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Acronyms and Abbreviations

A	Ampere
Ah	Ampere-hour
AC	Alternating Current
AEP	American Electric Power
AMI	Advanced Meter(ing) Infrastructure
AMS	Advanced Meter(ing) System
API	Application Programming Interface
AS	Ancillary Service
BESS	Battery Energy Storage System
BMS	Battery Management System
CCET	Center for the Commercialization of Electric Technologies
CIP	Critical Infrastructure Protection
CO2	Carbon Dioxide
CPP	Critical Peak Pricing
CREZ	Competitive Renewable Energy Zone
CT	Current Transducer
DAT	Discovery Across Texas
DAQ	Data Acquisition
DC	Direct Current
DID	Difference in Difference
DG	Distributed Generation
DNP3	Distributed Network Protocol 3
DOE	Department of Energy
DoS	Denial of Service
DP	Dual Polarization
DR	Demand Response
DSL	Digital Subscriber Line
DST	Discovery at Spring Trails
EID	Energy Internet Demonstration
EMS	Energy Management System
ePDC	Enhanced Phasor Data Concentrator
EPG	Electric Power Group
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ESCT	Energy Storage Computational Tool
ETT	Electric Transmission of Texas

EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FERC	Federal Energy Regulatory Commission
FRRS	Fast Response Regulation Service
GNIRE	Group NIRE (National Institute for Renewable Energy)
GSEC	Golden Spread Electric Cooperative
GW	Gigawatt
HAN	Home Area Network
HEM	Home Energy Management
HVAC	Heating, Ventilation, and Air Conditioning
Hz	Hertz
ICCP	Inter-Control Center Communications Protocol
IEC	International Electrotechnical Commission
I&CS	Interoperability and Cyber Security
IEEE	Institute of Electrical and Electronics Engineers
IOU	Investor Owned Utility
IP	Internet Protocol
IR	Interagency Report/ Internal Report
IRB	Internal Review Board
ISG	Intelligent Synchrophasor Gateway
ISO	Independent System Operator
kA	Kiloampere
kHz	Kilohertz
kV	Kilovolt
kVA	Kilovolt-ampere
kVAR	Kilovolt-ampere reactive
kW	Kilowatt
kWh	Kilowatt Hour
LMO	Lithium Manganese Oxide
LMP	Locational Marginal Pricing
LR	Legends Ranch
MHz	Megahertz
Ms	Milliseconds
MVA	Megavolt Ampere
MW	Megawatt
MWh	Megawatt Hour
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
NISTIR	National Institute of Standards and Technology Interagency Report

NOx	Nitrogen Oxide
O&M	Operations and Maintenance
PCT	Programmable Communicating Thermostat
PDC	Phasor Data Concentrator
PDMA	Phasor Data Mining Application
PEV	Plug-in Electric Vehicle
PF	Power Factor
PGDA	Phasor Grid Dynamics Analyzer
PI	Principal Investigator
PM	Project Manager / Particulate Matter
PMO	Project Management Office
PMP	Project Management Plan
PMTF	Phasor Measurement Task Force
PMU	Phasor Measurement Unit
PSCAD	Power System Computer Aided Design
PV	Photovoltaic (Solar)
QSE	Qualified Scheduling Entity
RC	Resistor-Capacitor
REP	Retail Electric Provider
RLC	Resistive Inductive Capacitive
ROS	Reliability Operations Subcommittee
RPS	Renewable Portfolio Standard
RTC	Reese Technology Center
RTDMS	Real-Time Dynamics Monitoring System
RTO	Regional Transmission Organization
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SCR	Short-Circuit Ratio
SEP	Smart Energy Profile
SGCT	Smart Grid Computational Tool
SF	Security Fabric
SFG	Security Fabric Gateway
SFTP	Secure File Transfer Protocol
SGRDP	Smart Grid Regional Demonstration Project
SMT	Smart Meter Texas
SMTP	Smart Meter Texas Portal
SOAP	Simple Object Access Protocol
SOC	State of Charge
SOx	Sulfur Oxide
SPEC	South Plains Electric Cooperative

SPP	Southwest Power Pool
SSL	Secure Sockets Layer
SwRI	Southwest Research Institute
SWiFT	Scaled Wind Farm Technology
TBR	To Be Reviewed
TBD	To Be Determined
TDSP	Transmission and Distribution Service Provider
TDD	Total Demand Distortion
TDU	Transmission and Distribution Utility
THDv	Total Harmonic Distortion (voltage)
THDi	Total Harmonic Distortion (current)
TMS	Transmission Management System
TOU	Time Of Use
TPR	Technology Performance Report
TTU	Texas Tech University
TXUE	TXU Energy
VPN	Virtual Private Network
UCM	Universal Circuit Monitor
URD	Underground Residential Distribution
UTA	University of Texas at Arlington
V	Volt
VAR	Volt-Amp(ere) Reactive
VPN	Virtual Private Network
VSOC	Voltage State of Charge
WAN	Wide Area Network
WiSE	Wind and Science Engineering

EXECUTIVE SUMMARY

Introduction

Texas has for more than a decade led all other states in the U.S. with the most wind generation capacity on the U.S. electric grid. The State recognized the value that wind energy could provide, and committed early on to build out the transmission system necessary to move power from the windy regions in West Texas to the major population centers across the state. It also signaled support for renewables on the grid by adopting an aggressive renewable portfolio standard (RPS). The joining of these conditions with favorable Federal tax credits has driven the rapid growth in Texas wind capacity since its small beginning in 2000. In addition to the major transmission grid upgrades, there have been a number of technology and policy improvements that have kept the grid reliable while adding more and more intermittent wind generation. Technology advancements such as better wind forecasting and deployment of a nodal market system have improved the grid efficiency of wind. Successful large scale wind integration into the electric grid, however, continues to pose challenges. The continuing rapid growth in wind energy calls for a number of technology additions that will be needed to reliably accommodate an expected 65% increase in future wind resources.

The Center for the Commercialization of Electric Technologies (CCET) recognized this technology challenge in 2009 when it submitted an application for funding of a regional demonstration project under the Recovery Act program administered by the U.S. Department of Energy[1]. Under that program the administration announced the largest energy grid modernization investment in U.S. history, making available some $3.4 billion in grants to fund development of a broad range of technologies for a more efficient and reliable electric system, including the growth of renewable energy sources like wind and solar. At that time, Texas was (and still is) the nation's leader in the integration of wind into the grid, and was investing heavily in the infrastructure needed to increase the viability of this important resource. To help Texas and the rest of the nation address the challenges associated with the integration of large amounts of renewables, CCET seized on the federal opportunity to undertake a multi-faceted project aimed at demonstrating the viability of new "smart grid" technologies to facilitate larger amounts of wind energy through better system monitoring capabilities, enhanced operator visualization, and improved load management. In early 2010, CCET was awarded a $27 million grant, half funded by the Department of Energy and half-funded by project participants. With this funding, CCET undertook the project named ***Discovery Across Texas*** which has demonstrated how existing and new technologies can

[1] In 2005, a consortium of Texas utilities, technology companies and universities formed CCET in Austin, Texas, to advance technology developments in the electric utility industry of Texas. During the next four years CCET completed a number of demonstration projects such as substation automation, demand response leveraging advanced metering systems, deployment of an initial synchrophasor system, and field testing of new remote terminal units. The seven demonstrations summarized in this report evolved from this experience and from leveraging new technology developments being deployed by member companies and the grid operator. That is, CCET leveraged other technology deployments in Houston, Dallas, Fort Worth, Austin and Lubbock that included solar communities, a wind technology testing center, synchrophasor monitoring and visualization systems, electric vehicles and smart homes.

better integrate wind power into the state's grid. The following pages summarize the results of seven technology demonstrations that will help Texas and the nation meet this wind integration challenge.

Wind Power in Texas

Statewide, wind power capacity in Texas has grown by more than 10,000 percent, from 116 megawatts (MW) in 2000 to 12,470 MW as of December 2014, and the Electric Reliability Council of Texas (ERCOT) has interconnection agreements in place for an additional 6,966 MW in 2015, as shown in the figure below.

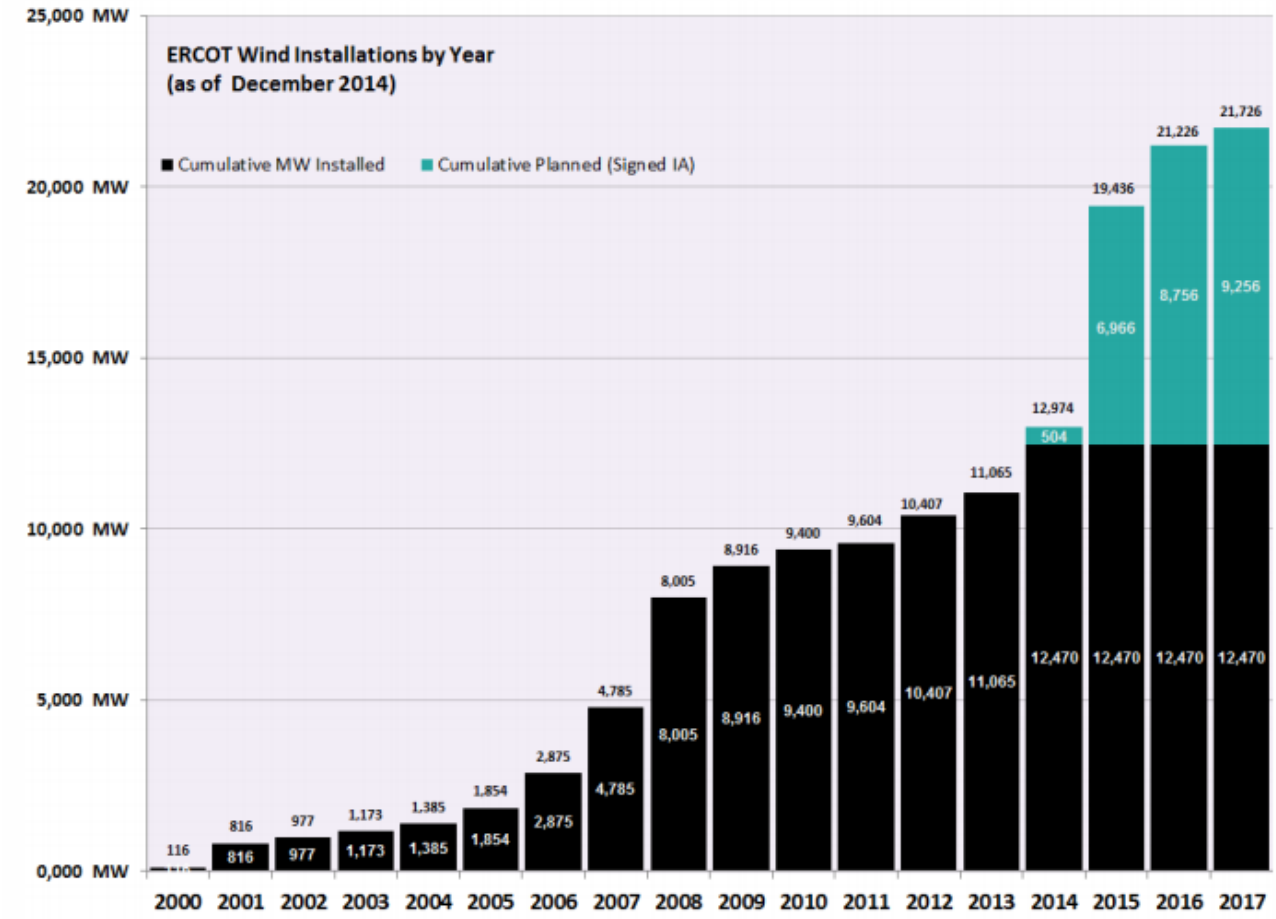


Figure 1. ERCOT Wind Capacity Installations

The installed wind capacity provides about 10% percent of the total grid generating capacity. In November of 2014, a new ERCOT wind record was set at 10,301 MW, which represented just over 33% of the load at that time. The increase in wind resources on the grid has required the development of about 3,600 miles of new transmission lines (shown in the figure below) into West Texas and the Panhandle area to move the power generated by those wind farms to the population centers in other

areas of Texas. This five-year $7 billion initiative was recently completed as part of an effort called Competitive Renewable Energy Zones (CREZ). Since the CREZ plan was developed to expand the transmission capacity to accommodate 18.5 gigawatts (GW) of wind farms, it may well have to be expanded to accommodate an even larger wind capacity since the State already has interconnection agreements in place for 23.9 GW of wind resources.

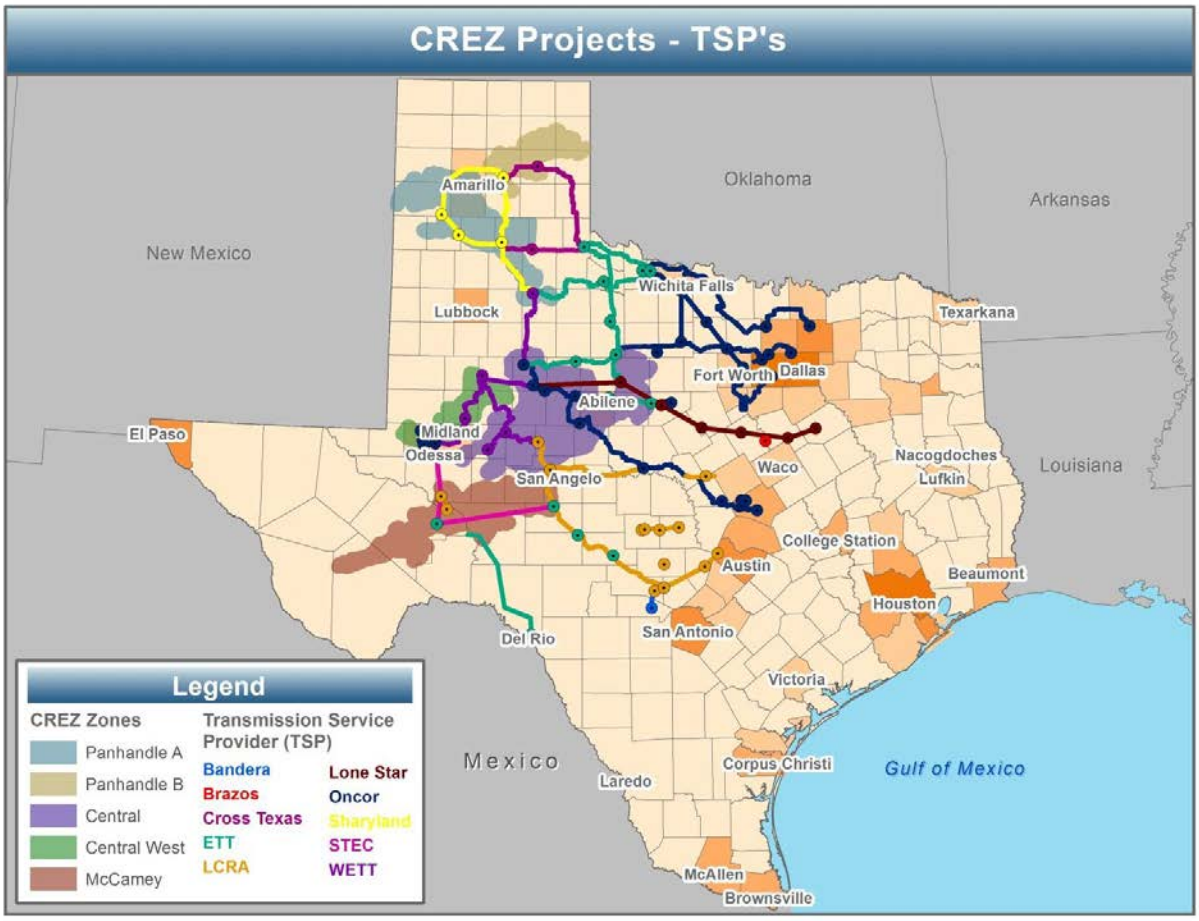


Figure 2. CREZ Transmission System Build Out

Project Location – Texas

This CCET project was primarily performed in an area encompassing about 85% of the state where the electric grid is managed by ERCOT. The project also included deployment and testing of a utility-scale battery, some additional synchrophasor efforts, and cyber security protection systems in the Northwest area of Texas (Panhandle) that is actually in the Southwest Power Pool (SPP) region. These areas are shown in the figure below.

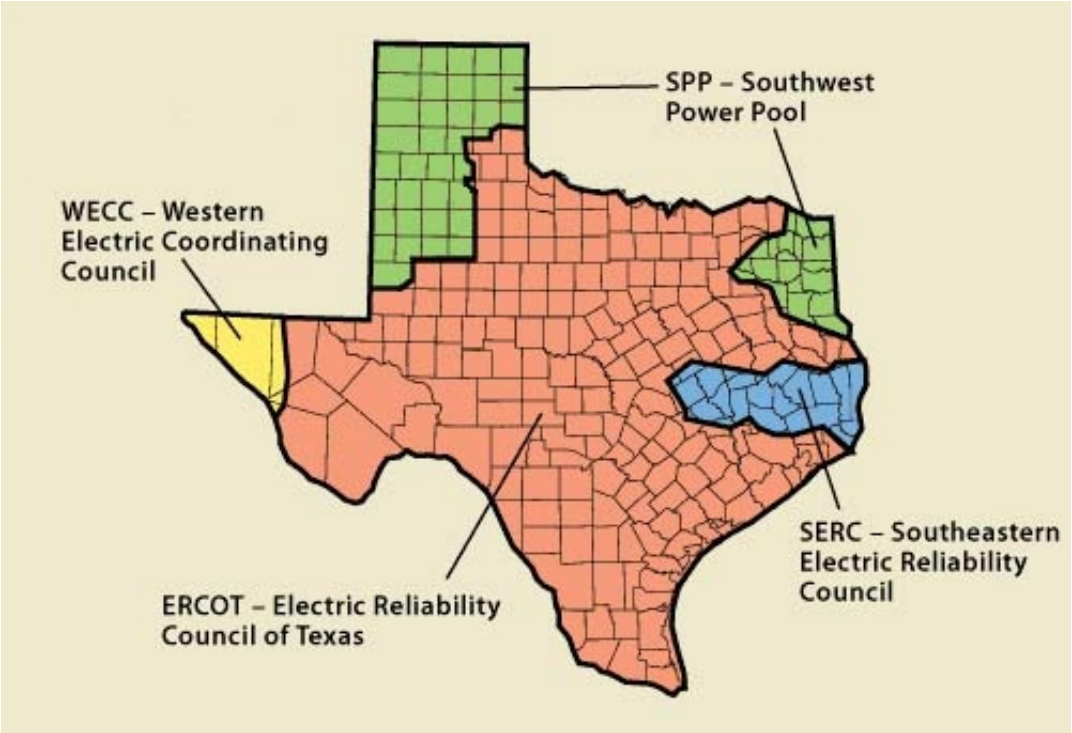


Figure 3. ERCOT and SPP Regions of Texas

Texas is unique among other regions with its high penetration of remote wind generation, one interconnection (ERCOT) entirely contained in the state, and one Independent System Operator (ISO), ERCOT. The ERCOT system is not interconnected across the state boundaries (except for three DC ties) and thus not subject to most regulatory rules of the Federal Energy Regulatory Commission (FERC). Texas deregulated the wholesale generation market in 1995 and opened the retail market to competition in 2002. As a result the generation and retail markets are now competitive while the transmission and distribution service providers (TDSPs) remain regulated by the Public Utility Commission. The investor-owned utilities were deregulated by the Texas Legislature while cooperatives and municipally-owned utilities were given the option to join the deregulated markets. ERCOT oversees and facilitates the competitive generation market where as many as 550 generation units compete for the provision of power on a daily basis and the retail markets where as many as 179 retail electric providers (REPs) compete for customer services.

In addition to leading the nation in wind generation plans, Texas also leads in the implementation of advanced metering systems. The most recent tally for the ERCOT region as of September 2014 indicates at least 6,849,921 smart meters have been deployed, and there are plans for installation of even more smart meters in future years.

Another unique aspect of Texas is the availability of the web-based Smart Meter Texas (SMT) Portal which hosts the 15-minute incremental meter data from many of those smart meters and is used for settlement purposes as well as permitting customers to view and share their current and historical

electrical usage information, and to bond home area network devices to their smart meter in support of demand response efforts.

Project Scope - Leverage Existing and Emerging Technology Resources

The Discovery Across Texas (DAT) project was carried out on real-time systems that leveraged a number of technologies already in place or under development in Texas. These technologies were:

- Initial synchrophasor network that was greatly expanded with more phasor measurement units, phasor data concentrators and enhanced visualization and monitoring software
- Wind testing facility with wind turbines at the Reese Technology Center in Lubbock
- Existing battery energy storage system (BESS) vendor with proven capabilities
- The CREZ transmission system expansion supporting wind farms throughout West Texas
- Emerging cyber security software from Intel/McAfee
- More than six million smart meters being installed throughout Texas
- Solar communities in Houston and Austin, the latter at the Austin Mueller Community which has rooftop solar, smart appliances and electric vehicles
- Existing programmable thermostats and gateways, and available consumer participants, involved in demand response programs in Dallas and Houston
- SMT portal for hosting and displaying consumer smart meter data
- Fleet of electric trucks owned and operated by Frito Lay in Fort Worth

These technologies facilitated the implementation and execution of seven different project components, or technical demonstration areas:

- Synchrophasor monitoring, visualization and event reporting
- Cyber security protection for synchrophasor data streams (Security Fabric)
- Distribution-level battery energy storage system
- Residential time-of-use pricing trials
- Circuit and transformer monitoring of residential solar
- Residential demand response using direct load control devices
- Fast response regulation service with fleet electric vehicles

The efforts and accomplishments of these project demonstrations are highlighted below.

Improving Grid Reliability with Synchrophasors

As a renewable and clean source of energy, sustained winds can be harnessed using wind turbines to provide great amounts of power, but this source is intermittent with limited predictability, and there can be periods of both too much and too little wind. Through this project, CCET demonstrated that new monitoring technologies can help integrate more wind resources while more effectively managing wind

power's effects on the grid. To help determine power quality conditions and identify developing disturbances on the grid, CCET's demonstration project used synchrophasor technology which measures power variations in real time. Phasor measurement units, or PMUs, measure the grid's voltage and phase angles to provide utilities with near real-time views of grid conditions. By time-stamping each measurement, synchrophasors enable utilities and ERCOT to compare measurements from different times, as well as different locations, thereby tracking power flows in real time, which can be useful for preventing disturbances and disruptions, including blackouts.

At the inception of this project, the ERCOT network was being monitored by PMUs at three locations. Synchrophasor data was being captured and streamed from those devices to a phasor data concentrator (PDC) at ERCOT. The data was then synchronized based on timestamps and displayed via a Real Time Dynamics Monitoring System (RTDMS), provided by Electric Power Group (EPG), which was running in the test environment at ERCOT. As part of this demonstration project, three utilities (Oncor Electric Delivery, American Electric Power, and Sharyland Utilities) committed to install PMUs at 13 additional locations, and to stream their synchrophasor data to ERCOT for monitoring and display in the RTDMS. After recognizing the true value proposition of this early warning network of devices, the utilities began adding PMUs at even more locations on their networks. As of November 2014, as shown in the figure below, the utilities had installed and are providing streaming synchrophasor data from 76 PMUs at 35 locations to the ERCOT RTDMS. These efforts also attracted the attention of other utilities across Texas who began planning for deployment of additional PMUs. Currently, ERCOT anticipates receiving streaming data from 94 PMUs at 46 different locations during the first quarter of 2015. This network of PMUs currently provides monitoring of about 78% of ERCOT's regional grid footprint, and the new planned additions will increase this to about 85% coverage of the state.

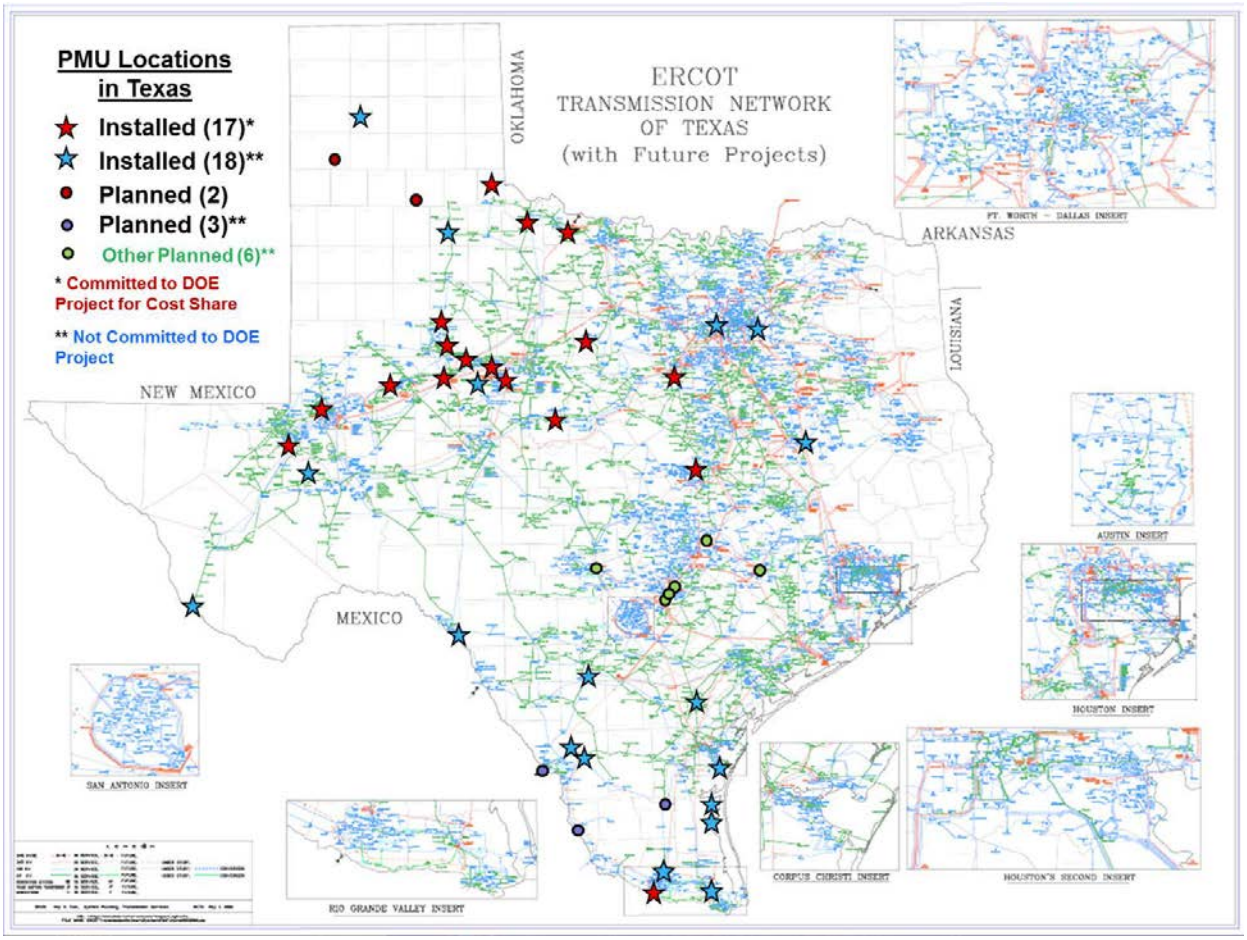


Figure 4. PMU Deployment in Texas

In addition to the ERCOT synchrophasor network, another objective of the project was to acquire data on the use of PMUs in tandem with wind turbines, and to evaluate their benefit to distribution grid operations. For this aspect of the project, Texas Tech University (TTU) worked with several electric cooperatives to deploy a synchrophasor network in the Texas Panhandle portion of SPP. Currently, this system consists of five PMUs, a PDC located at the Reese Technology Center and an RTDMS server located on the TTU campus. Two of these PMUs are also functioning as revenue meters for two wind generation assets: a 1.67 MW Alstom wind turbine and three 300 kilowatt (kW) wind turbines at the Sandia National Laboratories' Scaled Wind Farm Test (SWiFT) facility, while the third PMU is functioning as a revenue meter for a battery system which is located near the SWiFT facility. The red stars in the figure below indicate the existing PMU locations, and the yellow stars indicate possible future locations, three of which are already planned and will significantly expand the geographical area of the network and provide PMUs located near significant wind or natural gas generation assets.

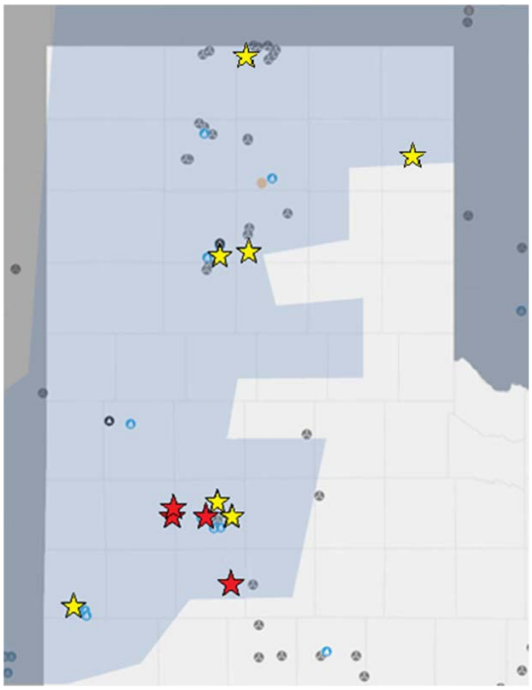


Figure 5. Current and Planned TTU PMU Locations

In addition to greatly expanding the synchrophasor network, a key goal of the project was to promote the benefits and prove that it could be beneficial to grid operators in the ERCOT control room. Through the collaborative efforts of the project team members, coupled with active participation by ERCOT and Texas utilities, Texas has become one of the first in the nation to use synchrophasor technology as an operator tool to improve grid reliability. The figure below shows the RTDMS in use at ERCOT.

Figure 6. RTDMS Provides Grid Reliability Indicators at ERCOT

By quickly pinpointing potential grid issues, synchrophasor technology based on readings 30 times per second helps utilities and ERCOT respond and compensate more quickly, thereby improving the reliability of wind energy and the grid as a whole. For example, in the figures below, the synchrophasor system quickly identified a potentially damaging grid oscillation originating from a malfunction at a wind farm in January 2014. This was an observation/detection not available from the traditional, slower supervisory control and data acquisition (SCADA) systems. The unit was constrained by the ERCOT grid operators who stopped the oscillation, and upon notice the wind farm operator quickly corrected the malfunction. This use of the RTDMS demonstrated that, during and after an energy oscillation, the grid operators can use synchrophasor data to trace a problem to its source, and typically identify the cause of the issue.

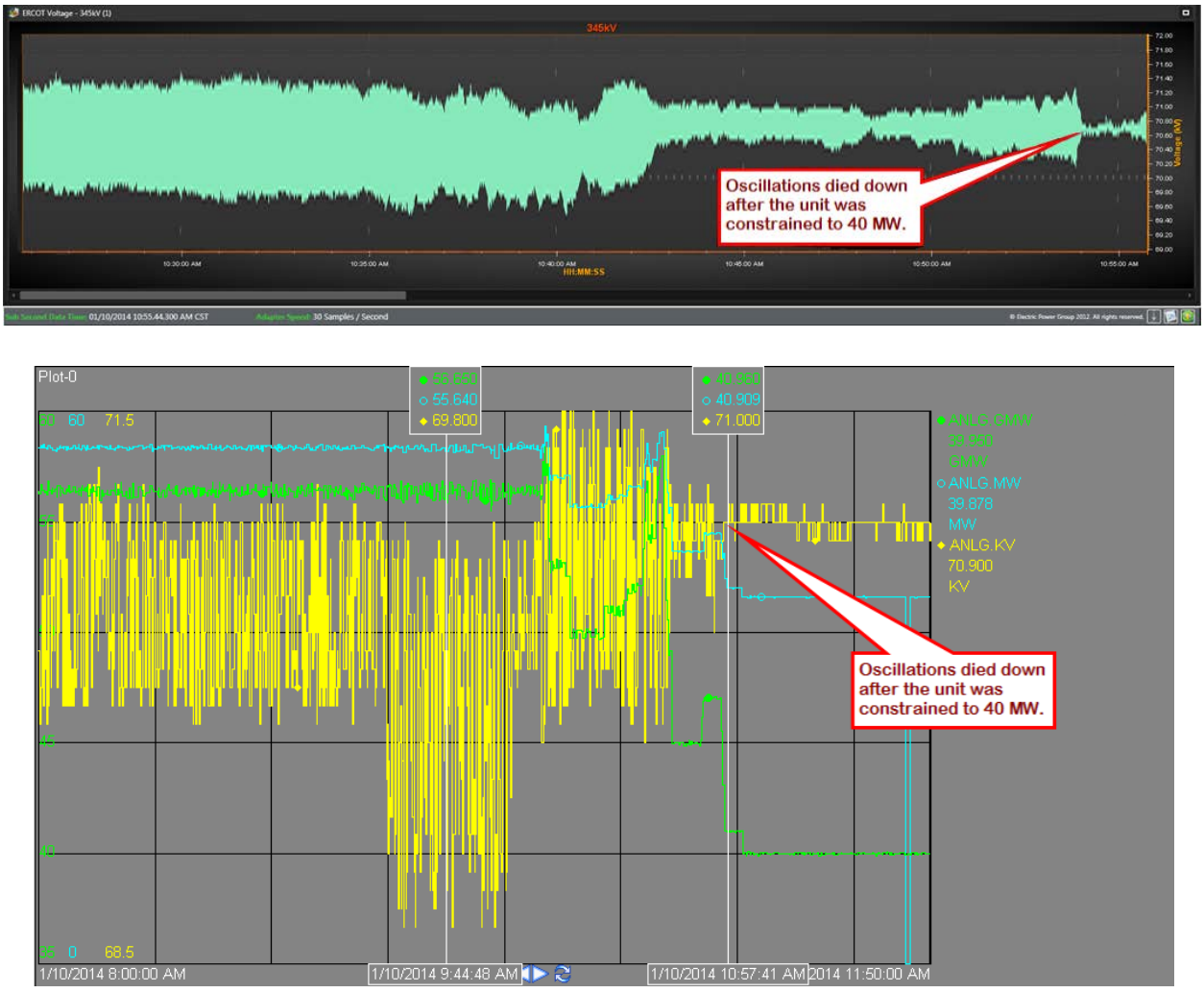


Figure 7. Reduction of Oscillations after Constraining the Plant to 40 MW on 10 January 2014

In addition to deploying large numbers of PMUs, and streaming that data to ERCOT for grid monitoring, the CCET project performed a number of studies and analyses to improve operations. These included:

- Baselining studies
- Data quality studies
- Lessons learned from mitigating PMU data loss
- Event analyses of generation outages and wind interactions
- Requirements for control room and network production upgrades
- ERCOT and utility operator training
- Slow scan synchrophasors
- Synchrophasor use cases

Another area of interest was in using synchrophasor data to improve generator model parameters. These mathematical models of generators are fundamental management tools for grid operators but sometimes the accuracy of such models are less than is needed for understanding the generator performance. The DAT project developed a computer algorithm that uses phasor data from near the generator to improve the parameter estimates of the generator model, and thus the accuracy of generation forecasts by ERCOT. Such computer-based automation capabilities are destined to become standard tools for generator owners and grid operators of the future.

ERCOT presently utilizes synchrophasor data for system oscillation detection, generator model validation, and post event analysis and reporting. In the future, intended uses include voltage stability monitoring and other applications of synchrophasor data for grid operations.

Security Fabric for Protection of Synchrophasor and Other Grid Systems

Synchrophasor systems are destined to become control room tools for grid management and therefore will need to be protected from cyber attacks under a Presidential directive known as Critical Infrastructure Protection (CIP). Based on this need, the CCET project included an effort to incorporate and validate the effectiveness of enhanced security protection mechanisms in a synchrophasor network. For this effort, Intel/McAfee provided Security Fabric components that are architected to address the seven security tenets of the National Institute of Standards and Technology (NIST) Interagency Report (NISTIR) 7628. One of the keys of their approach was to employ a hardware/firmware solution that provides exceptional security for applications, and does not require that the applications be modified. Once proven, this integrated suite of capabilities could provide a new commercial solution for protecting key assets in the electric industry.

The project employed contemporary concepts of silicon-driven security to stop attacks that easily defeat software-only security attempts. This approach provides a more secure framework for incorporating security in the physical hardware layers to better protect sensitive operations, i.e., providing authentication for every step of the boot sequence to eliminate infection by malware or root-level viruses. The project approach leveraged the hardware security, and provided a process named ‘whitelist

attestation' to verify the trust basis for all changes and transition control to promote changes at a safe and convenient time. The benefits of this approach include the following:

- Application whitelisting on management systems
- Movement of databases to secured management system with encrypted tunnel
- C37.118 data (standard for PMU accuracy and data communications) is only received from authorized nodes
- C37.118 data is exchanged between nodes using a secure tunnel
- Access to applications is limited to authorized clients
- Secure network time protocol communications

For this demonstration, EPG designed, integrated, validated, and tested the ability of the Security Fabric (SF) components to provide the required cyber security protection for its enhanced PDC (ePDC) and RTDMS applications (including the phasor grid dynamics analyzer or PGDA) in a laboratory environment. Once the testing was completed, the Security Fabric servers together with the EPG software were deployed at TTU. The TTU had a similar configuration in place without the Security Fabric protections, so this new set of servers (including the SF Gateway or SFG) and EPG software was intended to provide a parallel environment, as shown below, that leveraged the real-time PMU data streams at TTU.

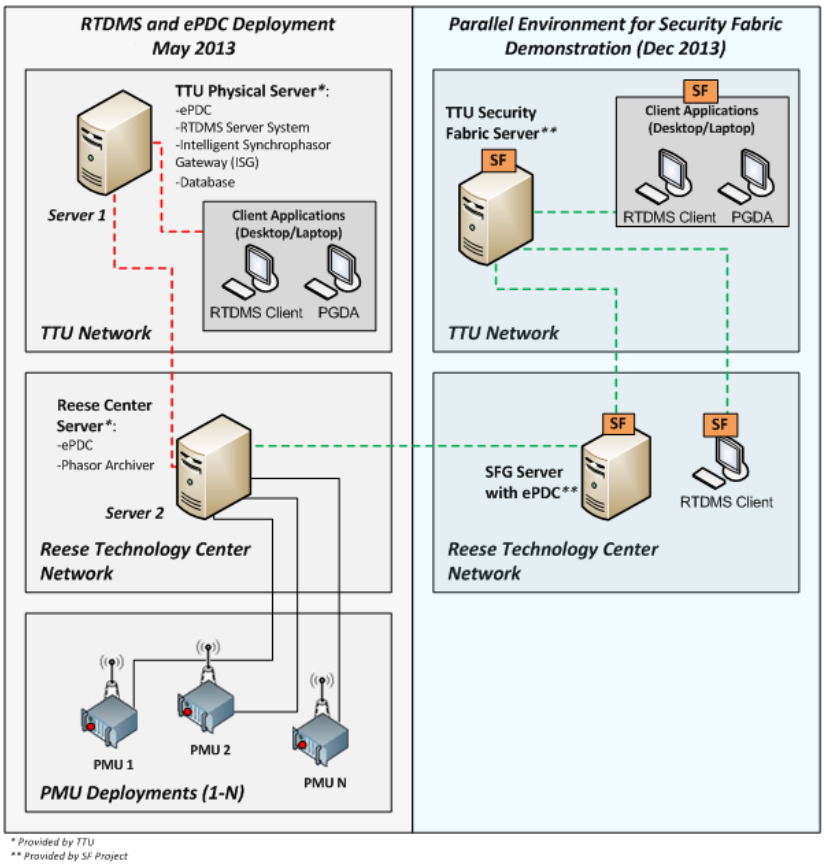


Figure 8. Security Fabric Test System at Texas Tech University and the Reese Technology Center

A field demonstration was performed on the TTU synchrophasor network to demonstrate the use of the Security Fabric to secure the phasor data stream between a "virtual Transmission Owner/Utility" and a "virtual ISO". The goal of the demonstration was to validate that the phasor data stream could be successfully secured from cyber attack while still delivering timely phasor data to the "virtual ISO's" RTDMS system. As a part of the demonstration, TTU faculty and students performed the following activities:

- The first activity was ***verification of security fabric requirement specifications***. This effort involved testing to determine whether the Security Fabric-enabled network at TTU satisfied the security requirement specifications provided by Intel/McAfee. The specifications were based on the "Guidelines for Smart Grid Cyber Security" NISTIR 7628 requirements.
- The second activity was ***penetration testing*** on the synchrophasor network without Security Fabric and the Security Fabric-enabled network***.*** This involved coding scripts to identify security vulnerabilities and injecting attacks by exploiting selected vulnerabilities found.

For the first activity, Intel/McAfee provided Security Fabric relevant security specifications that cover 11 categories of the NISTIR 7628 security requirements. The Security Fabric-enabled network at TTU was tested against these specifications. The process of testing in this part involved three basic activities: (1) *requirement acquisition* (communicating and assisting in the interpretation of the testing requirements according to National Institute of Standards and Technology or NIST standards), (2) *specification description* (providing feedback and clarification in defining proper security specifications), and (3) *specification verification* (verifying that the system satisfies the given security specifications). This process was time consuming due to the nature of evolving requirements and specifications development.

The results of this compliance testing, based on the details provided in the requirements specification, verified that 86.5% of the security specifications were satisfied. Additional testing on the part of TTU determined that the remaining requirements could be satisfied by 1) clarifying the specification so that the test intent, objectives, steps, and results were adequately defined, and 2) incorporating additional existing Intel/McAfee tools or applications.

In the next activity, TTU performed penetration testing on both the Security Fabric-enabled network and the unsecured network. Interestingly enough, the total number of vulnerabilities of the Security Fabric-enabled network was 13 which was seven more than those found in the non-Security Fabric environment. This higher count is because the secure system includes additional Intel/McAfee software monitoring and management components that are also vulnerable. In the findings, TTU pointed out the following:

- All but one of the vulnerabilities identified in the Security Fabric-enabled network were caused by misconfiguration errors, or because of older, less secure versions of software, so these were easily fixed.

- The connection between the two synchrophasor endpoints, ePDC and RTDMS, which was the real intent of this effort, proved to be more secure with Security Fabric.

Based on the findings of this effort, Intel/McAfee was able to resolve all of the identified vulnerabilities, and they have since updated the support guides to ensure that these potential vulnerabilities are mitigated during installation of the Security Fabric components.

Battery System Deployment on a Distribution System

Another important technology for wind integration is battery storage. For this effort, CCET was interested in assessing how battery storage can supplement wind turbines to improve wind-power efficiency. The overall objective was to test the ability of a BESS to perform various needed grid functions, such as peak shaving, load leveling, and frequency support. A secondary objective was to determine the economic viability of deploying these systems to support grid operations. The Reese Technology Center (RTC) near Lubbock, Texas, afforded an optimal location for satisfying the objectives since it was already established and outfitted as a wind test facility, it provided access to a distribution grid operated by a local cooperative that was very supportive of testing, and was close to TTU which had a staff capable of performing the BESS evaluations. The Team defined a detailed functional specification for a BESS, and then issued a competitive request for proposal. After negotiations, CCET awarded a contract to Xtreme Power (now Younicos) for a 1MW Lithium Manganese Oxide (LMO) BESS with the batteries provided by Samsung SDI. This system, pictured below, was built, tested, fielded, and connected to the grid in eight months, becoming fully operational in August 2013.

Figure 9. BESS Installed at the Reese Technology Center

The BESS houses 18 racks with 256 LMO batteries totaling 4,608 battery cells with a combined energy storage capacity of 1 MWh.

Figure 10. Racks of Batteries within the BESS Container

The BESS operates in conjunction with about 4.6 MW of wind generation at the site. This includes an Alstom ECO86 1.67 MW wind turbine, a Gamesa 2 MW wind turbine, and three V27 300kW Vestas turbines that were deployed as part of the SWiFT facility which currently produces 900 kW, and will eventually be expanded to produce 3.6 MW. The site also includes a 200-meter meteorological tower to provide unique atmospheric measurements for wind analysis. Two images of the SWiFT facility are shown below. The first figure below shows a view of the three SWiFT turbines and the meteorological tower. The second figure shows an aerial view of the SWiFT turbines and the close proximity of the BESS.

Figure 11. SWiFT Facility at RTC

Figure 12. Aerial View of the BESS and the SWiFT Facility Turbines

The BESS is operationally integrated into the grid of the South Plains Electrical Cooperative (SPEC) and is controlled by SPEC with assistance from Younicos. During the course of the project, the BESS was thoroughly tested to determine its ability to optimize the reliability of the grid by compensating for the

intermittency of wind, storing power during high wind- and providing power during low wind-conditions, reducing the daily peak load on the grid (and thus reducing demand charges), providing a ramping capability to stabilize the grid, and to potentially provide an ancillary service for fast response regulation service needed by the ISO to maintain the grid at 60 hertz (Hz). These and other potential uses of the BESS were exercised and evaluated as part of the project, and will continue to support its ongoing operation.

TTU researchers extensively modeled the battery system, the wind turbines, and the related SPEC substation loads, and then simulated a full range of system behaviors involving a set of battery functions. The models and simulation results were then validated during field testing of the BESS during 2014. The basic approach for testing, describing such aspects as time of year, time of day, and duration, is outlined in the table below. Based on this, a detailed testing schedule was developed and implemented, involving single function tests and then finally combinations of functions, to determine the feasibility and economic viability of these functions. Some individual results of these functional tests are included after the table.

Table 1. Overall BESS Testing Approach

Number	Test Type	Time of Year	Time of Day	Duration
1	Ramping	All year	Night	Seconds
2	Demand Response	Summer (May to August)	Day	Minutes to hours depending on peak loads
3	Frequency Support	All year	Night	Seconds
4	Wind Speed Drop	All year	When drop occurs	Seconds to minutes
5	FRRS	All year	When needed	Until frequency recovers

One of the tests performed was frequency response. When the frequency went below 60 Hz, the battery automatically ramped up to supply the required power and met the demand. In the figure below, which demonstrates the responsiveness of the BESS, the black line is frequency (dead band is set to 59.70 Hz), the orange line is system state of charge, and the blue line is kilowatt (kW) output (with a maximum setting at 400 kW).

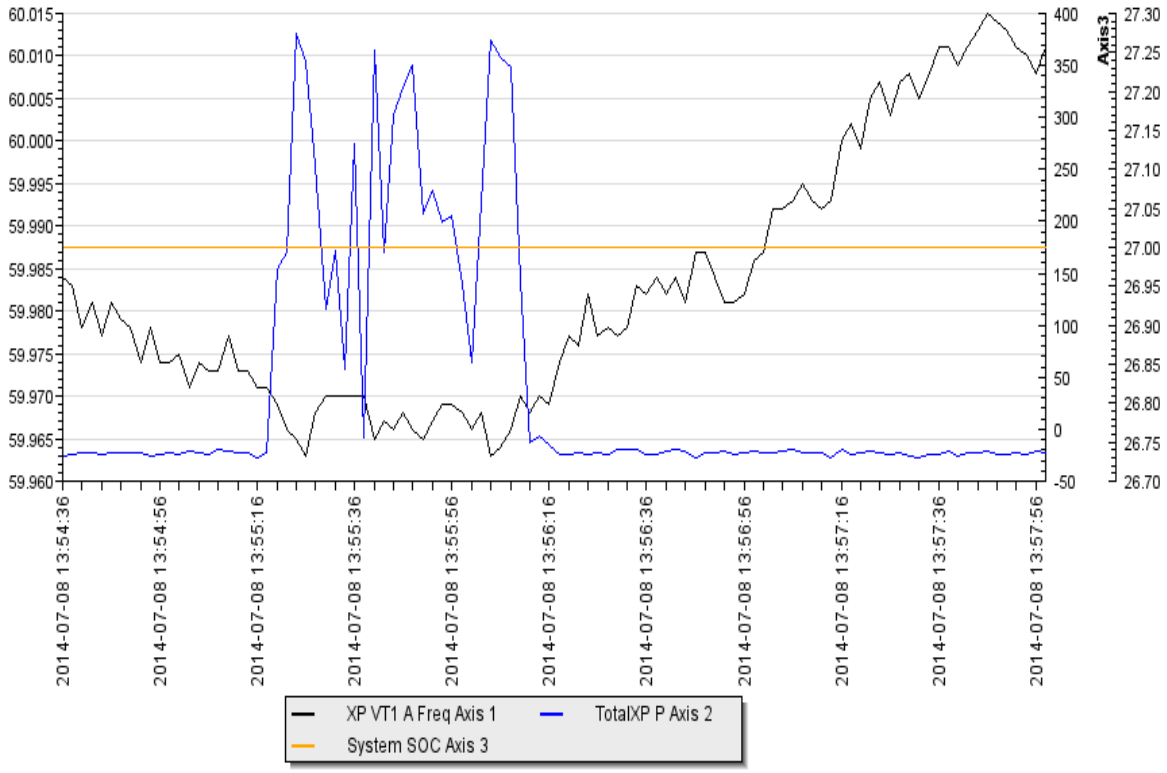


Figure 13. Under Frequency Event on July 08, 2014

Another core function of the BESS is to provide wind ramping/load leveling. The figures below show the battery following the wind profile according to the power generation and load demand. The green trace is the wind output for TTU-04 (Gamesa Wind Turbine) and the dark blue trace is the output of the BESS.

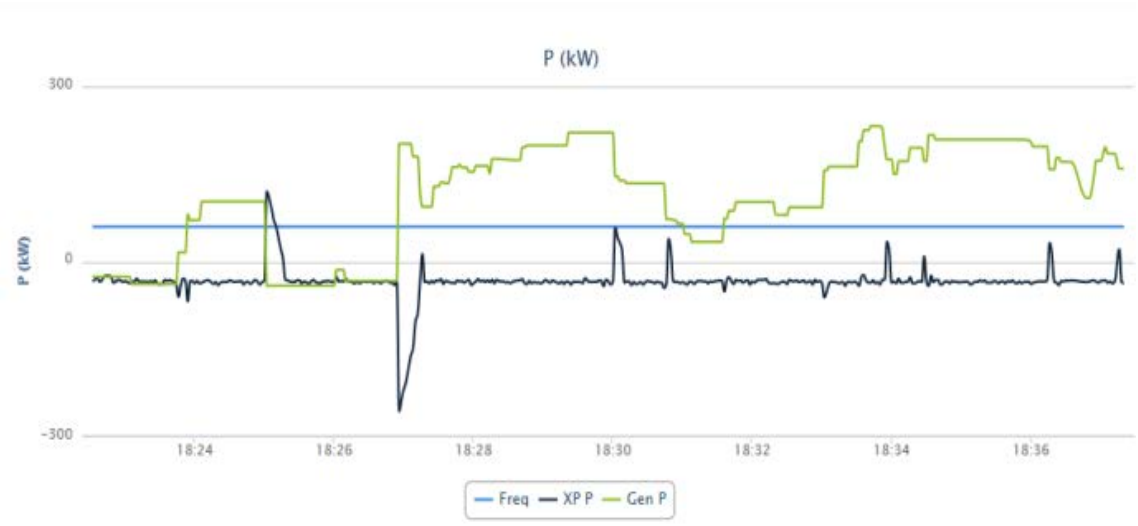


Figure 14. Load Leveling During August 2014

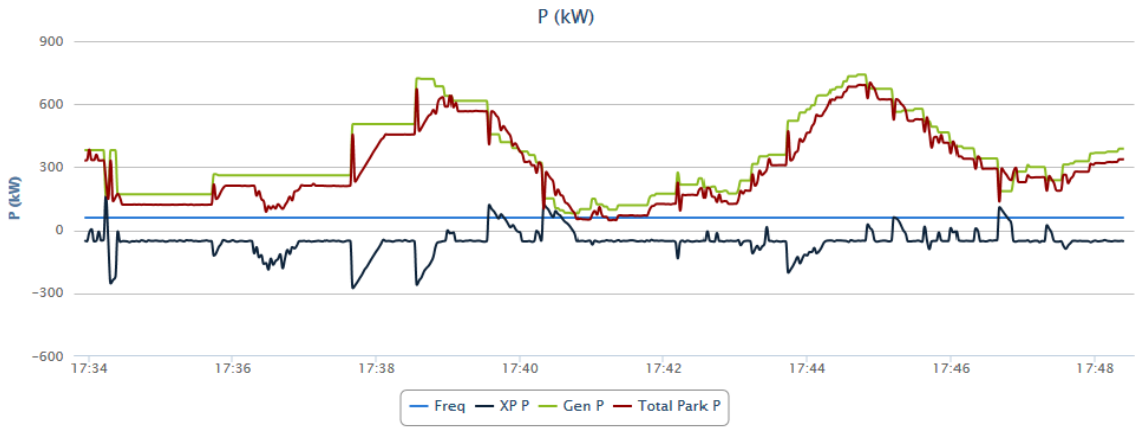


Figure 15. Load Leveling During October 2014

In addition to operating the battery in real time on SPEC's distribution system to learn the technical performance of the system, the team also evaluated the economics of an investment in a BESS. This involved two different activities: 1) development of a basic application to determine appropriate actions that increase profitability while considering battery life and 2) an economic analysis showing the return on investment using a DOE-supported evaluation tool known as the Energy Storage Computational Tool (ESCT).

For the first part, TTU developed an algorithm which weighed various factors. One of the most important factors is to determine the optimal time to charge and discharge the battery. The battery needs to be charged when demand and electricity cost are low and discharged when demand and electricity cost is high. It all depends on the purchase price of energy required to charge the battery and alternatively the sale price of energy to sell the excess power. The next important factor is to consider the load/demand and supply of the battery power or the available renewable power in an economic way considering the past, present and future cost analysis. Based on the algorithm, TTU implemented a basic application that reads the input data from an Excel file every 15 minutes, and then through an interface presents a recommended battery action after checking seven different cases. An example case is shown below:

> Case: If power generated from the wind turbine is less than the load demand, and the battery is in a charged state, then the condition "If present purchase price is greater than past energy to charge the battery" is checked. Then if the condition "If the future price is less than the current purchase price" is true, the recommended action is to "Discharge battery to load. Sell excess power. Charge battery in future." as shown below. If this is not the case, then recommend "Discharge battery to load. Purchase power to supply load".

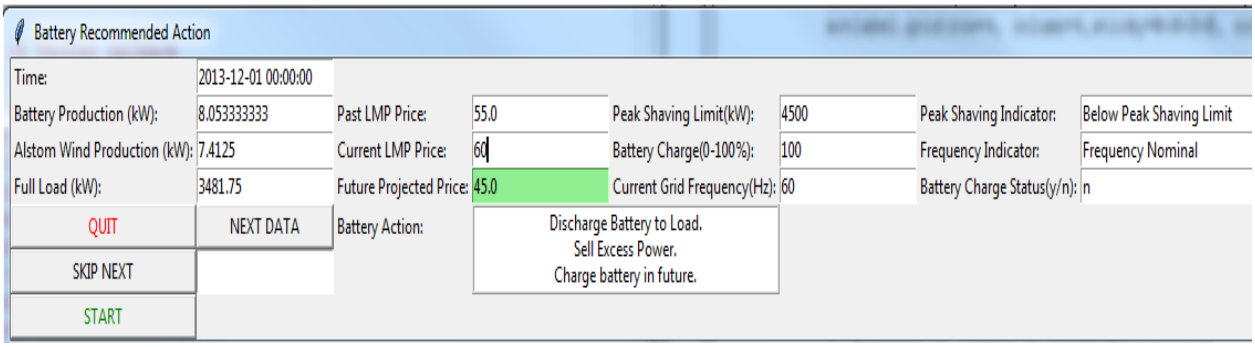


Figure 16. Algorithm Output – Discharge Battery to Load & Sell Excess Power

For the second part, the Team used the ESCT to perform a set of economic evaluations dependent on various factors such as the owner, type of market, location, and functional applications. To most fairly represent the economic potential in the Texas market, the Team performed four different sets of analysis, as outlined below. These sets represent various types of utilities, in both regulated and deregulated markets and located in different regions of the State, using a BESS to address diverse needs, from improved electric service reliability to ancillary services. It should be noted that the ESCT estimates of benefits primarily accrue to the owner of the BESS and do not easily represent multiple functions carried out simultaneously by multiple market participants.

The representative configurations of ownership, location, and functionality include:

1. 1 MW BESS on a distribution network owned by a utility in a deregulated market
2. 1 MW BESS on a distribution network owned by a utility in a regulated market (without demand charge management)
3. 1 MW BESS on a distribution network owned by a utility in a regulated market (with demand charge management)
4. 1 MW BESS on a transmission network owned by a generator in a regulated market

Of these four options, only #3 proved to be economically viable, although the feasibility of other options will improve as the cost of a BESS is reduced. The following table shows the parameters given as inputs to the ESCT for option #3.

Table 2. Parameters for Asset Characterization Module

Location of battery	Distribution
Market	Regulated
Owner	Utility (End User)
Type of Battery	Lithium-ion
Total name plate power output	1000 kW
Total name plate energy storage capacity	1000 kW hours (kWh)
Round trip efficiency	95%

Response time of BESS	0.005 seconds
Cycle life	4000 cycles
Expected year over demand growth of electric system	2%
Expected life time	20 years
Average inflation rate	2%
Discount rate in net present value analysis	7%
Total Installed cost of deployment	$2,000,000
Fixed charge rate to annualize cost of deployment	11%
Non-energy operations and maintenance (O&M) cost	$50,000/year
Primary application	Demand charge management
Selected secondary application(s)	Renewables energy time-shift and electric service power quality

The following table shows other data inputs for the ESCT, including energy storage (ES) load reduction and emissions such as carbon dioxide (CO2), particulate matter (PM), nitrogen oxide (NOx), and sulfur oxide (SOx).

Table 3. Review Benefit Calculation Inputs

		Select % using toggle			2014 Values		
Input Name	Unit	Low	Reference	High	Low	Reference	High
Average On-Peak Price of Electricity	$/MWh	100%	100%	100%	$ 100	$ 100	$ 100
CO2 Emissions Factor for Generation on the Margin	lbs/MWh	100%	100%	100%	1,372	1,372	1,372
SOx Emissions Factor for Generation on the Margin	lbs/MWh	100%	100%	100%	5.800	5.800	5.800
NOx Emissions Factor for Generation on the Margin	lbs/MWh	100%	100%	100%	2.60	2.60	2.60
PM Emissions Factor for Generation on the Margin	lbs/MWh	100%	100%	100%	2.205	2.205	2.205
Value of CO2	$/ton	100%	100%	100%	$ 20	$ 20	$ 20
Value of SOx	$/ton	100%	100%	100%	$ 520	$ 520	$ 520
Value of NOx	$/ton	100%	100%	100%	$ 3,000	$ 3,000	$ 3,000
Value of PM	$/ton	100%	100%	100%	$ 36,000	$ 36,000	$ 36,000
Average Monthly Load Reduction from ES at Peak	MW	100%	100%	100%	1.0	1.0	1.0
Average Monthly Load Reduction from ES at Partial-Peak	MW	100%	100%	100%	1.0	1.0	1.0
Average Monthly Load Reduction from ES at Off-Peak	MW	100%	100%	100%	1.0	1.0	1.0
Peak Demand Charge	$/MW-mo	100%	100%	100%	$ 11,590	$ 11,590	$ 11,590
Partial-Peak Demand Charge	$/MW-mo	100%	100%	100%	$ 2,650	$ 2,650	$ 2,650
Off-Peak Demand Charge	$/MW-mo	100%	100%	100%	$ 6,890	$ 6,890	$ 6,890
Number of Months that Demand Charges are Avoided	#	100%	100%	100%	5	5	5
Typical Number of Power Quality Events per Year	#	100%	100%	100%	10	10	10
Value of Avoided Power Quality Events	$/kw peak	100%	100%	100%	$ 5.0	$ 5.0	$ 5.0
Customer Peak Load	kW	100%	100%	100%	1,000	1,000	1,000
Total Renewable Energy Discharged for Arbitrage	MWh	100%	100%	100%	782	782	782
Total Renewable Energy Discharged for Energy Time-Shift	MWh	100%	100%	100%	782	782	782

The next table shows the cumulative benefit and cost table, based on the reference case analysis, with the total cost of deployment and total net benefit shown on the bottom right of the table. As you'll note in these results, for the 20-year period, the ESCT estimated:

- $2,309,600 in reduced electricity costs (mostly from reduced demand charges)
- $594,900 in improved power quality savings (includes voltage and frequency support)
- $546,600 in emissions savings

This total gross benefit of $3,451,000 results in a return on investment of $491,200 (after the cost of the BESS, annual O&M expenses, etc.) for this option (benefits/cost = 1.16). Note that without the estimated environmental benefits, which are based on the future existence of a market for monetizing reduced emissions, the net return would be a negative $55,400. Even under the favorable conditions of being able to serve all of the identified functions, a utility likely would not make such an investment until the regulatory rules allowed cost recovery of storage investments or at least the environmental benefits.

Table 4. Cumulative Benefit and Cost Table

	Cumulative Benefit and Cost Table				
	Benefits	Additional Benefits - Total Present Value over the Deployment Period	+	Primary and Secondary Benefits - Total Present Value over the Deployment Period	= Total Benefit - Present Value over the Deployment Period
Market Revenue	Arbitrage Revenue	$ -		$ -	$ -
	Capacity Market Revenue	$ -		$ -	$ -
	Ancillary Services Revenue	$ -		$ -	$ -
Improved Asset Utilization	Optimized Generator Operation (Non-Utility	$ -		$ -	$ -
	Optimized Generator Operation (Utility/Ratepayer)	$ -		$ -	$ -
	Deferred Generation Capacity Investments	$ -		$ -	$ -
	Reduced Congestion Costs (Non-Utility Merchant)	$ -		$ -	$ -
	Reduced Congestion Costs (Utility/Ratepayer)	$ -		$ -	$ -
T&D Capital Savings	Deferred Transmission Investments	$ -		$ -	$ -
	Deferred Distribution Investments	$ -		$ -	$ -
Energy Efficiency	Reduced Electricity Losses	$ -		$ -	$ -
Electricity Cost Savings	Reduced Electricity Cost (Consumer)	$ -		$ 2,309,600	$ 2,309,600.00
	Reduced Electricity Cost (Utility/Ratepayer)	$ -		$ -	$ -
Power Interruptions	Reduced Outages (Consumer)	$ -		$ -	$ -
	Reduced Outages (Utility/Ratepayer)	$ -		$ -	$ -
Power Quality	Improved Power Quality	$ -		$ 594,900	$ 594,900.00
Air Emissions	Reduced CO2 Emissions	$ -		$ 127,500	$ 127,500.00
	Reduced SOx Emissions	$ -		$ 13,900	$ 13,900.00
	Reduced NOx Emissions	$ -		$ 36,200	$ 36,200.00
	Reduced PM Emissions	$ -		$ 369,000	$ 369,000.00
	Total Gross Benefit	**$ -**		**$ 3,451,100**	**$ 3,451,100.00**
	Costs				
	Capital Cost of Deployment (fixed charge rate)				$ 2,406,800.00
	Operating and maintenance costs not related to energy (labor for operation, plant maintenance, equipment wear leading to loss-				$ 546,900.00
	Decommissioning and Disposal Costs				$ 6,300.00
	Total Annual Cost of Deployment				**$ 2,959,900.00**
	Total Net Benefit				**$ 491,200.00**

While only very special conditions such as those identified for option #3, including capturing the monetary value of emissions reductions, would justify an unsubsidized investment by a utility in a BESS, demonstrations like this one are critical to understanding individual utility, system-wide and societal benefits of storage. As battery technology improvements continue to drive costs down, and the regulatory rules get modified to more completely reflect the values of storage, battery systems will find their way into the mainstream of technologies for grids challenged by large concentrations of renewable generation.

Pricing Incentives for Reshaping Residential Load

Another key aspect of the set of demonstrations is variable electric pricing designed to measure the willingness of consumers to change behavior, by either reducing energy use, or in some cases shifting certain home activities to times when electricity is cheaper. The objective of this effort was to determine the degree to which electric customers would alter their pattern of electricity consumption in response to electric prices that vary with the time of day, as well as measure their response to different types of pricing programs. As an example, wind power is most prevalent during the late evening and night-time hours, and this project was one of the first in the country to leverage inexpensive wind energy and offer a special night-time wind-enhanced electricity price that was significantly cheaper than day-time prices. Consumers that shifted their energy use from typical expensive hours (4 p.m. to 7 p.m.) to late evening hours (after 10 p.m.) were able to dramatically save on the expense of certain activities. Sixty-one homeowners voluntarily participated in the pricing experiments over the period of two years, and a like number of homes were unknowingly part of a control group for comparison.

Most of the participants in this study reside in a neighborhood known as the Mueller development which is situated about three miles from downtown Austin. The homes have energy efficient features, and the neighborhood has a high concentration of installed grid-tied solar photovoltaics (PV) and plug-in electric vehicles (PEVs). Basic demographic information and typical features of the homes are listed below:

Table 5. Demographic Data of Participants in Pricing and Control Groups

Demographic Information	Responses
Salary	43 survey respondents, or about 81%, claimed income above $75,000. One respondent claimed income between $300,000 and $1 million, and two participants claimed income above $1 million.
Ethnicity	51 respondents, or 82%, reported Caucasian ethnicity. Three respondents reported Hispanic ethnicity. Three reported Asian/Pacific Islander ethnicity. Five declined to respond.
Education	All respondents, except for one left blank, reported a college degree or higher. 42 respondents, or 71%, reported a postgraduate degree.
Home during weekdays	46% of the Pricing Group and 62% of the Control Group homes can typically be occupied on weekdays (daytime hours).
PEV ownership	34 plug-in electric vehicles (PEVs) are owned by the Pricing Group, consisting of 25 plug-in hybrids and 9 full electric vehicles compared to only 6 PEVs for the Control Group. **Note** - 34 PEVs in 62 homes is a much greater penetration than seen in the national market, providing a glimpse of potential future load shaping via shifting of vehicle charging schedules.
Cooking appliances	Predominantly natural gas. 27% have an electric oven.

Demographic Information	Responses
Laundry appliances	1 in 3 has an electric dryer even though natural gas is available.
Heating systems	90% have a gas furnace.
Water heaters	Natural gas
Average square footage	Approximately 2,000 square feet for both groups.
% of homes with programmable thermostats	100% of homes in both groups.

The homes within the Pricing Group and the Control Group were outfitted with home energy monitoring (HEM) systems. These devices attached to the home's individual electrical circuits within the breaker panel(s) and collected whole home and circuit (appliance) level energy use data in one-minute intervals. This energy use data was used to perform comparative analysis between and within the Pricing and Control Groups to characterize and quantify the Pricing Group's response to two experimental pricing programs outlined below which did not coincide or overlap at any time:

- A seasonal time-of-use (TOU) pricing experiment featuring a discounted night-time price per kilowatt-hour to encourage use of available inland (west Texas) wind generation every day during the five windiest months of the year (March through May, and November through December)
- A critical peak pricing (CPP) experiment invoking an expensive price per kilowatt-hour during defined peak hours on no more than 15 designated "critical peak" days during the four summer months (June through September). Critical peak days were "called" a day ahead by the project team based on forecasted next day weather conditions under the premise that extremely hot weather might coincide with ERCOT peak loads.

A CPP price of $0.64 per kilowatt hour (kWh) was only applied to the Pricing Group participants' energy consumption during the weekday (Monday – Friday) afternoon hours of 4 p.m. – 7 p.m. on "critical peak" days. To make the experimental pricing revenue neutral, there was an offsetting discount of approximately $0.016 per kWh on energy consumption during all non-peak hours of CPP event days. Twelve and 15 CPP days were called in 2013 and 2014, respectively.

For the wind enhancement pricing trial, the night-time electric rate for the Pricing Group was lowered to $0.0265 per kWh from 10 p.m. – 6 a.m. on all days during those months. To make the experimental pricing revenue neutral, there was an offsetting surcharge of approximately $0.02 per kWh on the participants' energy consumption during all other hours of those five months.

Over the course of this 20-month experiment (March 2013 – October 2014), the Pricing Group and Control Group received and paid their usual Austin Energy electric bills, which reflected the normal Austin Energy electric rates. To aid in recruitment of participants, and to reduce turnover, this effort provided all participants with an incentive. This monetary incentive was used to entice the Pricing Group participants to either shift their energy consumption to the "wind enhancement" time period (10 p.m. – 6 a.m. during certain months) or to reduce energy consumption during CPP times (4 p.m. – 7 p.m. in the

summer months). The project established a credit account with an initial balance of $200 for each participant in the Pricing Group. The credit account balance at any point in time, whether above or below that initial $200 amount, reflected the participant's degree of response to the pricing programs. If they reduced or shifted their use accordingly, then they actually accrued savings that were paid at the end of the experiment. Participants were able to track their progress and view their credit account through an online web portal display. For any participants who chose not to change their behavior, the pricing programs were designed to be revenue neutral meaning that participants who made no behavioral changes would not benefit nor be penalized. In fact, by the end of this effort, only 3% of the participants had deductions from their incentive account, and they were minor amounts.

Wind-Enhanced Pricing Results

In the wind-enhanced pricing experiments, the results showed that homeowners are responsive to pricing systems that will shift their electric load significantly to assist the grid manager, and improve system efficiencies, by making the system load more compatible with wind generation. The figure below compares Pricing Group to Control Group daily consumption patterns during the 2014 March to May wind pricing months, plotted in hourly percentage of daily total usage. The seasonal average hourly Texas wind generation is the dotted line in the background.

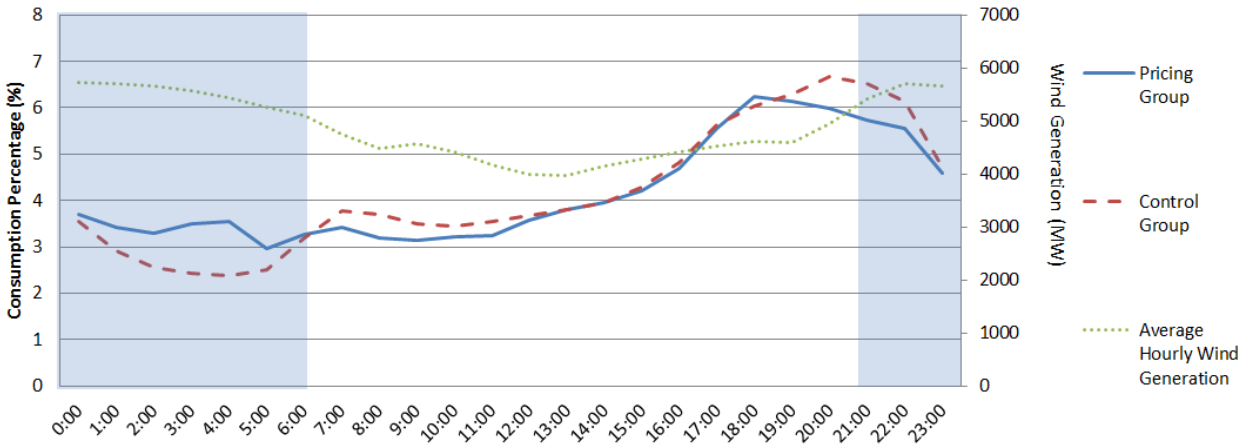


Figure 17. Pricing Group vs. Control Group 2014 March - May Wind Pricing Period

In contrast to the shifts evident in wind-pricing months (above), there is no clear shift in non-wind months (see graph below for June 2013). Energy consumption patterns for the Pricing and Control Groups are more similar in non-wind months.

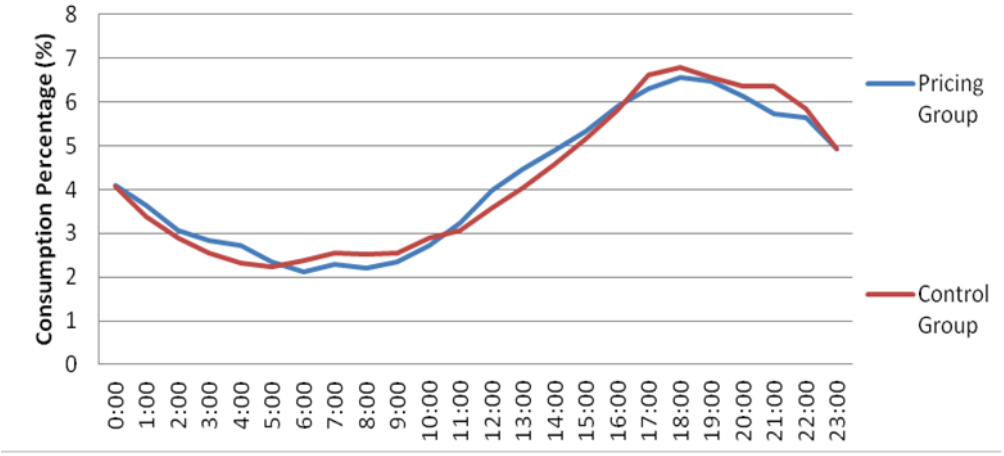


Figure 18. Pricing Group versus Control Group June 2014

Daytime/night time comparisons of overall electricity consumption for the Pricing and Control groups over all wind months during the experiment indicated a 4% difference, which is small but statistically significant considering what activities can be shifted to late evening or overnight hours (typically just PEV charging).

The average PEV charging consumption daily load shape is graphed below for owners of PEVs, for three different periods—before the trial started, during all wind months, and during the summer.

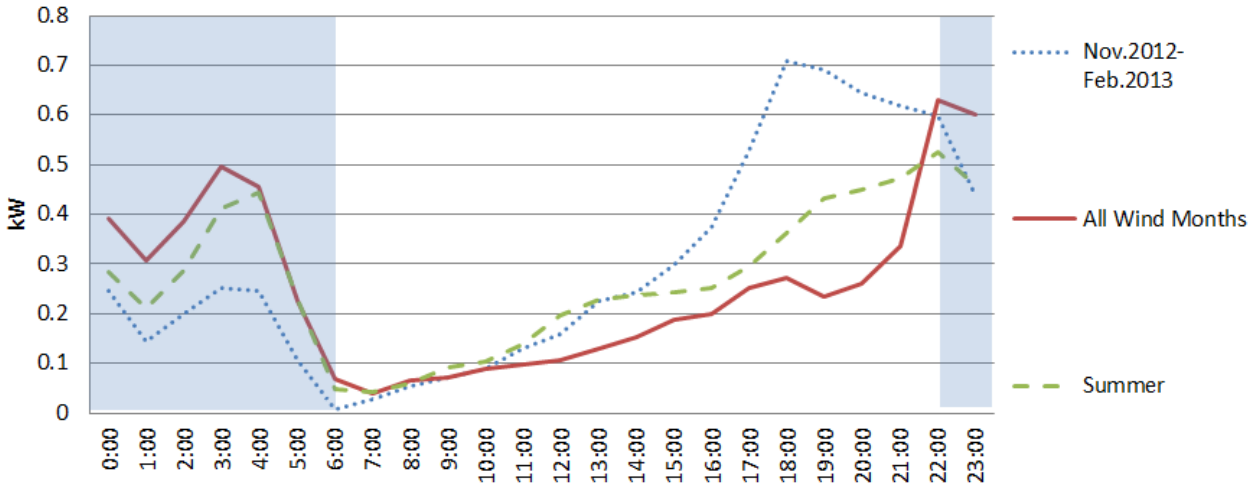


Figure 19. Pricing Group PEV Owners Average Charging Behavior

In the figure above, (blue dotted line versus solid red line) note the marked reduction in day time charging by PEV owners when the night-time wind pricing is in effect, taking advantage of very inexpensive overnight charging. Also note the partial rebound in day time charging during the summer

months (green dashed line) when wind pricing is not in effect. This summer rebound may be partially caused by the longer daylight hours and increase in evening activities in the summer time, calling for increased seasonal afternoon charging. But some participants stated that they went back to charging when it was convenient (including daytime hours) since the wind pricing was not in effect.

CPP Results

During the peak summer months, wind generation is very low so getting consumers to shift their load to the hours when the wind contribution is highest is not of much effect. So, a critical peak pricing program to simply encourage consumers to reduce or shift their load off the peak for a three-hour period (4 p.m. to 7 p.m.) is the most important for the efficiency of the ERCOT grid, and to make the grid manager's job easier when resources are limited. The CPP experiment showed that consumers will reduce their peak demand when they get a day-ahead notice and are provided an economic incentive to save money.

During the summer months of 2013, 12 CPP events were called. During 2014, that number was 15. The estimated kW savings achieved during those CPP events is shown in the tables below.

Table 6. 2013 Panel Data Analysis Results

Critical Peak Day	Daily High (F)	Estimated kW Savings
June 20th	98	0.5475
June 26th	101	0.7455
June 28th	104	0.7002
July 24th	97	0.4194
July 26th	99	0.3590
August 1st	103	0.2100
August 7th	103	0.7047
August 8th	104	0.6429
August 29th	99	0.2768
August 30th	102	0.2897
September 5th	96	0.1259
September 13th	97	0.3272
	Average Savings per Event:	**0.44 kW**

Table 7. 2014 Panel Data Analysis Results

Critical Peak Day	Daily High (F)	Estimated kW Savings
June 24th	93	-0.2484
June 30th	96	0.2840
July 2nd	97	0.0068
July 14th	97	0.2064
July 24th	101	0.0052
July 28th	99	0.1574
August 7th	102	0.2292
August 15th	101	0.1420
August 19th	96	0.5093
August 21st	103	0.5163
August 26th	101	0.2264
September 3rd	100	0.1601
September 9th	97	0.2082
September 11th	99	-0.0185
September 15th	88	0.2618
	Average Savings per Event:	**0.17 kW**

As evidenced in the tables above, CPP events in 2014 achieved less saving on average than in 2013. For comparison, the average reductions in demand were 0.44 kW or 15.27% in 2013, but only 0.17 kW or 6.15% in 2014. From responses to the final survey of the Pricing Group, the greatest cause of lesser savings the second summer (2014 versus 2013) was that participants made lifestyle changes at the beginning or early in the trials that were persistent throughout the trial period, thus reducing the apparent 2014 savings yielded by panel data analysis and historical baseline method. Examples include moving their PEV charging, laundry and dishwasher use to outside the on-peak window. A lesser behavioral impact on 2014 savings was customer fatigue. In consideration of these performance factors, the 2013 results were considered more representative of the group's CPP response.

Further analysis for Pricing Group members with PEVs revealed that around 62% of the CPP kW reductions were attributed to heating, ventilation and air conditioning (HVAC) and PEV related behavior change (HVAC @ 40%, PEVs @ 22%). For Pricing Group members without PEVs, around 57% of the CPP kW reduction was attributed to HVAC related behavior change. Apart from HVAC and PEV kW reductions, the other CPP kW reductions came from other uses with laundry and kitchen appliance consumption both found to be significant contributors.

Pricing Group members with electric vehicles (EVs) saved more energy during CPP events (0.46 kW versus 0.28 kW) than non-PEV owners, as depicted below for the 2013 events.

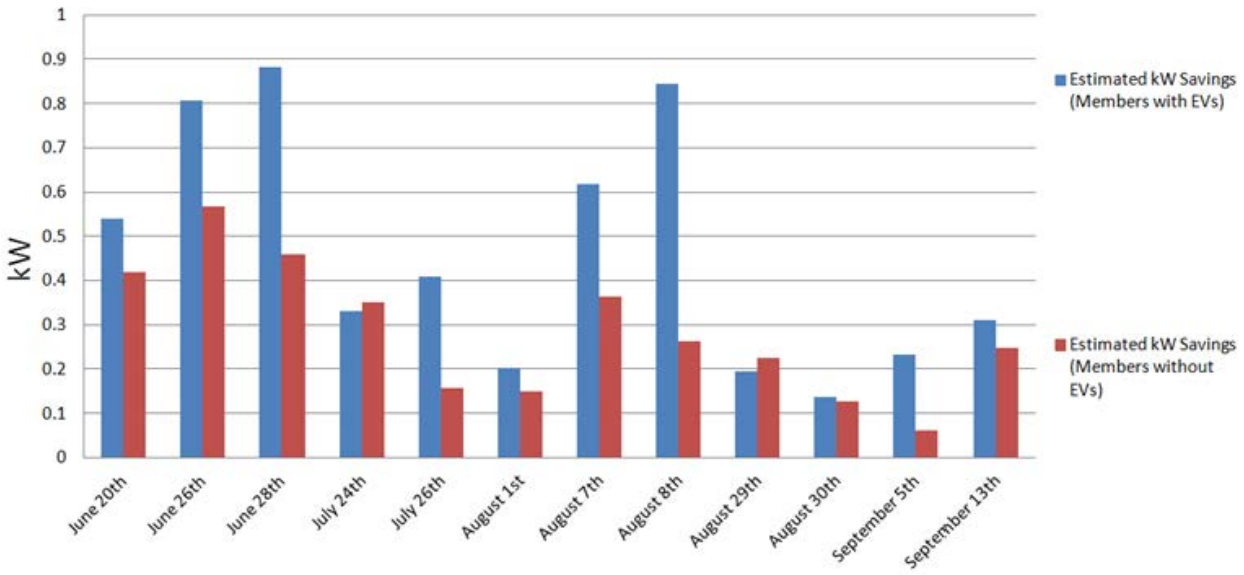


Figure 20. Comparing CPP Pricing Group Members with and without EVs

As expected, the Pricing Group participants who own PEVs exhibited more variability in responding to CPP events. If normal charging typically began when they arrived home, but they delayed that charging until after 7:00 p.m. during CPP events, then their savings were much higher than for those without PEVs. PEV charging is a high kW load that can often be delayed until later in response to pricing.

Although very successful, it should be noted that the Mueller community is not typical of communities throughout Texas, so one cannot analytically extrapolate these results to all of the ERCOT market. For perspective, however, if the 0.44 kW peak reductions per residence were fully realized statewide at Texas' 10,000,000 residential housing units, the system peak reduction would be 4,400 MW. If the wind-enhanced pricing trial were to be implemented statewide at every residential unit, successfully shifting 5% of load during shoulder months to night-time periods, the shifted load would equate to one half to two thirds of the current seasonally available overnight wind generation.

Solar Community-Grid Compatibility Challenges

Residential rooftop solar photovoltaic (PV) distributed generation is logically a good complement to wind resources on the grid since the solar contribution comes during the day while the bulk of the wind contribution (west Texas wind) is concentrated in the late evening and night-time hours. Concentrations of rooftop solar PV generation, however, bring their own challenges to the grid operator, and these are likely to be present during the shoulder months (March – June, and October – November) when the system demand is low, the sun is shining brightly, and west Texas wind is most abundant. The expected significant increase in solar adoption has raised a number of concerns for utilities, so the CCET project

included a component to monitor and assess the dynamics of a solar community as it interacts with the grid.

One of the challenge areas resulting from increasing market penetration of residential rooftop solar PV distributed generation is variations in electrical performance parameters on residential distribution circuits and behind the meter, such as excursions in load, power factor and voltage, as well as harmonic distortion effects. As reported herein, these issues arise from multiple interacting and dynamic factors, including distributed solar generation cancelling utility kW load, variable solar PV generation, the increasing harmonic current drawn from modern home appliances, and others.

To address the key challenge areas of concern, the CCET effort included residential circuit monitoring at two levels: 1) on 35 kilovolt (kV) underground residential distribution (URD) circuits in Houston, Texas, and 2) at the residential customer point of connection in Austin, Texas. The observations noted from these two efforts will help utilities anticipate the occurrence and assess the significance of potential power quality impacts in communities with a range of concentrations of solar PV and in making design and/or operational adjustments to mitigate such impacts.

For the first task, CenterPoint Energy led an effort to examine correlations between distributed solar PV generation and distributed circuit power quality impacts by measuring and comparing electrical parameters on a total of six 35 kV circuits in two neighborhoods in an area north of Houston, Texas, one with a moderate penetration of solar PV and the other with virtually no solar. The Harmony neighborhood (formerly Discovery at Spring Trails) has a high concentration of new homes (built in 2008 and after) with very efficient building features, energy efficient appliances, small (average 1.1 kW) rooftop or trestle-mounted solar PV systems, and HEM systems for monitoring electric and water use. The second neighborhood, Legends Ranch, includes similar type homes, but they are built without enhanced energy efficiency features and are not equipped with rooftop solar PV, energy efficient appliances or HEM systems, i.e. more typical of newer Texas neighborhoods. Specifically, this effort focused on analysis to compare and correlate solar PV generation to circuit parameters by installing universal circuit monitors (UCMs) and then measuring and calculating total harmonic current and voltage distortion (THDi and THDv, respectively), power factor (PF) and voltage at the distribution level as five minute averages in the two neighborhoods.

For the second task, a total of seven homes in the Mueller neighborhood in Austin, Texas, were monitored by Pecan Street for power quality parameters, solar PV production, and net load served by the utility. As mentioned before, the Mueller area is a relatively new, “green built” neighborhood with efficient home construction, energy efficient appliances, a high concentration of installed grid-tied solar PV and plug-in electric vehicles. This neighborhood has approximately 30% solar market penetration and the average installed system nameplate direct current (DC) capacity is 5.24 kW for each home having solar PV. In general, this investigation provided an opportunity to develop a more complete understanding of the interaction of solar PV with the distribution infrastructure. The root cause of any observed issues should be traceable to events occurring within the residential load, residential solar PV operation, or the utility distribution service. Information gained on the secondary side of the service

transformer can be compared with measurements at the distribution circuit level (even a different circuit) if the load type and distribution between the two circuits are similar. Previous studies have shown residential power factor to be .9 to .95 lagging, and typically of low distortion. The addition of solar PV and the proliferation of switch mode power supplies are changing these characteristics. The benefit to the utilities is an updated and more accurate characterization of the residential electrical load at the point of connection.

The homes monitored for this study were selected because they share two 50 kilovolt-amperes (kVA) distribution transformers, and because they are participating in Pecan Street research trials, whereby the residents have agreed to allow their energy usage to be monitored. The two transformers for the selected homes were monitored allowing the data to be compared with measurements on individual homes. The transformers were loaded as follows:

- Transformer 7007 has 10 connected houses, 3 with solar (30%); 18,800 square feet total
- Transformer 7006 has 8 Houses, 5 with solar (63%); 14,200 square feet of total

The solar monitoring data and analysis results identified a particular challenge of harmonic distortions from homes with solar during certain time periods, conditions of concern to the distribution utility. These harmonics can cause problems like degradation of conductors and insulating material in consumer appliance motors and utility transformers. Therefore it is important to gauge the total effect of these harmonics.

The observations of harmonic distortions in the DAT study were most prevalent in the shoulder months (March to May, and October to November in Texas) when home load is small (little or no HVAC load) on a sunny day when the solar unit is producing maximum power. Note that the solar unit from 10 a.m. until 4 p.m. is providing most of the power for the home and the grid-provided power is very low. The general conclusion of the study is that for homes with solar capable of providing all of the home's power use during a sunny day in the shoulder months, the harmonic distortions will be high, as shown in the two figures below which compare Harmony (solar) with Legends Ranch (no solar). The first figure represents a sunny day in April when solar production is able to cancel all but 20 kW of the entire utility load (60 homes). In contrast, the second figure is absent the solar PV influence so the THDi on the circuit varies throughout the day, and is lower in the daytime even though the kW load on the circuit is high.

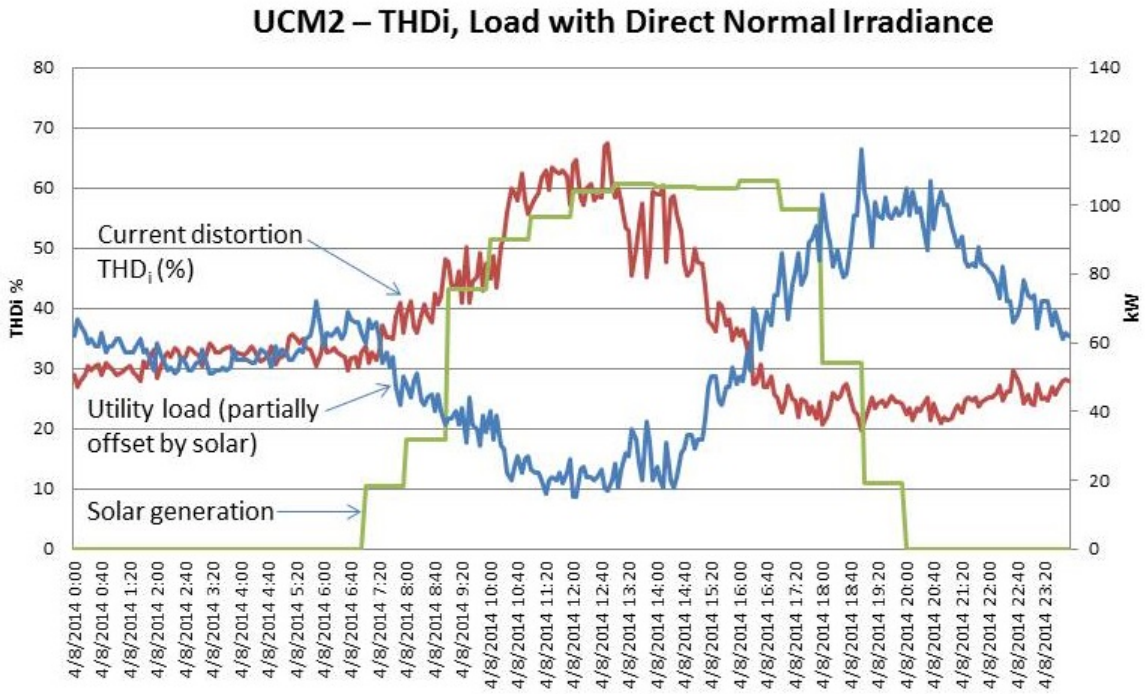


Figure 21. Movement of Harmony THDi, Solar Irradiance, and Utility Load on a Sunny Day in April

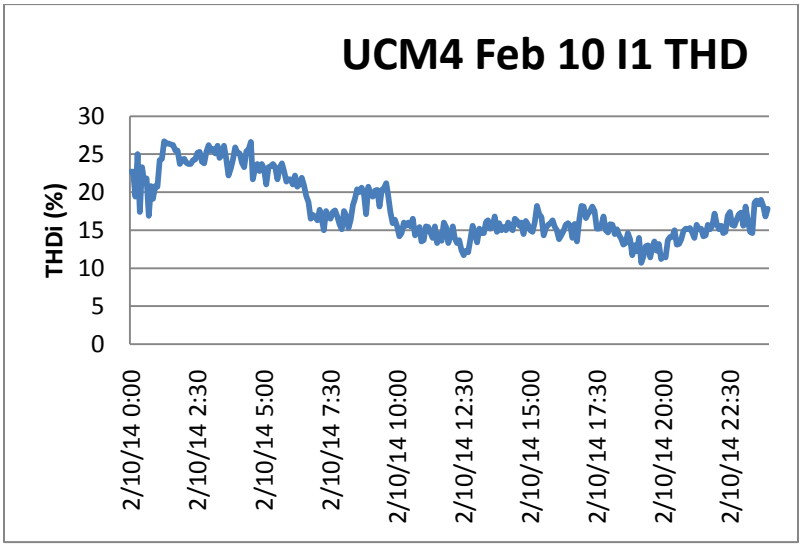


Figure 22. THDi Movement in Legends Ranch

To determine whether the THDi and PF behavior observed on the 35 kV URD circuits in Houston was unique to that neighborhood, similar monitoring and analysis was performed on the homes in the Mueller neighborhood in Austin. The same type of THDi and PF behavior as reported in Houston was observed in the Austin residential monitoring. For the Austin houses with larger solar arrays, longer periods of fundamental load cancelation were observed, though this will vary by day, weather, array

size, and home electricity usage. This behavior will likely be seen at some point during the year by any house where solar PV production can offset an appreciable portion of the total home kW load.

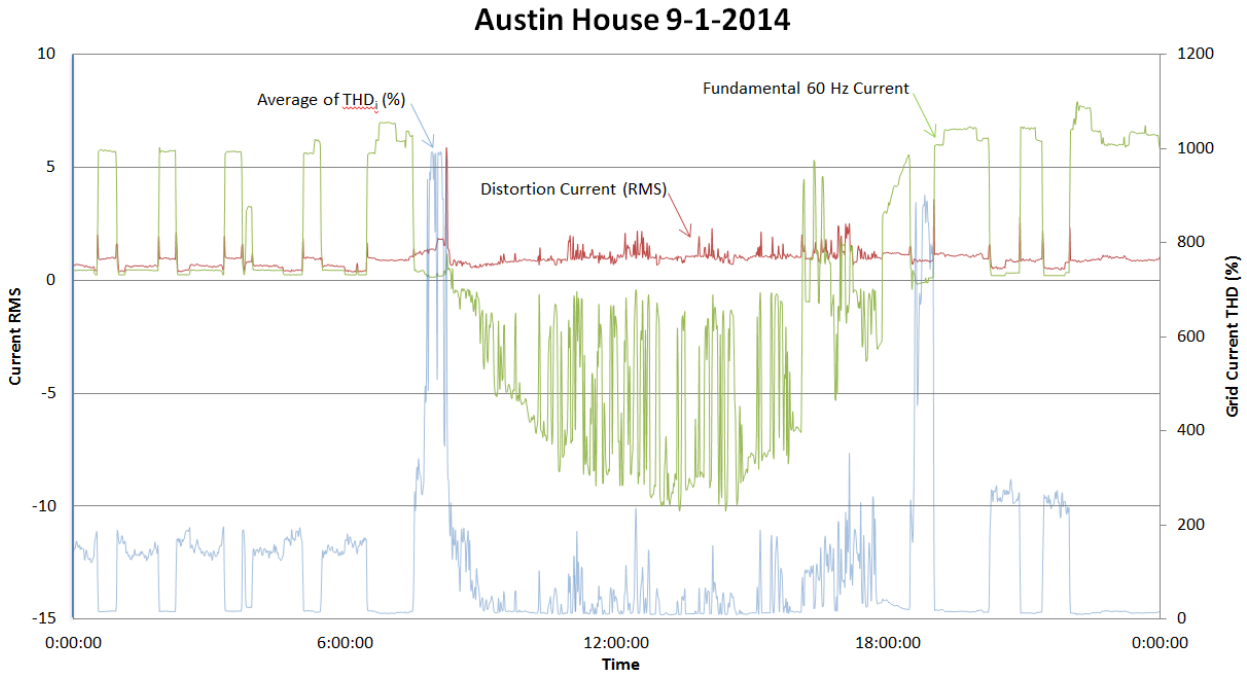


Figure 23. THDi Behavior for Home with Larger Solar PV System

In the figure above, the distortion current stays approximately the same during the entire day with variations that can be attributed to device usage, not solar production. During the daytime, solar capacity exceeds home load much of the time, driving the load on the utility (green line) negative, with oscillations due to cloud cover and home appliance operation (generally HVAC). During periods when the utility load (green line) is canceled and approaches zero for minutes to an hour at a time, the THDi spikes are very high, up to 1000%. This is due to the very low amounts of fundamental current supplied by the grid, not the solar production adding distortion to the grid.

Other findings of interest or conclusions include the following:

1. As the installed price of solar PV continues to decline, there will be continued increases in market penetration and average PV system capacity. Many homes already have several kW of installed solar PV and these homes produce their own real power (kW), which at times cancels the real power supplied from the utility. To the extent this condition exists in a given neighborhood, the customer at times would be drawing only distortion current and reactive power from the utility, leading to high harmonic current distortion (measured as THDi) and potentially a sagging power factor on distribution circuits.
2. It was shown that measured THDi can be significantly higher on distribution circuits that feed high concentrations of homes with solar PV as compared to those serving homes with little or

no PV. It is not clear that increased THDi is an immediate threat to reliability, but a review is suggested of the underlying assumptions of the Institute of Electrical and Electronics Engineers (IEEE) standard IEEE-519 regarding the damping effects of resistive loading. When the resistive loading is canceled by solar production, the impact of harmonics on grid stability may become an issue of concern that is not addressed by IEEE-519.

3. The PF variability on distribution circuits with high solar PV penetration will likely require enhanced monitoring and upsized (and fast acting) PF correction to meet operating standards. One means of mitigation could be volt-amp reactive (VAR) injection at the solar PV inverter, and this could require compensation to the PV owner (customer) for any added equipment cost and for kW production forfeited in producing the injected VAR.
4. The localized voltage boost associated with residential PV production is additive at the service transformer and will propagate to distribution voltage. The resulting boost on the distribution circuit should not be problematic if the magnitude and rate of voltage drift can be handled by the distribution transformer tap changers.
5. All houses on a common service transformer will experience boosted voltage from PV production on any one or more of the connected houses. The boosted voltage will vary at rapid ramp rates due to fast moving cloud cover affecting PV production. The magnitude and potential impacts of limiting case voltage changes at service voltage and the need for and means of local monitoring and mitigation are unknown and should be defined.
6. PV inverters conforming to industry standards do not add appreciably to voltage or current distortion.

An interesting suggestion from this analysis was the potential benefit of using distributed energy storage systems placed either behind the meter or in the utility infrastructure. Such storage could allow for solar energy to be collected and stored for use throughout the day, minimizing power quality impacts by smoothing out rapid PV production ramps and reducing the time that the residential load is entirely canceled by distributed generation.

Direct Load Control Enhancement via Dual Communication Paths

There are times when the energy demand may come close to exceeding available generation resources. At times like these, the ability to call upon other resources to reduce the demand is imperative. One such action is termed demand response (DR) whereby commercial and residential resources are tapped to reduce their energy use. A need for demand reduction for grid reliability may occur during the summer peak (e.g., 4 p.m. to 7 p.m.), but it is also likely during the shoulder months of March to May when wind resources provide a large percentage of generation. In fact, the most recent load control event which included rolling interruptions in ERCOT occurred not during a summer peak but during a morning peak in February 2011. That event occurred when extremely cold weather raised demand and 5,000 MW of gas and coal units went off line. The wind was blowing and producing about 3,500 MW of wind power, but there were no other immediate resources available. Under these circumstances, demand reduction from large industrial consumers saved the day, but it could have easily come from thousands of homes as well.

In the residential sector, some homes are equipped with technologies, such as smart programmable thermostats, that can be remotely controlled (direct load control) by utilities or retail electric providers (REPS) to reduce the amount of energy use when needed. The consumers are incentivized, either with free equipment to help them better manage their energy use and costs, or through some type of small monthly payment. In many cases, the remote access is via the Internet using the homeowner's broadband network to control the equipment. Although this approach is technically feasible and fairly easy to implement, remotely contacting and controlling the equipment in the participating homes during a demand response event has been problematic. For a number of reasons, the utility or REP has not been able to access a high percentage of these devices during critical times, lessening the effectiveness of these programs especially considering the costs involved. For example, one of the Texas REPs, TXU Energy (TXUE), has provided home area networks (HANs) comprised of programmable thermostats and gateways to thousands of customers with the intent of leveraging these devices during demand response events. Based on a historical online percentage, for every 10,000 thermostats participating in the TXUE program, only about 55% were able to be remotely accessed and cycled. Presuming each air conditioning system used an average of 1.5 kW, then the remaining 45% of offline devices equated to about 6,750 kW of load that could not be reduced during the critical time. To address this challenge, the CCET project undertook an effort to demonstrate that these results could be improved by leveraging other technologies to deliver the DR messages via a second communications path. This approach included the transmission of messages to the thermostats by using the transmission and distribution utility (TDU) networks and the residential smart meters, simultaneous pairing of the thermostats with both the Internet and the residential smart meter so they could receive messages using both paths, and use of the SMT Portal (SMTP) as a venue for distributing the messages to the utility networks. The figure below illustrates the high-level proposed architecture for this project.

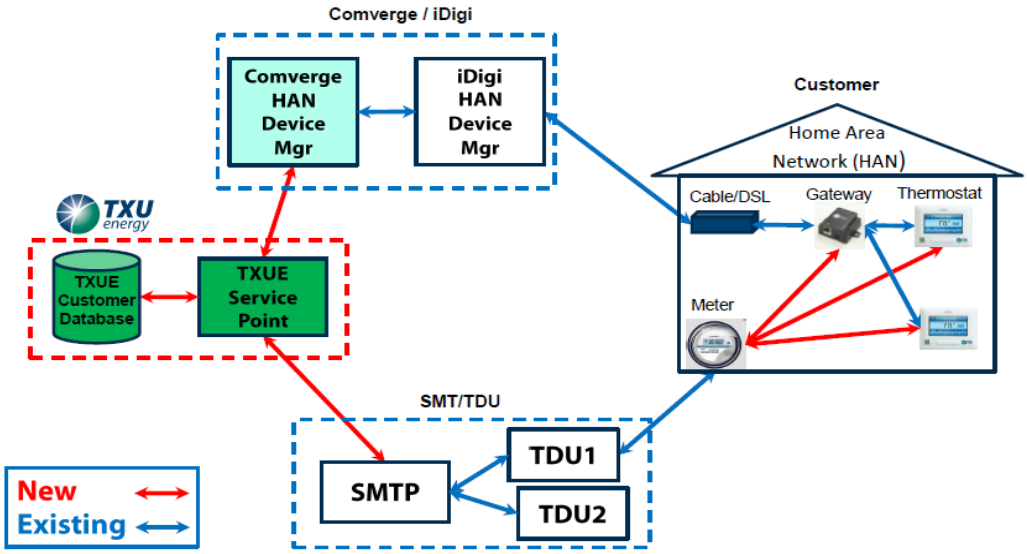


Figure 24. Proposed Architecture for Improving Demand Response Results

TXUE had thousands of homes already equipped with programmable thermostats, so the first solution was to remotely upgrade the software controls in these thermostats so they could also accept a signal through the home's smart meter. The technical laboratory and field tests of the dual-path system established the viability of employing both communication paths to improve reliability of communications while preserving the important ability to maintain a rich customer experience via information exchange supported by the Internet-based system. However, the prospect of completing the upgrade remotely over-the-air failed on the legacy equipment. Also, it was determined that many of them were not compliant with existing standards for communicating with the smart meter. The Team then evaluated two other approaches, but in each case there were only two viable options: 1) roll a truck and crew to replace the existing legacy equipment, or 2) send the equipment to the residence and have the homeowner install and configure the new equipment. The second option seemed viable, so tests were run using a friendly homeowner. Although the home testing proved that everything could be accomplished, and the DR messages could be sent and received via both paths, the testing also demonstrated that the actual equipment configuration process was fairly burdensome and problematic for a typical homeowner. Therefore, it was decided this option would not work. The first option, dispatching a crew, was deemed to be too expensive, so the project was halted. Therefore, while the dual path technology option is practical with new devices that are compliant with the standards, the retrofit of legacy equipment would require an expensive truck roll that could not be justified or financially supported by the project.

Aside from evaluating and demonstrating the dual path approach for improving DR, the project also explored the economic viability of DR in the ERCOT market. Since 2008, TXUE has initiated DR events across 13 days, including five pre-season tests. TXUE currently deploys a 15-minute, 100% cycling strategy, and the customer topology allows for TDU segmentation as well as sustained cycling within a region by rotating customer groups across 15-minute intervals. This approach allows TXUE to respond quickly to initial grid conditions with a predictable load reduction, and also allows for flexibility when extended cycling is required.

In order to estimate the average customer load reduction achieved during a DR event, 15-minute customer meter data was pulled for all days where DR was executed in 2011 and 2013. The figures below reflect a portion of the actual DR results based on a sample size of ~6,000 total customers. The first figure shows the effects of a single DR event triggered at 4:55 p.m. (not fully aligned with the 15-minute interval data). The subsequent set of figures shows the effects of one or more events triggered over several days in August 2011.

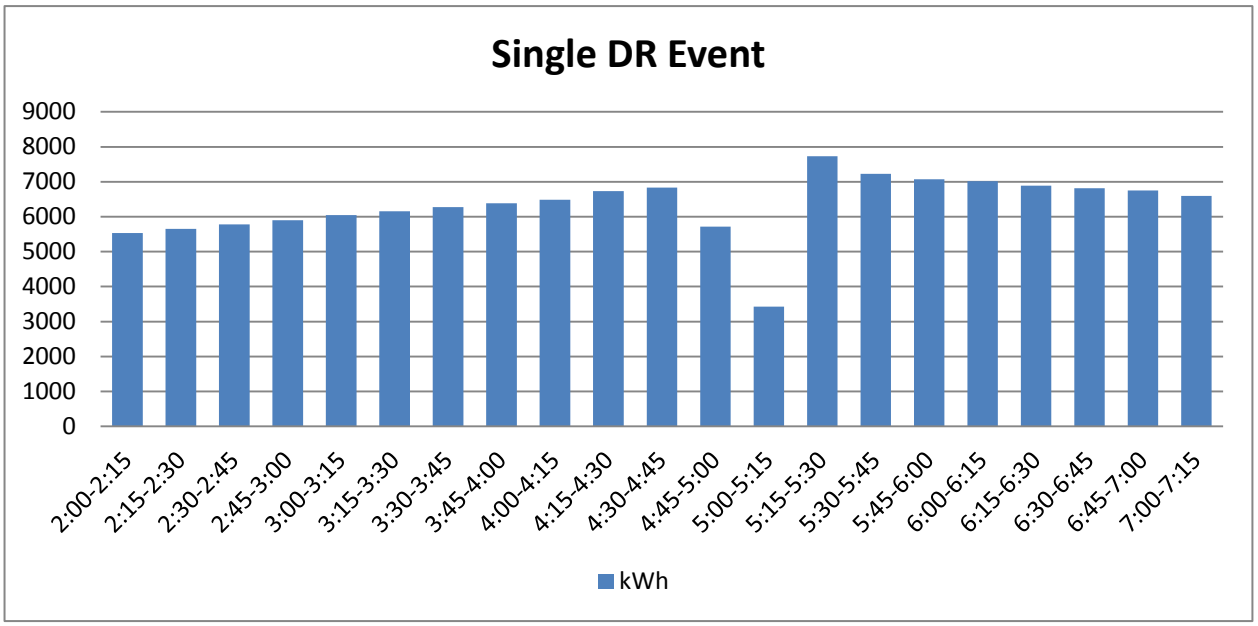
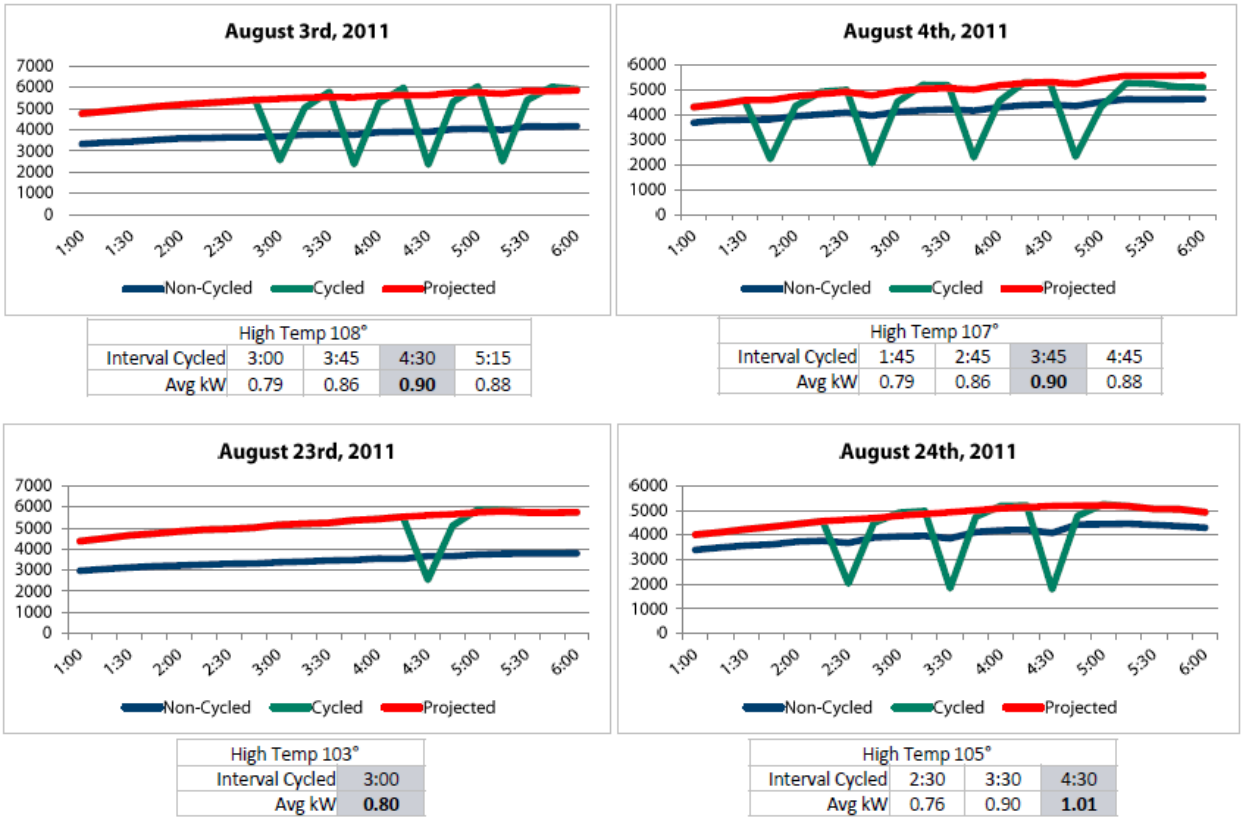


Figure 25. Single DR Event



High Temp 108°				
Interval Cycled	3:00	3:45	4:30	5:15
Avg kW	0.79	0.86	**0.90**	0.88

High Temp 107°				
Interval Cycled	1:45	2:45	3:45	4:45
Avg kW	0.79	0.86	**0.90**	0.88

High Temp 103°	
Interval Cycled	3:00
Avg kW	**0.80**

High Temp 105°			
Interval Cycled	2:30	3:30	4:30
Avg kW	0.76	0.90	**1.01**

Figure 26. Multiple DR Events

Analysis of the 13 cycling days reveals the average reduction per customer (difference between cycled and smoothed) ranges from 0.50 kWh to 1.0 kWh. The variation can be directly correlated to outdoor temperatures. When cycling was performed on days where temperatures were in the upper 90s (not shown above), the average reductions ranged from 0.55 kWh to 0.75 kWh per customer. As temperatures climbed above 100 degrees the average reductions ranged from 0.75 kWh to 1.0 kWh per customer.

These averages can be used to determine the incremental value of controlling additional thermostats. From a pure cost perspective, the following chart represents the potential annual value of managing peak load at the maximum ERCOT bid cap levels per megawatt hour (MWh). The table shows results for a suggested cycling of 1,000 homes for 15 minutes (maximum value per DR event) and then multiplies that by 10 DR events per year to derive the maximum annual value per 1,000 customers per year.

To better understand the results shown below, the bid caps are defined as part of a Public Utility Commission (PUC) rule that authorized high system-wide offer caps (SWOC) in stages. The first increase in the cap was from $3,000 to $4,500 as of August 2012. In October 2012[2], the PUC decided on additional increases to the SWOC: $5,000 beginning June 2013, $7,000 in June 2014, and $9,000 as of June 2015. The $90 standard cost shown in the table is a typical cost of energy plus demand charges faced by REPs in the Texas competitive market for residential services ($0.09/kWh).

Table 8. Annual Value Proposition

Bid Cap ($/MWh)	**$5,000**	**$7,000**	**$9,000**	**$5,000**	**$7,000**	**$9,000**
Less standard cost ($/MWh)	$90	$90	$90	$90	$90	$90
Opportunity value ($/MWh)	**$4,910**	**$6,910**	**$8,910**	**$4,910**	**$6,910**	**$8,910**
Average load shed per home for 15-minute event (kWh)	0.55	0.55	0.55	1.0	1.0	1.0
Customers cycled	1000	1000	1000	1000	1000	1000
Maximum value per DR event	$2,701	$3,801	$4,901	$4,910	$6,910	$8,910
# of DR events per year	10	10	10	10	10	10
Maximum annual value per 1,000 customers	**$27,005**	**$38,005**	**$49,005**	**$49,100**	**$69,100**	**$89,100**

While these results can be extrapolated for a much larger DR pool of homes, the respective cost of equipment, truck rolls, and support must also be extrapolated. For example, in the table below, if a REP determined that they could outfit a customer with a gateway and programmable thermostat for $300 (including equipment, truck roll cost, and ongoing support), it could take 6-10 years (depending on load

[2] https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.505/40268adt.pdf

shed amount) to recover that cost at the $5,000 bid cap, and 4-6 years at the $9,000 cap. Given that Texas is a competitive retail market, and customers can swap REPs at will, equipping them all with these devices with the primary intent of supporting DR would be a huge investment with equally great risk.

In summary, the project was unable to demonstrate the ability to improve DR results by sending the DR signals via two paths to a large number of homes. However, the project did prove that it can be accomplished so one could estimate that the REP could potentially reach another 35% of their residents, meaning only 10% of the population would be unreachable. Unfortunately, as shown above in the economic analysis, the amount of time (in years) that it takes to recover the initial up-front investment makes it difficult to justify the costs simply to provide a DR capability. Certainly the dual path approach should be considered in defining a workable architecture that can support DR, and especially if the equipment investment is going to be made by the REP anyway. Such a solution could be an important contribution in future DR program approaches where the dual path capability adds only a small incremental cost to the set of items needed to equip and engage the customer.

Fast Response Regulation Service using Fleet Electric Trucks

Frequency regulation is a grid ancillary service (AS) that allows electricity generators, including those with large battery energy storage systems, to bid services into the energy market to assist in maintaining the electric grid frequency at 60 Hz. Providers of this type of service guarantee to be able to adjust generation during a specified time period by either ramping up or ramping down production according to instructions in order to maintain the balance of generation/load on the grid, and thus the frequency. Traditionally, in the ERCOT market, this was accomplished through the dissemination of a four-second signal, with each frequency regulation generation resource then responding within their pre-established ramp rate until they met the full capacity specified in the signal. Participants in the frequency regulation market get paid whether they are called upon to adjust power or not, thus they are paid to be “on standby”. As shown in the figure below, ERCOT studies (data is from 2008) have determined that the need for fast response resources to provide regulation up (Reg Up) or regulation down (Reg Dn) services increases as the concentration of wind grows on the grid.

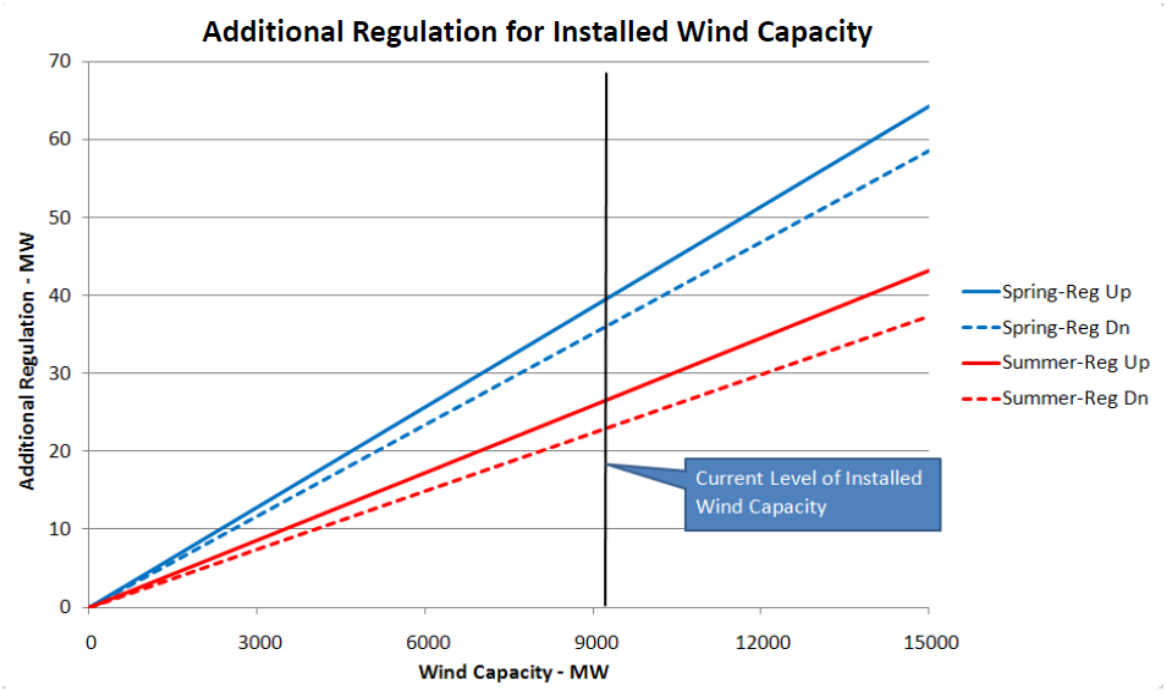


Figure 27. Results of a General Electric Study on Regulation Service

While the CCET DAT project was ongoing, ERCOT carried out a pilot project to find qualified resources willing to participate in an AS market called Fast Response Regulation Service (FRRS). Entities within ERCOT who could meet the technical requirements (primarily to respond with the promised kW of capacity within one second) were invited to participate. The purpose was to demonstrate that FRRS providers could improve ERCOT's ability to maintain grid frequency at 60 Hz when needed. The response requirements for this FRRS pilot basically limited participants to those with energy storage systems (batteries). Two large battery systems participated in the ERCOT pilot, and CCET seized on the opportunity to demonstrate that FRRS could also be provided by aggregated electric vehicles (EVs) without significant investment (such as a large-scale utility scale battery costing millions of dollars). In particular, supporting Reg Up services (the reducing of load on the system) could be as simple as "flipping a switch", i.e. turning the EV charger off. Regulation-down (the addition of load on the system) could be provided almost as quickly although the delivery of load to the grid from the batteries would require a more extensive management and control system. CCET participated by qualifying, placing bids, and delivering the needed FRRS in the AS market with a resource derived from a fleet of electric trucks.

Electric delivery trucks are new technologies that are finding their way into special markets where the travel requirements, convenience, and work schedules make the economics work. But as is usually the case, the economics are not currently favorable without government subsidies. However, the availability of being able to provide an additional service that generates revenue while the vehicles are stationary and essentially not being used would help the return on investment.

The CCET project leveraged the resources of Frito-Lay in Fort Worth to provide the electric vehicles while other team members developed the software and hardware capability to aggregate a set of 11 Frito-Lay trucks (shown below) so they acted as one resource capable of providing at least 100 kW of FRRS. The Frito-Lay trucks typically begin deliveries at about 3 a.m., return to home base about noon, and remain at that site for battery charging and loading of the next day's delivery until the next morning. This schedule is an ideal match for Frito-Lay's participation in the AS market since they were available to deliver the service when it was needed, and doing so would not detract from the primary duty of their trucks.

Figure 28. Frito-Lay Electric Truck and Charging Stations

This effort entailed the development and demonstration of an EV aggregation control system to support regulation-up services in response to an ERCOT signal or a detected deviation of grid frequency of greater than .09 Hz. The architecture for this effort is shown below, and leverages the EV supply equipment (EVSE), the energy management system (EMS), and the aggregator.

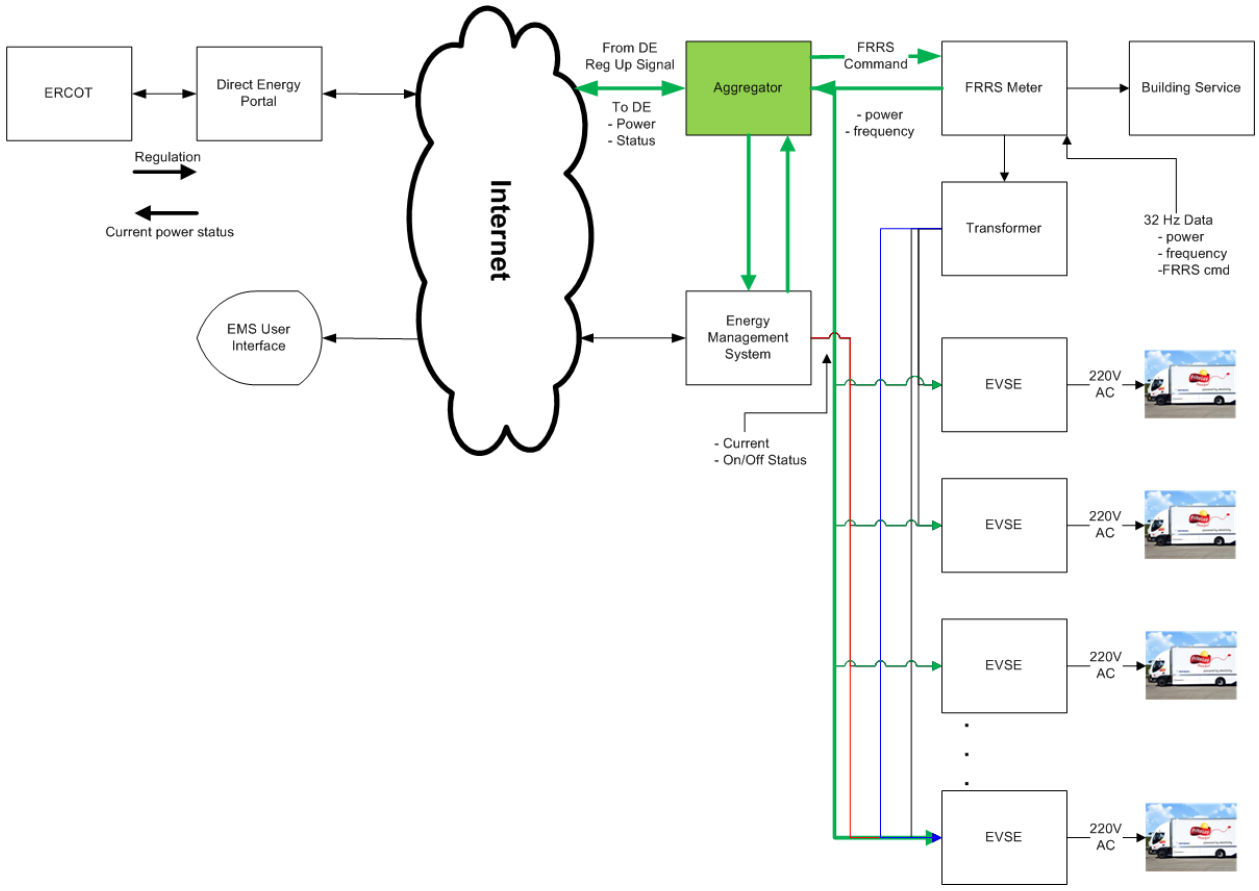


Figure 29. Architecture for Delivering FRRS from the Frito-Lay Facility

The following activities were conducted to create and ensure a successful deployment of technology:

- Identification and procurement of a utility revenue-grade meter to monitor power and grid frequency at a minimum of 32 Hz. After an extensive trade study of suitable meters to meet the requirements of the electrical infrastructure at the site, it was decided to build a custom power meter. The electrical infrastructure would have required either a complete replacement of the electrical panel box to split off building power from charger power or the acquisition of 12 revenue-grade power meters. Designing and building a custom meter that could monitor the 12 EV circuits after the panel box became the more cost-effective solution using National Instruments components. Total hardware costs were under $20,000 versus over $100,000 that would have been spent on individual power meters or redesigning the electrical panel box. The final solution, shown below, resulted in a compact, robust, fast, and inexpensive power meter/aggregation system package that is easy to install and remove without requiring extensive site improvements to the electrical infrastructure.

- Development of a software aggregation control system to manage an EV fleet in accordance with FRRS parameters.
- Establishment of a secure physical network interface to the ERCOT system in accordance with FRRS pilot requirements. In accordance with ERCOT rules, this interface was done through a qualified scheduling entity (QSE). A distributed network protocol 3 (DNP3) interface to the QSE was implemented over a secure virtual private network (VPN) tunnel. The QSE telemetered the information provided by the aggregation system to ERCOT on a 2-second interval. ERCOT verified they were receiving the telemetered data from the aggregation system.
- Development of the data collection, correlation, and delivery to ERCOT of the required meter data files within one day of each frequency regulation bid period. The eventual solution to this was somewhat manual due to the rules for a QSE. After each bid hour, data files were automatically downloaded through a remote agent to SwRI. The data files were converted to a Microsoft Excel format, and then emailed to the QSE. After review, the QSE then sent the files to ERCOT. This solution worked well for the pilot and could be further automated in a future deployment.
- Development and deployment of hardware for controlling the EV chargers within the FRRS established time frames for power responses.
- Installation and deployment of secure networking hardware for the interface between the QSE and ERCOT.

Leveraging these capabilities developed and provided by CCET, the EV fleet at Frito-Lay successfully bid into the ERCOT FRRS market and received compensation for providing energy capacity to the grid. This became the first time EVs have successfully participated in an ancillary service in ERCOT and the first time a fleet owner has received payment for providing these types of services using an EV fleet. The project results demonstrated that for the first time in the U.S. the battery capacity from a fleet of vehicles could be aggregated as an effective resource for grid management, and could do so without detracting from the primary vehicle purpose. Such resources in the future have appealing qualities for a

number of reasons, especially in that they can provide such services to the grid operator from disparate locations, and in varying quantities—truly a distributed grid resource.

Although the project was highly successful, the real issue is the economic value proposition since the goal was to define an additional revenue stream that would help justify the costs of electric trucks. In the ERCOT market, given the current market rules, and with energy being relatively inexpensive in Texas, there is little to no economic benefit that can be realized by small fleet owners participating in the FRRS market. As a part of this project, the Team looked at ancillary service prices paid for frequency regulation services in ERCOT for 2013 and up through March 2014. Average frequency regulation prices paid per 100 kWh, by hour, for 2013 are shown below.

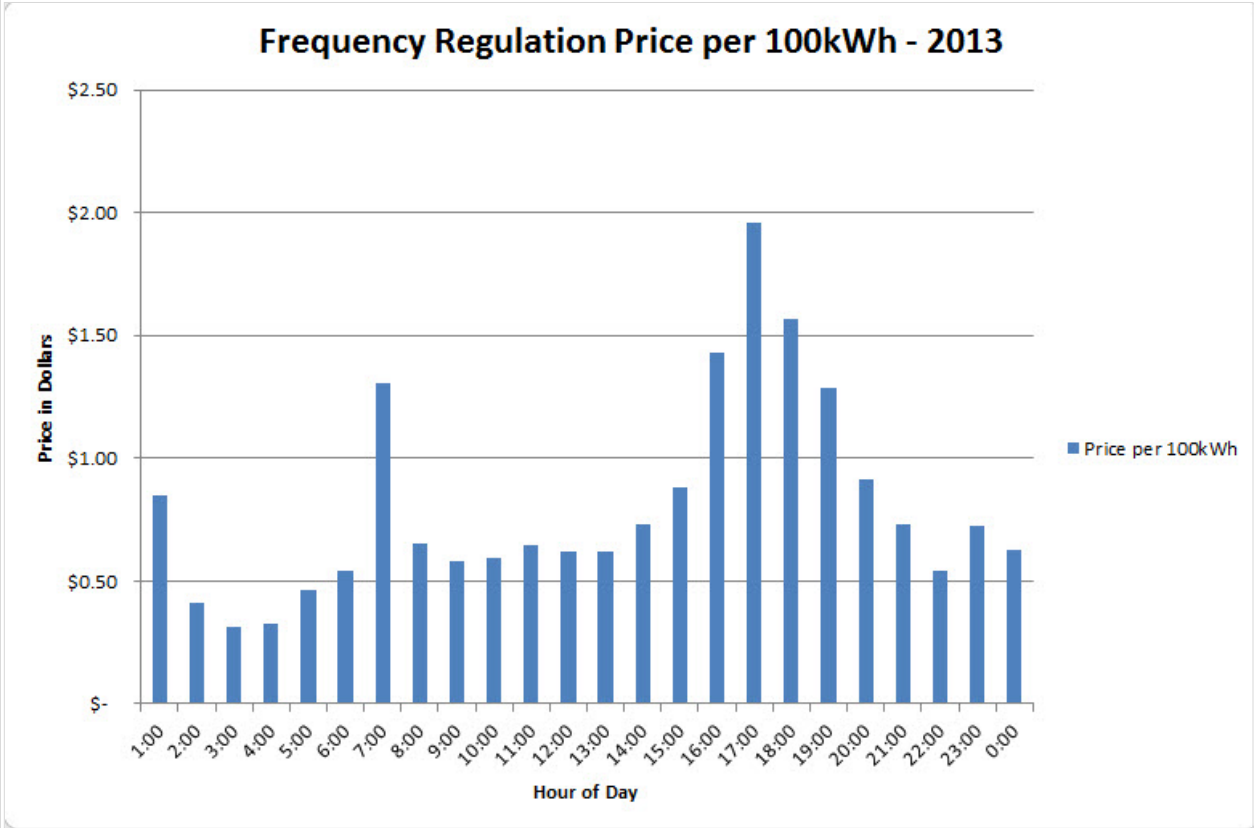


Figure 30. Average Frequency Regulation Price Per Hour Per 100 kWh in ERCOT for 2013

In 2013, there was a specific peak in frequency regulation pricing in the 6:00 a.m. – 7:00 a.m. time period, and a broader peak from 3:00 p.m. – 8:00 p.m. For the fleet in this project, the broader peak aligns well with the typical idle period of the vehicles, which do their deliveries between midnight and 10:00 a.m. and are loaded during the afternoon hours. Starting at around 5:00 p.m. they are all sitting on the chargers loaded and waiting for their next delivery run. The average price per 100 kWh, however, is relatively low, around $.80 – $1.95 per 100 kWh. Looking at a potential of 4 hours per day that the project fleet could realistically and reliably participate in the FRRS market (from 5:00 p.m. –

9:00 p.m.), the following table shows that for 2013 the average potential monthly revenue for a 100 kWh fleet was $135.01.

Table 9. 2013 Potential Revenue from Participating in the 5:00 – 9:00 p.m. Timeframe

Hour Ending	$ per 100 kWh	30 Days $
18:00	$1.57	$47.01
19:00	$1.28	$38.50
20:00	$0.92	$27.50
21:00	$0.73	$22.00
	Total	**$135.01**

Up through March 15, 2014, as shown below, the peak moved substantially, and also the price for frequency regulation services increased significantly.

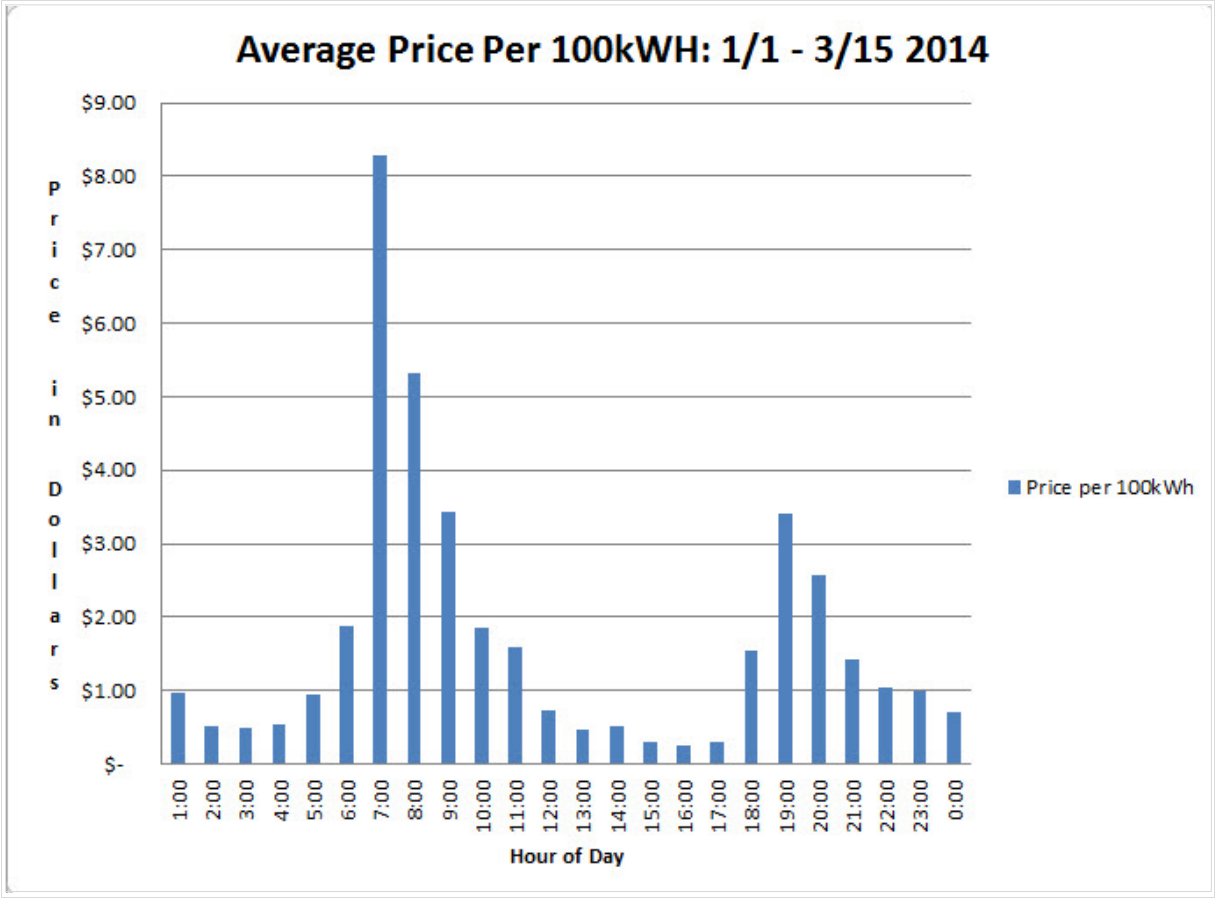


Figure 31. Average Frequency Regulation Price per Hour per 100 kWh in ERCOT for 2013

While the morning opportunity was not available for the project fleet due to their delivery schedules, the increase in price does have a positive effect on potential revenue, as shown below.

Table 10. 2014 Potential Revenue from Participating in the 5:00 p.m. – 9:00 p.m. Timeframe

Hour Ending	Price per 100 kWh	30 Days $
18:00	$1.55	$46.53
19:00	$3.40	$101.97
20:00	$2.58	$77.27
21:00	$1.42	$42.51
	Total	**$268.29**

The data shows that for 2014 the potential revenue was double that which was achievable in 2013. Even so, this was not sufficient to offset the costs of equipment, installation, and ongoing expenses. For example, all assets must go through a QSE to participate in market services, so there is a monthly price assessed by the QSE for maintaining the communications links to the asset and for representing them in the market (placing bids). The price for the QSE services for this project was $2,000 per month.

In order to be profitable in the current market structure, the fleet would need to be of an approximate capacity size of 1 MWh, however that is very unlikely. Alternatively, if the fleet could be flexible in its scheduling, it could place bids in more opportune time periods, reducing the size of the fleet needed to participate successfully from 1 MWh to 400 kWh, as shown below.

Table 11. 2014 Potential Revenue from Participating in the 6:00 a.m. – 11:00 a.m. Timeframe

Hour Ending	Price per 100 kWh	30 Days $
6:00	$1.89	$56.63
7:00	$8.28	$248.53
8:00	$5.33	$159.89
9:00	$3.42	$102.72
10:00	$1.86	$55.75
11:00	$1.60	$47.91
	Total	**$671.43**

There are also the potential jackpot scenarios, catching an hour where the price of energy skyrockets due to grid congestion. While this effort was operational in 2014 there were at least 4 such hours where the cost per MWh ranged from $284 to $4,999. Those hours were normalized in the calculations to remove skewing of the data.

This project, as stated earlier, was conducted in a market where energy is relatively inexpensive and plentiful, and the market is structured for large, stationary generation resources. In other markets, such as California where the price of electricity is significantly higher, the economics would be much more favorable.

Key Lessons Learned from Discovery Across Texas

- Demonstration projects carried out on real operating systems have the advantage of high relevance, but it takes constant effort to involve stakeholders and garner support to overcome potential constraints.
- Maintaining an active relationship with key market stakeholders who are the target users of the results is essential to project stability and effective outcomes.
- Synchrophasor technology is here to stay, it has numerous demonstrated benefits, and it will soon become a very critical guide and asset in control rooms for grid operators.
- Cyber security protection of grid systems is of rising concern and the prospects are good that the Security Fabric product demonstrated in this project will find market acceptance.
- Battery storage has a number of challenges that must be addressed before the technology becomes mainstream in electric markets, including regulatory rules that permit the dual role of both generation and load, and stakeholders must implement creative approaches that enable them to maximize the benefit streams from multiple functionalities.
- Interoperability among new devices and software in home energy management systems is a major market development inhibitor; radically low cost technologies coupled with market incentives are essential for DR to become economical and provide needed grid support.
- Electric vehicles are potentially valuable grid resources, but only special niche market players will participate in related AS markets in the near term.
- Energy efficient, high technology communities matched with rooftop solar and electric vehicles can be a valuable grid resource with the advent of time-of-use pricing to reshape load, but without incentives the costs will continue to limit the scale.
- Policy and technology applications for all-solar communities need to address the problem of harmonic distortion that appears to be common characteristics of solar communities.

Summary and Conclusions of the CCET Project

Summary

CCET engaged some 22 firms over a period of five years to carry out seven related but separable demonstration projects, all devoted to helping address the challenges of integrating more wind resources into the electric grid. These projects were all carried out on live operating systems in the market place, rather than isolated laboratory experiments. The projects were not developed in a vacuum based on an ideal optimal mix of technology options. To the contrary, they leveraged the availability of technologies already in or entering the market in Texas, such as synchrophasor systems, cyber security systems, the build out of the transmission system, smart meter deployments, consumer portals, wind generation and test facilities, home energy monitoring systems and electric vehicles in residential solar communities, and electric vehicle fleets. More importantly, these projects included direct participation by market stakeholders, including ERCOT

(the ISO), four TDSPs, one municipal utility and one electric cooperative, one REP, and sixty plus consumers.

Although the focus of the project was on mitigating the challenges of ever-increasing renewables integration into the electric grid, the project demonstrated the benefits of deploying smart grid technologies that are to become the mainstay of the grid of the future, and to identify both issues and solutions that could provide valuable insight to stakeholders and decision makers at the local, state, and national levels. Summarized below are the key highlights of and contributions made by this CCET project:

- **Synchrophasors**. This technology includes a wide array of monitoring, data processing, and wide area visualization systems to help utilities and grid operators better manage the electric grid to improve its reliability. It is focused specifically on providing improved, real-time monitoring of grid conditions, and providing better tools to help diagnose and respond to issues surrounding the intermittent nature of renewable energy sources providing power to the electric grid. As a result of this project, the state has greatly expanded its deployment of synchrophasor technologies which existed only as a "starter" system in 2009, and dramatically improved monitoring and early warning capabilities. Originally targeted to provide 13 PMUs, the participating utilities quickly discovered the tremendous benefits provided by PMUs, and they chose to add an additional 60 PMUs, which has significantly improved coverage across the state of Texas. Monitoring systems, such as RTDMS, and offline analysis tools, such as the PGDA, have been dramatically improved, and the participating utilities now all have and use those tools which are currently more commercially viable, as a result of this project. Also, to assist generator owners and grid operators with North American Electric Reliability Corporation (NERC) standards compliance, a new tool for validating generator models has been developed. More importantly, ERCOT has become one of the first ISOs nationwide to employ wide area visualization of PMUs as a tool to assist control room operators in more quickly and effectively diagnosing and resolving potential grid stability issues before they become a problem.
- **Security Fabric**. Building on the success of the CCET synchrophasor efforts, Intel/McAfee chose to deploy and demonstrate how its latest cyber security protection scheme could be employed to protect critical synchrophasor assets. This Security Fabric cyber security hardware and software solution was deployed on a parallel synchrophasor network to verify and validate that the communications network, the critical phasor data streams, and the important wide area visualization software could be better protected without the need to modify existing systems. Intel/McAfee worked with EPG and NIST to develop a set of test requirements based on NISTIR-7628. Using an independent third party, in this case TTU, cyber security experts tested the integrated synchrophasor and Security Fabric system to verify there was no performance degradation, that it complied with the relevant NISTIR-7628 requirements, and that it did not introduce new vulnerabilities. The testing accomplished its goal and did identify a few vulnerabilities, most of which were due to

configuration issues. As a result, Intel/McAfee has corrected those identified Security Fabric vulnerabilities, making it an even more viable cyber security protection solution and commercial offering, not only for protecting synchrophasor systems, but also any critical utility infrastructure.

- **Time-Of-Use Pricing**. This CCET project was able to leverage an existing residential solar community with homes equipped with circuit-level monitoring systems, and homeowners, many of whom possessed electric vehicles (another huge plus), who were committed to energy efficient lifestyles and technology, and who were already accustomed to participating in various types of grid-improvement behavioral experiments. The CCET project goal was twofold: 1) evaluate behavioral response to TOU pricing in energy-efficient smart-grid communities, and 2) adhere to its theme of wind integration by introducing the first ever TOU pricing program based on wind. The first goal was addressed with a very typical CPP program that spanned the four summer months, June to September, and involved higher prices from 4 p.m. to 7 p.m., but only on designated critical days. The second TOU pricing program was carried out daily over five winter months, November to December, and March to May. It involved very inexpensive energy prices at night, from 10 p.m. to 6 a.m. Again, the purpose of these programs was to measure the willingness of participants to change their behavior in response to the pricing programs, and the results proved to be very interesting. For the CPP portion, the customers responded by reducing their usage, primarily HVAC, an average of 15.27% during the first summer, although they were much lower, only 6.15%, the second summer. The lower, latter figure does indicate some customer fatigue with pricing programs, but, more importantly, surveys indicated that the reduced amount appears to be less in comparison with some other experiments because customers had made permanent behavioral changes and live in highly efficient houses, so there was less they could reduce during the critical periods. For the wind-enhanced pricing portion, participants managed to shift an average of 4% of their normal usage to overnight hours, and importantly to move their EV charging away from the peak late afternoon and evening hours to the high wind production hours. While 4% of total load may appear to be small, there aren't that many activities that can easily be shifted to those hours and a 4% shift makes a significant impact on the use of wind capacity when it is most available.
- **SMT Portal and Demand Response**. This CCET project focused on demonstrating that REPs in Texas could leverage the capabilities of the SMT Portal together with the utility AMI networks to dramatically improve the effectiveness of their demand response programs. Before this effort, REPs who offered demand response programs were relying on remote control of in-home devices, primarily gateways and programmable thermostats, to reduce usage when needed, but were only achieving about a 55% success rate using a broadband-only solution. The CCET project goal was to demonstrate that the utility AMI networks could be utilized as a second delivery path for demand response controls, and that the SMT Portal could be leveraged to deliver those messages across the AMI networks to the in-home devices. The SMT Portal, jointly funded by the three largest TDSPs in Texas, who also

happen to be participants in the CCET project, represents a unique opportunity to assist consumers and REPs in reducing energy usage, especially during critical events. The Portal is used to house all of the smart meter data for more than 6 million customers located in these TDSP service areas, is used for settlement purposes by ERCOT and the utilities, and provides historical energy use information to assist consumers in better managing their energy use. Additionally, the Portal can be leveraged to distribute information and commands to the smart meters over the respective AMI networks. For this project, the participating REP could use these capabilities to deliver their demand response messages to in-home devices over the AMI networks as well as the typical broadband path. Ultimately, the project proved that the SMT Portal capabilities could be leveraged to improve demand response results, but not without first overcoming challenges, such as incompatible legacy equipment that couldn't be remotely upgraded, lack of SEP-compliant devices that could pair with the home's meter to receive the necessary messaging, and a cumbersome process for configuring and registering devices to accept messages over two different communication paths. In terms of reductions, actual demand response events demonstrated reductions per household of from 0.55 kWh to 1.0 kWh, and that is based on a single 15-minute cycling of the home's HVAC unit. Economically, the demand response events demonstrated an annual value proposition (based on just 10 events per year) of between $27 and $89 per customer, depending on energy prices. However, considering the cost of procuring and installing a gateway and programmable thermostat in a home is about $300, the payback period is anywhere from 4 to 10 years. Given that Texas is a competitive retail market, and customers can swap REPs at will, equipping all homes with these devices is too much risk without other financial incentives. However, if the investment is going to be made anyway, the REP (or utility in a different market) should definitely consider the benefits of leveraging the AMI network as a second communications pathway to improve demand response results. Prospectively such a dual path system might be available at a low incremental cost with new installations and thermostats with a low-cost chip addition.

- **Solar Monitoring**. Solar represents another huge source of renewable energy, and provides a good companion to wind production because of the daily non-coincident timing of production but, like wind is also a source that is intermittent. Residential rooftop solar is becoming more prevalent, and this significant increase in solar adoption has raised some concerns for utilities across the nation. The CCET project goal was to evaluate variations in electrical performance parameters on residential distribution circuits and behind the meter, such as excursions in load, power factor and voltage, and harmonic distortion effects. These issues can arise from multiple interacting and dynamic factors, including distributed solar generation cancelling utility kW load, variable solar PV generation, increasing harmonic current drawn from modern home appliances, etc. The project first focused on comparing two neighborhoods, one with a high concentration of rooftop solar and one with almost no solar. The second effort looked at the secondary side of two residential transformers to monitor power quality parameters, solar PV production, and net load served by the utility for 18 homes. For the first effort, six 35 kV underground residential distribution circuits

were equipped with monitoring devices to better assess the dynamics of solar and communities as they interact with the electric grid. The focus was on measuring and calculating total harmonic current and voltage distortion (THDi and THDv, respectively), power factor (PF) and voltage at the distribution level in the two neighborhoods. The solar monitoring results identified a particular challenge of harmonic distortions from homes with solar during certain time periods, especially during the shoulder months, March to May, and October to November, in Texas when wind production constitutes a significant share of generation. These harmonics can cause problems like degradation of conductors and insulating material in consumer appliance motors and utility transformers. For the second effort, at the transformer level, it was noted that the distortion current stays approximately the same during the entire day with variations that can be attributed to device usage, not solar production. During the daytime, solar capacity exceeds home load much of the time, driving the load on the utility negative, with oscillations due to cloud cover and home appliance operation (generally HVAC). During periods when the utility load is cancelled and approaches zero, for periods from minutes to an hour at a time, the THDi spikes are very high, up to 1000%. This is due to the very low amounts of fundamental current supplied by the grid, not the solar production adding distortion to the grid. The general conclusion of this monitoring effort is that for homes with solar capable of providing all of the home's power use during a sunny day in the shoulder months, the harmonic distortions will be high and that vendors and grid operators will need to consider remedies as the incidence of rooftop solar communities expands.

- **Frequency Regulation using Fleet Electric Vehicles**. Frequency regulation is a grid ancillary service that allows electricity generators, including those with large battery energy storage systems, to bid services into the energy market to assist in maintaining the electric grid frequency at 60 Hz. Providers of this type of service guarantee to be able to adjust generation and/or load during a specified time period by either ramping up or ramping down production or reducing load in order to maintain the balance of generation/load on the grid, and thus the frequency. ERCOT studies have determined that the need for fast response resources to provide regulation up or regulation down services increases as the concentration of renewables, such as wind, grows on the grid. While the overall CCET project was ongoing, ERCOT carried out a pilot project to find qualified resources willing to participate in an ancillary service market called Fast Response Regulation Service (FRRS). The response requirements for this FRRS pilot basically limited participants to those with energy storage systems (batteries). Two large battery systems participated in the ERCOT pilot, and CCET seized on the opportunity to demonstrate that FRRS could also be provided by aggregating electric vehicles (EVs) without a significant incremental investment (since large-scale batteries cost millions of dollars). The CCET project leveraged the resources of Frito-Lay in Fort Worth to provide the EVs while other team members developed the software and hardware capability to aggregate a set of 11 Frito-Lay trucks so they acted as one resource capable of providing at least 100 kW of FRRS (minimum requirement). The Frito-Lay trucks typically begin deliveries about 3 a.m., return to home base about noon, and

remain at that site for battery charging and cargo loading until the next morning. This schedule was an ideal match for participation in FRRS since the trucks would be available to deliver the service when it was needed, and doing so would not detract from the primary duty of the trucks. This effort entailed the development and demonstration of an EV aggregation control system to support regulation-up services in response to an ERCOT signal or a detected deviation of grid frequency of greater than .09 Hz. The first task was to build a custom power meter that could monitor 12 EV circuits after the panel box, and this solution was achieved for under $20,000 versus over $100,000 that would have been spent on individual power meters or redesigning the electrical panel box. The second task was to develop a software aggregation control system able to manage the fleet in accordance with the FRRS parameters. Other tasks included establishment of a DNP3 interface over a VPN for providing telemetering information; development of a solution to collect, correlate and deliver the required meter data files to ERCOT; and installation and deployment of other hardware interface and control devices. Leveraging the CCET capabilities, the EV fleet at Frito-Lay successfully bid into the ERCOT FRRS market, delivered the required FRRS when needed, and received compensation for the service. This was the first time EVs had successfully participated in an ancillary service in ERCOT, and the first time a fleet owner had received payment for providing FRRS. The project results demonstrated that, for the first time in the U.S., EVs could be aggregated as an effective resource for grid management, and could do so without interfering with the primary vehicle purpose.

- **Utility-Scale Battery on a Distribution Network**. Battery storage is another important technology for the electric grid especially when operating as a companion for wind generation as well as for generally supporting consumers, utilities, and the grid operator.. When charged, batteries can perform a wide range of needed grid functions, including outage support, peak shaving, and frequency support. When uncharged, batteries can be used to store excess energy, and then deliver it instantly when needed, and during such cycles also provide frequency support . For this effort, CCET was interested in assessing how a battery energy storage system (BESS) could supplement wind farms to improve wind-power efficiency. The overall project objective was to demonstrate the ability of a BESS to perform various grid functions, especially those needed to support intermittent renewable resources, such as wind. A secondary objective was to determine the economic viability of deploying these systems to support actual grid operations. Typical projects deploy large-scale battery systems on transmission networks or small-scale batteries in neighborhoods. The CCET project was unique in that it chose a utility-scale battery (1 MW/1 MWh), but deployed it on a distribution network managed by an electric cooperative. Additionally, it had access to a wind test facility in Lubbock, so the BESS was deployed in tandem with wind turbines. While the BESS was being manufactured, Texas Tech researchers extensively modeled the wind turbines, and the related substation loads, and following installation of the BESS, the battery system, and then simulated a full range of system behaviors involving a set of battery functions. These system models were then validating during the course of the project, when the BESS was tested to demonstrate its ability to optimize grid reliability

by compensating for the intermittency of wind, storing power during high wind- and providing power during low wind-conditions, reducing the daily peak load on the grid (and thus reducing demand charges), providing a ramping capability to stabilize the grid, and to provide frequency regulation services to maintain the grid at 60 Hz. The BESS performed all of these functions extremely well. What remained was to determine the economic viability of investing in battery systems, with a financial return on investment provided by performing these grid functions. The result of numerous economic evaluations determined that there are only a few special conditions where a utility or generator could recover its full investment by performing the defined grid functions without subsidies, but the benefits to the combination of grid operators, utilities, and ultimately customers can definitely outweigh the costs of a BESS. As battery technology improvements continue to drive costs down, and the regulatory rules get modified to more completely reflect the value of storage, battery systems will be more widely deployed, especially in support of renewable generation resources, and on distribution grids.

Conclusions

As noted above, the CCET project successfully demonstrated how various smart-grid technologies can be used to significantly improve grid operations, not only around the challenges of large-scale wind integration, but more generally. It is expected that market stakeholders, in Texas and across the nation, will leverage the results of this project to address and mitigate the potential issues associated with increasing levels of renewable resources, such as wind and solar. In Texas, ERCOT will continue overseeing and expanding the synchrophasor system, South Plains Electric Cooperative and Texas Tech University will further leverage the battery capabilities, REPs in the ERCOT market will learn from the consumer behavior responses to develop more enticing pricing programs and improve DR capabilities, utilities will exploit the Intel/McAfee Security Fabric suite of products to better protect their critical electric assets, and large companies and potential aggregators will make use of the FRRS work in developing improved benefit streams for EV truck and potentially residential EV owners. Across the nation, the unique nature of the CCET project will provide information, insight and lessons learned to assist utilities and other grid operators in better managing and protecting their grid assets to deliver a more reliable and robust set of services that benefit consumers while leveraging available renewable resources, such as wind and solar.

Demonstration projects are not typically expected to result in the delivery of solutions that are market ready, although the intent is always to provide reliable results that will lead to such outcomes. While other demonstration results are also important, the CCET project has gone a long way in the direction of delivering products to the market. The synchrophasor system was developed from only a small “starter” system of three PMUs to a mature system of 94 PMUs deployed across Texas, with full associated monitoring capabilities at both ERCOT and the participating utilities, and the stakeholder process at ERCOT is near completion of protocol changes that will put the technology firmly in the control room as a grid operator tool; that is a condition equivalent of being in the market. The project also provides a solution for validating generator model parameters that

are certain to be needed to meet NERC guidelines. Further, Intel/McAfee is, as this report is being published, holding a press event in Washington, D.C. to launch the Security Fabric technologies developed and tested in this project. The BESS provides important results from a utility-scale battery system operating on a distribution system to complement the learning from two large-scale Texas battery systems operating on a transmission system, thus rounding out much needed information about ownership, location and functionality of battery systems that will feed the policy debate for fully defining the role of storage in the Texas markets. The FRRS project demonstrated the key changes that will need to occur in order to bring this capability for grid regulation into the Texas market when EV fleets become more prominent.

Preface

The Center for the Commercialization of Electric Technologies (CCET) has prepared this Final Technical Report for its smart grid regional demonstration project (SGRDP) in response to specified Department of Energy (DOE) reporting requirements. The format of this document follows DOE's Guidelines dated June 17, 2011.

As the final technical report, this document builds on the information that was provided in previous Technology Performance Reports (TPRs), the last of which was delivered in April 2014. It covers the project scope and overview, and then provides individual chapters for each of the seven project components:

- Synchrophasor monitoring, visualization and event reporting
- Synchrophasor security fabric
- Residential circuit monitoring
- Residential time-of-use pricing trials
- Residential demand response
- Distribution-level battery energy storage system
- Fast response regulation service with electric vehicles

Each chapter addresses the components in terms of anticipated benefits, stakeholder interactions, technical approach, performance results with metrics and benefits analyses, and conclusions with lessons learned and best practices.

1. INTRODUCTION

This document represents the final technical report for the CCET SGRDP entitled, "Technology Solutions for Wind Integration in Electric Reliability Council of Texas," commonly known as Discovery Across Texas. The CCET project was partially funded by DOE under the cooperative agreement DE-OE0000194 and partially funded by various CCET team members and stakeholders.

For further information on this report or any aspect of the project components, the relevant contacts are:

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2. SCOPE

This section provides relevant information on the overall project, the team members, the major demonstration components and objectives, the project milestones and schedule, the basic approach for interoperability and cyber security, and a list of acronyms. The subsequent sections 3 through 9 provide details on the planning, execution, and results of the seven project component demonstrations.

2.1 CCET

The CCET is a consortium of electric utilities, retail electric providers (REPs), and technology companies dedicated to developing new capabilities that will improve grid operations in Texas, and primarily for the Electric Reliability Council of Texas (ERCOT) region which covers about 85% of the state. CCET has performed a number of demonstration projects during its eight year history, the largest of which is this DOE project which involves demonstrations of innovative technologies to address challenges in seven different technology areas.

2.2 Overall Project Description

This project represented a multi-faceted synergistic approach to managing fluctuations in renewables, and more specifically wind power, in the large ERCOT electric grid through better system monitoring capabilities, enhanced operator visualization, and improved load management. The project demonstrated seven different technologies, organized around three main focus areas:

- **Synchrophasor**: It demonstrated the use of synchrophasor technology to assist in better determining grid operating status and margins that avoid either conservative operating margins or grid instability when moving remote wind resources through the ERCOT transmission grid to consumers. By taking advantage of this technology, ERCOT grid operators are now better able to accommodate wind resource variability, unexpected transmission line outages, or instability developments.
- **Smart Meter Texas Portal**: It demonstrated how ERCOT operators, transmission and distribution service providers (TDSPs), and REPs can leverage existing smart grid capabilities, including the Smart Meter Texas (SMT) Portal, to call upon controllable home area network (HAN) loads as part of initiated demand response (DR) events via the advanced meter systems (AMS) of utilities.
- **Future Smart Grid Community**: It demonstrated the benefits and potential issues associated with smart grid communities of the future that combine distribution-level energy storage systems and homes equipped with smart meters, solar photovoltaic (PV), load-interruptible DR appliances, efficient building envelope standards, and electric vehicle (EV) charging to demonstrate consumer responsiveness to variable electric pricing incentives.

All together, this project helped to define a new business model for managing renewable resources using a variety of combined yet separable smart grid components. ERCOT and other market participants are better informed and equipped to utilize this project's collection of tools to meet reliability needs across the entire interconnection in response to renewable fluctuations and a variety of grid disturbances. Further, the project helped the ERCOT competitive market better understand consumer behavior in the developing world of new technology that provides insight for new consumer incentives and program offerings that better integrate renewables into the grid.

2.3 Team Members

This CCET project represented a collaborative effort on the part of four ERCOT region utilities, electric cooperatives, a large Texas REP, a university, an EV fleet owner, third-party vendors, and technology firms. Additionally, this project benefited from advice and guidance provided by the CCET Board of Directors, a Project Management (PM) Board, and ERCOT, all of which comprised key players in the Texas electric market.

To address the project goals, CCET employed technical teams to address three high-level demonstration areas: synchrophasors, future smart grid community, and the SMT Portal. The final high level team organizational structure is shown below.

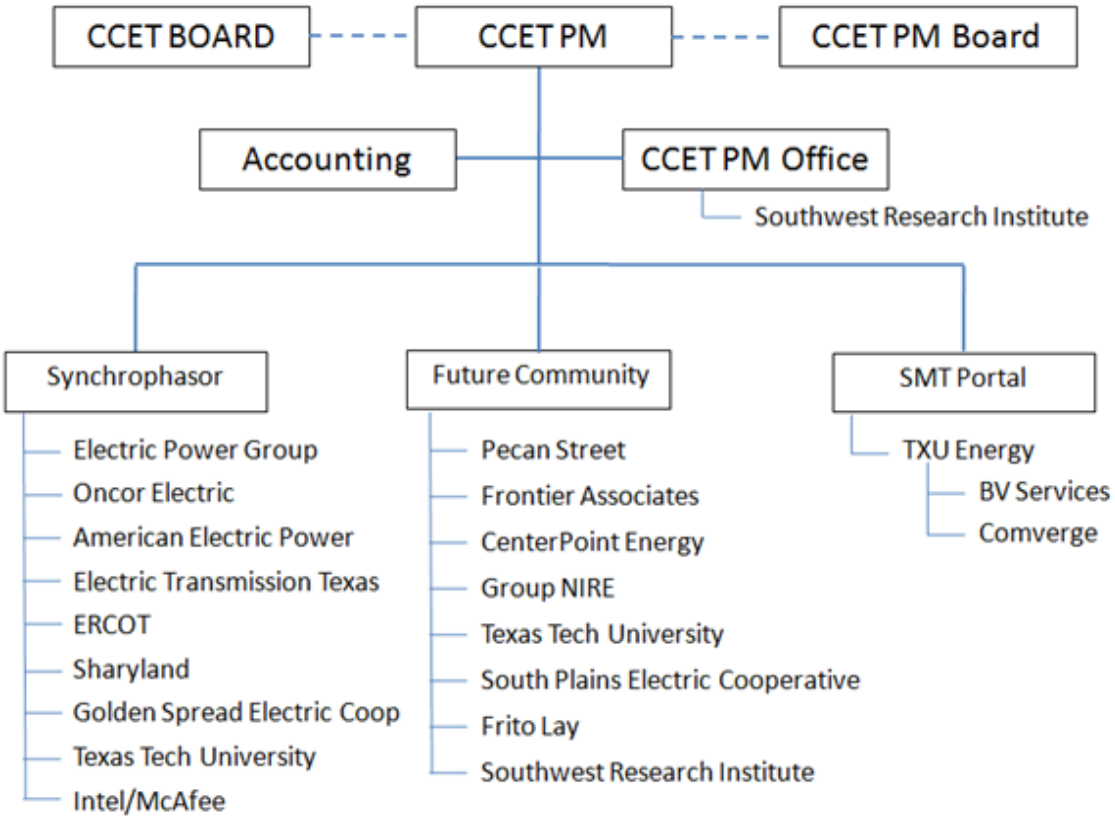


Figure 32. Final CCET Project Team Organization

The final team member descriptions are provided below, and organized by those that received DOE funds, those that provided cost share, and others that provided technical advice and oversight.

2.3.1 CCET

The CCET President served as the PM and was fully responsible for the successful execution of this project. He is governed by a Board of Directors that approves all projects. The CCET PM had access to Board members for assistance and support, and reported monthly to the Board on the programmatic status of the project. The CCET PM also had access to a special PM Board formed by technical leaders of the Board companies, and met monthly with this group for advice and guidance on the conduct of this project.

2.3.2 DOE-Funded Partners

2.3.2.1 BV Services

For this project, BV Services assisted CCET and TXU Energy with the SMT Planning portion, which involved dual-path demand response services. BV Services planned and managed this part of the project as well as led technical discussions and workshops regarding solution configurations, program design, testing approaches, and impacts to customers. BV Services resources have been working with TXU Energy and Comverge to support enhancements to the TXU Brighten® iThermostat program for the past couple of years.

2.3.2.2 Comverge

Comverge provides intelligent energy management solutions to utilities and commercial and industrial companies. Comverge worked with TXU Energy to develop its current Brighten® iThermostat program for residential and small commercial customers, which includes installing programmable thermostats and gateways, and providing software to manage the registration, installation, operation, and support of that program. For this project Comverge participated in the design, development, and testing of DR solutions.

2.3.2.3 Electric Power Group

Electric Power Group (EPG), a CCET member, served as the Team Lead for the Synchrophasor component. EPG has been involved in synchrophasor-related activities for many years in support of the Western and Eastern Interconnections. For this project, EPG provided software, including the Real Time Dynamics Monitoring System (RTDMS) and the Phasor Grid Dynamics Analyzer (PGDA), and professional and consulting services. They also have an enhanced phasor data concentrator (ePDC) which has been deployed as well. EPG is also closely involved in the development and implementation of ERCOT's synchrophasor monitoring system, and will continue to provide that support.

In early 2013, EPG formed an alliance with Intel/McAfee to investigate a new cyber security capability that greatly enhances the protection of data streams from phasor measurement units (PMUs) and PDCs to the grid operator. As part of this project, EPG integrated that new capability into their suite of products and then demonstrated its ability to provide enhanced protection for the critical data streams.

2.3.2.4 Frontier Associates

Frontier Associates, a CCET member, has been providing data collection, analysis, and various assessments for key market players in Texas, including utilities and ERCOT. For this project, they were responsible for the overall data collection and analysis planning, the methodology for the pricing experiments, and analysis of electrical data collected by utilities on residential distribution service lines in Houston and Austin. They developed the metrics and benefits reporting plan for those analyses. They helped to design the consumer pricing experiments, and provided the majority of data analysis, economic value assessments, and other inputs to the reports. They also provided advice and guidance to other project members performing data collection and analysis.

2.3.2.5 Group NIRE

Group NIRE, a CCET member, is a clean energy development company that provides project development, finance, and consulting services. It is currently developing wind projects and working with several renewable energy manufacturers of original equipment and component to commercialize new products and technologies. Group NIRE is affiliated with the National Institute for Renewable Energy and with the National Wind Resource Center.

Although Group NIRE received some minimal DOE funding, it was also a major cost share contributor for this project, and provided facilities for field testing and validation of various wind turbines at the Reese Technology Center (RTC) in Lubbock, Texas. For this project, Group NIRE facilitated access to the wind turbines and managed the installation of a utility-grade battery energy storage system (BESS) that was tested in various functional roles.

2.3.2.6 Pecan Street

Headquartered at The University of Texas at Austin, Pecan Street Inc. is a nonprofit research and development organization focused on developing and testing advanced technology, business models, and customer behavior surrounding advanced energy management systems. Pecan Street is focused on advancing understanding and solutions addressing utility system reliability, climate change, renewable energy integration, and customer needs and preferences. Its specific research expertise consists of creating, managing, protecting, analyzing, and responsibly sharing the highest quality original research data on how customers use electricity, natural gas, and water in their homes and businesses. For the CCET project, Pecan Street received DOE funds but was also a significant cost share partner. It was involved in facilitating new electricity pricing models, electric vehicle research, and sub-circuit level energy use data collection among select volunteer participants located in Austin's Mueller community. It

also provided engineering analysis of power quality data at the point of utility connection as affected by rooftop solar PV.

2.3.2.7 Southwest Research Institute

Southwest Research Institute (SwRI), a CCET member, is a large independent, nonprofit organization located in San Antonio, Texas, that provides applied research and development for both government and commercial clients. It has 11 technical divisions that offer a wide range of technical expertise and services in such areas as chemistry, space science, nondestructive evaluation, automation, engine design, mechanical engineering, electronics, and automation and data systems.

For the CCET project, SwRI provided project management office (PMO) support including the preparation of required management and technical reports for CCET and DOE. SwRI also provided some early cyber security evaluations and led the effort to provide fast response regulation service (FRRS) to ERCOT using fleet EVs.

2.3.2.8 Texas Tech University

Texas Tech University (TTU) is a teaching and research institution located in Lubbock, Texas. It is home to the Wind and Science Engineering (WiSE) Research Center, which is focused on how to efficiently harvest wind energy and mitigate wind-related damage. It is the only university in the nation that offers degree programs, from Bachelor to Ph.D., in wind energy related studies.

For the CCET project, TTU provided its exceptional knowledge, expertise, and analytic skills to facilitate the integration of wind turbines located at the RTC with a utility-scale battery system along with subsequent analysis of battery functionality to support dynamic, variable energy sources like wind. TTU also worked with several local electric cooperatives to install a synchrophasor network in the Texas Panhandle portion of the Southwest Power Pool (SPP). This network served to augment the data from the ERCOT network for the purposes of theory and model development and validation. The network was additionally utilized as a test-bed for the synchrophasor cyber security demonstration, where TTU cybersecurity researchers provided an independent analysis of the security system.

2.3.3 Cost Share Only Partners

2.3.3.1 American Electric Power/Electric Transmission Texas

American Electric Power (AEP) is a Board member of CCET and has been actively involved in the deployment of synchrophasor components. AEP committed resources to this effort and worked collaboratively with ERCOT, Oncor, Sharyland Utilities, and Electric Power Group to accomplish the objectives of the synchrophasor component. AEP installed PMUs, provided phasor data to ERCOT, and determined the best utilization of phasor data for management of AEP stations and the ERCOT grid.

Electric Transmission Texas (ETT) is a joint venture between subsidiaries of American Electric Power and MidAmerican Energy Holdings Company. ETT owns and operates transmission facilities within the ERCOT region of Texas. For this project, ETT installed a number of PMUs and provided the phasor data to ERCOT.

2.3.3.2 CenterPoint Energy

CenterPoint Energy is the TDSP for the Houston area, and a Board member of CCET. CenterPoint completed its own smart grid investment grant that provided for the deployment of smart meters and a distribution automation system in their service territory. As part of this project, they installed a number of circuit monitoring devices with the intent of comparing load shape curves among two similar neighborhoods, one with high-efficiency homes and rooftop solar PV, and another without solar. They collected data from those devices, and provided engineering input to the reports on observations of correlations between power usage, load profiles, voltage levels voltage and current harmonic distortion and power factor for both communities. Also, by comparing similarly sized homes at the two neighboring subdivisions, analysis shows the extent to which there is a sustained decrease in power usage and reduction in peak demand from solar-equipped homes. CenterPoint also compared the voltage levels at the two neighborhoods.

2.3.3.3 Electric Reliability Council of Texas

The ERCOT manages the flow of electric power to 24 million Texas customers, representing about 90 percent of the state's electric load. As the independent system operator for the region, ERCOT schedules power on an electric grid that connects more than 43,000 miles of high-voltage transmission lines and more than 550 generation units. ERCOT also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for 6.7 million premises in competitive choice areas. ERCOT is a membership-based 501(c) (4) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT's members include consumers, cooperatives, generators, power marketers, retail electric providers, investor-owned electric utilities (transmission and distribution providers), and municipal-owned electric utilities.

The ERCOT serves as an advisor on the CCET Board of Directors, and provided synchrophasor analysis and event reporting for this CCET project. The staff produces a daily PMU performance report that is distributed to members of ERCOT, and the CCET synchrophasor team. They also introduced the capabilities of synchrophasor technology to organized ERCOT stakeholder committees that are important to the implementation of the technology for active grid management.

2.3.3.4 Oncor

Oncor, a CCET Board member, is a large transmission and distribution utility and also a key transmission avenue for wind energy from West Texas to other parts of the ERCOT grid for consumers. Oncor

established a phasor network within the ERCOT grid, providing PMU installations and communications for streaming data to ERCOT. Oncor also supported the project's SMT planning efforts by conducting testing of various end use components.

2.3.3.5 Sharyland Utilities

Sharyland Utilities, a CCET member, was involved in the synchrophasor component of this project. Sharyland implemented PMUs at various locations, provided a phasor data stream to ERCOT, and determined the best use of phasor data for station management and the ERCOT grid.

2.3.3.6 TXU Energy

In 2002, the deregulated electricity market opened in Texas. At that time, TXU Energy began offering service as a certificated retail electric provider. One of their hallmark products is an intelligent thermostat and accompanying gateway that has been installed in thousands of consumer homes across Texas, and provides consumers with broadband access to the thermostats. For the CCET project, TXU Energy undertook a demand response program that involved sending load control signals through the SMT portal to the home thermostats and gateways. Those devices were also provisioned to some consumer smart meters so that they received the signals via the AMS networks as well as via the residential broadband networks. TXU Energy is a Board member of CCET.

2.3.4 Other Partners Providing Unfunded Technical Assistance or Oversight

2.3.4.1 Frito Lay

Frito Lay has a distribution facility with 12 fleet EVs that make deliveries during the nighttime and morning hours up until noon, and are therefore idle during the remainder of the day. For the FRRS portion of the project, Frito-Lay provided the EV fleet and charging infrastructure to support this demonstration.

2.3.4.2 Golden Spread Electric Cooperative

The Golden Spread Electric Cooperative (GSEC) is a consumer-owned public utility that provides electric service for its rural distribution cooperative members. It serves consumers located in the Oklahoma Panhandle and an area covering 24 percent of Texas land area including the Panhandle, South Plains, and Edwards Plateau Regions. It provides the power and service for the South Plains Electric Cooperative which was involved in this project. For the CCET project, GSEC deployed a number of PMUs to provide comparative data on their area of Texas with respect to wind events.

2.3.4.3 Intel/McAfee

Intel Corporation is an American multinational semiconductor chip maker, and three years ago they acquired McAfee, a manufacturer of computer security technology. Together they have undertaken to

integrate a wide range of security related products that tap into the security embedded in Intel hardware. For this project they provided extensive security expertise and security applications to support the Security Fabric demonstration which demonstrated significant cyber security protection to the synchrophasor technologies. Intel is a CCET member.

2.3.4.4 South Plains Electric Cooperative

The South Plains Electric Cooperative (SPEC) is a local, consumer-owned electric utility headquartered in Lubbock, Texas and serving the South Plains of West Texas. SPEC owns and operates the BESS purchased by the project and located at the RTC. SPEC is a CCET member.

2.3.5 CCET Advisory Boards

2.3.5.1 CCET Board of Directors

The CCET Board of Directors provided oversight of the project and assistance as needed. The Principal Investigator for the project is also the President and Chief Operating Officer of CCET and reports to the Board.

2.3.5.2 CCET PM Board

For this project, CCET created a PM Board from member CCET companies with specialized technical expertise in the project focus areas. The members of this Board provided unbiased, objective evaluations and assessments of all technical aspects of the project. This Board met monthly with the Principal Investigator and his team to review the technical project status, and provided advice and assistance on the direction of the project. Additionally, when the need arose, this Board convened to address specific technical issues or risks and provide early resolutions.

2.4 Project Overview

Texas currently has the largest installed wind generation capacity in the United States. With a growing electric load, the region served by the ERCOT grid reached an overall peak load of 68,305 megawatts (MW) in August 2011, and more recently reached a new winter record at 57,277 MW in January 2014. Increasing energy demand coupled with legislated renewable portfolio standards has focused efforts on inclusion of renewables and especially wind since 1999. As of December 2014, ERCOT had an installed wind capacity of 12,470 MW (see figure below) which provides about 10% of the ERCOT electricity needs. [3] In November of 2014, a new ERCOT wind record was set at 10,301 MW which represented just over 33% of the load at that time. [4] With the completion of new transmission lines into West Texas and the Panhandle area of Texas, it is estimated that the capacity of wind generation can grow to 18,500 MW, and a significant number of interconnection applications are signed and on file with ERCOT for

[3] ERCOT Monthly Operational Overview at http://www.ercot.com/content/committees/board/keydocs/2014/ERCOT_Monthly_Operational_Overview_201410.pdf
[4] ERCOT Quick Facts at http://www.ercot.com/content/news/presentations/2014/ERCOT_Quick_Facts_112014.pdf

wind farms that would take advantage of this new transmission capability (shown as Cumulative Planned in the figure below). Further, wind farms also are being added in the coastal areas of South Texas, presenting somewhat different power profiles to system operators than the wind from West Texas. All wind farms are distant from the main load centers, and present grid management challenges for ERCOT's system operators in accommodating both grid reliability and generation dispatch related to wind variability.

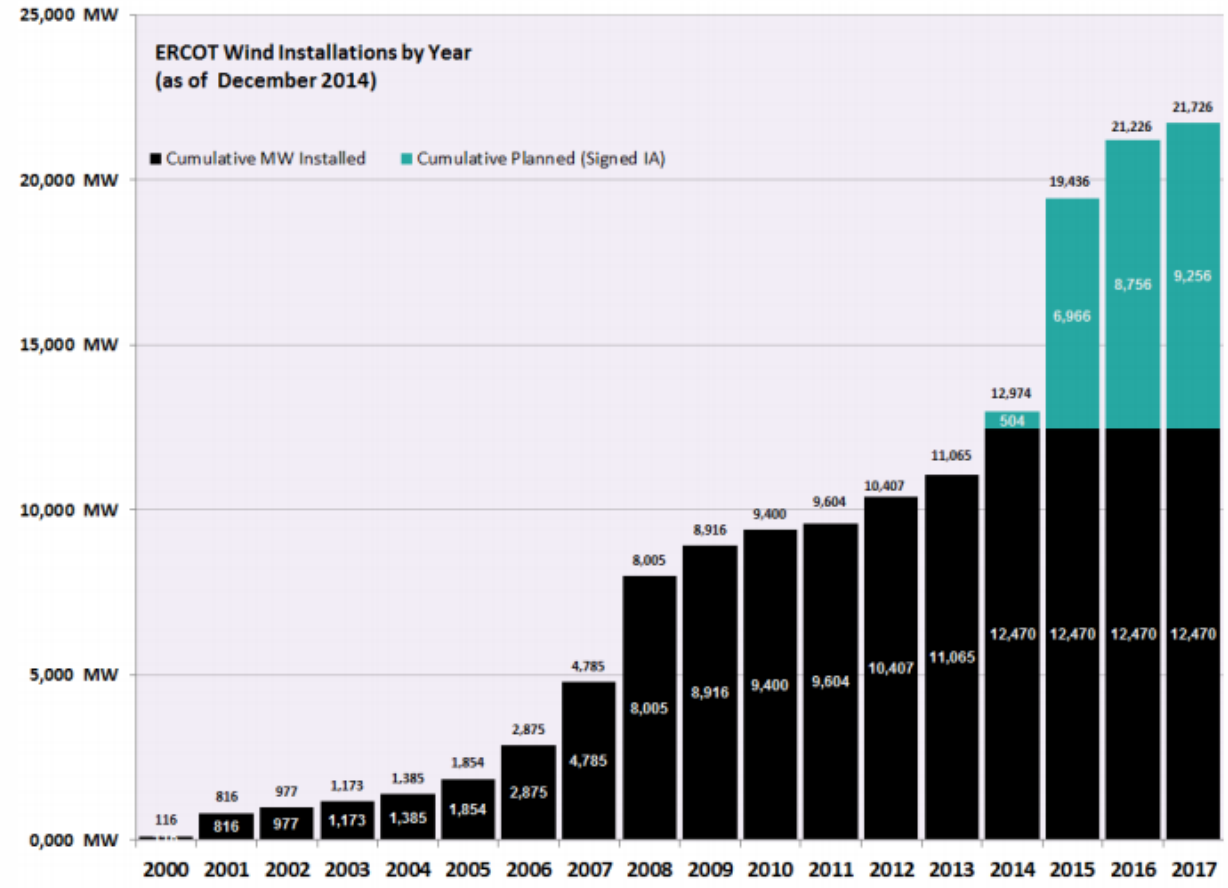


Figure 33. ERCOT Wind Installations by Year

The challenges to the Texas electric grid posed by this additional growth in wind generation underscores the need to establish new response mechanisms to wind variability. This project represented a multi-faceted synergistic approach to managing fluctuations in wind power in the large ERCOT transmission grid through better system monitoring capabilities, enhanced operator visualization, improved load management, and consumer response to pricing incentives.

2.4.1 Project Location

This project was primarily performed in the ERCOT region, although the utility-scale battery and some additional synchrophasor efforts were performed in the Northwest area of Texas that is actually in the SPP region. These regions are shown in the figure below.

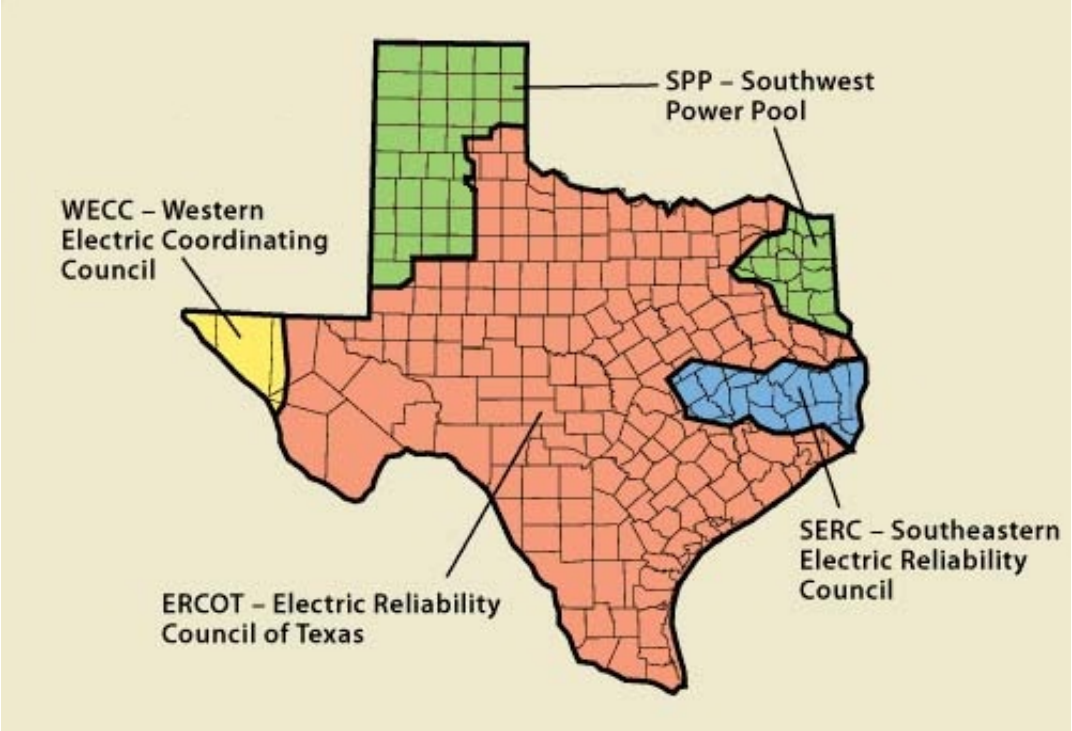


Figure 34. ERCOT and SPP Regions of Texas

Texas is unique among other regions with its high penetration of remote wind generation, one interconnection (ERCOT) entirely contained in the state, and one Independent System Operator (ISO), ERCOT. Texas includes a deregulated energy market for the large investor-owned segment, with TDSPs providing regulated wires and meter services to customers, and competitive REPs servicing and billing these customers. Municipal utilities and electric cooperatives which typically operate in a regulated market are invited to participate in the deregulated market. Texas not only leads the nation in wind generation plans, but also in the implementation of advanced metering systems. The most recent tally for the ERCOT region as of September 2014 [5] indicates at least 6,849,921 smart meters have been deployed, and there are plans for installation of even more smart meters in future years.

[5] AMWG Monthly Market Report at http://www.ercot.com/content/meetings/amwg/keydocs/2014/1022/AMWG_Monthly_Market_Reports_and_Formats_10_16_14_v1_0.ppt

Another unique aspect of Texas is the availability of the web-based SMT Portal which hosts the 15-minute incremental meter data from many of those smart meters and is used for settlement purposes as well as permitting customers to view and share their current and historical electrical usage information, and to bond home area network devices to their smart meter in support of demand response efforts.

2.4.2 Original Plan for Achieving Project Objectives

The purpose of this project was to demonstrate that Texas, and the rest of the nation, can manage increasing levels of wind power by accomplishing various objectives intended to deliver wide-area visualization through smart grid technologies applied at the system operator level; related operator control through DR as a resource utilizing AMS capability; wind variability control through energy storage; and application of DR, distributed generation (DG), and load reshaping at smart-grid equipped residential communities.

2.4.2.1 Demonstrating Wide-Area Grid Monitoring and Visualization using Synchrophasors

The Synchrophasor Team originally comprised ERCOT, TDSPs, and EPG. This group, through a prior CCET project, had already recognized the need to monitor the grid variability due to wind resources and had deployed PMUs at three locations along with an initial version of visualization software at ERCOT. The objective of this aspect of the project was to expand the synchrophasor capability to at least 16 locations. The overall role was to stream data from the PMUs to the respective TDSPs who would then furnish it to the grid operator.

Through the prior CCET project and with DOE's support, ERCOT had a first generation software package for data management, visualization, and post-event analysis, and the plan was to improve the capabilities of this software. The objective was to potentially demonstrate the benefits of synchrophasor monitoring and analysis in effectively managing power reliability associated with variable wind power resources. An ultimate objective was to improve the software, the data streaming and processing capabilities, and the communications network to a level that would facilitate placement in the ERCOT control room as an ancillary tool for grid operators. All of this would require a collaborative effort to implement and maintain the supporting infrastructure, develop effective monitoring metrics, and identify, design, test, and deploy tools and procedures to improve overall grid operations and control based on the synchrophasor data system.

2.4.2.2 Demonstrating Aspects of the Future Smart Grid Residential Community

The Future Community Team originally comprised several entities in an area North of Houston. The goal of the project was to demonstrate the benefits of equipping an existing, developing solar community with a variety of smart grid technologies, including home area network (HAN) devices, home energy management (HEM) systems, residential storage systems, and plug-in electric vehicles (PEVs), and then perform various electric pricing experiments to measure consumer behavioral changes in response to

variable pricing incentives. Additionally, the original concept included the monitoring of the solar community and a neighboring community at various feeders to define potential benefits and issues related to communities with heavy concentrations of solar and potentially PEVs.

Further, the original project envisioned deployment and analysis of a large battery system in conjunction with a solar farm to support community assets such as a water treatment plant and potentially community PEV charging stations.

2.4.2.3 Demonstrating Demand Response by Leveraging the Smart Meter Texas Portal

The TDSPs had jointly begun to develop an SMT Portal that would ultimately host and provide access to the 15-minute incremental smart meter data by REPs and consumers. The original objective was to collaborate with the SMT Portal Team and execute a planning effort to define additional functionality for enhancing the SMT Portal to support the project objectives.

2.4.3 Revised Plan for Achieving Project Objectives

In late 2011, due primarily to significant cost share issues, CCET was forced to cease all project activities until such time as it was able to restructure the project with several new partners. The changes in team composition, and additional activities that have become part of the project plan, are described below.

2.4.3.1 Synchrophasor

For the synchrophasor part of the project, the team was expanded to include TTU which was interested in building its own synchrophasor network in conjunction with wind turbines located on a distribution network at the nearby RTC. TTU is located in Lubbock, Texas, in the northern Texas panhandle area, which is part of the SPP rather than ERCOT, so this provided an opportunity to investigate reliability in another area of Texas. Additionally, GSEC, which provides generation and transmission resources for a number of rural electric cooperatives, joined the team to provide additional locations for siting PMUs.

Furthermore, the synchrophasor efforts were expanded to include a demonstration of unique cyber security protection capabilities for synchrophasor assets by Intel/McAfee. The objective was to implement a parallel synchrophasor network in Lubbock, Texas, and have TTU perform independent cyber security testing of these new protection schemes.

2.4.3.2 Smart Grid Residential Community

The restructured project leveraged a solar community equipped with smart grid technologies in Austin, Texas, that provided a test bed similar to that originally planned in Houston. Pecan Street, which also has an SGRDP, and manages several related efforts in this community, was able to support the planned pricing experiments designed by team member Frontier Associates. The intent of conducting consumer pricing experiments remained the same, and this team planned, recruited participants, executed the

experiments, and collected and organized the data from ongoing pricing trials supplied to Frontier Associates for analysis of consumer response to pricing experiments.

The utility-scale battery which was originally envisioned in line with a solar farm was situated in conjunction with adjacent wind turbines at the RTC in Lubbock. The wind turbines and related projects are managed by Group NIRE, and these activities are situated on a local distribution network owned by SPEC. They both have a close affiliation with TTU which performs analysis on the wind turbines and extended their scope to include analysis on the battery system.

2.4.3.3 SMT Portal

As the SMT Portal continued to be enhanced, TXU Energy, a REP, joined the project to ascertain the benefit of using the SMT Portal to improve its DR initiatives. Many of these DR programs already exist and typically operate by sending signals through residential broadband networks to various HAN devices that then curtail the devices or adjust settings to conserve energy use during critical times; however, for a variety of reasons, the broadband approach has seen limited success. The Team, therefore, focused on demonstrating the feasibility of improving those DR efforts by also transmitting DR signals through the SMT Portal and across the TDSP AMS networks to the same residential HAN devices located behind the smart meters.

2.4.4 Project Timeline

This section includes high-level schedules of the CCET project activities performed by the various project components. The project included three phases, and each phase is represented by a separate figure.

The figure below shows the primary scheduled activities for Phase I which was conducted from January through May 2010.

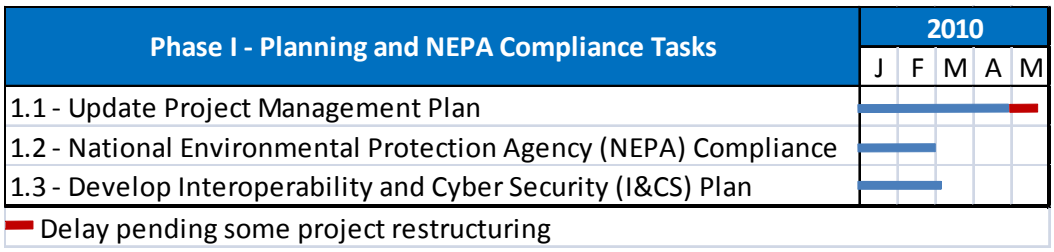


Figure 35. Primary Phase I Activities

This next schedule is for Phase II which began in June 2010 and concluded in October 2012.

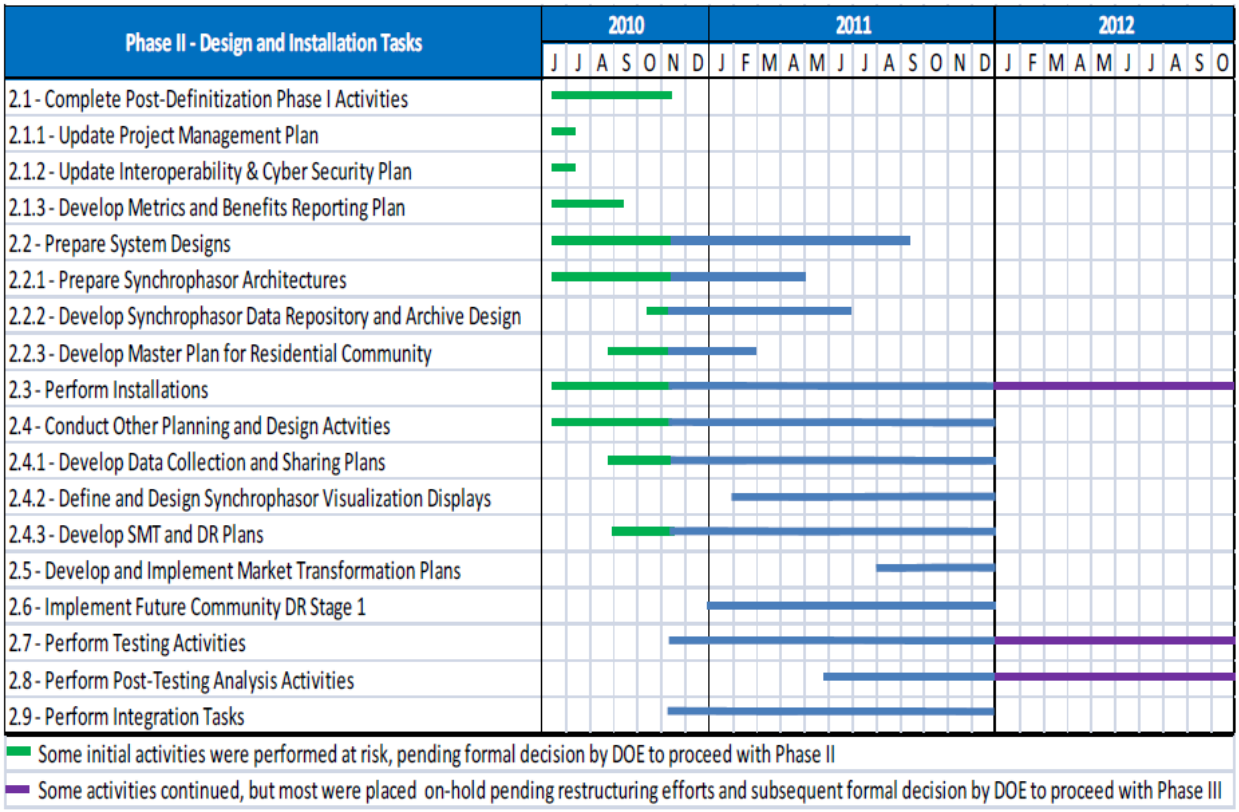


Figure 36. Primary Phase II Activities

The schedule shown below is for Phase III.

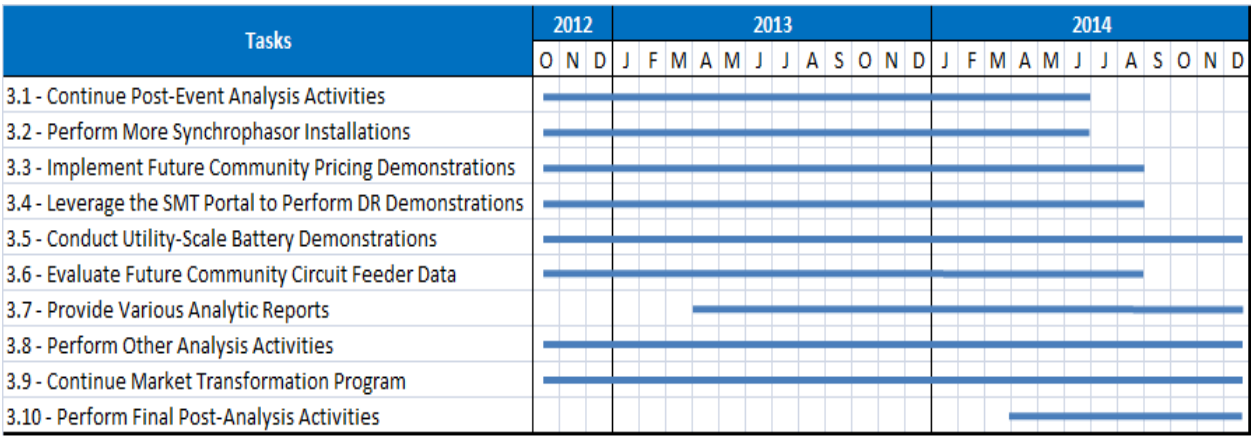


Figure 37. Primary Phase III Activities

2.4.5 Key Project Milestones

The key project milestones for the CCET project are listed in the table below. The milestones served as key verification dates for measuring progress, and they were typically characterized as deliverables to

provide a verification method for accomplishing the milestone on time. During project performance, CCET reported the milestone status as part of the required Monthly Progress Report.

The table identifies the respective project phase, milestone description and planned completion date.

Table 12. Key Project Milestones

Phase	Milestone Description	Planned Completion
I	Update the PMP	05/25/2010
I	Prepare NEPA Environmental Questionnaires	02/26/2010
I	Update I&CS Plan	03/08/2010
II	Update the PMP	11/26/2010
II	Update I&CS Plan	11/26/2010
II	Develop metrics and benefits reporting plan	01/28/2011, 05/16/2011
II	Complete system design documents	09/09/2011
II	Provide quarterly build metrics	Quarterly as of 3Q11
II	Create initial market transformation plan	12/16/2011
III	Update the PMP	12/14/2012
III	Update the I&CS Plan	01/15/2013
III	Update the metrics and benefits reporting plan	01/30/2013
III	Provide quarterly build metrics	Quarterly as of 4Q12
III	Prepare interim TPRs	09/30/2013,04/30/2014
III	Prepare Final Report	12/30/2014

2.4.6 Key Decision Points

Decision points were used by the CCET Team and DOE to assess the technical status, results, funding requirements, programmatic needs, and relevant risk factors of the project. The success criteria at these decision points was used to assess achievement of specific goals which were typically at the end of each phase or at appropriate points in the project execution.

The success criteria shown below are objective and stated in terms of specific measurable and repeatable data. Some of these success criteria pertained to desirable outcomes, results and observations from the demonstration efforts, and encompassed certain project aspects such as:

- Validation/confirmation/identification of scientific/engineering knowledge
- Cost savings expected over existing technologies
- Performance enhancements to existing technologies
- Reduction in health, safety and environmental risks
- Ease of installation, operation, and maintenance
- Decrease in capital, operating, and maintenance cost

Listed below are the decision points and success criteria for each one.

Decision Point 1 – Planning and NEPA Compliance

- Updated project management plan (PMP) completed and submitted to DOE
- NEPA Environmental Questionnaires completed and provided to DOE
- Interoperability & Cyber Security (I&CS) Plan completed and provided to DOE

Go/No-Go Decision Point 1 – End of Phase I

- Previous Decision Point 1 successfully accomplished
- Project efforts on schedule and within budget
- Plans for Phase II approved

Decision point 2 – Design and Installation

- System design documents completed and provided to DOE
- Market transformation plan completed and provided to DOE
- Quarterly build metrics provided to DOE

Go/No-Go Decision Point 2 – End of Phase II

- Previous Decision Point 2 successfully accomplished
- Project efforts on schedule and within budget
- Plans for Phase III approved

Decision Point 3 – Demonstration and Analysis

- Quarterly build metrics provided to DOE
- Interim TPRs provided to DOE
- Final report provided to DOE

2.5 Major Demonstration Components and Smart Grid Technologies and Systems

As summarized earlier in this report, the project began with three primary components: synchrophasor, future community, and SMT portal. As a result of the described restructuring effort that ultimately attracted new team partners, while retaining the same project goals and objectives, the project expanded its scope to cover seven technical demonstrations as part of these three components.

- Synchrophasor
    - Synchrophasor monitoring, visualization and event reporting
    - Synchrophasor Security Fabric

- Future Community
    - Residential circuit monitoring
    - Residential time-of-use pricing trial
    - Distribution-level battery energy storage system
    - Fast response regulation service with fleet electric vehicles
- SMT Portal
    - Residential demand response

For each of these technology components, there is a myriad of information to relate regarding aspects such as technologies and systems demonstrated, smart grid functions and applications, expected benefits, stakeholder interactions, project plans, data collection efforts, benefits analysis, results and conclusions. Rather than address the individual components in each of these areas, CCET has chosen to organize and present this information by technology component so that the reader gains a clear understanding of each component as a project, from inception through planning and demonstration execution to results and conclusions. The individual components are therefore contained in separate sections, as outlined below.

Section 3.0 – Synchrophasor monitoring, visualization and event reporting
Section 4.0 – Synchrophasor Security Fabric
Section 5.0 – Residential circuit monitoring
Section 6.0 – Residential time-of-use pricing trial
Section 7.0 – Residential demand response
Section 8.0 – Distribution-level battery energy storage system
Section 9.0 – Fast response regulation service with fleet electric vehicles

2.6 Basic Interoperability and Cyber Security Approach

One of the key requirements for the DOE SGRDPs was to ensure that interoperability and cyber security were addressed. For this project, CCET chose a cross-cutting approach whereby interoperability and cyber security efforts were integrated into each technical component of the project. The technical approaches for performing these cross-cutting efforts are outlined in the next two sub-sections.

2.6.1 Interoperability

The CCET project members took measures to ensure that technologies in this project complied with documented standards for interoperability. During the project, the demonstrated technologies were exercised and evaluated to ensure they interoperated with both the existing electrical infrastructure as well as anticipated grid enhancements.

- **Synchrophasor network**: The teams chose devices from proven commercial vendors that had been in field use for years and had been validated by their vendors as satisfying interoperable

standards. Although communication issues were defined, these were related more to operating frequencies, environment and atmospherics rather than interoperability.

- **Security Fabric:** This suite of capabilities incorporates integrated devices and functionality that are commercially available individually. Interoperability testing among the suite of devices was performed by Intel/McAfee and the vendors proposing products for this suite.
- **Utility-scale BESS**: For the BESS, the vendor, the local cooperative SPEC, and TTU were responsible for any necessary interoperability testing. The BESS vendor performed laboratory testing and replicated that testing when the BESS was fielded. Since the BESS is a self-contained unit, using proven and reliable technologies, no issues were anticipated and none were revealed. There were still potential data transmission, storage and data visualization issues, but none of these were expected to be related to interoperability, and field testing verified this.
- **Residential HANs**: The HAN devices were chosen by the partners based partly on compliance with standards and partly on their technological capabilities. One set of these HAN devices selected for the pricing program was rigorously tested as part of its own demonstration project.
- **SMT Portal and DR**: Another set of HAN devices that were used for DR underwent both laboratory and field testing to demonstrate interoperability with both smart meters and broadband networks. The testing did in fact reveal that some older fielded devices actually had issues with interoperability and these findings were documented and revealed to the respective REP. To continue the DR program, the REP and CCET chose to leverage newly fielded devices that were guaranteed by the vendor to be compliant with interoperability standards. These devices also underwent both laboratory and field testing to validate their compliance.
- **Distribution-level monitoring systems**: The TDSP implementing the neighborhood circuit monitoring effort was responsible for performing all necessary interoperability testing.
- **FRRS**: The team followed established ERCOT standards implemented in similar efforts and verified through a certification process.

2.6.2 Cyber Security

The CCET project members recognized the importance of cyber security assessments as part of the project, and they were committed to ensuring adequate protection of all significant project components. However, many of the cyber security activities identified in NIST IR 7628 were either being performed outside the project scope, or the project activities had not yet matured to the point where cyber security assessments had been conducted.

As part of this project, CCET has implemented a compliant cyber security strategy to ensure protection of several key components:

- **Synchrophasor network**: The two largest Texas TDSPs and ERCOT implemented a network with PMUs and PDCs. This network employs secure communications, and the visualization results provide insights to grid operators, but the data and systems are not yet being used for grid control. When the latter occurs, the TDSPs will be responsible for expanding their current cyber security audits to include their portions of the synchrophasor network. Additionally, CCET

demonstrated a new data protection system (Security Fabric) at TTU that addresses the seven tenets of the National Institute of Standards and Technology (NIST) Interagency Report (NISTIR) 7628 and is designed specifically to monitor and deny intrusions between the TDSP PDC and the Independent System Operator's ePDC/RTDMS.

- **Security Fabric:** This suite of capabilities provides cyber security solutions, and both Intel and McAfee are national leaders in the security realm**.** Although they tested the protection capabilities of this suite, it was also independently tested by TTU as part of this project.
- **Utility-scale BESS**: During and after installation, the BESS underwent field testing to ensure that is satisfied all functional specifications, and was capable of performing all defined functions. As part of this effort, the BESS vendor performed cyber security assessments.
- **Residential HANs**: This project leveraged HAN assets of another DOE SGDRP to evaluate the effect of various consumer pricing models. That other project was responsible for all cyber security assessments on their HAN devices and PEVs.
- **SMT Portal and DR**: This project included DR events utilizing HAN assets that belonged to a REP in Texas. These experiments leveraged the control capabilities of the SMT Portal to distribute pricing signals over TDSP networks to HAN devices located behind residential smart meters. The TDSPSs are responsible for ensuring adequate cyber security protection on their meter networks, and the HAN device vendors and the REP ensured that the specific devices were compliant with all cyber security standards. Also, the SMT portal underwent a series of independent cyber security assessments and all findings were resolved.
- **Distribution-level monitoring systems**: One TDSP deployed monitoring systems on a distribution network to provide comparative analysis of electrical parameters in two different residential communities, one with solar and one without solar. That TDSP was responsible for ensuring adequate cyber security protection on that monitoring network. The distribution level monitoring was complemented by monitoring and analysis at the residential point of connection on a sampling of homes, performed by Pecan Street Inc.
- **FRRS**: This effort utilized data capture and reporting mechanisms that are similar to those in use by other market participants, and all of this was verified during the certification process.

3. SYNCHROPHASOR MONITORING, VISUALIZATION AND EVENT REPORTING

3.1 Introduction

Through a prior CCET project, team members had already recognized the need to monitor the grid variability due to wind resources, and they had deployed PMUs at three locations along with an initial version of visualization software at ERCOT. The objective of this aspect of the project was to expand the synchrophasor capability to at least 16 locations. The overall role was to stream data from the PMUs to the respective TDSPs who would then furnish it to ERCOT, the grid operator.

Another objective was to demonstrate the benefits of synchrophasor monitoring and analysis in effectively managing power reliability associated with variable wind power resources. This was to be accomplished by improving the visualization software, the data streaming and processing capabilities, and the communications network to a level that would facilitate placement in the ERCOT control room as an ancillary tool for grid operators. All of this required a collaborative effort to implement and maintain the supporting infrastructure, develop effective monitoring metrics, and identify, design, test, and deploy tools and procedures to improve overall grid operations and control based on the synchrophasor data system.

This demonstration effort has enabled ERCOT to better manage the transmission grid to accommodate the very large quantities of wind generation that are coming onto the grid in remote locations, and to detect and identify potential undesirable conditions on the grid and enable ERCOT operators to make adjustments to resolve the conditions. These activities directly related to improving the overall operating reliability of the grid, and provided economic value by increasing the amount of wind that can be successfully integrated with the transmission grid.

This effort demonstrated a wide array of benefits related to the deployment of PMUs, including:

- A method for establishing and maintaining a reliable synchrophasor network to provide real-time dynamic information (i.e. voltage, frequency, location, and time) on large-scale wind resources and their impact on the transmission grid, including assessing the optimal number and location of PMUs for effective wind integration, thereby advancing transmission operations management practices.
- The use of synchrophasor measurements to identify precursor conditions to undesirable grid performance and behavior, or to grid interruptions which, in turn, can lead to analysis, investigation, and ultimately changes in operating procedures or actions to facilitate integration of intermittent resources, hence improving grid reliability when employing large amounts of variable renewable energy sources.

- Lessons learned from wind dynamics monitoring and management that can be replicated and transferred to other parts of the U.S., thereby promoting the use of variable renewable energy sources.

The PMUs, and the associated streaming, monitoring, and analysis capabilities, provide measurements that can be used for recalibrating engineering models, including voltages, transmission line loadings and angle measurements, small signal stability monitoring, and damping. They also provide measurements for identifying precursors to grid interruptions, such as low voltage margins, poor system damping, low frequency oscillations, and transmission system angles. Lessons learned that can be transferred from this project component's efforts include data adequacy, data quality, reliability and robustness for real time grid operations, wind integration, and reliability management.

The key project activities included:

- Establishing a robust synchrophasor network
- Validating and managing the synchrophasor data
- Performing analysis and assessment of grid performance based on synchrophasor data
- Reviewing and updating policies and procedures related to managing and maintaining the synchrophasor network and data storage archives.
- Supporting an ERCOT stakeholder process which is in the process of defining protocol changes needed to integrate synchrophasor monitoring technology into the control room.

At the inception of this project, the ERCOT network was being monitored by PMUs at three locations (one in northwest Texas, and two in southern Texas). Synchrophasor data was being captured and streamed from those devices to an ePDC at ERCOT. The data was then synchronized based on timestamps and displayed via the EPG RTDMS, which was running in the test environment at ERCOT. As part of this demonstration project, three TDSPs (Oncor Electric Delivery, American Electric Power, and Sharyland Utilities) committed to install PMUs at 13 additional locations, and to stream their synchrophasor data to ERCOT for monitoring and display in the RTDMS. After recognizing the true value proposition of this early warning network of devices, the TDSPs began adding PMUs at even more locations on their networks. As of December 2014, the TDSPs had installed and are providing streaming synchrophasor data from 76 PMUs at 35 locations to the ERCOT RTDMS. These efforts also attracted the attention of other utilities across Texas who began planning for deployment of additional PMUs. Currently, ERCOT anticipates receiving data from 94 PMUs at 46 different locations during the first quarter of 2015. This network of PMUs currently provides monitoring of about 78% of ERCOT's regional grid footprint, and this will increase to about 85% coverage in 2015.

In addition to the ERCOT synchrophasor network, another objective of the project was to acquire data on the use of PMUs in tandem with wind turbines, and to evaluate their benefit to distribution grid operations. For this aspect of the project, TTU worked with several electric cooperatives to deploy a synchrophasor network in the Texas Panhandle portion of SPP. This included devices that are directly measuring power from wind turbines at the RTC, not only providing data on the performance of the

wind turbines, but also supporting a distribution grid, both of which were different from the ERCOT efforts. Additionally, this network provided a unique value given its location. As this network is electrically isolated from ERCOT, but located closely to the ERCOT transmission grids, it is likely that any events which occur in both systems can be attributed to environmental factors in the region such as high temperature or high winds. Additionally, this region is effectively a peninsula with limited connectivity to the rest of the SPP and the Eastern Interconnect. These factors made this synchrophasor network an ideal complement to the ERCOT system, providing an independent dataset for the testing of theories and the development of new engineering models which will aid future wind energy efforts.

3.2 Anticipated Benefits

Broadly, the expected benefits of the CCET demonstration project are a more reliable electric grid that can facilitate effective management of and responses to increased wind resources in Texas and from supporting the deployment of new products, technologies, and infrastructure to help grid operators better manage and respond to potential grid issues. Specific smart grid benefits that are supported by the synchrophasor component include:

- Provides transmission grid planners and operators with a high-resolution “picture” of conditions throughout the grid
- Furnishes critical parameters (voltage, current and frequency) that represent the overall health of the power system at much higher sampling rates
- Delivers improved power system monitoring and visualization to aid power system operators’ situational awareness and help them forestall grid collapse through better recognition and response to evolving grid events
- Assists in validation and derivation of system parameters used in power-system models and analytical tools to design and operate a more reliable grid
- Enhances grid throughput and utilization of existing grid assets
- Provides faster and improved forensic analysis following a disturbance that impacts the power system
- Provides necessary experience with synchrophasor systems to control room operators through training sessions and support of a stakeholder review process at ERCOT

3.3 Interactions with Key Stakeholders

The CCET synchrophasor team includes members from several of the largest utilities in Texas, and ERCOT, the grid operator for more than 85% of Texas. It also includes key members from the SPP area of Texas, including TTU and GSEC. It further includes one of the key application developers for the synchrophasor domain, EPG. Finally, team members are working closely with an ERCOT task force which is building stakeholder consensus for control room use of the technology as a tool for improved grid management.

3.4 Technical Approach

This section provides a detailed description of the technical approach, the questions to be addressed, and the methods used to answer them. The first part, Project Plan, identifies the steps taken to demonstrate the technology. The second part, Data Collection and Benefits Analysis, defines the technical approach for conducting the benefits analysis.

3.4.1 Project Plan

This section covers the tasks that have been performed in support of the synchrophasor networks.

3.4.1.1 Key Tasks

For the Synchrophasor component, the Team performed the following tasks:

- Established a robust synchrophasor network
    - Designed and implemented a communications network capable of delivering synchrophasor data from each of the TDSPs to ERCOT in a timely and reliable manner
    - Designed and implemented a production grade computer environment to support the RTDMS wide-area monitoring and visualization system
    - Provided the capability for the participating TDSP operators to view the RTDMS displays remotely from their respective offices, thus providing the capability for both ERCOT and the TDSP operators to view the same screens and see the same information during grid events
    - Provided training to both ERCOT and TDSP operators in the use and interpretation of the RTDMS wide-area monitoring system
- Validated and managed the synchrophasor data
    - Evaluated the PMU data collection, reliability and robustness
        - Validated that all data sent by a TDSP is successfully and timely received by ERCOT
        - Validated that all data received by ERCOT is faithfully archived in the appropriate phasor data base
    - Evaluated the overall reliability of the PMU data communications network
    - Developed phasor data performance standards
    - Implemented and maintained a phasor performance monitoring system
- Performed analysis and assessment of events
    - Performed baseline angle separation and alarm limit analyses for the ERCOT grid
    - Performed post-event analysis and forensics on grid events and disturbances
    - Developed baseline performance measures for wind generation
    - Assessed the impact of wind generation on system inertial and governor frequency response
    - Assessed low voltage ride through performance of wind generation

    - Detected, monitored and analyzed power system oscillations and the interaction of wind generation
    - Implemented a means of validating model-based predictions of generator response to disturbances
- Developed, updated, and managed policies and procedures related to managing and maintaining the synchrophasor network and the data archives
    - Phasor data repository design and implementation requirements and data archiving policies
    - Data sharing policies (inside and outside ERCOT)
    - Phasor data management policies (e.g. PMU naming convention, change management)
    - PMU location selection principles and criteria
    - PMU use cases

3.4.1.2 ERCOT Synchrophasor Network

When the CCET effort began in January 2010, the ERCOT grid contained PMUs at three locations and an earlier version of the RTDMS visualization software. The plan under the DOE cooperative agreement was to increase this number of PMUs to 16 locations total, and to improve the RTDMS. Although not all directly related to the project, as of December 2014, the ERCOT grid has 83 PMUs in service (76 actually stream data) at 35 locations, and this number is expected to increase to about 100 PMUs (with 94 streaming data) at 46 locations in the near future. ERCOT now recognizes the tremendous value that synchrophasors can offer its grid operators, so it is making plans to transition the data streams and internal monitoring software to production grade hardware so that operators can begin taking advantage of the alert features.

In recognition of the value that synchrophasors can provide to grid operations, ERCOT's Reliability Operations Subcommittee (ROS) created a Phasor Measurements Task Force (PMTF) in September 2013, comprised of representatives from TDSPs, Qualified Scheduling Entities (QSEs), Resource Entities, and ERCOT, and tasked with the following scope of work:

- How will synchrophasor data be used in ERCOT (real-time monitoring, unit model validation, etc.)? What are the current and planned uses by ERCOT? What are current and planned uses by TSPs and generators?
- What kinds of locations of PMUs are needed to meet this use(s)? How will these locations be determined?
- What are the data latency and quality requirements and other specifications, in order to meet the intended uses? Should these vary depending on the kind of PMU location?
- Who should install and own the PMUs? Who should be responsible for the communications from the PMUs?
- How should synchrophasor data be treated in terms of confidentiality?
- What reporting should be established for synchrophasor data?

- What data retention should be established for synchrophasor data?
- What are the CIP implications/requirements for the use of this data?

The PMTF's findings were presented to and accepted by the ROS in late October 2014, and the PMTF will be retired following its December 2014 meeting.

Regarding the network topology, the TDSPs have tried various communication configurations to transmit the PMU data to ERCOT. Those in well-established areas of the state have had fewer issues with communications, but it also has to do with placement of the PMUs. Initially, some TDSPs transmitted their streams directly from their PMUs to the ERCOT ePDC. However, since mid-2014, all of the TDSPs now transmit their data streams from their respective PDCs to the ERCOT ePDC.

3.4.1.3 TTU Synchrophasor Network

The synchrophasor network being deployed by TTU in the Texas Panhandle portion of SPP (shown in light blue in the figure below) began in late 2012 following the restructuring of the project. Currently, the system consists of five PMUs, an ePDC server located at the RTC and an RTDMS server located on the TTU campus. The first operational PMU is a National Instruments PMU located at the TTU campus. A second operational PMU is located in a Lyntegar Electric Cooperative-owned substation in Lynn County. Three additional PMUs are located at the RTC. Two of these PMUs are also functioning as revenue meters for two wind generation assets: the 1.67 MW Alstom wind turbine and three 300 kilowatt (kW) wind turbines at the scaled wind farm test (SWiFT) facility, while the third PMU is functioning as a revenue meter for the BESS which is located near the SWiFT facility. The red stars in the figure below indicate the existing PMU locations.

An expansion of the TTU network to more locations is planned for early 2015. The yellow stars in the figure below indicate possible future locations. Three units are already planned for locations in Hale, Plains and Oldham counties, and this will significantly expand the geographical area of the network and provide PMUs located near significant wind or natural gas generation assets.

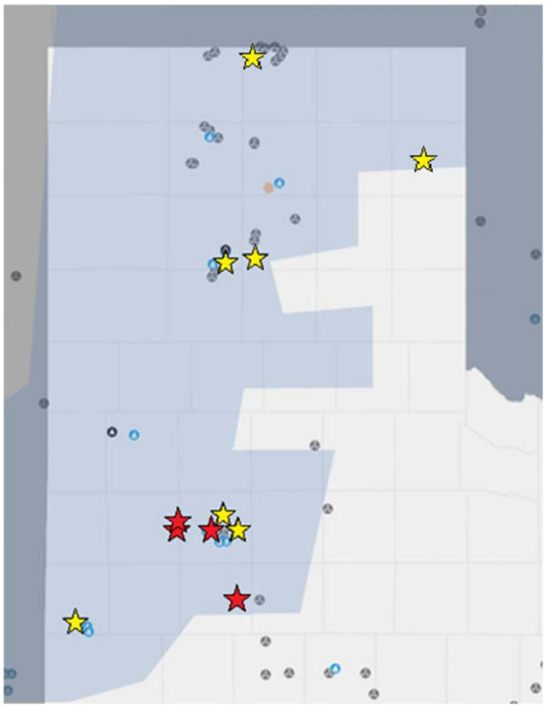


Figure 38. Current and Planned TTU PMU Locations

3.4.2 Data Collection and Benefits Analysis

To support the validation and analysis portions of the Synchrophasor component, the following data has been and will continue to be collected, retained, and analyzed:

- Synchrophasor data is retained in full resolution for the entire demonstration period. This data contains at least voltage, frequency, location, and time. Most of the PMUs sample at 30 samples per second while others record at 20 samples per second. This data has been used for the baselining analysis, together with State Estimator data recorded by the ERCOT Energy Management System (EMS). This data is also used to monitor the overall performance of the PMU network, including the communications network and the computer network infrastructure.
- Daily reports summarizing the overall performance of each of the PMUs reporting to the ERCOT ePDC are prepared and disseminated. These reports help to identify poorly performing PMUs, and identify communications and computer network delays which can interfere with reliable delivery and presentation of synchrophasor data to the ERCOT grid operators.
- ERCOT grid events, such as loss of generation or load, severe voltage dips, or sustained oscillations that are detected by the RTDMS wide-area monitoring and visualization system are also retained and analyzed. The events can be played back for review and operator training, and can be analyzed using an offline tool, the PGDA.

Additionally, the full synchrophasor data is scanned for unusual signatures, such as low-level oscillations that are characteristic of electromechanical interactions between generation and load, as well as

control-system driven oscillations. Synchrophasor data can also be used and compared to dynamic simulations to validate the performance of generator dynamic models with recorded performance.

The TTU portion of the synchrophasor network allows for positioning of PMUs at sites that have value for both wide area monitoring and for gathering data on individual generation or load assets. This ensures that the data set will be extremely useful for a wide variety of wind-related research. The TTU team is also identifying events such as generation trips and sub-harmonic oscillations and correlating those events with SPP wind energy contribution data, the operation of specific wind generation assets, or events which are also noted in ERCOT for which a cause has not been established.

3.5 Performance Results

This section covers the operation of smart grid technologies and systems, including the demonstration results; impact metrics and benefits analyses; and any stakeholder feedback received to date.

3.5.1 Operation of Smart Grid Technologies and Systems

This section primarily discusses the demonstration results for:

- PMU monitoring coverage
- Baselining study
- Data quality study
- Lessons learned from mitigating PMU data loss
- Event analyses of generation outages and wind interactions
- Requirements for control room and network production upgrades
- ERCOT and TDSP operator training
- Generator model validation
- Slow scan synchrophasors
- Synchrophasor use cases

3.5.1.1 PMU Monitoring Coverage

At the inception of this demonstration project, the ERCOT synchrophasor network consisted of PMUs at three locations and a single PDC installed and operated by AEP, and a single PDC and RTDMS wide area visualization system installed at ERCOT (installation was sponsored by CCET with DOE matching funding support). The demonstration for this project anticipated that the three participating TDSPs (Oncor Electric, AEP, and Sharyland Utilities) would install a total of 13 additional PMUs at 13 locations on their respective transmission networks, and provide the associated synchrophasor signals to ERCOT.

During the first two years of this project, the TDSPs identified additional locations where they could support the installation of PMUs. As of December 2014, the TDSPs have installed and are providing

streaming synchrophasor data from 76 PMUs[6] at 35 locations across ERCOT as shown in the figure below. Although not all of the PMUs are directly funded by or formally part of this project, their data feeds certainly provide measured contributions to grid performance and event evaluations. Additionally, it is expected that other ERCOT TDSPs will soon be providing data from additional PMUs being installed in their substations to ERCOT. Currently, ERCOT anticipates receiving data from 94 PMUs (out of 100) at 46 different locations by the end of the year.

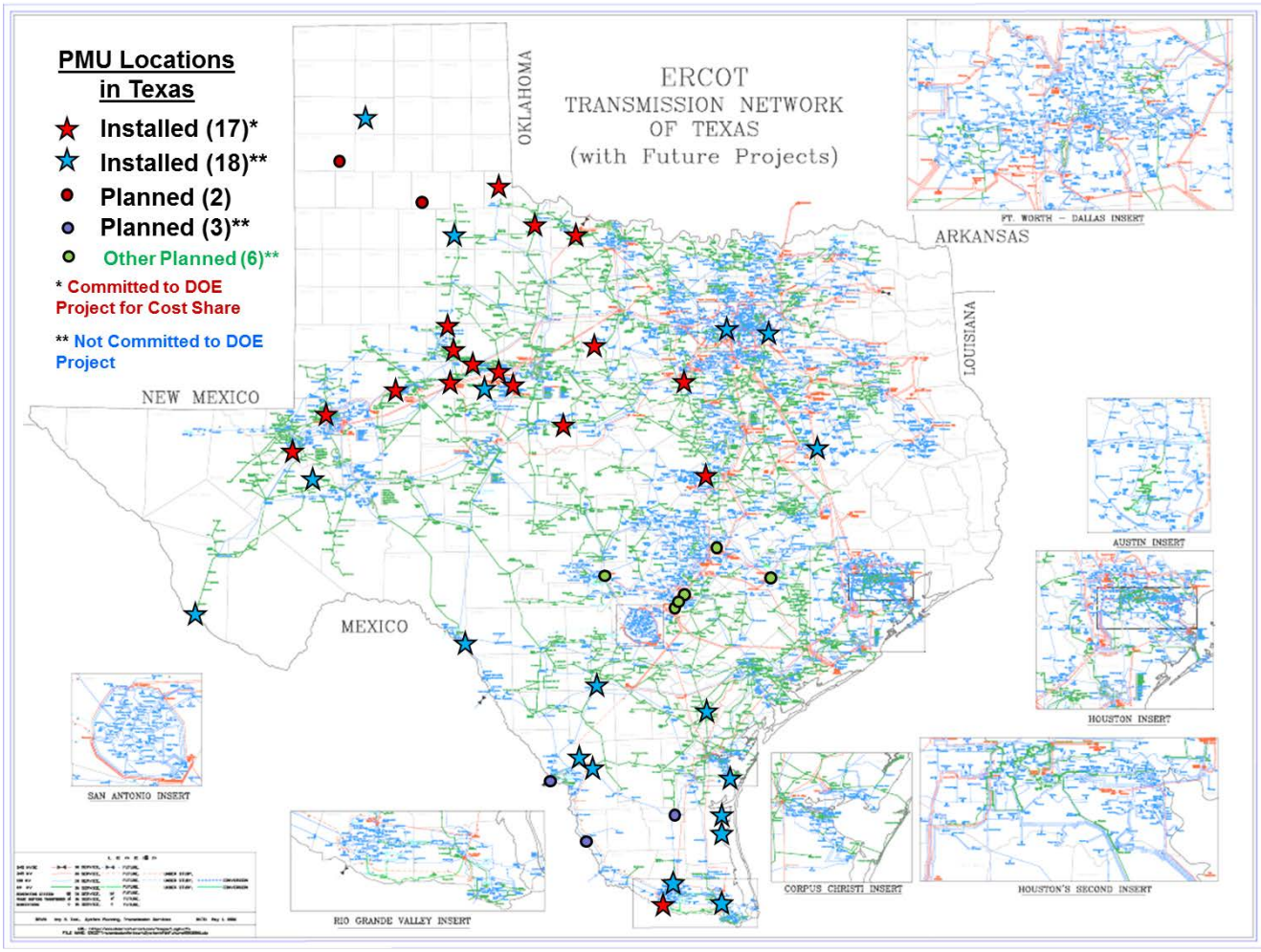


Figure 39. PMU Locations in Texas

During 2012 and the first part of 2013, the ERCOT ePDC received synchrophasor data streams from two TDSP-owned PDCs (Oncor and AEP). After adding new communications networks, Sharyland chose to stream its data directly from its two PMUs. This unusual data configuration worked quite well, and enabled the addition of new PMUs without the need to first install a local PDC at the TDSP. In mid-2014,

[6] There are 83 PMUs currently installed, which includes multiple PMUs at some substations. Signals from 76 PMUs are being used for wide-area monitoring.

Sharyland redirected their two direct-feed PMUs into a Sharyland-owned PDC which supplies data (including three new PMU data streams) to the ERCOT ePDC.

At ERCOT, the ePDC and RTDMS had initially been running on servers in ERCOT's test environment while the operational support capabilities were evaluated. In early 2013, planning began for the installation of production grade servers and associated hardware. This migration was completed in September 2013.

At TTU, the ePDC and RTDMS systems have been installed and running since May 2013. Their synchrophasor network, which is in the SPP region (not ERCOT), currently consists of two stable PMU installs with high data availability and three additional installs which initially had very low data availability, but which are now performing reasonably well. The two high data availability PMUs are located on the TTU campus and at a Lyntegar-owned substation in Lynn County. The three lower availability PMUs are all located at the RTC near the SWiFT wind turbine facilities. Two of the PMUs are connected over a 900 megahertz (MHz) encrypted Ethernet radio link to the BESS location, where the signals are moved onto a fiber optic communications circuit which connects to the Reese ePDC. The BESS PMU is also connected to this fiber system. An additional 3-6 PMUs are planned to be added to this network during 2015.

Initially, PMU radios linked to the Reese campus offices, where the ePDC is located. However, these links had low availability due to poor signal strength negatively impacted by line-of-sight problems. These two radio links were redirected to the battery installation in late 2013, where they are now tied to the fiber optic network, significantly improving the data availability. The battery is much closer to the PMUs and has excellent line-of-site to both locations. An additional challenge in achieving high data availability has been the processing/conversion of the data being extracted from the revenue meters (Lynn County substation and the three PMUs near the SWiFT facility at Reese). This data is converted from a proprietary communications protocol used by the revenue meter into a C37.118 protocol used by the ePDC via a custom-built data conversion algorithm. However, tuning the conversion algorithm to successfully identify and remove the additional end-of-field codes which the proprietary protocol occasionally generates has been challenging.

3.5.1.2 Baselining Study

In order to both validate the accuracy of the synchrophasor data being delivered to ERCOT, and to begin the process of establishing alert and alarm levels to inform the grid operators of emerging conditions on the system, a baselining study was initiated. The study evaluated both synchrophasor data and about 16,000 state estimator cases from the ERCOT EMS for the year 2012.

The synchrophasor data included all the PMUs that were installed and providing data to ERCOT (some were added during 2012, and thus covered only a portion of the year). The synchrophasor data was down-sampled from the nominal data rate of 30 samples per second to one sample per second to streamline the analysis.

The baselining analysis included a clustering study that identified PMU locations where the voltages and voltage angles moved in unison with nearby PMUs, as a means of identifying unique monitoring regions within the ERCOT grid. A total of six regions were identified, and similarly performing PMUs were thus clustered. The clustering study also compared the voltage magnitude and angles as measured by the synchrophasor network with the same metrics from the state estimator study results to validate the comparability of the two data monitoring systems.

The baselining analysis next analyzed, for the entire calendar year 2012, the ranges of voltage magnitude, voltage angles relative to a reference substation, and voltage angle differences (pairs) between PMUs in different regional clusters. This analysis was done for each of the anticipated 42 substations that are expected to ultimately have PMUs providing synchrophasor data to the ERCOT control center. The analysis also identified maximum and minimum values for each of the study metrics. Results from this baselining analysis were presented to the project team, and are attached to this report at the end of this section as Attachment 1.

Because the ERCOT grid was changing significantly between the start of 2012 and the end of 2013 with the addition of new 345 kV competitive renewable energy zone (CREZ) circuits that would dramatically alter the characteristics of the grid, it was determined that the experience-based operating limits that might be determined from this baselining study (based on the 2012 grid configuration) would not be reasonable limits based on the expanded ERCOT grid (including the new CREZ lines). Thus, it was determined to perform an update of the study based on the first six months of 2013.

As part of the 2012 baselining analysis, an analysis of the voltage magnitudes and voltage angles (relative to a reference substation) of PMUs which were geographically clustered was performed, to determine if representative PMUs from within clusters could be used individually to effectively monitor the overall ERCOT grid performance. The results of that analysis were included in the 2012 baselining analysis. For the 2013 baseline update analysis, it was recognized that new CREZ transmission lines had been added, which would change the electrical characteristics of the grid, and new PMUs (substations) had also been added. To verify the previously identified clusters, an updated cluster analysis was performed based on data from January-June 2013. The updated cluster analysis identified some minor changes in the makeup of the cluster groups. In general, the results corroborated the findings of the 2012 cluster analysis except for South 2, which did not track well with the other nearby substations. The updated cluster analysis report is attached as Attachment 2.

The first update study analyzed, for the period January-June 2013, the ranges of voltage magnitude, voltage angles relative to a reference substation, and voltage angle differences (pairs) between PMUs in different regional clusters, as did the 2012 Baselining study. This update study identified that, compared to the same time period in 2012, the ranges of voltage magnitudes, voltage angles relative to the reference substation, and voltage angle pairs for the first six months of 2013 had smaller deviations (minimum to maximum), and smaller angle spreads. This is consistent with the changes that would be expected when transmission lines are added between outlying locations and the load pockets to strengthen the grid. The first update study is attached to this report as Attachment 3.

During the first six months of 2013, nine new 345 kV transmission lines were completed as part of the CREZ project. Additionally, 19 new 345 kV transmission lines were completed between July 1 and December 19, 2013. As before, these lines were expected to change the electrical characteristics of the grid. To track those changes, data for the remainder of 2013 was collected and analyzed to monitor the changes in voltage magnitude and voltage angle ranges caused by the ongoing additions of CREZ transmission lines. Additionally, initial alarm setting values were determined for use in the ERCOT RTDMS system. This study update for the full twelve months of 2013, identified as Baselining Study Update #2, is attached as Attachment 4.

Because several CREZ transmission lines were completed late in 2013, and seven more lines were completed in the first quarter of 2014 (the last line was completed in March 2014), a third update of the baselining study was performed, based on data for February through July 2014. For this update, only voltage angles were analyzed, as the alarm limits based on voltage angles would have been most affected by the addition of new transmission lines. The conclusions from this third update study are:

1. The voltage angles for substations in the West Texas and Panhandle areas have tightened (smaller angles referenced to central Texas) 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.
2. A redistribution of power has occurred among several transmission lines in the Valley area.
3. 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.
4. The new CREZ lines added in March 2014 are not expected to result in any further major changes in voltage angle monthly medians.

Recommended RTDMS alarm limits are included in this third update study. This final Baseline Study Update #3 is attached as Attachment 5.

3.5.1.3 Data Quality Study

In order for ERCOT to achieve a production quality phasor monitoring system that can be relied upon in real-time operations, three conditions must be met: 1) the data must be flowing reliably from the PMU to the grid operator's console, 2) the data must be valid, and 3) the data must be monitoring the critical locations (right places). In early 2013, an analysis of the overall synchrophasor data flow and data quality was initiated to address this first condition, and to identify improvements that might be needed to successfully achieve the first condition.

The goals of the study were to:

- Identify nodes in the phasor network that might be affecting data availability (dropout).
- Classify identified dropout issues by severity and frequency.

- Determine likely causes of data dropouts at identified locations.
- Propose solutions to help eliminate identified data availability problems.

Two of the TDSP's were providing their PMU data streams to ERCOT via TDSP-owned PDCs with associated data bases. To validate the flow of data, data extracts from each of the TDSP data bases were requested. However, for the specific dates selected for analysis, data from only one TDSP was available. It was decided to complete the initial study using data from a single TDSP, and then to repeat the analysis for the other TDSPs at a later date. While the initial study results concluded that all the sub-second synchrophasor data was reliably being delivered from the TDSP into the ERCOT ePDC and RTDMS databases, there were gaps in some of the second-average and minute-average data that was also being saved in the RTDMS database. An incompatibility between the data and the database storage routines was identified and corrected in early July. A review of the data base consistency has confirmed that this has corrected all of the identified issues from the initial study. The study was then extended to analyze the data streams from the other two TDSPs. A review of the data base consistency between each TDSP's local data base with the ERCOT database identified minor issues (primarily associated with local storage and data quality flagging). The Final Data Quality Study is attached as Attachment 6.

As part of their scope, the ERCOT PMTF updated and enhanced the ERCOT Communications Handbook to include a section on synchrophasors. The Data Quality validation process that was used for the aforementioned Data Quality Study has been incorporated into the ERCOT Communications Handbook, as a guide for ERCOT market participants and TDSPs who plan to add PMUs to their respective equipment. A copy of the Data Quality section of the ERCOT Communications Handbook is attached for reference as Attachment 7.

3.5.1.4 Lessons Learned from Mitigating PMU Data Loss

During the first two years of this project, the synchrophasor data volume has increased from 3 PMUs reporting at the outset to 83 PMUs reporting as of November 2014 (of which 76 are being used for operations monitoring). Since September 2011, daily reporting statistics have been tracked for each of the PMUs. As indicated in the summary plot below, which presents monthly average values through November 2014, early in the project when new PMUs were added, their availability and data quality was initially low but improved rapidly. As the participants have gained experience adding PMUs in their respective networks, the initial reporting performance of the newer PMUs has started higher and improved more rapidly. The data availability metric has been essentially 100% since identification and correction of a data base storage timing issue in early 2014—an issue identified as part of the Data Quality Study.

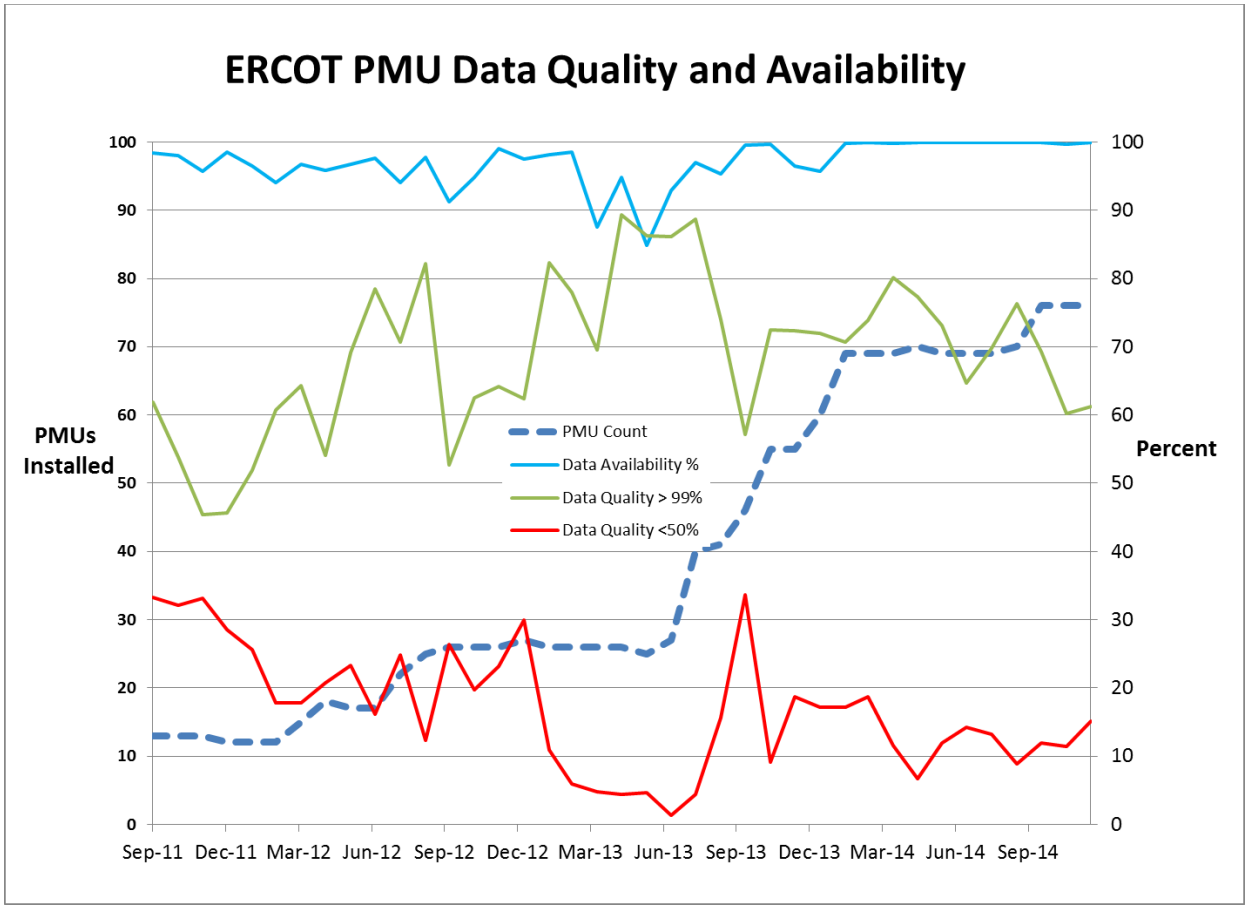


Figure 40. ERCOT PMU Data Quality and Availability

The most common challenges to achieving high overall PMU data quality have been securing a reliable communications channel between the PMU and the TDSP PDC, and getting a good time stamp signal into the PMU. As is characteristic for most utilities in North America, the ERCOT grid is represented by both legacy TDSP communications networks, and newer, more robust communications paths. Where PMUs were relying on the legacy communications networks, some tuning of the network was needed in order to improve the overall reliability of the PMU data stream. In three cases, it was not possible to achieve the necessary bandwidth and communications reliability to support the PMU data stream, so those PMUs were removed from the data network.

Sharyland initially attempted to utilize a wireless carrier for the first link of their PMU data stream from one of their substations. The wireless carrier disconnected the data stream after only a few days of operation, and refused to provide service to Sharyland—the carrier was not anticipating the volume of data represented by the PMU data stream. To complete the communications link to their substation, Sharyland had a hard-wire communications line installed.

Two PMU signals in the AEP PMU data stream are being provided voluntarily by their respective generation plant owners. Unfortunately, since providing PMU data is not high on the plant owners' priorities, these units are not being adequately supported, so the data quality from these PMUs is lower than desired, and the signals are not as useful as they might otherwise be. These and other minor local issues are the primary reasons for the metric of Data Quality <50% remaining up at about 10%. At this time, ERCOT has elected to continue utilizing these lower quality signals, which still provide some useful monitoring, rather than turning these signals off.

On one occasion, a network card on a collocated ERCOT-owned switching device, in the AEP facility where AEP's T-1 connection interconnected with the ERCOT wide area network, was causing random delays in transmission, causing the AEP PMU data stream to drop out for short periods of time. Diagnostic testing by both AEP and ERCOT validated that connections to their respective ports on the network switch were working properly, but testing across the switch was not performed. After several weeks of poor performance, an onsite technician removed and reseated the network card, duplicating the problem. The network card was replaced, and the intermittent data dropouts ceased. In this case, neither organization was sufficiently aware of the interface configuration to be able to test across the switch as part of their routine diagnostic testing.

3.5.1.5 Event Analysis of Generation Outages

The ERCOT RTDMS system automatically captures event files when significant generation is lost (e.g., loss of a unit 400 MW or greater). These event files are then analyzed to assess the overall performance of the grid, including frequency dip and initial inertial frequency recovery, to compare against the interconnection frequency bias, voltage dips (location and magnitude), and angle swings across the grid. These results are being accumulated and tabulated, together with grid configuration metrics such as total amount of generation on-line, mix of generation on-line, level of wind production, etc. Statistical analysis of these event metrics will be used to identify performance trends.

Additionally, on several occasions, minor sustained oscillations have been detected on the ERCOT grid. Using the synchrophasor data, these oscillations are evaluated with respect to location of the strongest signal (find the PMU closest to the source), the frequency and damping characteristics of the oscillation, and any identified interactions with other generation. The results are then tabulated, together with grid configuration metrics such as total amount of generation on-line, mix of generation, level of wind production, etc. In most of these cases, the source of the oscillations could be identified and confirmed through communications with the respective generation owners. In each case where a specific generator could be identified, the oscillations were confirmed to have been caused by incorrect settings in one of the generator control systems. This demonstrates the capability of the PMU monitoring system to be able to identify improperly performing control systems, and to enable the grid operators to contact the generation owners to effect corrective changes in the control settings. While this is not yet being accomplished in real time, the technology demonstrates the potential for being able to perform these analyses in near real time.

As additional PMUs are added to the ERCOT grid, the ability to detect, locate, and diagnose control-system caused oscillations will improve.

3.5.1.6 Event Analysis of Wind Interactions

Given that this demonstration project was focused on identifying interactions between wind generation and the ERCOT grid, and demonstrating improved capability to manage the grid with large amounts of wind generation operating, the first phase of the synchrophasor component efforts focused on expanding the PMU monitoring network and upgrading the computer network. At the same time, additional transmission had been under construction as part of the CREZ transmission expansion program to support the projected expansion in wind generation. The planned projects were expected to improve or add nearly 7,000 circuit miles of transmission lines and more than 17,000 mega-volt amperes (MVA) of capacity to the grid. By the end of 2013, nearly all of the CREZ transmission expansion had been completed and placed into operation. This has facilitated construction of new wind generation across Texas.

At the beginning of 2010, there was 10,069 MW of wind generation installed on the ERCOT grid, and the peak wind production was recorded at 7,016 MW (June 2010). By the end of 2013, the ERCOT grid had more than 11,000 MW of installed wind capacity, the most of any state in the nation, and this was increased to 11,493 MW by October 2014. In November of 2014, a new ERCOT wind record was set at 10,301 MW which represented nearly 33% of the load at that time. Wind generation is forecast to increase to more than 18,500 MW installed.

Analysis of the recorded synchrophasor data for 2012 and 2013 was undertaken to examine potential interactions between wind generation and the ERCOT grid. Initial analysis identified low-level oscillations in the range of 5.0 – 5.5 hertz (Hz) which are detectible at substations near the large wind generation areas in ERCOT. These oscillations are likely driven by control systems, as the frequencies are too high for typical electromechanical oscillations. It has also been observed that the oscillatory frequencies differ by region. More analysis was required to identify the grid conditions under which these oscillations appear, and whether they have the potential to interact with other generation. This study is described in Section 3.5.1.9.

Additionally, when unusual events occur on the grid, through the enhanced monitoring provided by the synchrophasor network, ERCOT is now able to quickly identify the nature of the event, and initiate corrective actions. An example of this enhanced monitoring and analysis capability occurred on January 10th, 2014, at about 8:30 a.m. After logging on to the RTDMS system, ERCOT Operations Engineers noticed oscillations on the RTDMS displays. Since the oscillations were showing up only at one location, a Wind Farm PMU, ERCOT looked at the generation at the Wind Farm unit close to the Wind Farm PMU. It was generating about 56 MW. These oscillations were showing up even though there was no line outage at the substation. (In October 2011, ERCOT had observed oscillations due to a line outage at the same Wind Farm substation).

In order to reduce the oscillations, ERCOT advised the wind farm unit to turn OFF their automatic voltage regulator. This did not help to reduce the oscillations. To reduce oscillations, the wind farm was curtailed to 45 MW output. This reduced the oscillations to some extent. Since the oscillations did not go away completely, the wind farm was further constrained to 40 MW and the oscillations finally went away. It was found that oscillations were present in the system since 6:15 p.m. of January 9, 2014 and lasted through the morning of January 10, 2014 until the unit was finally curtailed to less than 40 MW. Analysis of these oscillations using the PGDA tool indicated that the dominant mode that was present was 3.3 Hz. The voltage oscillations had a magnitude of about 1 kilovolt (kV). 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, the wind farm operator pulled back the updates which finally stopped the oscillations. After that, no oscillations were observed even when the plant was generating again at greater than 50 MW. A copy of the January 9-10, 2014 Wind Oscillation Event is attached as Attachment 8.

3.5.1.7 Event Analysis of Generator Control System Interactions

Another example of the benefits of the enhanced monitoring and analysis capability provided by the synchrophasor network occurred in mid-February, 2014, when ERCOT operations engineers noticed oscillations on the RTDMS displays when they first logged into the system in the morning. Upon analysis, it was found that the oscillations were showing up only on one PMU signal at the West 4 substation. ERCOT looked at the generation at the hydro unit close to West 4 PMU. It was generating about 25 MW. It was found that when the unit went offline at about 10:00 am, the oscillations died down. 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. Analysis of these oscillations using PGDA indicated that the dominant mode that was present was 1.8 Hz. ERCOT worked 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 the plant operator 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 alternately. 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 p.m. It was found that the oscillations were significantly reduced after the control cards were replaced. A copy of the Event Report is attached as Attachment 9.

3.5.1.8 Wind Characteristics - Inertial Frequency Response Study

Texas has the greatest amount of wind generation online 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.

The study's analysis summarizes four illustrative scenarios that collectively concluded 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. The study 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. It is attached as Attachment 10.

3.5.1.9 Oscillation Data Mining Study

As with every type of generation, both the characteristics of the generation and the associated control systems can cause local (and sometimes grid-wide) oscillations that have the potential to cause everything from power quality problems (e.g. flickering lights) to growing system-wide power swings and instability (e.g. Western Electricity Coordinating Council 1996 system breakup). Early detection, identification, and mitigation of oscillations prevent system vulnerability and customer complaints. Because wind generation is relatively new to the electric grid, its interactions with the grid are still being discovered. As the level of wind generation increases, oscillations which might be caused by improperly tuned control systems can possibly grow to high energy levels and interact with the rest of the grid. Baselining these grid oscillations is crucial to understanding their origins and ensuring reliable operation of grid.

As part of this effort, EPG has been retaining a full resolution record of all the synchrophasor data collected on the ERCOT grid since 2011. In order to better understand the types of oscillations that are present on the grid, and how those oscillations change over time, this Oscillation Data Mining study was undertaken to investigate oscillations in ERCOT and identify any interactions associated with increasing levels of wind generation.

This study focused on identifying unknown oscillations, determining the sources of these oscillations, determining the type of oscillation (wind related or driven by control systems), and baselining the oscillation characteristics (mode damping and energy). The study considered phasor data from January 2012 through mid-2014. PMUs near wind farms were selected for analysis. A Phasor Data Mining Application (PDMA) was created to perform the detailed scanning of the PMU data. The data scanning process identified "clean" data (using the C37.118 status information), then analyzed successive 60 second intervals of data for any oscillations with less than 8% damping. The results were then aggregated by frequency band, for each PMU, for each month. Analytics such as the level of occurrence during the month, and the highest oscillation energy recorded each month, were tabulated.

The study identified 10 distinct oscillatory modes in the ERCOT grid. Four of the modes were present throughout the two and a half year study period, and a fifth was present in both 2012 and 2013, but is no longer present in 2014. All 10 modes were compared to their corresponding recorded regional wind production to assess any relationship between the presence of, and energy level of, the mode and wind generation.

The study concluded that one ongoing mode (0.9 Hz) appears to be related to the level of wind production, while the other three ongoing modes (5.0, 5.4, and 6.0 Hz) appear to be related to wind generator control systems. The full study is attached as Attachment 11.

3.5.1.10 Requirements for Control Room and Network Production Upgrades

During 2012 and early 2013, the minimum requirements for the computer and communications infrastructure needed to support the use of synchrophasor-based wide-area monitoring and visualization in the ERCOT control room were developed. Several possible configurations were examined, ranging from a single-instance implementation on production grade servers to a fully redundant implementation complete with staging and test environments. In early 2013, ERCOT decided to proceed with a single-instance implementation on production grade servers, with an associated network configuration. An illustration of the network configuration is shown below. EPG supplied an upgraded version of the RTDMS wide-area monitoring and visualization system, and had assisted ERCOT in configuring that version on the test system, in preparation for installation on the new production grade hardware. The new hardware was delivered in late July 2013 and the installation was completed in September 2013.

While ERCOT had been using the RTDMS monitoring capabilities within its Operations Engineering organization for several years to analyze grid events after-the-fact, in mid-2014 ERCOT migrated the RTDMS client software into the control room to provide the operators access to the real-time monitoring capabilities of RTDMS. ERCOT's operators are now able to detect emerging oscillations and perform post-event analysis after generating unit trips.

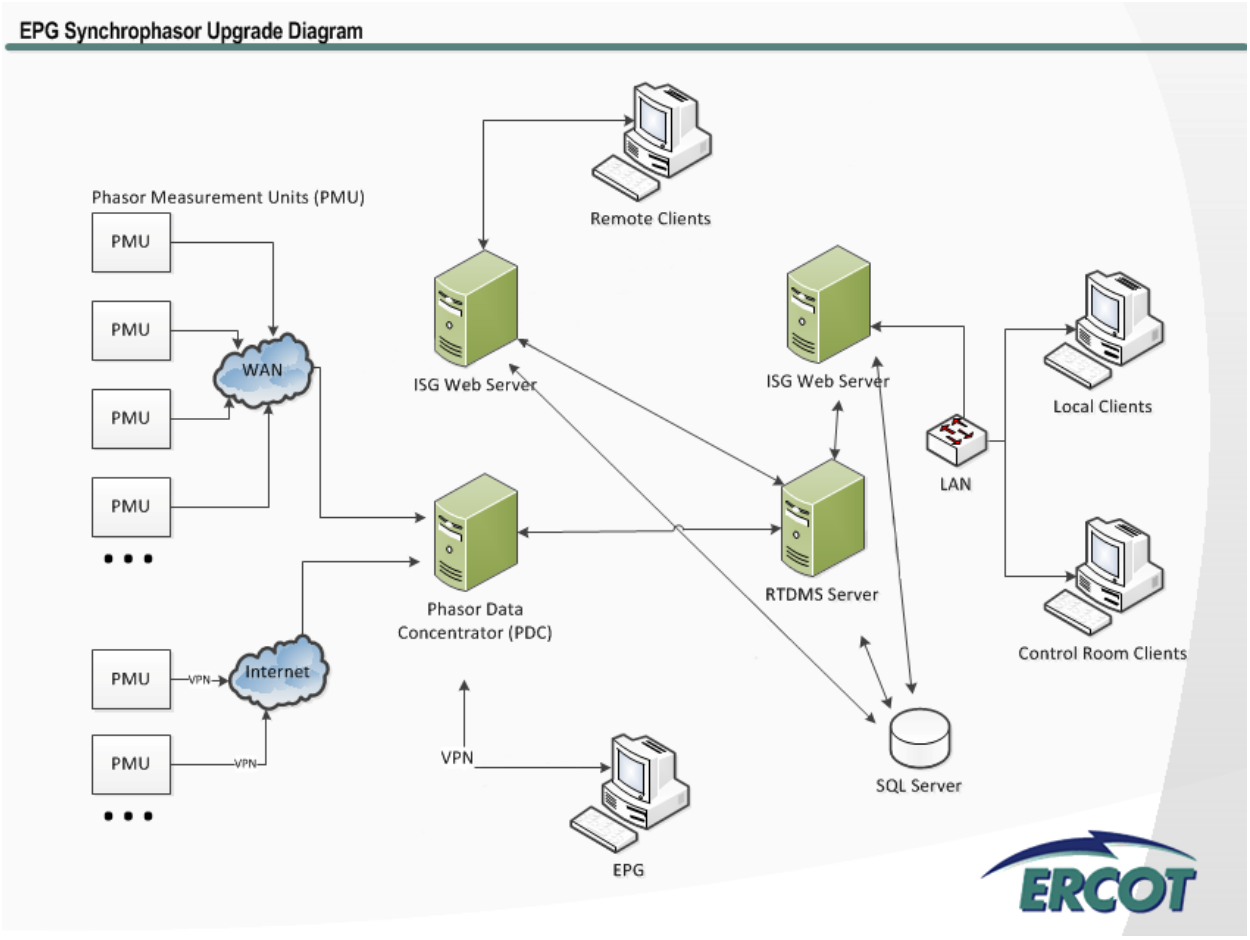


Figure 41. Synchrophasor Upgrade Diagram

3.5.1.11 Operator Training

In late September 2013, two on-site training sessions were conducted at ERCOT. A two-day training session covering the theory and practice of using the RTDMS wide area visualization system in real-time operations was provided to 38 operators from ERCOT and its member TDSPs. Additionally, a one-day training session covering the theory and practice of using the PGDA off-line analysis tool was provided to 23 operators and engineers from ERCOT and its member TDSPs.

In September 2014, a second two-day training session covering both RTDMS and PGDA was conducted at ERCOT. This training was provided to 44 participants, including both ERCOT operations personnel, and engineering and operations personnel from 17 ERCOT member organizations.

The training materials for both the 2013 and 2014 training sessions are posted on-line. The 2013 training materials are posted on the CCET website. The 2014 training materials are posted on the EPG website. Participant review comments from both the 2014 RTDMS and PGDA training sessions are included as Attachment 12.

3.5.1.12 Generator Model Validation

The need for accurate generator dynamic modeling was highlighted in late 2011 during a scheduled transmission outage for maintenance. During the outage planning, ERCOT simulated the grid conditions that would be present during the outage and concluded that the wind generation connected to the portion of the grid where the outage would occur would remain stable; however, after removing the transmission line from service, severe voltage oscillations were experienced by the wind generator, resulting in loss of the generation. Utilizing the synchrophasor data recorded during the event, ERCOT planners were able to determine that the performance of the wind generation predicted by the dynamic outage planning studies did not match the actual performance of the wind generation. Changes to the dynamic model parameters were provided by the generation owner and incorporated into the ERCOT models. While ERCOT may be confident that this generator model is now accurate, there are hundreds of other generators that could be unintentionally misrepresented in ERCOT's dynamic studies. Utilizing synchrophasor data to validate predicted grid performance offers the potential of avoiding unexpected outages due to inaccurately modeled generation and load.

Synchrophasor data can be used to aid grid planners in validating the generator models upon which their dynamic simulation studies rely. Through separate CCET-sponsored research on behalf of ERCOT, researchers at the University of Texas at Arlington (UTA) developed algorithms that have the potential of directly validating the parameters that describe individual generators connected to the ERCOT grid by using synchrophasor data collected where the generator interconnects the grid. As part of this project, EPG, working in collaboration with UTA, implemented the generator parameter model validation algorithms into an off-line analysis tool. The algorithms have been tested with both simulated data and recorded synchrophasor data, to the extent possible, in order to demonstrate the potential for the algorithms to assist grid planners in validating their dynamic models. A summary of this new tool is attached at Attachment 13.

3.5.1.13 Slow Scan Synchrophasors

The Oncor EMS includes the capability to capture time-stamped voltage magnitude and voltage angle (synchrophasor) data in their substation Remote Terminal Units (RTUs), and to deliver that synchrophasor data into their Transmission Management System (TMS). Oncor has begun to implement this feature, bringing time-stamped data into their TMS at a rate of three samples per minute. This slow scan data is then delivered into the Oncor PI Historian using the Inter-Control Center Communications Protocol (ICCP). A Visual Studio Web service is used to process the data for display to the user. These displays include phase angles across transmission lines, phase angles between selected locations, phase angles relative to a selected location, and system stress using a relative phase angle dial indication. An illustration of the relative phase angle dial is shown below.

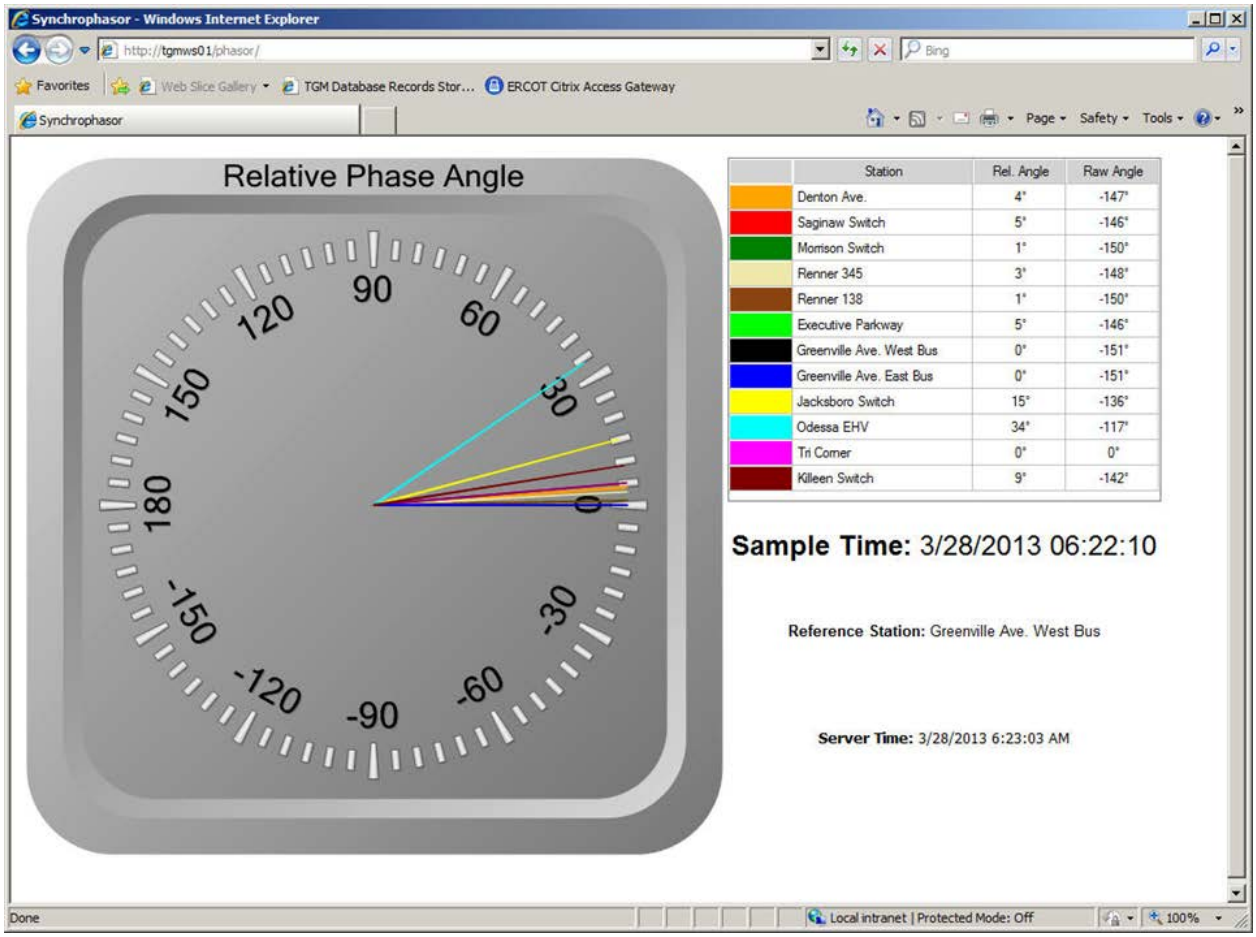


Figure 42. Relative Phase Angle Dial Illustration

Oncor is in the process of enabling this capability at more locations, stabilizing the data collection process, analyzing the data to establish alarm and notification limits, and developing a training program and operational procedures for deployment into the operational environment.

The key benefit of leveraging this slow scan synchrophasor data is the ability to monitor a significantly larger portion of the Oncor grid because the slow scan rate and limited data packet size make it possible to enable this capability at essentially every Oncor substation which is already using synchrophasor-enabled protective relays. The slow scan data cannot, however, be used to inform the operators about oscillatory events, nor can it be used to assist in validating dynamic generator models.

This slow scan data can potentially also be made available to ERCOT via the existing ICCP data link between Oncor and ERCOT. It has not yet been determined whether this expanded capability will be useful to ERCOT, in conjunction with the high speed synchrophasor data already being collected and displayed, or if this slow scan approach can be applied at other TDSPs.

3.5.1.14 Synchrophasor Use Cases

While the deployment of PMUs for the project was based on availability (PMUs were installed where the communications capability was sufficient, and the location was desirable for monitoring), part of the project plan included developing PMU location selection principles and criteria that can be used to site future PMUs. In support of this objective, the project team developed a set of 16 synchrophasor use cases as shown below. These use cases, summarized below, describe the grid operations application, grid scope, and the need. Over the past year or so, event analysis has been used to validate a number of these use cases. Of the 16 identified use cases, ERCOT has already experienced and applied synchrophasor technology to nine of the use cases. Full details of these use cases and their supporting sample events are included as Attachment 14.

Table 13. Synchrophasor Use Cases

Use Case	Need	Grid Scope	Streaming 30 Samples/Sec	Slow Speed 3 Samples/Min	Local Event Capture
High Stress Across System (High Phase Angle) Observed	Wide area metric that uses phase angle as a measure of the degree of power flow from one region to another, or from one station to another. 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)	Wide Area	Yes	Yes	
Small Signal Stability – Damping is Low	Small signal oscillation is generally across a large area of the grid, and can be noted with a low damping ratio. PMU data can advise the Shift Engineer about both known and unknown oscillations at location(s)	Wide Area	Yes		
Small Signal Stability – Emerging Oscillation Observed	Small signal oscillation is generally across a large area of the grid, and can be noted as a new oscillation frequency or mode not seen before. PMU data can advise the Shift Engineer about both known and unknown oscillations at location(s)	Wide Area	Yes		
Voltage Oscillation Observed	This is a regional phenomenon in one area of the ERCOT grid. The cause may be over-control of generator exciters or reactive controls in low electrical strength areas of the grid. 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	Regional	Yes		

Voltage Instability Monitoring (real-time P-V or Q-V curve)	This involves regional voltage instability based on deteriorating grid conditions noted with real-time tracking of P-V or Q-V curves. PMU data (real, reactive power and voltage) can advise the Shift Engineer indirectly on high grid stress under low voltage deteriorating conditions	Regional	Yes		
Detection of Subsynchronous Interactions (not necessarily resonance, just below 60 Hz)	Detection of subsynchronous (<60 Hz) interactions at a higher frequency than those with small signal stability or emerging oscillation. Oscillation frequency can advise Shift Engineer	Local Regional	Yes		
Integrate PMU Data into State Estimator	PMU phase angles can be used to validate the state estimator results used in control rooms (locates differences which reflects anomalies in models used for state estimation)	Wide Area	Yes	Yes	
System Disturbance – Capture and Interpretation	PMU data is useful for event analysis and for determining the root cause of events and their locations	Regional	Yes	Yes, not high resolution	Yes
Generator Parameter Determination	Generator parameters in actual settings versus models used in stability studies don't always match actual transient behavior in system events. 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)	Local	Yes		Yes
Major Load Parameter Determination	Similar to generator parameter determination, but this addresses load models that behave differently than models being used.	Local	Yes		Yes

PMU-Based Fault Location	PMU data is used to detect a fault on the network, and algorithms provide grid operator with estimate of likely location of the fault, and the fault characteristics. Shift Engineer reviews fault information and determines need for reclosing test	Local Regional	Yes		Yes
Phase Angle Across Breaker for Reclosing Action	PMU data is useful during an event to identify stress across system, and validate safe restoration actions. System operator reviews phase angle and voltage on both sides of an open breaker and determines need and ability to successfully reclose the breaker		Yes	Yes	
Synchronous Resonance Identification and Mitigation	ERCOT planning guide revision request (PGRR) 027 needs subsynchronous resonance (SSR) detection algorithms related to series capacitors to determine what capacitors to swap out	Regional	Yes		
Transmission Characteristics Determination	PMU voltage magnitude and phase angle measurements at the two ends of a transmission line can be used to compute the characteristics of the transmission line, and to validate the modeling used for studies	Regional	Yes		Yes
Dynamic Transmission Line Ratings using PMU Monitoring	PMU data will be used to monitor the change in transmission line resistance versus temperature. For example, at x temperature, the resistance deviation is y at this z sag level. The temperature will be independent and used in an offline study which will use apparent resistance to determine the sag	Regional	Yes		
Validation of Control Devices (e.g. SVC) Performance	PMU data can be used to validate the performance of control devices, such as SVCs, following grid events. The Shift Engineer reviews the measured performance, and compares it to expected performance	Regional	Yes		Yes

3.5.2 Metrics and Benefits Analysis

The anticipated benefits of development and deployment of a synchrophasor network in the ERCOT grid are focused around improving the grid operators' ability to manage large amounts of wind generation.

3.5.2.1 Operational Benefits

There is a wide array of potential operational benefits through the deployment of PMUs, some of which include:

- Identification of emerging grid conditions which, if not properly mitigated, lead to loss of generation or load
- Identification and correction of undesirable generation interactions, such as oscillations
- Identification of discrepancies between measured and predicted grid response to events, including frequency bias and dynamic response, generator dynamic response, and load dynamic response.

Benefits identified to date (and described previously) have included detection and identification of undesirable performance of generator control systems, and generator dynamic modeling discrepancies (differences between predicted and actual performance). While loss of generation occurred in at least two of these identified events, the generation lost was the source of the discrepancy, and no customer load was lost.

In one incident in early 2014, ERCOT detected that a specific generating unit was causing low level oscillations on the grid, which was adversely impacting customer power quality. At the request of ERCOT, the generator operator agreed to avoid use of the misbehaving generator during a high load period, so as to avoid adverse power quality impacts. Subsequently, upon replacement of a control component within the generator, ERCOT was able to use its real-time synchrophasor monitoring system to verify that the oscillations had been eliminated, allowing release of the operating limits on the offending generator.

In each of these events, no customer load has been lost, thus, quantification of benefits, such as mitigation costs or economic loss, is a challenge at this time.

3.5.2.2 Build Metrics and Benefits

The average cost of purchasing, installing, and supporting synchrophasor equipment is difficult to quantify since these costs are impacted by many variables, not the least of which are:

- Is this a new PMU or is it an upgrade to an existing PMU?
- Is this the first PMU at the chosen location or are others already in place?
- Are appropriate high-speed communications already available, or will they be required?
- Are secure communications paths available, or will they be required?

- Does the TDSP already have the requisite servers to support the monitoring software and data archiving needs, or will they be required?
- Are the costs (being donated as cost share contributions) limited to certain aspects of an installation?
- How much did the costs increase from 2010 to 2014 (long-term project)?

Considering that each installation is different, the following provides some basic cost information related specifically to this project.

- The average cost of a PDC was $13,374, but these costs ranged from $7,500 (software only) to $28,350 (hardware, software, IT support).
- The average cost of a PMU was $23,835, but these costs ranged from $13,020 (multiple hardware units only) to $247, 278 (including communications and field installation).
- A typical ePDC license cost ranged from $16,000 to $30,000 but this was vendor specific.
- Monitoring software costs can be priced by seat, by number of users, or as part of an annual maintenance and support contract, and different customers may receive discounts. These costs ranged from $10,000 (discounted in 2010) to $32,000 (in 2014).

3.5.2.3 Impact Metrics and Benefits

The benefits derived from the installation of a synchrophasor monitoring system are primarily associated with improved real time grid monitoring, improved grid modeling capability, improved understanding of the performance of the grid (e.g. baselining and post event analysis), and improved diagnostic capabilities. While each of these has the potential to reduce overall costs, the actual savings are difficult to assess.

- Improved real time grid monitoring – as illustrated in Section 3.5.1.6, using the synchrophasor system, the ERCOT grid operators were able to detect and proactively manage an emerging oscillation condition on the grid, preventing potential loss of generation and/or unacceptable customer power quality degradation
- Improved grid modeling capability – as noted in Section 3.5.1.12, the ability to use synchrophasor data following routine grid events to verify and, if needed, adjust the parameters used to model generating units, enables the grid operator to improve the accuracy of the modeling tools used to establish all the operational limits on the grid. With more accurate operational limits, power delivery (efficiency) may be optimized while reliability is enhanced.
- Improved understanding of the performance of the grid – through the use of baselining analysis, the monitoring and alarming capability of the synchrophasor network can be tuned to alert the grid operator to abnormal operating conditions, providing both an early warning system and backup monitoring capability to the energy management system. For instance, the baselining studies have confirmed that in the event of an outage of the energy management system, the synchrophasor voltage angle spreads between substations provides an accurate indication of the power flows on the network. Moreover, the synchrophasor network provides enhanced ability to analyze and evaluate the grid performance following disturbances. These two capabilities enhance the overall reliability of the grid, and reduce the potential for unneeded

curtailments and outages during abnormal operating conditions, thus improving the efficiency of the grid operation.

- Improved diagnostic capabilities – the synchrophasor system enables the automatic capture of high resolution data, which enhances the grid operator's ability to identify all the precursor events leading up to a grid event such as loss of generation or transmission. This high resolution data enables the operators to quickly and easily sequence the events (while the EMS can identify all the switching events which occur, the EMS timestamp is generally not sufficiently accurate to provide sequencing information), providing a clear event sequence timeline. Often, this higher resolution data is able to identify precursor events which might otherwise be more difficult to link to the event. This enhanced diagnostic capability both reduces the time needed to perform detailed analyses, and improves the accuracy.

3.5.3 Stakeholder Feedback

The TDSPs have indicated significant benefits being provided by synchrophasors, and are continuing to expand the number of PMUs in their territories. In late 2013, ERCOT formed a phasor measurement task force, with the intent of developing protocols and guides for incorporating the synchrophasor monitoring system into its control room operations. As noted earlier, this task force has recently completed its work, and its protocols and guides (including the Communications Handbook) are now available for ERCOT member systems to utilize. Additionally, ERCOT has provided remote access to its grid monitoring displays so that the TDSPs can visualize what's happening not only in their territory but across the ERCOT grid.

3.6 Conclusions

This section covers projections of demonstration and commercial scale system performance as well as lessons learned and best practices.

3.6.1 Projections of Demonstration and Commercial Scale System Performance

With the experiences gained in measuring and monitoring the ERCOT grid using synchrophasors, ERCOT has moved this technology into their control center, and is using the results not to define actions, but to help inform them about the performance of the grid, and emerging conditions on the grid. The benchmarking and baselining activities have provided the confidence that the synchrophasor-based monitoring accurately represents the condition of the ERCOT grid, and thus can be relied upon during brief outages of the EMS system. Moreover, the synchrophasor monitoring system is successfully identifying emerging conditions on the grid, such as control-system caused oscillations. This has enabled ERCOT operators to quickly identify the source of the oscillations and mitigate their impacts. As the monitoring system continues to expand coverage of the ERCOT grid, it is expected that the synchrophasor-based measurement of grid performance following disturbances will be increasingly utilized to enable validation and improvement of engineering modeling of the grid.

3.6.2 Lessons Learned and Best Practices

There are several lessons learned as part of development of the ERCOT synchrophasor network. First and foremost is to monitor, measure and validate that the synchrophasor data being sent from the substation is faithfully and reliably delivered through the communications network and into the central data base (such as at ERCOT). During the early development of the ERCOT synchrophasor network, the team was focused on connecting additional PMU units, and initiating the data flows. Validating that the data was being reliably delivered all the way to the RTDMS data base (at ERCOT) was a secondary goal. Moreover, without reliable monitoring tools, neither the TDSPs nor ERCOT had easy visibility of the day-to-day synchrophasor data flow across the network. The first step in ensuring that the data was flowing reliably was to modify the visualization software to provide an automated means for preparing daily monitoring reports and then distribute those reports to the TDSPs and ERCOT. Next was to validate that the monitoring report was accurate. Lastly, the data being archived (which was being used to create the monitoring report) was validated against the data being sent. Completion of this enabled the team to confidently rely on the daily performance reports.

The second major lesson learned was the importance of benchmarking the results of the synchrophasor data with the EMS data, to validate that both systems produced comparable results. This was accomplished initially as part of the 2012 Baselining Study.

A third lesson learned was to perform clustering analyses, to validate that PMUs which appeared to be geographically (and electrically) near each other did, in fact, perform similarly. This also enabled ERCOT to select representative PMUs from with a cluster for real-time monitoring purposes.

Finally, through the performance of baselining studies, alarm limits could be established for use in the RTDMS synchrophasor monitoring system which would effectively alert the grid operators when conditions were nearing, or exceeding limits based on the synchrophasor measurements, independently from the EMS system alarms. These baselining studies also confirmed that the grid stresses, and corresponding alarm limits, did indeed change when new transmission lines were placed in service (as was the case during 2012 and 2013).

Replication of these lessons in other grids is expected to improve the performance of the synchrophasor network, enhance the confidence in the resulting measurements, and improve the overall cost/benefit relationship.

4. SYNCHROPHASOR SECURITY FABRIC

4.1 Introduction

Another synchrophasor demonstration effort focused on incorporating enhanced security protection mechanisms in the synchrophasor network. For this effort, Intel/McAfee provided Security Fabric components that are architected to address the seven security tenets of the NISTIR 7628 for synchrophasor networks. EPG, a member of the CCET Team, integrated those capabilities with its monitoring, visualization and reporting platforms (ePDC, RTDMS, and Security Fabric Gateway (SFG)) to demonstrate secure data transport and data visualization.

One of the key concepts of the Security Fabric approach is the separation of the Electric Grid Business Process and the Security Process. The Electric Grid Business Process is a mechanism by which electricity is delivered to the customers while the Security Process is a separate, but parallel mechanism by which the Electric Grid Business Process can be protected. Therefore, making the business-security distinction for separation of the two mechanisms is important. The Security Process ensures that the endpoints and the communications are managed and monitored in the security context without interfering with the Business Process, thereby allowing the existing technology to continue to function, but with security in place. In this design, the security surrounds the existing technologies, thereby insulating them from threats without having to modify the grid technologies themselves.

The technical objectives of this effort included:

- Intrusion detection using protocol whitelisting
- Attack detection and remediation
- Secure encryption communications operating efficiently at all levels
- Audit logging and real-time correlation
- Upgrades for devices already operating in the field

The project employed contemporary concepts of silicon-driven security to stop attacks that easily defeat software-only security attempts. This provides a more secure framework for incorporating security in the physical hardware layers to better protect sensitive operations i.e. providing authentication for every step of the boot sequence to detect infection by malware or root-level viruses. The project approach leveraged the hardware security, and provided whitelist attestation to verify the trust basis for all changes and transition control to promote changes at a safe and convenient time.

For this demonstration, EPG designed, integrated, validated, and tested the Security Fabric enhancements to its ePDC and RTDMS applications in its laboratory environment. This testing was completed in early December 2013. In mid-December 2013, the Security Fabric servers together with the EPG software were deployed at TTU. A field demonstration was performed on the TTU

synchrophasor network to demonstrate the use of the Security Fabric to secure the phasor data stream between a "virtual Transmission Owner/Utility" and a "virtual ISO". The goal of the demonstration was to validate that the phasor data stream could be successfully secured from cyber attack while still delivering timely phasor data to the "virtual ISO's" wide-area monitoring and visualization system. As a part of the demonstration, TTU faculty and students performed compliance and penetration testing of the Security Fabric system, and documented their findings. Their assessment is included as Attachment 16.

4.2 Anticipated Benefits

Broadly, the expected benefits of the CCET demonstration project are to be derived from a more reliable electric grid that can facilitate effective management of and responses to increased wind resources in Texas and from supporting the deployment of new products, technologies, and infrastructure to help customers make informed decisions about their energy usage. Customers are to be empowered to effectively and reliably manage their peak demand, therefore resulting in reduced customer electricity costs, reduced system-wide capacity needs, reduced electrical losses, and reduced environmental impacts. Specific smart grid benefits that are potentially supported by the synchrophasor Security Fabric component include:

- Application whitelisting on managed systems
- Movement of databases to secured management system with encrypted tunnel
- C37.118 data (standard for PMU accuracy and data communications) is only received from authorized nodes
- C37.118 data is exchanged between nodes using a secure tunnel
- Access to applications is limited to authorized clients
- Secure network time protocol communications

4.3 Interactions with Key Stakeholders

The Security Fabric suite of capabilities is still evolving, but its first set of capabilities was intended to provide a requisite level of cyber security protections without impacting existing operations or performance, and without having to modify the applications requiring protection. While development and testing was ongoing, interaction with stakeholders was limited, but once the testing was completed, a number of stakeholders expressed keen interest in the potential for not only securing synchrophasor networks but any network requiring cyber security protection schemes.

4.4 Technical Approach

This section provides a detailed description of the technical approach, the questions to be addressed, and the methods used to answer them. The first part, Project Plan, includes illustrations of the system configurations, defines initial steps to achieve effective deployment, identifies the steps taken to demonstrate the technology (including test procedures), and outlines the approach to conduct analysis

to assess performance. The second part, Data Collection and Benefits Analysis, defines the technical approach for conducting the benefits analysis, including the methodology and algorithms when appropriate.

4.4.1 Project Plan

The Security Fabric project was intended to demonstrate the capability to securely deliver synchrophasor data between two separate entities (e.g. a TDSP and ISO) while defending against cyber-attack. This demonstration was developed in three phases.

In the first phase, several PMUs installed near TTU (on the campus, at the RTC, and in nearby utility substations), delivered their synchrophasor data to an ePDC located at the RTC. One of the unique features of this network is that it directly monitors the output of several wind generators connected to the local distribution utility network. This enables "close-up" monitoring of any wind-related interactions with the grid. The ePDC at the RTC represented, for the purposes of this demonstration project, a "virtual TDSP" PDC. The time-aligned synchrophasor data from the RTC ePDC was then streamed over the TTU communications network to an ePDC located in the Engineering Building on the TTU campus, and from there into the RTDMS wide-area monitoring and visualization system. The equipment located in the Engineering Building represented, for the purposes of this demonstration project, a "virtual ISO". At TTU, the synchrophasor data was displayed in RTDMS and stored in a phasor archiver for post-event analysis using the PGDA. This first phase has been operational since early 2013.

In the second phase, a test configuration consisting of a Security Fabric-enabled ePDC (SF-ePDC) together with a Security Fabric-enabled RTDMS (SF-RTDMS) was established in the EPG laboratory in Pasadena, CA. A simulated data stream was delivered into the SF-ePDC, and the SF-RTDMS was configured to provide wide-area monitoring and visualization of that data. This test system was then subjected to cyber-attack to validate the design and performance of the Security Fabric elements, monitor the impact of the Security Fabric on the overall performance of the synchrophasor tools (SF-ePDC and SF-RTDMS), and measure the latency introduced by the Security Fabric. The second phase was completed in late 2013 with a successful demonstration, in the EPG laboratory, of the Security Fabric-enabled ePDC and RTDMS applications maintaining normal operation while withstanding simulated cyber-attacks.

In the third phase, a second instance of the ePDC, equipped as the SF-ePDC, was installed at the RTC, and a synchrophasor data stream from the first ePDC was delivered to the SF-ePDC. The output synchrophasor data stream from the SF-ePDC was directed to the SF-RTDMS located in the Electrical Engineering Building on the TTU campus. Like the first instance of RTDMS, this SF-RTDMS also provides wide-area monitoring and visualization, and the data stream is stored in a phasor archiver. Startup testing of this parallel configuration, shown below, was completed in December 2013, and TTU collaborators spent much of 2014 performing compliance and penetration testing on the SF-enabled network, and side-by-side comparative performance testing, the results of which are captured in this report.

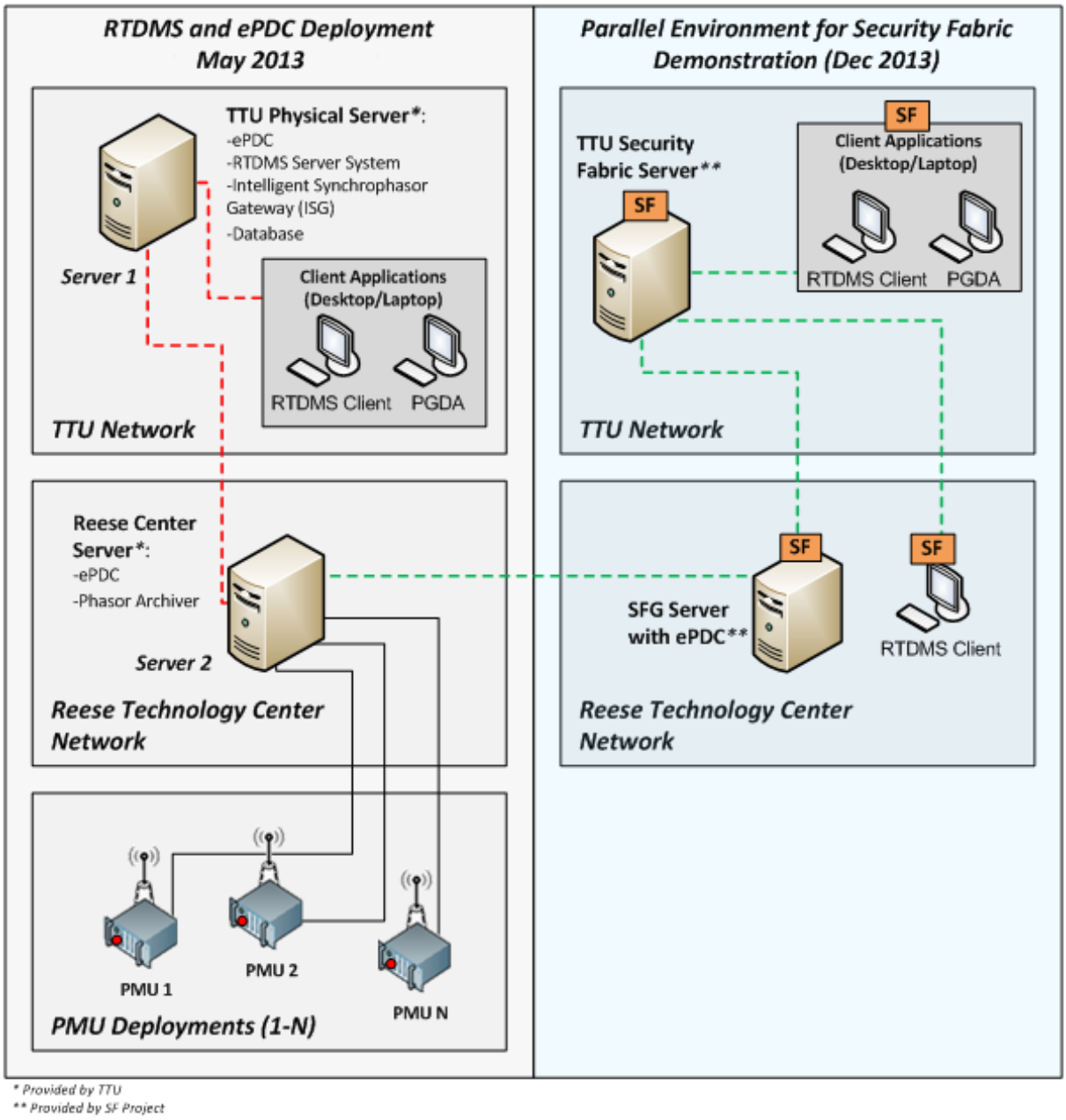


Figure 43. Basic Synchrophasor Network and the Security Fabric-enabled Network at TTU

While intentional cyber-attack testing initiated by TTU collaborators was planned, the Security Fabric has already proven its voracity by monitoring, defending against, and logging numerous attempts to gain access to various components in the overall system from the external Internet. The initial results and analysis of the Security Fabric monitoring of these intrusion attempts is included in Attachment 15.

As part of the third phase, the security testing performed at TTU consisted of two parts, both of which were black-box testing.

- The first part was ***verification of security fabric requirement specifications***. The study of security requirements, acquisition of appropriate requirements and development of security specifications are critical to thorough testing results. This effort involved testing to determine whether the Security Fabric-enabled network at TTU satisfied the security requirement specifications provided by Intel/McAfee. The specifications were based on the "Guidelines for Smart Grid Cyber Security" NISTIR 7628 requirements (http://www.nist.gov/smartgrid/upload/nistir-7628_total.pdf). The verification of the specifications iterated through evolving changes of the requirement specifications.
- The second part was ***penetration testing*** on both the synchrophasor network without Security Fabric and the Security Fabric-enabled Network at TTU***.*** This involved coding scripts to identify security vulnerabilities and injecting attacks by exploiting selected vulnerabilities found. The details of specific types of tests performed for both parts along with the results are described in Section 4.5.1 and Attachment 16.

4.4.2 Data Collection and Benefits Analysis

To support the validation and analysis portions of the Security Fabric component, the following data was collected, retained, and analyzed:

- Synchrophasor data was retained in full resolution for the entire demonstration period from both the ePDC-RTDMS network and the SF-ePDC – SF-RTDMS networks. This data was used to monitor the overall performance of the TTU PMU network, including the communications network and the computer network infrastructure. Data from the two networks was compared to validate that the data flowing through the SF-enabled network was unaltered by the Security Fabric components.
- Grid events, such as loss of generation or load, severe voltage dips, or sustained oscillations that were detected by the TTU RTDMS wide-area monitoring and visualization system were also retained and analyzed.

Additionally, the full synchrophasor data was scanned for unusual signatures, such as low-level oscillations which are characteristic of electromechanical interactions between generation and load, as well as control-system driven oscillations. Because the TTU PMU network was monitoring a distribution network with both local thermal and wind generation, it was expected that interactions between different types of generation might be more visible in this network.

Performance metrics from both the phase one network and the SF-enabled network were compared both during normal operation and during cyber-attack testing to identify and calibrate the impact of the Security Fabric on the overall delivery of synchrophasor data between the SF-ePDC and the SF-RTDMS components.

4.5 Performance Results

This section covers the operation of smart grid technologies and systems, including the demonstration results; impact metrics and benefits analyses; and any stakeholder feedback received to date.

4.5.1 Operation of Smart Grid Technologies and Systems

The functional goal of the Security Fabric demonstration was to demonstrate delivery of a synchronized PMU data stream over a secure communications framework for the Internet Protocol (IP) interconnection between two locations: a Security Fabric-enabled ePDC at the RTC connected to the virtual ISO's ePDC (represented by an ePDC located at TTU). The functional goal of this demonstration for data visualization security was to enable an RTDMS client and RTDMS server with Security Fabric to provide secure data visualization for the TTU synchrophasor system.

The first phase of this demonstration was the establishment of a synchrophasor network at Reese Technology Center and TTU. For this first phase, the ePDCs at Reese and TTU were both in place and operational. The RTDMS is operational at TTU, along with an RTDMS Client, which provides the wide-area monitoring and visualization capabilities. Phasor Archivers (to store the synchrophasor data stream) are installed and operational. Four PMUs are currently delivering data to the Reese Technology Center. This represented the baseline system against which the performance of the Security Fabric-enabled system was compared when the additional Security Fabric-enabled components were installed at TTU.

The results of security testing performed at TTU are described in the next two subsections.

4.5.1.1 Summary of Security Fabric NISTIR Requirement Specifications Testing Results

A panel of experts from NIST, TTU, and Intel/McAfee convened to identify the relevant Security Fabric security specifications that cover 11 categories of the NISTIR 7628 security requirements. The Security Fabric-enabled network at TTU was tested against these specifications. The process of testing in this part involved three basic activities: (1) *requirement acquisition* (communicating and assisting in the interpretation of the testing requirements according to NIST standards), (2) *specification description* (providing feedback and clarification in defining proper security specifications), and (3) *specification verification* (verifying that the system satisfies the given security specifications). This process is time consuming due to the nature of evolving requirements and specifications development.

The table below shows the respective specifications by category and a general indication of whether or not that requirement was satisfied through testing for each of the 74 specifications. The table results indicate that 86.5% of these security specifications were satisfied. By being diligent, and testing beyond the specifications, the TTU Team determined that the remaining requirements could be satisfied by 1) clarifying the specification so that the test intent, objectives, steps, and results are adequately defined, and 2) incorporating additional existing Intel/McAfee tools or applications. The detailed specifications,

their corresponding verification results, and suggested revisions are provided in Appendix A of Attachment 16.

Table 14. Overview of Verification Result

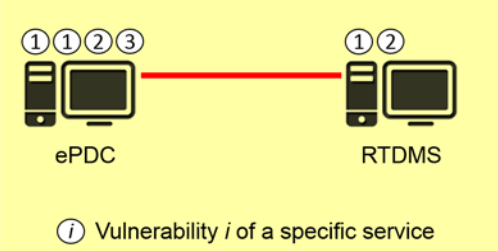
Spec. #	Requirement	Result
Category 1: Access Control (SG.AC)		
1	SG.AC-2 Remote Access Policy and Procedures	Satisfactory
2	SG.AC-3 Account Management	Need Clarification
3	SG.AC-4 Access Enforcement	Satisfactory
4	SG.AC-5 Information Flow Enforcement	Satisfactory
5	SG.AC-6 Separation of Duties	Need Clarification
6	SG.AC-7 Least Privilege	Need Clarification
7	SG.AC-8 Unsuccessful Login Attempts	Satisfactory
8	SG.AC-9 Smart Grid Information System Use Notification	Satisfactory
9	SG.AC-10 Previous Logon Notification	Need Clarification
10	SG.AC-12 Session Lock	Satisfactory
11	SG.AC-13 Remote Session Termination	Satisfactory
12	SG.AC-15 Remote Access	Satisfactory
13	SG.AC-18 Use of External Information Control Systems	Satisfactory
14	SG.AC-19 Control System Access Restrictions	Satisfactory
15	SG.AC-20 Password	Satisfactory
Category 2: Audit and Accountability (SG.AU)		
16	SG.AU-2 Auditable Events	Satisfactory
17	SG.AU-3 Content of Audit Records	Satisfactory
18	SG.AU-4 Audit Storage Capacity	Satisfactory
19	SG.AU-5 Response to Audit Processing Failure	Satisfactory
20	SG.AU-6 Audit Monitoring, Analysis, and Reporting	Satisfactory
21	SG.AU-7 Audit Reduction, and Report Generation	Satisfactory
22	SG.AU-8 Time Stamps	Satisfactory
23	SG.AU-9 Protection of Audit Information	Satisfactory
24	SG.AU-10 Audit Record Retention	Satisfactory
25	SG.AU-11 Conduct and Frequency of Audits	Satisfactory
26	SG.AU-14 Security Policy Compliance	Satisfactory
27	SG.AU-15 Audit Generation	Satisfactory
28	SG.AU-16 Non-Repudiation	Satisfactory
Category 3: Security Assessment and Authorization (SG.CA)		
29	SG.CA-4 Smart Grid Information System Connections	Satisfactory
30	SG.CA-6 Continuous Monitoring	Satisfactory
Category 4: Configuration and Management (SG.CM)		
31	SG.CM-6 Configuration Setting	Satisfactory
32	SG.CM-7 Configuration for Least Functionality	Satisfactory
33	SG.CM-8 Component Inventory	Satisfactory
Category 5: Continuity of Operation (SG.CP)		
34	SG.CP-10 Recovery and Reconstitution	Satisfactory

Spec. #	Requirement	Result
35	SG.CP-11 Fail-Safe Response	Satisfactory
Category 6: Identification and Authentication (SG.IA)		
36	SG.IA-3 Authenticator Management	Satisfactory
37	SG.IA-4 User Identification and Authentication	Satisfactory
38	SG.IA-5 Device Identification and Authentication	Satisfactory
39	SG.IA-6 Authenticator Feedback	Satisfactory
Category 7: Incident Response (SG.IR)		
40	SG.IR-6 Incident Monitoring	Satisfactory
Category 8: Development and Maintenance (SG.MA)		
41	SG.MA-2 Legacy Smart Grid Information System Upgrades	Satisfactory
42	SG.MA-6 Remote Maintenance	Satisfactory
Category 9: Risk Assessment (SG.RA)		
43	SG.RA-4 Risk Assessment	Satisfactory
44	SG.RA-6 Vulnerability Assessment and Awareness	Need Additional Tool
Category 10: Communication Protection (SG.SC)		
45	SG.SC-2 Communications Partitioning	Satisfactory
46	SG.SC-3 Security Function Isolation	Satisfactory
47	SG.SC-4 Information Remnants	Satisfactory
48	SG.SC-5 Denial-of-Service Protection	Satisfactory
49	SG.SC-6 Resource Priority	Satisfactory
50	SG.SC-7 Boundary Protection	Satisfactory
51	SG.SC-8 Communication Integrity	Satisfactory
52	SG.SC-9 Communication Confidentiality	Satisfactory
53	SG.SC-10 Trusted Path	Satisfactory
54	SG.SC-11 Cryptographic Key Establishment and Management	Satisfactory
55	SG.SC-12 Use of Validated Cryptography	Satisfactory
56	SG.SC-15 Public Key Infrastructure Certificates	Satisfactory
57	SG.SC-18 System Connections	Satisfactory
58	SG.SC-19 Security Roles	Satisfactory
60	SG.SC-20 Message Authenticity	Satisfactory
61	SG.SC-21 Secure Name/Address Resolution Service	Not Applicable
62	SG.SC-22 Fail in Known State	Need Clarification
63	SG.SC-23 Thin Nodes	Need Clarification
64	SG.SC-24 Honeypots	Not Applicable
65	SG.SC-25 Operating System Independent Applications	Satisfactory
66	SG.SC-26 Confidentiality of Information at Rest	Satisfactory
67	SG.SC-27 Heterogeneity	Satisfactory
68	SG.SC-28 Virtualization Technique	Satisfactory
69	SG.SC-29 Application Partitioning	Satisfactory
70	SG.SC-30 Smart Grid Information Partitioning	Satisfactory
Category 11: Information Integrity (SG.SI)		
71	SG.SI-2 Flaw Remediation	Need Additional Tool

Spec. #	Requirement	Result
72	SG.SI-4 Monitoring Tools and Techniques	Satisfactory
73	SG.SI-6 Security Function Verification	Satisfactory
74	SG.SI-9 Error Handling	Satisfactory

4.5.1.2 Summary of Penetration Testing Results

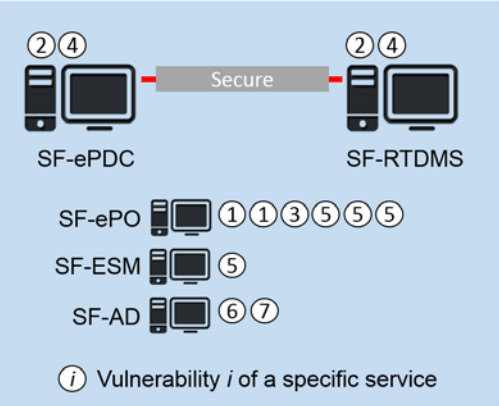
The figure below shows overview results of the penetration testing performed at TTU on the synchrophasor network *without Security Fabric.* The right of the figure summarizes different types of vulnerabilities found along with their corresponding possible attacks/effects. The first two vulnerabilities could result in man-in-middle attacks (hacker makes independent connections with, and relays data to, each end point of a process). On the other hand, the database open access vulnerability came from the violation of PCI DSS (https://www.pcisecuritystandards.org/security_standards) whose consequence of successful exploitation would allow an attacker to steal information from the database. As shown in the table, the vulnerabilities are categorized by their causes: *misconfiguration of protocol* and *misconfiguration of policy.* The diagram on the left of the figure shows where the vulnerabilities were found. Each circle represents a specific vulnerability found for each specific service. For example, the *SMB signing disabled* vulnerability was found in two of the ePDC services and in one of the RTDMS service components contributing to three vulnerabilities out of a total of six vulnerabilities in the TTU synchrophasor system.



Vulnerabilities	Possible Attacks/Effects
Misconfiguration of protocol	
(1) SMB signing disabled	Man-in-Middle
(2) RD Protocol supports weak cipher	Man-in-Middle
Misconfiguration of policy	
(3) Database Open access	Loss of Data

Figure 44. Vulnerabilities in the TTU Synchrophasor System Without SF

The next figure shows the vulnerabilities detected in the Security Fabric-enabled network**.**



Vulnerabilities	Possible Attacks/Effects
Misconfiguration of protocol	
(1) SMB signing disabled	Man-in-Middle
(2) RD protocol supports weak cipher	Man-in-Middle
(4) DoS in remote desktop	DoS
(5) X.509 mismatch	Eavesdropping
(6) TLS/SSL support weak cipher	Man-in-Middle
(7) TLS/SSL support SSLv2	Man-in-Middle
Misconfiguration of policy	
(3) Database open access	Loss of Data

Figure 45. Vulnerabilities in the TTU Security Fabric-enabled Network

Using the same notation as in the previous figure, the diagram on the left above indicates the location of the vulnerability. For example, testing revealed six vulnerabilities within the SF-ePO: three of type (5), X.509 mismatch; two of type (1), SMB signing disabled; and one of type (3), Database open access. The table on the right shows that the SF-enabled system had four types of vulnerabilities (4-7) that were not found in the non-SF-enabled network. The DoS in remote desktop is the most critical one as it could lead to a Denial of Service (DoS) attack so it required immediate attention but was easily mitigated by updating the version of remote desktop. The rest of the vulnerabilities are considered severe, but they are often harder to exploit and may not provide the same access to the affected systems. It should be noted that all of the identified vulnerabilities were mitigated by Intel/McAfee.

As explained previously, the diagram indicates that the total number of vulnerabilities of the Security Fabric-enabled network is 13 which is more than the six found in the non-SF environment. This higher count is because the SF-enabled system includes additional components (e.g., SF-ePO, SF-ESM, and SF-AD) that are also vulnerable. However, a number of points here are important to note:

- All but one of the vulnerabilities identified were caused by misconfiguration or older, less secure versions of software, so these were easily fixed.
- The connection between the two endpoints, ePDC and RTDMS, in the SF-enabled version actually had less vulnerability than the non-SF-enabled version, so it is providing a higher level of protection which was the objective.
- All of the identified vulnerabilities have been mitigated, and Intel/McAfee has updated its support guides to ensure that these potential vulnerabilities are identified and mitigated during installation of the SF.

The details for each of the vulnerabilities, and the scripts used to identify the vulnerabilities during penetration testing are presented in Appendix B of Attachment 16.

4.5.2 Metrics and Benefits Analysis

The Security Fabric was designed to address all seven of the NISTIR 7628 security guidelines. The approach integrated the best of breed commercial technologies to operate in parallel with the synchrophasor applications. The approach was designed to be compatible with standard IT processes, and was designed for interoperability. The approach leveraged the silicon capability of server hardware in secure identification/authentication, together with partitioned servers and virtual machines running the application software. While the Security Fabric has some "knowledge" about the application it is protecting (such as which devices the application is expected to communicate with), the application does not need to be modified in order to be protected by the Security Fabric. In achieving this design goal, the Security Fabric is extensible to cover other critical operating functions that demand cyber security protection. The specific metrics to be captured and reported are unique to this project, and were defined during laboratory testing and device integration.

4.5.2.1 Operational Benefits

The benefit of the Security Fabric approach is to provide data transport security for an IP connection between two locations without the need to make special modifications to the applications that will be communicating across the connection, and without materially affecting the performance between the applications. Success in this demonstration enhances the deployment and use of synchrophasor applications inside the operating control rooms of independent system operators by eliminating concerns about the security of the data being delivered from the TDSPs.

4.5.2.2 Build Metrics and Benefits

Associated hardware and software costs for this project component were born by Intel/McAfee and were not contributed as cost share in order to avoid any continuing ownership or licensing obligations.

4.5.2.3 Impact Metrics and Benefits

The application of the Security Fabric framework does not result in any energy savings or environmental pollution reductions so no impact metrics are defined.

4.5.3 Stakeholder Feedback

During the development, installation, and testing of the Security Fabric products, there was no direct stakeholder involvement or feedback. Since that time, ERCOT and a number of TDSPs have expressed in interest in the testing results, and in learning more about how this technology can be applied to other systems requiring significant cyber security protection schemes.

4.6 Conclusions

This section covers projections of demonstration and commercial scale system performance as well as lessons learned and best practices.

4.6.1 Projections of Demonstration and Commercial Scale System Performance

As noted above, the benefit of the Security Fabric approach is to provide data transport security for an IP connection between two locations without the need to make special modifications to the applications that will be communicating across the connection, and without materially affecting the performance of the applications. In this project, the synchrophasor data flow between a simulated TDSP PDC and an ERCOT PDC was secured by the Security Fabric. A natural extension of this approach will be to encapsulate the synchrophasor data flow across the TDSP network between the PMU at the substation and the PDC. Extension of the Security Fabric approach to other critical infrastructure applications is also anticipated.

4.6.2 Lessons Learned and Best Practices

Almost immediately upon connecting the Security Fabric 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 protected devices. In general, the attacks observed consisted of generic secure shell 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 someone tried to access one of the protected services, but again, the systems were successful in denying those attempts.

During security fabric testing performed at TTU, the Team first performed an initial exploration of every accessible node in the overall network. During this testing, the Team discovered a vulnerability in an SEL-734 PMU that allowed one to bypass authentication in the PMU's software controller. This type of vulnerability could lead to denial of service, and loss of data confidentiality and integrity. Such a vulnerability is new and not publically documented before. The vulnerability is due to the implementation flaws of the software controller of specific-domain hardware. Even a powerful scanner was not able to detect this vulnerability, so it needs to be addressed when these types of PMUs are deployed in external environments that may not be secure.

With respect to best practices, upon discovery of potentially nefarious network activity, all passwords in all systems should be reviewed for their strength, and where necessary, the password strength increased. Also, a password rotation policy should be standard procedure to regularly change passwords. Furthermore, in some instances, such as the synchrophasor network, the practice of allowing only whitelisted IP addresses to access the system can reduce the vulnerability to successful intrusion.

5. RESIDENTIAL CIRCUIT MONITORING

5.1 Introduction

Residential rooftop solar PV distributed generation is logically a good complement to wind resources on the grid since the solar contribution comes during the day while the bulk of the wind contribution (west Texas wind) is concentrated in the late evening and night-time hours. Concentrations of rooftop solar PV generation, however, bring their own challenges to the grid operator, and these are likely to be present during the shoulder months (March – June, and October – November) when the system demand is low, the sun is shining brightly, and west Texas wind is most abundant. A somewhat similar challenge occurs for high wind contributions during these same months. Taken together, solar plus wind concentrations during the shoulder months may present a number of challenges both to the distribution utilities and the grid operator. This circuit monitoring component of the CCET project was intended to investigate and inform the stakeholders in the ERCOT market about the key challenges of concentrated rooftop solar PV distributed generation on the distribution system, and identify areas where research is needed to more fully understand and deal with these challenges.

One of the challenge areas resulting from increasing market penetration of residential rooftop solar PV distributed generation is variations in electrical output and performance parameters on residential distribution circuits and behind the meter, such as excursions in net load on the utility, power factor, voltage, and harmonic distortion effects. As reported herein, these issues arise from multiple interacting and dynamic factors, including variable distributed solar generation cancelling utility kW load, increasing harmonic current drawn by modern home appliances, and others.

This project component included residential circuit monitoring at two levels: 1) on 35 kV underground residential distribution (URD) circuits in Houston, Texas, and 2) at the residential customer point of connection in Austin, Texas. CenterPoint Energy provided data collection and analysis for the 35kV monitoring effort in Houston, while Pecan Street Inc. provided data collection and analysis for the residential service monitoring effort in Austin. The following subsections provide detailed discussions of conditions at both locations.

5.1.1 Power Quality on 35 kV Underground Residential Circuits

CenterPoint Energy led an effort to examine correlations between distributed solar PV generation and distributed circuit power quality impacts by measuring and comparing electrical parameters on a total of six 35 kV circuits in two neighborhoods in an area north of Houston, Texas, one with a moderate penetration of solar PV and the other with virtually no solar.

The Harmony neighborhood (formerly Discovery at Spring Trails) has a high concentration of new homes (built in 2008 and after) with very efficient building features, energy efficient appliances, small (average

1.1 kW) rooftop or trestle-mounted solar PV systems, and HEM systems for monitoring electric and water use. The second neighborhood, Legends Ranch, includes similar type homes, but they are built without enhanced energy efficiency features and are not equipped with rooftop solar PV, energy efficient appliances or HEM systems, i.e. more typical of newer Texas neighborhoods.

5.1.2 Power Quality at the Residential Service Point of Connection

A total of seven homes in the Mueller neighborhood in Austin, Texas, were monitored for power quality parameters, solar PV production and net load served by the utility. The Mueller area is a relatively new, "green built" neighborhood with efficient home construction, energy efficient appliances, a high concentration of installed grid-tied solar PV and plug-in electric vehicles.

In the Mueller neighborhood, approximately 210 out of the 650 homes on the dedicated distribution circuit have solar PV, so the neighborhood has approximately 30% solar market penetration. The average installed system nameplate DC capacity is 5.24 kW for each home having solar PV.

The homes monitored for this study were selected because they share two 50 kilovolt-amperes (kVA) distribution transformers, and because they are participating in Pecan Street research trials, whereby the residents have agreed to allow their energy usage to be monitored. The two transformers for the selected homes were monitored allowing the data to be compared with measurements on individual homes. The transformers were loaded as follows:

- Transformer 7007 has 10 connected houses, 3 with solar (30%); 18,800 total square feet
- Transformer 7006 has 8 Houses, 5 with solar (63%); 14,200 total square feet

5.2 Anticipated Benefits

Ultimately, the expected benefits of the CCET demonstration project would derive from a more reliable electric grid that could facilitate effective management of and responses to increased wind and solar resources in Texas and from supporting the deployment of new products, technologies, and infrastructure to help customers make informed decisions about their energy usage. Customers would be empowered to effectively and reliably manage their peak demand, therefore resulting in reduced customer electricity costs, reduced system-wide capacity needs, reduced electrical losses, and reduced environmental impacts. Specific smart grid benefits that are potentially supported by the residential circuit monitoring component center around informing utilities about potential PV impacts to power quality and reliability. The following two sub-sections provide more detail on these potential benefits.

5.2.1 Power Quality on 35 kV URD Circuits

Other research has been being undertaken by organizations like Electric Power Research Institute (EPRI), the California electric utilities, the Smart Inverter Working Group, equipment manufacturers and others in the U.S. and abroad to measure and mitigate power quality impacts coincident with residential solar

PV installations, ramp rates from varying solar production, response of solar inverters to system transients, and other issues. This CCET effort was focused on collecting electrical data, performing graphical analyses and making observations about how power quality varies with daily and seasonal swings in load and PV production in targeted installations in Houston. This effort did not extend to defining or testing solutions.

Specifically, this effort focused on analysis to compare and correlate solar PV generation to circuit parameters by measuring and calculating total harmonic current and voltage distortion (THDi and THDv, respectively), power factor (PF) and voltage at the distribution level as 5 minute averages in two neighborhoods, one with a small to moderate installed capacity of solar PV and one without solar PV generation. The observations noted from this effort, combined with findings in the other "Residential Service Point of Connection" element of this investigation (below), will help utilities anticipate the occurrence and assess the significance of potential power quality impacts in communities with a range of concentrations of solar PV and in making design and/or operational adjustments to mitigate such impacts.

5.2.2 Power Quality at the Residential Service Point of Connection

In general, this investigation provided an opportunity to develop a more complete understanding of the interaction of solar PV with the distribution infrastructure. The root cause of any observed issues should be traceable to events occurring within the residential load, residential solar PV operation, or the utility distribution service. Information gained on the secondary side of the service transformer can be compared with measurements at the distribution circuit level (even a different circuit) if the load type and distribution between the two circuits are similar.

Previous studies (Grady, *et al.*, 1993) have shown residential power factor to be .9 to .95 lagging, and typically of low distortion.[7] The addition of solar PV and the proliferation of switch mode power supplies are changing these characteristics.

The benefit to the utilities is an updated and more accurate characterization of the residential electrical load at the point of connection.

5.3 Interactions with Key Stakeholders

The primary stakeholders in the 35kV URD circuit monitoring study were the electric utilities who have an obligation to deliver electricity with power quality meeting industry standards. Analysis observations and conclusions have been discussed among the electric utilities on the project team.

[7] Grady, W. Mack and Robert J. Gilleskie, Harmonics and How They Relate to Power Factor, EPRI Power Quality Issues & Opportunities Conference (PQA'93), San Diego, CA, November 1993.

Stakeholders interested in the monitoring at the service point of connection included utilities, manufacturers of distribution equipment and consumer appliances, and the residential customers themselves. The utilities on the team have analyzed and discussed the data and findings. Customer participants in this study have been provided feedback on the findings. Consumer electronics companies on Pecan Street research teams, including LG Electronics, Schneider Electric, and others, will be made aware of the impact of their devices on the grid, as observed in this investigation. Analyses and observations also will be shared with distribution equipment manufacturers.

5.4 Technical Approach

This section provides a detailed description of the Project Plan and the Data Collection and Benefits Analysis.

5.4.1 Project Plan

The goal of the monitoring and analysis in Houston and in Austin was to identify, and quantify to the extent possible, the effects of solar PV distributed generation on power quality in neighborhoods with a significant concentration of installed distributed solar PV. Implementation steps included:

- Identification of the presence and potential drivers of power quality impacts.
- Identification of data needed for analysis.
- Identification, procurement, and installation of data monitoring and collection equipment.
- Development of a system to collect and store data.
- Performance of data analysis.
- Establishment and characterization of instructive correlations among power quality, loads, and solar production.
- Differentiation of effects in neighborhoods with and without significant distributed solar PV installed capacity.
- Suggestion of areas for further study to address technical challenges and maintain quality of service.

5.4.2 Data Collection and Benefits Analysis

Details are provided below for the 35 kV URD circuit monitoring and residential service connection monitoring and analysis efforts.

5.4.2.1 Power Quality Impacts from Solar PV on 35 kV URD Circuits

For this effort, CenterPoint monitored three 35 kV URD circuits in each of two neighborhoods. The following table provides some information on the circuits, including respective universal circuit monitor (UCM) identification numbers, home counts, average square footage, and the amount of installed solar PV for the Harmony and Legends Ranch neighborhoods:

Table 15. Basic Home Information for Both Neighborhoods

Legends Ranch	# Homes	Average Square Feet	Solar kW Installed[8]	Average Solar kW per Home[9]
UCM4	43	3,272		
UCM5	44	3,740		
UCM6	94	1,156		
Harmony				
UCM2	60	3,361	66	1.10
UCM3	26	4,418	30	1.15
UCM7	40	2,739	46	1.15
			142	1.13

As represented above, installed capacity was 142 kW in 126 homes, or slightly greater than an average of 1 kW per home, for the three monitored circuits in Harmony. The largest known single installation was reported to be 6 kW.

It should also be noted that there were initially some technical issues related to data communications, streaming, storage, and integrity with the original installed monitors, but all of these issues were resolved by the installation of new monitoring equipment in January 2014. From that point forward, the following parameters were captured by SATEC PM174 PQ Monitors.

- Power Factor
- Frequency
- Voltage
- Current
- THDv
- THDi
- Real Power
- Reactive Power
- Apparent Power

The data was collected as average values for each five-minute interval. The analysis also utilized the following weather data for the site: hourly temperature, relative humidity, and direct and horizontal solar irradiance (used as a proxy for solar PV generation which was not directly metered).

The analysis looked for correlations between THDi, THDv, voltage, solar PV output, and URD circuit load (kW). Power quality impacts at Legends Ranch (no solar) and Harmony were compared in magnitude

[8] Note: installed solar PV capacity in Legends Ranch is unknown, but is reported to be minimal or zero.
[9] Ibid.

and seasonality. Power quality performance was compared to findings from monitoring at the residential point of connection (below).

5.4.2.2 Power Quality Impacts from Solar PV at the Residential Service Point of Connection

The basic steps applied for the service point of connection monitoring were identical to the 35 kV URD circuit monitoring approach—identify data needed, install data collection equipment and analyze the data.

Seven homes were selected for monitoring in Austin. These homes were served by two different transformers, and one of the transformer clusters had high solar PV penetration. One home in the Houston Harmony neighborhood was also monitored to explore similarities and differences between the 35 kV URD circuit data and the customer service line data and to examine whether the solar inverter was contributing to high THDi.

The Team connected a Power Standards Lab PQube power quality and energy monitor/analyzer at the meter and installed E-Gauge sub-meter data collectors at the main power panel to collect and calculate the following:

PQube at Customer meter:

- Volts (leg-neutral, 12-cycle average)
- Volts (leg-leg, 12-cycle average)
- Amps (12-cycle average)
- Ambient temperature and relative humidity (%)
- Frequency
- Harmonic voltage distortion (% THD_v)
- Harmonic current distortion (% THD_i)
- Flicker
- kW
- kilo-volt amperes (kVA)
- kVA reactive (kVAR)
- Total power factor

E-Gauge sub-metering:

- Net usage
- Actual usage
- PV generation
- Heating, ventilation, and air conditioning (HVAC) condensing unit
- HVAC air handler
- Electric vehicle charging

- Clothes washer and dryer
- Dishwasher
- Disposal
- Kitchen appliances 1
- Kitchen appliances 2
- Oven 1
- Oven 2
- Refrigerator 1
- Refrigerator 2
- Microwave
- Lights 1
- Lights 2
- Sub-panel

Via cooperation with Austin Energy, data was collected on the two service transformers:

- Voltage
- kVAR-hrs
- Phase angle
- Ambient temperature
- Transformer enclosure temperature
- Hotspot temperature
- Current
- THDi
- THDv
- % Load
- Power factor

Graphical analysis was most useful in finding and reporting correlations between fundamental current, distortion current from home appliances, THDi, net utility load (net solar production) and power factor.

5.5 Performance Results

5.5.1 Operation of Smart Grid Technologies and Systems

From this point forward in this document, reporting of results combine the Houston 35 kV URD circuit monitoring and the Austin residential point of connection monitoring efforts, as they work in tandem to explain the observations.

The five minute interval data for the 35 kV URD circuit was graphed and then statistically analyzed to quantify the degree of correlation between concurrent values of solar production and several other parameters (power factor, voltage, THDi and THDv).

THDi = distortion current (amps) / fundamental current (+ or -)

In the equation above, two things can increase THDi: 1) increasing distortion current (such as by adding advanced home electronics with switch-mode power supplies, compact florescent lamps, low quality solar PV inverters, high efficiency HVAC equipment with variable speed fans and compressors, etc.), and 2) reduced fundamental current drawn from the utility, such as when solar kW production cancels most (or all) of the demand for utility-supplied fundamental current. When the denominator of the THDi equation approaches zero (for example, when solar production offsets the entire home load, which readily happens in cool weather), the THDi value approaches infinity.

Data was collected and analyzed from February 2014 through October 2014, which allowed examination of seasonal differences in circuit parameters for both Harmony and Legends Ranch. Additionally, monitoring of a Harmony house by Pecan Street at the service connection that was also on a circuit monitored by CenterPoint provided the opportunity to cross-reference observations between Houston and Austin, and to postulate drivers for circuit behavior, as presented below.

The following are the primary observations from these investigations:

1. In both Harmony and Legends Ranch, THDi varies throughout the day, operating within a seasonal range.

   In Harmony, cooler months such as February to March (graphed below) are characterized by light overall utility circuit loading due to seasonally reduced HVAC demand, concurrent with strong solar PV production that offsets most of the utility circuit load on cool sunny days, driving the THDi to higher values.

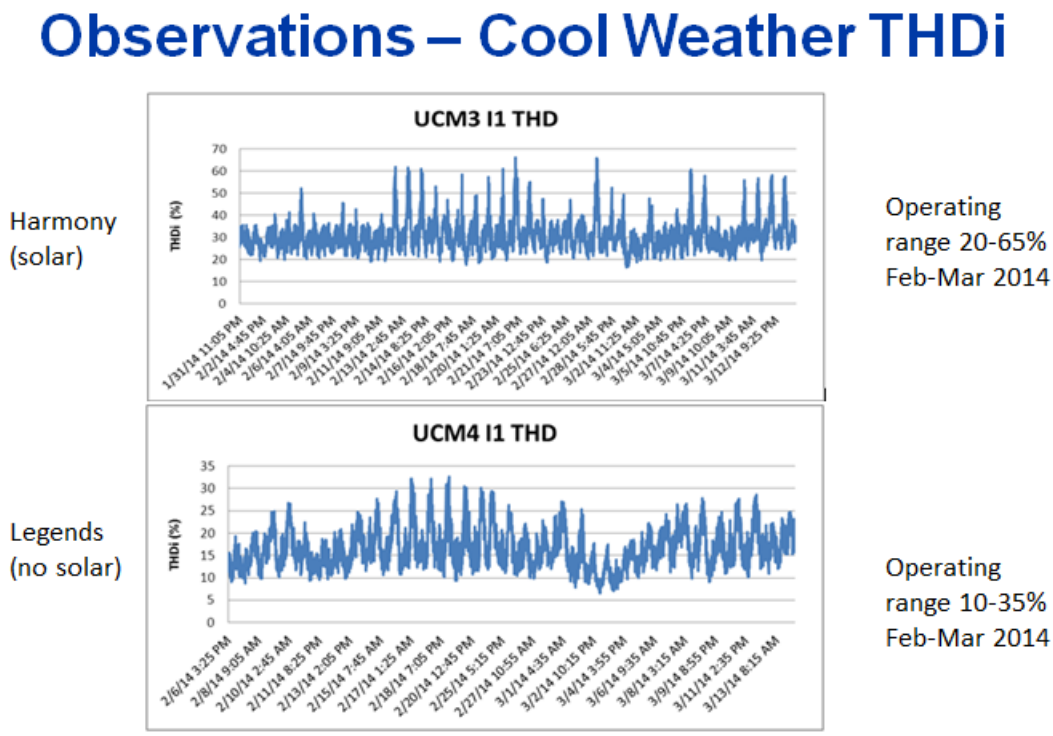


Figure 46. Observations for Cool Weather THDi

In contrast as shown below, hot weather during July to August, which calls for longer HVAC run times, causes the utility-supplied kW to far exceed the available solar production as shown below. This "washes out" the harmonic currents, keeping THDi lower than in cooler weather (shown above).

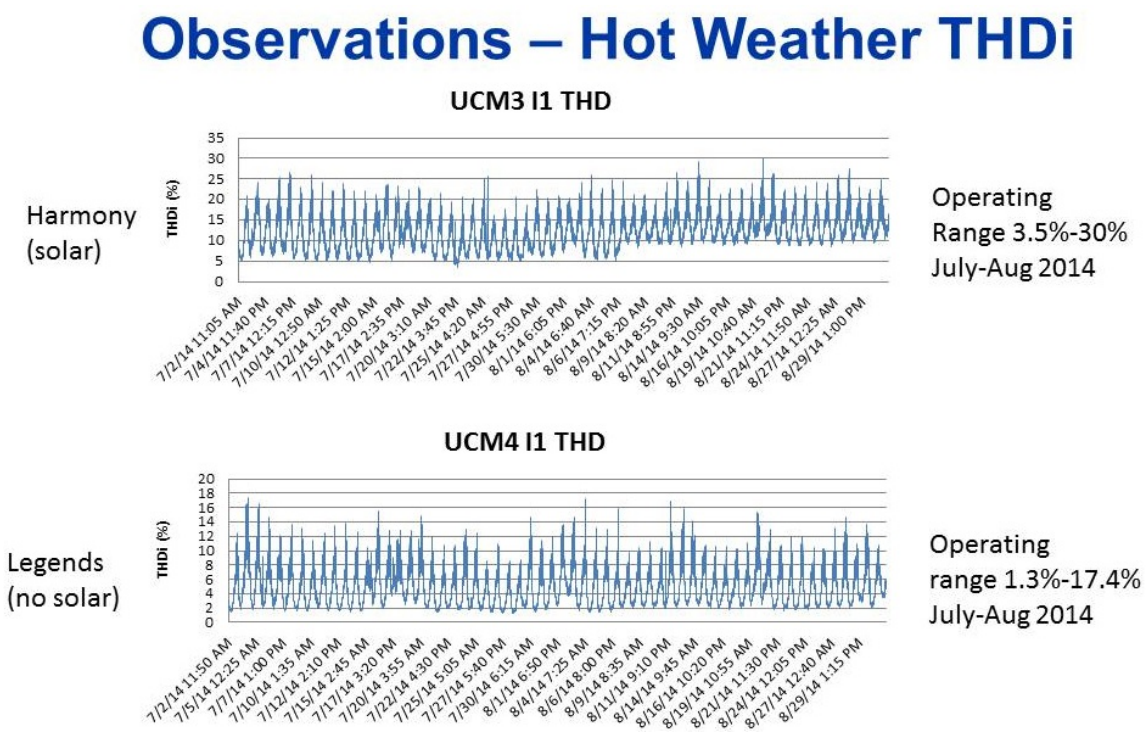


Figure 47. Observations for Hot Weather THDi

It is important to note that the daily cycles in THDi (above) are not the result of large magnitude variations in harmonic distortion current inside the home. The harmonic distortion current measured at the home consistently varies in a range of only 1 to 5 amps for each 120 volt (v) leg, as shown on the next graph from a home in Harmony which has a 1 kW PV system installed.

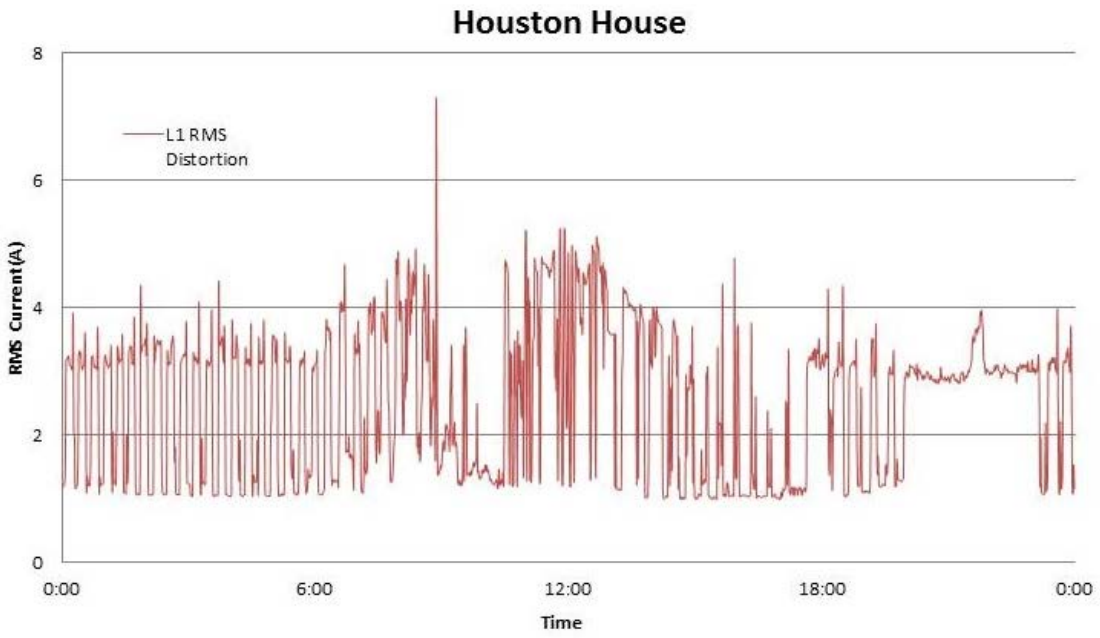


Figure 48. Harmonic Distortion Current Measured at a Houston Harmony Home

The cancellation of utility load (fundamental current) by solar production, as in the day-time hours on the next graph, can cause the THDi in a given home to spike to several hundred percent (blue line) and fluctuate based on HVAC cycling and cloud cover (rapidly varying solar output). The green line below is grid current delivered by the utility to serve the net load. Note that when the green line approaches zero, the blue line (THDi) spikes.

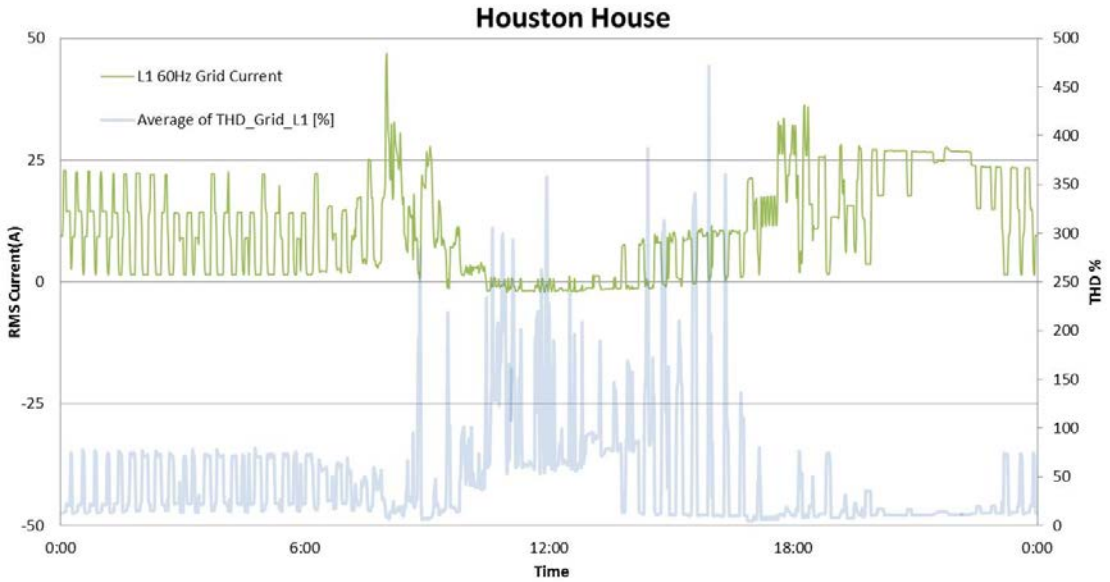


Figure 49. Relationship of THDi to Grid-Supplied Fundamental Current

Thus, elevated THDi is not a result of increased harmonic current—the numerator of the THDi equation—but rather a result of the denominator (fundamental current from the utility) approaching zero at net-zero load (when solar PV production balances home load). This is a dynamic balance that cycles throughout the course of a 24-hour period on a given home, depending on solar production (as affected by cloud cover) and home load (e.g. cycling HVAC and other appliance loads).

At the distribution circuit level, the next graph of UCM2 in Harmony illustrates the relative movement of THDi, solar production and net utility load throughout a sunny day in April, when solar production is able to cancel all but 20 kW of the entire utility load (60 homes).

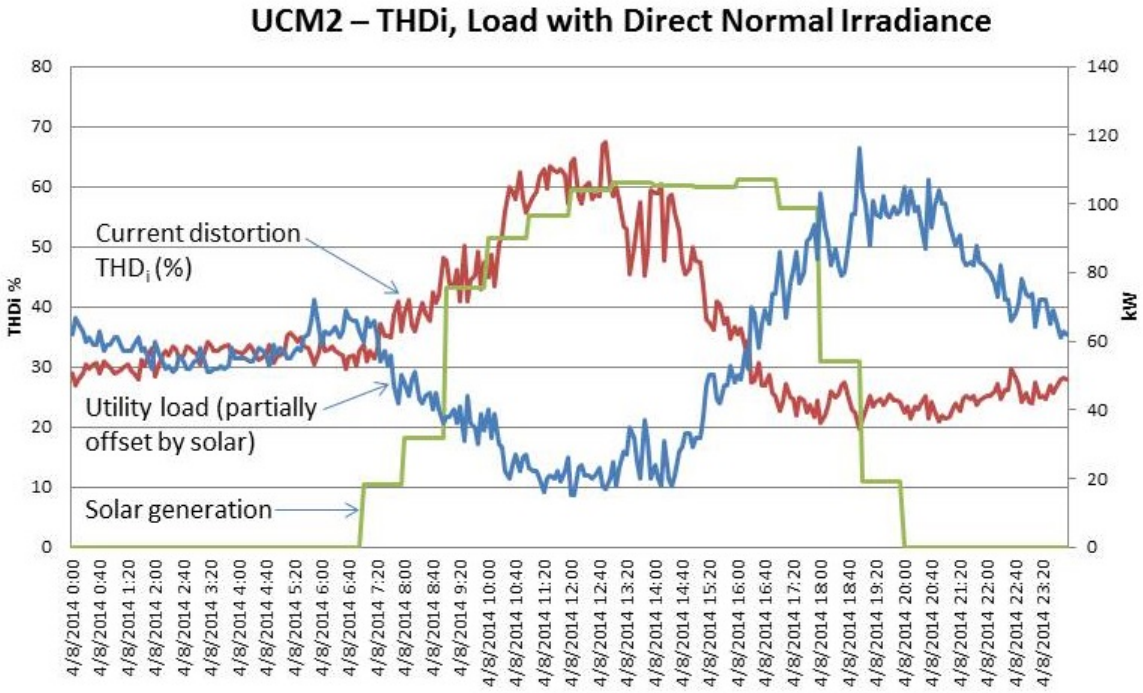


Figure 50. Movement of Harmony THDi, Solar Irradiance, and Utility Load on a Sunny April Day

In contrast, as shown below, with the absence of the solar PV influence, THDi on the Legends Ranch circuits varies throughout the day, and is lower in the daytime, when kW load on the circuit is higher than at night.

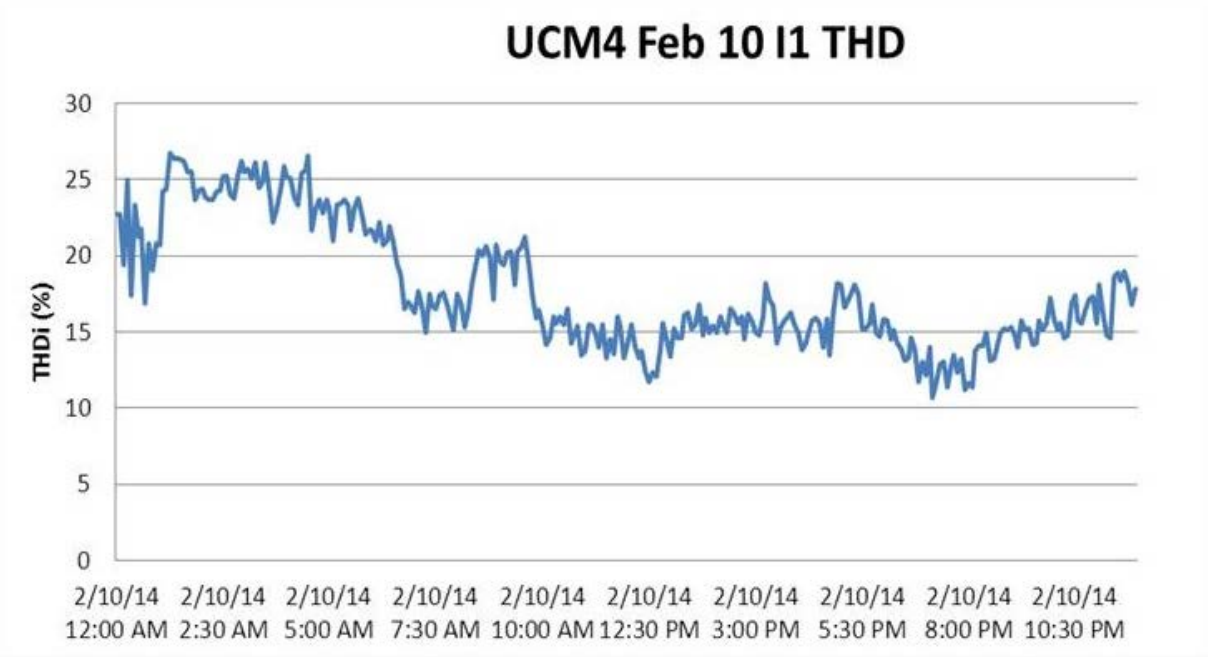


Figure 51. THDi Movement in Legends Ranch

Based on the results shown above, the Team drew the following conclusions:

1. THDi at distribution voltage:

   - Reflects a dynamic composite of all the varying loading conditions for each connected service transformer
   - Is unique per circuit
   - Varies throughout the day
   - Depends primarily on the weather (HVAC load, i.e. seasonal) and the amount of solar PV generation offsetting the utility load

   The solar inverter does not add significant distortion to the grid; rather the presence of solar production enables the steady distortion from other devices to appear higher relative to utility loads.

2. In communities with significant solar PV installed, there is an inverse and seasonal relationship between PF and solar production at distribution voltage.

   The resulting daily swings in PF are depicted in the Harmony UCM2 graph below. PF dips as solar PV offsets circuit load. This is an April day (not a very high HVAC load).

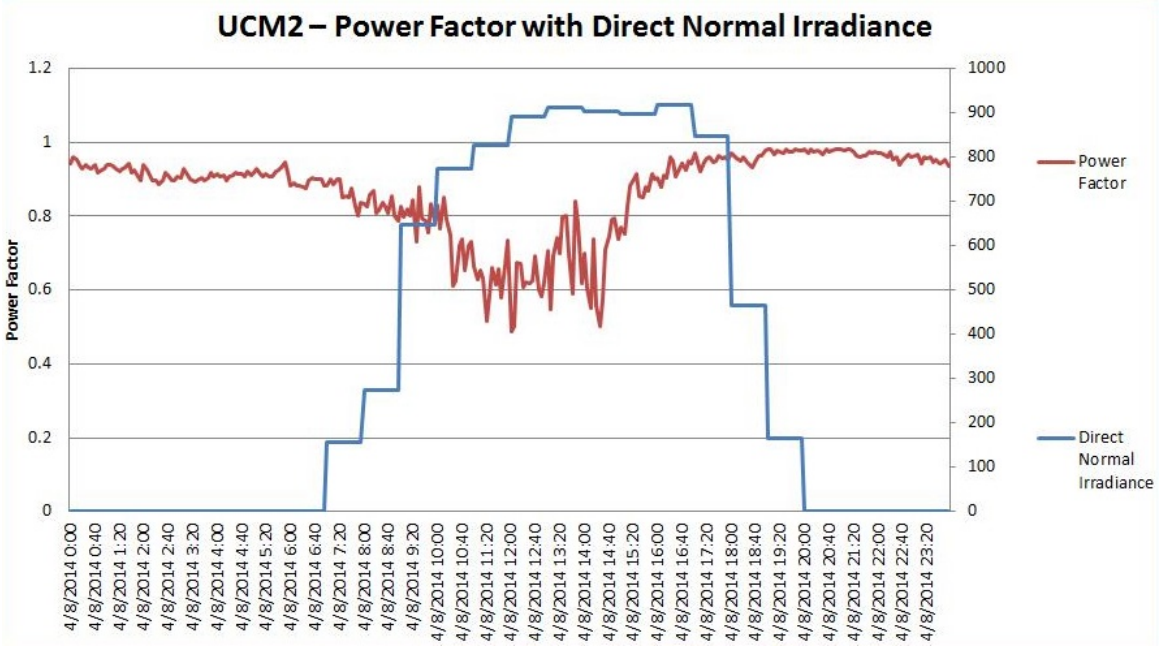


Figure 52. Daily Swings in PF During April 2014

Seasonal graphs of PF follow for Harmony and Legends Ranch, showing much milder daily PF swings in hotter weather, as with the seasonal swings of THDi in the previous graphs, due to the higher load on the circuit.

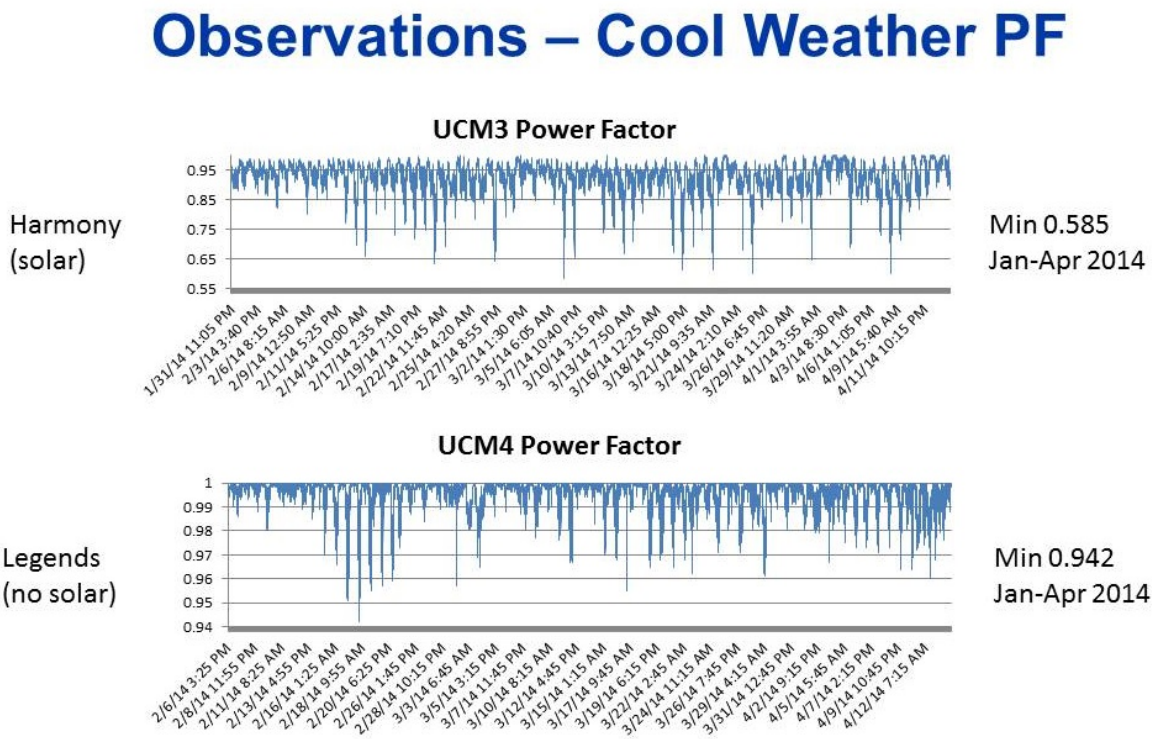


Figure 53. Cool Weather PF Observations

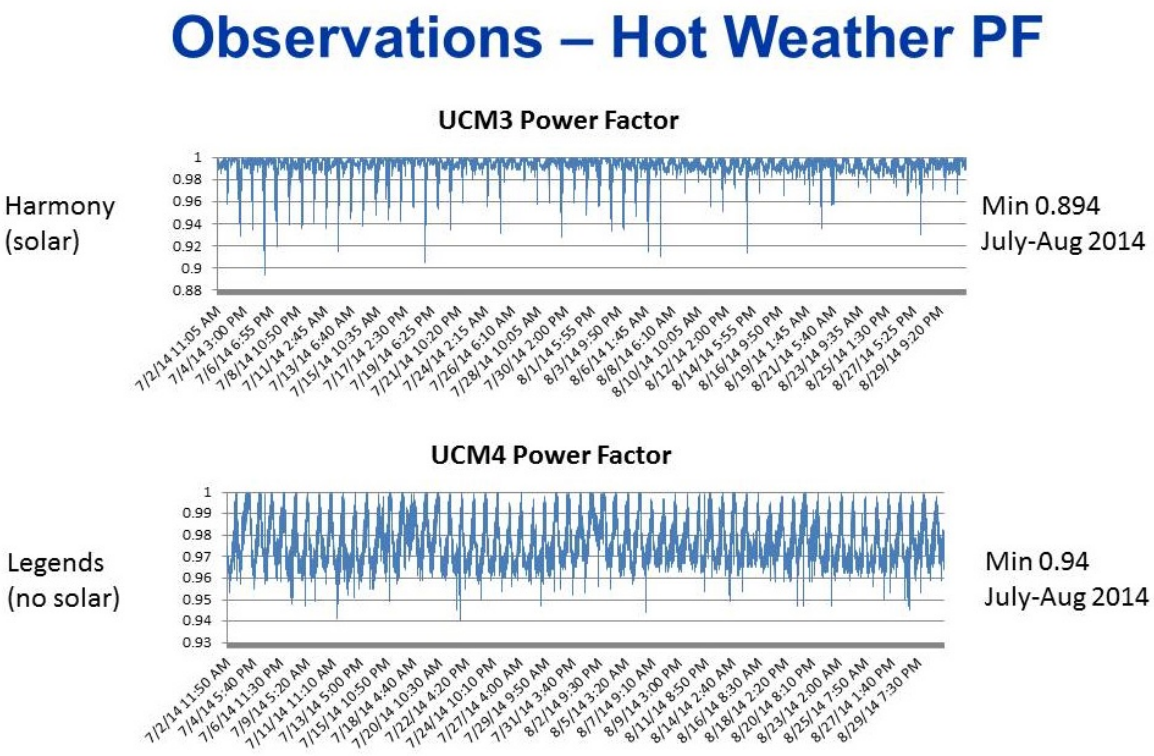


Figure 54. Hot Weather PF Observations

3. To determine whether the THDi and PF behavior observed on the 35 kV URD circuits in Houston was unique to that neighborhood, similar monitoring and analysis was performed on the homes in the Mueller neighborhood in Austin. The same type of THDi and PF behavior as reported for the home in Houston was observed in the Austin residential monitoring. For the Austin houses with larger solar arrays, longer periods of fundamental load cancelation were observed, though this will vary by day, weather, array size, and home electricity usage. This behavior will likely be seen at some point during the year by any house where solar PV production can offset an appreciable portion of the total home kW load.

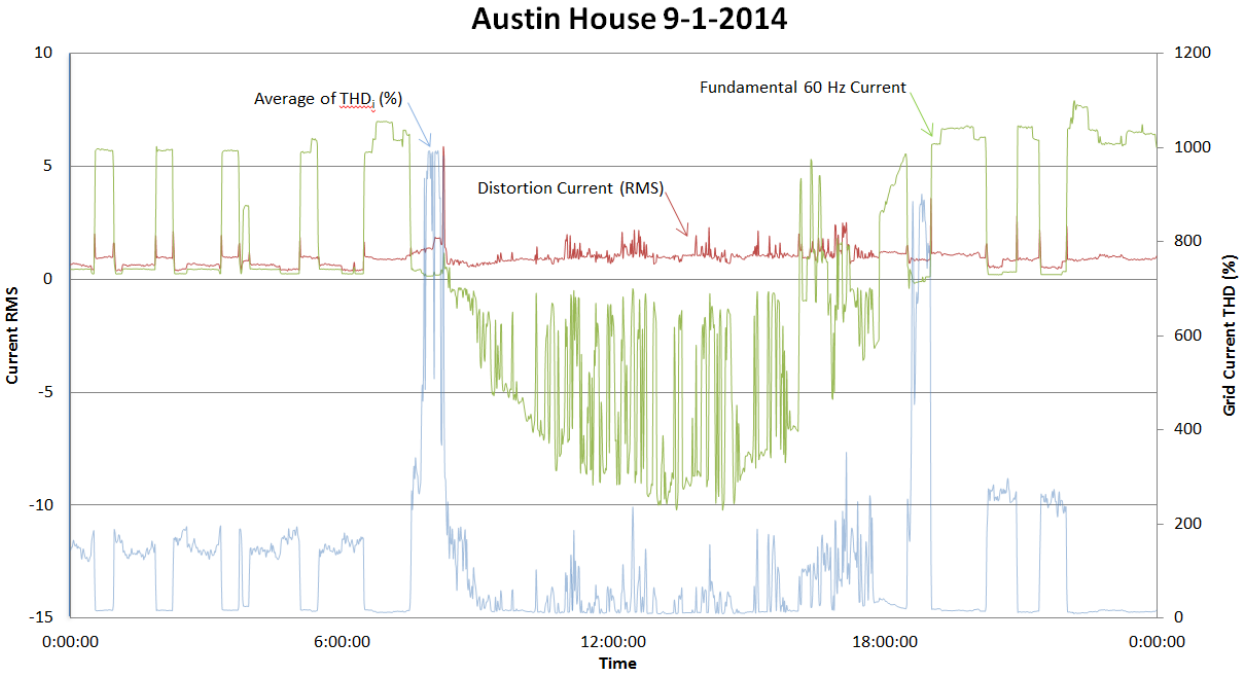


Figure 55. THDi Behavior for Home with Larger Solar PV System

In the figure above, the distortion current stays approximately the same during the entire day with variations that can be attributed to device usage, not solar production. During the daytime, solar capacity exceeds home load much of the time, driving the net utility load (green line) negative, with oscillations due to cloud cover and home appliance operation (generally HVAC). During periods when the net utility load is canceled and approaches zero for minutes to an hour at a time, the THDi spikes are very high, up to 1000%. Again, this is due to the very low amounts of fundamental current supplied by the grid, not the solar production adding distortion to the grid.

4. Referring to the graph below, PF at the service connection for a house with several kW of solar PV installed capacity varies from 1 to -1 during the day, changing rapidly based on load and solar production. Pecan Street analyzed PF at the individual residential service connection. As mentioned above in #2, the Harmony circuit showed a general drop in PF during solar production hours. With PF being defined as real power divided by total apparent power, during

periods of solar production the real power delivered to a given house from the utility can be negative (as in #3 above), with real power flow to the utility and away from the load.

In the next graph, an example day for a single home in the Mueller neighborhood shows a large number of negative/positive swings in utility load and PF, and periods of operation at very low PF.

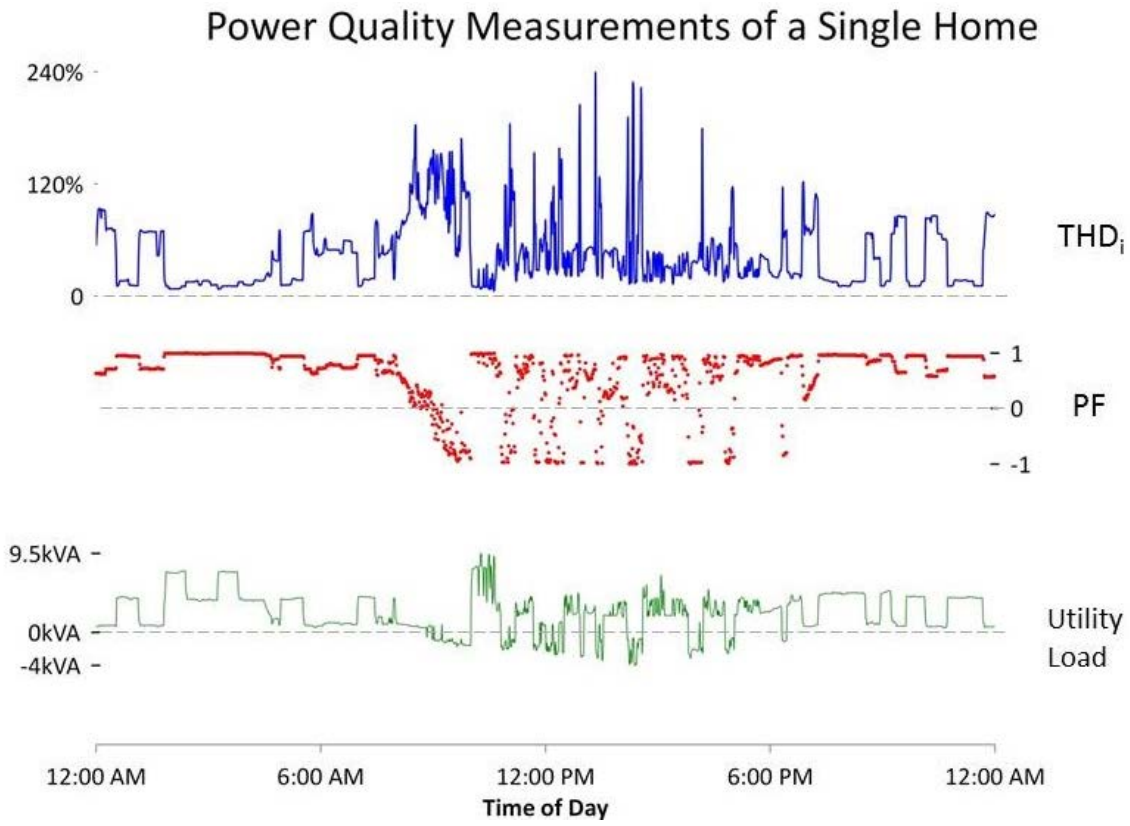


Figure 56. Power Quality Measurements for Single Home in Austin

It should be noted that this home also shows large swings of THDi as the total load hovers around 0 kVA. Note also that the power factor starts dropping as the solar generation comes online. In this case, the utility load is also significantly more dynamic than might normally be seen.

Referring to the figure above, notice that this home, which has an electric vehicle and solar PV, went from being a 2 kVA net generator at roughly 10 a.m. to a 9.5 kVA net load in less than one sample period (one minute), indicating a rate of change of over 11.5 kVA/minute. This is a substantial and rapid increase in power consumption not typically seen in traditional residential loads. However, in homes with large solar PV, HVAC, and PEV charging capacities/loads, such rapid changes will now be fairly frequent.

In addition, the power factor at this home remains at levels well below 0.9 total PF (which measures displacement and distortion based power factor) for long periods of time. The impact on the distribution circuit will be determined by the resolved combination of localized real and reactive power at each service transformer. The utility typically controls power factor on their distribution circuits by adding switched capacitor banks to cancel out the inductance of transmission line or motor loads.

There are existing guidelines for current harmonic distortion on the grid, typically expressed as Total Demand Distortion (TDD). TDD is the ratio of instantaneous distortion current to total available supply current, as compared to THDi, which is the ratio of distortion current to instantaneous fundamental current. Inductor/capacitor trap circuits are used to mitigate harmonics. The TDD of the house above, which is representative of all houses in the study, is not particularly high, less than 5%. However, IEEE-519, the standard for total distortion limits in distribution circuit design, assumes that the effective source impedance of the distribution grid is loaded with some amount of resistance effectively damping the possibility of oscillation and loss of power factor control. It is unknown to the authors the impact of removing the resistive load (through the generation of real power from solar production) on the stability of what is effectively an RLC (resistive-inductive-capacitive) circuit. The removal of the real resistance R by high levels of solar PV generation may induce a high Quality Factor LC resonant circuit, resulting in potential instability on individual loops or circuits.

The house above goes from being a net load on the utility to being a net generator at least 14 times in one day. Utility scale capacitor banks are switched according to utility operational practice, which is likely not fast enough to handle the change rates seen here.

In addition the capacitor banks can only cancel lagging VARs and cannot cancel leading VARs or VARs due to distortion currents. Switch mode power supplies can commonly draw over 100% THD in the current waveform, and therefore the utilities may increasingly find themselves in the situation where the power factor correction methods employed only correct lagging VARs while doing nothing for the periods of time when a residential load is leading or distorted. Separate measures must be taken to effectively cancel leading VARs or distortion VARs.

Smart inverters with reactive power support for both phase angle and distortion could be employed and would eliminate the issues, as would storage for voltage control, but right now there is little or no economic incentive for the residential customer to participate in these markets. Future research might identify the value of ancillary services provided by these technologies as well as potential methods to incentivize or compensate those who adopt and deploy them.

5. 35 kV URD circuit voltage was found to be weakly correlated to solar production in Houston. The Austin monitoring compared voltage at the service transformer to coincident voltage at a connected house (ID# 1185) with a sizable installed PV system. The next figure indicates that

when the PV is producing, the house service voltage at the customer's meter (red line) exceeds the transformer voltage (blue line), i.e. the PV is supporting the utility-supplied voltage, as expected. The opposite is true at night, when the PV is not producing.

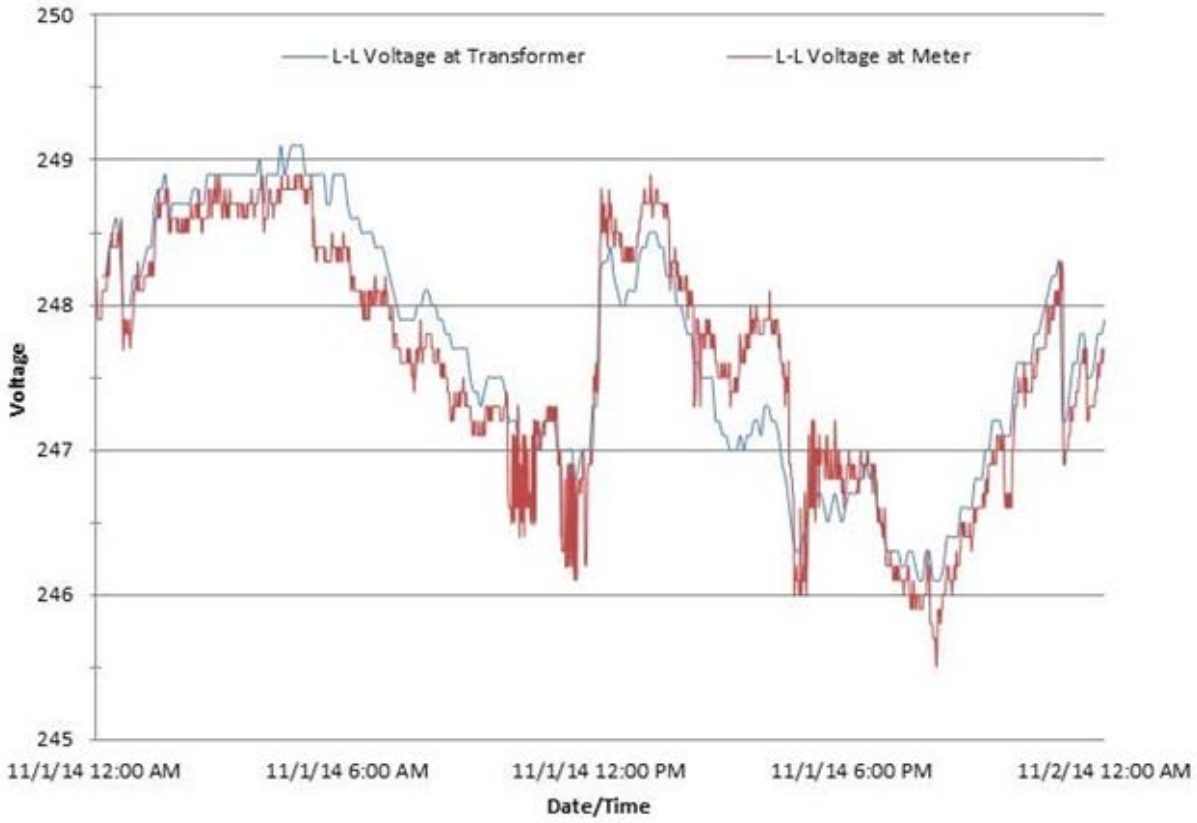


Figure 57. Comparative Voltage at Service Transformer and at House with Solar PV

In the figure above, note that the voltage and the rate of change in voltage (ramp rate) at the customer meter varies significantly throughout the morning, day, and evening. Examination of net load (house load minus solar production) and voltage (next graph) revealed that voltage was inversely related to net load, and the steeper voltage ramp rates corresponded to rapid changes in net load of several kW.

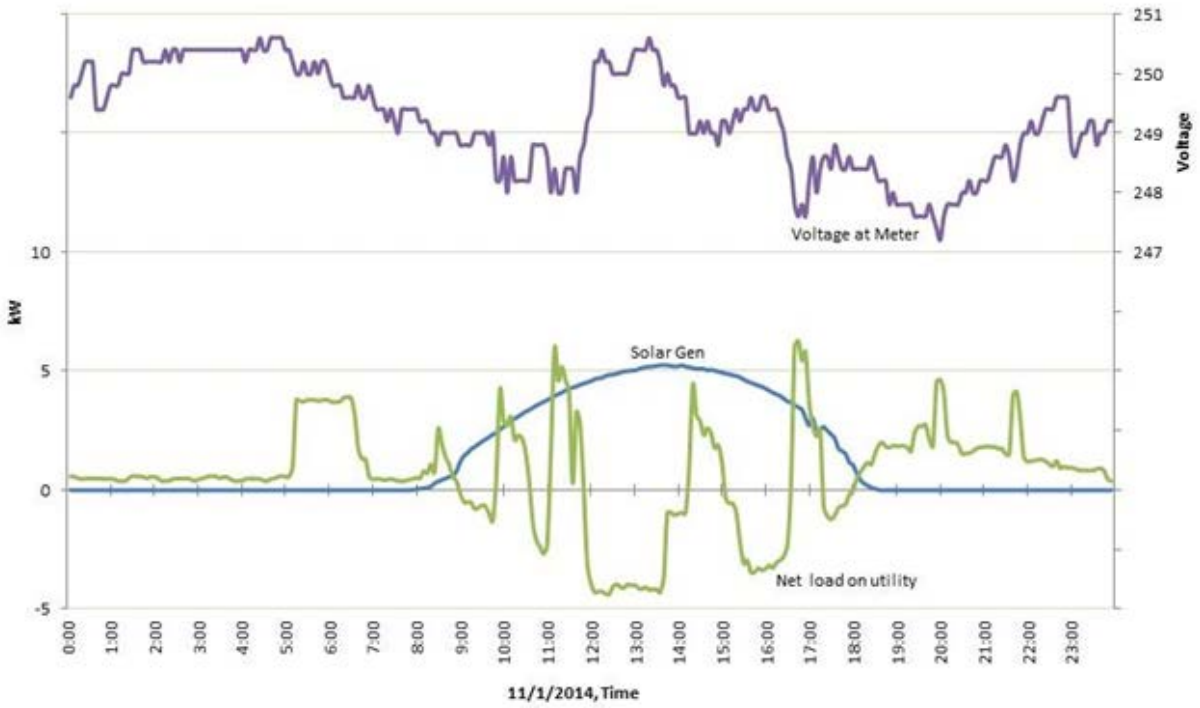


Figure 58. Voltage as Related to Net Load on Utility

The solar PV generation profile was very smooth this day, and thus it did not contribute to the rapid net load and voltage changes. On a day with intermittent cloud cover, varying solar generation would add additional voltage variability, as would concurrent large load changes on houses connected to the same service transformer. Other events or operations on the distribution side of the service transformer could also add to voltage variations. Further study is needed to determine the prevalence, magnitude, and potential consequences (to the customer and the utility) of limiting case localized voltage fluctuations and the need for local monitoring and mitigation.

5.5.2 Metrics and Benefits Analysis

5.5.2.1 Operational Benefits

1. This investigation presents observations, analysis and findings, and it poses questions and recommends further research.
2. A better understanding of drivers behind power quality on residential distribution circuits will greatly benefit utilities provide reliable and stable power to their residential customers via improved:
    a. Planning for reliability
    b. Monitoring and active mitigation if needed
    c. Interconnection specifications
    d. Distribution equipment specifications

3. From this investigation, a better understanding has been developed of power quality at the residential point of connection in the presence of PV production as relates to voltage, power factor, and THDi.
4. A better understanding has been gained of the overall magnitude of distortion current draw by modern in-home devices and appliances. Examples are compact florescent lamps, switch mode power supplies, variable speed HVAC fans and compressors, and other electronic appliances. Such devices are themselves susceptible to power quality upsets.
5. From this investigation, a better understanding has been gained of the behavior of circuit parameters during times when PV production approximately equals the total load of the home. At such times, the utility is only "supplying" distortion current and reactive power, potentially resulting in impacts on stability, voltage control and equipment lifetime. These impacts include at the local level:
    - Increased power dissipation in fixed resistance devices due to higher voltage levels,
    - The potential for inverters to shut down in a safety response to overvoltage situations,
    - Locally poor power factor due to high density solar installations, and
    - Increased voltage rate of change, both up and down, leading to local voltage instability.
6. At the grid distribution level, increased switching of tap-changing and power factor correction devices could lead to reduced equipment lifetimes, insufficient voltage and power factor control, the need for more extensive monitoring and potentially faster acting power factor and voltage control equipment.

5.5.2.2 Build Metrics and Benefits

Build metrics typically focus on equipment costs associated with and reported for a project. Although CenterPoint and Pecan Street invested significant resources for this effort, the only equipment costs included as cost share are related to the initial purchase of six UCMs, and that cost was $89,128.

5.5.2.3 Impact Metrics and Benefits

Impact metrics typically define reductions in energy use and in environmental emissions as a result of technology implementations. These are not deemed relevant to this project.

5.5.3 Stakeholder Feedback

The primary stakeholders in the 35kV URD circuit monitoring were the electric utilities who have an obligation to deliver electricity with power quality meeting industry standards. Analysis observations and conclusions have been discussed among the electric utilities on the project team, and they will discuss them as well with their suppliers of distribution equipment.

Stakeholders in the monitoring at the service point of connection included the utilities, manufacturers of consumer appliances, and the residential customers themselves. The utilities on the team have analyzed and discussed the data and findings. Consumer electronics companies will be made aware of

the impact of their devices on power quality, as observed in this investigation. Customer participants in this study will be provided feedback on the findings of this study, although no feedback is requested or expected from them.

5.6 Conclusions

5.6.1 Projections of Demonstration and Commercial Scale System Performance

1. The circuit monitoring and analysis performed in this study assists utility stakeholders and system planners in anticipating the degree of power quality impacts on residential distribution circuits as solar PV market penetration increases. This knowledge will help the utilities make adjustments to their system design, equipment specifications, and operations in order to more accurately and efficiently predict, detect and address such conditions in order to maintain reliable electric service within the parameters of industry standards.
2. As the installed price of solar PV continues to decline, there will be continued increases in market penetration and average PV system capacity. Many homes already have several kW of installed solar PV. Such homes produce their own real power (kW), which at times cancels the real power supplied from the utility. To the extent this condition exists in a given neighborhood, the customer at times would be drawing only distortion current and reactive power from the utility and may be back feeding real power to the utility, leading to high THDi and potentially a sagging power factor on distribution circuits.
3. It was shown that measured THDi can be significantly higher on distribution circuits that feed high concentrations of homes with solar PV as compared to those serving homes with little or no PV. It is not clear that increased THDi is an immediate threat to reliability, but a review is suggested of the underlying assumptions of IEEE-519 regarding the damping effects of resistive loading. When the resistive loading is canceled by solar production, the impact of harmonics on grid stability may become an issue of concern that is not addressed by IEEE-519.
4. The PF variability on distribution circuits with high solar PV penetration will likely require enhanced monitoring and upsized (and fast acting) PF correction to meet operating standards. One means of mitigation could be VAR injection at the solar PV inverter. This gives rise to the discussion of compensation to the PV owner (customer) for any added equipment cost and for kW production forfeited in producing the injected VAR.
5. The localized voltage boost associated with residential PV production is additive at the service transformer and will propagate to distribution voltage. The resulting boost on the distribution circuit should not be problematic if the magnitude and rate of voltage change can be handled by existing utility voltage control equipment.
6. All the houses on a common service transformer will experience voltage fluctuations throughout the day, caused by a number of factors which can act concurrently, including operation of larger home loads (e.g. HVAC and other large appliance loads), variability of solar production, changing loads at other premises served by the same service transformer, and other events or operations on the distribution side of the service transformer. Further study should be undertaken to determine the prevalence, magnitude, and potential consequences (to the customer and the

utility) of limiting case localized service voltage fluctuations and the need for local monitoring and mitigation.

7. This study confirmed with a high level of certainty that PV inverters conforming to industry standards do not add appreciably to voltage or current distortion.
8. Further investigation is suggested into the cost/benefit of stronger standards for harmonic distortion and power factor for residential devices to mitigate the increase in relative distortion (THD_i) in the presence of "zero net load" conditions occurring with solar PV generation. The current Energy Star standards for power factor on a CFL light bulb are only 0.5. Some homes in the subject Austin neighborhood have been found with 40-70 of these devices operating at any given time, yielding a total load of up to 1 kW at a PF of 0.6.
9. Expanded research is suggested on the need, feasibility, cost-benefit, and market implementation of distributed energy storage systems, placed either behind the meter or in the utility infrastructure. Such storage could allow for solar energy to be collected and stored for use throughout the day, minimizing power quality impacts by smoothing out rapid PV production ramps and if necessary mitigating zero net load instabilities.

5.6.2 Lessons Learned and Best Practices

The following outlines some lessons learned from this project:

- The 35 kV URD circuit monitors initially installed suffered from a lack of data storage capacity. Ensure that the monitoring equipment contains sufficient data storage, and provide a means for reliably transmitting that data.
- There were communication issues during the setup and testing phases (35 kV). Existing radio networks were easily interfered with from tall trees in the area so a decision was made to use fiber optic lines. First, there were issues with identifying the service providers since the project involved two different neighborhoods. Second, the fiber optic lines were continually being cut or dug up due to ongoing construction in the Harmony neighborhood. When the new URD circuit monitors were installed in January 2014, all communications were converted to a cellular network. So, it's important to carefully assess communications design requirements.
- The 35 kV URD circuit configuration of a neighborhood under construction changes over time, and therefore the URD circuits were redesigned as a new developer restarted the building of new homes in the Harmony neighborhood. This affected the ongoing reliability of the data being collected until the URD circuits were finalized, and the monitoring devices were relocated to better advantage.
- The project team worked with the developers and builders to get updated information on the homes as they were completed and connected to the 35 kV circuits. Certain information needed for analysis was obtainable from the developer and builders (square feet, information on installed HVAC). For studies such as this, it is important that these relationships be established early, and that the data capture efforts are established and standardized.
- Collecting energy usage, power quality, and solar generation information across multiple hardware systems highlights the need for local data storage capacity. The systems used at the

residential level used three different communications backhauls and there is difficulty in keeping them all online simultaneously over extended periods.

- Some manufacturers of power quality monitors have difficulty in calculating all parameters correctly in periods where the “load” becomes a generator such as with solar generation.

6. RESIDENTIAL TOU PRICING TRIAL

6.1 Introduction

The objective of this project was to determine the degree to which electric customers would alter their pattern of electricity consumption in response to electric prices that vary with the time of day, as well as measure their response to pricing that is triggered by predicted system critical peak conditions. To achieve these goals, this effort involved a 20-month experiment applying two distinct time-of-use (TOU) pricing programs. Running from March 2013 through October 2014, this experiment initially included 62 homes in a Pricing Group and another 62 homes in a Control Group.

Most of the participants in this study reside in a neighborhood known as the Mueller development which is situated about three miles from downtown Austin. The neighborhood is built on space vacated by relocation of the old municipal airport. Construction of single-family homes began in August 2007. The homes have energy efficient features, and the neighborhood has a high concentration of installed grid-tied solar photovoltaics and plug-in electric vehicles (PEVs). Electric and natural gas distribution is provided to the neighborhood. Basic demographic information and typical features of the homes are listed in the table below:

Table 16. Demographic Data of Participants in Pricing Group and Control Group

Demographic Information	Responses
Salary	• 43 survey respondents, or about 81%, claimed income above $75,000. • One respondent claimed income between $300,000 and $1 million, and two participants claimed income above $1 million.
Ethnicity	• 51 respondents, or 82%, reported Caucasian ethnicity. • Three respondents reported Hispanic ethnicity. • Three reported Asian/Pacific Islander ethnicity. • Five declined to respond.
Education	• All respondents, except for one left blank, reported a college degree or higher. • 42 respondents, or 71%, reported a postgraduate degree.
Home during weekdays	• 46% of the Pricing Group and 62% of the Control Group homes are typically occupied on weekdays (daytime hours).
PEV ownership	• 34 PEVs are owned by the Pricing Group, consisting of 25 plug-in hybrids and 9 full electric vehicles compared to only 6 PEVs for the Control Group. • **Note** - 34 PEVs in the Pricing Group compared to only 6 in the Control Group is a large difference, affecting load profile and comparative results, so this was considered during the analysis. • **Note** - 34 PEVs in 62 homes is a much greater penetration than seen in the national market, providing a glimpse of potential future load shaping via shifting of vehicle charging schedules.
Cooking appliances	• Predominantly natural gas.

Demographic Information	Responses
	• 27% have an electric oven.
Laundry appliances	• 1 in 3 has an electric dryer even though natural gas is available.
Heating systems	• 90% have a gas furnace.
Water heaters	• Natural gas
Average square footage	• Approximately 2,000 square feet for both groups.
% of homes with remotely programmable thermostats	• 100% of homes in both groups.

The pricing experiment consisted of two pricing programs which did not coincide or overlap at any time:

- A seasonal TOU pricing experiment featuring a discounted night-time price per kilowatt-hour to encourage use of available inland (west Texas) wind generation during the five windiest months of the year (March through May, November and December), and
- A critical peak pricing (CPP) experiment invoking an expensive price per kilowatt-hour (kWh) during designated peak hours on "critical peak" days during four summer months (June through September). Critical peak days were called a day ahead by the project Team based on forecasted next day weather conditions under the premise that extremely hot weather would stress the system, calling for voluntary load reductions.

The homes within the Pricing Group and the Control Group were outfitted with home energy monitoring (HEM) systems. These devices attached to the home's individual electrical circuits within the breaker panel(s) and collected whole home and circuit (appliance) level energy use data in one-minute intervals. This data was made available to the consumers through a web-based interface so they could review the respective circuit-level energy use. This energy use data was used by the project to perform comparative analysis between and within the Pricing and Control Groups to characterize and quantify the Pricing Group's response to the two experimental pricing programs.

Translation of the results of these experiments from this test group to the general population of Texas will require adjustments for many factors, including weather, demographics, home construction, residential distributed solar production, and market penetration of PEVs and home automation. The analysis described herein evaluates consumer behavior by "energy-savvy" residents with energy efficient homes, appliances, and remotely programmable thermostats. Therefore, it is intentionally more representative of a "future community" where such features are more common.

6.2 Anticipated Benefits

Broadly, the anticipated benefits of these pricing experiments were centered on gaining a better understanding of the effectiveness of pricing drivers to aid in management of and response to increased wind resources in Texas (TOU trial) and critical system peak events (CPP trial). Information gained in these experiments was expected to support the deployment of new products, technologies, and

infrastructure to help customers make informed decisions about their energy usage in response to pricing drivers. The approach being tested here encourages customers to effectively and reliably manage the timing of their energy consumption as well as their peak demand in order to reduce their electricity bill. System benefits of positive customer response will be an increased coincidence of system load and night time wind generation, with corresponding reduced environmental impacts by offsetting generation using fossil fuels, and reduced system-wide capacity needs.

The two pricing experiments attempt to quantify the behavioral response of residential customers to pricing drivers. The seasonal TOU rate structure encourages shifting of consumption to the overnight period (10 p.m. and 6 a.m.) during certain months. The other is a voluntary demand reduction rate structure that goes into effect for a few days of the year (June – September) upon day-ahead notification when an ERCOT system critical peak condition is judged to be a strong possibility. These pricing trials give an indication of the degree to which the test group of customers can be expected to be aware and responsive to pricing drivers of the two types.

6.3 Interactions with Key Stakeholders

Over the course of the demonstration project, findings from the trials were presented and discussed at team meetings and public forums. Stakeholders include policy makers and interested parties, including ERCOT, Austin Energy, other utilities and retail electric providers, as well as members of the academic and energy-related products and services communities. Concurrent complimentary studies (e.g. residential PEV charging profiles) provide additional value to the body of research when taken as a whole.

Other key stakeholders include the actual pricing trial participants. In an interview with a sample of participants, they shared their approaches to shifting energy usage and ideas for adjusting the pricing regimes for improved effectiveness.

6.4 Technical Approach

This section provides a detailed description of the technical approach. The first part, Project Plan, identifies the basic pricing program rate structures, how customers were incentivized to participate, and the communications strategy employed to recruit participants. The second part, Data Collection and Benefits Analysis, defines the data collection and management, data visualization and analysis.

6.4.1 Project Plan

The following provides information on the overall project plan.

6.4.1.1 Incentive Account Tracking

Over the course of this 20-month experiment (March 2013 – October 2014), the Pricing Group and Control Group received and paid their usual Austin Energy electric bills, which reflected the normal Austin Energy electric rates.

A monetary incentive was used to entice the Pricing Group participants to either shift their energy consumption to the "wind enhancement" time period (10 p.m. – 6 a.m. during certain months) or to reduce energy consumption during CPP times (4 p.m. – 7 p.m. in the summer months). The project established a credit account with an initial balance of $200 for each participant in the Pricing Group. The credit account balance at any point in time, whether above or below that initial $200 amount, reflected the participant's degree of response to price signals. Participants were able to view their credit account through an online web portal display as shown in the example figure below.

PERIOD	USAGE	PRICING TRIAL BILL	AUSTIN ENERGY BILL	ADJUSTMENT CREDIT
Mar 1, 2013 - Mar 31, 2013	674 kWh	$59	**$62**	$3
Apr 1, 2013 - Apr 30, 2013	703 kWh	$58	**$67**	$9
May 1, 2013 - May 31, 2013	658 kWh	$54	**$58**	$3
Jun 1, 2013 - Jun 30, 2013	1050 kWh	$128	**$138**	$10
Jul 1, 2013 - Jul 31, 2013	1088 kWh	$114	**$128**	$14
Total	4173 kWh	$413	$453	$239.0

Figure 59. Example of Web Portal Display of Representative Pricing Information for One Participant

The value of the credit in the account was adjusted every month at the time the participant received his or her electric bill. The "adjustment credit" reflected the difference between what the participant actually paid Austin Energy and what they would have paid if Austin Energy actually charged the pricing trial rates. Account balances provided feedback to the participants regarding their results in this experiment.

6.4.1.2 Critical Peak Pricing Rate Structure and Trial Design

The rate structures for both TOU programs were designed to be revenue neutral. This meant that, on average, if a participant chose to make no changes in their usage behavior, they would see no savings, but they also would not be penalized. The participants were not really informed of this approach, it was just intended to ensure that the real focus was on measuring behavioral changes.

For the CPP trial, a price of $0.64 per kWh was applied to the Pricing Group participants' energy consumption during the weekday (Monday – Friday) afternoon hours of 4 p.m. – 7 p.m. on "critical peak" days during the four summer months, June through September. To make the experimental pricing revenue neutral, there was an offsetting discount of approximately $0.016 per kWh on energy consumption during all non-peak hours of CPP event days. In 2013, 12 CPP days were called, and in 2014, 15 CPP days were called.

The plan was to call a maximum number of CPP events each month, according to the tables below, based on a minimum threshold temperature. The number of CPP events was adhered to during the project, but for 2014, the thresholds were revised downward due to it being a cooler summer.

Table 17. 2013 Goals and Thresholds for Calling Peak Days

Month	Threshold Temperature (^{o}F)	Maximum Monthly Peak Events
June	102	3
July	103	4
August	103	5
September	102	3

Table 18. 2014 Goals and Thresholds for Calling Peak Days

Month	Threshold Temperature (^{o}F)	Maximum Monthly Peak Events
June	101	3
July	101	4
August	103	5
September	100	3

The day-ahead CPP call was made by Frontier Associates to simulate a call by a utility or a retail electric provider anticipating an extremely high next-day system load. The following diagram presents the process that was employed to determine how and when to call a CPP event and notify the participants.

CPP Decision Flow Diagram:

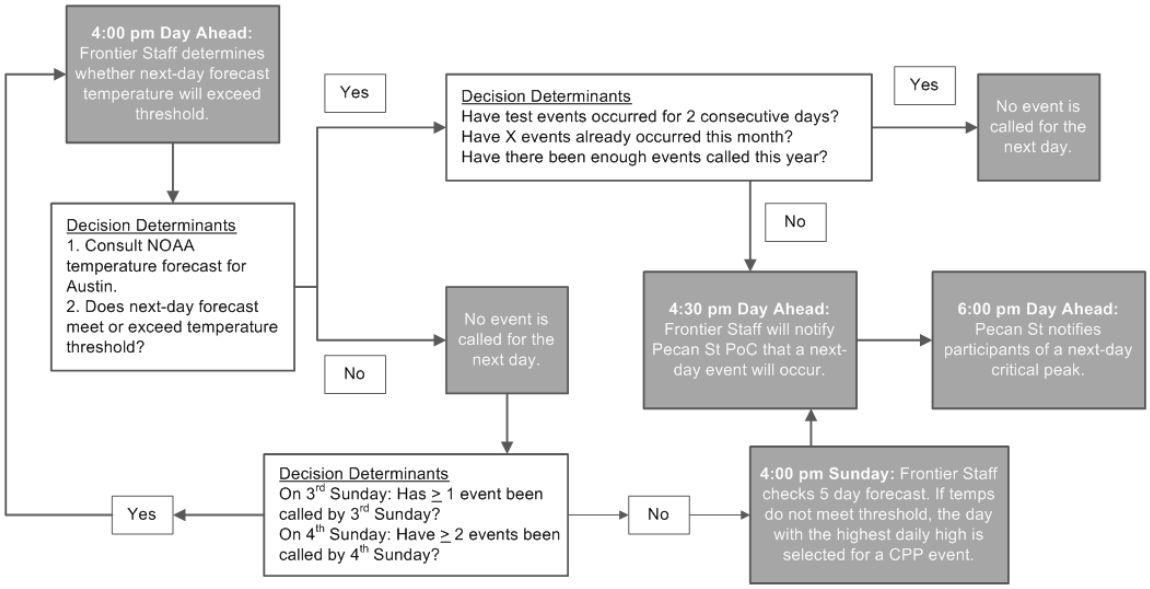


Figure 60. Flowchart for Calling Next-Day CPP Events

By notification of a next day CPP event, participants were able to take appropriate measures to shift energy use to outside the peak time frame the following day to avoid the high electricity rates during those three hours.

6.4.1.3 Wind Enhancement Rate Structure and Trial Design

For the wind enhancement pricing trial, the night-time electric rate for the Pricing Group during the five windiest months (March, April, May, November, and December) was lowered to $0.0265 per kWh. This price applied to energy consumption in the hours from 10 p.m. – 6 a.m. on all days during those months. To make the experimental pricing revenue neutral, meaning there would be no loss if the customer did not change their behavior, there was an offsetting surcharge of approximately $0.02 per kWh on the participants' energy consumption during all other hours of those five months. All customers were informed of the pricing methodology before they opted to participate.

6.4.1.4 Calculation of Pricing Trial Electric Bills

The pricing trial electric rates consisted of these components:

1. Customer charge (the same as Austin Energy's charge) – a flat rate of $10.
2. Baseline (existing Austin Energy) rates – applied only to consumption during non-wind hours and non-CPP hours.
3. Wind period rates – applied to consumption during wind hours
4. Surcharge rates – applied to total monthly consumption during non-wind hours

5. Discount rates – applied to consumption on CPP event days during hours other than 4 p.m. through 7 p.m.

The pricing trial rate formulas were:

1. Wind Enhancement Period:

   Customer charge + [Baseline rates x (consumption between 6 a.m. – 10 p.m.)] + [Wind Price x (consumption between 10 p.m. - 6 a.m.)] + [Surcharge Rate x (consumption between 6 a.m. – 10 p.m.)]

2. CPP Period:

   Customer Charge + [Baseline rates x (consumption during all hours other than during called critical peak days, 4 p.m.-7 p.m.)] + [Critical Peak Price x (consumption during 4 p.m.-7 p.m. on called critical peak days)] + [Discounted rate x (consumption during all hours on event days other than 4 p.m. – 7 p.m.)]

If a Pricing Group participant's bill differed from his or her actual Austin Energy bill, the difference, whether positive or negative, was added to his or her credit balance. Once again, the participants started with a $200 credit adjustment balance. At the end of the pricing trial, participants with positive credit adjustment balances were entitled to cash payments equal to the amount of the final credit adjustment balance in their accounts, up to a maximum of $700 per customer. Participants with negative credit adjustment balances did not owe anything.

6.4.1.5 Participant Communication Strategy

Recruitment of pricing trial participants began in February 2013 with an outreach program designed to target residents living at the Mueller community in Austin. Owners of single-family residential homes were contacted via e-mail and asked for their participation in the TOU pricing trial. Most residents contacted were part of an earlier Pecan Street Energy Internet Demonstration (EID) program funded by another DOE cooperative agreement. These participants had the requisite HEM systems and legal participation agreements in place. The primary goal of recruiting from the EID pool for the pricing trial was to get a representative sample of participants that had a PEV.

Before the official start of the experiment in March 2013, the Pricing Group received e-mail communications outlining the experiment design and ideas for shifting or reducing their energy consumption. For instance, ideas included shifting laundry use to after 10 p.m. during the five wind enhancement months or reducing air conditioner use during CPP hours during the four summer months. The Team held one in-person workshop for the Pricing Group to further detail the trial's design, goals, and research benefits. Each member of the Pricing Group was given secure access to a personal online web portal to check the monthly status of their energy usage, their pricing trial bill, Austin Energy bill, and their adjustment credit balance.

On the web portal, in addition to pricing trial information, the Pricing Group participants had access to the following information:

- Monthly whole home energy use in kWh
- Monthly energy cost in U.S. dollars per appliance
- Energy generation cost in U.S. dollars if the participant has solar panels
- Real-time energy consumption in kWh
- Monthly energy cost comparison to other participants within the same zip code
- Monthly energy usage trends

During the summer months, Pricing Group participants also received cell-phone Short Message Service (SMS or "text") messages and e-mail communications by 6:00 p.m. the day before a CPP day. The sample text message content shown below was designed to be strictly a factual reminder about the upcoming CPP day and the pricing rate.

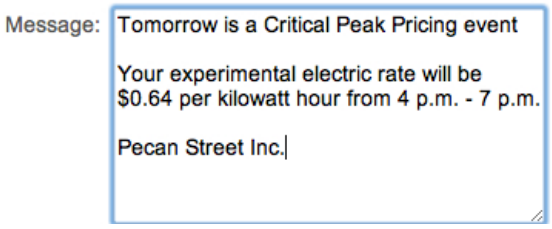


Figure 61. Example TOU Group Text Message

6.4.2 Data Collection and Benefits Analysis

6.4.2.1 Energy Data Collection

The HEM system installed in each home was a commercially available, off-the-shelf product extensively tested against other competing systems installed in 100 single-family homes during a one-year test bed trial in 2011 (as part of another project). The results of the tests found the selected HEM system to have superior reliability, durability, accuracy, and customer support. Licensed master electricians installed a majority of the HEM systems under the prior EID program and maintained the HEM devices for the Pricing Group participants. Participating homes had one or two HEM systems installed, based on their unique circuit configuration.

Each HEM system is composed of:

- HEM device (energy data monitor)
- HomePlug adapter (power line communication device) allowing communications from the HEM system to the participant's Internet gateway
- Up to twenty-four (24) 50-amp current transformers (CTs) for measuring consumption on individual circuits within the home

The HEM system directly measures electricity use for the whole home and a number of circuits at one-minute intervals. Individual circuits typically monitored include:

- Refrigerator
- Furnace and air handler
- Clothes dryer
- Clothes washer
- Oven and cook-top range
- Microwave
- Electric vehicle level II charger
- Lighting - whole home
- Lighting - individual room
- Plug loads
- Solar generation (if installed)

The HEM system allowed the collection of one-minute interval disaggregated data at a resolution that could detect granular changes in the energy use of individual appliances which was critical in characterizing behavioral changes in response to pricing signals. The data from the HEM system was streamed through the participants' Internet gateway to Pecan Street's server cluster where it was stored in a secure database environment.

6.4.2.2 Data Management and Cyber-Security Considerations

As of October 2014, the database contained over 183 million records and continues to grow at a rate of 3 million records per day. Given the size and diversity of data, Pecan Street established a highly available, scalable database architecture that adheres to the organization's DOE-approved cyber-security plan protecting the identity of all participants while organizing the data so that it is accessible to appropriate parties. A data warehousing strategy was employed that integrates the energy use, participant and survey data sets into common schema or systems, with emphasis on commonalities in the data such as participant, measurement type, and time-stamp.

Due to the intimate and confidential nature of some data being collected, data security is a critical aspect of the data integration and storage. As such, the main security principle applied is protection of the project participants' identities and privacy. The database adheres to a Cyber-Security Plan approved by DOE which protects the identity of all research participants and organizes the data so that it is accessible to approved researchers. The plan requires that any personally identifiable information must be kept in a separate database from all other data on the home and linked by a master database accessible only to Pecan Street staff via a 2-factor authentication process.

6.4.2.3 Data Visualization

The Team created a series of anonymized data visualizations that are rendered through an online web portal to communicate the energy data collected from Pricing and Control Group participants. These visualizations show energy load profiles for the groups and a geospatial "heat map" rendering of energy consumption that is scaled and generalized at the community level in order to protect against identification of individual home locations.

6.4.2.4 Data Analysis

The analysis methods are described below, and the results are presented in section 6.5. Conclusions are summarized in section 6.6.

6.4.2.4.1 CPP Trial

Data on electricity usage profiles on critical peak days was analyzed using three different statistical methods, specifically looking for evidence of reduction in usage between 4 p.m. and 7 p.m. on called event days. The first method discussed below, "fixed panel data analysis," is considered the primary method, yielding the most reliable results[10]. The other two methods, also discussed below, "historical baseline method" and "difference in difference method," were used for comparison purposes only.

1. Fixed effects panel data analysis:
   The Team performed panel data analysis, taking time and weather into consideration. This method segregates the weather effects from the behavior change during the peak event, giving more representative results. Panel data are a set of variables measured on multiple observational units at multiple time periods. In this case, a whole summer dataset is analyzed including both the Pricing Group and the Control Group. Fixed effects panel data analysis, rather than random effects panel data analysis, is applied when time independent effects for each entity are correlated with the predictors. In this case, only parameters that vary over time are taken into consideration, such as hourly temperature and whether or not it is a peak period. The model was initially designed as follows:

$$(kW)_{it} = \alpha_i + \beta_1*(cdh)_t + \beta_2*(Event)_{it} + \beta_3*(hourstart17)_t + \beta_4*(hourstart18)_t + \sum_{k=5}^{10} \beta_k*(dayofweek)_t + \varepsilon_i$$

   Where:

   - cdh" indicates the cooling degree hours from 4-5 p.m., 5-6 p.m., and 6-7 p.m. (cooling degree hours = max(hourly temperature-70,0))

[10] This method is also employed more frequently in analysis of dynamic rate pilots (re: Orlando, Ernest, Lawrence Berkeley National Laboratory, "Quantifying the Impacts of Time-based Rates, Enabling Technology, and Other Treatments in Consumer Behavior Studies: Protocols and Guidelines," LBNL-6301E , July 2013)

- "i" is each individual (each Pricing Group and Control Group member)
- "t" is each summer afternoon hour (16:00-17:00,17:00-18:00 and 18:00-19:00 each day from June 1st to September 30th)

For 2013, based on 12 events, it was implemented as:

$$(kW)_{it} = \alpha_i + \sum_{k=1}^{12} \beta_k*(cppevent_k)_{it} + \beta_{13}*(cdh)_t + \beta_{14}*(Event)_{it} + \beta_{15}*(hourstart17)_t + \beta_{16}*(hourstart18)_t + \sum_{k=17}^{22} \beta_k*(dayofweek)_t + \varepsilon_{it}$$

For 2014, based on 15 events, it was implemented as:

$$(kW)_{it} = \alpha_i + \sum_{k=1}^{15} \beta_k*(cppevent_k)_{it} + \beta_{16}*(cdh)_t + \beta_{17}*(Event)_{it} + \beta_{18}*(hourstart17)_t + \beta_{19}*(hourstart18)_t + \sum_{k=20}^{25} \beta_k*(dayofweek)_t + \varepsilon_{it}$$

2. Historical baseline analysis:
   A historical baseline analysis, along with the difference in difference (DID) analysis, was used to provide alternative savings estimates for reference and comparison to panel data analysis results. For each CPP event, estimated kW savings were based on the following equation:
   kW savings = Baseline Average Peak kW – CPP Period Average Peak kW
   Where:
   - Baseline Average Peak kW = average kW demand recorded 4:00 p.m. - 7:00 p.m. during the four non-peak weekdays immediately preceding the called CPP day
   - CPP Period Average Peak kW = average kW demand recorded 4:00 p.m. - 7:00 p.m. on the called CPP day

   The example in the table below shows the kW savings calculation for a single event day - 20 June 2013. Note that in this example, the fourth preceding weekday actually occurred the prior week and since it was much cooler, it was not included in the average baseline calculation.

Table 19. Example of Critical Peak Pricing Day kW Savings Calculation (Day Matching Method)

Day	Temperature	Baseline Period kW	CPP kW	kW savings
20-Jun	98		2.099958789	
19-Jun	98	2.89702902		
18-Jun	95	2.35090962		
17-Jun	99	2.88479677		
~~14-Jun~~*	~~93~~	~~2.08545660~~		
Average		2.71091180	2.099958789	0.61095301

* Not used in average (unseasonably cool day)

3. Difference in difference analysis:

   Difference in difference (DID) analysis, along with historical baseline analysis, were used to provide alternative savings estimates for reference and comparison to panel data analysis results. DID analysis can be used when hourly load data for all customers in the treatment group and control group are available before and during the treatment period. We can use pooled cross-sectional data to isolate and quantify the effects of these rate treatments on one or more measures of load response.[11] A simple linear regression can be used to perform the analysis:

   $$Y=\alpha_0+\delta_0 D_2+ \alpha_1 D_m+ \delta_1 D_2 D_m+\varepsilon$$

   Where:

   - Y = hourly kW for each household
   - D_2 = a dummy variable that takes on a value of unity if the observation is from the treatment period and zero otherwise
   - $D_{m\,=}$ a dummy variable that takes on a value of unity if the observation is for a member of the treatment group and zero otherwise

   The coefficient of interest is δ_1 because it defines the interaction between the time period and the treatment dummies, $D_2 * D_{m.}$[12] In other words, coefficient δ_1 estimate is the kW savings estimate we were looking for.

   Event day 4:00-7:00 p.m. is used as the treatment period and the previous non-event weekday (4:00-7:00 p.m.) is used as the control period.

6.4.2.4.2 Wind Enhancement Pricing Trial

Data was analyzed primarily by calculating and comparing the average percentage and kWh daily consumption per home during the period of 10 p.m. to 6 a.m. to that during the period of 6 a.m. to 10 p.m. The 24 hour usage distribution was examined to quantify the degree of shifting accomplished by the participants in response to the seasonal TOU pricing which encouraged night time consumption.

Shifting of specific loads was evaluated in similar fashion for expected candidate end uses, such as vehicle charging, kitchen appliance use, and laundry-related tasks.

6.5 Performance Results

6.5.1 Operation of Smart Grid Technologies and Systems

Detailed analysis results are reported in this section. They are summarized in bullet form in section 6.6, "Conclusions."

[11] Orlando, Ernest, Lawrence Berkeley National Laboratory, "Quantifying the Impacts of Time-based Rates, Enabling Technology, and Other Treatments in Consumer Behavior Studies: Protocols and Guidelines," LBNL-6301E , July 2013

[12] Ibid.

6.5.1.1 Overall Results - Adjustment Credit Account Analysis

Each Pricing Group participant's credit adjustment of $200 was adjusted monthly based on their respective TOU pricing results. The analysis results described below depict the adjusted credit balances (not including the initial $200 credit).

Overall, there was a positive response to pricing signals as indicated by the levels of adjustment credit earned by the Pricing Group participants. 97% of participants had positive credits while 3% (two participants) had deductions on their incentive account. 84% of participants had earnings greater than $40 (in addition to the $200 incentive credit) and the maximum adjustment credit earned was $280.57, not including the initial credit. The average adjustment credit earned was $125.13, for an average payout of $325.13 to participants in this experiment.

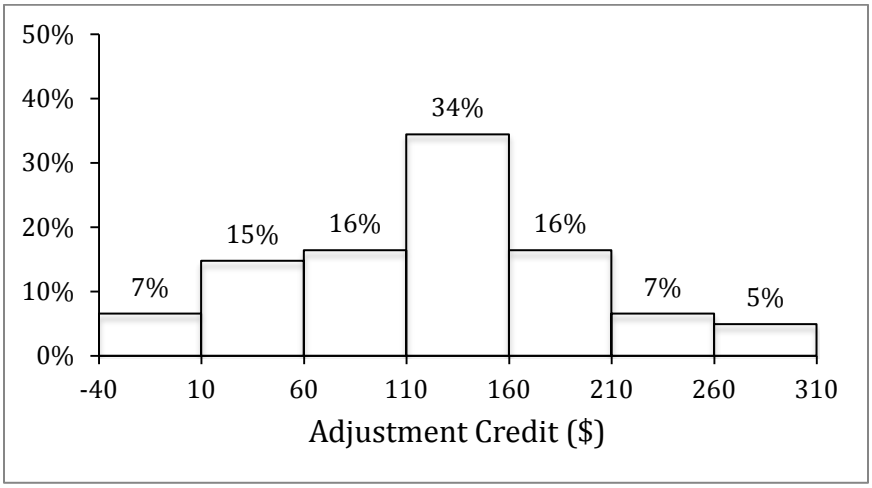


Figure 62. Adjustment Credit Earnings Distribution

The graphs in the figures above and below reflect the distribution of incentive credits earned by the participants over the course of the pricing trial. On the lower end, approximately 7% of the Pricing Group participants (4 out of 61) earned less than $10 in adjustment credit (in addition to the $200 initial credit). On the higher end, roughly 5% of the Pricing Group participants (3 out of 61) earned greater than $260 in credit. The predominant amount of credit earned over the course of the project was in the range of $110 to $160 (not including the $200 incentive credit). Even though the largest incentive amount earned was significantly below the maximum allowable amount of $700, overall there was a positive response to the TOU pricing programs.

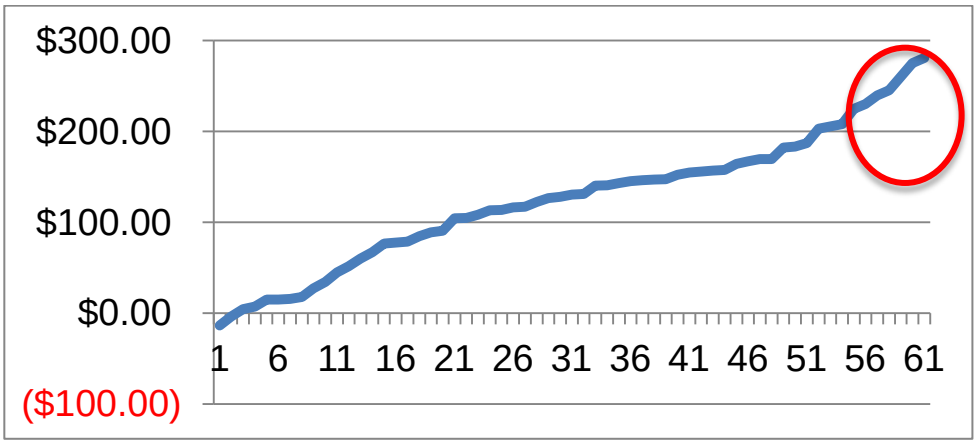


Figure 63. TOU Incentives Payout Distribution

For the five participants who received the largest payouts, the Team compared their savings during the wind months versus the summer months. The results are shown below. These participants generally earned the majority of their credit in the wind pricing months, except for one (circled).

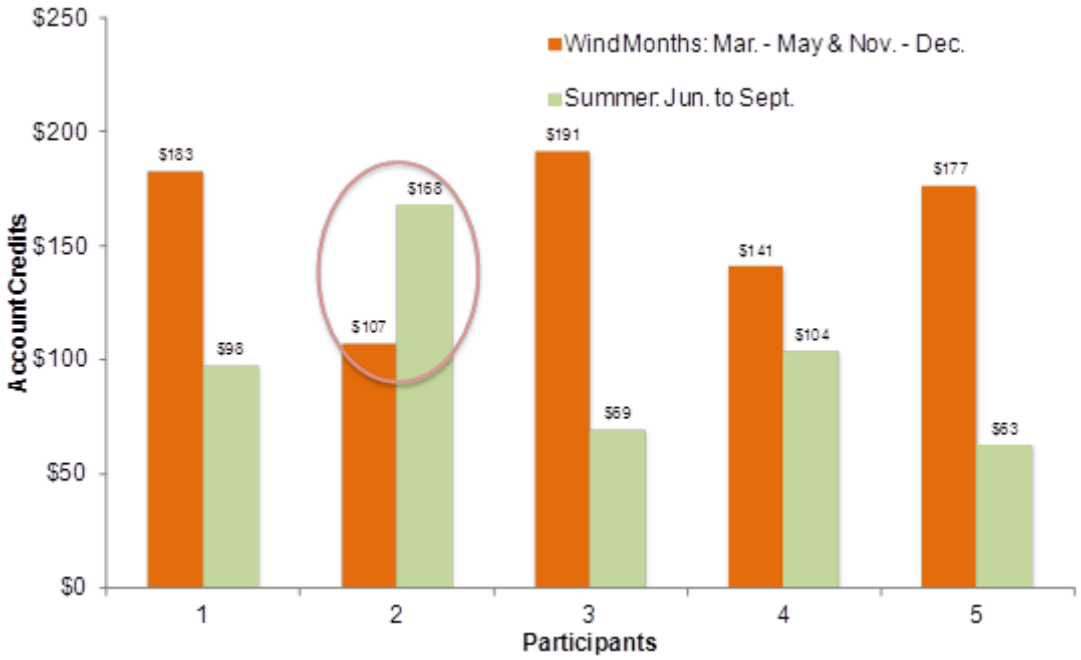


Figure 64. Wind Months Savings versus Summer Months Savings

This analysis was repeated for those participants who received the 10 median payouts. The comparison results are shown below. These participants also generally earned the majority of their credit in the wind pricing months, except for one (circled).

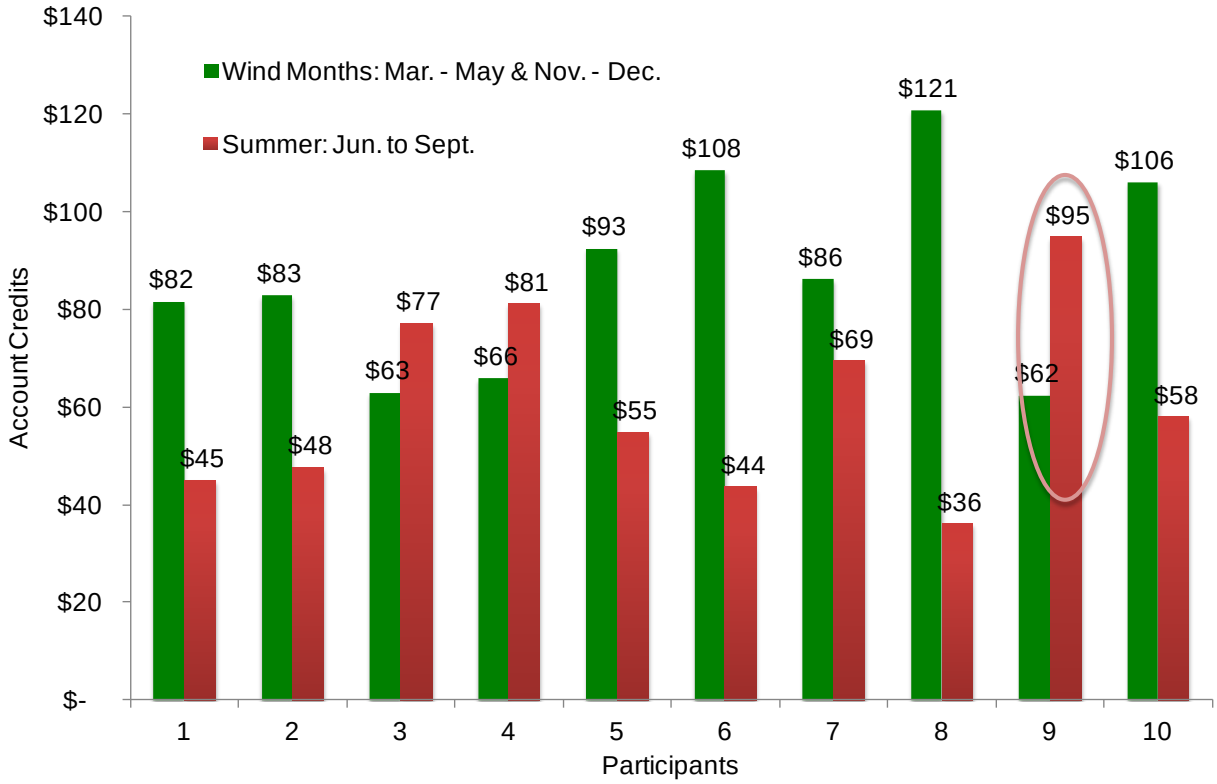


Figure 65. Median Payout Accounts – Wind Months Savings versus Summer Months Savings

6.5.1.2 CPP Trial Results

Results are presented below for the three statistical methods used to estimate the demand reduction for critical peak days. The first method presented, "fixed panel data analysis," is considered the most reliable and thus the primary method of analysis. Specific observations are reported on the breakdown of end uses contributing to CPP reductions, PEV owner CPP response, and a comparison of CPP responses for homes that are occupied versus unoccupied during weekday afternoons.

6.5.1.2.1 Panel Data Analysis

Using panel data analysis as the primary analysis method applied to hourly consumption data, Frontier found the following CPP demand reductions per event:

2013: 0.44 kW or 15.27% reduction in demand

2014: 0.17 kW or 6.15% reduction in demand

The tables below provide further data on each CPP event day.

Table 20. 2013 Panel Data Analysis Results

Critical Peak Day	Daily High (F)	Estimated kW Savings
June 20th	98	0.5475
June 26th	101	0.7455
June 28th	104	0.7002
July 24th	97	0.4194
July 26th	99	0.3590
August 1st	103	0.2100
August 7th	103	0.7047
August 8th	104	0.6429
August 29th	99	0.2768
August 30th	102	0.2897
September 5th	96	0.1259
September 13th	97	0.3272
	Average Savings per Event:	**0.44 kW**

Table 21. 2014 Panel Data Analysis Results

Critical Peak Day	Daily High (F)	Estimated kW Savings
June 24th	93	-0.2484
June 30th	96	0.2840
July 2nd	97	0.0068
July 14th	97	0.2064
July 24th	101	0.0052
July 28th	99	0.1574
August 7th	102	0.2292
August 15th	101	0.1420
August 19th	96	0.5093
August 21st	103	0.5163
August 26th	101	0.2264
September 3rd	100	0.1601
September 9th	97	0.2082
September 11th	99	-0.0185
September 15th	88	0.2618
	Average Savings per Event:	**0.17 kW**

As one can see from the tabulations above, CPP events in 2014 achieved less peak reductions on average than in 2013. The figure below graphically illustrates the range and variability of results for the two years.

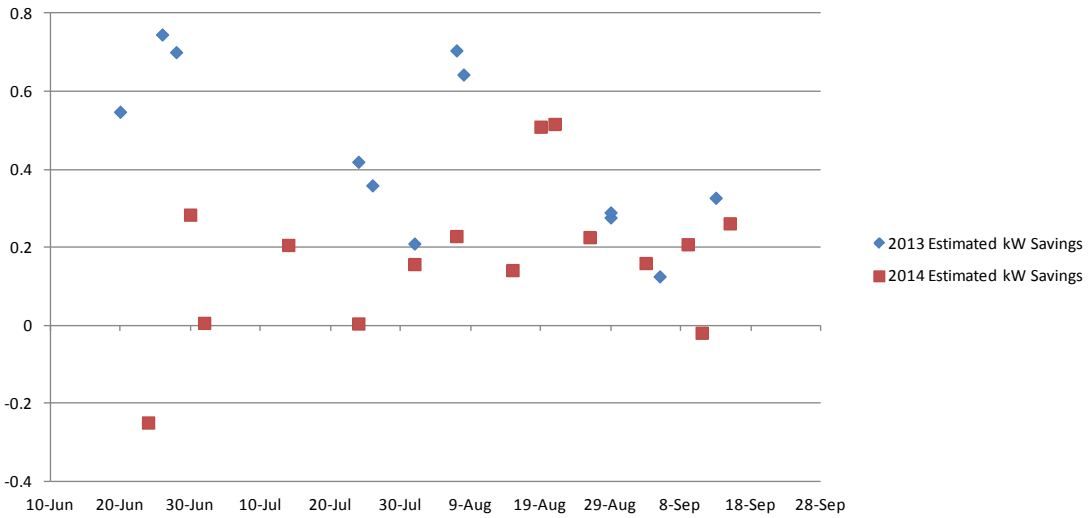


Figure 66. 2013 versus 2014 CPP Events Savings Comparison

Although the absolute magnitude of the peak reductions averaged less than 0.5 kW, the percentage peak reduction of 15% in 2013 is in line with other studies. Regarding the reductions averaging less than 0.5 kW, it is important to note that according to final survey responses from the Pricing Group, participants made lifestyle changes early in the trials that shifted load away from the peak hours. The changes were persistent throughout the entire trial period, thus diminishing the CPP reductions since the baseline (non-CPP summer day) loads were already reduced by load shifting. Examples include shifting of PEV charging, laundry and kitchen appliance use to after 10 p.m. when possible, as a matter of routine.

The differing levels of response in the summer of 2013 versus 2014 bear further discussion. Responses to the final survey of the Pricing Group indicated that many participants experienced “customer fatigue” during the second summer (2014). Respondents reported competing priorities and disappointing electricity cost savings. One quarter stated that they did not participate in the second summer’s CPP trial at all, and it is plausible that the others participated to a lesser degree the second summer for similar reasons.

In consideration of these performance factors:

- The 2013 results were used in breakdown analysis.
- The CPP peak reductions reported here can be considered incremental to the on-peak load shifts realized in a TOU pricing environment, whereby participants already have a somewhat reduced baseline load during peak hours.
- It can be expected that voluntary CPP programs like this one that rely on deliberate participant action will produce widely varying responses and will struggle to maintain persistence.

The next section reports results of two alternate analysis methods for quantifying CPP kW reductions: "historical baseline method" and "difference in difference method." They provide diverse approaches to the calculations.

6.5.1.2.2 Results from Alternate Analysis Methods

For comparison purposes only, the historical baseline method and difference in difference method were used as alternate methods for calculating the CPP kW savings. Results for the multiple analysis methods are tabulated below.

Table 22. CPP Peak Reduction Results

	Estimated 2013 Peak Reduction	Estimated 2014 Peak Reduction
Historical baseline method	0.29 kW	0.085 kW
Panel data analysis	0.44 kW	0.17 kW
Difference in difference method	0.498 kW	0.245 kW

As seen above, the alternate estimates envelope the values from the panel data analysis, which is considered the most reliable method for estimating kW demand savings from this study.

6.5.1.2.3 Breakdown Analysis of CPP kW Savings

Further investigation was conducted to determine which end-uses contributed to the peak load reduction during the 12 CPP events in 2013. Peak load reduction was postulated as most likely coming from the following end-use appliances, for which participants could voluntarily reduce usage in the 4 p.m. to 7 p.m. window: HVAC, PEV charging, kitchen appliances, and laundry-related usage.

Among these end-uses, the first two categories were found to contribute the most to the energy reduction. Considering the fact that 40% of the participants in the Pricing Group have PEVs, the Team conducted this part of the analysis by first dividing the group into two subgroups: with and without PEVs. Since HVAC usage is weather-sensitive, sub-metered HVAC consumption was used with panel data analysis to estimate average HVAC kW reductions for each CPP event. For those who own PEVs, the day-matching ("historical baseline") method described in prior sections was used to calculate PEV kW savings for each CPP event. For the subgroup owning PEVs, kW savings breakdown analysis results are tabulated and graphed on the following pages.

Table 23. 2013 Breakdown Analysis of kW Savings - Participants with PEVs

	Estimated Total kW Savings	HVAC kW Savings	Estimated PEV kW Charging Savings	The Rest
June 20th	0.5390	0.1714	0.1123	0.2553
June 26th	0.8075	0.3481	0.3234	0.1360
June 28th	0.8816	0.4032	0.2225	0.2559

July 24th	0.3298	0.1325	0.0446	0.1527
July 26th	0.4097	0.1774	0.0928	0.1395
August 1st	0.2023	0.1253	-0.2143	0.2913
August 7th	0.6167	0.252	0.1462	0.2185
August 8th	0.8449	0.3014	0.2019	0.3416
August 29th	0.1939	0.0633	0.1057	0.0249
August 30th	0.1377	0.0064	0.2312	-0.0999
September 5th	0.2317	0.0923	0.0100	0.1294
September 13th	0.3102	0.1358	-0.0465	0.2209
Average	0.459	0.184	0.102	0.173
% of Total	N/A	40.13%	22.34%	37.53%

Table 24. 2013 Breakdown Analysis of kW Savings - Participants without PEVs

	Estimated Total kW Savings	**HVAC kW Savings**	**The Rest**
June 20th	0.4181	0.2499	0.1682
June 26th	0.5674	0.3725	0.1949
June 28th	0.458	0.2570	0.2010
July 24th	0.3504	0.2262	0.1242
July 26th	0.1574	0.0864	0.0710
August 1st	0.1506	0.1315	0.0191
August 7th	0.3623	0.2702	0.0921
August 8th	0.2627	0.0991	0.1636
August 29th	0.2259	0.0343	0.1916
August 30th	0.1276	0.0384	0.0892
September 5th	0.0618	0.1368	-0.0750
September 13th	0.2465	0.0445	0.2020
Average	0.282	0.162	0.120
% of Total	N/A	57.45%	42.55%

From the two tables above, for Pricing Group members with PEVs, around 62% of the CPP kW reductions were attributed to HVAC and PEV related behavior change (HVAC @ 40%, PEVs @ 22%). For Pricing Group members without PEVs, around 57% of the CPP kW reduction was attributed to HVAC related behavior change.

Apart from HVAC and PEV charging reductions, the other 40% or so of total CPP kW reductions came from other end uses. The Team conducted in-depth analysis on sub-metered laundry and kitchen appliance consumption and found both to be significant contributors, with additional reductions distributed unremarkably throughout multiple end uses.

6.5.1.2.4 PEV Owners Reduce Peak Load More than Non-PEV Owners

In general, Pricing Group members with PEVs saved more energy during CPP events (0.46 kW versus 0.28 kW) than non-PEV owners, as depicted in the graph below for the 2013 events.

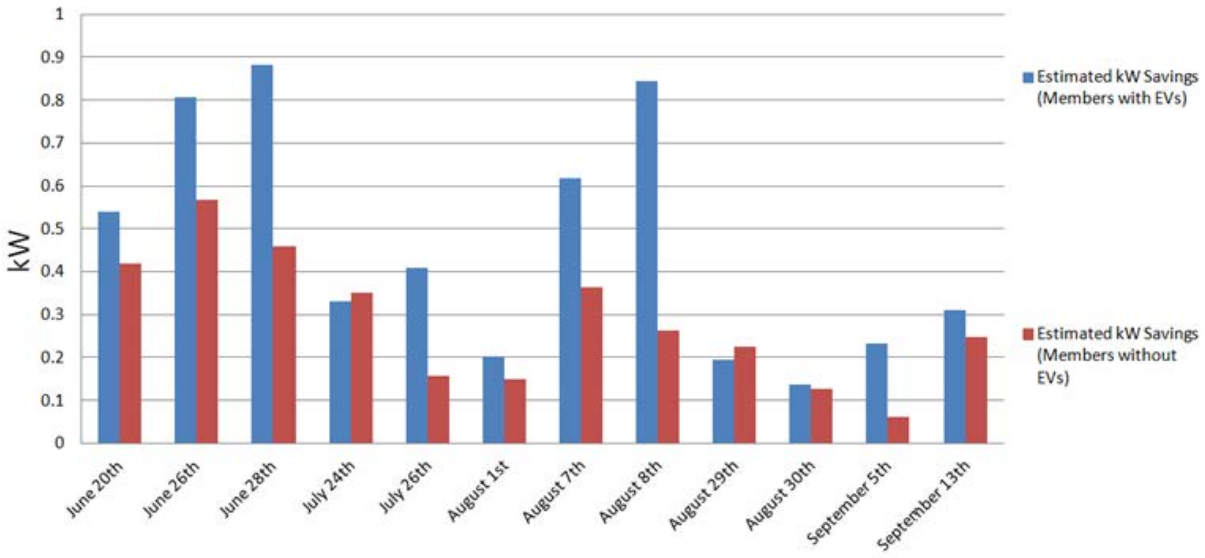


Figure 67. Overall 2013 kW Savings Comparison of CPP Participants With and Without EVs

The Pricing Group participants who own PEVs also exhibited more variability in responding to CPP events. For those who charged in the afternoons, if they delayed that charging until after 7:00 p.m. during CPP events, their peak load reductions were much higher than for those without PEVs. PEV charging is a high kW load that can often be delayed until later in response to pricing. See section 6.5.1.3.2 for a comprehensive discussion of PEV charging response.

