be setup in ePO to perform different administrative tasks. ePO user accounts may be disabled. Also no console access will be enabled on the end point (WRL) for any user. Any administrative task to be performed on the end-point will be performed from EPO.

Verification Results

Issue Identified – specification needs more information. The specification does not describe roles and responsibilities in the proposed system. Without the defined roles and responsibilities, it is not possible to test whether the Separation of Duties constraints are enforced in the proposed system. The separation of duties constraint is commonly used to solve the problem of conflict of interest. The specification should also address where conflicts of interest occur and show how the separation of duties can be enforced in the system.

A.1.6 Least Privilege (SG.AC-7)

Requirement

1. The organization assigns the most restrictive set of rights and privileges or access needed by users for the performance of specified tasks; and
2. The organization configures the Smart Grid information system to enforce the most restrictive set of rights and privileges or access needed by users.

Additional Considerations

1. The organization authorizes network access to organization-defined privileged commands only for compelling operational needs and documents the rationale for such access in the security plan for the Smart Grid information system.
2. The organization authorizes access to organization-defined list of security functions (deployed in hardware, software, and firmware) and security-relevant information.

Category

Integrity

Specification

ePO provides users, roles, permissions, and groups to allow the administrator to define the least permission possible for each user to do his/her job.

1. The organization assigns the most restrictive set of rights and privileges as need to for users to perform the needed tasks.
2. The organization configures the policy to enforce the most restrictive controls that still enable the users to perform their tasks.

User accounts must be created on the EPO (server-side) with different levels of privileges for performing different tasks so that the users can perform only those tasks as are allowed by their role. On the client-side, there would be no user account and not even root access for a remote user.

Verification Results

Issue Identified – specification needs more information. Without the descriptions of roles and responsibilities, it is not possible to test if the least privilege constraints are enforced in the proposed system. The least privilege refers to the fact that every user must be able to access only the resources that are necessary for completing their assigned tasks. Verifying the least privilege property requires: (1) role and its associated responsibilities, (2) list of user privileges (i.e., access authorization), and (3) system configuration settings and corresponding documents.

A.1.7 Unsuccessful Login Attempts (SG.AC-8)

Requirement

The Smart Grid information system enforces a limit of organization-defined number of consecutive invalid login attempts by a user during an organization-defined time period.

Supplemental Guidance

Because of the potential for denial of service, automatic lockouts initiated by the Smart Grid information system are usually temporary and automatically released after a predetermined time period established by the organization. Permanent automatic lockouts initiated by a Smart Grid information system must be carefully considered before being used because of safety considerations and the potential for denial of service.

Additional Considerations

1. The Smart Grid information system automatically locks the account/node until released by an administrator when the maximum number of unsuccessful attempts is exceeded; and
2. If a Smart Grid information system cannot perform account/node locking or delayed logins because of significant adverse impact on performance, safety, or reliability, the system employs alternative requirements or countermeasures that include the following:
 - a. Real-time logging and recording of unsuccessful login attempts; and
 - b. Real-time alerting of a management authority for the Smart Grid information system when the number of defined consecutive invalid access attempts is exceeded.

Category

Integrity

Specification

ePO has a configurable number of user login attempts before the account is locked for a period of time.

The remote access login into the WRL instances via ssh is protected by username/password mechanism, but may be set to Certificate auth. All Endpoint login attempts are monitored by ESM.

ESM monitors login attempts whether it fails or succeeds. So, alarms will be raised if there are a suspicious number of failed login attempts for actions to be taken. Also, ESM can be configured to monitor for a certain number of failed logins followed by a successful login.

Verification Results

Satisfactory. The proposed system has real-time logging and recording of login attempts (both successful and unsuccessful), which can be configured to alert the system administrator when the number of defined consecutive invalid access attempts exceeds the organization-defined number.

A.1.8 Smart Grid Information System Use Notification (SG.AC-9)

Requirement

The Smart Grid information system displays an approved system use notification message or banner before granting access to the Smart Grid information system that provides privacy and security notices consistent with applicable laws, directives, policies, regulations, standards, and guidance.

Supplemental Guidance

1. Smart Grid information system use notification messages can be implemented in the form of warning banners displayed when individuals log in to the Smart Grid information system.
2. Smart Grid information system use notification is intended only for Smart Grid information system access that includes an interactive interface with a human user and is not intended to call for such an interface when the interface does not currently exist.

Category

Integrity

Specification

ePO has a configurable message on the login screen. ESM has a warning message on the login screen.

Verification Results

Satisfactory. The two parts of the proposed system, namely ePO and ESM can display the system use notification message before system access.

A.1.9 Previous Logon Notification (SG.AC-10) – Wait for ePO verification

Requirement

The Smart Grid information system notifies the user, upon successful logon, of the date and time of the last logon and the number of unsuccessful logon attempts since the last successful logon.

Category

Unique

Specification

The last login notification made on any system will be recorded in ESM. User can query this information in ESM, and it is displayed after login.

ePO tracks the user logins and a query can be built that displays this information in a dashboard and the dashboard can be configured as the default screen, therefore the user sees the last login date/time when he logs in.

Verification

Issue Identified – additional information required for testing. Only the verification of ESM is satisfied, but information related to the ePO is necessary to fully satisfy this requirement. The figure below shows the last login notification on the ESM system and the number of unsuccessful login attempts since the last successful login.

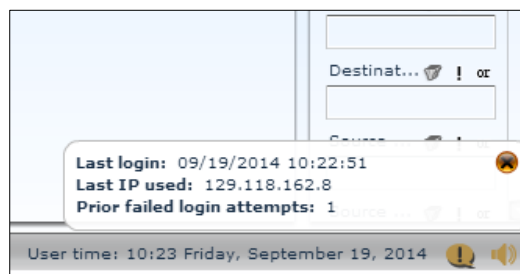


Figure 1. Message notification after successful logon from ESM.

However, at the time of finalizing this report, the evidence of last login notification on the ePO system is not available.

A.1.10 Session Lock (SG.AC-12)

Requirement

The Smart Grid information system—

1. Prevents further access to the Smart Grid information system by initiating a session lock after an organization-defined time period of inactivity or upon receiving a request from a user; and
2. Retains the session lock until the user reestablishes access using appropriate identification and authentication procedures.

Supplemental Guidance

A session lock is not a substitute for logging out of the Smart Grid information system.

Additional Considerations

The Smart Grid information system session lock mechanism, when activated on a device with a display screen, places a publicly viewable pattern onto the associated display, hiding what was previously visible on the screen.

Category

Unique

Specification

EPO and ESM time out after a certain time period of inactivity and the user is logged out. User must authenticate again to reestablish the session.

Verification Results

Satisfactory. ESM Web component has a feature to “set console timeout value” for the current session on the ESM console to remain open as long as there is activity. We can define the amount of time with no activity before the session closes. To set this value, (1) On the ESM console, select *System Properties* followed by *Login Security* (2) In *UI Timeout Value*, select number of minutes that must pass with no activity, then click *OK* to update the configuration. The figure below shows the current setting in the system which is still disabled.



| Standard Login Settings: | | | |
|----------------------------------|------|--|----------------------------------------|
| Allowed failed login attempts: | 3 | | (Use 0 for unlimited retries) |
| Failed login attempts timeframe: | 1440 | | minutes (Use 0 to disable timeout) |
| Failed login lockout duration: | 0 | | minutes (Use 0 to disable restriction) |
| UI timeout value: | 0 | | minutes (Use 0 to disable timeout) |

Figure 2. Part of Login Security property from ESM component.

The ePO web component also has a feature to set “session timeout interval” for the current session on ePO. We can define this value by select *Menu* and followed by *Server Settings* from *Configuration*. Then, we select the last item, which is *User Session*. Shows the current setting of session timeout interval from the ePO component.

| | |
|---------------------------------------------|----|
| Default session timeout interval (minutes): | 60 |
| Maximum session timeout interval (minutes): | 60 |

Figure 3. Current Setting of session timeout interval from ePO web component.

A.1.11 Remote Session Termination (SG.AC-13)

Requirement

The Smart Grid information system terminates a remote session at the end of the session or after an organization-defined time period of inactivity.

Additional Considerations

Automatic session termination applies to local and remote sessions.

Category

Unique

Specification

Remote login to ESM terminates after configurable time limit has been exceeded. The remote access to the windows are disabled. Removing the ESM remote login is potentially viable as well (only local login allowed)

Verification Results

Satisfactory. ESM Web component has a feature to “set console timeout value” for the current session on the ESM console to remain open as long as there is an activity. We can define the inactive time duration before the session closes. To set this duration value, execute the following steps: (1) On the ESM console, select *System Properties* followed by *Login Security* (2) In *UI Timeout Value*, select the number of minutes that must pass with no activity, then click *OK* to update the configuration. The figure below shows current settings in the system which is still disabled.

Standard Login Settings:

Allowed failed login attempts: (Use 0 for unlimited retries)

Failed login attempts timeframe: minutes (Use 0 to disable timeout)

Failed login lockout duration: minutes (Use 0 to disable restriction)

UI timeout value: minutes (Use 0 to disable timeout)

Figure 4. Part of Login Security property from ESM component.

The ePO web component also has a feature to set “session timeout interval” for the current session on the ePO. We can define this value by selecting *Menu* followed by *Server Settings* from *Configuration*. Then the last item, *User Session* is selected. The figure below shows the current setting of session timeout interval from the ePO component.

| | |
|---------------------------------------------|----|
| Default session timeout interval (minutes): | 60 |
| Maximum session timeout interval (minutes): | 60 |

Figure 5. Current Setting of session timeout interval from ePO web component.

A.1.12 Remote Access (SG.AC-15)

Requirement

The organization authorizes, monitors, and manages all methods of remote access to the Smart Grid information system.

Supplemental Guidance

Remote access is any access to a Smart Grid information system by a user (or a process acting on behalf of a user) communicating through an external network (e.g., the Internet).

Requirement Enhancement

1. The organization authenticates remote access, and uses cryptography to protect the confidentiality and integrity of remote access sessions;
2. The Smart Grid information system routes all remote accesses through a limited number of managed access control points;

3. The Smart Grid information system protects wireless access to the Smart Grid information system using authentication and encryption. Note: Authentication applies to user, device, or both as necessary; and
4. The organization monitors for unauthorized remote connections to the Smart Grid information system, including scanning for unauthorized wireless access points on an organization-defined frequency and takes appropriate action if an unauthorized connection is discovered.

Additional Considerations

1. Remote access to Smart Grid information system component locations (e.g., control center, field locations) is enabled only when necessary, approved, authenticated, and for the duration necessary;
2. The organization employs automated mechanisms to facilitate the monitoring and control of remote access methods;
3. The organization authorizes remote access for privileged commands and security-relevant information only for compelling operational needs and documents the rationale for such access in the security plan for the Smart Grid information system; and

The organization disables, when not intended for use, wireless networking capabilities internally embedded within Smart Grid information system components.

Category Unique

Specification

- 1) Security Fabric leverages authentication on all accesses to endpoints (SSH) and back-end servers (user credentials). It also enforces encryption on all connections unless specifically configured not to encrypt.
- 2) The Security Fabric enforces access to services from a specific set of source and destination systems as part of its policy. Therefore it is possible to define a limited number of managed access points.
- 3) NA - wireless currently not managed by Security Fabric
- 4) The remote access to the end-point systems is monitored and recorded in ESM, and alarms on detection. Responses to these actions can be defined in ePO.

The remote access to the Server side systems (EPO, AD, ESM) are monitored

- a. NA - Organizational Policy
- b. Monitoring via ESM is automatable
- c. NA - Operational Policy
- d. NA - wireless currently not managed by Security Fabric

Verification Results

Satisfactory. All access to endpoints and back-end servers requires authentication with encryption to protect the credential of the user as shown below. The ESM system can be configured to monitor and record all remote access attempts.

| Host | Port | Service | Description |
|-------------|------|---------------|---------------------------------------------|
| WRL (TTU) | 22 | ssh | OpenSSH 6.0 (protocol 2.0) |
| WRL (TTU) | 3389 | ms-wbt-server | Microsoft Terminal Service |
| WRL (Reese) | 22 | Ssh | OpenSSH 6.0 (protocol 2.0) |
| WRL (Reese) | 3389 | ms-wbt-server | Microsoft Terminal Service |
| ePO | 3389 | ms-wbt-server | Microsoft Terminal Service |
| ESM | 22 | Ssh | protocol 2.0 with 2048 (RSA) |
| ESM | 23 | Ssh | libssh 0.5.2 (protocol 2.0) with 2048 (RSA) |

Table 2. Remote Access to Security Fabric Enabled System.

A.1.13 Use of External Information Control Systems (SG.AC-18)

Requirement

The organization establishes terms and conditions for authorized individuals to—

1. Access the Smart Grid information system from an external information system; and
2. Process, store, and transmit organization-controlled information using an external information system.

Supplemental Guidance

External information systems are information systems or components of information systems that are outside the authorization boundary established by the organization and for which the organization typically has no direct supervision and authority over the application of security requirements or the assessment of security requirement effectiveness.

Requirement Enhancements

1. The organization imposes restrictions on authorized individuals with regard to the use of organization-controlled removable media on external information systems.

Additional Considerations

1. The organization prohibits authorized individuals from using an external information system to access the Smart Grid information system or to process, store, or transmit organization-controlled information except in situations where the organization (a) can verify the implementation of required security controls on the external information system as specified in the organization's security policy and security plan, or (b) has approved Smart Grid information system connection or processing agreements with the organizational entity hosting the external information system.

Category

Common Governance, Risk, and Compliance (GRC) Requirement

Specification

- 1) Configure management instance firewall such that incoming connections may only be initiated from specific sources external to the network. Ensure that the firewall only allows specific protocols from those sources. Finally, ensure that the user access is strictly enforced from the Operational Instance. NOTE: Full control is not yet implemented, but monitoring of the operations on the system can be accomplished via the SIEM.
- 2) Managing the actions of processing, storing, and transmitting information on external system requires a Data Loss Prevention (DLP) product on the external system. NOTE: NOT IN DEMONSTRATION INSTANCE).

In order to fully implement this requirement, the external instance must be fitted with DLP software, and the operational instant must be configured to allow only the external instance to connect on specific ports with services listening that are configured with proper user access restrictions.

Verification Results

Satisfactory. The specification provides the condition to access 1) the smart grid information system from an external information system and 2) the process and store and to transmit the smart grid information using an external information system. For example, the condition may be operated via firewall configure management and Data Loss Presentation (DLP) system. However, the DLP system has not been implemented in the current SF-enabled system yet.

A.1.14 Control System Access Restrictions (SG.AC-19)

Requirement

The organization employs mechanisms in the design and implementation of a Smart Grid information system to restrict access to the Smart Grid information system from the organization's enterprise network.

Supplemental Guidance

Access to the Smart Grid information system to satisfy business requirements needs to be limited to read-only access.

Category

Common Governance, Risk, and Compliance (GRC) Requirements

Specification

The endpoint is able to control the network traffic into and out of the Management instance. Therefore, it is possible to restrict network access to the endpoint even from the organization's enterprise network (or from any other location).

Verification Results

Satisfactory. The endpoints (i.e., the agent of security fabric components, which are WRLs on both RTDMS and ePDC) control the communication between entities in the network by using the security policy from ePO. Partial policies from ePO web interface are shown below.

| SECURITY FABRIC IPTFW 0.1:SFIPFW_1000 > Security Fabric IPTFW Configuration > My Default | |
|------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Enter IpTables: | <pre># S2-Layer2 Note this comment is used by the script to detect the policy type is L2 in tcp 129.118.26.8 1113 out tcp 129.118.26.8 1113 in tcp 129.118.105.50 1113 out tcp 129.118.105.50 1113 in tcp 0.0.0.0 3389 out tcp 0.0.0.0 3389 out udp 129.118.26.8 123 out udp 129.118.105.50 123 in tcp 129.118.26.8 1433 out tcp 129.118.19.210 1433 in tcp 129.118.105.44 6688 out tcp 129.118.105.44 6688</pre> |

Figure 6. IP Table Firewall rule in ePO policy.

A.1.15 Password (SG.AC-20)

Requirement

The organization—

1. Designates individuals authorized to post information onto an organizational information system that is publicly accessible;
2. Trains authorized individuals to ensure that publicly accessible information does not contain nonpublic information;
3. Reviews the proposed content of publicly accessible information for nonpublic information prior to posting onto the organizational information system;
4. Reviews the content on the publicly accessible organizational information system for nonpublic information on an organization-defined frequency; and
5. Removes nonpublic information from the publicly accessible organizational information system, if discovered.

Supplemental Guidance

Information protected under the Privacy Act and vendor proprietary information are examples of nonpublic information. This requirement addresses posting information on an organizational

information system that is accessible to the general public, typically without identification or authentication.

Category

Common Governance, Risk, and Compliance (GRC) Requirement

Specification

- 1.1. Password policies can be configured in ePO (for user login to the ePO console)
- 1.2. Password strength can be defined in ePO.
- 1.3. ESM may have specific password strength requirement policy.
- 1.4. Credential rotation is not tracked by ePO, nor is extended non-use.

Verification Results

Satisfactory. The ESM has the password policy as follows: (1) at least eight characters long (2) at least one number (3) at least one punctuation or symbol (4) at least one uppercase, and (5) different from previous password by four characters.

The screenshot displays a user configuration form in the ePO system. It includes fields for 'User name' (set to 'administrator'), 'Logon status' (set to 'Enabled'), and 'Authentication type'. Under 'Authentication type', there are three options: 'Change authentication or credentials', 'ePO authentication', and 'Windows authentication'. The 'ePO authentication' option is selected, showing fields for 'Password' and 'Confirm password'. Below these, there are fields for 'User name' and 'Domain' under 'Windows authentication', and a 'Personal Certificate Subject DN Field' and 'Upload Certificate File' button under 'Certificate Based Authentication'. A red message at the bottom states: 'The CA certificate for client certificate authentication has not been configured yet.'

Figure 7. Password Policy for each user in ePO system.

There are three levels of policy (applied to each user) to choose from ePO system, which are (1) *low criticality*: any password strength (2) *Medium criticality*: apply the environment's password policy via Active Directory (3) *High criticality*: no password, leverage certificate authentication only. The figure above shows the password policy for ePO system.

A.2 Audit and Accountability (SG.AU)

Periodic audits and logging of the Smart Grid information system need to be implemented to validate that the security mechanisms present during Smart Grid information system validation testing are still installed and operating correctly. These security audits review and examine a Smart Grid information system's records and activities to determine the adequacy of Smart Grid information system security

requirements and to ensure compliance with established security policy and procedures. Audits also are used to detect breaches in security services through examination of Smart Grid information system logs. Logging is necessary for anomaly detection as well as forensic analysis.

A.2.1 Auditable Events (SG.AU-2)

Requirement

The organization—

1. Develops, based on a risk assessment, the Smart Grid information system list of auditable events on an organization-defined frequency;
2. Includes execution of privileged functions in the list of events to be audited by the Smart Grid information system; and
3. Revises the list of auditable events based on current threat data, assessment of risk, and post-incident analysis.

Supplemental Guidance

The purpose of this requirement is for the organization to identify events that need to be auditable as significant and relevant to the security of the Smart Grid information system.

Requirement Enhancements

1. The organization should audit activities associated with configuration changes to the Smart Grid information system.

Category

Common Technical Requirements, Integrity

Specification

1. Define list of events that must be stored for future security analysis by the McAfee ePO and McAfee ESM systems.
2. Ensure that all events are monitored, logged, and reported up to the ePO and ESM systems.

Verification Results

Satisfactory. List of auditable events can be selected in both McAfee ePO system (as shown below) and McAfee ESM system (as shown in the second figure). Moreover, users at ePO can also define their own events as shown in the third figure. All defined events are monitored and can be reported to user of both ESM and ePO systems as shown in the fourth and fifth figures, respectively.

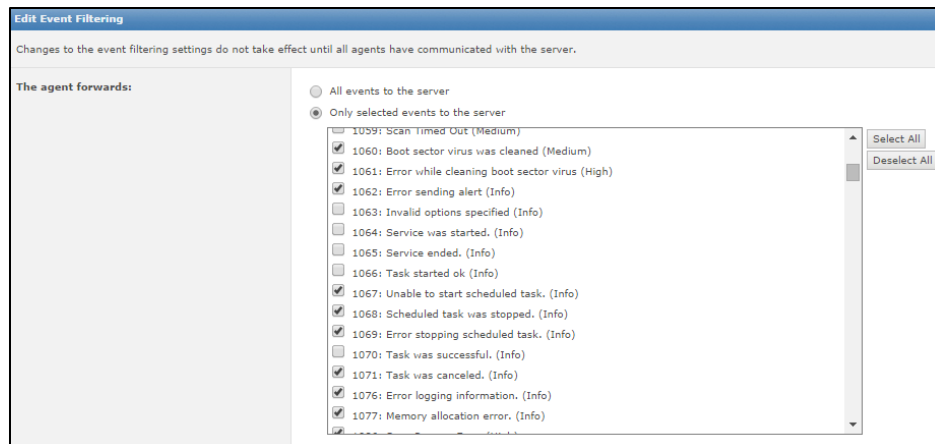


Figure 8. Event Filtering in ePO system.

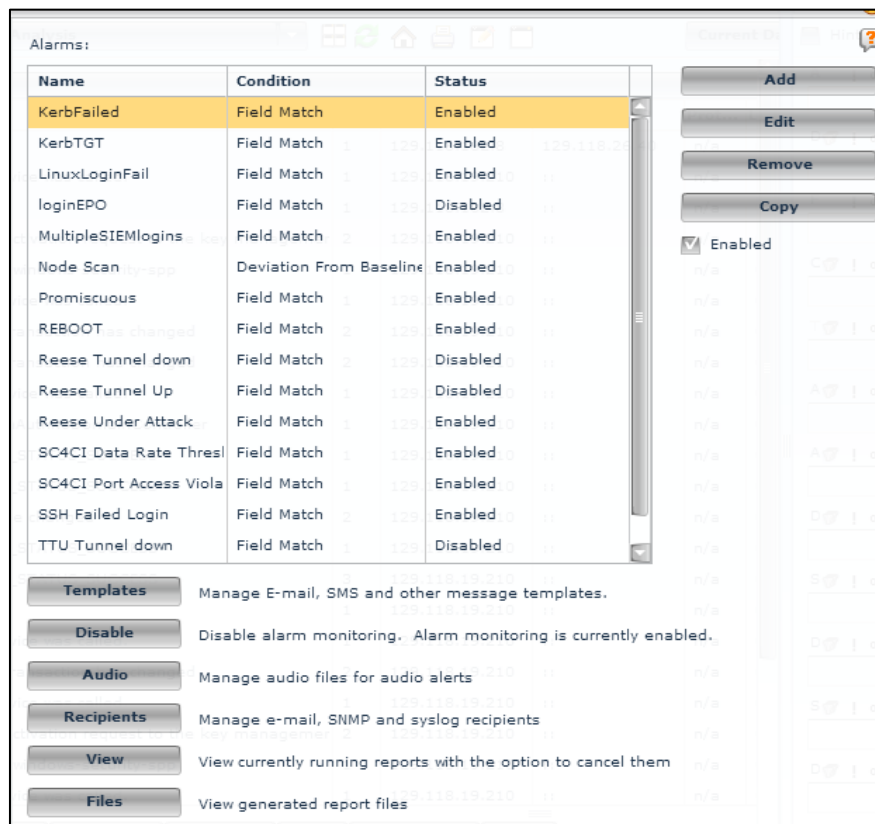


Figure 9. Event Editor and Filtering in ESM system.