6.5.1.2.5 Occupied versus Unoccupied Homes Energy Usage During CPP Events

The graph in the figure below shows that homes that are typically occupied on weekday afternoons in both the Control Group and Pricing Group used more energy overall than homes that are normally unoccupied at those times. The Pricing Group homes managed significant reductions during CPP events, with the occupied homes turning in the most impressive CPP performance.

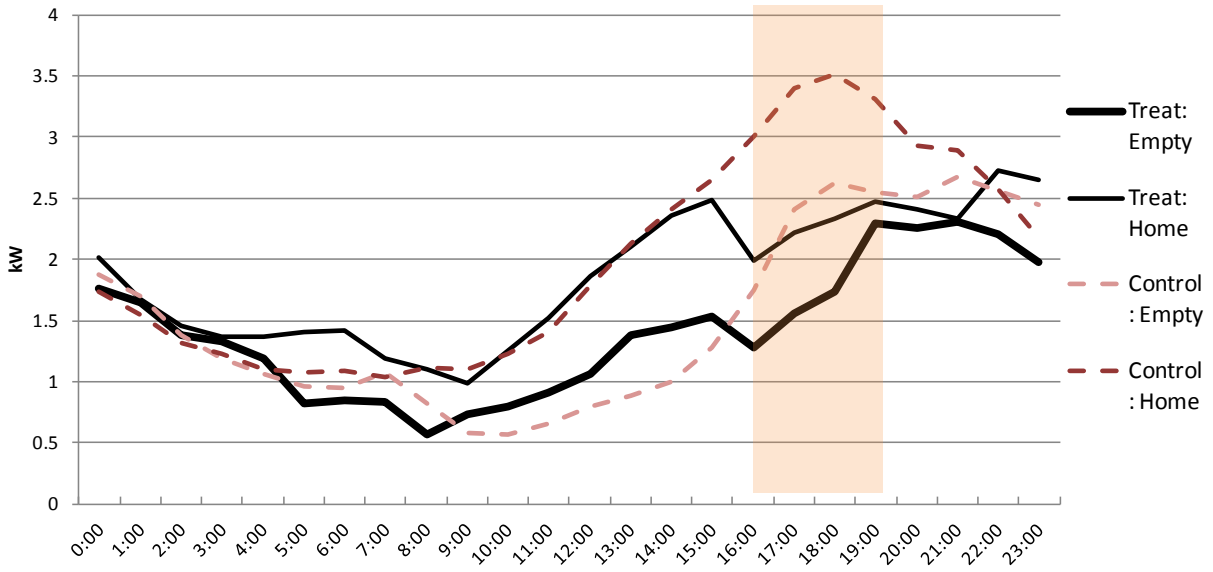


Figure 68. 2013 CPP Savings for Occupied versus Unoccupied Homes

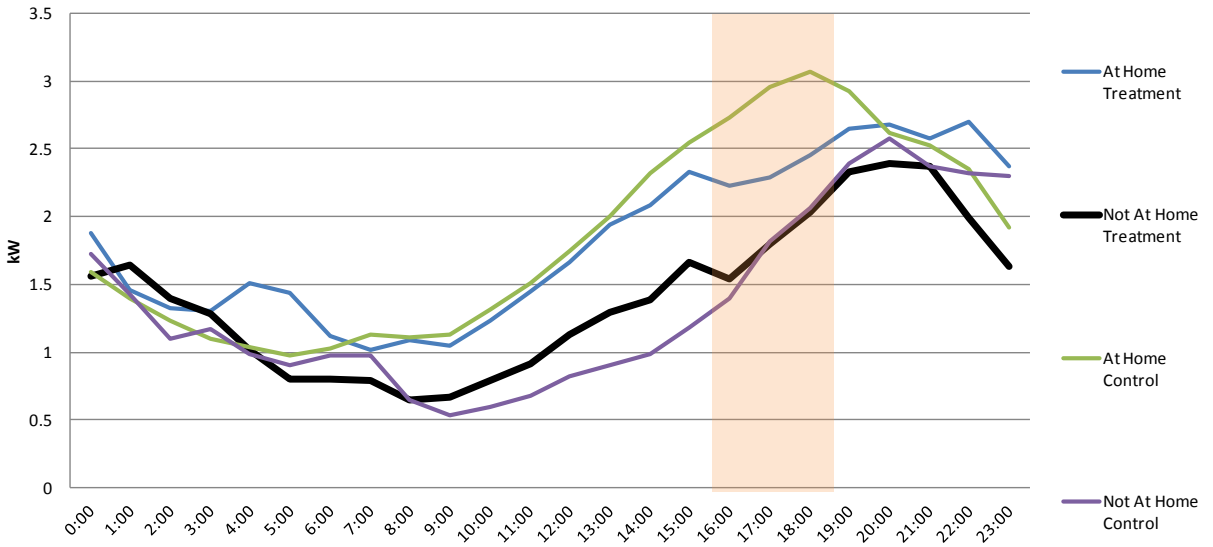


Figure 69. 2014 CPP Savings for Occupied versus Unoccupied Homes

The graphs above allow a meaningful comparison of occupied ("Home") and unoccupied ("Empty") homes for the Control group and the Pricing ("Treatment") Group during the peak time frame of 4 p.m. to 7 p.m. on CPP event days. Note that the occupied/unoccupied load shapes for the Pricing Group and the Control Group are virtually identical until the 4 p.m. hour.

The Control Group has no response in the 4 p.m. to 7 p.m. time frame as they are not informed of the CPP event, thus indicating default behavior in the absence of CPP program participation. It can be observed that the occupied homes naturally use more energy during the day than unoccupied homes, likely indicating that the use of programmable thermostats is reducing energy cost for unoccupied homes.

In contrast to the default behavior of the Control Group, note the significant response of the Pricing Group at the 4 p.m. hour for both the occupied and unoccupied homes. Both exhibit marked step reductions at 4 p.m., indicating that (1) residents who are home take action to consume less energy, primarily by reducing HVAC and PEV charging usage as reported elsewhere in this report, and (2) residents who are not home also take action on those days to reduce HVAC usage, likely once again using their programmable thermostats, in some cases accessing them remotely to change settings, as indicated in participant feedback.

Note that the magnitude of the response to a critical peak event call is slightly greater for homes where the residents are home. This is because these homes have both higher default consumption and the means and opportunity to reduce consumption by manual action.

6.5.1.2.6 No Conservation Effect from CPP Trial

No reduction in total energy consumption was found on called critical peak days versus non-event days.

6.5.1.2.7 Comparison with Other CPP Trials

Frontier Associates conducted a literature review of journal articles about CPP trials across North America.[13] The results were as follows:

[13] Faruqui, Ahmad and Sanem Sergici. "Household response to dynamic pricing of electricity: a survey of 15 experiments." The Brattle Group. 31 August 2010. Published Online.
"Understanding Electric Utility Customers – Summary Report." 2012 Technical Report by EPRI.
Faruqui, Ahmad and Jenny Palmer. "Dynamic Pricing of Electricity and its Discontents." The Brattle Group. August 3, 2011.
Wolak, F. A. (2006). Residential customer response to real-time pricing: The Anaheim Critical-Peak
Faruqui, Ahmad and Sanem Sergici. "Arcturus: International Evidence on Dynamic Pricing."
Faruqui, Ahmad, Sanem Sergici, and Neil Lessem. "Impact Evaluation of Ontario's Time-of-Use Rates: First Year Analysis." Prepared for the Ontario Power Authority. The Brattle Group. November 26, 2013.
Faruqui, Ahmad and Sanem Sergici. "The Power of Experimentation: New evidence on residential demand response." The Brattle Group. May 11, 2008.

- Compared with other CPP trials, the demand reduction measured in this trial (15%) is on the low side. CPP tariffs typically induce a drop in peak demand between 13 and 20%. Customers with central air conditioners display a response in the 15 to 20% range. For customers with enabling technologies, such as remotely accessible and programmable thermostats, which were generally available to the participants in this trial, the reduction grows to between 25 and 45 percent.
- Some pilots found persistence over multiple years. One pilot experiment in Maryland found that customers actually became more price-responsive in the second summer of the trial – not the case in this trial. However, most articles made no conclusions about the persistence of the effects of the pricing scheme over several years.

6.5.1.2.8 CPP Trial - Final Survey of Participants

In November 2014, after the study period ended, additional input was sought from Pricing Group participants via a final survey with a few targeted questions. 55% responded and the responses relating to the CCP trial are summarized here:

- Most participants made lifestyle changes the first few months of the trial in response to TOU wind pricing, shifting load away from afternoon peak hours to after 10 p.m. where feasible, e.g. PEV charging, operating laundry, and running the dishwasher. Many of these changes persisted throughout the entire trial period. Note: This persistent shift decreased the measured CPP reductions in summer months.
- 80% of the Pricing Group participated in the 2013 (first summer) CPP program. Of the active participants:
    - One quarter did not participate in the second summer's CPP trial
    - Many respondents reported "fatigue" from participating in the program. Two respondents mentioned the difficulty of maintaining participation with small children.
    - Virtually all reduced their HVAC use, almost half of them by pre-cooling the home before the event period started (4 p.m.) on called event days.
    - About half adopted some of their CPP response actions into their summertime routine *every day*, not just on event days.
    - 20% of respondents who were at home during a typical weekday afternoon reported that they intentionally left the house during a called event period. Note that this result is surprisingly high and would not likely persist long term.

6.5.1.3 Wind Enhancement Pricing Trial Results

Seasonal TOU pricing, specifically night time "Wind Enhancement Pricing" in this study, was put in place for the months of March to May and November to December in 2013 and 2014 (the wind pricing months) in an attempt to cause participants to shift some of their usage of electricity to the overnight hours to be served by west Texas wind generation. The Team compared the Pricing Group's 24-hour electricity consumption pattern during these months to the Control Group's consumption pattern.

Consumption patterns for certain sub-metered end uses (PEV charging, kitchen appliances, and laundry) were also examined to characterize any observed shifts.

Due to the differing levels of PEV ownership between the Pricing and Control Groups – 34 PEVs (56%) in the Pricing Group versus only 6 PEVs (10%) in the Control Group – the Pricing Group's consumption patterns *during the trial* were also compared to their own *pre-trial* consumption patterns.

6.5.1.3.1 Response to TOU Pricing - Overall Consumption

The figures below compare Pricing Group to Control Group daily consumption patterns during the 2013 and 2014 wind pricing months, plotted in hourly percentage of daily total usage. The seasonal average hourly Texas wind generation is represented by the dotted line in the background.[14] Note that shifting electricity consumption from day time to overnight supports better matching of load to wind resources.

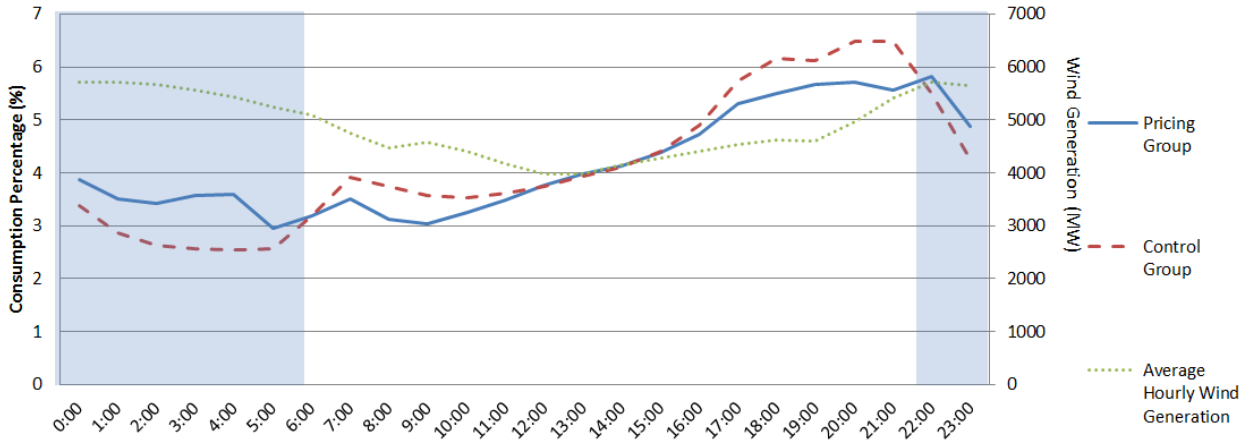


Figure 70. Pricing Group versus Control Group 2013 March - May Wind Pricing Period

[14] Wind Generation Data Source:
http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13424&reportTitle=Hourly%20Aggregated%20Wind%20Output&showHTMLView=&mimicKey
Note: The curves shown include inland and coastal wind generation

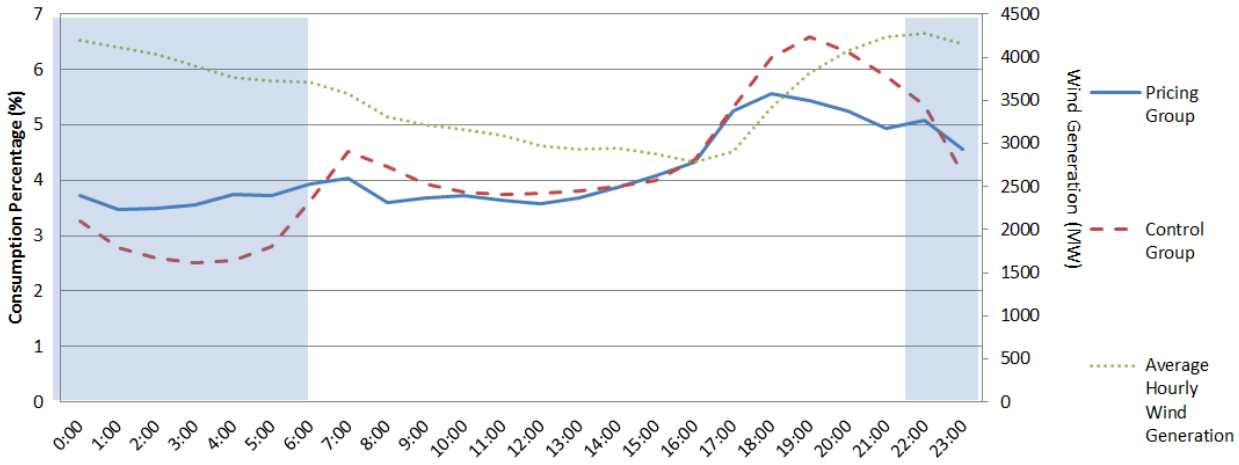


Figure 71. Pricing Group versus Control Group 2013 Nov-Dec Wind Pricing Period

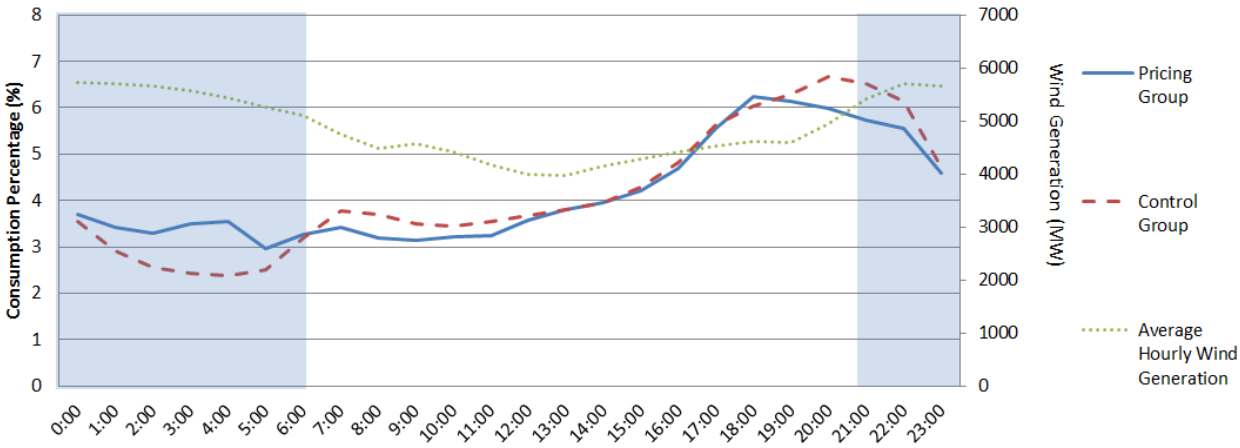


Figure 72. Pricing Group versus Control Group 2014 March – May Wind Pricing Period

In contrast to the shifts evident in wind-pricing months (above), there is a weaker shift in non-wind months (see graph below for June 2014).

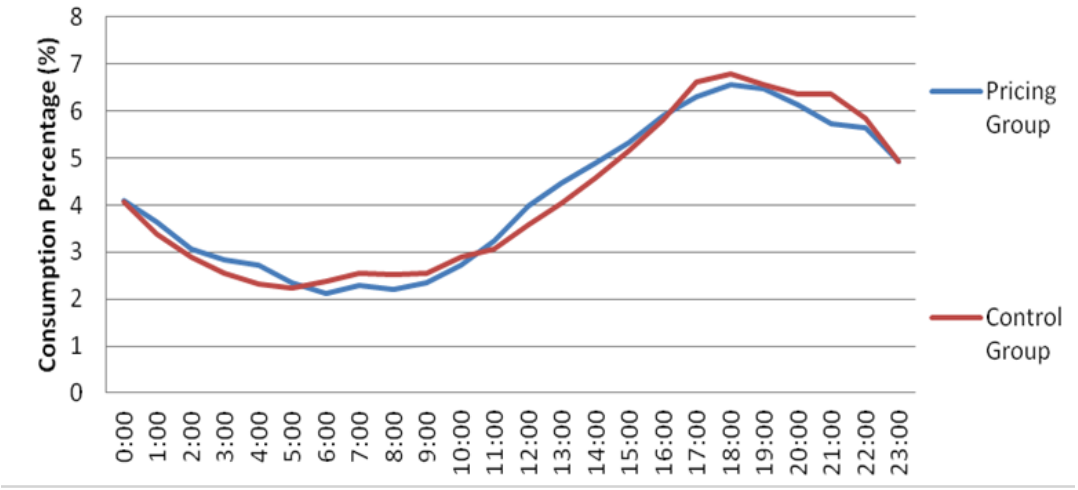


Figure 73. Pricing Group versus Control Group June 2014

Daytime/night time splits of overall electricity consumption for the Pricing and Control groups are compared below, indicating a 4% difference, which is small but statistically significant.

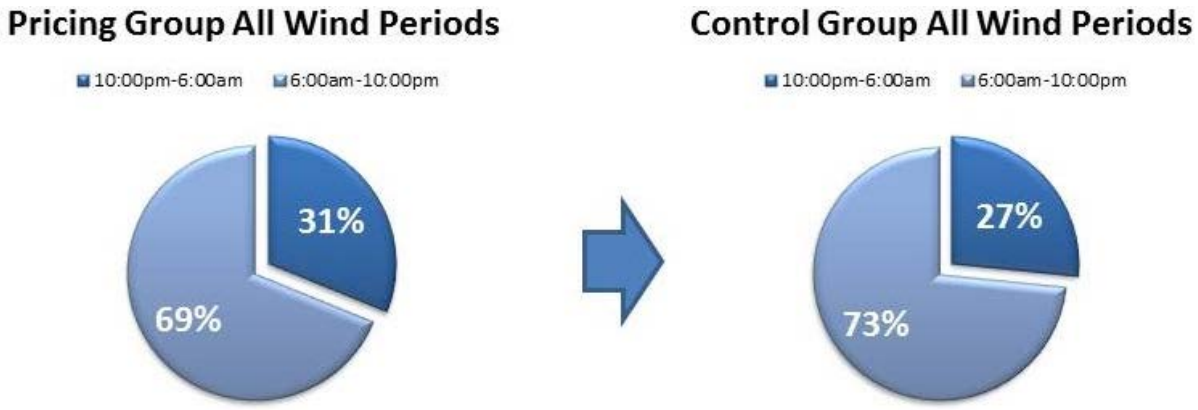


Figure 74. Pricing Group versus Control Group Consumption - All Wind Pricing Months

The 4% finding is determined to be 4-5% based on discussions summarized in the next section.

6.5.1.3.2 Response to TOU Pricing – PEV Charging

This 4% difference in day/night consumption between the Pricing and Control Groups (27% versus 31% as seen above) cannot directly be assumed to be a load "shift" because of the differing levels of PEV ownership between the groups (56% or 34 PEVs in the Pricing Group, only 10% or 6 PEVs in the Control Group). Type 2 PEV charging, at 240 volts and approximately 6 kW, or approximately equal to the demand of a 5-ton air conditioner, is the largest single consumption that can be shifted to night time. Furthermore, due to the widespread pre-trial practice of charging their PEVs throughout the day, as

found for participants in these trials, it is meaningful to compare the Pricing Group's pre-trial consumption to its own trial period consumption (figure below).

Figure 75. Pricing Group versus Self, Pre-Trial versus Trial Period

The 5% shift of consumption to night time (26% to 31% shown above) due to the TOU pricing is slightly greater than the 4% difference between the Pricing and Control Groups. This led us to conclude that there is a 4-5% shift to overnight use by the Pricing Group.

The percentage of PEV ownership in the Pricing Group affects the amount of day time load available to shift to night time. The following discussion examines PEV charging behavior, as affected by TOU pricing.

The percentage of PEV charging done at night saw a very impressive shift to night time in response to the TOU pricing for both plug in hybrids and full electric vehicles, as depicted by the pie charts below. This indicates that influencing the timing of PEV charging is important for shaping load.

Figure 76. Pricing Group PEV Owners Shift in Percent Night Time Charging

The average PEV charging consumption daily load shape is depicted in the next two graphs for owners of plug-in hybrids and full electric PEVs, for three different periods—before the trial started, during all wind months, and during the summer. It was suspected that charging behavior would differ between the two types of PEVs, so they are graphed separately.

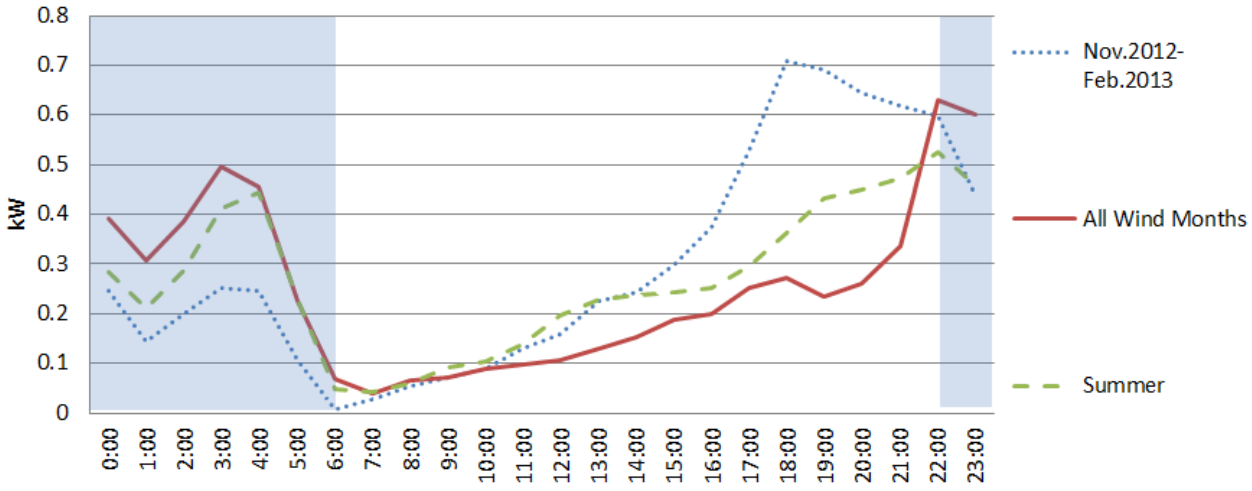


Figure 77. Pricing Group Hybrid PEV Owners Average Charging Behavior

In the figure above, (dotted line versus solid line) note the marked reduction in day time charging by hybrid owners when the TOU wind pricing is in effect, taking advantage of very inexpensive overnight charging. Also note the partial rebound in day time charging during the summer months (dashed line) when wind pricing is not in effect. This summer rebound may be partially caused by the longer daylight hours and increase in evening activities in the summer time, calling for increased seasonal afternoon charging due to the short range of hybrids. Some participants stated in the final survey responses that they went back to charging when it was convenient (including daytime hours) when the TOU pricing was not in effect.

A similar graph is shown below for the full electric PEV owners.

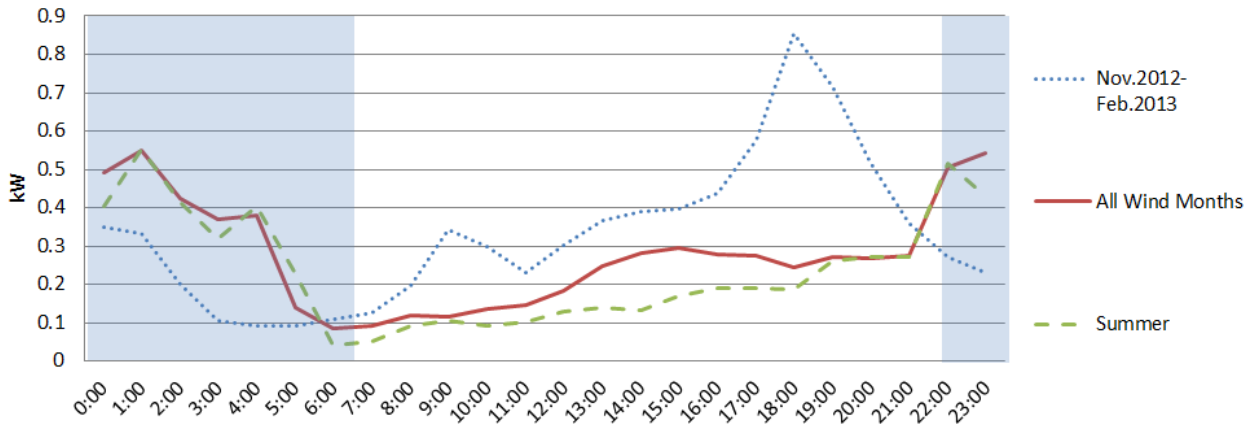


Figure 78. Pricing Group Full Electric PEV Owners Average Charging Behavior

In the above figure, the full electric PEV owners also showed a marked reduction in day time charging when the TOU wind pricing is in effect (dotted line versus solid line). But note that the summer rebound is not seen in this case (dashed line), likely because full electric PEVs often have the range needed to handle the evening tasks, allowing charging to be scheduled for overnight.

Because summer on-peak charging is of interest for system planning, and since charging is not highly correlated to weather, it is useful to compare the charging behavior of plug-in hybrid and full electric PEV owners in the 4 p.m. to 7 p.m. window, with and without TOU wind pricing.

Table 25. PEV Charging Response to Pricing

Period of Interest	Average kW Weekday non-Holiday 4 p.m. – 7 p.m. Plug in Hybrid PEV Owners	Average kW Weekday non-Holiday 4 p.m. – 7 p.m. Full Electric PEV Owners
Pre-Trial (default behavior)	0.5376 kW	0.6226 kW
TOU Wind Pricing Months	0.2414 kW	0.2655 kW
Summer (no TOU pricing)	0.3032 kW	0.1888 kW

It is likely that the average pre-trial charging load (0.6226 kW) for full electric PEVs was boosted by the higher typical charge rate for these vehicles versus some of the hybrids.

As noted in the preceding graphs and table, the pre-trial default behavior for both hybrid and full electric PEV owners was to charge for convenience during the day time hours, peaking at around 6 p.m. as reported elsewhere, upon arriving back home from work.[15]

Response to the TOU pricing was very pronounced for PEV owners as a group, resulting in greater than a 50% reduction in daytime charging and 4 p.m. to 7 p.m. charging. Night time charging nearly doubled.

Feedback from participant PEV owners indicated that the pricing incentives and educational outreach offered with these trials prompted them to learn how to program their vehicle for overnight charging, rather than charging at will during the day or simply manually starting to charge at 10 p.m. Not surprisingly, changes in charging behavior were found in this study to be persistent over the period of this study for most participants as they became part of the daily routine.

Relevant supporting research on PEVs revealed the following, giving more impetus to the need to influence the timing of PEV charging:

- 2013 total PEV Sales in US were 97,500 (1.6% of the 6 million total automobiles sold)[16]
- PEV sales are projected to grow at 16% per year between 2014 and 2023;[17] Texas is expected to be a leading state for growth in PEV sales
- Sales of PEVs are running 50/50 between plug-in hybrid and full electric[18] (breakdown in our participant group was 3:1 in favor of hybrids)
- With battery capacities of only 8-16 kWh, a fully charged plug-in hybrid uses all-electric drive for only the first 15-30 miles, then switches to series-parallel electric/combustion engine drive after batteries reach a minimum charge state. This short range encourages a pattern of frequent charging throughout the day.
- Longer range electric vehicles expected in the next 2-5 years,[19] with their higher charge rates (up to 15 kW) making it critical to understand and influence charging behavior.

6.5.1.3.3 Response to TOU Pricing – Other End Uses

In addition to PEV charging, the Team also analyzed the Pricing Group's pattern of daily consumption for individually sub-metered end uses, looking for loads being shifted to after 10 p.m. Kitchen appliance

[15] Faruqui, Ahmad, Ryan Hledik, Armando Levy, and Alan Madian. "Will Smart Prices Induce Smart Charging of Electric Vehicles?" The Brattle Group. July 2011 (page 7)
[16] Inside EVs, September 2014 Plug-In Electric Vehicle Sales Report Card, http://insideevs.com/september-2014-plug-electric-vehicle-sales-report-card/ (accessed December, 2014)
[17] Navigant Research, Green Car Congress, December 1, 2014, http://www.greencarcongress.com/forecasts/ (accessed December, 2014)
[18] Inside EVs, September 2014 Plug-In Electric Vehicle Sales Report Card, http://insideevs.com/september-2014-plug-electric-vehicle-sales-report-card/ (accessed December, 2014)
[19] Brad Berman, "The Coming Era of Long-Range Electric Cars," Plug-in Cars, Oct 19, 2014, http://www.plugincars.com/coming-era-long-range-electric-cars-130203.html (accessed 10/30/14) "300+ mi ranges by 2017" per Volkswagen official

use, water heating and laundry-related consumption would normally be expected to provide significant load shifting impact. In fact, participant surveys reported that dishwashing and laundry activities were often shifted to after 10 p.m. However, these changes did not produce dramatic shifts, largely because the Mueller community is served by natural gas, so the majority of cooking and water heating is fueled by natural gas.

Daytime HVAC use is not a candidate for shifting to overnight; also the wind months are shoulder months (low heating and cooling energy required). So, aside from shifting of PEV charging, water heating and laundry related loads to night time, the balance of load shifting was observed to be split unremarkably among various end uses of electricity in these homes.

6.5.1.3.4 No Conservation Effect from Wind Enhancement TOU Trial

The Team calculated the total annual electricity use of the Pricing Group on a rolling 12-month basis, looking for a downward trend which would indicate a "conservation effect" developing during the trial. None was noted.

Applying a different perspective, the Pricing Group's average kWh consumption in August 2013 (1,387 kWh) was compared to August 2014 (1,379 kWh). The two are virtually identical without weather adjustment, despite August 2014 being a milder month, again indicating no conservation effect.

6.5.1.3.5 Comparison to Other TOU Pricing Trials

This study estimates a 4-5% shift from day time to overnight consumption as reported above. This response is in alignment with the 3-6% impacts found in other studies.[20]

6.5.1.3.6 Wind Enhancement Trial - Final Survey of participants

In November 2014, after the study period ended, additional input was sought from Pricing Group participants via a final survey with a few targeted questions. 55% responded, and the responses relating to the TOU wind pricing trial are summarized here:

- Just over half of survey respondents indicated they altered their energy use to take advantage of cheaper overnight power during the TOU trial.
    - It is interesting that only HALF of a volunteer trial group actively participated by trying to shift load to save money.
    - Most active participants made lifestyle changes at the beginning of the trial in response to TOU wind pricing, shifting load away from afternoon peak hours, to after 10 p.m. where feasible, e.g. charging PEV, doing laundry, and running the dishwasher.
    - 80% of those who actively participated said that the trial resulted in persistent changes to their energy consumption patterns. This indicates they practiced this "learned"

[20] Faruqui, Ahmad and Sanem Sergici. "Household response to dynamic pricing of electricity: a survey of 15 experiments." The Brattle Group. 31 August 2010. Published Online

behavior during the CPP trial months as well, thereby reducing the average kW reduction of the Pricing Group in the CPP trial.

- Virtually all PEV owners in these programs stated that they shifted their car charging to alternate times, but the measured impact of this shift is diminished by the fact that many participants had already shifted their car charging to after 10 p.m. as a matter of routine during the wind pricing trial.
- One third shifted their laundry and dishwasher activities to after 10 p.m. Participants would have realized greater savings had this community not featured - almost exclusively - natural gas furnaces, water heaters, and clothes dryers.

6.5.2 Metrics and Benefits Analysis

6.5.2.1 Operational Benefits

Critical peak pricing is a tool for motivating the customer, using avoidance of high dynamic electric rates, to curtail or shift load away from peak hours on days when high loads are predicted to approach or exceed system capacity. Customers voluntarily sign on to a special plan with a CPP structure, typically with the customer's goal being to save money by opportunistically adjusting their consumption in response to critical peak events. This is beneficial to the utility system and to the customer, helping to avoid system emergencies.

TOU wind pricing in this study offers to save the customer money when the customer shifts consumption to night time. This increased night time load helps utilize west Texas wind generation that peaks at night. This shift decreases the impact on other generation assets trying to follow the system load at night (fossil-fired plants reducing load or cycling on/off) and can reduce afternoon system peak loads.

6.5.2.2 Build Metrics and Benefits

The build metrics focus on hardware and software items expended to support the project. For this pricing effort, about $449,312 was expended for hardware and software computing resources and licenses to support the testing and data analysis efforts, and $11,250 was spent on the purchase of 50 NEST thermostats for in-home testing.

6.5.2.3 Impact Metrics and Benefits

Metrics for rigorously estimating the potential impact of the pricing incentives, as found in this study, on the Texas market would be based upon extrapolating and adjusting the predicted responses to homeowners with more typical residential building styles and demographics. Several prerequisites and adjustments would be needed:

- Prerequisites
  - Advanced metering (interval meters)
  - Sufficient pricing incentive to induce behavior change
- Adjustments
  - Weather
  - HVAC equipment variables – mix of heating types (electric strip, heat pump, gas furnace), efficiency (heat pump), and use of programmable thermostats
  - Quality of construction and condition of the home
  - Conditioned square footage
  - Demographics – ability and likelihood of pricing response
  - Green commitment
  - Mix of electric versus natural gas or liquid propane fueled appliances (water heating, clothes drying, cooking)
  - PEV penetration and mix of vehicle types (plug in hybrid versus full electric)
  - Degree of acceptance of special rate plans of this nature

6.5.2.3.1 CPP Impact

- Critical Peak Pricing reduced peak consumption on event days by the following amounts:

  Summer 2013: 0.44 kW or 15.27% reduction in demand
  Summer 2014: 0.17 kW or 6.15% reduction in demand

- Because of interaction with the TOU pricing trial and second year "fatigue" reported by participants, a peak demand reduction of 0.44 kW (15%) per residence can be estimated from this CPP trial, with the qualifications that it is a reasonable impact estimate for the *initial year* of a CPP program, when the response to a *day-ahead CPP notification* is implemented in a "*non-automated*" fashion (without remote web- or AMI-enabled notification and curtailment action, i.e. fully relying on the customer to take action), in a demographic group such as represented in this study, in *energy efficient housing stock* with programmable thermostats, and in a pricing environment that *also features other incentives to move load off the afternoon peak*, such as TOU pricing. This CPP study's ratio of peak to off-peak electricity rate was approximately 5:1.
- If a 15% peak reduction was realized for all residential load in ERCOT, which comprises about half of the estimated 68,000 MW system peak load for 2014, the peak reduction would be 5,100 MW. This study did not attempt to estimate *achievable* performance.
- Environmental impact – Since there was no significant reduction in total consumption on critical peak days versus other summer days, there is no environmental impact from CPP

6.5.2.3.2 TOU Wind Enhancement Pricing Impact

- It is meaningful to compare the megawatt hours (MWh) potentially shifted in response to seasonal "wind enhancement" TOU pricing to the amount of wind generation in ERCOT during the shoulder months.
  - Calculations show that if the TOU wind enhancement pricing trial were to be implemented statewide at every residential unit, successfully shifting about 5% of the 24-hour consumption during shoulder months to night-time periods, the shift would equate to roughly one third to one half of the seasonally available overnight wind generation currently available.[21] This study did not attempt to estimate *achievable* performance.
  - In the future, it is anticipated that this percentage would trend lower, assuming wind generation continues to grow at a faster rate than residential loads.
- Environmental impact – With simple cycle combustion turbines providing marginal generation on peak, shifting of electricity consumption from daytime to night time may have estimable environmental impact. However, the modeling required for such estimations was beyond the scope of this study.

6.5.3 Stakeholder Feedback

6.5.3.1 Stakeholders

Stakeholders included policy makers and interested parties, including ERCOT, Austin Energy, other utilities and REPs, as well as members of the academic and energy-related products and services communities. These stakeholders have indicated that the findings of these trials will be useful in planning across Texas, informing continued study and decision making on the use of pricing programs such as CPP and TOU rates, and for addressing the challenges of increased market penetration of PEVs. The participants also provided feedback through their behavioral changes and also during surveys and interviews, and their opinions on these pricing programs and how they were executed will continue to inform other stakeholders.

[21] Estimate uses 2012 EIA data on total Texas residential electricity consumption and ERCOT 2012 data on total wind generation. The proportion of residential electricity consumption occurring during shoulder months was estimated using ERCOT's 2012 report of Actual Energy Use by Month (available at http://www.ercot.com/news/press_releases/show/26382, accessed 12/2/2014). The total amount of wind generation occurring during shoulder months was derived from ERCOT's Energy by Fuel Type, 2002-2013 report (available at http://www.ercot.com/news/presentations/, accessed 12/2/2014). The proportion of wind generation occurring during nighttime hours of shoulder months was estimated using monthly wind generation profiles for west Texas wind in Assessment of Wind/Solar Co-Located Generation in Texas (available at http://www.cleanenergyassociates.com/wp-content/uploads/2013/03/AE-Colocated-Solar-Wind-Study-20090923.pdf, accessed 12/2/2014).

6.5.3.2 Participants

The following is applicable to both the CPP and wind enhancement pricing trials.

On December 10, 2013, a subset of residents participating in the pricing trial met with Pecan Street and Frontier to discuss the project and provide feedback. Participants were asked questions in an informal setting to gain more understanding of their responses to the pricing options and the text message alerts.

- Each of the residents present at the meeting had made changes to their electricity use at the onset of the project due to gaining more knowledge about the program itself and not necessarily due to the pricing triggers. Energy use that could be switched to overnight or off-peak hours was generally moved early in the trial period, if convenient, with electric vehicle charging being the biggest contributor to this shift. When convenient, other electric loads were also moved, such as dishwasher use or laundry activities.
- The residents generally reacted to the critical peak alerts with peak load reductions if possible and convenient. Access to a remote-controlled thermostat, which all the Pricing Group participants had, was key to reacting to these alerts by being able to change the set point temperature in their homes. If a participant worked from home, pre-cooling was often done and the thermostat was set higher during the 4 p.m. to 7 p.m. window. Otherwise, comfort was chosen over conservation.
- One resident who worked from home scheduled his daily energy use around the pricing trial and potential alerts, including pre-cooling the house before 4 p.m. every day, so that even if a critical peak day alert was called, no changes were needed.
- None of the interviewed residents stated that the program was too difficult to manage, or a nuisance. Again, convenience, comfort and conservation commitment were the deciding factors on program participation. The monetary incentive was more of a bonus for participating in the trial. Interviewees even mentioned that the 64 cent/kWh CPP rate might need to be increased to become a more effective incentive.

In November 2014, after the study period ended, additional input was sought from Pricing Group participants via a final survey with a few targeted questions. 55% responded, and their responses were previously reported in sections 6.5.1.2.8 and 6.5.1.3.6.

6.6 Conclusions

6.6.1 Projections of Demonstration and Commercial Scale System Performance

6.6.1.1 CPP Trial

This trial defined critical peak consumption as kWh consumed between 4 p.m. and 7 p.m. on critical peak days called a day in advance. An experimental rate of $0.64/kWh was applied to this peak consumption, whereas the normal incremental rate is $0.11/kWh.

Conclusions:

- Critical Peak Pricing reduced peak consumption on event days by the following amounts:
  Summer 2013: 0.44 kW or 15.27% reduction in demand
  Summer 2014: 0.17 kW or 6.15% reduction in demand
- Because of interaction with the TOU pricing trial and second year "fatigue" reported by participants, a peak demand reduction of 0.44 kW (15%) per residence can be estimated from this CPP trial, with the qualifications that it is a reasonable impact estimate for the *initial year* of a CPP program, when the response to a *day-ahead CPP notification* is implemented in a "*non-automated*" fashion (without remote web- or AMI-enabled notification and curtailment action, i.e. fully relying on the customer to take action), in a demographic group such as represented in this study, in *energy efficient housing stock*, and in a pricing environment that also features other incentives to move load off the afternoon peak, such as TOU pricing. This CPP study's ratio of peak to off-peak electricity rate was approximately 5:1.
- A CPP regime such as implemented in this study - featuring day-ahead event calling and fully voluntary event day action required of participants - has drawbacks:
  - Critical Peak days are not always recognized one day ahead. This drawback indicates the need for a backup "same day" call regime, but communications and response on a same day basis are inherently problematic.
  - Planners must realize that peak reductions will be diminished by other peak load shifting programs in effect.
  - To be effective, the pricing must be punitive enough to strongly induce voluntary curtailment or shifting; otherwise, customers will find it not worth the inconvenience or discomfort of responding.
  - For a CPP program as structured in this study to be effective in reducing on-peak load on days when peak reduction proves critical, the following must occur:
    - The entity calling the CPP event must correctly predict the weather and system operating parameters 24 hours in advance.
    - The customer must be *able* and *have the means* and *the will* to take physical action to reduce load at the proper time
  - It can be expected that a non-automated CPP regime such as used in this trial will produce widely varying responses from one call to the next and will struggle to maintain persistence.
- Critical Peak Pricing can be effective in shifting load for participants that own PEVs, once those participants receive prompting and training on how to program their EV chargers. However, it is highly desirable that PEV owners avoid on-peak charging on *all days* whenever feasible. This desired persistent behavior is more effectively encouraged by other types of programs such as TOU pricing. Once non-essential on-peak charging is minimized, it will be unavailable as a load shift in response to a critical peak call.

- The largest individual contributors to CPP demand reduction *for PEV owners* were found to be HVAC and PEV charging, as shown in the 2013 data presented below. Other contributors were laundry and kitchen appliance use (e.g. dishwashers) which can be shifted to off-peak run times.

Table 26. (2013) CPP Peak Demand Reduction per Event (PEV Owners)

	Estimated Total kW Reduction	HVAC kW Reduction	Estimated PEV kW Charging Reduction	The Rest
Average	0.45875	0.184092	0.102483	0.172175
% of Total	N/A	40.13%	22.34%	37.53%

The largest individual contributor to CPP demand reduction *for non-PEV owners* was HVAC.

Table 27. (2013) CPP Peak Demand Reductions per Event (Non-PEV Owners)

	Estimated Total kW Reduction	HVAC kW Reduction	The Rest
Average	0.282392	0.162233	0.120158
% of Total	N/A	57.45%	42.55%

The end use constituents of kW reductions will have a significantly different makeup in different weather zones, with different demographics, different market penetrations of PEVs, urban versus rural areas, with/without the availability of natural gas or propane for space and water heating and clothes drying, and with/without other pricing programs in place that shift load away from peak hours.

- Homes that are typically occupied on weekday afternoons use more energy overall than homes that are normally unoccupied at those times. Occupied homes turned in the most impressive CPP demand reductions in this study because these homes have higher default consumption (occupied on weekdays) and the opportunity to reduce consumption by occupants taking action.

6.6.1.2 Wind Enhancement Pricing Trial

This trial attempted to induce load shifting from daytime to overnight hours. A very low experimental price of $0.0265/kWh was applied to consumption between 10 p.m. and 6 a.m. in the months (March-May and November-December) when inland wind generation is most available, while a surcharge was applied to consumption during the daytime. The ratio of peak to off-peak rates (“rate ratio”) was about 4:1.

Conclusions:

- "Wind enhancement" TOU pricing caused a shift of 4-5% of the average daily consumption from day time to overnight hours. This finding is in alignment with the 3-6% impacts found in other studies [22].
- A consumption shift of 5% across Texas is roughly estimated to utilize one third to one half of the seasonally available overnight wind generation.
- Pricing responses in different locales would be affected by weather zone, demographics, market penetration and daily miles traveled by PEVs (e.g. urban versus rural areas), and the availability of natural gas. This voluntary study group of participants was not a typical demographic. They were highly educated and "energy savvy". Half of them were likely to be at home during weekdays. Their homes had a high technology penetration in general and were energy efficient. Most of them used natural gas for water heating and clothes drying, reducing the potential for electric load shifting. One third of them owned electric vehicles.
- A TOU pricing regime is an effective and reliable pricing program for moving load off-peak, as customers are constantly encouraged to shift load. They are rewarded for persistent behavior change, and such change can become a part of their daily routine.
- Persistence of beneficial behaviors is aided by technology (e.g. programmable thermostats, appliance timers, PEV charge scheduling).
- Education, outreach, and reinforcement are important enablers of persistent change in energy consumption patterns.
- Electric vehicle (PEV) charging, typically at 3.3 kW or 6 kW, is the largest singular end use load that can be shifted to night time. But in the absence of pricing incentives, education and outreach, new PEV owners do not necessarily set a programmed charging schedule, let alone set charging for overnight hours.
- Default behavior of the PEV owners in this study, as found in other studies, was to charge the vehicle for convenience during the day, year-round, charging heavily during peak hours of 4 p.m. to 7 p.m., i.e. upon returning home from work. This study found that daytime charging is just as prevalent among full electric PEV owners as among hybrid PEV owners.
- With pricing incentives and prompting, PEV owners will shift most of their daily electric vehicle charging to overnight. If the pricing incentives are seasonal, some of the PEV owners, especially hybrid owners, will revert to daytime charging when the pricing incentives are not in effect.
- PEV charging behavior change results are broken down in the table below for hybrid and full electric PEVs. The reductions from "Pre-Trial" to "Wind Pricing" months indicate response to pricing. The difference between "Pre-Trial" and "Summer" months indicates persistent positive learned behavior, aided by technology (charge scheduling), executed even in the absence of TOU pricing.

22 Faruqui, Ahmad and Sanem Sergici. "Household response to dynamic pricing of electricity: a survey of 15 experiments." The Brattle Group. 31 August 2010. Published Online

Table 28. PEV Charging Demand Changes

Period of Interest	Average Charging kW Weekday non-Holiday 4 p.m. – 7 p.m. Plug-In Hybrid Owners	Average Charging kW Weekday non-Holiday 4 p.m. – 7 p.m. Full Electric PEV Owners
Pre-Trial (default behavior)	0.5376 kW	0.6226 kW
TOU Wind Pricing Months	0.2414 kW	0.2655 kW
Summer (no TOU pricing)[23]	0.3032 kW	0.1888 kW

- Regional PEV market trends and owner charging profiles should be studied and monitored for system planning and infrastructure impacts, particularly as longer range vehicles come to market in the next 2-5 years.
- In summary, maximizing residential PEV charging overnight will:
  - Support increased use of available Texas inland wind generation
  - Require compelling pricing incentives and education/outreach
  - Be sensitive to PEV market penetration and type of vehicles
  - Mitigate potential system peak impacts (on-peak charging)

6.6.2 Lessons Learned and Best Practices

The following outlines the major lessons learned and best practices from these pricing trials.

- Planners must account for the interactive effects of multiple pricing programs running concurrently or sequentially. One or both programs can produce lesser measured results than would be expected if implemented in isolation. This is demonstrated by the results from these CPP and TOU pricing trials, which were conducted with the same participants over alternating periods. The apparent on-peak kW reductions from the CPP trial were significantly reduced by persistent behavior changes first elicited by the preceding TOU trial. The two pricing programs were chasing some of the same candidate end use load shifts – electric vehicle charging, kitchen appliance usage (cooking, dishwashing) and laundry-related usage (washer, dryer, water heating).
- As the TOU trial was a more consistent savings opportunity available for months at a time, whereas the CPP trial involved only a few days over the entire summer, the participants saved more from the TOU trial. They responded to the TOU trial by putting in place the scheduling and behavior change needed to capitalize on inexpensive overnight power when available. These changes, or learned behavior, remained in place throughout the study period for many participants, as indicated in the final survey responses, thus diminishing the measured load reductions from the CPP trial.

[23] As noted previously, in the conclusions from the CPP trial, PEV owners FURTHER reduce their charging by another 0.102 kW on called critical peak days in the summer.

- Not all customers who sign up for a pricing program will actually participate, and changes in their situations can cause them to drop out over time. Participants can suffer from 'customer fatigue'. Response to pricing programs appears to be enthusiastic and successful in the beginning when the program is new and the educational and outreach messages are fresh. As mentioned by participants in the final survey responses, interest can fade over time, other priorities take over, perhaps savings are not perceived to be high enough for the inconvenience involved, and the incentives begin to have less direct effect on behavior. These factors point to a need for intense and continuous outreach, feedback, and reinforcement.
- PEV charging is vital for shaping load patterns. Electric vehicles are the largest load in a residential home that can be scheduled with flexibility. Most charging can be performed overnight, when the vehicle is not in use, and the charge will often be sufficient for the activities of the following day. Educating PEV owners about charge scheduling is a big first step in shifting these loads. Without such instruction, charging times are erratic and concentrated in the afternoon-evening hours (4 p.m. – 10 p.m.). Participants indicated that they do not immediately learn how to program the charging times when they purchase the vehicle. In these trials, for homes with a PEV, charging load accounted for nearly 25% of the peak load shift on critical peak days and was a key element in shifting load to overnight hours during wind pricing months.
- CPP programs that call events "real-time" with demand response actions that are automated (with opt out provision) and do not call for physical action by the participant[24] should produce more impact and be more persistent than a program such as the one implemented in this trial, which requires a deliberate response by the homeowner.
- Programmable HVAC thermostats, and in fact all appliances with programmable scheduling, are powerful tools for shifting load. They can be set up to take advantage of TOU rates like the wind-enhancement and critical peak rates in this trial.
- In trials such as these, reliable, interoperable communications are essential. Uninterrupted data communications are needed to ensure reliable meter data collection and system feedback. Data caching is needed to compensate for downed wireless connections.

[24] e.g. Gulf Power Energy Select pricing program; http://smartgridcc.org/wp-content/uploads/2013/07/CS_Gulf-Power.pdf (accessed December 2014)

7. RESIDENTIAL DEMAND RESPONSE

7.1 Introduction

TXU Energy launched the Brighten® iThermostat and Brighten® Conservation Program in June of 2008. The program included a Zigbee-enabled programmable thermostat that communicates to a Zigbee enabled gateway. The gateway was connected to the Internet via a customer-provided router to give customers a full range of remote thermostat controls and reporting, which could be accessed from most computers and smart phones. This program had two main purposes: 1) provide an incentive for recruiting and retaining customers in the highly competitive retail market, and 2) serve as a demand response (DR) program that could respond to market needs and reduce load during critical periods.

The initial 2008 pilot started as a customer self-install model with the option for professional installation. Results of the self-install model quickly revealed that less than 35% of the devices came "online" primarily because customers didn't bother to install the thermostat and/or the gateway. The program was then converted to a 100% professional installation model in 2009 where trained technicians installed the thermostat and gateway, then provisioned the equipment to ensure remote connectivity. By switching to a professional installation model TXU Energy was able to ensure initial connectivity; however, the percentage of online devices available for DR still remained well below anticipated levels. While some of the offline devices could be attributed to hardware issues, vendor quality assurance, and software issues, many were assumed to be the result of other customer-driven issues (disconnecting the gateway, Internet issues, etc.). As the customer base grew, so did the number of offline devices that were not able to receive a DR command.

While much of the DR market has focused on adjusting thermostat set points for a number of consecutive hours, TXU Energy implemented a DR program based on 15-minute cycling of air conditioning units. Based on a historical online percentage, for every 10,000 thermostats participating in the Brighten® Conservation Program, TXU Energy was only able to cycle approximately 5,500 air conditioners. Assuming each air conditioning system used an average of 1.5 kW, then the remaining 4,500 offline devices equated to approximately 6,750 kW of load that could not be reduced during a DR event. Since Texas has a Smart Meter Texas (SMT) portal that is capable of delivering DR signals to customer thermostats via the transmission and distribution utility (TDU) advanced metering infrastructure (AMI) network, the purpose of this project was to leverage that capability and provide two communication paths to the thermostat, one via the Internet and one via the AMI network. By utilizing both paths, TXU Energy expected to increase the percentage of controllable devices to over 95%, providing a better return on their investment in customer equipment.

The planned devices for this effort included:

- Gateway. The fielded Internet-capable configuration employed a gateway that transferred signals to and from the Internet to the thermostat. The concept was to pair (bind) that gateway to the residential smart meter so that it could receive signals over both communication paths.
- Programmable control thermostat (PCT). The PCT controls a home's heating and cooling system and it can be programmed to automatically change temperature at certain times of the day, generally to save energy. TXU Energy had deployed various models of PCTs in support of its iThermostat DR program.
- Smart meter. Texas has installed more than 6 million residential smart meters, and homes participating in this project are so equipped. For the initial demonstrations, this project planned to leverage the Landis & Gyr smart meters deployed in the Oncor Electric territory.
- Cable/DSL modem. These devices support the existing DR programs which use the Internet and provide the customers with the ability to control their PCTs and monitor various results.
- SMT Portal (SMTP). This software system houses archived 15-minute increment data from each of the residential smart meters, and provides a means for customers to review their usage. It also allows residents to pair in-home devices to their smart meter. The system also supports the market with the capability to delivery DR signals to the smart meters, and subsequently any in-home devices paired to that individual meter.

The figure below illustrates the high-level proposed architecture for this project.

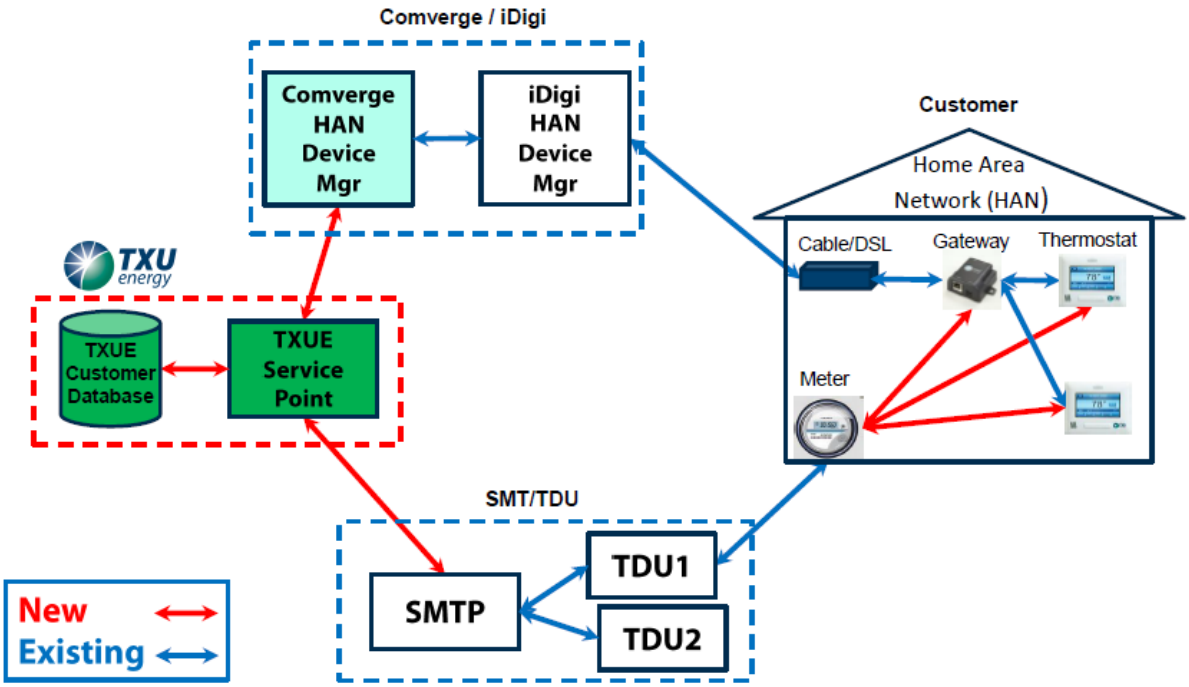


Figure 79. SMT Planning Project Architecture

7.2 Anticipated Benefits

Broadly, the expected benefits of the CCET demonstration project were to be derived from a more reliable electric grid that could facilitate effective management of and responses to increased wind resources in Texas and from supporting the deployment of new products, technologies, and infrastructure to help customers make informed decisions about their energy usage. Customers would be empowered to effectively and reliably manage their peak demand, therefore resulting in reduced customer electricity costs, reduced system-wide capacity needs, reduced electrical losses, and reduced environmental impacts. Specific smart grid benefits that were potentially supported by the residential DR component included:

- Improved DR results with more load shed during critical periods as a result of DR signals reaching more thermostats.
- A proven, viable means for delivering DR signals to more thermostats, especially those unreachable via the Internet or not equipped with a broadband connection, by utilizing dual communication paths.
- Greater return on investment for the SMT portal by providing REPs and other third parties with a viable means of reaching in-home devices via the utility AMI networks.

7.3 Interactions with Key Stakeholders

This project was sponsored by TXU Energy, a major REP in the Texas market, and the lessons learned were to be shared by all REPs. The device and dual communications path testing was supported by major TDUs and they were to be informed of the results. Improved DR results are of interest to ERCOT.

7.4 Technical Approach

This section provides a detailed description of the technical approach. The first part, Project Plan, includes illustrations of the system configurations, defines initial steps to achieve effective deployment, identifies the steps taken to demonstrate the technology (including test procedures), and outlines the approach to conduct analysis to assess performance. The second part, Data Collection and Benefits Analysis, defines the technical approach for conducting the benefits analysis, including the methodology and algorithms when appropriate.

7.4.1 Project Plan

This project was divided into two phases. The first phase focused on defining the appropriate architecture and the best equipment configuration to support the objectives, discovering any issues that may need to be resolved, and generally proving the concept. It involves experimentation and interoperability testing in a utility smart meter laboratory to determine what's feasible and how. The second phase was to focus on building and deploying the technologies to demonstrate the dual-path DR capability, including an application that leverages the SMT application programming interface (API) for

delivering DR signals via the AMI network. It would design and implement a solution. The objectives for these two phases are shown in the figure below, and the testing steps are defined after that.

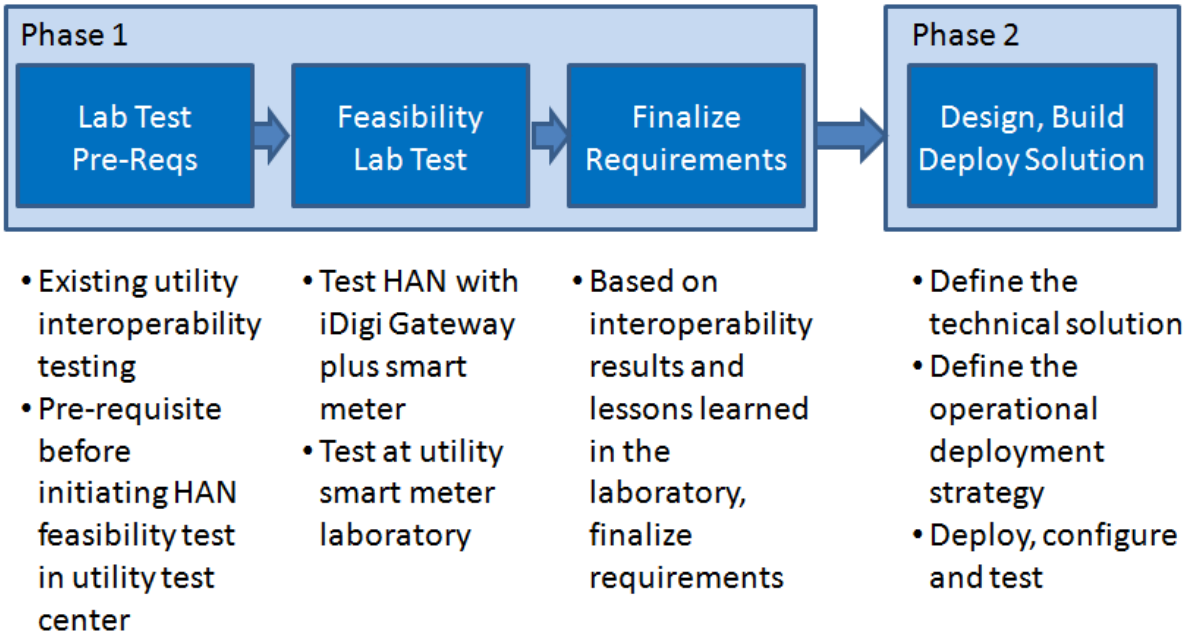


Figure 80. Phased Development of Dual Path Capability

Phase 1 – Laboratory Test at the HAN Test Laboratory

The objective of this test was to determine which configuration would support communication via both paths, the Internet and the SMT/AMI network. The scope of the testing involved the following:

- Initiated SMT commands from the Landis & Gyr test tool.
- Initiated vendor commands from their back-office system at the REP via Internet.
- Provisioned/De-provisioned the meter with the gateway (using SMT).
- Tested interoperability between the meter and the gateway.
- Tested interoperability from the meter to the PCT via the gateway.
- Verified ability to maintain connection with the vendor back-office system and the meter.
- Tested and discovered what happens at the PCT when it received the vendor proprietary DR command (via the Internet) as well as the smart energy profile (SEP) DR command (via the SMT).

Phase 1 – Feasibility Test at the Production Test Meter Laboratory

This second level of testing had three objectives:

- Determine if it was possible for a customer to switch out a gateway or would it require a truck roll with a trained installer.

- Become familiar (hands on) with the use of the SMT API.
- Verify work around for any identified vendor provisioning issue.

The scope of this testing included the following:

- Initiated SMT commands from SMT user interface simple object access protocol (SOAP) tool into SMT test environment connected to the utility production test meter laboratory.
- Initiated vendor commands from back-office system via the Internet.
- Tested use cases of leveraging both communication paths to support the existing DR program.
- Tested work-arounds to vendor issue.
- Documented the combined installation/commissioning process and evaluated the potential for a customer self-install.

Phase 1 – Perform In-Home Test and Finalize Requirements

The objectives of the in-home test included:

- Determine if it is reasonable to expect a customer to self-install by switching out the gateway, provisioning the devices (if necessary), and contacting the vendor for verification.
- Work around any vendor DR issues.
- Work around any vendor global setting configurations from previous testing.

Based on the testing results, the Team determined the viability of proceeding to Phase 2. Although the approach was viable technically, it was determined that it would not be viable economically since the devices could not be updated remotely, and the customer self-install process proved to be problematic so it would require dispatching a team to install new equipment. Therefore, it was decided that the effort would not continue with Phase 2.

Phase 2 – Define, Deploy, Validate and Exercise the Dual Path DR Capability

Upon successful completion of Phase 1, and a GO decision, the Team would have conducted Phase 2. It would have:

- Defined the appropriate technical solution.
- Defined an operational deployment strategy.
- Developed an implementation schedule.
- Developed the software to interface with the SMT.
- Implemented the deployment strategy.
- Incrementally tested DR with both communications paths.
- Analyzed and documented DR results.

7.4.2 Data Collection and Benefits Analysis

TXU Energy already performs DR events to support grid stability. Once the team validated a workable solution for the dual path approach, the DR events would be called using both communication paths, and the results would be documented, compared, and analyzed. In anticipation of Phase 2, and deployment/configuration of an appropriate dual-path solution, the team had defined its approach to reporting/validation as well as the methodology for data capture and analysis. Since Phase 2 did not occur, this portion of the reporting and analysis did not occur.

7.5 Performance Results

This section covers the operation of smart grid technologies and systems, including the demonstration results; impact metrics and benefits analyses; and any stakeholder feedback received to date.

7.5.1 Operation of Smart Grid Technologies and Systems

The current use of broadband networks to deliver DR signals to in-home devices has not achieved a high percentage of success, thus limiting the economic benefits of performing residential DR. The proposed solution was to also transmit the DR signals across the AMI networks, through the smart meter to the in-home thermostats. The Team anticipated technical hurdles that would need to be resolved so that the HAN devices could accept signals through two different communication networks. However, the Team anticipated that, once resolved, the improved success rate of these DR efforts could significantly contribute to reducing electric load across the grid when needed, and improve the economic viability of providing free thermostats to customers.

The Team began Phase 1 with the equipment configuration most widely deployed in the field, those being gateways configured as controllers paired to White Rodgers PCTs. Early testing and analysis revealed the following:

- The configuration of the White Rodgers PCTs supported a unique type of DR signal, but they were not SEP 1.x compliant so they were not configured to accept the DR signals that would be transmitted via the SMT.
- The existing White Rodgers PCTs were not configured to use production certificates which are required to pair with the smart meters.
- The gateways and PCTs would require software upgrades, and they were not remotely upgradable.
- The existing Digit x2 gateways were configured as ZigBee coordinators, and the PCTs could not pair with two coordinators, one being the gateway and one being the smart meter.
- The onboard memory for the PCTs was insufficient to add SEP text messaging.
- The cost to upgrade these devices would require a truck roll with a technician, and that cost was deemed infeasible. Estimates ranged from $55 - $180 per customer to roll a truck and

update/replace the gateways, depending on what was technically feasible. If new PCTs were required, this could cost an additional $180 per customer.

The Team then conducted a workshop to evaluate alternative approaches to overcome the defined issues. They decided to repeat Phase 1 and continue with the dual path approach but switch configuration to a new product (Carrier PCT) that had been deployed by TXU Energy more recently. That approach is outlined below, and followed by results of the various testing.

HAN Test Laboratory

The objective of this test was to determine which configuration would support communication via both paths, the Internet and the SMT/AMI network. The scope of the testing involved the following:

- Initiated SMT commands from the Landis & Gyr test tool.
- Initiated vendor commands from their back-office system at the REP via Internet.
- Provisioned/De-provisioned the meter with the gateway (using SMT).
- Tested interoperability between the meter and the gateway.
- Tested interoperability from the meter to the PCT via the gateway.
- Verified ability to maintain connection with the vendor back-office system and the meter.
- Tested and discovered what happens at the PCT when it received the vendor proprietary DR command (via the Internet) as well as the SEP DR command (via the SMT).

The results of this testing revealed the following:

- Of eight possible combinations of gateway and HAN network configuration, one configuration accomplished a “partial pass”.
- One configuration supported the necessary communication via the new SMT/AMI path and provided partial communication via the existing vendor/Internet path.
- Defined three issues to review with the vendor to determine potential for full pass:
    - DR command via vendor system had an issue with the provisioning process—tested a work around
    - Telemetry data from the PCT to the vendor back-office system was not received. It is used for validation and also provides a customer-rich experience
    - Vendor framework global settings are based on gateway type. The router settings are different from the production controller environment settings
- Raised the question of whether or not the combined installation/commissioning process could be addressed by a customer performing a self-install to avoid the costly truck rolls.

Production Test Meter Laboratory

This second level of testing had three objectives:

- Determine if it is possible for a customer to swap out the gateway or if it will require a truck roll with a trained installer.
- Gain experience with the SMT HAN application programming interfaces.
- Verify work around for previously identified vendor provisioning issue.

The scope of this testing included the following:

- Sent various DR commands to the devices in the test laboratory using the SMT simple object access protocol (SOAP) tool interface.
- Initiated vendor commands from the back-office system via the Internet.
- Tested work-arounds to vendor issue.
- Documented the combined installation/commissioning process and evaluated the potential for a customer self install.

The findings of this testing were:

- Fully satisfied second objective. The team gained first-hand experience using SMT APIs.
- Partially satisfied first objective. The team evaluated approaches for a hybrid install process (call center supported installation process).
- Complete test could not be finalized. The vendor back-office test system experienced an outage.
- Team felt confident that all issues were resolved or could be worked around. They decided to repeat the test at the home of a “friendly” (TXU Energy employee), as outlined below.

In-Home Test

The objectives of the in-home test included:

- Determine if it is reasonable to expect a customer to self-install by swapping out the gateway, provisioning the devices (if necessary), and contacting the vendor for validation.
- Verify work around for vendor DR issue from previous testing.
- Verify work around for vendor global setting constraints from previous testing.

The findings of the testing included the following:

- The vendor back-office test system continued to experience challenges with full communications to the PCT. The vendor indicated that the optimal solution, and one that would be needed for actual operational implementation, would be to establish a second set of back-

office systems focused on this new approach that uses gateways configured as routers. The estimated cost of that set-up was about $400,000.

- The team was successfully able to bond the PCT to the smart meter using the SMT Portal.
- A DR signal as well as general message was sent to the PCT through the smart meter via the SMT Portal.
- Documented steps required to reconfigure the HAN in order to support the dual-path communication approach.

7.5.2 Metrics and Benefits Analysis

As part of this project, there were two key items that the Team focused on for analysis. The first was the general economic viability of residential DR in Texas. The second was the feasibility of using the SMT to provide a dual path communications solution that could improve DR results.

7.5.2.1 Operational Benefits

One of the key operational benefits explored is the economic viability of DR in the ERCOT market. Since 2008, TXU Energy has initiated DR events across 13 days, including five pre-season tests. TXU Energy currently deploys a 15-minute, 100% cycling strategy, and the customer topology allows for TDU segmentation as well as sustained cycling within a region by rotating customer groups across 15-minute intervals. This approach allows TXU Energy to respond quickly to initial grid conditions with a predictable load reduction, and also allows for flexibility when extended cycling is required.

In order to estimate the average customer load reduction achieved during a DR event, 15-minute customer meter data was pulled for all days where DR was executed in 2011 and 2013. The data included results for both cycled (online) and non-cycled (offline) customers. The two groups were then analyzed to:

1) Measure usage reduction for cycled customers.
2) Measure usage for non-cycled customer to establish a baseline trend.
3) Apply baseline trend to cycled customers.
4) Calculate difference between actual DR reduction and baseline for cycled customers.

The figures below reflect a portion of the actual DR results based on a sample size of ~6,000 total customers. The first figure shows the effects of a single DR event triggered at 4:55 p.m. (not fully aligned with the 15-minute interval data). The subsequent set of figures shows the effects of one or more events triggered over several days in August 2011.

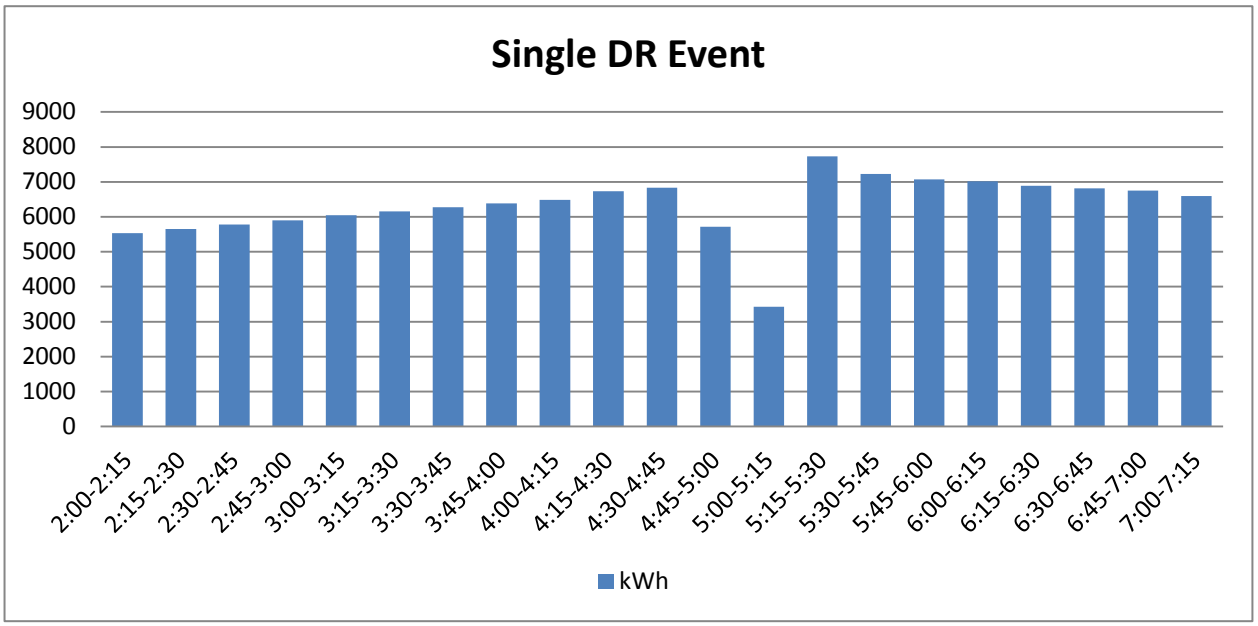
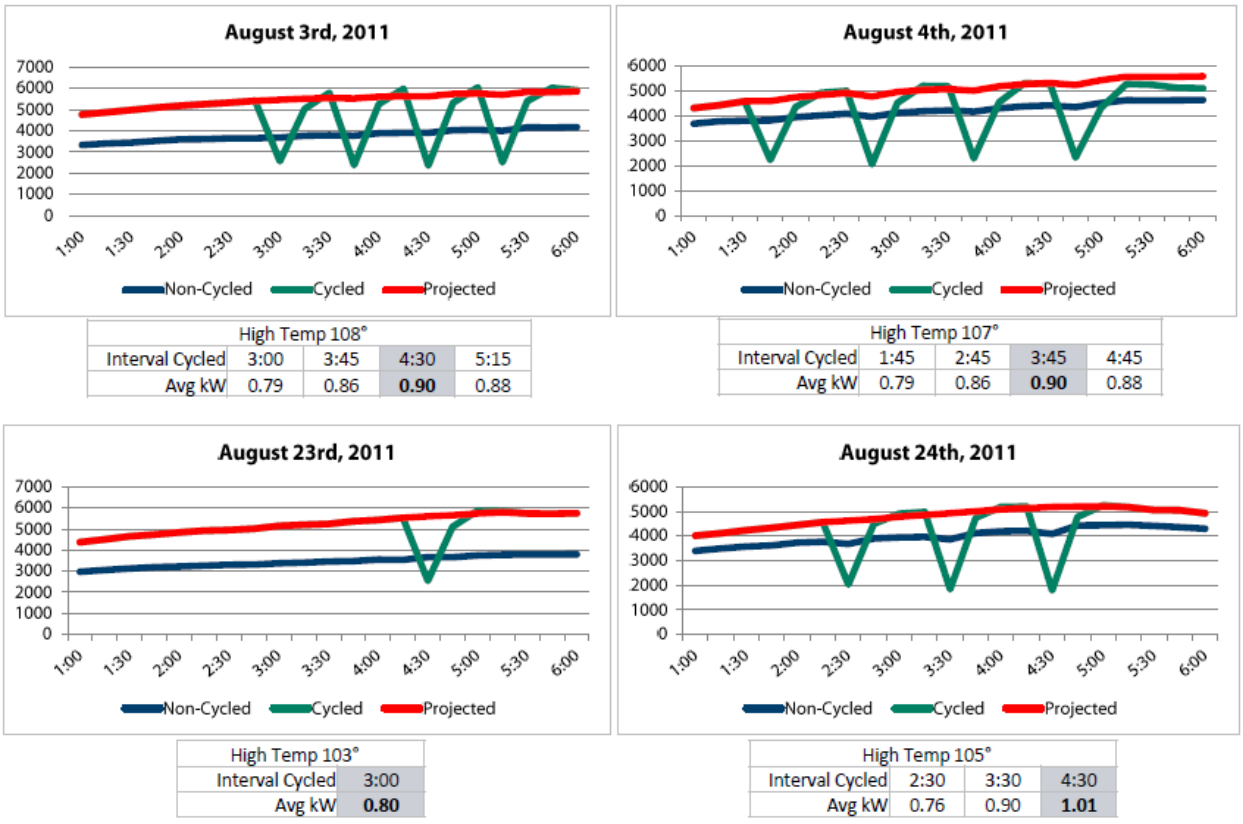


Figure 81. Single DR Event



High Temp 108°				
Interval Cycled	3:00	3:45	4:30	5:15
Avg kW	0.79	0.86	**0.90**	0.88

High Temp 107°				
Interval Cycled	1:45	2:45	3:45	4:45
Avg kW	0.79	0.86	**0.90**	0.88

High Temp 103°	
Interval Cycled	3:00
Avg kW	**0.80**

High Temp 105°			
Interval Cycled	2:30	3:30	4:30
Avg kW	0.76	0.90	**1.01**

Figure 82. Multiple DR Events

Analysis of the 13 cycling days reveals the average reduction per customer (difference between cycled and smoothed) ranges from 0.50 kWh to 1.0 kWh. The variation can be directly correlated to outdoor temperatures. Cycling performed on days where temperatures were in the upper 90s (not shown above) yielded average reductions ranging from 0.55 kWh to 0.75 kWh per customer. As temperatures climbed above 100 degrees, the average reductions ranged from 0.75 kWh to 1.0 kWh per customer.

These averages can be used to determine the incremental value of controlling additional thermostats. From a pure cost perspective, the following chart represents the potential annual value of managing peak load at the maximum ERCOT bid cap levels. The table shows results for a suggested cycling of 1,000 homes for 15 minutes (maximum value per DR event) and then multiplies that by 10 DR events per year to derive the maximum annual value per 1,000 customers per year. While these results can be extrapolated for a much larger DR pool of homes, the respective cost of equipment, truck rolls, and support must also be extrapolated. For example, in the table below, if a REP determined that they could outfit a customer with a gateway and PCT for $300 (including equipment, truck roll cost, and ongoing support), it could take 6-10 years (depending on load shed amount) to recover that cost at the $5,000 bid cap, and 4-6 years at the $9,000 cap. Given that Texas is a competitive retail market, and customers can swap REPs at will, equipping them all with these devices with the primary intent of supporting DR would be a huge investment with equally great risk.

To better understand the results shown below, the bid caps are defined as part of a Public Utility Commission (PUC) rule that authorized high system-wide offer caps (SWOC) in stages. The first increase in the cap was from $3,000 to $4,500 as of August 2012. In October 2012, the PUC decided on additional increases to the SWOC: $5,000 beginning June 2013, $7,000 in June 2014, and $9,000 as of June 2015. The $90 standard cost shown in the table is a typical cost of energy plus demand charges faced by REPs in the Texas competitive market for residential services ($0.09/kWh).

Table 29. Annual Value Proposition

Bid Cap ($/MWh)	**$5,000**	**$7,000**	**$9,000**	**$5,000**	**$7,000**	**$9,000**
Less standard cost ($/MWh)	$90	$90	$90	$90	$90	$90
Opportunity value ($/MWh)	**$4,910**	**$6,910**	**$8,910**	**$4,910**	**$6,910**	**$8,910**
Average load shed per home for 15-minute event (kWh)	0.55	0.55	0.55	1.0	1.0	1.0
Customers cycled	1000	1000	1000	1000	1000	1000
Maximum value per DR event	$2,701	$3,801	$4,901	$4,910	$6,910	$8,910
# of DR events per year	10	10	10	10	10	10
Maximum annual value per 1,000 customers	**$27,005**	**$38,005**	**$49,005**	**$49,100**	**$69,100**	**$89,100**

A second key operational benefit explored is the feasibility of improving DR with SMT and dual-path communications. The testing demonstrated that it is technical feasible to perform DR using a dual communications path strategy. However, there are a number of technical issues that must be addressed before it will be easily accomplished. Without operational trials, this project was unable to demonstrate the ability to improve DR results by sending the DR signals via two paths. One could estimate that the REP could potentially reach another 35% of their residents, meaning only 10% of the population was unreachable. However, as shown above in the economic analysis, the amount of time (in years) that it takes to recover the initial up-front investment makes it difficult to justify the costs simply to provide a DR capability. Certainly the dual path approach should be considered in defining a workable architecture that can support DR, and especially if the equipment investment is going to be made by the REP anyway. Such a solution could be an important contribution in future DR program approaches where the dual path capability adds only a small incremental cost to the set of items needed to equip and engage the customer.

7.5.2.2 Build Metrics and Benefits

Build metrics address equipment investments made for a project. For this DR effort, TXU Energy provided cost share in the amount of $801,000 to cover the expenses related to installation and service, and some administrative support, for 1385 customers from 2011 to 2013.

7.5.2.3 Impact Metrics and Benefits

Impact metrics use reductions in energy use to compute reductions in respective environmental emissions for such things as carbon dioxide (CO2), particulate matter (PM), nitrogen oxide (NOx), and sulfur oxide (SOx). For the project, the calculation presumes a base of 6000 customers participating in 13 events with an average reduction in energy use of .75 kWh.

In computing pollutant emission reductions, the following formulas were used:

- CO2: 0.00068956 tons/kWh
- SOx: 0.00263084 kg/kWh
- NOx: 0.00117934 kg/kWh
- PM2.5: 0.001 kg/kWh

For the 13 project events, the resulting pollutant reductions were estimated to be:

- CO2: 40.34 tons
- SOx: 153.90 tons
- NOx: 68.99 tons
- PM2.5: 58.5 tons

If TXU were to continue and hold 10 DR events for a similar sized customer base and achieve similar energy use reductions, the annual pollutant emission reductions would be about:

- CO2: 31.03 tons
- SOx: 118.39 tons
- NOx: 53.07 tons
- PM2.5: 45 tons

7.5.3 Stakeholder Feedback

ERCOT and the TDUs are very supportive of DR efforts in Texas. TXU Energy has been able to support market demands and lower load when the grid was threatened with instability. It would be beneficial if all customers were enrolled in DR programs, but this would require a huge investment, and there is currently no way for REPs to easily and quickly recover the costs of such an investment.

Regarding the SMT, it is jointly funded by several of the TDUs and since it is capable of supporting DR, the TDUs would appreciate that service being fully exploited. Some REPs may explore this possibility, although it's more likely that third parties, such as home security companies, may look to leverage the ability to pair certain HAN devices to the residential smart meter and deliver DR or other services leveraging the capabilities within the SMT.

7.6 Conclusions

This section covers projections of demonstration and commercial scale system performance as well as lessons learned and best practices.

7.6.1 Projections of Demonstration and Commercial Scale System Performance

REPs like TXU Energy are already performing DR and equipping residential homes with devices that can support DR during critical times. With market incentives, these programs can be greatly expanded to not only broaden the number of homes with PCTs but also to extend the capabilities to other valuable in-home devices like water heaters, pool pumps, and electric vehicle charging stations.

For REPs with current DR programs leveraging PCTs or other in-home devices, they need to continue to explore alternatives to recover and maintain device connectivity. Multiple points of failure require a comprehensive strategy to identify and recover stranded devices:

- Proactive device monitoring and recovery to identify offline devices and implement remote recover processes.

- Proactive customer outreach with a comprehensive communication strategy (e-mail, outbound calling, direct mail, etc.) to trigger customer-initiated recovery.
- Customer surveys to identify customer characteristics for future targeting.
- Exploration of alternative hardware and network solutions.
- Analysis of the data and determination of optimal strategies for improved DR: logical groupings of homes that can sustain longer cycling or deeper setbacks, customers more willing to be inconvenienced when market conditions demand it, better ways to cycle or adjust thermostats without customer inconvenience that would support arbitrage, etc.

7.6.2 Lessons Learned and Best Practices

Although this project never achieved full operational capability, it did indicate a number of valuable lessons learned and best practices.

7.6.2.1 Lessons Learned

- There is a large number of early adopter PCTs in the field that are propriety in nature, and that are not SEP compliant. Even with newer PCTs that are SEP compliant, there still might be technical challenges in configuring them to support DR programs.
- Equipping a residential home with gateways, or even swapping out existing gateways, which is an item that typically plugs into an electric outlet, is a task that a homeowner can easily accomplish. With just a bit of instruction, they can easily walk through the process of pairing the gateways with other HAN devices, or even pairing them to the smart meter.
- Developing a dual path network will require a gateway configured as a router, not a controller, and the difference is not easily understood by the routine consumer.
- The differences in PCT configurations, and the fact that they are wall-mounted and connected to wires in the home, makes swapping out these devices much more of a challenge for homeowners.
- Leveraging the SMT to bond PCTs with smart meters and support DR programs will work for customers who don't have broadband service.
- Newly introduced PCTs are now SEP 1.x compliant, and some are even SEP 2.x compliant. Additionally, they are equipped with slots for two communications cards, so they could easily be configured to support both Wi-Fi and ZigBee, allowing for dual path communications and control.
- DR programs require SEP-capable in-home devices. Even the large box retailers are now selling PCTs that can support DR. Within Texas, the SMT provides a means for provisioning/bonding those devices to the smart meter so they can participate in DR programs. However, this will require that the REP educate the consumer, and that someone incent them to participate.
- Even at market caps of $9,000, it will be very difficult for REPs in Texas to justify the expense of equipping a home with DR-enabled devices simply to perform DR. For greater market participation and penetration, new incentive programs will need to be established at the Federal

or State level to incentivize introduction of these devices into more homes, and to make them available at critical times to support DR.

7.6.2.2 Best Practices

The resource investment in this project has resulted in key findings for TXU Energy that should be considered by stakeholders addressing the need for DR to contribute to ERCOT grid relief and in using SMT technology to do so. Those key findings include:

Customer Experience and Engagement:

1) The Texas electricity customer has an option of which provider they want to use to provide electricity to their home so the load reduction experience must be agreed to and present an opportunity for the customer.
2) A load reduction program should provide customers with options including:
    a. Whether or not they choose to participate in any given event
    b. Which thermostat they want to utilize (regardless of their REP)
    c. Incentives to either reduce on their own or participate in a REP DR program

Cost Effectiveness:

1) Without TDU investment, REPs will not be able to effectively deliver a DR program as defined here and bear the full burden of the costs.
2) As shown in the previous Table, Annual Value Proposition, DR value does not cover the cost of a thermostat program as defined here either.
3) The market is evolving such that customers are willing to pay for a thermostat and installation (or self-install as that option becomes easier) thus sharing the cost burden.

Flexible Technology:

1) REPs, TDUs, and hardware and software developers must be willing to develop technology that is flexible enough to interact with each other in order to make the most of their individual capabilities.
2) As Texas remains a competitive market, REPs will be encouraged to develop unique offerings with unique partners to maintain their competitive advantage which should further benefit the ERCOT market.

As the market evolves and new technologies are introduced to Texas consumers, REPS and TDUs will need to be prepared to respond in ways that address the above key findings to continue to be relevant players in this ecosystem. Energy efficiency is now a familiar term to Texas consumers, and they are beginning to understand the part that they play in helping the state. REPs and TDUs must provide the mechanisms through which they can participate and ultimately benefit the grid.

8. DISTRIBUTION-LEVEL BATTERY ENERGY STORAGE SYSTEM

8.1 Introduction

As part of the future community component, CCET was interested in investigating the benefits of deploying a battery energy storage system (BESS) in conjunction with wind turbines on a distribution-level grid. The overall objective was to test the ability of the BESS to perform various needed grid functions, such as peak shaving, load leveling, and frequency support. A secondary objective was to determine the economic viability of deploying these systems to support grid operations. The RTC near Lubbock, Texas, afforded an optimal location for satisfying the objectives since it was already established and outfitted as a wind test facility, it provided access to a distribution grid operated by a local cooperative that was very supportive of testing, and was close to TTU which had a staff capable of performing the BESS evaluations. The Team defined a detailed functional specification for a BESS, and then issued a competitive request for proposal. After negotiations, CCET awarded a contract to Xtreme Power (now Younicos) for a 1 megawatt (MW) Lithium Manganese Oxide (LMO) BESS. This system, pictured below, was built, tested, fielded, and connected to the grid in eight months, becoming fully operational in August 2013.

Figure 83. BESS Installed at the Reese Technology Center

The BESS houses 18 racks with 256 batteries totaling 4,608 battery cells with a combined energy storage capacity of 1 megawatt hour (MWh).

Figure 84. Racks of Batteries within the BESS Container

The BESS operates in conjunction with about 4.6 MW of wind generation at the site. This includes an Alstom ECO86 1.67 MW wind turbine, a Gamesa 2 MW wind turbine, and three V27 300kW Vestas turbines that were deployed by Sandia National Laboratories as part of its new Scaled Wind Farm Technology (SWiFT) facility which currently produces 900 kW, and will eventually be expanded to produce 3.6 MW. The site also includes a 200-meter meteorological tower to provide atmospheric measurements for wind analysis. Two images of the SWiFT facility are shown below. The first figure below shows a view of the three SWiFT turbines and the meteorological tower. The second figure shows an aerial view of the SWiFT turbines and the close proximity of the BESS.

Figure 85. SWiFT Facility at Reese Technology Center

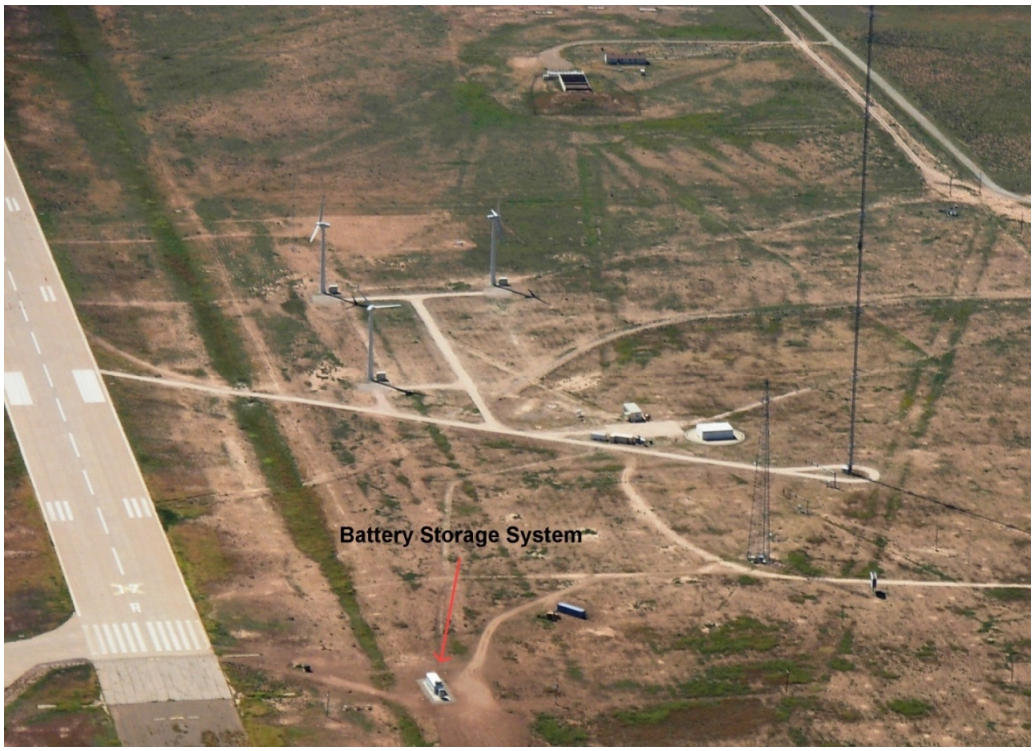


Figure 86. Aerial View of the BESS and the SWiFT Facility Turbines

The BESS is operationally integrated into the grid of the South Plains Electrical Cooperative and is controlled by SPEC with assistance from Younicos. During the course of the project, the BESS was thoroughly tested to determine its ability to support a number of functions and hence increase its value. Most importantly, it is being utilized to supply some of the energy necessary to meet the demands of a local substation electric load, especially during peak periods. For that purpose, it is typically charged during periods of low demand, which often coincide with high wind generation. However, since the battery system is connected to the utility grid, it does not need dedicated wind power to be charged.

The battery and wind generation are connected such that they are only used for local capacity and do not feed back onto the transmission grid beyond the boundaries of SPEC. The electrical system layout is shown below.

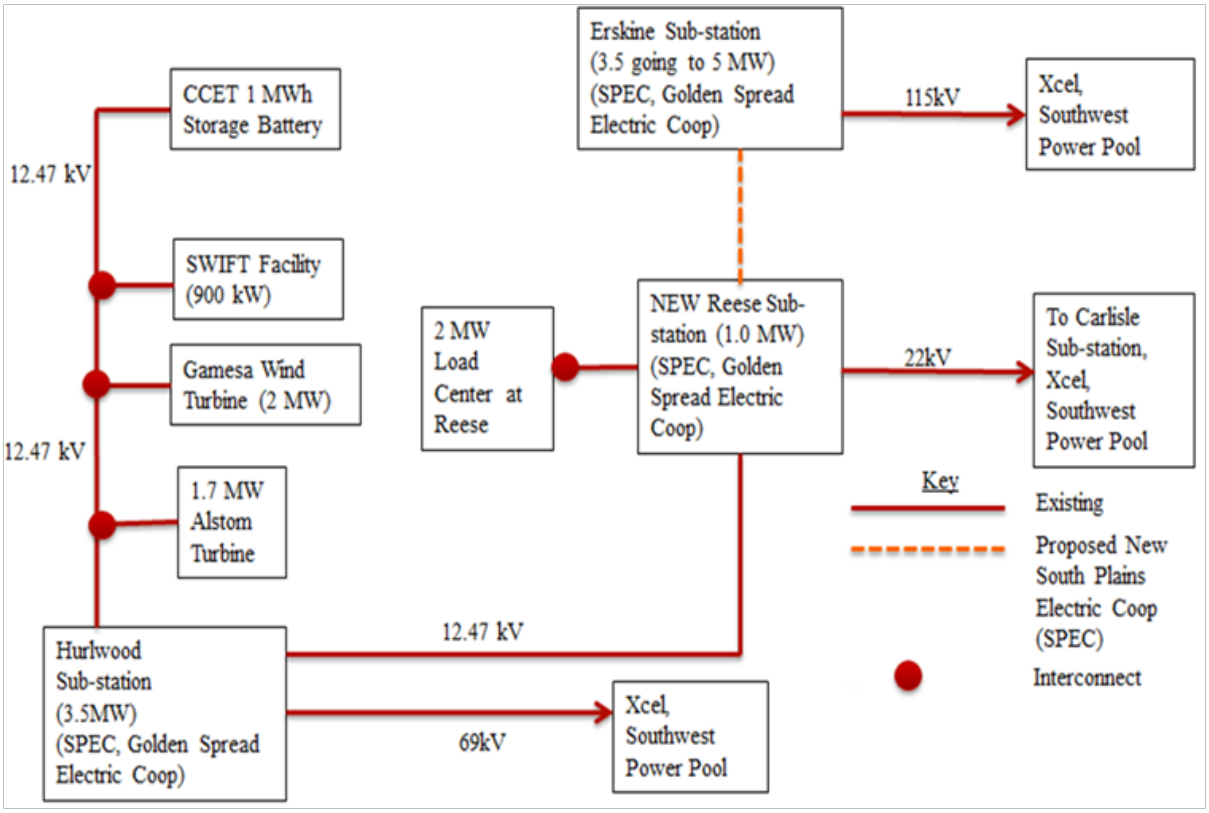


Figure 87. Reese Technology Center Electrical Layout

The BESS is connected via a bi-directional converter through a transformer to the main distribution grid. It is connected at the 12.47 kV medium voltage level, and can be charged or discharged by the bi-directional converter as shown below to manage power flow into the grid.

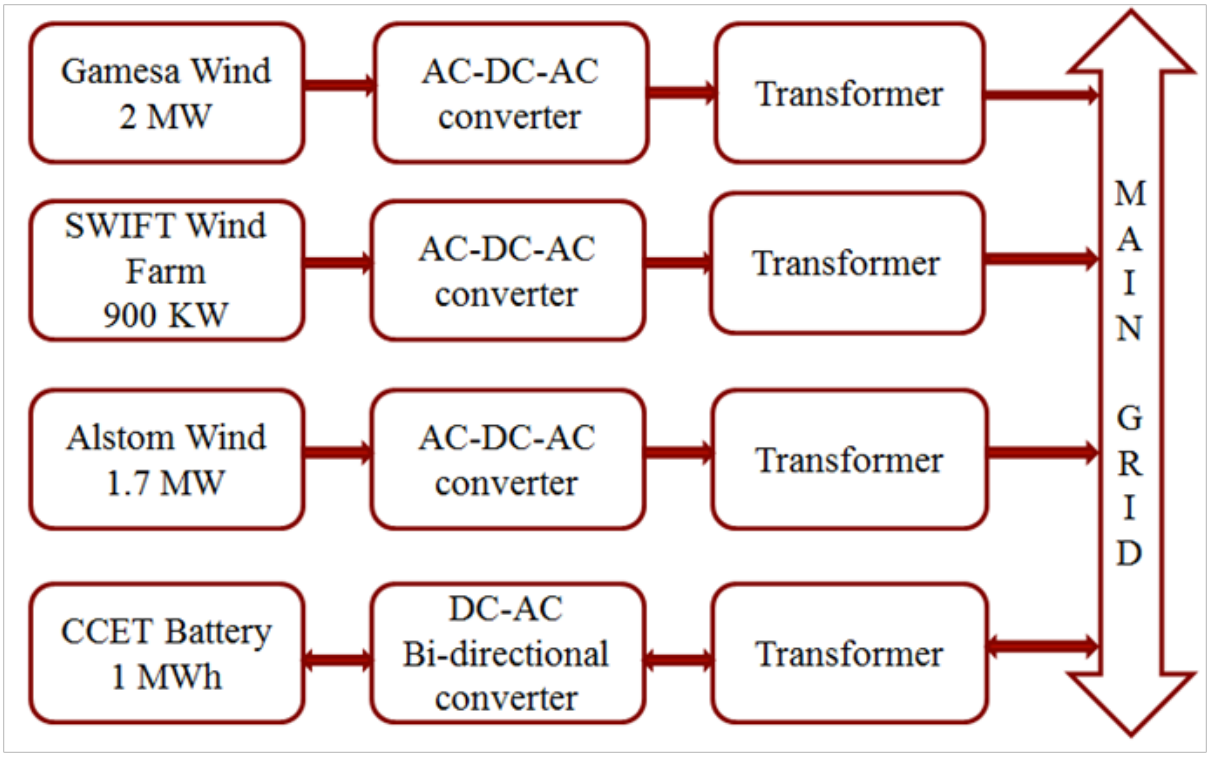


Figure 88. BESS Block Diagram

The BESS utilizes a series of deep-cycle LMO batteries developed by Samsung and designed for use in renewable energy applications. In addition to peak shaving for the local cooperative, SPEC, the BESS is also designed to perform other operations such as mitigating intermittent fluctuations of nearby wind turbines, regulating the distribution bus voltage through management of reactive power generation, serving as "spinning" reserve, and providing frequency support during the loss of generation.

8.2 Anticipated Benefits

Broadly, the expected benefits of the CCET demonstration project derive from a more reliable electric grid that can facilitate effective management of and responses to increased wind resources in Texas and from supporting the deployment of new products, technologies, and infrastructure to help customers make informed decisions about their energy usage. Customers are empowered to effectively and reliably manage their peak demand, therefore resulting in reduced customer electricity costs, reduced system-wide capacity needs, reduced electrical losses, and reduced environmental impacts. Specific smart grid benefits that were anticipated for the BESS included:

- Capture cheap wind power during periods of high renewable generation and low demand
- Feed real power into the SPEC distribution grid during peak demand periods
- Make renewable energy generation sources more dispatchable
- Make energy from renewable energy generation sources more valuable

- Serve as very fast frequency support to counteract loss of generation effects
- Serve as ramp support to offset fast decline of wind

8.3 Interactions with Key Stakeholders

The major interaction with stakeholders during the project was through the local utility, SPEC. TTU worked closely with SPEC to determine the potential roles of the BESS and how its performance could be maximized to help its customers. GSEC and SPP indicated an interest in the benefits derived from this system, and ERCOT and the CCET member utilities were extremely interested in discovering the value proposition for battery systems of this scale.

8.4 Technical Approach

This section provides a detailed description of the technical approach, the questions to be addressed, and the methods used to answer them. The first part, Project Plan, identifies the steps taken to demonstrate the technology, and outlines the approach to conduct analysis to assess performance. The second part, Data Collection and Benefits Analysis, defines the technical approach for conducting the benefits analysis, including the methodology and algorithms when appropriate.

8.4.1 Project Plan

The 1 MW BESS was installed at the RTC to work in connection with 4.6 MW of wind generation at the site. The battery was utilized in conjunction with the wind facility to potentially supply all of the energy necessary to meet the electric load demands of the Hurlwood substation. The plan was to install the BESS and then evaluate its ability to support a wide array of functions that would improve its overall value for the grid.

The first step was to create very detailed and specific models for the battery, the wind turbines, and the utility network from the RTC to the substation using power system computer aided design (PSCAD) to simulate the performance of the battery under several operating conditions such as:

- Offset load management – Charge the battery during periods of high wind and discharge the battery during the period of high load (peak load shaving).
- Ramp operation – Use the battery to supply energy when the wind speed drops rapidly, thereby countering the effective loss of the wind generation, providing time for other generation to be brought online.
- Frequency management – Discharge the battery at maximum rate to support the grid during frequency dips.

Once the system was modeled in PSCAD, the second step was to exercise the battery and perform a wide array of functional testing to determine potential uses for a BESS of this scale. These results were

then analyzed and used to validate the modeling results. Additionally, a third step was to perform an analysis to determine the economic viability for such a system.

8.4.2 Data Collection and Benefits Analysis

The technical approach included collection of a wide array of data including daily power production, wind speed and price data for the wind turbines, as well as the parametric data for the BESS. The latter included:

- Ramp rate and frequency for grid stabilization.
- Performance of the battery as a function of the state of charge (SOC), temperature and the number of charge and discharge cycles. This also includes how well the energy flow is managed, in addition to how the transients and faults affect the battery.
- Response of the battery to steady state and transient requirements.
- Reliability of the battery as a function of performance.
- Parameters that affect the reliability of the battery such as over-current, over-voltage, under-voltage, and temperature.
- Power quality of the energy system at the connection point to the grid.

A complete analysis of power quality was performed on the output voltage from the battery, and the inverter connecting the battery to the grid. Because the battery was connected to the utility grid, transient analysis such as three-phase shorts, single-phase shorts, and open circuit conditions could not be performed on the system. The transient analysis was, therefore, conducted by simulating the system and injecting the faults to determine how the components performed. Load flow and steady stated analysis were conducted to determine the optimal flow of power in the system.

8.5 Performance Results

This section covers the three main thrust areas: modeling and simulation, analysis of wind data, battery testing, and an economic analysis.

8.5.1 BESS Modeling and Simulation Efforts

Various types of generic models are available for the purpose of battery modeling, and these were investigated by the Team. A literature search indicated that the electrochemical polarization in Li-ion batteries leads to an inaccurate simulation of charge and discharge transients. Taking this factor into consideration, the Dual Polarization (DP) model was chosen for modeling the battery. This model has refined the description of polarization characteristics and simulated the concentration polarization and the electrochemical polarization separately. The resulting basic model for a battery cell is shown below.

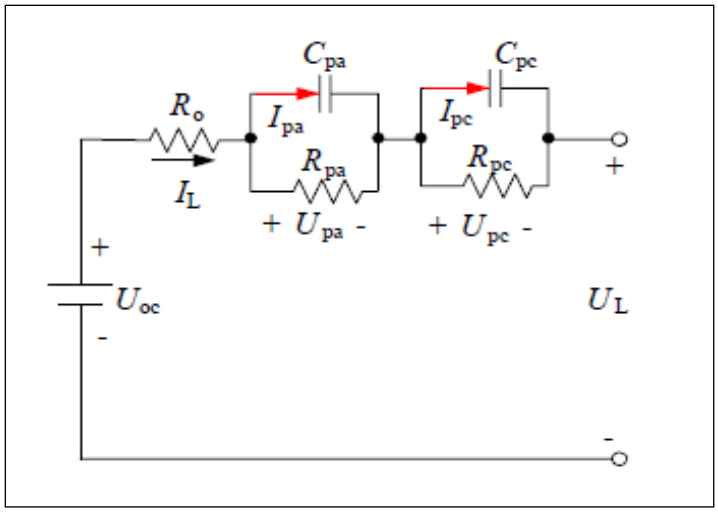


Figure 89. Basic Circuit of DP Model

The figure below shows the circuit with battery life-time and DP model [25]. This circuit has been modeled in PSCAD to obtain a 1 MW battery.

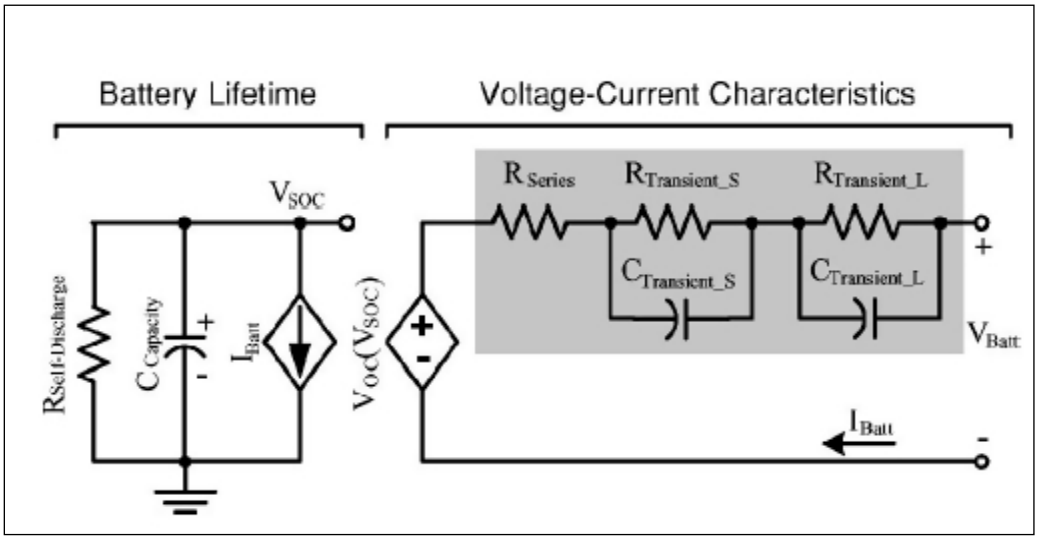


Figure 90. Accurate Battery Model

[25] Min Chen; Rincon-Mora, G.A, "Accurate electrical battery model capable of predicting runtime and I-V performance," Energy Conversion, IEEE Transactions on vol.21, no.2, pp.504,511, June 2006 doi: 10.1109/TEC.2006.874229

For the figure above, the characteristics are:

R_{series}	- Sudden voltage drop
$R_{transient_S}$ and $C_{transient_S}$	- First time constant
$R_{transient_L}$ and $C_{transient_L}$	- Second time constant
V_{batt}	- Battery terminal voltage
$C_{capacity}$	- Equivalent of energy stored in battery
Vsoc	- Open-circuit voltage
$R_{self\text{-}discharge}$	- Ignored according to capacity retention

The discharge is controlled by current flowing out of the terminals of the battery. To discharge capacitor – I_{Batt} flows out through the current controlled current source. When the current flows out to load, it also discharges the capacitor, so the V_{SOC} also starts to decrease since the V_{SOC} controls the V_{oc} to control the terminal voltage V_{Batt}.

The charge current comes into the capacitor as reverse current flow. To charge the capacitor – I_{Batt} flows into the current controlled current source.

Based on the information above, the basic building block of a BESS, the modules, was formed by configuring the cells in series. Two system modules were then connected in series configuration and paired with tray-level battery management systems (BMSs) to form a rack-mountable system tray assembly.

8.5.1.1 Single Cell Battery Model

With reference to the above assembly and the calculations, initially a single cell of the battery system was modeled with the voltage at 4.12 volts (V), a nominal voltage at 3 V and current at 60 amps (A). The circuit is shown below.

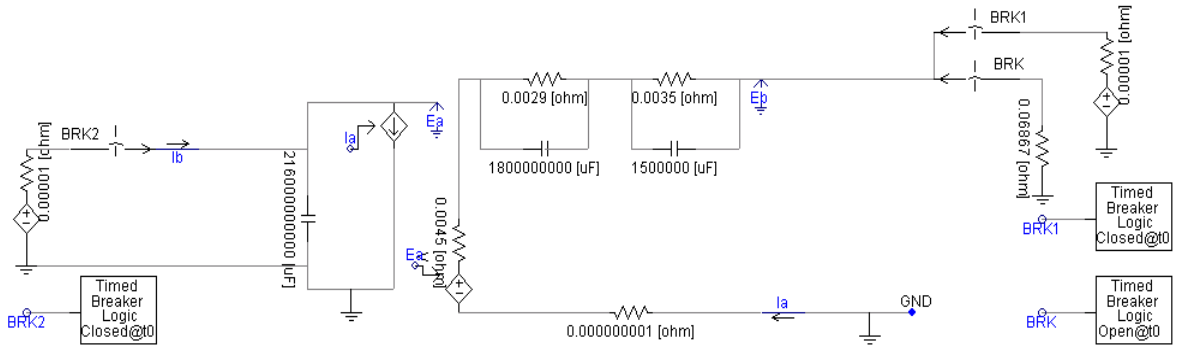


Figure 91. Single Cell Battery Model

The figure below shows the controls to enable the battery roll-off before it drops further in reaching the lowest operating point.

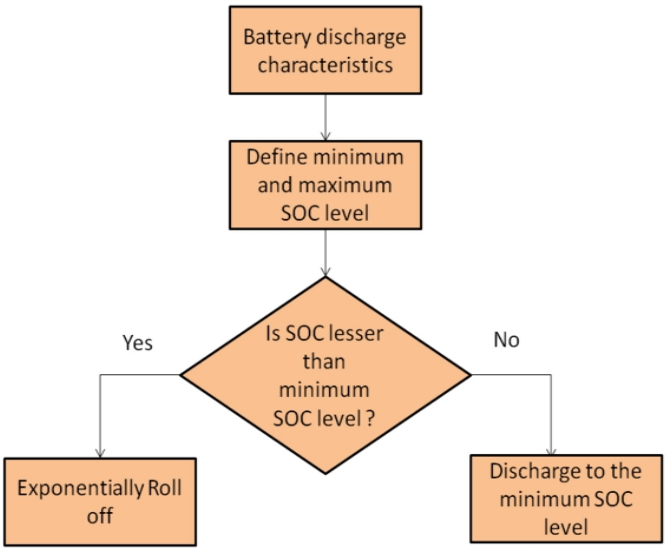


Figure 92. Control Algorithm of the Battery Cell

Based on the control algorithm above, the battery was charged to its full capacity of 4.12 V through the direct current (DC) voltage source. The battery was made to discharge at a 1 C rate (60 Ah) through a resistive load of 0.0689 ohm until it reached the minimum operating voltage of 3.0 V at which time the battery was made to exponentially roll off to zero (the line indicating the steady rate of increase or decrease levels off—basically curves away at an exponential rate). The battery voltage was observed as the battery discharged over time. Once the minimum operating voltage was reached, the comparator enabled the battery voltage "E_b" to roll off at 3600 seconds. The figure below shows the implementation of the controls as they were modeled in PSCAD. The voltage source at the right side of the model was used to charge the battery with 4.12 V during which the BRK1 breaker was closed and the BRK breaker was open. After the charging of battery, the BRK1 was opened and the BRK was closed so that the battery discharged through the load of 0.06867 ohm. The current "Ia" was used to charge or discharge the battery $C_{capacity}$ dynamically. The output from the comparator was fed through a parallel connection of voltage source and a resistor of 0.6867 ohm to observe and plot the roll off at 3600 seconds.

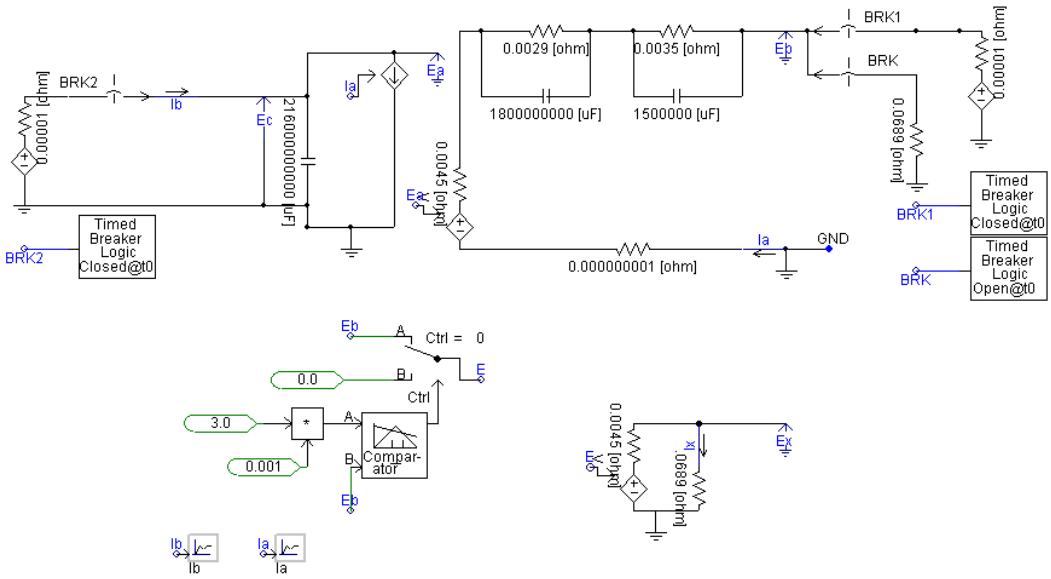


Figure 93. Model of the Single Cell Battery with Controls

8.5.1.2 Discharge Characteristics of Various C Rates

A C-rate is a measure of the rate at which a battery is discharged relative to its maximum capacity. The battery (1 MWh) operates until the minimum SOC level (760 V) at 1C which means the battery discharges at a constant current of 1200 A until it reaches minimum SOC of the battery in 1 hour. If the 1200 amp-hour (Ah) battery is charged/discharged at a current of 600 A in 2 hours then it is called C/2 rate. If the 1200 Ah battery is charged/discharged at a current of 1200 A in 1 hour it is called 1C rate. If the 1200 Ah battery is charged/discharged at a current of 2400 A in 1/2 hour it is called 2C. The simulation results are shown below for various battery C rates given the 4.12 V, 60 Ah battery.

The battery discharge characteristics for 1C are shown below. The battery voltage was at 4.12 V initially and discharged up to the lowest operating voltage of 3.0 V for one hour (3600 seconds) at a constant rate of 60 A.

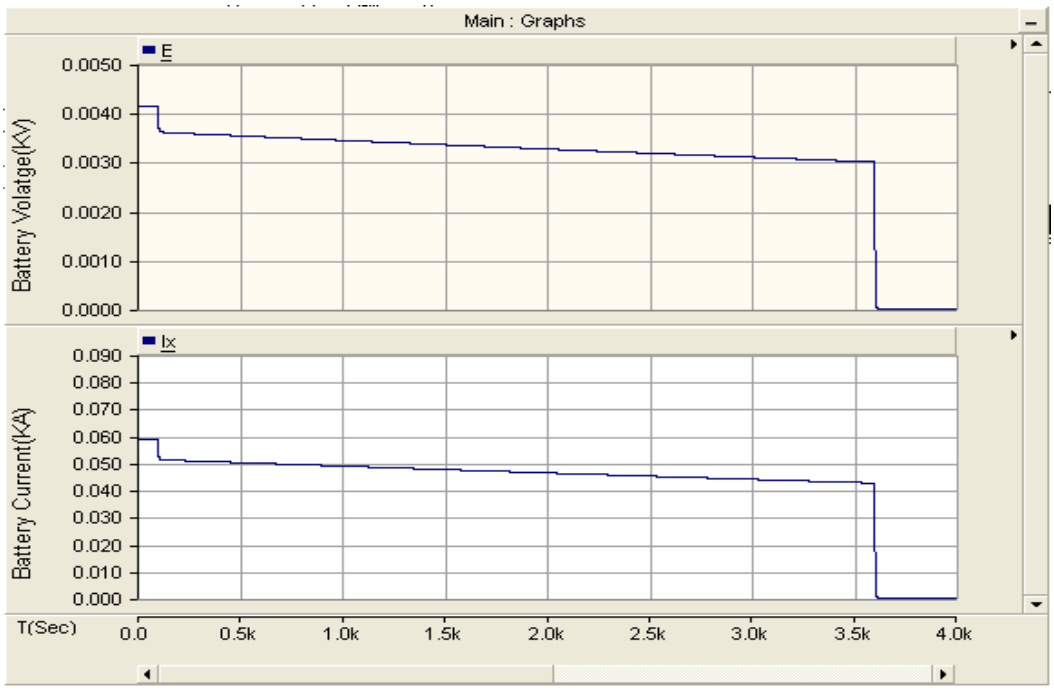


Figure 94. Battery Discharge at 1C rate

Similarly the battery discharge characteristics for C/2 battery are shown below. The battery voltage was at 4.12 V initially and discharged up to the lowest operating voltage of 3.0 V for two hours (7200 seconds) at a constant rate of approximately 30 A.

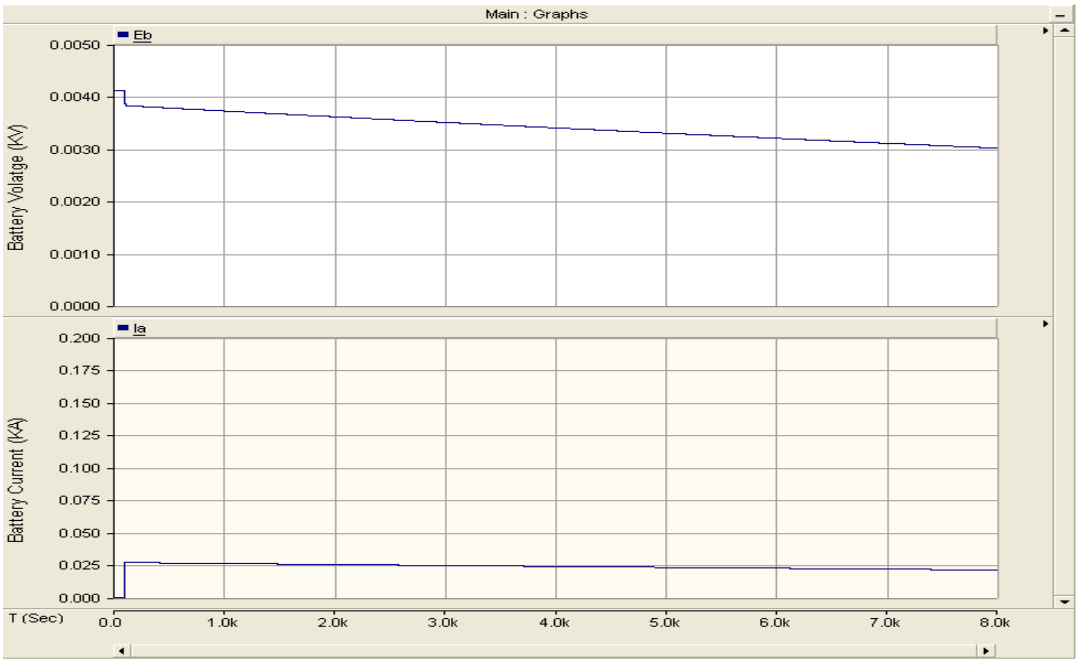


Figure 95. Battery Discharge at C/2 Rate

The battery discharge characteristics for 2C are shown below. The battery voltage was at 4.12 V initially and discharged up to the lowest operating voltage of 3.0 V for half an hour (1800 seconds) at a constant rate of approximately 90 A.

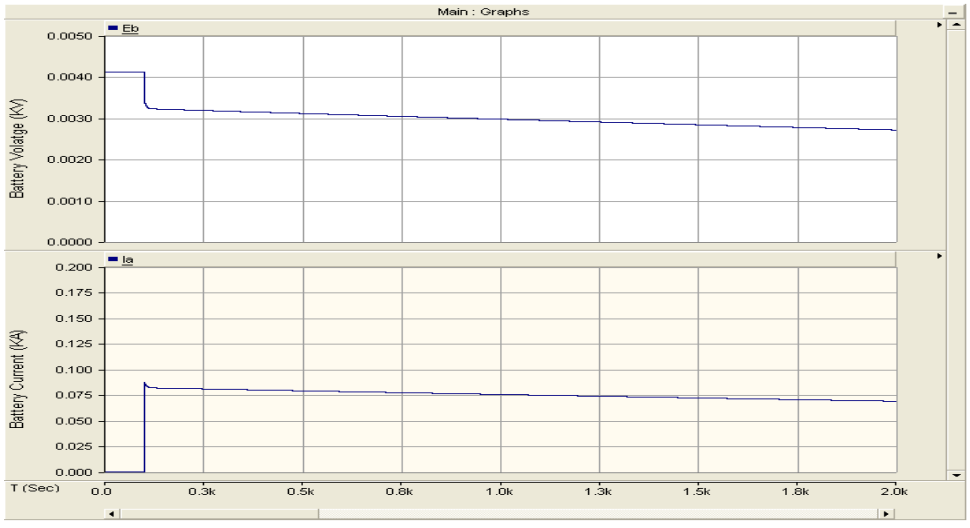


Figure 96. Battery Discharge at 2C Rate

Similarly the battery discharge characteristics for 3C are shown below. The battery voltage was at 4.12 V initially and discharged up to the lowest operating voltage of 3.0 V for 15 minutes (900 seconds) at a constant rate of approximately 110 A.

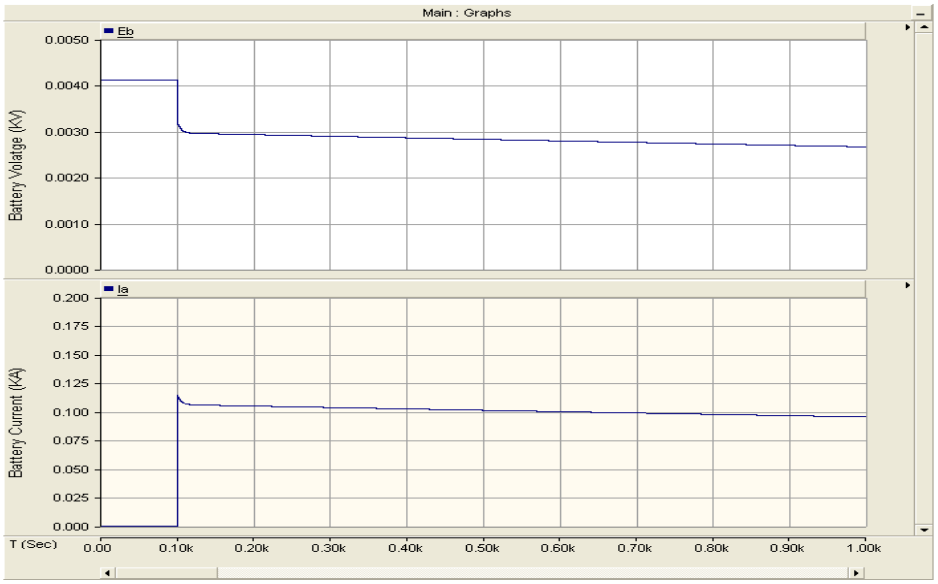


Figure 97. Battery Discharge at 3C Rate

The above simulation results are tabulated as shown below:

Table 30. Results for Different C Rates

Battery Cell Parameters	**Cell**	**Simulation Results**			
		C/2 (30 Ah)	1C (60 Ah)	2C (120 Ah)	3C (180Ah)
Nominal Voltage	3.7 V	3.7 V	3.7 V	3.6 V	3.6 V
Operating Voltage	3.0-4.12 V	3.0-4.12 V	2.9 – 4.12 V	2.8 – 4.12 V	2.8 – 4.12 V
Design Capacity	60 Ah	60 Ah	60 Ah	60 Ah	60 Ah
Battery Current	60 A	28 A	50 A	90 A	120 A

8.5.1.3 Validation of the Battery Modeling

The figure below shows the simulation data compared to the experimental cell data of a 4.12 V, 60 Ah LMO single cell. The simulation of the single cell battery model in PSCAD was saved to an output file. Using the MATLAB program, the simulation data of battery voltage was read from PSCAD and the experimental data was read from an Excel file. The graphs were plotted and the slopes were calculated

as 0.0002 for experimental and 0.000196 for simulated data respectively. The percentage of error in the model is found to be 0.2% and is calculated as follows[26]:

% of error = [(Simulated slope-experimental slope)/experimental slope] *100

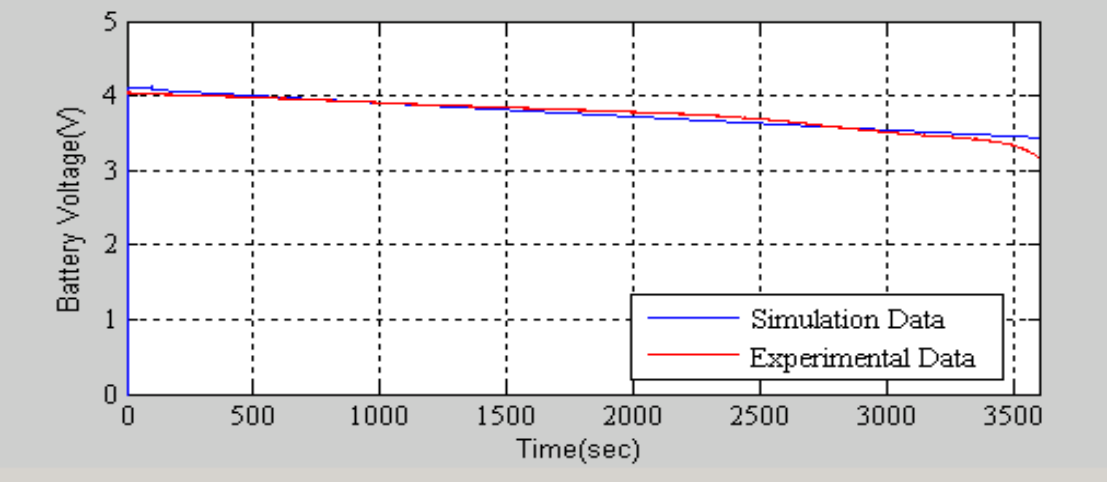


Figure 98. Comparison of Simulation and Experimental Results of 1C (60 A)

8.5.1.4 Stacked Cell Battery Model

The battery terminal voltage response includes voltage drop with a sudden and a slow response curve and hence the battery terminal voltage response is described in the short and long term operating conditions by the resistor-capacitor (RC) network. The basic building blocks of the BESS, modules, were formed by configuring the cells in series. To obtain a 1 MWh battery, an operating voltage of 760 V to 1053 V with a nominal operating voltage of 947 V and 1200 Ah was considered. The battery was charged to 4.12 V and discharged slowly to reach the nominal voltage of 3.7 V at 3600 seconds. The 16 single cells were stacked in series, and further stacked up to get 256 cells (256 cells *4.12 V =1055 V) with a voltage of 1055 V.

Once the single cell of 3.7 V was modeled, 256 such cells were stacked in series to obtain a voltage of 1055 V and current of 60 A. Modules were connected in parallel to increase the current to 1200 Ah with 1055 V and resistive load of 0.78916 ohm. The battery was charged to 1055 V and made to discharge slowly and made to exponentially roll off at 3600 seconds as shown below.

[26] Broughton, Kathleen. "A Tale of Two Processes: Simulation vs. Experimentation." University of Illinois, Chicago, 2011. Web. 23 Sept. 2014. http://www.slideshare.net/broughtonkm/simulation-vs-experimentation-a-tale-of-two-processes

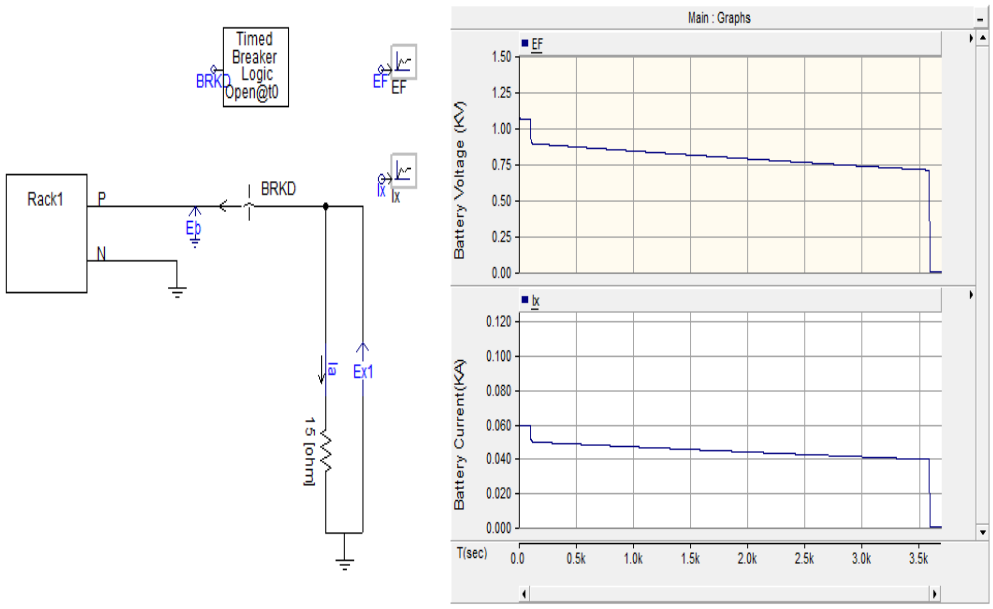


Figure 99. Voltage and Current (V & I) Waveforms of the 1055 V, 60 Ah Battery System

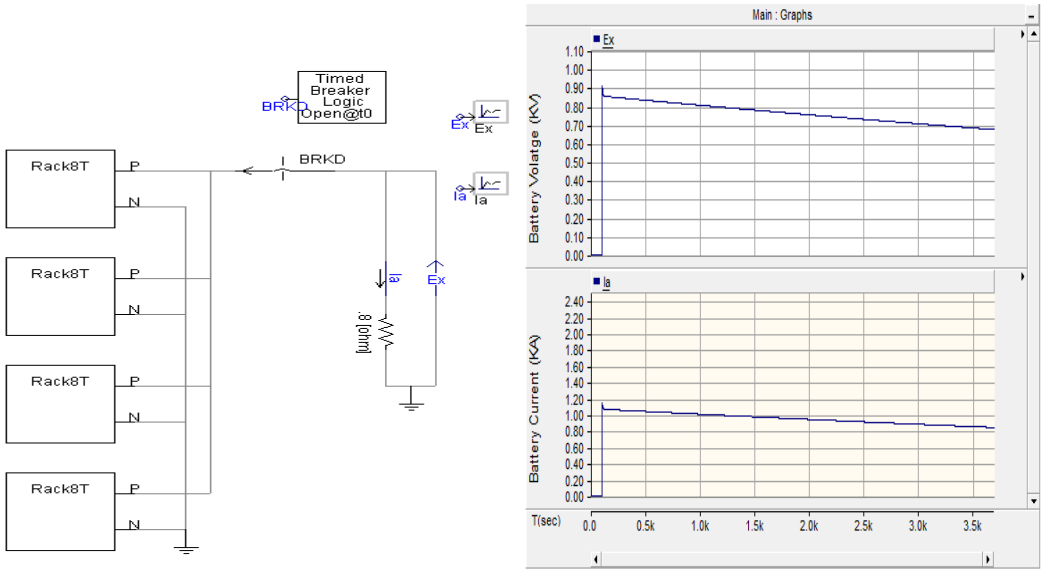


Figure 100. V & I Waveforms of the 1055 V, 1200 Ah Battery System

8.5.1.5 Electrical Equivalent Cell Model

Equivalent circuit models are often used to simplify the calculation whereby a complex circuit is represented in its simplest form to enable analysis of the circuit models. The equivalent circuits describe the electrical behavior of the model. Also issues with node compatibility, accuracy, memory space requirements, and run time of a particular program in PSCAD are overcome by using the electrical circuit model.

The expression for the controlled voltage source is given by the following equation [27] with E_0 - battery constant voltage, E - no-load battery voltage, K - polarization voltage, Q - battery capacity (Ah), ∫idt - actual battery charge, A - exponential zone amplitude, and B - exponential zone time inverse.

$$E = E_0 - K\frac{Q}{Q - \int i\,dt} + A\exp(-B \times \int i\,dt)$$

Instead of stacking the cells, the equivalent circuit for the 1 MWh battery was modeled and analyzed for the discharge characteristics of a resistive load. The calculation of parameters of the electrical equivalent cell was similar to the procedure of a single cell. Assuming battery was at charged state, the usable capacity can be modeled by a full capacity capacitor $C_{capacity}$. By setting the initial value to be 1200 V, the battery was initially fully charged (SOC is 100%). C capacity will not change with current variation. When the battery was charged or discharged, the controlled current course, I_{Batt} was used to charge or discharge $C_{capacity}$ so that the SOC represented by Voltage SOC (VSOC) changed dynamically. Hence the battery run time or the discharge slope was obtained until the battery voltage reached the end of discharge or the minimum operating voltage. The battery was charged to 1053 V and made to discharge slowly and made to roll off at 3600 seconds at 1C rate as shown by battery voltage, Eb, in the figure below. The current across the resistive load was also found to be discharging slowly from 1200 Ah as shown by battery current, Ix, in the second figure below.

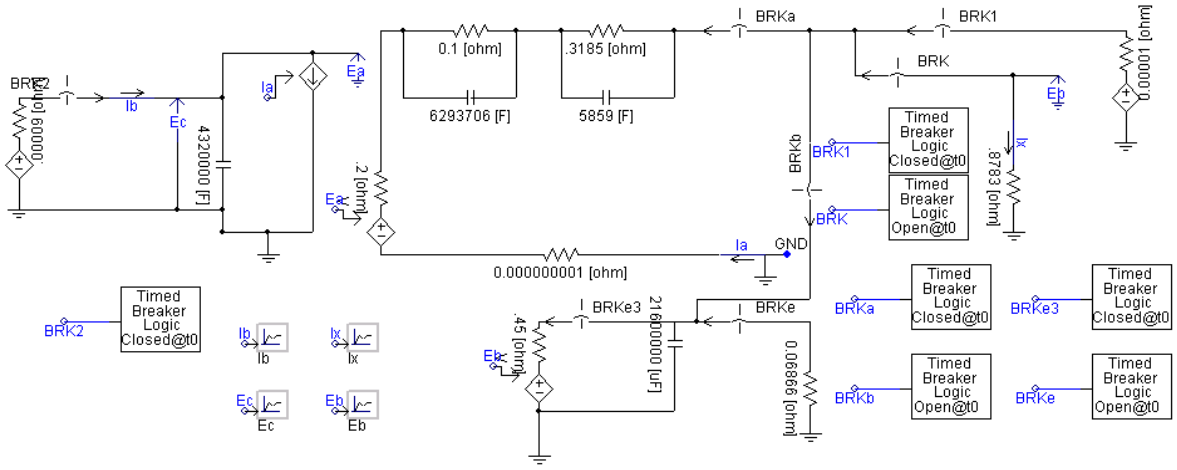


Figure 101. Equivalent Model of the 1MWH Battery

[27] Ali, S. M., Pattanayal, P., Sanki, P., & Sabat, R. R. (2012). Modeling and control of grid-connected hybrid photovoltaic distributed generation system. International Journal of Engineering Sciences & Emerging Technologies, 4(1), 125-132.

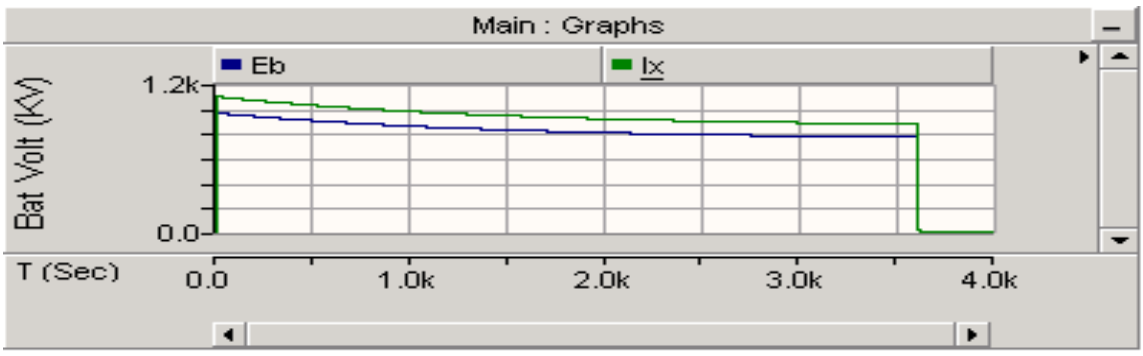
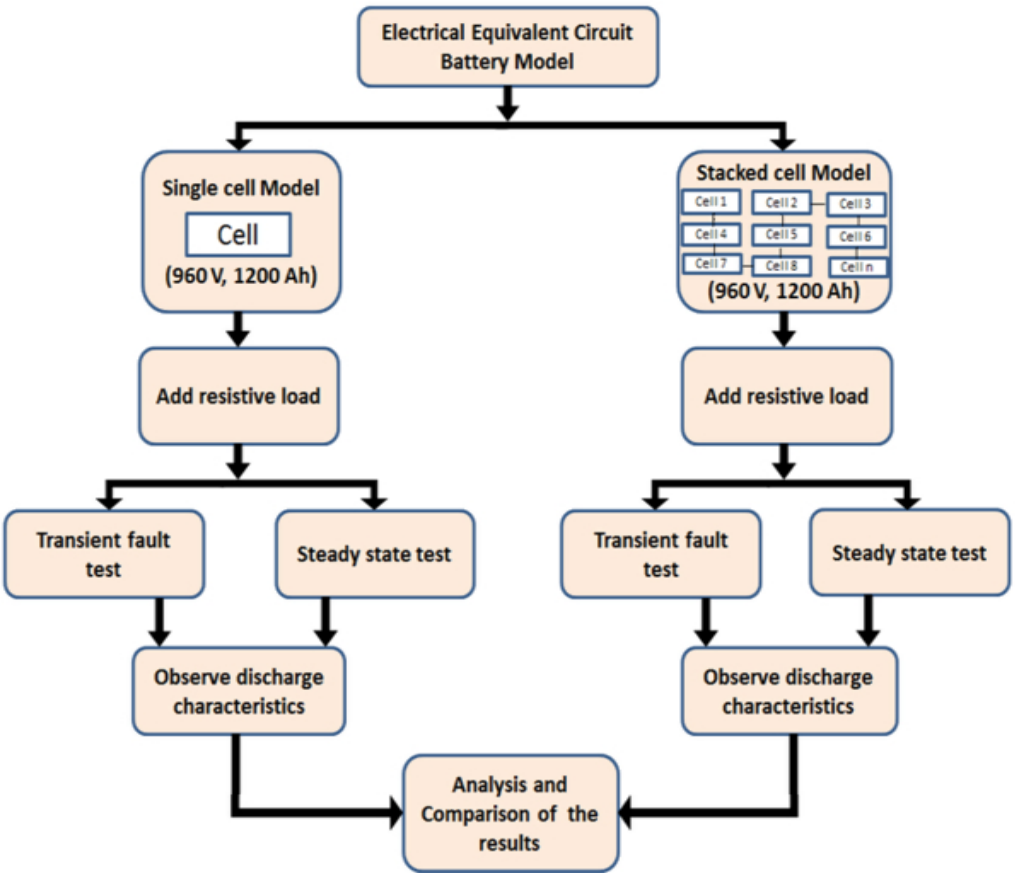


Figure 102. V & I Waveforms of the 1 MW Battery System

8.5.1.6 Single and Stacked Cell Battery System Comparison

The two types of battery models, such as “stacked cell model” and “single cell model”, of a 1 MWh LMO battery were taken into consideration to study the discharge characteristics. The approach was based on the use of the Dual Polarization Model (one of the Electrical Equivalent Circuit Models also called Two Time Constant Model). The purpose was to build and simulate the battery models in PSCAD. Also the battery models were compared and analyzed on their performance during faults when connected to the resistive load at 1C discharge rate.



The figure above

Figure 103. Process Flow for Analysis of Battery Modeling

describes the process flow analysis of the battery modeling to analyze the models in terms of discharge characteristics, speed, performance, stability, and compatibility. The "single cell model" was constructed using the electrical equivalent circuit. In an attempt to simulate the "stacked cell model", initially one cell of the battery rated at 4.12 V, 60 Ah was modeled in PSCAD, and then the cells were connected in series and parallel to build the model of 1 MWh battery module. The key results include the modeling of single cell and stacked cell models of the 1 MWh battery. The discharge characteristics of the battery models rated at 960 V, 1200 Ah were analyzed for the faults applied near the resistive load. The models were tested for node compatibility, compilation issues, and the response effectiveness when connected to the resistive load.

8.5.1.6.1 Single Cell Discharge Characteristics

In order to compare the performance of the stacked cell model with the single cell model, the stacked cell model was built in PSCAD. Once the single cell of 4.12 V, 60 Ah was modeled, the electrical equivalent single cell was modeled for 1055 V and 1200 Ah using the equations of dual polarization. The models were analyzed for the battery discharge characteristics for the resistive load as shown below. The voltage source at the right side of the model was used to charge the battery with 1100 V during which the BRK1 breaker was closed and the BRK breaker was open. After the charging of the battery, the BRK1 was opened and the BRK was closed so that the battery discharged through the load of 0.8775 ohm. The current "I_a" was used to charge or discharge the battery $C_{capacity}$ dynamically. The output from the comparator was fed through a parallel connection of voltage source and a resistor of 0.8775 ohm to observe and plot the roll off at 3600 seconds.

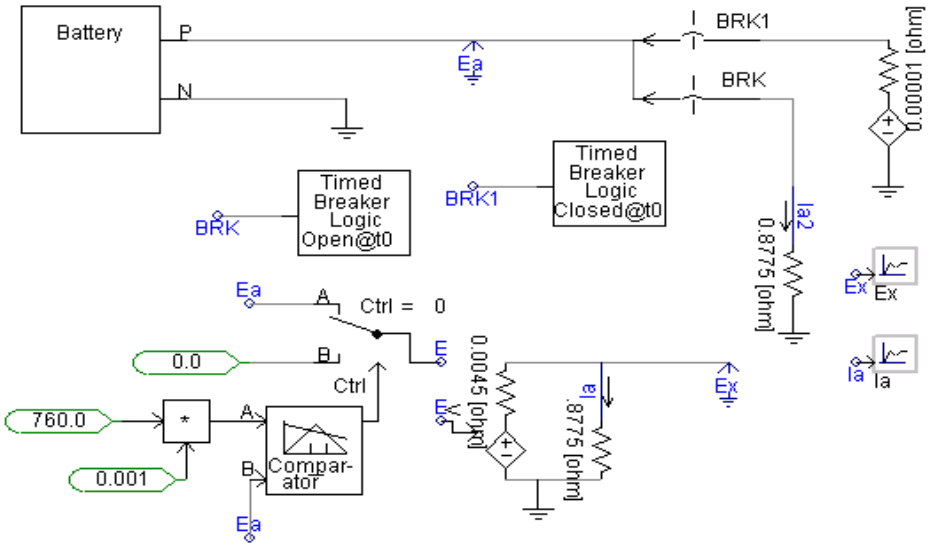


Figure 104. 1 MWh Battery Equivalent Single Cell Model in PSCAD with Controls

The open circuit voltage was set to the maximum voltage as 1053 V. The battery was charged to 1053 V and made to discharge slowly and made to roll off at 3600 seconds at 1C rate as shown by battery

voltage, “Ex”, as shown in the figure below. The resistive load was calculated to be 0.8775 ohm for the current to discharge at a constant rate of 1200 Ah as shown by battery current, “I_a”.

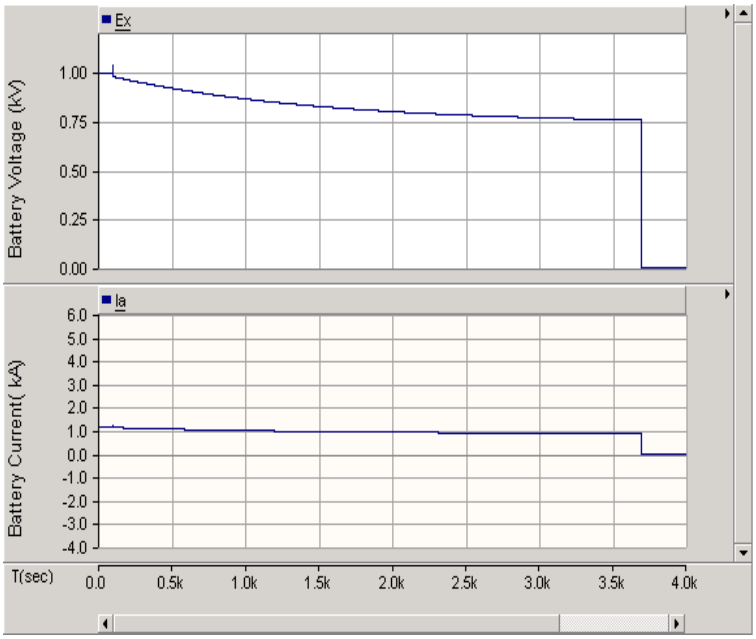


Figure 105. Voltage & Current Waveforms of the 1 MWh Battery

8.5.1.6.2 Stacked Cell Discharge Characteristics

The stacked cell model system with controls and the obtained discharge curve is shown below.

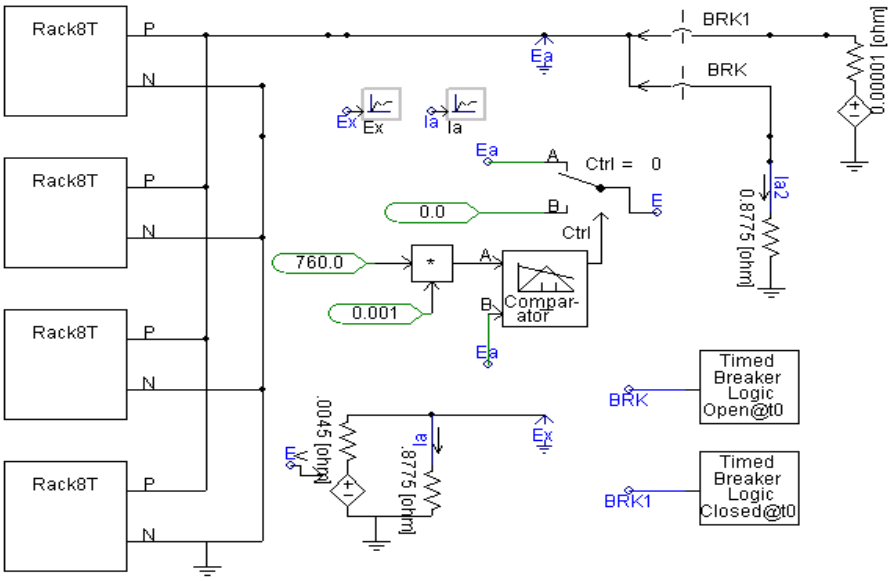


Figure 106. 1 MWh Battery Stacked Cell Model in PSCAD with Controls

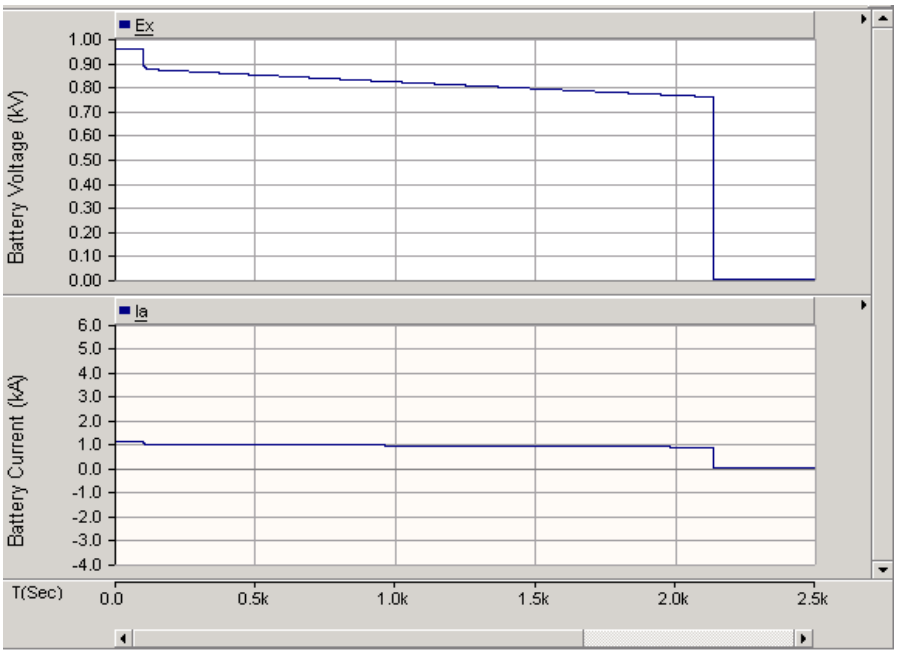


Figure 107. Voltage & Current Waveforms of the 1 MWh Battery

8.5.1.6.3 Transient Analysis of the Single and Stacked Cell Models

The single cell and stacked cell models were analyzed with the resistive load for their steady state performance. The single phase fault was applied to the system in the figure below, near the battery module at 500 seconds.

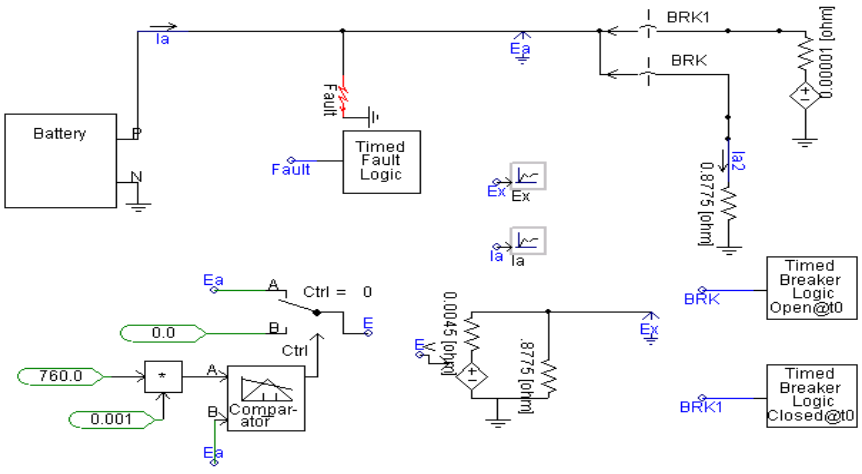


Figure 108. Fault Applied to 1 MWh Battery Equivalent Single Cell Model in PSCAD

The response of the system is plotted below.

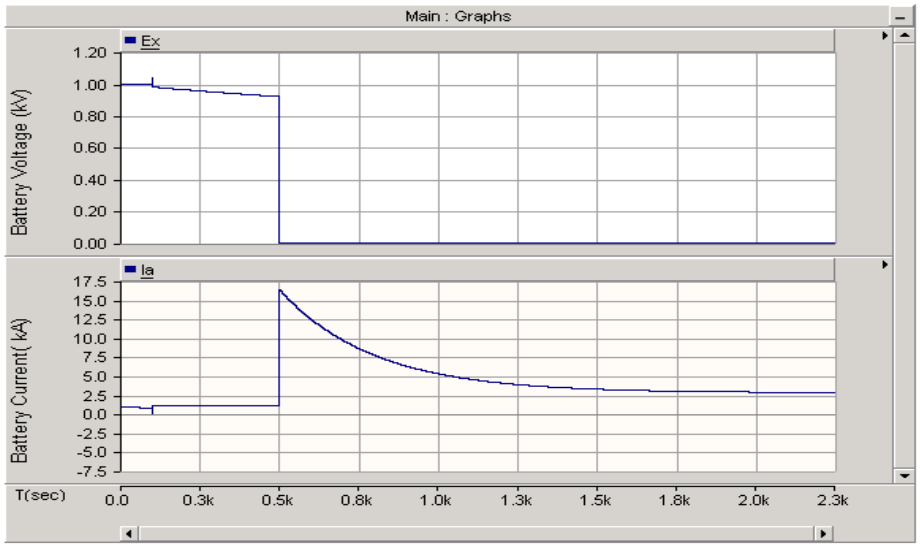


Figure 109. V& I Waveforms of the Single Cell Model

Similarly, the single phase fault was applied near the battery module, at 1500 seconds, to the system as shown below.

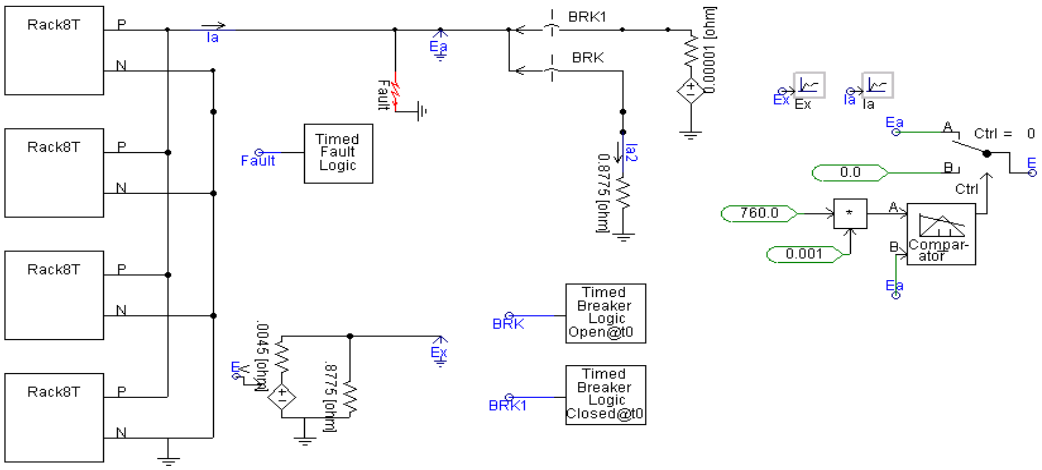


Figure 110. Fault Applied to 1 MWh Battery Stacked Cell Model

The response is shown below and it was observed that both systems were discharging until applying the fault after which the system dropped to zero.

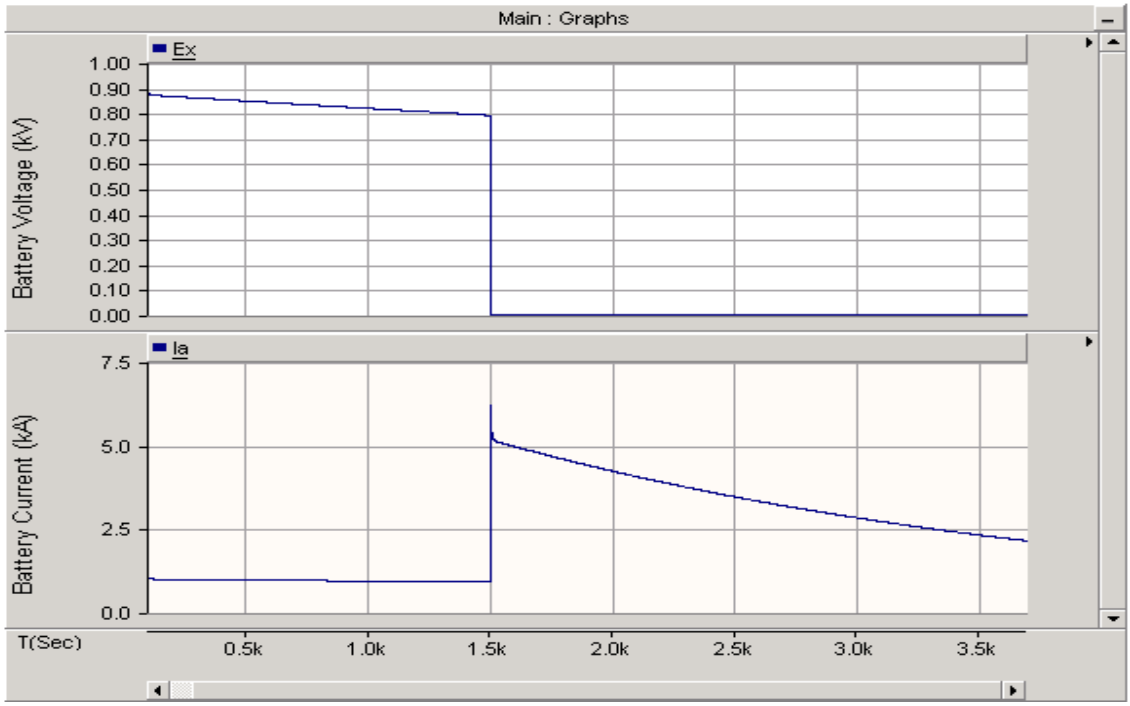


Figure 111. V&I Waveforms of the Stacked Cell Model

The battery models were compared and analyzed on their performance during steady state and transient conditions when connected to the resistive load at 1C discharge rate. It was compared for the performance of the battery models as a single cell and as a stacked cell, when connected to a resistive load. It was observed from the simulation results that the electrical equivalent circuit model of a single cell was more accurate with voltage and current than the stacked model, and it has discharge characteristics, speed, performance, stability, and compatibility. It could be easily integrated in future for higher end applications with the grid. The simulation demonstrated that the stacked model had some loss of voltage due to the stacking of cells, and it has node compatibility in PSCAD.

8.5.1.7 Battery Controllers' Comparison

A comparison study on the operational performance of a battery-connected grid system with bi-directional grid-connected inverter and conventional PQ controller in steady state conditions was performed. The two different methods of control were implemented in PSCAD and the results were compared. Initially the battery was modeled using the combination of runtime based and dual polarization technique (electrical equivalent circuit model). The LMO battery cell was modeled for a rated capacity of 1 MWh. The nominal voltage representing the end of the linear zone of discharge characteristics was considered to be 760 V. The capacity of the battery used in the simulation was 1200 Ah and that parameter did not affect the discharge curve. The maximum voltage when the battery was

fully charged was considered to be 1053 V. Some of the parameters that were not taken into consideration were the self – discharge resistance, temperature effects and memory effects. Internal resistance and battery capacity was assumed to be constant and did not vary with amplitude of the current [28].

8.5.1.7.1 PQ Controller

The modeled battery shown below was connected to a three-phase inverter. The converted DC signal from the battery was given to a transformer to step up the voltage to 12.5 kV. The inverter was controlled using a simple PQ controller.

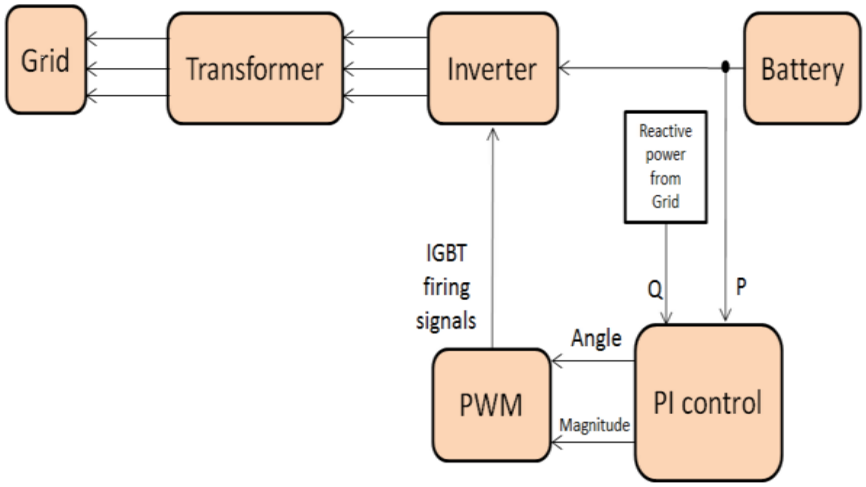


Figure 112. Battery – Grid System with PQ controller

[28] Anthony W. Ma. "Modeling and Analysis of a Photovoltaic System with a Distributed Energy Storage System. "Thesis. California Polytechnic State University, 2012. May 2012. Web. Aug. 2014

The PI controller block in the above figure was modeled in PSCAD as shown below.

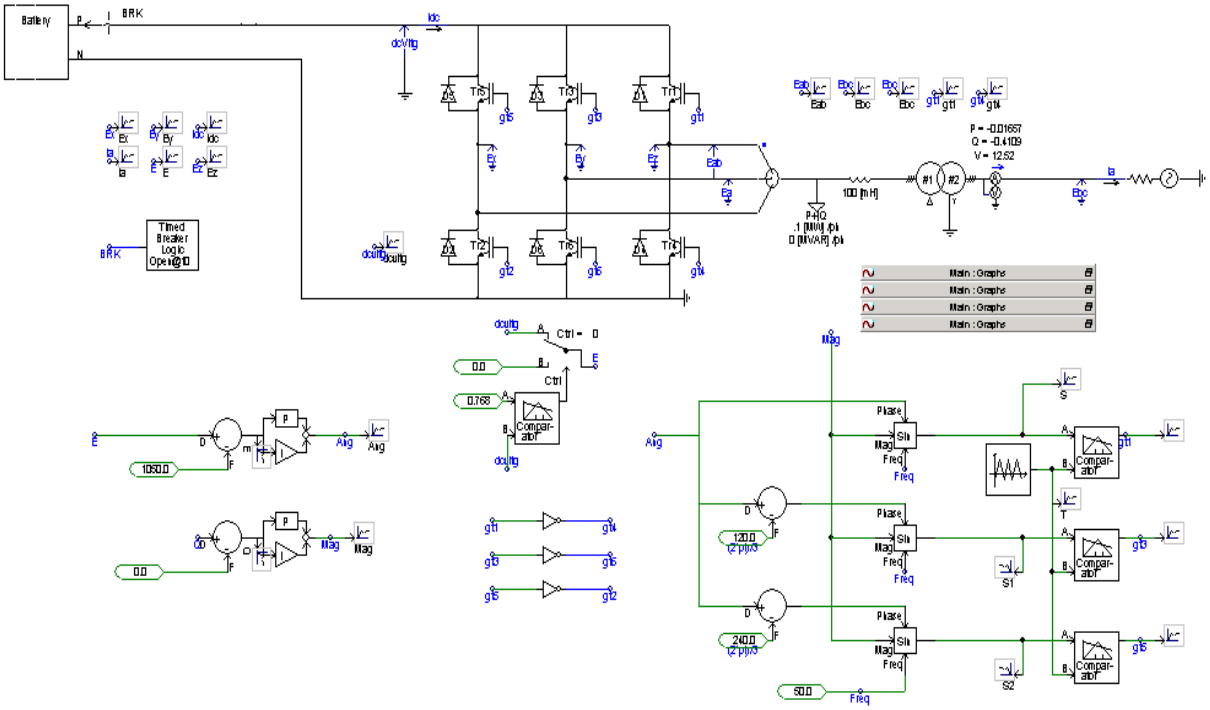


Figure 113. Battery-Connected Grid System using PQ Control in PSCAD

The battery output DC voltage was labeled as “E” and the reactive power was named as “Q”. The measured DC output was compared with the maximum battery voltage and the difference was given to the PI controller as shown below.

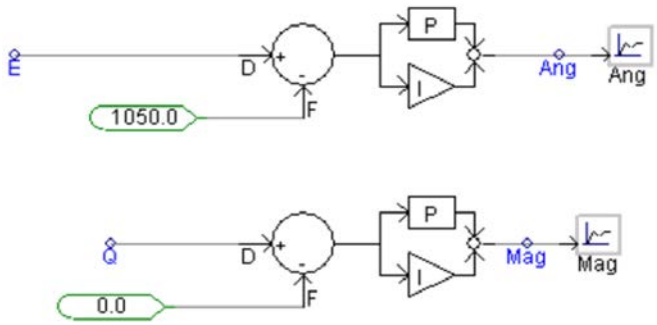


Figure 114. PI controller

The implementation of the controls shows that DC battery voltage, “E”, was found to be 960 V, and the grid current, “Ia”, was observed with oscillations as in the figure below.

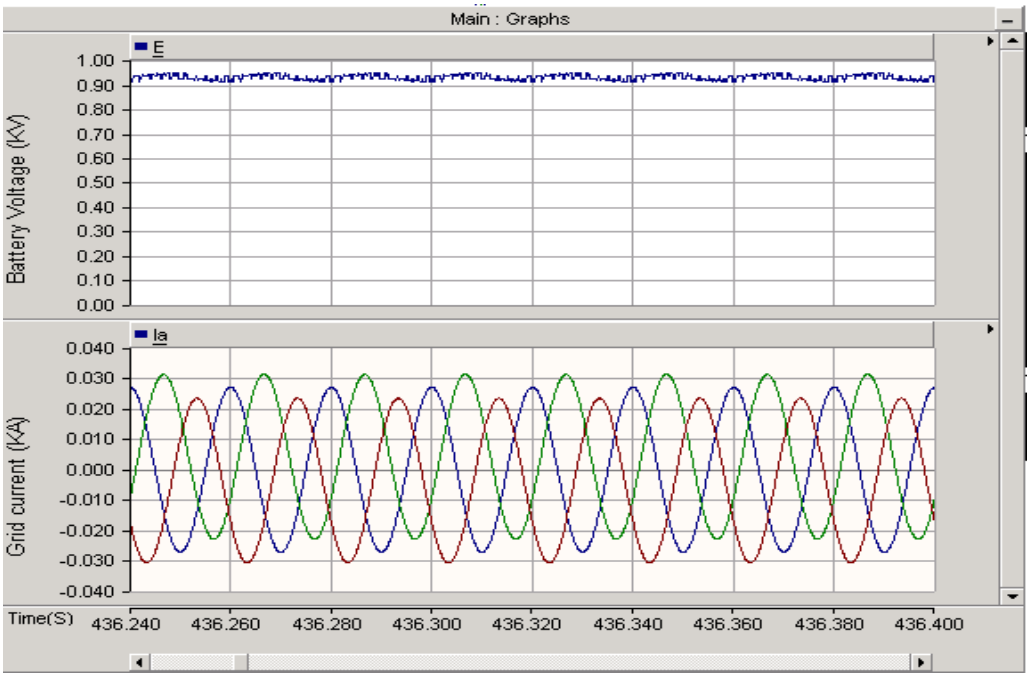


Figure 115. Battery Voltage and Grid Current Waveforms

8.5.1.7.2 Vector Controller

The above system with the PI controller has the buck converter and an inverter which is capable of bi-directional flow to charge/discharge the battery from the grid. The controller was found to be less effective for implementation in the study of advanced battery technology.

In an electric power system the PQ theory is found to be ineffective and hence it has been modified with various referenced current generation techniques. However, with reference current generation, an effective current control technique is required to improve the system performance [29]. Hence an advanced vector control (current controlled voltage source) was developed and the block diagram was modified as below.

[29] Tsengenes, Georgios A., and Georgios A. Adamidis. "22." Performance Evaluation of PI and Fuzzy Controlled Power Electronic Inverters for Power Quality Improvement. INTECH Open Access, 2012.Print.

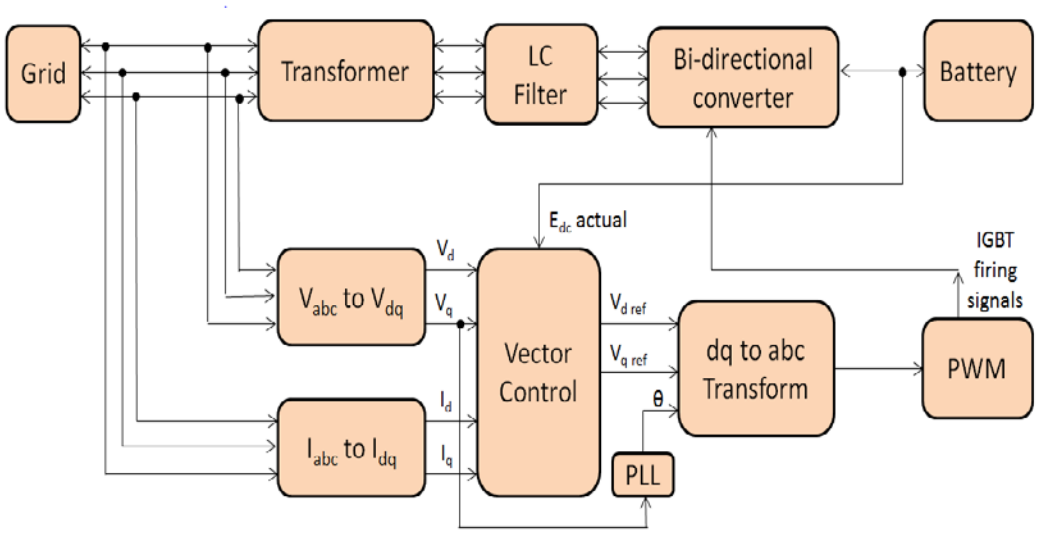


Figure 116. Battery – Grid System with Vector Controller

The battery voltage was given to a bi-directional converter where the DC power initially was converted into DC, and the V_{LL}rms voltage was calculated using the following equation [30] and given to the LC filter.

$$V_{LL}(\text{rms}) = 0.612\, m_a\, v_d$$

Where m_a is amplitude modulation and V_d is battery voltage.

The bidirectional controller was implemented with 6 insulated gate bipolar transistor (IGBT) switches (gt1, gt2, gt3, gt4, gt5, gt6) in parallel with a diode to enable double-sided current flow. The three phase bi-directional converter shown in the figure below had phases controlled with 120-degree shift from each other.

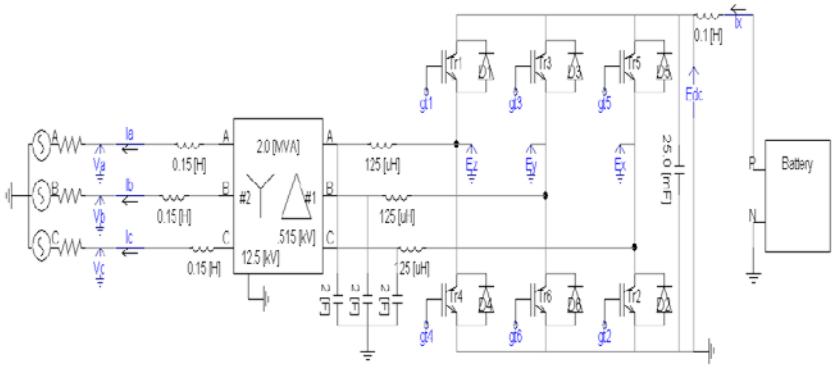


Figure 117. Grid-tied 1 MWh Battery System

[30] Mohan, Ned, Tore M. Undeland, and William P. Robbins. "8." Power Electronics: Converters, Applications, and Design. New York: Wiley, 2002. Print.

The ripple on the total current was relatively small with the small capacitance of 25 mF at the low side for acceptable voltage ripple. The bi-directional converter can operate to have double-sided power flow. The objective of the pulse width-modulated three phase converter was to shape and control the three phase output voltages in magnitude and frequency with a constant input voltage of V_d to be 1050 V. The converter shown above consisted of three legs for each phase. The output was independent of the output load current since one of the two switches in a leg was always 'on' at any instant. In order to produce a sinusoidal output waveform at a desired frequency, a sinusoidal control signal at the desired frequency was compared with the triangular waveform switching frequency and was kept constant along with its amplitude V_{tri}. The triangular waveform was V_{tri} switching at a frequency of 750 Hz to switch the converter switches. The control signal $V_{control}$ was used to modulate the switch duty ratio and had a frequency of 60 Hz which is the desired fundamental frequency of the converter voltage output. Using the amplitude modulation equation, the value was calculated to be 0.8. The frequency modulation m_f was calculated to be 12.5. The voltage at the battery terminal was found to be 1 MW with voltage of 1053 V and 1200 A. The DC power was converted into AC power and the Vll(rms) was calculated to be 514.08 V with the amplitude modulation of 0.8. The voltage was stepped up through a transformer and connected to the grid at 12.5 kV.

The measured values were converted from abc to αβ transformation [31] . The obtained transformation was transformed to dq as below where U_d and U_q are the coordinates of the dq rotating reference frame and "ωt" is the angular position of the rotating frame [32]. The angle was then calculated using the third equation with U_d and U_q values.

$$\mathrm{Ud} = \cos(\omega t)\,\mathrm{U}\alpha + \sin(\omega t)\mathrm{U}\beta$$

$$\mathrm{Uq} = -\sin(\omega t)\,\mathrm{U}\alpha + \cos(\omega t)\mathrm{U}\beta$$

$$\angle \mathrm{U} = \mathrm{atan2}\left(\frac{\mathrm{U_q}}{\mathrm{U_d}}\right)$$

The transformed d and q parameters were fed into the vector control as shown in the figure below.

[31] "Documentation Center." Perform Transformation from Three-phase (abc) Signal to αβ0 Stationary Reference Frame or the Inverse. Mathworks, 13 Aug. 2014. http://www.mathworks.com/help/physmod/sps/powersys/ref/abctoalphabetazeroalphabetazerotoabc.html.

[32] "Documentation Center." Perform Transformation from αβ0 Stationary Reference Frame to Dq0 Rotating Reference Frame or the Inverse. Mathworks, <http://www.mathworks.com/help/physmod/sps/powersys/ref/alphabetazerotodq0dq0toalphabetazero.html>.

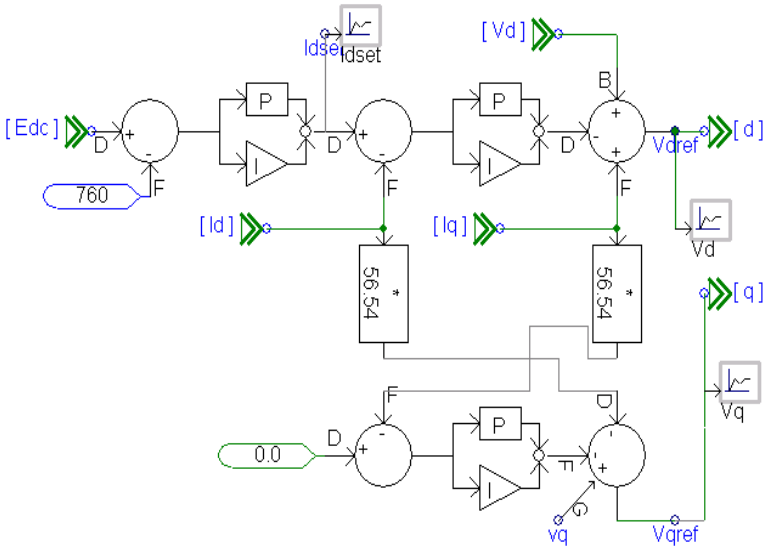


Figure 118. Grid-side Vector Controller

The current reference was obtained from the DC voltage control loop with Edc (battery output voltage). The voltage was manipulated to achieve the reference current in the current control loop. The vector control was built based on the current control [33].

$$V_d = Rid + L\frac{di_d}{dt} - \omega Li_q + ud$$

$$V_q = Riq + L\frac{di_q}{dt} - \omega Li_d + uq$$

Where V_d,V_q, i_d, and i_q are the voltages and currents of the dq reference frame.

$$\begin{bmatrix} Va1 \\ Vb1 \\ Vc1 \end{bmatrix} = \begin{bmatrix} \cos\theta & -\sin\theta \\ \cos\left(\theta - \frac{2\pi}{3}\right) & -\sin\left(\theta - \frac{2\pi}{3}\right) \\ \cos\left(\theta + \frac{2\pi}{3}\right) & -\sin\left(\theta + \frac{2\pi}{3}\right) \end{bmatrix} \begin{bmatrix} Vd \\ Vq \end{bmatrix}$$

The angle "ang, θ" from the above equations was obtained from the phase locked loop (PLL). Hence the produced angles, Vd and Vq, are converted into V_{abc} values as shown below to get the Va1, Vb1, and Vc1. These voltages were used to switch the IGBT signals of the inverter. The sine wave was compared with the triangular waveform generator switching at higher frequency at 750 Hz with initial phase angle of 0 deg and 50% duty cycle with maximum and minimum output level to be -1 and +1 respectively.

[33] M, Devadarshanam, Manjunatha B.M, and Damodaram K. "Modeling and Simulation of PWM Line Converter Feeding to Vector Controlled Induction Motor Drive." International Journal of Advanced Research in Computer Science and Software Engineering 2.8 (2012): 321-327.

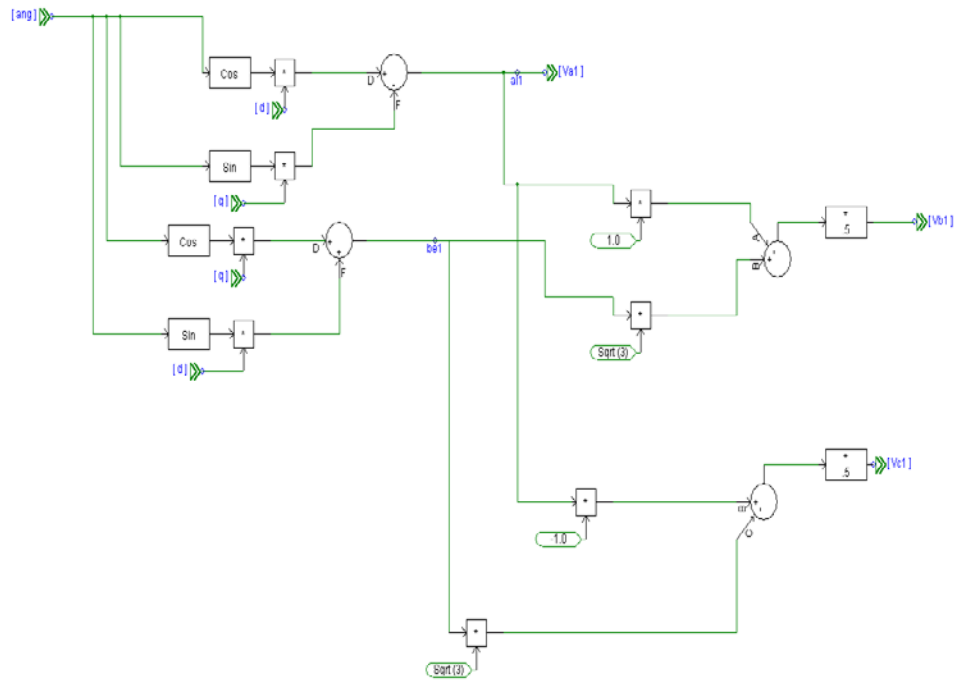


Figure 119. dq-abc Transformation

The signals were used to fire the IGBT switches in the converter to enable the battery charge and discharge performance of the battery. Also it was observed that when the battery was in its discharging state, the vector controller produced better results of grid voltage and current as shown below when compared to that of the PQ controller.

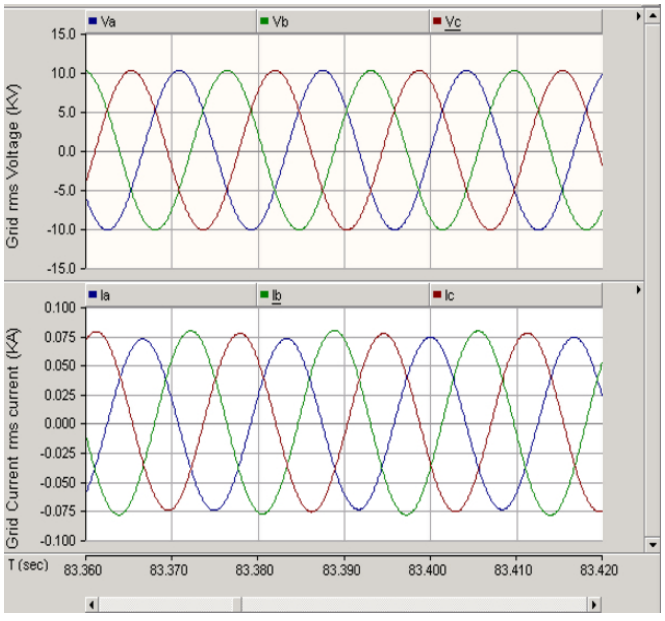


Figure 120. Voltage and Current Waveforms at the Grid

The simulation results of the PQ control and vector control were compared and it was observed that the vector control produced more accurate results than the PQ control. The use of current control and voltage control in the vector control method enables the battery to operate at different charge rates without much change to the system except for the setting of the current reference generated from the voltage control. Thus the bi-directional converter using vector control for the battery to grid application provided greater efficiency, system stability and reduced power oscillations to the system.

8.5.1.8 System Analysis

8.5.1.8.1 Grid-connected Battery System

The vector control method was used to fire the IGBT switches of the converter. The converter acted both as an inverter (DC to AC) and rectifier (AC to DC) to enable bi-directional energy flow between the grid and the battery. With reference to the vector control assembly [34], the implication with vector controls was used to simulate the grid-tie battery system for voltage and current control. The voltage from the grid was obtained and the V_a, V_b, and V_c were transformed into dq values using the following equations [35]:

$$V_d = \frac{2}{3}\left(V_a \sin(\omega t) + V_b \sin\left(\omega t - \frac{2\pi}{3}\right) + V_c \sin\left(\omega t + \frac{2\pi}{3}\right)\right.$$

$$V_q = \frac{2}{3}\left(V_a \cos(\omega t) + V_b \cos\left(\omega t - \frac{2\pi}{3}\right) + V_c \cos\left(\omega t + \frac{2\pi}{3}\right)\right.$$

$$V_0 = \frac{1}{3}(V_a + V_b + V_c)$$

The current was obtained from the grid and the I_a, I_b, and I_c were transferred into I_d and I_q. The PLL as shown below was used for the PSCAD simulation. The PLL was a control system that generated the output signal to be in phase with the input signal. The PLL constituted the phase detector (PD) block, Loop filter (LF) and the voltage controlled oscillator (VCO). The PD block generated the error directly proportional to the phase difference between input and output voltage. The loop filter reduced the input phase error with AC components. The error produced was given as, e= V sin (θ-θ'). The PLL locked the θ=θ' such that error=0. The VCO generated the frequency shift and phase outputs with respect to given central frequency as a function of input voltage.

[34] NREL, Dynamic Models for Wind Turbines and Wind Power Plants (NREL/SR-5500-52780), October 2011, [Online]. Available: http://www.nrel.gov/docs/fy12osti/52780.pdf. [Accessed 21 May 2014]

[35] MathWorks Documentation Center. Perform Park Transformation from Three-phase (abc) Reference Frame to Dq0 Reference Frame. [Online].Available: http://www.mathworks.com/help/physmod/sps/powersys/ref/abc_to_dq0transformation.html. [Accessed 27 May 2014].

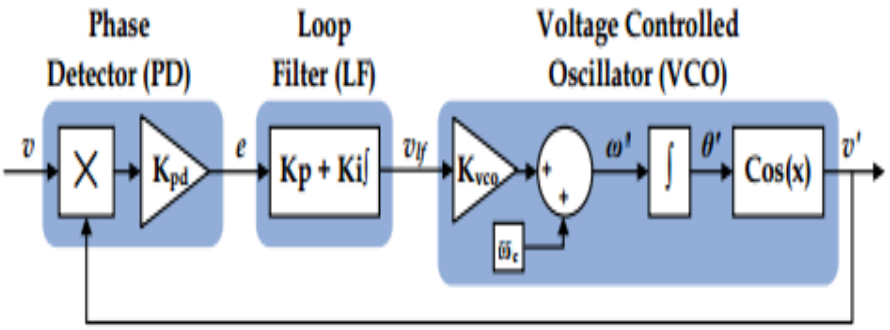


Figure 121. Phase Locked Loop [36]

The above simplified PLL block diagram was implemented in PSCAD. The grid voltage V_{abc} transformed into V_q voltage and was multiplied with the generated voltage at the voltage-controlled oscillator (VCO). The error produced at the phase detector was taken as e(t). The proportional (K_p) and integral (K_i) terms of the loop filter are given by the following equation.

$$e(t) = k_p\, e(t) + k_i \int_0^t e(t)dt$$

The K_p and K_i were the tuning parameters adjusted to obtain the desired current "e(t)" as output. The generated angle was used to convert the dq parameters to abc parameters which were used to switch the IGBTs of the converter.

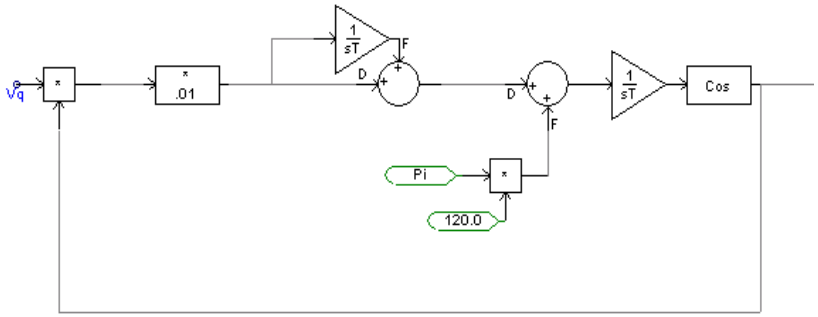


Figure 122. PLL in PSCAD

The PLL was used to control the angle between the inverter and the grid and to considerably change the angle between grid side and inverter side voltage to enable the battery charge and discharge characteristics. The ωc value was calculated as 2π*60.

[36] Gao, S., & Barnes, M. (2012). Phase-locked loop for AC systems: Analyses and comparisons.

Simulating the system, the battery was charged from 850 V to 1150 V at 3600 seconds at 1C as shown by battery voltage, Edc, and at current of 1200 Ah as shown by battery current, Ix, in the figure below.

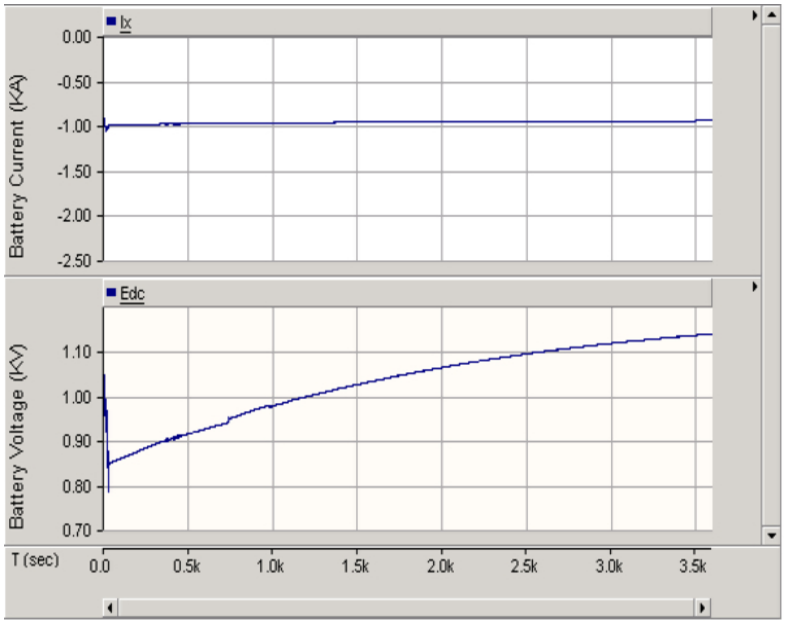


Figure 123. Battery Charge Characteristics at 1C Rate

Similarly the battery discharge was observed from 1050 V to 760 V at 3600 seconds at 1C rate as shown by battery voltage, Edc, and at current of 1200 Ah as shown by battery current, Ix, below.

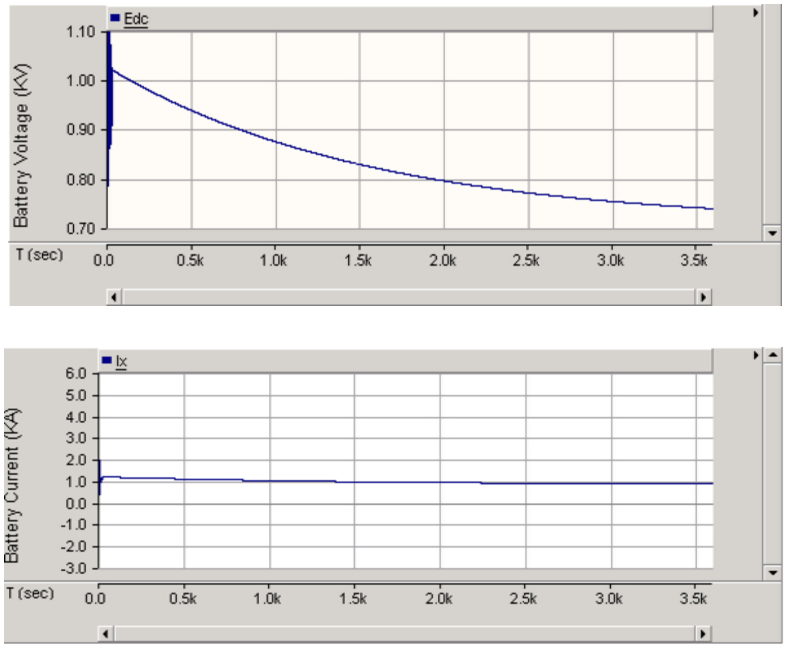


Figure 124. Battery Discharge Characteristics at 1C Rate

8.5.1.8.2 Grid-Connected Wind System

A wind turbine (synchronous generator) was modeled for 1.7 MW power produced with a constant mean wind speed (13m/s) and was connected to the grid at 12.5 kV. The damp wind fluctuations were ignored. The turbine voltage was 690 V and the $V_{DC\ bus}$ was calculated to be 1600 V. With the aim to build the DC bus, the storage capacitance value was calculated to be 1.32 F. The resistor was calculated as 1.948 ohm. The breaker circuit was calculated based on the load time constant, $T_r = 3\tau = 3RC$, and was obtained as 7.71408. An inductor was added in order to model a current source at the input of the inverter. I_{dc} was calculated to be 1062.5 A and the inductance was calculated as 3.014 H [37].

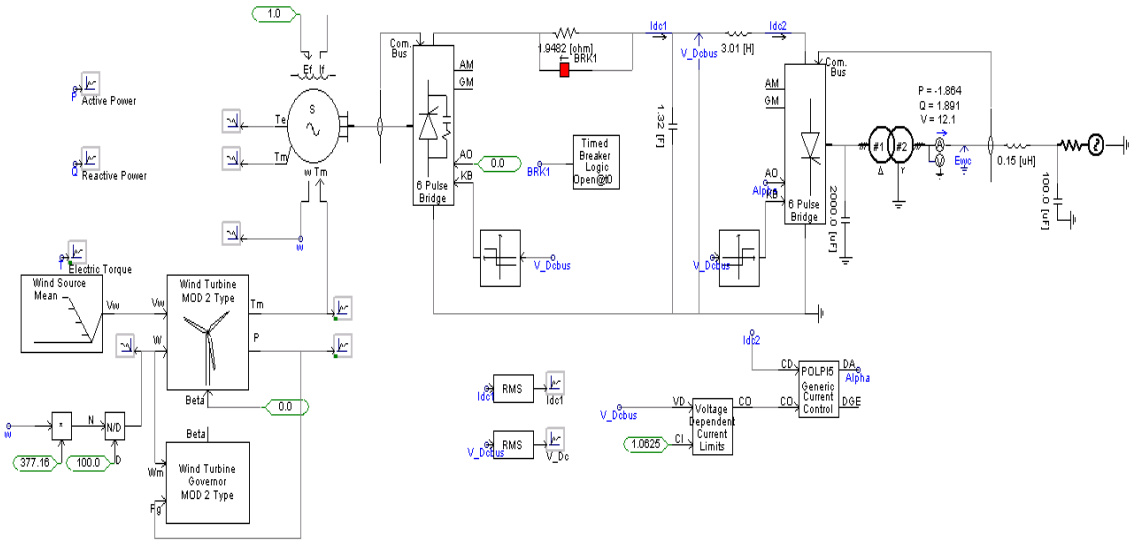


Figure 125. Wind Grid-Tied System in PSCAD

The machine rated angular mechanical speed was calculated to be 3.77 radians per second (rad/sec). The number of pole pairs used was 100. The rotor radius and rotor area were 31.77 meters (m) and 3171.2 meters squared (m^2), respectively. The air density was considered to be 1.225 kilograms per meter cubed (kg/ m^3) with the gear ratio as 1. The wind turbine governor component shown in the above figure had the variable pitch control enabled with rated electrical efficiency frequency of the machine as 3.7716 rad/sec. The synchronous generator used in the simulation was rated for voltage of 0.69 kV and current at 821.25 A. The proportional gain and integral gain values of the PI regulator parameters were 6.2 degrees per unit. The speed damping parameters were set to zero. The blade actuator parameters had the pitch angle lower limit and pitch angle upper limit set to be 0 and 25 degrees, respectively. The figure above shows the wind turbine model configuration where the electrical power created by the synchronous generator is diode rectified to DC, switched into three-phase AC with a thyristor inverter and connected to the grid via a step-up transformer. The figure below presents the performance of the above model operating at 1.7 MW capacity under steady state wind

[37] "PSCAD ® Version 4.2 Wind Turbine Applications Technical Paper". PSCAD: Power System Simulation. Cedrat, Manitoba HVDC Research Center Inc., Jan. 2006. Web. 17 June 2014.

operation. The parameters such as turbine power (1.7 MW), active power (1.5 MW), reactive power (≈ 0 MW), electric torque (490 k NM) and mechanical speed (3.4 rad/sec) were observed from simulation.

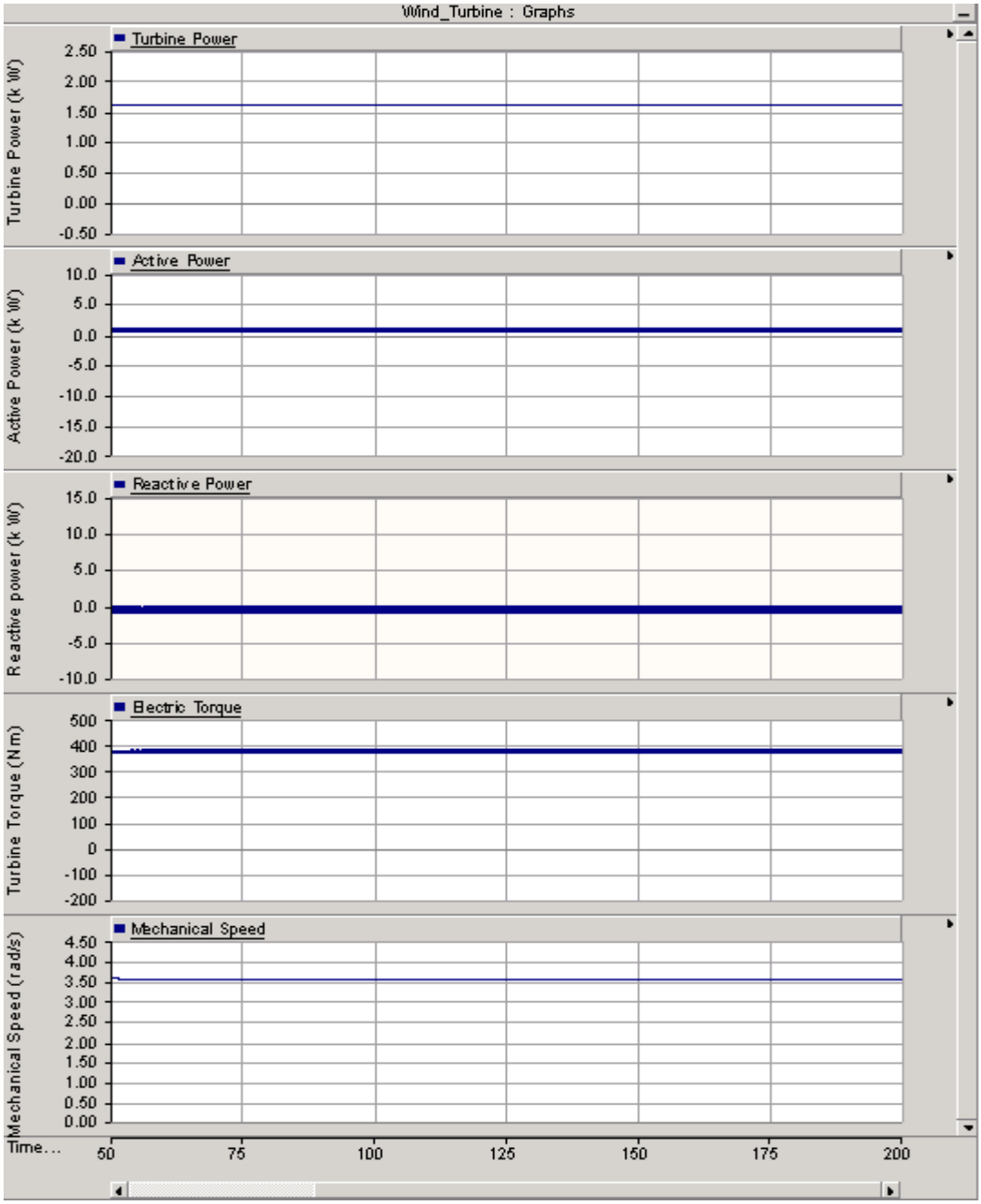


Figure 126. Wind Turbine Model Parameters

The rms grid voltage (Vg_{rms} was 12.5 kV. The V_{base} was calculated as 10.2 kV. The simulation results observed at the grid are shown below. The current obtained when simulating the wind turbine connected grid system was 580 A.

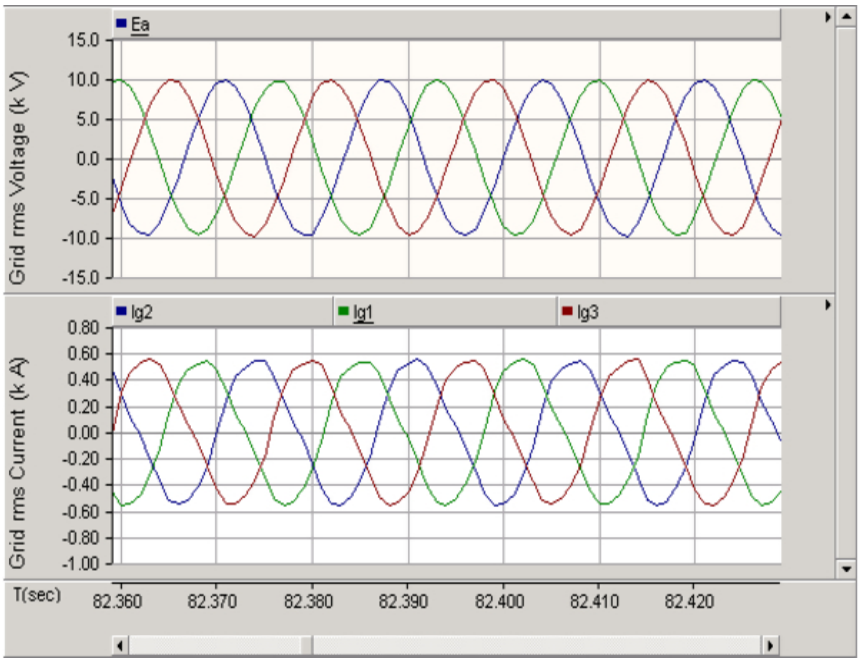


Figure 127. Voltage and Current at Grid

8.5.1.8.3 Grid-connected Battery System – Fault Analysis

The battery system was connected to the 12.5 kV grid through a resistor of 0.1 ohm. A three-phase fault to ground was applied near the grid to the grid-connected battery system as shown below.

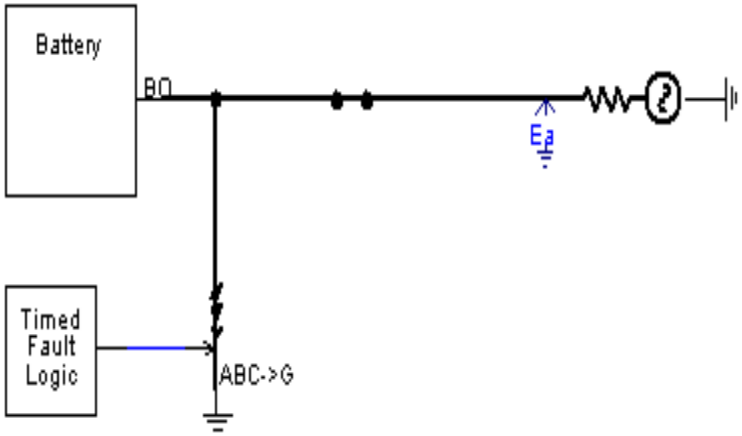


Figure 128. Battery to Grid – Fault

The transient state analysis of the battery discharge characteristic shown below was observed to be ≈ 1000 V until time at 110 seconds and had a very small reduction in voltage level during the three-phase fault period applied between 110-113 seconds. The voltage resumed back after the fault period and

attained its steady state condition. The battery current was found to be increasing during the fault period and settled after the fault at 1180 A.

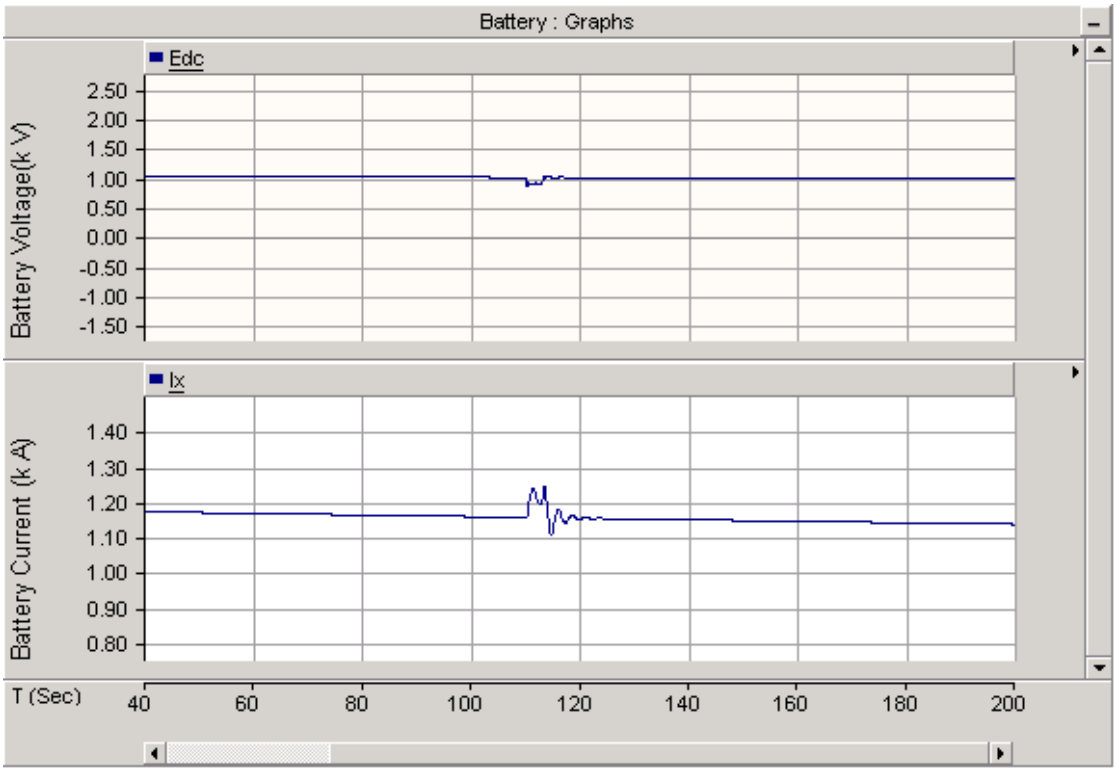


Figure 129. Battery Response– Fault

The plots in the next figure show the grid response while the battery system was connected to it during transient conditions. The grid rms voltage was found to be 12.2 kV and decreased during the fault while the grid rms current increased during the fault.

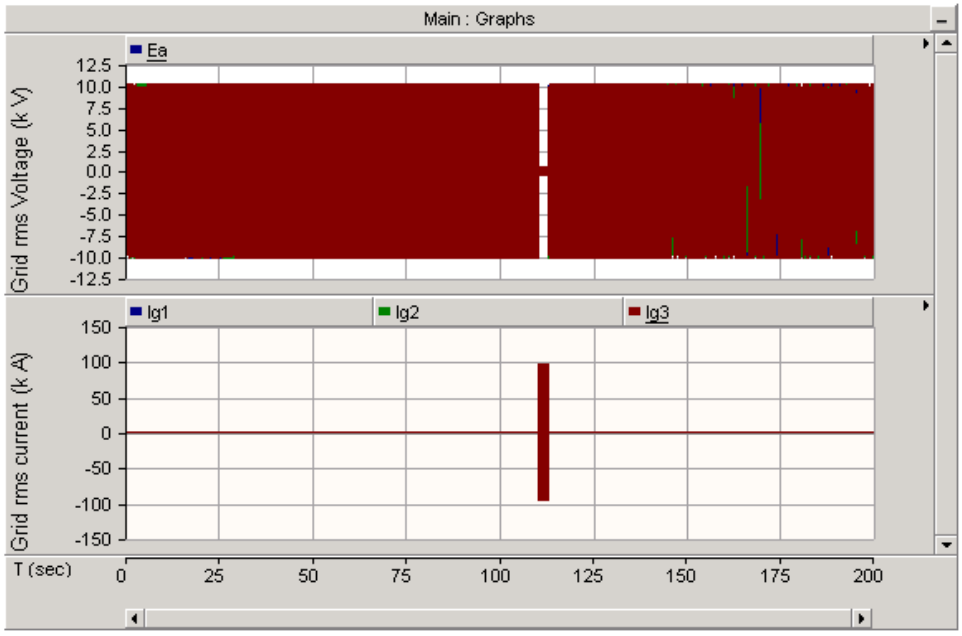


Figure 130. Grid Response – Fault

8.5.1.8.4 Grid-connected Wind System – Fault Analysis

A three-phase fault to ground is applied between 110 -113 seconds near the grid to the system shown below.

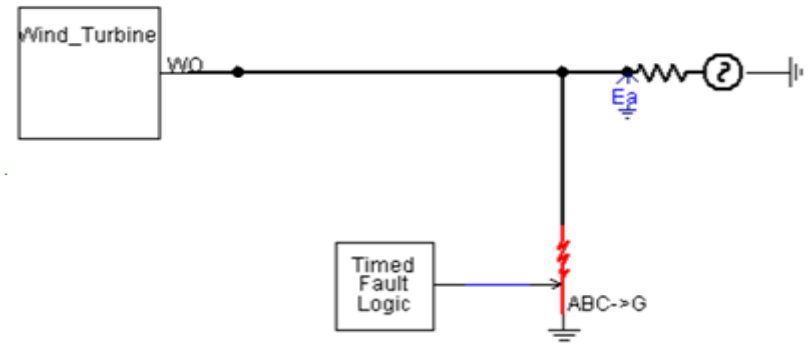


Figure 131. Wind to Grid – Fault

The transient state analysis of the wind connected to the grid shows in the figure below that the turbine power dropped, active power of the generator dropped, mechanical speed of the turbine increased, reactive power of the generator increased, and electric torque of the generator decreased.

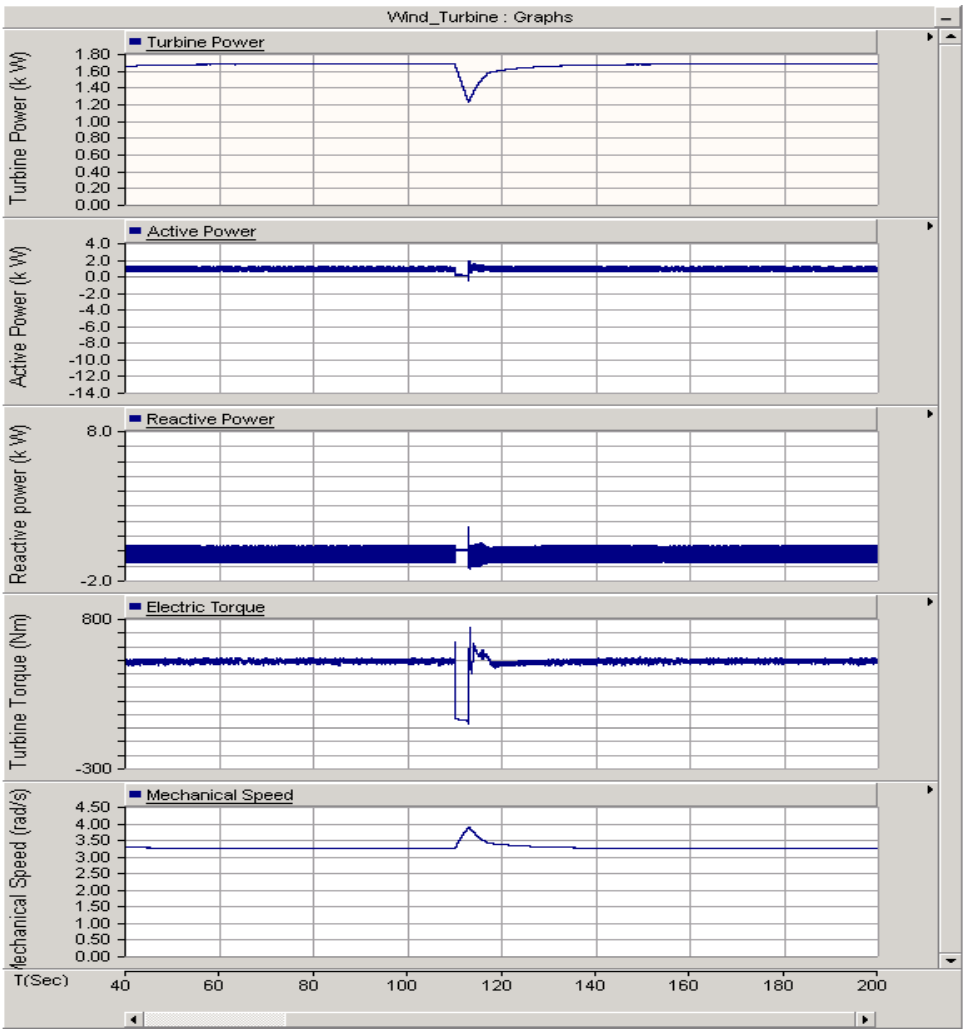


Figure 132. Wind turbine Response - Fault

8.5.1.8.5 Grid-connected Wind System – Fault Analysis

The system shown below was constructed as modules and built with PSCAD using battery and wind modules. The three-phase voltage source model in PSCAD was used as a grid.

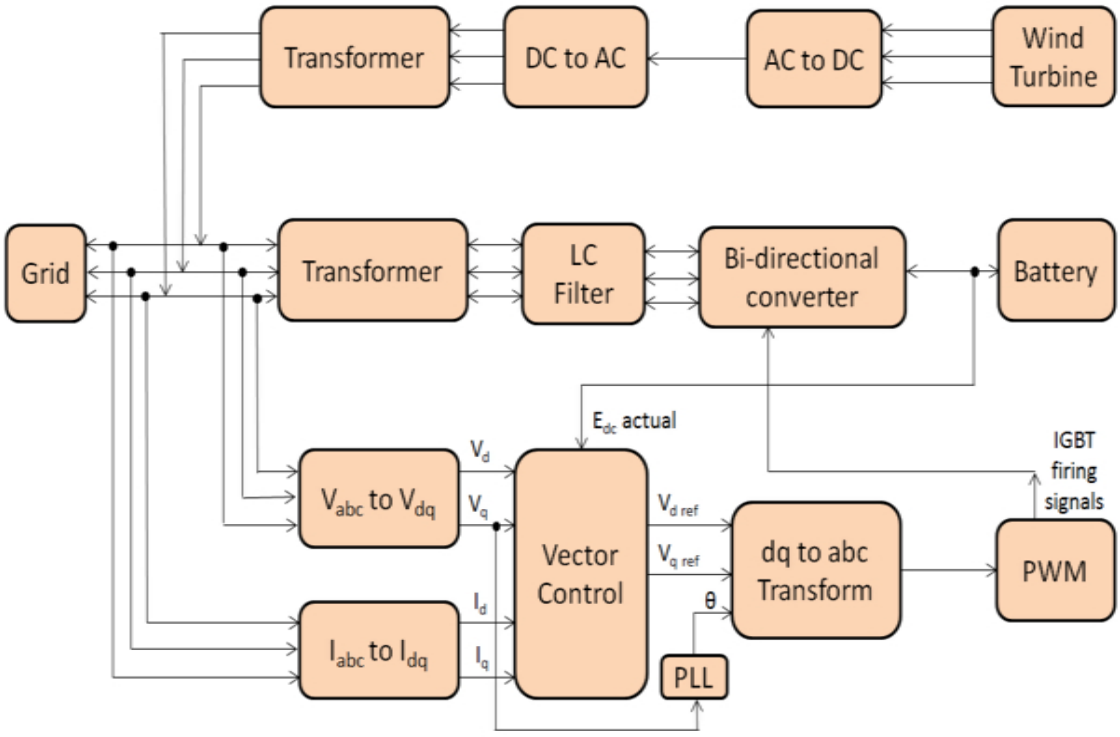


Figure 133. Configuration of Grid-Connected Wind and Battery System

The transient analysis was conducted by simulating the above system and injecting the three-phase faults to determine how the components would perform.

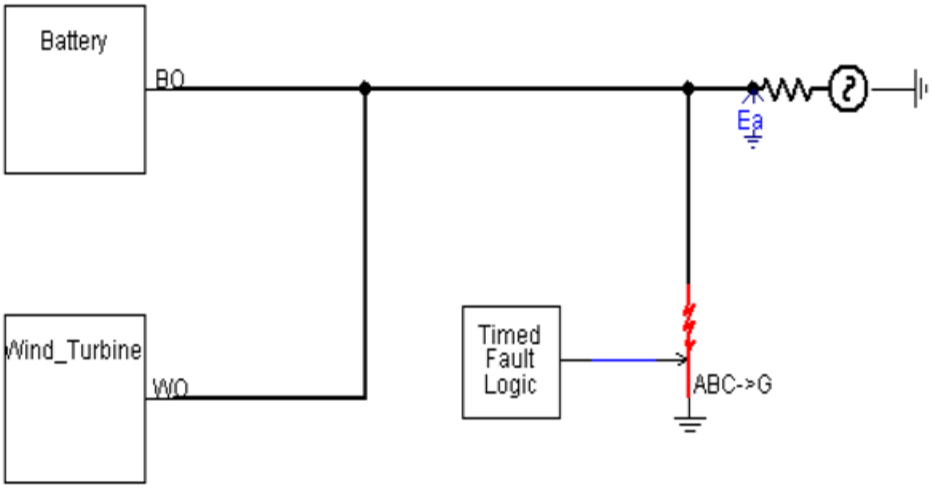


Figure 134. System under Fault Application

A three-phase fault was introduced into the system for a 3-second interval beginning at the 110 second time and the corresponding effects on battery and wind module were observed as shown below; basically, the battery current increased and the battery voltage dropped and had oscillations during the fault.

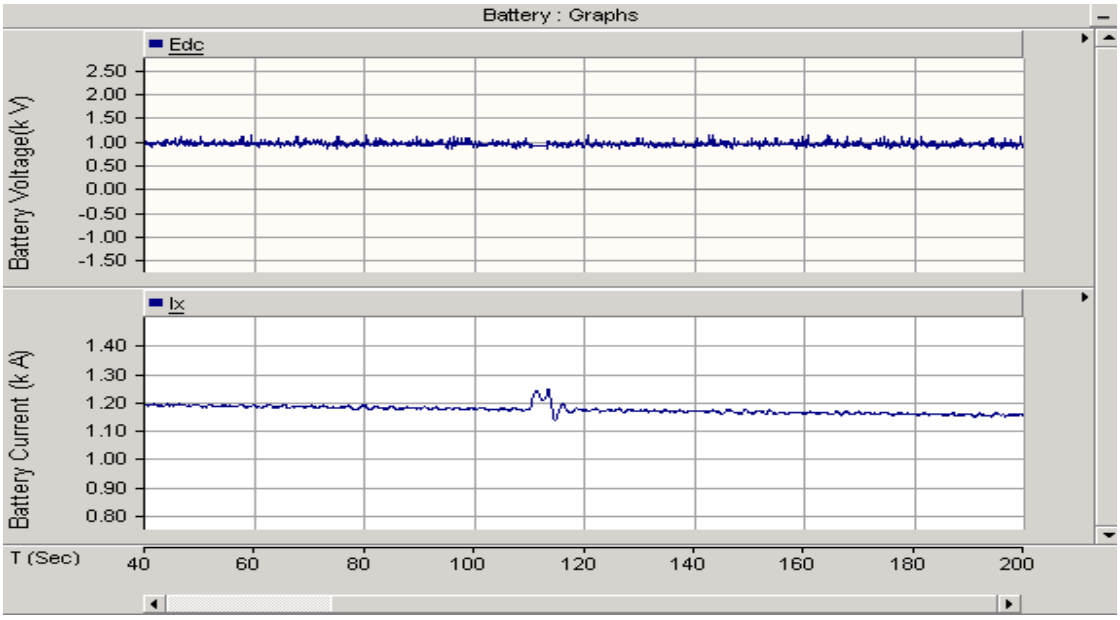


Figure 135. Effects on the Battery

Also it was observed that the turbine power dropped, active power of the generator dropped, mechanical speed of the turbine increased, reactive power of the generator increased, and the electric torque of the generator decreased. These results are evidenced below.

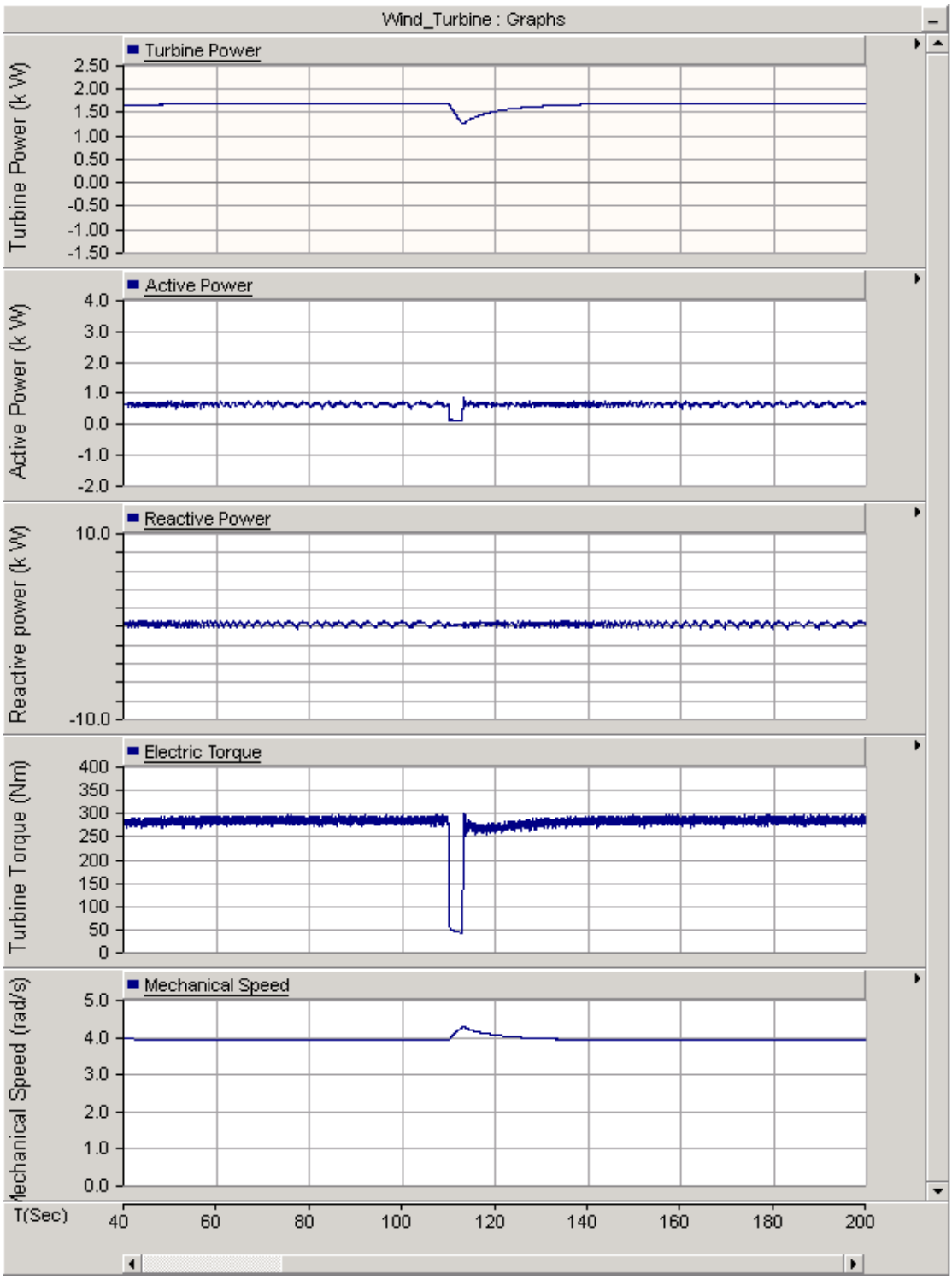


Figure 136. Effects on 1.67 MW Wind Turbine

The three-phase fault introduced into the system for a 3-second interval beginning at the 110 second time and the corresponding effects on the grid when the battery is connected to the system were observed as shown below. The grid voltage dropped and the grid current increased during the fault period.

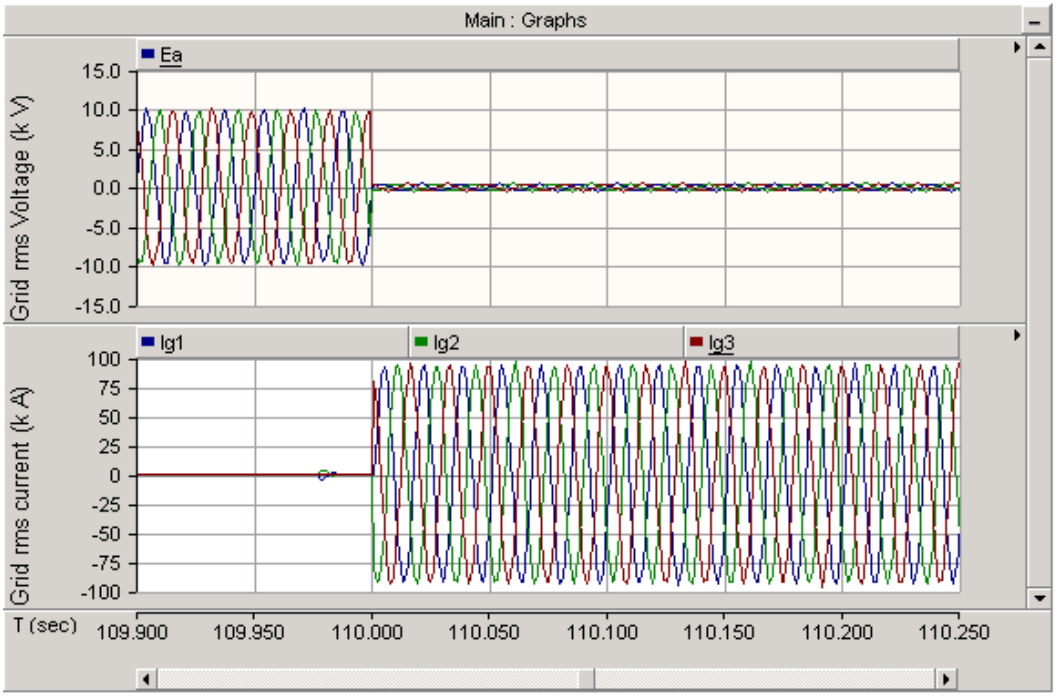


Figure 137. Grid Voltage and Current Response to Fault at 110 Seconds

8.5.1.9 Weak/Strong Grid Analysis

Basically, a grid (or an electrical line) is considered to be “weak” when the voltage and frequency fluctuate, potentially making the system unstable. Conversely, a “strong” grid is stable with not much variation in voltage or frequency. As in the figure below, if the impedance were larger, then the fault level and short circuit ratios would be less, and the grid would be considered weaker. For this analysis, the appropriate size of the wind turbine will be such that the value of the short circuit ratio must be around 20.

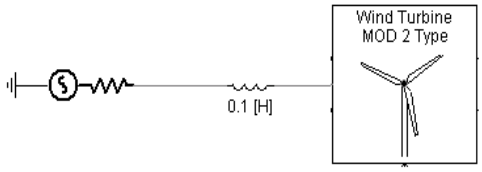


Figure 138. Impedance between Grid and Wind Turbine

If the value of the short circuit ratio (SCR) is equal to or above 20, then the system is considered strong whereas a SCR value below 20 represents a weak grid. The equations below were used to determine a strong/weak grid:

$$S = \frac{U^2}{Z}$$

Where,

S - Three-phase short circuit apparent Power of the grid/fault level

U - rms value of the nominal voltage of the grid

Z - Impedance between source and load $(\sqrt{(R^2 + X_L{}^2)})$

$$\mathrm{Tan}(\Psi_k) = \frac{2\pi f_g L}{R}$$

Where,

Ψ_k - network impedance angle/net angle

R ,L - selected to obtain the appropriate Ψ_k

f_g - nominal grid frequency (60Hz) [38]

The battery storage system constitutes the power of 1 MWh and the wind turbine constitutes the power of 1.7 MW. Thus the system size, S_n, was taken to be the sum of the total power of both battery and wind turbine and was calculated to be 2.7 MW. The grid voltage, U, is 12.5 kV. The net angle is taken as 30 for the calculation. Assuming the short circuit ratio varied from 2 to 30, the impedance values were calculated. Plugging the known values in the above equations, the R and L values were obtained and tabulated as in the figure below. Remember that SCR values of 20 or higher were considered indicative of a strong grid.

[38] JawwadZafar, Salman Ahmed Rajput, "Integration of Wind Energy Converters into an Existing Distribution Grid, Maximum of Wind Energy Converters for a 40 kV Substation" Chalmers University of Technology, 2005

S_n, System size=2.6MW
U, Grid =12.5KV

		Net angle		
Short circuit ratio (SCR)	30	30	50	50
	R(ohm)	L(H)	R(ohm)	L(H)
2	26.0224	0.0399	19.3145	0.0611
4	13.0112	0.0199	9.6573	0.0305
6	8.6741	0.0133	6.4382	0.0204
8	6.5056	0.01	4.6286	0.0153
10	5.2045	0.008	3.8629	0.0122
12	4.3371	0.0066	3.2191	0.0102
14	3.7175	0.0057	2.7592	0.0087
16	3.2528	0.005	2.4143	0.0076
18	2.8914	0.0044	2.1461	0.0068
20	2.6022	0.004	1.9315	0.0061
22	2.3657	0.0036	1.7559	0.0056
24	2.1685	0.0033	1.6095	0.0051
26	2.0017	0.0031	1.4857	0.0047
28	1.8587	0.0028	1.3796	0.0044
30	1.7348	0.0027	1.2876	0.0041

Strong grid

Figure 139. Impedance Table for Different SCR Values

The resistor and inductor values were plotted for varying SCR values. The values from the above figure were plotted as a graph shown below and it was observed that the lower the R and L values, the stronger the grid system due to the high SCR values (at 20 or higher).

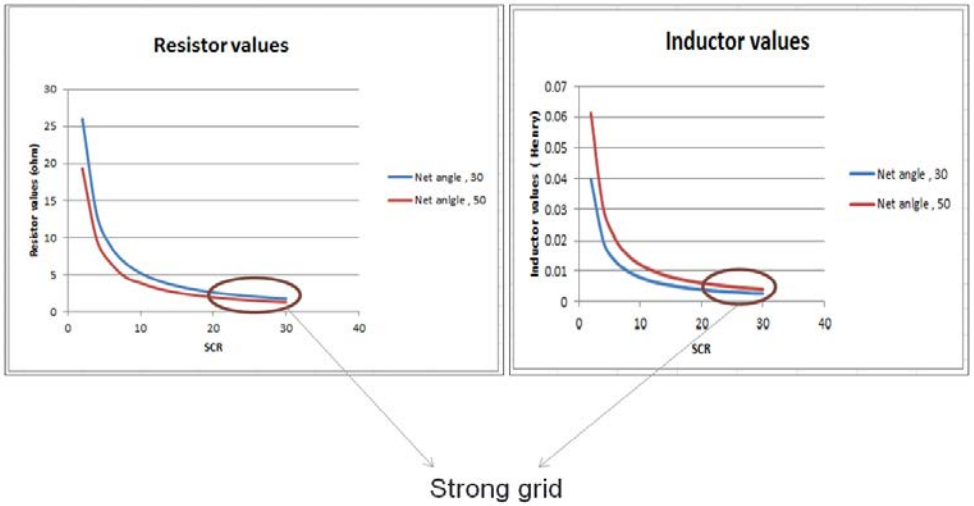


Figure 140. Graph on Strong/Weak Grid

8.5.1.9.1 Grid-connected to Battery System

The battery system was connected to the 12.5 kV grid through a variable inductor and a variable resistor. The multiport switch, modeled in PSCAD and shown below, enabled variance of the R and L values in the SCR range of 8 to 26. Thus, the project settings in PSCAD were adjusted to have multiple runs so that for each run the SCR value changed and thereby took the corresponding R and L values through the multiport switch. The battery system was initially connected to a weak grid for the first run with an SCR value of 8 and the corresponding calculated R and L values as 6.5056 ohm and 0.01 H, respectively. The use of a multiport switch enabled the change in the impedance values and caused the battery system to be connected to a strong grid.

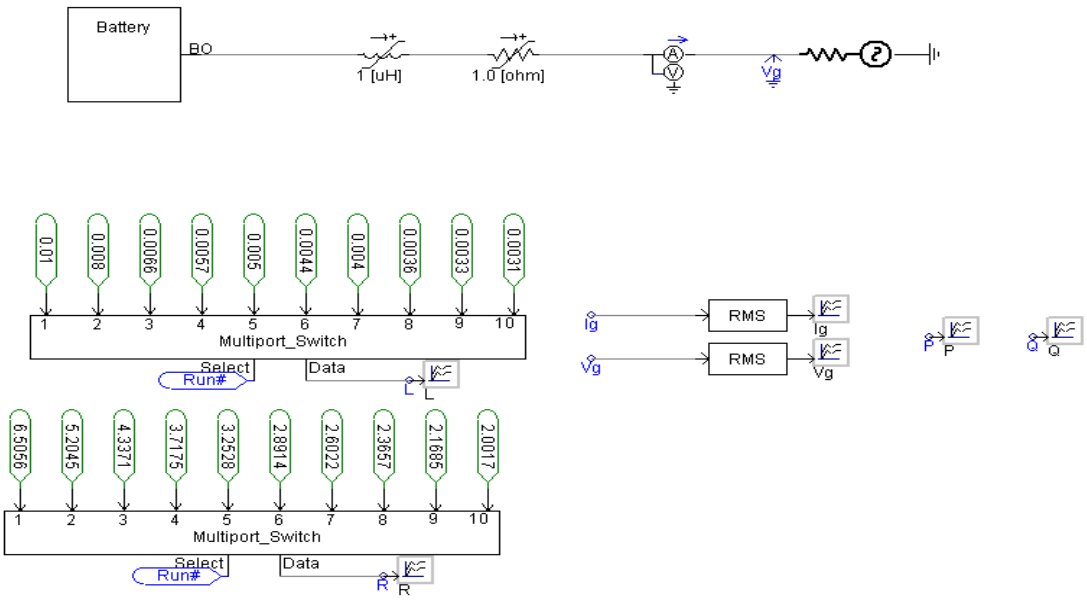


Figure 141. Battery to Grid

The response of the battery and grid parameters were observed. The multiple run values were saved to a file and the data was extracted through MATLAB and plotted as shown below. The steady state analysis of the battery connected to grid did not show any variation with the values changed from weak to strong grid.

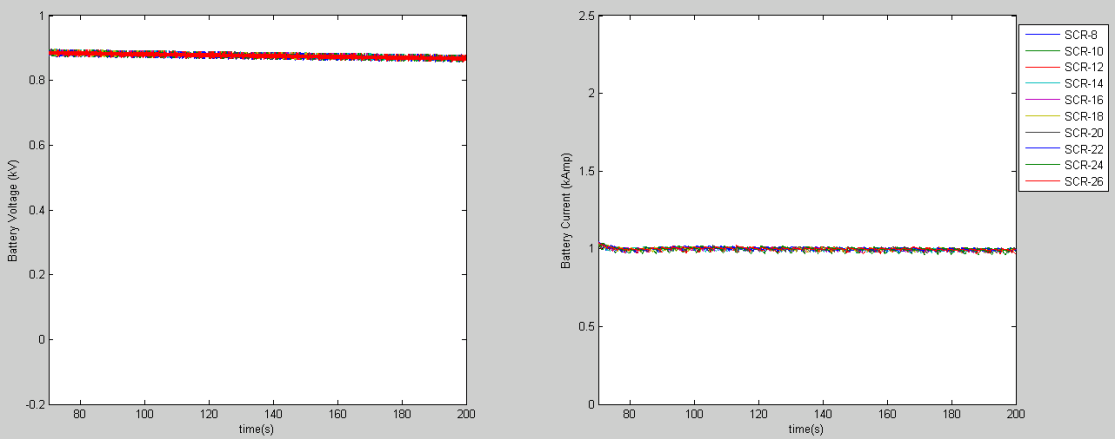


Figure 142. Battery Voltage and Current

The battery discharge was observed in the battery voltage in the left figure and was observed to be 960 V until 200 seconds and continued to discharge until the nominal voltage at 3600 seconds. The battery current in the right figure was found to be settling at 1100 A.

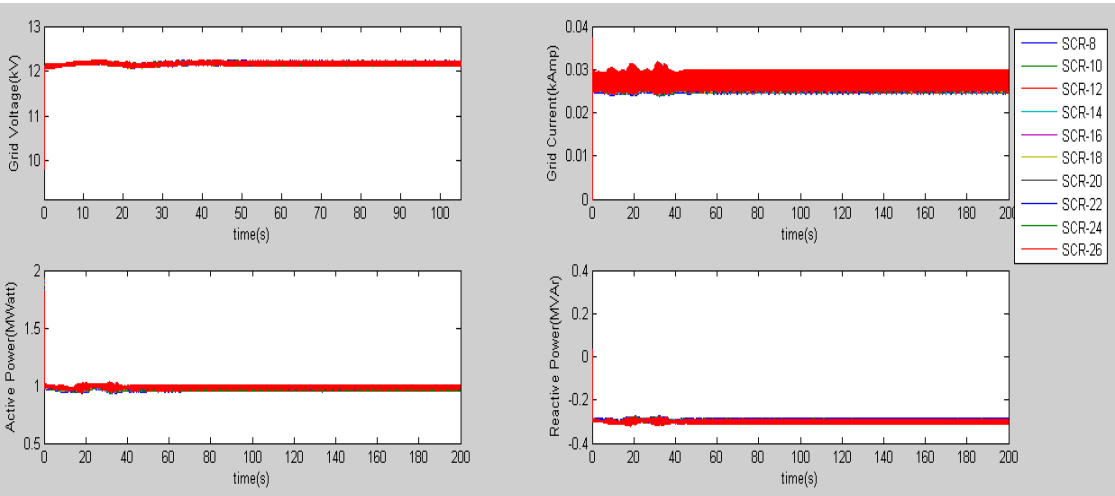


Figure 143. Grid - Voltage and Current (top) & Active and Reactive Power (bottom)

The plots above shows the grid response when a battery system is connected to it. The grid rms voltage was found to be 12.2 kV and the grid rms current was 30 A. The active power at the grid was 1 MW and the reactive power at the grid was -0.3Mvar. The response graphs in the above figures show the legend with the SCR varying from 8 to 26. The legend was used to observe the response of the system when it transferred from a weak to strong grid. Both the grid and battery response did not show much variation during that transition from weak to strong grid.

8.5.1.9.2 Grid-connected to Battery System-Fault

A three phase fault to ground was applied near the grid to the grid-connected battery system. The transient state analysis of the battery connected to grid showed variations when the impedance values were changed from weak to strong grid through the SCR. The plots below show the grid response when the battery system was connected during transient conditions. The grid rms voltage was found to be 12.2 kV and decreased during the fault. The grid rms current was 30A initially but increased during the fault. The active power at the grid reduced and the reactive power at the grid increased during the fault and settled after oscillations. Both the grid and battery discharge characteristics showed considerable changes in transition from weak to strong grid during the time when the fault was applied. The figure below shows the zoomed-in view of the grid voltage and current for a weak grid with SCR taken to be 8 (weak grid). The active and reactive power was found have high oscillations during the fault.

Figure 144. Response at the Grid during Fault (Weak)

The following figure is simulated for SCR to be 26 (strong grid). Thus it is evident that the strong grid sustained the oscillations and tended to reach steady state faster as compared to a weak grid. The oscillations were found to be comparatively less in a weak grid.

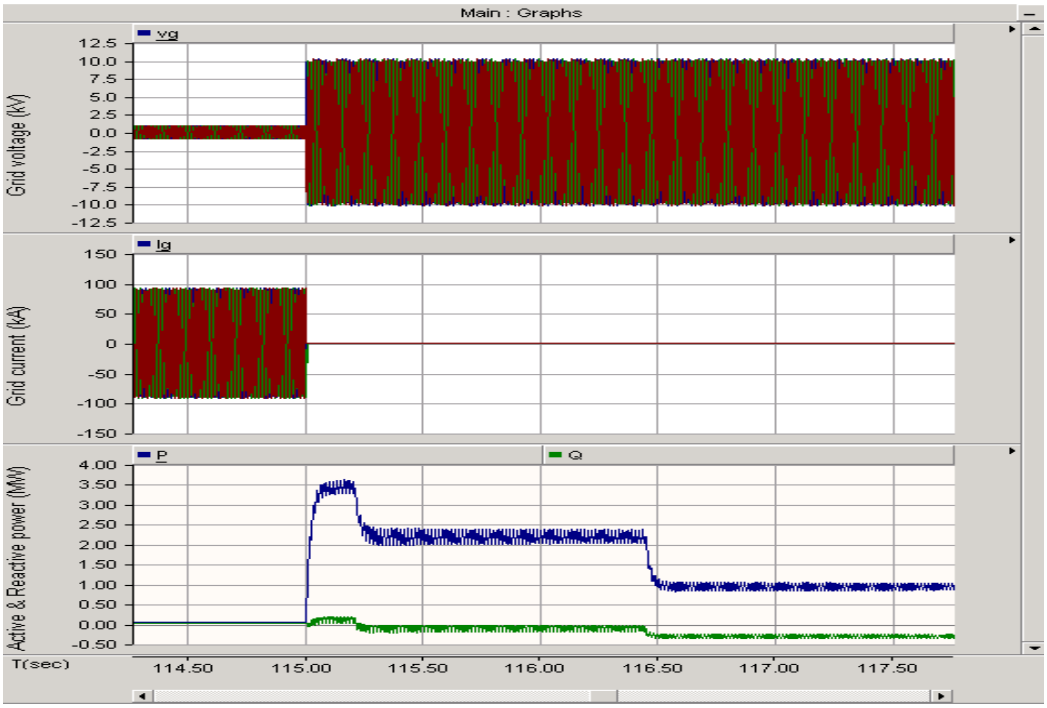


Figure 145. Response at the Grid during Fault (Strong)

The battery discharge characteristic in the following figure was simulated for weak grid and was observed to be 1000 V until time at 110 seconds and had a reduction in voltage level during the three-phase fault period applied between 110-113 seconds. The voltage resumed back after the fault period and attained its steady state condition. The battery current increased to 1180 A during the fault period and settled after the fault at 1100 A.

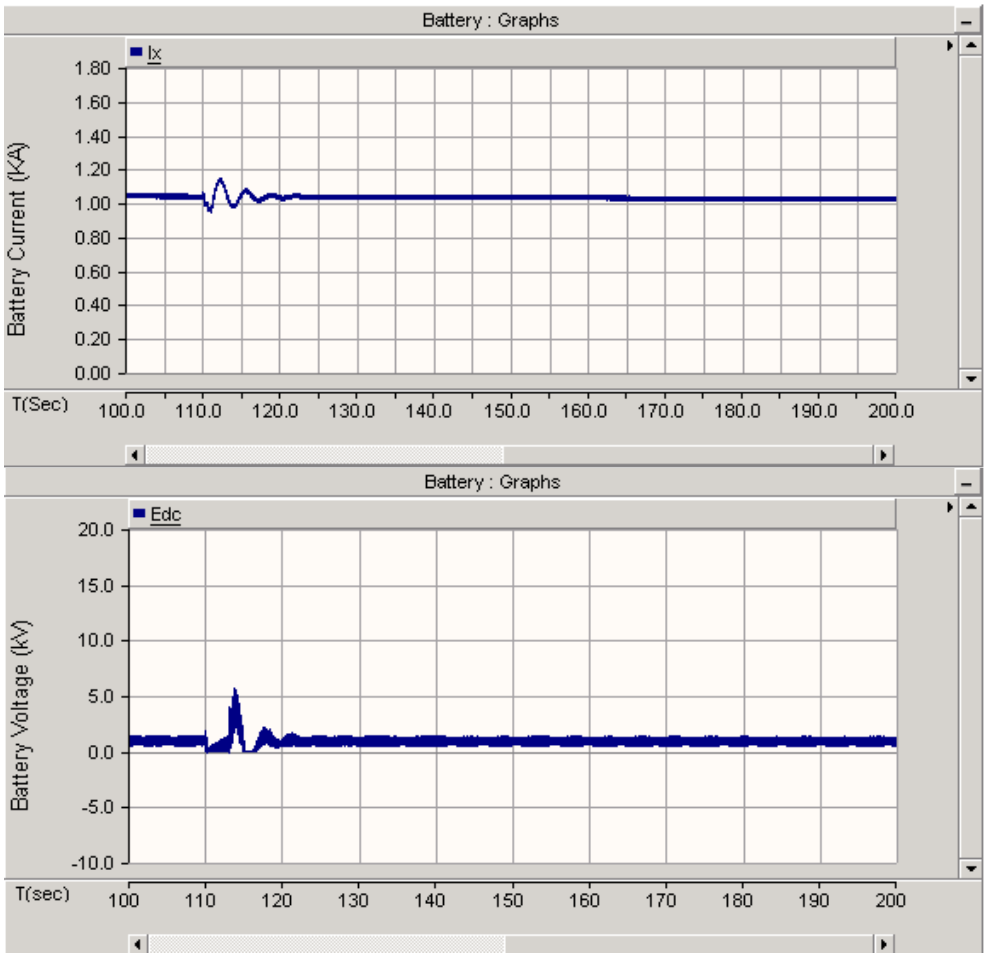


Figure 146. Response at the Battery during Fault (Weak)

The battery discharge characteristic in the following figure was simulated for strong grid and is observed to be 1000 V until time at 110 seconds and had very small distortions and oscillations in voltage level during the three-phase fault period applied between 110-113 seconds. The voltage resumed back after the fault period and attained its steady state condition. The battery current was increased to 1300 A during the fault period and settled after the fault at 1100 A.

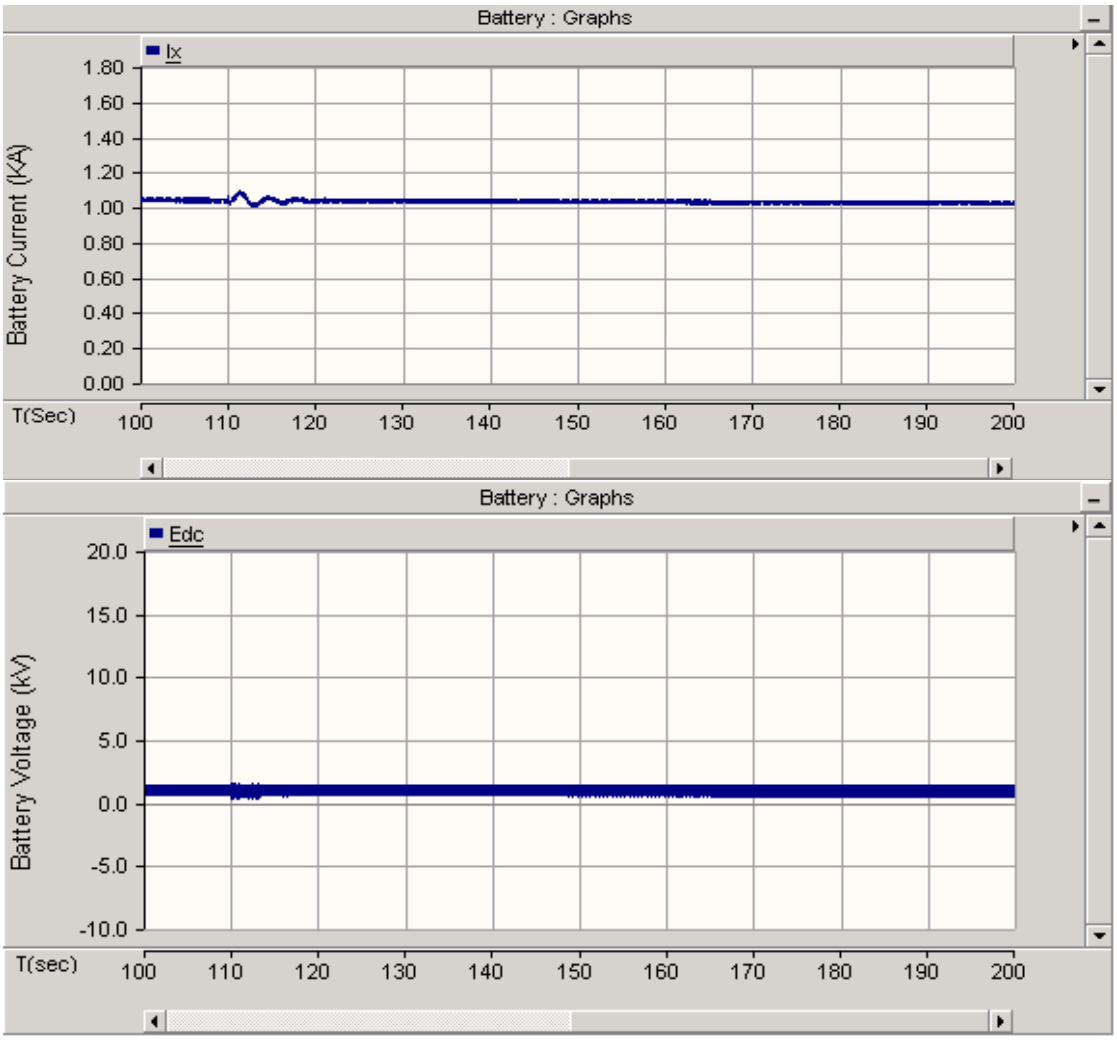


Figure 147. Response at the Battery during Fault (Strong)

A comparison of the preceding graphs show variations and oscillations were controlled better in the strong grid than in the weak grid.

8.5.1.9.3 Grid-connected Wind System

The wind system was connected to the 12.5 kV grid through a variable inductor and a variable resistor. The table modeled in PSCAD was used to vary the R and L values according to the SCR range of 8 to 26. Thus the project settings in PSCAD were adjusted to have multiple runs so that for each run the SCR value changed by reading the corresponding R and L values from the look-up table. The wind system was initially connected to a weak grid for the first run with SCR value of 8 and the corresponding calculated R and L values were 6.5056 ohm and 0.01 H, respectively. The use of the look-up table enabled the change in impedance values and caused the wind system to be connected to a strong grid.

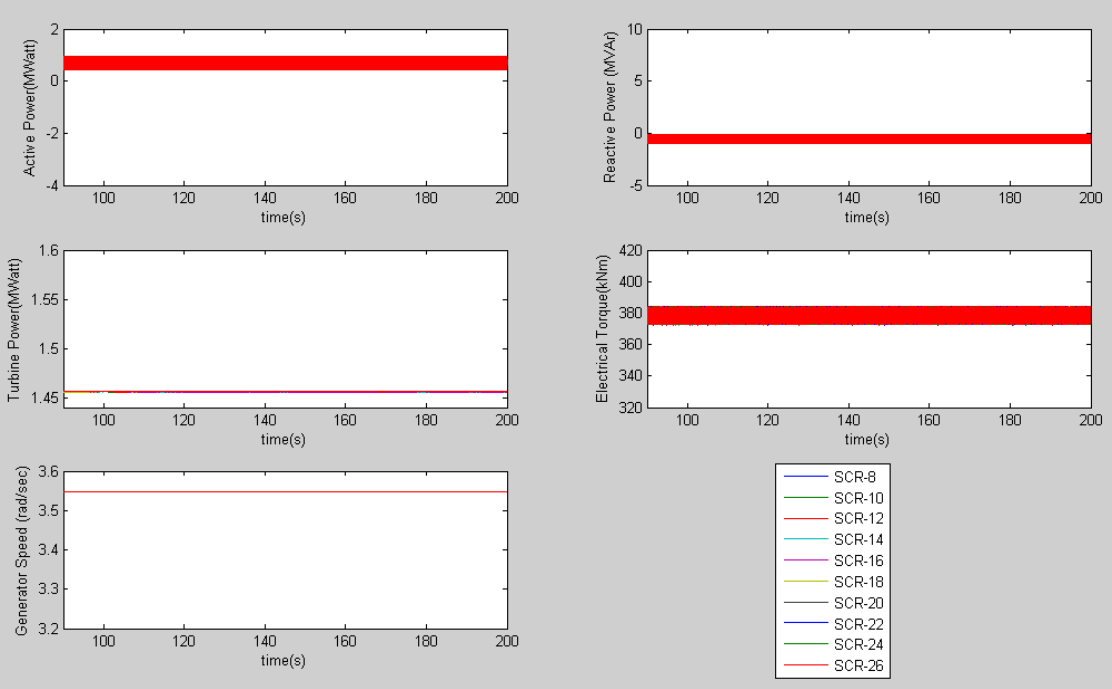


Figure 148. Response of Wind-Connected Grid System

The responses from the wind turbine and grid parameters were observed. The multiple run values were saved to a file and the data was extracted through MATLAB and plotted. The steady state analysis of the wind system connected to grid did not show any variation with the values changed from weak to strong grid. From the above figure, it was observed that active power was 1.7 MW and the turbine power was 1.5 MW. The reactive power was approximately equal to be 0. The mechanical speed was 3.77 rad/sec. The turbine was determined to be 400 kilonewton meters (kNm).

The plots in the figure below show the grid response when the wind system was connected to it. The grid rms voltage was found to be 12.2 kV and the grid rms current was 280 A. The active power at the grid was 1.7 MW and the reactive power at the grid was 0.5 MVAR. The response graphs show the legend with the SCR varying from 8 to 26. The legend observes the response of the system transfer from weak to strong grid. Both the grid and wind turbine response did not show much variation in transition from weak to strong grid.

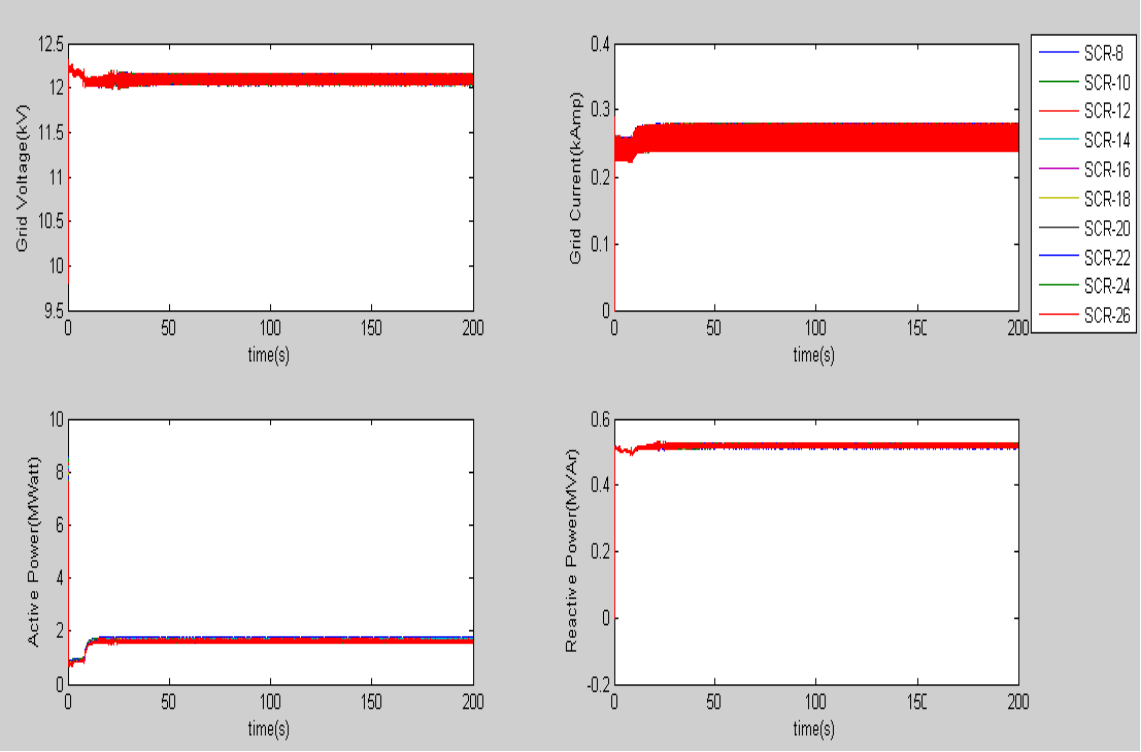


Figure 149. Grid - Voltage and Current (top) & Active and Reactive Power (bottom)

8.5.1.9.4 Grid-connected Wind System-Fault

A three-phase fault to ground was applied near the grid to the system as shown below. The transient state analysis of the wind connected to grid showed variations when the values were changed from weak to strong grid through the SCR.

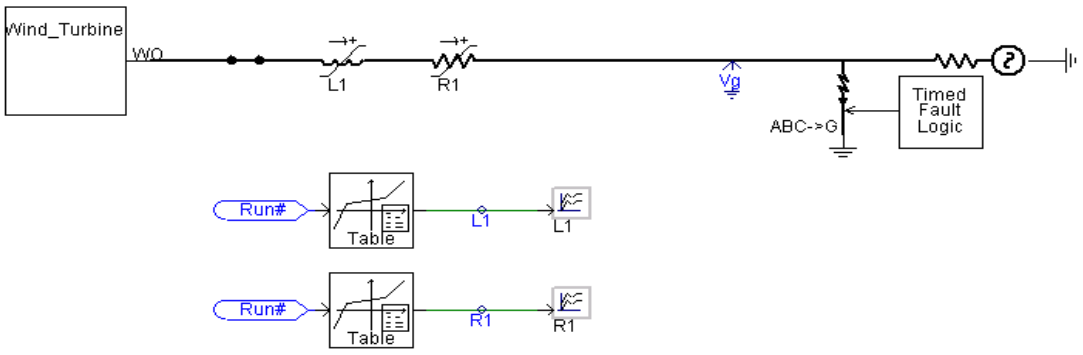


Figure 150. Wind-Connected Grid System with Fault Applied near the Grid

The active power, reactive power and electric torque parameters in the figure below were found to have unsteady response when simulated for a weak grid condition at low SCR of 8. While the response was

stabilized as the SCR increased and simulated for a strong grid with an SCR of 26. The three-phase fault was applied between 110 and 113 seconds. The plots below show the grid response when the wind system was connected to it during transient conditions. The grid rms voltage was found to be 12.2 kV and decreased during the fault. The grid rms current was 280A initially but increased during the fault. The active power at the grid reduced and the reactive power at the grid increased during the fault and settled after oscillations.

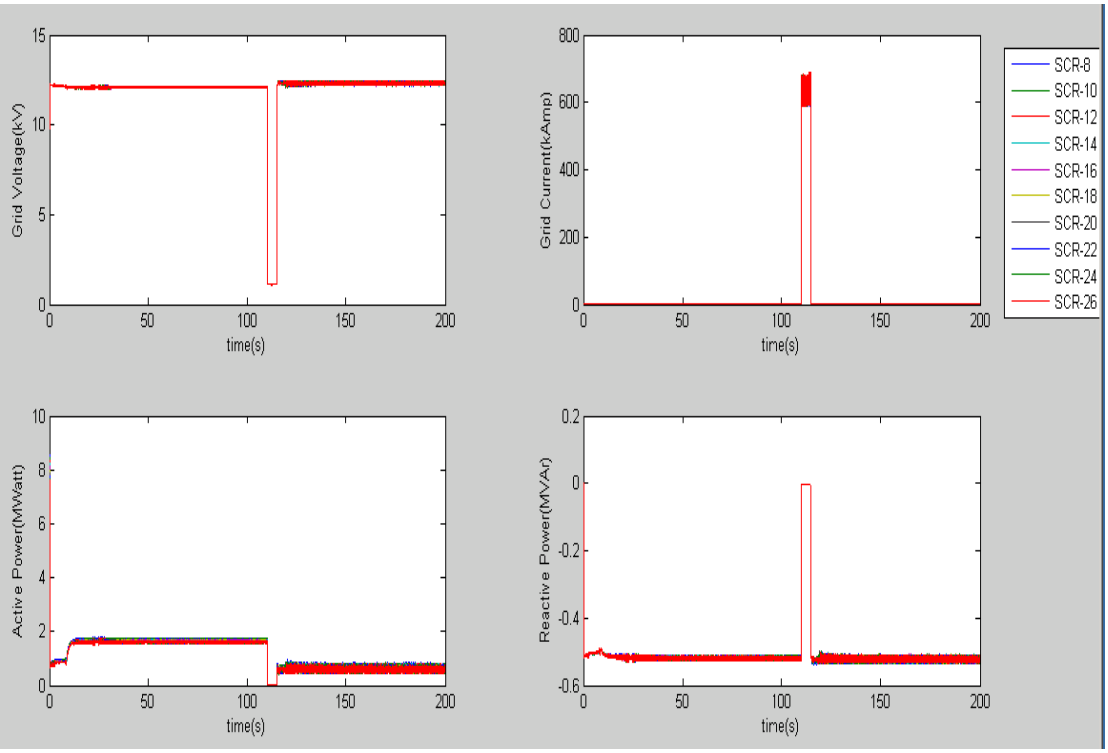


Figure 151. Grid - Voltage and Current (Top) & Active and Reactive Power (Bottom)

8.5.1.9.5 The Complete System

The battery system and the wind system were connected to the 12.5 kV grid through a variable inductor and a variable resistor as shown below. Look-up tables and project settings were made the same as described in previous sections and were adjusted to have multiple runs so the SCR values changed and took the corresponding R and L values through the multiport switch. The battery system and wind system were initially connected to a weak grid for the first run with SCR value of 8 and the corresponding calculated R and L values were 6.5056 ohm and 0.01 H, respectively.

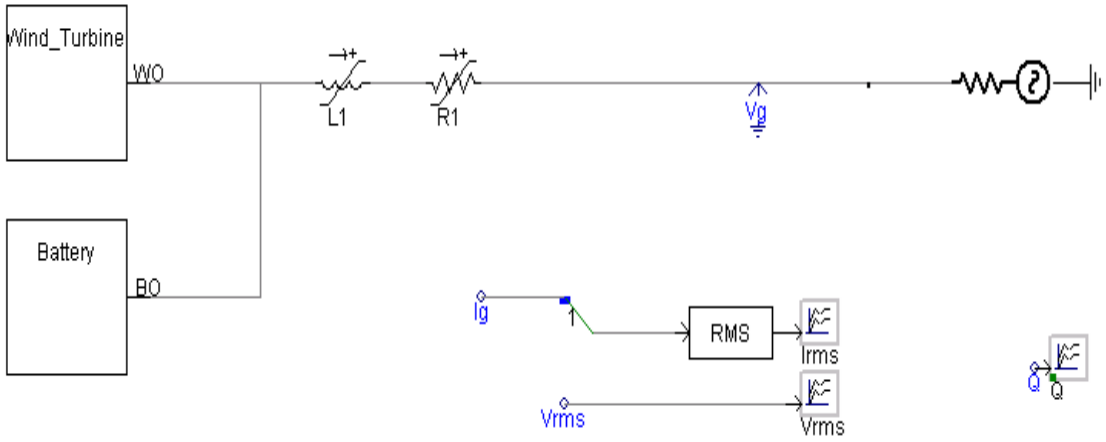


Figure 152. Complete System with Battery, Wind Connected to Grid

The response of the battery, wind turbine, and grid parameters were observed. The multiple run values were saved to a file and the data was extracted through MATLAB and plotted as shown below. The steady state analysis of the battery and wind connected to grid did not show any variation with the values changed from weak to strong grid. The battery discharge was observed in the battery voltage to be 960 V until time for 200 seconds and continued to discharge until the nominal voltage at 3600 seconds. The battery current was found to be settling at 1100 A.

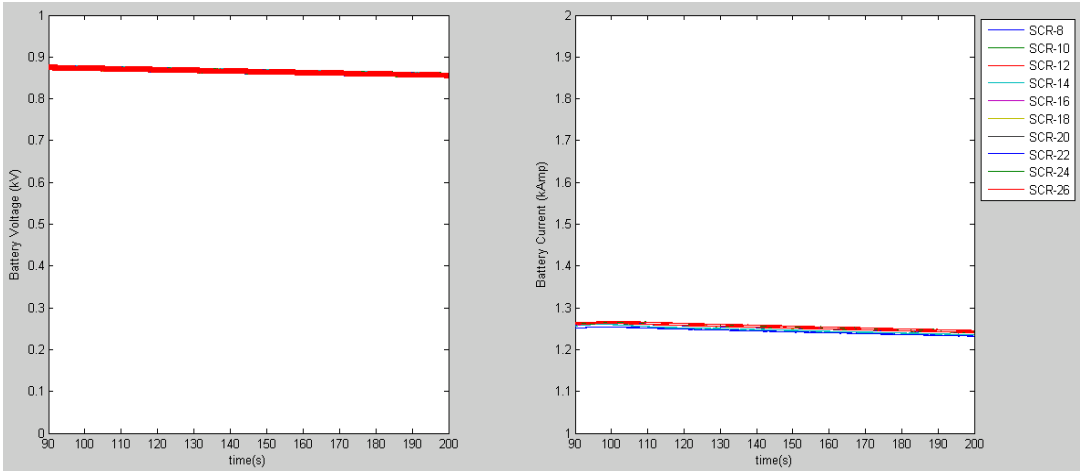


Figure 153. Battery Response when Wind Connected to Grid

From the following figure it was observed that the active power was 1.3 MW and the turbine power was ≈ 1.5 MW. The reactive power was approximately equal to 0. The mechanical speed was 3.77 rad/sec. The turbine was obtained to be 400kNm. The oscillations at the initial conditions were due to the addition of filters to the wind system.

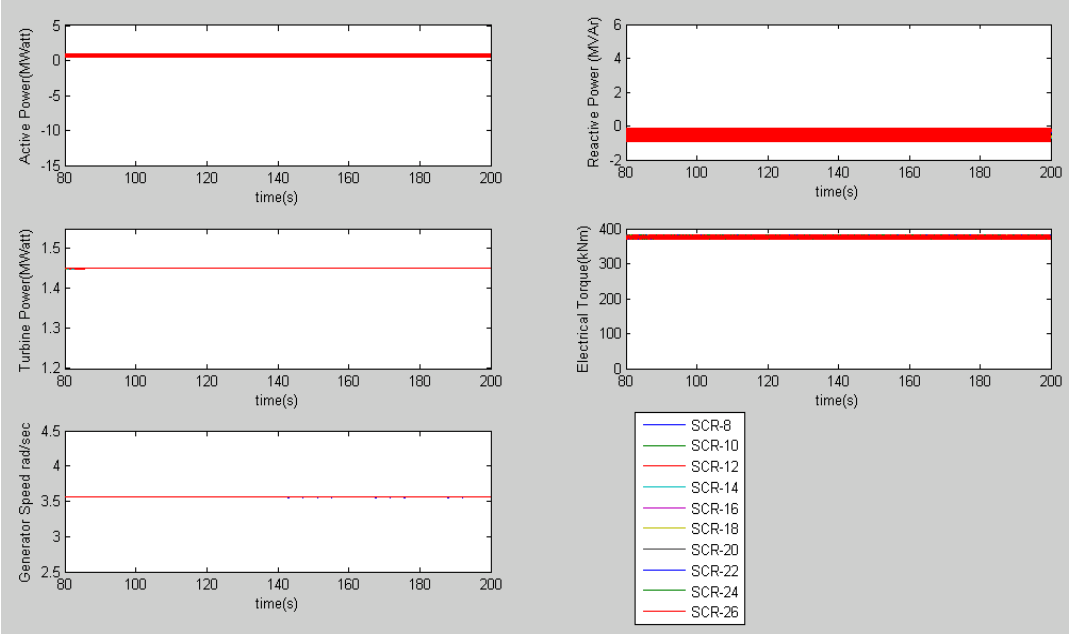


Figure 154. Wind Response when Battery Connected to Grid

The plots below show the grid response when battery and wind system were connected to it. The grid rms voltage was found to be 12.0 kV and the grid rms current was 350 A. The active power at the grid was 2.7 MW and the reactive power was 0.2 MVAR. The grid, wind and battery response did not show much variation in transition from weak to strong grid.

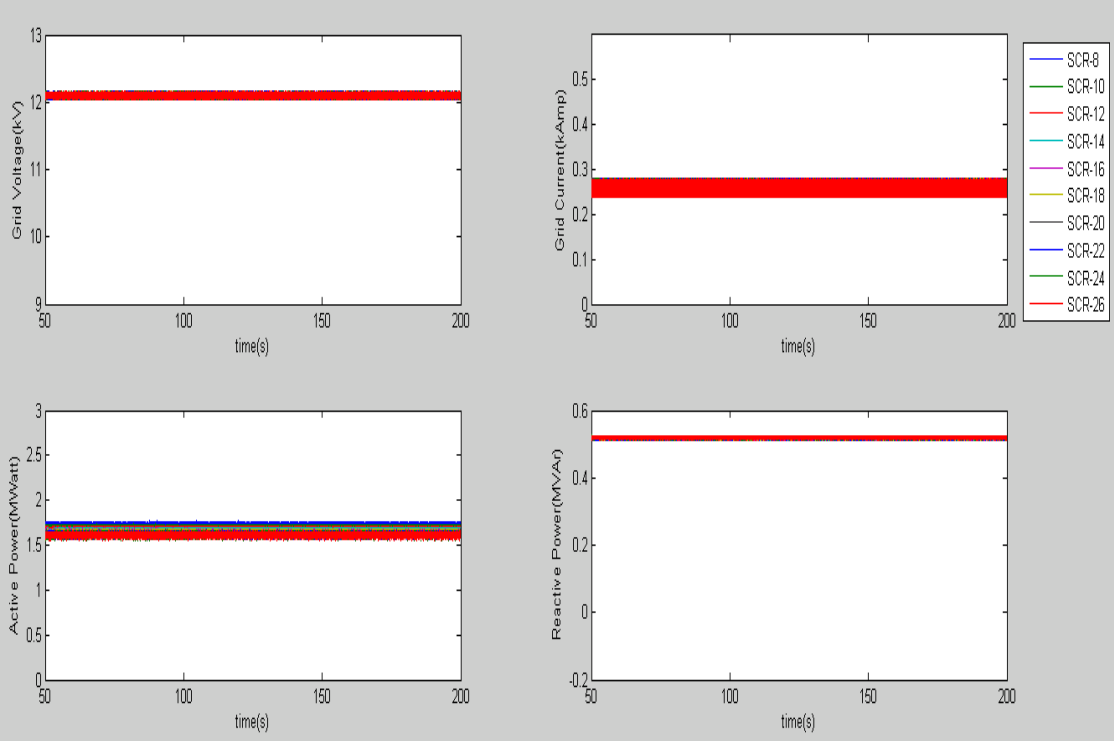


Figure 155. Grid Response when Battery and Wind Connected to It

8.5.1.9.6 The Complete System-Fault

A three-phase fault to ground was applied near the grid to the system as shown below. The transient state analysis of the battery, wind connected to grid showed variations with battery, wind and grid components when the impedance values were changed from weak to strong grid through the SCR.

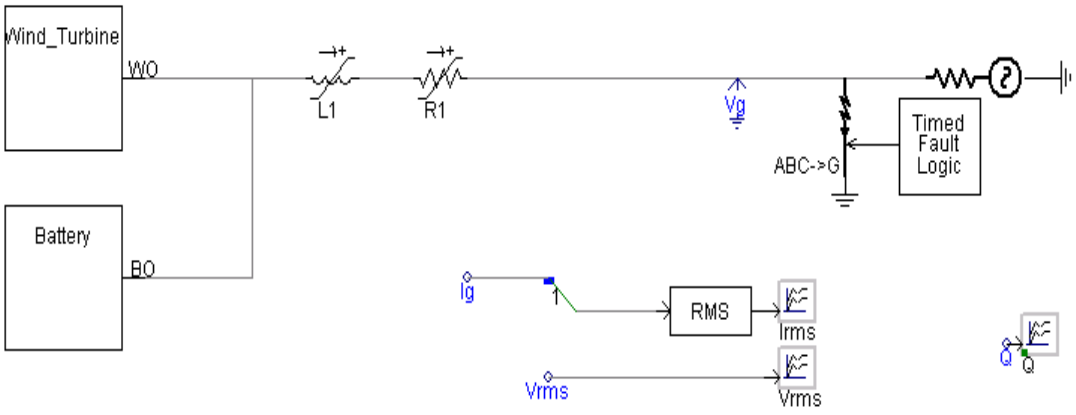


Figure 156. Complete System with Three-Phase Fault

The battery discharge characteristic for weak grid condition in the figure below was observed to be 1000 V (“Edc”) until time at 110 seconds and had a reduction in voltage level during the three-phase fault period applied between 110 -113 seconds. The voltage resumed back after the fault period and attained its steady state condition. The battery current was found to be increasing to 2500 A during the fault period and settled after the fault at 1100 A.

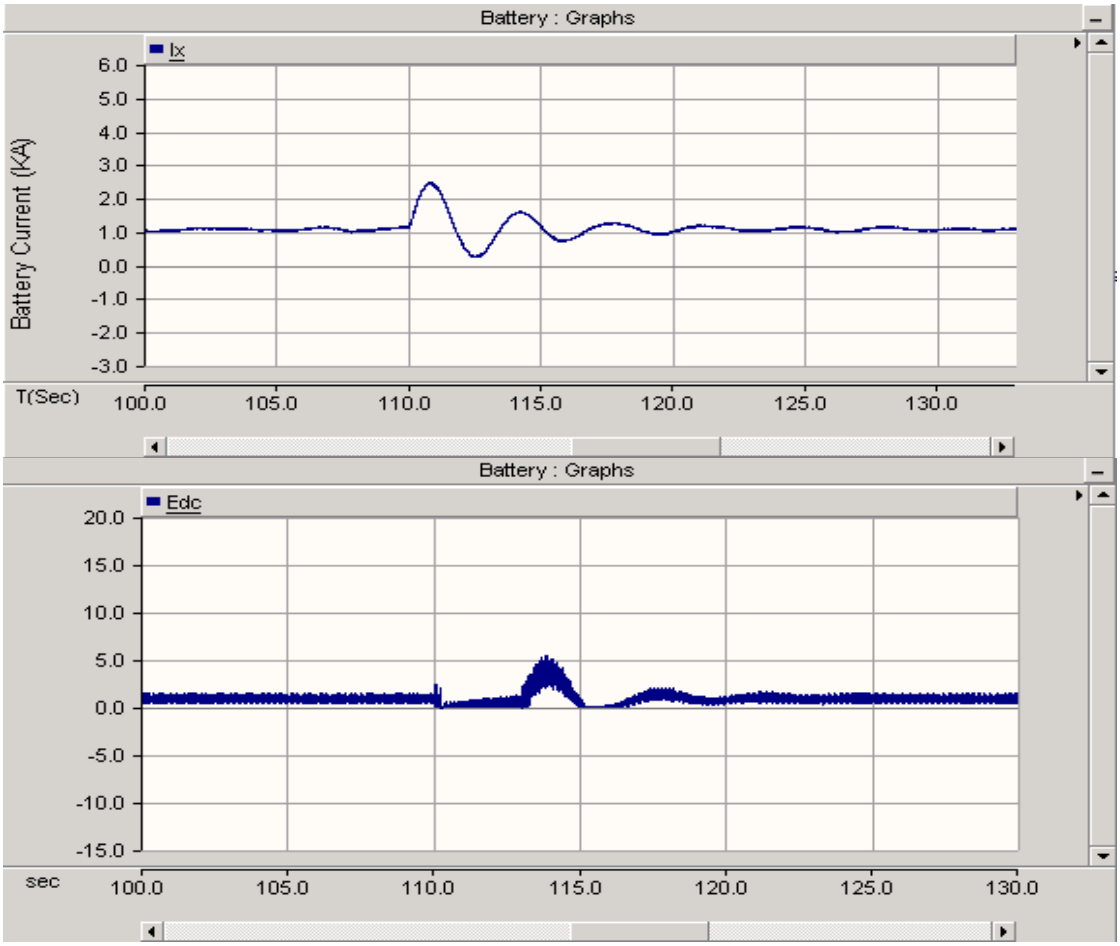


Figure 157. Battery Response when Wind Connected to Grid with Fault (Weak)

The battery discharge characteristic for weak grid condition shown below was observed to be 1000 V (“Edc”) until time at 110 seconds and had a reduction in voltage level during the three-phase fault period applied between 110-113 seconds. The voltage resumed back after the fault period and attained its steady state condition. The battery current was found increasing to 1800 A during the fault period and settled after the fault at 1100 A.

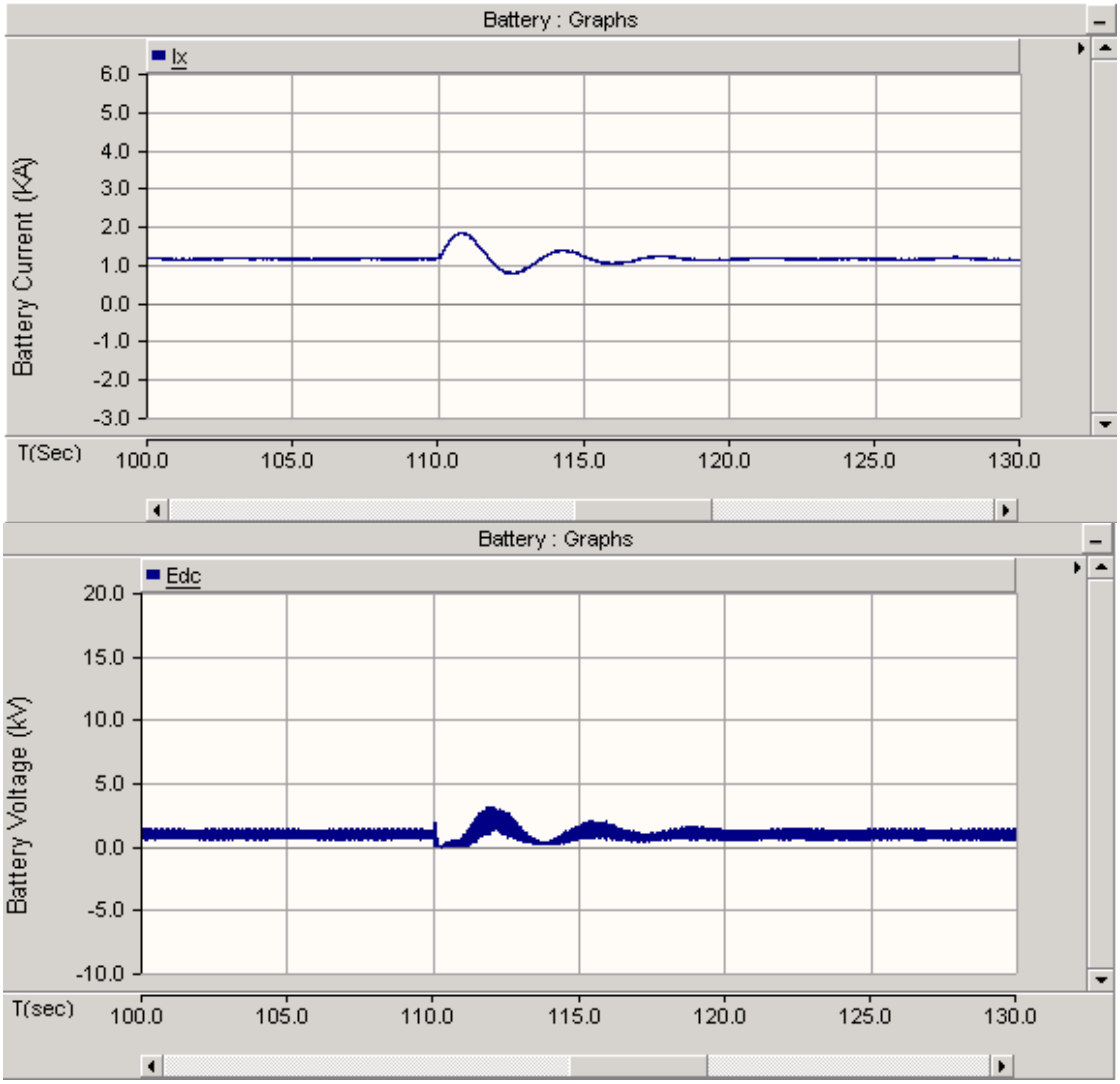


Figure 158. Battery Response when Wind Connected to Grid with Fault (Strong)

From the above results, it was observed that the weak grid had high overshoot for 1 second in current and voltage which was not so with the strong grid where the overshoot during the fault was comparatively less.

The transient state analysis of the wind turbine connected to grid along with battery showed variations when the values were changed from weak to strong grid through the SCR. The active power, reactive power and electric torque parameters in the figure to the left were found to have unsteady response when simulated for a weak grid condition at low SCR of 8. While the response was stabilized as the SCR increased and was simulated for a strong grid with SCR of 26 in the figure to the right. The three-phase fault was applied between 110 and 113 seconds.

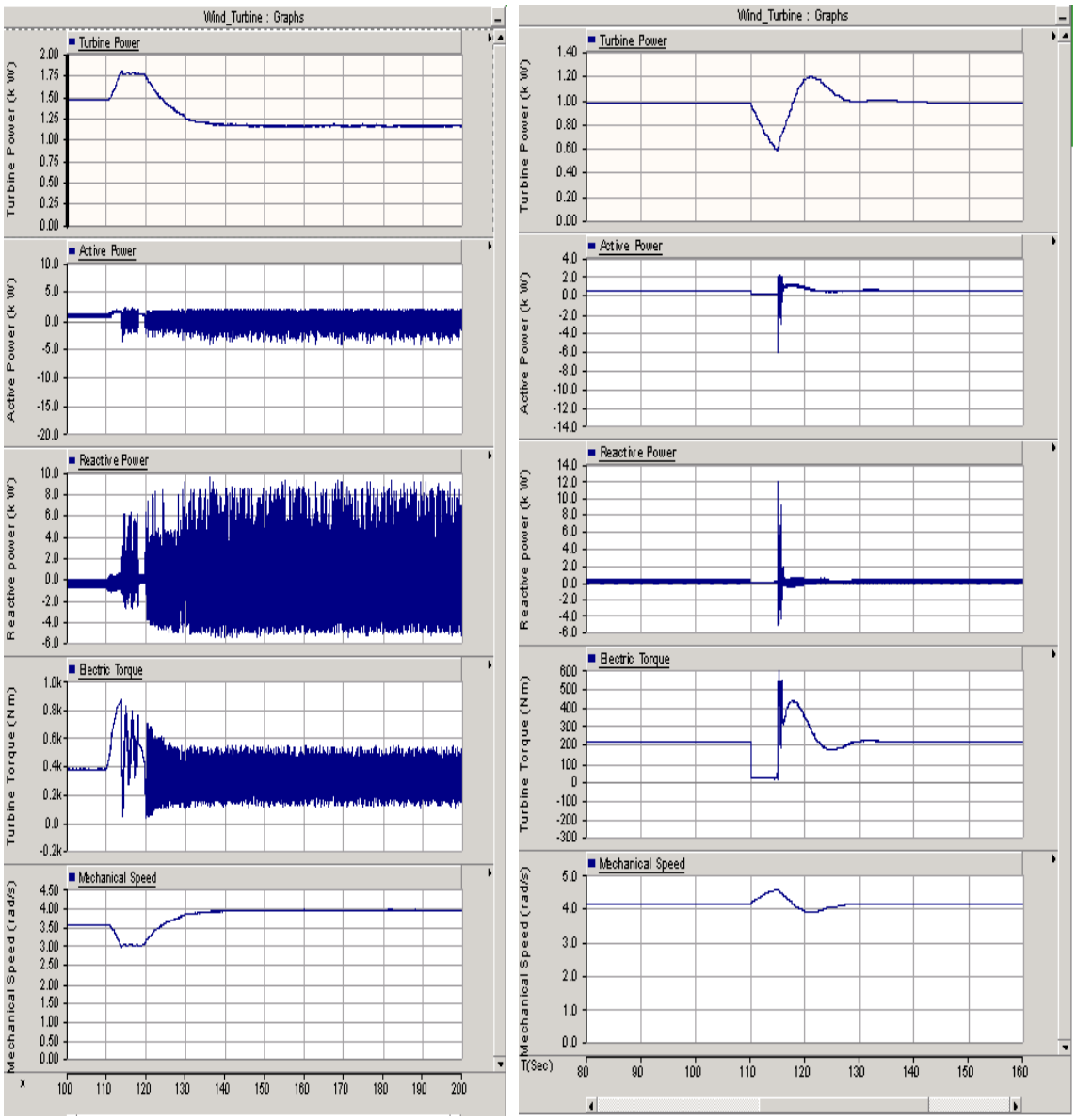


Figure 159. Wind Response - Battery to Grid with Fault – Weak (left), Strong (right)

The plots show the grid response when battery and wind system were connected to it during transient conditions. The grid rms voltage was found to be 12.2 kV and decreased during the fault. The grid rms current was 350 A initially but increased during the fault. The active power at the grid reduced and the reactive power at the grid increased during the fault and settled after oscillations.

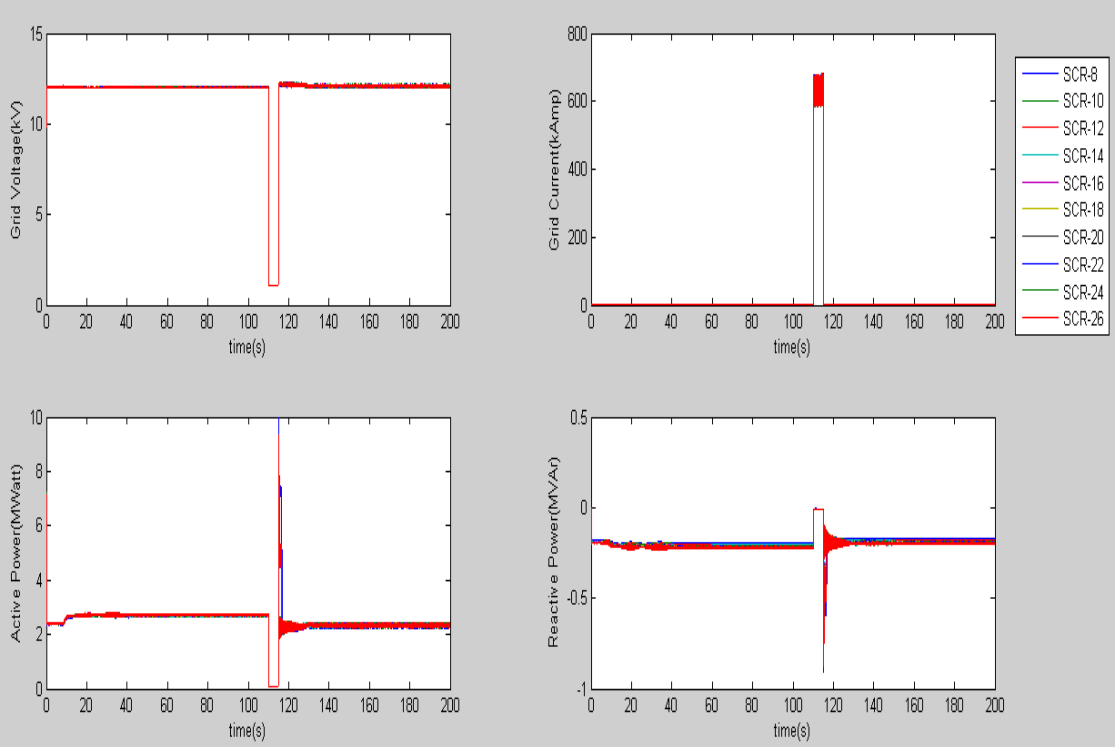


Figure 160. Grid Response when Battery and Wind Connected to It

In the above simulations, the performance of the equivalent 1MWh battery circuit and wind turbine parameters was analyzed with the weak/strong concept. It was observed from the above analysis that the controls play a vital role and require optimization of the battery and wind parameters so that when the system reaches unstable conditions such as transient fault conditions in a weak grid, the effective controls and addition of control filters would resume the stable operation of the grid. In this project, the addition of the 1 MW BESS to the wind connected grid system cannot help the system as the controls are separate for both battery and wind. However, once the fault conditions, voltage dip or frequency fluctuations as well as low power generation at the wind turbines are sensed by the controls in the battery system, the battery can respond to actively support the system.

8.5.2 Analysis of Wind Turbine Data

Beginning in April 2013, the Team began collecting and analyzing wind turbine data from the resources at the RTC. This included the Alstom turbine, and later the Gamesa turbines. The figures below show the daily average data of the power sent to the local substation in kW, the turbine production, during the months when the battery was tested in 2014 from June to October. The power production and cost analysis is done to provide a baseline for the performance of economic dispatch analysis to determine optimal battery charge/discharge schedules.

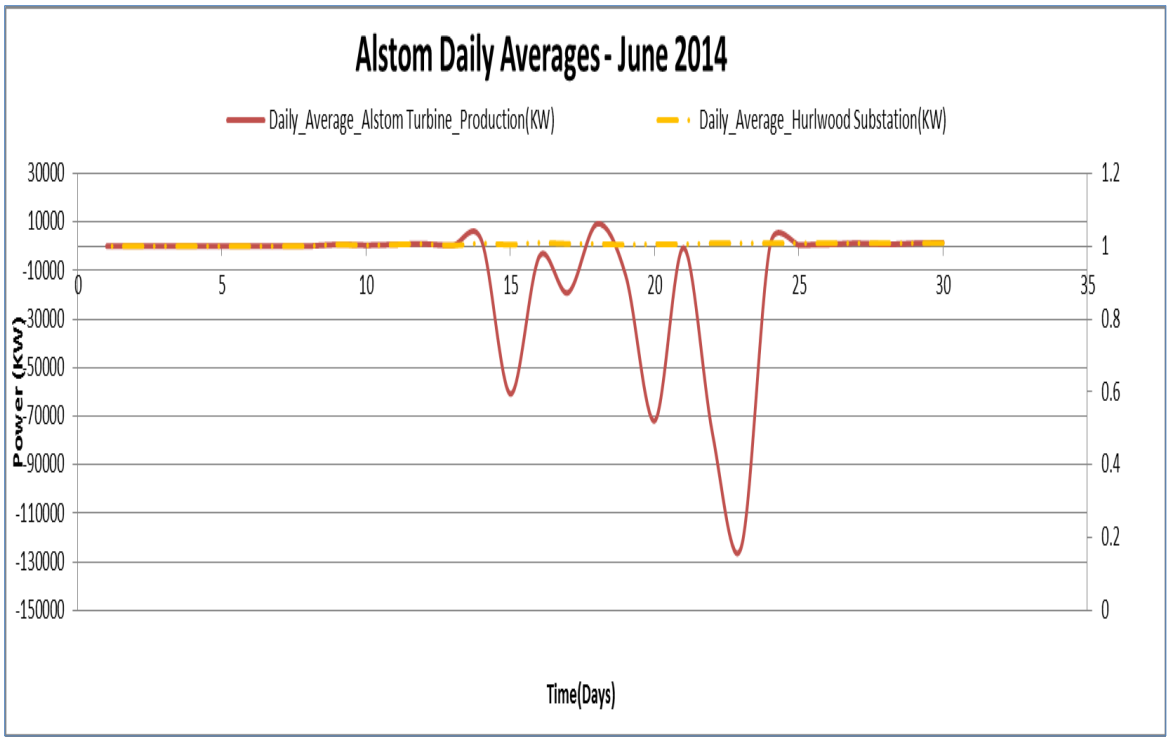


Figure 161. Alstom-Daily Averages for June 2014

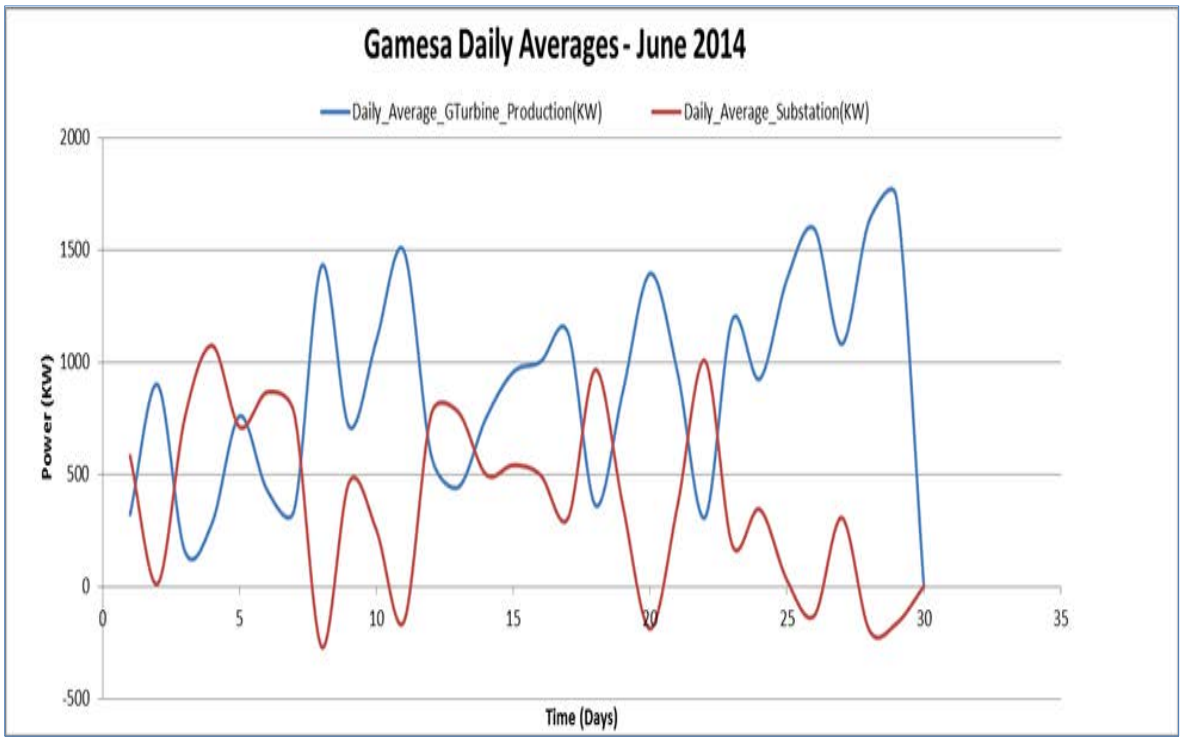


Figure 162. Gamesa-Daily Averages for June 2014

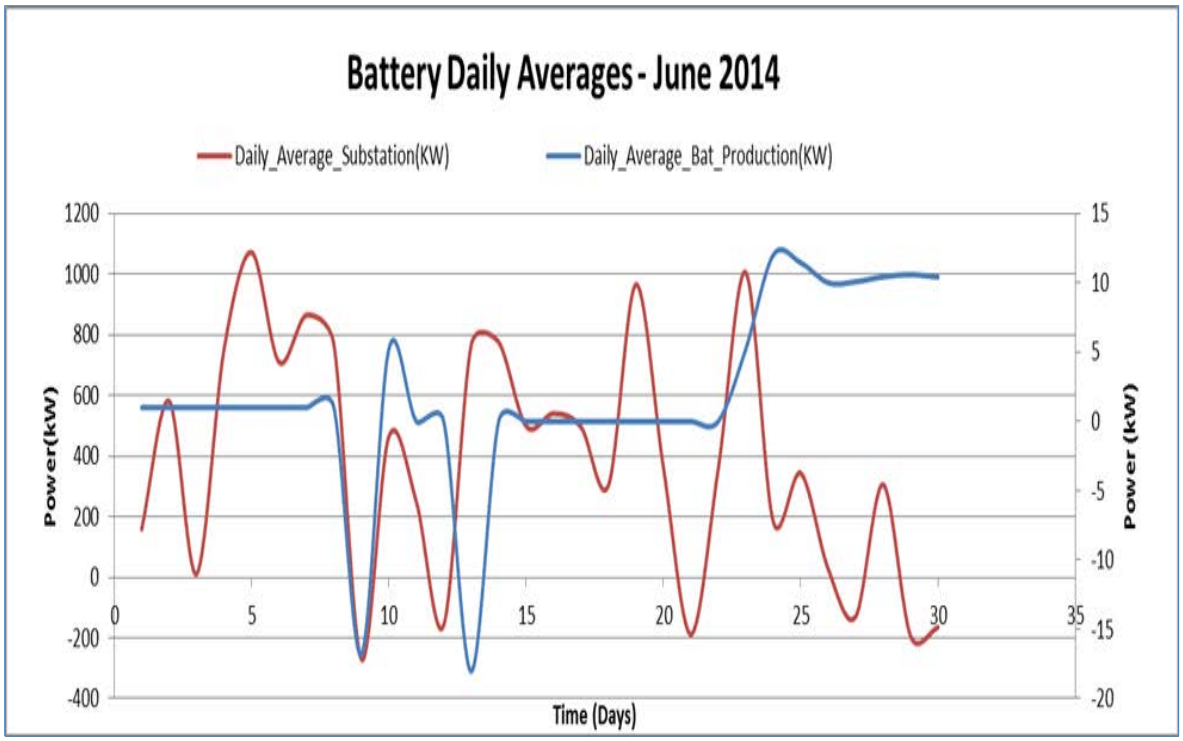


Figure 163. Battery-Daily Averages for June 2014

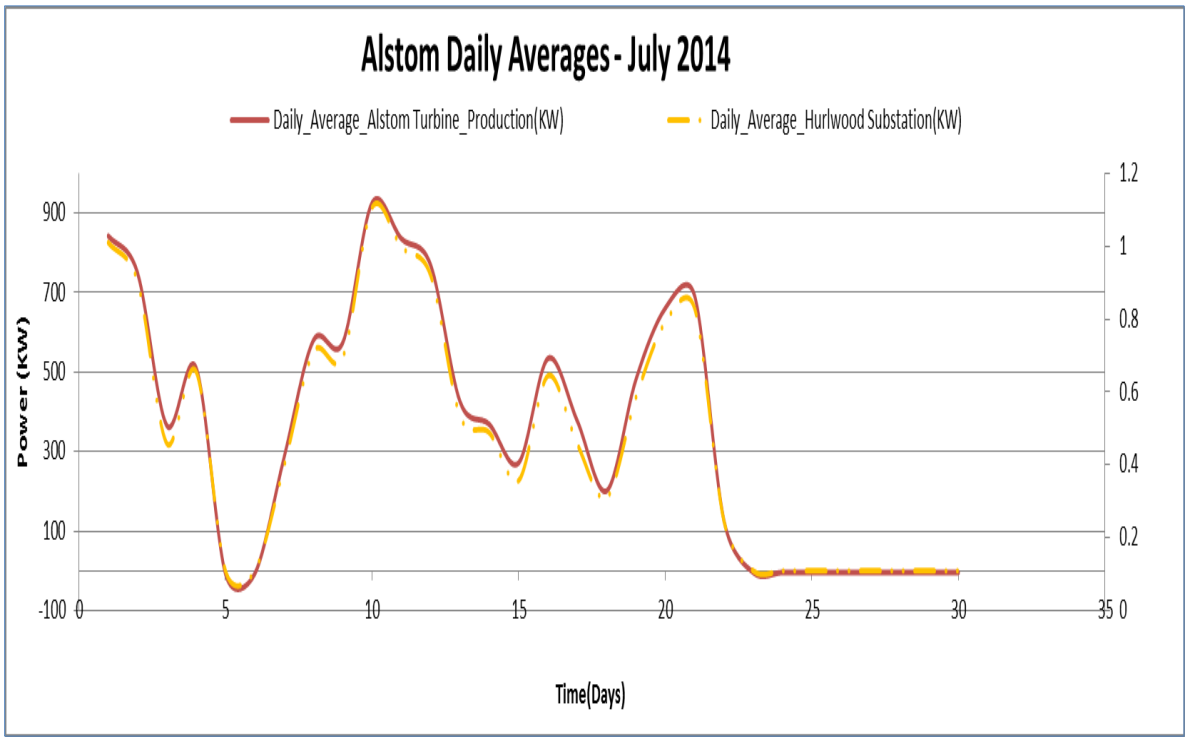


Figure 164. Alstom-Daily Averages for July 2014

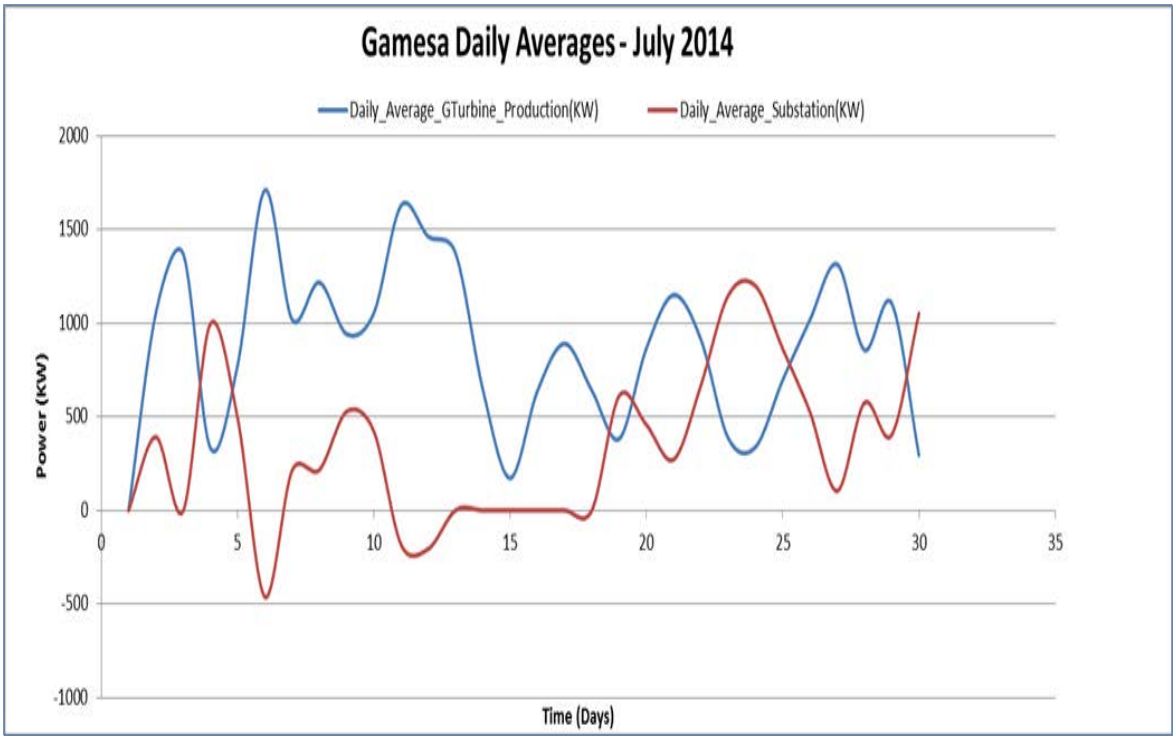


Figure 165. Gamesa-Daily Averages for July 2014

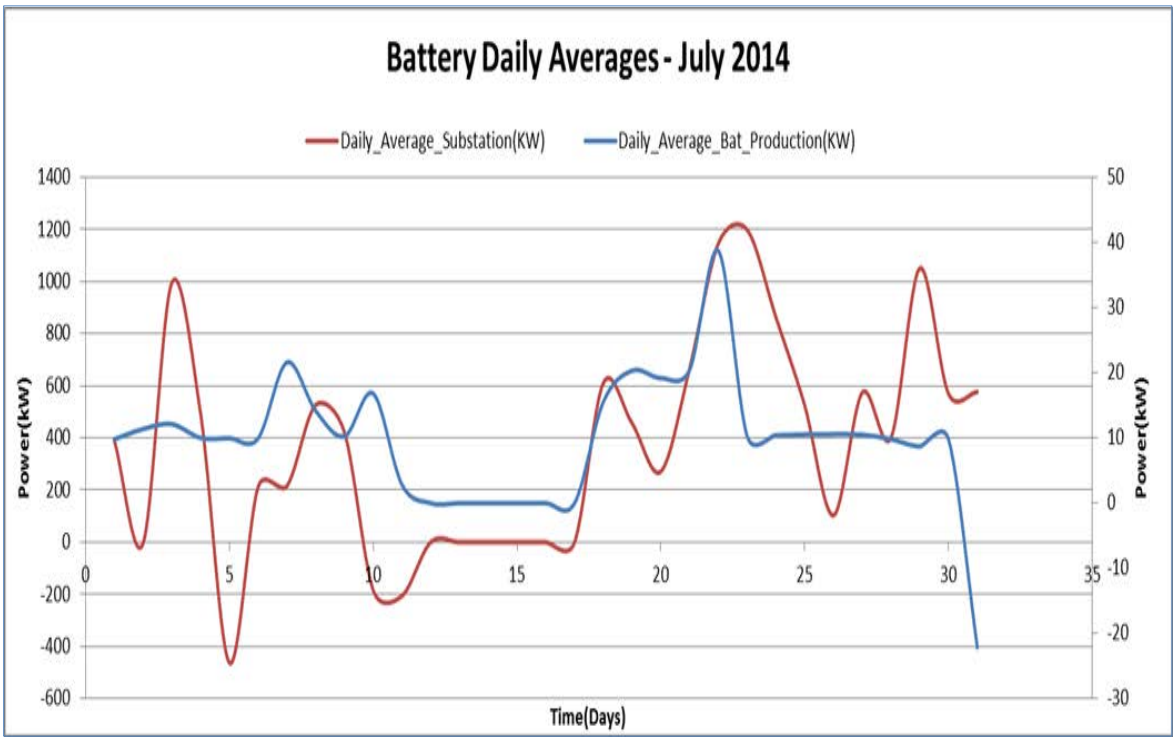


Figure 166. Battery-Daily Averages for July 2014

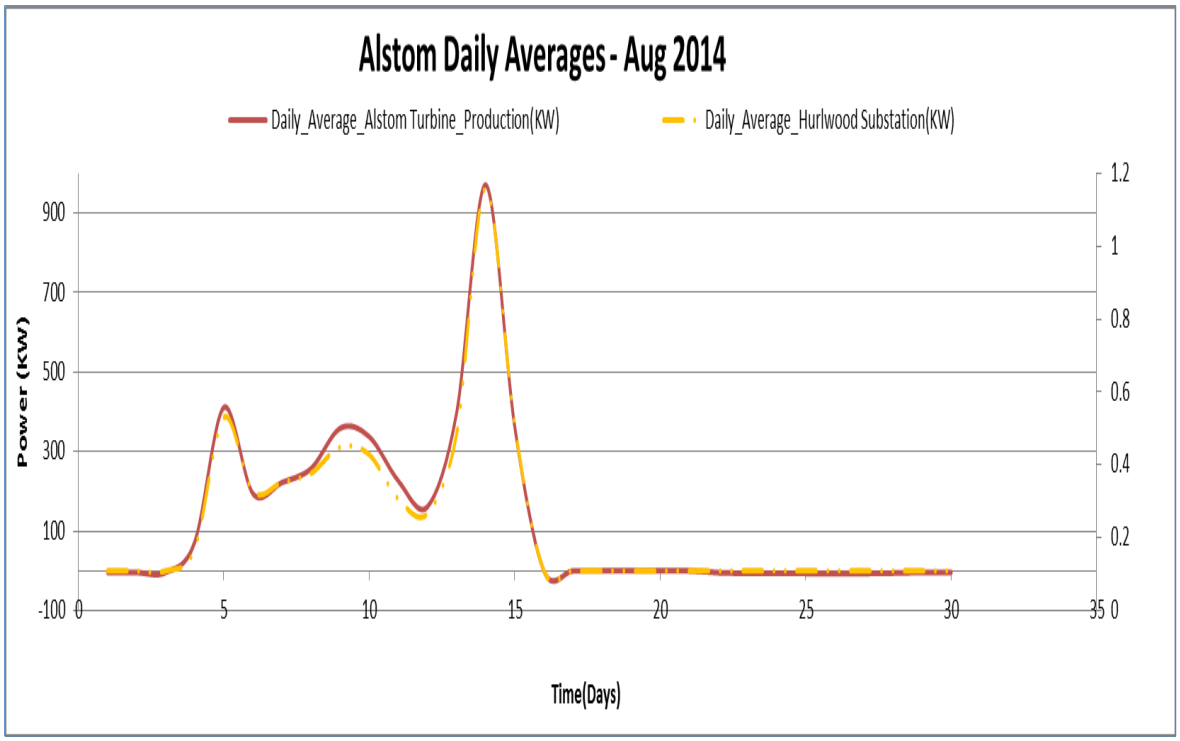


Figure 167. Alstom-Daily Averages for August 2014

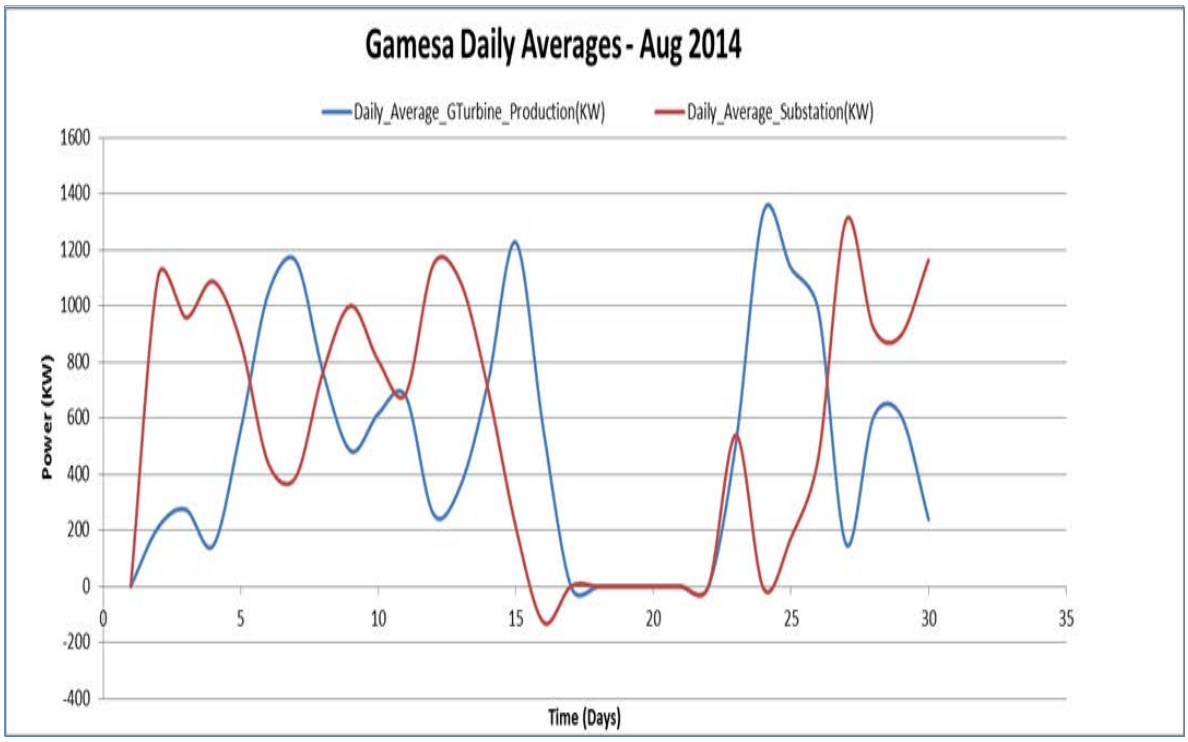


Figure 168. Gamesa-Daily Averages for August 2014

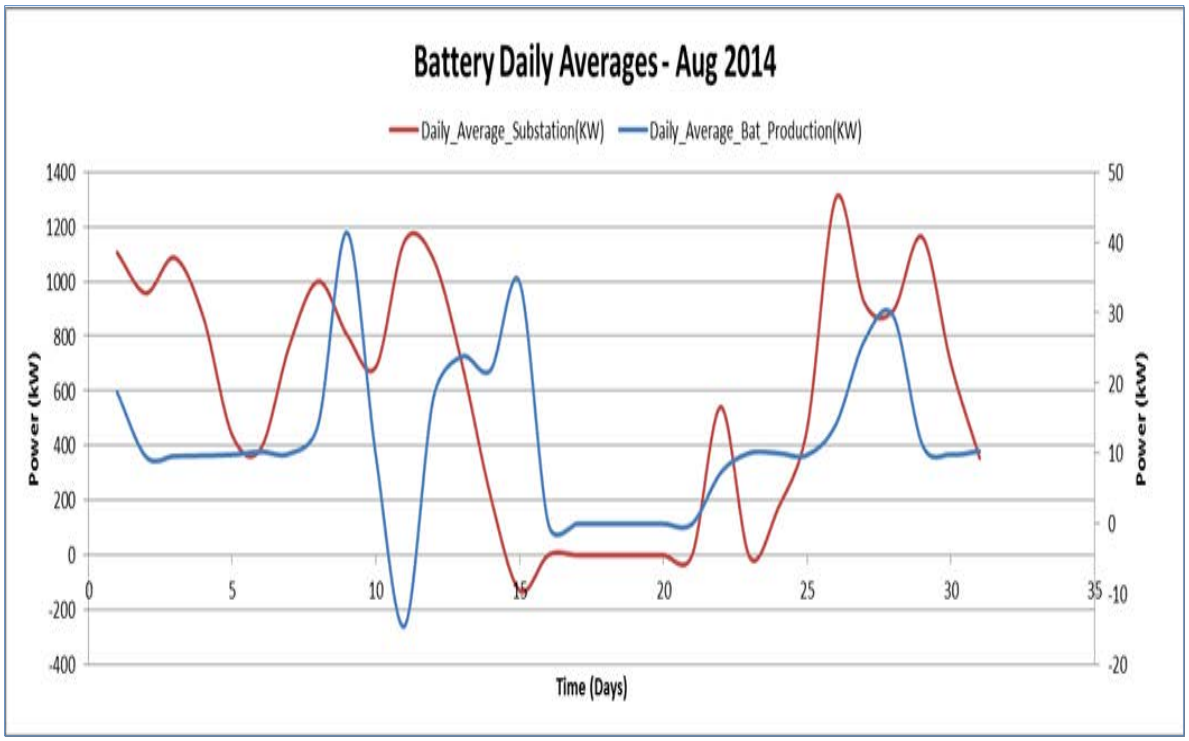


Figure 169. Battery-Daily Averages for August 2014

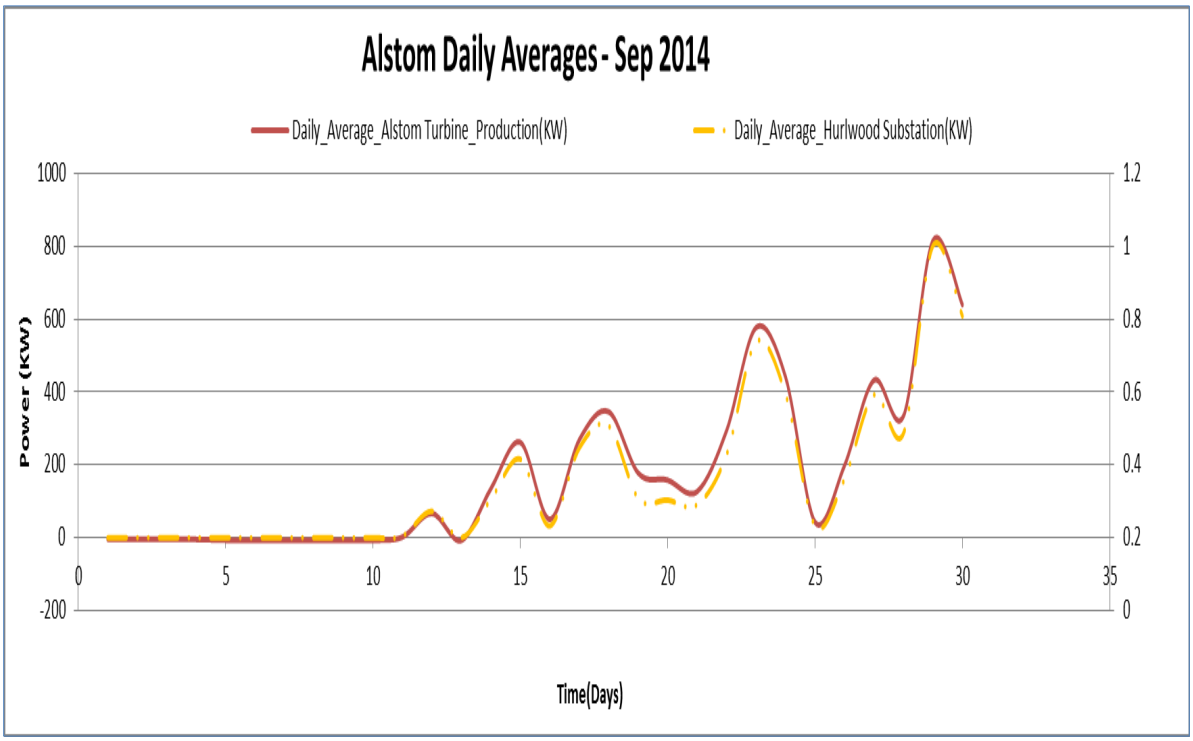


Figure 170. Alstom-Daily Averages for September 2014

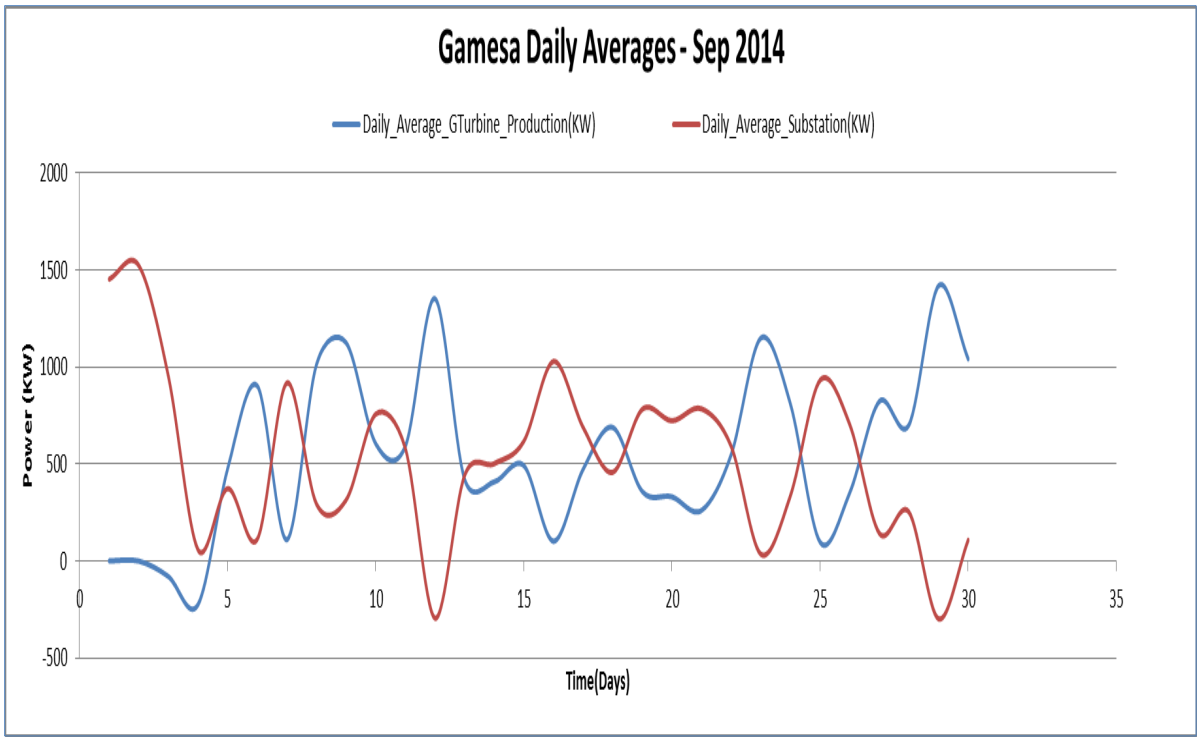


Figure 171. Gamesa-Daily Averages for September 2014

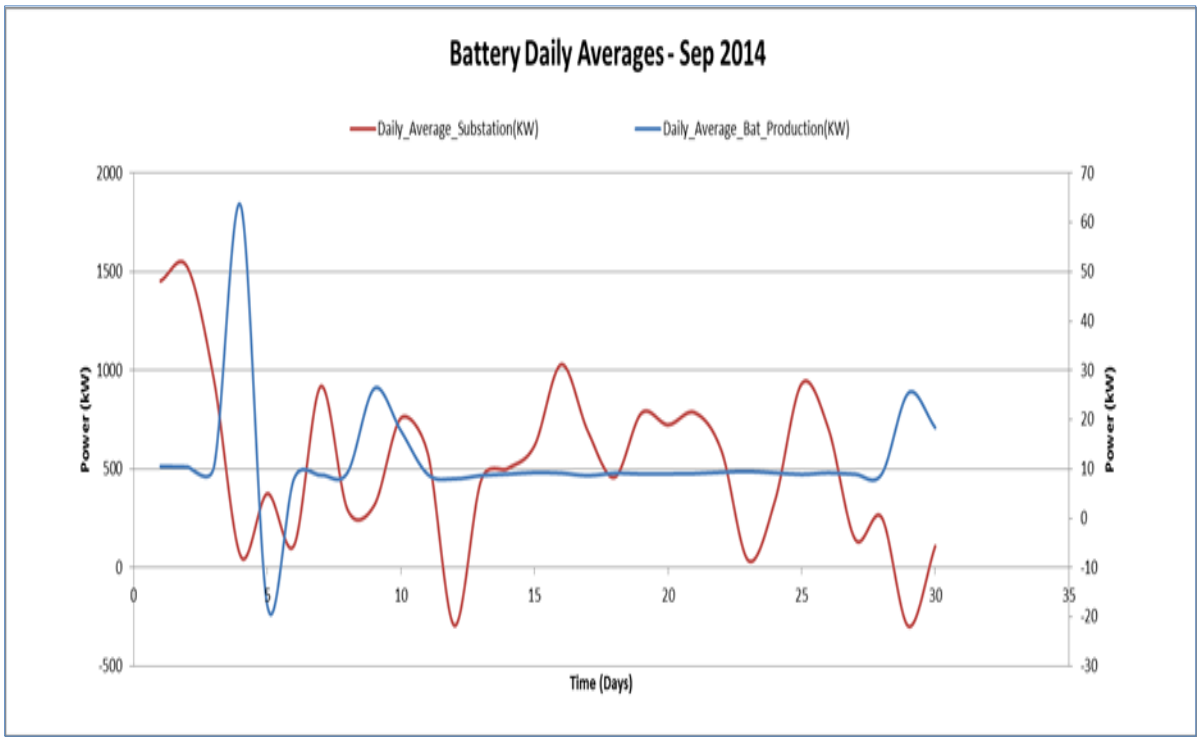


Figure 172. Battery-Daily Averages for September 2014

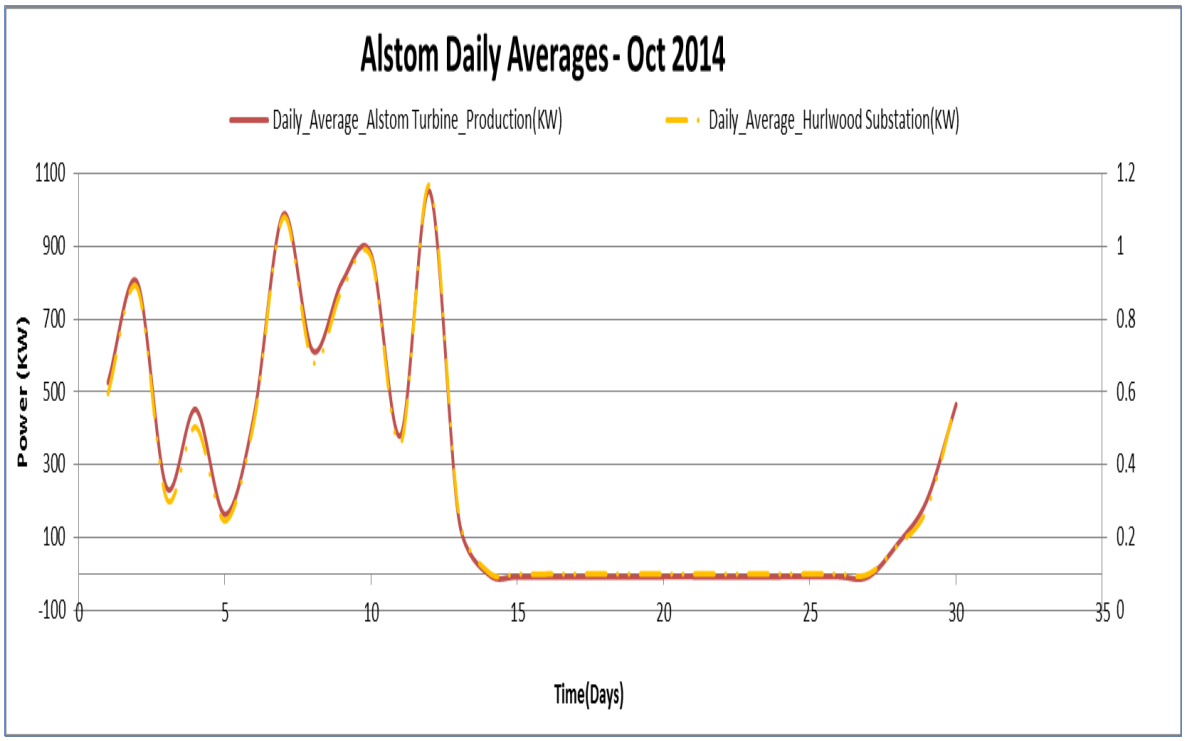


Figure 173. Alstom-Daily Averages for October 2014

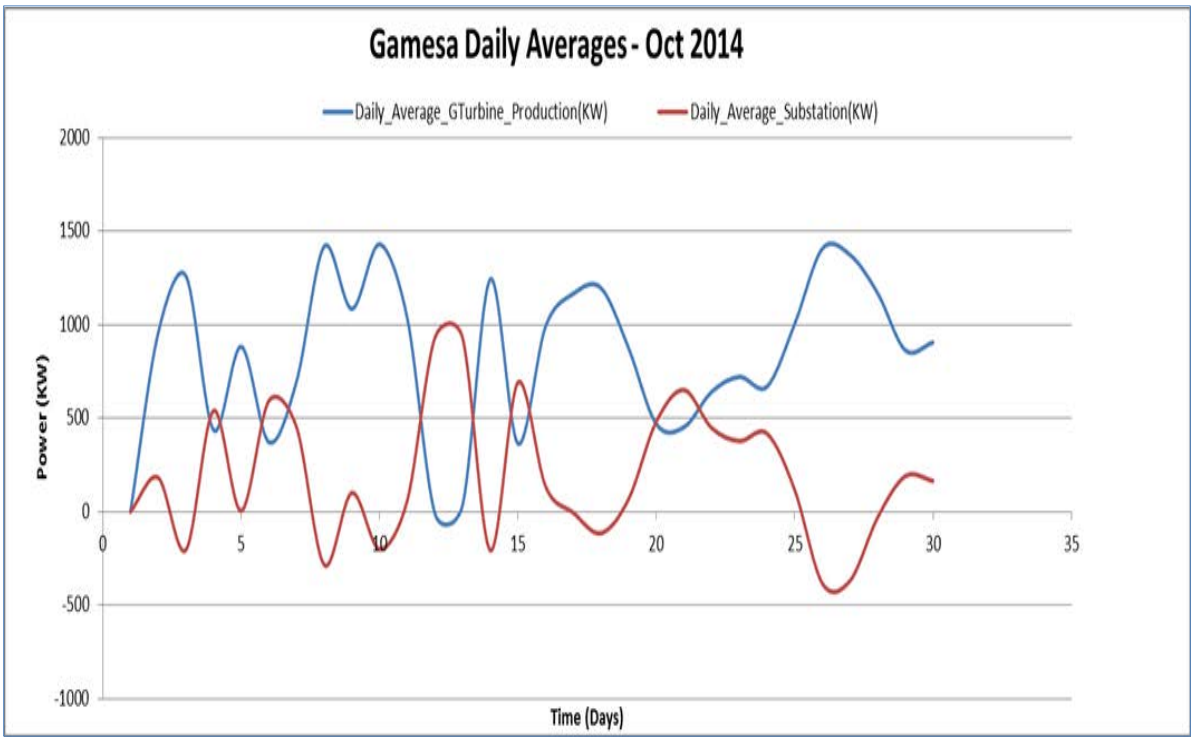


Figure 174. Gamesa-Daily Averages for October 2014

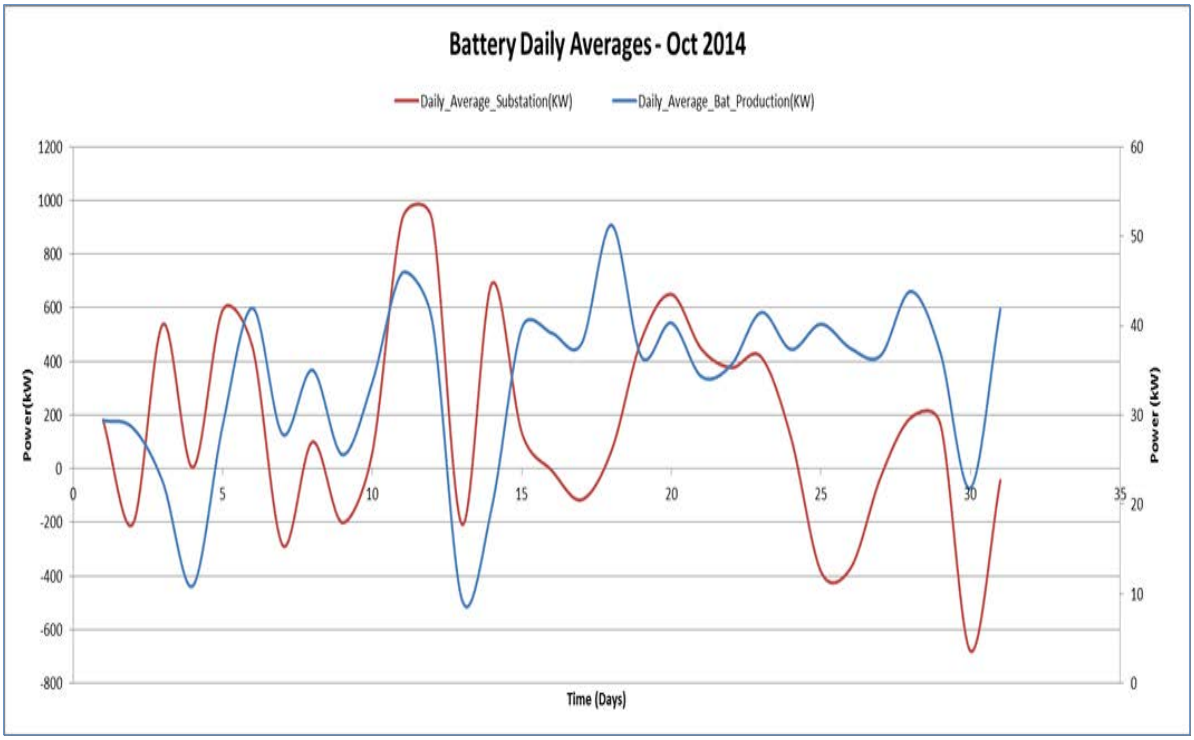


Figure 175. Battery-Daily Averages for October 2014

8.5.3 Battery Testing in 2014

The BESS testing was performed during 2014. The basic approach for testing, describing such aspects as time of year, time of day, and duration, is outlined in the table below. This is then followed with test results.

Table 31. Overall BESS Testing Approach

Number	Test Type	Time of Year	Time of Day	Duration
1	Ramping	All year	Night	Seconds
2	Demand Response	Summer (May to August)	Day	Minutes to hours depending on peak loads
3	Frequency Support	All year	Night	Seconds
4	Wind Speed Drop	All year	When drop occurs	Seconds to minutes
5	FRRS	All year	When needed	Until frequency recovers

8.5.3.1 Ramp Support

The battery was ramped to an SOC of 50%. It was charged at a rate of 250 kW for 15 minutes, or until reaching 50% SOC. Then charge rate was increased to 500 kW for 15 minutes, or until reaching 50% SOC. Later was the charged to 750 kW and 1000 kW for 15 minutes, or until 50% SOC.

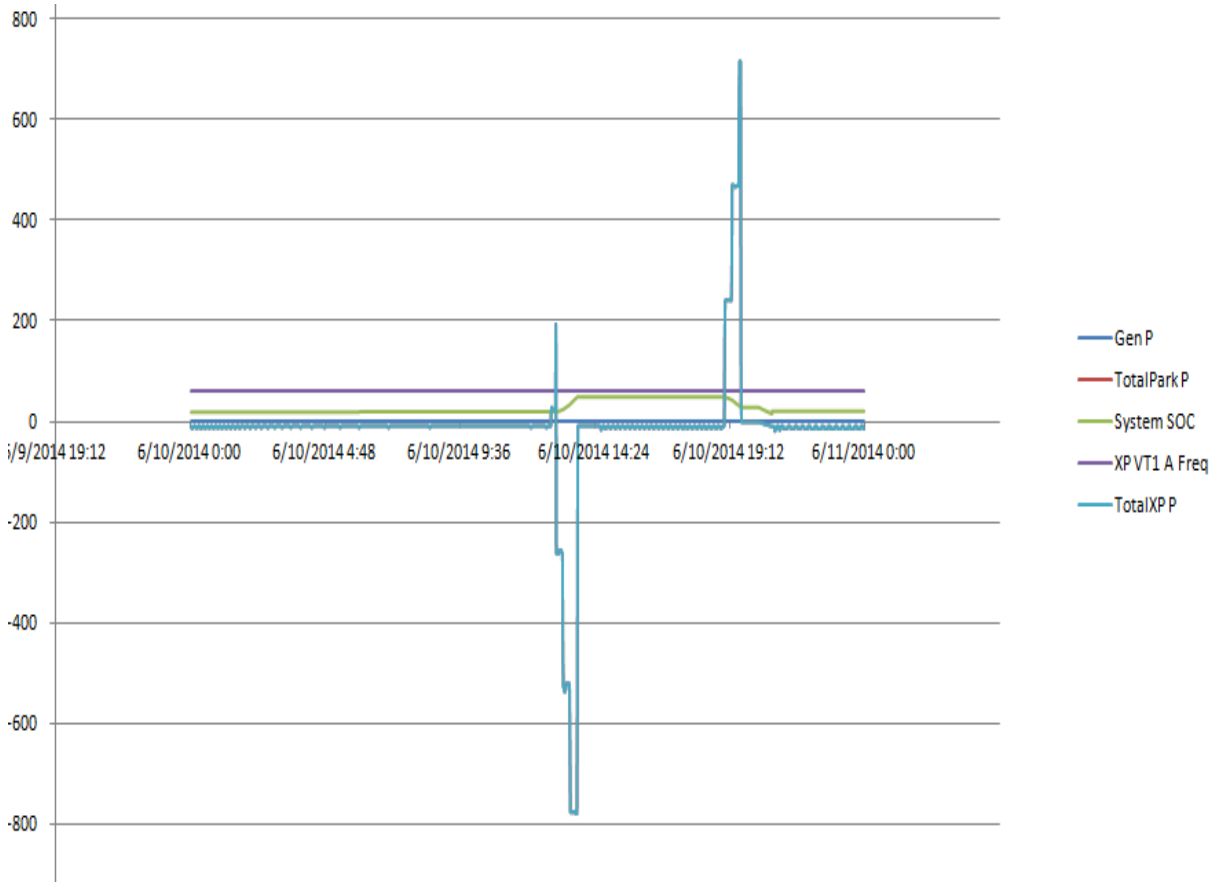


Figure 176. Ramp Support Test on June 9, 2014

8.5.3.2 Frequency Response

When the frequency went below 60 Hz, the battery ramped up to supply the required power and meet the demand. The black line is frequency (dead band is set to 59.70Hz), the orange line is system SOC, and the blue line is kW output (with a maximum setting at 400 kW). The following figure demonstrates that the system responded very well.

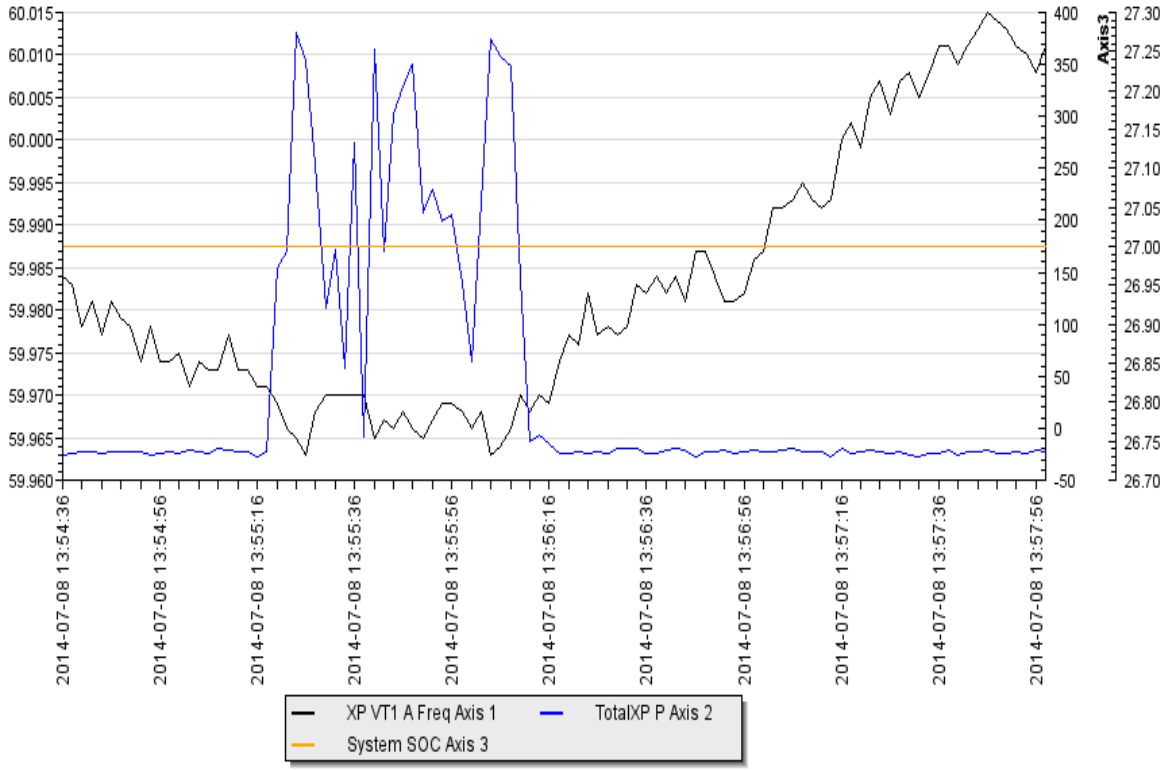


Figure 177. Under Frequency Event on July 08, 2014

8.5.3.3 Wind Ramping/Load Leveling

The figures below show the battery following the wind profile according to the power generation and load demand. The green trace is the wind output for TTU-04 (Gamesa Wind Turbine) and dark blue trace is the output of the battery.

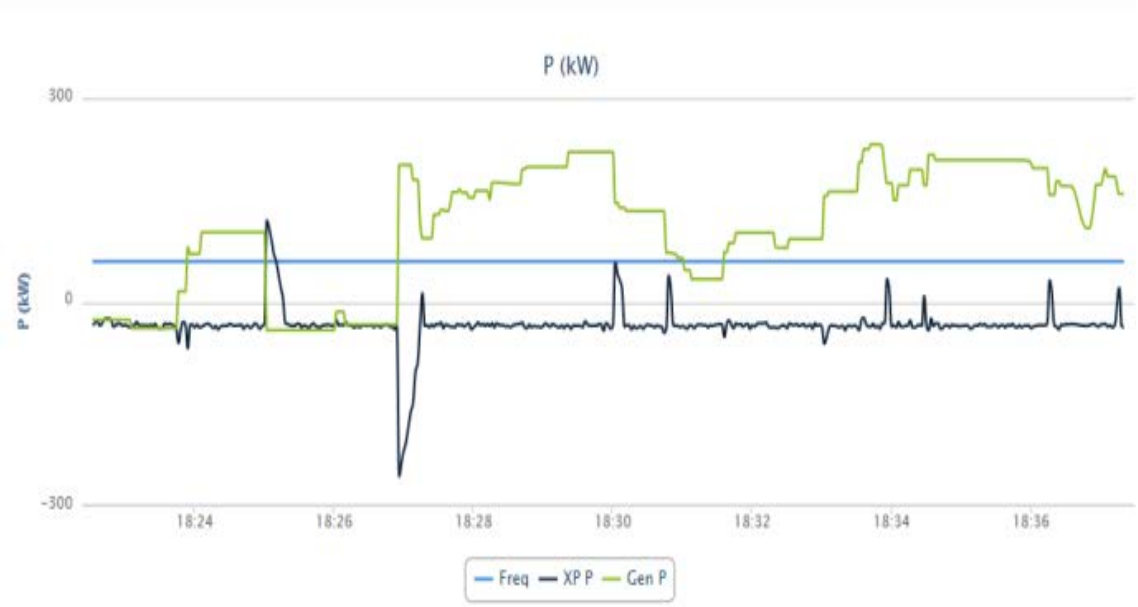


Figure 178. Load Leveling During August 2014

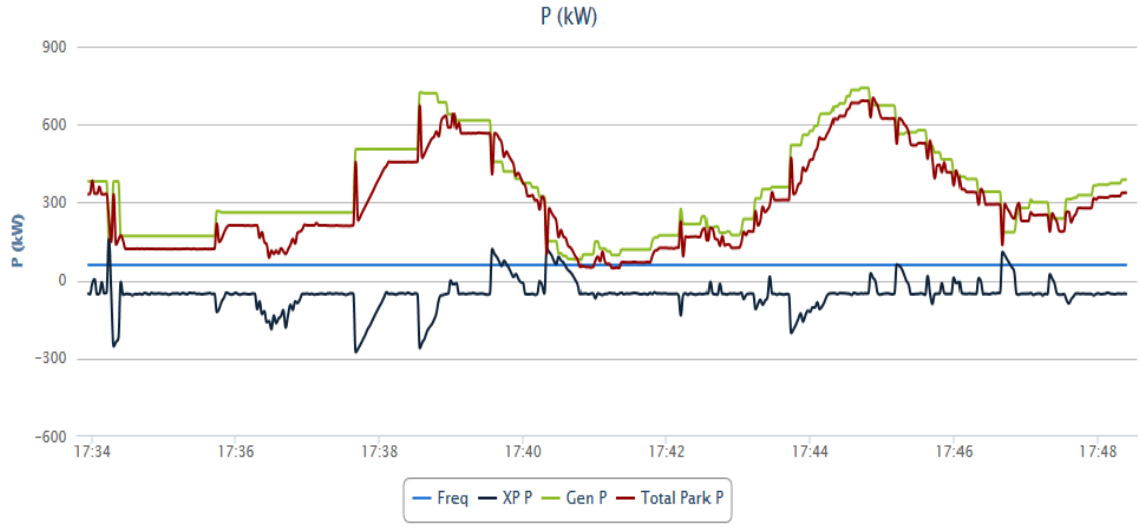


Figure 179. Load Leveling During October 2014

8.5.3.4 Demand Reduction

The following figure shows the battery providing peak reduction/demand shaving. Younicos charged the battery to 90% SOC and discharged the battery at 1000 KW for 53 minutes or when the SOC reached 10%.

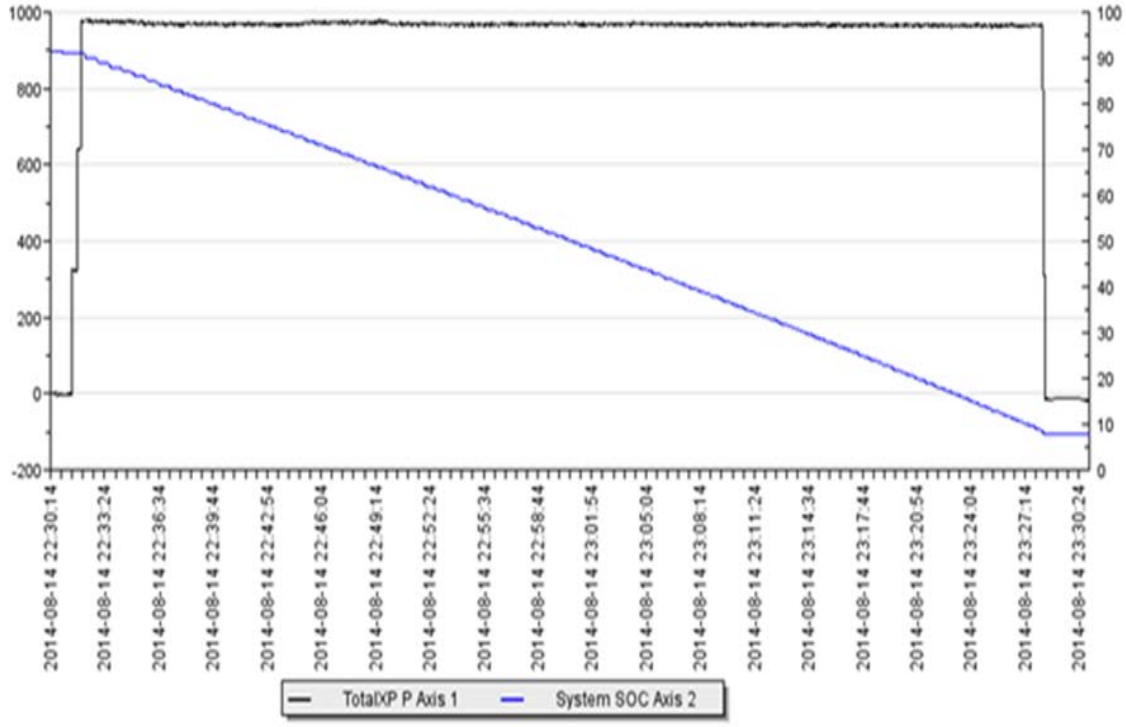


Figure 180. Demand Reduction during August 2014

8.5.4 Economic Analysis

There are a wide range of uses for a BESS, from local voltage stability to actually providing power to homes and businesses in rural areas. However, the solutions are expensive and the benefits depend greatly on the functionality that can be delivered. Hence an economic analysis is essential to decide the feasibility of any given storage system, and there are various factors that need to be considered when performing the analysis. One of the most important factors is to determine the optimal time to charge and discharge the battery. The battery needs to be charged when demand and electricity cost are low and discharged when demand and electricity cost is high. When to perform which operation depends on the purchase price of the energy, to charge the battery, and alternatively the selling price of the energy, to sell the power stored in the battery. The next important factor is to consider the load/demand and supply of the battery power or the available renewable power in an economic way, considering the past, present, and future cost analysis. The following algorithm provides an analysis of a solution for determining appropriate battery actions to increase profit while considering depreciation of the battery life. The algorithm for the analysis is laid out as follows with reference to the flowchart in the figure below that. The objectives are defined and the evaluations are done taking the available data, risks and

assumptions to decide the best optimal solution for the economic performance of the battery. The following steps are considered in the algorithm.

1. Maximize operation and minimize cost
2. Optimal time to charge (energy purchase shifting), load profile (daily, annual)
3. Economic evaluations:
    - Cost analysis
    - Cost-minimization analysis
    - Cost-effective analysis
    - Cost-benefit analysis
    - Cost-utility analysis
4. Data, assumptions, and risks
    - BESS round trip efficiency
    - BESS life span in cycles
    - Rated power
    - Rated discharge time and capacity
    - Renewable energy availability
5. Cost
    - BESS capital cost
    - BESS operating cost (energy-related/not energy-related)
    - Differential cost of energy
    - LMP
    - Present and future values
6. Compare, decide and conclude

The algorithm is based on the various input data such as: battery production (MW), wind production (MW), load (kW), local marginal price (LMP), and frequency response of the system, as shown in the figure below. The inputs are fed into the algorithm as shown and then the battery performance or its recommended action is obtained as outputs.

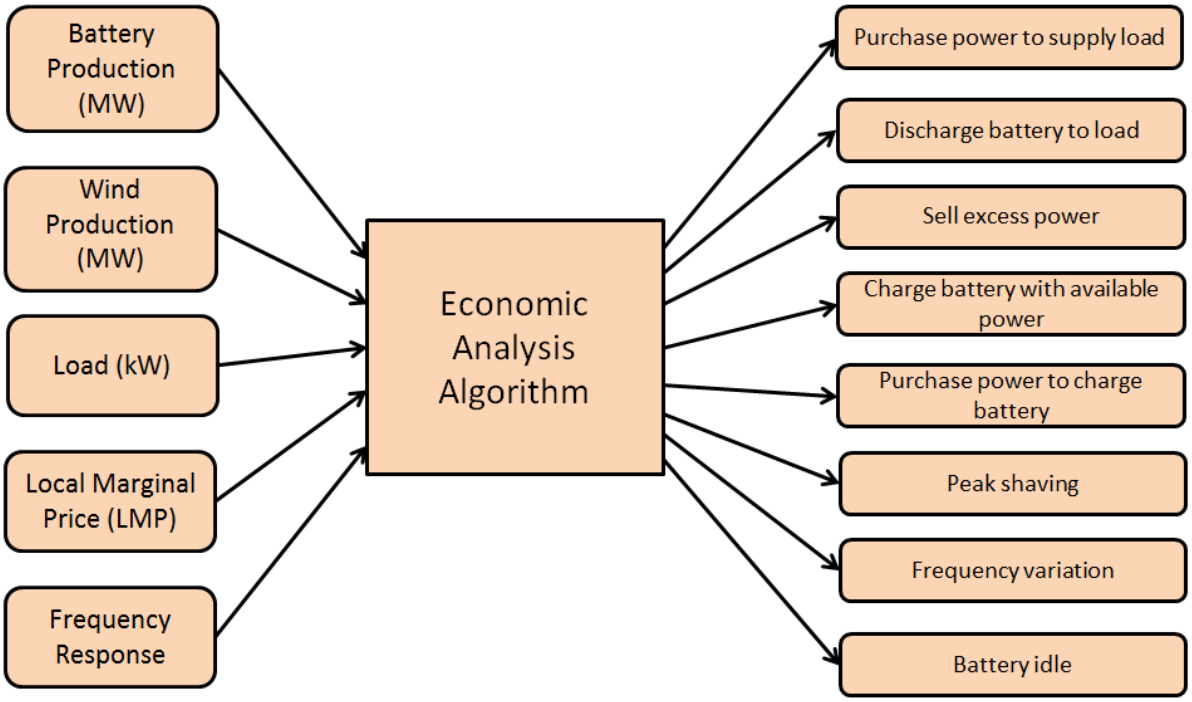


Figure 181. Economic Analysis Block Diagram

The flowchart was laid out for the analyses of the battery operation for its optimal performance and economic benefits.

8.5.4.1 Algorithm for Power Supply Less Than Load

The generalized flowchart in the figure below considers when the wind power is greater than the load and when it is less than the load. For both conditions, the battery state of charge is considered as well as the past, present and future cost of energy. The algorithm includes decisions at various conditions and then terminates with the stop condition at the end. The algorithm is run by a Python program that reads values from an Excel file with updated data every 15 minutes, and then executes its logic programming.

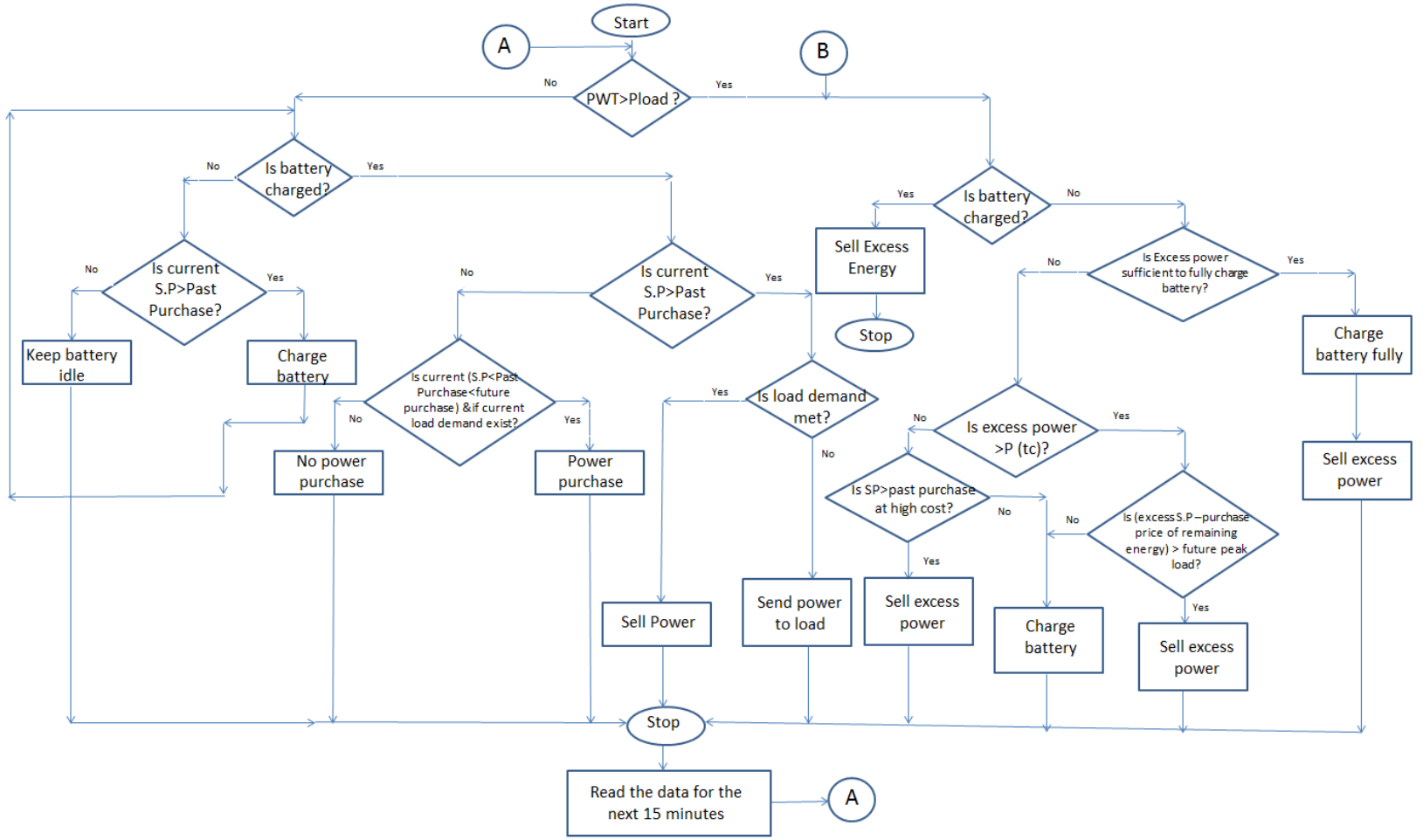


Figure 182. General Algorithm for Power Supply Greater or Lesser Than the Load

The flowchart below considers the possible cases when the power supply from the renewable source is less and unable to meet the load. The various battery charge states are considered and the decisions are made based on the differential cost of energy required to purchase or sell power.

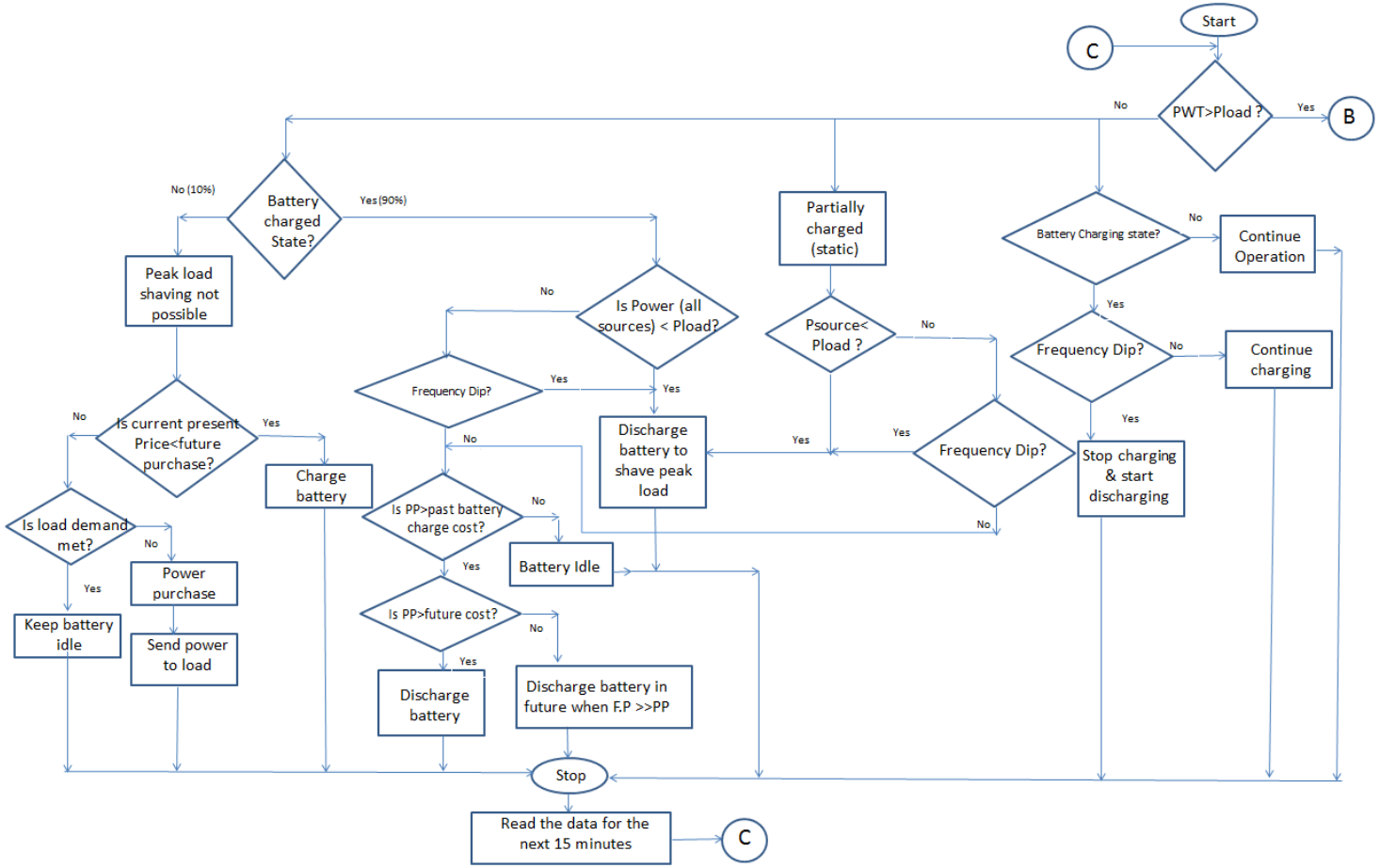


Figure 183. Algorithm with its Emphasis When Power Supply Lesser than the Load

8.5.4.2 Analysis and Simulation Results

The above flowcharts are explained as follows:

Assumptions:

1) Battery capacity is 1 MWh
2) Wind capacity is 1.7 MW
3) Maximum load is considered to be between 2 MW to 3 MW
4) Charge the battery with constant charge rate, i.e., constant C rate
5) If a battery is charged, it is charged to no more than 90% SOC
6) If a battery is discharged, it is discharged to at least 20% SOC
7) Program reads the data every 15 minutes from the Excel files

The Python program reads the data from the Excel files and presents the recommended battery action in a graphical user interface as shown below. Some of the conditions and cases from the flowcharts above are explained as follows:

Case 1:

If power from the wind turbine is greater than the load demand, and the battery is in a discharged state, then the condition "Excess power is sufficient to charge the battery" is met. The next decision is whether or not to use the excess wind power to charge the battery, or to sell the excess wind power and charge the battery later. If the excess energy can be sold at a higher price than the current purchase price (cost to charge the battery), then the recommended action is to "Sell excess power. Charge battery in future".

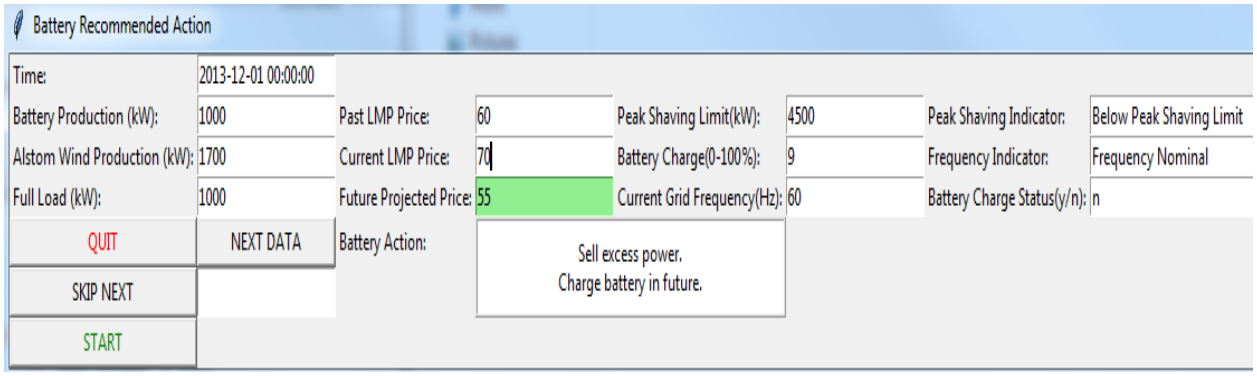


Figure 184. Algorithm Output – Sell Excess Power & Charge Battery in Future

Case 2:

If power from the wind turbine is greater than the load demand, and the battery is in a discharged state, then the condition "Excess power is sufficient to charge the battery" is met. The next decision is whether or not to use the excess wind power to charge the battery, or to sell the excess wind power and charge the battery later. If the excess energy cannot be sold at a higher price than the current purchase price (cost to charge the battery), then the recommended action is to "Charge battery with excess power".

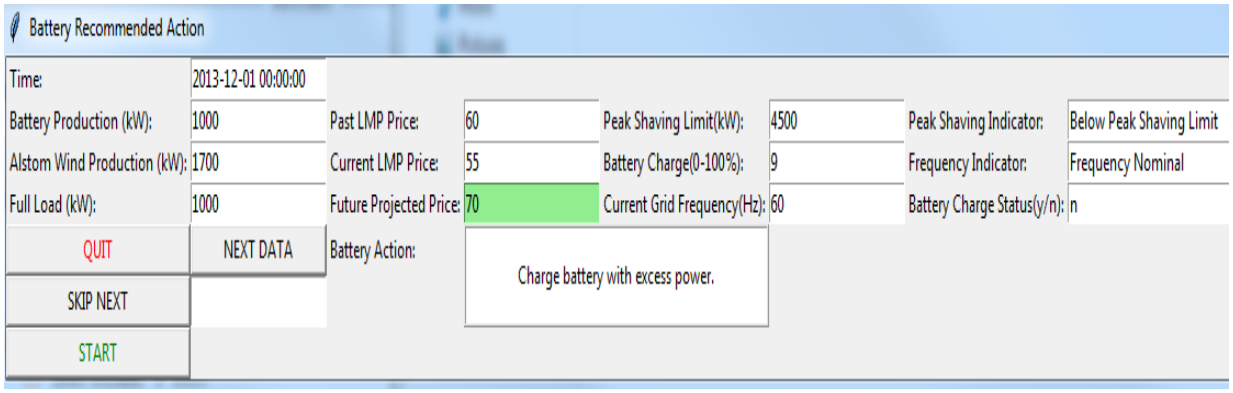


Figure 185. Algorithm Output – Charge Battery

Case 3:

If power generated from the wind turbine is greater than load demand, and the battery is in a charged state, then the decision and action(s) are based on energy pricing. For this case, it is determined that the present selling pricing is greater than the purchase price used to charge the battery. If the present selling price is greater than the future selling price", then the recommended action is to "Sell excess energy. Discharge battery in present," as shown in the first figure below. If not, the recommendation is to "Sell excess energy. Discharge battery in future," as shown in the second figure.

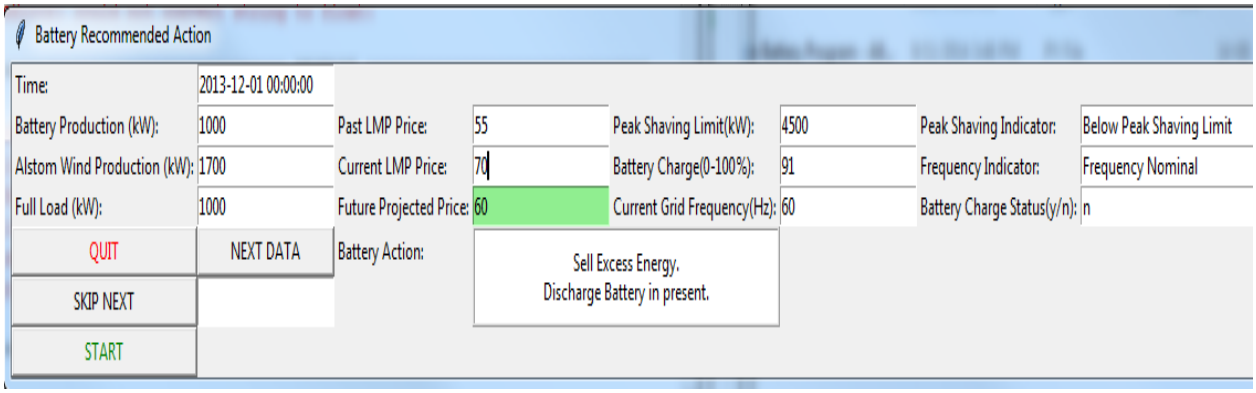


Figure 186. Algorithm Output – Sell Excess Energy & Discharge Battery at Present

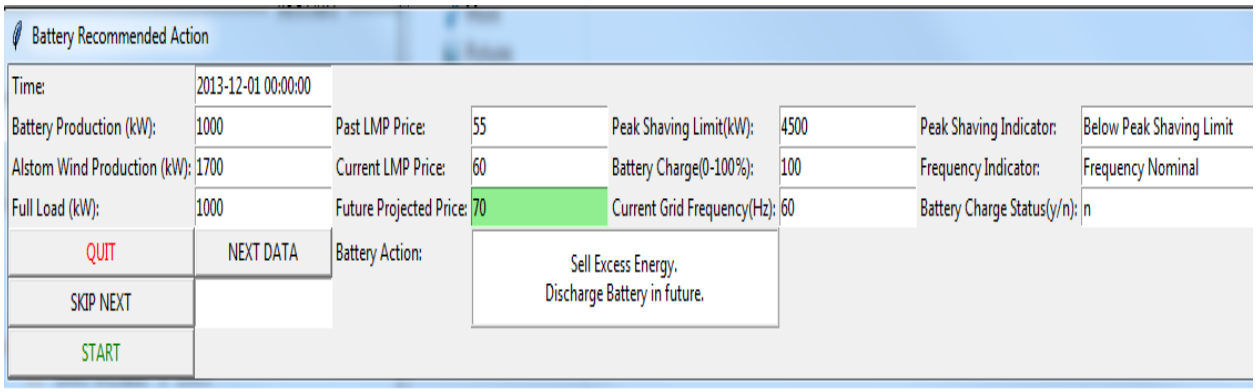


Figure 187. Algorithm Output – Sell Excess Energy & Discharge Battery in Future

Case 4:

If power generated from the wind turbine is greater than the load demand, and the battery is in a charged state, then the decision and action(s) are based on energy pricing. For this case, it is determined that the present selling pricing is less than the purchase price used to charge the battery. The recommended action is to "Sell excess power. Keep battery idle".

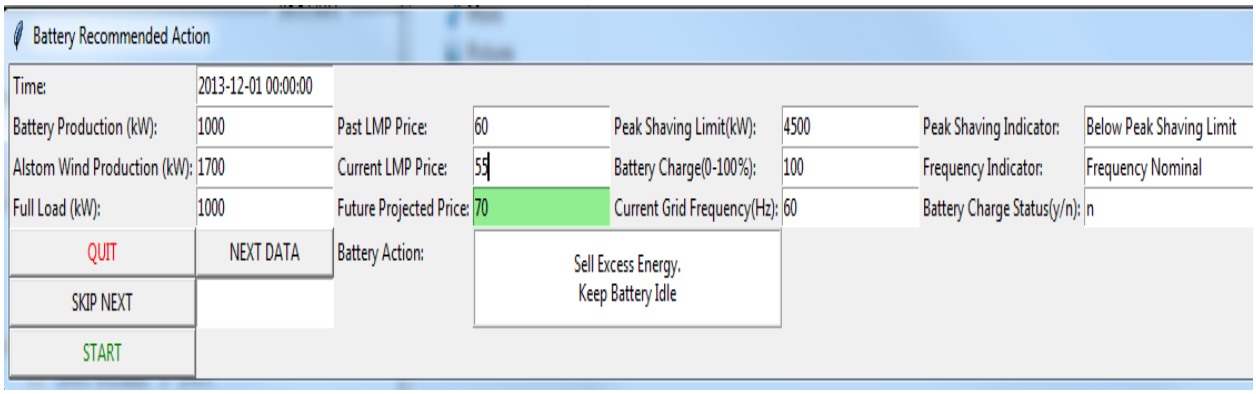


Figure 188. Algorithm Output – Sell Excess Power and Keep Battery Idle

Case 5:

If power generated from the wind turbine is less than the load demand, and the battery is in a charged state, then the decision and action(s) are based on energy pricing. It is determined that the current purchase price is greater than the purchase price used to charge the battery". If the future price is less than the current purchase price, the recommended action is to "Discharge battery to load. Sell excess power. Charge battery in future," as shown in the first figure below. If not, the recommendation is to "Discharge battery to load. Purchase power to supply load," as in the second figure.

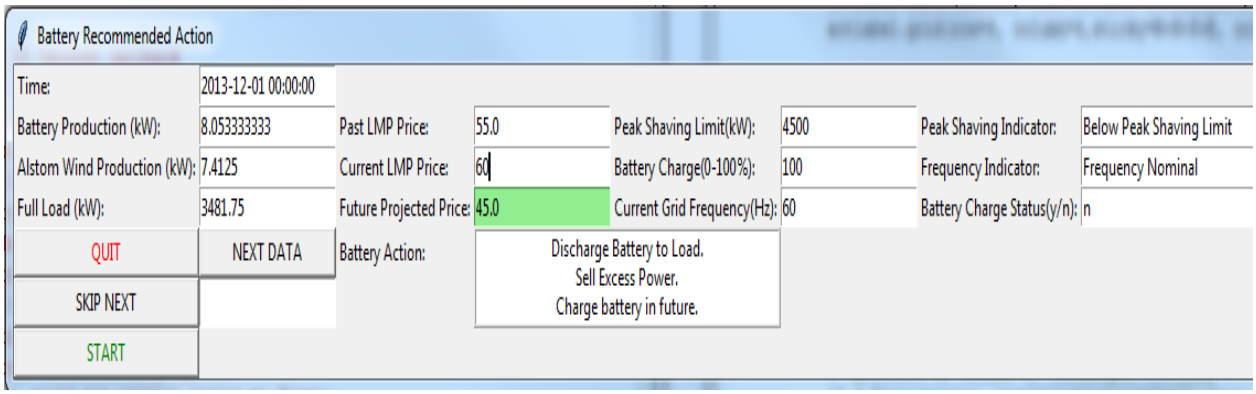


Figure 189. Algorithm Output – Discharge Battery to Load & Sell Excess Power

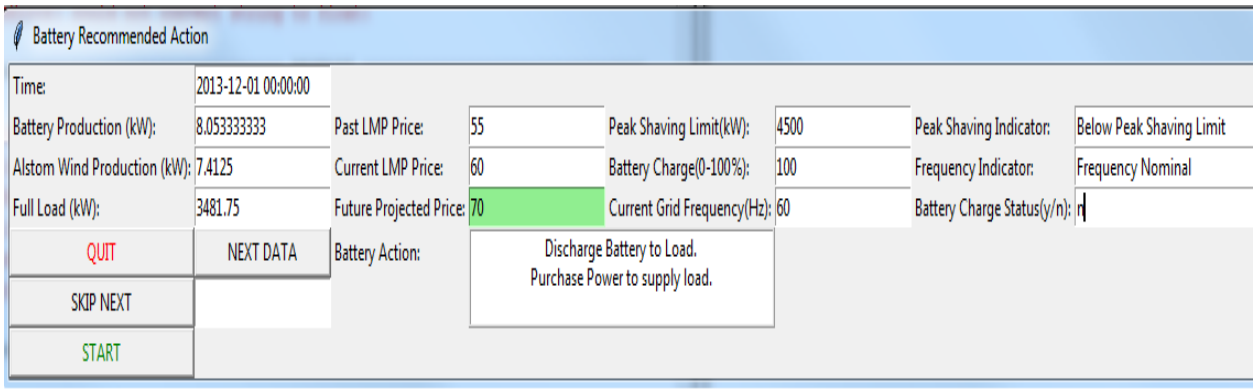


Figure 190. Algorithm Output – Discharge Battery in Future & Purchase Power for the Load

Case 6:

If power generated from the wind turbine is less than the load demand, and the battery is in a charged state, then the decision and action is based on energy pricing. If the current purchase price is less than the price used to charge the batter, the recommended action is to "Purchase power, send to the load. Keep battery idle".

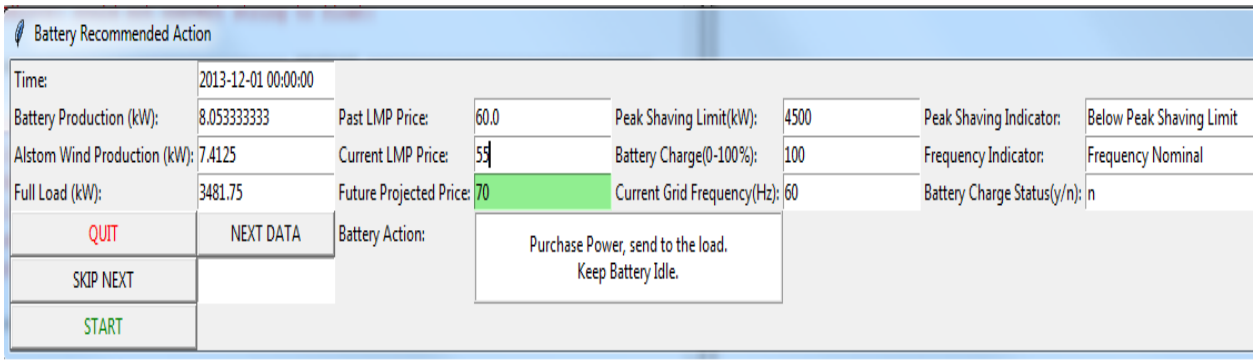


Figure 191. Algorithm Output – Purchase Power Now and Send it to the Load

Case 7:

If power generated from the wind turbine is less than the load demand, and the battery is in a discharged state, then the decision and action is based on energy pricing. If the current purchase price is less than the future price, then the recommended action is to "Charge battery".

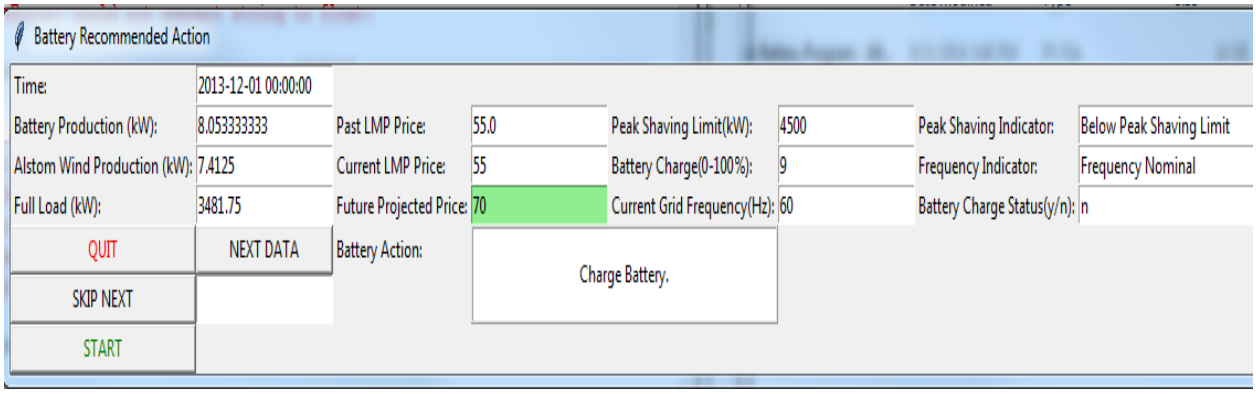


Figure 192. Algorithm Output – Charge Battery

As presented in the cases above, the algorithm is useful to predict the suggested utilization of the battery in an effective way to maximize profit based on factors such as load demand, wind production, battery state, and energy costs. The battery cost and operational cost were not included in this analysis, but the operational condition of the battery is considered and the recommended battery action is decided by comparing with known past LMP values, present cost values and predicted future LMP data. The algorithm also analyzes the need for peak shaving and to alert the operator for any frequency variations.

8.5.4.3 Energy Storage Computational Tool Results

For identifying, quantifying, and monetizing the benefits of grid-connected energy storage, DOE recommends using the Excel-based energy storage computational tool (ESCT) which was funded by DOE and developed by Navigant.

- The ESCT characterizes energy storage projects by identifying the storage technologies employed and identifying the applications pursued. These parameters are defined for two different modules, the asset characterization module and the data input module. Each requires various inputs, and these are outlined in the next two sub-sections.
- Based on this characterization, the tool identifies the economic, reliability and environmental benefits the storage project will yield.
- The ESCT guides the user in entering data required for calculating the monetary value of benefits and associated capital and operations and maintenance (O&M) costs.
- The ESCT prepares graphs and tables that summarize the costs and benefits of the project to help illustrate the project's overall value.

Some flexibility is required in using the ESCT to perform the economic analysis since the true economic value of a BESS will be greatly dependent on various factors such as the owner, type of market, location, and functional applications. For example, utilities in a deregulated market typically cannot own generation assets like a BESS for the purpose of generating revenue, so they are limited to using a BESS to perform functions such as voltage support or grid reliability for which they would receive the normal regulated rate of return. This is currently true in the ERCOT market for the large investor-owned utilities (IOUs), but not for smaller utilities owned by rural cooperatives or cities. In other markets, large utilities can and do own generation assets, and even in ERCOT non-utility generators could own a BESS. Therefore, it's difficult to quantify the value proposition for a BESS under a single set of conditions.

Also, it should be noted that the ESCT determines the potential applications (source of revenue/savings) based on a certain set of built-in conditions that can limit results. Also, the tool limits the number of applications to three, a primary and two secondary applications. While this may be sufficient in most cases, it would be beneficial to allow more because certain applications, such as demand charge management or renewables energy time-shift, are more appropriate at specific times of the year rather than throughout the entire year.

To most fairly represent the economic potential in the Texas market, the Team performed four different sets of analysis, as outlined below. These sets represent various types of utilities, in both regulated and deregulated markets and located in different regions of the State, using a BESS to address diverse needs, from improved electric service reliability to ancillary services. It should be noted that the ESCT estimates of benefits primarily accrue to the owner of the BESS and do not easily represent multiple functions carried out simultaneously by multiple market participants.

The representative configurations of ownership, location and functionality include:

To most fairly represent the potential, this section includes four different sets of analysis:

1. 1MW BESS on a distribution network owned by a utility in a deregulated market. In Texas, this would be an IOU
2. 1MW BESS on a distribution network owned by a utility in a regulated market (without demand charge management). In Texas, this would be a cooperative or a municipal utility
3. 1MW BESS on a distribution network owned by a utility in a regulated market (with demand charge management). In Texas, this would be a cooperative or a municipal utility
4. 1MW BESS on a transmission network owned by a generator in a regulated market

Additionally, since battery costs are expected to be reduced by 50% in the next three years or so, this section includes one final set of analysis that re-evaluates the economics of option #1 with a 1MW BESS that costs half of what it did in this project.

8.5.4.3.1 Value Proposition for the 1MW BESS Owned by an IOU in a Deregulated Market

Asset Characterization Module

The following table shows the parameters given as inputs to the ESCT for this option. They are based on a 1MW BESS deployed on a distribution network and owned by an IOU operating in a deregulated market.

Table 32. Parameters for Asset Characterization Module

Location of battery	Distribution
Market	Deregulated
Owner	Utility
Type of Battery	Lithium-ion
Total name plate power output	1000 kW
Total name plate energy storage capacity	1000 kWh
Round trip efficiency	95%
Response time of BESS	0.005 seconds
Cycle life	4000 cycles
Average/Expected year over demand growth of electric system	2%
Expected life time	20 years
Average inflation rate	2%
Discount rate in net present value analysis	7%
Total Installed cost of deployment	$2,000,000
Fixed charge rate to annualize cost of deployment	11%
Non energy O&M cost with replacement cost	$50,000/year
Expected decommissioning & disposal cost	$25,000
Primary application	Electric service reliability
Selected secondary application(s) *	T&D upgrade deferral, Voltage support

* For this option, the ESCT only offered these alternatives.

On simulating the module using the above mentioned inputs, the following figure shows the potential benefits.

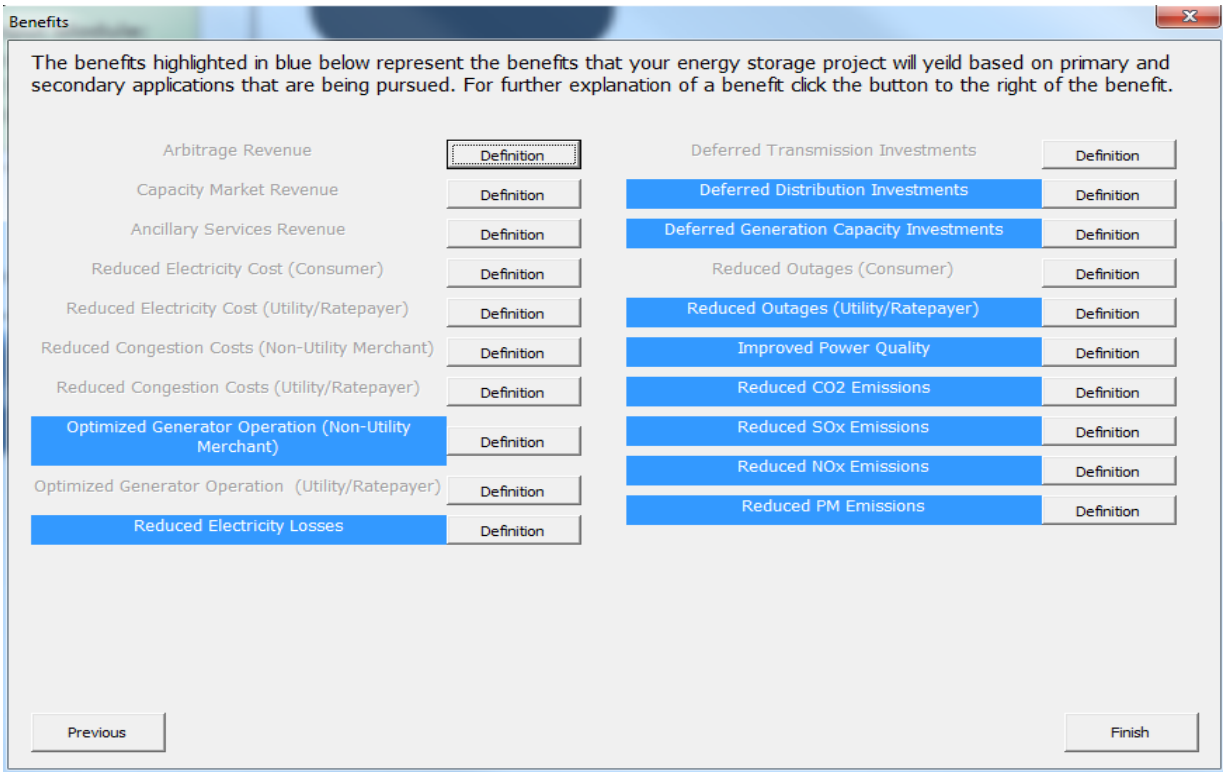


Figure 193. Results of Asset Characterization Module

Data Input Module

The following table shows the default inputs available in the ESCT tool for data input module analysis.

Table 33. Review Benefit Calculation Inputs *

		Select % using toggle			2014 Values		
Input Name	Unit	Low	Reference	High	Low	Reference	High
Distribution Capacity Deferred	kVA	100%	100%	100%	50	50	50
Annual Fixed Charge Rate for Distribution Capital Investment	%	100%	100%	100%	11	11	11
Capital Cost of Deferred Distribution Capacity	$/kVA	100%	100%	100%	$ 420	$ 420	$ 420
Yearly O&M Costs of Deferred Distribution Capacity	$/year	100%	100%	100%	$ 10,000	$ 10,000	$ 10,000
Initial Year of Distribution Deferral	year	100%	100%	100%	2014	2014	2014
Final year of Distribution Deferral	year	100%	100%	100%	2016	2016	2016
Capital Cost of Conventional Voltage Support Solution	$/kVAR	100%	100%	100%	$ 18	$ 18	$ 18
Nameplate Reactive Power Capacity of Energy Storage	kVAR	100%	100%	100%	1,000	1,000	1,000
Annual Fixed Charge Rate for Voltage Support Capital Investment	%	100%	100%	100%	11	11	11
Capital Cost of Conventional Electric Service Reliability Solution	$/kW	100%	100%	100%	$ 1,000	$ 1,000	$ 1,000
Annual Fixed Charge Rate for Electric Service Reliability Capital Investment	%	100%	100%	100%	11	11	11

* The $1,000/kW for capital cost of conventional electric service reliability is based on average 2013 cost estimates for utility-scale electricity generating plants defined in a report from the Energy Information Administration at http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf.

Computational Module with Reference Case and Senstivity Case Analyses

The computational module generates results based on reference case analysis and sensitivity case analysis from the above mentioned inputs.

The following table shows the cumulative benefit and cost table, with the total cost of deployment and total net benefit shown on the bottom right of the table. As you'll note in these results, the ESCT estimated $34,300 in deferred distribution investments, $23,500 in improved power quality savings, and $1,308,600 in reduced outages. This total gross benefit of $1,366,400 results in a $1,593,500 loss (considering the cost of the BESS, annual O&M expenses, etc.) for this option.

Table 34. Cumulative Benefit and Cost Table

Cumulative Benefit and Cost Table

	Benefits	Additional Benefits - Total Present Value over the Deployment Period	+	Primary and Secondary Benefits - Total Present Value over the Deployment Period	=	Total Benefit - Present Value over the Deployment Period
Market Revenue	Arbitrage Revenue	$ -		$ -		$ -
	Capacity Market Revenue	$ -		$ -		$ -
	Ancillary Services Revenue	$ -		$ -		$ -
Improved Asset Utilization	Optimized Generator Operation (Non-Utility	$ -		$ -		$ -
	Optimized Generator Operation	$ -		$ -		$ -
	Deferred Generation Capacity Investments	$ -		$ -		$ -
	Reduced Congestion Costs (Non-Utility Merchant)	$ -		$ -		$ -
	Reduced Congestion Costs (Utility/Ratepayer)	$ -		$ -		$ -
T&D Capital Savings	Deferred Transmission Investments	$ -		$ -		$ -
	Deferred Distribution Investments	$ -		$ 34,300		$ 34,300.00
Energy Efficiency	Reduced Electricity Losses	$ -		$ -		$ -
Electricity Cost Savings	Reduced Electricity Cost (Consumer)	$ -		$ -		$ -
	Reduced Electricity Cost (Utility/Ratepayer)	$ -		$ -		$ -
Power Interruptions	Reduced Outages (Consumer)	$ -		$ -		$ -
	Reduced Outages (Utility/Ratepayer)	$ -		$ 1,308,600		$ 1,308,600.00
Power Quality	Improved Power Quality	$ -		$ 23,500		$ 23,500.00
Air Emissions	Reduced CO2 Emissions	$ -		$ -		$ -
	Reduced SOx Emissions	$ -		$ -		$ -
	Reduced NOx Emissions	$ -		$ -		$ -
	Reduced PM Emissions	$ -		$ -		$ -
	Total Gross Benefit	**$ -**		**$ 1,366,400**		**$ 1,366,400.00**
	Costs					
	Capital Cost of Deployment (fixed charge rate)					$ 2,406,800.00
	Operating and maintenance costs not related to energy (labor for operation, plant maintenance, equipment wear leading to					$ 546,900.00
	Decommissioning and Disposal Costs					$ 6,300.00
	Total Annual Cost of Deployment					**$ 2,959,900.00**
	Total Net Benefit					**$ (1,593,500.00)**

The following figures show the results of the sensitivity case analysis which, as shown in the first figure, uses a range from 80% (low) to 120% (high) of the reference case values.

Table 35. Sensitivity Case Analysis Settings

		Select % using toggle			2014 Values		
Input Name	Unit	Low	Reference	High	Low	Reference	High
Distribution Capacity Deferred	kVA	80%	100%	120%	40	50	60
Annual Fixed Charge Rate for Distribution Capital Investment	%	80%	100%	120%	9	11	13
Capital Cost of Deferred Distribution Capacity	$/kVA	80%	100%	120%	$ 336	$ 420	$ 504
Yearly O&M Costs of Deferred Distribution Capacity	$/year	80%	100%	120%	$ 8,000	$ 10,000	$ 12,000
Initial Year of Distribution Deferral	year	80%	100%	120%	1611.2	2014	2416.8
Final year of Distribution Deferral	year	80%	100%	120%	1612.8	2016	2419.2
Capital Cost of Conventional Voltage Support Solution	$/kVAR	80%	100%	120%	$ 14	$ 18	$ 22
Nameplate Reactive Power Capacity of Energy Storage	kVAR	80%	100%	120%	800	1,000	1,200
Annual Fixed Charge Rate for Voltage Support Capital Investment	%	80%	100%	120%	9	11	13
Capital Cost of Conventional Electric Service Reliability Solution	$/kW	80%	100%	120%	$ 800	$ 1,000	$ 1,200
Annual Fixed Charge Rate for Electric Service Reliability Capital Investment	%	80%	100%	120%	9	11	13

Table 36. Results of Sensitivity Case Analysis

Cumulative Gross Benefits over the Deployment Period (Present Value)	Low Case	Reference Case	High Case
Arbitrage Revenue	$ -	$ -	$ -
Capacity Market Revenue	$ -	$ -	$ -
Ancillary Services Revenue	$ -	$ -	$ -
Optimized Generator Operation (Non-Utility Merchant)	$ -	$ -	$ -
Optimized Generator Operation (Utility/Ratepayer)	$ -	$ -	$ -
Deferred Generation Capacity Investments	$ -	$ -	$ -
Reduced Congestion Costs (Non-Utility Merchant)	$ -	$ -	$ -
Reduced Congestion Costs (Utility/Ratepayer)	$ -	$ -	$ -
Deferred Transmission Investments	$ -	$ -	$ -
Deferred Distribution Investments	$ -	$ 34,300	$ -
Reduced Electricity Cost (Consumer)	$ -	$ -	$ -
Reduced Electricity Cost (Utility/Ratepayer)	$ -	$ -	$ -
Reduced Outages (Consumer)	$ -	$ -	$ -
Reduced Outages (Utility/Ratepayer)	$ 837,900	$ 1,308,600	$ 1,884,300
Improved Power Quality	$ 12,000	$ 23,500	$ 34,000
Reduced CO2 Emissions	$ -	$ -	$ -
Reduced SOx Emissions	$ -	$ -	$ -
Reduced NOx Emissions	$ -	$ -	$ -
Reduced PM Emissions	$ -	$ -	$ -
Total Benefit	**$ 849,900**	**$ 1,366,400**	**$ 1,918,300**

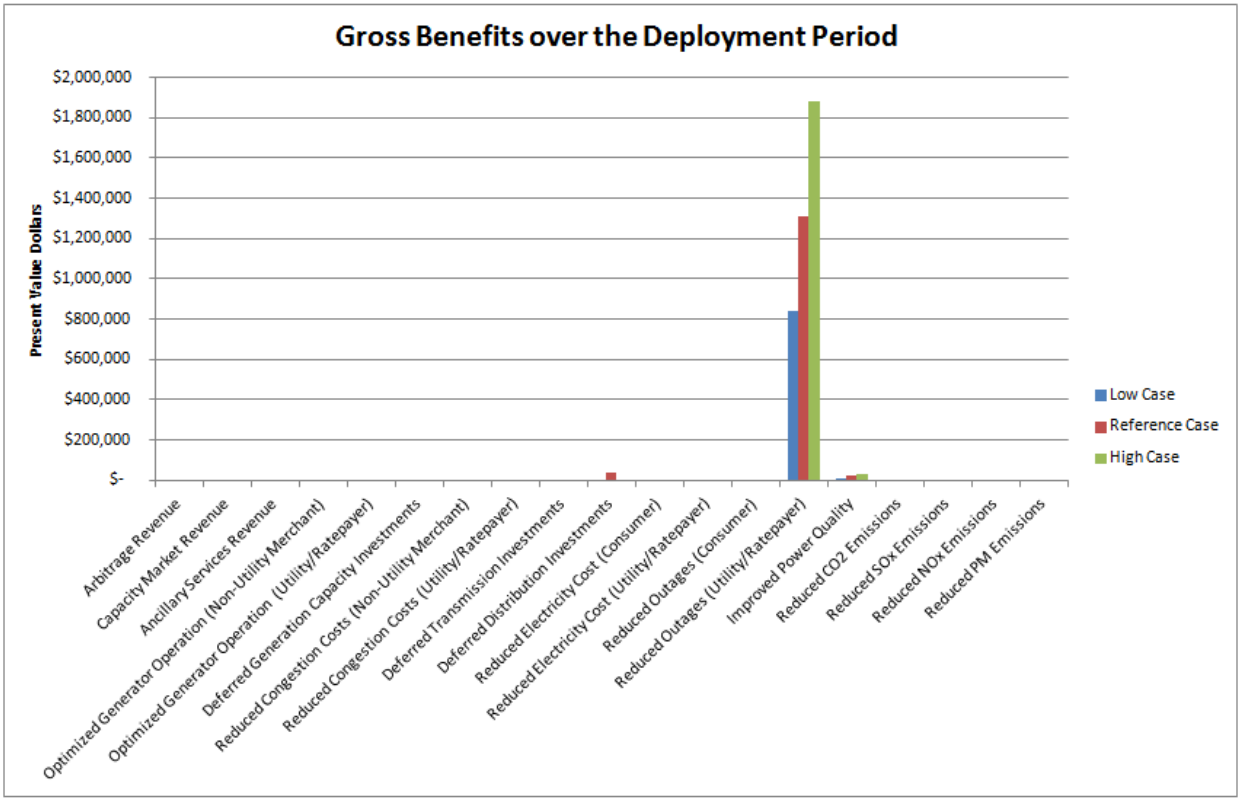


Figure 194. Graphic Results of Sensitivity Case Analysis

8.5.4.3.2 Value Proposition for the 1MW BESS Owned by a Utility in a Regulated Market

Asset Characterization Module

The following table shows the parameters given as inputs to the ESCT for this option. They are based on a 1MW BESS deployed on a distribution network and owned by a utility operating in a regulated market which means they can use the BESS to generate revenue. Although the ESCT does provide an application for demand charge management, this option below focuses more on renewables and wind integration support. The option presented in the next subsection will include demand charge management as an application.

Table 37. Parameters for Asset Characterization Module

Location of battery	Distribution
Market	Regulated
Owner	Utility
Type of Battery	Lithium-ion
Total name plate power output	1000 kW
Total name plate energy storage capacity	1000 kWh
Round trip efficiency	95%
Response time of BESS	0.005 seconds
Cycle life	4000 cycles
Average/Expected year over demand growth of electric system	2%
Expected life time	20 years

Average inflation rate	2%
Discount rate in net present value analysis	7%
Total Installed cost of deployment	$2,000,000
Fixed charge rate to annualize cost of deployment	11%
Non energy O&M cost with replacement cost	$50,000/year
Expected decommissioning & disposal cost	$25,000
Primary application	Renewables energy time-shift
Selected secondary application(s) *	Wind generation grid integration, voltage support

* For this option, the ESCT also offered two of the standard options, T&D upgrade deferral and electric service reliability, both of which were used in option #1 so the benefits of choosing those other options could be manually calculated.

On simulating the module using the above mentioned inputs, the following figure shows the potential benefits.

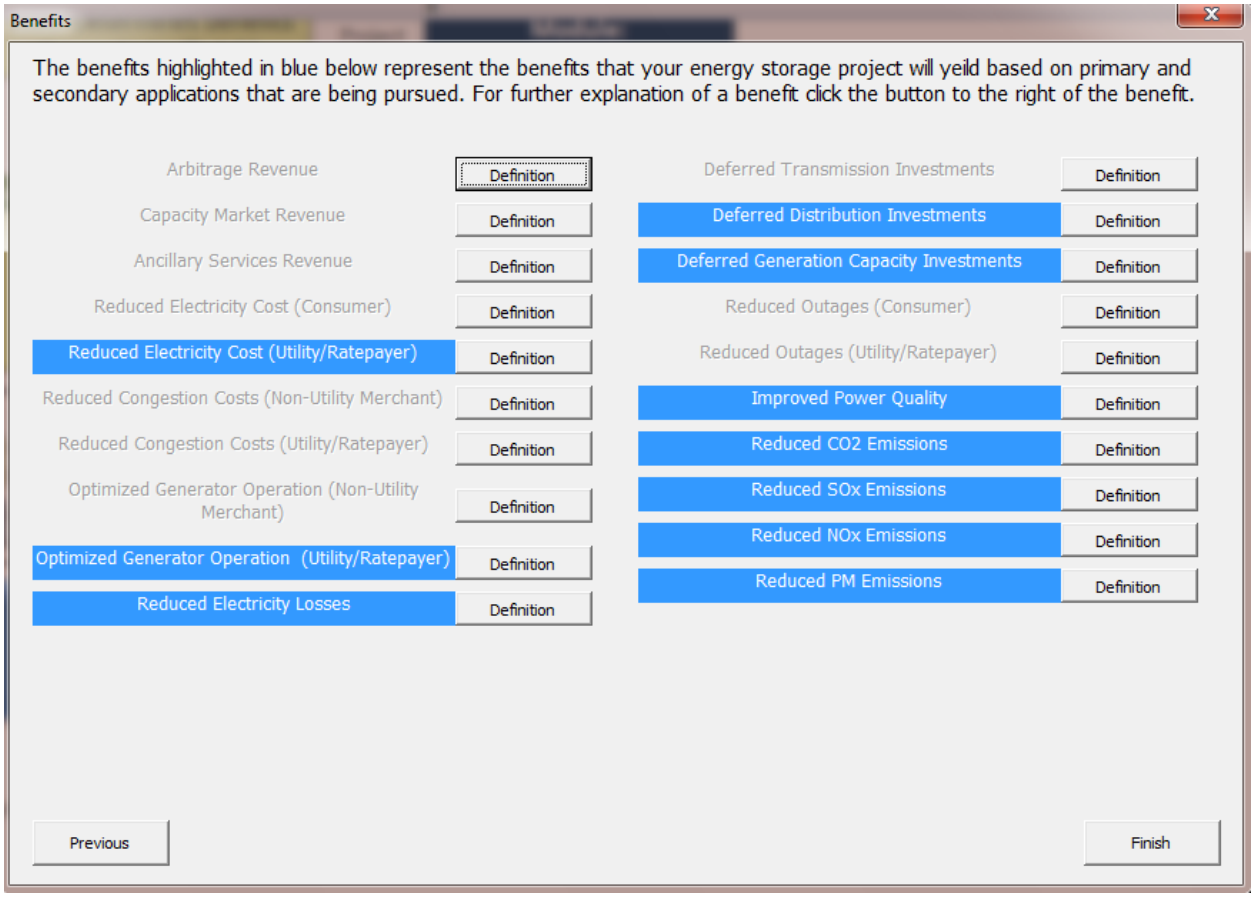


Figure 195. Results of Asset Characterization Module

Data Input Module

The following table shows the inputs entered through the ESCT tool for data input module analysis.

Table 38. Review Benefit Calculation Inputs

		Select % using toggle			2014 Values		
Input Name	Unit	Low	Reference	High	Low	Reference	High
Average Variable Peak Generation Costs	$/MWh	100%	100%	100%	$ 70	$ 70	$ 70
CO2 Emissions Factor for Generation on the Margin	lbs/MWh	100%	100%	100%	1,372	1,372	1,372
SOx Emissions Factor for Generation on the Margin	lbs/MWh	100%	100%	100%	5.800	5.800	5.800
NOx Emissions Factor for Generation on the Margin	lbs/MWh	100%	100%	100%	2.60	2.60	2.60
PM Emissions Factor for Generation on the Margin	lbs/MWh	100%	100%	100%	2.205	2.205	2.205
Value of CO2	$/ton	100%	100%	100%	$ 20	$ 20	$ 20
Value of SOx	$/ton	100%	100%	100%	$ 520	$ 520	$ 520
Value of NOx	$/ton	100%	100%	100%	$ 3,000	$ 3,000	$ 3,000
Value of PM	$/ton	100%	100%	100%	$ 36,000	$ 36,000	$ 36,000
Average Variable Renewable Generation Costs	$/MW	100%	100%	100%	$ 2	$ 2	$ 2
Total Renewable Energy Discharged for Arbitrage	MWh	100%	100%	100%	782	782	782
Total Renewable Energy Discharged for Energy Time-Shift	MWh	100%	100%	100%	782	782	782
Capital Cost of Conventional Voltage Support Solution	$/kVAR	100%	100%	100%	$ 18	$ 18	$ 18
Nameplate Reactive Power Capacity of Energy Storage	kVAR	100%	100%	100%	1,000	1,000	1,000
Annual Fixed Charge Rate for Voltage Support Capital Investment	%	100%	100%	100%	11	11	11

Computational Module with Reference Case and Senstivity Case Analyses

The computational module generates results based on reference case analysis and sensitivity case analysis from the above mentioned inputs.

The following table shows the cumulative benefit and cost table, based on the reference case analysis, with the total cost of deployment and total net benefit shown on the bottom right of the table. As you'll note in these results, for the 20-year period, the ESCT estimated $632,800 in reduced electricity costs, $23,500 in improved power quality savings, and $546,600 in emissions savings. This total gross benefit of $1,202,900 results in a $1,757,000 loss (considering the cost of the BESS, annual O&M expenses, etc.) for this option.

Table 39. Cumulative Benefit and Cost Table

	Cumulative Benefit and Cost Table					
	Benefits	**Additional Benefits - Total Present Value over the Deployment Period**	**+**	**Primary and Secondary Benefits - Total Present Value over the Deployment Period**	**=**	**Total Benefit - Present Value over the Deployment Period**
Market Revenue	Arbitrage Revenue	$ -		$ -		$ -
	Capacity Market Revenue	$ -		$ -		$ -
	Ancillary Services Revenue	$ -		$ -		$ -
Improved Asset Utilization	Optimized Generator Operation (Non-Utility	$ -		$ -		$ -
	Optimized Generator Operation (Utility/Ratepayer)	$ -		$ -		$ -
	Deferred Generation Capacity Investments	$ -		$ -		$ -
	Reduced Congestion Costs (Non-Utility Merchant)	$ -		$ -		$ -
	Reduced Congestion Costs (Utility/Ratepayer)	$ -		$ -		$ -
T&D Capital Savings	Deferred Transmission Investments	$ -		$ -		$ -
	Deferred Distribution Investments	$ -		$ -		$ -
Energy Efficiency	Reduced Electricity Losses	$ -		$ -		$ -
Electricity Cost Savings	Reduced Electricity Cost (Consumer)	$ -		$ -		$ -
	Reduced Electricity Cost (Utility/Ratepayer)	$ -		$ 632,800		$ 632,800.00
Power Interruptions	Reduced Outages (Consumer)	$ -		$ -		$ -
	Reduced Outages (Utility/Ratepayer)	$ -		$ -		$ -
Power Quality	Improved Power Quality	$ -		$ 23,500		$ 23,500.00
Air Emissions	Reduced CO2 Emissions	$ -		$ 127,500		$ 127,500.00
	Reduced SOx Emissions	$ -		$ 13,900		$ 13,900.00
	Reduced NOx Emissions	$ -		$ 36,200		$ 36,200.00
	Reduced PM Emissions	$ -		$ 369,000		$ 369,000.00
	Total Gross Benefit	**$ -**		**$ 1,202,900**		**$ 1,202,900.00**
	Costs					
	Capital Cost of Deployment (fixed charge rate)					$ 2,406,800.00
	Operating and maintenance costs not related to energy (labor for operation, plant maintenance, equipment wear leading to loss-					$ 546,900.00
	Decommissioning and Disposal Costs					$ 6,300.00
	Total Annual Cost of Deployment					**$ 2,959,900.00**
	Total Net Benefit					**$ (1,757,000.00)**

The following figures show the results of the sensitivity case analysis which, as shown in the first figure, uses a range from 80% (low) to 120% (high) of the reference case values.

Table 40. Sensitivity Case Analysis Settings

		Select % using toggle			2014 Values		
Input Name	Unit	Low	Reference	High	Low	Reference	High
Average Variable Peak Generation Costs	$/MWh	80%	100%	120%	$ 56	$ 70	$ 84
CO2 Emissions Factor for Generation on the Margin	lbs/MWh	80%	100%	120%	1,098	1,372	1,646
SOx Emissions Factor for Generation on the Margin	lbs/MWh	80%	100%	120%	4.640	5.800	6.960
NOx Emissions Factor for Generation on the Margin	lbs/MWh	80%	100%	120%	2.08	2.60	3.12
PM Emissions Factor for Generation on the Margin	lbs/MWh	80%	100%	120%	1.764	2.205	2.646
Value of CO2	$/ton	80%	100%	120%	$ 16	$ 20	$ 24
Value of SOx	$/ton	80%	100%	120%	$ 416	$ 520	$ 624
Value of NOx	$/ton	80%	100%	120%	$ 2,400	$ 3,000	$ 3,600
Value of PM	$/ton	80%	100%	120%	$ 28,800	$ 36,000	$ 43,200
Average Variable Renewable Generation Costs	$/MW	80%	100%	120%	$ 2	$ 2	$ 2
Total Renewable Energy Discharged for Arbitrage	MWh	80%	100%	120%	626	782	938
Total Renewable Energy Discharged for Energy Time-Shift	MWh	80%	100%	120%	626	782	938
Capital Cost of Conventional Voltage Support Solution	$/kVAR	80%	100%	120%	$ 14	$ 18	$ 22
Nameplate Reactive Power Capacity of Energy Storage	kVAR	80%	100%	120%	800	1,000	1,200
Annual Fixed Charge Rate for Voltage Support Capital Investment	%	80%	100%	120%	9	11	13

Table 41. Sensitivity Case Analysis Results

Cumulative Gross Benefits over the Deployment Period (Present Value)	Low Case	Reference Case	High Case
Arbitrage Revenue	$ -	$ -	$ -
Capacity Market Revenue	$ -	$ -	$ -
Ancillary Services Revenue	$ -	$ -	$ -
Optimized Generator Operation (Non-Utility Merchant)	$ -	$ -	$ -
Optimized Generator Operation (Utility/Ratepayer)	$ -	$ -	$ -
Deferred Generation Capacity Investments	$ -	$ -	$ -
Reduced Congestion Costs (Non-Utility Merchant)	$ -	$ -	$ -
Reduced Congestion Costs (Utility/Ratepayer)	$ -	$ -	$ -
Deferred Transmission Investments	$ -	$ -	$ -
Deferred Distribution Investments	$ -	$ -	$ -
Reduced Electricity Cost (Consumer)	$ -	$ -	$ -
Reduced Electricity Cost (Utility/Ratepayer)	$ 404,700	$ 632,800	$ 911,000
Reduced Outages (Consumer)	$ -	$ -	$ -
Reduced Outages (Utility/Ratepayer)	$ -	$ -	$ -
Improved Power Quality	$ 12,000	$ 23,500	$ 34,000
Reduced CO2 Emissions	$ 65,500	$ 127,500	$ 220,600
Reduced SOx Emissions	$ 7,200	$ 13,900	$ 24,200
Reduced NOx Emissions	$ 18,900	$ 36,200	$ 62,700
Reduced PM Emissions	$ 189,100	$ 369,000	$ 637,900
Total Benefit	**$ 697,400**	**$ 1,202,900**	**$ 1,890,400**

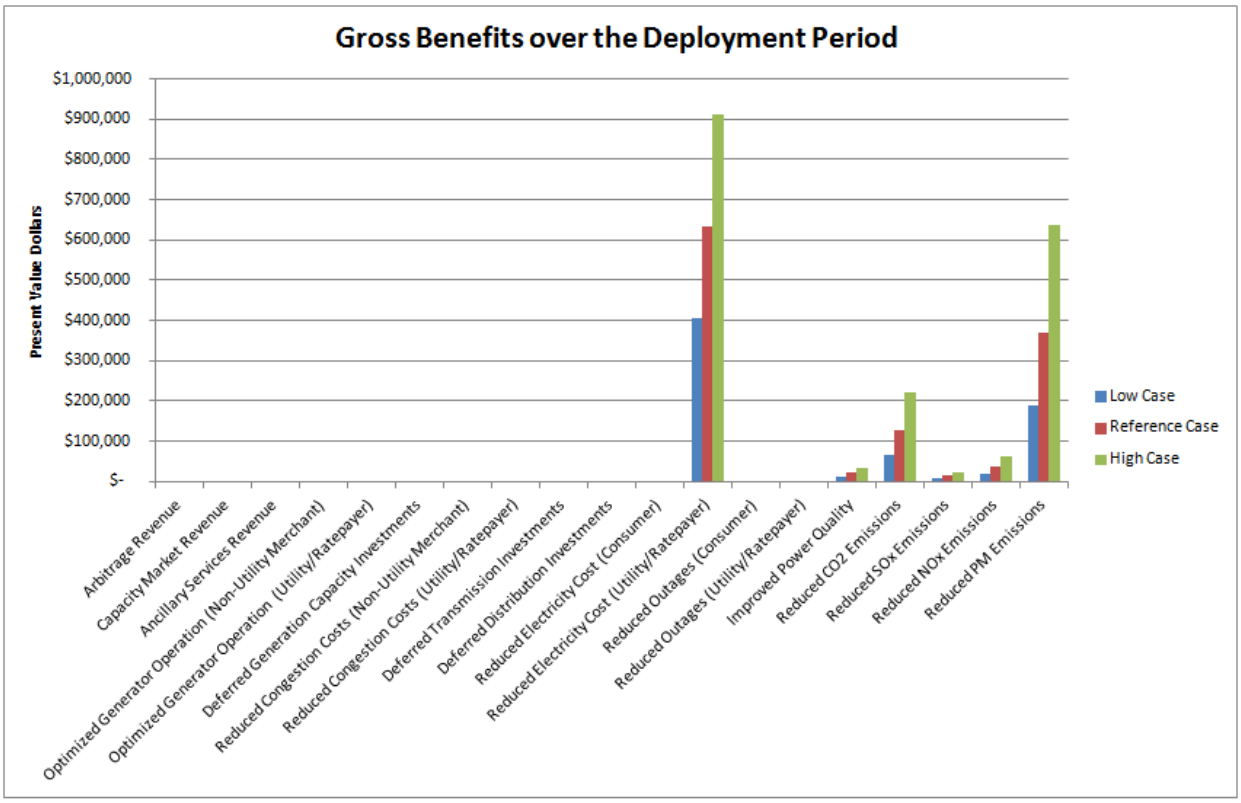


Figure 196. Graphic Representation of Sensitivity Case Analysis

8.5.4.3.3 Value Proposition for the 1MW BESS Owned by a Utility in a Regulated Market to Offset Demand Charges

Asset Characterization Module

The following table shows the parameters given as inputs to the ESCT for this option. They are based on a 1MW BESS deployed on a distribution network and owned by a utility operating in a regulated market which means they can use the BESS to generate revenue. For this option, the primary application is demand charge management.

Table 42. Parameters for Asset Characterization Module

Location of battery	Distribution
Market	Regulated
Owner	Utility (End User)
Type of Battery	Lithium-ion
Total name plate power output	1000 kW
Total name plate energy storage capacity	1000 kWh
Round trip efficiency	95%
Response time of BESS	0.005 seconds
Cycle life	4000 cycles
Average/Expected year over demand growth of electric system	2%
Expected life time	20 years

Average inflation rate	2%
Discount rate in net present value analysis	7%
Total Installed cost of deployment	$2,000,000
Fixed charge rate to annualize cost of deployment	11%
Non energy O&M cost with replacement cost	$50,000/year
Expected decommissioning & disposal cost	$25,000
Primary application	Demand charge management
Selected secondary application(s) *	Renewables energy time-shift, electric service power quality

* For this option, the ESCT also offered TOU energy cost management and electric service reliability, both of which were used in option #1 so their benefits could be considered.

On simulating the module using the above mentioned inputs, the following figure shows the potential benefits.

Figure 197. Results of Asset Characterization Module

Data Input Module

The following table shows the inputs entered through the ESCT tool for data input module analysis.

Table 43. Review Benefit Calculation Inputs

		Select % using toggle			2014 Values		
Input Name	Unit	Low	Reference	High	Low	Reference	High
Average On-Peak Price of Electricity	$/MWh	100%	100%	100%	$ 100	$ 100	$ 100
CO2 Emissions Factor for Generation on the Margin	lbs/MWh	100%	100%	100%	1,372	1,372	1,372
SOx Emissions Factor for Generation on the Margin	lbs/MWh	100%	100%	100%	5.800	5.800	5.800
NOx Emissions Factor for Generation on the Margin	lbs/MWh	100%	100%	100%	2.60	2.60	2.60
PM Emissions Factor for Generation on the Margin	lbs/MWh	100%	100%	100%	2.205	2.205	2.205
Value of CO2	$/ton	100%	100%	100%	$ 20	$ 20	$ 20
Value of SOx	$/ton	100%	100%	100%	$ 520	$ 520	$ 520
Value of NOx	$/ton	100%	100%	100%	$ 3,000	$ 3,000	$ 3,000
Value of PM	$/ton	100%	100%	100%	$ 36,000	$ 36,000	$ 36,000
Average Monthly Load Reduction from ES at Peak	MW	100%	100%	100%	1.0	1.0	1.0
Average Monthly Load Reduction from ES at Partial-Peak	MW	100%	100%	100%	1.0	1.0	1.0
Average Monthly Load Reduction from ES at Off-Peak	MW	100%	100%	100%	1.0	1.0	1.0
Peak Demand Charge	$/MW-mo	100%	100%	100%	$ 11,590	$ 11,590	$ 11,590
Partial-Peak Demand Charge	$/MW-mo	100%	100%	100%	$ 2,650	$ 2,650	$ 2,650
Off-Peak Demand Charge	$/MW-mo	100%	100%	100%	$ 6,890	$ 6,890	$ 6,890
Number of Months that Demand Charges are Avoided	#	100%	100%	100%	5	5	5
Typical Number of Power Quality Events per Year	#	100%	100%	100%	10	10	10
Value of Avoided Power Quality Events	$/kw peak	100%	100%	100%	$ 5.0	$ 5.0	$ 5.0
Customer Peak Load	kW	100%	100%	100%	1,000	1,000	1,000
Total Renewable Energy Discharged for Arbitrage	MWh	100%	100%	100%	782	782	782
Total Renewable Energy Discharged for Energy Time-Shift	MWh	100%	100%	100%	782	782	782

Computational Module with Reference Case and Senstivity Case Analyses

The computational module generates results based on reference case analysis and sensitivity case analysis from the above mentioned inputs.

The following table shows the cumulative benefit and cost table, based on the reference case analysis, with the total cost of deployment and total net benefit shown on the bottom right of the table. As you'll note in these results, for the 20-year period, the ESCT estimated $2,309,600 in reduced electricity costs (mostly from reduced demand charges), $594,900 in improved power quality savings (includes voltage and frequency support), and $546,600 in emissions savings. This total gross benefit of $3,451,000 results in a return on investment of $491,200 (after the cost of the BESS, annual O&M expenses, etc.) for this option.

Table 44. Cumulative Benefit and Cost Table

	Cumulative Benefit and Cost Table					
	Benefits	**Additional Benefits - Total Present Value over the Deployment Period**	**+**	**Primary and Secondary Benefits - Total Present Value over the Deployment Period**	**=**	**Total Benefit - Present Value over the Deployment Period**
Market Revenue	Arbitrage Revenue	$ -		$ -		$ -
	Capacity Market Revenue	$ -		$ -		$ -
	Ancillary Services Revenue	$ -		$ -		$ -
Improved Asset Utilization	Optimized Generator Operation (Non-Utility	$ -		$ -		$ -
	Optimized Generator Operation (Utility/Ratepayer)	$ -		$ -		$ -
	Deferred Generation Capacity Investments	$ -		$ -		$ -
	Reduced Congestion Costs (Non-Utility Merchant)	$ -		$ -		$ -
	Reduced Congestion Costs (Utility/Ratepayer)	$ -		$ -		$ -
T&D Capital Savings	Deferred Transmission Investments	$ -		$ -		$ -
	Deferred Distribution Investments	$ -		$ -		$ -
Energy Efficiency	Reduced Electricity Losses	$ -		$ -		$ -
Electricity Cost Savings	Reduced Electricity Cost (Consumer)	$ -		$ 2,309,600		$ 2,309,600.00
	Reduced Electricity Cost (Utility/Ratepayer)	$ -		$ -		$ -
Power Interruptions	Reduced Outages (Consumer)	$ -		$ -		$ -
	Reduced Outages (Utility/Ratepayer)	$ -		$ -		$ -
Power Quality	Improved Power Quality	$ -		$ 594,900		$ 594,900.00
Air Emissions	Reduced CO2 Emissions	$ -		$ 127,500		$ 127,500.00
	Reduced SOx Emissions	$ -		$ 13,900		$ 13,900.00
	Reduced NOx Emissions	$ -		$ 36,200		$ 36,200.00
	Reduced PM Emissions	$ -		$ 369,000		$ 369,000.00
	Total Gross Benefit	**$ -**		**$ 3,451,100**		**$ 3,451,100.00**
	Costs					
	Capital Cost of Deployment (fixed charge rate)					$ 2,406,800.00
	Operating and maintenance costs not related to energy (labor for operation, plant maintenance, equipment wear leading to loss-					$ 546,900.00
	Decommissioning and Disposal Costs					$ 6,300.00
	Total Annual Cost of Deployment					**$ 2,959,900.00**
	Total Net Benefit					**$ 491,200.00**

The following figures show the results of the sensitivity case analysis which, as shown in the first figure, uses a range from 80% (low) to 120% (high) of the reference case values.

Table 45. Sensitivity Case Analysis Settings

		Select % using toggle			2014 Values		
Input Name	Unit	Low	Reference	High	Low	Reference	High
Average On-Peak Price of Electricity	$/MWh	80%	100%	120%	$ 80	$ 100	$ 120
CO2 Emissions Factor for Generation on the Margin	lbs/MWh	80%	100%	120%	1,098	1,372	1,646
SOx Emissions Factor for Generation on the Margin	lbs/MWh	80%	100%	120%	4.640	5.800	6.960
NOx Emissions Factor for Generation on the Margin	lbs/MWh	80%	100%	120%	2.08	2.60	3.12
PM Emissions Factor for Generation on the Margin	lbs/MWh	80%	100%	120%	1.764	2.205	2.646
Value of CO2	$/ton	80%	100%	120%	$ 16	$ 20	$ 24
Value of SOx	$/ton	80%	100%	120%	$ 416	$ 520	$ 624
Value of NOx	$/ton	80%	100%	120%	$ 2,400	$ 3,000	$ 3,600
Value of PM	$/ton	80%	100%	120%	$ 28,800	$ 36,000	$ 43,200
Average Monthly Load Reduction from ES at Peak	MW	80%	100%	120%	0.8	1.0	1.2
Average Monthly Load Reduction from ES at Partial-Peak	MW	80%	100%	120%	0.8	1.0	1.2
Average Monthly Load Reduction from ES at Off-Peak	MW	80%	100%	120%	0.8	1.0	1.2
Peak Demand Charge	$/MW-mo	80%	100%	120%	$ 9,272	$ 11,590	$ 13,908
Partial-Peak Demand Charge	$/MW-mo	80%	100%	120%	$ 2,120	$ 2,650	$ 3,180
Off-Peak Demand Charge	$/MW-mo	80%	100%	120%	$ 5,512	$ 6,890	$ 8,268
Number of Months that Demand Charges are Avoided	#	80%	100%	120%	4	5	6
Typical Number of Power Quality Events per Year	#	80%	100%	120%	8	10	12
Value of Avoided Power Quality Events	$/kw peak	80%	100%	120%	$ 4.0	$ 5.0	$ 6.0
Customer Peak Load	kW	80%	100%	120%	800	1,000	1,200
Total Renewable Energy Discharged for Arbitrage	MWh	80%	100%	120%	626	782	938
Total Renewable Energy Discharged for Energy Time-Shift	MWh	80%	100%	120%	626	782	938

Table 46. Sensitivity Case Analysis Results

Cumulative Gross Benefits over the Deployment Period (Present Value)	Low Case	Reference Case	High Case
Arbitrage Revenue	$ -	$ -	$ -
Capacity Market Revenue	$ -	$ -	$ -
Ancillary Services Revenue	$ -	$ -	$ -
Optimized Generator Operation (Non-Utility Merchant)	$ -	$ -	$ -
Optimized Generator Operation (Utility/Ratepayer)	$ -	$ -	$ -
Deferred Generation Capacity Investments	$ -	$ -	$ -
Reduced Congestion Costs (Non-Utility Merchant)	$ -	$ -	$ -
Reduced Congestion Costs (Utility/Ratepayer)	$ -	$ -	$ -
Deferred Transmission Investments	$ -	$ -	$ -
Deferred Distribution Investments	$ -	$ -	$ -
Reduced Electricity Cost (Consumer)	$ 1,372,100	$ 2,309,600	$ 3,325,700
Reduced Electricity Cost (Utility/Ratepayer)	$ -	$ -	$ -
Reduced Outages (Consumer)	$ -	$ -	$ -
Reduced Outages (Utility/Ratepayer)	$ -	$ -	$ -
Improved Power Quality	$ 331,900	$ 594,900	$ 856,600
Reduced CO2 Emissions	$ 65,500	$ 127,500	$ 220,600
Reduced SOx Emissions	$ 7,200	$ 13,900	$ 24,200
Reduced NOx Emissions	$ 18,900	$ 36,200	$ 62,700
Reduced PM Emissions	$ 189,100	$ 369,000	$ 637,900
Total Benefit	**$ 1,984,700**	**$ 3,451,100**	**$ 5,127,700**

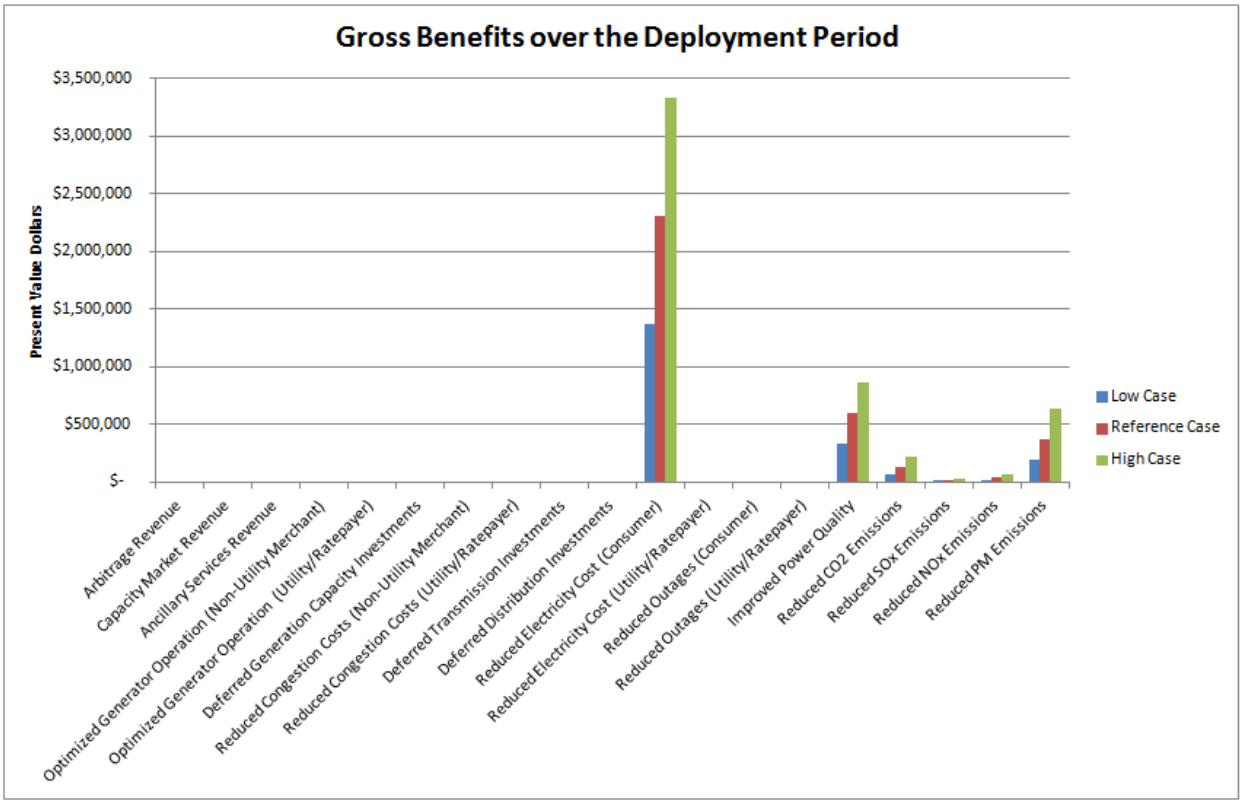


Figure 198. Graphic Representation of Sensitivity Case Analysis

8.5.4.3.4 Value Proposition for the 1MW BESS Owned by a Generator in a Deregulated Market

Asset Characterization Module

The following table shows the parameters given as inputs to the ESCT for this option. They are based on a 1MW BESS deployed on a distribution network and owned by a utility operating in a regulated market which means they can use the BESS to generate revenue.

Table 47. Parameters for Asset Characterization Module

Location of battery	Transmission
Market	Deregulated
Owner	Utility (End User)
Type of Battery	Lithium-ion
Total name plate power output	1000 kW
Total name plate energy storage capacity	1000 kWh
Round trip efficiency	95%
Response time of BESS	0.005 seconds
Cycle life	4000 cycles
Average/Expected year over demand growth of electric system	2%
Expected life time	20 years
Average inflation rate	2%

Discount rate in net present value analysis	7%
Total Installed cost of deployment	$2,000,000
Fixed charge rate to annualize cost of deployment	11%
Non energy O&M cost with replacement cost	$50,000/year
Expected decommissioning & disposal cost	$25,000
Primary application	Renewables capacity firming
Selected secondary application(s) *	Electric supply reserve capacity and voltage support

* For this option, the ESCT also offered renewables energy time-shift and wind generation grid integration, both of which were covered in other options.

On simulating the module using the above mentioned inputs, the following figure shows the potential benefits, which now include ancillary services.

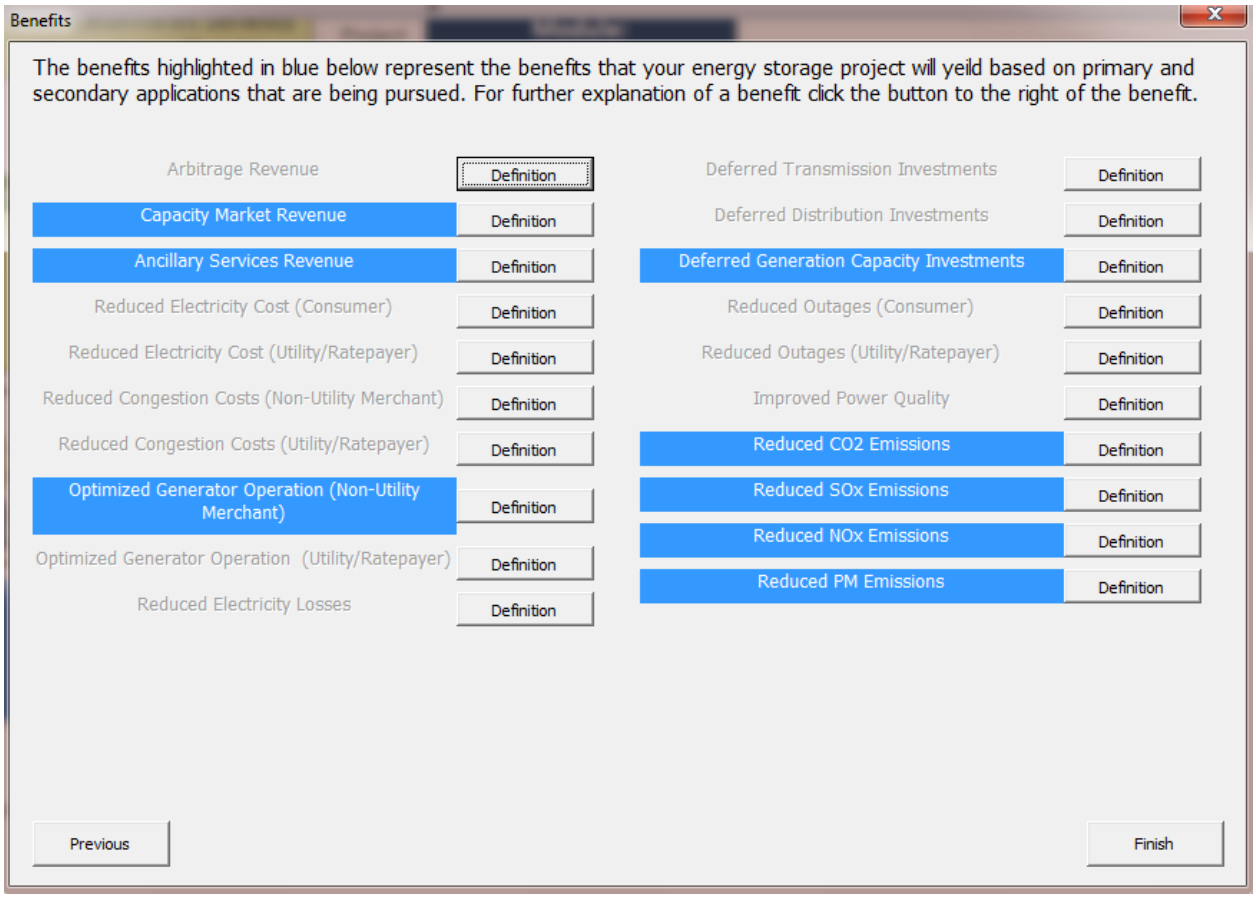


Figure 199. Results of Asset Characterization Module

Data Input Module

The following table shows the inputs entered through the ESCT tool for data input module analysis.

Table 48. Review Benefit Calculation Inputs

		Select % using toggle			2014 Values		
Input Name	Unit	Low	Reference	High	Low	Reference	High
CO2 Emissions Factor for Base Generation	lbs/MWh	100%	100%	100%	1,372	1,372	1,372
SOx Emissions Factor for Base Generation	lbs/MWh	100%	100%	100%	5.80	5.80	5.80
NOx Emissions Factor for Base Generation	lbs/MWh	100%	100%	100%	2.60	2.60	2.60
PM Emissions Factor for Base Generation	lbs/MWh	100%	100%	100%	2.205	2.205	2.205
Value of CO2	$/ton	100%	100%	100%	$ 20	$ 20	$ 20
Value of SOx	$/ton	100%	100%	100%	$ 520	$ 520	$ 520
Value of NOx	$/ton	100%	100%	100%	$ 3,000	$ 3,000	$ 3,000
Value of PM	$/ton	100%	100%	100%	$ 36,000	$ 36,000	$ 36,000
Average Value of Capacity on the Market	$/MW-h	100%	100%	100%	$ 18	$ 18	$ 18
Total Spinning-Reserve Services Provided	MW-h	100%	100%	100%	2,000	2,000	2,000
Average Price for Spinning Reserve Services	$/MW-h	100%	100%	100%	$ 4.50	$ 4.50	$ 4.50
Total Non-Spinning-Reserve Services Provided	MW-h	100%	100%	100%	500	500	500
Average Price for Non-Spinning Reserve Services	$/MW-h	100%	100%	100%	$ 3.00	$ 3.00	$ 3.00
Total Backup Supply Services Provided	MW-h	100%	100%	100%	150	150	150
Average Price for Backup Supply Services	$/MW-h	100%	100%	100%	$ 0.40	$ 0.40	$ 0.40
Marginal Operating Costs of Conventional Generation at Partial Load	$/MWh	100%	100%	100%	$ 46.06	$ 46.06	$ 46.06
Marginal Operating Costs of Conventional Generation at Optimal Load	$/MWh	100%	100%	100%	$ 45.60	$ 45.60	$ 45.60
CO2 Emissions Factor of Generation at Partial Load	lbs/MWh	100%	100%	100%	1,372	1,372	1,372
CO2 Emissions Factor of Generation at Optimal Load	lbs/MWh	100%	100%	100%	1,372	1,372	1,372
SOx Emissions Factor of Generation at Partial Load	lbs/MWh	100%	100%	100%	5.800	5.800	5.800
SOx Emissions Factor of Generation at Optimal Load	lbs/MWh	100%	100%	100%	5.800	5.800	5.800
NOx Emissions Factor of Generation at Partial Load	lbs/MWh	100%	100%	100%	2.600	2.600	2.600
NOx Emissions Factor of Generation at Optimal Load	lbs/MWh	100%	100%	100%	2.600	2.600	2.600
PM Emissions Factor of Generation at Partial Load	lbs/MWh	100%	100%	100%	2.205	2.205	2.205
PM Emissions Factor of Generation at Optimal Load	lbs/MWh	100%	100%	100%	2.205	2.205	2.205
Annual Reactive Power Capacity Available for Voltage Support	MVAR-yr	100%	100%	100%	500.0	500.0	500.0
Annual Capacity Payment for Voltage Support	$/MVAR-y	100%	100%	100%	$ 1,000	$ 1,000	$ 1,000
Effective Load Carrying Capacity of Renewable Post-Firming	%	100%	100%	100%	10	10	10
Effective Load Carrying Capacity of Renewable Pre-Firming	%	100%	100%	100%	10	10	10
Hours of Renewable Energy Capacity Sold	hr	100%	100%	100%	7,500.0	7,500.0	7,500.0
Nameplate Capacity of Renewable Resource	MW	100%	100%	100%	10	10	10
Capacity Factor of Renewable Resource	%	100%	100%	100%	12	12	12

Computational Module with Reference Case and Senstivity Case Analyses

The computational module generates results based on reference case analysis and sensitivity case analysis from the above mentioned inputs.

The following table shows the cumulative benefit and cost table, based on the reference case analysis, with the total cost of deployment and total net benefit shown on the bottom right of the table. As you'll note in these results, for the 20-year period, the ESCT estimated $736,100 in ancillary services revenue and $11,800 in improved asset utilization. This total gross benefit of $747,900 results in a loss of

$2,212,000 (after the cost of the BESS, annual O&M expenses, etc.) for this option. However, this option was only run to capture the anciallary services potential, which could be added to other options.

Table 49. Cumulative Benefit and Cost Table

	Cumulative Benefit and Cost Table				
	Benefits	**Additional Benefits - Total Present Value over the Deployment Period**	**+**	**Primary and Secondary Benefits - Total Present Value over the Deployment Period**	**= Total Benefit - Present Value over the Deployment Period**
Market Revenue	Arbitrage Revenue	$ -		$ -	$ -
	Capacity Market Revenue	$ -		$ -	$ -
	Ancillary Services Revenue	$ -		$ 736,100	$ 736,100.00
Improved Asset Utilization	Optimized Generator Operation (Non-Utility	$ -		$ 11,800	$ 11,800.00
	Optimized Generator Operation (Utility/Ratepayer)	$ -		$ -	$ -
	Deferred Generation Capacity Investments	$ -		$ -	$ -
	Reduced Congestion Costs (Non-Utility Merchant)	$ -		$ -	$ -
	Reduced Congestion Costs (Utility/Ratepayer)	$ -		$ -	$ -
T&D Capital Savings	Deferred Transmission Investments	$ -		$ -	$ -
	Deferred Distribution Investments	$ -		$ -	$ -
Energy Efficiency	Reduced Electricity Losses	$ -		$ -	$ -
Electricity Cost Savings	Reduced Electricity Cost (Consumer)	$ -		$ -	$ -
	Reduced Electricity Cost (Utility/Ratepayer)	$ -		$ -	$ -
Power Interruptions	Reduced Outages (Consumer)	$ -		$ -	$ -
	Reduced Outages (Utility/Ratepayer)	$ -		$ -	$ -
Power Quality	Improved Power Quality	$ -		$ -	$ -
Air Emissions	Reduced CO2 Emissions	$ -		$ -	$ -
	Reduced SOx Emissions	$ -		$ -	$ -
	Reduced NOx Emissions	$ -		$ -	$ -
	Reduced PM Emissions	$ -		$ -	$ -
	Total Gross Benefit	**$ -**		**$ 747,900**	**$ 747,900.00**
	Costs				
	Capital Cost of Deployment (fixed charge rate)				$ 2,406,800.00
	Operating and maintenance costs not related to energy (labor for operation, plant maintenance, equipment wear leading to loss-				$ 546,900.00
	Decommissioning and Disposal Costs				$ 6,300.00
	Total Annual Cost of Deployment				**$ 2,959,900.00**
	Total Net Benefit				**$ (2,212,000.00)**

The following figures show the results of the sensitivity case analysis which, as shown in the first figure, uses a range from 80% (low) to 120% (high) of the reference case values.

Table 50. Sensitivity Case Analysis Settings

		Select % using toggle			2014 Values		
Input Name	Unit	Low	Reference	High	Low	Reference	High
CO2 Emissions Factor for Base Generation	lbs/MWh	80%	100%	120%	1,098	1,372	1,646
SOx Emissions Factor for Base Generation	lbs/MWh	80%	100%	120%	4.64	5.80	6.96
NOx Emissions Factor for Base Generation	lbs/MWh	80%	100%	120%	2.08	2.60	3.12
PM Emissions Factor for Base Generation	lbs/MWh	80%	100%	120%	1.764	2.205	2.646
Value of CO2	$/ton	80%	100%	120%	$ 16	$ 20	$ 24
Value of SOx	$/ton	80%	100%	120%	$ 416	$ 520	$ 624
Value of NOx	$/ton	80%	100%	120%	$ 2,400	$ 3,000	$ 3,600
Value of PM	$/ton	80%	100%	120%	$ 28,800	$ 36,000	$ 43,200
Average Value of Capacity on the Market	$/MW-h	80%	100%	120%	$ 15	$ 18	$ 22
Total Spinning-Reserve Services Provided	MW-h	80%	100%	120%	1,600	2,000	2,400
Average Price for Spinning Reserve Services	$/MW-h	80%	100%	120%	$ 3.60	$ 4.50	$ 5.40
Total Non-Spinning-Reserve Services Provided	MW-h	80%	100%	120%	400	500	600
Average Price for Non-Spinning Reserve Services	$/MW-h	80%	100%	120%	$ 2.40	$ 3.00	$ 3.60
Total Backup Supply Services Provided	MW-h	80%	100%	120%	120	150	180
Average Price for Backup Supply Services	$/MW-h	80%	100%	120%	$ 0.32	$ 0.40	$ 0.48
Marginal Operating Costs of Conventional Generation at Partial Load	$/MWh	80%	100%	120%	$ 36.84	$ 46.06	$ 55.27
Marginal Operating Costs of Conventional Generation at Optimal Load	$/MWh	80%	100%	120%	$ 36.48	$ 45.60	$ 54.72
CO2 Emissions Factor of Generation at Partial Load	lbs/MWh	80%	100%	120%	1,098	1,372	1,646
CO2 Emissions Factor of Generation at Optimal Load	lbs/MWh	80%	100%	120%	1,098	1,372	1,646
SOx Emissions Factor of Generation at Partial Load	lbs/MWh	80%	100%	120%	4.640	5.800	6.960
SOx Emissions Factor of Generation at Optimal Load	lbs/MWh	80%	100%	120%	4.640	5.800	6.960
NOx Emissions Factor of Generation at Partial Load	lbs/MWh	80%	100%	120%	2.080	2.600	3.120
NOx Emissions Factor of Generation at Optimal Load	lbs/MWh	80%	100%	120%	2.080	2.600	3.120
PM Emissions Factor of Generation at Partial Load	lbs/MWh	80%	100%	120%	1.764	2.205	2.646
PM Emissions Factor of Generation at Optimal Load	lbs/MWh	80%	100%	120%	1.764	2.205	2.646
Annual Reactive Power Capacity Available for Voltage Support	MVAR-yr	80%	100%	120%	400.0	500.0	600.0
Annual Capacity Payment for Voltage Support	$/MVAR-y	80%	100%	120%	$ 800	$ 1,000	$ 1,200
Effective Load Carrying Capacity of Renewable Post-Firming	%	80%	100%	120%	8	10	12
Effective Load Carrying Capacity of Renewable Pre-Firming	%	80%	100%	120%	8	10	12
Hours of Renewable Energy Capacity Sold	hr	80%	100%	120%	6,000.0	7,500.0	9,000.0
Nameplate Capacity of Renewable Resource	MW	80%	100%	120%	8	10	12
Capacity Factor of Renewable Resource	%	80%	100%	120%	10	12	14

Table 51. Sensitivity Case Analysis Results

Cumulative Gross Benefits over the Deployment Period (Present Value)	Low Case	Reference Case	High Case
Arbitrage Revenue	$ -	$ -	$ -
Capacity Market Revenue	$ -	$ -	$ -
Ancillary Services Revenue	$ 471,000	$ 736,100	$ 1,059,800
Optimized Generator Operation (Non-Utility Merchant)	$ 7,600	$ 11,800	$ 17,200
Optimized Generator Operation (Utility/Ratepayer)	$ -	$ -	$ -
Deferred Generation Capacity Investments	$ -	$ -	$ -
Reduced Congestion Costs (Non-Utility Merchant)	$ -	$ -	$ -
Reduced Congestion Costs (Utility/Ratepayer)	$ -	$ -	$ -
Deferred Transmission Investments	$ -	$ -	$ -
Deferred Distribution Investments	$ -	$ -	$ -
Reduced Electricity Cost (Consumer)	$ -	$ -	$ -
Reduced Electricity Cost (Utility/Ratepayer)	$ -	$ -	$ -
Reduced Outages (Consumer)	$ -	$ -	$ -
Reduced Outages (Utility/Ratepayer)	$ -	$ -	$ -
Improved Power Quality	$ -	$ -	$ -
Reduced CO2 Emissions	$ -	$ -	$ -
Reduced SOx Emissions	$ -	$ -	$ -
Reduced NOx Emissions	$ -	$ -	$ -
Reduced PM Emissions	$ -	$ -	$ -
Total Benefit	**$ 478,600**	**$ 747,900**	**$ 1,077,000**

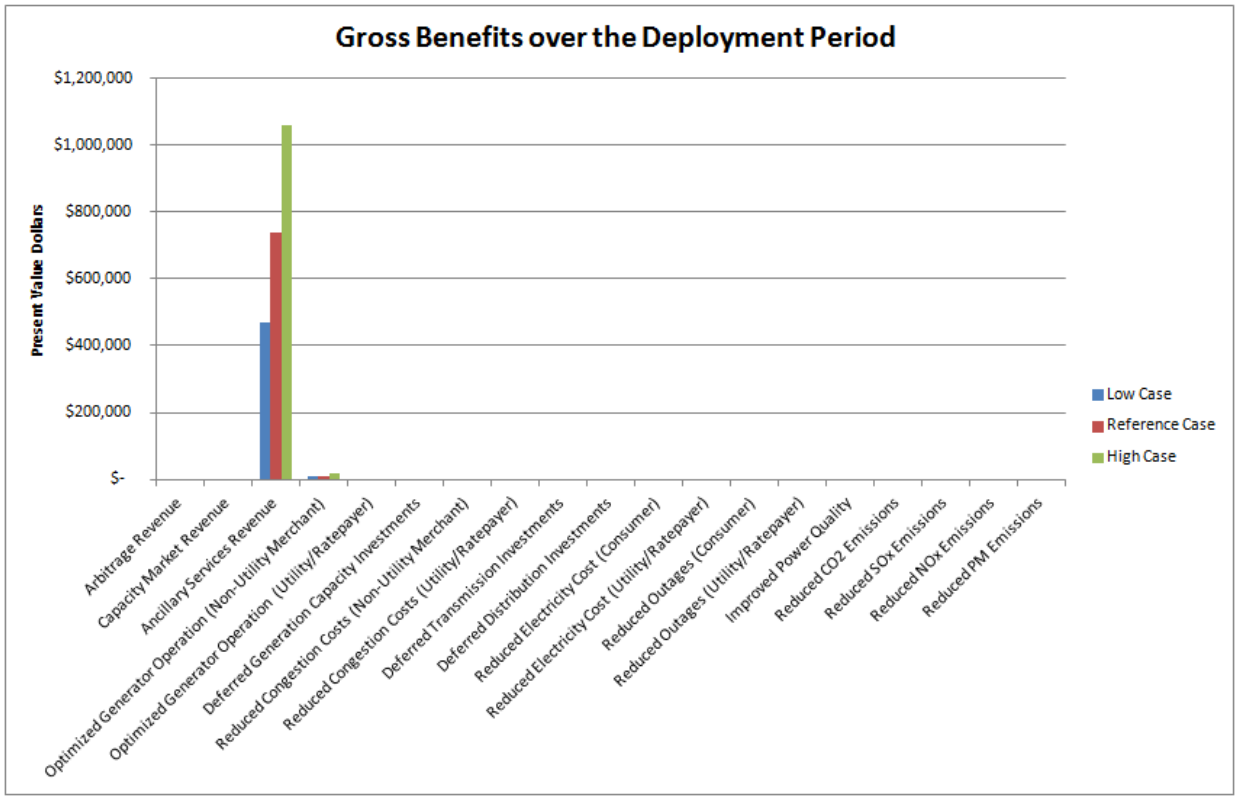


Figure 200. Graphic Representation of Sensitivity Case Analysis

8.5.4.3.5 Value Proposition for the 1MW BESS Owned by a Utility in a Deregulated Market – Reducing the BESS Cost by 50%

Asset Characterization Module

As shown earlier for option #1, the following table shows the parameters given as inputs to the ESCT for this option. They are based on a 1MW BESS deployed on a distribution network and owned by a utility operating in a deregulated market. In this option, the total installed cost of deployment has been cut in half, and is now $1,000,000.

Table 52. Parameters for Asset Characterization Module

Location of battery	Distribution
Market	Deregulated
Owner	Utility
Type of Battery	Lithium-ion
Total name plate power output	1000 kW
Total name plate energy storage capacity	1000 kWh
Round trip efficiency	95%
Response time of BESS	0.005 seconds
Cycle life	4000 cycles
Average/Expected year over demand growth of electric system	2%
Expected life time	20 years
Average inflation rate	2%
Discount rate in net present value analysis	7%
Total Installed cost of deployment	$1,000,000
Fixed charge rate to annualize cost of deployment	11%
Non energy O&M cost with replacement cost	$50,000/year
Expected decommissioning & disposal cost	$25,000
Primary application	Electric service reliability
Selected secondary application(s) *	T&D upgrade deferral, Voltage support

* For this option, the ESCT only offered these alternatives.

On simulating the module using the above mentioned inputs, the following figure shows the potential benefits.

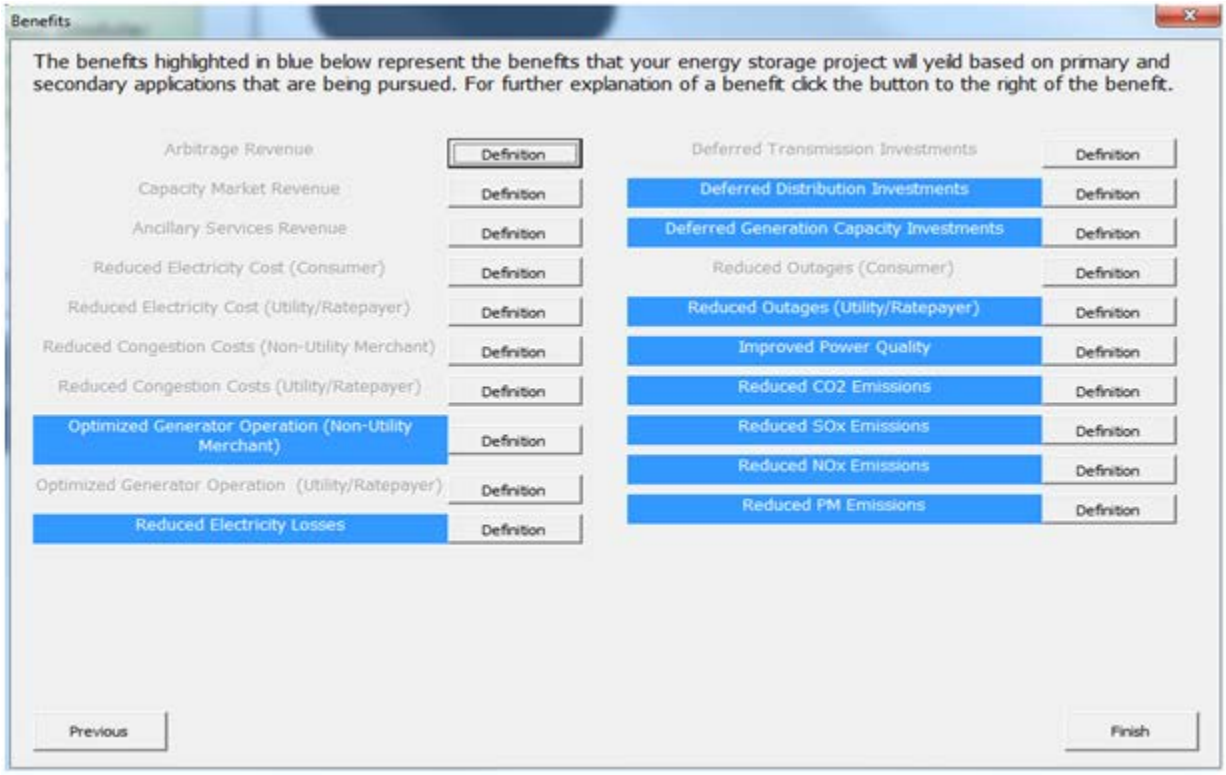


Figure 201. Results of Asset Characterization Module

Data Input Module

The following table shows the inputs entered through the ESCT tool for data input module analysis.

Table 53. Review Benefit Calculation Inputs

		Select % using toggle			2014 Values		
Input Name	Unit	Low	Reference	High	Low	Reference	High
Distribution Capacity Deferred	kVA	100%	100%	100%	50	50	50
Annual Fixed Charge Rate for Distribution Capital Investment	%	100%	100%	100%	11	11	11
Capital Cost of Deferred Distribution Capacity	$/kVA	100%	100%	100%	$ 420	$ 420	$ 420
Yearly O&M Costs of Deferred Distribution Capacity	$/year	100%	100%	100%	$ 10,000	$ 10,000	$ 10,000
Initial Year of Distribution Deferral	year	100%	100%	100%	2014	2014	2014
Final year of Distribution Deferral	year	100%	100%	100%	2016	2016	2016
Capital Cost of Conventional Voltage Support Solution	$/kVAR	100%	100%	100%	$ 18	$ 18	$ 18
Nameplate Reactive Power Capacity of Energy Storage	kVAR	100%	100%	100%	1,000	1,000	1,000
Annual Fixed Charge Rate for Voltage Support Capital Investment	%	100%	100%	100%	11	11	11
Capital Cost of Conventional Electric Service Reliability Solution	$/kW	100%	100%	100%	$ 1,000	$ 1,000	$ 1,000
Annual Fixed Charge Rate for Electric Service Reliability Capital Investment	%	100%	100%	100%	11	11	11

Computational Module with Reference Case and Senstivity Case Analyses

The computational module generates results based on reference case analysis and sensitivity case analysis from the above mentioned inputs.

The following table shows the cumulative benefit and cost table, based on the reference case analysis, with the total cost of deployment and total net benefit shown on the bottom right of the table. For the earlier option #1, this total gross benefit of $1,366,400 resulted in a $1,593,500 loss. In this option #5, with the BESS cost reduced to $1,000,000, the capital cost of deployment was reduced, so the loss over the 20-year period is now significantly less at $390,200.

Table 54. Cumulative Benefit and Cost Table

	Cumulative Benefit and Cost Table				
	Benefits	**Additional Benefits - Total Present Value over the Deployment Period**	**+**	**Primary and Secondary Benefits - Total Present Value over the Deployment Period**	**=** **Total Benefit - Present Value over the Deployment Period**
Market Revenue	Arbitrage Revenue	$ -		$ -	$ -
	Capacity Market Revenue	$ -		$ -	$ -
	Ancillary Services Revenue	$ -		$ -	$ -
Improved Asset Utilization	Optimized Generator Operation (Non-Utility	$ -		$ -	$ -
	Optimized Generator Operation (Utility/Ratepayer)	$ -		$ -	$ -
	Deferred Generation Capacity Investments	$ -		$ -	$ -
	Reduced Congestion Costs (Non-Utility Merchant)	$ -		$ -	$ -
	Reduced Congestion Costs (Utility/Ratepayer)	$ -		$ -	$ -
T&D Capital Savings	Deferred Transmission Investments	$ -		$ -	$ -
	Deferred Distribution Investments	$ -		$ 34,300	$ 34,300.00
Energy Efficiency	Reduced Electricity Losses	$ -		$ -	$ -
Electricity Cost Savings	Reduced Electricity Cost (Consumer)	$ -		$ -	$ -
	Reduced Electricity Cost (Utility/Ratepayer)	$ -		$ -	$ -
Power Interruptions	Reduced Outages (Consumer)	$ -		$ -	$ -
	Reduced Outages (Utility/Ratepayer)	$ -		$ 1,308,600	$ 1,308,600.00
Power Quality	Improved Power Quality	$ -		$ 23,500	$ 23,500.00
Air Emissions	Reduced CO2 Emissions	$ -		$ -	$ -
	Reduced SOx Emissions	$ -		$ -	$ -
	Reduced NOx Emissions	$ -		$ -	$ -
	Reduced PM Emissions	$ -		$ -	$ -
	Total Gross Benefit	**$ -**		**$ 1,366,400**	**$ 1,366,400.00**
	Costs				
	Capital Cost of Deployment (fixed charge rate)				$ 1,203,100.00
	Operating and maintenance costs not related to energy (labor for operation, plant maintenance, equipment wear leading to loss-				$ 546,900.00
	Decommissioning and Disposal Costs				$ 6,300.00
	Total Annual Cost of Deployment				**$ 1,756,600.00**
	Total Net Benefit				**$ (390,200.00)**

If the market can reduce the cost of a BESS by 50% or so, then by adding other potential applications, such as demand charge reduction and ancillary services, it's conceivable that a BESS could be a break-even proposition or even generate net revenue over a 20-year period.

Itshould be noted that the net benefits calculated by this ESCT include considerable value for environmental benefits that cannot be directly captured by a utility making the investment today. The rationale of the tool is that energy storage systems can reduce system losses by reducing system peak demand which translates into a reduction in emissions if peak load losses are reduced by a significant degree compared to the slight increase in off-peak losses and/or if peak generation units have lower or

similar emissions factors to base load units. Alternatively, by providing certain ancillary services, storage systems can enable conventional generation resources to be operated at more optimal conditions resulting in an emissions benefit. The calculation for this benefit assumes standard values for emission reductions based on estimates from literature. A future regulatory system may create an active emissions market allowing better estimates of these benefits.

8.5.5 Metrics and Benefits Analysis

This section covers the build and impact metrics for the BESS.

8.5.5.1 Build Metrics and Benefits

The base cost for development, testing and fielding of the 1MWh BESS was $1,700,000. An additional $295,933 was spent to prepare the site, implement monitoring and communications, and interconnect the BESS with the local grid. An additional $40,000 was expended for a short-term vendor support contract. These costs do not include the wind turbines nor do they include the synchrophasor monitoring network. They also do not include costs incurred by SPEC in managing and monitoring the BESS.

8.5.5.2 Impact Metrics and Benefits

The impact metrics typically define quantitative energy or emission savings, while benefits may not be easily quantifiable. The benefits include:

- Optimized generator operation: Storage devices used will be providing energy during peak times and may enable conventional generators to operate closer to their optimal loading conditions thus improving overall generation system performance.
- Deferred generation capacity investments: To defer a transmission or distribution upgrade using energy storage, the unit is located downstream of stained assets and charged during off-peak times and discharged during peak times. This will effectively shift load away from the peak time of the system reducing the need for utility investments in generation capacity to meet peak load.
- Reduced electricity losses: To defer a transmission or distribution upgrade using energy storage, the unit is located downstream of strained assets and charged during off-peak times and discharged during peak times. This will effectively reduce the peak load on the transmission and distribution system, thereby reducing losses overall.

There are impact metrics associated with energy savings and reduced CO2, SOx, NOx, and PM emissions.

- The BESS is used to shift peak electricity usage as a means of saving demand charges, but the actual amounts will vary depending on the actual peaks, the cost of electricity driving the demand charges, how the demand charges are derived (highest versus rolling average), and the

accuracy of forecasting peaks coupled with the ability of battery operators to have the system fully charged when needed.

- The reduced emissions use the following formulas:
  - CO2: 0.00068956 tons/kWh
  - SOx: 0.00263084 kg/kWh
  - NOx: 0.00117934 kg/kWh
  - PM2.5: 0.001 kg/kWh
- The savings over a 20-year period based on the ESCT results are as follows:
  - CO2: $127,500
  - SOx: $13,900
  - NOx: $36,200
  - PM2.5: $369,000

8.5.6 Stakeholder Feedback

To date, there are no documented observations from stakeholders on the impact of this project. ERCOT, SPP, GSEC and the CCET utility members have all shown an interest in energy storage, but as the testing of the BESS wasn't completed until late this year, the stakeholders have not yet had time to study the results of this analysis. Two TDSPs have deployed small community systems as a way of evaluating the potential for that use, and one TDSP even funded a study by the Brattle Group[39] to evaluate the economic feasibility of storage in Texas.

8.6 Conclusions

This section covers projections of demonstration and commercial scale system performance as well as lessons learned and best practices.

8.6.1 Projections of Demonstration and Commercial Scale System Performance

The BESS has proven that such a system can service a distribution utility and support multiple functions, individually or combined to optimize operational needs, reduce operational costs, or provide ancillary services that will generate return revenue to offset costs. The project demonstrated how effectively a 1MW BESS can be leveraged to level loads that are served by intermittent renewables, such as solar and wind. It proved how a BESS can reduce demand charges through peak shaving, while also providing invaluable frequency support and perhaps participation in ancillary services such as FRRS. Although a BESS of this scale is expensive, in the future utilities may be able to fund these resources through a rate case, and it is suggested in the Brattle Group study that the costs of energy storage devices will be halved in the next 3-5 years, making such investments much more attractive.

[39] The Value of Distributed Electricity Storage in Texas
http://www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf

8.6.2 Lessons Learned and Best Practices

The following outlines some of the key lessons learned and best practices for fielding a BESS.

- From the time one begins drafting a request for proposal to the date of actual installation and operation of a system like the BESS can take as much as a year. The team began drafting its technical specification, and the actual request for proposal in October 2012. The solicitations were released in early November, and the proposals were evaluated and negotiated during December (this process typically takes 1-2 months longer). The factory acceptance test was performed in July 2013, and the BESS was deployed, installed and energized in August 2013.
- Items such as batteries and inverters have long lead times, and even with proper planning, schedule delays can occur. Although some projects have experienced delays in procuring the necessary amount of batteries, this project did not have such an issue, but it did incur an unexpected one-month delay in receiving the requisite transformer.
- Financial stability of the battery system vendor is paramount given the lengthy development period. Typically, the vendor is integrating components, like the batteries, from other suppliers, and it's important to ensure that they all get paid. The team implemented a phased pay-out schedule tied to specific deliverables and, in each case, required verification that the appropriate suppliers had been paid.
- Financial stability of the battery system vendor doesn't end when the system is actually fielded. Typically, the first year of system operation will include some on-site repairs, spare parts, etc., and these are usually covered under a warranty agreement with the vendor. However, if they encounter financial hardships, then this can impose serious delays on operations when problems arise. During this project, the vendor did declare bankruptcy, and was eventually purchased by another company. There were some delays, and some issues in transferring support and warranty agreements, but fortunately all parties were committed to the success of the project and these issues were resolved fairly quickly.
- Proper selection and tuning of parameters are needed for optimization and design of the Phase Locked Loop (PLL).
- Controllers need to be optimized to increase the SCR.
- The battery model used in the simulation needs to be validated either by experimental testing of a battery cell in the laboratory or by obtaining the information from the battery manufacturer.
- The controllers need to be optimized to allow the battery respond to the to the wind profile depending on the generation and load demand.
- The controllers should also be optimized to allow the battery respond to the under frequency events on a battery – wind connected grid system.
- The optimized controller for the battery management system should be able to respond to the frequency deviations thereby providing ramp support to stabilize the grid.

9. FAST RESPONSE REGULATION SERVICE WITH FLEET ELECTRIC VEHICLES

9.1 Introduction

Frequency regulation is a grid ancillary service that allows electricity generators, including those with large battery energy storage systems, to bid services into the energy market to assist in maintaining the electric grid frequency at 60 Hz. Providers of this type of service guarantee to be able to adjust generation during a specified time period by either ramping up or ramping down production according to instructions in order to maintain the balance of generation/load on the grid, and thus the frequency. Traditionally, in the ERCOT market, this was accomplished through the dissemination of a four-second signal, with each frequency regulation generation resource then responding within their pre-established ramp rate until they met the full capacity specified in the signal. Participants in the frequency regulation market get paid whether they are called upon to adjust power or not, thus they are paid to be "on standby". As shown in the figure below, ERCOT studies (data is from 2008) have determined that the need for fast response resources increase as the concentration of wind grows on the grid. This project was developed to demonstrate the capability of addressing frequency regulation through the use of aggregated electric vehicle (EV) fleets to provide one type of fast response resources.

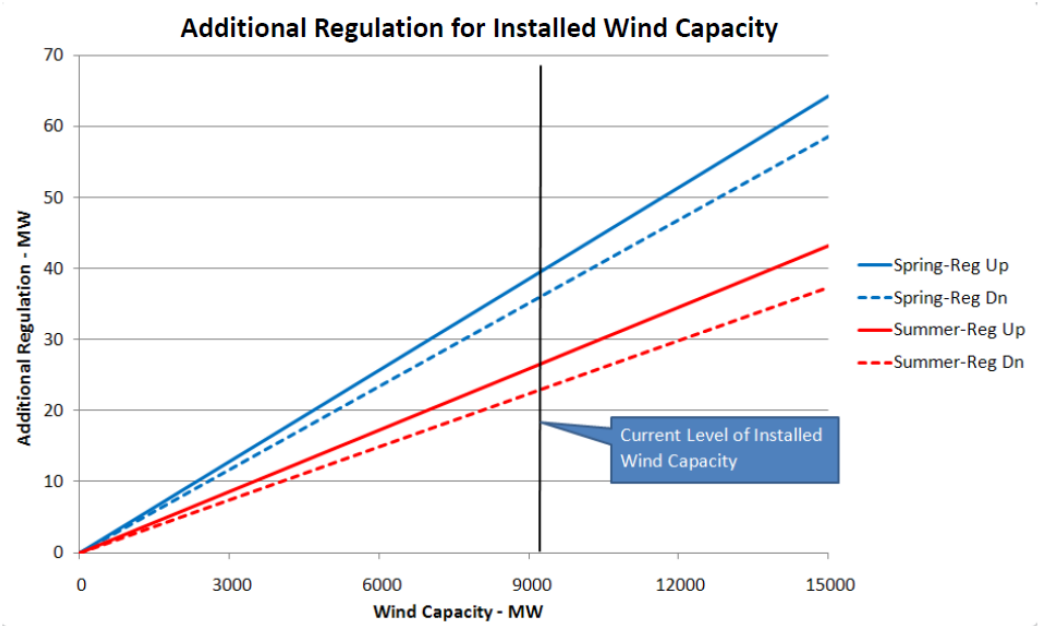


Figure 202. Results of a GE Study on Regulation Service Assuming 5-Minute Nodal Dispatch [40]

[40] Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements, http://www.uwig.org/attchb-ercot_a-s_study_final_report.pdf

In January 2013, ERCOT began a new pilot program to provide fast response regulation service (FRRS). In this type of frequency regulation, signals from ERCOT are responded to at full power within one second of signal receipt. Additionally, participants in FRRS monitor grid frequency, and can respond automatically when a deviation of .09 Hz or greater is detected. ERCOT's goal is to develop regulation services that can respond faster to grid frequency deviations, thus saving both in reduced congestion (and its associated costs to the market) and in reduced frequency regulation services since it won't require as many participants standing idle and ready to provide frequency regulation.

Battery energy storage systems can serve as an ideal provider for FRRS since batteries have a much faster response time than gas or coal-fired generators which must ramp to the regulation goal based on the simple physics of heating or cooling boilers. A great resource for batteries that could serve this purpose without significant investment (such as a large-scale utility scale battery costing millions of dollars) is through the use of EVs. In particular, supporting regulation-up services (the reducing of load on the system) can be as simple as "flipping a switch", i.e. turning the EV charger off. Regulation-down (the addition of load on the system) could be provided almost as quickly although the delivery of load to the grid would be managed by the EV battery management system (BMS) and so would be slightly slower.

The purpose of this part of the CCET project was to demonstrate an FRRS capability using an EV fleet at the Frito-Lay Distribution Facility in Fort Worth, Texas. Frito-Lay has a fleet of 11 EVs that are used primarily at night for deliveries around the Dallas/Fort Worth metroplex. These vehicles are typically charged during the day, when grid loads are highest and the need for frequency regulation is most apparent. This effort entailed the development and demonstration of an EV aggregation control system to support regulation-up services in response to either an ERCOT signal or a detected deviation of grid frequency of greater than .09 Hz. FRRS services were then bid into the market in one-hour intervals that matched the times the vehicles were drawing a load from the grid (charging), thus providing an excellent source for power reduction to support FRRS. The architecture for this effort is shown below, and includes the EV supply equipment (EVSE), the EMS, and the aggregator..

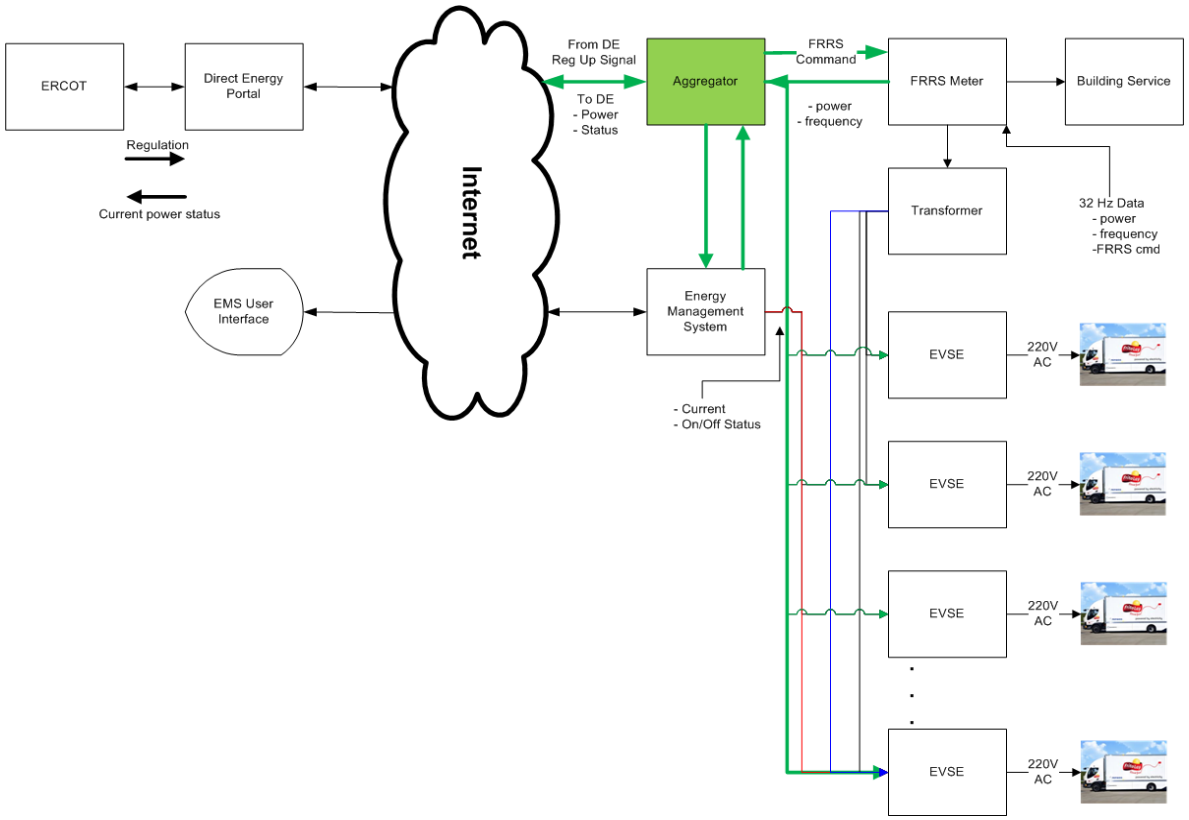


Figure 203. Architecture for Delivering FRRS from the Frito-Lay Facility

The EV fleet at Frito-Lay successfully bid into the ERCOT FRRS market and received compensation for providing energy capacity to the grid. This became the first time EVs have successfully participated in an ancillary service in ERCOT and the first time a fleet owner has received payment for providing these types of services using an EV fleet.

9.2 Anticipated Benefits

Broadly, the expected benefits of the CCET demonstration project will be derived from a more reliable electric grid that can facilitate effective management of and responses to increased wind resources in Texas and from supporting the deployment of new products, technologies, and infrastructure to help customers make informed decisions about their energy usage. Specific smart grid benefits that are potentially supported by the FRRS component include:

- Enhanced grid capability to manage wind variation onto the grid by using temporary energy storage services as provided by EV fleets to help manage frequency deviations caused by wind.
- Pollution reduction as a result of decreased fossil-based energy production by enabling increased use of wind generation and then using EVs as a mechanism to manage frequency to meet short-term grid reliability needs.

9.3 Interactions with Key Stakeholders

The team worked closely with ERCOT and the qualified scheduling entity (QSE) in developing and implementing the bid strategy, and in compliance and validation of the actual regulation service. The Texas TDUs were informed of the project results, and other TDUs and ISOs have expressed an interest in learning more about the potential demonstrated by this project.

9.4 Technical Approach

This section provides a detailed description of the technical approach. The first part, Project Plan, identifies the steps taken to demonstrate the technology. The second part, Data Collection and Benefits Analysis, defines the technical approach for conducting the benefits analysis, including the methodology and algorithms when appropriate.

9.4.1 Project Plan

This effort consisted of design, development, integration, and deployment of technologies to utilize an existing EV fleet to deliver FRRS. The following activities were conducted to create and ensure a successful deployment of technology:

- Identification and procurement of a utility revenue-grade meter to monitor power and grid frequency at a minimum of 32 Hz. After an extensive trade study of suitable meters to meet the requirements of the electrical infrastructure at the site, it was decided to build a custom power meter. The electrical infrastructure would have required either a complete replacement of the electrical panel box to split off building power from charger power or the acquisition of 12 revenue-grade power meters. Designing and building a custom meter that could monitor the 12 EV circuits after the panel box became the more cost-effective solution. The solution used the National Instruments suite of components, including a CompactRIO DAQ computer, with associated voltage, current, and relay modules. Total hardware costs were under $20,000 versus over $100,000 that would have been spent on individual power meters or redesigning the electrical panel box. The solution also allowed for a minimally-invasive installation suitable for future deployments. A further advantage was in data collection speed; this system exceeds International Electrotechnical Commission (IEC) and ERCOT requirements for metering. Finally, with data collection and aggregation logic co-located on the same hardware, the processing and response times were increased since all data was flowing at hardware speed without going through communication interfaces. The final solution, shown below, resulted in a compact, robust, fast, and inexpensive power meter/aggregation system package that is easy to install and remove without requiring extensive site improvements to the electrical infrastructure.

- Development of a software aggregation control system to manage an EV fleet in accordance with FRRS parameters.
- Establishment of an interface to an existing on-site EMS that reported EV status information. After getting well into design of the system, it was decided that an interface with the on-site EMS was not necessary to accomplish the goals of the project, and so this interface was not developed.
- Establishment of a secure physical network interface to the ERCOT system in accordance with FRRS pilot requirements. In accordance with ERCOT rules, this interface was done through a QSE. A distributed network protocol 3 (DNP3) interface to the QSE RTU was implemented over a secure virtual private network (VPN) tunnel. The QSE telemetered the information provided by the aggregation system to ERCOT on a 2-second interval. ERCOT verified they were receiving the telemetered data from the aggregation system.
- Development of the data collection, correlation, and delivery to ERCOT of the required meter data files within one day of each frequency regulation bid period. The eventual solution to this was somewhat manual due to the rules for a QSE. After each bid hour, data files were automatically downloaded through a remote agent to SwRI. The data files were converted to a Microsoft Excel format, and then emailed to the QSE. After review, the QSE then sent the files to ERCOT. This solution worked well for the pilot and could be further automated in a future deployment if desired.
- Development and deployment of hardware for controlling the EV chargers within the FRRS established time frames for power responses.
- Installation and deployment of secure networking hardware for the interface between the QSE and ERCOT.
- Laboratory testing of all interfaces, using simulators, to verify communications pathways, data receipt and responses, and timing to enact FRRS power changes on the EV fleet, prior to deployment.

Success in this project revolved around a few key data items:

- Ability to monitor grid frequency and detect deviations of .09 Hz from the base 60 Hz. The final system detected frequency deviations of .001 Hz. The deployment grid frequency is configurable and can be changed while the system is running.
- Ability to implement FRRS protocol within 60 cycles (one second) of either a detected deviation or an ERCOT instruction. The final system repeatedly and consistently responded within 30 cycles (500 milliseconds (ms)).
- Ability to monitor and log fleet power consumption at a minimum of 32 Hz during an FRRS bid period. The final system monitored and logged power data at 40 Hz.

9.4.2 Data Collection and Benefits Analysis

Data collection focused on the requirements of ERCOT to provide verification of the ability to provide services that were bid into the ancillary services market. This included the monitoring and recording of grid frequency at greater than 31 times a second, amount of power being consumed by the EV fleet, amount of power being managed in accordance to the bid into the FRRS market, reaction times to grid frequency events, and EV fleet behavior during, going into, and coming out of a grid frequency event.

To satisfy the ERCOT data collection requirements, a data acquisition (DAQ) system was developed that monitored the electrical distribution circuit to each EV charging station. The DAQ collected voltage and current from each circuit every 25 ms, or approximately 40 times per second. The readings were summed to provide the total power consumption of the fleet. Additionally the current readings were combined with one voltage reading to compute grid frequency using a Fast Fourier Transform algorithm. The EV aggregation system also computed the bid capacity by summing the power readings from the subset of chargers that were computed to be participating in the bid since the last 25 ms increment. The combined data readings, as well as the computed frequency were logged into a telemetry file every 25 ms. These files were saved and downloaded from the system after each bid hour.

Methodologies to determine the direct benefits of this system to increase wind energy reaching the grid are beyond the scope of this project. The primary focus was to prove that EVs can be used with the grid in a manner that would increase wind energy use. Those benefits are realized by a fleet that can successfully regulate their charge rate in accordance to grid frequency, thus preventing the need to provide additional power plant generated energy to provide additional energy into the grid. While the amount of wind energy actually on the grid doesn't change during a frequency decline, the amount of traditional power plant generation is affected in that it is not increased when frequency declines. Instead the amount of load represented by the vehicles is removed from the grid, freeing up that energy for other uses and maintaining the percentage of wind versus traditional generation that is currently on the grid. This means that more energy consumed by loads on the grid are satisfied by wind, and that less controllable energy generation from gas and coal plants is needed to supply that load. This in fact increases the consumption of wind compared to traditional, and reduces emissions since the traditional plants don't need to increase production and thus emissions.

9.5 Performance Results

This section covers the operation of smart grid technologies and systems, including the demonstration results; impact metrics and benefits analyses; and stakeholder feedback.

9.5.1 Operation of Smart Grid Technologies and Systems

The final system for FRRS fleet management was an autonomous system that ran 24/7/365. Each week, the bid schedule for the following week was uploaded into the system, setting its bid calendar. When a bid hour began, the system started monitoring power and computing frequency, deploying vehicles as needed to satisfy the bid. When the bid hour ended, the system entered an idle state until the next bid hour began.

The system consisted of three operational components:

1. Power monitoring and control system
2. Aggregation system
3. Remote access and data management system

For the purposes of this system, the following terms are defined:

- Deploy or deployment: turning off the EV chargers so that power is not able to flow to them.
- Undeploy or Undeployment: turning on the EV chargers so that power is able to flow to them.
- Setpoint: the lower and upper frequencies as determined by ERCOT for deploying and undeploying assets. For this pilot the deployment frequency was 59.98 Hz, and the un-deployment frequency was 59.99 Hz.
- Recall: same as undeploy.

The power monitoring component used a field programmable gate array to collect power values from each EV charger circuit every 25 ms, provide summated fleet power values, and compute grid frequency. These values were fed to the aggregation system. The control system component was listening for aggregator commands to deploy or undeploy vehicles. Upon receiving an aggregator command, the control system sent commands to the appropriate relays that then sent an electronic signal to the charger contactors to either open or close them, in effect “flipping the switch” on them to turn them on or off. The power monitoring system was also responsible for recording the data during bid hours for ERCOT validation.

The aggregation system contained the logic for managing the EV charger fleet in accordance to the bid schedule and the grid frequency. The aggregator’s first task was to determine if the system was in a bid hour. If so, then it next checked to see if it was already in a deployment to determine whether it should compare frequency to the deployment setpoint or the recall setpoint. It then looked at frequency and determined if it should issue a command to the chargers. Finally, if it was undeployed, in a bid hour, and

not at a deployment setpoint, the aggregator created a prediction of which chargers should be turned off in the next 25 ms increment of time, based on their individual power readings and the amount of power bid into the market. The aggregator ran on a 25 ms loop time to align with the power monitoring and control system. Its prediction algorithm provided the decision speed needed for deploying within 60 cycles of a frequency deviation beyond the setpoint. To summarize, the sequence of decisions made by the aggregator were:

- Determine if the current system time was within a bid hour
- Determine if the system was currently in a deploy mode
- Determine if frequency required a command and issue command
- Predict the next deployment if not currently in a deployment

If the current system time was not in a bid hour, then the aggregator sat idle.

The third component, remote access and data management, was a web-based component that allowed for remote management of the system. The entering and uploading of bid schedules was done through this component. Downloading of data files occurred automatically after each bid hour through the remote system. Changes to the configuration of the system were managed through the remote system, and could be uploaded and implemented while the system was running. Synchronization between the remote data directory and the local data directory was also managed by the remote system to ensure that data files were successfully downloaded before being deleted from the deployed system. With this component there was no need to access the deployed system locally; all system and data management was handled by the remote client. The remote access system used an SSL connection over a private VPN to secure the data transactions and prevent unauthorized access to the aggregation system. Access to various reporting and troubleshooting logs was also done through the remote access system.

9.5.2 Metrics and Benefits Analysis

After the project was completed, some specific metrics and benefits were defined. This section provides some insight into what those metrics and benefits are. They primarily revolve around two key concepts: 1) ability to participate in FRRS according to the rules outlined by ERCOT, and 2) the economic benefits realized from using an EV fleet for FRRS. The operational metrics include:

- Power response to FRRS signals. This metric measures the EV fleet response to an FRRS signal based on an appropriate power level and maintaining that power level for the defined time period without significant deviation.
- Frequency deviation detection. This metric involves capturing frequency from the grid at 32 Hz sampling rates and the detection of deviations at a resolution of 0.01 Hz.
- Time to implement FRRS signal. Participation in the ERCOT FRRS pilot requires implementation at either the specified power level or at full offered power with 60 cycles (1 second) of either notification via ERCOT signal or detection of frequency deviation through power line monitoring. This metric captures the implementation time.

- Percent of successful deployments in offering period. This metric indicates the success rate for meeting deployment obligations during the offering period (1 hour). The metric combines the ability to implement within 60 cycles and the ability to sustain deployment to within 95% - 110% of obligated capacity, both of which are required for successful response.
- Percent of successful deployments during pilot. This metric compares the results of responding to all of the offering periods during the pilot.
- Economic impact or benefit to fleet owner. This metric compares the revenue generated through participation in FRRS versus any penalties that would have been assessed by ERCOT as a result of unsuccessful deployments. This metric was compiled for each offering period, and for the pilot period.

9.5.2.1 Operational Metrics and Benefits

Ultimately, the economic benefit to the fleet owner will be defined based on not only potential revenue but also considering the costs to configure a fleet for participation and any operational impacts as a result of participation in the FRRS offerings.

These next sections discuss the defined metrics. Data was collected from over 150 simulated and actual bid hours, representing over 21,500,000 data points taken between December 11, 2013, and February 28, 2014, the end of the ERCOT pilot. Simulated bid hours represent where the system was set to deploy 10 kW of power, allowing the data collection, computation, and recording components of the system to run without requiring a large number of vehicles to be on the chargers. Actual bid hour represents where the entire fleet was available and the deployment power was set to 100 kW, the minimum that could be bid into the ERCOT market. As it turns out, 147 of the 150 hours were simulated. The issues causing this are discussed in the lessons learned section of this document.

9.5.2.2 Power Response to FRRS Signals

For each simulated and actual bid hour enacted by the system, the system responded to 100% of the frequency deviations at the specified deployment setpoint. Each frequency event, defined as when the frequency declined below 50.98 Hz, was responded to by the system recognizing the frequency and sending deploy signals to the chargers. The system recalled from a deployment 100% of the time when the frequency subsequently increased to above 59.991 Hz. In no instances was it found that the system did not maintain a deployment for either the entire frequency decline event period, or the end of the bid hour, whichever came first. For deployments that crossed hour boundaries in back-to-back bid hours, the system successfully maintained the deployment across the hour mark without deviation.

9.5.2.3 Frequency Deviation Detection

Each 1-hour data file that was collected by the system was found to contain 144,000 data readings. This correlates to 1 reading every 25 ms, or a data collection rate of 40 Hz, exceeding the requirement for 32 Hz data capture. The system records frequency at .001 Hz precision, exceeding the standard of .01 Hz.

This was calibrated in the lab using a calibrated signal generator. During system qualification time and actual bid hours, system data files were validated by ERCOT using their readings and were found to be within expectations with their frequency readings. It should be noted that frequency is not consistent at the .01Hz level across the grid and that readings taken in any one location can be affected by local variations in the grid, such as nearby heavy equipment like arc welders or dynamometers. In fact one aspect of the FRRS program was to automate the deployments based on local frequency readings in order to increase the speed in which resources react and more quickly mitigate the effects of frequency variation than can be done through detection and dispatch from a central point.

9.5.2.4 Time to Implement FRRS Signal

The requirement was to implement an FRRS deployment within 60 cycles of detecting a frequency decline where frequency dropped below 59.98 Hz. The system successfully deployed to each frequency event within 450-600 ms 100% of the time.

9.5.2.5 Percent of Successful Deployments in Offering Period

For each deployment power specified (either 10 kW or 100 kW) the system was able to achieve 100% deployment of whatever capacity was available within 60 cycles with a deployment power level of 95% - 110% percent of obligated capacity. It should be noted that most of the hours were simulated at low deployment power levels (typically at 10%, although other percentages were also used in simulation). The system consistently deployed either maximum available capacity or obligated capacity in the 95% – 110% range, whichever was lower.

As it turned out during this pilot period, there were extensive mechanical problems with the vehicles that could not be fixed due to the vehicle vendor not honoring maintenance commitments in a timely manner. This caused issues that prevented full obligated capacity being available, requiring the actual bid hour to be converted into a simulated hour.

9.5.2.6 Percent of Successful Deployments during Pilot

Because of ongoing maintenance problems with the EV fleet, only 3 hours within the pilot became actual bid hours, and of those 3 only 1 hour was completely successful (shown below). For the other two hours, it was determined in a post-mortem analysis that fleet processes changed the parameters of the fleet. For example, on one day, an ice storm hit the Dallas/Ft. Worth area and so several of the trucks did not go out for their runs. As a result they were fully charged when the bid hour arrived and thus were not drawing charge from the grid, resulting in total power consumption for the fleet less than 100 kW, the minimum obligated capacity for FRRS services. While the system successfully deployed the remaining capacity (approximately 70 kW) during that bid hour, the fleet as a whole did not successfully meet the requirements for the bid hour since it did not show a deployment of 100 kW of load being removed from the grid during a frequency event. In the other 1 hour instance, a vehicle was charged in the shop during the day after its deliver run in order to be used for driver education. As such the vehicle

achieved full charge within 10 minutes of the bid hour and then stop charging, reducing the total fleet capacity to below the 100 kW threshold. Since two of the other 12 vehicles were out for maintenance during the entire pilot time, having even 1 vehicle that did not adhere to its normal schedule took the fleet out of consideration for deployment.

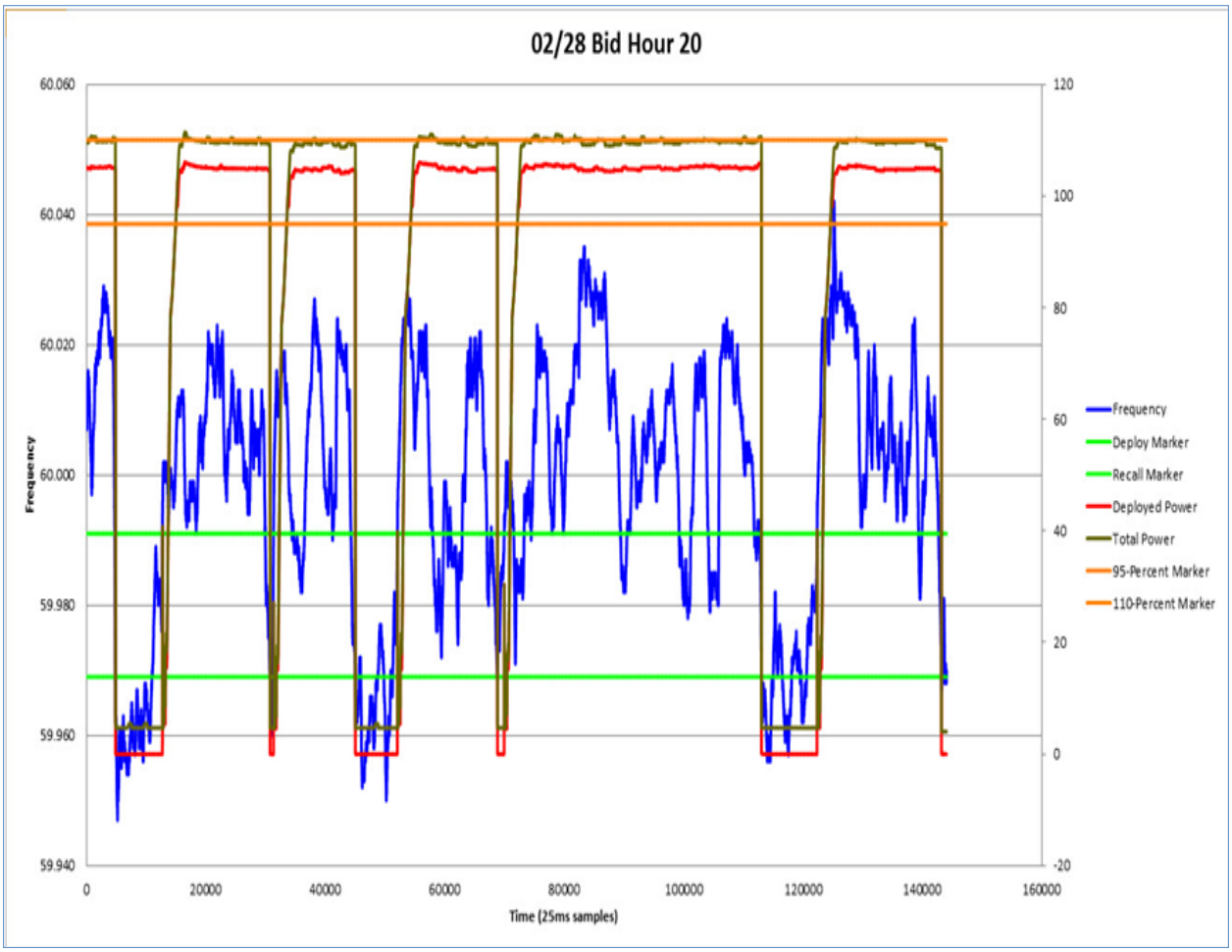


Figure 204. Successful Deployment of FRRS

9.5.2.7 Economic Impact or Benefit to Fleet Owner

In the ERCOT market, given the current market rules, and with energy being relatively inexpensive in Texas, there is little to no economic benefit that can be realized by small fleet owners by participating in the FRRS market. As a part of this project, the Team looked at ancillary service prices paid for frequency regulation services in ERCOT for 2013 and up through March 2014. Average frequency regulation prices paid per 100 kWh, by hour, for 2013 are shown below.

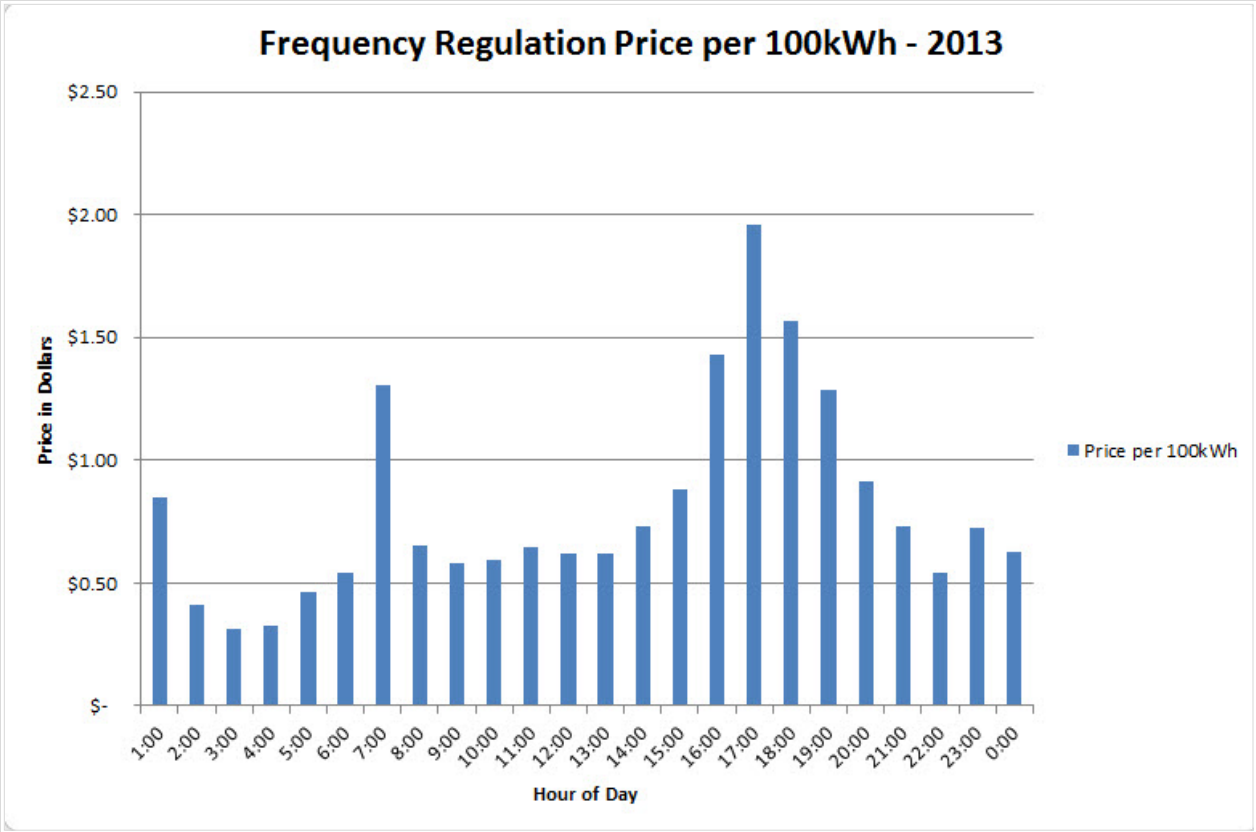


Figure 205. Average Frequency Regulation Price Per Hour Per 100 kWh in ERCOT for 2013

In 2013, there was a specific peak in frequency regulation pricing in the 6:00 a.m. - 7:00 a.m. time period, and a broader peak from 3:00 p.m. - 8:00 p.m. For the fleet in this project, the broader peak aligns well with the typical idle period of the vehicles, which do their deliveries between midnight and 10:00 a.m. and are loaded during the afternoon hours. Starting at around 5:00 p.m. they are all sitting on the chargers loaded and waiting for their next delivery run. The average price per 100 kWh, however, is relatively low, around $.80 - $1.95 per 100 kWh. Looking at a potential of 4-hours per day that the project fleet could realistically and reliably participate in the FRRS market (from 5:00 p.m. – 9:00 p.m.), the following table shows that for 2013 the average potential monthly revenue for a 100 kWh fleet was $135.01.

Table 55. 2013 Potential Revenue from Participating in the 5:00 p.m. – 9:00 p.m. Timeframe

Hour Ending	$ Per 100 kWh	30 Days $
18:00	$1.57	$47.01
19:00	$1.28	$38.50
20:00	$0.92	$27.50
21:00	$0.73	$22.00
	Total	**$135.01**

Up through March 15, 2014, as shown below, the peak moved substantially, and also the price for frequency regulation services increased significantly.

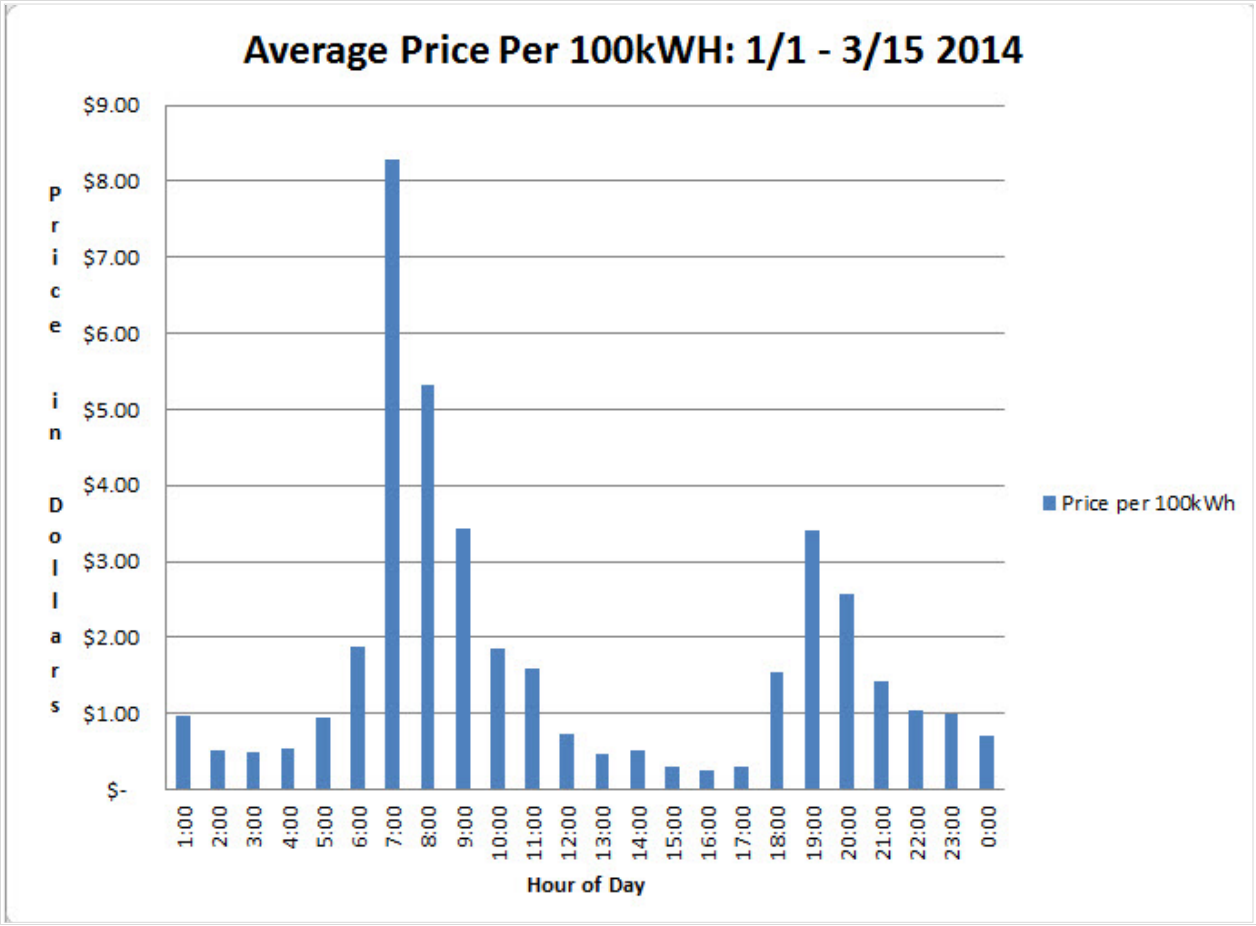


Figure 206. Average Frequency Regulation Price per Hour per 100 kWh in ERCOT for 2013

While the morning opportunity was not available for the project fleet due to their delivery schedules, the increase in price does have a positive effect on potential revenue, as shown below.

Table 56. 2014 Potential Revenue from Participating in the 5:00 p.m. – 9:00 p.m. Timeframe

Hour Ending	Price per 100 kWh	30 Days $
18:00	$1.55	$46.53
19:00	$3.40	$101.97
20:00	$2.58	$77.27
21:00	$1.42	$42.51
	Total	**$268.29**

The data shows that for 2014 the potential revenue was double that which was achievable in 2013. Even so, this was not sufficient to offset the costs of equipment, installation, and ongoing expenses. For example, all assets must go through a QSE to participate in market services, so there is a monthly price assessed by the QSE for maintaining the communications links to the asset and for representing them in the market (placing bids). The price for the QSE services for this project was $2,000 per month.

In order to be profitable in the current market structure, the fleet would need to be of an approximate capacity size of 1 MWh, however that is very unlikely. Alternatively, if the fleet could be flexible in its scheduling, it could place bids in more opportune time periods, reducing the size of the fleet needed to participate successfully from 1 MWh to 400 kWh, as shown below.

Table 57. 2014 Potential Revenue from Participating in the 6:00 a.m. – 11:00 a.m. Timeframe

Hour Ending	Price per 100 kWh	30 Days $
6:00	$1.89	$56.63
7:00	$8.28	$248.53
8:00	$5.33	$159.89
9:00	$3.42	$102.72
10:00	$1.86	$55.75
11:00	$1.60	$47.91
	Total	**$671.43**

There are also the potential jackpot scenarios, catching an hour where the price of energy skyrockets due to grid congestion. While this effort was operational in 2014 there were at least 4 such hours where the cost per MWh ranged from $284 to $4,999. Those hours were normalized in the calculations to remove skewing of the data.

This project, as stated earlier, was conducted in a market where energy is relatively inexpensive and plentiful, and the market is structured for large, stationary generation resources. In other markets, such as California where the price of electricity is significantly higher, the economics would be much more favorable.

9.5.2.8 Build Metrics

Build metrics are related to equipment types, numbers and costs. As identified earlier, the Team purchased various NI hardware and software to implement the FRRS capabilities, and these purchases amounted to about $15,579.

9.5.2.9 Impact Metrics

Impact metrics are related to reductions in energy use which also drive reductions in pollution emissions. One could presume that using fleet EVs to reduce the need for traditional generators

providing regulation service would also reduce fossil-based fuels and hence pollution emissions. However, the Team has no information relative to the types and sizes of potential reductions in traditional generation that could be achieved by using EV fleets to provide FRRS.

9.5.3 Stakeholder Feedback

ERCOT validated the successful delivery of FRRS using the fleet electric vehicles, and referenced the participation of this project in a review of its FRRS pilot [41].

9.6 Conclusions

This section covers projections of demonstration and commercial scale system performance as well as lessons learned and best practices.

9.6.1 Projections of Demonstration and Commercial Scale System Performance

From a technology perspective, the technology built to enable the fleet to participate in FRRS services according to the requirements of the FRRS program works reliably and consistently. From installation in early December 2013 through the end of February 2014, the EV aggregation system ran 24/7 without missing a reading or event. The aggregation system was built with future deployments in mind and is small, self-contained, requires minimum disruption of the existing electrical system, and is built of low-cost but highly reliable and accurate off-the-shelf components. Since the system was built with the same components used for other smart grid applications such as synchrophasor units it is expected that it would continue to run for many years without interruption in normal operating conditions. The system is easily replicable; new systems for managing up to 12 vehicles could be created and installed in 1-2 weeks, plus shipping times for ordered components. Enabling the system for larger vehicle fleets would require additional hardware and some minor coding changes, but could be easily and inexpensively done. What would be beneficial is to estimate how large of a fleet would be required for the effort to be profitable. Since the aggregation costs are not very sensitive to scale, and the QSE costs would probably be the same regardless of scale, such an addition would be informative.

9.6.2 Lessons Learned and Best Practices

While executing this project, the Team did learn some lessons and best practices, and those are shared herein.

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http://www.ercot.com/content/meetings/tac/keydocs/2014/0327/11._TAC_Final_Report_on_FRRS_Pilot_as_of_3-25-14.ppt

9.6.2.1 EV Fleet Size for Adequate Market Participation

This pilot was conducted using a vehicle fleet of 12 vehicles and 12 chargers. Each vehicle consumed between 9-11 kW during normal charging, for approximately 4 hours, tailing down in the last hour as the battery reached full state of charge. The minimum power requirement for participating in the ERCOT FRRS pilot was 100 kW, meaning that the program had two additional vehicles over the minimum limit in which to satisfy a bid hour. The project could have had 3 good bid hours each day based on the above conditions, but the Team learned that having 100 kW of power available was a challenge due to several unforeseen factors.

One of the primary reasons for not always meeting the 100 kW power limit was vehicle maintenance issues. These vehicles are an older generation model, so there were issues with the vehicles requiring maintenance, and not just typical hardware mechanical issues; several vehicles had software issues that affected their ability to accurately charge. Therefore, at times, there were only 7 - 8 vehicles available so the fleet could not deliver sufficient power to satisfy the FRRS delivery requirements.

9.6.2.2 EV Fleet Behavior and Processes

Another issue to be considered for the future is fleet behavior and processes. This project had access to extensive vehicle route data and vehicle charge data, and was able to develop a bidding scheme for when the vehicles would be optimally on the chargers pulling full charge. Processes at the facility, however, frequently interrupted the planned schedule. Issues such as shop charging (using a non-aggregated charger in the shop to charge a vehicle) for driver education or after scheduled maintenance would result in a fully charged vehicle being in place during the bid hour when the expectation was that it would need to be charged. Weather, which prevented some vehicles from making deliveries, caused problems because the vehicles were not discharged as anticipated. Loading schedules were occasionally flexible, resulting in vehicles being removed from chargers when they were expected to be available. There were also vehicles left at the loading dock for extended periods after they were loaded instead of being returned to the chargers. All of these typical operational incidents demonstrated that analyzing just fleet route and charging statistics is not sufficient for planning participation in an ancillary service market, but rather it is important to understand the fleet processes so that behavior can be incorporated into the equation.

9.6.2.3 Market Rules for Participation in Ancillary Services

The current ERCOT market rules are designed for stationary, large scale generation facilities where generation is their primary, and in many cases, only mission. ERCOT did define a lower power capacity limit for participation in the FRRS service (100 kW vs. 1 MW normal) pilot, however, having to meet a defined minimum power level with aggregated small scale assets can be a real challenge.

Compounding this challenge is the requirement that all bids be entered into the market 1 week in advance, meaning that a fleet owner has to predict the status and availability of their vehicles for the

following week. Considering the nature of the vehicles, and all the things that can happen to a vehicle when it is driven (from maintenance to accidents to not being used on a given day), it would be best if a fleet owner has a significant over-capacity on-hand (in the order of 50%) in order to meet unforeseen events. Even then that does not guarantee sufficient availability; it just statistically minimizes the more common problems that can occur.

The market structure for frequency regulation is first and foremost a pay for capacity, where market participants are paid for the capacity they make available. What they are really paying for is idle time of the asset, assuming that it is doing nothing during that period of the bid and so the asset owner is getting paid for making the asset available "in case it is needed". FERC Order 755 attempted to introduce an additional payment, pay for performance, in order to further reimburse assets that are actually used in an event. However, pay for capacity remains the primary reason for making an asset available for frequency regulation. For the EV fleet owner, this means an adequate number of vehicles must remain in position and be available just in case their service is needed during that bid timeframe.

Two recommendations are put forward for future EV fleet implementations for FRRS or other types of capacity-based services.

1. Consider over-sizing the participating fleet to incorporate the normal (90%) cases that can reduce fleet size for the bid duration due to maintenance, accidents, use outside of normal practices, or other statistically predictable conditions.
2. Change the market rules to pay EV fleets (or other aggregated small scale assets) based on performance without the requirement for a known capacity size to be specified in advance, and allow for shorter duration delivery of services.

Over-sizing, while computable based on typical statistics methods and databases on vehicle performance and behavior, would limit fleets from participating unless they were of substantial size. For example, in the ERCOT market which has a limit of 100 kW, an oversized fleet where vehicles charged at a normal 10 kW would be around 15 vehicles, in order to ensure that 10 would be available for any bid hour to meet the capacity requirement.

Changing the market rules would require two fundamental changes: changing the pay structure to allow for increased pay for performance as the only payment to EV fleets or pay for capacity for dynamically-sized power assets like a fleet; and increased telemetry to the ISO to know what is available in any given moment for the service.

A change in the payment structure could allow for increased participation of EV fleets in the market. Currently the payment structure in ERCOT is for an hour; however, it could be reduced to 5 minute increments based on telemetered data. This would allow the fleet to be able to participate for more hours of the day, and participate every day no matter what their vehicle usage is.

Another way the payment structure could be changed would be to pay for performance only, increasing that payment to justify participation. In this instance the fleet owner only gets paid for assets that actually get deployed, but at a rate that incentivizes making them available whenever possible. Telemetering the current fleet size data to the ISO would allow them to know what is available at any given time for their short-term planning purposes.

The primary argument for a dynamically-sized asset would be the ISO's need to know what assets they have available to respond to an event, particularly an N-1 event. Because of the number of assets there are in a grid, the computations to arrive at the next dispatch decision take several minutes and so cannot or do not run in true real time. This project has shown that the fleet capacity does not change much during the bid timeframe (hour); rather, it changes during the day or days preceding such that it can be significantly different from the bid prediction made a week earlier. Minor changes, such as a vehicle plugging-in or being unplugged, can be statistically calculated and managed in the wider picture of the whole grid.

9.6.2.4 Market Rules for Bidding into the Market

The current process that was used for the ERCOT FRRS pilot was similar for other frequency regulation services designed for stationary assets; submit bids one week in advance for the following week. With a gas turbine generation plant that never moves and has a sole purpose of producing power, or a large battery system that is stationary, this should be an easy exercise. For a mobile asset that has a second primary purpose where lots of things can happen to the asset outside of energy generation, this becomes a difficult challenge.

The ERCOT FRRS pilot did allow for canceling a bid 24 hours in advance, but even that is not always sufficient. For example, the fleet owner bid hours were in the evening. During the day, one of the vehicles was charged and used for driver training after its route. The training did not drain the battery nearly as much as the normal delivery route does and as a result the vehicle reached full state of charge during the bid hour and thus became unusable for the FRRS service. Here again, having extra capacity available to bid would resolve this type of situation.

Since EVs are dynamic energy assets, they need a more flexible process for bidding into the market. Some markets allow for bids 1 hour in advance. This would be a more appropriate method for EV fleet participation in FRRS with a better guarantee of success for the bid hour.

9.6.2.5 Market Rules for Connecting to the Market

In ERCOT, QSEs are the only ones who can actually bid into the market. As a result, with any intermediary in a process, there is a fee associated with their service. QSEs actually communicate with ERCOT through telemetry, and they are responsible for setting up, maintaining, and getting telemetry from any assets they manage. This means there is a set-up cost for a fleet owner to connect to the QSE, and ongoing maintenance/connection costs for the telemetry link. These costs can be excessive for

small fleet owners, and make it difficult to realize positive net revenue from FRRS. Until the conditions change, this will remain a significant barrier to participation by small assets like an EV fleet, especially in Texas where electric prices are relatively low.

10. SUMMARY AND CONCLUSIONS OF THE CCET PROJECT

10.1 Summary

CCET engaged some 22 firms over a period of five years to carry out seven related but separable demonstration projects, all devoted to helping address the challenges of integrating more wind resources into the electric grid. These projects were all carried out on live operating systems in the market place, rather than isolated laboratory experiments. The projects were not developed in a vacuum based on an ideal optimal mix of technology options. To the contrary, they leveraged the availability of technologies already in or entering the market in Texas, such as synchrophasor systems, cyber security systems, the build out of the transmission system, smart meter deployments, consumer portals, wind generation and test facilities, home energy monitoring systems and electric vehicles in residential solar communities, and electric vehicle fleets. More importantly, these projects included direct participation by market stakeholders, including ERCOT (the ISO), four TDSPs, one municipal utility and one electric cooperative, one REP, and sixty plus consumers.

Although the focus of the project was on mitigating the challenges of ever-increasing renewables integration into the electric grid, the project demonstrated the benefits of deploying smart grid technologies that are to become the mainstay of the grid of the future, and to identify both issues and solutions that could provide valuable insight to stakeholders and decision makers at the local, state, and national levels. Summarized below are the key highlights of and contributions made by this CCET project:

- **Synchrophasors**. This technology includes a wide array of monitoring, data processing, and wide area visualization systems to help utilities and grid operators better manage the electric grid to improve its reliability. It is focused specifically on providing improved, real-time monitoring of grid conditions, and providing better tools to help diagnose and respond to issues surrounding the intermittent nature of renewable energy sources providing power to the electric grid. As a result of this project, the state has greatly expanded its deployment of synchrophasor technologies which existed only as a “starter” system in 2009, and dramatically improved monitoring and early warning capabilities. Originally targeted to provide 13 PMUs, the participating utilities quickly discovered the tremendous benefits provided by PMUs, and they chose to add an additional 60 PMUs, which has significantly improved coverage across the state of Texas. Monitoring systems, such as RTDMS, and offline analysis tools, such as the PGDA, have been dramatically improved, and the participating utilities now all have and use those tools which are currently more

commercially viable, as a result of this project. Also, to assist generator owners and grid operators with NERC standards compliance, a new tool for validating generator models has been developed. More importantly, ERCOT has become one of the first ISOs nationwide to employ wide area visualization of PMUs as a tool to assist control room operators in more quickly and effectively diagnosing and resolving potential grid stability issues before they become a problem.

- **Security Fabric**. Building on the success of the CCET synchrophasor efforts, Intel/McAfee chose to deploy and demonstrate how its latest cyber security protection scheme could be employed to protect critical synchrophasor assets. This Security Fabric cyber security hardware and software solution was deployed on a parallel synchrophasor network to verify and validate that the communications network, the critical phasor data streams, and the important wide area visualization software could be better protected without the need to modify existing systems. Intel/McAfee worked with EPG and NIST to develop a set of test requirements based on NISTIR-7628. Using an independent third party, in this case TTU, cyber security experts tested the integrated synchrophasor and Security Fabric system to verify there was no performance degradation, that it complied with the relevant NISTIR-7628 requirements, and that it did not introduce new vulnerabilities. The testing accomplished its goal and did identify a few vulnerabilities, most of which were due to configuration issues. As a result, Intel/McAfee has corrected those identified Security Fabric vulnerabilities, making it an even more viable cyber security protection solution and commercial offering, not only for protecting synchrophasor systems, but also any critical utility infrastructure.
- **Time-Of-Use Pricing**. This CCET project was able to leverage an existing residential solar community with homes equipped with circuit-level monitoring systems, and homeowners, many of whom possessed electric vehicles (another huge plus), who were committed to energy efficient lifestyles and technology, and who were already accustomed to participating in various types of grid-improvement behavioral experiments. The CCET project goal was twofold: 1) evaluate behavioral response to TOU pricing in energy-efficient smart-grid communities, and 2) adhere to its theme of wind integration by introducing the first ever TOU pricing program based on wind. The first goal was addressed with a very typical CPP program that spanned the four summer months, June to September, and involved higher prices from 4 p.m. to 7 p.m., but only on designated critical days. The second TOU pricing program was carried out daily over five winter months, November to December, and March to May. It involved very inexpensive energy prices at night, from 10 p.m. to 6 a.m. Again, the purpose of these programs was to measure the willingness of participants to change their behavior in response to the pricing programs, and the results proved to be very interesting. For the CPP portion, the customers responded by reducing their usage, primarily HVAC, an average of 15.27% during the first summer, although they were much lower, only 6.15%, the second summer. The lower, latter figure does indicate some customer fatigue with pricing programs, but, more importantly, surveys indicated that the reduced amount appears to be less in comparison with some other experiments

because customers had made permanent behavioral changes and live in highly efficient houses, so there was less they could reduce during the critical periods. For the wind-enhanced pricing portion, participants managed to shift an average of 4% of their normal usage to overnight hours, and importantly to move their EV charging away from the peak late afternoon and evening hours to the high wind production hours. While 4% of total load may appear to be small, there aren't that many activities that can easily be shifted to those hours and a 4% shift makes a significant impact on the use of wind capacity when it is most available.

- **SMT Portal and Demand Response**. This CCET project focused on demonstrating that REPs in Texas could leverage the capabilities of the SMT Portal together with the utility AMI networks to dramatically improve the effectiveness of their demand response programs. Before this effort, REPs who offered demand response programs were relying on remote control of in-home devices, primarily gateways and programmable thermostats, to reduce usage when needed, but were only achieving about a 55% success rate using a broadband-only solution. The CCET project goal was to demonstrate that the utility AMI networks could be utilized as a second delivery path for demand response controls, and that the SMT Portal could be leveraged to deliver those messages across the AMI networks to the in-home devices. The SMT Portal, jointly funded by the three largest TDSPs in Texas, who also happen to be participants in the CCET project, represents a unique opportunity to assist consumers and REPs in reducing energy usage, especially during critical events. The Portal is used to house all of the smart meter data for more than 6 million customers located in these TDSP service areas, is used for settlement purposes by ERCOT and the utilities, and provides historical energy use information to assist consumers in better managing their energy use. Additionally, the Portal can be leveraged to distribute information and commands to the smart meters over the respective AMI networks. For this project, the participating REP could use these capabilities to deliver their demand response messages to in-home devices over the AMI networks as well as the typical broadband path. Ultimately, the project proved that the SMT Portal capabilities could be leveraged to improve demand response results, but not without first overcoming challenges, such as incompatible legacy equipment that couldn't be remotely upgraded, lack of SEP-compliant devices that could pair with the home's meter to receive the necessary messaging, and a cumbersome process for configuring and registering devices to accept messages over two different communication paths. In terms of reductions, actual demand response events demonstrated reductions per household of from 0.55 kWh to 1.0 kWh, and that is based on a single 15-minute cycling of the home's HVAC unit. Economically, the demand response events demonstrated an annual value proposition (based on just 10 events per year) of between $27 and $89 per customer, depending on energy prices. However, considering the cost of procuring and installing a gateway and programmable thermostat in a home is about $300, the payback period is anywhere from 4 to 10 years. Given that Texas is a competitive retail market, and customers can swap REPs at will, equipping all homes with these devices is too much risk without other financial incentives. However, if the investment is going to

be made anyway, the REP (or utility in a different market) should definitely consider the benefits of leveraging the AMI network as a second communications pathway to improve demand response results. Prospectively such a dual path system might be available at a low incremental cost with new installations and thermostats with a low-cost chip addition.

- **Solar Monitoring**. Solar represents another huge source of renewable energy, and provides a good companion to wind production because of the daily non-coincident timing of production but, like wind is also a source that is intermittent. Residential rooftop solar is becoming more prevalent, and this significant increase in solar adoption has raised some concerns for utilities across the nation. The CCET project goal was to evaluate variations in electrical performance parameters on residential distribution circuits and behind the meter, such as excursions in load, power factor and voltage, and harmonic distortion effects. These issues can arise from multiple interacting and dynamic factors, including distributed solar generation cancelling utility kW load, variable solar PV generation, increasing harmonic current drawn from modern home appliances, etc. The project first focused on comparing two neighborhoods, one with a high concentration of rooftop solar and one with almost no solar. The second effort looked at the secondary side of two residential transformers to monitor power quality parameters, solar PV production, and net load served by the utility for 18 homes. For the first effort, six 35 kV underground residential distribution circuits were equipped with monitoring devices to better assess the dynamics of solar and communities as they interact with the electric grid. The focus was on measuring and calculating total harmonic current and voltage distortion (THDi and THDv, respectively), power factor (PF) and voltage at the distribution level in the two neighborhoods. The solar monitoring results identified a particular challenge of harmonic distortions from homes with solar during certain time periods, especially during the shoulder months, March to May, and October to November, in Texas when wind production constitutes a significant share of generation. These harmonics can cause problems like degradation of conductors and insulating material in consumer appliance motors and utility transformers. For the second effort, at the transformer level, it was noted that the distortion current stays approximately the same during the entire day with variations that can be attributed to device usage, not solar production. During the daytime, solar capacity exceeds home load much of the time, driving the load on the utility negative, with oscillations due to cloud cover and home appliance operation (generally HVAC). During periods when the utility load is cancelled and approaches zero, for periods from minutes to an hour at a time, the THDi spikes are very high, up to 1000%. This is due to the very low amounts of fundamental current supplied by the grid, not the solar production adding distortion to the grid. The general conclusion of this monitoring effort is that for homes with solar capable of providing all of the home's power use during a sunny day in the shoulder months, the harmonic distortions will be high and that vendors and grid operators will need to consider remedies as the incidence of rooftop solar communities expands.
- **Frequency Regulation using Fleet Electric Vehicles**. Frequency regulation is a grid ancillary service that allows electricity generators, including those with large battery energy storage

systems, to bid services into the energy market to assist in maintaining the electric grid frequency at 60 Hz. Providers of this type of service guarantee to be able to adjust generation and/or load during a specified time period by either ramping up or ramping down production or reducing load in order to maintain the balance of generation/load on the grid, and thus the frequency. ERCOT studies have determined that the need for fast response resources to provide regulation up or regulation down services increases as the concentration of renewables, such as wind, grows on the grid. While the overall CCET project was ongoing, ERCOT carried out a pilot project to find qualified resources willing to participate in an ancillary service market called Fast Response Regulation Service (FRRS). The response requirements for this FRRS pilot basically limited participants to those with energy storage systems (batteries). Two large battery systems participated in the ERCOT pilot, and CCET seized on the opportunity to demonstrate that FRRS could also be provided by aggregating electric vehicles (EVs) without a significant incremental investment (since large-scale batteries cost millions of dollars). The CCET project leveraged the resources of Frito-Lay in Fort Worth to provide the EVs while other team members developed the software and hardware capability to aggregate a set of 11 Frito-Lay trucks so they acted as one resource capable of providing at least 100 kW of FRRS (minimum requirement). The Frito-Lay trucks typically begin deliveries about 3 a.m., return to home base about noon, and remain at that site for battery charging and cargo loading until the next morning. This schedule was an ideal match for participation in FRRS since the trucks would be available to deliver the service when it was needed, and doing so would not detract from the primary duty of the trucks. This effort entailed the development and demonstration of an EV aggregation control system to support regulation-up services in response to an ERCOT signal or a detected deviation of grid frequency of greater than .09 Hz. The first task was to build a custom power meter that could monitor 12 EV circuits after the panel box, and this solution was achieved for under $20,000 versus over $100,000 that would have been spent on individual power meters or redesigning the electrical panel box. The second task was to develop a software aggregation control system able to manage the fleet in accordance with the FRRS parameters. Other tasks included establishment of a DNP3 interface over a VPN for providing telemetering information; development of a solution to collect, correlate and deliver the required meter data files to ERCOT; and installation and deployment of other hardware interface and control devices. Leveraging the CCET capabilities, the EV fleet at Frito-Lay successfully bid into the ERCOT FRRS market, delivered the required FRRS when needed, and received compensation for the service. This was the first time EVs had successfully participated in an ancillary service in ERCOT, and the first time a fleet owner had received payment for providing FRRS. The project results demonstrated that, for the first time in the U.S., EVs could be aggregated as an effective resource for grid management, and could do so without interfering with the primary vehicle purpose.

- **Utility-Scale Battery on a Distribution Network**. Battery storage is another important technology for the electric grid especially when operating as a companion for wind generation as well as for generally supporting consumers, utilities, and the grid operator..

When charged, batteries can perform a wide range of needed grid functions, including outage support, peak shaving, and frequency support. When uncharged, batteries can be used to store excess energy, and then deliver it instantly when needed, and during such cycles also provide frequency support . For this effort, CCET was interested in assessing how a battery energy storage system (BESS) could supplement wind farms to improve wind-power efficiency. The overall project objective was to demonstrate the ability of a BESS to perform various grid functions, especially those needed to support intermittent renewable resources, such as wind. A secondary objective was to determine the economic viability of deploying these systems to support actual grid operations. Typical projects deploy large-scale battery systems on transmission networks or small-scale batteries in neighborhoods. The CCET project was unique in that it chose a utility-scale battery (1 MW/1 MWh), but deployed it on a distribution network managed by an electric cooperative. Additionally, it had access to a wind test facility in Lubbock, so the BESS was deployed in tandem with wind turbines. While the BESS was being manufactured, Texas Tech researchers extensively modeled the wind turbines, and the related substation loads, and following installation of the BESS, the battery system, and then simulated a full range of system behaviors involving a set of battery functions. These system models were then validating during the course of the project, when the BESS was tested to demonstrate its ability to optimize grid reliability by compensating for the intermittency of wind, storing power during high wind- and providing power during low wind-conditions, reducing the daily peak load on the grid (and thus reducing demand charges), providing a ramping capability to stabilize the grid, and to provide frequency regulation services to maintain the grid at 60 Hz. The BESS performed all of these functions extremely well. What remained was to determine the economic viability of investing in battery systems, with a financial return on investment provided by performing these grid functions. The result of numerous economic evaluations determined that there are only a few special conditions where a utility or generator could recover its full investment by performing the defined grid functions without subsidies, but the benefits to the combination of grid operators, utilities, and ultimately customers can definitely outweigh the costs of a BESS. As battery technology improvements continue to drive costs down, and the regulatory rules get modified to more completely reflect the value of storage, battery systems will be more widely deployed, especially in support of renewable generation resources, and on distribution grids.

10.2 Conclusions

As noted above, the CCET project successfully demonstrated how various smart-grid technologies can be used to significantly improve grid operations, not only around the challenges of large-scale wind integration, but more generally. It is expected that market stakeholders, in Texas and across the nation, will leverage the results of this project to address and mitigate the potential issues associated with increasing levels of renewable resources, such as wind and solar. In Texas, ERCOT will continue overseeing and expanding the synchrophasor system, South Plains Electric Cooperative and Texas Tech University will further leverage the battery capabilities, REPs in the ERCOT market

will learn from the consumer behavior responses to develop more enticing pricing programs and improve DR capabilities, utilities will exploit the Intel/McAfee Security Fabric suite of products to better protect their critical electric assets, and large companies and potential aggregators will make use of the FRRS work in developing improved benefit streams for EV truck and potentially residential EV owners. Across the nation, the unique nature of the CCET project will provide information, insight and lessons learned to assist utilities and other grid operators in better managing and protecting their grid assets to deliver a more reliable and robust set of services that benefit consumers while leveraging available renewable resources, such as wind and solar.

Demonstration projects are not typically expected to result in the delivery of solutions that are market ready, although the intent is always to provide reliable results that will lead to such outcomes. While other demonstration results are also important, the CCET project has gone a long way in the direction of delivering products to the market. The synchrophasor system was developed from only a small "starter" system of three PMUs to a mature system of 94 PMUs deployed across Texas, with full associated monitoring capabilities at both ERCOT and the participating utilities, and the stakeholder process at ERCOT is near completion of protocol changes that will put the technology firmly in the control room as a grid operator tool; that is a condition equivalent of being in the market. The project also provides a solution for validating generator model parameters that are certain to be needed to meet NERC guidelines. Further, Intel/McAfee is, as this report is being published, holding a press event in Washington, D.C. to launch the Security Fabric technologies developed and tested in this project. The BESS provides important results from a utility-scale battery system operating on a distribution system to complement the learning from two large-scale Texas battery systems operating on a transmission system, thus rounding out much needed information about ownership, location and functionality of battery systems that will feed the policy debate for fully defining the role of storage in the Texas markets. The FRRS project demonstrated the key changes that will need to occur in order to bring this capability for grid regulation into the Texas market when EV fleets become more prominent.

Attachment 1. Baselining Analysis 2012

Baselining Analysis 2012

Discovery Across Texas Project

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Song Xue

May 28, 2013

External Version

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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 {tate 9stimator /omparison

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 !nalysis for ±oltage and !ngle 5ifferences

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 System[1] (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 8,060259, and US Patent 8,401,710.

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.

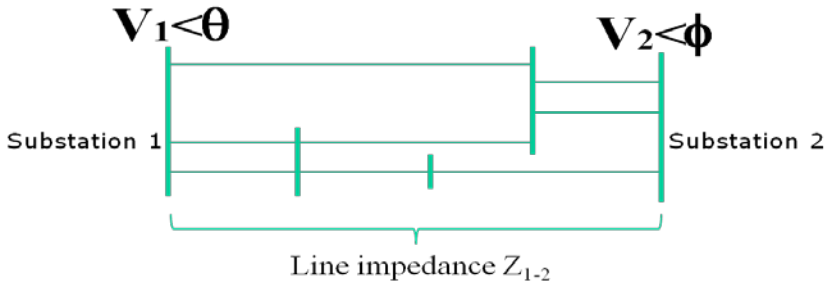
Data availability for state estimator data was low. ERCOT produces state estimator cases every 5 minutes for a total of 105,120 possible cases per year. EPG received about 16,000 cases which represent about 15.22 % data availability. Even though SE cases were available approximately 15.2% of the time, 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:

<40%	41% to 60%	61% to 80%	>80%
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

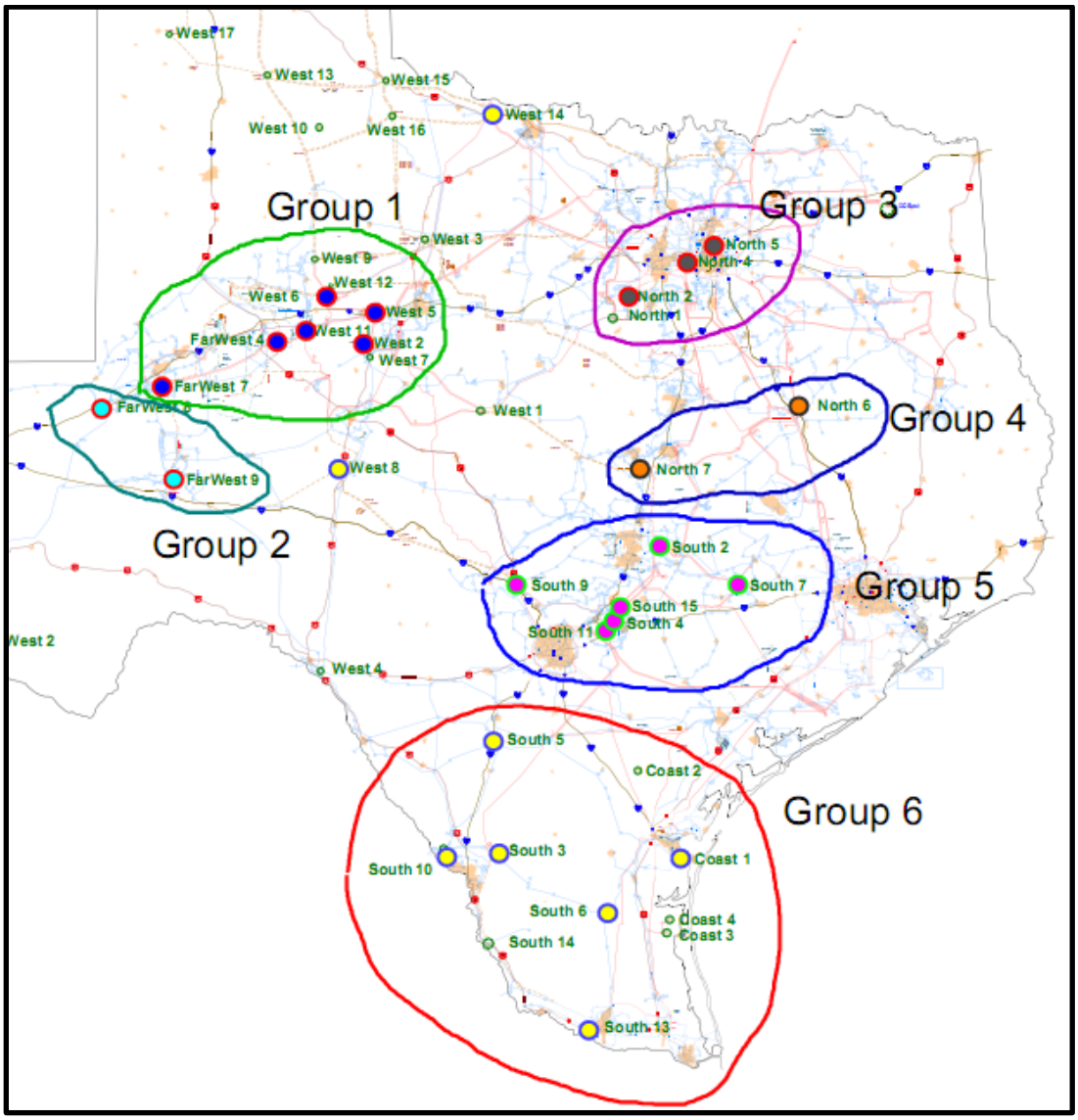
Phase angles differences are indicators of power flow and direction. Power flow follows voltage angle difference as per the following diagram and equation:



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

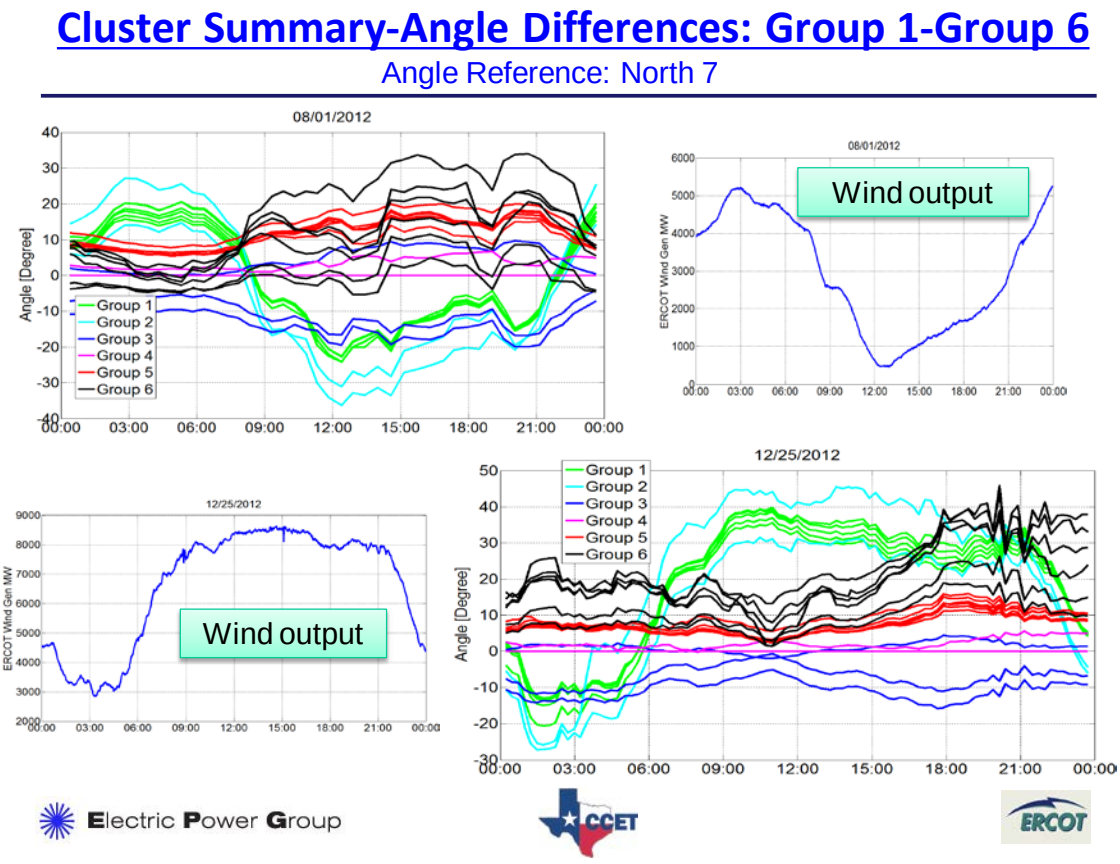
Any change in Power flow or impedance will be reflected in a change in voltage phase angle difference between two locations.

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:



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:

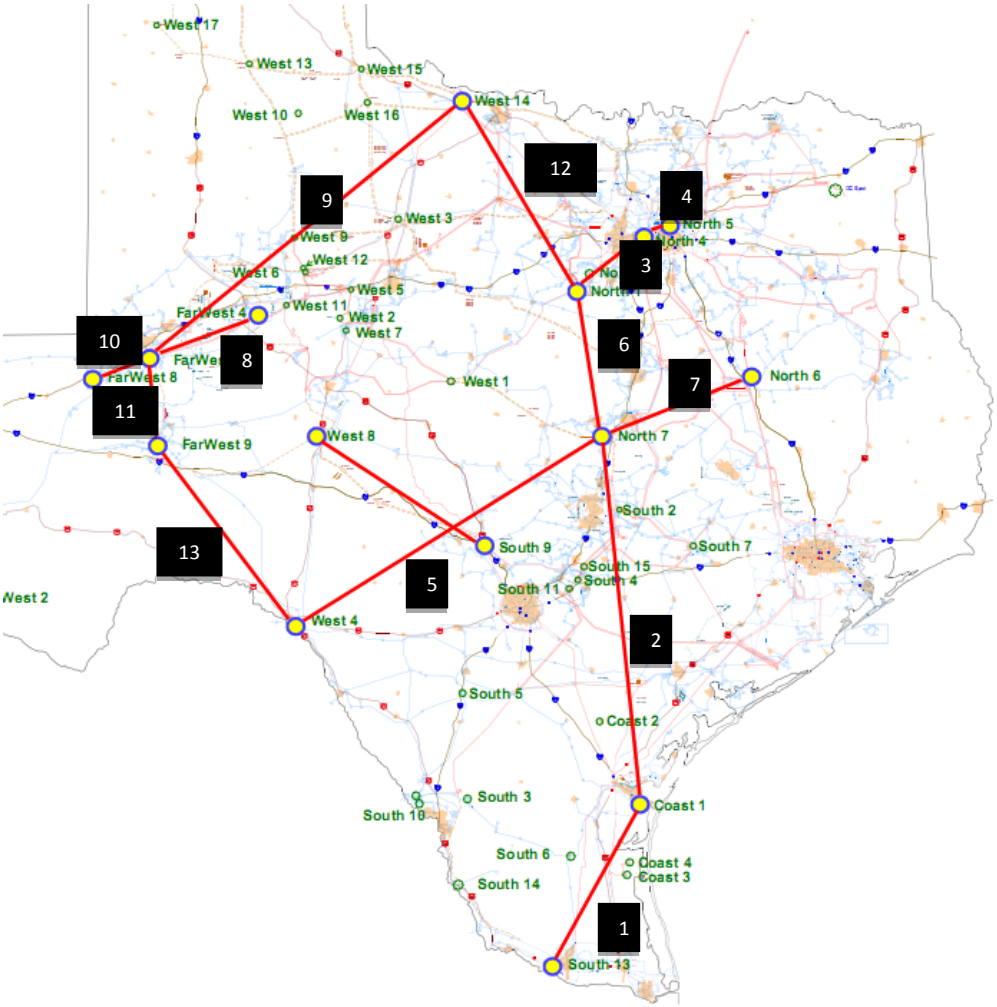
1. August 1, 2012 – Peak load day
2. November 23, 2012 – Low load day
3. December 25, 2012 – Maximum wind Day

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 is 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 reasonable 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 DIFERENCES

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 4and 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 form 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 f 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

				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	68.00	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

			Phasor Data			State Estimator Data								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	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	99.98%	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	98.99%	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				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	N/A			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				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	N/A			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

a. 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														
			Phasor-Normal			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 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 {ubstations Identified for !ngle 5ifference !nalysis

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

TABLE 3: ANGLE PAIRS FOR BASELINE ANALYSIS

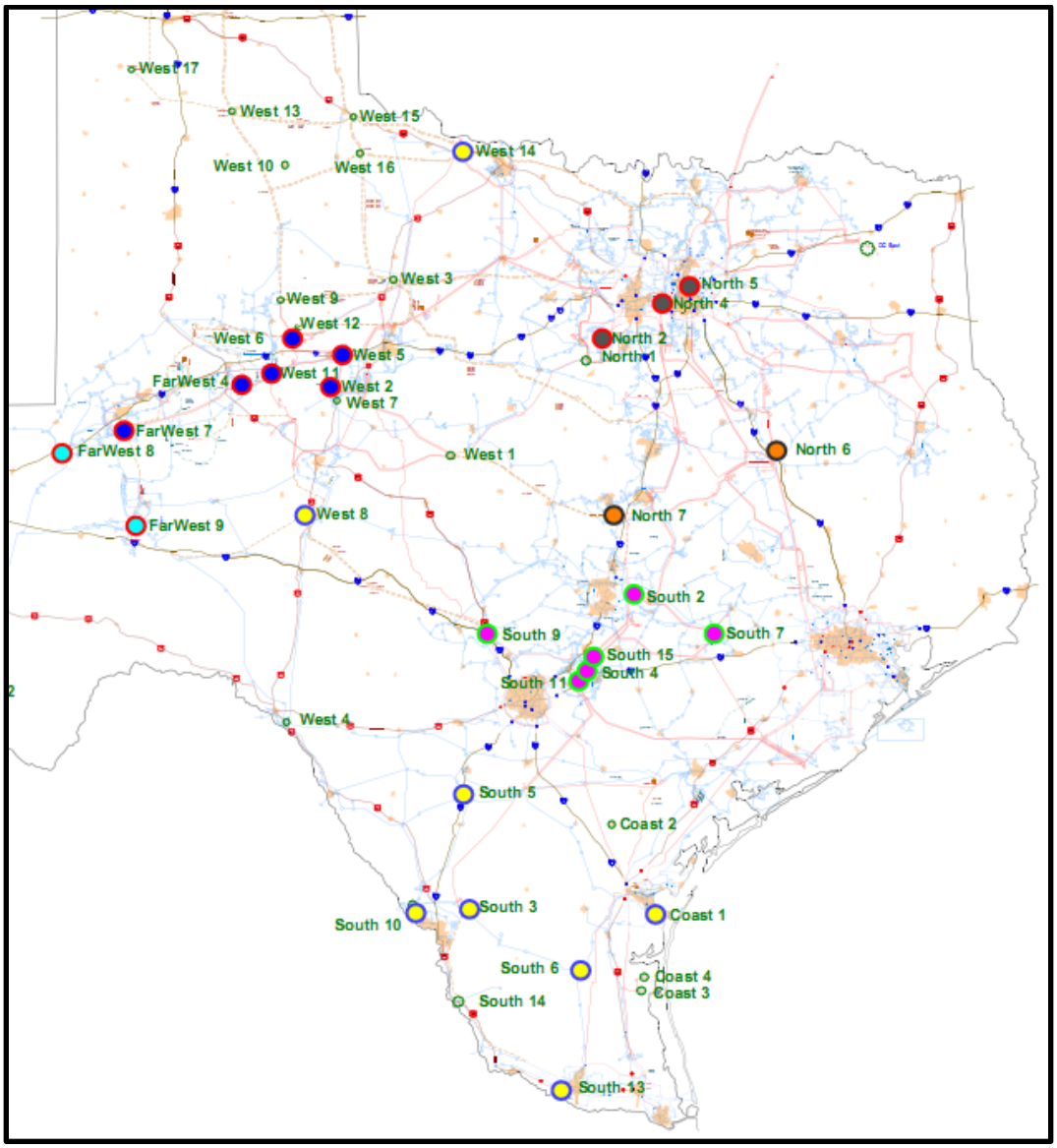
PAIRS WITH PHASOR DATA AVAILABLE

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

	Angle Pair	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	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
16	Coast 1-South 10*	138kV	Phasor data is not available for these pairs					-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						-11.52	4.01	0.44	65.6%	15.5
30	West 8*-South 9*	345kV						-35.64	42.66	4.98	58.4%	78.3
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

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:

   i. 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 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	-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	No phasor data is available for these pairs			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. **aÌ·ÈÅYʤY ¦yƎfŜă ¦yŘŜ₪ b₴₪YÌ·f /₴yŘ₪ú₴yãŸ** Under normal conditions the maximum angles and the Max-Min spreads for these three pairs are:

FarWest 7-North 7	52.6	89.7
West 5-North 7	52.4	80.9

k. **DŜySŜNI·f wŜǎdztúǎY** 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. **[ƛY'ƛűǎY** 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

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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:

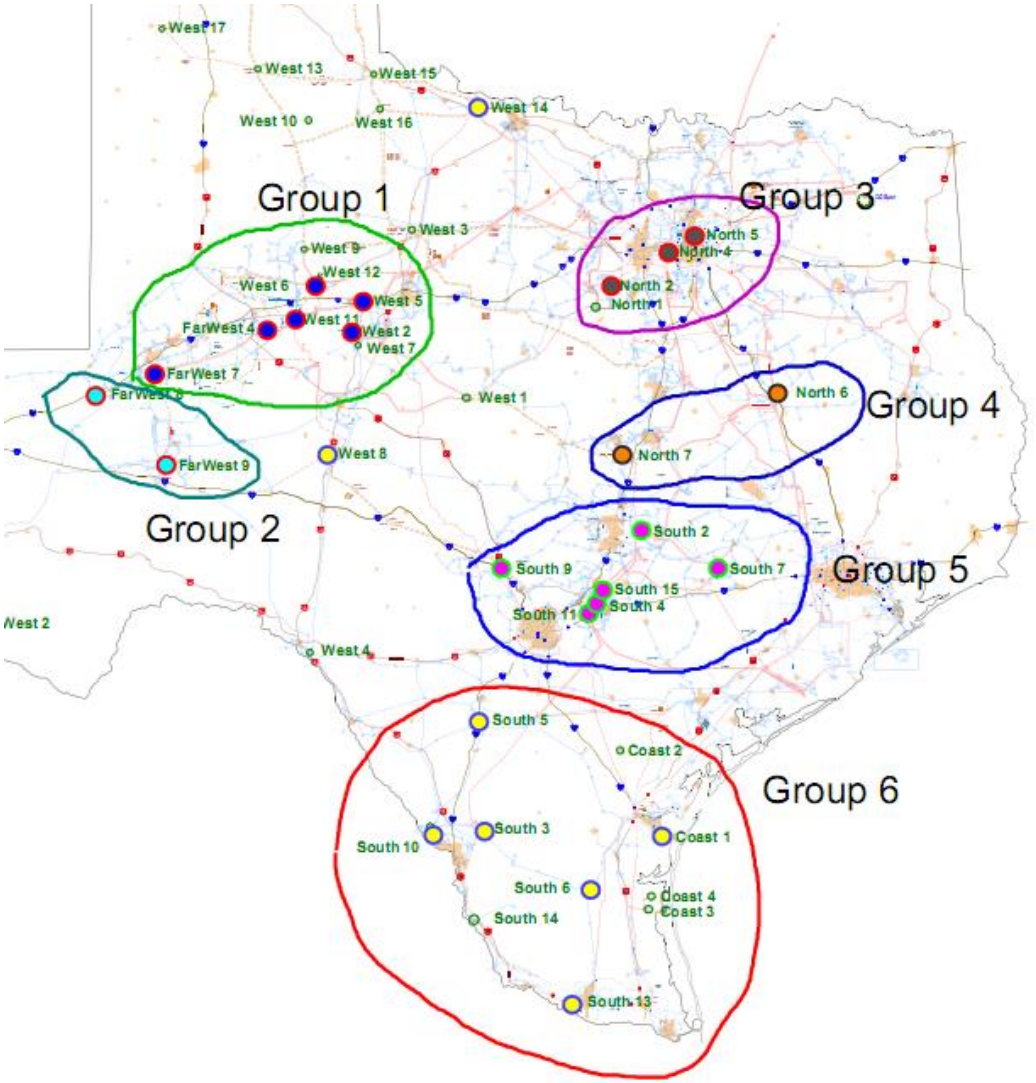
- South 2
- South 4
- South 7
- South 9
- South 11
- South 15

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



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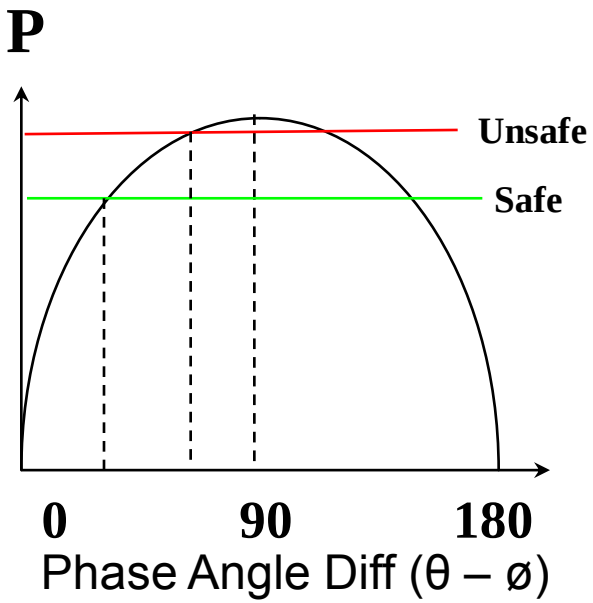
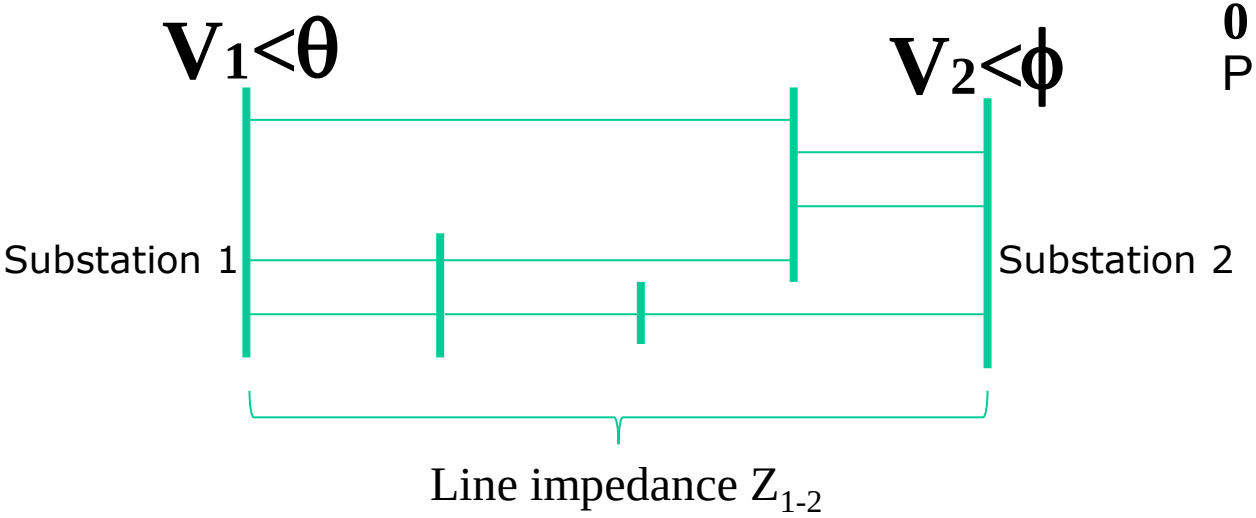
Phase angles differences as indicators of power flow

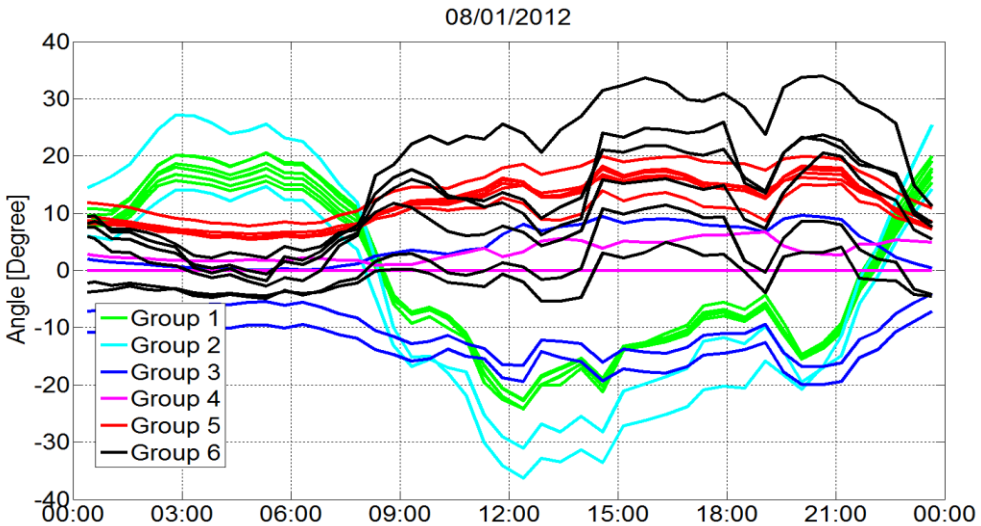
- Power flow follows voltage angle difference
  - Power flow: $P = V_1 V_2 \sin(\theta - \phi)/Z$
- Any change in Power flow or impedance will be reflected in a change in voltage phase angle difference between two locations

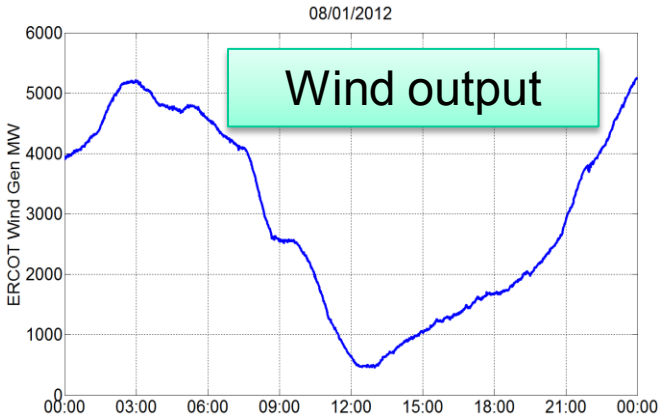


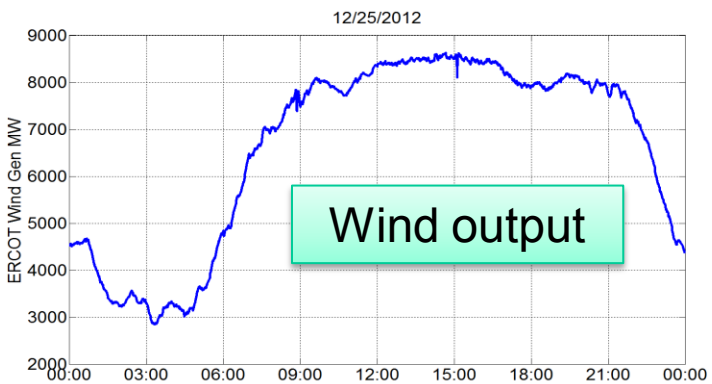


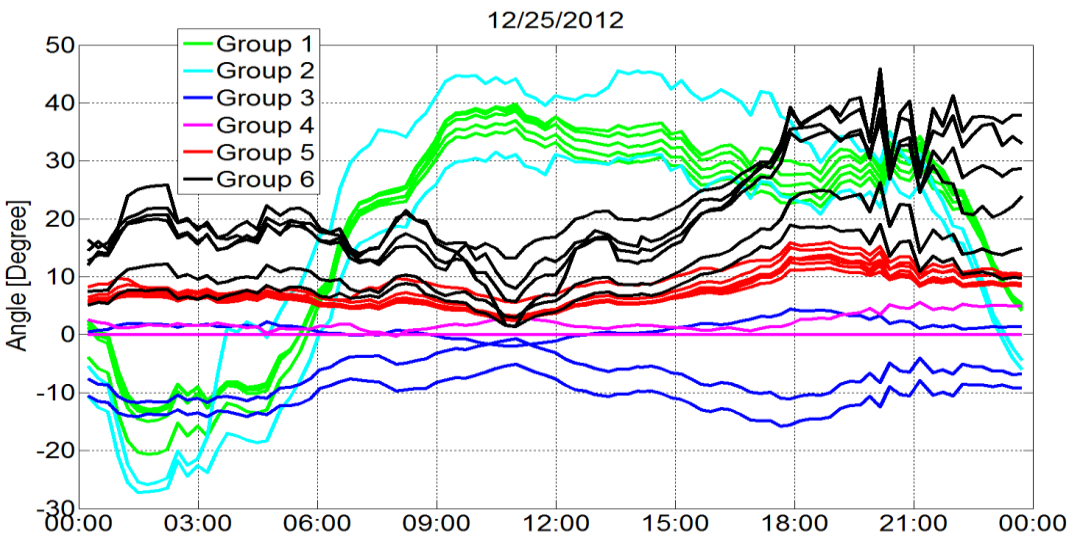
Cluster Summary-Angle Differences: Group 1-Group 6

Angle Reference: North 7









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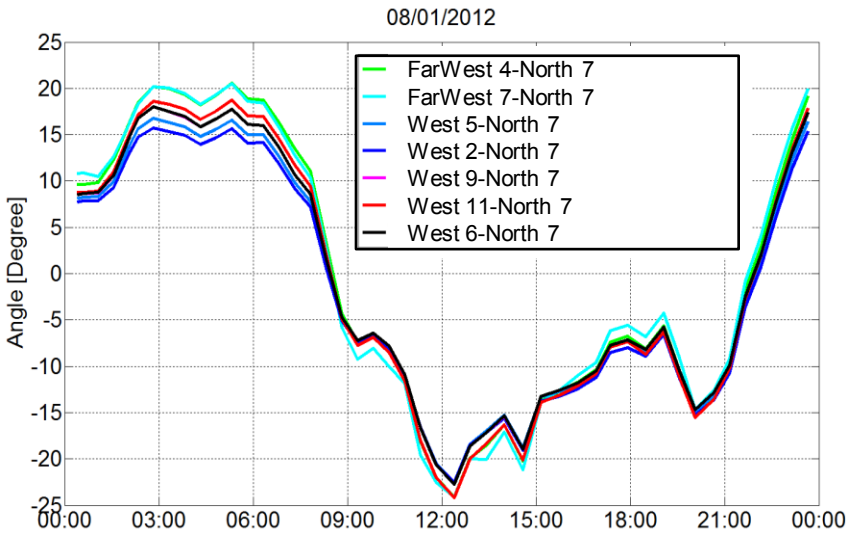
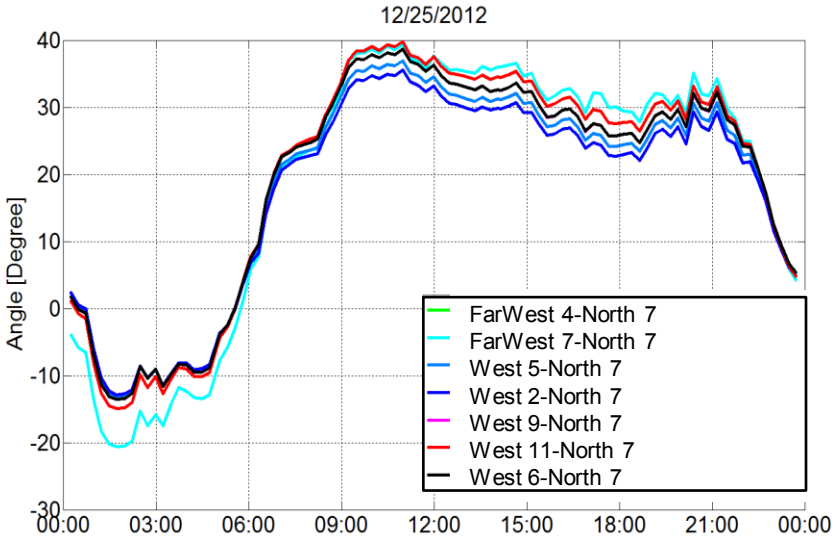
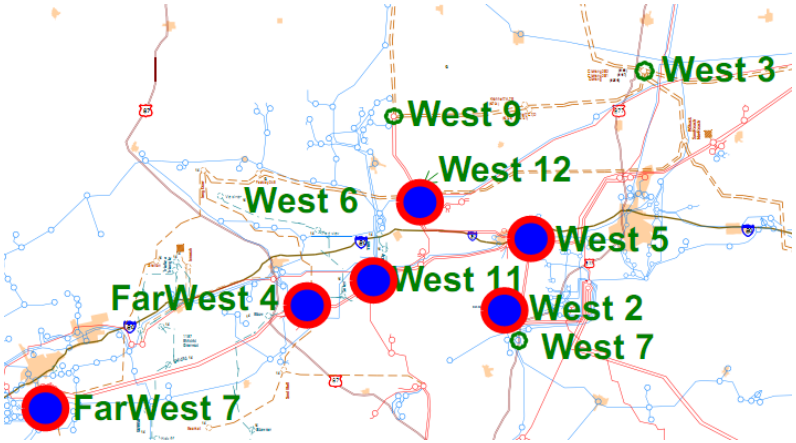
Group 1: Central







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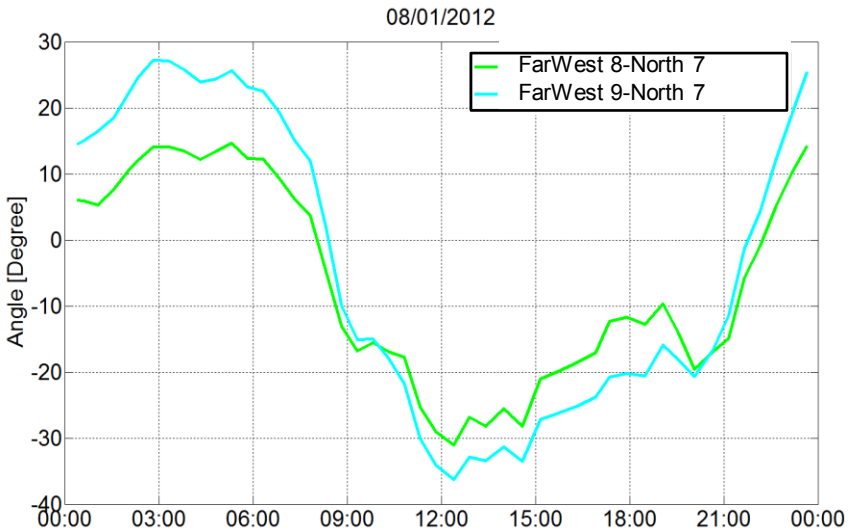
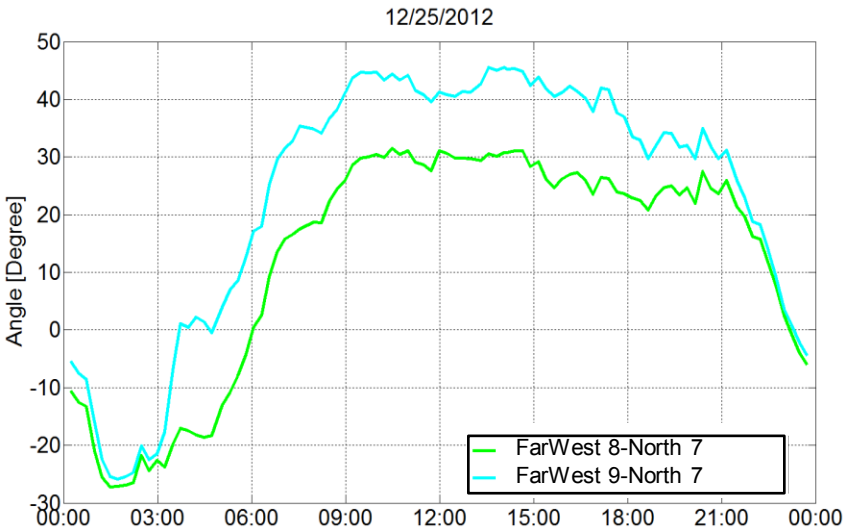
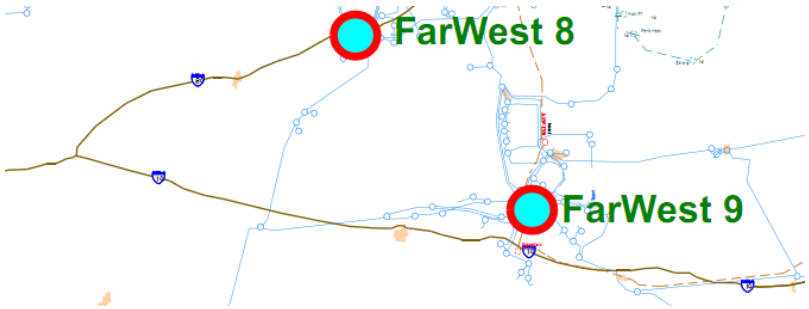
Group 2: West Texas







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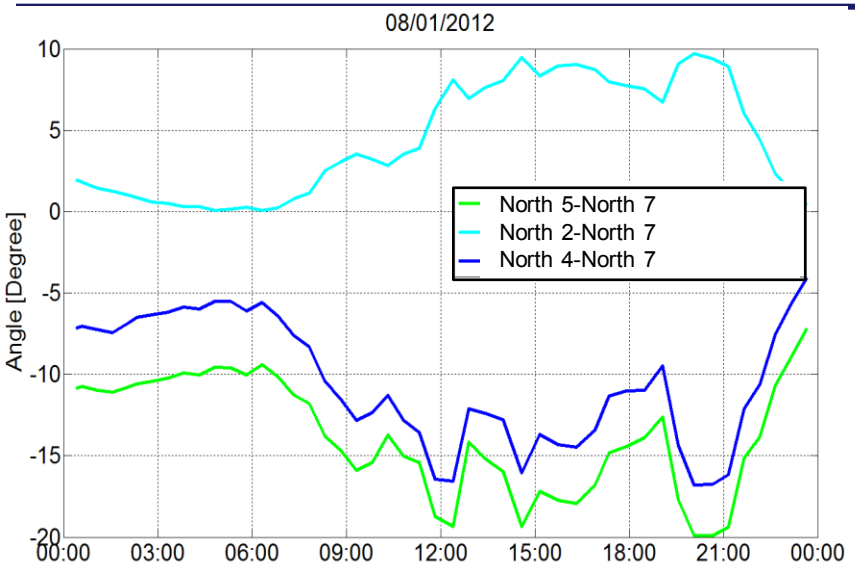
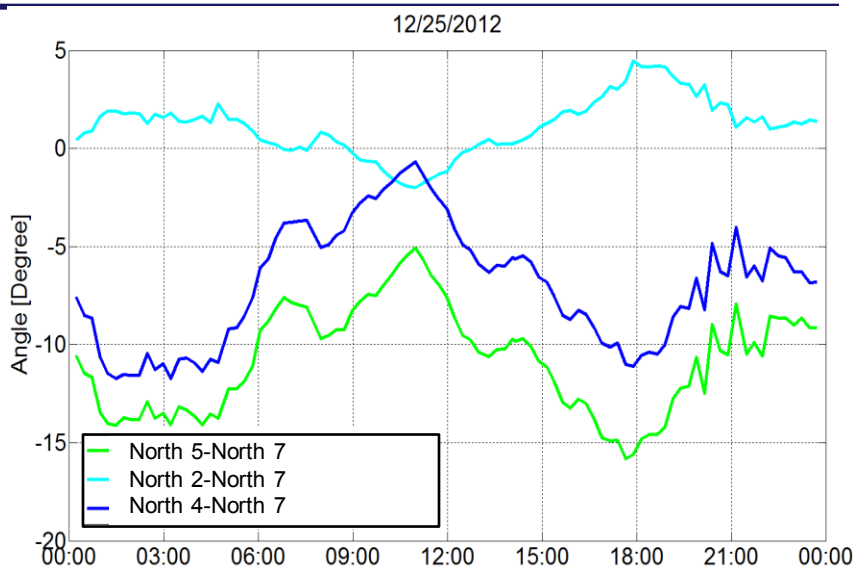
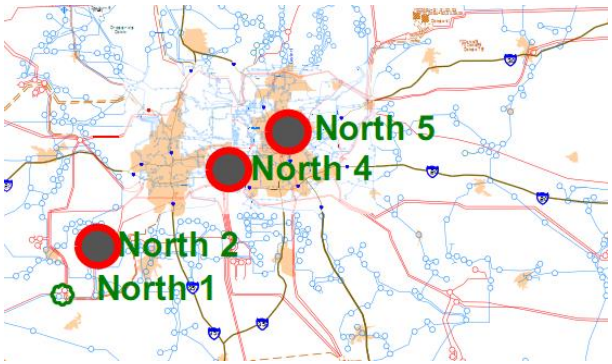
Group 3: Dallas







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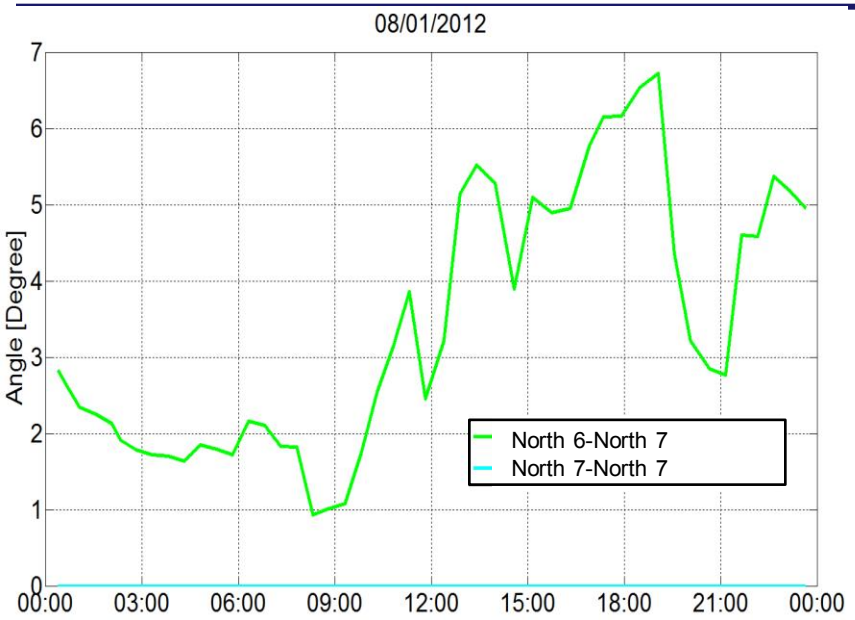
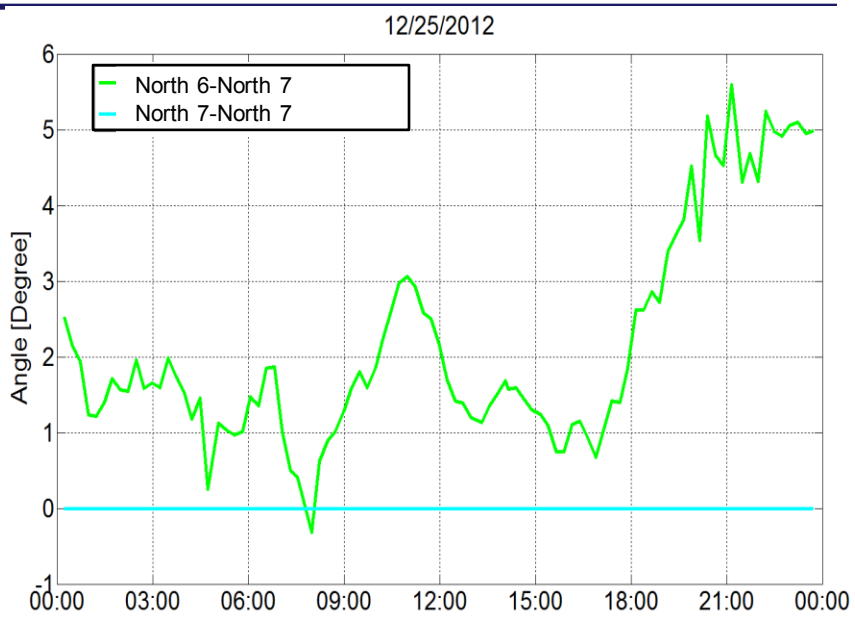
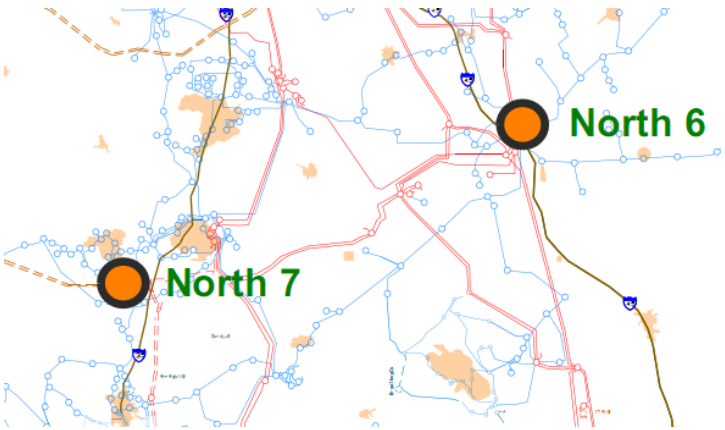
Group 4: East and Central East







Electric Power Group

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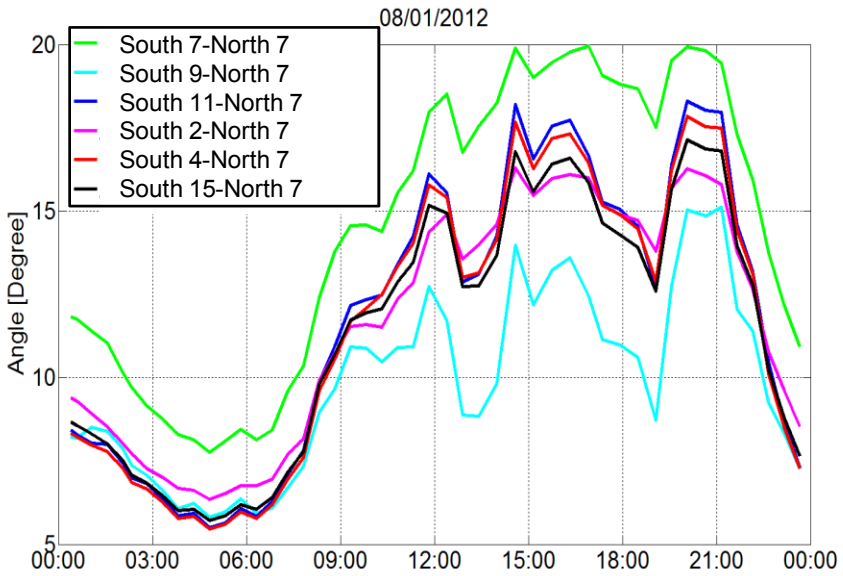
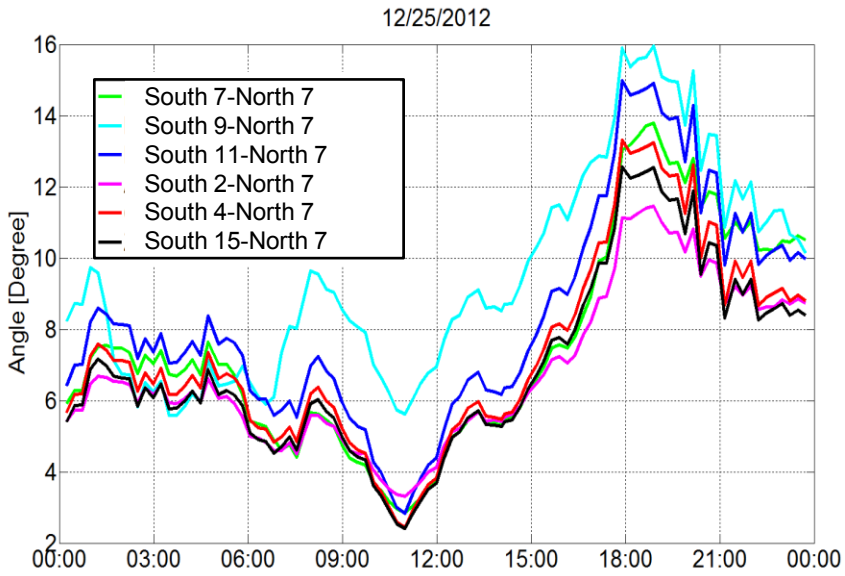
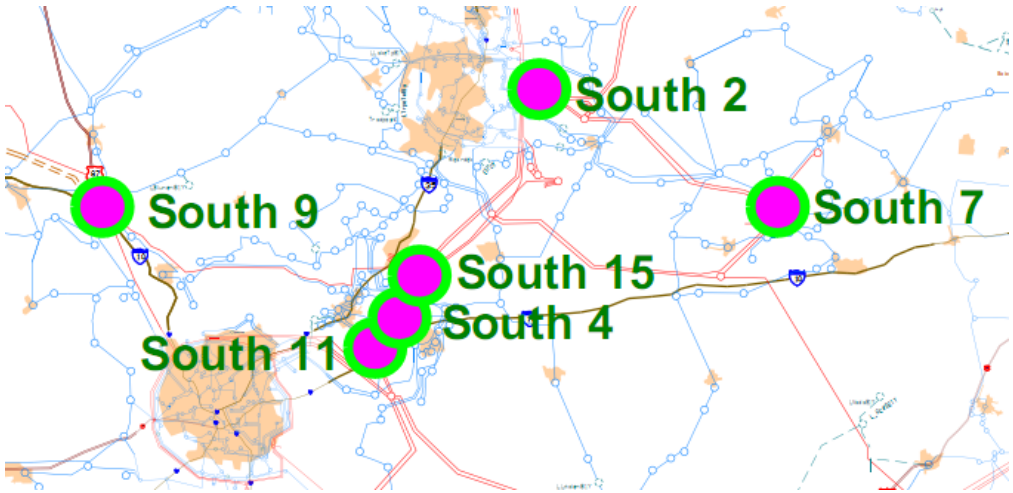
ERCOT

Group 5: Central East







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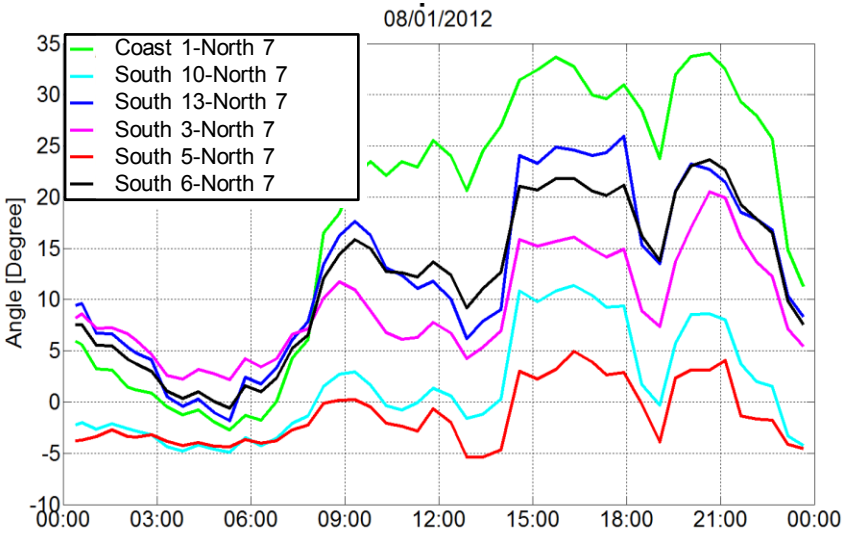
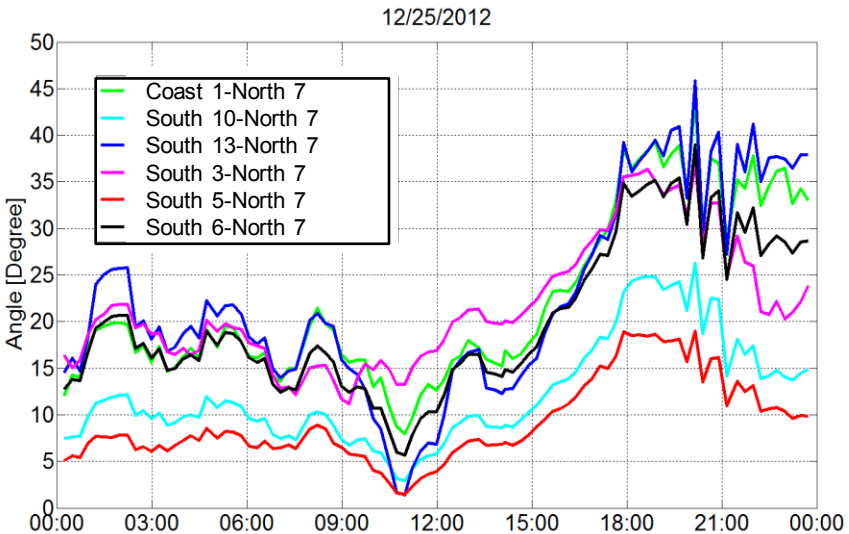
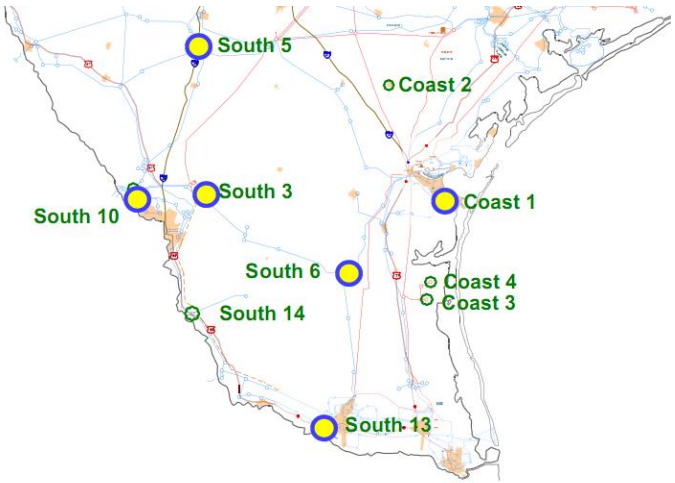
Group 6: Valley







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Appendix B

CCET Discovery Across Texas

State Estimator versus Phasor Comparison

External Version

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Phasor vs. State Estimator Comparison

- Thirteen angle pairs were selected for comparison based on phasor measurement unit 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 comparisons 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

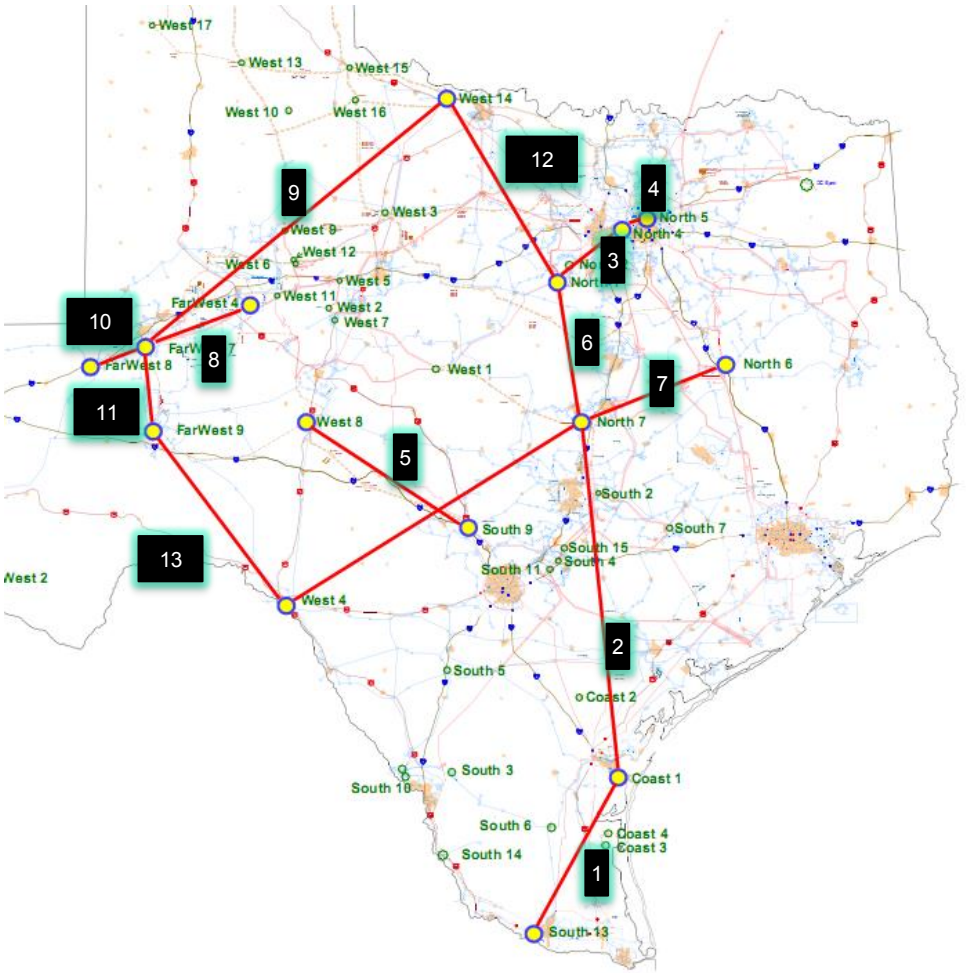
Angle Pairs with PMUs in Service

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

Days Analyzed:

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

Location of Angle Pairs with PMUs in Service



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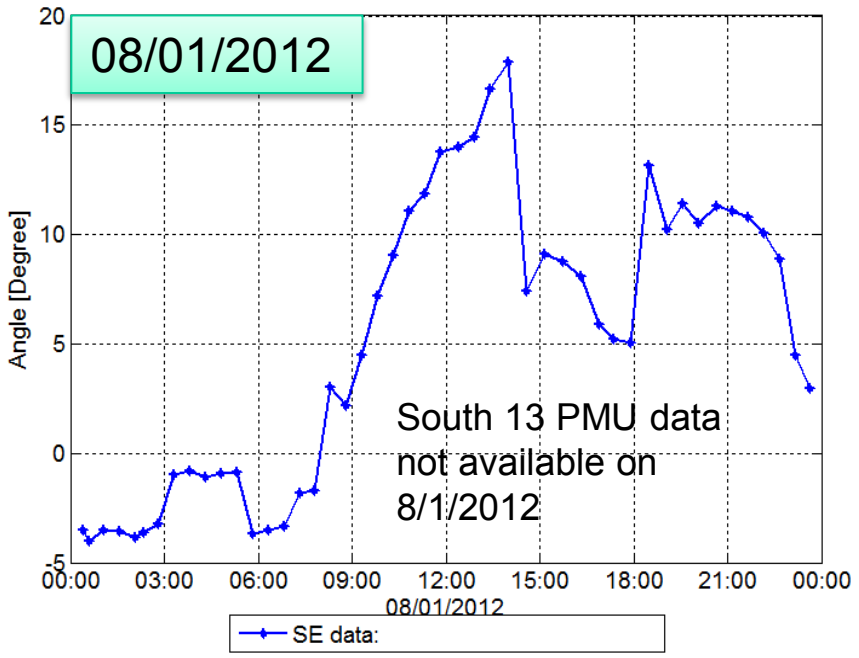
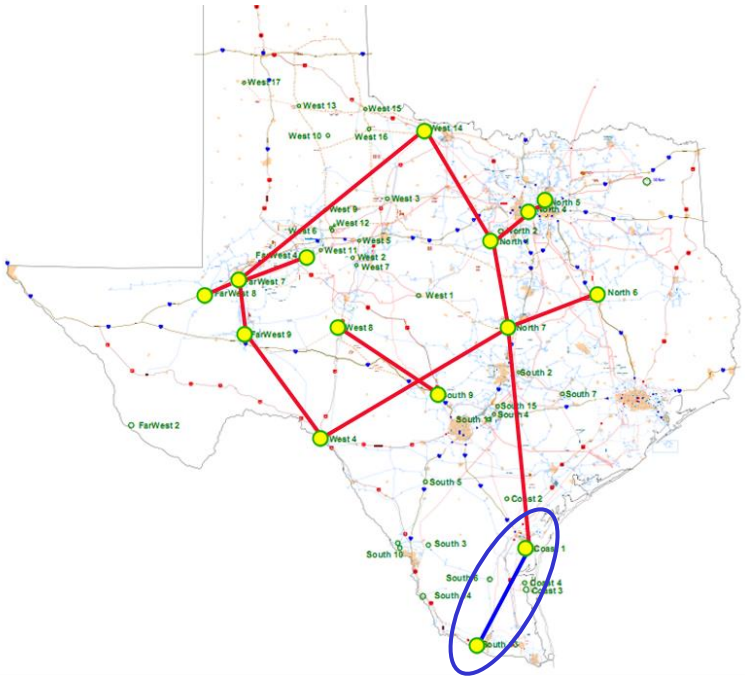
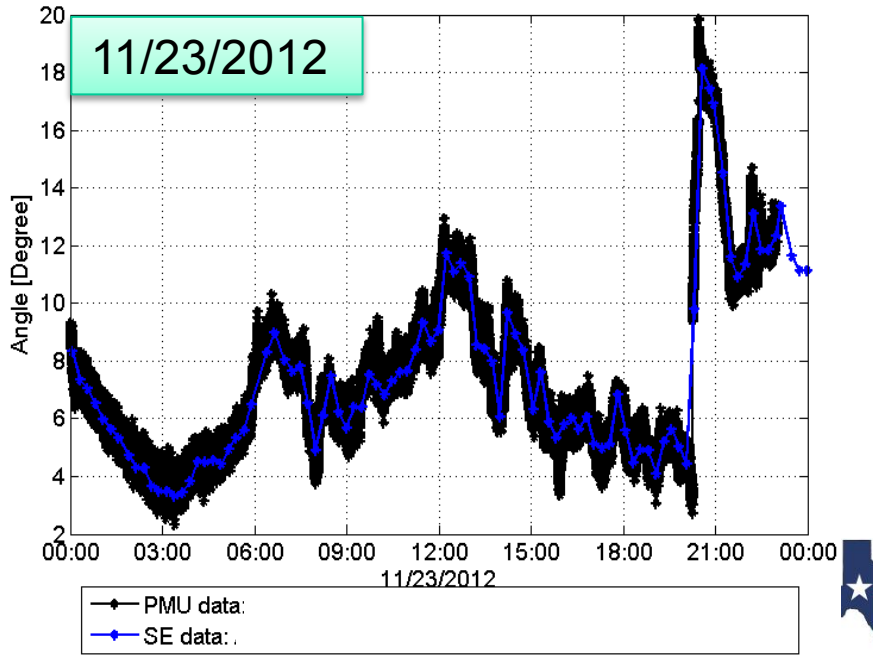
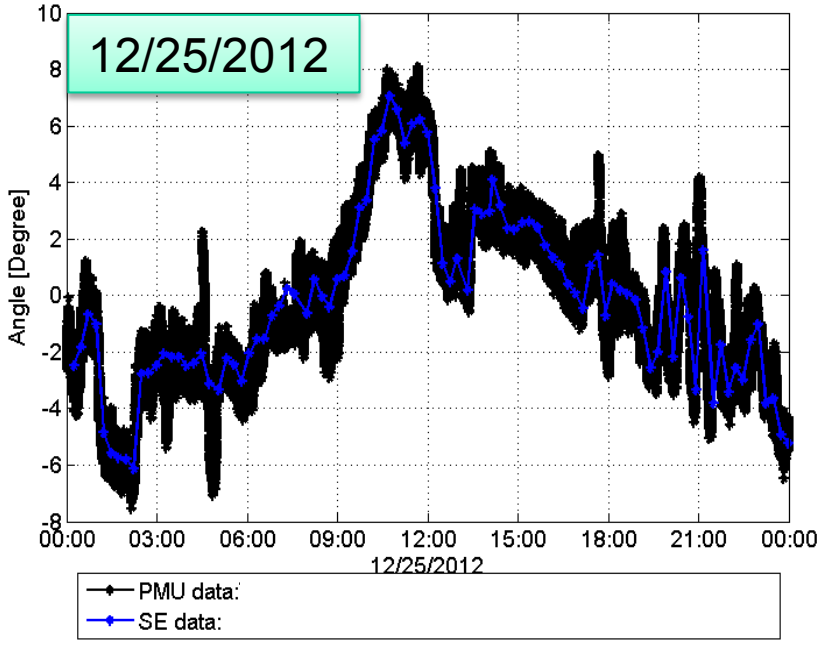
Coast 1-South 13

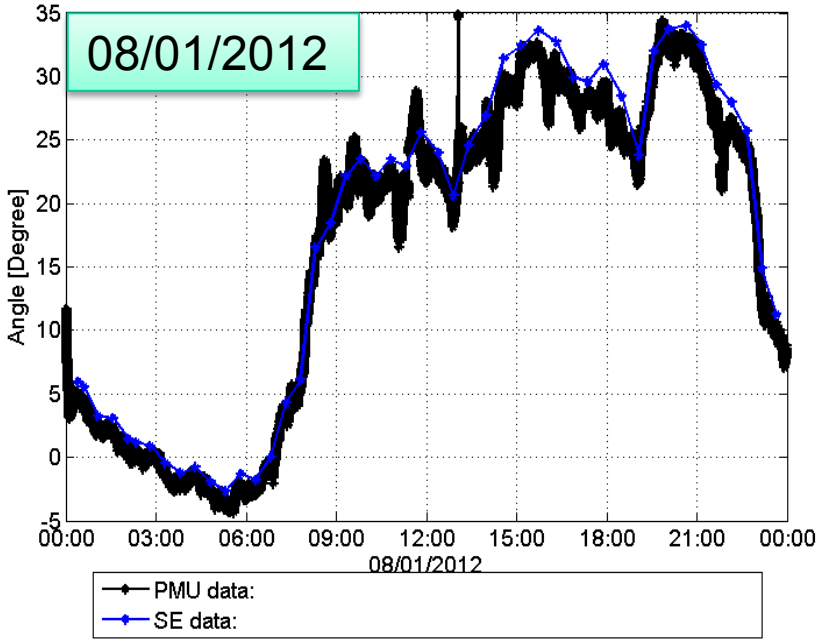


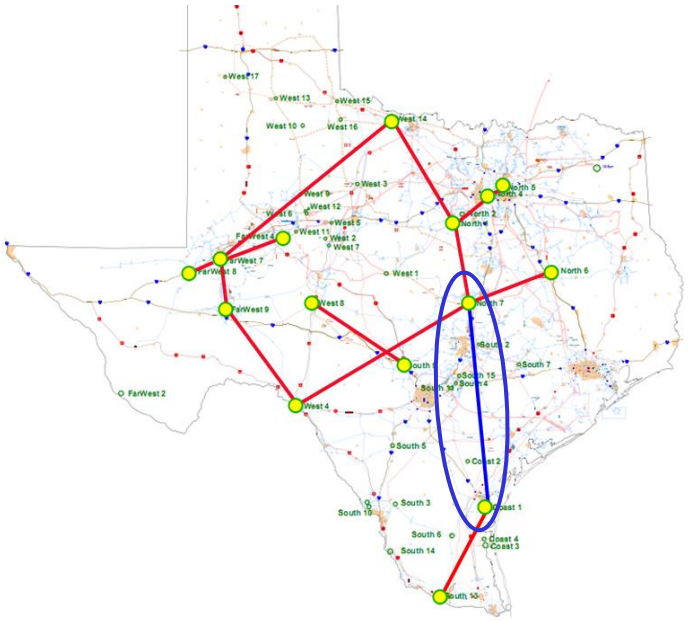


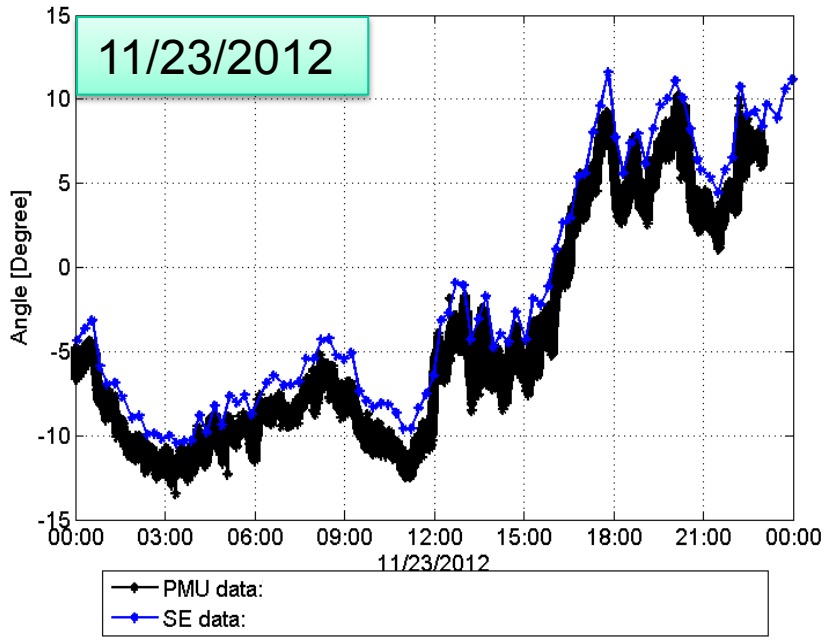


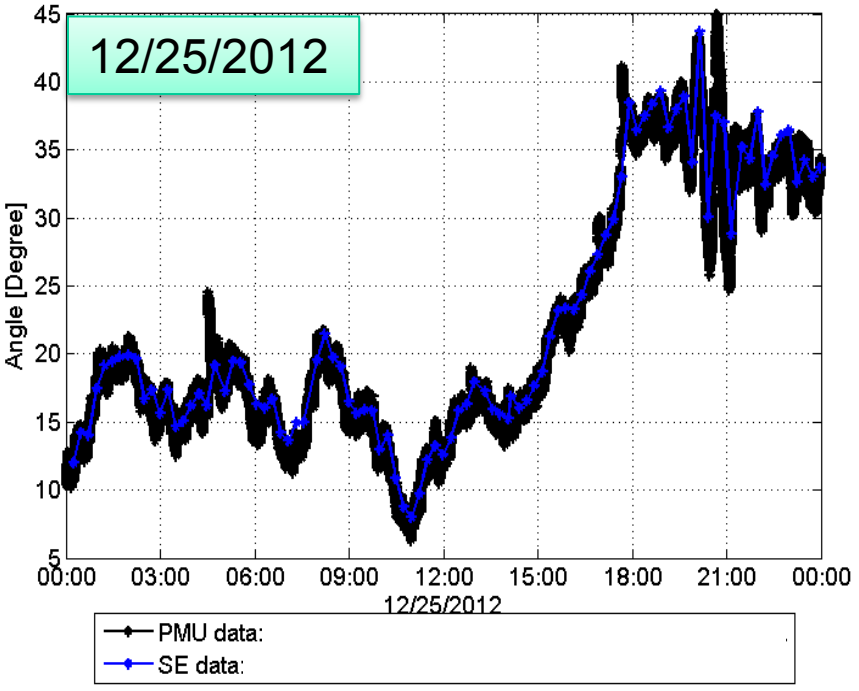


Coast 1-North 7

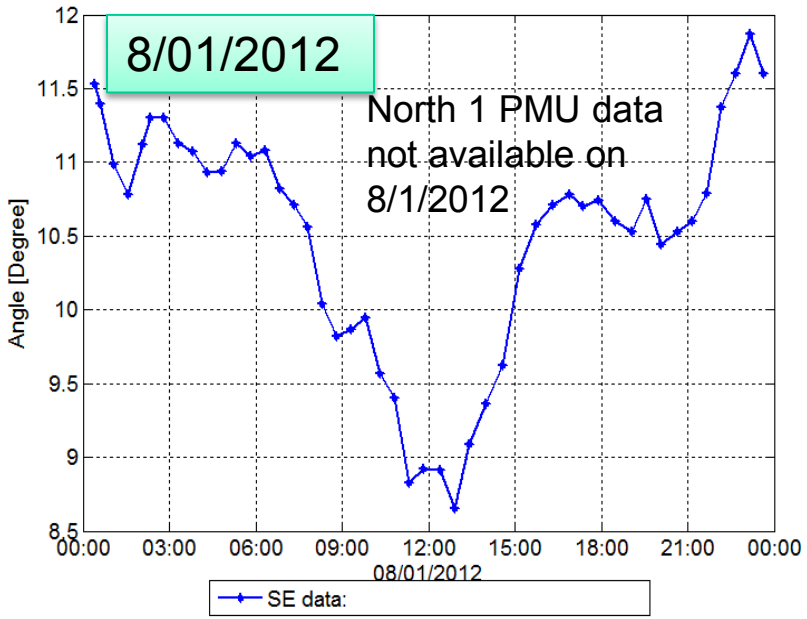


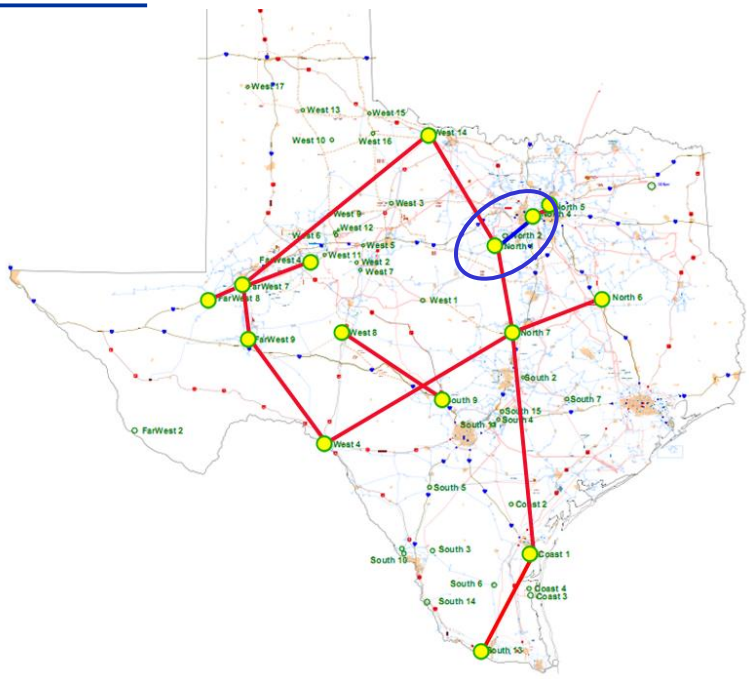


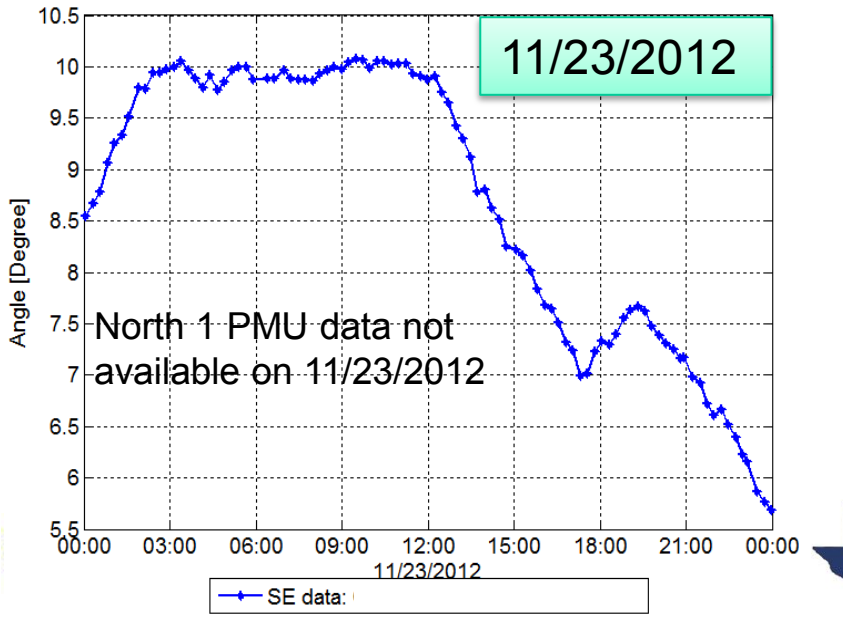


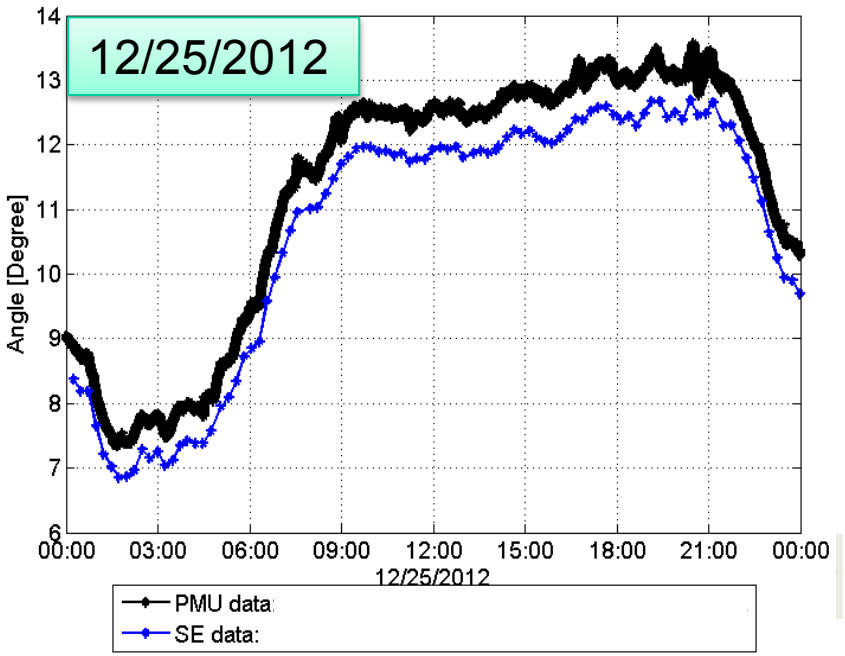


North 1-North 4

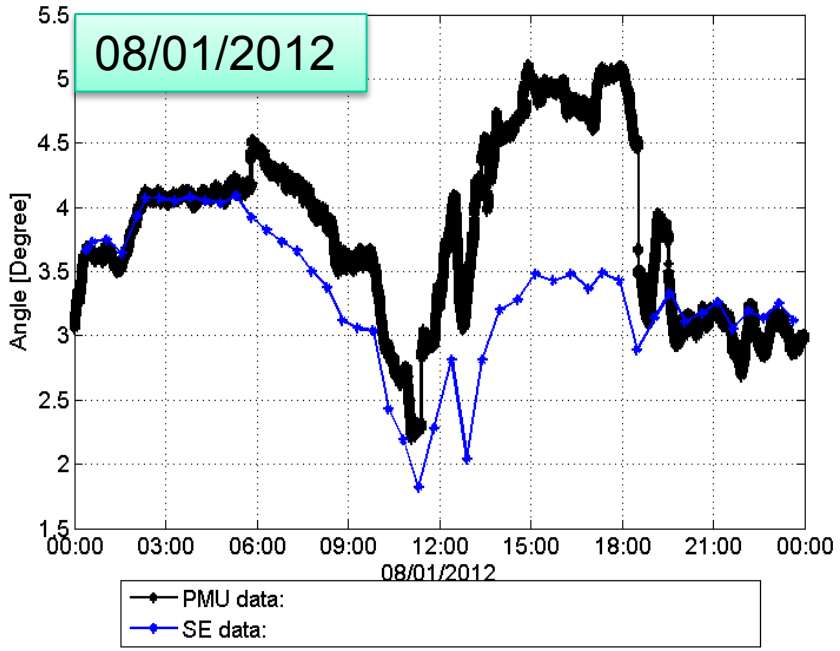


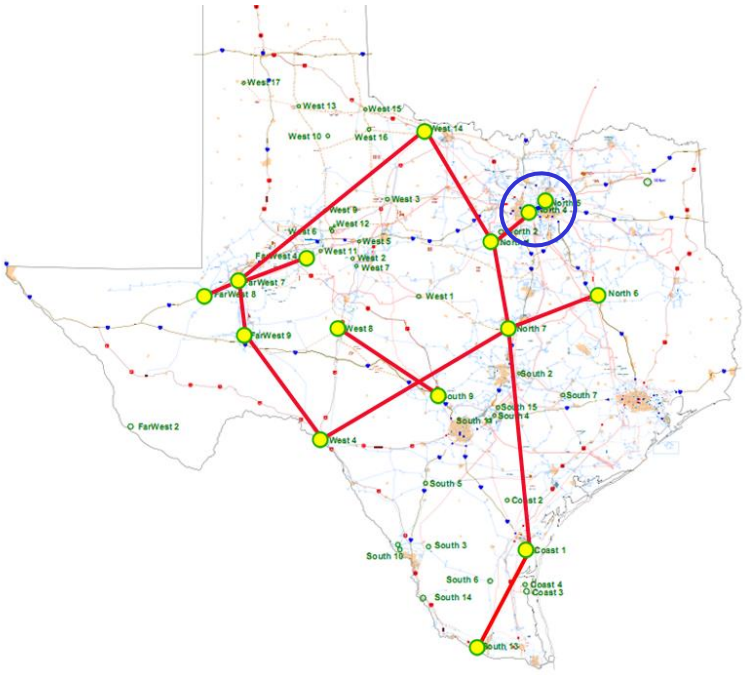


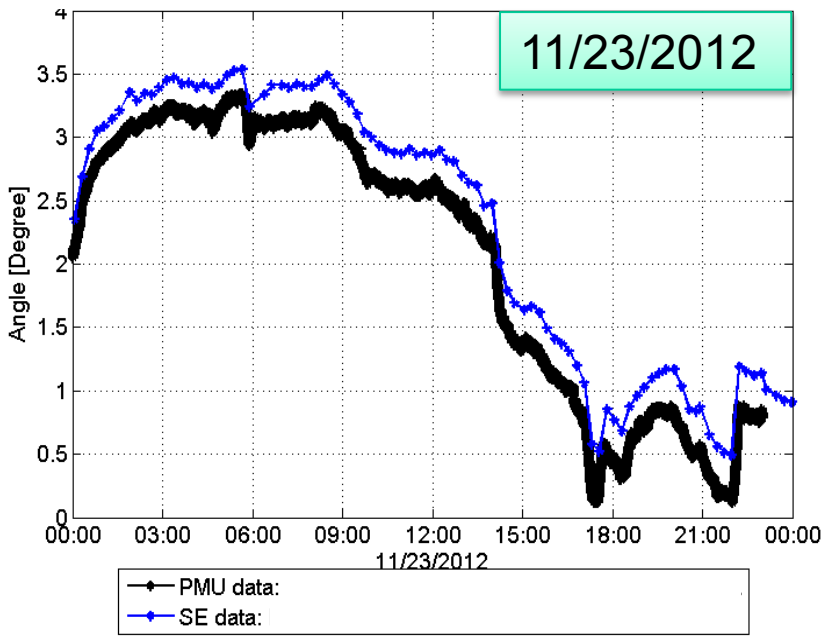


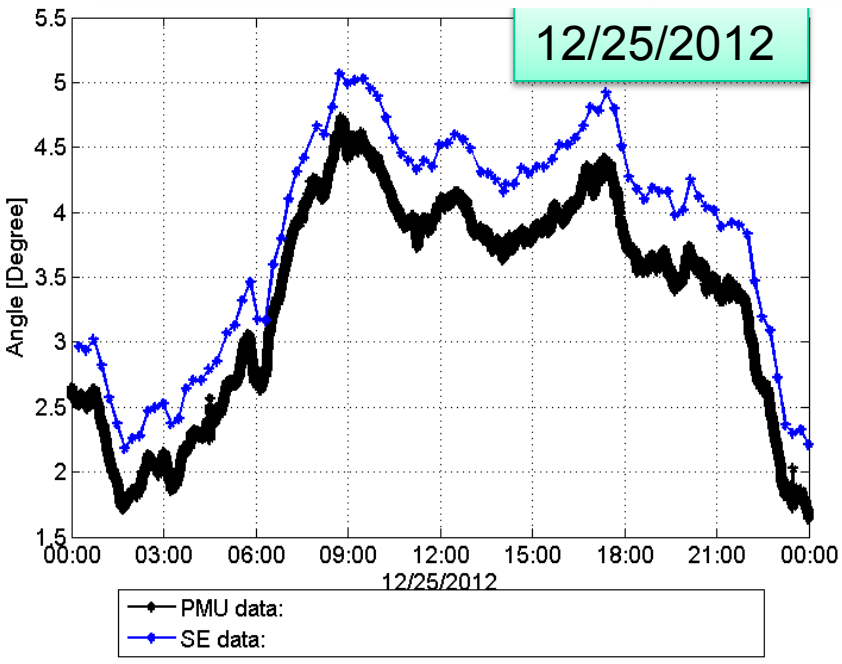


North 4-North 5

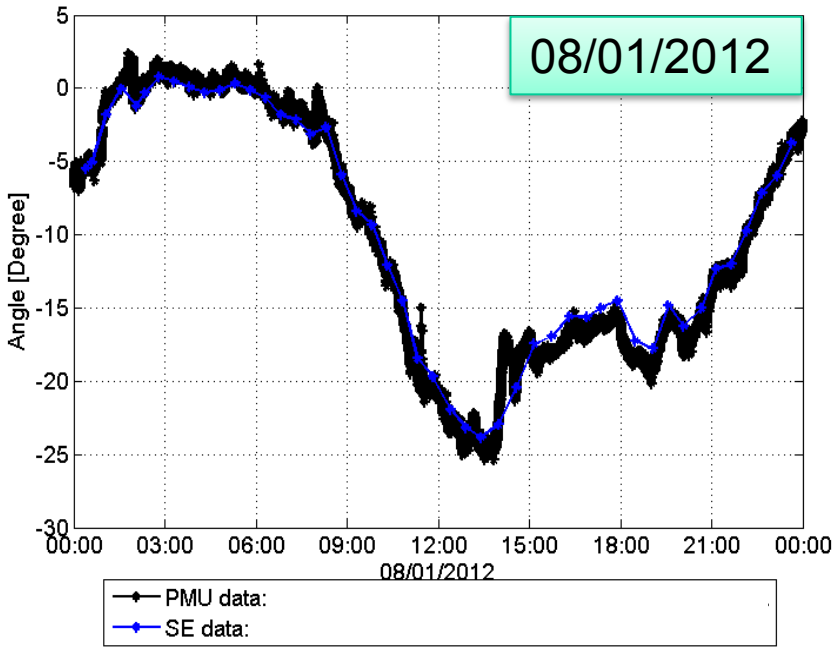


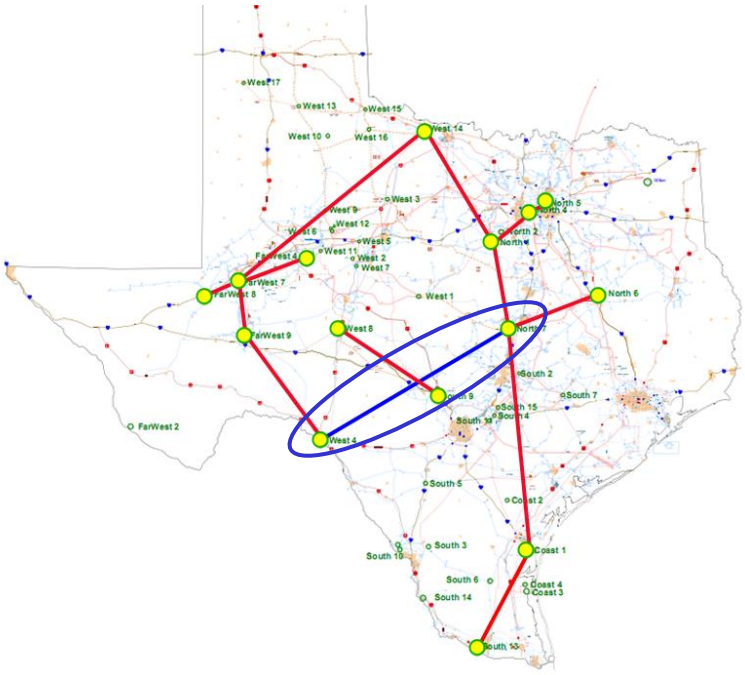


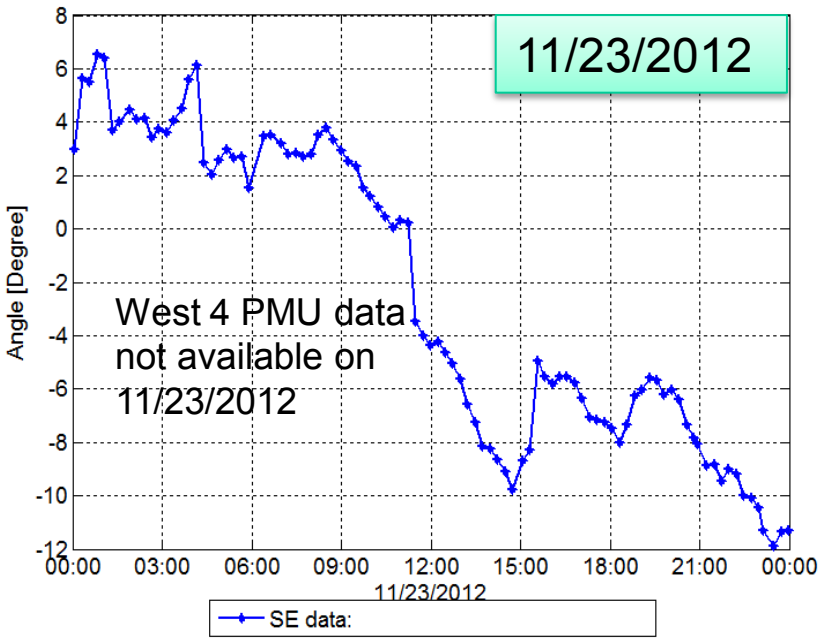


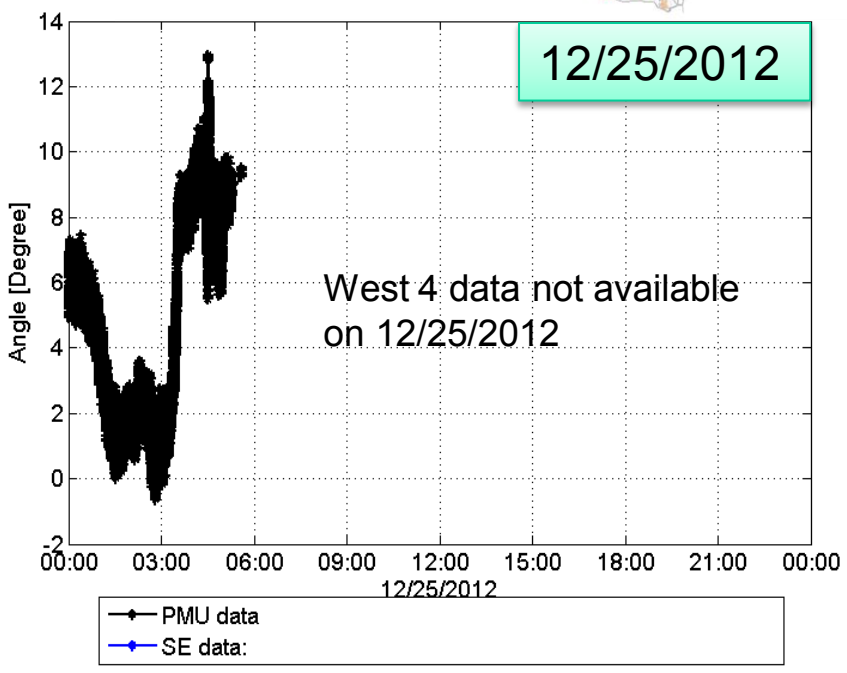


West 4-North 7

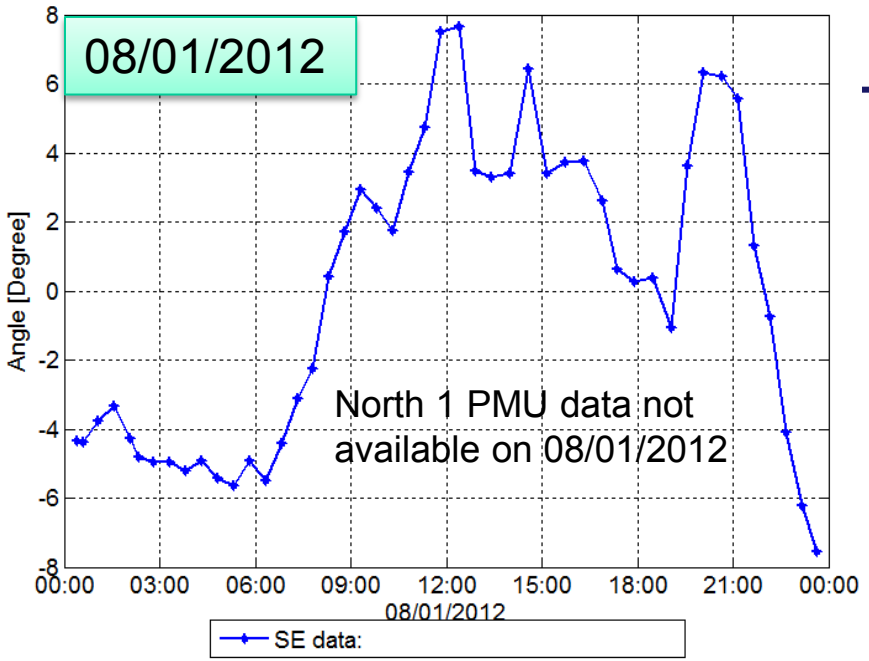


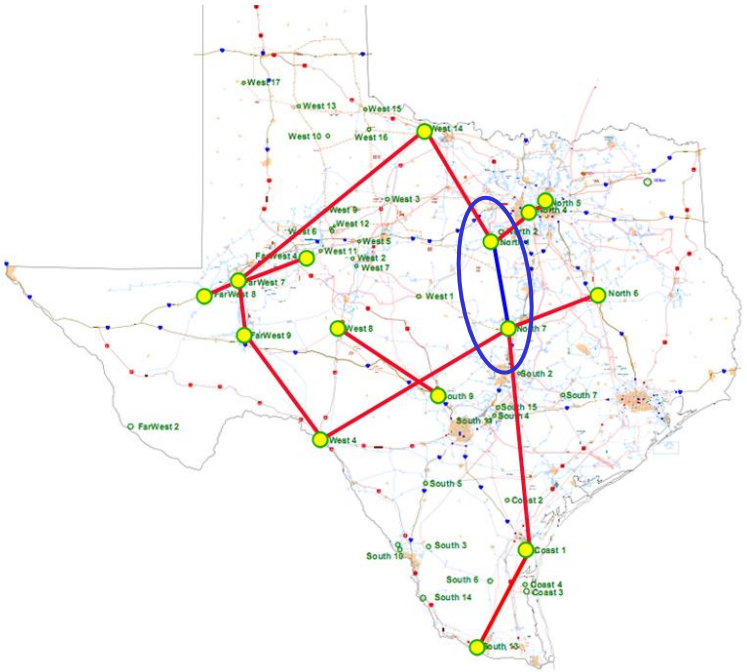


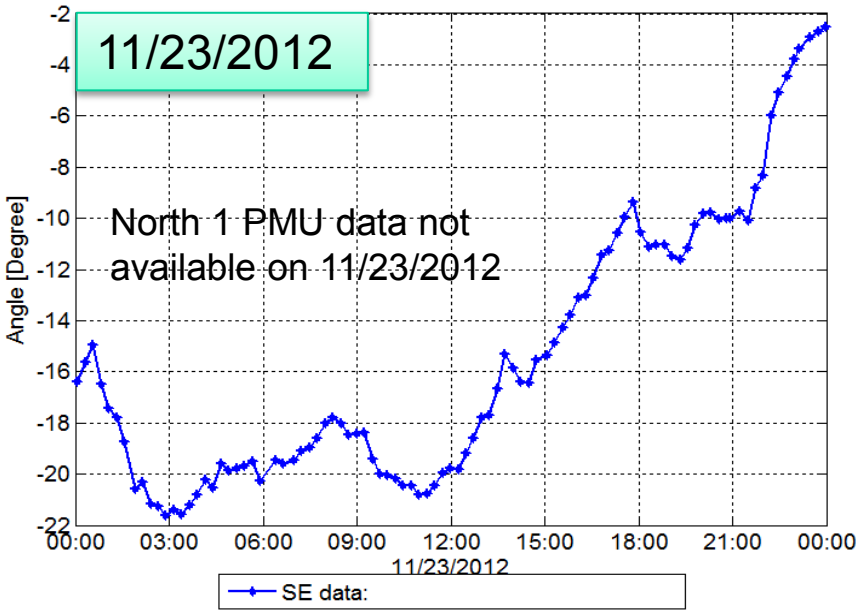


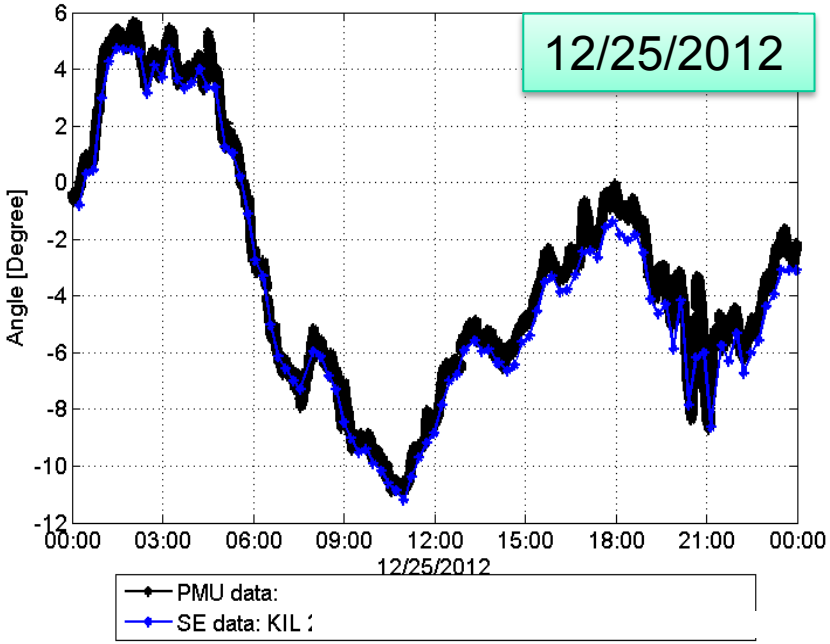


North 7-North 1

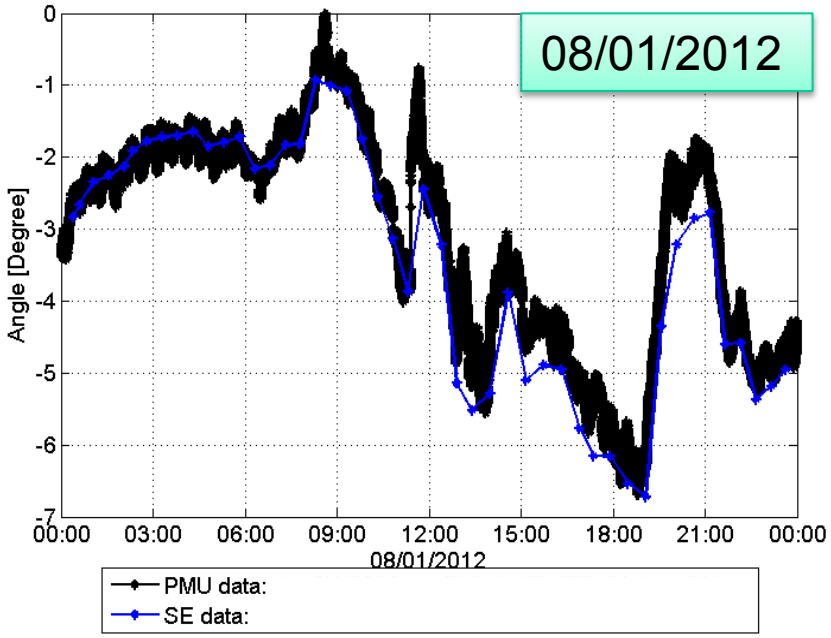


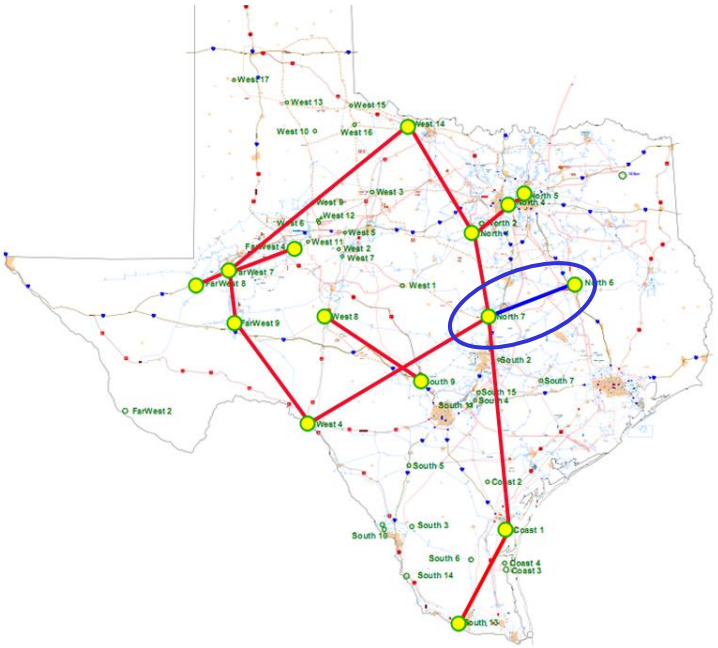


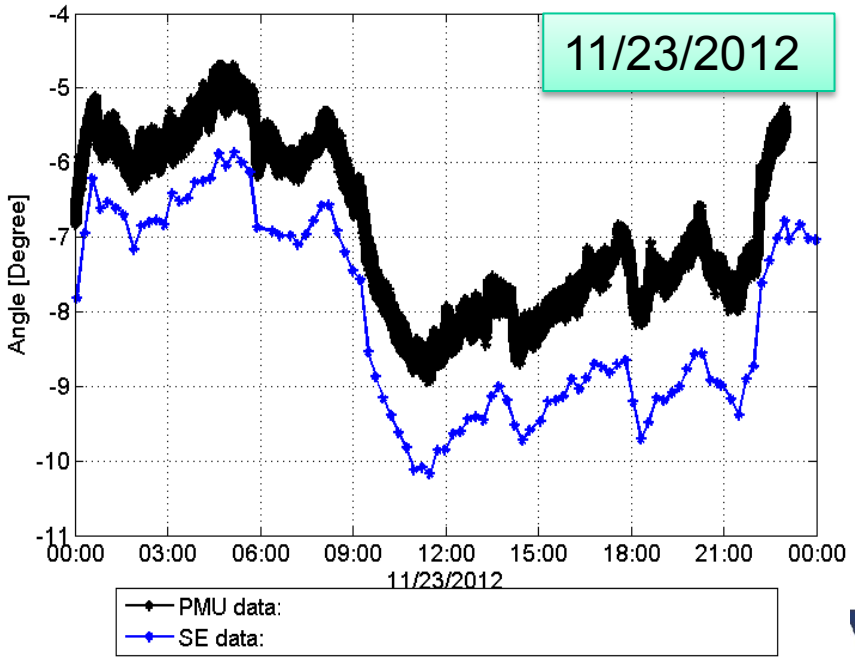


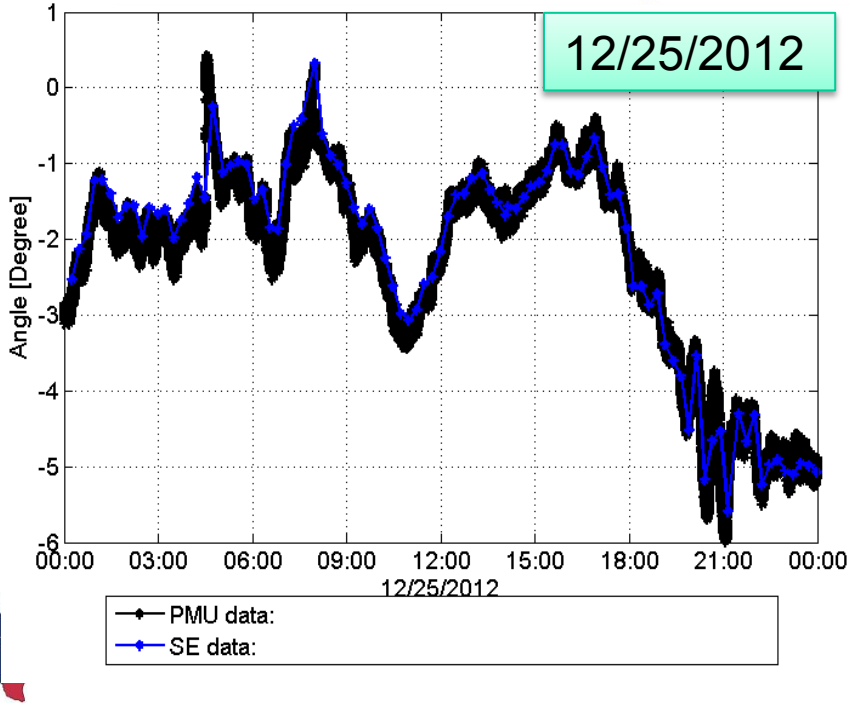


North 7-North 6

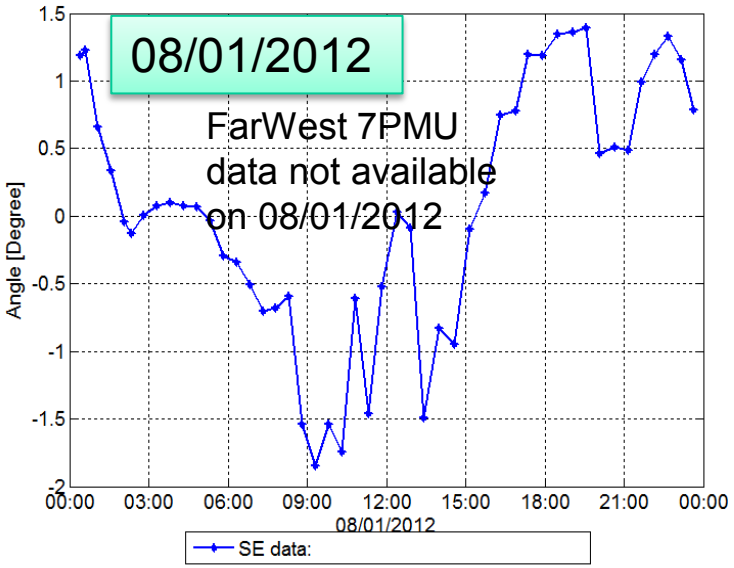


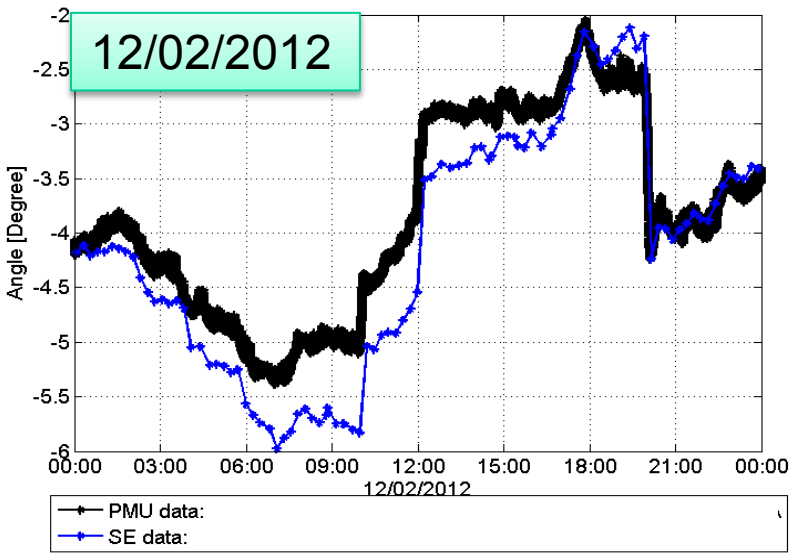


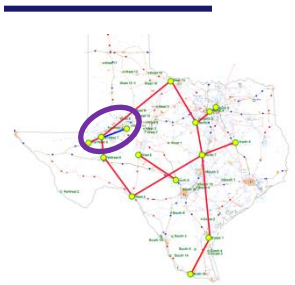


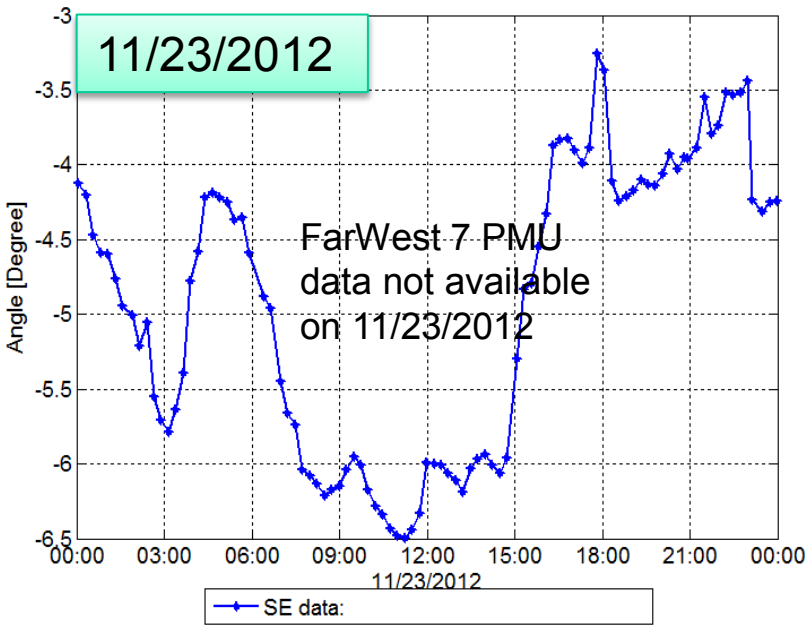


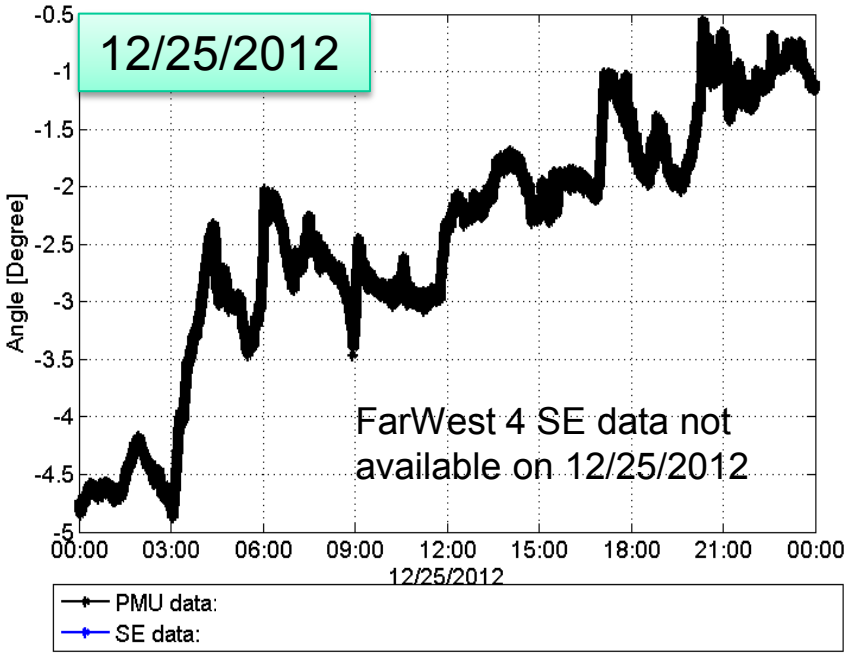
FarWest 7-FarWest 4











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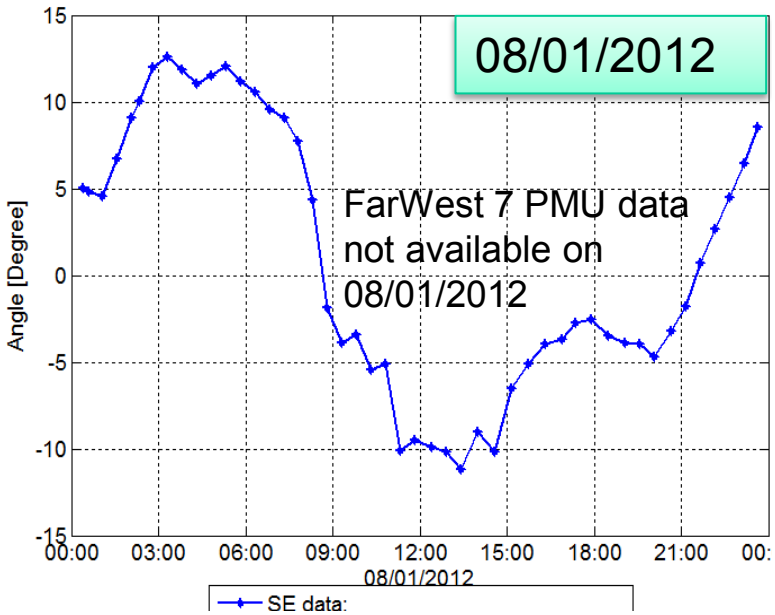
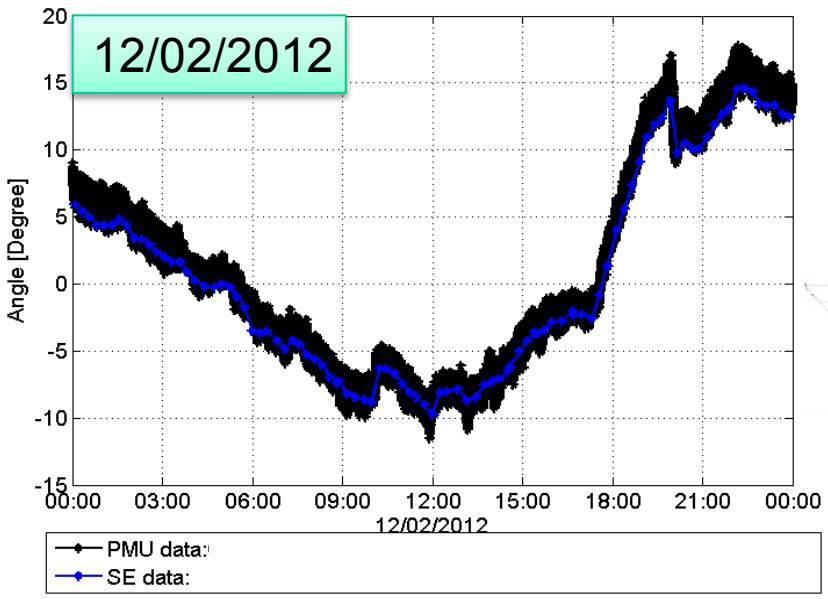
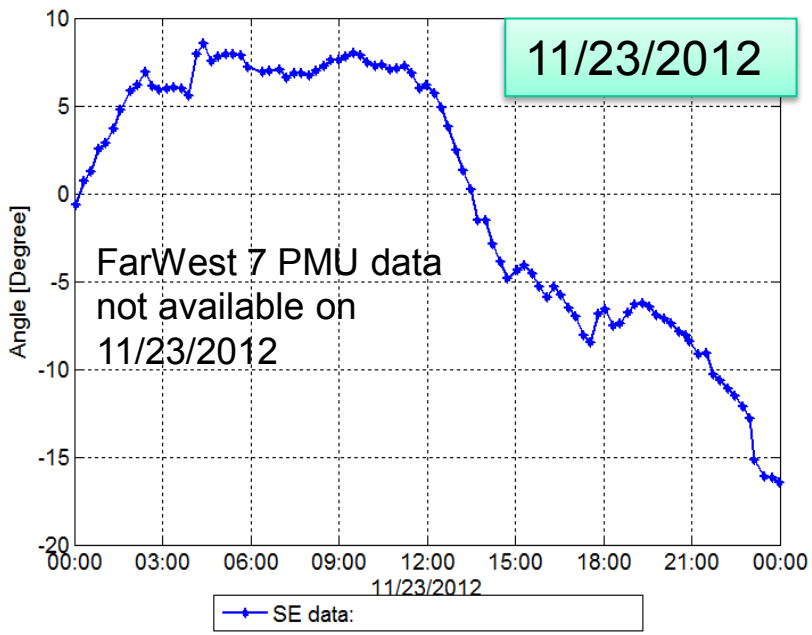
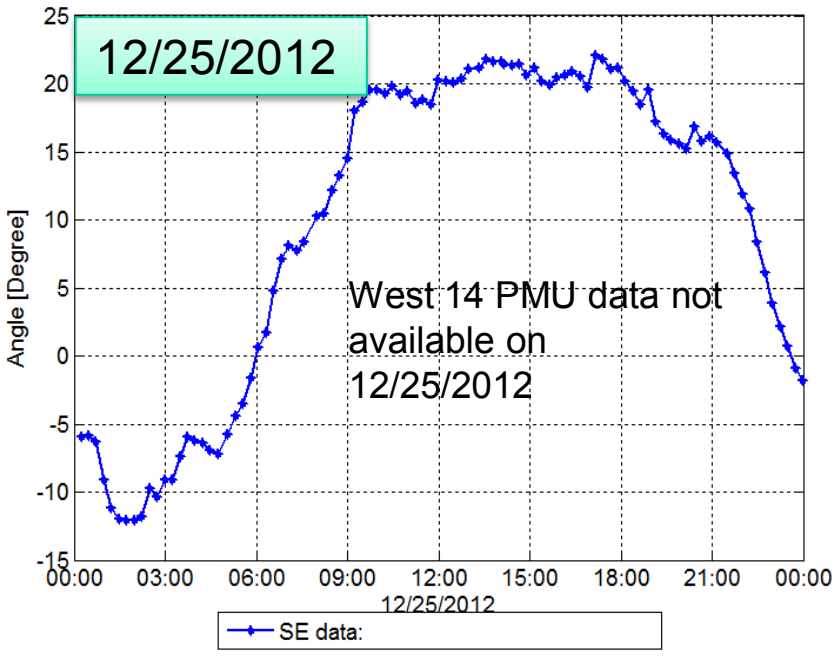
FarWest 7-West 14

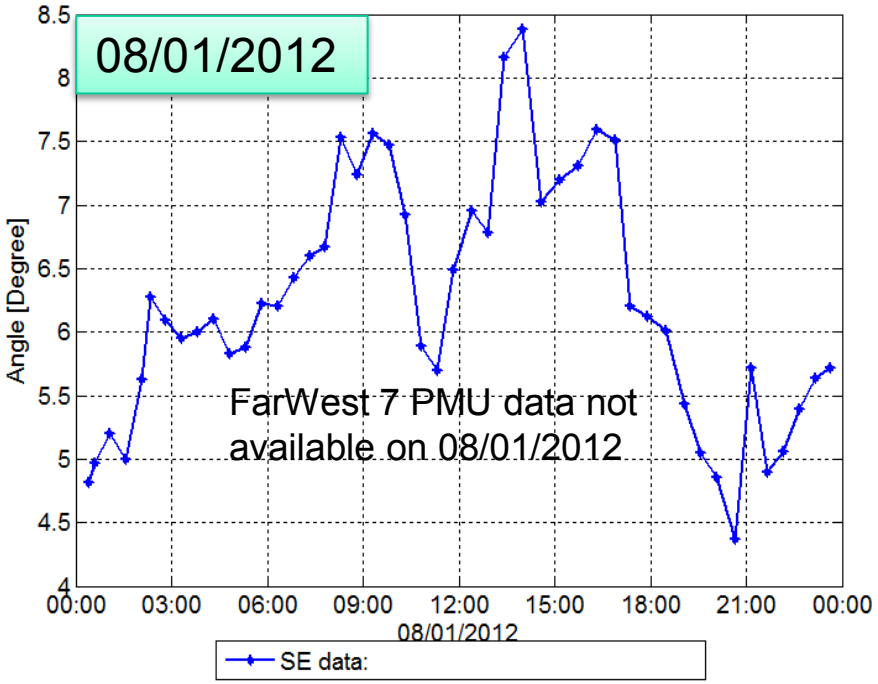


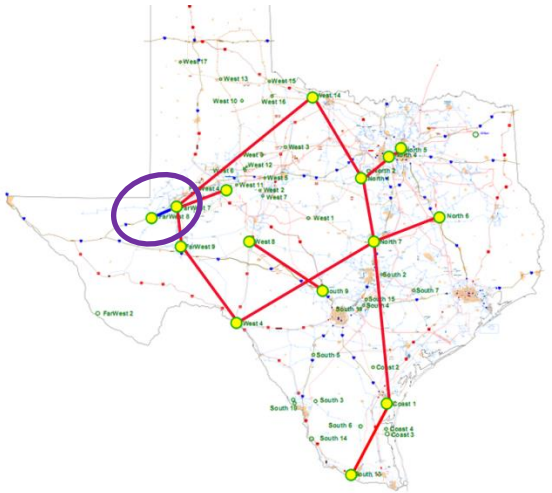


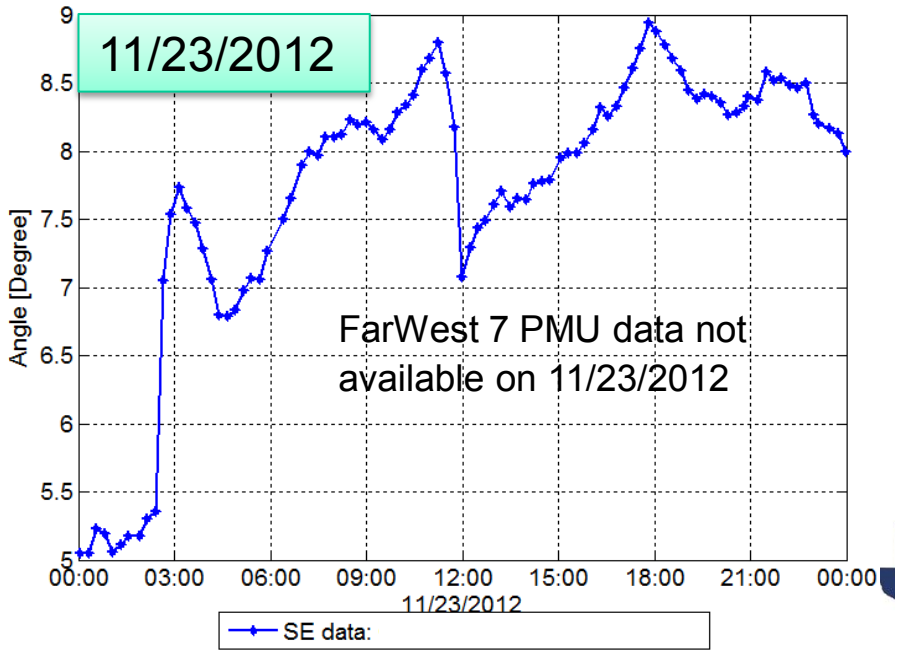


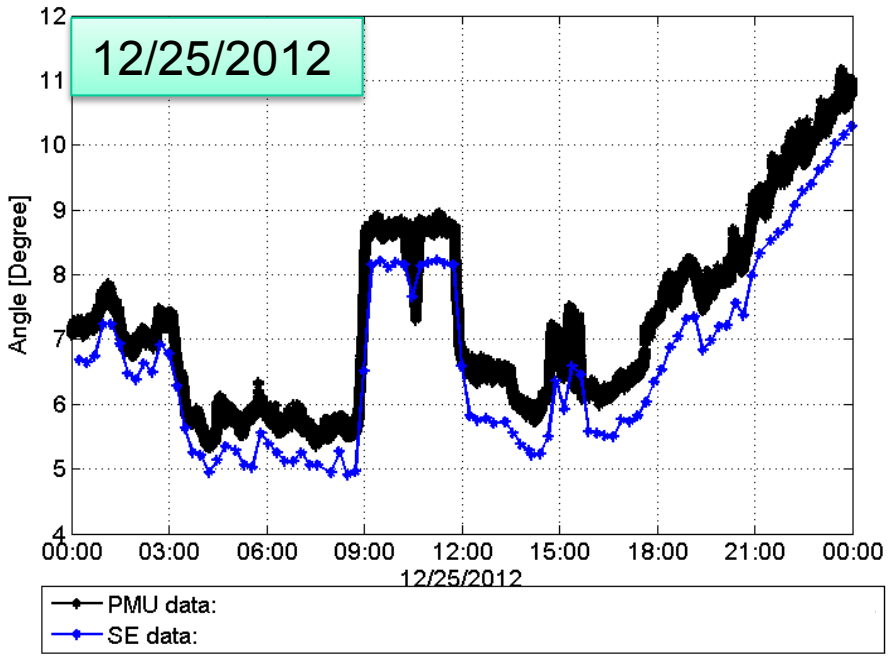


FarWest 7-FarWest 8

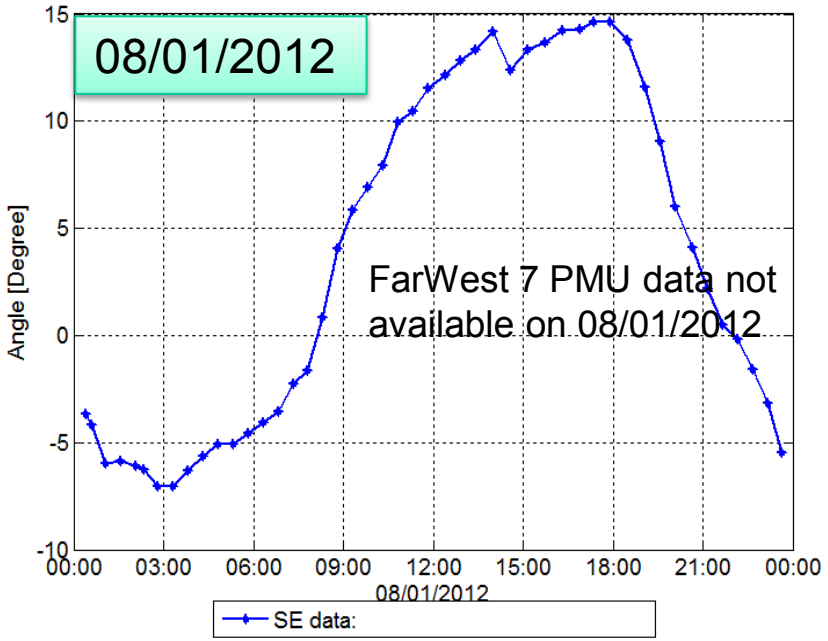


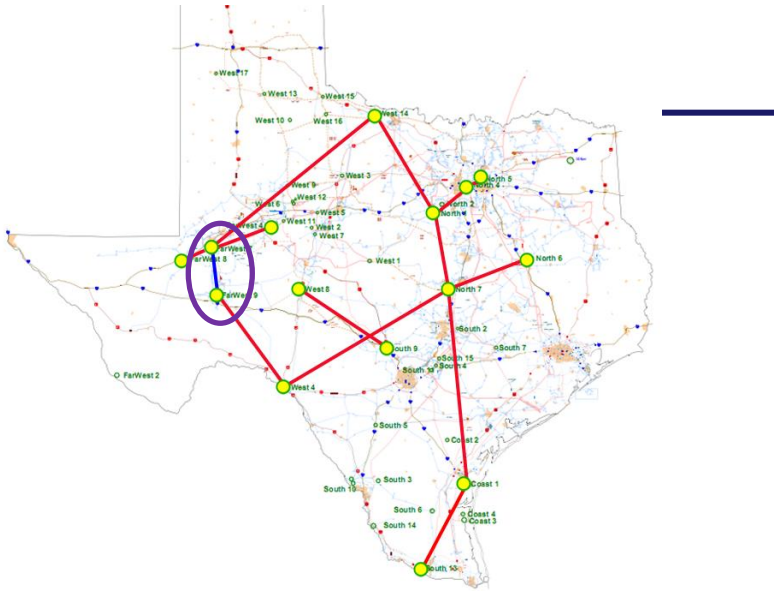


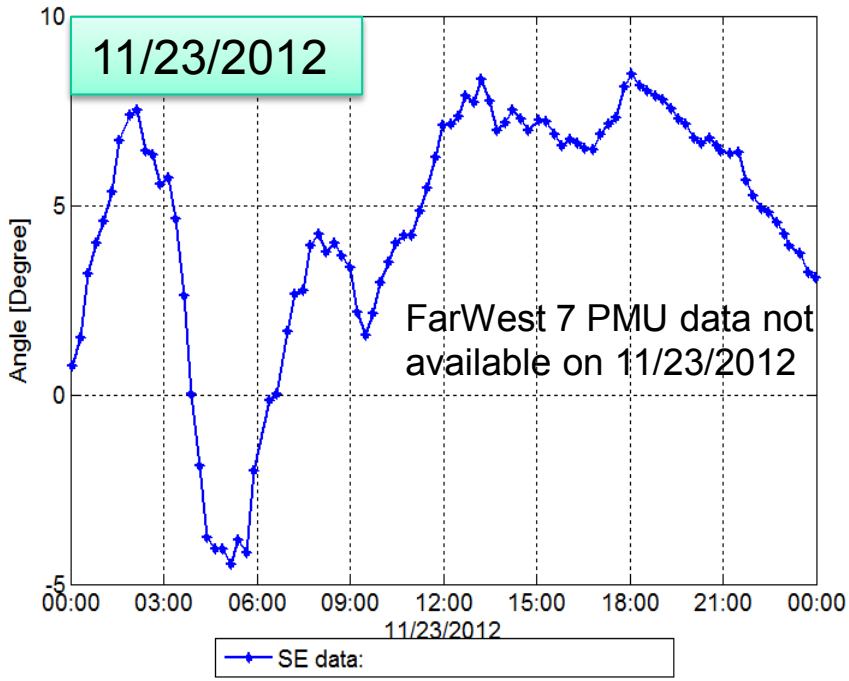


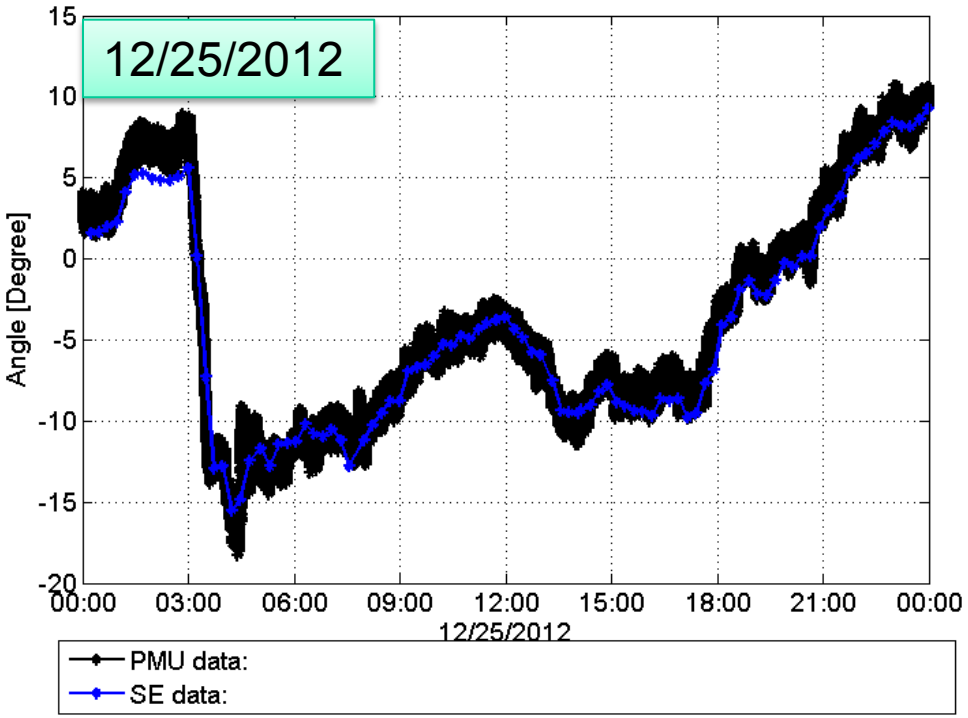


FarWest 7-FarWest 9

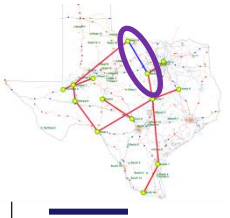


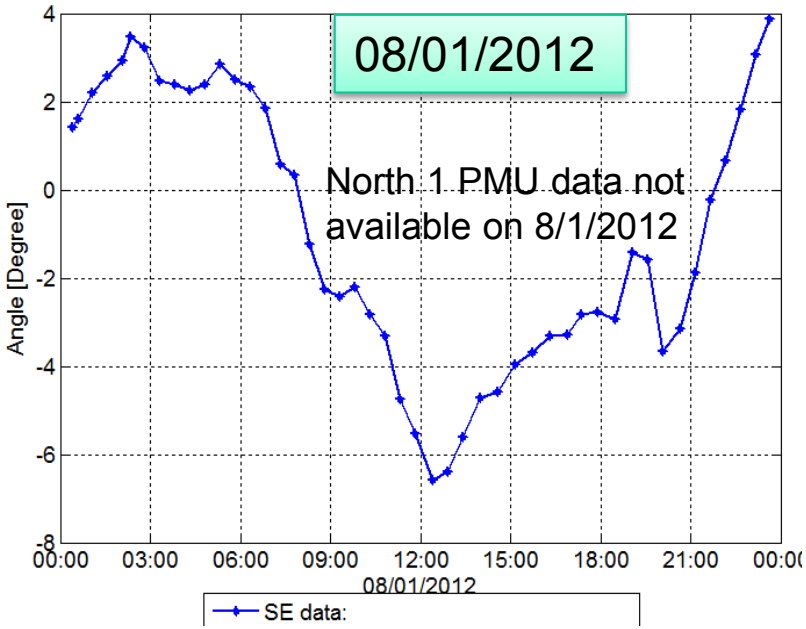


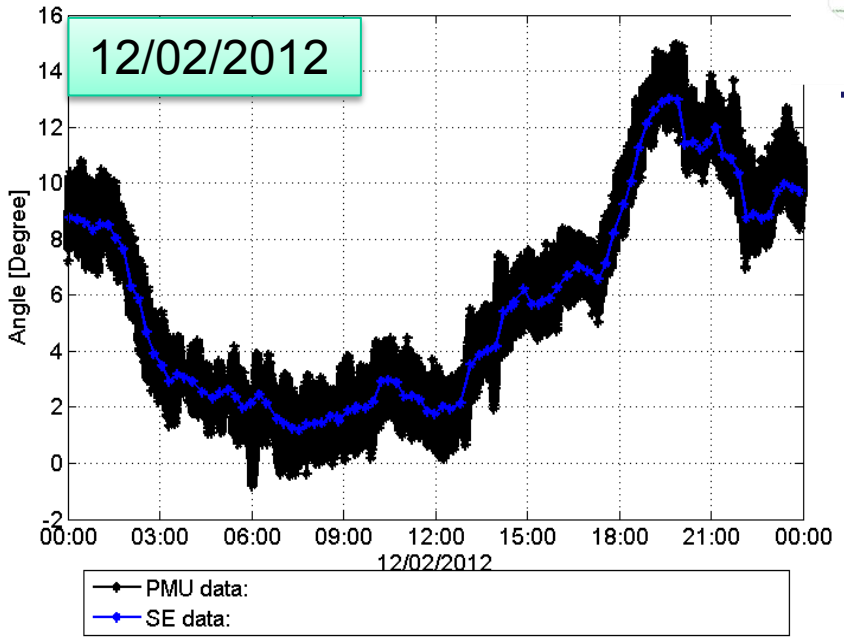


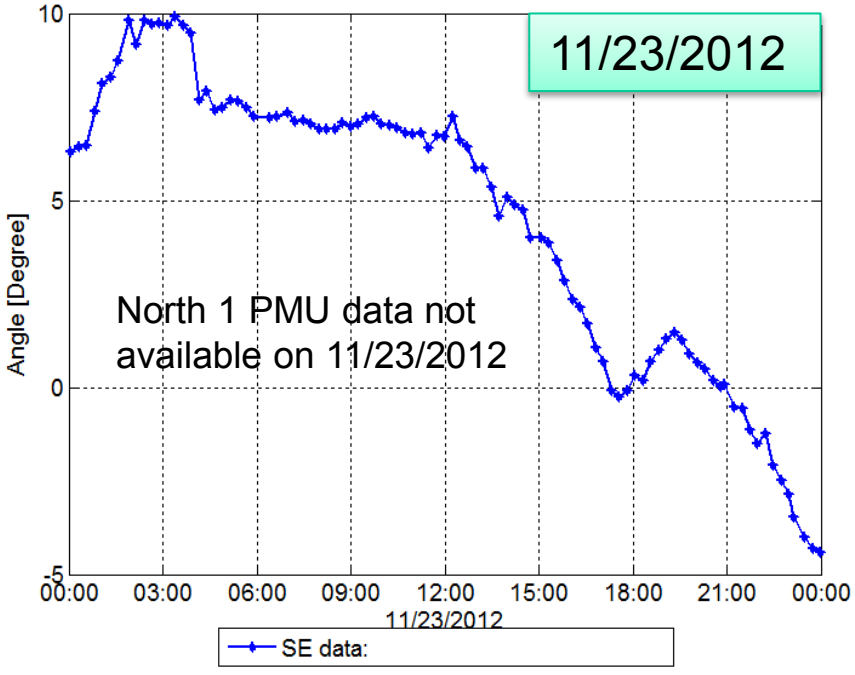


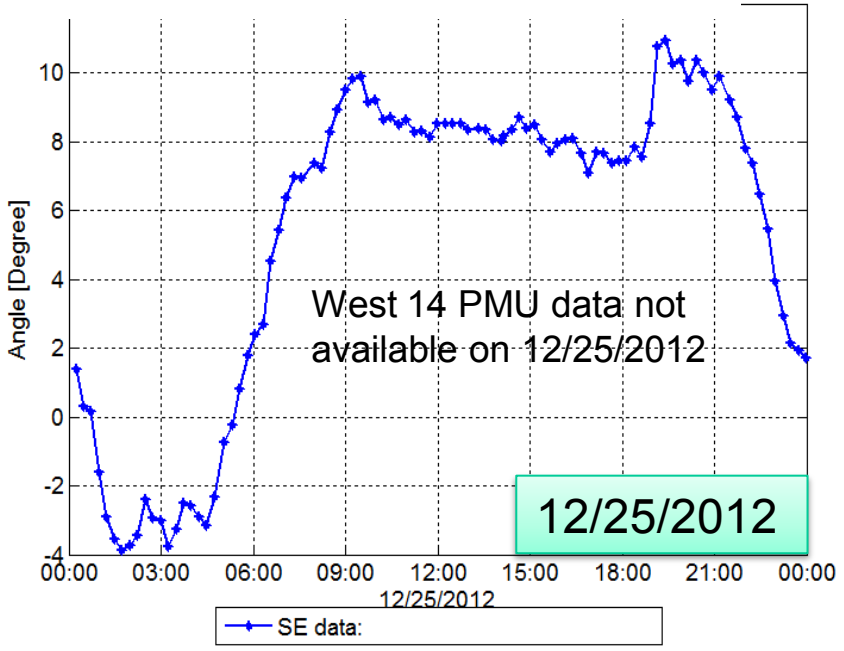
West 14-North 1











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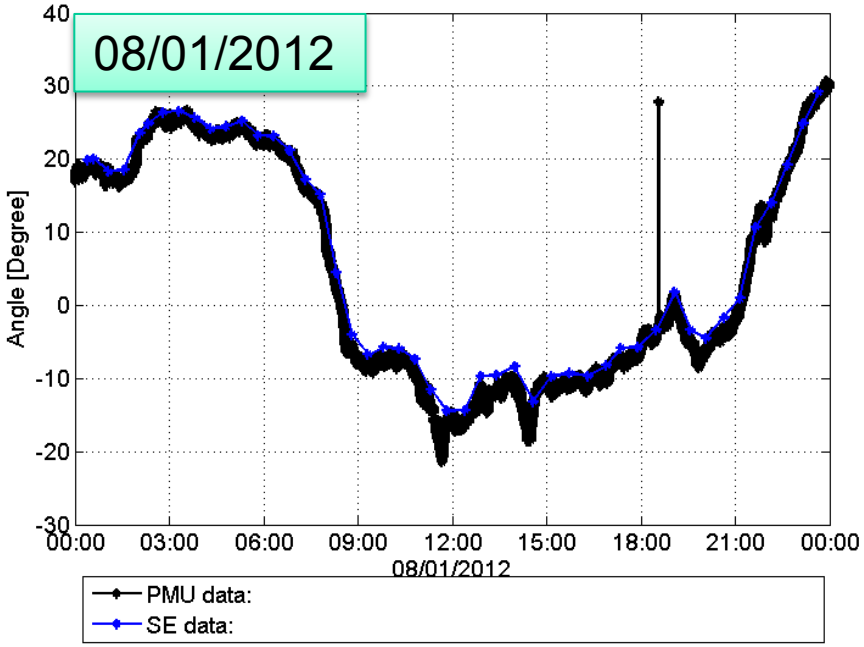
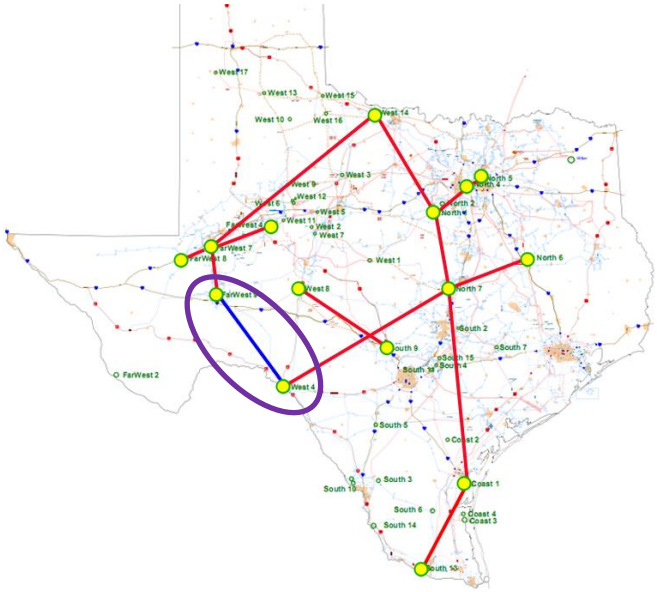
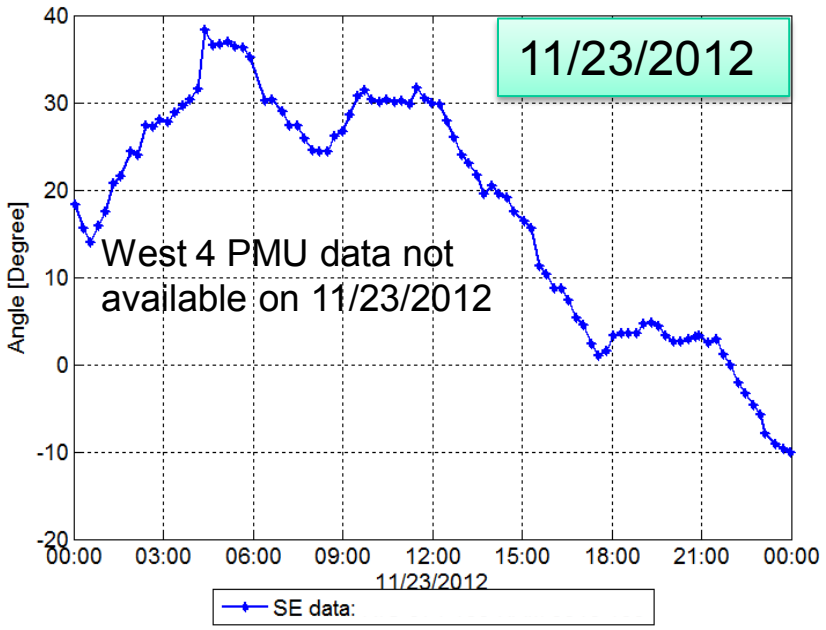
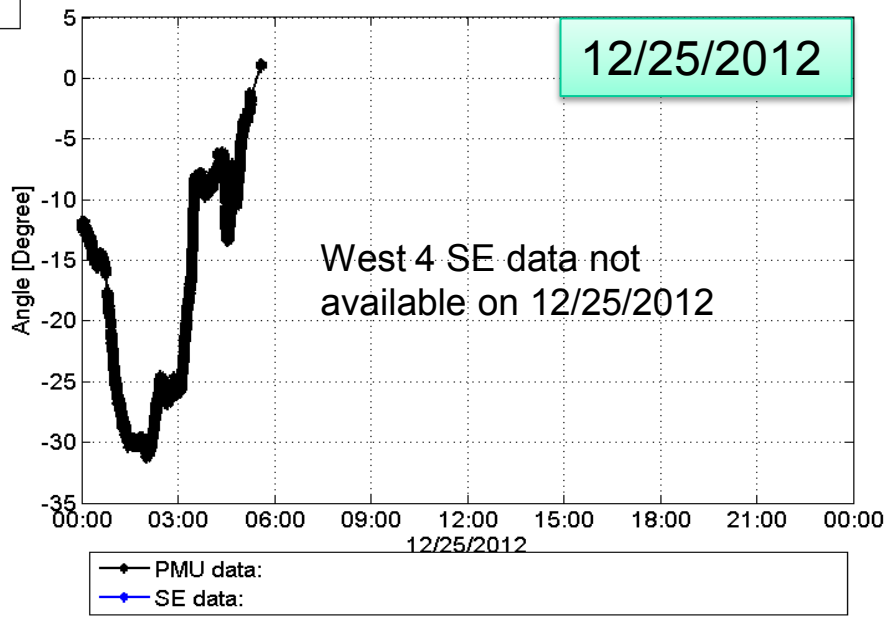
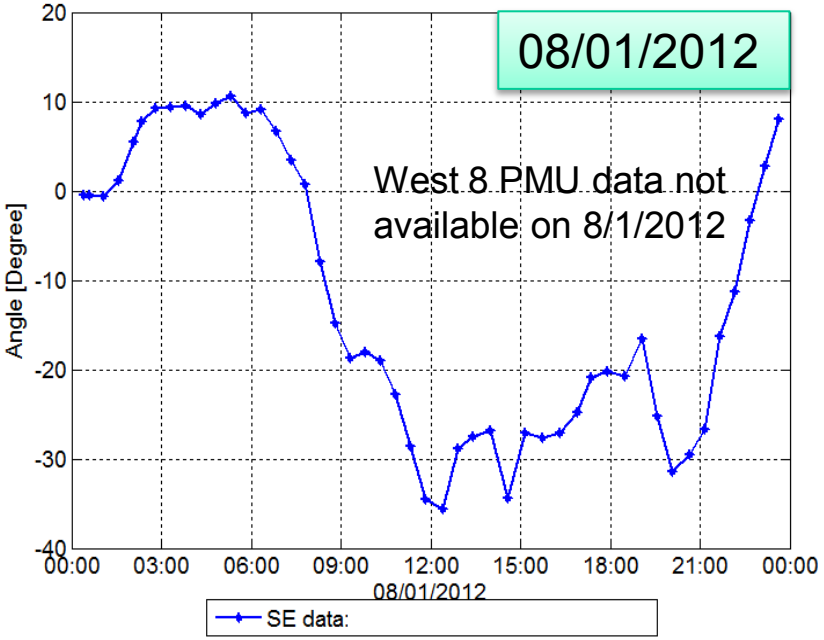


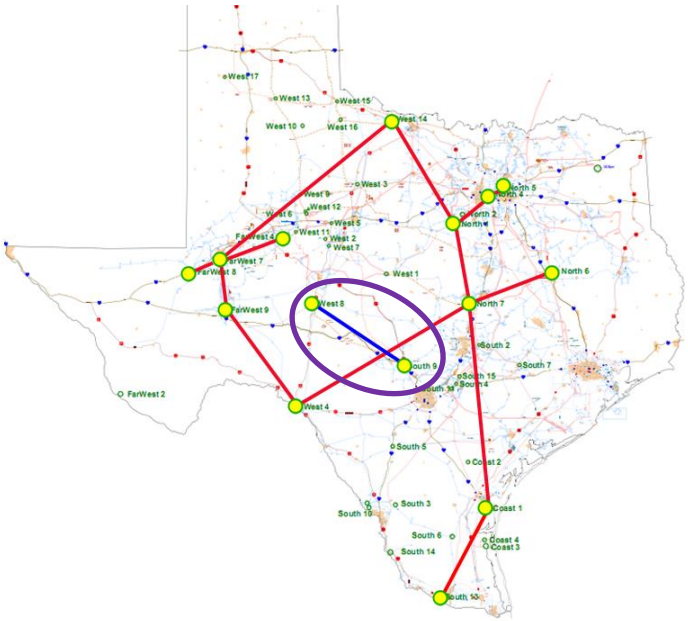






West 8-South 9





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

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

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Appendix C

Baseline Analysis - Voltage Magnitudes Box Whiskers and Time Duration Curves

For: CCET Discovery Across Texas Project

Available Upon Request

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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

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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:

Electric Power Group

Romulo Barreno
Ajay Das
Song Xue

August 20, 2013

External Version

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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		4 Days
03/28 to 03/31/2013		4 Days
	Total	**8 days**

B. Data Availability

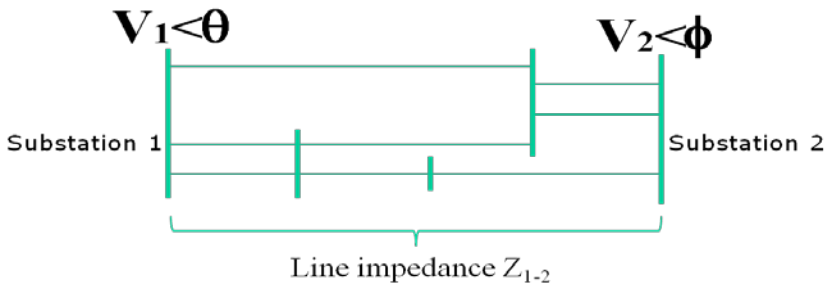
ERCOT produces state estimator cases every 5 minutes for a total of 105,120 possible cases per year. For six months, the total number of possible cases is 52,560; EPG received approximately 15,330 cases, which means the availability of SE data for the first six months of 2013 was approximately 29.2 %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



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.

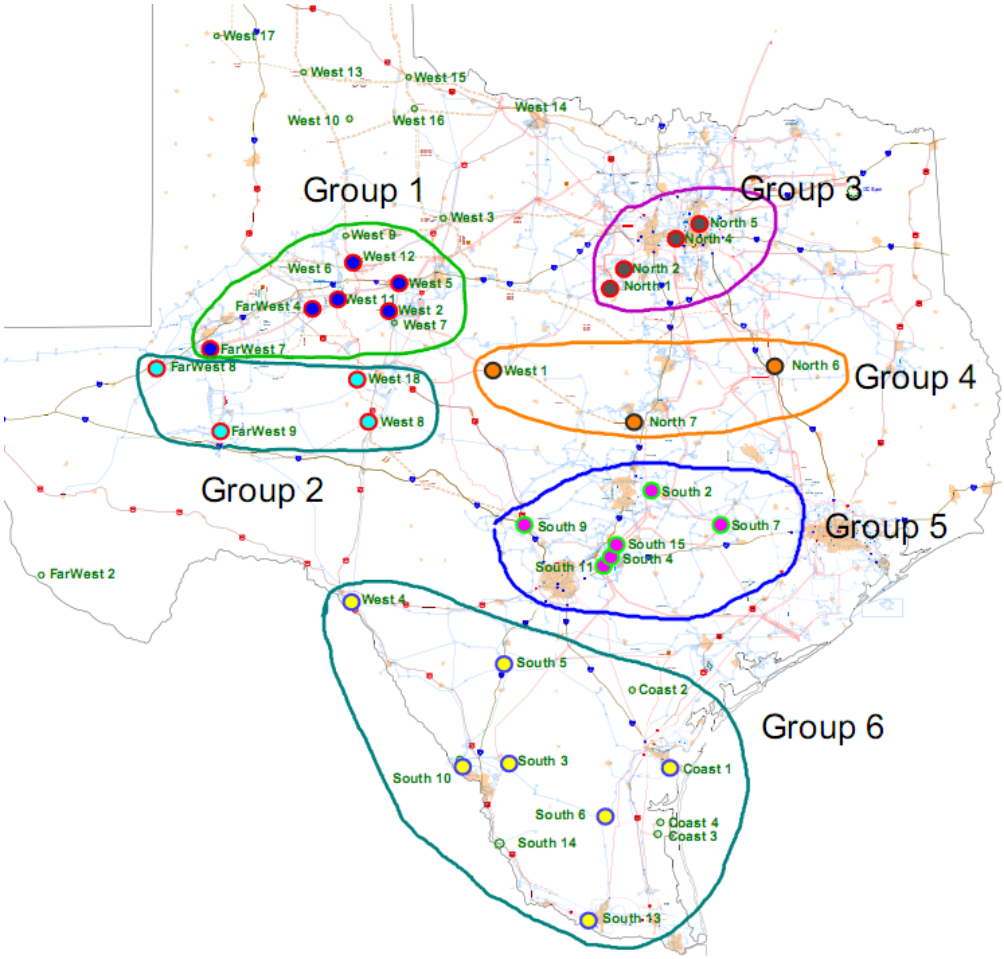
In the 2012 Baselining Study, EPG grouped substations based on geographical proximity as shown in the map and table below in order to find trends regarding angle differences referenced to North 7. The results of the 2012 study showed that there was strong correlation between the substations in Group 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.

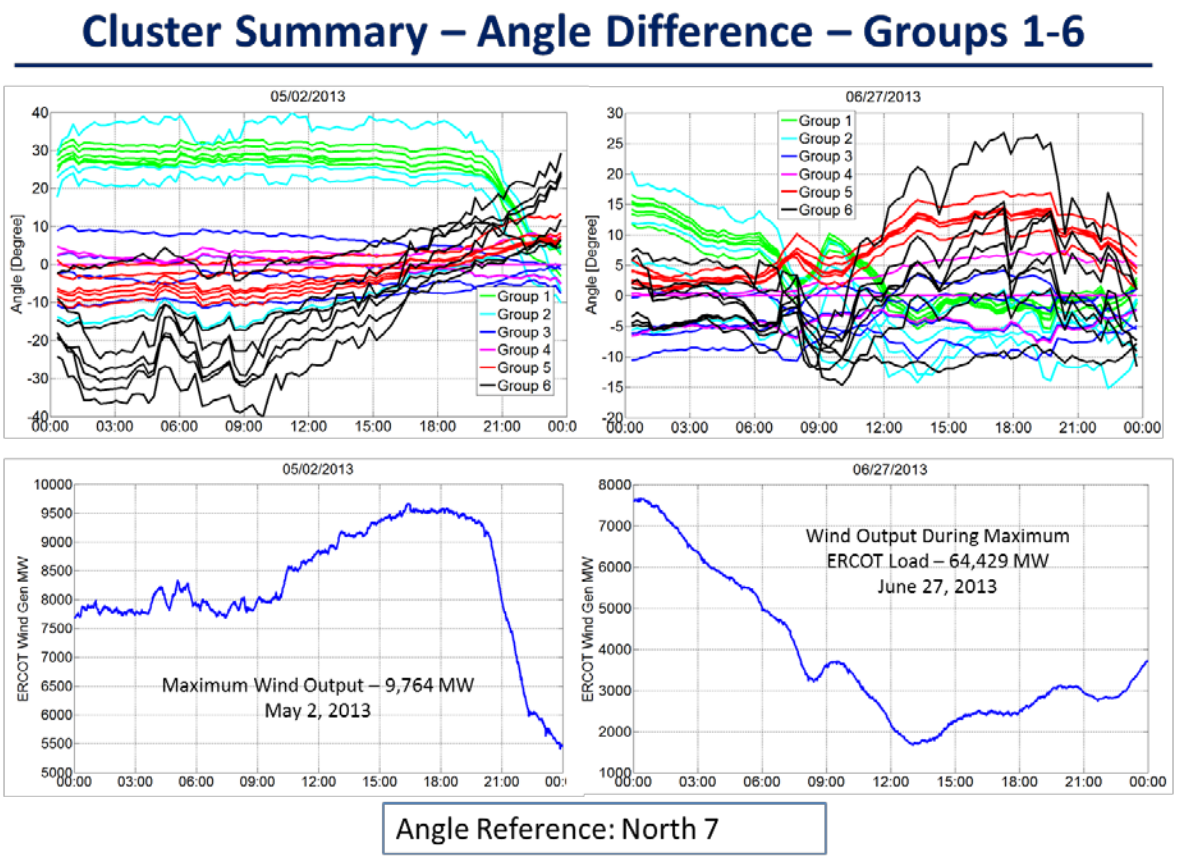
Below is a map with the geographical location of the substations in the groups and below it are listed the six groups and the substations in each group.



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:



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 for 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 observed behavior 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 difference 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 degree range most of the day. All of 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 between 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 degree range.
e. In Group 3, the 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, the 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

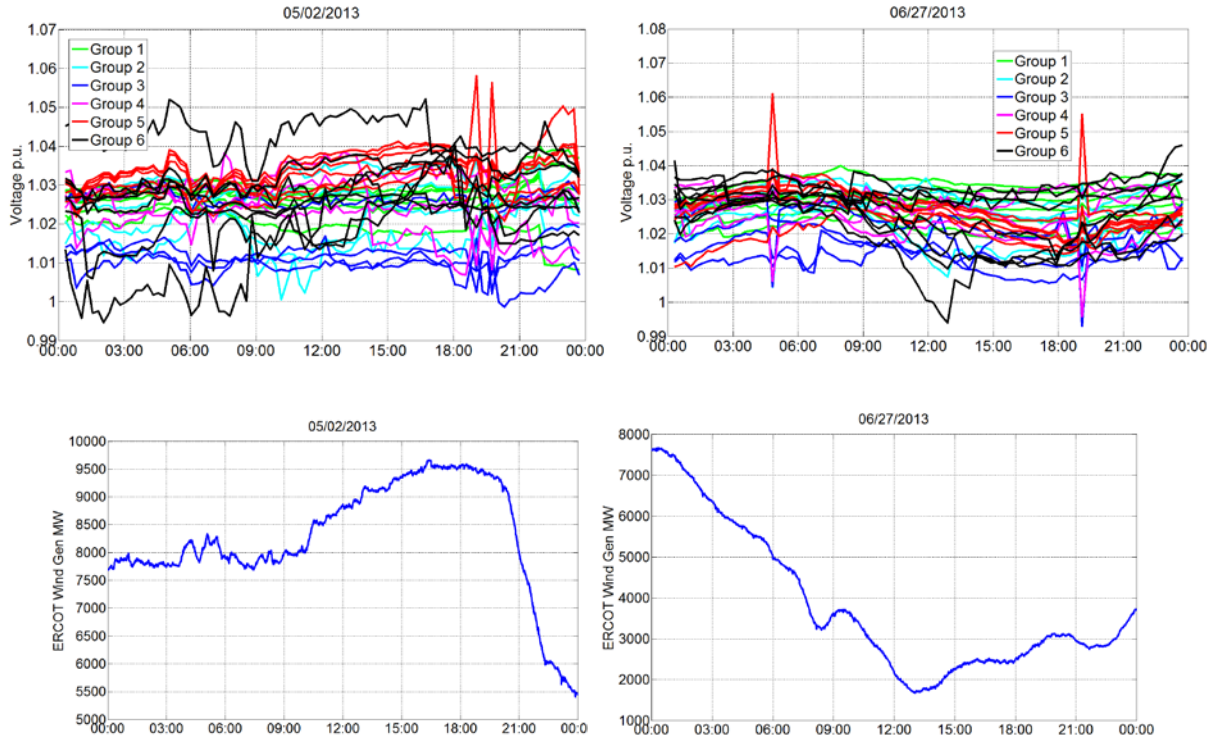
morning, to load increase in late morning to late afternoon, and to load decrease and mild wind increase in the evening.

7. CLUSTER ANALYSIS – VOLTAGE MAGNITUDES

Using the same six groups as for the phase angle difference 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 per unit (pu) range whereas for the maximum wind output, low load day (May 2), the voltages operated within a wider range: 1 pu to 1.05 pu. 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

a. **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 about 1%. On June 27, the voltages in this group operated in the 1.017 and 1.04 range. 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 pu range with FarWest 9 fluctuating the most between 1.027 and 1.00 pu. On June 27, the voltage at FarWest 8 spiked down 1% at about 5 a.m. 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 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 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 pu.
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:

a. 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.
b. 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.
c. Maximum group average voltages observed were in Group 6 (141.78kV) and Group 5 (356.12 kV).
d. 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.
e. The 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

Electric Power Group

ERCOT

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:

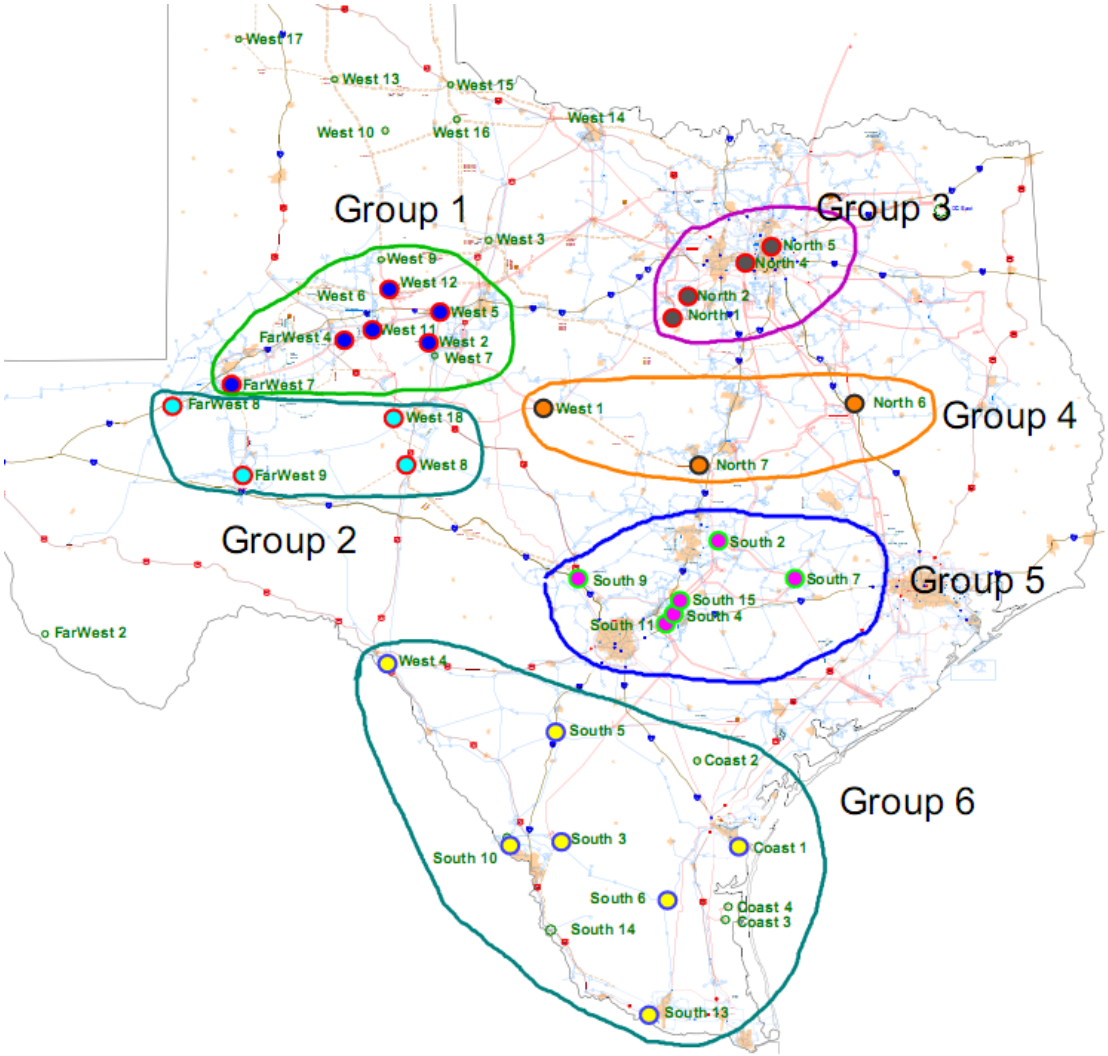
- South 7
- South 9
- South 11
- South 2
- South 4
- South 15

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



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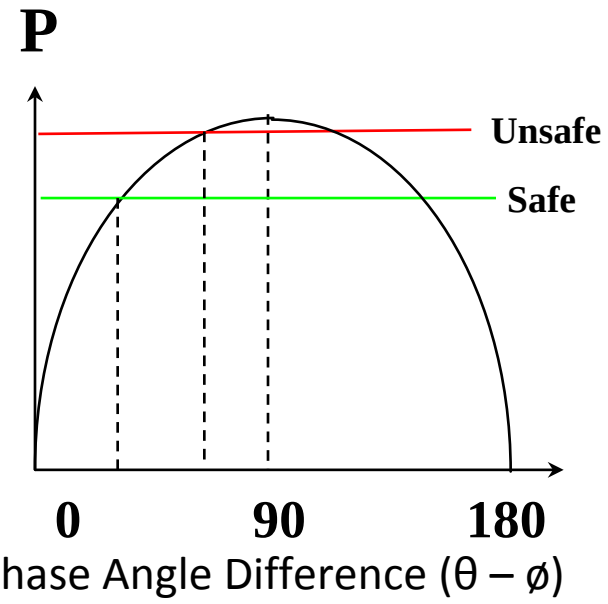
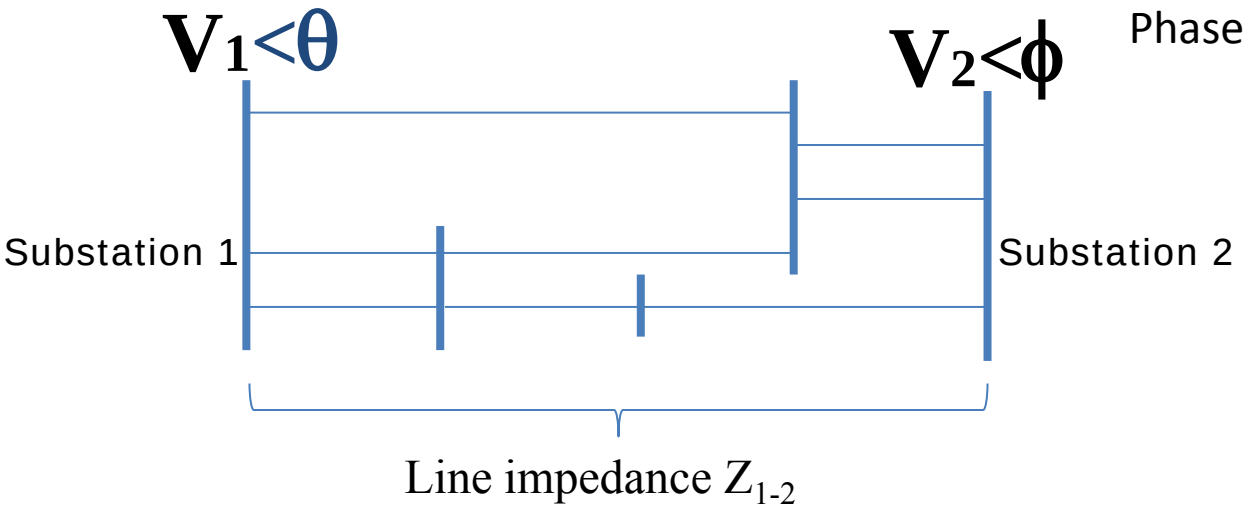
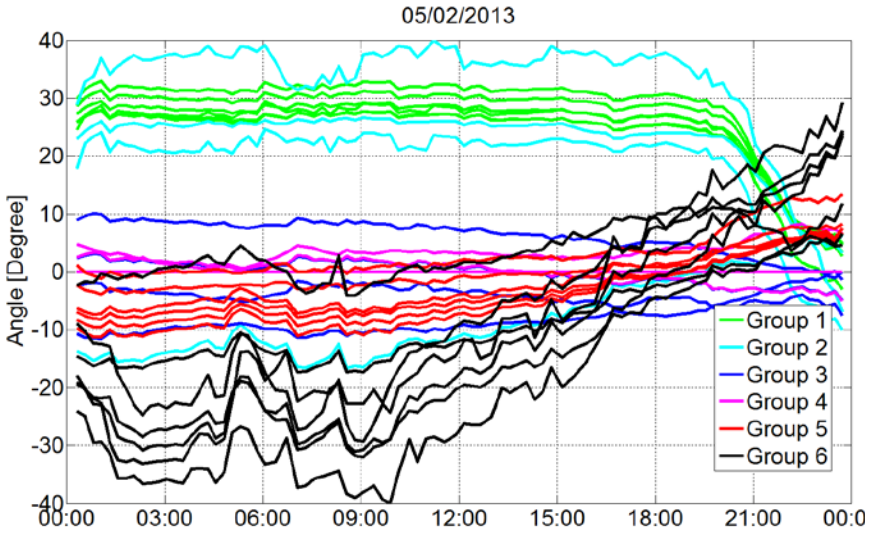
Phase Angles Differences as Indicators of Power Flow

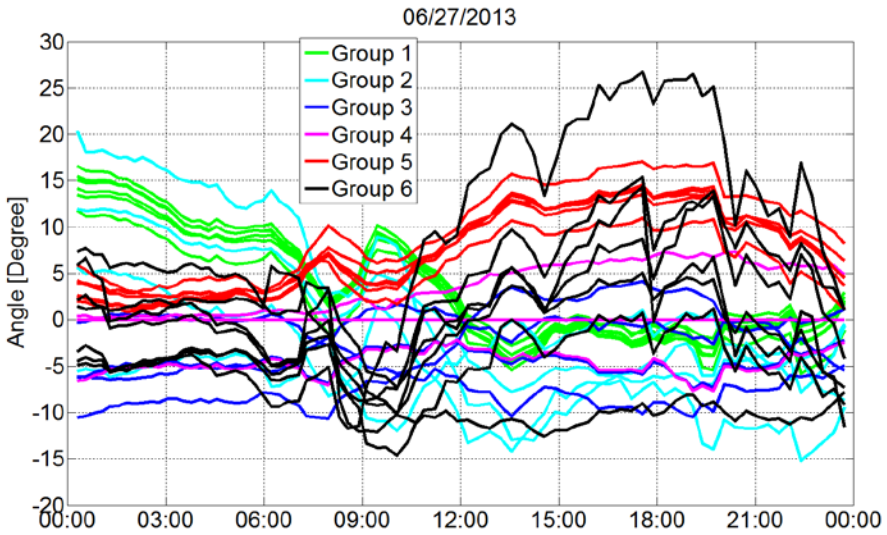
- Power flow follows voltage angle difference
  - Power flow: $P = V_1 V_2 \sin(\theta - \phi)/Z$
- Any change in power flow or impedance will be reflected in a change in voltage phase angle difference between two locations

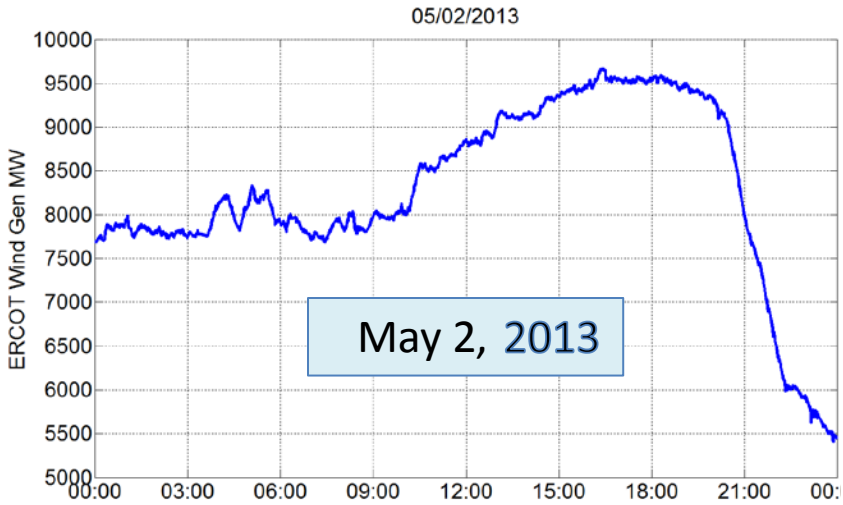


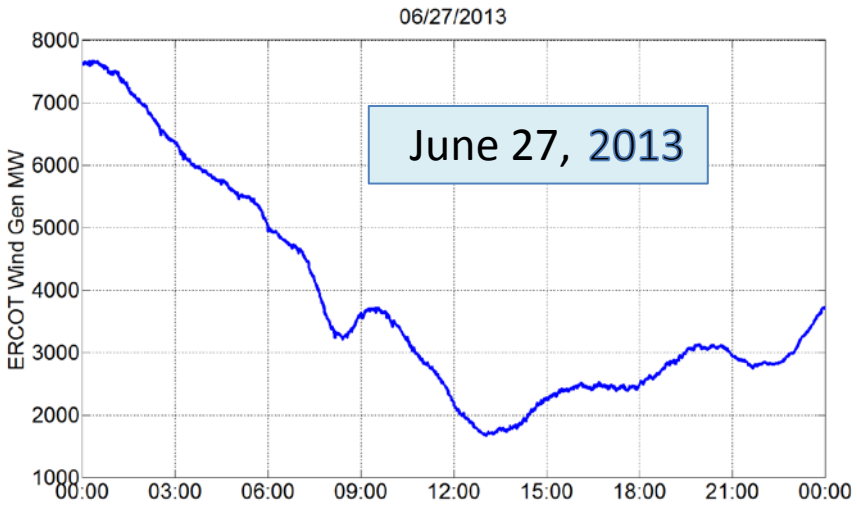


Cluster Summary – Angle Difference – Groups 1-6









Angle Reference: North 7

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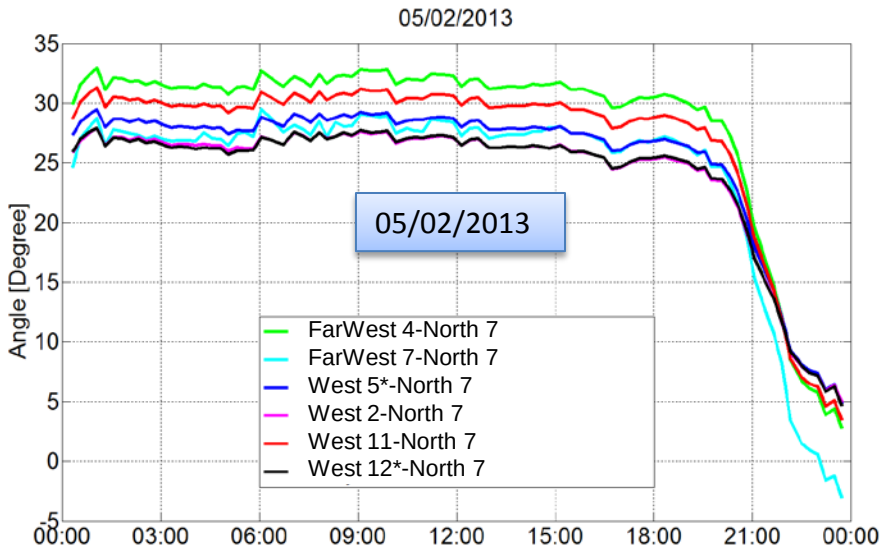
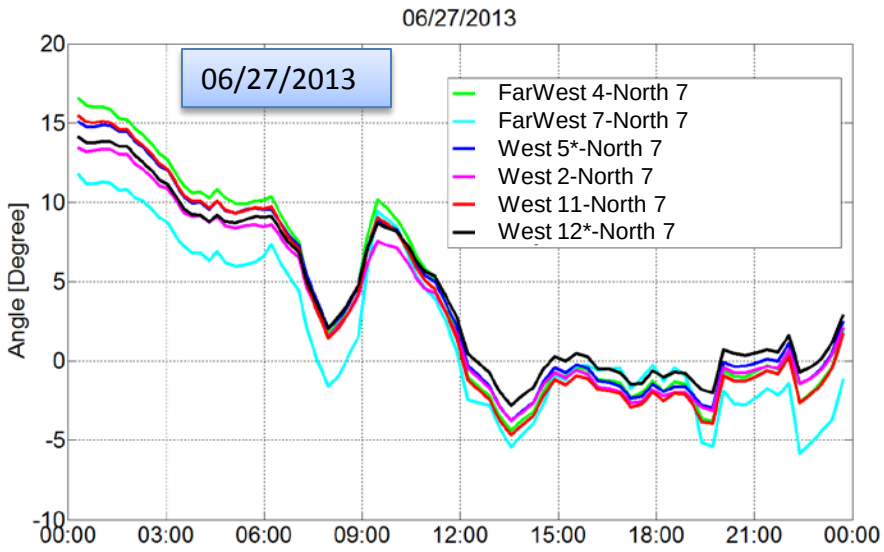
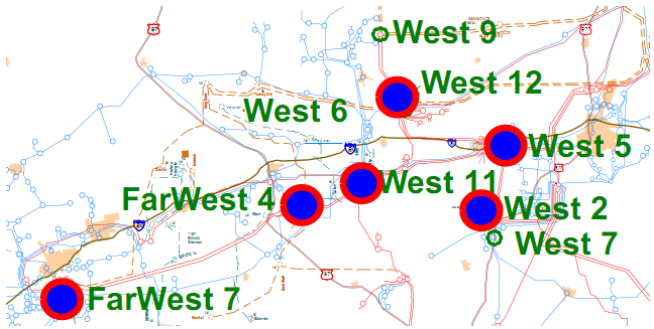
Group 1 – West Texas



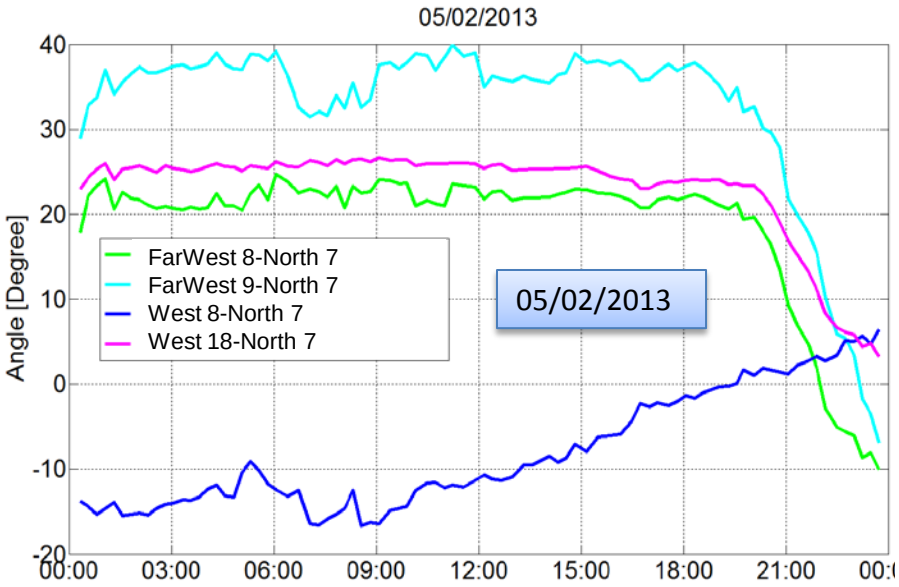


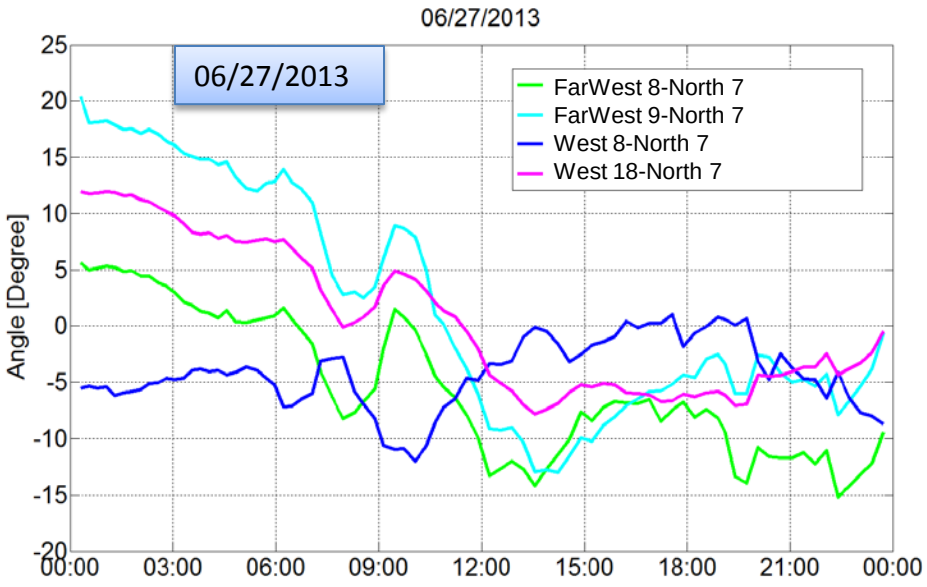


New lines in the area:

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

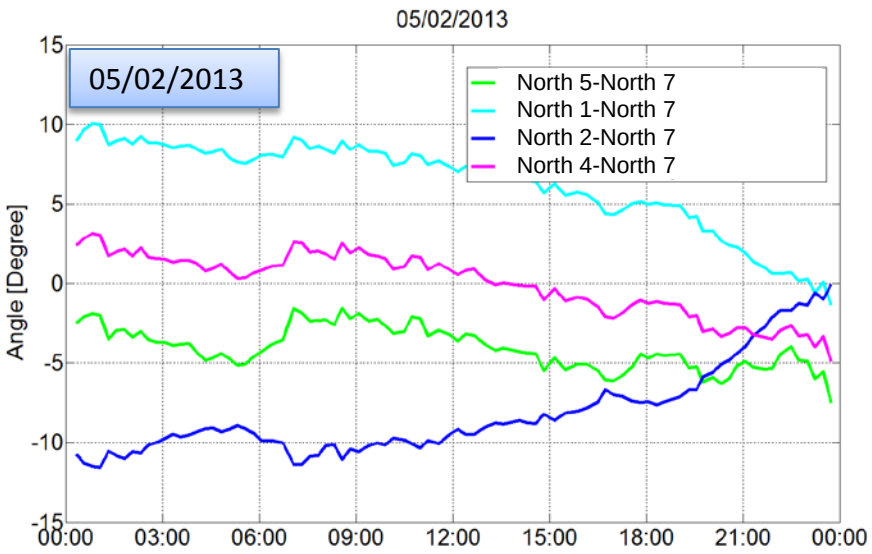


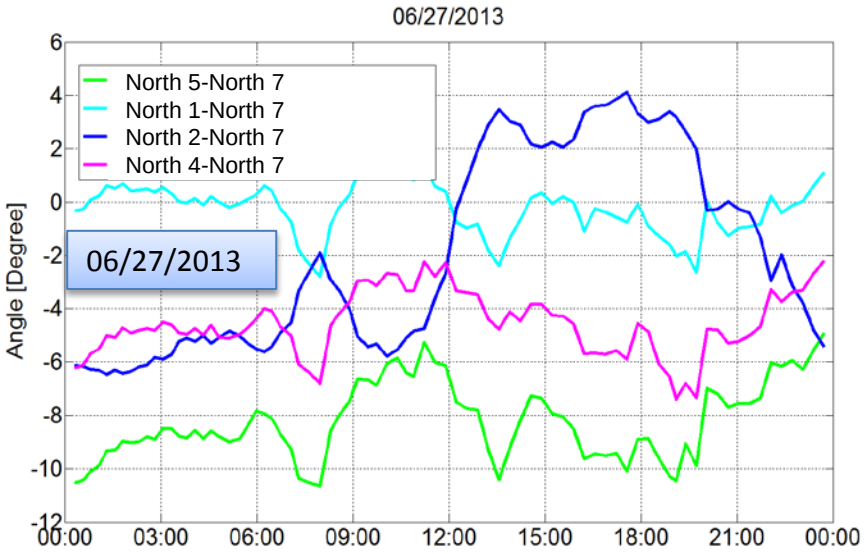


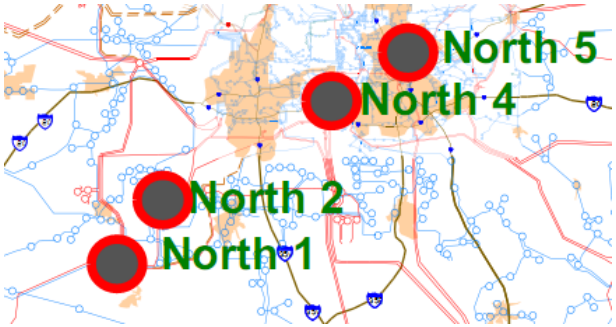
New lines in the area:

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

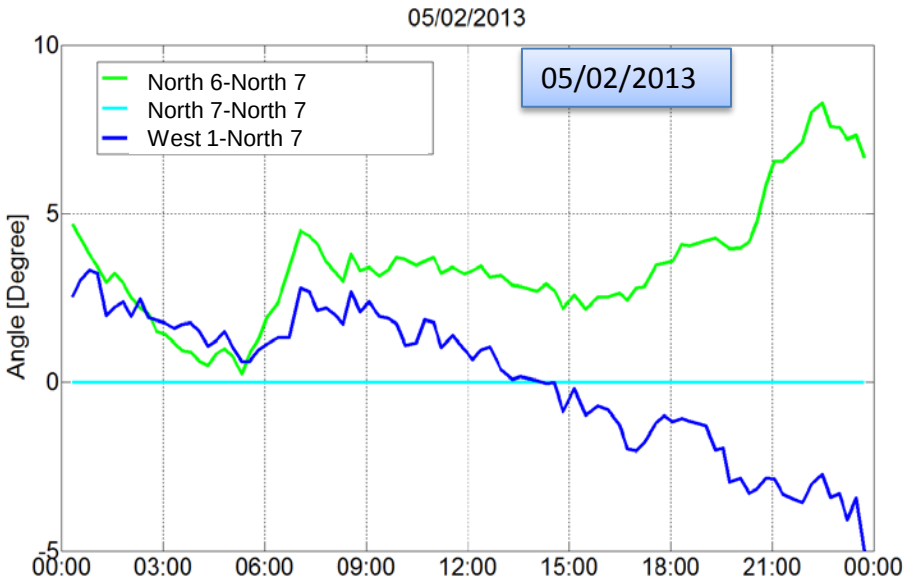
Group 3 - Dallas

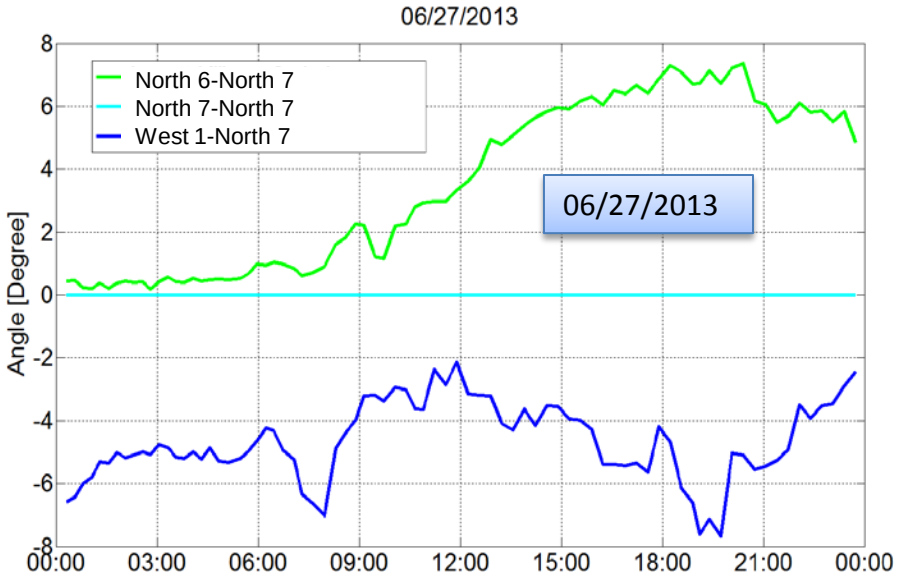


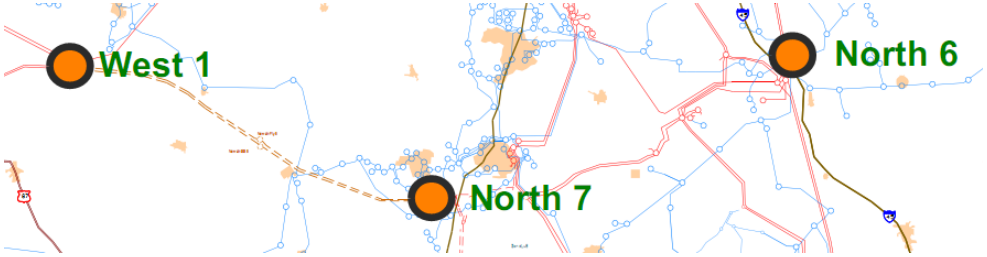




Group 4 – Central East







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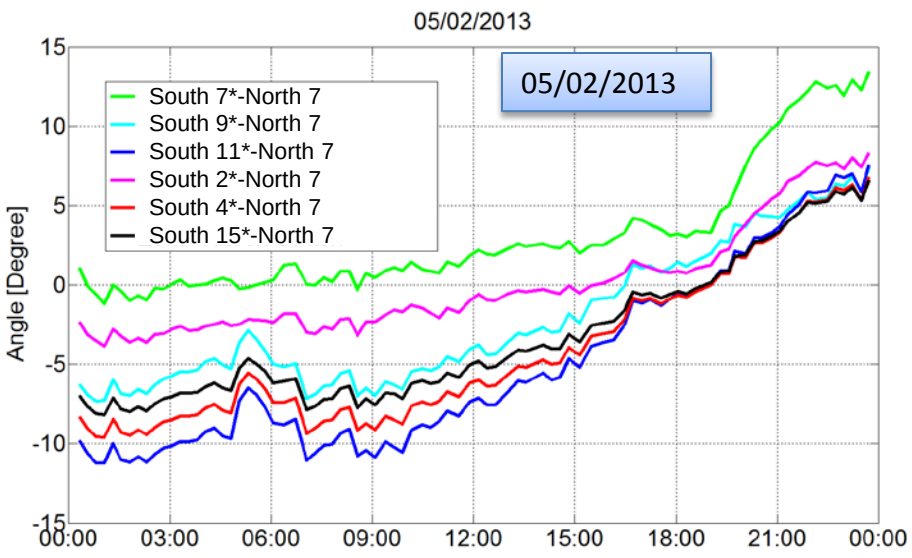
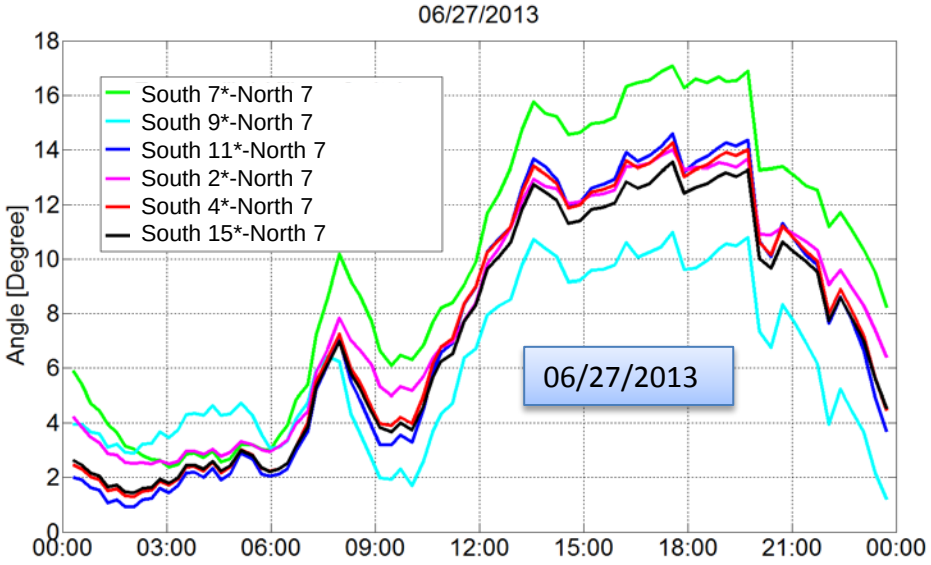
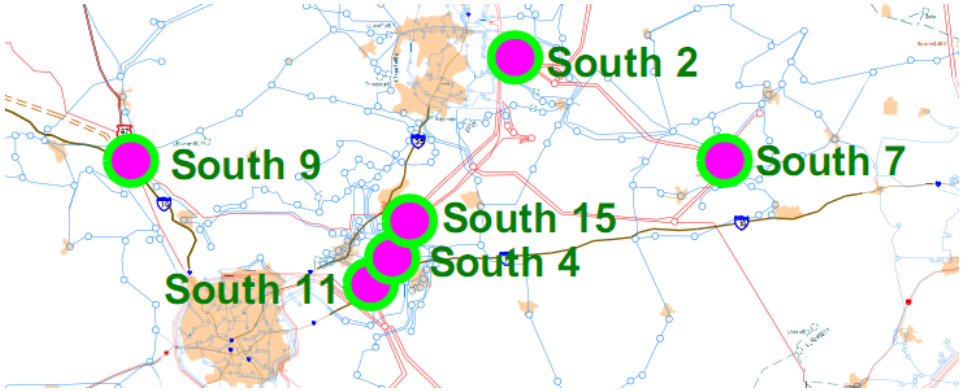
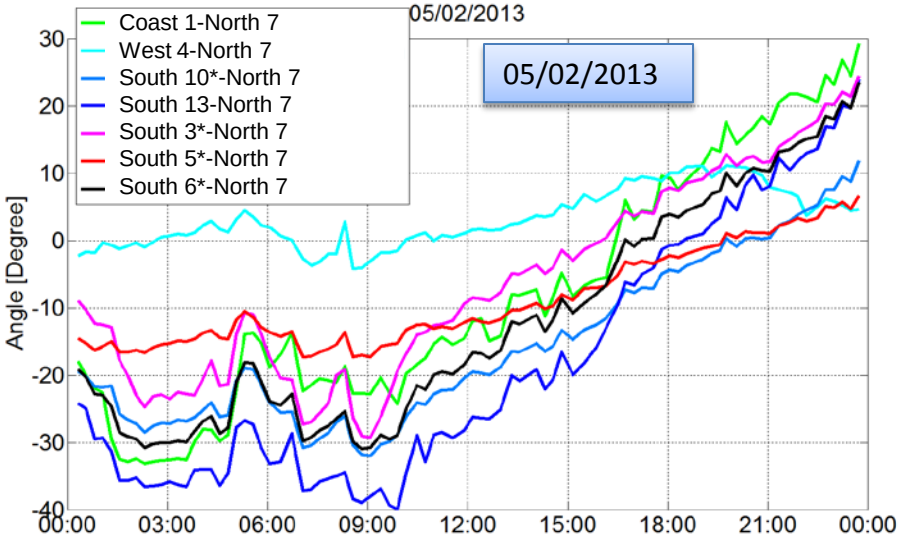
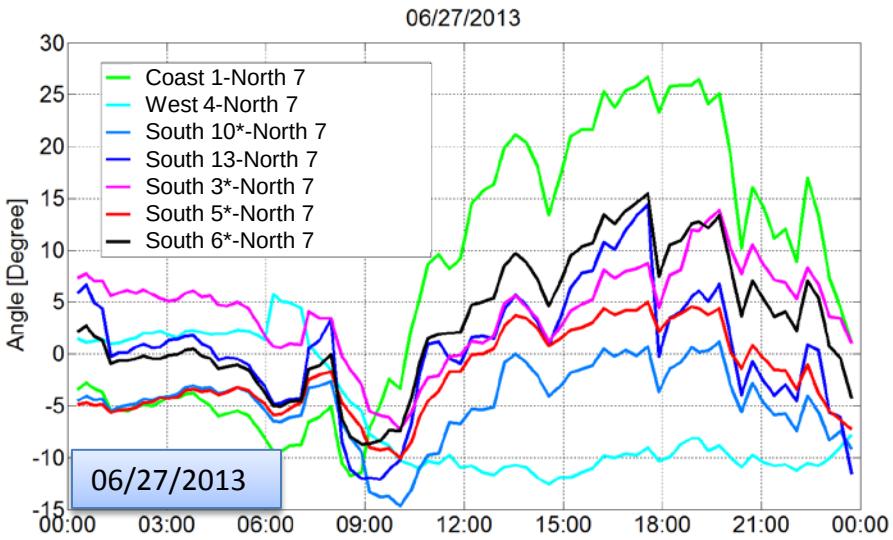


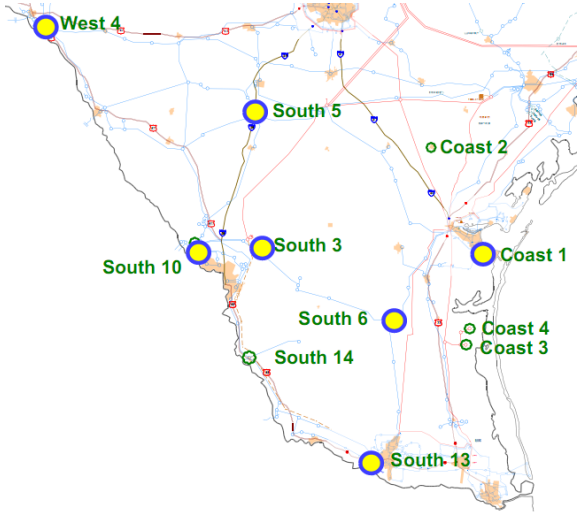




Group 6 – Valley (South)







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 & C 9l-:

- West 1
- North 6
- North 7

Group 5 – 345 C l-f East:

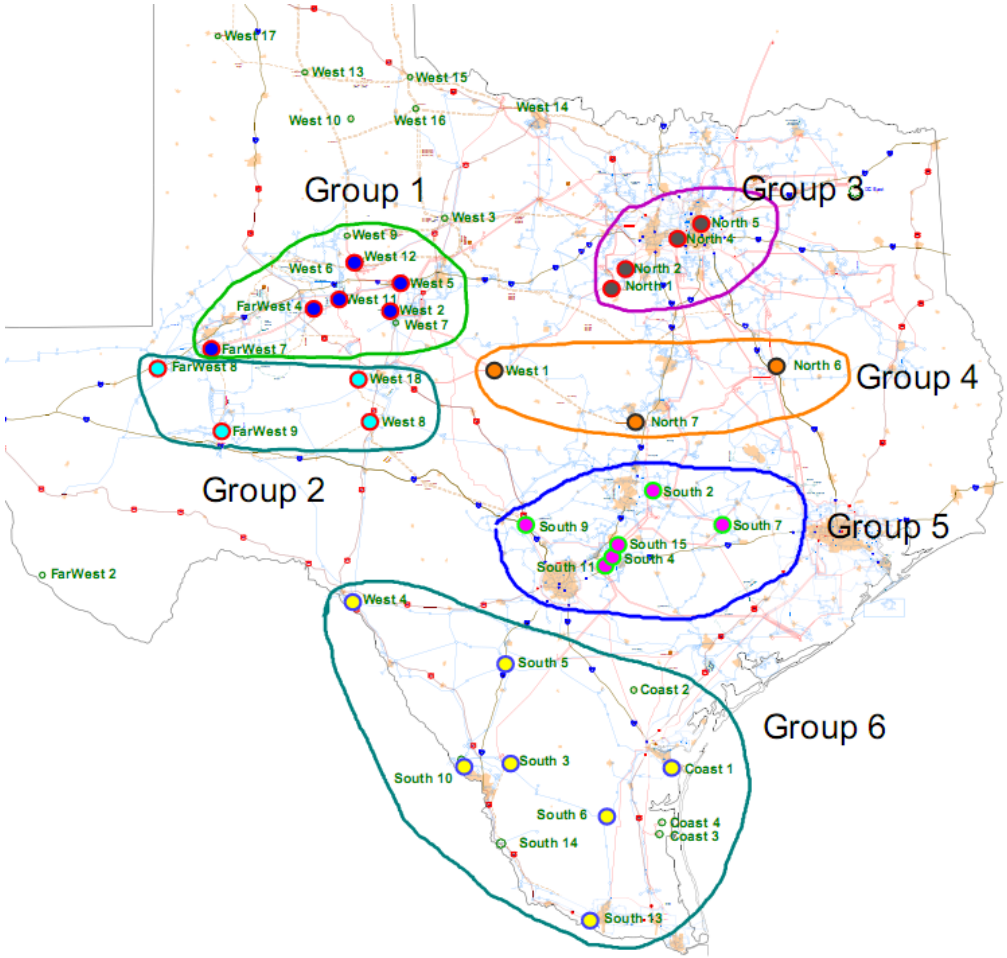
- South 7
- South 9
- South 11
- South 2
- South 4
- South 15

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

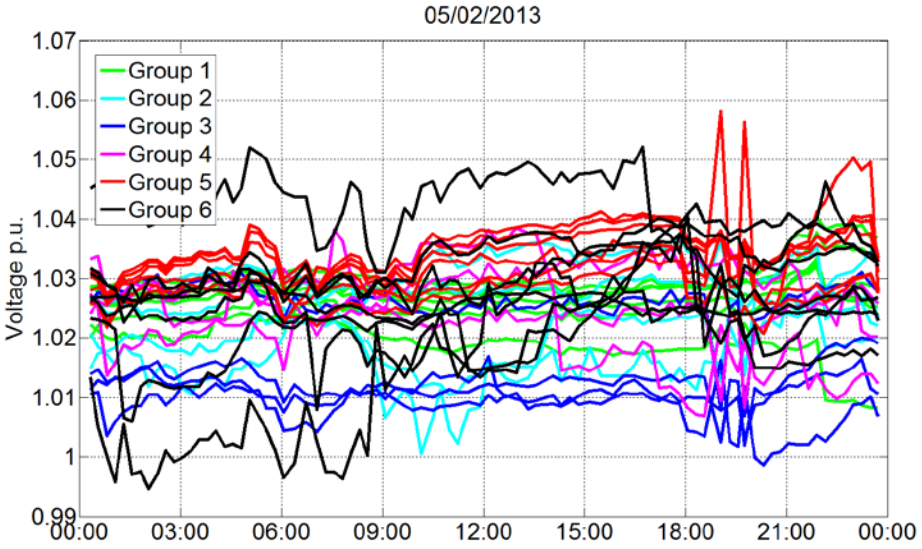
Cluster Locations: Groups 1-6

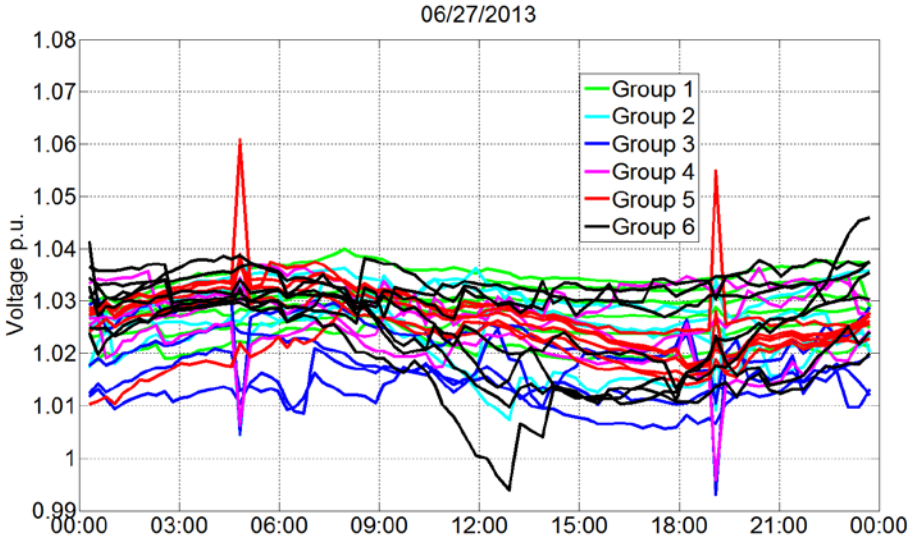


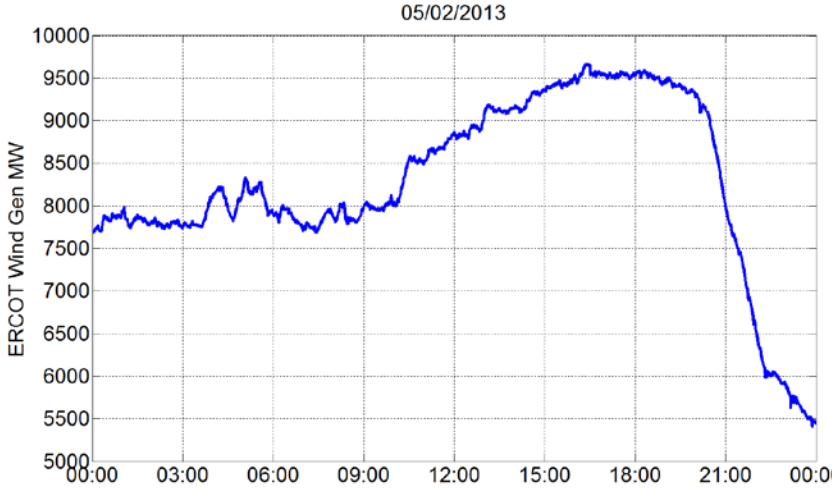
Groups 1-6 - Daily Average Voltages

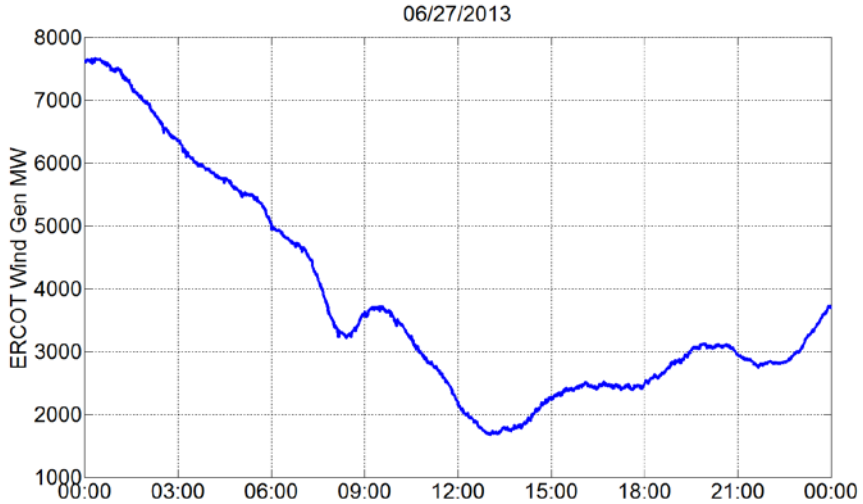
		5/2/2013		6/27/2013	
		Average(kV)	Average(p.u.)	Average(kV)	Average(p.u.)
Group 1	FarWest 4	355.15	1.03	354.67	1.03
	FarWest 7	351.85	1.02	352.35	1.02
	West 5*	355.07	1.03	355.43	1.03
	West 2*	355.17	1.03	357.14	1.04
	West 11	354.20	1.03	353.60	1.02
	West 12*	353.43	1.02	355.87	1.03
Group 2	FarWest 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



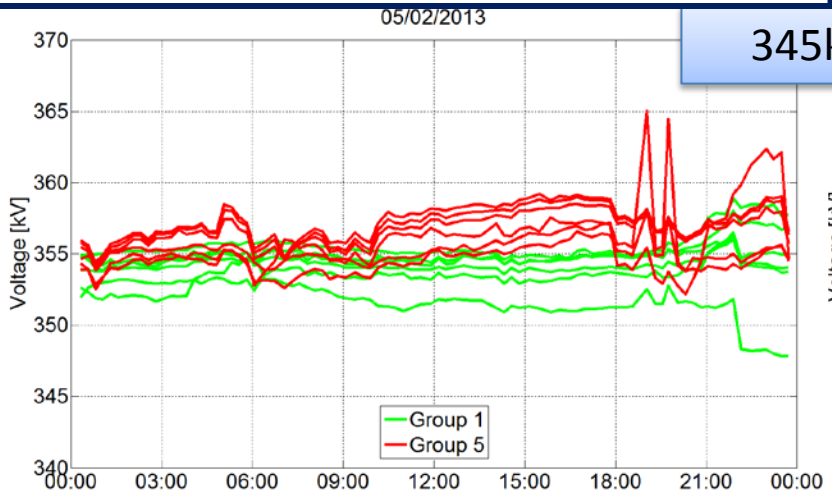


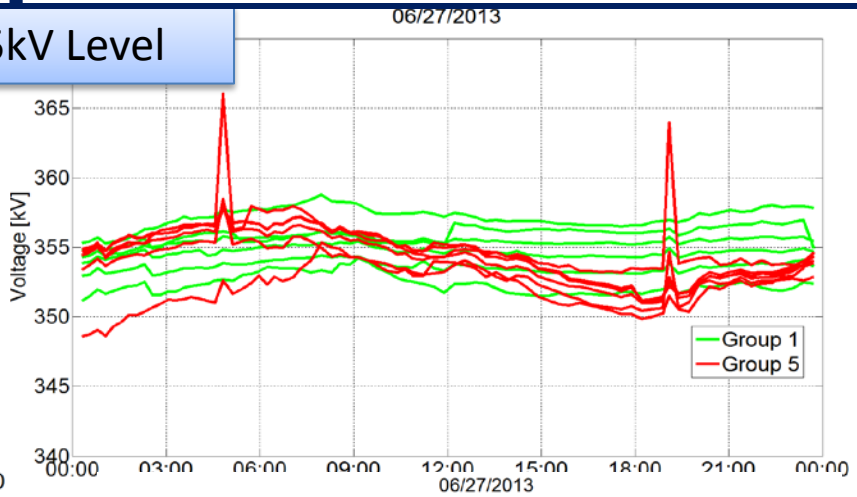




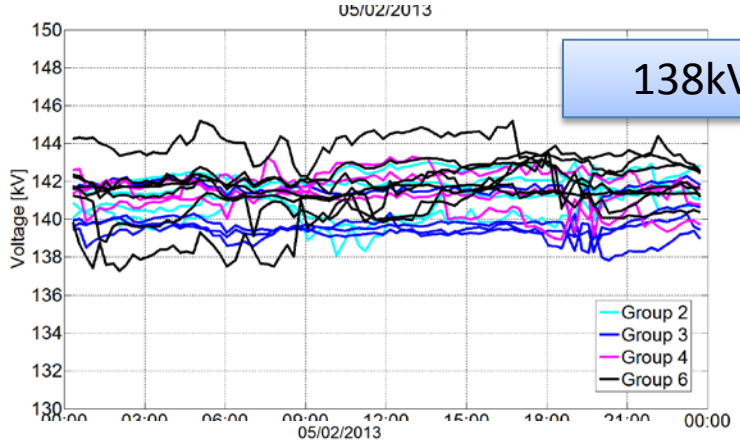
Groups 1-6

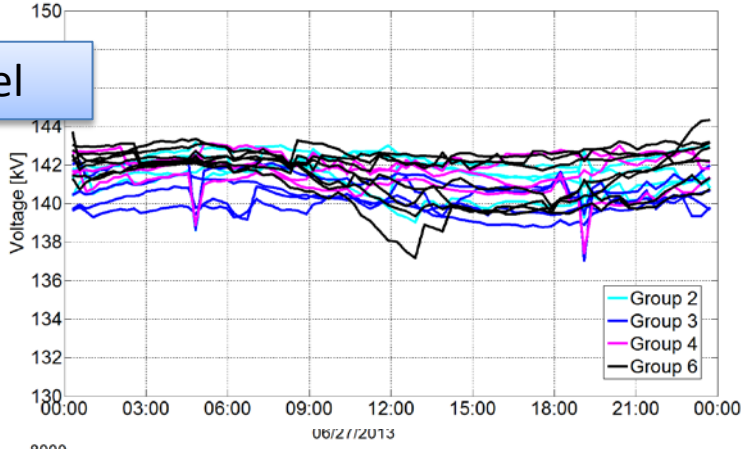
345kV Level

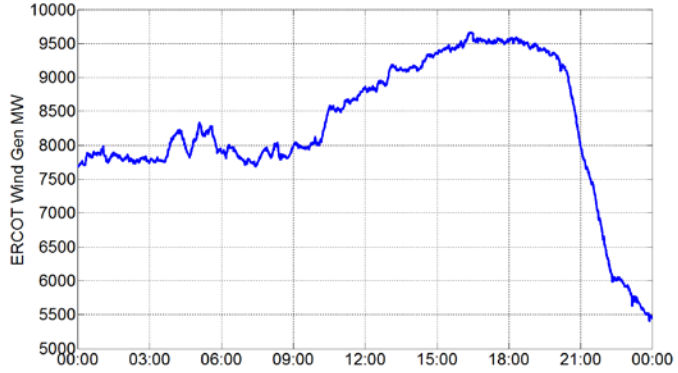


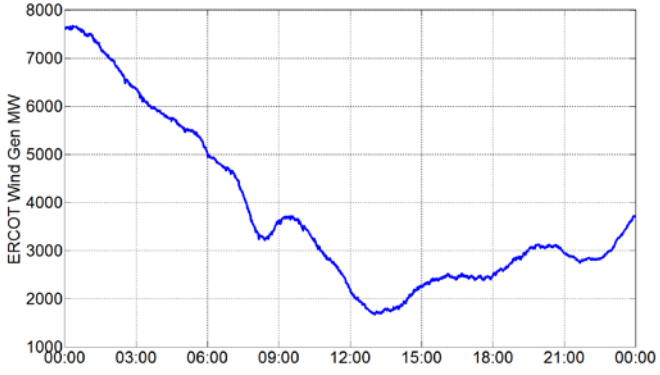


138kV Level

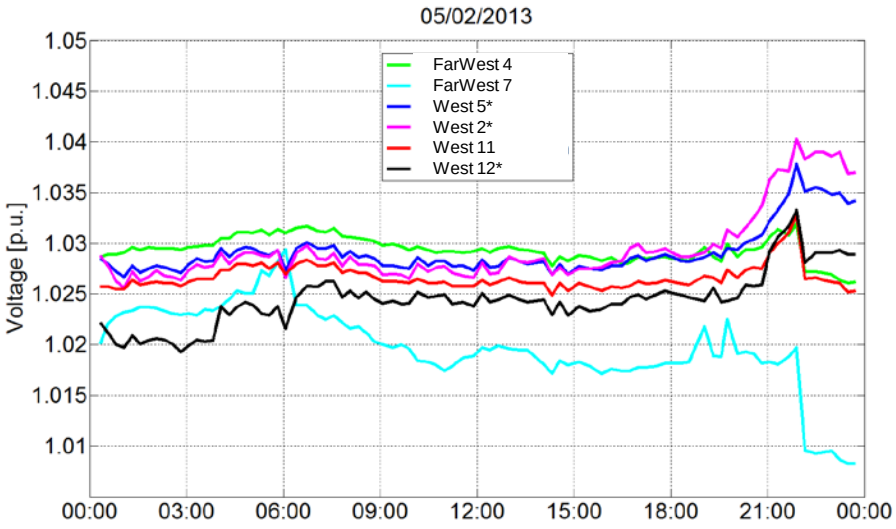


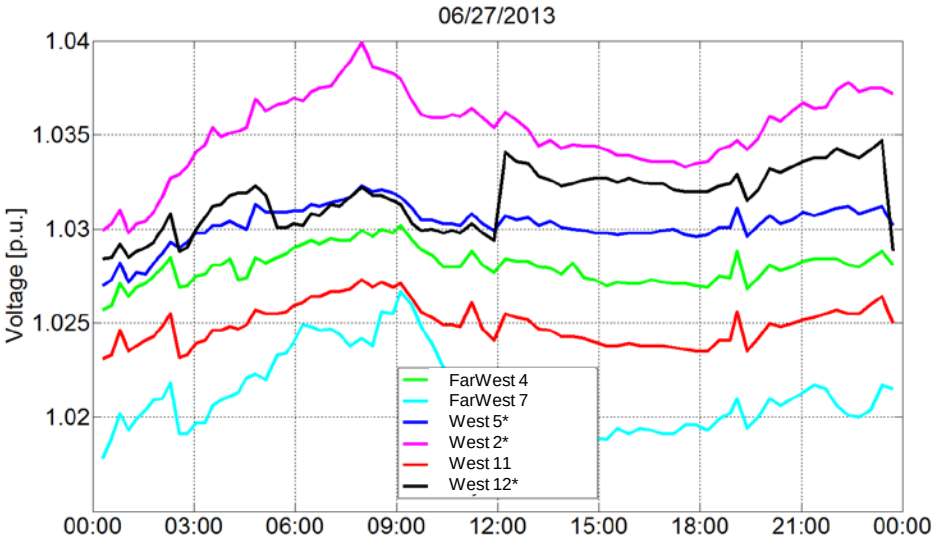


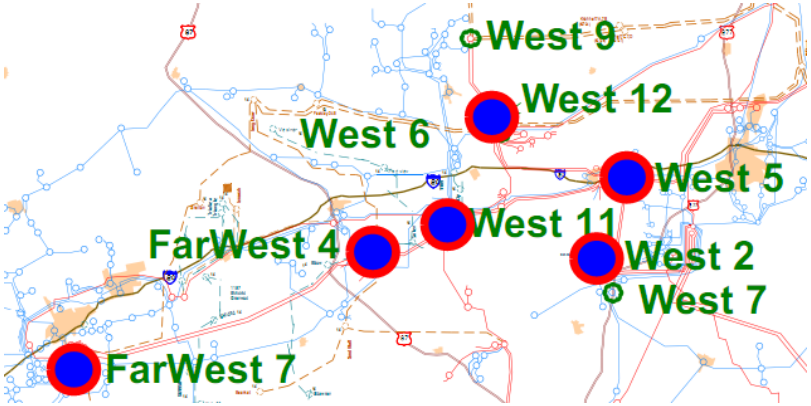




Group 1 – West Texas







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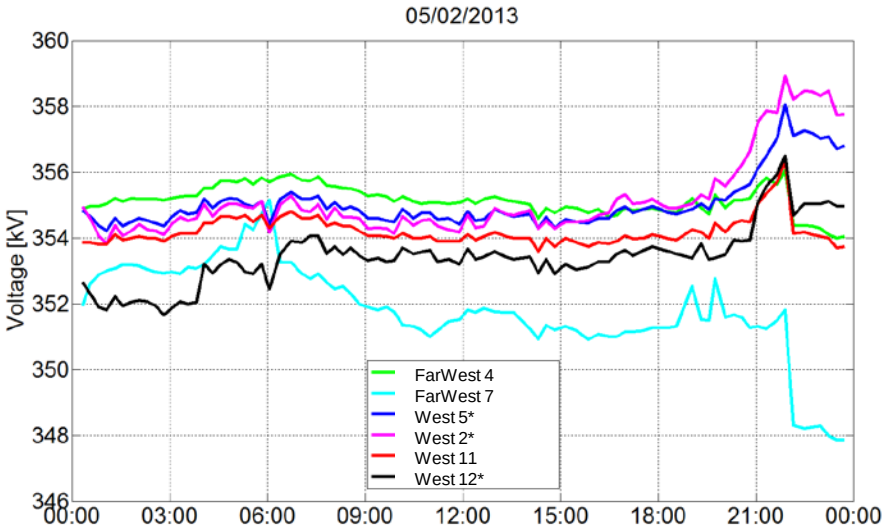

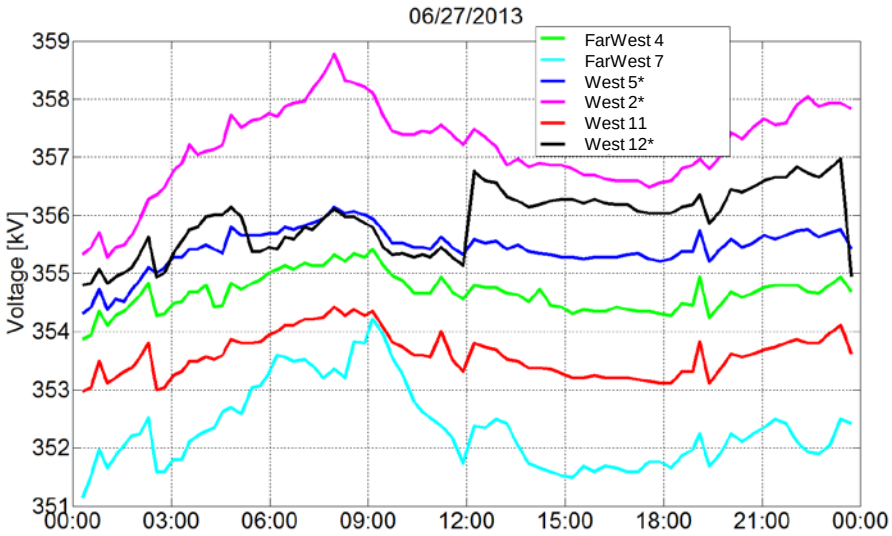

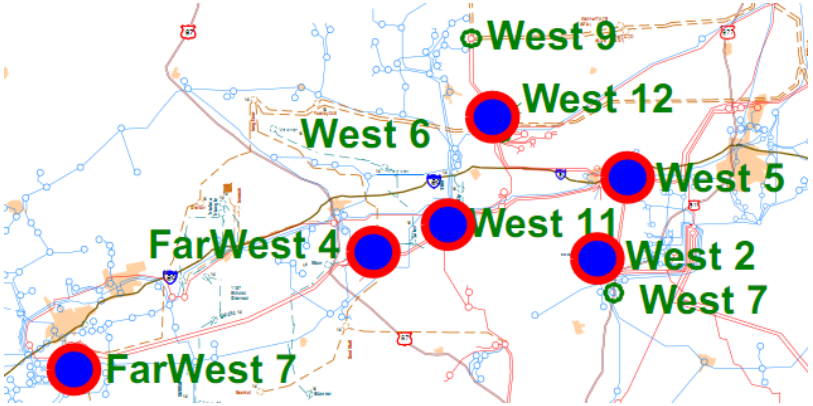

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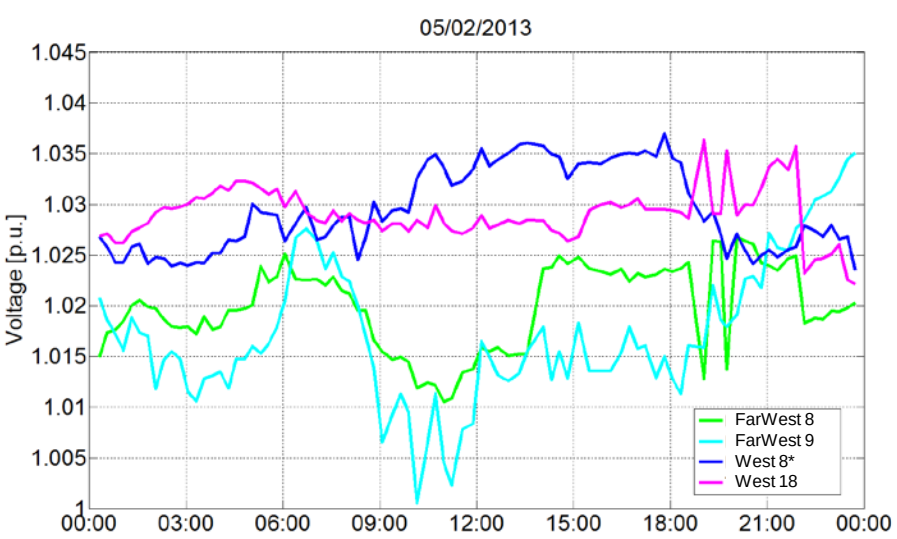

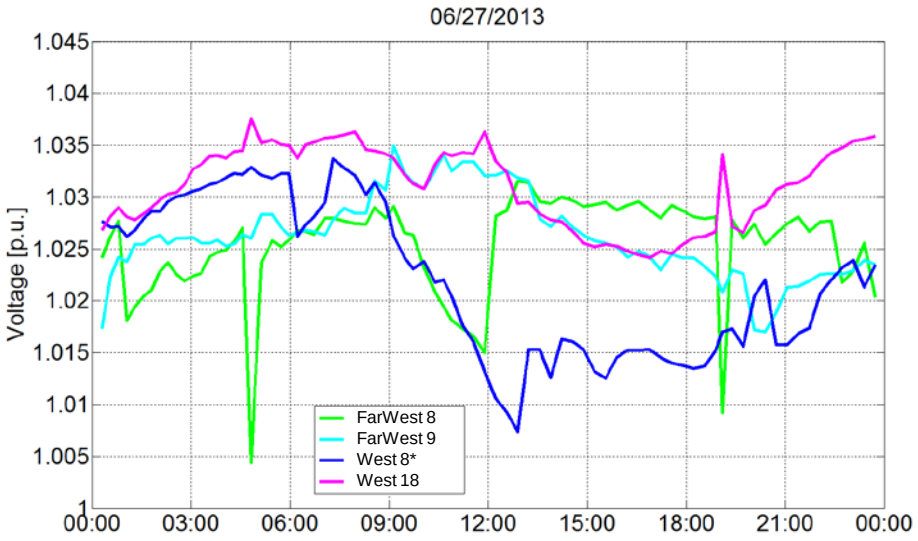

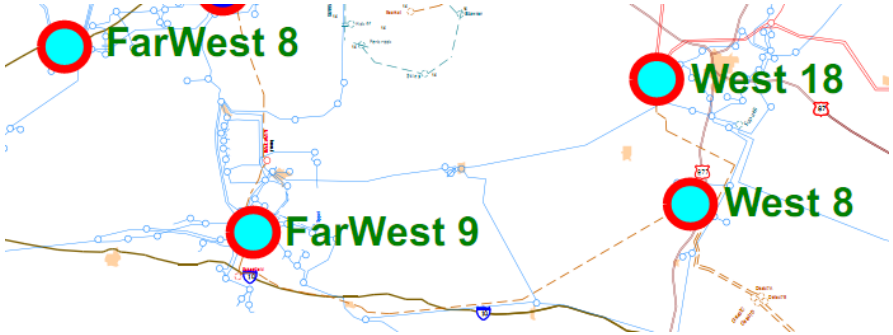

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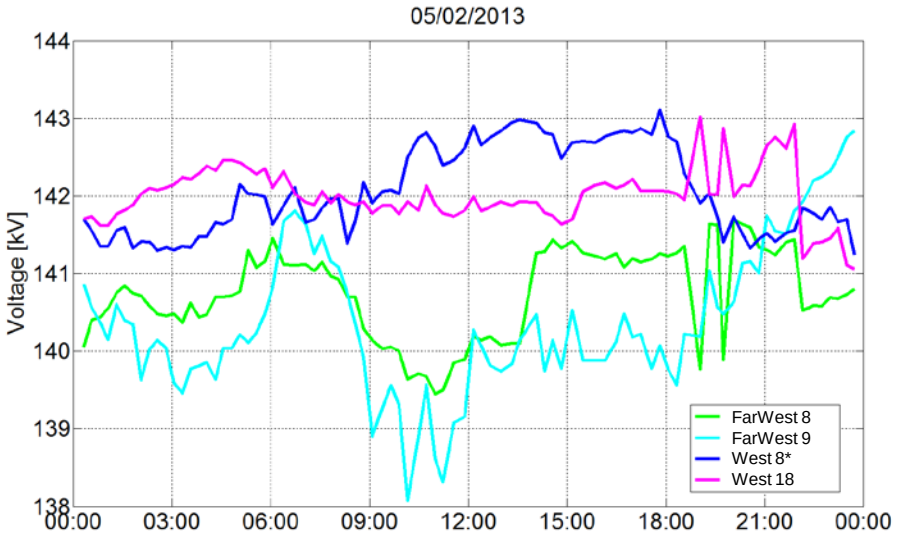
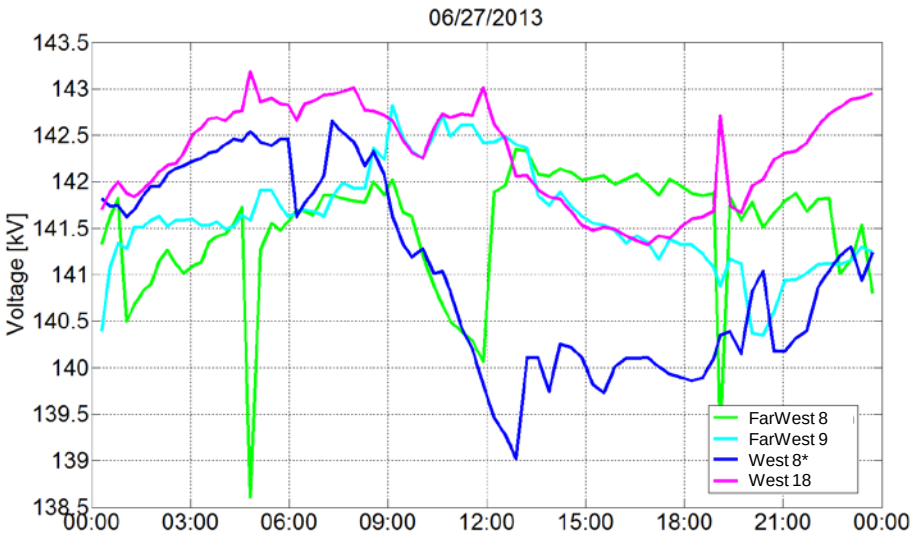
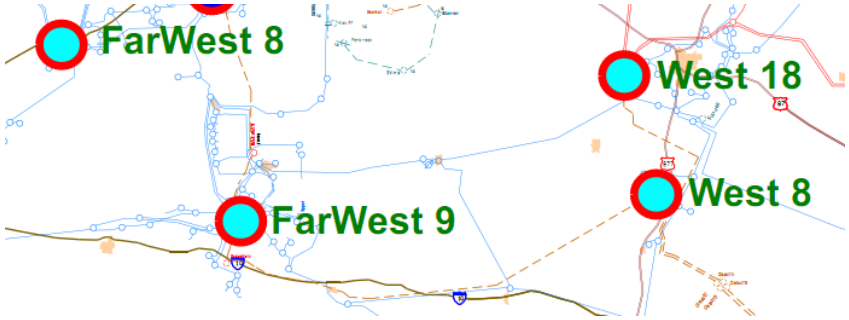
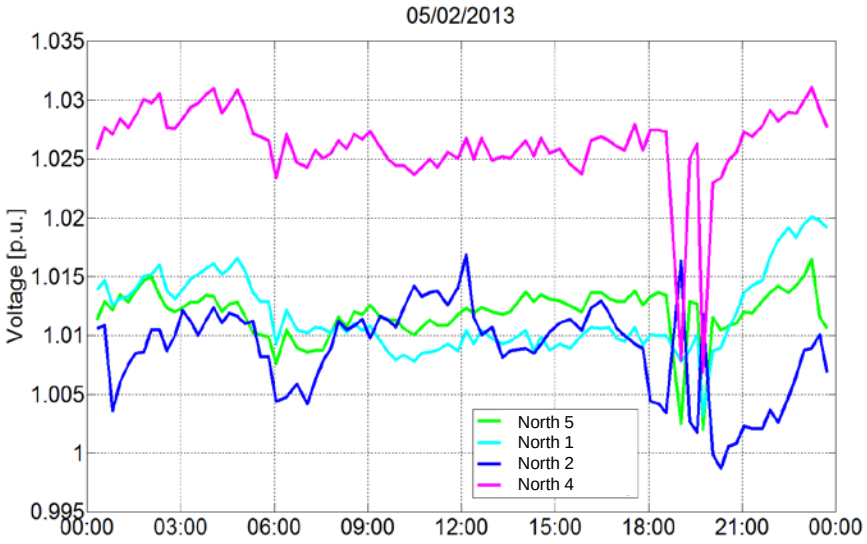
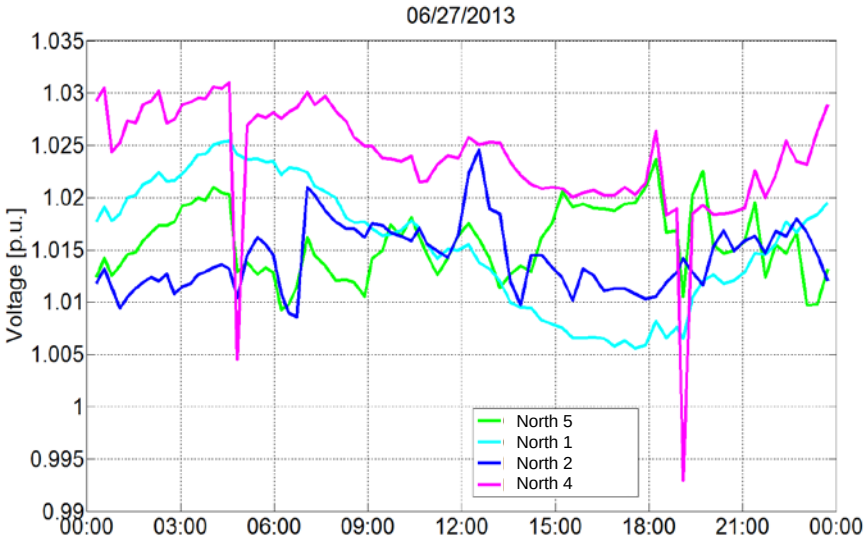


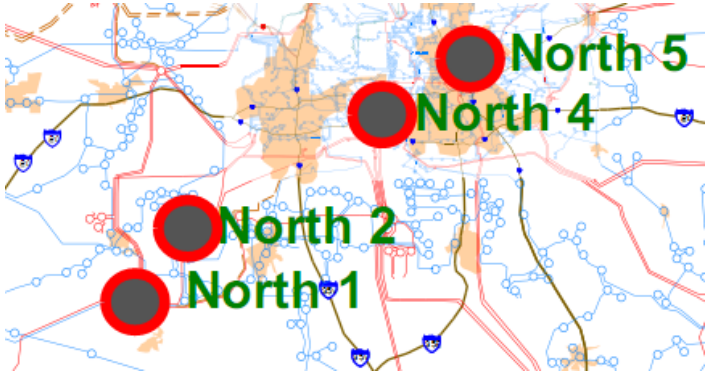




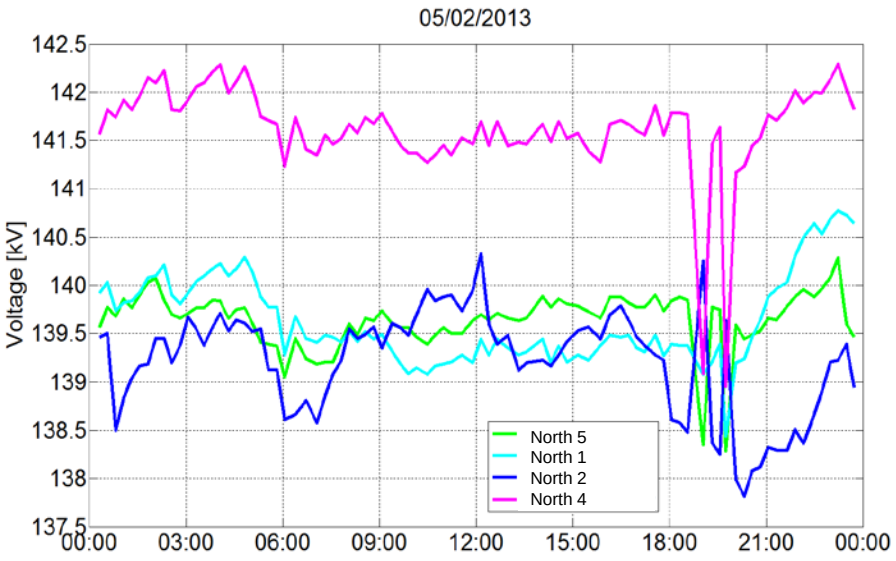
Group 3 - Dallas

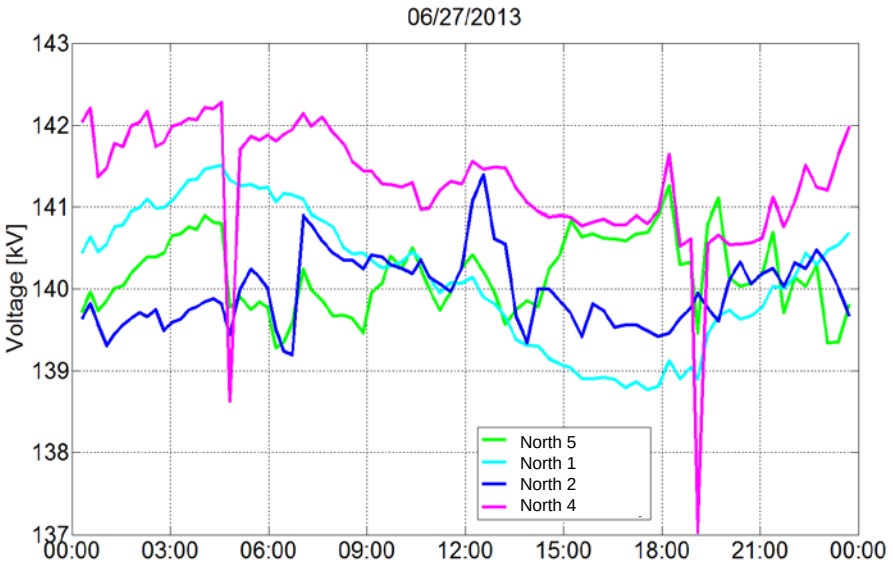


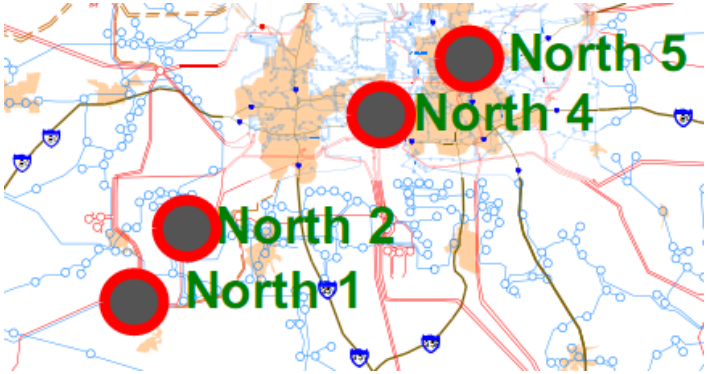




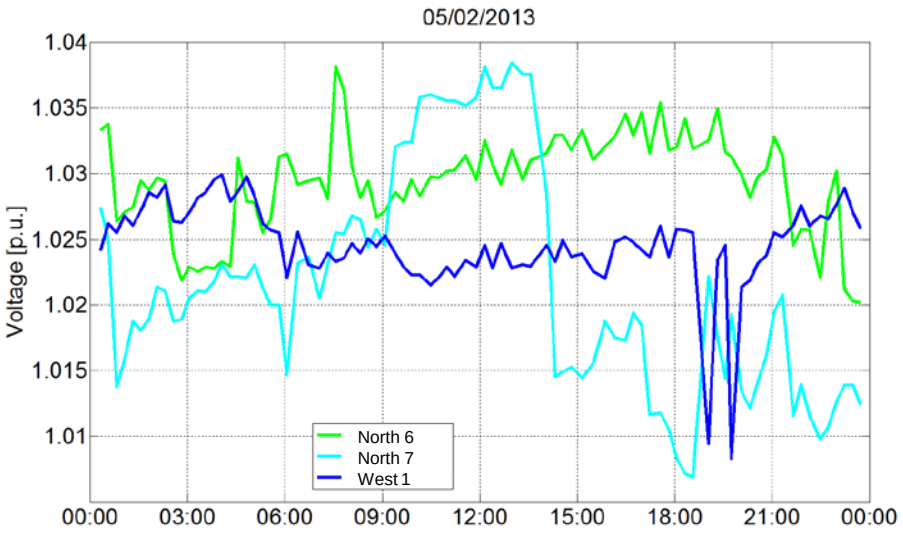
Group 3 - Dallas

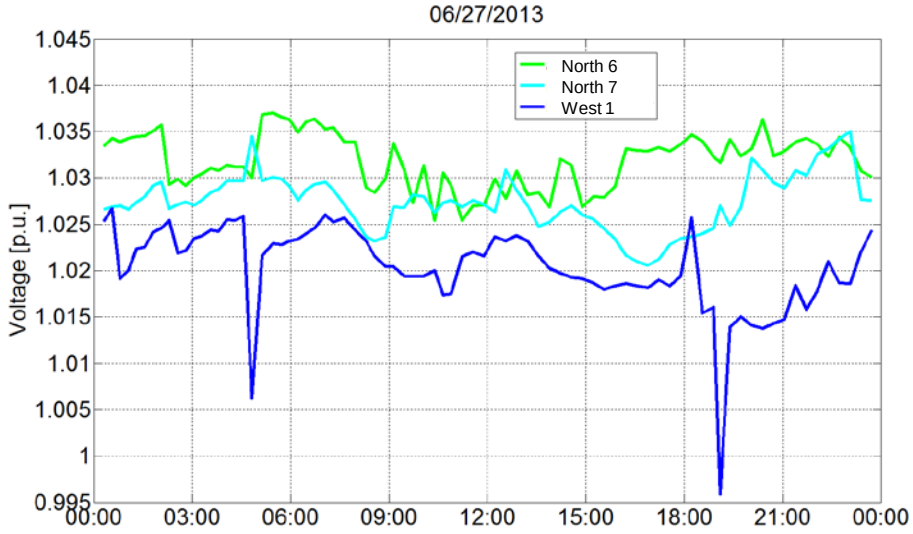


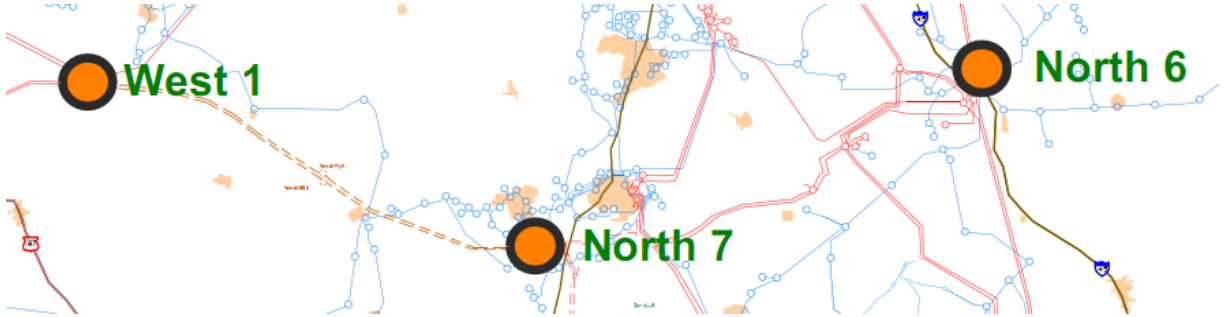




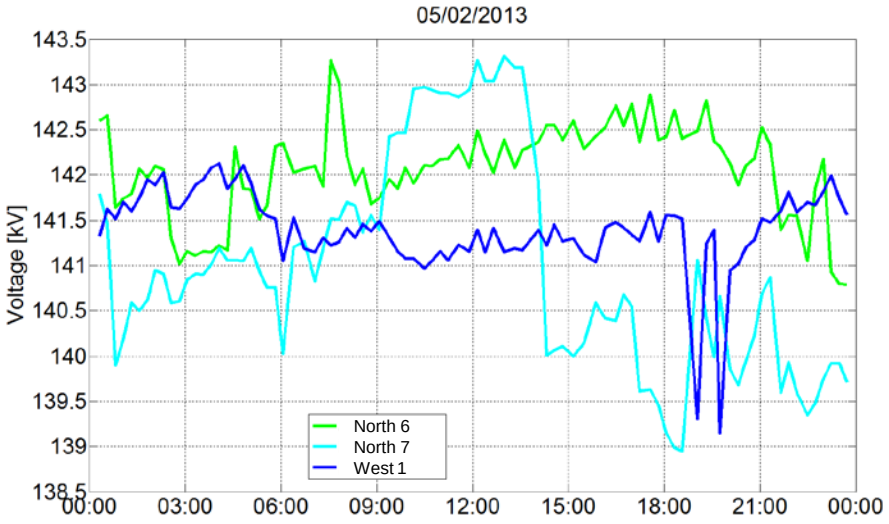
Group 4 – Central East

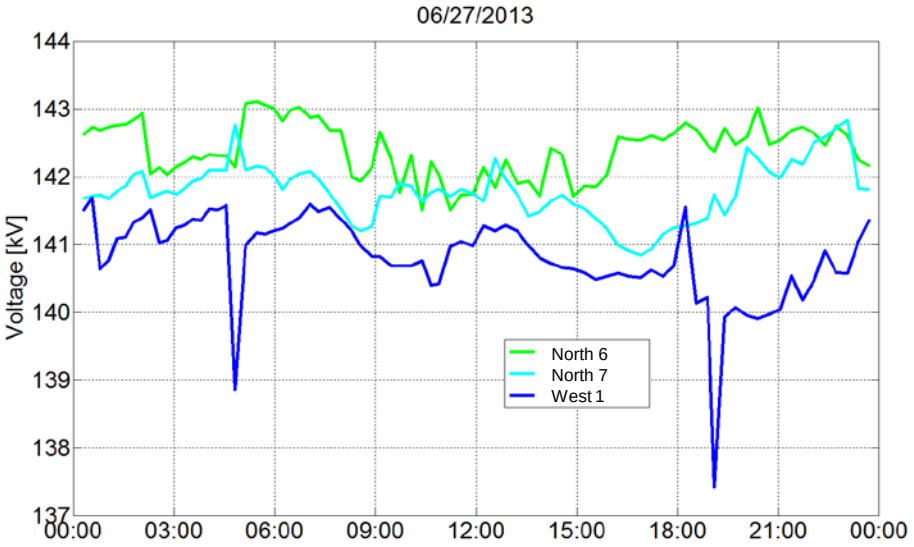


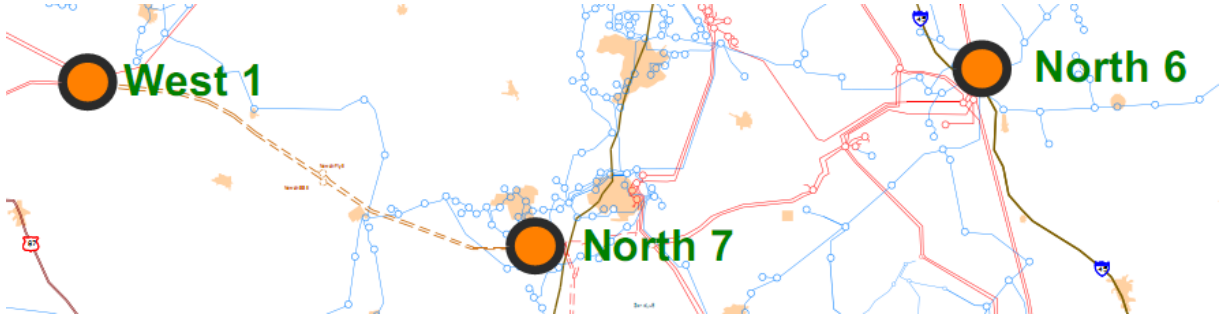




Group 4 – Central East







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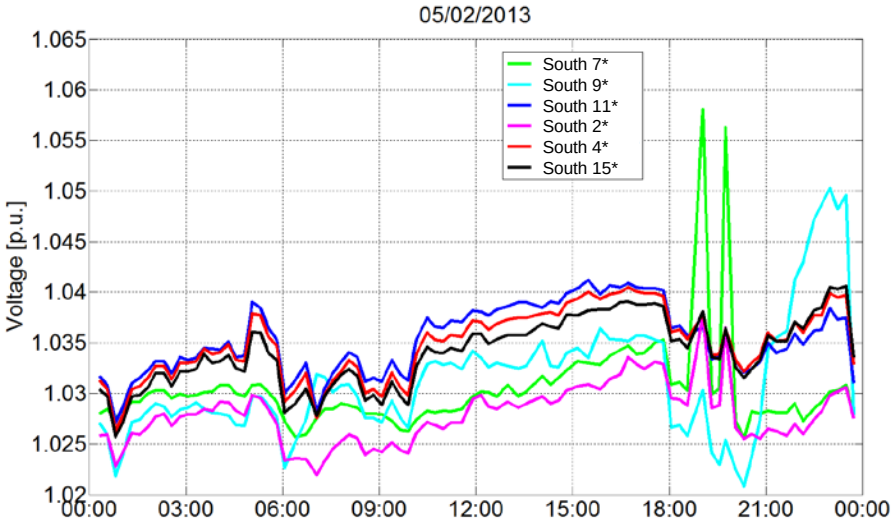

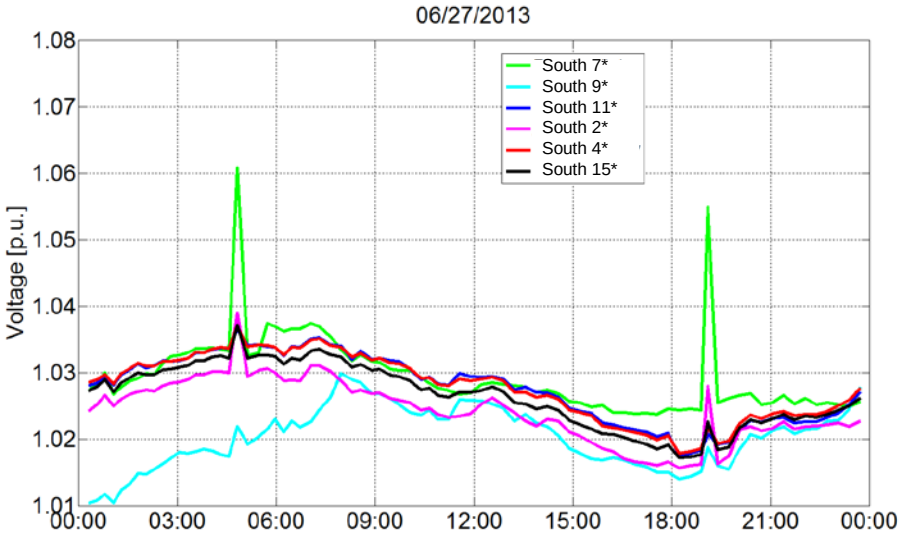

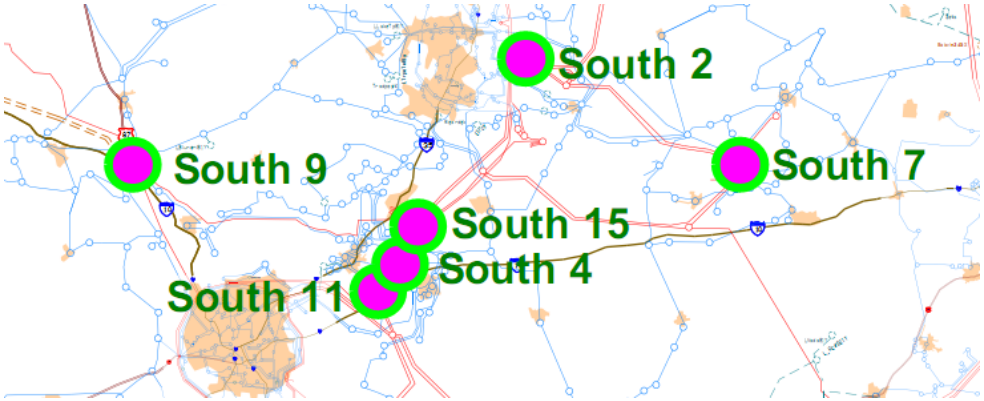

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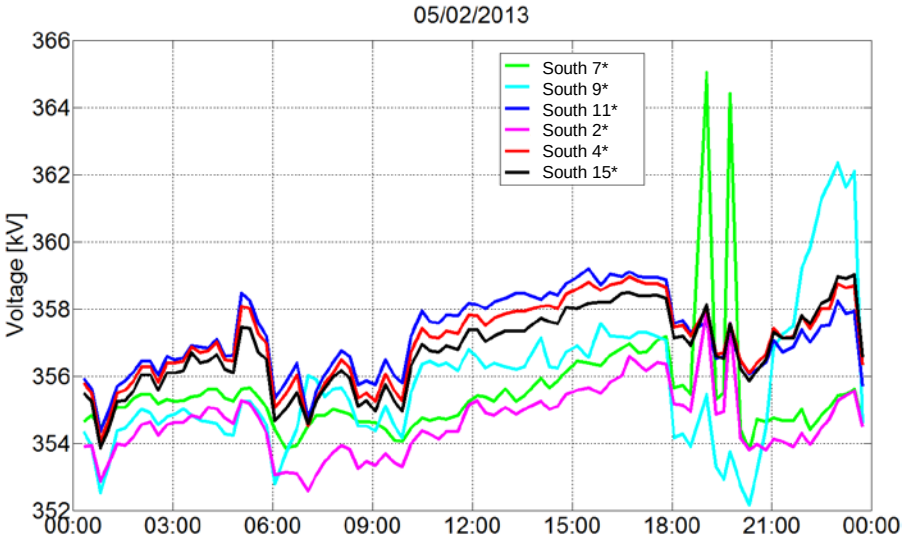
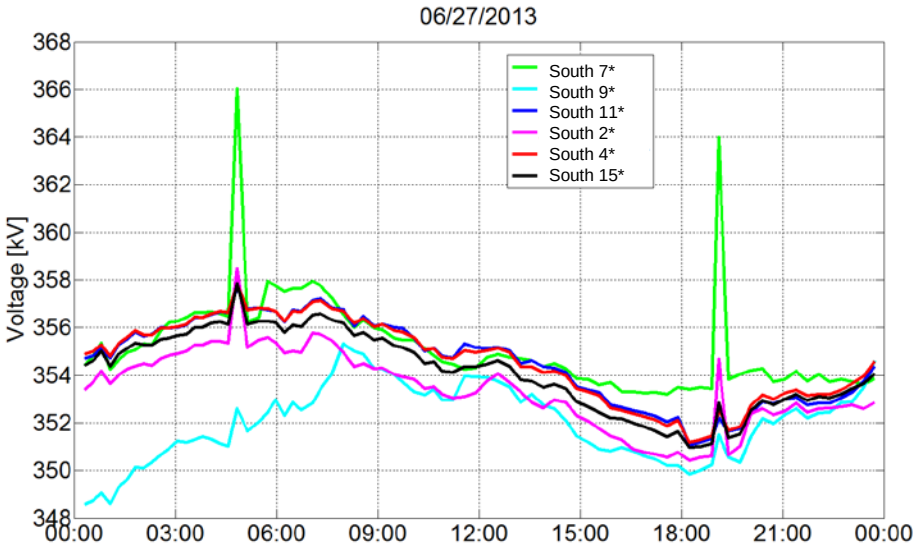
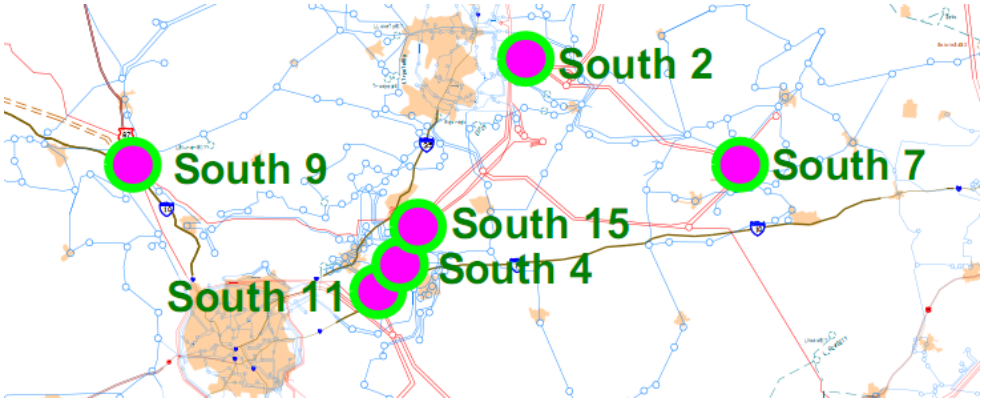
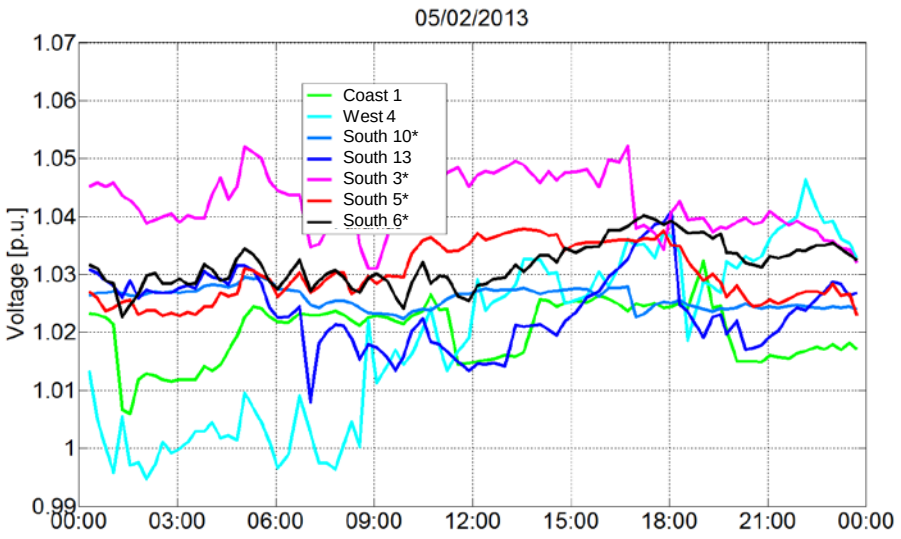
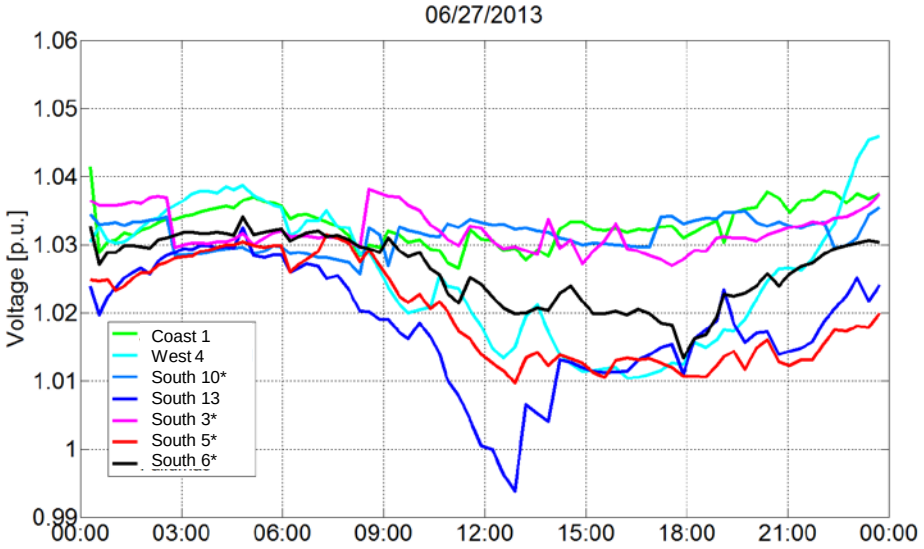


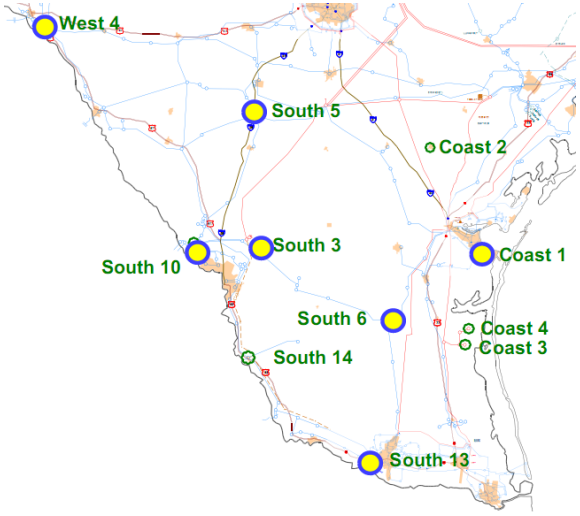




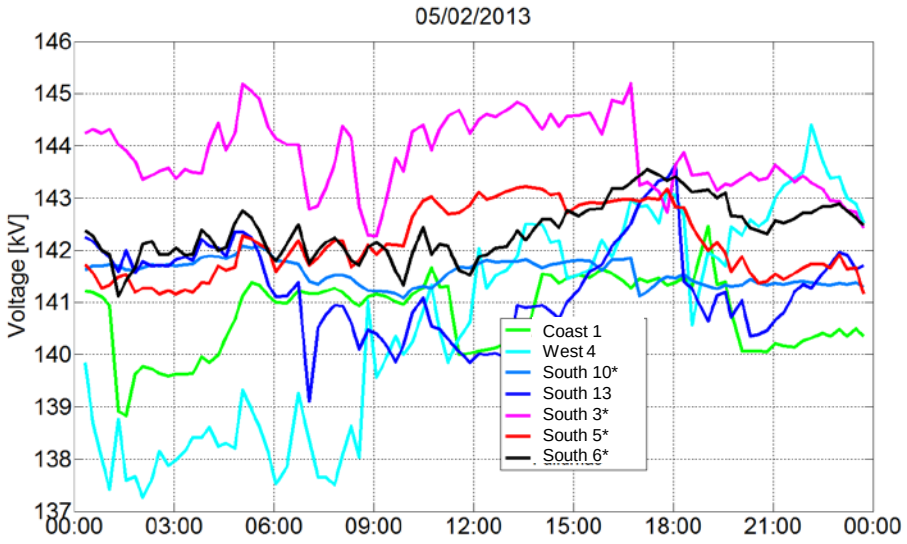
Group 6 – Valley (South)

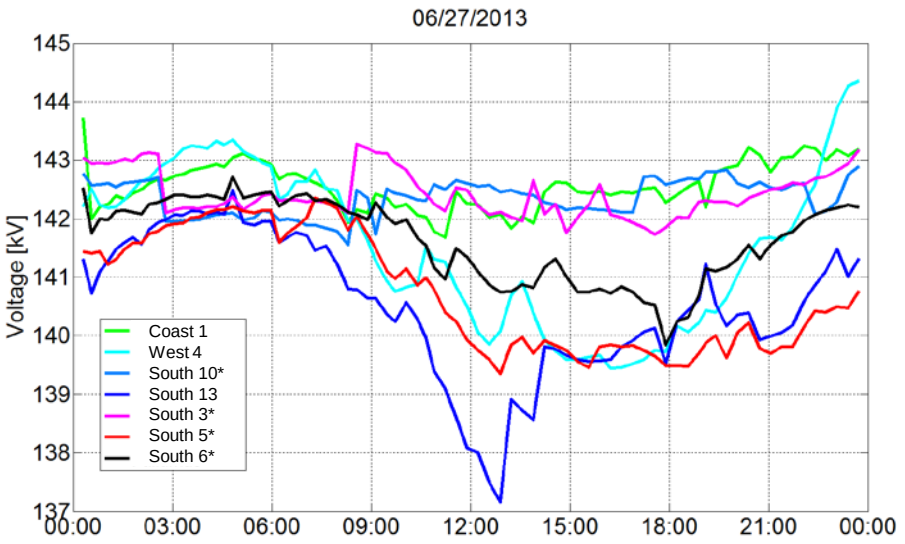


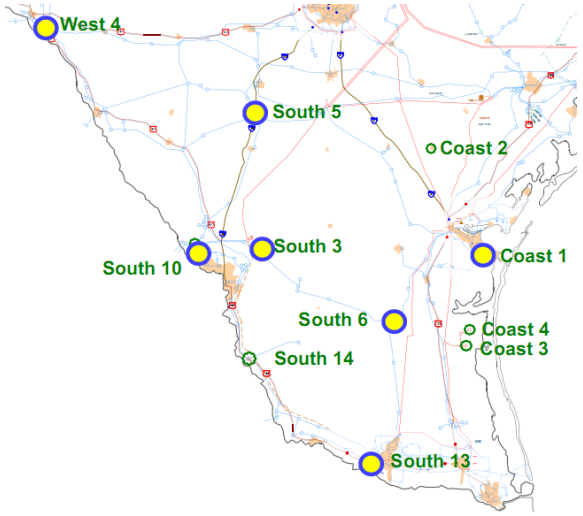




Group 6 – Valley (South)







Attachment 3. Updated Baselining 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 were dded 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 the a) Cluster Analysis, b) Comparison Analysis and c) 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 several 345 kV lines added to the ERCOT system during the January to June 2013 time period.

2. PROJECT SCOPE

A. Baseline Analysis for Voltage and Angle Differences

This study update analyzed historical performance of the ERCOT grid, using State Estimator data plus phasor data for January to June 2013 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 first 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 pairs 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 System[1] (RTDMS), and voltage and angle difference alarm settings for use in RTDMS to alert operators when grid stress is approaching limits.

This results from this report should be considered preliminary. 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 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 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 (SPS). EPG performed the following actions before the phasor data provided by ERCOT could be used for statistical analysis:

1. Downloaded the ERCOT data provided in MySQL format
2. Converted ERCOT binary format data into alphanumeric format
3. Converted MySQL data to CSV data files for use in Matlab data analysis programs.
4. Linked ERCOT data though the MySQL server to the EPG local ePDC database tool to allow downloading as CSV files to the local computer.
5. Down-sampled phasor data from 30 SPS to 1 SPS, and downloaded it to the local computer for analysis.
6. Applied status flag filtering to perform the first step in data cleaning
7. Developed data filtering algorithms and wrote code in Matlab to perform the second step of data filtering.
8. Addressed small data dropouts by interpolation techniques or filled dropouts with blanks.

[1] ® Electric Power Group. Built upon GRID-3P platform, US Patent 7,233,843, US Patent 8,060259, and US Patent 8,401,710.

This process of data setup, downloading, cleaning and fixing data dropouts 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 it 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 display it in 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 percentage 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 the locations for which PMUs are planned are new and, therefore, there was no state estimator data available for those substations or pair of 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	Line 1	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 with SE data for the first six months of 2013. EPG used the Power World simulator, provided by ERCOT, 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		4 Days
	Total	**8 days**

C. Data Availability

Data availability for the phasor data 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 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 available data. 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			
<40%	**41% to 60%**	**61% to 80%**	**>80%**
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 DIFERENCES

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-whisker 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. Obtained and processed phasor data and state estimator data.
2. Extracted information to identify max, min, and average values from these data sources. Prepared summary tables showing results of all data, including data saved during events.
3. Used phasor and SE data to develop weekly box-whisker graphs and time duration curves for angle differences.
4. Identified 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 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. Analyzed results, identified limits, and reported results for each pair selected.

C. Study Approach

Electric Power Group used the following approach:

1. Obtained available phasor data and state estimator data from ERCOT.
2. Extracted phasor data and conditioned it for processing.
3. Solved state estimator cases and saved solved cases.
4. Selected 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. Identified the substations and subsets of substations and pairs for which phasor data is available.
6. Developed statistical charts including time duration curve and box-whisker graphs for voltage magnitudes and angles, and for angle pairs.
7. Performed statistical analysis to identify angle difference limits for the pairs selected under all conditions. Summarized angle difference limits.
   - Established limits for normal operation based on the criteria described in the corresponding methodology. Summarized 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		
	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	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

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 was low because these PMUs were 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 indicated 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

				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	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 on 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 bus with 15.4 kV, and West 4 138 kV bus with 6.95 kV.

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 29 substations had data availability greater than 70%.

ii. Both phasor data and state estimator data point to West 4 and Coast 4 as 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 41 show voltage spreads 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 shows a comparison of voltage magnitude averages as well as Max-Min spreads for 2012 and 2013.

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

				STATE ESTIMATOR DATA - 2012				STATE ESTIMATOR DATA-2013			
No	Substation	Base kV	Region	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.

Evaluation 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-²hisker ±oltage tlots - 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 substation went up 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 fluctuated 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 20 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 12 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 2.
r. South 10: the median changes constantly with a 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 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 outage 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 degree 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 baselining study, but 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)

			Phasor Data - 1/1/13 to 6/30/13					State Estimator Data - 1/1/13 to 6/30/13				
No	Angle Pair FROM - TO	Base kV	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-whisker 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 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 are 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-month 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 period for 2012 and 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 insufficient data in 2012; in these cases, EPG 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

			VOLTAGE ANGLE - MEDIAN		
#	Substation A	Substation B	2012	2013	Difference
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 of 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 tightened 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

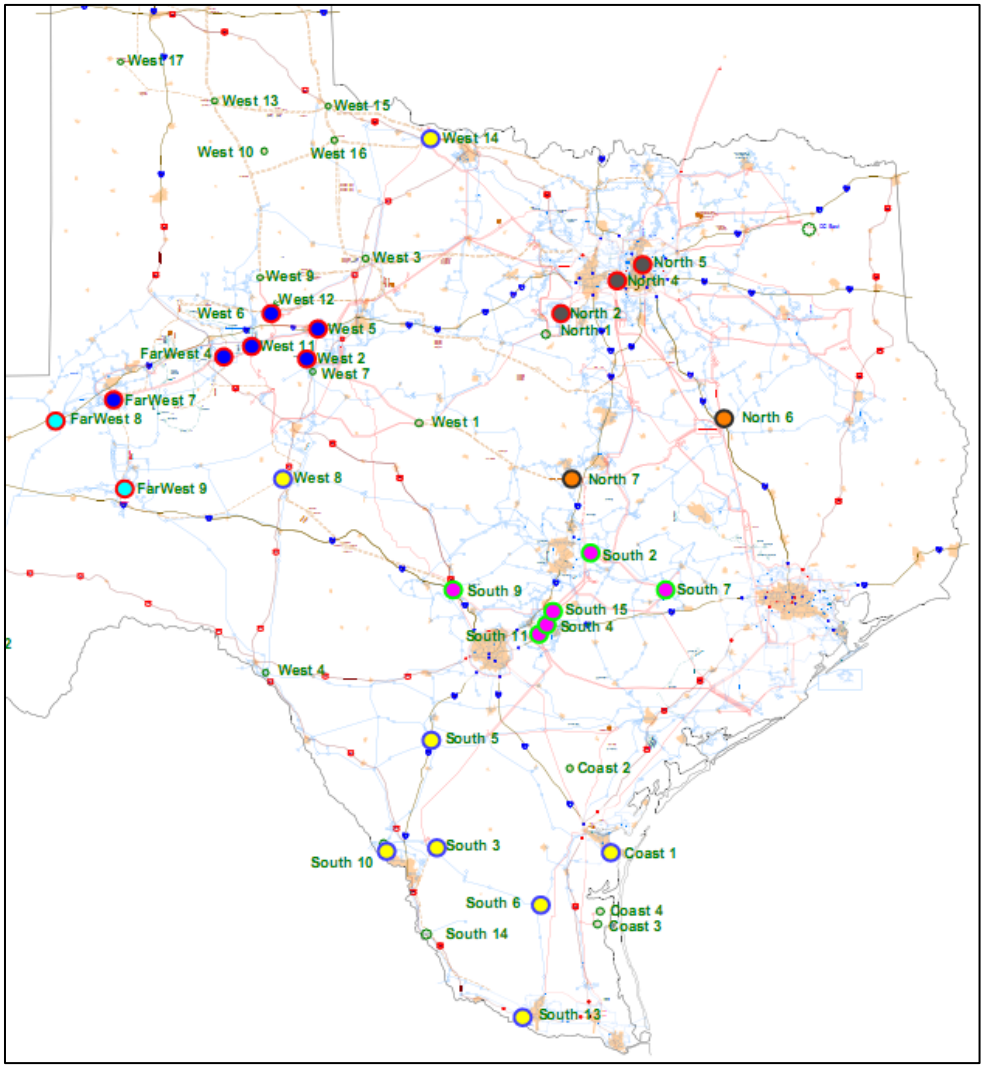
A. Pairs of Substations Identified for Angle Difference Analysis

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 the PMU was recently added to the ERCOT grid

* denotes substations without existing PMUs or w/o a 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, EPG 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, so no phasor results are provided for those pairs.

Data availability for those pairs which had at least one PMU recently added (see those designated with a + sign) 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 to South 10 (84.8%).

Observation of Table C-1 results shows the following:

1. Five pairs show Max-Min angle spreads greater than 80 degrees: Coast 1-North 7, West 5 -North 7, FarWest 7-North 7, FarWest 9-West 4, and FarWest 9-South 9.
2. The lowest Max-Min angle spreads occurred on the following pairs: North 1 to North 4, FarWest 7 to FarWest 8, and West 11 to West 8.
3. 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

			Phasor Data - 1/1/13 to 06/30/13					State Estimator Data - 1/1/13 to 06/30/13				
	Angle Pair	Base kV	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															
			Phasor Data			State Estimator Data - 1/1/13 to 06/30/13										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	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.

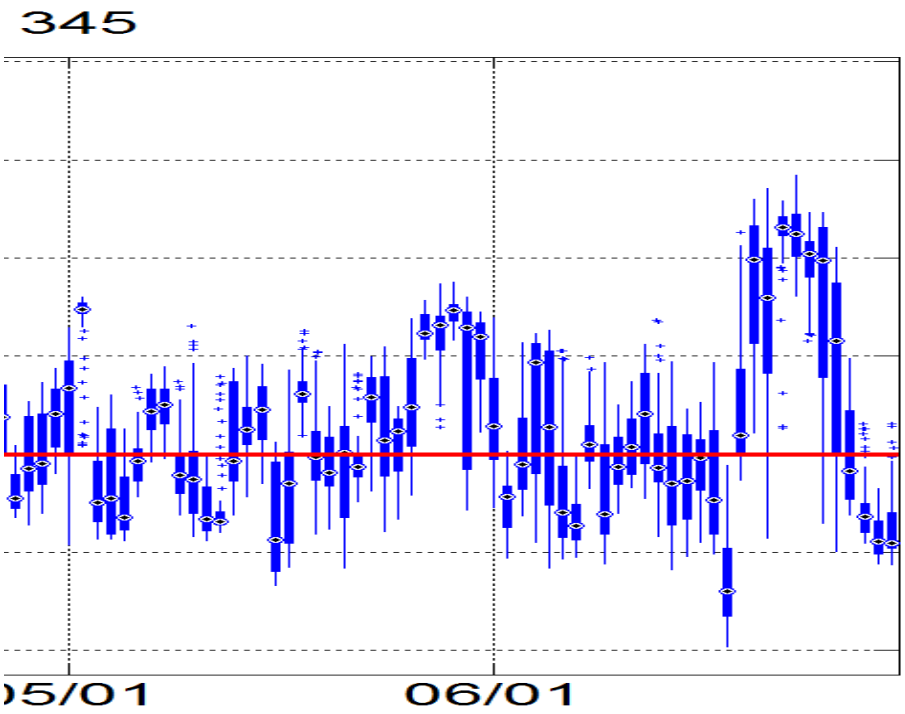
Box-whisker and time duration curves were developed for each of the pairs analyzed. Angle differences that may be the result of contingencies were excluded by reviewing points of inflection, that is, points that significantly deviated from the normal operation trend observed in the box-whisker plots. 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 ! bove

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 had positive angle 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- ² hisker tlots

a. Several angle pairs exhibited abrupt changes in angle that may be due to outages or construction work. Some of these changes lasted several days before returning to the original values. If this is the case, the “normal operations” angle differences may need to be revisited with feedback from ERCOT operation personnel.
b. If there were extended outages, EPG would 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 jumps 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 difference changes were due to events in the system.