Automatic Responses

Response Builder
1 Description
2 Filter
3 Aggregation

What is this response's name, target language, and event type? Is the response enabled?

| | |
|---------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Name: | <input style="width: 90%;" type="text" value="Bad Binary has been detected in Enterprise"/> |
| Description: | <div style="border: 1px solid #ccc; padding: 5px; min-height: 40px;">This response sends an email notification when a binary with very low Trust Level as per Application Control GTI Cloud Server is found in Enterprise.</div> |
| Language: | <div style="border: 1px solid #ccc; padding: 2px;">English ▼</div> |
| Event: | <div>Event group: <div style="border: 1px solid #ccc; padding: 2px;">ePO Notification Events ▼</div></div> <div>Event type: <div style="border: 1px solid #ccc; padding: 2px;">Threat ▼</div></div> |
| Status: | <input type="radio"/> Enabled <input checked="" type="radio"/> Disabled |

Figure 10. Automatic Responses for specific events in ePO system.

| All Events | | | | | | |
|------------|------------------------------------------------------|-------|----------------|----------------|---------|---|
| Seve... | Rule Message | Ev... | Source IP | Destination IP | Prot... | L |
| 19 | User Login | 1 | 129.118.162.8 | 129.118.26.40 | n/a | |
| 25 | A privileged service was called. | 1 | 129.118.19.210 | :: | n/a | |
| 25 | Login attempt | 1 | 129.118.162.8 | :: | n/a | |
| 50 | Client sent an activation request to the key manager | 2 | 129.118.19.210 | :: | n/a | |
| 15 | 8196-microsoft-windows-security-spp | 1 | 129.118.19.210 | :: | n/a | |
| 25 | A privileged service was called. | 1 | 129.118.19.210 | :: | n/a | |
| 50 | The state of a transaction has changed | 2 | 129.118.19.210 | :: | n/a | |
| 50 | The state of a transaction has changed | 2 | 129.118.19.210 | :: | n/a | |
| 25 | A privileged service was called. | 1 | 129.118.19.210 | :: | n/a | |
| 45 | NELOG_NetlogonAuthNoDomainController | 1 | 129.118.19.210 | :: | n/a | |
| 25 | EVENT_SERVICE_STATUS_SUCCESS | 1 | 129.118.19.210 | :: | n/a | |
| 25 | EVENT_SERVICE_STATUS_SUCCESS | 1 | 129.118.19.210 | :: | n/a | |
| 50 | Service start type changed | 2 | 129.118.19.210 | :: | n/a | |

Figure 11. Event log for ESM system.

| | Event Received Time | Threat Type | Event ID | Threat Target IPv4 Add | Reporter PayLoad | Reporter Type | Event Description | Threat Target IP Address |
|--|---------------------|-----------------------|----------|------------------------|----------------------|---------------|-------------------|--------------------------|
| | 11/22/13 4:54:34 PM | Reported Event-Nov:21 | 35400 | 129.118.26.8 | IPT/FIREWALL VIOLATI | Firewall | IPTFW DOS Attack | 0:0:0:0:1111:2222:33 |
| | 11/22/13 4:54:34 PM | Reported Event-Nov:21 | 35400 | 129.118.26.8 | IPT/FIREWALL VIOLATI | Firewall | IPTFW DOS Attack | 0:0:0:0:1111:2222:33 |
| | 11/22/13 5:00:26 PM | Reported Event-Nov:21 | 35400 | 129.118.105.50 | IPT/FIREWALL VIOLATI | Firewall | IPTFW DOS Attack | 0:0:0:0:1111:2222:33 |
| | 11/22/13 5:00:26 PM | Reported Event-Nov:21 | 35400 | 129.118.105.50 | IPT/FIREWALL VIOLATI | Firewall | IPTFW DOS Attack | 0:0:0:0:1111:2222:33 |
| | 11/22/13 5:00:26 PM | Reported Event-Nov:21 | 35400 | 129.118.105.50 | IPT/FIREWALL VIOLATI | Firewall | IPTFW DOS Attack | 0:0:0:0:1111:2222:33 |
| | 11/22/13 5:00:25 PM | Reported Event-Nov:22 | 35403 | 129.118.105.50 | IPTABLES LEVEL 3 WEF | Firewall | IPTFWUpdated | 0:0:0:0:1111:2222:33 |
| | 11/22/13 5:00:26 PM | Reported Event-Nov:22 | 35403 | 129.118.105.50 | IPTABLES LEVEL 3 WEF | Firewall | IPTFWUpdated | 0:0:0:0:1111:2222:33 |
| | 11/22/13 4:54:34 PM | Reported Event-Nov:22 | 35403 | 129.118.26.8 | IPTABLES LEVEL 3 WEF | Firewall | IPTFWUpdated | 0:0:0:0:1111:2222:33 |
| | 11/22/13 4:54:34 PM | Reported Event-Nov:22 | 35403 | 129.118.26.8 | IPTABLES LEVEL 3 WEF | Firewall | IPTFWUpdated | 0:0:0:0:1111:2222:33 |
| | 11/22/13 4:54:34 PM | Reported Event-Nov:22 | 35403 | 129.118.26.8 | IPTABLES LEVEL 3 WEF | Firewall | IPTFWUpdated | 0:0:0:0:1111:2222:33 |
| | 11/22/13 4:54:33 PM | Reported Event-Nov:22 | 35403 | 129.118.26.8 | IPTABLES LEVEL 3 WEF | Firewall | IPTFWUpdated | 0:0:0:0:1111:2222:33 |

Figure 12. Event log in ePO system.

A.2.2 Content of Audit Records (SG.AU-3)

Requirement

The Smart Grid information system produces audit records for each event. The record contains the following information:

- Data and time of the event,
- The component of the Smart Grid information system where the event occurred,
- Type of event,
- User/subject identity, and
- The outcome of the events.

Additional Considerations

1. The Smart Grid information system provides the capability to include additional, more detailed information in the audit records for audit events identified by type, location, or subject; and
2. The Smart Grid information system provides the capability to centrally manage the content of audit records generated by individual components throughout the Smart Grid information system.

Category

Common Technical Requirements, Integrity

Specification

1. Define list of events that must be stored for future security analysis by the McAfee ePO and McAfee ESM systems.
2. Include the following fields in each audit record:
 - Date and time
 - Asset ID
 - Type of event
 - User/subject identity (if applicable, else the machine principal)
 - Outcome of event

Include additional information as needed on location, subject, type, etc. Audit records are centrally managed in the ESM.

Verification Results

Satisfactory. McAfee ESM system can be configured to include additional information to the defined auditable event. An example of audited event that meet the criteria of the requirement is shown below.

| Device: Local Receiver-ELM - EPO-SF wmi events | | | |
|------------------------------------------------|--------------------------|----------------|-----------------------|
| First Time: | 09/26/2014 09:00:00 | Last Time: | 09/26/2014 09:00:00 |
| Duration: | 00:00:00.000 | | |
| Source IP: | 129.118.19.210 | Dest. IP: | :: |
| Protocol: | n/a | | |
| Source Port: | n/a | Dest. Port: | n/a |
| Event Subtype: | success | | |
| Source MAC: | 00:00:00:00:00:00 | Dest. MAC: | 00:00:00:00:00:00 |
| VLAN: | 0 | | |
| Source User: | EPO-SF\$ | Dest. User: | |
| Total: | 1 | | |
| Signature ID: | 43-263046730 | Normalized ID: | 1209008128 |
| Severity: | 25 | | |
| Src. GUID: | | Dest. GUID: | |
| Domain: | epg | | |
| Application: | c:\windows\system32\lsas | Host: | epo-sf.epg.secfab.org |
| Source Zone: | Beaverton | Dest. Zone: | |

Figure 13. Content of audit event from ESM.

A.2.3 Audit Storage Capacity (SG.AU-4)

Requirement

The organization allocates organization-defined audit record storage capacity and configures auditing to reduce the likelihood of such capacity being exceeded.

Supplemental Guidance

The organization considers the types of auditing to be performed and the audit processing requirements when allocating audit storage capacity.

Category

Common Technical Requirements, Integrity

Specification

1. NA/Organizational
2. Ensure that all file systems and historian databases have sufficient space allocated to store the appropriate quantity of events. Event storage includes device file system as well as back-end situational awareness systems such as ePO/ESM databases.
3. On device: enable log rotation. For remote logging, define only those events and logs on the endpoint that are appropriate for determining security metrics on the back-end. Do not simply include all logs.

Verification Results

Satisfactory. While the specification does not describe the capacity of audit record storage for the proposed system, there is a policy (log rotation) for reducing the likelihood of exceeding capacity on device in WRL (Wind River Linux) on both TTU and Reese sites.

A.2.4 Response to Audit Processing Failures (SG.AU-5)

Requirement

The Smart Grid information system—

1. Alerts designated organizational officials in the event of an audit processing failure; and
2. Executes an organization-defined set of actions to be taken (e.g., shutdown Smart Grid information system, overwrite oldest audit records, and stop generating audit records).

Supplemental Guidance

Audit processing failures include software/hardware errors, failures in the audit capturing mechanisms, and audit storage capacity being reached or exceeded.

Requirement Enhancements

1. The Smart Grid information system provides a warning when allocated audit record storage volume reaches an organization-defined percentage of maximum audit record storage capacity; and
2. The Smart Grid information system provides a real-time alert for organization defined audit failure events.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

1. in ePO, define personnel that may be notified. Enter them into the "Contacts" section.
2. define ePO Automated Responses to notify one or more "Contacts" via email that an event of interest has occurred on an endpoint.
3. NA/Organizational (organization documents these actions for personnel to enact)
4. Organizationally defined actions will be taken upon audit processing failures. For example: person X is notified via email when a processing error occurs.
5. NA/Organizational (organization defines the percentage of capacity usage to alert on)
6. Endpoint: NA/Organizational (logs on endpoint are remotely monitored, so log file overflow does not concern Security Fabric) [see SG.AU-4.1]
7. NA/Organizational (organization defines alerts that should be near-real-time in nature, e.g. network whitelisting violation, or firewall violation)
8. Events are being monitored in near-real-time by both ePO and ESM.

When events are captured by ePO, the system state can be immediately altered and automated responses triggered. When events are captured by ESM, a notification is sent to ePO, triggering a state change, and an automated response can be triggered.

Verification Results

Satisfactory. The proposed system has the mechanism to alert security administrator by sending an email to the specified contact person when specific event occurs. This mechanism can be used when there is a failure in processing of audit records. The figure below shows an example of email message to contact a person when there is a new update for software component.

The mail server is not configured. If the mail server is not properly configured, this action will fail.

Recipients: ... *

Importance: Medium ▼

Subject: "{responseRuleName}" event received

Insert variable: List of All Values ▼ Additional Information ▼ Insert

Body:

ePolicy Orchestrator Notification
Response Name: {responseRuleName}
Description: Sends an e-mail notification when "New Software Component Update Available" event is received.
Updated software component: {listOfAdditionalInfo}

Insert variable: List of All Values ▼ Additional Information ▼ Insert

Figure 14. Alerting mechanism in ePO system.

A.2.5 Audit Monitoring, Analysis, and Reporting (SG.AU-6)

Requirement

The organization—

1. Reviews and analyzes Smart Grid information system audit records on an organization-defined frequency for indications of inappropriate or unusual activity and reports findings to management authority; and
2. Adjusts the level of audit review, analysis, and reporting within the Smart Grid information system when a change in risk occurs to organizational operations, organizational assets, or individuals.

Supplemental Guidance

Organizations increase the level of audit monitoring and analysis activity within the Smart Grid information system based on, for example, law enforcement information, intelligence information, or other credible sources of information.

Additional Considerations

1. The Smart Grid information system employs automated mechanisms to integrate audit review, analysis, and reporting into organizational processes for investigation and response to suspicious activities;

2. The organization analyzes and correlates audit records across different repositories to gain organization-wide situational awareness;
3. The Smart Grid information system employs automated mechanisms to centralize audit review and analysis of audit records from multiple components within the Smart Grid information system; and
4. The organization integrates analysis of audit records with analysis of performance and network monitoring information to further enhance the ability to identify inappropriate or unusual activity.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

1. NA/Organizational: organization defines the frequency
2. The platform assists in the gathering of data and identifies inappropriate or unusual activity.
3. NA/Organizational: notification to the appropriate management authority is left to the discretion of the organization
4. NA/Organizational: depends upon the organization's response to specific triggers by changing the level of audit, review, analysis, and reporting.

Verification Results

Satisfactory. ESM and ePO provide a mechanism for monitoring the audit records, analysis using the defined condition, and reporting the content from audit records. These evidences were captured in Figures 8, 10-12, and the two below.

| Reporting | |
|----------------------------------------------|-----------------------------|
| Queries & Reports | |
| Failed Login Attempts in Last 30 Days | |
| User Name | Number of Audit Log Entries |
| administrator | 7 |
| admin | 1 |
| sa | 1 |
| Total | 9 |

Figure 15. Report generation from ePO system.

Add Report

1. Enter a name and description for this report.

Report Name:

Description:

2. When do you want this report to run?

Condition: [Edit conditions](#)

Daily at 12:00 AM

3. (OPTIONAL) What format options do you want to use to run the queries for this report?

Time Zone: (GMT-05:00) Central Time (US & Canada)

Date Format: mm/dd/yyyy

Language: English

Figure 16. Report generation in ESM.

A.2.6 Audit Reduction, and Report Generation (SG.AU-7)

Requirement

The Smart Grid information system provides an audit reduction and report generation capability.

Supplemental Guidance

Audit reduction and reporting may support near real-time analysis and after-the-fact investigations of security incidents.

Additional Considerations

1. The Smart Grid information system provides the capability to automatically process audit records for events of interest based on selectable event criteria

Category

Common Governance, Risk, and Compliance (GRC)

Specification

A mechanism exists on the ESM and ePO to allow generation of reports and will support near real-time analysis. Search functionality in the ESM enables audit reduction. Reporting, Dashboards, and Queries in ePO also enable the conversion from raw data into information for human consumption by reducing, sorting, filtering, and leveraging visualization techniques.

Verification Results

Satisfactory. ESM and ePO have the mechanism for report generation as shown in Figures 15-16. In term of audit reduction, both components provide event filtering and the condition for report generation as shown in the next two figures, respectively.

6. (OPTIONAL) Specify filter values to apply to all components included in the report. When you add components to the report you will be able to specify additional filter values for each individual component that will override these values.

Enter values to filter the report data for this notification.

| | | |
|------------------------|--------------|---------|
| Time Range | Previous Day | |
| Devices | Local ESM | |
| Access_Resource | | ! or |
| Agent_GUID | | ! or |
| Analyzer_DAT_Version | | ! or |
| Application | | ! or Aa |
| Application_Layer | | ! or |
| Application_Protocol | | ! or Aa |
| Area | | ! or |
| ASN/Geo Destination ID | | ! or |

Enable reporting. Reports are currently disabled.

Manage report conditions

Manage e-mail addresses for report recipients

Figure 17. Event filtering in report generation from ESM.

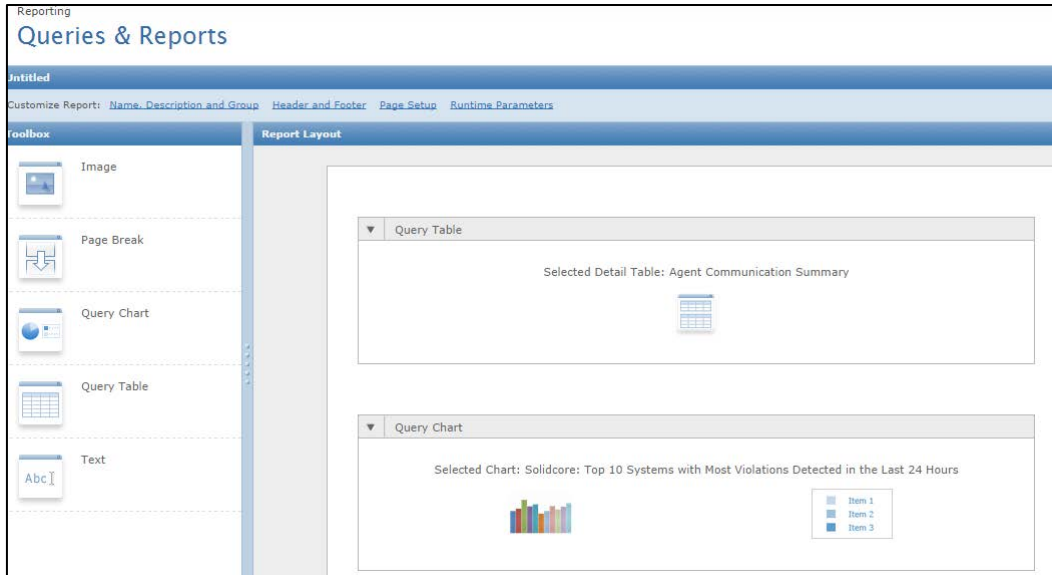


Figure 18. Event filtering in report generation from ePO.

A.2.7 Time Stamps (SG.AU-8)

Requirement

The Smart Grid information system uses internal system clocks to generate time stamps for audit records.

Supplemental Guidance

Time stamps generated by the information system include both date and time, as defined by the organization.

Requirement Enhancements

1. The Smart Grid information system synchronizes internal Smart Grid information system clocks on an organization-defined frequency using an organization-defined time source.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

Regardless of whether the information system uses internal system clocks, the Security Fabric platform leverages internal clocks to generate accurate time stamps for audit records.

- clock synchronization using NTP is supported, and a time source is required
- frequency of synchronization is configurable in the platform

- The platform ensures that the platform synchronizes its internal clocks at the configured frequency using the configured time source(s).

Verification Results

Satisfactory. The content of audit record in both ePO and ESM uses the internal system clocks (which can acquire the time from NTP by specifying the server as shown below) to generate time stamps for the record as shown in the audit content records from Figures 12-13.

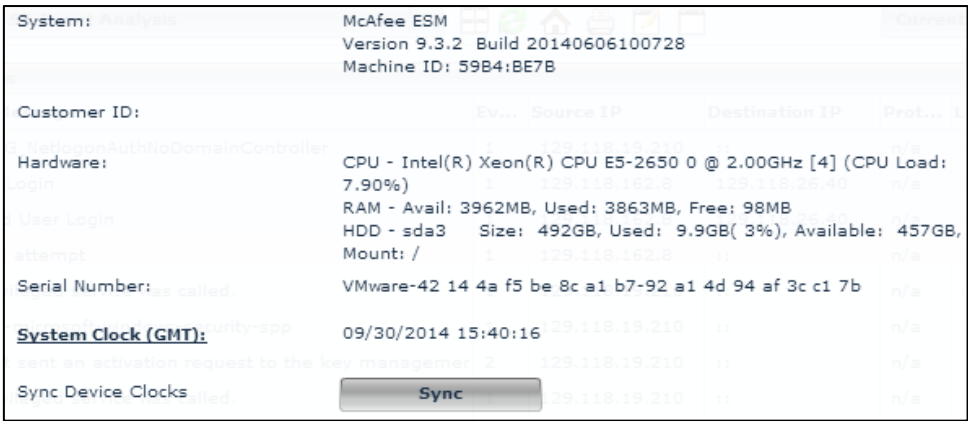


Figure 19. ESM system clock configuration.

A.2.8 Protection of Audit Information (SG.AU-9)

Requirement

The Smart Grid information system protects audit information and audit tools from unauthorized access, modification, and deletion.

Supplemental Guidance

Audit information includes, for example, audit records, audit settings, and audit reports.

Additional Considerations

1. The Smart Grid information system produces audit records on hardware-enforced, write-once media.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

The platform protects audit information and audit tools from unauthorized access, modification, and deletion via authentication and authorization controls (access control).

Access to specific functional components is managed by the permissions assigned to the roles on each resource.

Verification Results

Satisfactory. Both ESM and ePO have the authentication and authorization controls to protect the system from unauthorized access as shown in Table 1.

A.2.9 Audit Record Retention (SG.AU-10)

Requirement

The organization retains audit logs for an organization-defined time period to provide support for after-the-fact investigations of security incidents and to meet regulatory and organizational information retention requirements.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

1. NA/Organizational
2. Audit records, including logs, are retained for a configurable amount of time as required to support investigations and regulatory requirements.

Verification Results

Satisfactory. The proposed system does not define the time period to provide support for after-the-fact investigations of security incidents. However, the provider of the system (McAfee) claims to use the available space as the measure of how long the message can retain in the system. The following is what provider's claim:

- The proposed system provided space for 500GB
- 1061.8MB is used for the base (available space for keeping record is around 400GB)
- The **estimate** for daily event is around 2.35MB
- 400GB/2.35MB is around 466.33 years

If the daily event does not exceed the estimated value, all events can be stored in the proposed system.

A.2.10 Conduct and Frequency of Audits (SG.AU-11)

Requirement

The organization conducts audits on an organization-defined frequency to assess conformance to specified security requirements and applicable laws and regulations.

Supplemental Guidance

Audits can be either in the form of internal self-assessment (sometimes called first-party audits) or independent, third-party audits.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

1. NA/Organizational (defined frequency)
2. NA/Organizational (audits relative to defined frequency)
3. Regular audits are measured for compliance with the security requirements, processes and regulations. A combination of Technical controls + Policy compliance tools are required.

Verification Results

Satisfactory. ESM and ePO can automatically generate the report according to the organization defined time. This mechanism helps the organizations to conduct the audit based on their defined frequency to assess conformance to their own specified security requirement.

A.2.11 Security Policy Compliance (SG.AU-14)

Requirement

The organization demonstrates compliance to the organization's security policy through audits in accordance with the organization's audit program.

Supplemental Guidance

Periodic audits of the Smart Grid information system are implemented to demonstrate compliance to the organization's security policy. These audits—

1. Assess whether the defined cyber security policies and procedures, including those to identify security incidents, are being implemented and followed;
2. Document and ensure compliance to organization policies and procedures;

3. Identify security concerns, validate that the Smart Grid information system is free from security compromises, and provide information on the nature and extent of compromises should they occur;
4. Validate change management procedures and ensure that they produce an audit trail of reviews and approvals of all changes;
5. Verify that security mechanisms and management practices present during Smart Grid information system validation are still in place and functioning;
6. Ensure reliability and availability of the Smart Grid information system to support safe operation; and
7. Continuously improve performance.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

Compliance to the security policy is tracked through event collection and correlation, assessments/analytics, and identification of potential security concerns. It is left to the organization to demonstrate compliance to the security policy.

Verification Results

Satisfactory. The security policy in Smart Grid system is described electronically in policy management of ePO system. To demonstrate the compliance of the policy, the organization needs to specify events to be monitored in the organization defined security policy in both ePO and ESM. This requires experiential knowledge of ePO and ESM systems (e.g., see SG.AC-2 as an example of security policy specification and SG.AU-2, SG.AU-5, SG.AU-7 for audit and report generation).

A.2.12 Audit Generation (SG.AU-15)

Requirement

The Smart Grid information system—

1. Provides audit record generation capability and generates audit records for the selected list of auditable events; and
2. Provides audit record generation capability and allows authorized users to select auditable events at the organization-defined Smart Grid information system components.

Supplemental Guidance

Audit records can be generated from various components within the Smart Grid information system.

Additional Considerations

1. The Smart Grid information system provides the capability to compile audit records from multiple components within the Smart Grid information system into a Smart Grid information system-wide audit trail that is time-correlated to within an organization-defined level of tolerance for relationship between time stamps of individual records in the audit trail.

Category

Common Technical Requirements, Integrity

Specification

Ensure the audit records are generated for specific auditable events as defined by authorized users.

Verification Results

Satisfactory if the specification explicitly states what or how the audit generation can be done in the proposed system. In other words, ESM and ePO, as the centralization of security management in proposed system, allow user to specify event to be monitored (as shown in SG.AU-6 and SG.AU-2). Moreover, both ESM and ePO have the ability to automatically generate the report (as shown in SG.AU-7).

A.2.13 Non-Repudiation (SG.AU-16)

Requirement

The Smart Grid information system protects against an individual falsely denying having performed a particular action.

Supplemental Guidance

Non-repudiation protects individuals against later claims by an author of not having authored a particular document, a sender of not having transmitted a message, a receiver of not having received a message, or a signatory of not having signed a document. Non-repudiation services are implemented using various techniques (e.g., digital signatures, digital message receipts, and logging).

Category

Unique Technical Requirements

Specification

ESM event monitoring coupled with log files will prevent individuals from falsely denying specific actions.

Verification Results

Satisfactory. Non-repudiation services are implemented using logging techniques (i.e., event monitoring and audit generation) in both ESM and ePO systems as shown in SG.AU-2, SG.AU-6, SG.AU-7, SG.AU-8 and SG.AU-9).

A.3 Security Assessment and Authorization (SG.CA)

Security assessments include monitoring and reviewing the performance of Smart Grid information system. Internal checking methods, such as compliance audits and incident investigations, allow the organization to determine the effectiveness of the security program. Finally, through continuous monitoring, the organization regularly reviews compliance of the Smart Grid information systems. If deviations or nonconformance exist, it may be necessary to revisit the original assumptions and implement appropriate corrective actions.

A.3.1 Smart Grid Information System Connections (SG.CA-4)

Requirement

The organization—

1. Authorizes all connections from the Smart Grid information system to other information systems;
2. Documents the Smart Grid information system connections and associated security requirements for each connection; and
3. Monitors the Smart Grid information system connections on an ongoing basis, verifying enforcement of documented security requirements.