9. PAIRS FOR REAL TIME MONOTORING

A. Criteria for {election of !ngle tairs for wealπ¢ime aonitoring

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 with 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 (Pl·ŇŴǎú Selected for RealπTime Monitoring

The transmission paths selected for monitoring are shown 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 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 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 the ERCOT system. EPG expects that the 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

			ALARM LIMITS - NORMAL CONDITIONS								
			Phasor Data		RECOMMENDED ALARM LIMITS				SE Data-Normal		
No	Proposed Angle Pairs FROM - TO	Base kV	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 table 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 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 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 37 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. This is 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 results 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 issues and solutions.

b. **Monitoring Locations**: EPG recommends monitoring the angle pairs shown in section 9.C. 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-Whisker Plots and Time Duration Curves

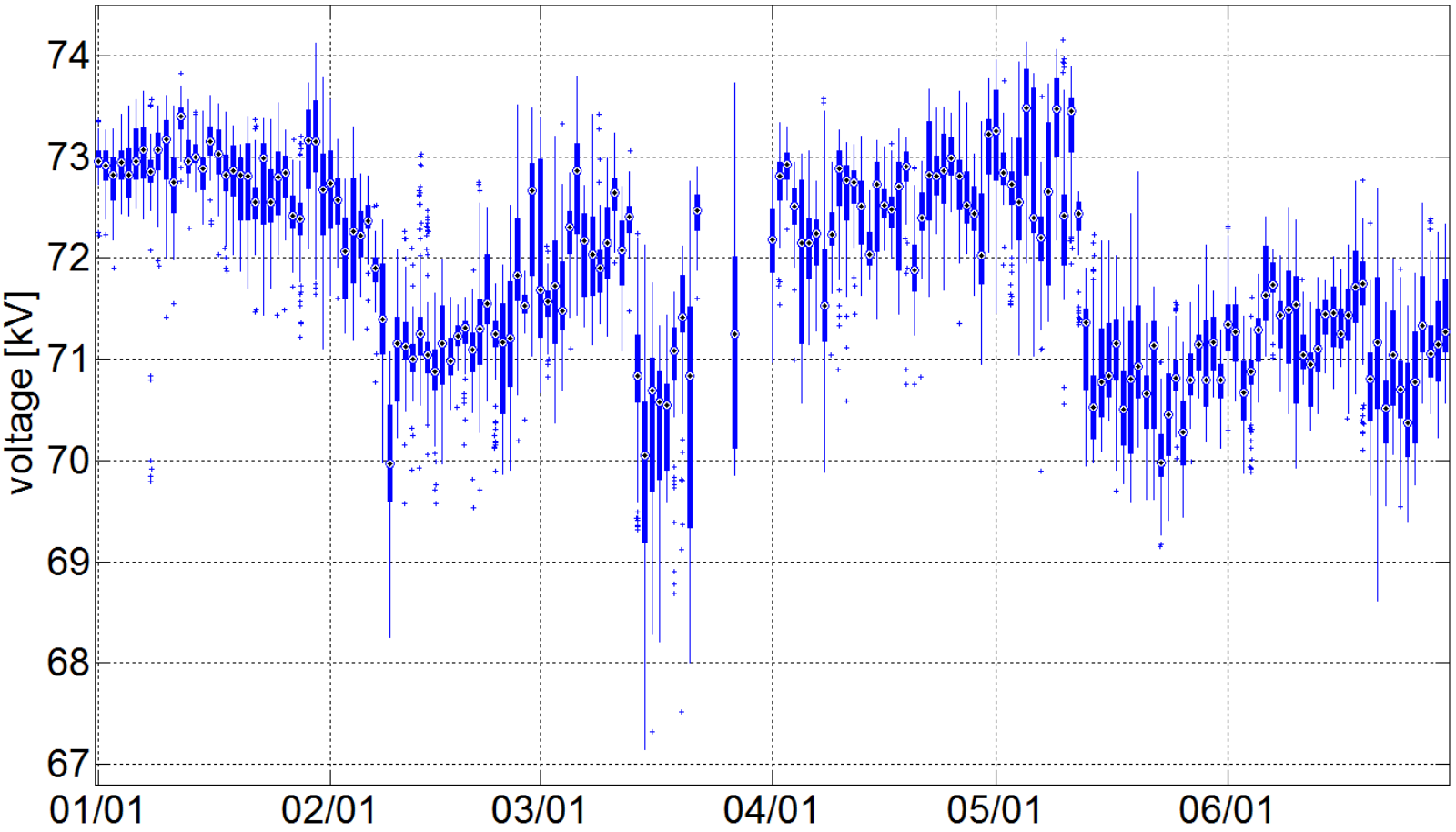
External Version

Electric Power Group

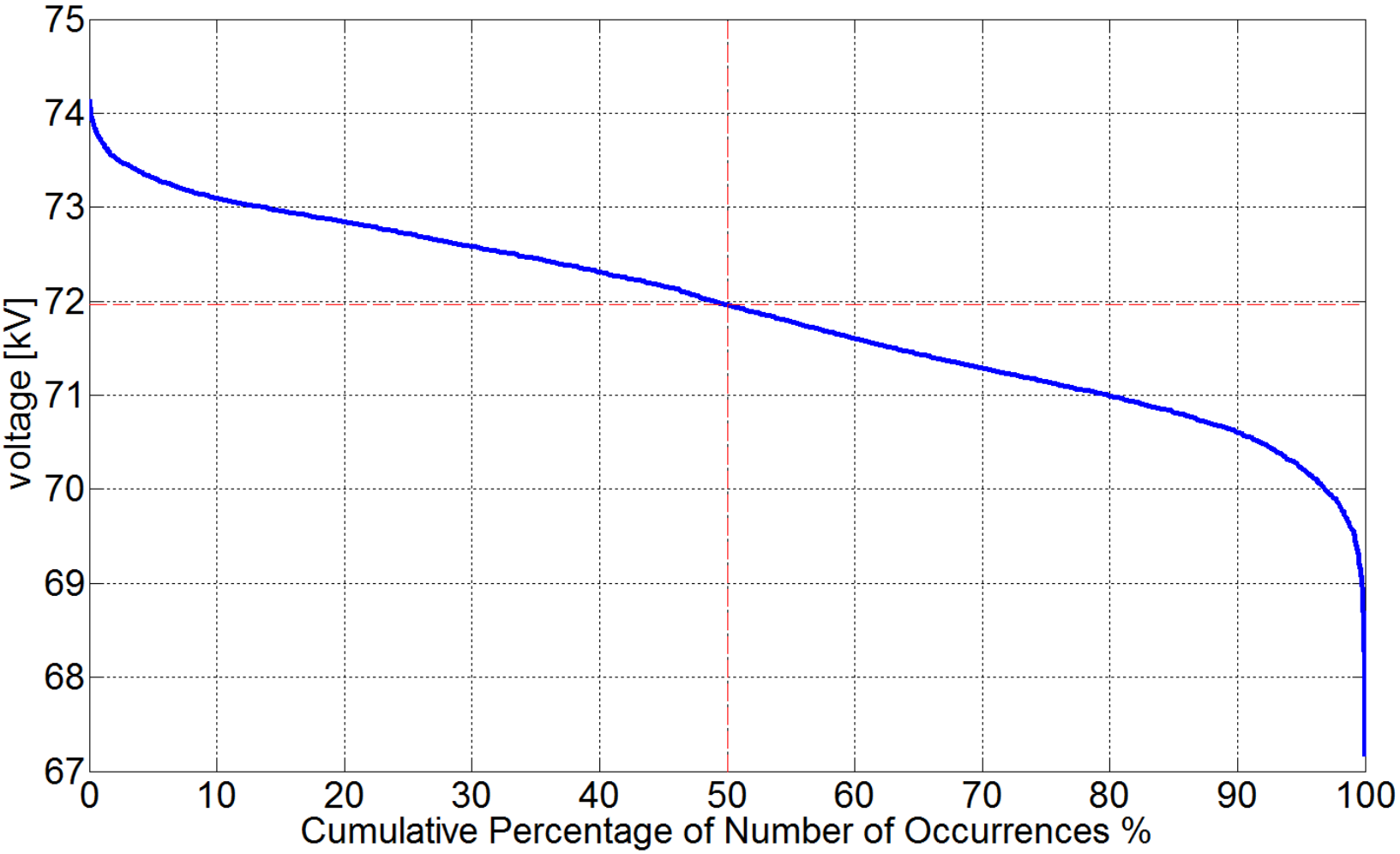
CCET

ERCOT

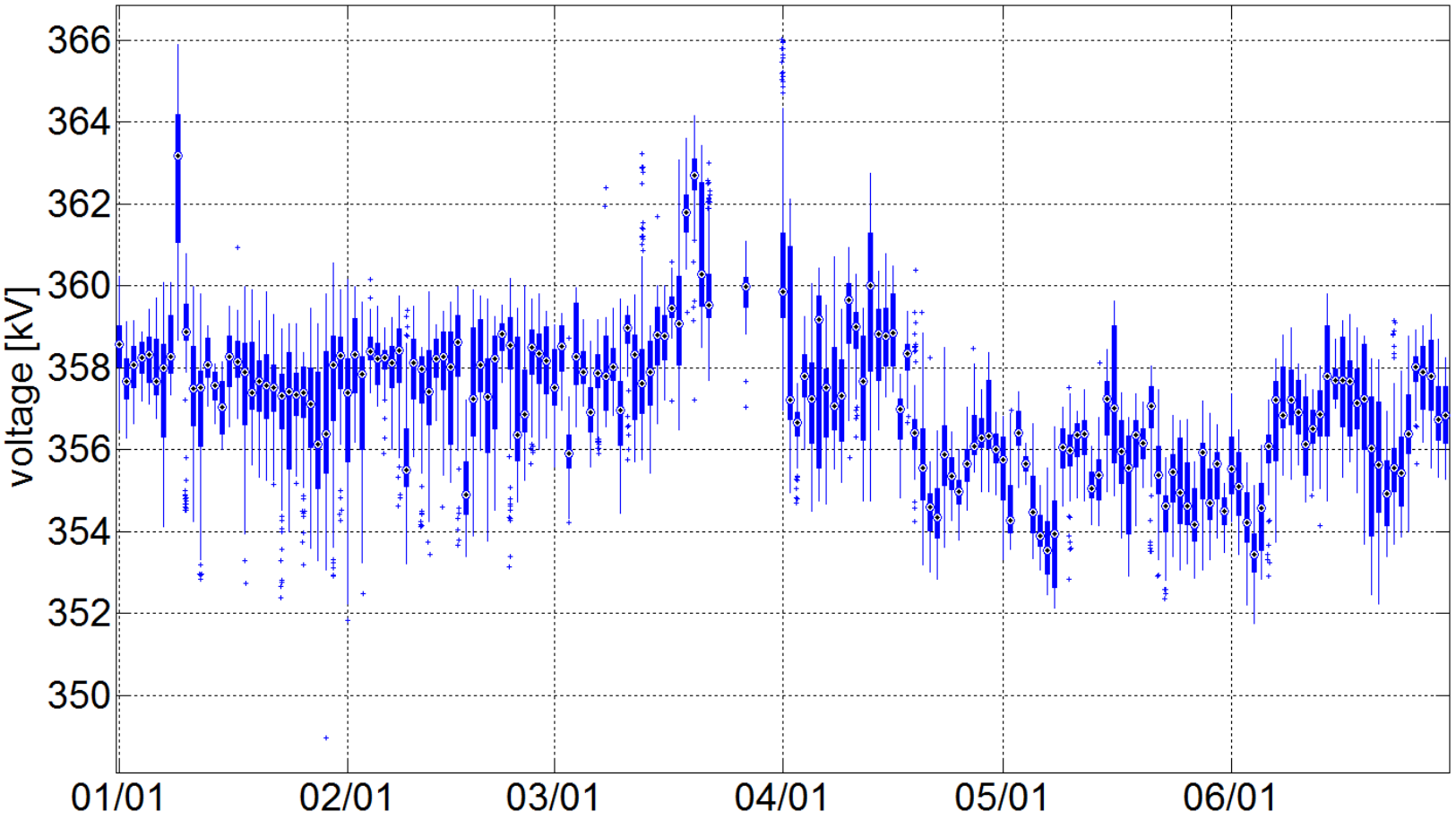
West 10



West 10


75
74
73
72
71
70
69
68
67
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

West 14


366
364
362
360
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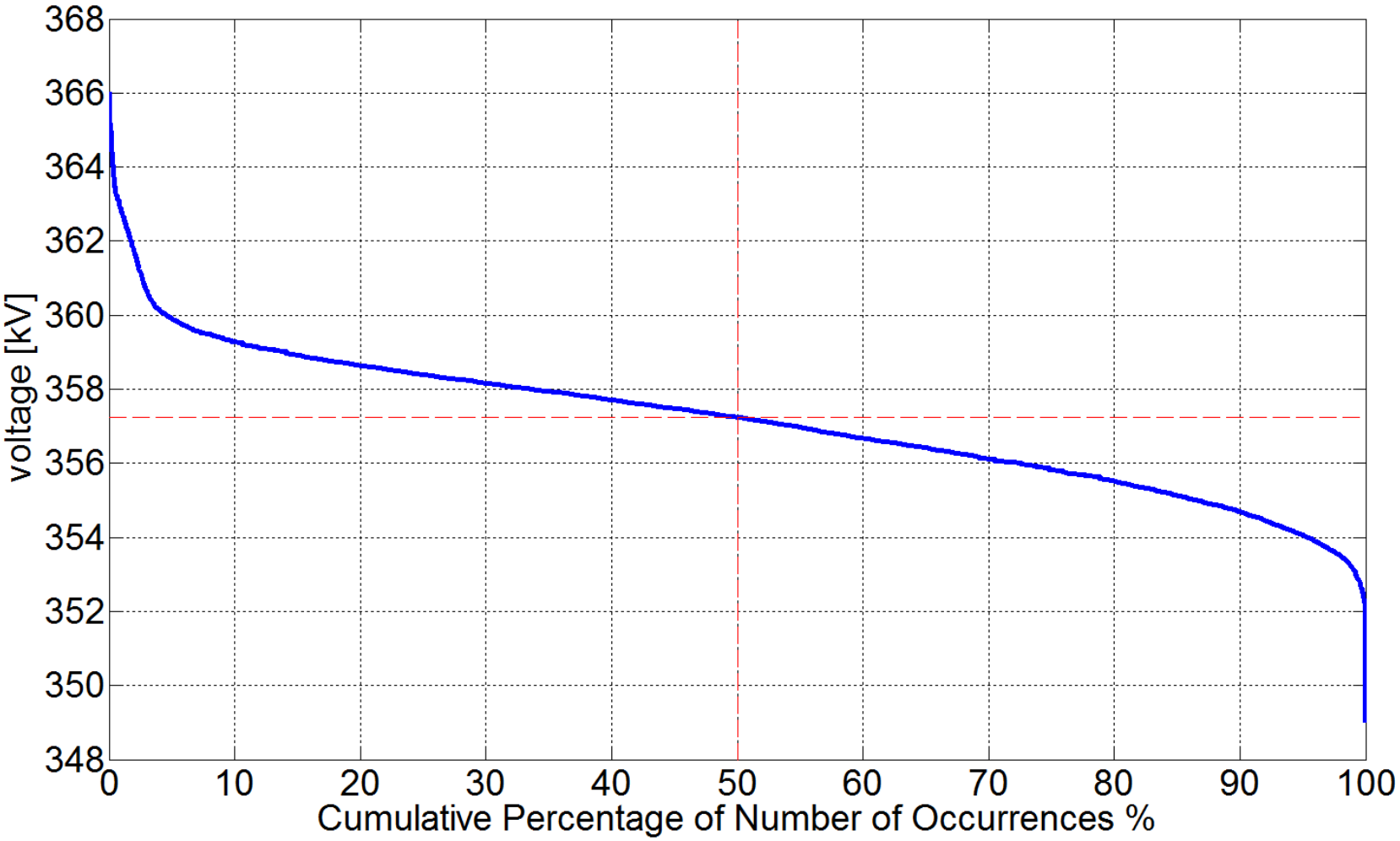
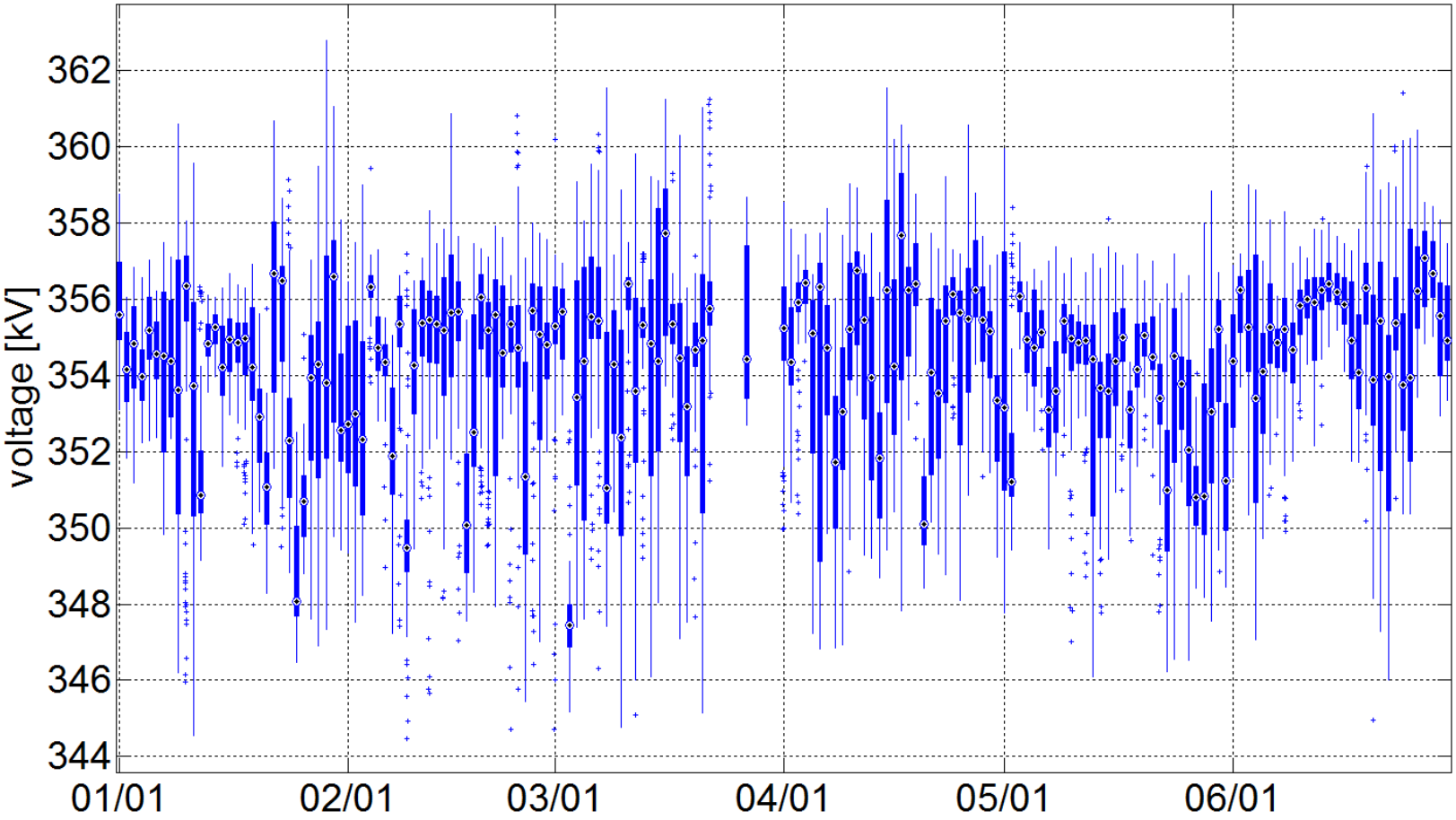
354
352
350
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

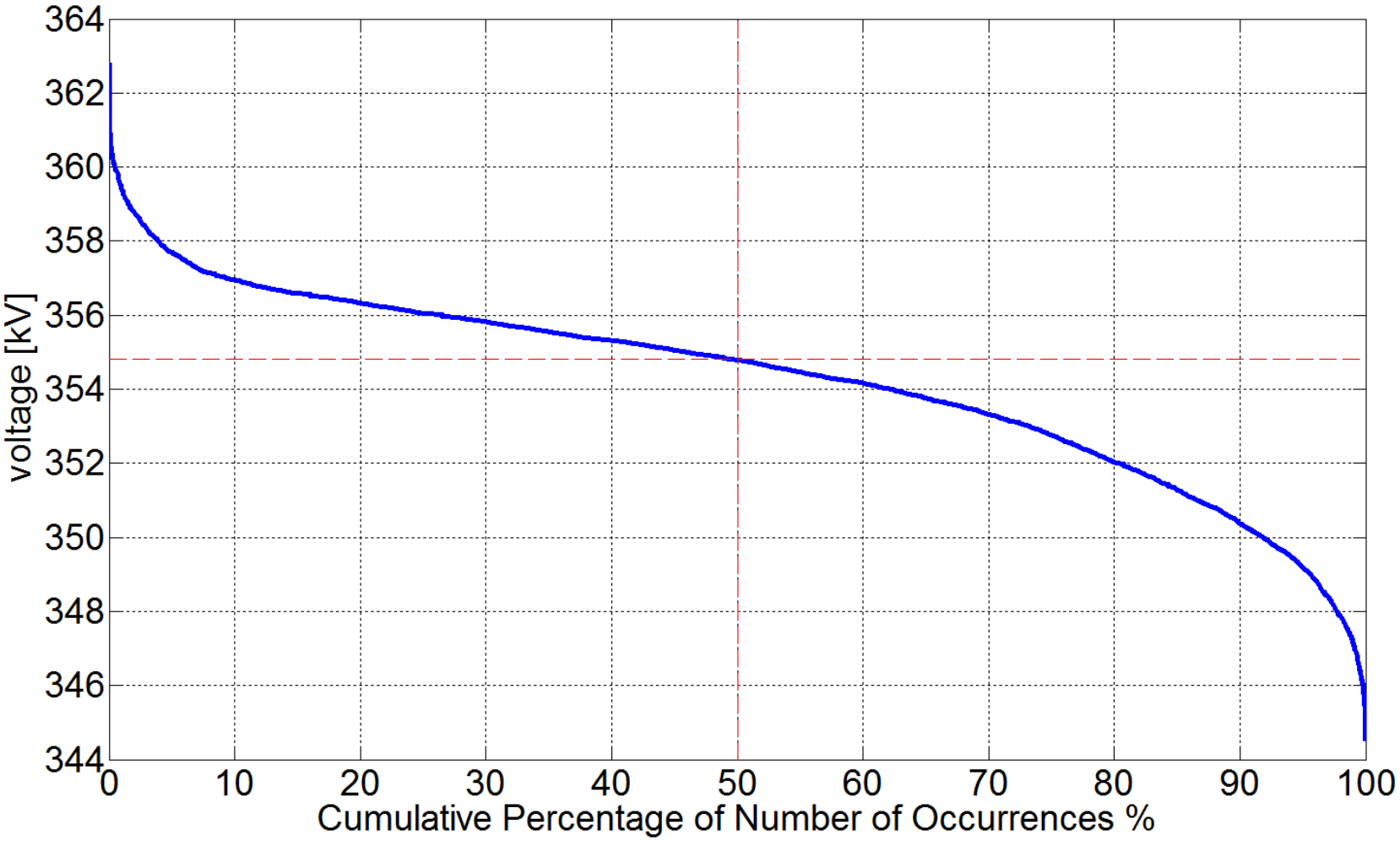
West 14


368
366
364
362
360
358
356
354
352
350
348
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

West 1*


voltage [kV]
362
360
358
356
354
352
350
348
346
344
01/01
02/01
03/01
04/01
05/01
06/01

West 1*


364
362
360
358
356
354
352
350
348
346
344
voltage [kV]
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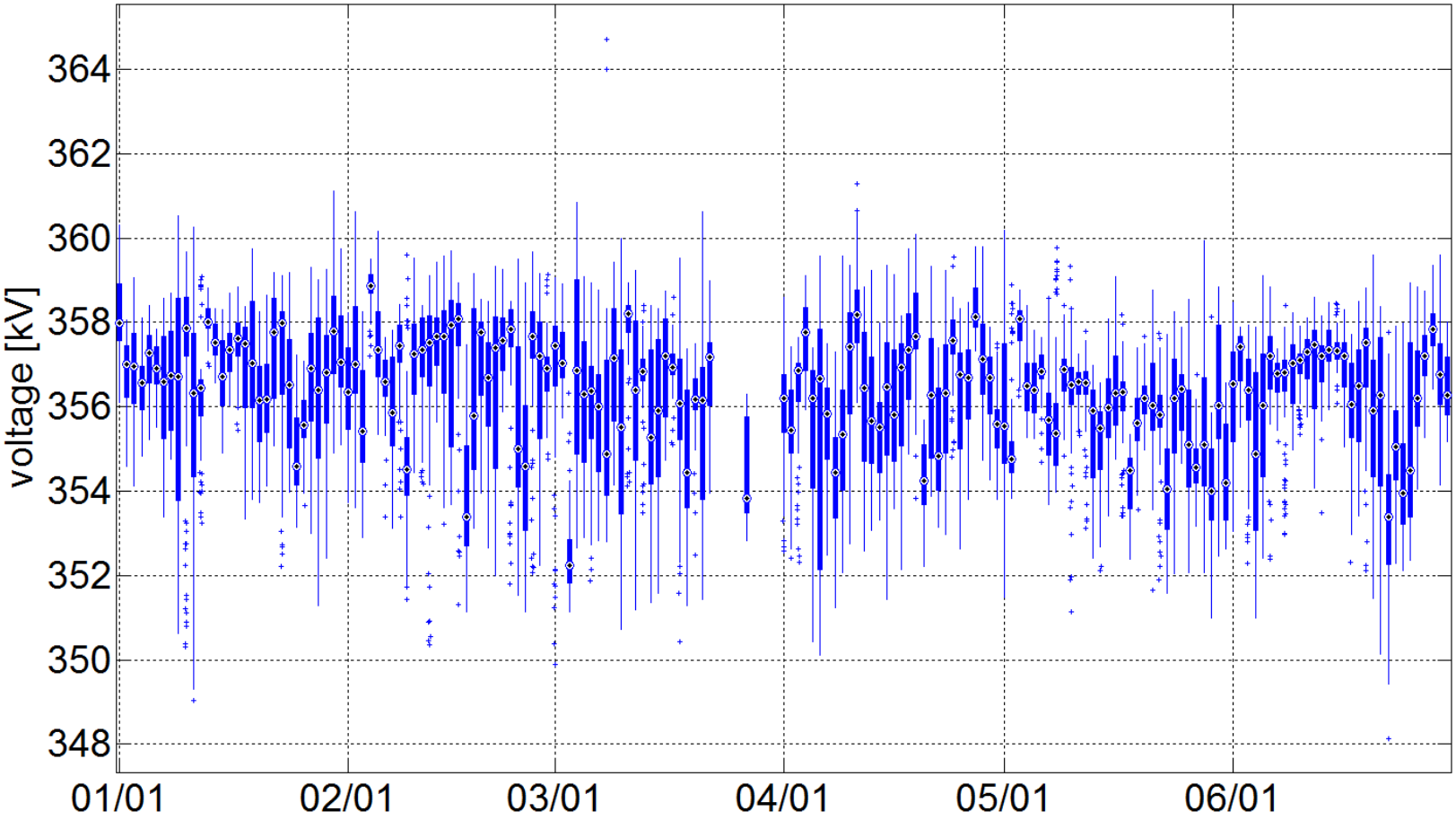
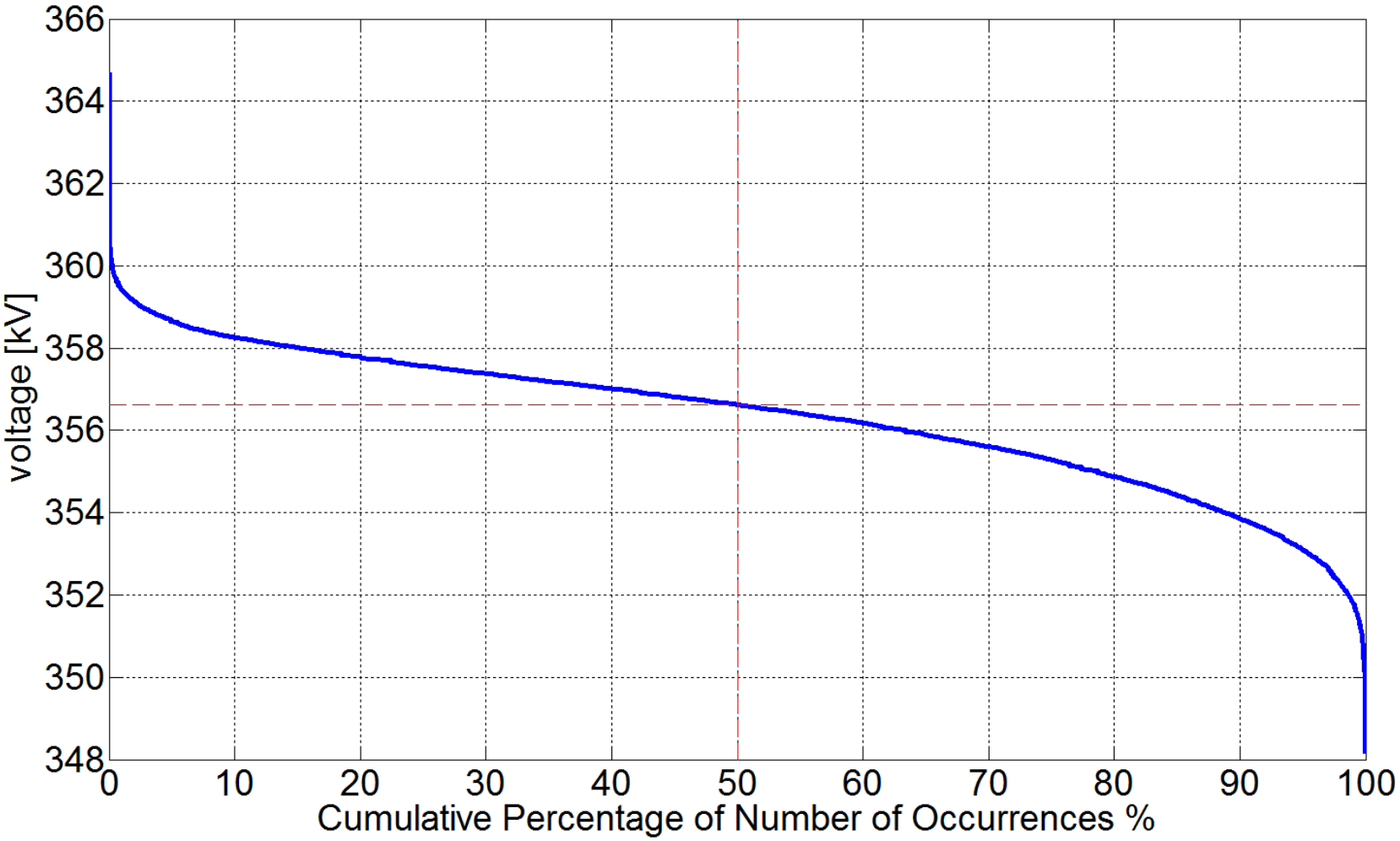
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

West 2*


voltage [kV]
364
362
360
358
356
354
352
350
348
01/01
02/01
03/01
04/01
05/01
06/01

West 2*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364
362
360
358
356
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voltage [kV]
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10
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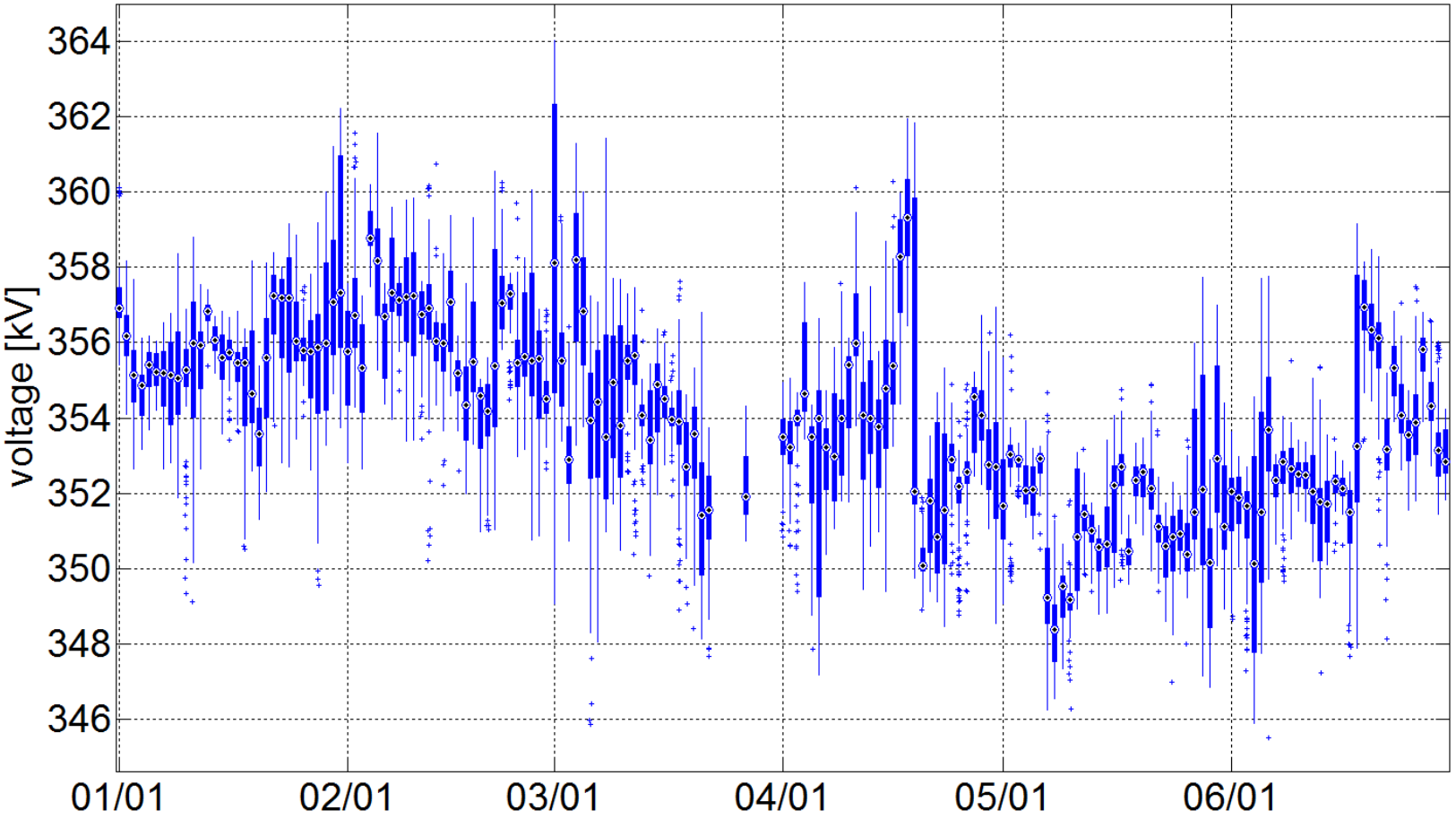
80
90
100
Cumulative Percentage of Number of Occurrences %

West 9*


voltage [kV]
364
362
360
358
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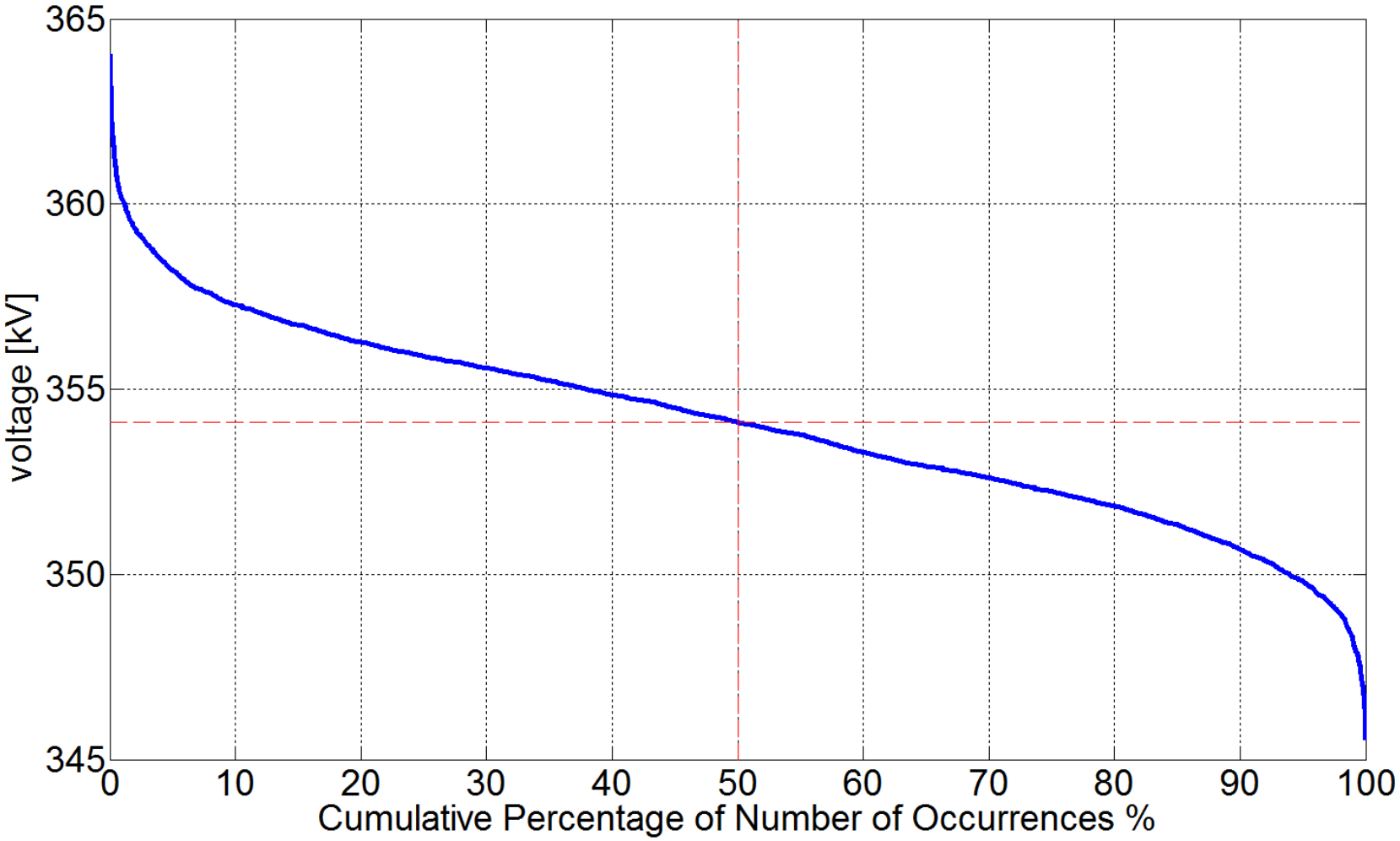
352
350
348
346
01/01
02/01
03/01
04/01
05/01
06/01

West 9*


365
360
355
350
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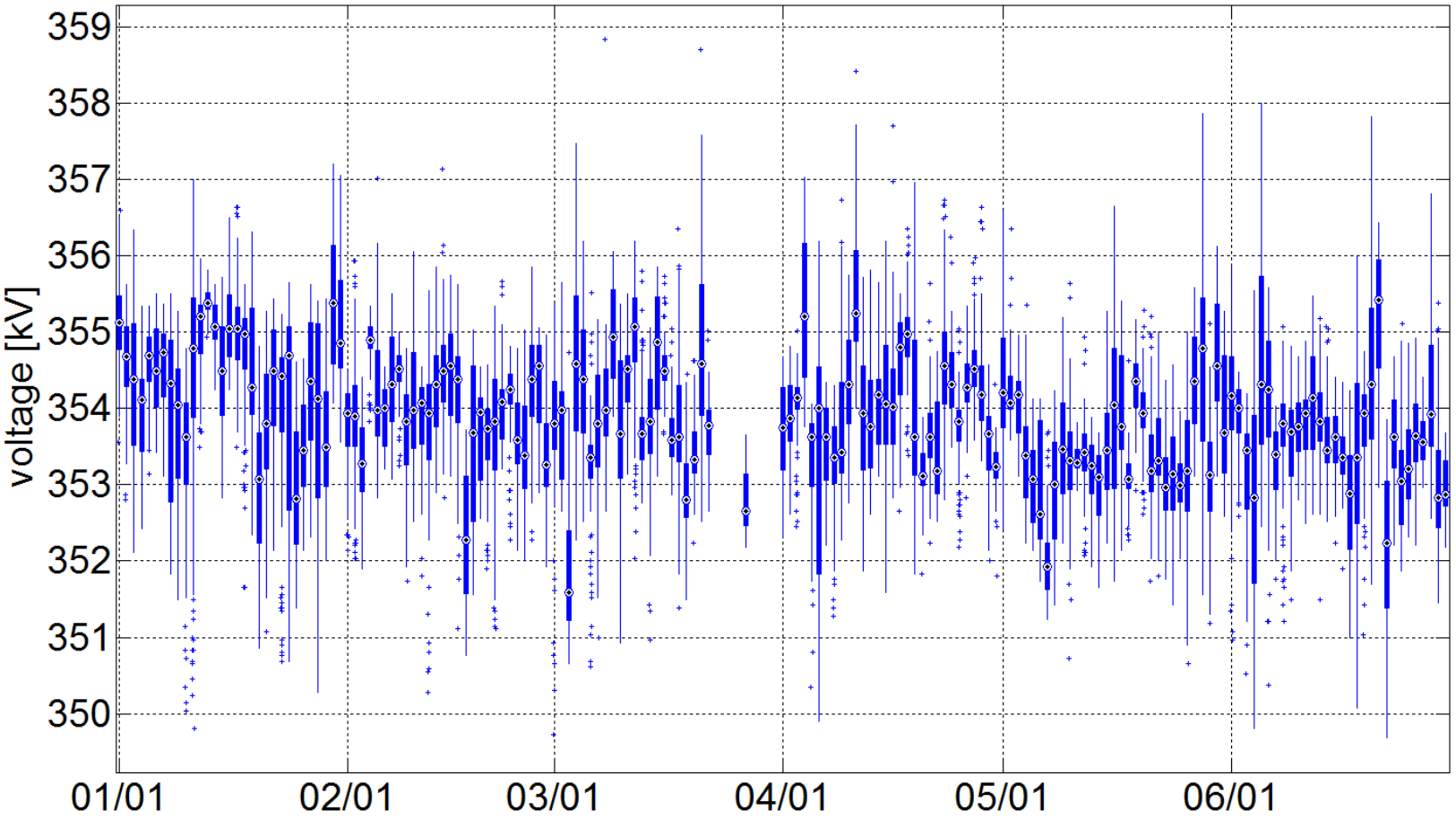
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

West 11


359
358
357
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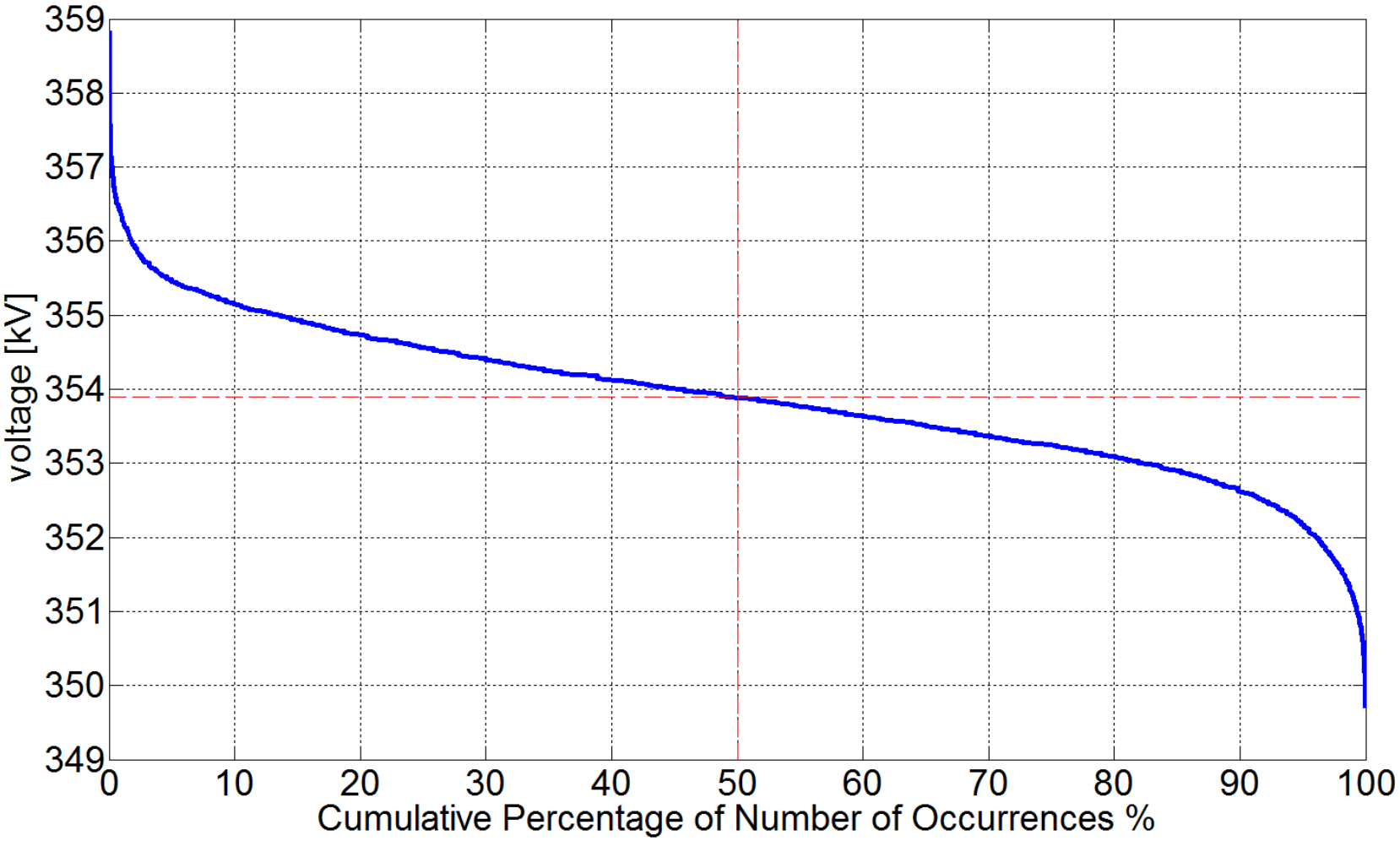
352
351
350
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

West 11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353
352
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350
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voltage [kV]
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10
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30
40
50
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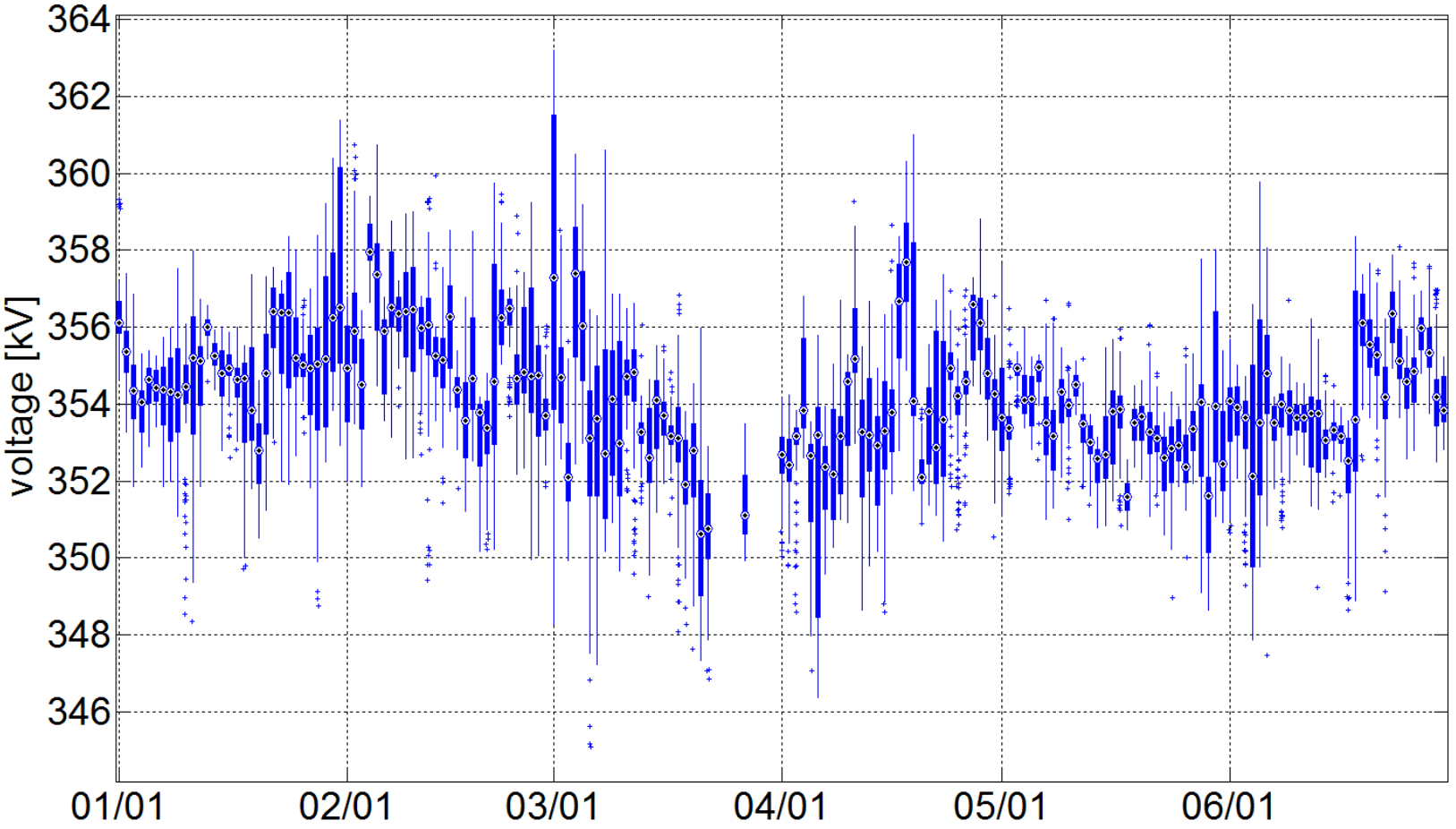
80
90
100
Cumulative Percentage of Number of Occurrences %

West 12*


364
362
360
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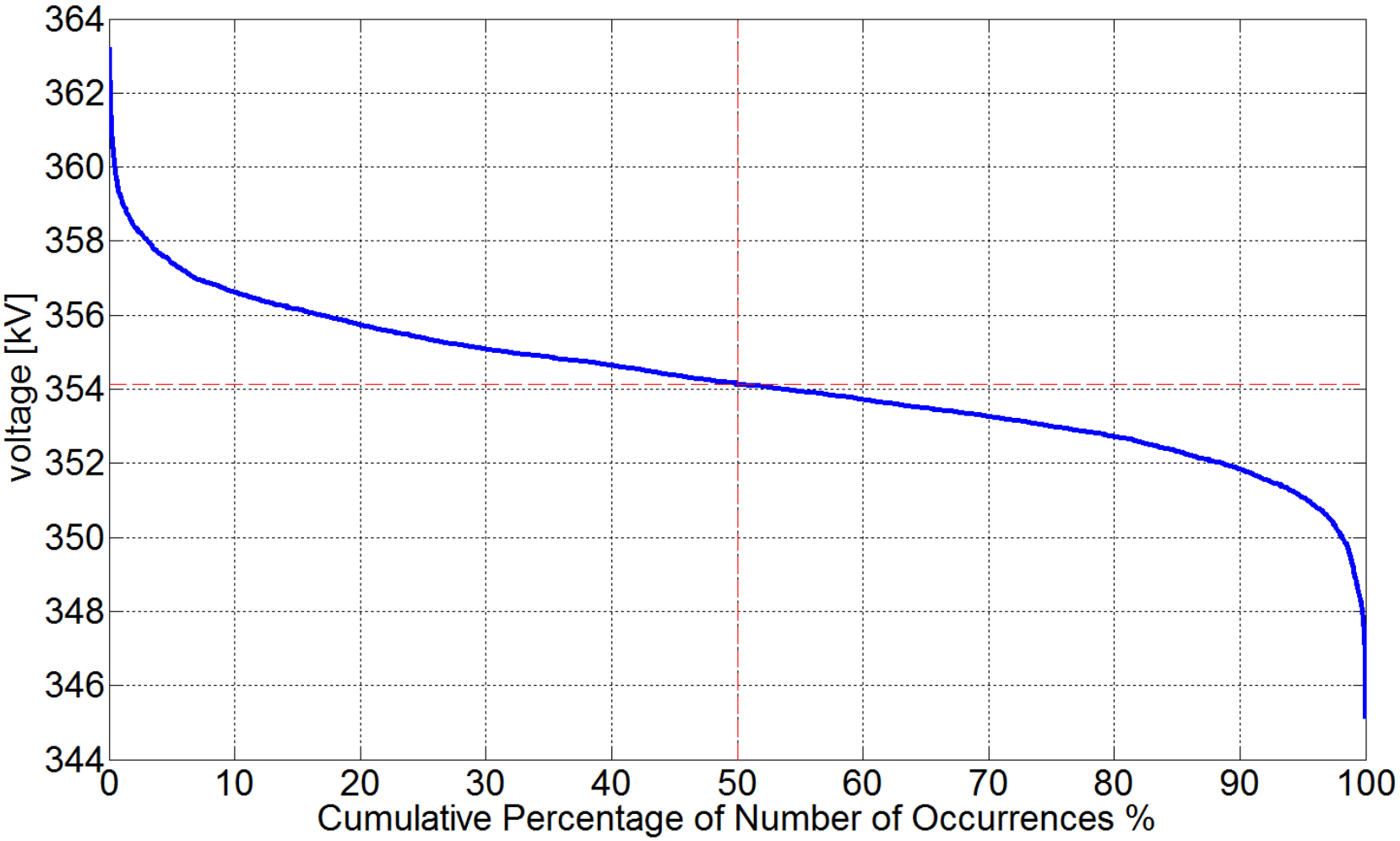
346
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

West 12*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360
358
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354
352
350
348
346
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voltage [kV]
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10
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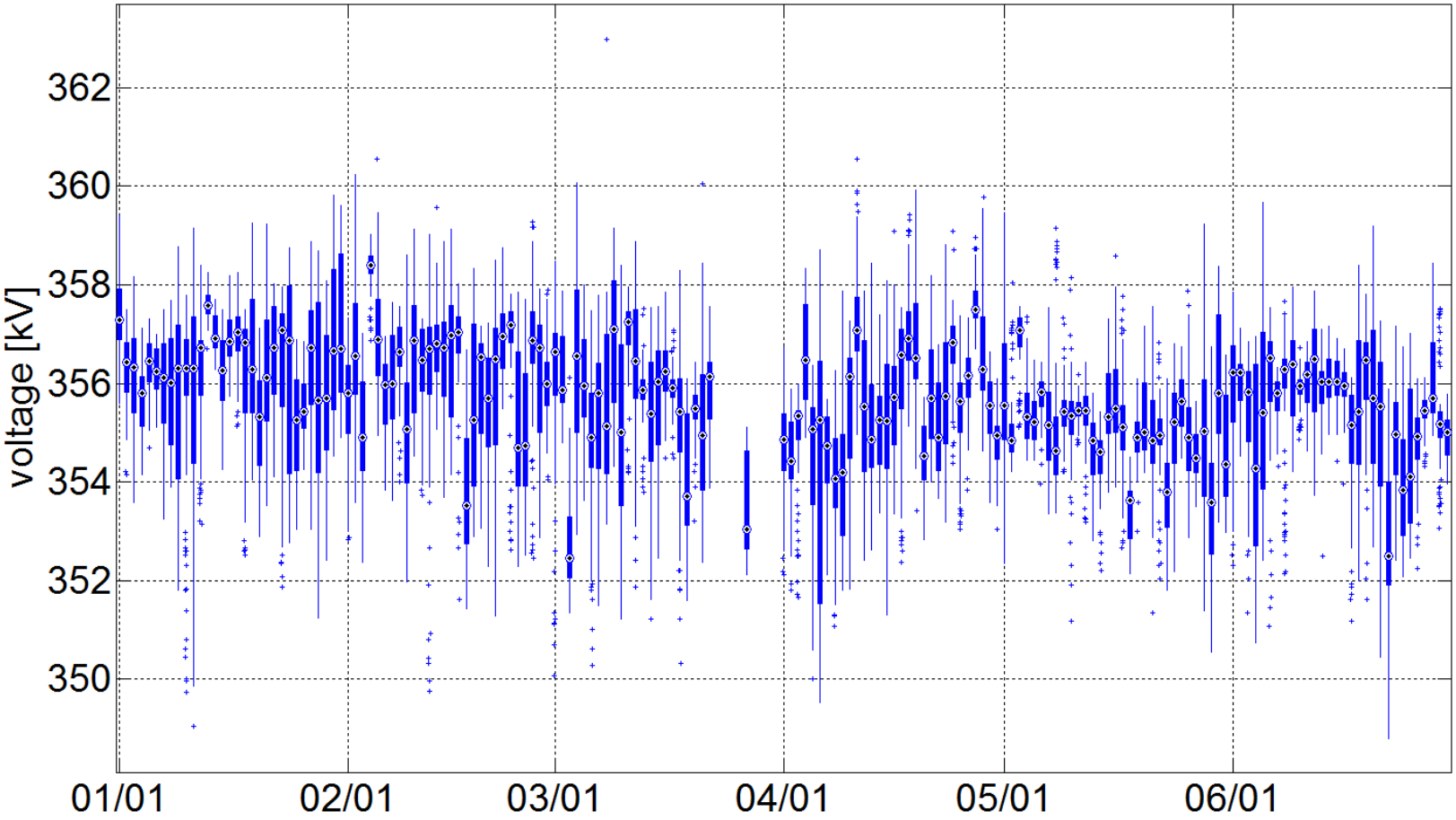
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

West 5*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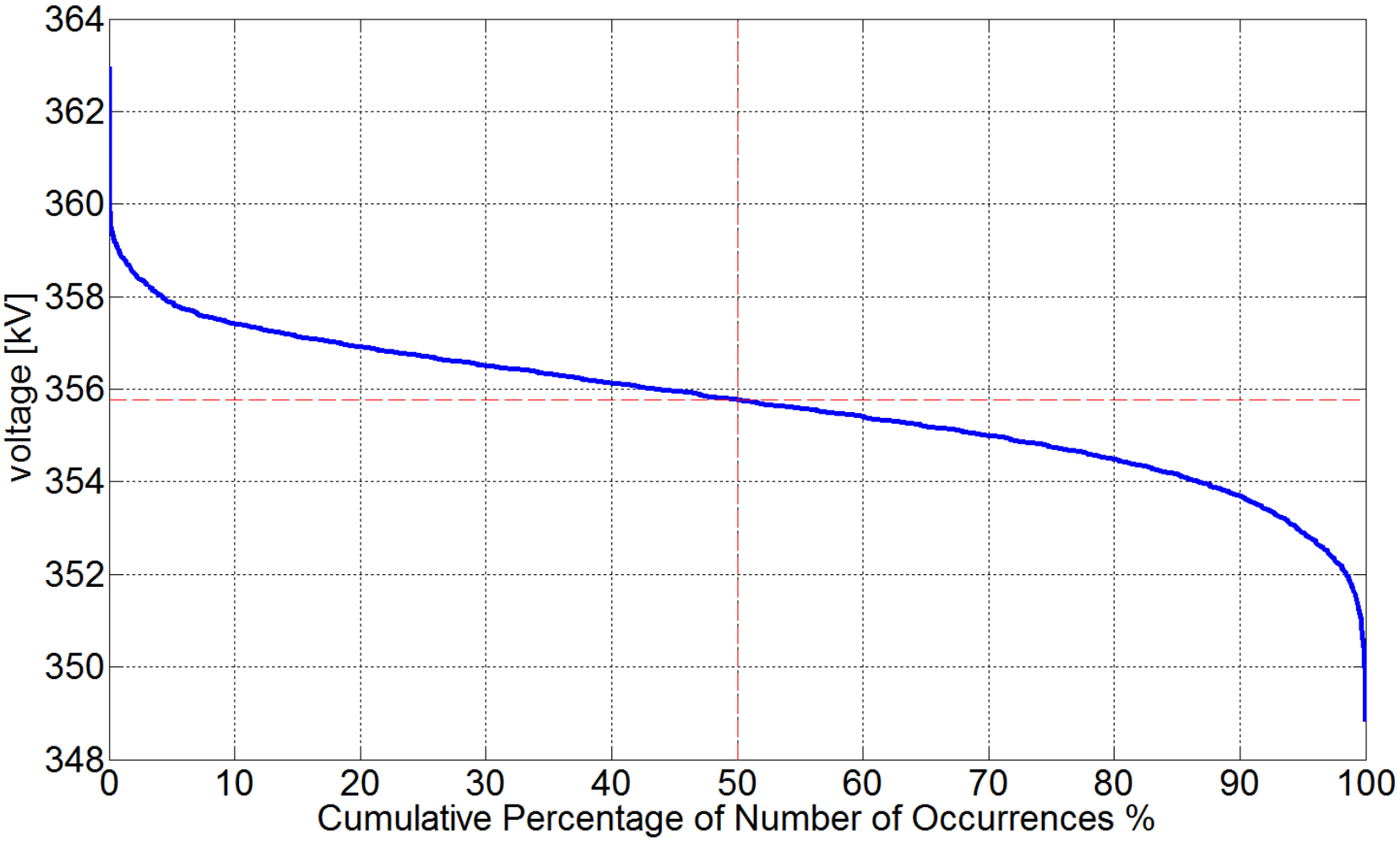
360
358
356
354
352
350
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

West 5*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362
360
358
356
354
352
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voltage [kV]
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10
20
30
40
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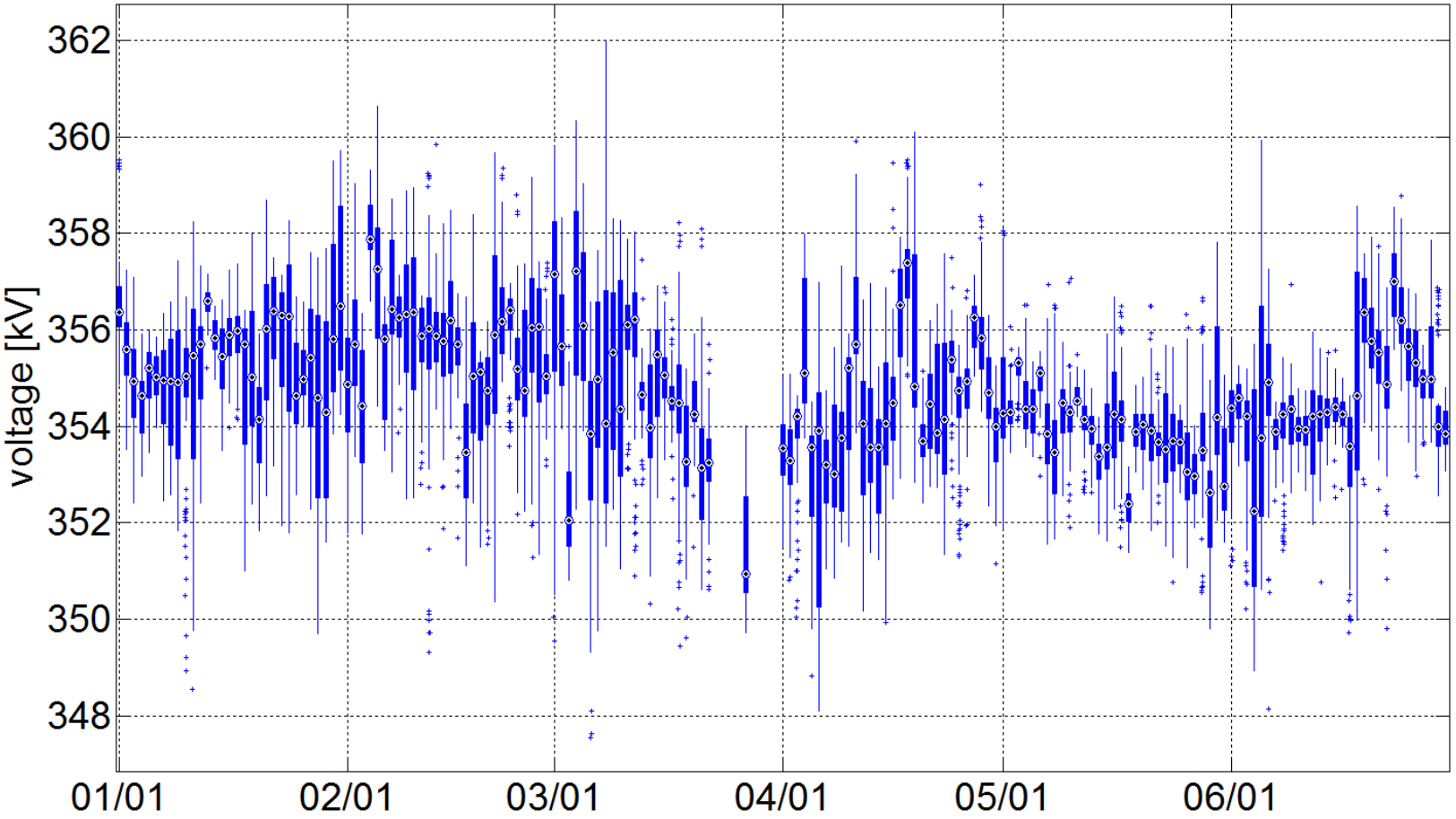
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

West 6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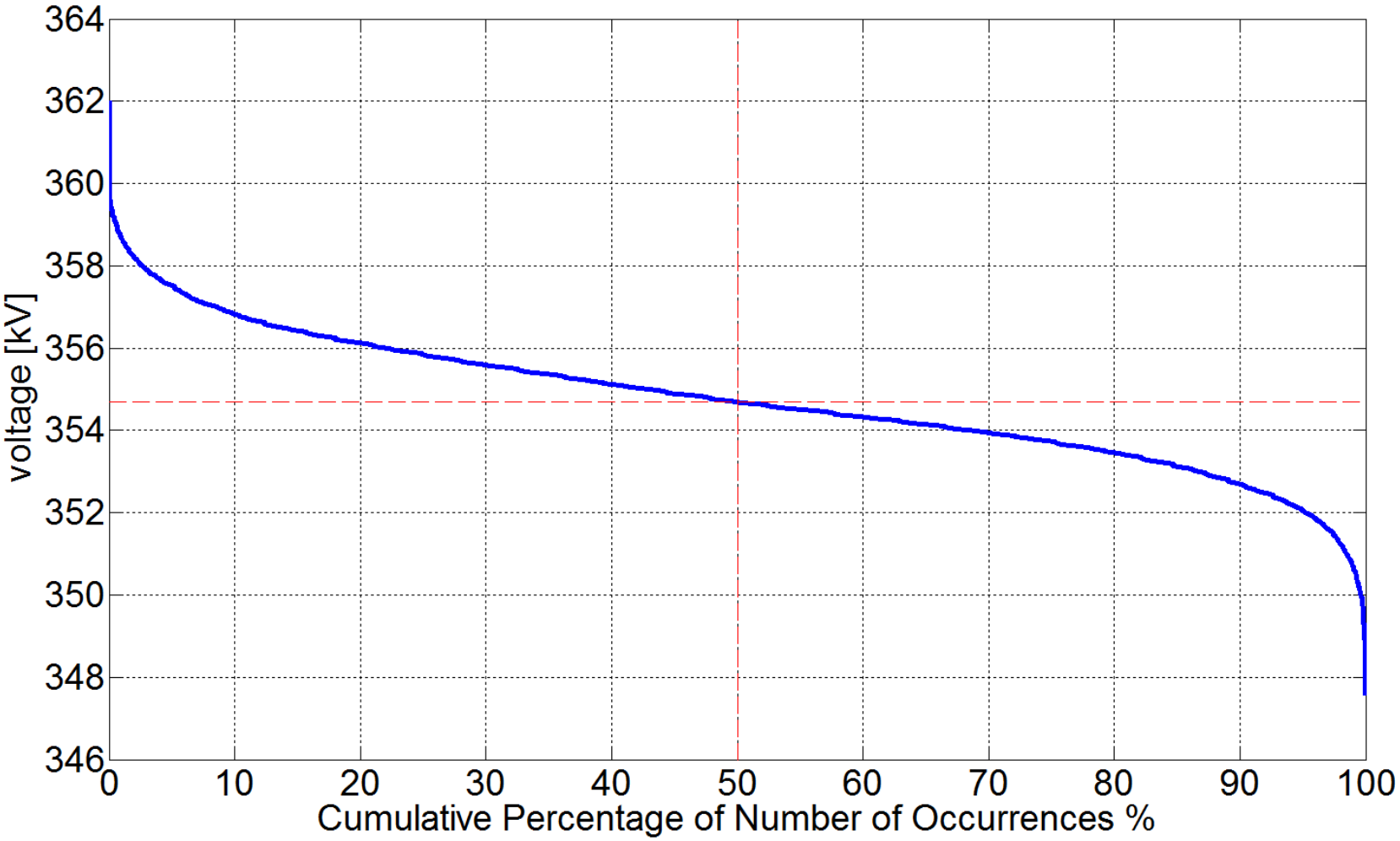
352
350
348
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

West 6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voltage [kV]
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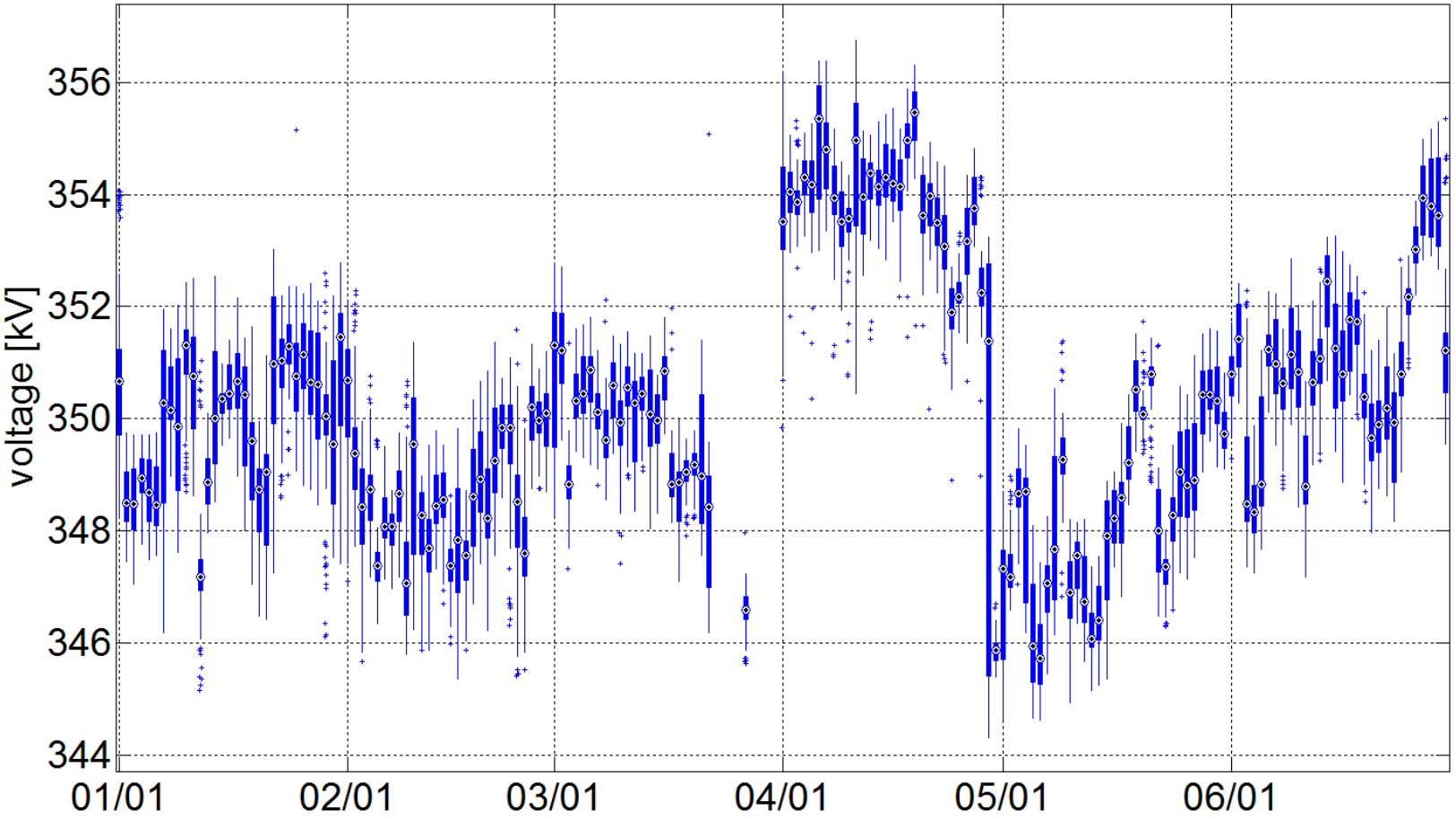
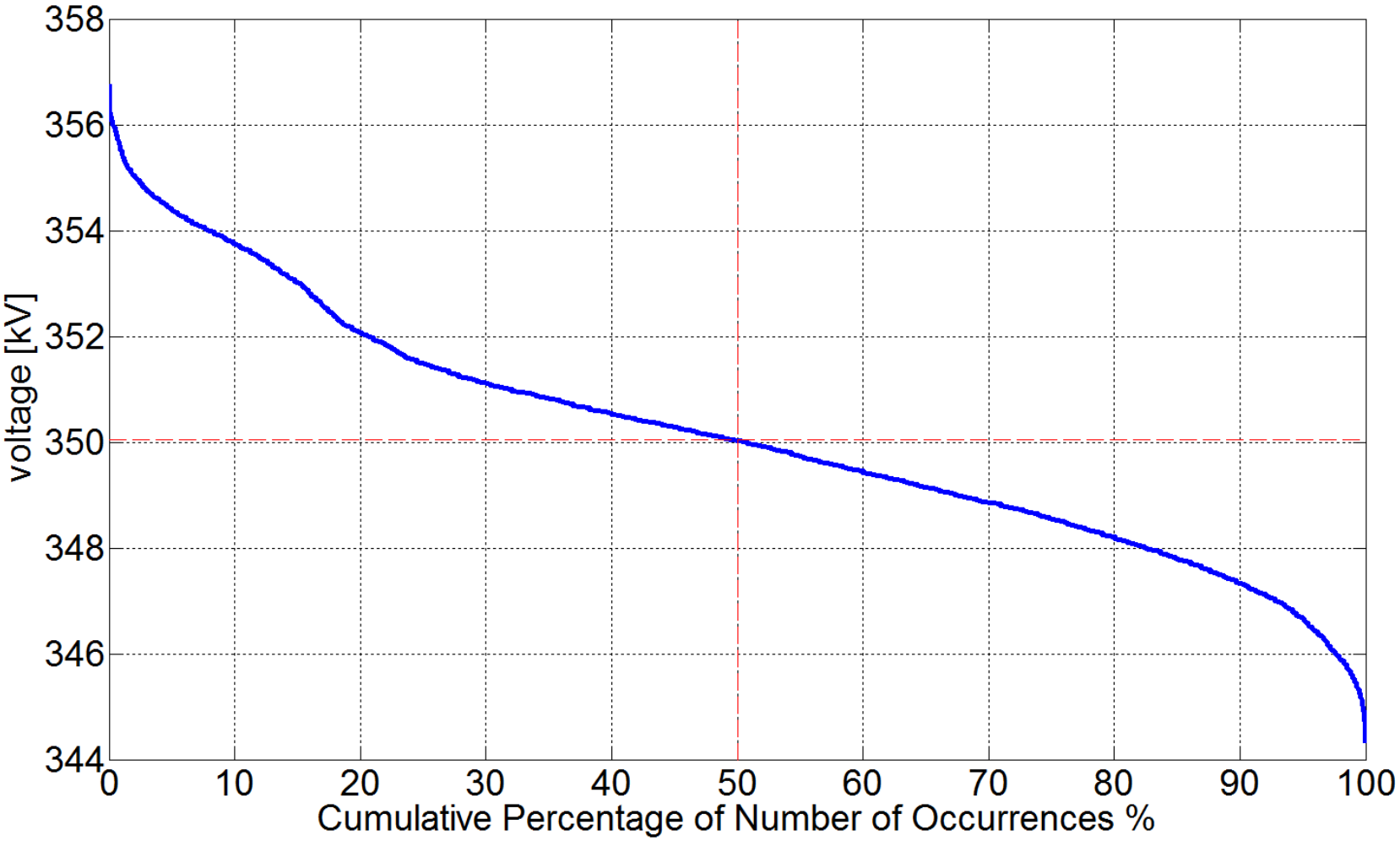
80
90
100
Cumulative Percentage of Number of Occurrences %

North 1


voltage [kV]
356
354
352
350
348
346
344
01/01
02/01
03/01
04/01
05/01
06/01

North 1


358
356
354
352
350
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voltage [kV]
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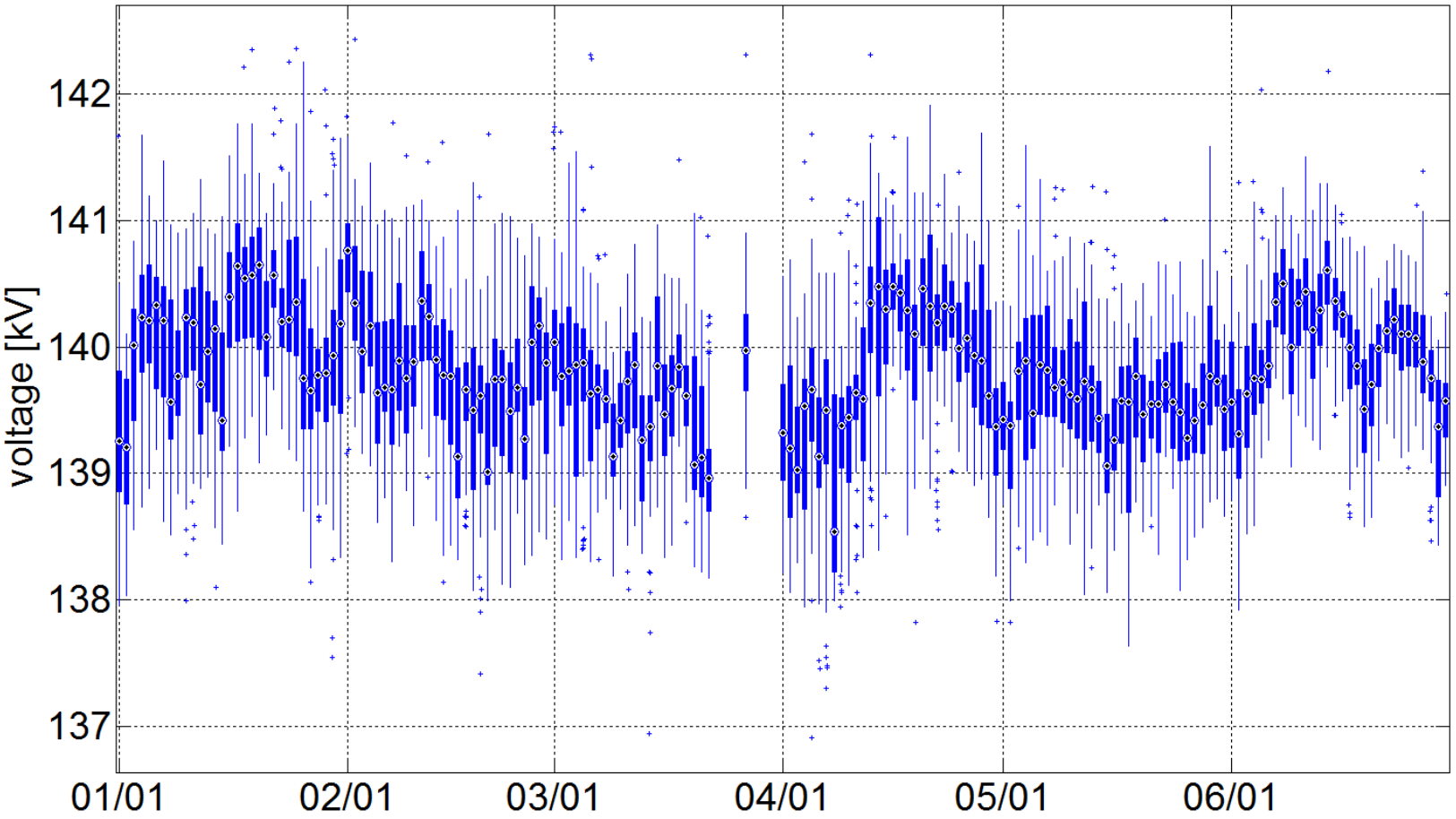
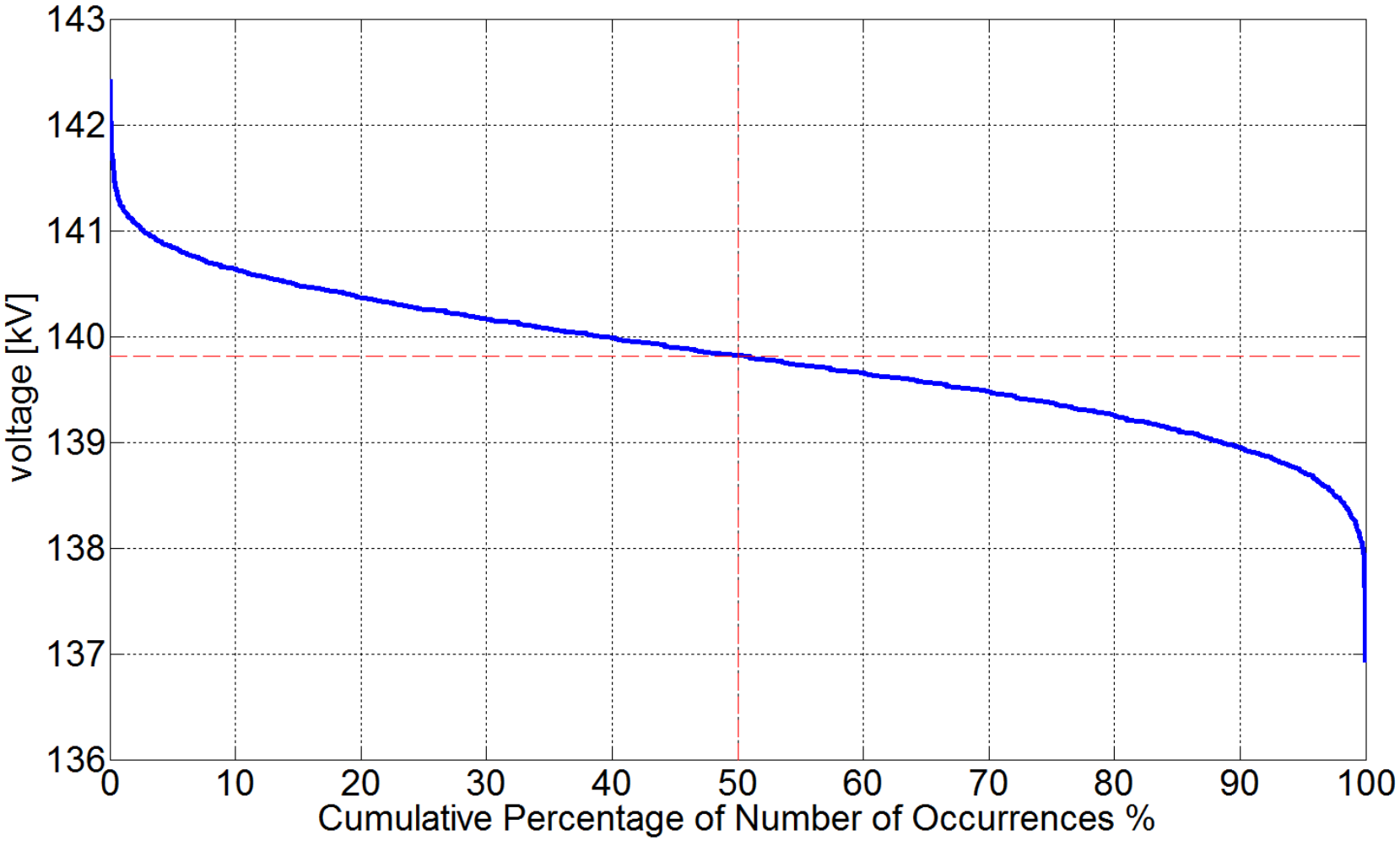
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

North 2


142
141
140
139
138
137
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

North 2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142
141
140
139
138
137
136
voltage [kV]
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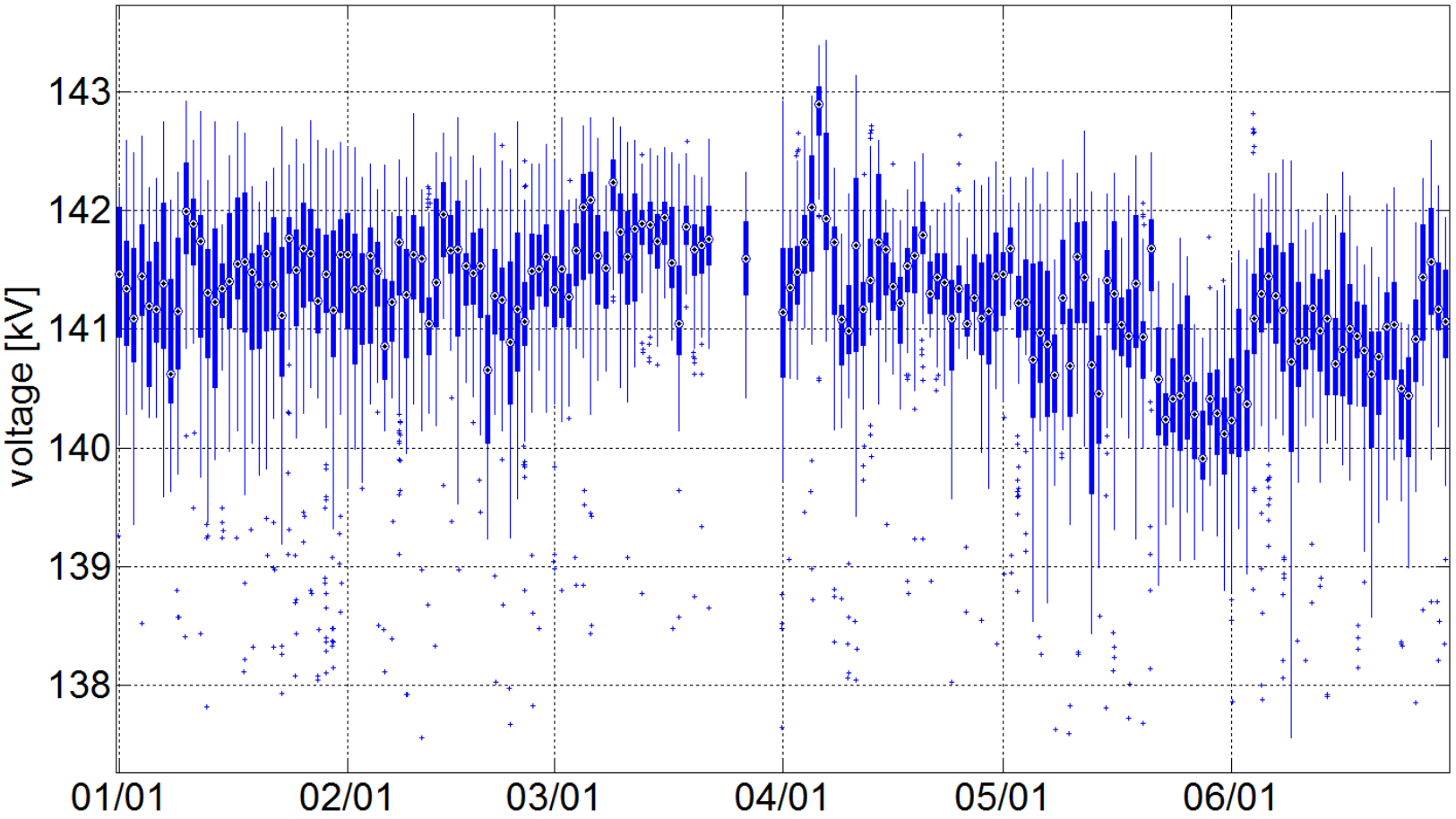
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

North 4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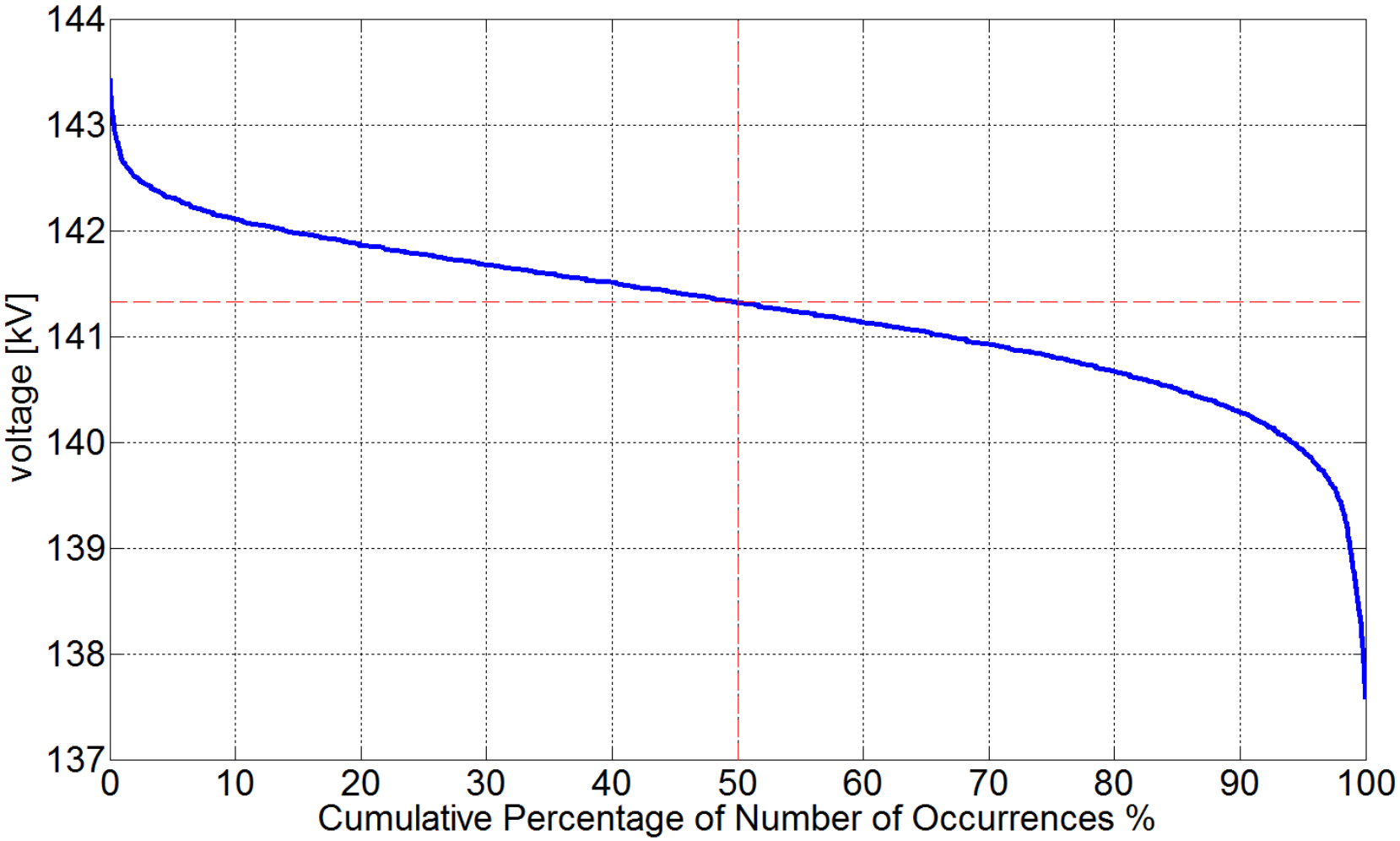
142
141
140
139
138
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

North 4


144
143
142
141
140
139
138
137
voltage [kV]
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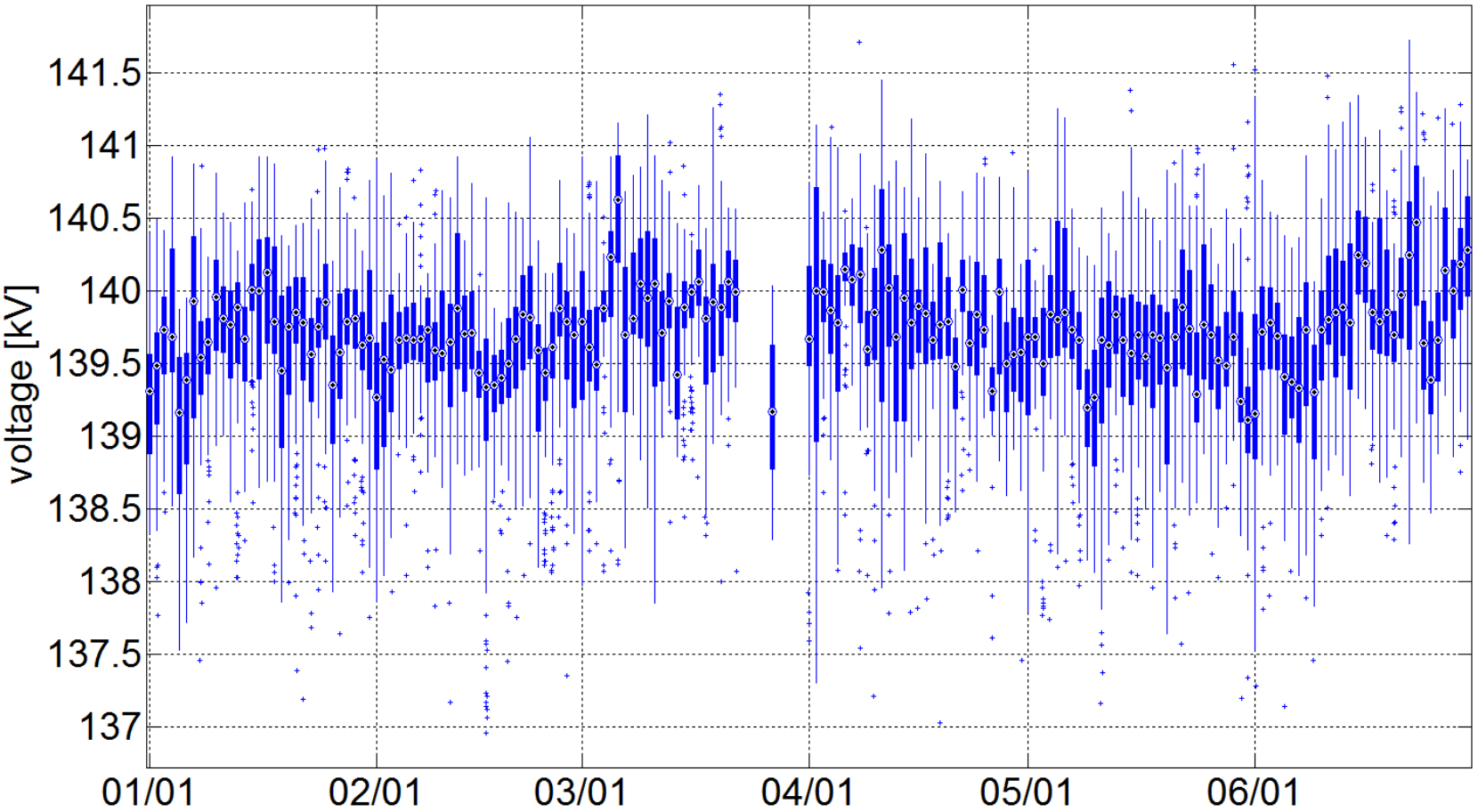
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

North 5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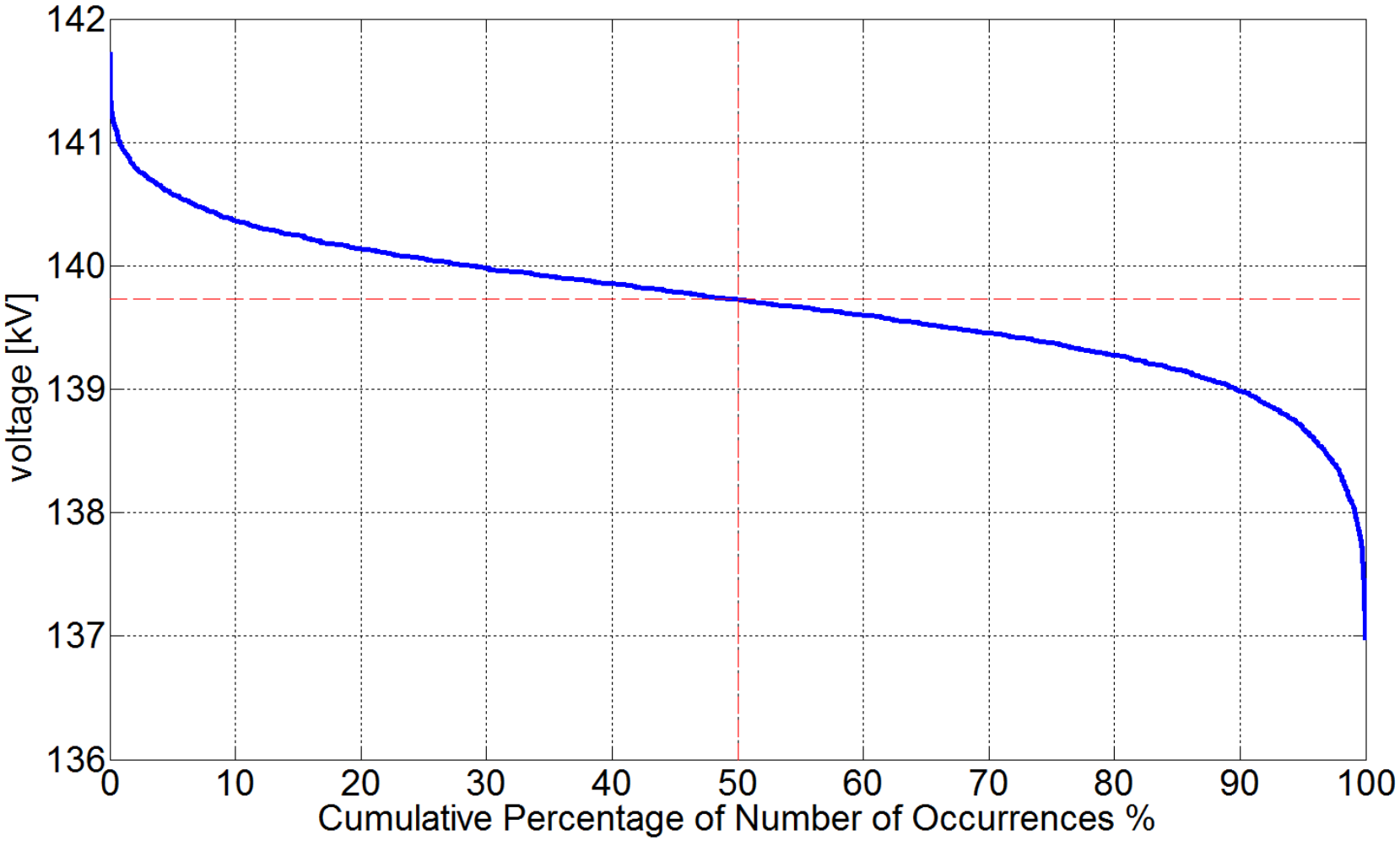
141
140.5
140
139.5
139
138.5
138
137.5
137
01/01
02/01
03/01
04/01
05/01
06/01

North 5


142
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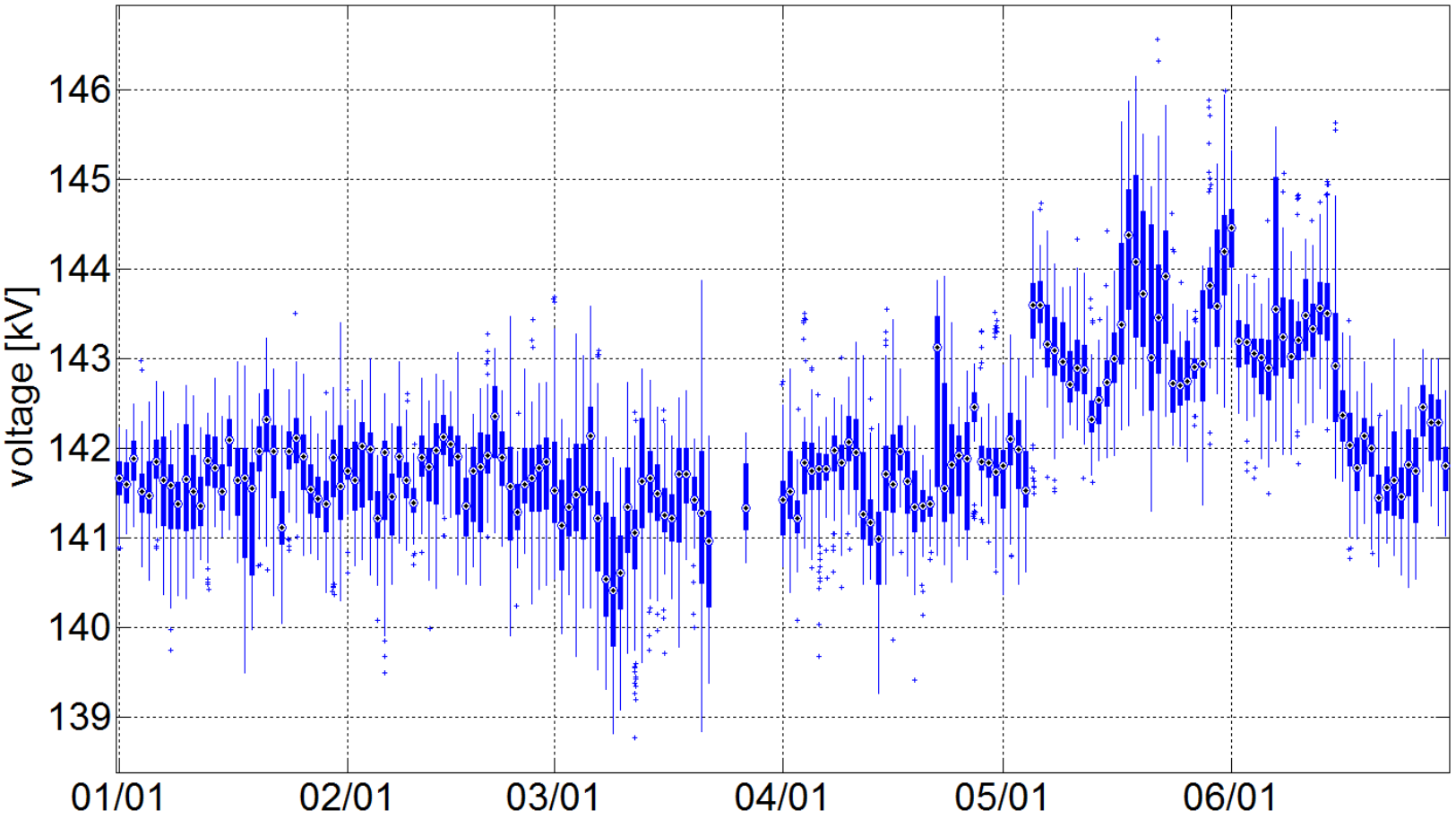
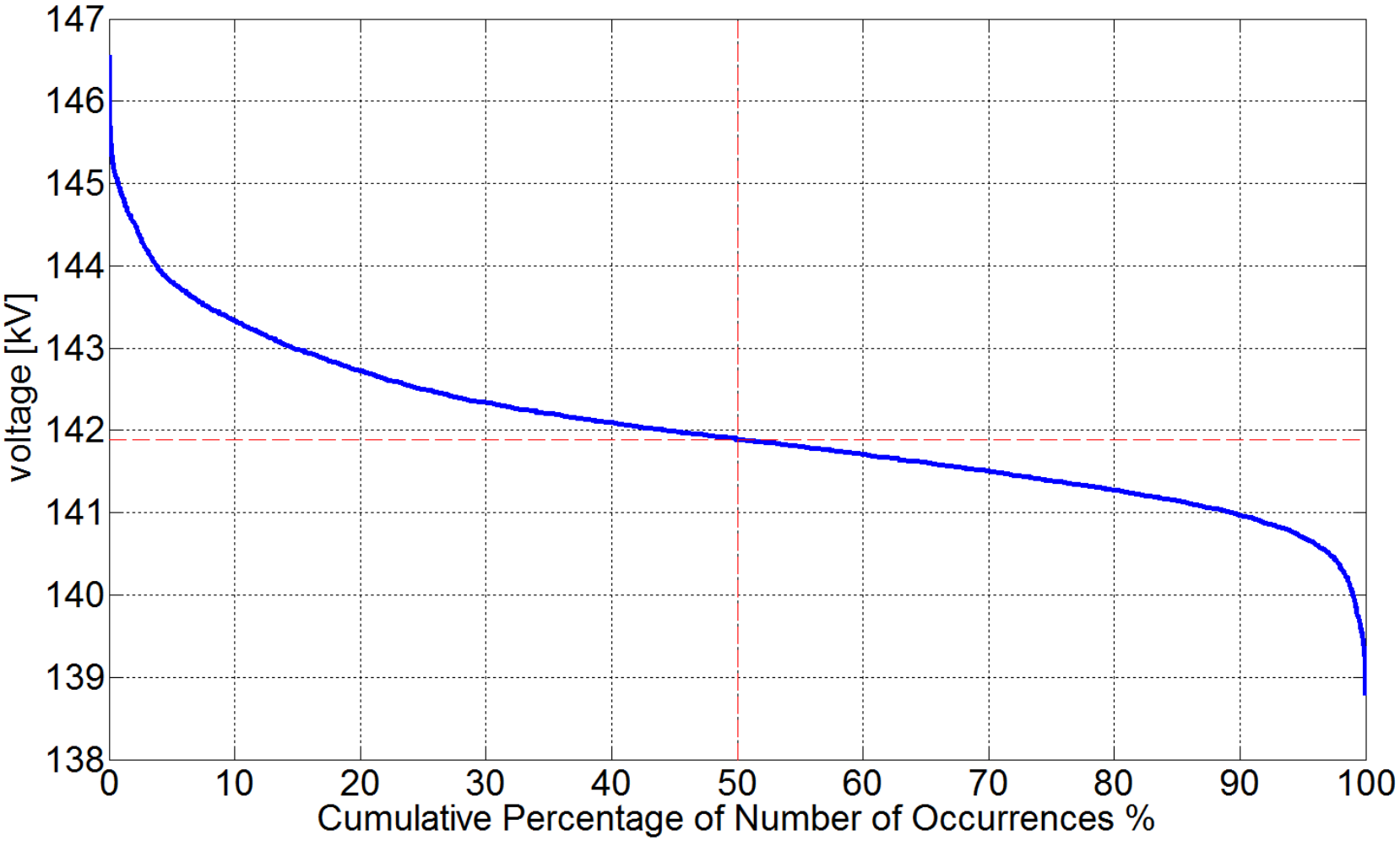
140
139
138
137
136
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

North 6


voltage [kV]
146
145
144
143
142
141
140
139
01/01
02/01
03/01
04/01
05/01
06/01

North 6


147
146
145
144
143
142
141
140
139
138
voltage [kV]
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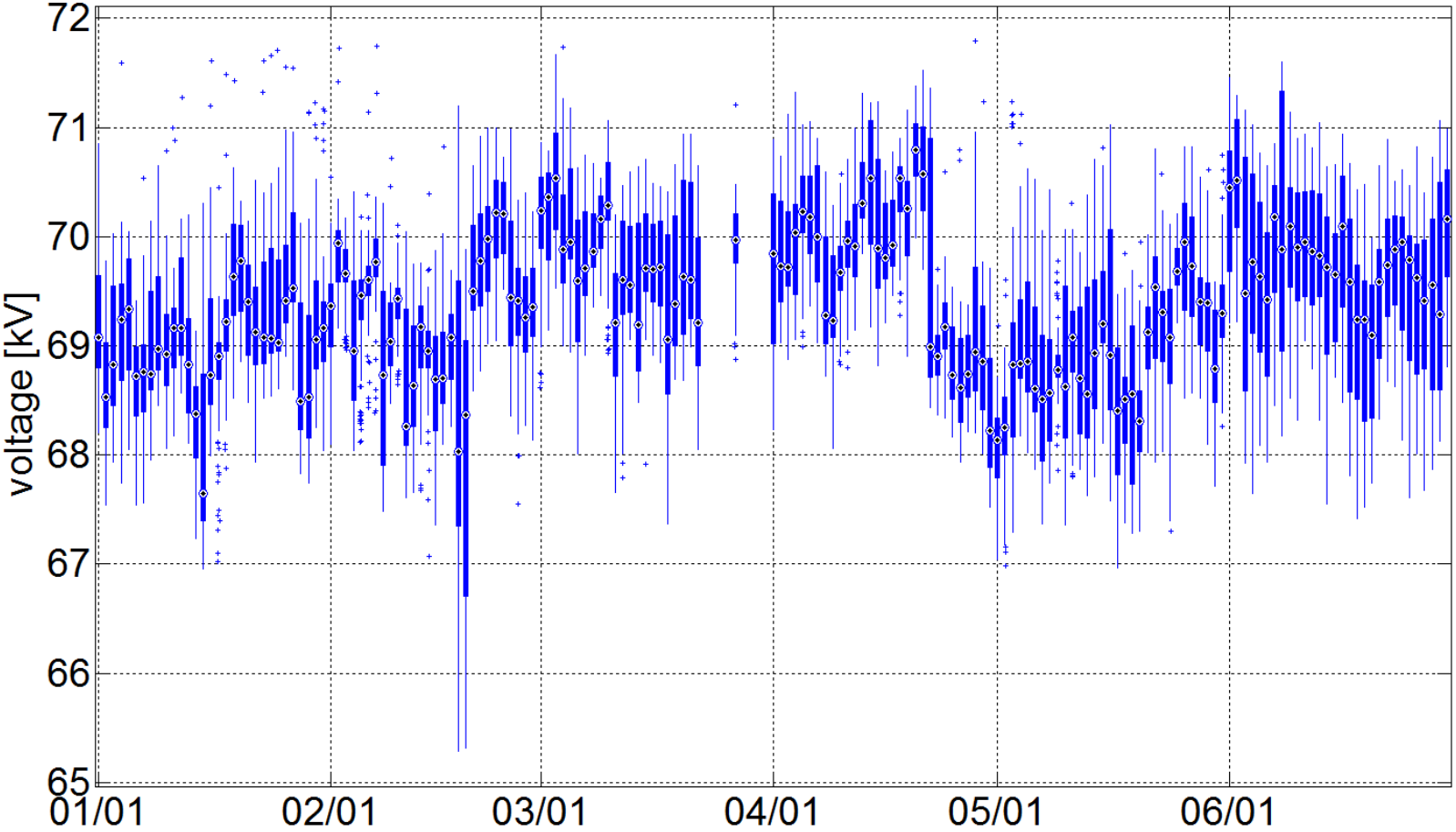
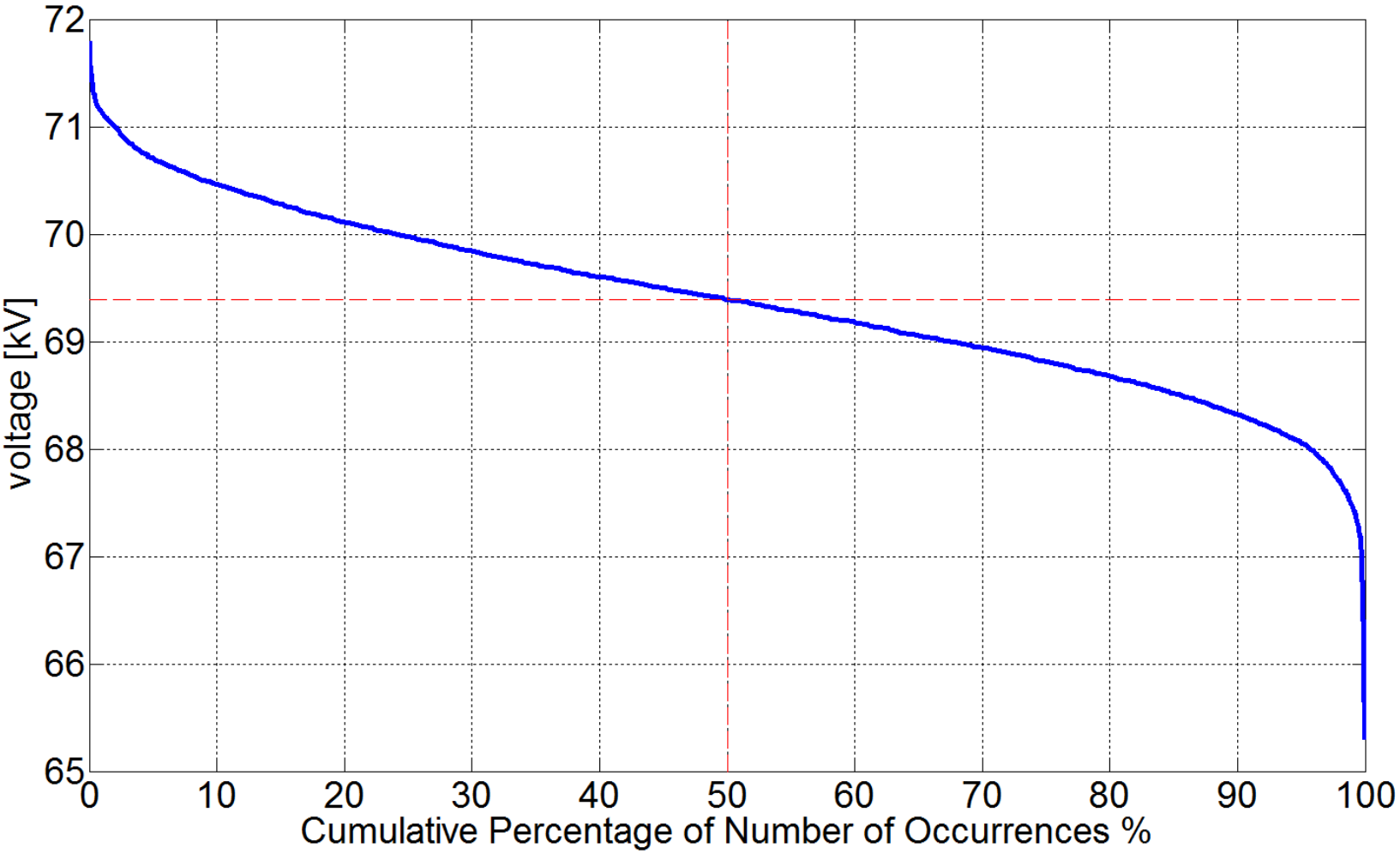
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

FarWest 2*



FarWest 2*


72
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69
68
67
66
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voltage [kV]
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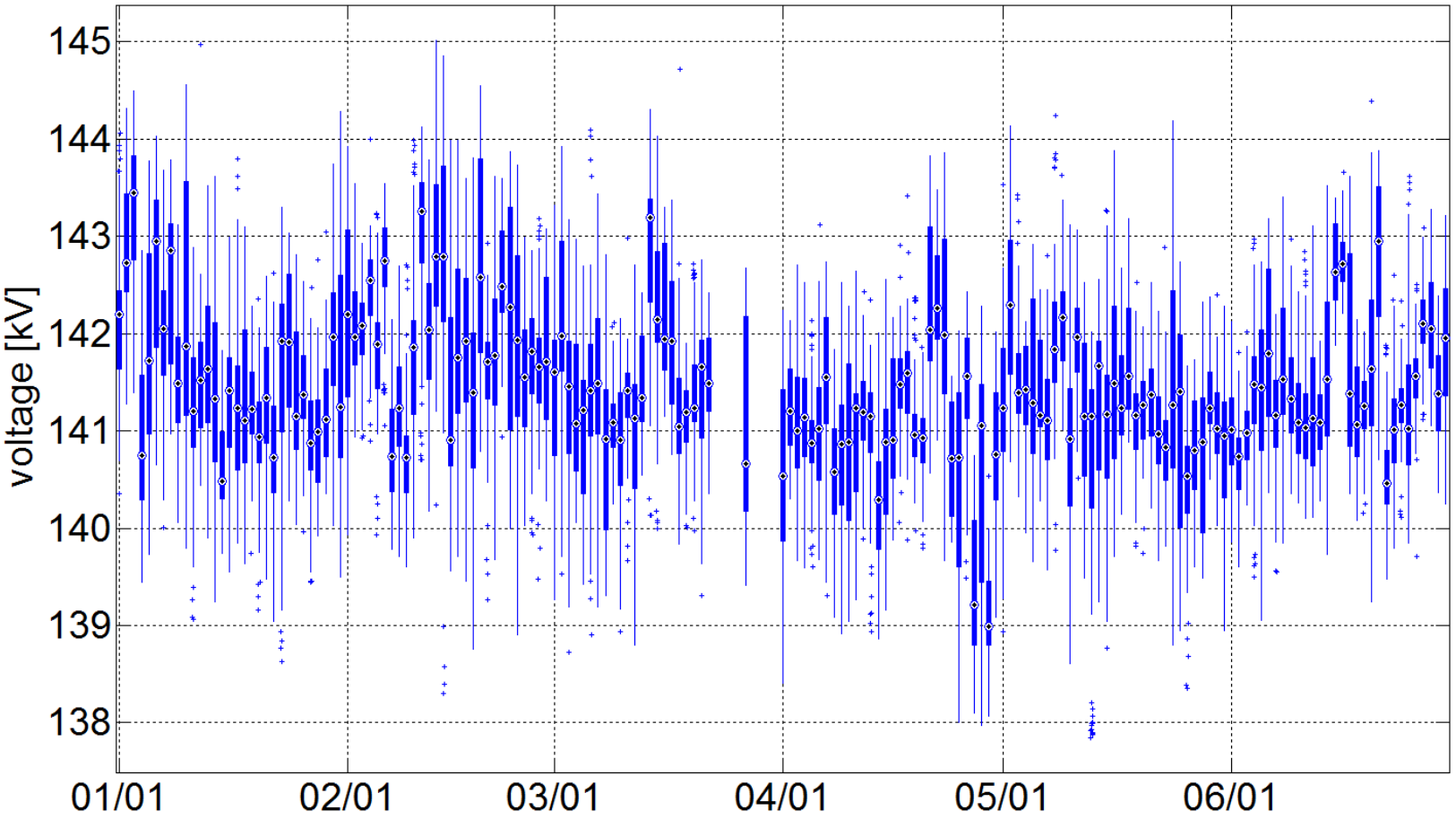
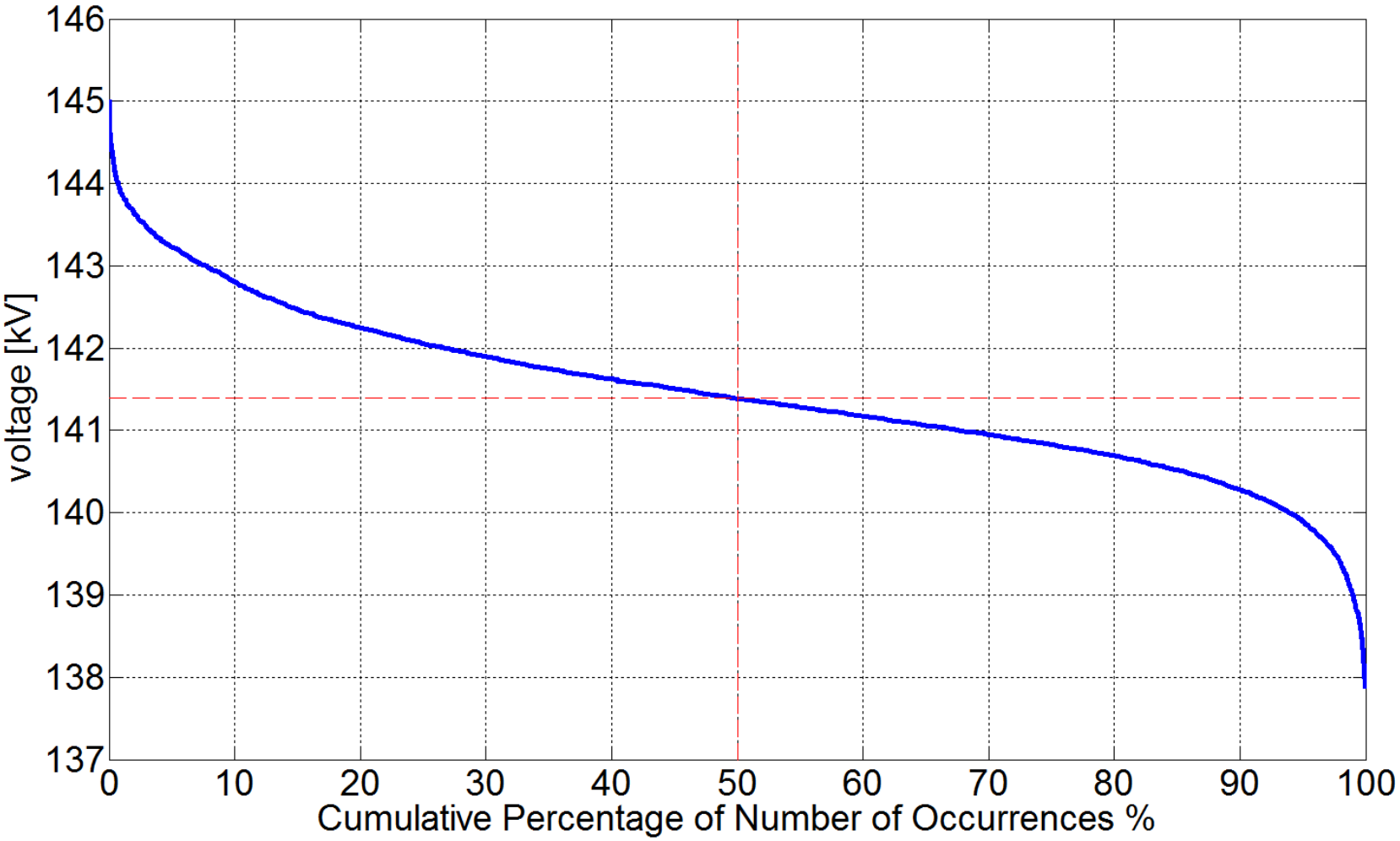
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

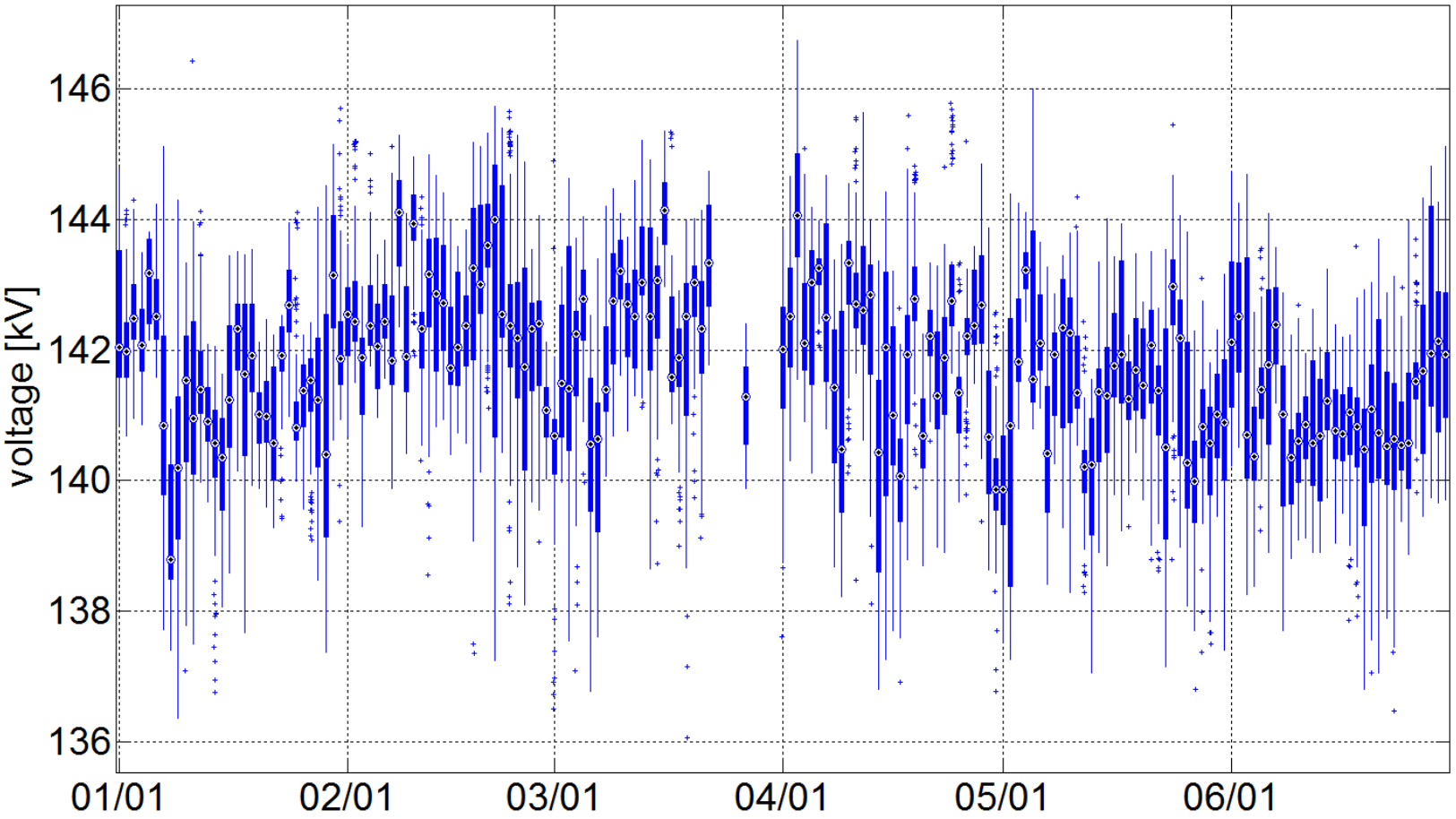
North 7


145
144
143
142
141
140
139
138
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

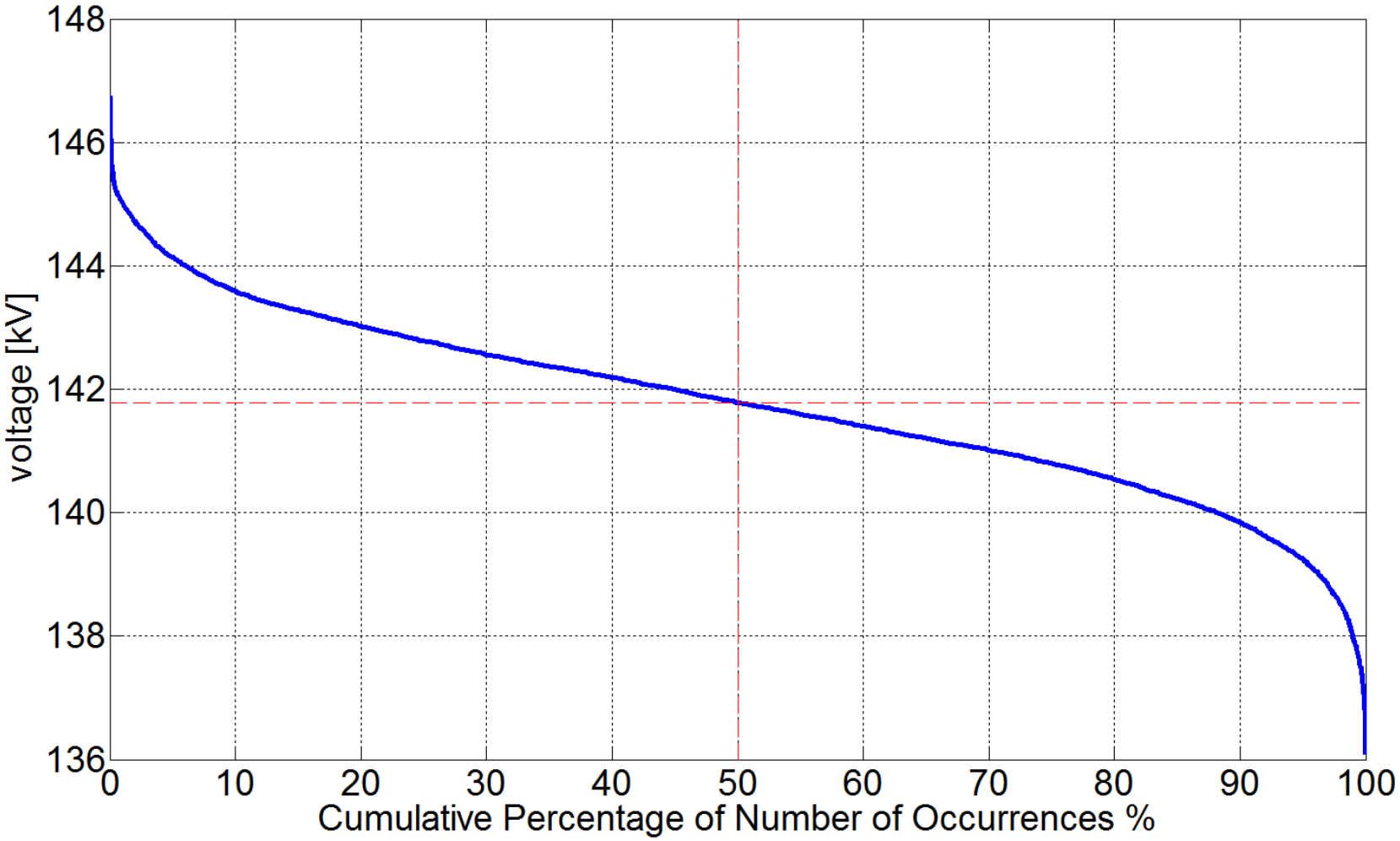
North 7


146
145
144
143
142
141
140
139
138
137
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

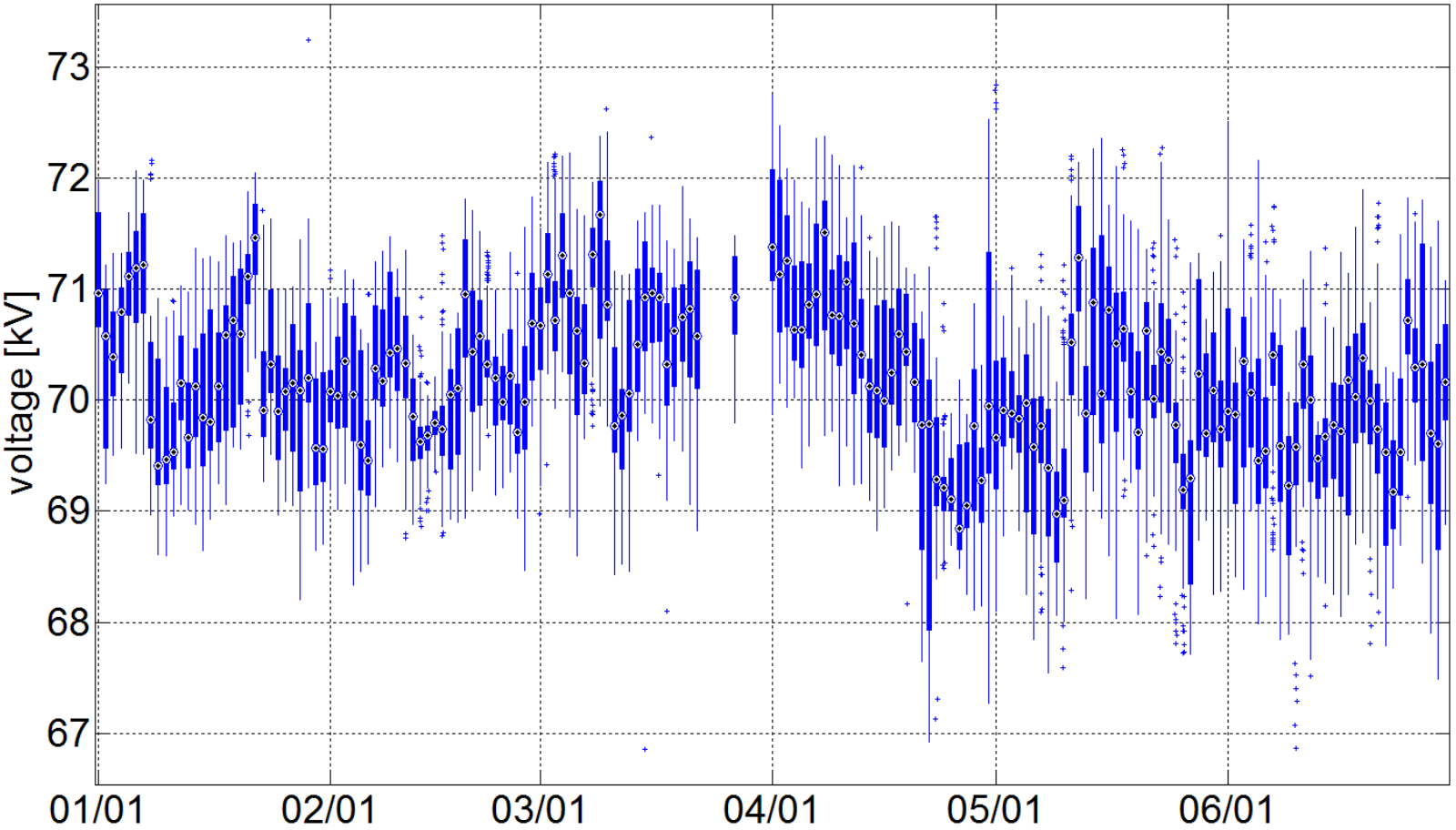
West 4


146
144
142
140
138
136
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

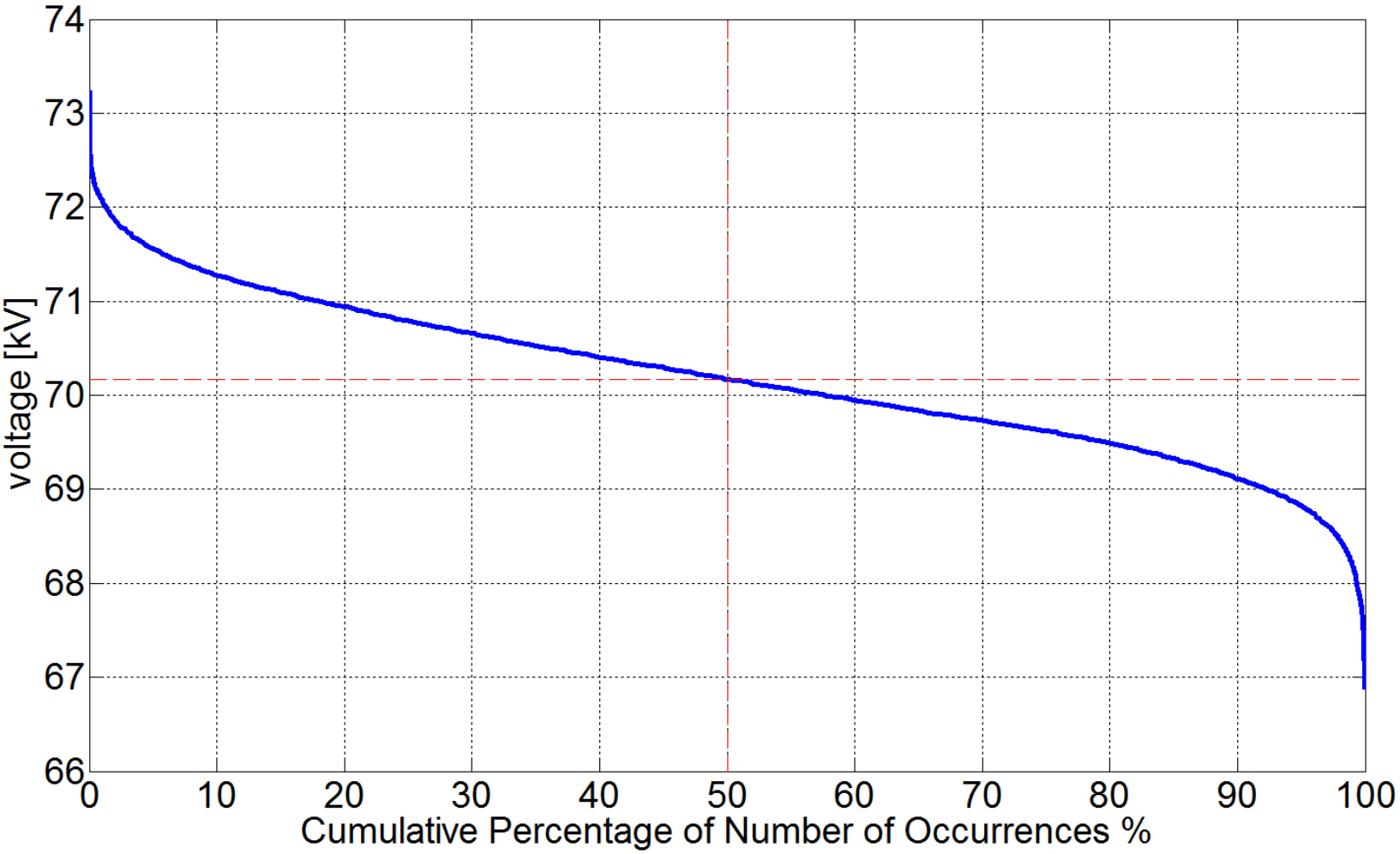
West 4


148
146
144
142
140
138
136
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

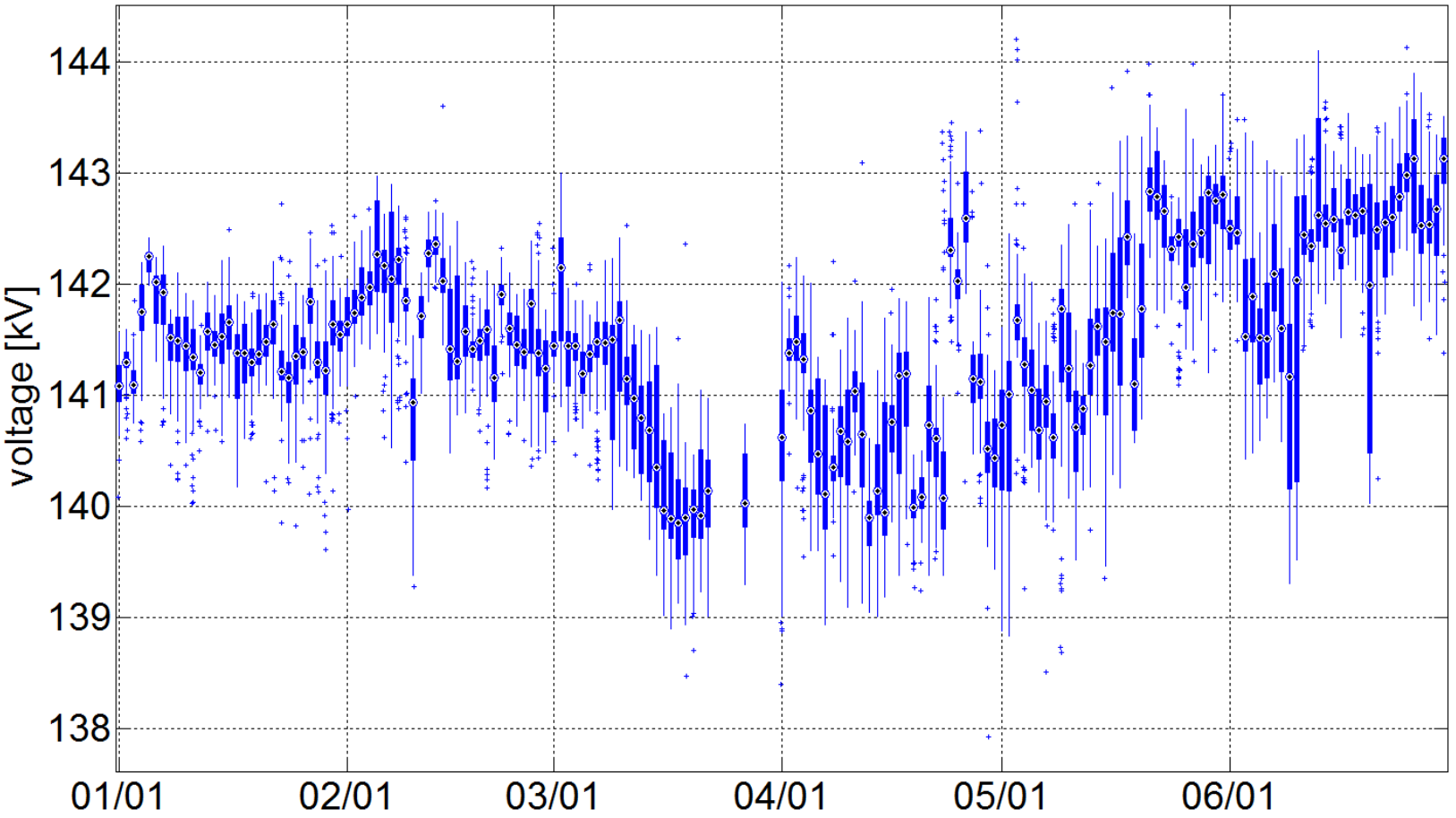
Coast 2*



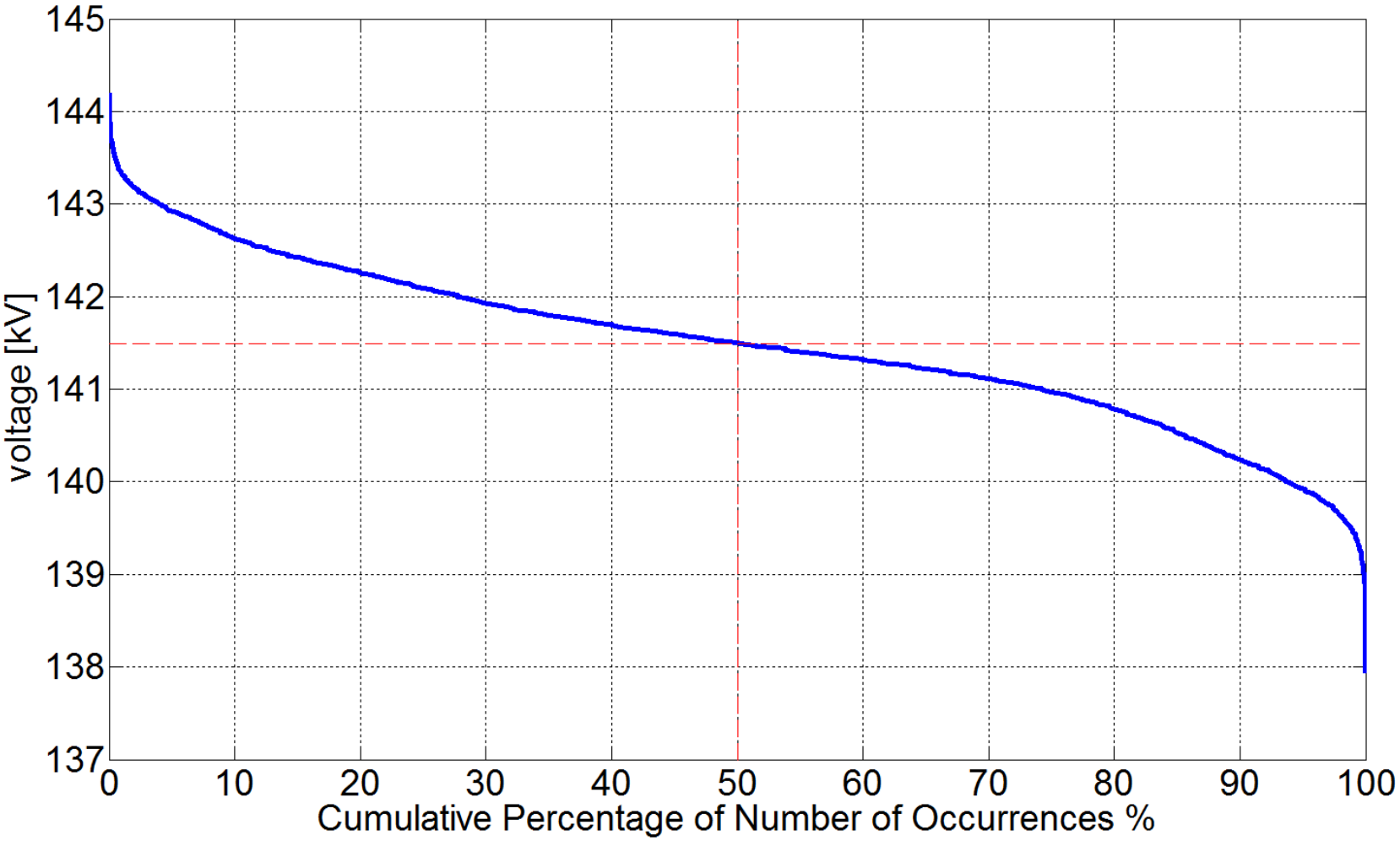
Coast 2*


74
73
72
71
70
69
68
67
66
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

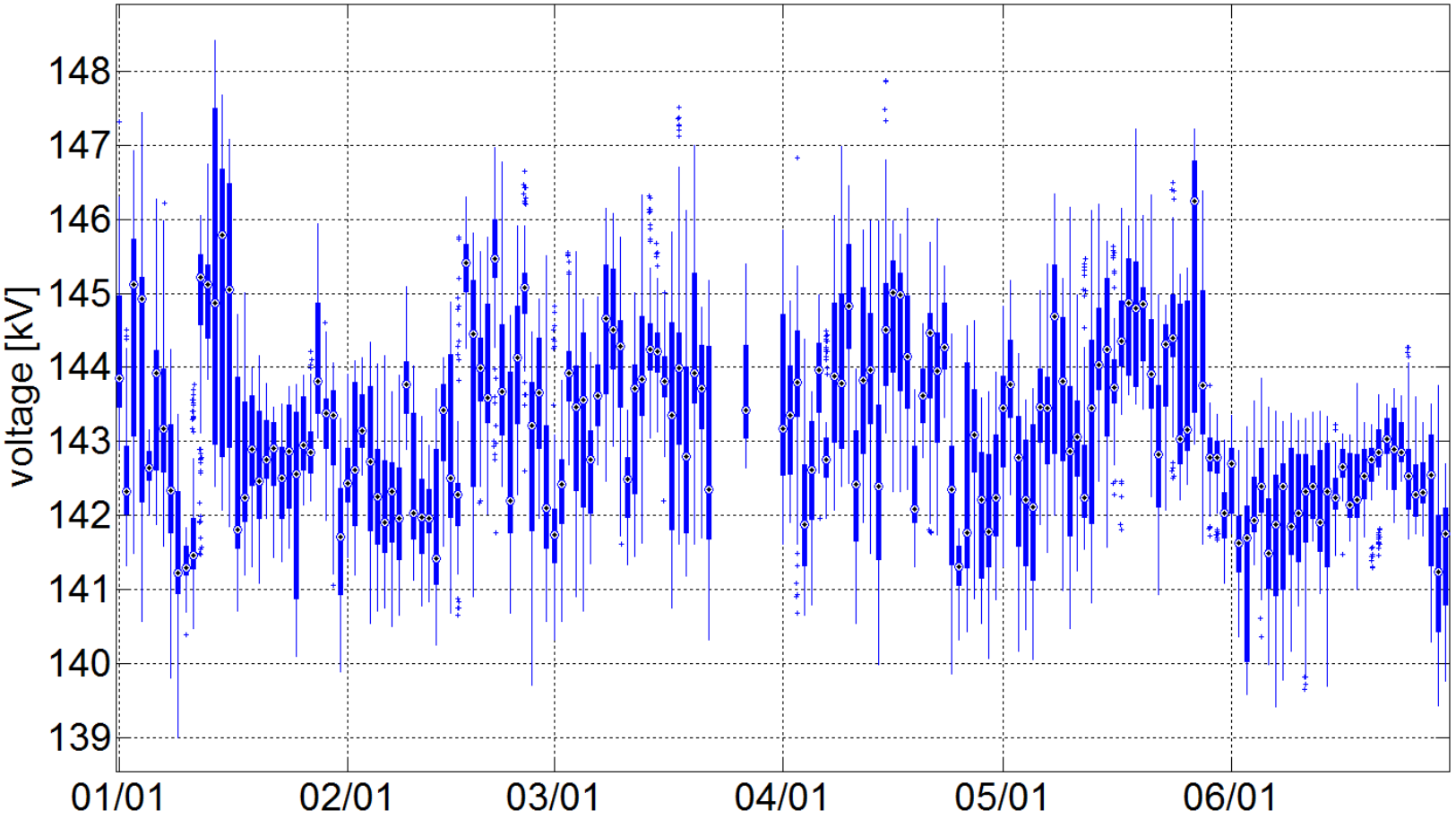
Coast 1


144
143
142
141
140
139
138
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

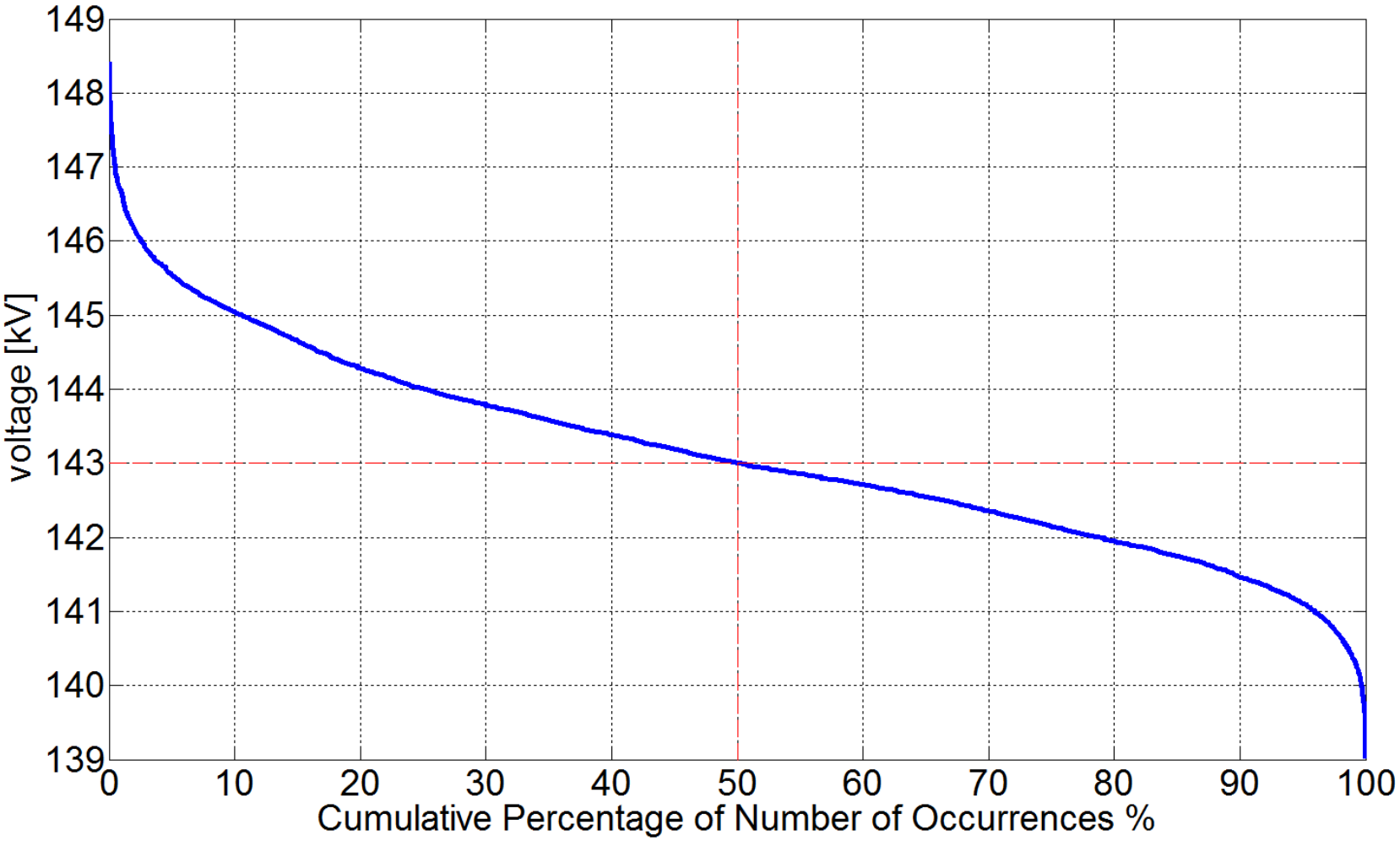
Coast 1


145
144
143
142
141
140
139
138
137
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

South 3*


voltage [kV]
148
147
146
145
144
143
142
141
140
139
01/01
02/01
03/01
04/01
05/01
06/01

South 3*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voltage [kV]
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30
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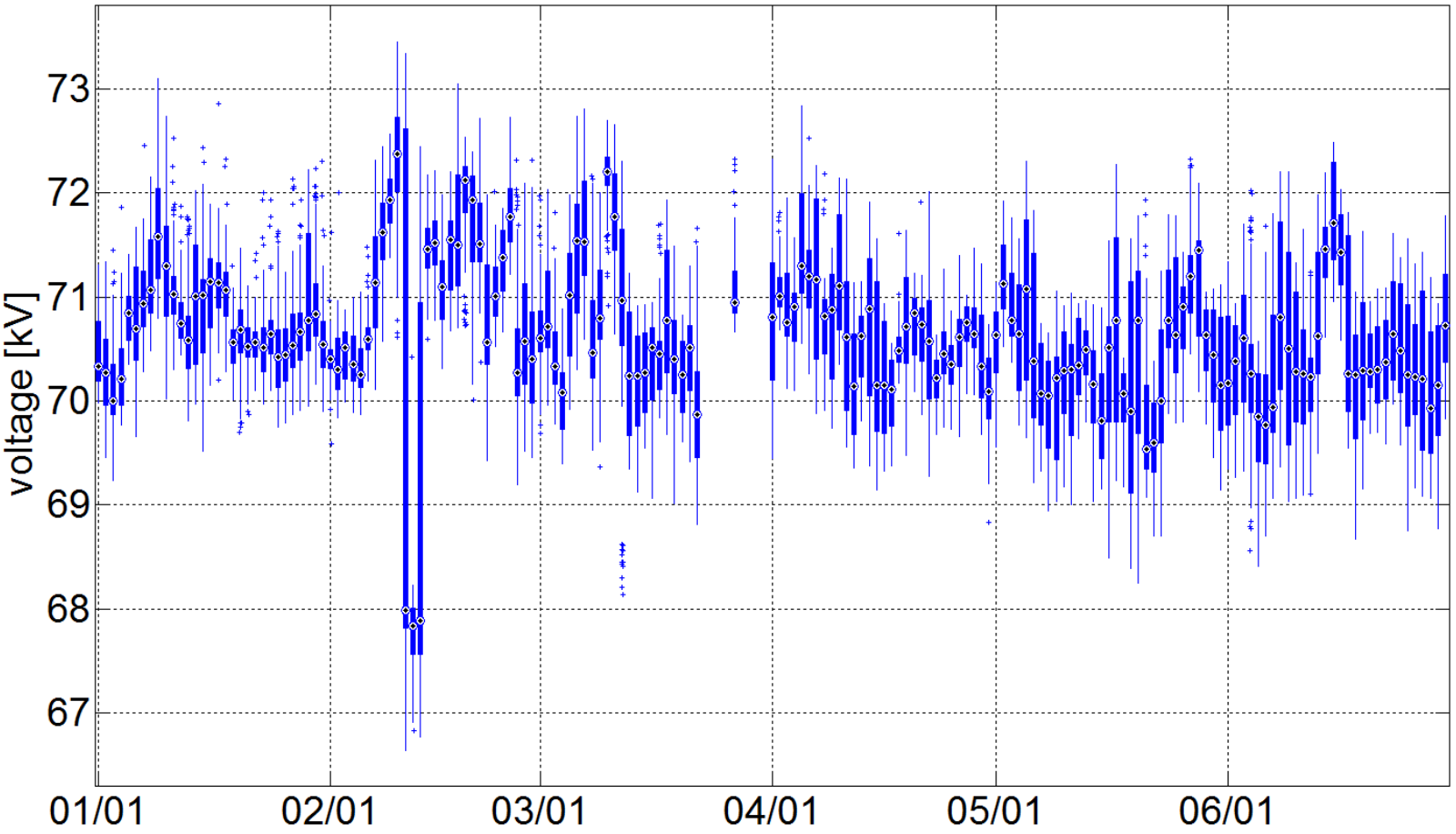
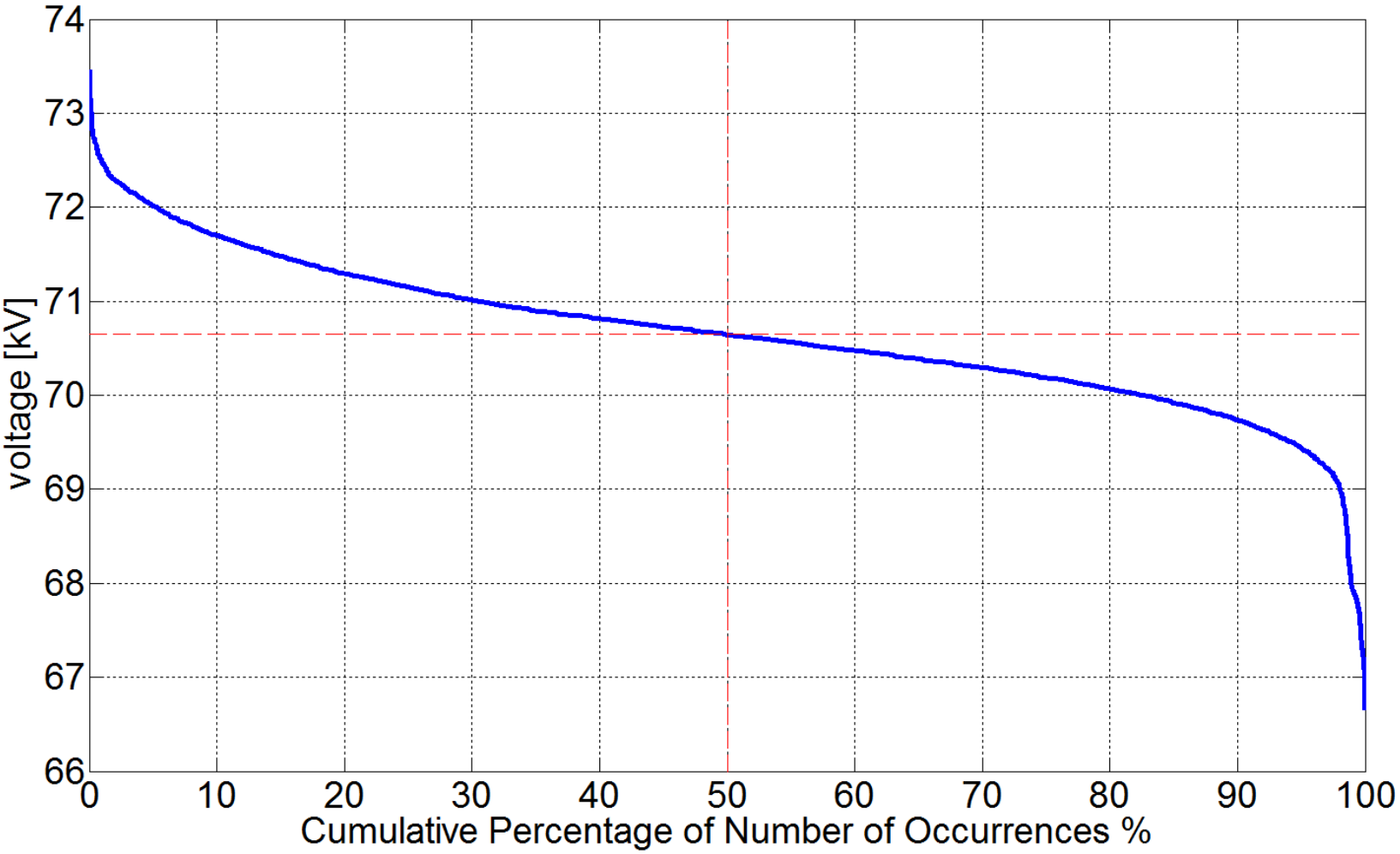
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

South 5*



South 5*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73
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66
voltage [kV]
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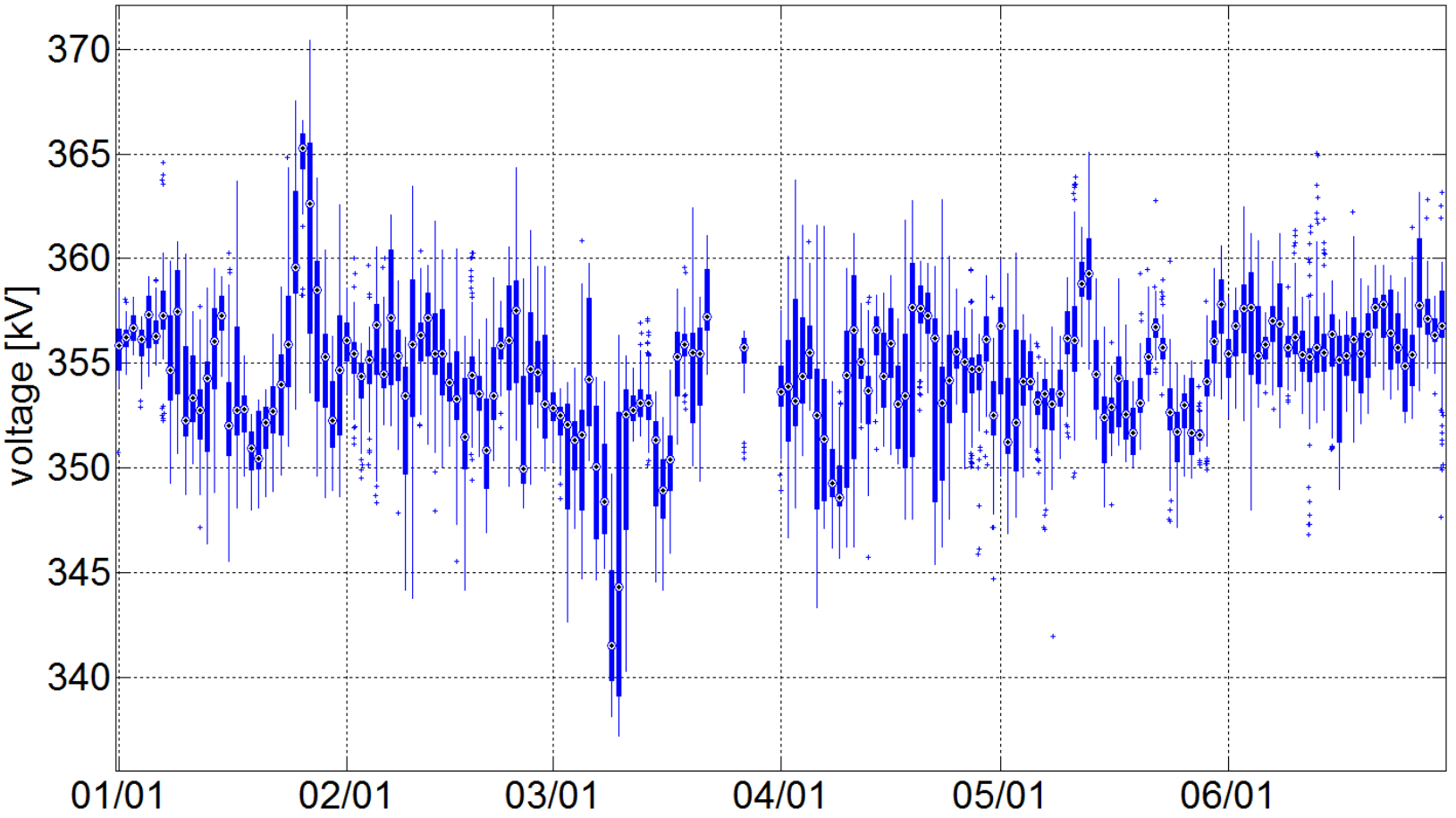
80
90
100
Cumulative Percentage of Number of Occurrences %

Coast 4


370
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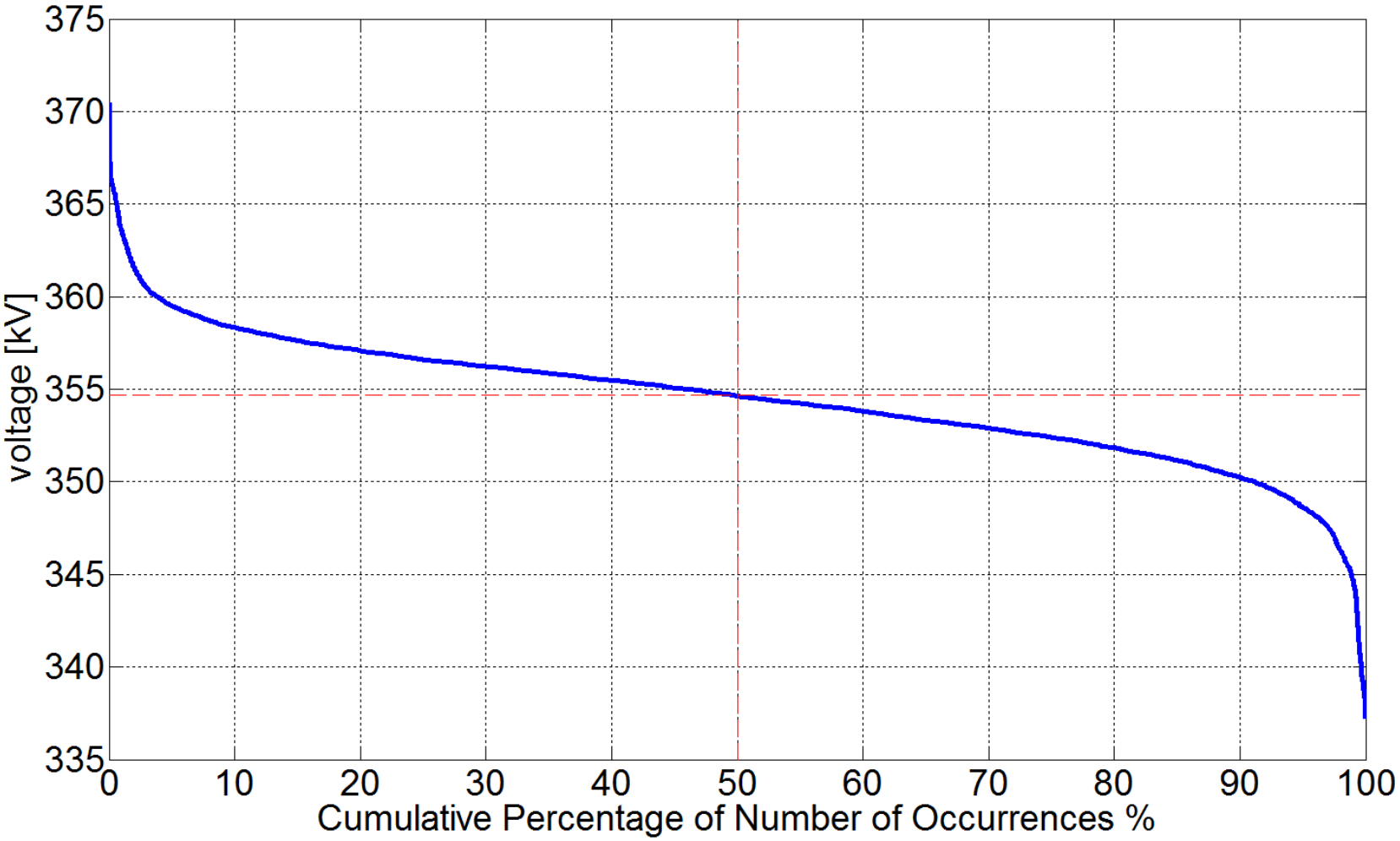
340
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

Coast 4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370
365
360
355
350
345
340
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voltage [kV]
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10
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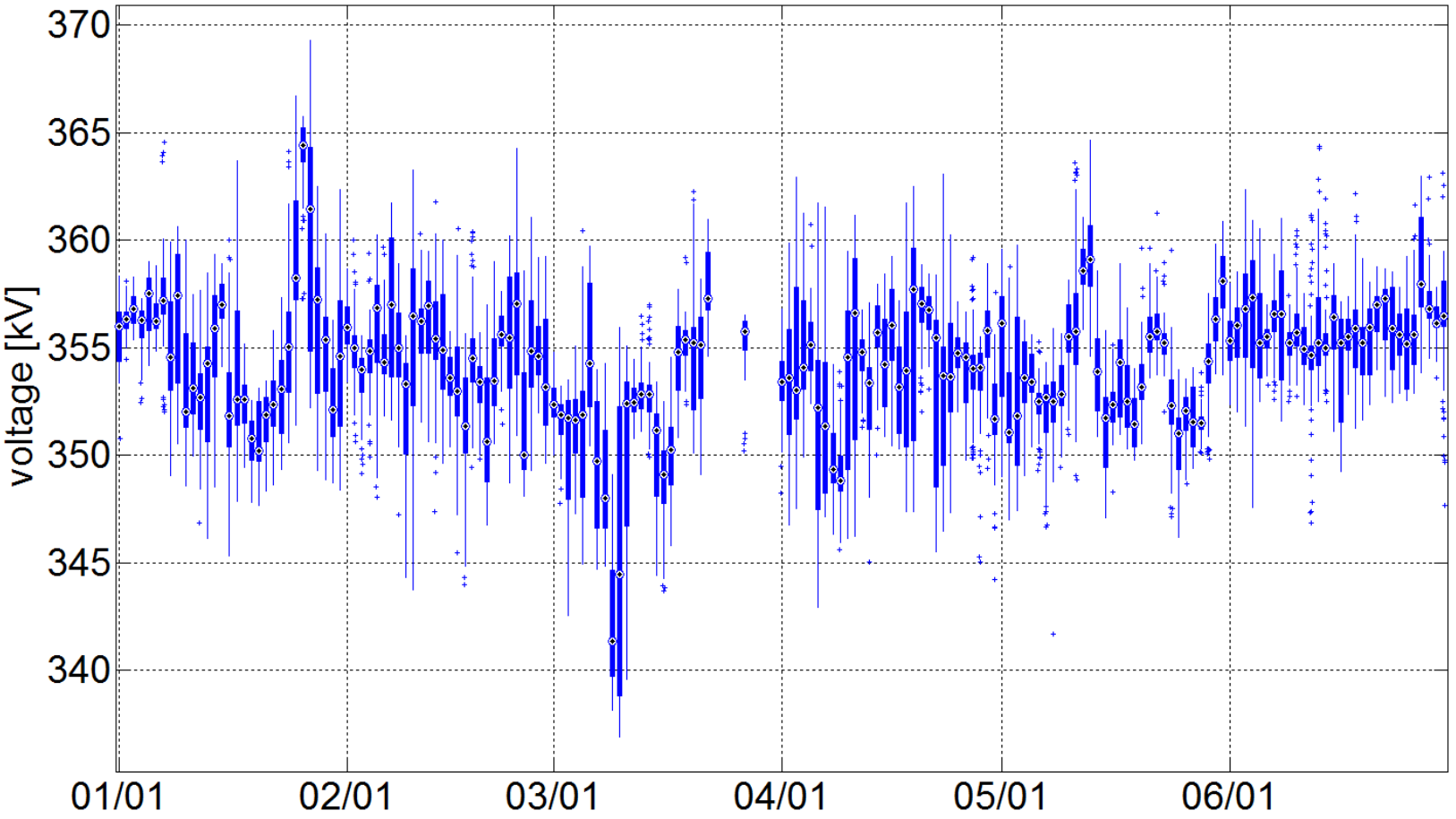
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

Coast 3


370
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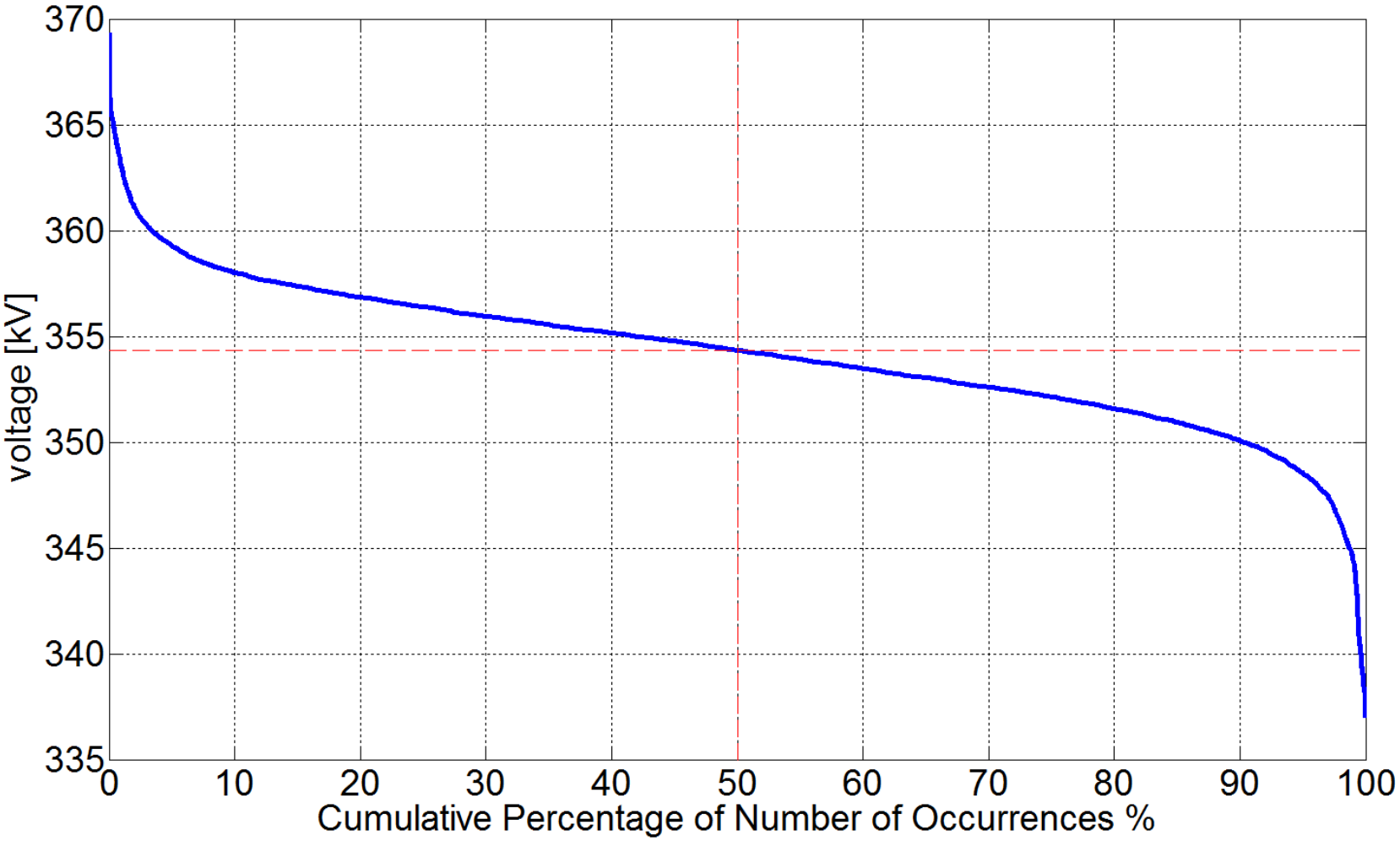
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

Coast 3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voltage [kV]
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10
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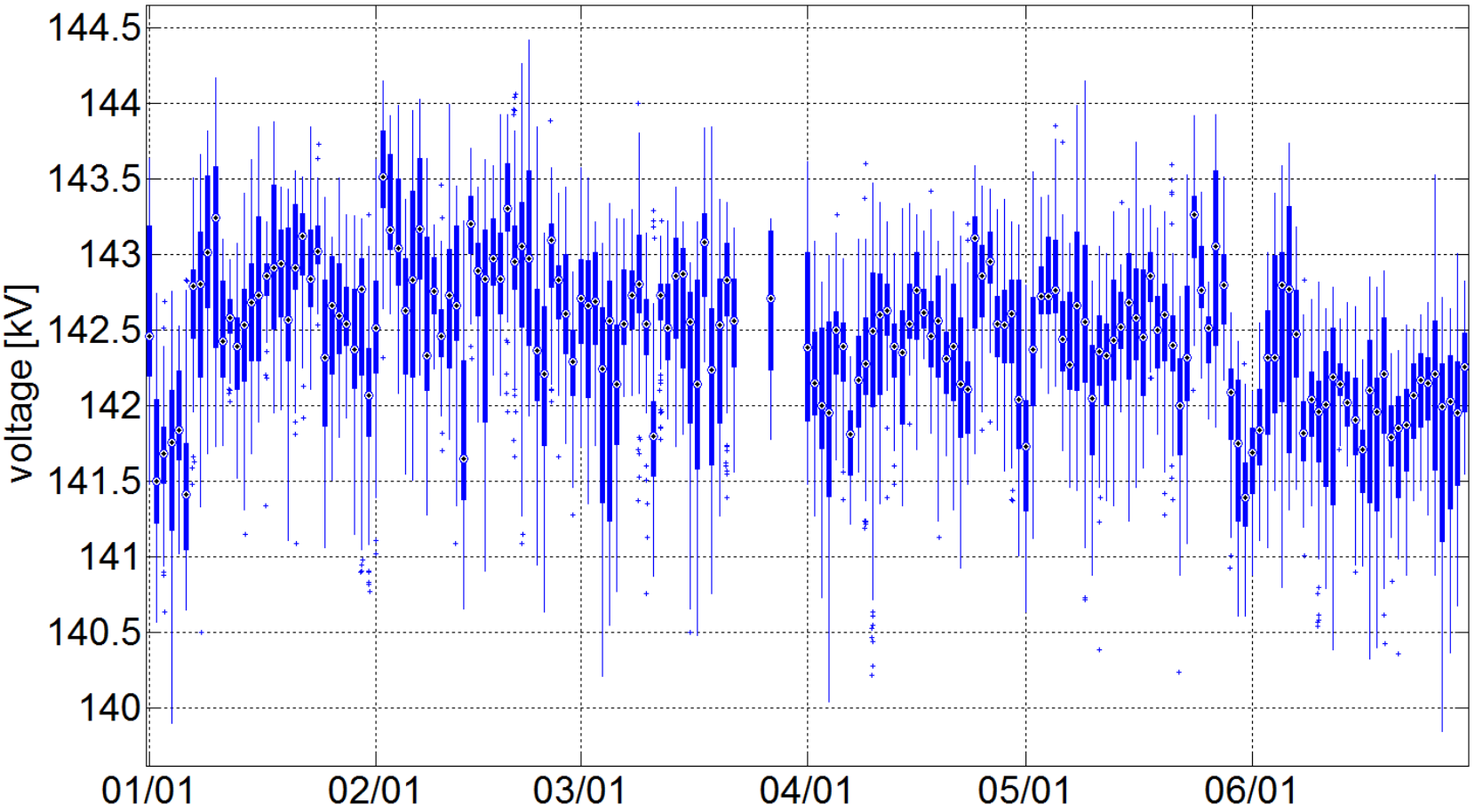
80
90
100
Cumulative Percentage of Number of Occurrences %

South 6*


144.5
144
143.5
143
142.5
142
141.5
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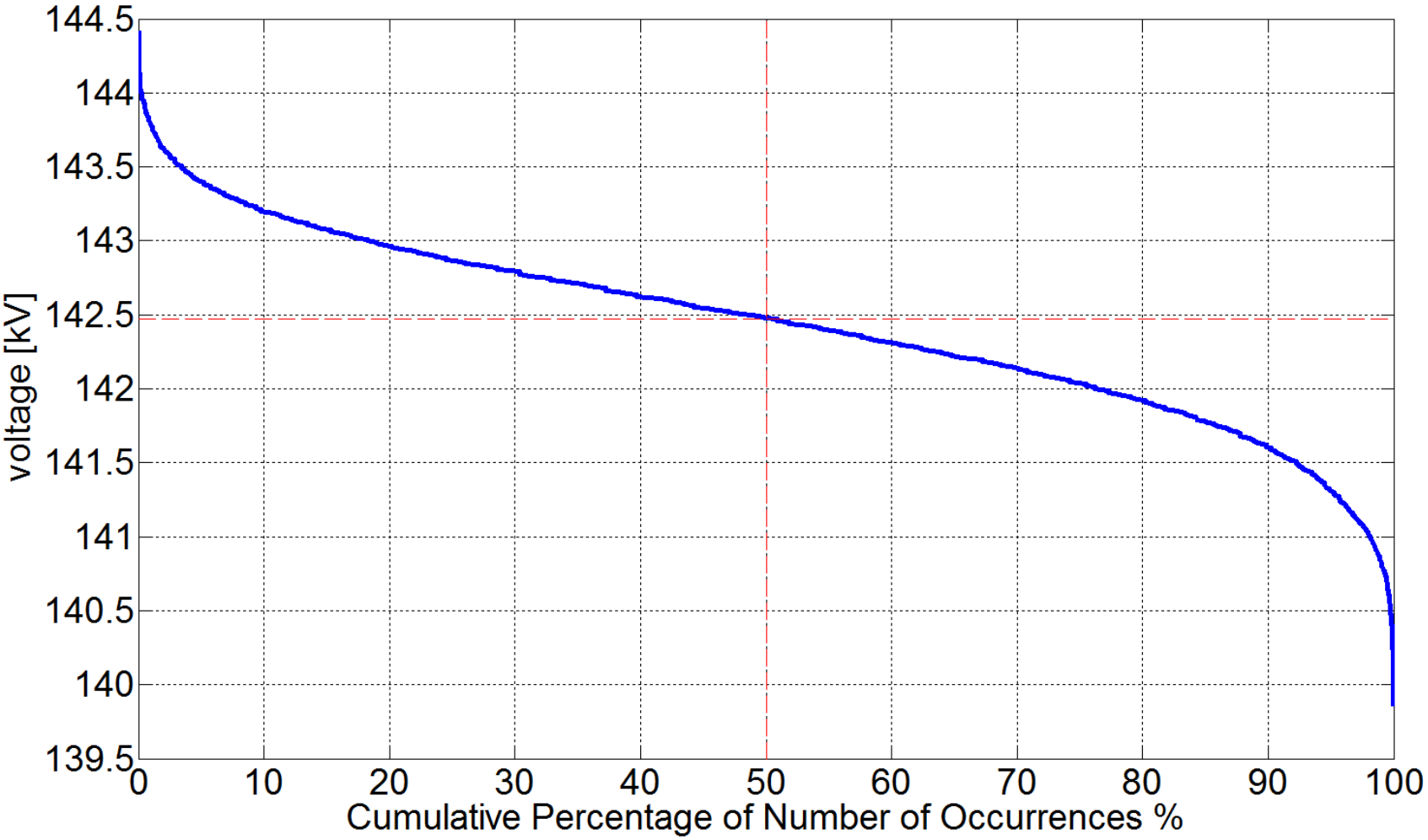
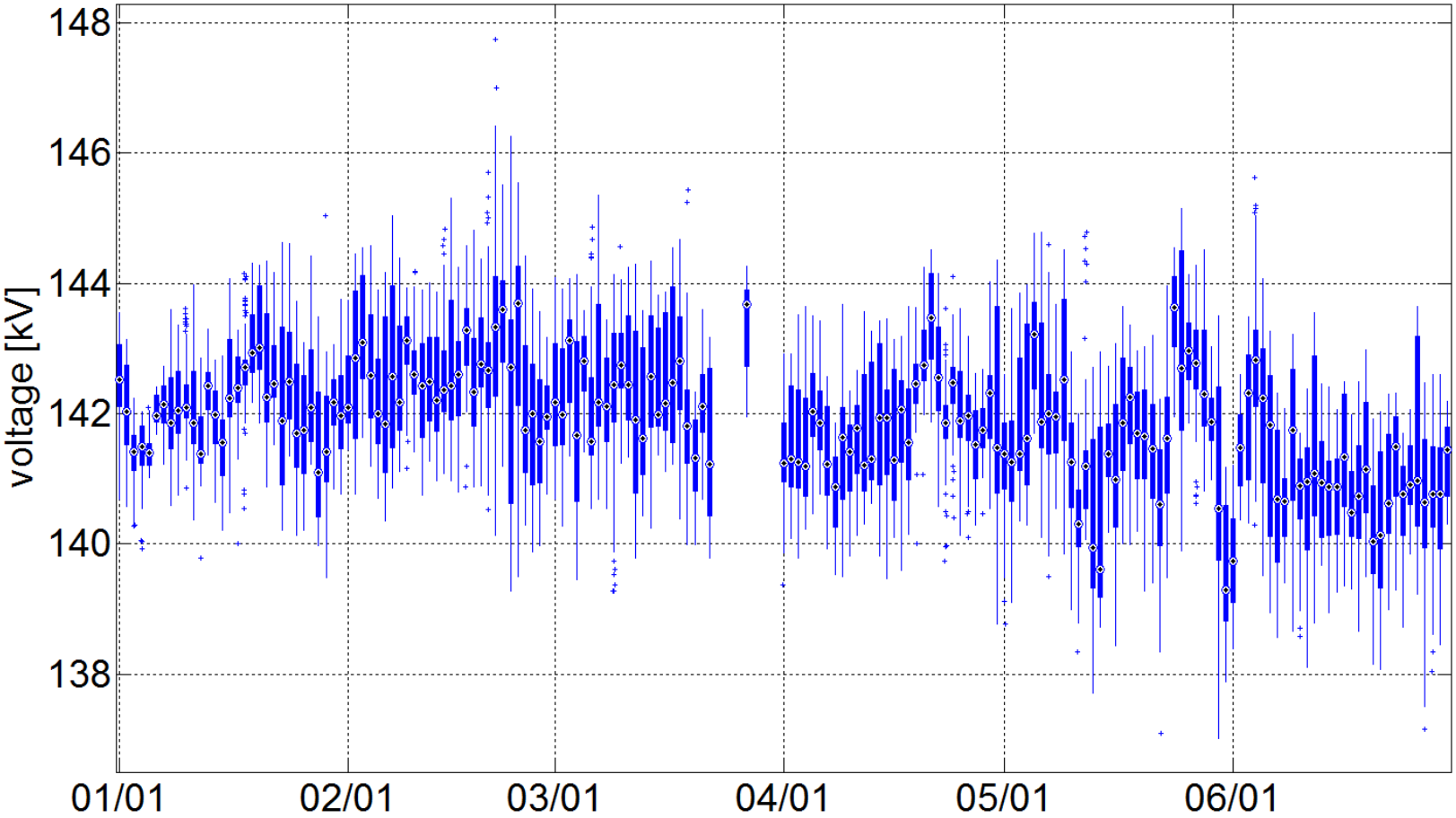
140.5
140
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

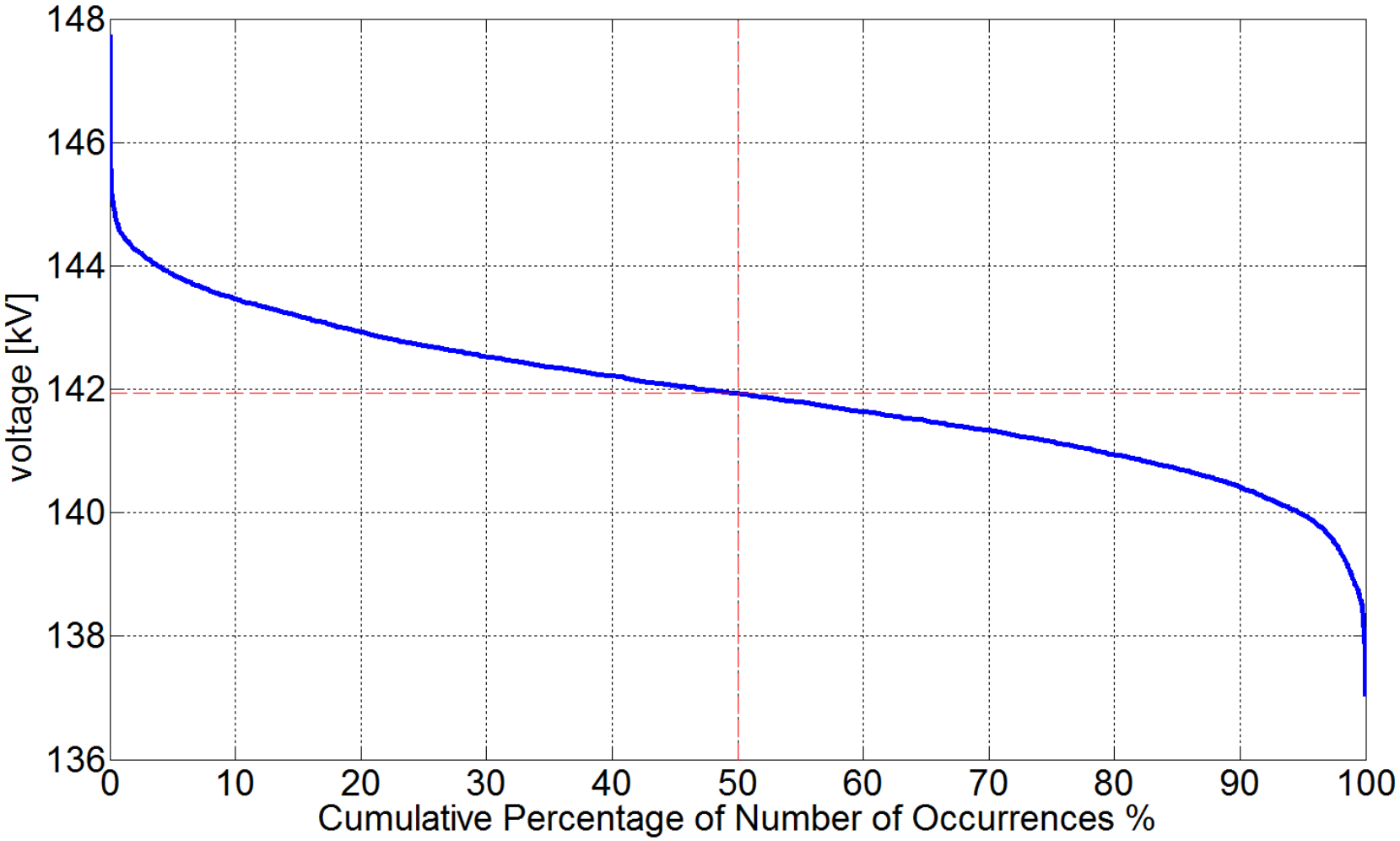
South 6*


144.5
144
143.5
143
142.5
142
141.5
141
140.5
140
139.5
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

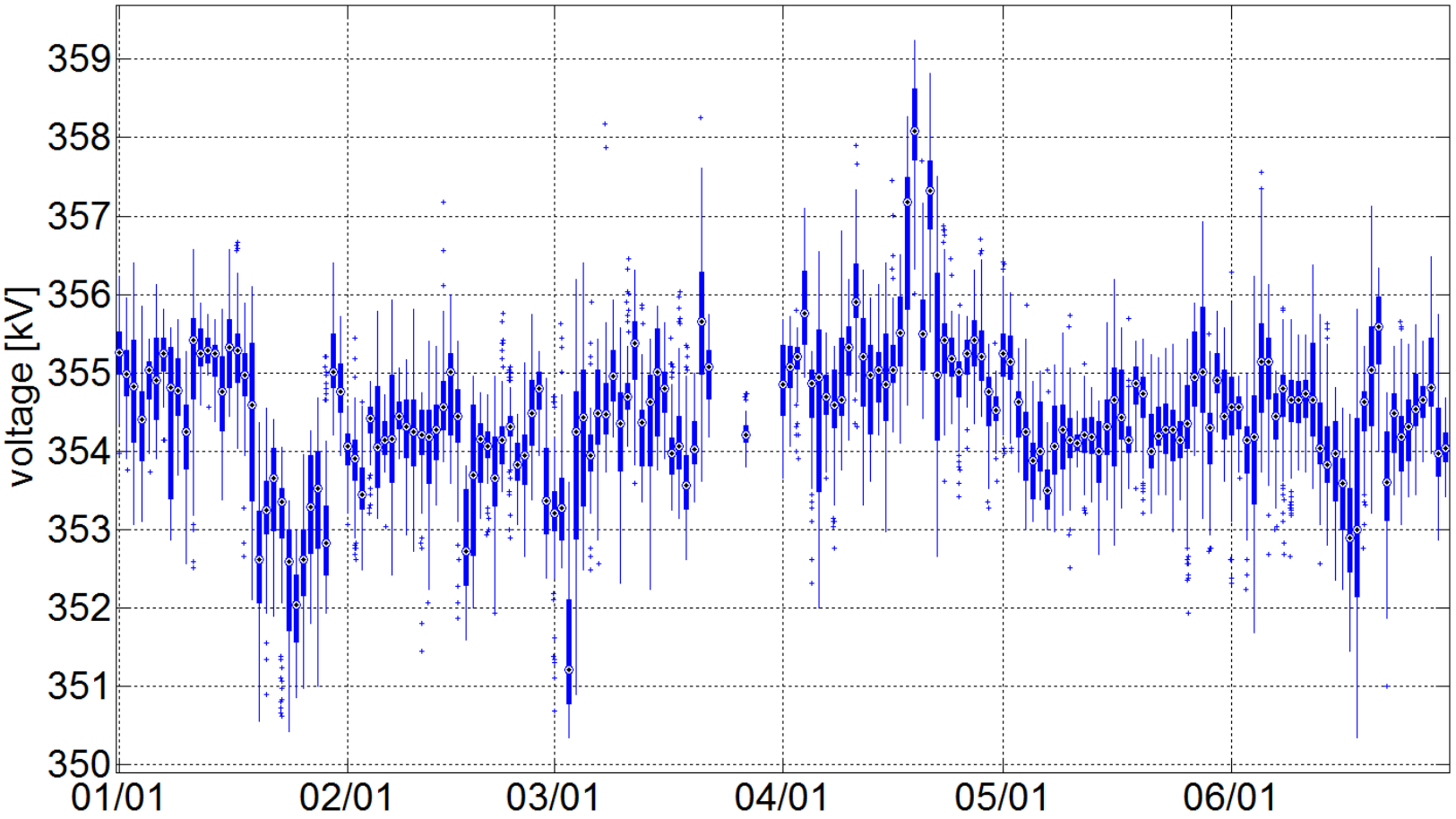
South 13


148
146
144
142
140
138
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

South 13


148
146
144
142
140
138
136
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

FarWest 4


voltage [kV]
359
358
357
356
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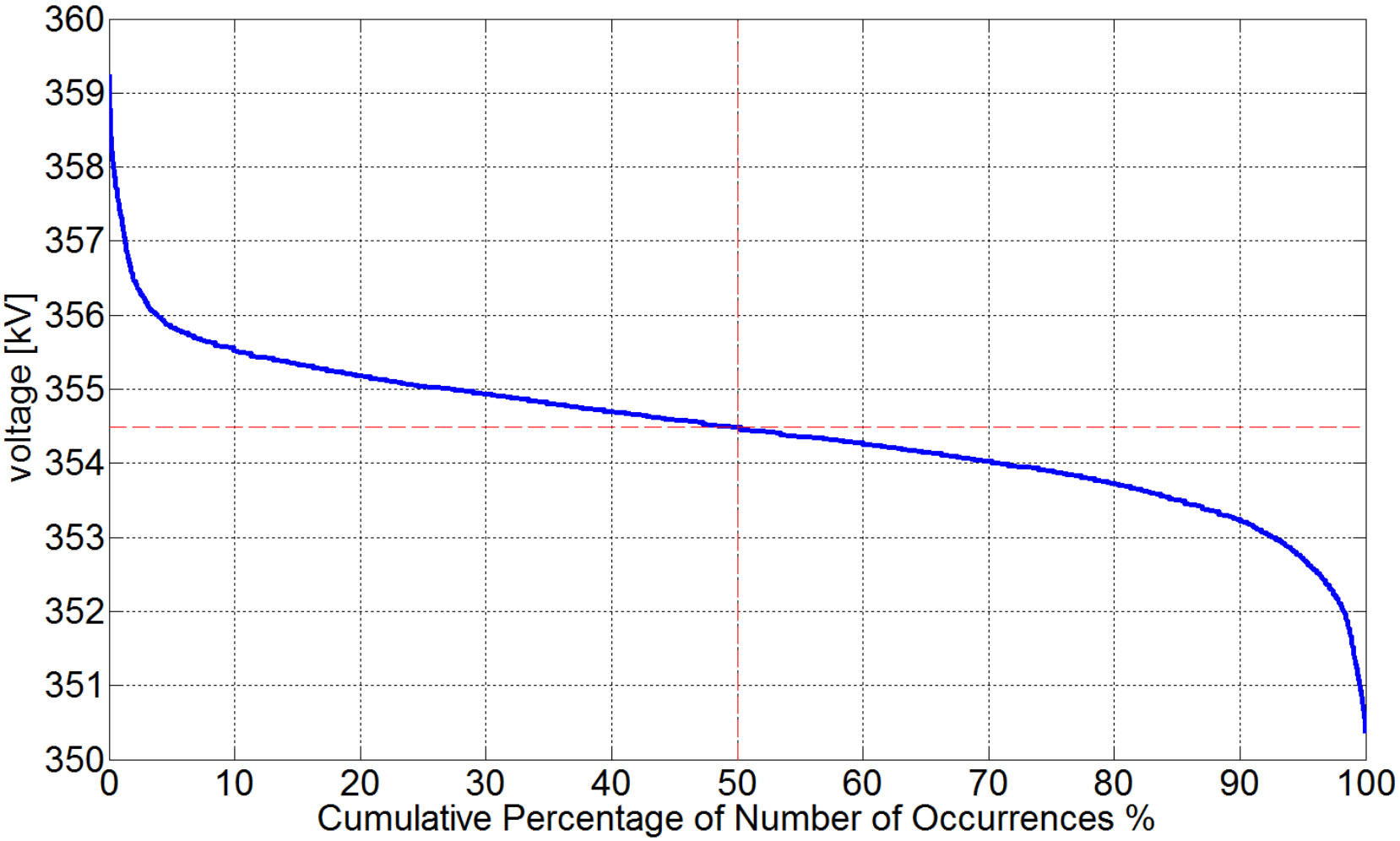
353
352
351
350
01/01
02/01
03/01
04/01
05/01
06/01

FarWest 4


360
359
358
357
356
355
354
353
352
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350
voltage [kV]
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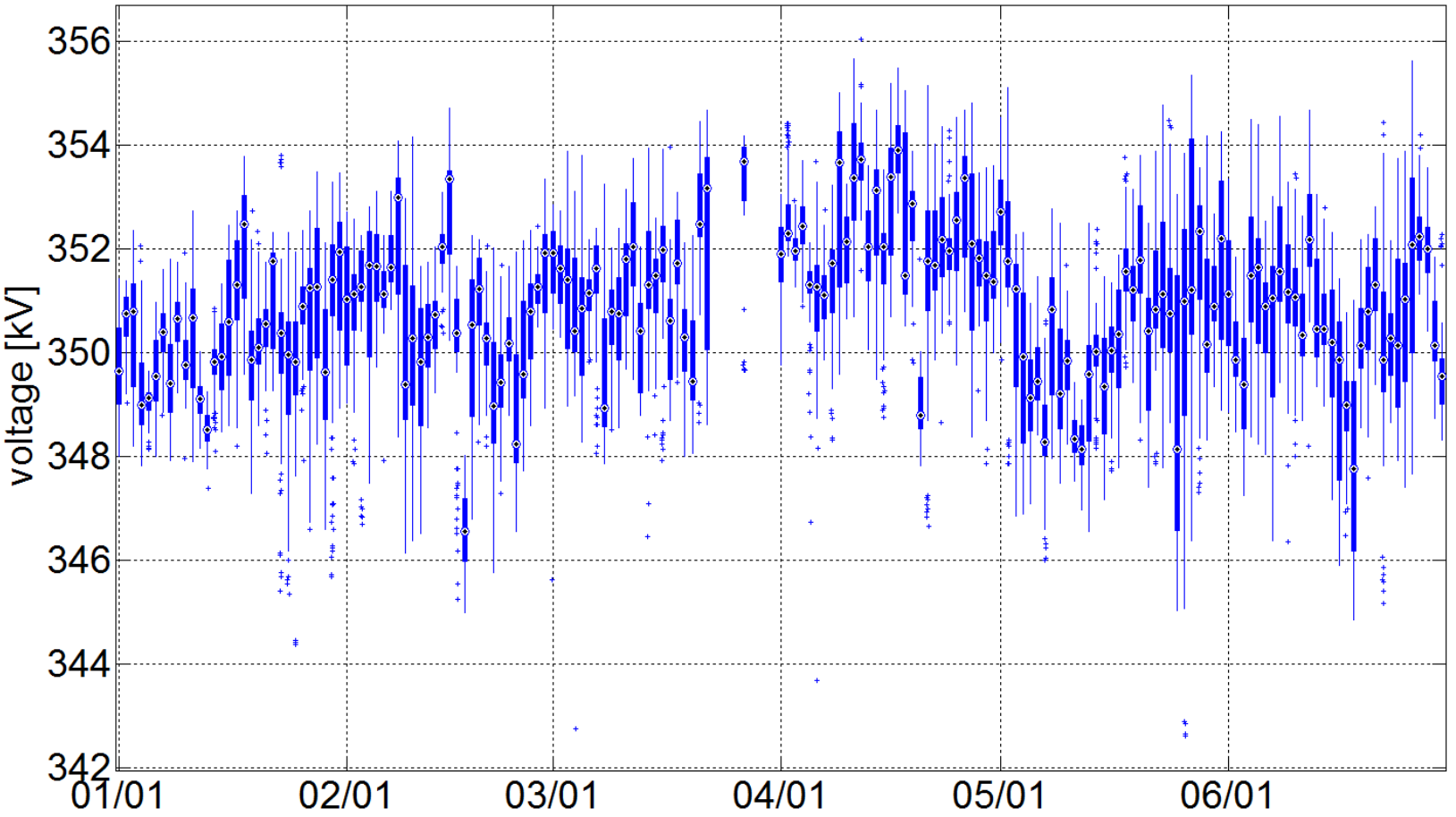
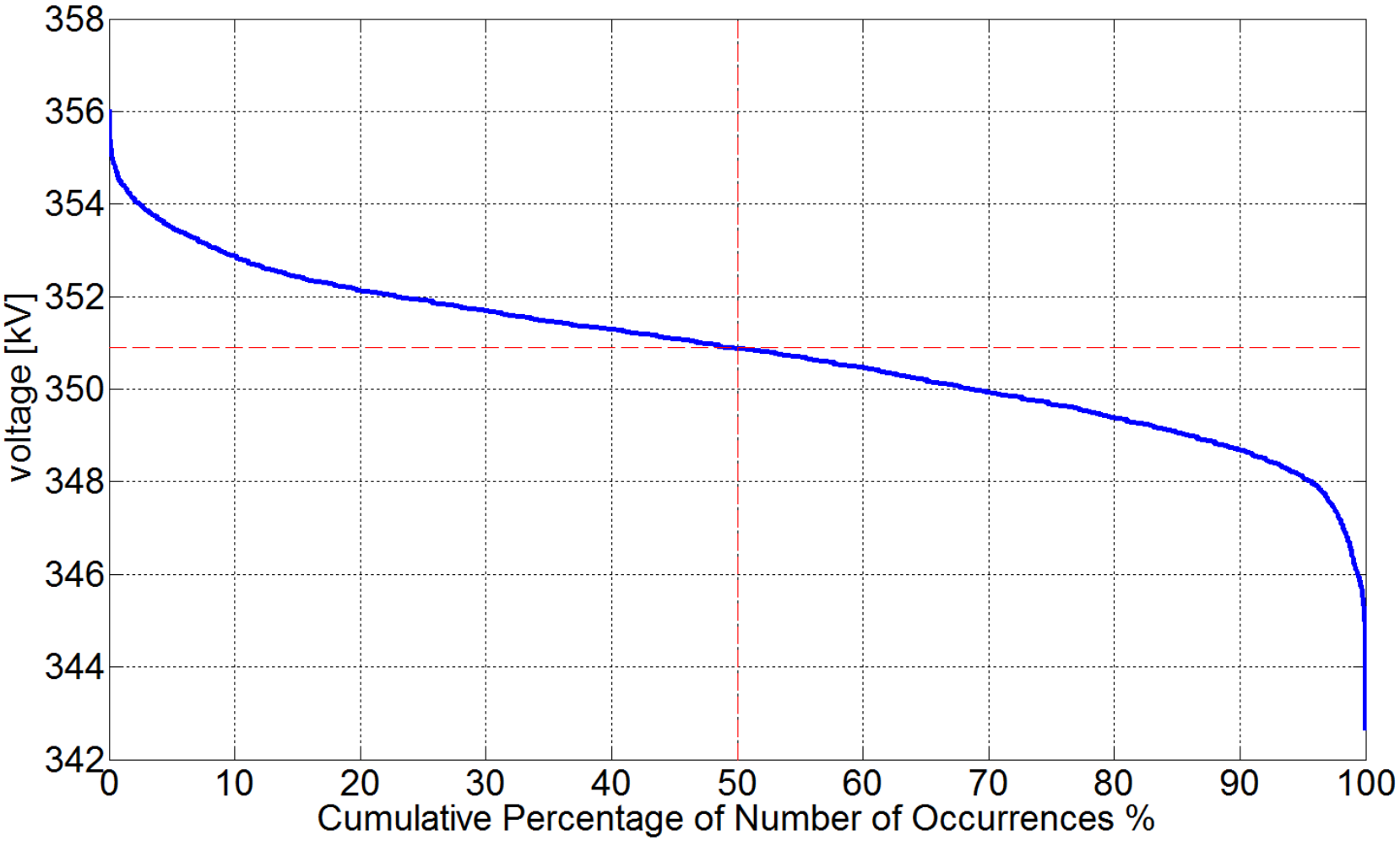
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

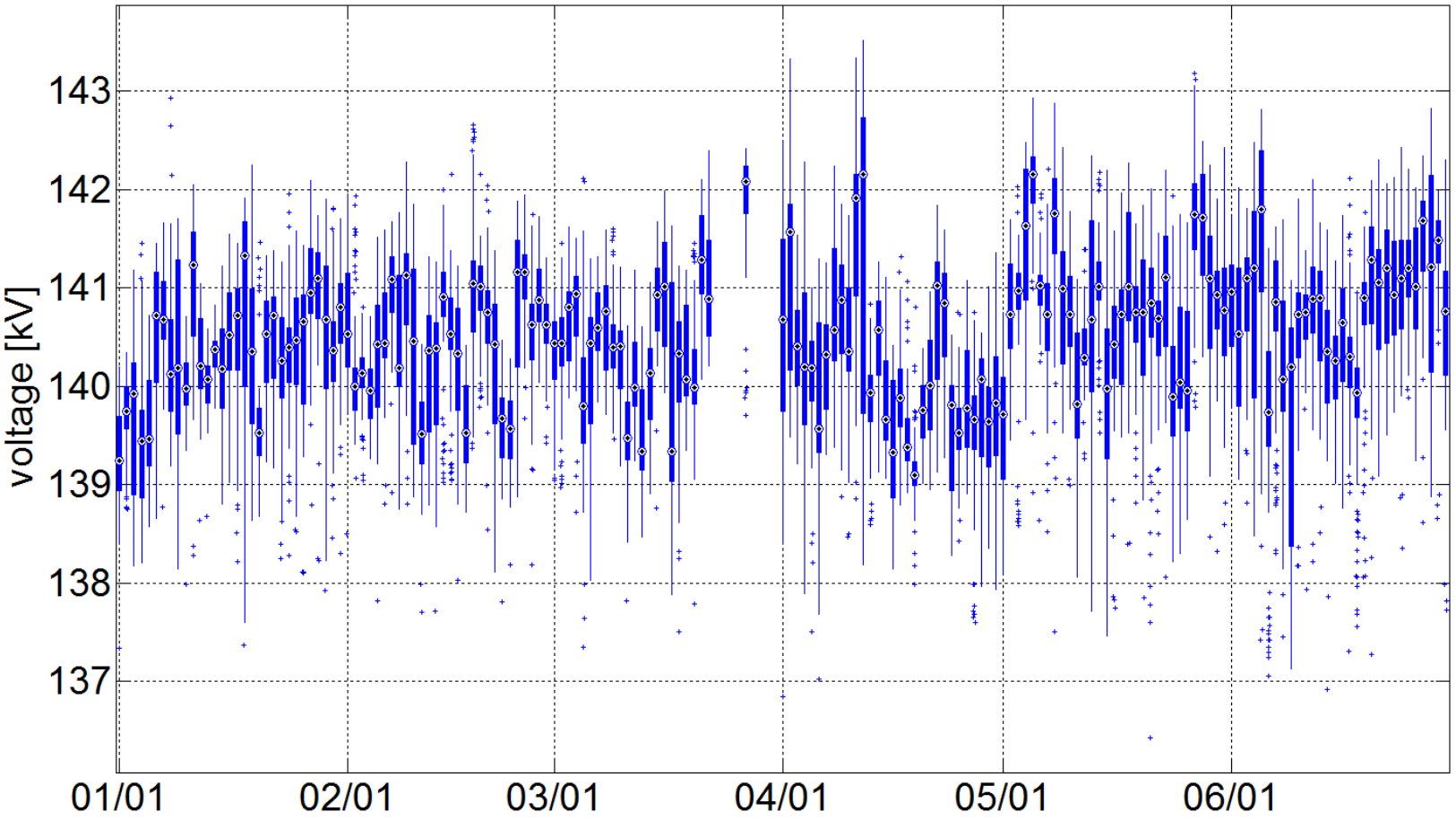
FarWest 7


voltage [kV]
356
354
352
350
348
346
344
342
01/01
02/01
03/01
04/01
05/01
06/01

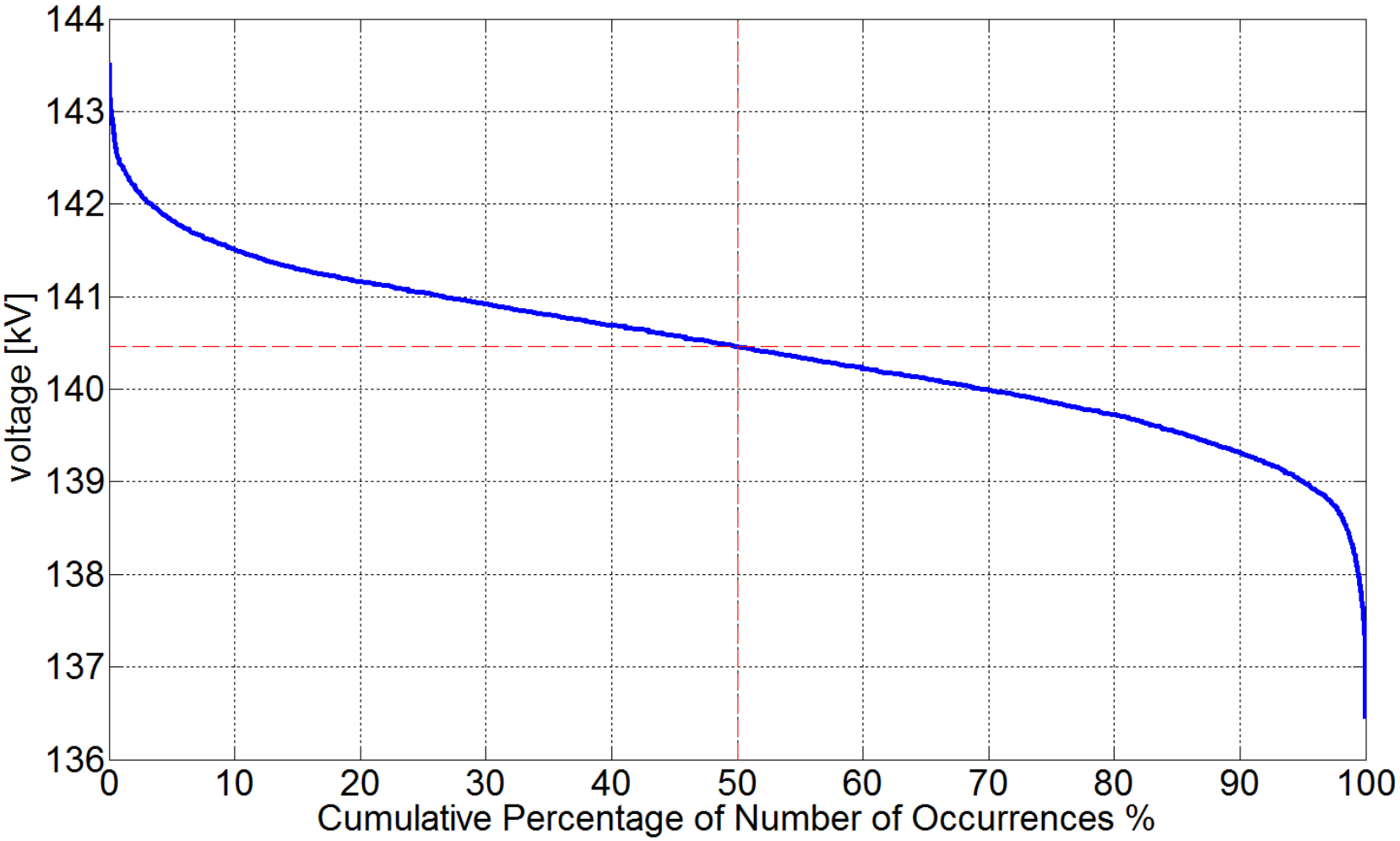
FarWest 7


358
356
354
352
350
348
346
344
342
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

FarWest 8


143
142
141
140
139
138
137
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

FarWest 8


144
143
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141
140
139
138
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136
voltage [kV]
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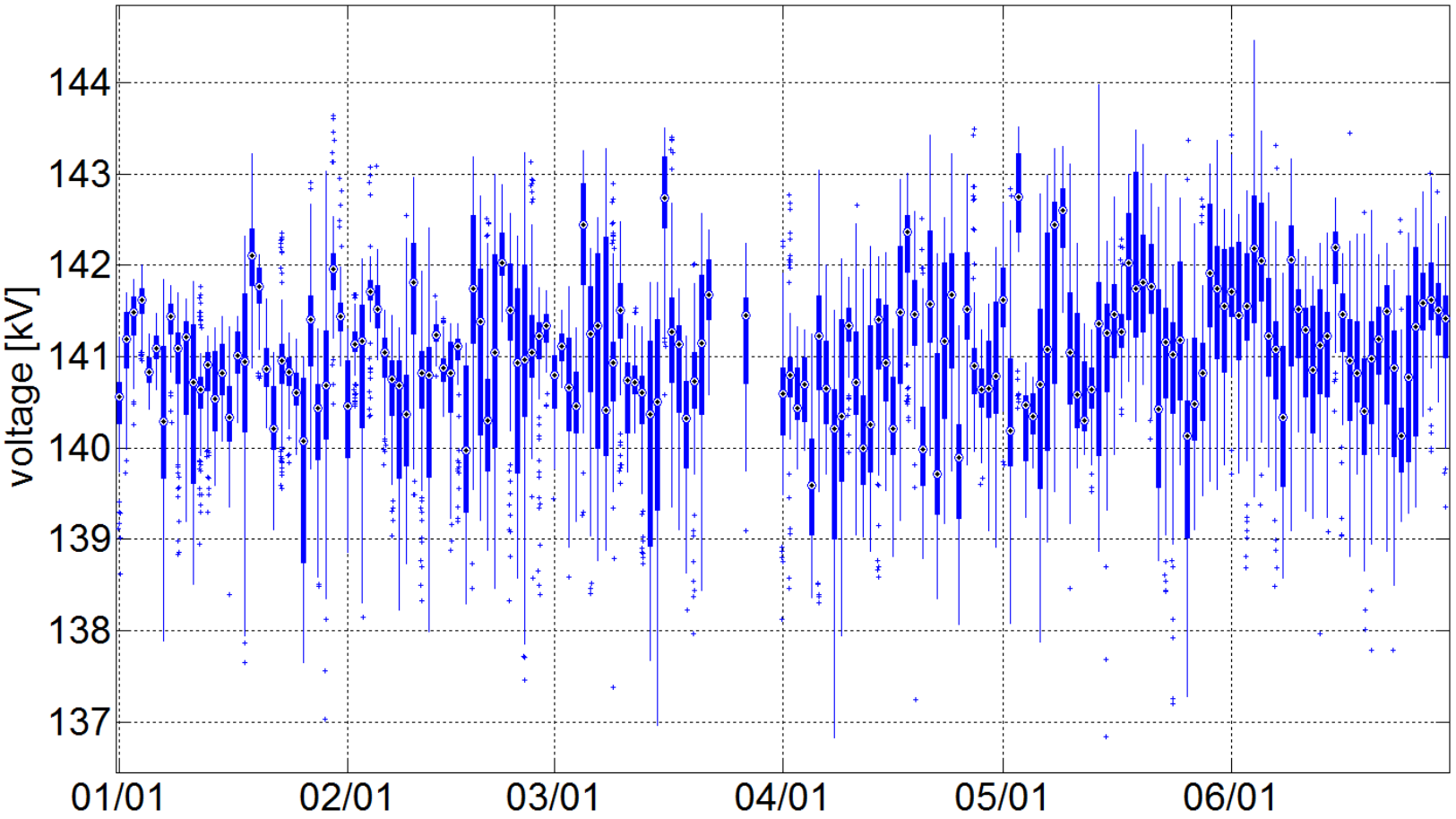
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

FarWest 9


voltage [kV]
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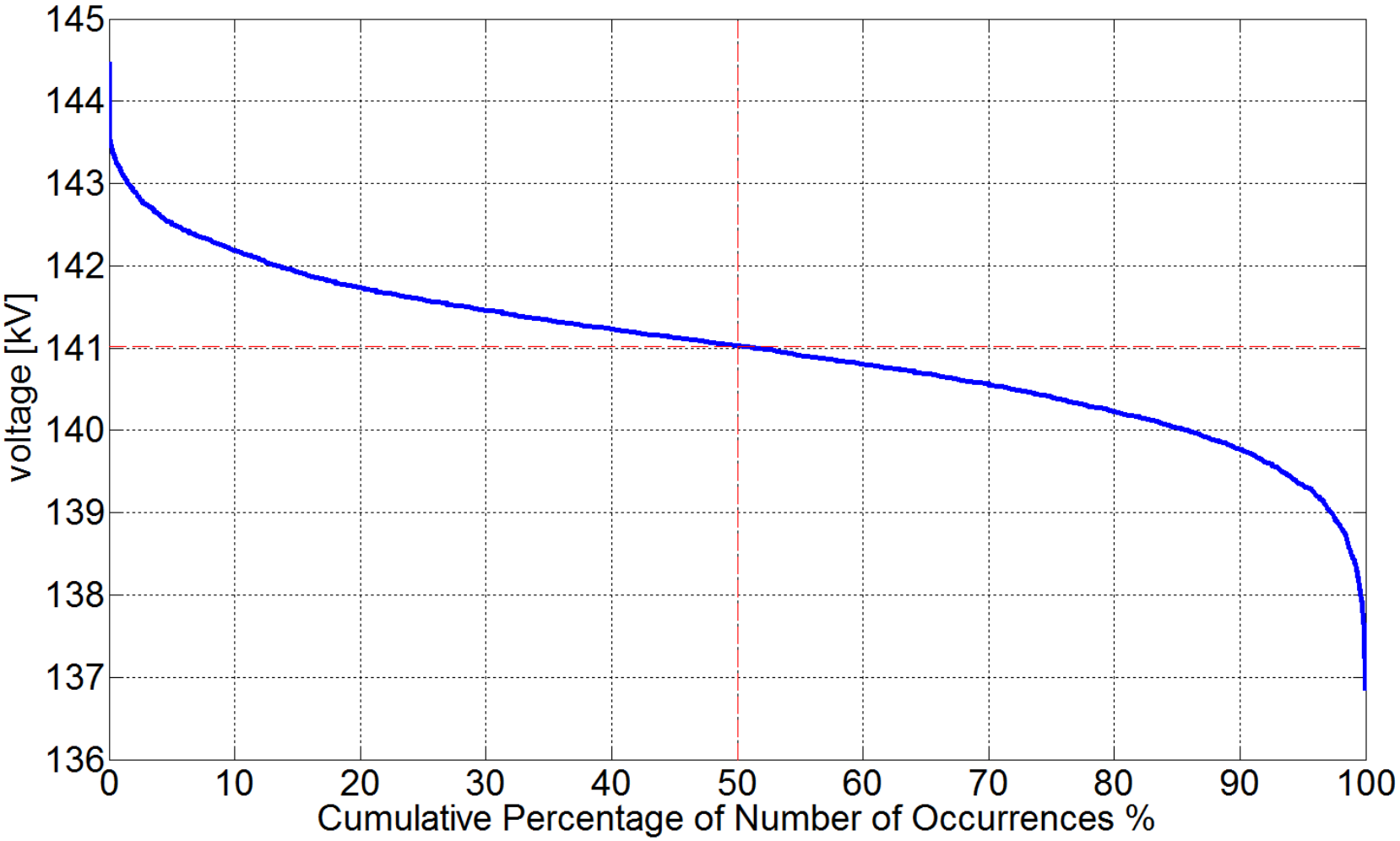
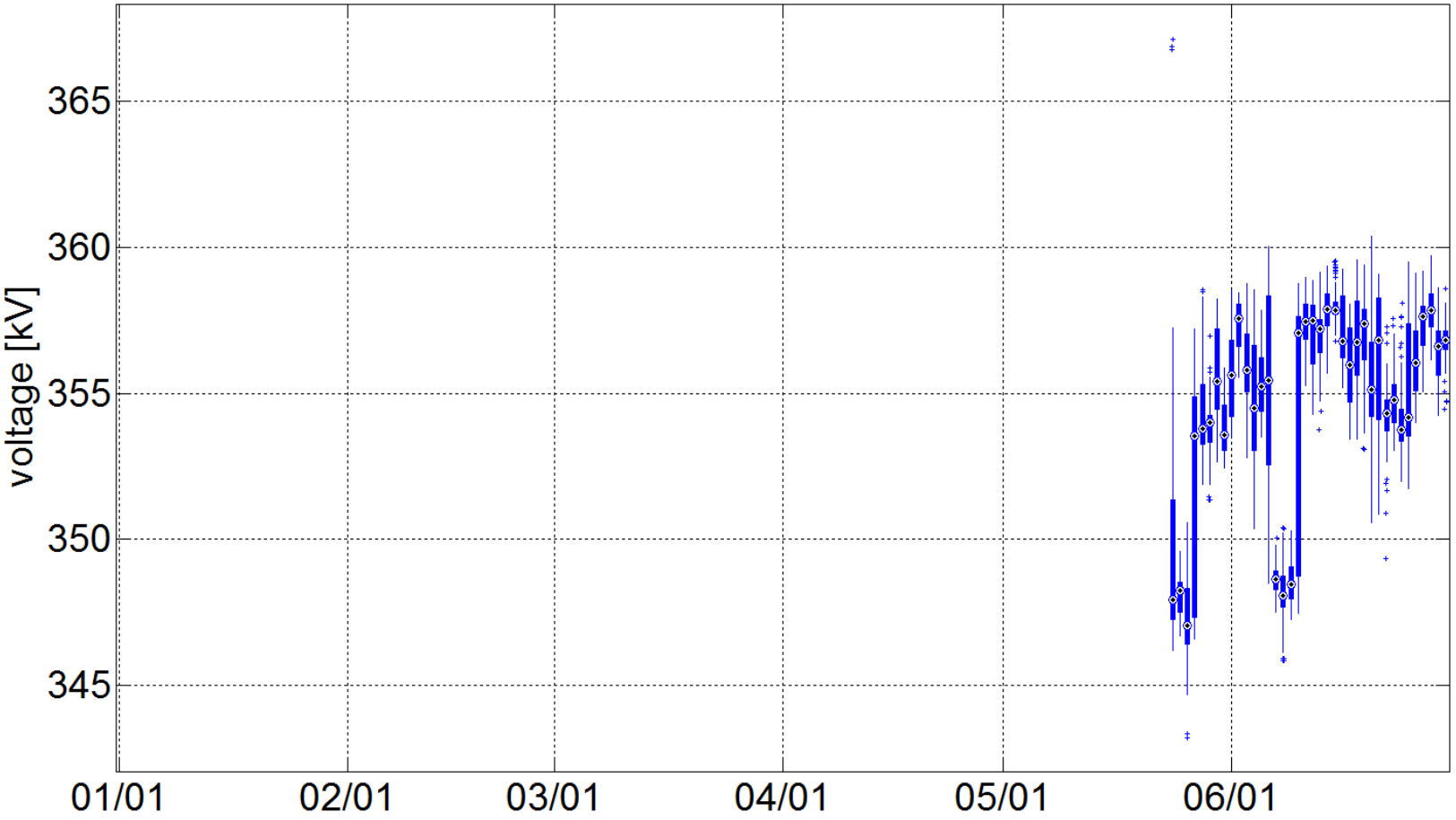
143
142
141
140
139
138
137
01/01
02/01
03/01
04/01
05/01
06/01

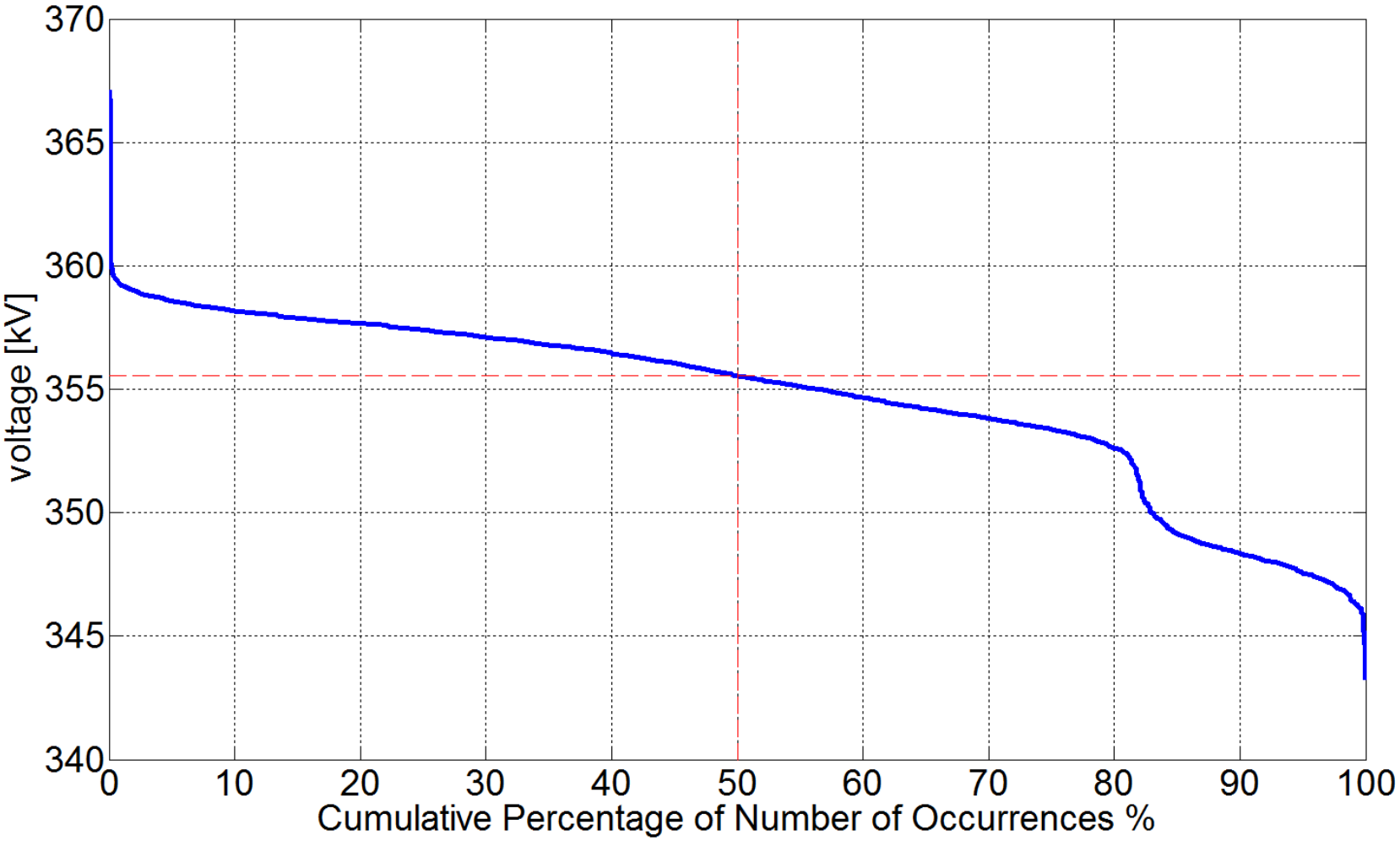
FarWest 9


145
144
143
142
141
140
139
138
137
136
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

West 8*



West 8*


370
365
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voltage [kV]
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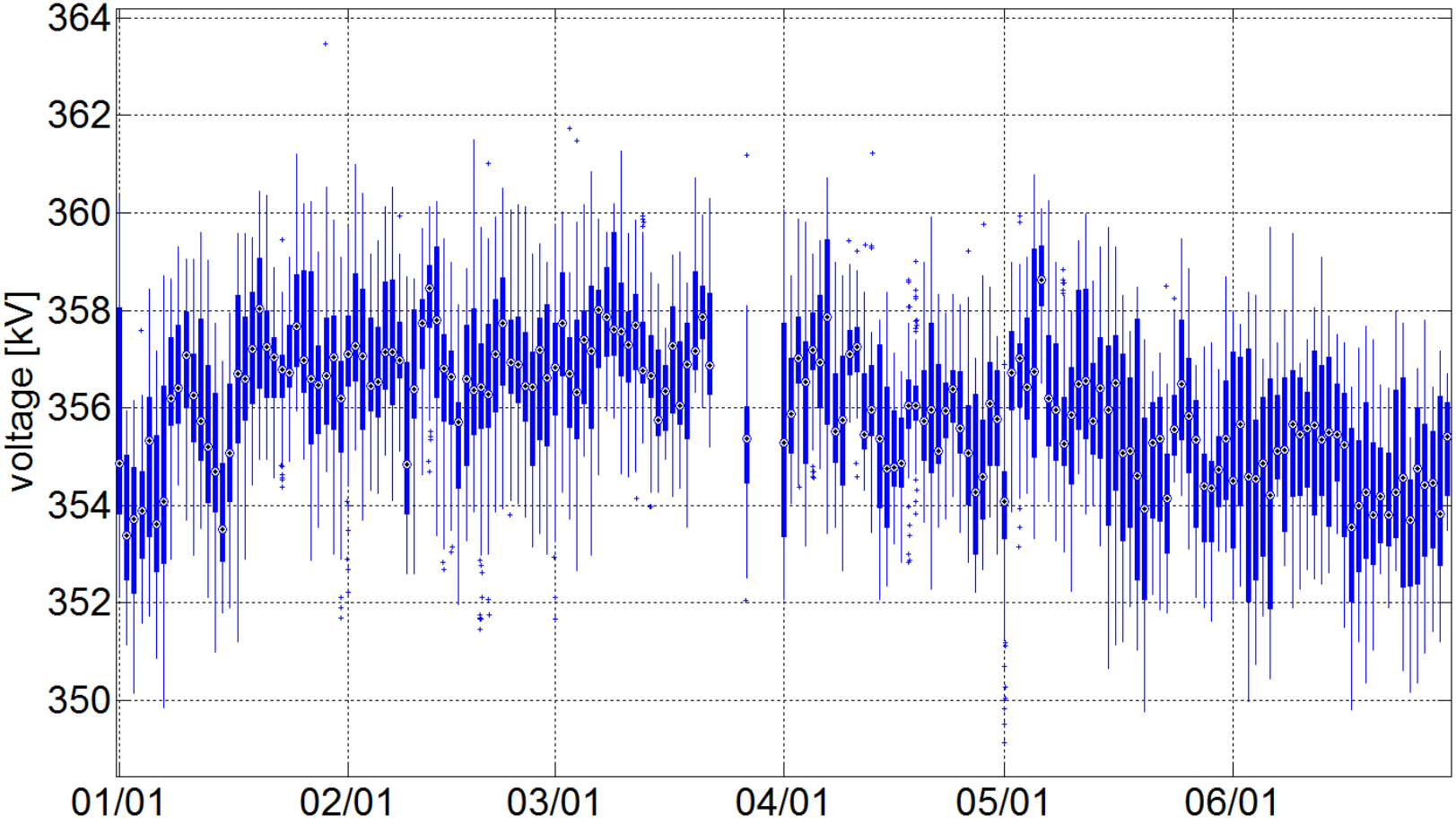
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

South 15*


364
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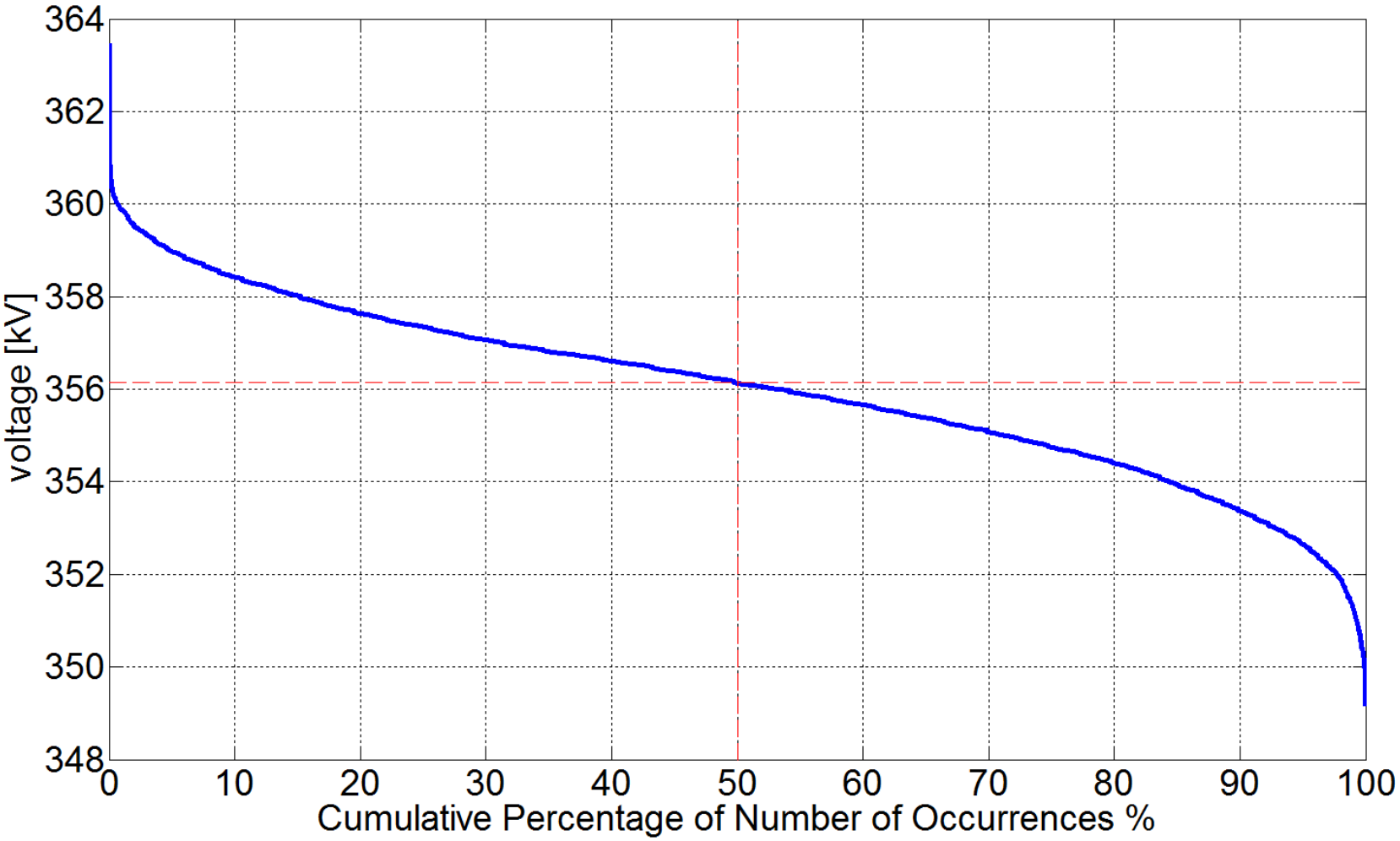
352
350
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

South 15*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358
356
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voltage [kV]
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10
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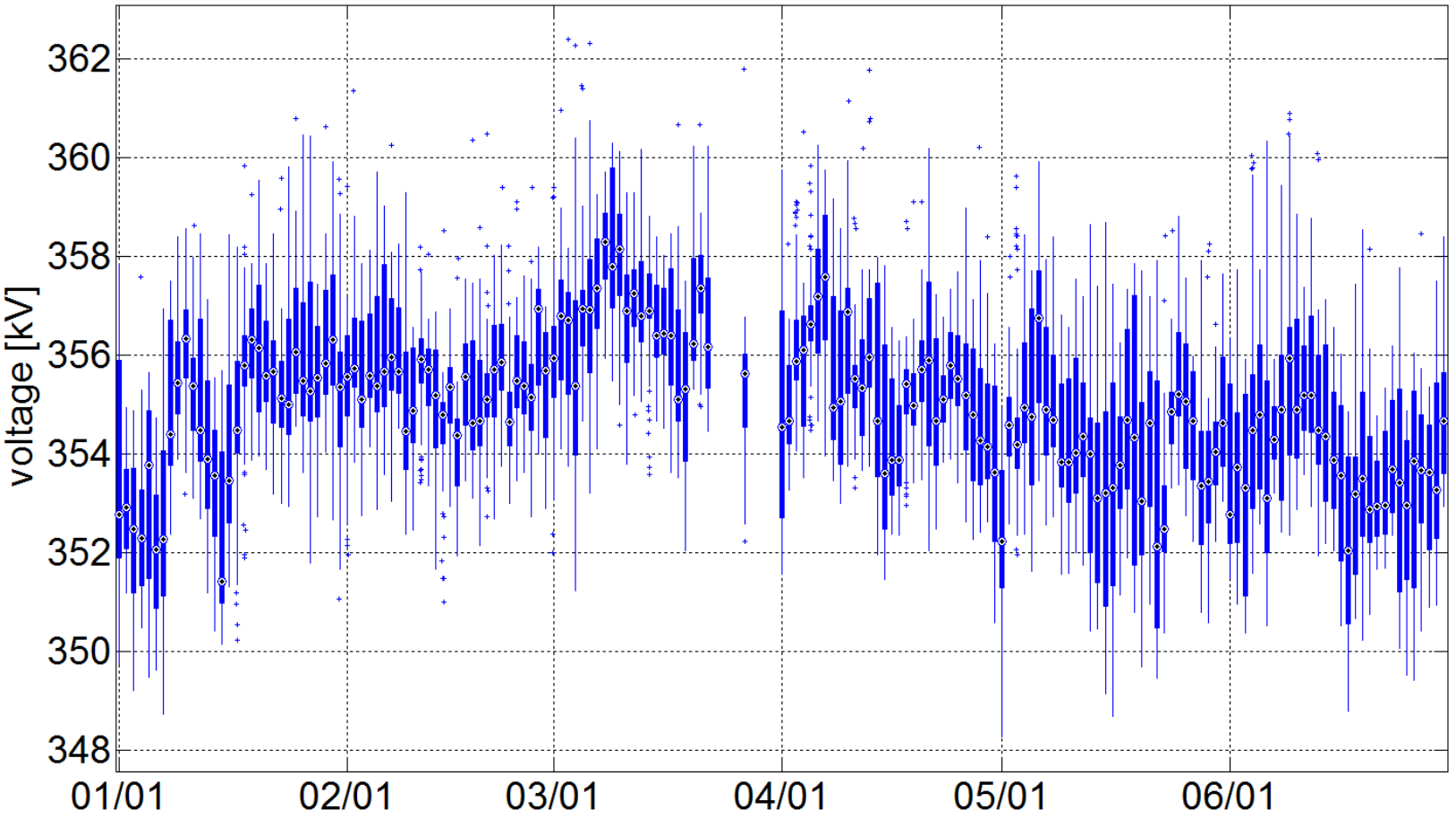
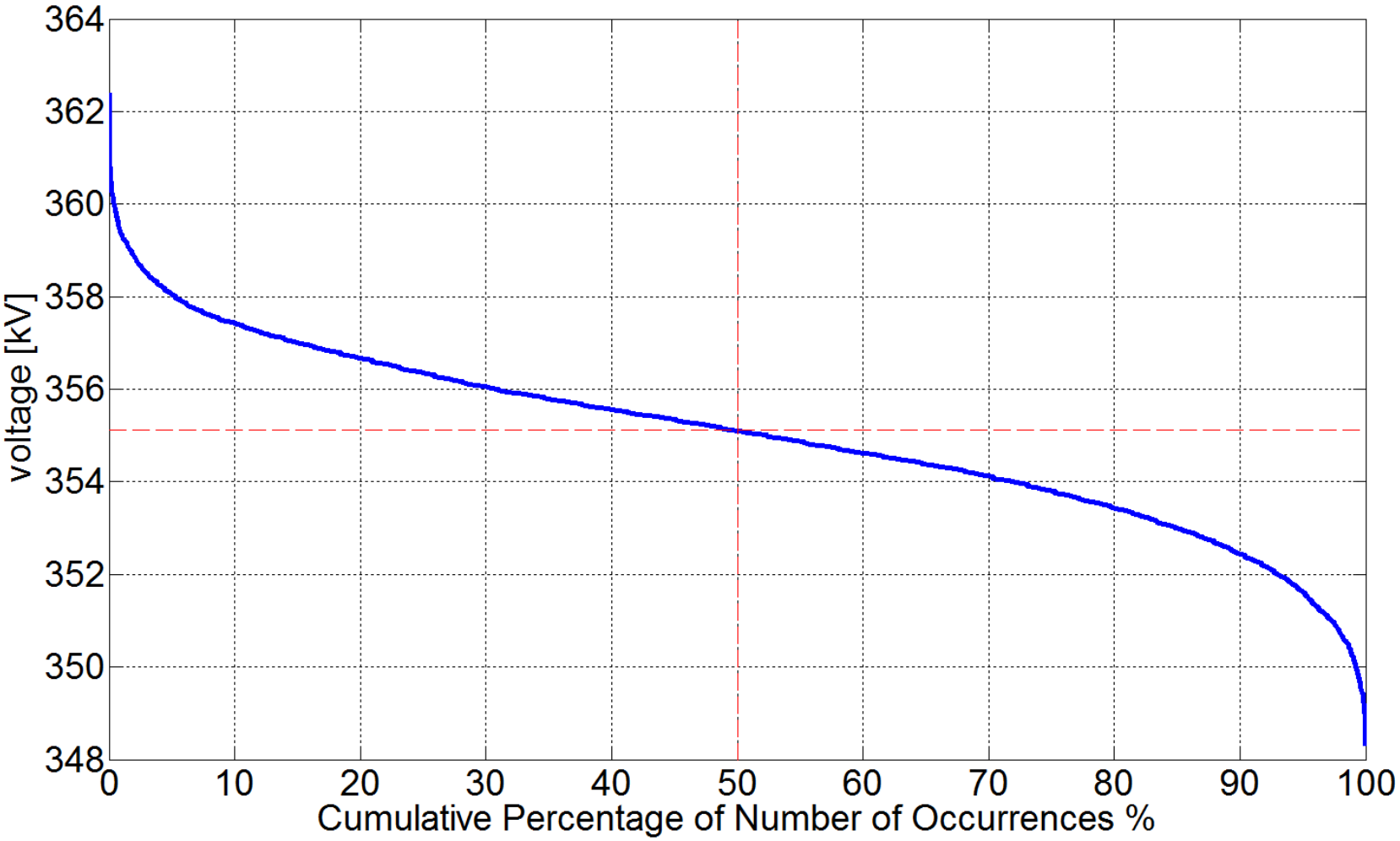
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

South 2*


voltage [kV]
362
360
358
356
354
352
350
348
01/01
02/01
03/01
04/01
05/01
06/01

South 2*


364
362
360
358
356
354
352
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voltage [kV]
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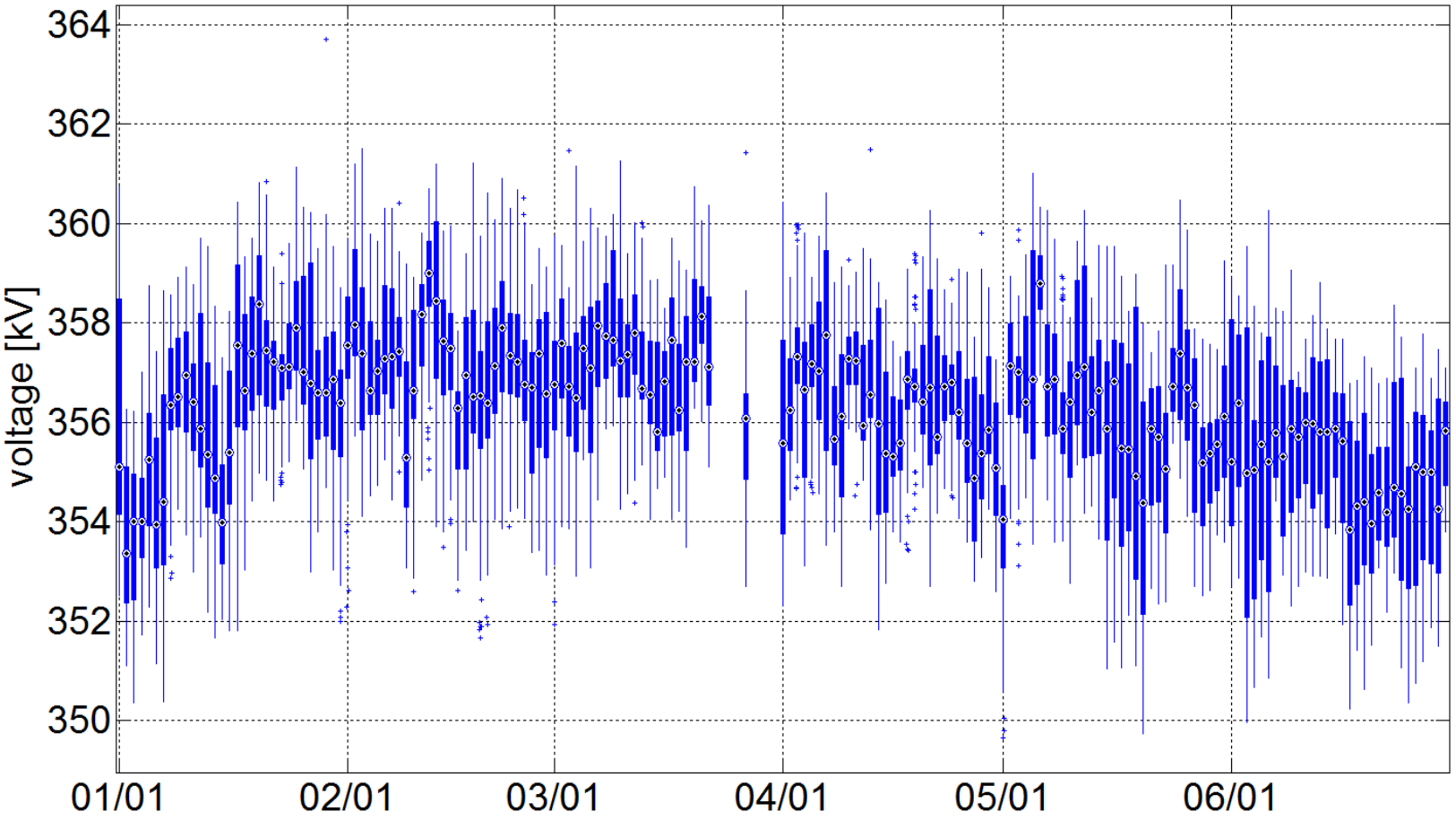
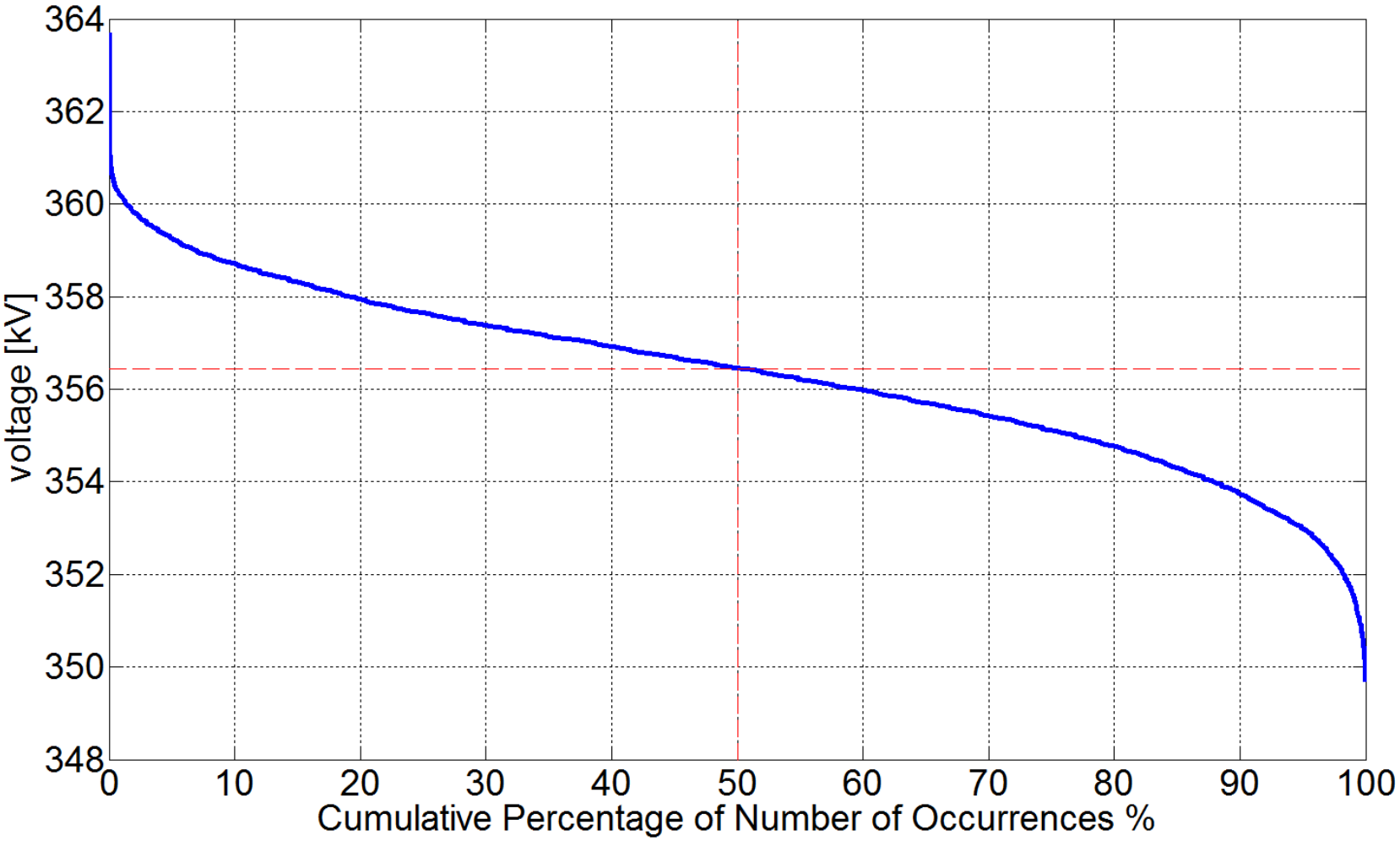
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

South 4*


364
362
360
358
356
354
352
350
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

South 4*


364
362
360
358
356
354
352
350
348
voltage [kV]
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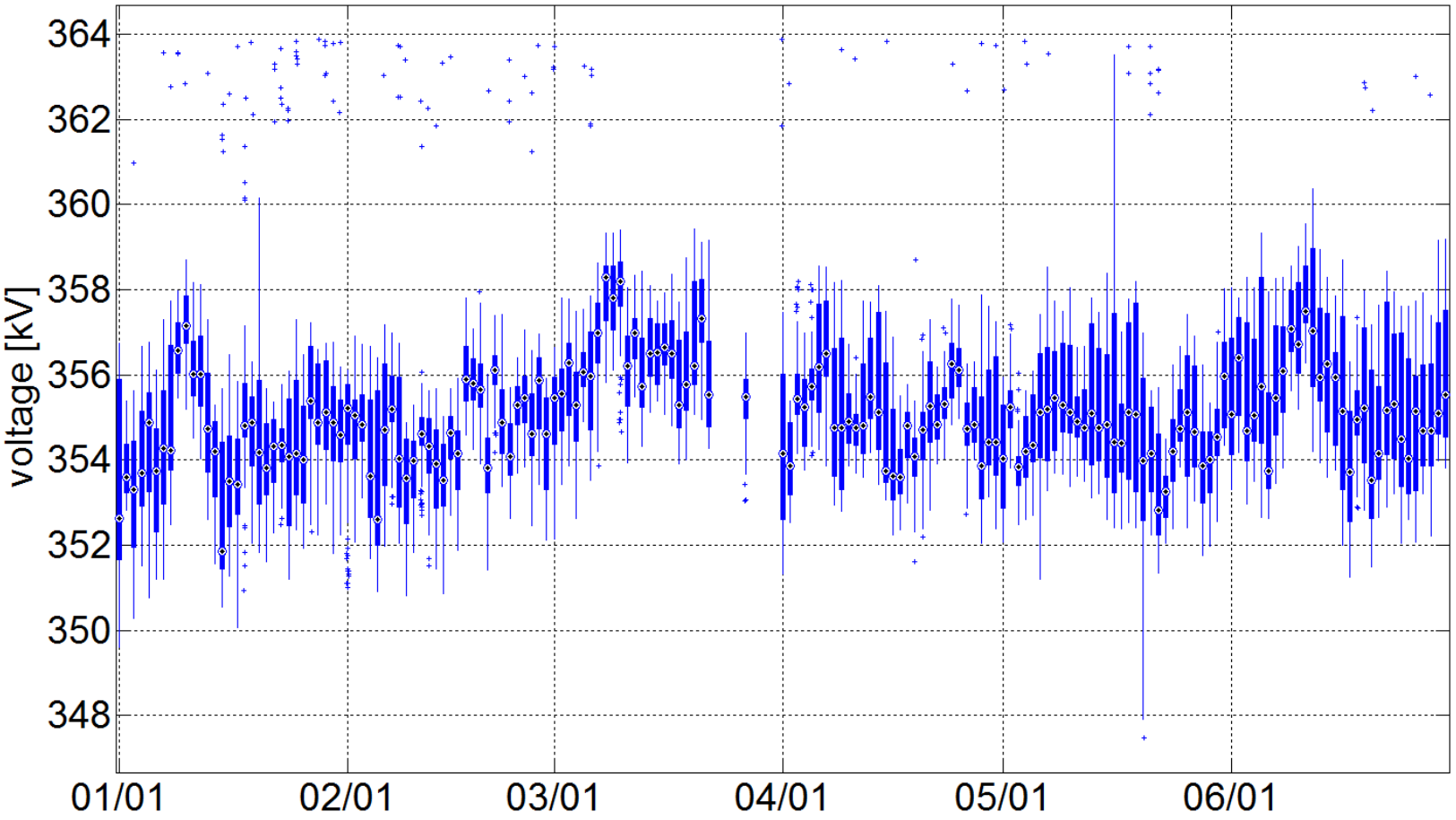
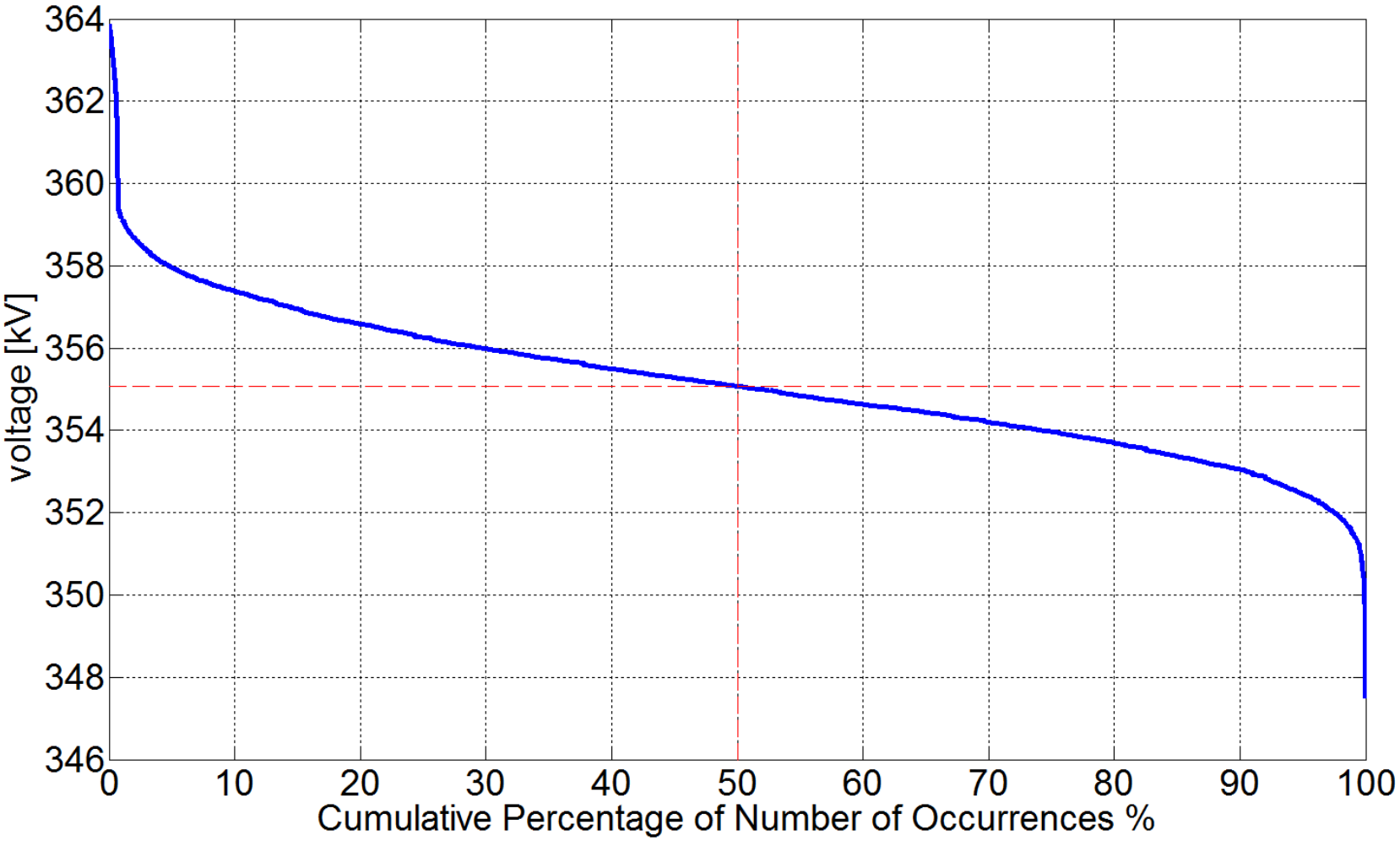
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

South 7*


voltage [kV]
364
362
360
358
356
354
352
350
348
01/01
02/01
03/01
04/01
05/01
06/01

South 7*


364
362
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354
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voltage [kV]
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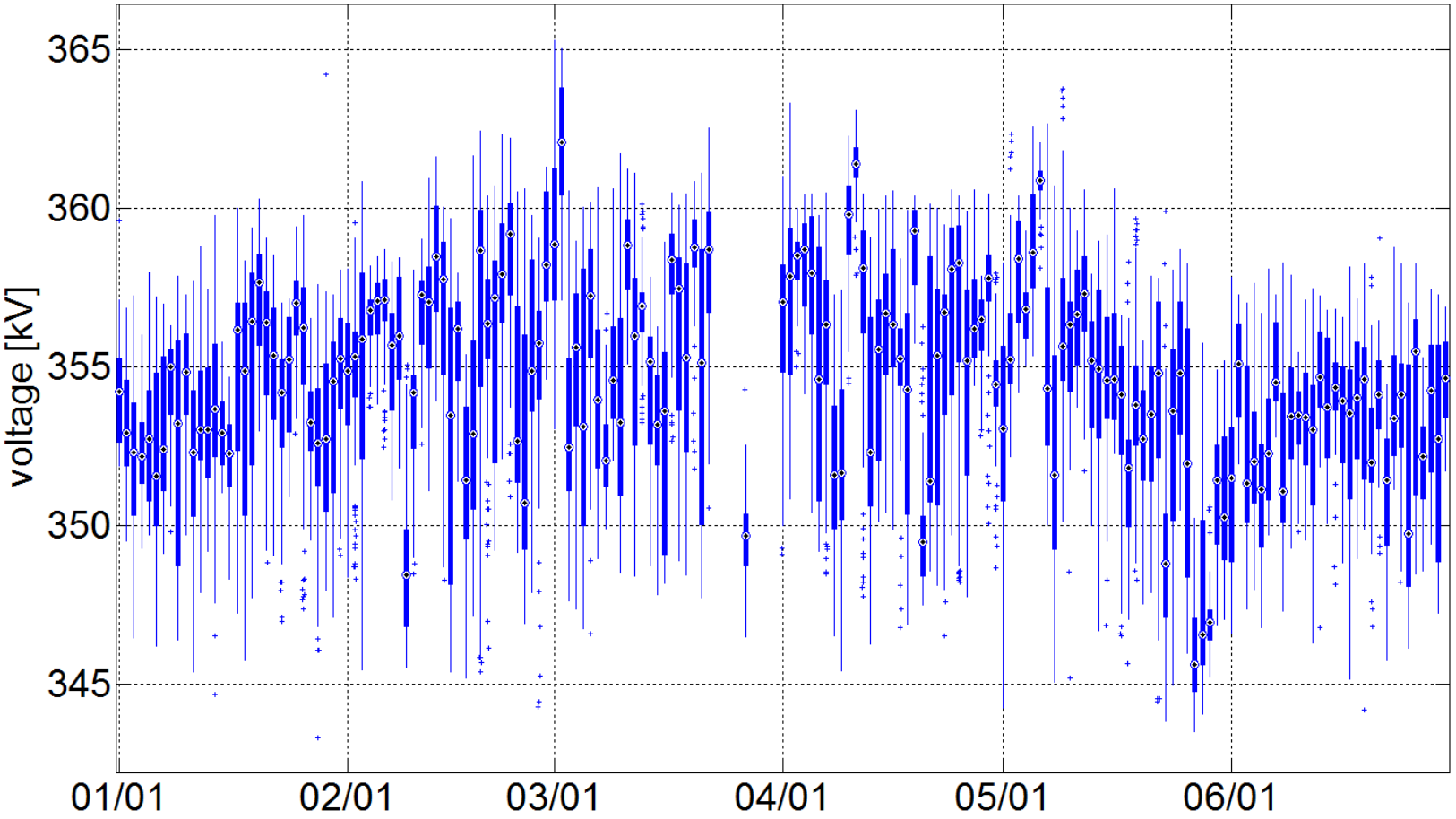
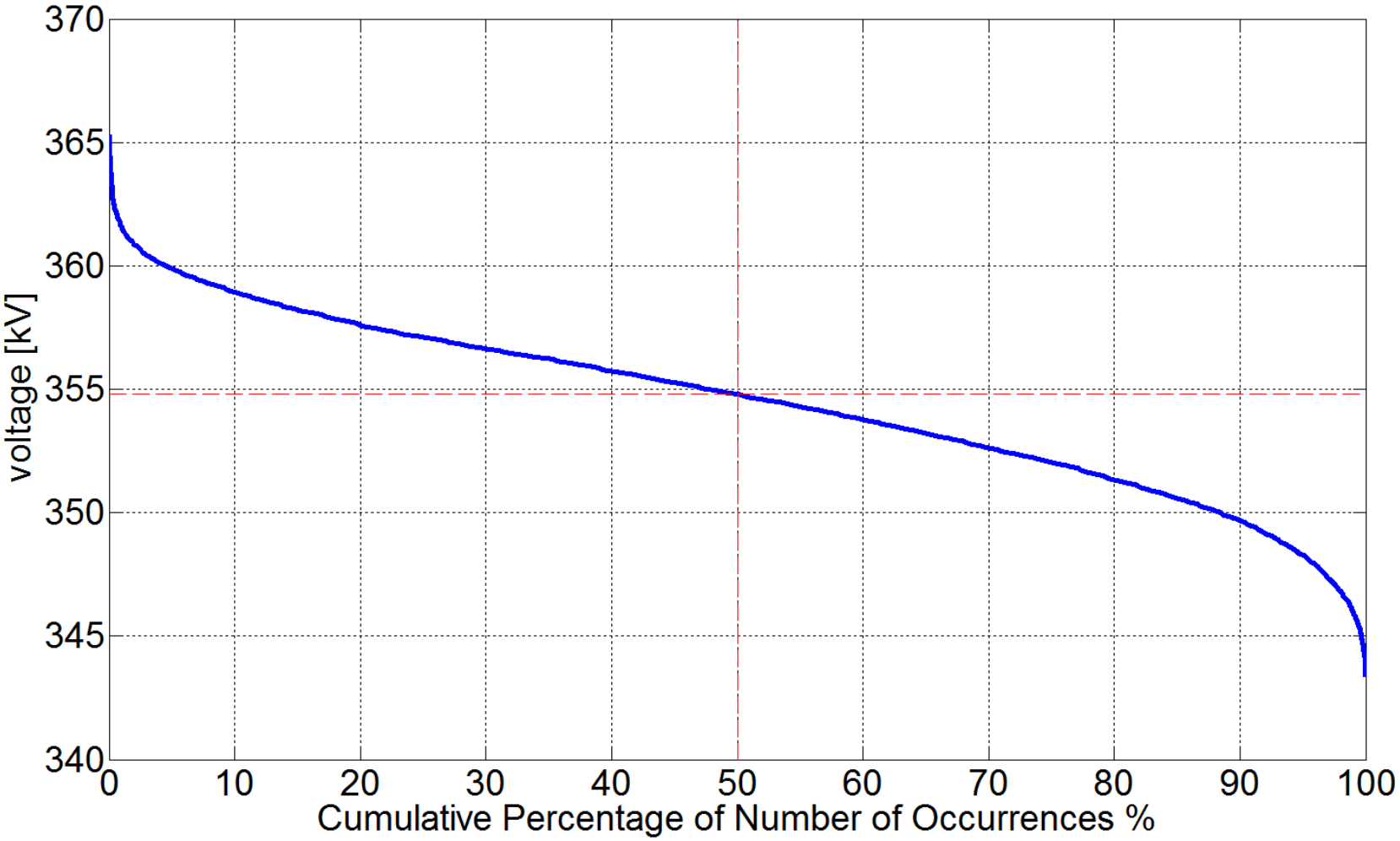
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

South 9*



South 9*


370
365
360
355
350
345
340
voltage [kV]
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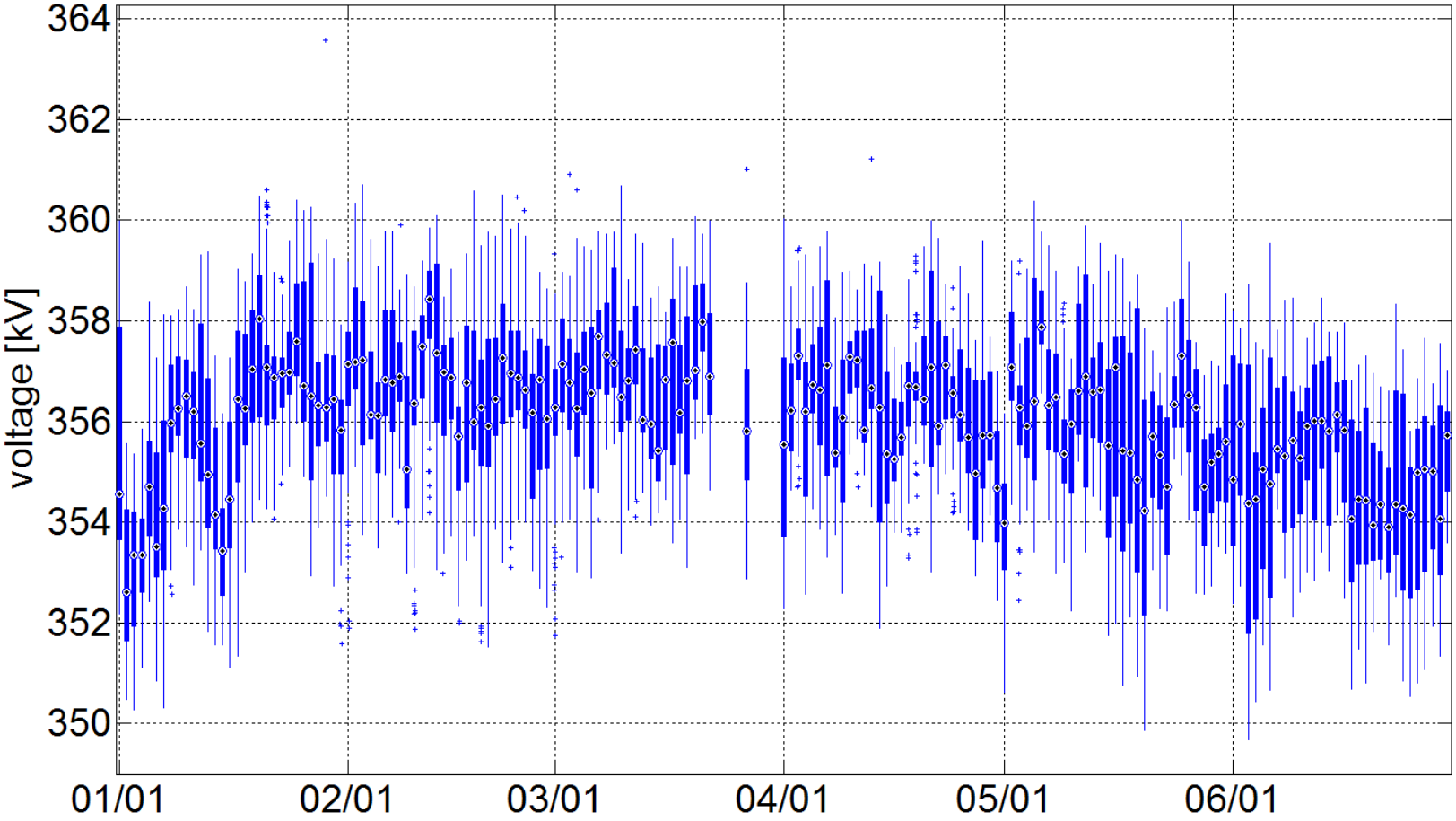
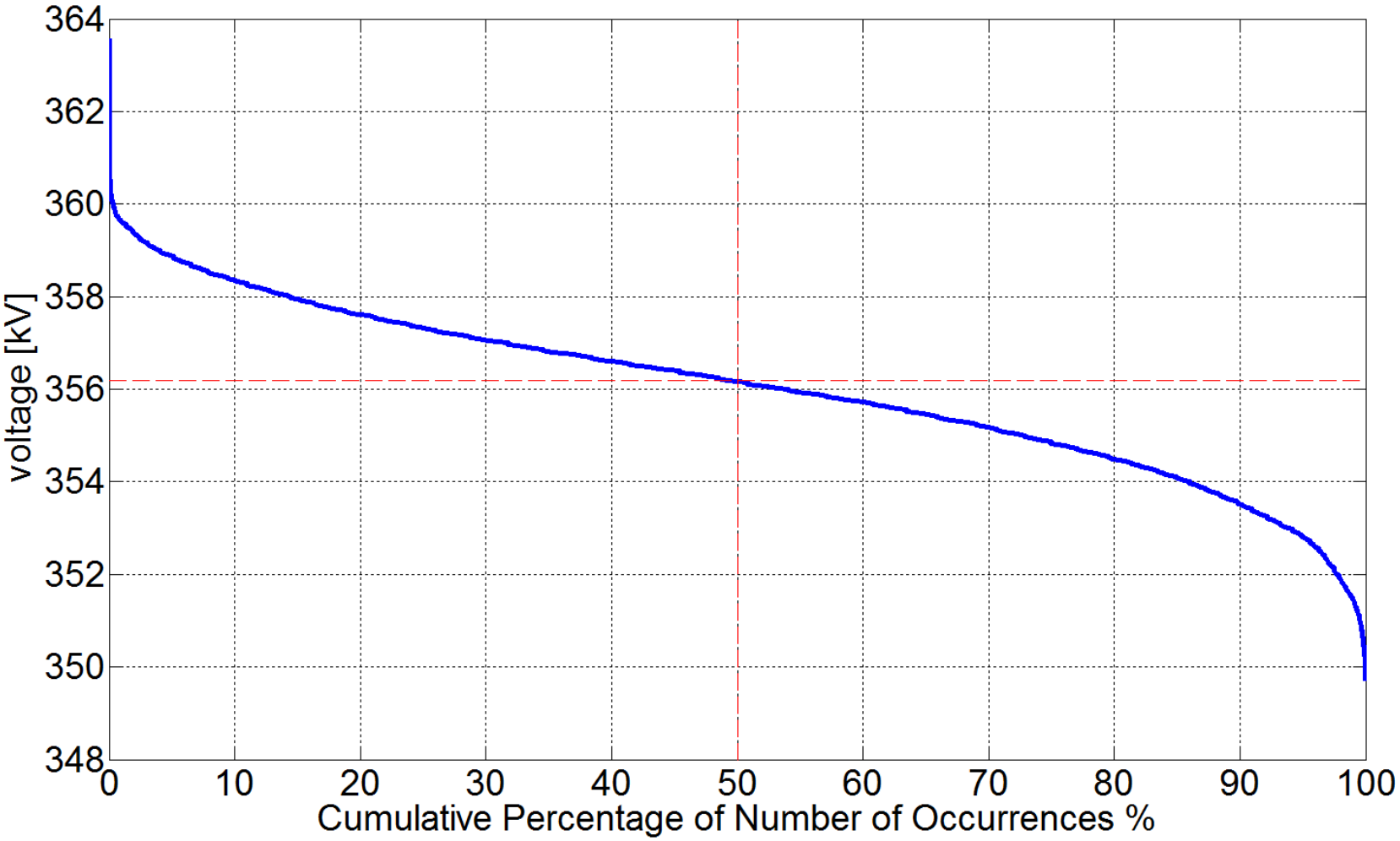
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

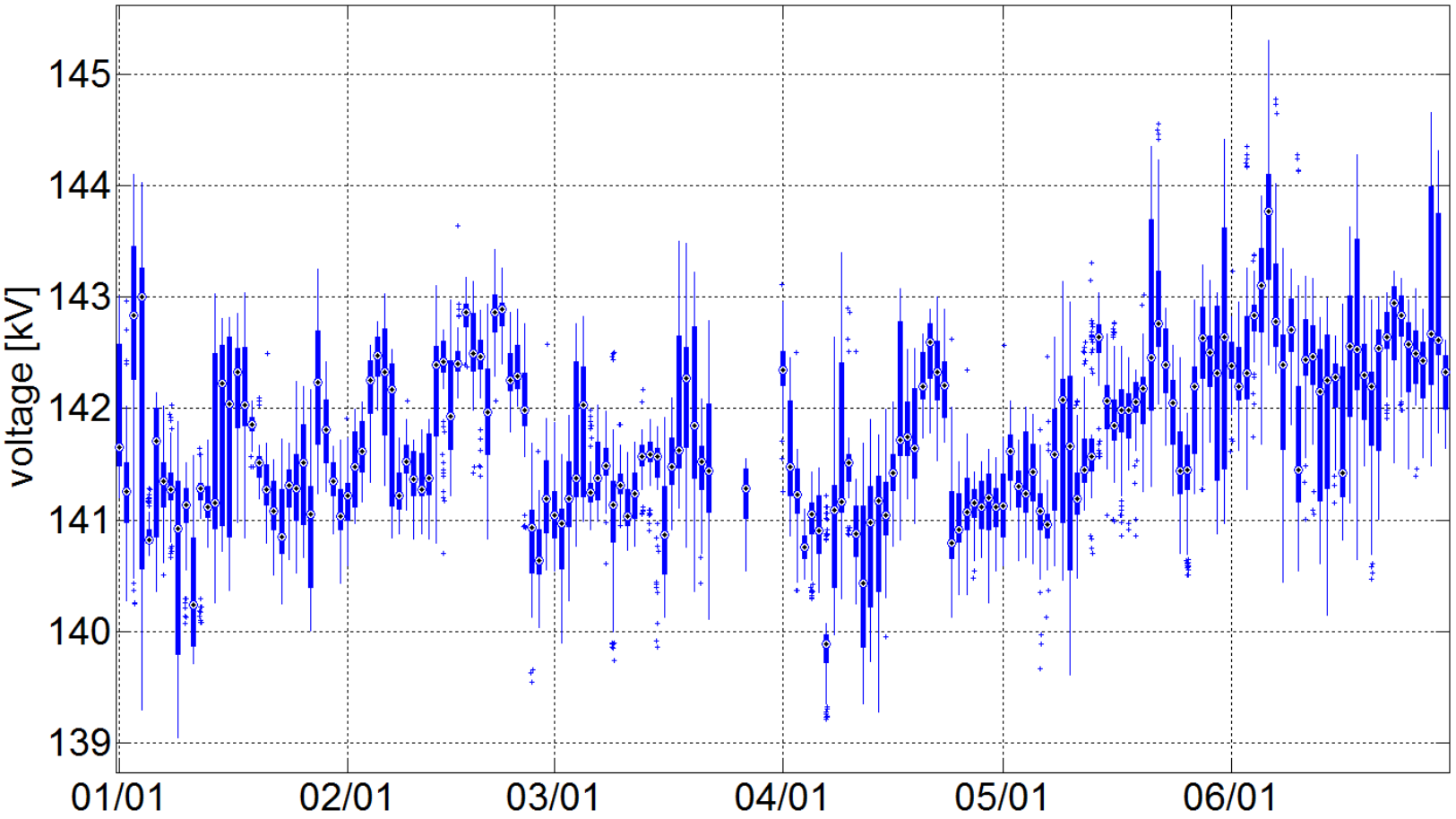
South 11*


364
362
360
358
356
354
352
350
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01

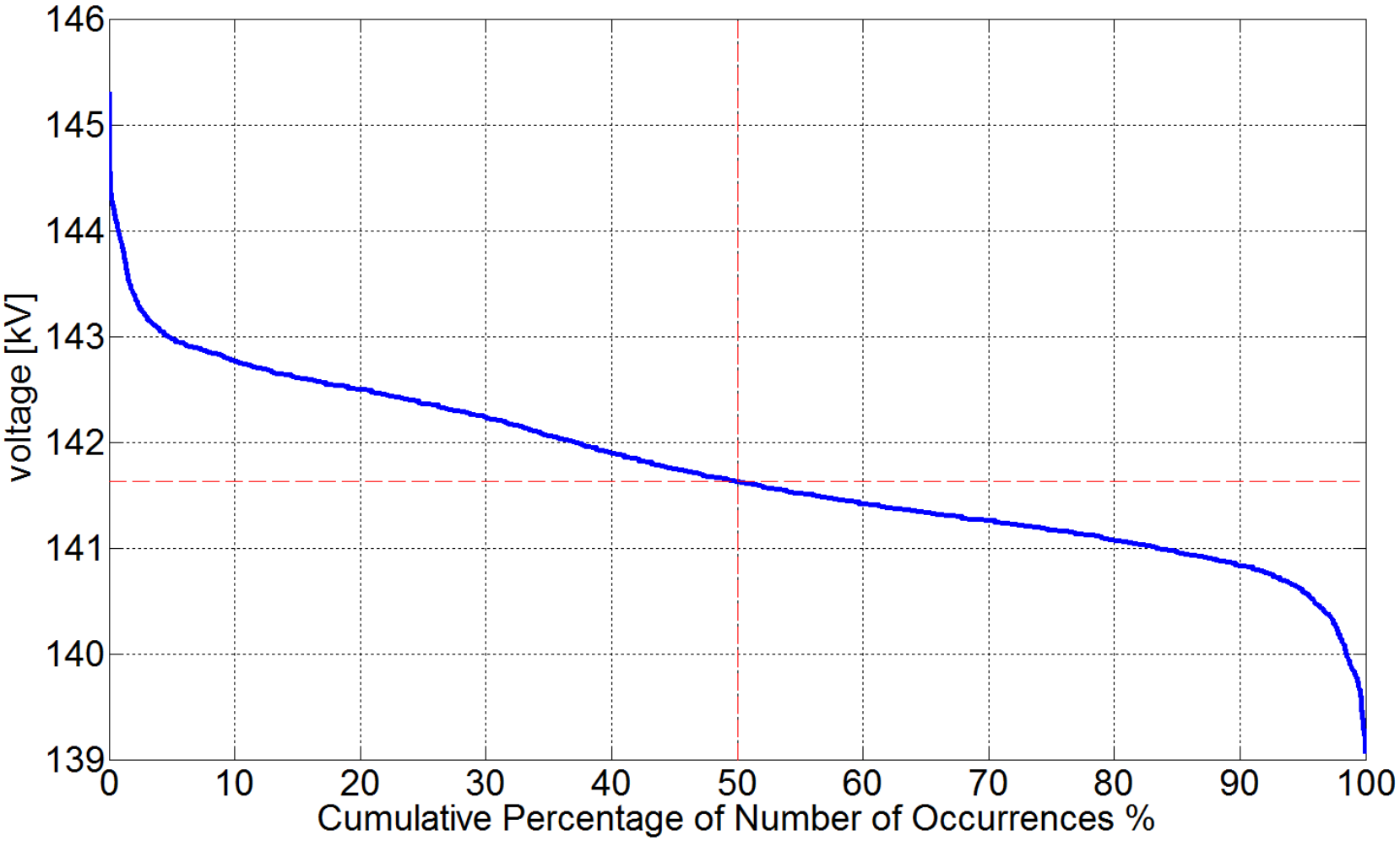
South 11*


364
362
360
358
356
354
352
350
348
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

South 10*


voltage [kV]
145
144
143
142
141
140
139
01/01
02/01
03/01
04/01
05/01
06/01

South 10*


146
145
144
143
142
141
140
139
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

Appendix A – Part 2

CCET Discovery Across Texas project

Baseline Analysis Update - Voltage Magnitudes

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

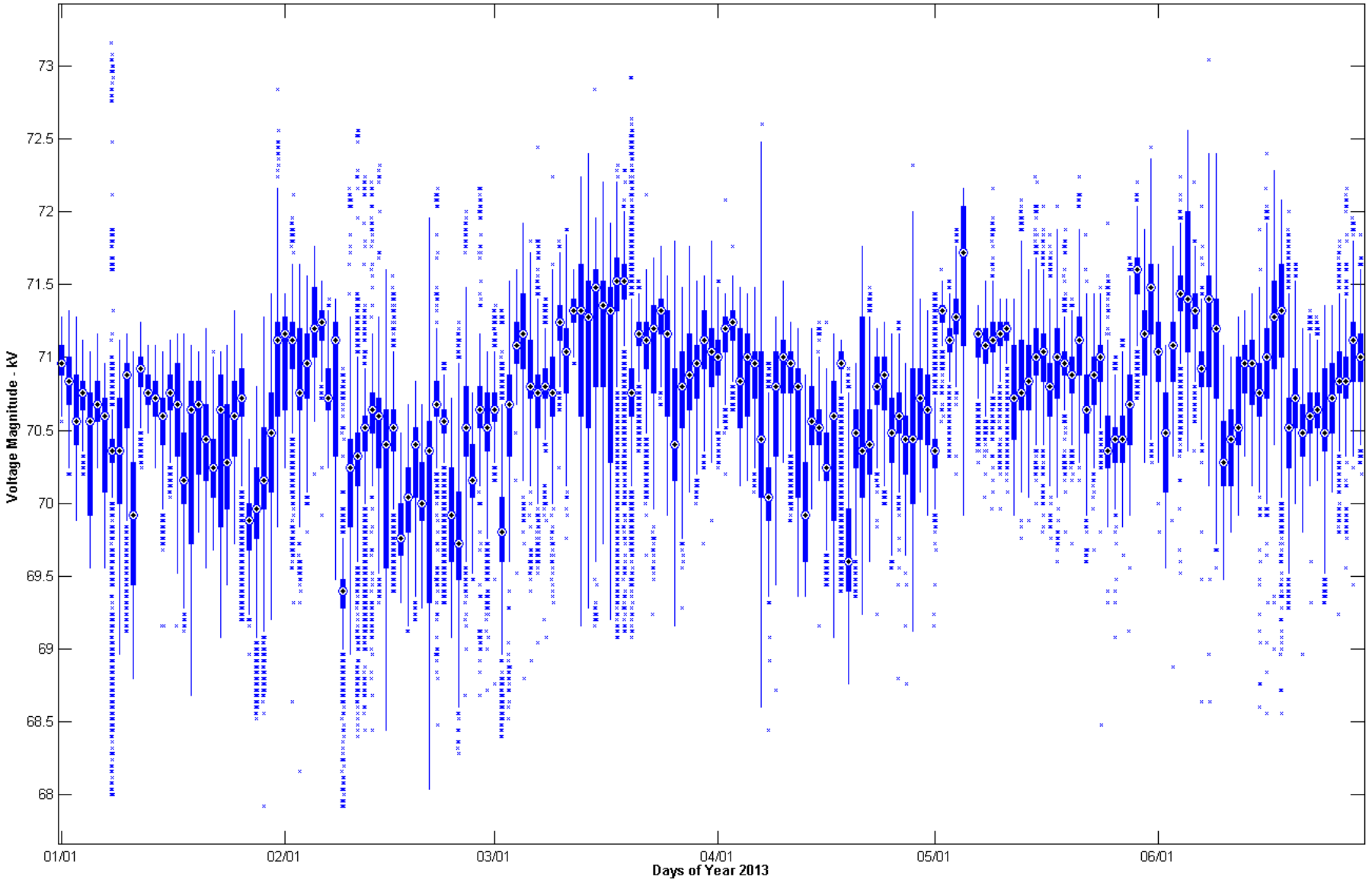
External Version

Electric Power Group

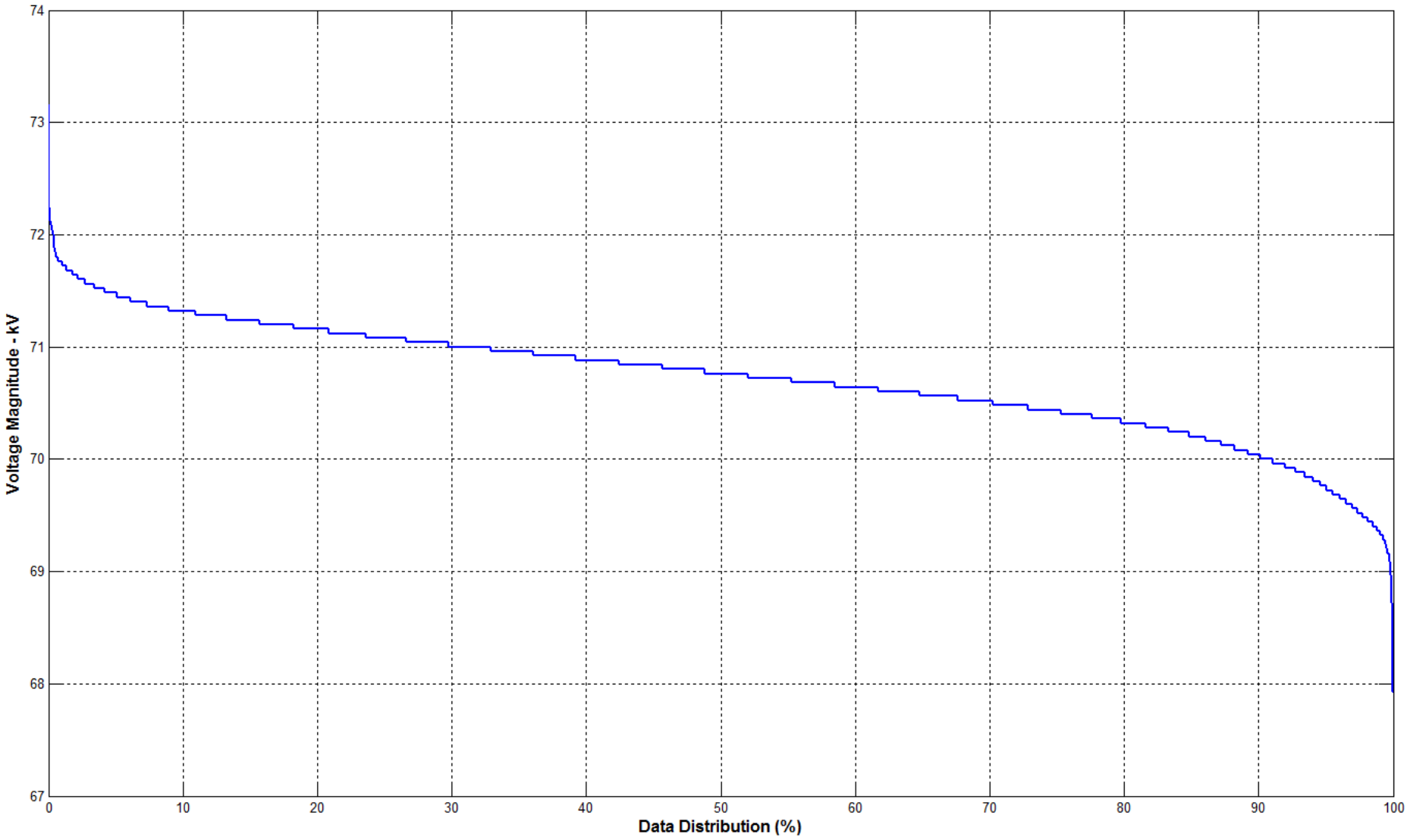
CCET

ERCOT

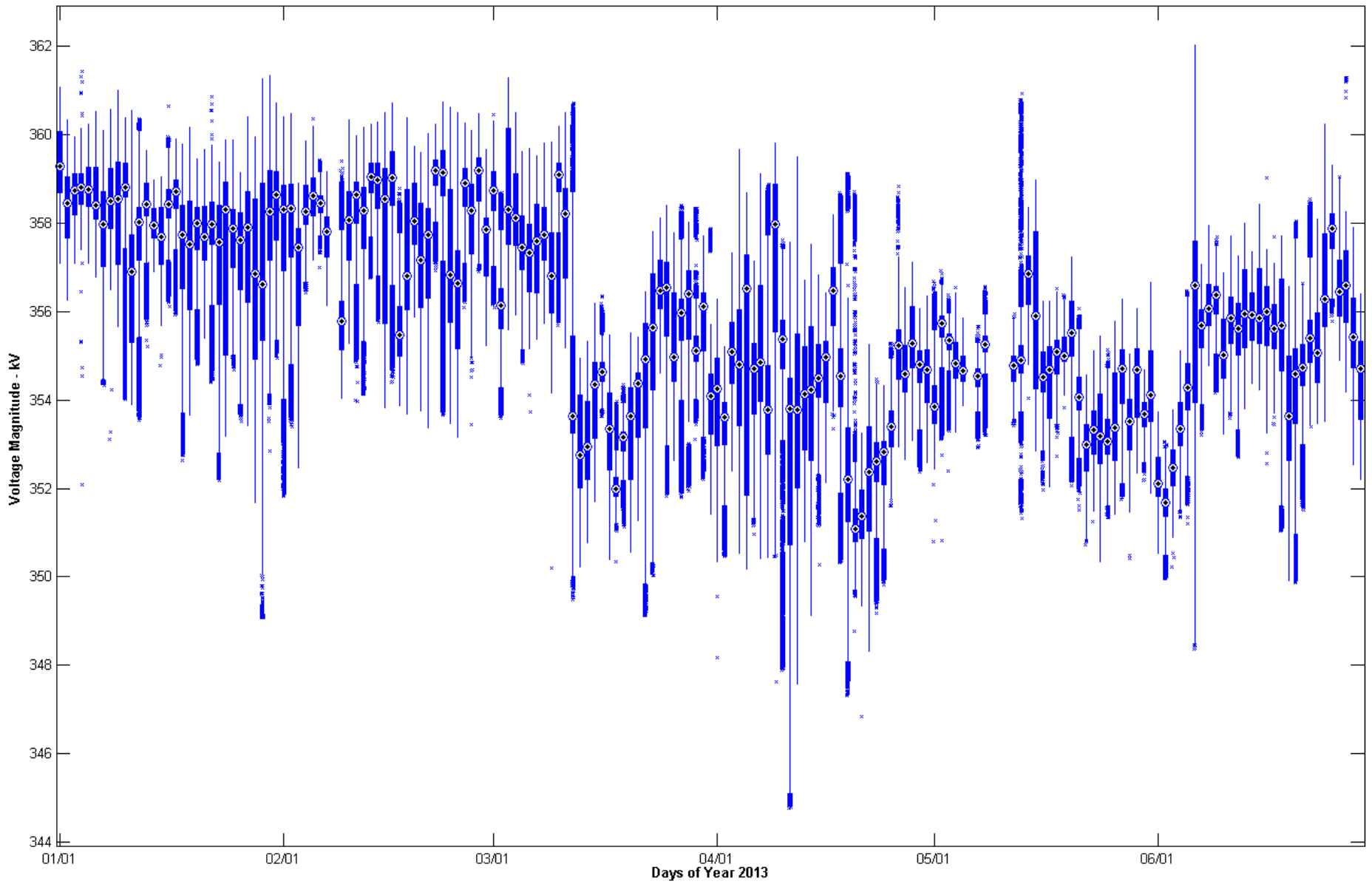
West 10 – Voltage Magnitude



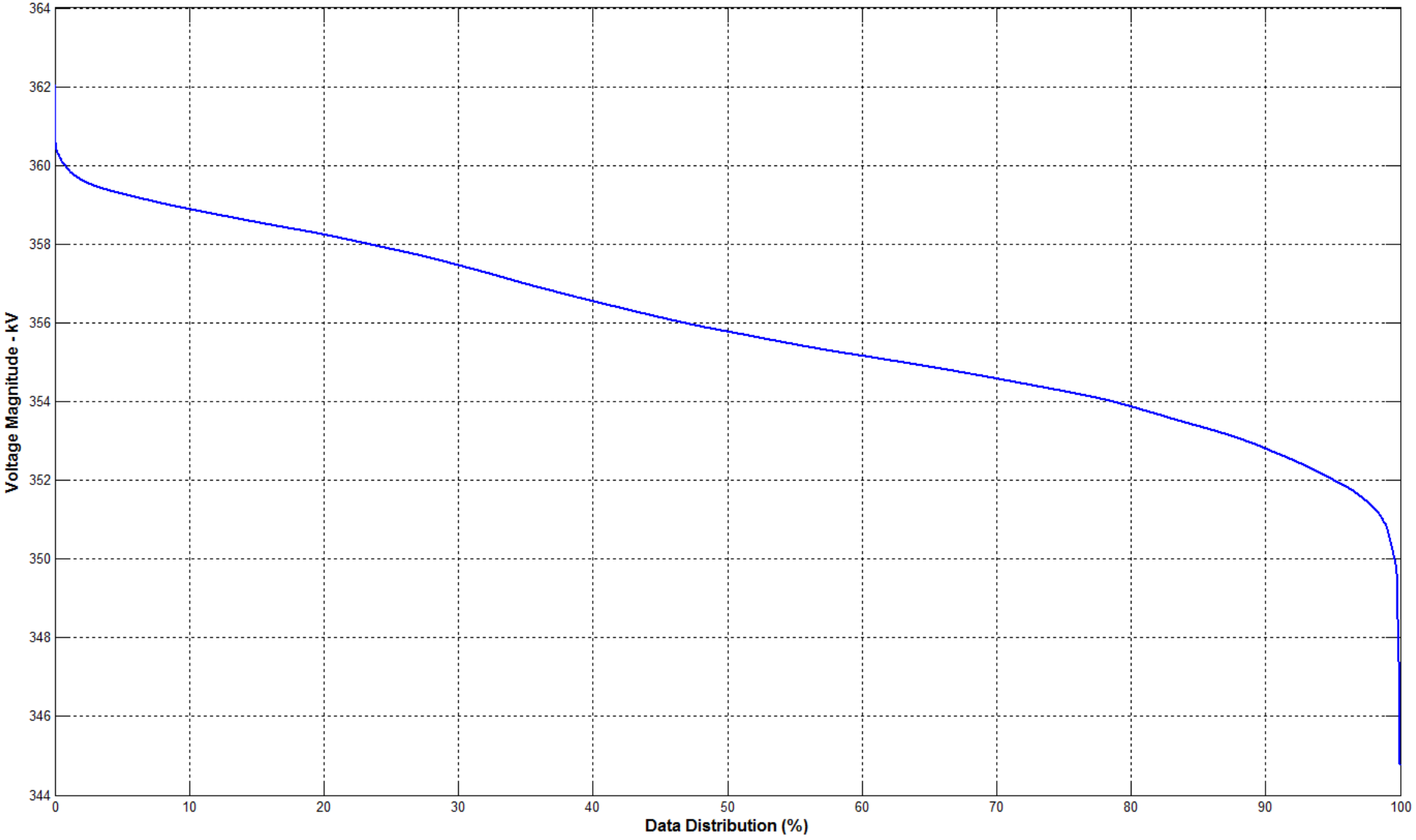
West 10 – Voltage Magnitude



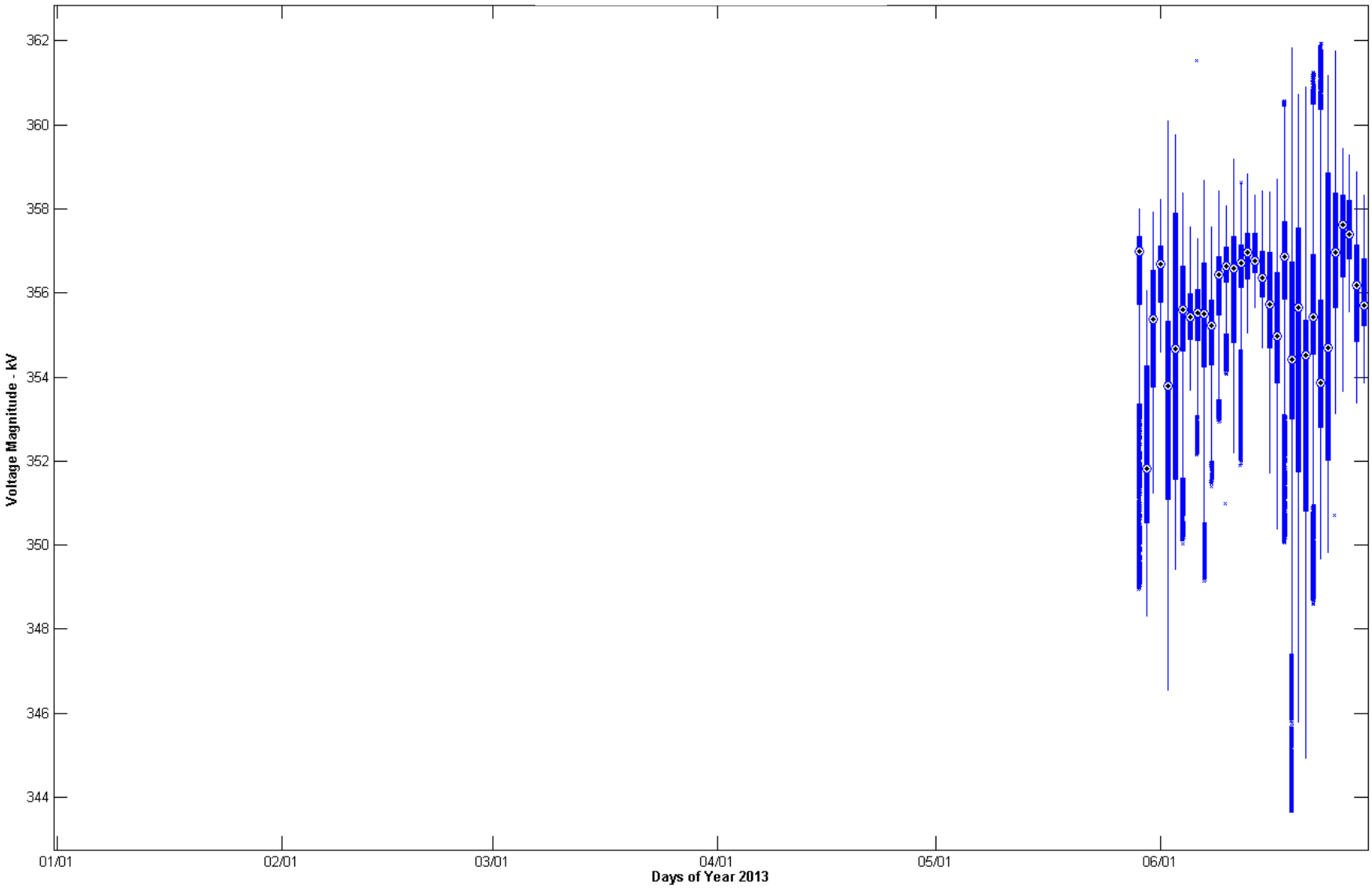
West 14 – Voltage Magnitude



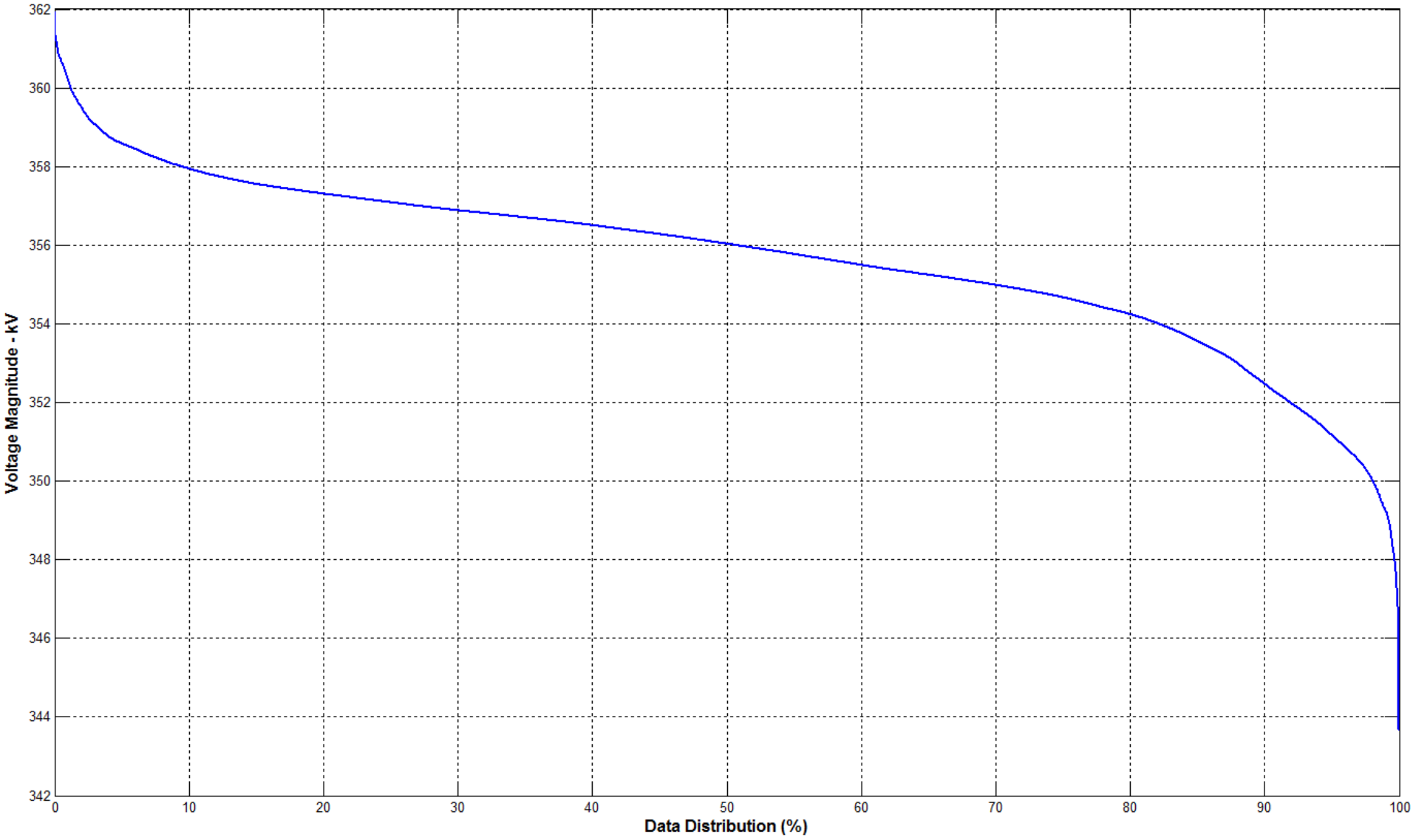
West 14 – Voltage Magnitude



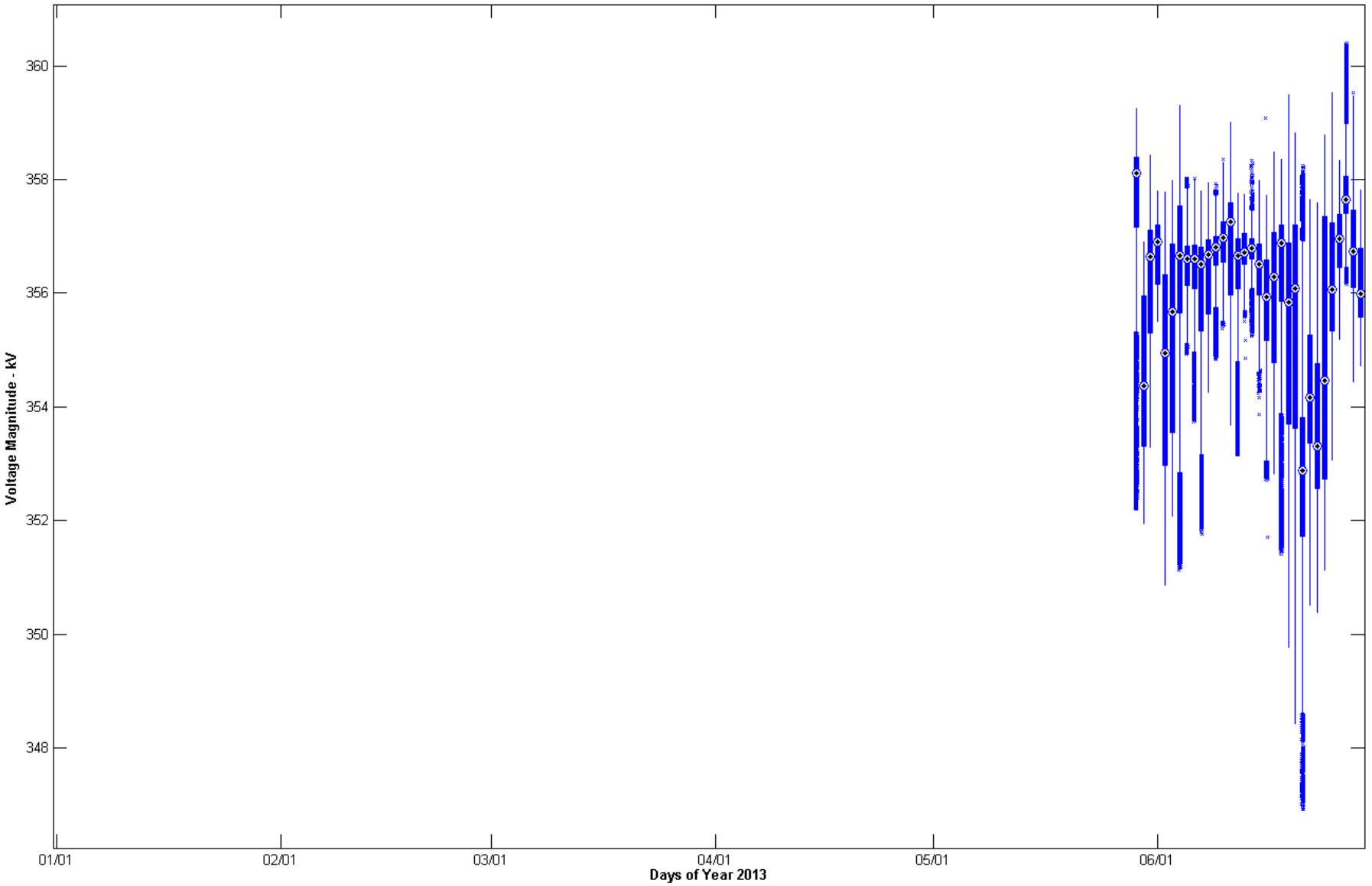
West 1 – Voltage Magnitude



West 1 – Voltage Magnitude



West 2 – Voltage Magnitude



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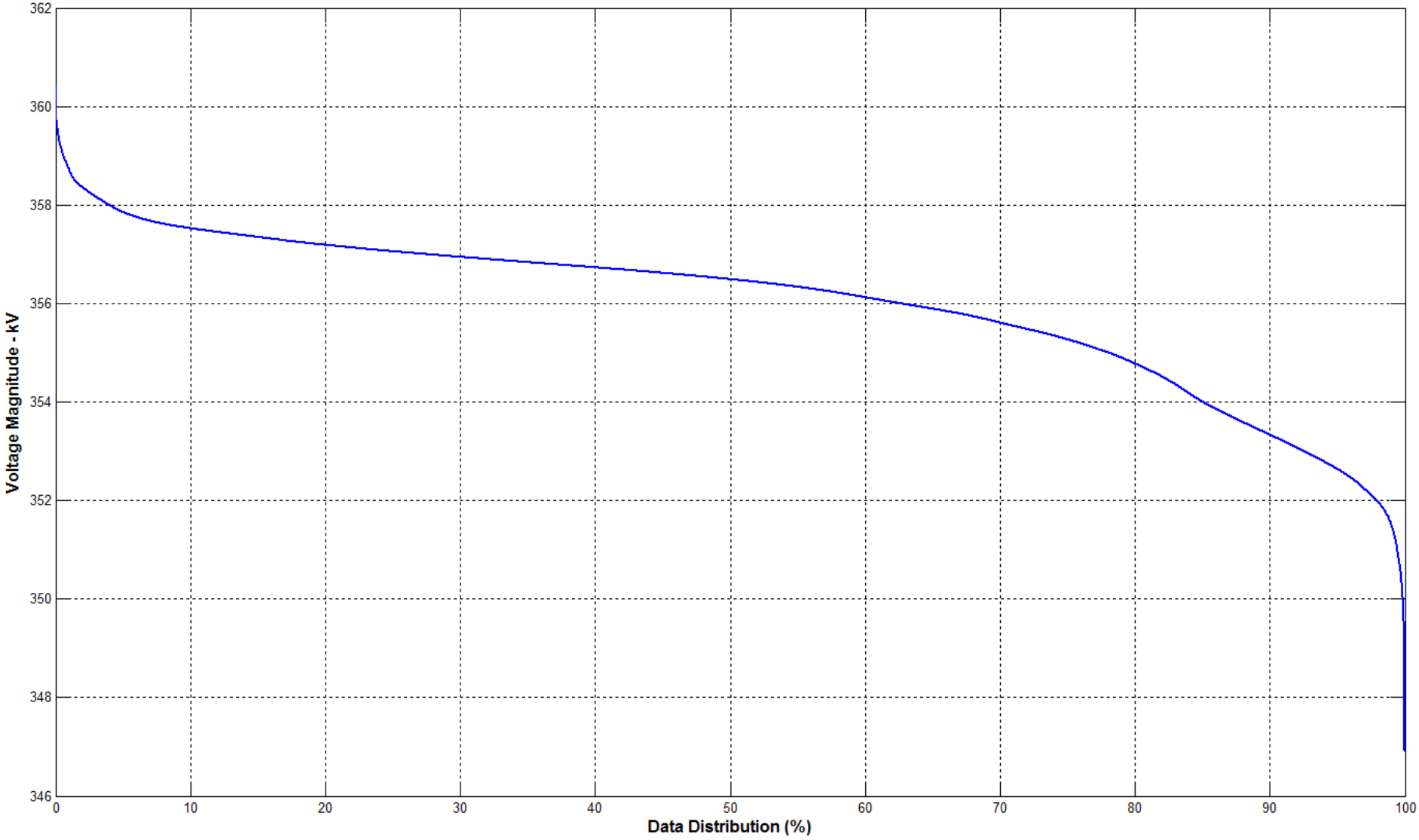
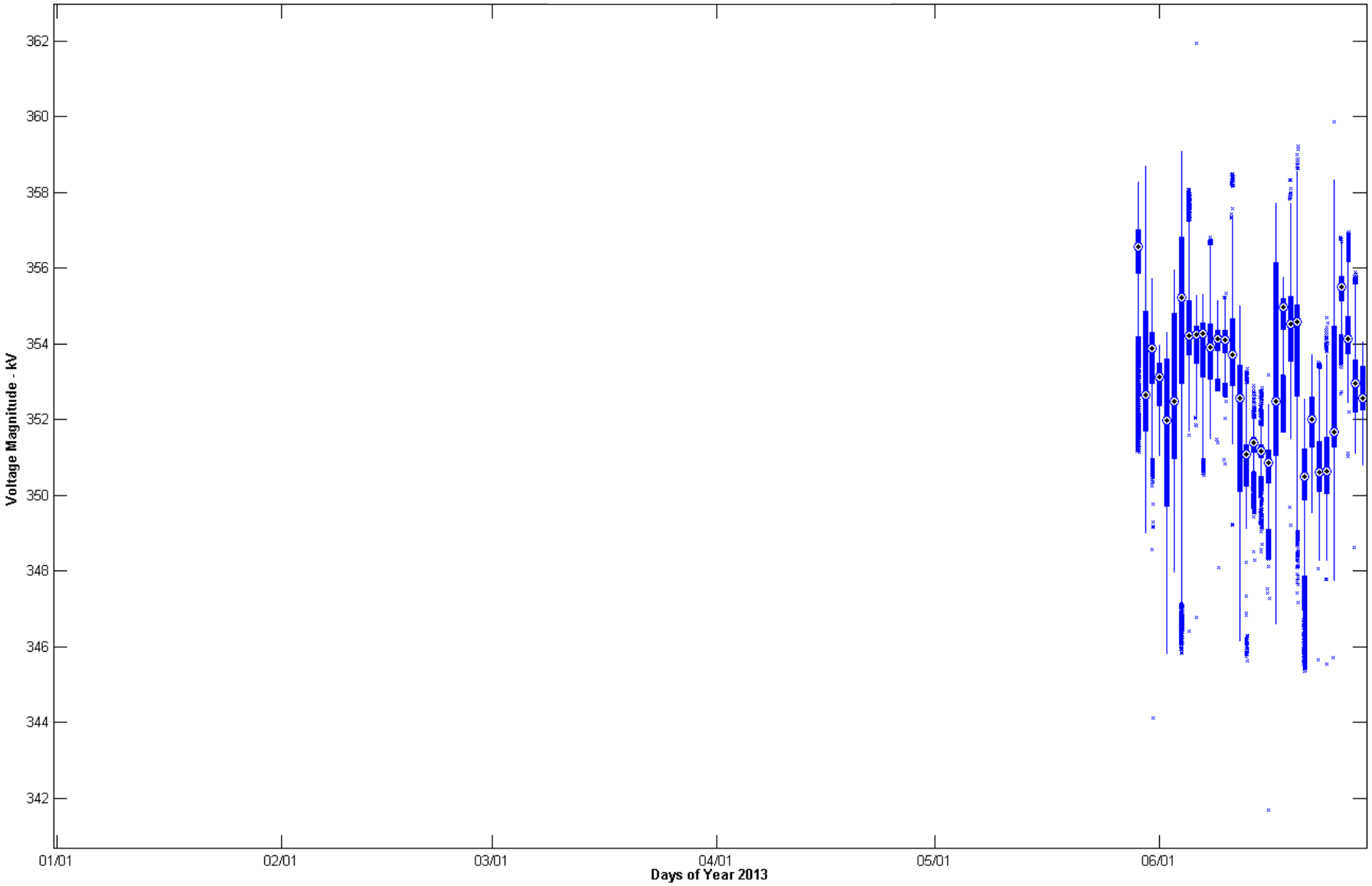
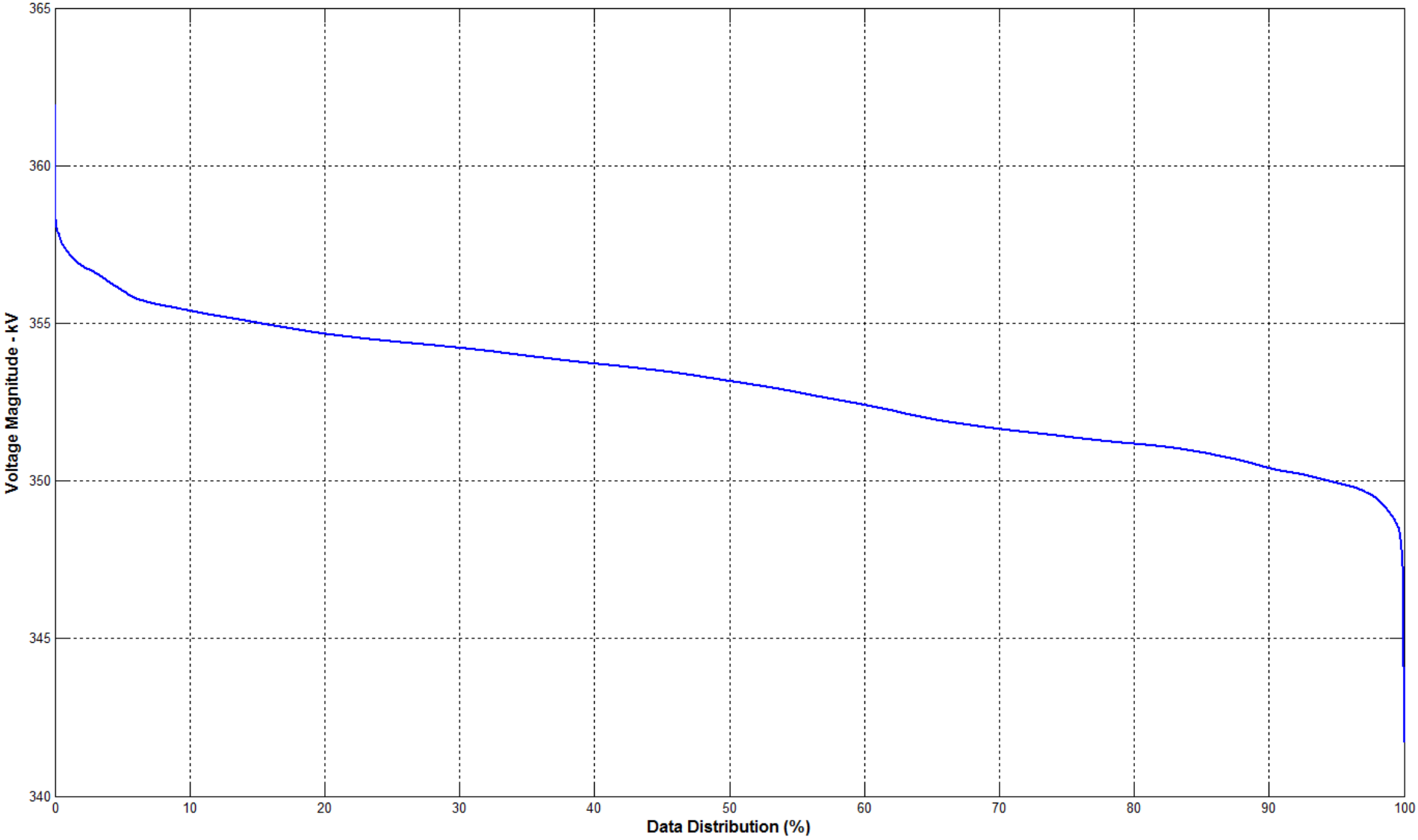


West 9 – Voltage Magnitude



West 9 – Voltage Magnitude



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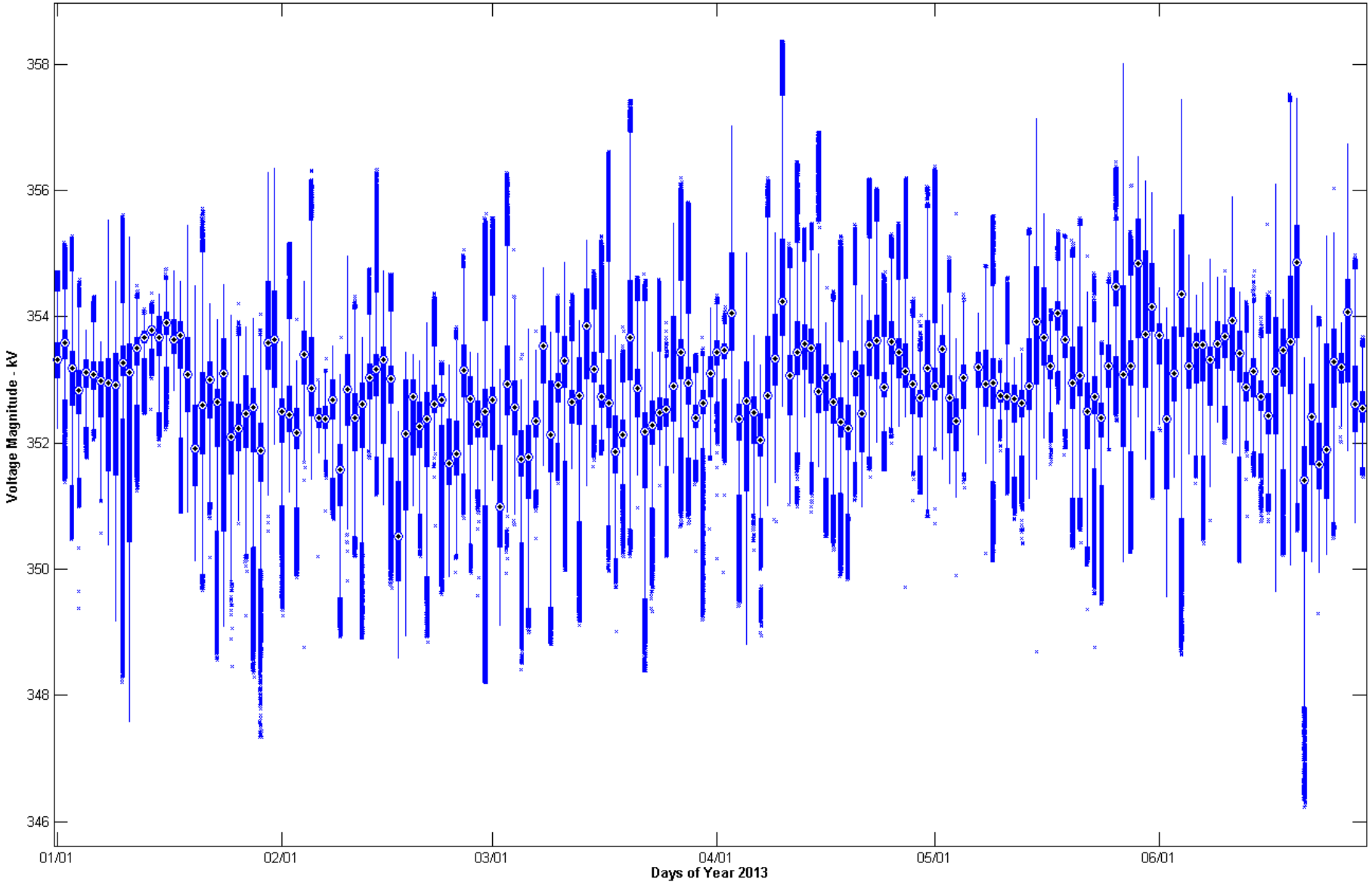

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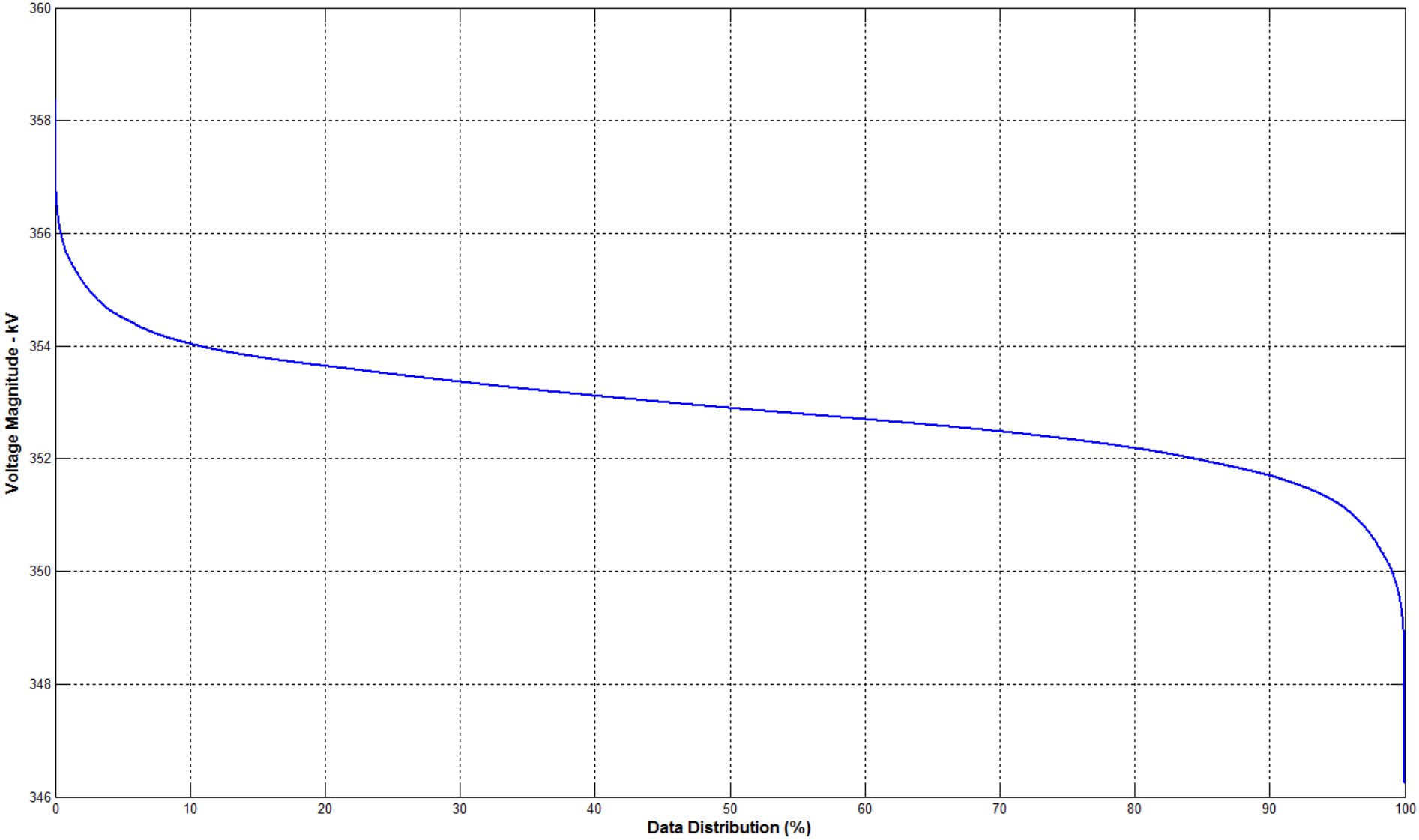

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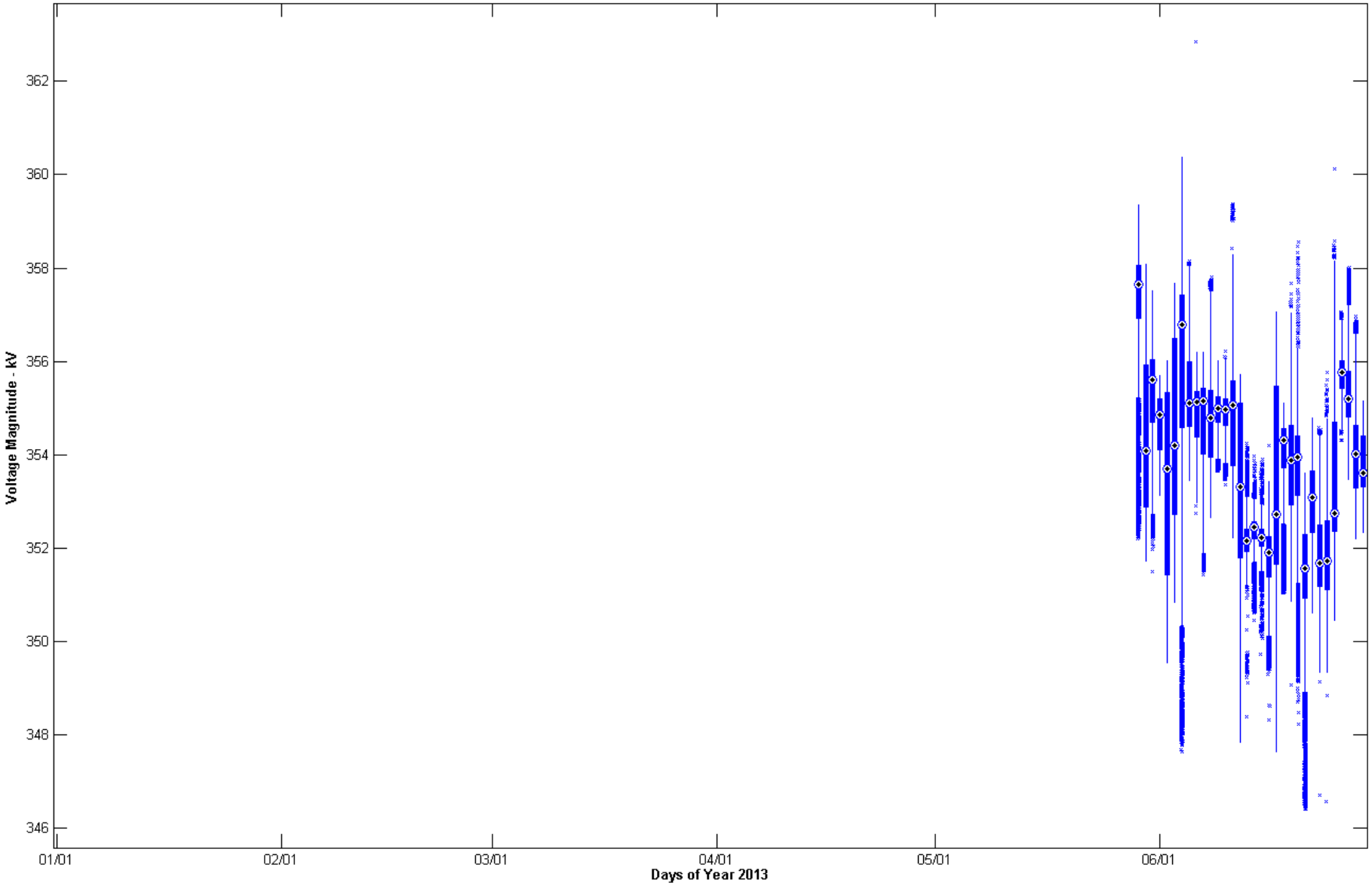

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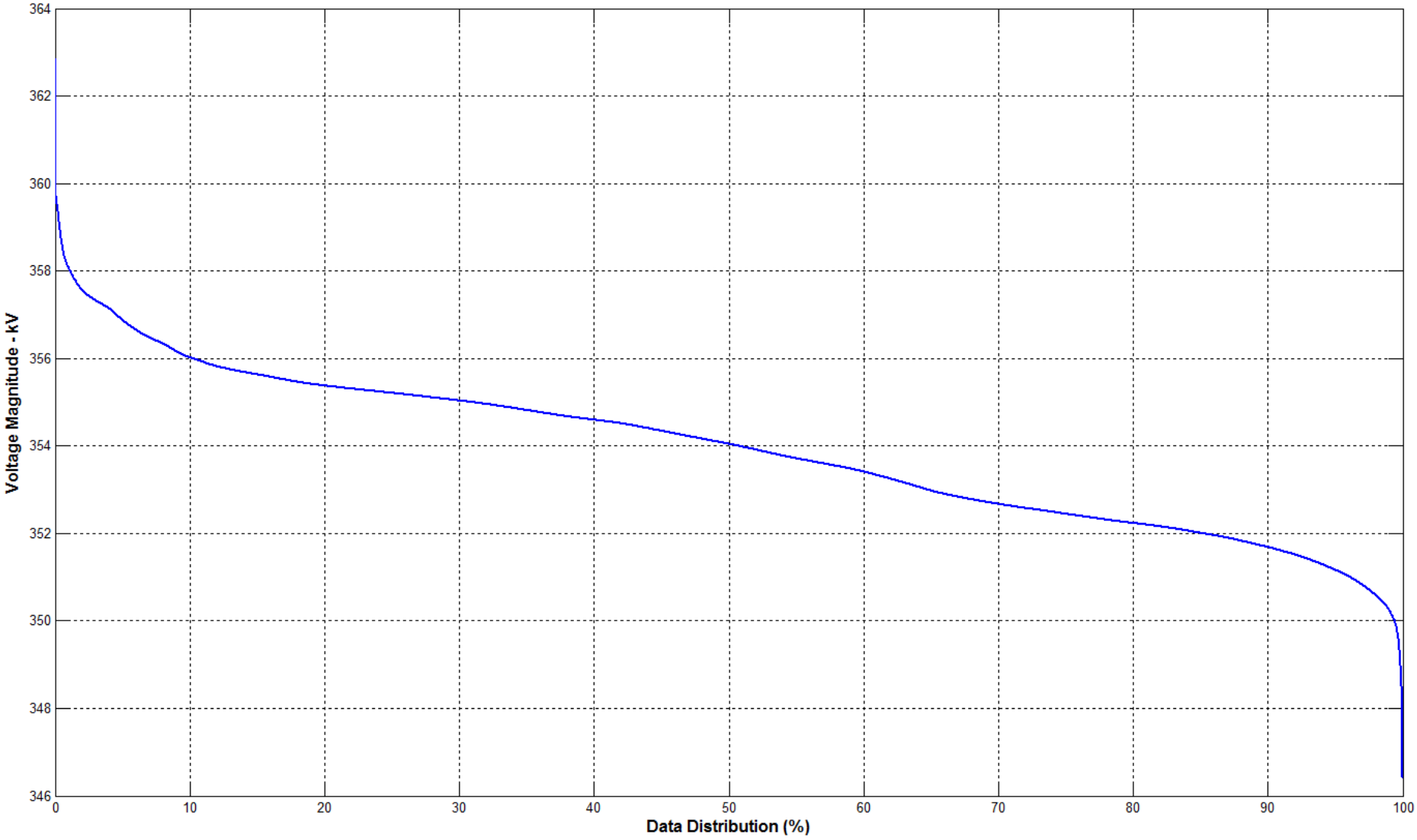
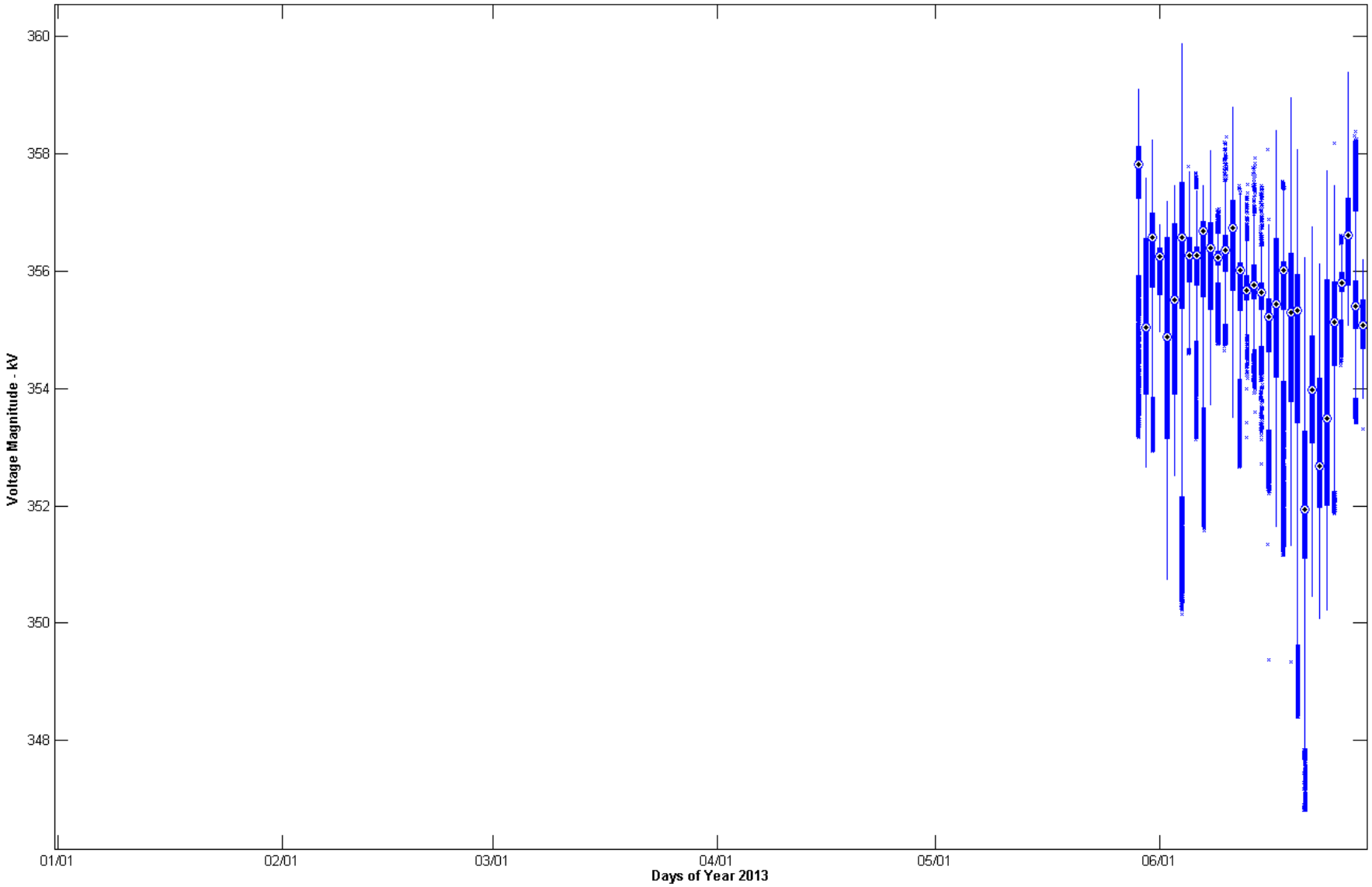
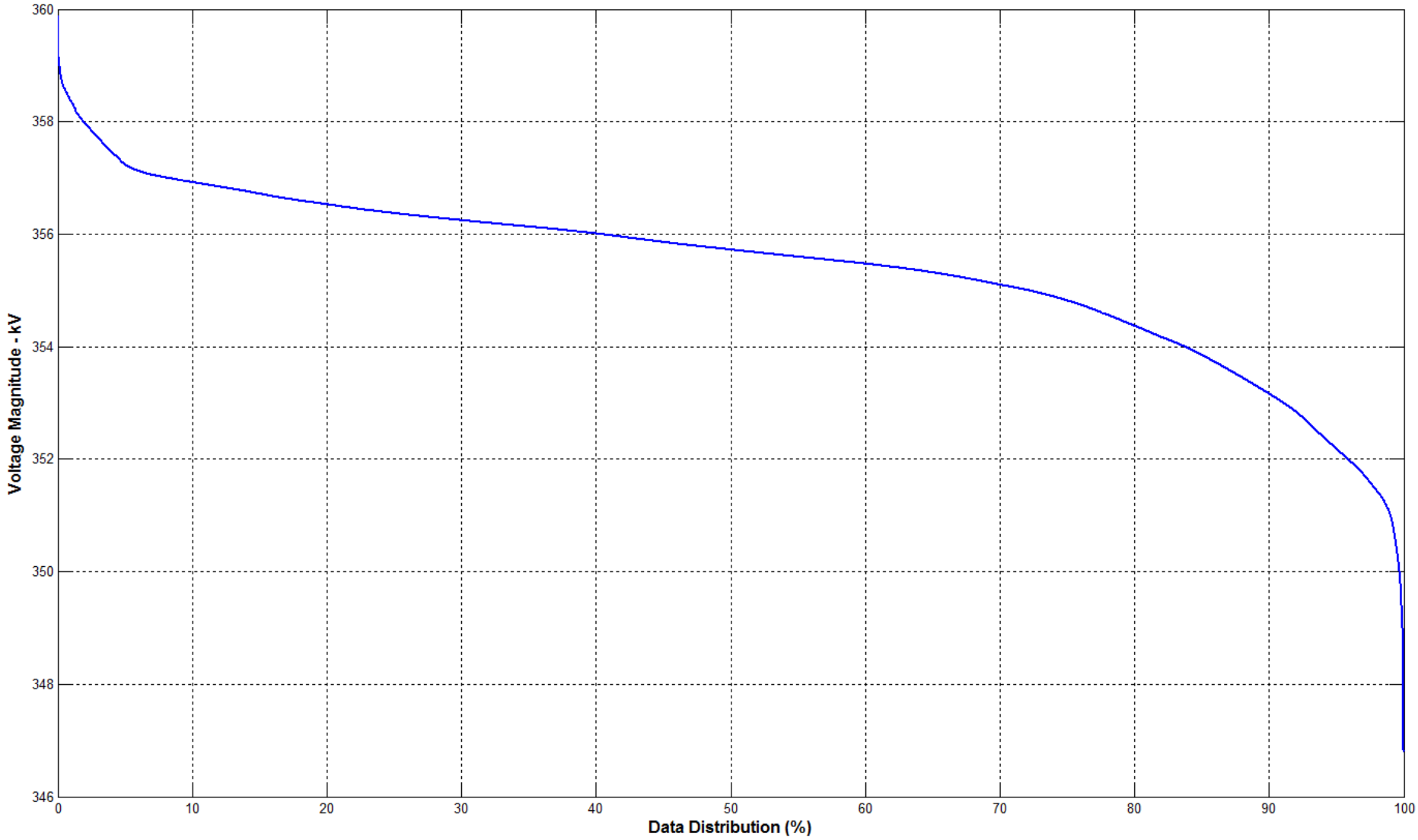


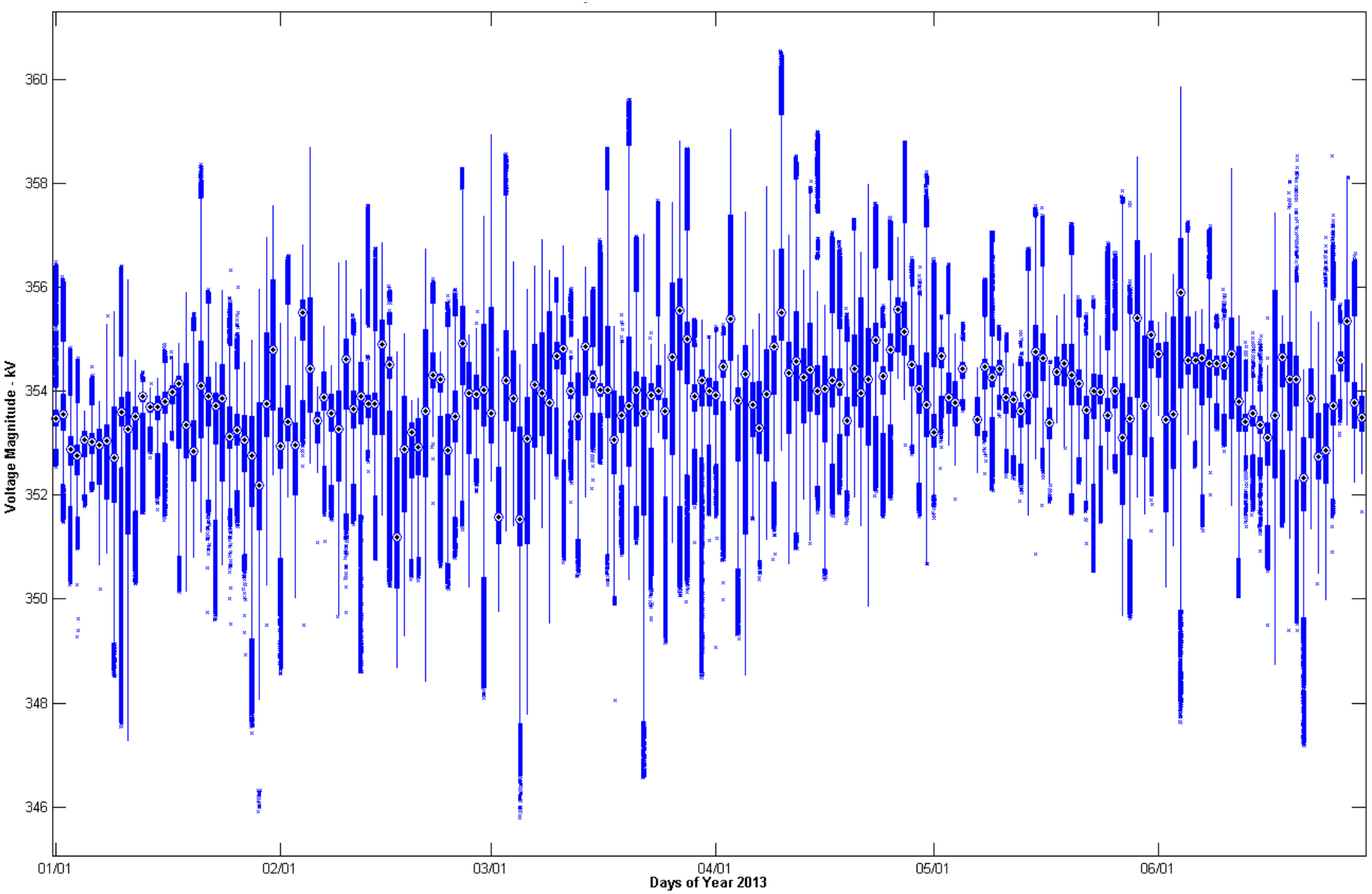
West 5 – Voltage Magnitude



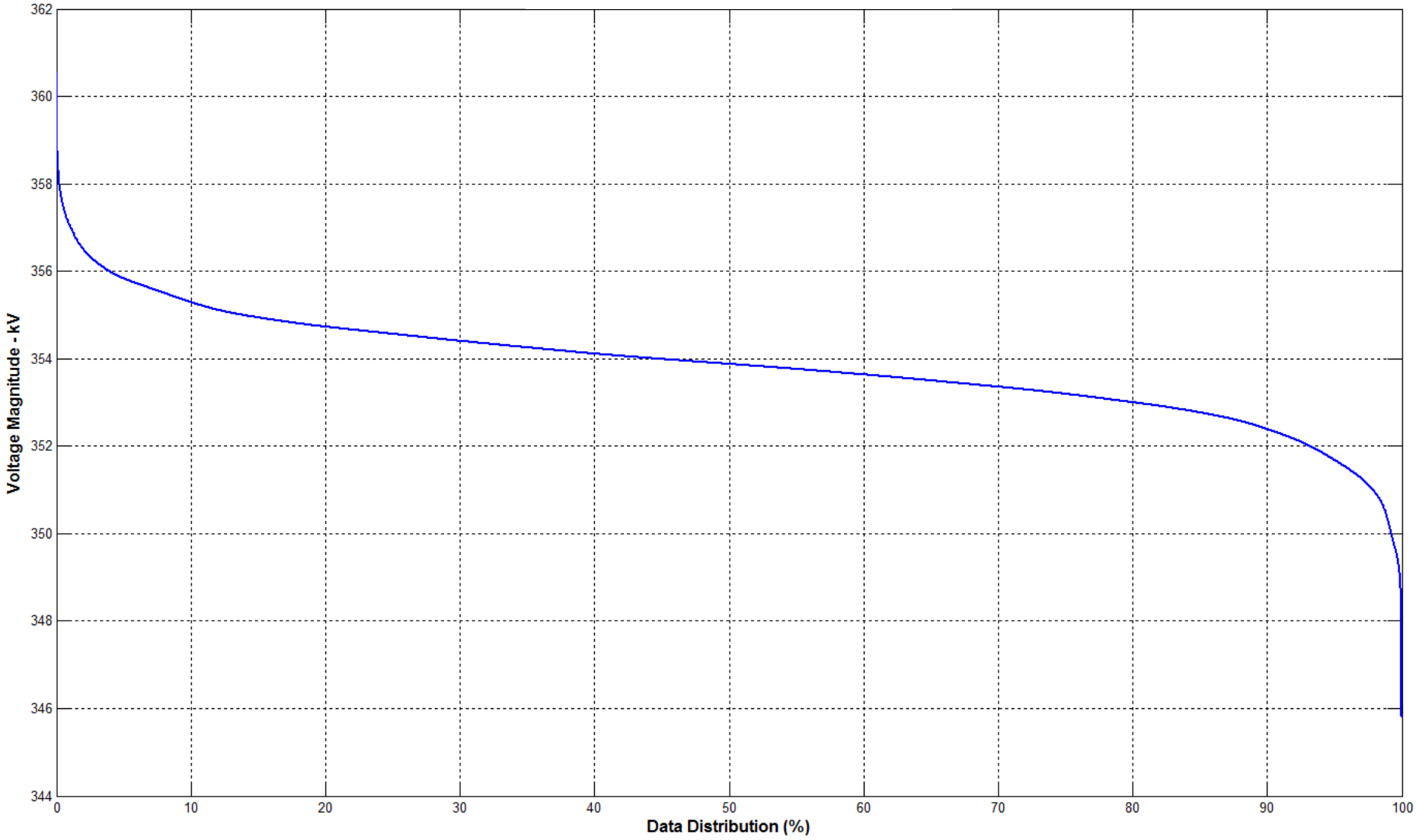
West 5 – Voltage Magnitude



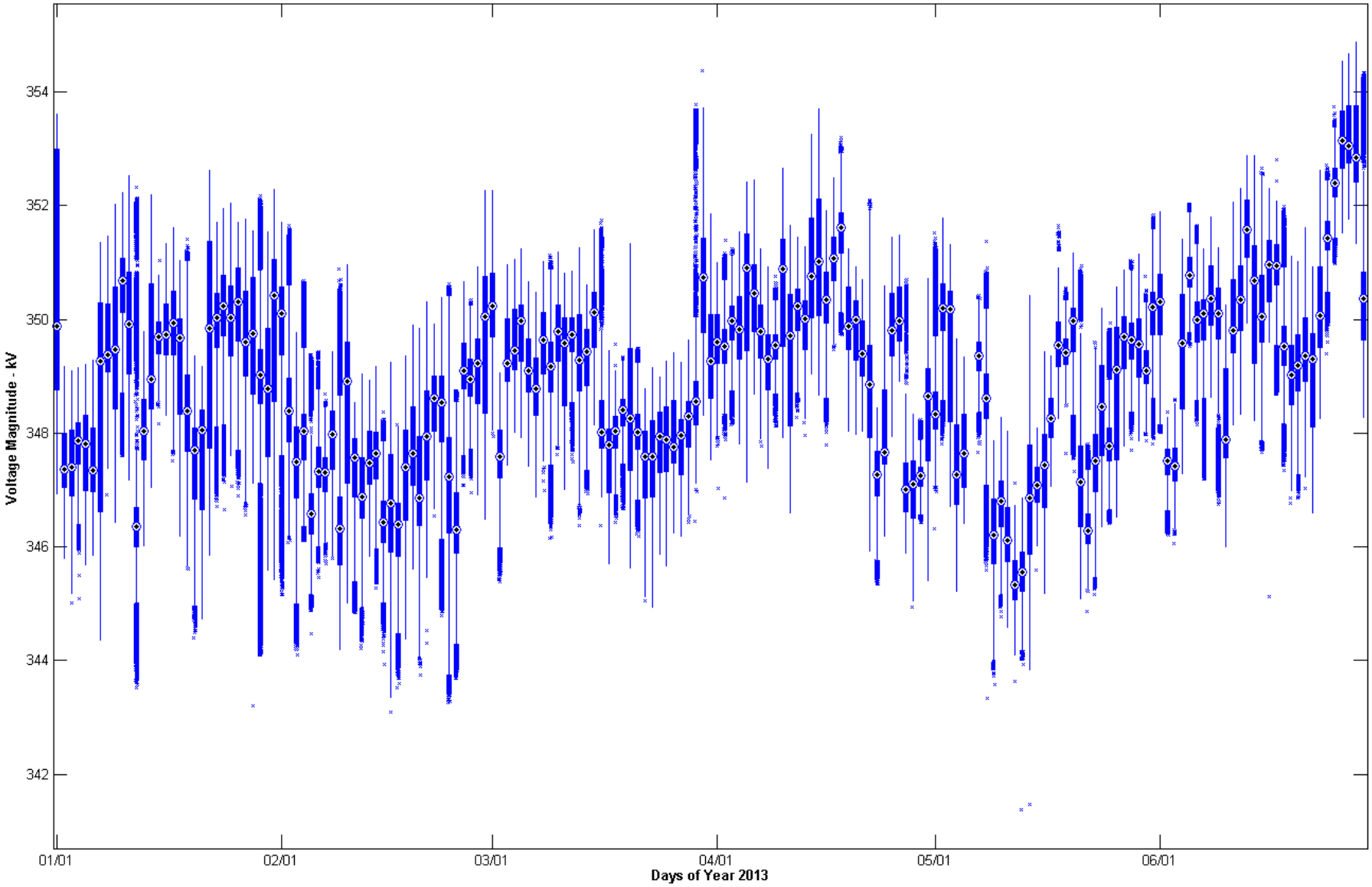
West 6 – Voltage Magnitude



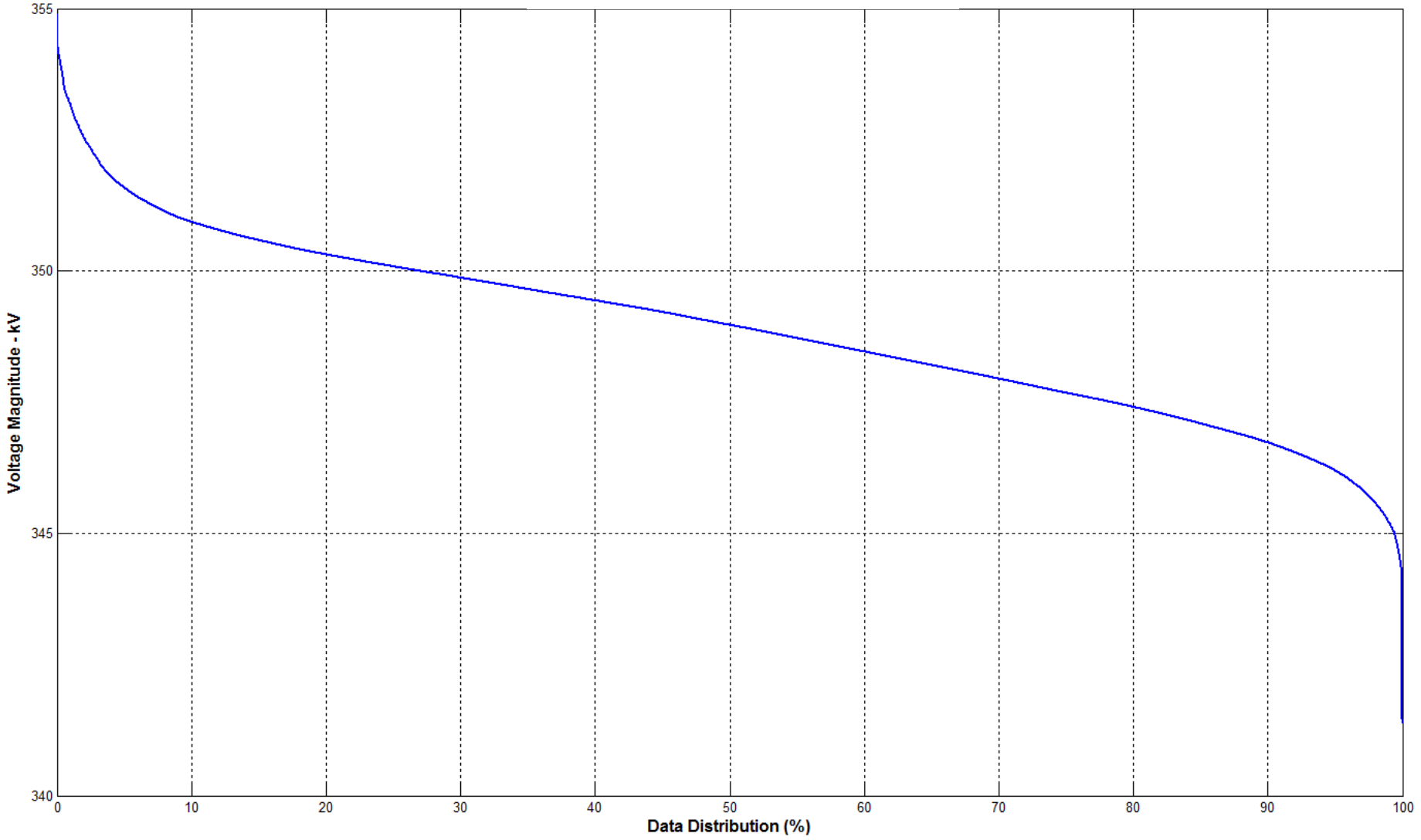
West 6 – Voltage Magnitude



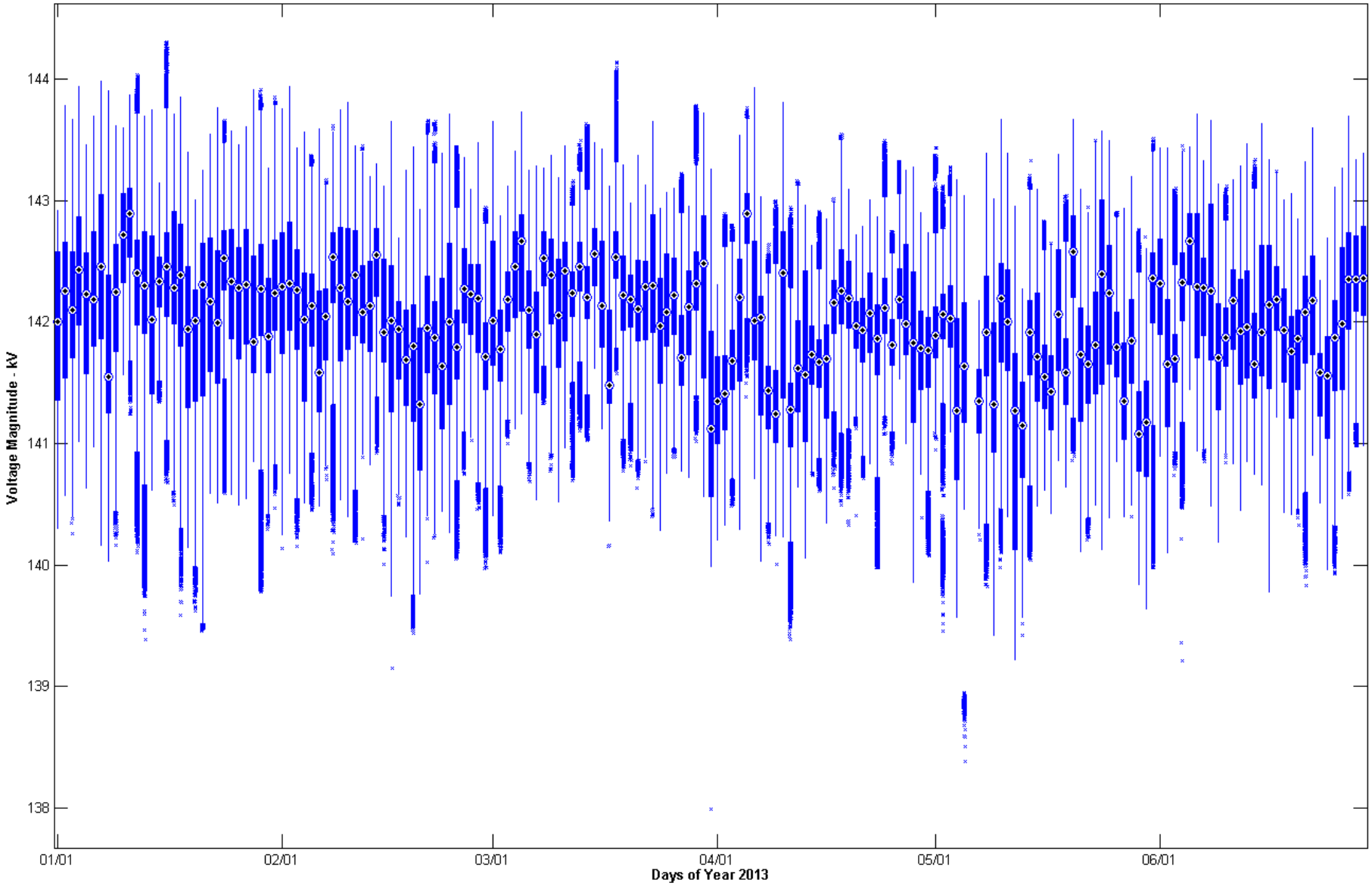
North 1 – Voltage Magnitude



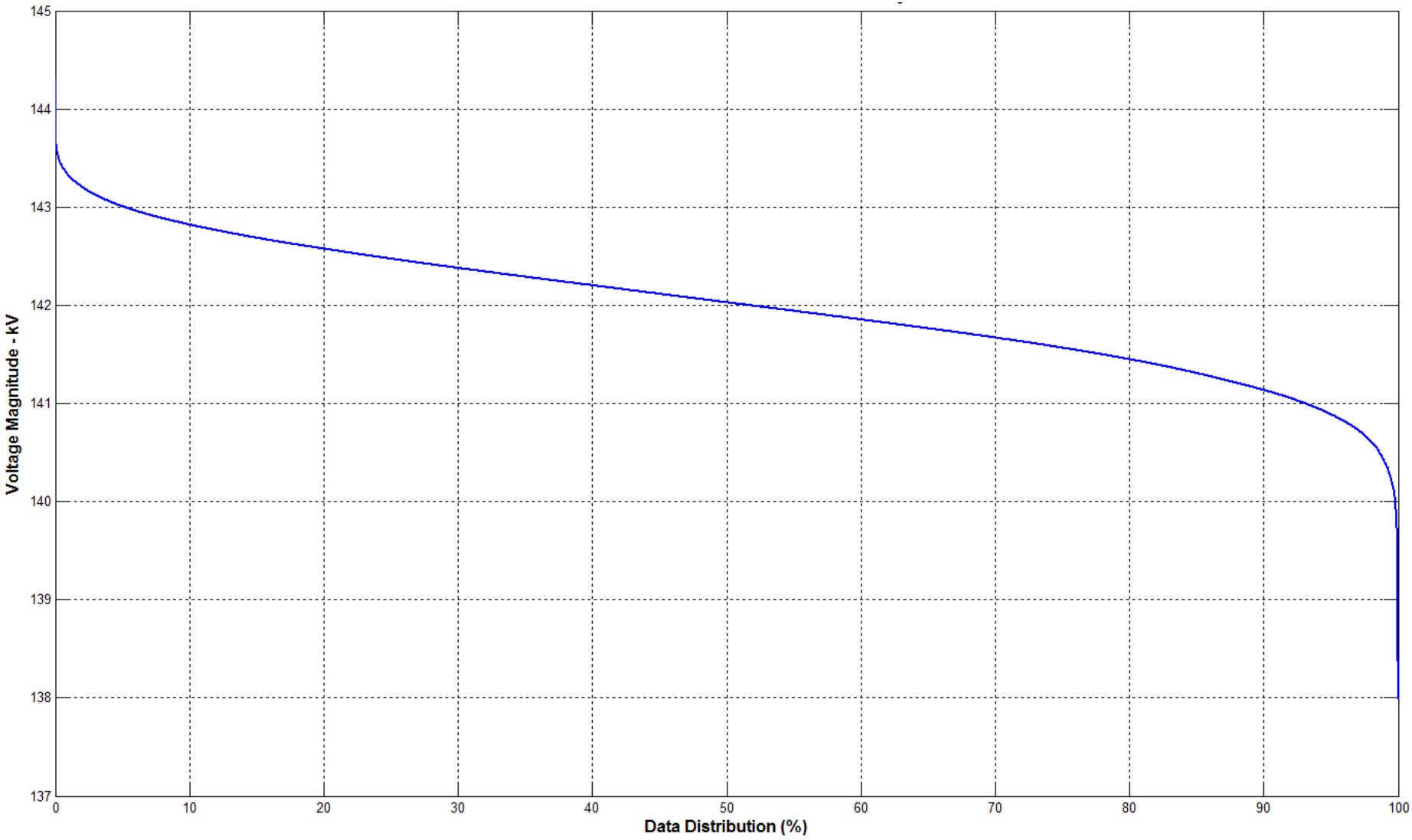
North 1 – Voltage Magnitude



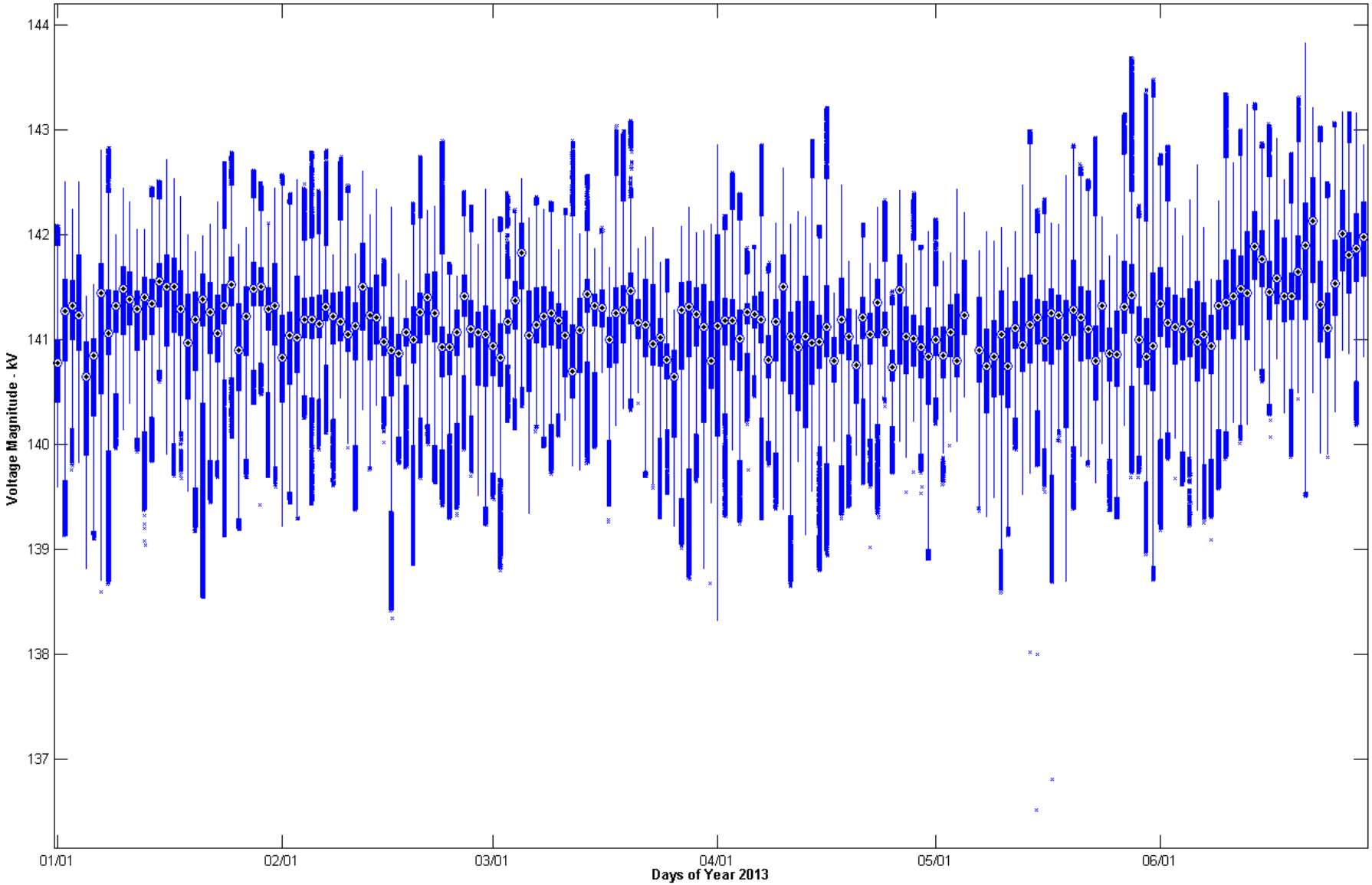
North 4 – Voltage Magnitude



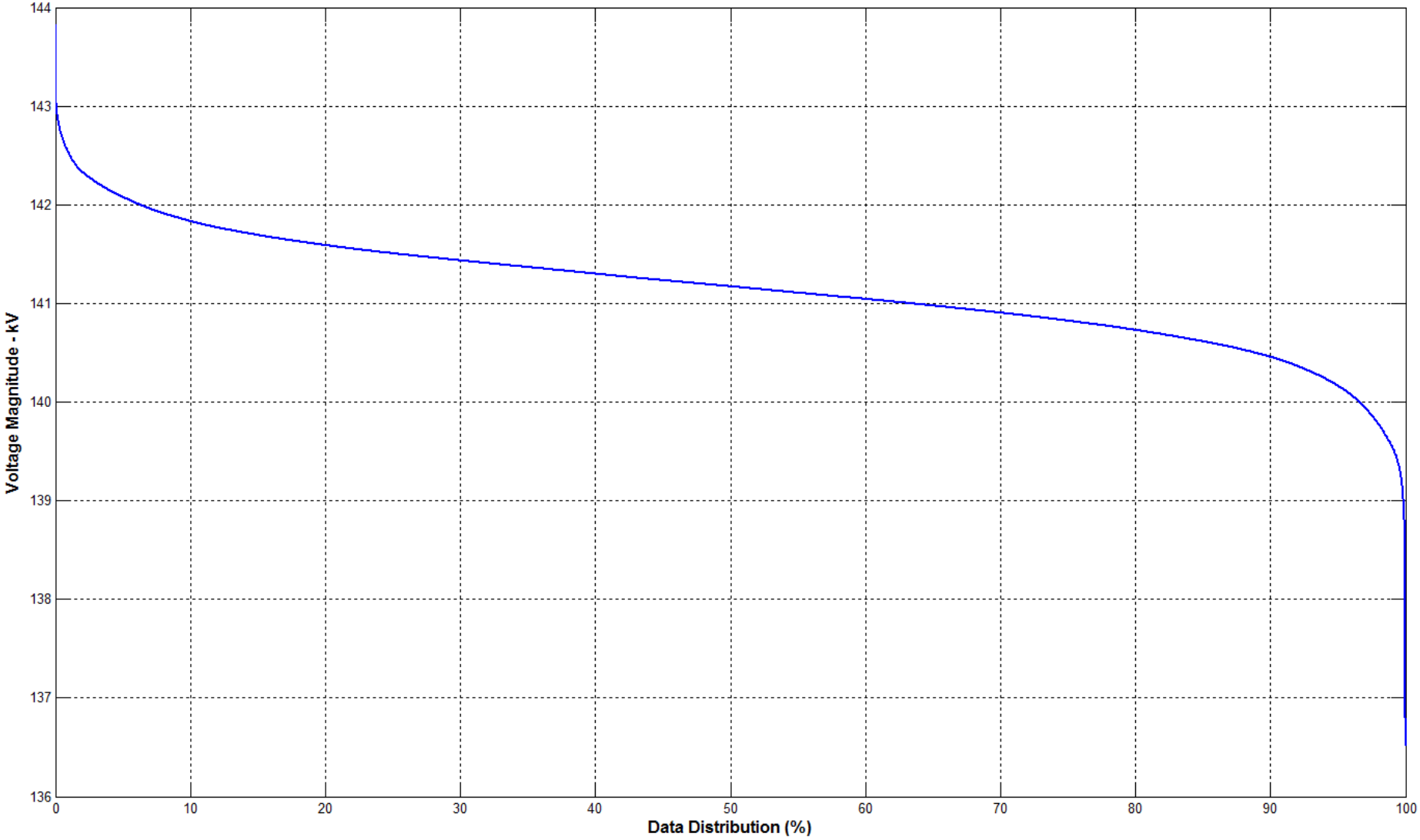
North 4 – Voltage Magnitude



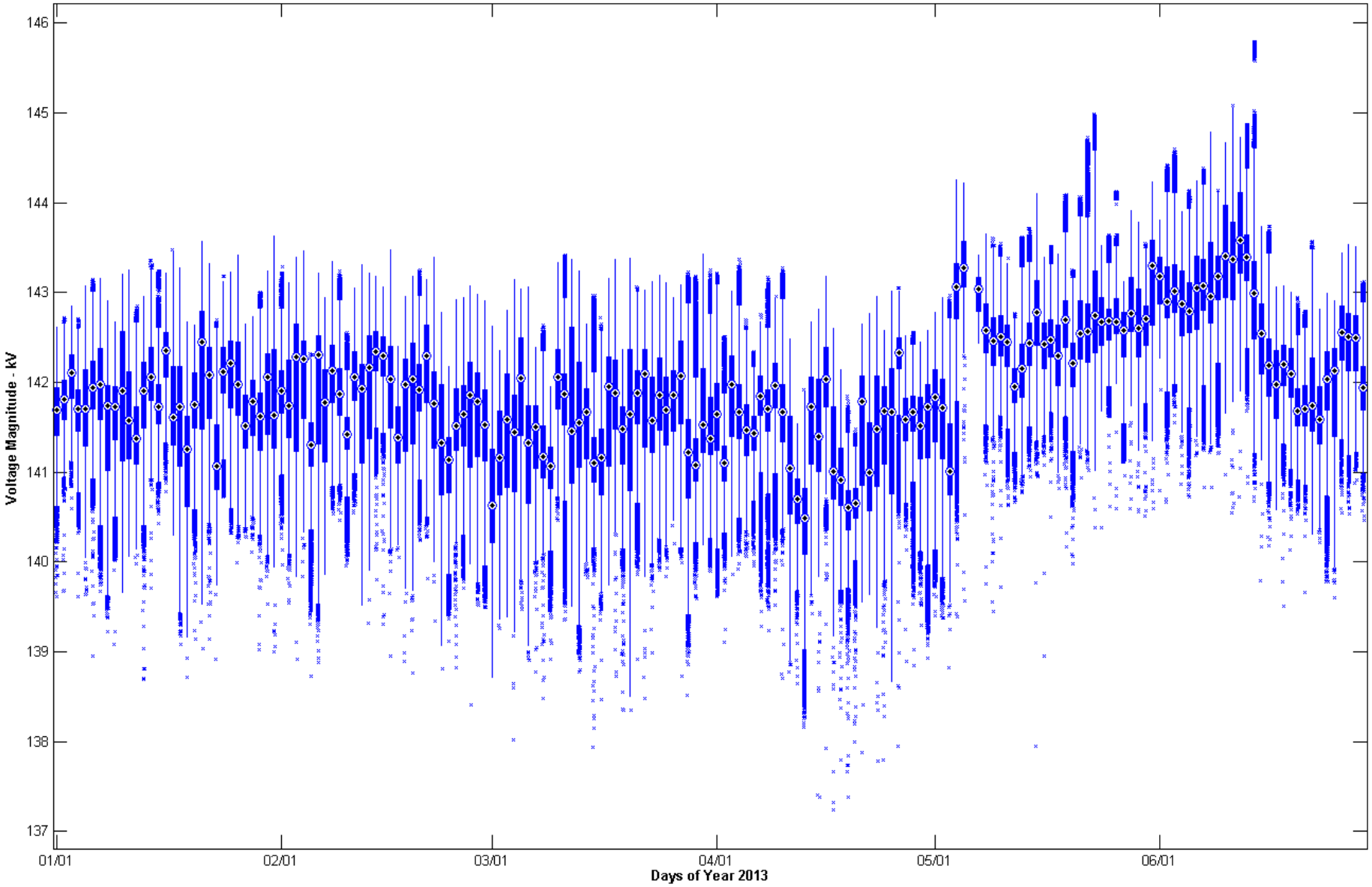
North 5 – Voltage Magnitude



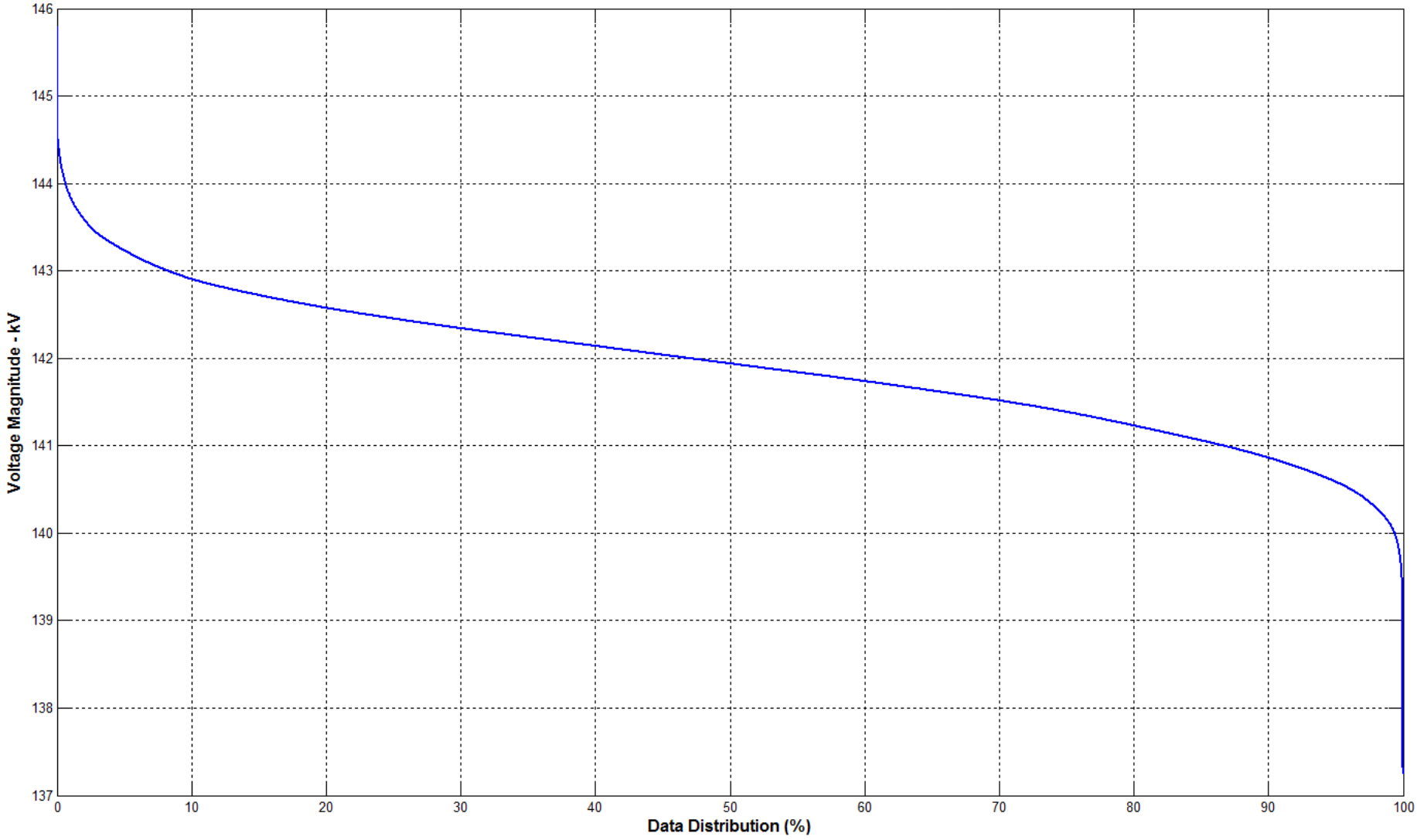
North 5 – Voltage Magnitude



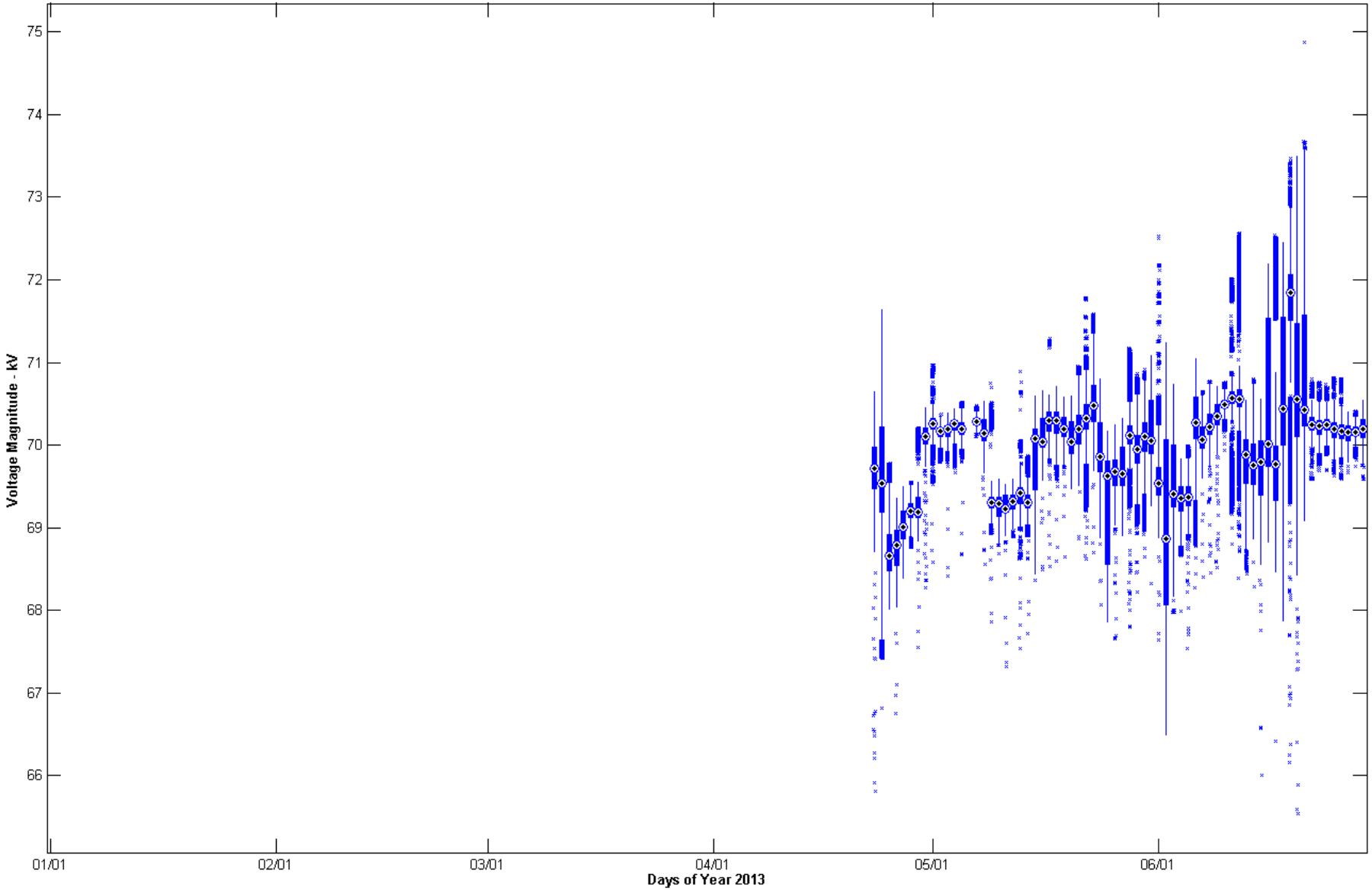
North 6 – Voltage Magnitude



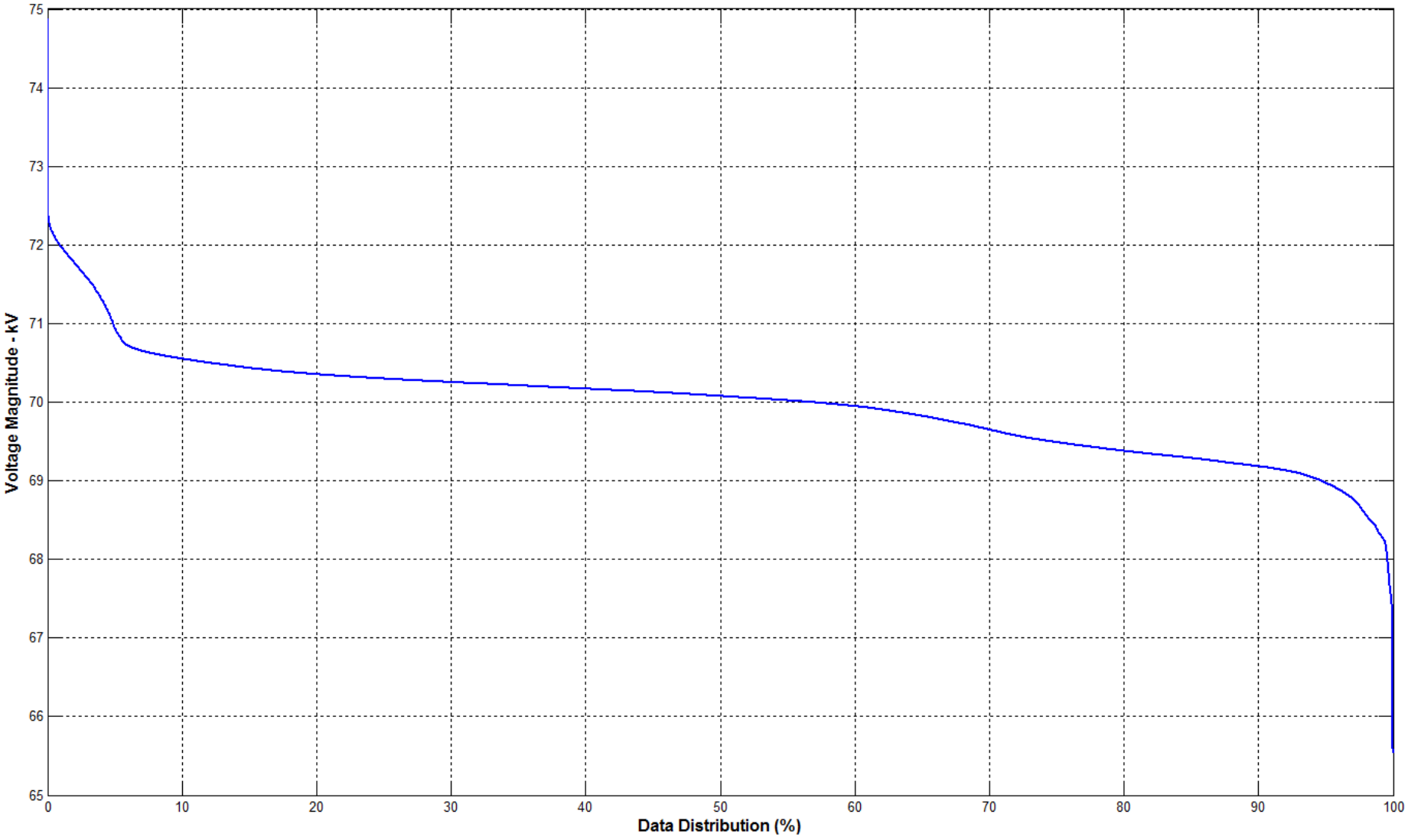
North 6 – Voltage Magnitude



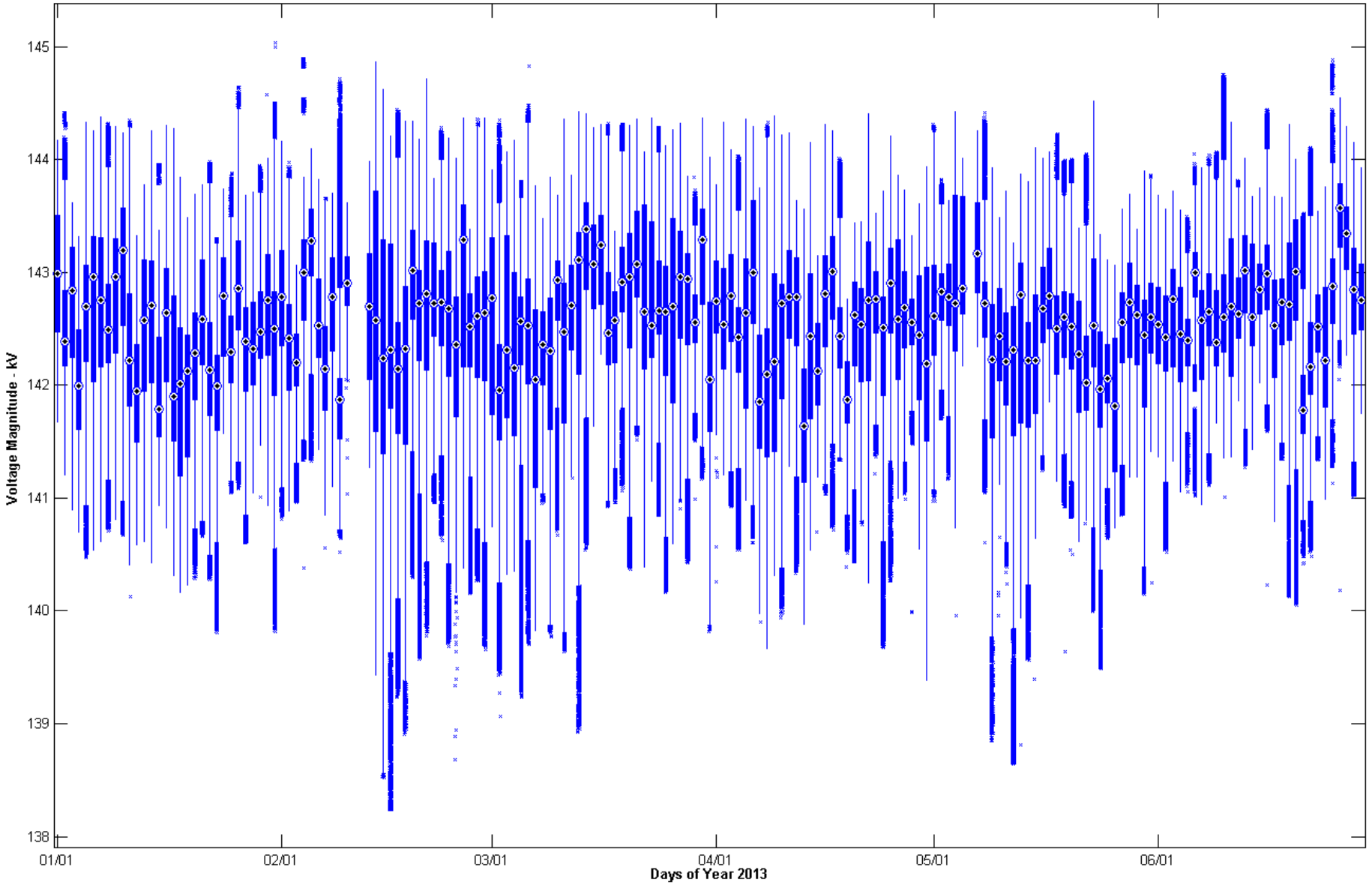
FarWest 2 – Voltage Magnitude



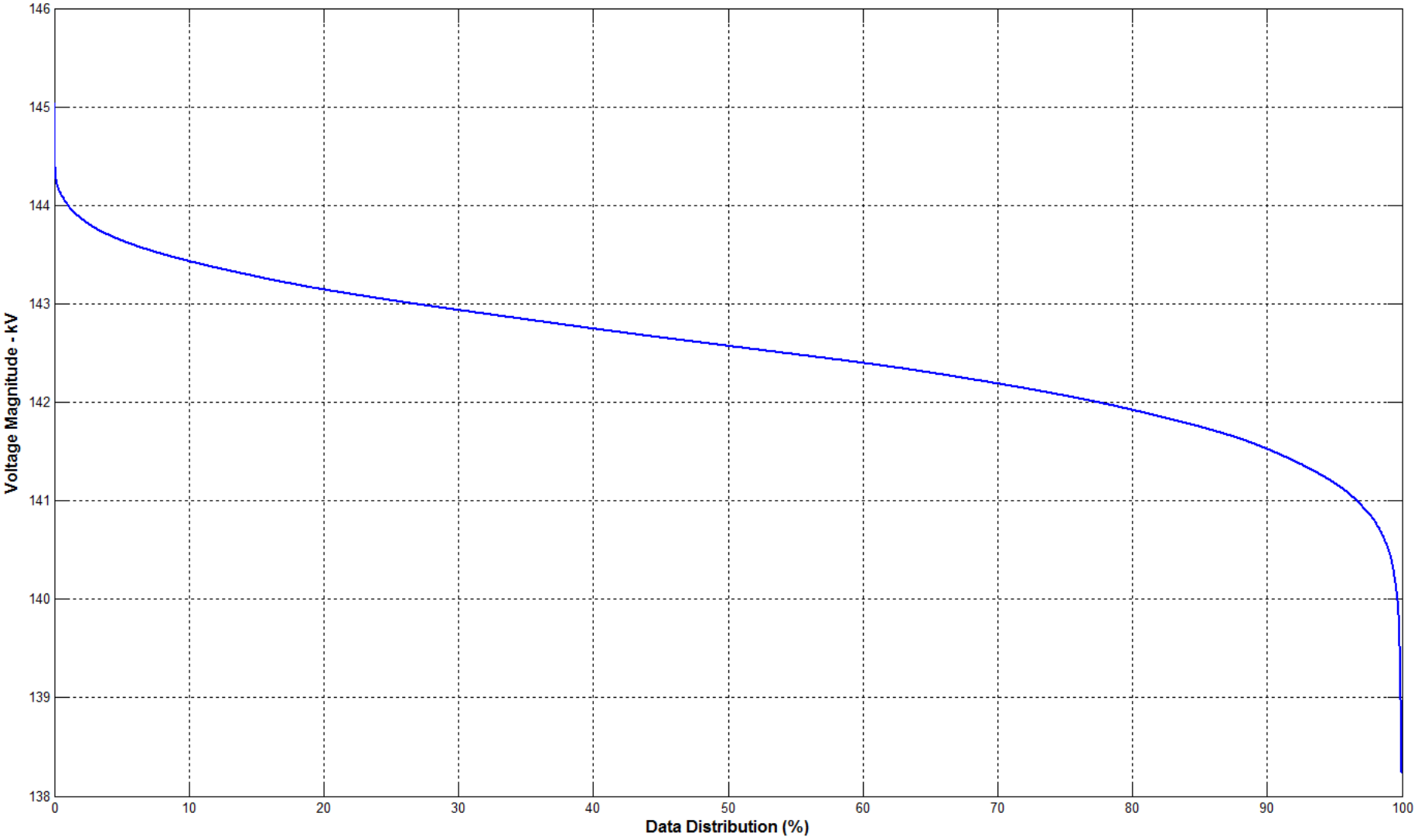
FarWest 2 – Voltage Magnitude



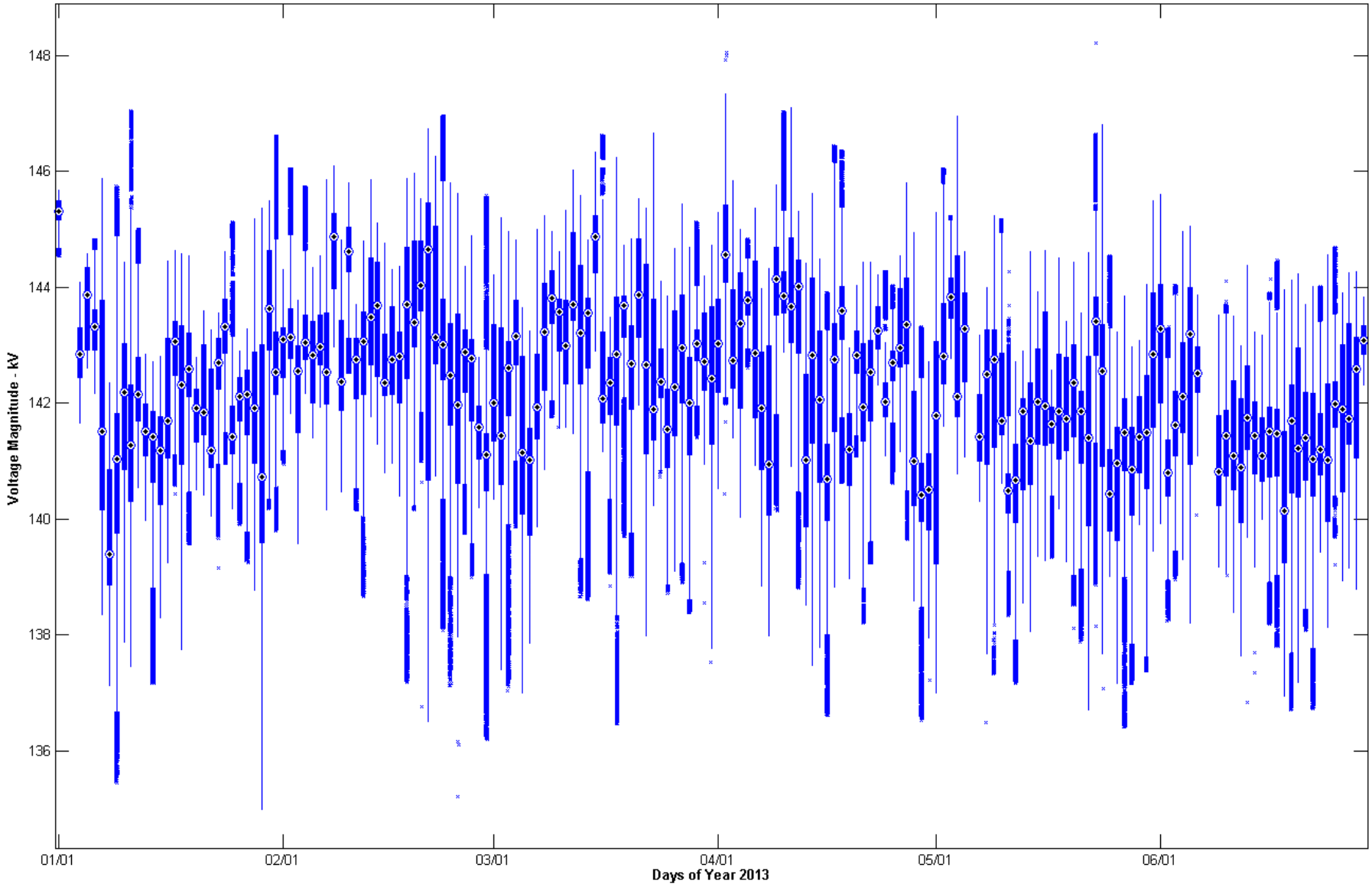
North 7 – Voltage Magnitude



North 7 – Voltage Magnitude



West 4 – Voltage Magnitude



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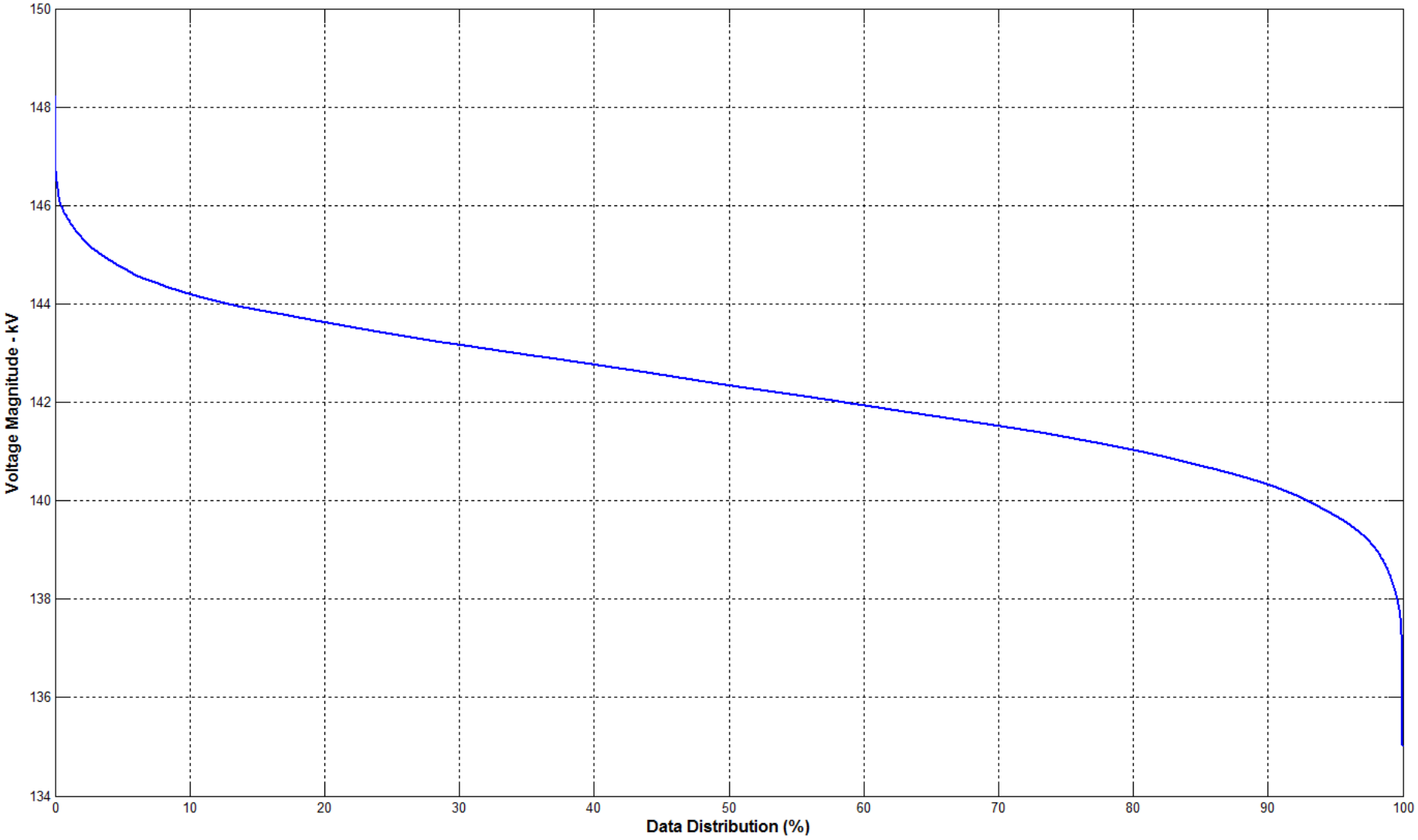
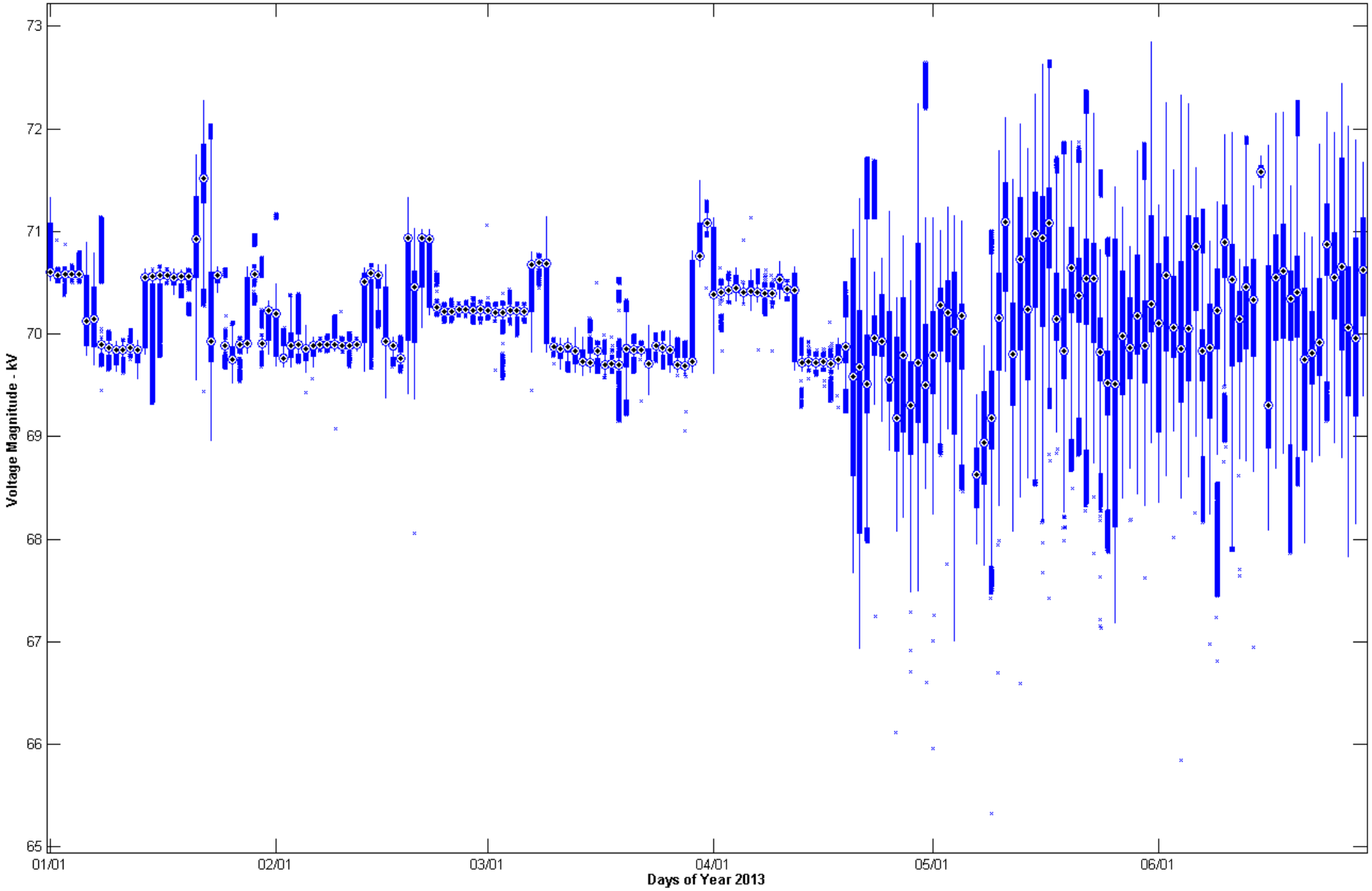
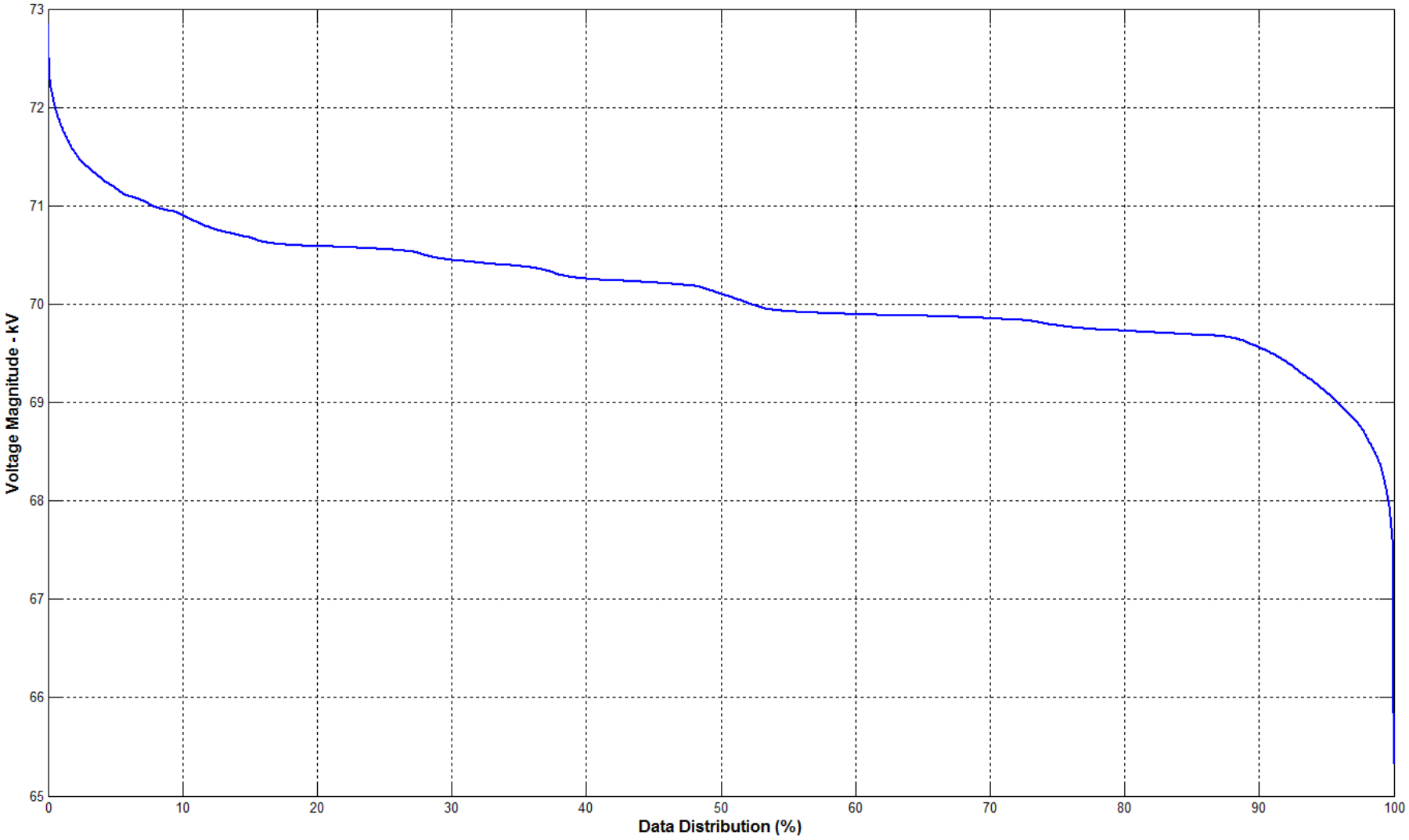


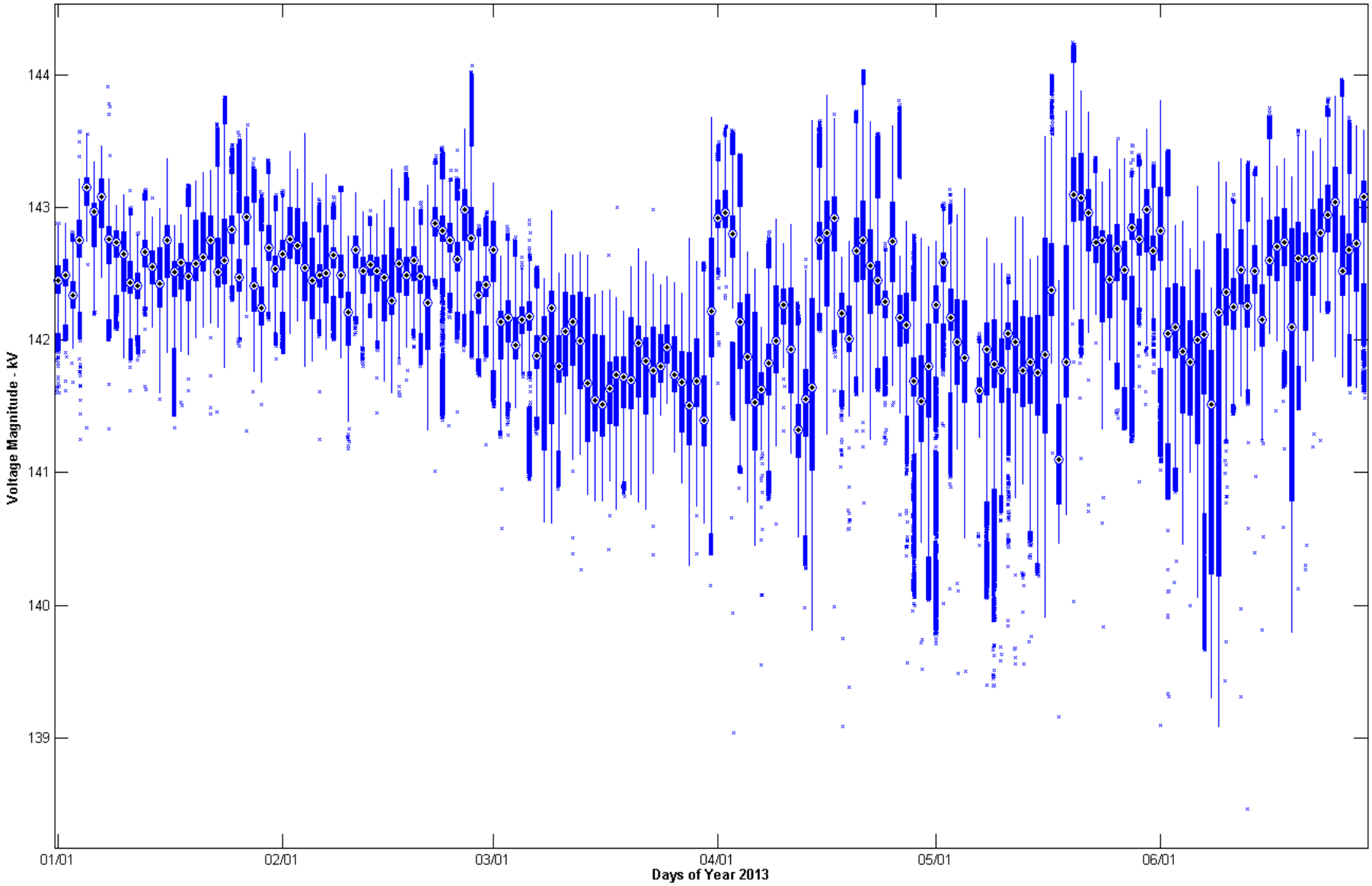
Coast 2 – Voltage Magnitude



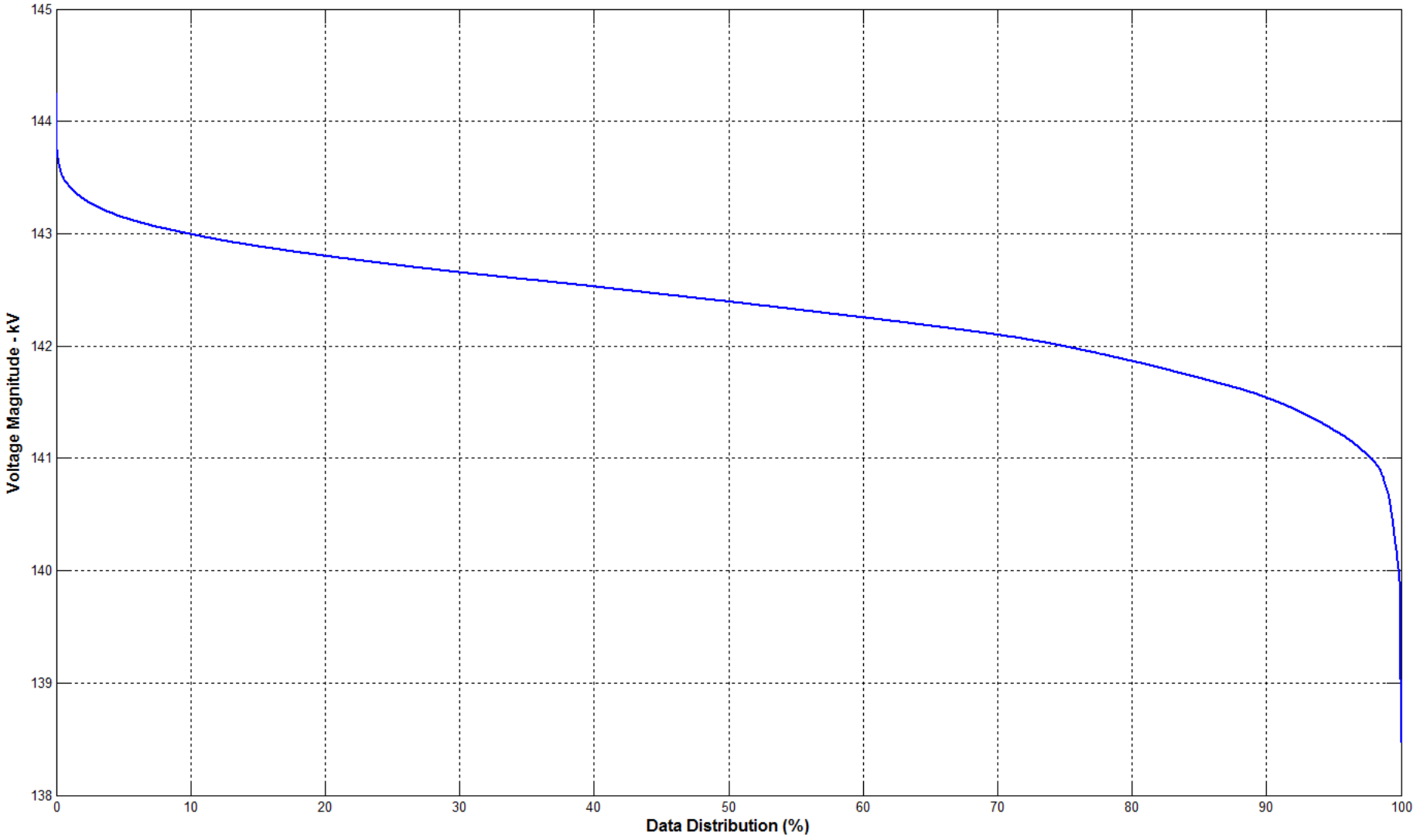
Coast 2 – Voltage Magnitude



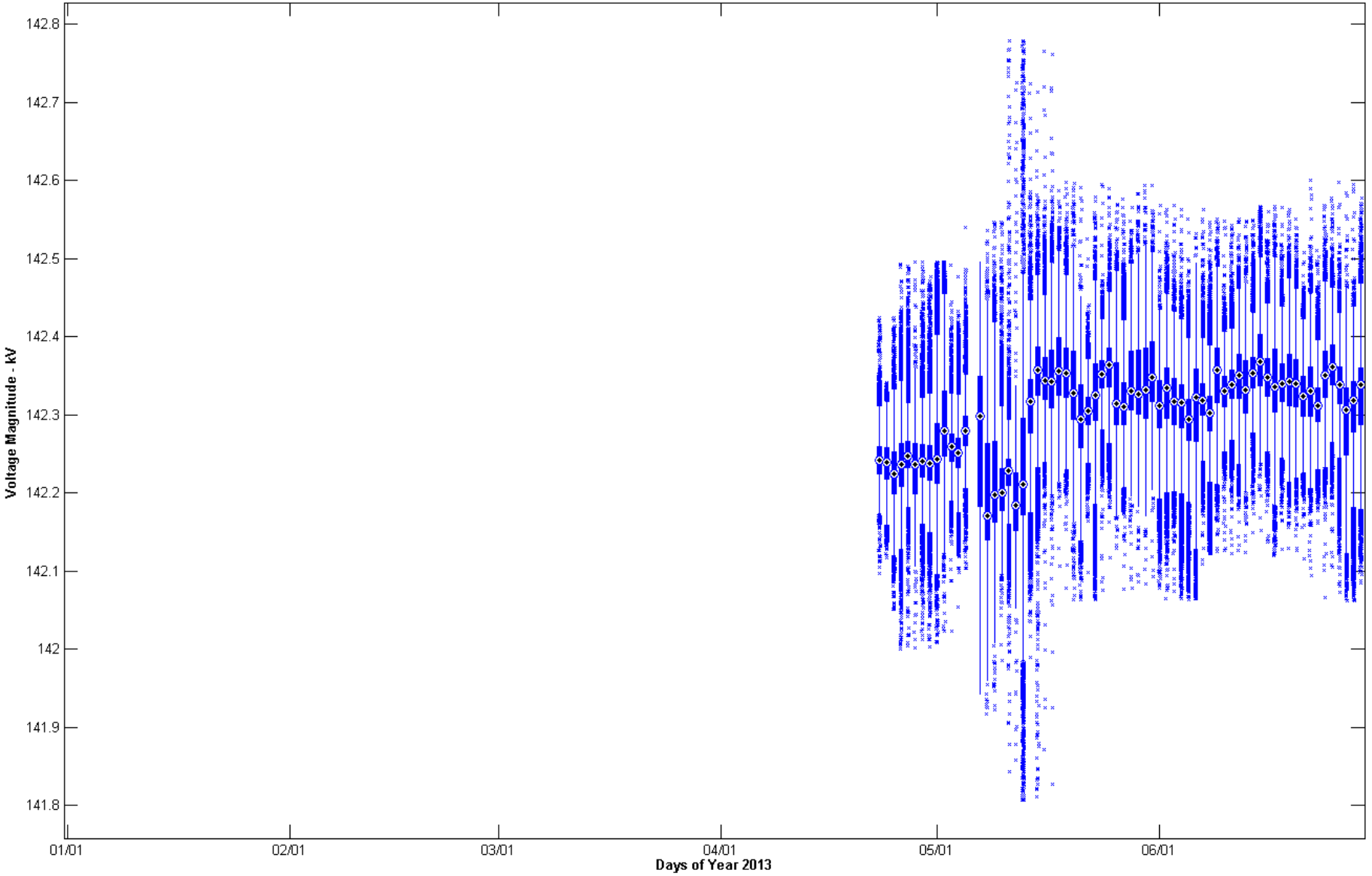
Coast 1 – Voltage Magnitude



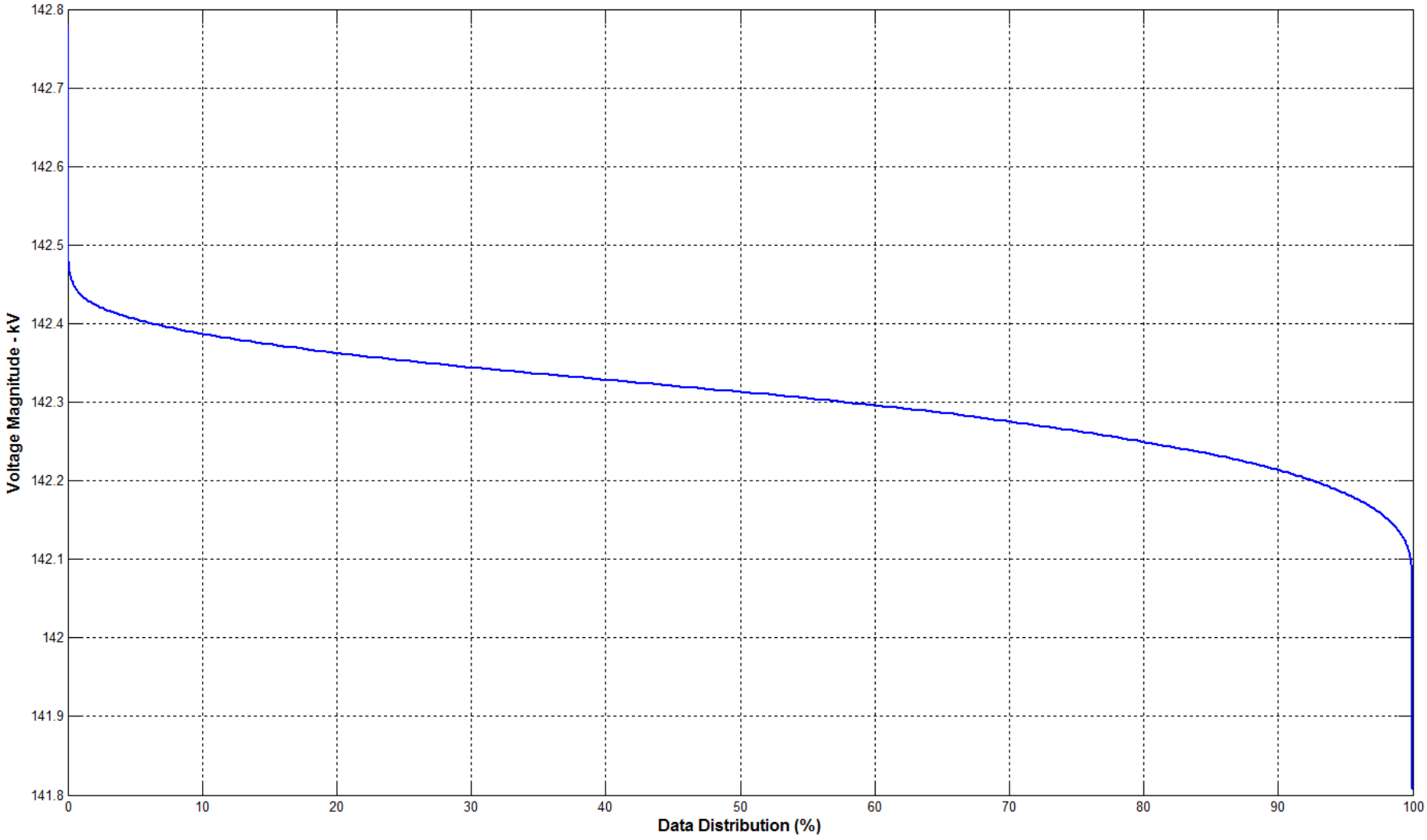
Coast 1 – Voltage Magnitude



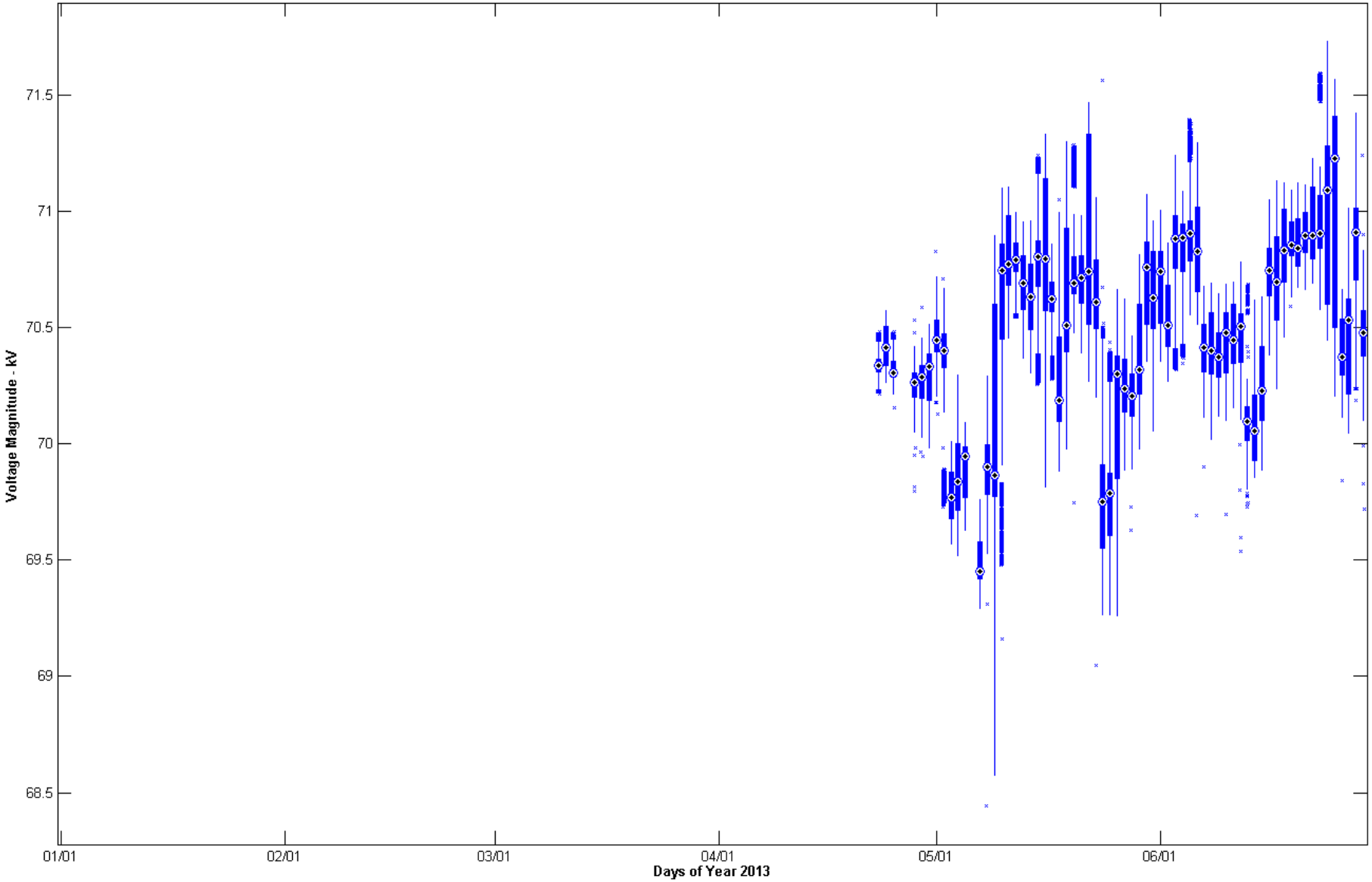
South 3 – Voltage Magnitude



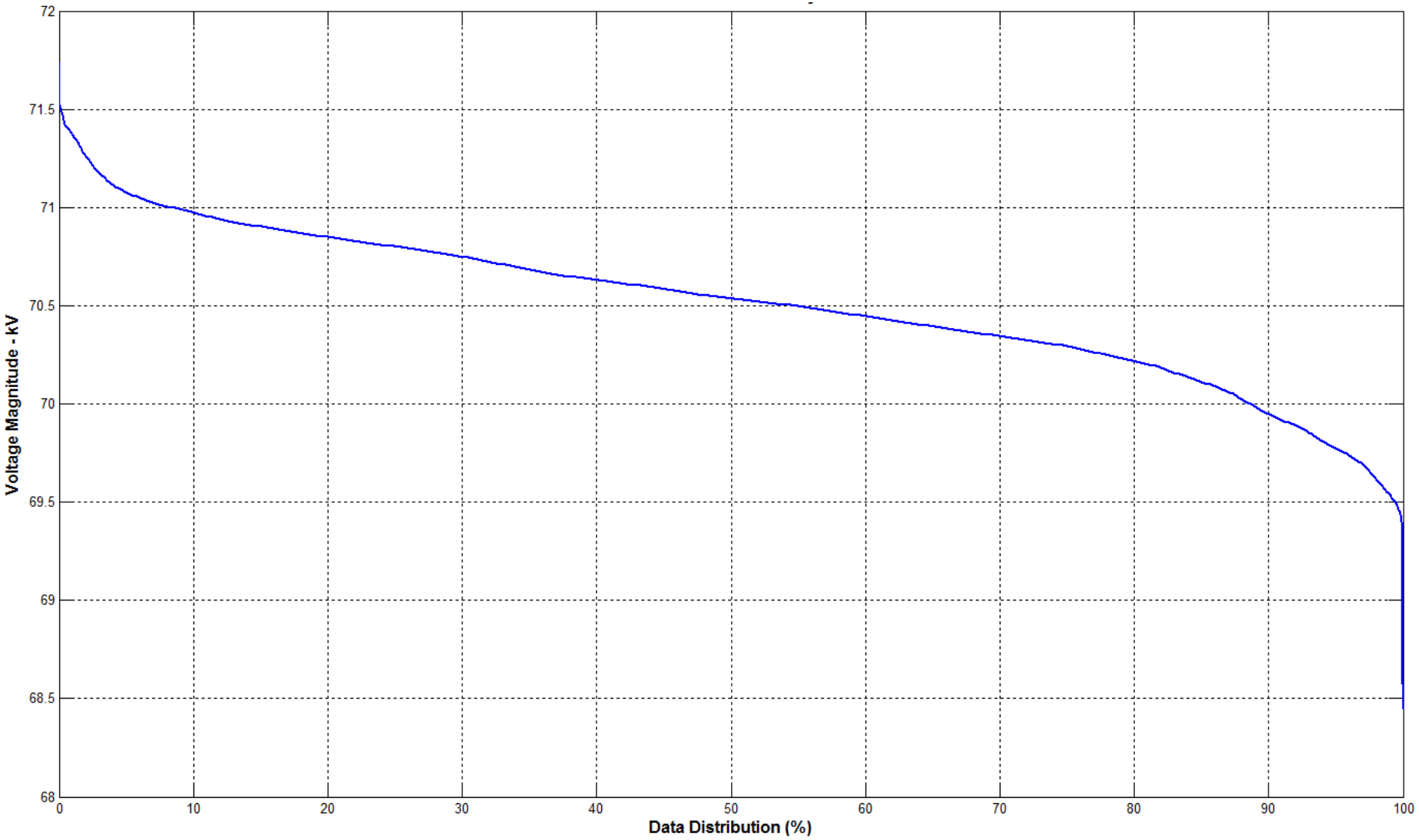
South 3 – Voltage Magnitude



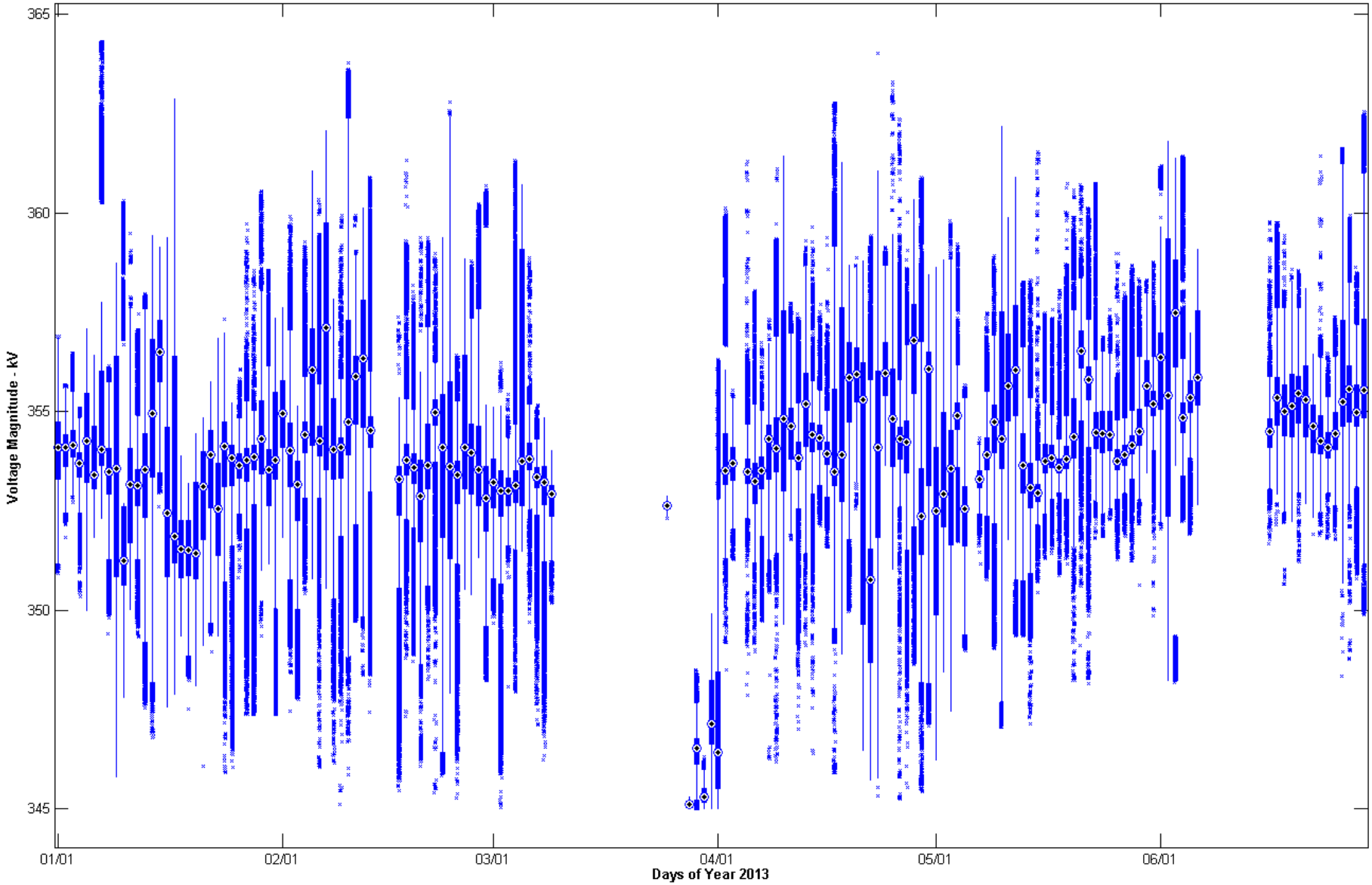
South 5 – Voltage Magnitude



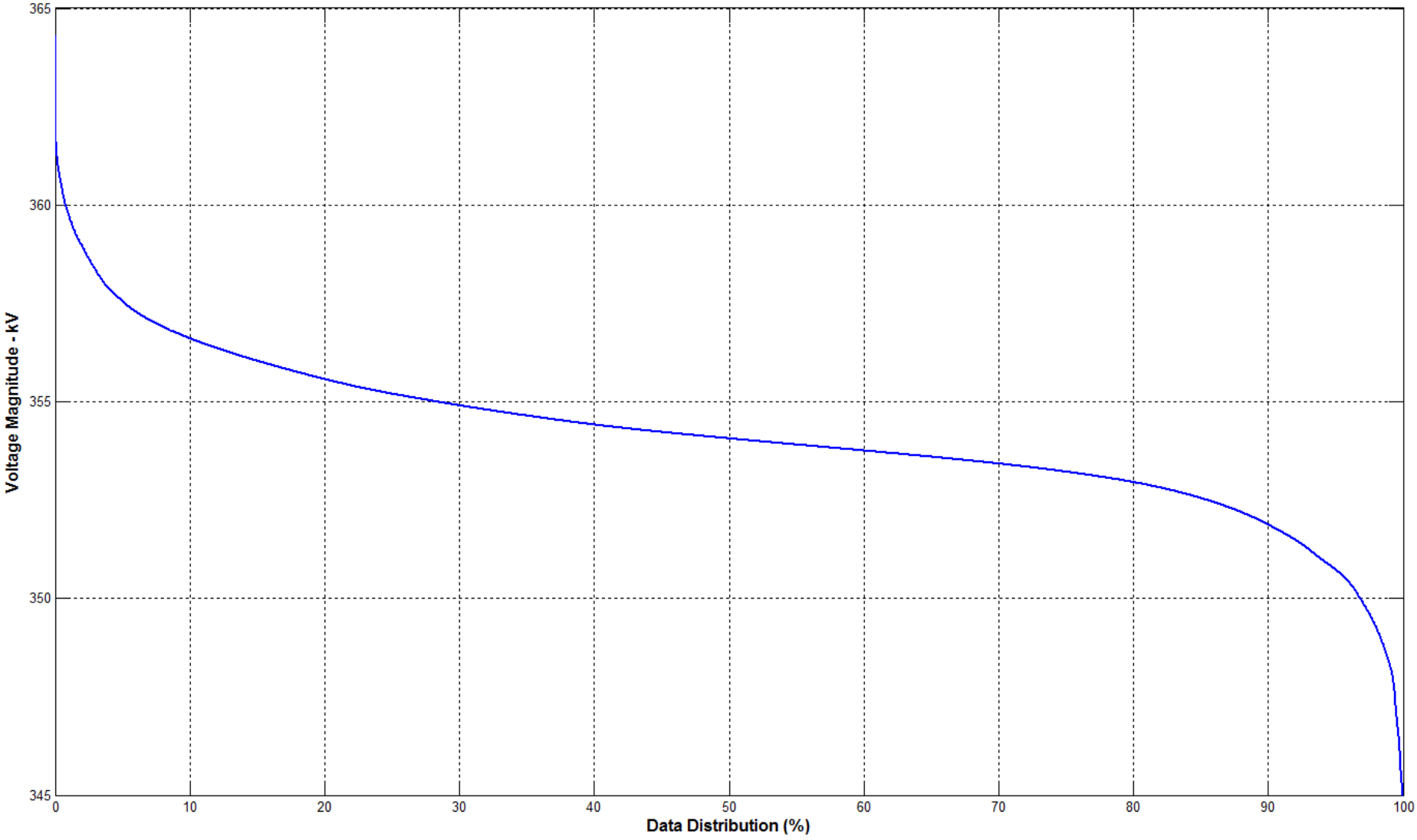
South 5 – Voltage Magnitude



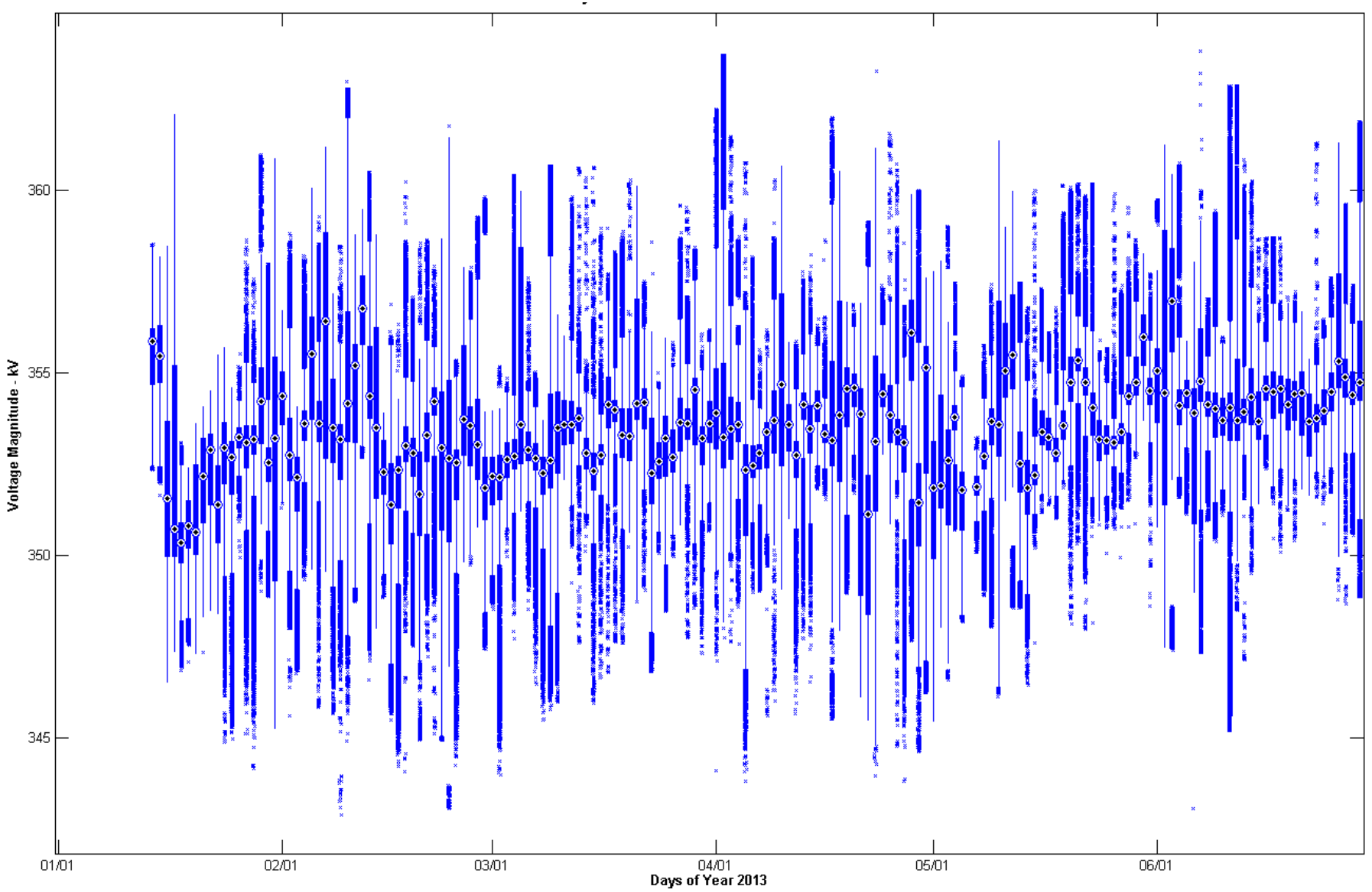
Coast 4 – Voltage Magnitude



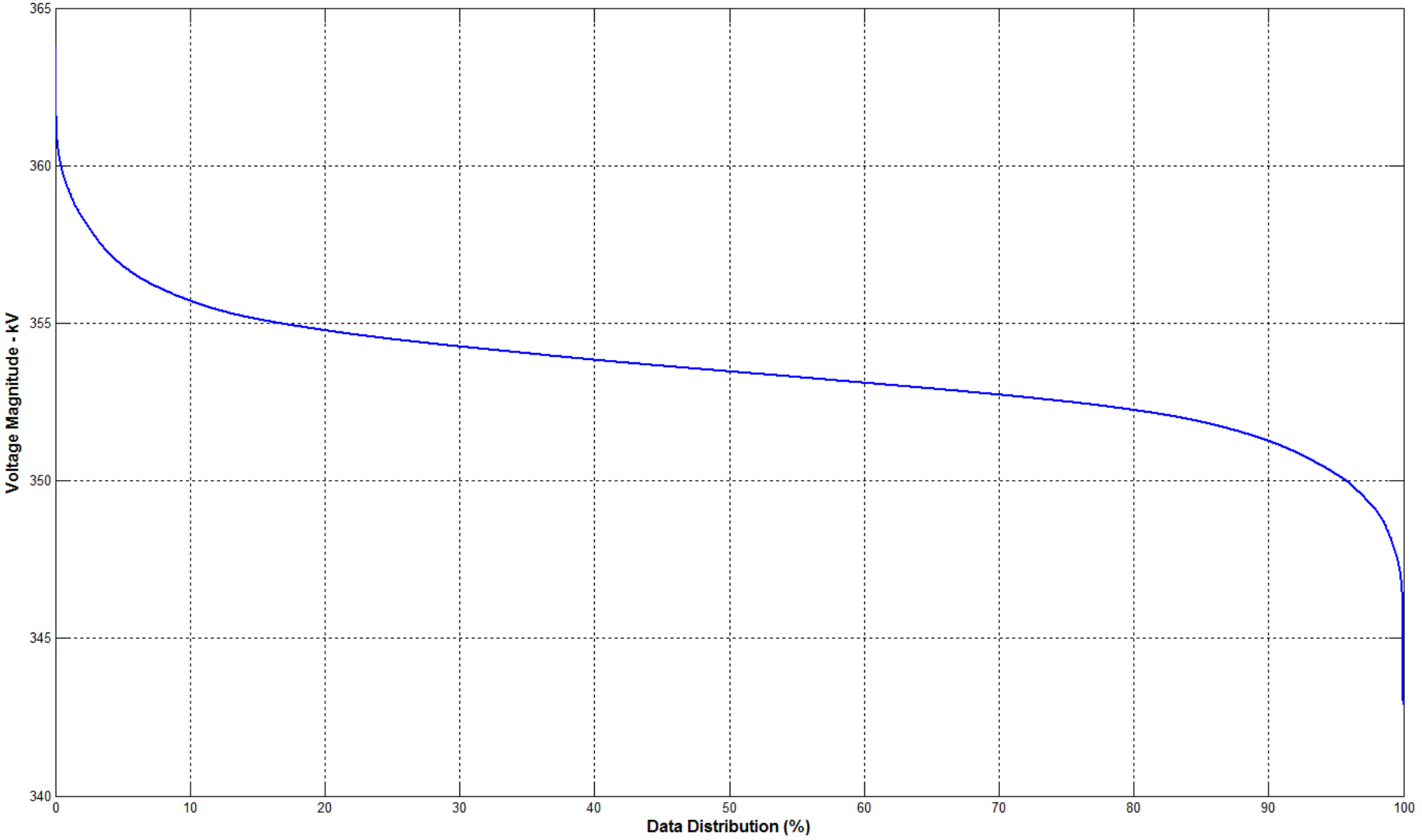
Coast 4 – Voltage Magnitude



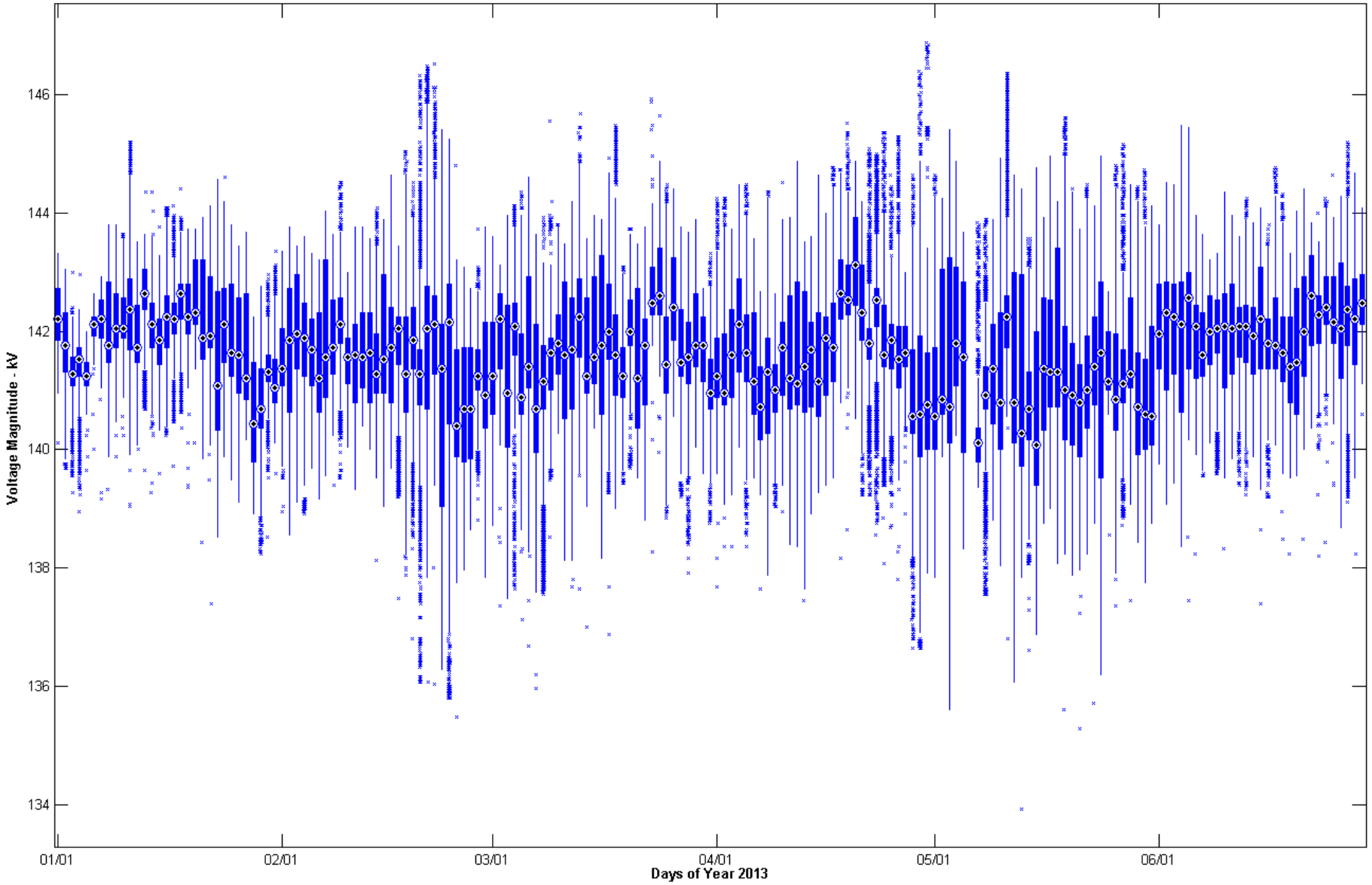
Coast 3 – Voltage Magnitude



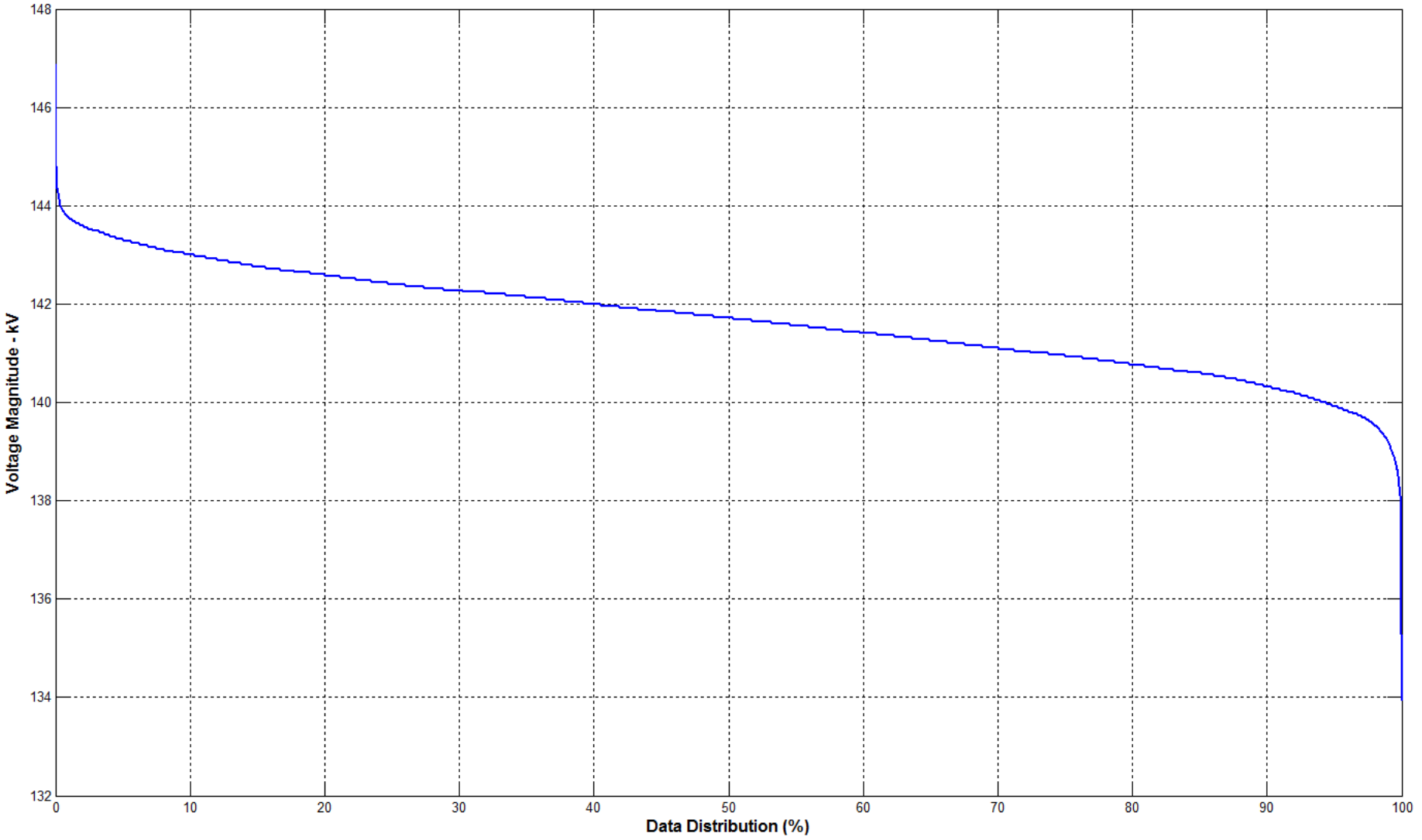
Coast 3 – Voltage Magnitude



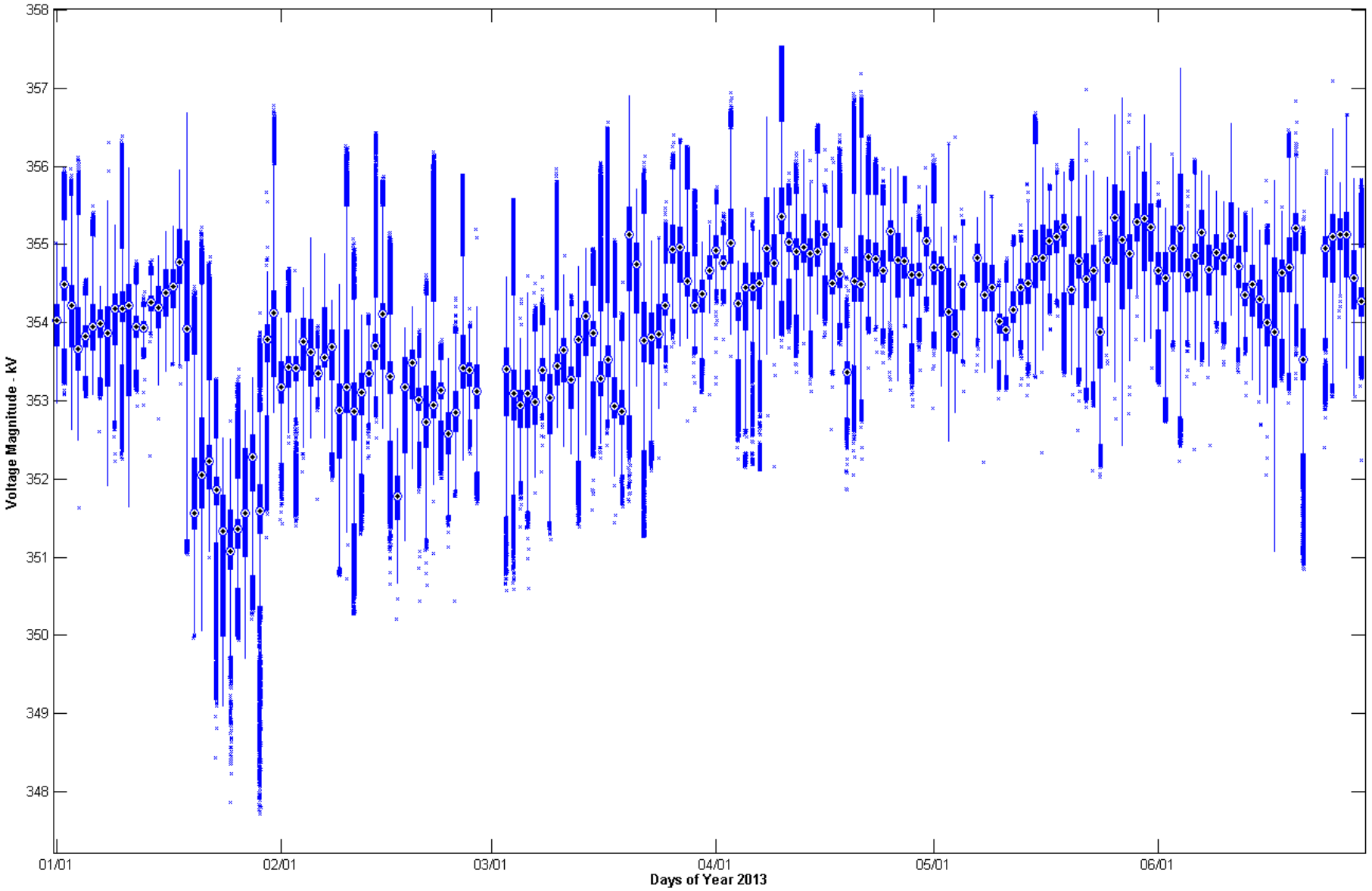
South 13 – Voltage Magnitude



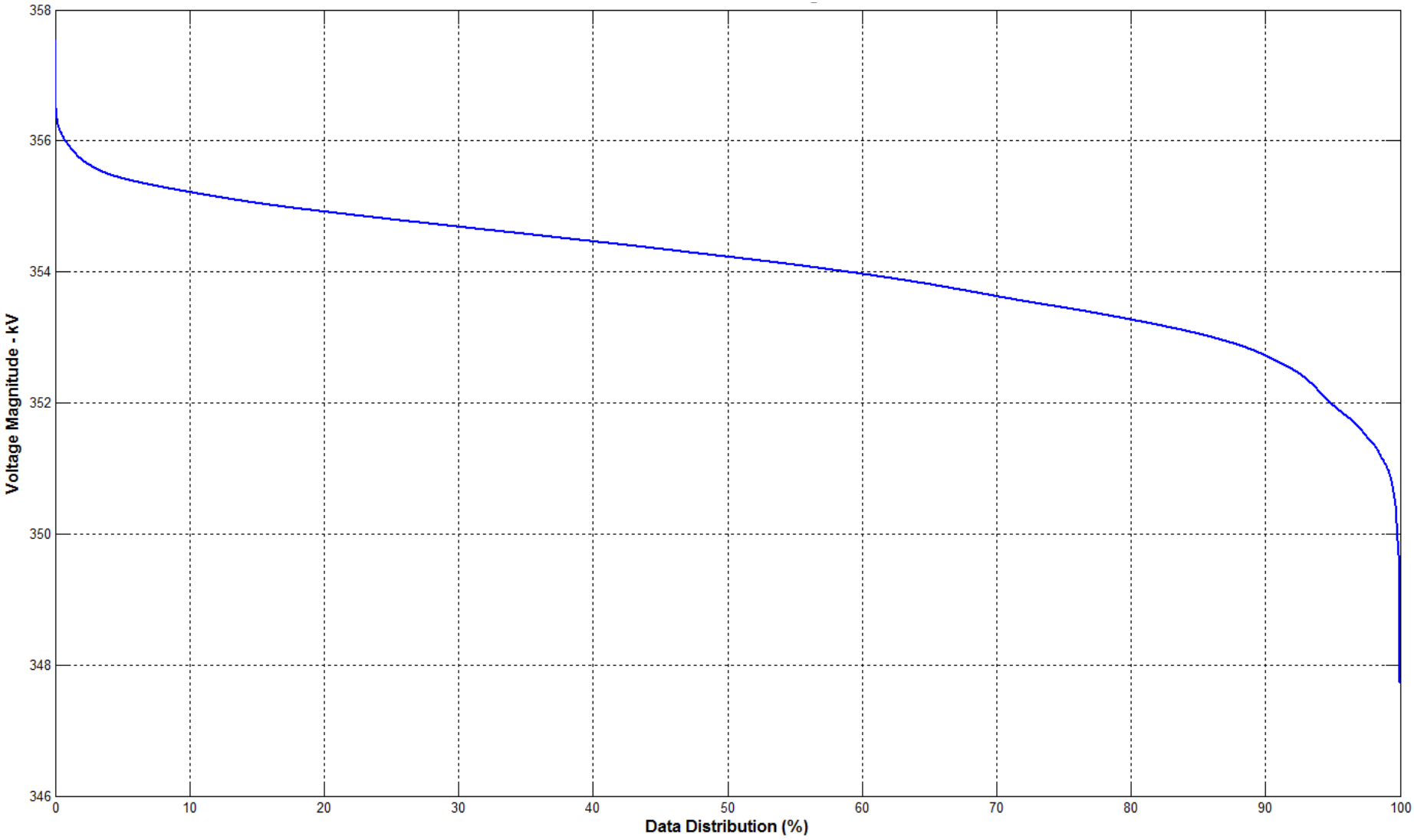
South 13 – Voltage Magnitude



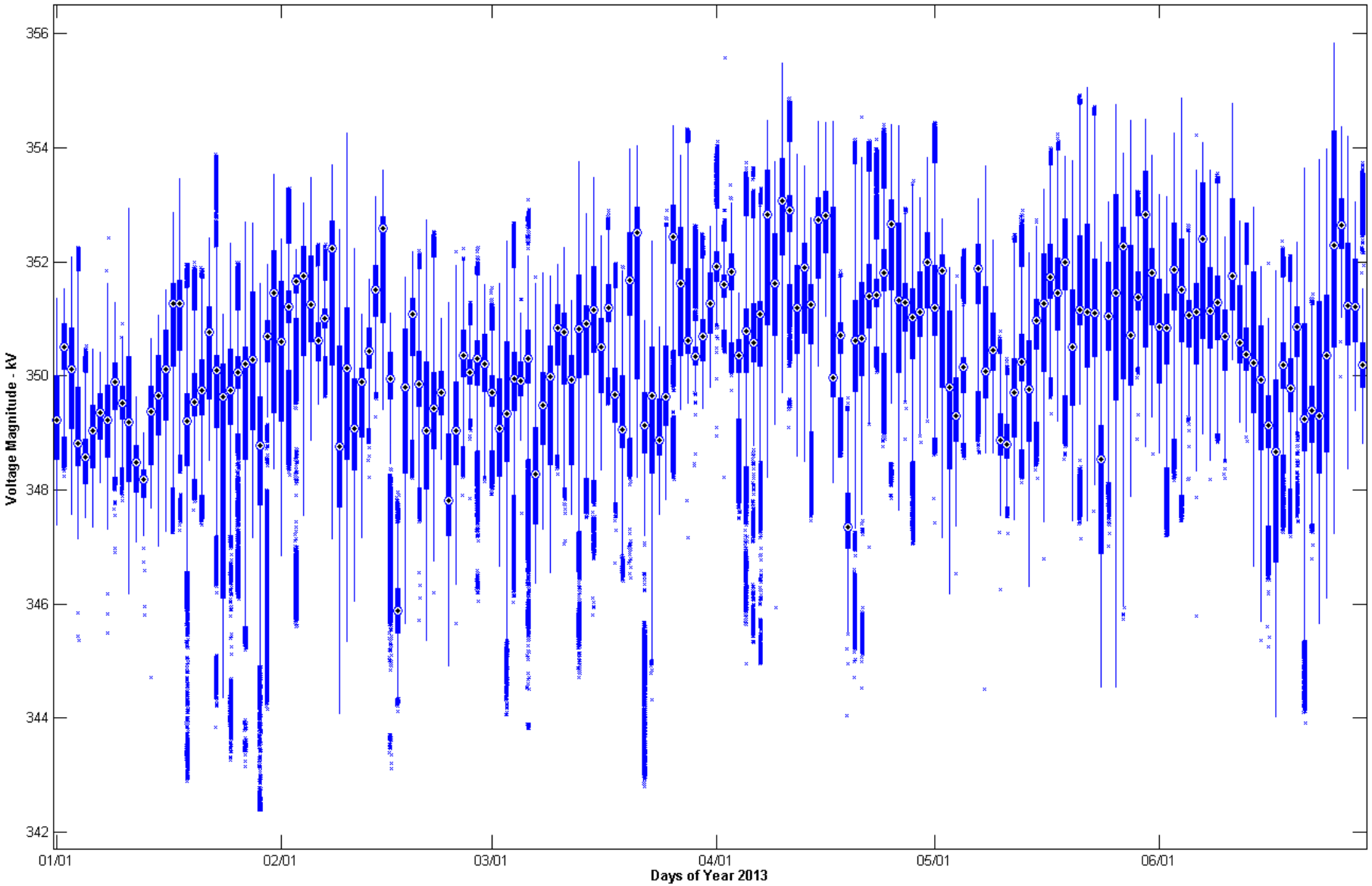
FarWest 4 – Voltage Magnitude



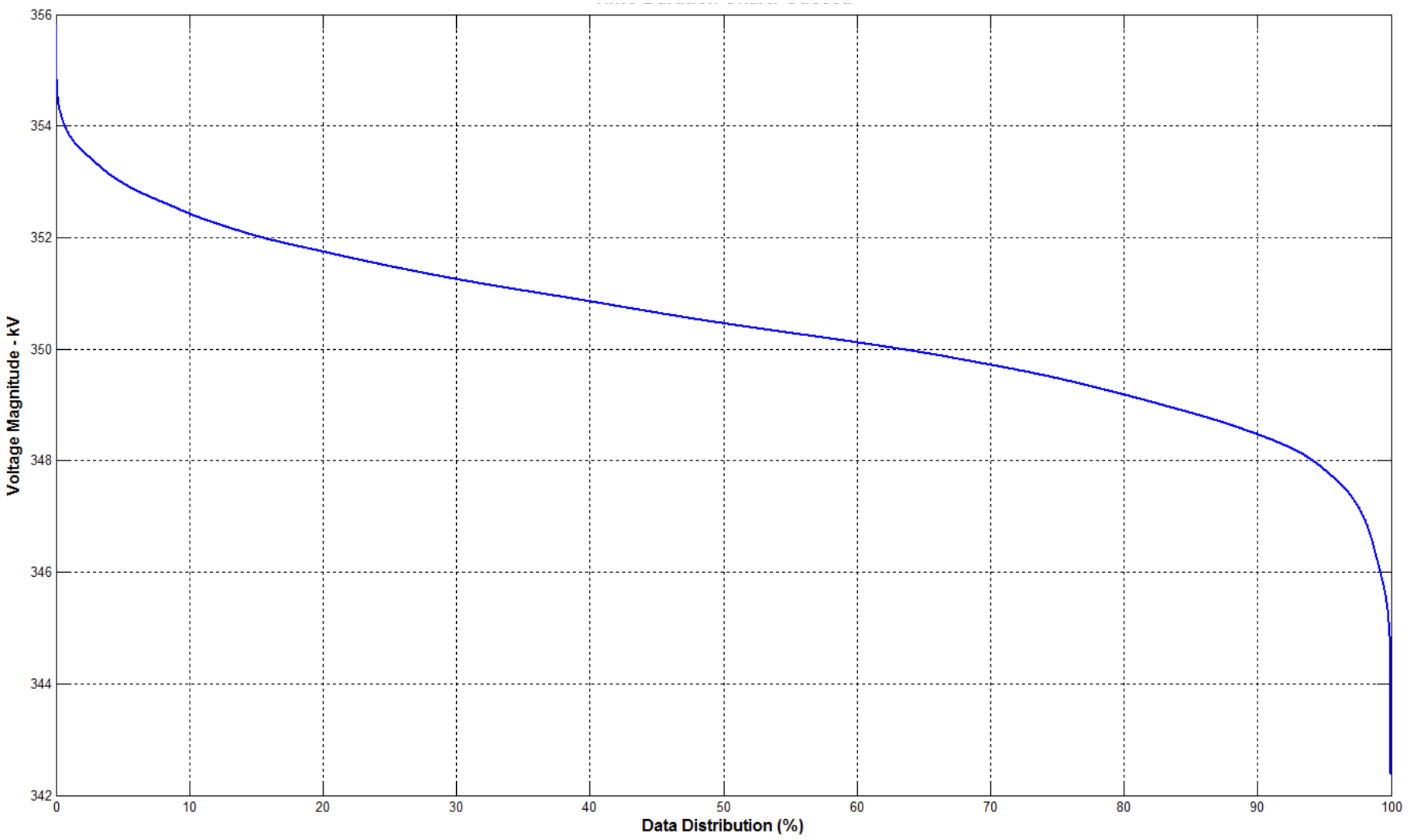
FarWest 4 – Voltage Magnitude



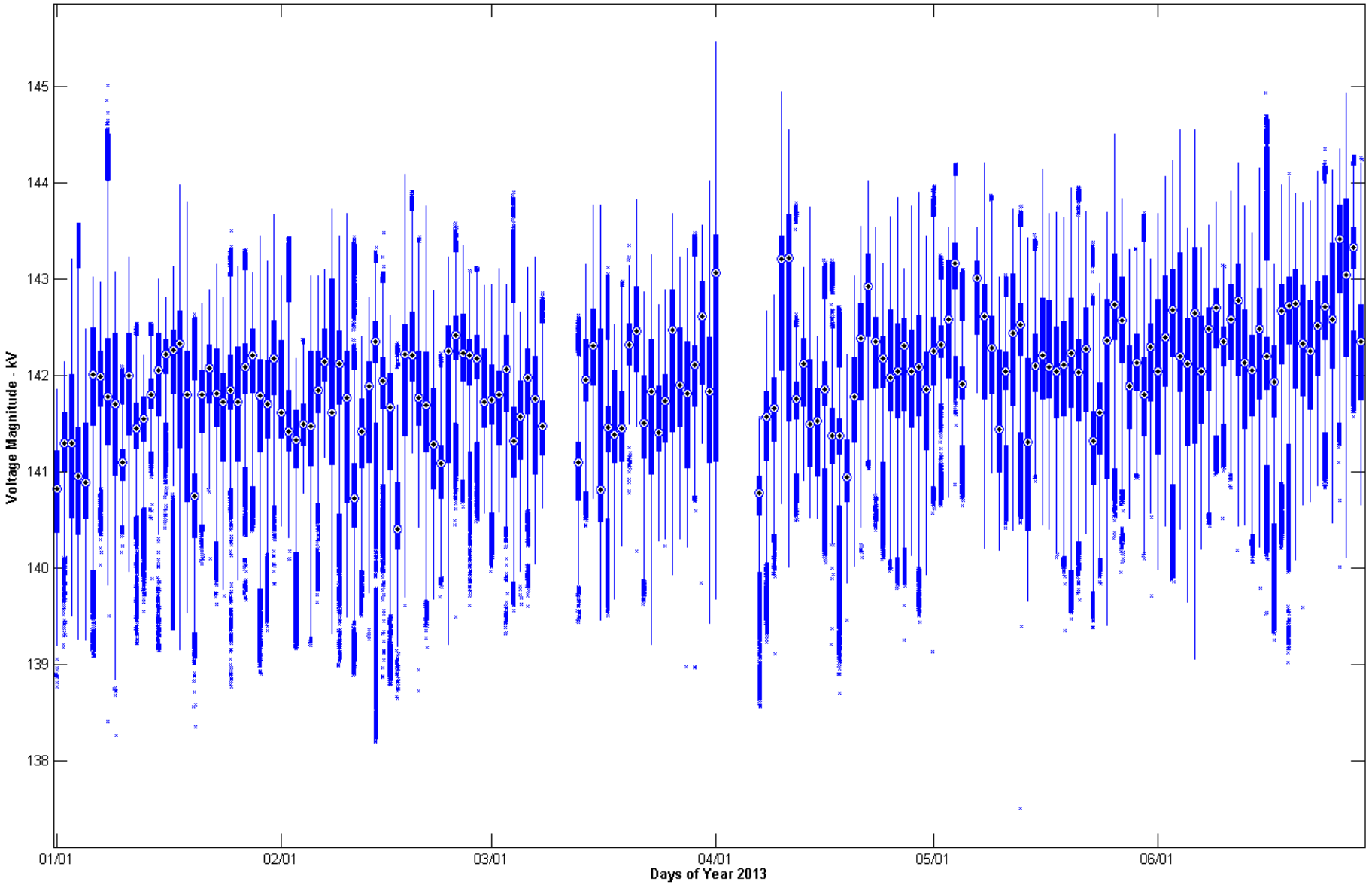
FarWest 7 – Voltage Magnitude



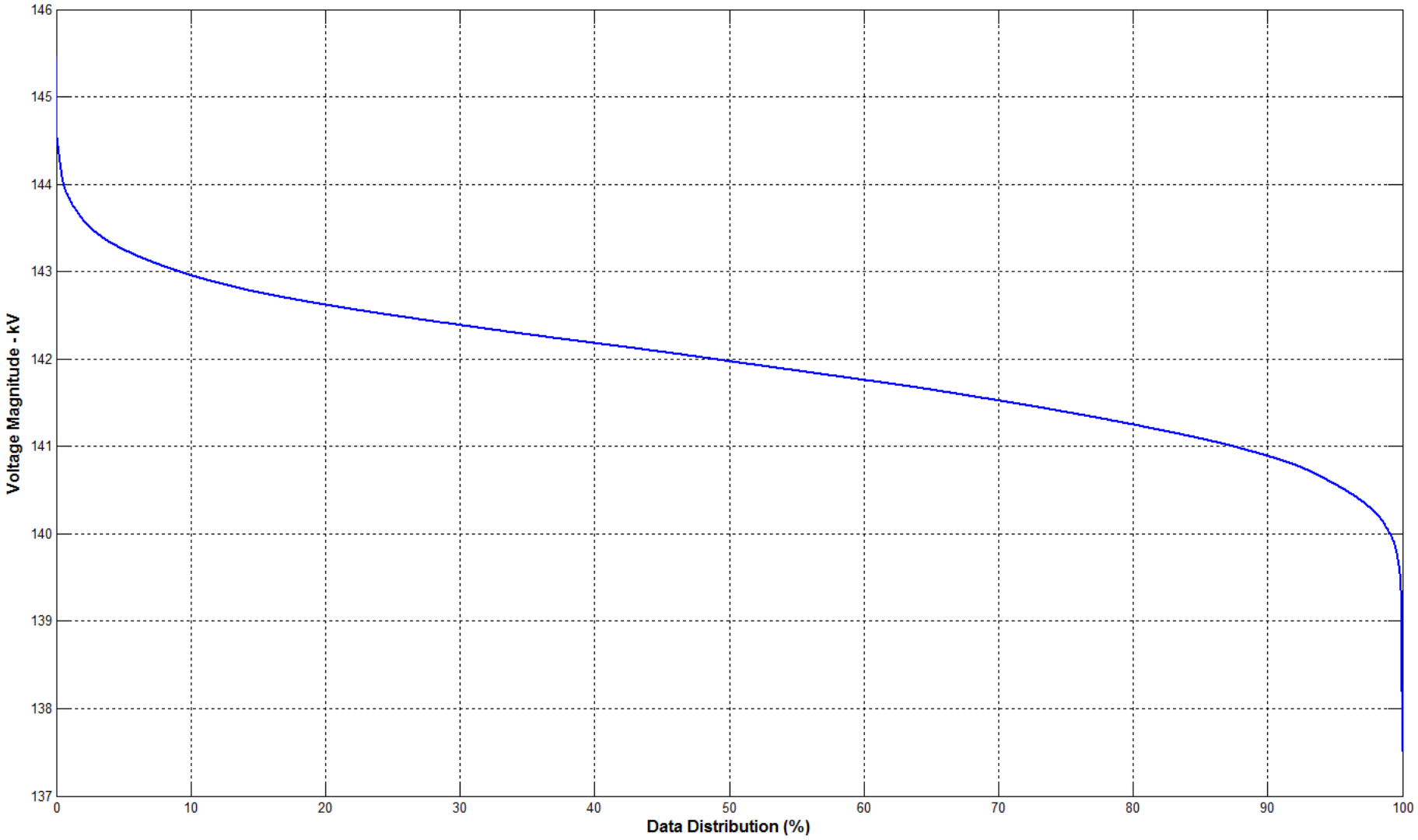
FarWest 7 – Voltage Magnitude



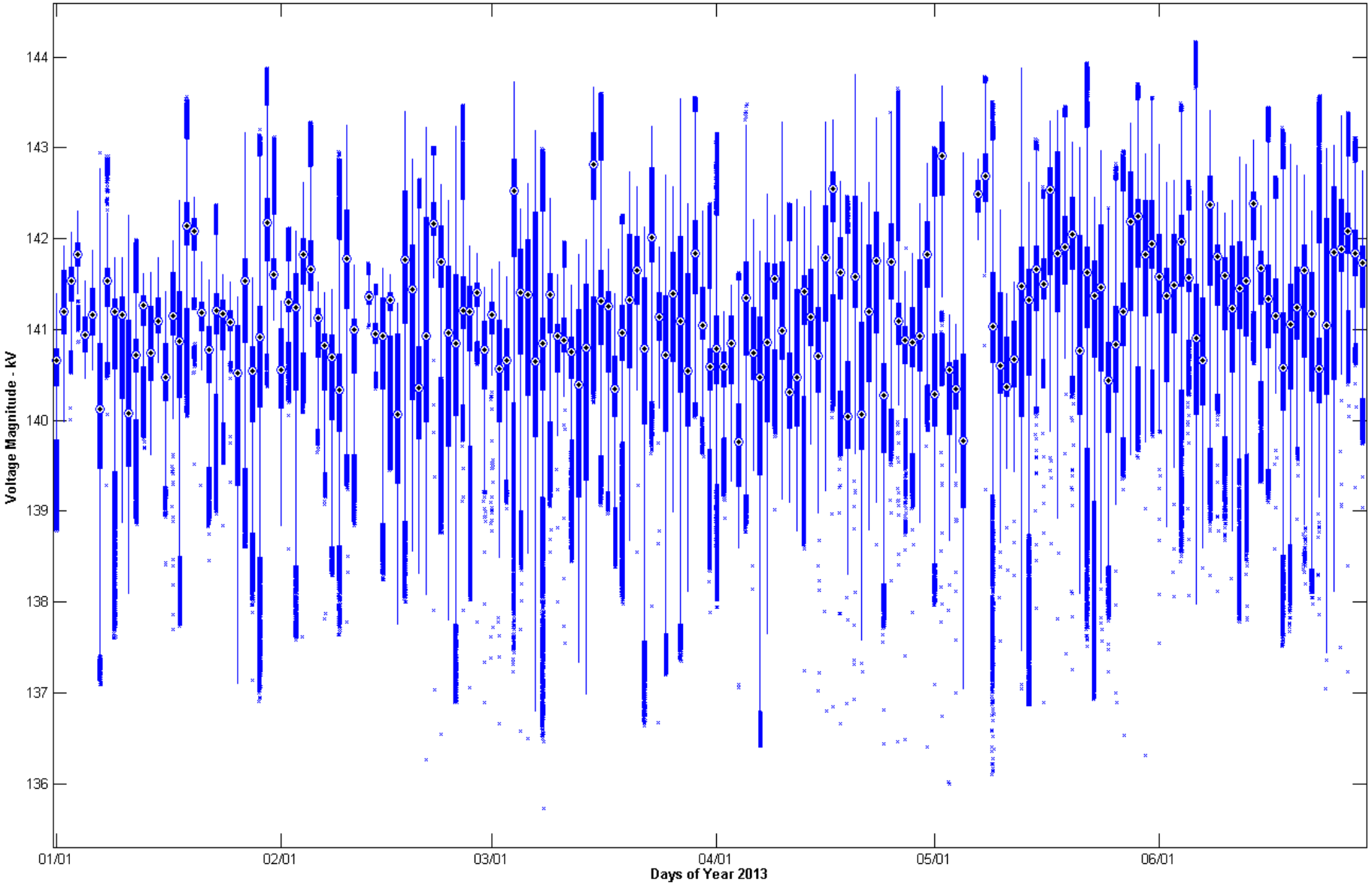
FarWest 8 – Voltage Magnitude



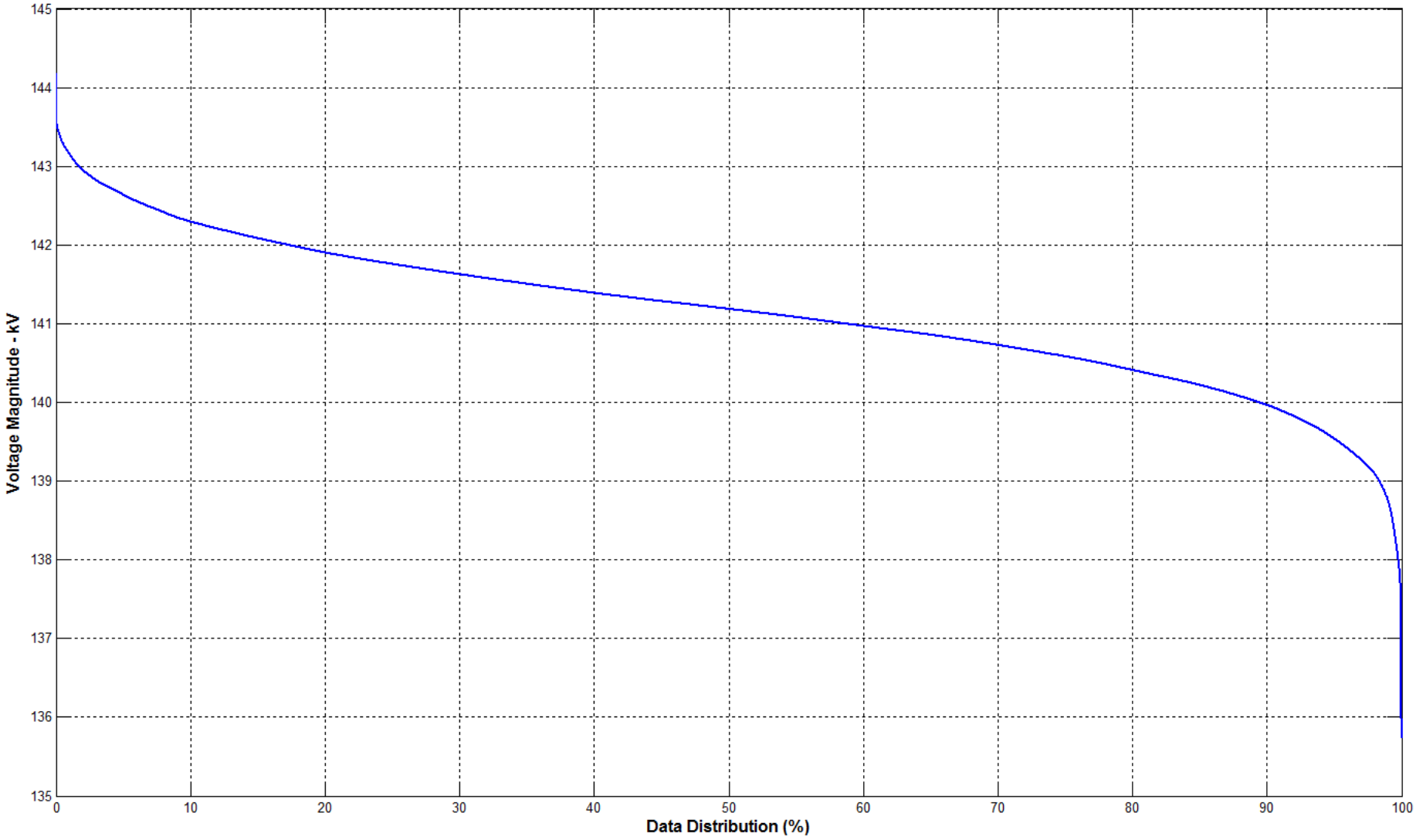
FarWest 8 – Voltage Magnitude



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-Whisker Plots and Time Duration Curves

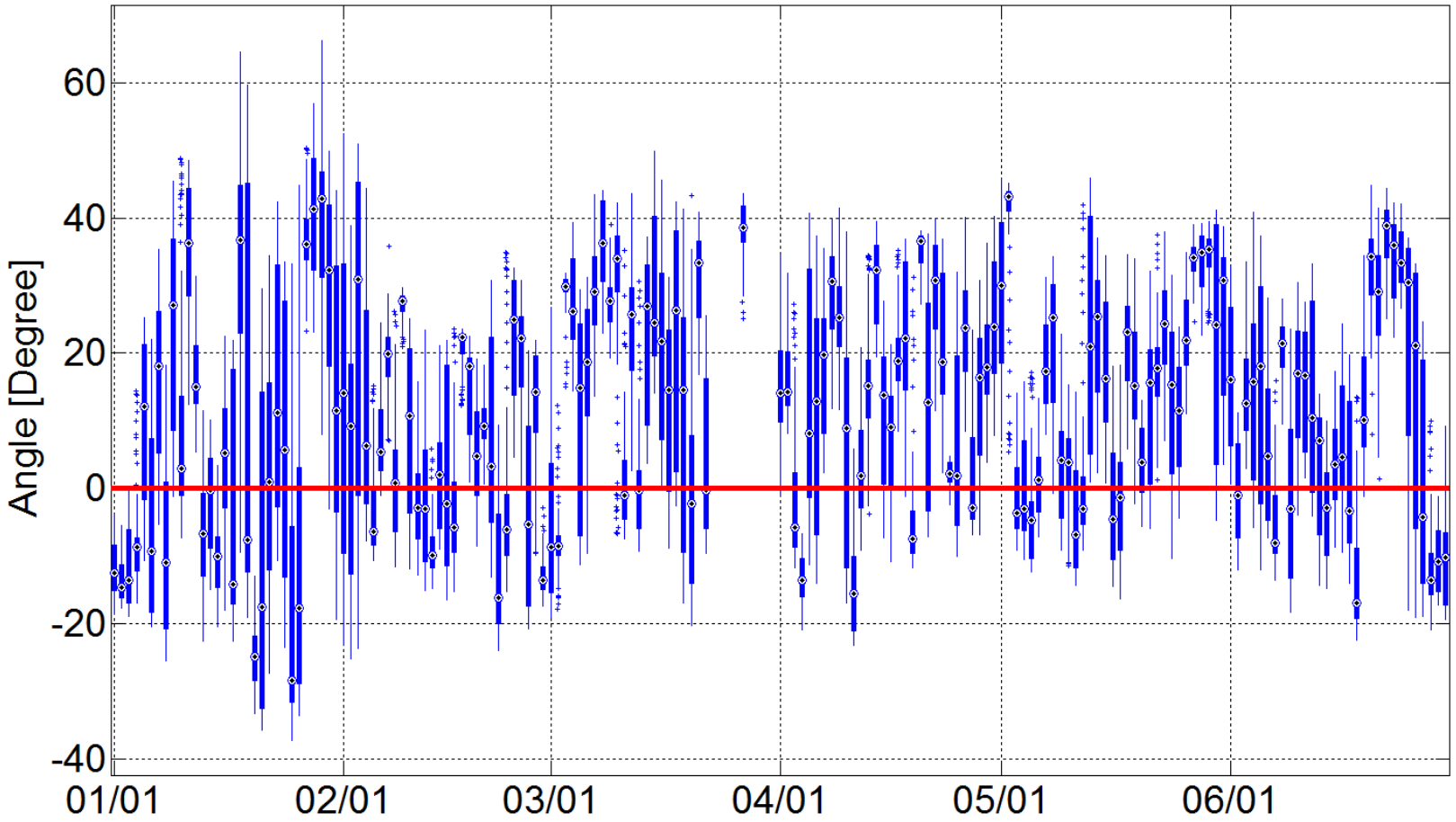
External Version

Electric Power Group

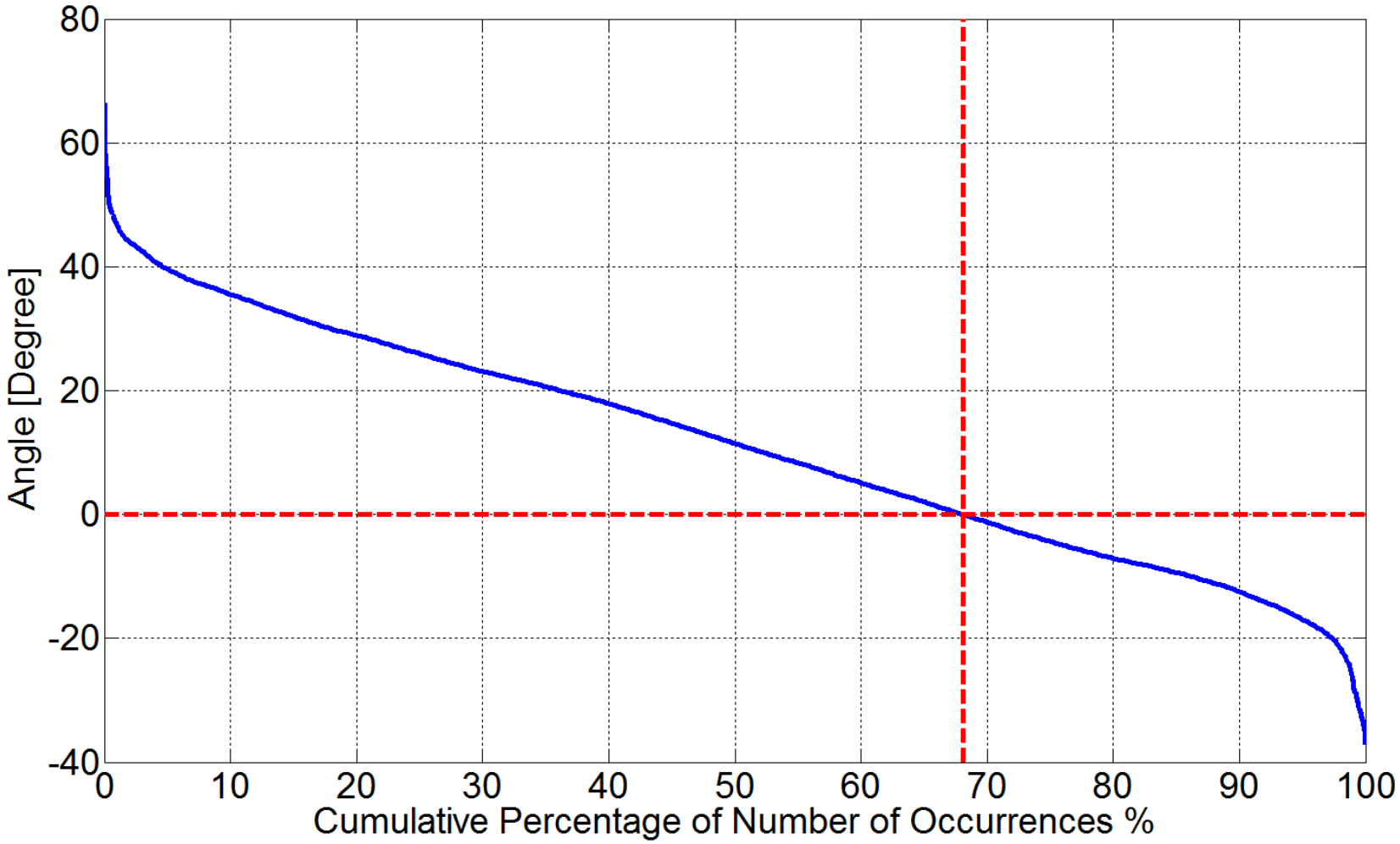
CCET

ERCOT

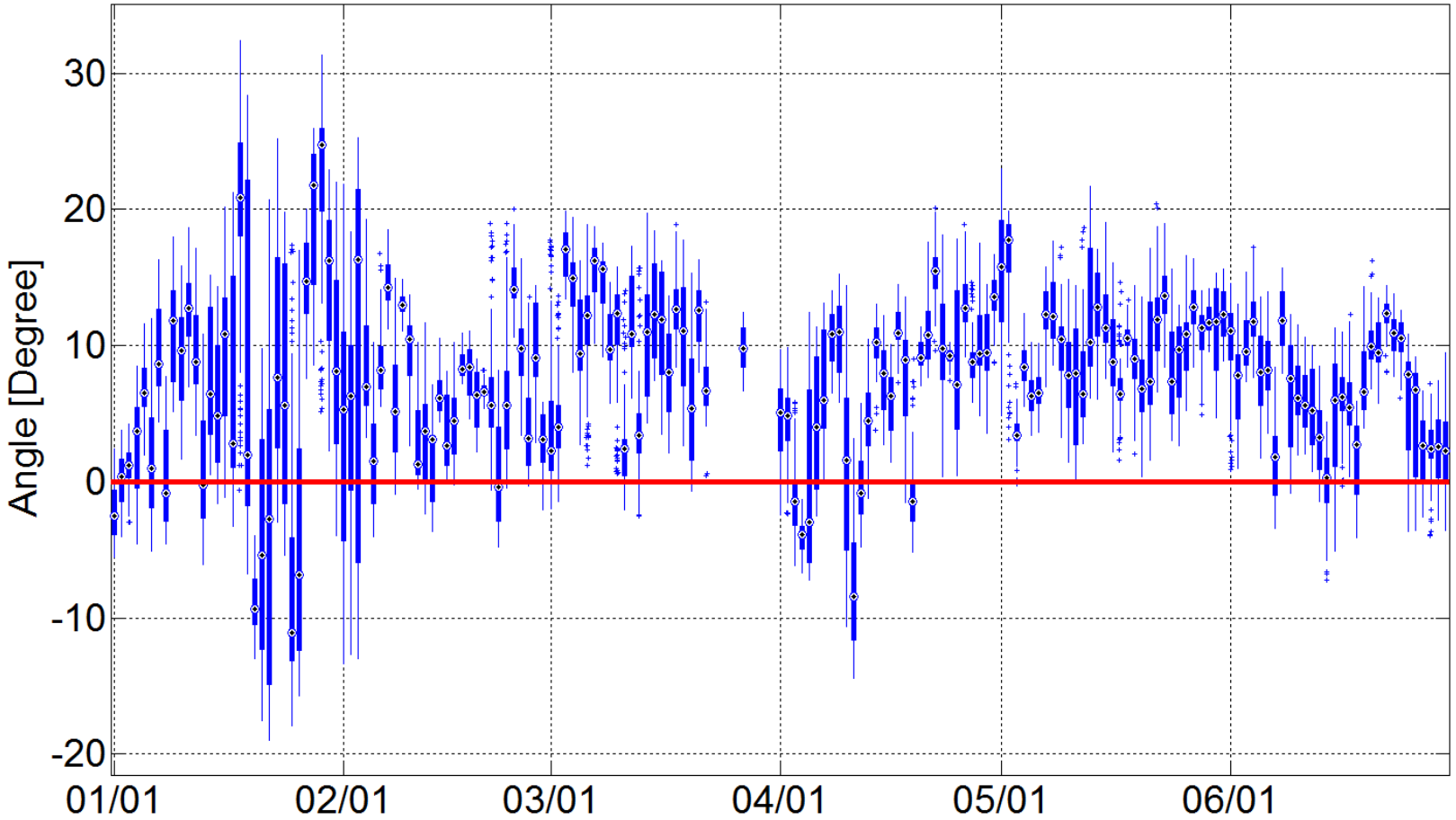
West 10-North 7



West 10-North 7



West 14-North 7



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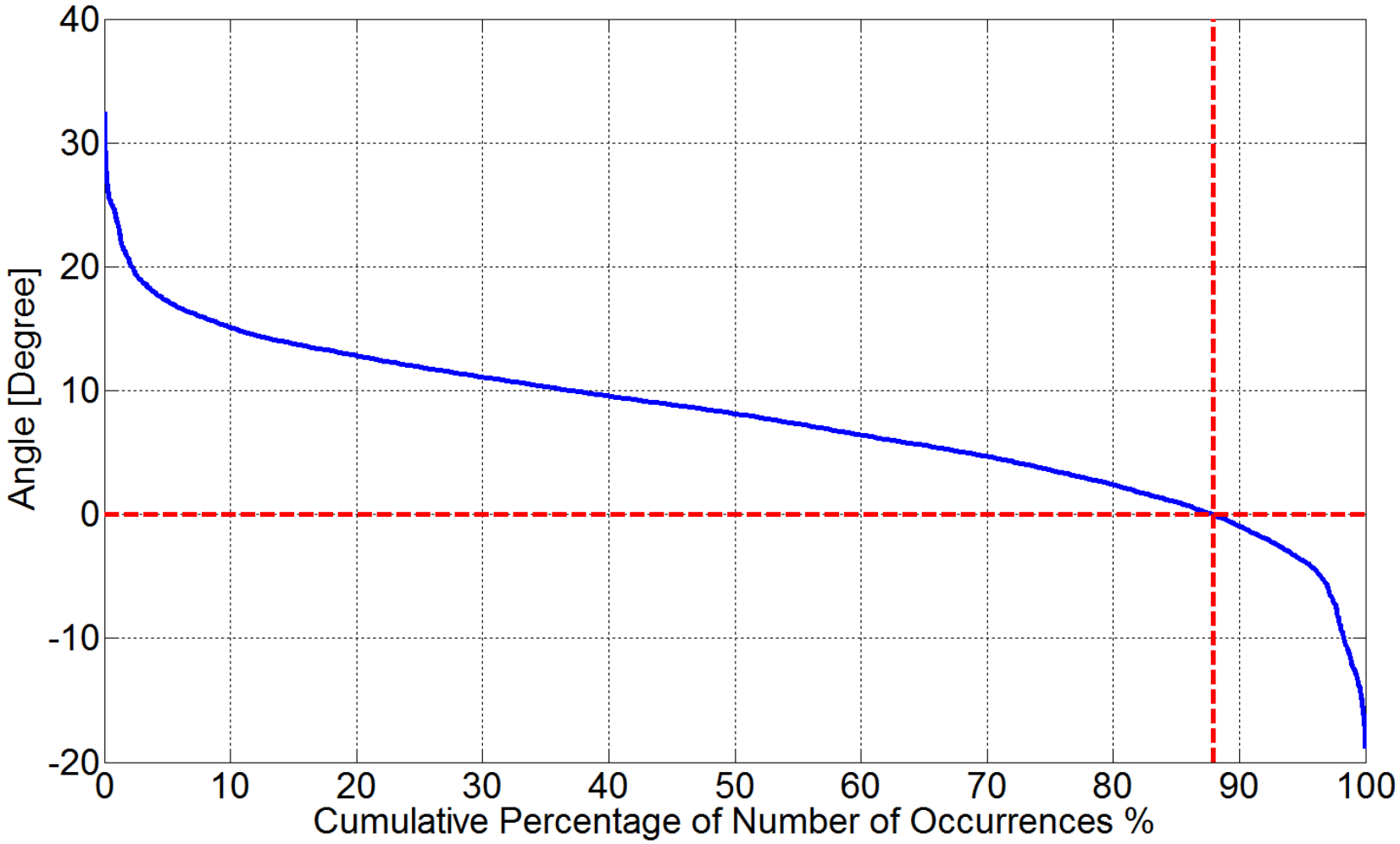
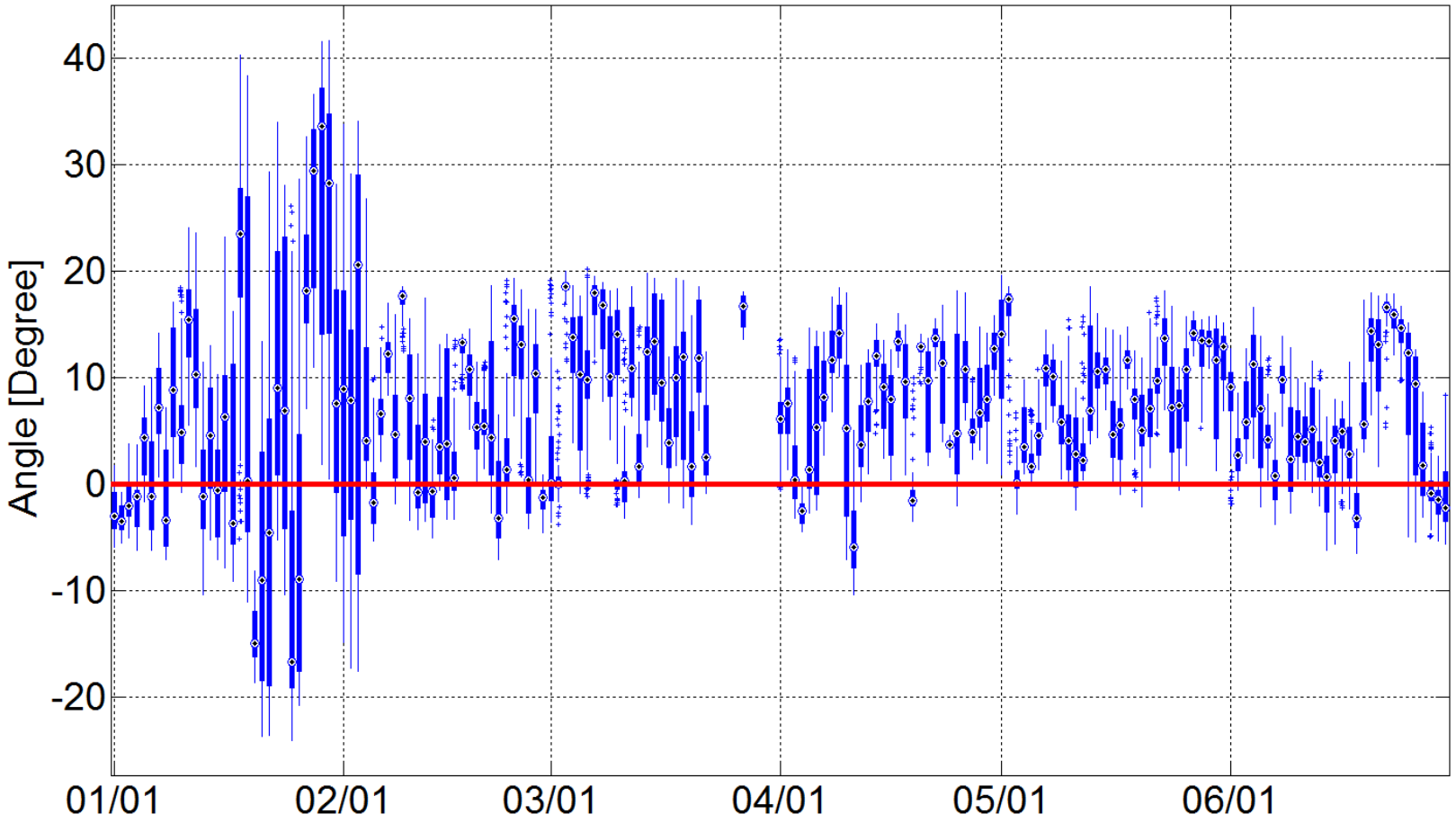


West 1*-North 7



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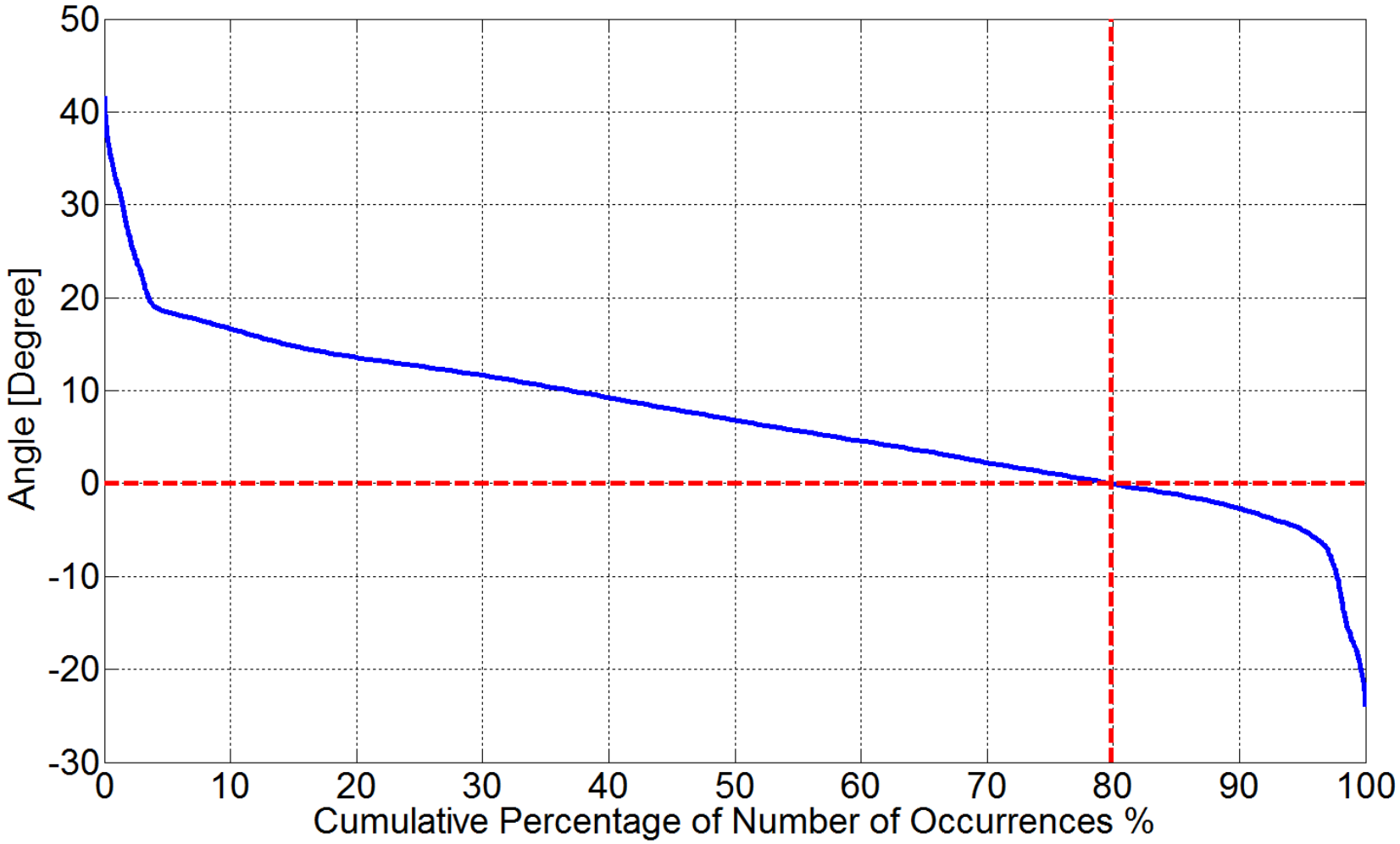

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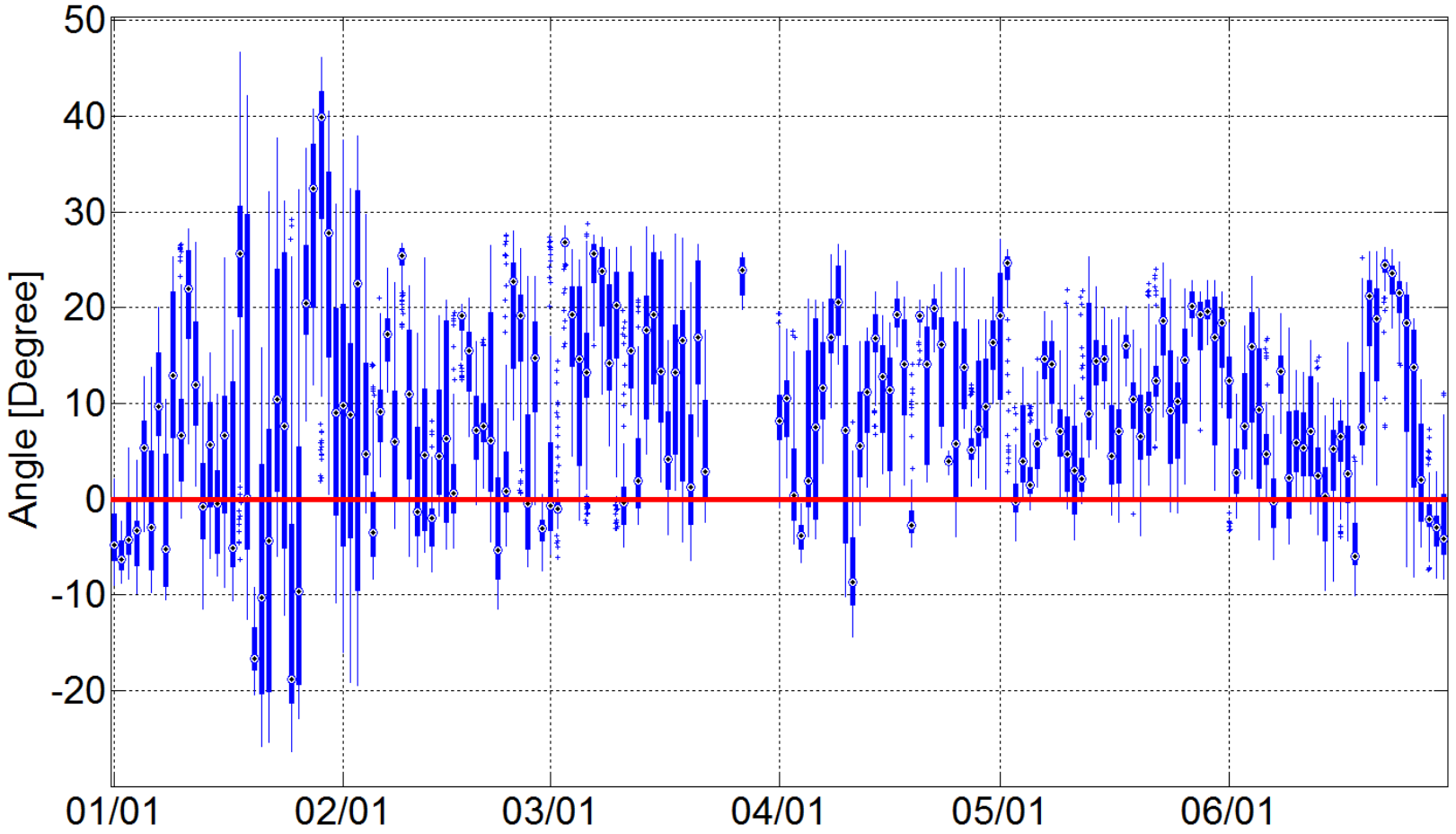

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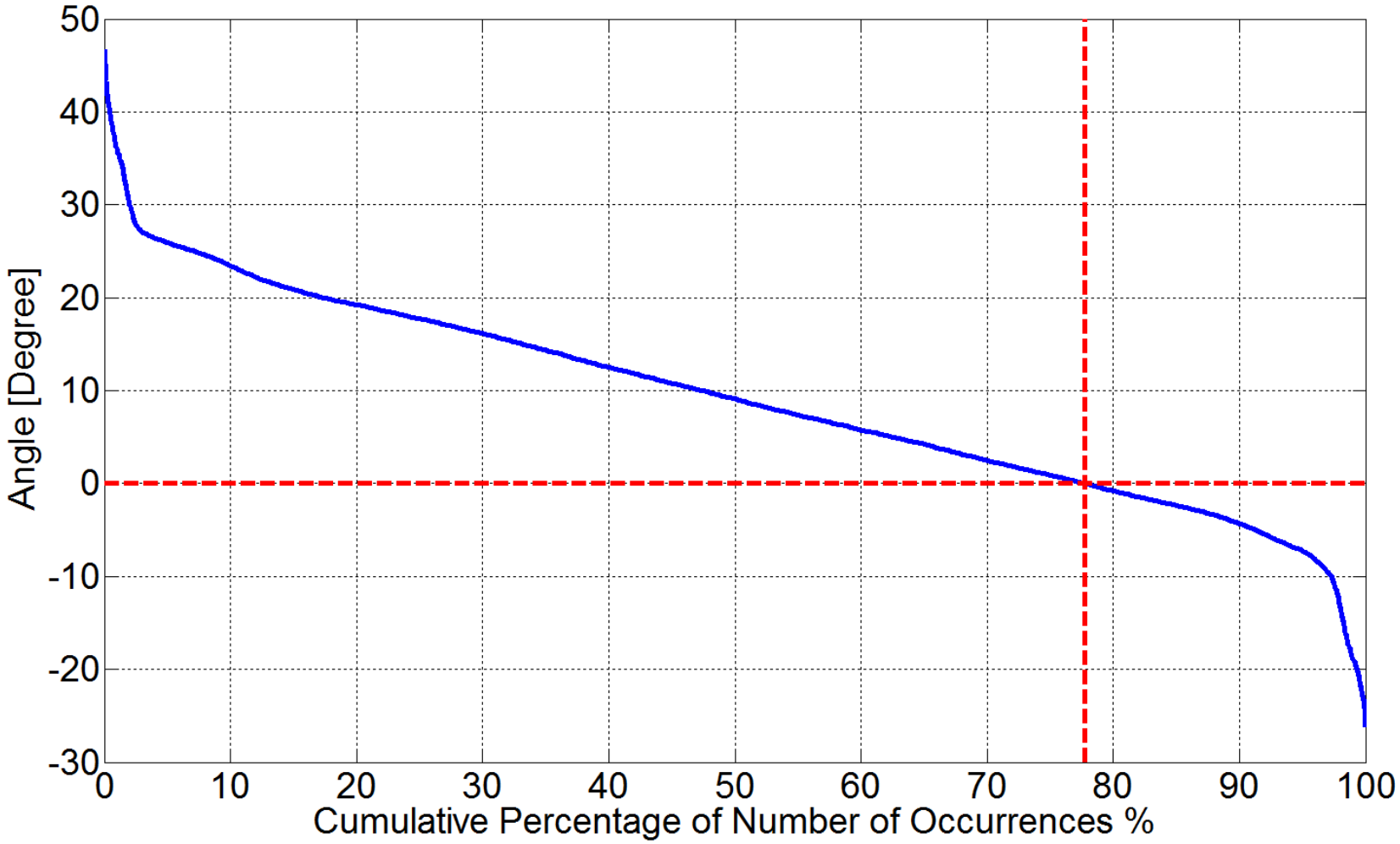
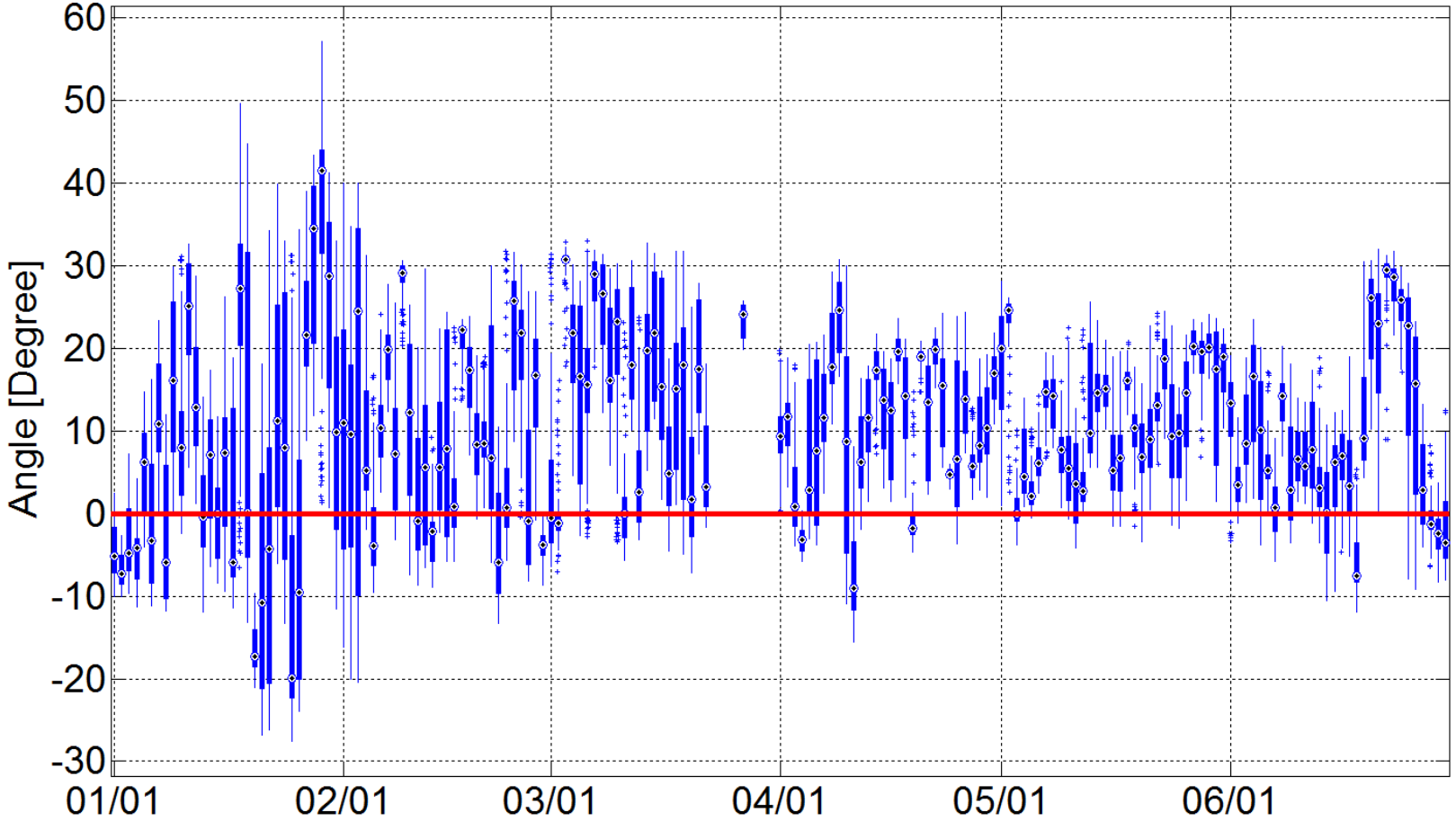
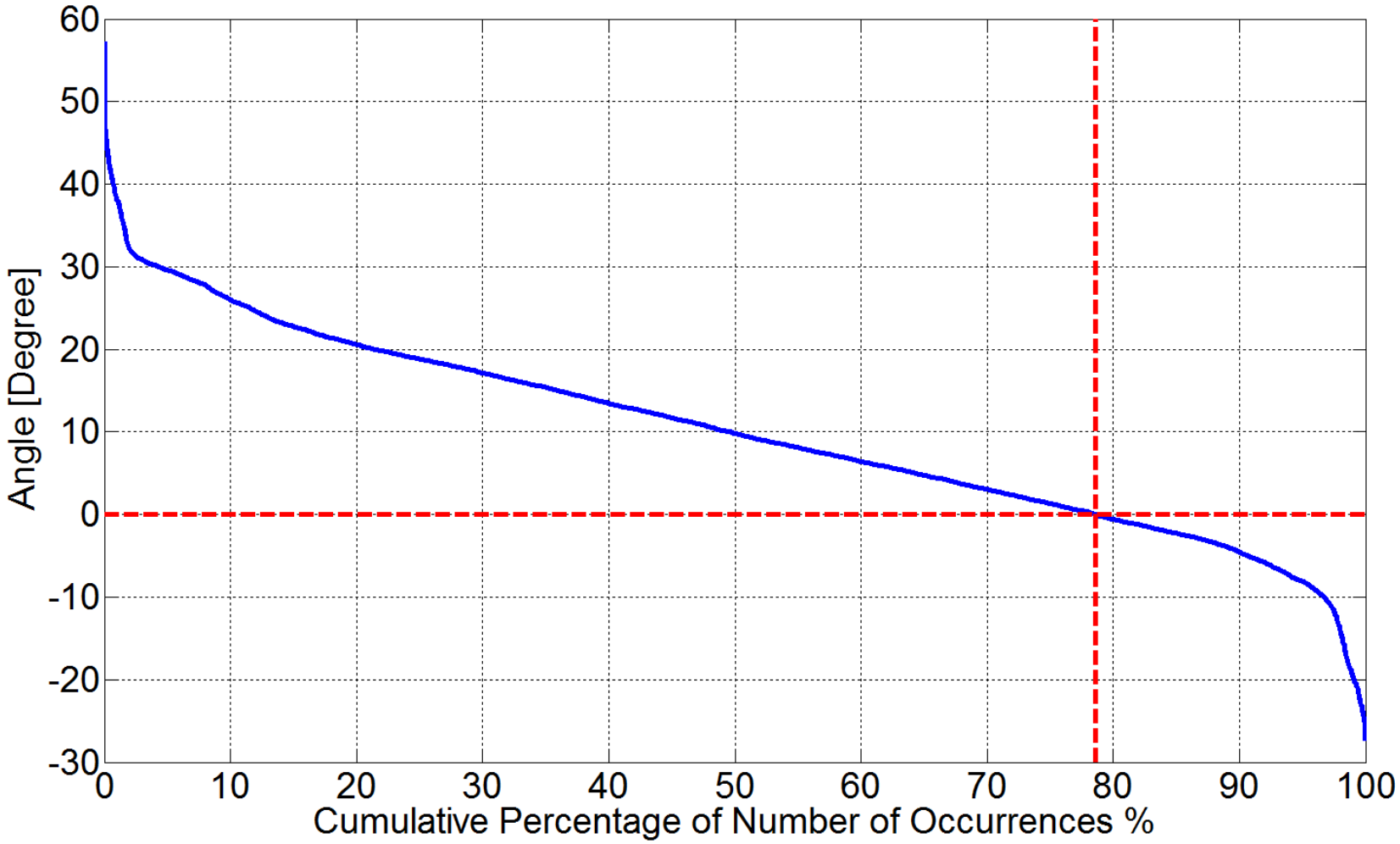


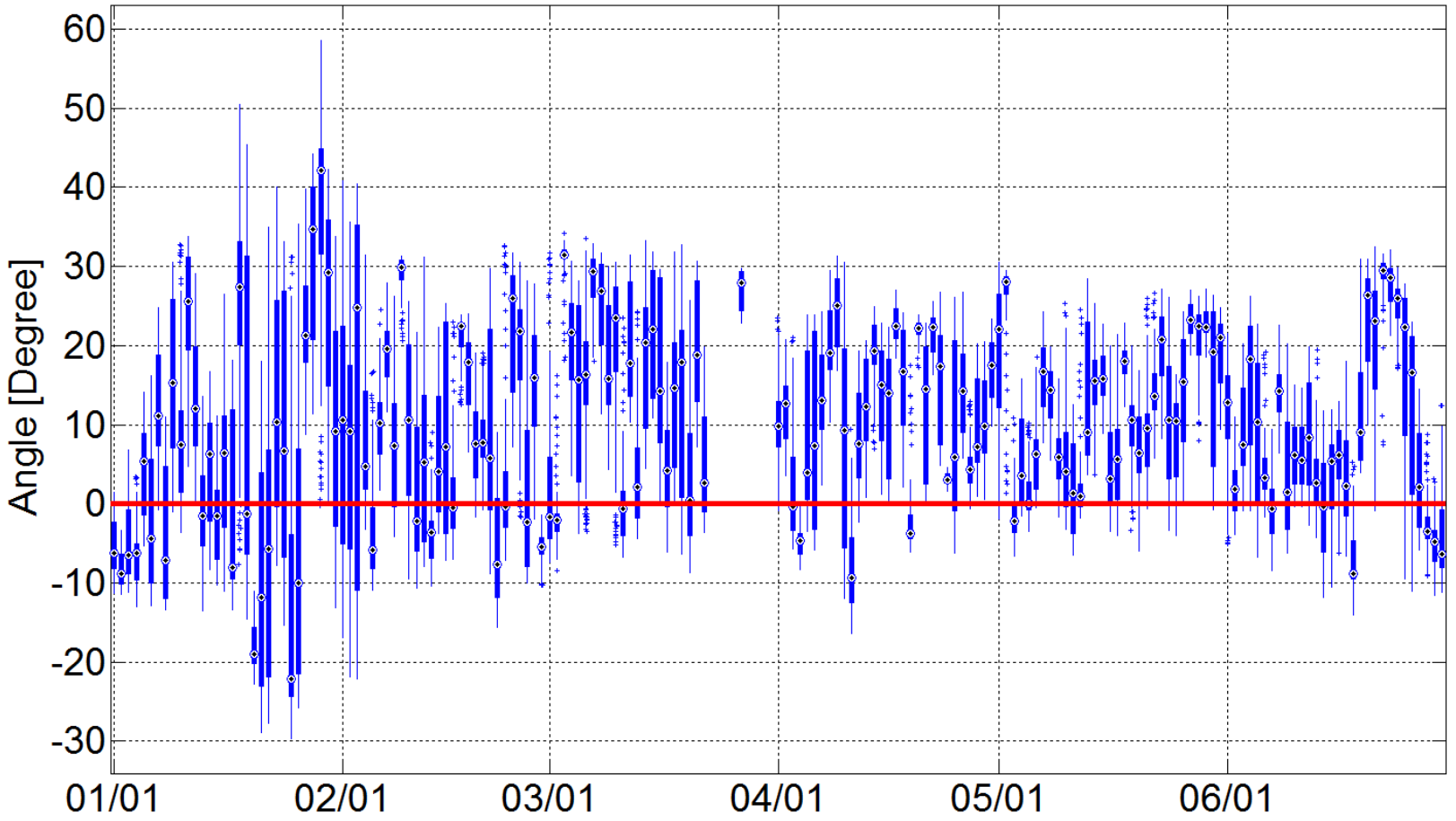
West 9*-North 7



West 9*-North 7



West 11-North 7



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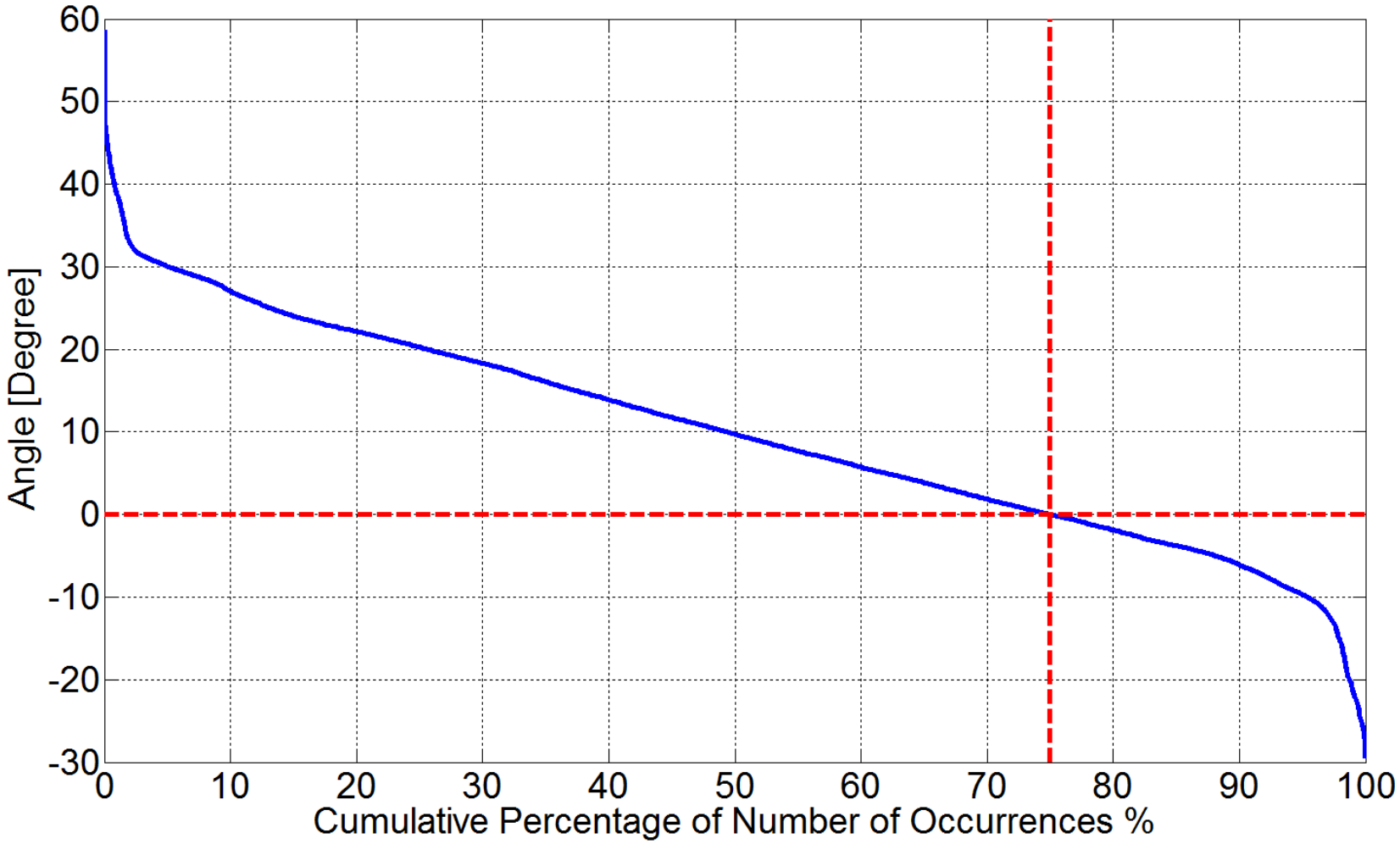

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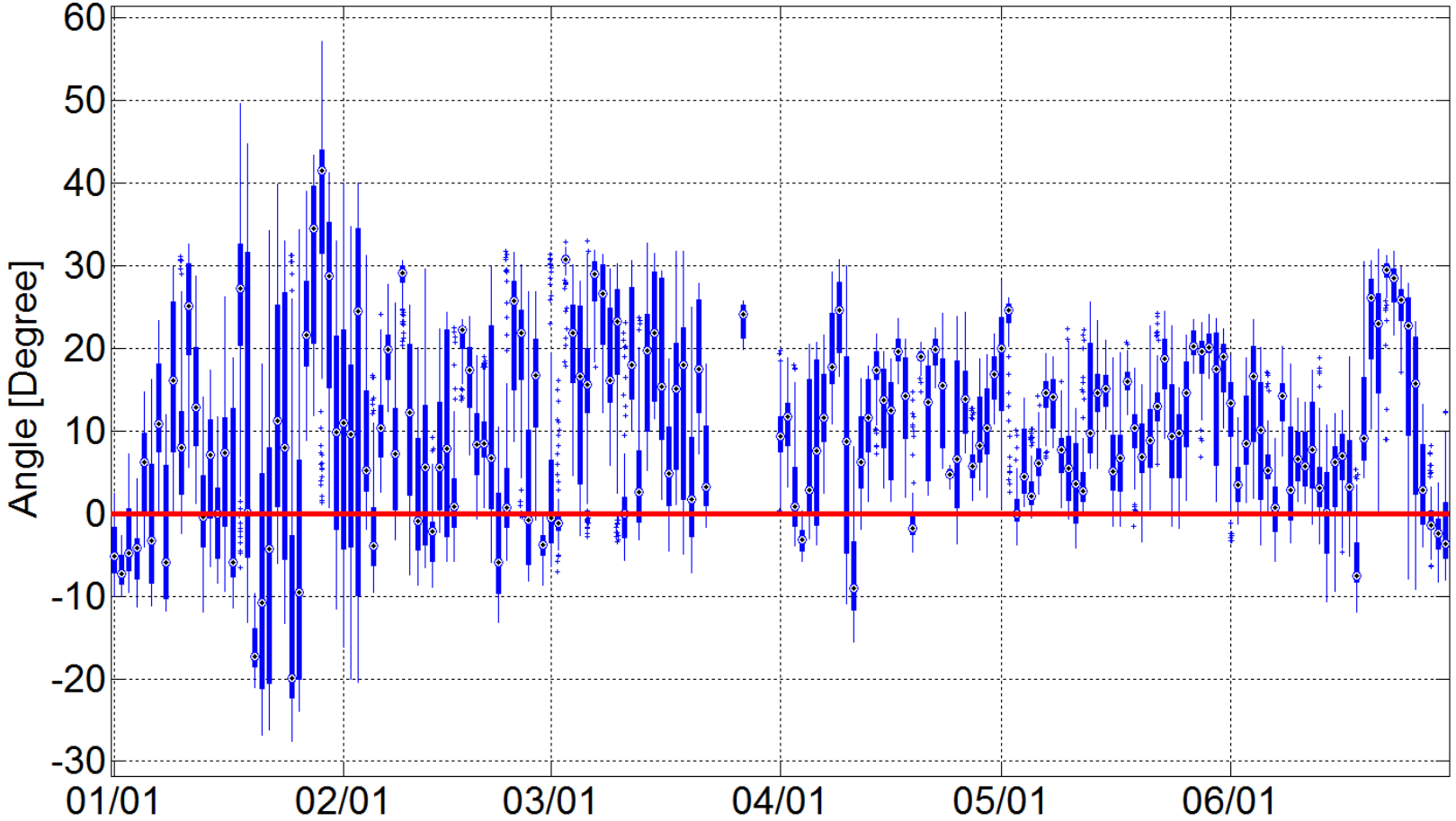

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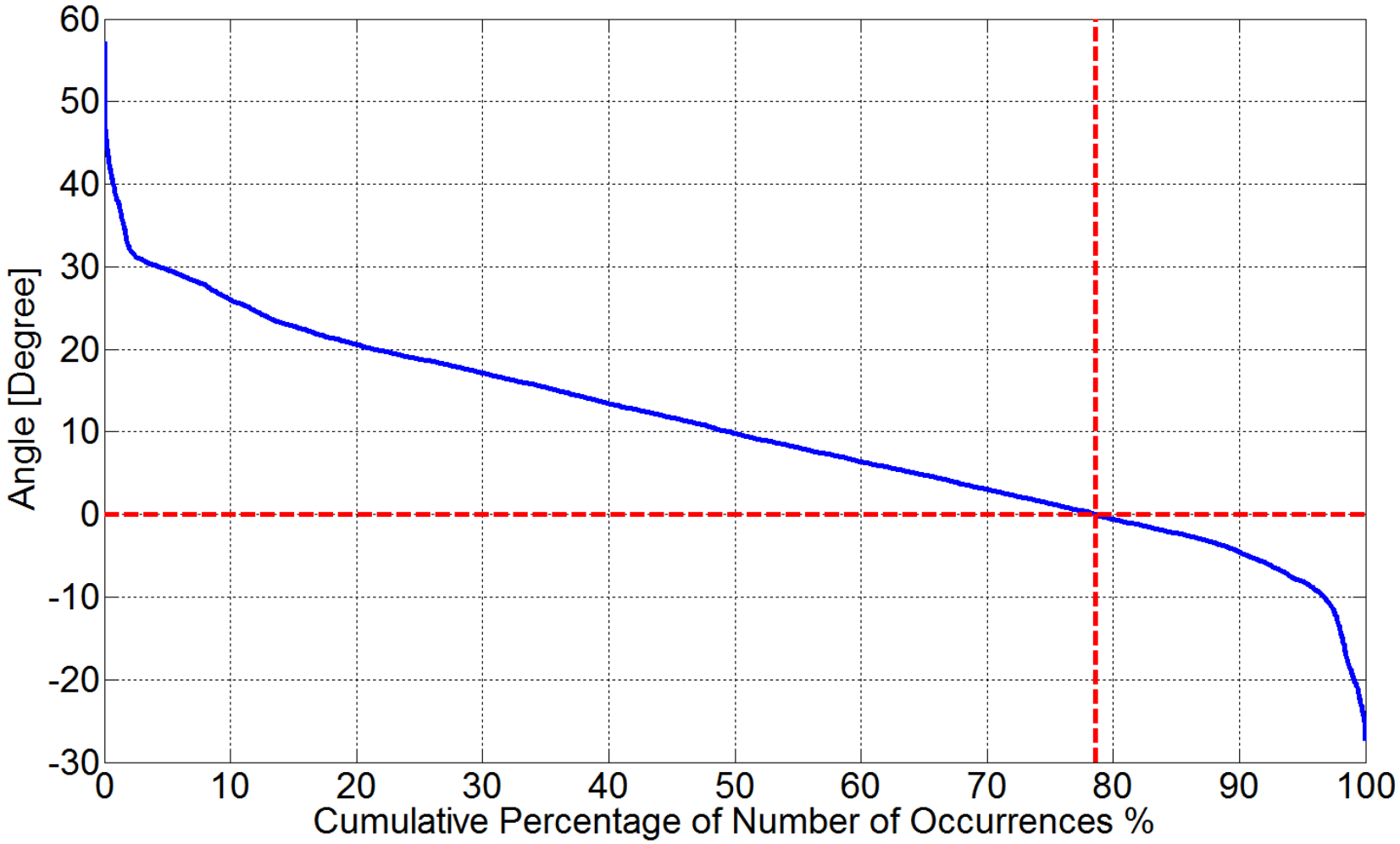

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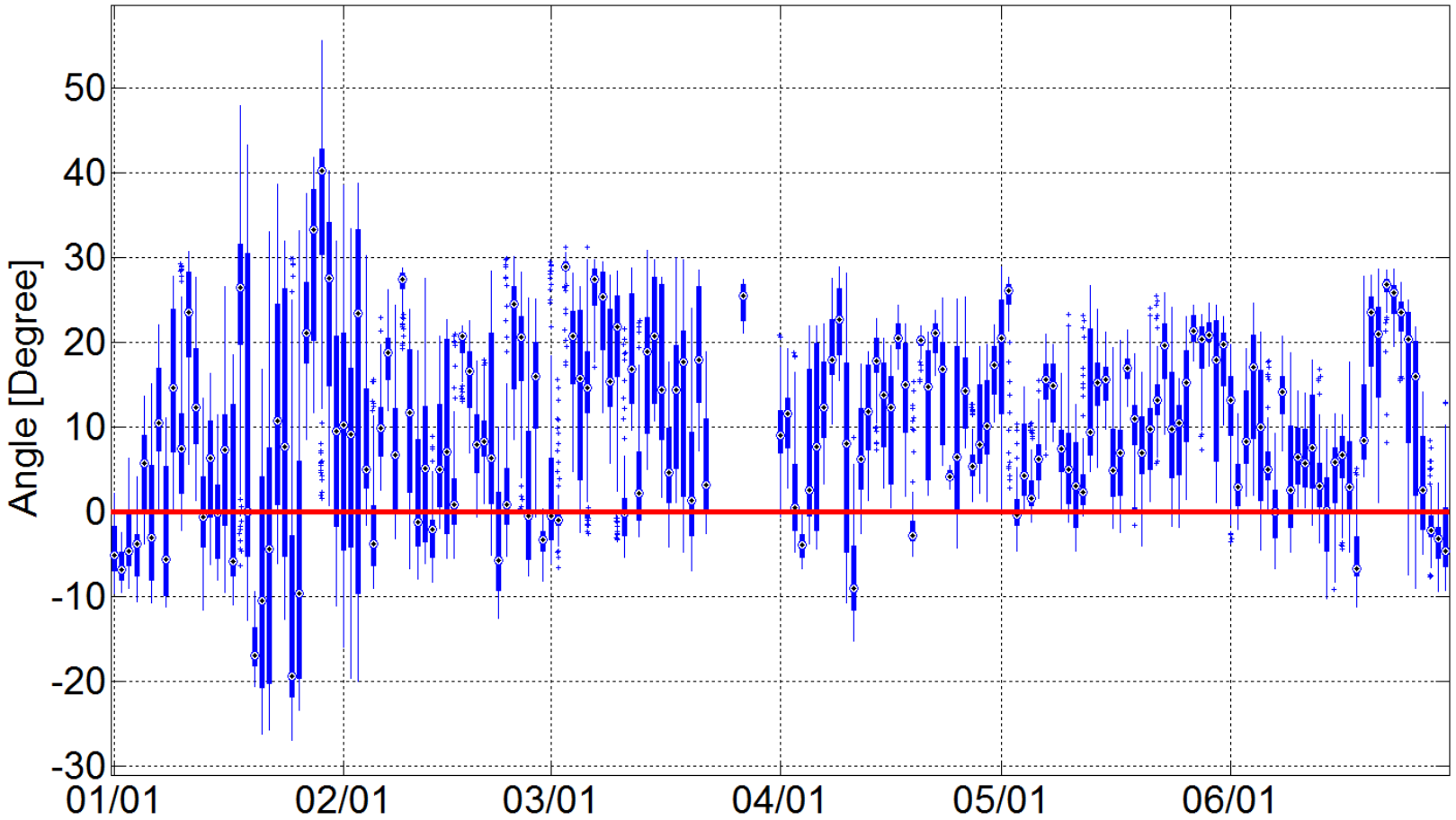

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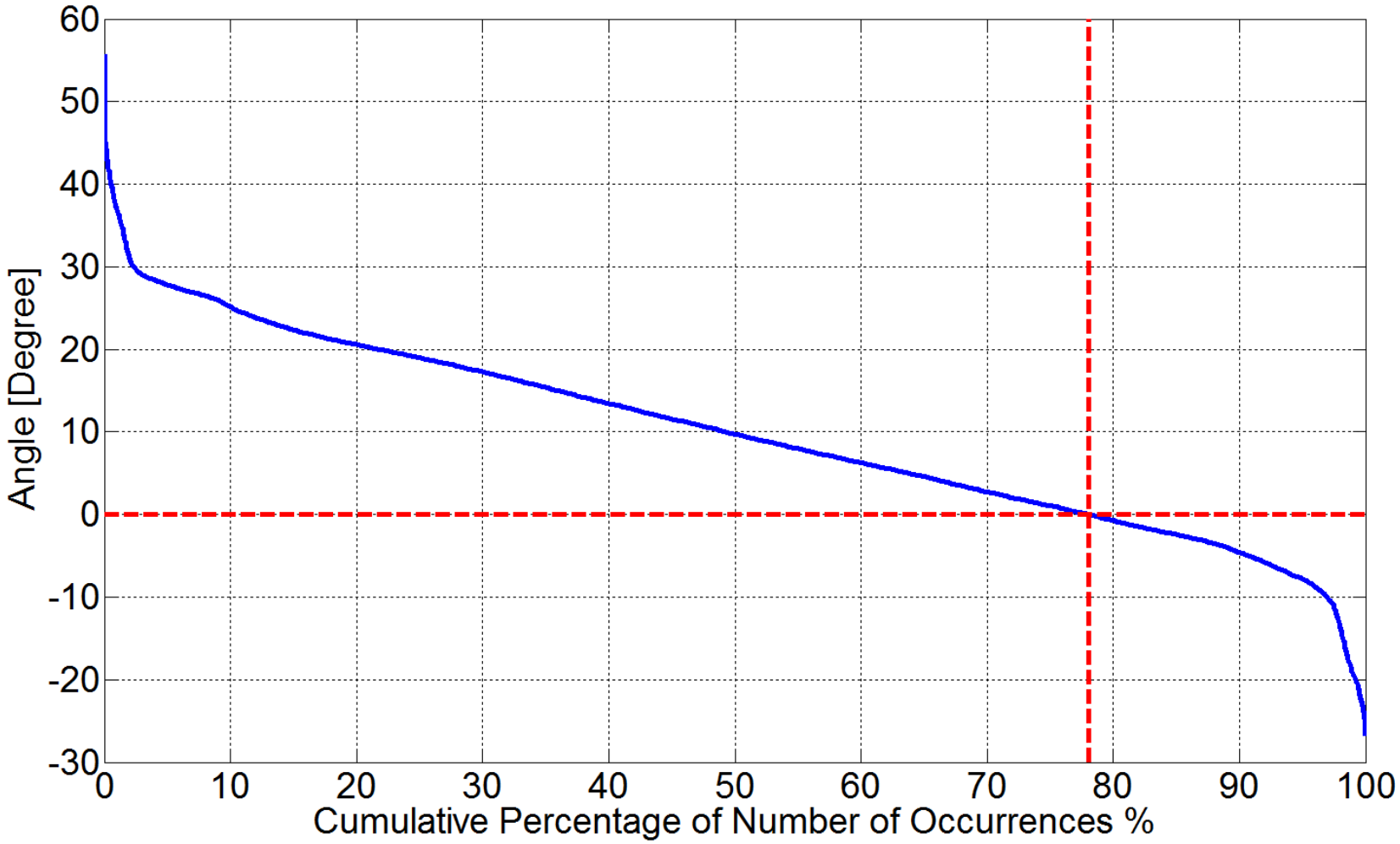
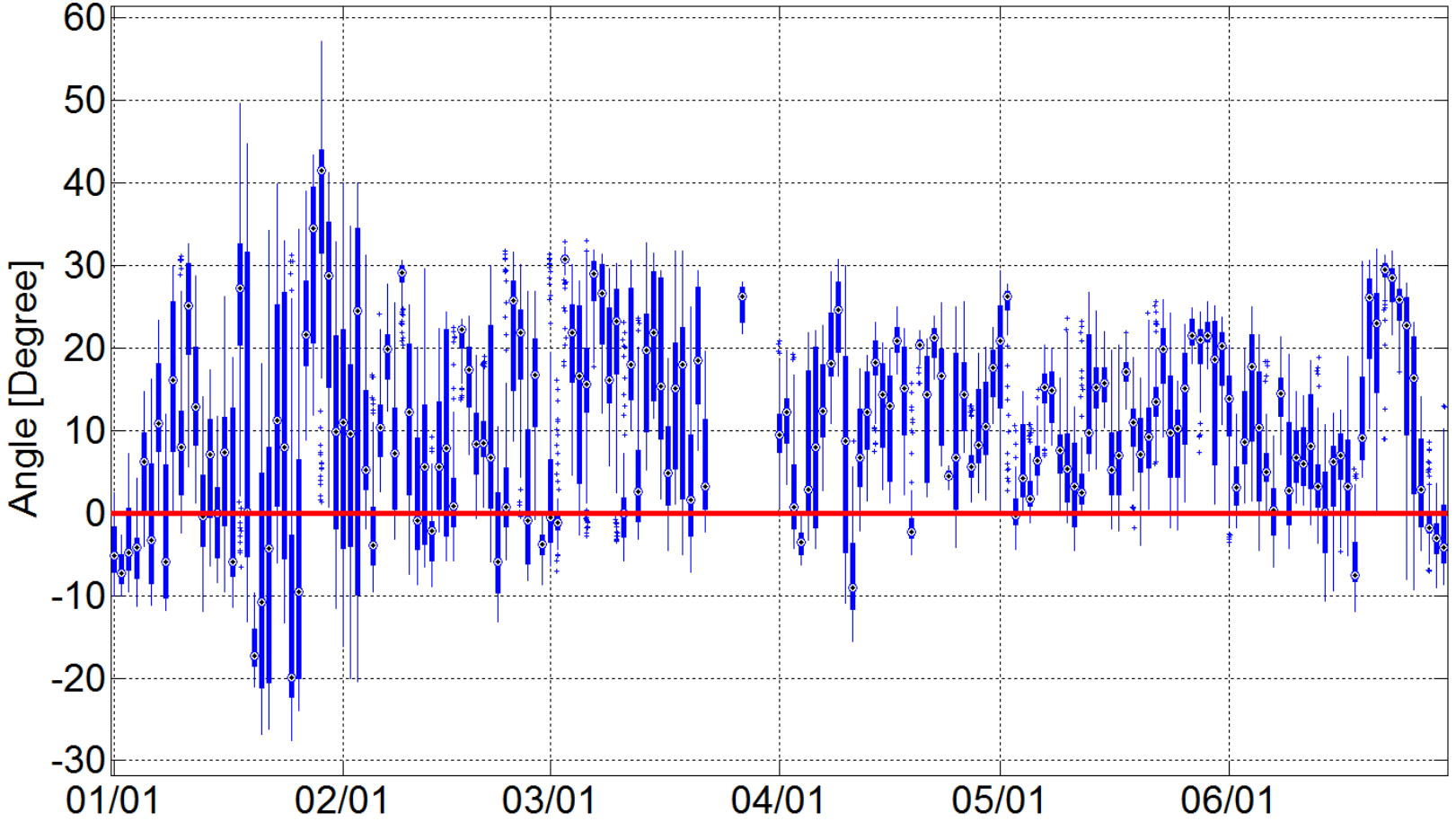


West 6-North 7



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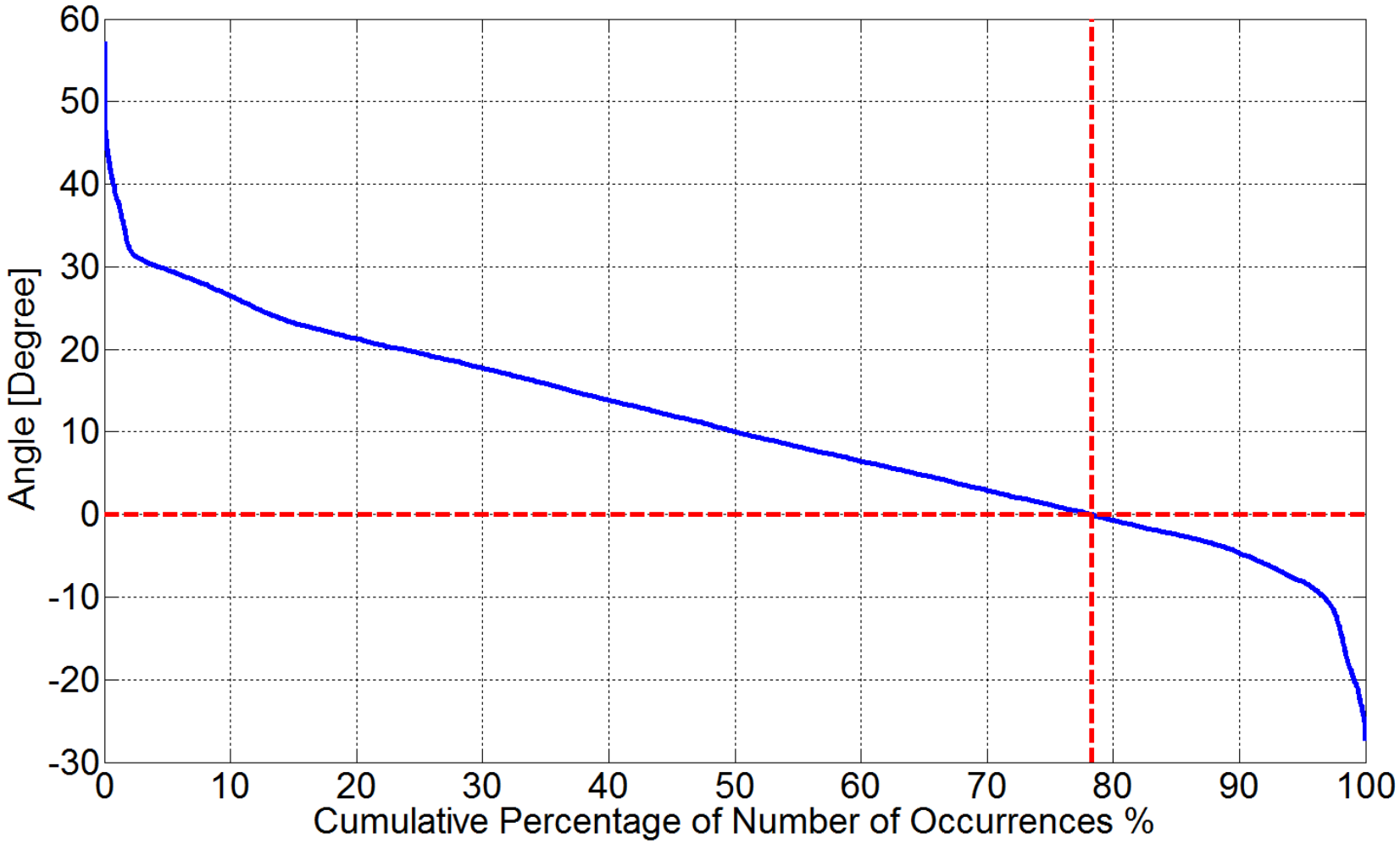

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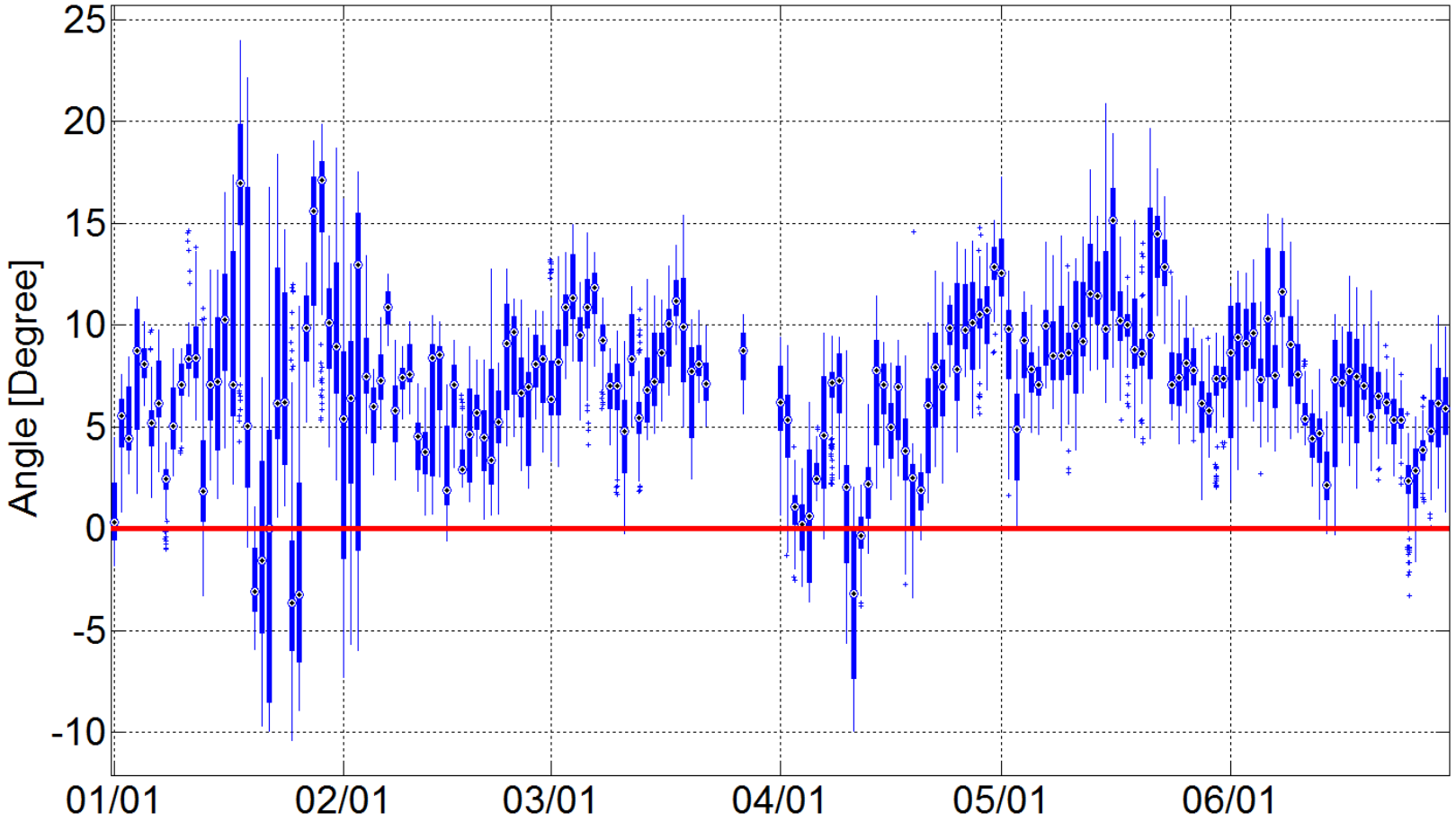
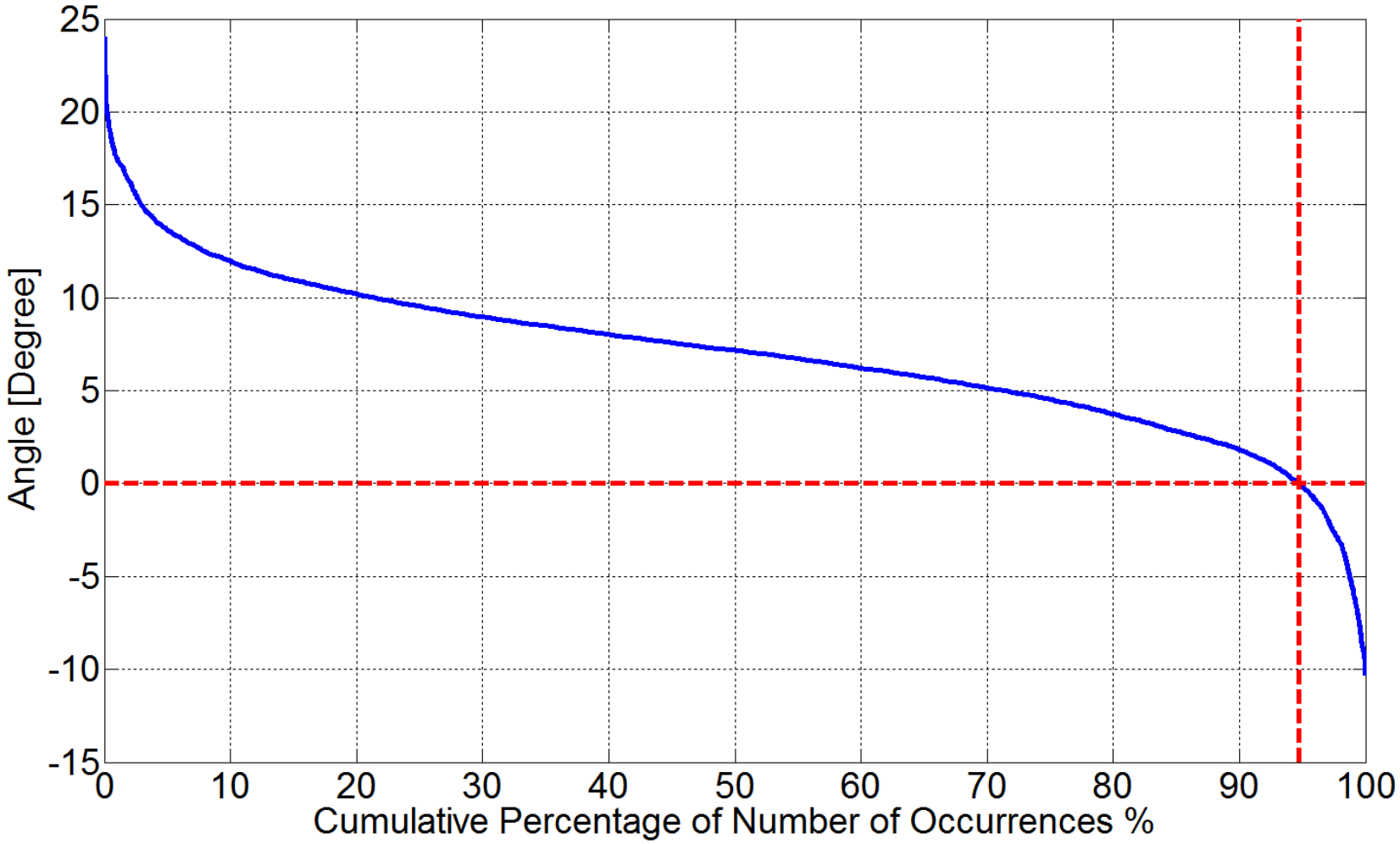


North 1-North 7



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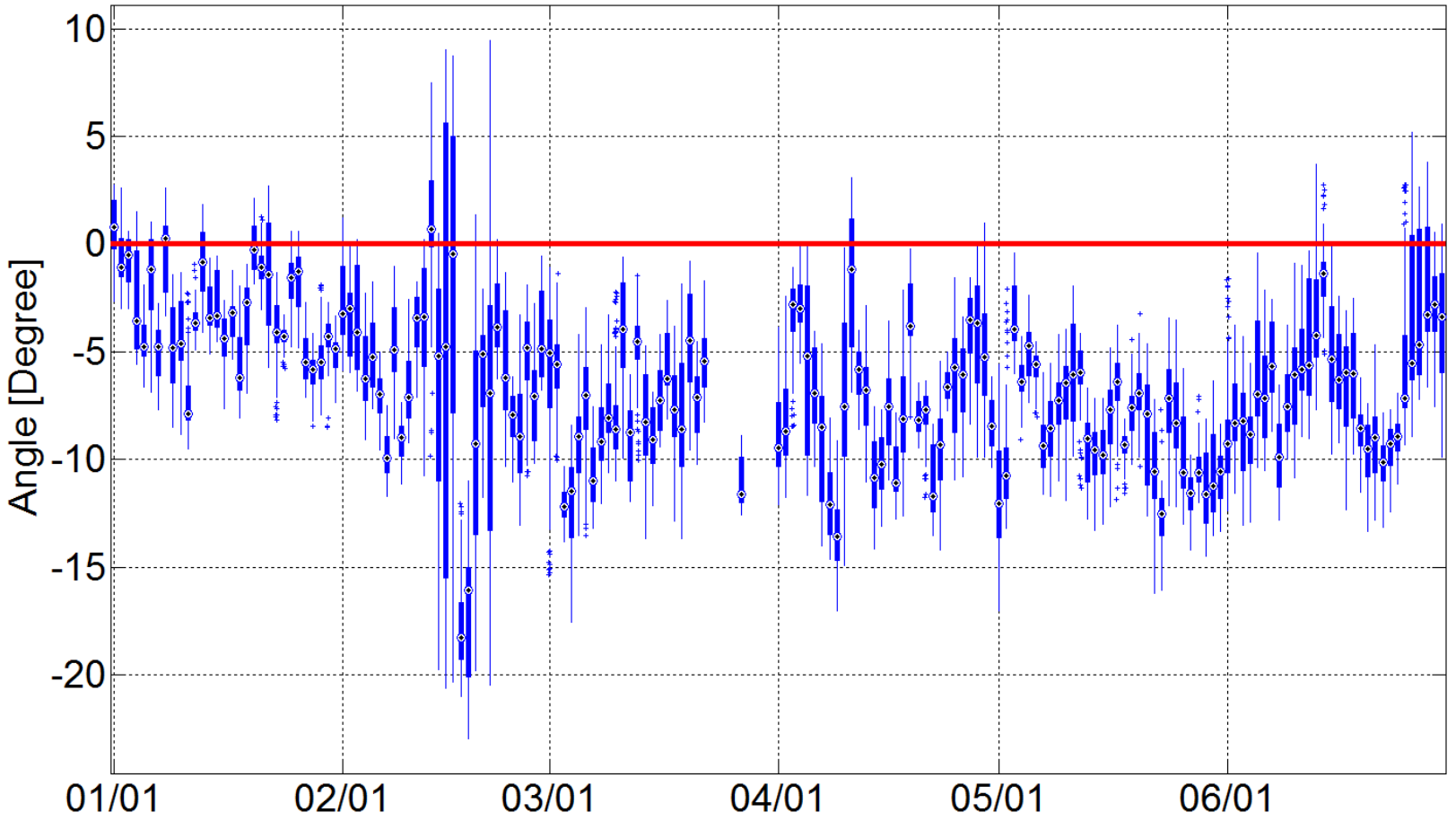

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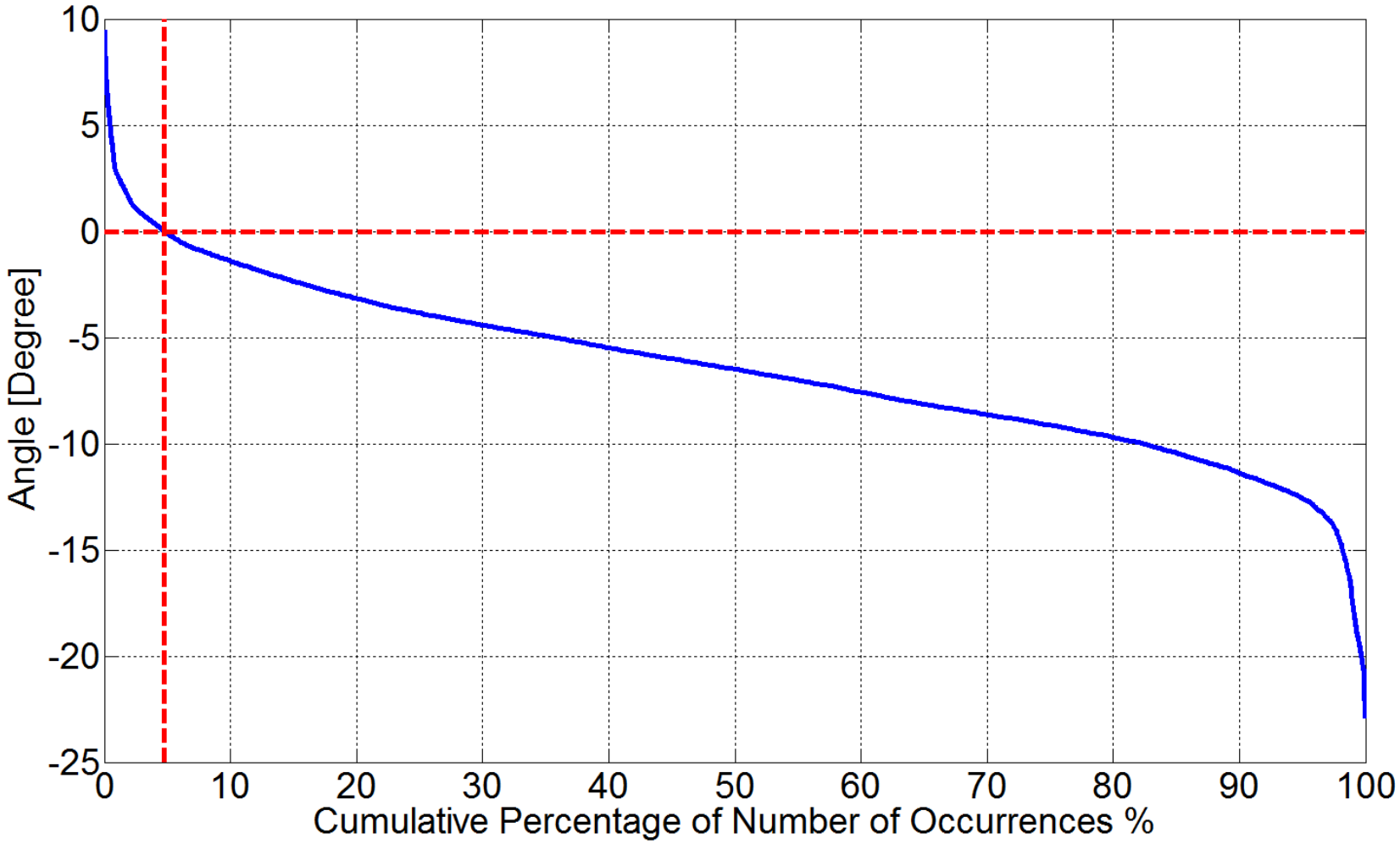

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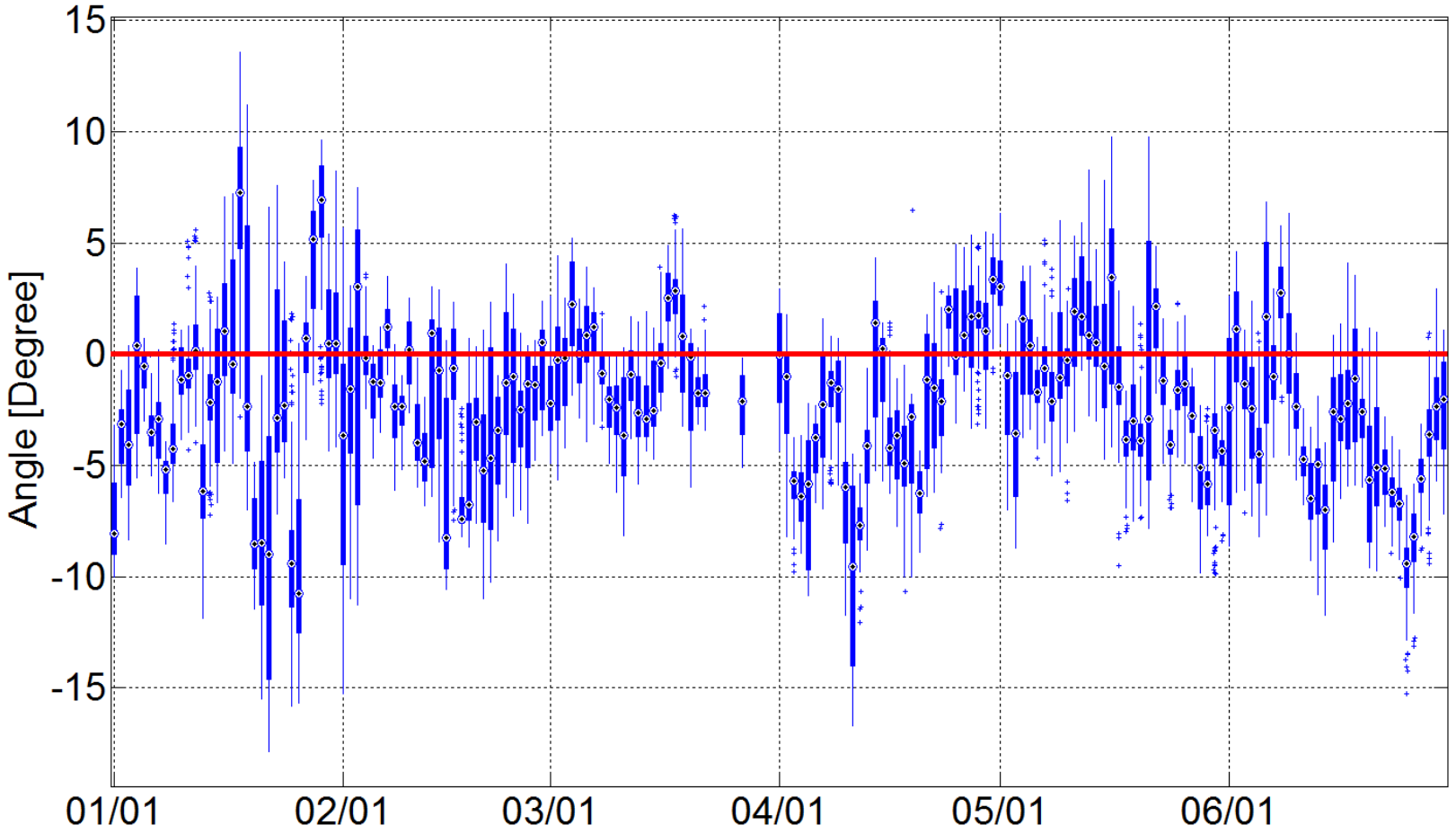

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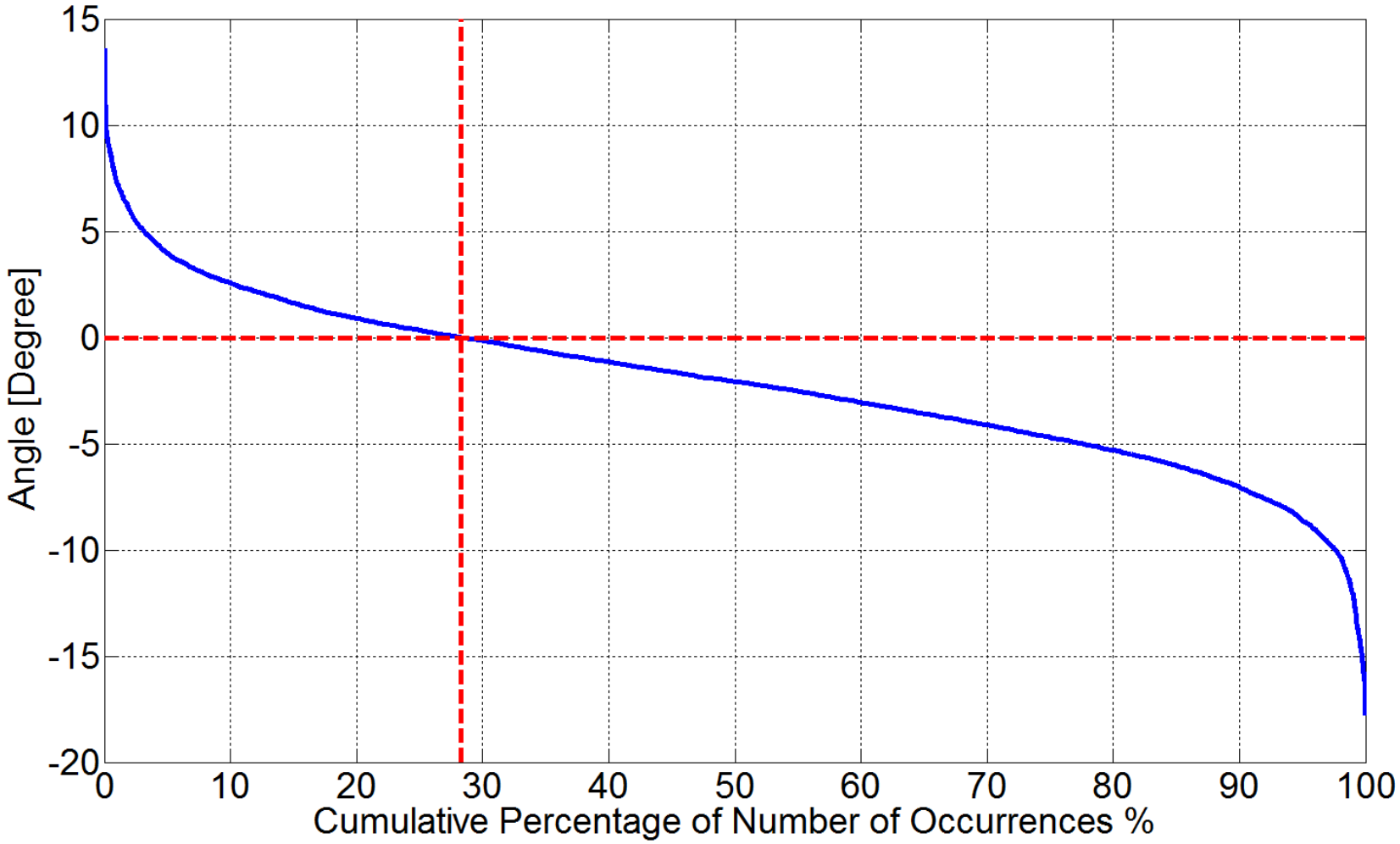

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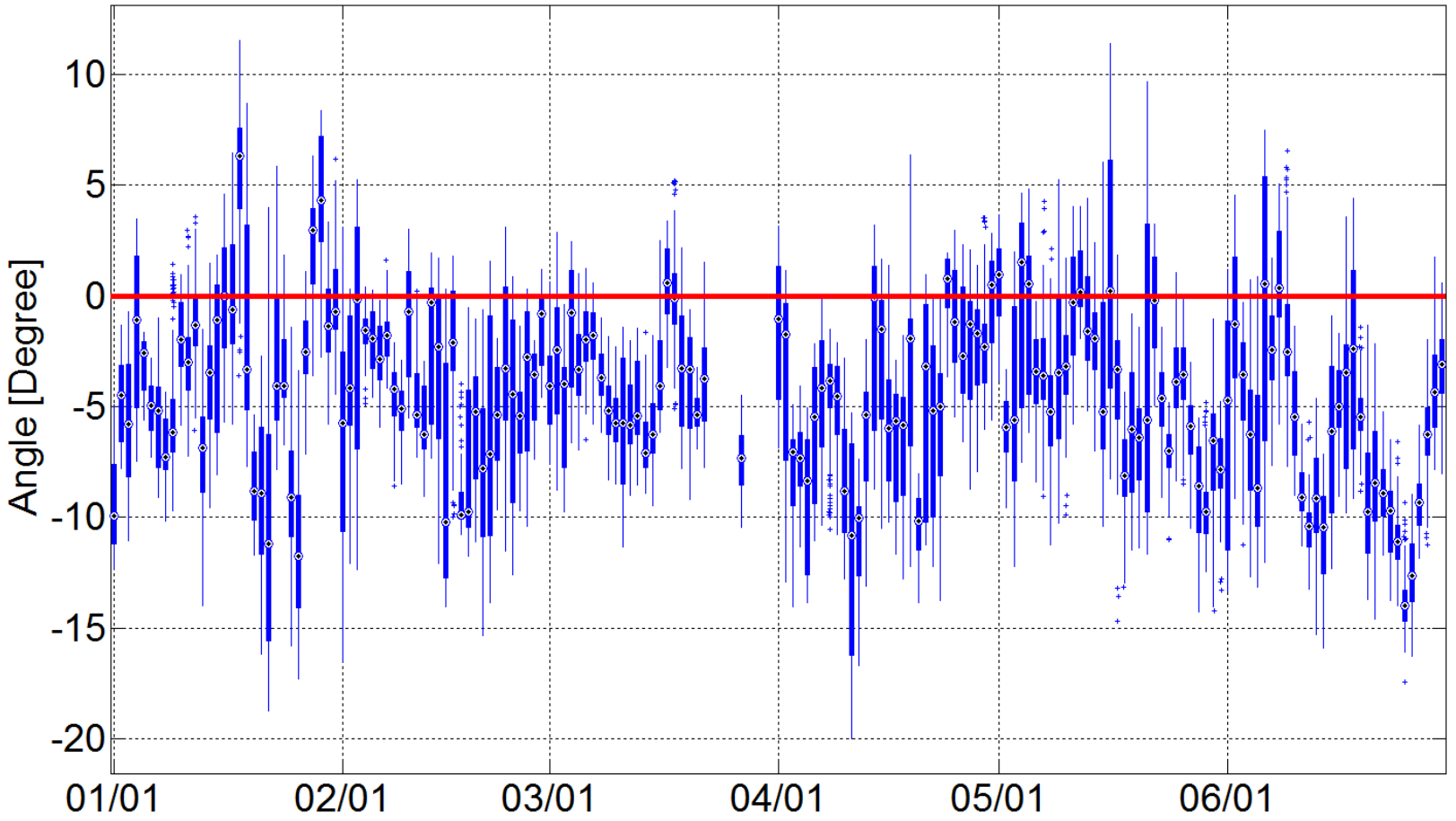

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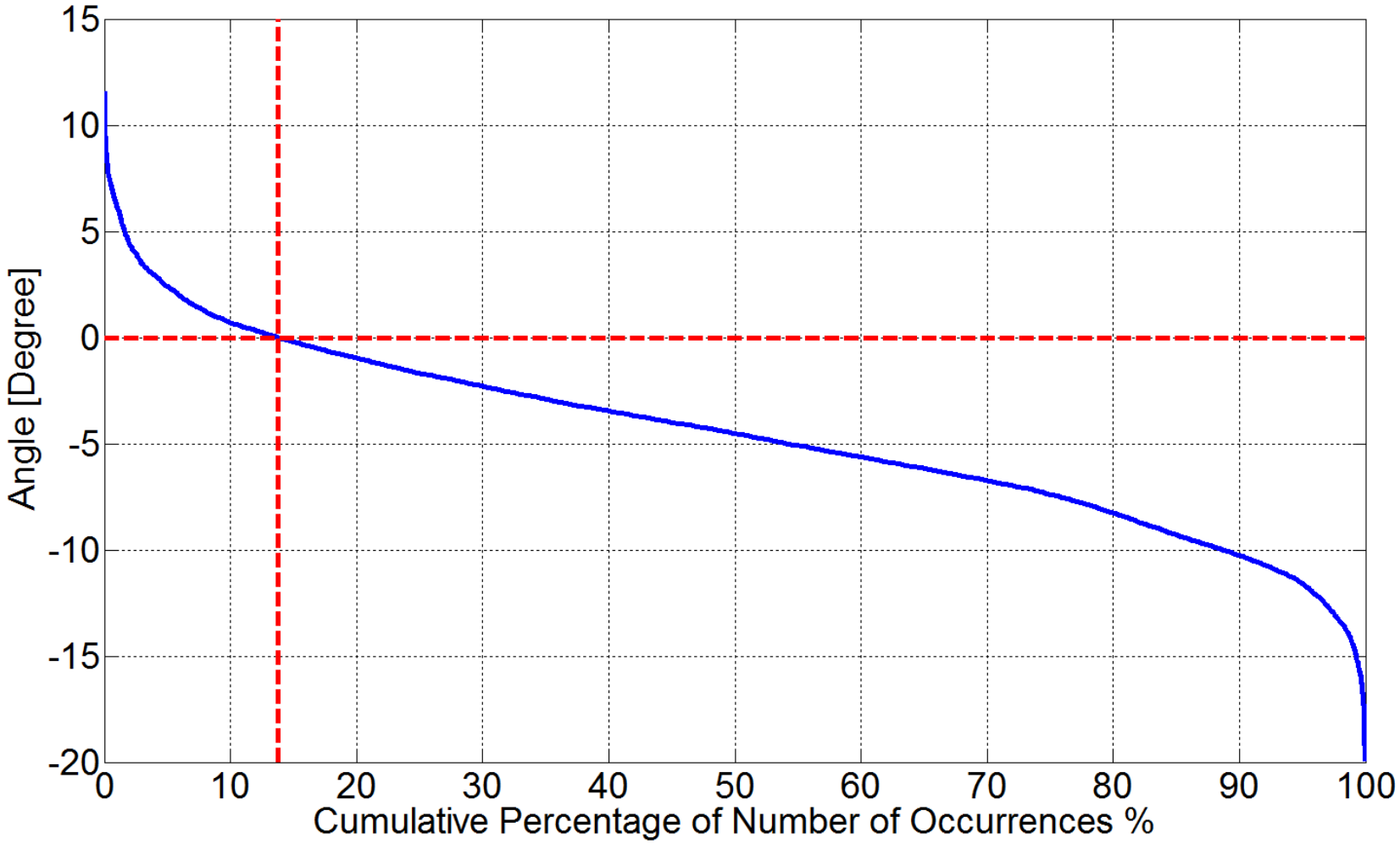

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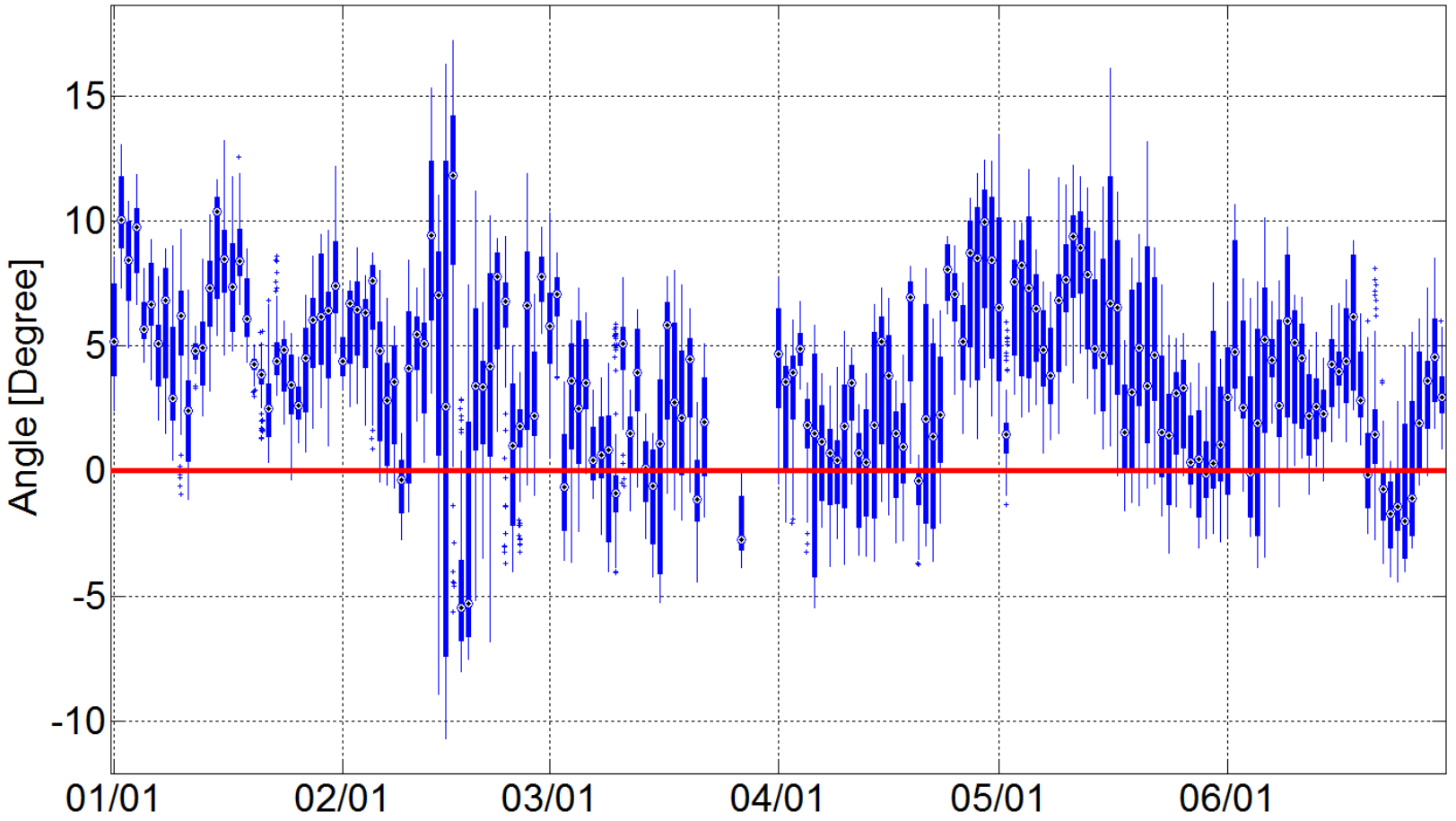

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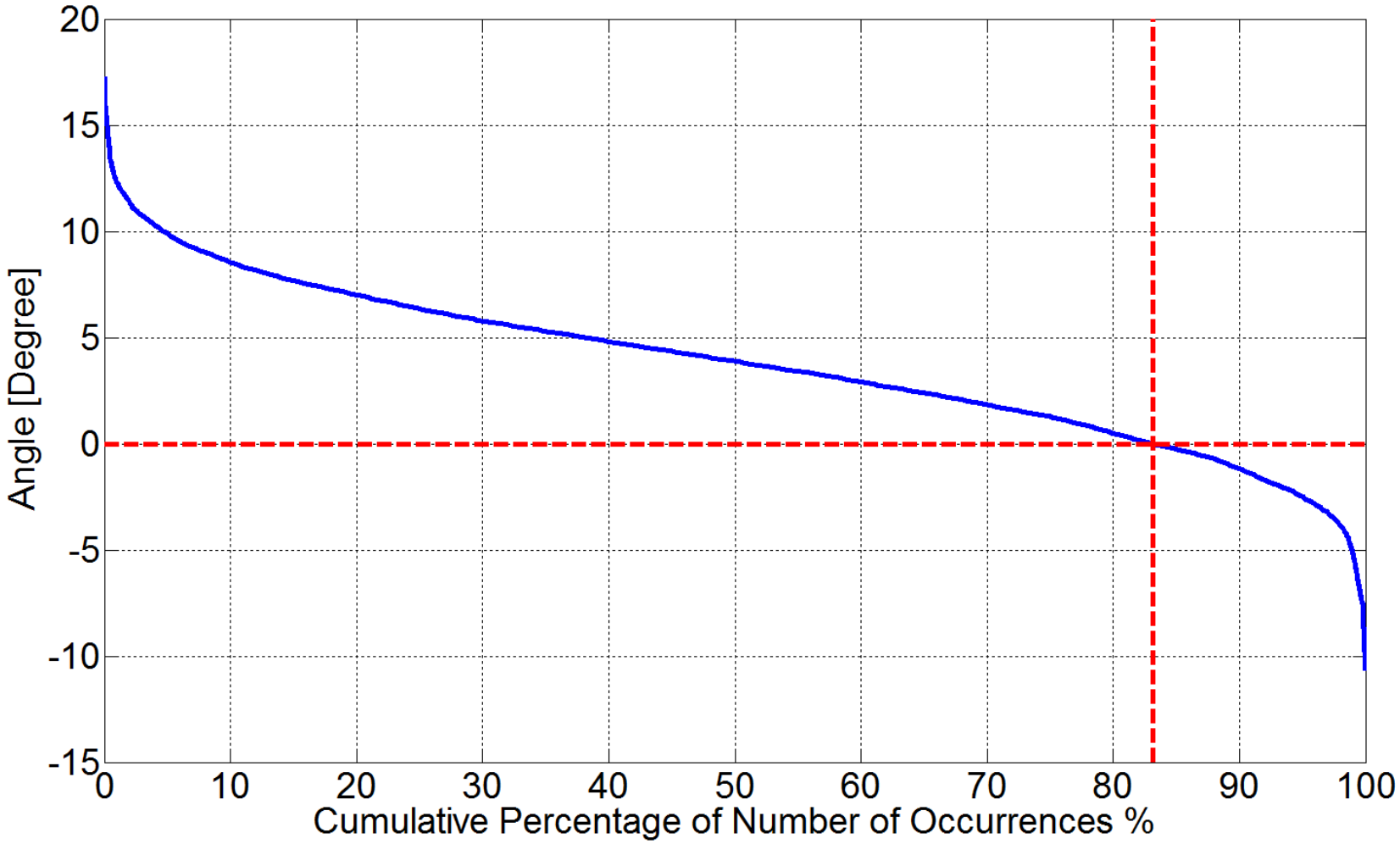
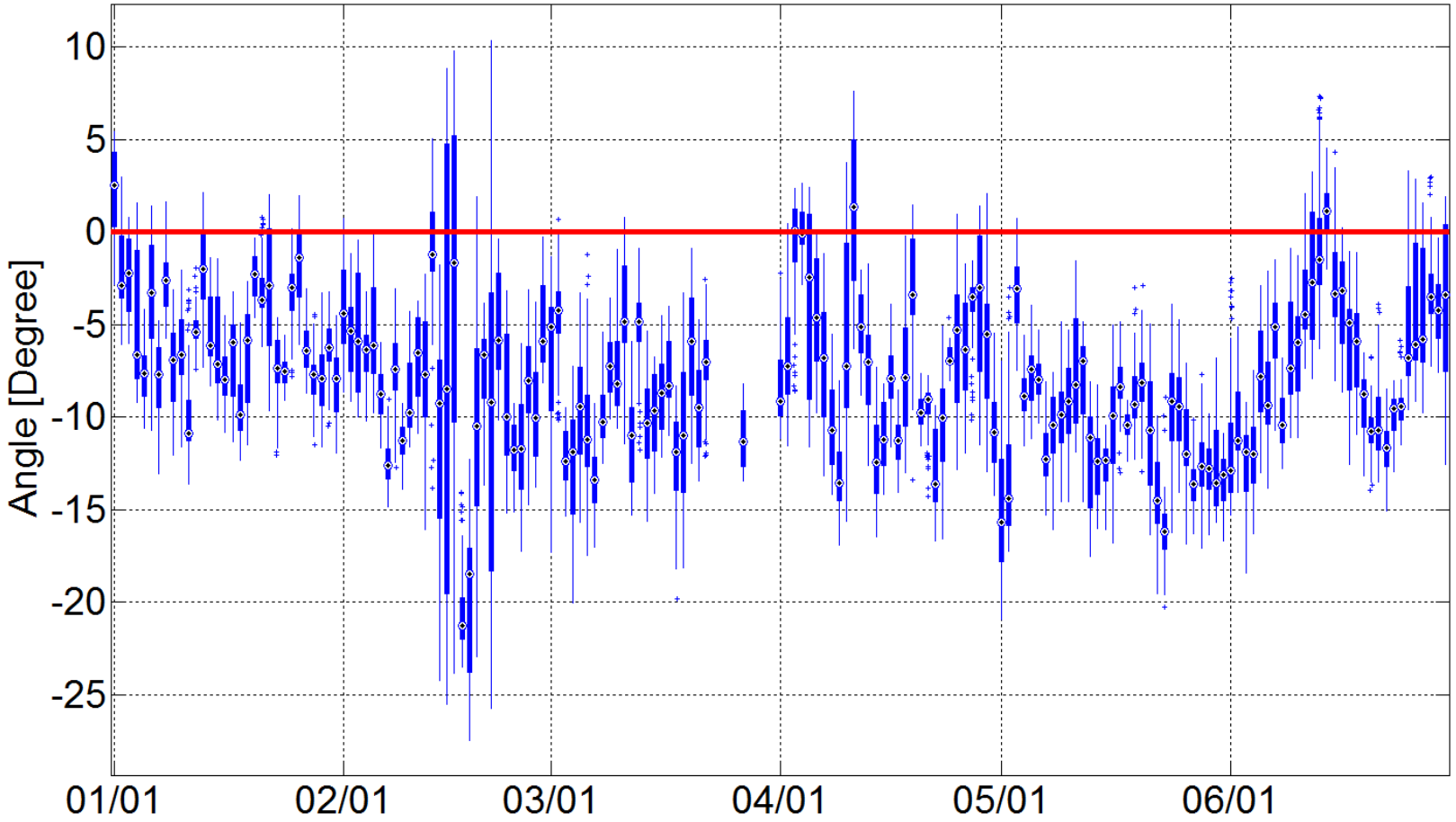
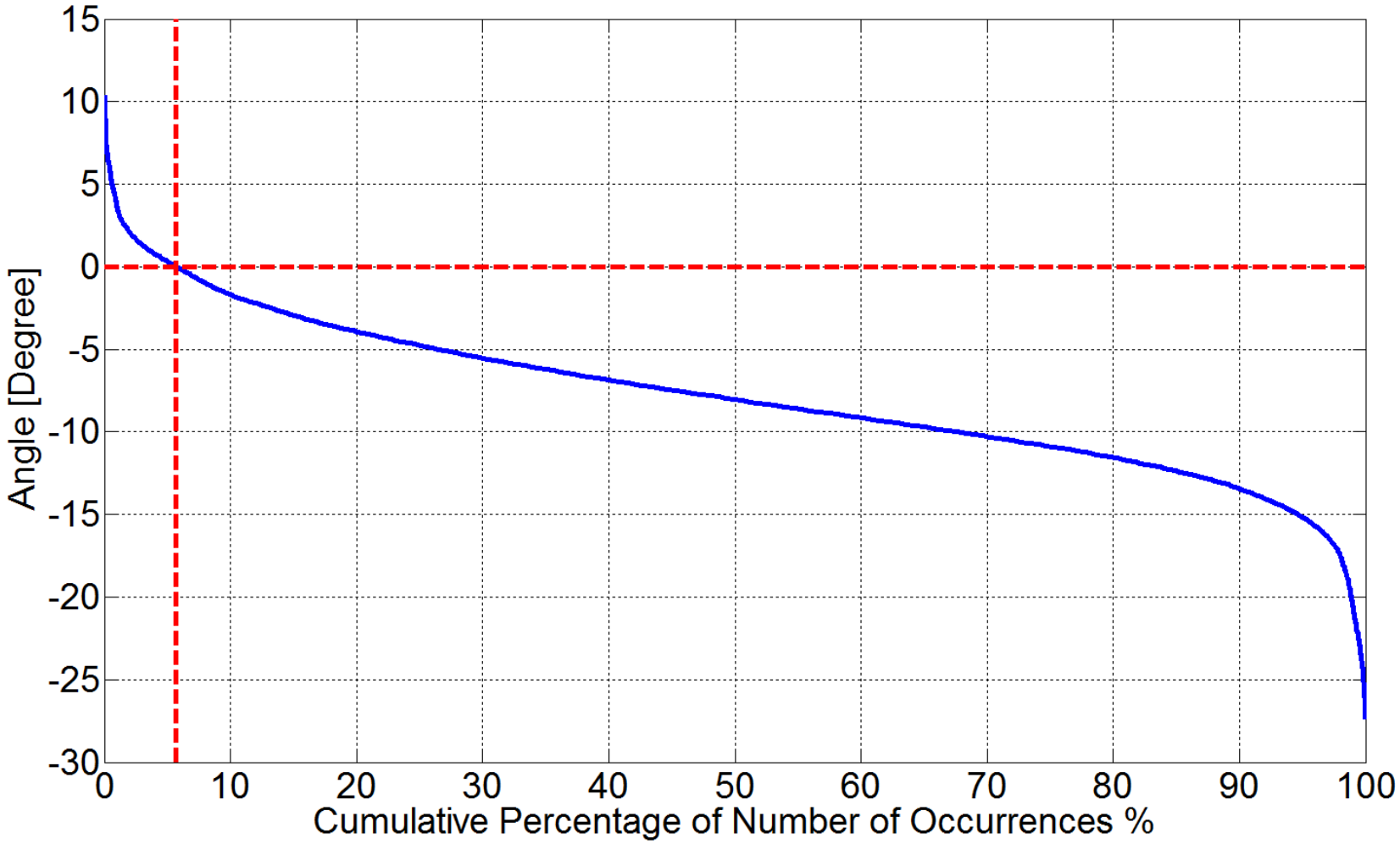


FarWest 2*-North 7



FarWest 2*-North 7



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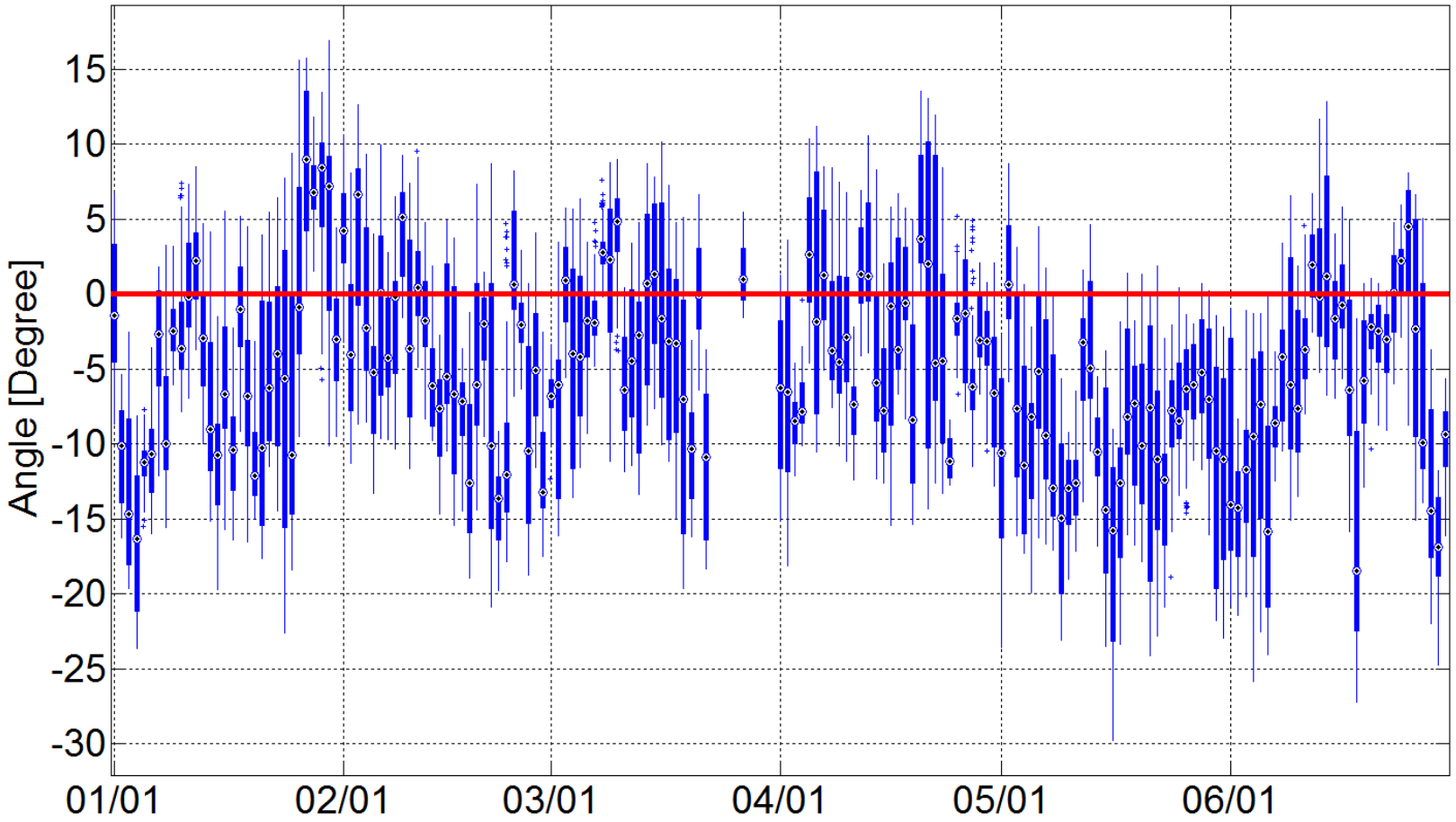

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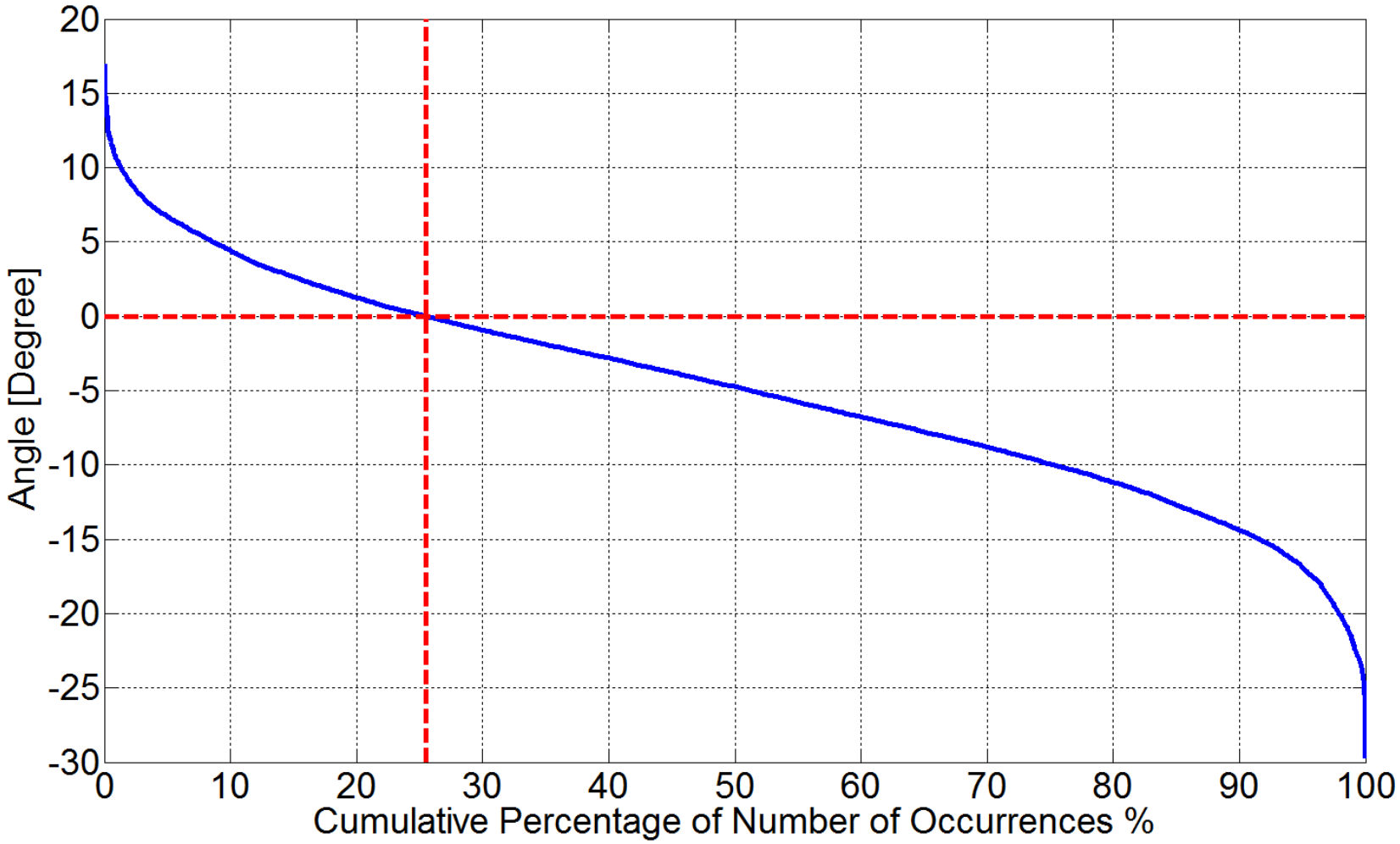
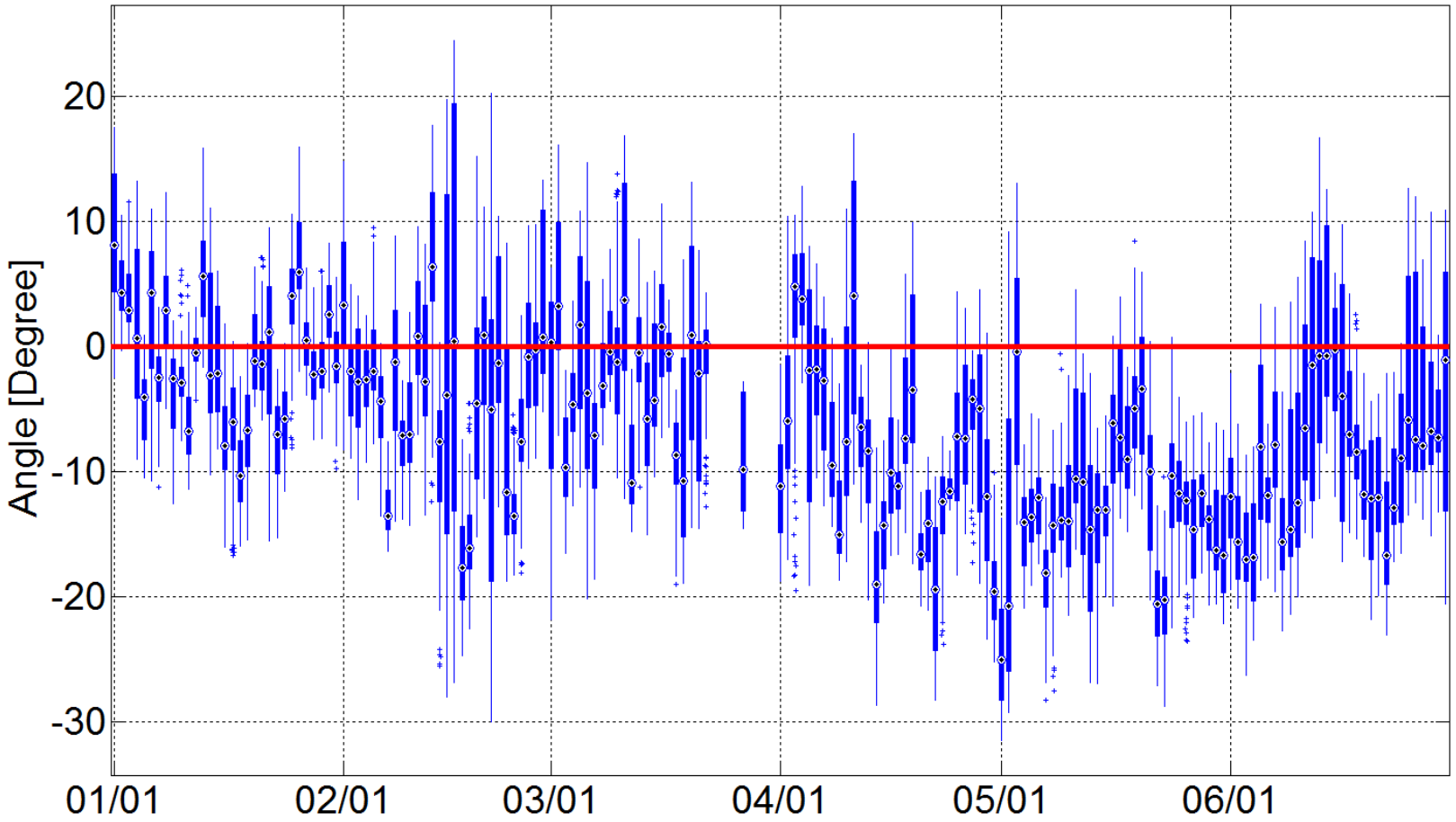


Coast 2*-North 7



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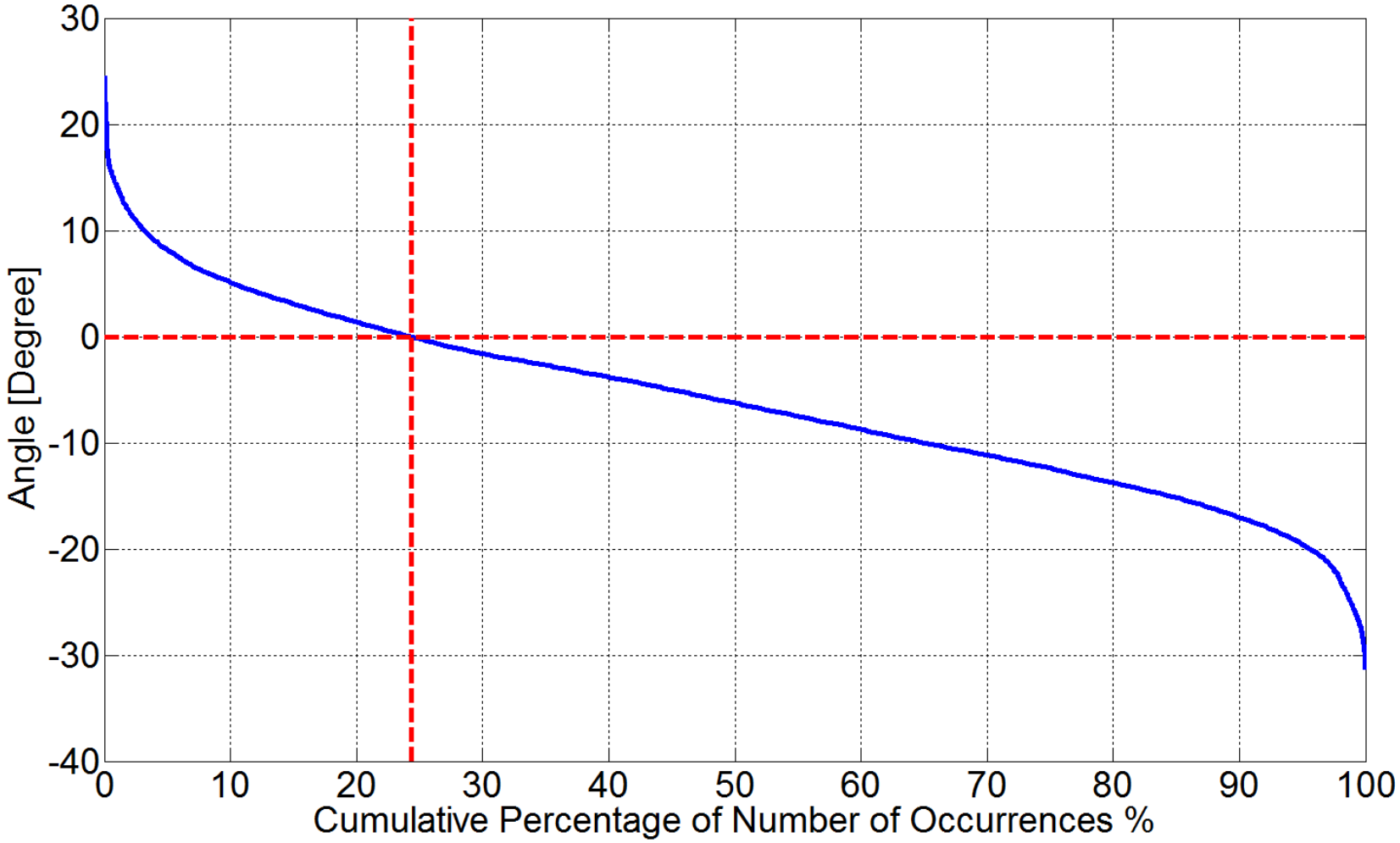
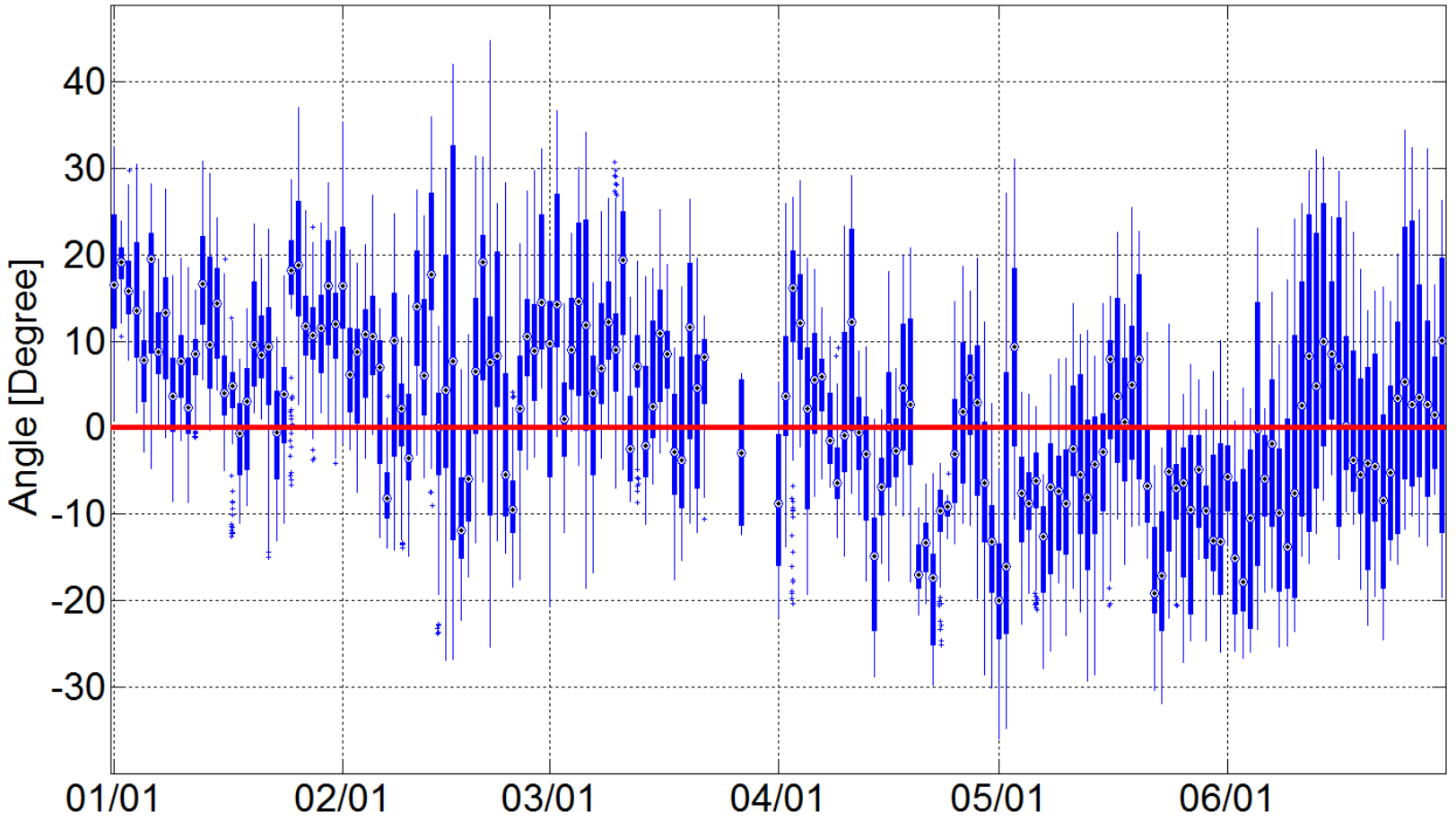


Coast 1-North 7



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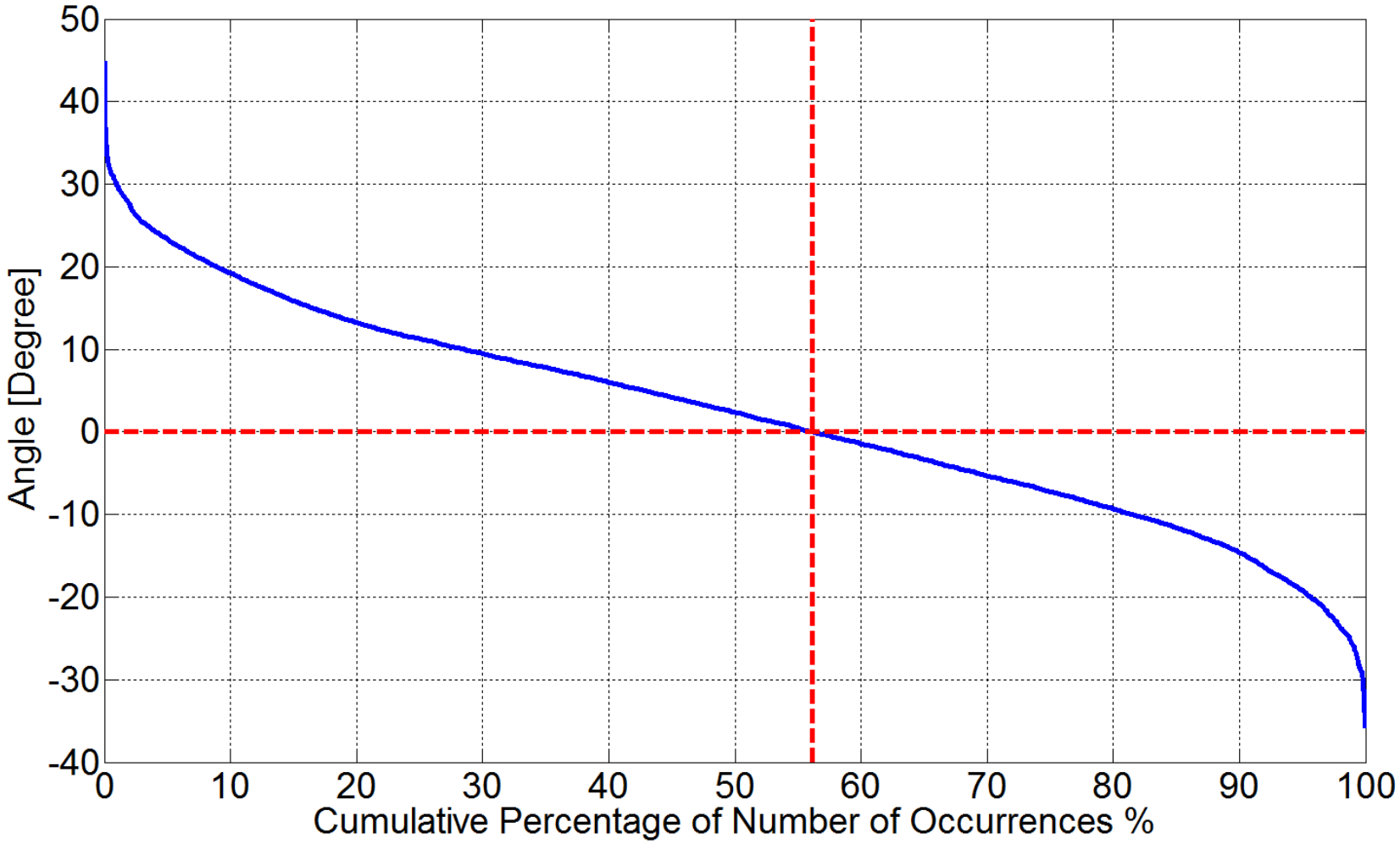
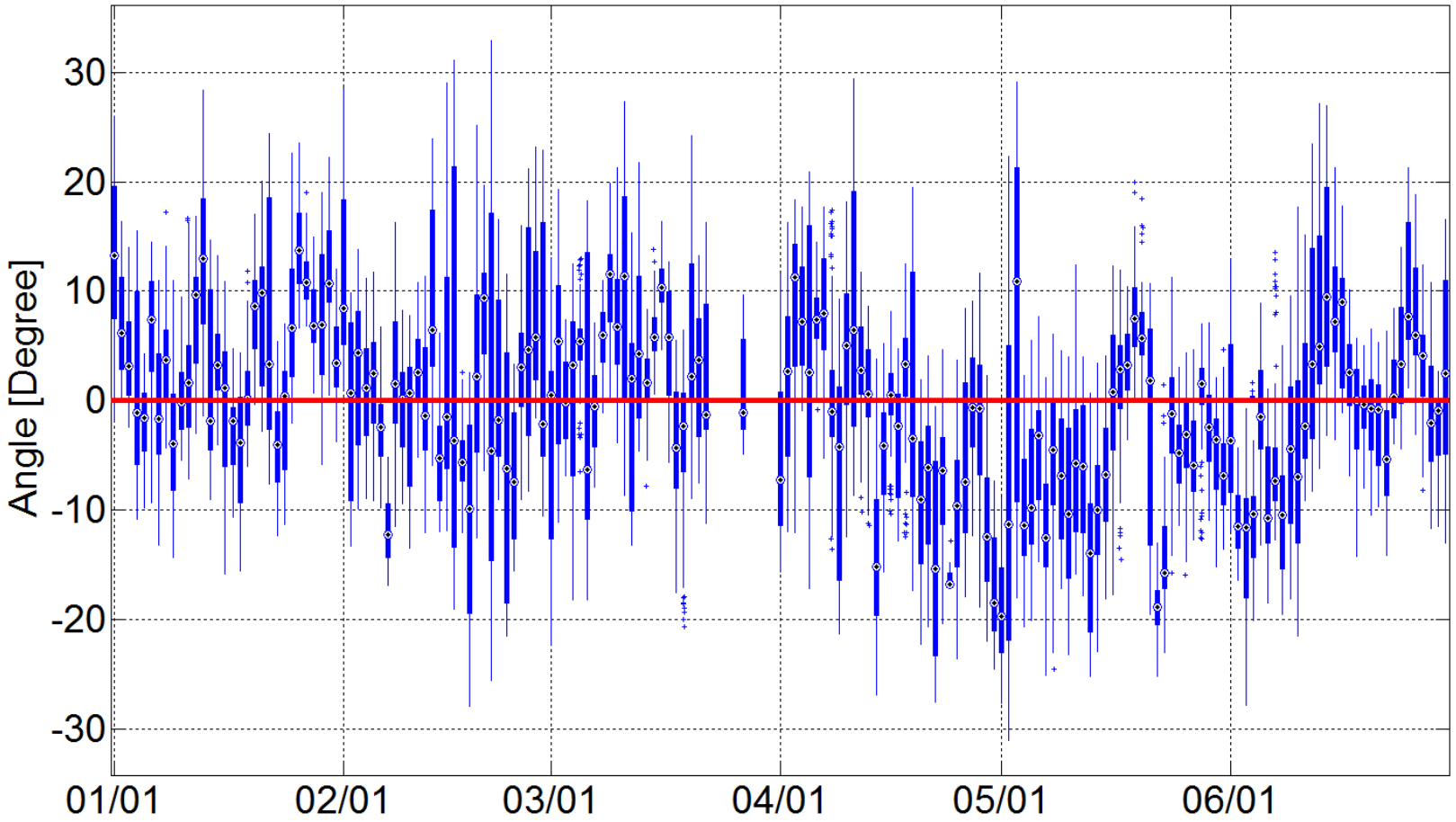


South 3*-North 7



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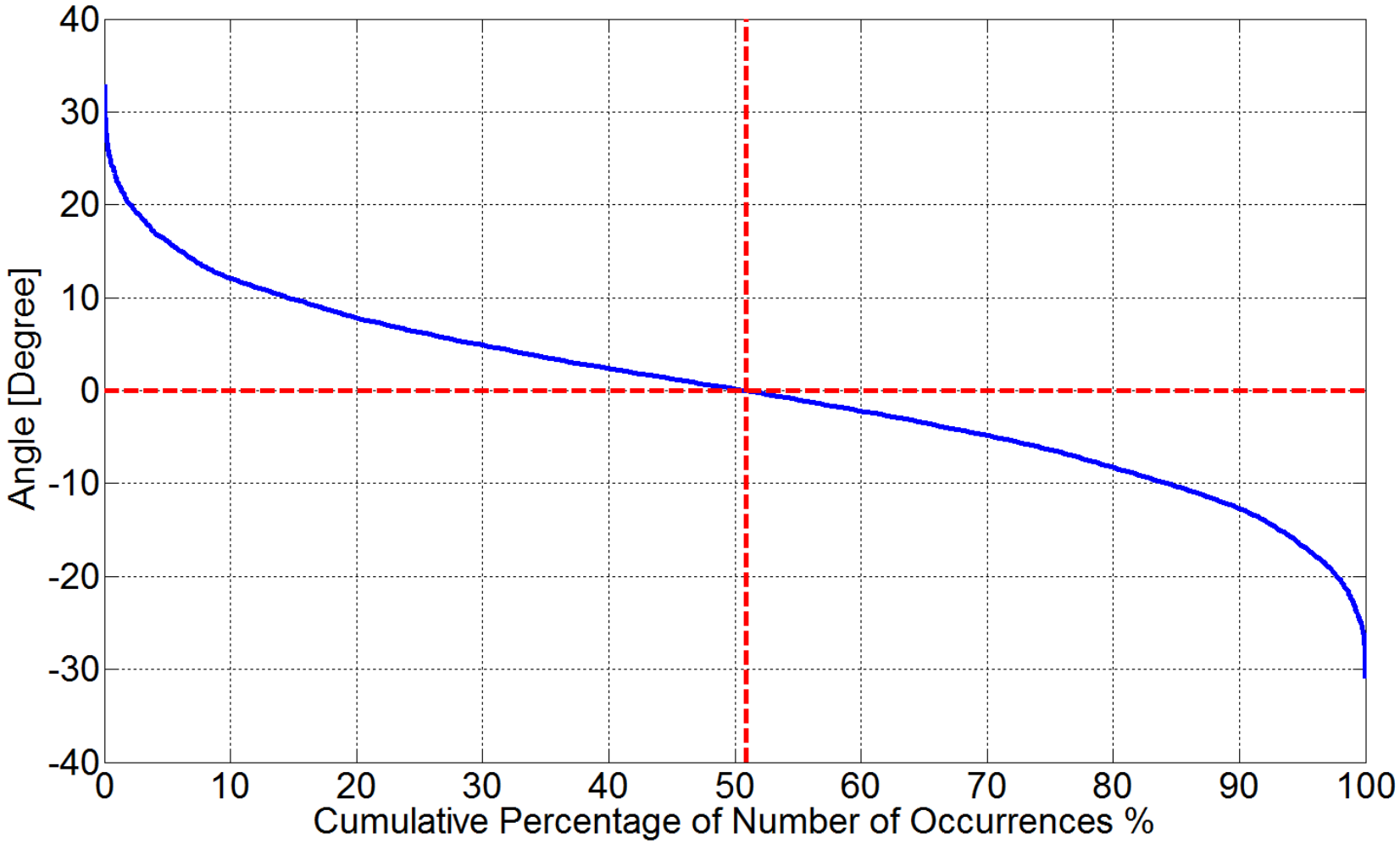

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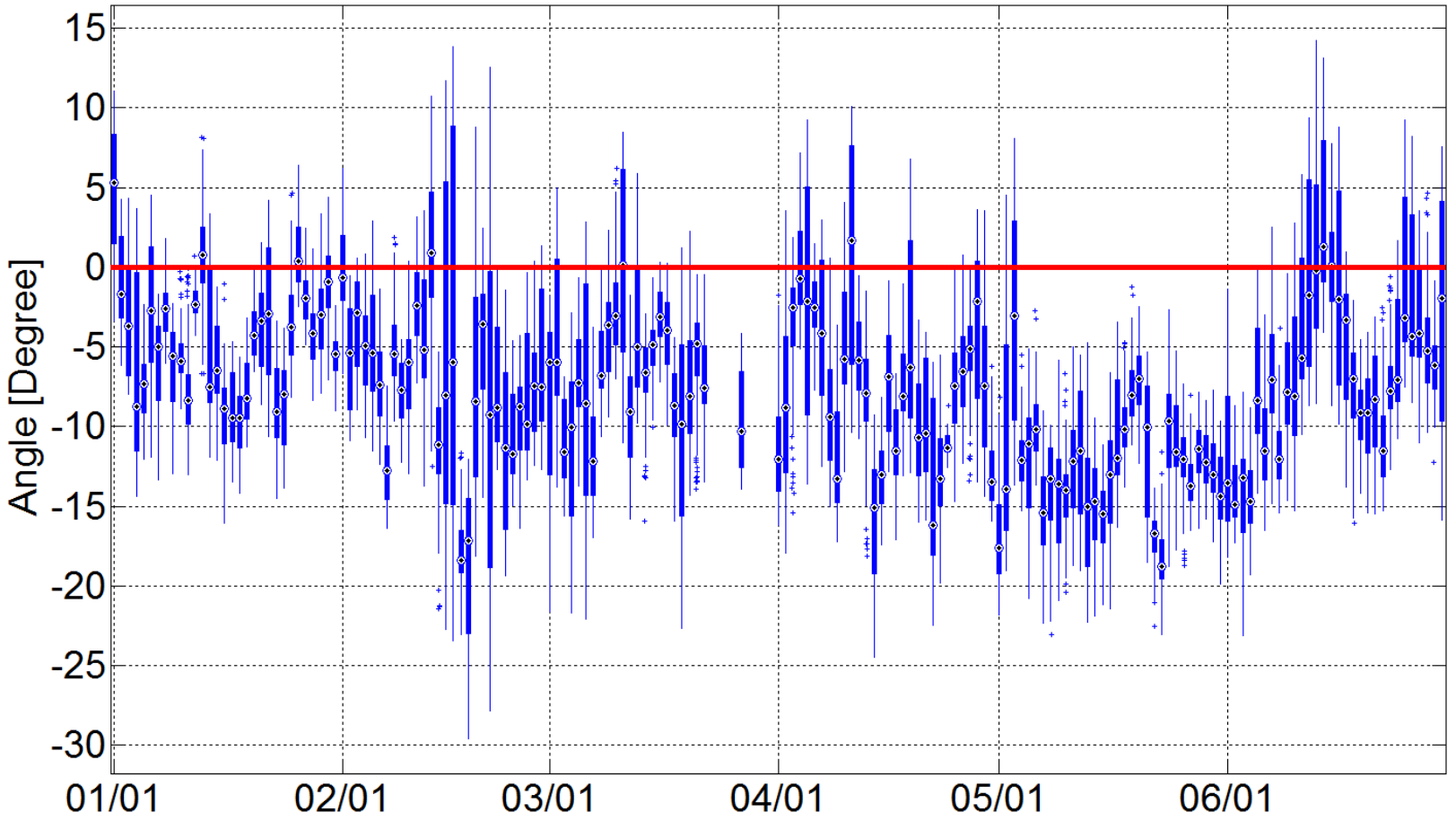

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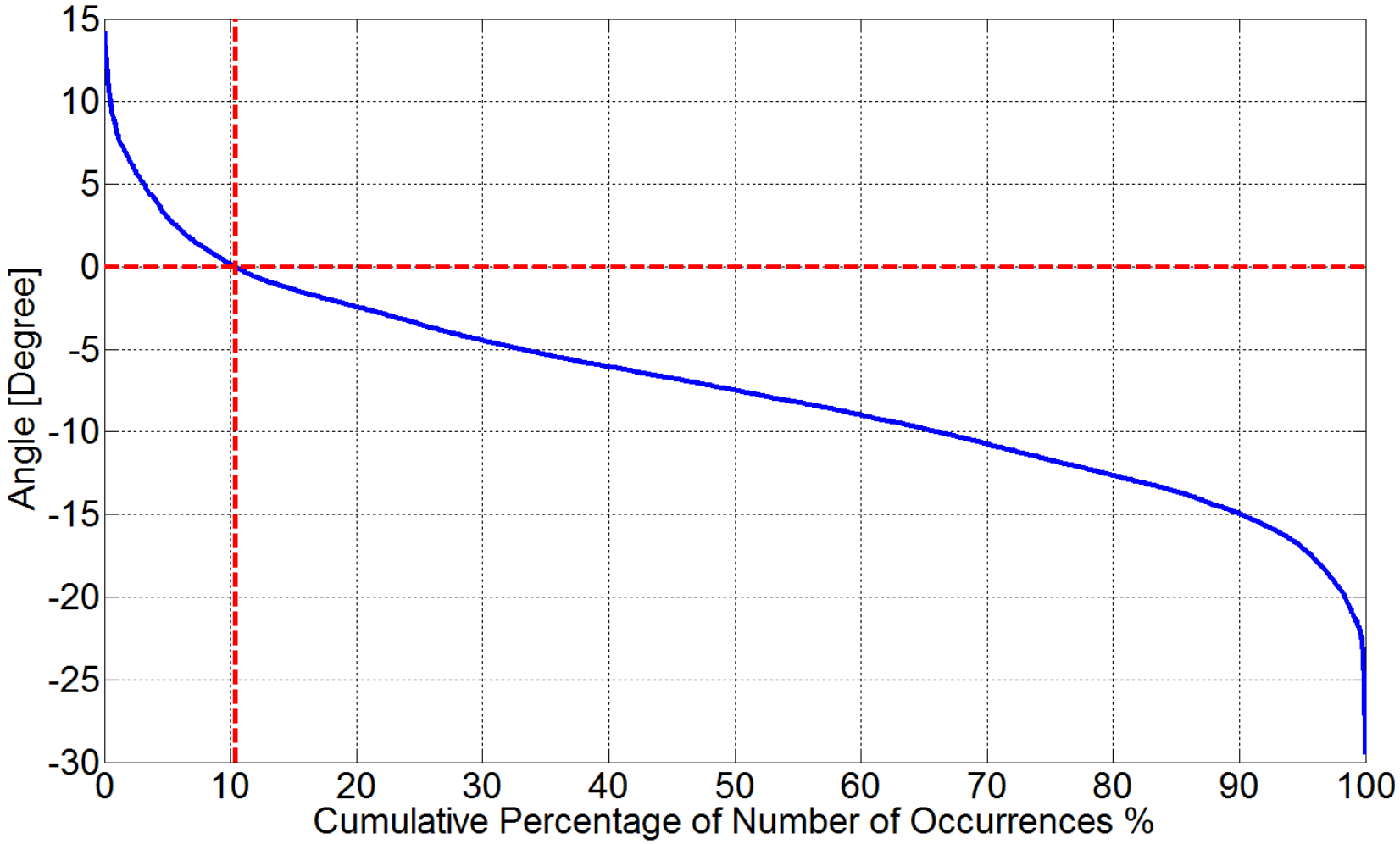

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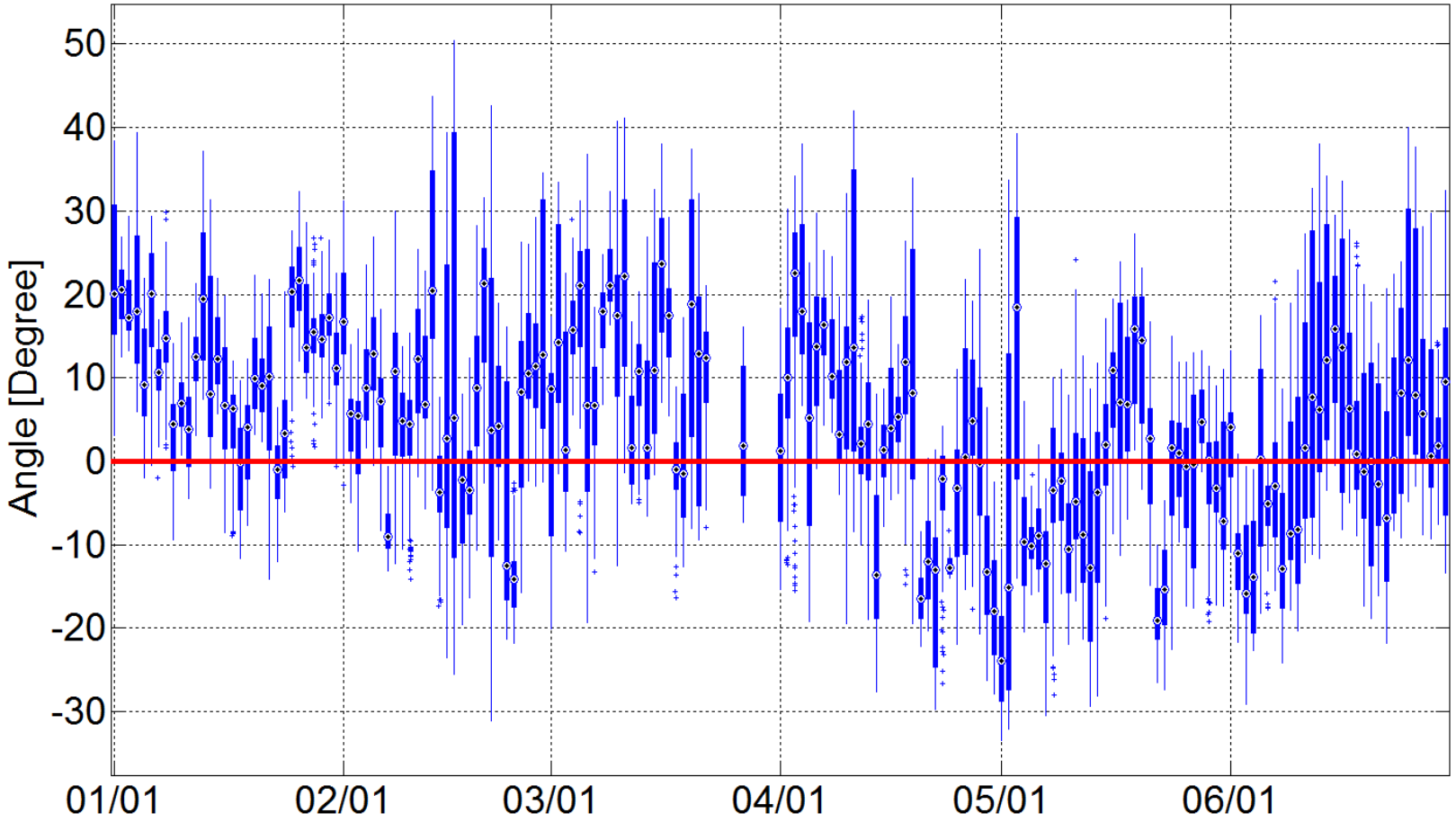

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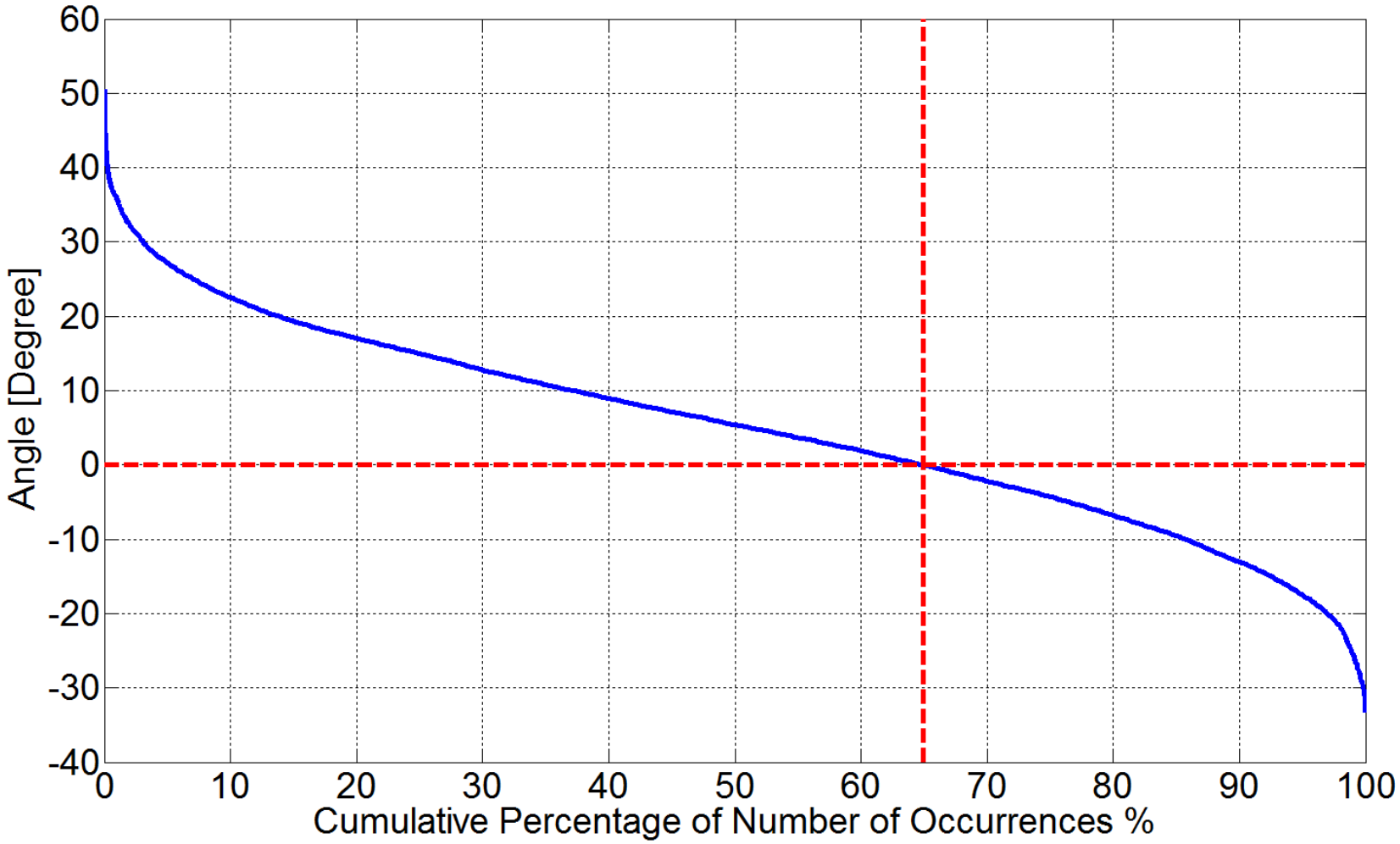
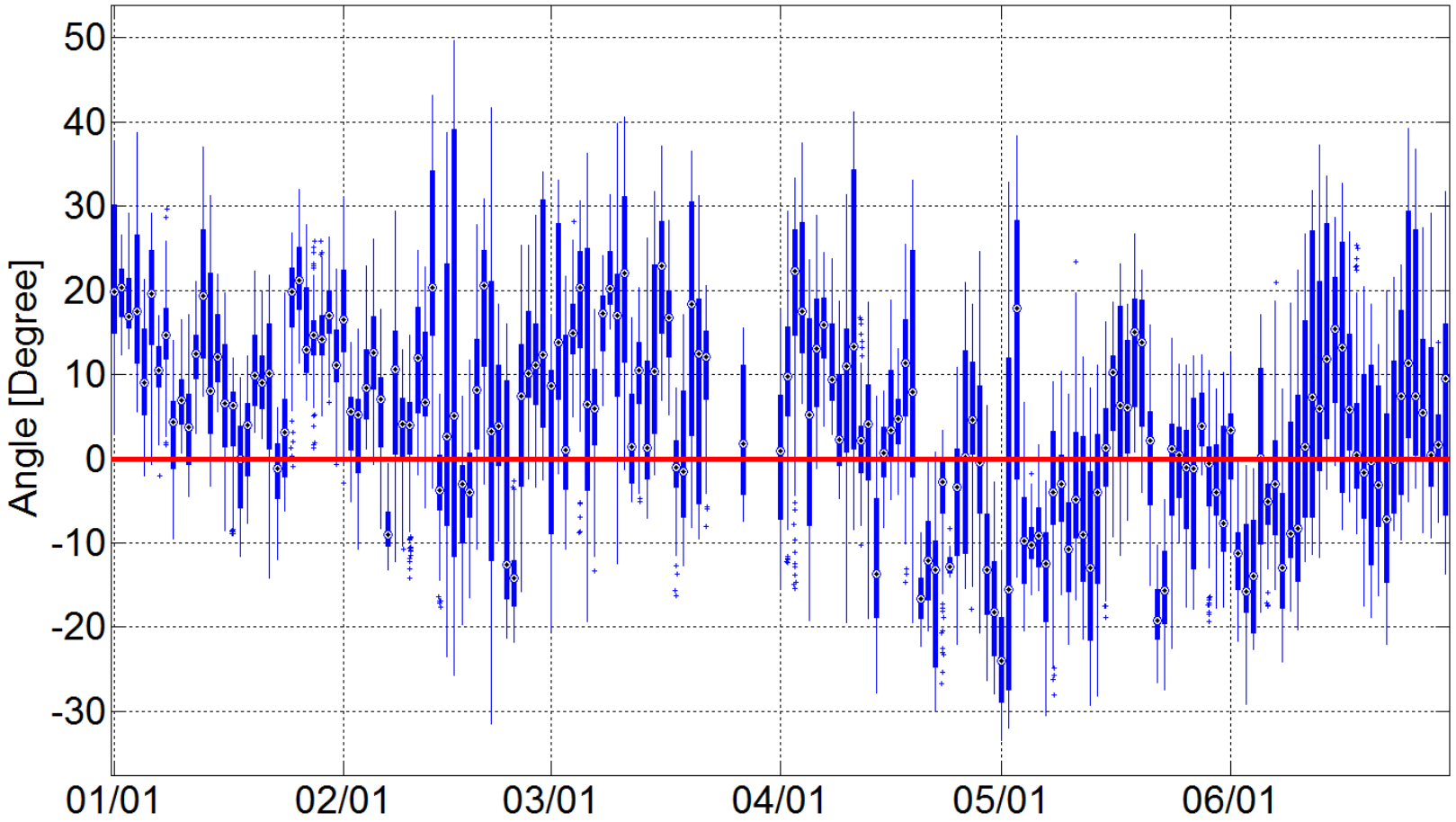
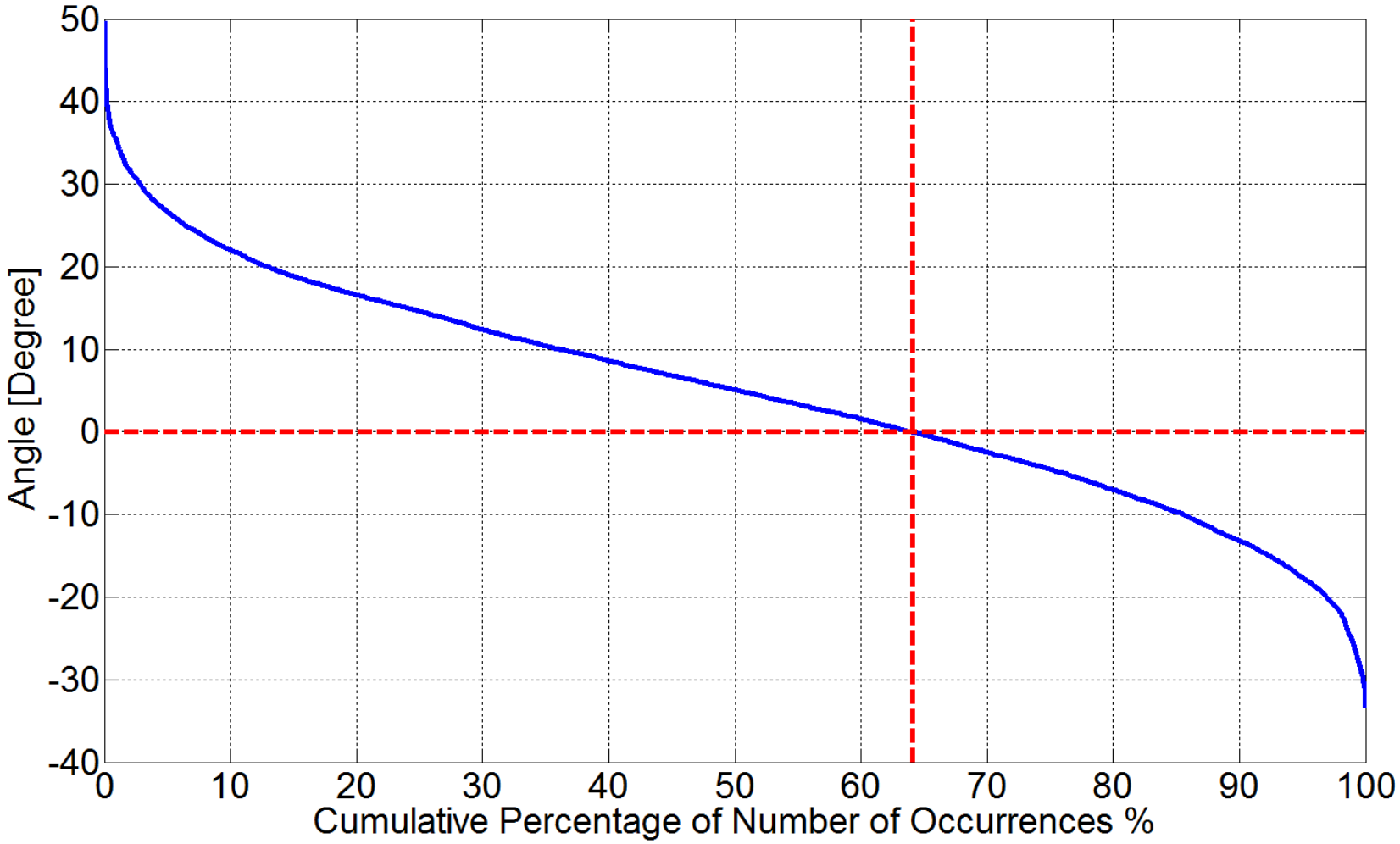


Coast 3-North 7



Coast 3-North 7



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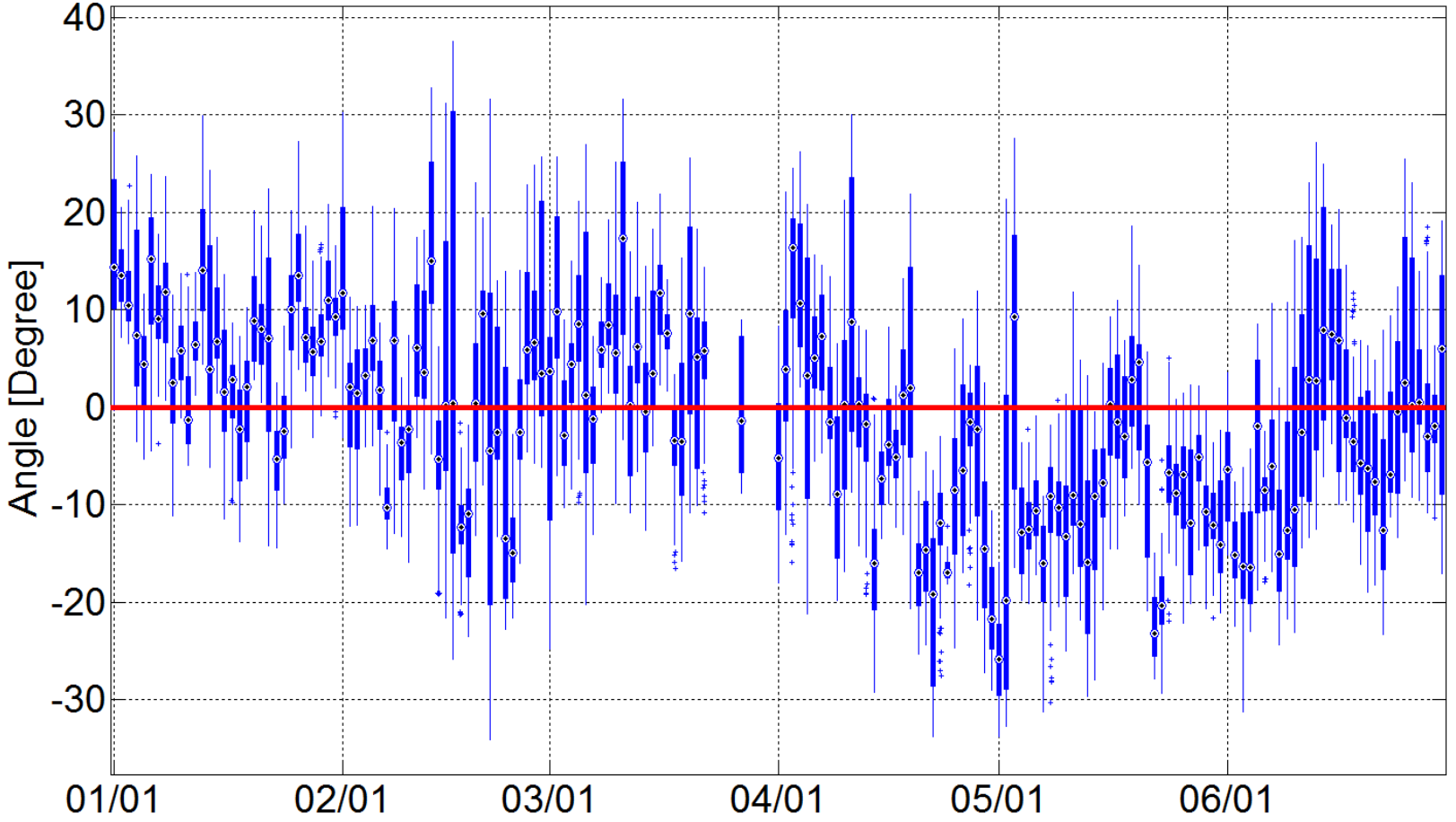

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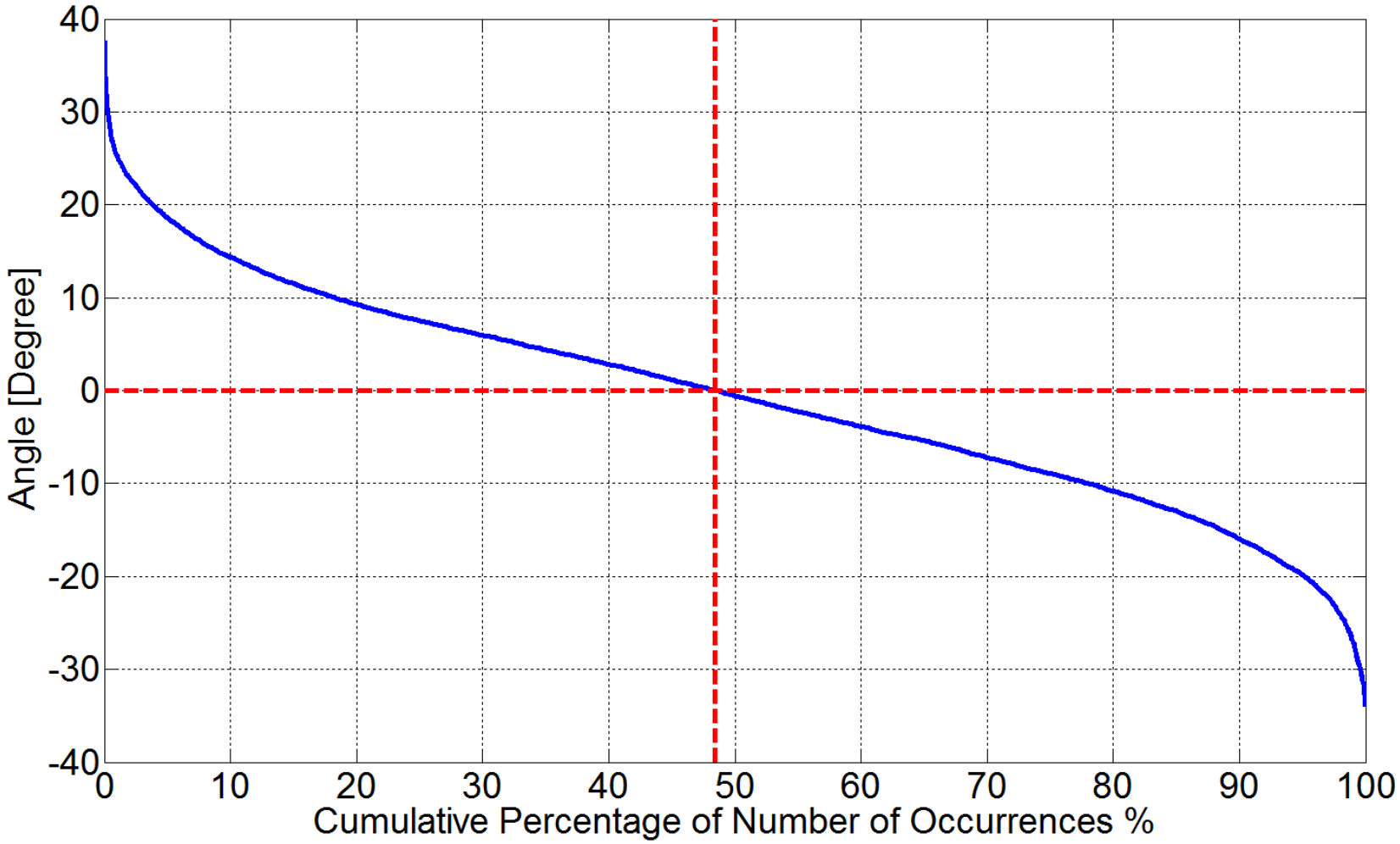
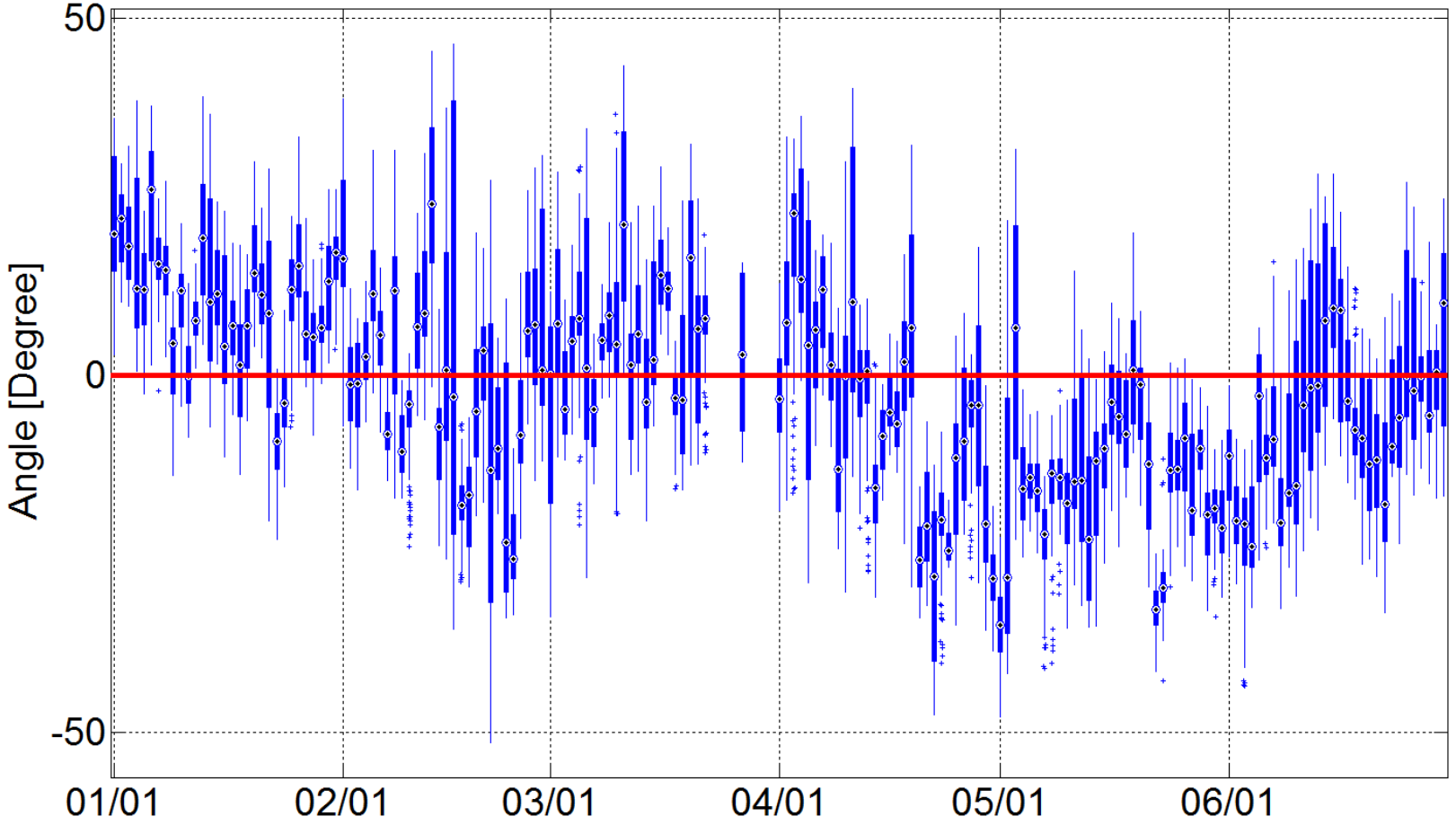


South 13-North 7



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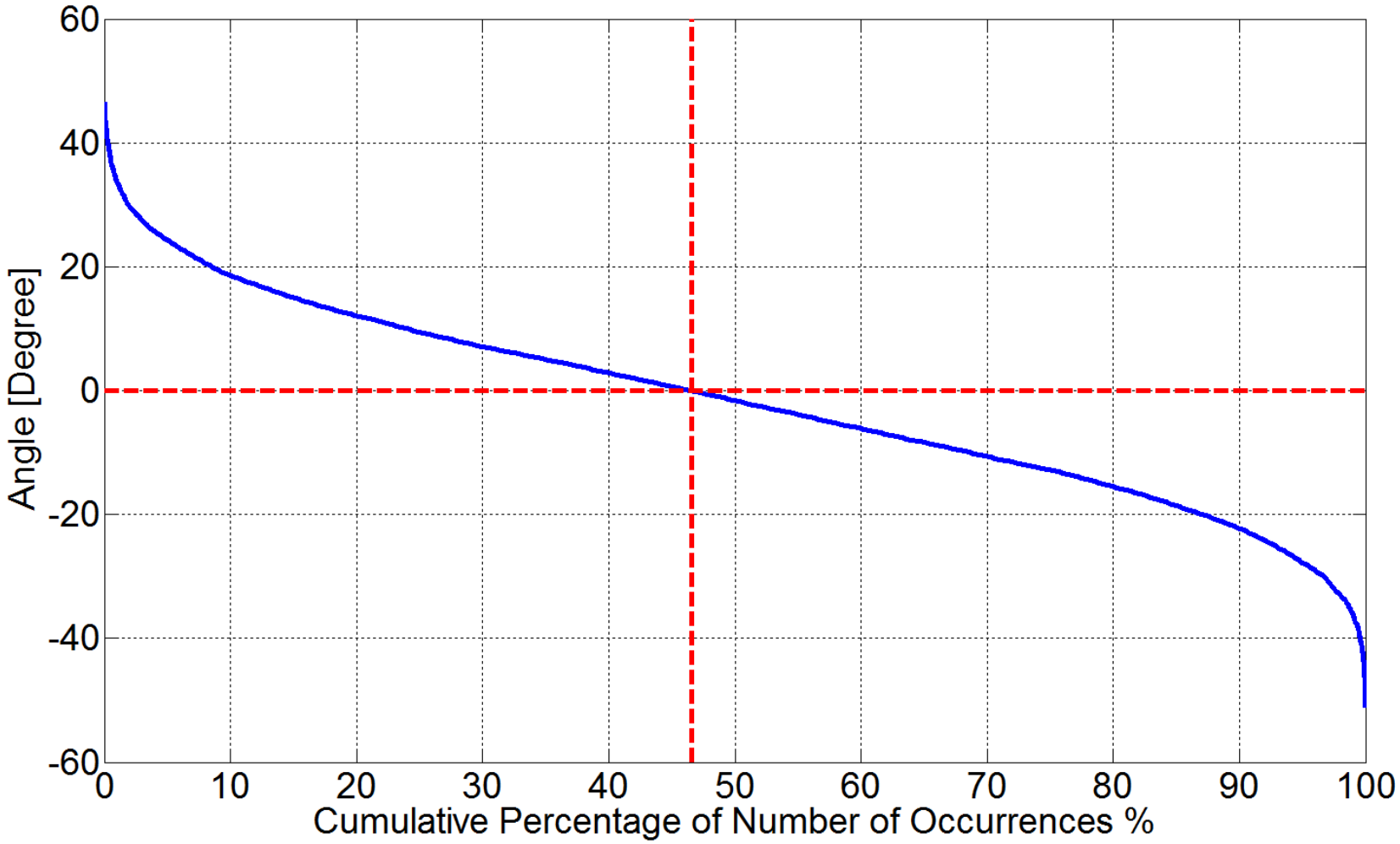
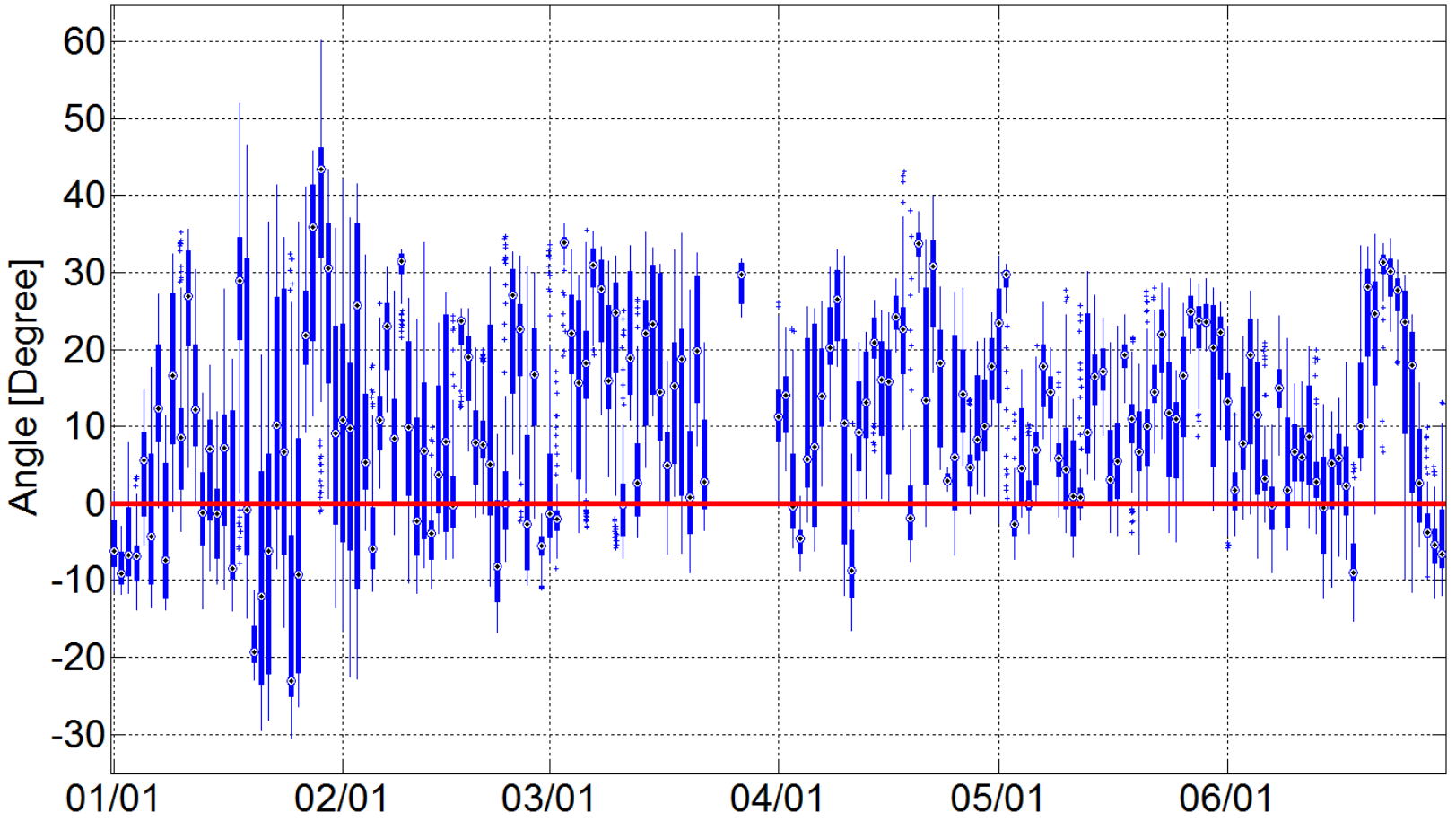
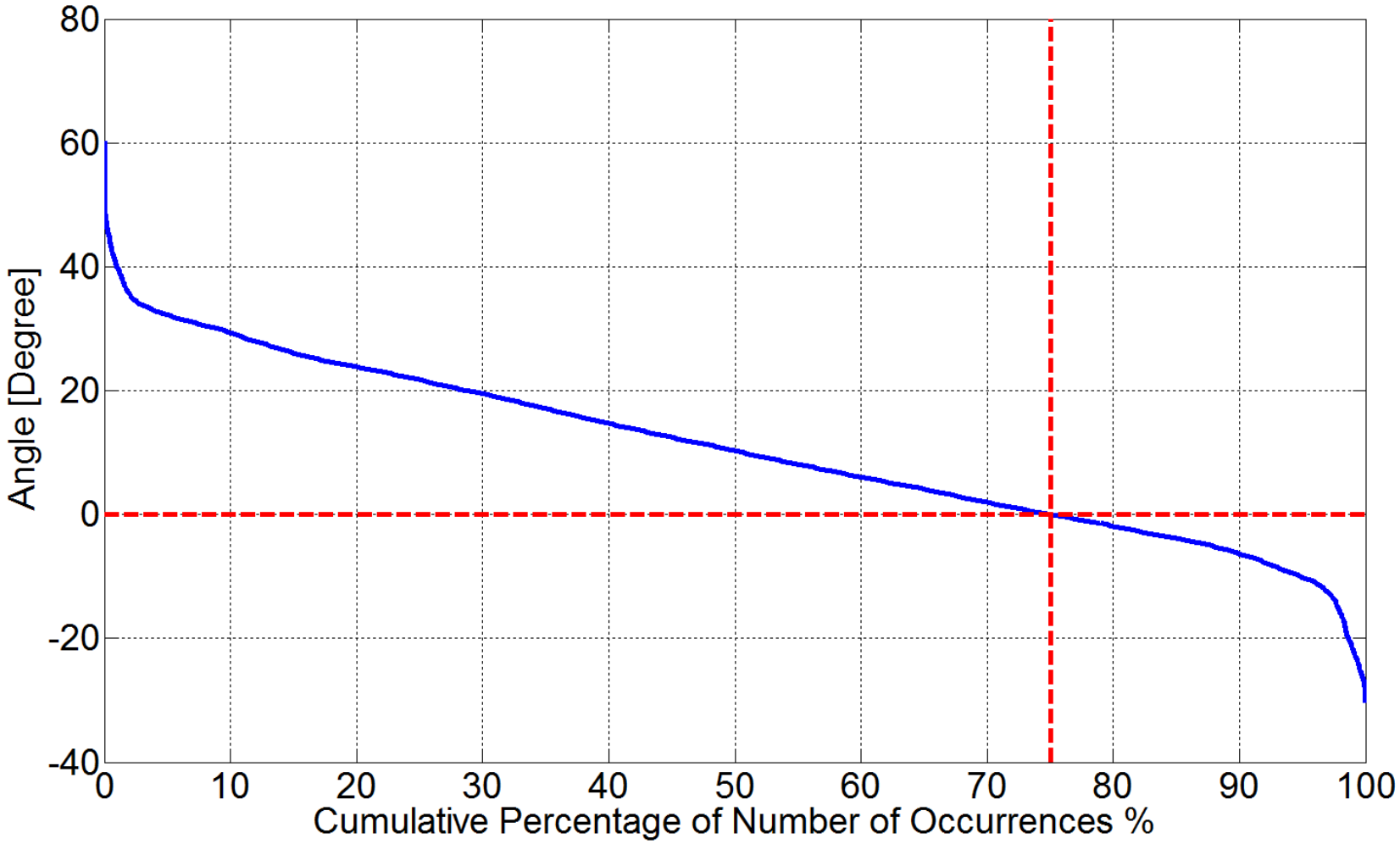


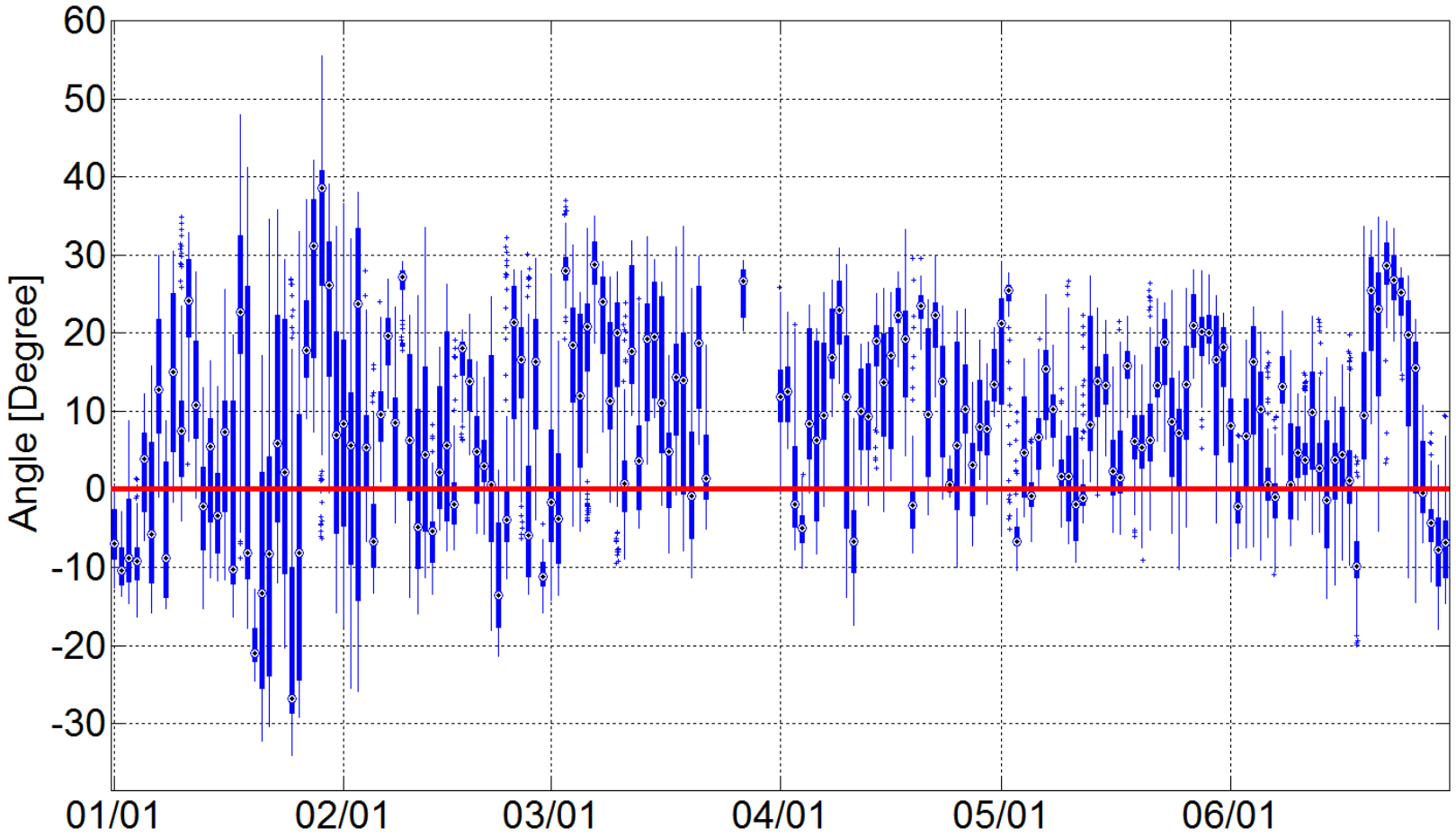
FarWest 4-North 7



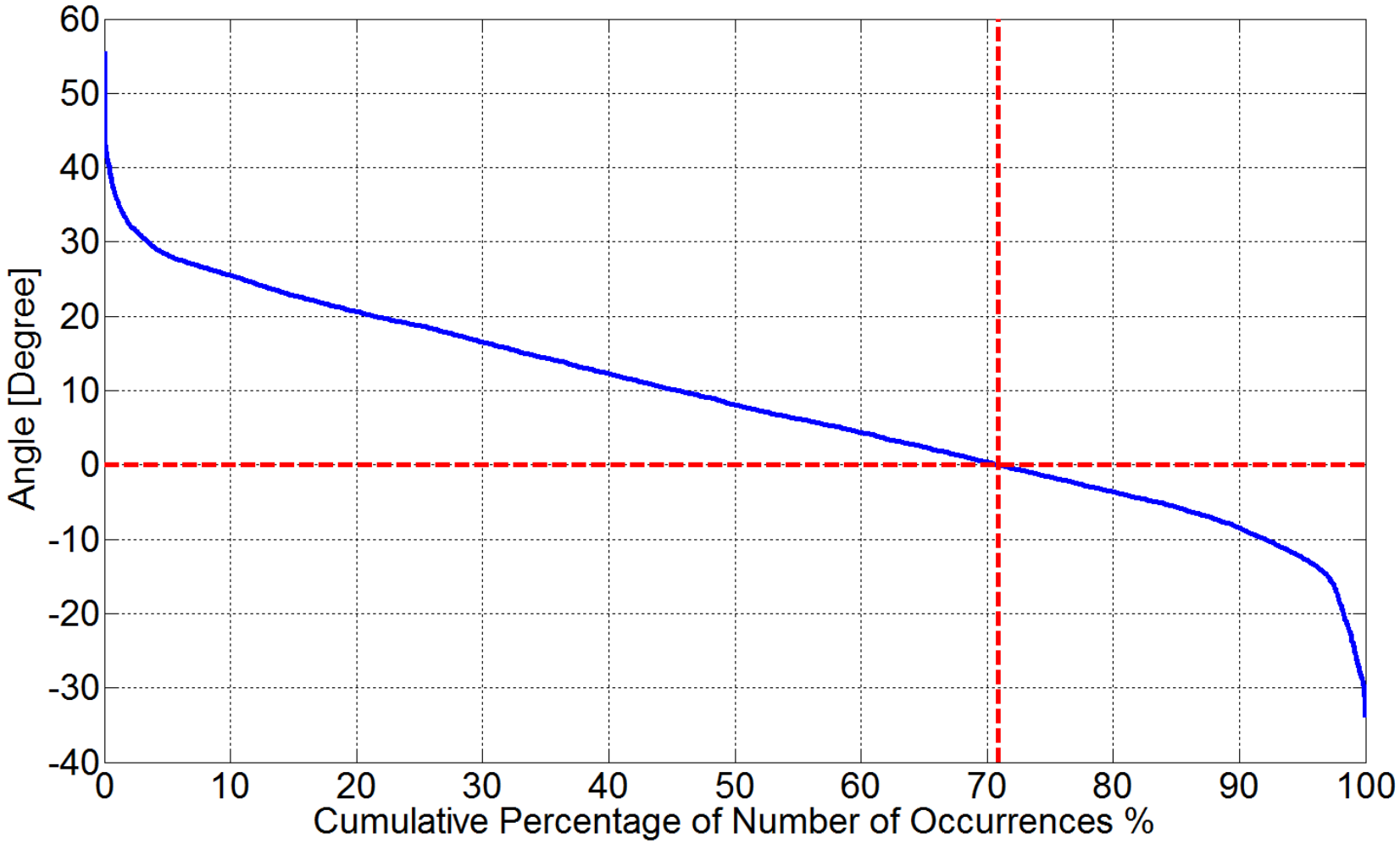
FarWest 4-North 7



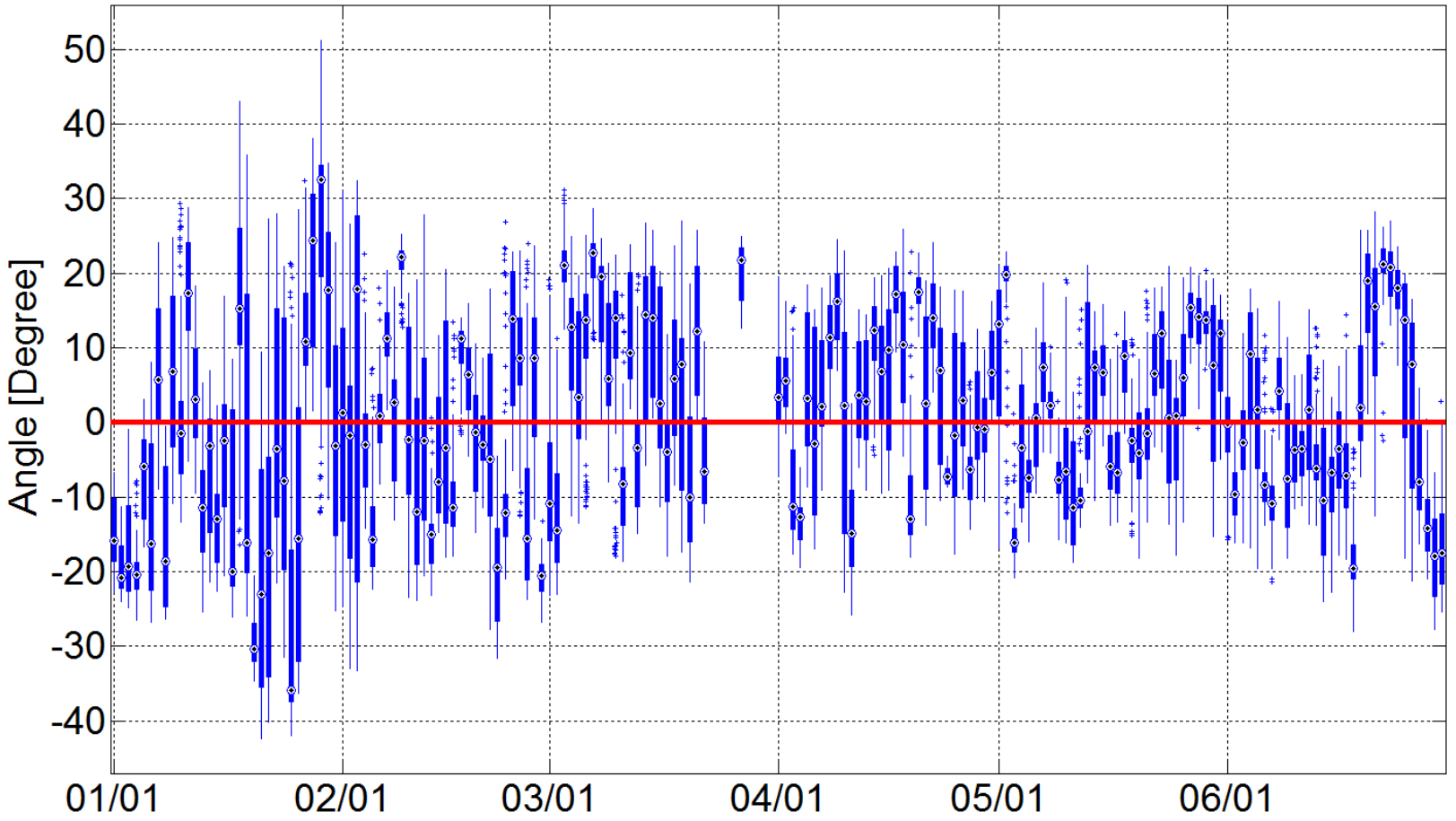
FarWest 7-North 7



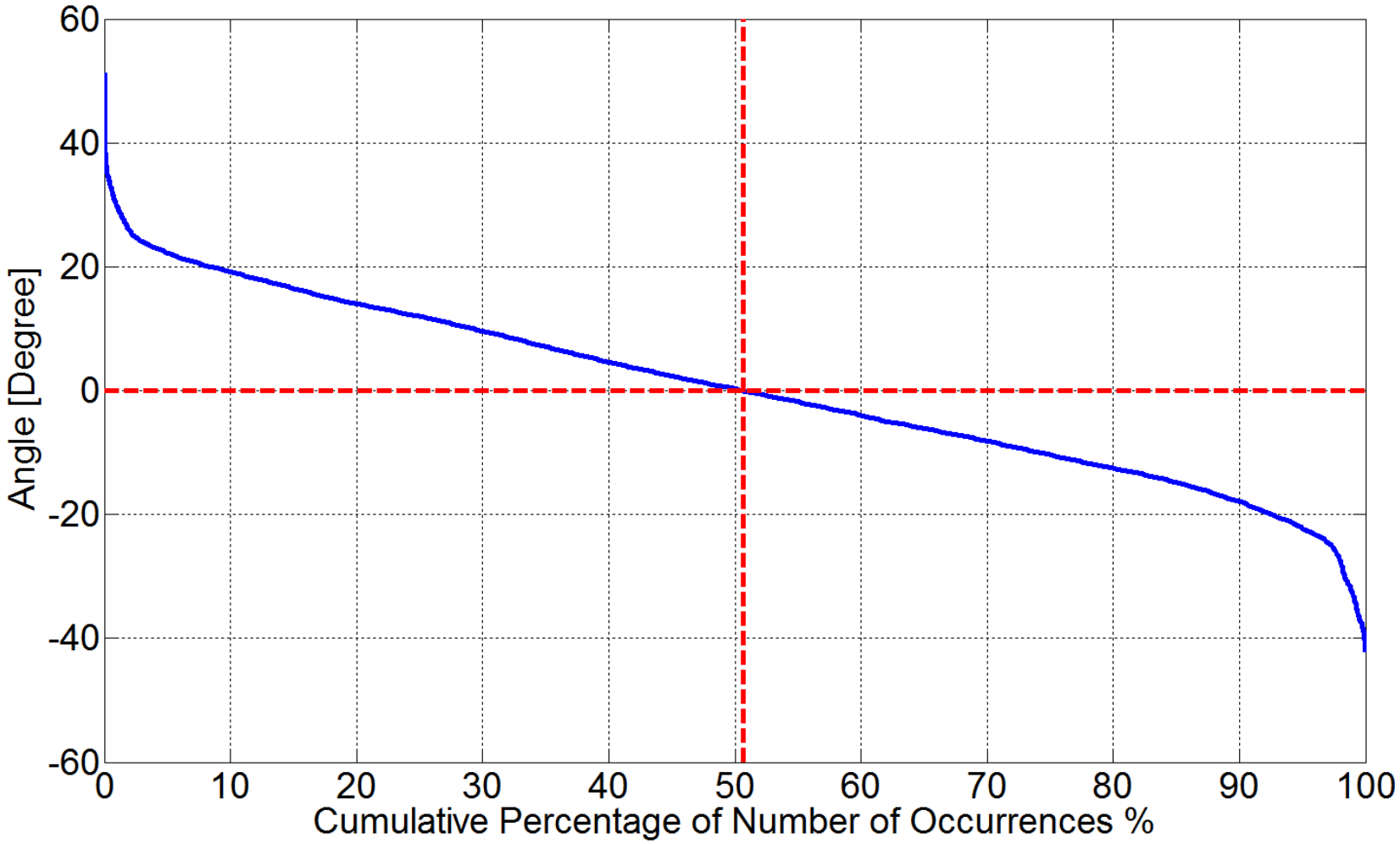
FarWest 7-North 7



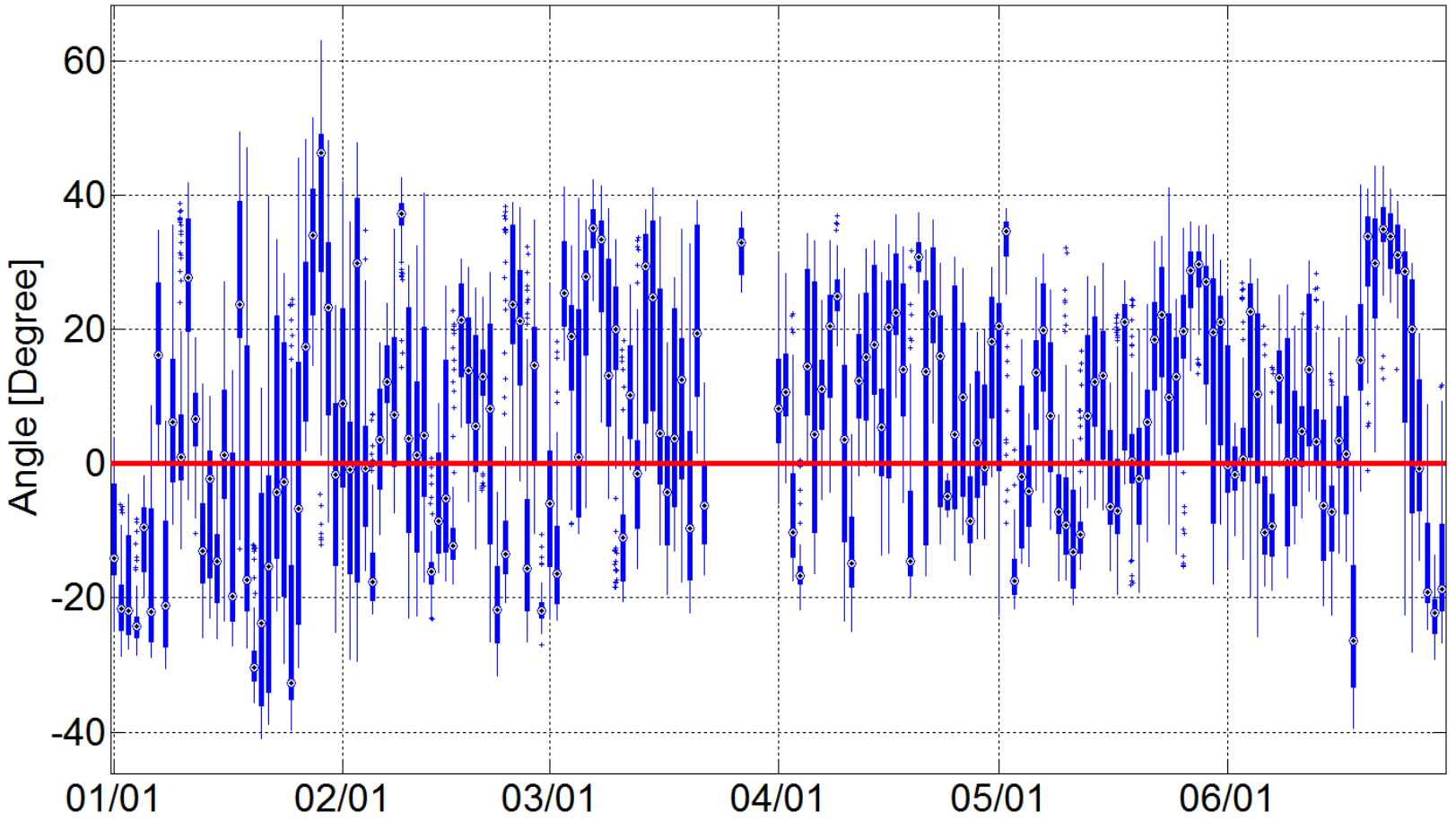
FarWest 8-North 7



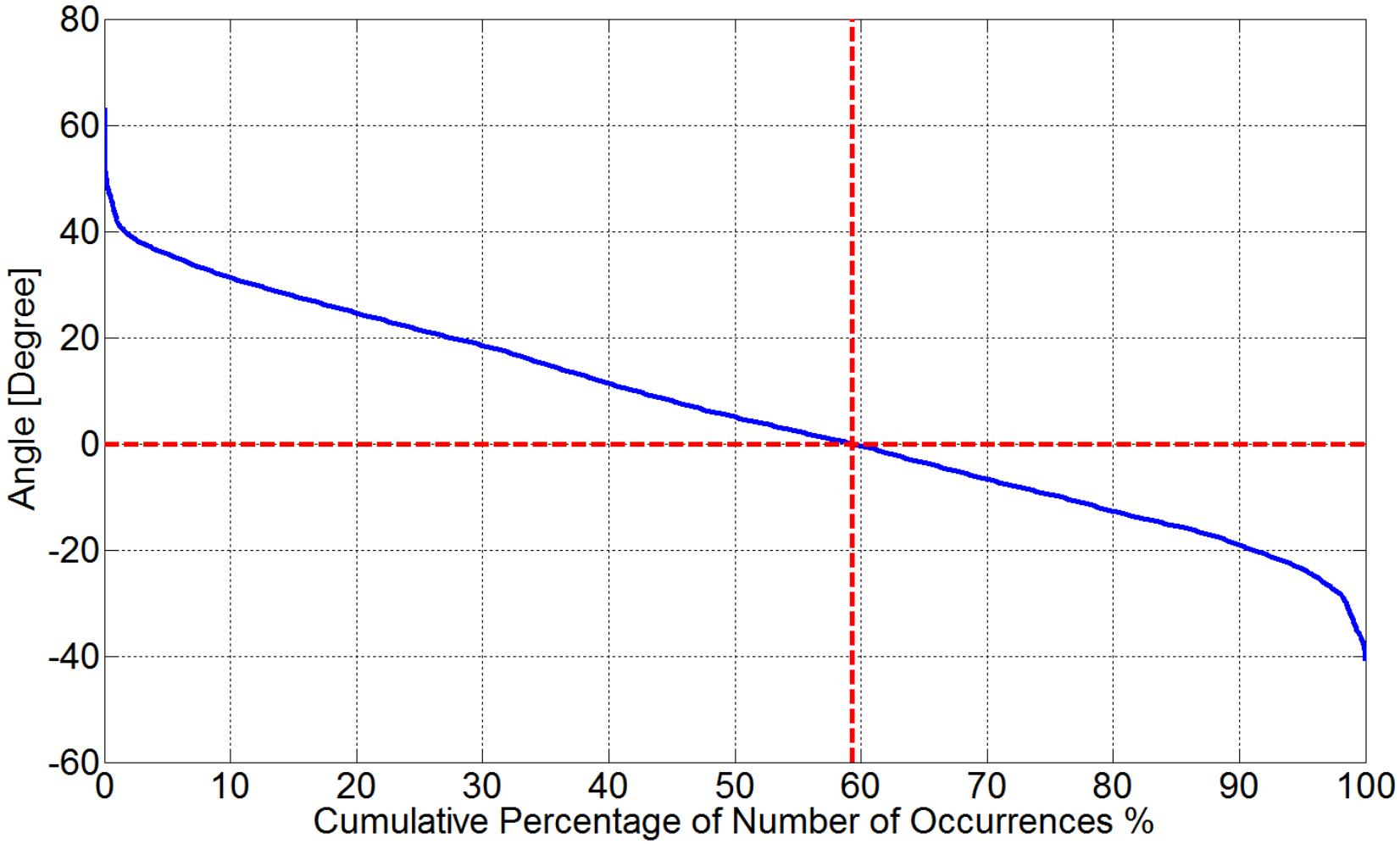
FarWest 8-North 7



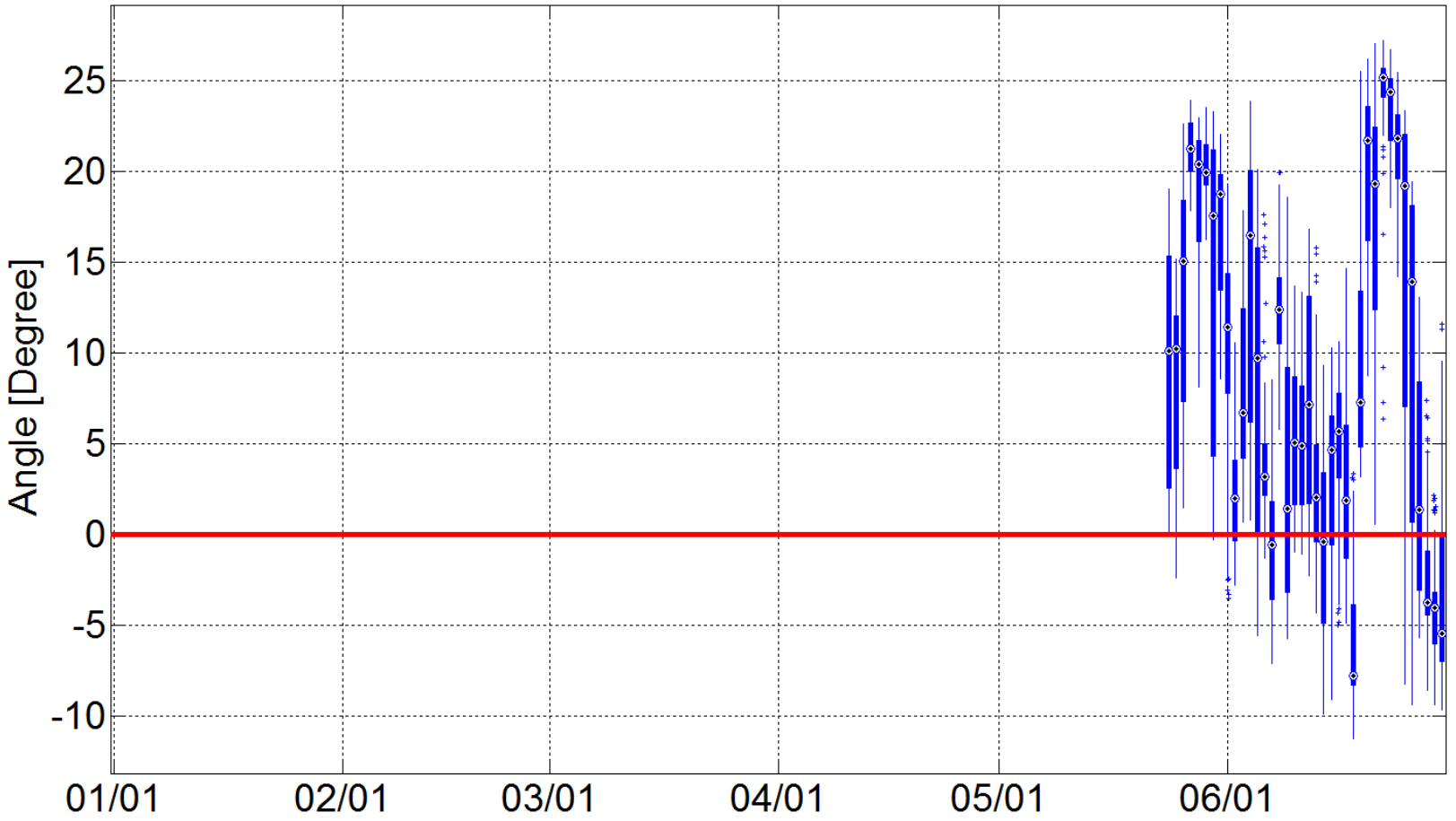
FarWest 9-North 7



FarWest 9-North 7



West 8*-North 7



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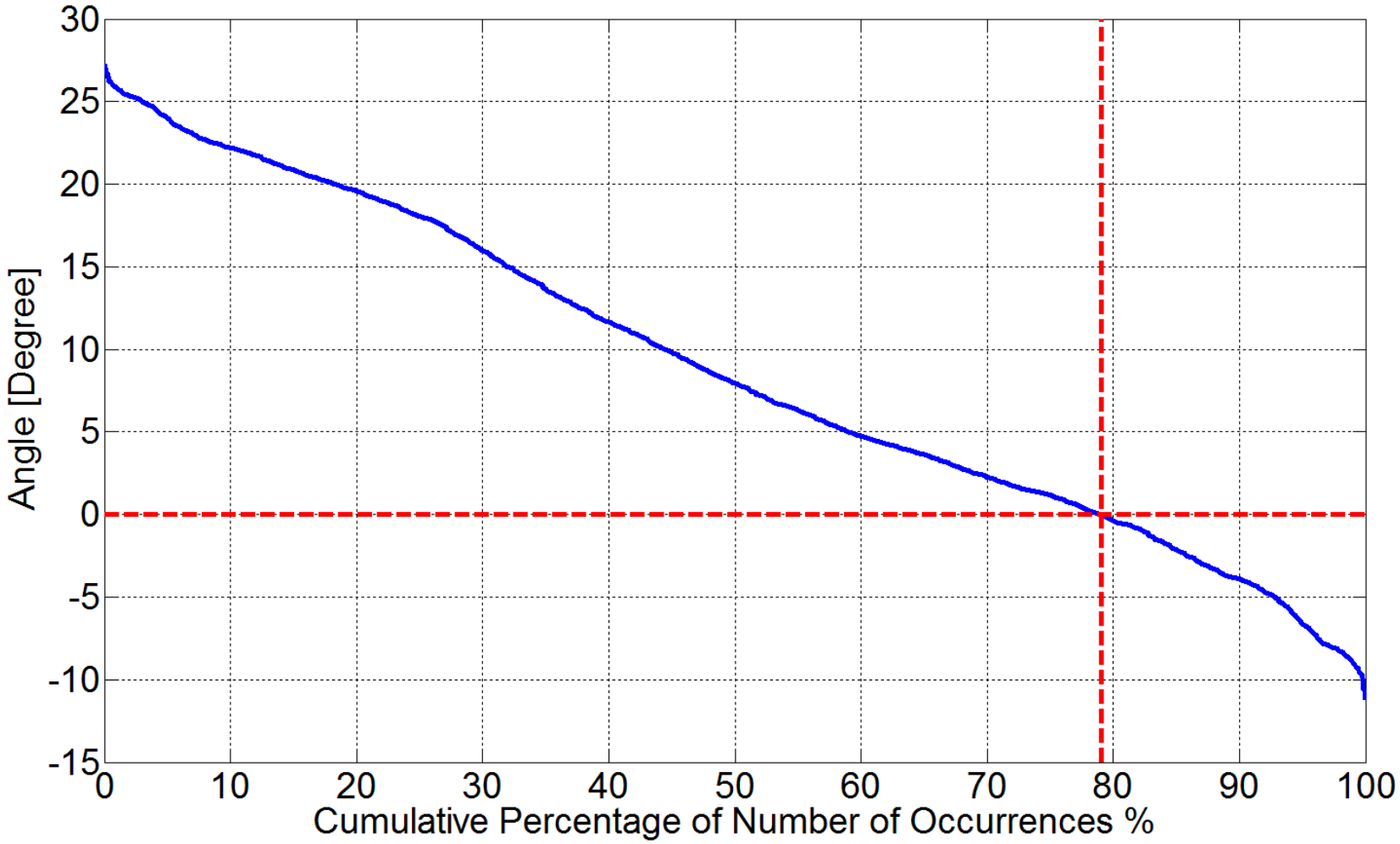

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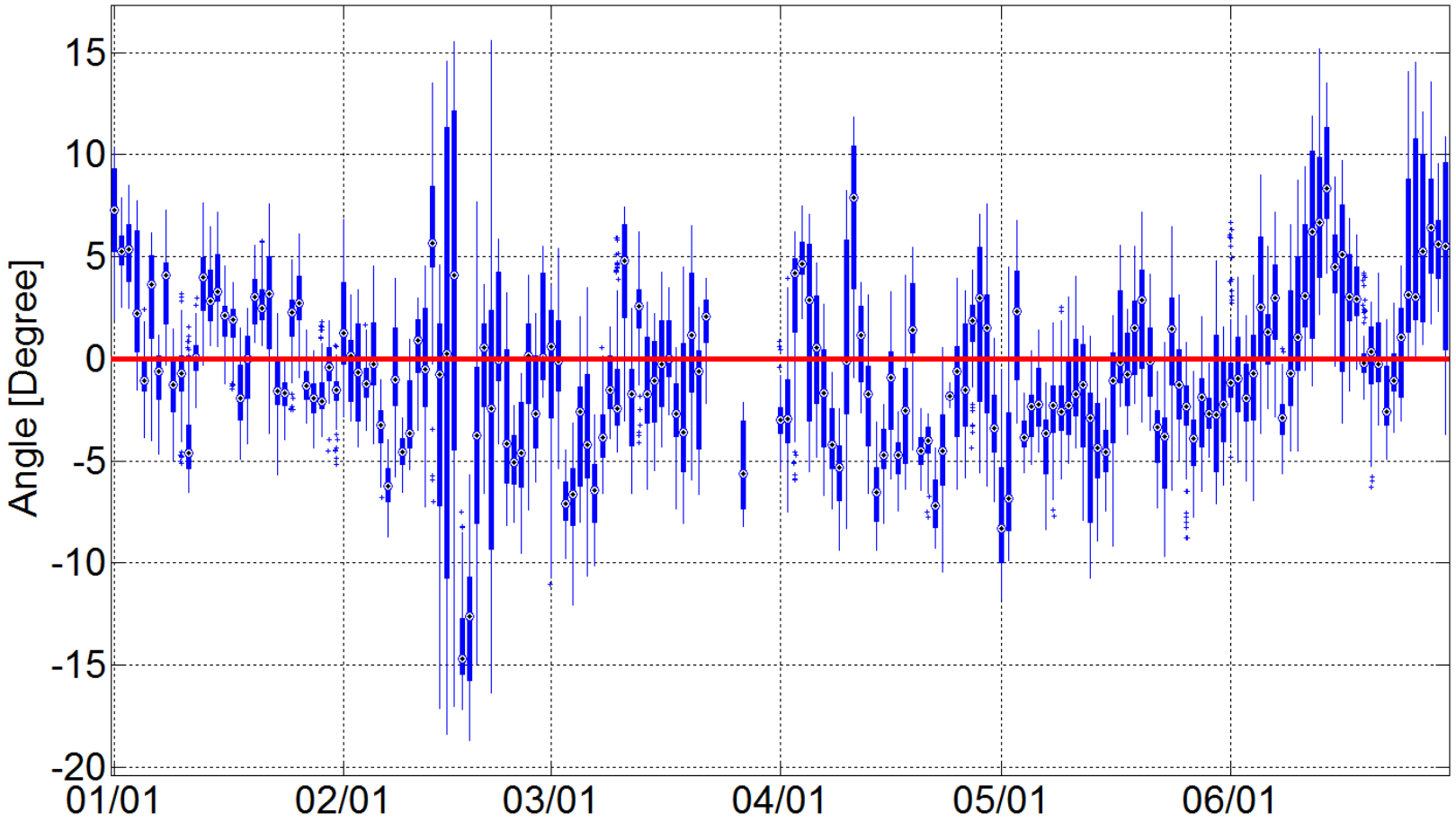

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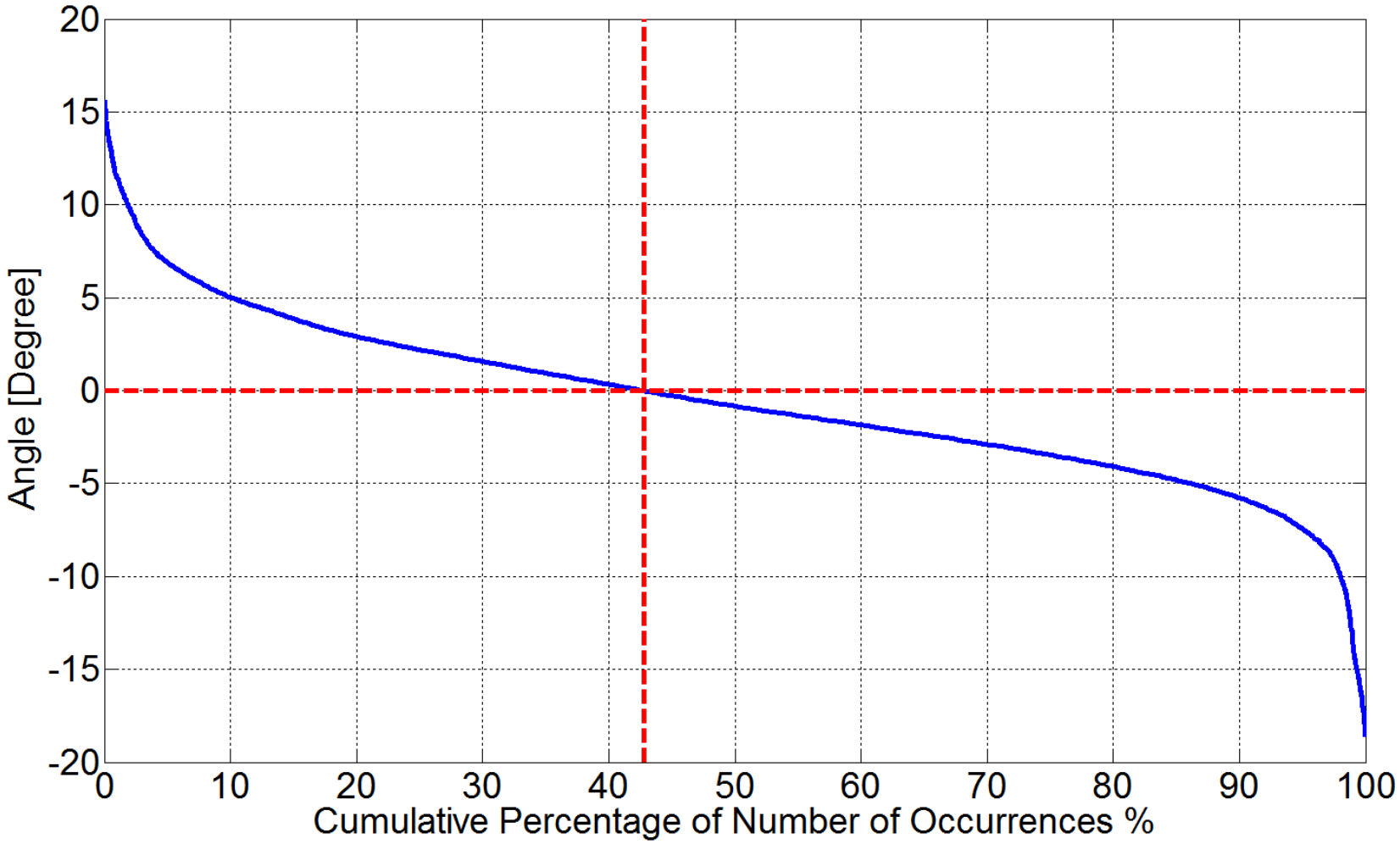

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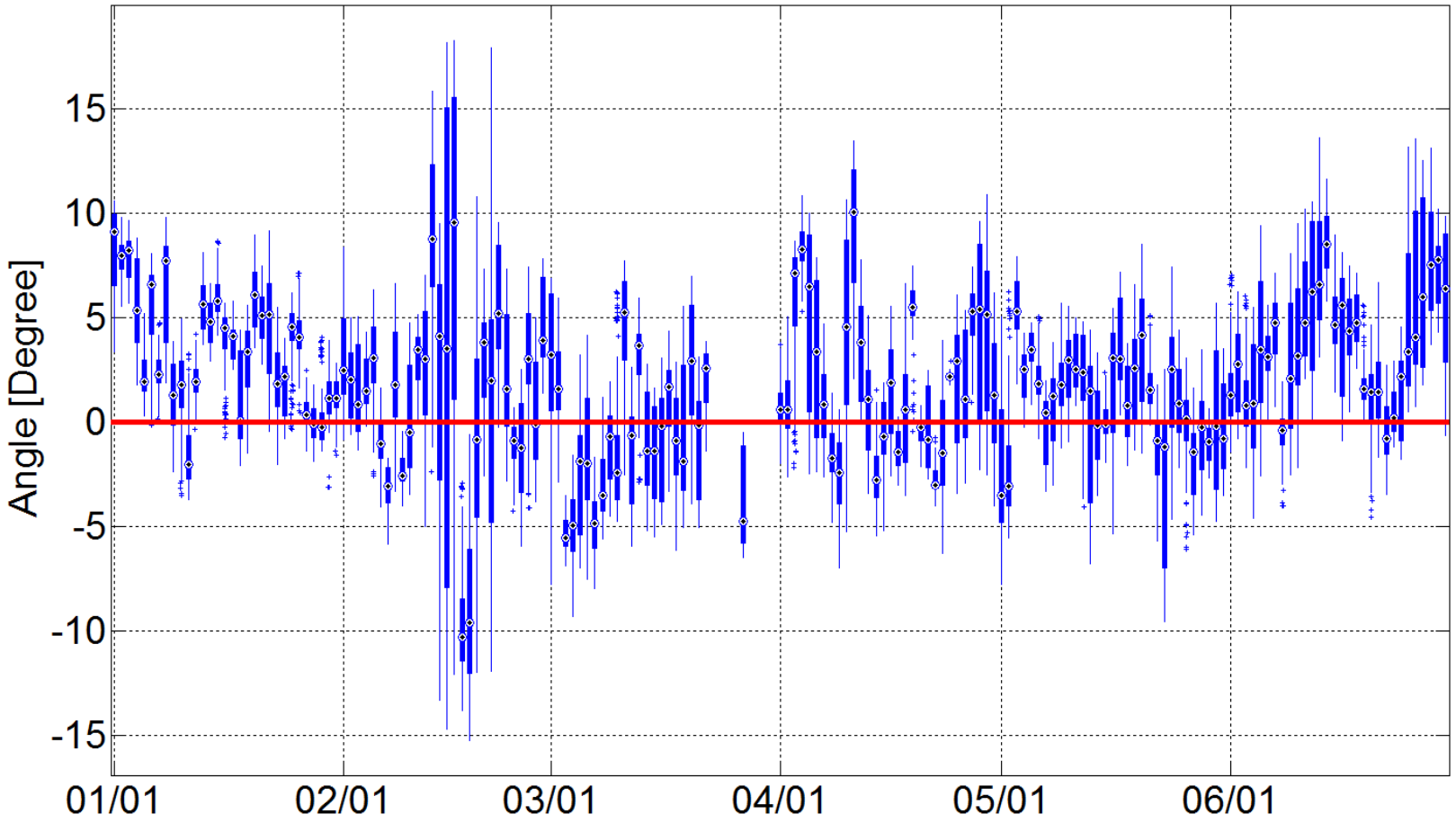

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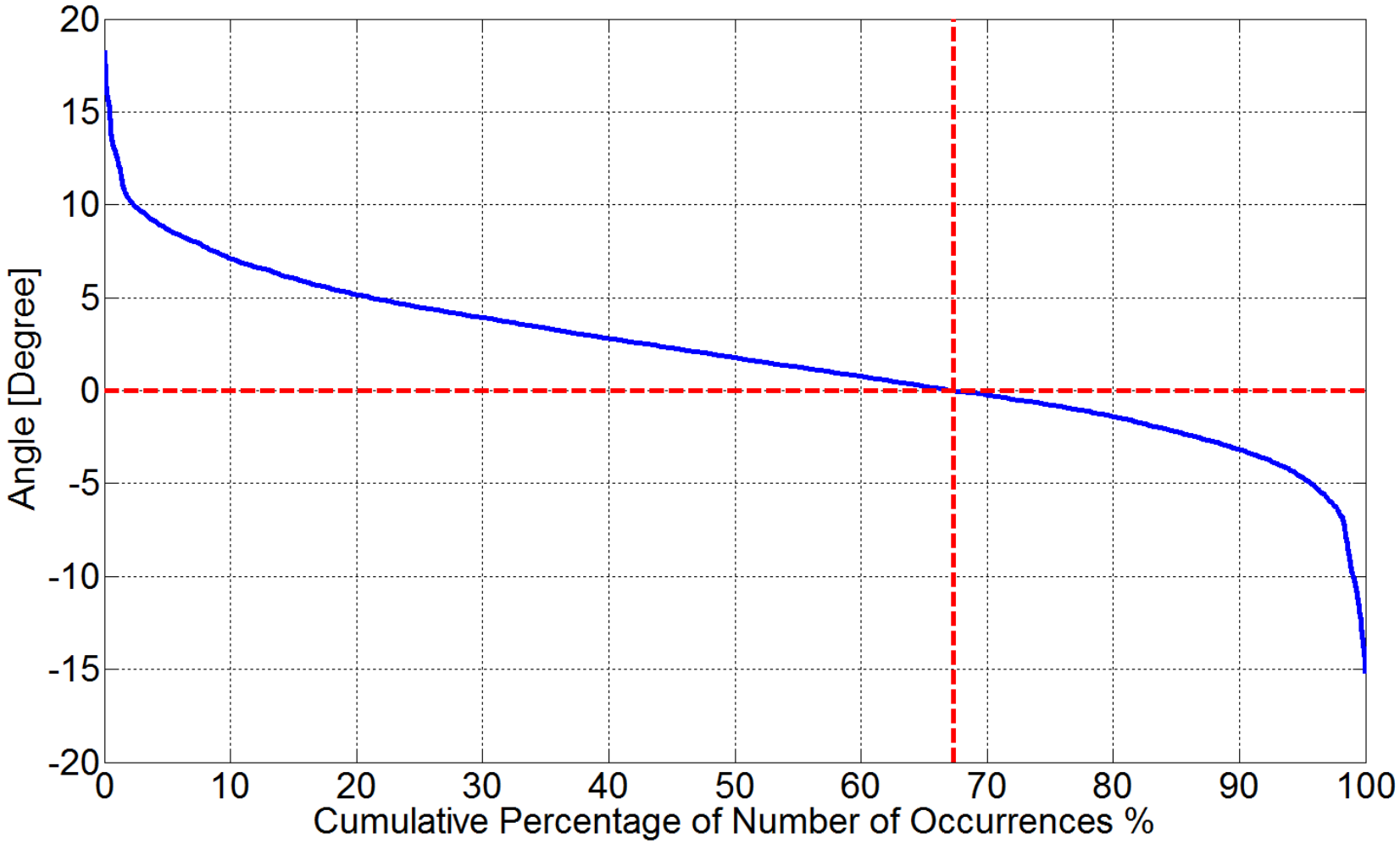

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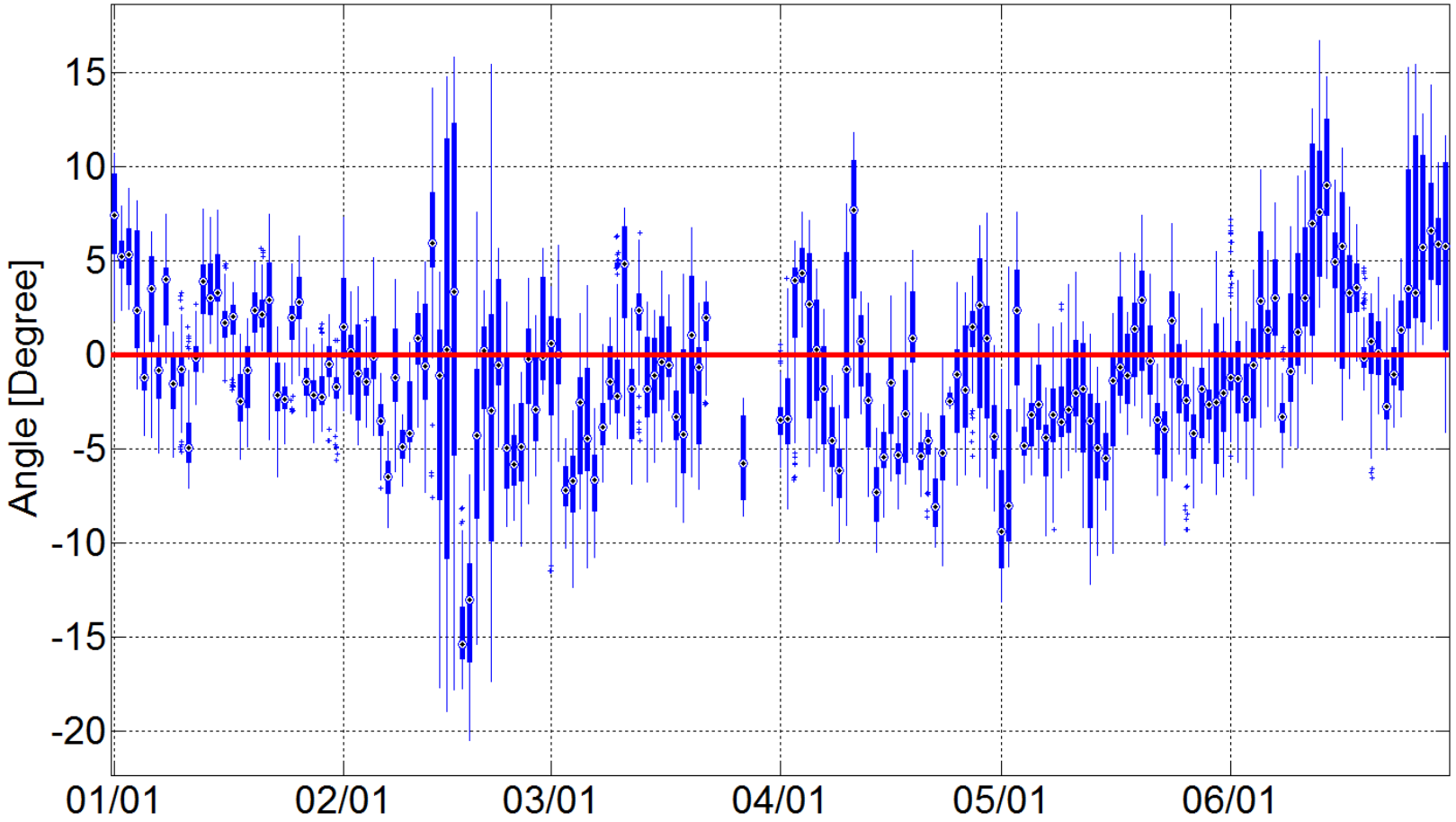

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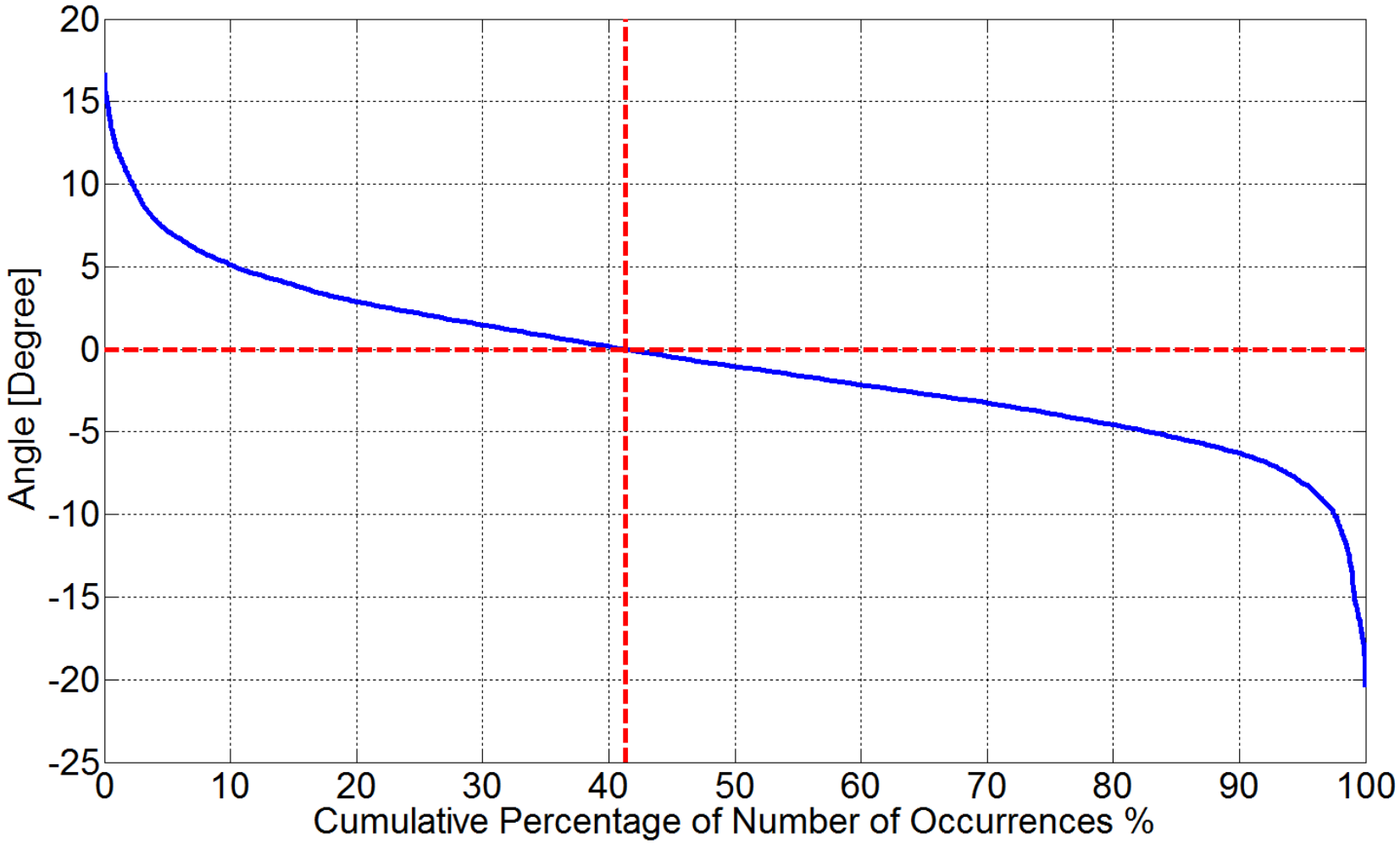
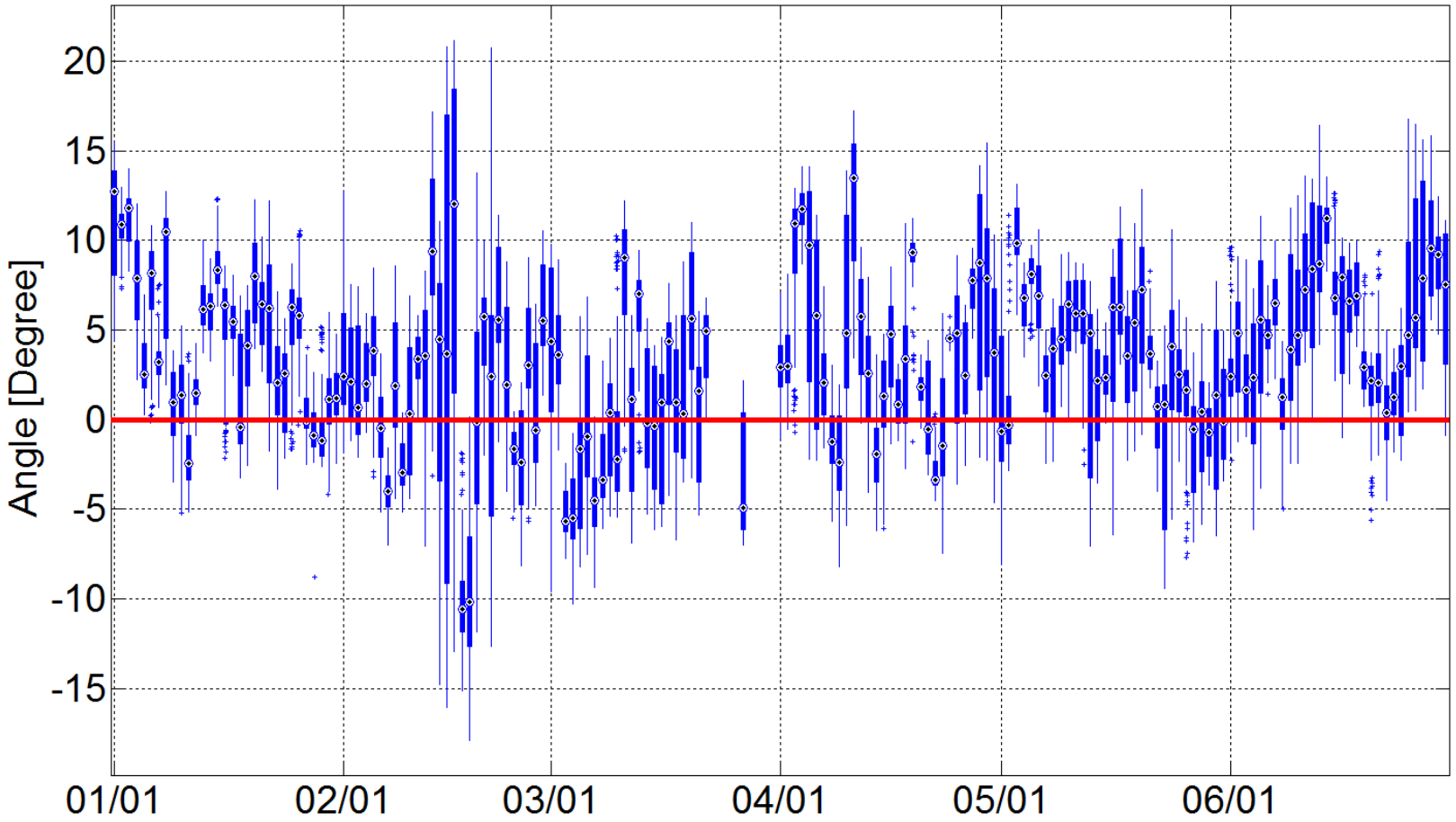


South 7*-North 7



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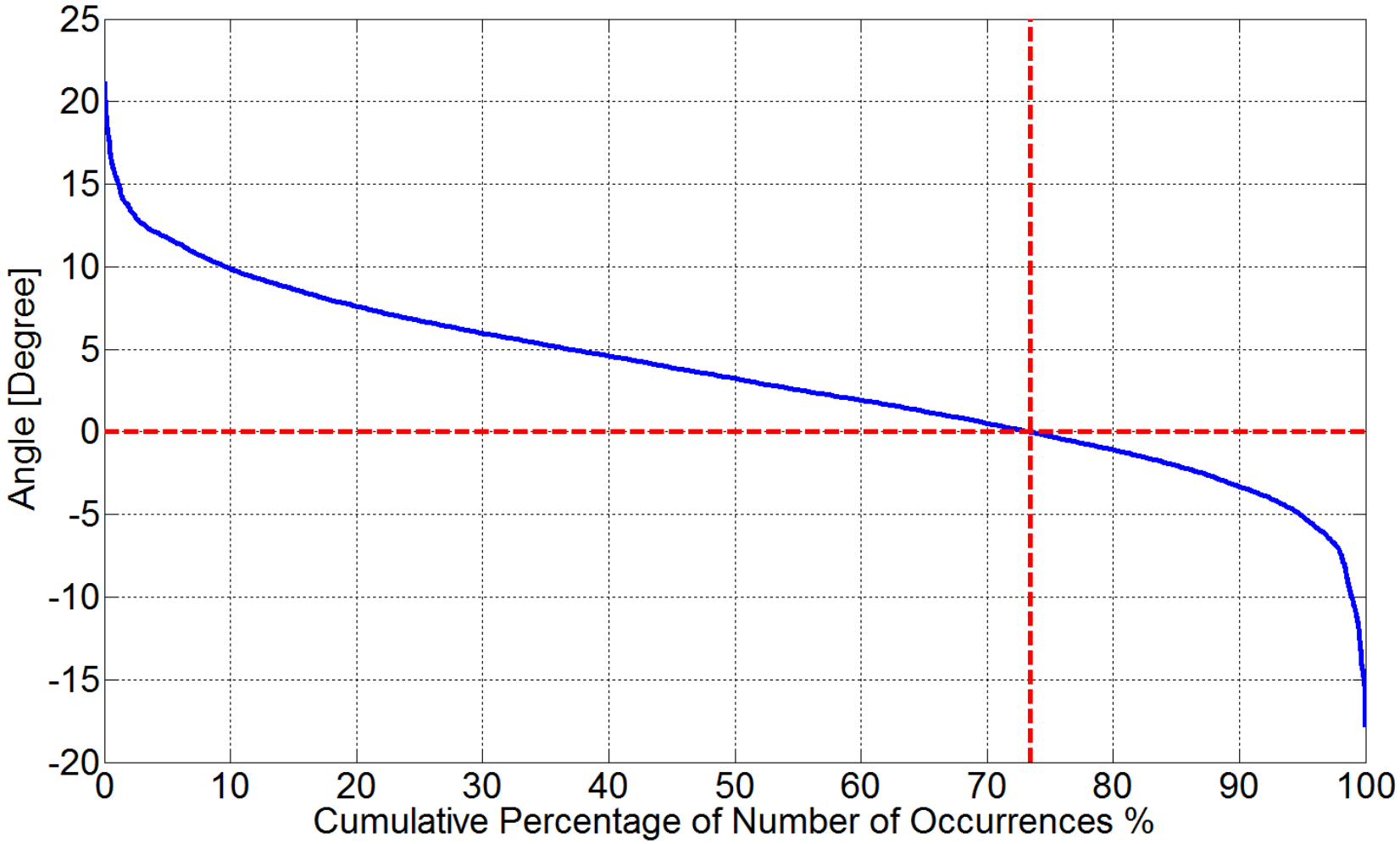
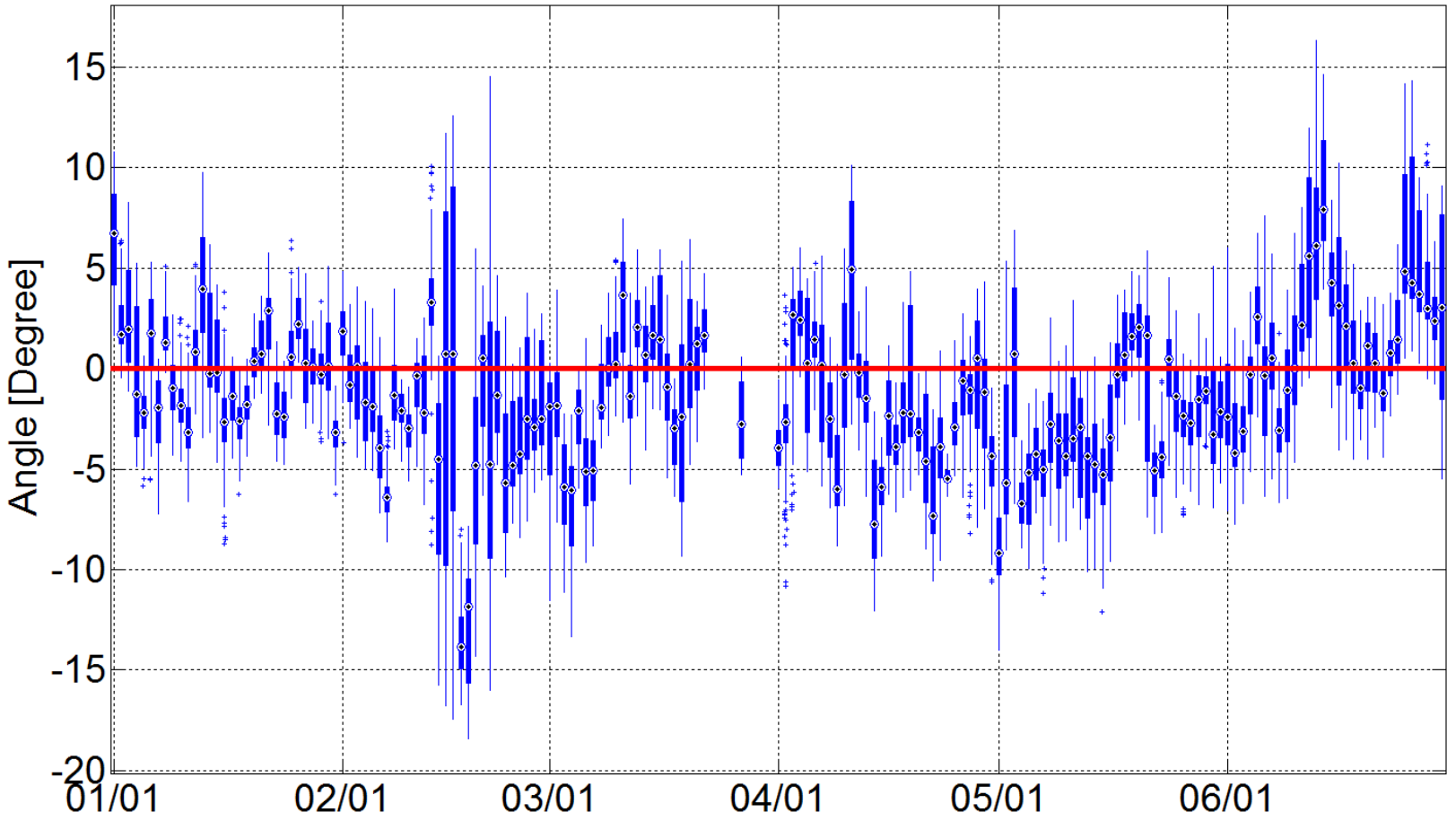


South 9*-North 7



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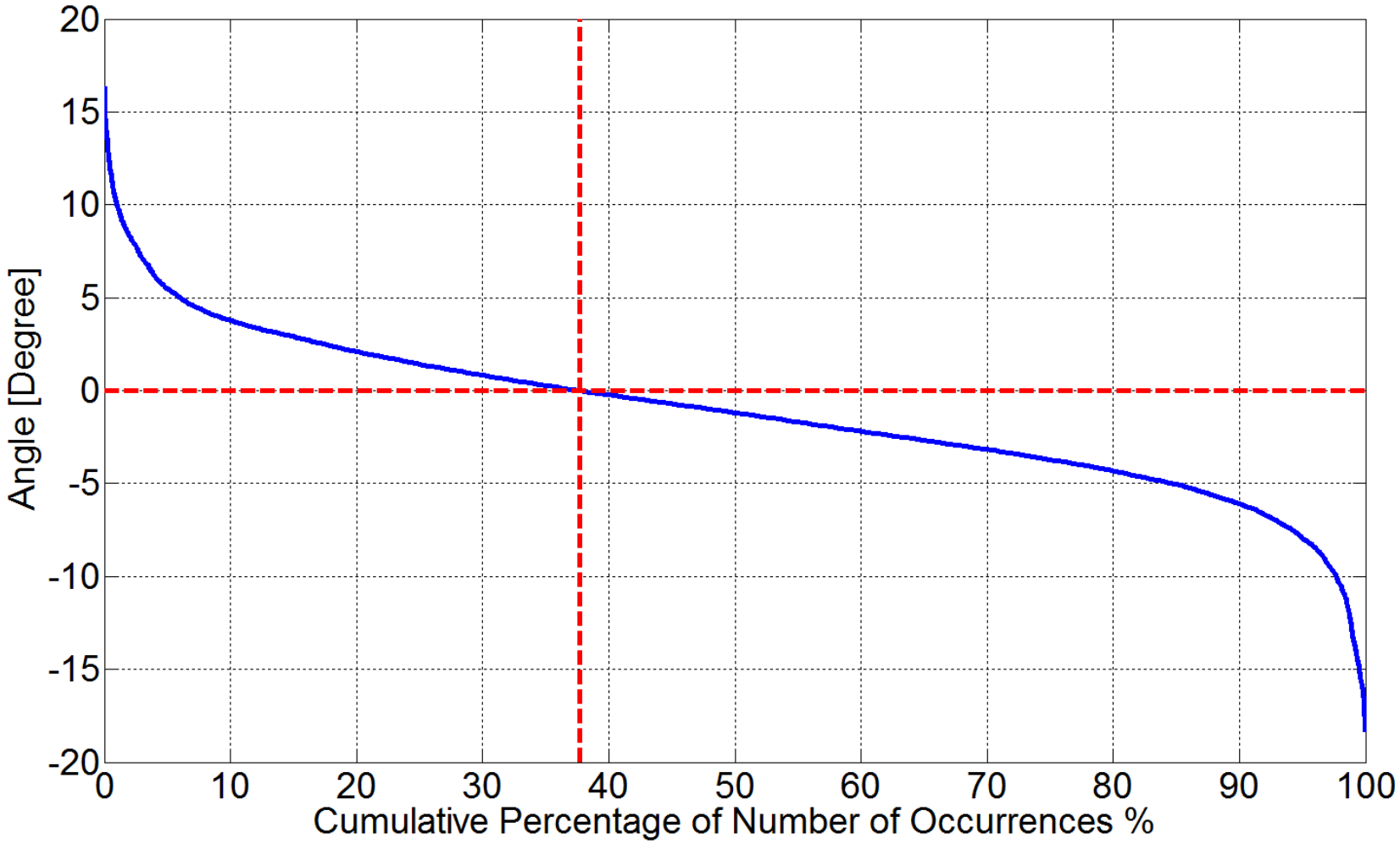
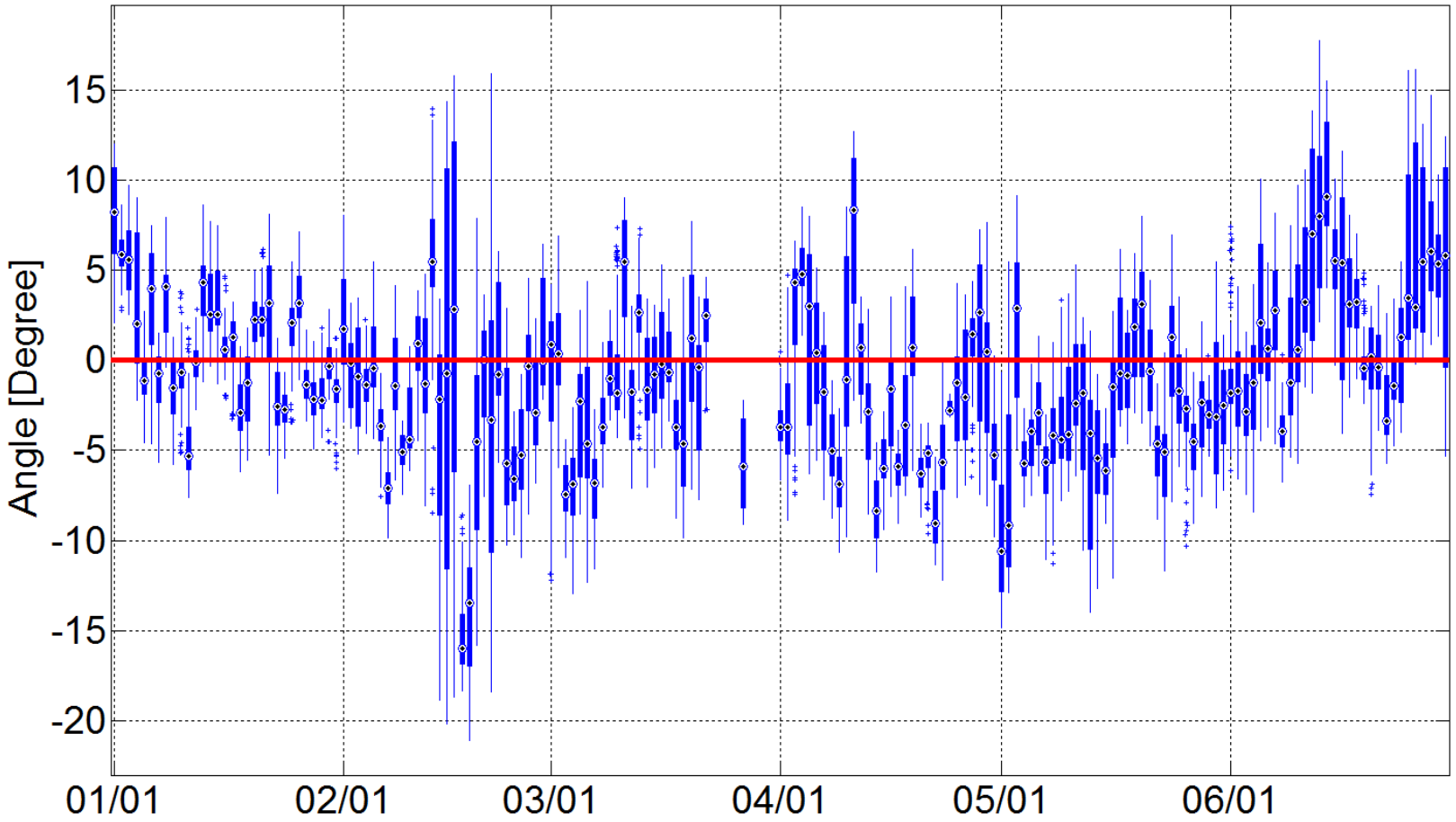
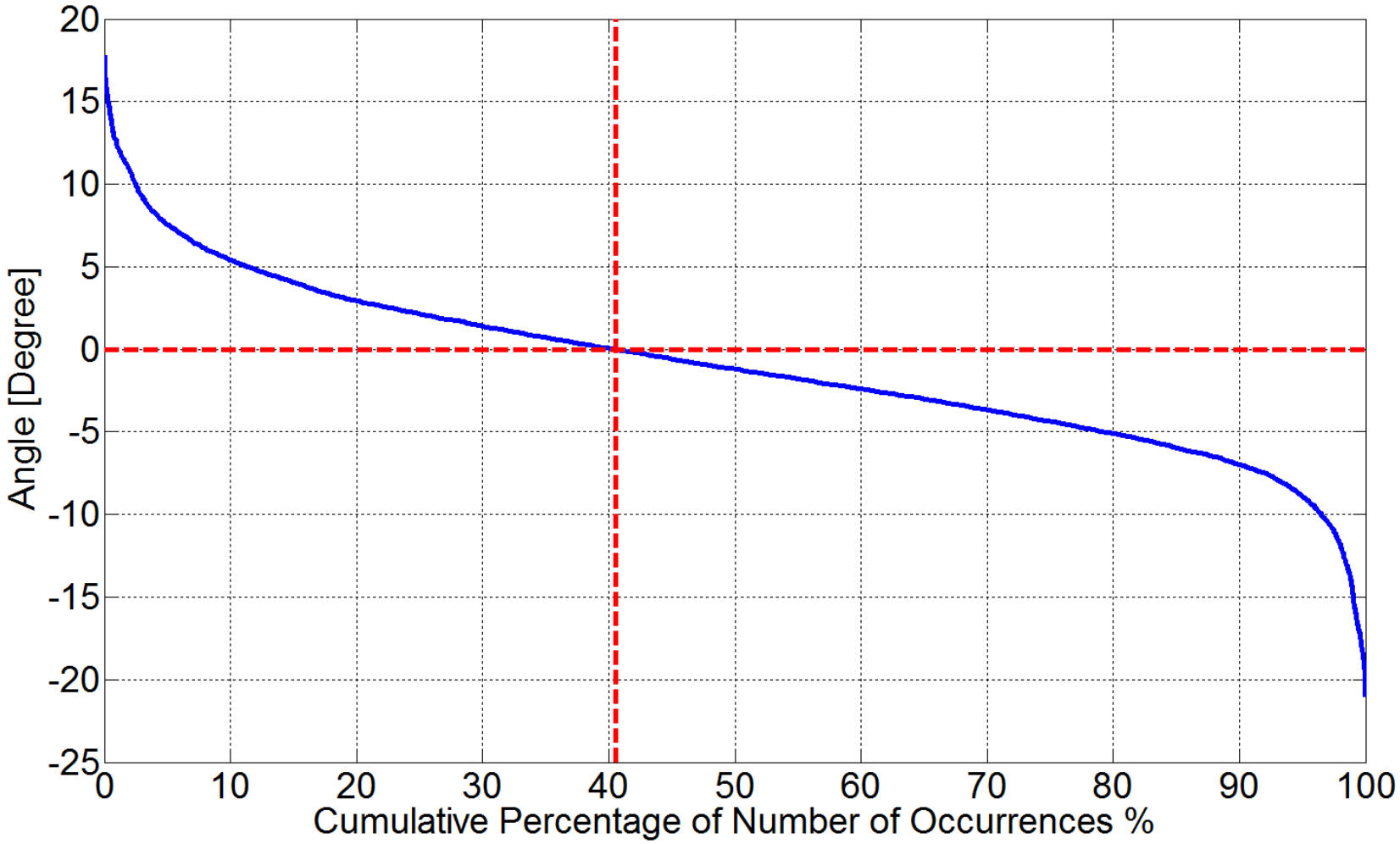


South 11*-North 7



South 11*-North 7



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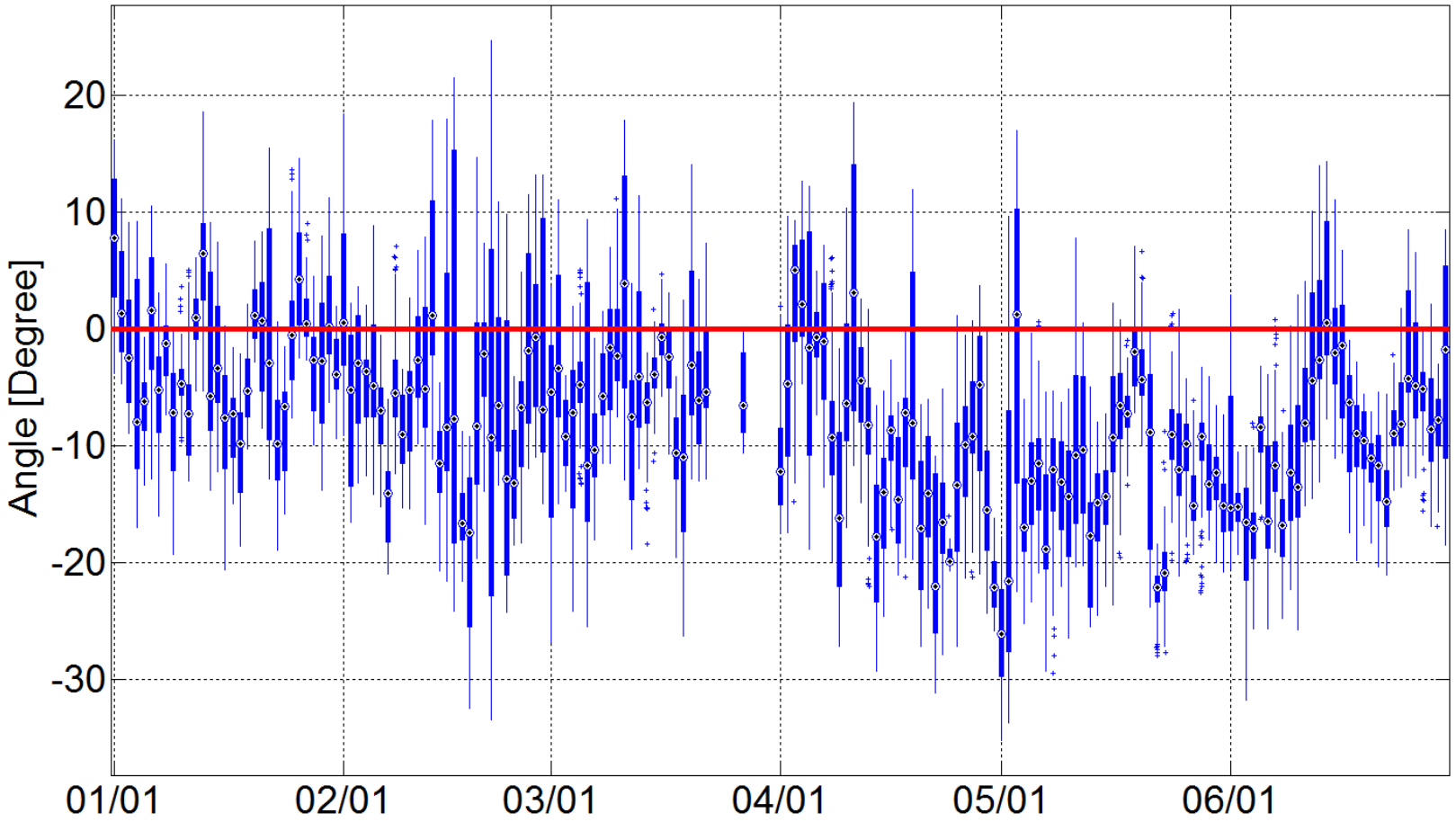

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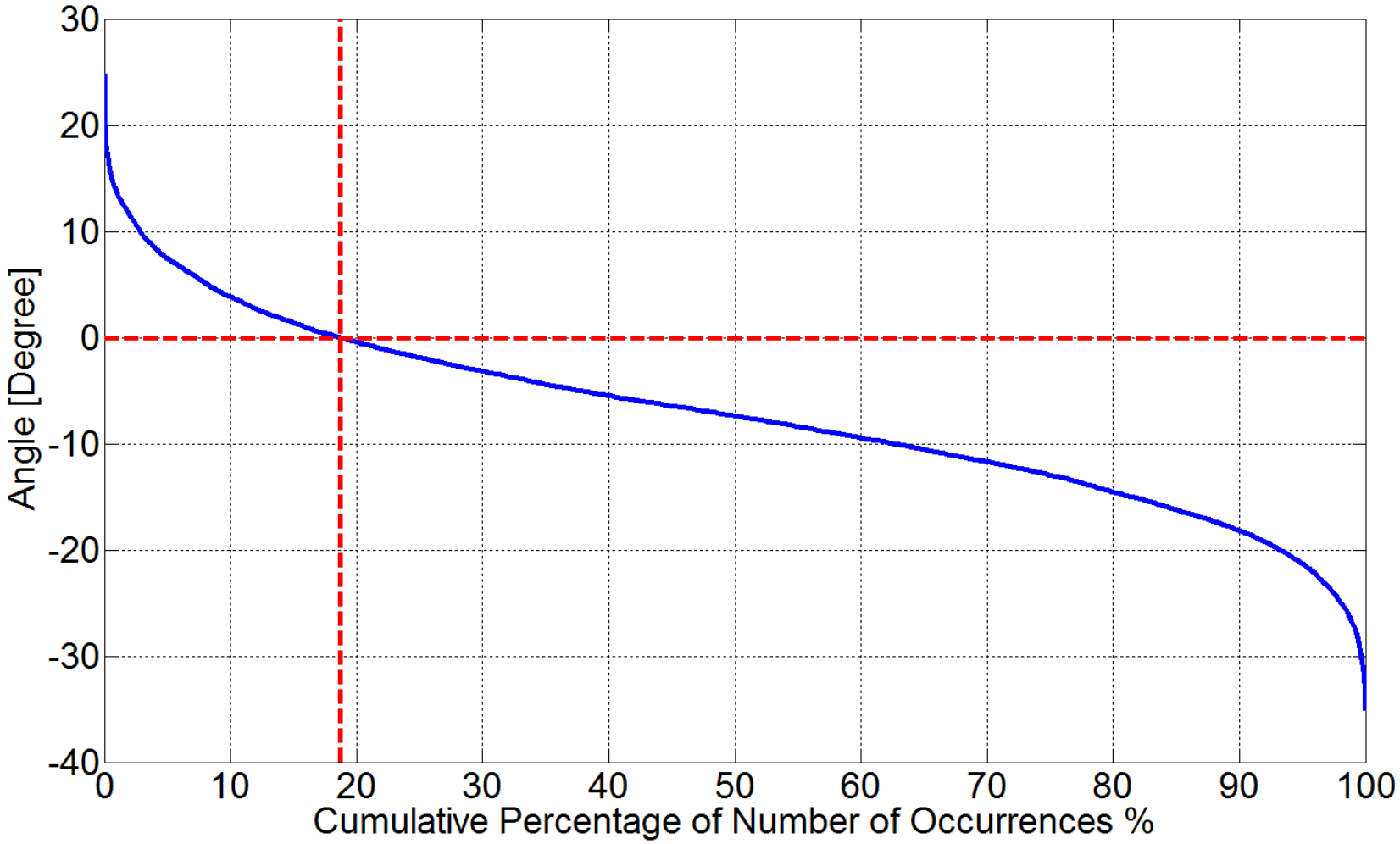


Appendix B – Part 2

CCET Discovery Across Texas project

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

Phasor Data: January to June 2013

Box-Whisker Plots and Time Duration Curves

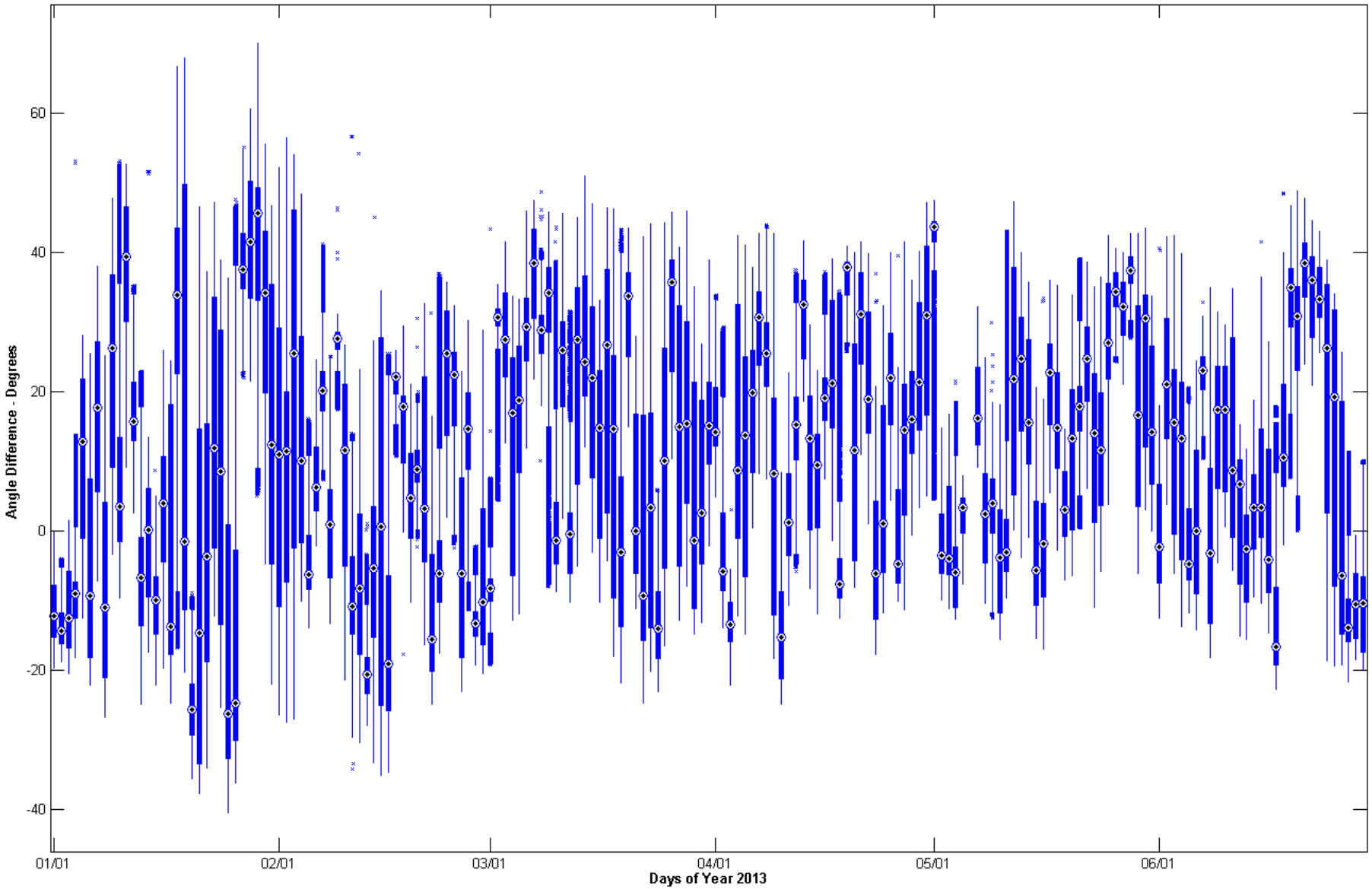
External Version

Electric Power Group

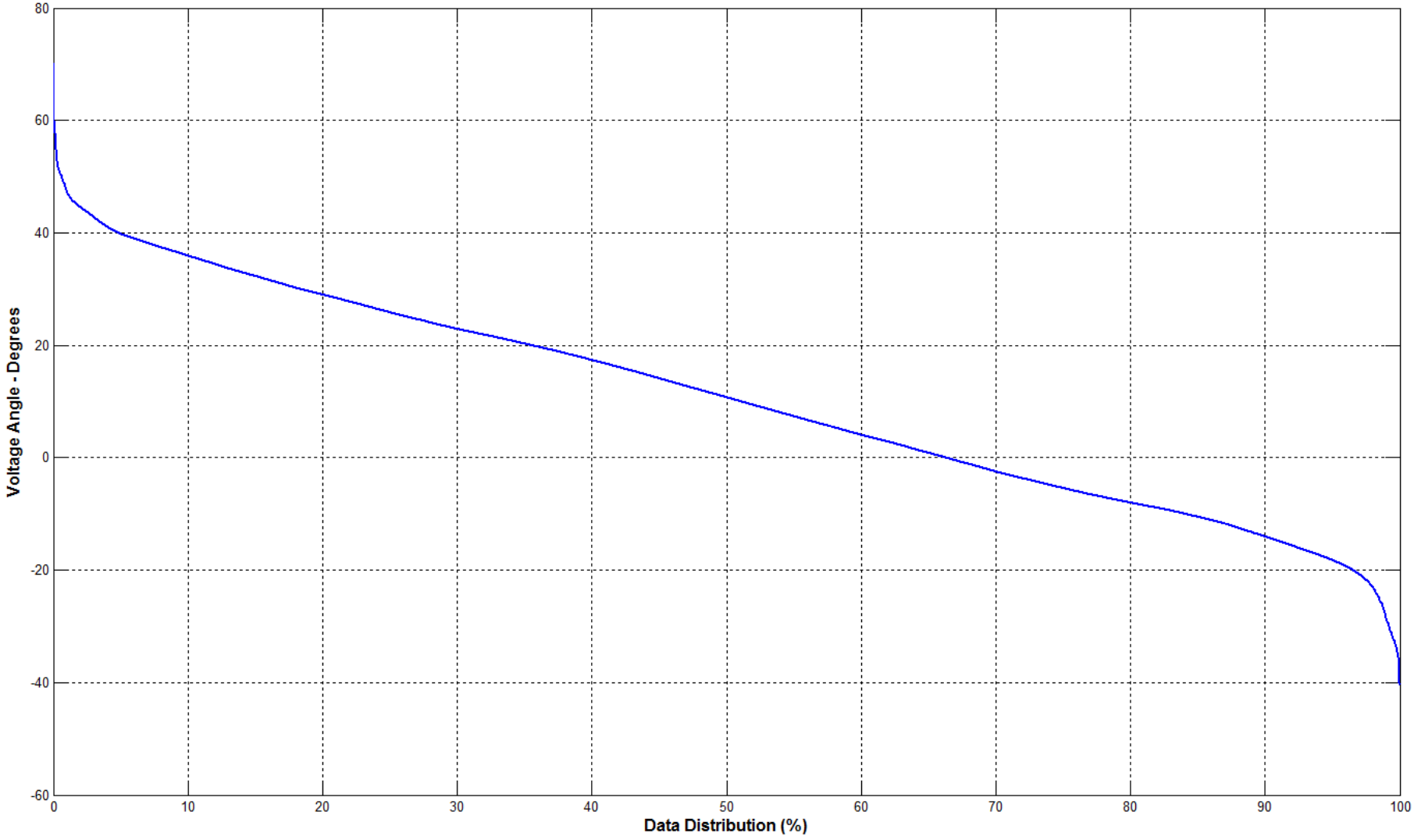
CCET

ERCOT

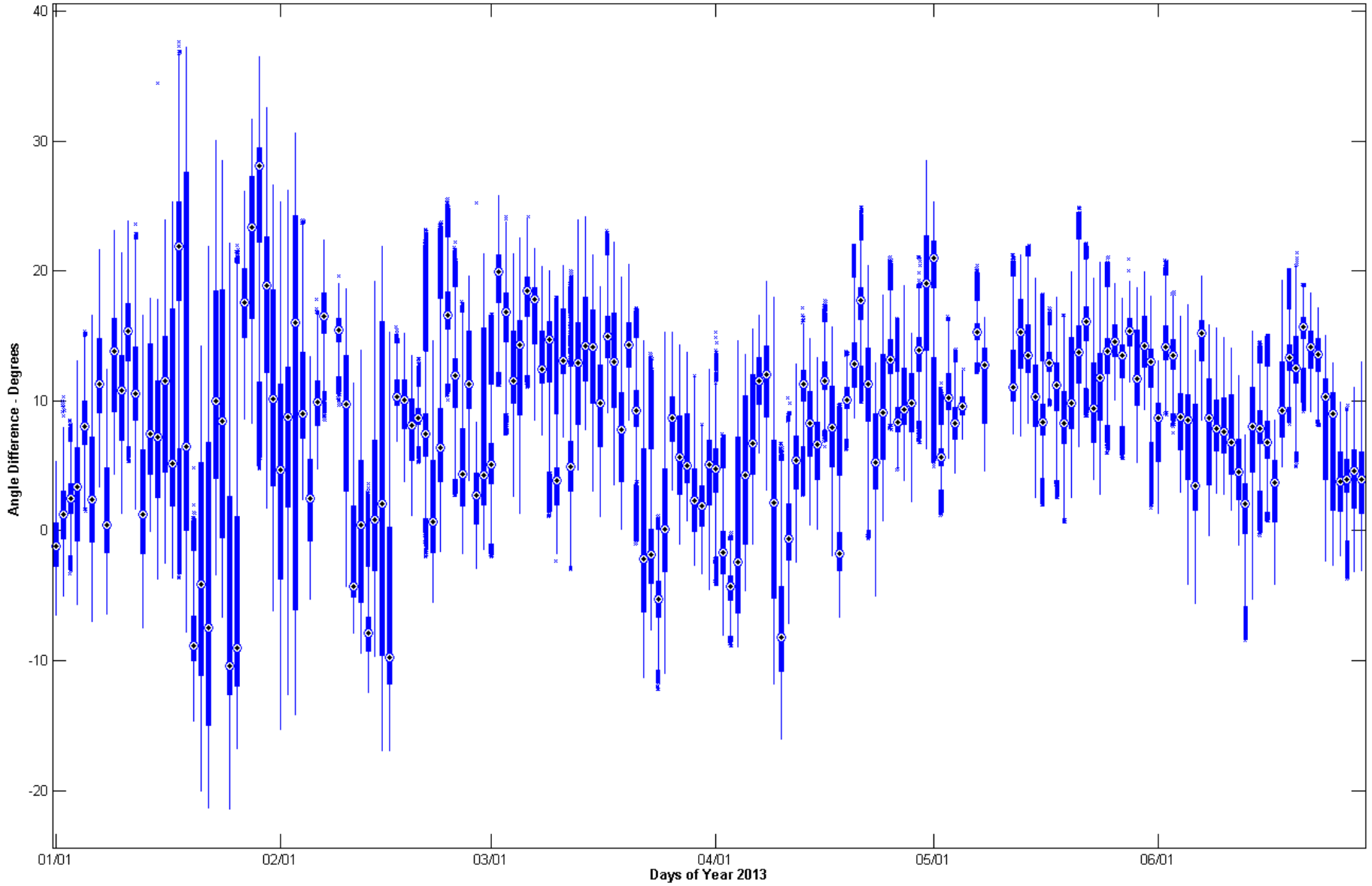
West 10 – Voltage Angle



West 10 – Voltage Angle



West 14 – Voltage Angle



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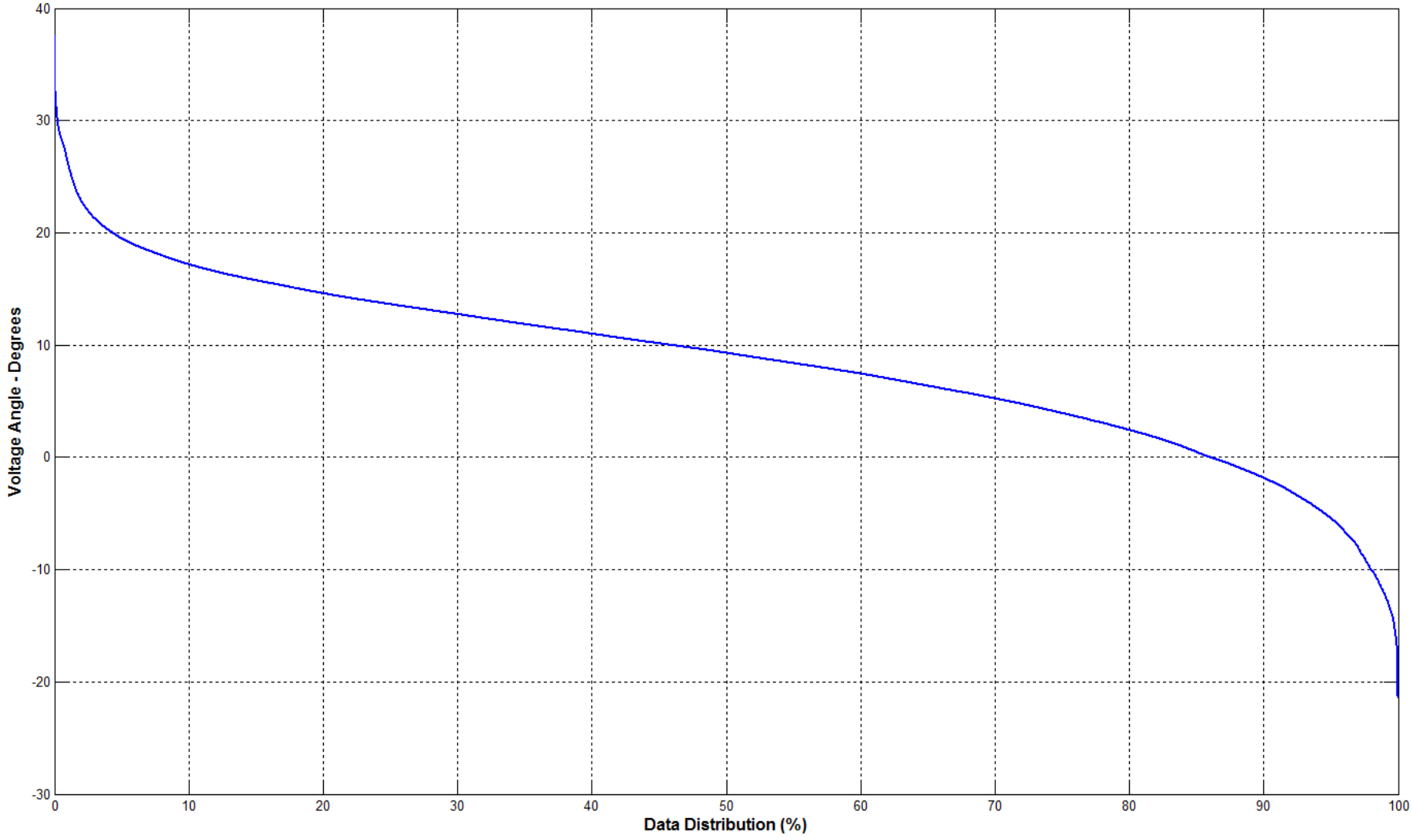
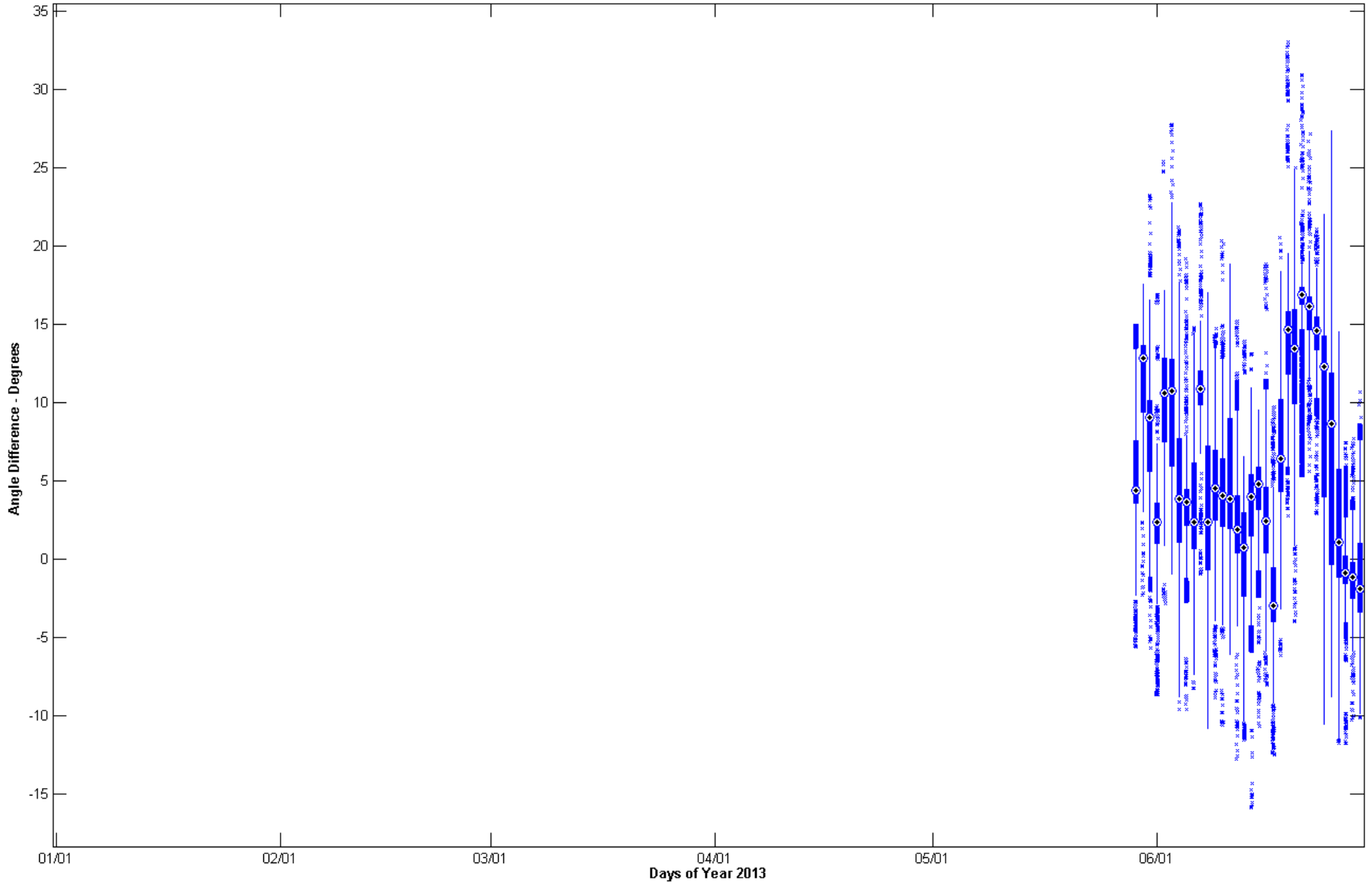
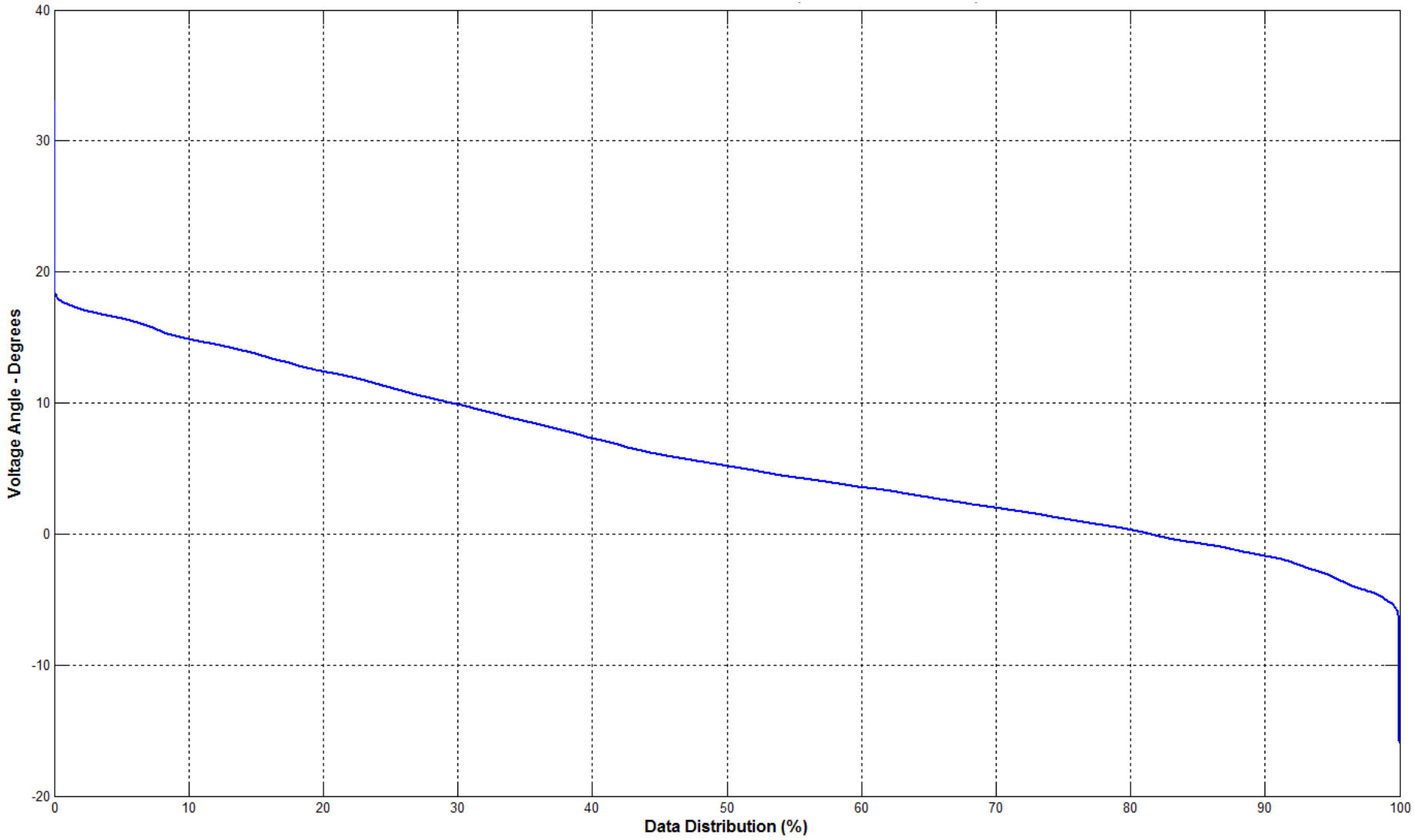


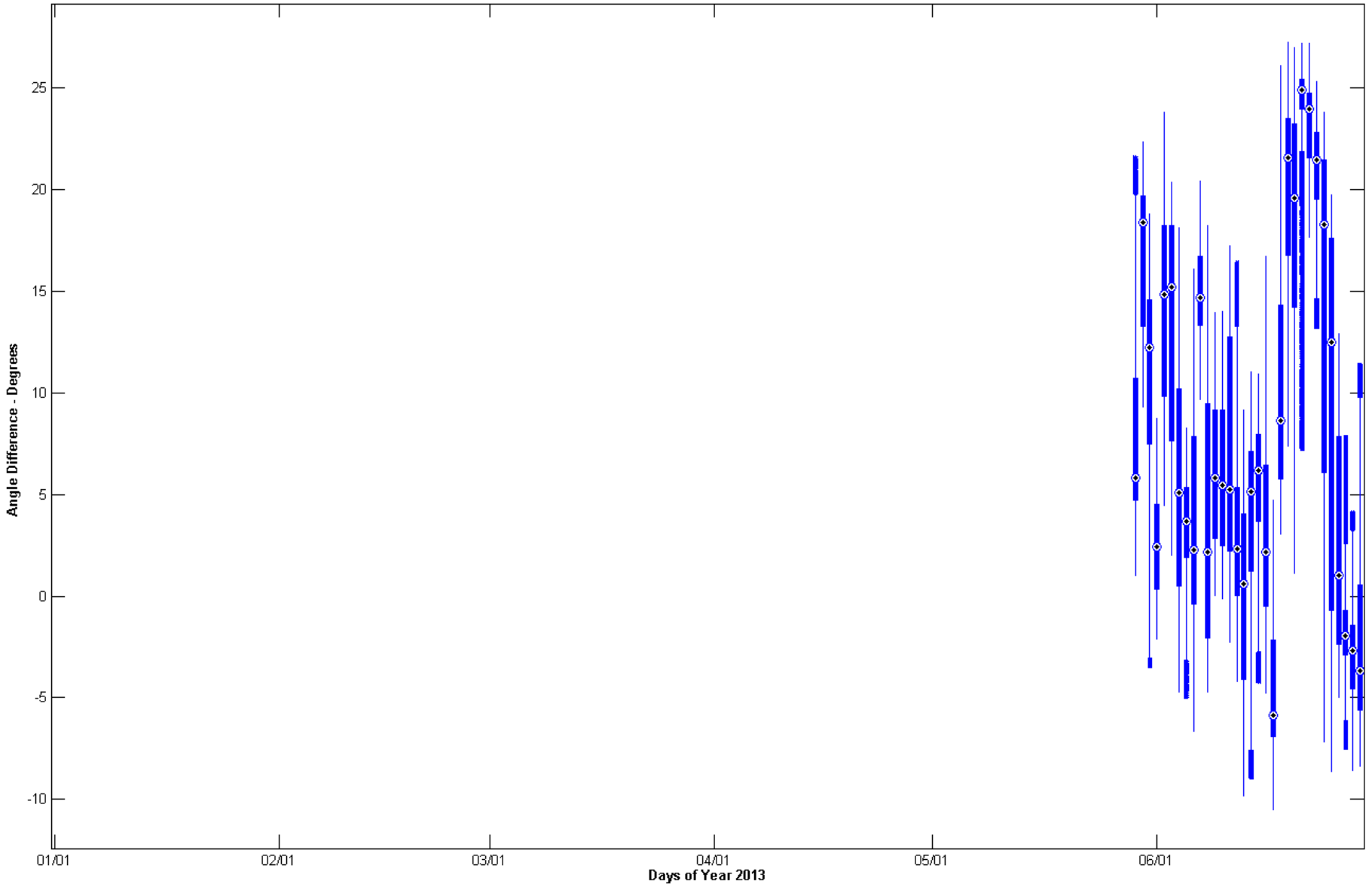
West 1 – Voltage Angle



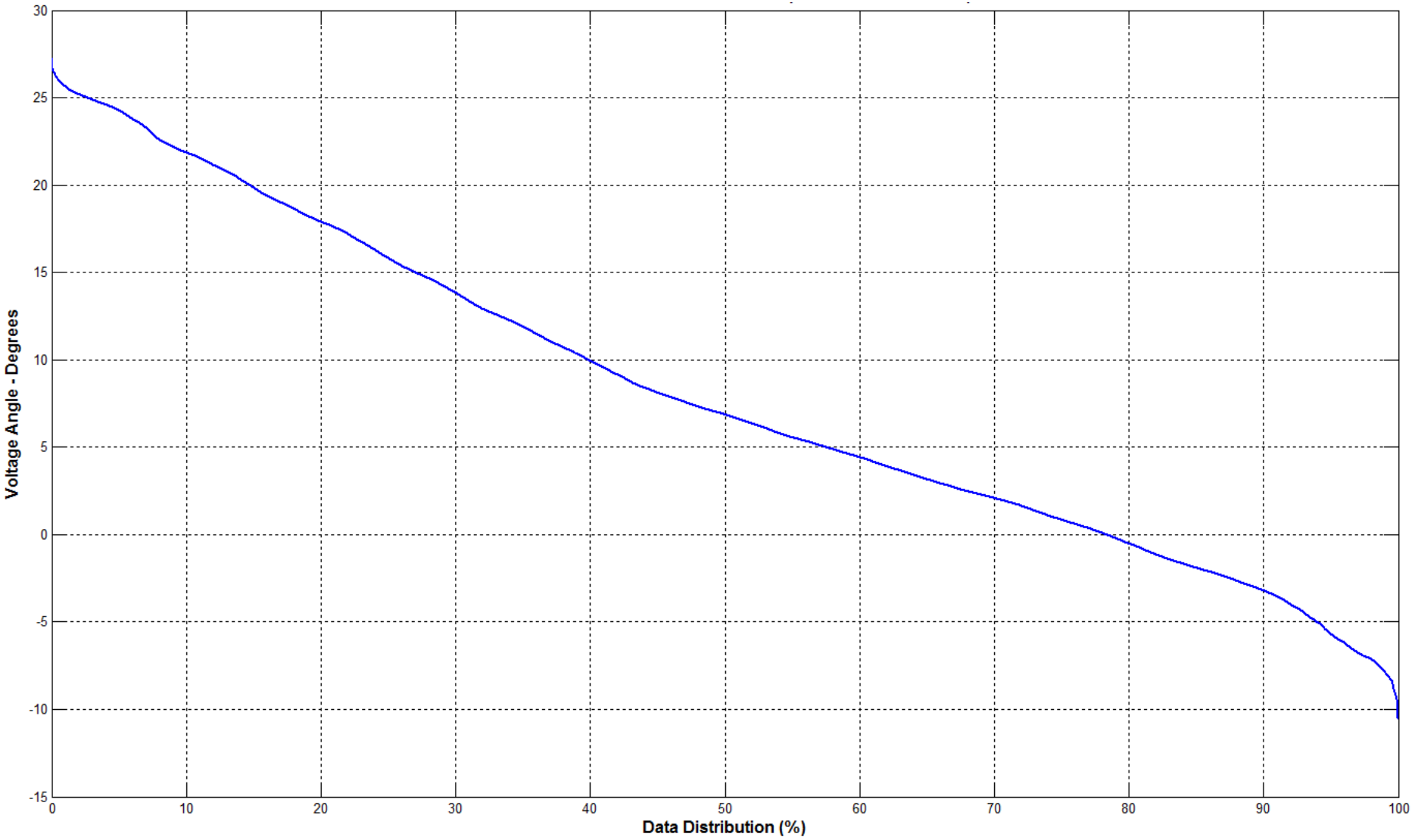
West 1 – Voltage Angle



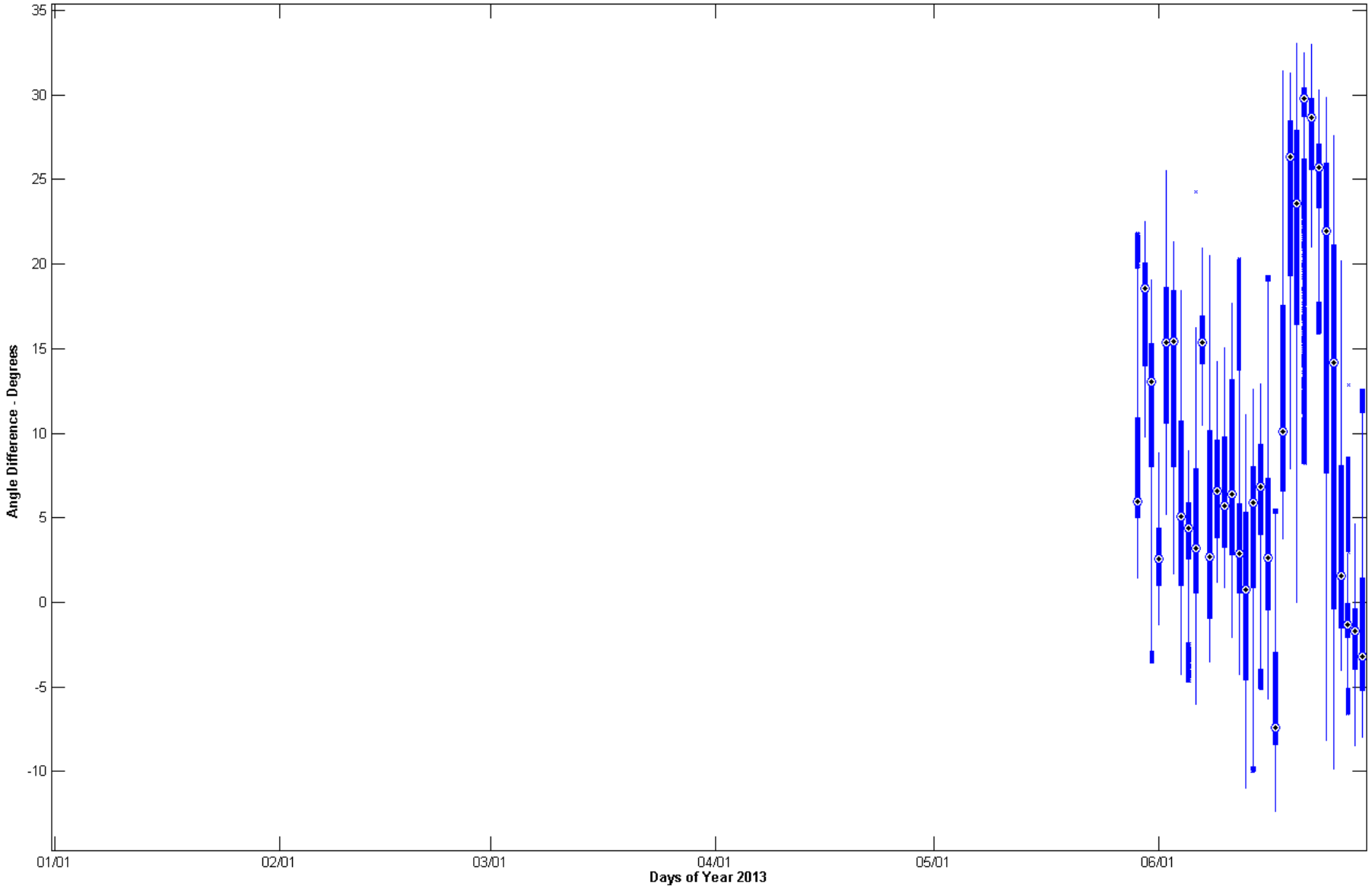
West 2 – Voltage Angle



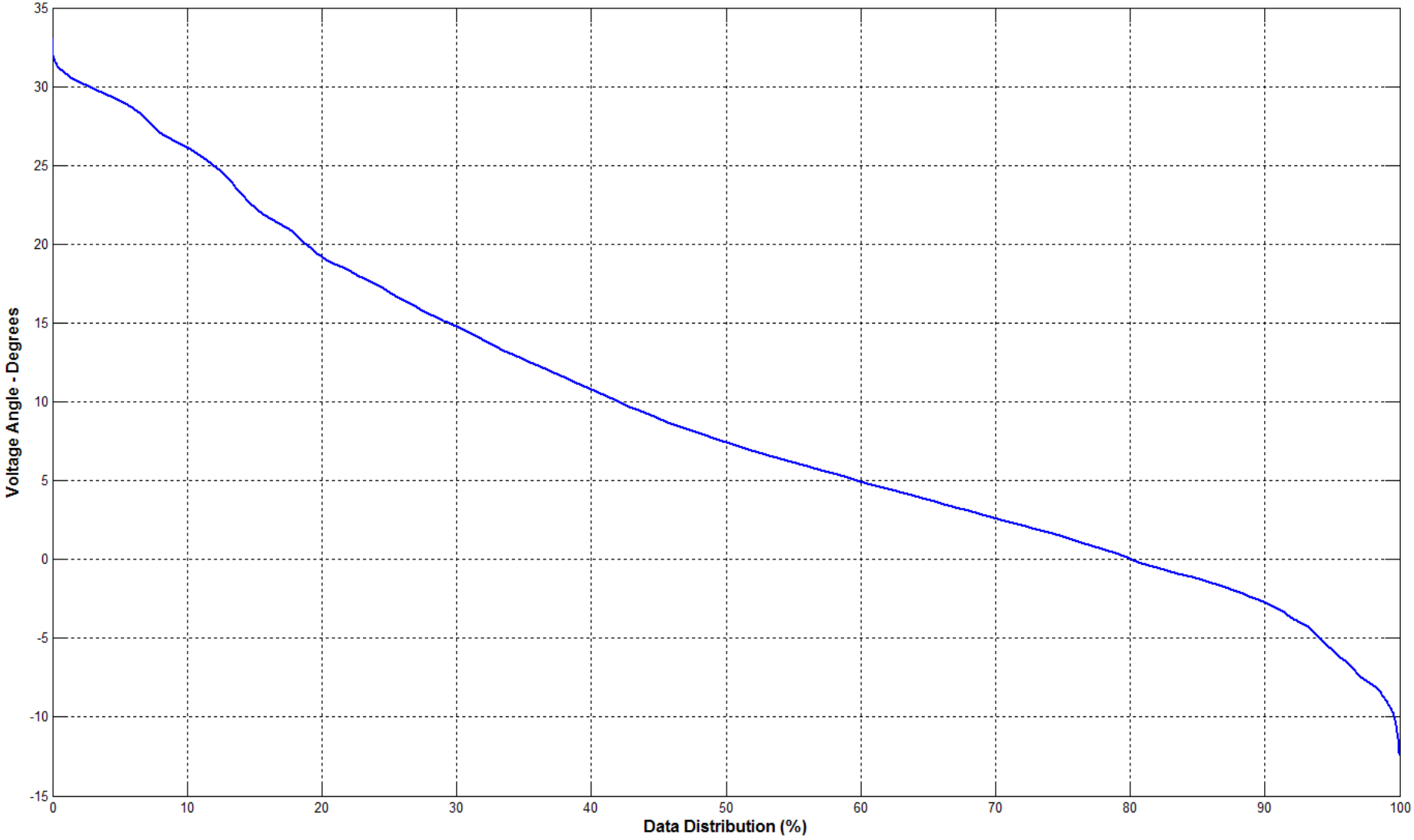
West 2 – Voltage Angle



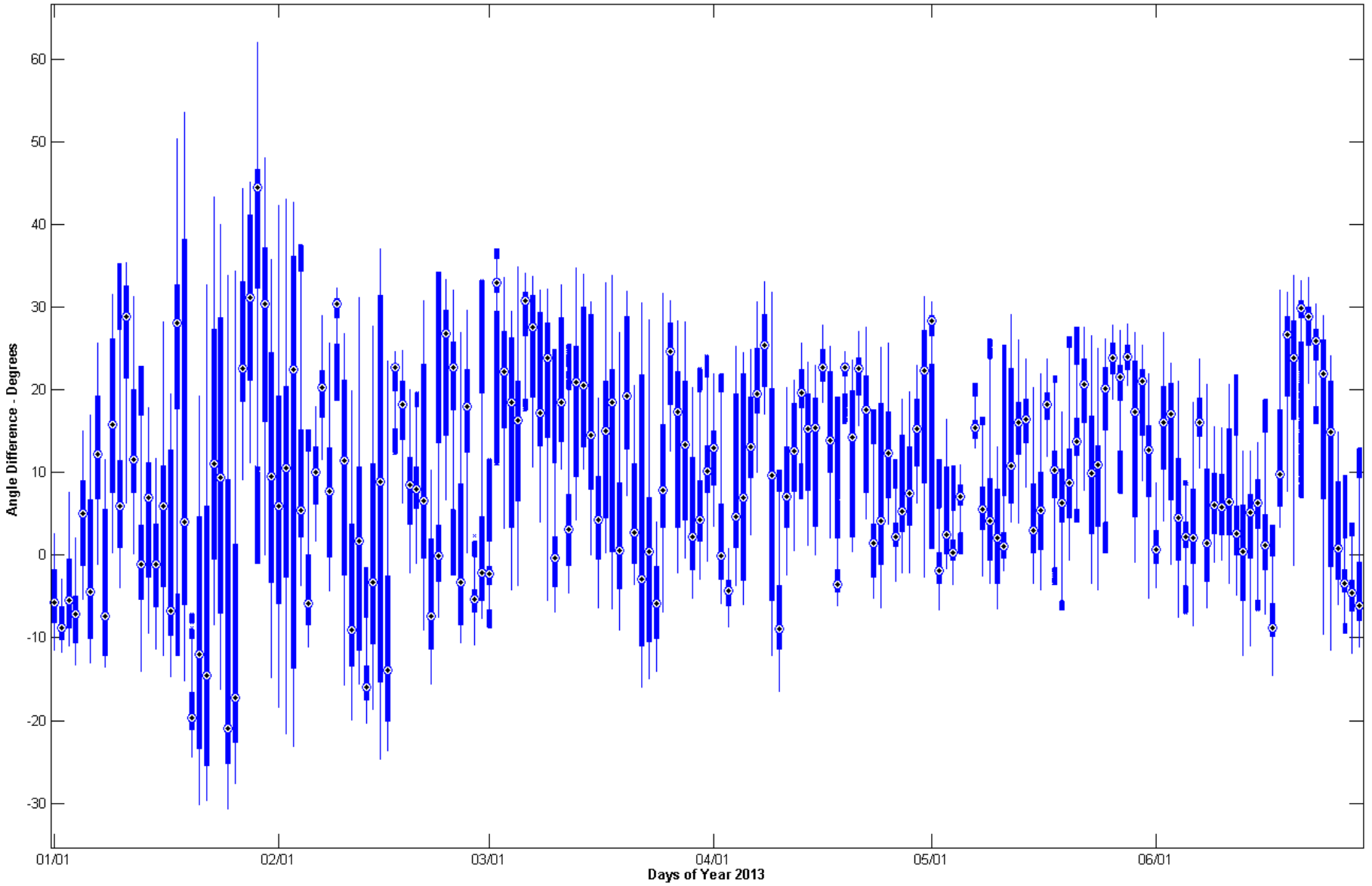
West 9 – Voltage Angle



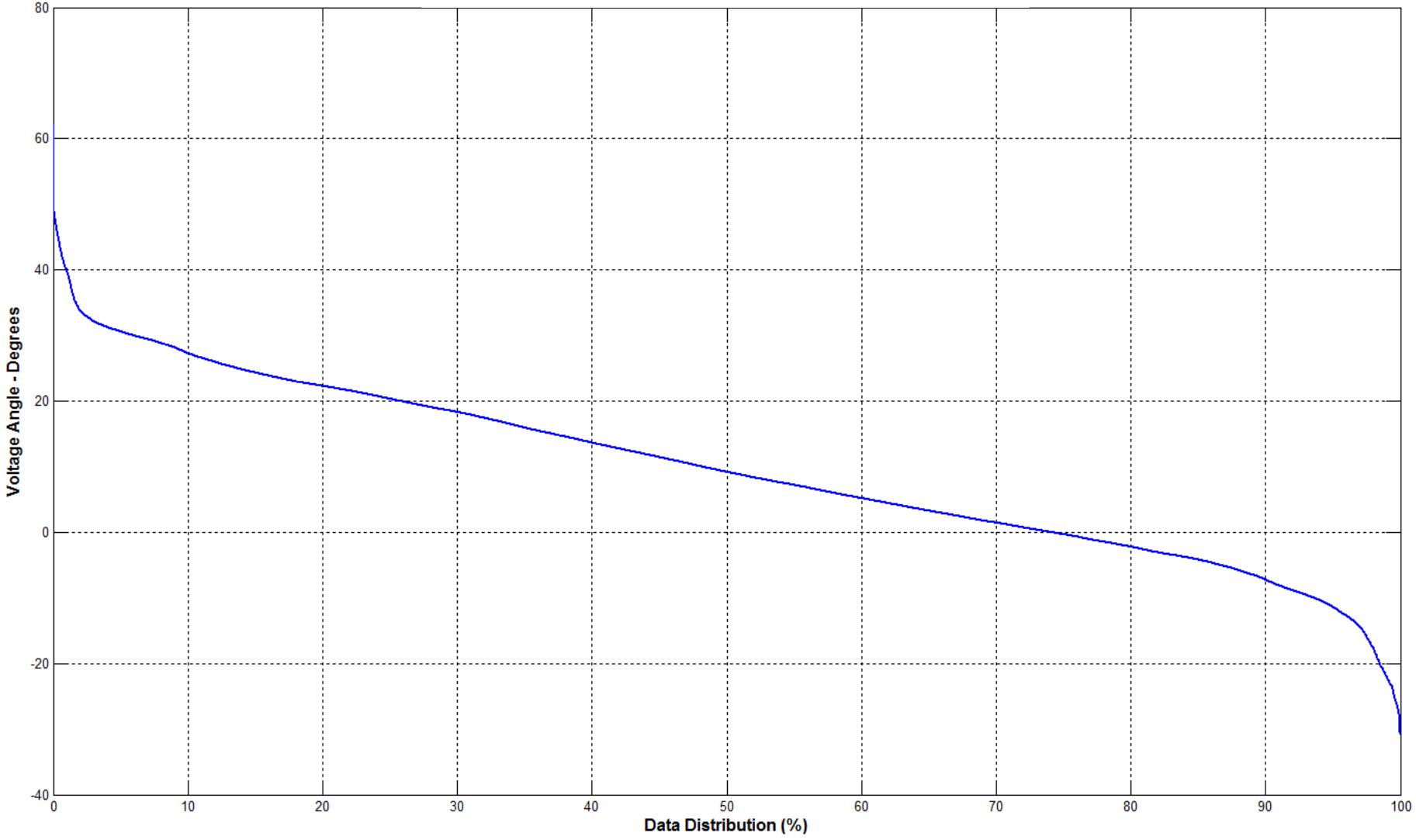
West 9 – Voltage Angle



West 11– Voltage Angle



West 11– Voltage Angle



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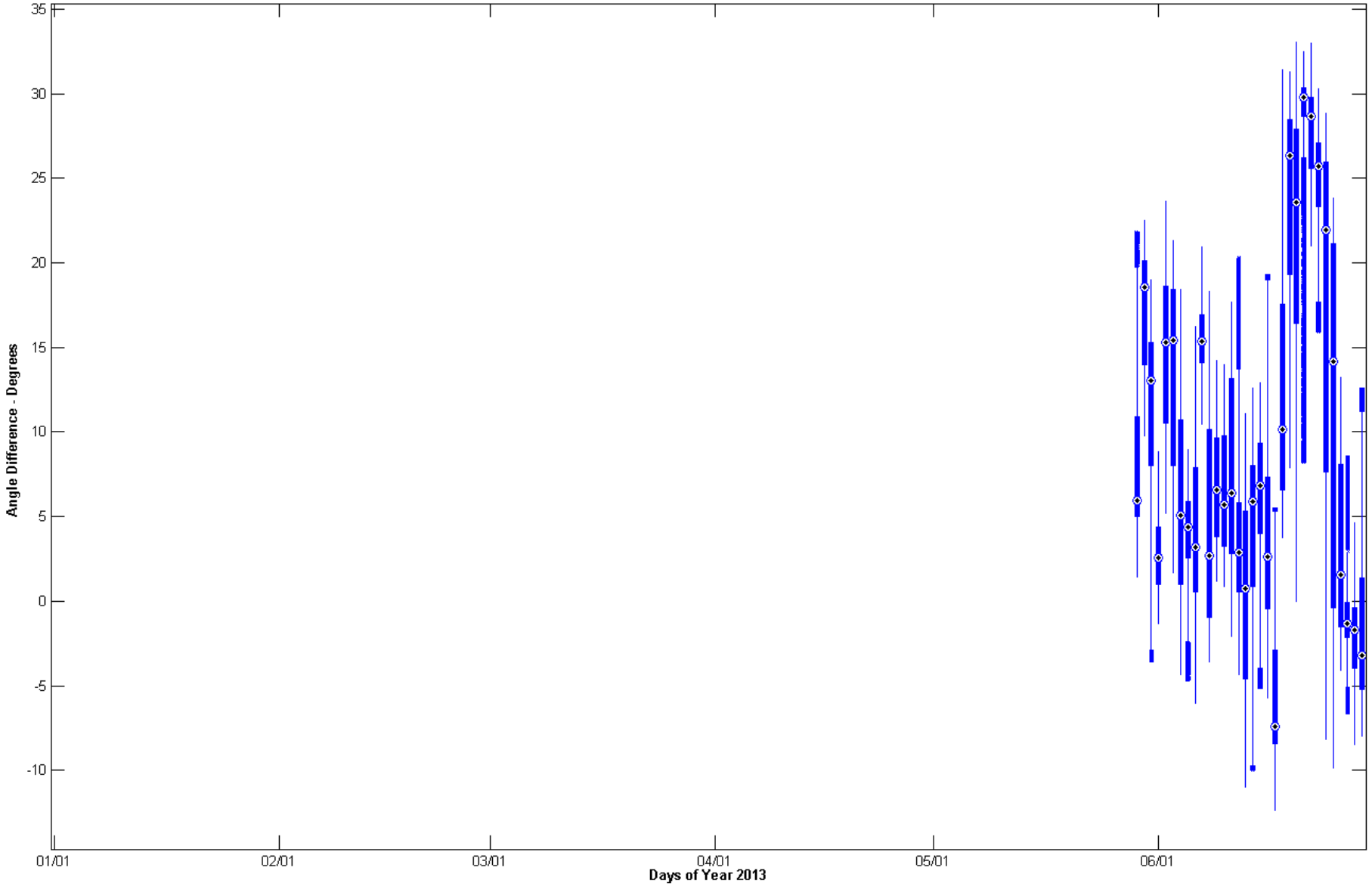

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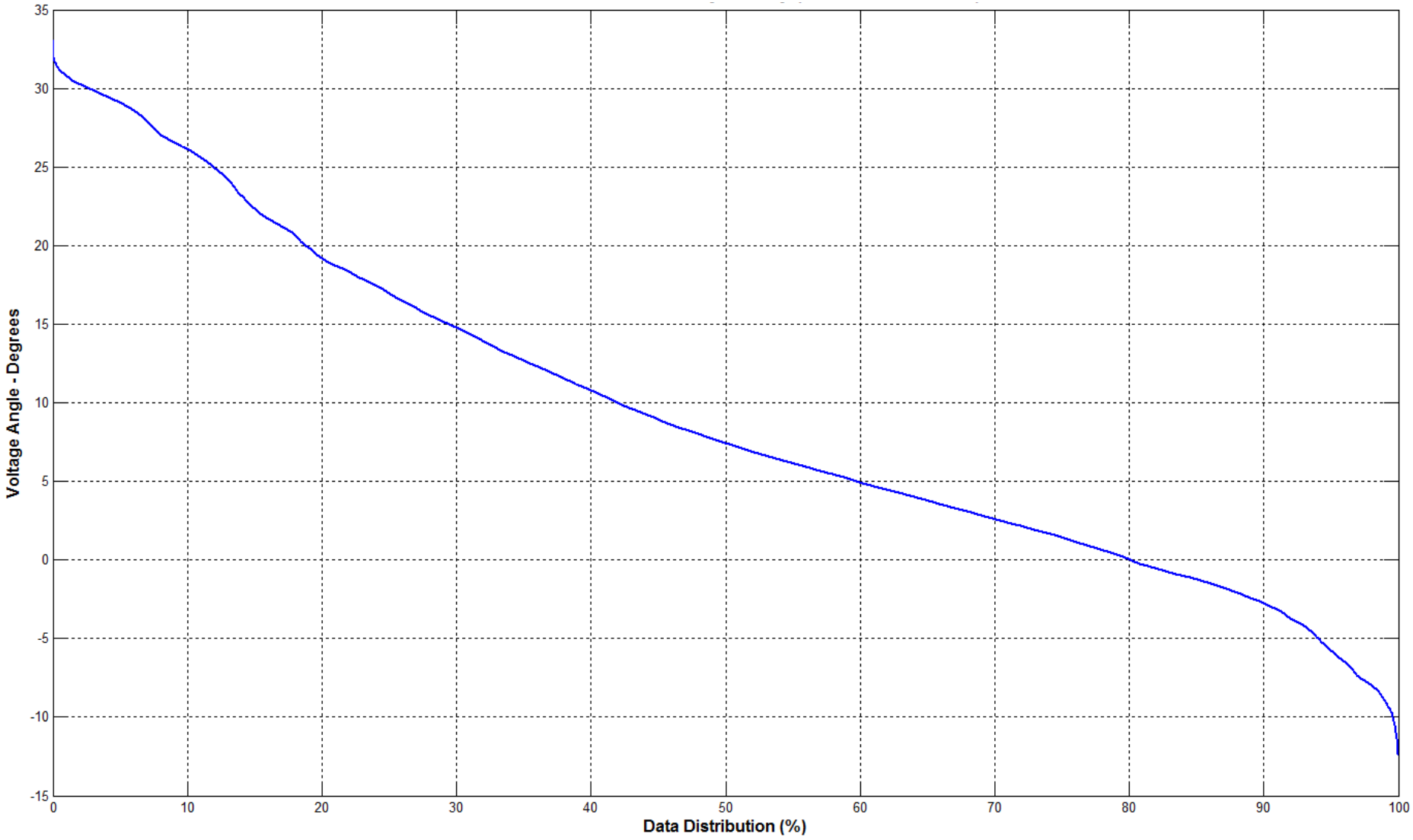
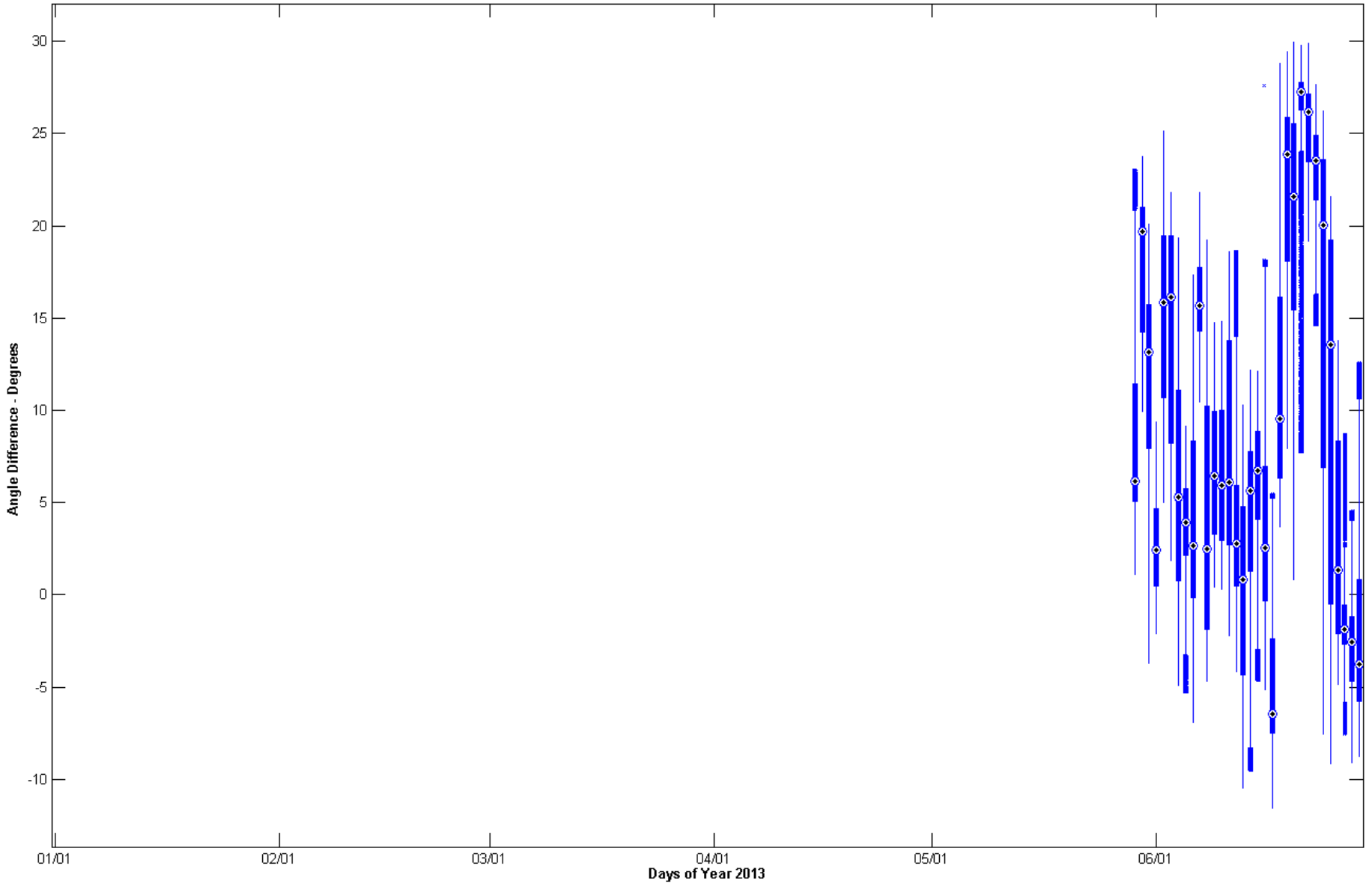
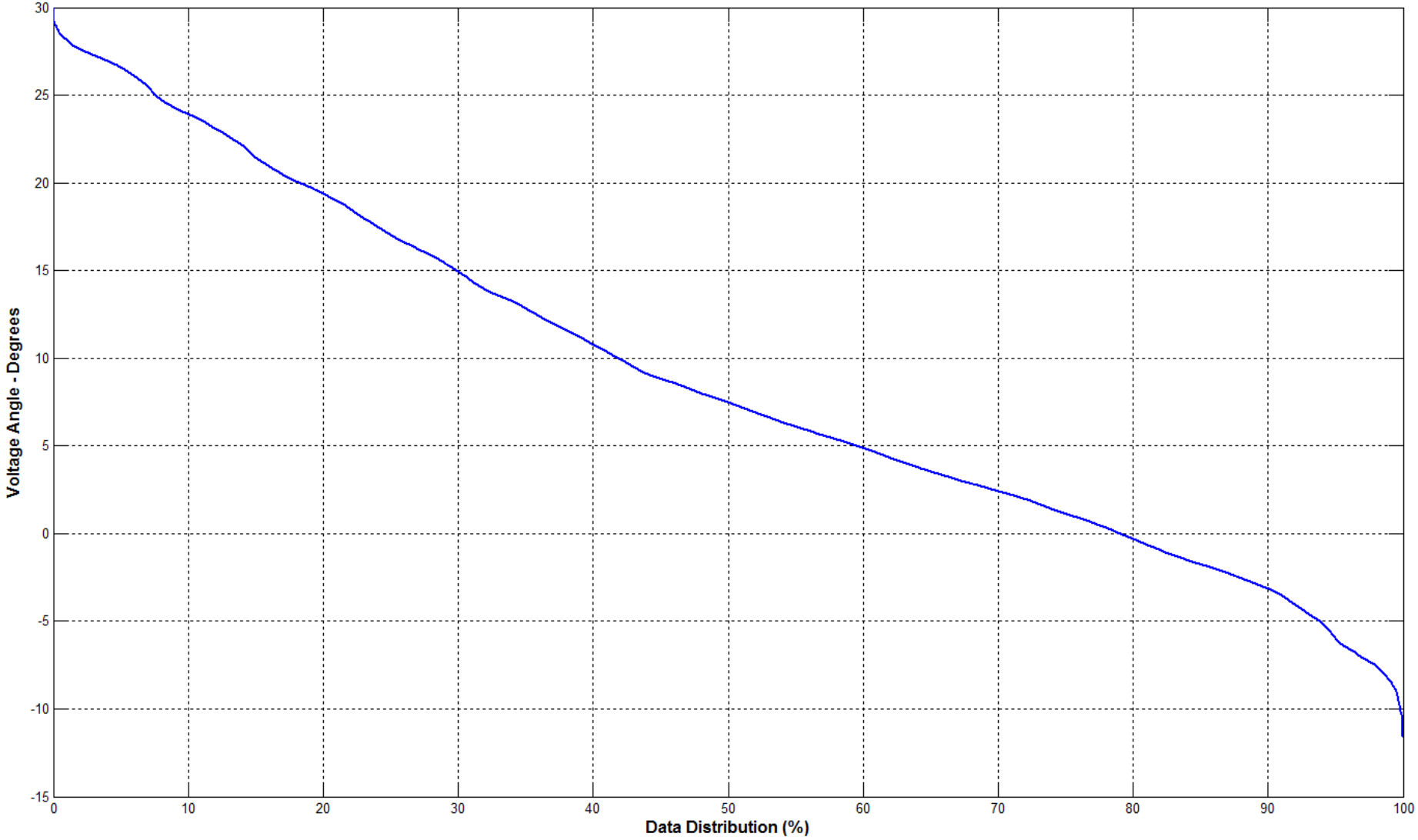