Supplemental Guidance

The organization considers the risk that may be introduced when a Smart Grid information system is connected to other information systems, both internal and external to the organization, with different security requirements. Risk considerations also include Smart Grid information systems sharing the same networks.

Additional Considerations

1. All external Smart Grid information system and communication connections are identified and protected from tampering or damage.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

1. Any the information system on the platform requesting a service from any other information system, it be, server side or end point, is authenticated before establishing connection. Kerberos V5 protocol is used to authenticate end points systems for secure communication services and HTTPS with PKI is used to authenticate web server (EPO) and agent.
 - a. Every information system within the platform would need to be authorized to connect to an external system.
 - b. same as above
2. ESM is configured to monitor and record the start/stop/reset of the connections.
3. Information is available near real-time.

Verification Results

Satisfactory. Security Policy in ePO has the features to configure the authorization of all connection from the Smart Grid information system to other information systems (see SG.AC-4 and SG.AC-19). All of security policy is appeared in electronic form and can be printed as the document for audition. All allowed connection could be monitored via ESM (see SG.AU-6 and SG.AU-15).

A.3.2 Continuous Monitoring (SG.CA-6)

Requirement

The organization establishes a continuous monitoring strategy and implements a continuous monitoring program that includes:

1. Ongoing security requirements assessments in accordance with the organizational continuous monitoring strategy; and
2. Reporting the security state of the Smart Grid information system to management authority on an organization-defined frequency.

Supplemental Guidance

A continuous monitoring program allows an organization to maintain the security authorization to operate of a Smart Grid information system over time in a dynamic operational environment with changing threats, vulnerabilities, technologies, and missions/business processes.

The selection of an appropriate subset of security requirements for continuous monitoring is based on the impact level of the Smart Grid information system, the specific security requirements selected by the organization, and the level of assurance that the organization requires.

Additional Considerations

1. The organization employs an independent assessor or assessment team to monitor the security requirements in the Smart Grid information system on an ongoing basis;

2. The organization includes as part of security requirements continuous monitoring, periodic, unannounced, in-depth monitoring, penetration testing, and red team exercises; and
3. The organization uses automated support tools for continuous monitoring.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

1. ESM (automated tool) is the continuous monitoring tool on the platform.
2. Reporting the security state of the information system to management authority (in EPO) on a defined frequency.

Verification Results

Satisfactory. Ongoing security requirements assessments in accordance with the organizational continuous monitoring strategy can be defined in ESM, which is a tool for continuous monitoring (see SG.AU-15 and SG.AU-6). The security state of the Smart Grid information system for managing the authority can be reported by using ePO (see SG.AU-6).

A.4 Configuration and Management (SG.CM)

The organization's security program needs to implement policies and procedures that create a process by which the organization manages and documents all configuration changes to the Smart Grid information system. A comprehensive change management process needs to be implemented and used to ensure that only approved and tested changes are made to the Smart Grid information system configuration. Smart Grid information systems need to be configured properly to maintain optimal operation. Therefore, only tested and approved changes should be allowed on a Smart Grid information system. Vendor updates and patches need to be thoroughly tested on a non-production Smart Grid information system setup before being introduced into the production environment to ensure that no adverse effects occur.

A.4.1 Configuration Settings (SG.CM-6)

Requirement

The organization—

1. Establishes configuration settings for components within the Smart Grid information system;
2. Monitors and controls changes to the configuration settings in accordance with organizational policies and procedures;
3. Documents changed configuration settings;
4. Identifies, documents, and approves exceptions from the configuration settings; and
5. Enforces the configuration settings in all components of the Smart Grid information system.

Additional Considerations

1. The organization employs automated mechanisms to centrally manage, apply, and verify configuration settings;
2. The organization employs automated mechanisms to respond to unauthorized changes to configuration settings; and
3. The organization incorporates detection of unauthorized, security-relevant configuration changes into the organization's incident response capability to ensure that such detected events are tracked, monitored, corrected, and available for historical purposes.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

1. Configuration settings are defined in ePO policy
2. Monitoring of changes is managed via the policy definitions in the policy catalog on ePO.
 - a. NA - organizational policy
3. The policy compare functionality can be leveraged to determine what has changed.
 - a. NA - organizational policy
 - b. NA - organizational policy
 - c. NA - organizational policy
4. Enforcement of configuration settings in all components is tracked in ePO.

Verification Results

Satisfactory. The security policy for all components (as shown in the first figure) within the Smart Grid information system can be configured in ePO (see SG.AC-19). The policy changes can be monitored via the policy definitions in the policy catalog on ePO as shown in the second figure.

| System Tree | Systems | | | | | | |
|---------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------|---------------|---------------------------|----------------|---------------|---------------------|
| | Assigned Policies | Assigned Client Tasks | Group Details | Agent Deployment | | | |
| ▼ My Organization | Preset: This Group and All Subgroups ▼ Custom: None ▼ Quick find: <input type="text"/> <input type="button" value="Apply"/> <input type="button" value="Clear"/> <input type="checkbox"/> Show selected rows | | | | | | |
| Reese Tech Center | | | | | | | |
| ▼ TTU | | | | | | | |
| Security Management | | | | | | | |
| ► Lost&Found | | | | | | | |
| | <input type="checkbox"/> | System Name ▲ | Managed State | Tags | IP Address | User Name | Last Communication |
| | <input type="checkbox"/> | ACE-SF | Unmanaged | | | | |
| | <input type="checkbox"/> | DC-SF | Managed | Server | 129.118.26.37 | administrator | 5/29/14 4:29:17 PM |
| | <input type="checkbox"/> | EPO-SF | Managed | Server | 129.118.19.210 | administrator | 10/6/14 10:33:56 AM |
| | <input type="checkbox"/> | ESM-SF | Unmanaged | | | | |
| | <input type="checkbox"/> | Reese-SF | Managed | SFState_UnderAttack, Work | 129.118.105.50 | root | 6/5/14 4:29:38 AM |
| | <input type="checkbox"/> | TTU-SF | Managed | SFState_UnderAttack, Work | 129.118.26.8 | root | 7/29/14 2:30:46 PM |

Figure 20. Components controlled by Security Fabric Environment.

| Compare Policies | | |
|---------------------------------|--------------------------|---------------------------|
| Product: | McAfee Agent | Category: Repository |
| | | Show: All Policy Settings |
| Settings | Policy 1 | Policy 2 |
| Compare policies: | McAfee Default | My Default |
| Settings that are different: | --- | 3 |
| Settings that are identical: | --- | 25 |
| Policy Object Details | | |
| Assignment: | 1 | 1 |
| Owner: | Administrators | Administrators |
| Advanced | | |
| Find nearest method | 0 | 0 |
| Maximum Hop Limit | 15 | 15 |
| Maximum Ping Timeout | 30 | 30 |
| Override Client Sites | 1 | 1 |
| Internet Manager | | |
| Include Repositories by Default | 0 | 0 |
| Number of Disabled Sites | 0 | 0 |
| Number of Sitelist Order | 0 | 2 |
| Sitelist Order:0 | [Value does not exist] | ePO_EPO-SF |
| Sitelist Order:1 | [Value does not exist] | McAfeeHttp |
| Proxy Settings | | |
| Allow Bypass Local Address | 0 | 0 |

Figure 21. Policy comparison for tracking the changing of policy in ePO.

A.4.2 Configuration for Least Functionality (SG.CM-7)

Requirement

1. The organization configures the Smart Grid information system to provide only essential capabilities and specifically prohibits and/or restricts the use of functions, ports, protocols, and/or services as defined in an organizationally generated “prohibited and/or restricted” list; and
2. The organization reviews the Smart Grid information system on an organization-defined frequency or as deemed necessary to identify and restrict unnecessary functions, ports, protocols, and/or services.

Supplemental Guidance

The organization considers disabling unused or unnecessary physical and logical ports on Smart Grid information system components to prevent unauthorized connection of devices, and considers designing the overall system to enforce a policy of least functionality.

Category

Common Technical Requirements, Integrity

Specification

1. Firewall policy is defined in EPO. Configure policies to apply firewall rules on the systems for exposing only ports or protocols that are needed, and deny all others (therefore creating a default list of prohibited or restricted" resources.
 - a. Only capabilities specifically allowed by the firewall are exposed
 - b. All functionality not explicitly allowed is denied

Verification Results

Satisfactory. Firewall policy defined in ePO (as shown in Figure 6) can be configured to allow the organization providing only essential capabilities and specifically prohibits and/or restricts the use of functions, ports, protocols, and/or services as defined in an organizationally. All of the firewall policy can be viewed and modified in ePO system (see SG.AU-19).

A.4.3 Component Inventory (SG.CM-8)

Requirement

The organization develops, documents, and maintains an inventory of the components of the Smart Grid information system that—

1. Accurately reflects the current Smart Grid information system configuration;
2. Provides the proper level of granularity deemed necessary for tracking and reporting and for effective property accountability;
3. Identifies the roles responsible for component inventory;
4. Updates the inventory of system components as an integral part of component installations, system updates, and removals; and
5. Ensures that the location (logical and physical) of each component is included within the Smart Grid information system boundary.

Supplemental Guidance

The organization determines the appropriate level of granularity for any Smart Grid information system component included in the inventory that is subject to management control (e.g., tracking, reporting).

Additional Considerations

1. The organization updates the inventory of the information system components as an integral part of component installations and information system updates;
2. The organization employs automated mechanisms to maintain an up-to-date, complete, accurate, and readily available inventory of information system components; and
3. The organization employs automated mechanisms to detect the addition of unauthorized components or device into the environment and disables access by components or devices or notifies designated officials.

Category

Common Technical Requirements, Integrity

Specification

- 1. The inventory of (security) components/controls is tracked by ePO and regularly refreshed.
- 2. Installs, updates (and removals) modify the (security) inventory tracked on ePO.

Verification Results

Satisfactory. All agents, security components (i.e., Wind River Linux front-end), in security fabric system are listed, tracked and controlled in ePO system as shown in Figure 20 and Figure 22.

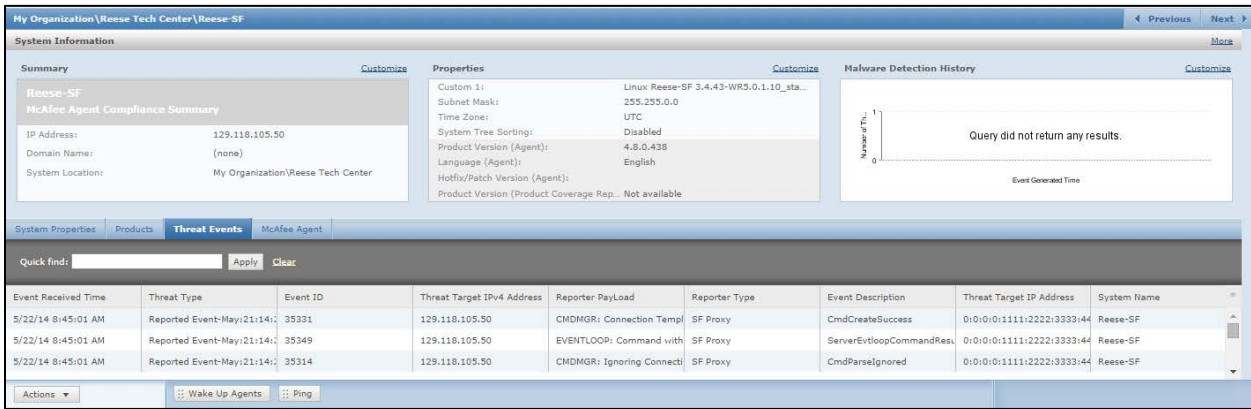


Figure 22. Status of controlled agent in ePO system.

A.5 Continuity of Operations (SG.CP)

Continuity of operations addresses the capability to continue or resume operations of a Smart Grid information system in the event of disruption of normal system operation. The ability for the Smart Grid information system to function after an event is dependent on implementing continuity of operations policies, procedures, training, and resources. The security requirements recommended under the continuity of operations family provide policies and procedures for roles and responsibilities, training, testing, plan updates, alternate storage sites, alternate command and control methods, alternate control centers, recovery and reconstitution and fail-safe response.

A.5.1 Smart Grid Information System Recovery and Reconstitution (SG.CP-10)

Requirement

The organization provides the capability to recover and reconstitute the Smart Grid information system to a known secure state after a disruption, compromise, or failure.

Supplemental Guidance

Smart Grid information system recovery and reconstitution to a known secure state means that—

1. All Smart Grid information system parameters (either default or organization-established) are set to secure values;
2. Security-critical patches are reinstalled;
3. Security-related configuration settings are reestablished;
4. Smart Grid information system documentation and operating procedures are available;
5. Application and Smart Grid information system software is reinstalled and configured with secure settings;
6. Information from the most recent, known secure backups is loaded; and
7. The Smart Grid information system is fully tested.

Requirement Enhancements

1. The organization provides compensating security controls (including procedures or mechanisms) for the organization-defined circumstances that inhibit recovery to a known, secure state; and
2. The organization provides the capability to reimage Smart Grid information system components in accordance with organization-defined restoration time periods from configuration-controlled and integrity-protected media images representing a secure, operational state for the components.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

1. Leveraging the virtualization capabilities, a compromised endpoint VM can simply be replaced to bring the device back to the original "clean" state.
2. The capability to reimage the information system is inherent in the platform's architecture

Verification Results

Satisfactory. The application modules (ePDC and RTDMS) in security fabric framework are deployed as the virtualization operating system on top of ESXi hypervisor component. Any disruption, compromise, or failure in the application modules can be recovered and reconstituted into the secure state (i.e., state that security administrator known that there is no failure in the system).

A.5.2 Fail-Safe Response (SG.CP-11)

Requirement

The Smart Grid information system has the ability to execute an appropriate fail-safe procedure upon the loss of communications with other Smart Grid information systems or the loss of the Smart Grid information system itself.

Supplemental Guidance

In the event of a loss of communication between the Smart Grid information system and the operational facilities, the on-site instrumentation needs to be capable of executing a procedure that provides the maximum protection to the controlled infrastructure. For the electric sector, this may be to alert the operator of the failure and then do nothing (i.e., let the electric grid continue to operate). The organization defines what “loss of communications” means (e.g., 5 seconds or 5 minutes without communications). The organization then defines the appropriate fail-safe process for its industry.

Additional Considerations

1. The Smart Grid information system preserves the organization-defined state information in failure.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

Upon loss of communications with other systems (especially the management system (ePO), monitoring system (ESM), and AAA system (Active Directory)), the endpoint continues to function in its last known good condition.

Loss of an entire endpoint node is remediated by deploying a new node with the same virtual instances

Verification Results

Satisfactory. Since the ePO and ESM, the central management and audition component in security fabric, are loosely coupled with the main communication components (entire endpoints, i.e., McAfee agent in Wind River Linux on ePDC and RTDMS), the loss of communications between control system (ePO and ESM) and communication node will cause less effect to smart grid information system. However, the event auditing in communication nodes might not be able to log in ESM and ePO.

In case of losing an entire endpoint, because of virtualization technique, security administrator can deploy the new node using the image from the previously known working states.

A.6 Identification and Authentication (SG.IA)

Identification and authentication is the process of verifying the identity of a user, process, or device, as a prerequisite for granting access to resources in a Smart Grid information system.

A.6.1 Authenticator Management (SG.IA-3)

Requirement

The organization manages Smart Grid information system authentication credentials for users and devices by—

1. Defining initial authentication credential content, such as defining password length and composition, tokens;
2. Establishing administrative procedures for initial authentication credential distribution; lost, compromised, or damaged authentication credentials; and revoking authentication credentials;
3. Changing/refreshing authentication credentials on an organization-defined frequency; and
4. Specifying measures to safeguard authentication credentials.

Supplemental Guidance

Measures to safeguard user authentication credentials include maintaining possession of individual authentication credentials, not loaning or sharing authentication credentials with others, and reporting lost or compromised authentication credentials immediately.

Additional Considerations

1. The organization employs automated tools to determine if authentication credentials are sufficiently strong to resist attacks intended to discover or otherwise compromise the authentication credentials; and
2. The organization requires unique authentication credentials be provided by vendors and manufacturers of Smart Grid information system components.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

In back-end management system, ePO, the credential (username/password) requirements can be defined to enforce minimum strength requirements.

On front-end systems, the M2M credentials for mutual authentication are implemented via Kerberos. Therefore, the tickets are well defined in KRB standards. In addition, the credentials (keys) for mutual authentication and encryption on the Security Communication Channel are implemented by distributing the public key of the endpoint Mgmt Instance back to ePO, signing the public key (thus a certificate is generated), registering the Machine principal with Kerberos (creating the keytab file), and returning all to the endpoint.

Initial credential distribution is supported in the commissioning/provisioning steps for the platform's endpoints (described in above).

In case of credential compromise, loss, damage, etc. the re-provisioning workflow will generate new credentials for the endpoints to ensure that the communications can continue.

Revoking M2M credentials on the endpoint can be implemented by removing the instance in question in Kerberos, and causing a new kinit to execute. This will force the connection attempt to fail, thus enforcing the credential revocation.

Revoking credentials in Active Directory/KRB, ePO and ESM is implemented by changing the login credentials (password) or locking the account.

However, the system can be leveraged to create scheduled tasks, such as refreshing the credentials on a recurring basis.

The authenticators are available on the server side systems which are locked down for public access. Only authenticated and authorized users can access them. The authenticators are neither shared nor communicated in any form over network, and are encrypted in the database on the server side (ePO). The default credentials are modified for security reasons after initial installation.

On the endpoint, the credentials (keys) are stored in secured folders (leveraging Access Control mechanisms in Wind River Linux) to secure the credentials.

Verification Results

Satisfactory. The authenticator management for user in ePO and ESM (see SG.AC-20) satisfies this requirement. For device to device, the proposed system uses the Kerberos as the authenticator. In case of lost, compromised, or damaged authentication credentials, the re-provisioning of credentials will generate new credentials for all endpoint to ensure that the communications are secure. The key management for device-to-device authentication in ePO is below.

The screenshot shows a window titled "Edit Security Keys" with a blue header. Below the header is a descriptive text: "Use the agent-server secure communication keys to protect communication between the ePO server and agents. Use the repository keys to sign and validate packages in the repositories." The window is divided into four main sections:

- Agent-server secure communication keys:** This section contains a list of keys with a scroll bar. The visible entries are:
 - EPO-SF (2,048 bits - i3oqsWGgiu70d+f89gC7P93qYfAZJrKoW9kHoYpHPH0=) - 4 agents - Master
 - EPO-SF (1,024 bits - QsiwC3HckuM+argcmgwu5VQIYIE=) - 0 agents - Master
 - Legacy (1,024 bits - HMW9L9yM2AbJY8qrvnNCNjPYXA=) - 0 agentsTo the right of the list are buttons: "New Key", "Delete", "Export", "Make Master", and "View Agents".
- Local master repository key pairs:** This section contains two entries, each with "Export Key Pair" and "Export Public Key" buttons:
 - EPO-SF (2,048 bits - LhUWNKJhyBGQ3uKr/WWbphNXKeNZh0Tg59tMKL/IFXk=)
 - EPO-SF (1,024 bits - 3/icZeYfFvjvrdBFXsLrxuFoVQE=)
- Other repository public keys:** This section contains a list of keys with a scroll bar. The visible entries are:
 - McAfee (2,048 bits - w+o9878uc1l8PtsKAxW6zP8J5huS4OSVKKtXe2XBVKI=)
 - McAfeeSIA (2,048 bits - Z7TIHcF5j+akkDwCGqanABMavX7uSBb7/NNxjB8Qyk=)
 - McAfee (1,024 bits - H7LGIPbRtARjG6MsNaop1QOFaU=)
 - McAfeeSIA (1,024 bits - F1HjTzscUsaIb27nQtAdoFh8RI=)To the right of the list are buttons: "Delete" and "Export".
- Import and back up keys:** This section contains three buttons: "Import", "Back Up All", and "Restore All".

Figure 23. Device-to-Device Key Management in ePO.

A.6.2 User Identification and Authentication (SG.IA-4)

Requirement

The Smart Grid information system uniquely identifies and authenticates users (or processes acting on behalf of users).

Additional Considerations

1. The Smart Grid information system uses multifactor authentication for—
 - a. Remote access to non-privileged accounts;
 - b. Local access to privileged accounts; and
 - c. Remote access to privileged accounts.

Category

Unique Technical Requirements

Specification

1. Users are identified by username/password credential mechanism on the back-end systems. The M2M software stack is identified/authenticated by KRB tickets.
2. Authentication of users is implemented using username/password credentials

The M2M software stack is authenticated using KRB tickets

Verification Results

Satisfactory. The remote access to privileged account on both ESM and ePO uses the username/password authentication (see Table 1 in SG.AC-4) as the identification and authentication. For machine-to-machine communication, the Kerberos technique is used for identifying and authenticating machines to establish the connection among them (see Figure 23 in SG.IA-3).

A.6.3 Device Identification and Authentication (SG.IA-5)

Requirement

The Smart Grid information system uniquely identifies and authenticates an organization-defined list of devices before establishing a connection.

Supplemental Guidance

The devices requiring unique identification and authentication may be defined by type, by specific device, or by a combination of type and device as deemed appropriate by the organization.

Requirement Enhancements

1. The Smart Grid information system authenticates devices before establishing remote network connections using bidirectional authentication between devices that is cryptographically based; and
2. The Smart Grid information system authenticates devices before establishing network connections using bidirectional authentication between devices that is cryptographically based.

Category

Unique Technical Requirements

Specification

1. The organization **MUST** define the list of devices for which identification and authorization is required before establishing a connection in this platform. Otherwise, the connections will be denied. This applies to all M2M communications as well as any other communications, including, but not limited to the Security Channel, data channels, etc. (e.g. NTP, DB connections, etc)
2. The SF device must uniquely identify an organization-defined device using KRB protocol before establishing a connection.
3. The SF device must authenticate an organization-defined device using KRB protocol before establishing a connection.

The device connections are established only after they are authenticated by Kerberos.

Verification Results

Satisfactory. The identification and authentication of devices in the proposed system are managed in the ePO system (see SG.CM-6 and SG.CM-8). The communication among end-points (device nodes) uses the Kerberos protocol for identification and authentication (see Figure 23 in SG.IA-3).

A.6.4 Authenticator Feedback (SG.IA-6)

Requirement

The authentication mechanisms in the Smart Grid information system obscure feedback of authentication information during the authentication process to protect the information from possible exploitation/use by unauthorized individuals.

Supplemental Guidance

The Smart Grid information system obscures feedback of authentication information during the authentication process (e.g., displaying asterisks when a user types in a password). The feedback from the Smart Grid information system does not provide information that would allow an unauthorized user to compromise the authentication mechanism.

Category

Unique Technical Requirements

Specification

Masked passwords - The authentication process does not exchange the secrets that identify a user over the Internet in a clear text format. An encrypted session is established and only then the username/password is exchanged. The password entered by the user on the user interface is always obscure.

On invalid entry of the username or password, the server throws a generic message which doesn't indicate the reason of the access failure.

Verification Results

Satisfactory. Both ESM and ePO components use masked passwords technique (i.e., displaying asterisks when a user types in a password for logging to the system) to obscure feedback of authentication information during the authentication process. The next two figures show the application of masked passwords for both systems. The feedback from the Smart Grid information system does not provide information that would allow an unauthorized user to compromise the authentication mechanism.

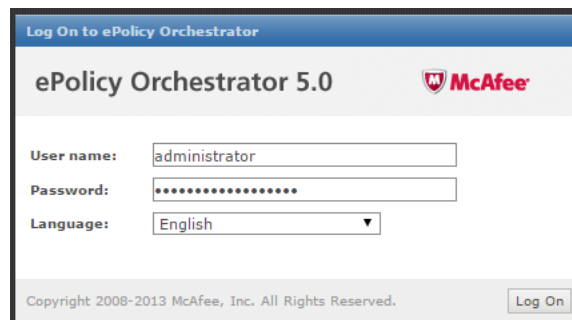


Figure 24. Masked password in ePO system.



Figure 25. Masked password in ESM system.

A.7 Incident Response (SG.IR)

Incident response addresses the capability to continue or resume operations of a Smart Grid information system in the event of disruption of normal Smart Grid information system operation. Incident response entails the preparation, testing, and maintenance of specific policies and procedures to enable the organization to recover the Smart Grid information system's operational status after the occurrence of a disruption. Disruptions can come from natural disasters, such as earthquakes, tornados, floods, or from manmade events like riots, terrorism, or vandalism. The ability for the Smart Grid information system to function after such an event is directly dependent on implementing policies, procedures, training, and resources in place ahead of time using the organization's planning process. The security requirements recommended under the incident response family provide policies and procedures for incident response monitoring, handling, reporting, testing, training, recovery, and reconstitution of the Smart Grid information systems for an organization.

A.7.1 Incident Monitoring (SG.IR-6)

Requirement

The organization tracks and documents Smart Grid information system and network security incidents.

Additional Considerations

1. The organization employs automated mechanisms to assist in the tracking of security incidents and in the collection and analysis of incident information.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

1. Both endpoint and network security incidents are tracked in ESM and/or ePO
2. Records of the incidents can be found in ESM

Verification Results

Satisfactory. The security incidents (described in ePO and ESM event specifications shown in SG.AU-2) can be tracked in the proposed systems (as shown in Figure 11 and Figure 12 in SG.AU-2).

A.8 Smart Grid Information System Development and Maintenance (SG.MA)

Security is most effective when it is designed into the Smart Grid information system and sustained, through effective maintenance, throughout the life cycle of the Smart Grid information system. Maintenance activities encompass appropriate policies and procedures for performing routine and preventive maintenance on the components of a Smart Grid information system. This includes the use of both local and remote maintenance tools and management of maintenance personnel.

A.8.1 Legacy Smart Grid Information System Upgrades (SG.MA-2) – Update Specification

Requirement

The organization develops policies and procedures to upgrade existing legacy Smart Grid information systems to include security mitigating measures commensurate with the organization's risk tolerance and the risk to the Smart Grid information system.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

1. This is the definition of the Security Fabric. The organization develops policies to upgrade legacy systems to the SF platform without affecting the legacy applications.
2. Establish policies for security measures and mitigating controls as per the organization's risk tolerance combined with the risk to the system.

Verification Results

Satisfactory if the specification describes techniques related to virtualization of applications and security manager. The proposed system uses the virtualization technique, which separates security management from the application (i.e., legacy smart grid information system). By applying this technique, the organization can develop (or upgrade) security policy and procedures without affecting the legacy system.

A.8.2 Remote Maintenance (SG.MA-2)

Requirement

The organization policy and procedures for remote maintenance include:

1. Authorization and monitoring the use of remote maintenance and diagnostic activities;
2. Use of remote maintenance and diagnostic tools;
3. Maintenance records for remote maintenance and diagnostic activities;
4. Termination of all remote maintenance sessions; and
5. Management of authorization credentials used during remote maintenance.

Requirement Enhancements

The organization—

1. Requires that remote maintenance or diagnostic services be performed from an information system that implements a level of security at least as high as that implemented on the Smart Grid information system being serviced; or
2. Removes the component to be serviced from the Smart Grid information system and prior to remote maintenance or diagnostic services, sanitizes the component (with regard to organizational information) before removal from organizational facilities and after the service is performed, sanitizes the component (with regard to potentially malicious software) before returning the component to the Smart Grid information system.

Additional Considerations

1. The organization requires that remote maintenance sessions are protected through the use of a strong authentication credential; and
2. The organization requires that (a) maintenance personnel notify the Smart Grid information system administrator when remote maintenance is planned (e.g., date/time), and (b) a management authority approves the remote maintenance.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

1. Authorization and monitoring are available for all Security Fabric Nodes/Endpoints being maintained. This is performed via the ePO Security/Management Communication Channel.
2. Remote maintenance and diagnostics are enabled for all Security Fabric Nodes/Endpoints. This is performed via the ePO Security/Management Communication Channel.
3. NA - Organizational Policy

4. Termination of all remote maintenance sessions is automatically performed by the agents that communicate from the endpoint back to the ePO server. This is performed via the ePO Security/Management Communication Channel.
5. The credentials for remote maintenance are automatically managed by ePO and the endpoint agent.
6. The maintenance and diagnostics operations are initiated and controlled by ePO, which has an enhanced level of security, at least equal to the endpoint's.
7. NA - Organizational policy. However, verifying the integrity of the device using a measured boot process as well as remote authentication ensures sanitized devices. Also, application whitelisting ensures that no additional software has been placed on the device, further ensuring the device is sanitized.

Verification Results

Satisfactory. Remote maintenance for the devices deployed the proposed system can be done in the ePO system (see SG.CM-6 and SG.CM-8), which requires authentication for maintainer (see SG.AC-4).

A.9 Risk Assessment (SG.RA)

Risk management planning is a key aspect of ensuring that the processes and technical means of securing Smart Grid information systems have fully addressed the risks and vulnerabilities in the Smart Grid information system.

An organization identifies and classifies risks to develop appropriate security measures. Risk identification and classification involves security assessments of Smart Grid information systems and interconnections to identify critical components and any areas weak in security. The risk identification and classification process is continually performed to monitor the Smart Grid information system's compliance status.

A.9.1 Risk Assessment (SG.RA-4)

Requirement

The organization—

1. Conducts assessments of risk from the unauthorized access, use, disclosure, disruption, modification, or destruction of information and Smart Grid information systems; and
2. Updates risk assessments on an organization-defined frequency or whenever significant changes occur to the Smart Grid information system or environment of operation, or other conditions that may impact the security of the Smart Grid information system.

Supplemental Guidance

Risk assessments take into account vulnerabilities, threat sources, risk tolerance levels, and security mechanisms planned or in place to determine the resulting level of residual risk posed to

organizational operations, organizational assets, or individuals based on the operation of the Smart Grid information system.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

The following capabilities are enabled by leveraging the ESM's security event gathering and log file gathering tools:

- Monitoring the logins to the endpoint management instance and access attempts to protected data sets (e.g. configuration files)
- Monitor outgoing connections from the Application that must be blocked from the Management instance
- Monitor for DOS attacks on management instance network interfaces
- Monitoring the protected data sets (e.g. configuration files)
- Monitoring the protected data sets (e.g. configuration files)

The Security Fabric tracks the risk of endpoints and the connections between them in near real-time using the ESM.

Verification Results

Satisfactory. The risk assessments for this proposed system are described in automatic response feature in both ESM and ePO. However, a security administrator need to know where or what the risk is in the smart grid information system in order to provide the counter-measure to mitigate those risk (see Figure 10 in SG.AU-2). For example, the connection from brute-force attempt logging to the system from attackers can be suspend by using the automatic response provided by security administrator.

A.9.2 Vulnerability Assessment and Awareness (SG.RA-6)

Requirement

The organization—

1. Monitors and evaluates the Smart Grid information system according to the risk management plan on an organization-defined frequency to identify vulnerabilities that might affect the security of a Smart Grid information system;
2. Analyzes vulnerability scan reports and remediates vulnerabilities within an organization-defined time frame based on an assessment of risk;

3. Shares information obtained from the vulnerability scanning process with designated personnel throughout the organization to help eliminate similar vulnerabilities in other Smart Grid information systems;
4. Updates the Smart Grid information system to address any identified vulnerabilities in accordance with organization's Smart Grid information system maintenance policy; and
5. Updates the list of Smart Grid information system vulnerabilities on an organization-defined frequency or when new vulnerabilities are identified and reported.

Supplemental Guidance

Vulnerability analysis for custom software and applications may require additional, more specialized approaches (e.g., vulnerability scanning tools to scan for Web-based vulnerabilities, source code reviews, and static analysis of source code). Vulnerability scanning includes scanning for ports, protocols, and services that should not be accessible to users and for improperly configured or incorrectly operating information flow mechanisms.

Requirement Enhancements

1. The organization employs vulnerability scanning tools that include the capability to update the list of Smart Grid information system vulnerabilities scanned; and
2. The organization includes privileged access authorization to organization-defined Smart Grid information system components for selected vulnerability scanning activities to facilitate more thorough scanning.

Additional Considerations

1. The organization employs automated mechanisms on an organization-defined frequency to detect the presence of unauthorized software on organizational Smart Grid information systems and notifies designated organizational officials;
2. The organization performs security testing to determine the level of difficulty in circumventing the security requirements of the Smart Grid information system; and
3. The organization employs automated mechanisms to compare the results of vulnerability scans over time to determine trends in Smart Grid information system vulnerabilities.

Category

Common Governance, Risk, and Compliance (GRC)

Specification

Applies to Security Fabric with presence of automated vulnerability scans (NOTE: requires a vulnerability detection engine that feeds into ESM, such as McAfee Vulnerability Manager Product. This is not currently bundled in security Fabric.)

Applies to Security Fabric with presence of Automated Patch Management systems such as McAfee Remediation Manager. This is not currently bundled in security Fabric.

Leverage ePO update mechanism to update security controls to protect against detected vulnerabilities

Applies to Security Fabric with presence of Automated vulnerability scans where the vulnerability results are stored in centralized systems such as ESM and ePO (NOTE: requires a vulnerability detection engine that feeds into ESM, such as McAfee Vulnerability Manager product. This is not currently bundled in security Fabric.)

Verification Results

Issue Identified – need additional tool. Vulnerability analysis for custom software and applications is currently not included in the SF system. If the Vulnerability Analysis was included, then the specification would have been testable and likely satisfied.

A.10 Smart Grid Information System and Communication Protection (SG.SC)

Smart Grid information system and communication protection consists of steps taken to protect the Smart Grid information system and the communication links between Smart Grid information system components from cyber intrusions. Although Smart Grid information system and communication protection might include both physical and cyber protection, this section addresses only cyber protection. Physical protection is addressed in SG.PE, Physical and Environmental Security.

A.10.1 Communications Partitioning (SG.SC-2)

Requirement

The Smart Grid information system partitions the communications for telemetry/data acquisition services and management functionality.

Supplemental Guidance

The Smart Grid information system management communications path needs to be physically or logically separated from the telemetry/data acquisition services communications path.

Category

Unique Technical Requirements

Specification

The Smart Grid information system management communications path needs to be physically or logically separated from the telemetry/data acquisition services communications path.

Verification Results

Satisfactory if the specification describes how the security management communications are separated from functional communication. The proposed system separates the security management communication (e.g., event logging/monitoring, device-node management) from the functional communication (e.g., smart-grid information exchange between ePDC and RTDMS) by using the security management modules (i.e., Wind River Linux as security patching on Hypervisor component in Security Fabric Framework) to manage the communication channel for both security management and smart-grid communications.

A.10.2 Security Function Isolation (SG.SC-3)

Requirement

The Smart Grid information system isolates security functions from non-security functions.

Additional Considerations

1. The Smart Grid information system employs underlying hardware separation mechanisms to facilitate security function isolation; and
2. The Smart Grid information system isolates security functions (e.g., functions enforcing access and information flow control) from both non-security functions and from other security functions.

Category

Unique Technical Requirements

Specification

EPO provides the framework to define policies independent of each other. A particular policy can also be individually applied to a system or group of systems. This way it allows separation of security and non-security functions.

Leverage virtualization technology to create separation between OT and IT workloads. Also separation of network resources, storage resources, and peripheral resources.

Verification Results

Satisfactory. The proposed system isolates security functions from non-security functions by using the virtualization techniques on the hardware that supports ESXi Hypervisor¹.

¹ <http://www.vmware.com/products/vsphere-hypervisor>

A.10.3 Information Remnants (SG.SC-4)

Requirement

The Smart Grid information system prevents unauthorized or unintended information transfer via shared Smart Grid information system resources.

Supplemental Guidance

Control of Smart Grid information system remnants, sometimes referred to as object reuse, or data remnants, prevents information from being available to any current user/role/process that obtains access to a shared Smart Grid information system resource after that resource has been released back to the Smart Grid information system.

Category

Unique Technical Requirements

Specification

For inter-process communication or access to shared resources, the hypervisor and separation kernel prevent unauthorized access to the data.

EPO policies allow only communication between its managed nodes. Any unidentified (remnant) node which wouldn't be managed in EPO would never be able to exchange information with any managed node in the platform. Any unauthorized node within managed nodes (remnant) will not be able to interrupt or communicate with active nodes as the policy would not be set for such a node.

Verification Results

Satisfactory. Since the security modules (Wind River Linux) cover managed nodes (i.e., ePDC and RTDMS), any unidentified nodes cannot access the data inside the managed nodes without authentication. The communications among managed nodes are encrypted using public-key infrastructure and specified in ePO. Unauthorized nodes cannot retrieve the information from the secured communication channel.

A.10.4 Denial-of-Service Protection (SG.SC-5)

Requirement

The Smart Grid information system mitigates or limits the effects of denial-of-service attacks based on an organization-defined list of denial-of-service attacks.

Supplemental Guidance

Network perimeter devices can filter certain types of packets to protect devices on an organization's internal network from being directly affected by denial-of-service attacks.

Additional Considerations

1. The Smart Grid information system restricts the ability of users to launch denial-of-service attacks against other Smart Grid information systems or networks; and
2. The Smart Grid information system manages excess capacity, bandwidth, or other redundancy to limit the effects of information flooding types of denial-of-service attacks.

Category

Unique Technical Requirements

Specification

Firewall rules have been setup both on the end-point and server side. All the well-known DOS attacks will be filtered by the firewall and would protect the assets. ESM has been built into the security platform which raises alarms on suspicious activities like zero day DOS escaping firewall allowing immediate action to be taken.

Monitor FW protects internal DOS attacks between instances (in VM)

Firewall also prevents any outgoing data from the end-point node which prevents the DOS attack coming from inside the trusted network.

PROVIDE Firewall instance TO LIMIT ACCESS TO SERVER INSTANCES (ePO, ESM, ACE, AND AD)

On the device, the separation kernel prevents one instance from utilizing the resources of another instance, so resource exhaustion cannot occur.

Verification Results

The proposed system can be prevented or mitigated the effected of known (organization defined-list) DoS by using firewall (see SG.AC-5).

A.10.5 Resource Priority (SG.SC-6)

Requirement

The Smart Grid information system prioritizes the use of resources.

Supplemental Guidance

Priority protection helps prevent a lower-priority process from delaying or interfering with the Smart Grid information system servicing any higher-priority process. This requirement does not apply to components in the Smart Grid information system for which only a single user/role exists.

Category

Unique Technical Requirements

Specification

Priority protection helps prevent a lower-priority process from delaying or interfering with the Smart Grid information system servicing any higher-priority process. This requirement does not apply to components in the Smart Grid information system for which only a single user/role exists.

The lower priority security process cannot interfere with the higher priority Grid process due to the separation kernel. All processes between OT (operational/Grid) are separated from the IT (Security) processes. The IT-side is assumed to be running the low priority security processes, leaving the high priority OT processes running in the Application VM.

Availability is ensured for the OT-side.

Verification Results

Satisfactory. Both functional components (ePDC and RTDMS) and security components (McAfee Agent) are deployed in the same hardware using the virtualization technique. The ESXi hypervisor can set priority for each virtualization modules as shown in the document² of resource management guideline for ESXi version 5.0.

A.10.6 Boundary Protection (SG.SC-7)

Requirement

1. The organization defines the boundary of the Smart Grid information system;
2. The Smart Grid information system monitors and controls communications at the external boundary of the system and at key internal boundaries within the system;
3. The Smart Grid information system connects to external networks or information systems only through managed interfaces consisting of boundary protection devices;

² <https://pubs.vmware.com/vsphere-50/topic/com.vmware.ICbase/PDF/vsphere-esxi-vcenter-server-50-resource-management-guide.pdf>.

4. The managed interface implements security measures appropriate for the protection of integrity and confidentiality of the transmitted information; and
5. The organization prevents public access into the organization's internal Smart Grid information system networks except as appropriately mediated.

Supplemental Guidance

Managed interfaces employing boundary protection devices include proxies, gateways, routers, firewalls, guards, or encrypted tunnels.

Requirement Enhancements

1. The Smart Grid information system denies network traffic by default and allows network traffic by exception (i.e., deny all, permit by exception);
2. The Smart Grid information system checks incoming communications to ensure that the communications are coming from an authorized source and routed to an authorized destination; and
3. Communications to/from Smart Grid information system components shall be restricted to specific components in the Smart Grid information system. Communications shall not be permitted to/from any non-Smart Grid system unless separated by a controlled logical/physical interface.

Additional Considerations

1. The organization prevents the unauthorized release of information outside the Smart Grid information system boundary or any unauthorized communication through the Smart Grid information system boundary when an operational failure occurs of the boundary protection mechanisms;
2. The organization prevents the unauthorized exfiltration of information across managed interfaces;
3. The Smart Grid information system routes internal communications traffic to the Internet through authenticated proxy servers within the managed interfaces of boundary protection devices;
4. The organization limits the number of access points to the Smart Grid information system to allow for better monitoring of inbound and outbound network traffic;
5. Smart Grid information system boundary protections at any designated alternate processing/control sites provide the same levels of protection as that of the primary site; and
6. The Smart Grid information system fails securely in the event of an operational failure of a boundary protection device.

Category

Unique Technical Requirements

Specification

1. Boundary is created on each end node by implementing the Separation Kernel. That separates IT/OT and places a security boundary in between the OT and everything outside of the device. There is now a device boundary being enforced.
2. Define the Boundary of the system:
 - a. WRL Management instance that separates the OT from the outside of the device between nodes and other external devices
 - b. VxWorks Monitor that separates the OT from the WRL instanceSystem monitors and controls both boundaries using policy (from ePO). ESM monitors the boundaries by collecting events from WRL and VxWorks instances. EPO manages all the nodes under the security fabric platform configuring the boundary between other nodes and other devices. ESM monitors the events detected on each of these boundaries.
3. Define managed interfaces consisting of boundary protection devices: firewalls in WRL and VxWorks. All traffic going external to the device must pass through the WRL firewall. All traffic moving from instance to instance (inside the device) must pass through the VxWorks monitor firewall. No traffic shall traverse any boundary that is not specifically allowed.
4. The WRL boundary creates an encrypted, mutually authenticated tunnel to pass all data between nodes. All communication between nodes and ePO are encrypted, as is all data passed between nodes and ESM. Kerberos tickets and communication are not encrypted, however, the tickets themselves are already double-encrypted, so the communication channel encryption is not required. The VxWorks boundary is internal to the device, so it cannot be accessed externally, thus no encryption is required between the VM instances.
5. Public access is prevented by the WRL instance blocking unmediated communications from occurring.

Verification Results

Satisfactory. The proposed system defines the boundary of the system by using the functional of operation: (1) *internal-boundary*: domain-specific application (ePDC and RTDMS) and (2) *external-boundary*: security management application (security components). All communications in the proposed system can be monitored and controlled by external boundary components (see SG.AU-2). All communication between internal-boundary parts are encrypted and enforced by the security policy (e.g., firewall rules) from external-boundary parts (see SG.AC-5 and SG.AC-19).

A.10.7 Communication Integrity (SG.SC-8)

Requirement

The Smart Grid information system protects the integrity of electronically communicated information.

Requirement Enhancements

1. The organization employs cryptographic mechanisms to ensure integrity.

Additional Considerations

1. The Smart Grid information system maintains the integrity of information during aggregation, packaging, and transformation in preparation for transmission.

Category

Unique Technical Requirements

Specification

The communication integrity between server-side (EPO/ESM) and end-point systems (WRL) is ensured by HTTPS sessions. The communication integrity between end-point systems is established with Kerberos authenticating the systems themselves and the information being exchanged over TLS (Transport Layer Security).

All the communications happen over TCP which ensures base integrity of package delivery to application.

Communications between McAfee Agent (in WRL) and ePO are signed for integrity.

Verification Results

Satisfactory. The proposed system supports the protocols that guarantee the integrity of information as shown below.

| Communication Pair | | Protocol |
|---------------------------|---------|-----------------|
| User | ESM/ePO | HTTPS |
| ESM/ePO | WRL | HTTPS |
| WRL | WRL | TLS |

Table 3. Communication Protocol among components in SF.

A.10.8 Communication Confidentiality (SG.SC-9)

Requirement

The Smart Grid information system protects the confidentiality of communicated information.

Requirement Enhancements

1. The organization employs cryptographic mechanisms to prevent unauthorized disclosure of information during transmission.

Category

Unique Technical Requirements

Specification

Any sort of information exchange between systems in security platform is over TLS (Transport Layer Security) which ensures the confidentiality.

Verification Results

Satisfactory. The proposed system supports the protocols that guarantee the confidentiality of information as shown in Table 3 in SG.SC-8.

A.10.9 Trusted Path (SG.SC-10)

Requirement

The Smart Grid information system establishes a trusted communications path between the user and the Smart Grid information system.

Supplemental Guidance

A trusted path is the means by which a user and target of evaluation security functionality can communicate with the necessary confidence.

Category

Unique Technical Requirements

Specification

The only means by which the user interacts with end-point systems is via EPO and ESM. This interaction happens over HTTPS sessions and is secured.

Note: SSH port is open on end-point systems which provides another means of interacting but this port will be closed in the future. At this point, the SSH communication is also over the SSL and is secure.

The trusted communications path is tracked in ePO.

Verification Results

Satisfactory. The communication between users and the security functionality of the proposed system (ePO and ESM) uses the secured protocol (i.e., HTTPS) as shown in Table 1 in SG.AC-5.

A.10.10 Cryptographic Key Establishment and Management (SG.SC-11)

Requirement

The organization establishes and manages cryptographic keys for required cryptography employed within the information system.

Supplemental Guidance

Key establishment includes a key generation process in accordance with a specified algorithm and key sizes, and key sizes based on an assigned standard. Key generation must be performed using an appropriate random number generator. The policies for key management need to address such items as periodic key changes, key destruction, and key distribution.

Requirement Enhancements

1. The organization maintains availability of information in the event of the loss of cryptographic keys by users.

Category

Common Technical Requirements, Confidentiality

Specification

- Keys: (1) McAfee Agent Key & Cert (2) Kerberos Key (3) ePO Certificate (4) ESM Certificate (5) AD Certificate
- Provisioning: MA creates X501 Key Pair, sends to ePO for signing (generates certificate), ePO creates Machine principal in AD, generates Kerberos key pair and AD certificate, returns all to the WRL on the node.
- Random number generator leverages Intel hardware.
- Keys are changed regularly on a schedule every year by implementing the expiration on the certificate, and to update the key, simply re-run the provisioning.
- Key Distribution is automated through ePO.
- Key Destruction does not required CRL, rather a node is deprovisioned by removing Kerberos entry.
- Keys will be generated and stored in the TPM in the future.
- Destruction is implemented by generating a new key (in TPM)
- Cryptographic keys are not managed by users

Verification Results

Satisfactory. The proposed system establishes and manages the cryptographic keys that require for cryptography function within the information system. Part of key management in the proposed system is shown as Figure 23 in SG.IA-4.

A.10.11 Use of Validated Cryptography (SG.SC-12)

Requirement

All of the cryptography and other security functions (e.g., hashes, random number generators, etc.) that are required for use in a Smart Grid information system shall be NIST Federal Information Processing Standard (FIPS) approved or allowed for use in FIPS modes.

Supplemental Guidance

For a list of current FIPS-approved or allowed cryptography, see Chapter Four Cryptography and Key Management in NIST IR-7628.

Category

Common Technical Requirements, Confidentiality

Specification

All of the cryptography and other security functions (e.g., hashes, random number generators, etc.) that are required for use in a Smart Grid information system are NIST Federal Information Processing Standard (FIPS) approved or allowed for use in FIPS modes.

Crypto Libs:

- OpenSSL for ePO & ESM
- OpenSSL for TLS connections device-to-device
- OpenSSH for connection to Mgmt VM (will be removed in future)
- Active Directory for Key Generation (Kerberos)
- ePO key generation (in Java) using standard libs (and cert signing)

Verification Results

Satisfactory. From the McAfee Enterprise Security Manager (ESM) version 9.3.0 Product Guide³, ESM component supports FIPS 140-2 but the user of ESM must select the FIPS mode as the first time log on to the system and the selection is permanent. The current deployed system did not enable FIPS mode.

The table below shows the validation FIPS for both ePO and McAfee Agent. For more detail about FIPS-compliant see <https://kc.mcafee.com/corporate/index?page=content&id=KB75739>.

| Component | Validation Link |
|--------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| ePO | http://csrc.nist.gov/groups/STM/cmvp/documents/140-1/1401val2011.htm#1587 |
| McAfee Agent | http://csrc.nist.gov/groups/STM/cmvp/documents/140-1/1401val2011.htm#1588 |

Table 4. FIPS-compliant for ePO and McAfee Agent.

A.10.12 Public Key Infrastructure Certificates (SG.SC-15)

Requirement

For Smart Grid information systems that implement a public key infrastructure, the organization issues public key certificates under an appropriate certificate policy or obtains public key certificates under an appropriate certificate policy from an approved service provider.