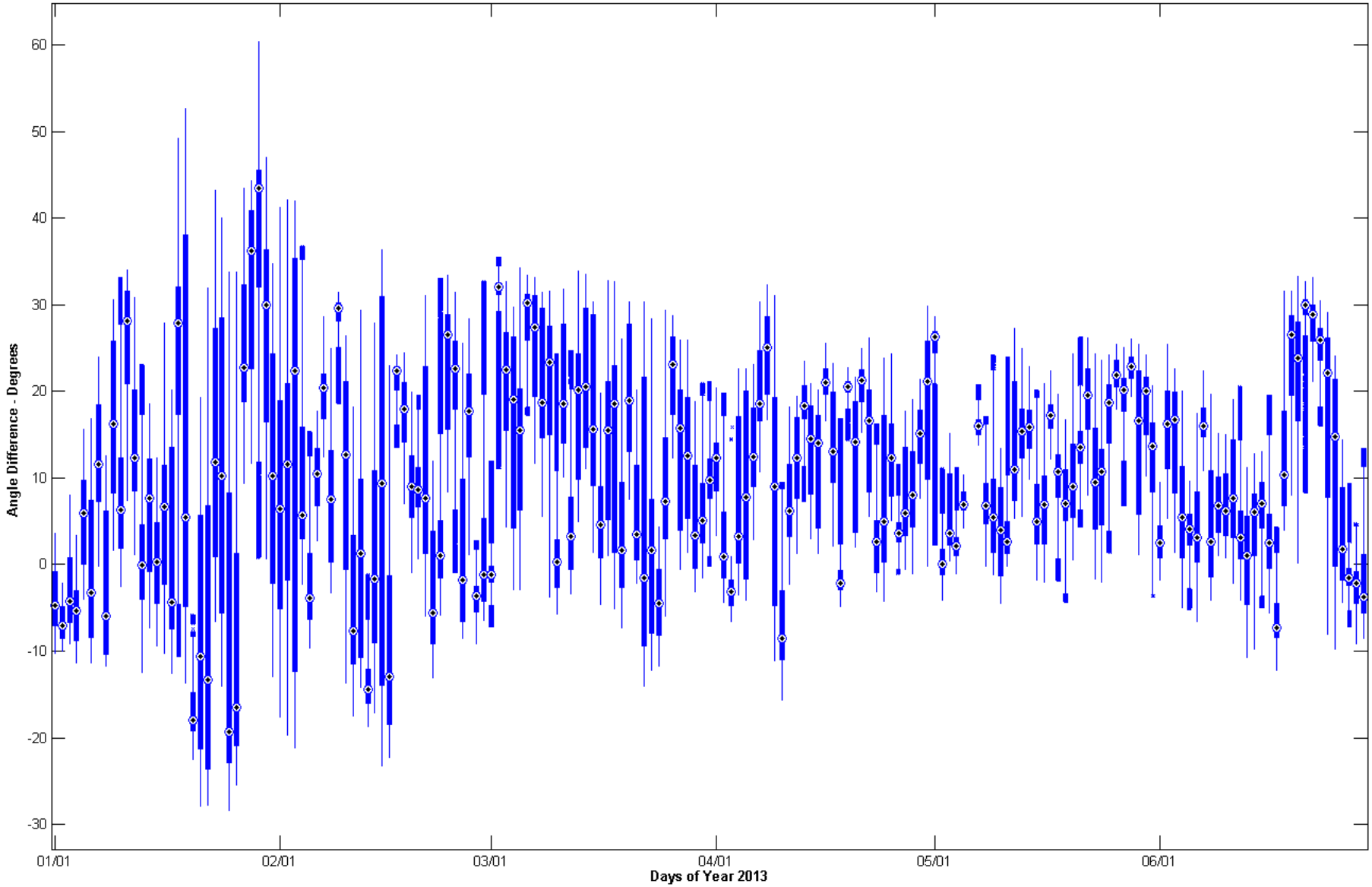
West 5 – Voltage Angle



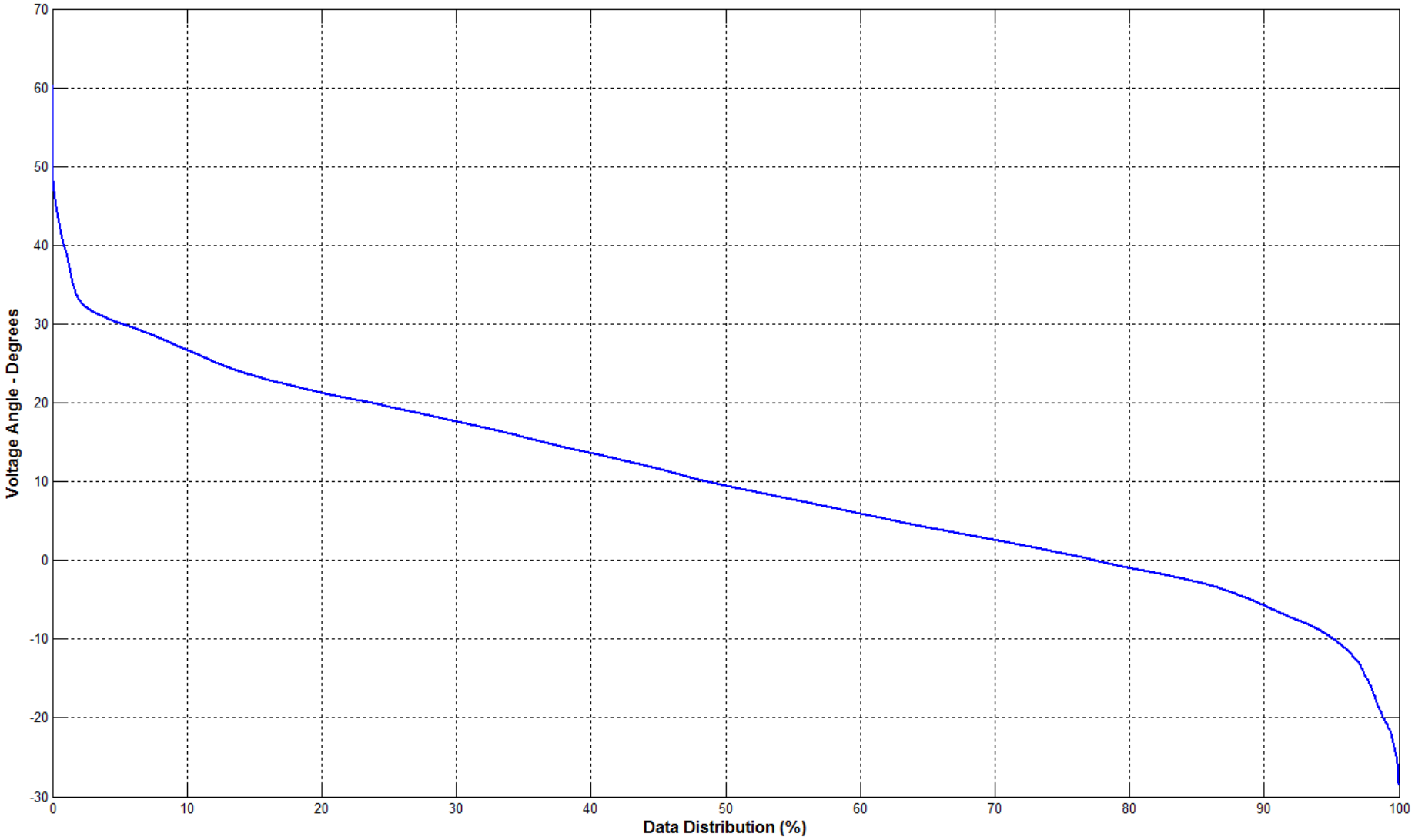
West 5 – Voltage Angle



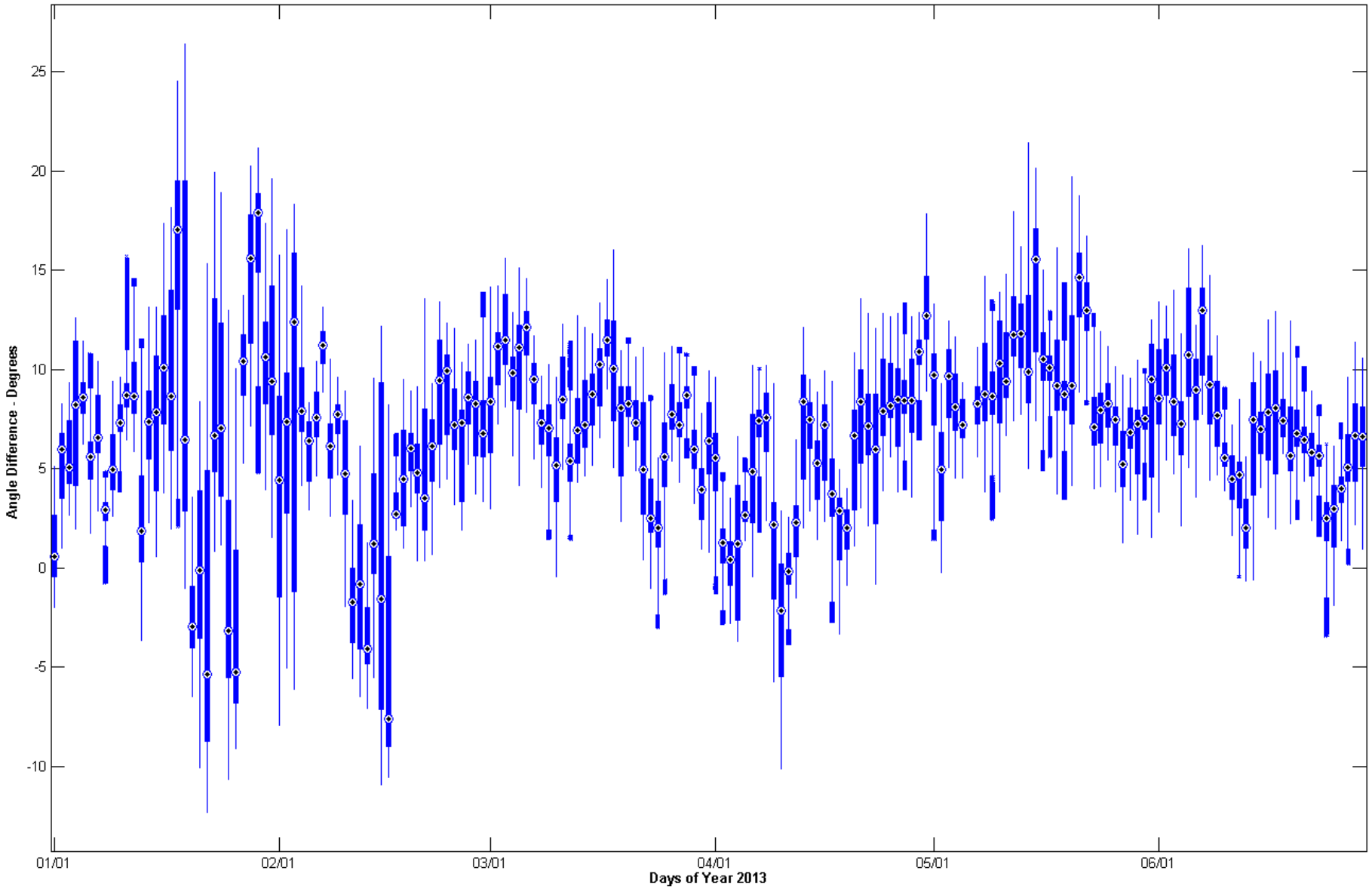
West 6 – Voltage Angle



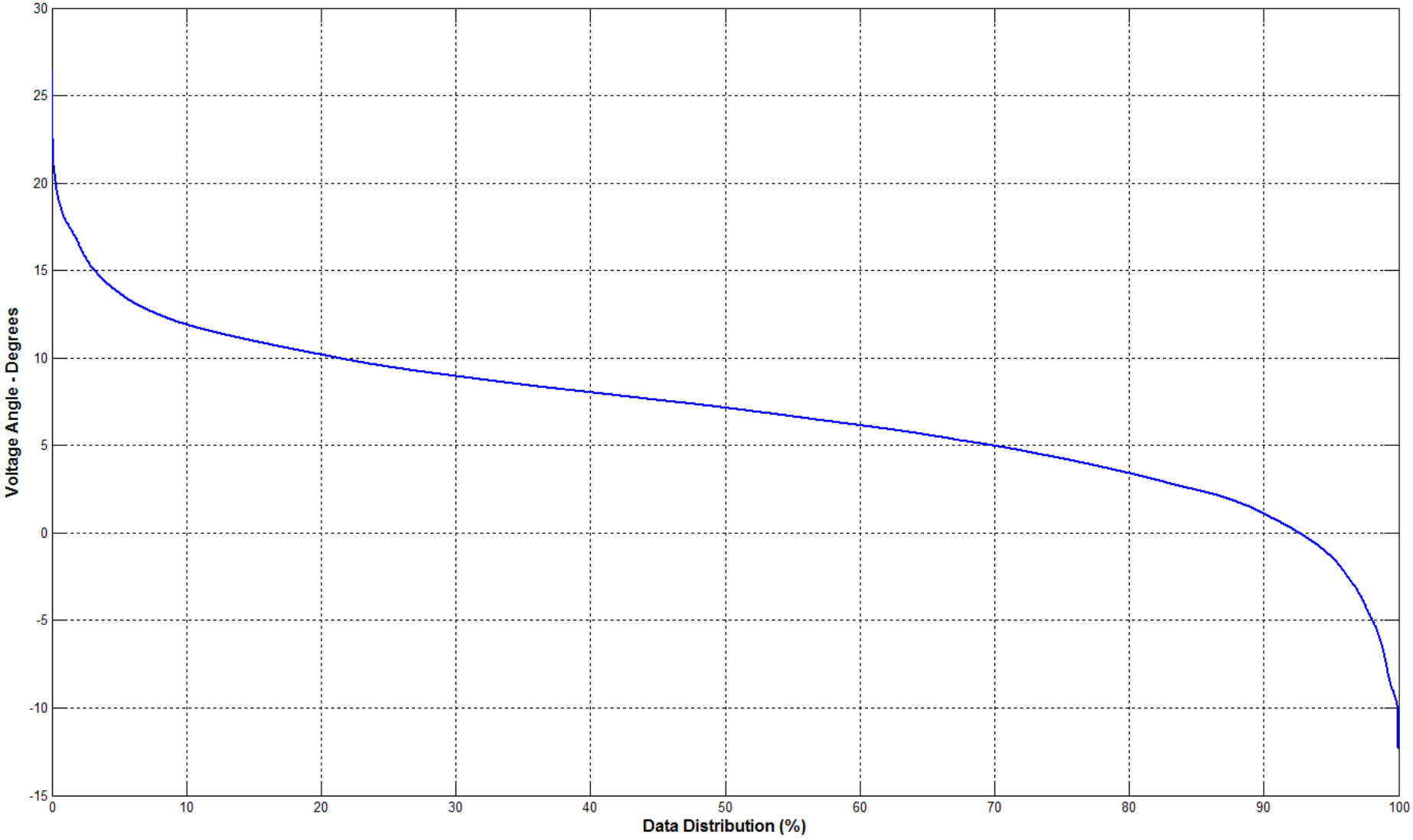
West 6 – Voltage Angle



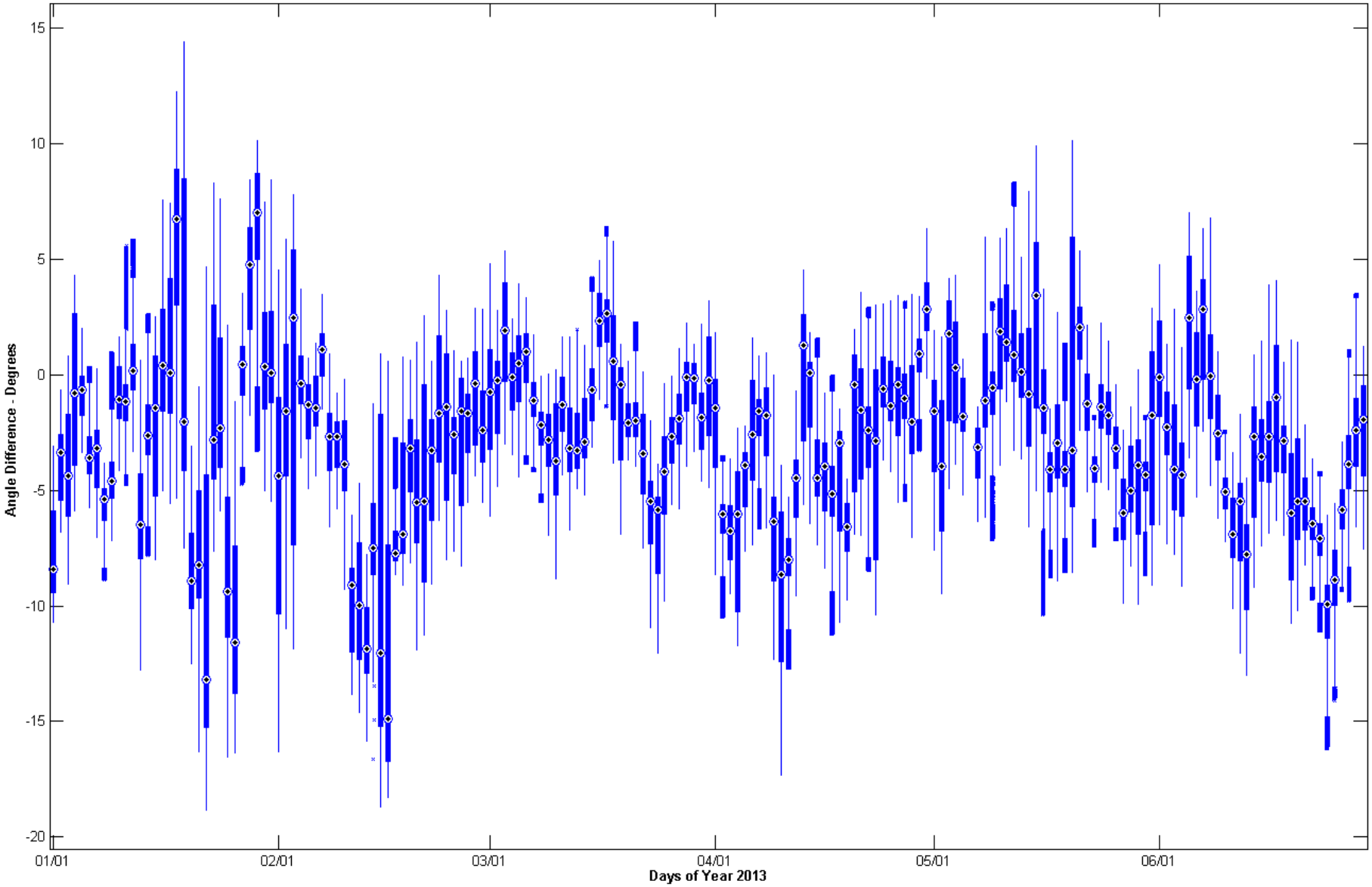
North 1 – Voltage Angle



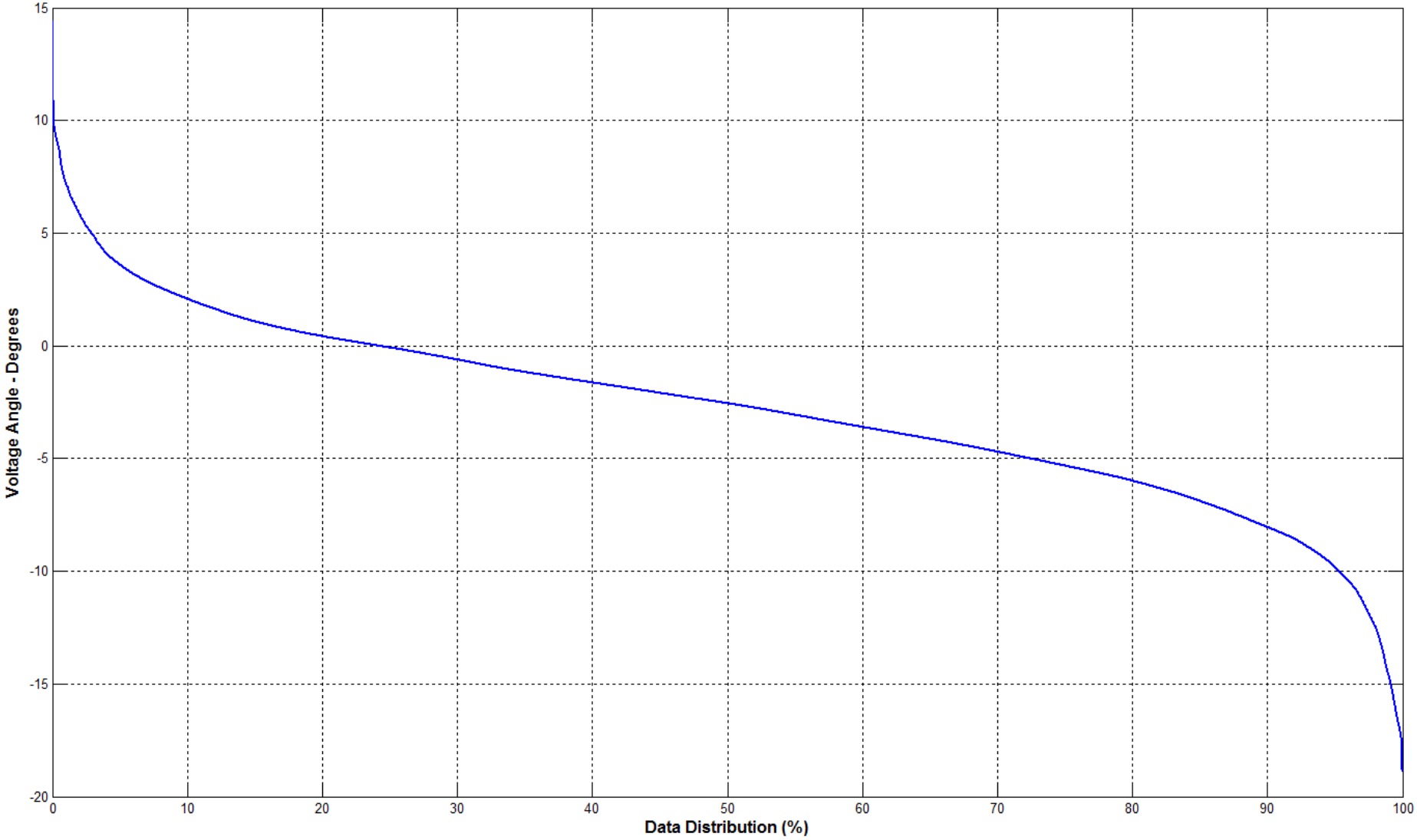
North 1 – Voltage Angle



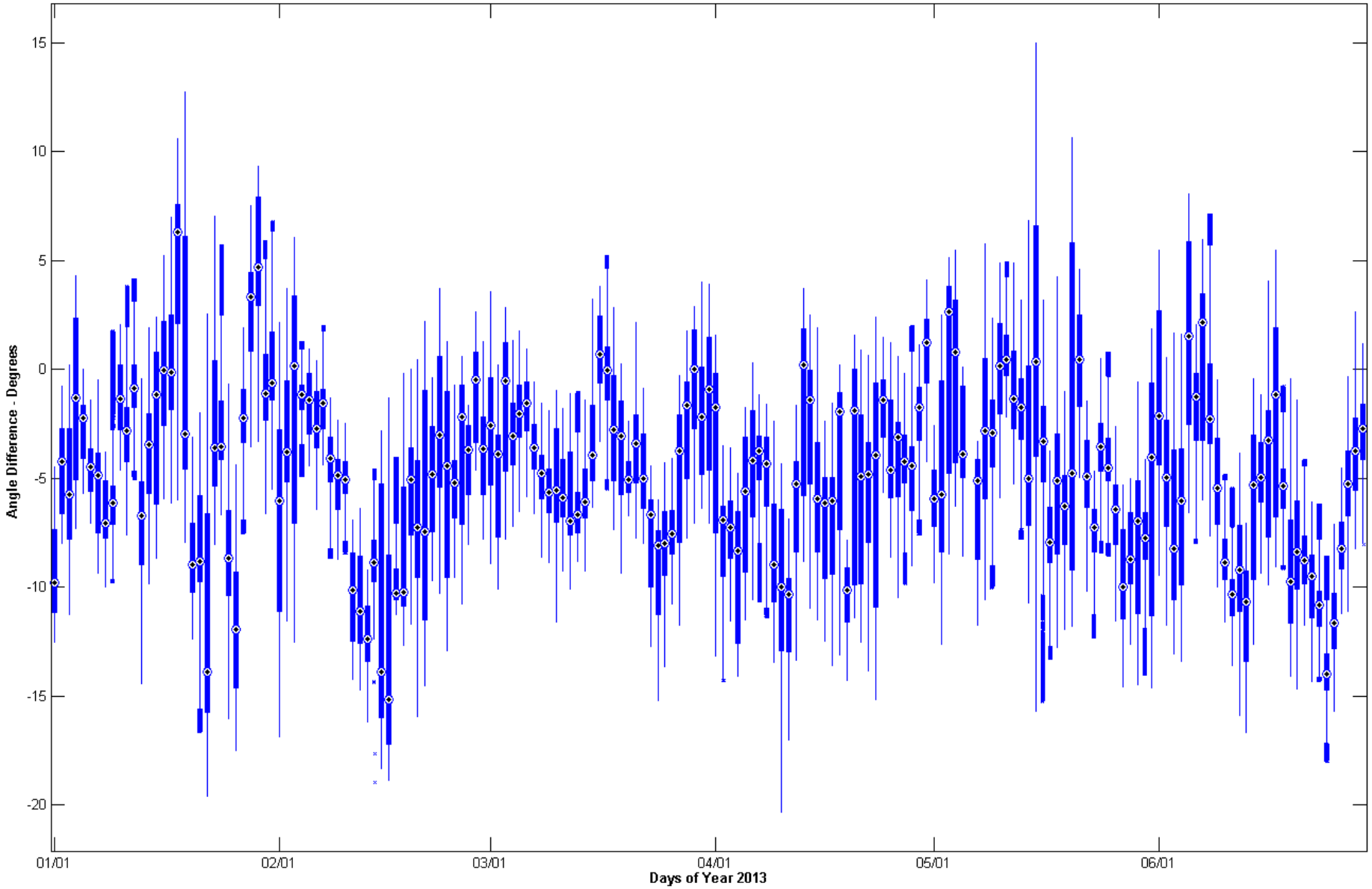
North 4 – Voltage Angle



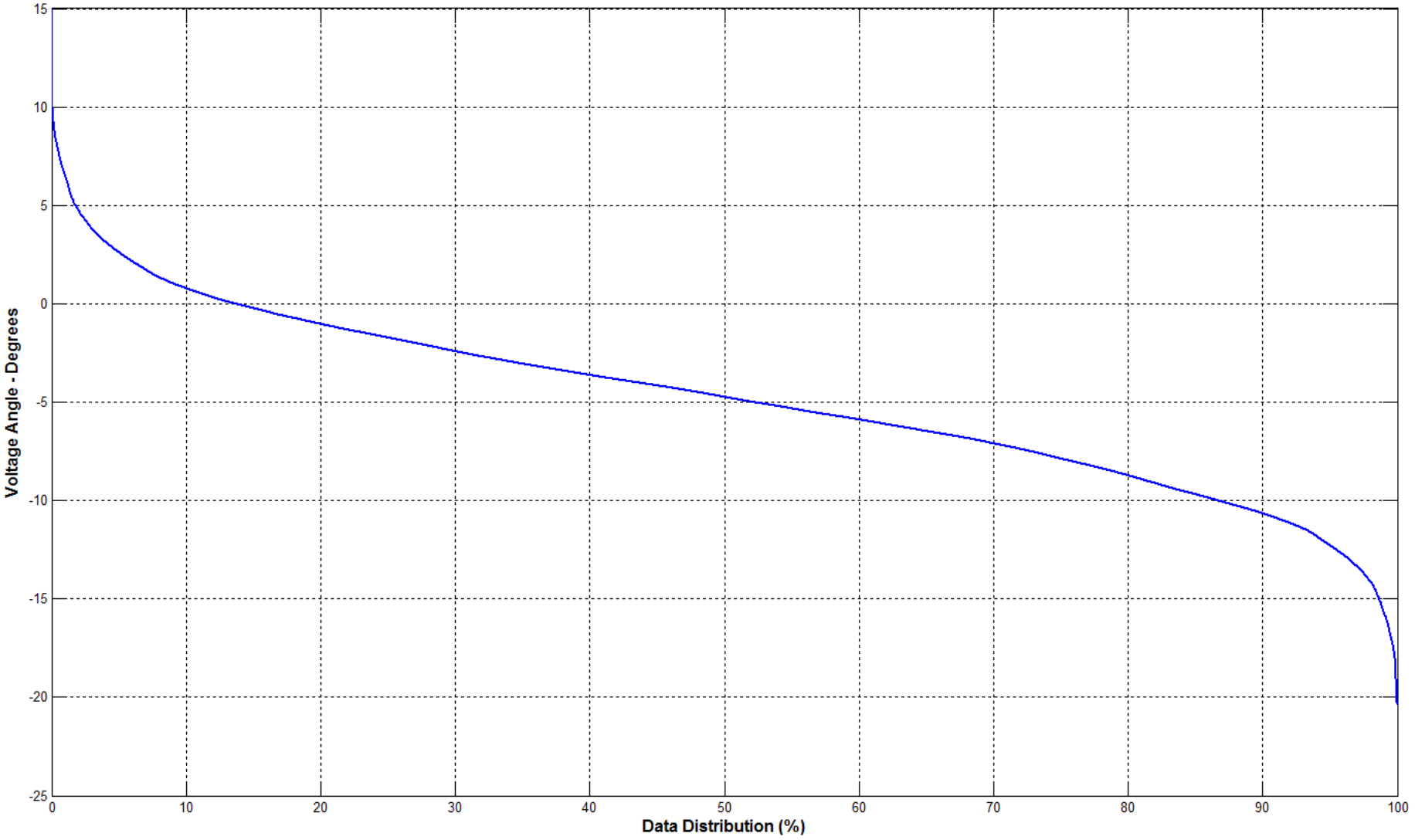
North 4 – Voltage Angle



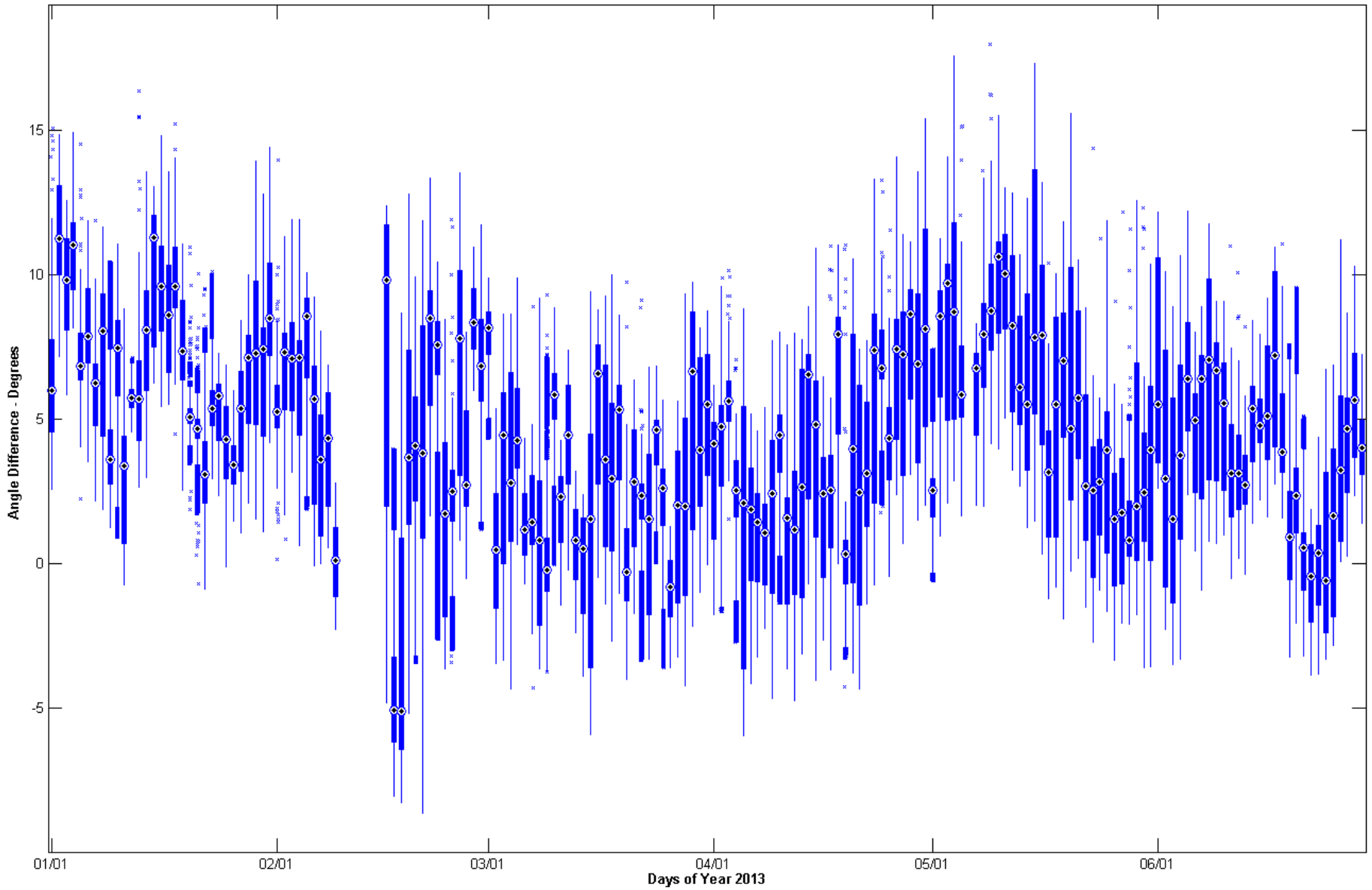
North 5 – Voltage Angle



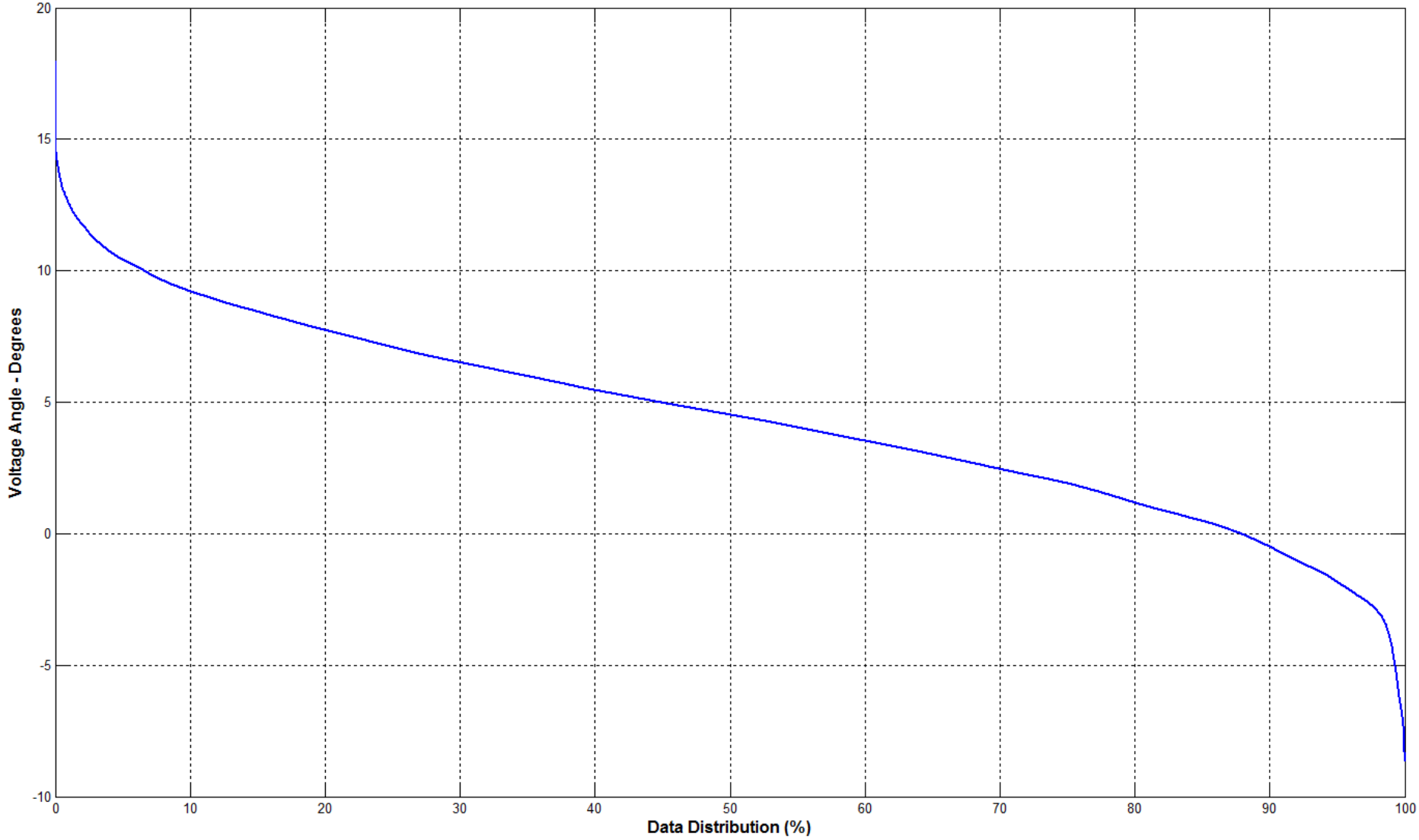
North 5 – Voltage Angle



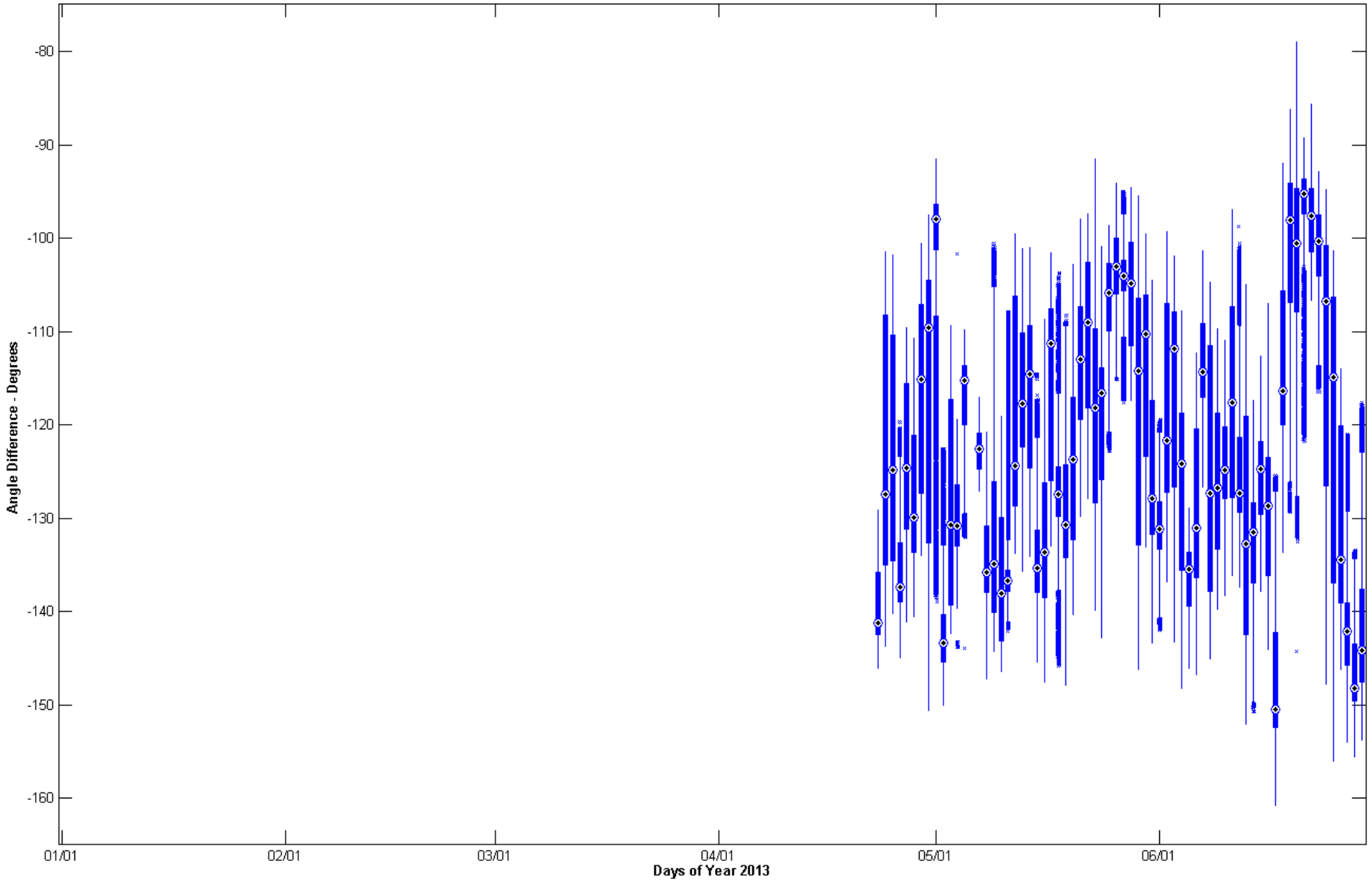
North 6 – Voltage Angle



North 6 – Voltage Angle



FarWest 2 – Voltage Angle



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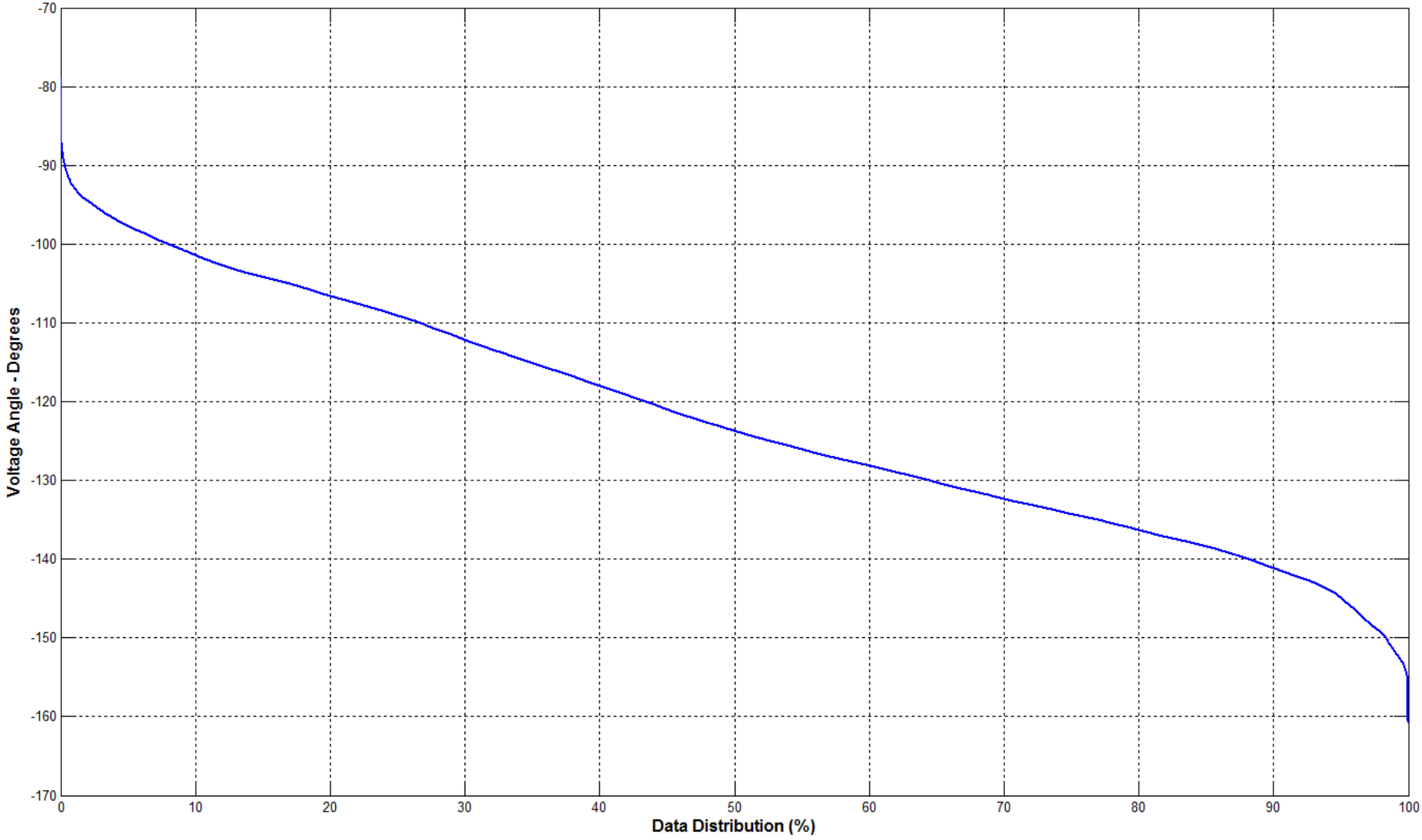

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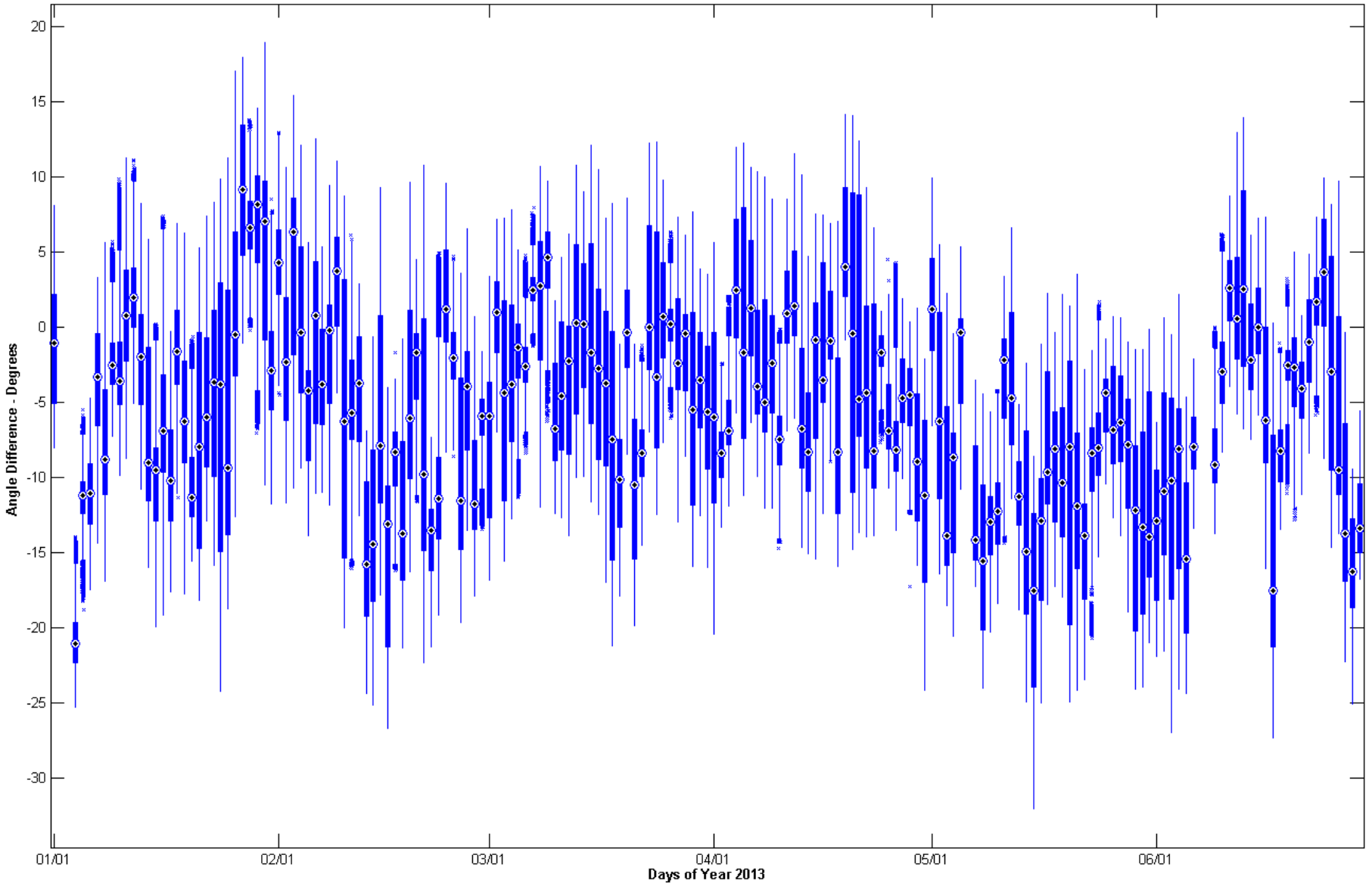
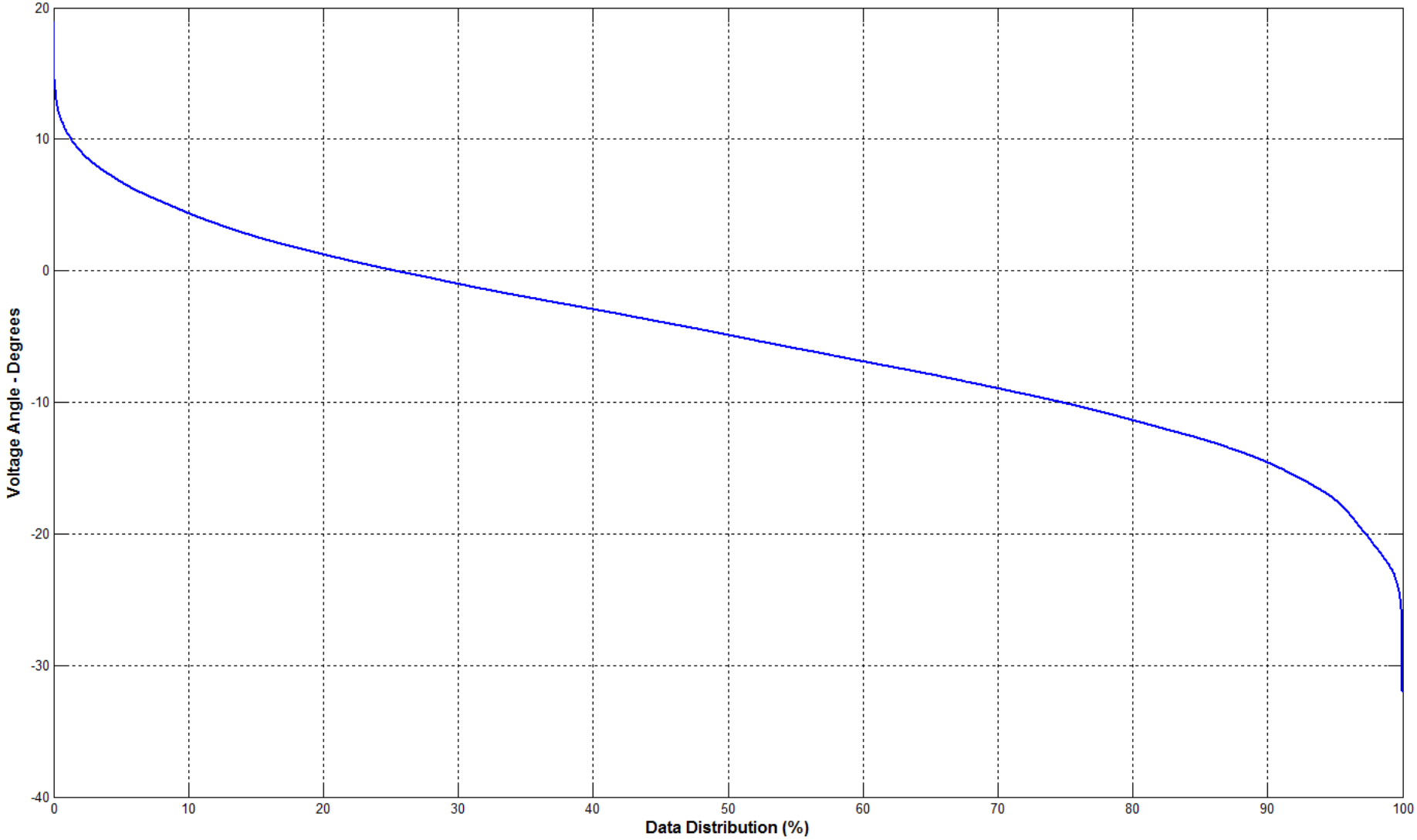
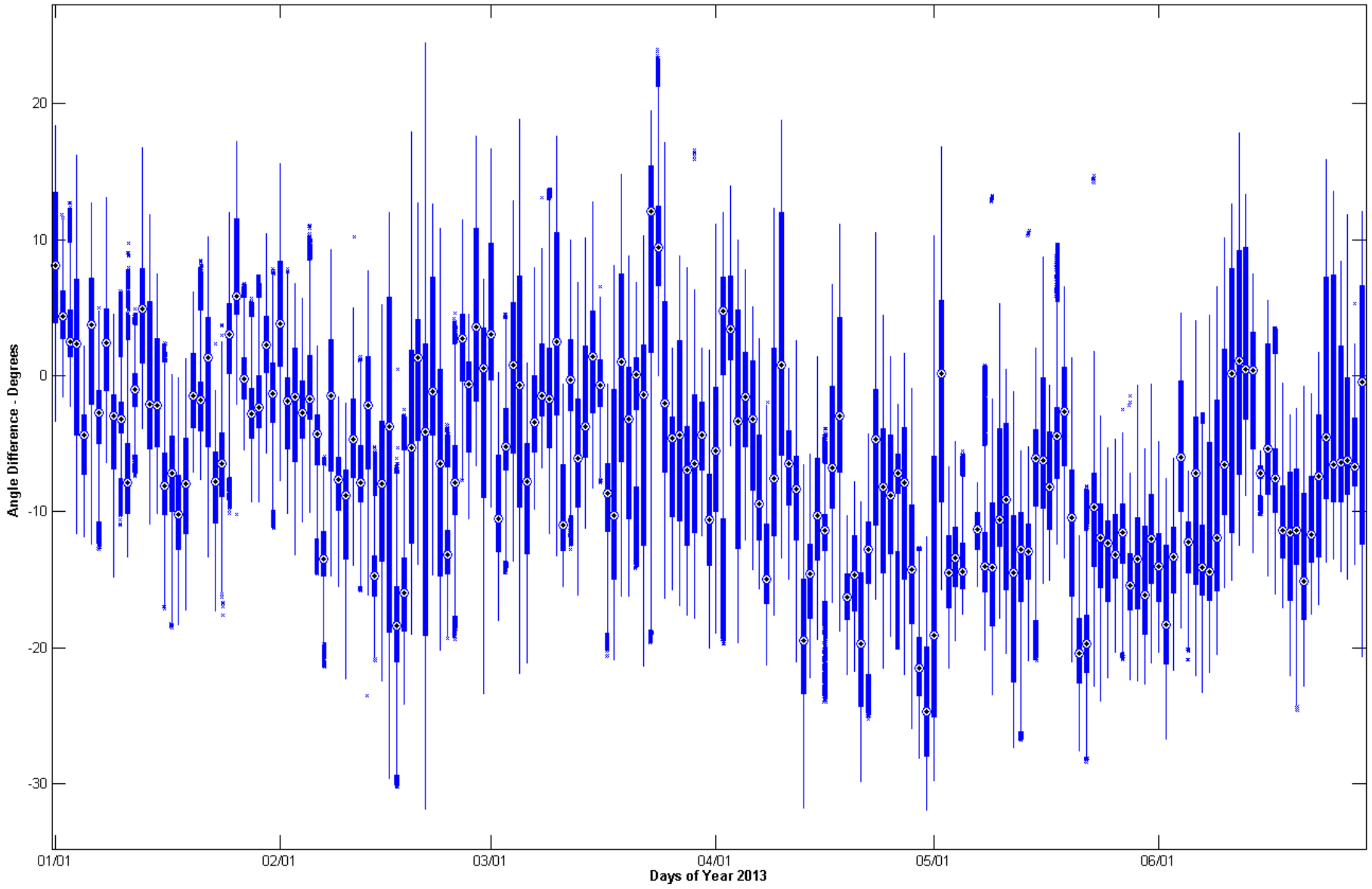


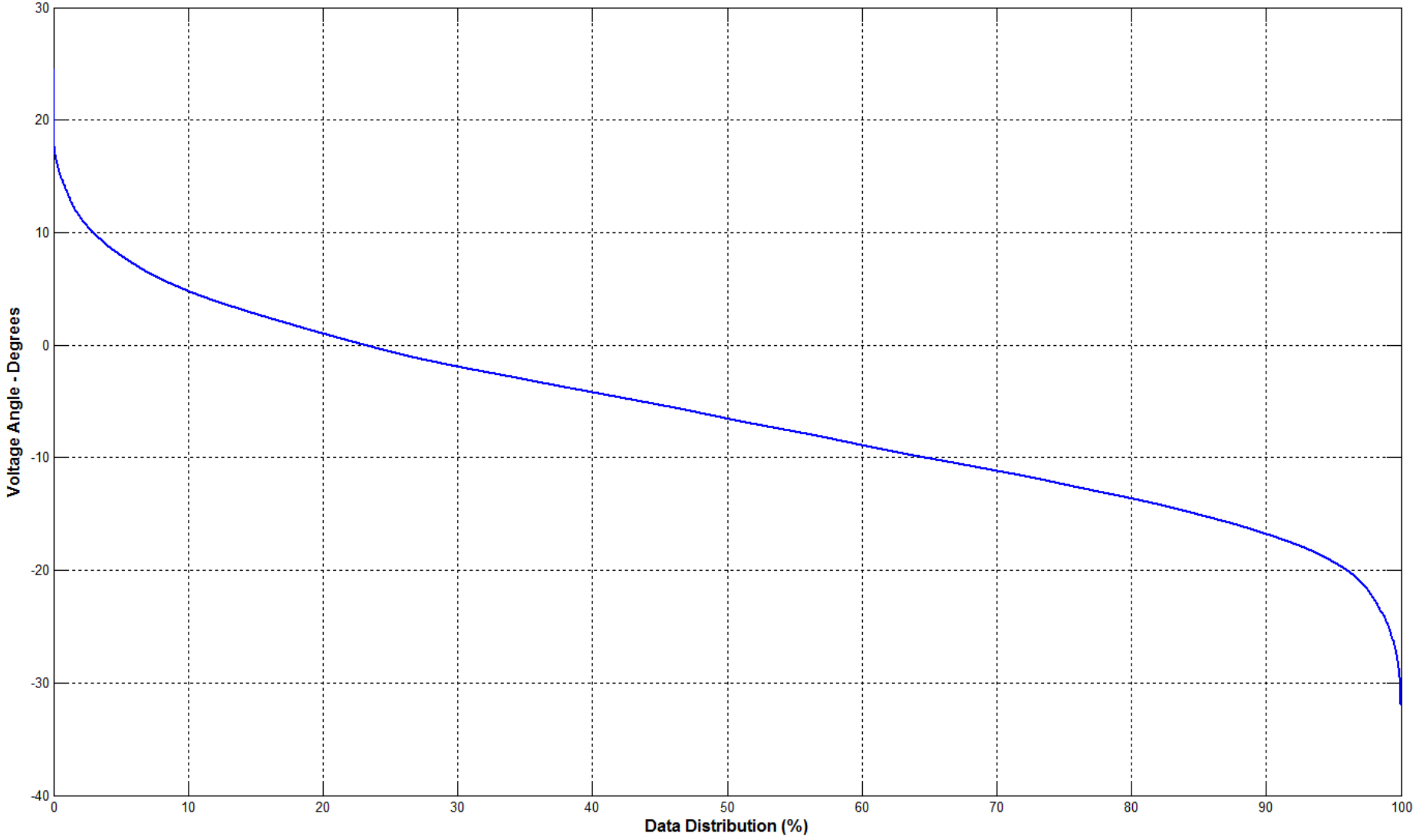
West 4 – Voltage Angle



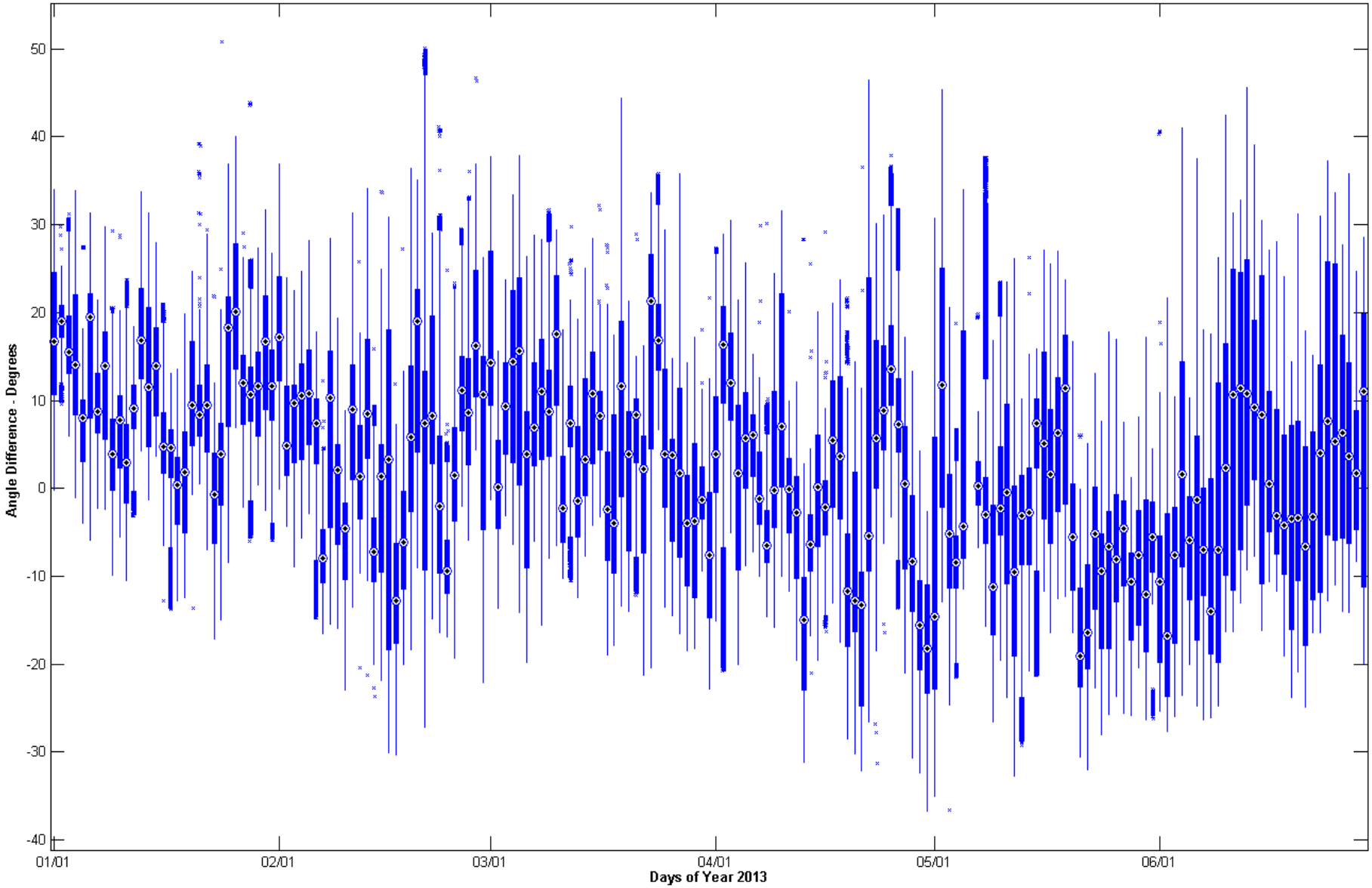
Coast 2 – Voltage Angle



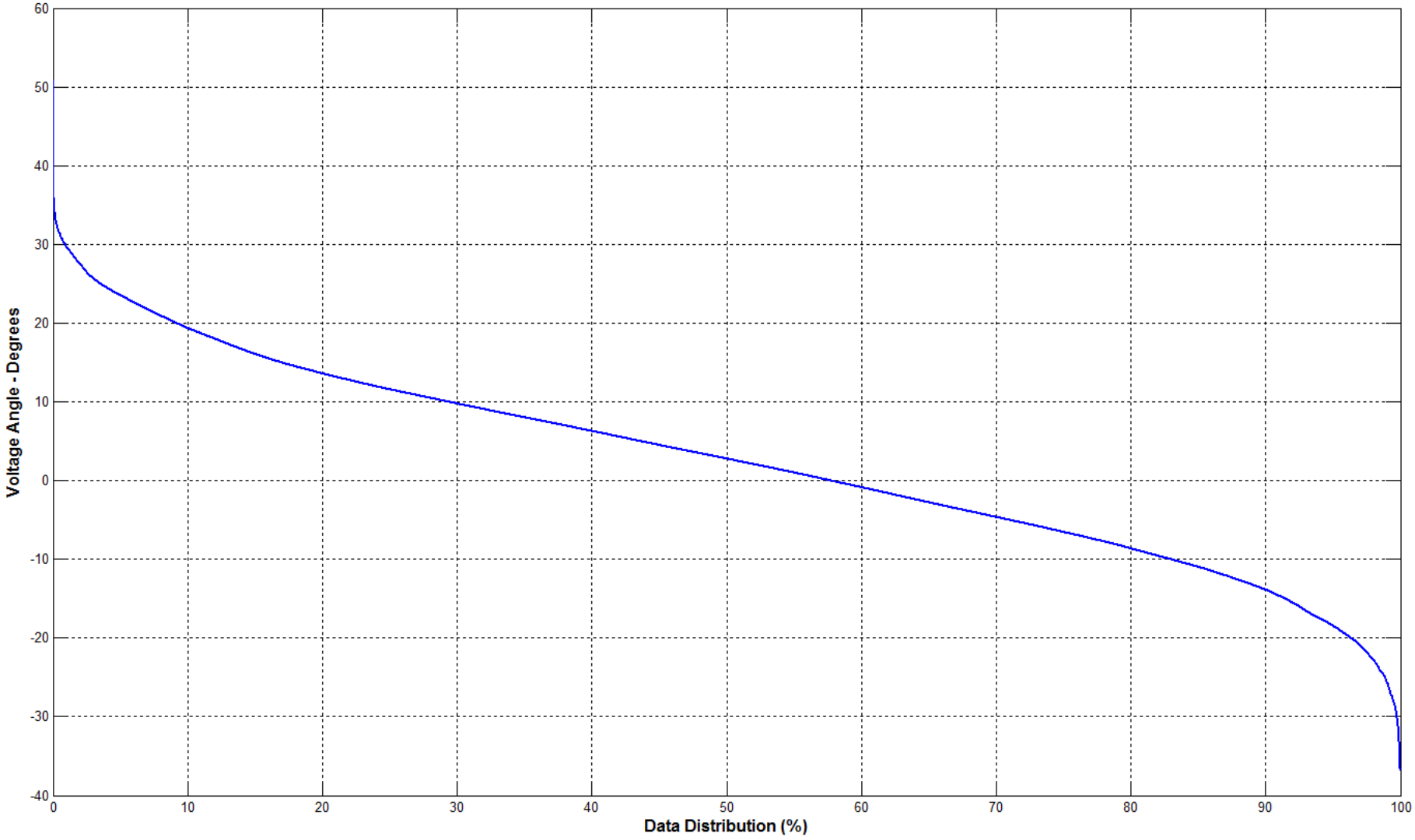
Coast 2 – Voltage Angle



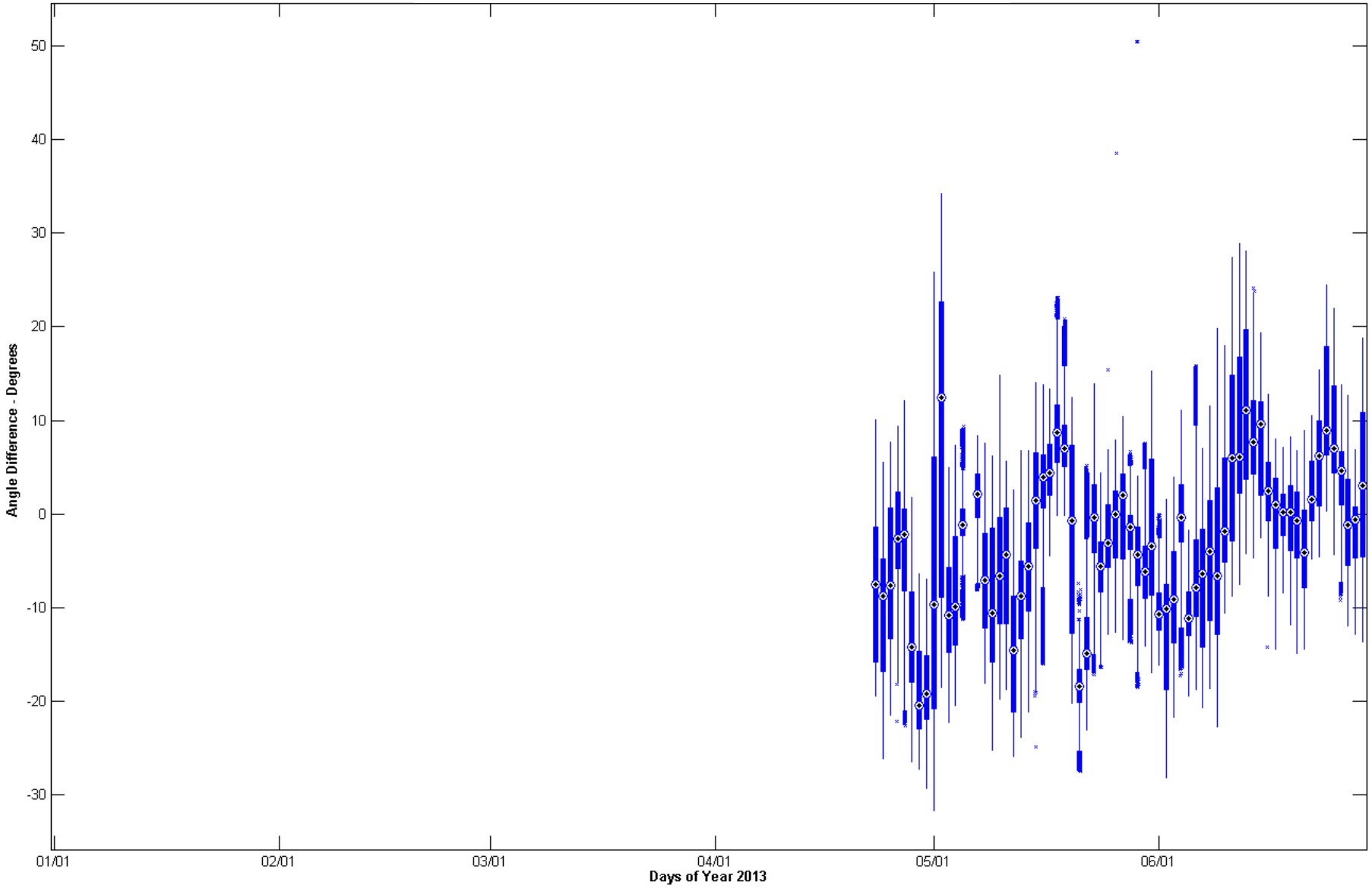
Coast 1 – Voltage Angle



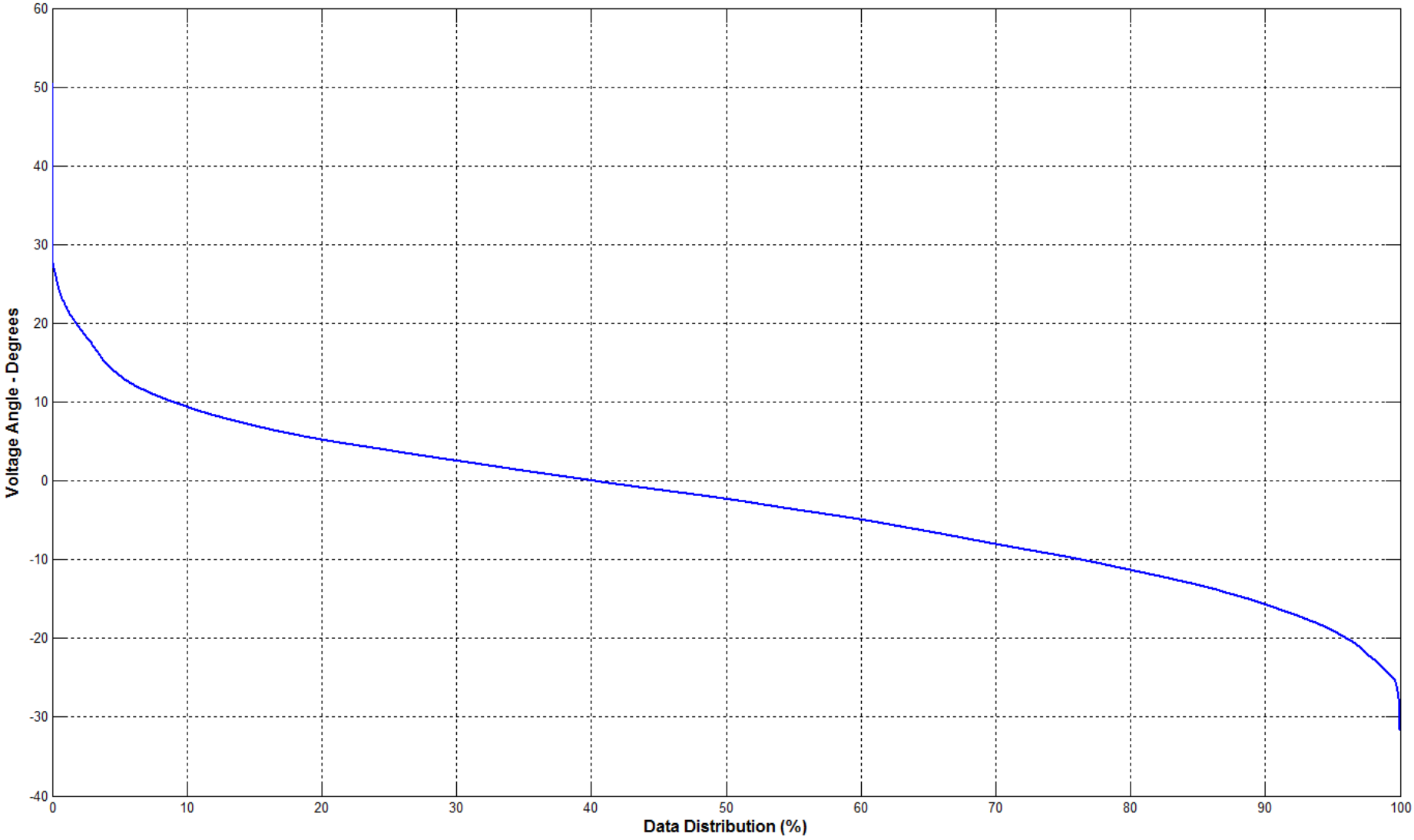
Coast 1 – Voltage Angle



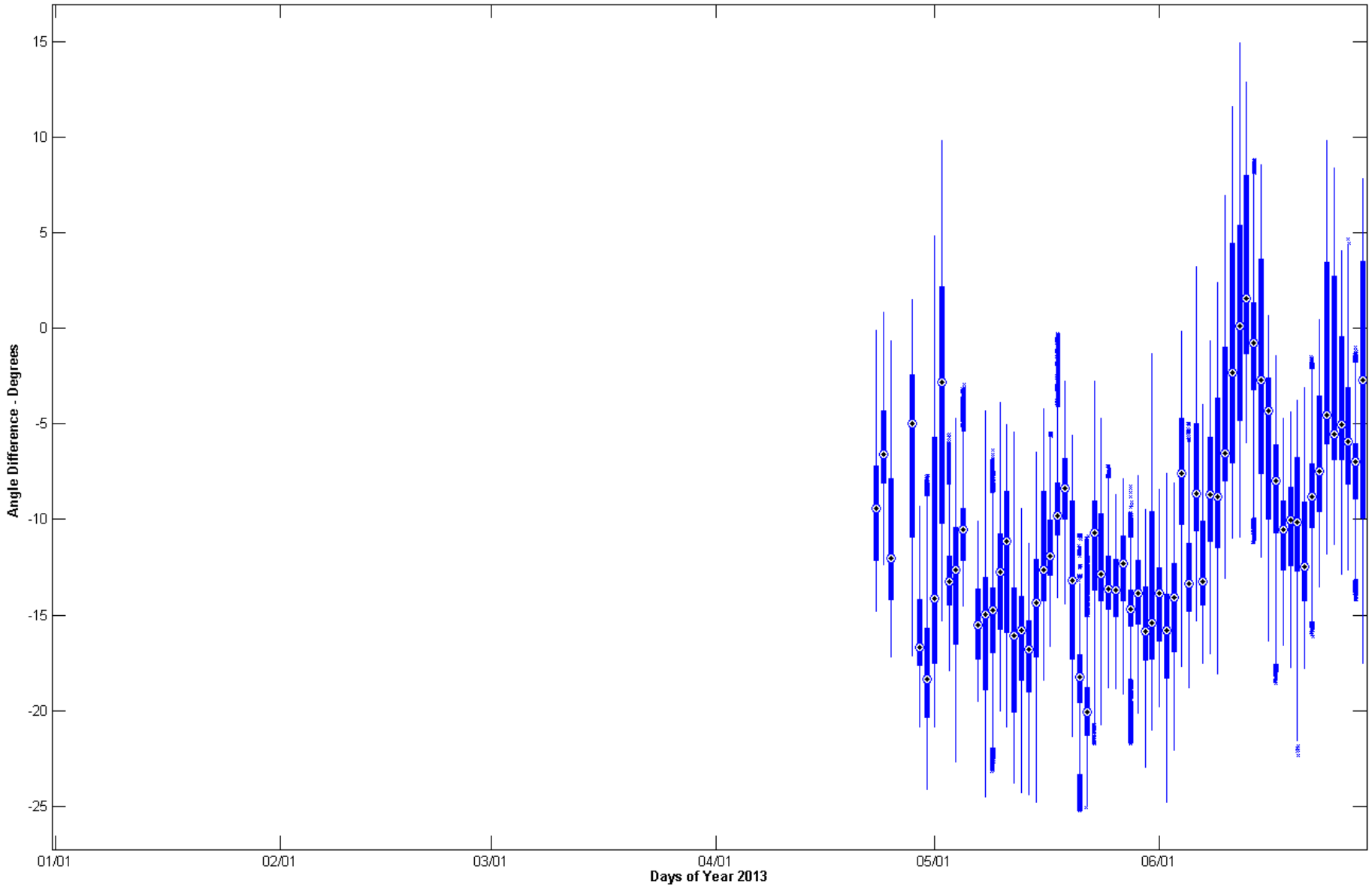
South 3 – Voltage Angle



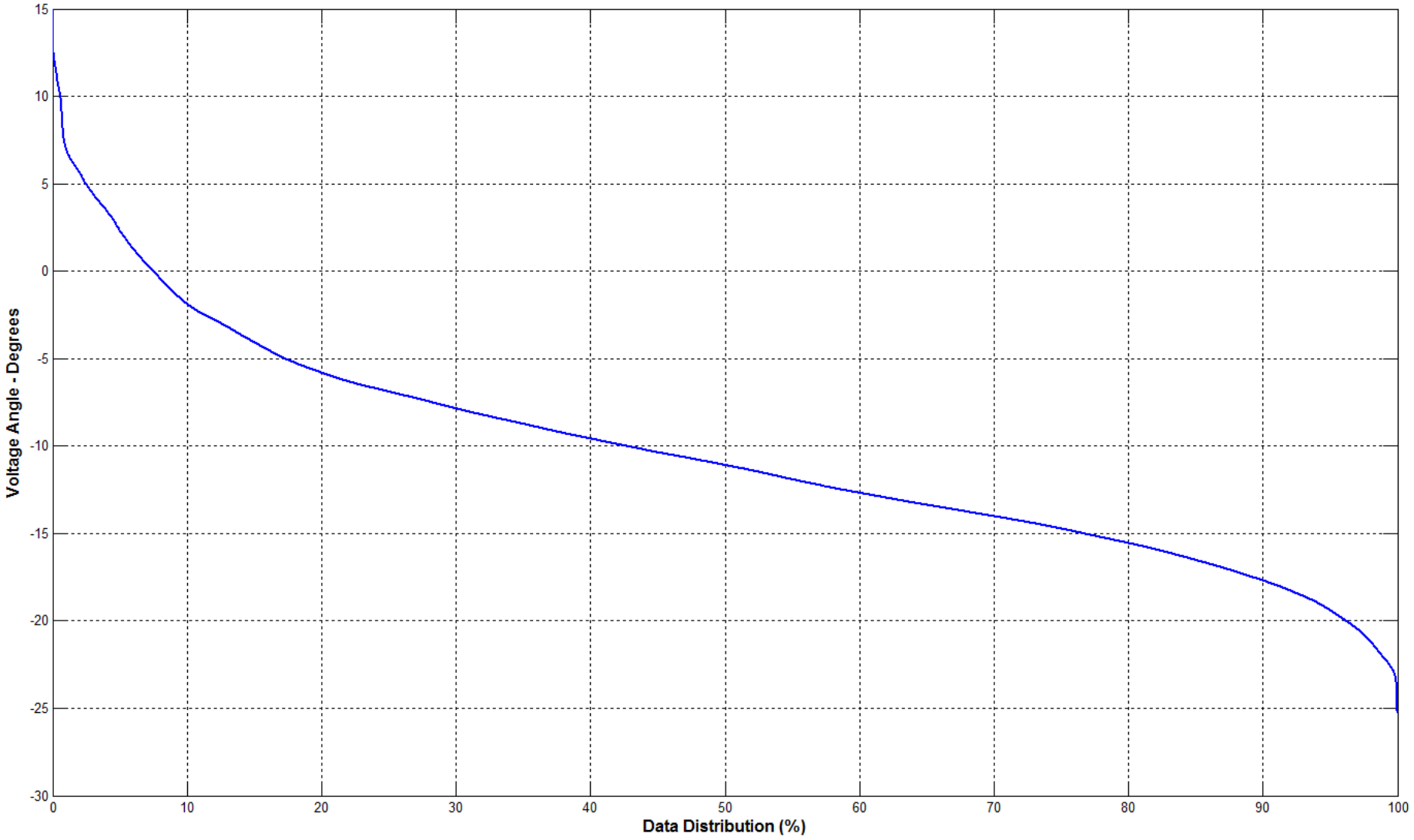
South 3 – Voltage Angle



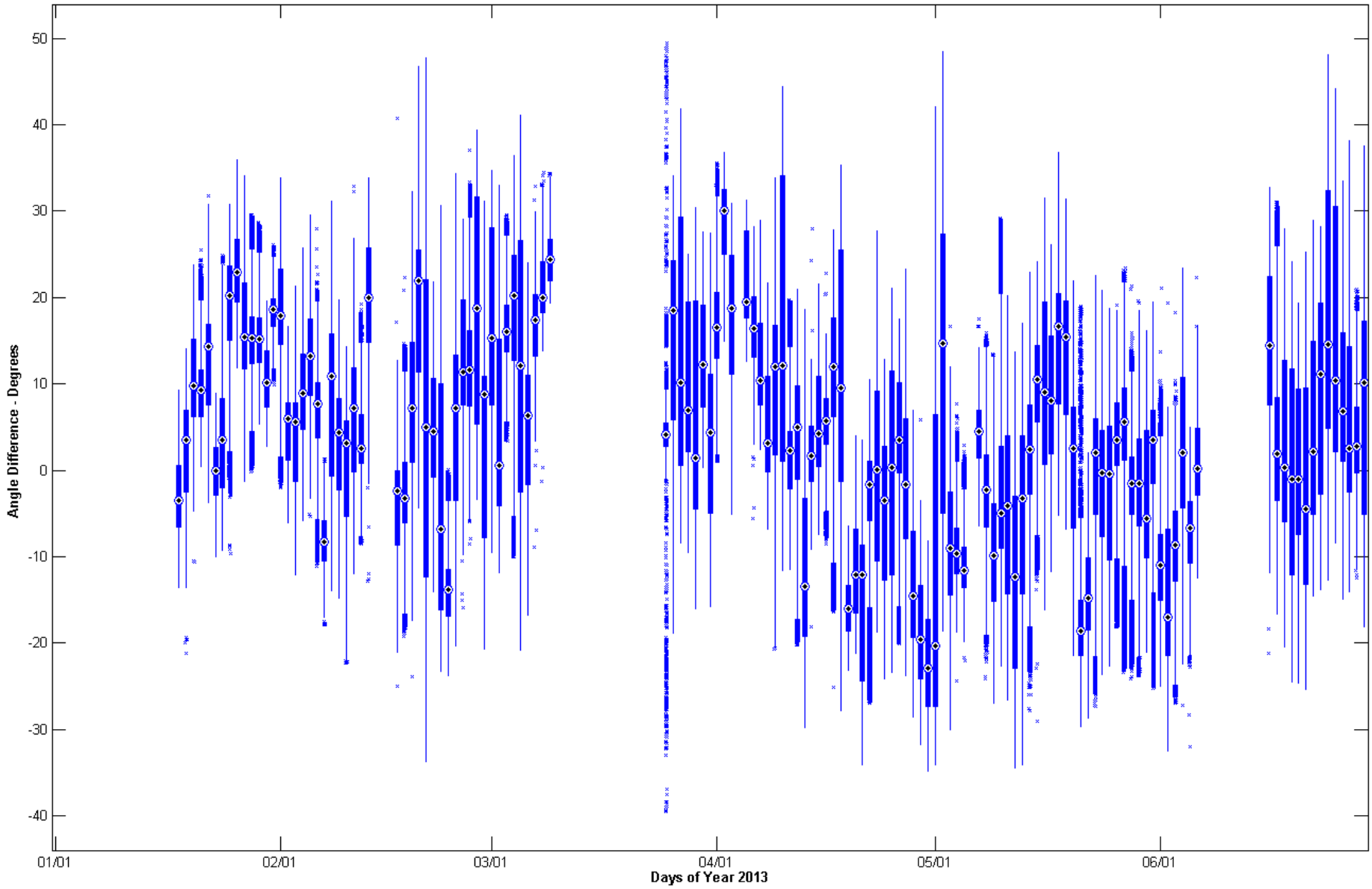
South 5 – Voltage Angle



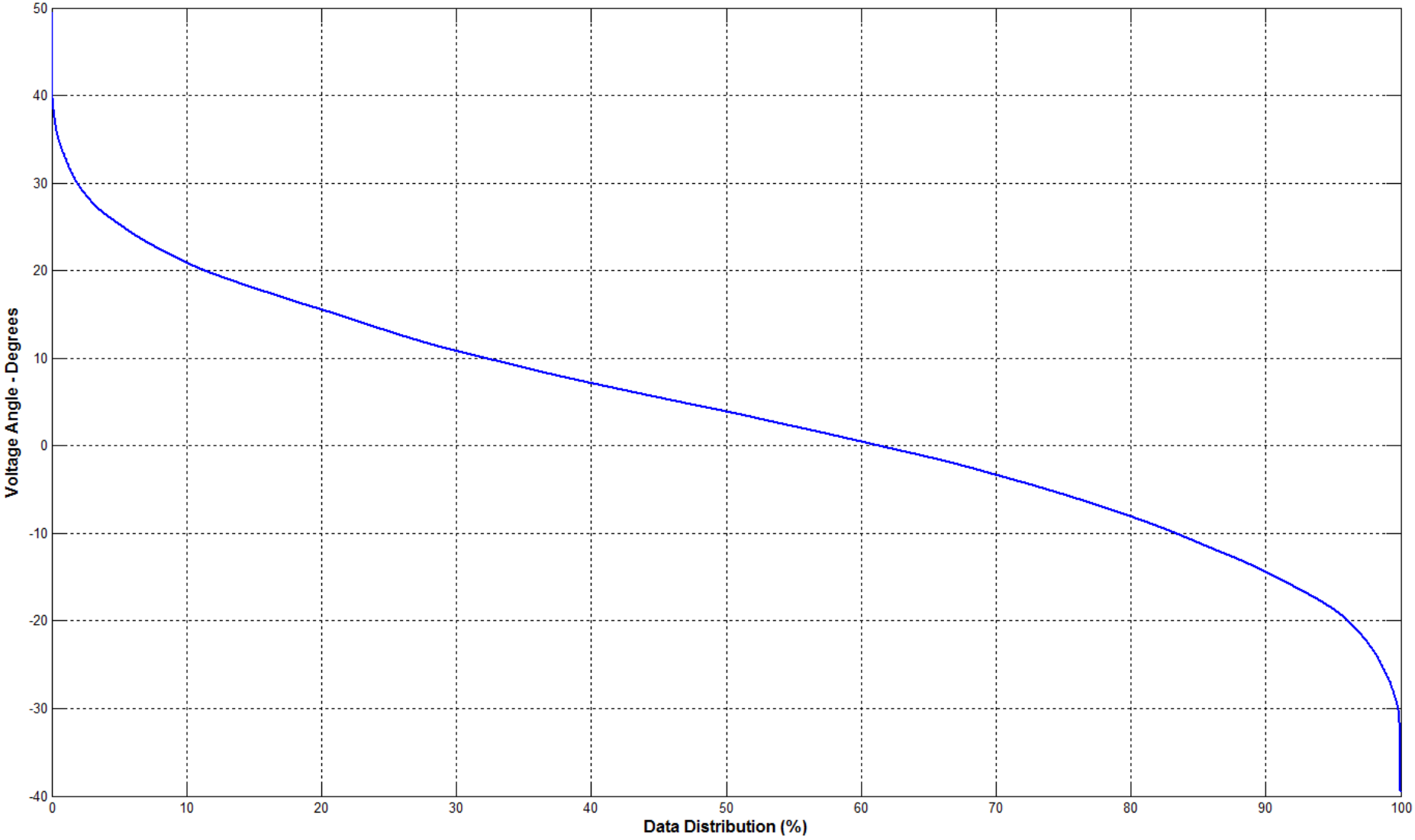
South 5 – Voltage Angle



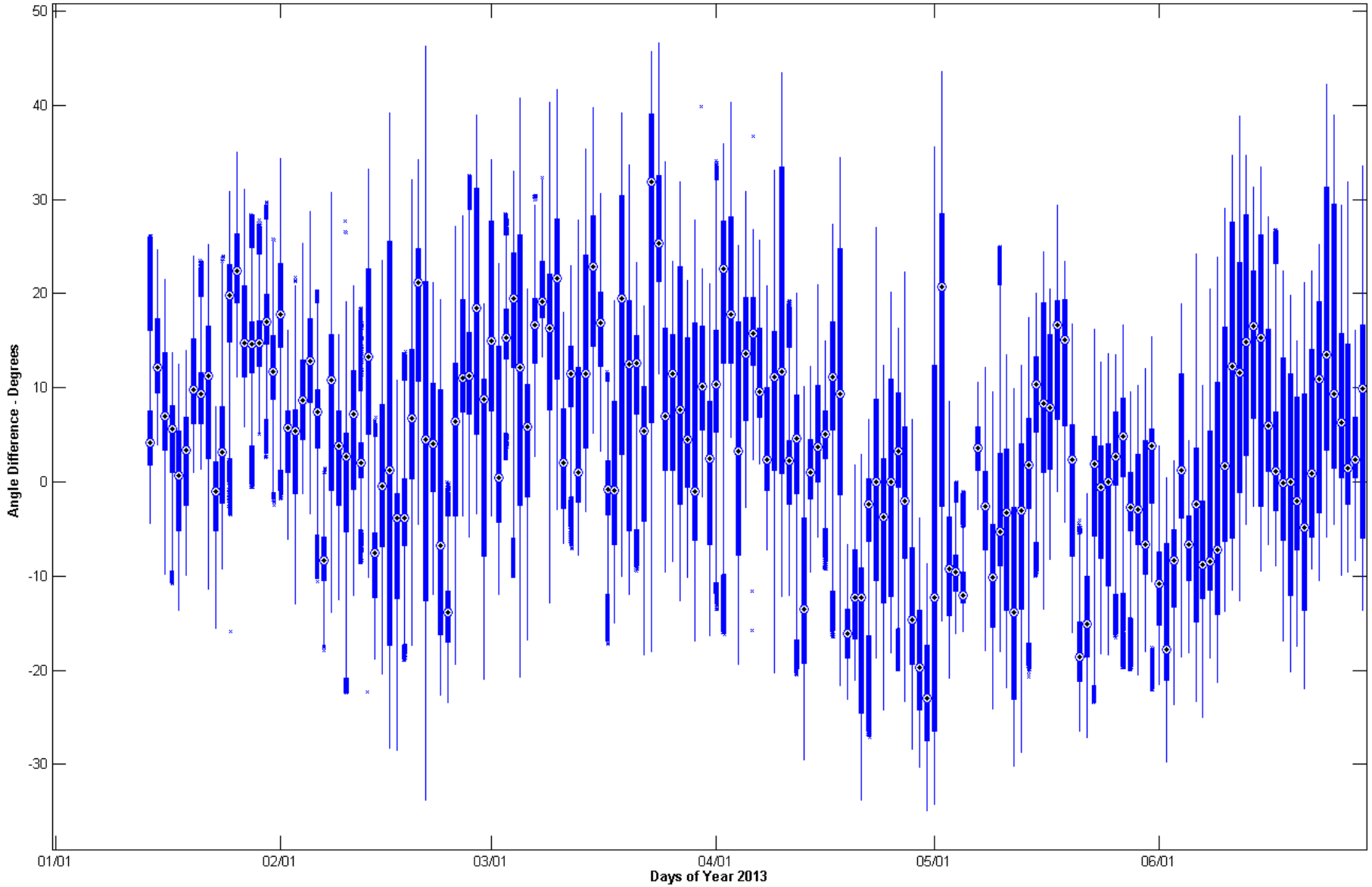
Coast 4 – Voltage Angle



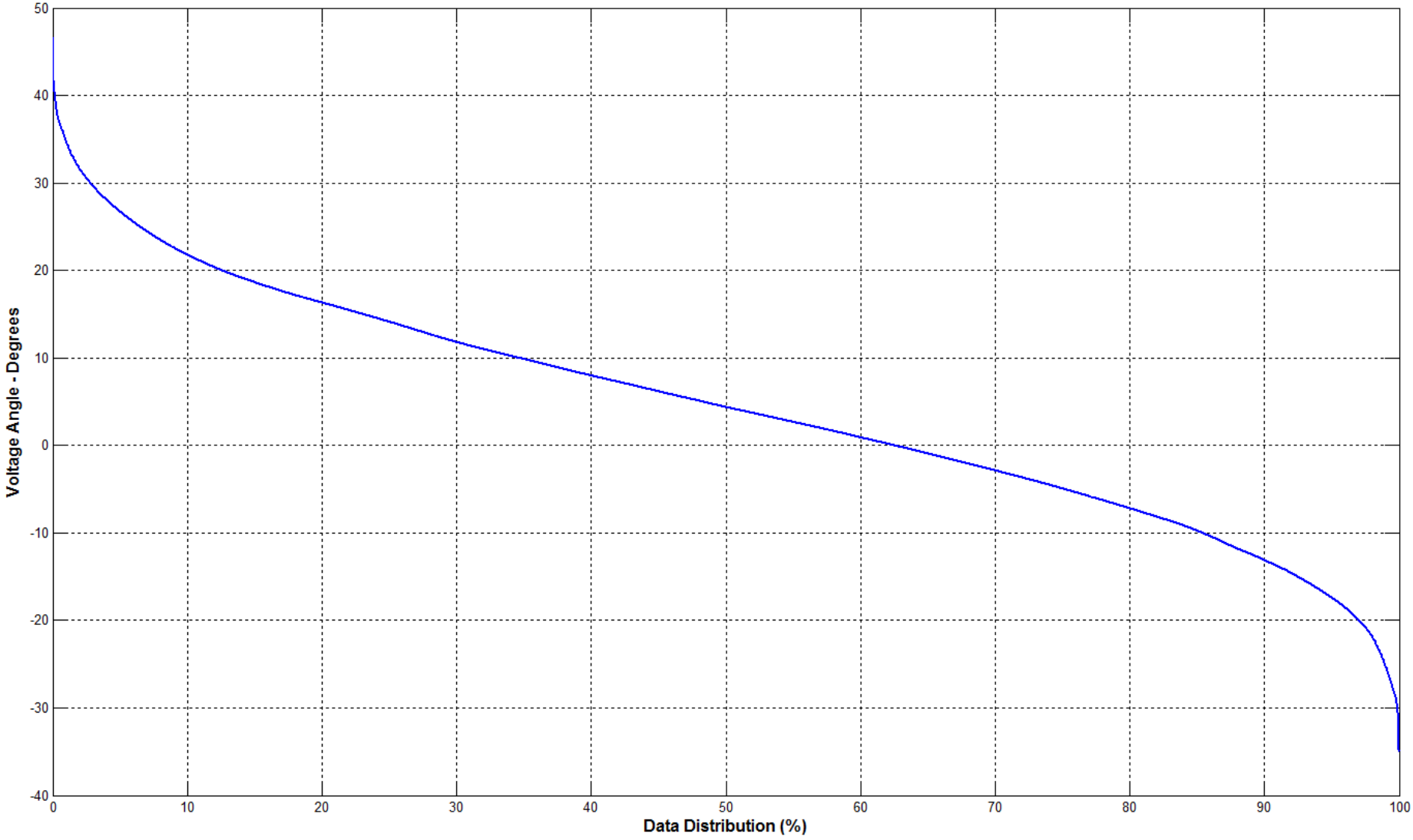
Coast 4 – Voltage Angle



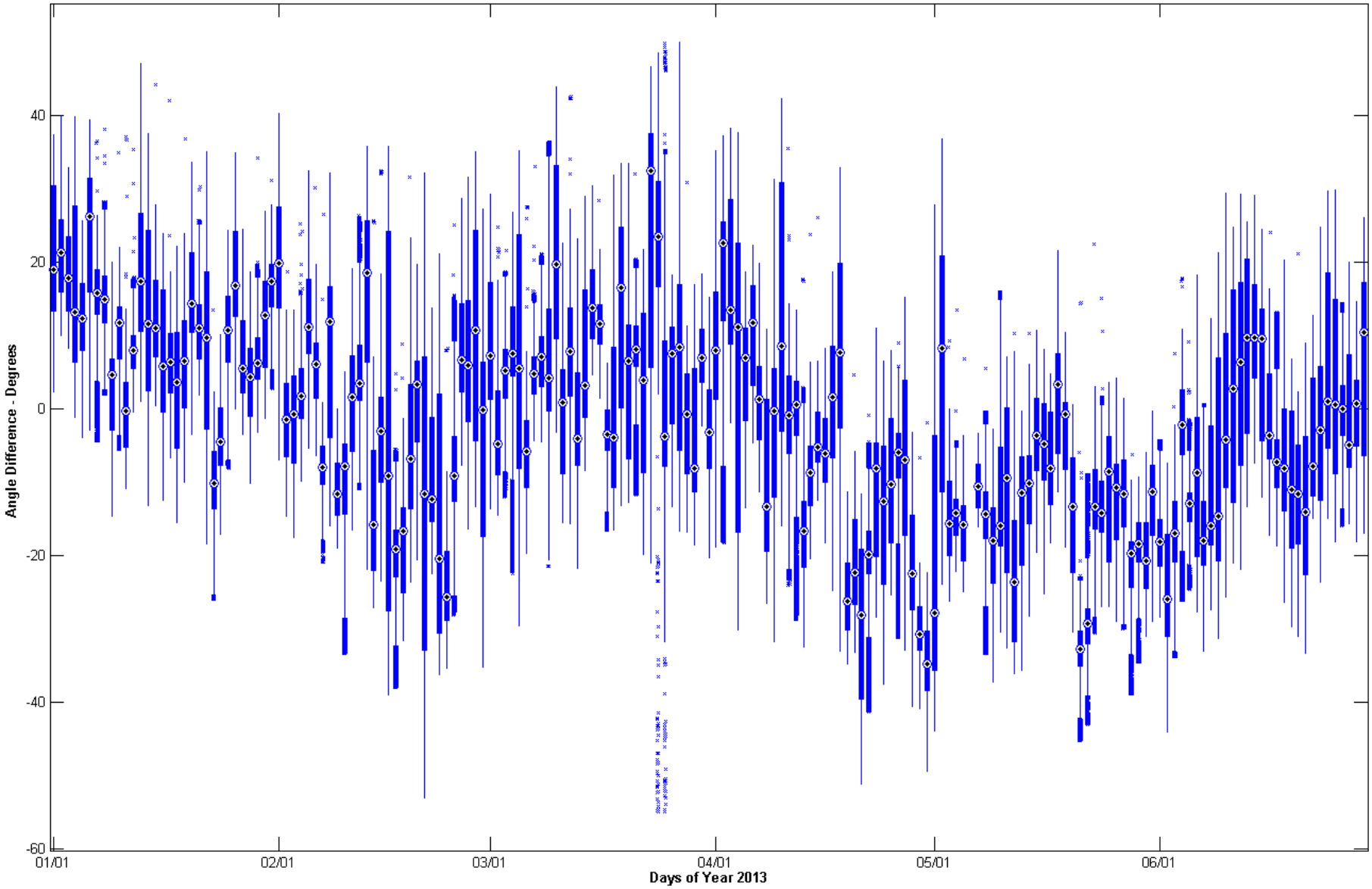
Coast 3 – Voltage Angle



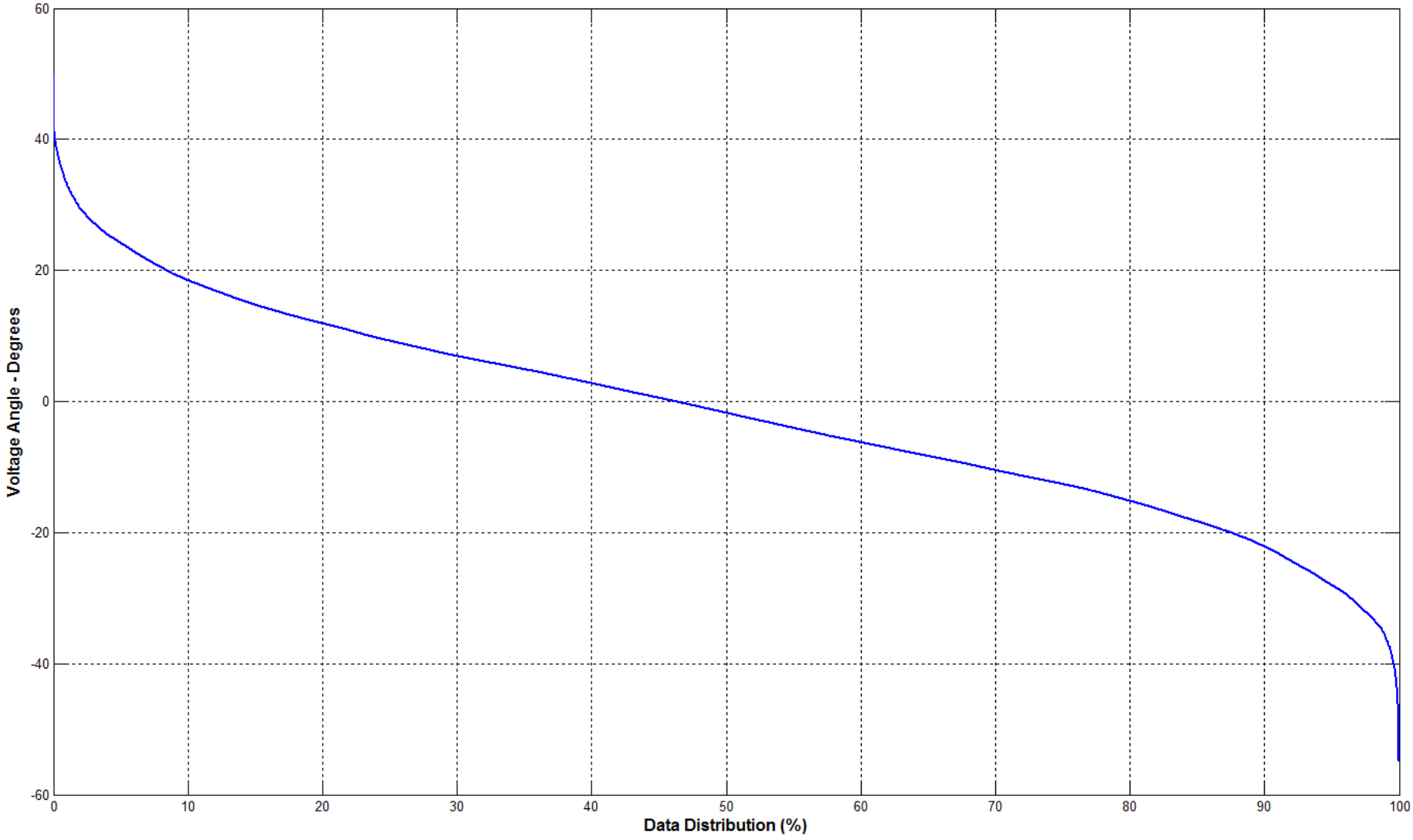
Coast 3 – Voltage Angle



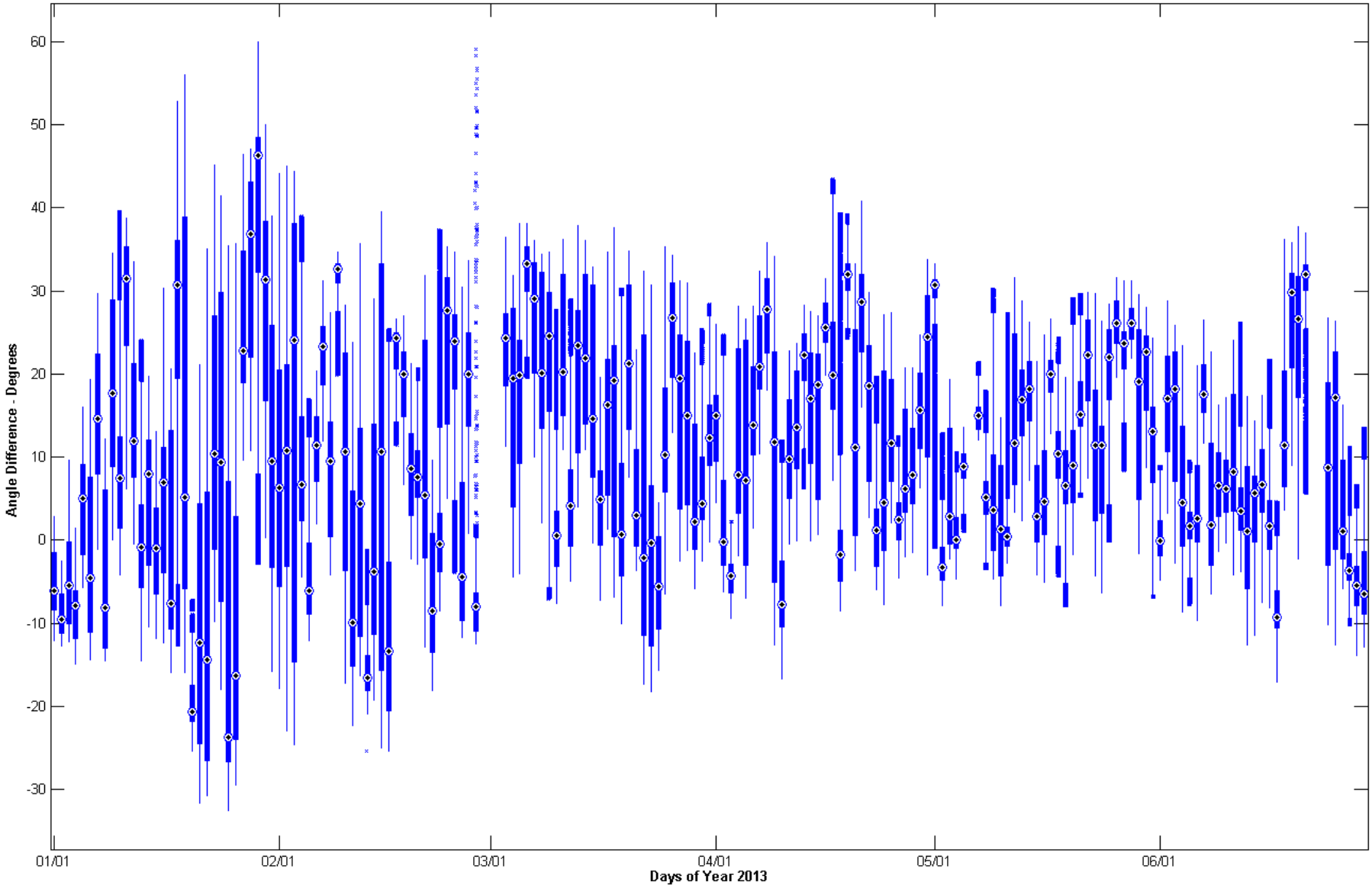
South 13 – Voltage Angle



South 13 – Voltage Angle



FarWest 4 – Voltage Angle



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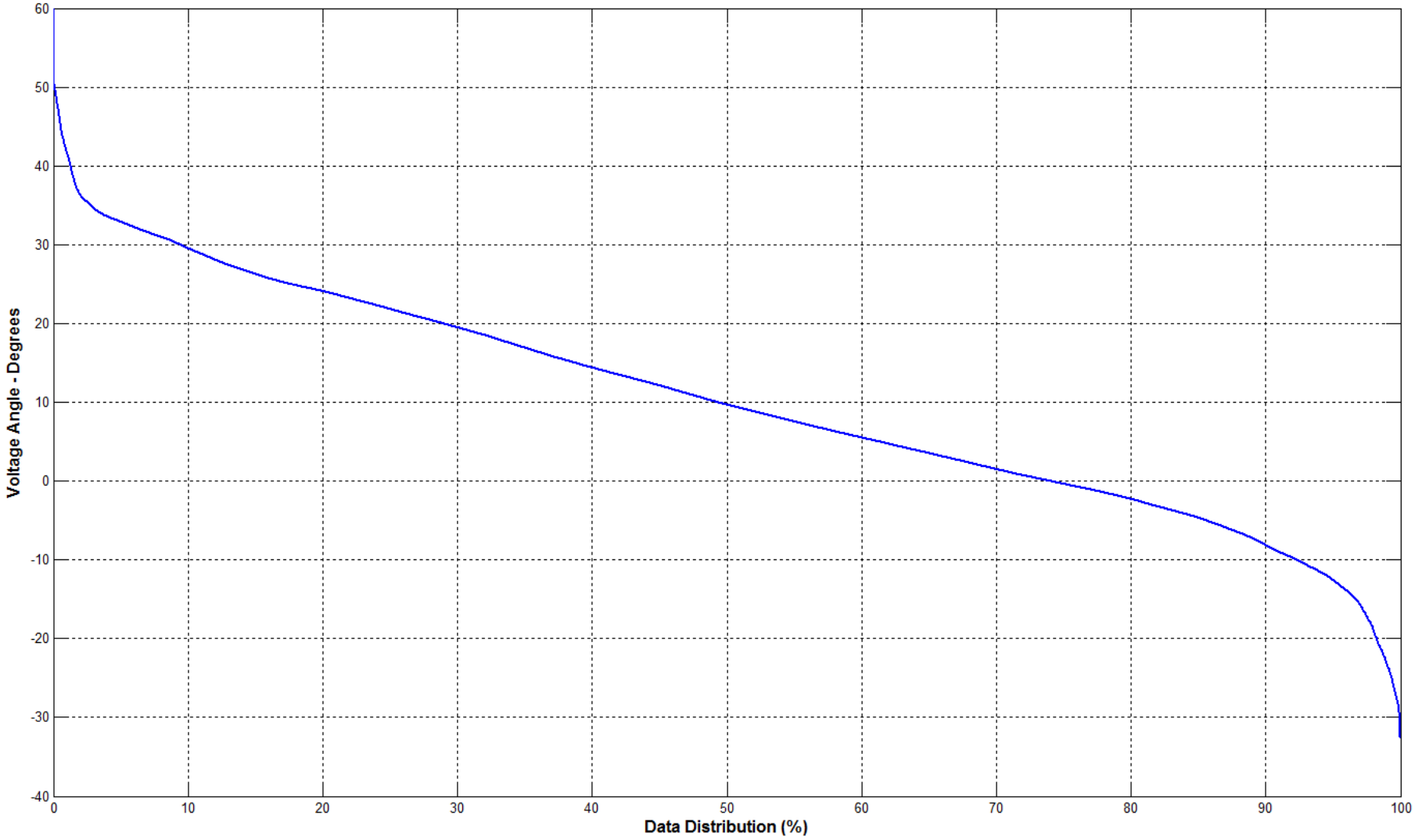
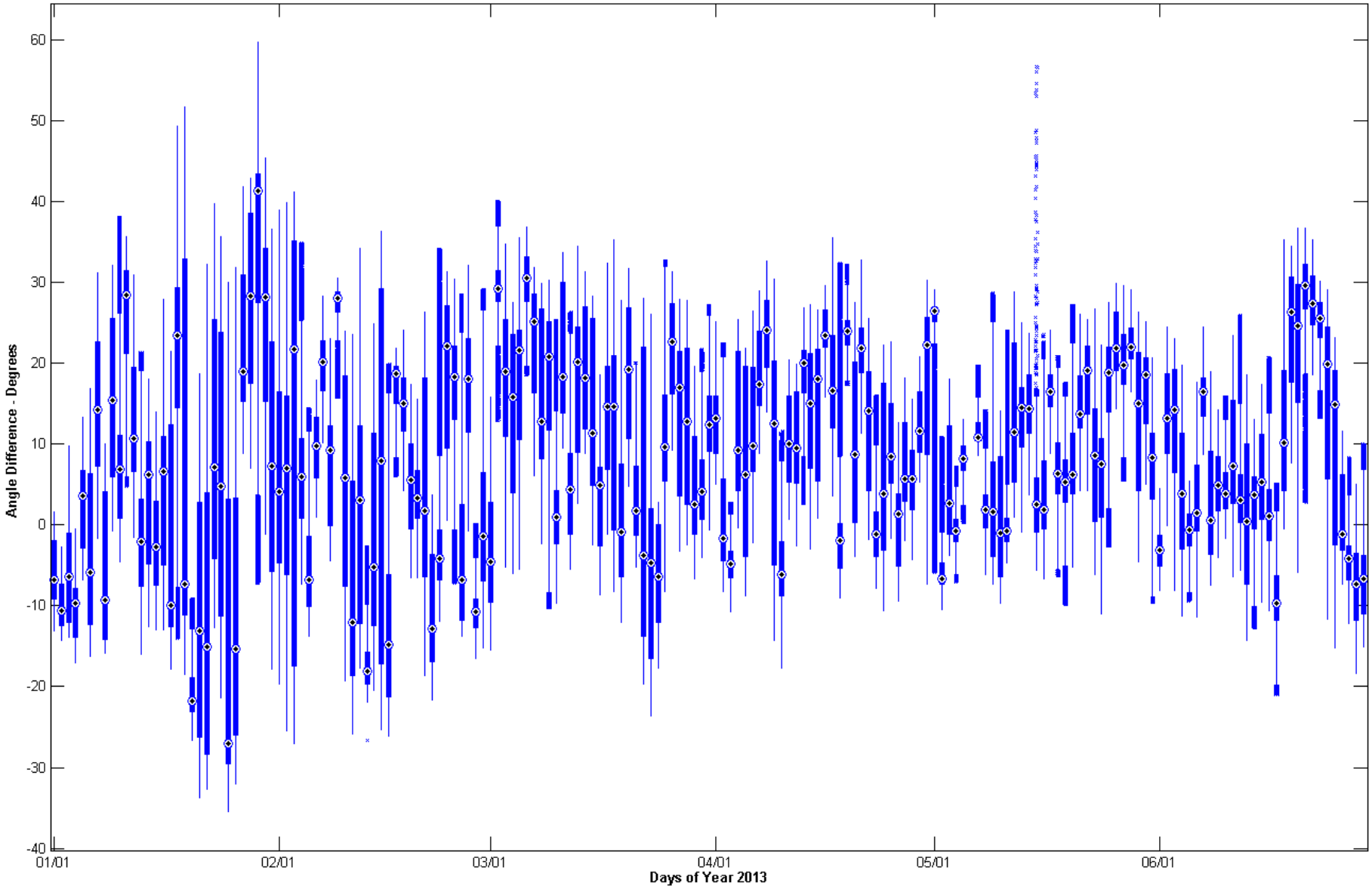
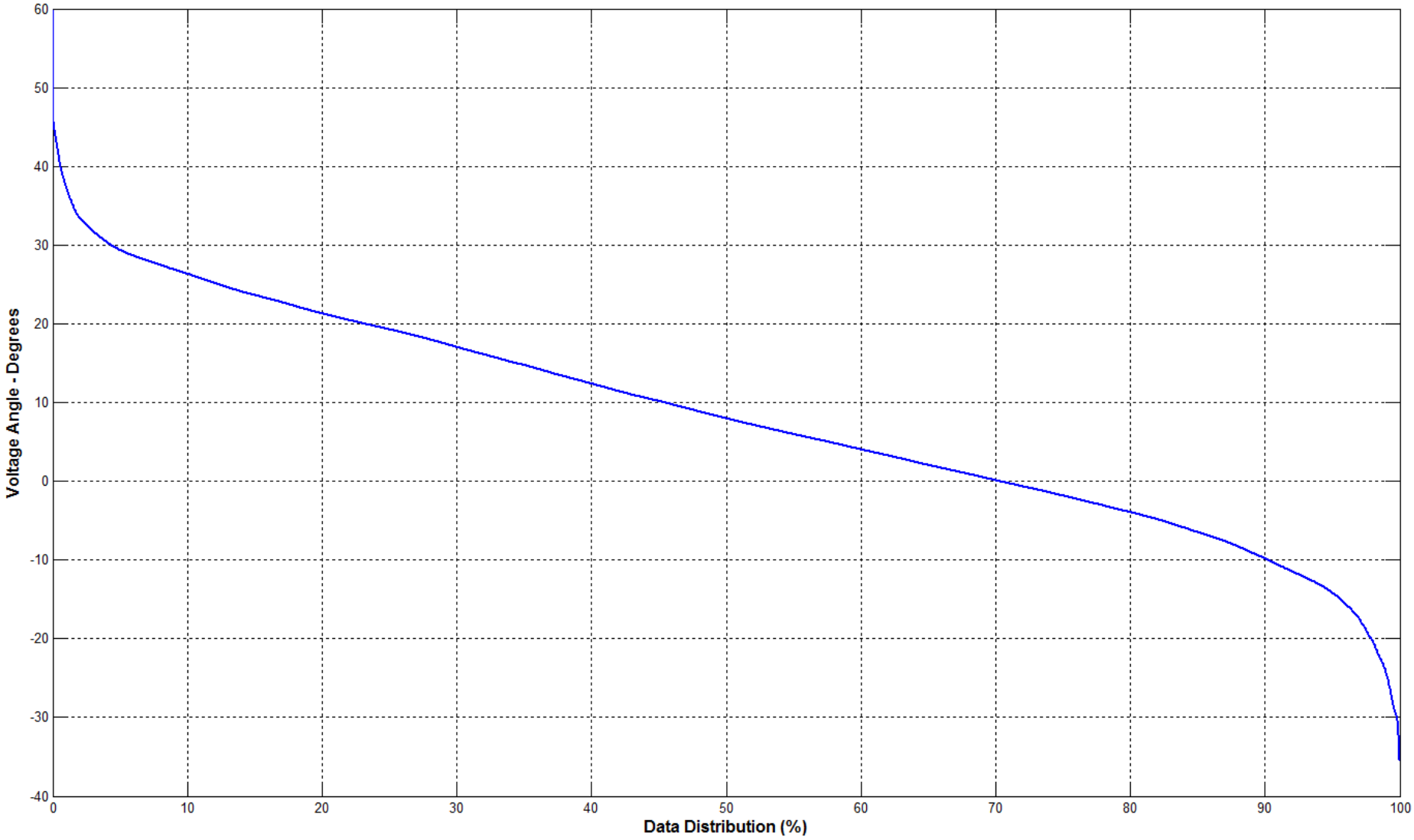


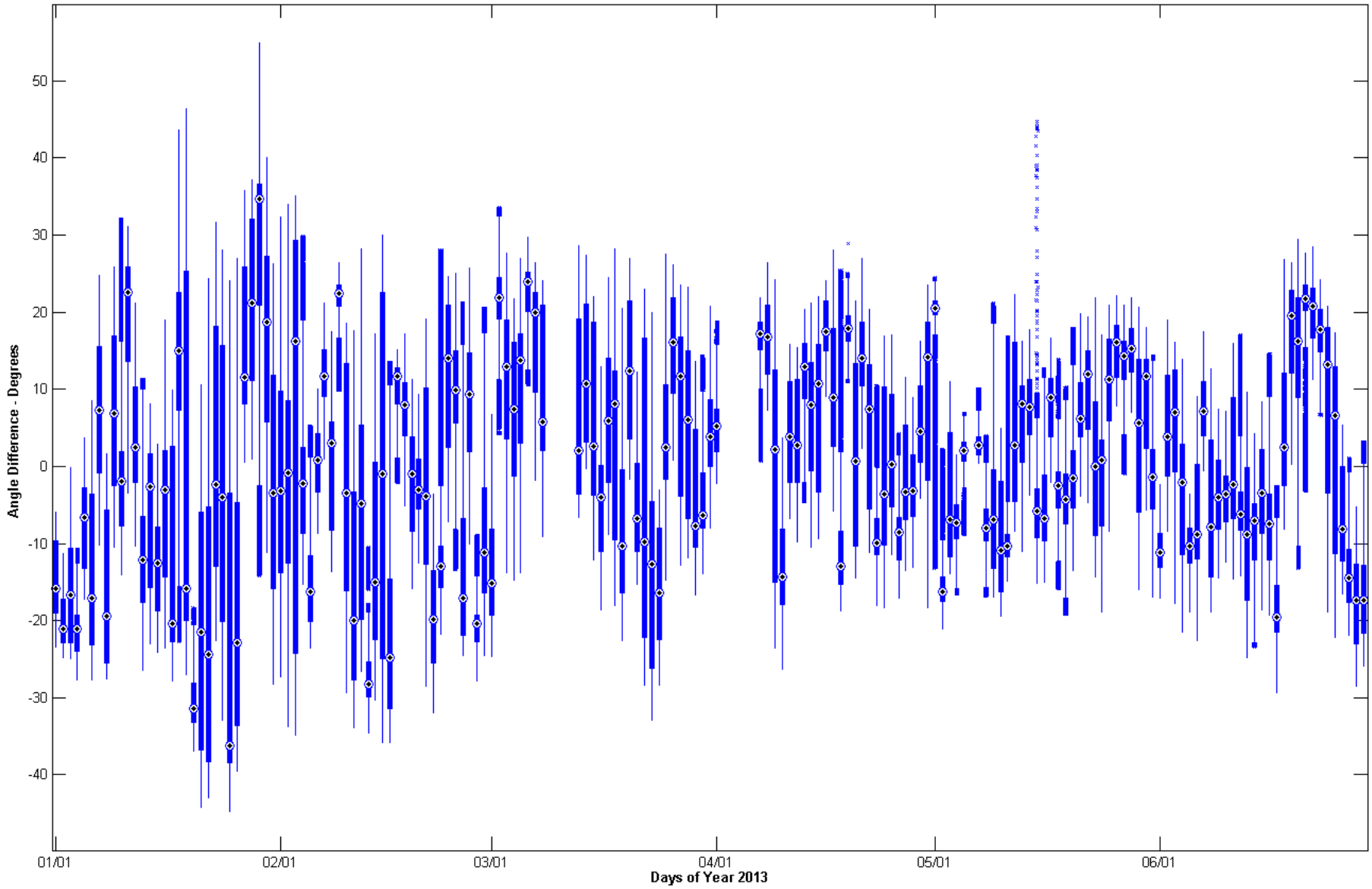
FarWest 7 – Voltage Angle



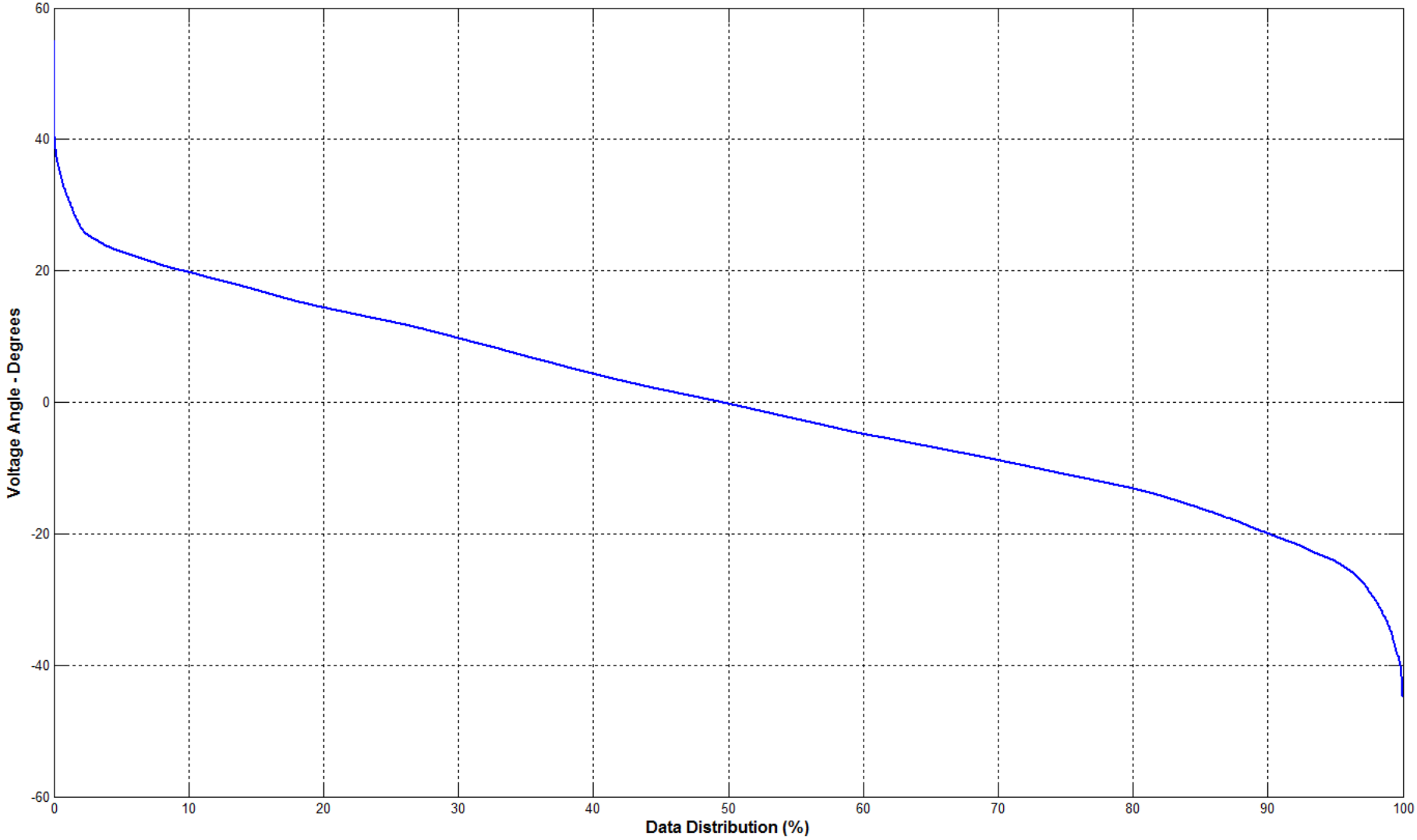
FarWest 7 – Voltage Angle



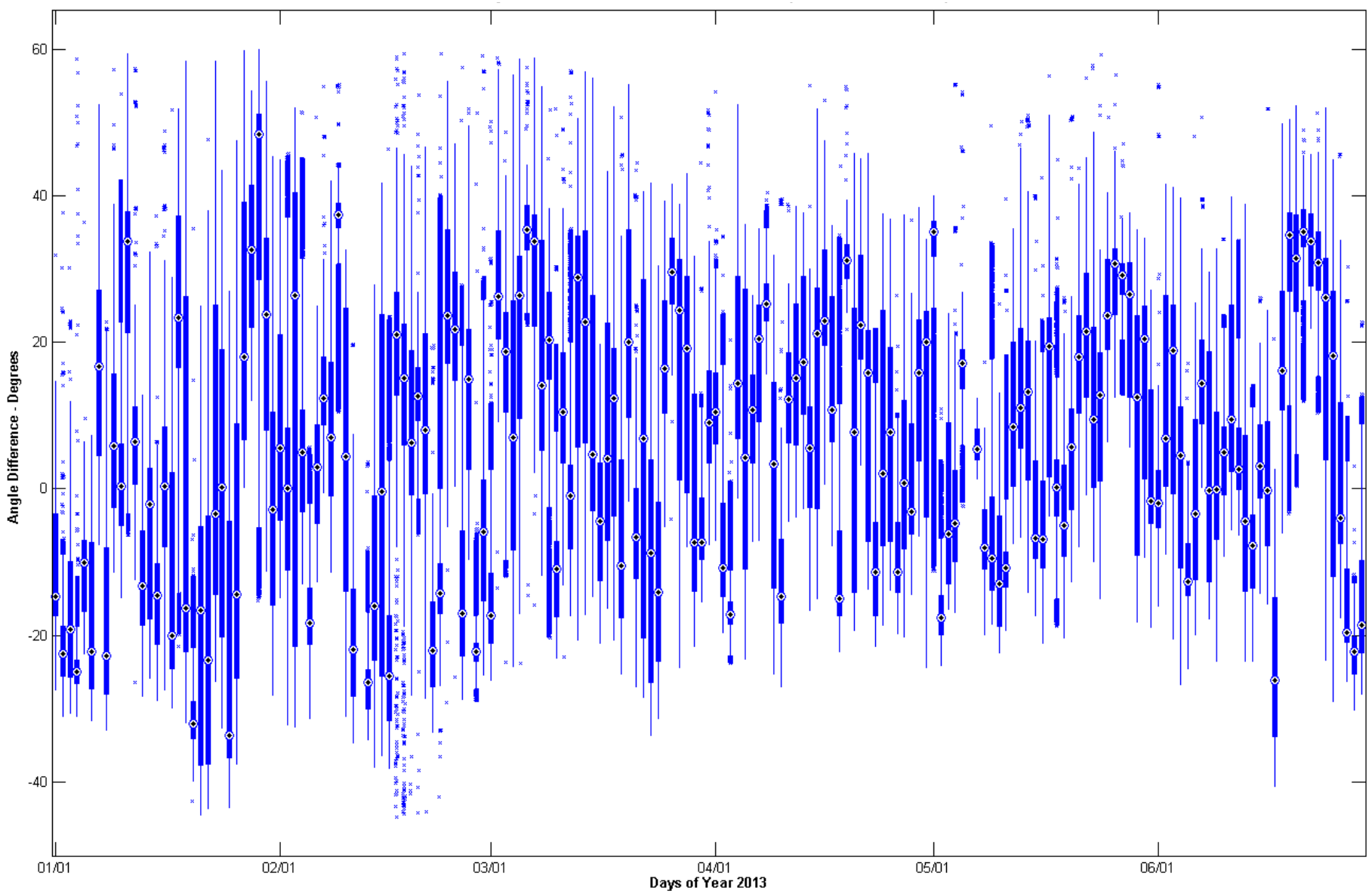
FarWest 8 – Voltage Angle



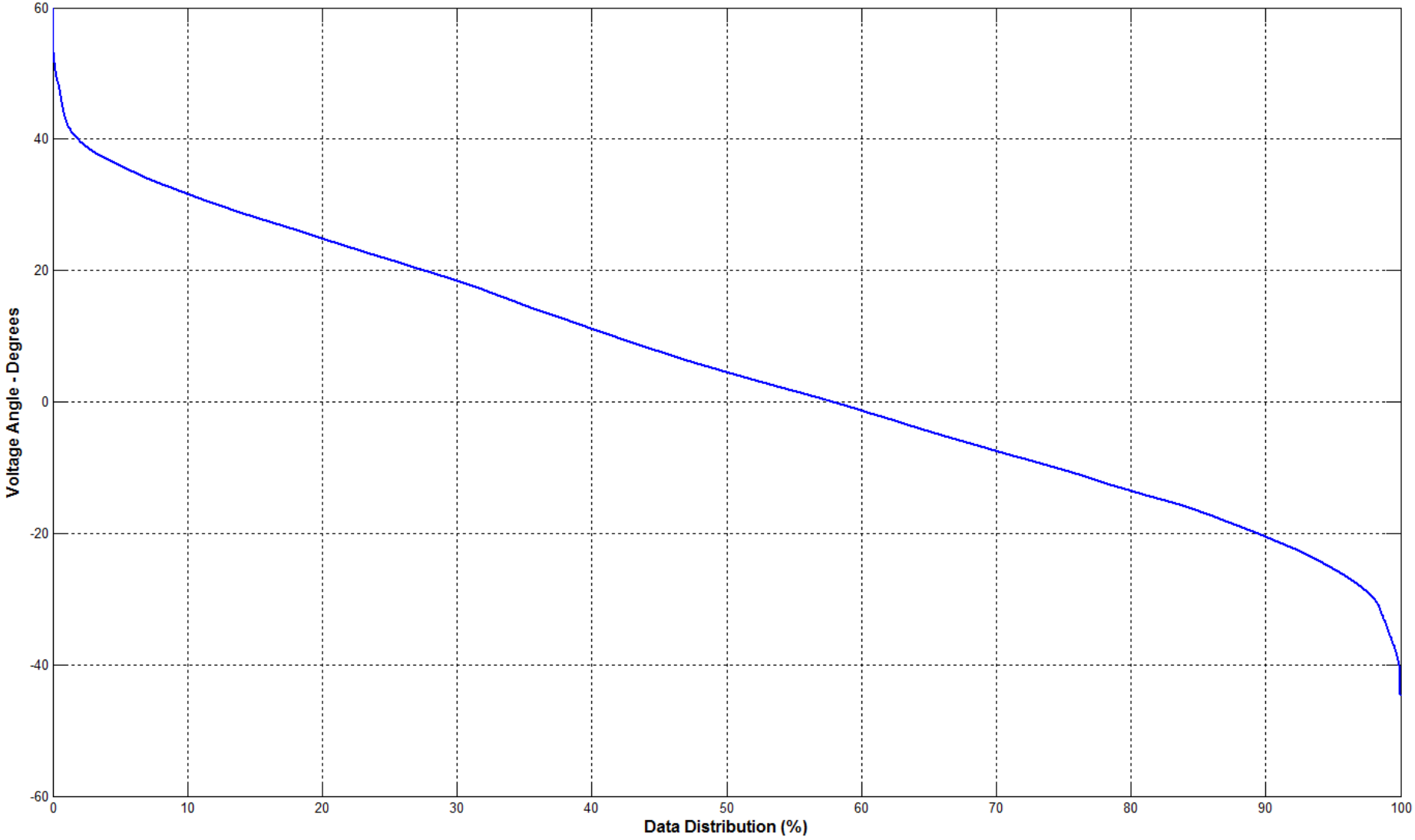
FarWest 8 – Voltage Angle



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

Electric Power Group

CCET

ERCOT

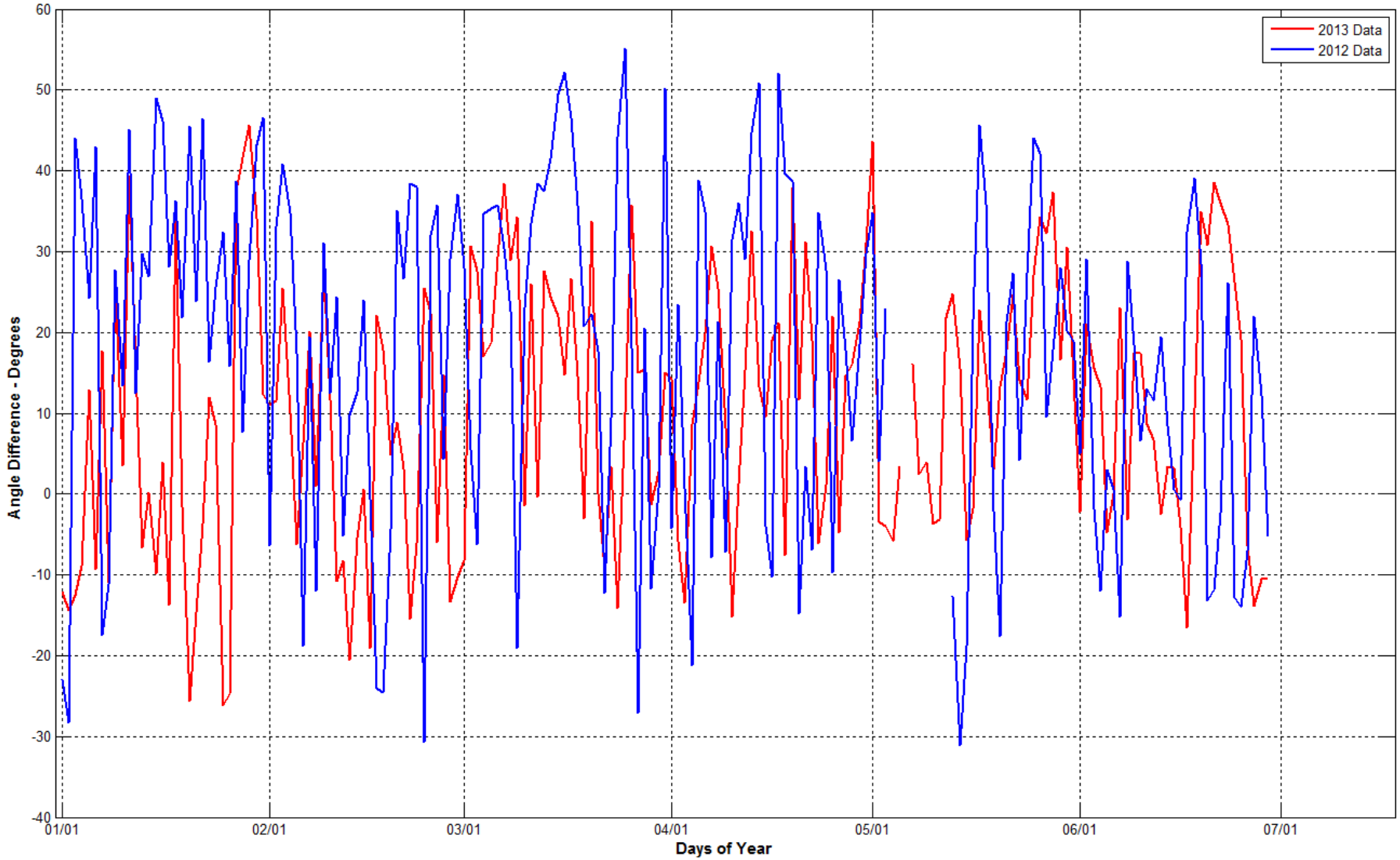
Overview

- 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.
- 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 as a result of the addition of the CREZ lines to the ERCOT grid during the first six months of 2013.

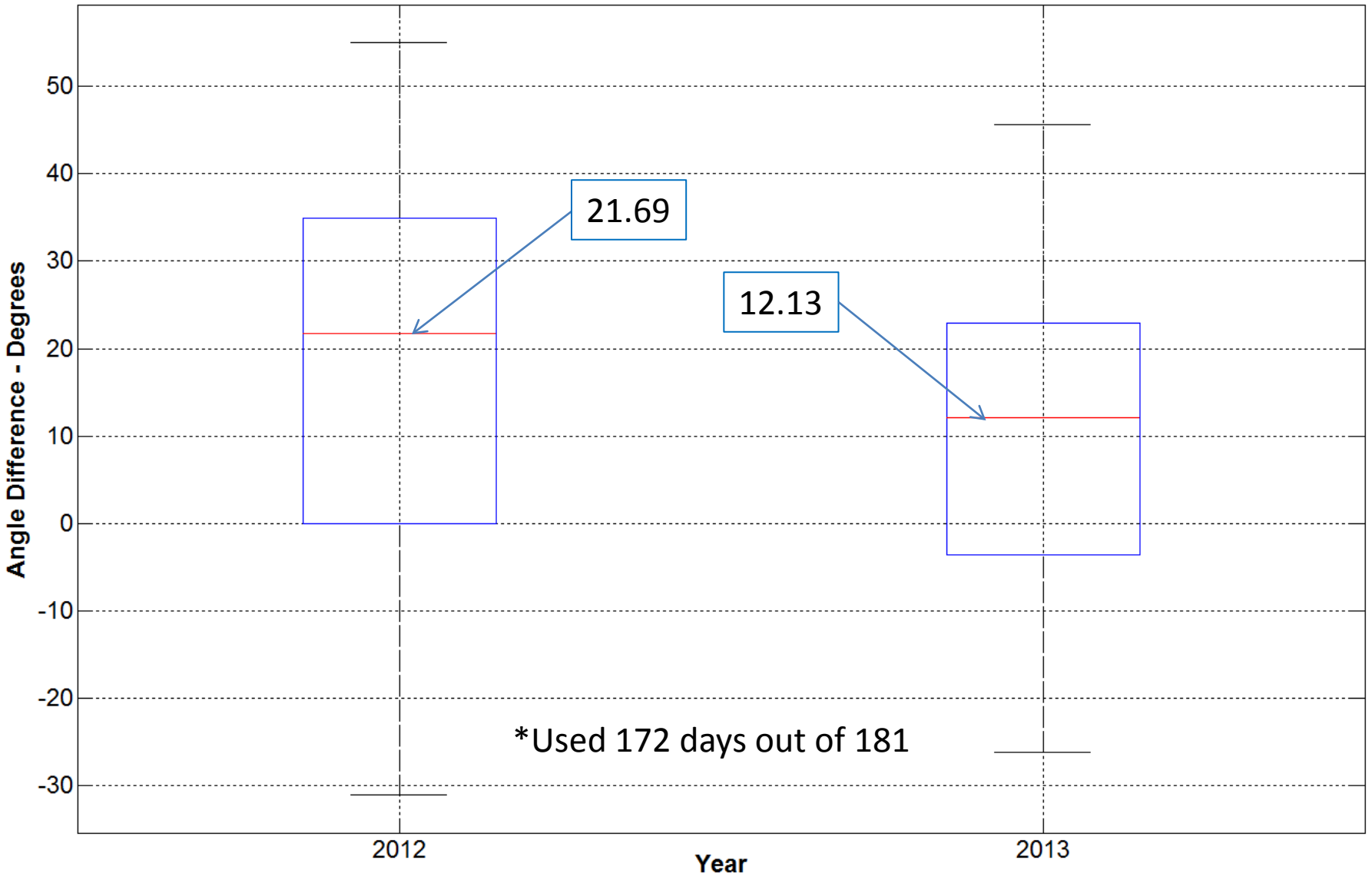
CREZ 345 kV LINES IN SERVICE THE FIRST SIX MONTHS 0F 2013 (Subject to Confirmation by ERCOT)

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

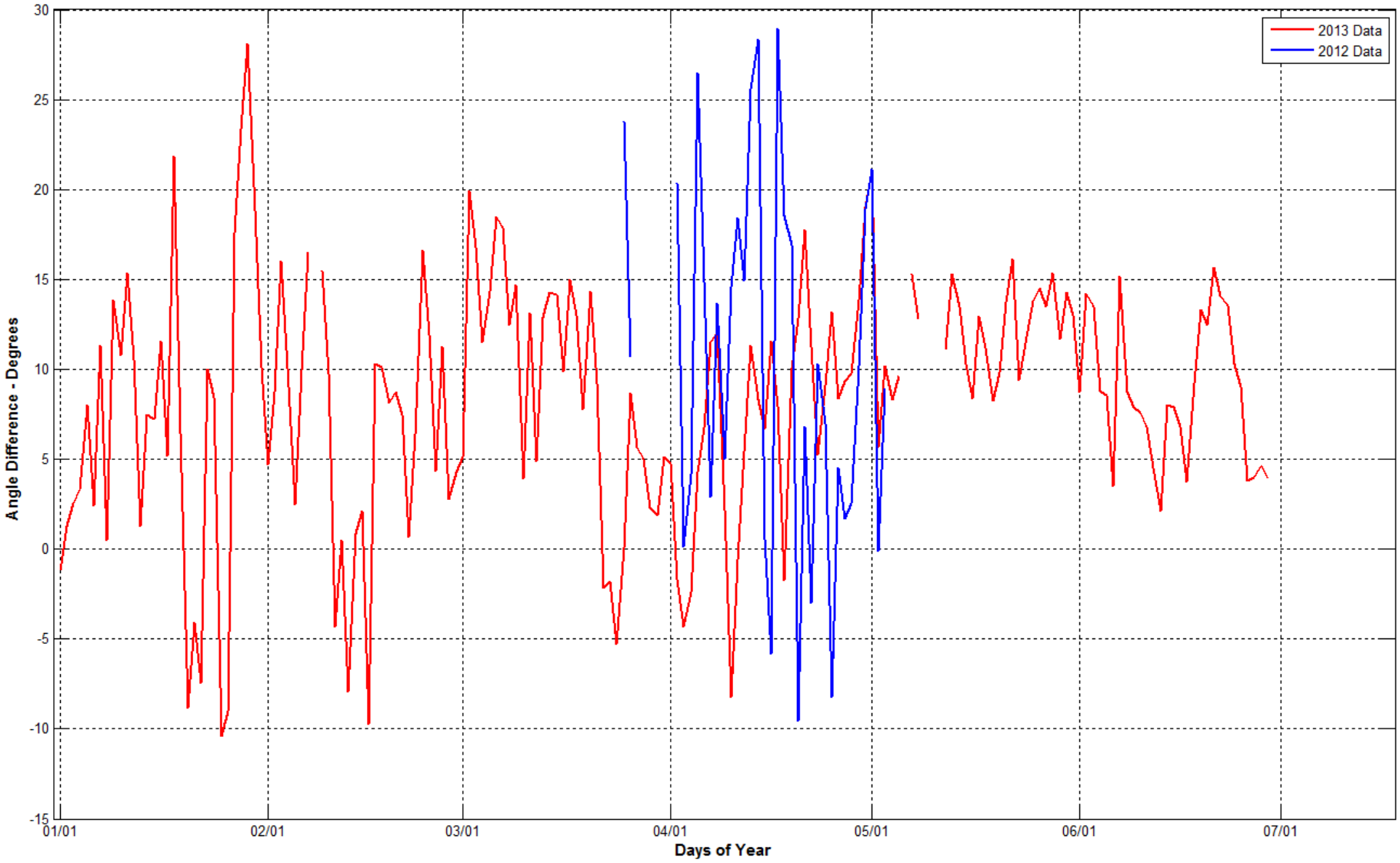
West 10 – North 7



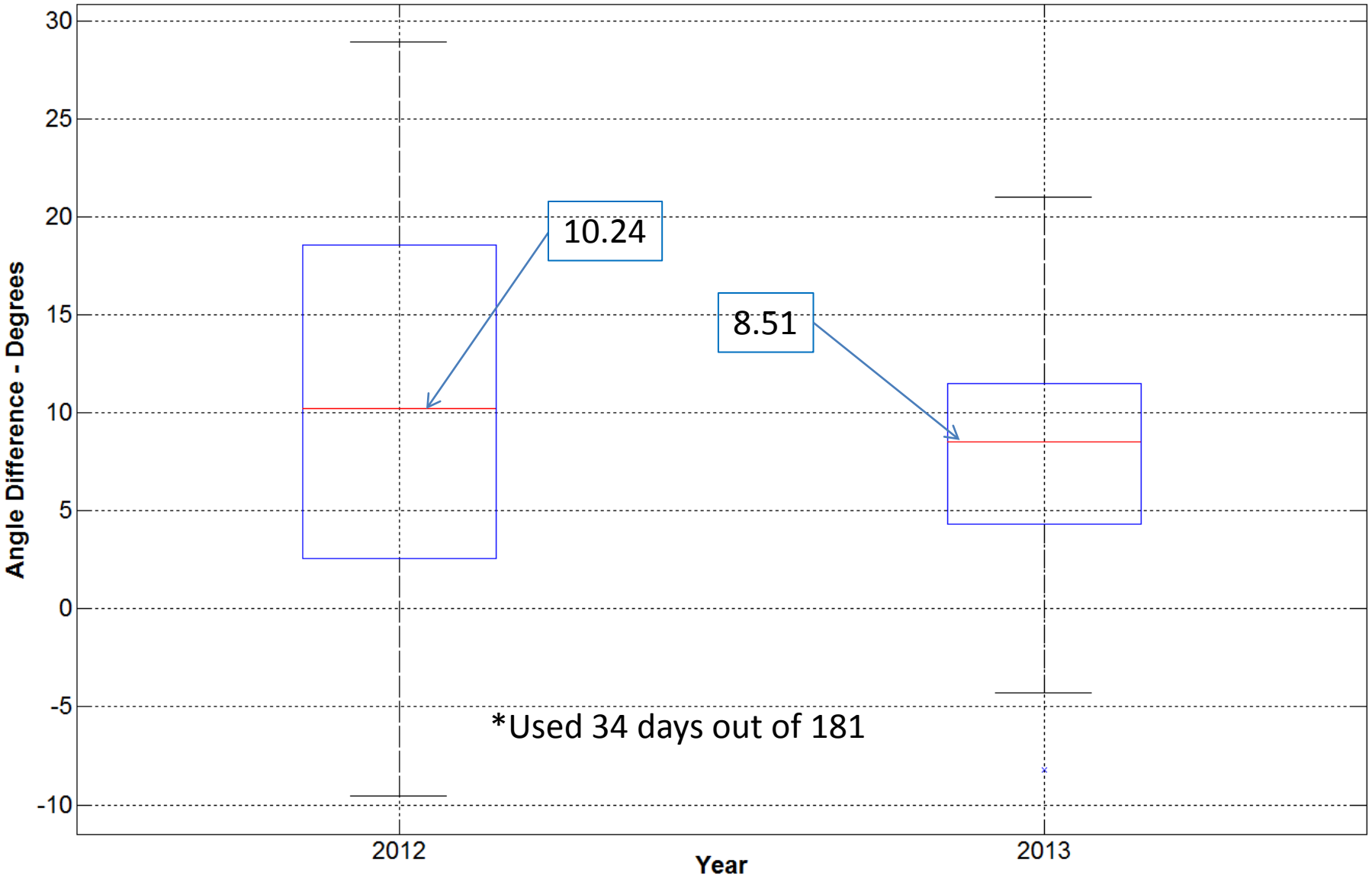
West 10 – North 7



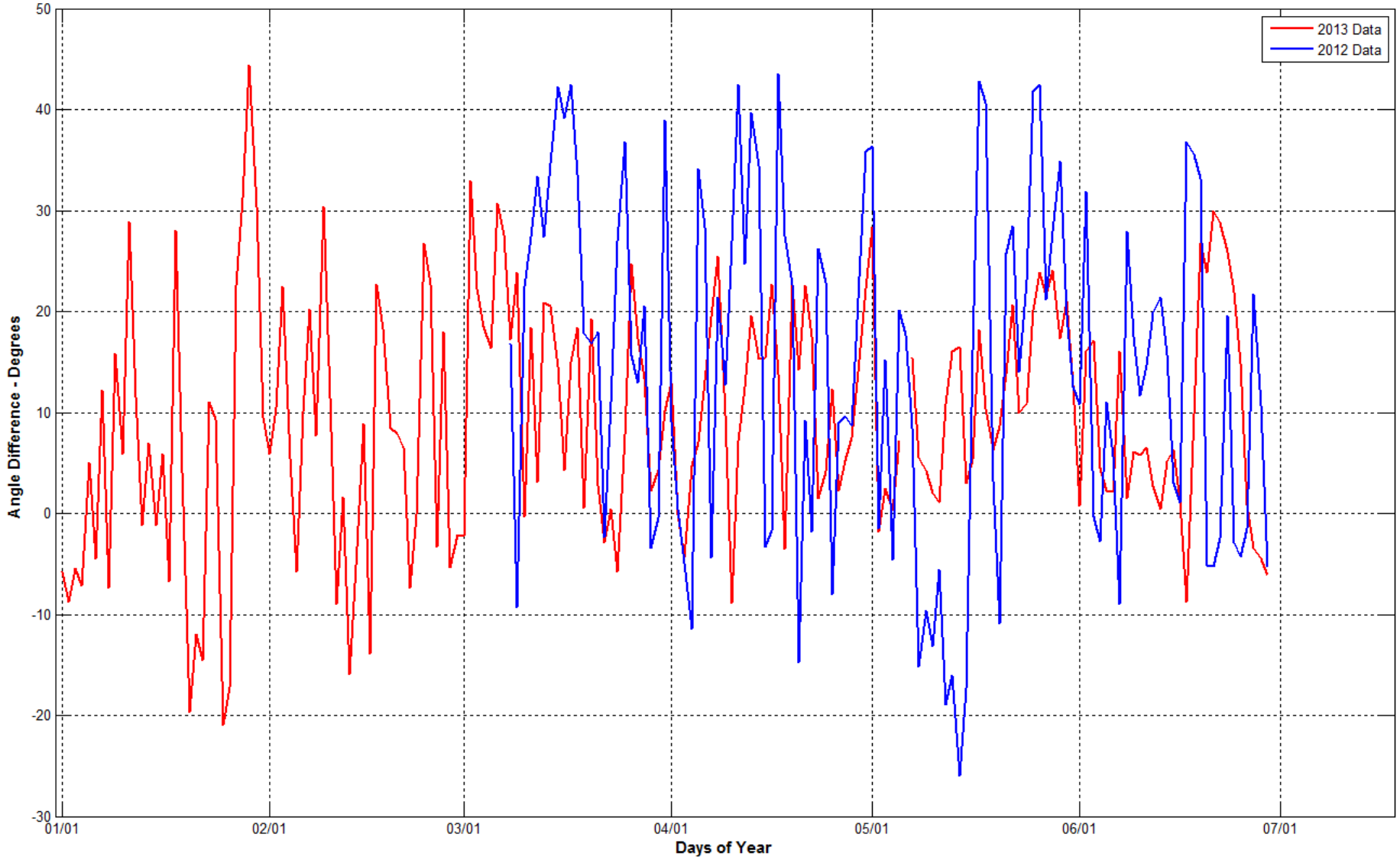
West 14– North 7



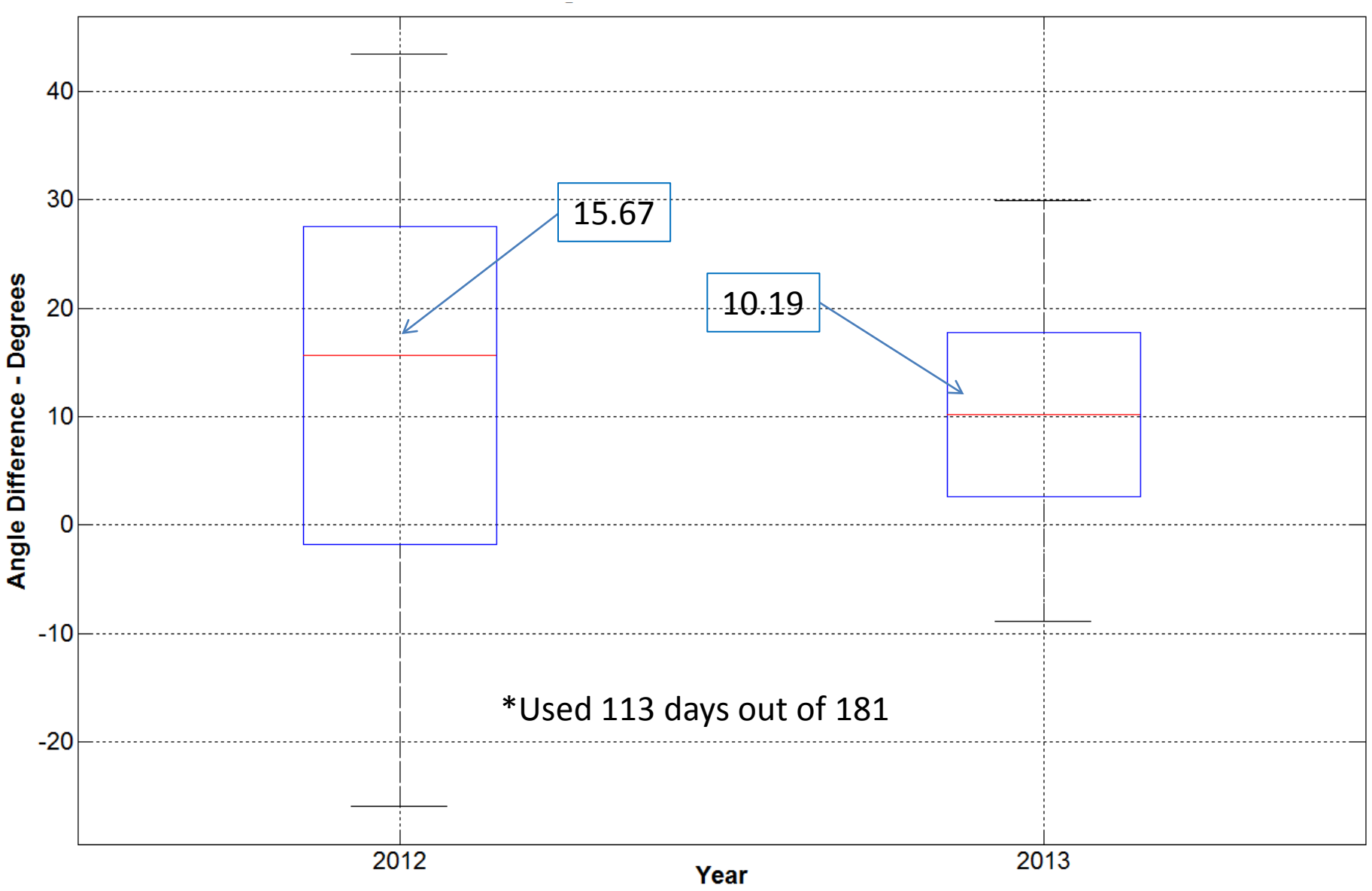
West 14 – North 7 *



West 11– North 7



West 11– North 7 *



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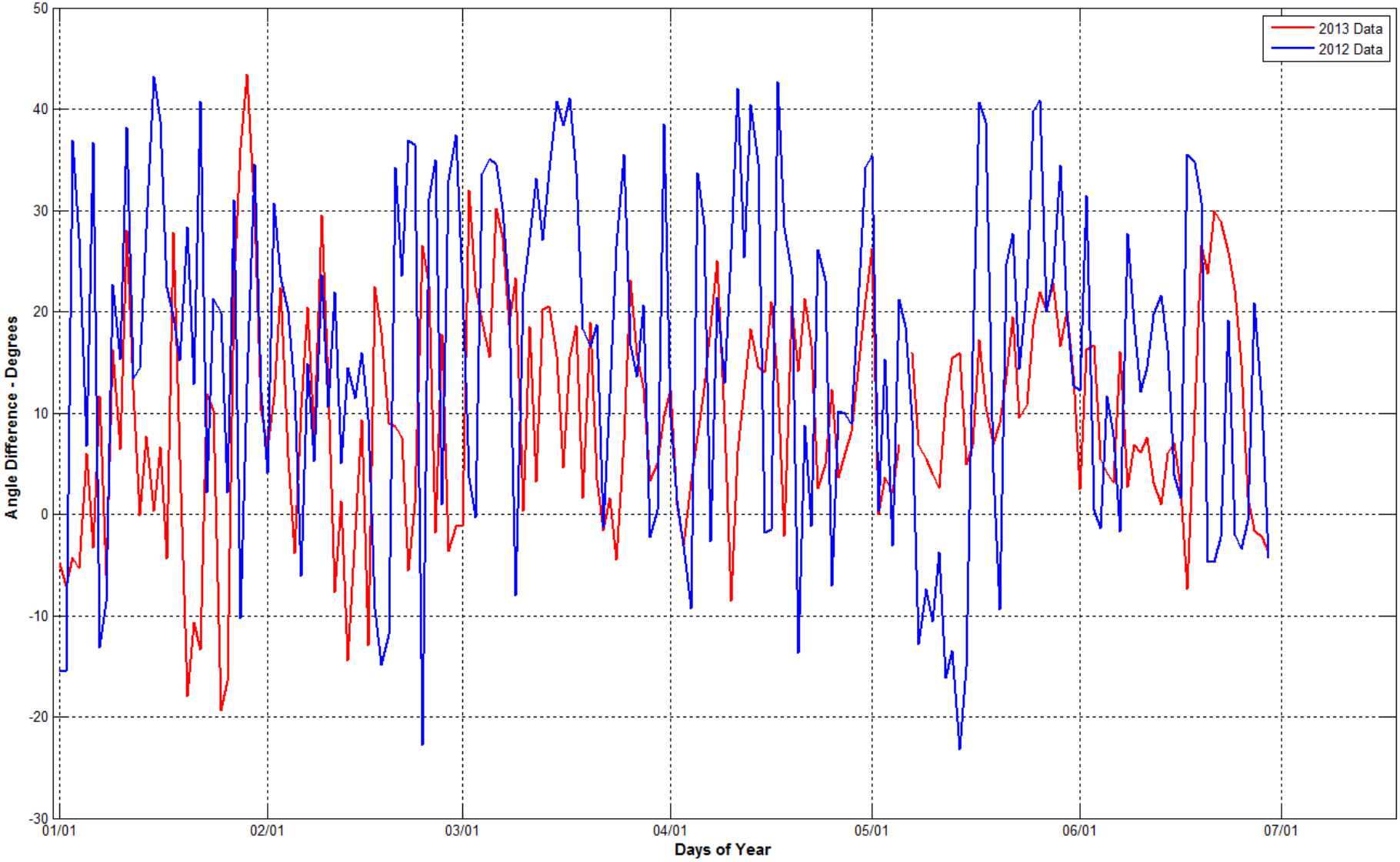

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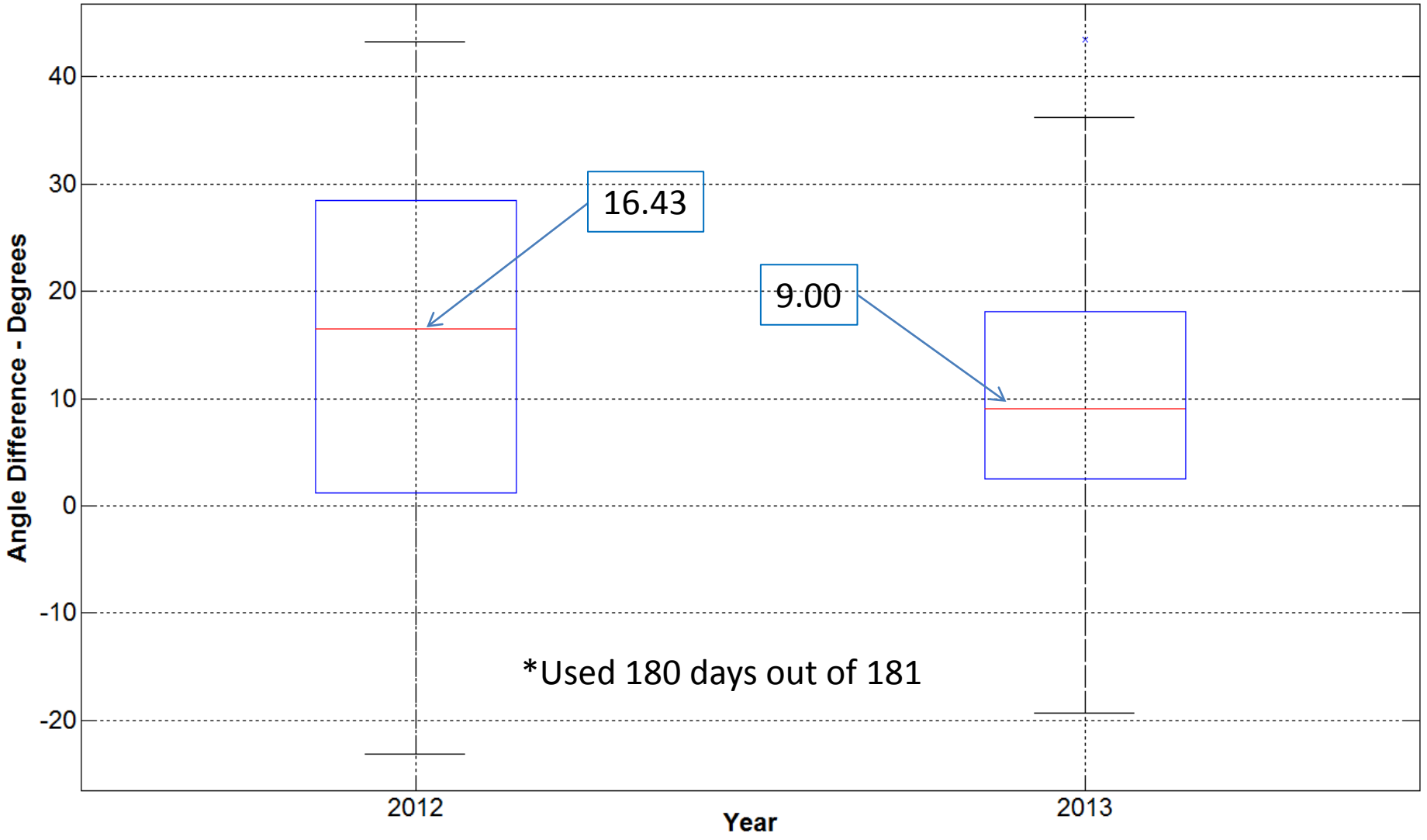
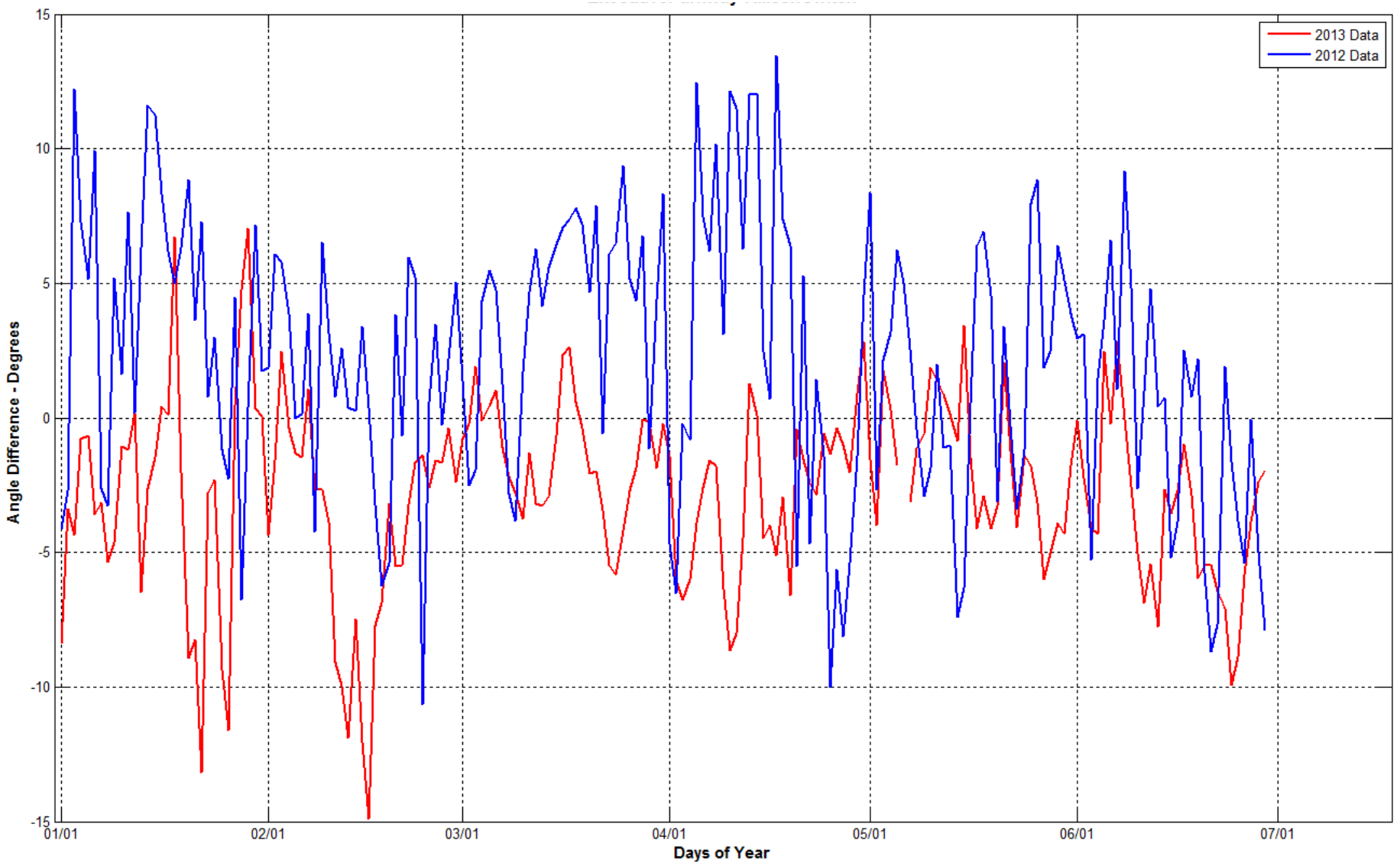


North 4 – North 7



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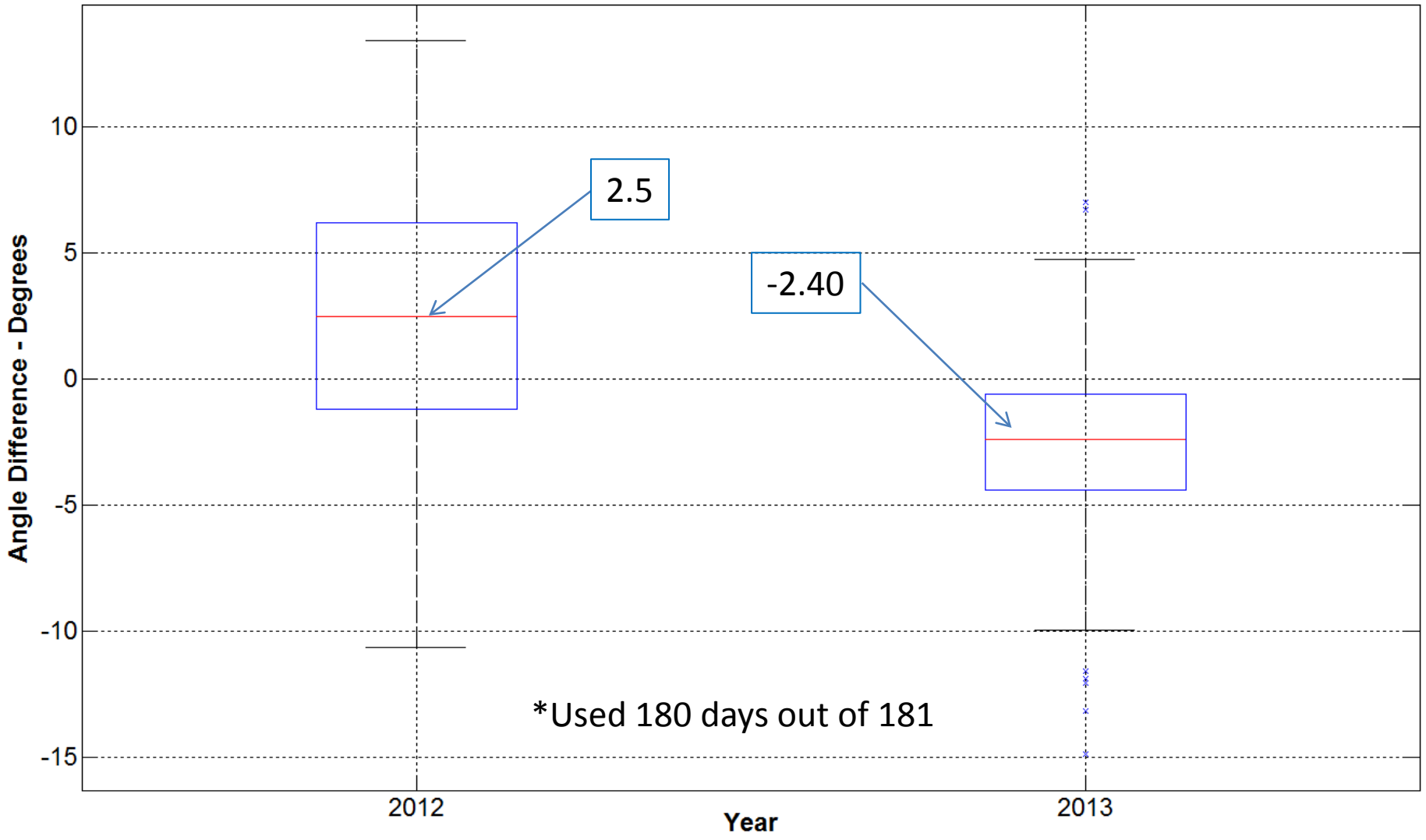

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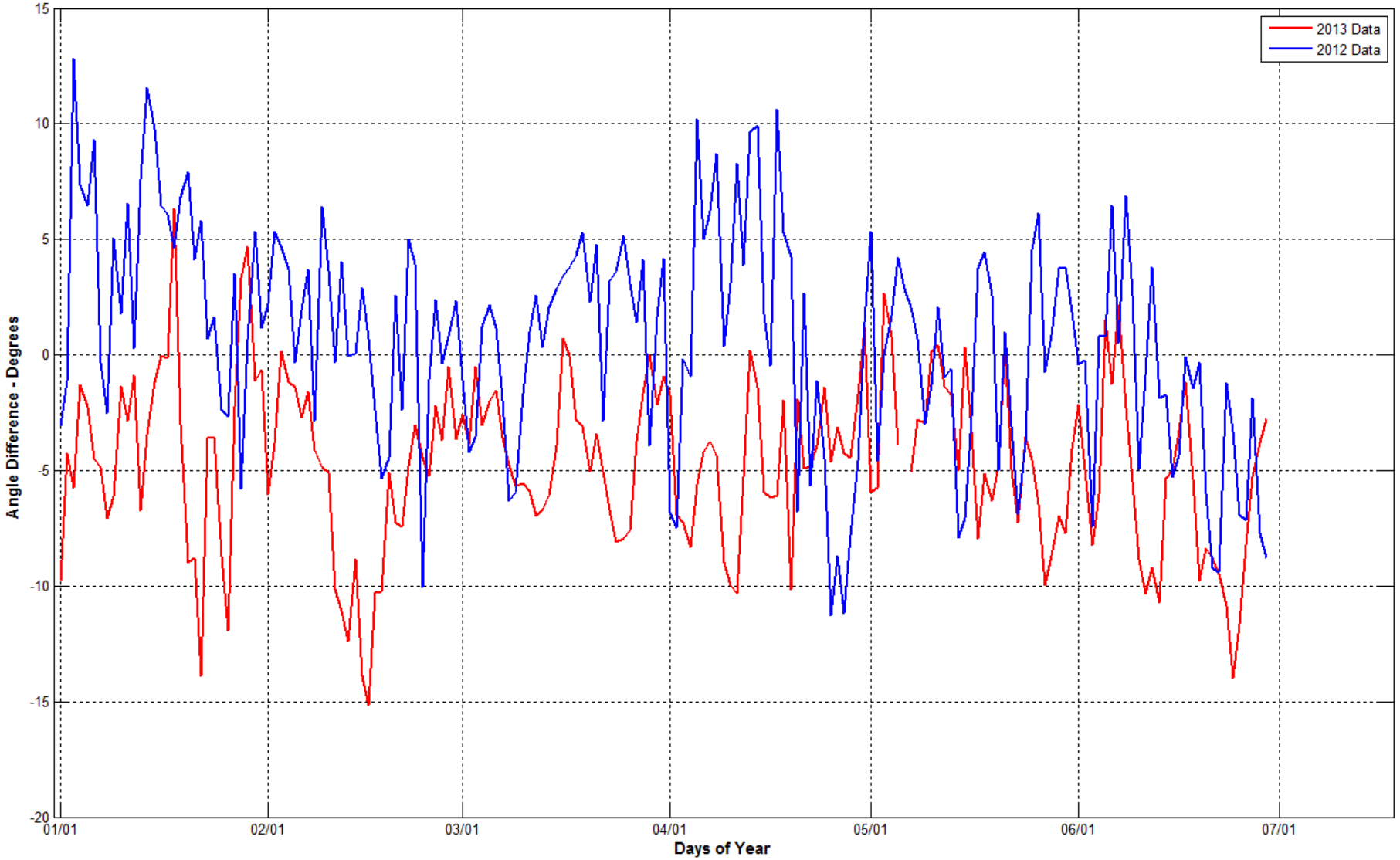

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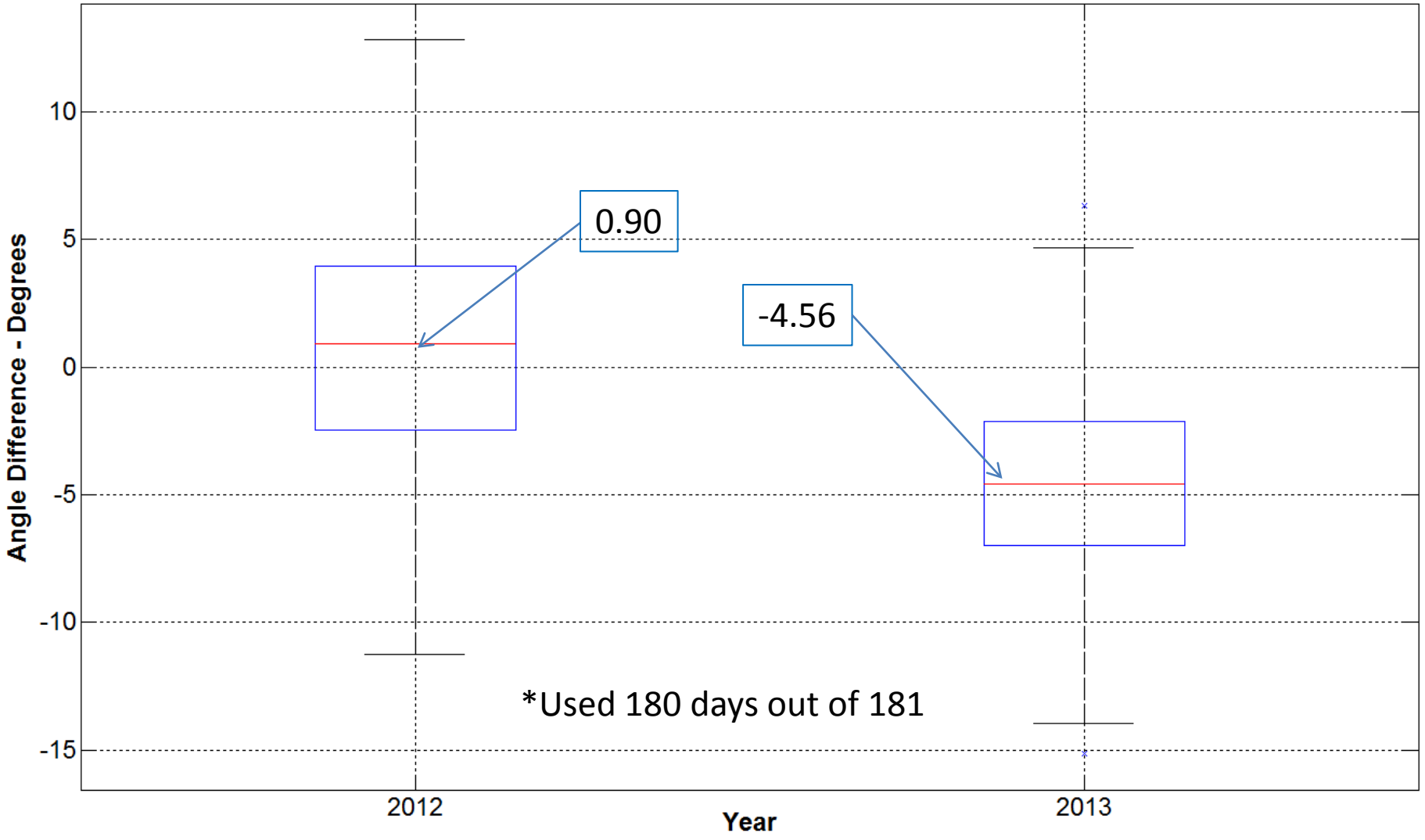
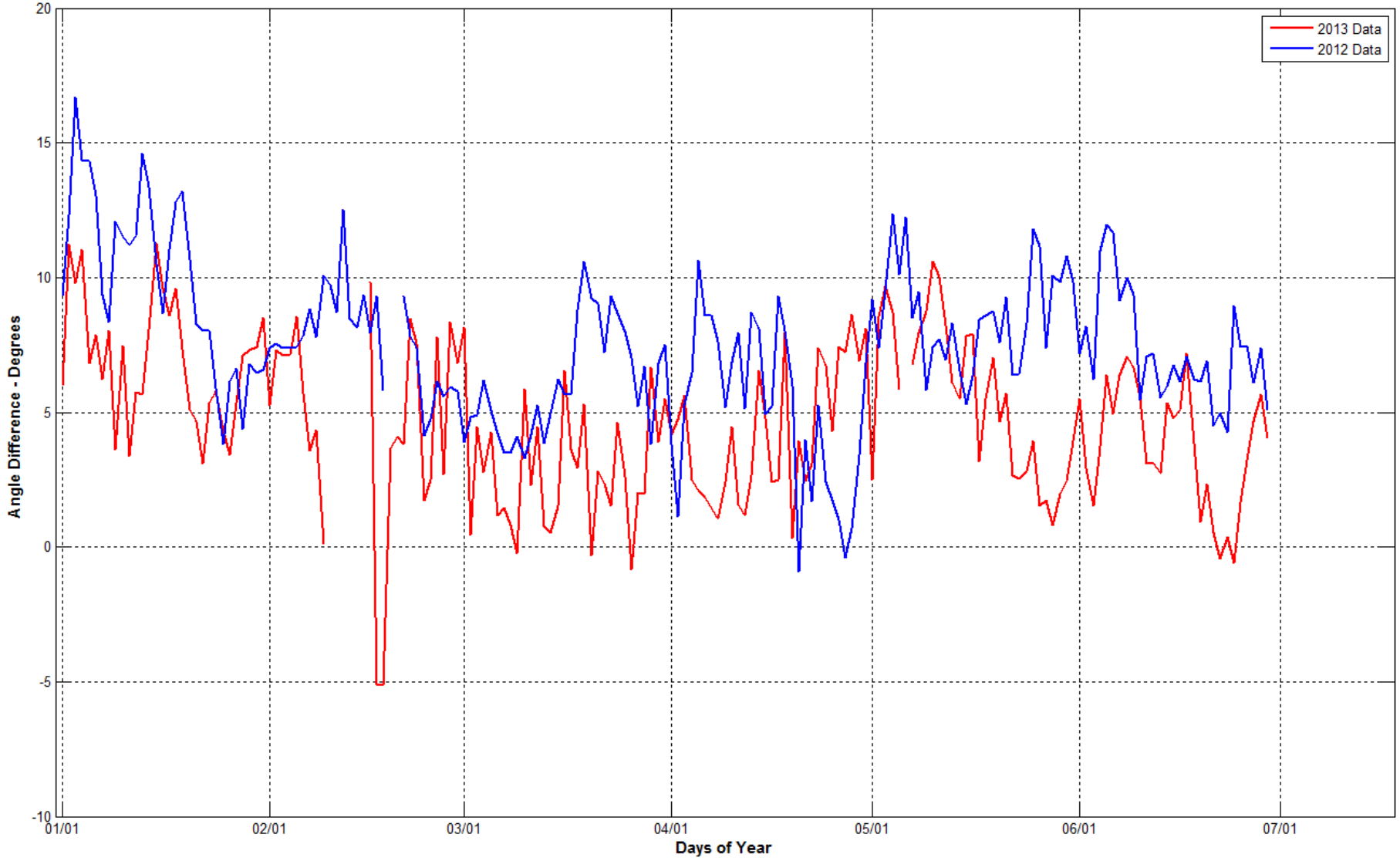
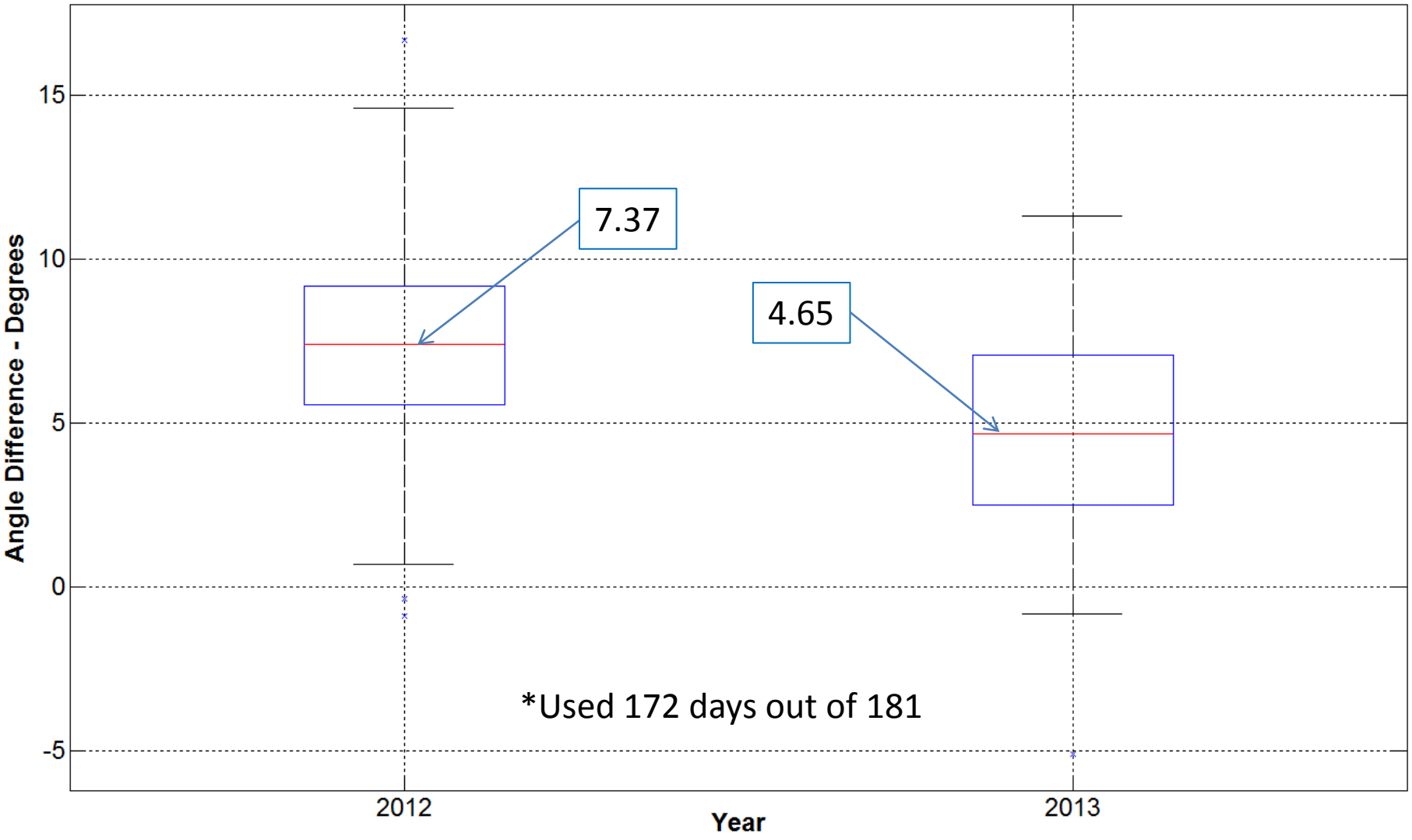


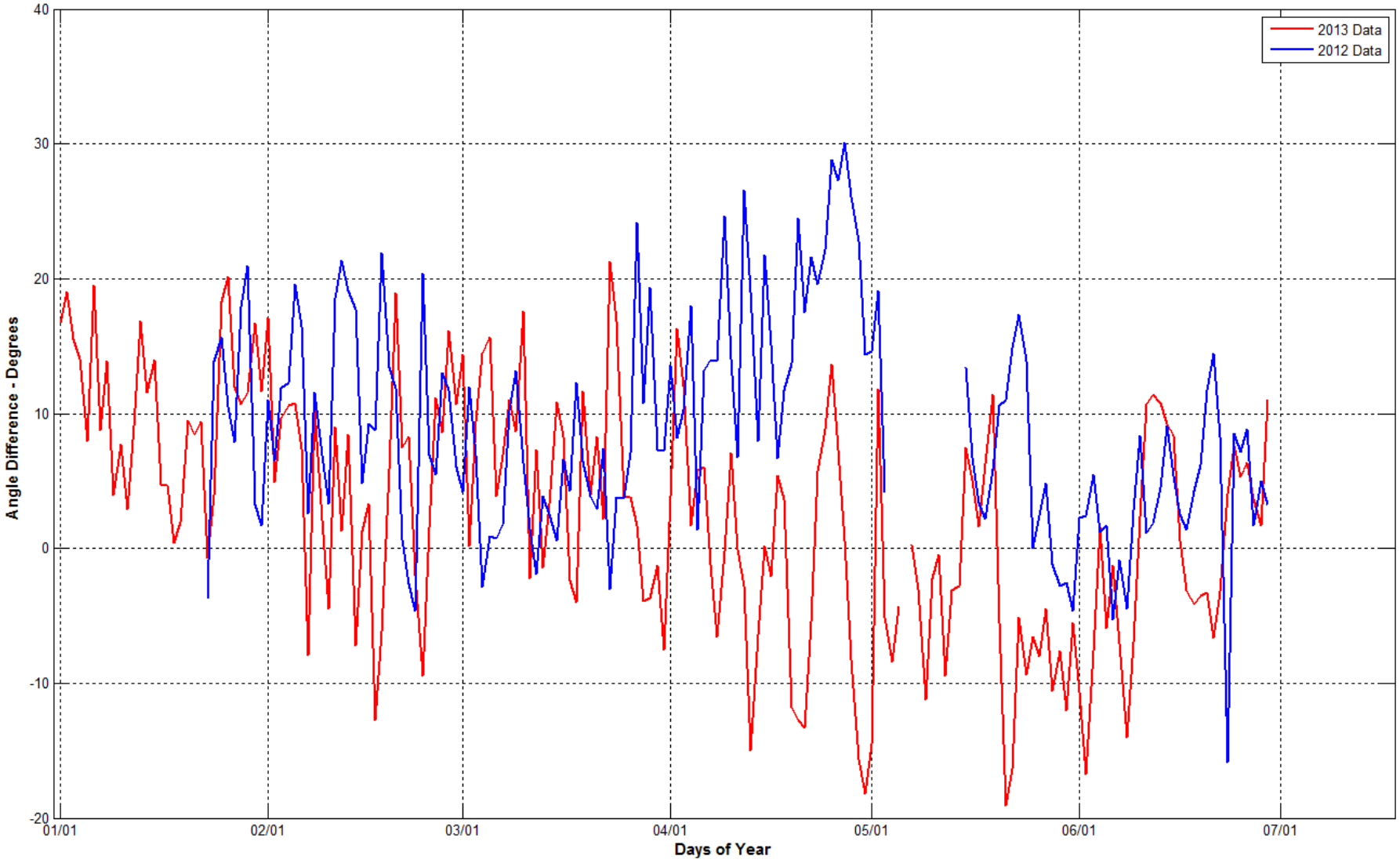
North 6 – North 7



North 6 – North 7



Coast 1 – North 7



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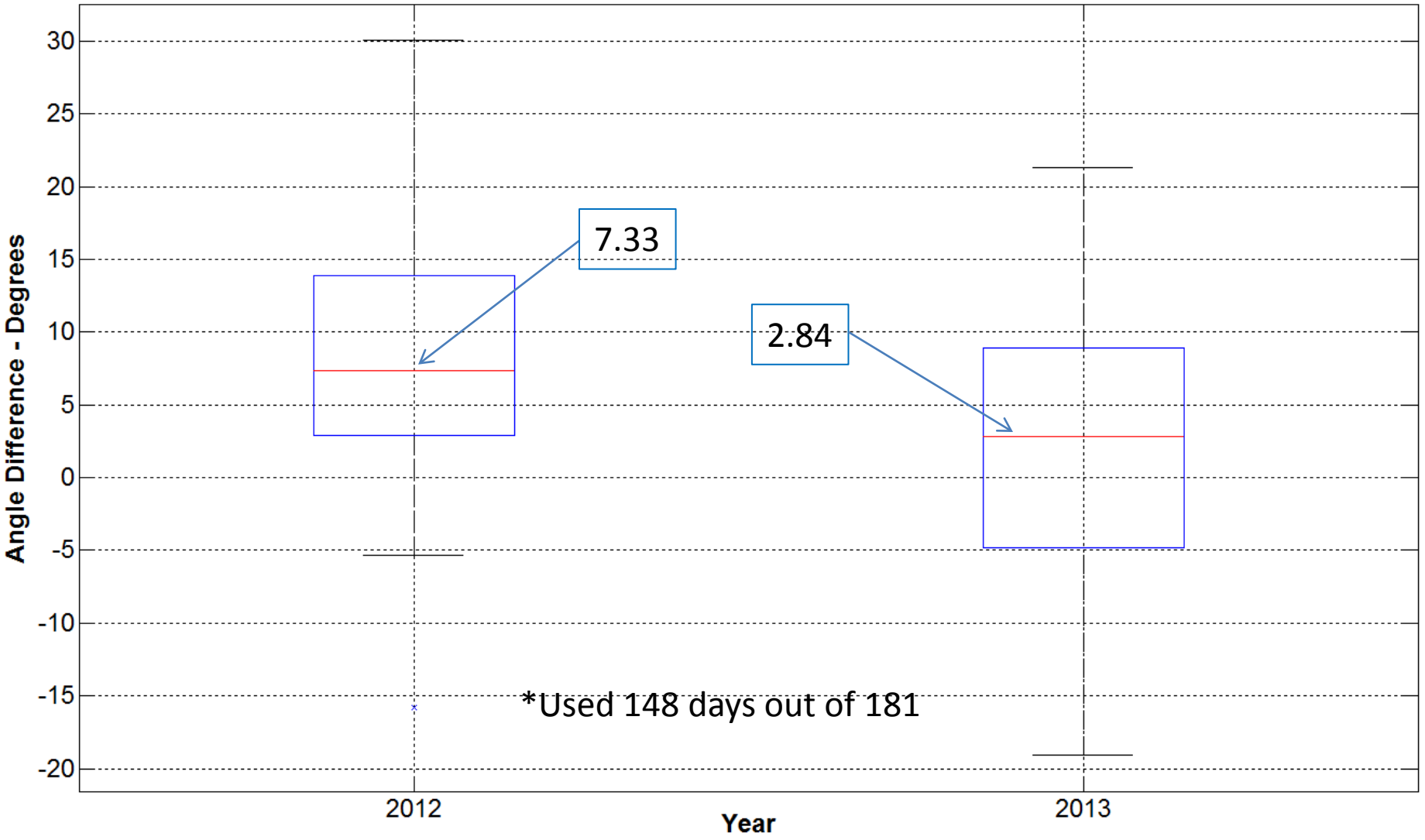

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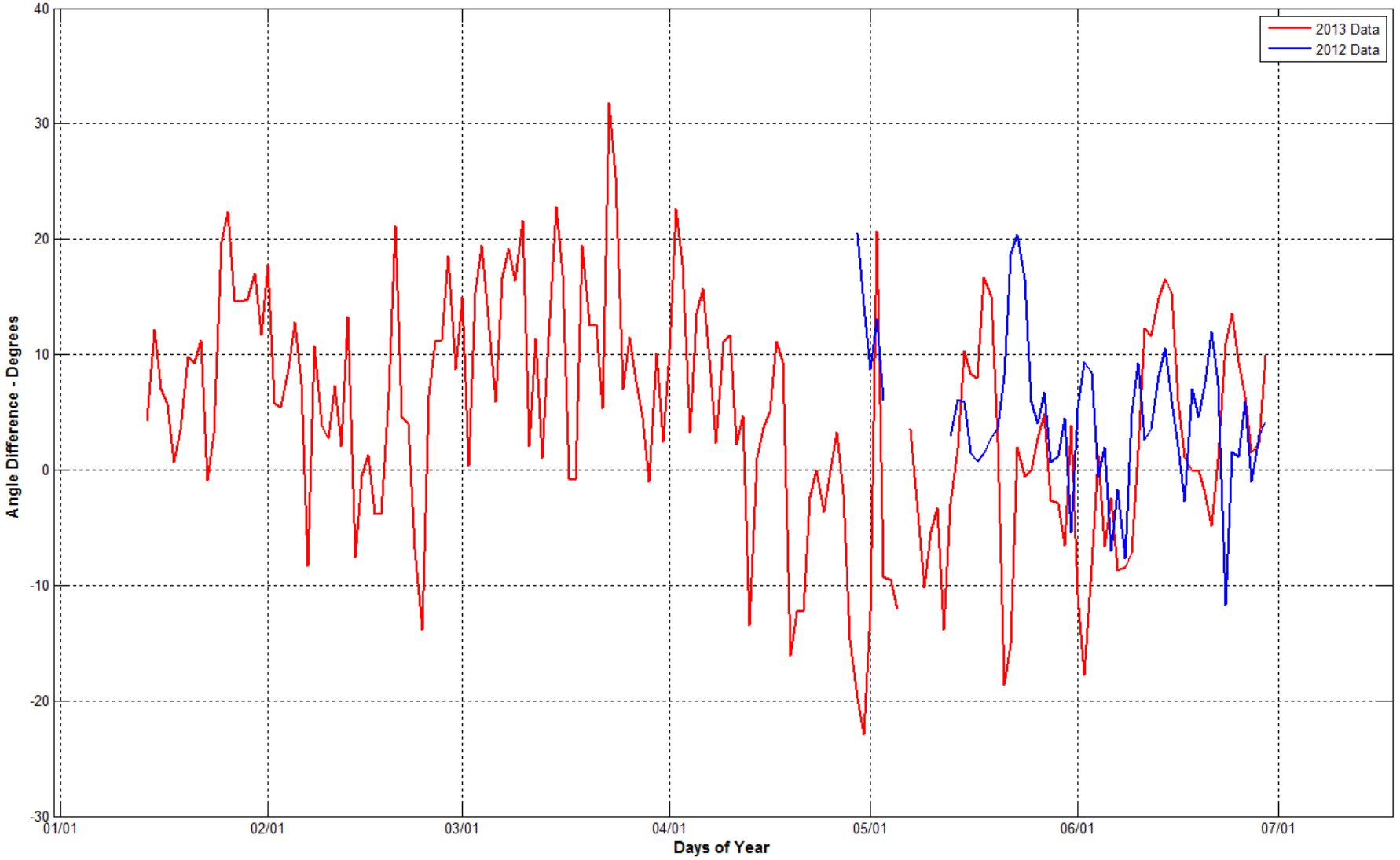

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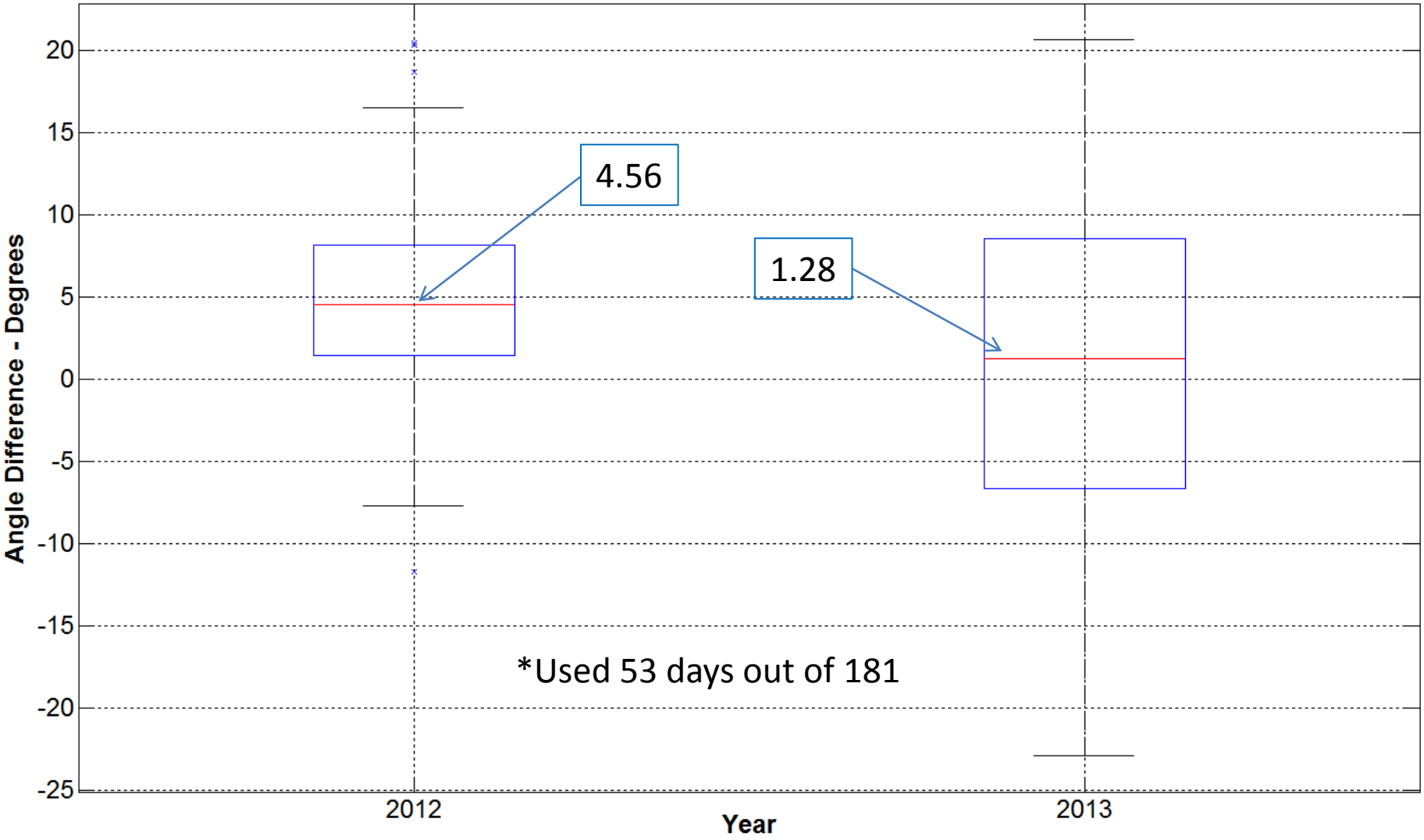
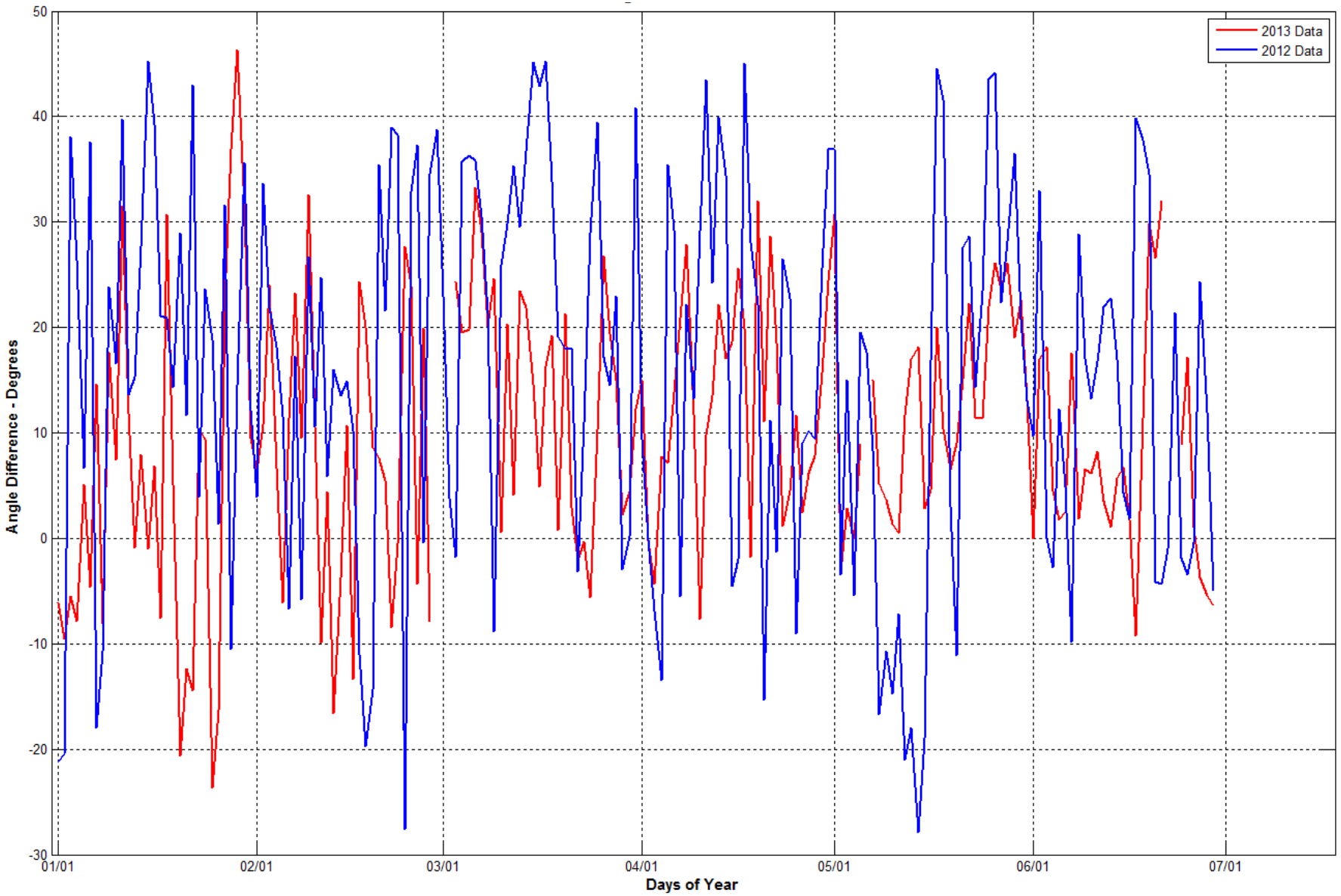


FarWest 4 – North 7



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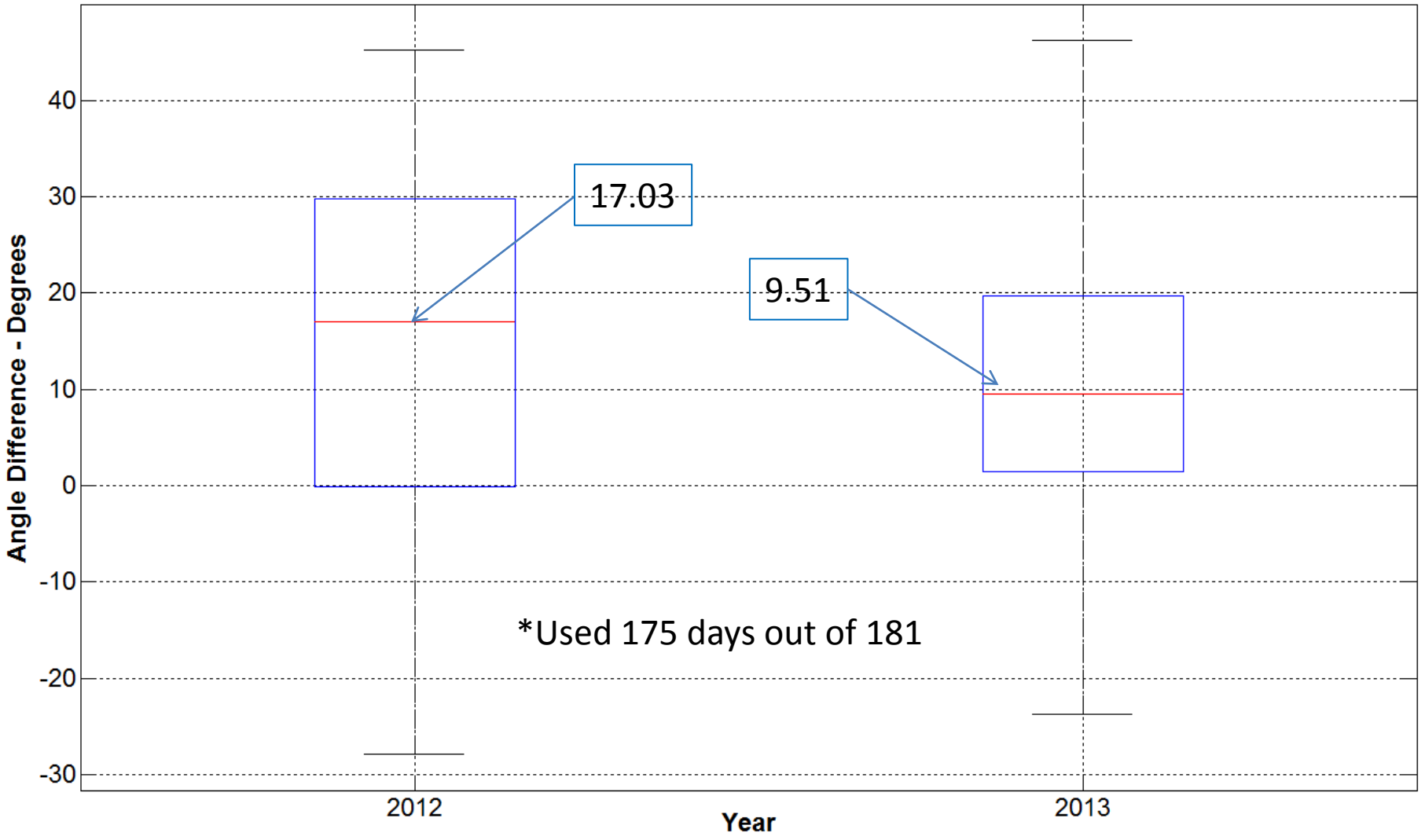
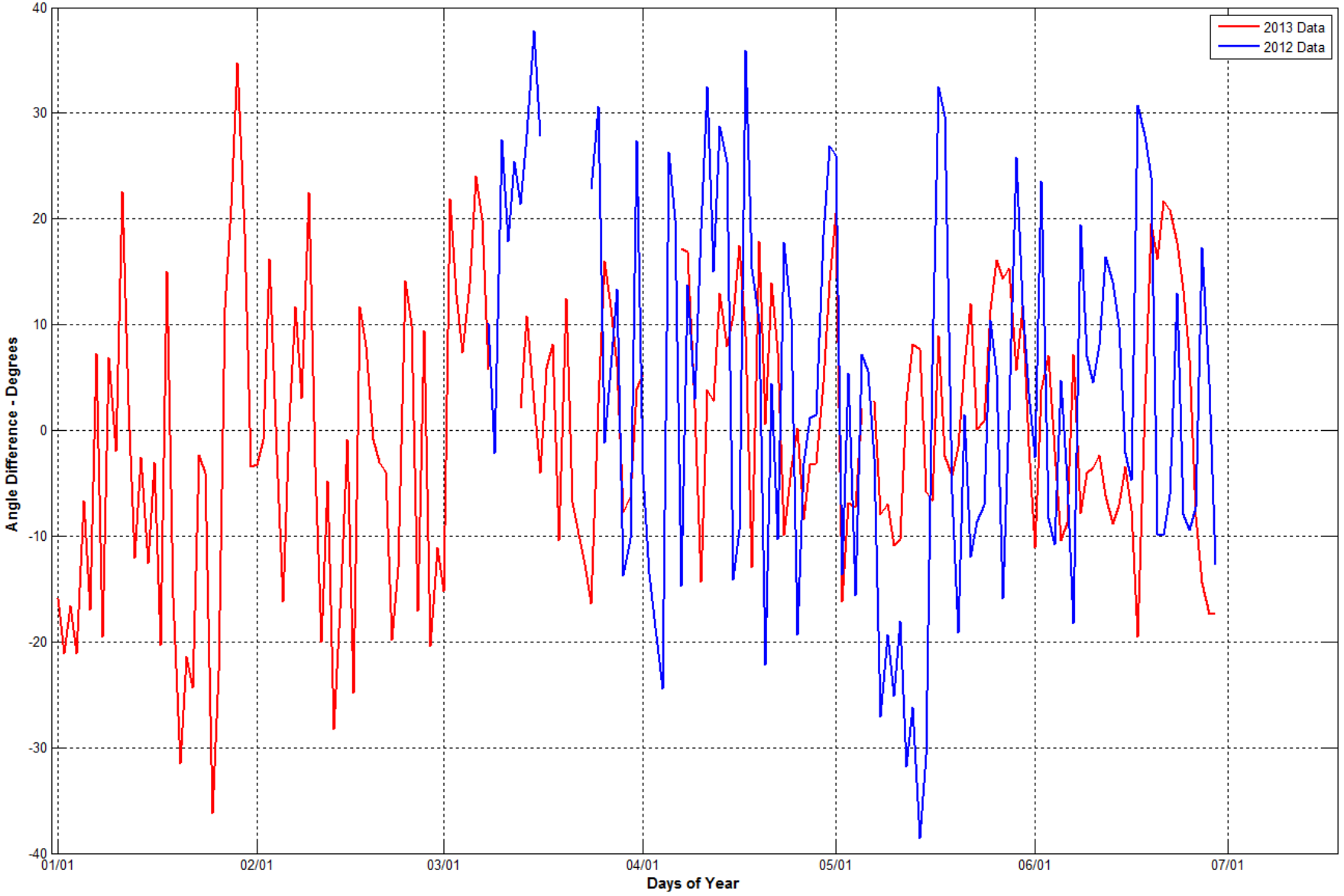


FarWest 8 – North 7



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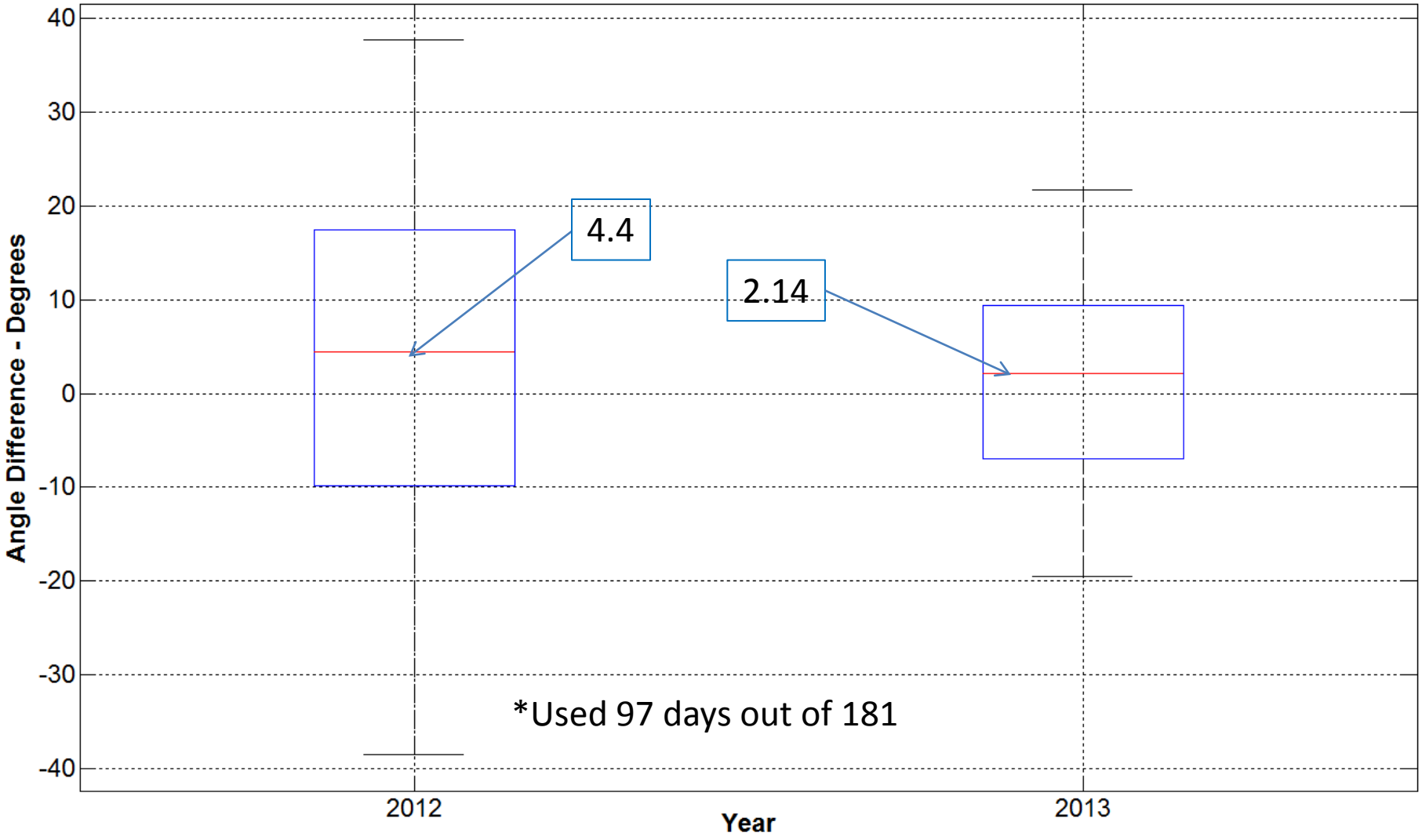

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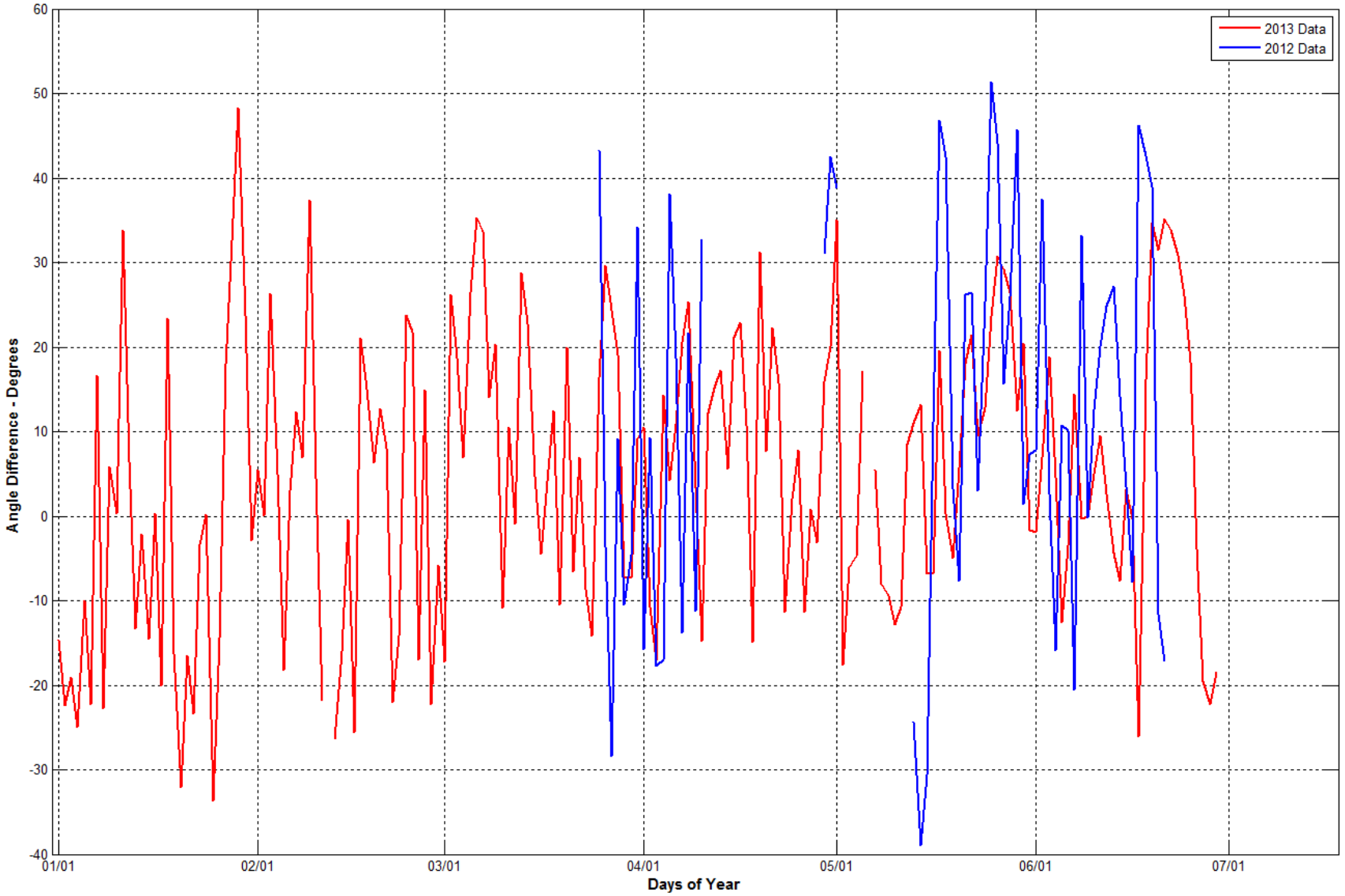

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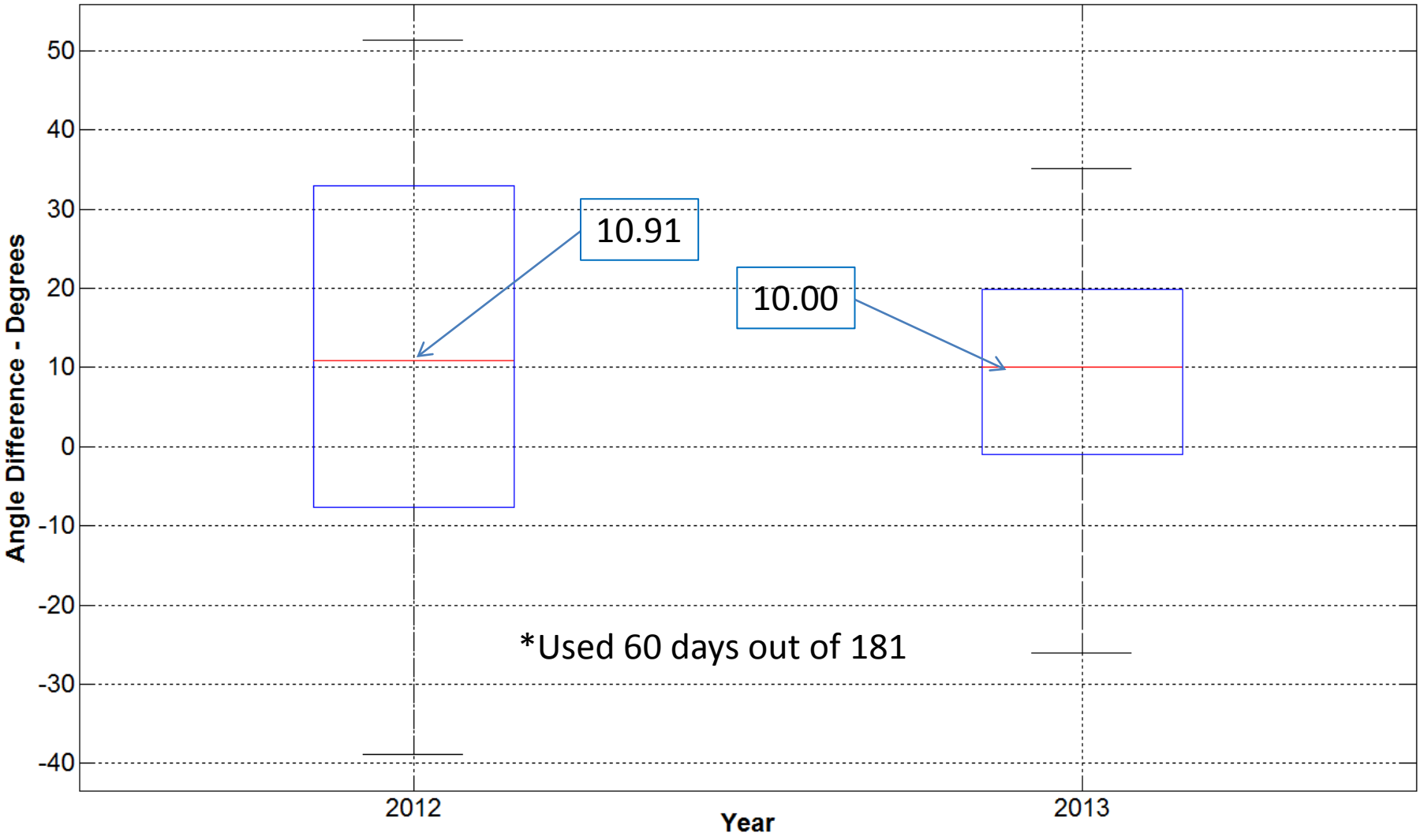


Appendix D – Part 1
CCET Discovery Across Texas project

Baseline Analysis Update – Angle Differences

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

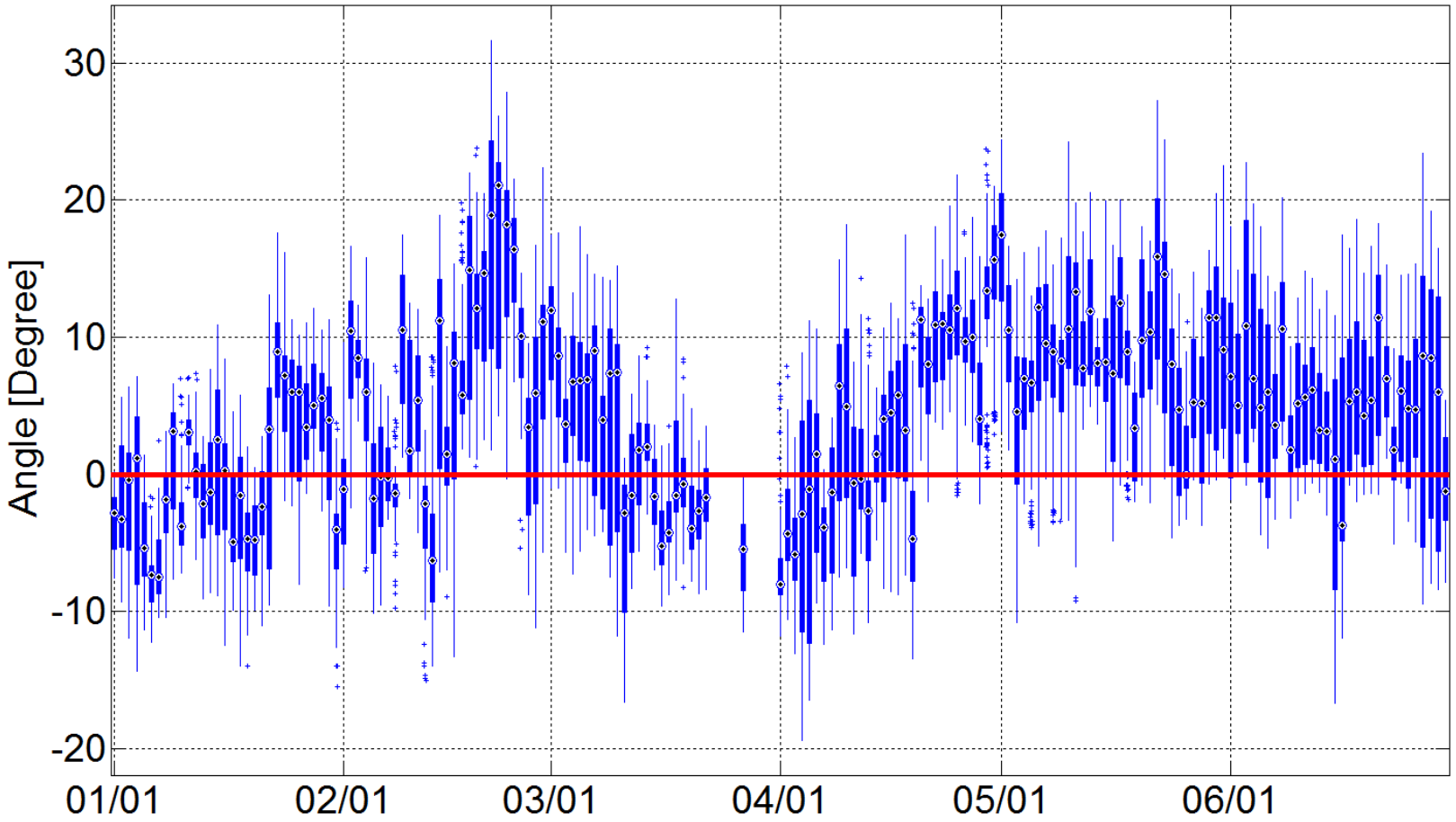
External Version

Electric Power Group

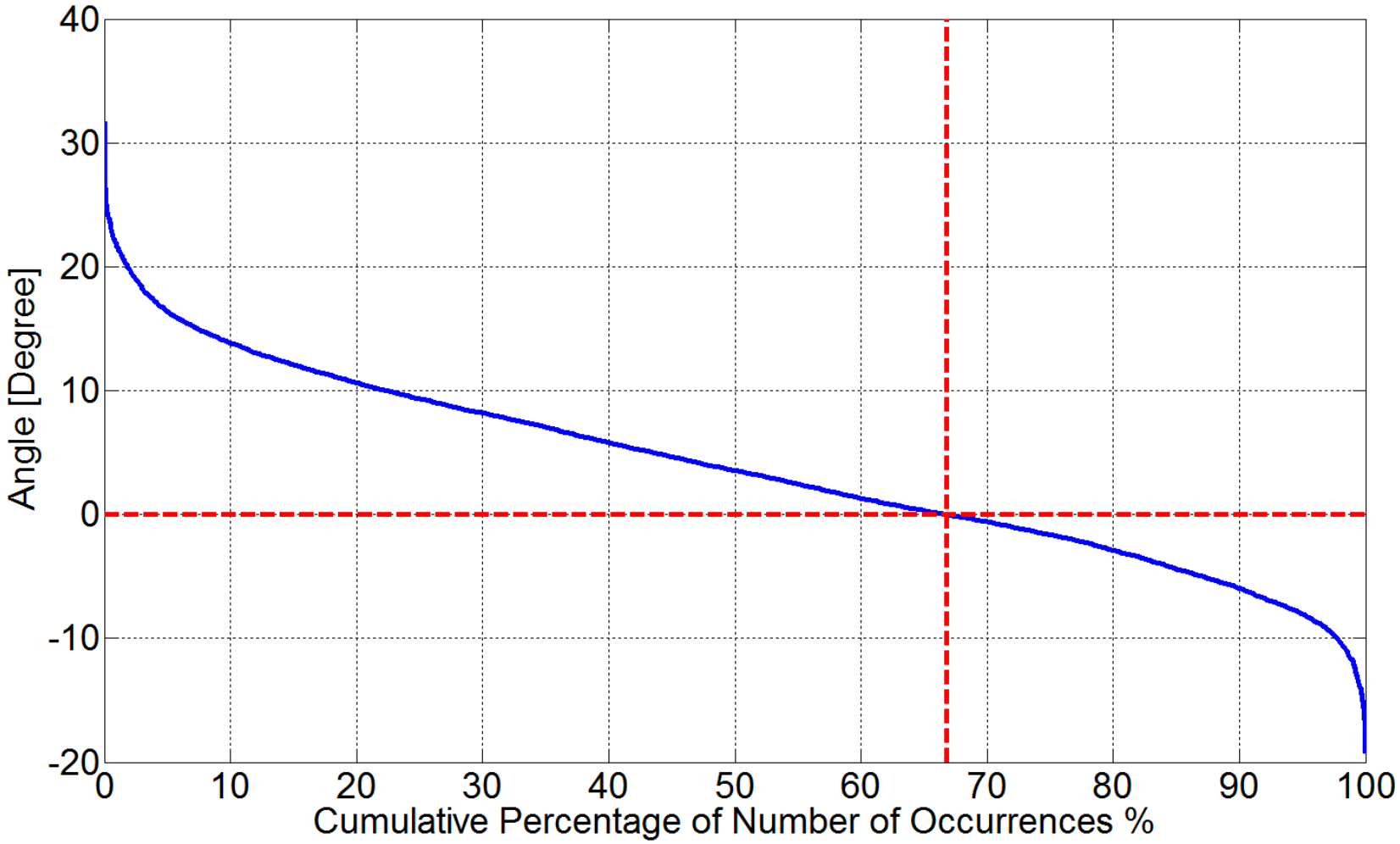
CCET

ERCOT

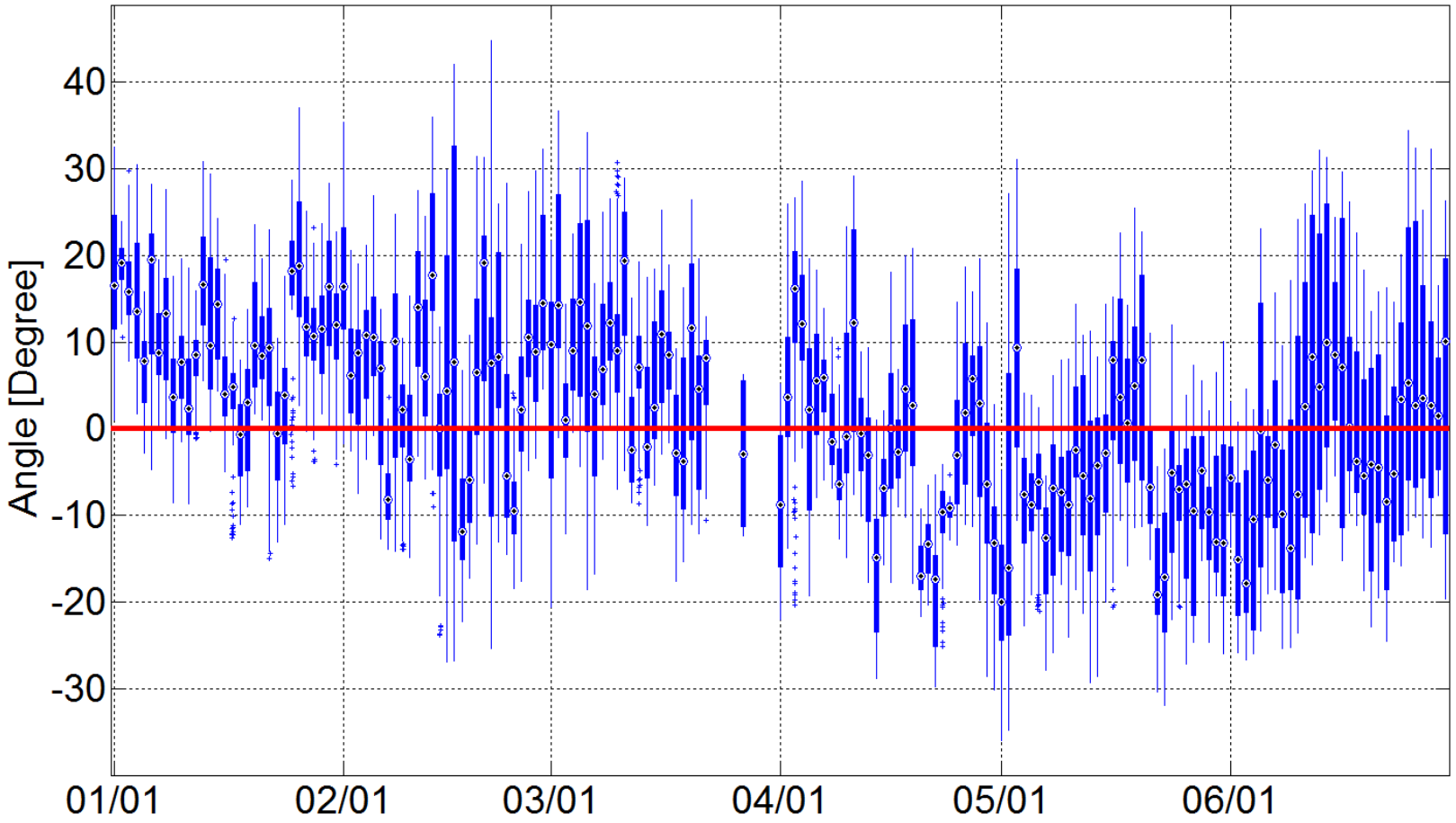
Coast 1-South 13



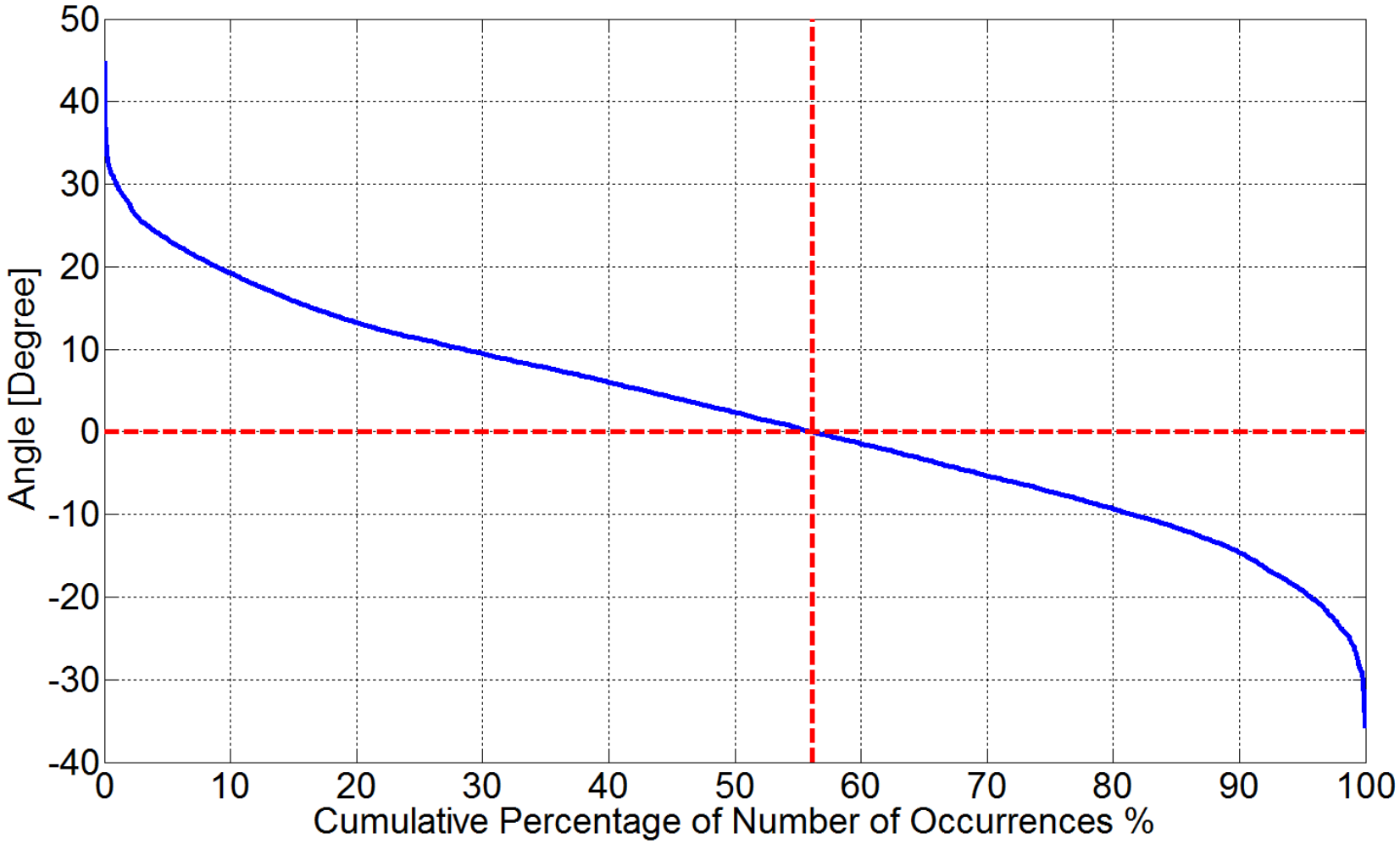
Coast 1-South 13



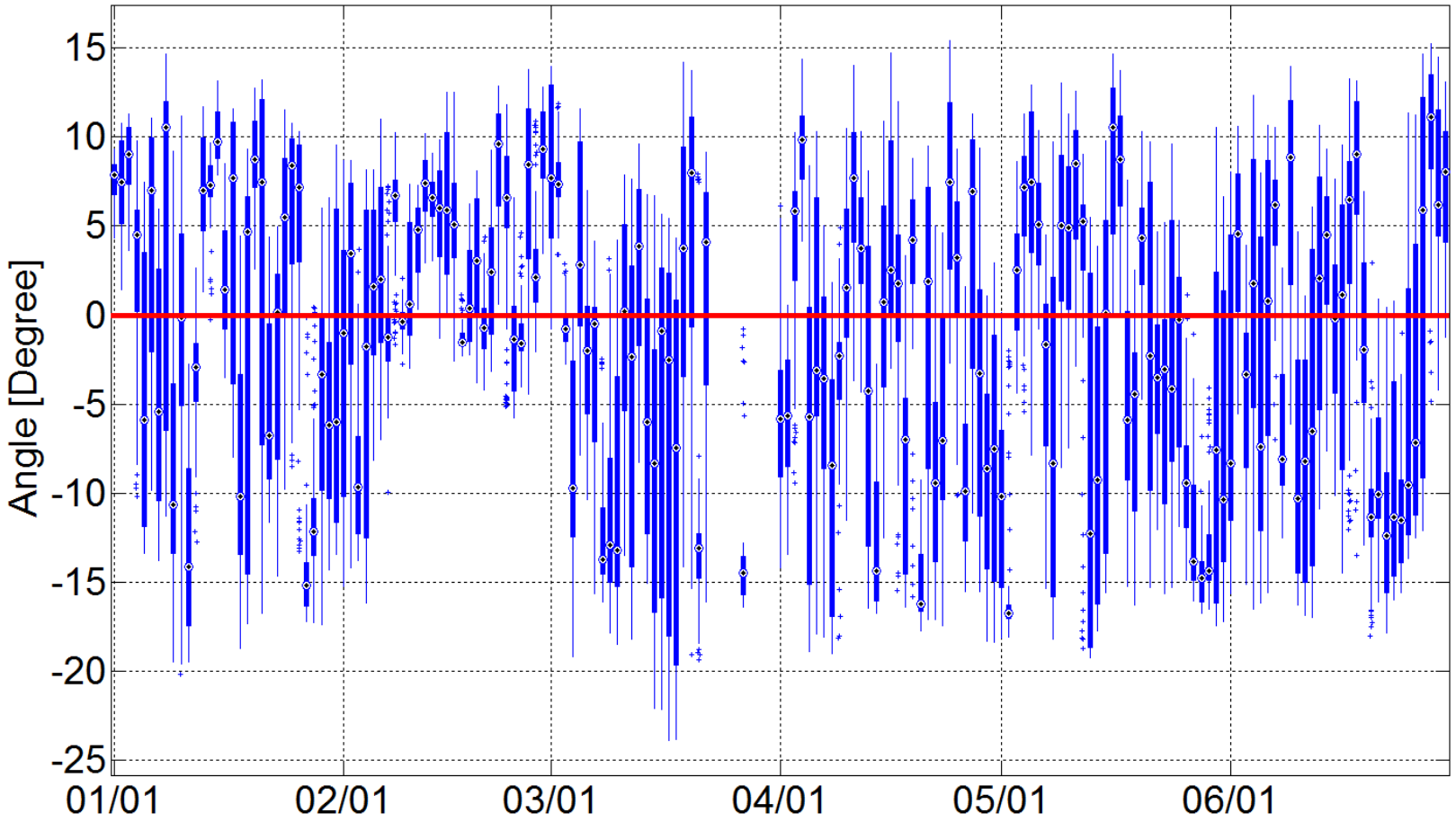
Coast 1-North 7



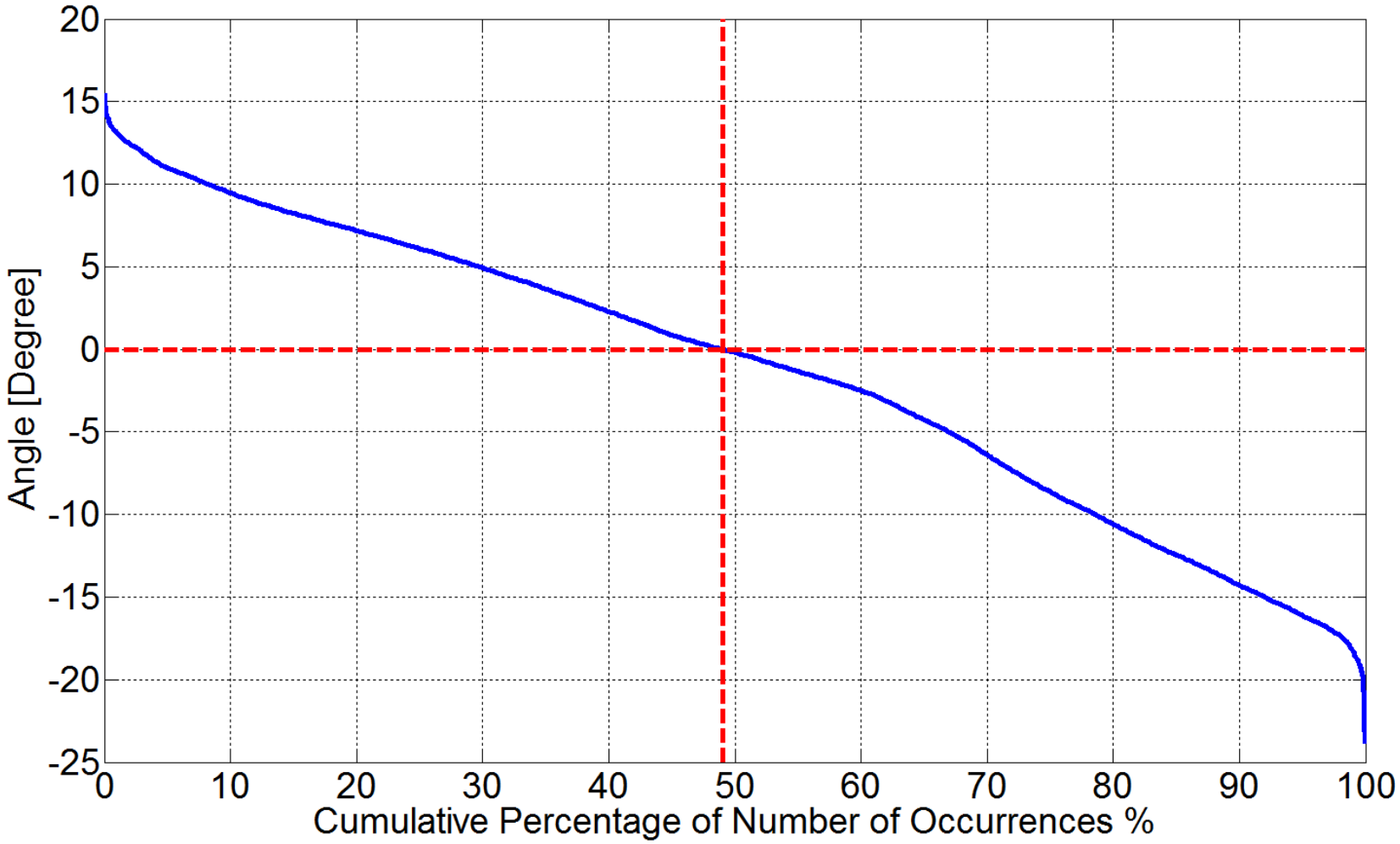
Coast 1-North 7



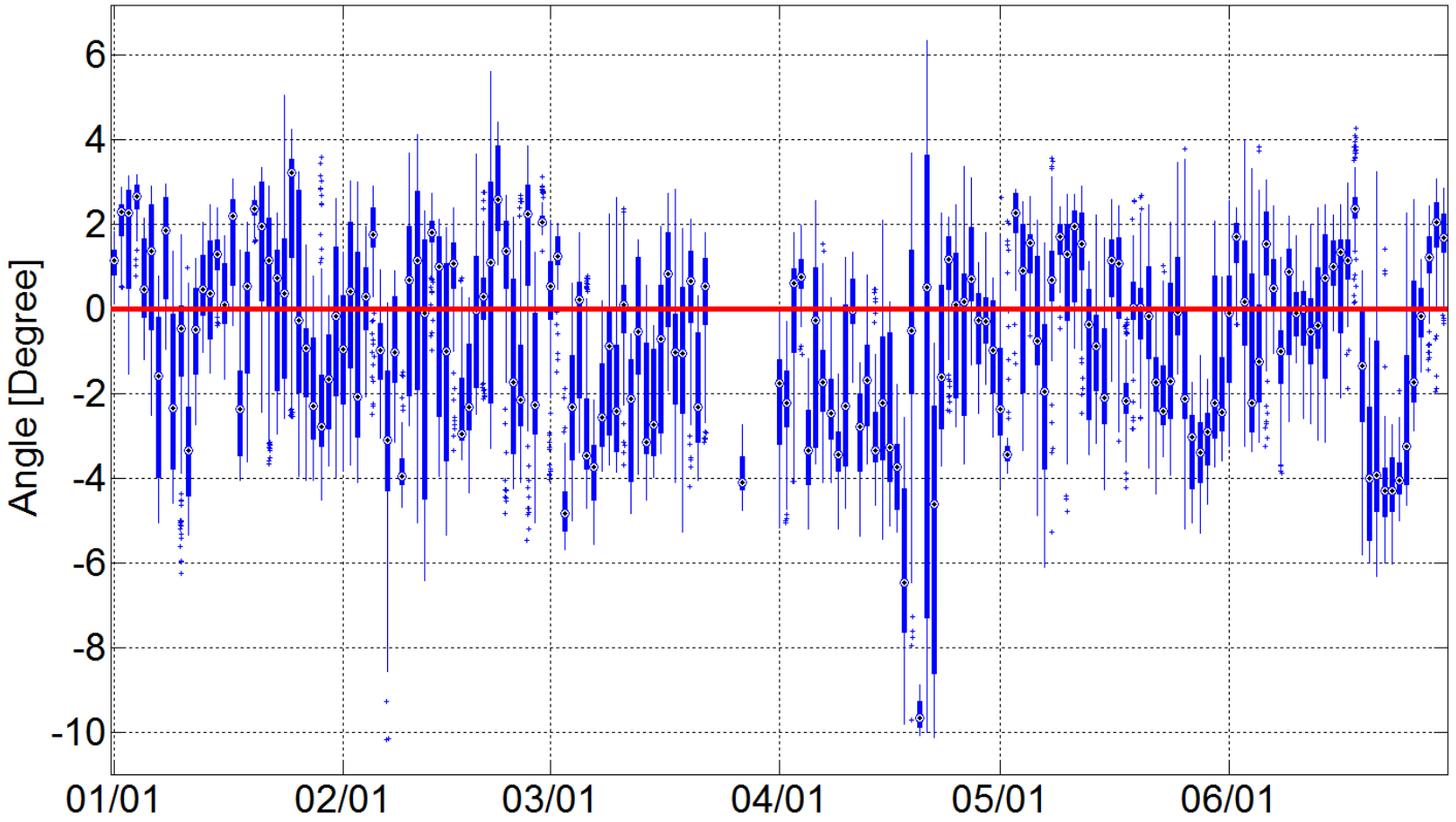
West 5*-West 10



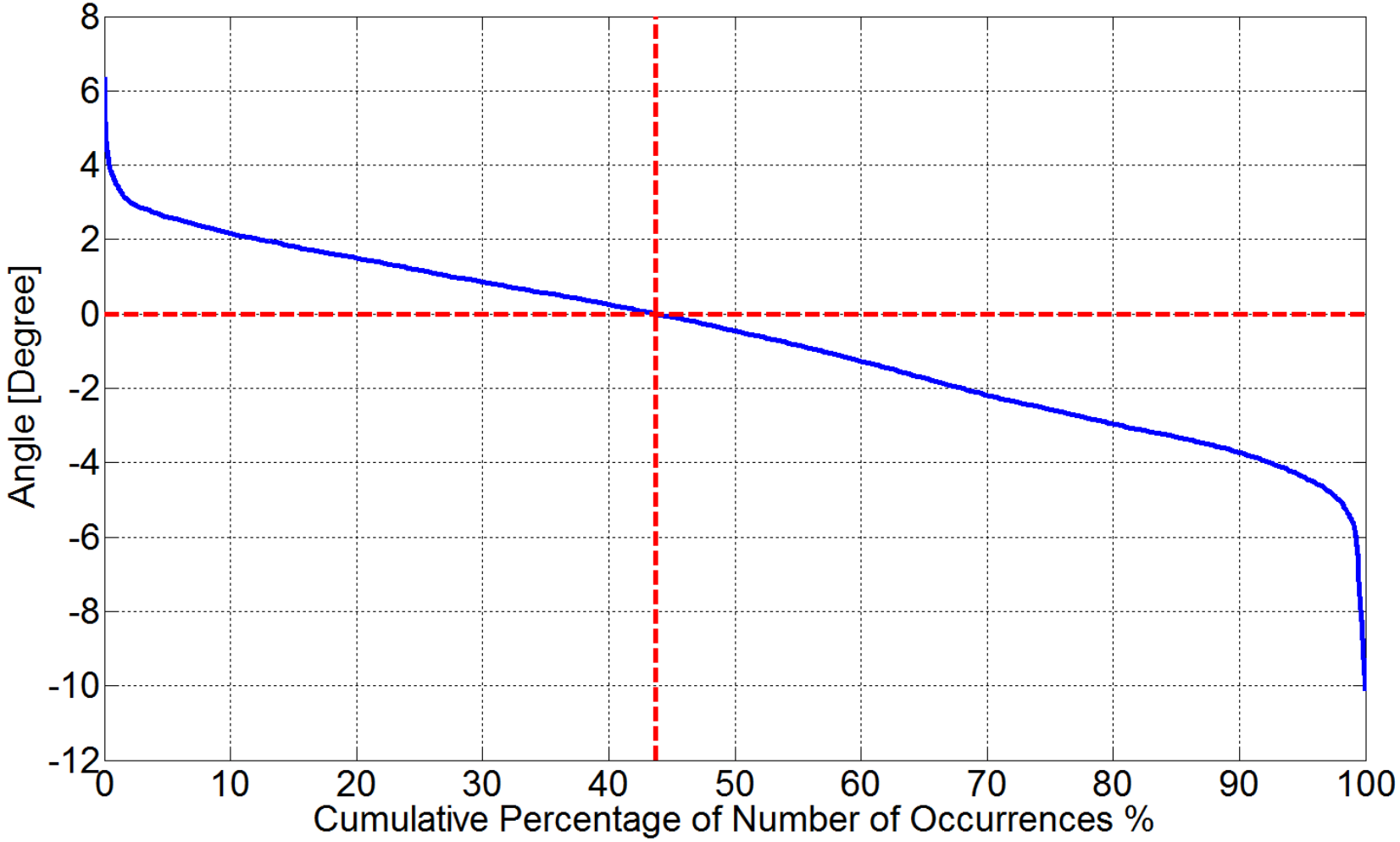
West 5*-West 10



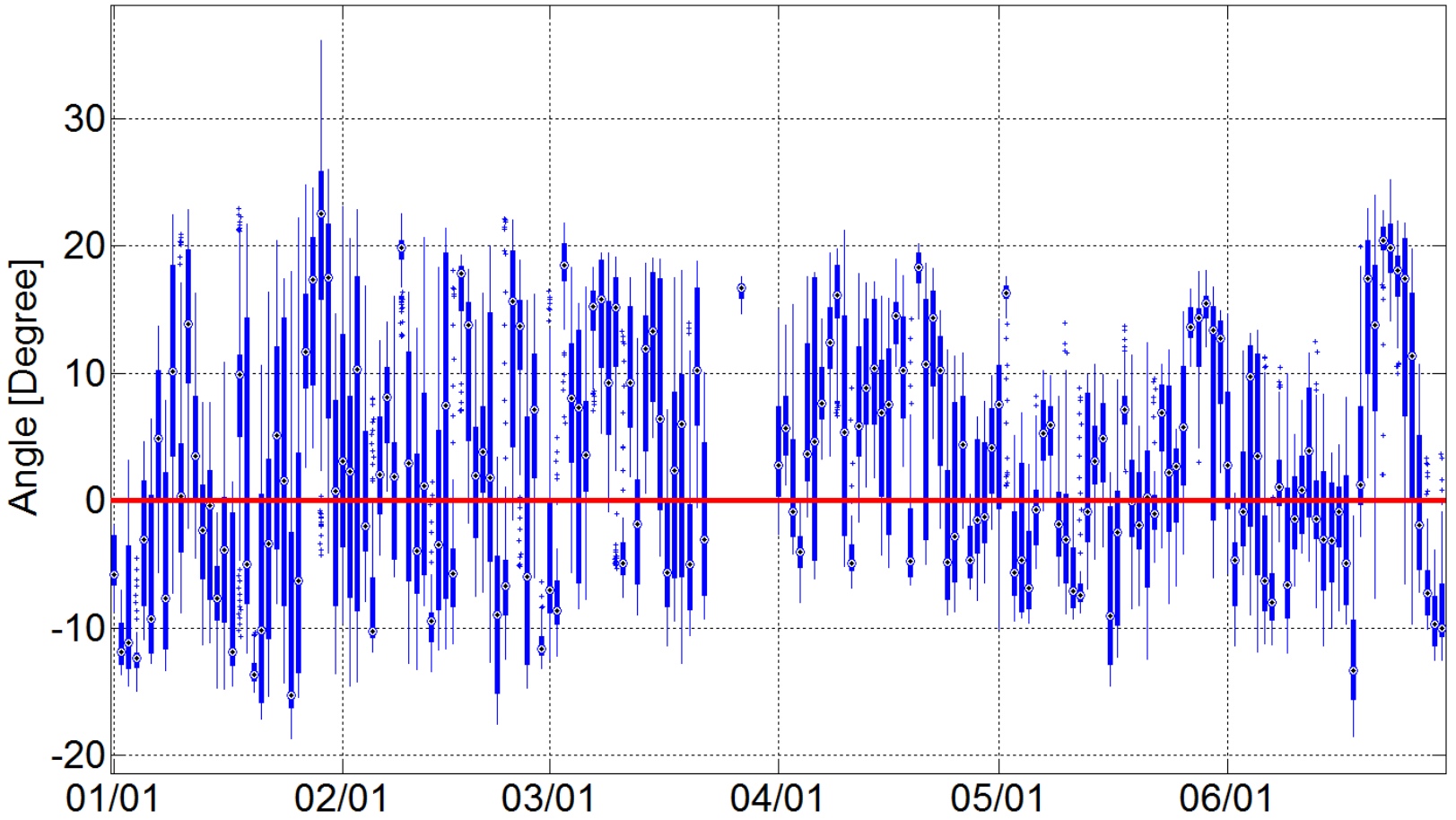
West 5*-FarWest 4



West 5*-FarWest 4



West 5*-North 1



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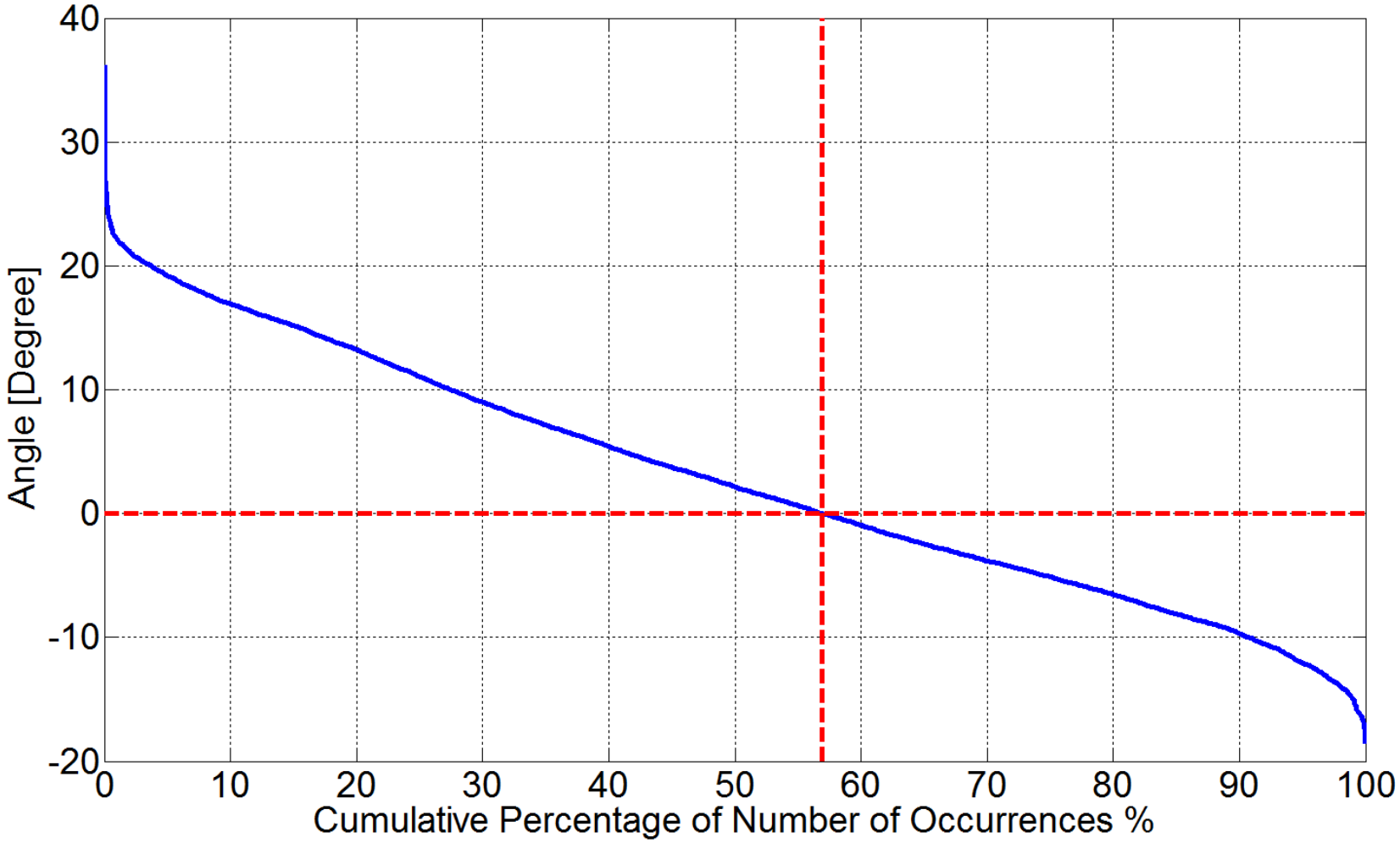

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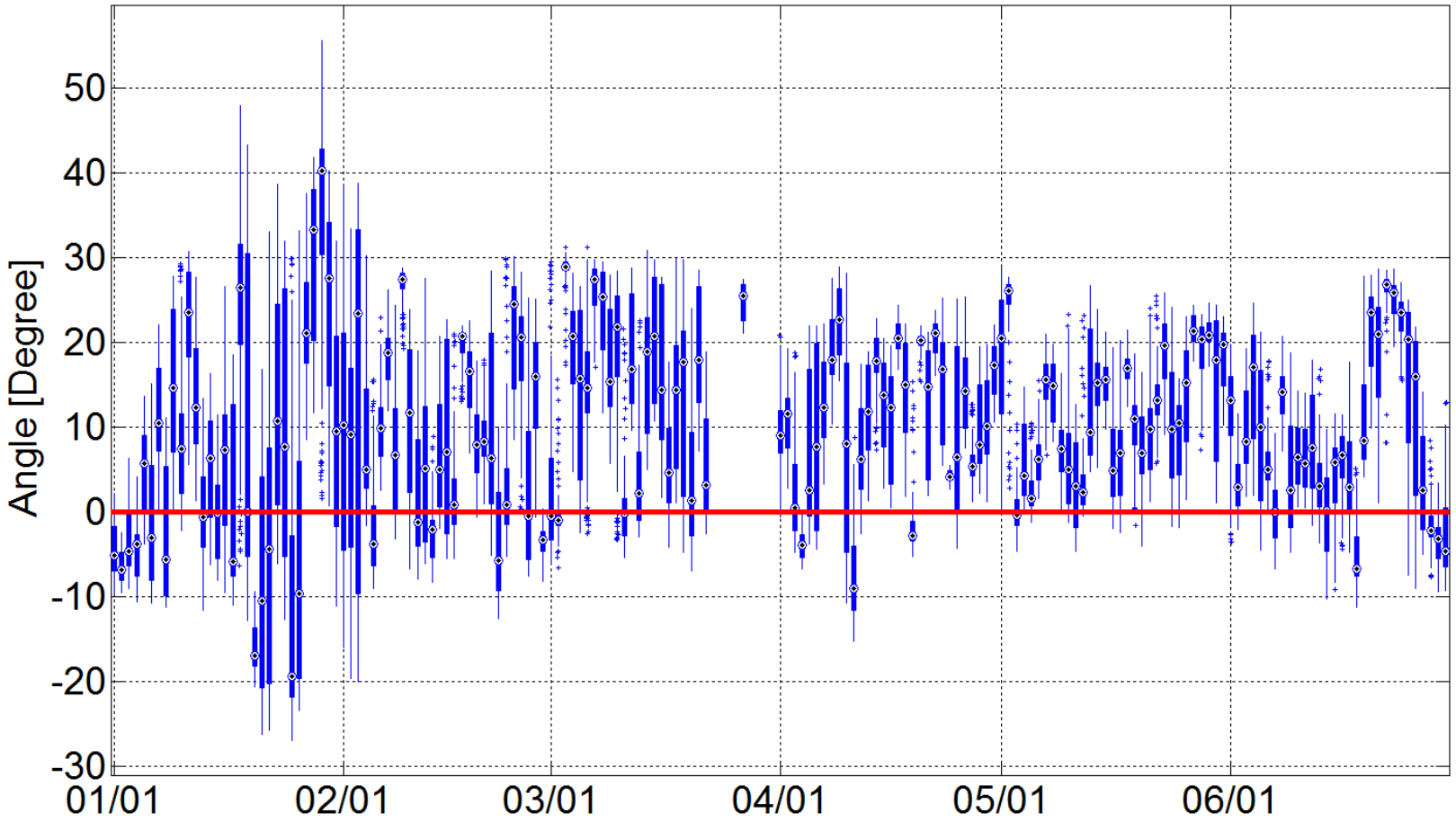
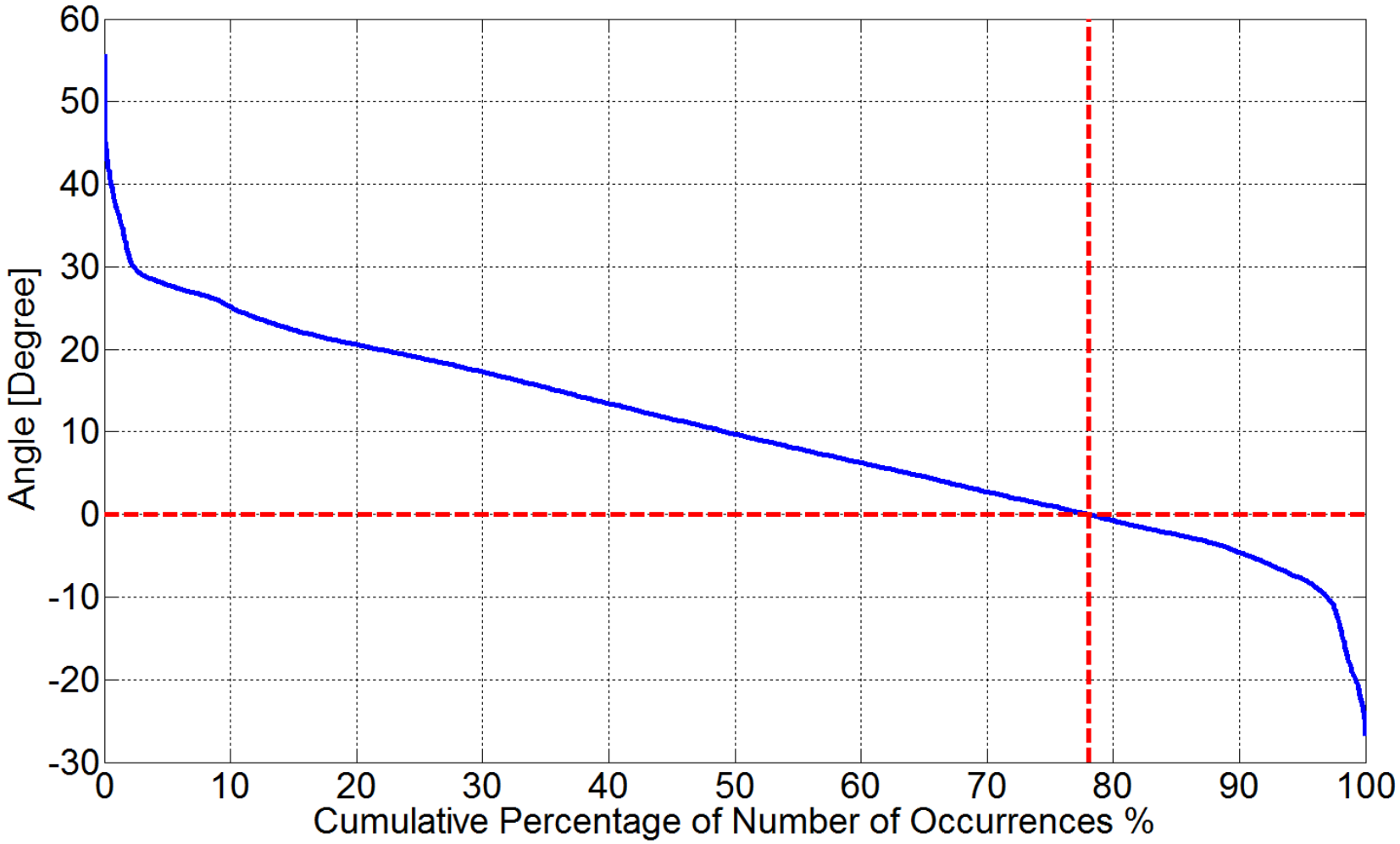
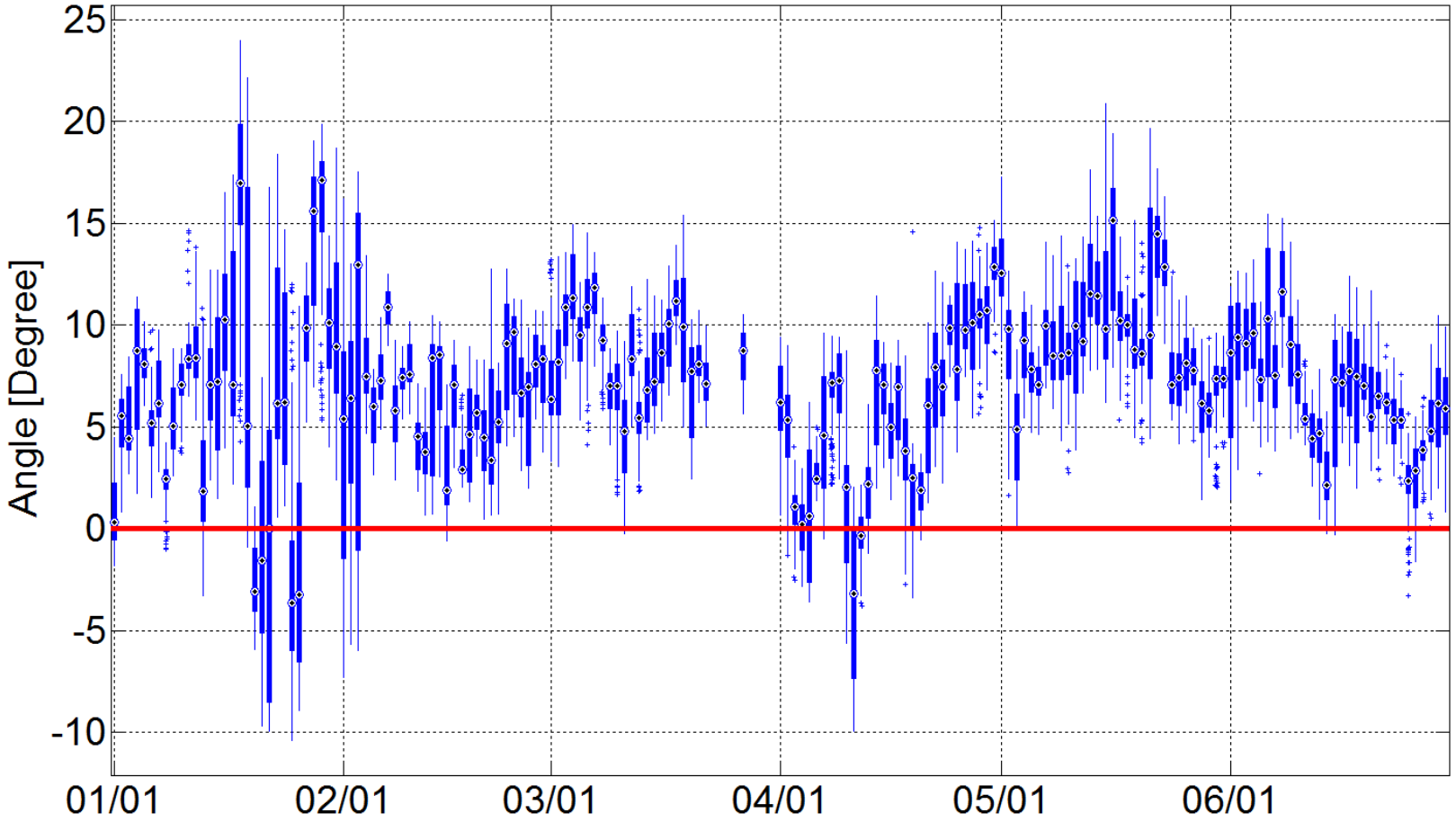


West 5*-North 7



North 1-North 7



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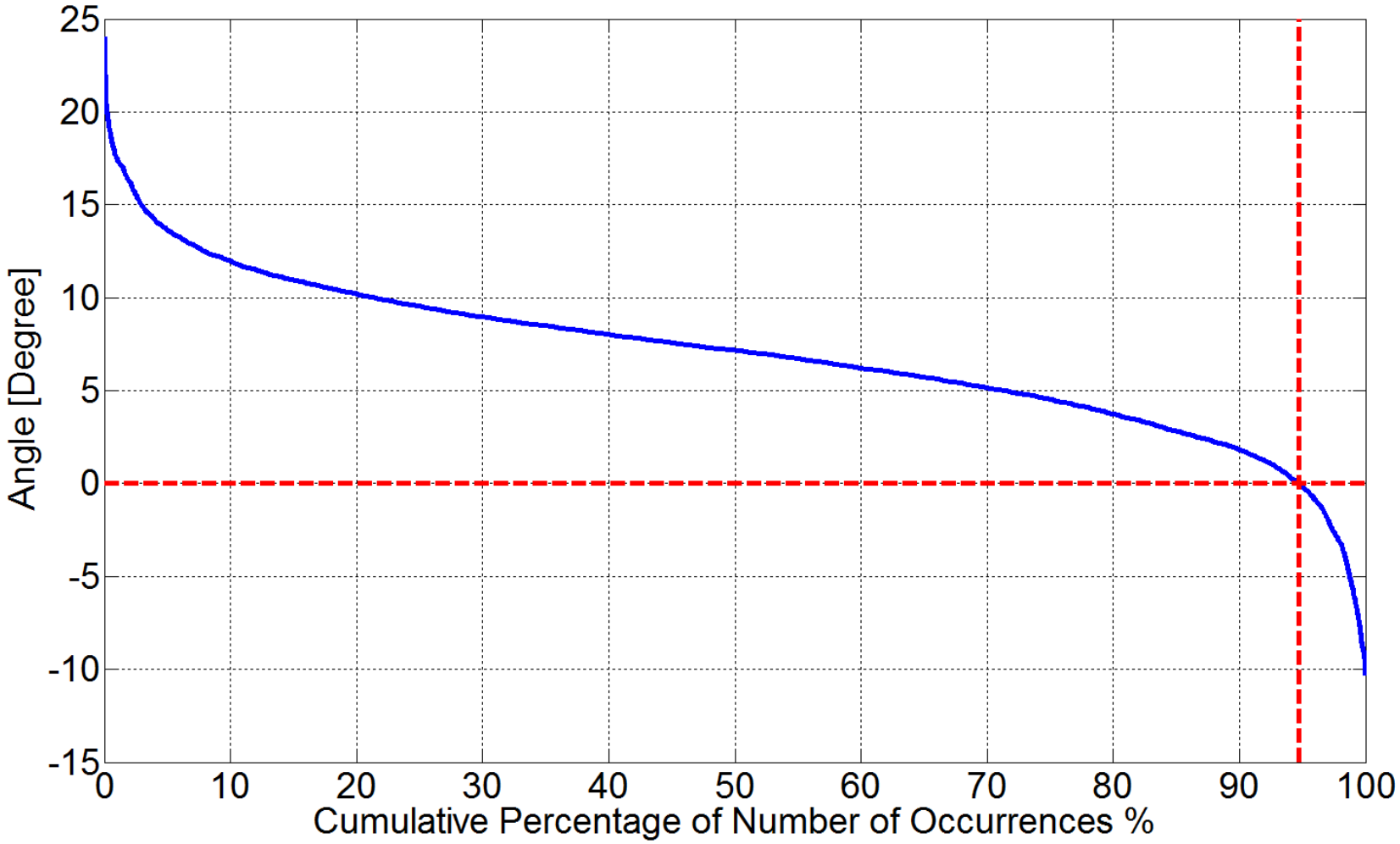

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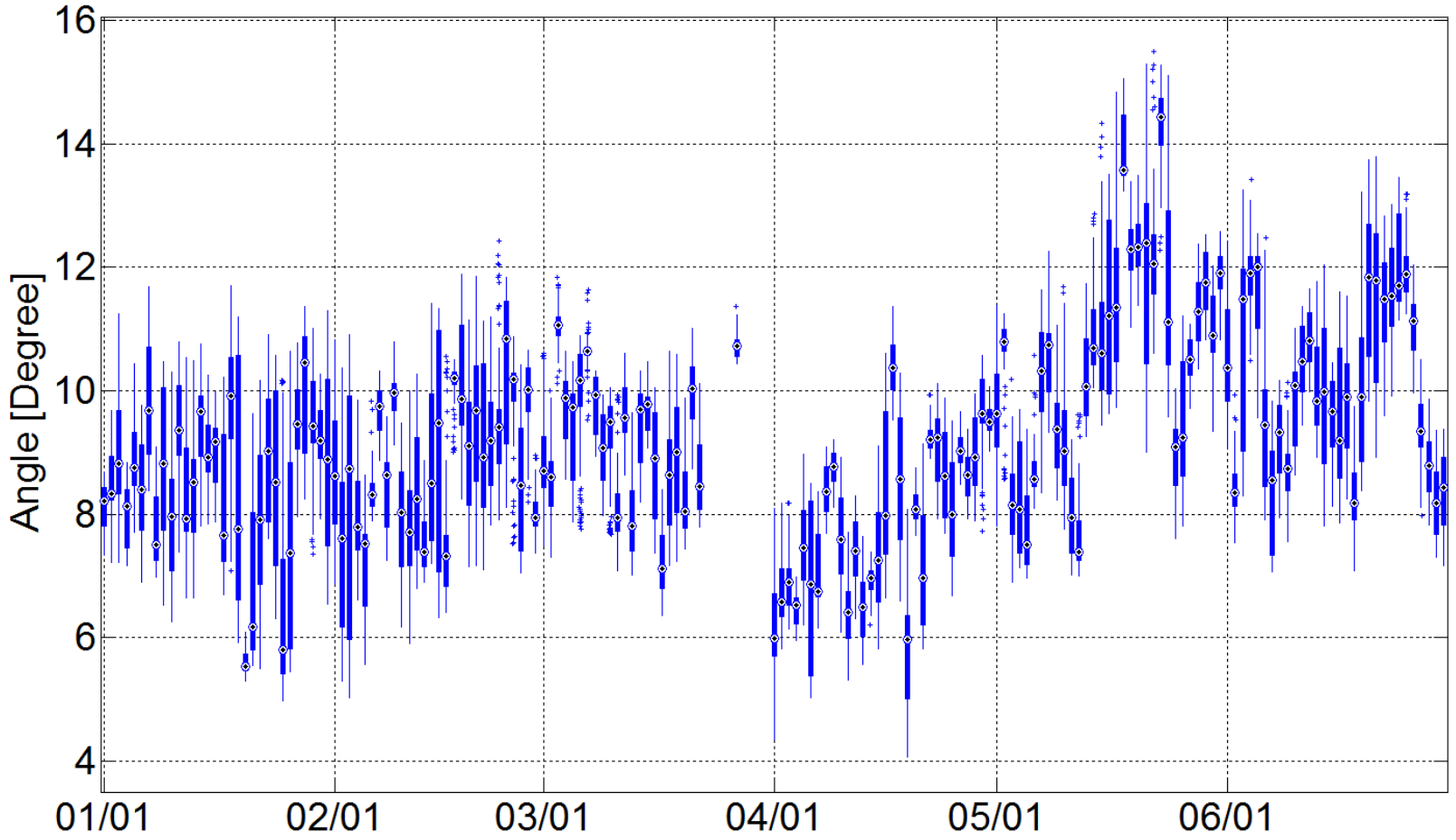

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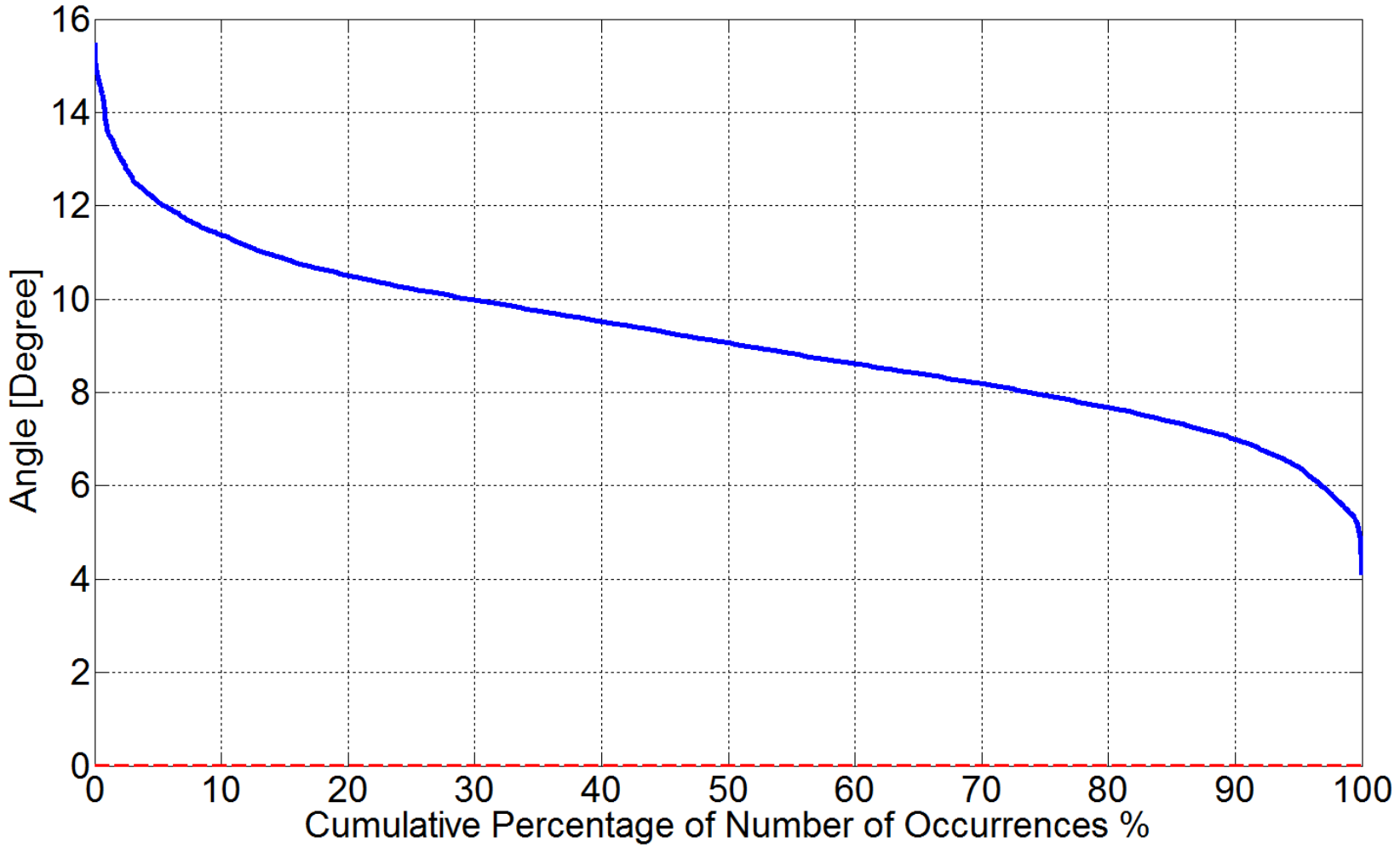

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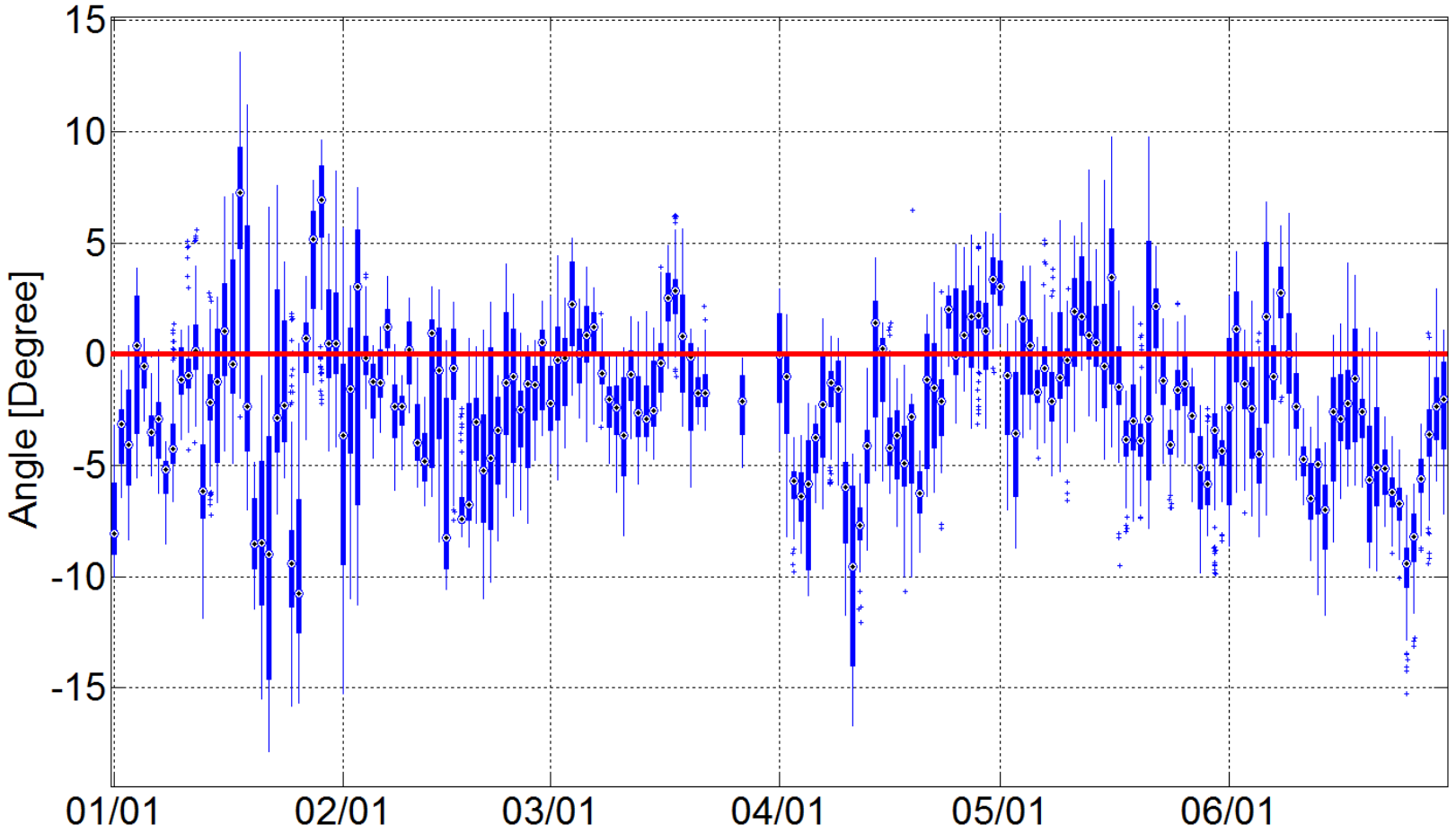

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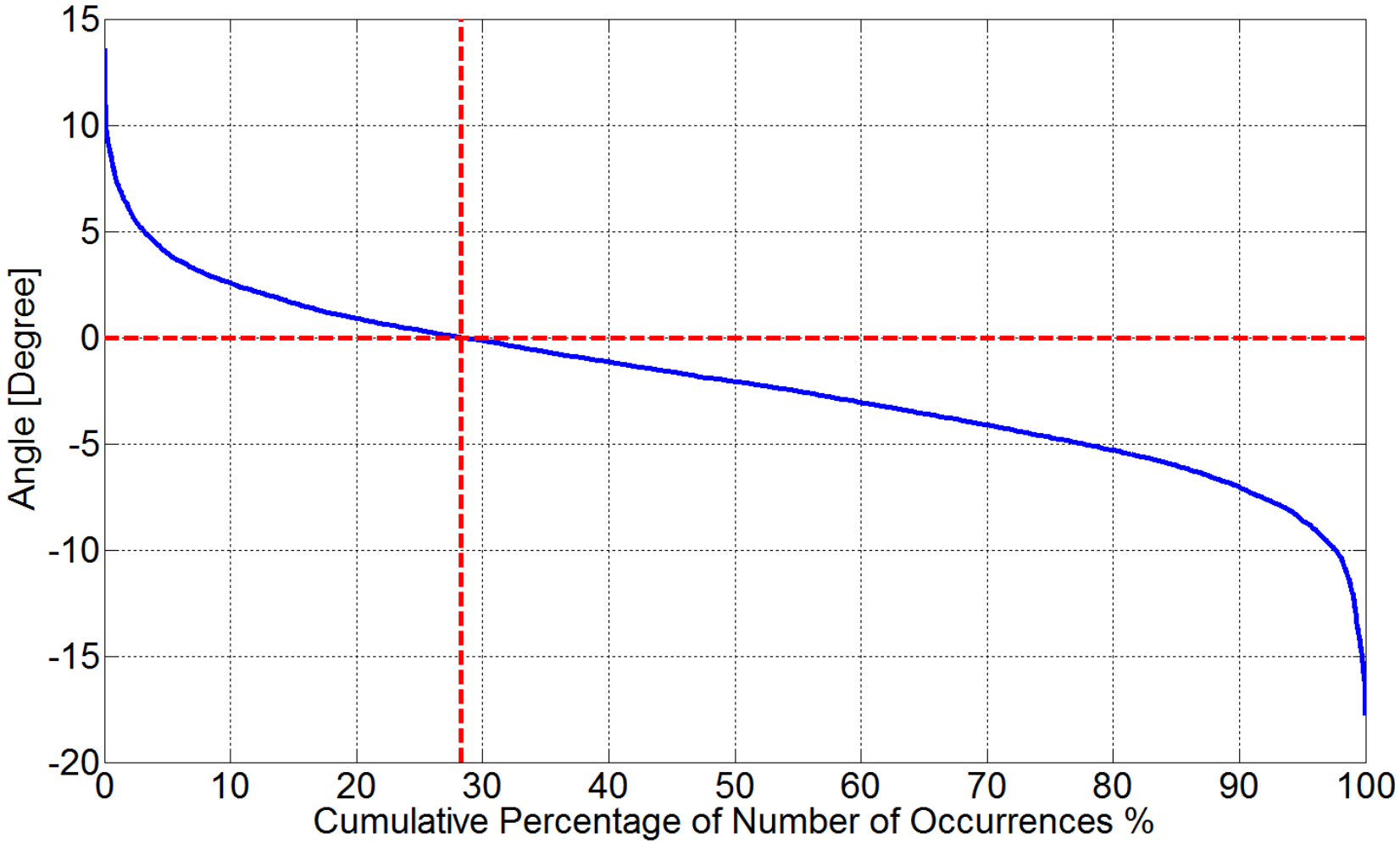

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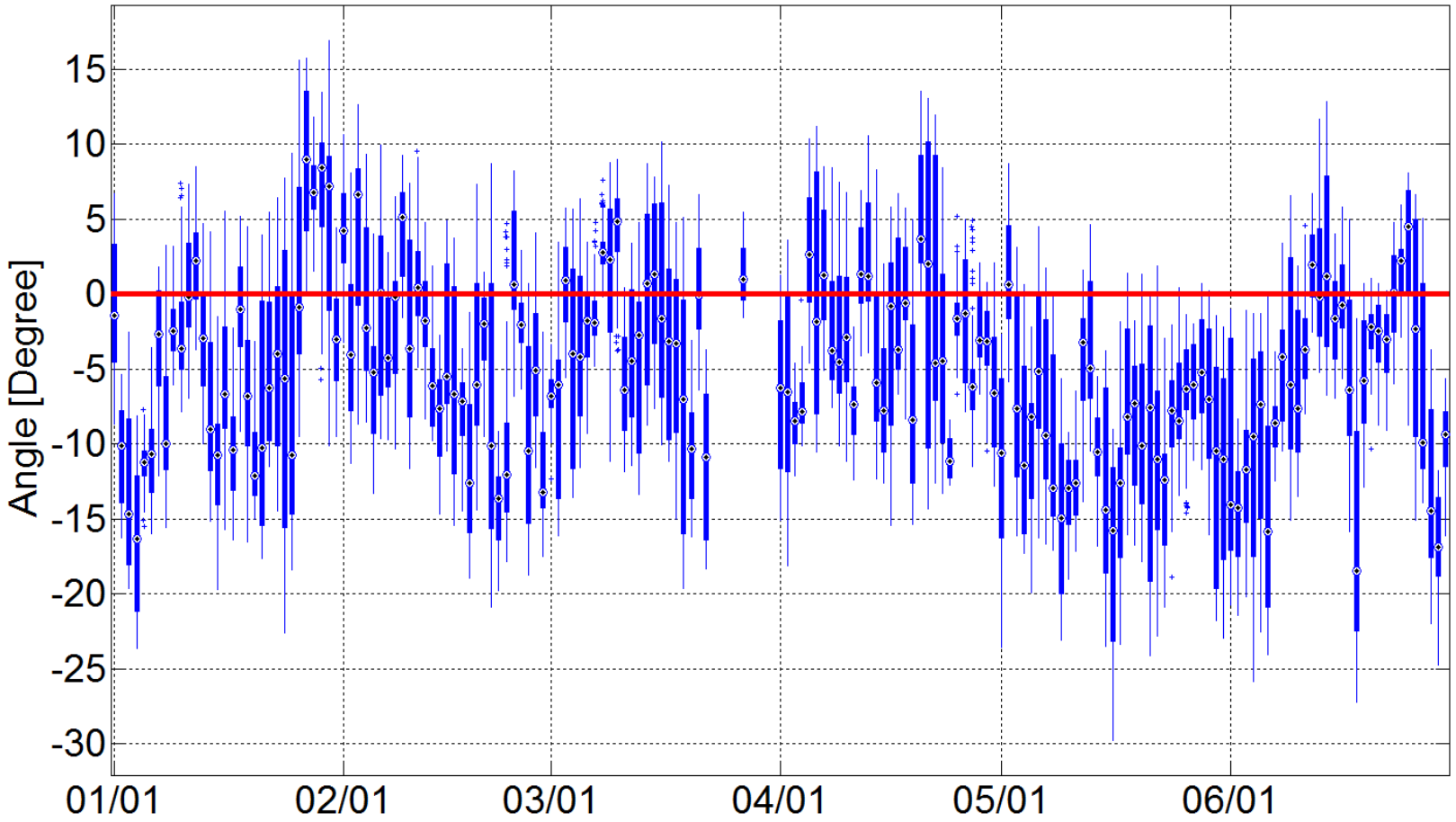

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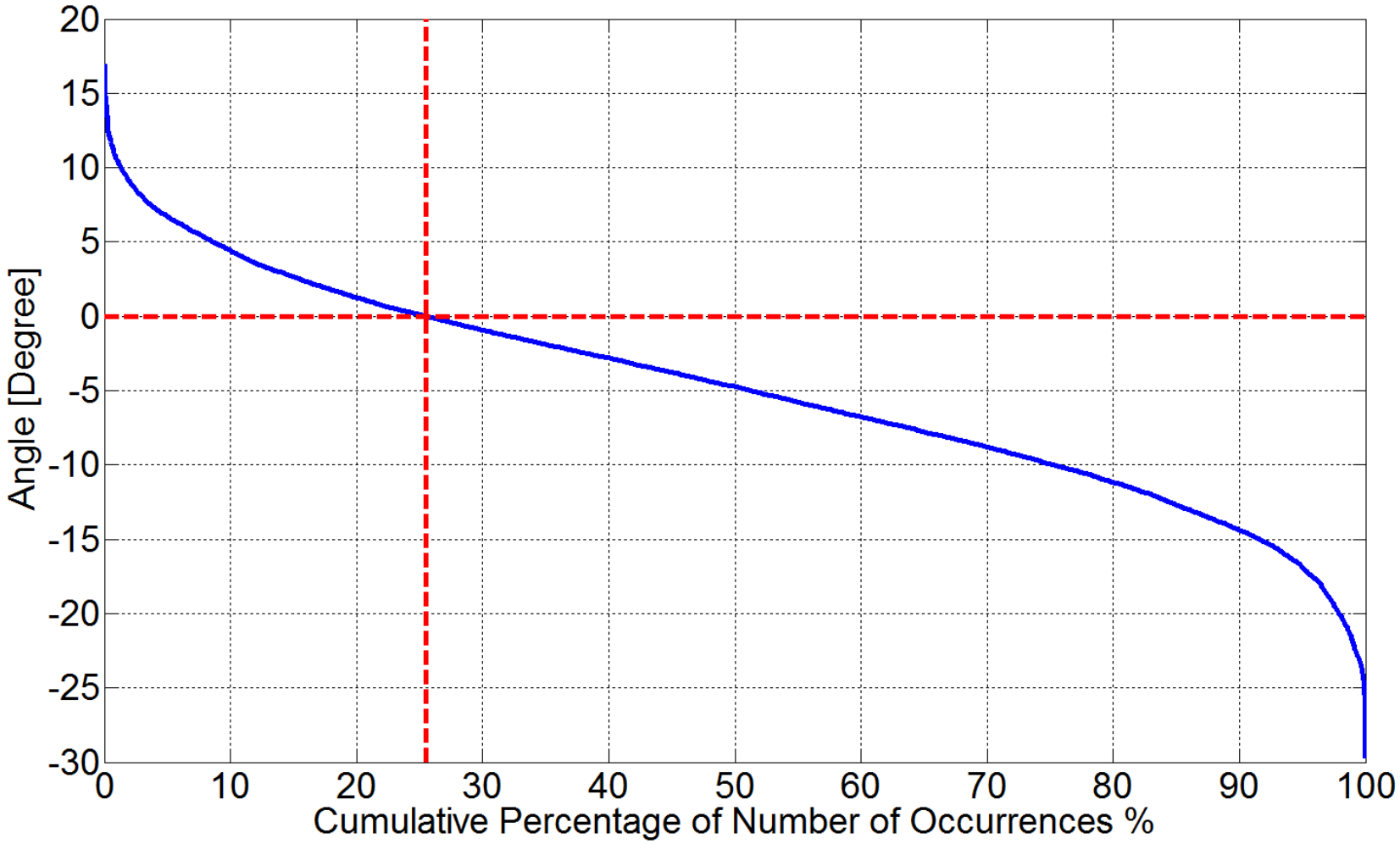

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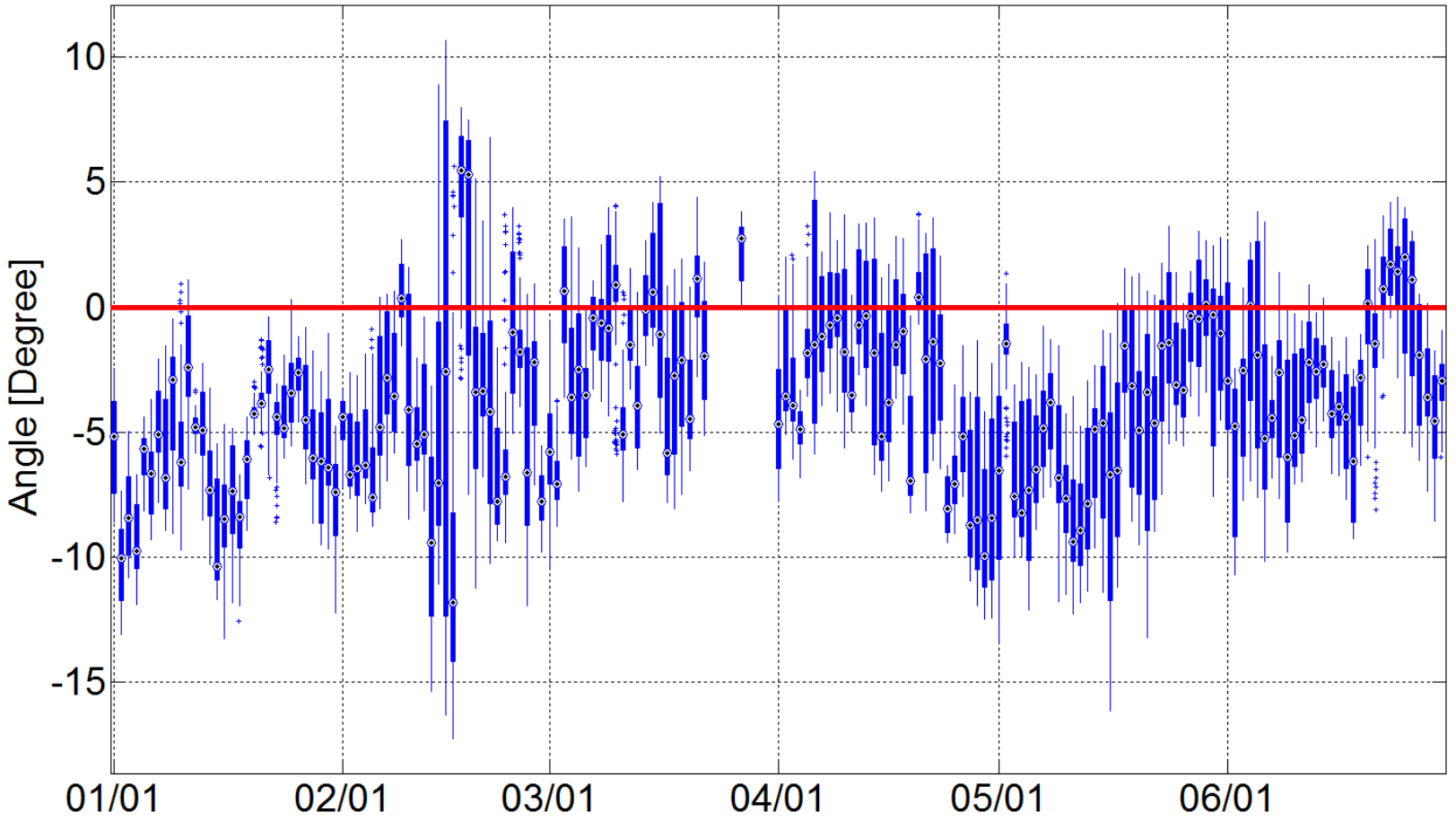

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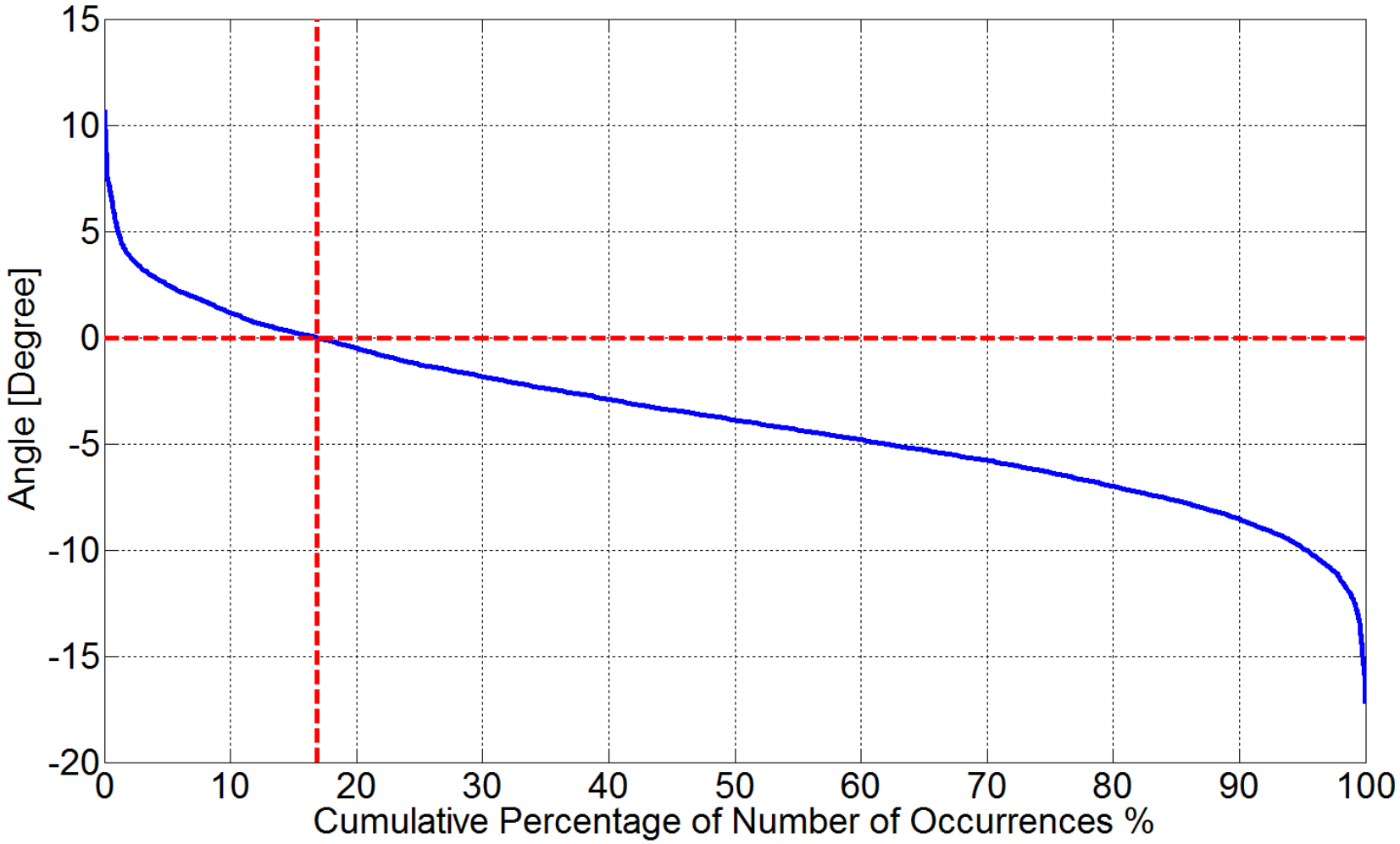

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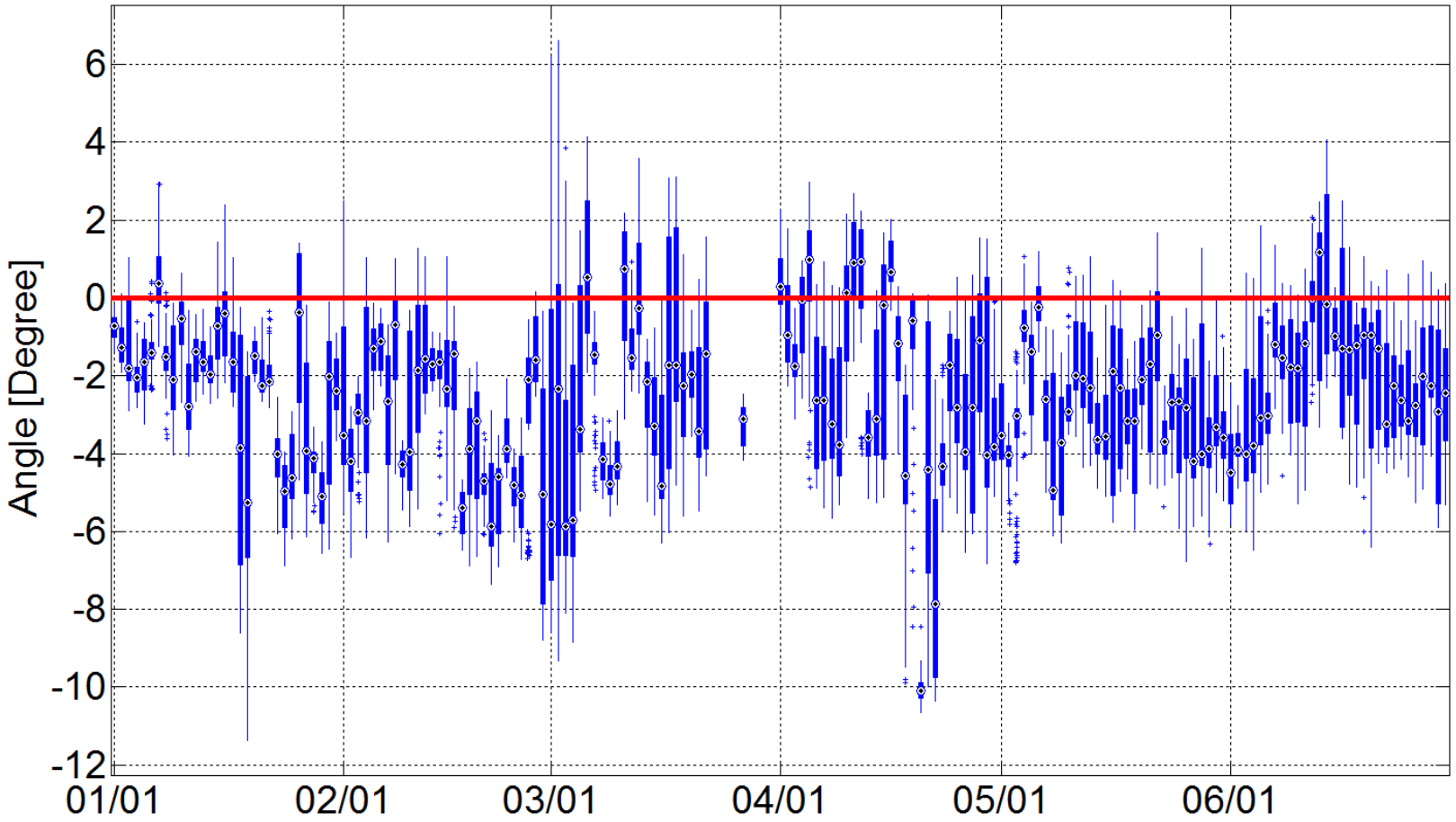
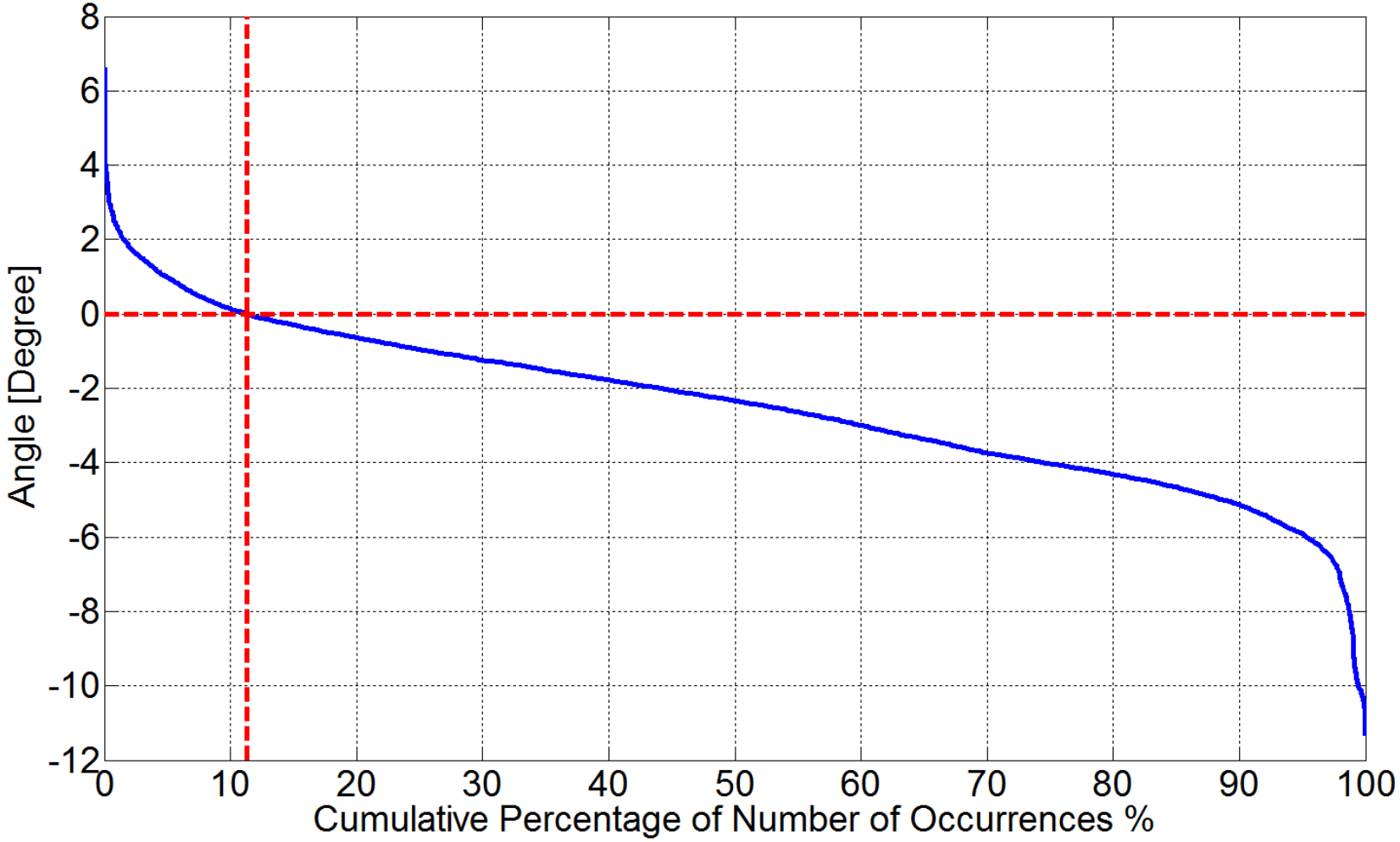
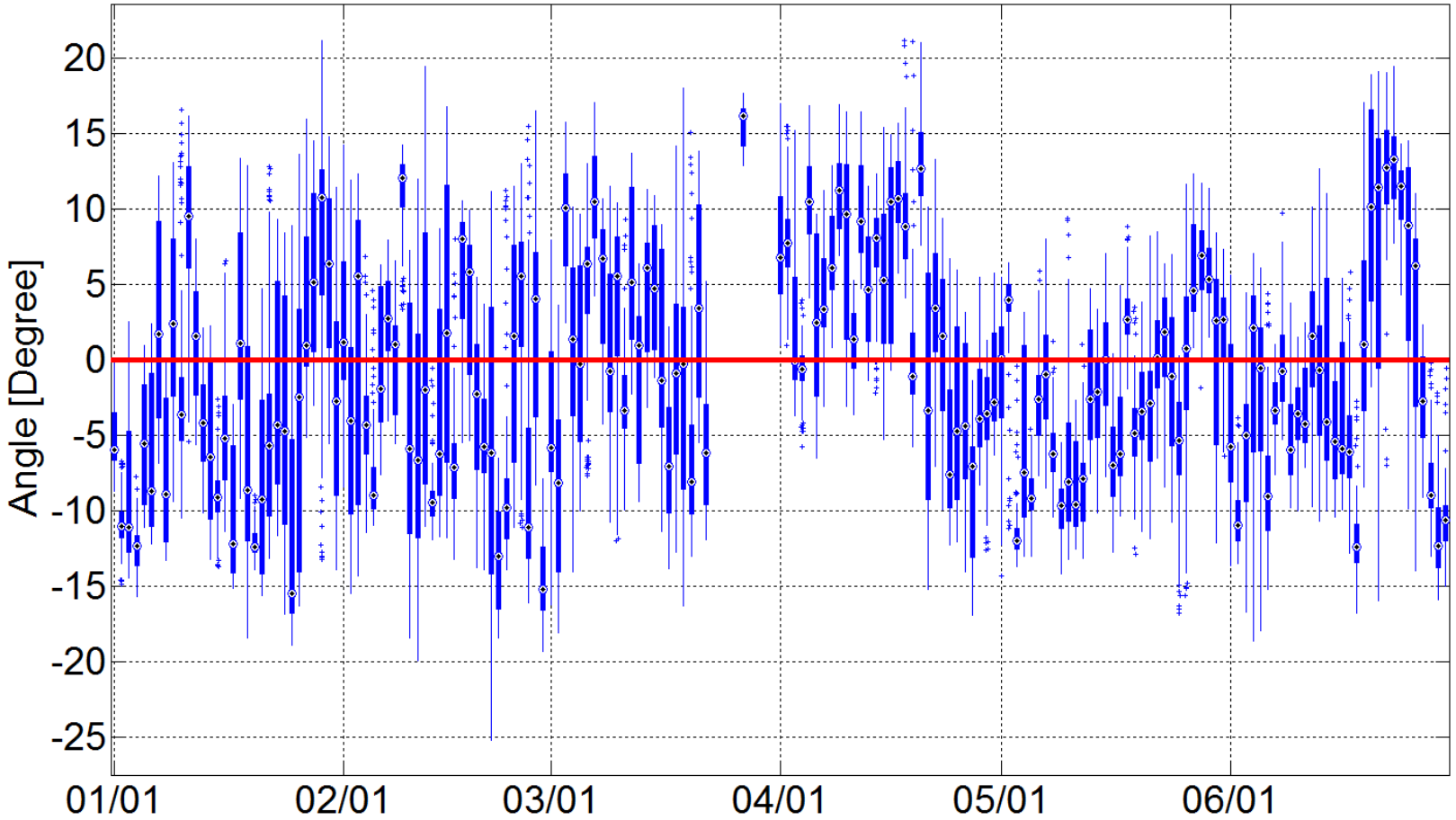


FarWest 7-FarWest 4



FarWest 7-West 14



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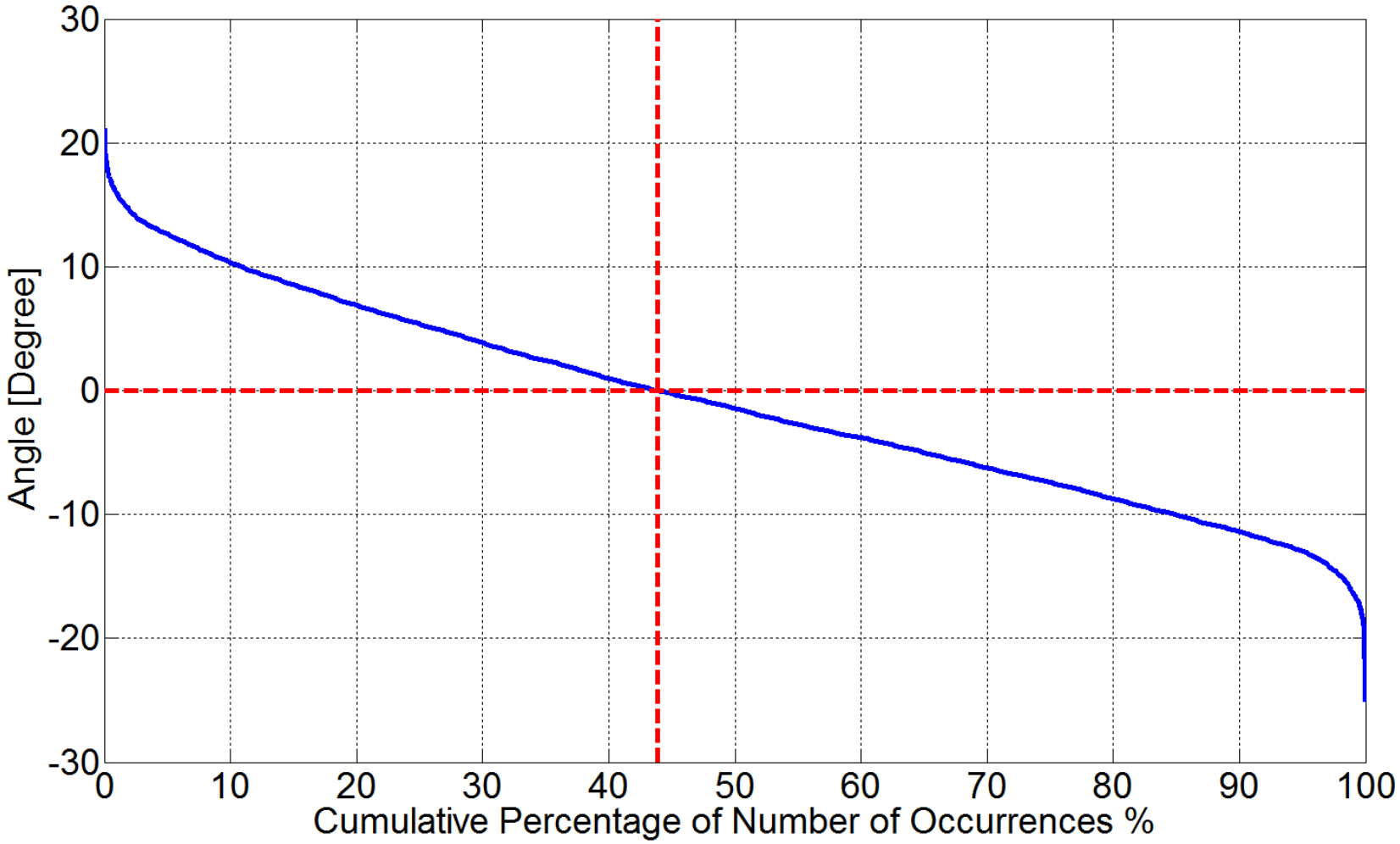
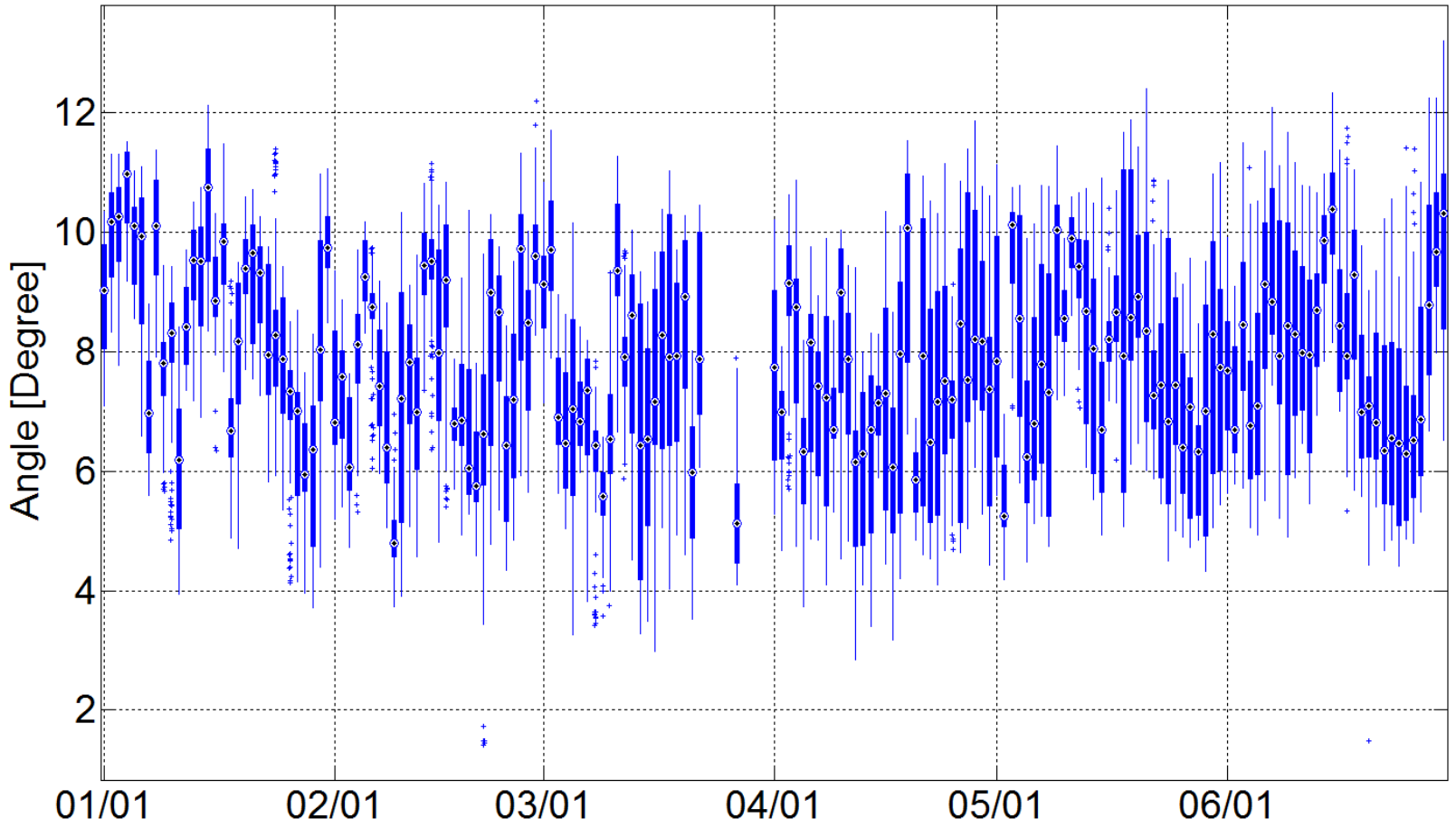


FarWest 7-FarWest 8



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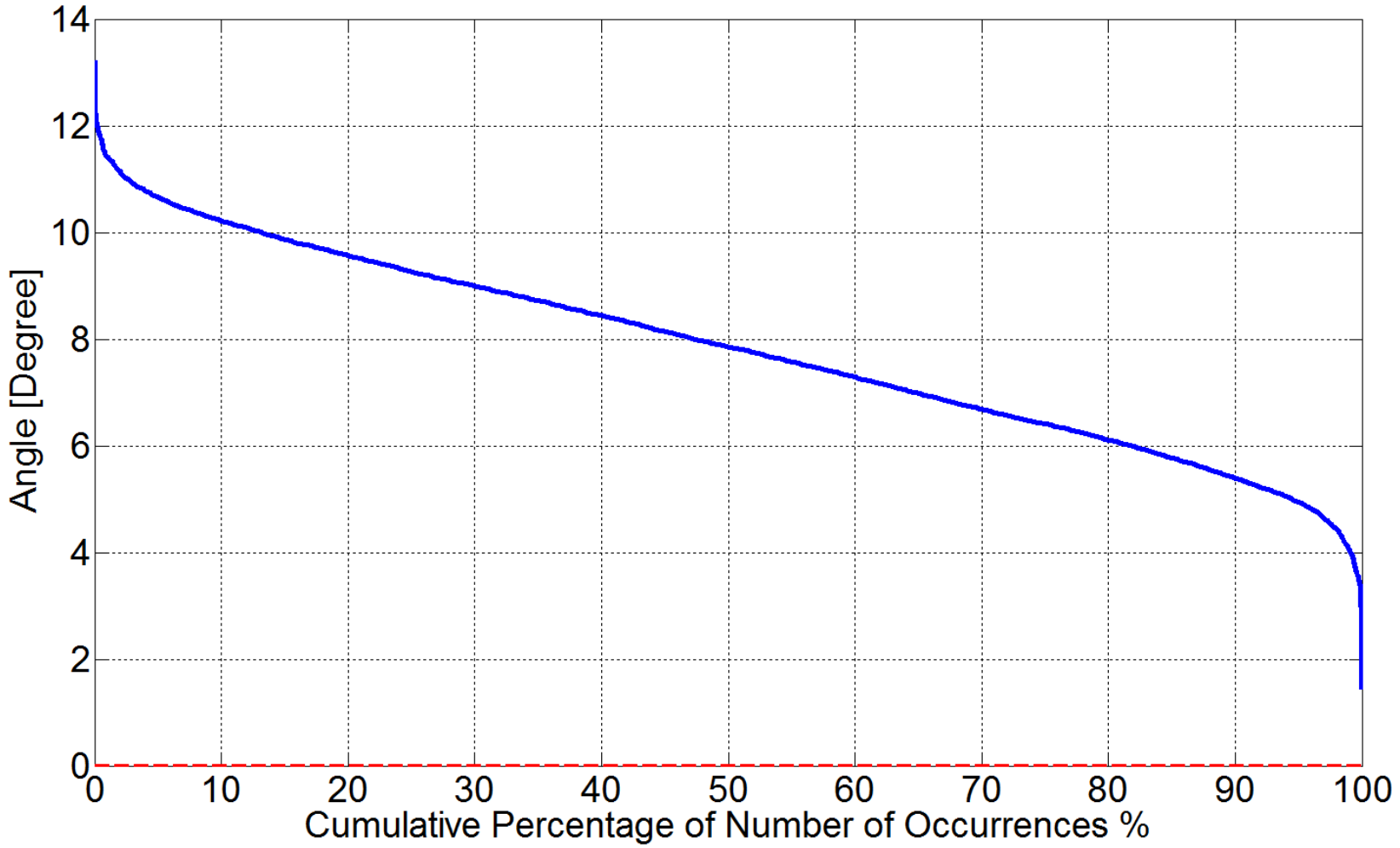
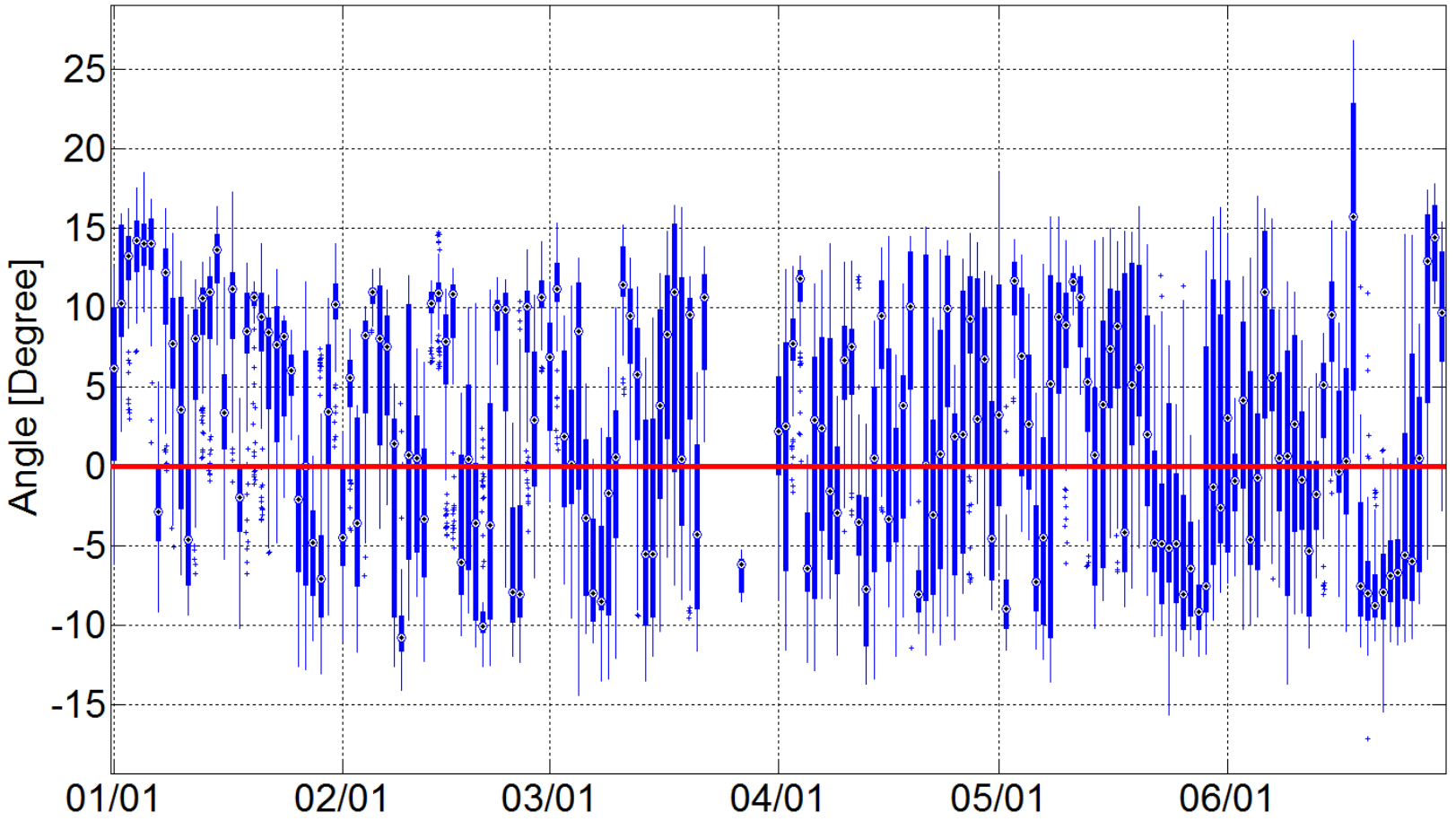


FarWest 7-FarWest 9



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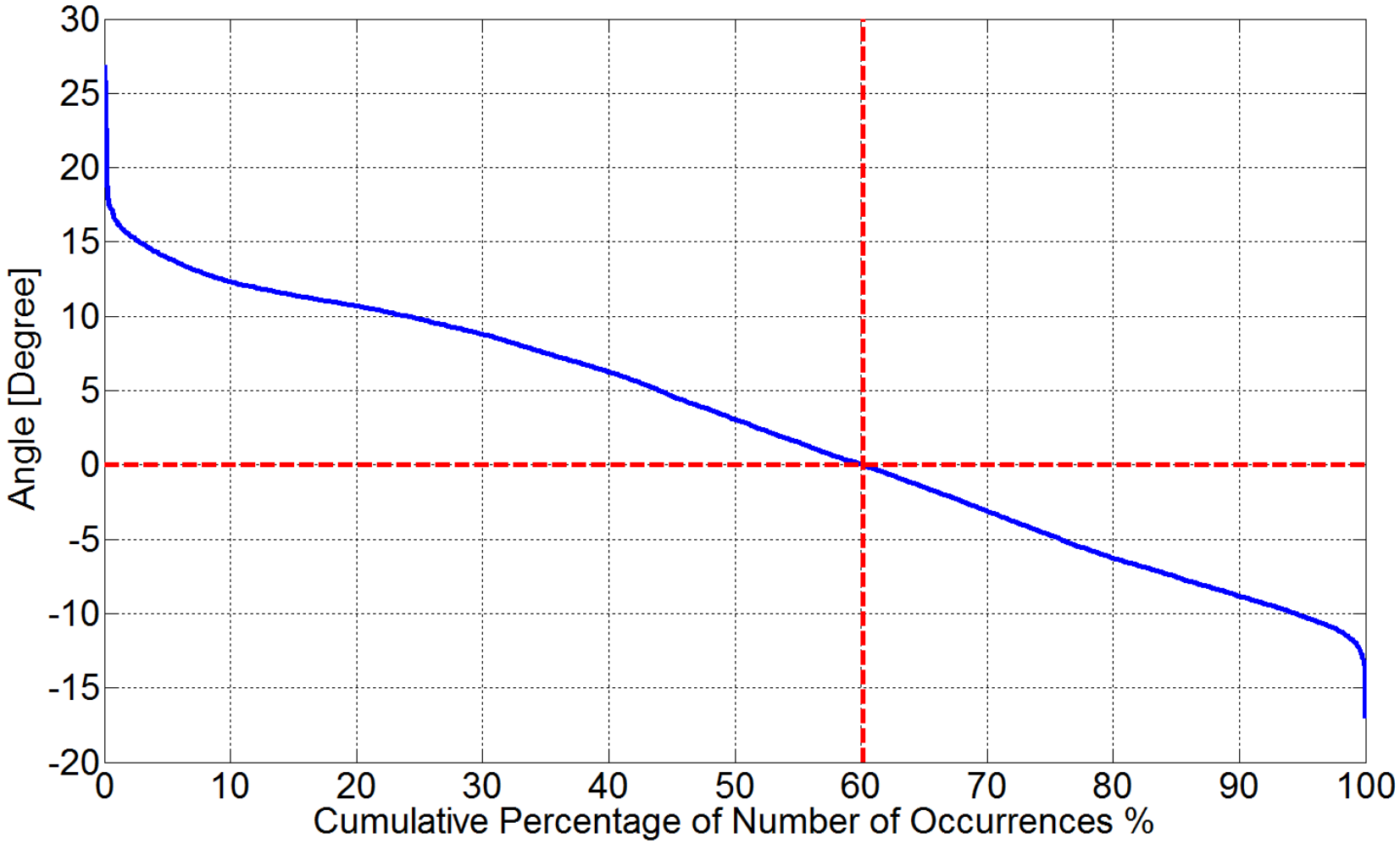
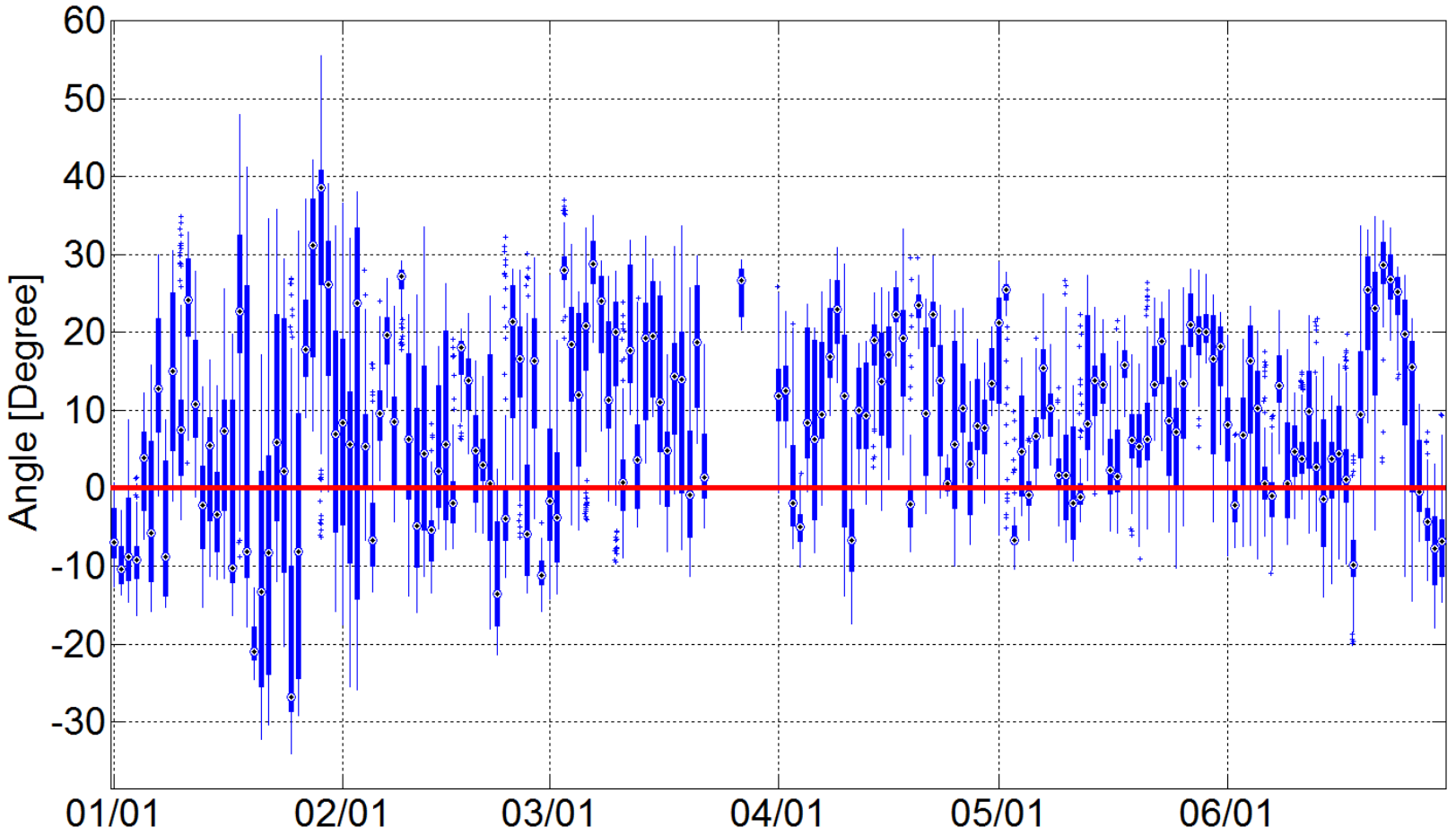
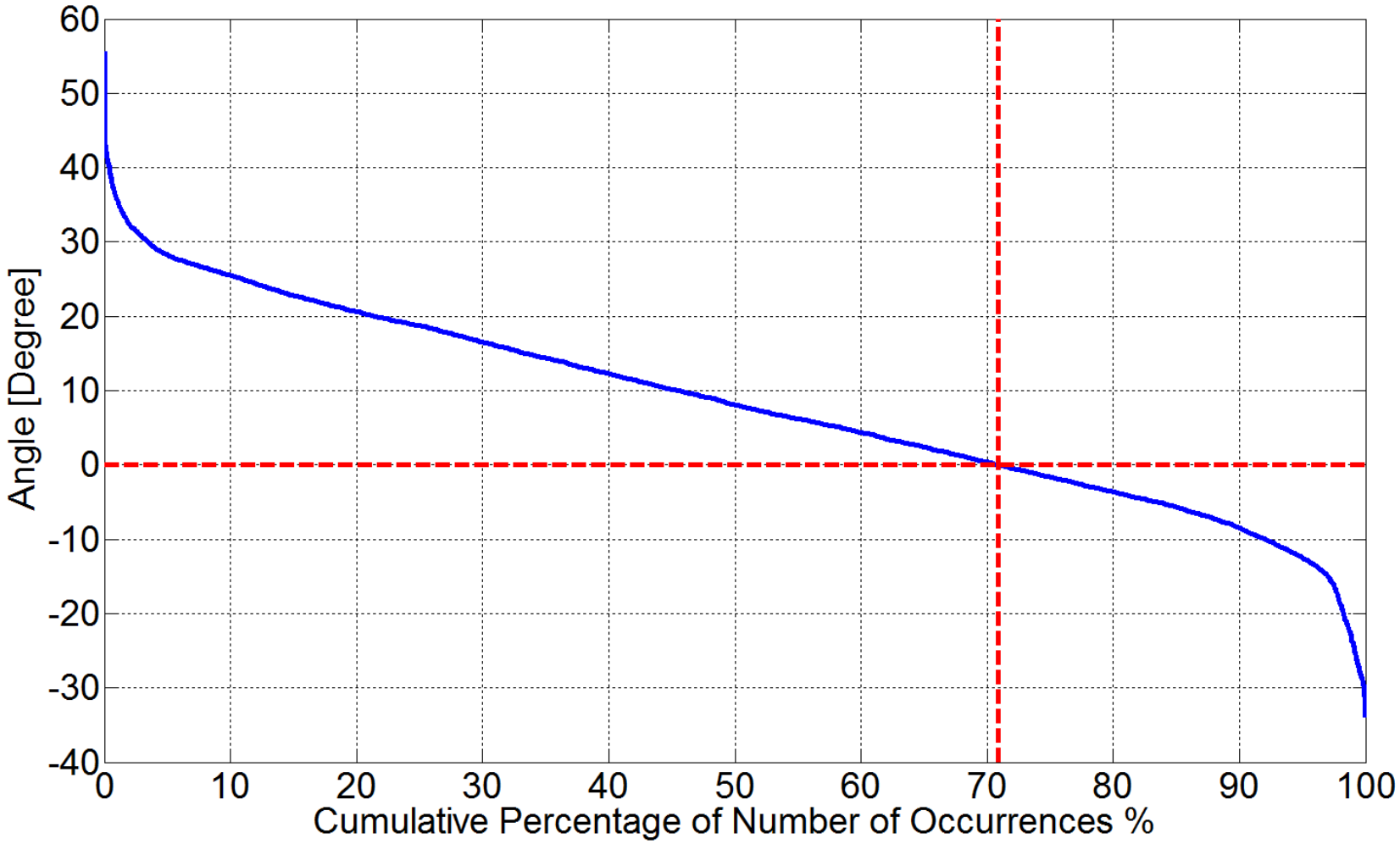


FarWest 7-North 7



FarWest 7-North 7



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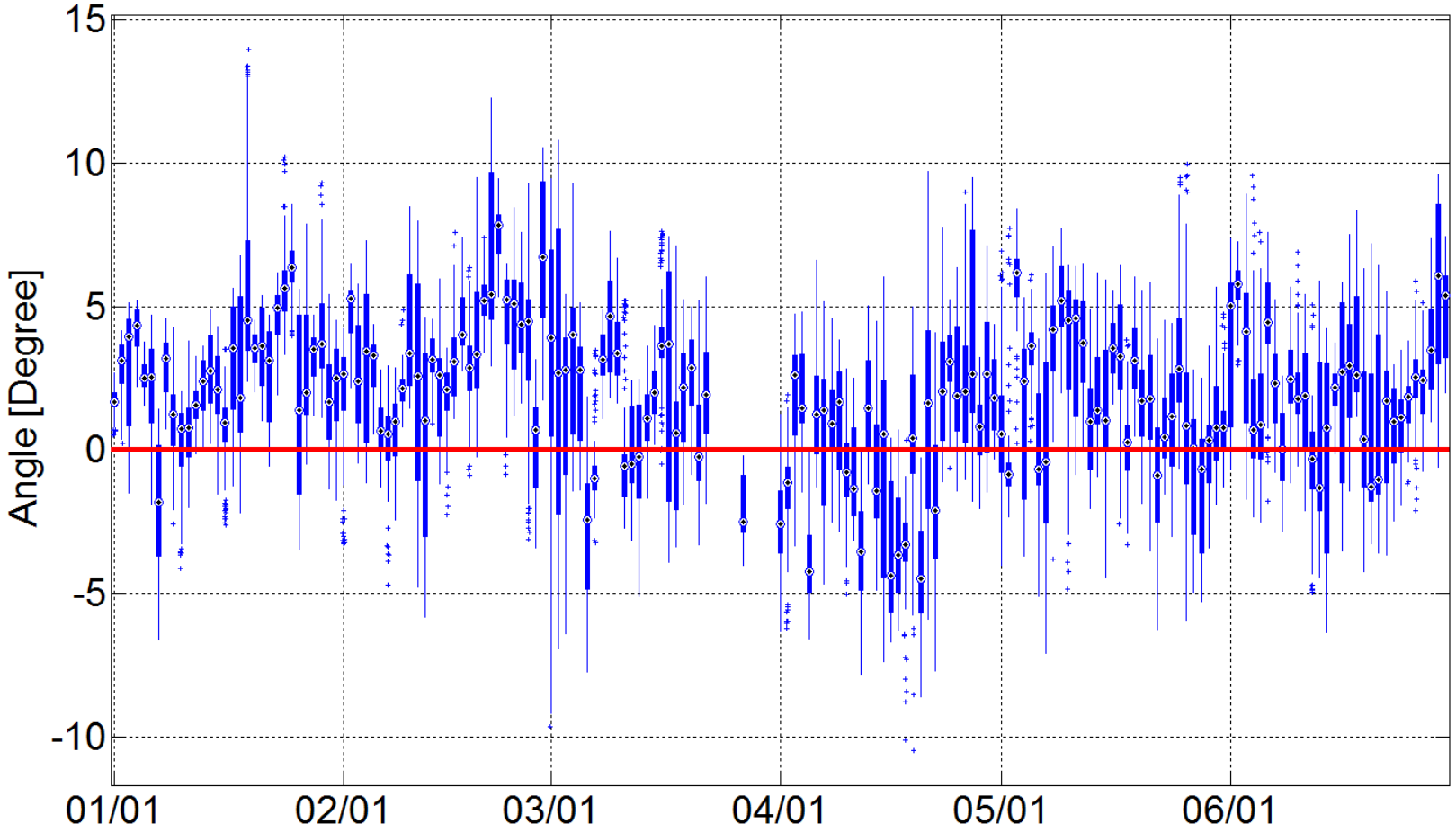
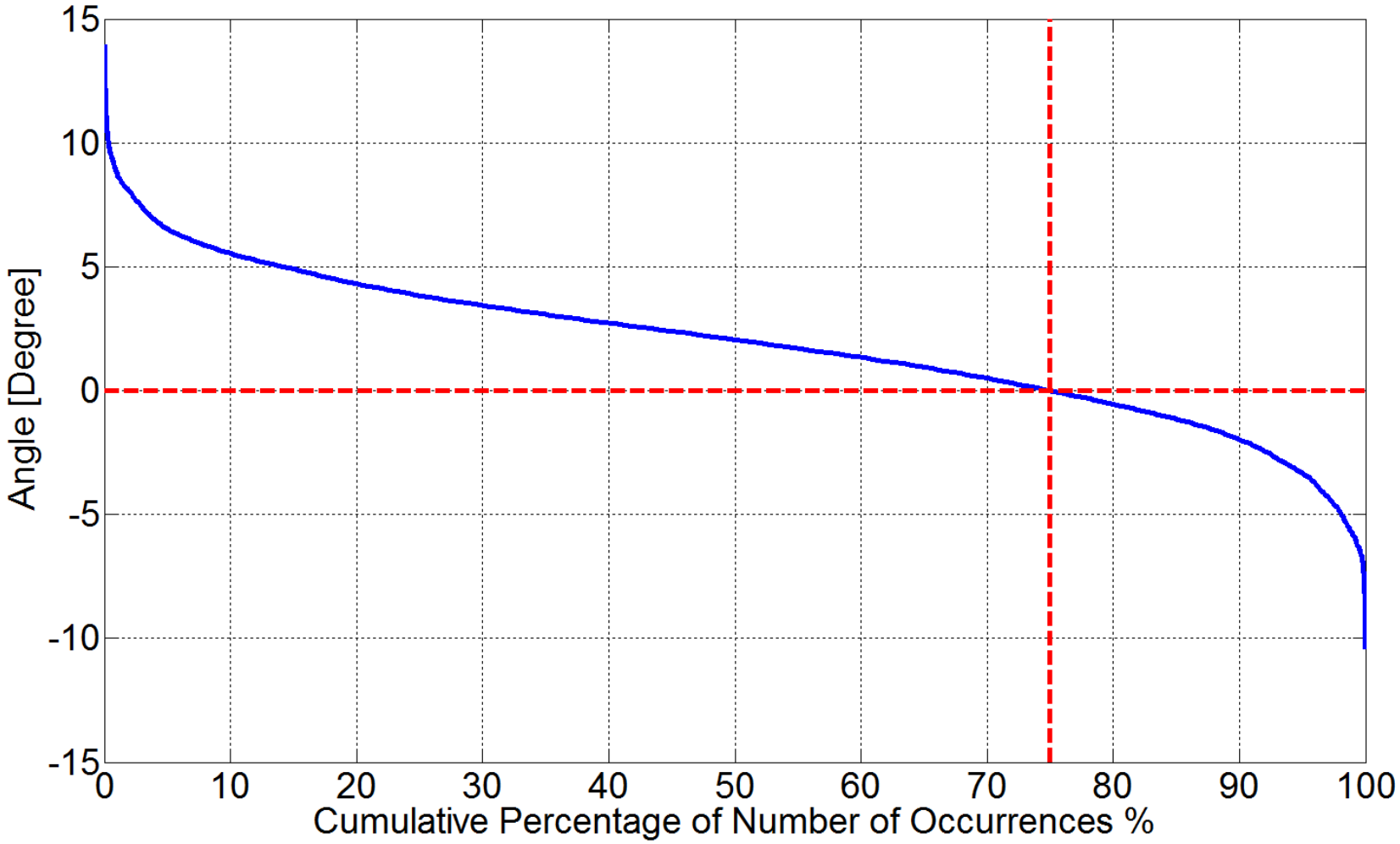


West 9*-FarWest 7



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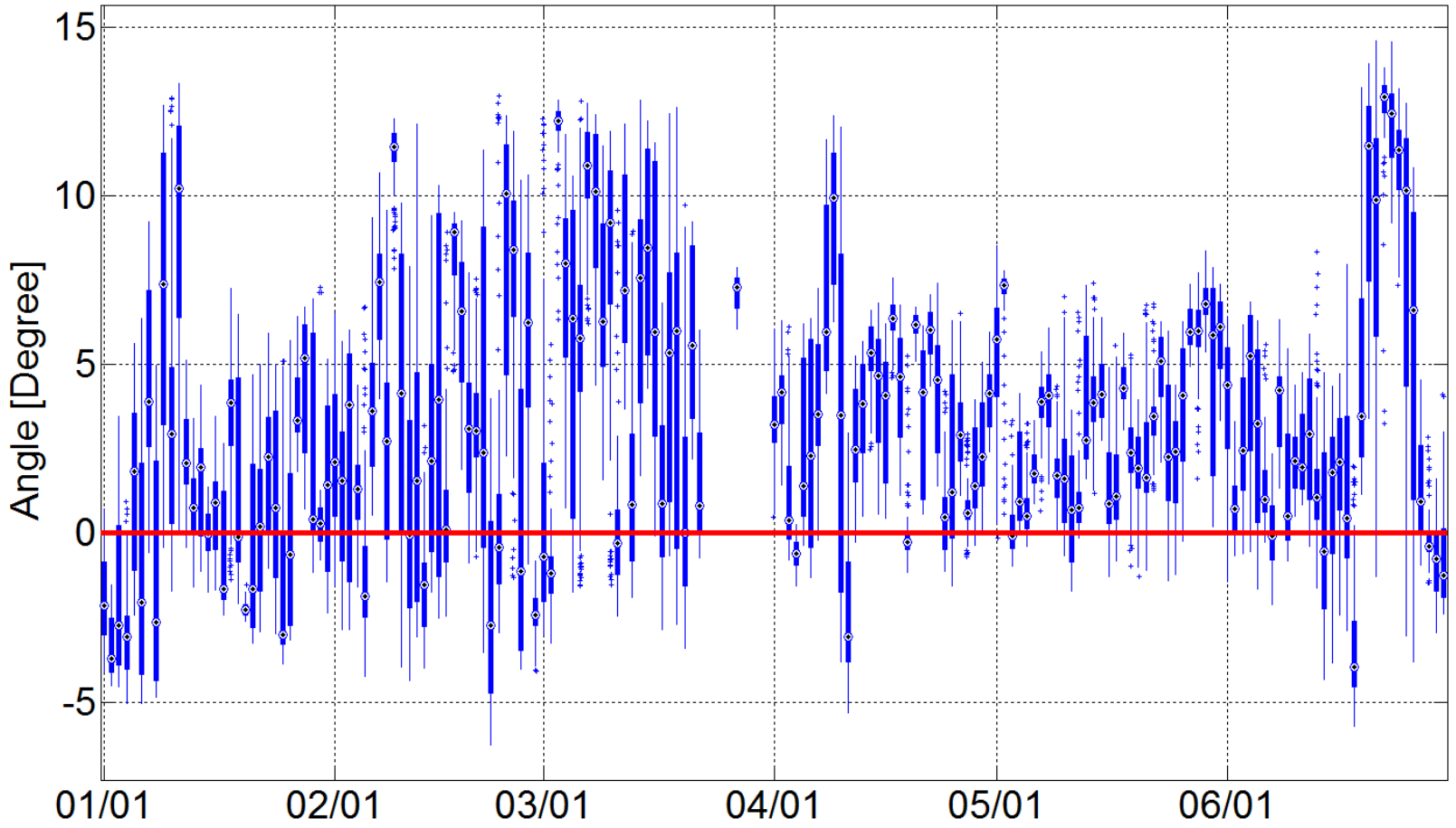
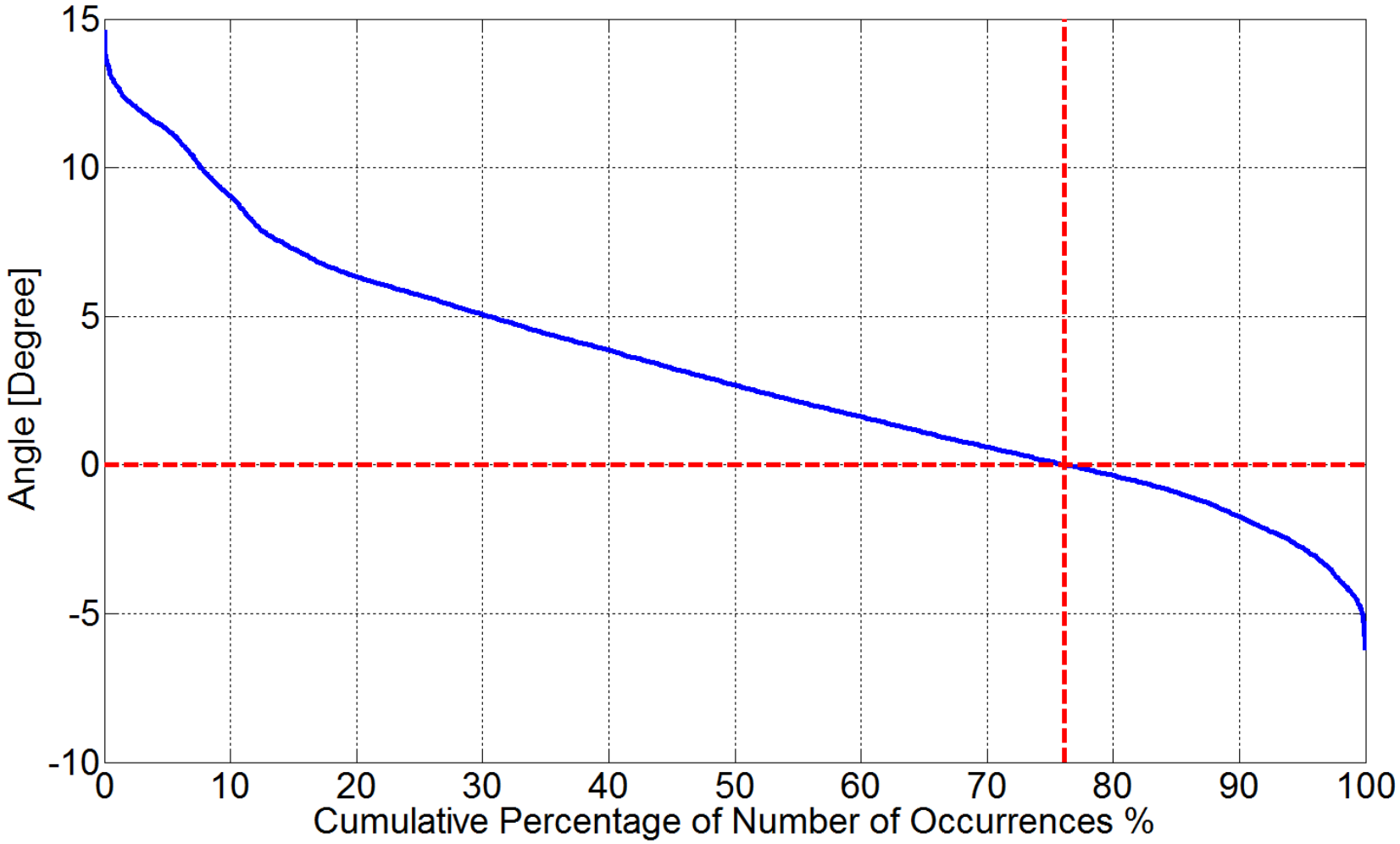


West 9*-West 1*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10
5
0
-5
-10
Angle [Degree]
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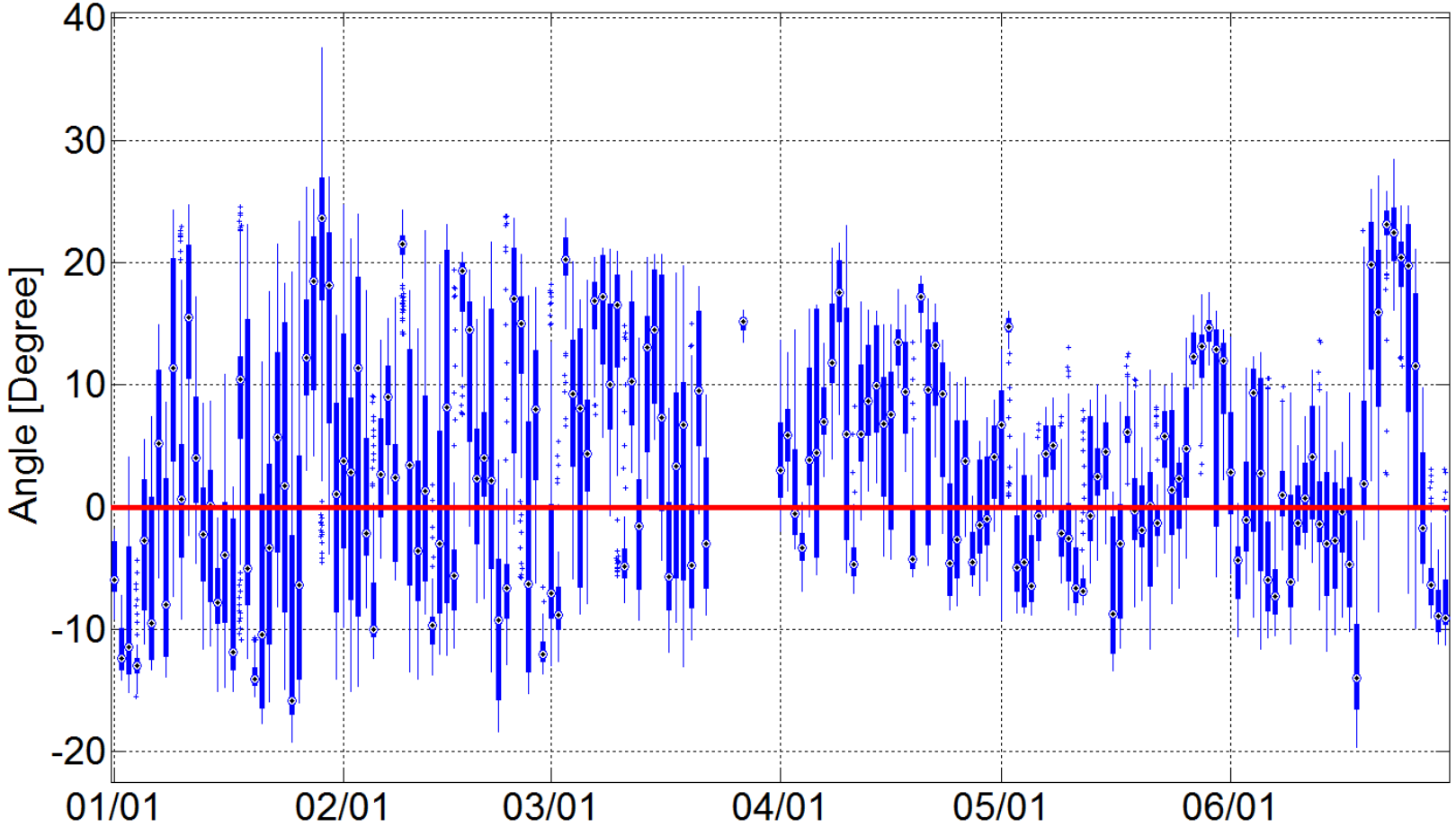
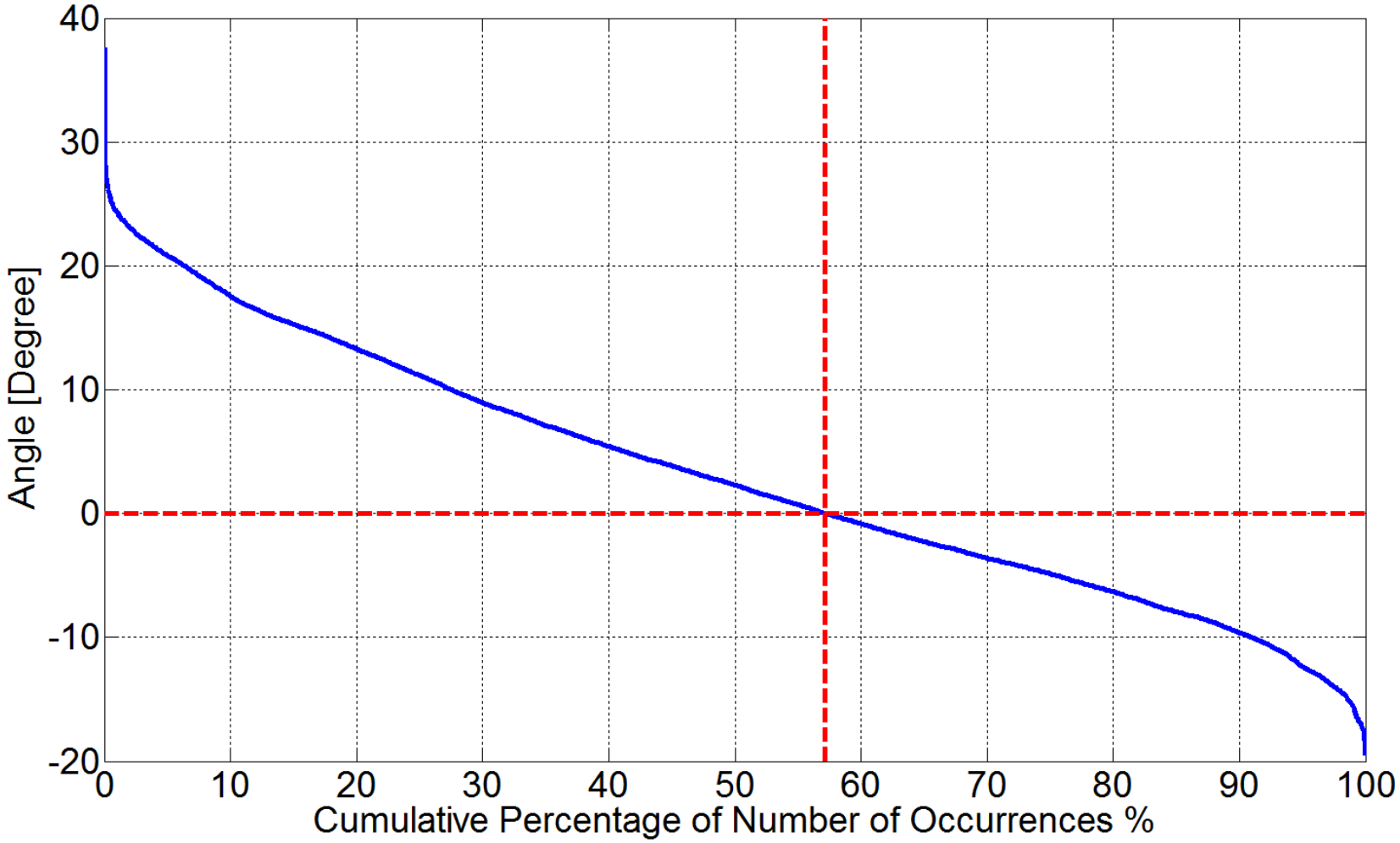
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

West 9*-North 1



West 9*-North 1



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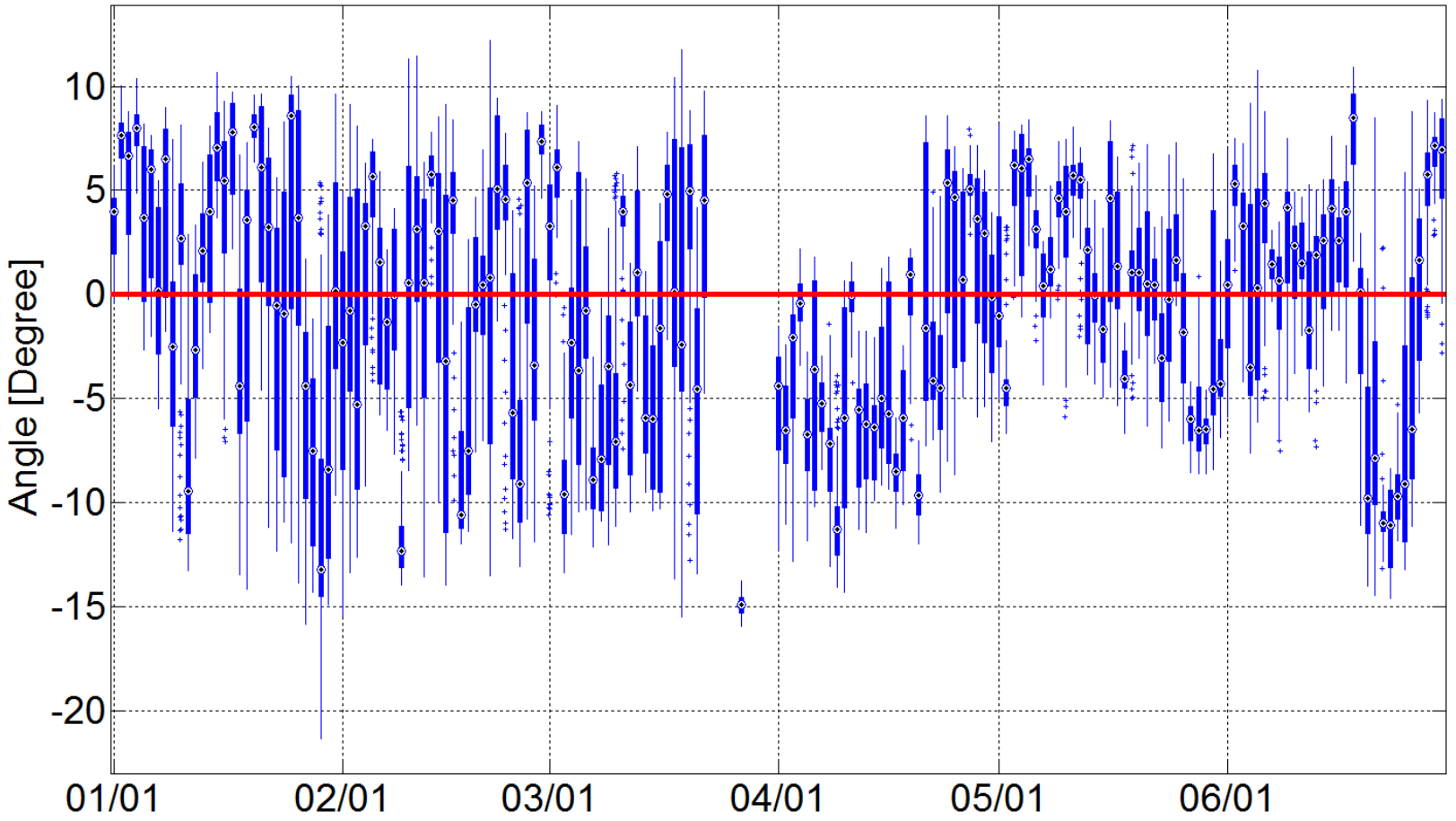
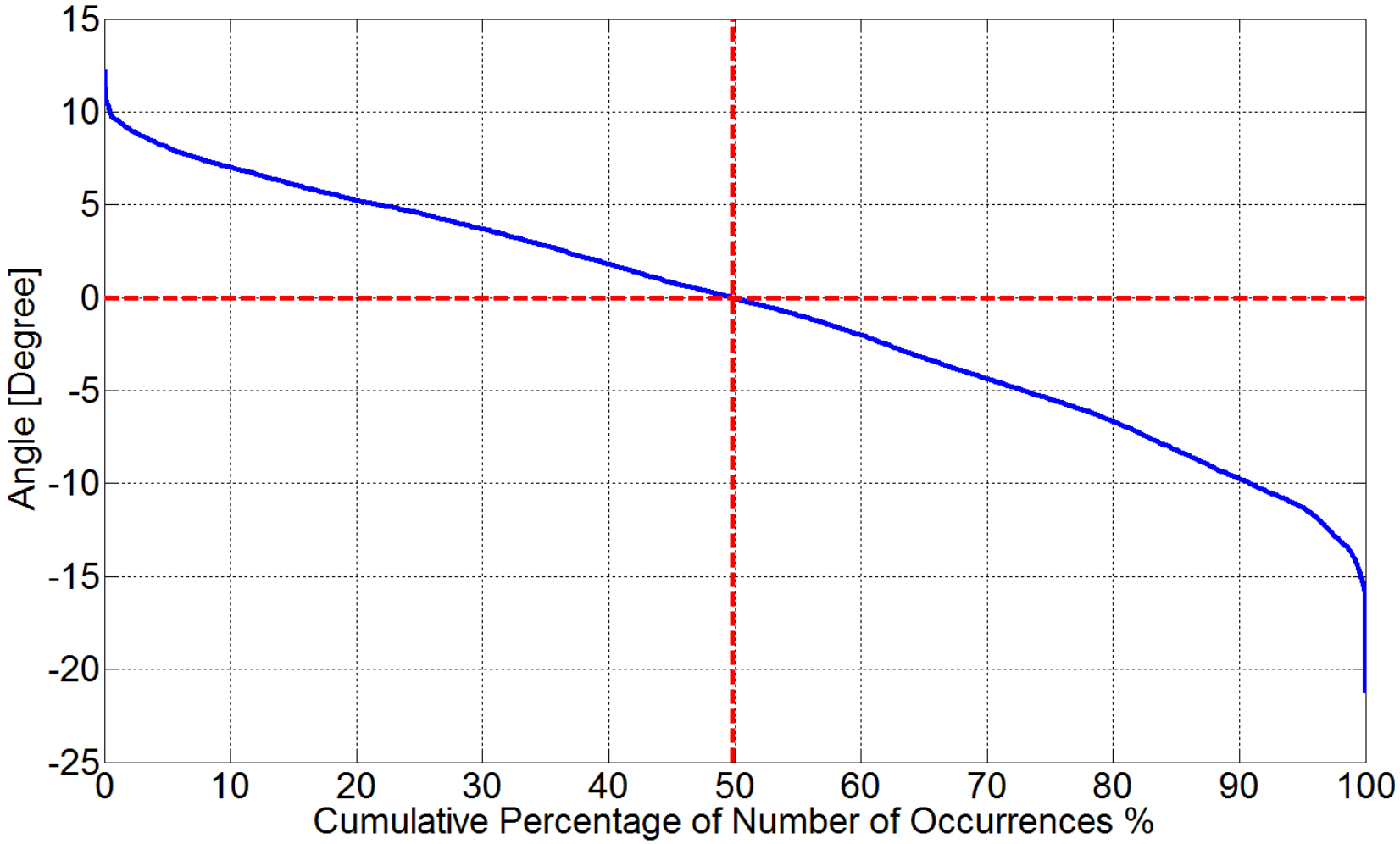


West 14-West 5*



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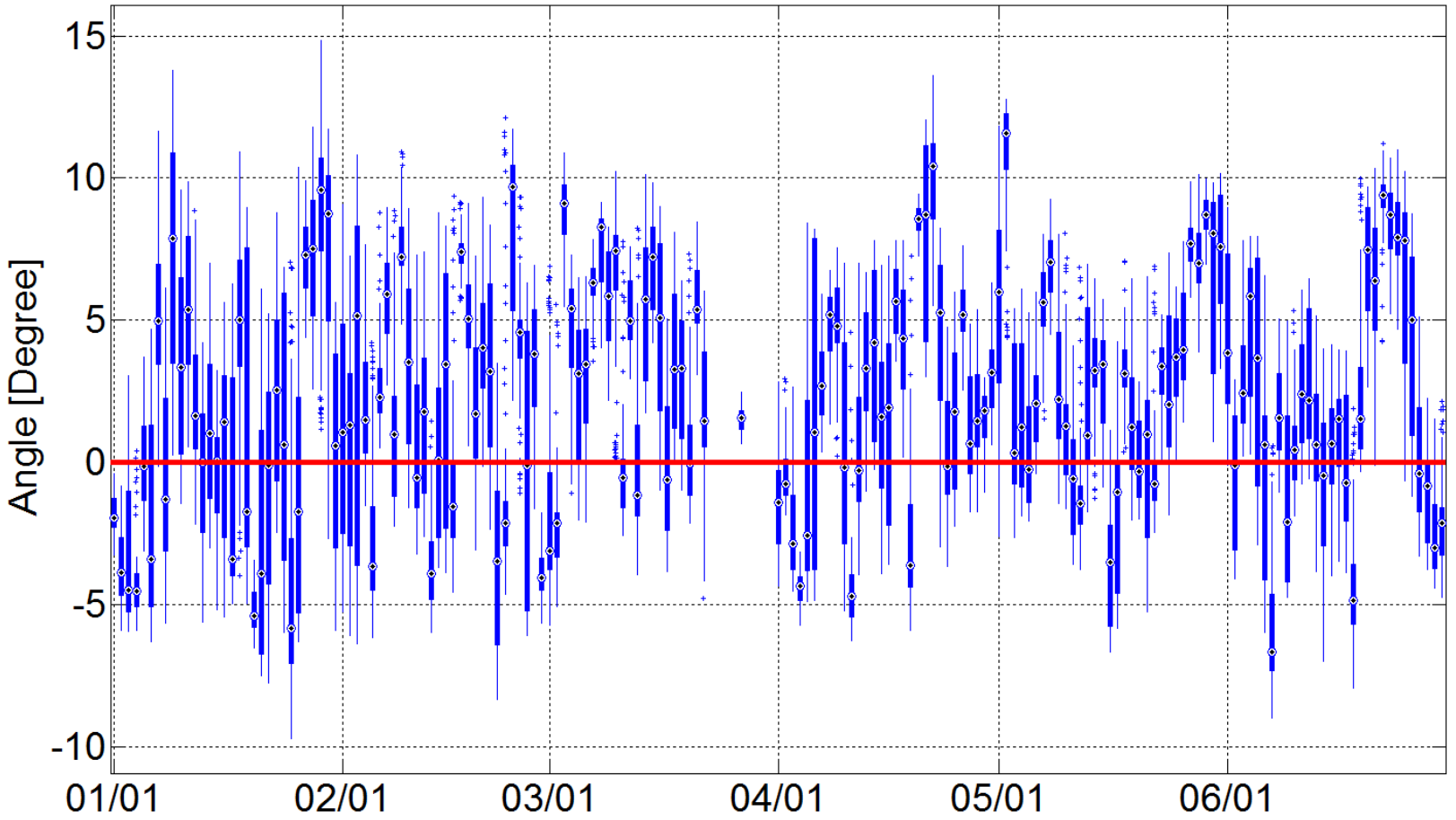

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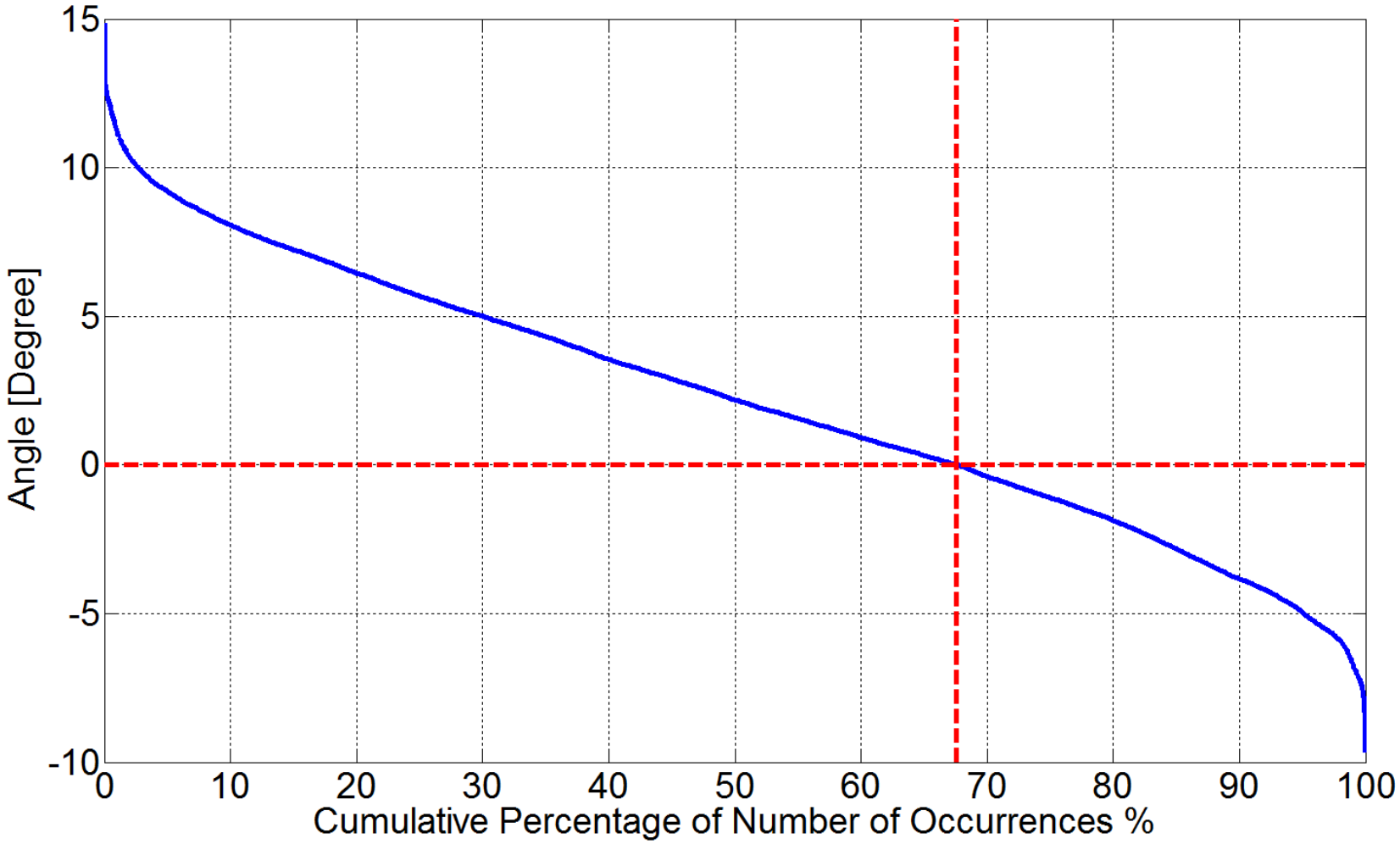

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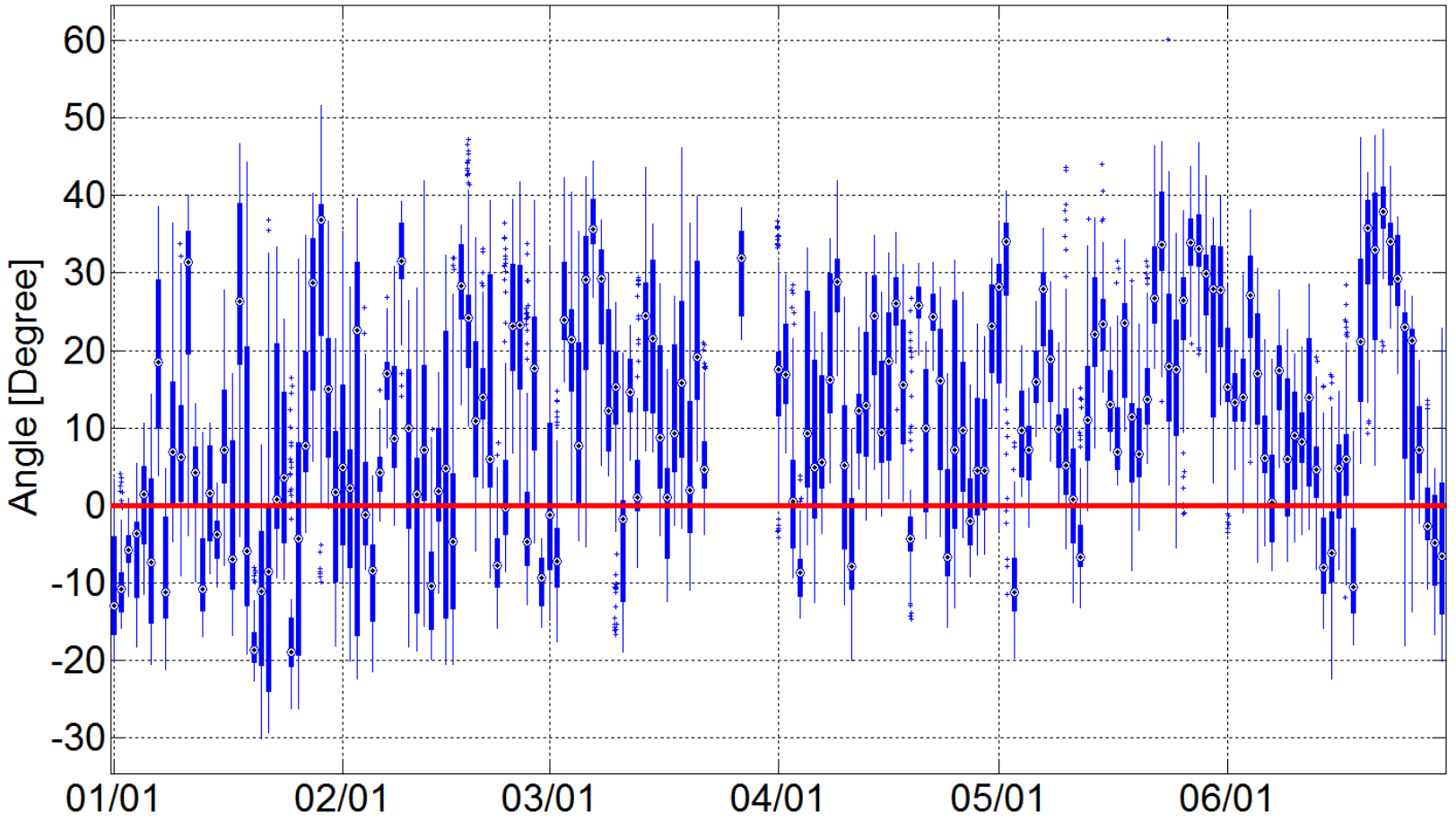
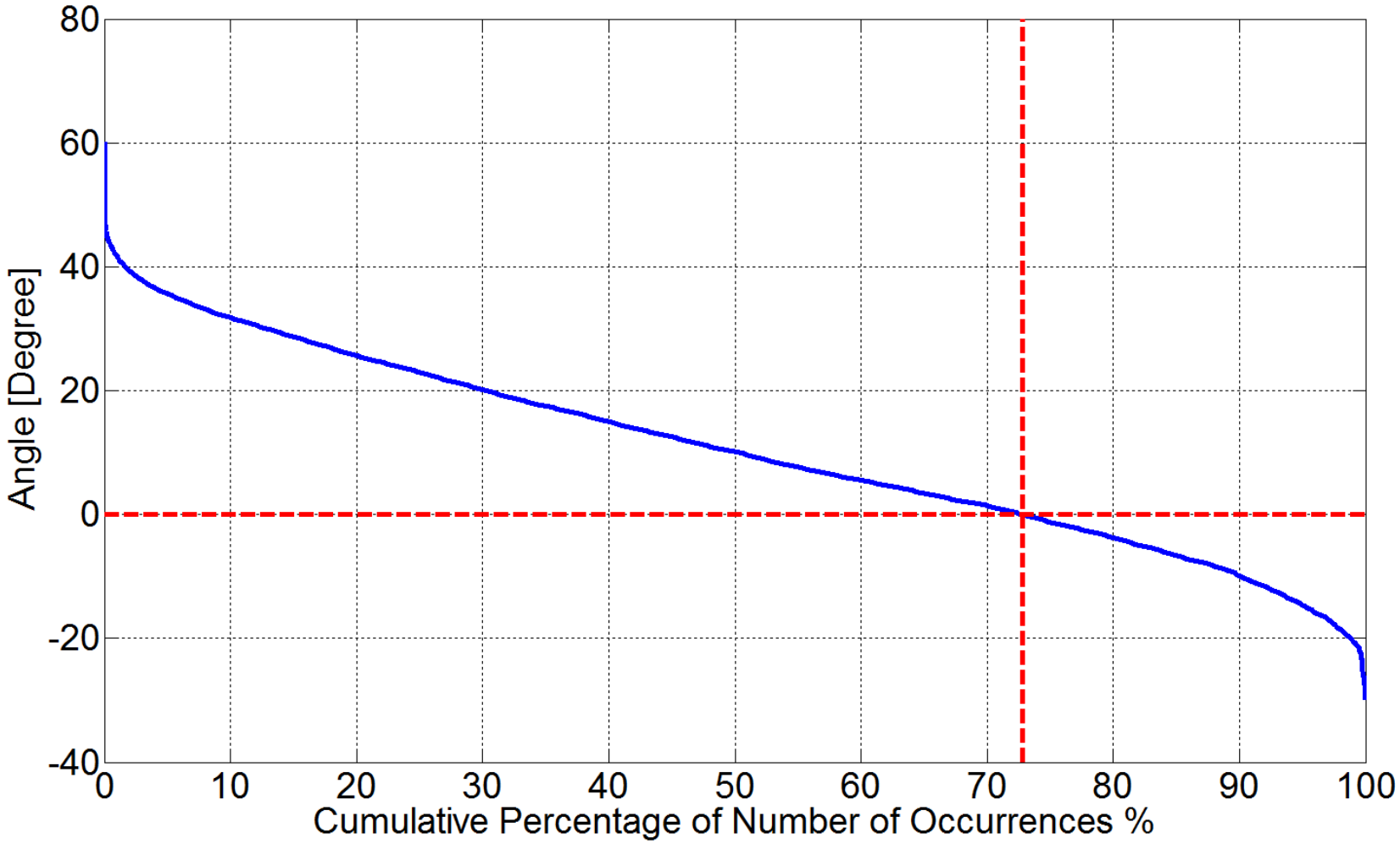
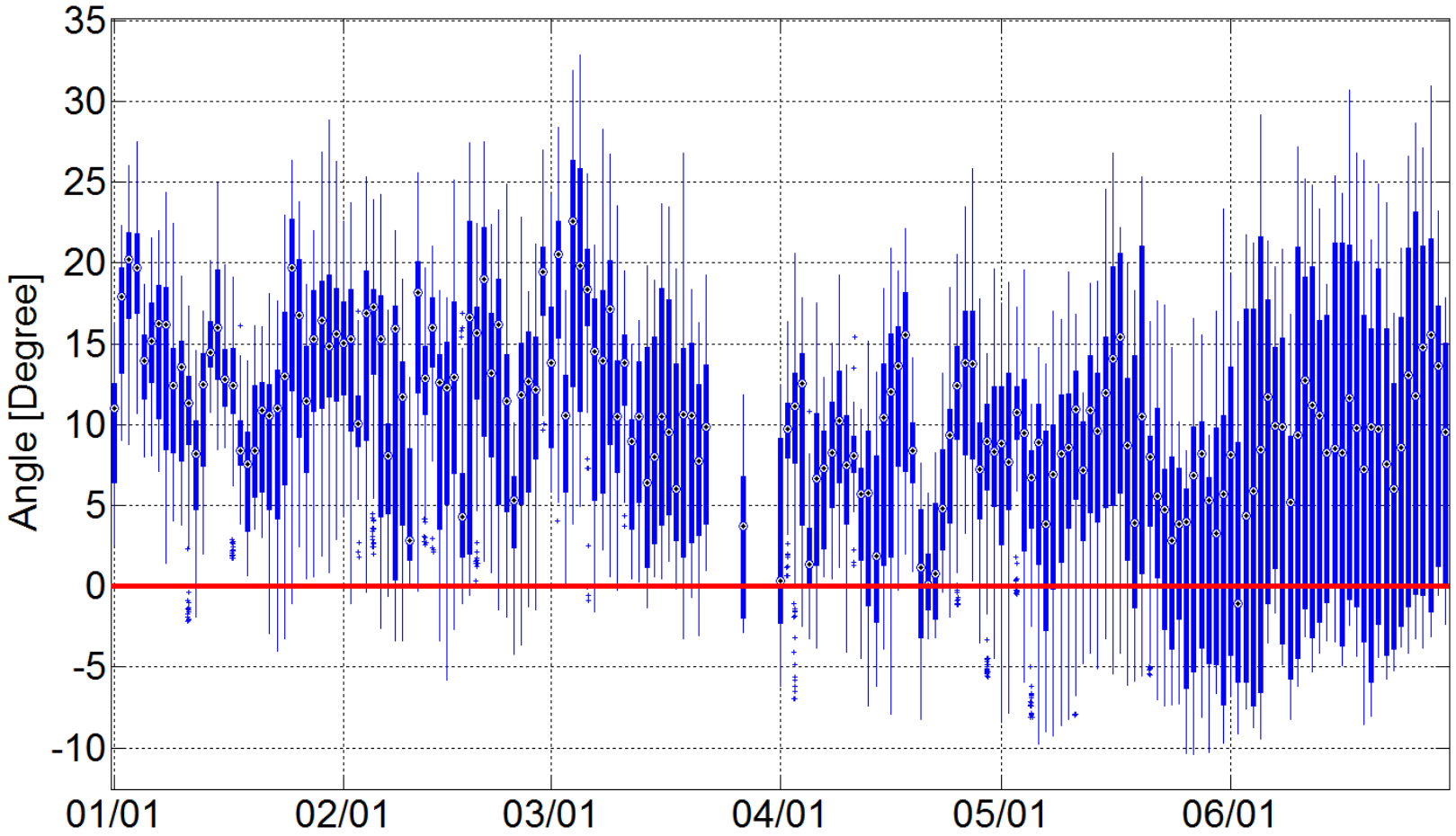


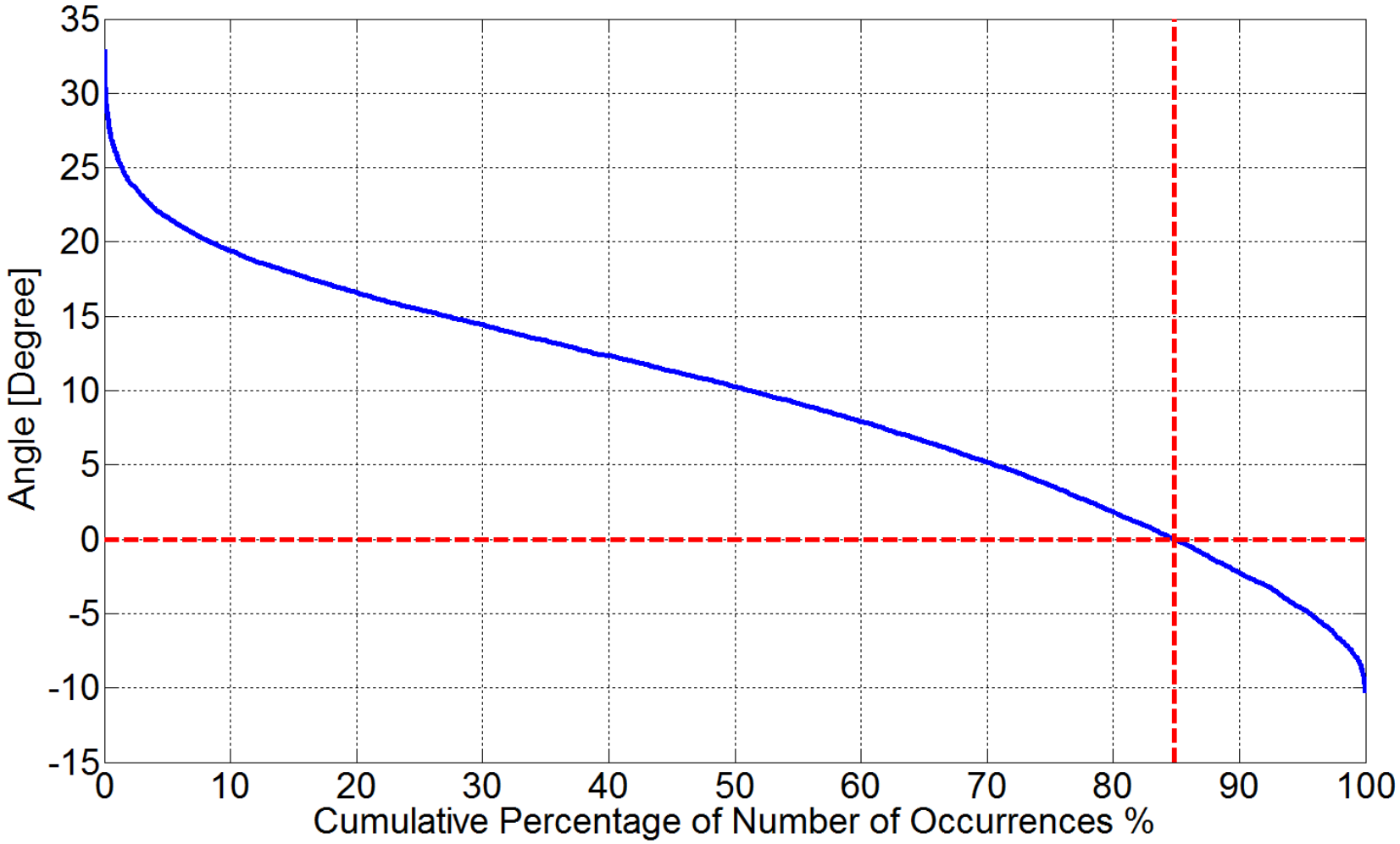
FarWest 9-West 4



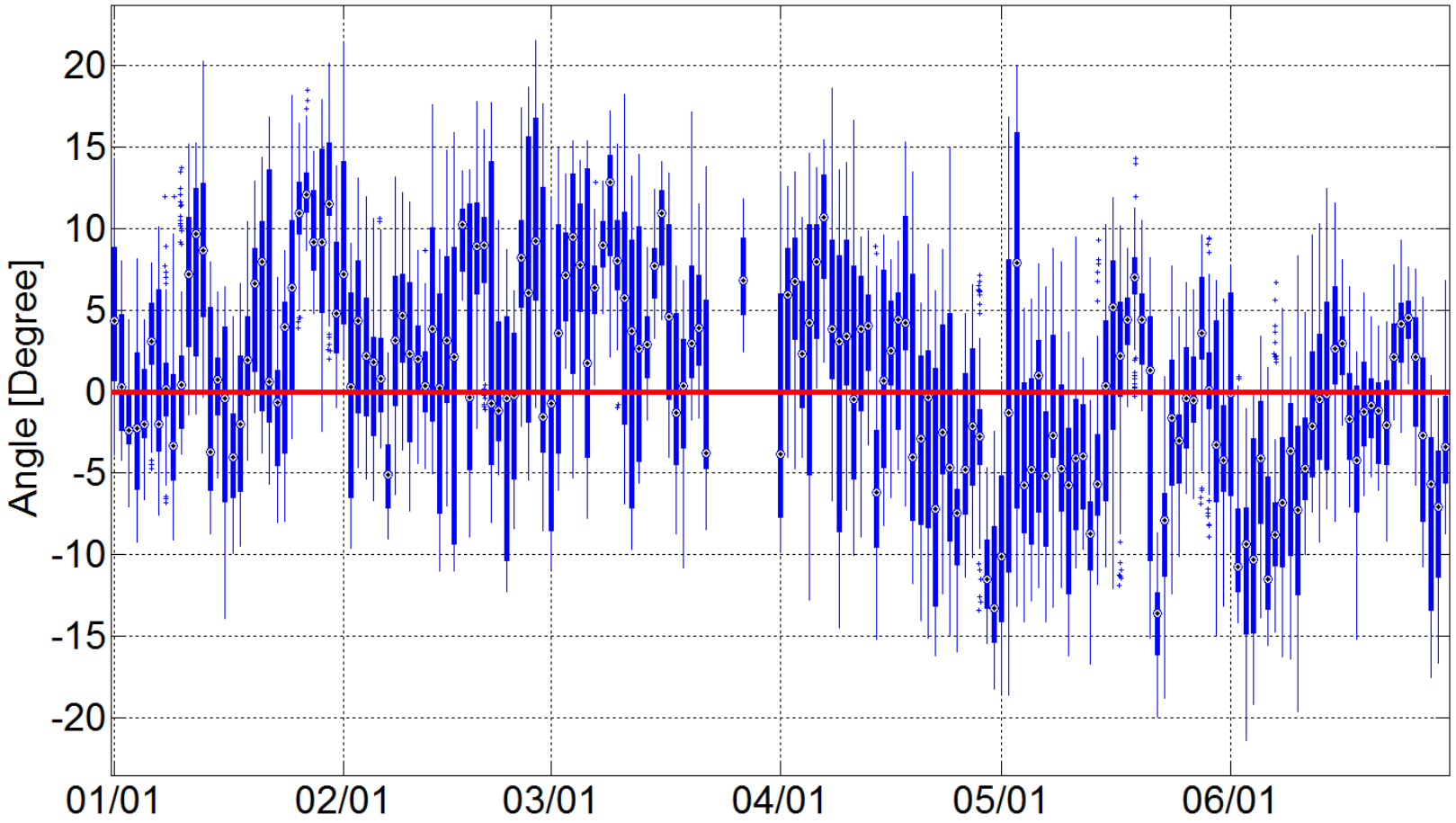
Coast 1-South 10*



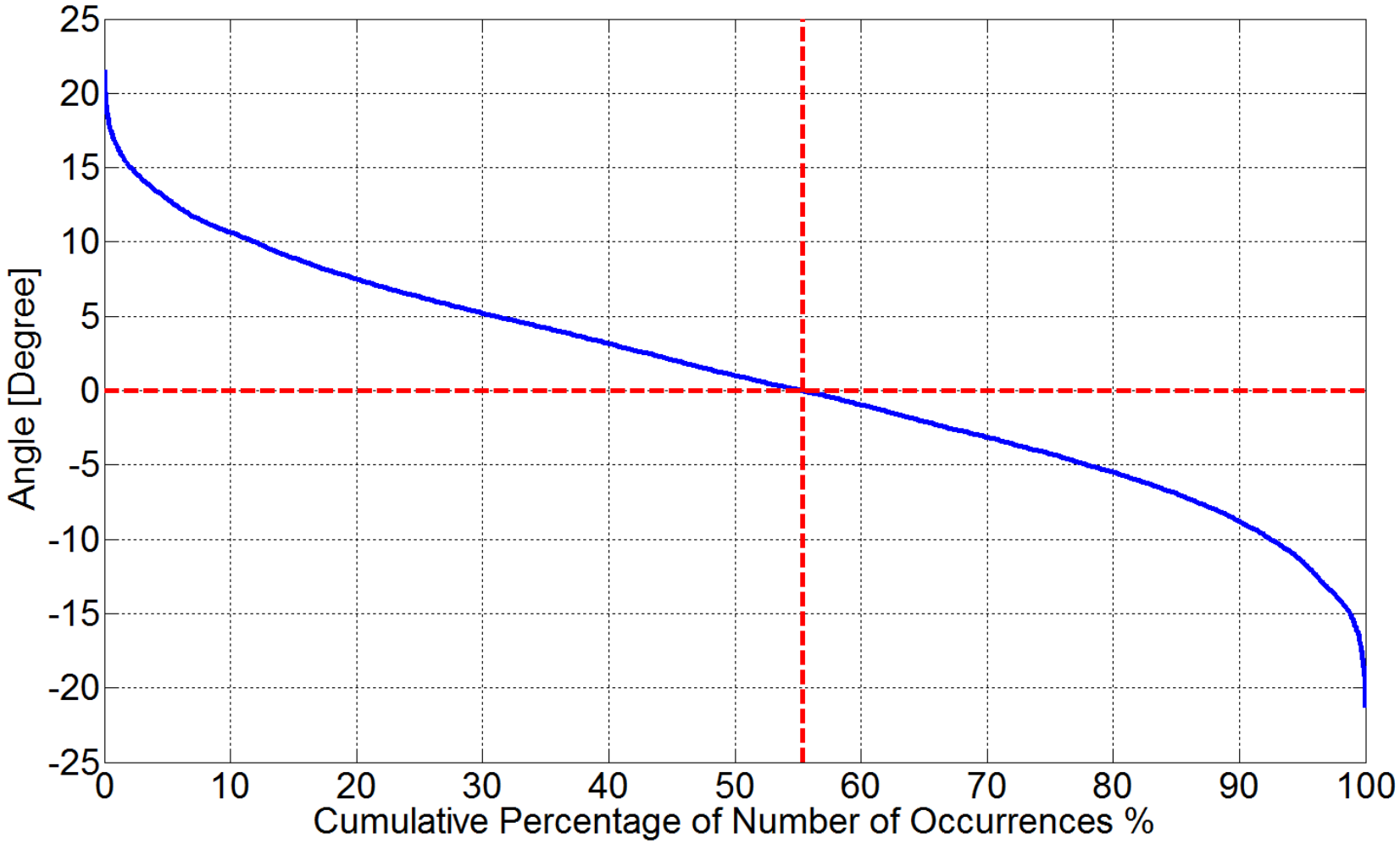
Coast 1-South 10*



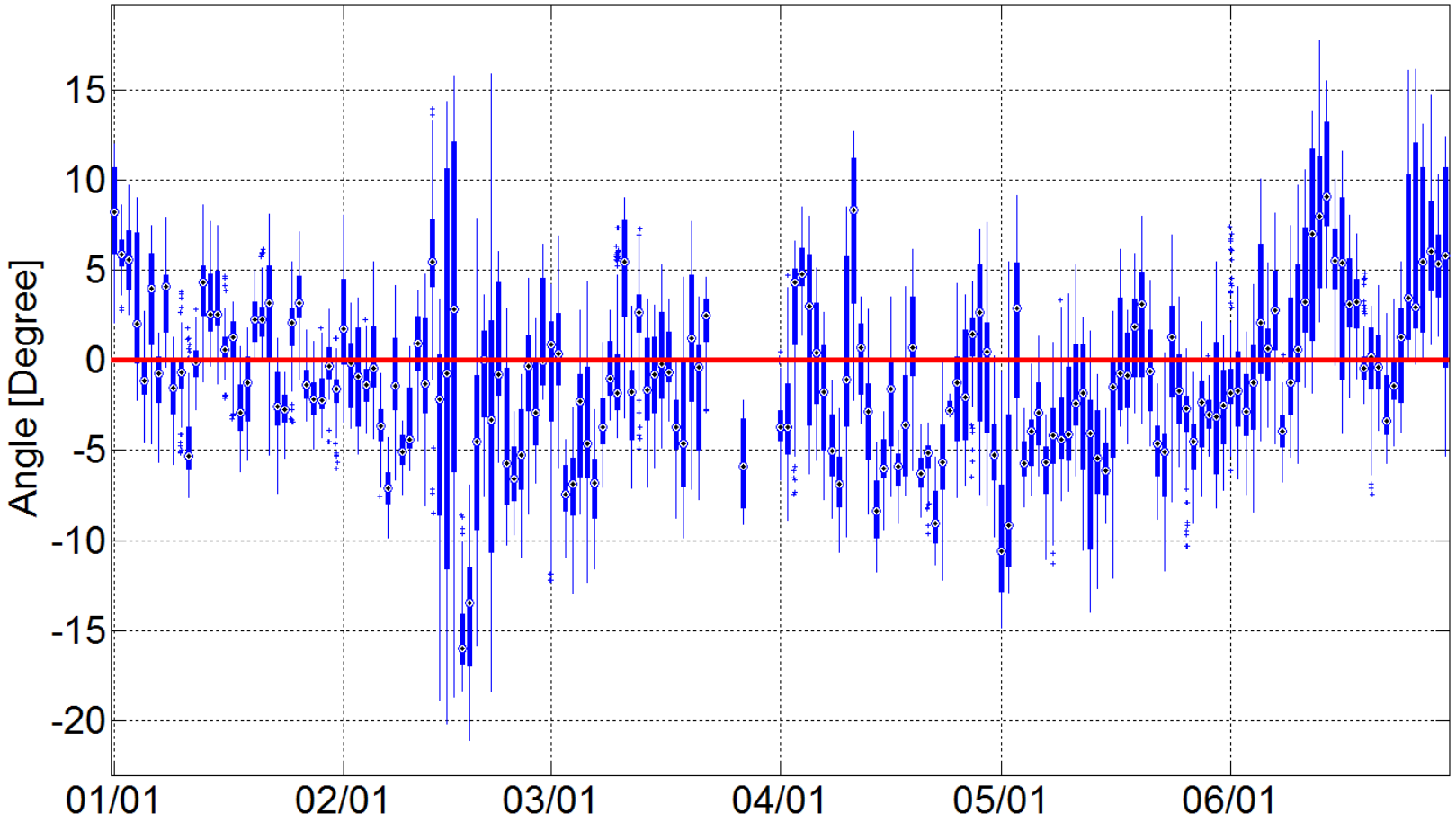
South 3*-South 11*



South 3*-South 11*



South 11*-North 7



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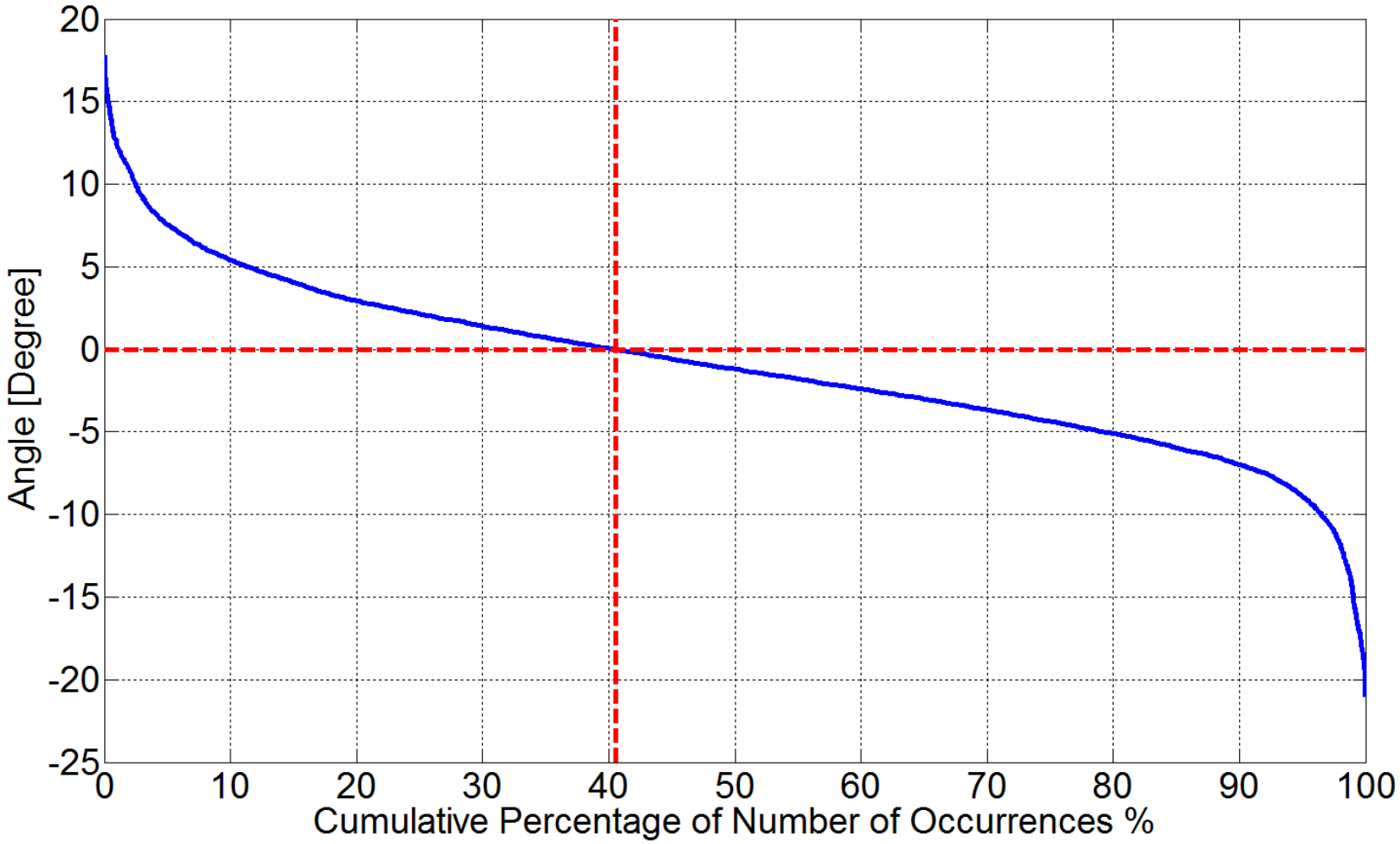

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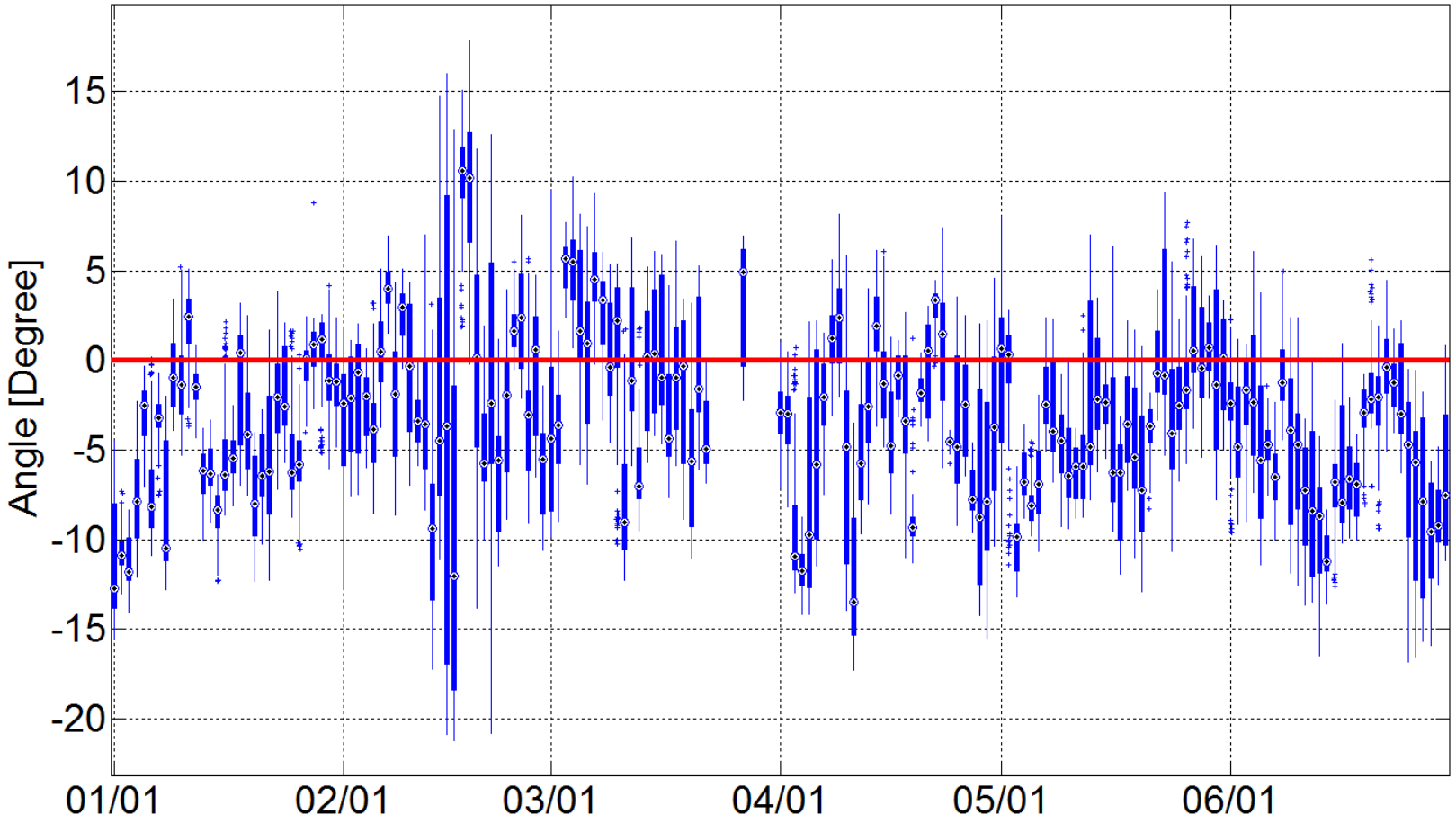
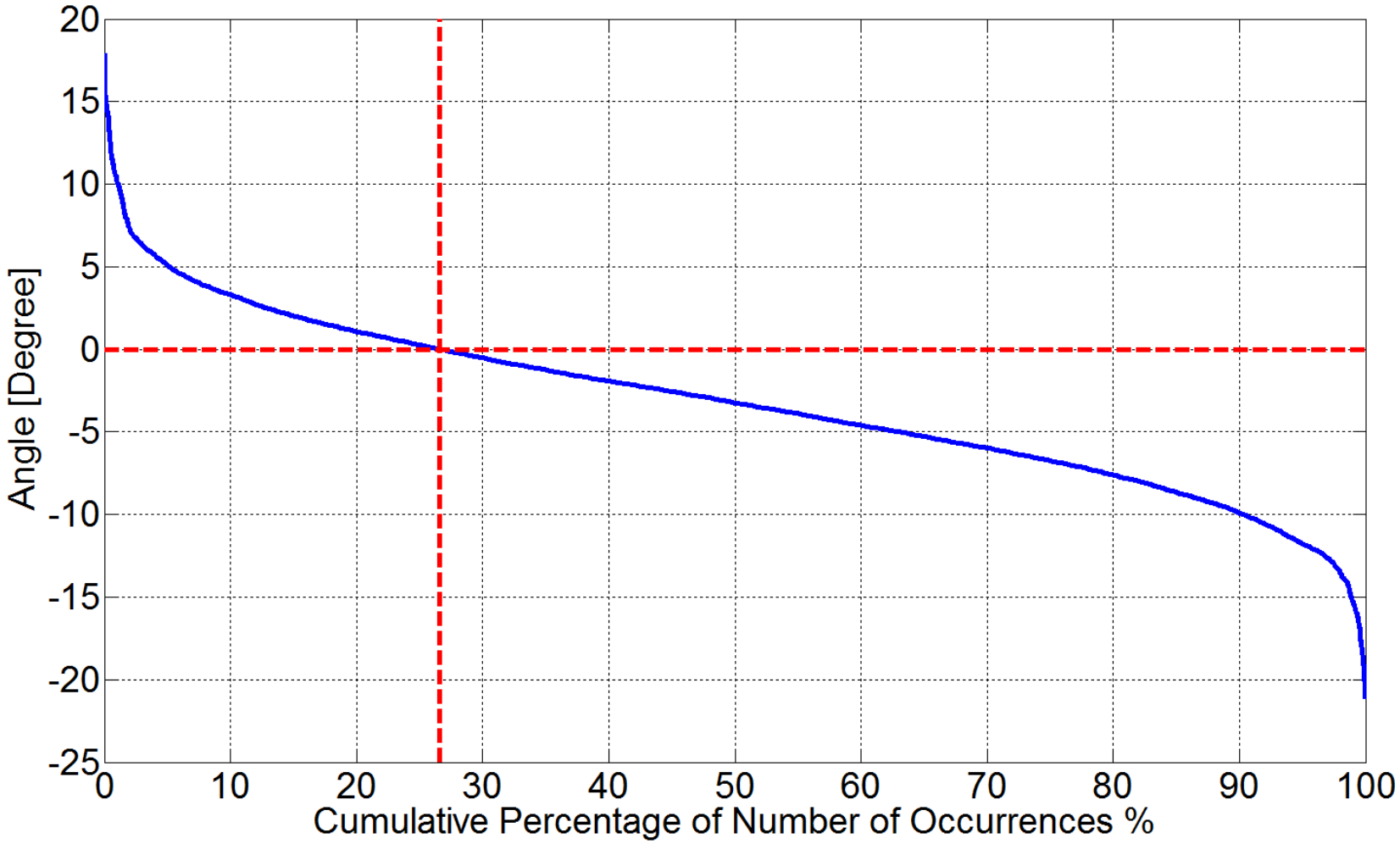


North 7-South 7*



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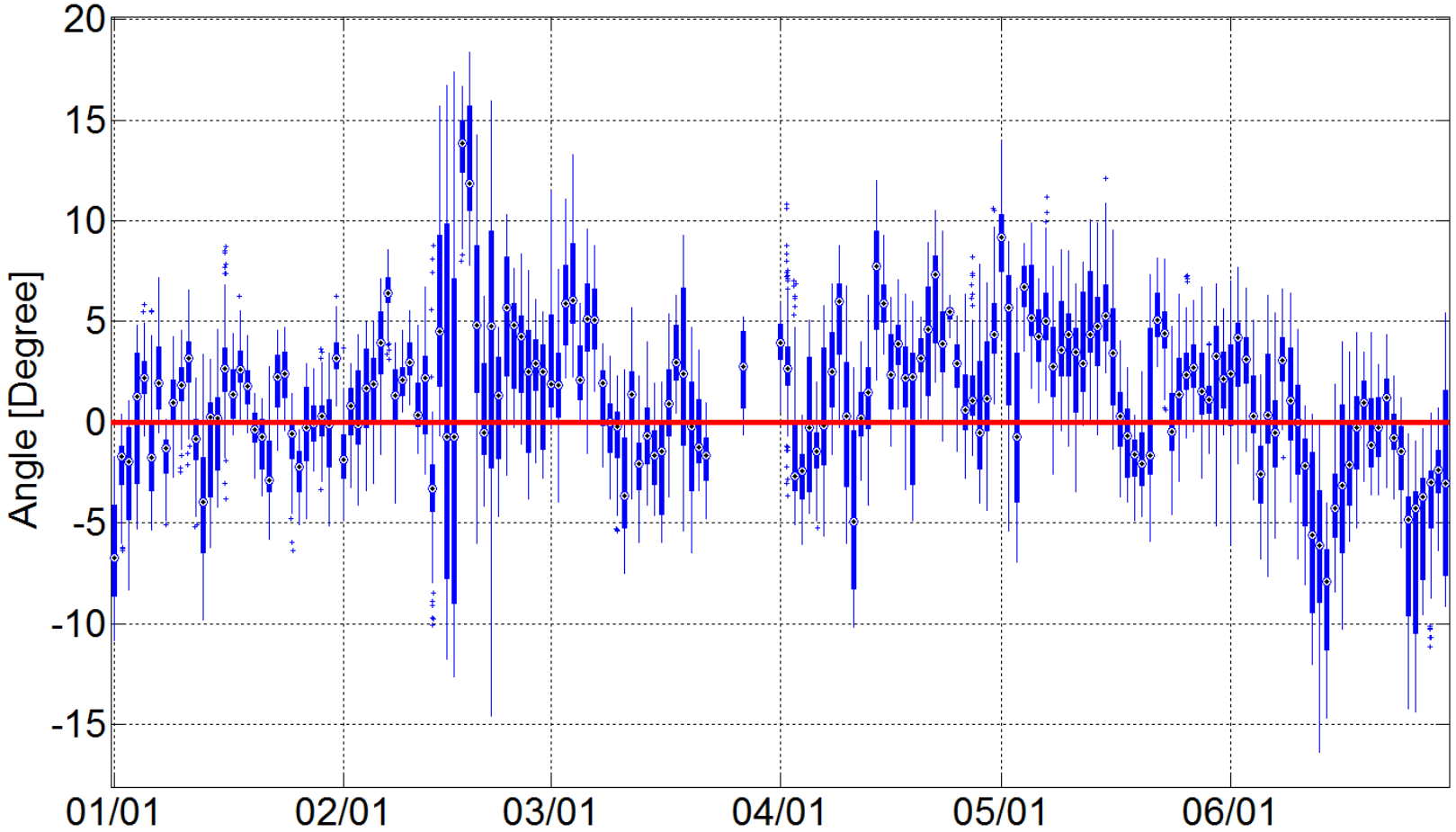

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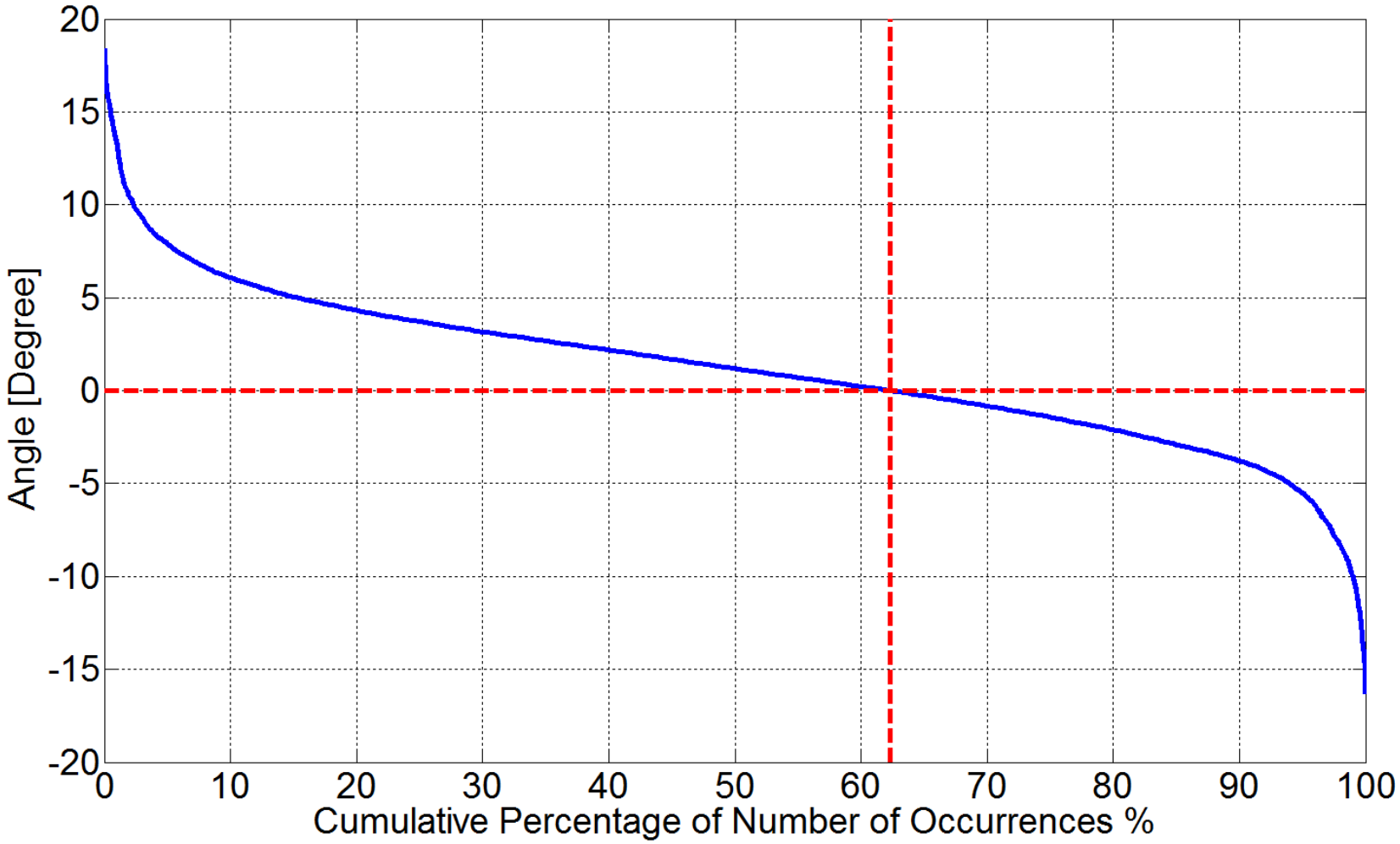