Supplemental Guidance

Registration to receive a public key certificate needs to include authorization by a supervisor or a responsible official and needs to be accomplished using a secure process that verifies the identity of the certificate holder and ensures that the certificate is issued to the intended party.

Category

Common Technical Requirements, Confidentiality

Specification

Security Fabric uses certificates, generates certs, validates the certificates, but also not enforce any rules on the CA so that self-signed certs can be leveraged if needed (depends on the list of "approved" service providers... is the entity itself "approved"?).

³

https://kc.mcafee.com/resources/sites/MCAFEE/content/live/PRODUCT_DOCUMENTATION/24000/PD24719/en_US/esm_930_product%20guide_en-us.pdf

Verification Results

Satisfactory. McAfee agent creates X509 key pair and sends to public key information to ePO for signing (creating certificate). The ePO component also creates McAfee agent principal in active directory, generates key pair, active directory certificate, and then returns all certificates to McAfee agents. The approved CA in this proposed system is ePO component.

A.10.13 System Connections (SG.SC-18)

Requirement

All external Smart Grid information system and communication connections are identified and protected from tampering or damage.

Supplemental Guidance

External access point connections to the Smart Grid information system need to be secured to protect the Smart Grid information system. Access points include any externally connected communication end point (for example, dial-up modems).

Category

Common Technical Requirements, Confidentiality

Specification

1. All connections must pass through the Management Firewall, and the Monitor Firewall.
2. All tunneled data must pass through the Communication Manager else be blocked.

Verification Results

Satisfactory. The external smart grid information system in this proposed system is the McAfee Agent. All communications among the McAfee Agents are defined in ePO (see SG.AC-5) and secured by using TLS protocol (as shown in Table 3 in SG.SC-8).

A.10.14 Security Roles (SG.SC-19)

Requirement

The Smart Grid information system design and implementation specifies the security roles and responsibilities for the users of the Smart Grid information system.

Supplemental Guidance

Security roles and responsibilities for Smart Grid information system users need to be specified, defined, and implemented based on the sensitivity of the information handled by the user. These roles may be defined for specific job descriptions or for individuals.

Category

Common Technical Requirements, Integrity

Specification

EPO provides the framework to create security roles on the server side providing separation of duties. Different accounts can be setup in EPO to perform different administrative tasks. Also no console access will be enabled on the end point (WRL) for any user. Any administrative task to be performed on the end-point will be performed from EPO.

Currently there is an SSH listener on the endpoint, this will go away in the future, thereby denying any type of login to the Mgmt VM. Therefore, there are no roles, or users on that VM and all operations must be performed in ePO.

The platform ships with one role configured: Administrator. The user at any point can create additional roles on the fly in EPO to limit the duties of different users to various assets and resources. One role is provided out-of-the-box, and the end-user is responsible for defining the actual roles required to correctly, and securely, manage the devices. The actual roles are deployment-dependent.

Verification Results

Satisfactory. The proposed system specifies the security role as “Administrator”, which is responsible for (1) creating different users to manage various assets and resources (delegate administrative task to different users) (2) performing administrative task on ePO component.

A.10.15 Message Authenticity (SG.SC-20)

Requirement

The Smart Grid information system provides mechanisms to protect the authenticity of device-to-device communications.

Supplemental Guidance

Message authentication provides protection from malformed traffic, misconfigured devices, and malicious entities.

Additional Considerations

Message authentication mechanisms should be implemented at the protocol level for both serial and routable protocols.

Category

Common Technical Requirements, Integrity

Specification

On the end point side, Kerberos V5 is used for authenticating device-to-device communication on the security fabric platform. Kerberos ensures strong authentication as it doesn't exchange the secrets over the wire. Once authenticated, the M2M communication is sent via encrypted tunnels, thereby verifying the message authenticity over the wire.

Further, the communications between ePO and the Agent are signed. These cannot be altered in any way without detection.

Server side systems (EPO/ESM) authenticate the user with username/password mechanism and authenticate devices with PKI. EPO/ESM systems communicate over SSL ensuring that the information is encrypted over Internet and sort of provide out of band secure communication.

Device-to-ESM (secure syslog data) is over encrypted tunnels.

Other connections, for example, NTP traffic, are also sent via encrypted tunnels using the M2M communication path (TLS).

Verification Results

Satisfactory. The authenticity of device-to-device communication in the proposed system has the protection as shown below.

| Device-To-Device | Protected By |
|-----------------------------|---------------------|
| McAfee Agent – McAfee Agent | Kerberos V5 |
| ePO – McAfee Agent | HTTPS |
| ESM – ePO | SSL |
| ESM – McAfee Agent | TLS |

Table 5. Protocol for protecting message authenticity of device-to-device communication.

A.10.16 Secure Name/Address Resolution Service (SG.SC-21)

Requirement

The organization is responsible for—

1. Configuring systems that provide name/address resolution to supply additional data origin and integrity artifacts along with the authoritative data returned in response to resolution queries; and
2. Configuring systems that provide name/address resolution to Smart Grid information systems, when operating as part of a distributed, hierarchical namespace, to provide the means to indicate the security status of child subspaces and, if the child supports secure resolution services, enabled verification of a chain of trust among parent and child domains.

Category

Common Technical Requirements, Integrity

Specification

DNS is not leveraged in the security Fabric

Verification Results

Issue Identified – deemed not applicable. The specification and the proposed system do not appear to support the requirements. It is recommended that this requirement category and the specification be removed.

A.10.17 Fail in Known State (SG.SC-22) – Incomplete information

Requirement

The Smart Grid information system fails to a known state for defined failures.

Supplemental Guidance

Failure in a known state can be interpreted by organizations in the context of safety or security in accordance with the organization's mission/business/operational needs. Failure in a known secure state helps prevent a loss of confidentiality, integrity, or availability in the event of a failure of the Smart Grid information system or a component of the Smart Grid information system.

Additional Considerations

1. The Smart Grid information system preserves defined system state information in failure.

Category

Common Technical Requirements, Integrity

Specification

In the case of a failure, the system will maintain the current policy definitions.

Verification Results

Issue Identified – specification needs definition. The system specification must define the (known/anticipated) deviations from normal operations (failure states) and describe how the system defines states such as loss of system confidentiality, integrity, or availability.

A.10.18 Thin Nodes (SG.SC-23) – Incomplete information

Requirement

The Smart Grid information system employs processing components that have minimal functionality and data storage.

Supplemental Guidance

The deployment of Smart Grid information system components with minimal functionality (e.g., diskless nodes and thin client technologies) reduces the number of endpoints to be secured and may reduce the exposure of information, Smart Grid information systems, and services to a successful attack.

Category

Unique Technical Requirements

Specification

The deployment of Smart Grid information system components with minimal functionality (e.g., diskless nodes and thin client technologies) reduces the number of endpoints to be secured and may reduce the exposure of information, Smart Grid information systems, and services to a successful attack.

Verification Results

Issue Identified – needs information. The specification needs further information on (1) what the *thin nodes* are and (2) where the *thin nodes* deployed in the proposed system.

A.10.19 Honeypots (SG.SC-24) – Consider to be removed from specification

Requirement

The Smart Grid information system includes components specifically designed to be the target of malicious attacks for the purpose of detecting, deflecting, analyzing, and tracking such attacks.

Additional Considerations

1. The Smart Grid information system includes components that proactively seek to identify Web-based malicious code.

Category

Unique Technical Requirements

Specification

1. Embedded firewall in the Management instance is able to both detect and deflect network attacks. Encrypted TLS tunnels between nodes leverage mutual authentication prior to establishing a connection, thus are able to detect and prevent impersonation attacks, man-in-the-middle attacks, eavesdropping, and data modification enroute.
2. All events are forwarded to the ESM for analysis. The ESM correlates events and generates alarms in order to update the state in ePO
3. All events from all endpoints (and their connections) are forwarded to the ESM. Therefore, it is possible to track attacks as they make their way through the environment, and even apply policy in response to the attacks, or even prior to the attack reaching a particular endpoint.

Verification Results

Issue Identified – requirement is not applicable to the SF system. *Honeypots* are a computer, data or network site that *appears to be part of a network but is actually isolated and monitored*, and which seems to contain information or a resource of value to attackers. There is no description of the elements and functionality of Honeypots in the SF system. Recommend this requirement be removed from the specification.

A.10.20 Operating System Independent Applications (SG.SC-25)

Requirement

The Smart Grid information system includes organization-defined applications that are independent of the operating system.

Supplemental Guidance

Operating system-independent applications are applications that can run on multiple operating systems. Such applications promote portability and reconstitution on different platform architectures, thus increasing the availability for critical functionality while an organization is under an attack exploiting vulnerabilities in a given operating system.

Category

Unique Technical Requirements

Specification

1. The OS independence is built into the design of the platform. There is a separation between the Operational Instance and the Management Instance, so that the security can run NEXT TO, but independent of ANY OS.
2. The organization-defined applications are physically separated from the security applications, services, and capabilities. Therefore, the security does not depend on the environment (OS, etc) of the applications, and the applications are kept separate (different VM) from the security aspects.

Verification Results

Satisfactory. The proposed system uses virtualization technique for separating the domain-specific applications (ePDC and RTDMS) from security applications. Both domain-specific and security application are run on top of ESXi virtualization machine (see SG.SC-3). Because of virtualization, domain-specific application can run on desired operating system without changing anything in order to include the proposed system as the security application. Please note that the proposed system is not an application but it is a security architecture.

A.10.21 Confidentiality of Information at Rest (SG.SC-26)

Requirement

The Smart Grid information system employs cryptographic mechanisms for all critical security parameters (e.g., cryptographic keys, passwords, security configurations) to prevent unauthorized disclosure of information at rest.

Supplemental Guidance

For a list of current FIPS-approved or allowed cryptography, see Chapter Four Cryptography and Key Management in NIST IR-7628.

Category

Unique Technical Requirements

Specification

Access to confidential information, such as Keys, Passwords, and security configurations are protected in a separate OS. Access to these keys from the Operational Instance is strictly blocked. There is no path to these resources from inside of the device or from outside of the device (once SSH listener has been removed). All controls are enacted from within the remote security console, and the Mgmt Instance is a black-box without any login or shell capabilities.

Currently, there is an SSH listener on the Mgmt Instance. This allows login (root only) and shell access. As soon as is feasible this interface shall be removed to prevent all access to the confidential information.

Verification Results

Satisfactory. From the McAfee Enterprise Security Manager (ESM) version 9.3.0 Product Guide⁴, ESM component supports FIPS 140-2 when the user of ESM selects the FIPS mode the first time he/she logs on to the system. The setup is permanent. Note: current deployed system did not enable FIPS mode.

For the details of FIPS on ePO components, please see SG.SC-12.

A.10.22 Heterogeneity (SG.SC-27)

Requirement

The organization employs diverse technologies in the implementation of the Smart Grid information system.

Supplemental Guidance

Increasing the diversity of technologies within the Smart Grid information system reduces the impact from the exploitation of a specific technology.

Category

Unique Technical Requirements

Specification

The security platform protects the systems from exploitation irrespective of the technologies used. The security platform design allows integration of security products from different vendors employing

⁴

https://kc.mcafee.com/resources/sites/MCAFEE/content/live/PRODUCT_DOCUMENTATION/24000/PD24719/en_US/esm_930_product%20guide_en-us.pdf

different technologies. Therefore, a consistent security API is in place to protect the Operational components with heterogeneous security controls.

By deploying in this manner, the homogeneity of the information systems is preserved to reduce the impact of exploitation, while consistent security APIs protect the systems consistently and allow for automated threat response and remediation across not just those nodes under attack, or victims of compromise, but also those not yet affected by the threat.

Verification Results

Satisfactory. The proposed system allows the integration of security products from different developers (as the core contribution of security fabric systems⁵).

A.10.23 Virtualization Technique (SG.SC-28)

Requirement

The organization employs virtualization techniques to present gateway components into Smart Grid information system environments as other types of components, or components with differing configurations.

Supplemental Guidance

Virtualization techniques provide organizations with the ability to disguise gateway components into Smart Grid information system environments, potentially reducing the likelihood of successful attacks without the cost of having multiple platforms.

Additional Considerations

1. The organization employs virtualization techniques to deploy a diversity of operating systems environments and applications;
2. The organization changes the diversity of operating systems and applications on an organization-defined frequency; and
3. The organization employs randomness in the implementation of the virtualization.

Category

Unique Technical Requirements

⁵ http://www.gridwiseac.org/pdfs/forum_papers11/speicher_paper_part3_gi11.pdf

Specification

Virtualization techniques are employed in the platform to deploy different operating systems and their respective applications. A diversity of operating systems are deployable into the platform to ensure homogeneity. The OS and applications can be changed as required by the organization's policy.

Verification Results

Satisfactory. The proposed system uses ESXi hypervisor⁶ as a mechanism for virtualization (separating domain-specified applications from security-function applications).

A.10.24 Application Partitioning (SG.SC-29)

Requirement

The Smart Grid information system separates user functionality (including user interface services) from Smart Grid information system management functionality.

Supplemental Guidance

Smart Grid information system management functionality includes, for example, functions necessary to administer databases, network components, workstations, or servers, and typically requires privileged user access. The separation of user functionality from Smart Grid information system management functionality is either physical or logical.

The intent of this additional consideration is to ensure that administration options are not available to general users. For example, administration options are not presented until the user has appropriately established a session with administrator privileges.

Additional Considerations

1. The Smart Grid information system prevents the presentation of Smart Grid information system management-related functionality at an interface for general (i.e., non-privileged) users.

Category

Unique Technical Requirements

⁶ <http://www.vmware.com/products/vsphere-hypervisor>

Specification

The application functionality is completely separated from the Management functionality via the hypervisor and virtualization of the instances. Therefore, the Smart Grid management components require a completely different level of access much higher level of access required, depending on application) than the User-level functional components on the device.

The management functionality in the security platform is completely handled by EPO which is physically isolated from the end-point where the application instances would be running. The management functionality (EPO) is only presented to the authenticated users and with privileged access.

Verification Results

Satisfactory. The proposed system separates user functionality (ePDC and RDTMS) from security management functionality by using ESXi hypervisor. The security management functionality is handled by ePO, which allows only authenticated users to access.

A.10.25 Smart Grid Information System Partitioning (SG.SC-30)

Requirement

The organization partitions the Smart Grid information system into components residing in separate physical or logical domains (or environments).

Supplemental Guidance

An organizational assessment of risk guides the partitioning of Smart Grid information system components into separate domains (or environments).

Category

Common Technical Requirements, Integrity

Specification

In a given information system, the partitions (Windows & Linux) are configured to have different network interfaces. The windows network interface is a virtual interface whose gateway is the Linux partition. This way the management interface for Windows is the Linux instance and are logically separated.

The network configuration of the externally facing network adapters, in the Management Partition, are configurable such that they are on any networks or VLANs needed. If there are multiple network interfaces, each can be configured onto a different network or VLAN allowing each of the internal instances (assuming there are multiple that must be partitioned into their own networks) to be routed through different network interfaces.

Verification Results

Satisfactory. The ePO, ESM and the McAfee agent play important roles in the proposed system for monitoring and controlling the security in target system. The following is the main task for each component; (1) ePO provides the overall security policy for McAfee agents (2) ESM monitors the specified event, and (3) McAfee agent enforces the policy from ePO at end-point. The specification should address the components (i.e., ePO, ESM, and McAfee agent) in the proposed system and how they reside in separate physical or logical domains.

A.11 Smart Grid Information System and Information Integrity (SG.SI)

Maintaining a Smart Grid information system, including information integrity, increases assurance that sensitive data have neither been modified nor deleted in an unauthorized or undetected manner. The security requirements described under the Smart Grid information system and information integrity family provide policy and procedure for identifying, reporting, and correcting Smart Grid information system flaws. Requirements exist for malicious code detection. Also provided are requirements for receiving security alerts and advisories and the verification of security functions on the Smart Grid information system. In addition, requirements within this family detect and protect against unauthorized changes to software and data; restrict data input and output; check the accuracy, completeness, and validity of data; and handle error conditions.

A.11.1 Flaw Remediation (SG.SI-2)

Requirement

The organization—

1. Identifies, reports, and corrects Smart Grid information system flaws;
2. Tests software updates related to flaw remediation for effectiveness and potential side effects on organizational Smart Grid information systems before installation; and
3. Incorporates flaw remediation into the organizational configuration management process.

Supplemental Guidance

The organization identifies Smart Grid information systems containing software and firmware (including operating system software) affected by recently announced flaws (and potential vulnerabilities resulting from those flaws). Flaws discovered during security assessments, continuous monitoring, or under incident response activities also need to be addressed.

Additional Considerations

1. The organization centrally manages the flaw remediation process. Organizations consider the risk of employing automated flaw remediation processes on a Smart Grid information system;

2. The organization employs automated mechanisms on an organization-defined frequency and on demand to determine the state of Smart Grid information system components with regard to flaw remediation; and
3. The organization employs automated patch management tools to facilitate flaw remediation to organization-defined Smart Grid information system components.

Category

Common Technical Requirements, Integrity

Specification

1. ESM monitors and records the syslogs and events on end-point systems. ESM can help detect flaws with respect to a system on the platform. The remediation would be the action taken by the administrator of ESM.
2. The ESM integration to ePO enables the communication of machine state to ePO. This allows ePO to update specific dashboards to report flaw in the systems.

Verification Results

Issue Identified – need additional tool. If the proposed system included the vulnerability analysis tools (e.g., FoundStone from McAfee), this requirement would have been satisfied. Although ESM can help detect flaws by logging the result of operational failures (e.g., system down based on some specific event), the security administrator still needs to identify the cause of logged failures in order to identify the flaw.

A.11.2 Smart Grid Information System Monitoring Tools and Techniques (SG.SI-4)

Requirement

The organization monitors events on the Smart Grid information system to detect attacks, unauthorized activities or conditions, and non-malicious errors.

Supplemental Guidance

Smart Grid information system monitoring capability can be achieved through a variety of tools and techniques (e.g., intrusion detection systems, intrusion prevention systems, malicious code protection software, log monitoring software, network monitoring software, and network forensic analysis tools). The granularity of the information collected can be determined by the organization based on its monitoring objectives and the capability of the Smart Grid information system to support such activities.

Additional Considerations

1. The Smart Grid information system notifies a defined list of incident response personnel;

2. The organization protects information obtained from intrusion monitoring tools from unauthorized access, modification, and deletion;
3. The organization tests/exercises intrusion monitoring tools on a defined time period;
4. The organization interconnects and configures individual intrusion detection tools into a Smart Grid system-wide intrusion detection system using common protocols;
5. The Smart Grid information system provides a real-time alert when indications of compromise or potential compromise occur; and
6. The Smart Grid information system prevents users from circumventing host-based intrusion detection and prevention capabilities.

Category

Common Governance, Risk, and Compliance (GRC) Requirements

Specification

The information systems are monitored via ESM to detect attacks, unauthorized activities, and malicious errors. All logs may be sent to the ESM, so all events may be monitored on the back-end including attacks, unauthorized activities, and malicious errors.

Verification Results

Satisfactory. The proposed system can monitor events to detect attacks, unauthorized activities or conditions, and non-malicious errors by using ESM and ePO event monitoring (see SG.AU-2, SG.AU-3, SG.AU-5, SG.AU-6, SG.AU-10, and SG.AU-16).

A.11.3 Security Functionality Verification (SG.SI-6)

Requirement

1. The organization verifies the correct operation of security functions within the Smart Grid information system upon
 - a. Smart Grid information system startup and restart; and
 - b. Command by user with appropriate privilege at an organization-defined frequency; and
2. The Smart Grid information system notifies the management authority when anomalies are discovered.

Additional Considerations

1. The organization employs automated mechanisms to provide notification of failed automated security tests; and
2. The organization employs automated mechanisms to support management of distributed security testing.

Category

Common Governance, Risk, and Compliance (GRC) Requirements

Specification

1. At startup, the measured boot data ensures that the endpoint has not been tampered with. In addition, the agent reports in so that communication can be reestablished with ePO.
2. The agent checks in with ePO (via a heartbeat message) at a configurable interval to notify ePO that the security capabilities are still functional.
3. ePO Automated Responses can be configured to respond to events in ePO with predetermined actions or tasks based on which events (anomalies) were detected.
4. ePO policy defines the organization's conditions to the endpoint. Implementing the policy on the endpoint ensures the correct operation of the security functions.
5. ePO Automated Responses define the organizations responses to anomalies, and ensures that the proper responses will follow the appropriate events.

Anomalies that are detected on the endpoint create events that are sent to ePO and/or ESM. These anomalies are then analyzed and if appropriate, reported out. Automated responses can be configured to notify via email of specific events, and dashboards and reports can be leveraged as well.

Verification Results

Satisfactory. The proposed system uses the consistency of *boot string* on the device as the conditions for verifying correct operation of security functions when system starts up or restarts. On the operation time, the proposed system can configure the interval time for checking the security capabilities among devices via *heartbeat message*, which is recorded in ePO component. Any defined anomaly events detected in operation time can be responded by ePO Automated Responses function (see SG.AU-5).

A.11.4 Error Handling (SG.SI-9)

Requirement

The Smart Grid information system—

1. Identifies error conditions; and
2. Generates error messages that provide information necessary for corrective actions without revealing potentially harmful information that could be exploited by adversaries.

Supplemental Guidance

The extent to which the Smart Grid information system is able to identify and handle error conditions is guided by organizational policy and operational requirements.

Category

Common Technical Requirements, Integrity

Specification

Error conditions are detected either on the endpoint via events, or on the back-end ePO/ESM systems based on events being sent back.

The error messages generated by the endpoint are sent to ePO. These messages are not visible to anyone outside of the appropriate personnel that is authorized to view them.

Verification Results

Satisfactory. The error conditions are defined as the auditable event in both ePO and ESM (see SG.AU-2). The information in error message can be customized and viewed only by authorized person (see SG.AU-3, SG.AU-7, SG.AU-8, and SG.AU-9).

Appendix B: TTU Security Testing Part 2

Penetration Testing Results

The general process of penetration testing involves identifying vulnerabilities of the system (via scanner and manual) and exploiting the promising vulnerability with the goal to breach the system. This appendix gives details of the vulnerabilities that have been exploited successfully to the TTU synchrophasor network including the security fabric-enabled network as well. For each of the vulnerabilities below, the descriptions, summarized findings, scripts coded to identify vulnerability (e.g., scan network ports or test unsecured software), and detailed results of vulnerability identification and/or penetration testing are given. In many cases, suggestions of how to remove the vulnerability that leads to exploit are also described. This appendix reports seven types of the vulnerability exploits as mentioned in the main report.

B.1 MS12-020: Vulnerabilities in Remote Desktop Could Allow Remote Code Execution

Descriptions: The Remote Desktop Protocol (RDP) implementation in Microsoft Windows XP SP2 and SP3, Windows Server 2003 SP2, Windows Vista SP2, Windows Server 2008 SP2, R2, and R2 SP1, and Windows 7 Gold and SP1 does not properly process packets in memory, which allows remote attackers to execute arbitrary code by sending crafted RDP packets triggering access to an object that (1) was not properly initialized or (2) is deleted, aka "Remote Desktop Protocol Vulnerability."

Findings: As shown below, there are five remote desktop services in the system. Three (top three rows of the table) are in security fabric environment and two are not.

| Component | IP Address | Result |
|-----------|------------|--------|
|-----------|------------|--------|

| | | |
|----------|----------------|------|
| SF-ePDC | 129.118.105.50 | Fail |
| SF-RTDMS | 129.118.26.8 | Fail |
| SF-AD | 129.118.26.37 | Pass |
| ePDC | 129.118.105.44 | Pass |
| RTDMS | 129.118.19.167 | Pass |

Table 6. Affected Components and testing result for MS12-020 vulnerability in Security Fabric System

Scripts for testing exploits: Based on the potential vulnerability in testing system, Metasploit script is used for testing the exploitability of vulnerability MS12-020:

```
msf > use auxiliary/dos/windows/rdp/ms12_020_maxchannelids

msf exploit(ms12_020_maxchannelids) > set rhost [IP Address]

msf exploit(ms12_020_maxchannelids) > run
```

Where the parameter [IP Address] is IP address for machine to be tested (e.g., 129.118.105.50 for SF-ePDC).

Results:

1. Testing results on SF-ePDC on May 28, 2014:

```
[*] 129.118.105.50:3389 - Sending MS12-020 Microsoft Remote Desktop Use-
After-Free DoS

[*] 129.118.105.50:3389 - 210 bytes sent

[*] 129.118.105.50:3389 - Checking RDP status...

[-] 129.118.105.50:3389 - RDP Service Unreachable

[*] Auxiliary module execution completed
```

After exploiting the vulnerability on SF-ePDC, the connection to Remote Desktop Application service on SF-ePDC cannot be established. Therefore, SF-ePDC is vulnerable for Denial of Service by exploiting MS12-020 vulnerability.