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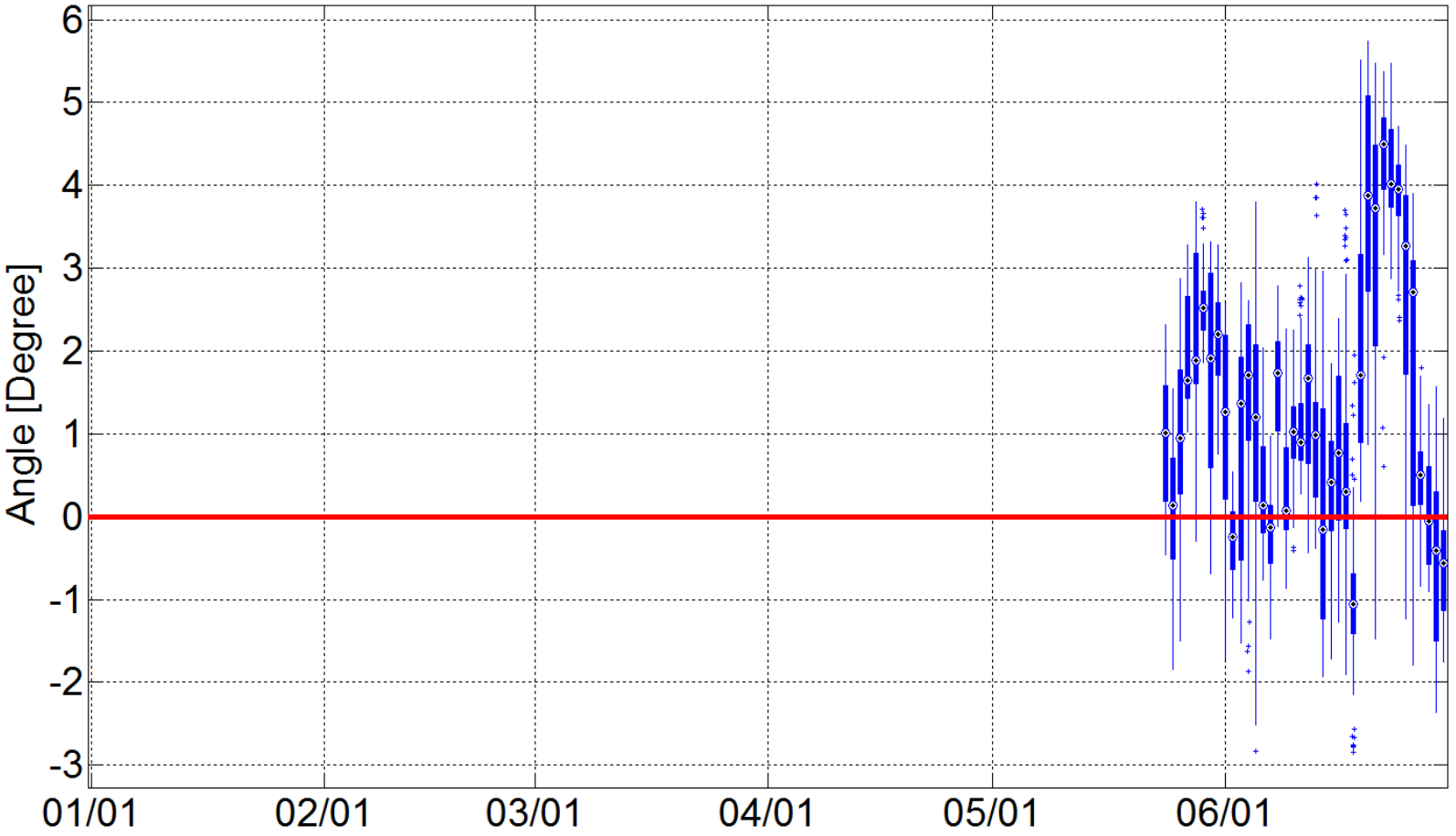
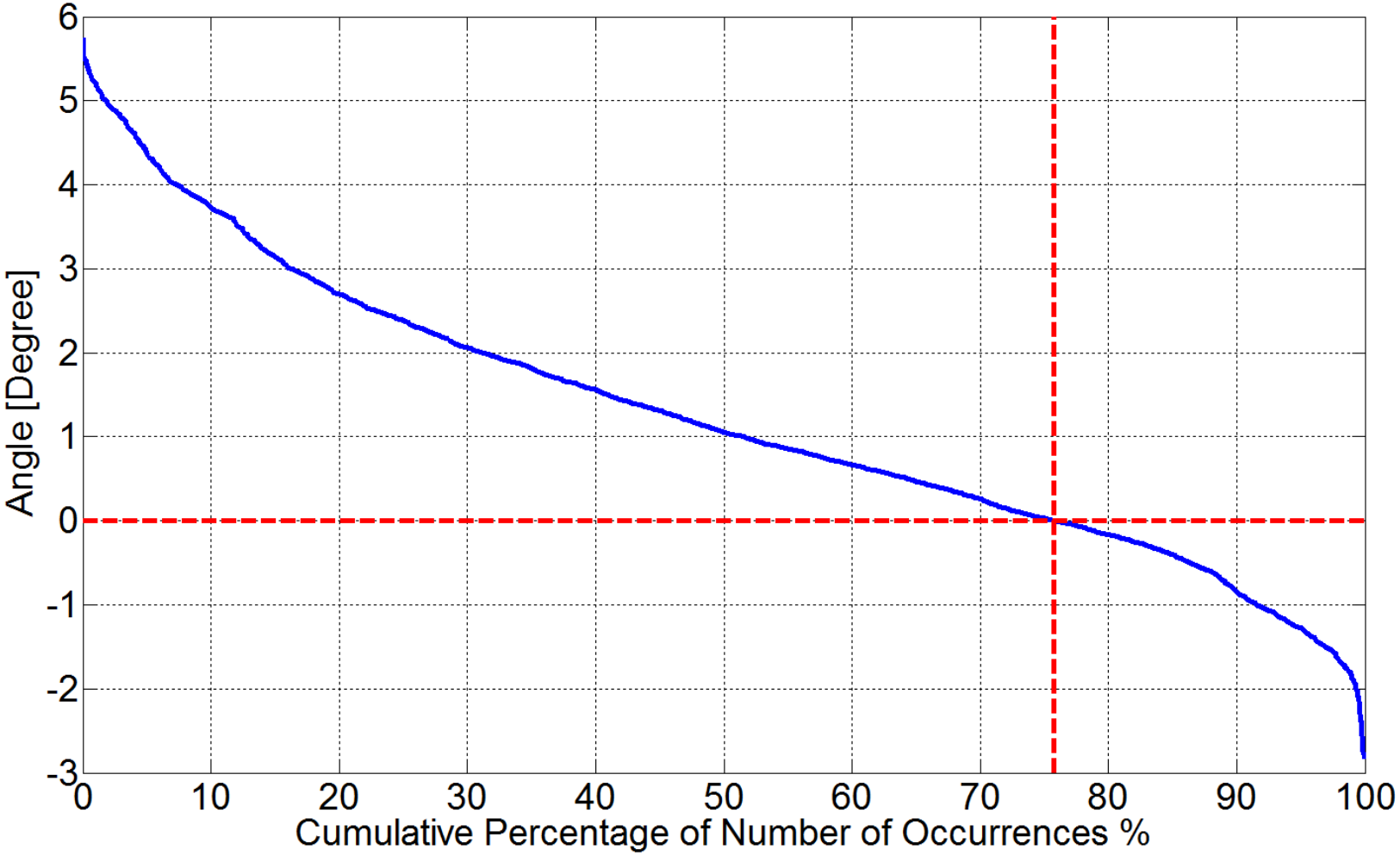
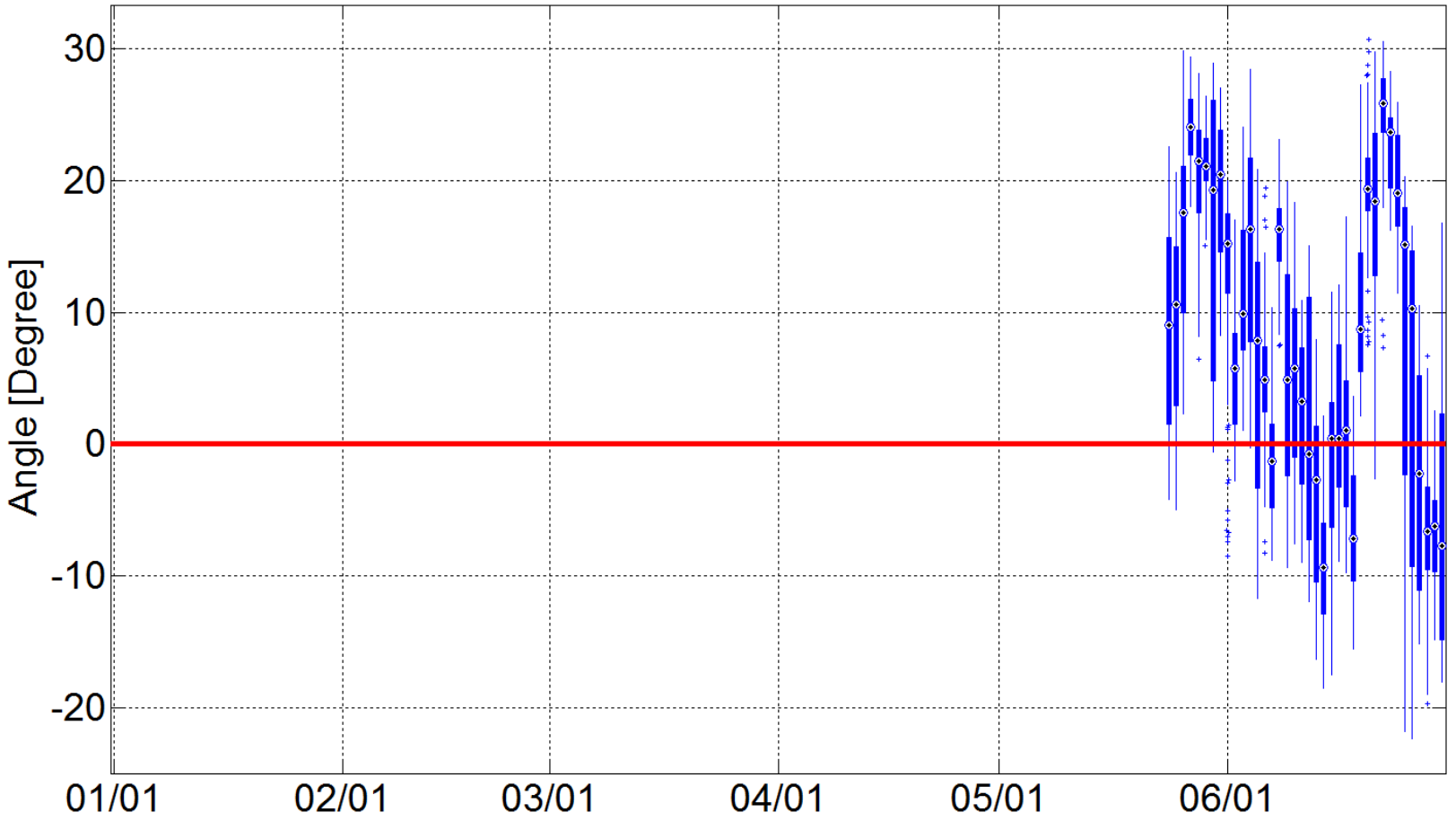


West 11-West 8*



West 8*-South 9*



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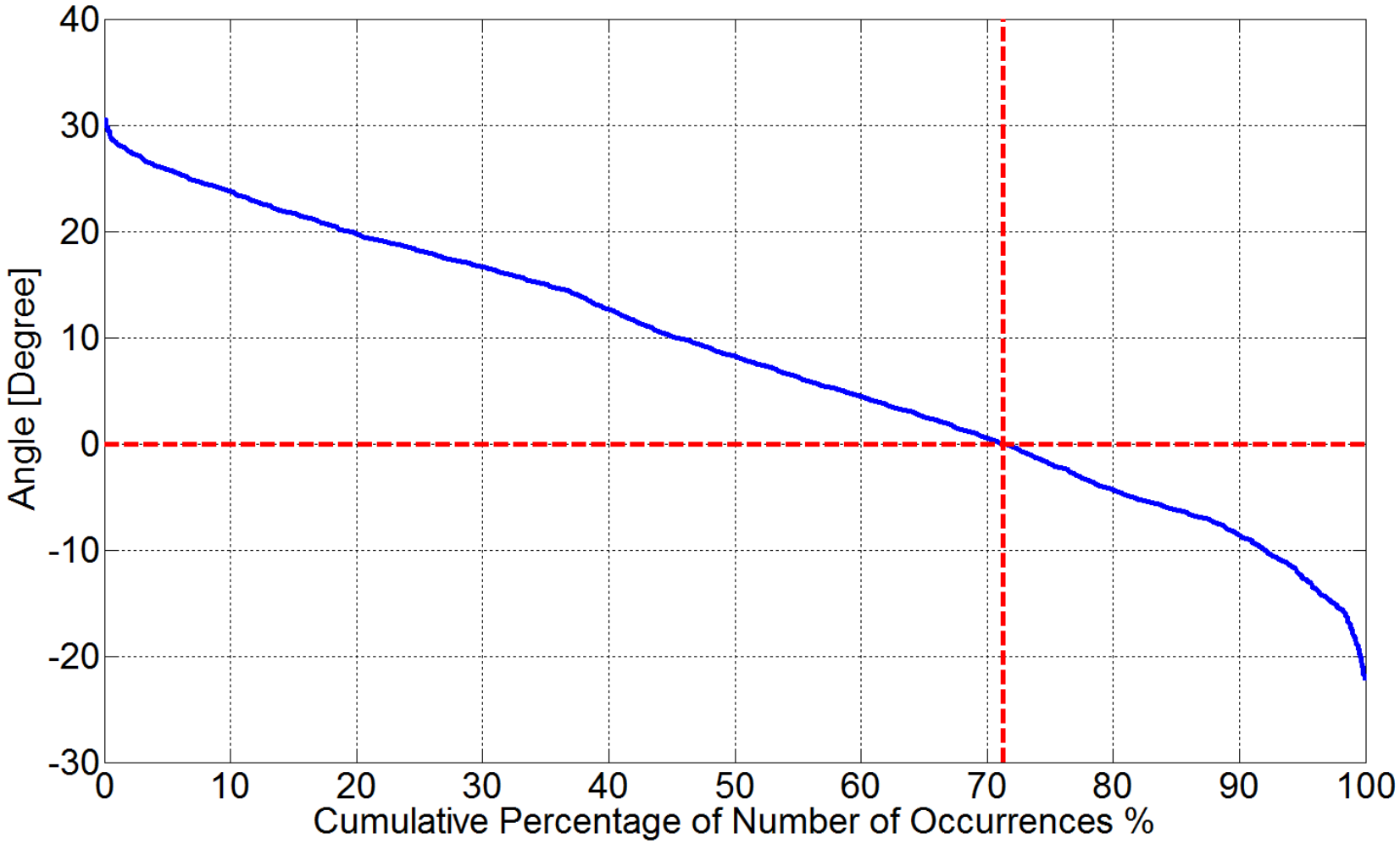
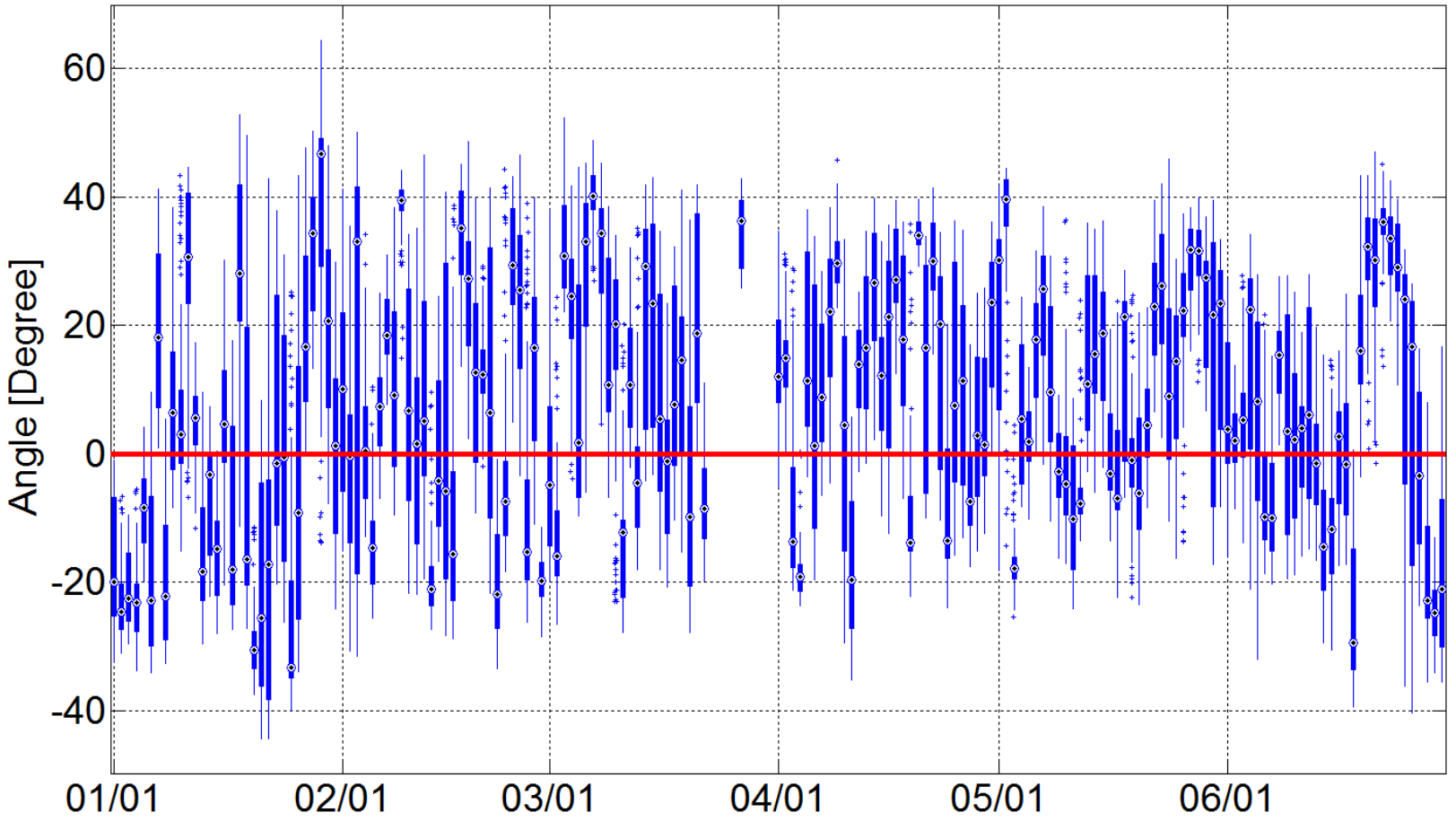
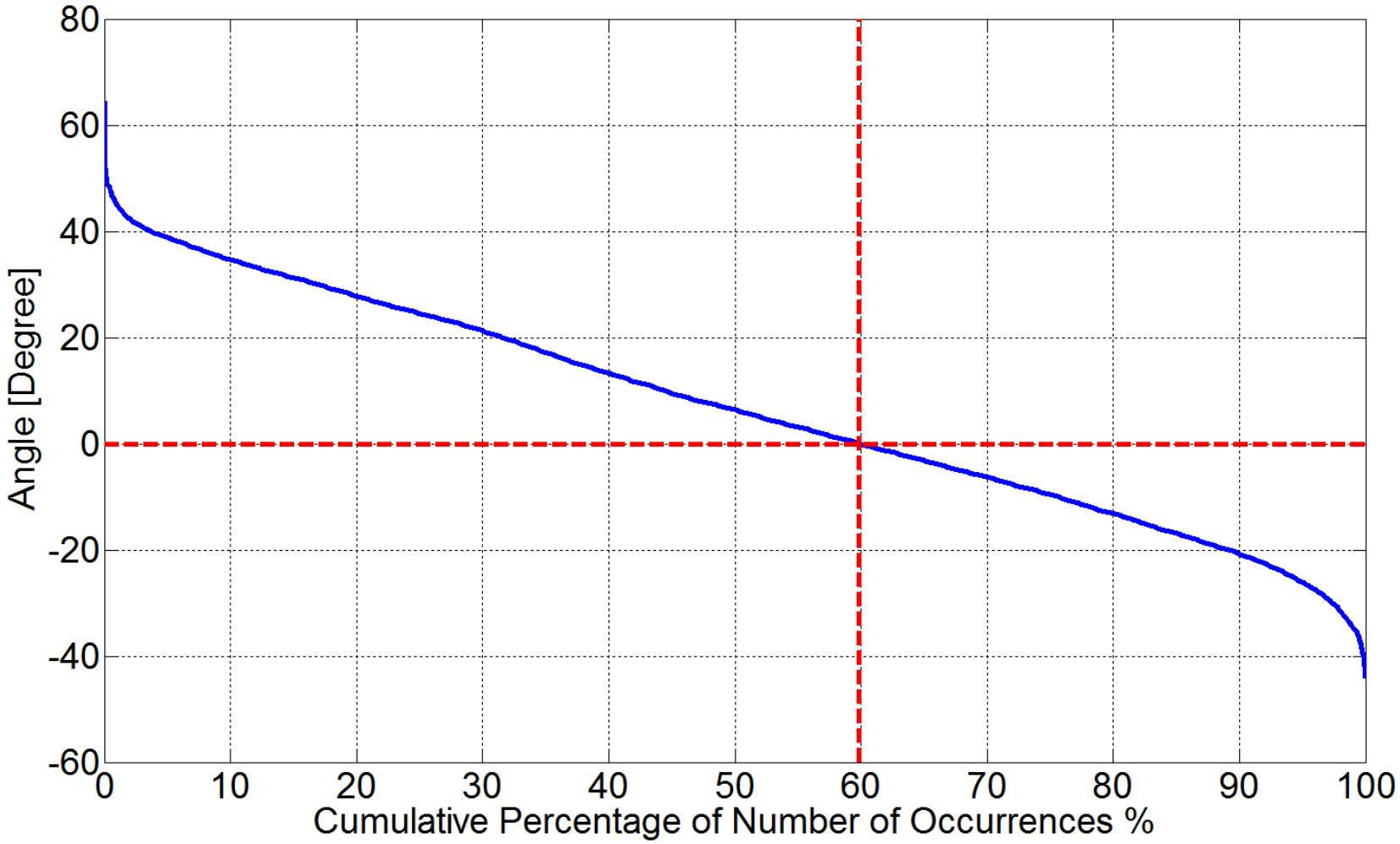


FarWest 9-South 9*



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-Whisker Plots and Time Duration Curves

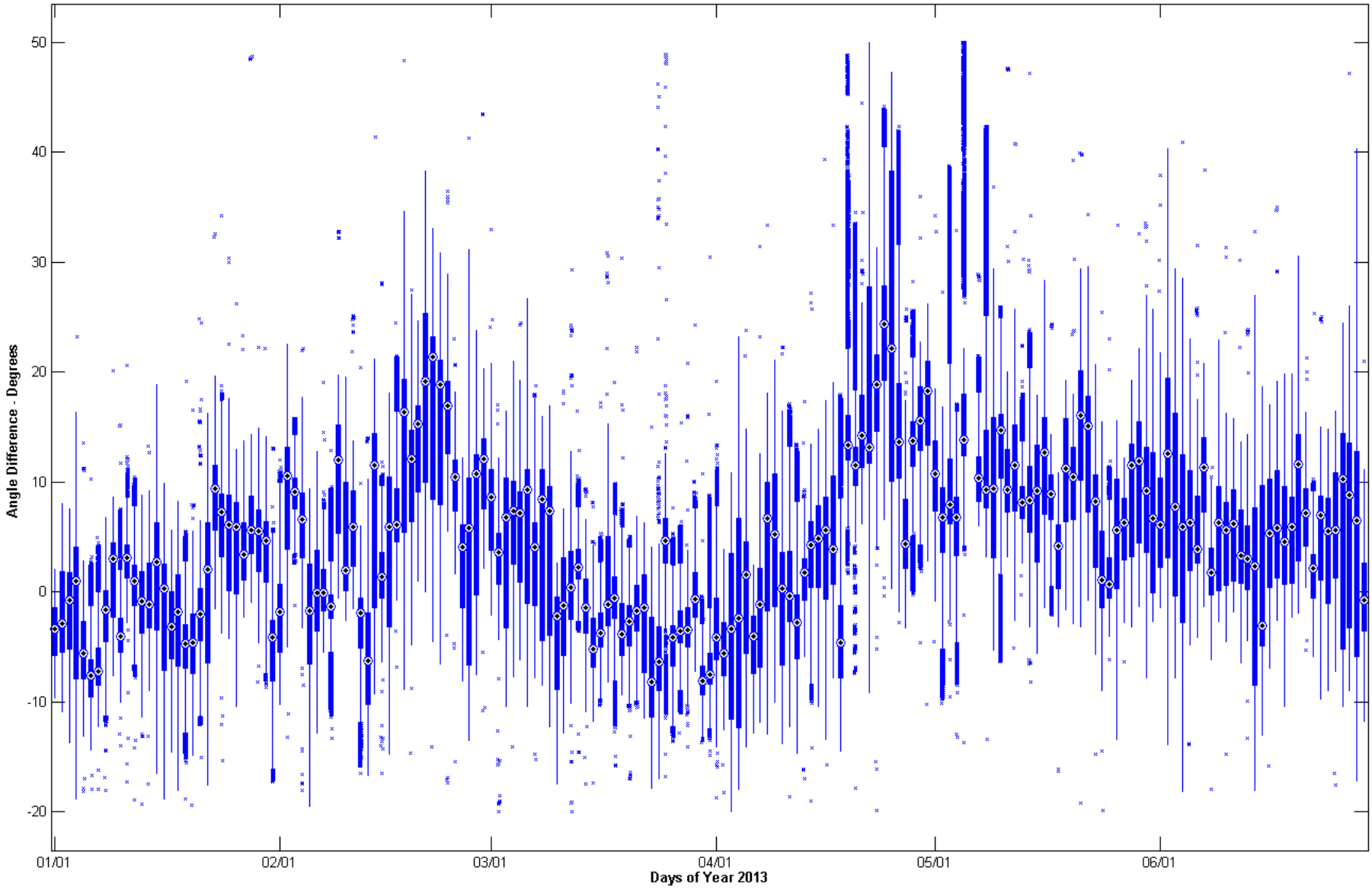
External Version

Electric Power Group

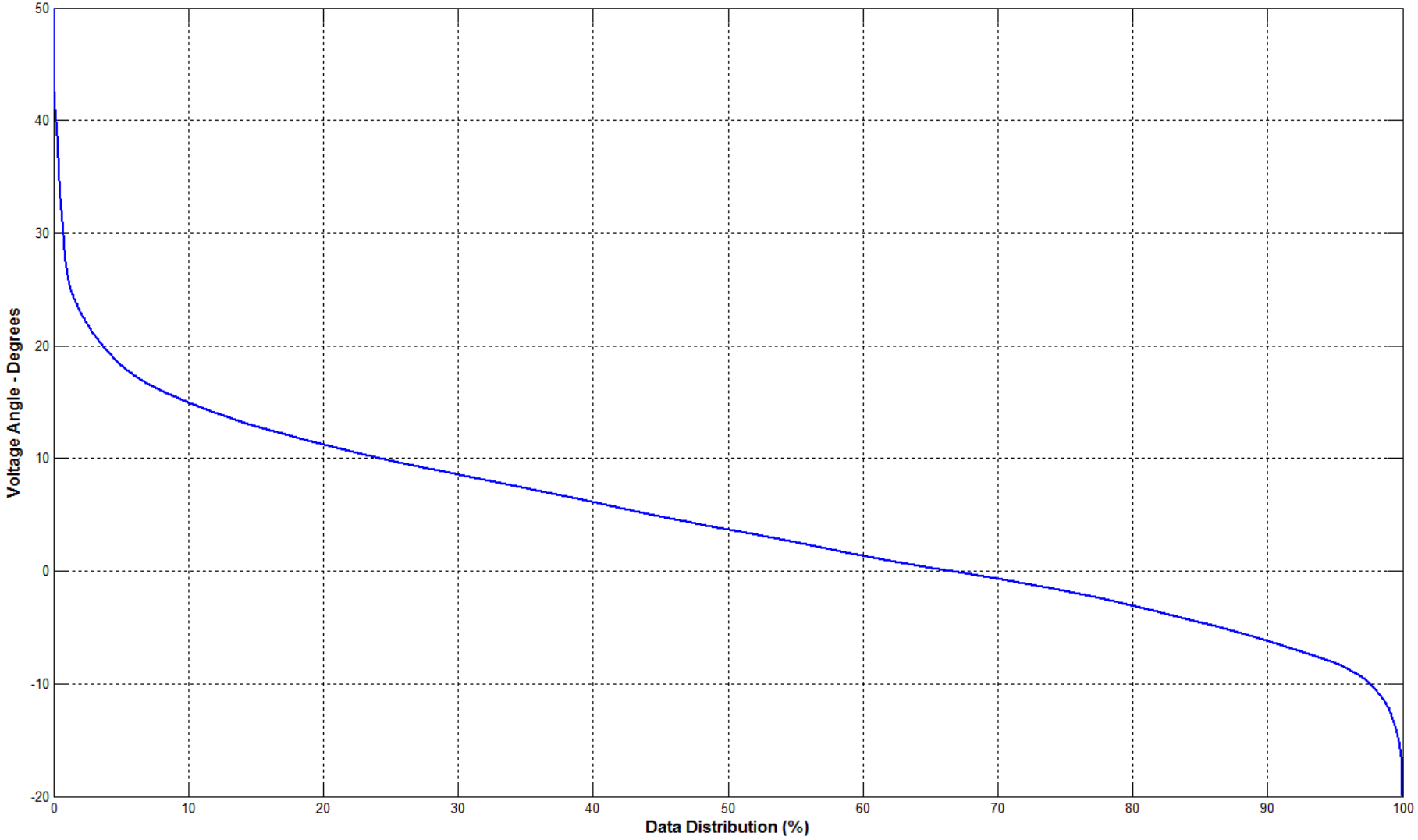
CCET

ERCOT

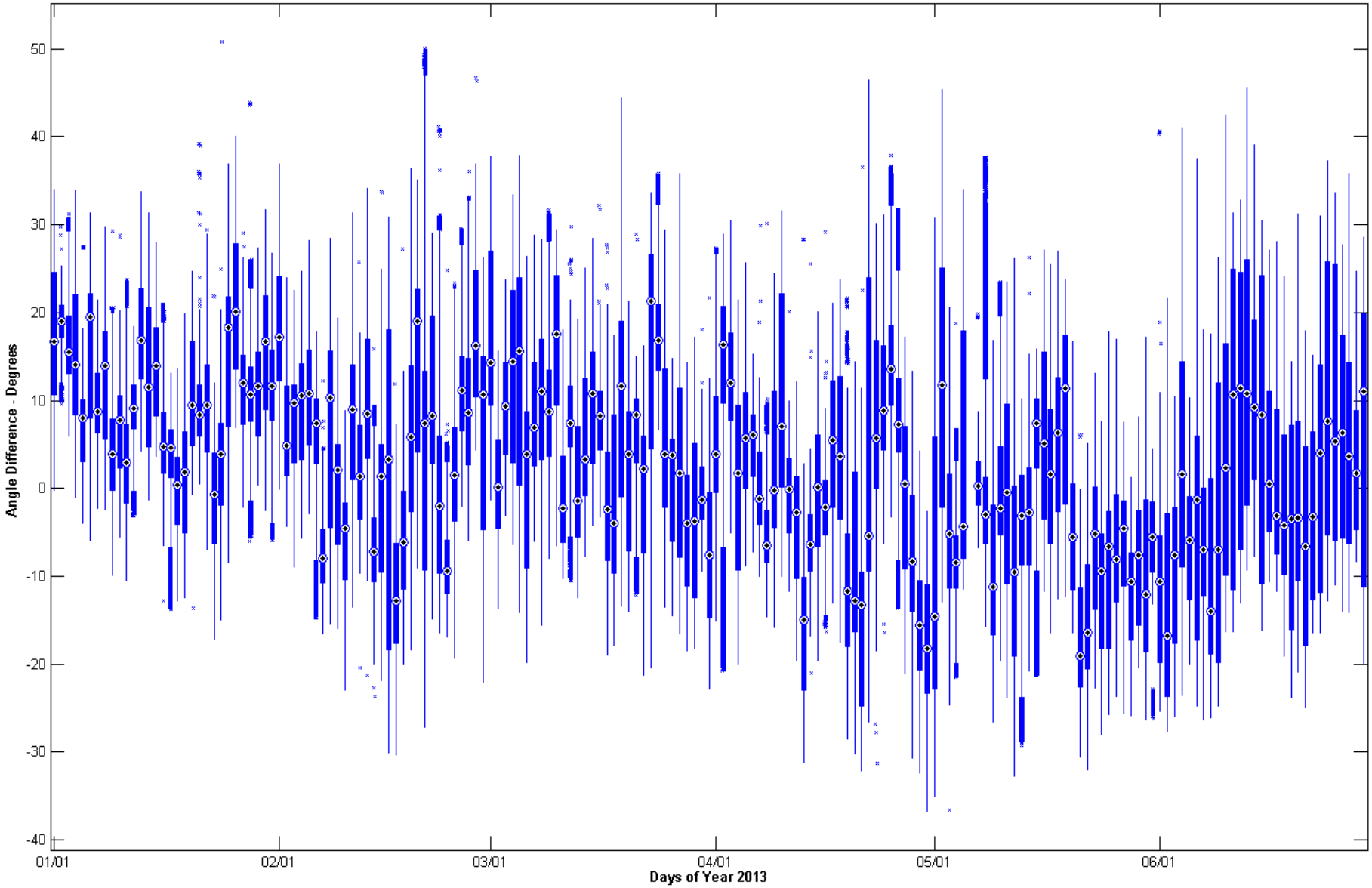
Coast 1 – South 13



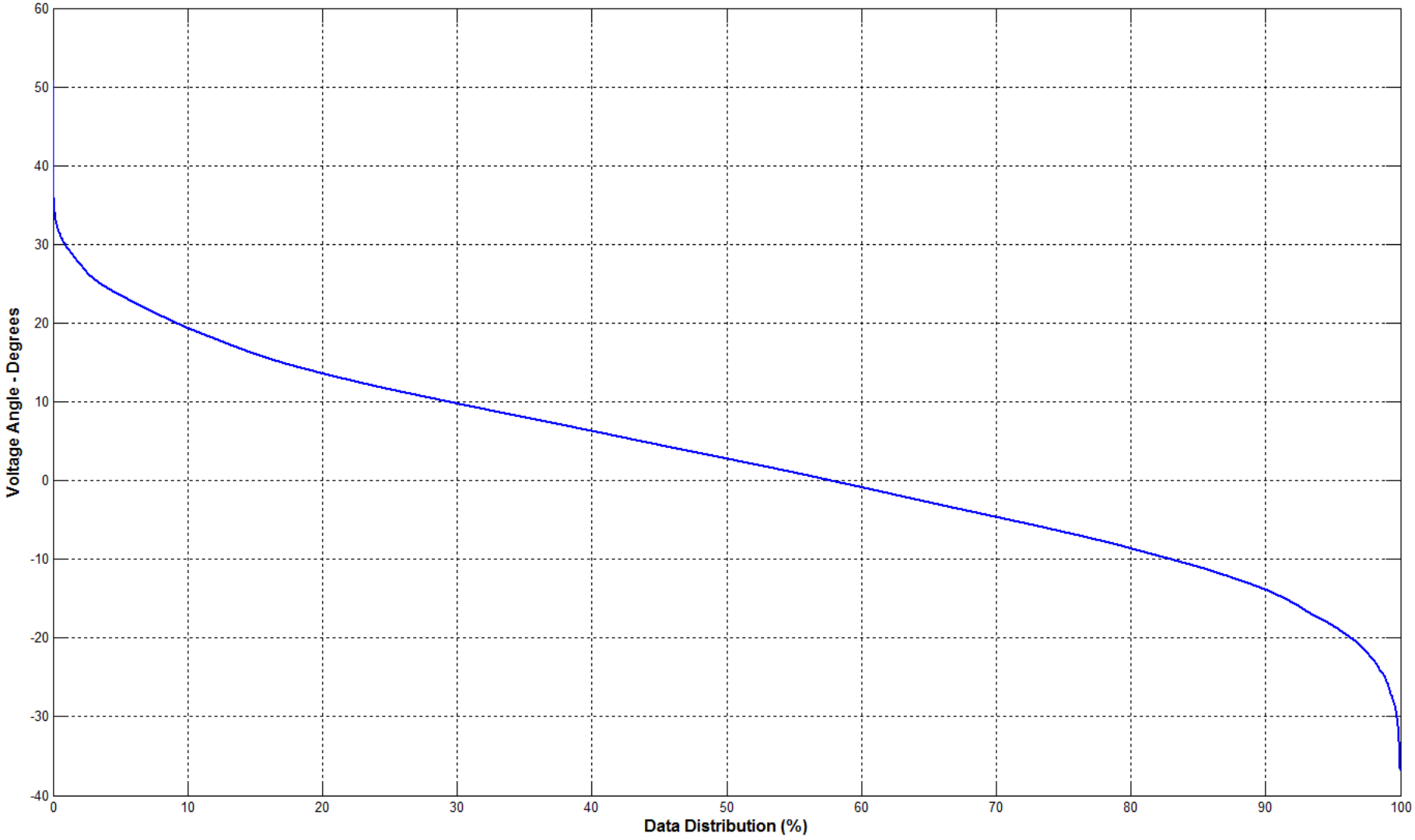
Coast 1 – South 13



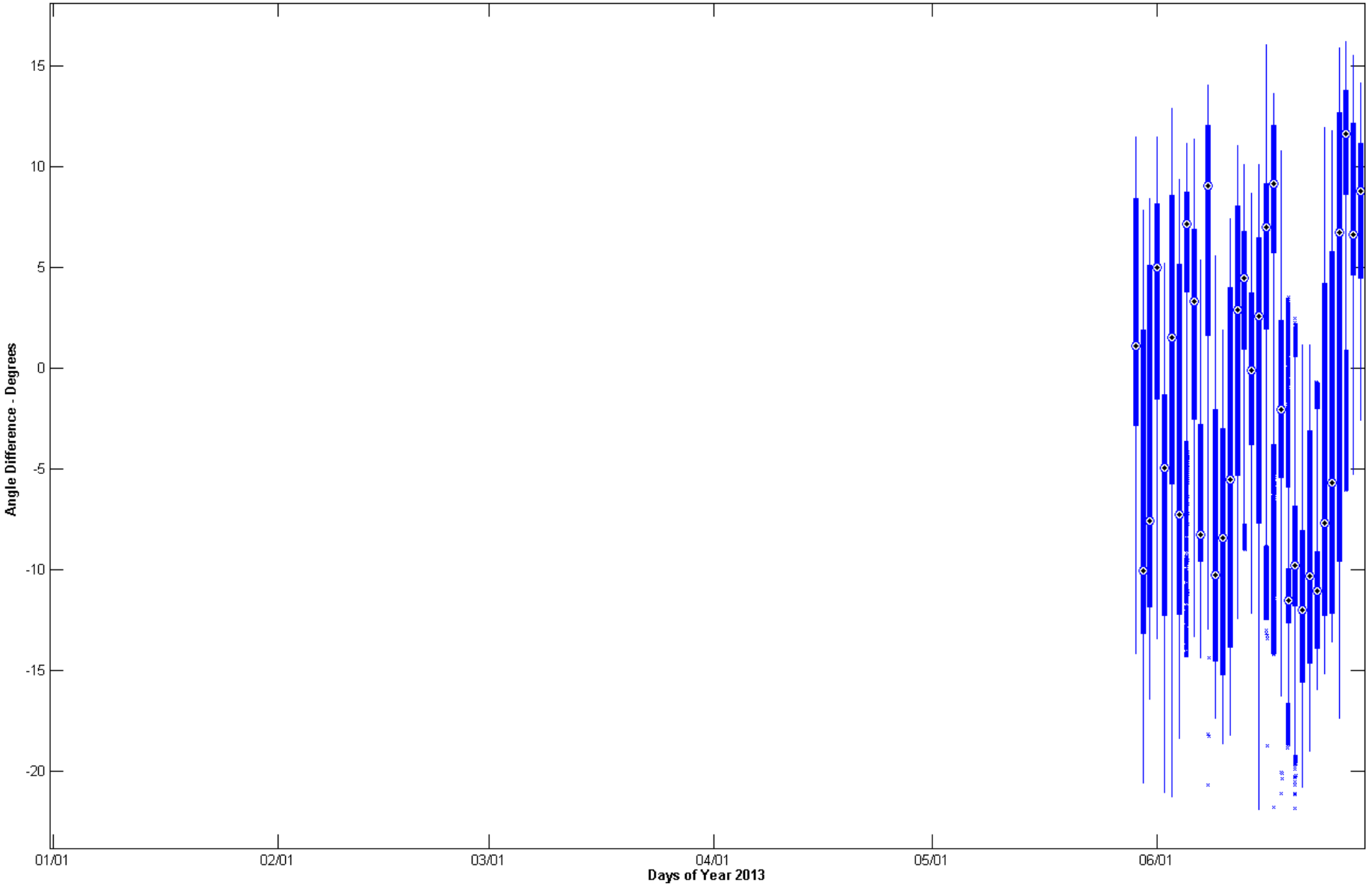
Coast 1 – North 7



Coast 1 – North 7



West 5 – West 10



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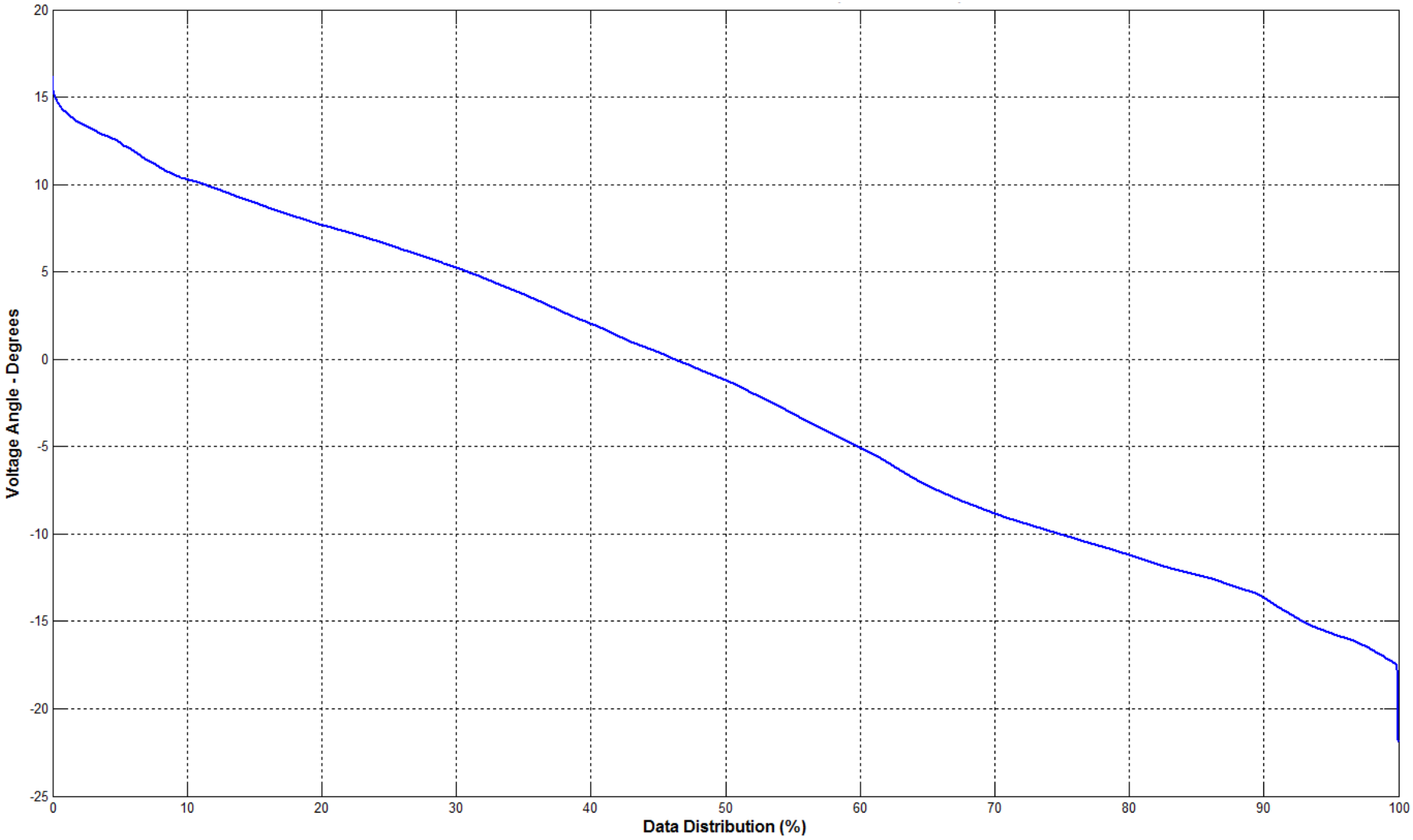

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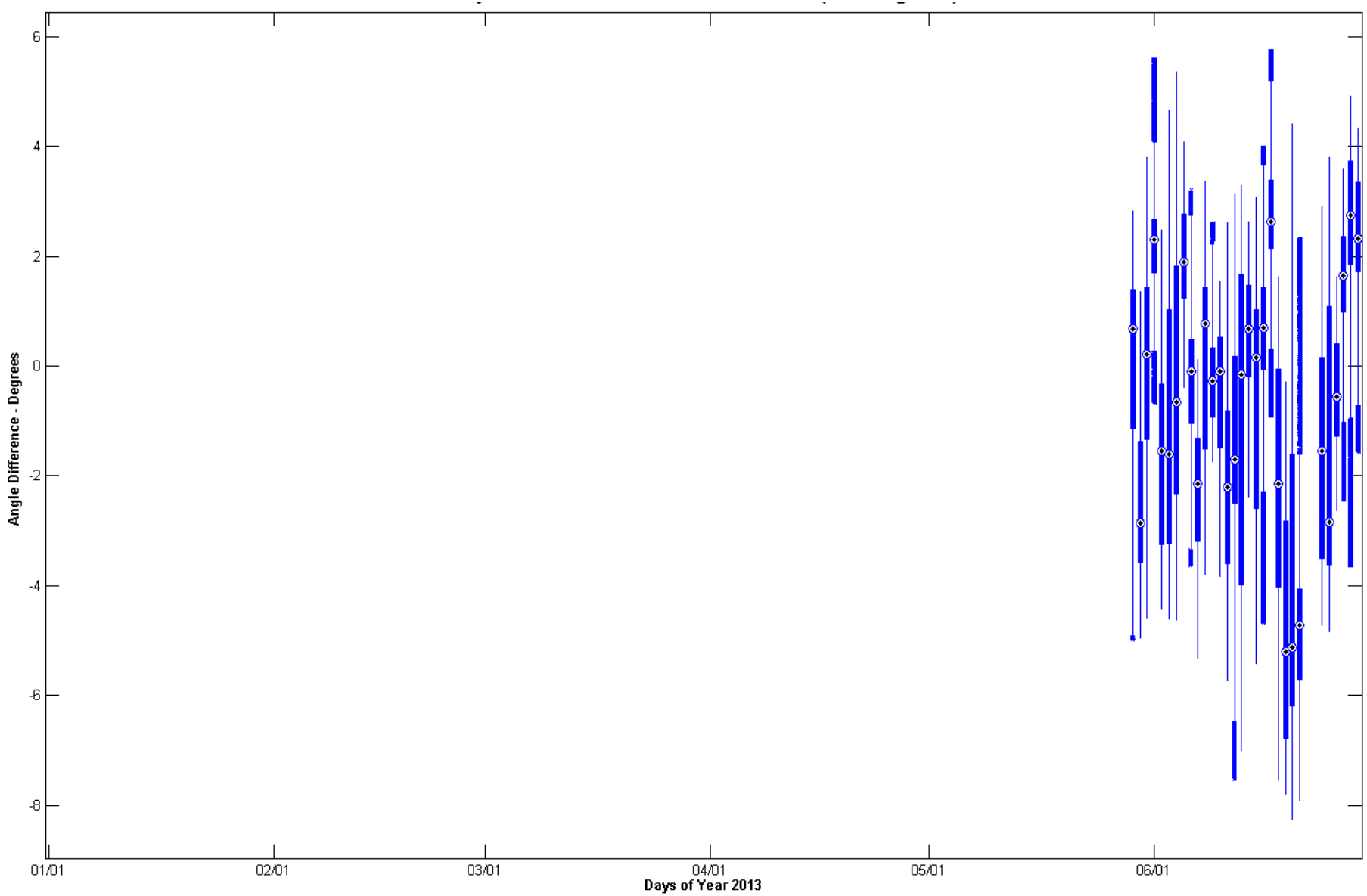

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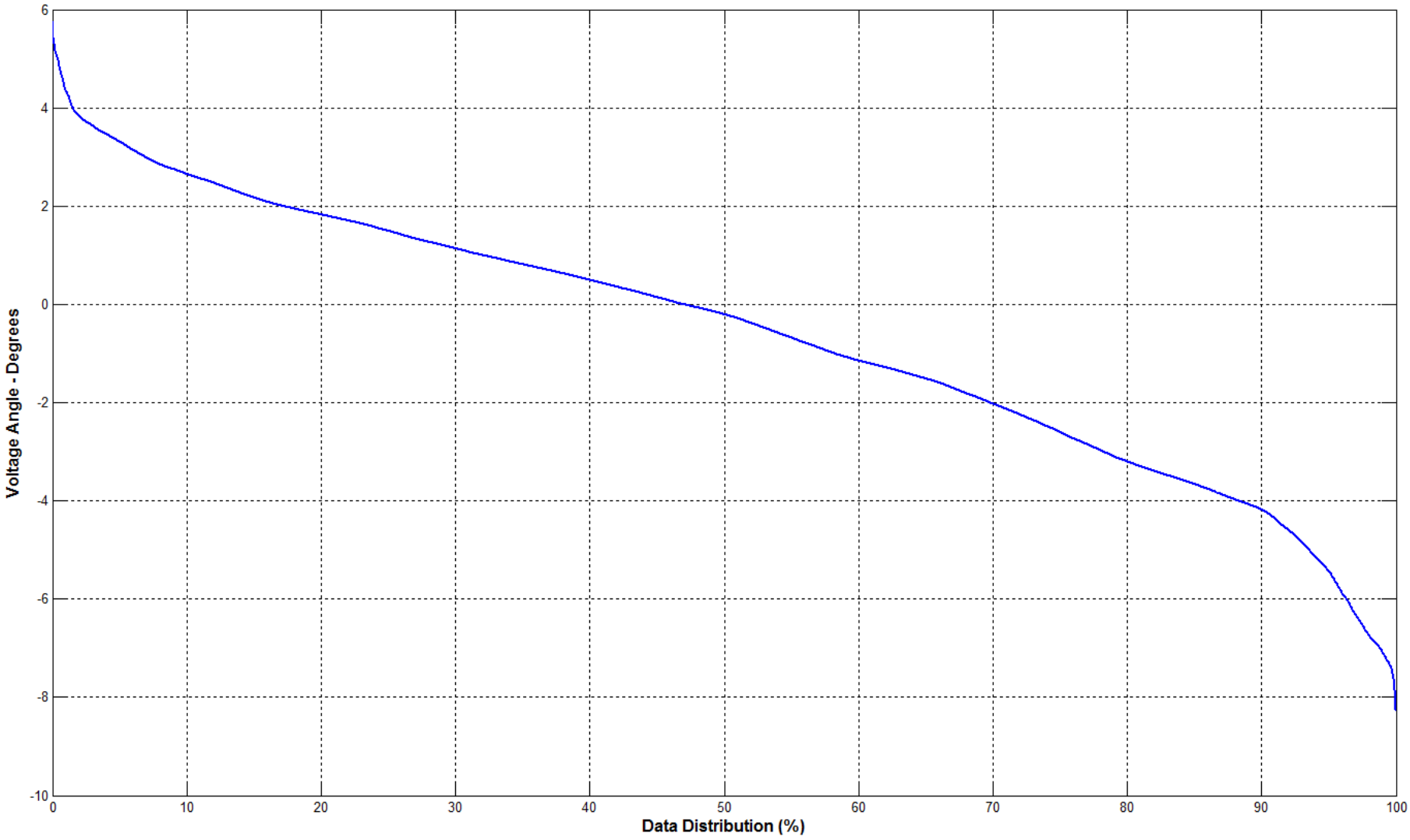

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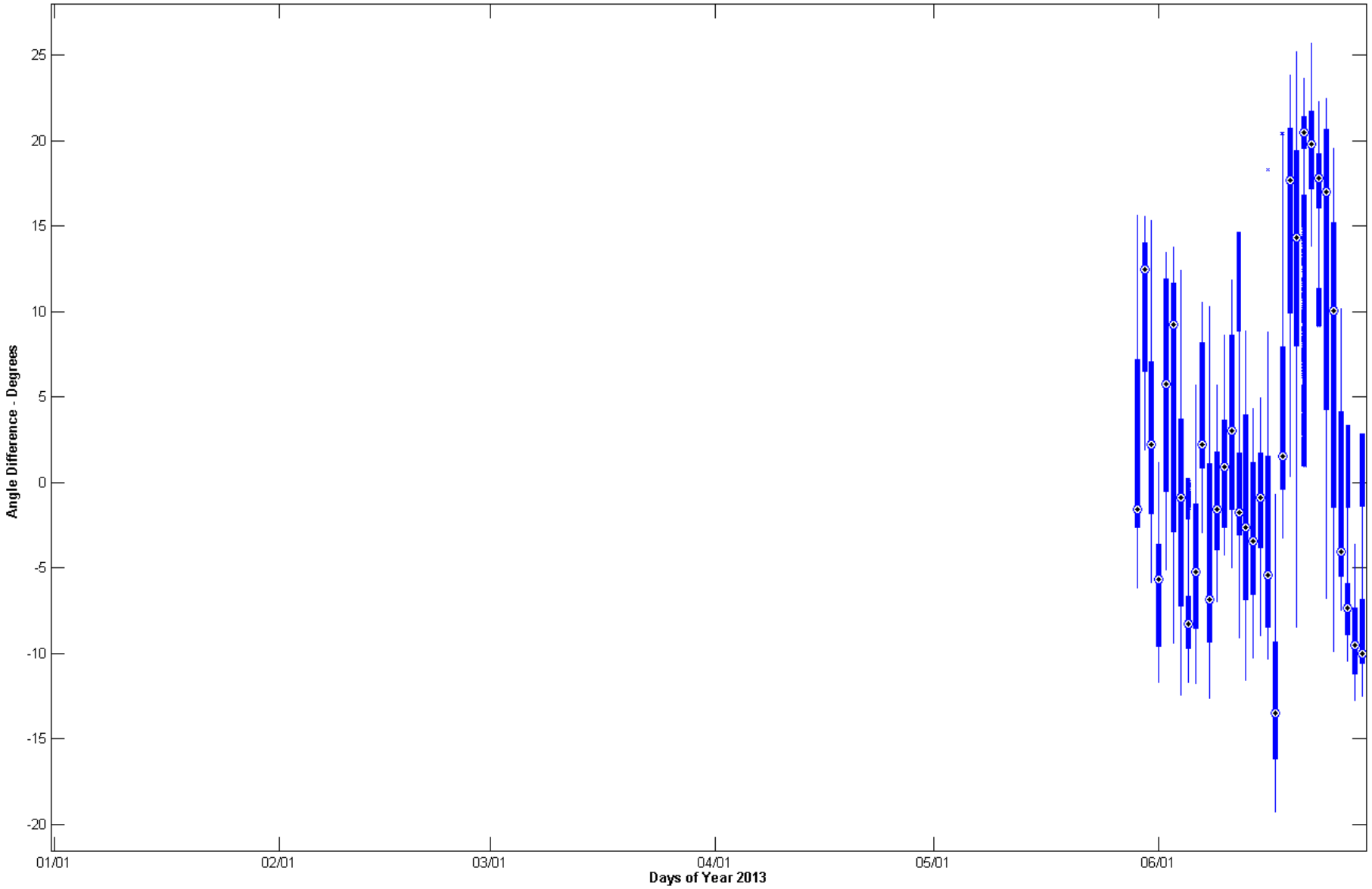

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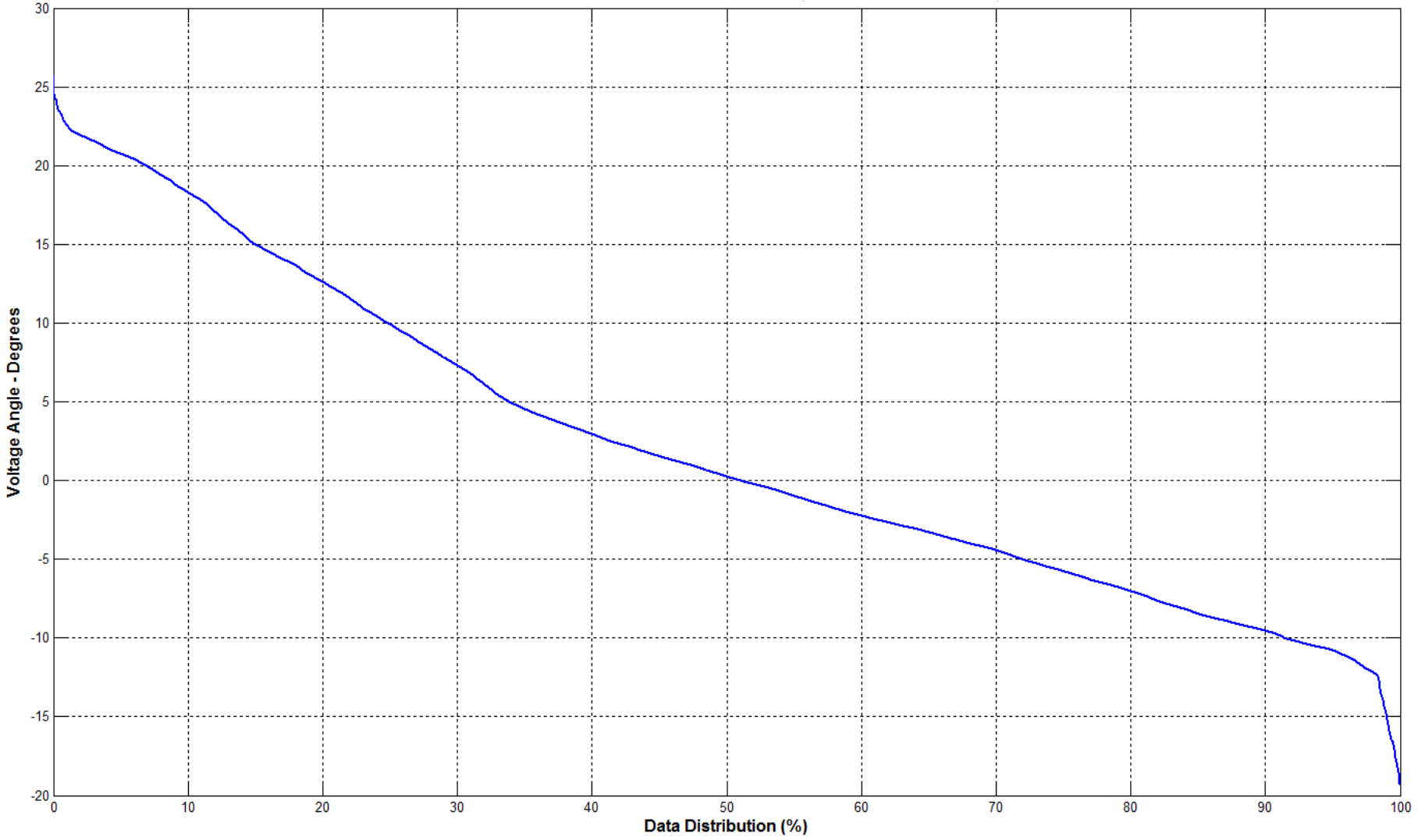

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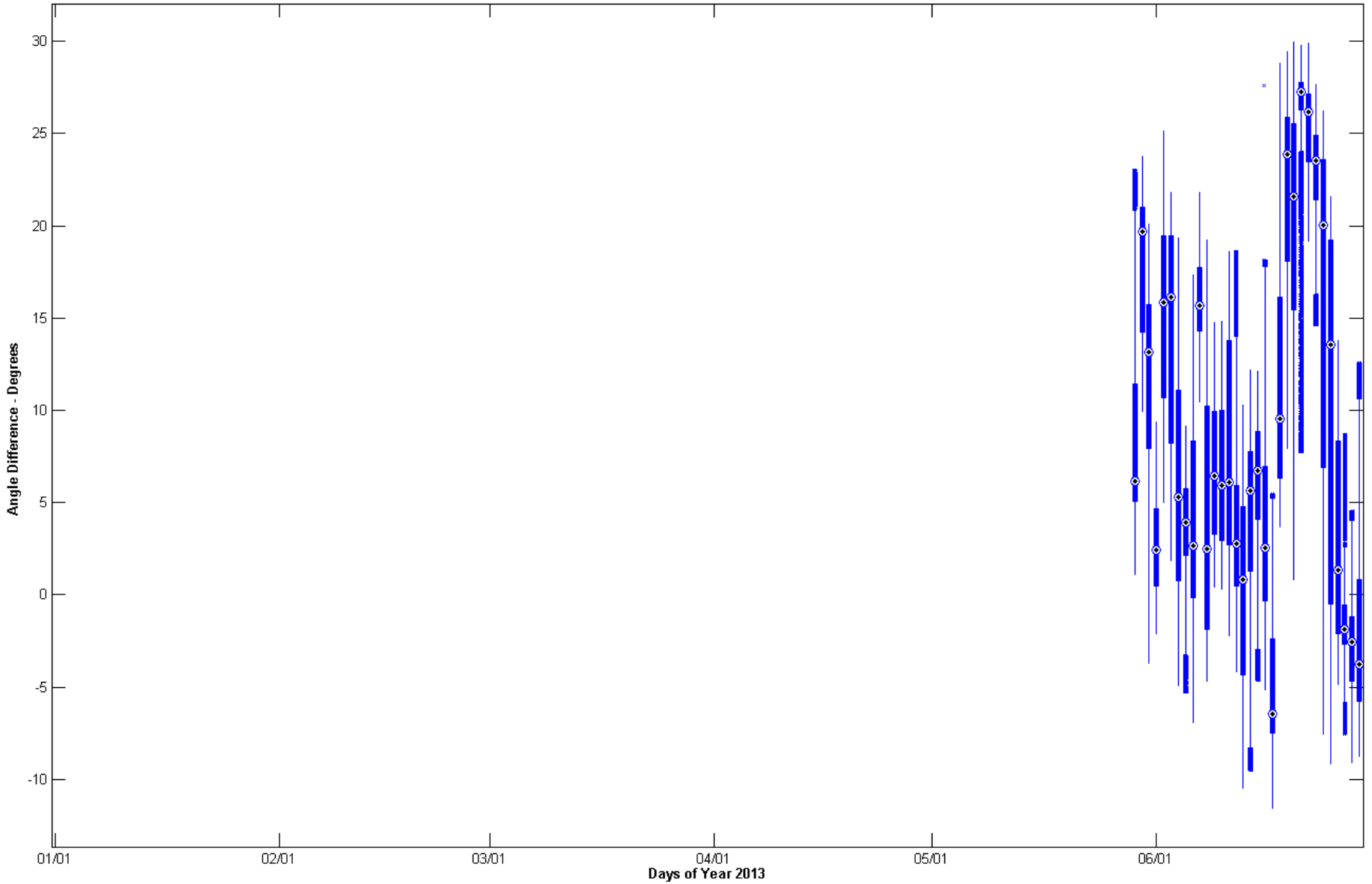

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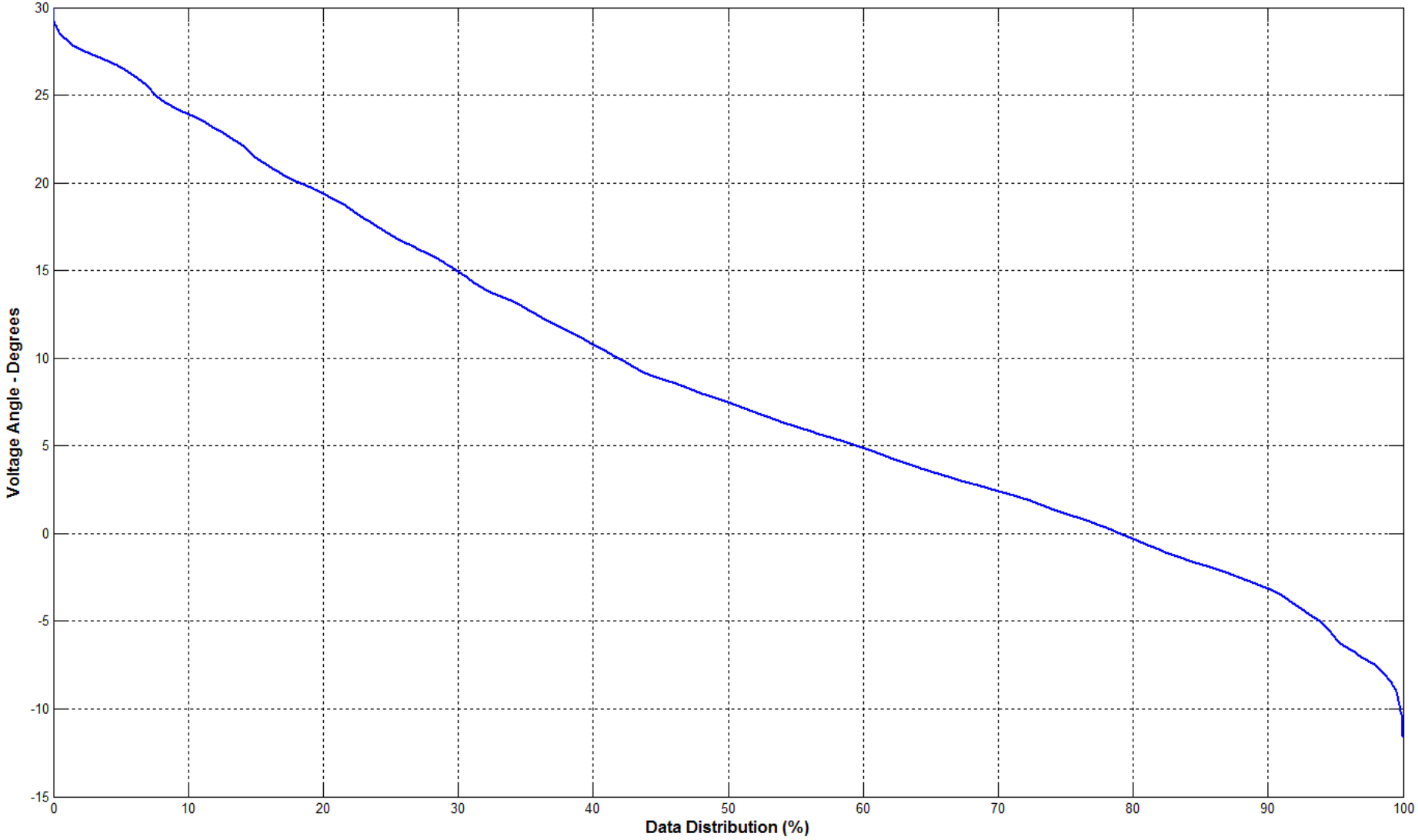

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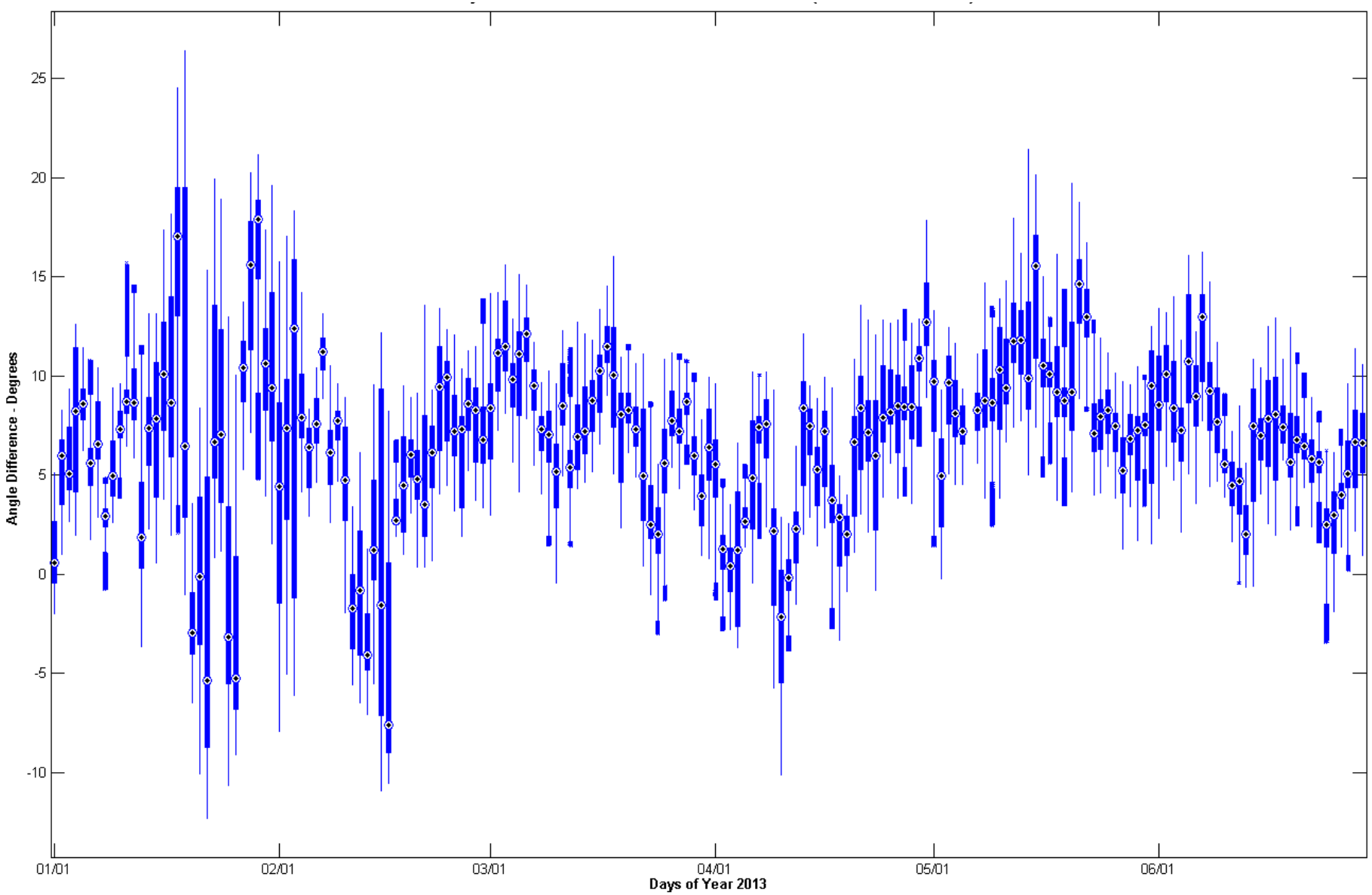

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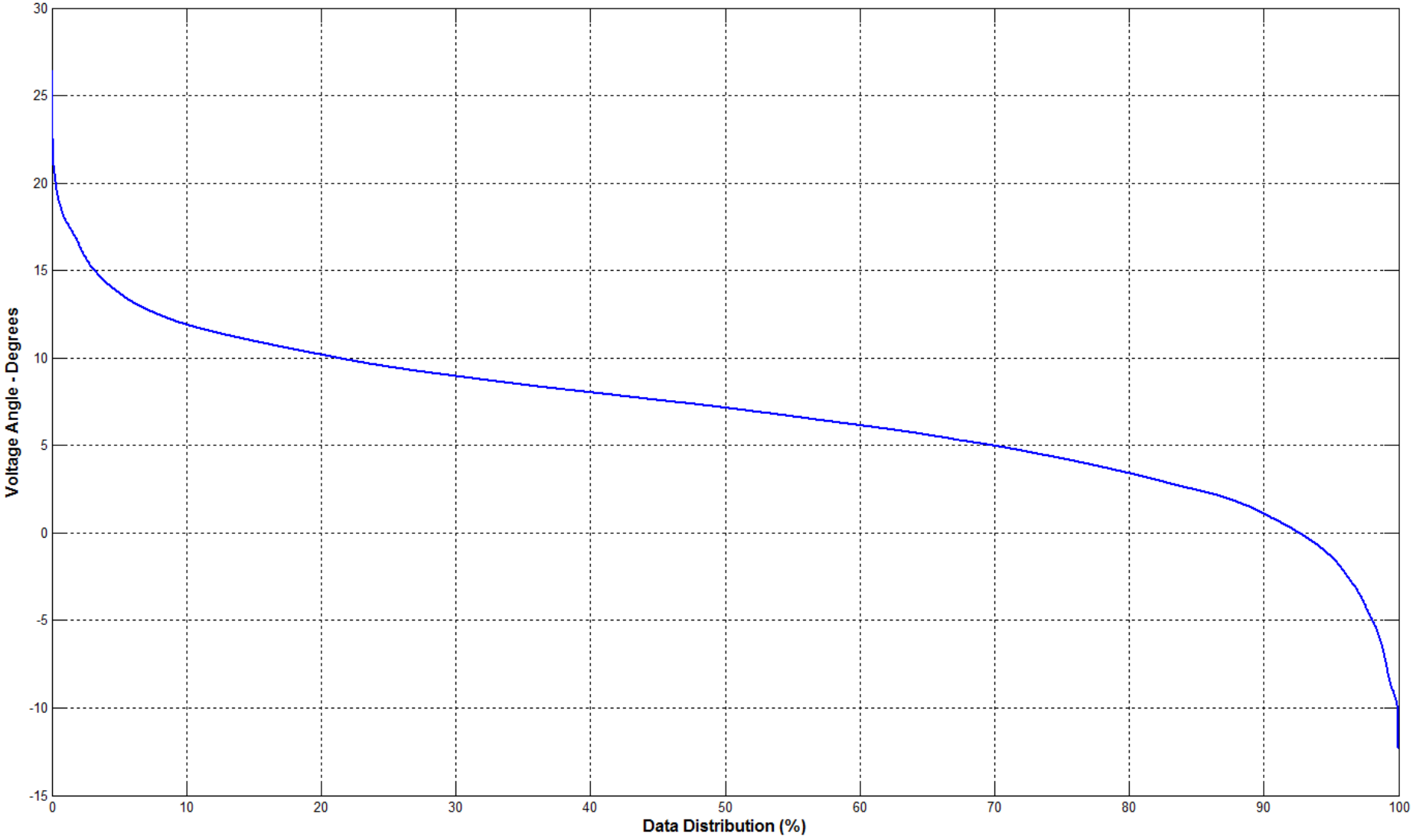

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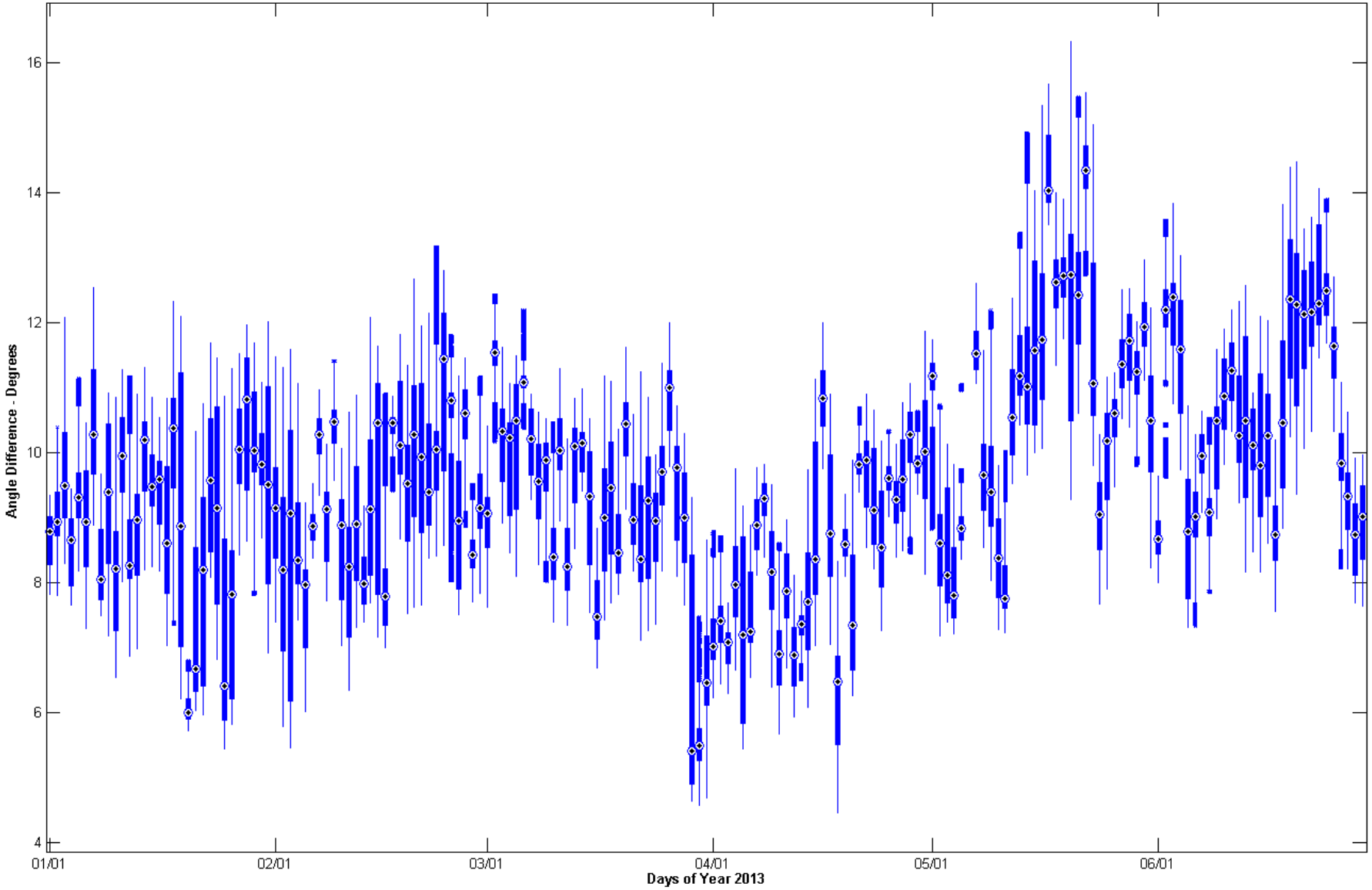

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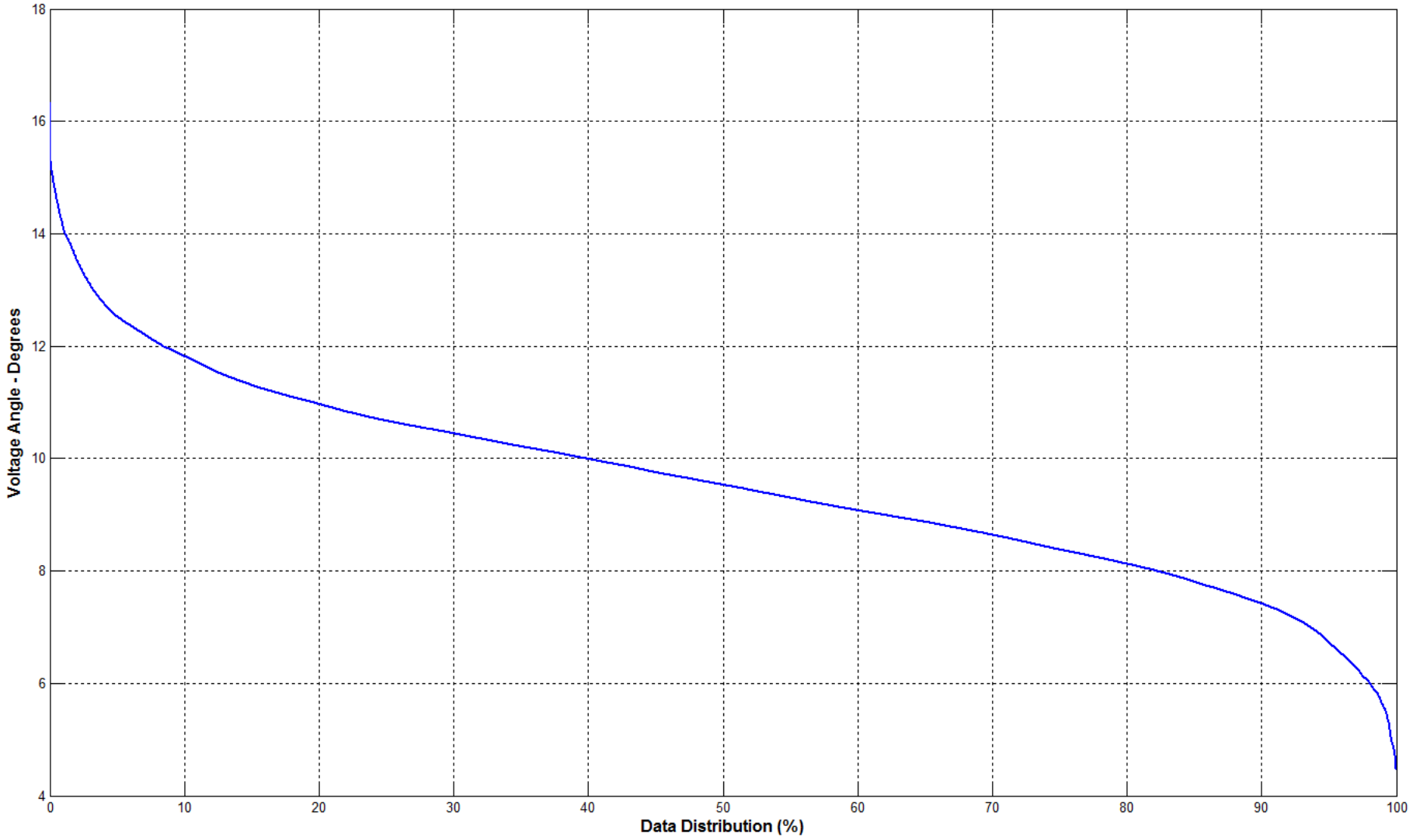

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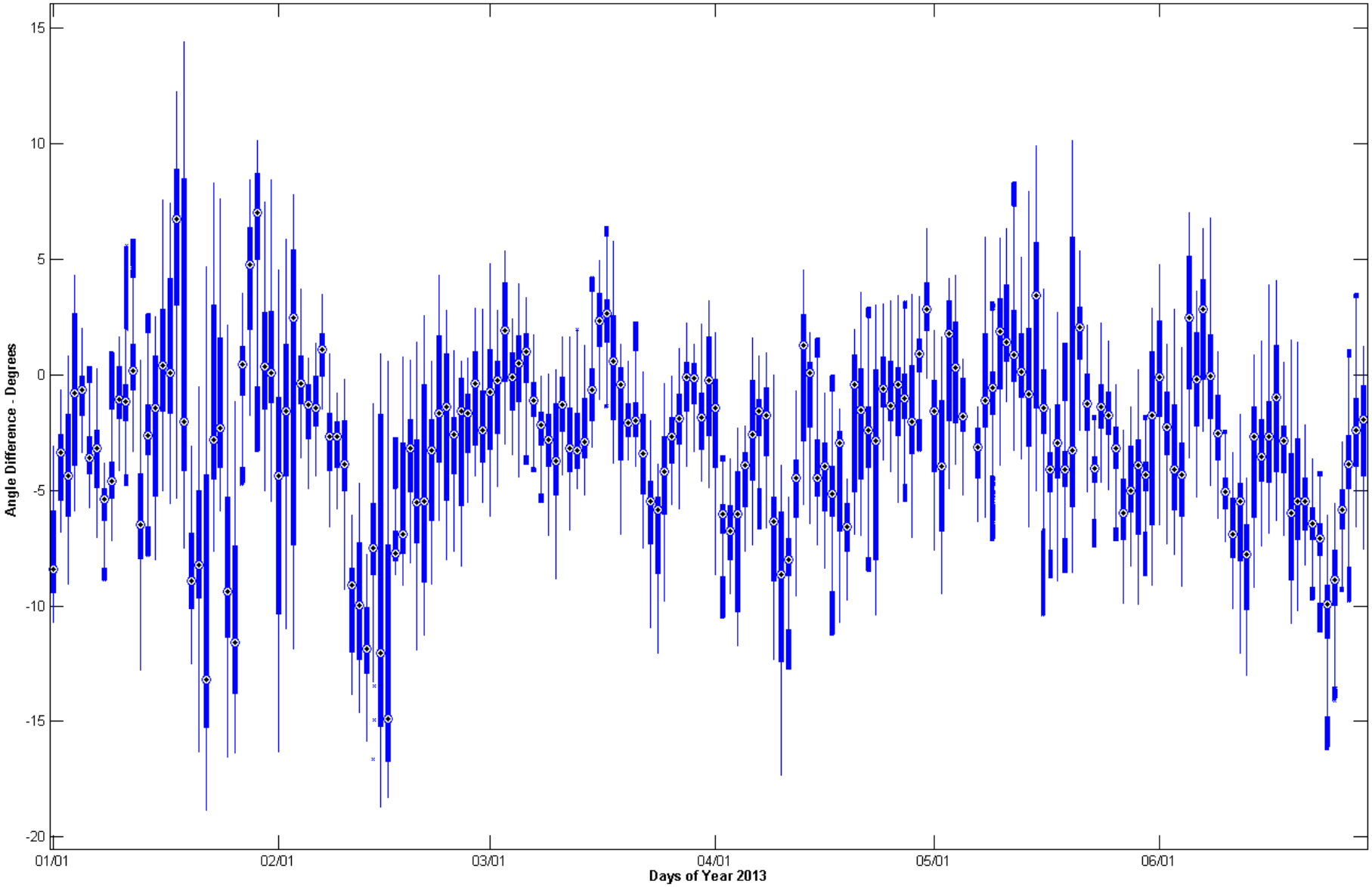

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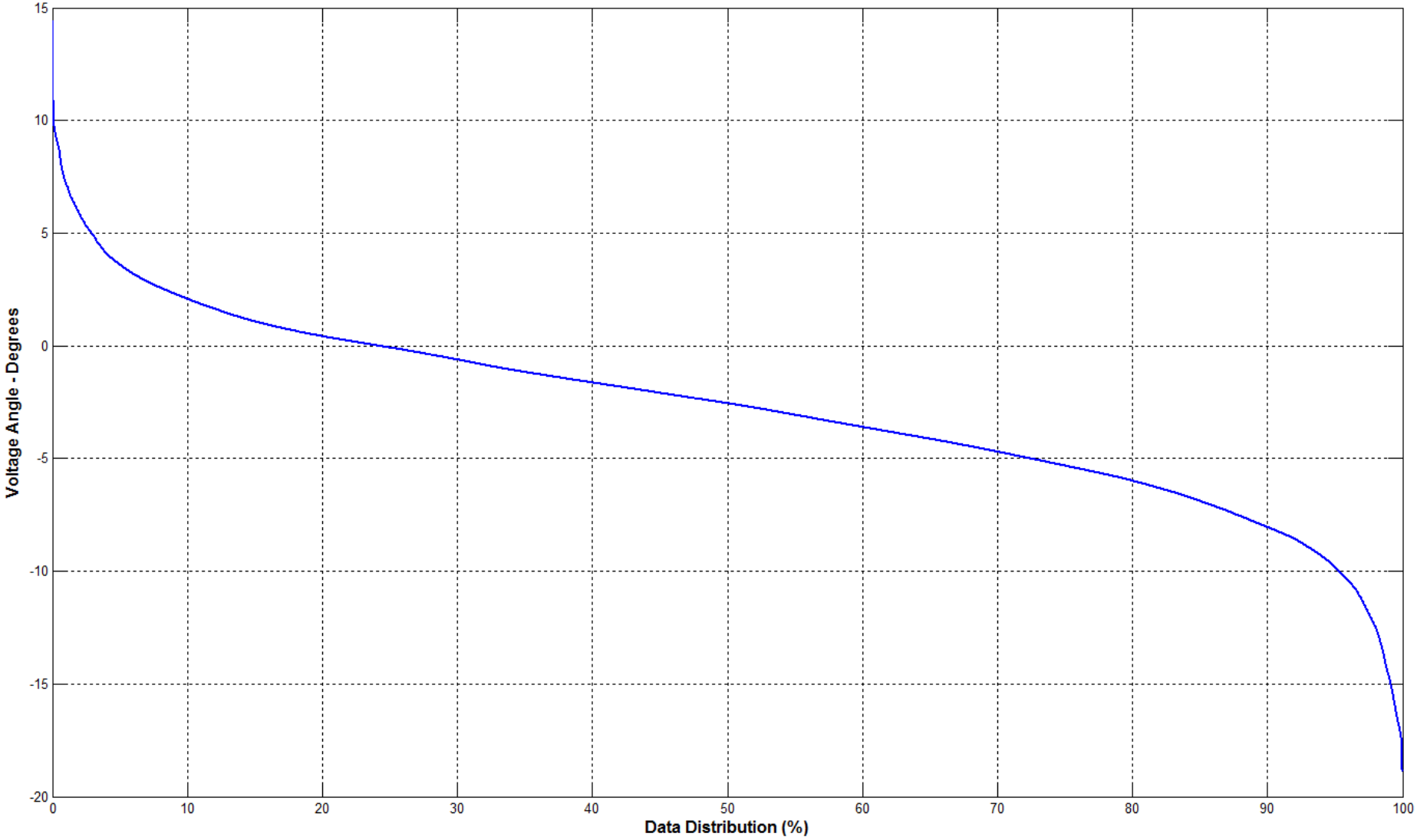

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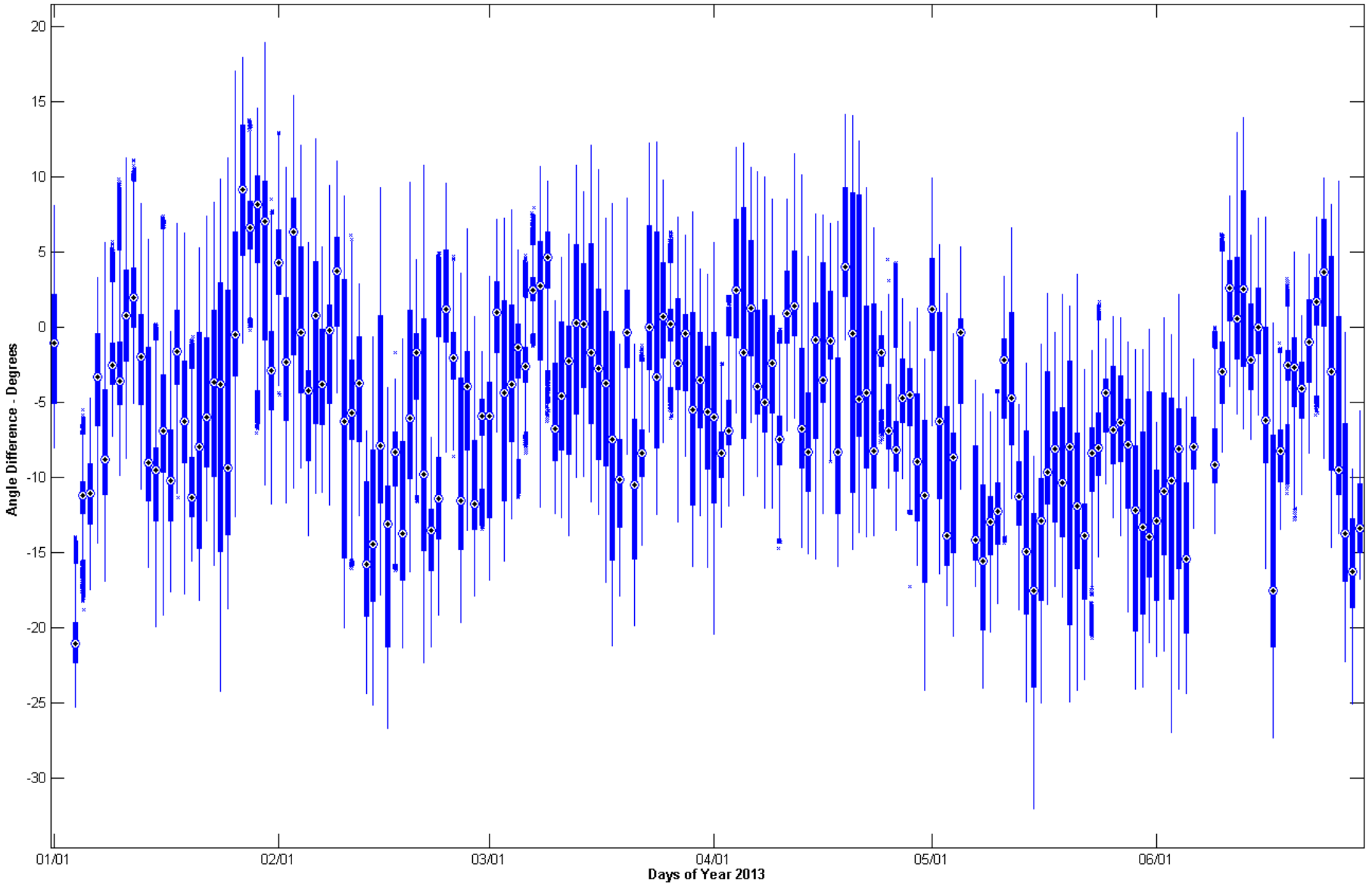

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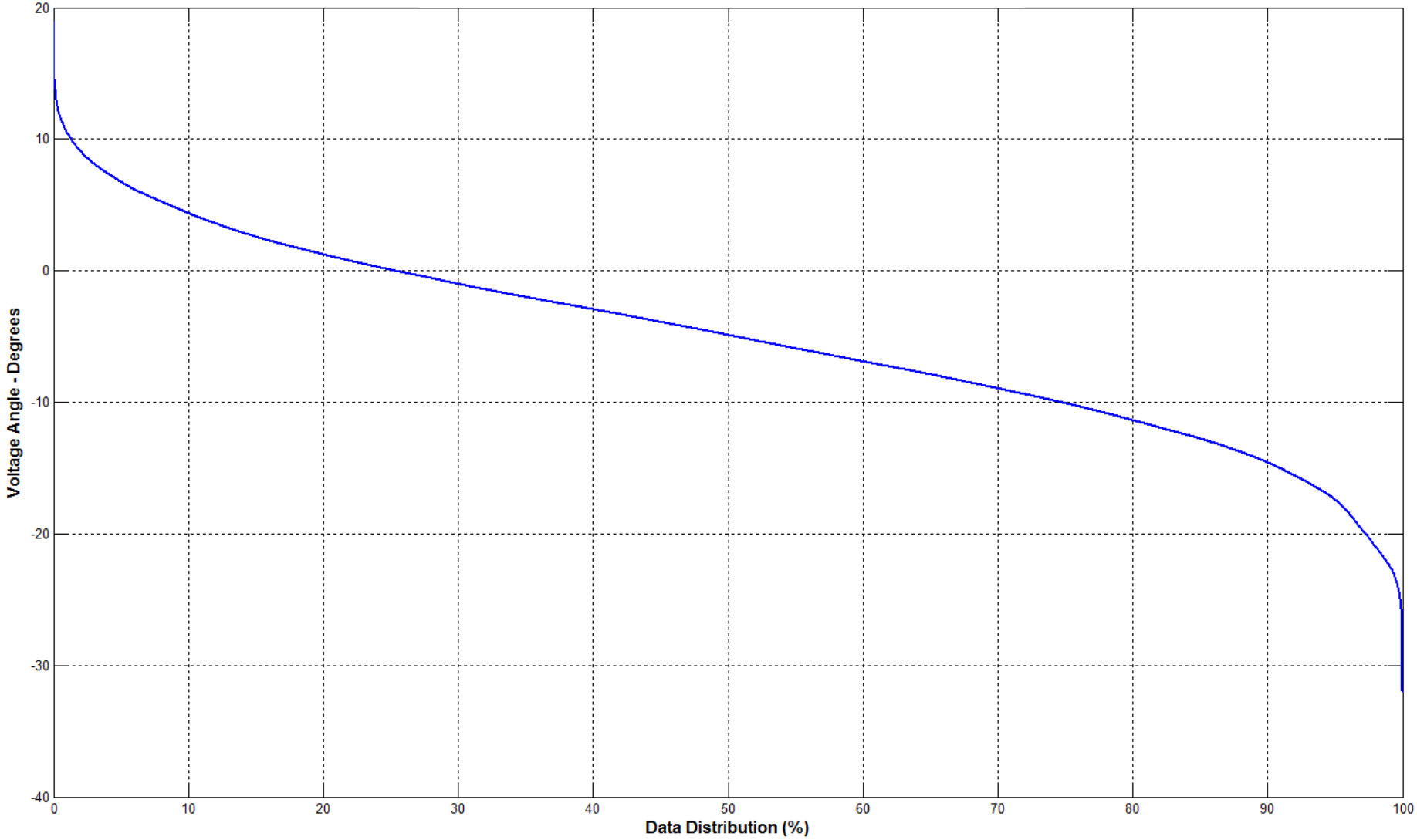

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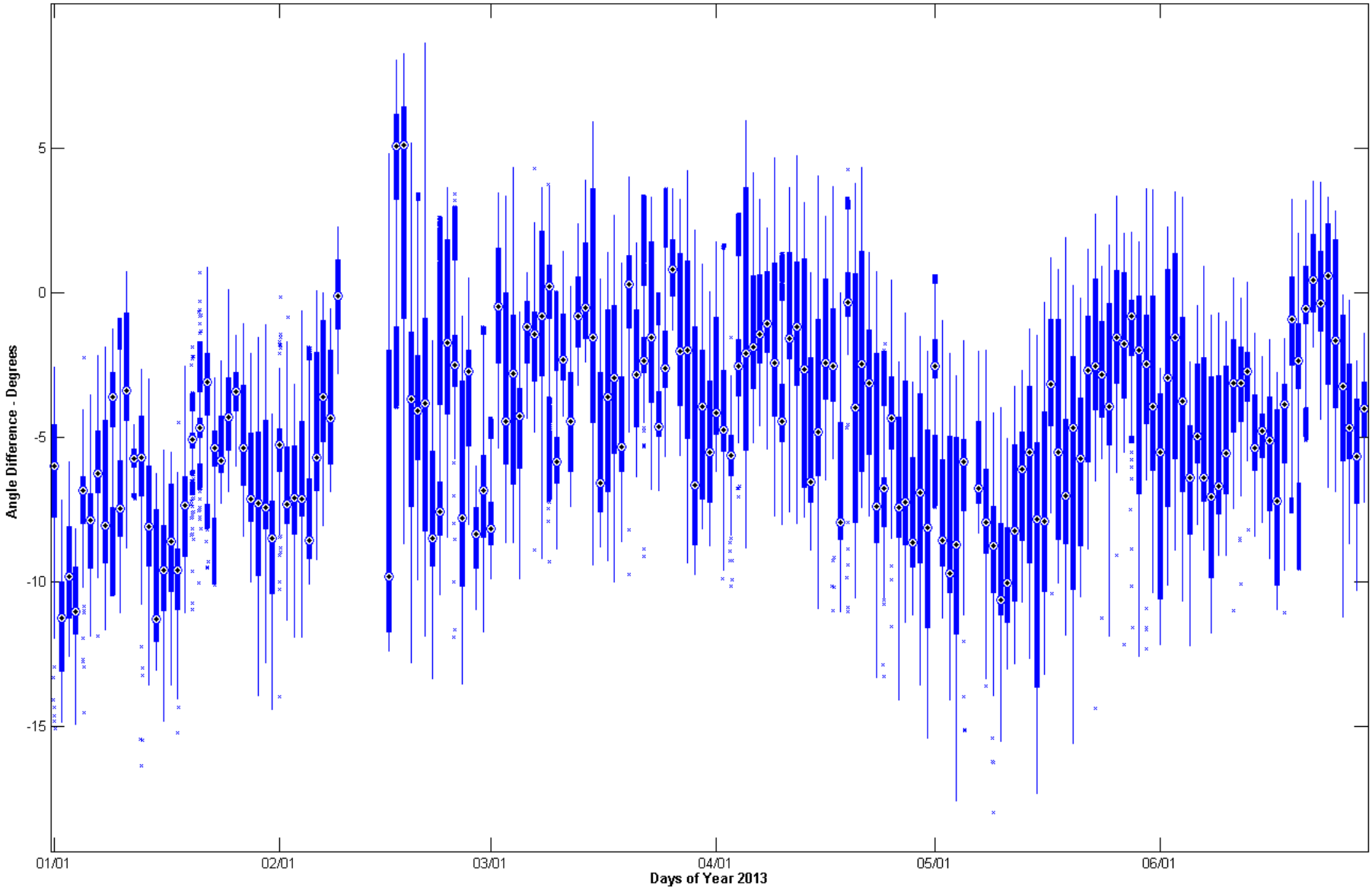

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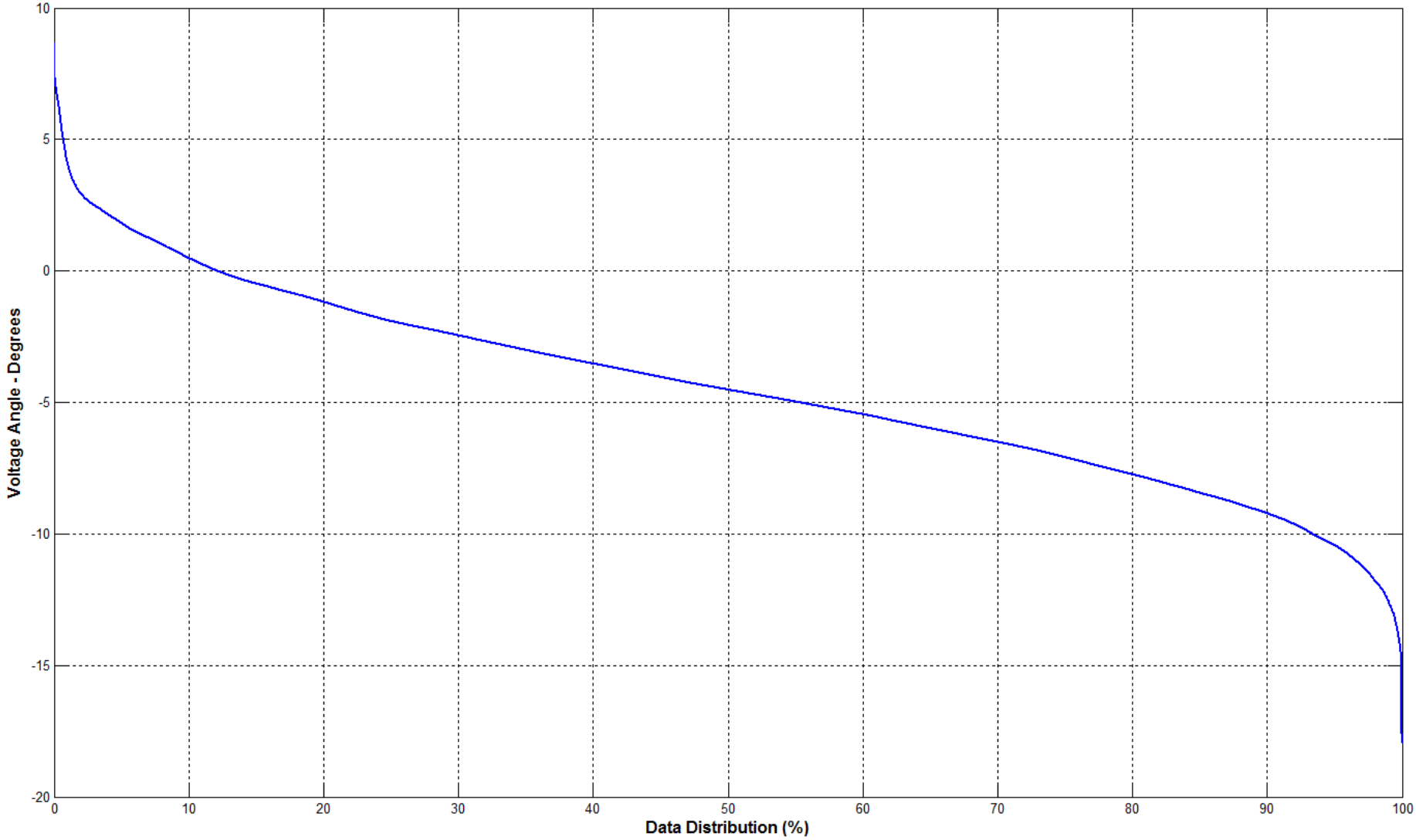

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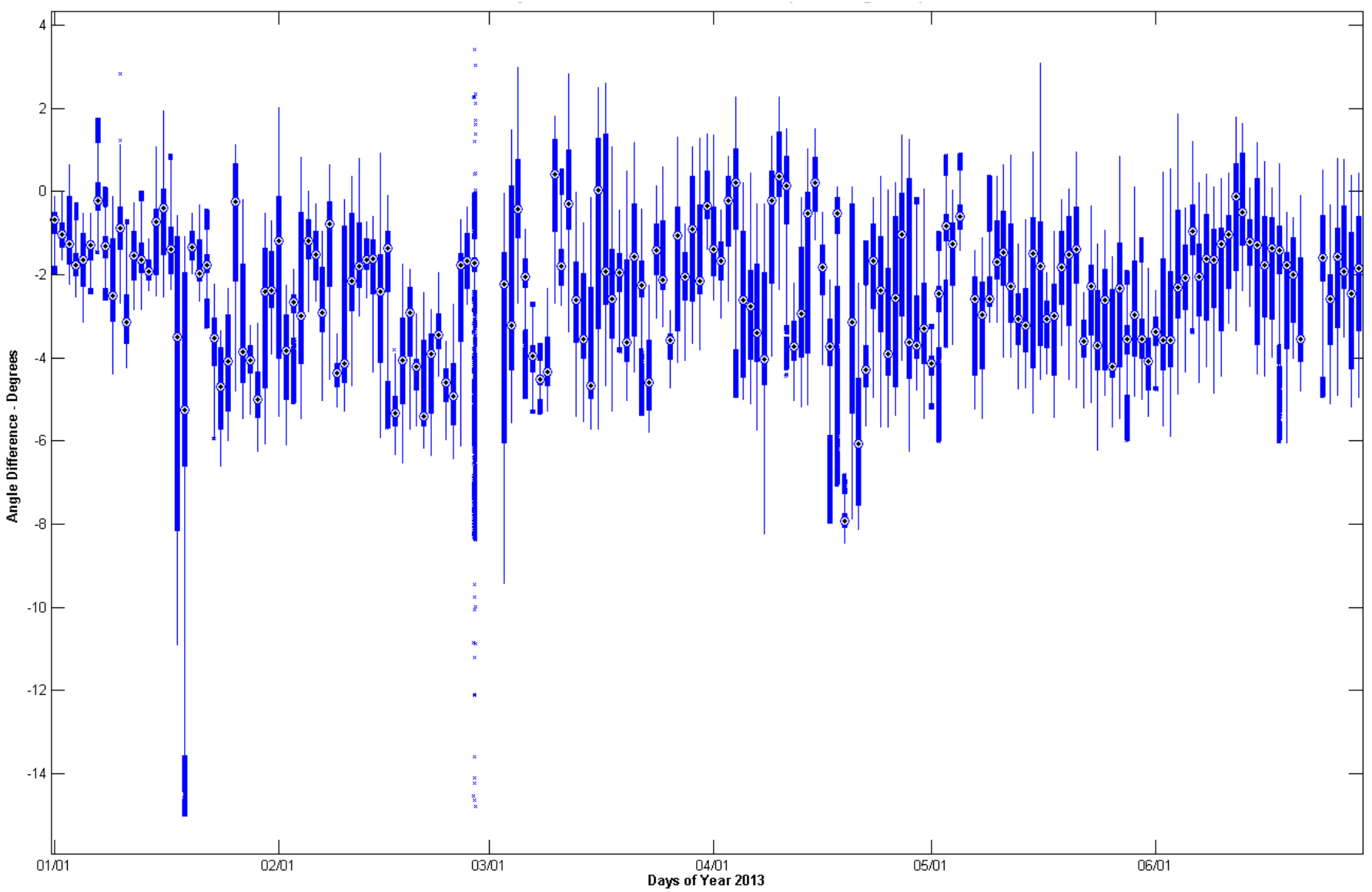

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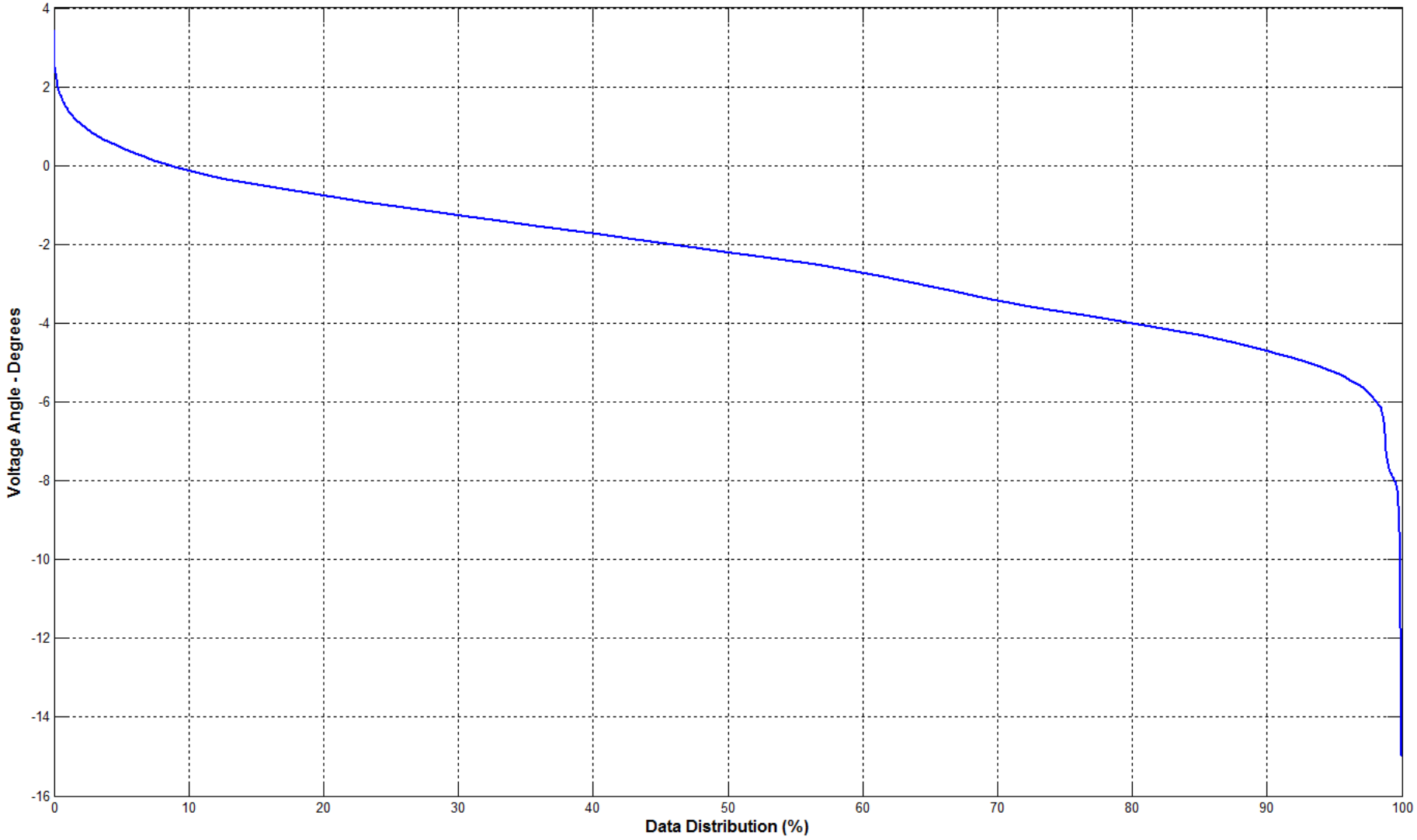

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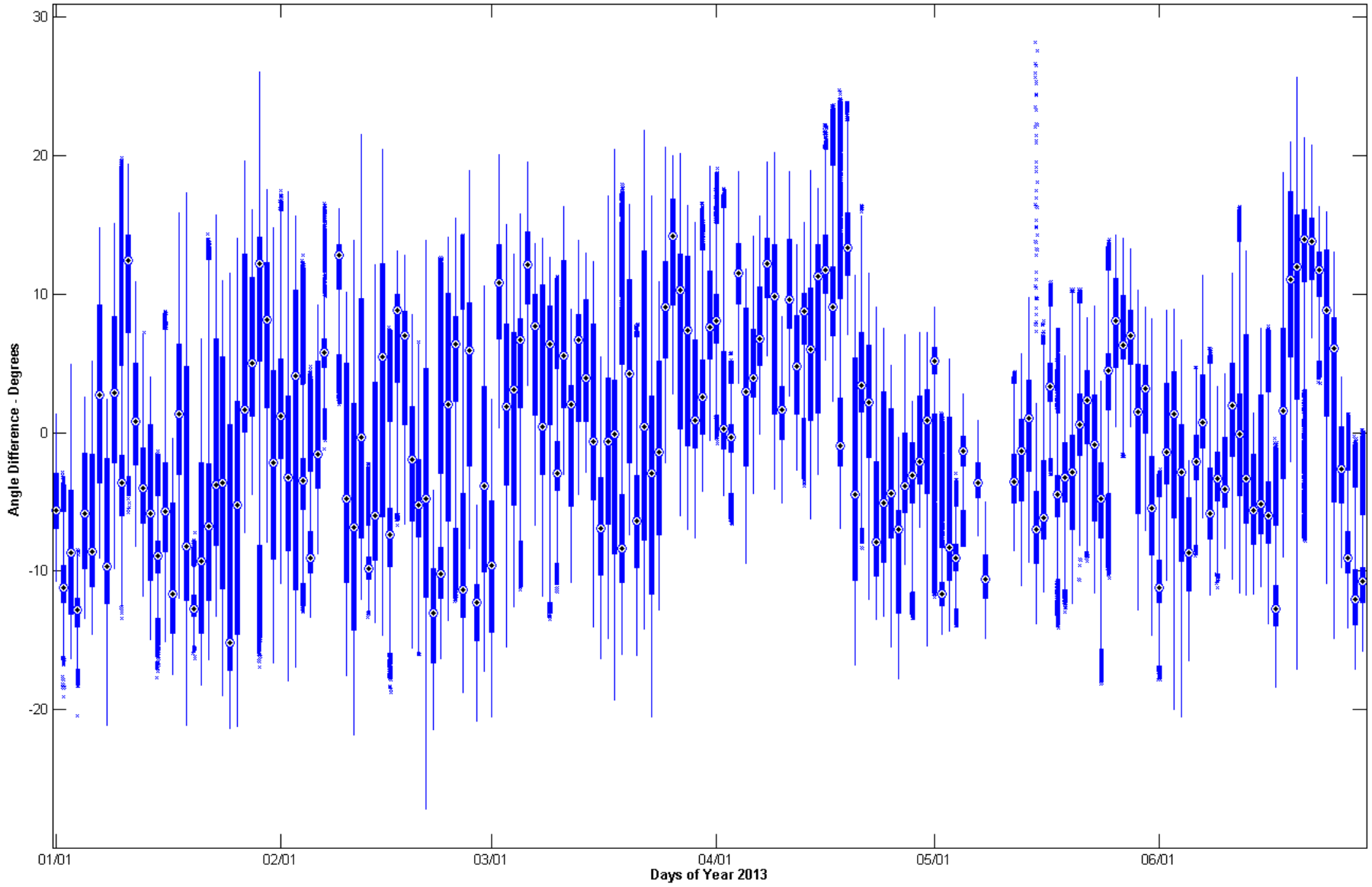

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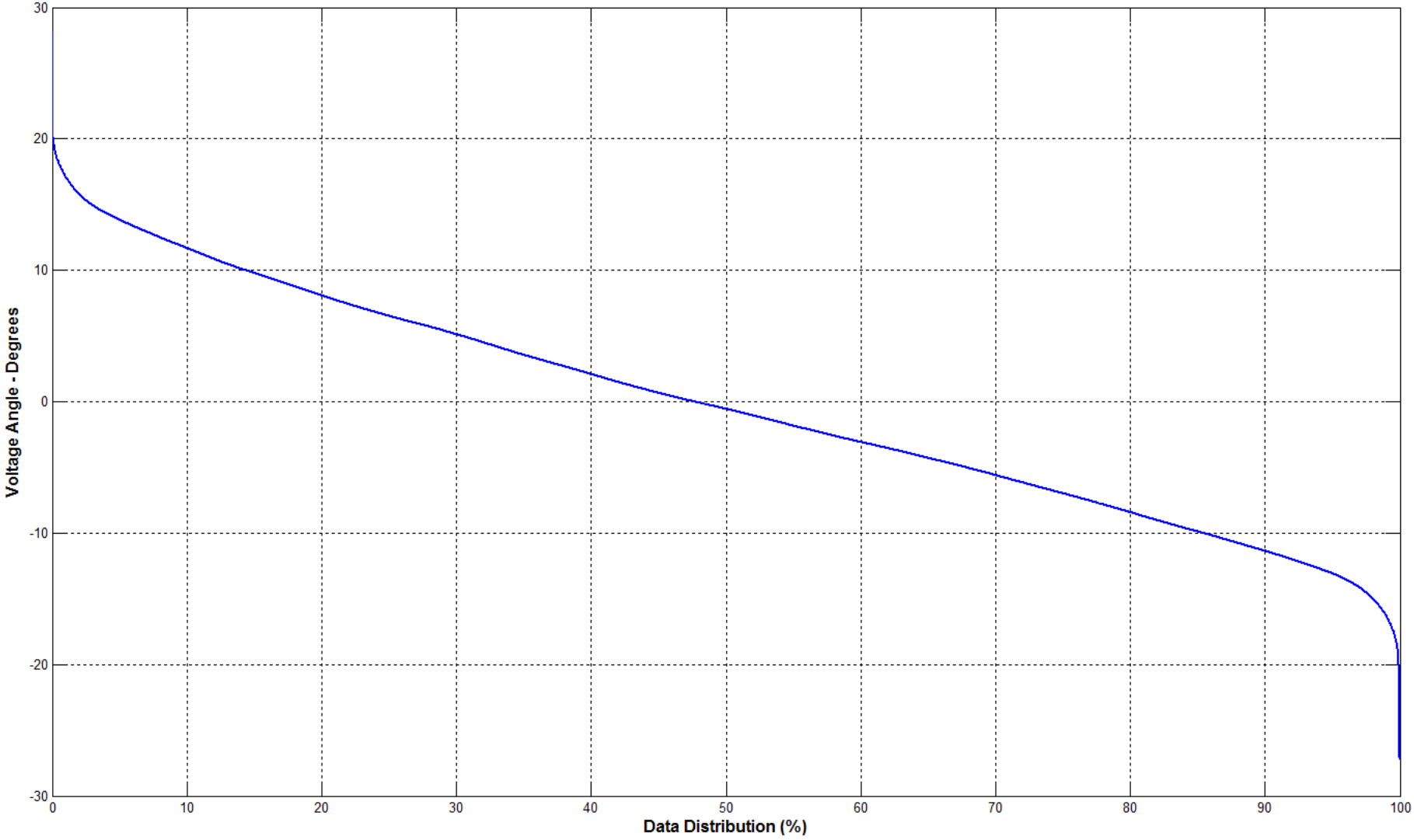

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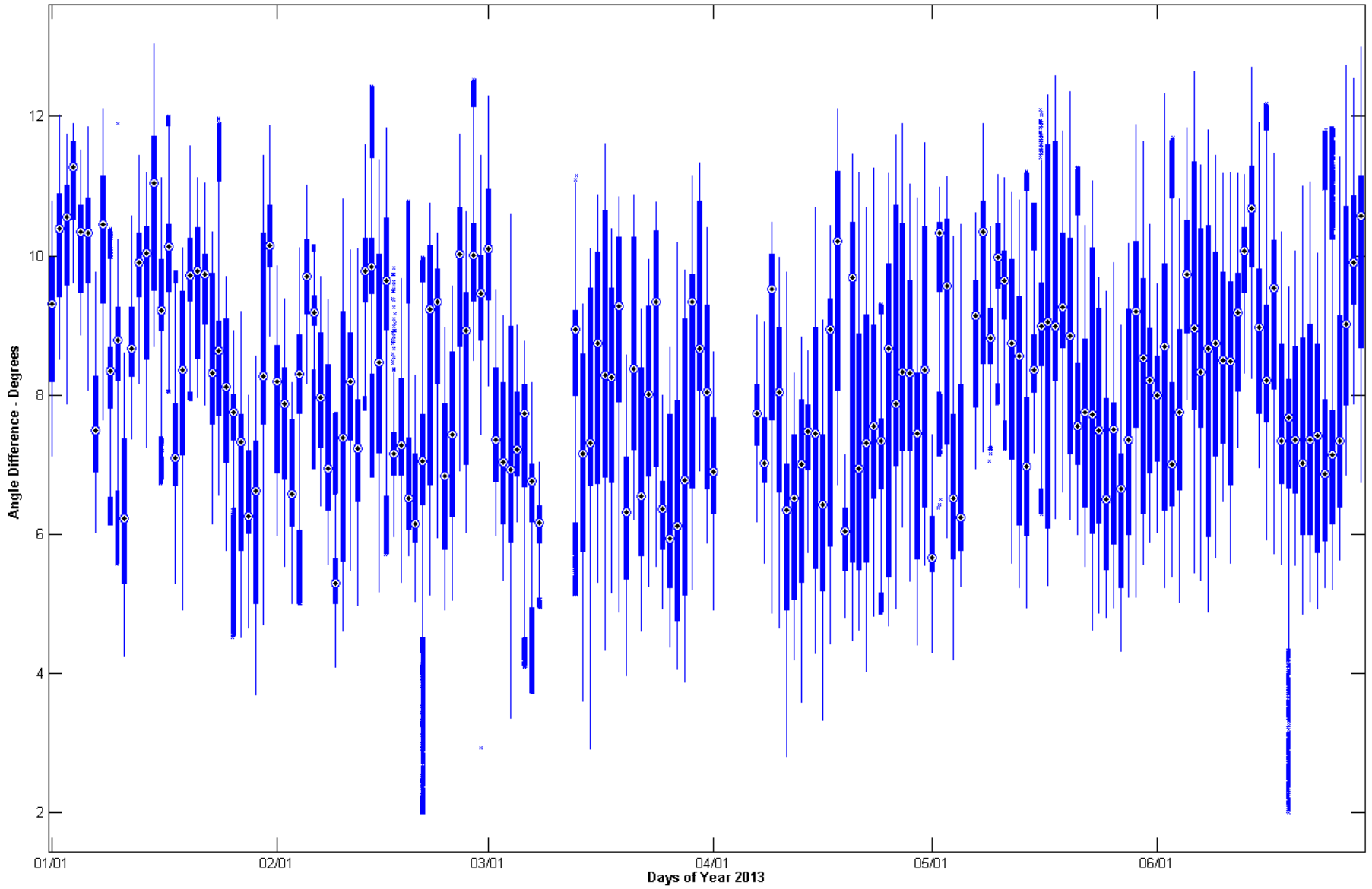

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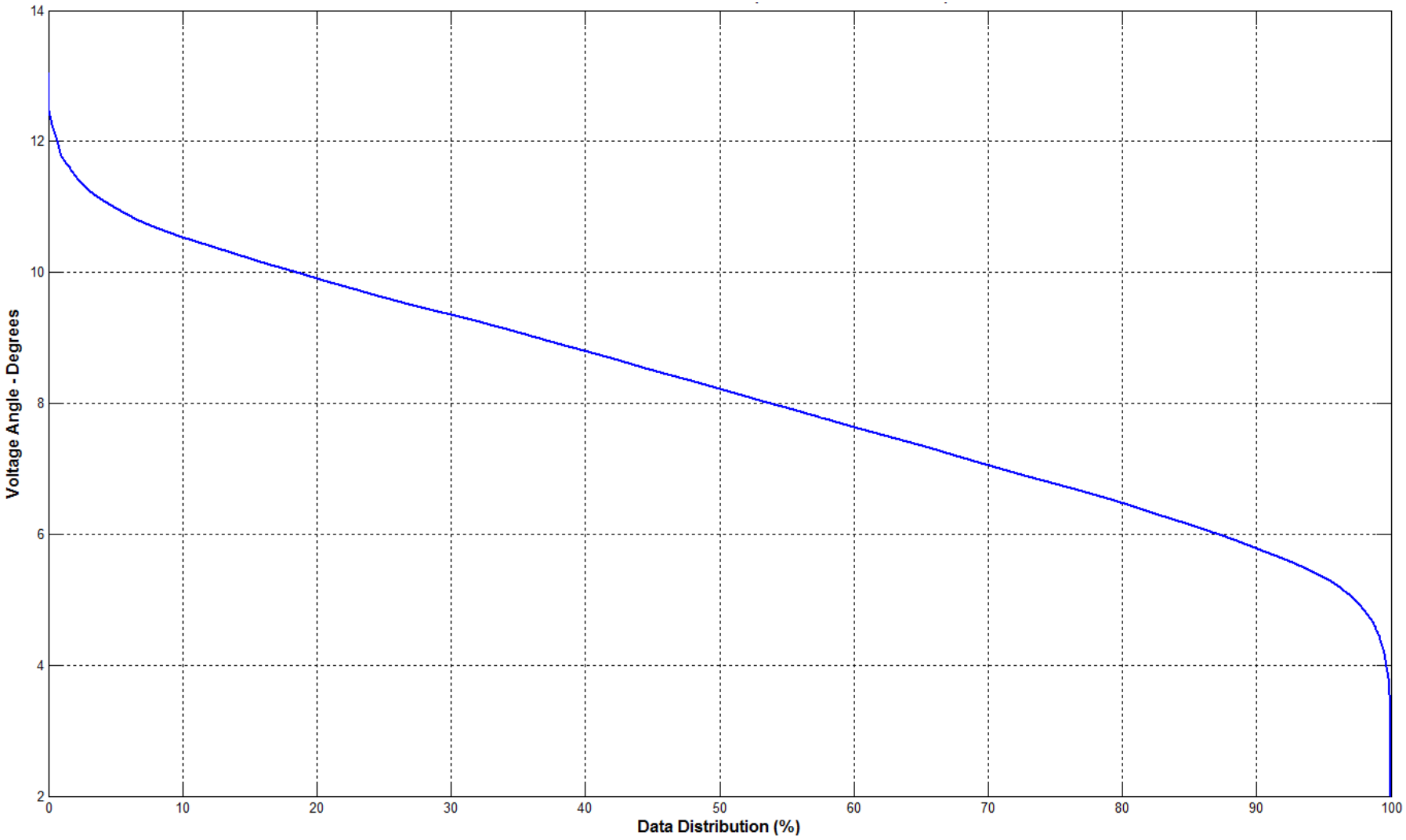

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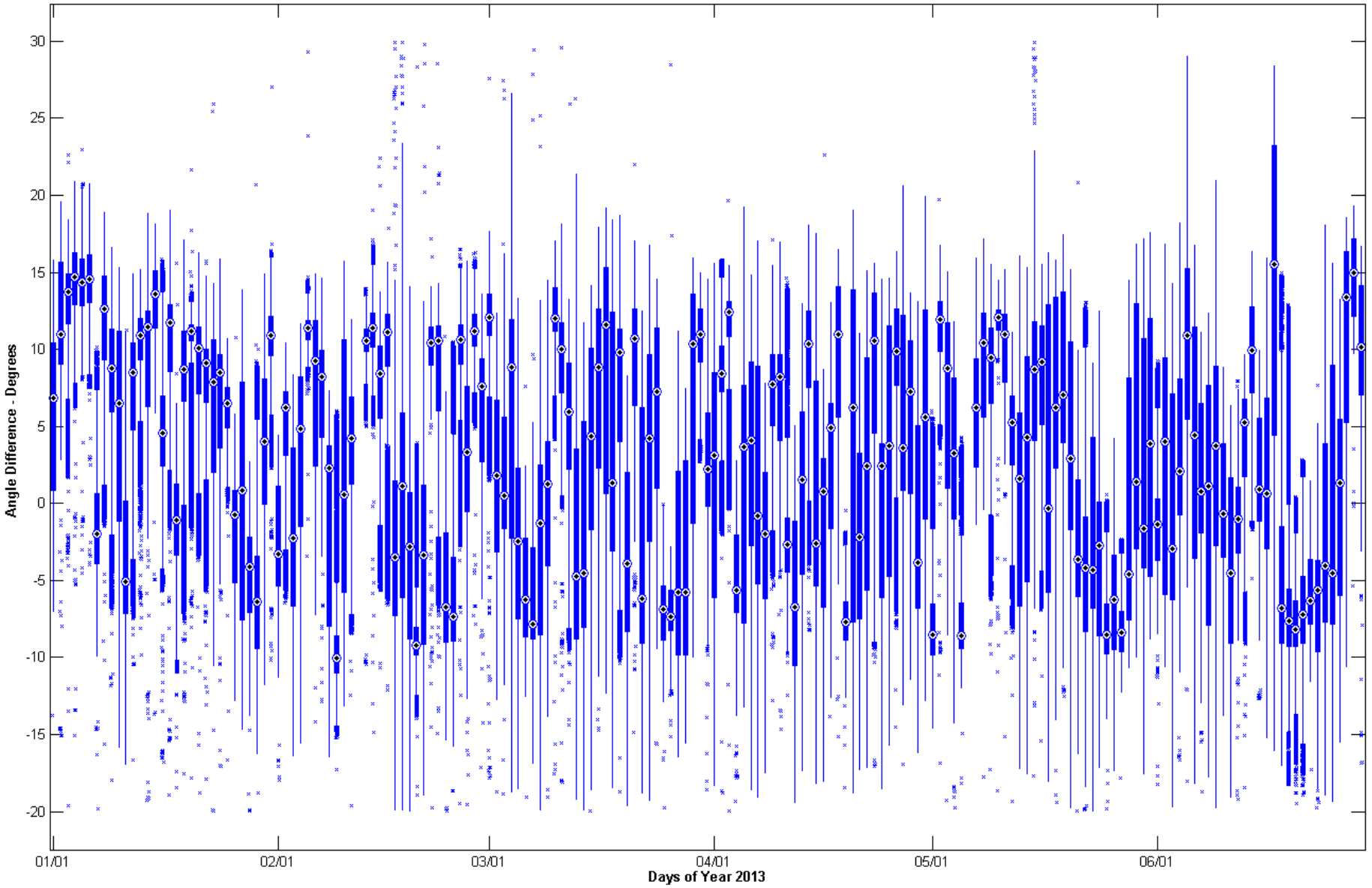

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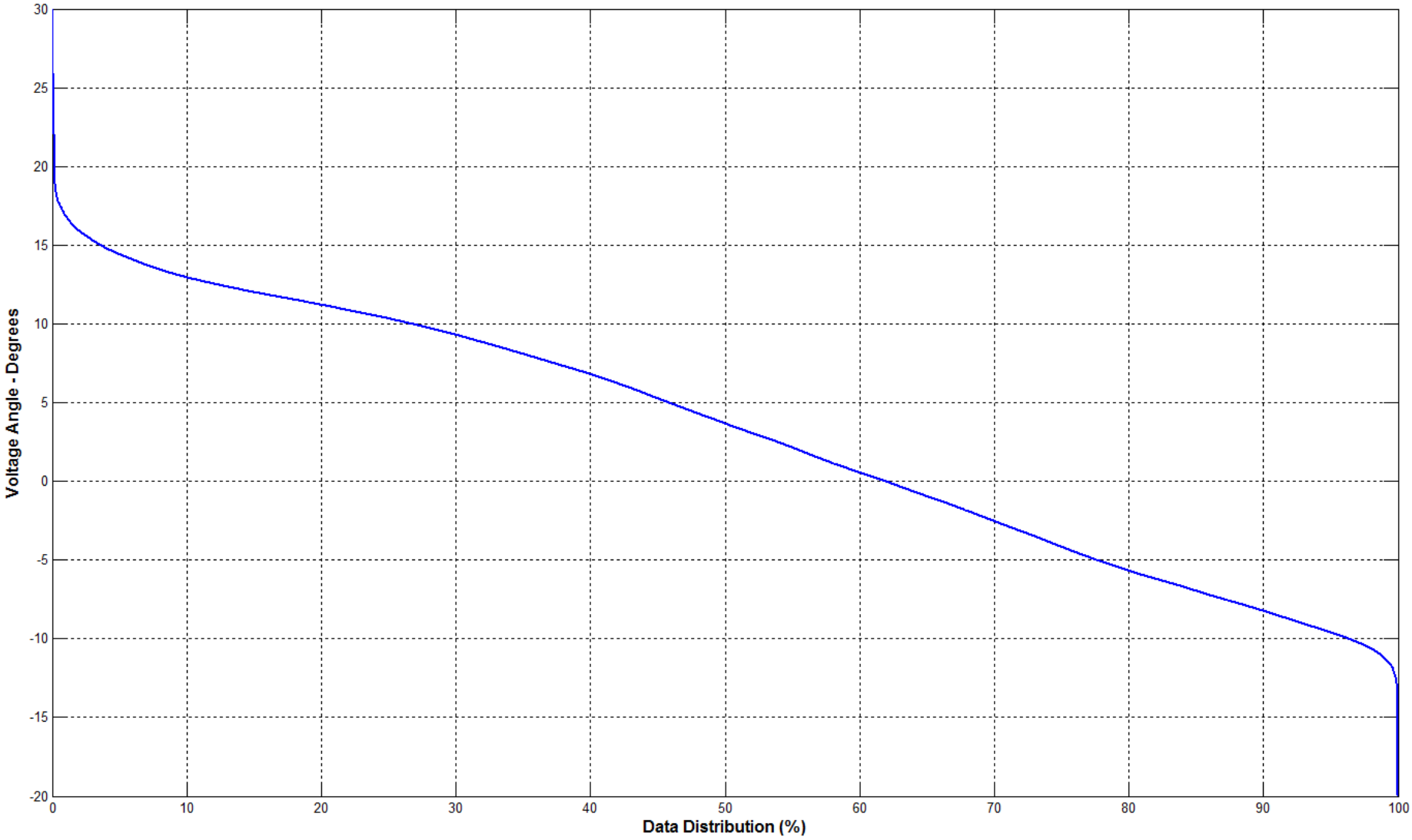

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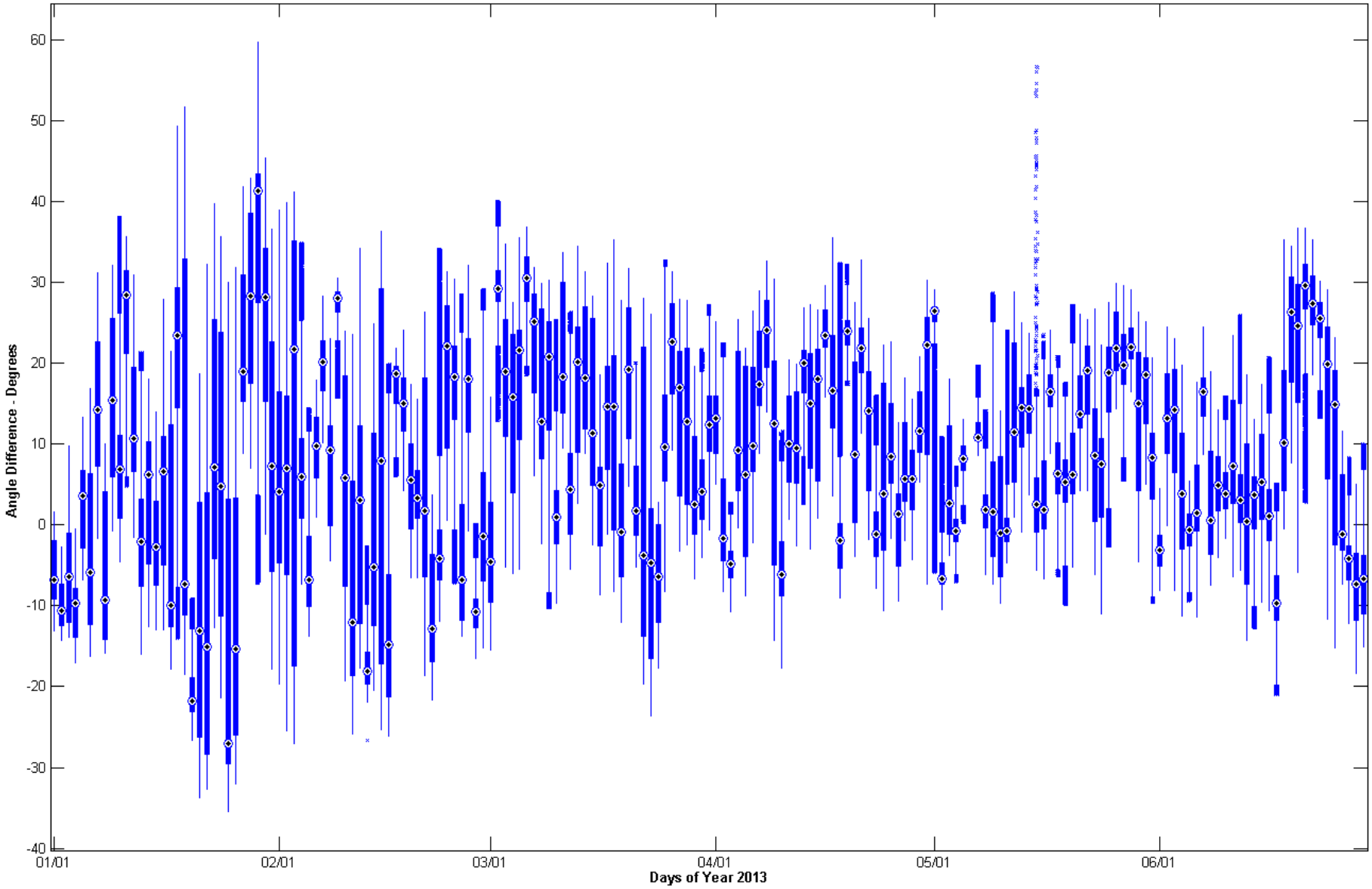

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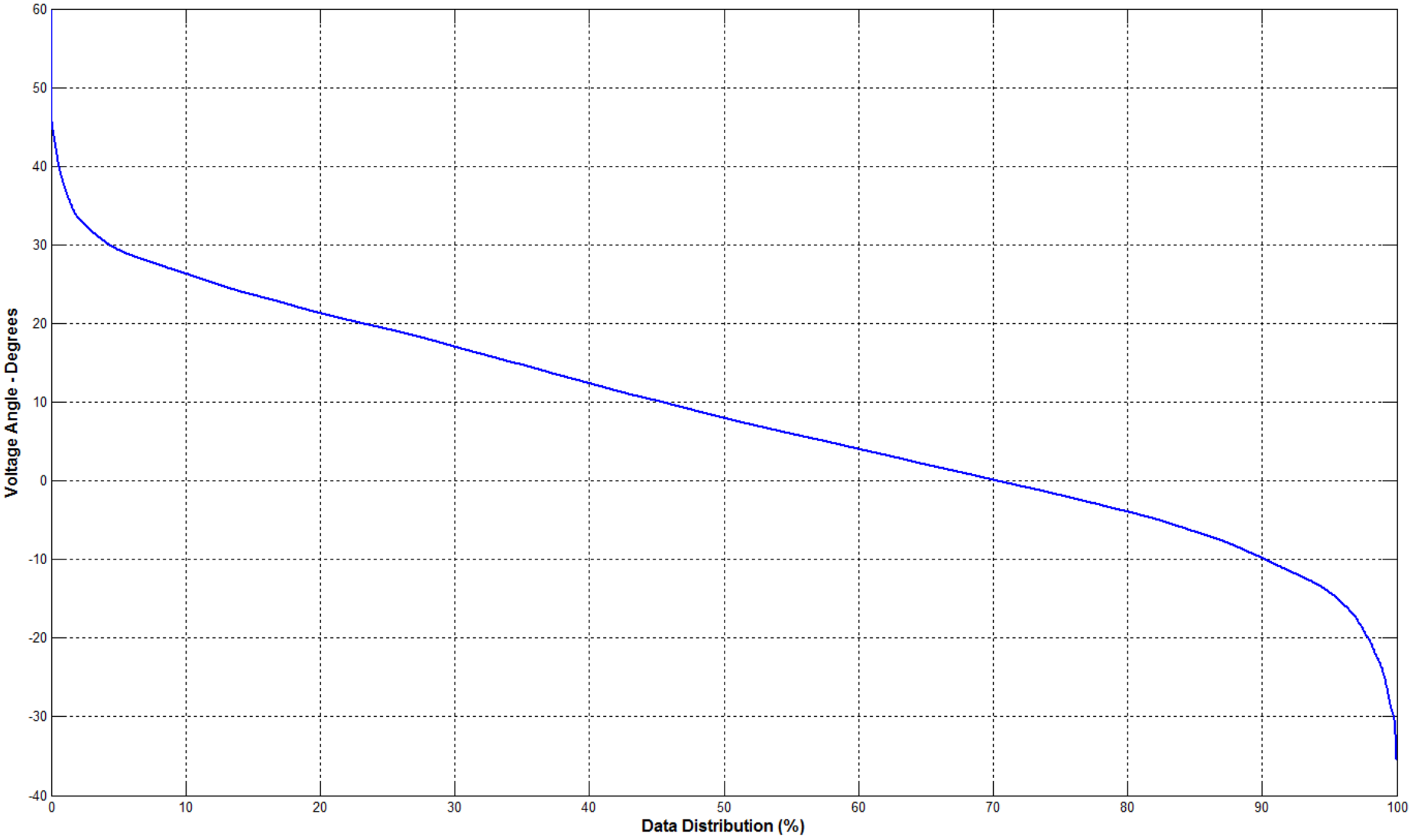

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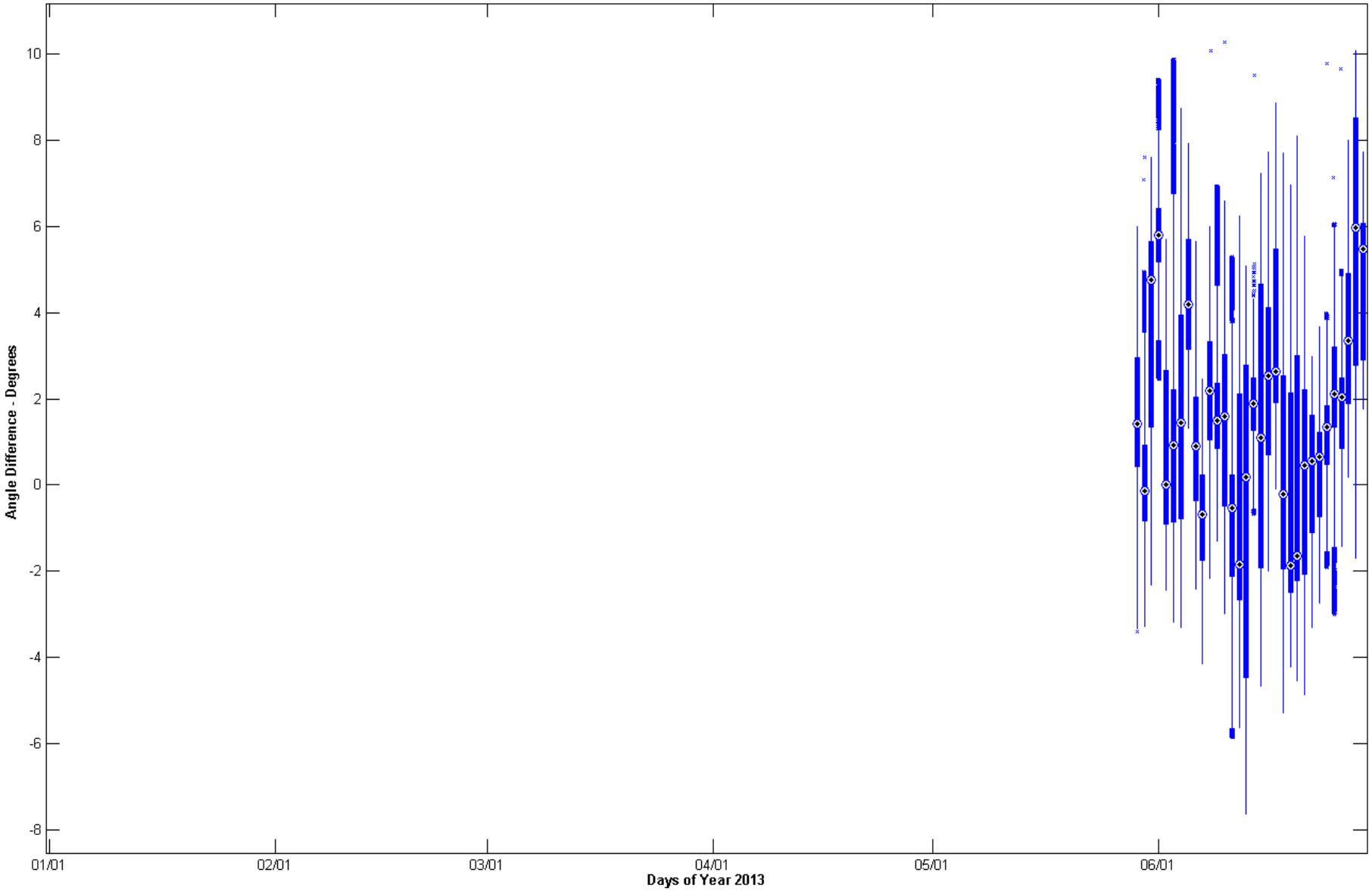

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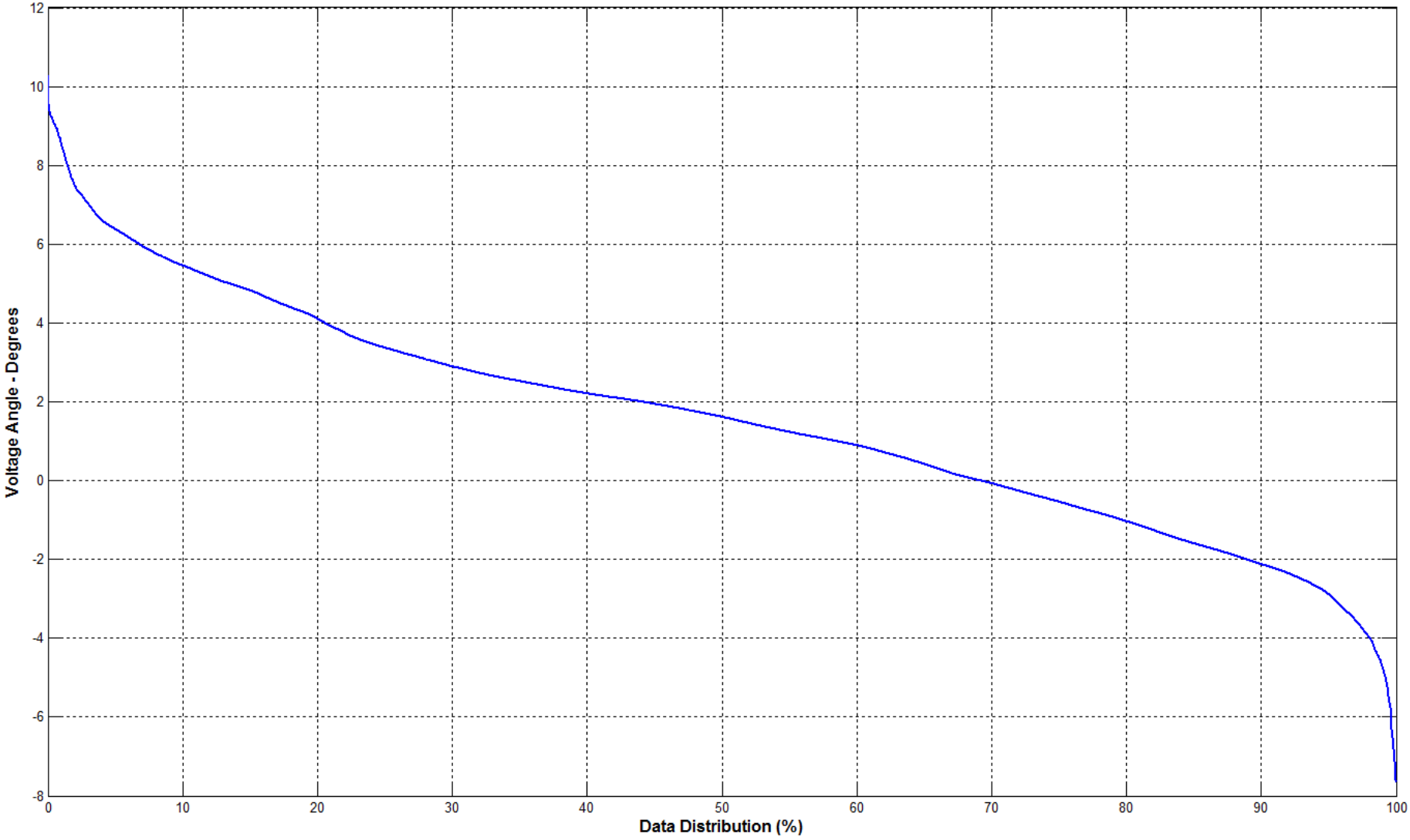

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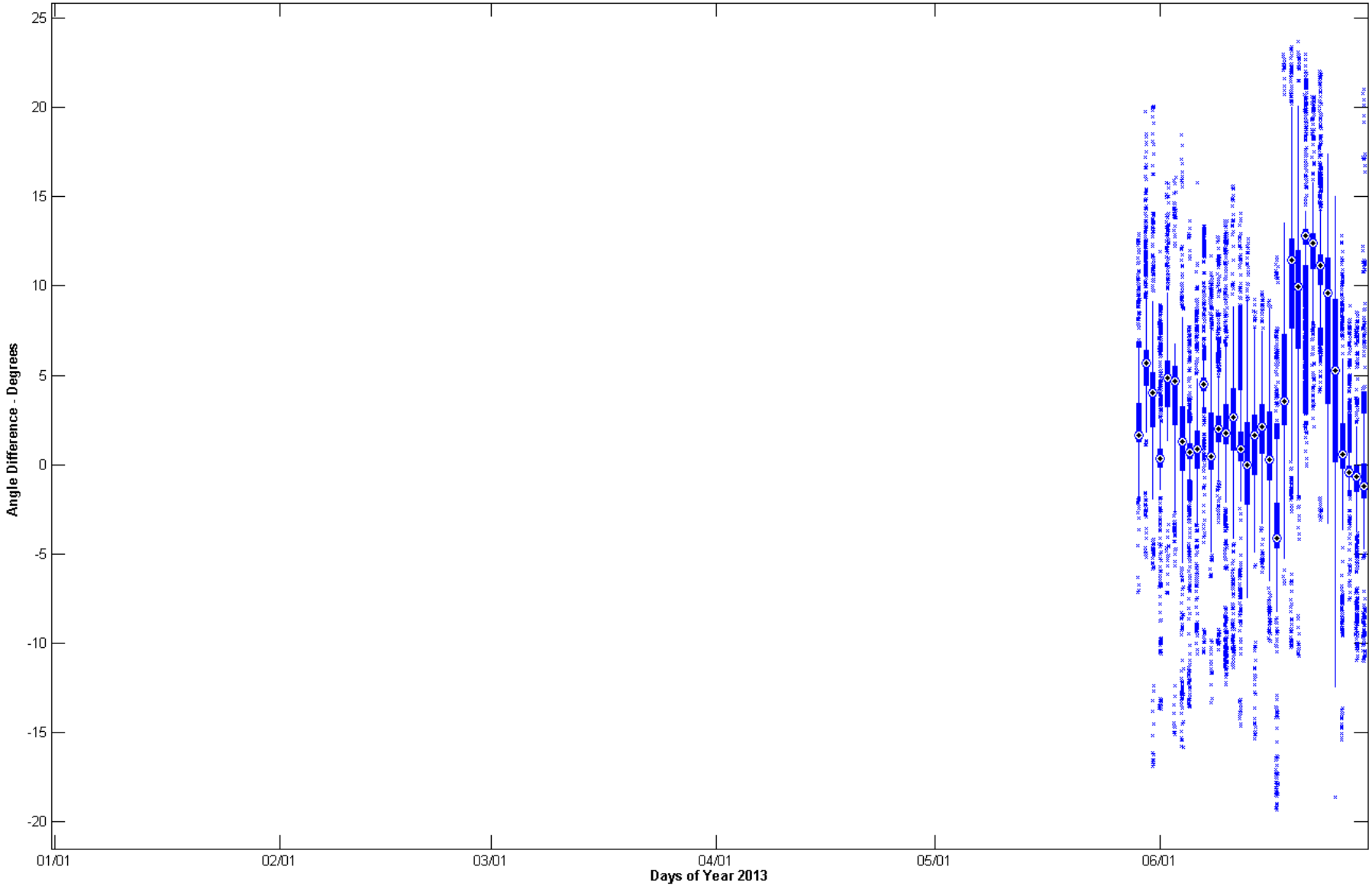
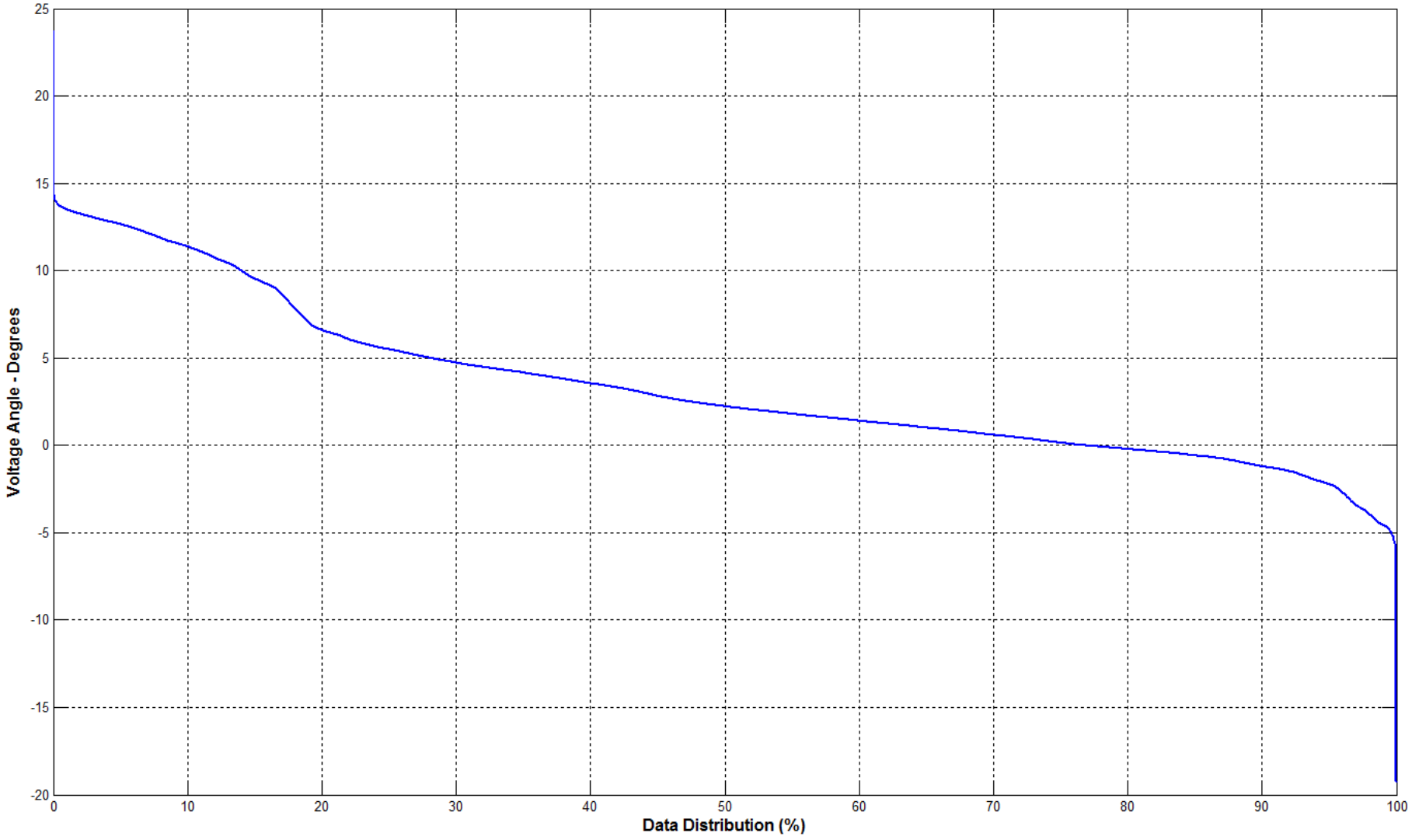
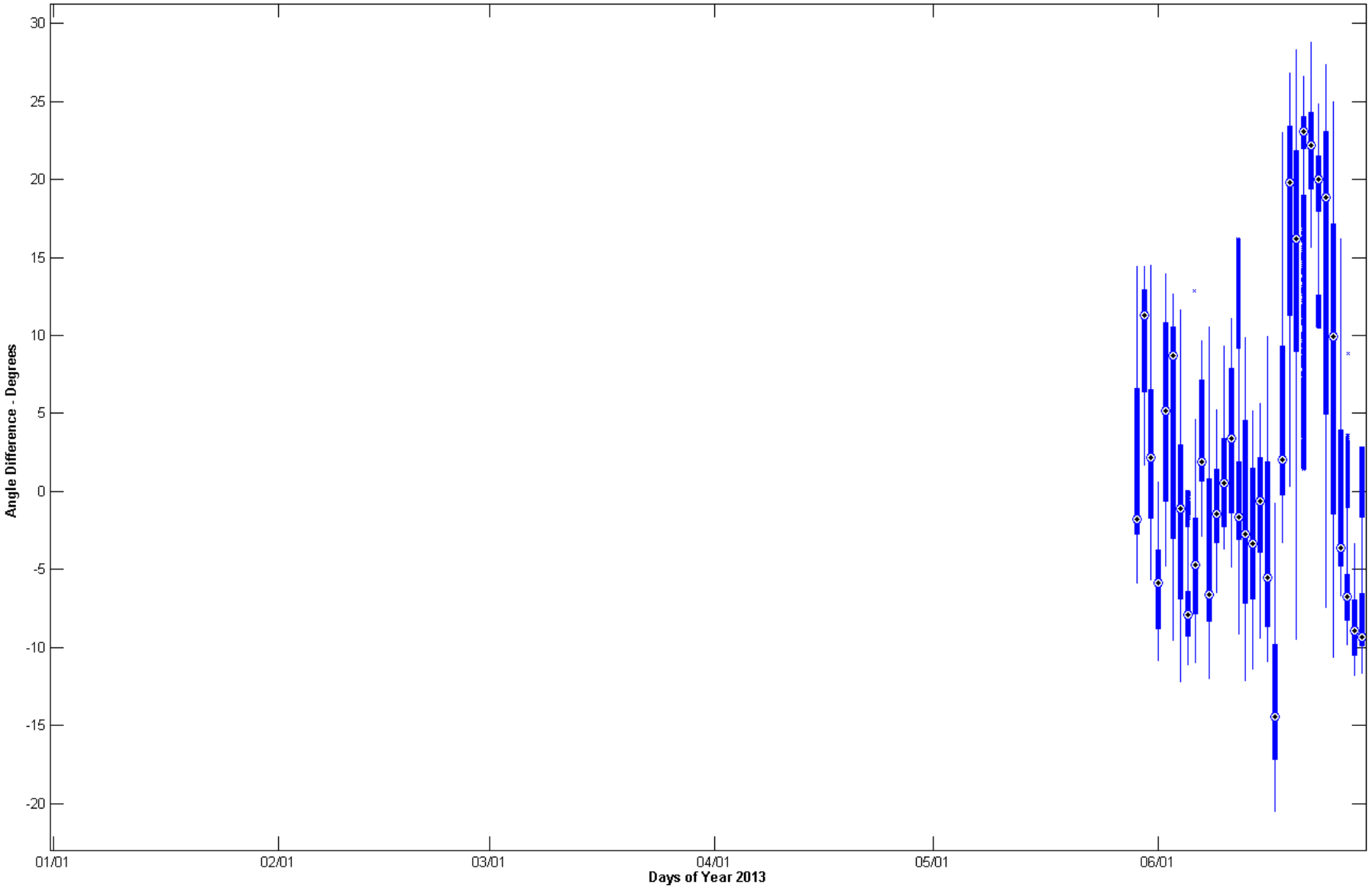

25
20
15
10
5
0
-5
-10
-15
-20
Angle Difference - Degrees
01/01
02/01
03/01
04/01
05/01
06/01
Days of Year 2013

West 9 – West 1


Voltage Angle - Degrees
25
20
15
10
5
0
-5
-10
-15
-20
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

West 9 – North 1



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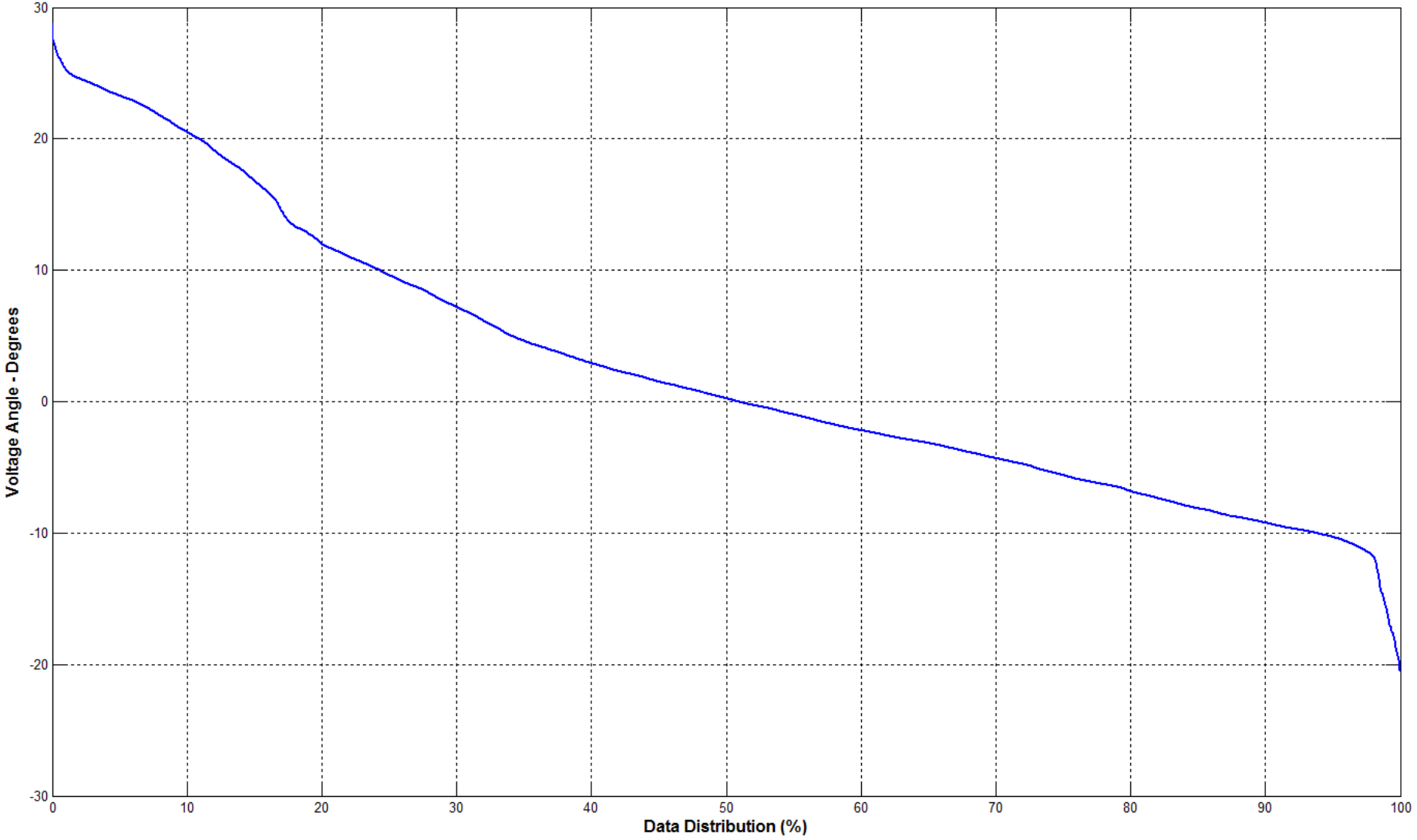
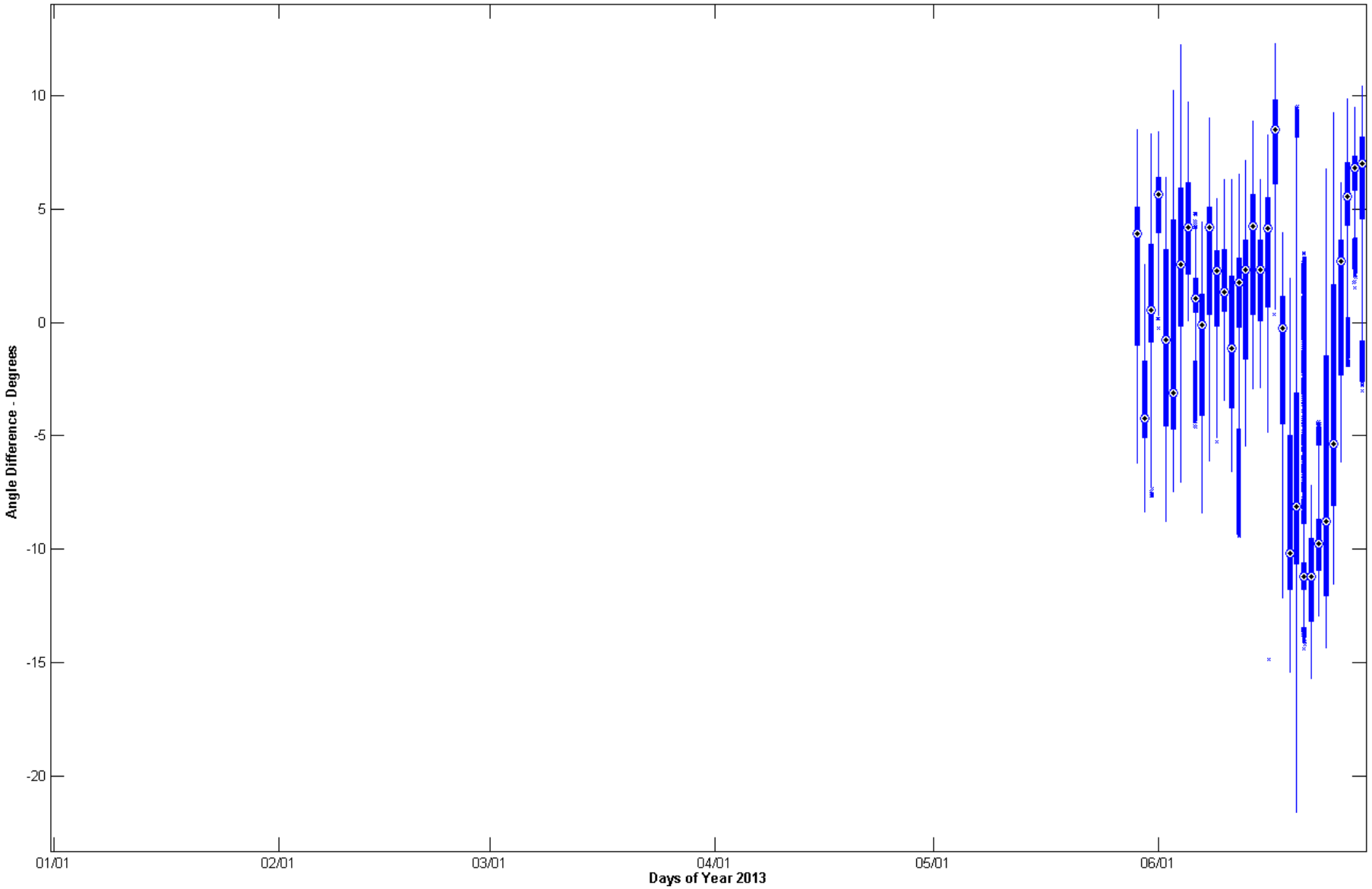


West 14 – West 5



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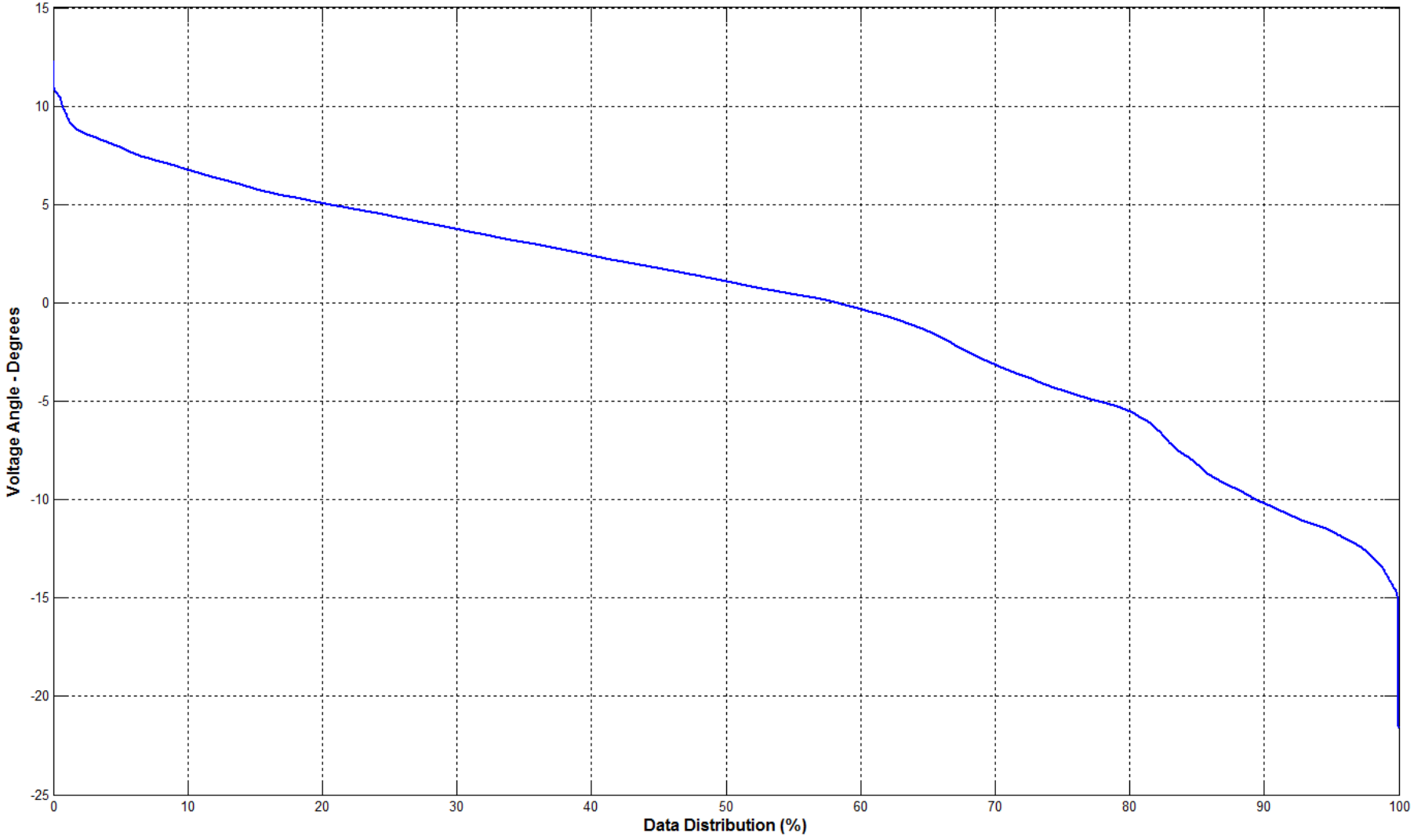

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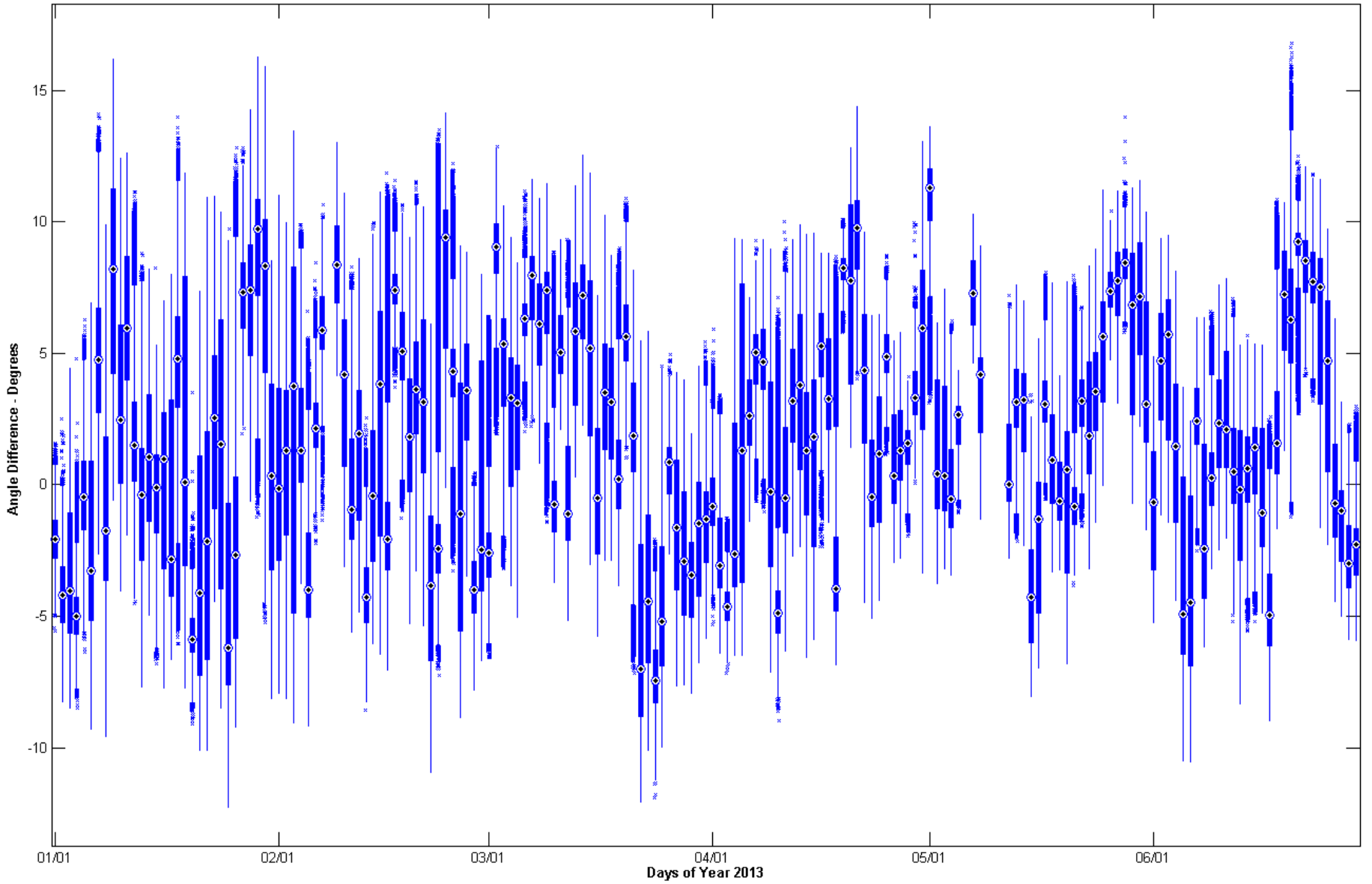

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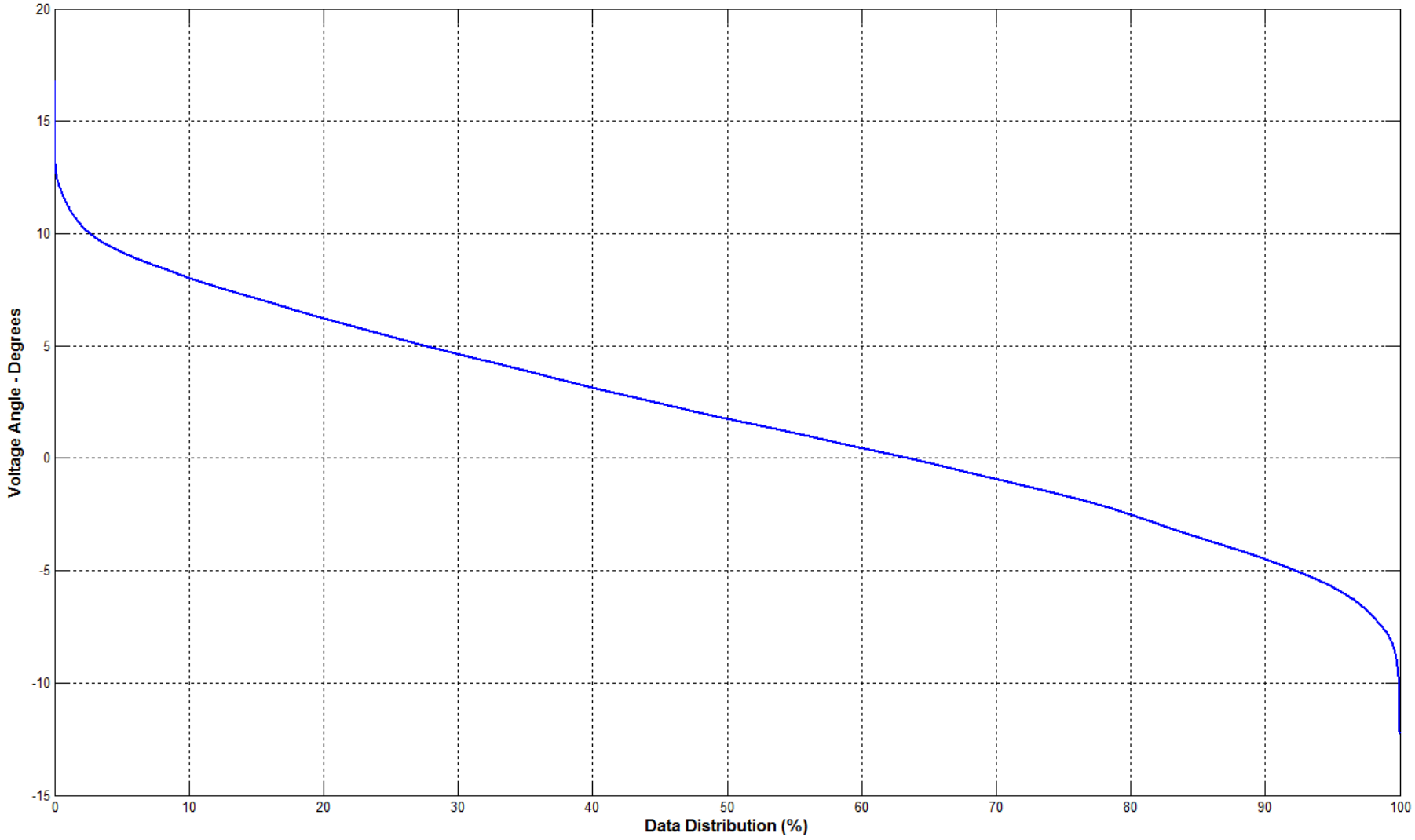

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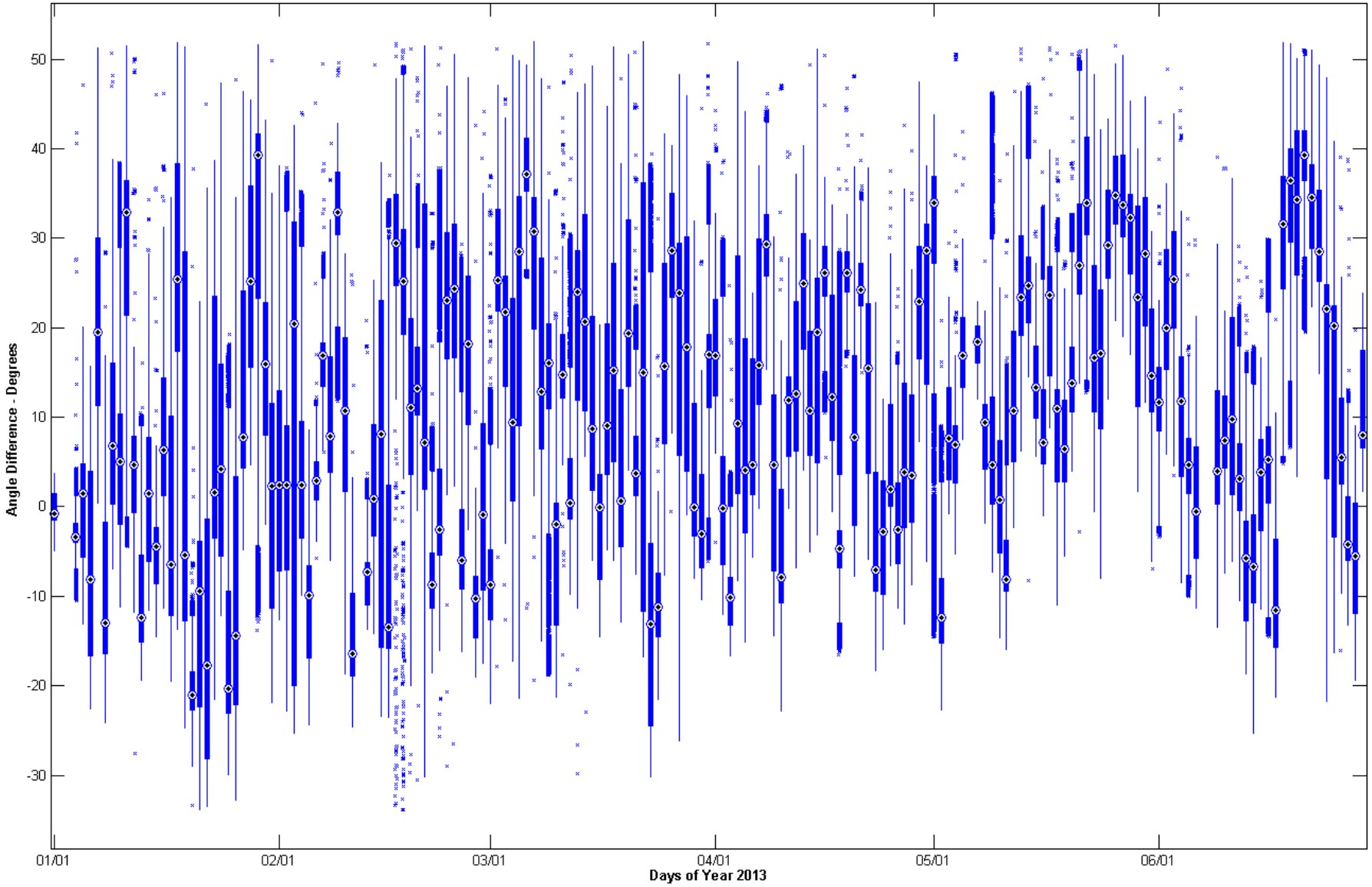

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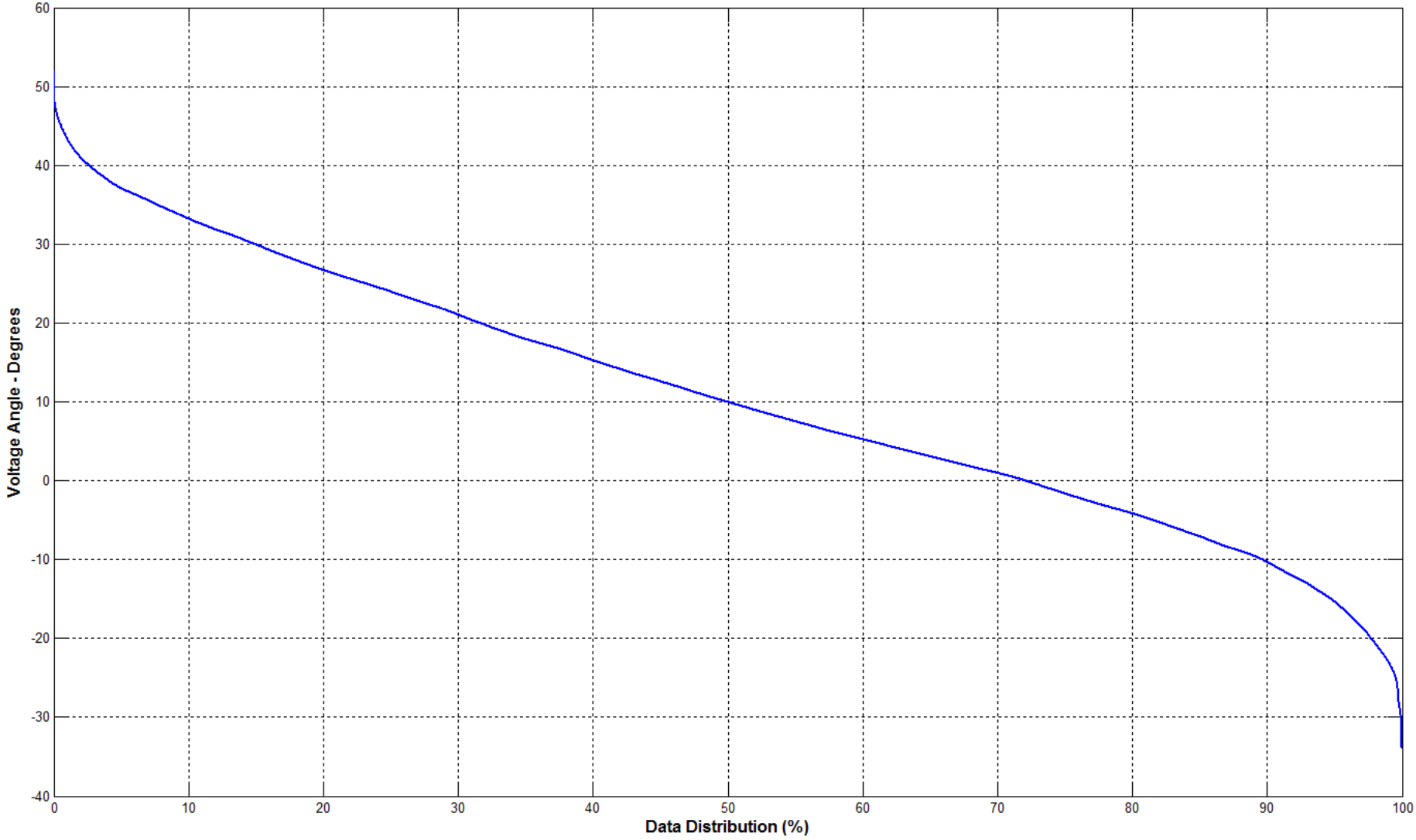

Attachment 4. Updated Baselining Study #2 for 2013

Baselining Analysis Update 2:

2013, 12-Months ~~2T~~ Data

Discovery Across Texas Project

Submitted By:

Electric Power Group

John Ballance
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June 30, 2014

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External Version

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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 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. 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 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.

This 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 new345 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 the ERCOT grid using State Estimator data plus phasor data from January 2012 to December 2013 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. Extracted key metric information (i.e., voltage, angles and angle differences).
2. Analyzed extracted data and developed a 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. Monitored voltages and angle differences (pairs) and developed 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. Prepared 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. Developed a comparison table to show the differences in results for voltages and angle differences using 2012 and 2013 data.
6. Prepared 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 the Real Time Dynamics Monitoring System[1] (RTDMS®), and voltage and angle difference alarm settings for use in RTDMS® to alert operators when grid stress is approaching limits.

The results presented in this report should be considered preliminary. 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 being analyzed, 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. Downloaded the ERCOT data provided in MySQL format.
2. Converted the ERCOT binary format data into alphanumeric format.
3. Converted MySQL data to comma-separated value (CSV) data files for use in MatLab data analysis programs.
4. Linked ERCOT data though the MySQL server to the EPG local *enhanced* Phasor Data Concentrator (*e*PDC™) 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 8,060259, and US Patent 8,401,710.

5. Down-sampled phasor data from 30 SPS to 1 SPS, and downloaded it to the local computer for analysis.
6. Applied status flag filtering to perform the first step in data cleaning.
7. Developed data filtering algorithms and wrote code in MatLab to perform the second step of data filtering.
8. Addressed small data dropouts by interpolation techniques or filled 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 substations 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 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 SE 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:

<20%	**20% to 60%**	**61% to 80%**	**>80%**
2013			
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
2012			
<40%	**41% to 60%**	**61% to 80%**	**>80%**
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 voltage 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-whisker 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. Obtained and processed phasor data and state estimator data.
2. Extracted information to identify max, min, and average values from these data sources. Prepared summary tables showing results of all data, including data saved during events.
3. Used phasor and SE data to develop weekly box-whisker graphs and time duration curves for angle differences.
4. Identified 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 as normal operating limits. A summary showing these normal operation limits was obtained using phasor and SE data and tabulated in the same table for comparison.
5. Analyzed results, identified limits, and reported results for each pair selected.

B. Study Approach

Electric Power Group used the following approach:

1. Obtained available phasor data and state estimator data from ERCOT.
2. Extracted phasor data and condition it for processing.
3. Solved state estimator cases and saved solved cases.
4. Selected 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. Identified the substations and subsets of substations, and pairs, for which phasor data is available.
6. Developed statistical charts including time duration curves and box-whisker graphs for voltage magnitudes and angles, and for angle pairs.
7. Performed statistical analyses to identify angle differences limits for the selected pairs under all conditions. Summarized angle difference limits.
   - Established limits for normal operation based on the criteria described in the corresponding methodology. Summarized 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 were 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 the 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 CCET 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 market 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 kV and 10.1 kV, respectively. Note that Coast 3 345 kV also has a high voltage spread (22.8 kV).
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 voltage 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 - CCET DISCOVERY ACROSS TEXAS PROJECT - VOLTAGE MAGNITUDES - ALL DATA
COMPARISON 2012 vs. 2013 (January 1 to December 31)

				STATE ESTIMATOR DATA - 2012				STATE ESTIMATOR DATA - 2013			
No	Substation	Base kV	Region	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.

Evaluation 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 VoltagePlots - 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 jV 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 kV 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 kV 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 kV 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 kV 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 kV to 355 kV) with large daily swings.
16. There was 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 kV to 365 kV (21 kV range), with a spike up around March 2.
19. South 10: the median voltage changes constantly with a 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 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 outage 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 the 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 Min	Max	Average	% Positive	Min Spread	% Data Available	State Estimator Data - 1/1/13 to 12/31/13 Min	Max	Average	Percent Positive	Min Spread
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 ERCOT; 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-whisker 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)

			DATA ANALYSIS RESULTS														
			Phasor-Normal			State Estimator Data - 1/1/13 to 12/31/13									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	-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 Jannuary 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.

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 the 2012 and 2013 conditions. They are 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 are in the section below.

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

Table 6 - VOLTAGE ANGLE COMPARISON (MONTHLY MEDIAN) 2012 vs. 2013

		VOLTAGE ANGLE MEDIAN		
#	Angle Pair	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. The 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. This is reflected by the 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.

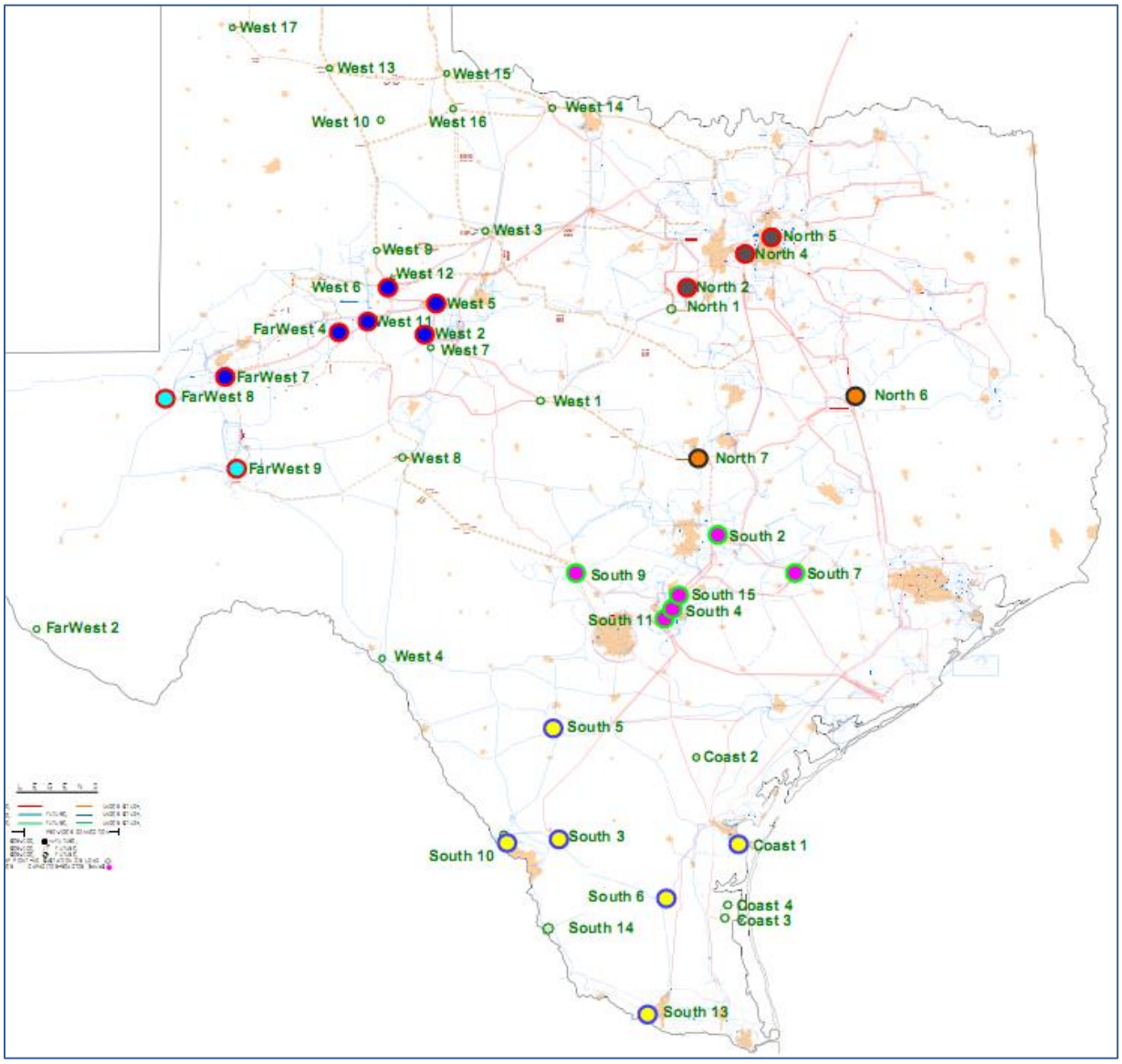
8. BASELINE ANALYSIS FOR ANGLE DIFFERENCES

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:

1. 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.
2. Max-Min angle spread of less than 15 degrees occurred on the following pairs: North 1 to North 4, FarWest 7 to FarWest 8, and West 11 to West 8.
3. Sixteen pairs have spreads between 15 and 40 degrees, and nine pairs have Max-Min spreads of between 40 to 80 degrees.
4. 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.
5. 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						Not enough data available				

* 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, provides 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 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 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 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 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, around the end of March 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		

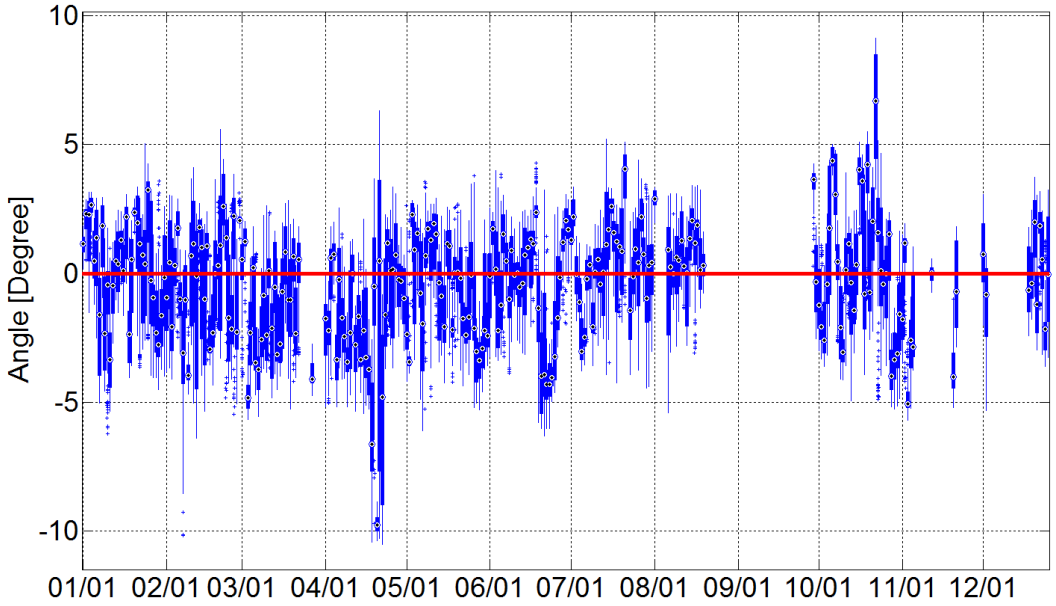
NOTE: These results were obtained with 2013 data.

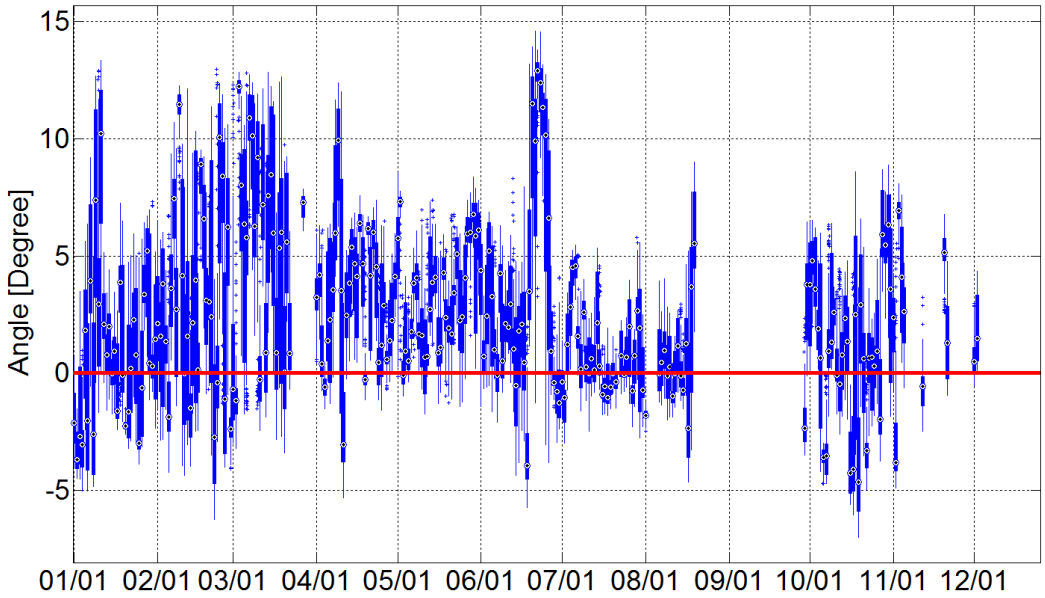
E. Observations from Table C-2

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 the July through December period. Since West 14 is the common substation for these three pairs, it is reasonable to suspect that the EMS data at West 14 needs to be checked.
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; this is 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 lasted several days before returning to the original values. If the abrupt changes are due to construction/maintenance work, then the "normal operations" angle differences may need to be revisited with feedback from ERCOT operations 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 MONOTORING

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 the 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 PMUs are 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								
				Phasor Data		RECOMMENDED ALARM LIMITS				SE Data-Normal		
No	Angle Pair FROM - TO		Base kV	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-month study period.

b. Phasor Data Availability for 2013

Several PMUs were installed in 2013, some of them in late 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 kV 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 higher than 15 kV: West 1, West 9, Coast 4, Coast 3, West 8, and South 9.

e. Voltage Angle Variability at 345 kV and 138 kV Substations (Reference: 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 (Reference: North 7) were observed 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 changes 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 as 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

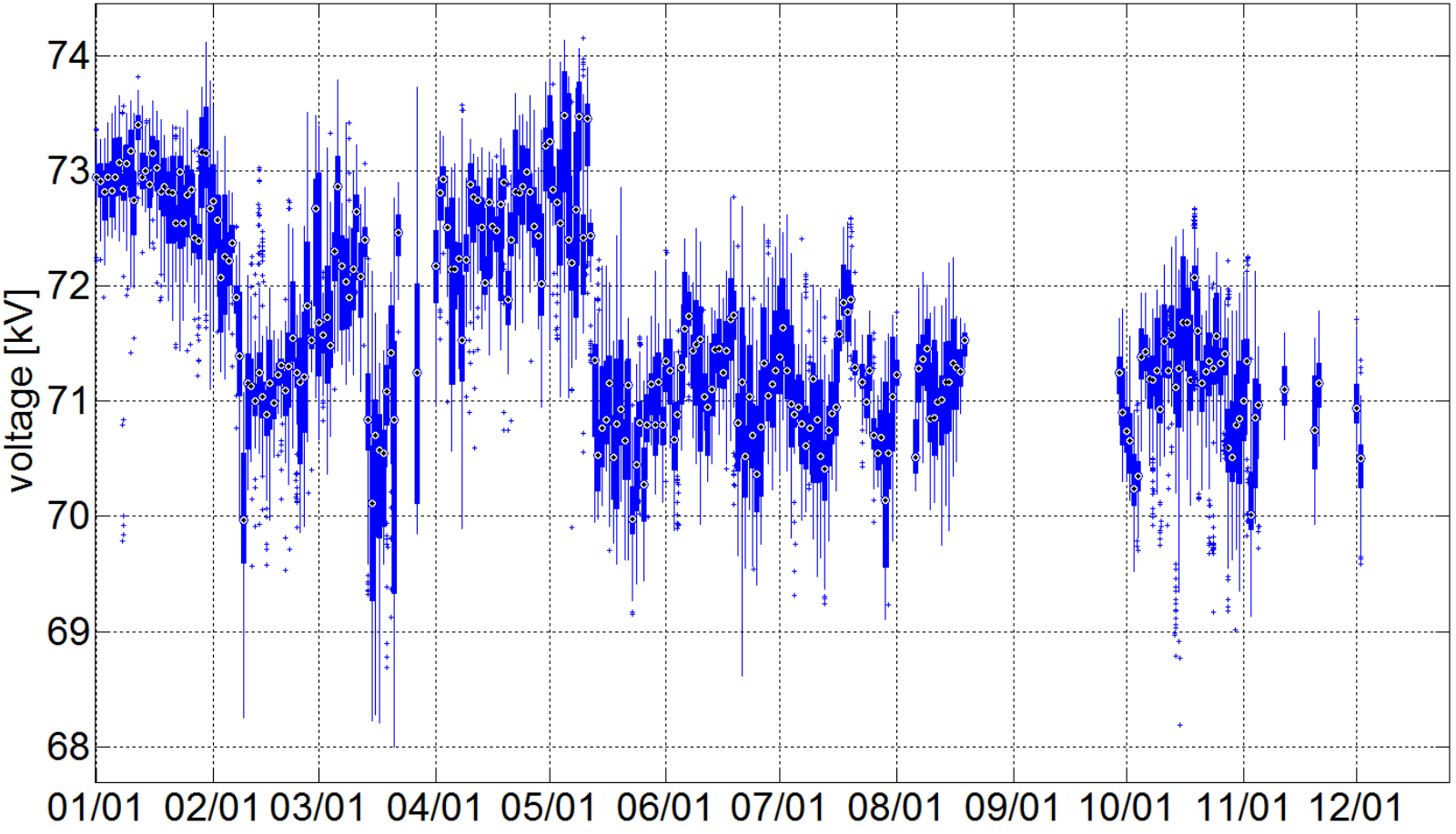
State Estimator Data: January to December 2013
Box-Whisker Plots and Time Duration Curves

Electric Power Group

CCET

ERCOT

West 10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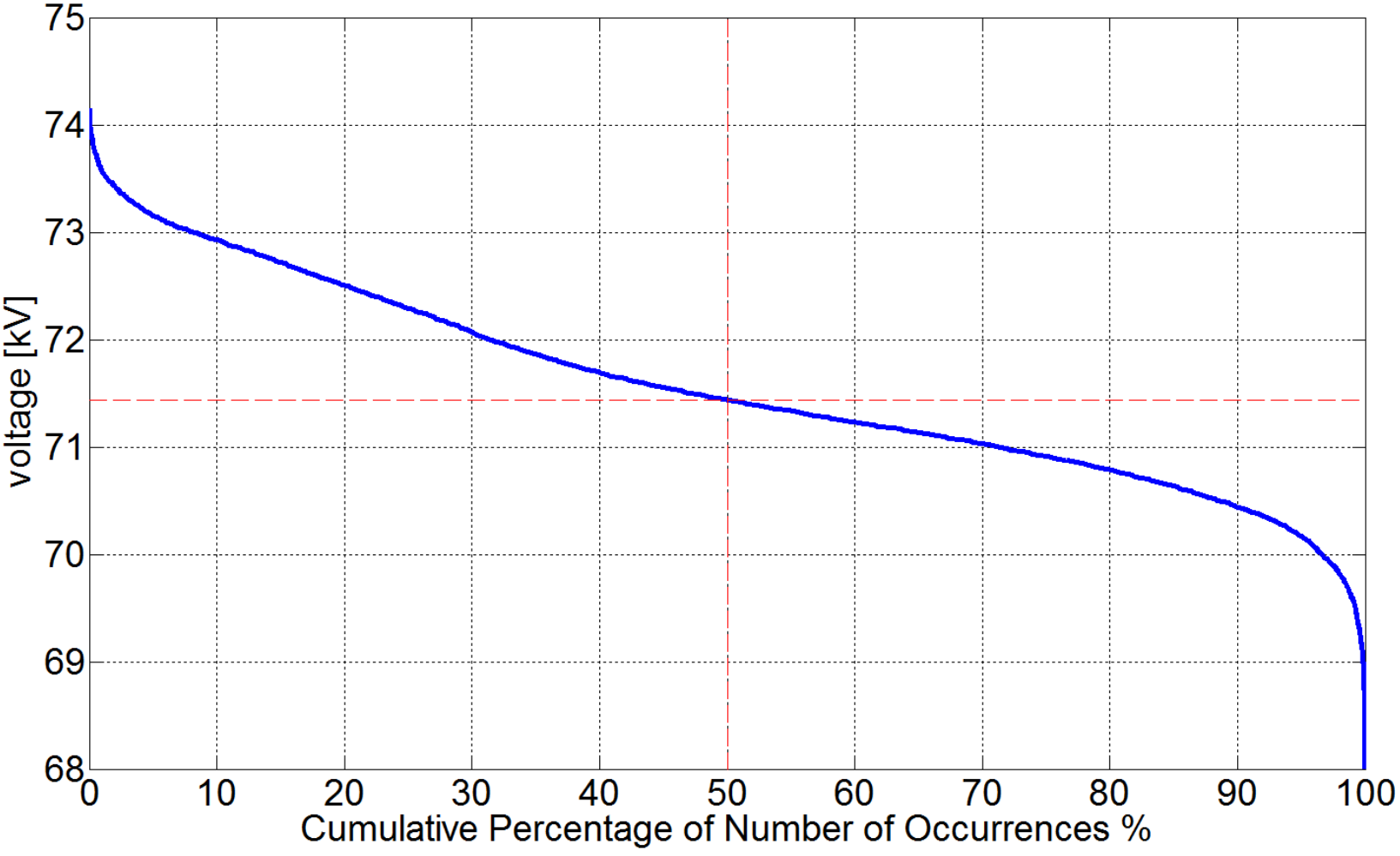
12/01

West 10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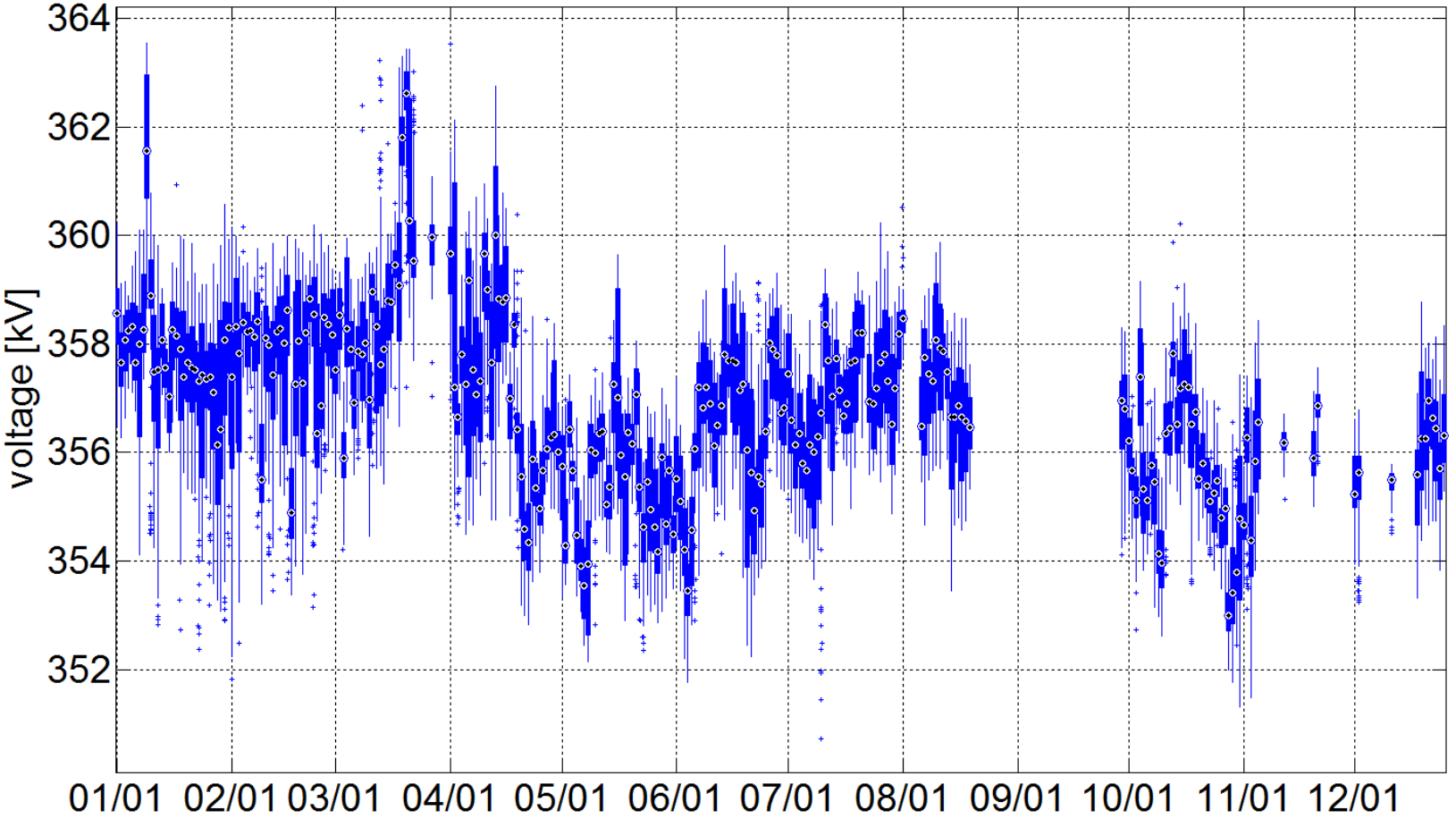
Cumulative Percentage of Number of Occurrences %

West 14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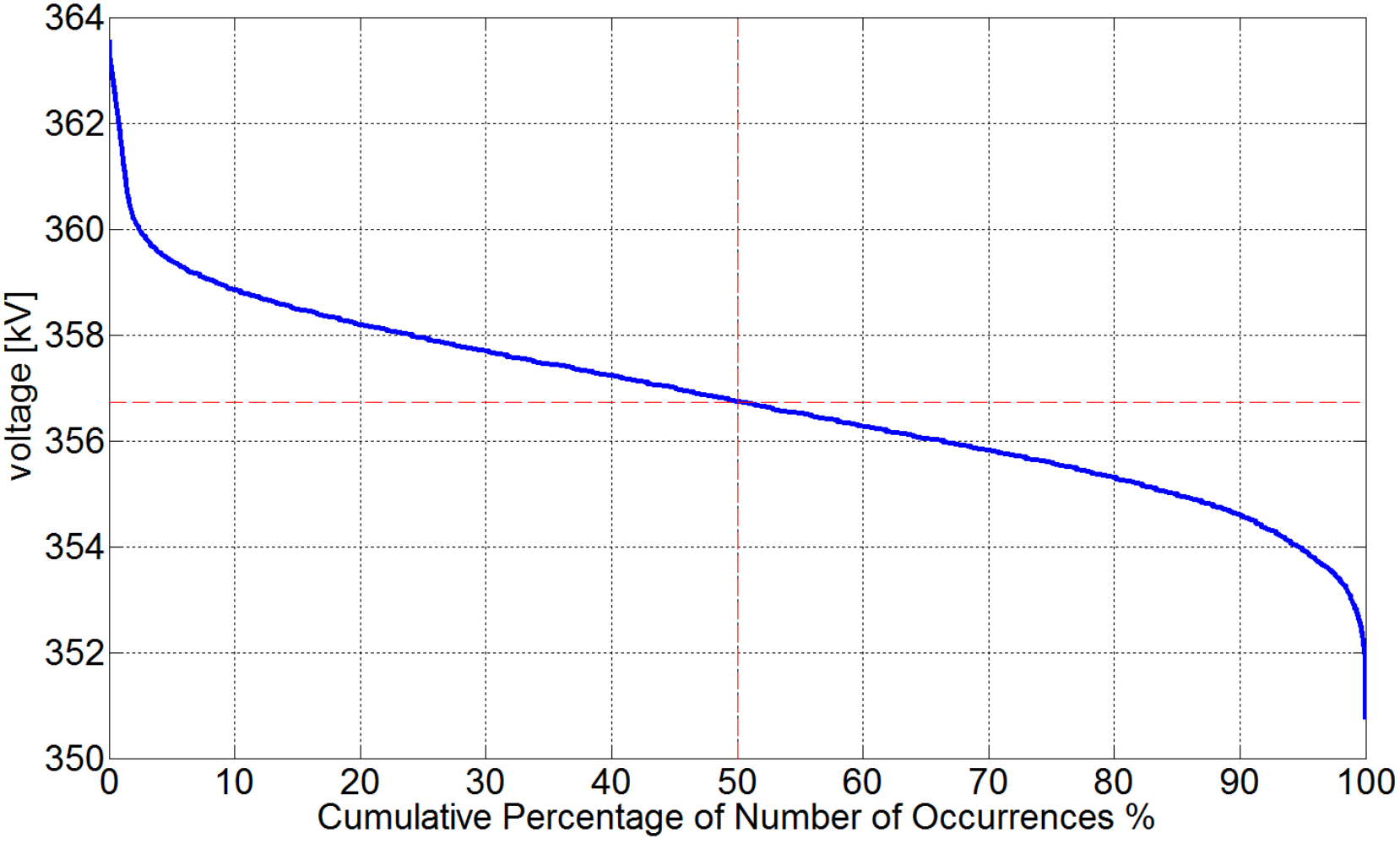
West 14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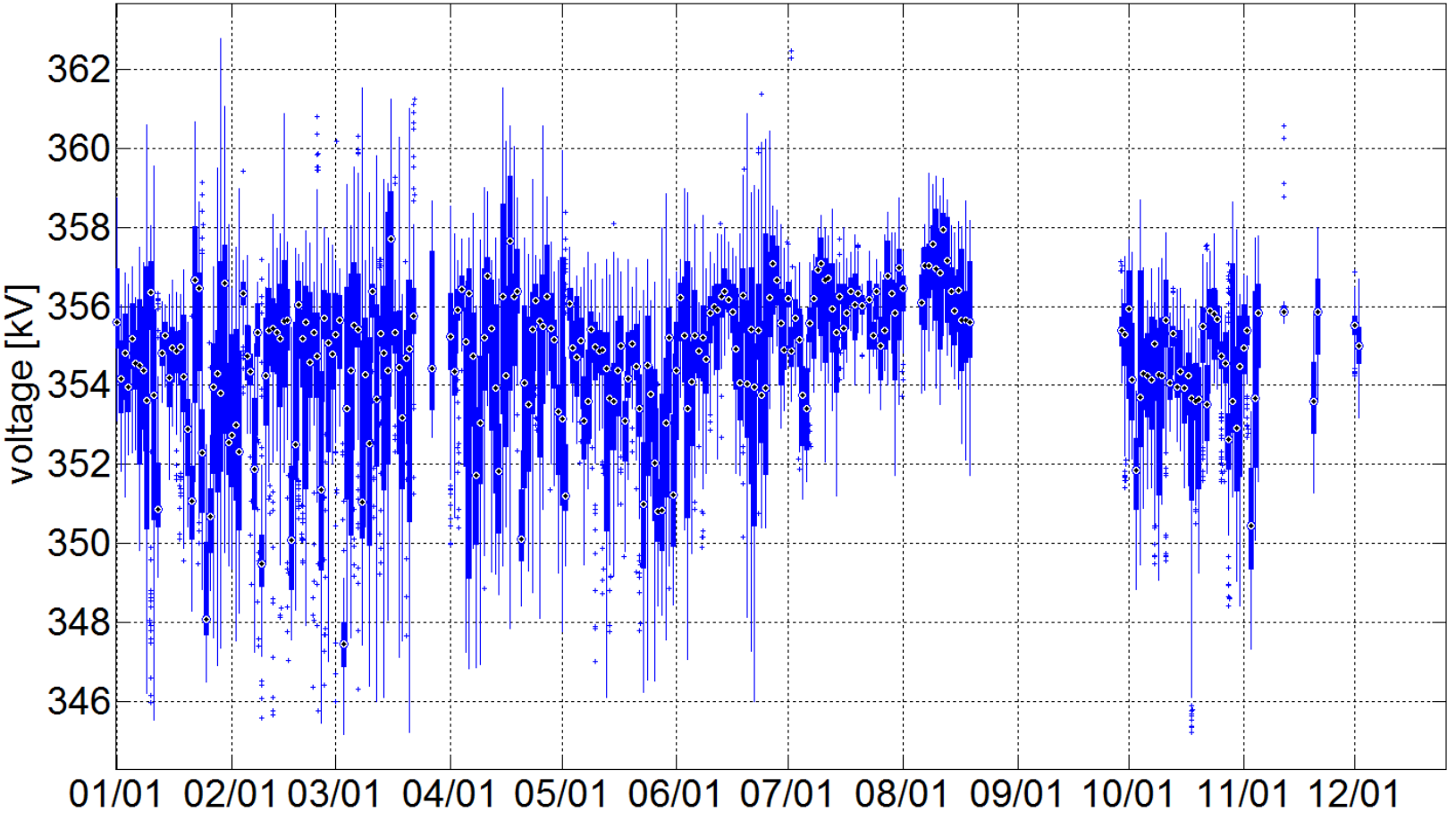
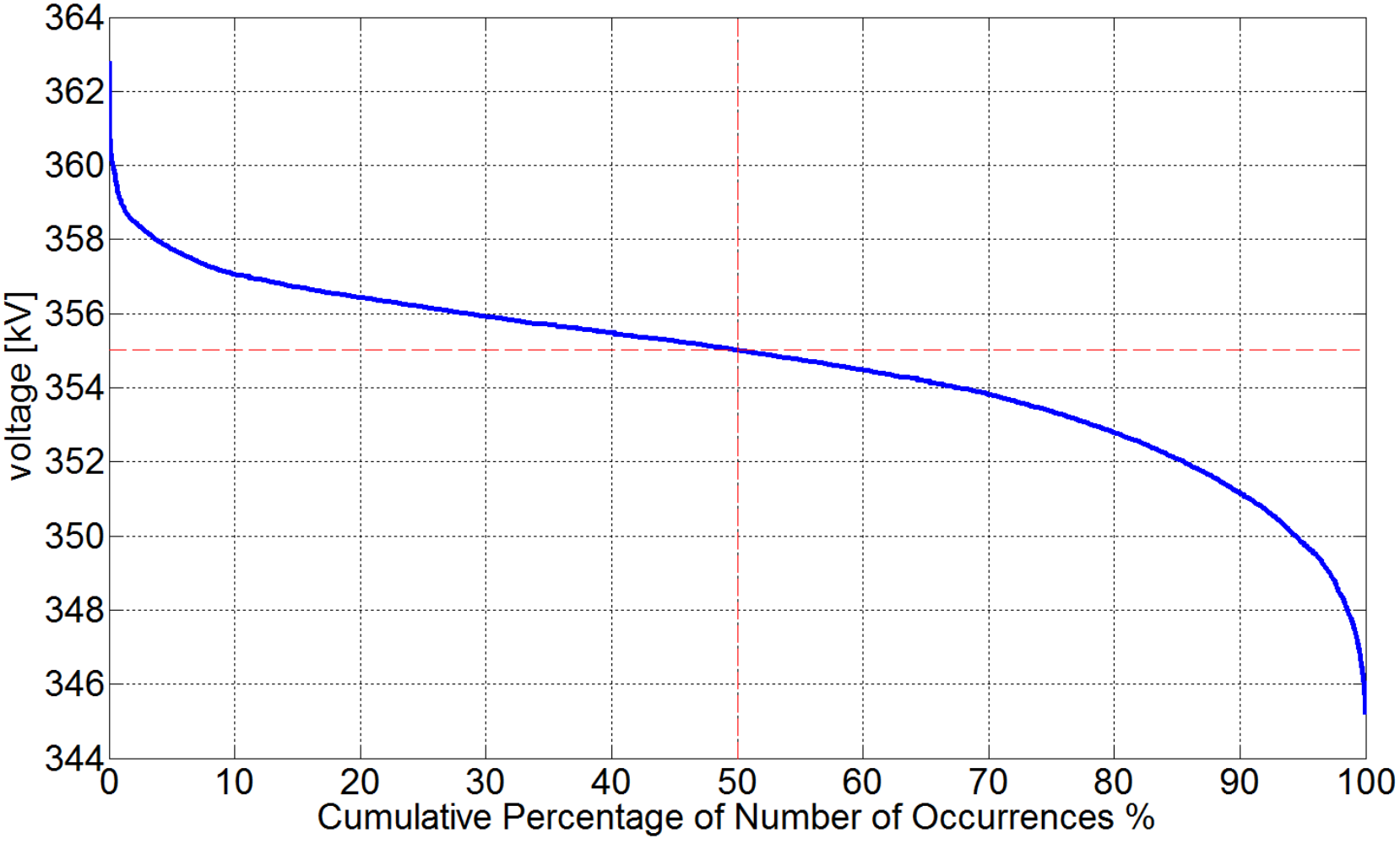
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

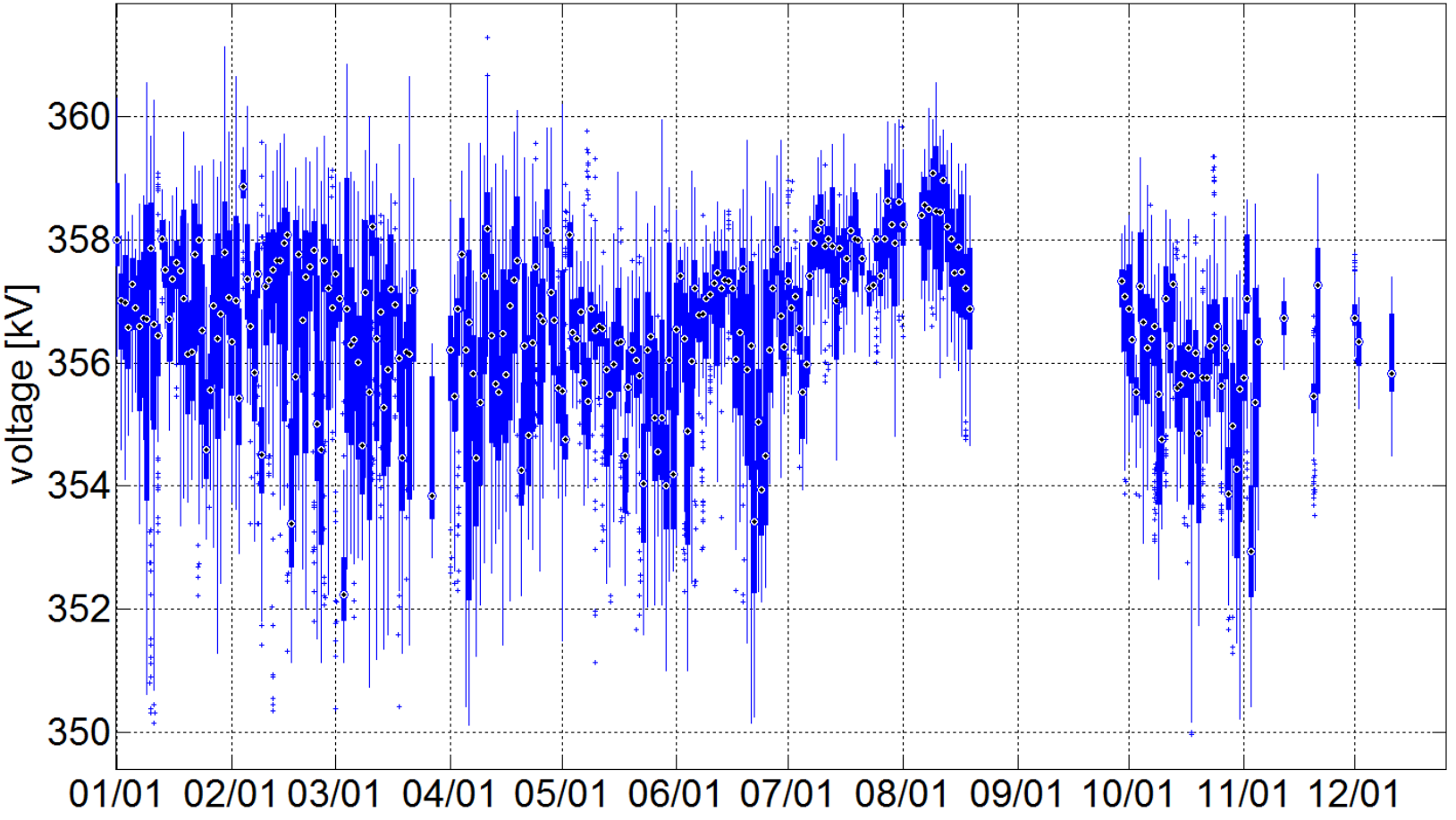
West 1


voltage [kV]
362
360
358
356
354
352
350
348
346
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

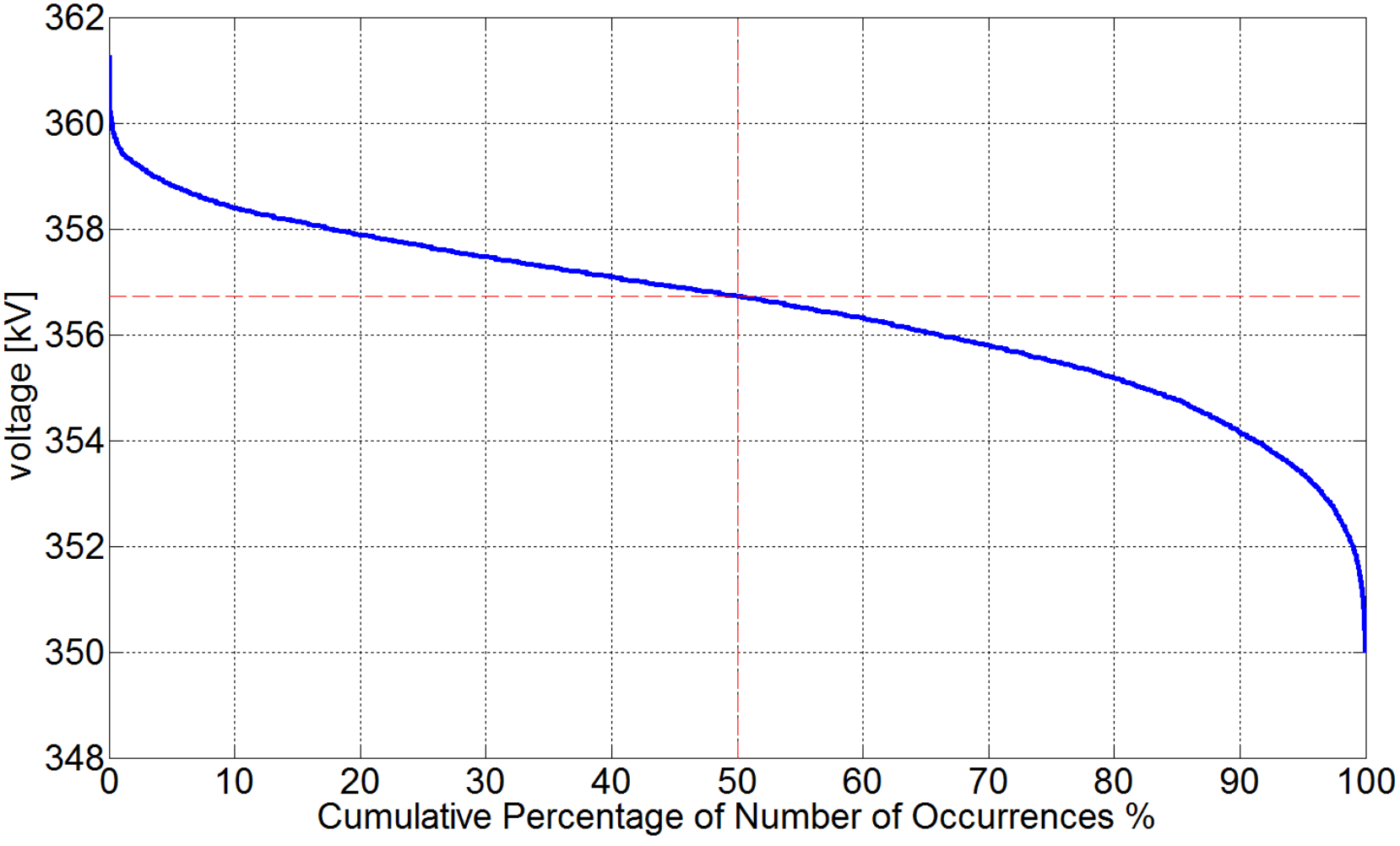
West 1


364
362
360
358
356
354
352
350
348
346
344
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

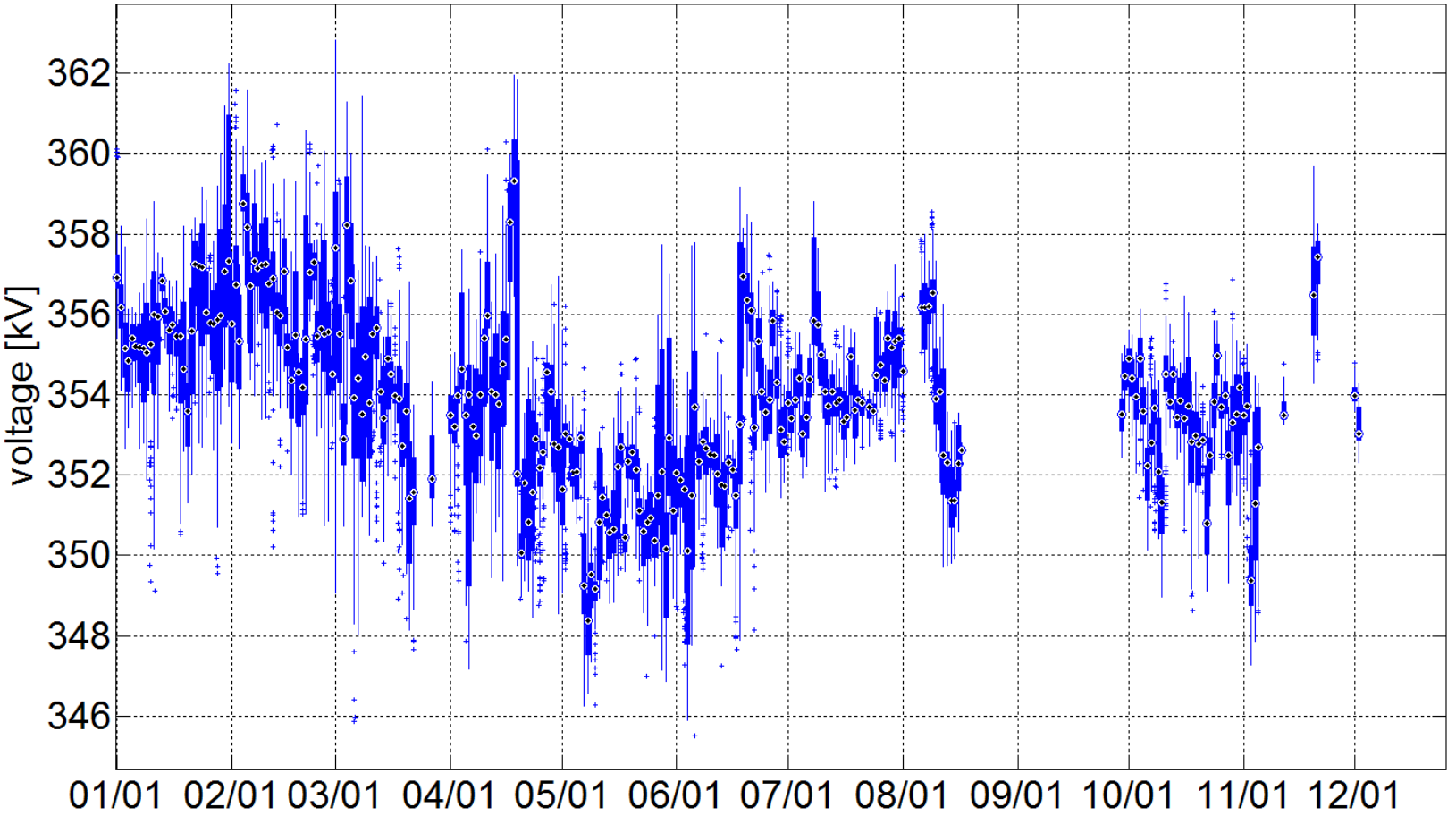
West 2


voltage [kV]
360
358
356
354
352
350
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

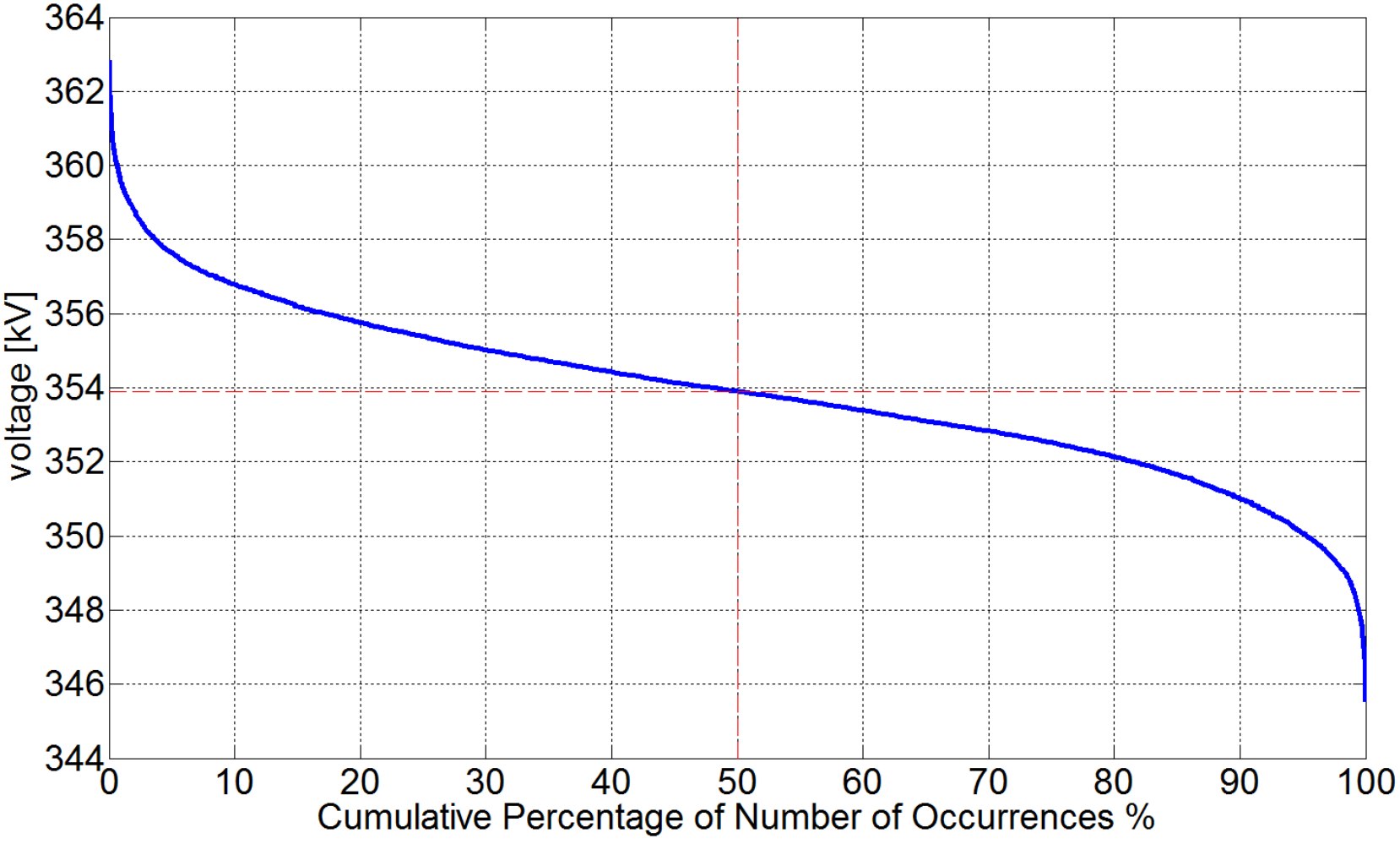
West 2


362
360
358
356
354
352
350
348
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

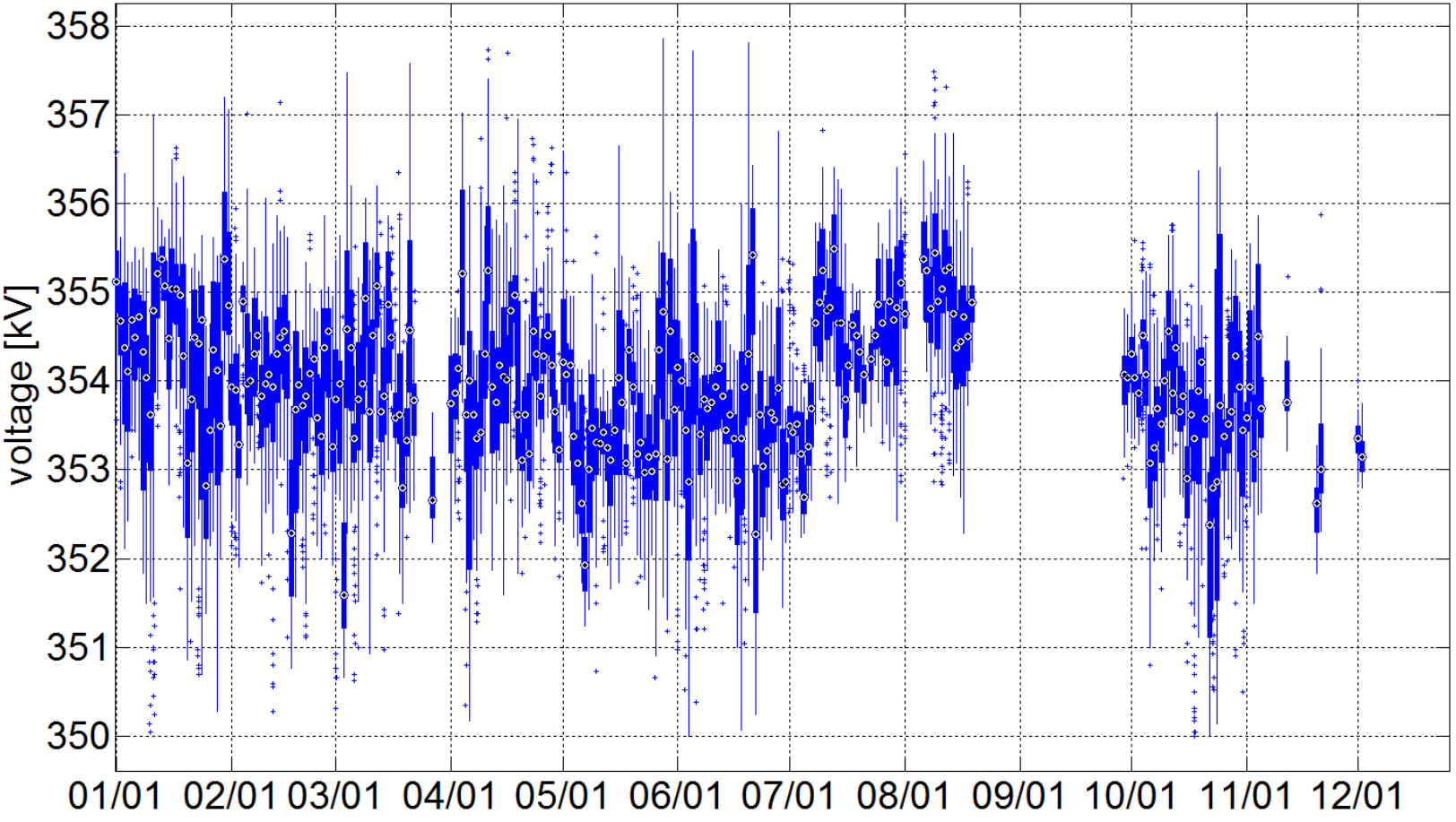
West 9*


voltage [kV]
362
360
358
356
354
352
350
348
346
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

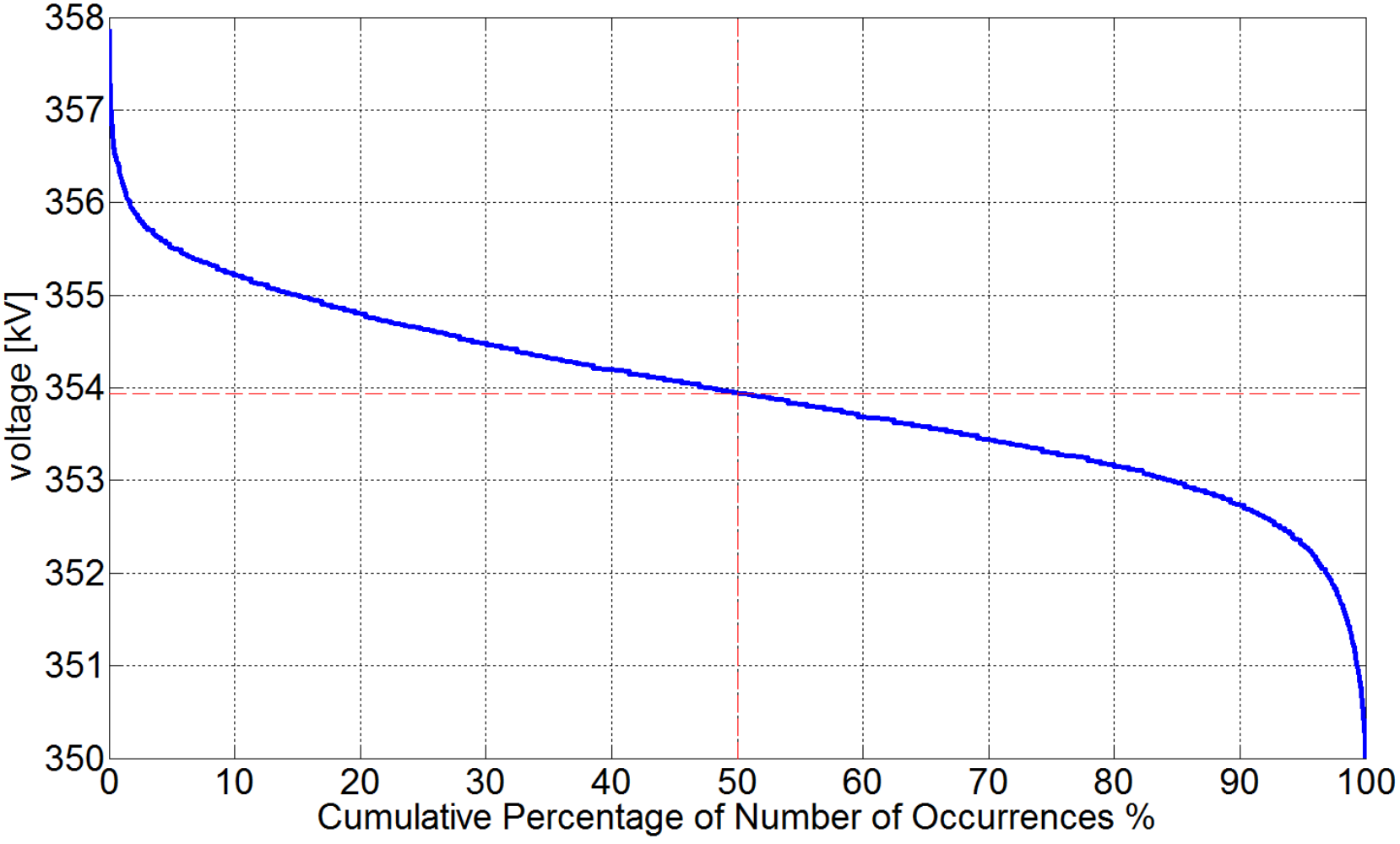
West 9*


364
362
360
358
356
354
352
350
348
346
344
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

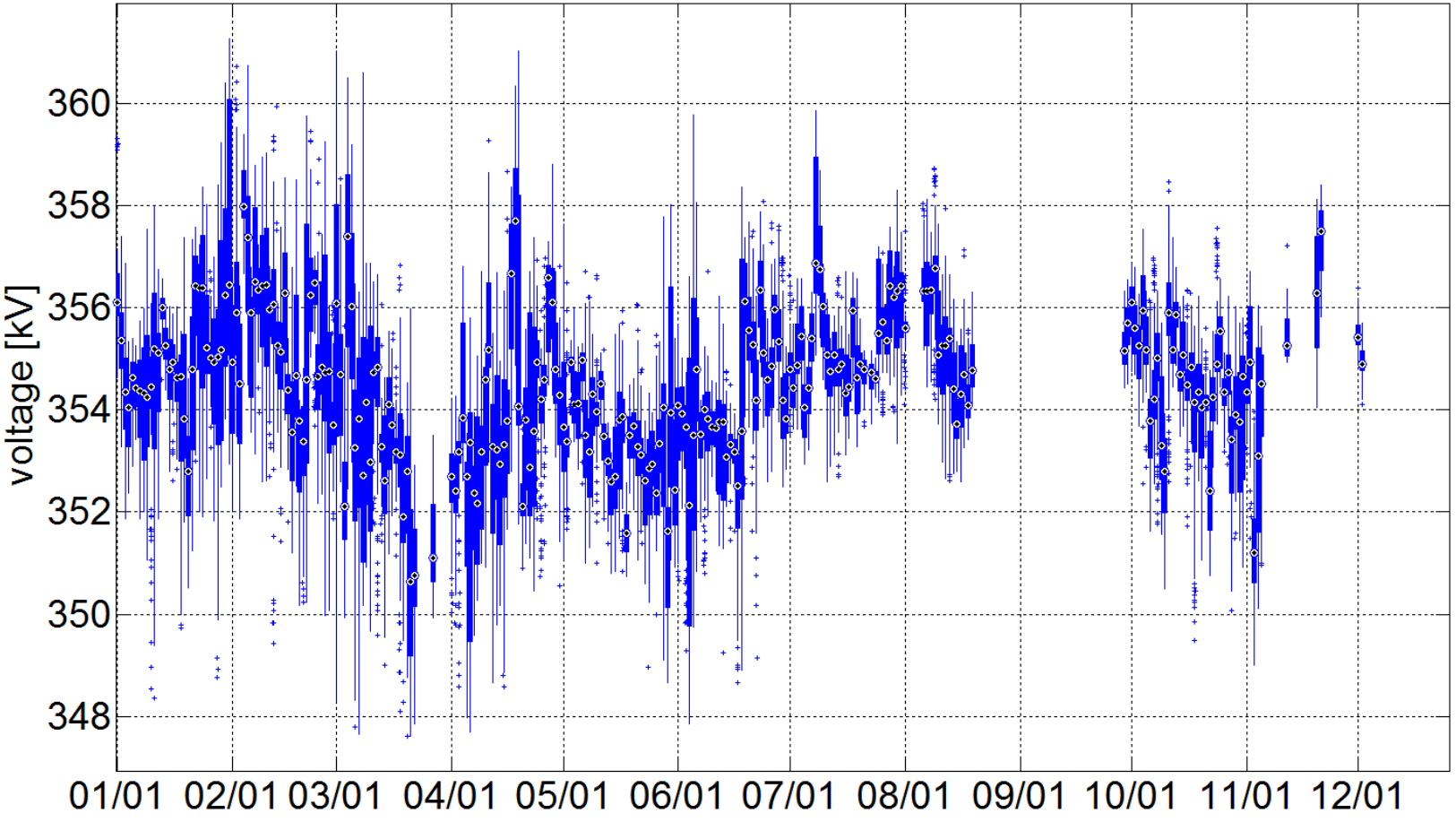
West 11


358
357
356
355
354
353
352
351
350
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

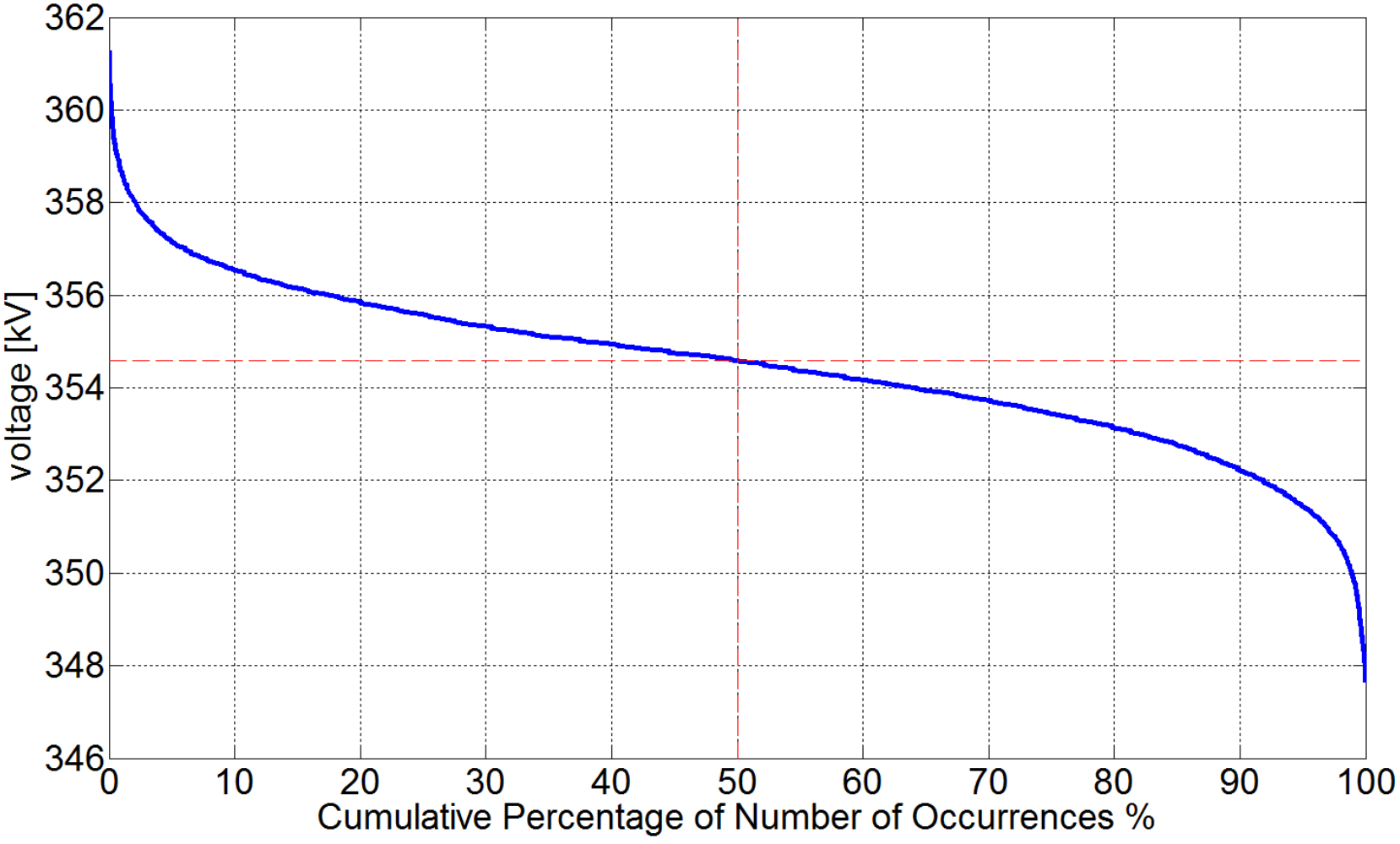
West 11


358
357
356
355
354
353
352
351
350
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

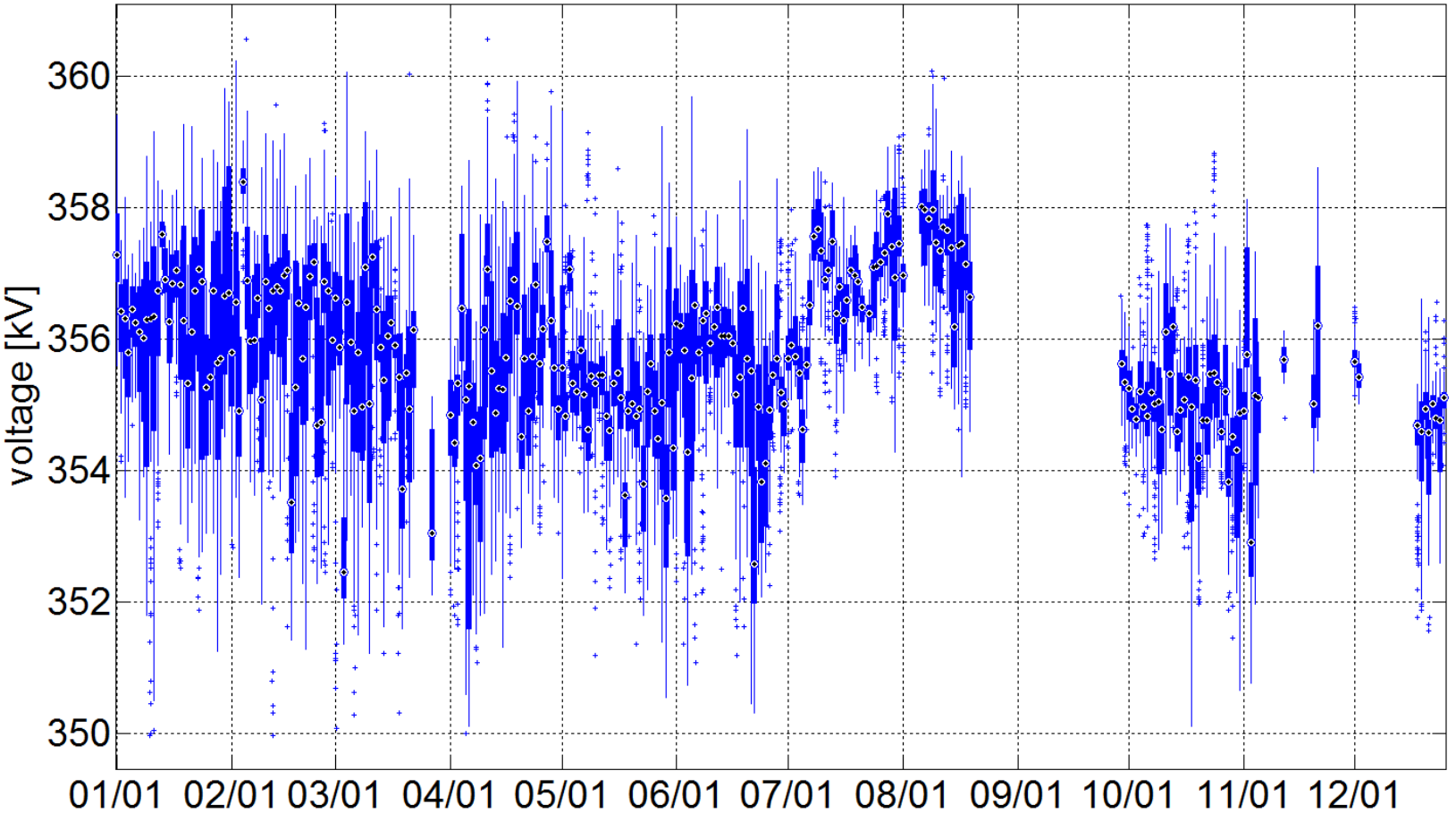
West 12


voltage [kV]
360
358
356
354
352
350
348
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

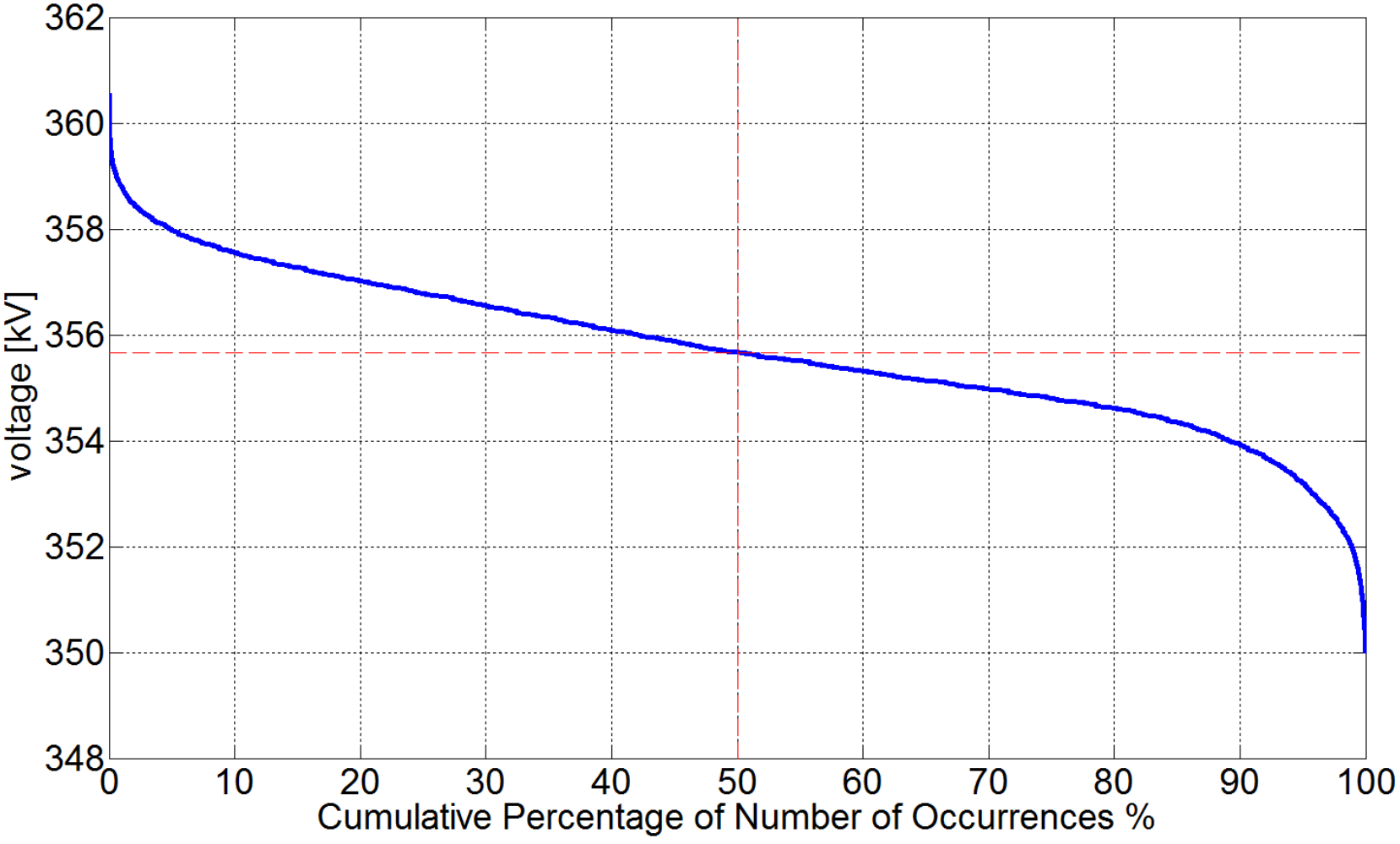
West 12


362
360
358
356
354
352
350
348
346
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

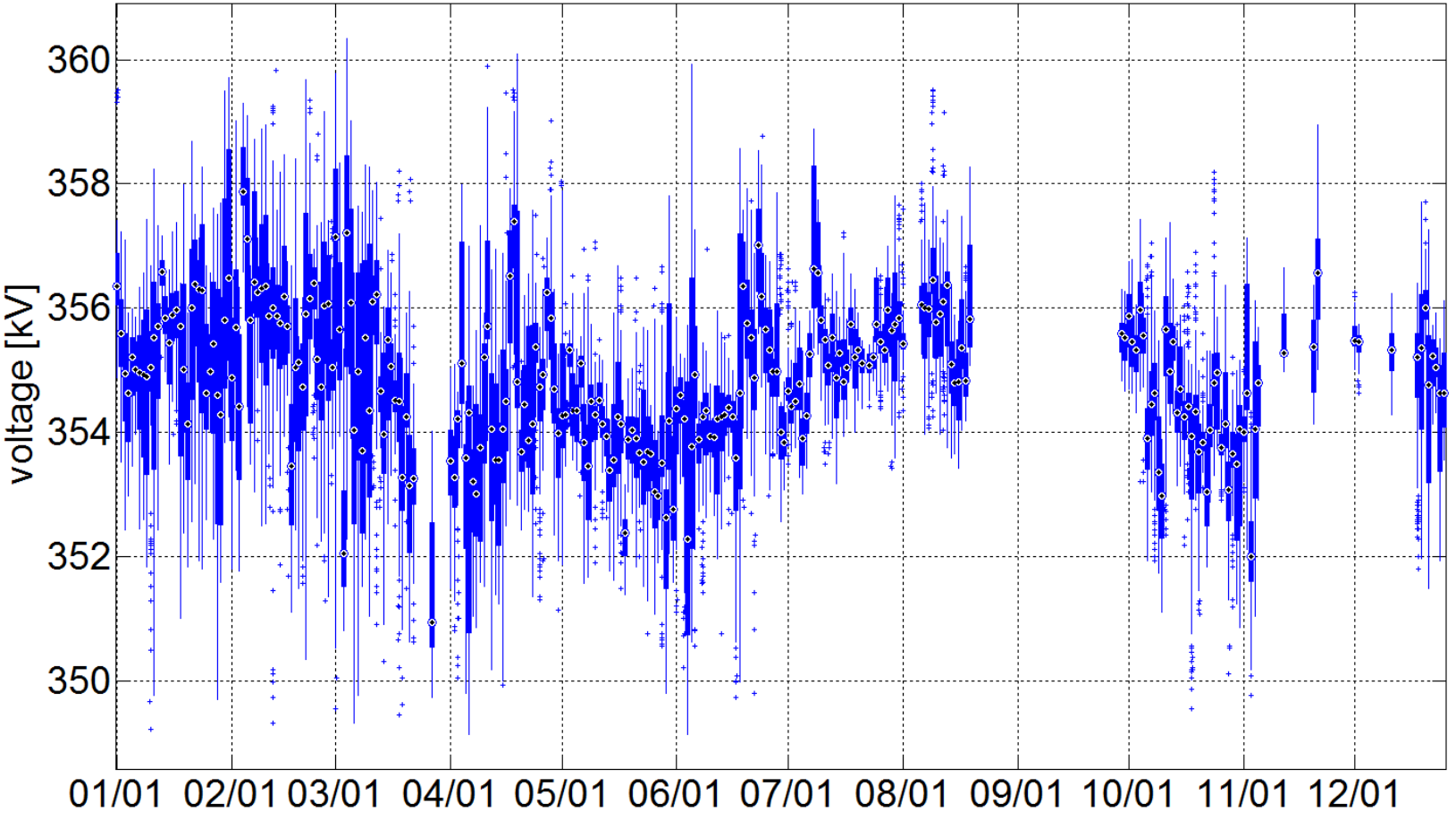
West 5


voltage [kV]
360
358
356
354
352
350
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

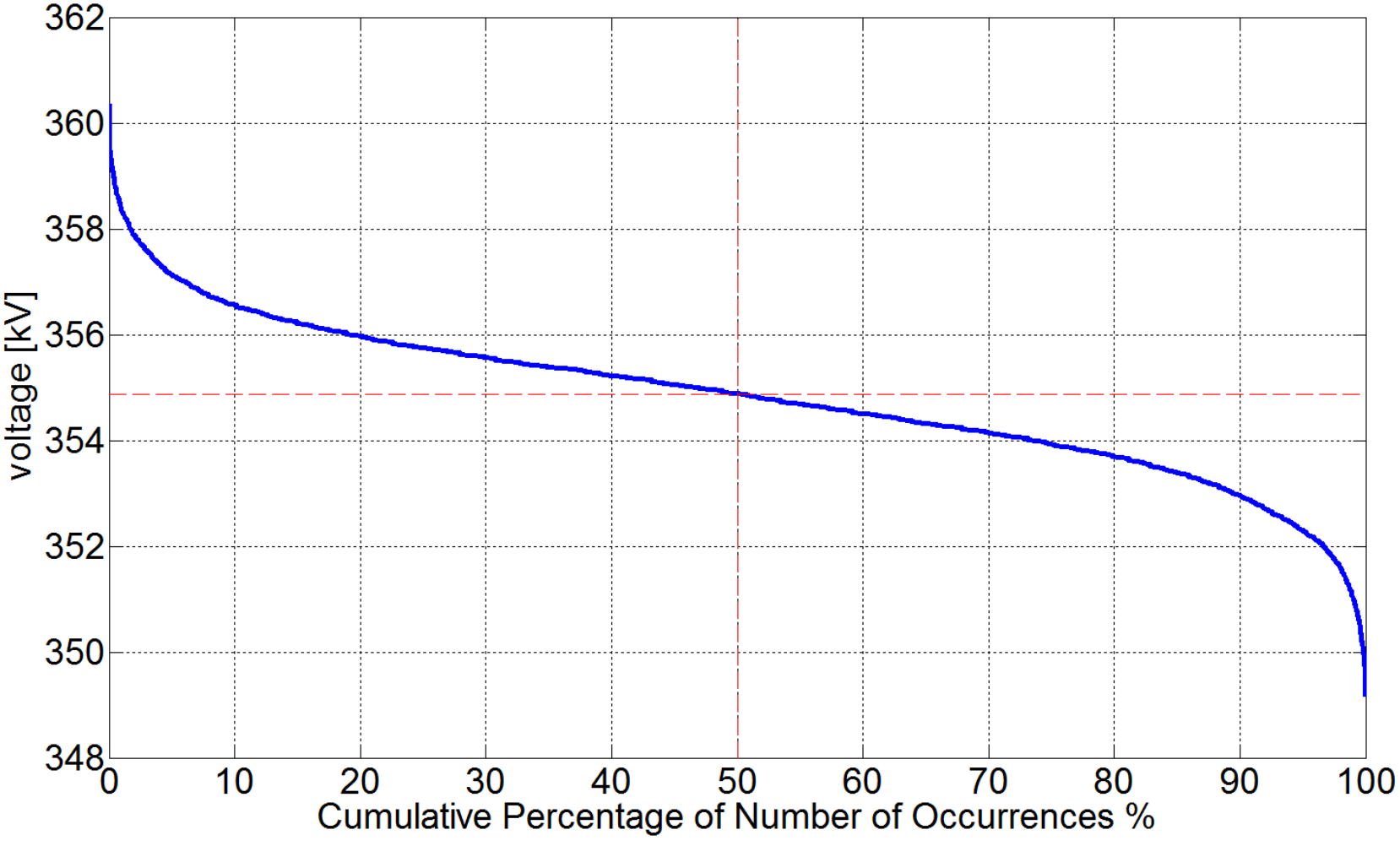
West 5


362
360
358
356
354
352
350
348
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

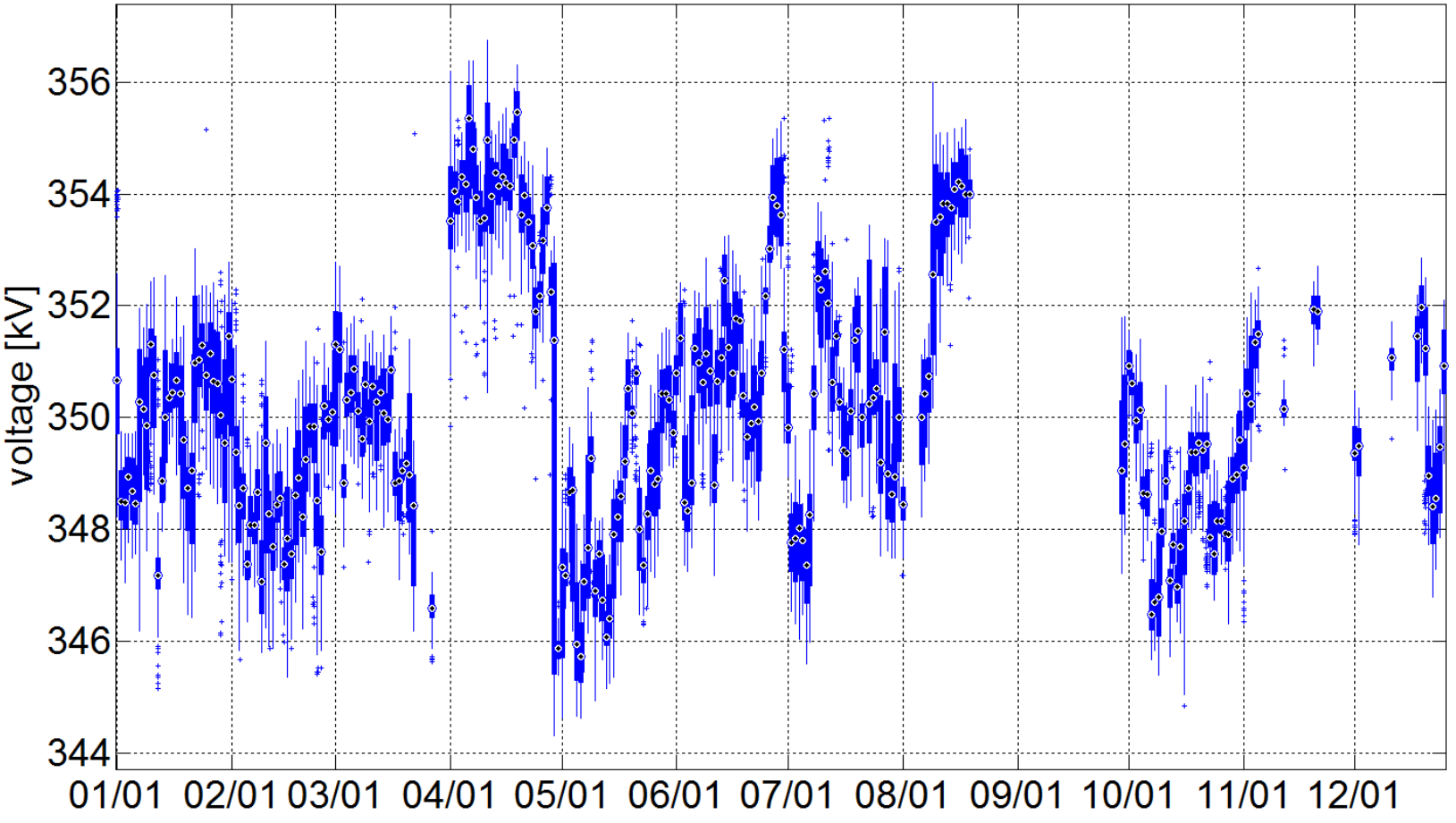
West 6


voltage [kV]
360
358
356
354
352
350
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

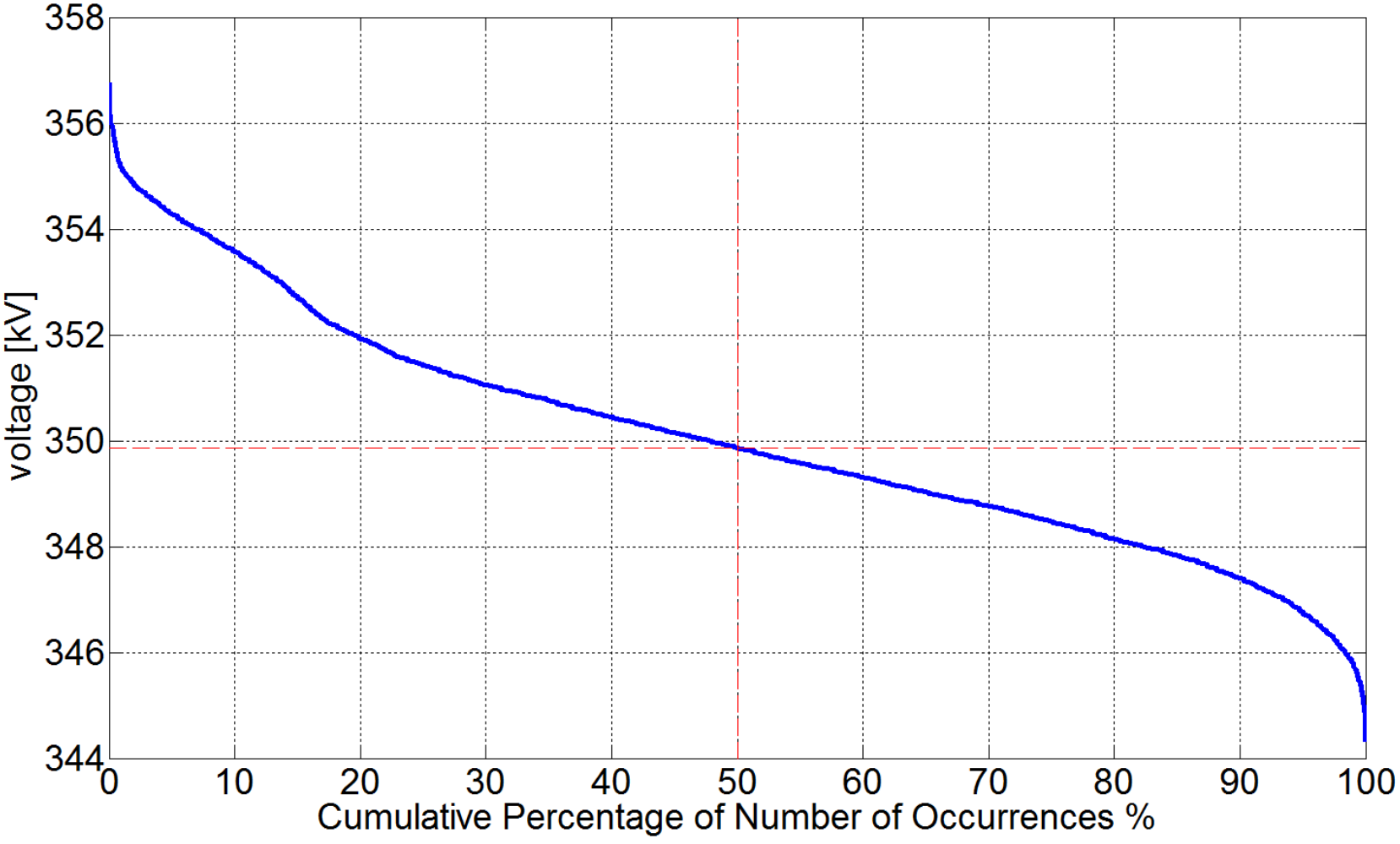
West 6


362
360
358
356
354
352
350
348
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

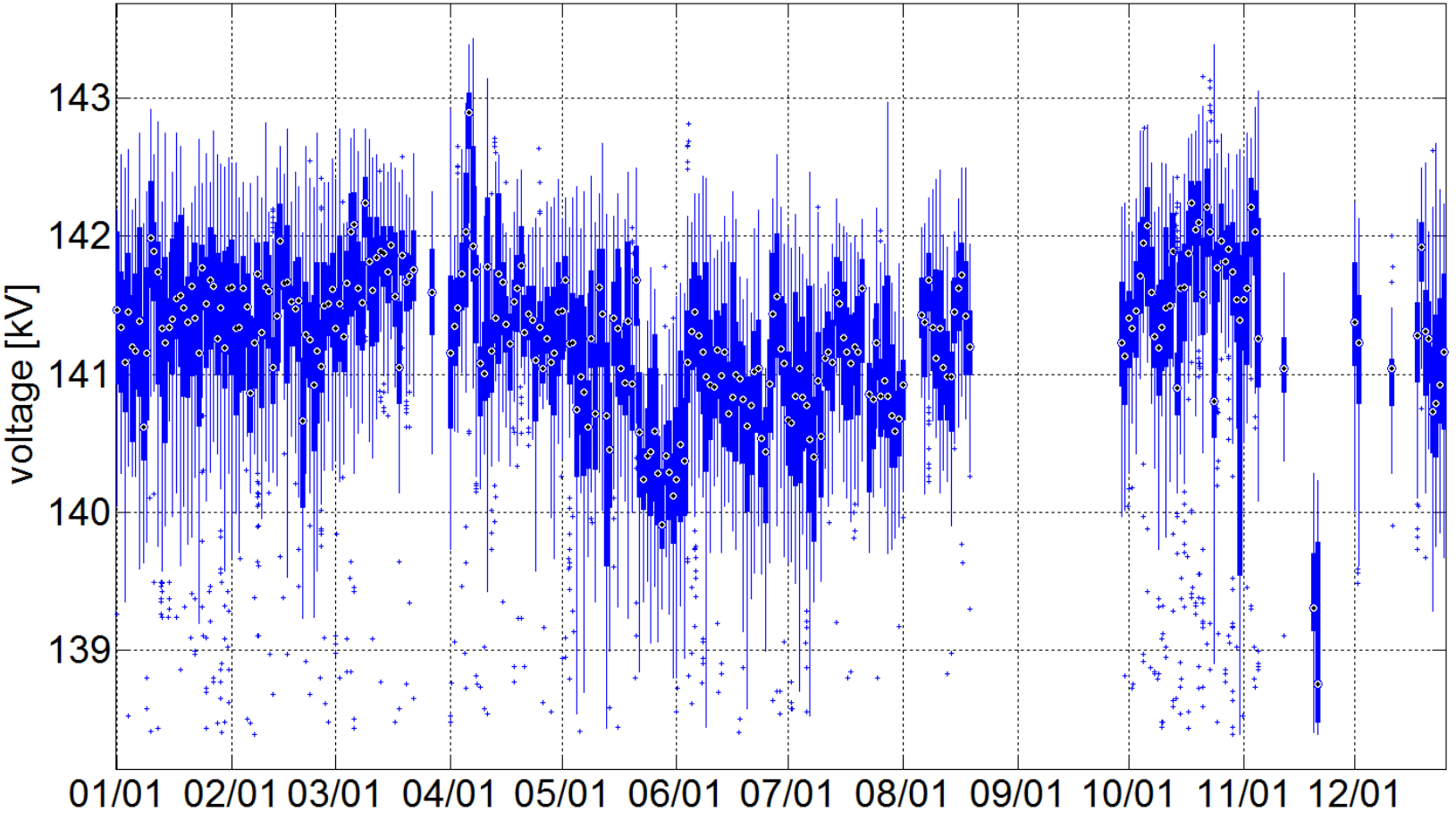
North 1


voltage [kV]
356
354
352
350
348
346
344
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

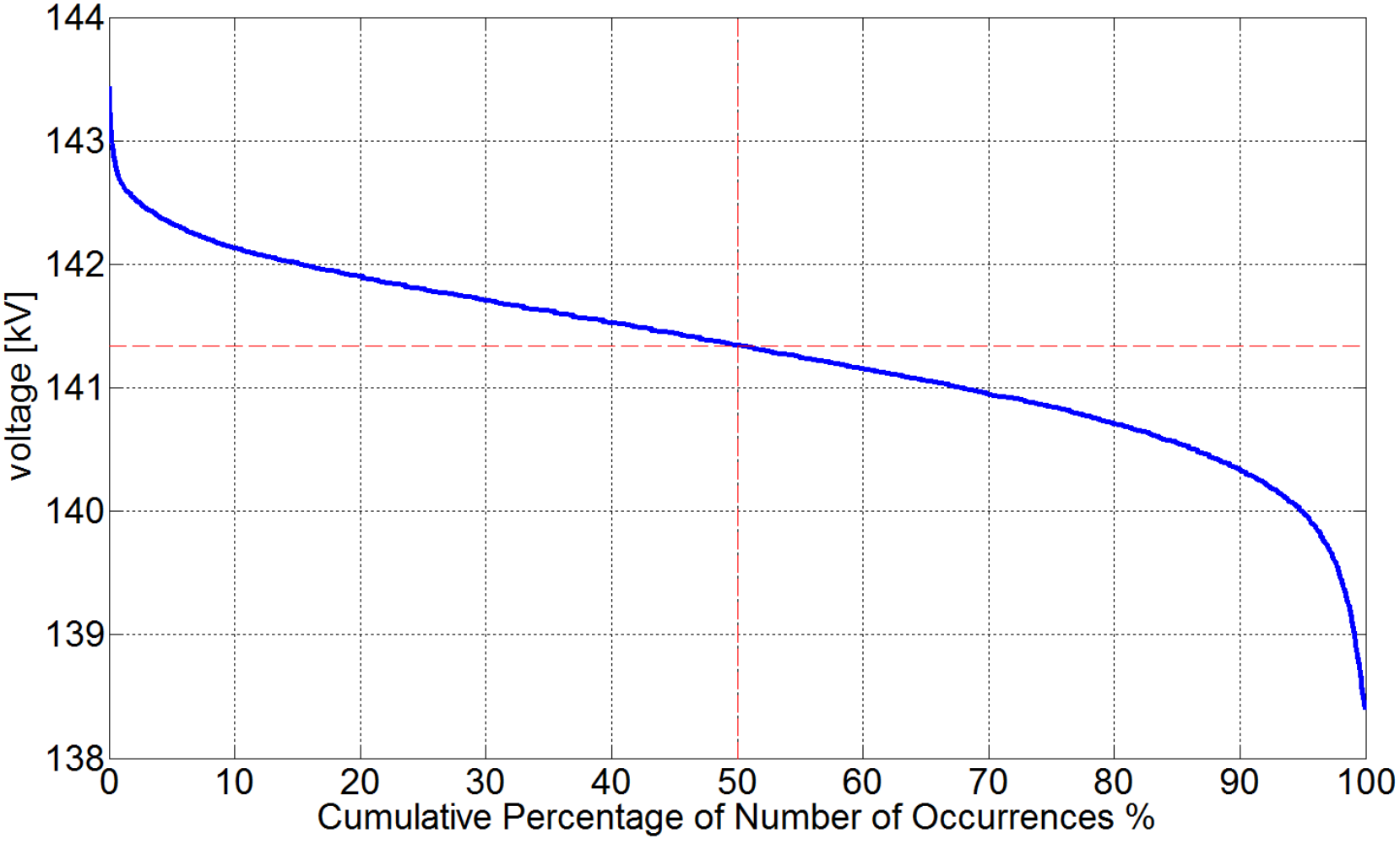
North 1


358
356
354
352
350
348
346
344
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

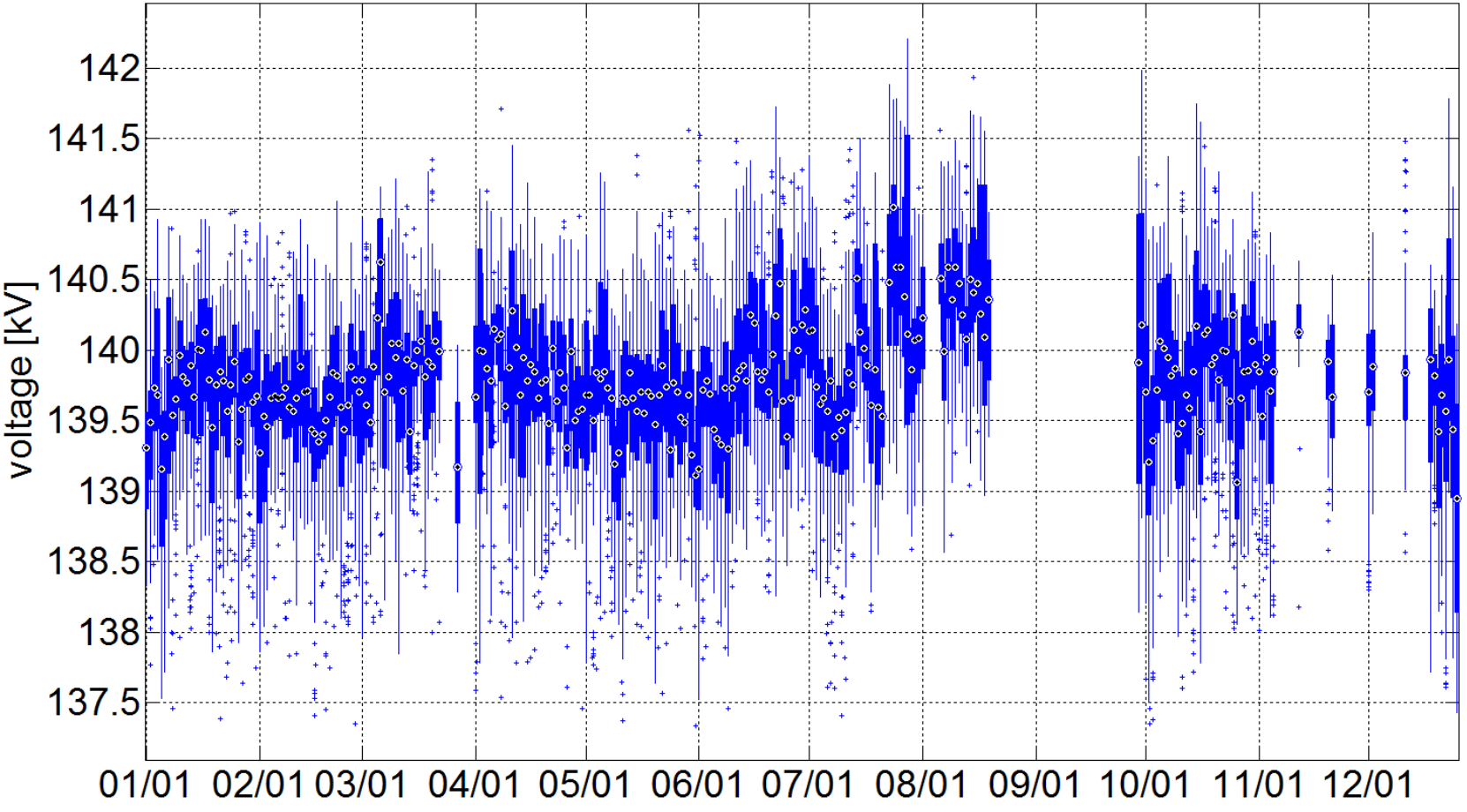
North 4


voltage [kV]
143
142
141
140
139
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

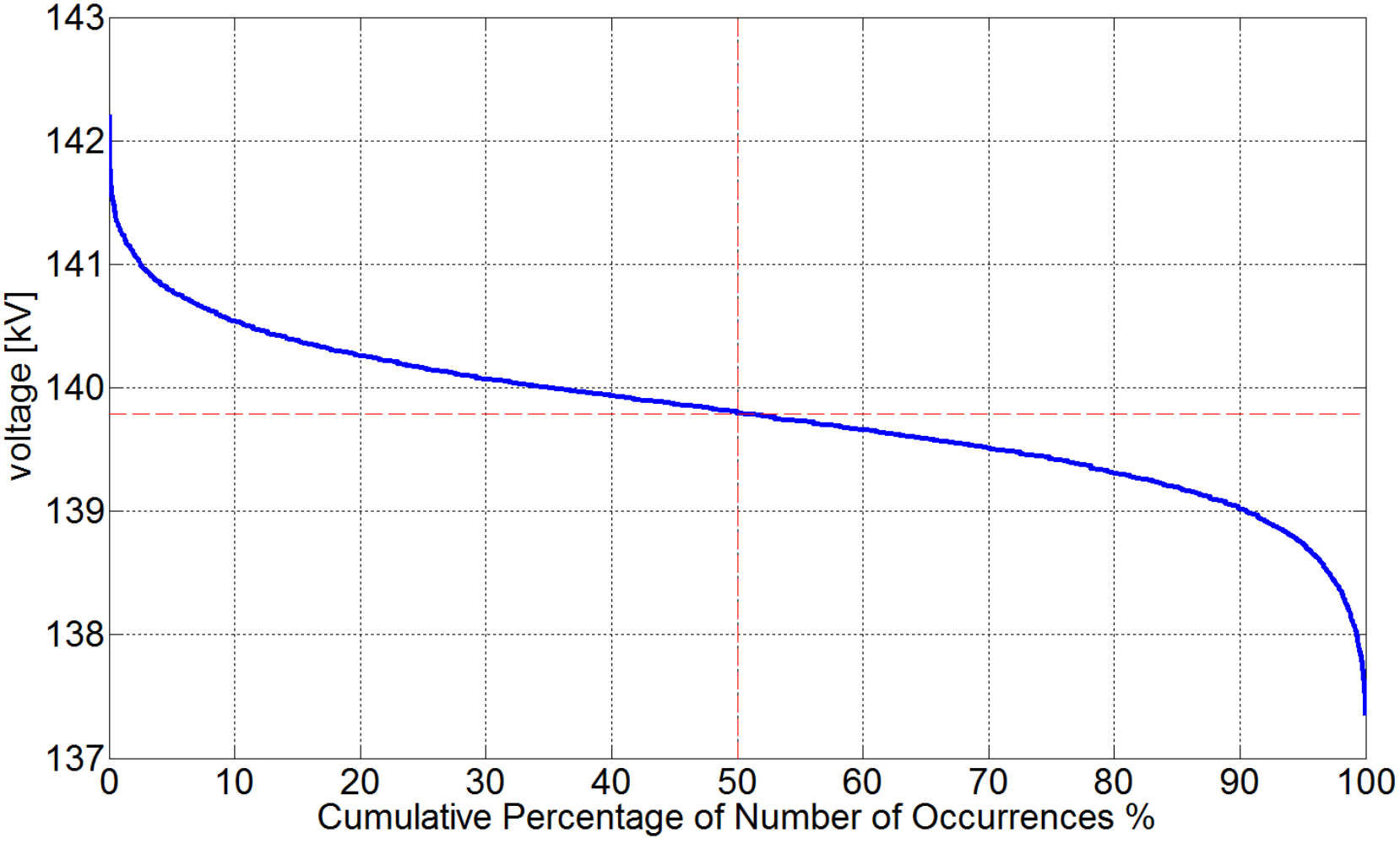
North 4


144
143
142
141
140
139
138
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

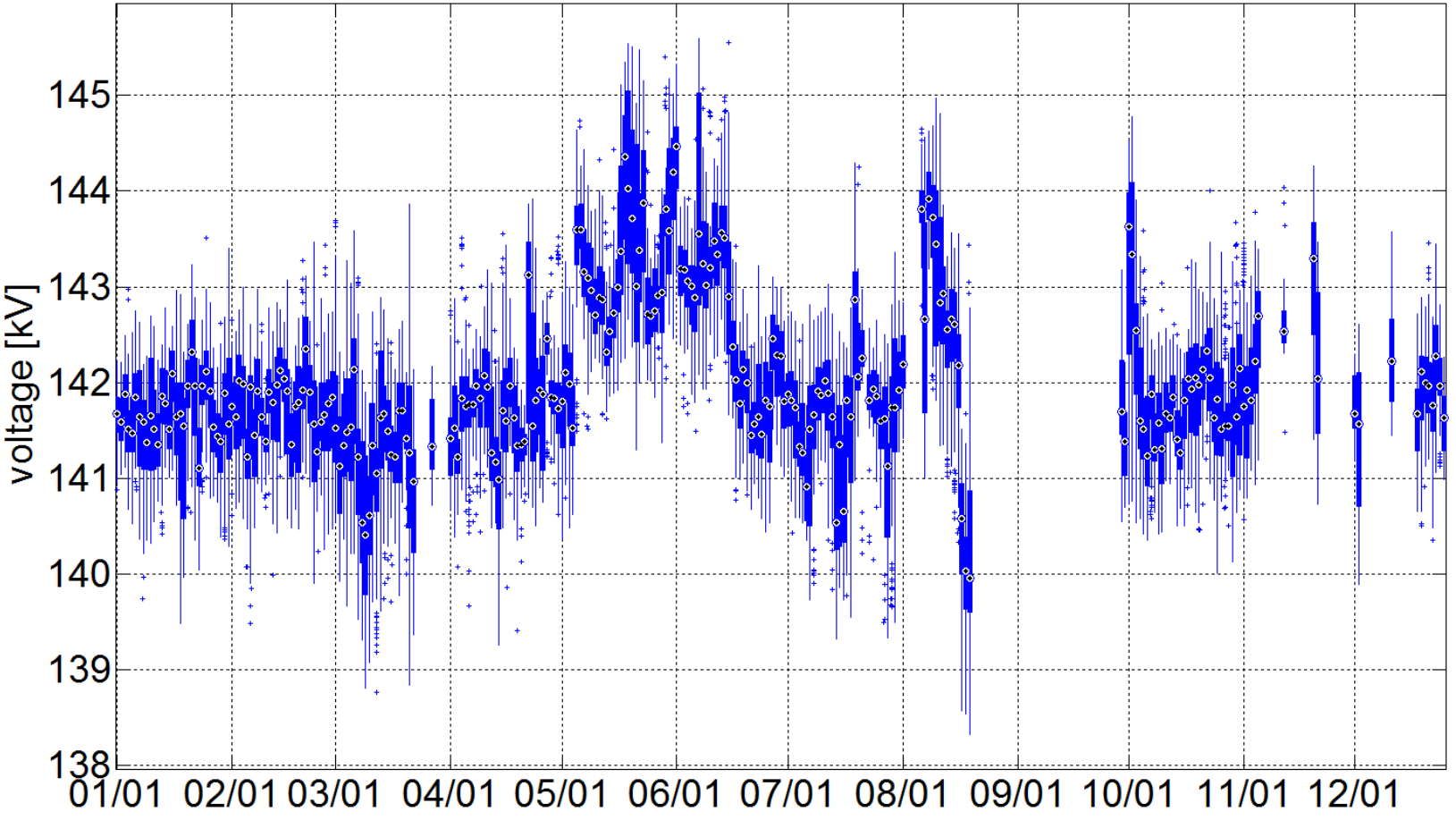
North 5


voltage [kV]
142
141.5
141
140.5
140
139.5
139
138.5
138
137.5
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

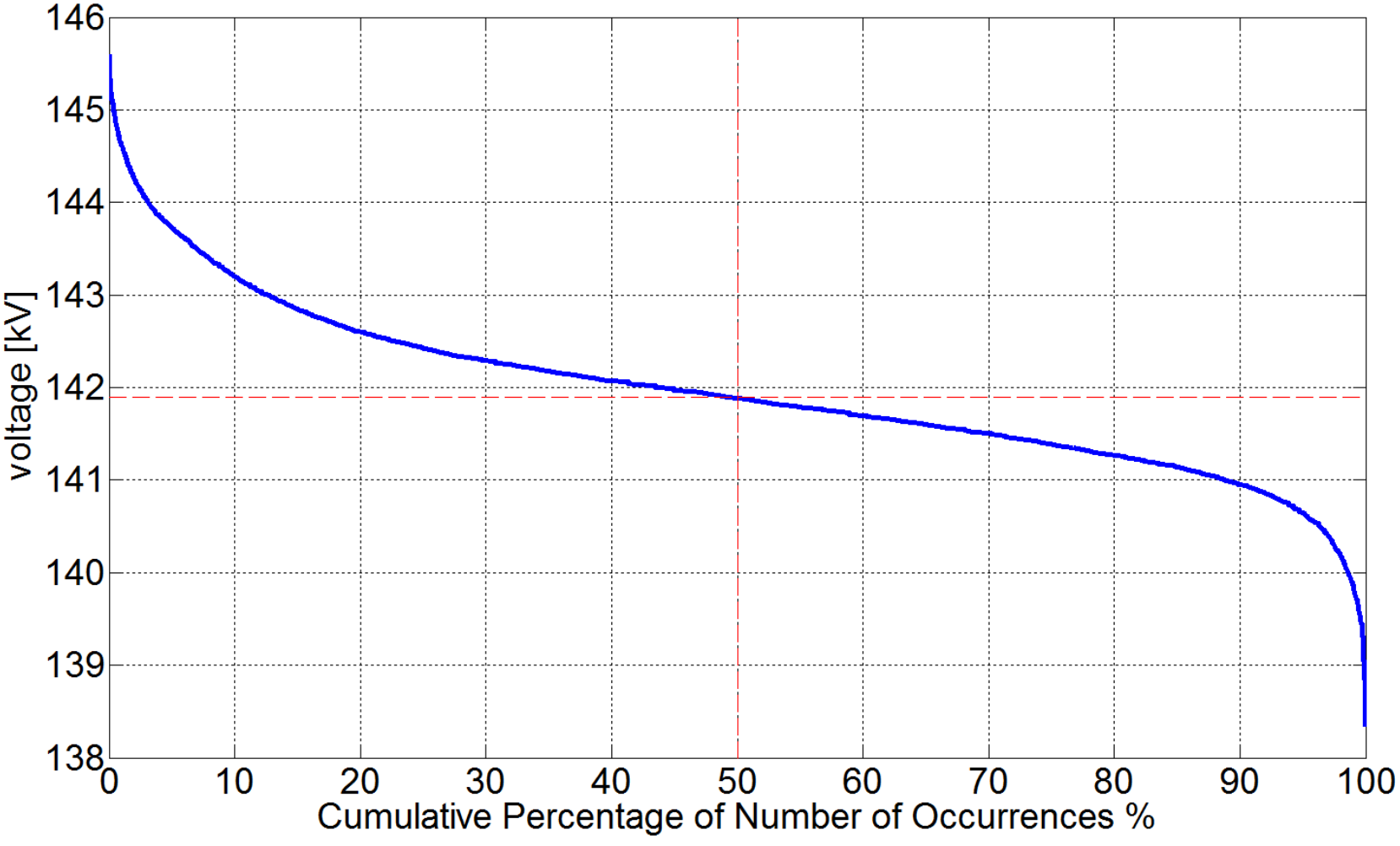
North 5


143
142
141
140
139
138
137
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

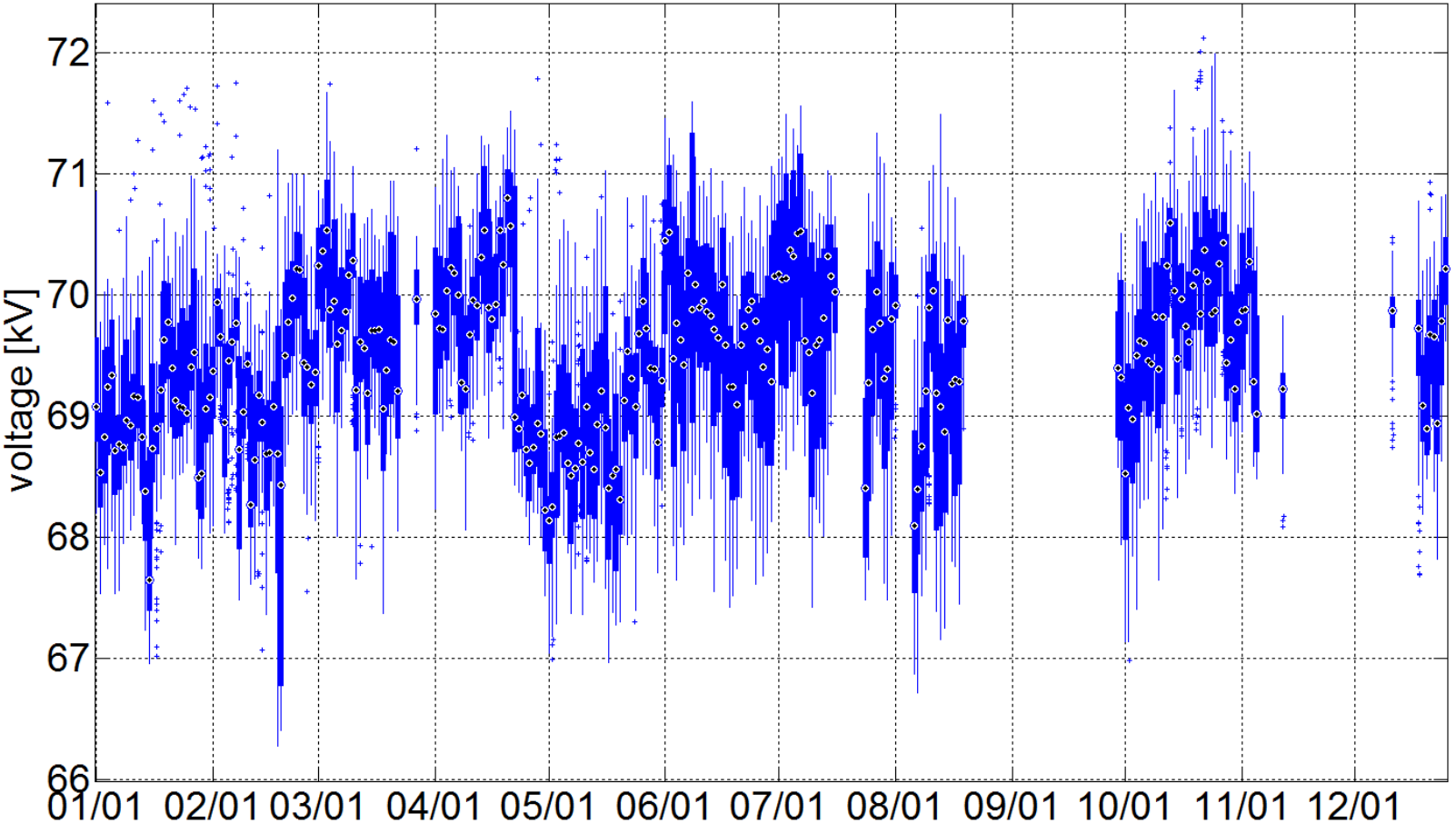
North 6


voltage [kV]
145
144
143
142
141
140
139
138
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

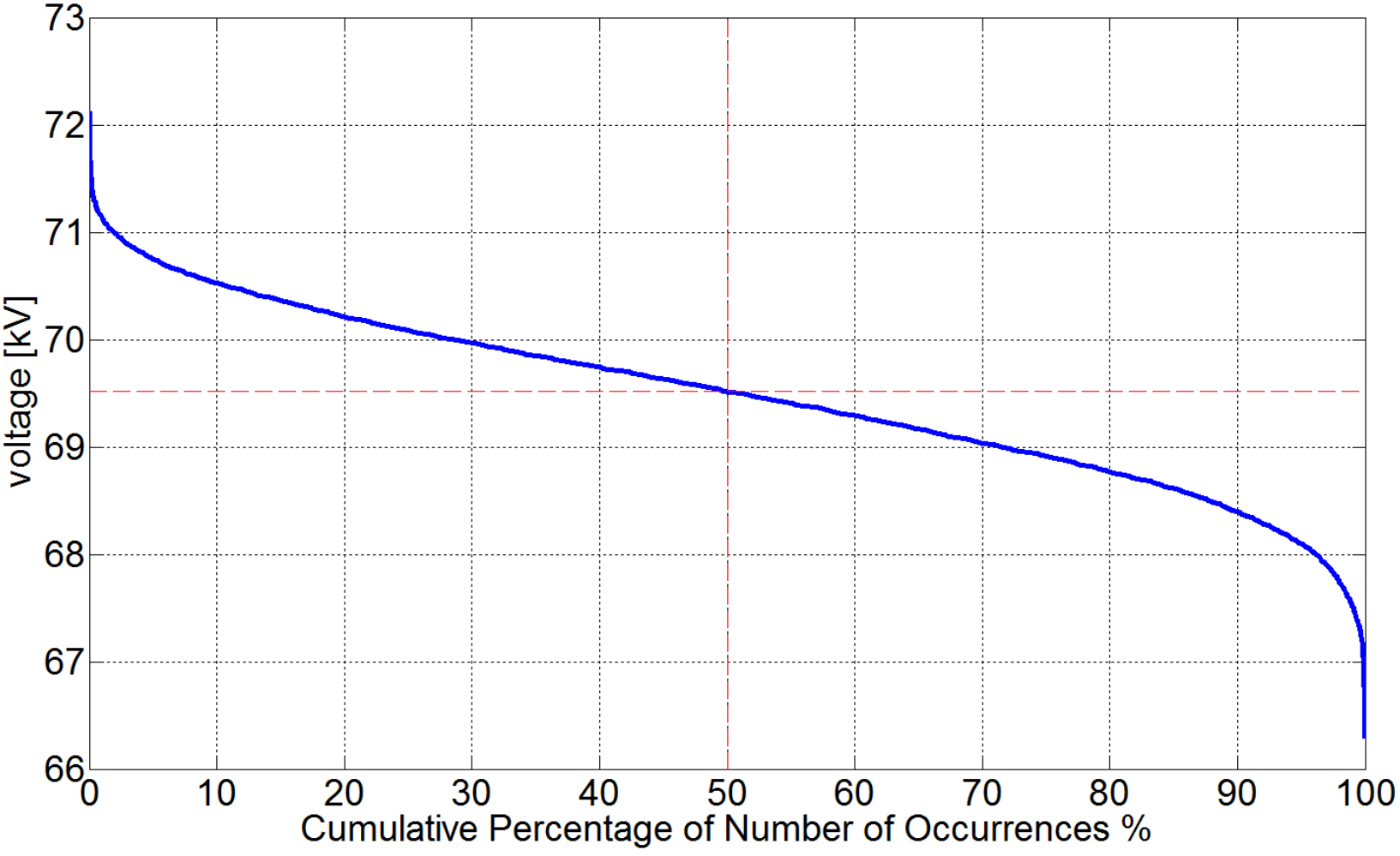
North 6


146
145
144
143
142
141
140
139
138
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

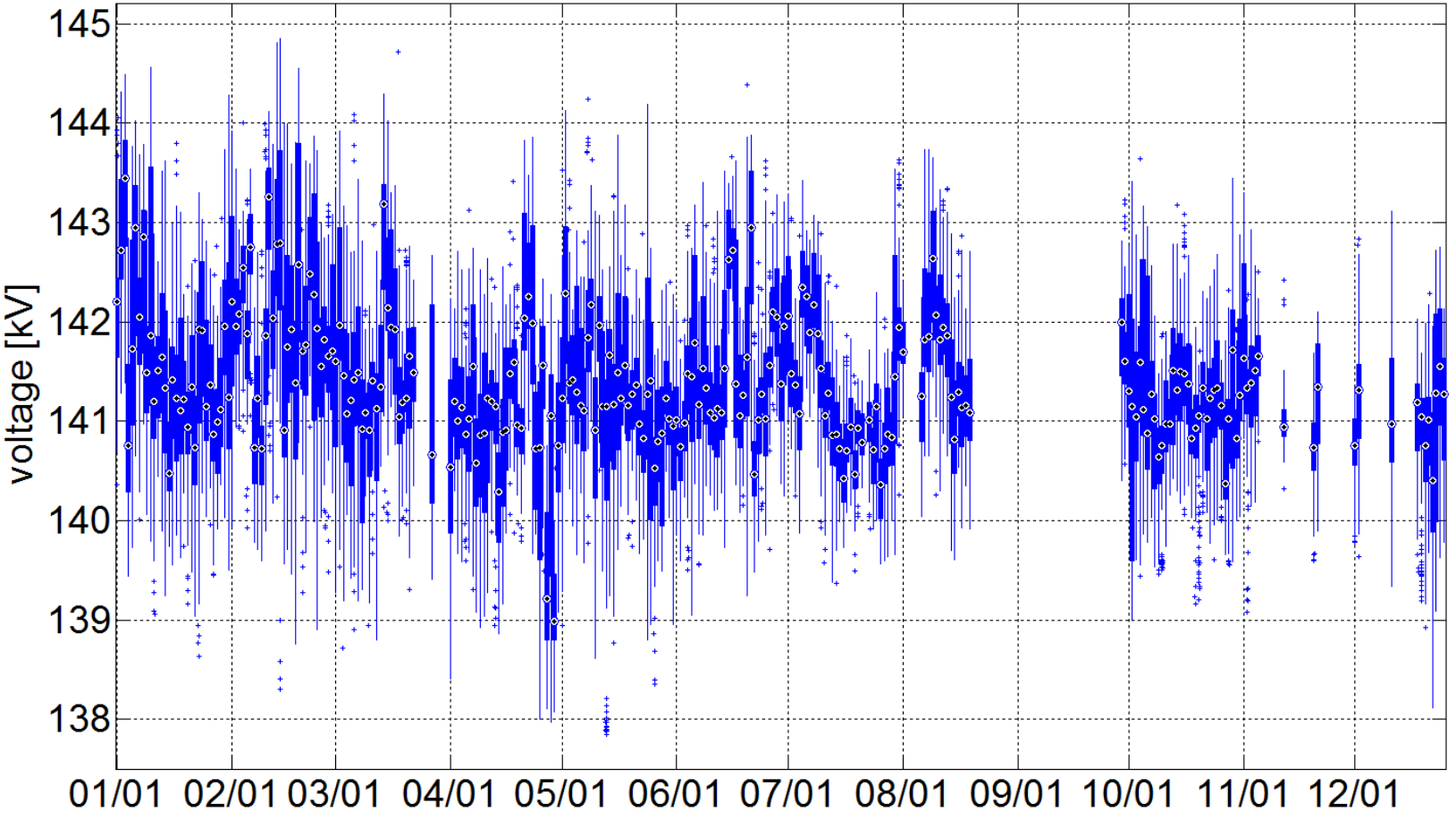
FarWest 2


voltage [kV]
72
71
70
69
68
67
66
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

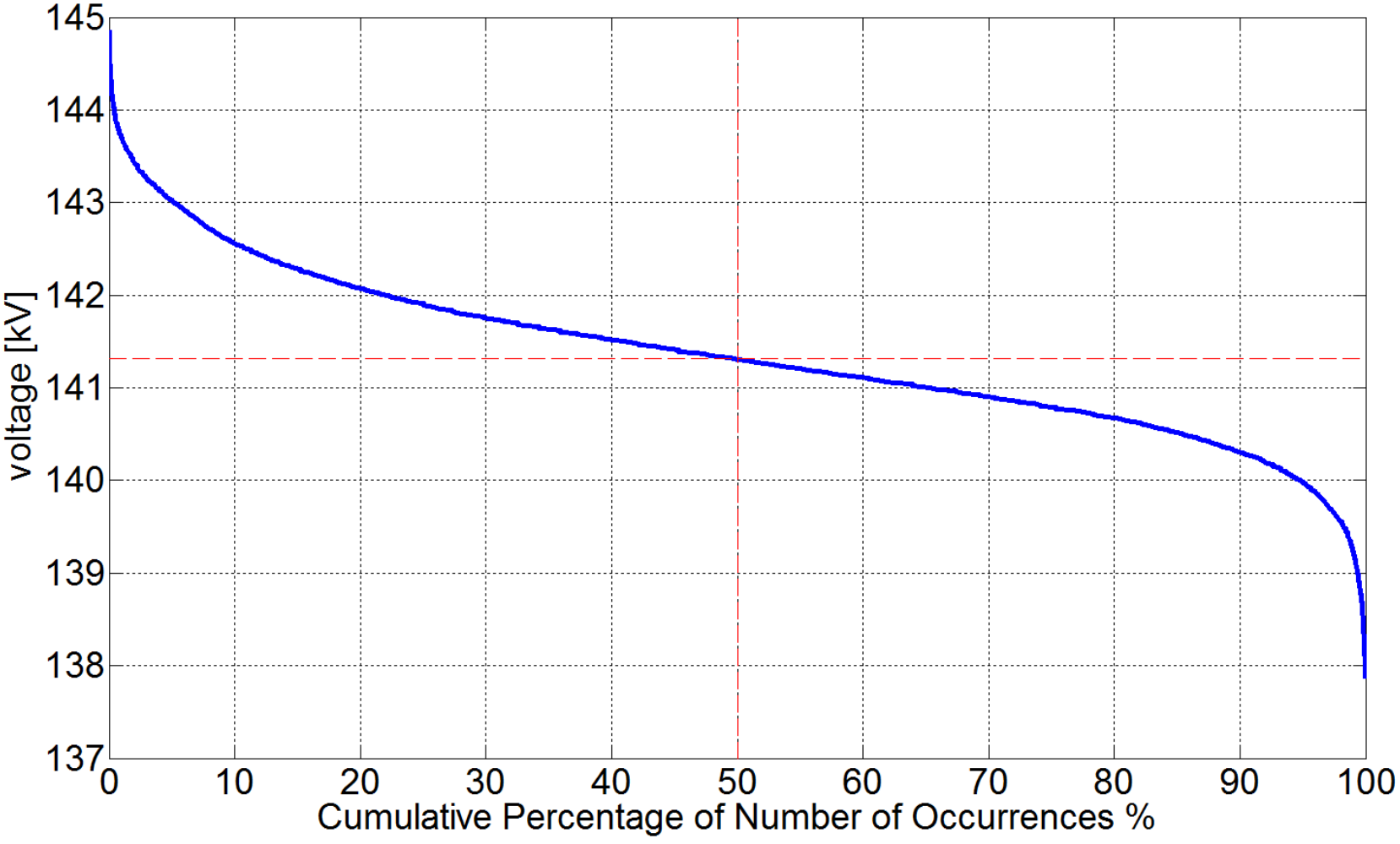
FarWest 2


73
72
71
70
69
68
67
66
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

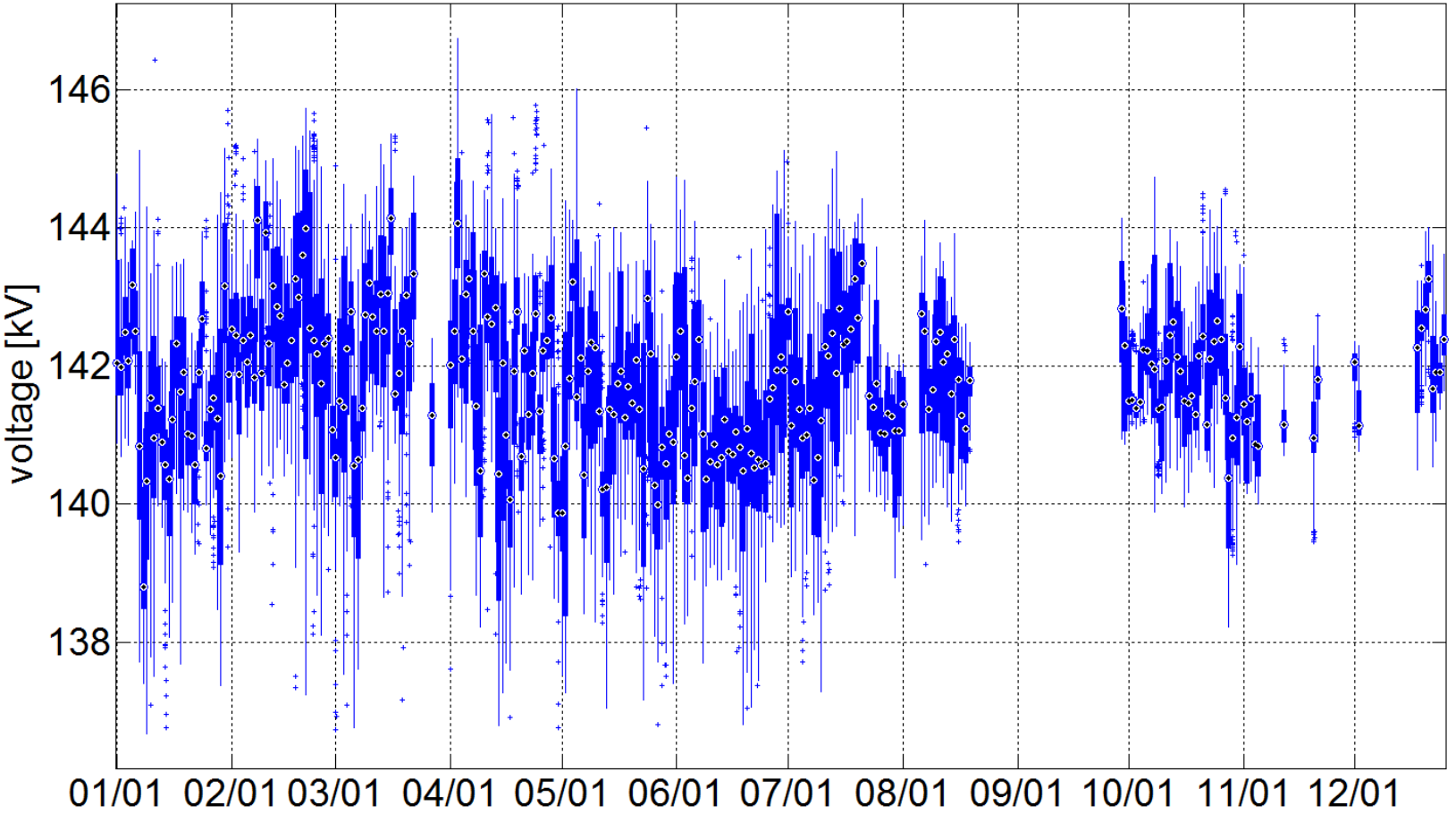
North 7


145
144
143
142
141
140
139
138
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

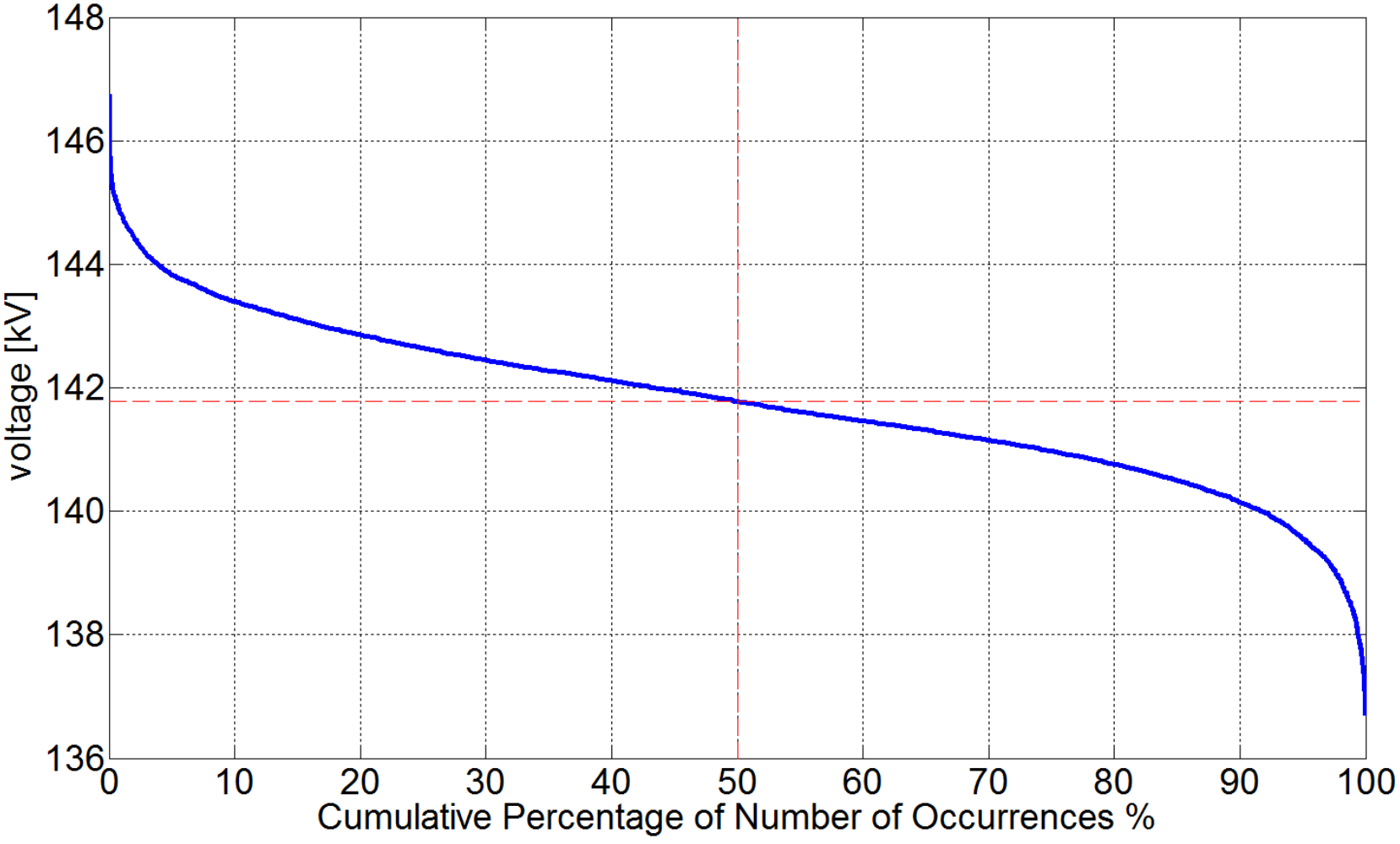
North 7


145
144
143
142
141
140
139
138
137
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

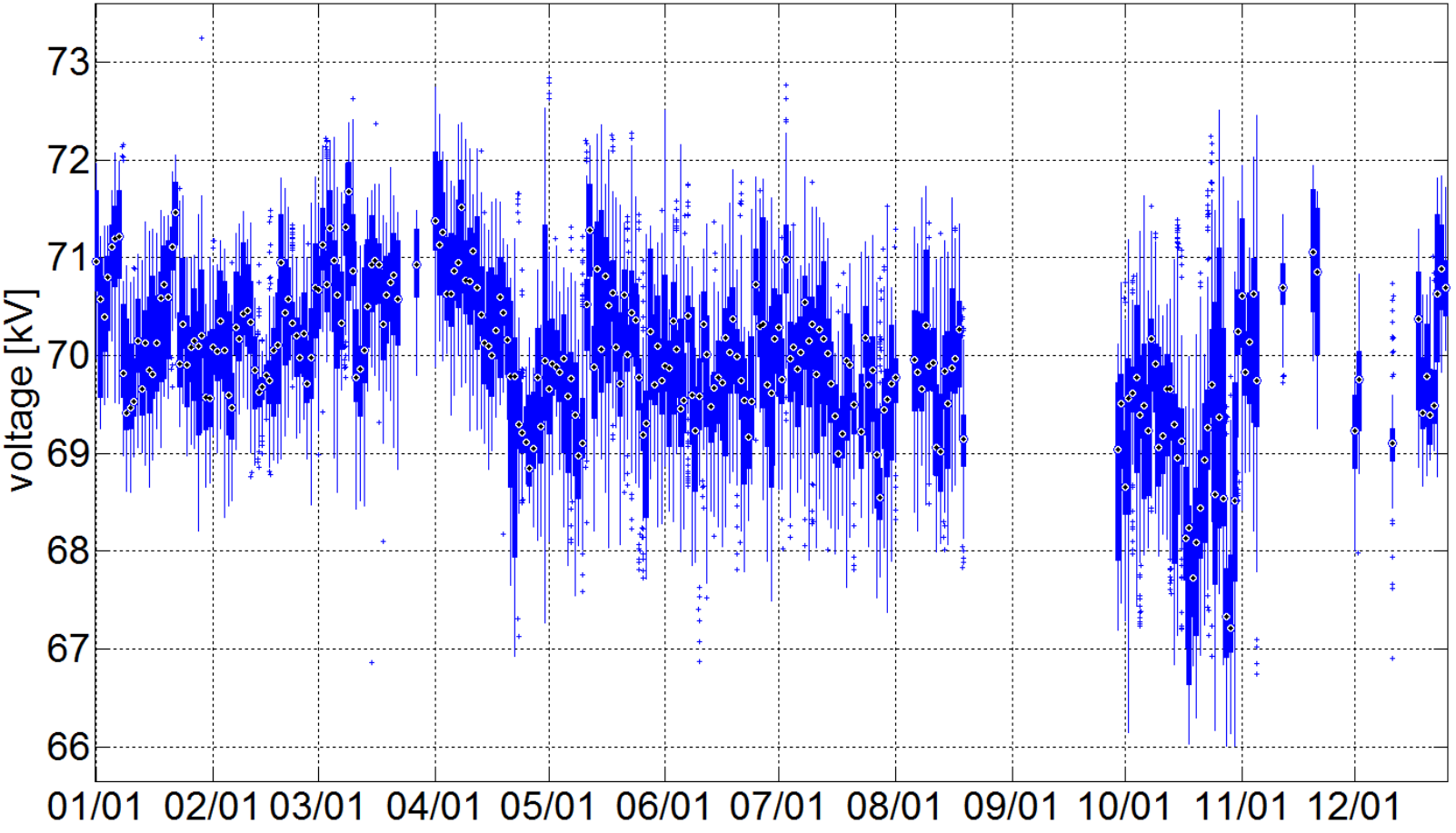
West 4


146
144
142
140
138
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

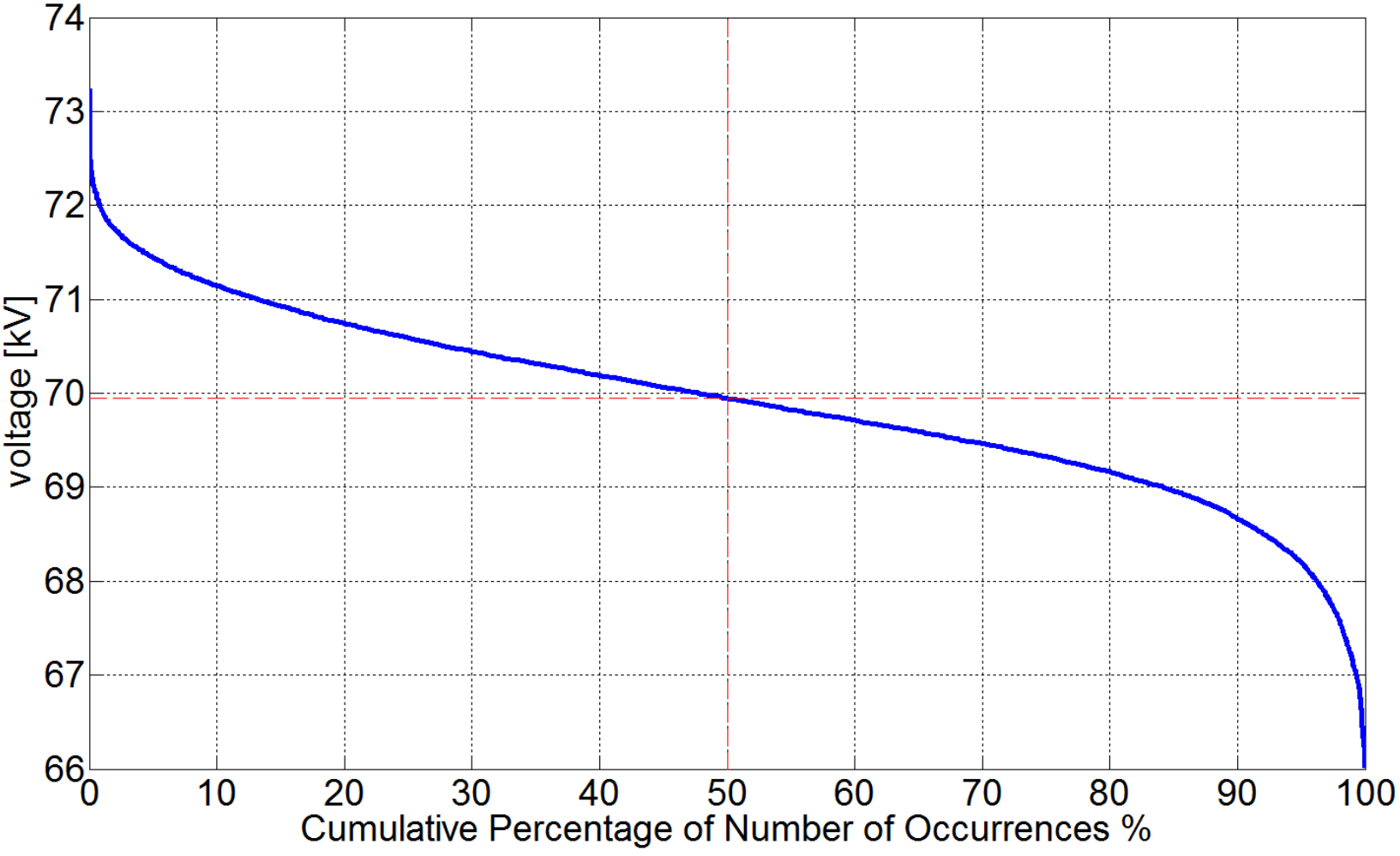
West 4


148
146
144
142
140
138
136
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

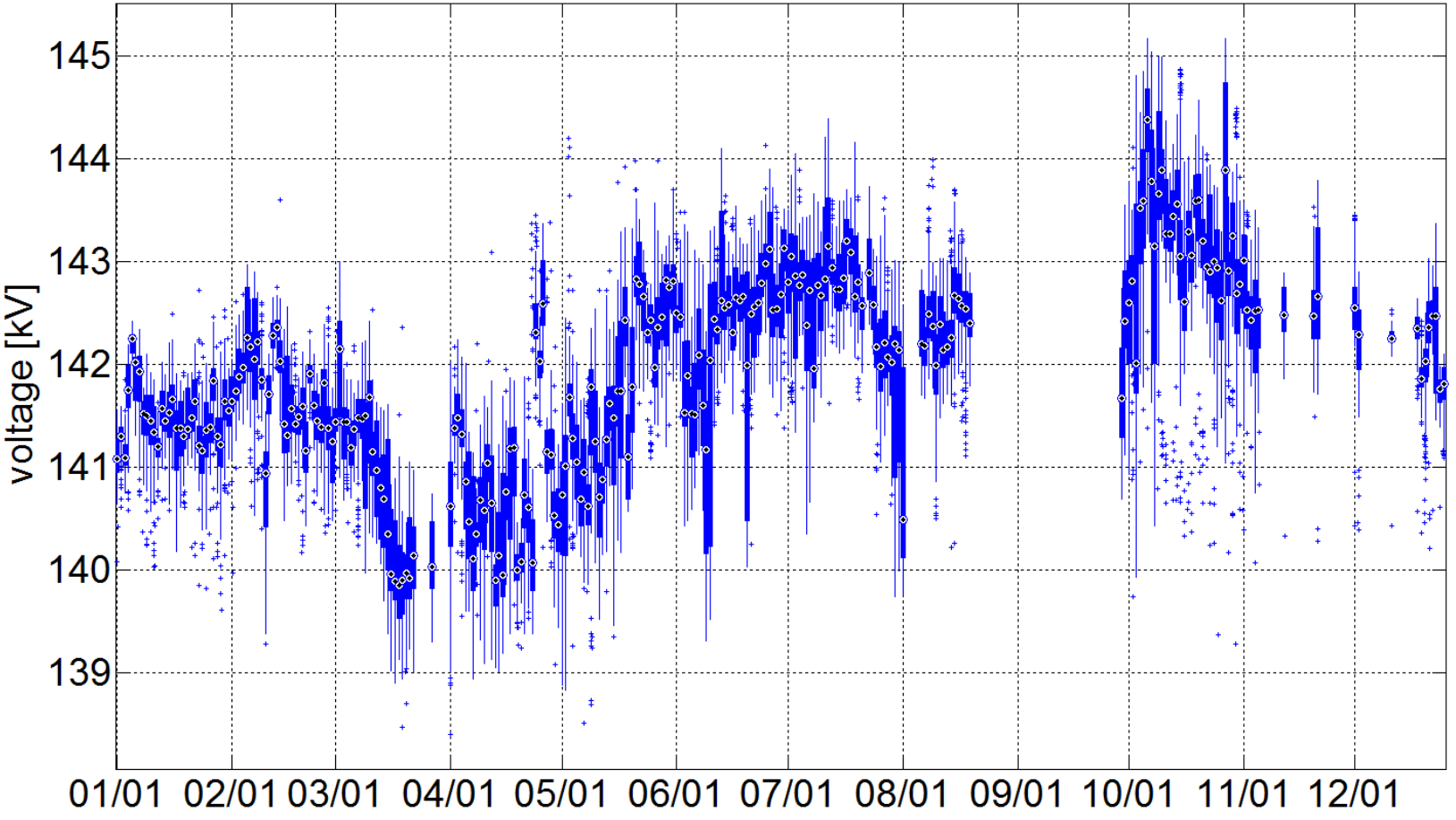
Coast 2


voltage [kV]
73
72
71
70
69
68
67
66
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

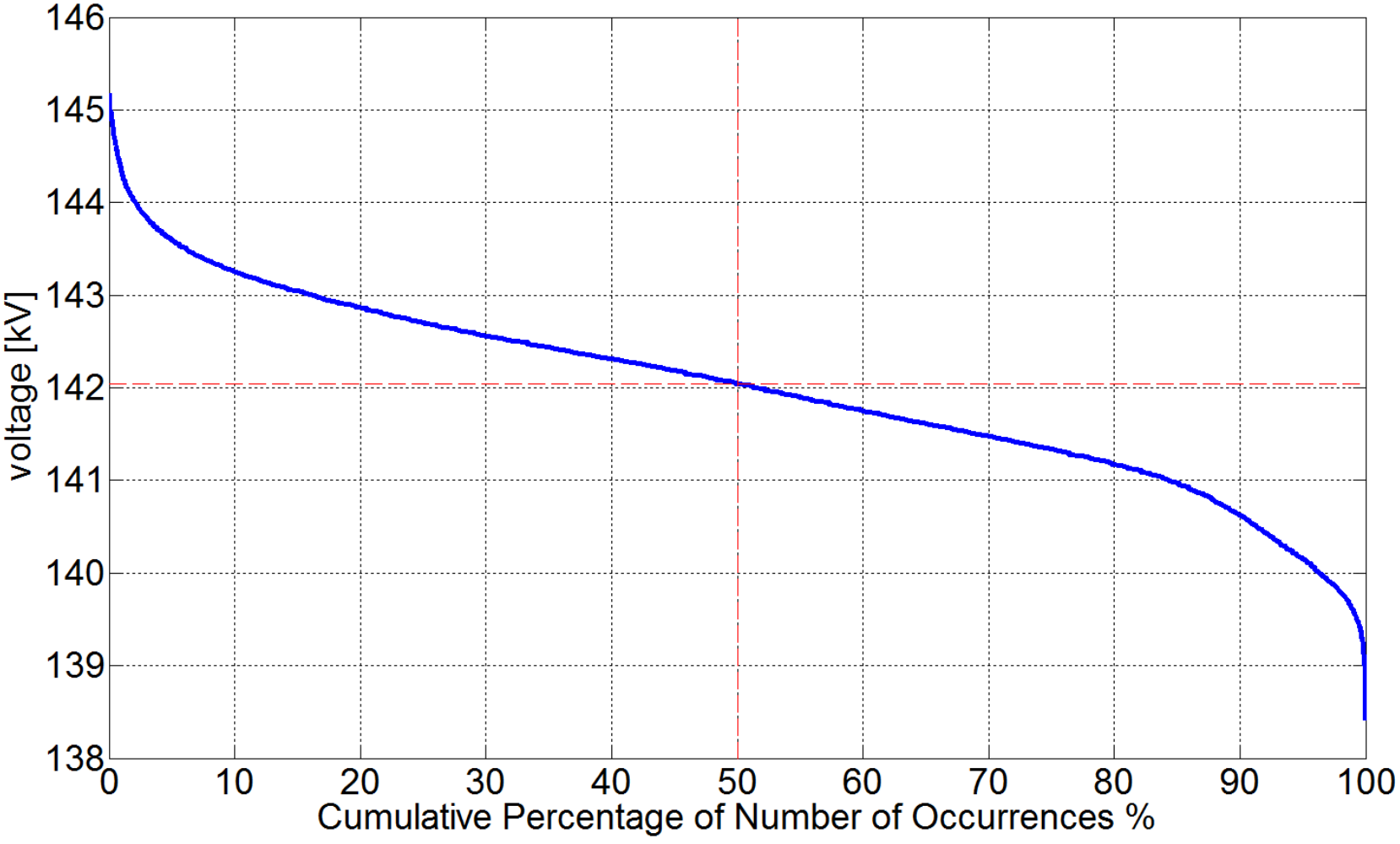
Coast 2


74
73
72
71
70
69
68
67
66
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

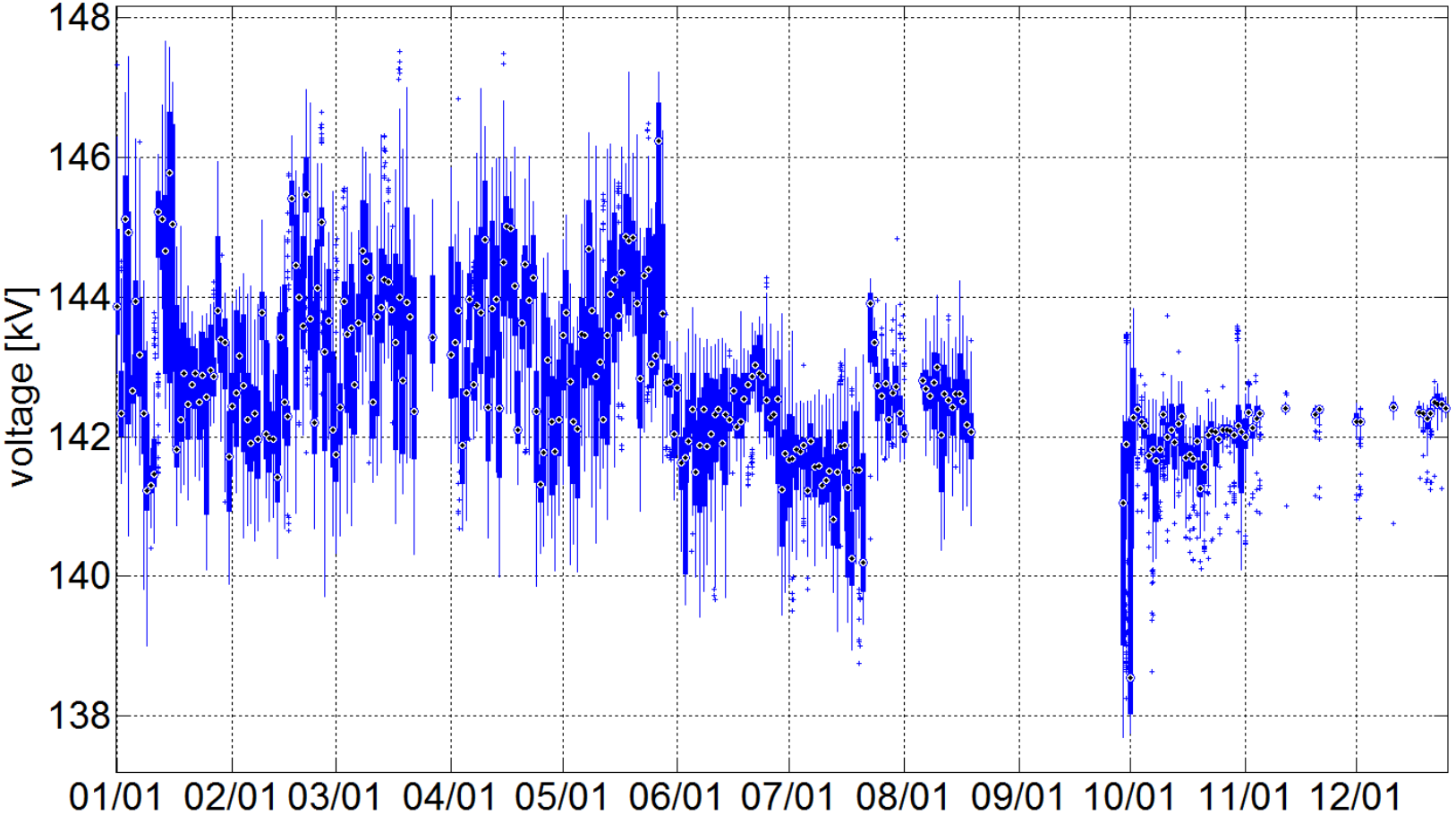
Coast 1


voltage [kV]
145
144
143
142
141
140
139
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

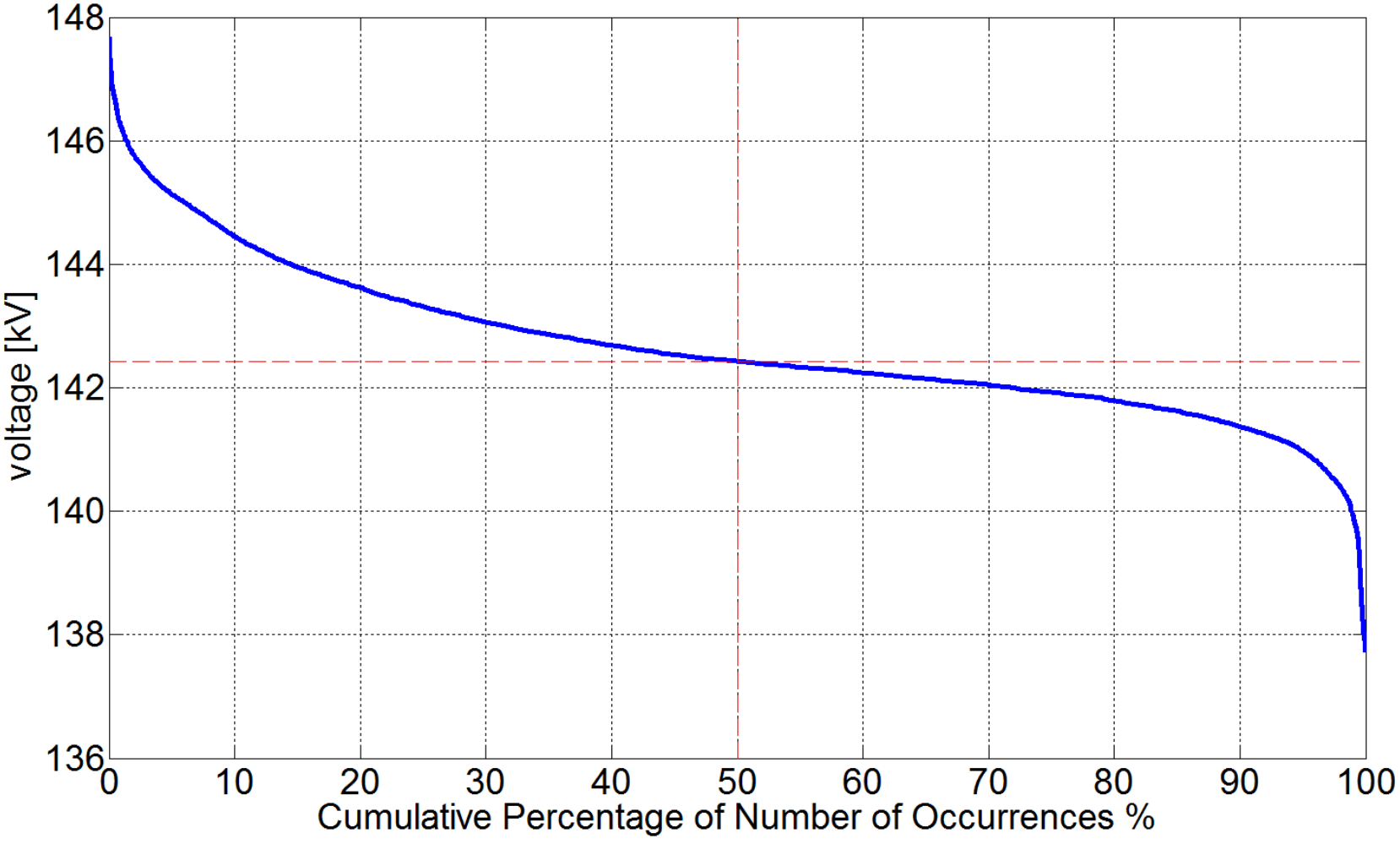
Coast 1


146
145
144
143
142
141
140
139
138
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

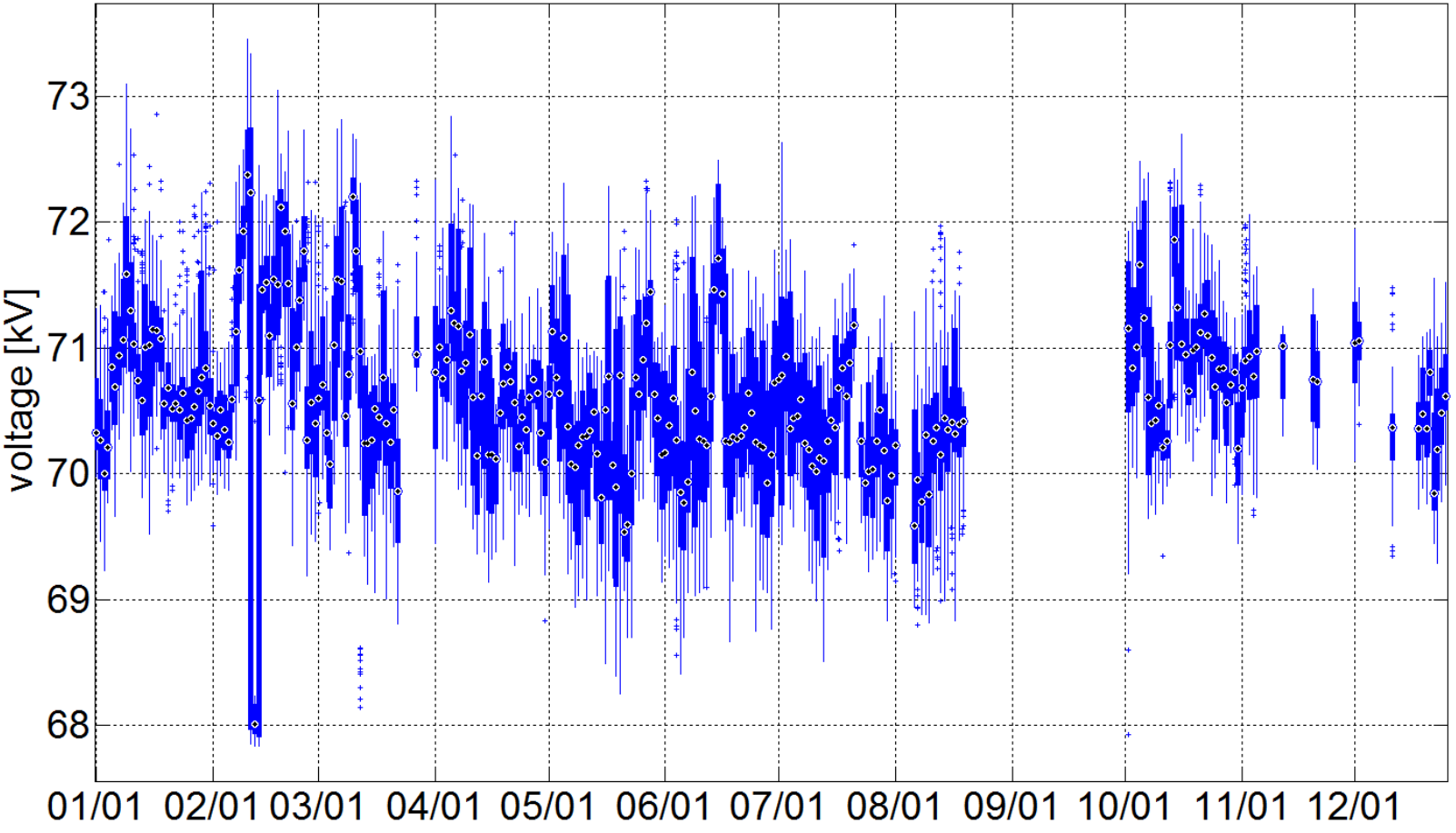
South 3


148
146
144
142
140
138
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

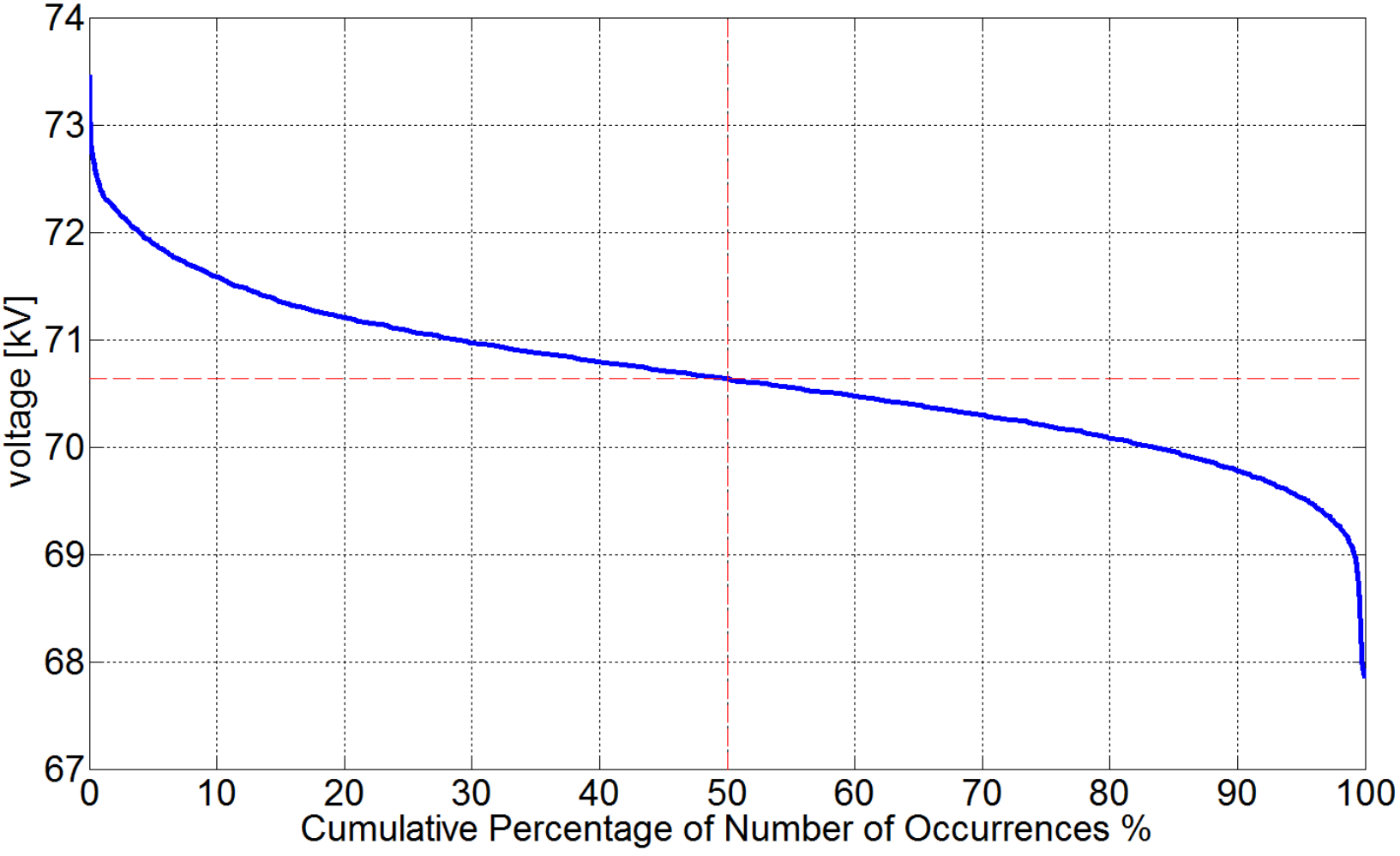
South 3


148
146
144
142
140
138
136
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

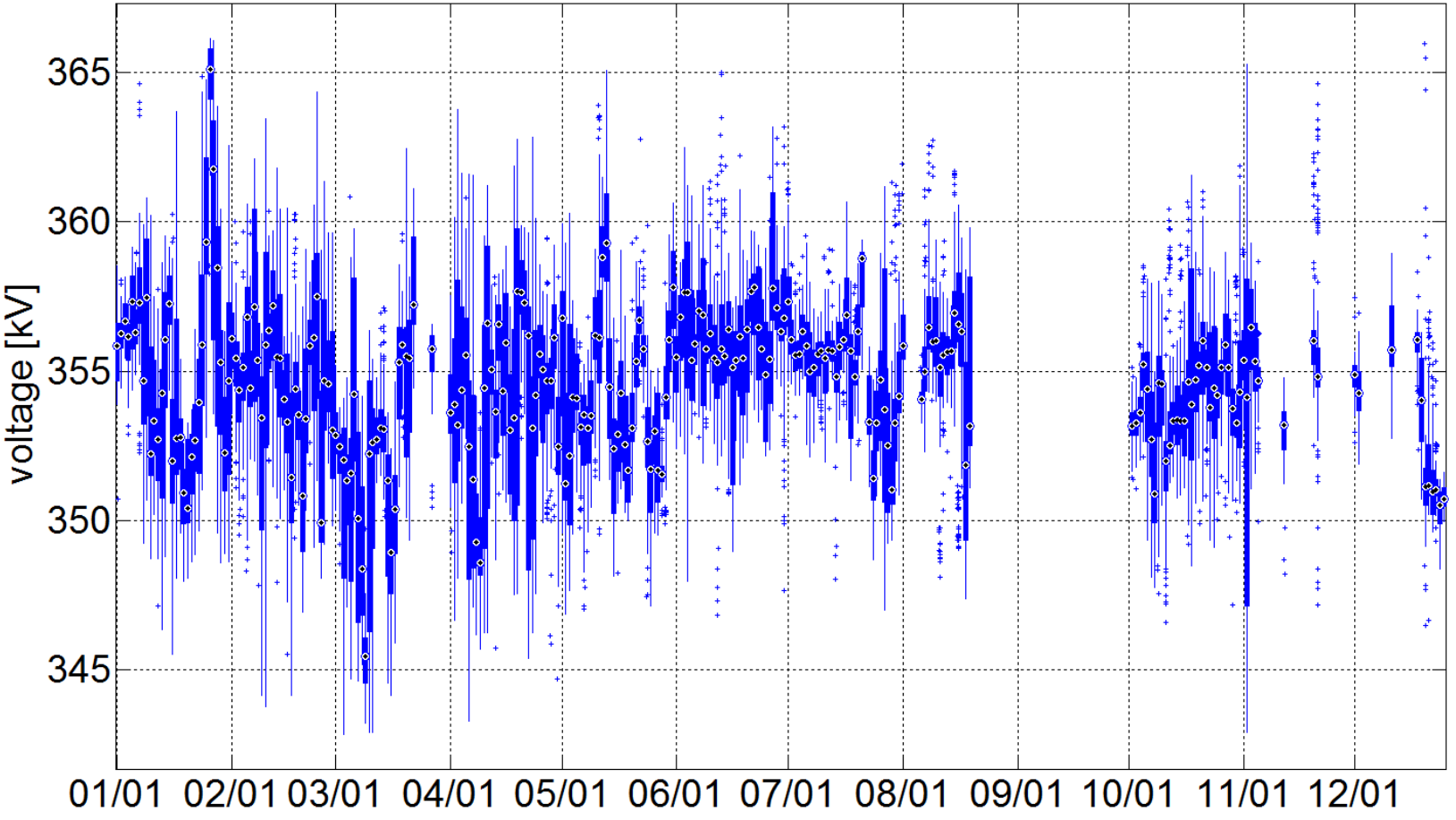
South 5


voltage [kV]
73
72
71
70
69
68
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

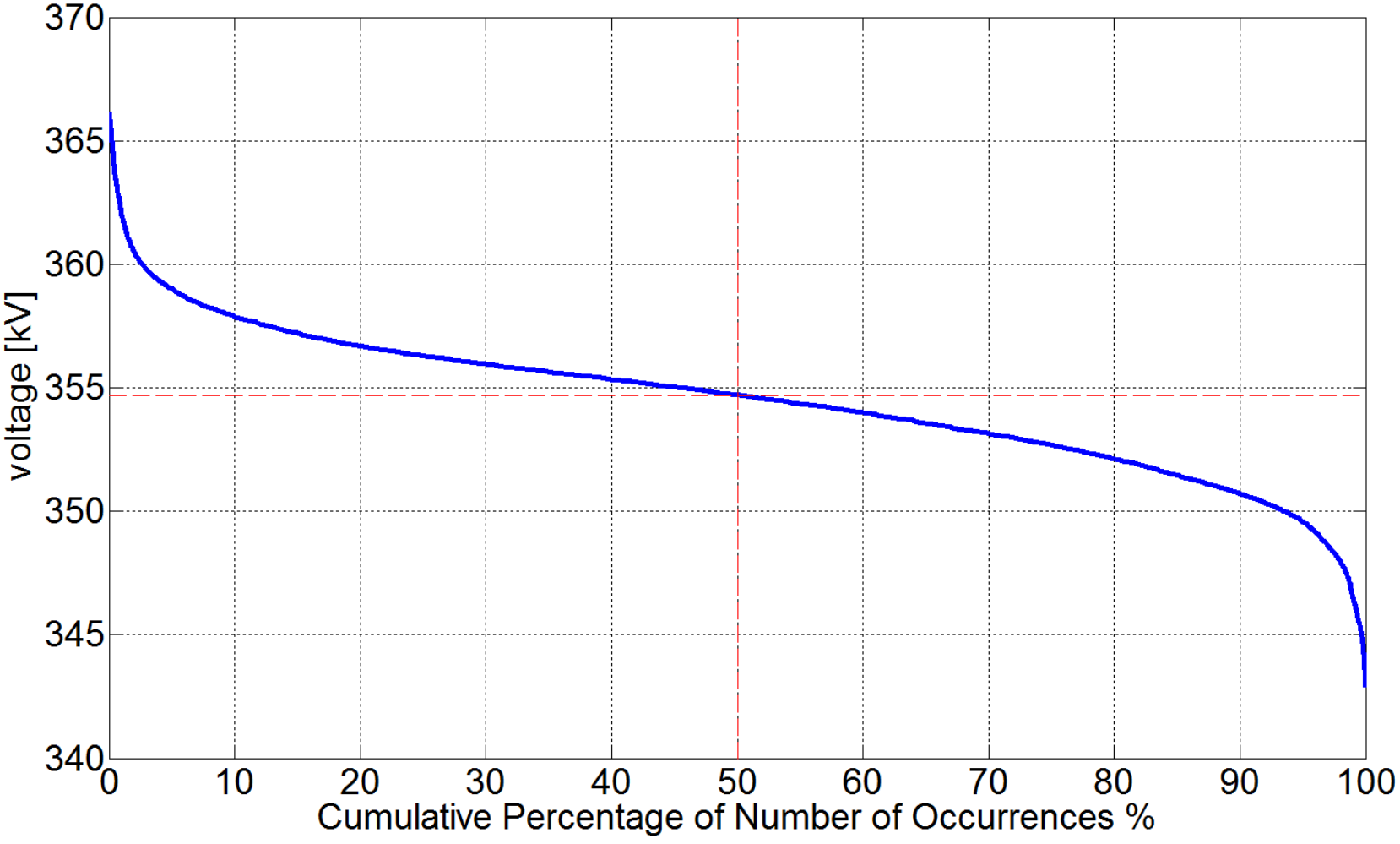
South 5


74
73
72
71
70
69
68
67
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

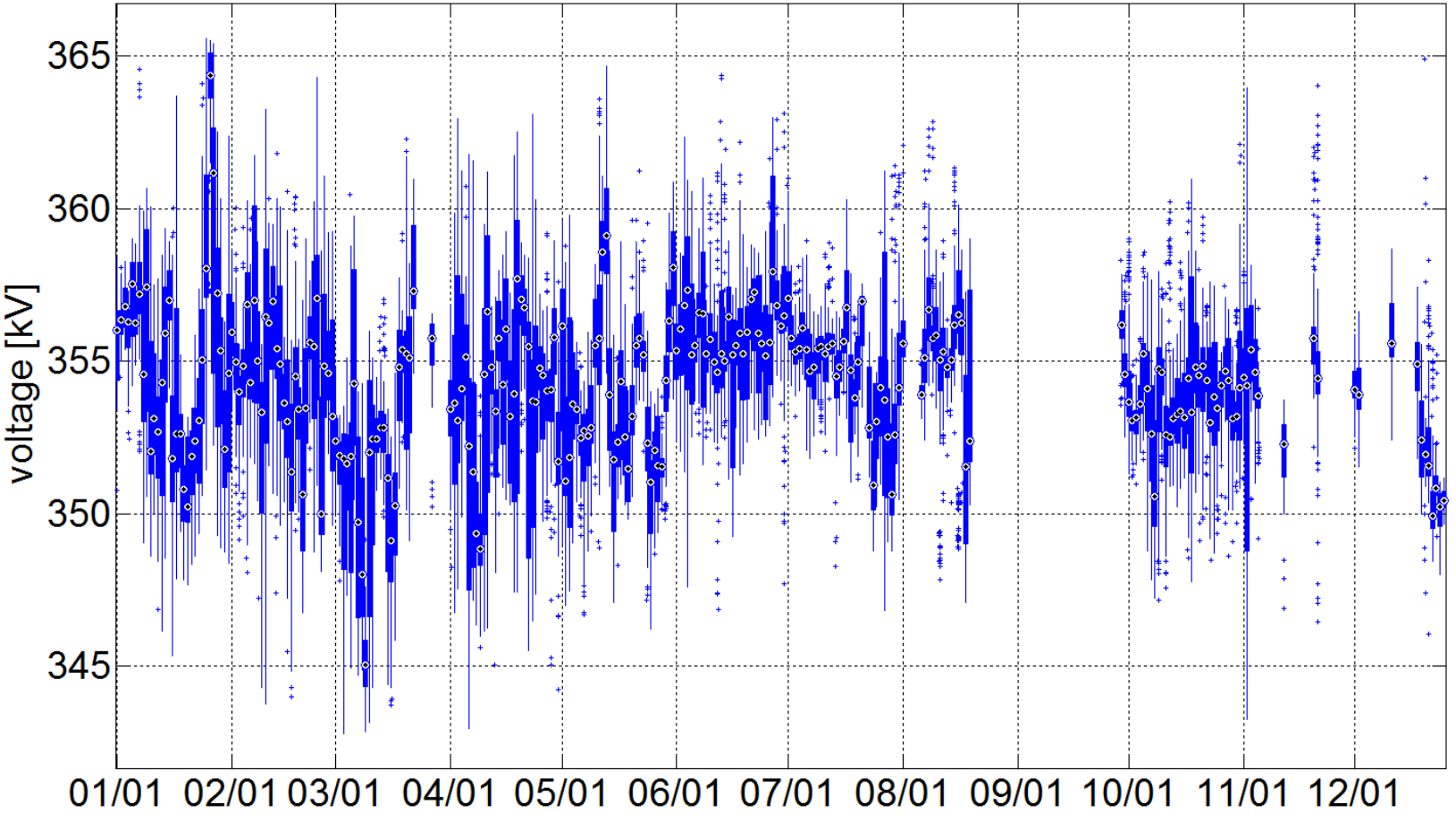
Coast 4


voltage [kV]
365
360
355
350
345
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

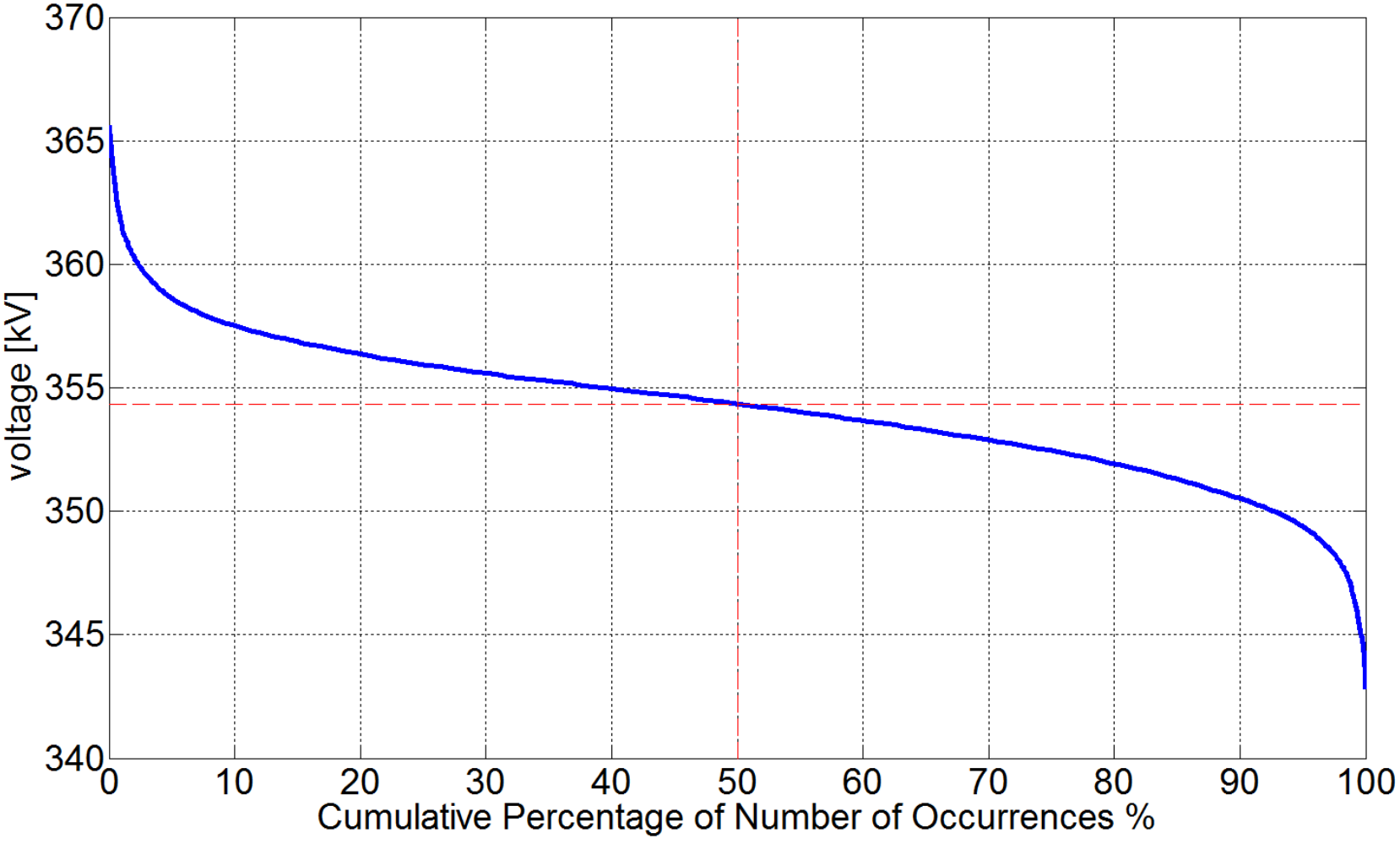
Coast 4


370
365
360
355
350
345
340
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

Coast 3


voltage [kV]
365
360
355
350
345
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

Coast 3


370
365
360
355
350
345
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voltage [kV]
0
10
20
30
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50
60
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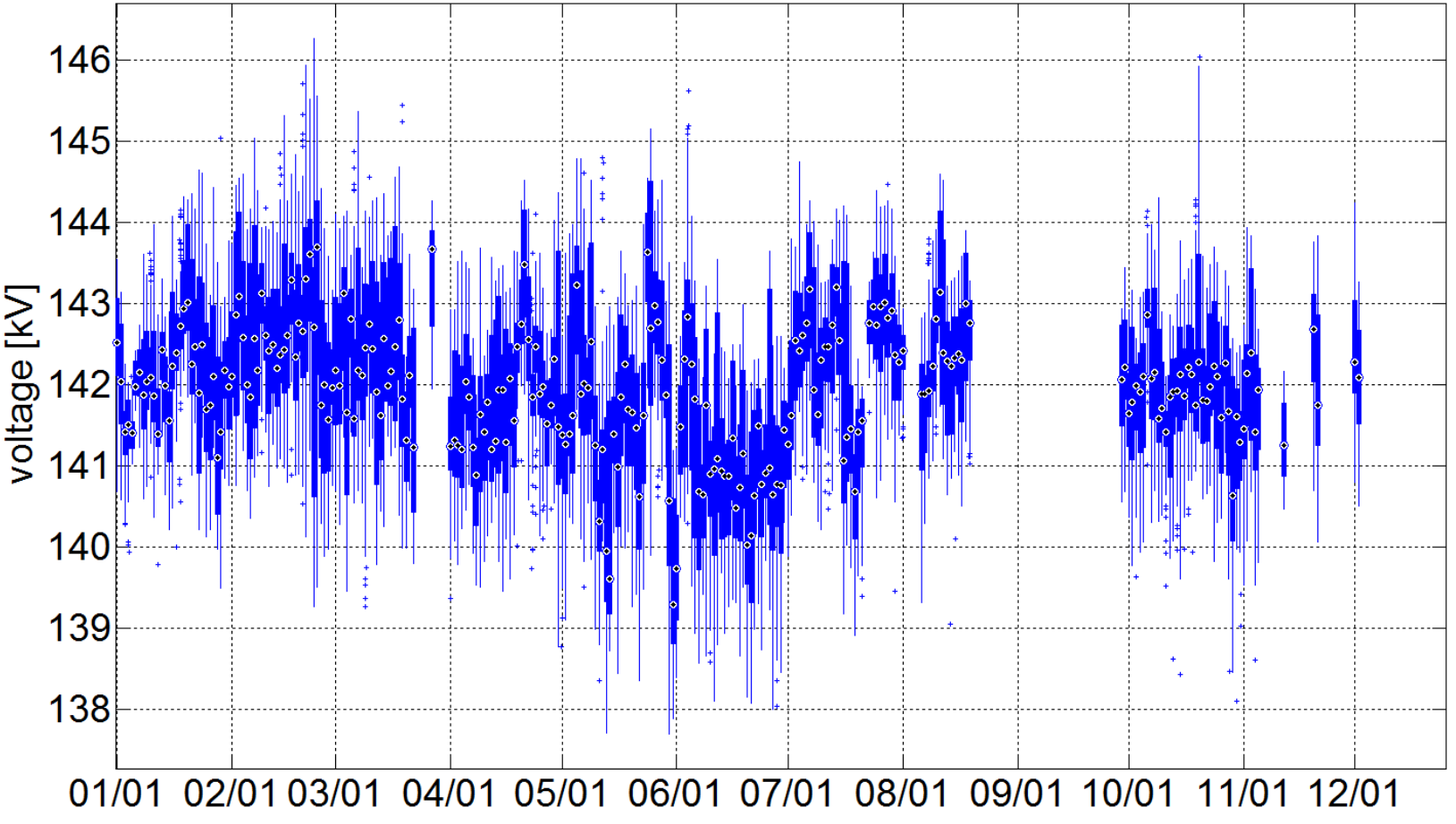
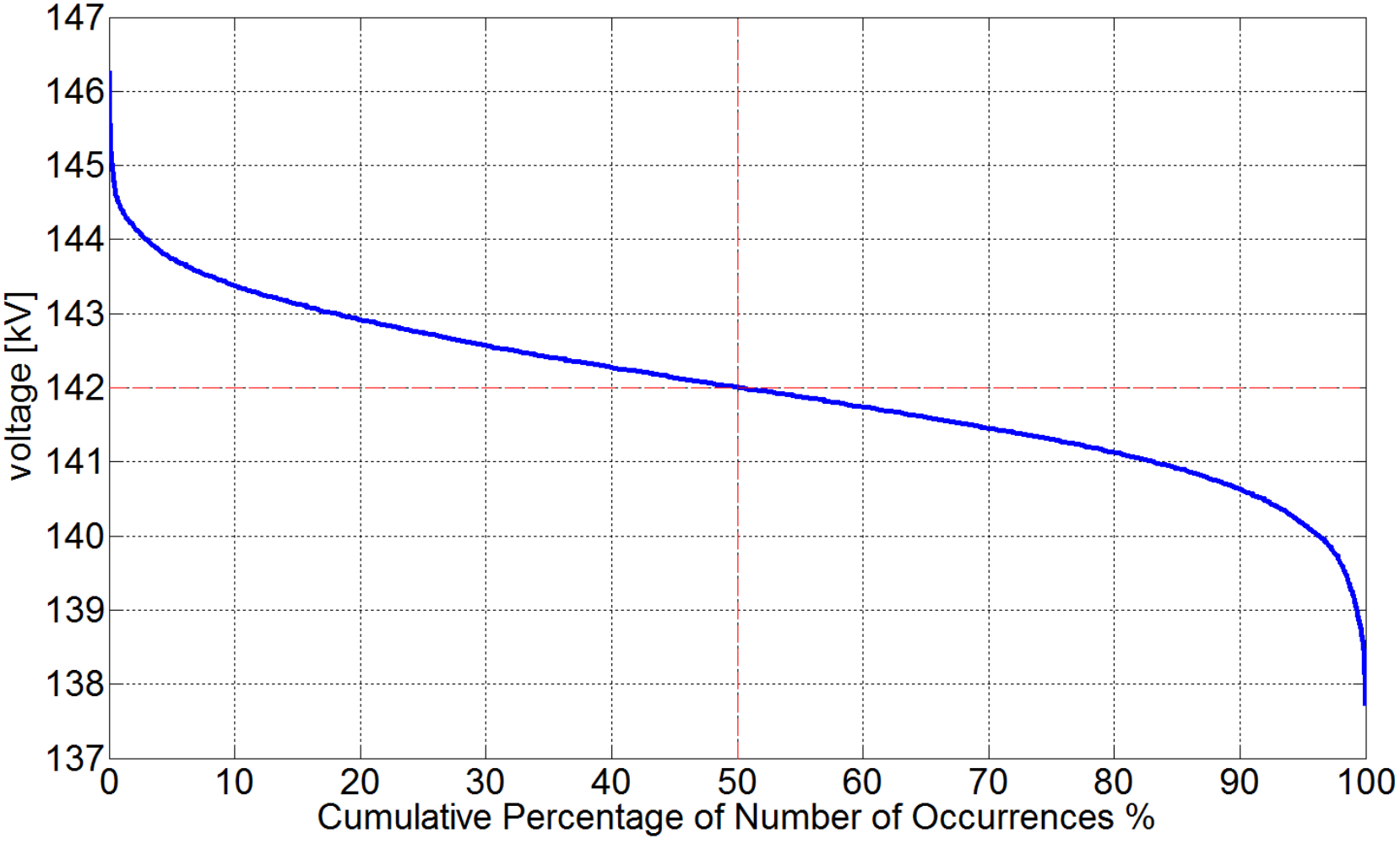
80
90
100
Cumulative Percentage of Number of Occurrences %

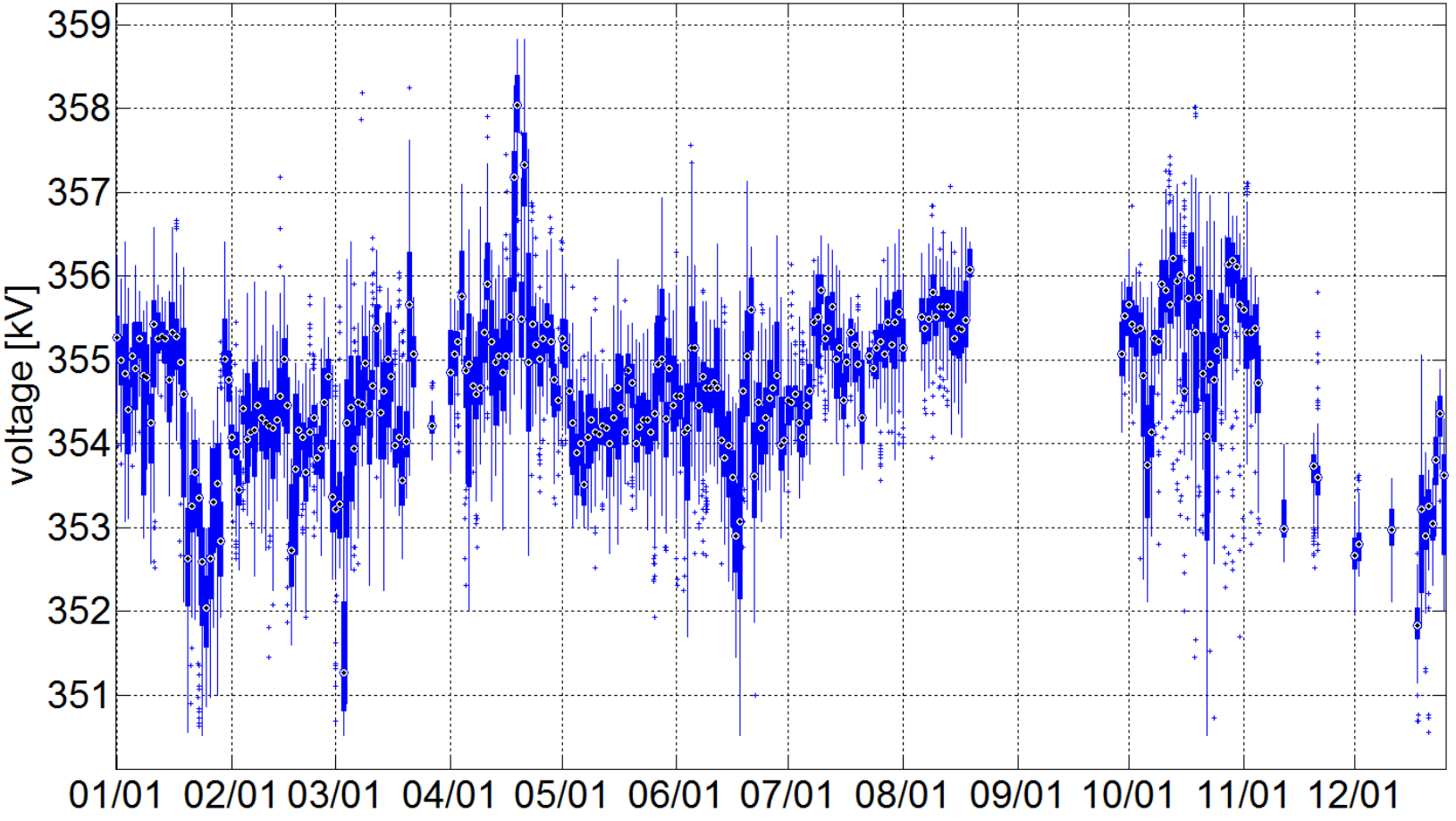
South 13


voltage [kV]
146
145
144
143
142
141
140
139
138
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

South 13


147
146
145
144
143
142
141
140
139
138
137
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

FarWest 4


voltage [kV]
359
358
357
356
355
354
353
352
351
01/01
02/01
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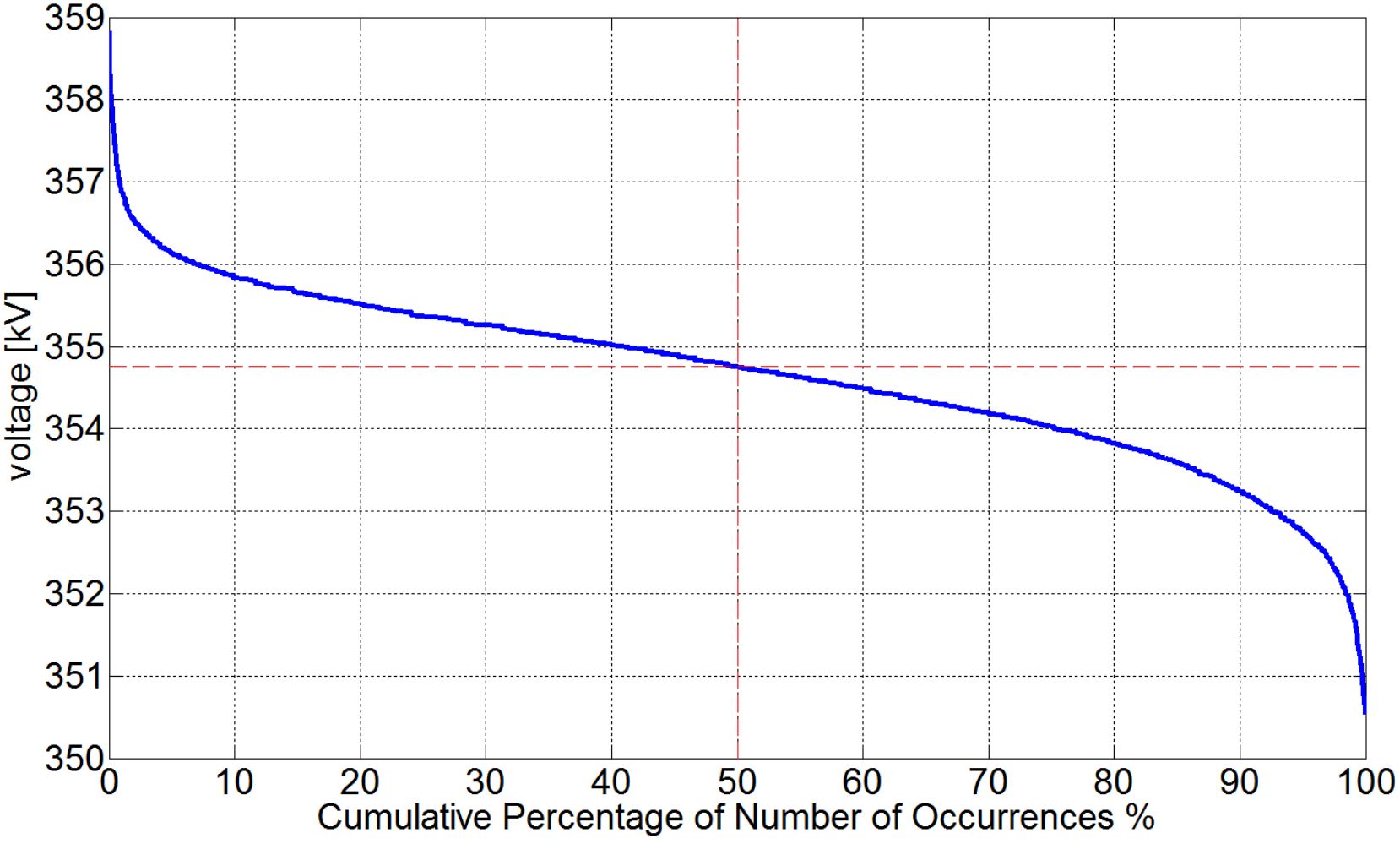
06/01
07/01
08/01
09/01
10/01
11/01
12/01

FarWest 4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358
357
356
355
354
353
352
351
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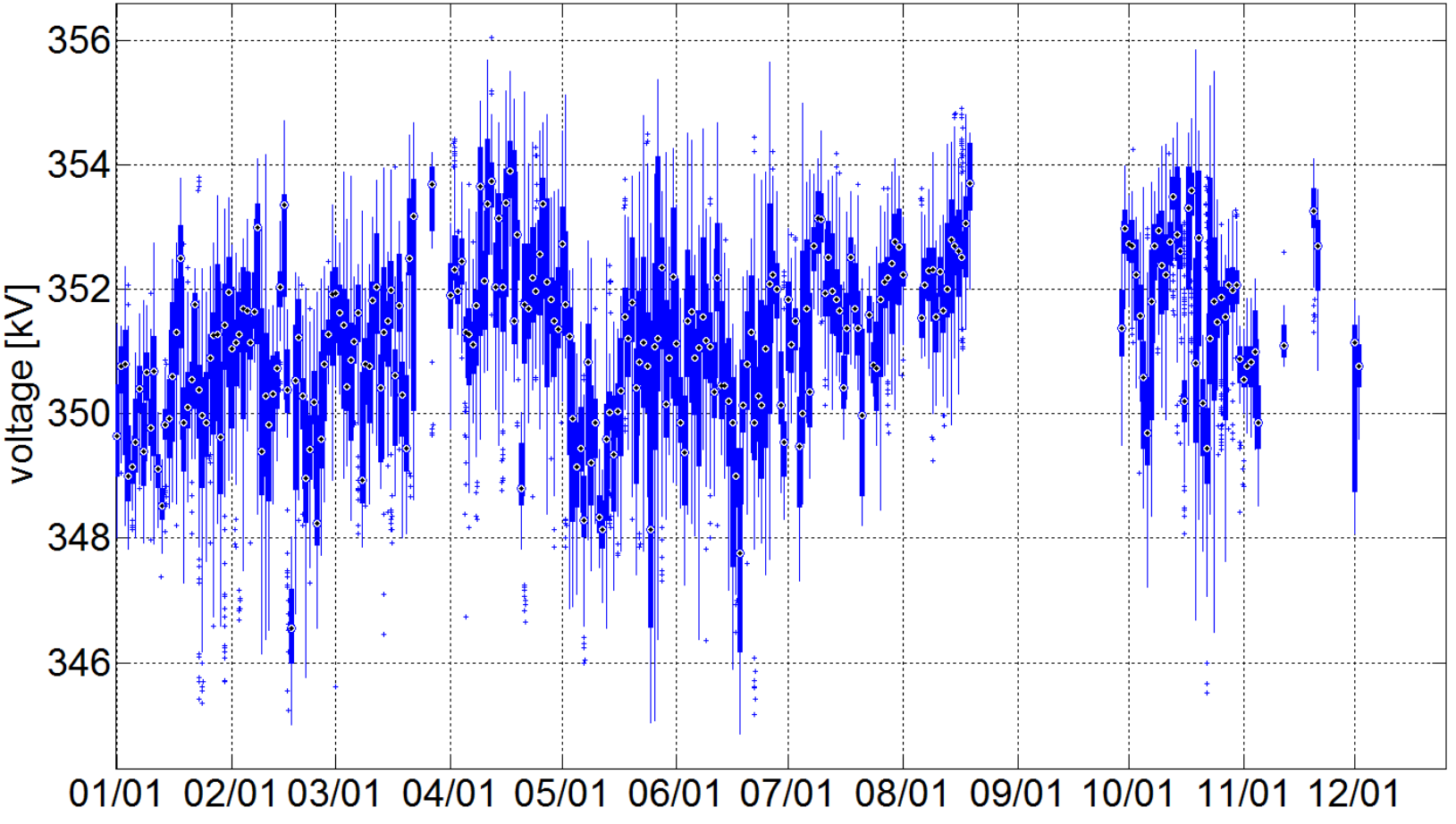
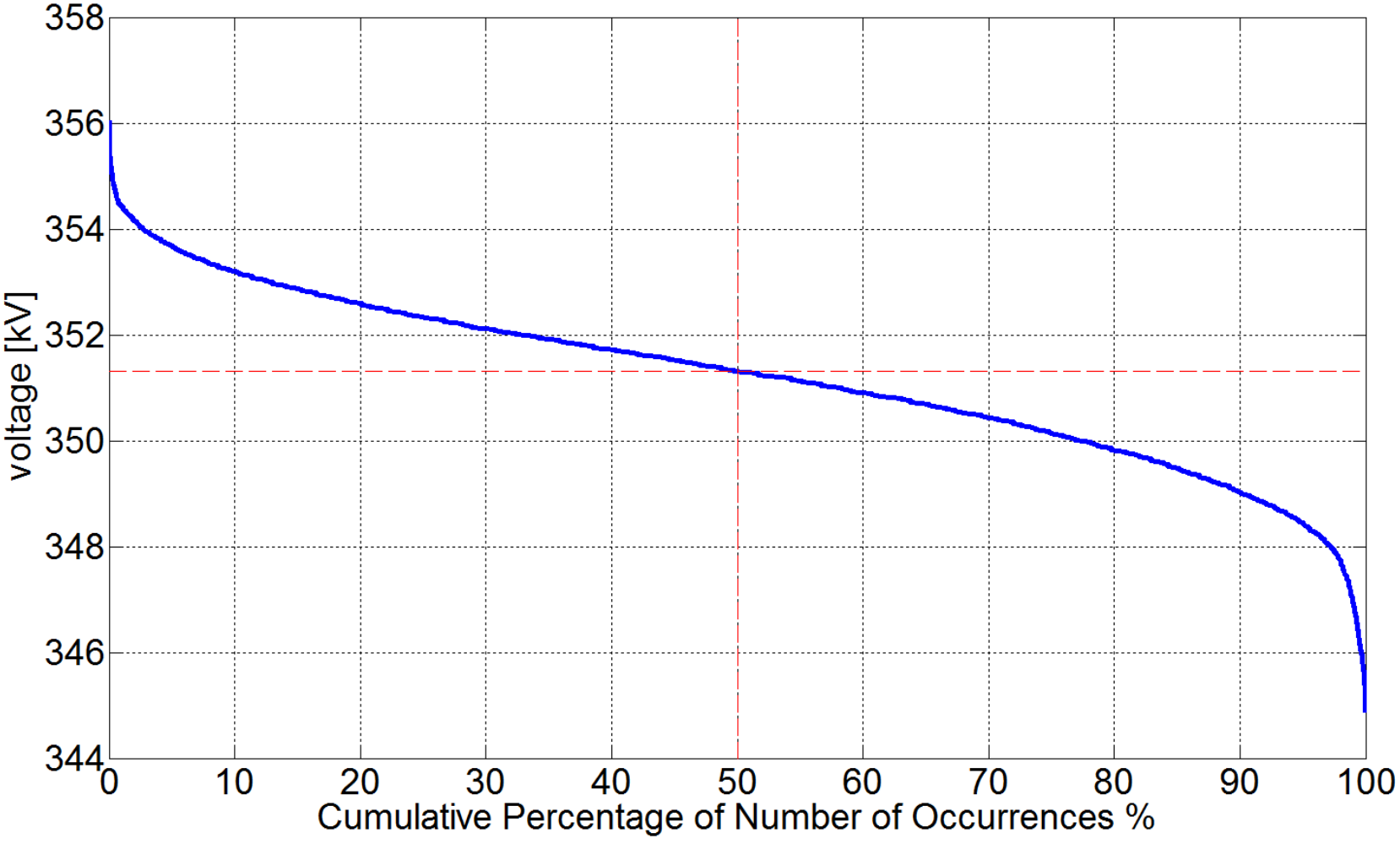
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

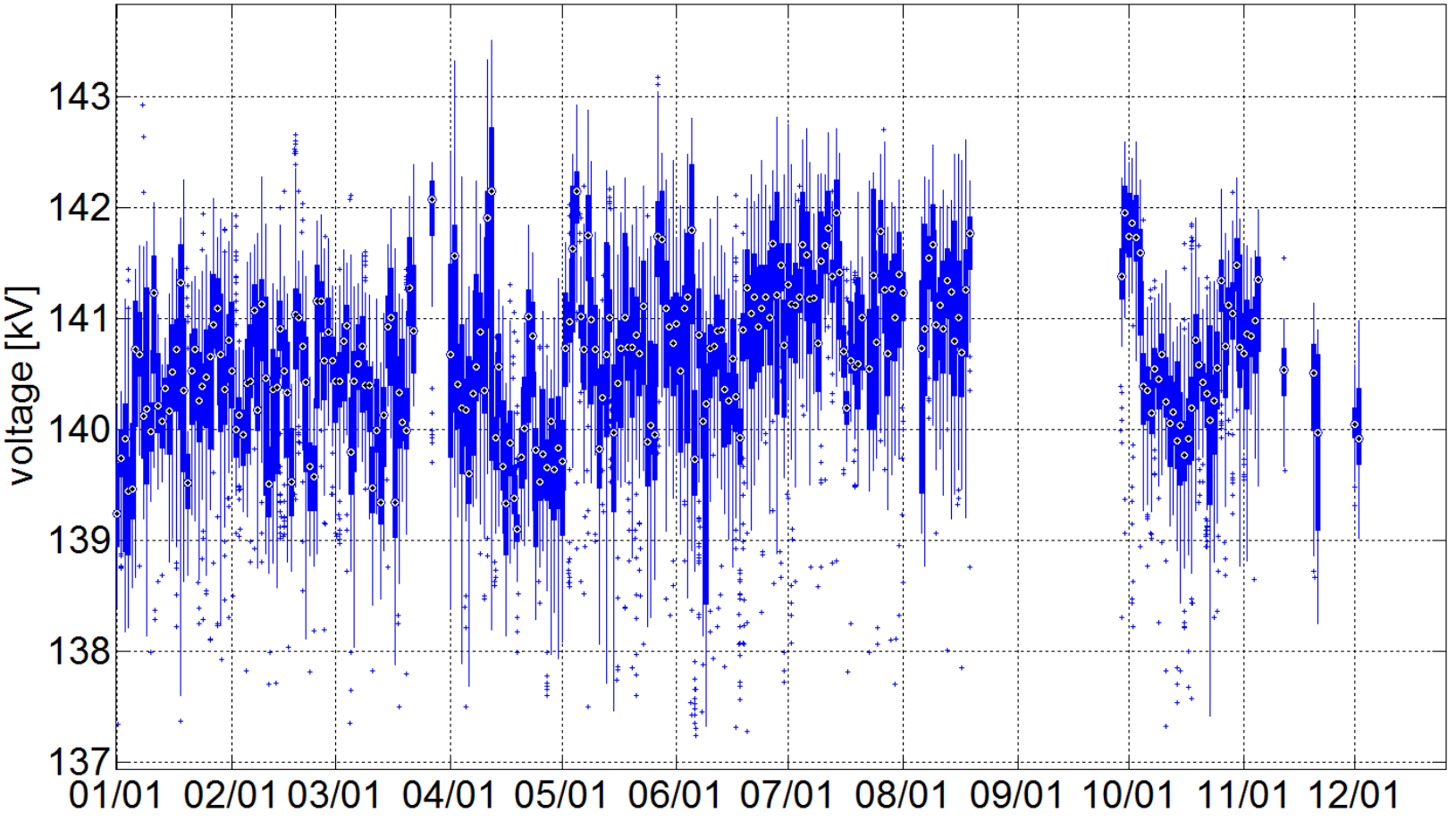
FarWest 7


356
354
352
350
348
346
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

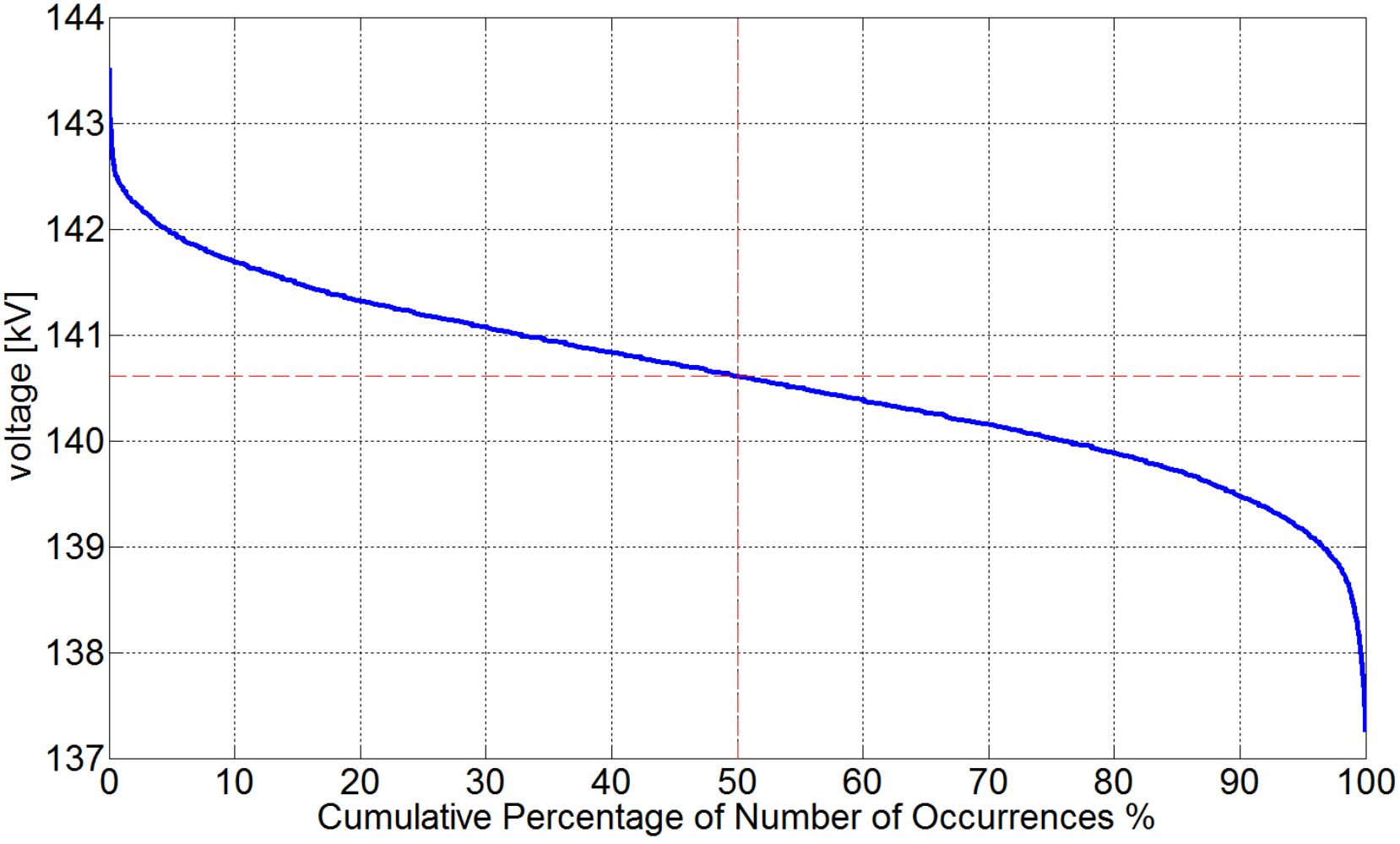
FarWest 7


358
356
354
352
350
348
346
344
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

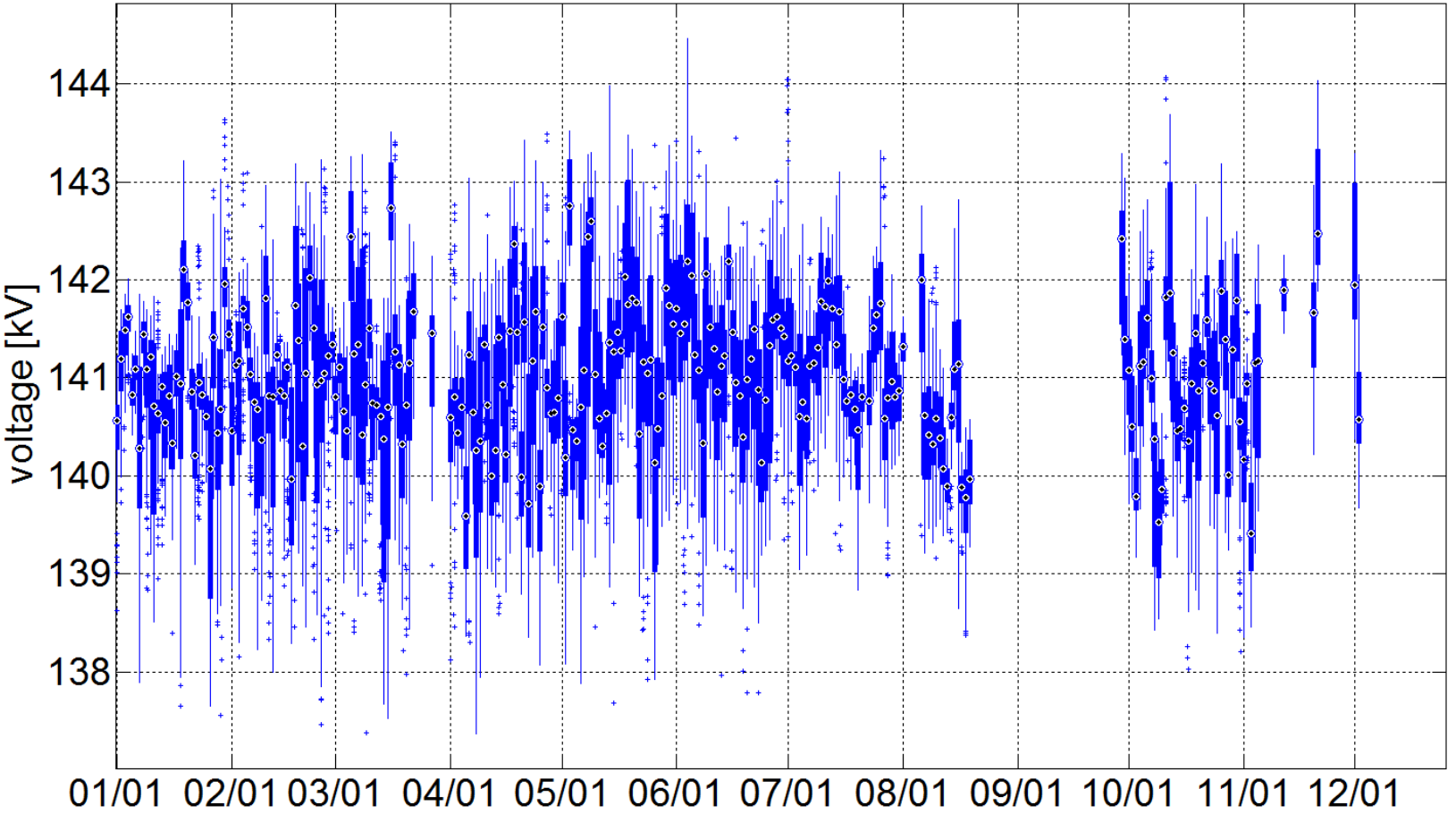
FarWest 8


voltage [kV]
143
142
141
140
139
138
137
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

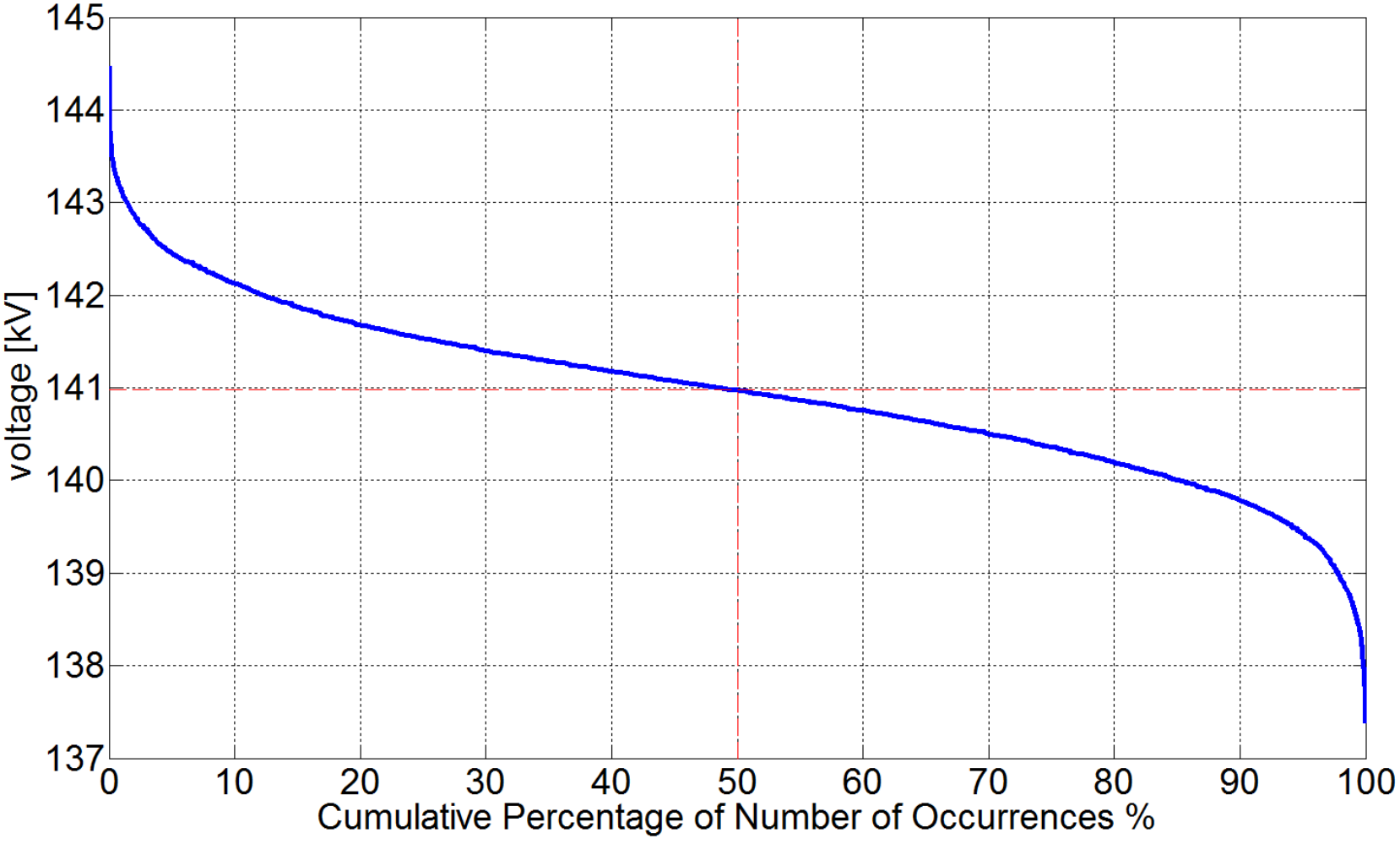
FarWest 8


144
143
142
141
140
139
138
137
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

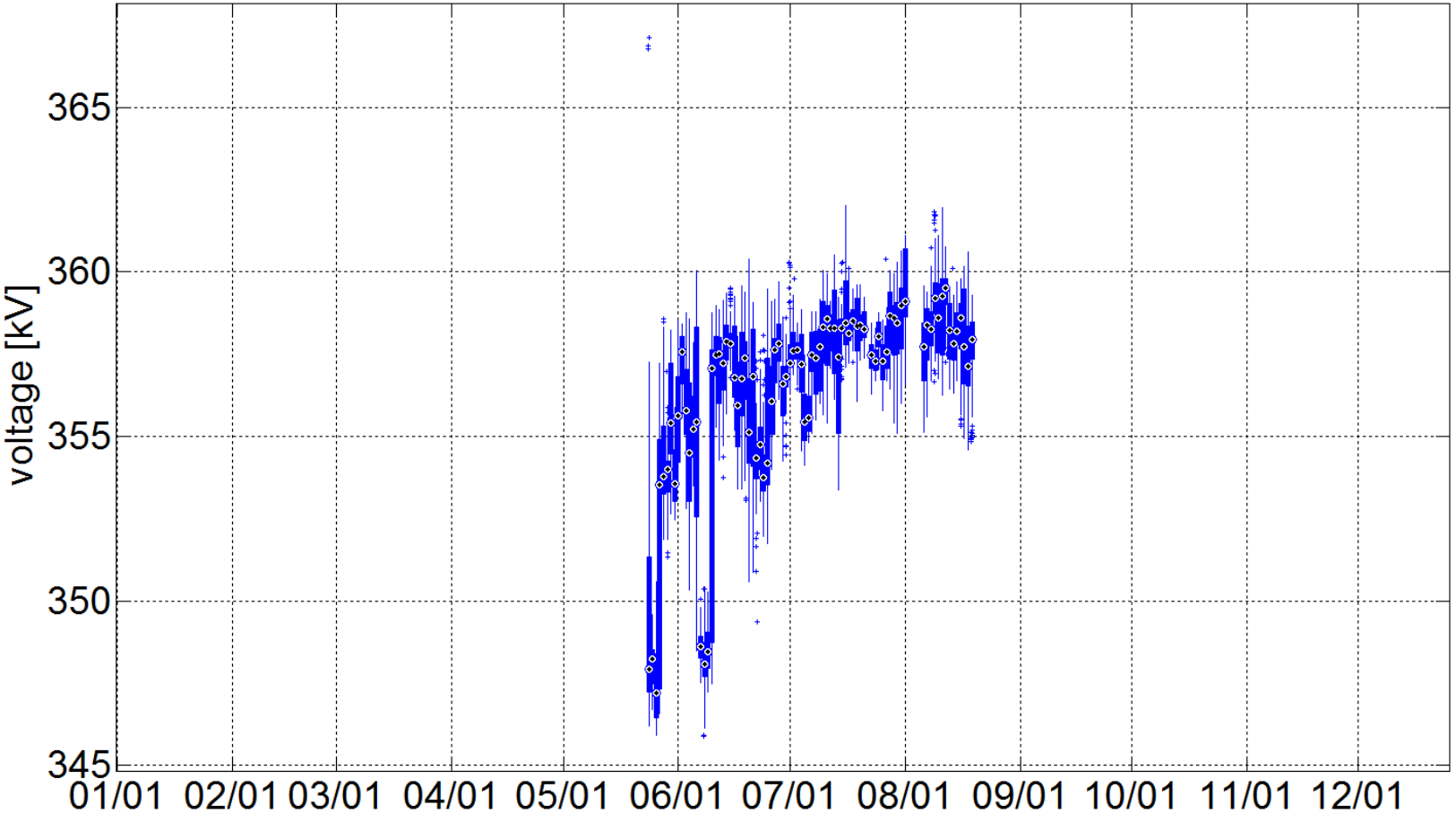
FarWest 9


voltage [kV]
144
143
142
141
140
139
138
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