2. Testing results on SF-RTDMS on May 28, 2014:

```
[*] 129.118.26.8:3389 - Sending MS12-020 Microsoft Remote Desktop Use-
After-Free DoS

[*] 129.118.26.8:3389 - 210 bytes sent
```

```
[*] 129.118.26.8:3389 - Checking RDP status...  
[-] 129.118.26.8:3389 - RDP Service Unreachable  
[*] Auxiliary module execution completed
```

After exploiting the vulnerability on SF-RTDMS, the connection to Remote Desktop Application service on SF-RTDMS cannot be established. Therefore, SF-RTDMS is vulnerable for Denial of Service by exploiting MS12-020 vulnerability.

3. Testing results on Active Directory on May 28, 2014:

```
[*] 129.118.26.37:3389 - Sending MS12-020 Microsoft Remote Desktop Use-  
After-Free DoS  
  
[*] 129.118.26.37:3389 - 210 bytes sent  
  
[*] 129.118.26.37:3389 - Checking RDP status...  
[-] 129.118.26.37:3389 - RDP Service Unreachable  
  
[*] Auxiliary module execution completed
```

After exploiting the vulnerability on Active Directory, the connection to Remote Desktop Application service on Active Directory can be established. Therefore, Active Directory component is not vulnerable for Denial of Service by exploiting MS12-020 vulnerability.

4. Testing results on ePDC machine on May 28, 2014:

```
[*] 129.118.105.44:3389 - Sending MS12-020 Microsoft Remote Desktop Use-  
After-Free DoS  
  
[*] 129.118.105.44:3389 - 210 bytes sent  
  
[*] 129.118.105.44:3389 - Checking RDP status...  
[-] 129.118.105.44:3389 - RDP Service Unreachable  
  
[*] Auxiliary module execution completed
```

After exploiting the vulnerability on ePDC, the connection to Remote Desktop Application service on ePDC can be established. Therefore, ePDC component is not vulnerable for Denial of Service by exploiting MS12-020 vulnerability.

5. Testing results on RTDMS machine on May 28, 2014:

```
[*] 129.118.19.167:3389 - Sending MS12-020 Microsoft Remote Desktop Use-
After-Free DoS

[*] 129.118.19.167:3389 - 210 bytes sent

[*] 129.118.19.167:3389 - Checking RDP status...

[-] 129.118.19.167:3389 - RDP Service Unreachable

[*] Auxiliary module execution completed
```

After exploiting the vulnerability on RTDMS, the connection to Remote Desktop Application service on RTDMS can be established. Therefore, RTDMS component is not vulnerable for Denial of Service by exploiting MS12-020 vulnerability.

Suggestion: To remove this vulnerability from the effected components (WRL on both Reese-site and TTU-site), where Microsoft Windows Server 2008 R2 SP1 is used as the back-ends, both machines need to download and apply the patch from <http://go.microsoft.com/fwlink/?LinkId=232664>.

The following are the list of websites that provide more details about this vulnerability:

- **TA12-073A** <http://www.us-cert.gov/ncas/alerts/TA12-073A>
- **CVE-2012-0002** <http://web.nvd.nist.gov/view/vuln/detail?vulnId=CVE-2012-0002>
- **CVE-2012-0152** <http://web.nvd.nist.gov/view/vuln/detail?vulnId=CVE-2012-0152>
- **MS12-020** <https://technet.microsoft.com/library/security/ms12-020>
- **MSKB 2671387** <http://support.microsoft.com/default.aspx?scid=kb;EN-US;2671387>
- <http://www.microsoft.com/downloads/details.aspx?familyid=6a07f99c-8ab4-4e44-8d48-6ac787dd2b51>

B.2 X.509 Certificate Subject CN Does Not Match the Entity Name

Descriptions: The subject common name (CN) field in the X.509 certificate does not match the name of the entity presenting the certificate.

Before issuing a certificate, a Certification Authority (CA) must check the identity of the entity requesting the certificate, as specified in the CA's Certification Practice Statement (CPS). Thus, standard certificate validation procedures require the subject CN field of a certificate to match the actual name of the entity presenting the certificate. For example, in a certificate presented by "https://www.example.com/", the CN should be "www.example.com".

In order to detect and prevent active eavesdropping attacks, the validity of a certificate must be verified, or else an attacker could then launch a man-in-the-middle attack and gain full control of the data stream. Of particular importance is the validity of the subject's CN that should match the name of the entity (hostname).

A CN mismatch most often occurs due to a configuration error, though it can also indicate that a man-in-the-middle attack is being conducted.

Findings: There are four services provided in testing system where X.509 Certificate Subject CN does not match with the entity name as shown below.

| Component | IP Address | Result |
|-----------|---------------------|---------------------------------------------------|
| SF-ePO | 129.118.19.210:443 | CN 'AH_EPO-SF' vs. '129.118.19.210' |
| SF-ePO | 129.118.19.210:8443 | CN 'EPO-SF' vs. '129.118.19.210' |
| SF-ePO | 129.118.19.210:8444 | CN 'Orion_ClientAuth_EPO-SF' vs. '129.118.19.210' |
| SF-ESM | 129.118.26.40:443 | CN 'esm.mcafee.local' vs. '129.118.26.40' |

Table 7. Affected Components and checking result on mismatch of X.509 certificate

Scripts for testing vulnerabilities: Based on the services with X.509 certificate in testing system, OpenSSL script is used for finding the vulnerability of mismatch CN and *nodename* in X.509:

```
$openssl s_client -connect [IP Address]:[Port] -show certificate
```

Where the parameter [IP Address] and [Port] are IP address and port of machine to be tested, respectively (e.g., 129.118.19.210:443 for SF-ePO machine on https port).

Result:

1. The partial output results of testing on port 443 of SF-ePO component:

```
CONNECTED(00000003)

depth=0 O = McAfee, OU = ePO, CN = AH_EPO-SF

verify error:num=20:unable to get local issuer certificate

verify return:1

depth=0 O = McAfee, OU = ePO, CN = AH_EPO-SF

verify error:num=27:certificate not trusted

verify return:1

depth=0 O = McAfee, OU = ePO, CN = AH_EPO-SF

verify error:num=21:unable to verify the first certificate

verify return:1
```

```

---

Certificate chain

 0 s:/O=McAfee/OU=ePO/CN=AH_EPO-SF

   i:/O=McAfee/OU=AH/CN=AH_CA_EPO-SF

---

```

As shown in the output the CN appeared (i.e., AH_EPO-SF) in X.509 certificate does not match with the node name of SF-ePO.

2. The partial output results of testing on port 8443 of SF-ePO component:

```

CONNECTED(00000003)

depth=1 O = McAfee, OU = Orion, CN = Orion_CA_EPO-SF

verify error:num=19:self signed certificate in certificate chain

verify return:0

---

Certificate chain

 0 s:/O=McAfee/OU=Orion/CN=EPO-SF

   i:/O=McAfee/OU=Orion/CN=Orion_CA_EPO-SF

 1 s:/O=McAfee/OU=Orion/CN=Orion_CA_EPO-SF

   i:/O=McAfee/OU=Orion/CN=Orion_CA_EPO-SF

---

```

As shown in the output the CN appeared (i.e., Orion_CA_EPO-SF) in X.509 certificate does not match with the node name of ePO.

3. The partial output results of testing on port 8444 of SF-ePO component:

```

CONNECTED(00000003)

depth=1 O = McAfee, OU = Orion, CN = Orion_CA_EPO-SF

verify error:num=19:self signed certificate in certificate chain

```

```

verify return:0

---

Certificate chain

0 s:/O=McAfee/OU=Orion/CN=Orion_ClientAuth_EPO-SF

   i:/O=McAfee/OU=Orion/CN=Orion_CA_EPO-SF

1 s:/O=McAfee/OU=Orion/CN=Orion_CA_EPO-SF

   i:/O=McAfee/OU=Orion/CN=Orion_CA_EPO-SF

---

```

As shown in the output the CN appeared (i.e., Orion_ClientAuth_EPO-SF) in X.509 certificate does not match with the node name of ePO.

4. The partial output results of testing on port 443 of SF-ESM component:

```

CONNECTED(00000003)

depth=0 C = US, ST = TX, L = Plano, O = McAfee, OU = Enterprise Security
Manager, CN = esm.mcafee.local, emailAddress = support@nitrosecurity.com

verify error:num=18:self signed certificate

verify return:1

depth=0 C = US, ST = TX, L = Plano, O = McAfee, OU = Enterprise Security
Manager, CN = esm.mcafee.local, emailAddress = support@nitrosecurity.com

verify return:1

---

Certificate chain

0 s:/C=US/ST=TX/L=Plano/O=McAfee/OU=Enterprise Security
Manager/CN=esm.mcafee.local/emailAddress=support@nitrosecurity.com

   i:/C=US/ST=TX/L=Plano/O=McAfee/OU=Enterprise Security
Manager/CN=esm.mcafee.local/emailAddress=support@nitrosecurity.com

1 s:/C=US/ST=TX/L=Plano/O=McAfee/OU=Enterprise Security
Manager/CN=esm.mcafee.local/emailAddress=support@nitrosecurity.com

```

```
i:/C=US/ST=TX/L=Plano/O=McAfee/OU=Enterprise Security
Manager/CN=esm.mcafee.local/emailAddress=support@nitrosecurity.com
```

As shown in the output the CN appeared (i.e., Orion_ClientAuth_EPO-SF) in X.509 certificate does not match with the node name of ESM.

Suggestion: To remove this mismatch of common name (CN) and node name in X.509 certificate, the subject's CN field in the X.509 certificate should reflect the name of the entity presenting the certificate (e.g., the hostname). We can accomplish this by generating a new certificate that is usually signed by a Certification Authority (CA) and trusted by both client and server.

B.3 SMB signing disabled

Descriptions: This system does not allow SMB signing. SMB signing allows the recipient of SMB packets to confirm their authenticity and helps prevent man in the middle attacks against SMB. SMB signing can be configured in one of three ways: disabled entirely (least secure), enabled, and required (most secure).

Findings: There are seven services provided in testing system where SMB signing is disabled. These are shown below.

| Component | IP Address | Result |
|-----------|----------------------|---------------------------------------------------|
| ePDC | 129.118.105.44:139 | Message signing disabled (dangerous, but default) |
| ePDC | 129.118.105.44:445 | Message signing disabled (dangerous, but default) |
| RTDMS | 129.118.19.167:445 | Message signing disabled (dangerous, but default) |
| SF-ePO | 129.118.19.210:139 | Message signing disabled (dangerous, but default) |
| SF-ePO | 129.118.19.210:445 | Message signing disabled (dangerous, but default) |
| SF-AD | 129.118.19.26.37:139 | Message signing required |
| SF-AD | 129.118.19.26.37:445 | Message signing required |

Table 8. Affected Components and checking result on mismatch of SMB signing disabled

Scripts for testing vulnerabilities: The result from Table 8 is gathered from running the script as follows:

```
$ nmap --script smb-security-mode.nse [-Pn] -p[port] [host]
```

Results:

1. The output results of testing on port 139 of SF-ePO component:

```
Starting Nmap 6.00 ( http://nmap.org ) at 2014-06-11 03:40 CDT
```

```
Nmap scan report for p3eepdc.ttu.edu (129.118.105.44)

Host is up (0.00097s latency).

PORT      STATE SERVICE
139/tcp   open  netbios-ssn

Host script results:
| smb-security-mode:
|   Account that was used for smb scripts: guest
|   User-level authentication
|   SMB Security: Challenge/response passwords supported
|_ Message signing disabled (dangerous, but default)

Nmap done: 1 IP address (1 host up) scanned in 1.27 seconds
```

2. The output results of testing on port 445 of SF-ePO component:

```
Nmap scan report for p3eepdc.ttu.edu (129.118.105.44)

Host is up (0.00092s latency).

PORT      STATE SERVICE
445/tcp   open  microsoft-ds

Host script results:
| smb-security-mode:
|   Account that was used for smb scripts: guest
|   User-level authentication
|   SMB Security: Challenge/response passwords supported
```

```
|_ Message signing disabled (dangerous, but default)
```

```
Nmap done: 1 IP address (1 host up) scanned in 1.27 seconds
```

3. The output results of testing on port 445 of RTDMS component:

```
Nmap scan report for p3ertdms.ttu.edu (129.118.19.167)
```

```
Host is up (0.00040s latency).
```

```
PORT      STATE SERVICE
```

```
445/tcp open  microsoft-ds
```

```
Host script results:
```

```
| smb-security-mode:
```

```
|   Account that was used for smb scripts: guest
```

```
|   User-level authentication
```

```
|   SMB Security: Challenge/response passwords supported
```

```
|_ Message signing disabled (dangerous, but default)
```

```
Nmap done: 1 IP address (1 host up) scanned in 2.27 seconds
```

4. The output results of testing on port 139 of SF-ePO component:

```
Starting Nmap 6.00 ( http://nmap.org ) at 2014-06-11 03:49 CDT
```

```
Nmap scan report for epo-sf.epg.secfab.org (129.118.19.210)
```

```
Host is up (0.00047s latency).
```

```
PORT      STATE SERVICE
```

```
139/tcp open  netbios-ssn
```

Host script results:

```
| smb-security-mode:  
  
|   Account that was used for smb scripts: guest  
  
|   User-level authentication  
  
|   SMB Security: Challenge/response passwords supported  
  
|_  Message signing disabled (dangerous, but default)
```

Nmap done: 1 IP address (1 host up) scanned in 0.07 seconds

5. The output results of testing on port 445 of SF-ePO component:

Starting Nmap 6.00 (<http://nmap.org>) at 2014-06-11 03:50 CDT

Nmap scan report for epo-sf.epg.secfab.org (129.118.19.210)

Host is up (0.00050s latency).

| PORT | STATE | SERVICE |
|---------|-------|--------------|
| 445/tcp | open | microsoft-ds |

Host script results:

```
| smb-security-mode:  
  
|   Account that was used for smb scripts: guest  
  
|   User-level authentication  
  
|   SMB Security: Challenge/response passwords supported  
  
|_  Message signing disabled (dangerous, but default)
```

Nmap done: 1 IP address (1 host up) scanned in 0.07 seconds

6. The output results of testing on port 139 of SF-AD component:

```
Starting Nmap 6.00 ( http://nmap.org ) at 2014-06-11 03:56 CDT
```

```
Nmap scan report for dc-sf.epg.secfab.org (129.118.26.37)
```

```
Host is up (0.00053s latency).
```

```
PORT      STATE SERVICE
```

```
139/tcp open  netbios-ssn
```

```
Host script results:
```

```
| smb-security-mode:
```

```
|   Account that was used for smb scripts: guest
```

```
|   User-level authentication
```

```
|   SMB Security: Challenge/response passwords supported
```

```
|_  Message signing required
```

```
Nmap done: 1 IP address (1 host up) scanned in 0.06 seconds
```

7. The output results of testing on port 445 of SF-AD component:

```
Starting Nmap 6.00 ( http://nmap.org ) at 2014-06-11 03:58 CDT
```

```
Nmap scan report for dc-sf.epg.secfab.org (129.118.26.37)
```

```
Host is up (0.00043s latency).
```

```
PORT      STATE SERVICE
```

```
445/tcp open  microsoft-ds
```

```
Host script results:
```

```
| smb-security-mode:
```

```
|   Account that was used for smb scripts: guest
```



```
| User-level authentication
| SMB Security: Challenge/response passwords supported
|_ Message signing required

Nmap done: 1 IP address (1 host up) scanned in 0.06 seconds
```

Suggestion: To remove this vulnerability, the administrator of the system needs to setup the operating system (e.g., Windows) to enable or require SMB signing appropriately. The method and effect of doing this depend on each system specification (as shown in more details in the following link <http://blogs.technet.com/b/josebda/archive/2010/12/01/the-basics-of-smb-signing-covering-both-smb1-and-smb2.aspx>). Be sure that SMB signing configuration is done for incoming connections (Server).

Moreover, we also need to configure Samba protocol to enable or require SMB signing as appropriate. To enable SMB signing, put the following in the Samba configuration file, typically `smb.conf`, in the global section:

```
server signing = auto
```

To require SMB signing, put the following in the Samba configuration file, typically `smb.conf`, in the global section:

```
server signing = mandatory
```

B.4 Remote Desktop Protocol over SSL supports weak RC4 cipher

Descriptions: Remote Desktop Protocol is a protocol by which Terminal Service provides desktop level access to a remote user. It can be used to remotely login and interact with a Windows machine. Since RDP transfers sensitive information about the user and the system, it can be configured to use encryption to provide privacy and integrity for its sessions. It is possible to configure RDP to use encryption algorithms that are considered insecure, such as RC4 40bit and RC4 56 bit.

Findings: As shown below, there are five services provided in testing system where Remote Desktop Protocol over SSL supports weak cipher can be exploited.

| Component | IP Address | Result |
|-----------|---------------------|----------------------------------------------|
| RTDMS | 129.118.19.167:3389 | RC4 40 bit and 50 bit are supported |
| SF-RTDMS | 129.118.26.8:3389 | RC4 40 bit and 50 bit are supported |
| SF-ePDC | 129.118.105.50:3389 | Cannot connect (wait for service to enable)? |

| | | |
|-------|---------------------|-------------------------------------|
| SF-AD | 129.118.26.37:3389 | RC4 40 bit and 50 bit are supported |
| ePDC | 129.118.105.44:3389 | RC4 40 bit and 50 bit are supported |

Table 9. Affected Components and checking result on RDP over SSL support weak cipher

Scripts for testing vulnerabilities: The result from Table 9 is generated by running the following script:

```
$ nmap --script rdp-enum-encryption -p[port] [host]
```

Results:

1. The output results of testing on port 3389 of RTDMS component:

```
Starting Nmap 6.46 ( http://nmap.org ) at 2014-07-07 04:42 CDT

NSE: Loaded 1 scripts for scanning.

NSE: Script Pre-scanning.

Initiating Ping Scan at 04:42

Scanning 129.118.19.167 [2 ports]

Completed Ping Scan at 04:42, 1.20s elapsed (1 total hosts)

Initiating Parallel DNS resolution of 1 host. at 04:42

Completed Parallel DNS resolution of 1 host. at 04:42, 0.00s elapsed

Initiating Connect Scan at 04:42

Scanning p3ertdms.ttu.edu (129.118.19.167) [1 port]

Discovered open port 3389/tcp on 129.118.19.167

Completed Connect Scan at 04:42, 0.00s elapsed (1 total ports)

NSE: Script scanning 129.118.19.167.

Initiating NSE at 04:42

Completed NSE at 04:42, 0.09s elapsed

Nmap scan report for p3ertdms.ttu.edu (129.118.19.167)

Host is up (0.00028s latency).

PORT      STATE SERVICE
```

```
3389/tcp open  ms-wbt-server
```

```
| rdp-enum-encryption:  
|   Security layer  
|     CredSSP: SUCCESS  
|     Native RDP: SUCCESS  
|     SSL: SUCCESS  
|   RDP Encryption level: Client Compatible  
|     40-bit RC4: SUCCESS  
|     56-bit RC4: SUCCESS  
|     128-bit RC4: SUCCESS  
|_   FIPS 140-1: SUCCESS
```

2. The output results of testing on port 3389 of SF-RTDMS component:

```
Starting Nmap 6.46 ( http://nmap.org ) at 2014-07-07 04:58 CDT
```

```
Nmap scan report for 129.118.26.8
```

```
Host is up (0.00048s latency).
```

```
PORT      STATE SERVICE
```

```
3389/tcp open  ms-wbt-server
```

```
| rdp-enum-encryption:  
|   Security layer  
|     CredSSP: SUCCESS  
|     Native RDP: SUCCESS  
|     SSL: SUCCESS  
|   RDP Encryption level: Client Compatible  
|     40-bit RC4: SUCCESS  
|     56-bit RC4: SUCCESS
```

```
|      128-bit RC4: SUCCESS
```

```
|_     FIPS 140-1: SUCCESS
```

```
Nmap done: 1 IP address (1 host up) scanned in 0.12 seconds
```

3. The output results of testing on port 3389 of SF-AD component:

```
NSE: Script Post-scanning.
```

```
Read data files from: /usr/local/bin/../../share/nmap
```

```
Nmap done: 1 IP address (1 host up) scanned in 1.34 seconds
```

```
Starting Nmap 6.46 ( http://nmap.org ) at 2014-07-07 04:51 CDT
```

```
NSE: Loaded 1 scripts for scanning.
```

```
NSE: Script Pre-scanning.
```

```
Initiating Parallel DNS resolution of 1 host. at 04:51
```

```
Completed Parallel DNS resolution of 1 host. at 04:51, 0.00s elapsed
```

```
Initiating Connect Scan at 04:51
```

```
Scanning dc-sf.epg.secfab.org (129.118.26.37) [1 port]
```

```
Discovered open port 3389/tcp on 129.118.26.37
```

```
Completed Connect Scan at 04:51, 0.00s elapsed (1 total ports)
```

```
NSE: Script scanning 129.118.26.37.
```

```
Initiating NSE at 04:51
```

```
Completed NSE at 04:51, 0.06s elapsed
```

```
Nmap scan report for dc-sf.epg.secfab.org (129.118.26.37)
```

```
Host is up (0.00051s latency).
```

```
PORT      STATE SERVICE
```

```
3389/tcp  open  ms-wbt-server
```

```
| rdp-enum-encryption:
|   Security layer
|     CredSSP: SUCCESS
|     Native RDP: SUCCESS
|     SSL: SUCCESS
|   RDP Encryption level: Client Compatible
|     40-bit RC4: SUCCESS
|     56-bit RC4: SUCCESS
|     128-bit RC4: SUCCESS
|_   FIPS 140-1: SUCCESS
```

NSE: Script Post-scanning.

Read data files from: /usr/local/bin/./share/nmap

Nmap done: 1 IP address (1 host up) scanned in 0.11 seconds

4. The output results of testing on port 3389 of ePDC component:

Starting Nmap 6.46 (<http://nmap.org>) at 2014-07-07 04:53 CDT

NSE: Loaded 1 scripts for scanning.

NSE: Script Pre-scanning.

Initiating Parallel DNS resolution of 1 host. at 04:53

Completed Parallel DNS resolution of 1 host. at 04:53, 0.00s elapsed

Initiating Connect Scan at 04:53

Scanning p3eepdc.ttu.edu (129.118.105.44) [1 port]

Discovered open port 3389/tcp on 129.118.105.44

Completed Connect Scan at 04:53, 0.00s elapsed (1 total ports)

NSE: Script scanning 129.118.105.44.

```

Initiating NSE at 04:53

Completed NSE at 04:53, 0.08s elapsed

Nmap scan report for p3eepdc.ttu.edu (129.118.105.44)

Host is up (0.00089s latency).

PORT      STATE SERVICE
3389/tcp  open  ms-wbt-server

| rdp-enum-encryption:
|
|   Security layer
|
|     CredSSP: SUCCESS
|
|     Native RDP: SUCCESS
|
|     SSL: SUCCESS
|
|   RDP Encryption level: Client Compatible
|
|     40-bit RC4: SUCCESS
|
|     56-bit RC4: SUCCESS
|
|     128-bit RC4: SUCCESS
|_
|     FIPS 140-1: SUCCESS

NSE: Script Post-scanning.

Read data files from: /usr/local/bin/../share/nmap

Nmap done: 1 IP address (1 host up) scanned in 0.14 seconds

```

Suggestion: Configure the remote desktop application to disallow the connection from weak cipher algorithm (e.g., <http://technet.microsoft.com/en-us/library/cc770833.aspx> for Windows Server 2008 R2).

B.5 TLS/SSL Server Supports Weak Cipher Algorithms

Descriptions: The TLS/SSL server supports cipher suites based on weak algorithms. This may enable an attacker to launch man-in-the-middle attacks and monitor or tamper with sensitive data. In general, the following ciphers are considered weak:

- So called "null" ciphers, because they do not encrypt data.
- Export ciphers using secret key lengths restricted to 40 bits. This is usually indicated by the word EXP/EXPORT in the name of the cipher suite.
- Obsolete encryption algorithms with secret key lengths considered short by today's standards, e.g. DES or RC4 with 56-bit keys.

Findings: As shown below, there is only one service provided in testing system that provided TLS/SSL Server, which supports weak cipher algorithm.

| Component | IP Address | Result |
|-----------|-------------------|-------------------------------------------------------------------------|
| SF-AD | 129.118.26.37:636 | RC4 128 bit with MD5 should not be used, due to cryptanalytical attacks |

Table 10 Affected Components and checking result on TLS/SSL support weak cipher

Scripts for testing vulnerabilities: The result from Table 10 is generated by running the following script:

```
$ nmap --script ssl-cert,ssl-enum-ciphers [-Pn] -p[port] [host]
```

Results:

1. The output results of testing on port 636 of SF-AD component:

```
Starting Nmap 6.00 ( http://nmap.org ) at 2014-06-12 06:47 CDT

Nmap scan report for dc-sf.epg.secfab.org (129.118.26.37)

Host is up (0.0069s latency).

PORT      STATE SERVICE
636/tcp   open  ldapssl

| ssl-cert: Subject: commonName=DC-SF.EPG.SECFAB.ORG
| Issuer: commonName=EPG-DC-SF-CA
| Public Key type: rsa
| Public Key bits: 2048
| Not valid before: 2014-05-30 18:56:29
| Not valid after: 2015-05-30 18:56:29
```

```

| MD5:    0a7d 977e a844 ae8c a409 ea60 fb44 e075
|
|_SHA-1: e75f f634 dda9 1458 ba51 3f31 26c2 82e2 717b 29fa
|
| ssl-enum-ciphers:
|
|   SSLv3
|
|     Ciphers (3)
|
|       TLS_RSA_WITH_3DES_EDE_CBC_SHA - strong
|
|       TLS_RSA_WITH_RC4_128_MD5 - unknown strength
|
|       TLS_RSA_WITH_RC4_128_SHA - strong
|
|     Compressors (1)
|
|       NULL
|
|   TLSv1.0
|
|     Ciphers (7)
|
|       TLS_ECDHE_RSA_WITH_AES_128_CBC_SHA - strong
|
|       TLS_ECDHE_RSA_WITH_AES_256_CBC_SHA - unknown strength
|
|       TLS_RSA_WITH_3DES_EDE_CBC_SHA - strong
|
|       TLS_RSA_WITH_AES_128_CBC_SHA - strong
|
|       TLS_RSA_WITH_AES_256_CBC_SHA - unknown strength
|
|       TLS_RSA_WITH_RC4_128_MD5 - unknown strength
|
|       TLS_RSA_WITH_RC4_128_SHA - strong
|
|     Compressors (1)
|
|       NULL
|
|_ Least strength = unknown strength

```

Nmap done: 1 IP address (1 host up) scanned in 0.56 seconds

Suggestions: Restrict the use of certain cryptographic algorithm and protocols. For more details on the restriction see <http://support.microsoft.com/kb/245030/>.

B.6 TLS/SSL Server Supports SSL version 2.0

Descriptions: Although the server accepts clients using TLS or SSLv3, it also accepts clients using SSLv2. SSLv2 is an older implementation of the Secure Sockets Layer protocol. It suffers from a number of security flaws allowing attackers to capture and alter information passed between a client and the server, including the following weaknesses:

- No protection from against man-in-the-middle attacks during the handshake
- Weak MAC construction and MAC relying solely on the MD5 hash function
- Exportable cipher suites unnecessarily weaken the MACs
- Same cryptographic keys used for message authentication and encryption
- Vulnerable to truncation attacks by forged TCP FIN packets

SSLv2 has been deprecated and is no longer recommended. Note that neither SSLv2 nor SSLv3 meet the U.S. FIPS 140-2 standard, which governs cryptographic modules for use in federal information systems. Only the newer TLS (Transport Layer Security) protocol meets FIPS 140-2 requirements. In addition, the presence of an SSLv2-only service on a host is deemed a failure by the PCI (Payment Card Industry) Data Security Standard.

Findings: As shown below, there is only one service in the tested system that provides TLS/SSL Server, which supports SSL version 2.0.

| Component | IP Address | Result |
|-----------|-------------------|------------------------------|
| SF-AD | 129.118.26.37:636 | SSL version 2.0 is supported |

Table 11. Affected Components and checking result on TLS/SSL support SSL version 2.0

Scripts for testing vulnerabilities: The result from Table 11 is generated by running the following script:

```
$ nmap --script sslv2 [-Pn] -p[port] [host]
```

Results:

1. The output results of testing on port 636 of SF-AD component:

```
Starting Nmap 6.46 ( http://nmap.org ) at 2014-07-07 04:29 CDT  
  
NSE: Loaded 1 scripts for scanning.
```

```
NSE: Script Pre-scanning.

Initiating Parallel DNS resolution of 1 host. at 04:30

Completed Parallel DNS resolution of 1 host. at 04:30, 0.00s elapsed

Initiating Connect Scan at 04:30

Scanning dc-sf.epg.secfab.org (129.118.26.37) [1 port]

Discovered open port 636/tcp on 129.118.26.37

Completed Connect Scan at 04:30, 0.00s elapsed (1 total ports)

NSE: Script scanning 129.118.26.37.

Initiating NSE at 04:30

Completed NSE at 04:30, 0.00s elapsed

Nmap scan report for dc-sf.epg.secfab.org (129.118.26.37)

Host is up (0.0030s latency).

PORT      STATE SERVICE
636/tcp   open  ldapssl
|  sslv2:
|    SSLv2 supported
|  ciphers:
|    SSL2_RC4_128_WITH_MD5
|_   SSL2_DES_192_EDE3_CBC_WITH_MD5

NSE: Script Post-scanning.

Read data files from: /usr/local/bin/./share/nmap

Nmap done: 1 IP address (1 host up) scanned in 0.06 seconds
```

Suggestions: Restrict the use of certain cryptographic algorithm and protocols. For more details about the restriction see <http://support.microsoft.com/kb/245030/>.

B.7 Database Open Access

Descriptions: The database allows any remote system the ability to connect to it. It is recommended to limit direct access to trusted systems because databases may contain sensitive data, and new vulnerabilities and exploits are discovered routinely for them. For this reason, it is a violation of PCI DSS section 1.3.7 to have databases listening on ports accessible from the Internet, even when protected with secure authentication mechanisms.

Findings: There are two services provided in testing system that provided database open access as shown in the table below.

| Component | IP Address | Result |
|-----------|---------------------|--------------------------------------|
| ePDC | 129.118.105.44:1433 | Running Microsoft SQL Server 2012 |
| SF-ePO | 129.118.19.210:1433 | Running Microsoft SQL Server 2008 R2 |

Table 12. Affected Components and checking result on database open access

Scripts for testing vulnerabilities: The results from the table above are generated by running the following script:

```
$ nmap -sV -p[port] [host]
```

Results:

1. The output results of testing on port 1433 of ePDC component:

```
Starting Nmap 6.46 ( http://nmap.org ) at 2014-07-18 05:39 CDT

Nmap scan report for p3eepdc.ttu.edu (129.118.105.44)

Host is up (0.00088s latency).

PORT      STATE SERVICE  VERSION
1433/tcp  open  ms-sql-s Microsoft SQL Server 2012

1 service unrecognized despite returning data. If you know the
service/version, please submit the following fingerprint at
http://www.insecure.org/cgi-bin/servicefp-submit.cgi :

SF-Port1433-TCP:V=6.46%I=7%D=7/18%Time=53C8F956%P=i686-pc-linux-gnu%r(ms-s
SF:ql-s,25,"\\x04\\x01\\0%\\0\\0\\x01\\0\\0\\0\\x15\\0\\x06\\x01\\0\\x1b\\0\\x01\\x02\\0\\x1c\\
```

```
SF:0\x01\x03\0\x1d\0\0\xff\x0b\0\x08\xaa\0\0\0\0");  
  
Service Info: OS: Windows; CPE: cpe:/o:microsoft:windows  
  
Service detection performed. Please report any incorrect results at  
http://nmap.org/submit/ .  
  
Nmap done: 1 IP address (1 host up) scanned in 12.36 seconds
```

2. The output results of testing on port 1433 of SF-ePO component:

```
Starting Nmap 6.46 ( http://nmap.org ) at 2014-07-18 05:43 CDT  
  
Nmap scan report for epo-sf.epg.secfab.org (129.118.19.210)  
  
Host is up (0.00072s latency).  
  
PORT      STATE SERVICE  VERSION  
  
1433/tcp  open  ms-sql-s Microsoft SQL Server 2008 R2 10.50.1600; RTM  
  
Service Info: OS: Windows; CPE: cpe:/o:microsoft:windows  
  
Service detection performed. Please report any incorrect results at  
http://nmap.org/submit/ .  
  
Nmap done: 1 IP address (1 host up) scanned in 6.16 seconds
```

Suggestions: To remove this vulnerability, the database server needs to be configured to only allow access from trusted systems. For example, the PCI DSS standard requires you to place the database in an internal network zone, segregated from the DMZ.

B.8 Heartbleed Vulnerability

Descriptions: Heartbleed is a security bug in the OpenSSL cryptography library. OpenSSL is a widely used implementation of the Transport Layer Security (TLS) protocol. Heartbleed may be exploited whether the party using a vulnerable OpenSSL instance for TLS is a server or a client.

Heartbleed results from improper input validation (due to a missing bounds check) in the implementation of the TLS heartbeat extension, the heartbeat being the basis for the bug's name. The vulnerability is classified as a buffer over-read, a situation where software allows more data to be read than should be allowed.

Findings: There are six potential services provided in testing system that might be affected by Heartbleed vulnerability as shown below.

| IP Address | Service | Heartbeat support | Exploitable |
|------------------------------|----------|-------------------|-------------|
| 129.118.19.210:443 (SF-ePO) | ssl/http | Yes | No |
| 129.118.19.210:8443 (SF-ePO) | ssl/http | No | No |
| 129.118.19.210:8444 (SF-ePO) | ssl/http | No | No |
| 129.118.26.40:443 (SF-ESM) | ssl/http | Yes | No |
| 129.118.26.37:636 (SF-AD) | ssl/ldap | No | No |
| 129.118.26.37:3269 (SF-AD) | ssl/ldap | No | No |

Table 13. Potential services that might be affected by Heartbleed vulnerability and the testing result.

Scripts for testing vulnerabilities: The result of checking the supporting Heartbeat extension from Table 13 is generated by running the following script:

```
$openssl s_client -connect [host]:[port] -tlsextdebug
```

Results:

1. The output results of testing on port 443 of SF-ePO component (support Heartbeat):

```
CONNECTED(00000003)

TLS server extension "renegotiation info" (id=65281), len=1

0001 - <SPACES/NULS>

TLS server extension "session ticket" (id=35), len=0

TLS server extension "heartbeat" (id=15), len=1

0000 - 01

depth=0 O = McAfee, OU = ePO, CN = AH_EPO-SF

verify error:num=20:unable to get local issuer certificate

verify return:1

depth=0 O = McAfee, OU = ePO, CN = AH_EPO-SF

verify error:num=27:certificate not trusted

verify return:1
```

```
depth=0 O = McAfee, OU = ePO, CN = AH_EPO-SF  
  
verify error:num=21:unable to verify the first certificate  
  
verify return:1
```

2. The output results of testing on port 8443 of SF-ePO component (not support Heartbeat):

```
CONNECTED(00000003)  
  
TLS server extension "EC point formats" (id=11), len=2  
  
0000 - 01  
  
0002 - <SPACES/NULS>  
  
depth=1 O = McAfee, OU = Orion, CN = Orion_CA_EPO-SF  
  
verify error:num=19:self signed certificate in certificate chain  
  
verify return:0
```

3. The output results of testing on port 8444 of SF-ePO component (not support Heartbeat):

```
CONNECTED(00000003)  
  
TLS server extension "EC point formats" (id=11), len=2  
  
0000 - 01  
  
0002 - <SPACES/NULS>  
  
depth=1 O = McAfee, OU = Orion, CN = Orion_CA_EPO-SF  
  
verify error:num=19:self signed certificate in certificate chain  
  
verify return:0
```

4. The output results of testing on port 443 of SF-ESM component (support Heartbeat):

```
CONNECTED(00000003)  
  
TLS server extension "renegotiation info" (id=65281), len=1  
  
0001 - <SPACES/NULS>  
  
TLS server extension "session ticket" (id=35), len=0
```

```
TLS server extension "heartbeat" (id=15), len=1
```

```
0000 - 01
```

```
depth=0 C = US, ST = TX, L = Plano, O = McAfee, OU = Enterprise Security  
Manager, CN = esm.mcafee.local, emailAddress = support@nitrosecurity.com
```

```
verify error:num=18:self signed certificate
```

```
verify return:1
```

```
depth=0 C = US, ST = TX, L = Plano, O = McAfee, OU = Enterprise Security  
Manager, CN = esm.mcafee.local, emailAddress = support@nitrosecurity.com
```

```
verify return:1
```

5. The output results of testing on port 636 of SF-AD component (not support Heartbeat):

```
CONNECTED(00000003)
```

```
TLS server extension "renegotiation info" (id=65281), len=1
```

```
0001 - <SPACES/NULS>
```

```
depth=0 CN = DC-SF.EPG.SECFAB.ORG
```

```
verify error:num=20:unable to get local issuer certificate
```

```
verify return:1
```

```
depth=0 CN = DC-SF.EPG.SECFAB.ORG
```

```
verify error:num=27:certificate not trusted
```

```
verify return:1
```

```
depth=0 CN = DC-SF.EPG.SECFAB.ORG
```

```
verify error:num=21:unable to verify the first certificate
```

```
verify return:1
```

6. The output results of testing on port 3269 of SF-AD component (not support Heartbeat):

```
CONNECTED(00000003)
```

```

TLS server extension "renegotiation info" (id=65281), len=1

0001 - <SPACES/NULS>

depth=0 CN = DC-SF.EPG.SECFAB.ORG

verify error:num=20:unable to get local issuer certificate

verify return:1

depth=0 CN = DC-SF.EPG.SECFAB.ORG

verify error:num=27:certificate not trusted

verify return:1

depth=0 CN = DC-SF.EPG.SECFAB.ORG

verify error:num=21:unable to verify the first certificate

verify return:1

```

Scripts for testing exploits:

For each service that supports Heartbeat extension, the following scripts from Metasploit framework are used to verify the exploitability of Heartbleed vulnerabilities:

```

msf> use auxiliary/scanner/ssl/openssl_heartbleed

msf auxiliary(openssl_heartbleed)> set rhosts [hosts]

msf auxiliary(openssl_heartbleed)> set rport [port]

msf auxiliary(openssl_heartbleed)> set tls_version [tls_version]

msf auxiliary(openssl_heartbleed)> run

```

Results:

1. The output results of exploiting on port 443 of SF-ePO component:

```

[*] 129.118.19.210:443 - Sending Client Hello...

[!] SSL record #1:

[!]      Type:      22

```



```

[!]      Version: 0x0301

[!]      Length:  54

[!]      Handshake #1:

[!]              Length: 50

[!]              Type:   Server Hello (2)

[!]              Server Hello Version:           0x0301

[!]              Server Hello random data:
b348b1b1a94512858f8685805a0694a04e2e3a6d1c8894ef844ad43f3cc38c60

[!]              Server Hello Session ID length: 0

[!]              Server Hello Session ID:

[!] SSL record #2:

[!]      Type:      22

[!]      Version: 0x0301

[!]      Length:   838

[!]      Handshake #1:

[!]              Length: 834

[!]              Type:   Certificate Data (11)

[!]              Certificates length: 831

[!]              Certificate #1:

[!]                      Certificate #1: Length: 828

[!]                      Certificate #1: #<OpenSSL::X509::Certificate:
subject=/O=McAfee/OU=ePO/CN=AH_EPO-SF, issuer=/O=McAfee/OU=
AH/CN=AH_CA_EPO-SF, serial=5957554068034109659, not_before=1970-01-01
00:00:00 UTC, not_after=2043-09-04 08:13:09 UTC>

[!] SSL record #3:

[!]      Type:      22

```

```

[!]      Version: 0x0301

[!]      Length:  525

[!]      Handshake #1:

[!]              Length: 521

[!]              Type:   Server Key Exchange (12)

[!] SSL record #4:

[!]      Type:      22

[!]      Version: 0x0301

[!]      Length:   4

[!]      Handshake #1:

[!]              Length: 0

[!]              Type:   Server Hello Done (14)

[*] 129.118.19.210:443 - Sending Client Hello...

[!] SSL record #1:

[!]      Type:      22

[!]      Version: 0x0301

[!]      Length:   54

[!]      Handshake #1:

[!]              Length: 50

[!]              Type:   Server Hello (2)

[!]              Server Hello Version:          0x0301

[!]              Server Hello random data:
2d38960b433d847cfe645621629474bdc575b92e64566268fd9549dd720cfa60

[!]              Server Hello Session ID length: 0

[!]              Server Hello Session ID:

```

```

[!] SSL record #2:

[!]   Type:      22

[!]   Version:  0x0301

[!]   Length:   838

[!]   Handshake #1:

[!]           Length: 834

[!]           Type:   Certificate Data (11)

[!]           Certificates length: 831

[!]           Certificate #1:

[!]                   Certificate #1: Length: 828

[!]                   Certificate #1: #<OpenSSL::X509::Certificate:
subject=/O=McAfee/OU=ePO/CN=AH_EPO-SF, issuer=/O=McAfee/OU=
AH/CN=AH_CA_EPO-SF, serial=5957554068034109659, not_before=1970-01-01
00:00:00 UTC, not_after=2043-09-04 08:13:09 UTC>

[!] SSL record #3:

[!]   Type:      22

[!]   Version:  0x0301

[!]   Length:   525

[!]   Handshake #1:

[!]           Length: 521

[!]           Type:   Server Key Exchange (12)

[!] SSL record #4:

[!]   Type:      22

[!]   Version:  0x0301

[!]   Length:    4

[!]   Handshake #1:

```

```

[!]          Length: 0

[!]          Type:    Server Hello Done (14)

[*] 129.118.19.210:443 - Sending Heartbeat...

[-] 129.118.19.210:443 - No Heartbeat response...

[-] 129.118.19.210:443 - Looks like there isn't leaked information...

[*] Scanned 1 of 1 hosts (100% complete)

[*] Auxiliary module execution completed

```

2. The output results of exploiting on port 443 of SF-ESM component:

```

[*] 129.118.26.40:443 - Sending Client Hello...

[!] SSL record #1:

[!]    Type:      22

[!]    Version: 0x0301

[!]    Length:   86

[!]    Handshake #1:

[!]          Length: 82

[!]          Type:    Server Hello (2)

[!]          Server Hello Version:          0x0301

[!]          Server Hello random data:
c4e23b82387803b7f00891353e6336f4f6e3506e535eaf88fd039675f74b1dd5

[!]          Server Hello Session ID length: 32

[!]          Server Hello Session ID:
2201cf9cb3a59d265c7f2149c2aa99354c9c80be4596e30de21c115cc04c3fb7

[!] SSL record #2:

[!]    Type:      22

[!]    Version: 0x0301

```

```

[!]      Length:  1961

[!]      Handshake #1:

[!]              Length: 1957

[!]              Type:   Certificate Data (11)

[!]              Certificates length: 1954

[!]              Certificate #1:

[!]                      Certificate #1: Length: 974

[!]                      Certificate #1: #<OpenSSL::X509::Certificate:
subject=/C=US/ST=TX/L=Plano/O=McAfee/OU=Enterprise Security
Manager/CN=esm.mcafee.local/emailAddress=support@nitrosecurity.com,
issuer=/C=US/ST=TX/L=Plano/O=McAfee/OU=Enterprise Security
Manager/CN=esm.mcafee.local/emailAddress=support@nitrosecurity.com,
serial=13709899052840045994, not_before=2013-05-15 04:11:47 UTC,
not_after=2023-05-15 04:11:47 UTC>

[!]                      Certificate #2:

[!]                      Certificate #2: Length: 974

[!]                      Certificate #2: #<OpenSSL::X509::Certificate:
subject=/C=US/ST=TX/L=Plano/O=McAfee/OU=Enterprise Security
Manager/CN=esm.mcafee.local/emailAddress=support@nitrosecurity.com,
issuer=/C=US/ST=TX/L=Plano/O=McAfee/OU=Enterprise Security
Manager/CN=esm.mcafee.local/emailAddress=support@nitrosecurity.com,
serial=13709899052840045994, not_before=2013-05-15 04:11:47 UTC,
not_after=2023-05-15 04:11:47 UTC>

[!] SSL record #3:

[!]      Type:      22

[!]      Version: 0x0301

[!]      Length:   525

[!]      Handshake #1:

[!]              Length: 521

[!]              Type:   Server Key Exchange (12)

```

```

[!] SSL record #4:

[!]   Type:      22

[!]   Version: 0x0301

[!]   Length:   4

[!]   Handshake #1:

[!]           Length: 0

[!]           Type:   Server Hello Done (14)

[*] 129.118.26.40:443 - Sending Client Hello...

[!] SSL record #1:

[!]   Type:      22

[!]   Version: 0x0301

[!]   Length:   86

[!]   Handshake #1:

[!]           Length: 82

[!]           Type:   Server Hello (2)

[!]           Server Hello Version:           0x0301

[!]           Server Hello random data:
337acc7669ec433106d31c05b5ca1dbe77349f1bef9bd4c84e6cfd55f73e95e9

[!]           Server Hello Session ID length: 32

[!]           Server Hello Session ID:
b27ce41b4a135dec4106a958c999c7c7f51405e27a3021f453a7cd9a6f49964e

[!] SSL record #2:

[!]   Type:      22

[!]   Version: 0x0301

[!]   Length:   1961

```

```

[!]      Handshake #1:

[!]          Length: 1957

[!]          Type:    Certificate Data (11)

[!]          Certificates length: 1954

[!]          Certificate #1:

[!]              Certificate #1: Length: 974

[!]              Certificate #1: #<OpenSSL::X509::Certificate:
subject=/C=US/ST=TX/L=Plano/O=McAfee/OU=Enterprise Security
Manager/CN=esm.mcafee.local/emailAddress=support@nitrosecurity.com,
issuer=/C=US/ST=TX/L=Plano/O=McAfee/OU=Enterprise Security
Manager/CN=esm.mcafee.local/emailAddress=support@nitrosecurity.com,
serial=13709899052840045994, not_before=2013-05-15 04:11:47 UTC,
not_after=2023-05-15 04:11:47 UTC>

[!]          Certificate #2:

[!]              Certificate #2: Length: 974

[!]              Certificate #2: #<OpenSSL::X509::Certificate:
subject=/C=US/ST=TX/L=Plano/O=McAfee/OU=Enterprise Security
Manager/CN=esm.mcafee.local/emailAddress=support@nitrosecurity.com,
issuer=/C=US/ST=TX/L=Plano/O=McAfee/OU=Enterprise Security
Manager/CN=esm.mcafee.local/emailAddress=support@nitrosecurity.com,
serial=13709899052840045994, not_before=2013-05-15 04:11:47 UTC,
not_after=2023-05-15 04:11:47 UTC>

[!] SSL record #3:

[!]      Type:      22

[!]      Version: 0x0301

[!]      Length:   525

[!]      Handshake #1:

[!]          Length: 521

[!]          Type:    Server Key Exchange (12)

[!] SSL record #4:

```

```
[!]      Type:      22

[!]      Version: 0x0301

[!]      Length:   4

[!]      Handshake #1:

[!]              Length: 0

[!]              Type:   Server Hello Done (14)

[*] 129.118.26.40:443 - Sending Heartbeat...

[-] 129.118.26.40:443 - No Heartbeat response...

[-] 129.118.26.40:443 - Looks like there isn't leaked information...

[*] Scanned 1 of 1 hosts (100% complete)

[*] Auxiliary module execution completed
```


Appendix C: Service Scanning

Service scanning is useful for both parts of the TTU testing activities. For verification of given security requirement specifications, the results of scanning help identify relevant services to test and for penetration testing, scanning results are the starting point of vulnerability exploits. We used *nmap* (network mapper)* as our service scanner. In our testing environments, there are 73 services, 25 of which are in the original network setup without Security Fabric Framework and 48 of which are in the Security Fabric-enabled (SF-enabled) network. The table below gives a summary of service components, where the top two are those in non-SF-enabled environment and the rest (highlighted) are those in the SF-enabled environment.

| Component | Number of Services |
|-----------|--------------------|
| RTDMS | 11 |
| ePDC | 14 |
| SF-RTDMS | 2 |
| SF-ePDC | 2 |
| SF-ePO | 15 |
| SF-ESM | 5 |
| SF-AD | 23 |

Table 14. Summary of Service Components in non-SF-enabled and SF-enabled environments.

The following provides detailed scanning results of each of the relevant system components mentioned above in the table.

RTDMS Server at TTU Main Campus (11 Services)

```
Starting Nmap 6.00 ( http://nmap.org ) at 2014-04-21 09:33 CDT

Nmap scan report for p3ertdms.ttu.edu (129.118.19.167)

Host is up (0.00031s latency).

Not shown: 989 filtered ports

PORT      STATE SERVICE      VERSION
80/tcp    open  http         Microsoft IIS httpd 7.5

| http-methods: Potentially risky methods: TRACE
```

* Lyon, G. F., 2009. Nmap Network Scanning: The Official Nmap Project Guide to Network Discovery and Security Scanning. Nmap Project at www.nmap.org.

|_See <http://nmap.org/nsedoc/scripts/http-methods.html>

|_http-title: IIS7

135/tcp open msrpc Microsoft Windows RPC

445/tcp open netbios-ssn

808/tcp open ccproxy-http?

1801/tcp open msmq?

2103/tcp open msrpc Microsoft Windows RPC

2105/tcp open msrpc Microsoft Windows RPC

2107/tcp open msrpc Microsoft Windows RPC

3389/tcp open ms-wbt-server Microsoft Terminal Service

49154/tcp open msrpc Microsoft Windows RPC

49165/tcp open msrpc Microsoft Windows RPC

Warning: OSScan results may be unreliable because we could not find at least 1 open and 1 closed port

Device type: general purpose

Running: Microsoft Windows 2008|Vista|7

OS CPE: cpe:/o:microsoft:windows_server_2008::beta3
cpe:/o:microsoft:windows_vista::- cpe:/o:microsoft:windows_vista::sp1
cpe:/o:microsoft:windows_7

OS details: Microsoft Windows Server 2008 Beta 3, Microsoft Windows Vista SP0 or SP1, Windows Server 2008 SP1, or Windows 7, Microsoft Windows Vista SP2 or Windows Server 2008

Network Distance: 2 hops

Service Info: OS: Windows; CPE: cpe:/o:microsoft:windows

Host script results:

| smb-security-mode:

| Account that was used for smb scripts: guest

```

|   User-level authentication

|   SMB Security: Challenge/response passwords supported

|_  Message signing disabled (dangerous, but default)

|_smbv2-enabled: Server supports SMBv2 protocol

|  smb-os-discovery:

|   OS: Windows Server 2008 R2 Standard 7601 Service Pack 1 (Windows Server 2008 R2
Standard 6.1)

|   NetBIOS computer name: P3ERTDMS

|   Workgroup: WORKGROUP

|_  System time: 2014-04-21 15:36:22 UTC-5


TRACEROUTE (using port 80/tcp)

HOP RTT      ADDRESS

1    2.09 ms  cpert01-vl62.ttu.edu (129.118.163.254)

2    0.31 ms  p3ertdms.ttu.edu (129.118.19.167)


OS and Service detection performed. Please report any incorrect results at
http://nmap.org/submit/ .

Nmap done: 1 IP address (1 host up) scanned in 96.92 seconds

```

ePDC Server at Reese Center (14 Services)

```

Starting Nmap 6.00 ( http://nmap.org ) at 2014-04-21 09:42 CDT

Nmap scan report for p3eepdc.ttu.edu (129.118.105.44)

Host is up (0.00090s latency).

Not shown: 986 filtered ports

PORT      STATE SERVICE      VERSION
80/tcp    open  http         Microsoft IIS httpd 7.5

```

```

|_http-title: IIS7

| http-methods: Potentially risky methods: TRACE

|_See http://nmap.org/nsedoc/scripts/http-methods.html

135/tcp open  msrpc           Microsoft Windows RPC
139/tcp open  netbios-ssn
445/tcp open  netbios-ssn
1027/tcp open  msrpc           Microsoft Windows RPC
1028/tcp open  msrpc           Microsoft Windows RPC
1037/tcp open  msrpc           Microsoft Windows RPC
1433/tcp open  ms-sql-s        Microsoft SQL Server 2011 11.00.2218.00
1801/tcp open  msmq?
2103/tcp open  msrpc           Microsoft Windows RPC
2105/tcp open  msrpc           Microsoft Windows RPC
2107/tcp open  msrpc           Microsoft Windows RPC
3389/tcp open  ms-wbt-server   Microsoft Terminal Service
8500/tcp open  msexchange-logcopier Microsoft Exchange 2010 log copier

Warning: OSScan results may be unreliable because we could not find at least 1 open
and 1 closed port

Device type: general purpose

Running: Microsoft Windows 7|Vista|2008

OS CPE: cpe:/o:microsoft:windows_7::professional cpe:/o:microsoft:windows_vista::-
cpe:/o:microsoft:windows_vista::sp1 cpe:/o:microsoft:windows_server_2008::sp1

OS details: Microsoft Windows 7 Professional, Microsoft Windows Vista SP0 or SP1,
Windows Server 2008 SP1, or Windows 7, Microsoft Windows Vista SP2 or Windows Server
2008

Network Distance: 3 hops

Service Info: OS: Windows; CPE: cpe:/o:microsoft:windows

```

Host script results:

|_nbstat: NetBIOS name: P3EEPDC, NetBIOS user: <unknown>, NetBIOS MAC:
d4:ae:52:a6:39:3a (Dell)

|_smbv2-enabled: Server supports SMBv2 protocol

| smb-security-mode:

| Account that was used for smb scripts: guest

| User-level authentication

| SMB Security: Challenge/response passwords supported

|_ Message signing disabled (dangerous, but default)

| smb-os-discovery:

| OS: Windows Server 2008 R2 Standard 7601 Service Pack 1 (Windows Server 2008 R2
Standard 6.1)

| NetBIOS computer name: P3EEPDC

| Workgroup: WORKGROUP

|_ System time: 2014-04-21 15:45:38 UTC-5

| ms-sql-info:

| [129.118.105.44:1433]

| Version: Microsoft SQL Server 2011

| Version number: 11.00.2218.00

| Product: Microsoft SQL Server 2011

|_ TCP port: 1433

TRACEROUTE (using port 445/tcp)

| HOP | RTT | ADDRESS |
|-----|-----|---------|
|-----|-----|---------|

| | | |
|---|---------|---------------------------------------|
| 1 | 6.36 ms | cppt01-v162.ttu.edu (129.118.163.254) |
|---|---------|---------------------------------------|

```
2    0.43 ms 129.118.251.123

3    1.12 ms p3eepdc.ttu.edu (129.118.105.44)
```

OS and Service detection performed. Please report any incorrect results at <http://nmap.org/submit/> .

Nmap done: 1 IP address (1 host up) scanned in 100.52 seconds

SF-RTDMS at TTU side (2 Services)

Starting Nmap 6.00 (<http://nmap.org>) at 2014-01-29 06:24 CST

Nmap scan report for eewrb001.ttu.edu (129.118.26.8)

Host is up (0.00037s latency).

Not shown: 998 filtered ports

| PORT | STATE | SERVICE | VERSION |
|------|-------|---------|---------|
|------|-------|---------|---------|

| | | | |
|--------|------|-----|----------------------------|
| 22/tcp | open | ssh | OpenSSH 6.0 (protocol 2.0) |
|--------|------|-----|----------------------------|

| ssh-hostkey: 1024 b5:2f:09:18:61:ba:28:d7:4f:9d:1f:3c:5d:b2:87:6d (DSA)

|_2048 7d:ff:f9:ac:d6:03:8a:3a:9c:2b:6a:39:ee:8a:72:42 (RSA)

| | | | |
|----------|------|---------------|----------------------------|
| 3389/tcp | open | ms-wbt-server | Microsoft Terminal Service |
|----------|------|---------------|----------------------------|

Warning: OSScan results may be unreliable because we could not find at least 1 open and 1 closed port

Device type: general purpose

Running (JUST GUESSING): Linux 3.X|2.6.X (91%)

OS CPE: cpe:/o:linux:kernel:3 cpe:/o:linux:kernel:2.6

Aggressive OS guesses: Linux 3.0 (91%), Linux 2.6.39 (88%), Linux 2.6.32 - 2.6.38 (88%), Linux 2.6.38 (88%), Linux 2.6.32 - 2.6.35 (88%), Linux 2.6.38 - 3.2 (85%)

No exact OS matches for host (test conditions non-ideal).

Network Distance: 2 hops

Service Info: OS: Windows

TRACEROUTE (using port 3389/tcp)

| HOP | RTT | ADDRESS |
|-----|-----|---------|
|-----|-----|---------|

| | | |
|---|----------|-------------------------------------|
| 1 | 16.58 ms | cp01-v162.ttu.edu (129.118.163.254) |
|---|----------|-------------------------------------|

| | | |
|---|---------|--------------------------------|
| 2 | 0.35 ms | ewrb001.ttu.edu (129.118.26.8) |
|---|---------|--------------------------------|

OS and Service detection performed. Please report any incorrect results at <http://nmap.org/submit/> .

Nmap done: 1 IP address (1 host up) scanned in 15.52 seconds

SF-ePDC at Reese side (2 Services)

Starting Nmap 6.00 (<http://nmap.org>) at 2014-01-29 06:19 CST

Nmap scan report for 129.118.105.50

Host is up (0.00093s latency).

Not shown: 998 filtered ports

| PORT | STATE | SERVICE | VERSION |
|------|-------|---------|---------|
|------|-------|---------|---------|

| | | | |
|--------|------|-----|----------------------------|
| 22/tcp | open | ssh | OpenSSH 6.0 (protocol 2.0) |
|--------|------|-----|----------------------------|

| ssh-hostkey: 1024 c5:2d:c4:eb:89:b2:1b:a3:33:5f:e0:68:e8:8d:f4:3d (DSA)

|_2048 b4:87:98:d2:a2:4a:d2:b2:e0:a0:c3:63:11:ab:55:30 (RSA)

| | | | |
|----------|------|---------------|----------------------------|
| 3389/tcp | open | ms-wbt-server | Microsoft Terminal Service |
|----------|------|---------------|----------------------------|

Warning: OSScan results may be unreliable because we could not find at least 1 open and 1 closed port

Device type: general purpose

Running (JUST GUESSING): Linux 3.X|2.6.X (93%)

OS CPE: cpe:/o:linux:kernel:3 cpe:/o:linux:kernel:2.6

Aggressive OS guesses: Linux 3.0 (93%), Linux 2.6.39 (88%), Linux 2.6.32 - 2.6.38 (88%), Linux 2.6.38 (88%), Linux 2.6.32 - 2.6.35 (88%), Linux 2.6.38 - 3.2 (85%)

No exact OS matches for host (test conditions non-ideal).

Network Distance: 3 hops

Service Info: OS: Windows

TRACEROUTE (using port 22/tcp)

| HOP | RTT | ADDRESS |
|-----|---------|----------------------------------------|
| 1 | 0.16 ms | cpirt01-v162.ttu.edu (129.118.163.254) |
| 2 | 0.41 ms | 129.118.251.123 |
| 3 | 0.93 ms | 129.118.105.50 |

SF-ePO (15 Services)

Starting Nmap 6.00 (<http://nmap.org>) at 2014-01-29 06:27 CST

Nmap scan report for epo-sf.epg.secfab.org (129.118.19.210)

Host is up (0.00040s latency).

Not shown: 985 closed ports

| PORT | STATE | SERVICE | VERSION |
|--------|-------|---------|-------------------------|
| 80/tcp | open | http | Microsoft IIS httpd 7.5 |

| http-methods: Potentially risky methods: TRACE

|_See <http://nmap.org/nsedoc/scripts/http-methods.html>

| | | | |
|---------|------|-------|-----------------------|
| 135/tcp | open | msrpc | Microsoft Windows RPC |
|---------|------|-------|-----------------------|

| | | | |
|---------|------|-------------|--|
| 139/tcp | open | netbios-ssn | |
|---------|------|-------------|--|

| | | | |
|---------|------|----------|--------------|
| 443/tcp | open | ssl/http | Apache httpd |
|---------|------|----------|--------------|

| ssl-cert: Subject: commonName=AH_EPO-SF/organizationName=McAfee

| Not valid before: 1970-01-01 00:00:00

|_Not valid after: 2014-01-29 06:29:01

|_http-title: 403 Forbidden

|_http-methods: No Allow or Public header in OPTIONS response (status code 403)


```

445/tcp  open  netbios-ssn

1433/tcp  open  ms-sql-s      Microsoft SQL Server 2008 R2 10.50.1600.00; RTM

2383/tcp  open  ms-olap4?

3389/tcp  open  ms-wbt-server?

8080/tcp  open  http          Apache httpd

|_http-title: 403 Forbidden

|_http-methods: No Allow or Public header in OPTIONS response (status code 403)

8081/tcp  open  tcpwrapped

8443/tcp  open  ssl/http      McAfee ePolicy Orchestrator http interface

|_http-title: Site doesn't have a title (text/html).

| ssl-cert: Subject: commonName=EPO-SF/organizationName=McAfee

| Not valid before: 1970-01-01 00:00:00

|_Not valid after: 2014-01-29 06:29:01

| http-methods: Potentially risky methods: PUT DELETE

|_See http://nmap.org/nsedoc/scripts/http-methods.html

49152/tcp open  msrpc        Microsoft Windows RPC

49153/tcp open  msrpc        Microsoft Windows RPC

49154/tcp open  msrpc        Microsoft Windows RPC

49155/tcp open  msrpc        Microsoft Windows RPC

Device type: general purpose

Running: Microsoft Windows 2008|7

OS CPE: cpe:/o:microsoft:windows_server_2008::sp2 cpe:/o:microsoft:windows_7

OS details: Microsoft Windows Server 2008 SP2, Microsoft Windows 7 or Windows
Server 2008 SP1

Network Distance: 2 hops

Service Info: OS: Windows; CPE: cpe:/o:microsoft:windows

```

Host script results:

|_nbstat: NetBIOS name: EPO-SF, NetBIOS user: <unknown>, NetBIOS MAC:
00:50:56:94:70:69 (VMware)

| smb-security-mode:

| Account that was used for smb scripts: guest

| User-level authentication

| SMB Security: Challenge/response passwords supported

|_ Message signing disabled (dangerous, but default)

|_smbv2-enabled: Server supports SMBv2 protocol

| smb-os-discovery:

| OS: Windows Server 2008 R2 Standard 7601 Service Pack 1 (Windows Server 2008 R2
Standard 6.1)

| NetBIOS computer name: EPO-SF

| Workgroup: EPG

|_ System time: 2014-01-29 12:29:50 UTC-6

| ms-sql-info:

| [129.118.19.210:1433]

| Version: Microsoft SQL Server 2008 R2 RTM

| Version number: 10.50.1600.00

| Product: Microsoft SQL Server 2008 R2

| Service pack level: RTM

| Post-SP patches applied: No

|_ TCP port: 1433

TRACEROUTE (using port 5900/tcp)

| HOP | RTT | ADDRESS |
|-----|-----|---------|
|-----|-----|---------|

```
1 14.29 ms cpvt01-v162.ttu.edu (129.118.163.254)

2 0.94 ms epo-sf.epg.secfab.org (129.118.19.210)

OS and Service detection performed. Please report any incorrect results at
http://nmap.org/submit/ .

Nmap done: 1 IP address (1 host up) scanned in 74.41 seconds
```

SF-ESM (5 Services)

```
Starting Nmap 6.00 ( http://nmap.org ) at 2014-01-29 06:35 CST

Nmap scan report for 129.118.26.40

Host is up (0.00049s latency).

Not shown: 995 filtered ports

PORT      STATE  SERVICE      VERSION

22/tcp    open   ssh          (protocol 2.0)

|_ssh-hostkey: 2048 d0:11:53:36:4b:b0:91:00:b9:7d:4f:d3:5a:f8:2c:bf (RSA)

23/tcp    open   ssh          libssh 0.5.2 (protocol 2.0)

|_ssh-hostkey: 2048 44:de:b2:ba:46:e3:10:48:43:e2:8f:34:4f:06:4e:26 (RSA)

80/tcp    open   http         Apache httpd

| http-title: 302 Found

|_Did not follow redirect to https://129.118.26.40/

|_http-methods: No Allow or Public header in OPTIONS response (status code 302)

443/tcp   open   ssl/http     Apache httpd

| ssl-cert: Subject:
commonName=esm.mcafee.local/organizationName=McAfee/stateOrProvinceName=TX/countryName
=US

| Not valid before: 2013-05-15 04:11:47

|_Not valid after: 2023-05-15 04:11:47

| http-robots.txt: 1 disallowed entry

|_/
```

```

|_sslv2: server supports SSLv2 protocol, but no SSLv2 cyphers

|_http-title: McAfee Enterprise Security Manager

4242/tcp closed vrml-multi-use

1 service unrecognized despite returning data. If you know the service/version,
please submit the following fingerprint at http://www.insecure.org/cgi-bin/servicefp-
submit.cgi :

SF-Port22-TCP:V=6.00%I=7%D=1/29%Time=52E8F5B2%P=i686-pc-linux-gnu%r(NULL,1

SF:2,"SSH-2\0.0-SSH_FIPS\r\n");

Device type: WAP|media device|webcam|specialized|general purpose|storage-
misc|broadband router

Running (JUST GUESSING): Netgear embedded (94%), Western Digital embedded (94%),
AXIS Linux 2.6.X (93%), Crestron 2-Series (91%), Linux 2.6.X|2.4.X (90%), Thecus
embedded (89%), Linksys Linux 2.4.X (89%)

OS CPE: cpe:/o:axis:linux:2.6 cpe:/o:crestron:2_series cpe:/o:linux:kernel:2.6.32
cpe:/o:linux:kernel:2.6.22 cpe:/o:linux:kernel:2.4 cpe:/o:linksys:linux:2.4
cpe:/o:linux:kernel:2.6

Aggressive OS guesses: Netgear DG834G WAP or Western Digital WD TV media player
(94%), AXIS 210A or 211 Network Camera (Linux 2.6) (93%), Crestron XPanel control
system (91%), Linux 2.6.32 (90%), Linux 2.6.31 (90%), OpenWrt Kamikaze 7.09 (Linux
2.6.22) (89%), OpenWrt Kamikaze 8.09 (Linux 2.4.35.4) (89%), Linux 2.6.26 (89%),
OpenWrt Kamikaze 8.09 (Linux 2.6.26) (89%), Thecus 4200 or N5500 NAS device (Linux
2.6.33) (89%)

No exact OS matches for host (test conditions non-ideal).

Network Distance: 2 hops

TRACEROUTE (using port 4242/tcp)

HOP RTT      ADDRESS
1    0.16 ms  cprt01-v162.ttu.edu (129.118.163.254)
2    0.46 ms  129.118.26.40

OS and Service detection performed. Please report any incorrect results at
http://nmap.org/submit/ .

```

Nmap done: 1 IP address (1 host up) scanned in 39.82 seconds

SF-AD (23 Services)

```
Starting Nmap 6.00 ( http://nmap.org ) at 2014-01-29 06:44 CST

Nmap scan report for dc-sf.epg.secfab.org (129.118.26.37)

Host is up (0.00032s latency).

Not shown: 977 closed ports

PORT      STATE SERVICE      VERSION

53/tcp    open  domain       Microsoft DNS 6.1.7601

| dns-nsid:

|_ bind.version: Microsoft DNS 6.1.7601 (1DB14556)

88/tcp    open  Kerberos-sec  Windows 2003 Kerberos (server time: 2014-01-29
18:45:31Z)

135/tcp   open  msrpc        Microsoft Windows RPC

139/tcp   open  netbios-ssn

389/tcp   open  ldap

445/tcp   open  netbios-ssn

464/tcp   open  kpasswd5?

593/tcp   open  ncacn_http   Microsoft Windows RPC over HTTP 1.0

636/tcp   open  ssl/ldap

| ssl-cert: Subject: commonName=DC-SF.EPG.SECFAB.ORG

| Not valid before: 2014-01-11 15:44:59

|_Not valid after:  2014-02-10 23:29:17

|_sslv2: server still supports SSLv2

1025/tcp  open  msrpc        Microsoft Windows RPC

1026/tcp  open  msrpc        Microsoft Windows RPC

1028/tcp  open  msrpc        Microsoft Windows RPC
```

```

1029/tcp open  ncacn_http      Microsoft Windows RPC over HTTP 1.0

1030/tcp open  msrpc             Microsoft Windows RPC

1031/tcp open  msrpc             Microsoft Windows RPC

1040/tcp open  msrpc             Microsoft Windows RPC

1042/tcp open  msrpc             Microsoft Windows RPC

1043/tcp open  msrpc             Microsoft Windows RPC

1051/tcp open  msrpc             Microsoft Windows RPC

3268/tcp open  ldap

3269/tcp open  ssl/ldap

|_sslsv2: server still supports SSLv2

| ssl-cert: Subject: commonName=DC-SF.EPG.SECFAB.ORG

| Not valid before: 2014-01-11 15:44:59

|_Not valid after: 2014-02-10 23:29:17

3389/tcp open  ms-wbt-server Microsoft Terminal Service

8081/tcp open  tcpwrapped

No exact OS matches for host (If you know what OS is running on it, see
http://nmap.org/submit/ ).

TCP/IP fingerprint:

OS:SCAN(V=6.00%E=4%D=1/29%OT=53%CT=1%CU=31931%PV=N%DS=2%DC=T%G=Y%TM=52E8F7F
OS:9%P=i686-pc-linux-gnu)SEQ(SP=FC%GCD=2%ISR=10B%TI=I%CI=I%II=I%SS=S%TS=7)O
OS:PS(O1=M5B4NW8ST11%O2=M5B4NW8ST11%O3=M5B4NW8NNT11%O4=M5B4NW8ST11%O5=M5B4N
OS:W8ST11%O6=M5B4ST11)WIN(W1=2000%W2=2000%W3=2000%W4=2000%W5=2000%W6=2000)E
OS:CN(R=Y%DF=Y%T=81%W=2000%O=M5B4NW8NNS%CC=N%Q=)T1(R=Y%DF=Y%T=81%S=O%A=S+%F
OS:=AS%RD=0%Q=)T2(R=Y%DF=Y%T=81%W=0%S=Z%A=S%F=AR%O=%RD=0%Q=)T3(R=Y%DF=Y%T=8
OS:1%W=0%S=Z%A=O%F=AR%O=%RD=0%Q=)T4(R=Y%DF=Y%T=81%W=0%S=A%A=O%F=R%O=%RD=0%Q
OS:=)T5(R=Y%DF=Y%T=81%W=0%S=Z%A=S+%F=AR%O=%RD=0%Q=)T6(R=Y%DF=Y%T=81%W=0%S=A

```

```
OS:%A=O%F=R%O=%RD=0%Q=)T7(R=Y%DF=Y%T=81%W=0%S=Z%A=S+%F=AR%O=%RD=0%Q=)U1(R=Y
OS:%DF=N%T=81%IPL=164%UN=0%RIPL=G%RID=G%RIPCK=G%RUCK=G%RUD=G)IE(R=Y%DFI=N%T
OS:=81%CD=Z)
```

Network Distance: 2 hops

Service Info: OS: Windows; CPE: cpe:/o:microsoft:windows

Host script results:

```
|_nbstat: NetBIOS name: DC-SF, NetBIOS user: <unknown>, NetBIOS MAC:
00:50:56:94:6f:1b (VMware)
```

```
| smb-security-mode:
```

```
|   Account that was used for smb scripts: guest
```

```
|   User-level authentication
```

```
|   SMB Security: Challenge/response passwords supported
```

```
|_ Message signing required
```

```
|_smbv2-enabled: Server supports SMBv2 protocol
```

```
| smb-os-discovery:
```

```
|   OS: Windows Server 2008 R2 Enterprise 7601 Service Pack 1 (Windows Server 2008
R2 Enterprise 6.1)
```

```
|   NetBIOS computer name: DC-SF
```

```
|   Workgroup: EPG
```

```
|_ System time: 2014-01-29 12:46:29 UTC-6
```

TRACEROUTE (using port 993/tcp)

| HOP | RTT | ADDRESS |
|-----|-----|---------|
|-----|-----|---------|

| | | |
|---|---------|----------------------------------------|
| 1 | 0.15 ms | cp1rt01-v162.ttu.edu (129.118.163.254) |
|---|---------|----------------------------------------|

```
2    0.29 ms dc-sf.epg.secfab.org (129.118.26.37)
```

```
OS and Service detection performed. Please report any incorrect results at  
http://nmap.org/submit/ .
```

```
Nmap done: 1 IP address (1 host up) scanned in 75.03 seconds
```