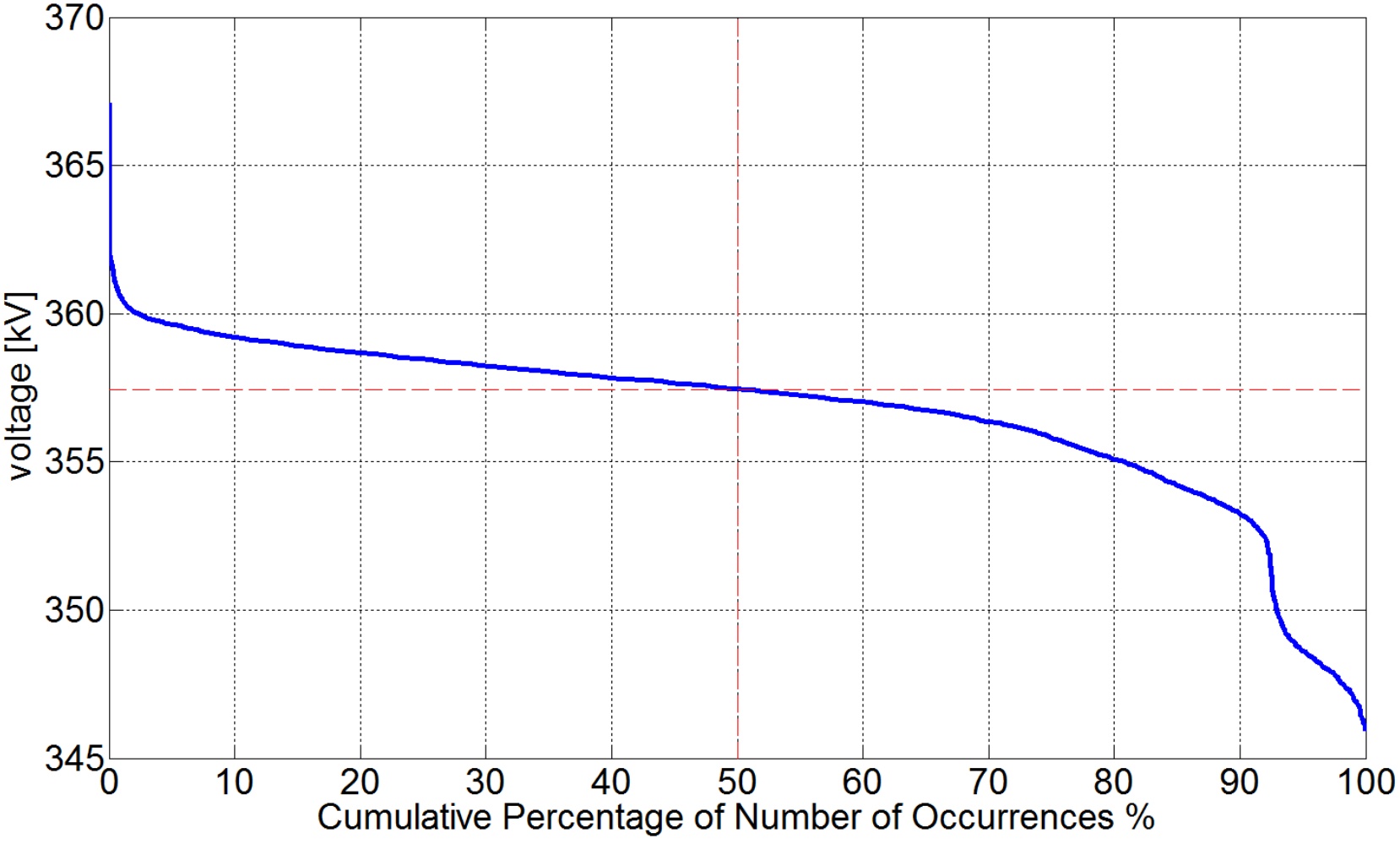
FarWest 9


145
144
143
142
141
140
139
138
137
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

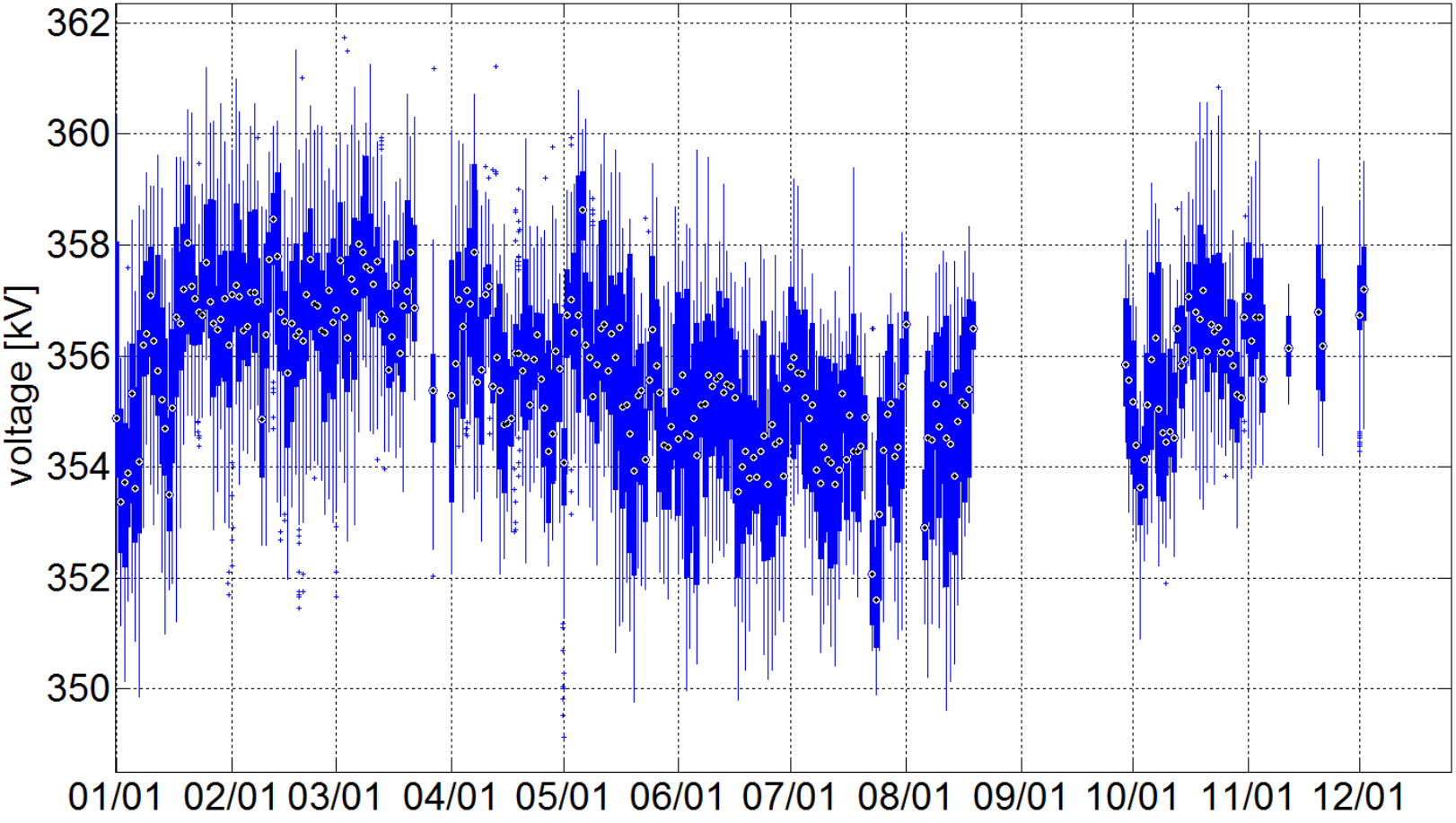
West 8


365
360
355
350
345
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

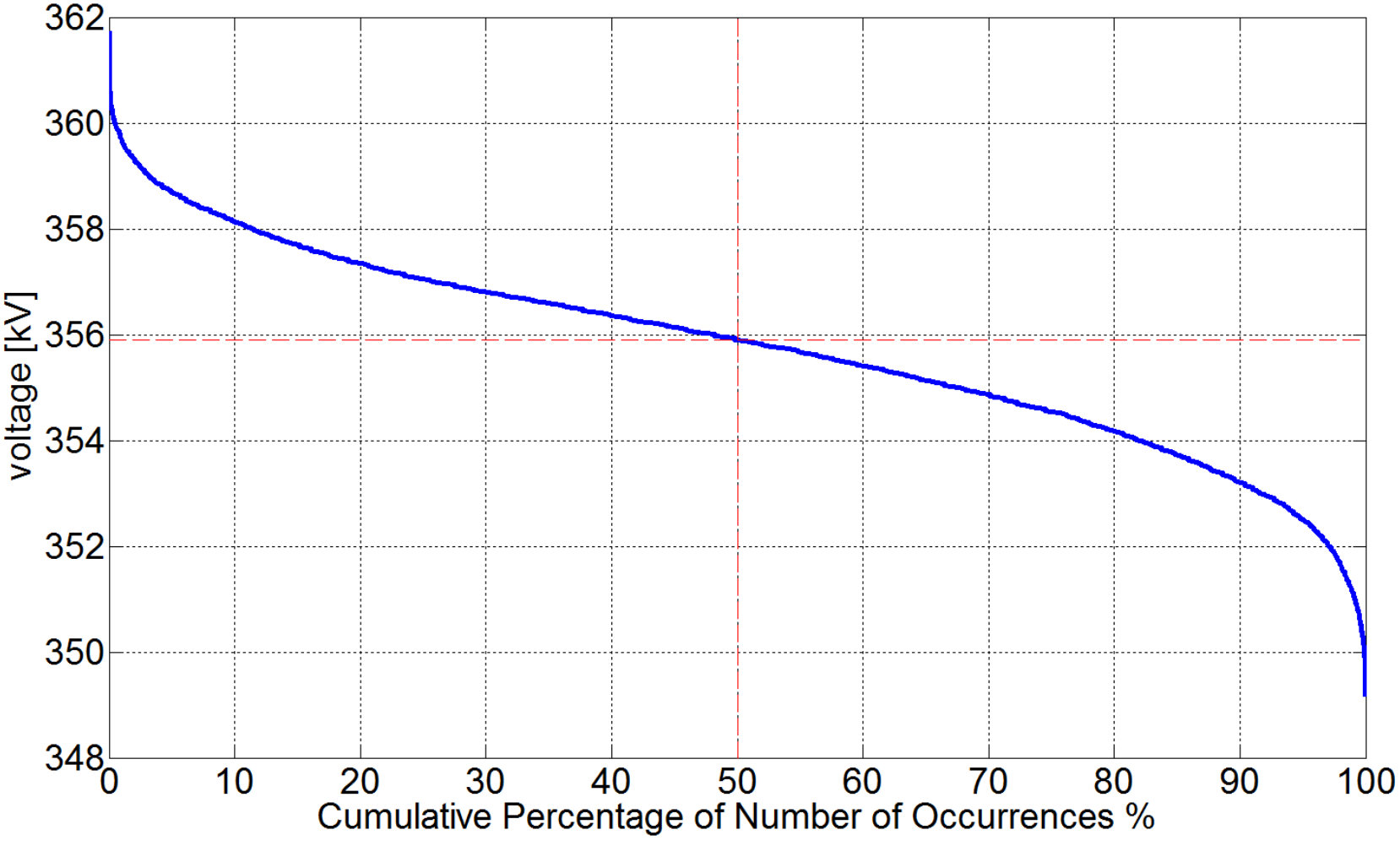
West 8


370
365
360
355
350
345
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

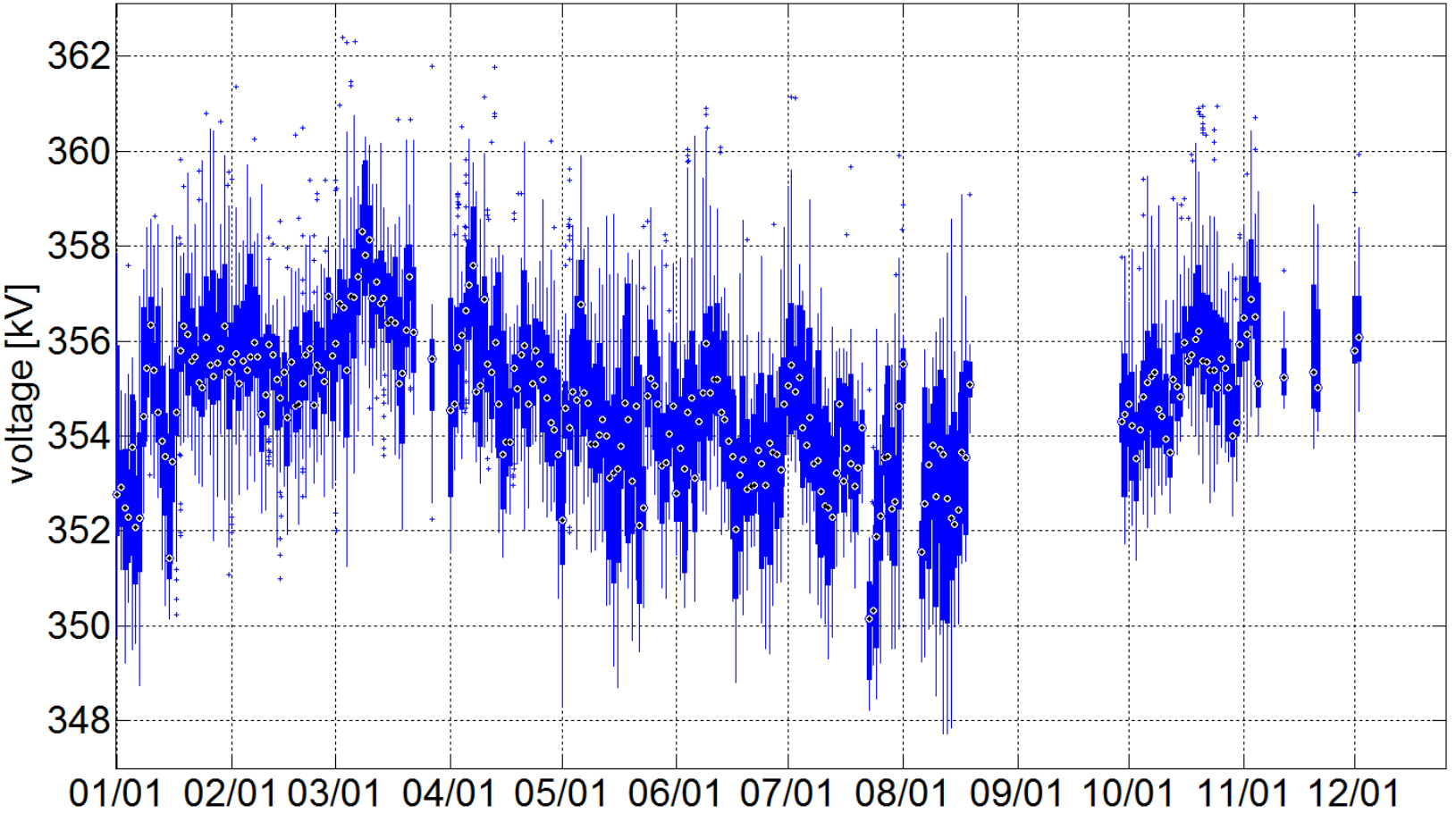
South 15*


362
360
358
356
354
352
350
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

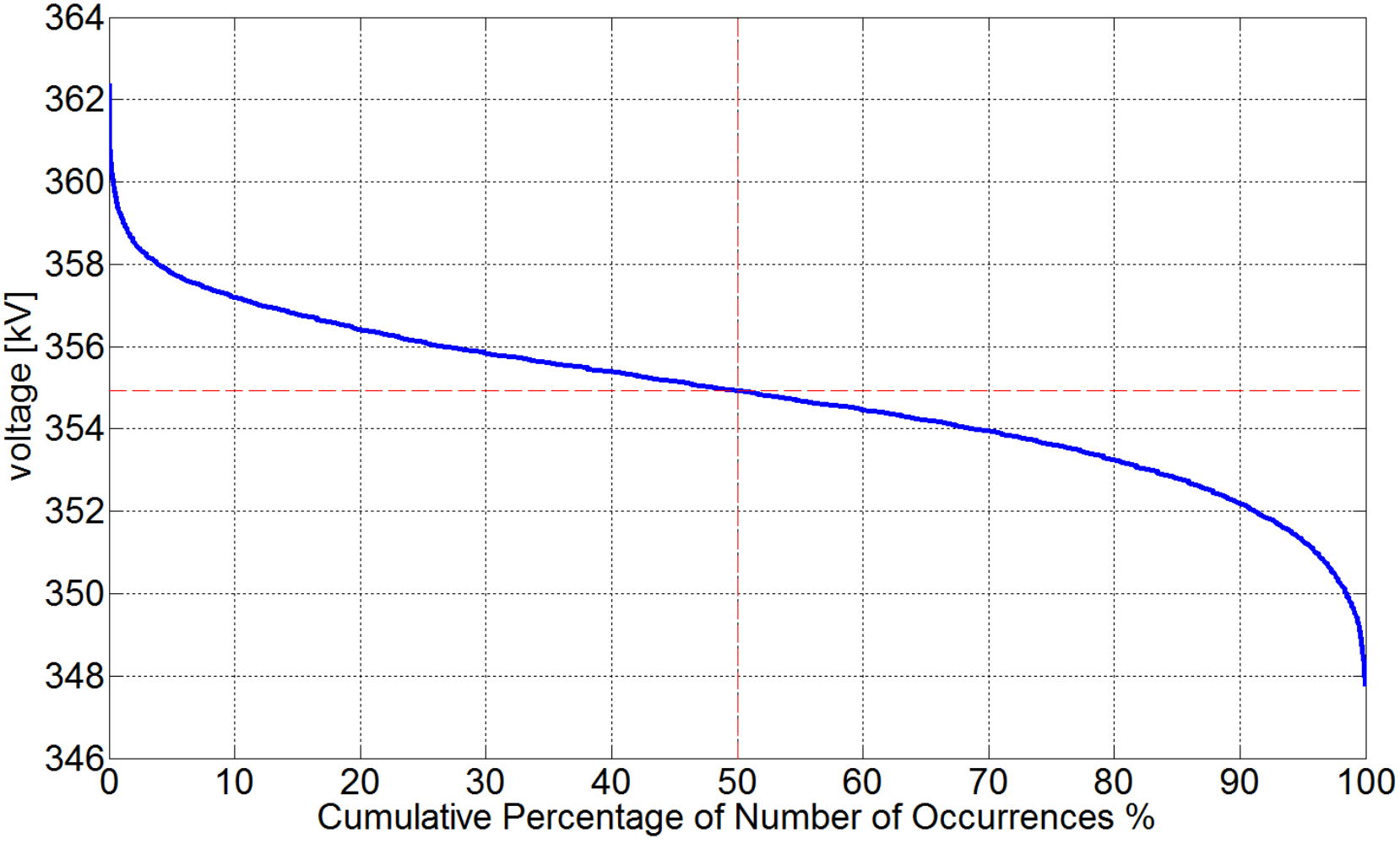
South 15*


362
360
358
356
354
352
350
348
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

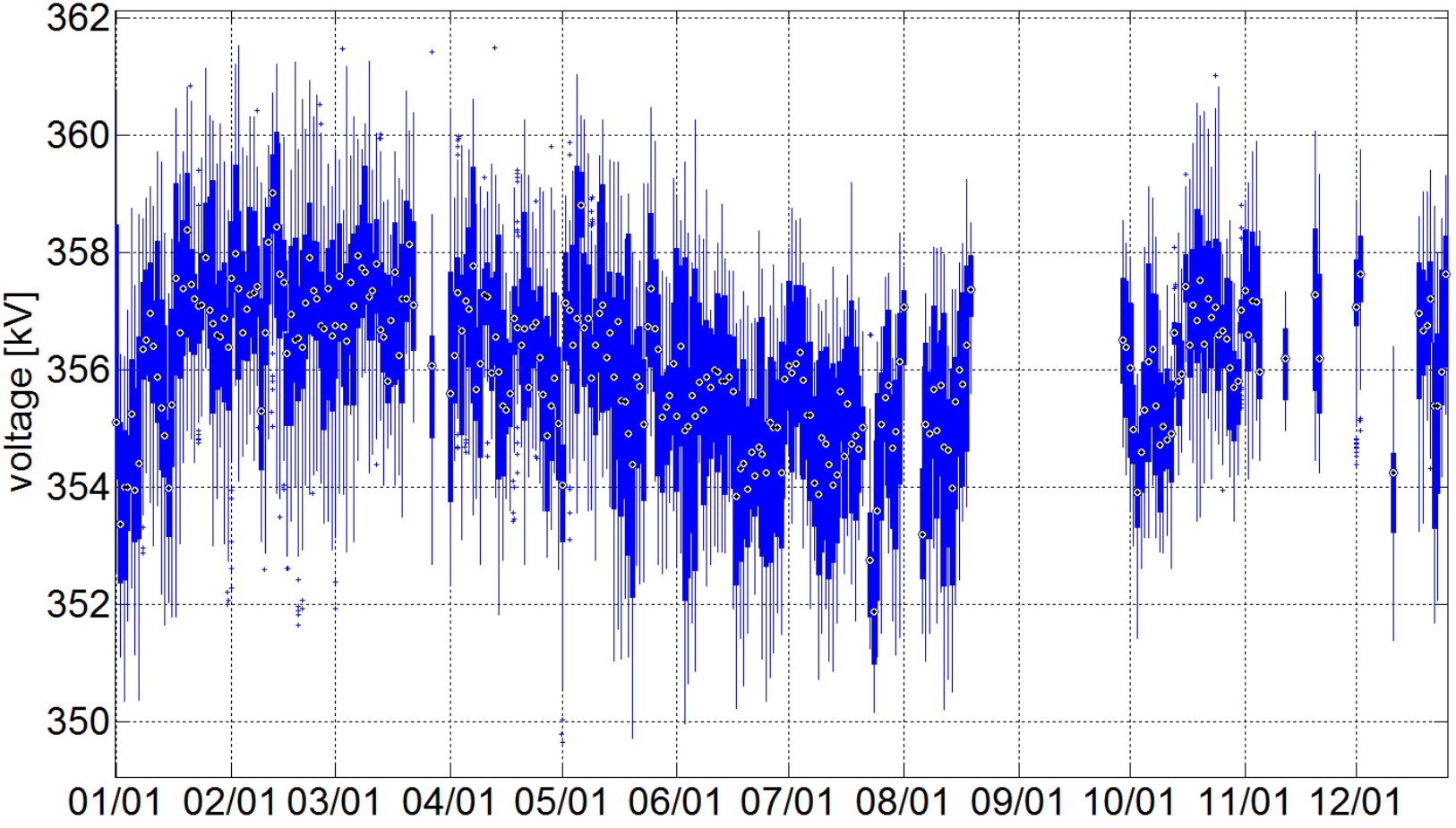
South 2*


voltage [kV]
362
360
358
356
354
352
350
348
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

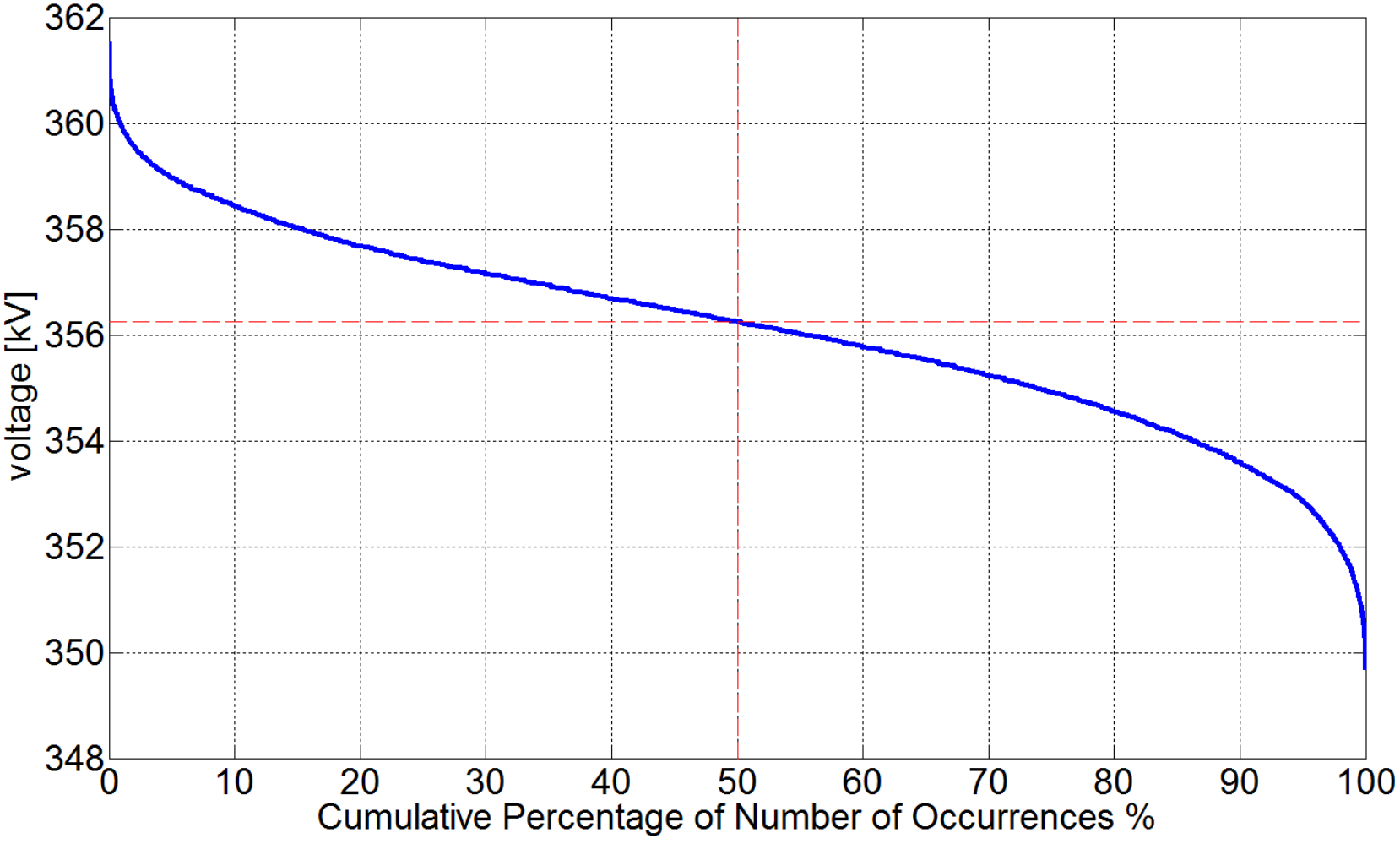
South 2*


364
362
360
358
356
354
352
350
348
346
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

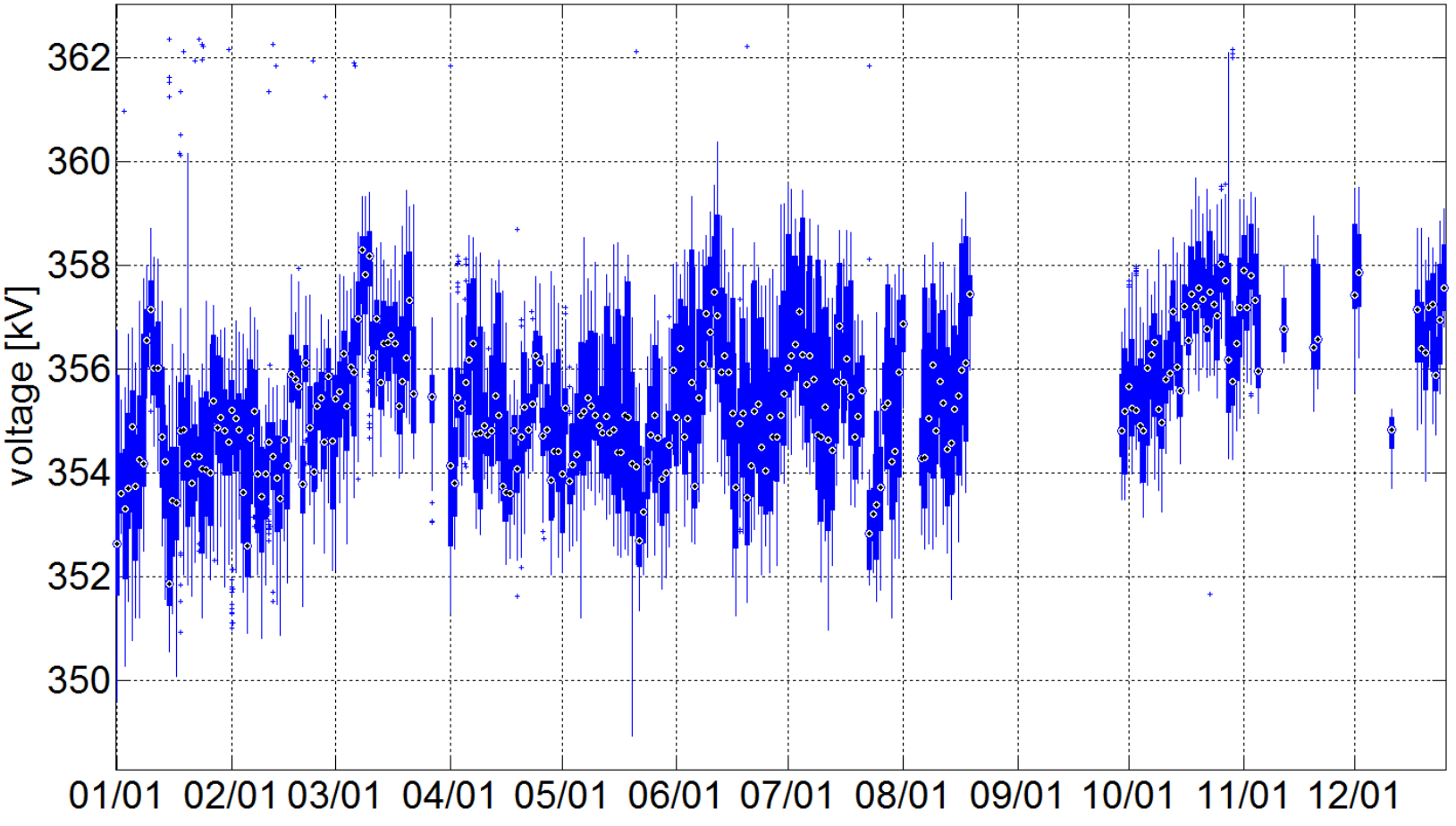
South 4*


362
360
358
356
354
352
350
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

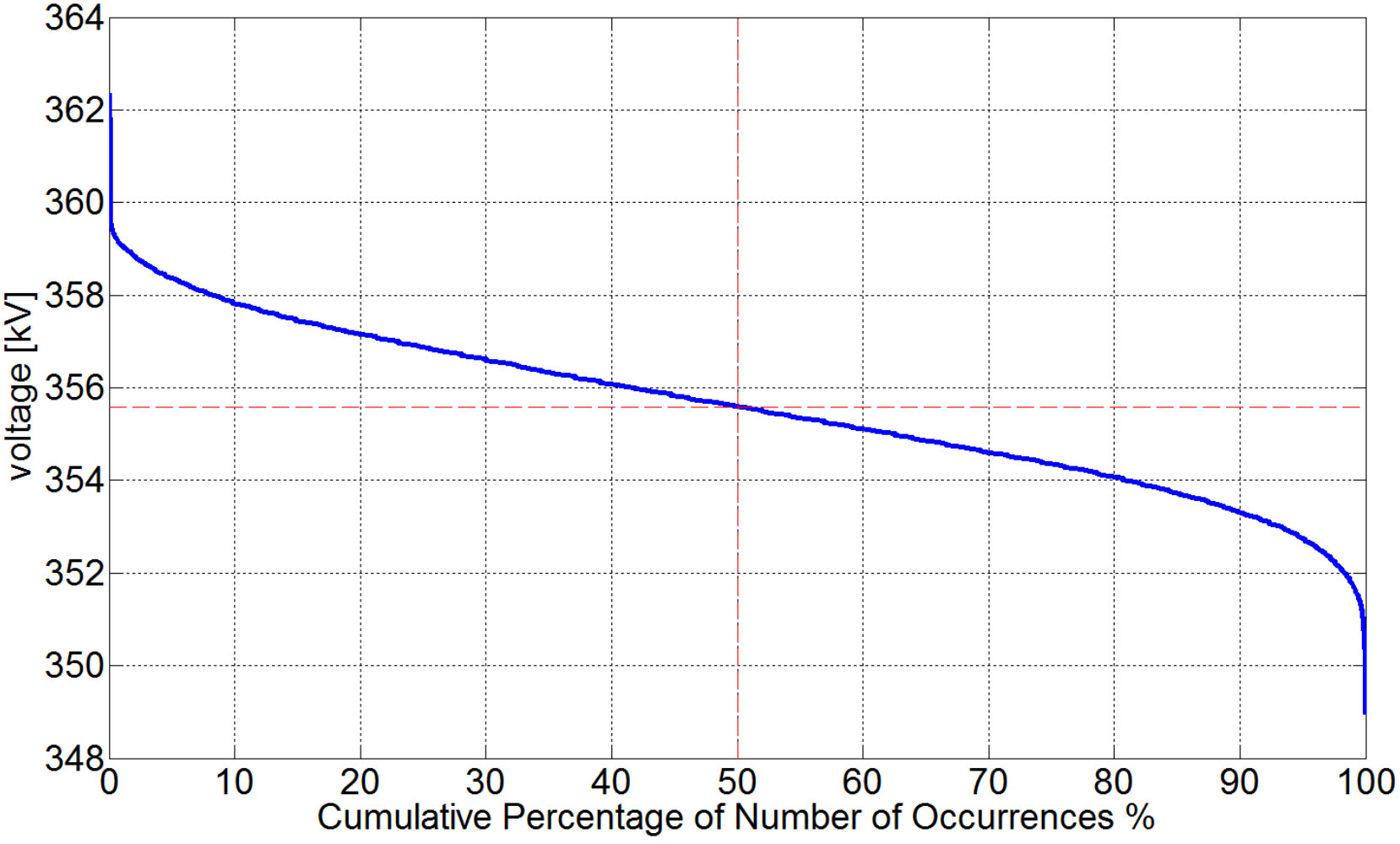
South 4*


362
360
358
356
354
352
350
348
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

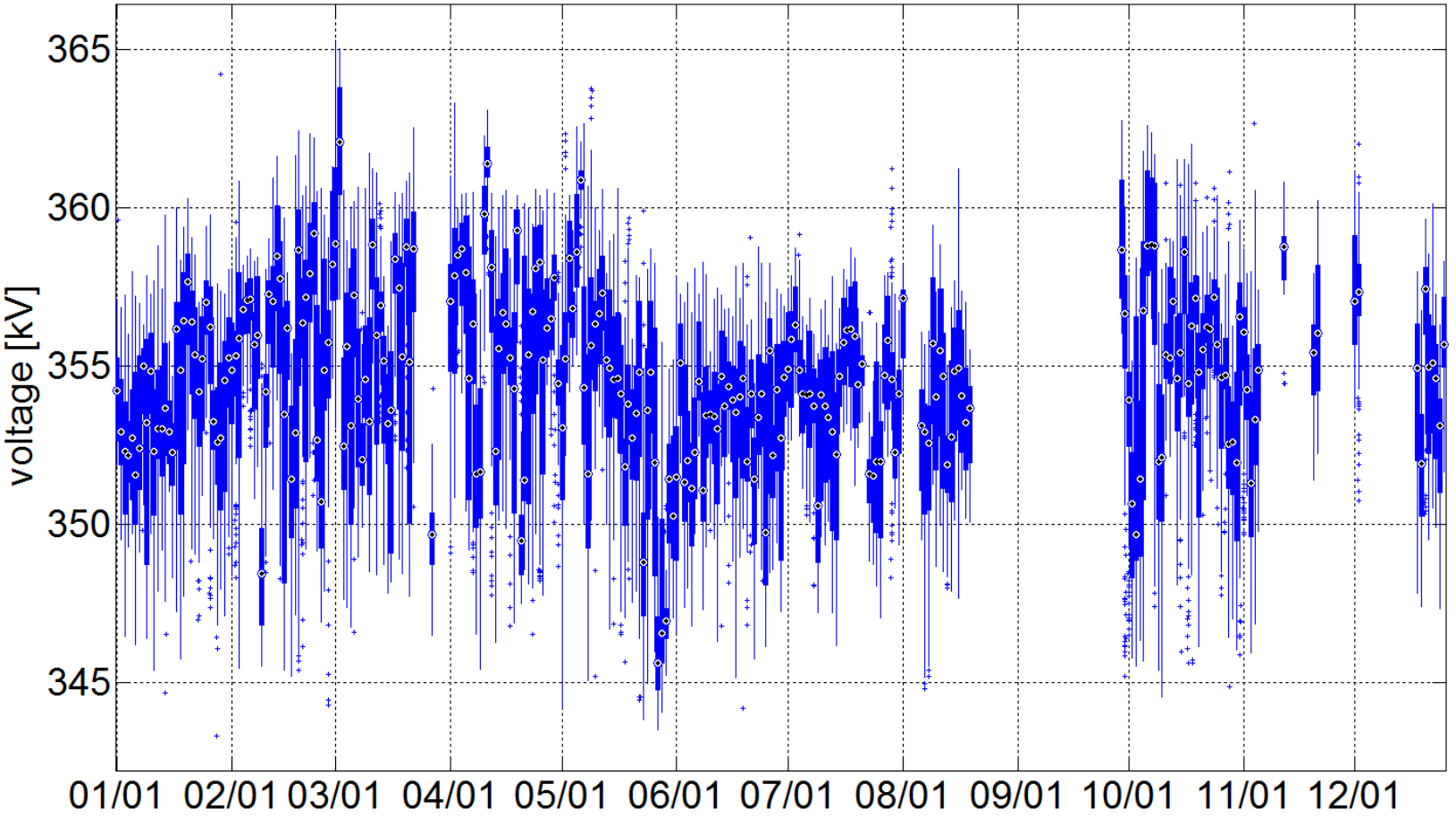
South 7*


voltage [kV]
362
360
358
356
354
352
350
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

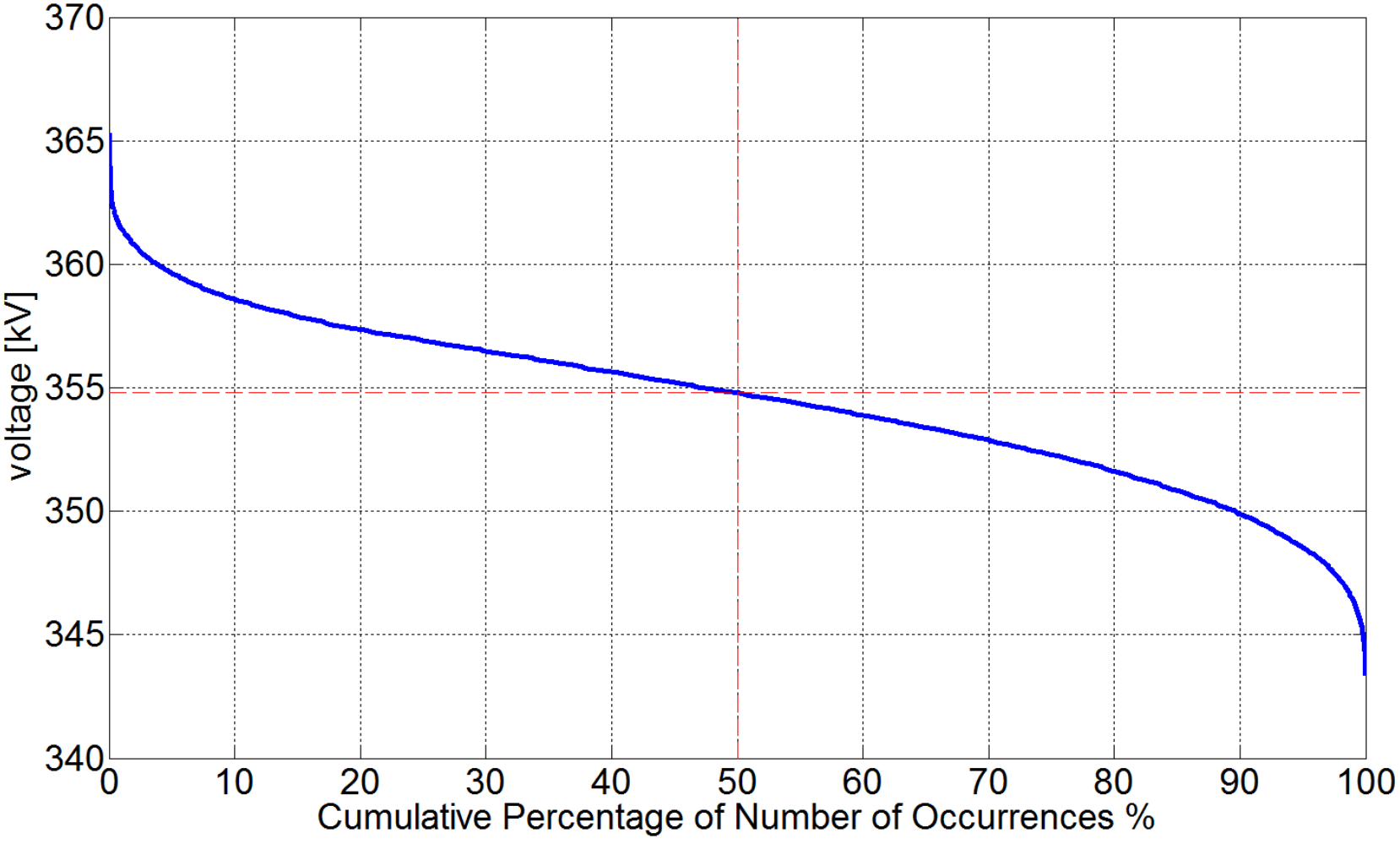
South 7*


364
362
360
358
356
354
352
350
348
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

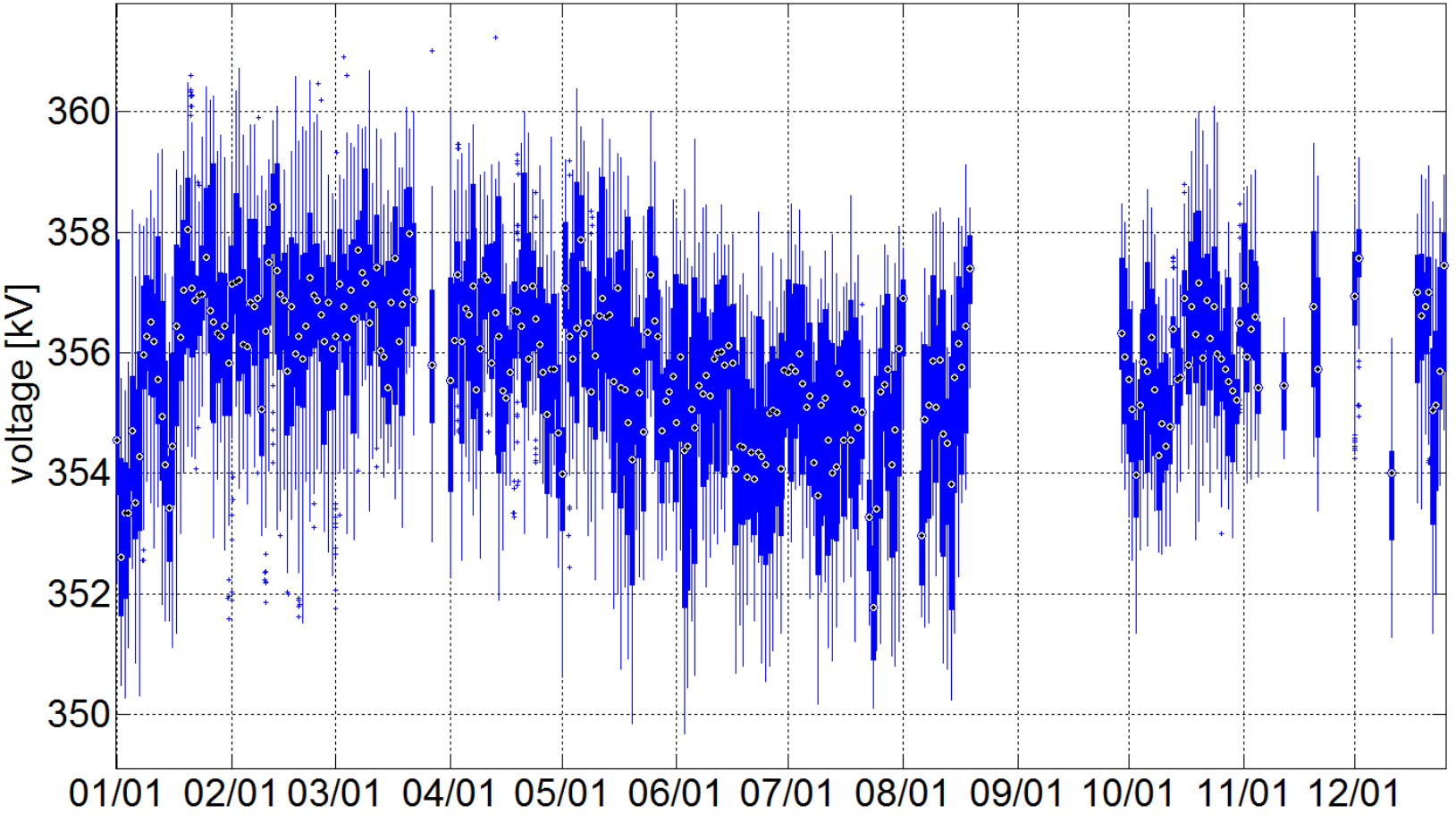
South 9*


365
360
355
350
345
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

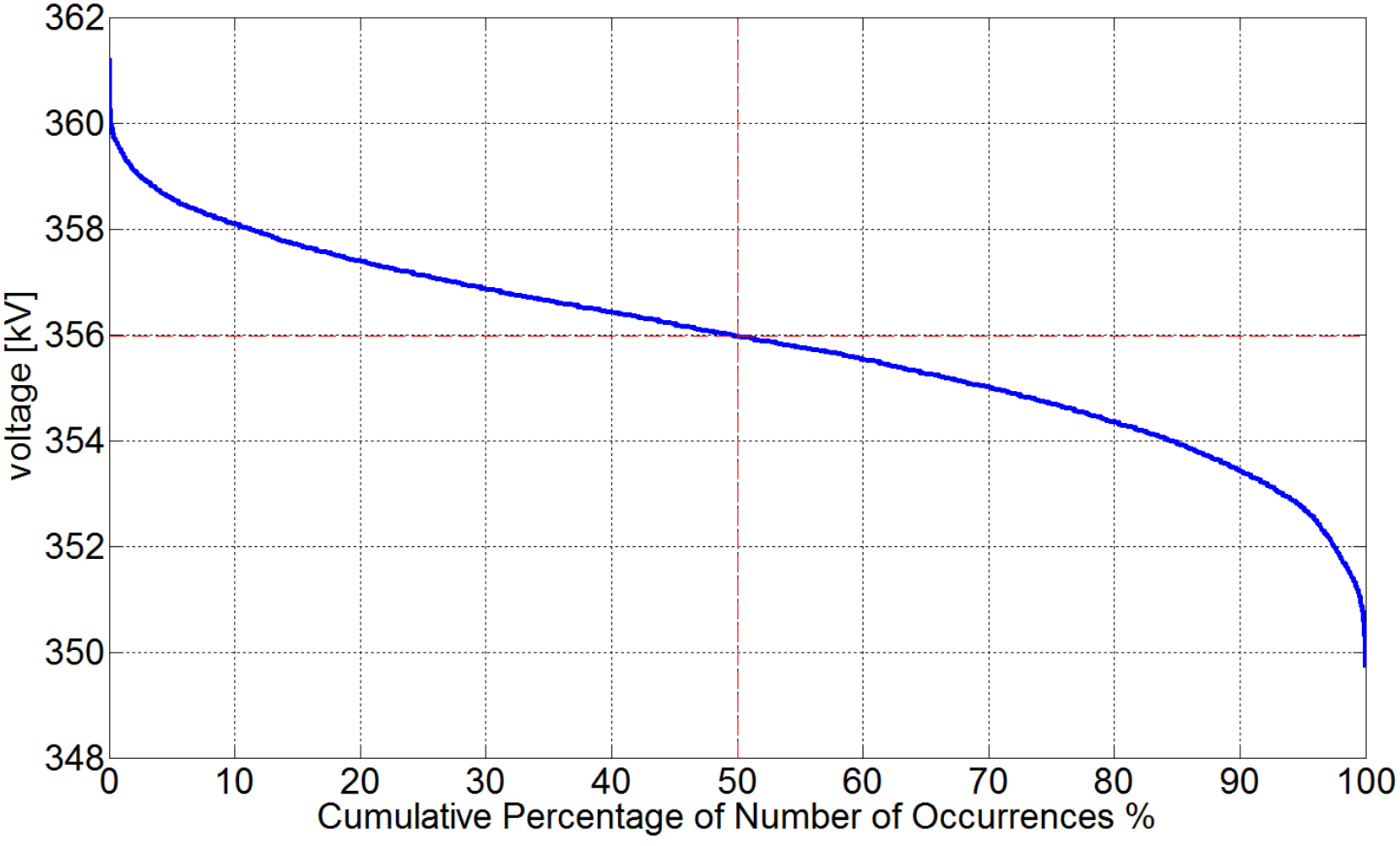
South 9*


370
365
360
355
350
345
340
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

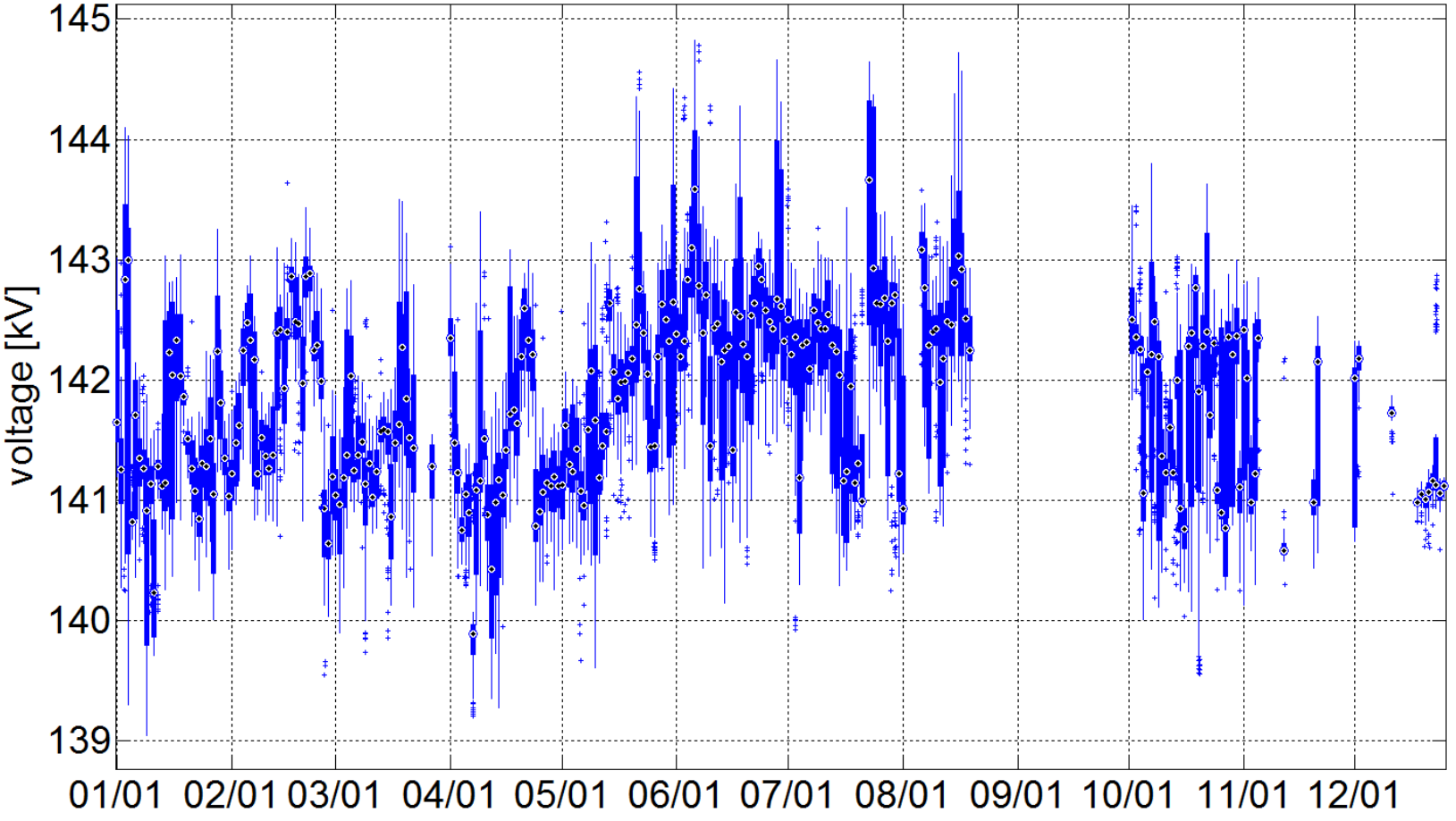
South 11*


voltage [kV]
360
358
356
354
352
350
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

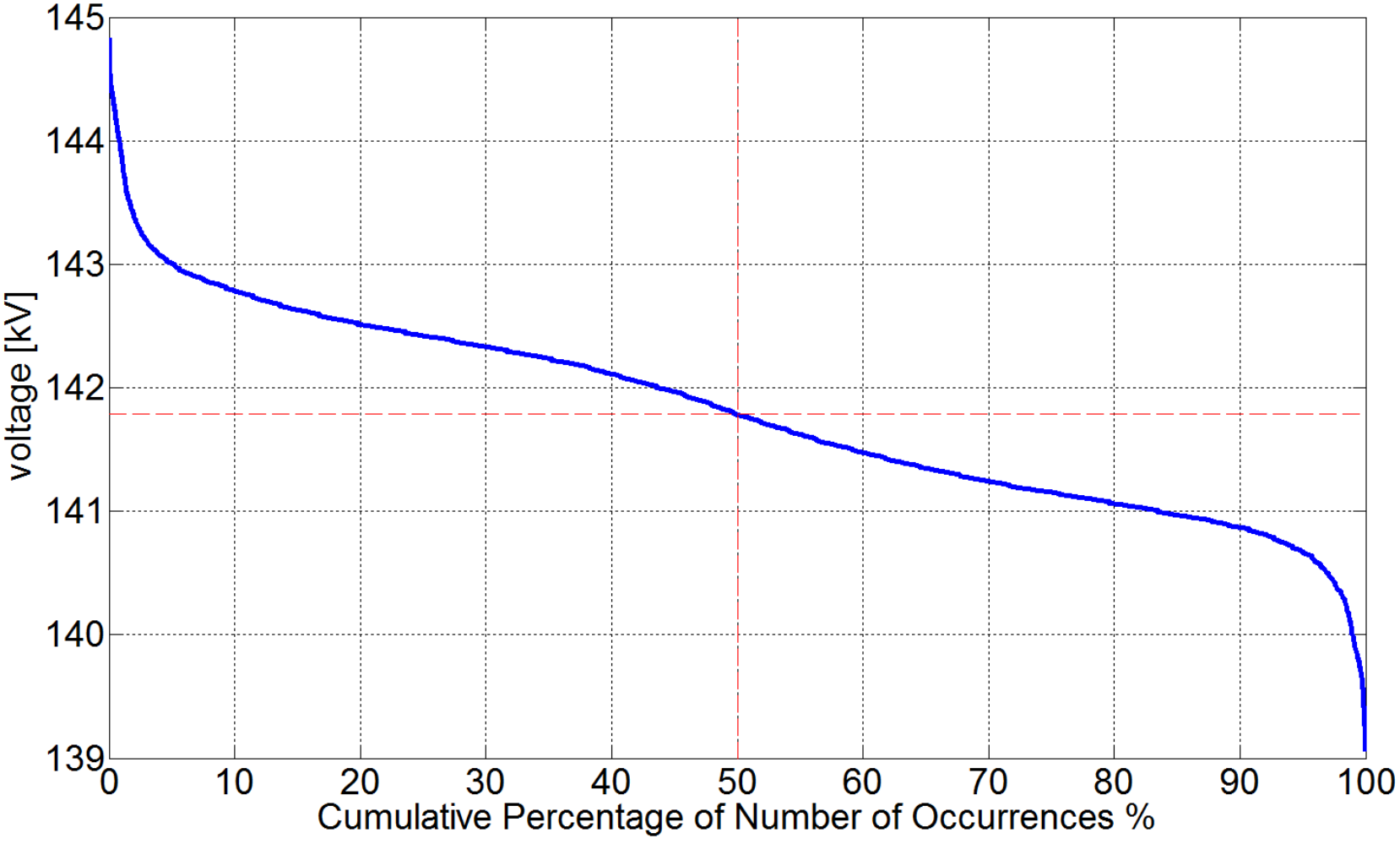
South 11*


362
360
358
356
354
352
350
348
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

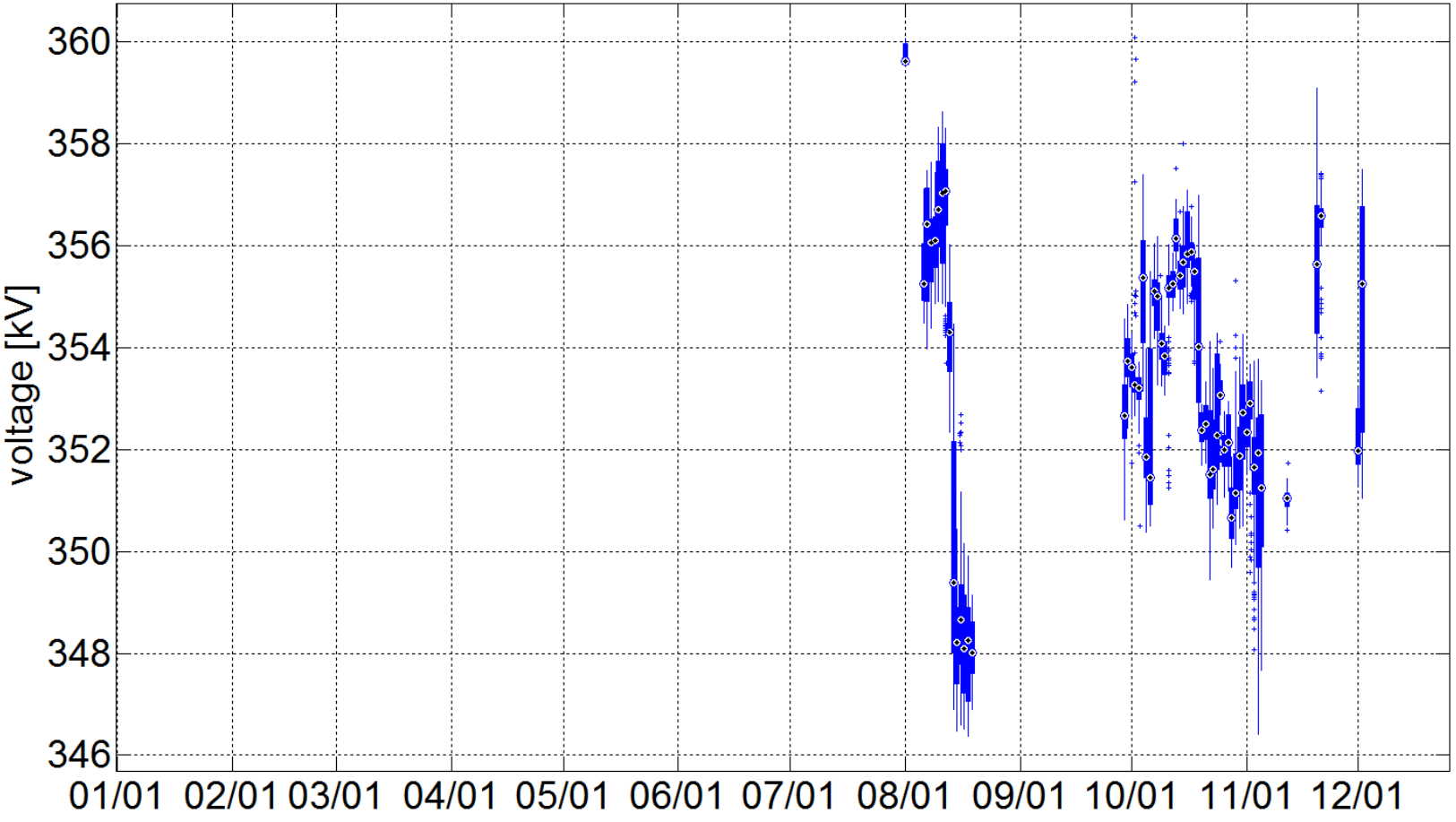
South 10*


145
144
143
142
141
140
139
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

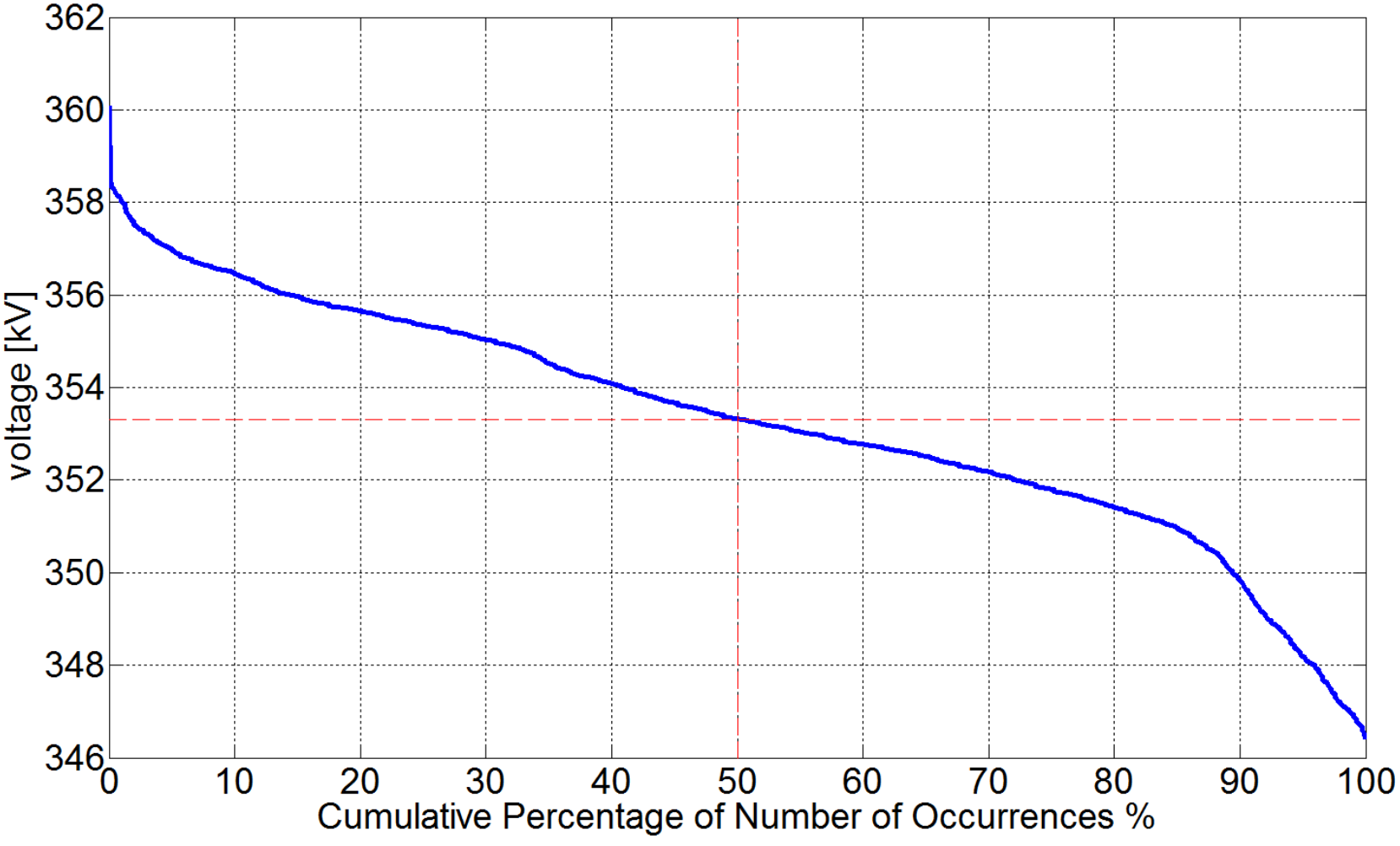
South 10*


145
144
143
142
141
140
139
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

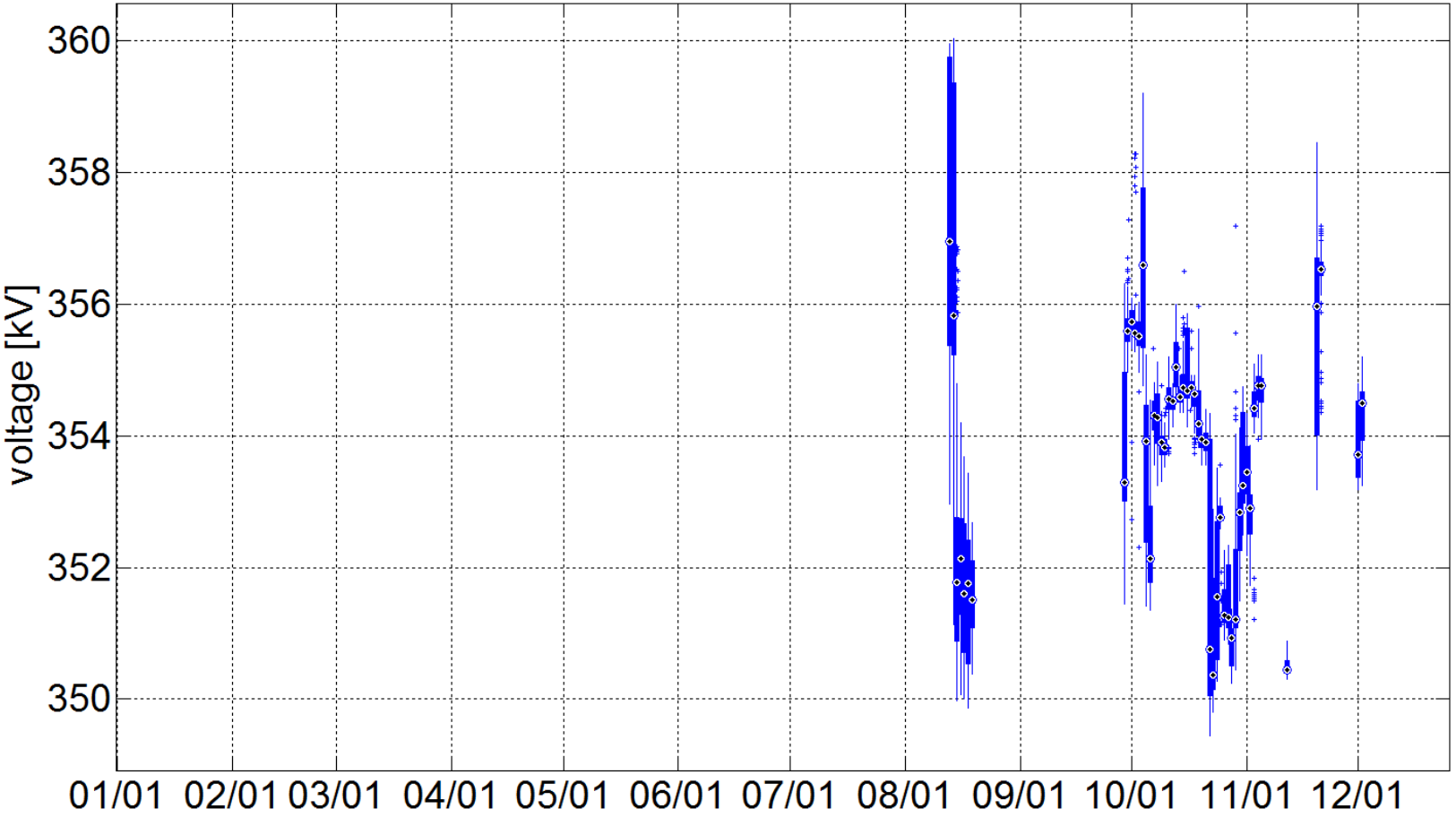
West 16*


voltage [kV]
360
358
356
354
352
350
348
346
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

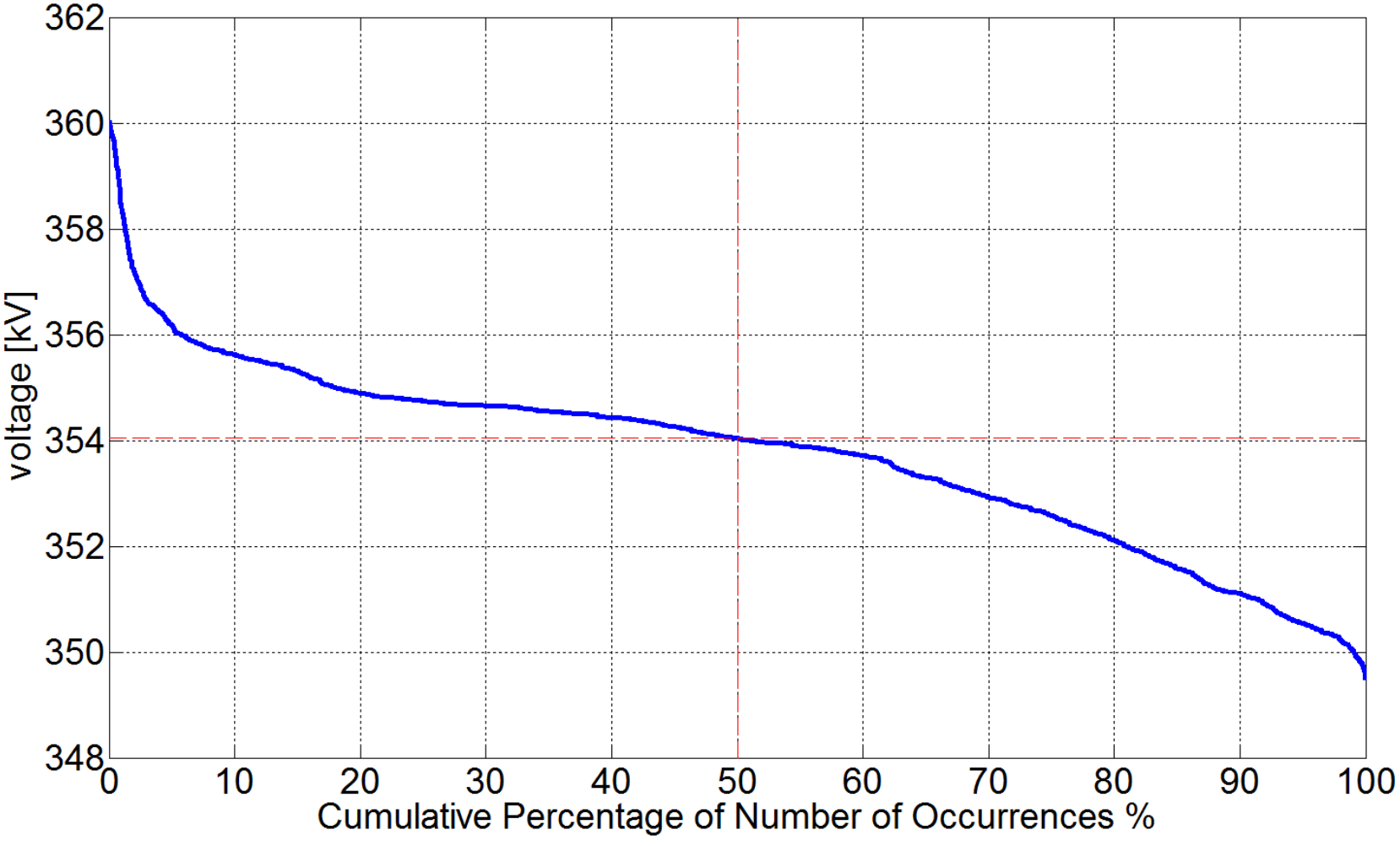
West 16*


362
360
358
356
354
352
350
348
346
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

West 15*


360
358
356
354
352
350
voltage [kV]
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01

West 15*


362
360
358
356
354
352
350
348
voltage [kV]
0
10
20
30
40
50
60
70
80
90
100
Cumulative Percentage of Number of Occurrences %

Appendix A – Part 2
CCET Discovery Across Texas project

Baseline Analysis Update #2
Voltage Magnitudes

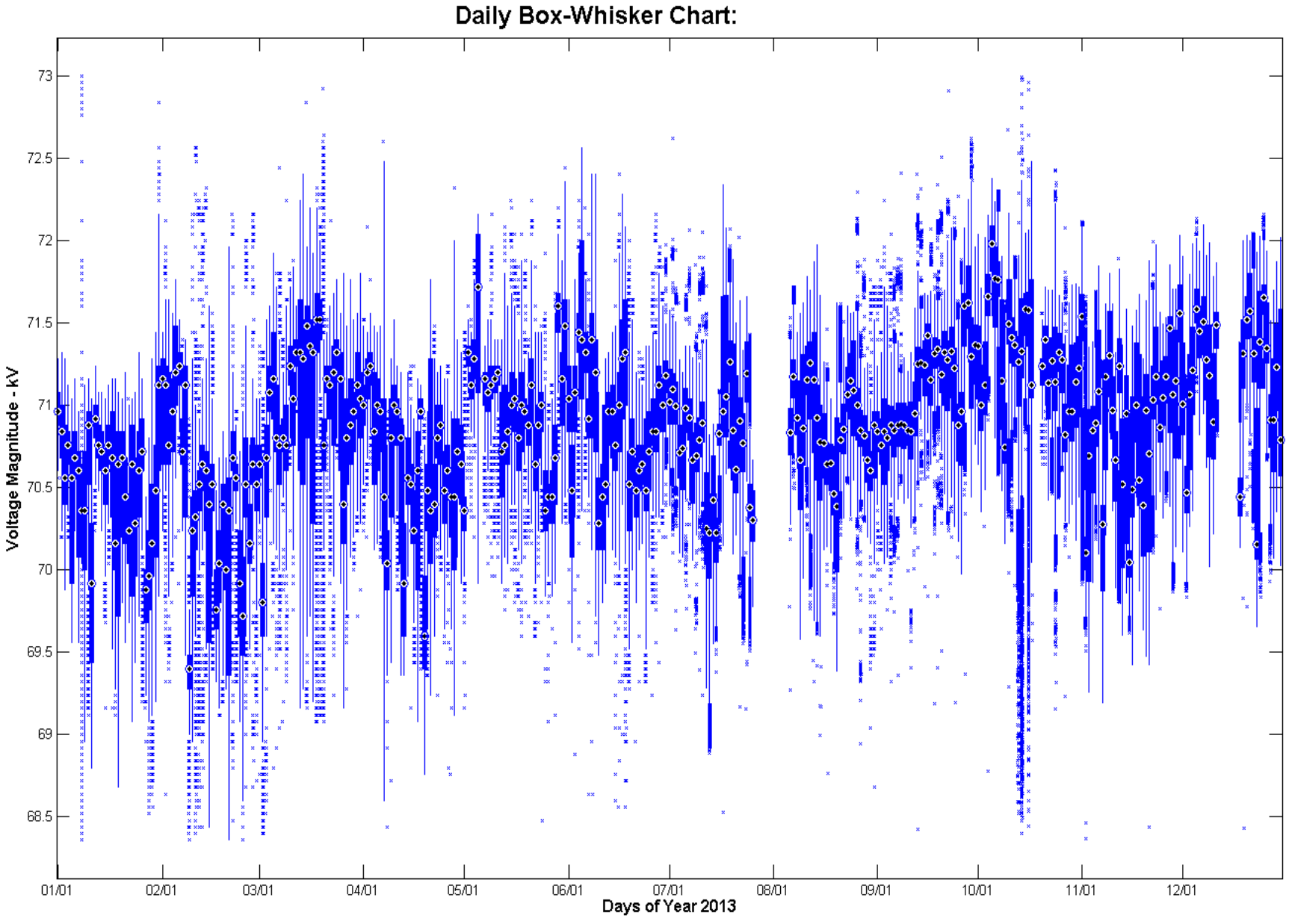
Phasor Data: January to December 2013
Box-Whisker Plots and Time Duration Curves

Electric Power Group

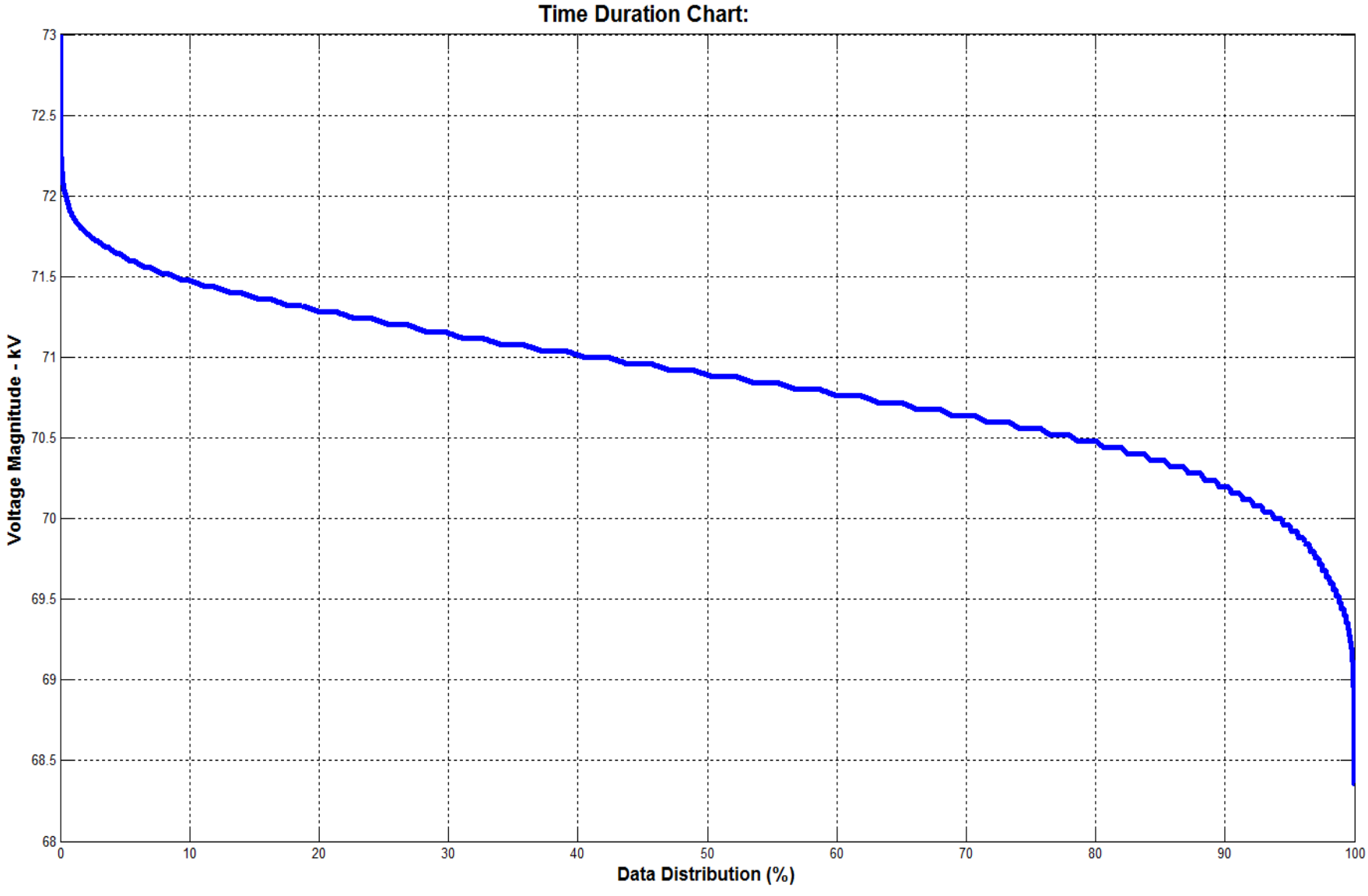
CCET

ERCOT

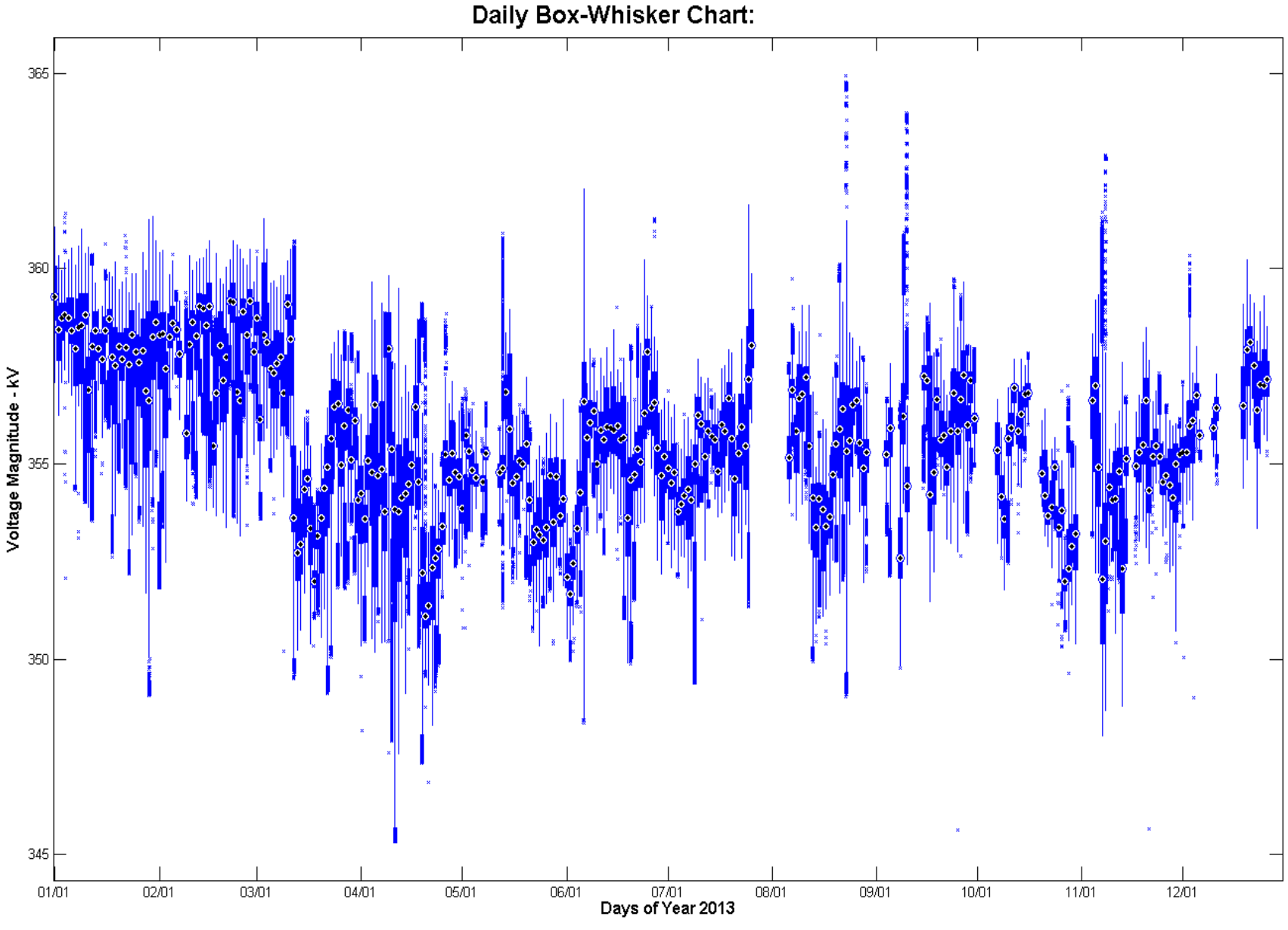
West 10


Daily Box-Whisker Chart:
Voltage Magnitude - kV
73
72.5
72
71.5
71
70.5
70
69.5
69
68.5
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

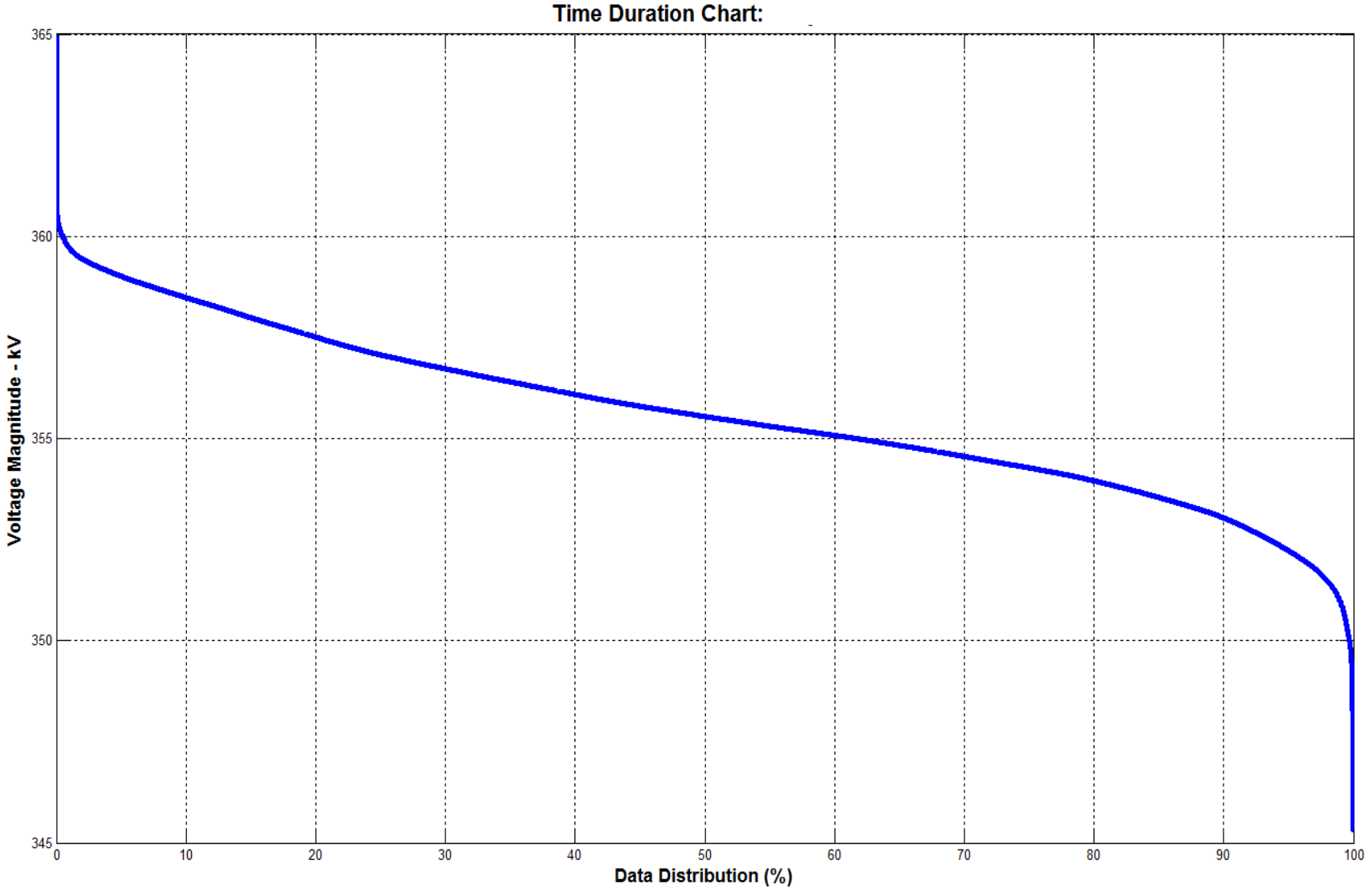
West 10


Time Duration Chart:
Voltage Magnitude - kV
Data Distribution (%)
73
72.5
72
71.5
71
70.5
70
69.5
69
68.5
68
0
10
20
30
40
50
60
70
80
90
100

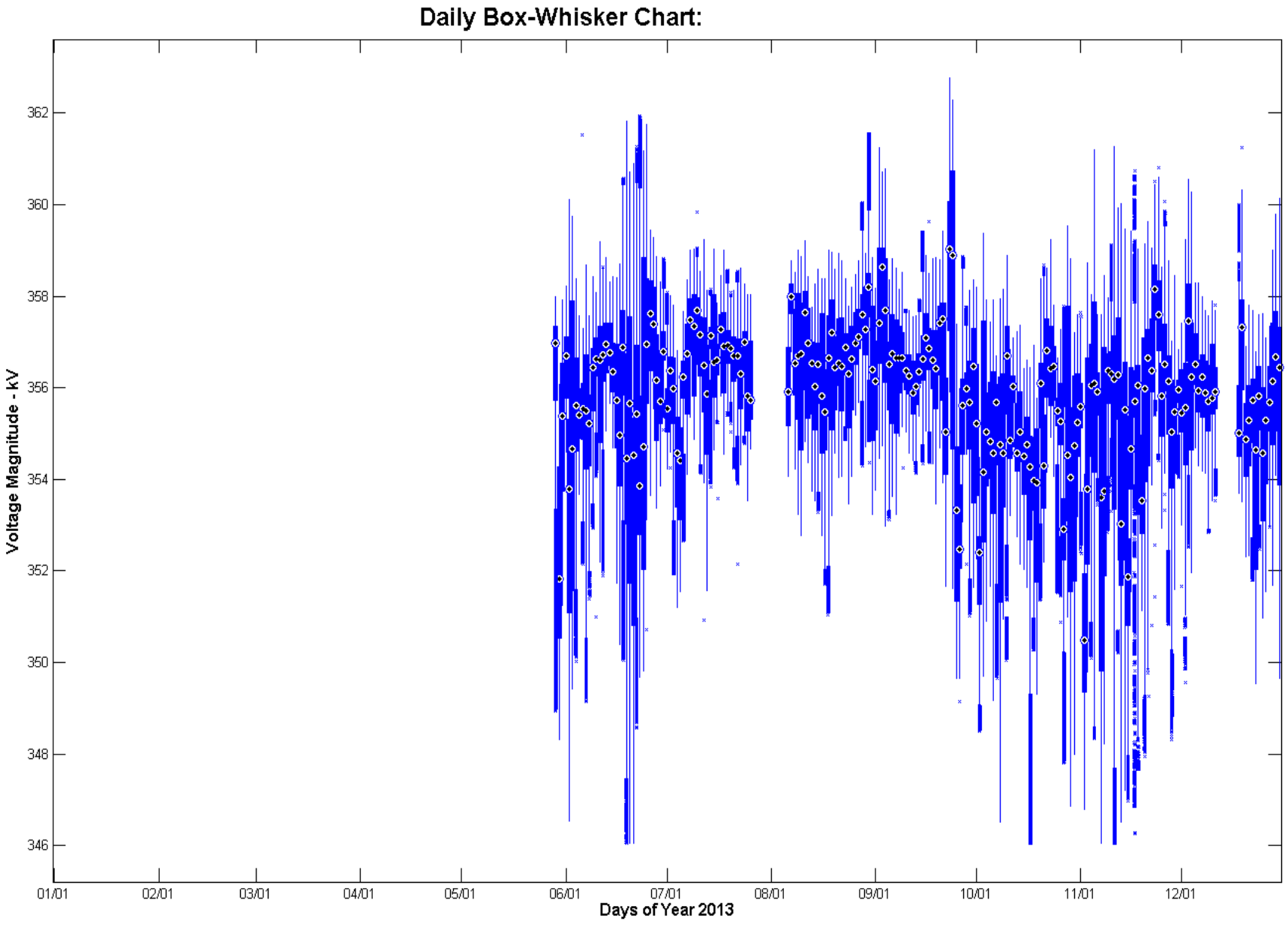
West 14


Daily Box-Whisker Chart:
Voltage Magnitude - kV
365
360
355
350
345
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

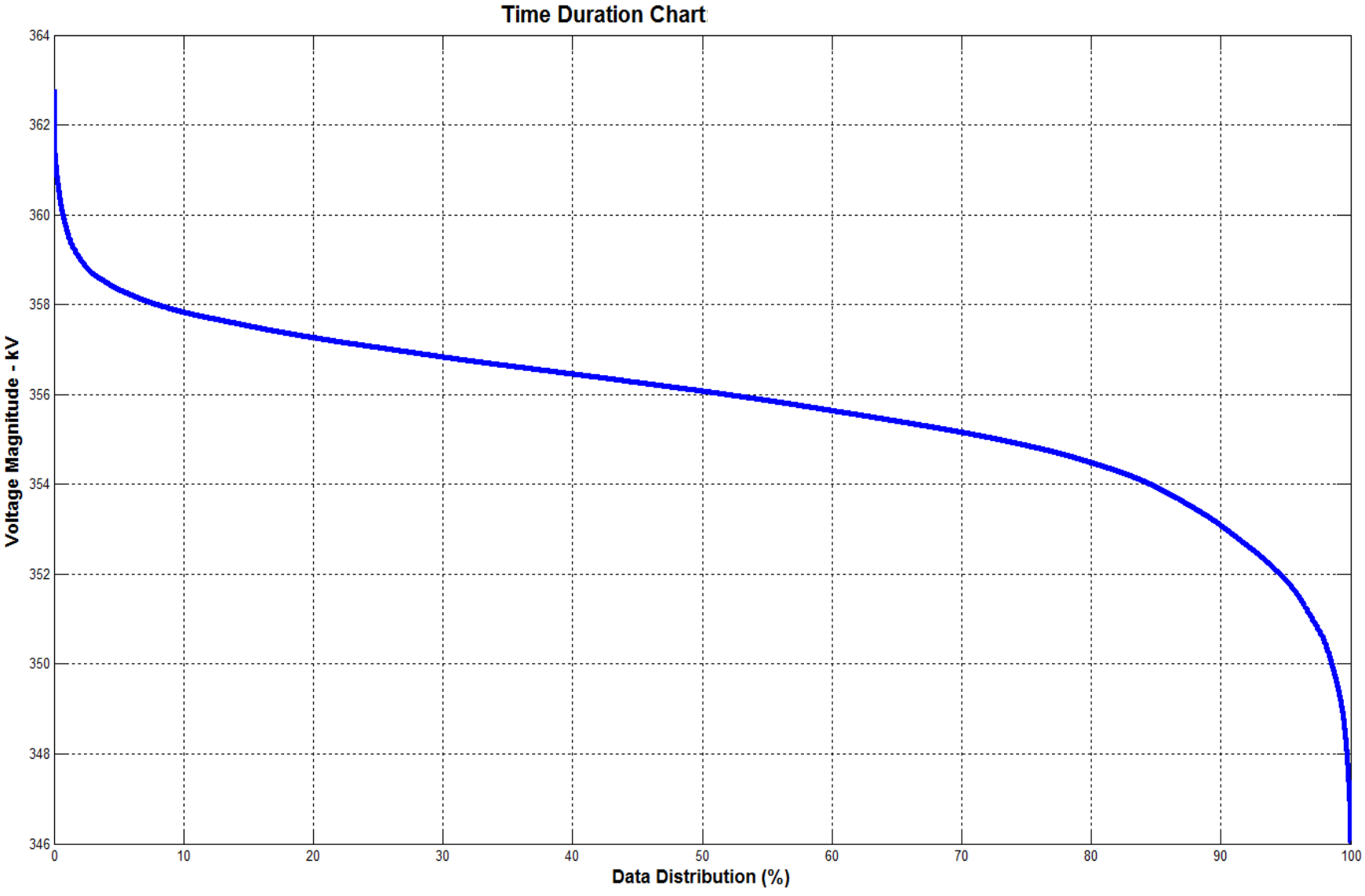
West 14


Time Duration Chart:
Voltage Magnitude - kV
365
360
355
350
345
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

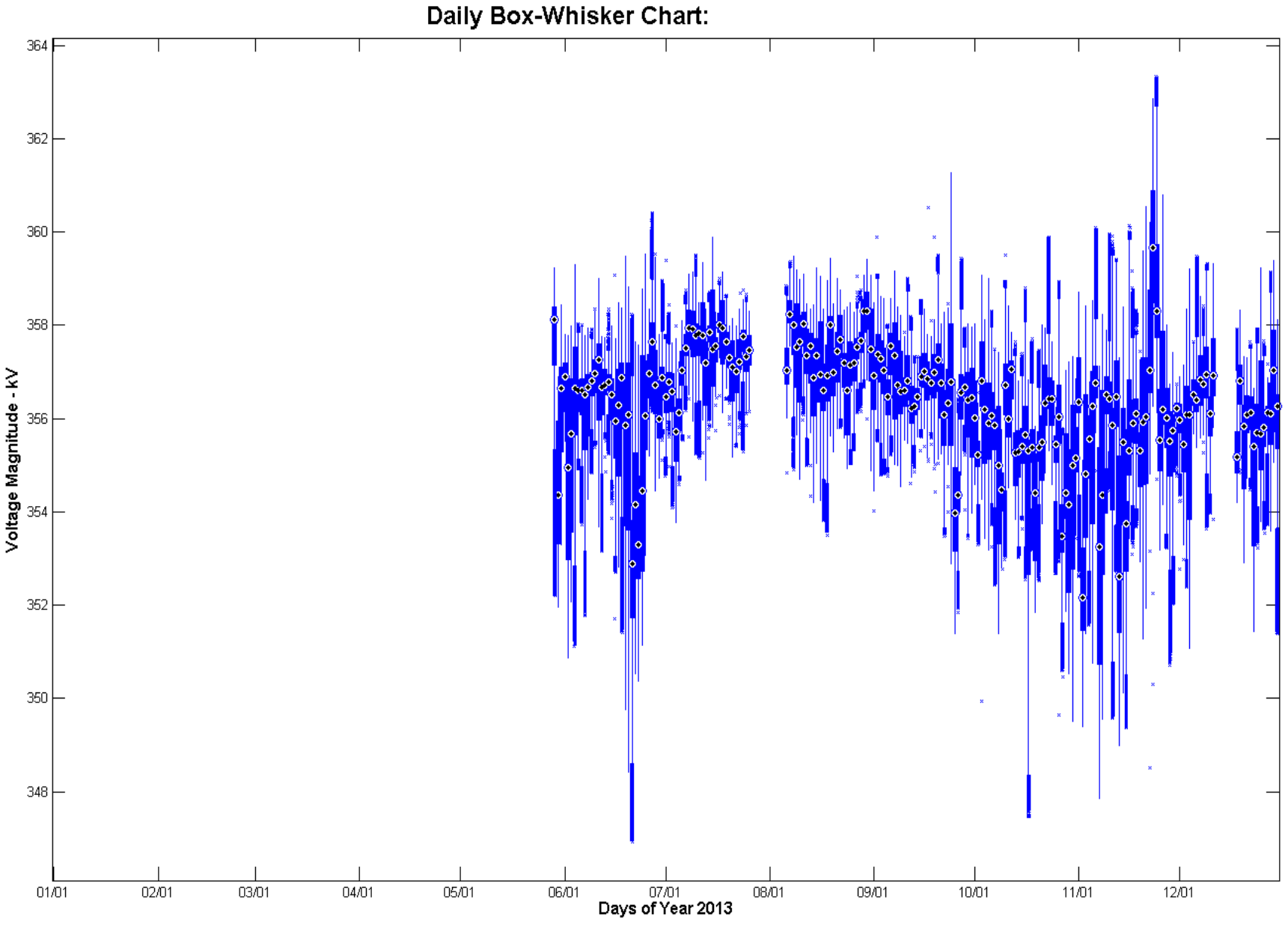
West 1


Daily Box-Whisker Chart:
Voltage Magnitude - kV
362
360
358
356
354
352
350
348
346
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

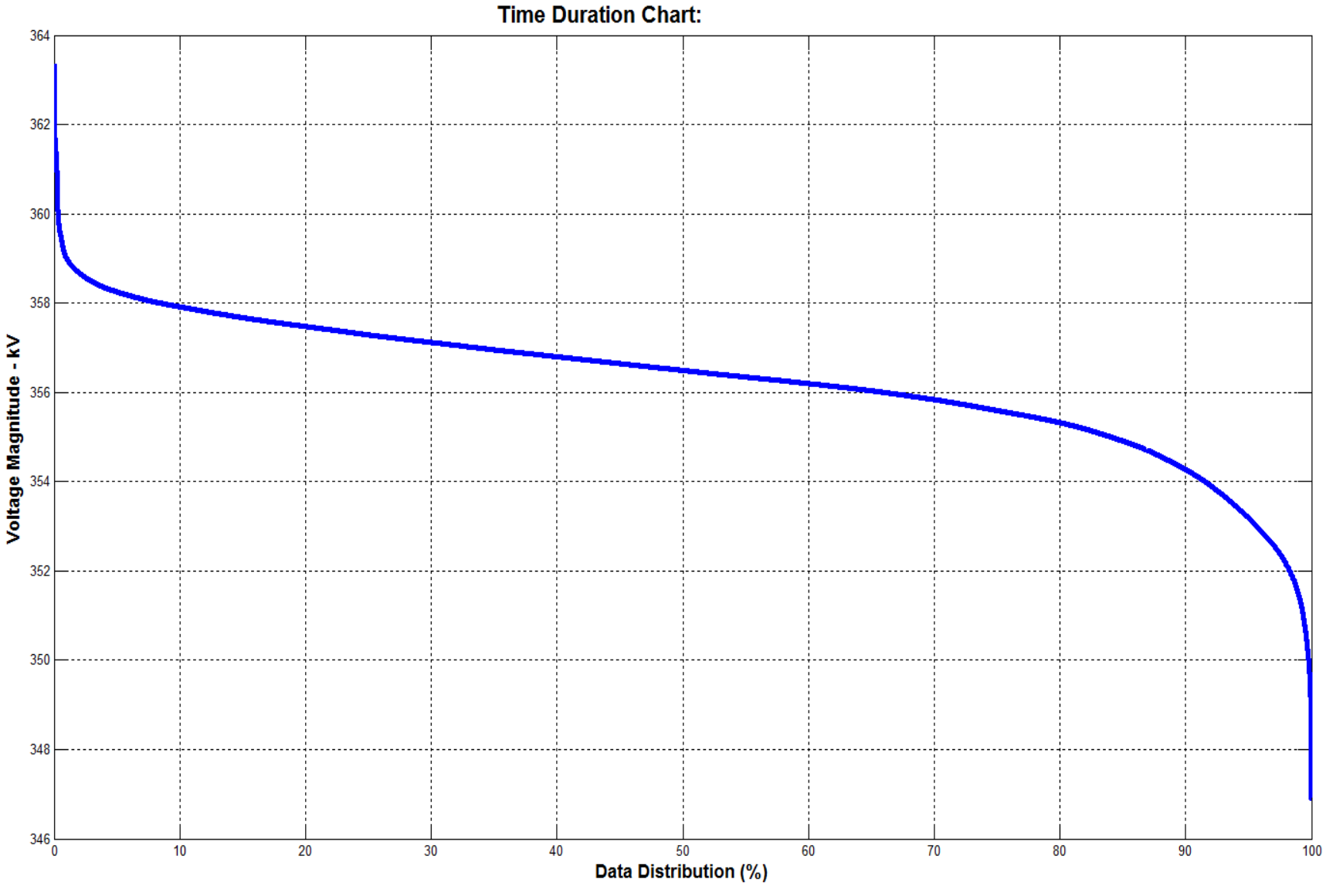
West 1


Time Duration Chart
Voltage Magnitude - kV
364
362
360
358
356
354
352
350
348
346
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

West 2


Daily Box-Whisker Chart:
Voltage Magnitude - kV
364
362
360
358
356
354
352
350
348
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

West 2


Time Duration Chart:
Voltage Magnitude - kV
364
362
360
358
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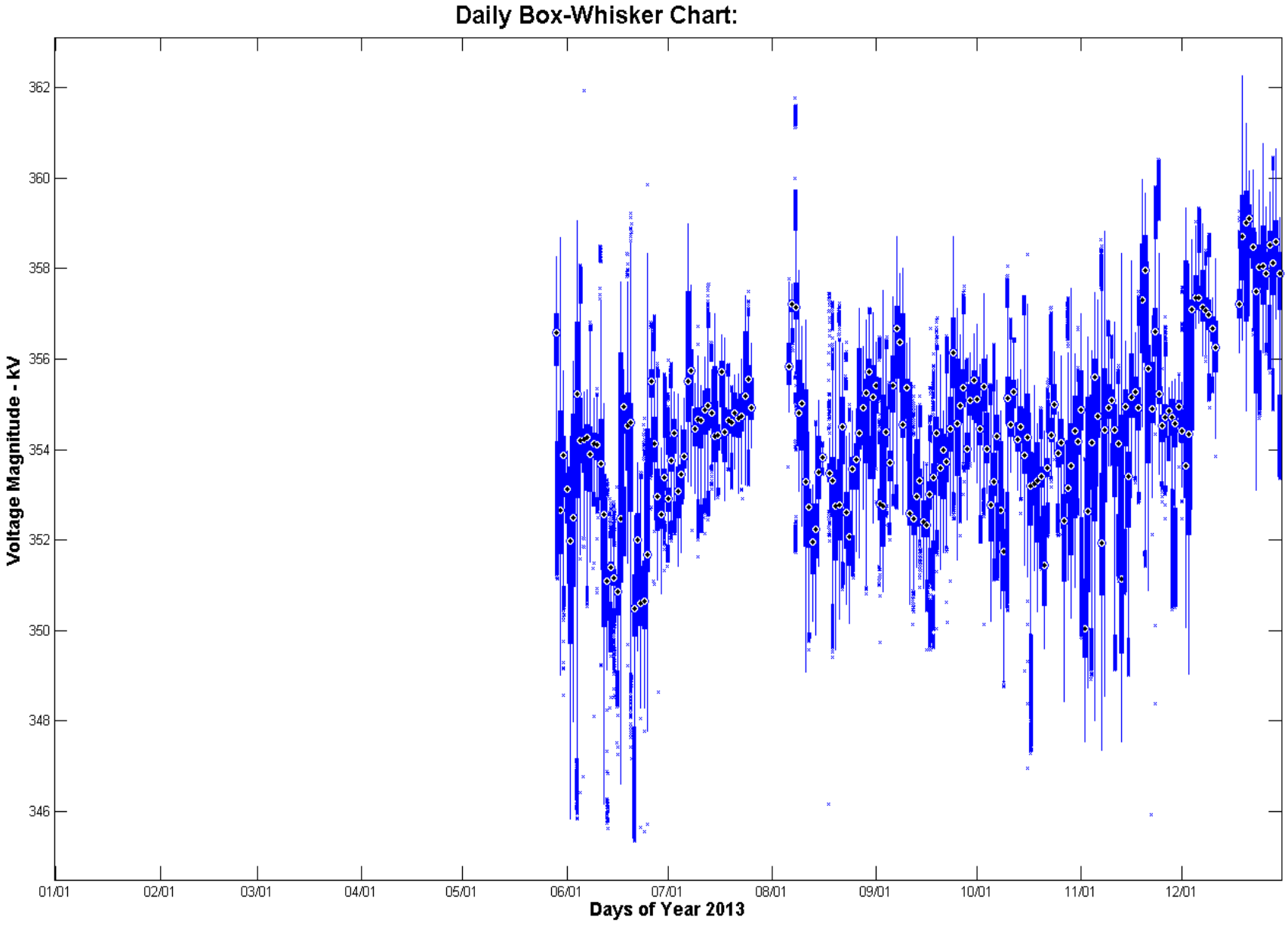
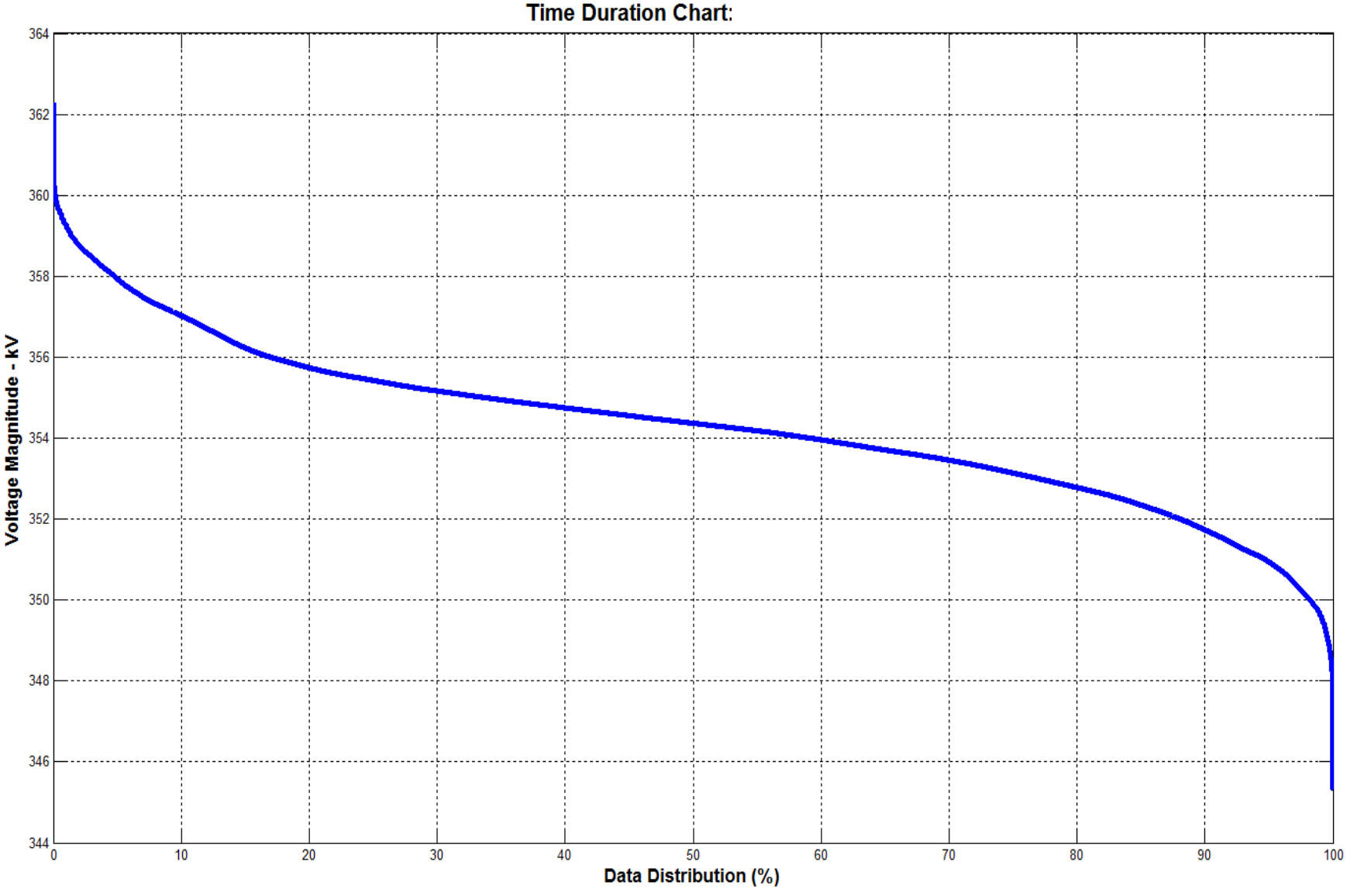
354
352
350
348
346
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

West 9


Daily Box-Whisker Chart:
Voltage Magnitude - kV
362
360
358
356
354
352
350
348
346
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

West 9


Time Duration Chart:
Voltage Magnitude - kV
364
362
360
358
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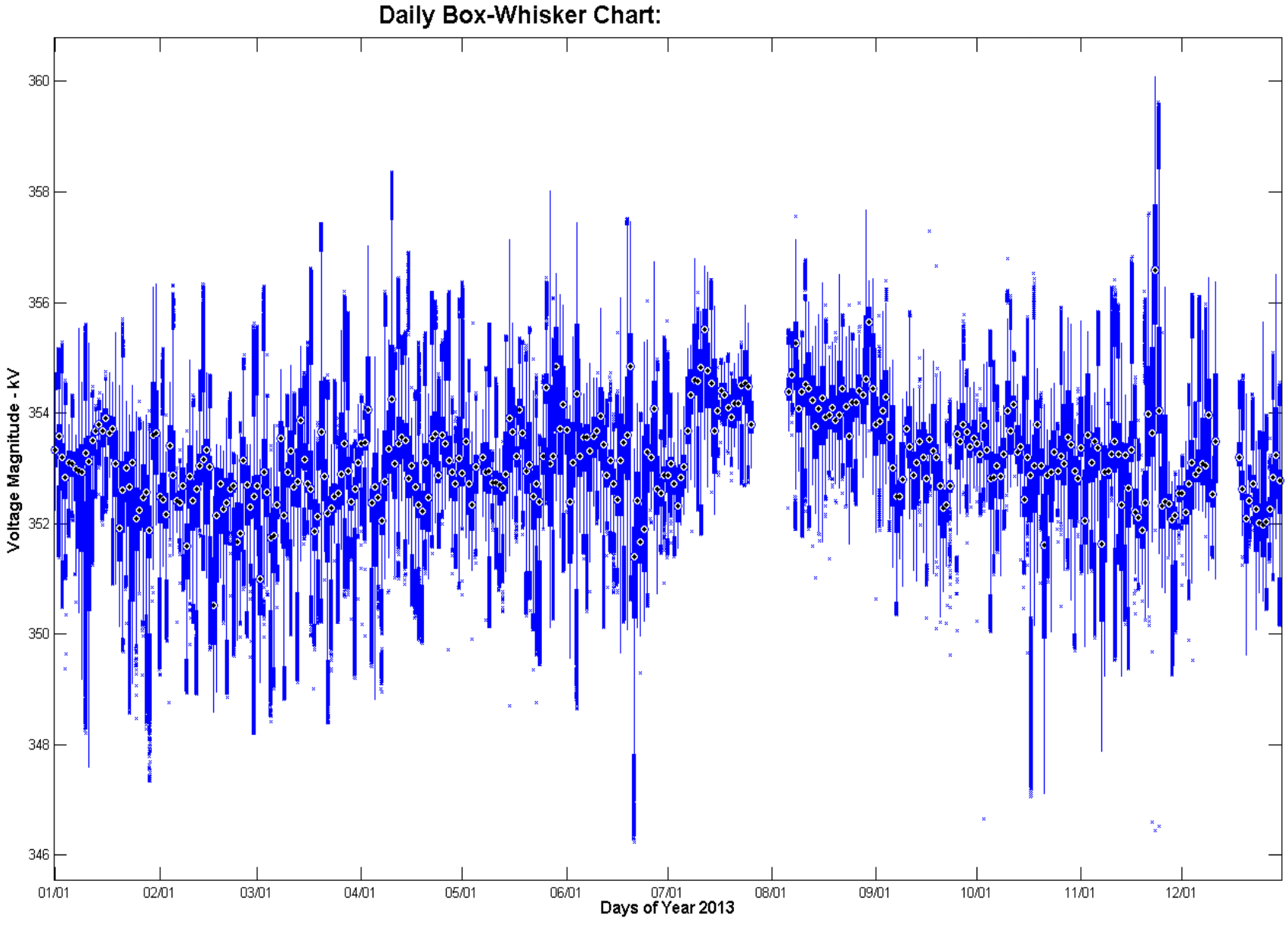
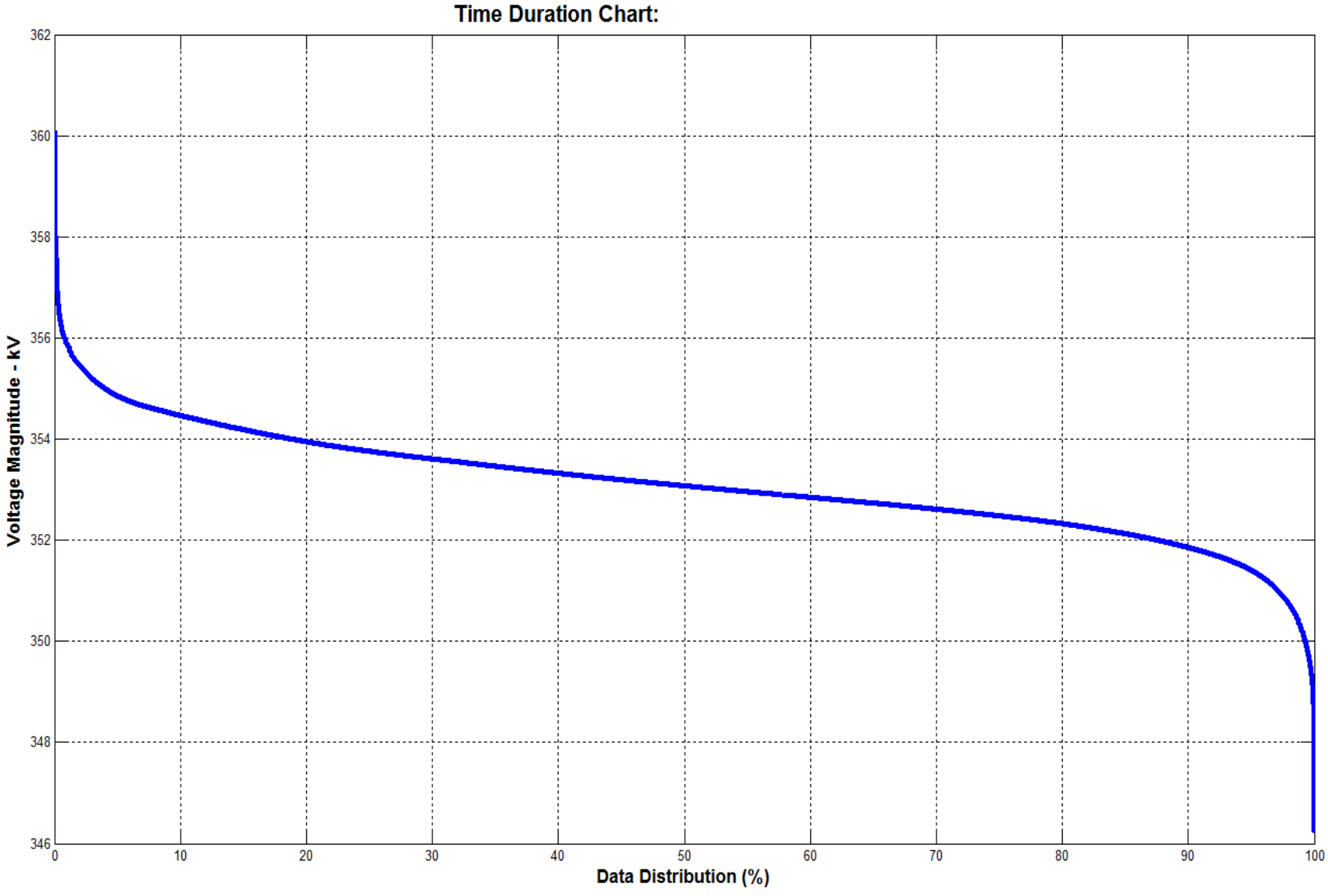
346
344
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

West 11


Daily Box-Whisker Chart:
Voltage Magnitude - kV
360
358
356
354
352
350
348
346
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

West 11


Time Duration Chart:
Voltage Magnitude - kV
362
360
358
356
354
352
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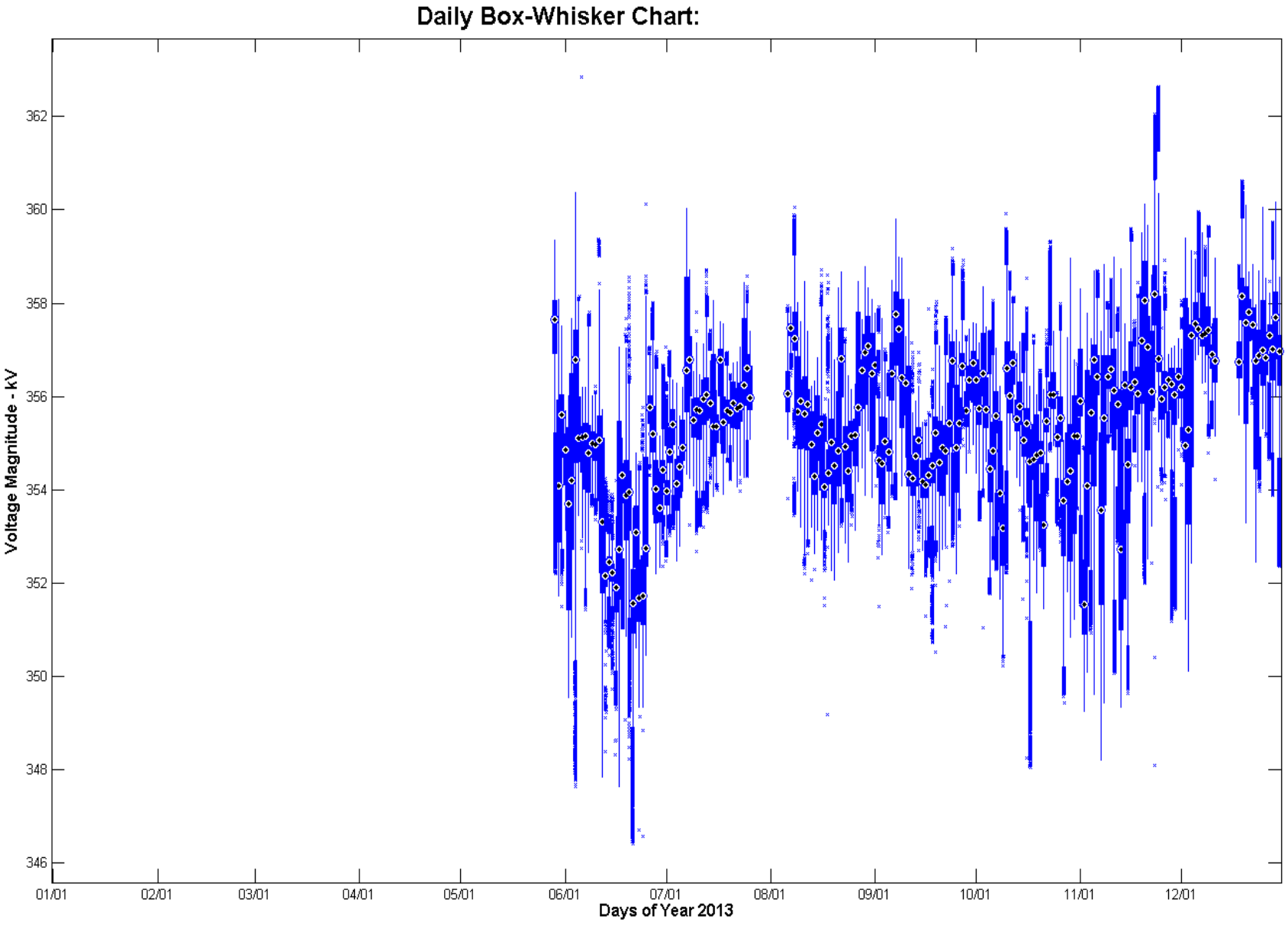
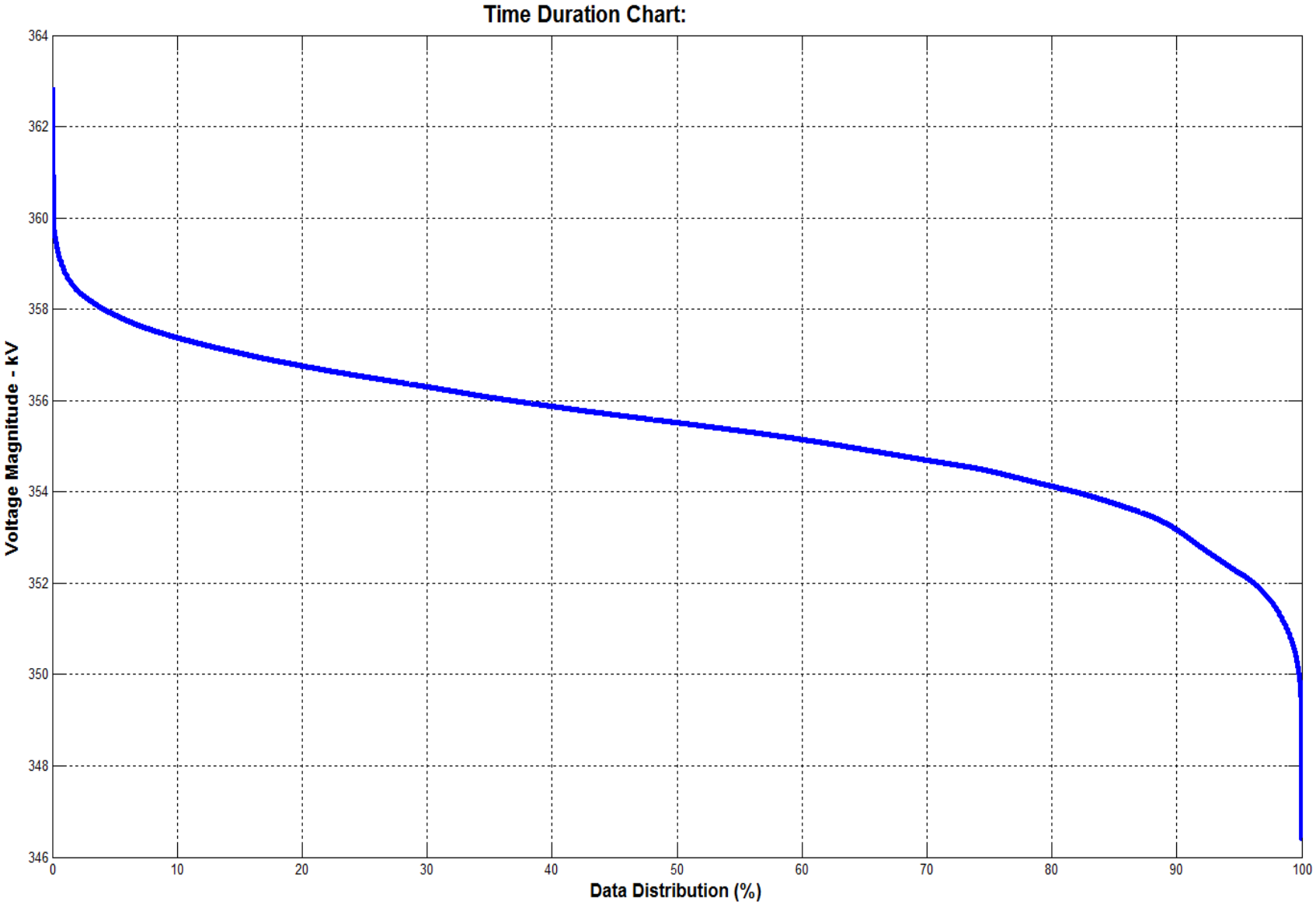
348
346
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

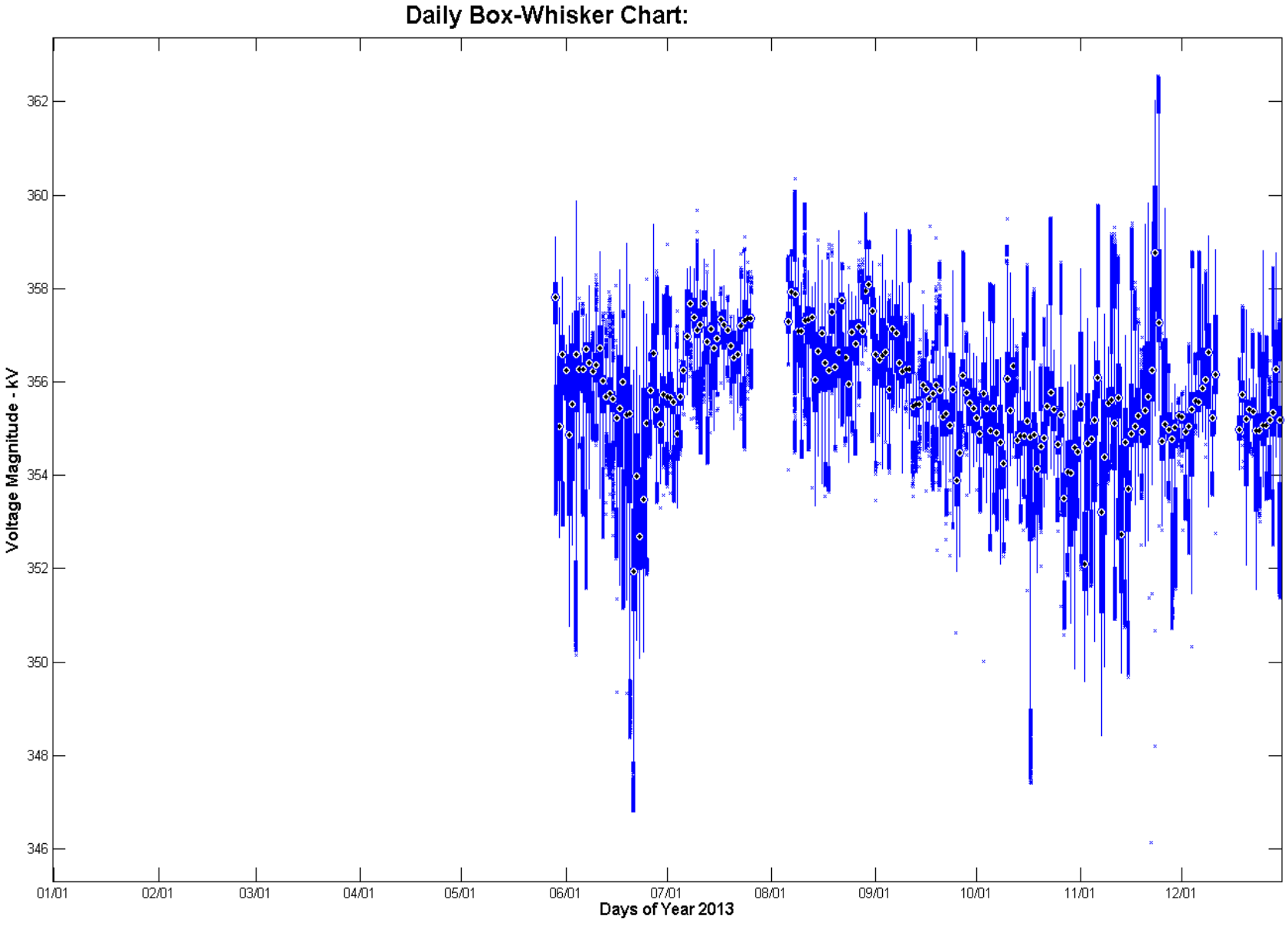
West 12


Daily Box-Whisker Chart:
Voltage Magnitude - kV
362
360
358
356
354
352
350
348
346
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

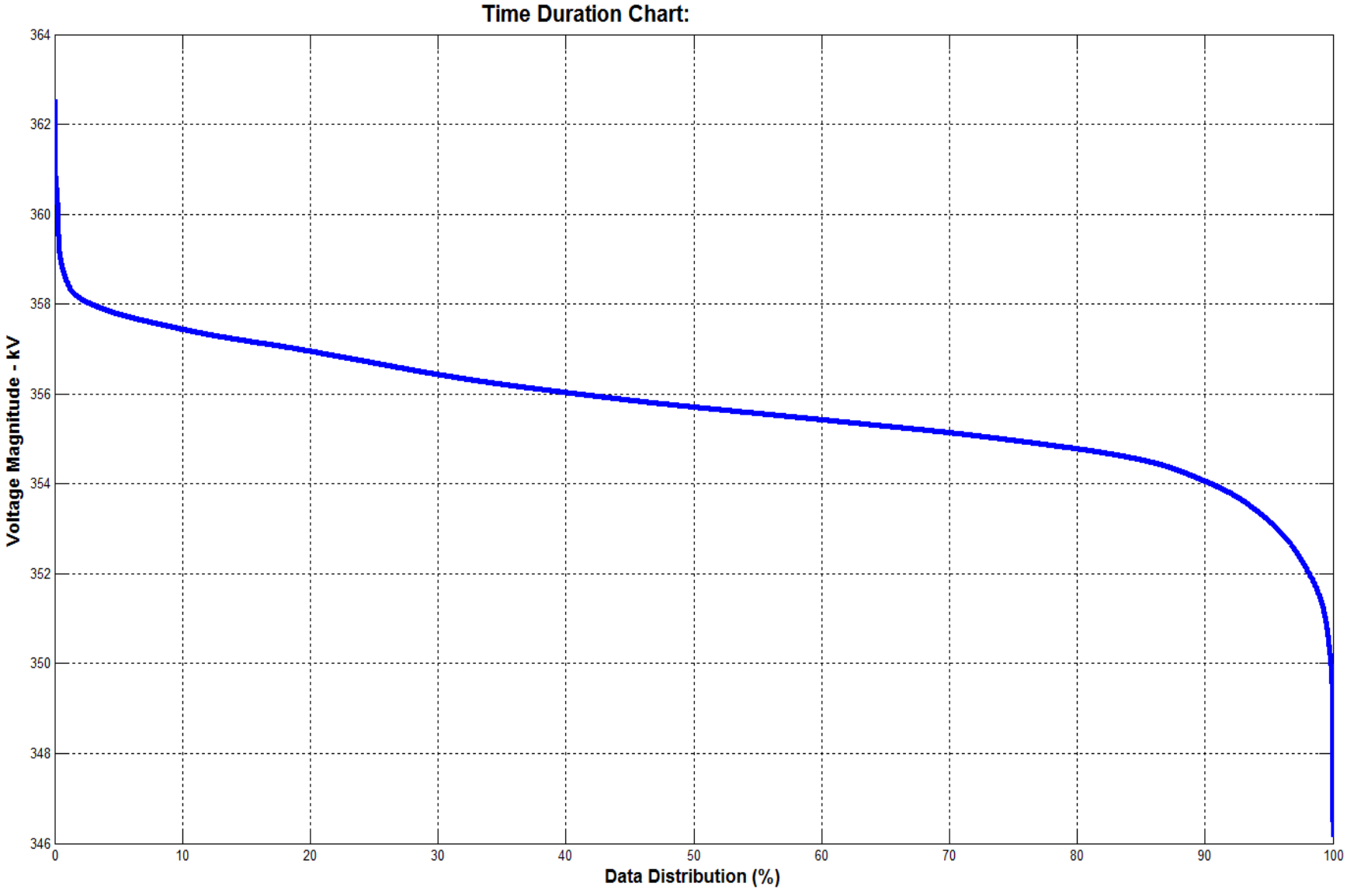
West 12


Time Duration Chart:
Voltage Magnitude - kV
364
362
360
358
356
354
352
350
348
346
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

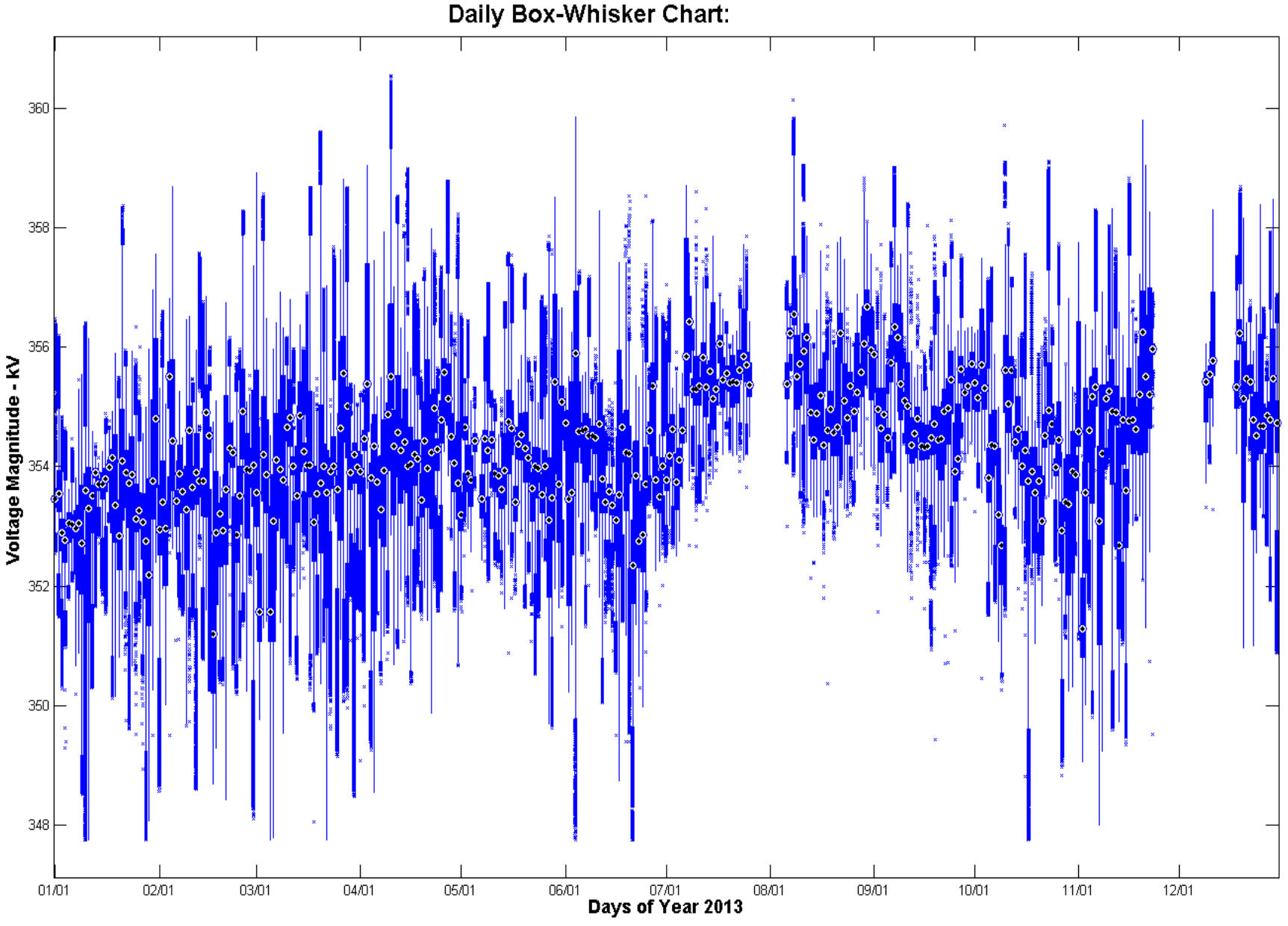
West 5


Daily Box-Whisker Chart:
Voltage Magnitude - kV
362
360
358
356
354
352
350
348
346
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

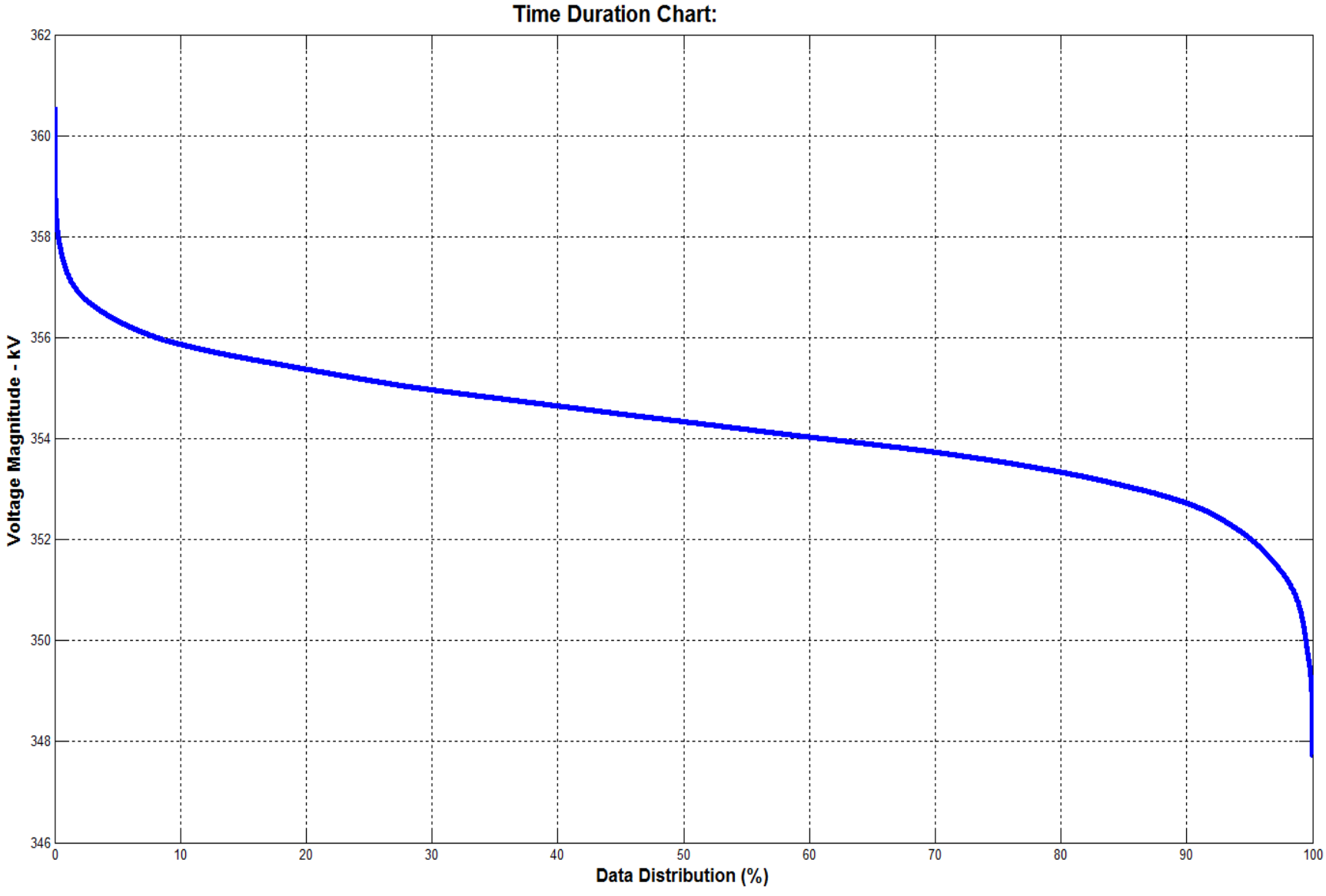
West 5


Time Duration Chart:
Voltage Magnitude - kV
364
362
360
358
356
354
352
350
348
346
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

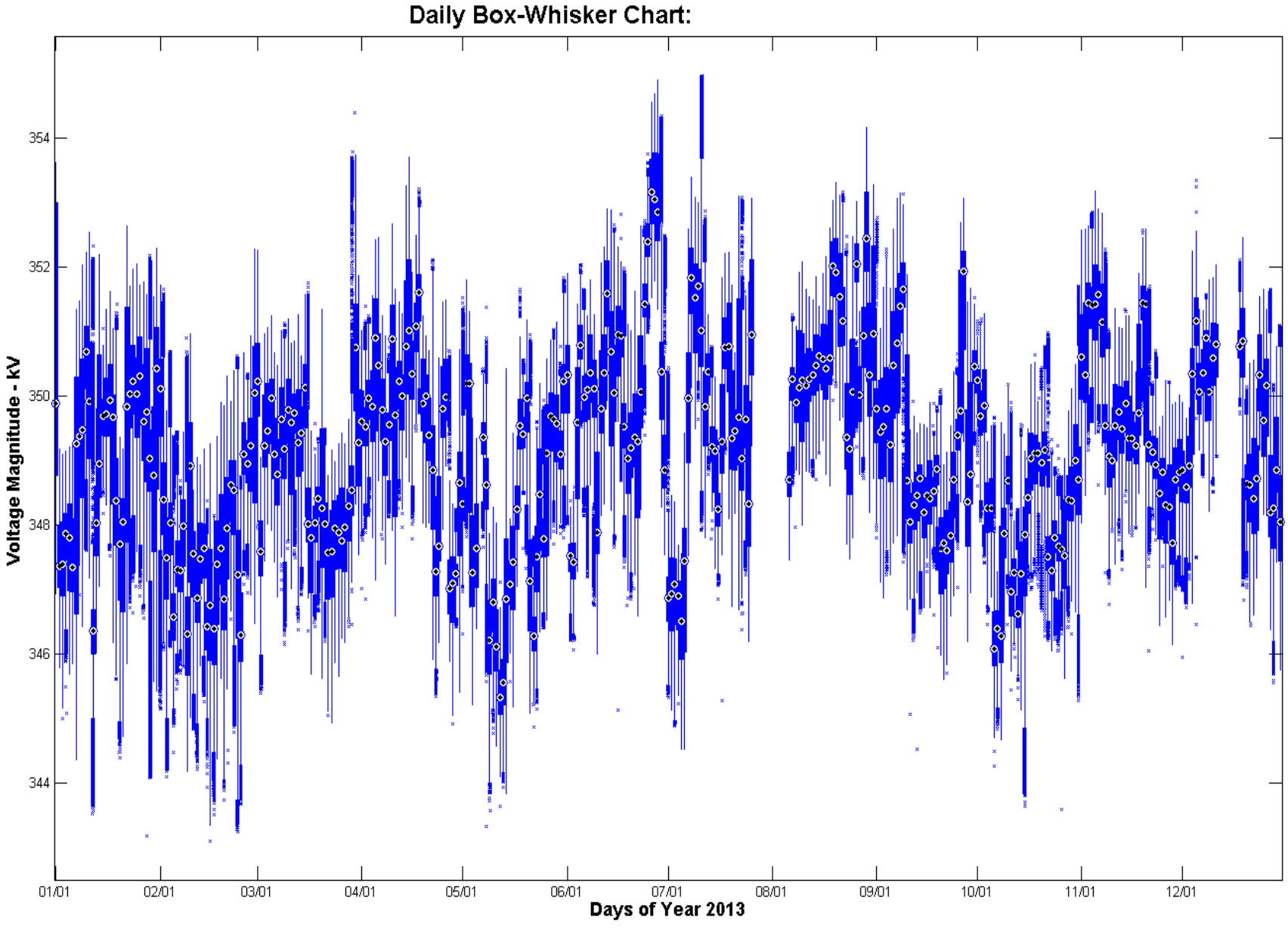
West 6


Daily Box-Whisker Chart:
Voltage Magnitude - kV
360
358
356
354
352
350
348
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

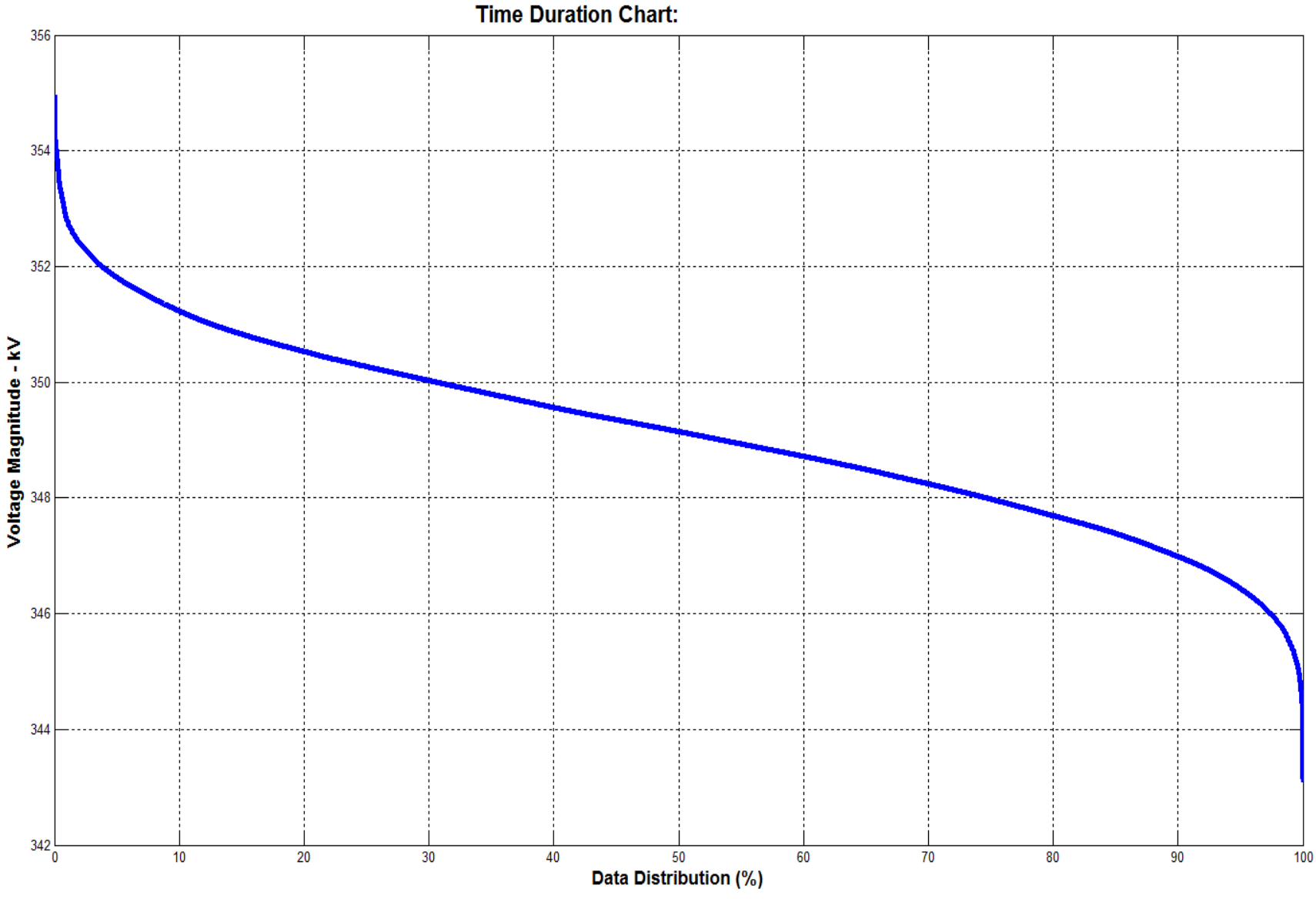
West 6


Time Duration Chart:
Voltage Magnitude - kV
362
360
358
356
354
352
350
348
346
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

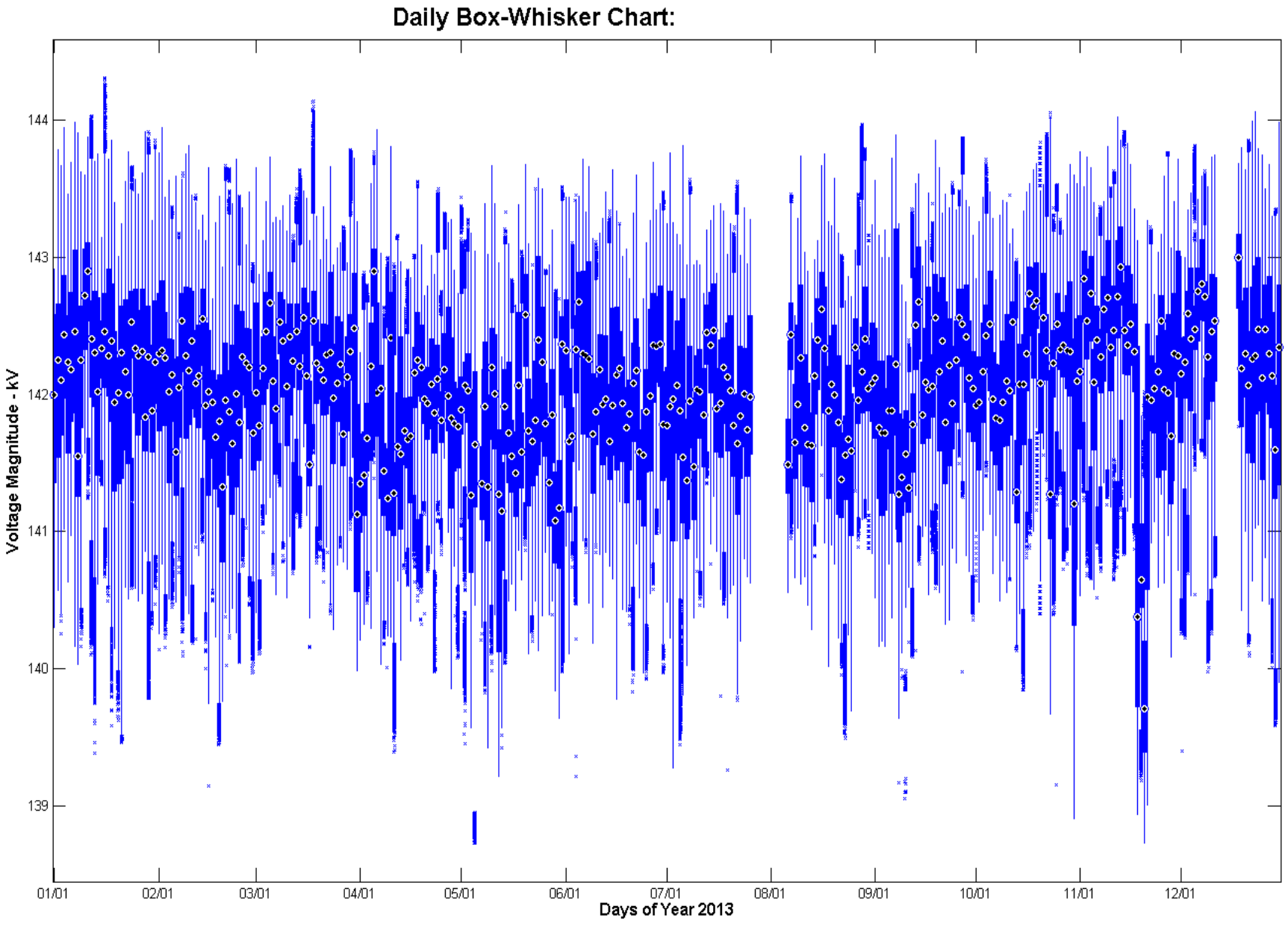
North 1


Daily Box-Whisker Chart:
Voltage Magnitude - kV
354
352
350
348
346
344
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

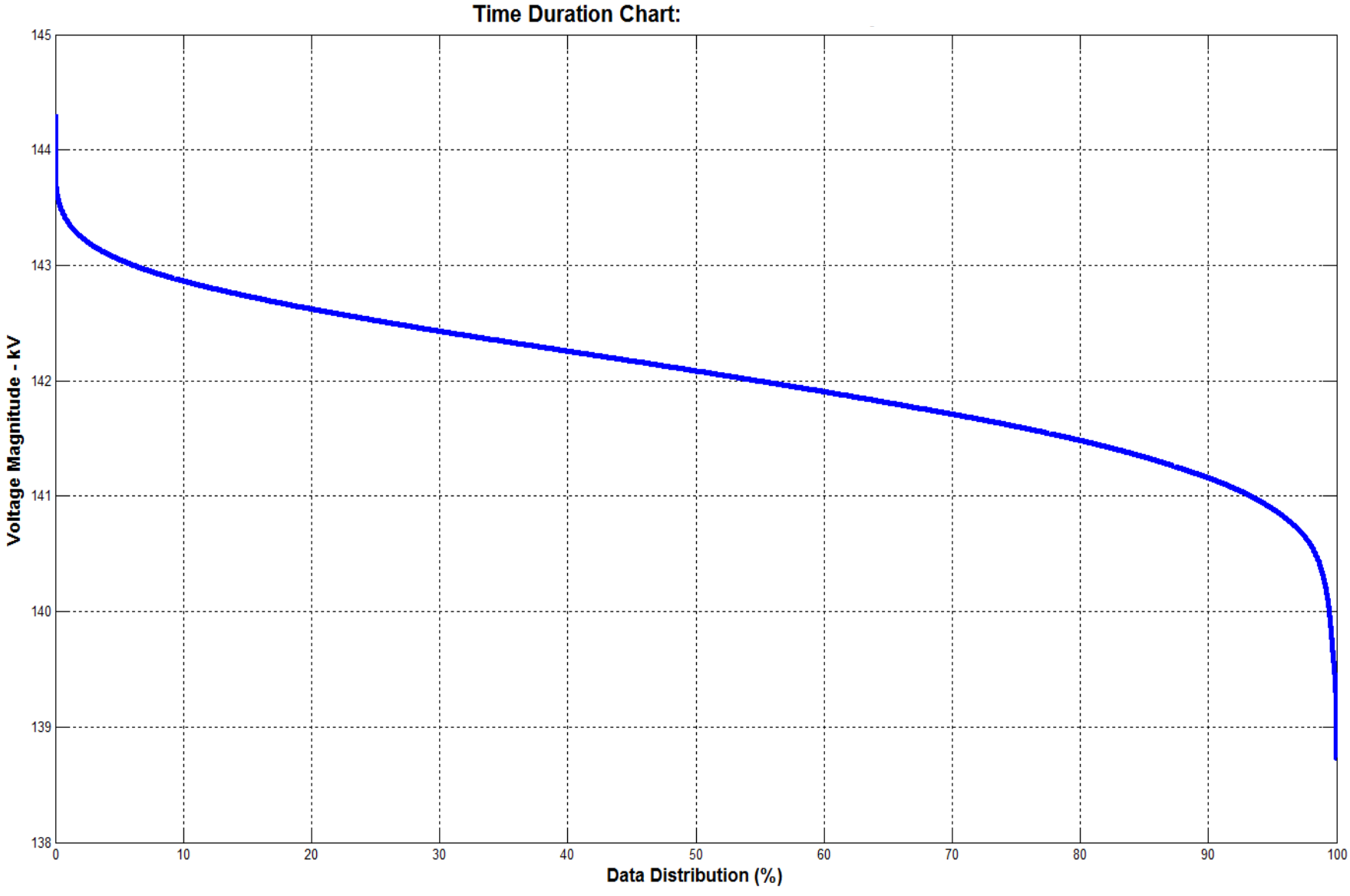
North 1


Time Duration Chart:
Voltage Magnitude - kV
356
354
352
350
348
346
344
342
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

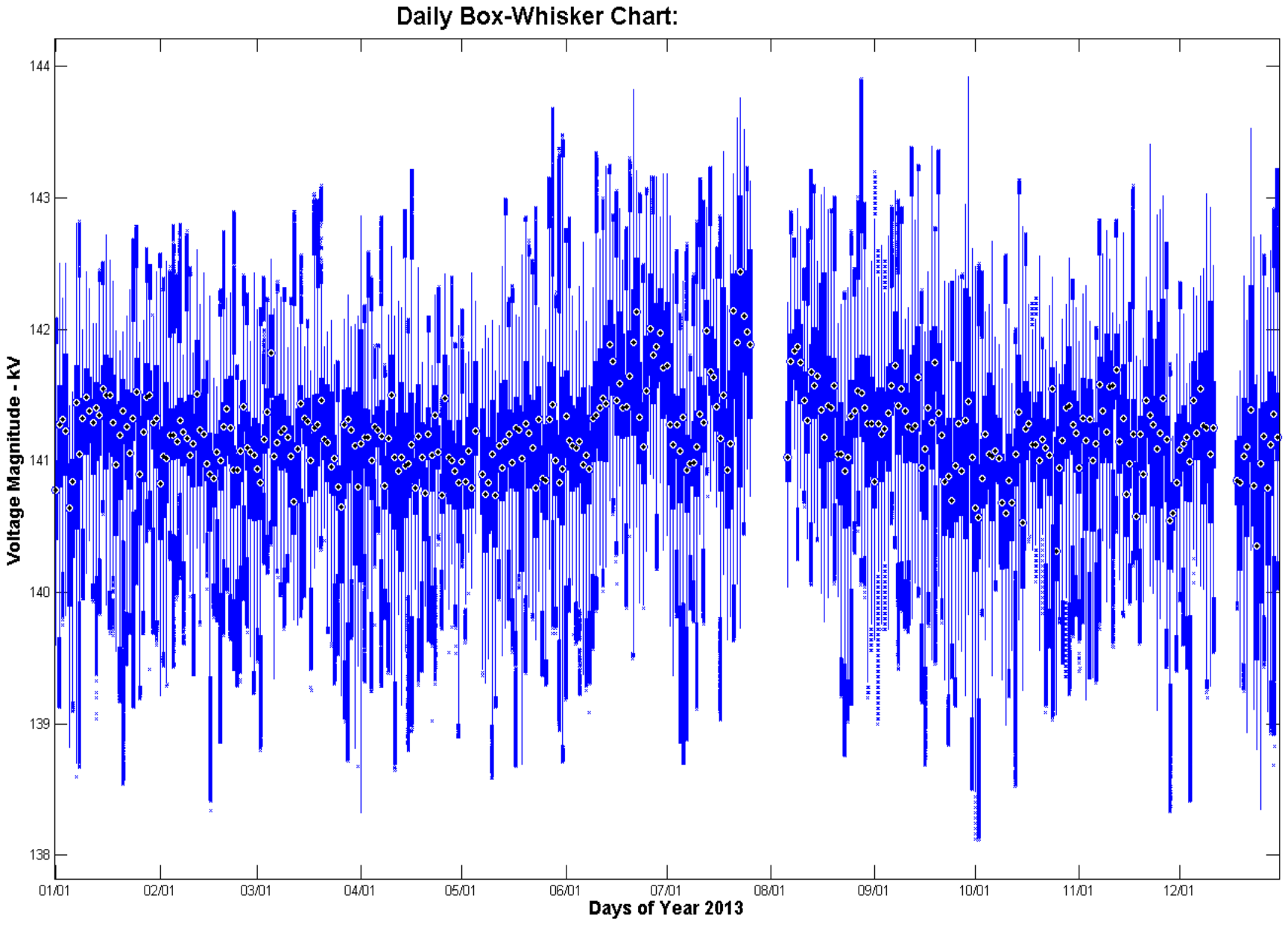
North 4


Daily Box-Whisker Chart:
Voltage Magnitude - kV
144
143
142
141
140
139
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

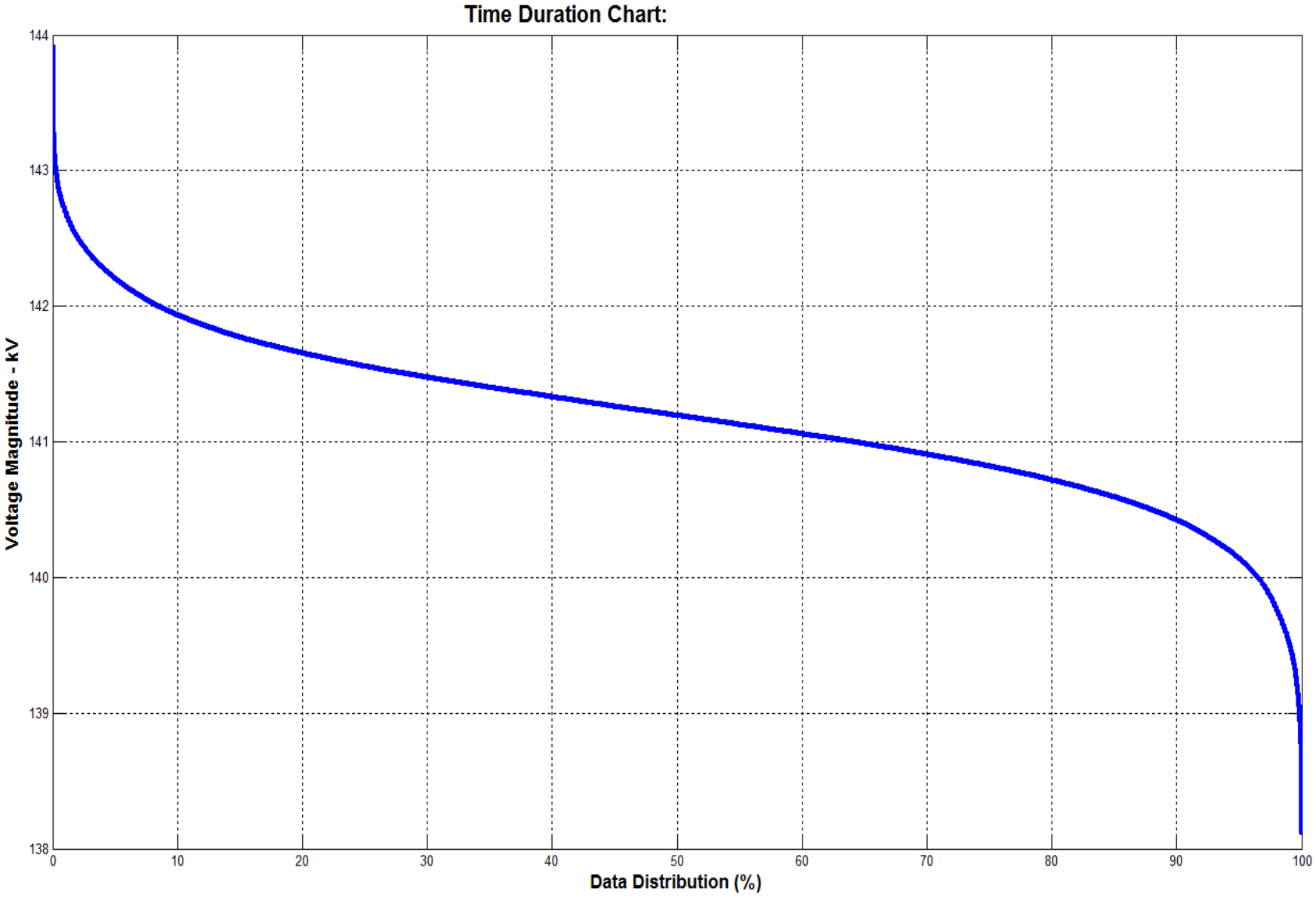
North 4


Time Duration Chart:
Voltage Magnitude - kV
145
144
143
142
141
140
139
138
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

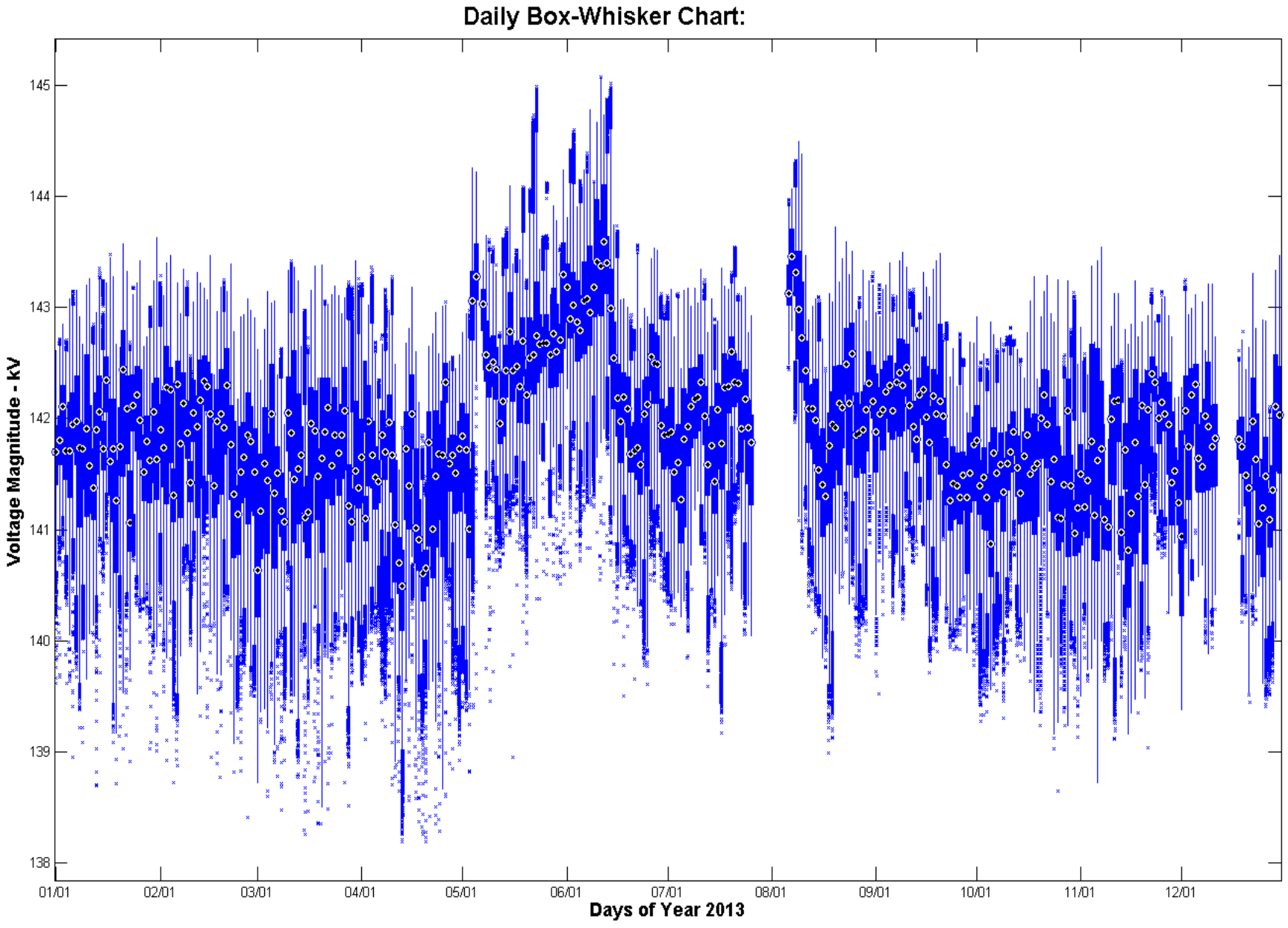
North 5


Daily Box-Whisker Chart:
Voltage Magnitude - kV
144
143
142
141
140
139
138
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

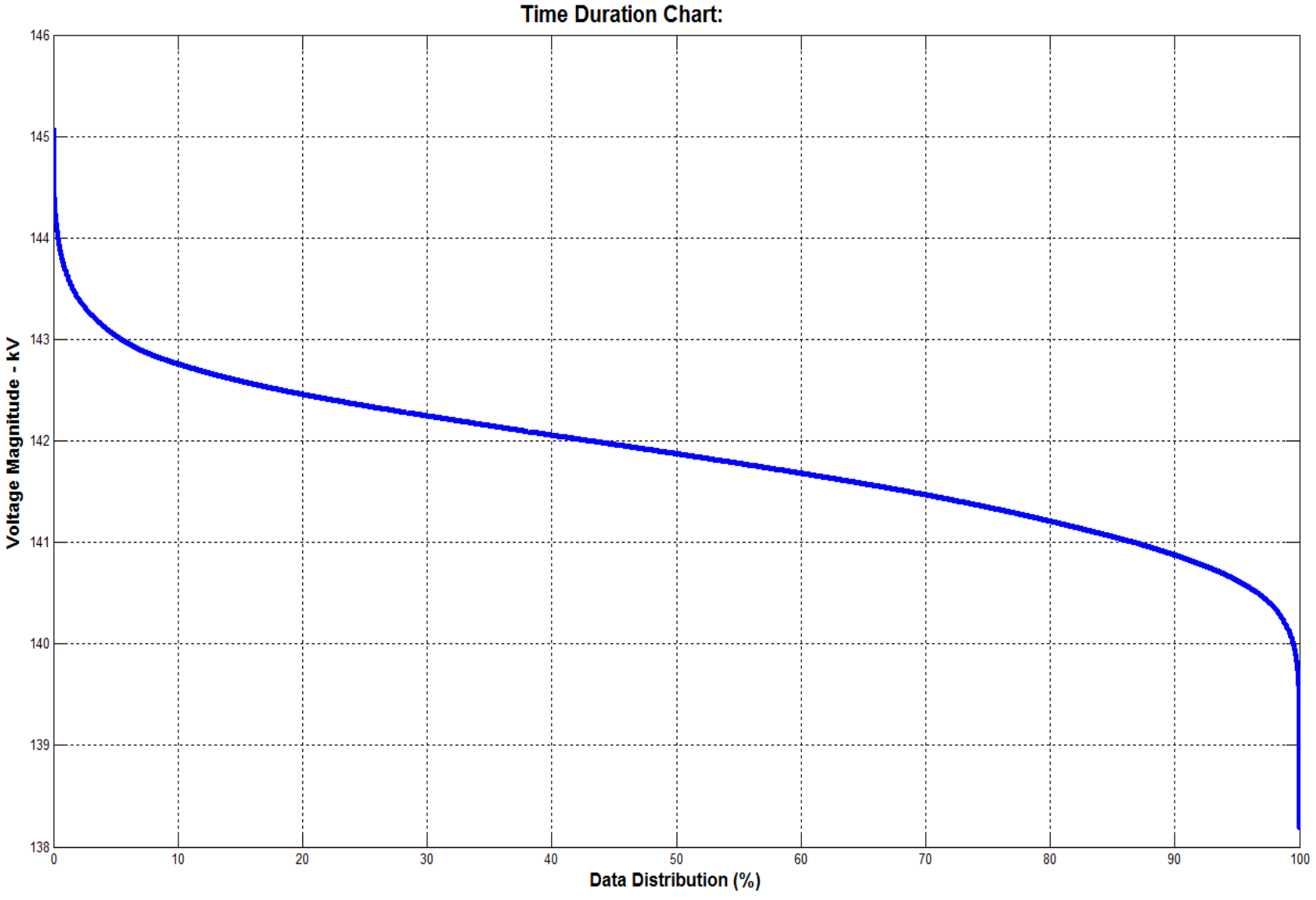
North 5


Time Duration Chart:
Voltage Magnitude - kV
144
143
142
141
140
139
138
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

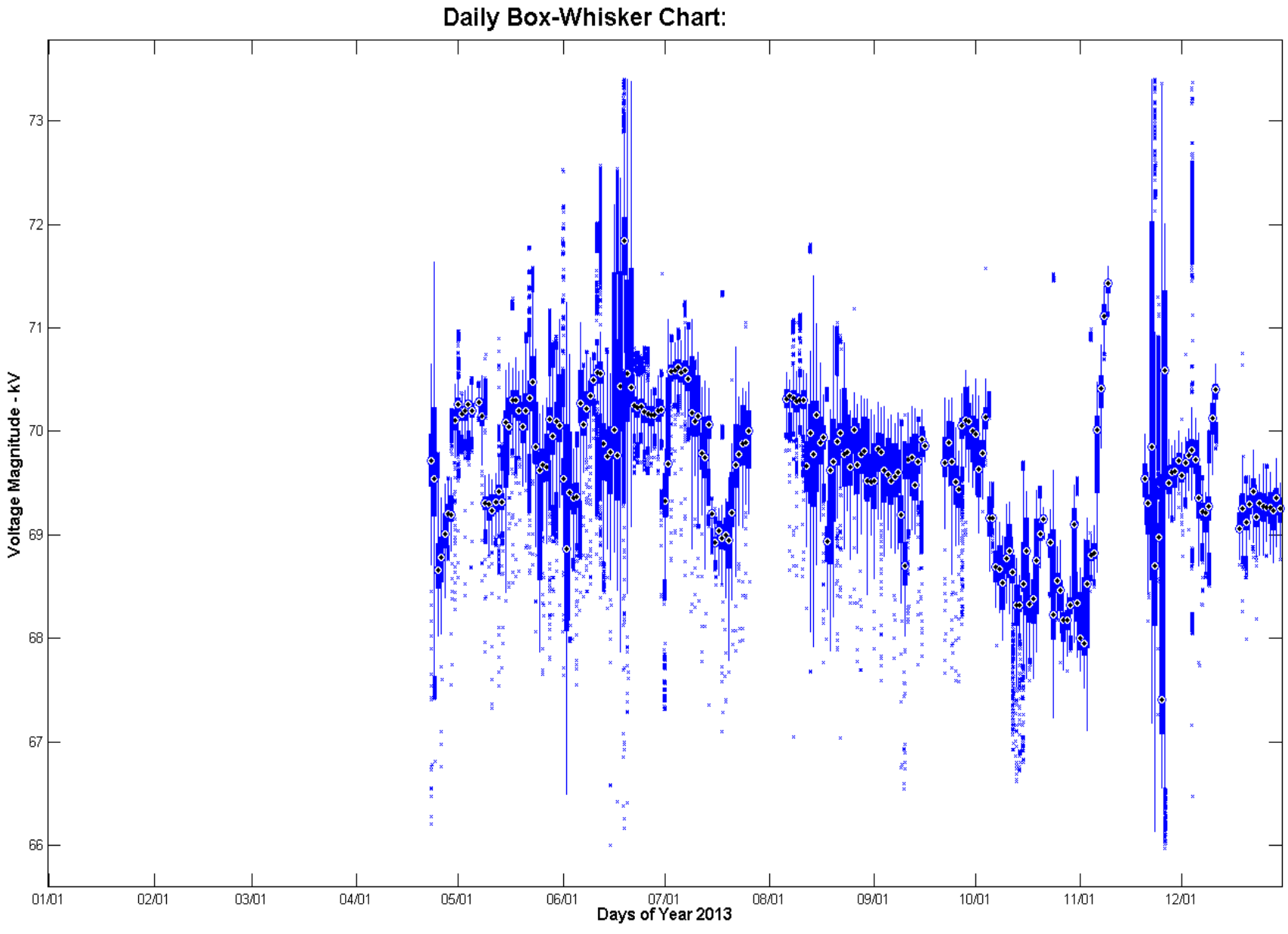
North 6


Daily Box-Whisker Chart:
Voltage Magnitude - kV
145
144
143
142
141
140
139
138
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

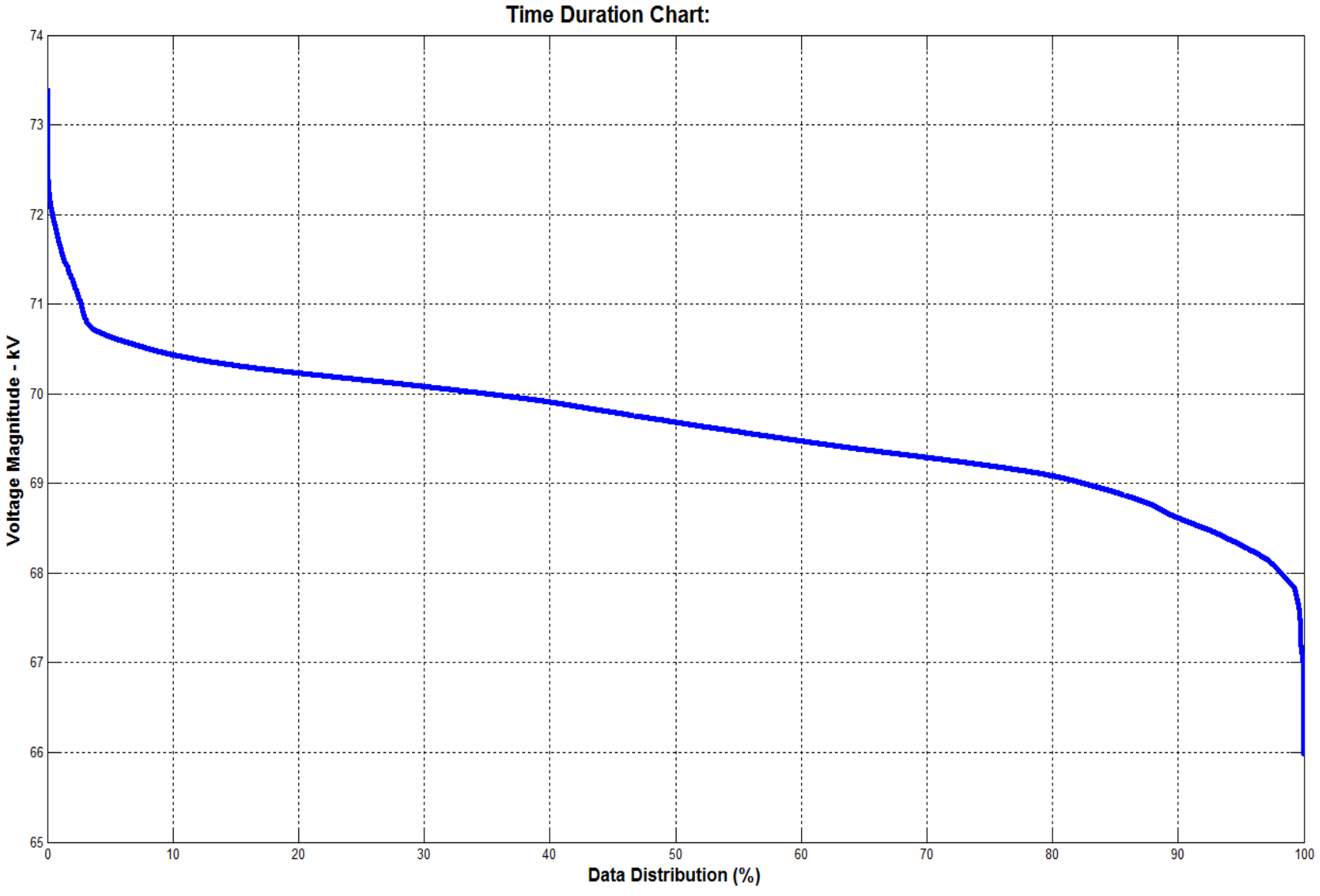
North 6


Time Duration Chart:
Voltage Magnitude - kV
Data Distribution (%)
146
145
144
143
142
141
140
139
138
0
10
20
30
40
50
60
70
80
90
100

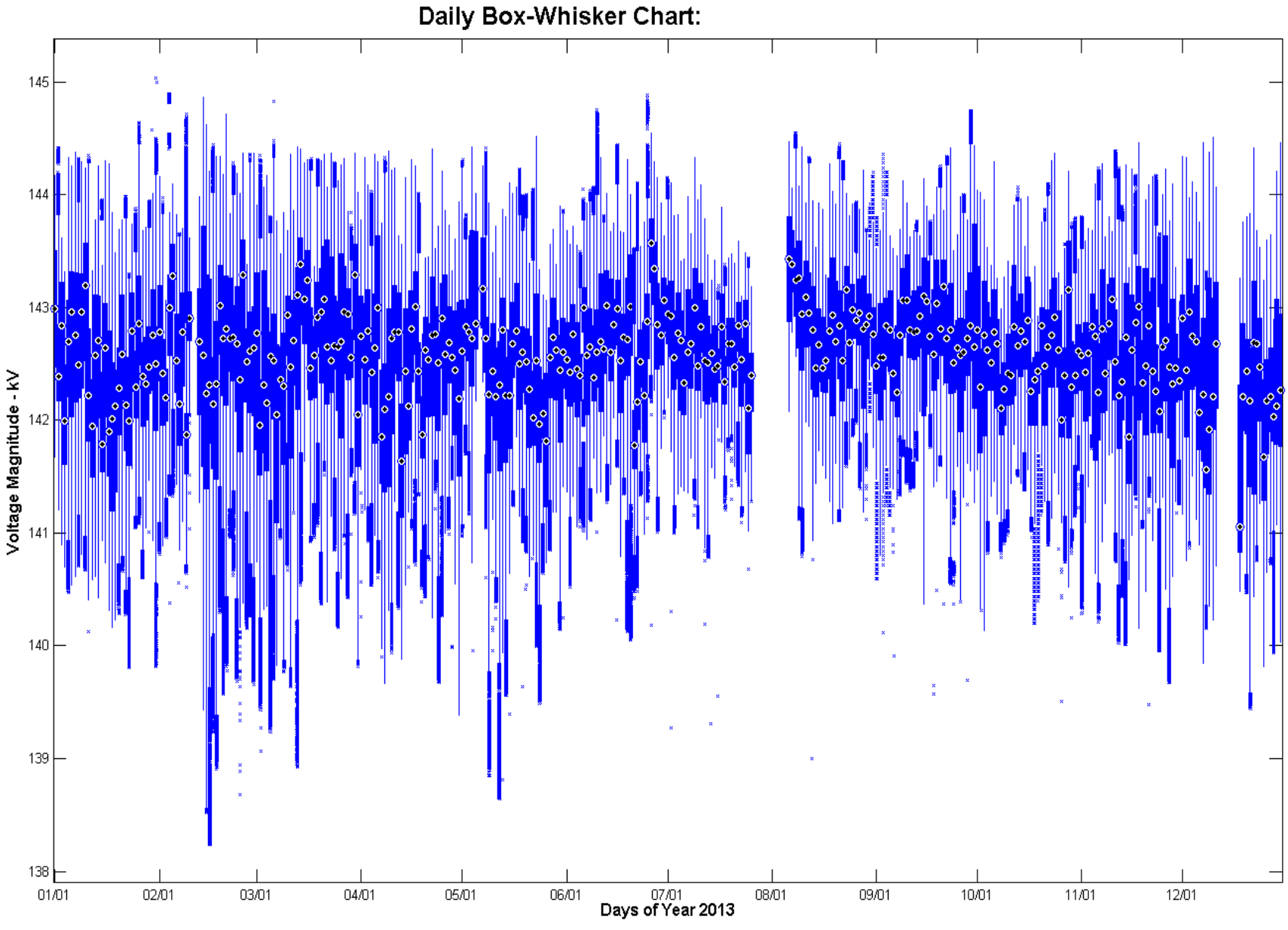
FarWest 2


Daily Box-Whisker Chart:
Voltage Magnitude - kV
73
72
71
70
69
68
67
66
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

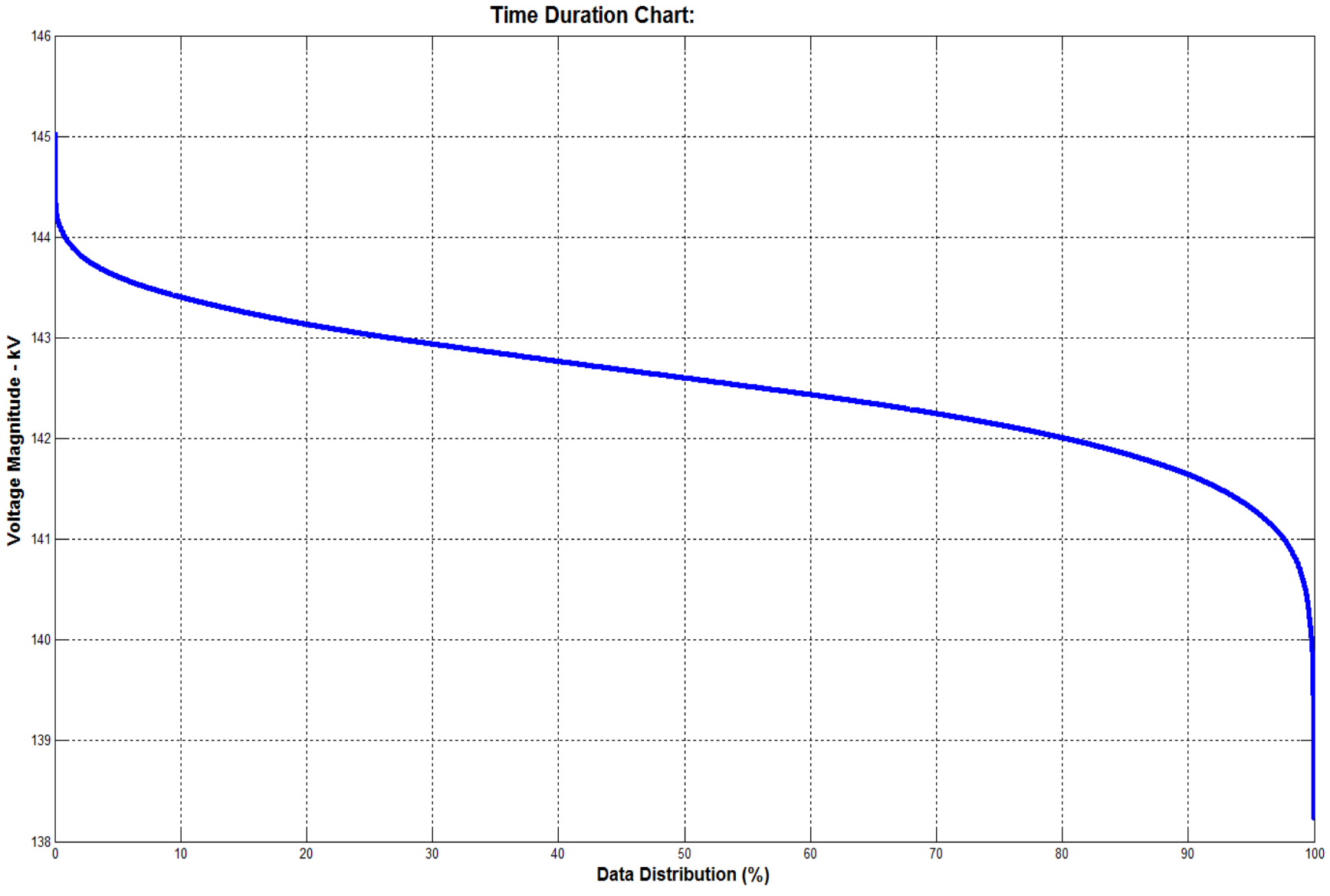
FarWest 2


Time Duration Chart:
Voltage Magnitude - kV
74
73
72
71
70
69
68
67
66
65
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

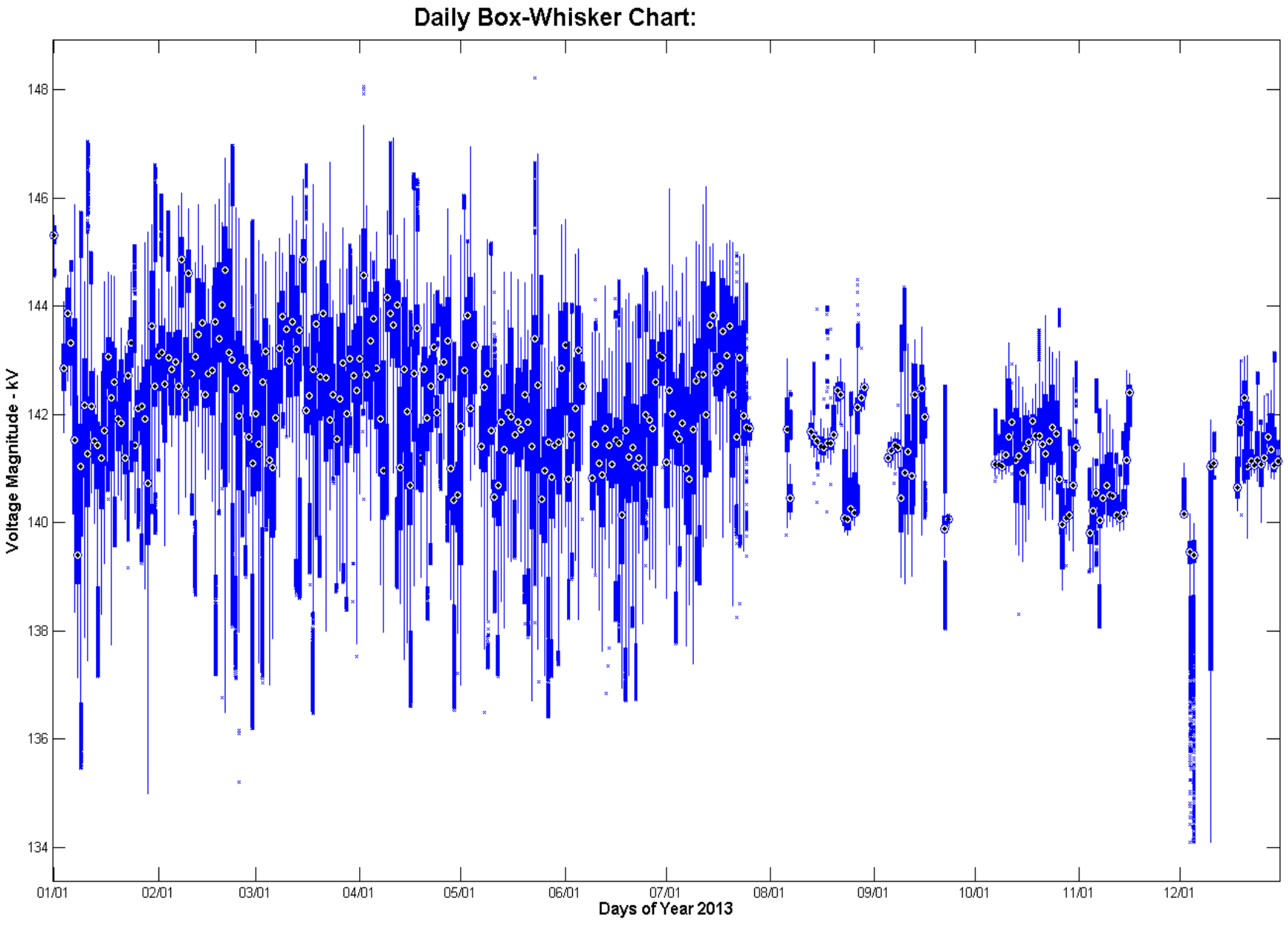
North 7


Daily Box-Whisker Chart:
Voltage Magnitude - kV
145
144
143
142
141
140
139
138
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

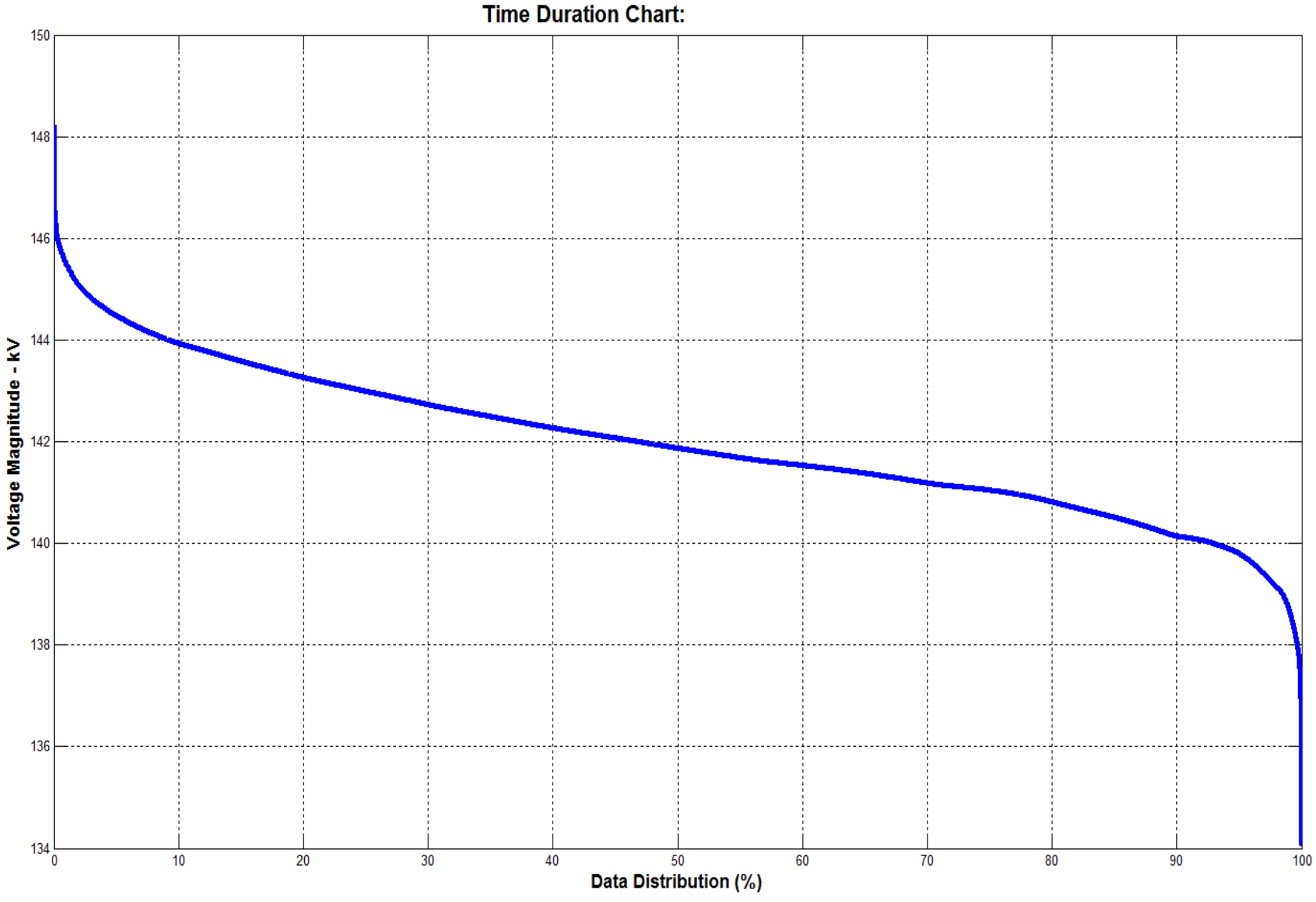
North 7


Time Duration Chart:
Voltage Magnitude - kV
146
145
144
143
142
141
140
139
138
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

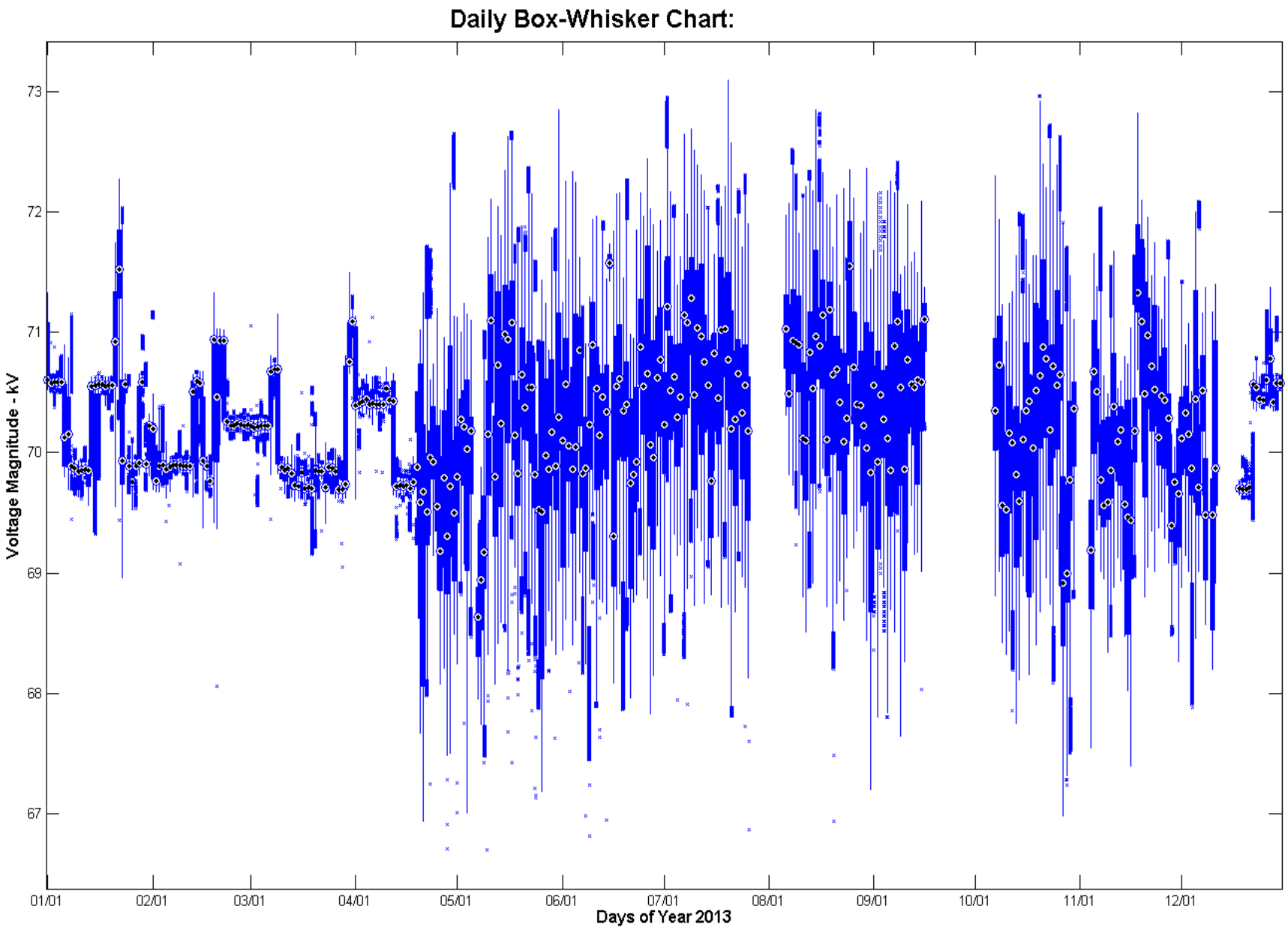
West 4


Daily Box-Whisker Chart:
Voltage Magnitude - kV
148
146
144
142
140
138
136
134
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

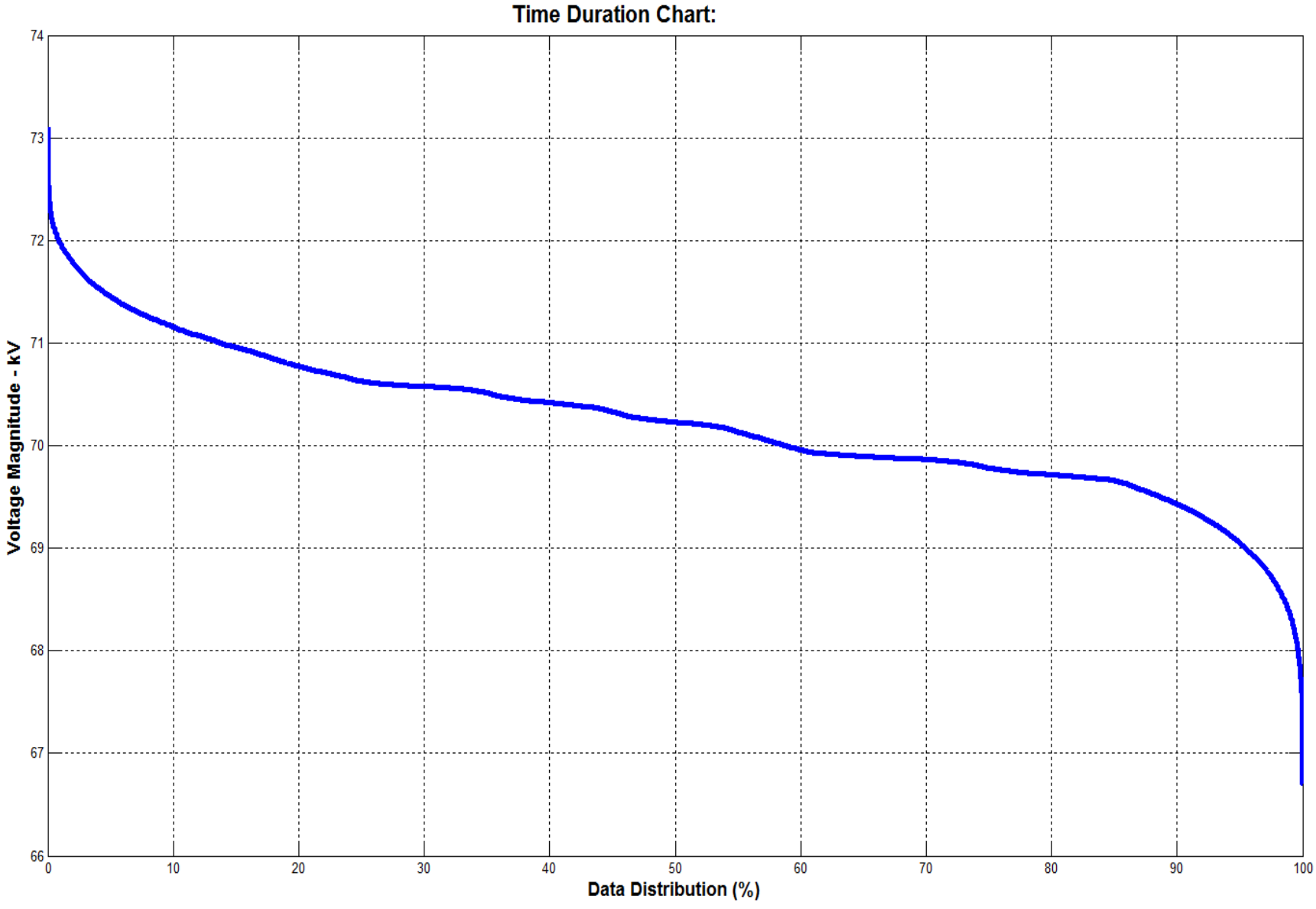
West 4


Time Duration Chart:
Voltage Magnitude - kV
150
148
146
144
142
140
138
136
134
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

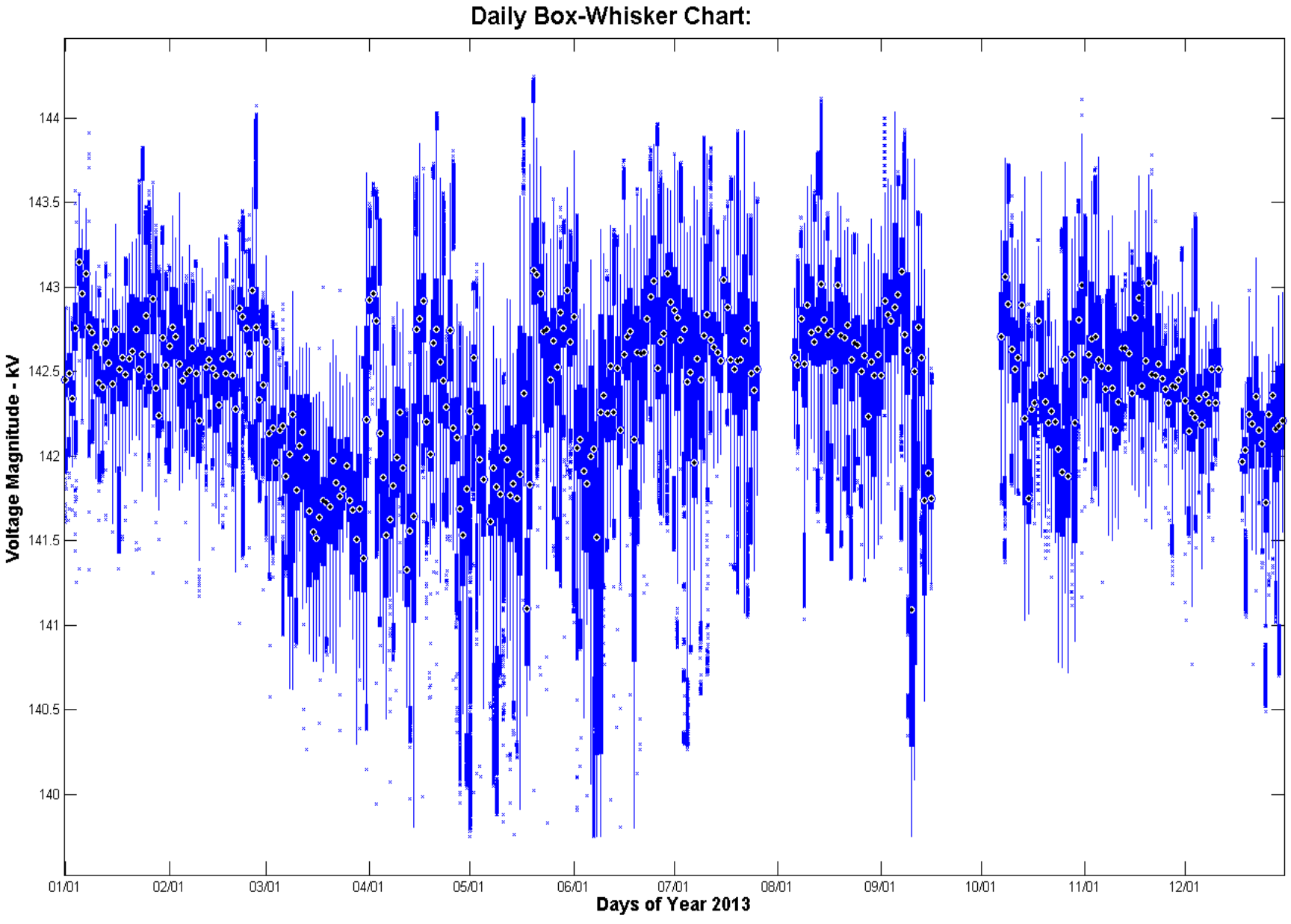
Coast 2


Daily Box-Whisker Chart:
Voltage Magnitude - kV
73
72
71
70
69
68
67
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

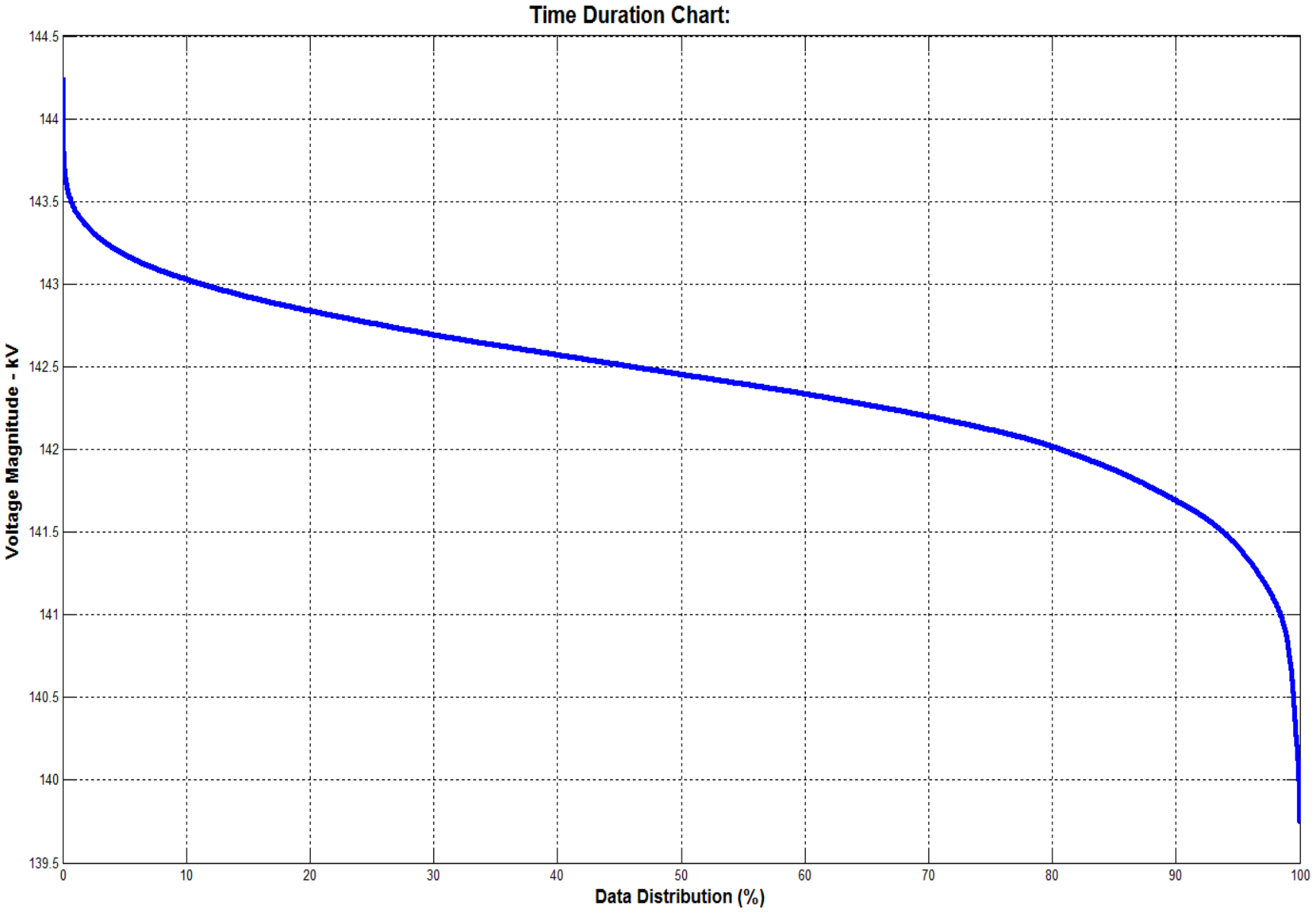
Coast 2


Time Duration Chart:
Voltage Magnitude - kV
Data Distribution (%)
74
73
72
71
70
69
68
67
66
0
10
20
30
40
50
60
70
80
90
100

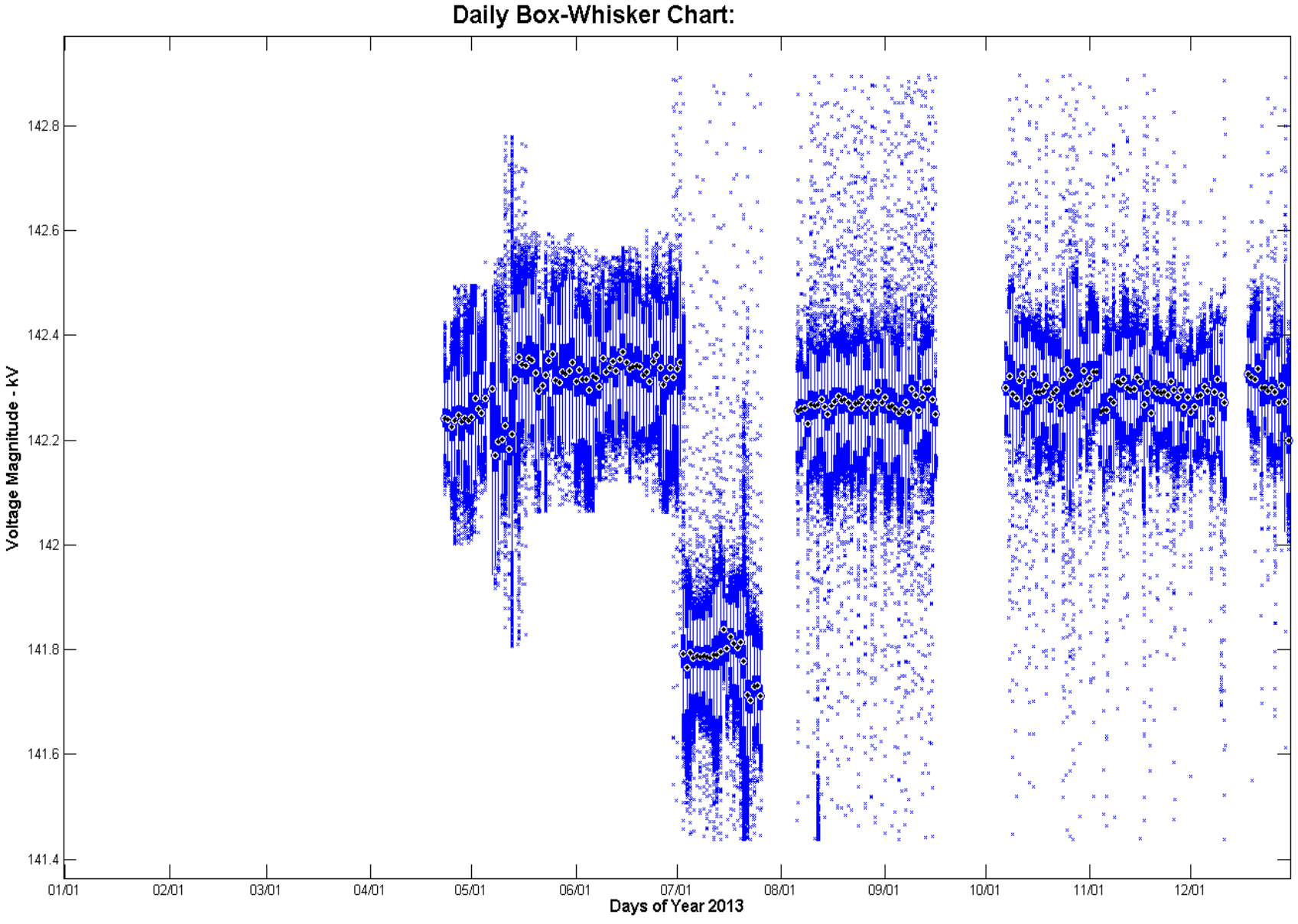
Coast 1


Daily Box-Whisker Chart:
Voltage Magnitude - kV
144
143.5
143
142.5
142
141.5
141
140.5
140
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

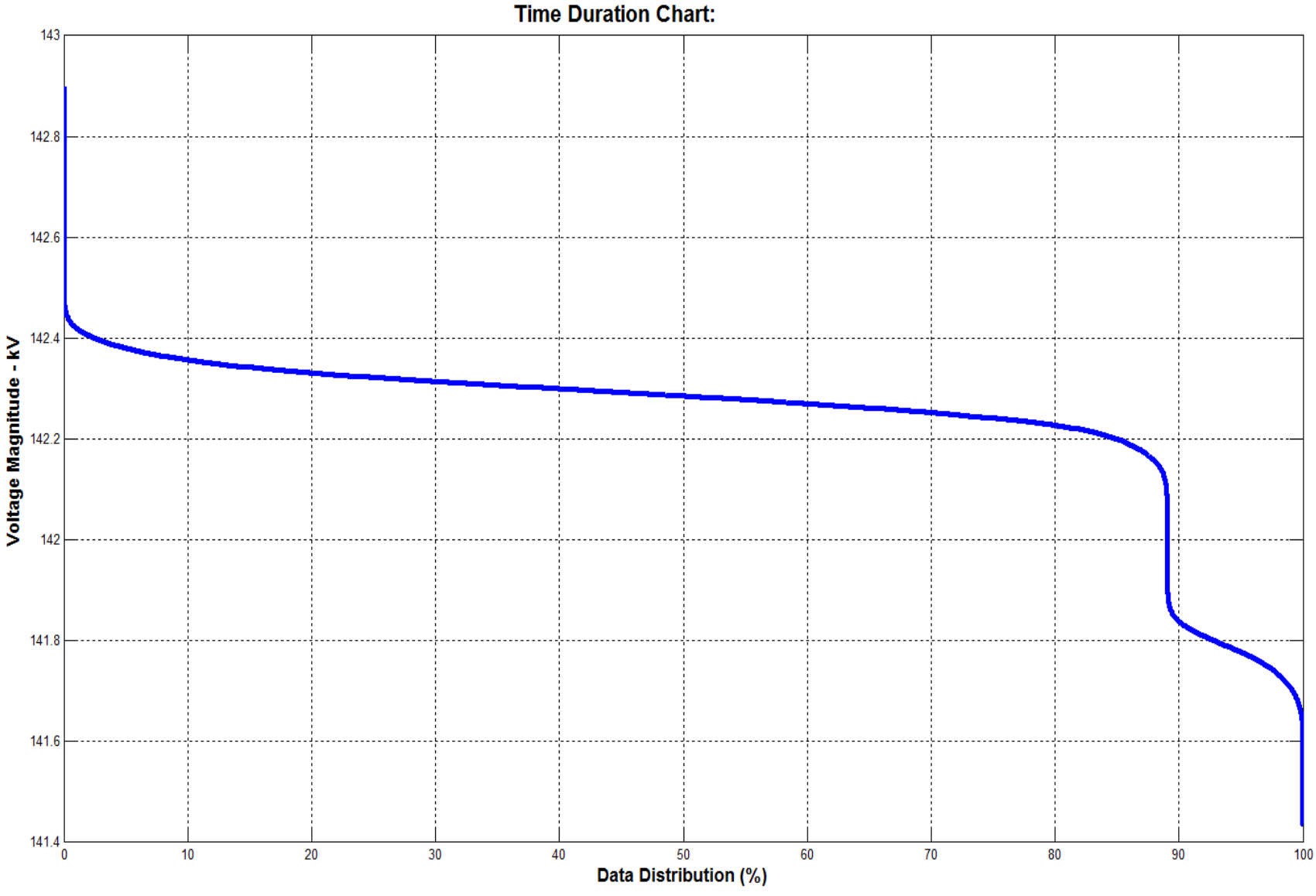
Coast 1


Time Duration Chart:
Voltage Magnitude - kV
144.5
144
143.5
143
142.5
142
141.5
141
140.5
140
139.5
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

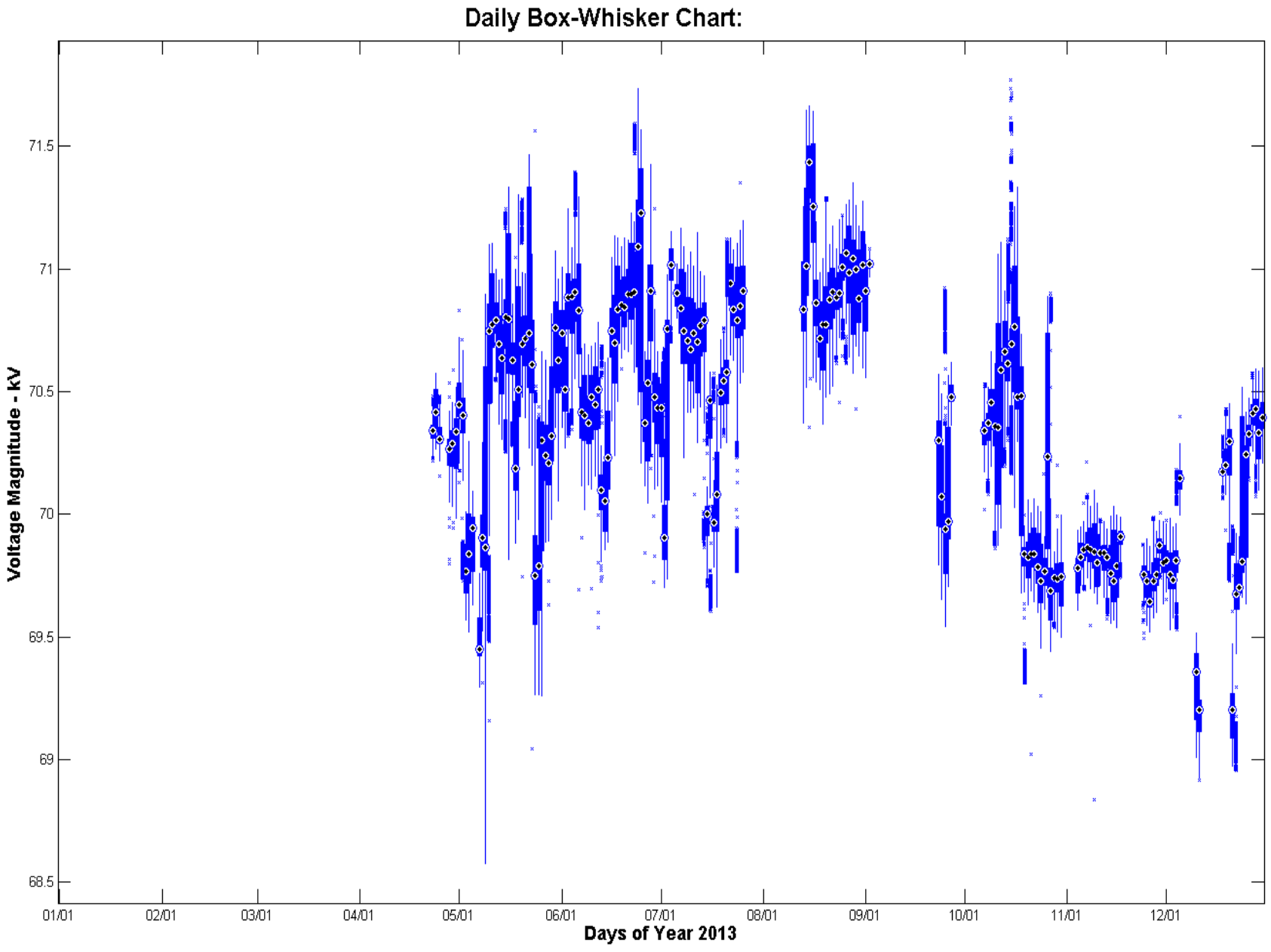
South 3


Daily Box-Whisker Chart:
Voltage Magnitude - kV
142.8
142.6
142.4
142.2
142
141.8
141.6
141.4
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

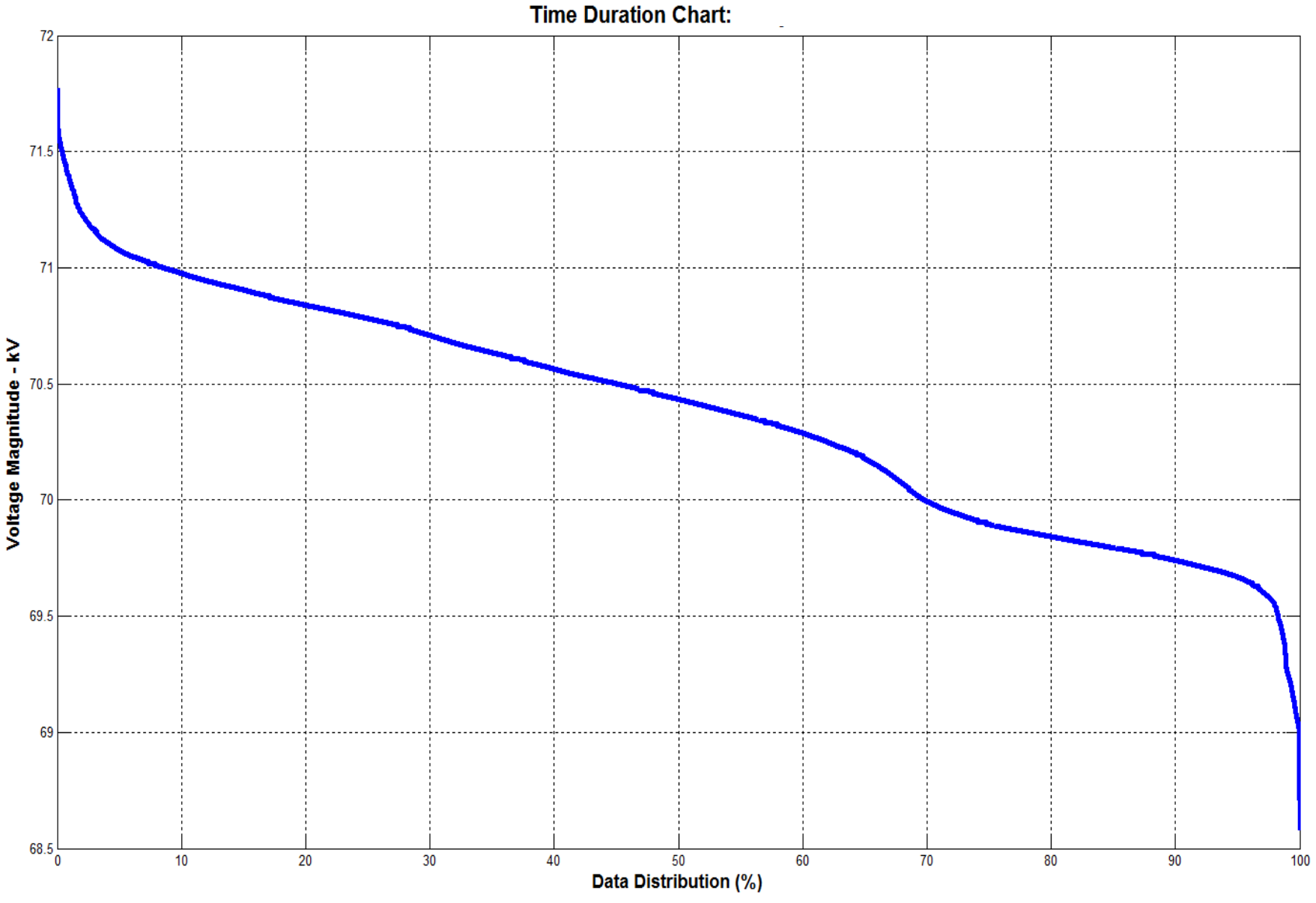
South 3


Time Duration Chart:
Voltage Magnitude - kV
143
142.8
142.6
142.4
142.2
142
141.8
141.6
141.4
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

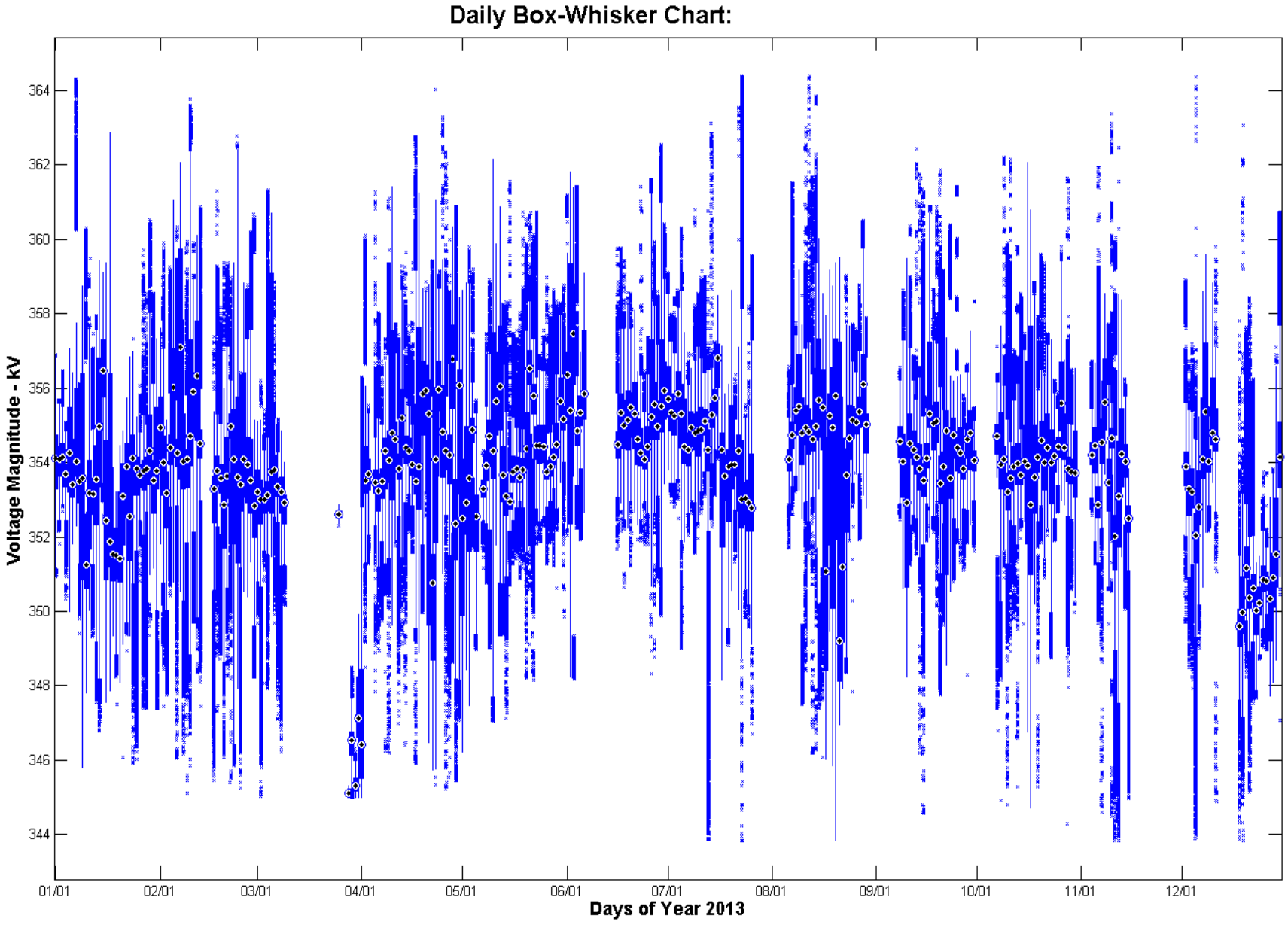
South 5


Daily Box-Whisker Chart:
Voltage Magnitude - kV
71.5
71
70.5
70
69.5
69
68.5
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

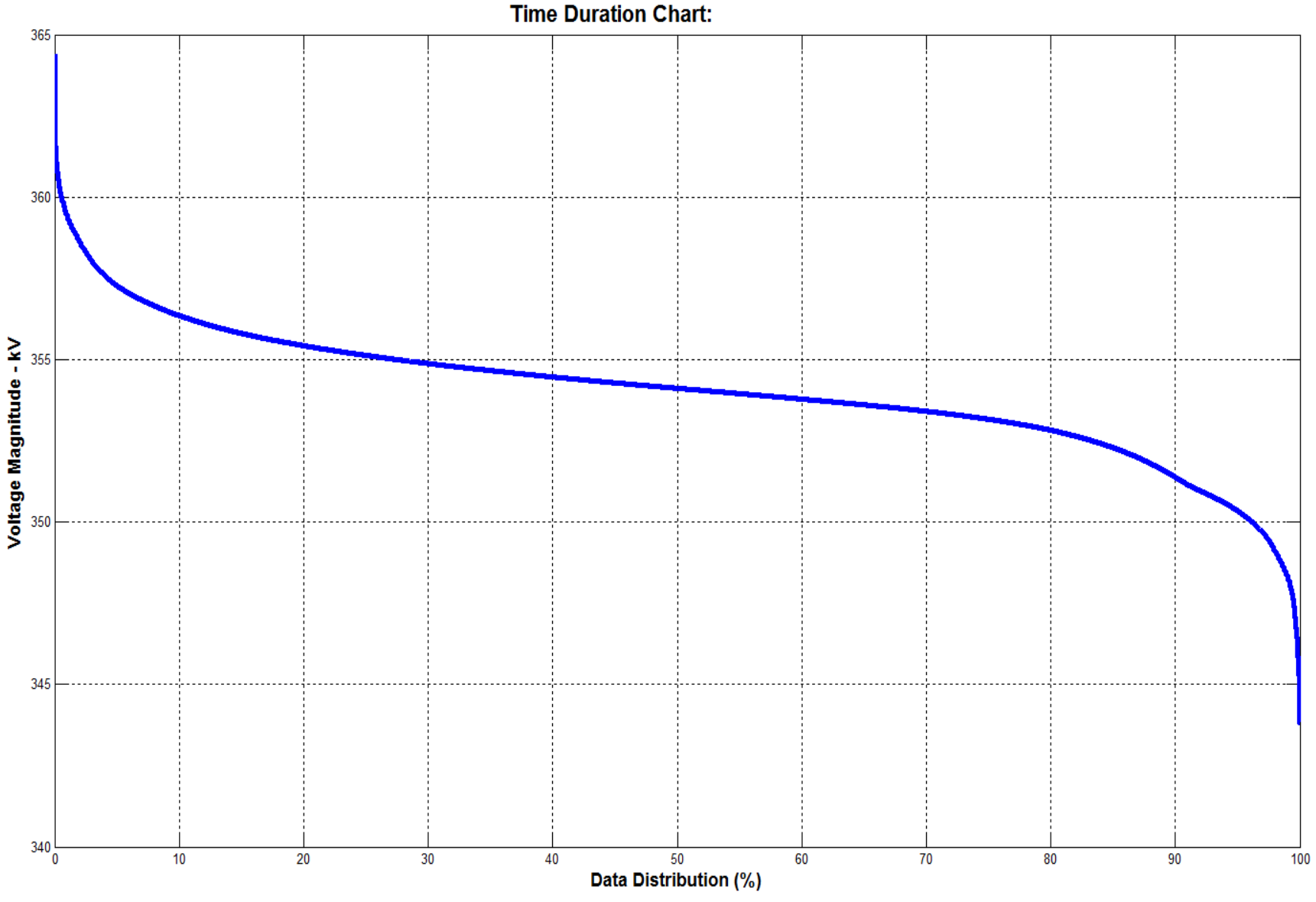
South 5


Time Duration Chart:
Voltage Magnitude - kV
72
71.5
71
70.5
70
69.5
69
68.5
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

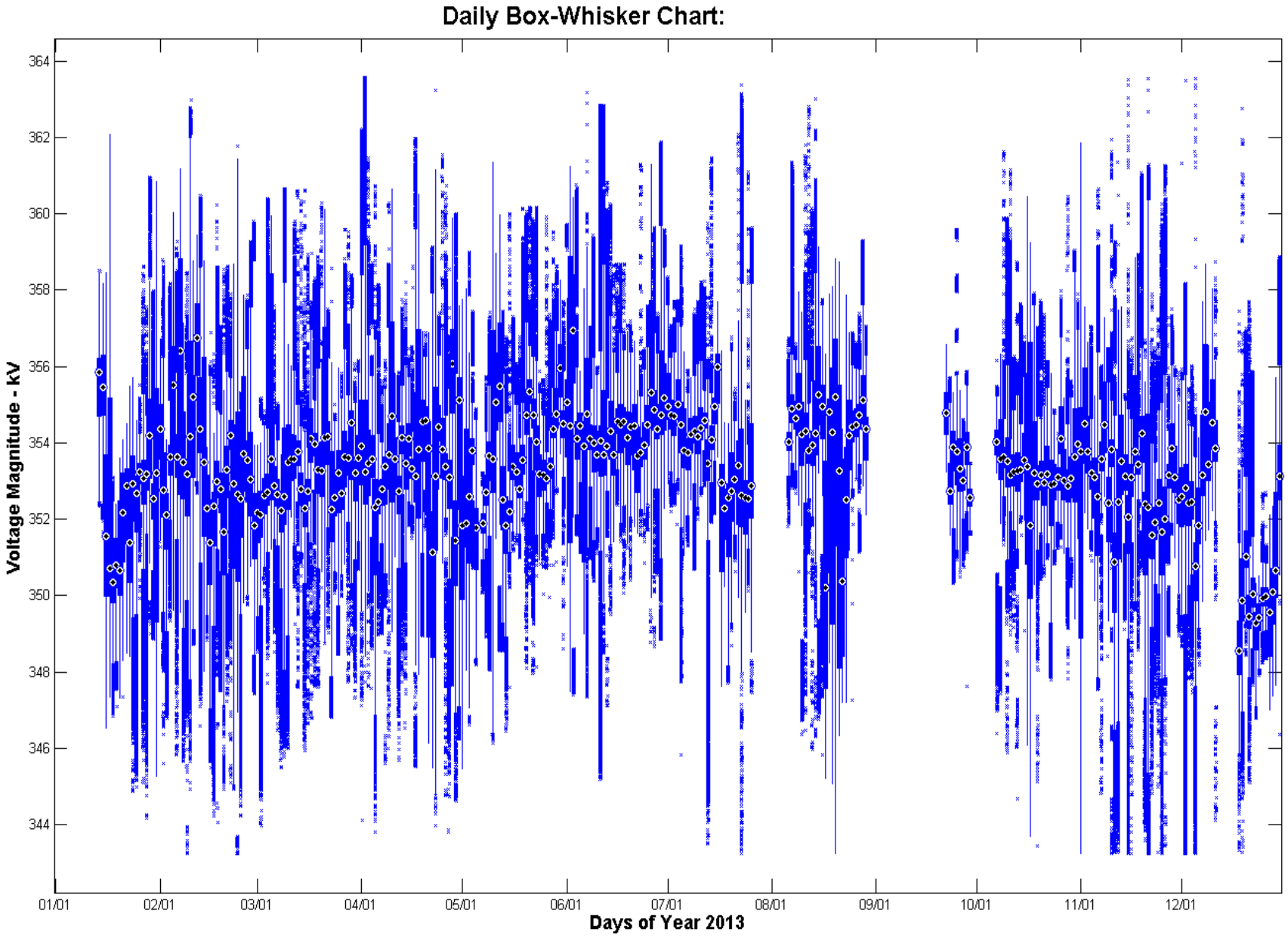
Coast 4


Daily Box-Whisker Chart:
Voltage Magnitude - kV
364
362
360
358
356
354
352
350
348
346
344
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

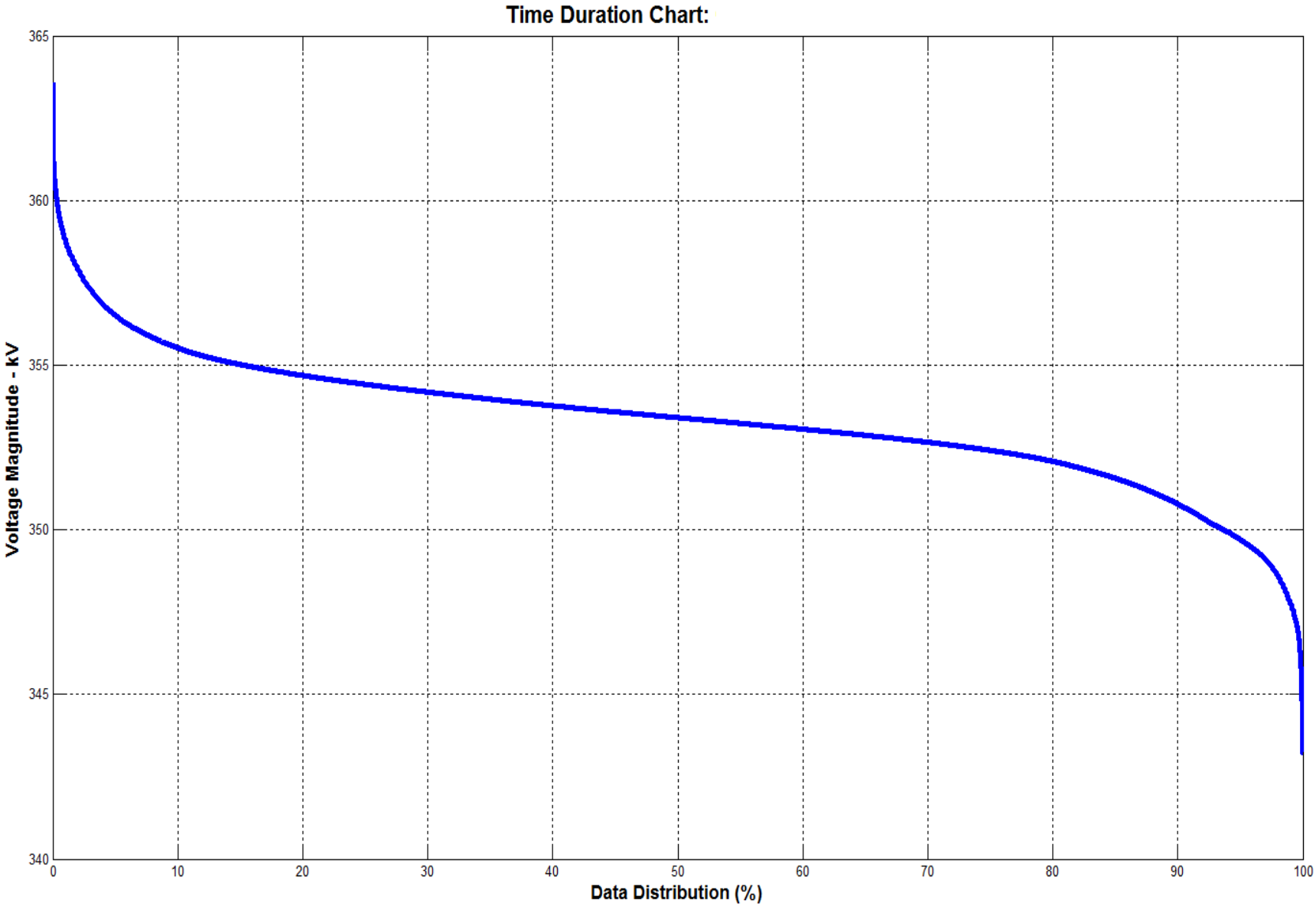
Coast 4


Time Duration Chart:
Voltage Magnitude - kV
365
360
355
350
345
340
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

Coast 3


Daily Box-Whisker Chart:
Voltage Magnitude - kV
364
362
360
358
356
354
352
350
348
346
344
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

Coast 3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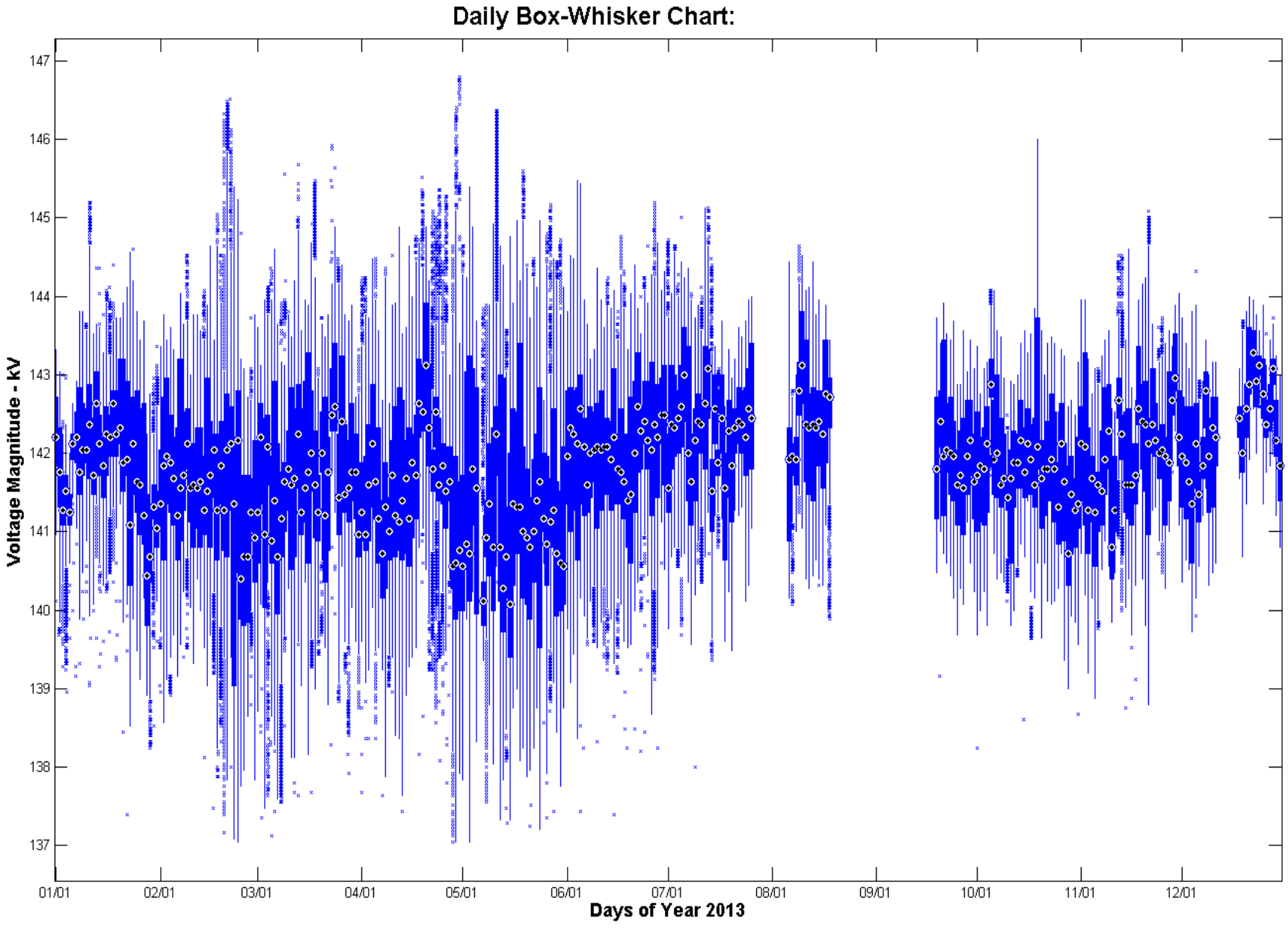
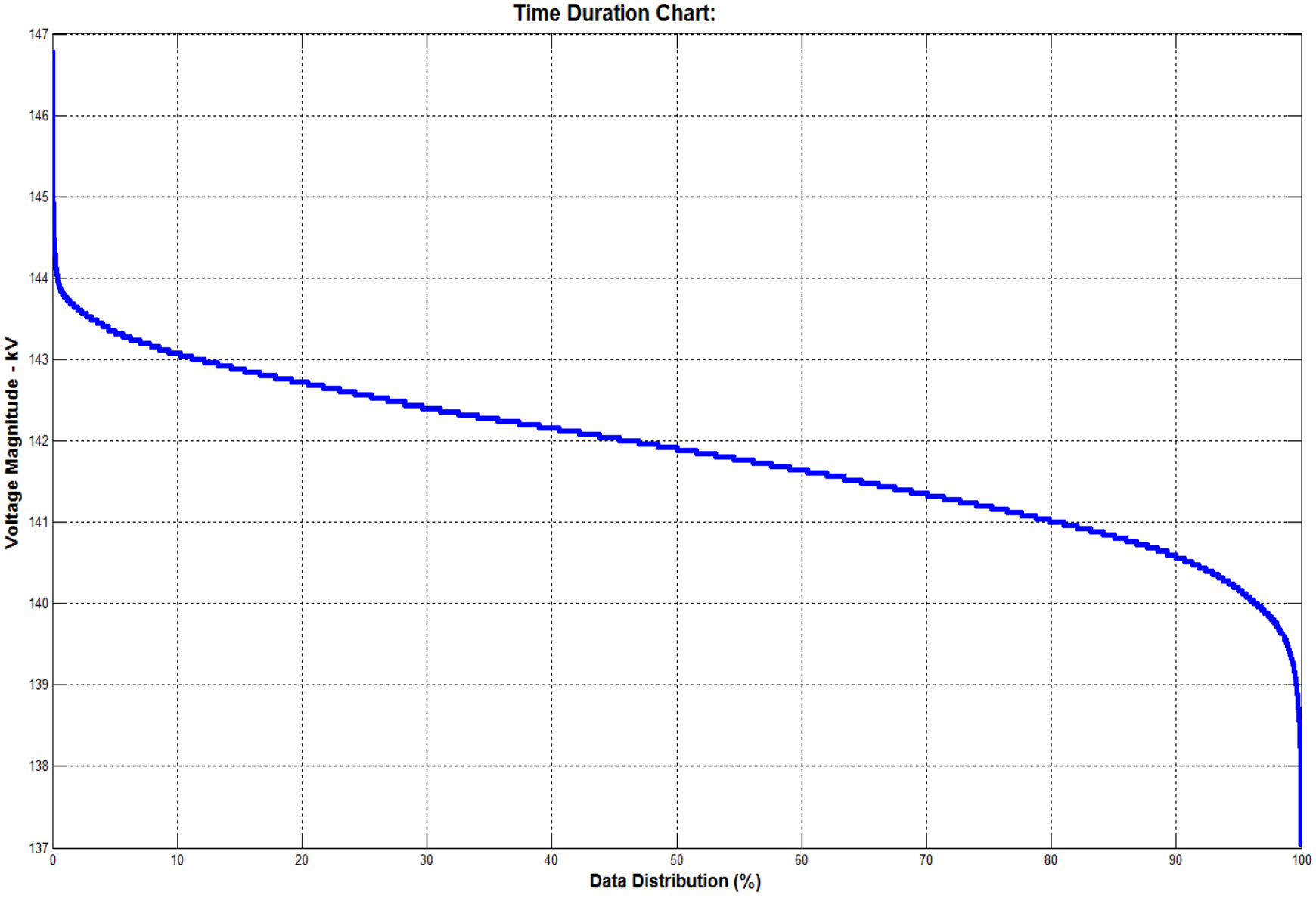
Voltage Magnitude - kV
365
360
355
350
345
340
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

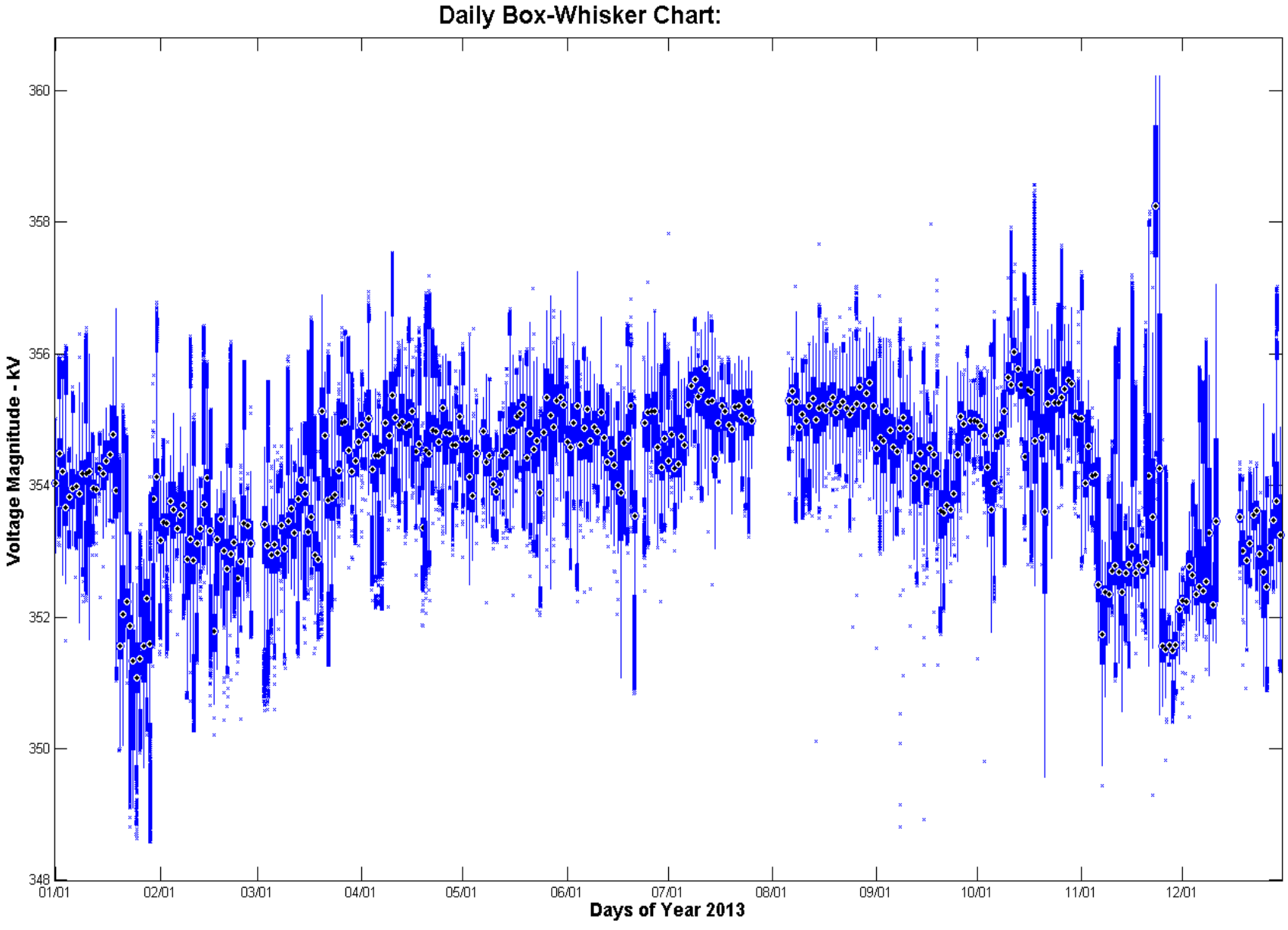
South 13


Daily Box-Whisker Chart:
Voltage Magnitude - kV
147
146
145
144
143
142
141
140
139
138
137
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

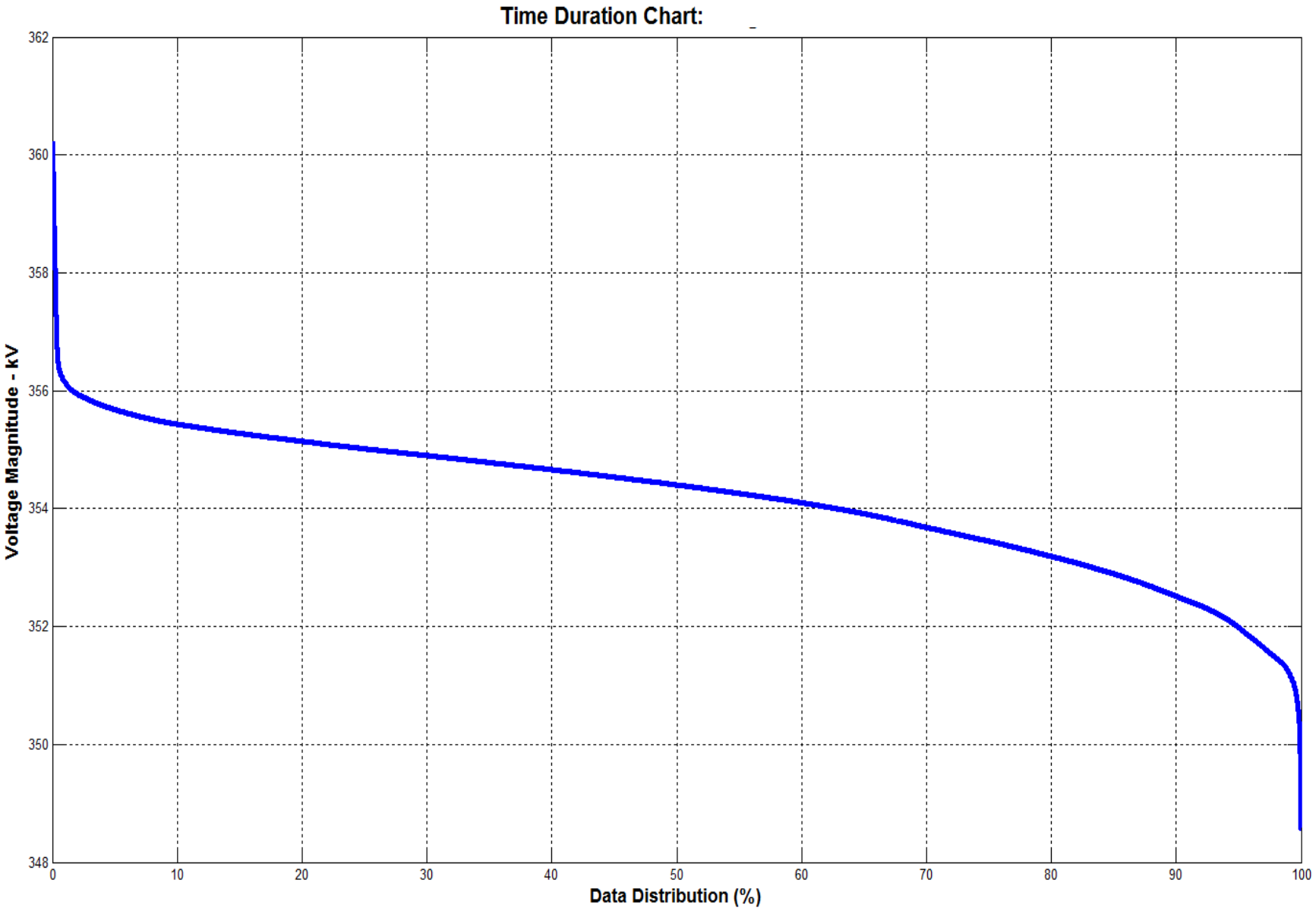
South 13


Time Duration Chart:
Voltage Magnitude - kV
147
146
145
144
143
142
141
140
139
138
137
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

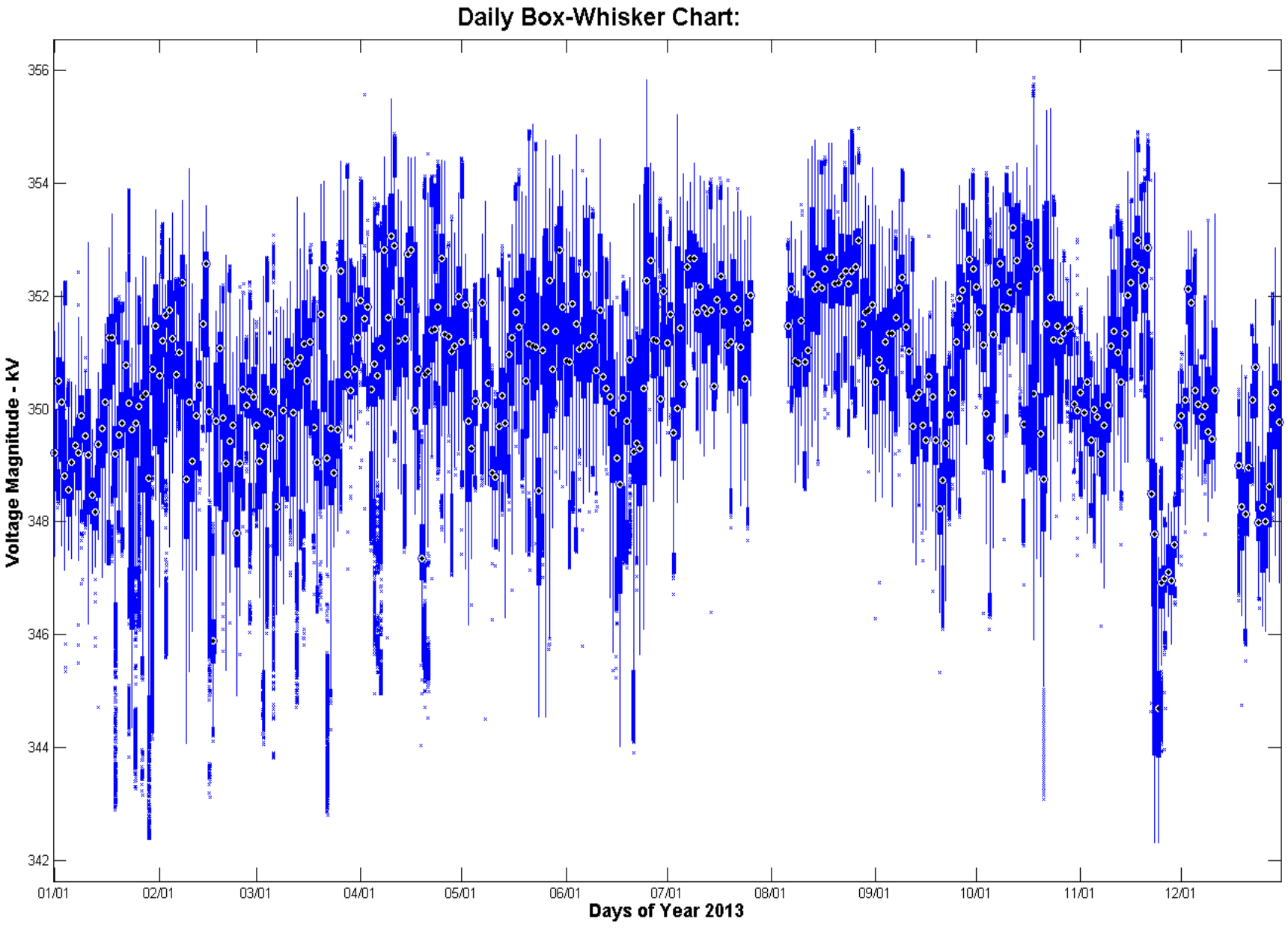
FarWest 4


Daily Box-Whisker Chart:
Voltage Magnitude - kV
360
358
356
354
352
350
348
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

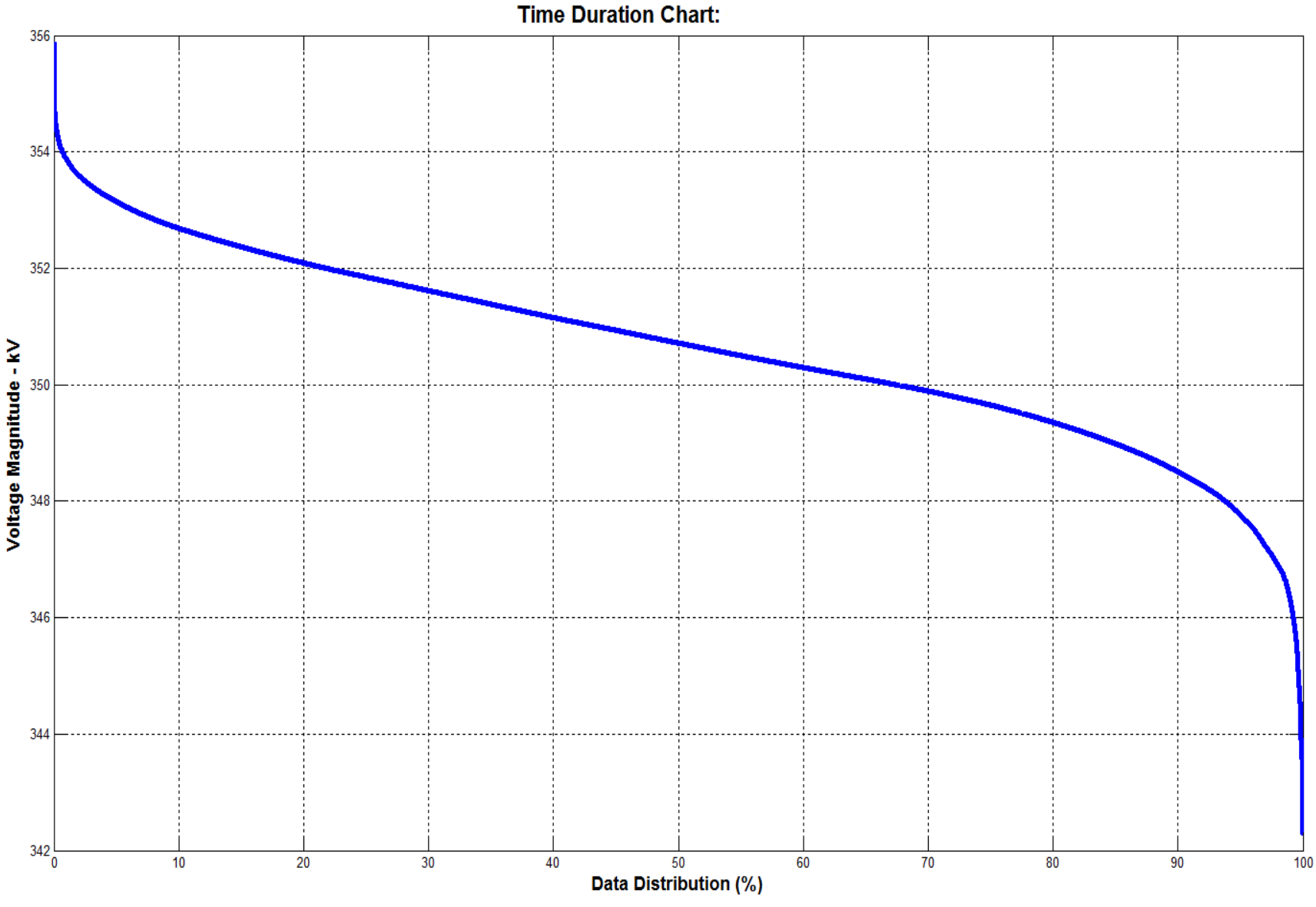
FarWest 4


Time Duration Chart:
Voltage Magnitude - kV
362
360
358
356
354
352
350
348
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

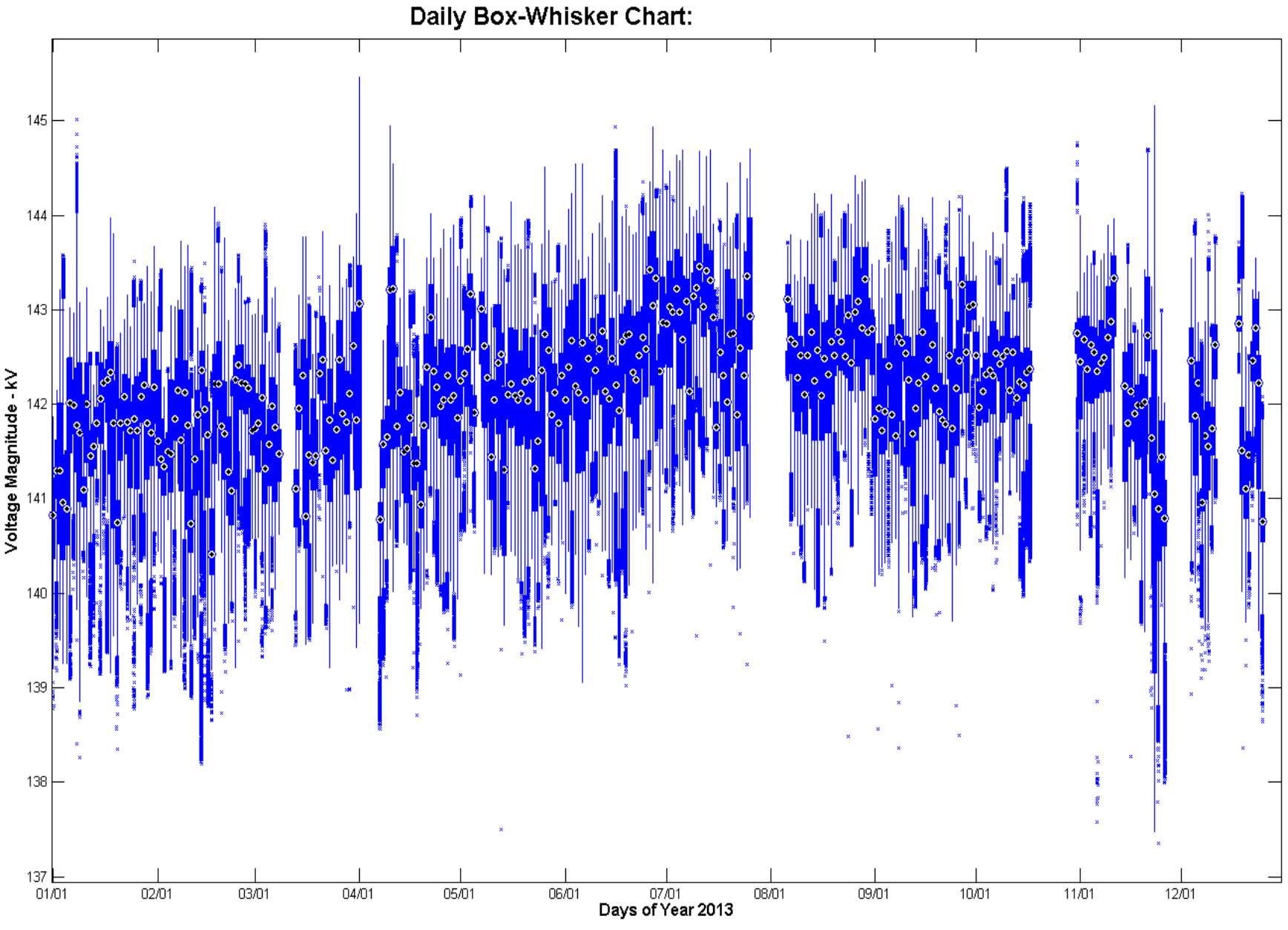
FarWest 7


Daily Box-Whisker Chart:
Voltage Magnitude - kV
356
354
352
350
348
346
344
342
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

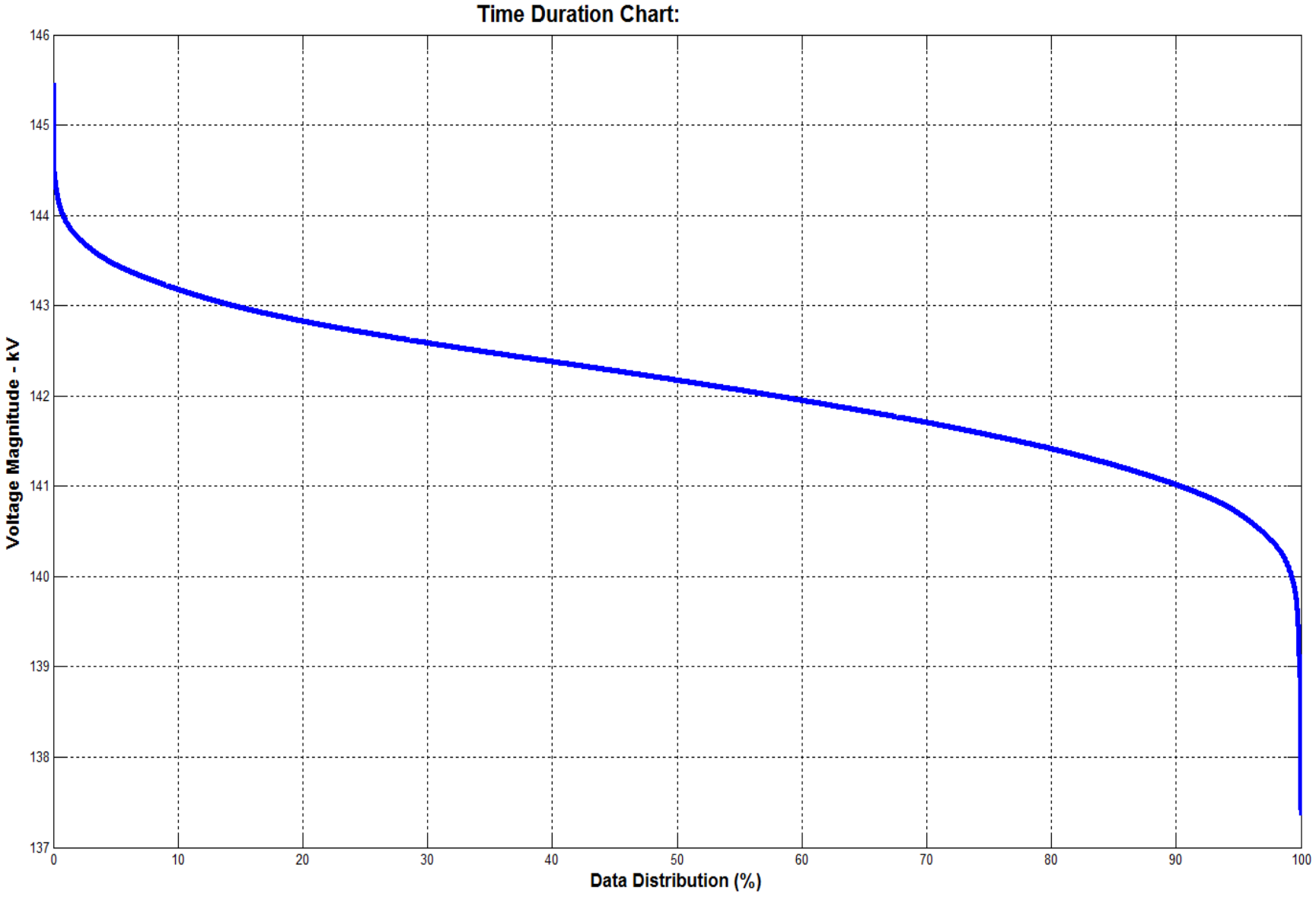
FarWest 7


Time Duration Chart:
Voltage Magnitude - kV
356
354
352
350
348
346
344
342
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

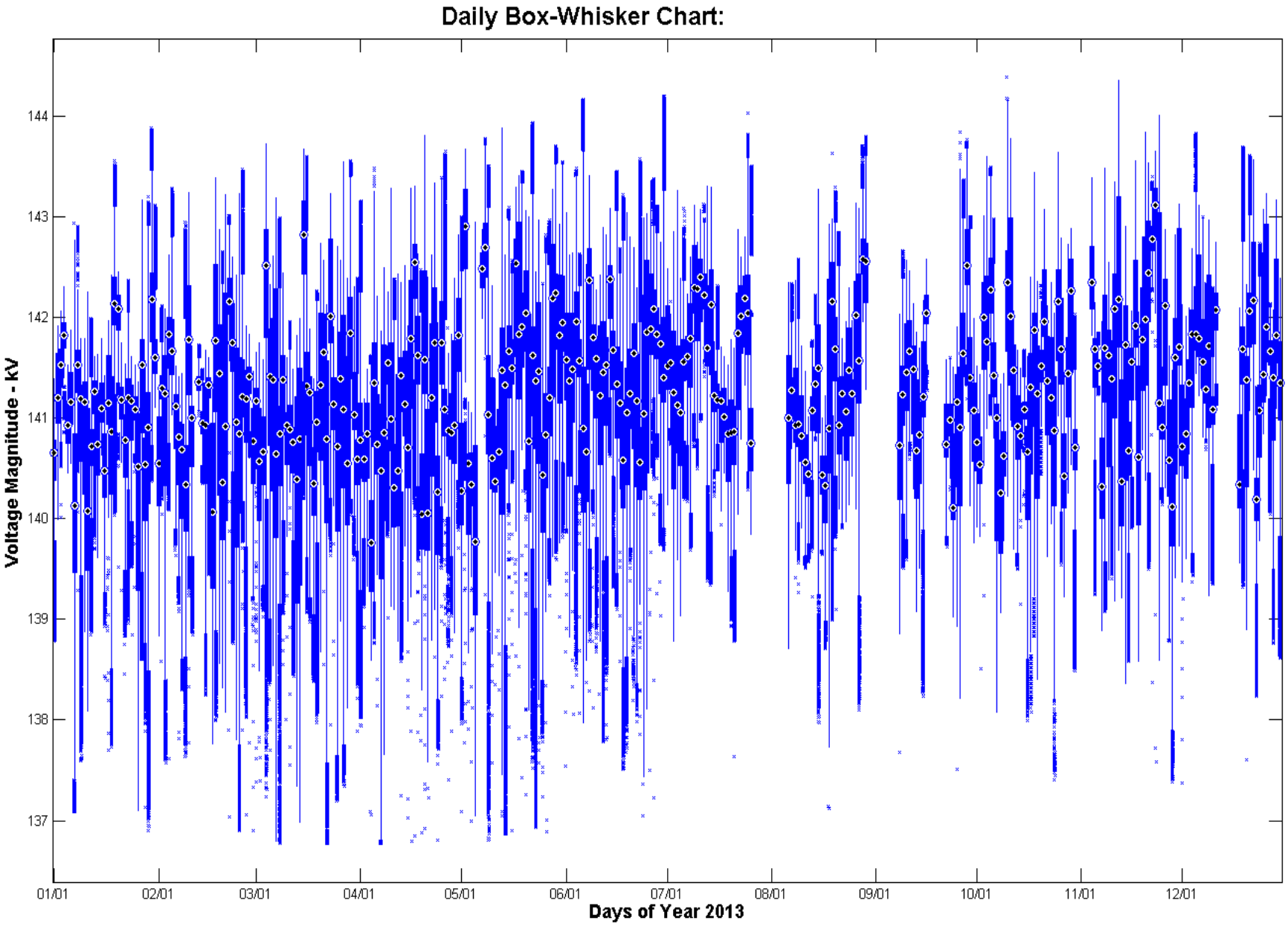
FarWest 8


Daily Box-Whisker Chart:
Voltage Magnitude - kV
145
144
143
142
141
140
139
138
137
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

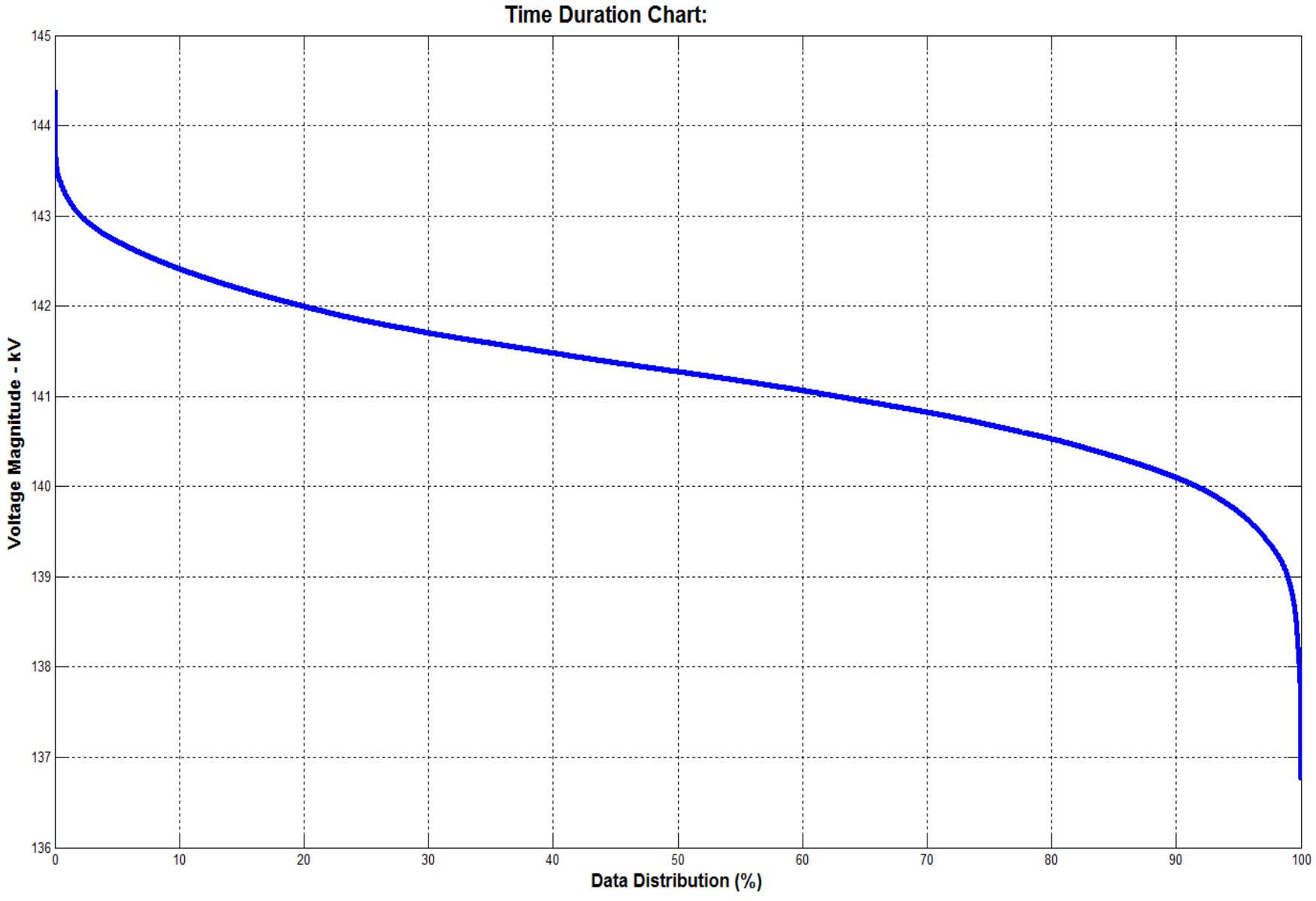
FarWest 8


Time Duration Chart:
Voltage Magnitude - kV
Data Distribution (%)
146
145
144
143
142
141
140
139
138
137
0
10
20
30
40
50
60
70
80
90
100

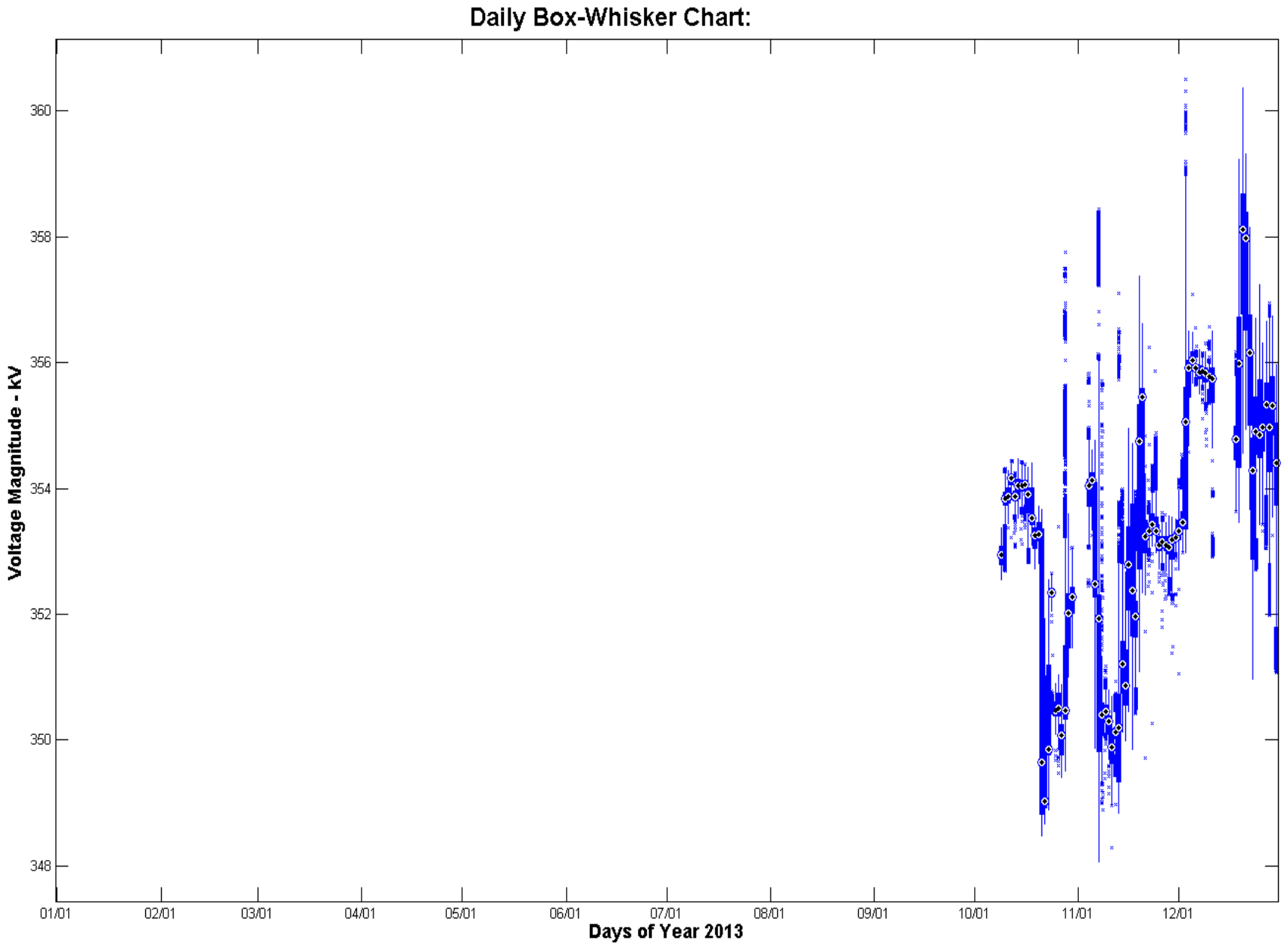
FarWest 9


Daily Box-Whisker Chart:
Voltage Magnitude - kV
144
143
142
141
140
139
138
137
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

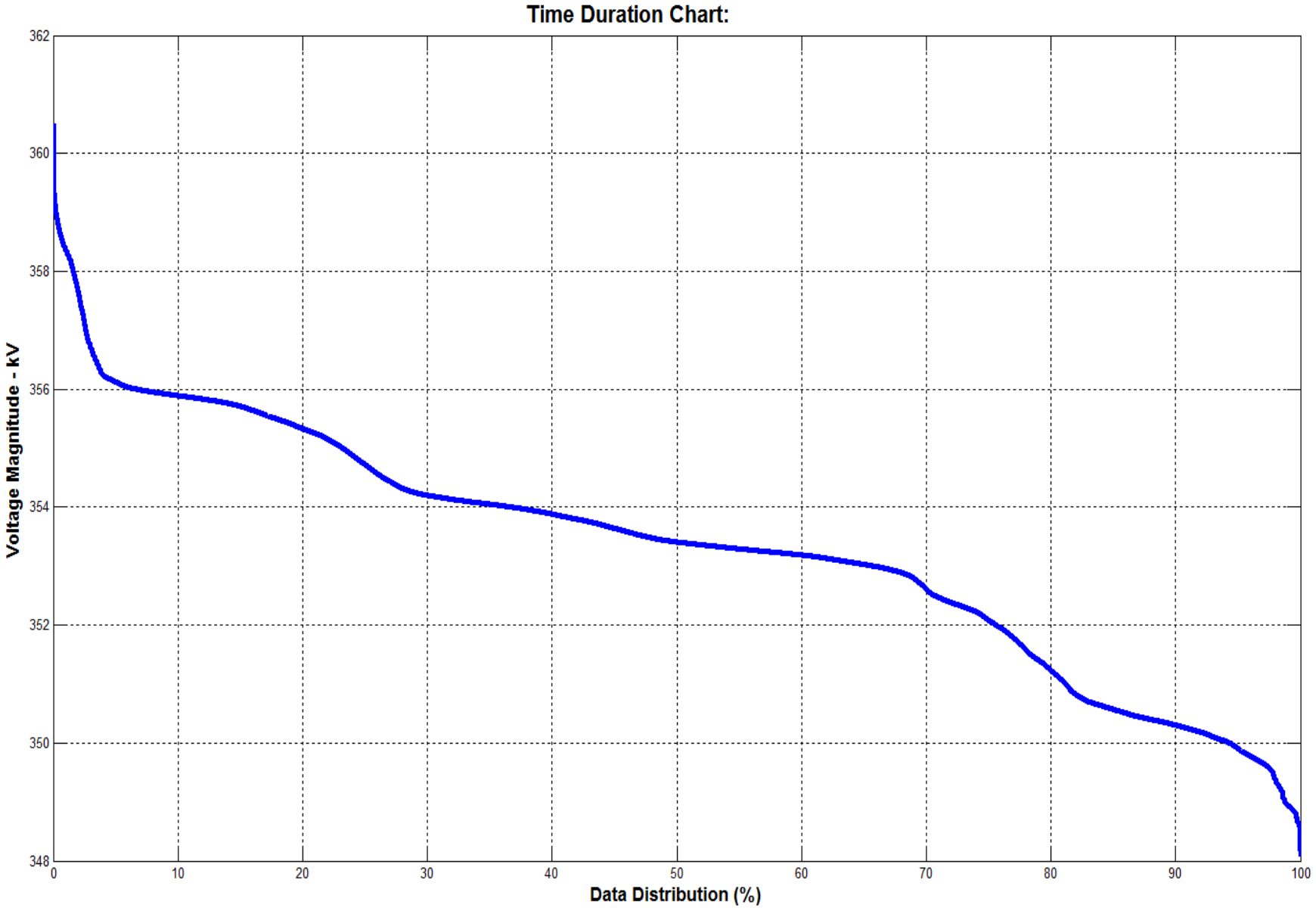
FarWest 9


Time Duration Chart:
Voltage Magnitude - kV
145
144
143
142
141
140
139
138
137
136
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

West 15


Daily Box-Whisker Chart:
Voltage Magnitude - kV
360
358
356
354
352
350
348
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

West 15


Time Duration Chart:
Voltage Magnitude - kV
362
360
358
356
354
352
350
348
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

Appendix B – Part 1
CCET Discovery Across Texas project

Baseline Analysis Update - Voltage Angles (Reference: North 7)

State Estimator Data: January to December 2013

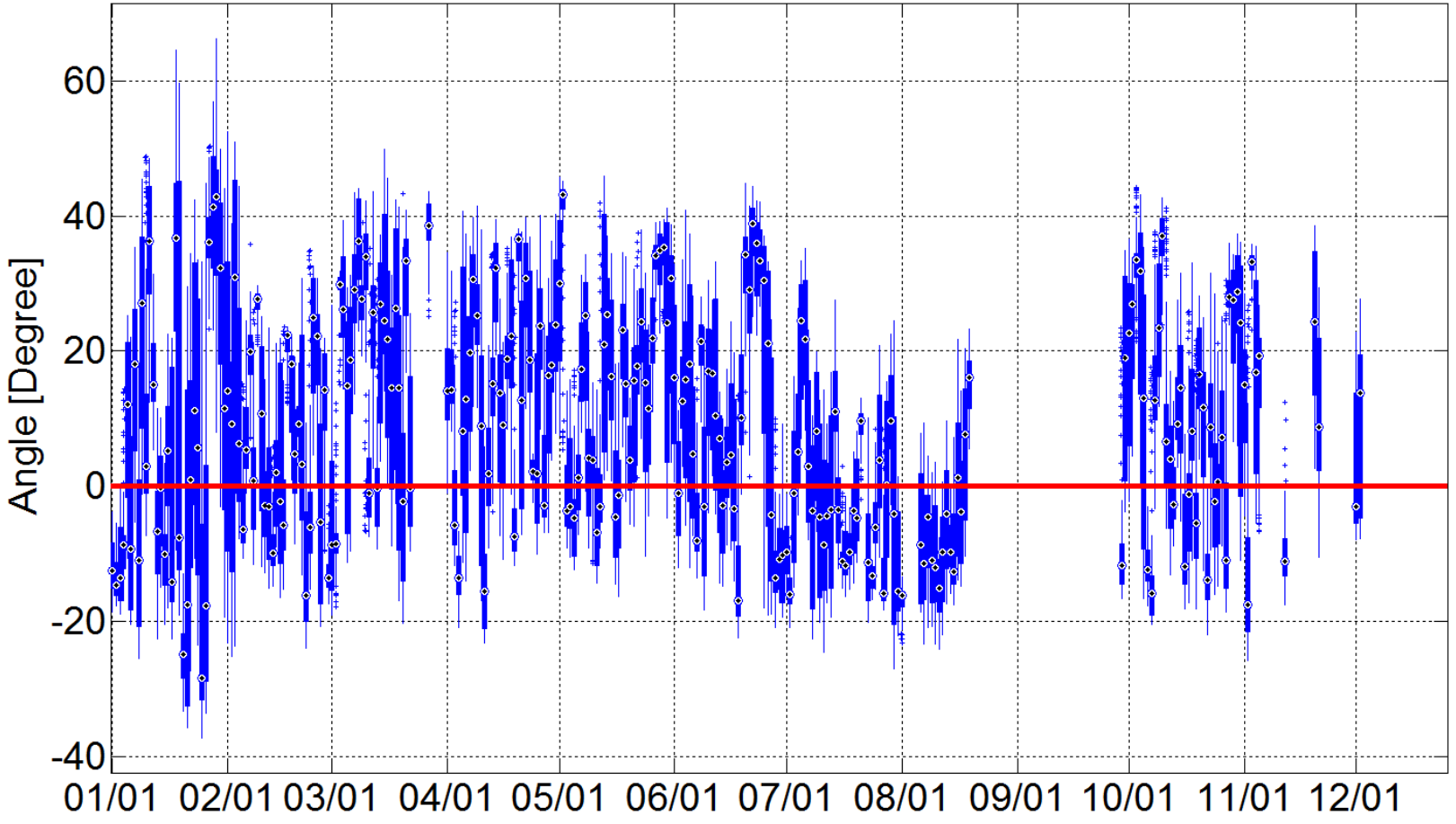
Box-Whisker Plots and Time Duration Curves

Electric Power Group

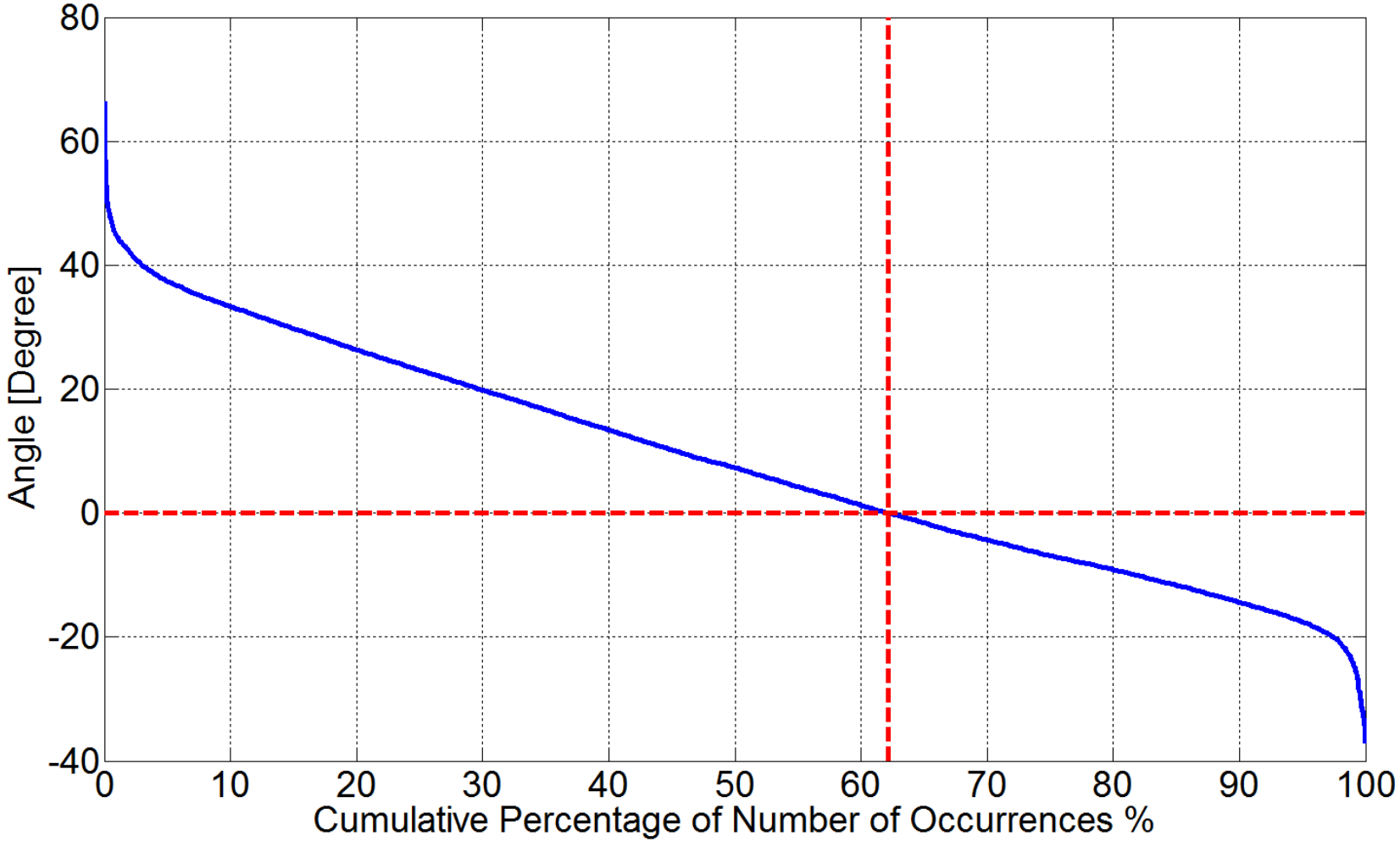
CCET

ERCOT

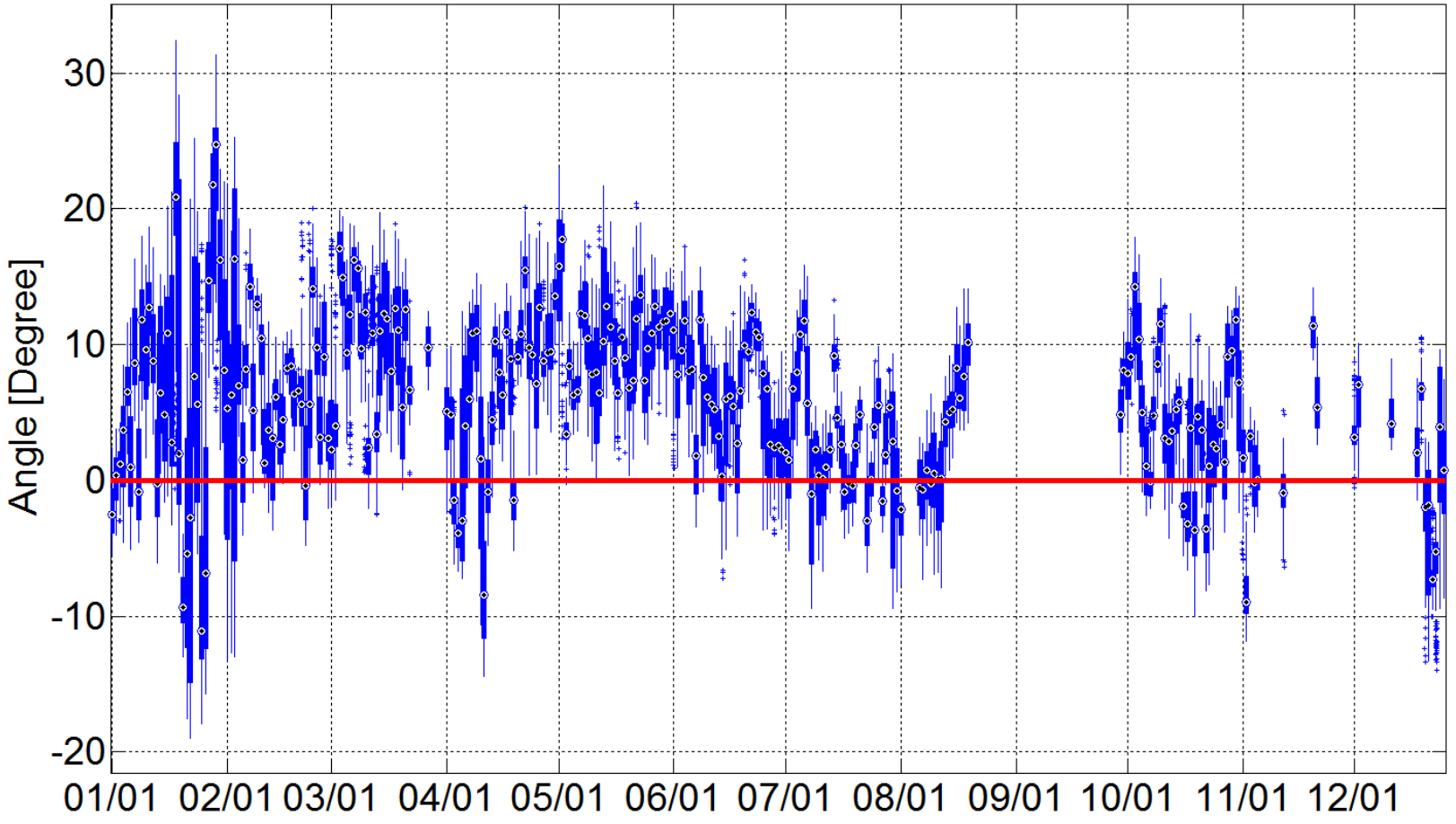
West 10-North 7



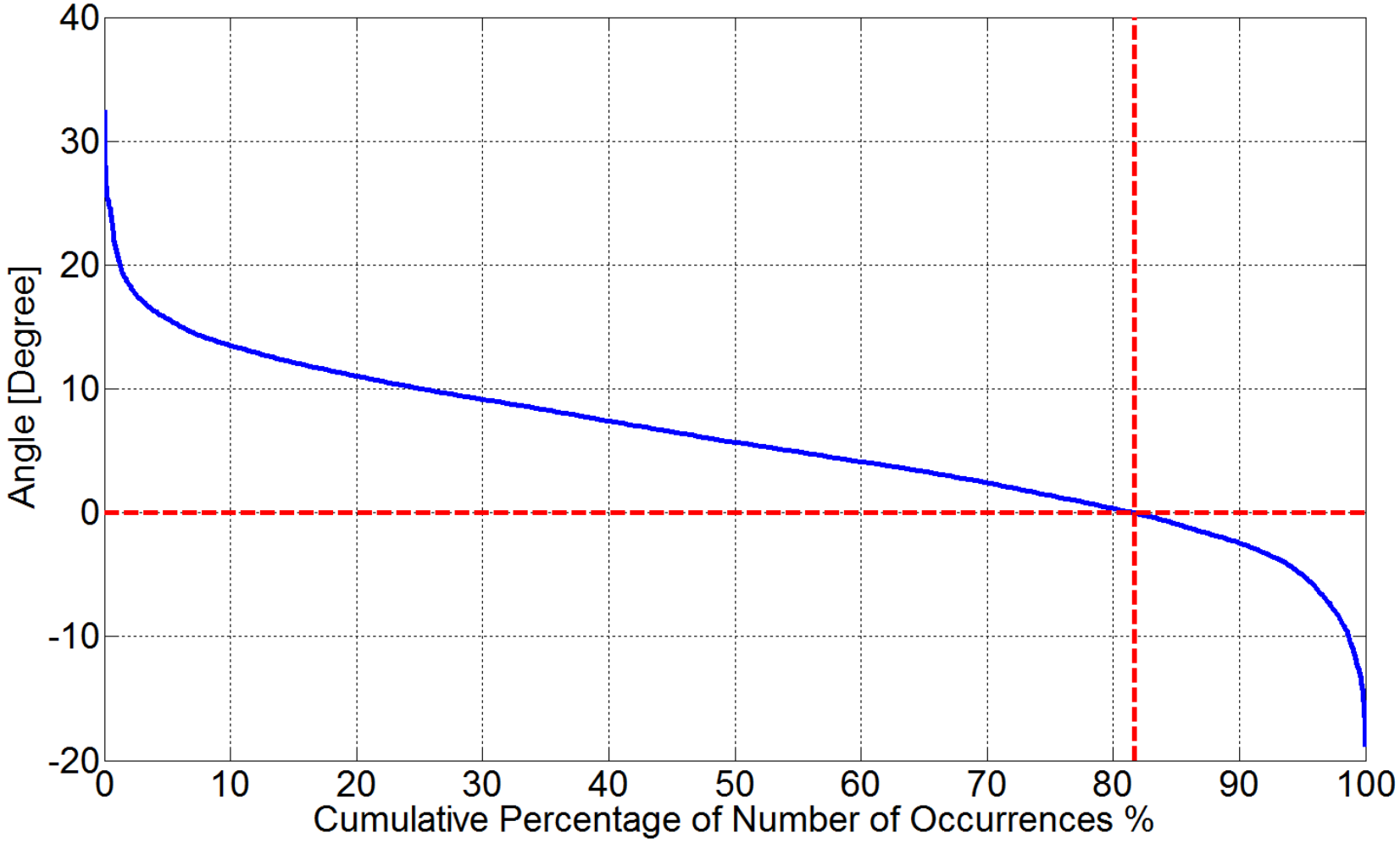
West 10-North 7



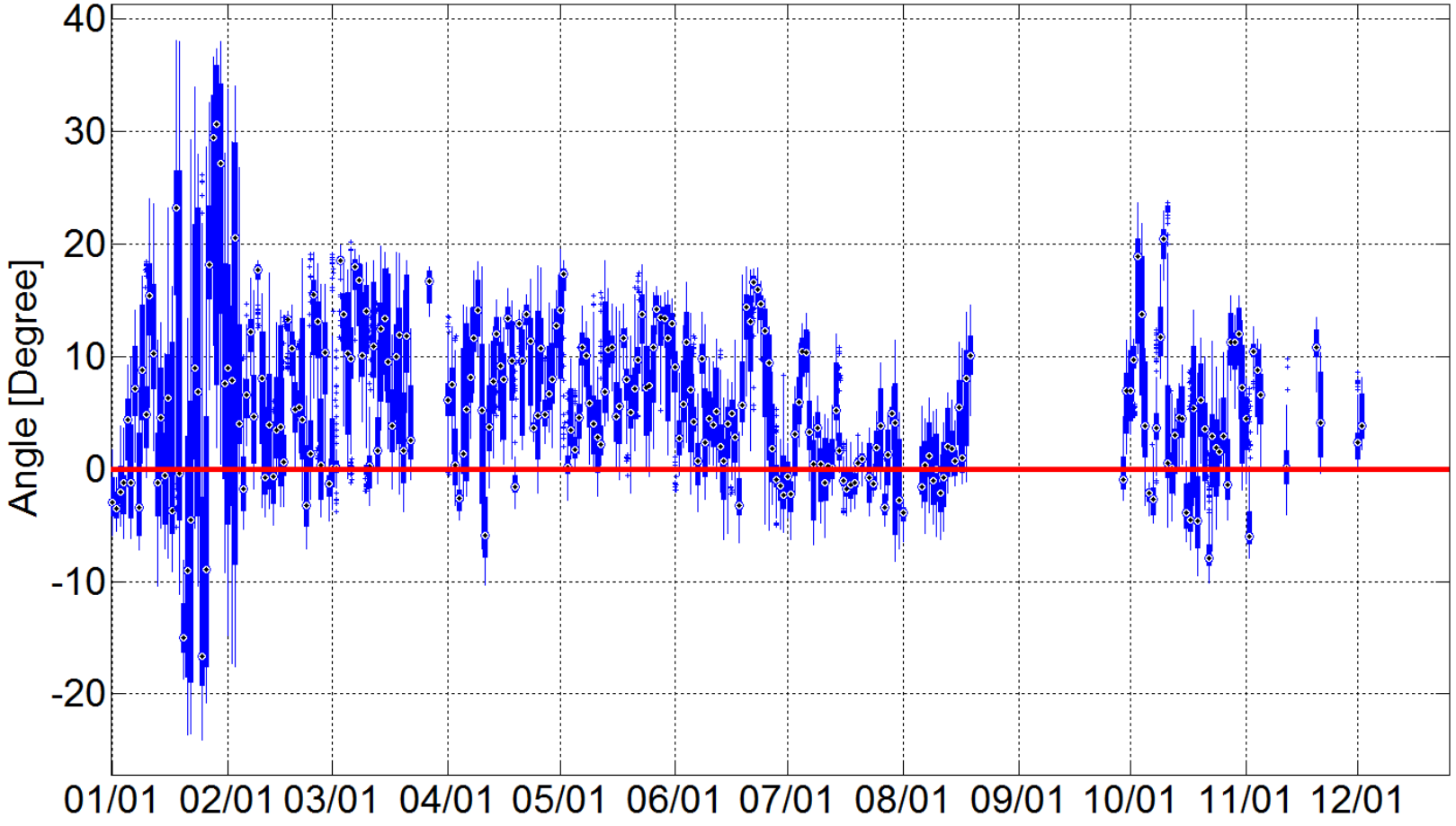
West 14-North 7



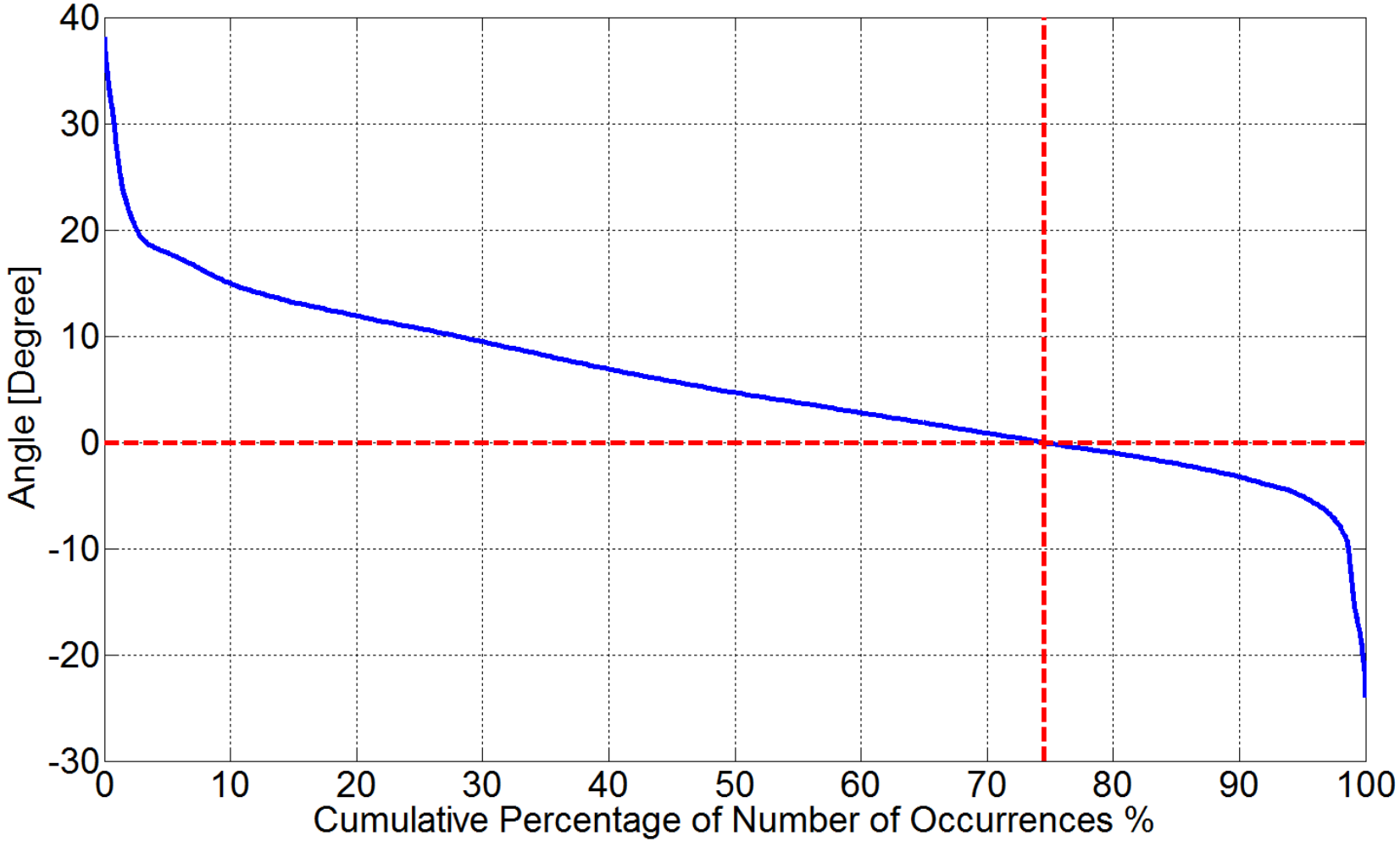
West 14-North 7



West 1-North 7



West 1-North 7



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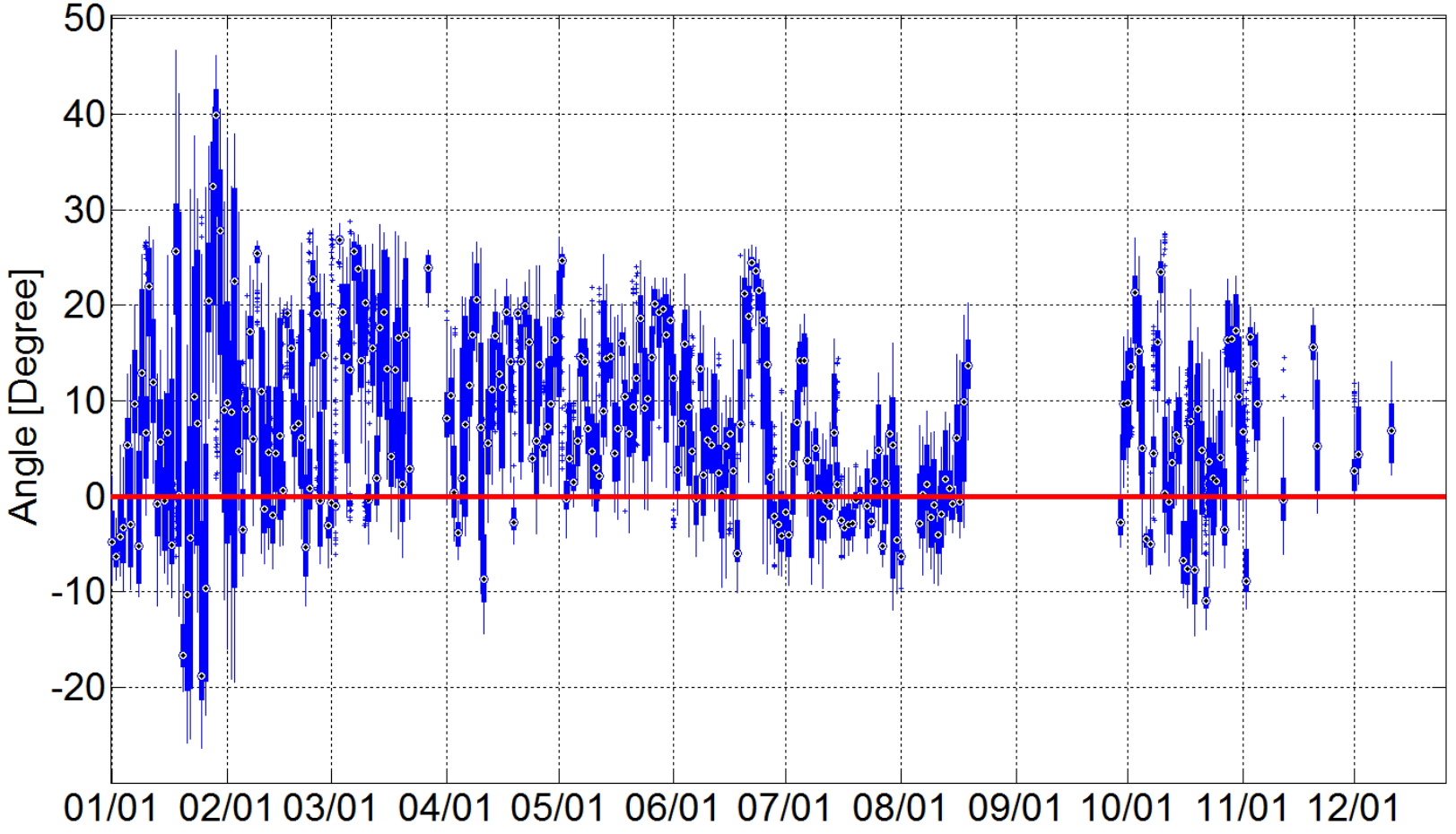
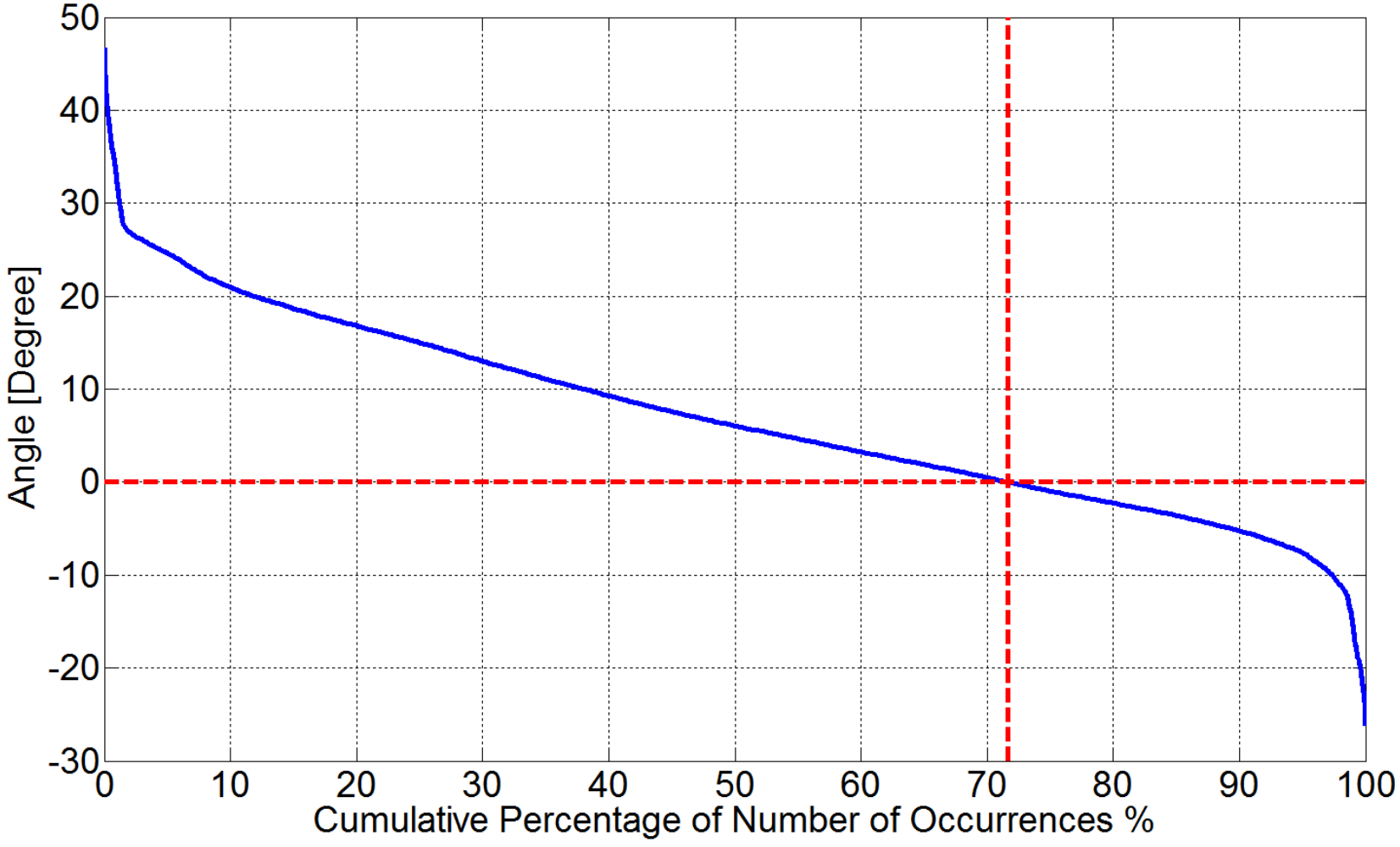
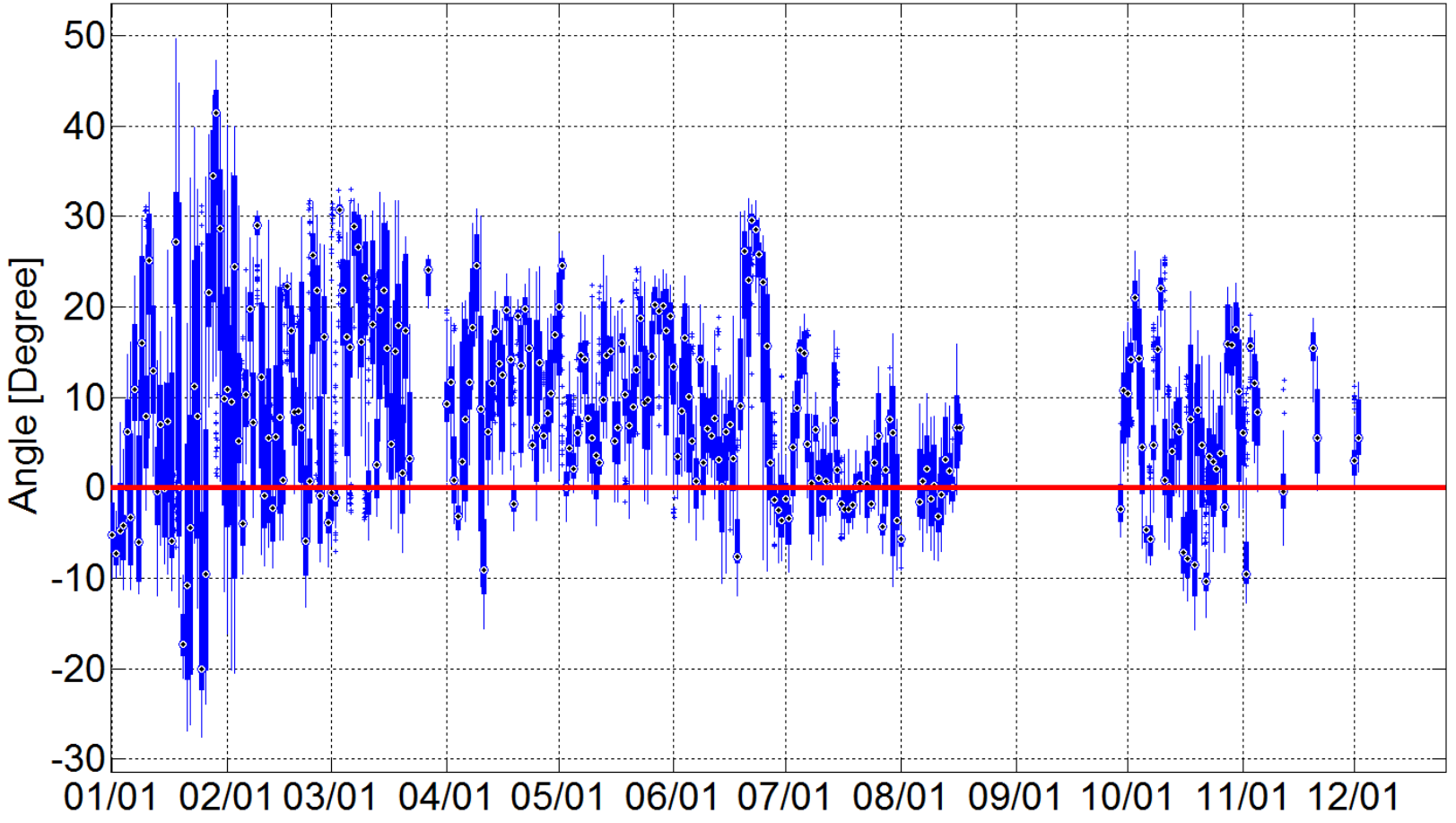


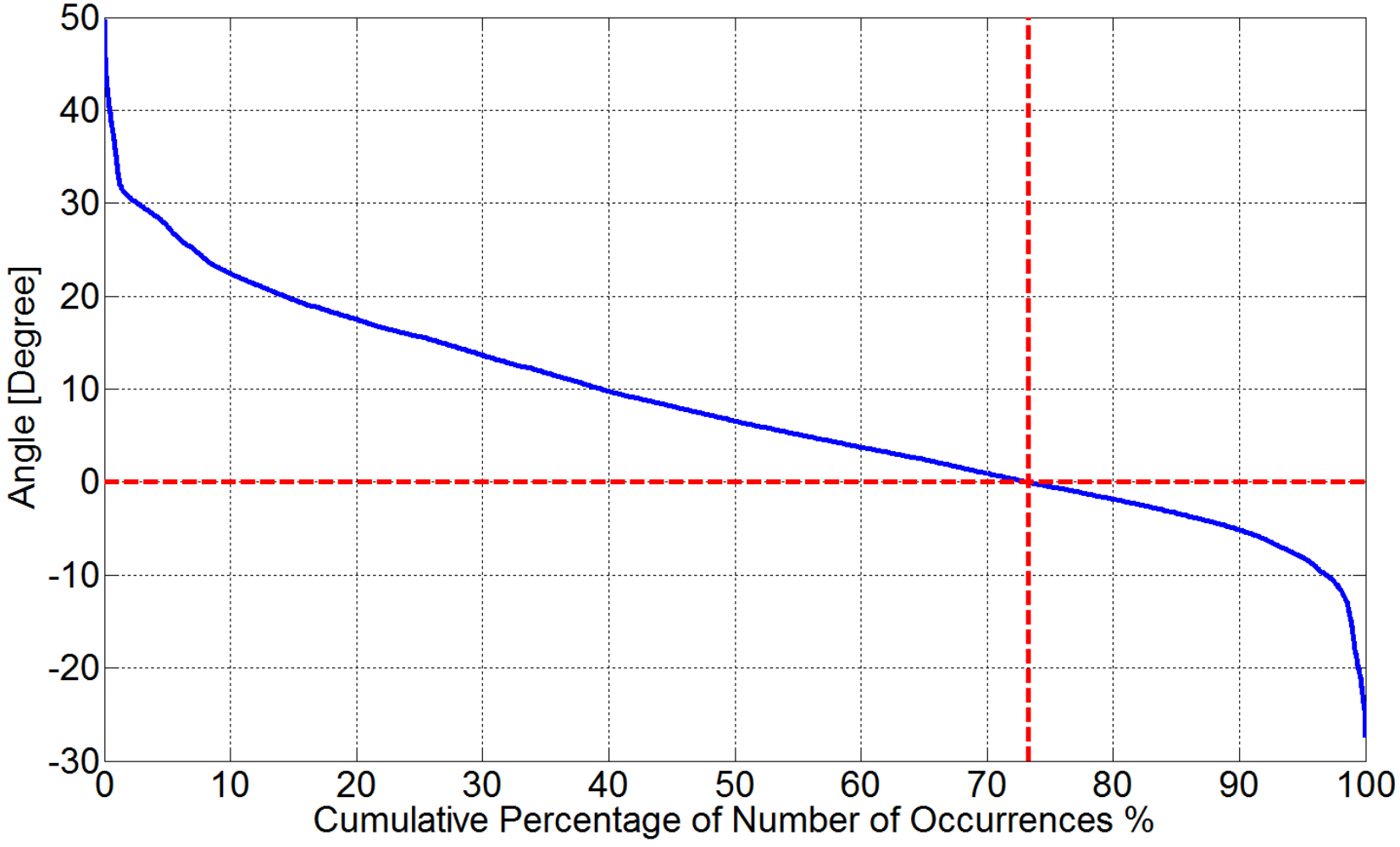
West 2-North 7



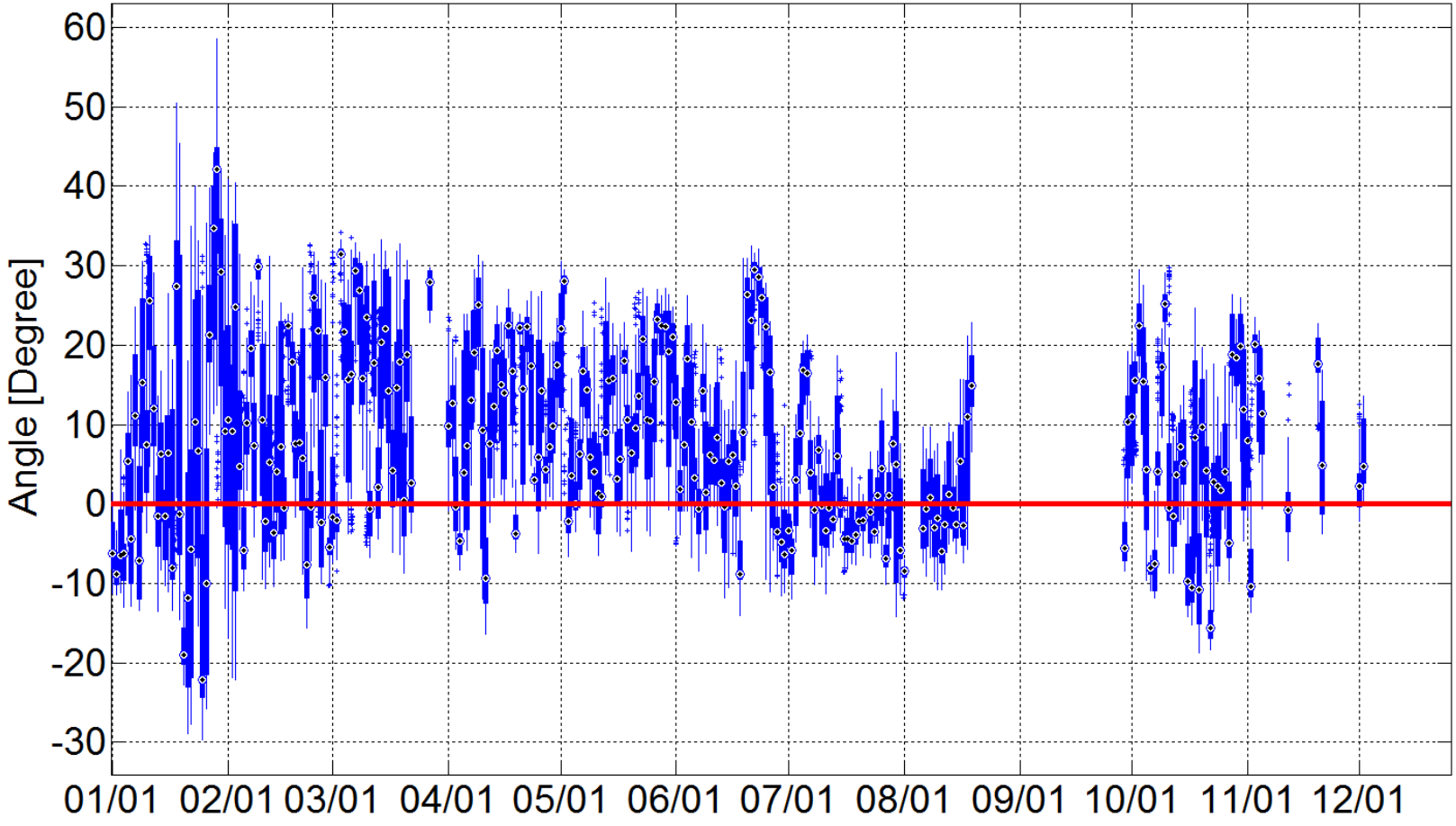
West 9-North 7



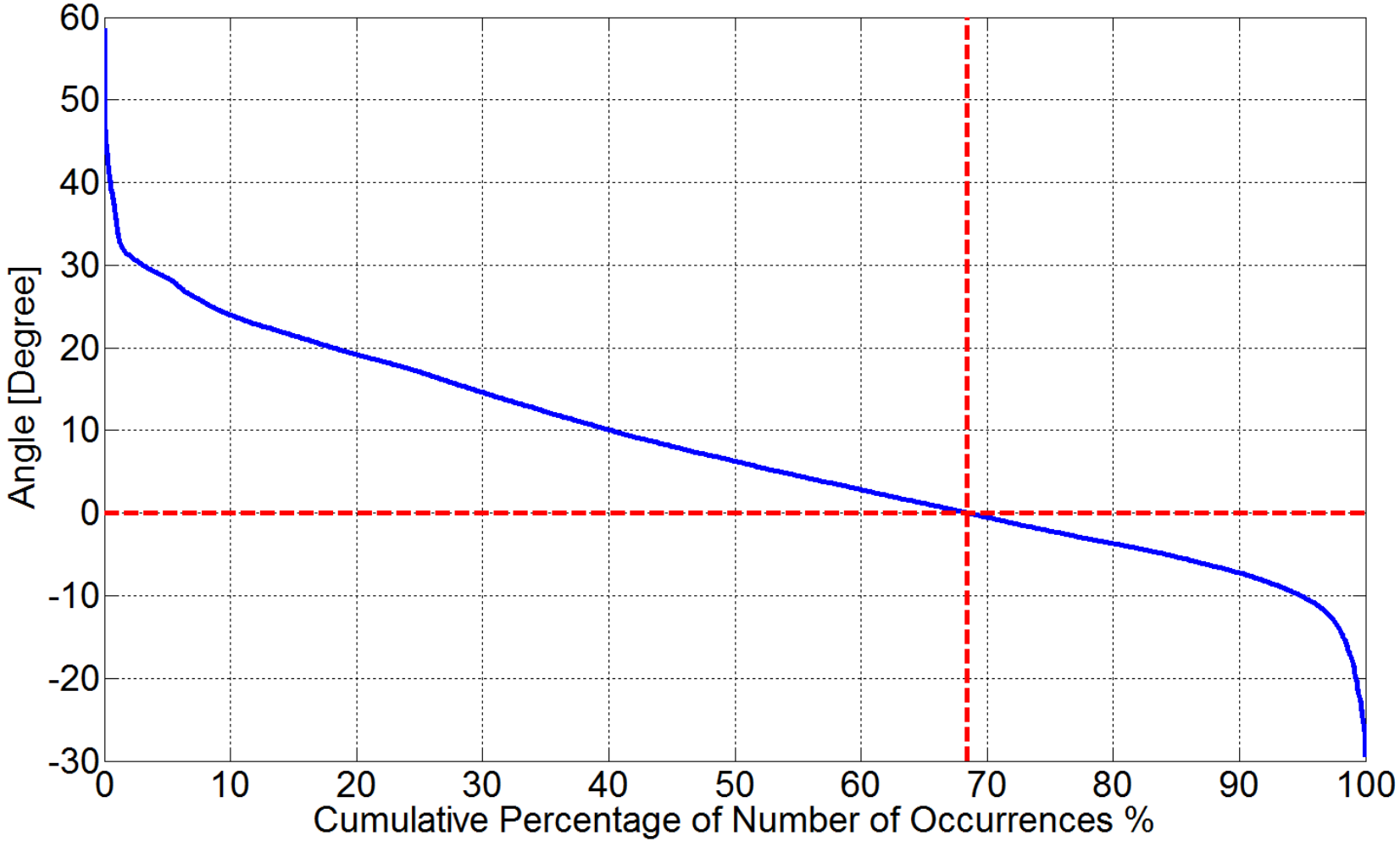
West 9-North 7



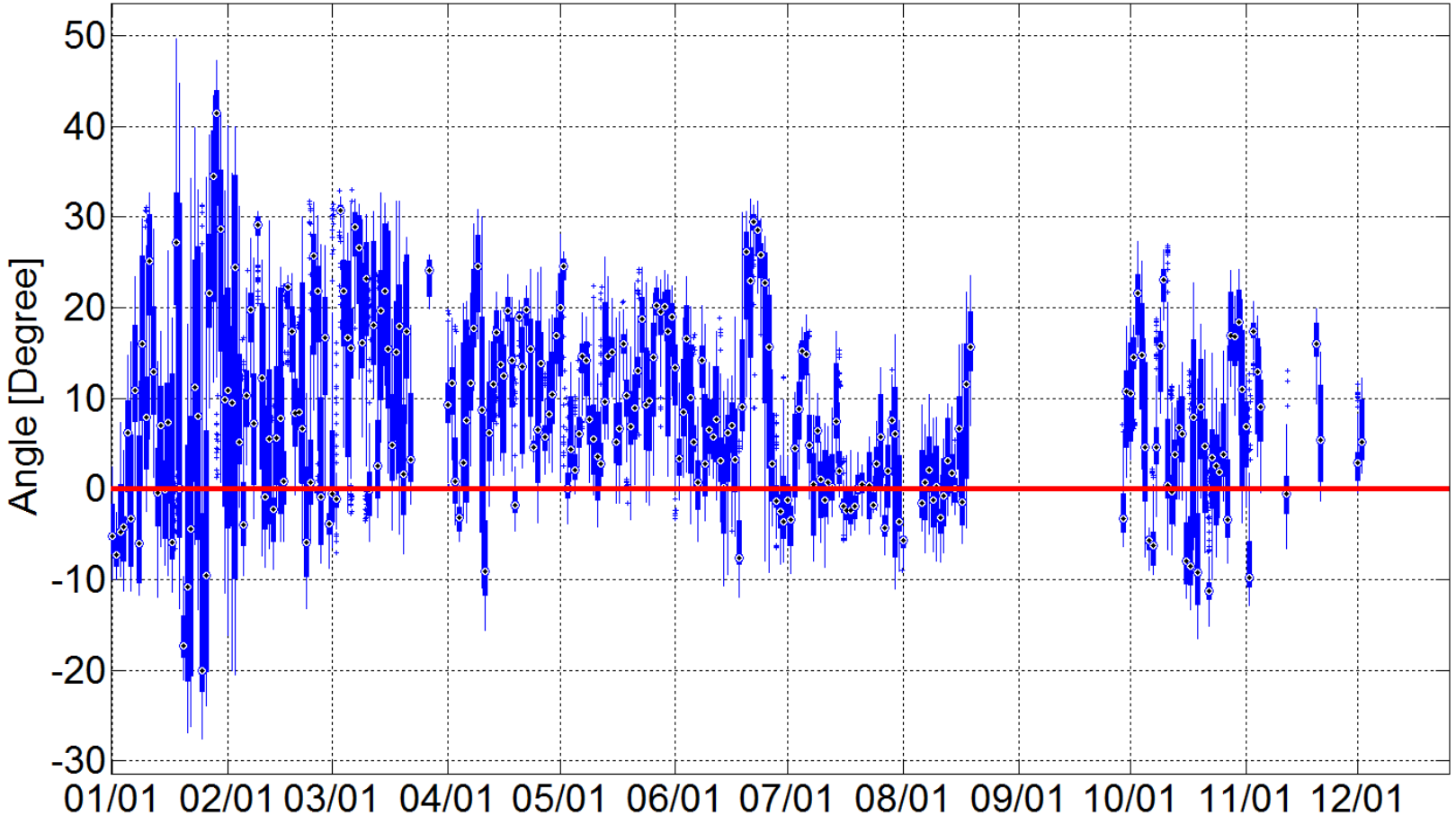
West 11-North 7



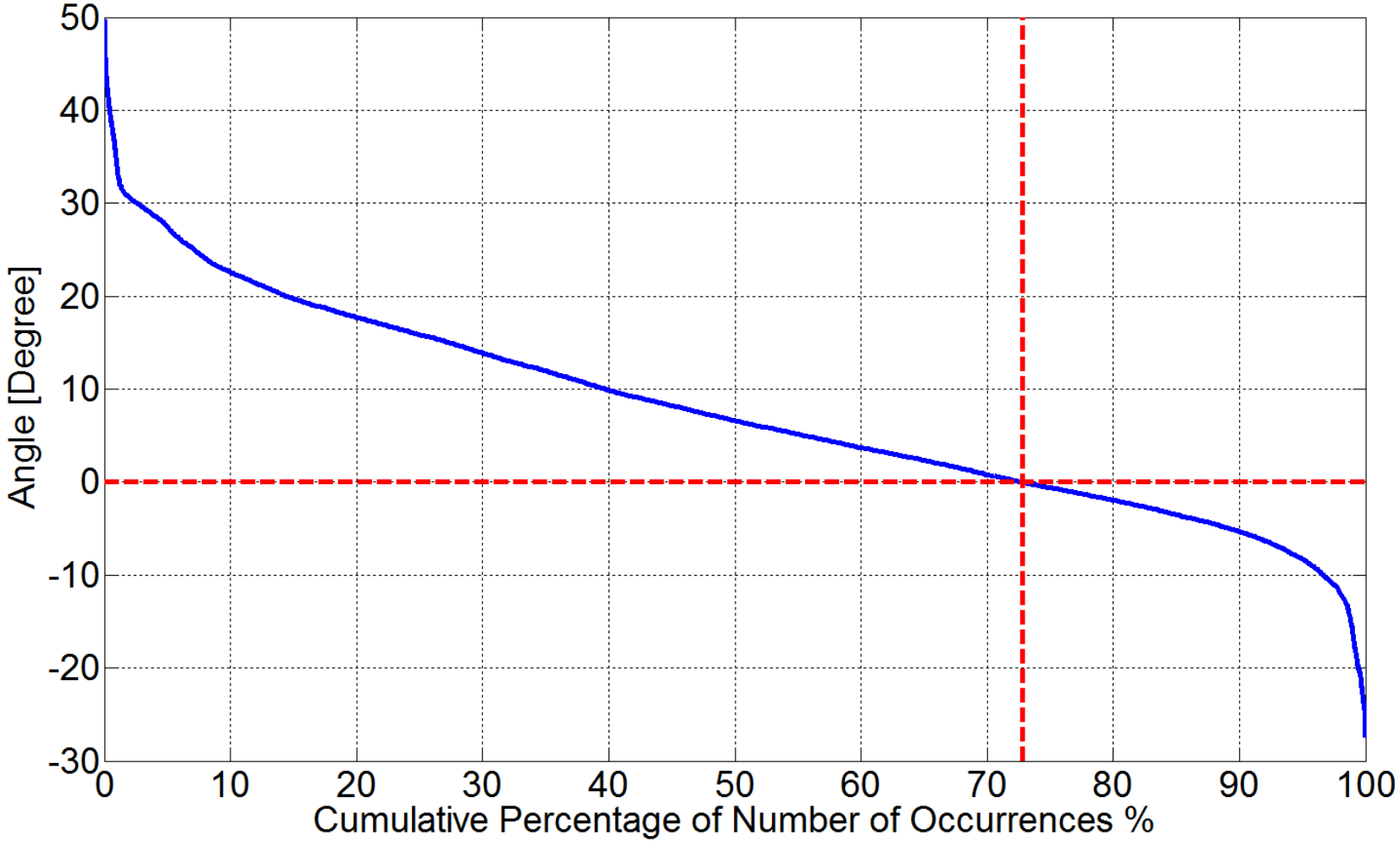
West 11-North 7



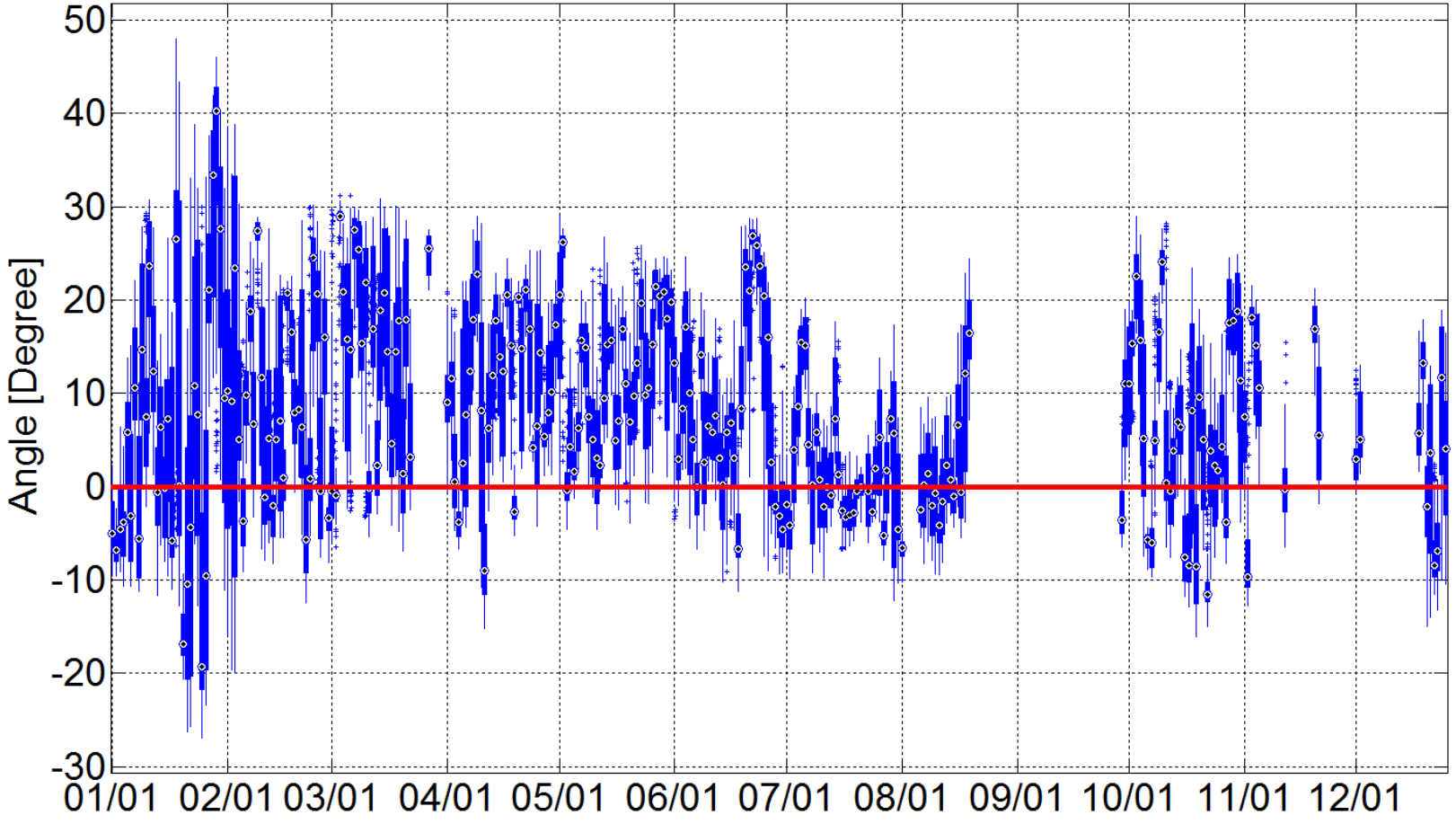
West 12-North 7



West 12-North 7



West 5-North 7



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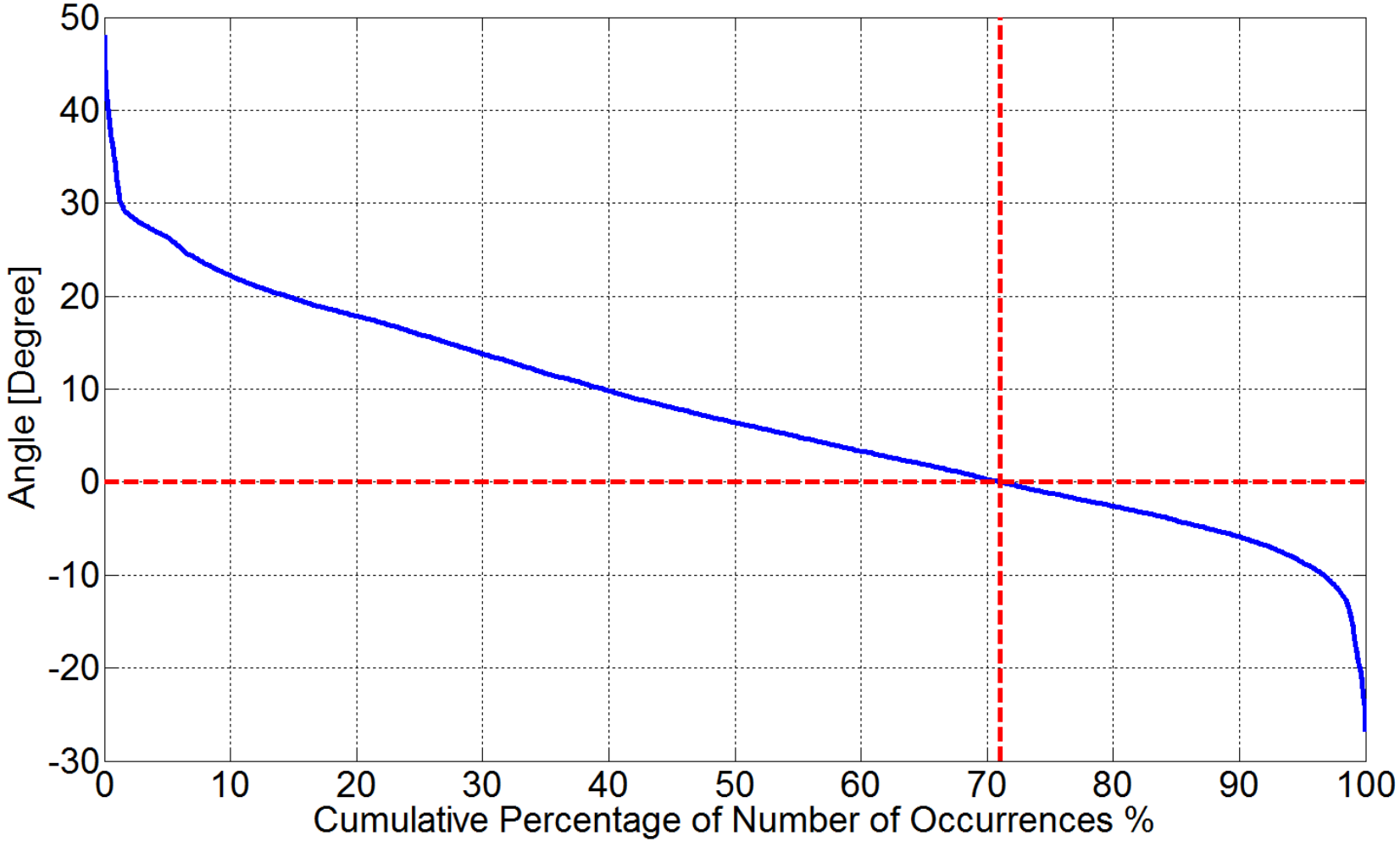
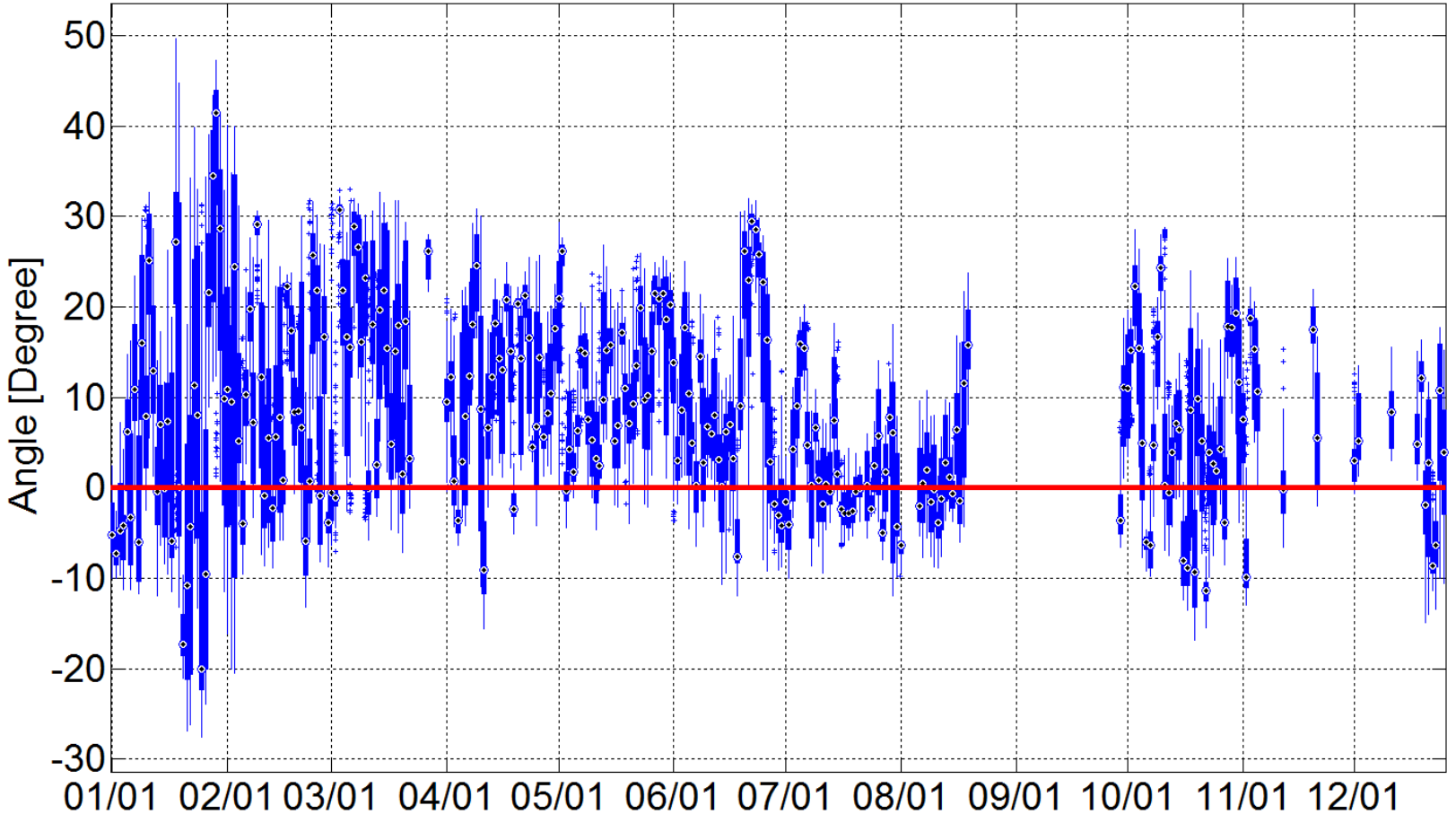
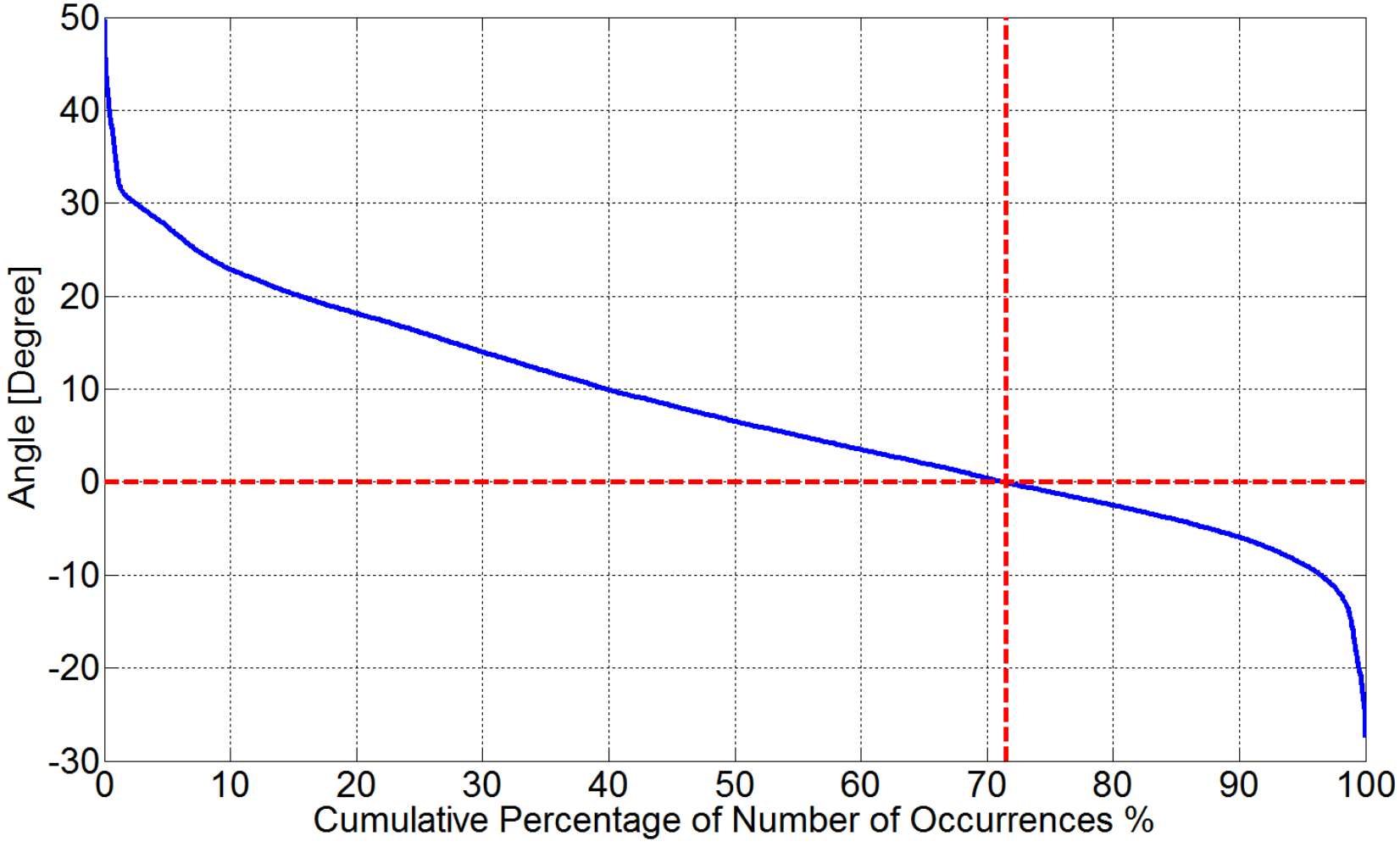


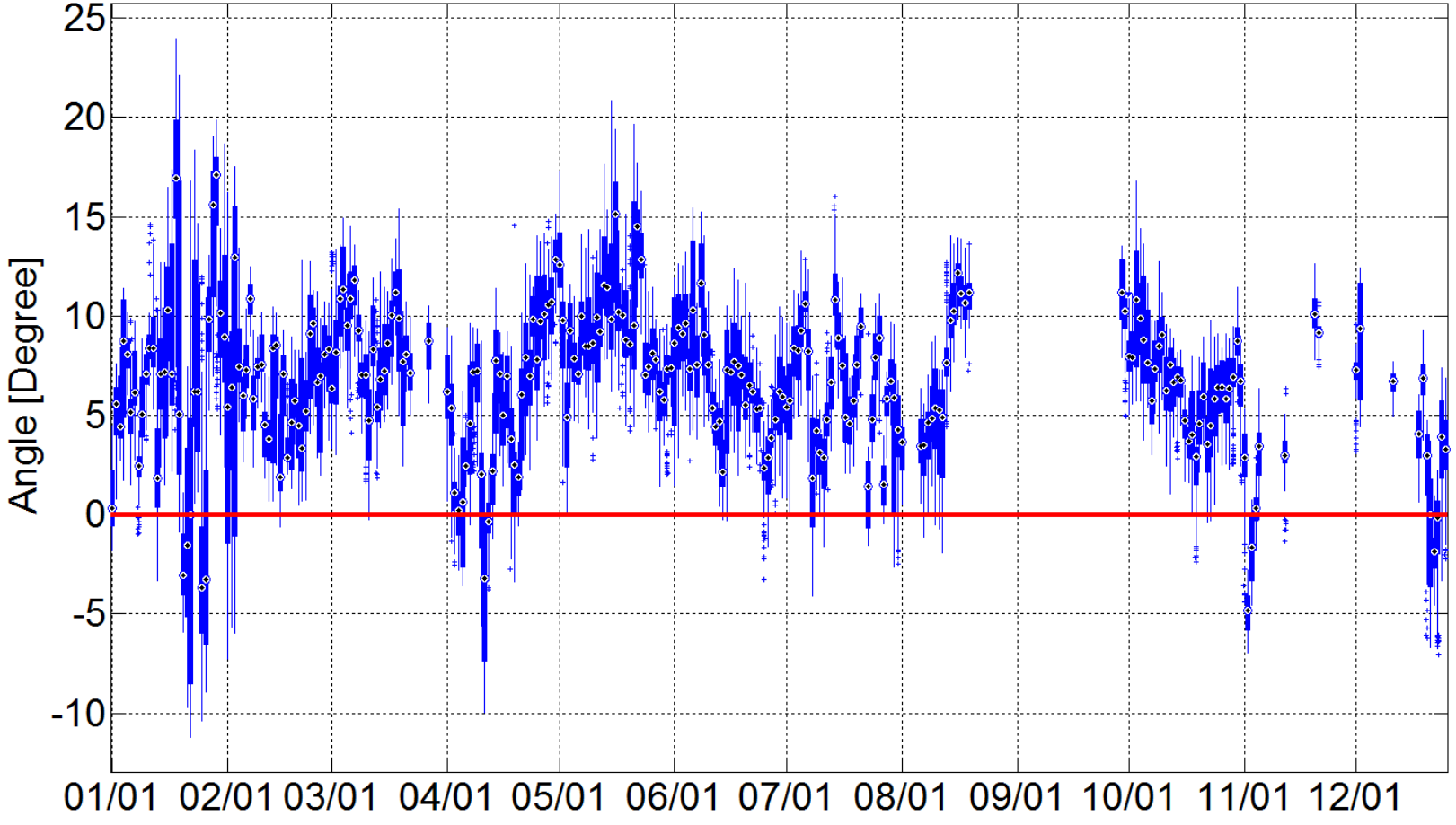
West 6-North 7



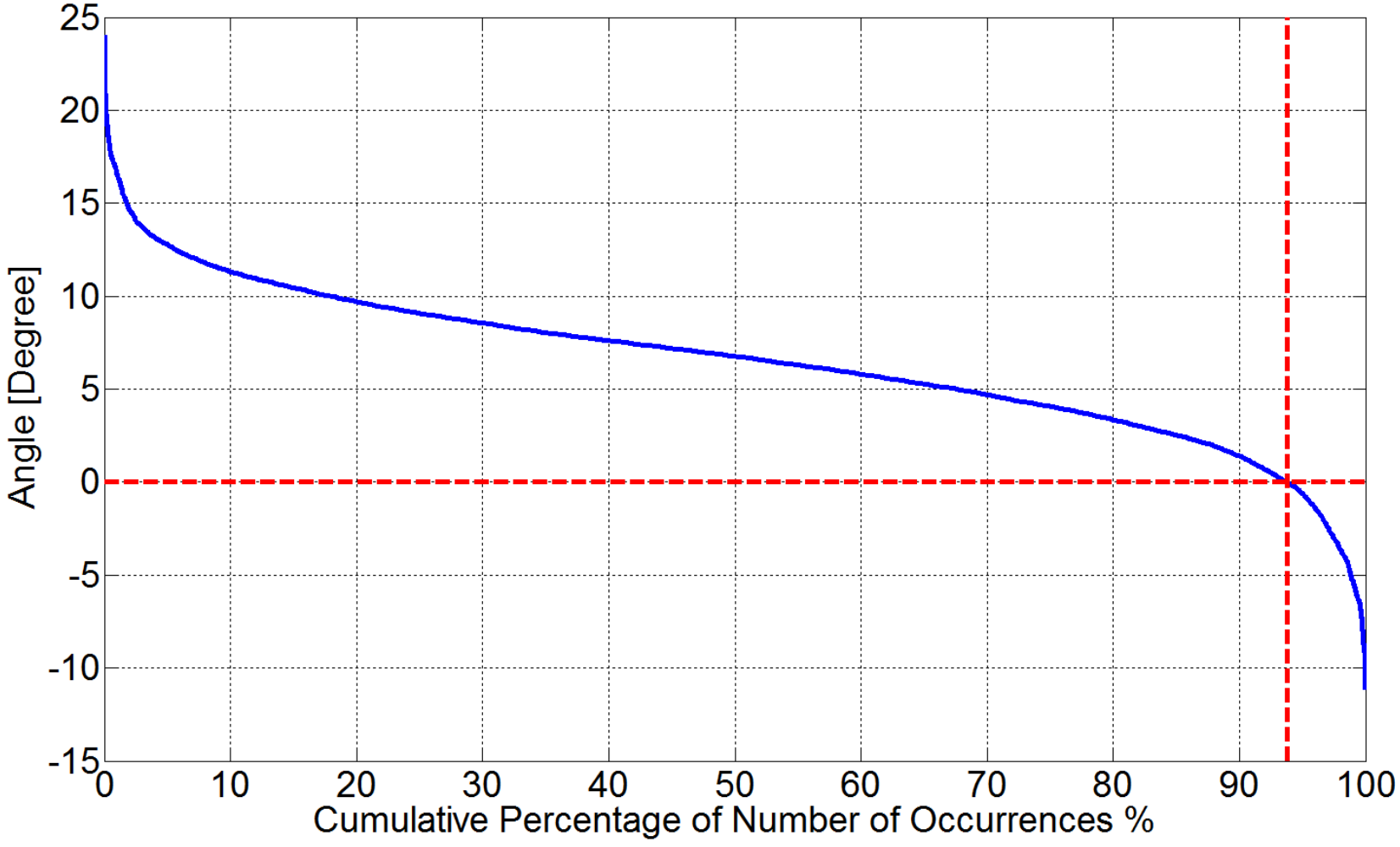
West 6-North 7



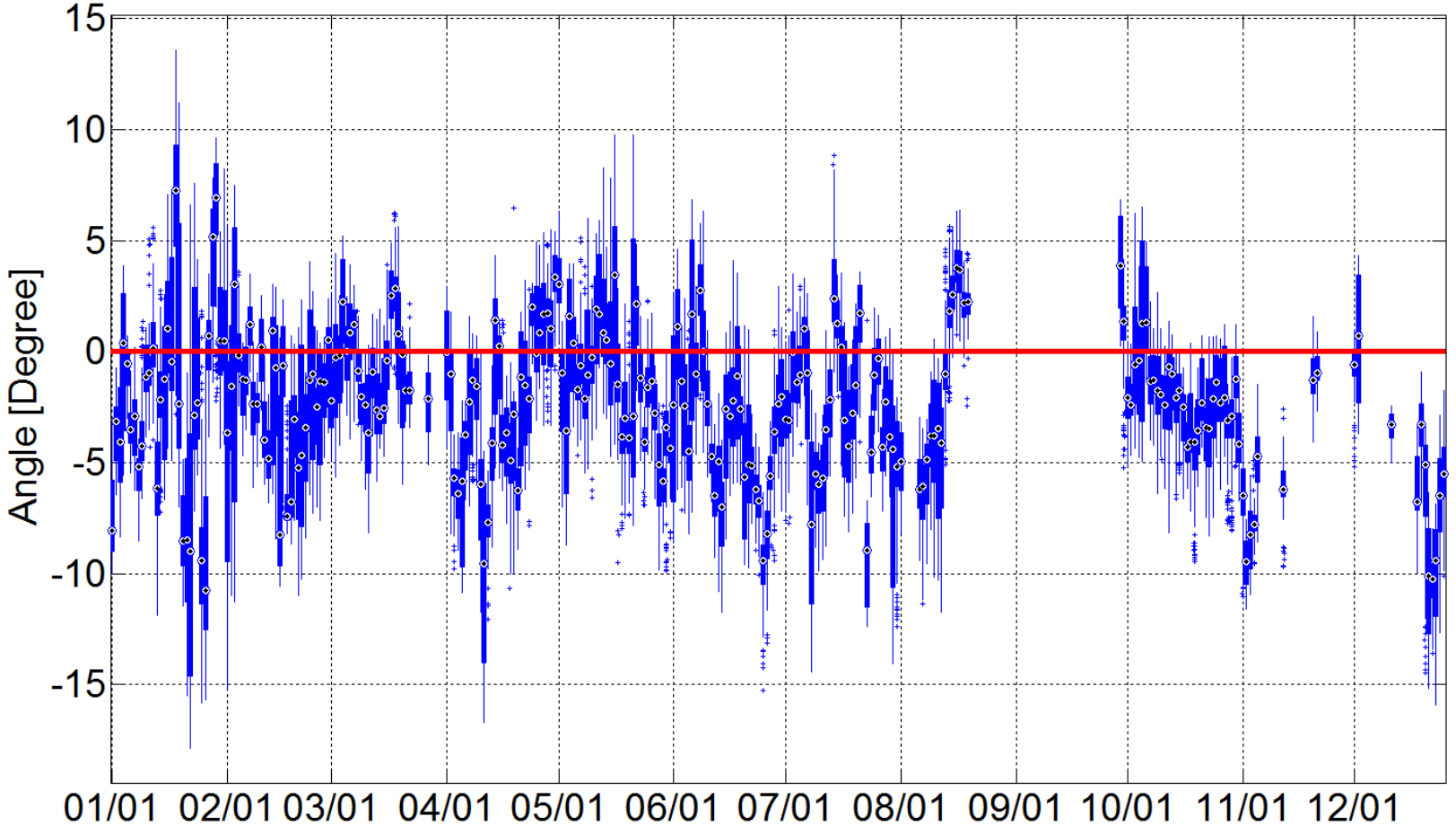
North 1-North 7



North 1-North 7



North 4-North 7



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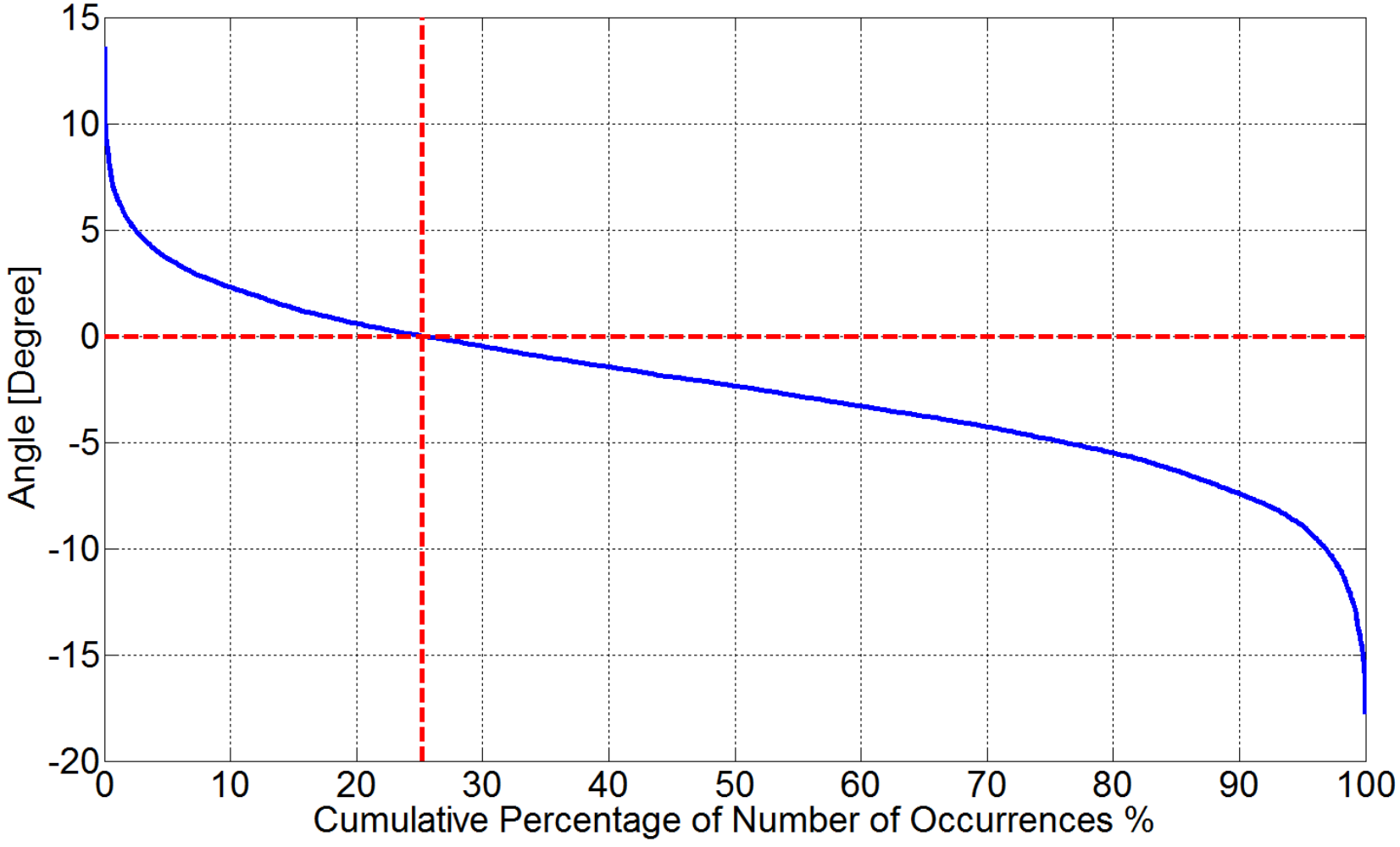
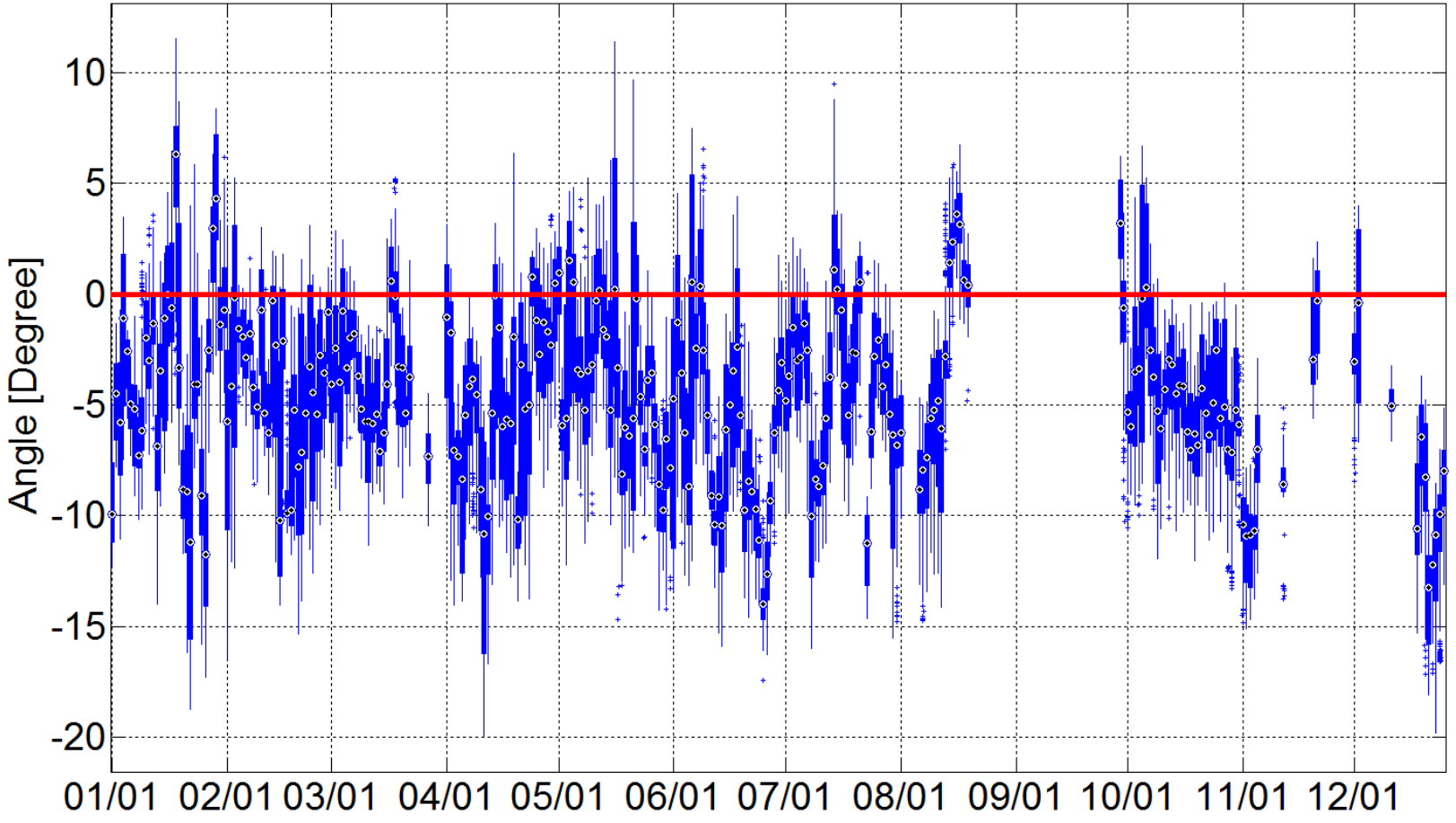


North 5-North 7



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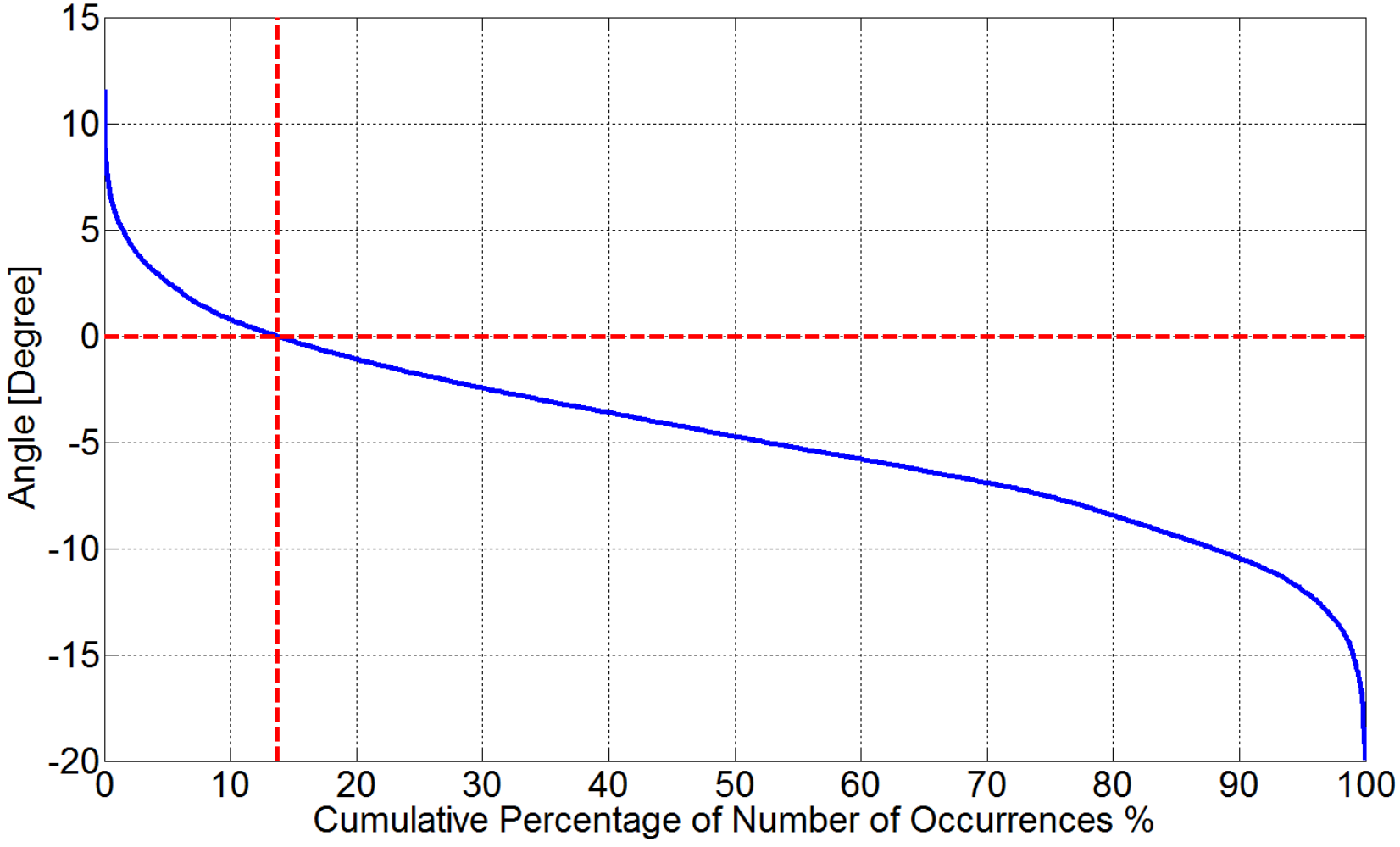
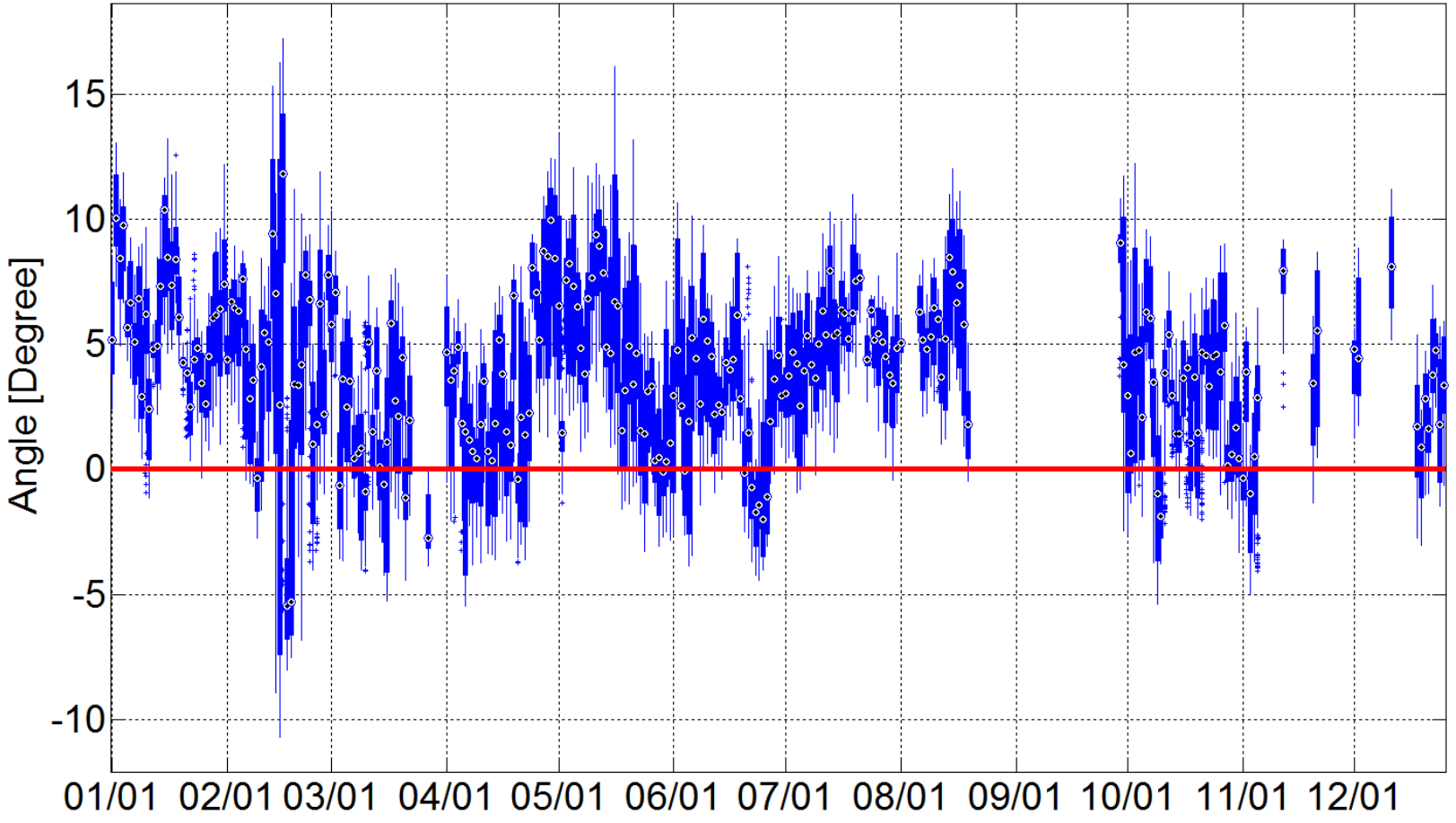


North 6-North 7



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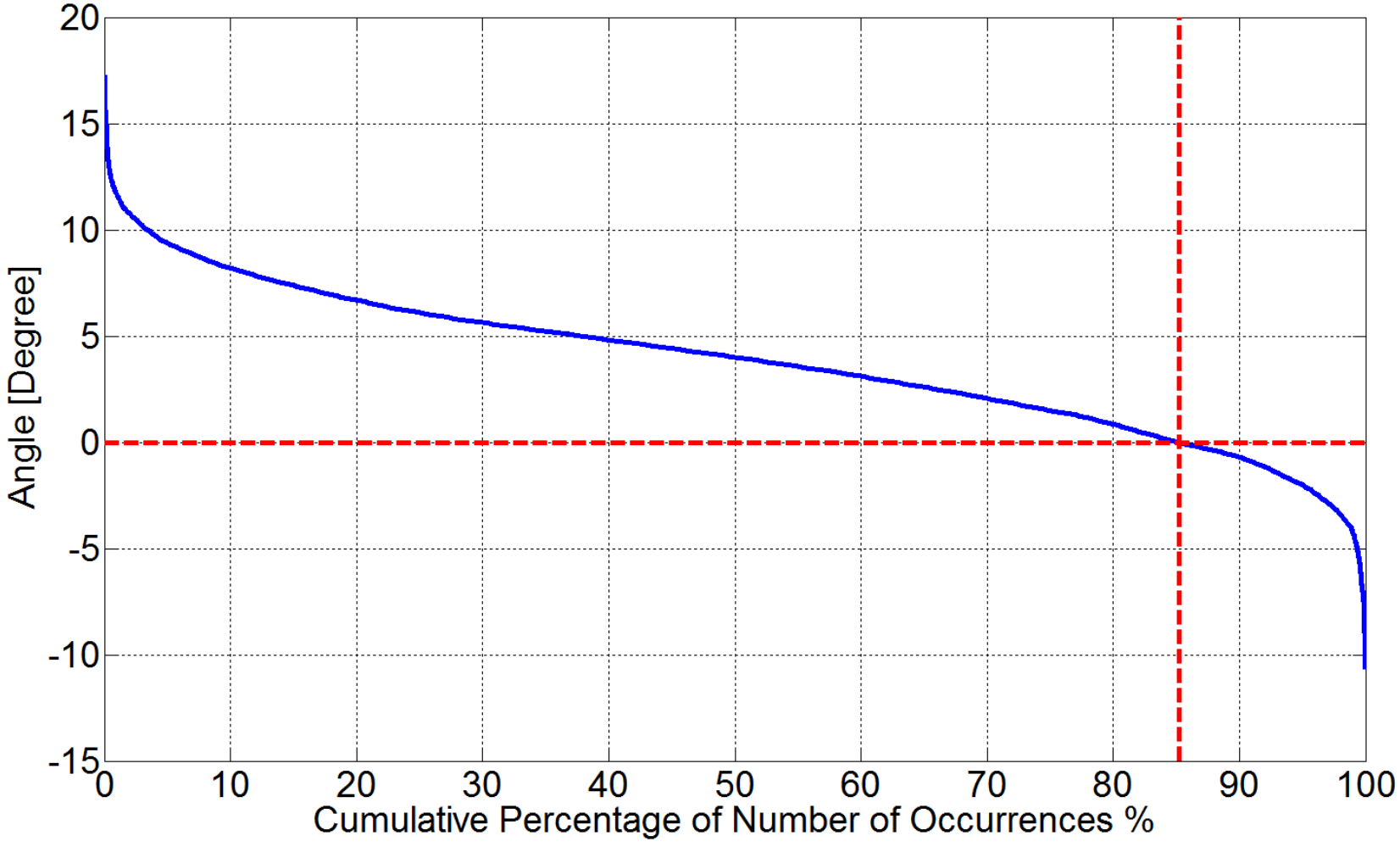

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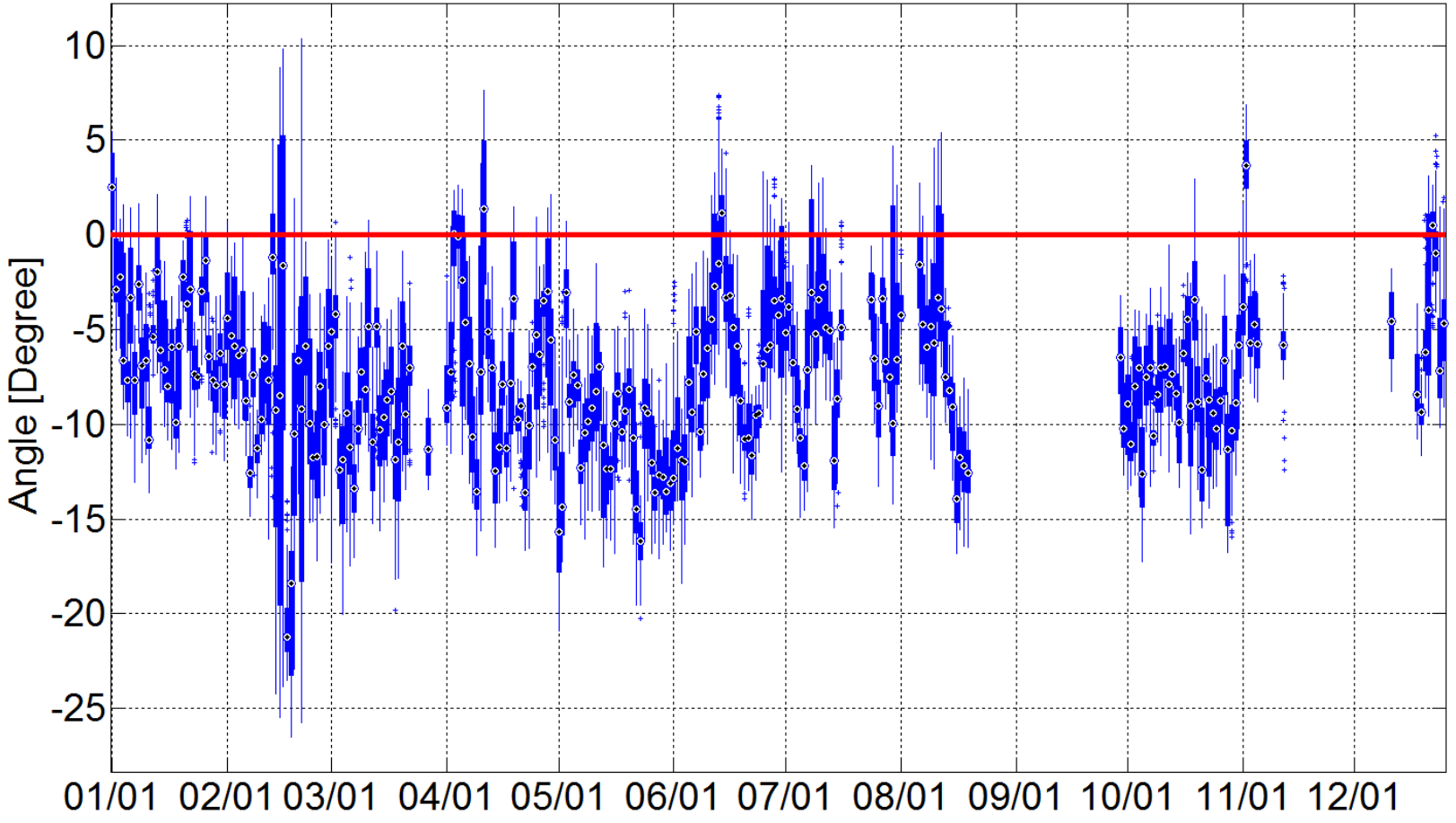

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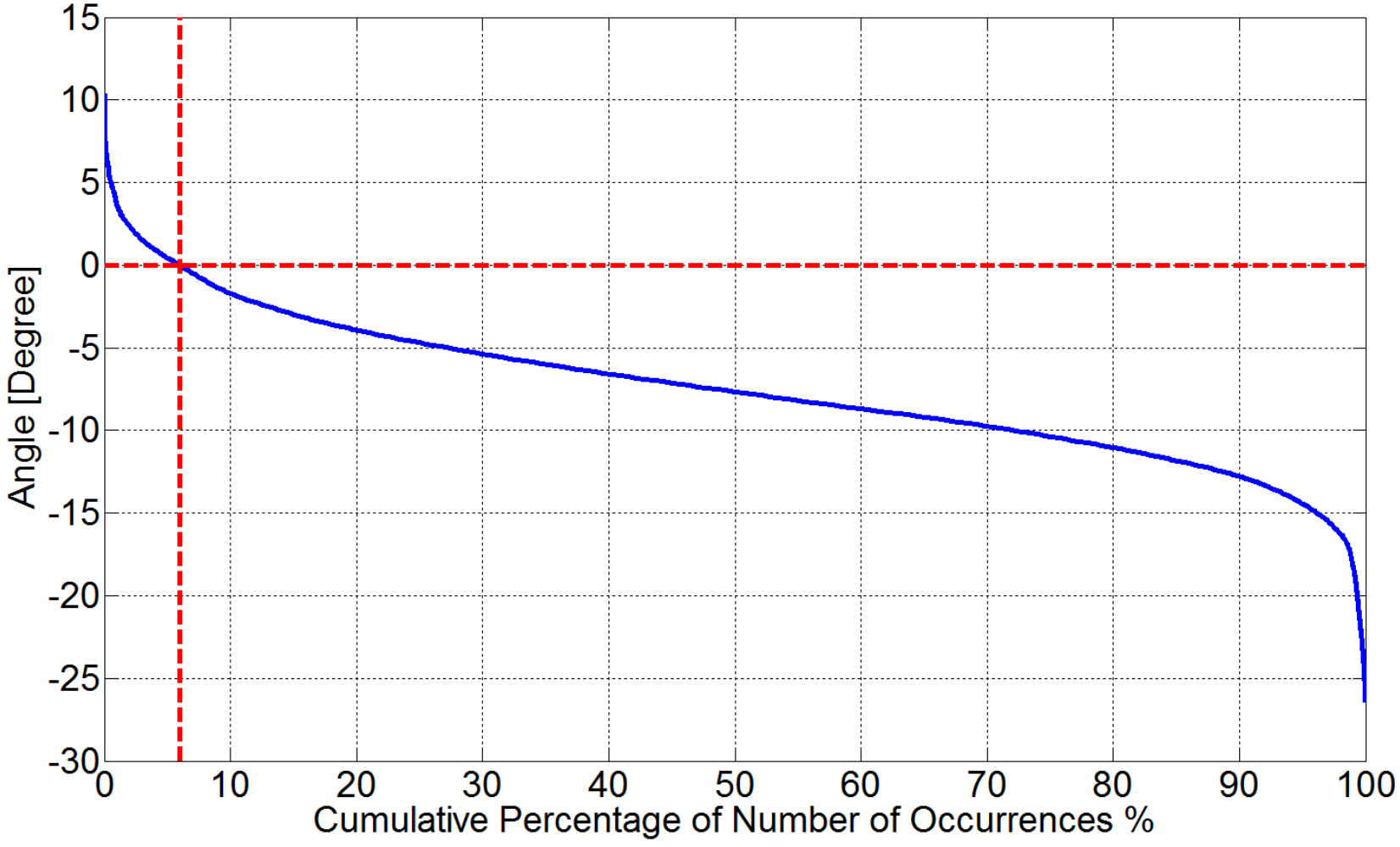

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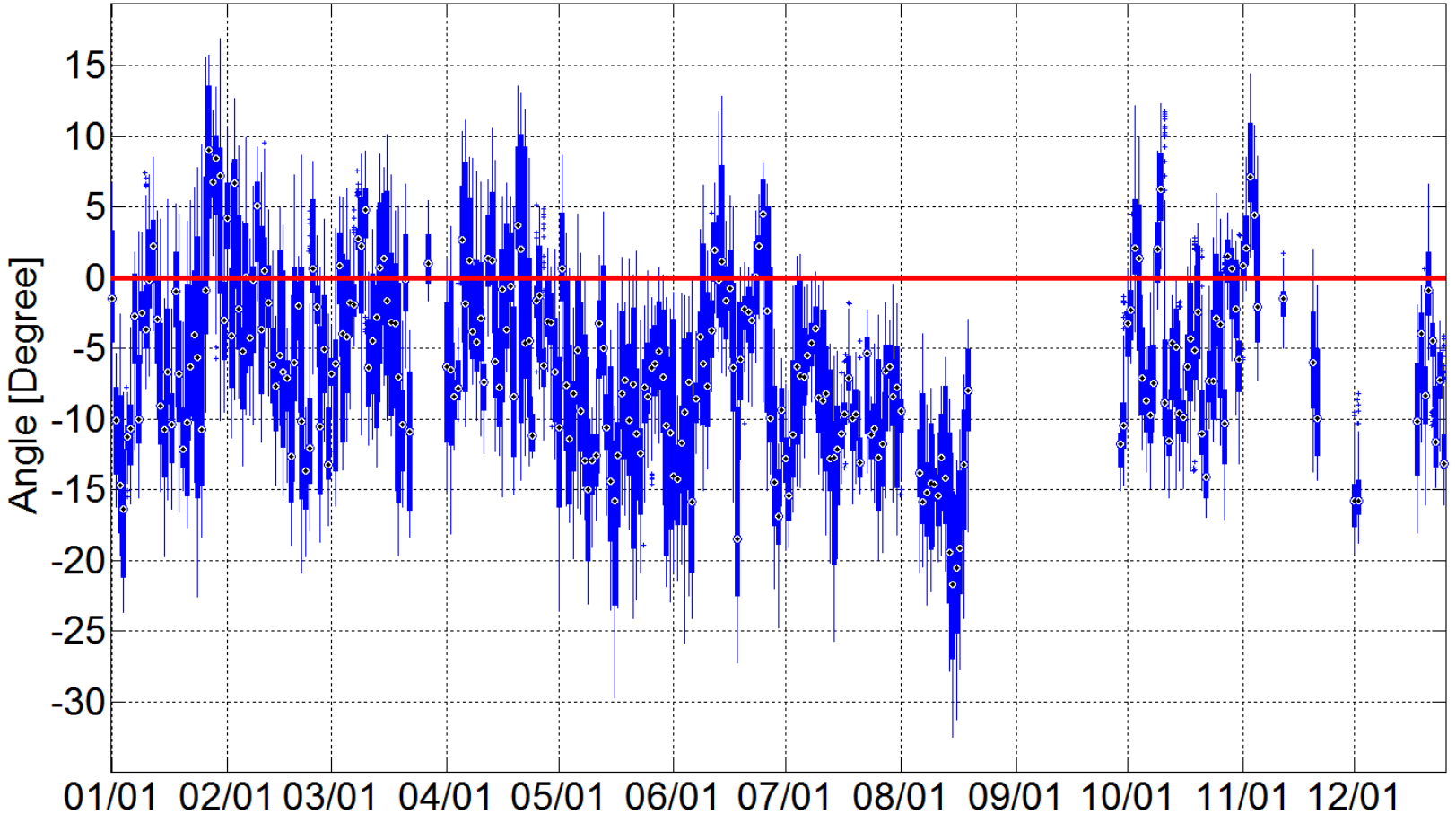

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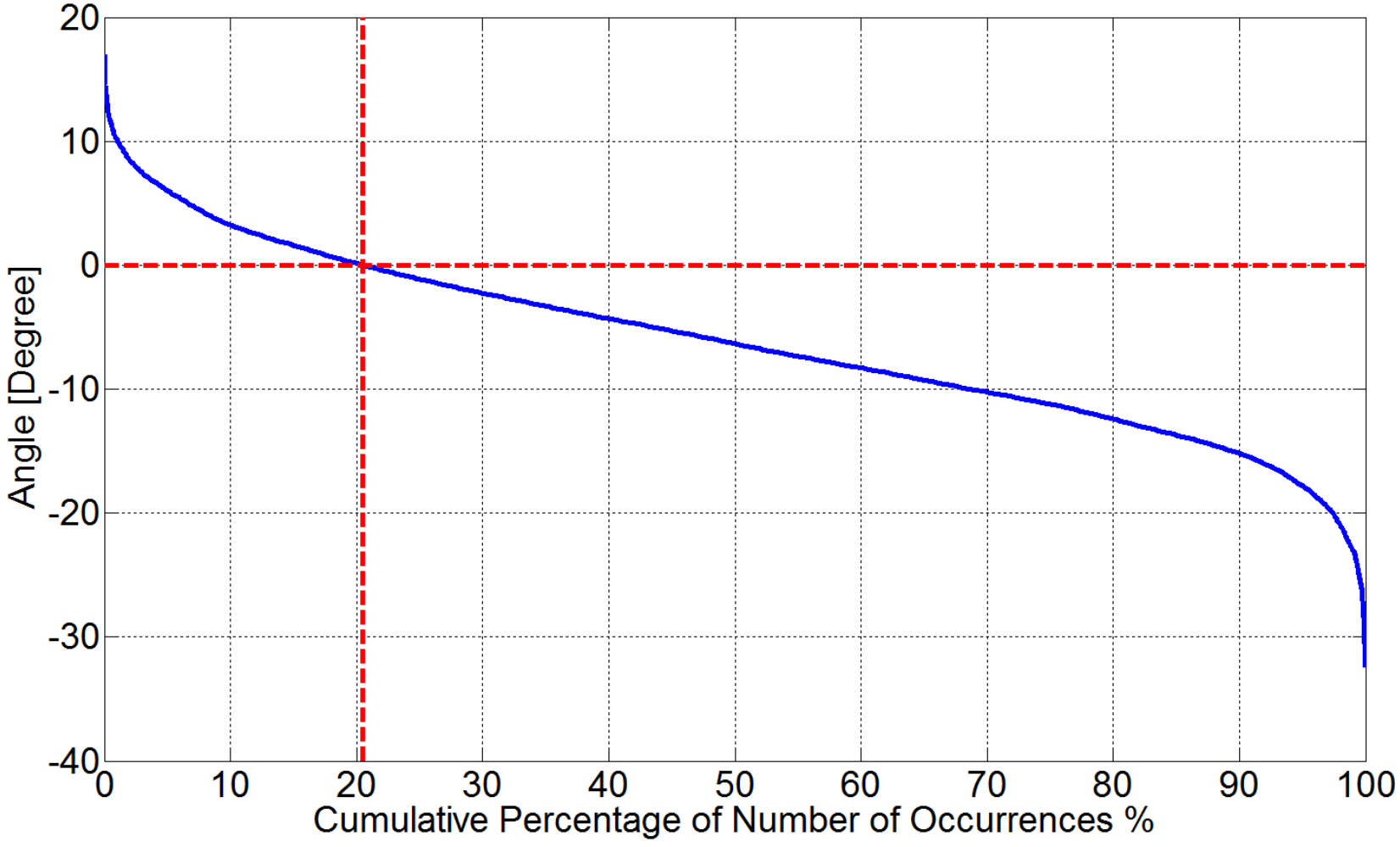

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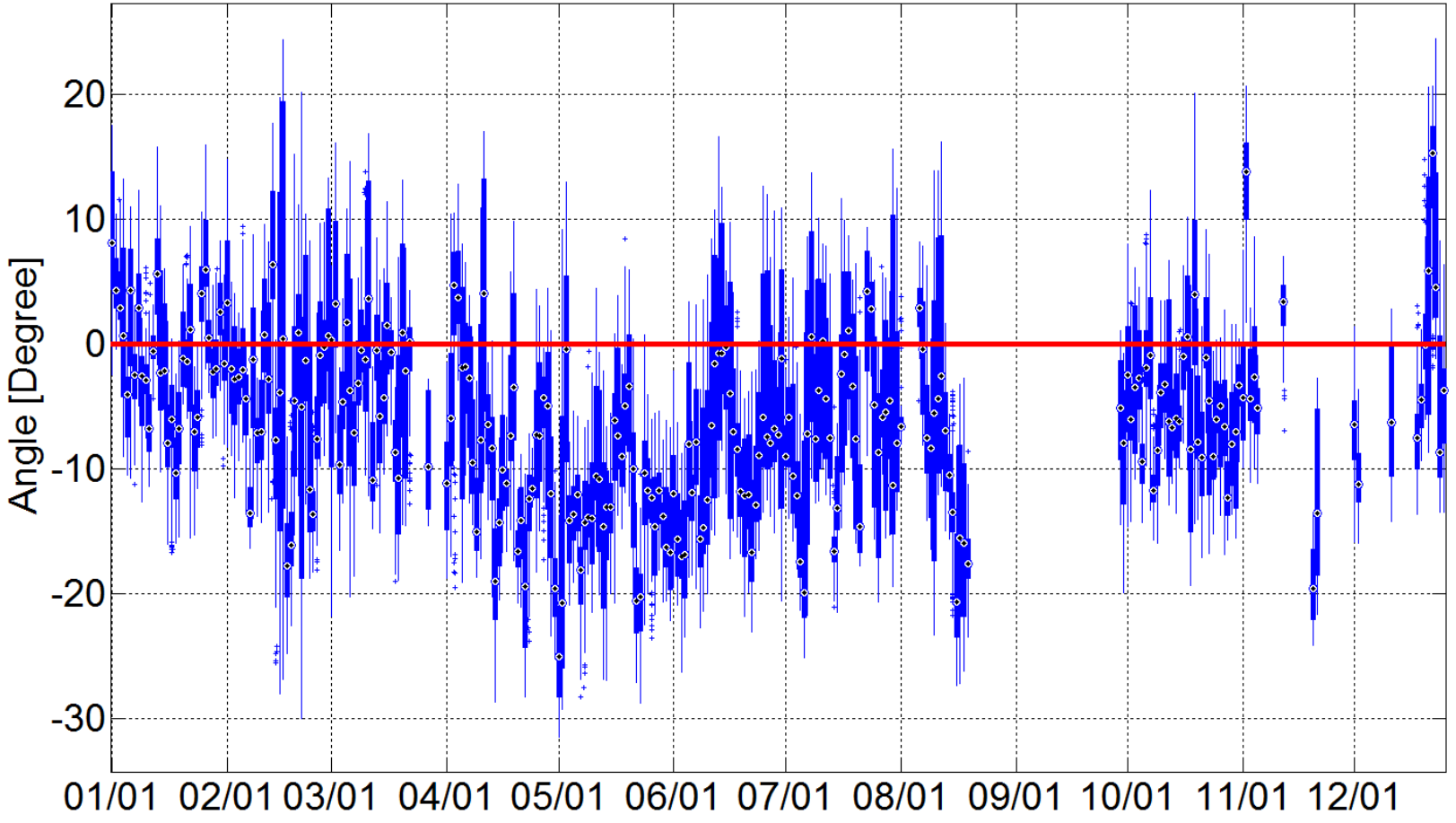

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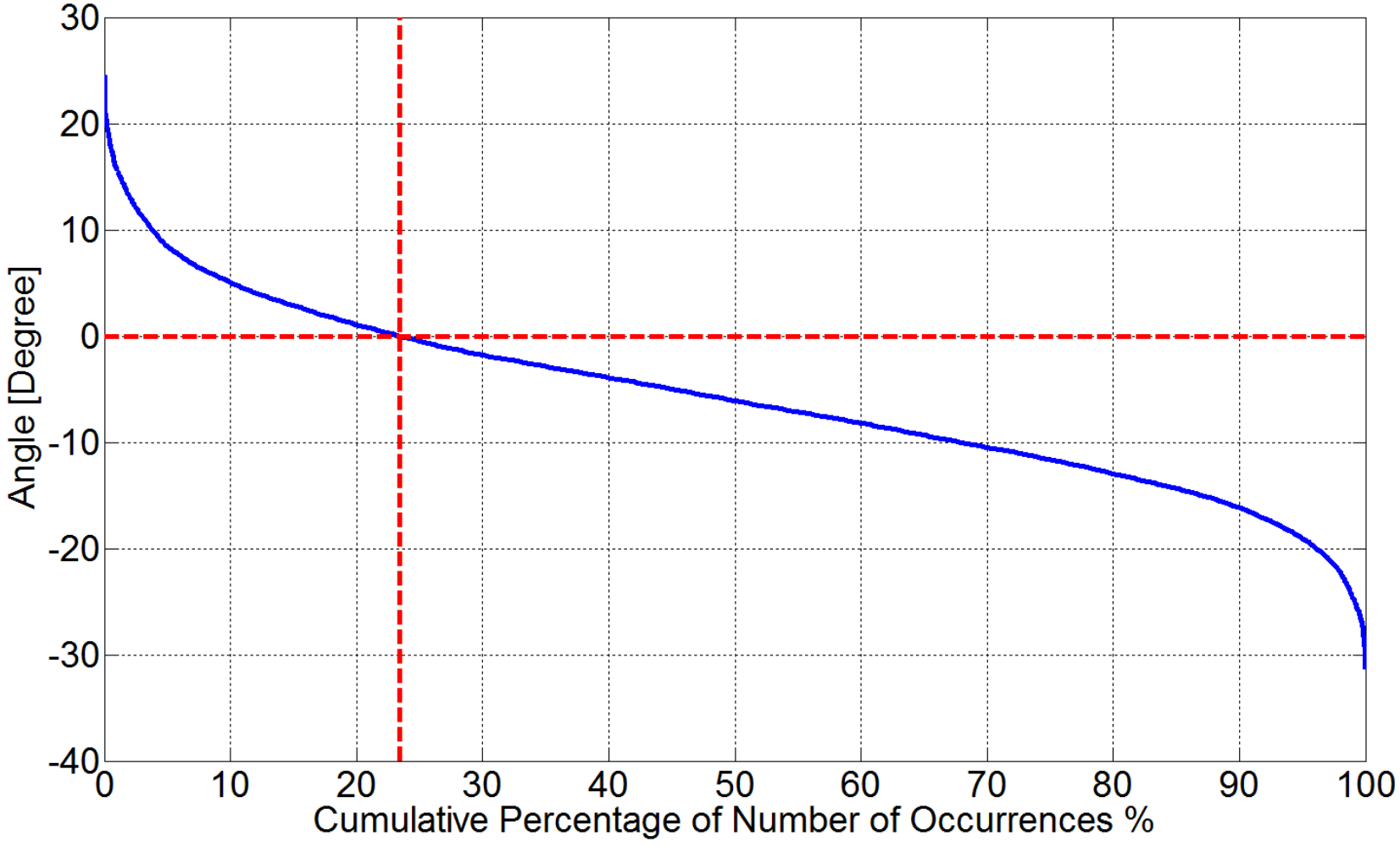

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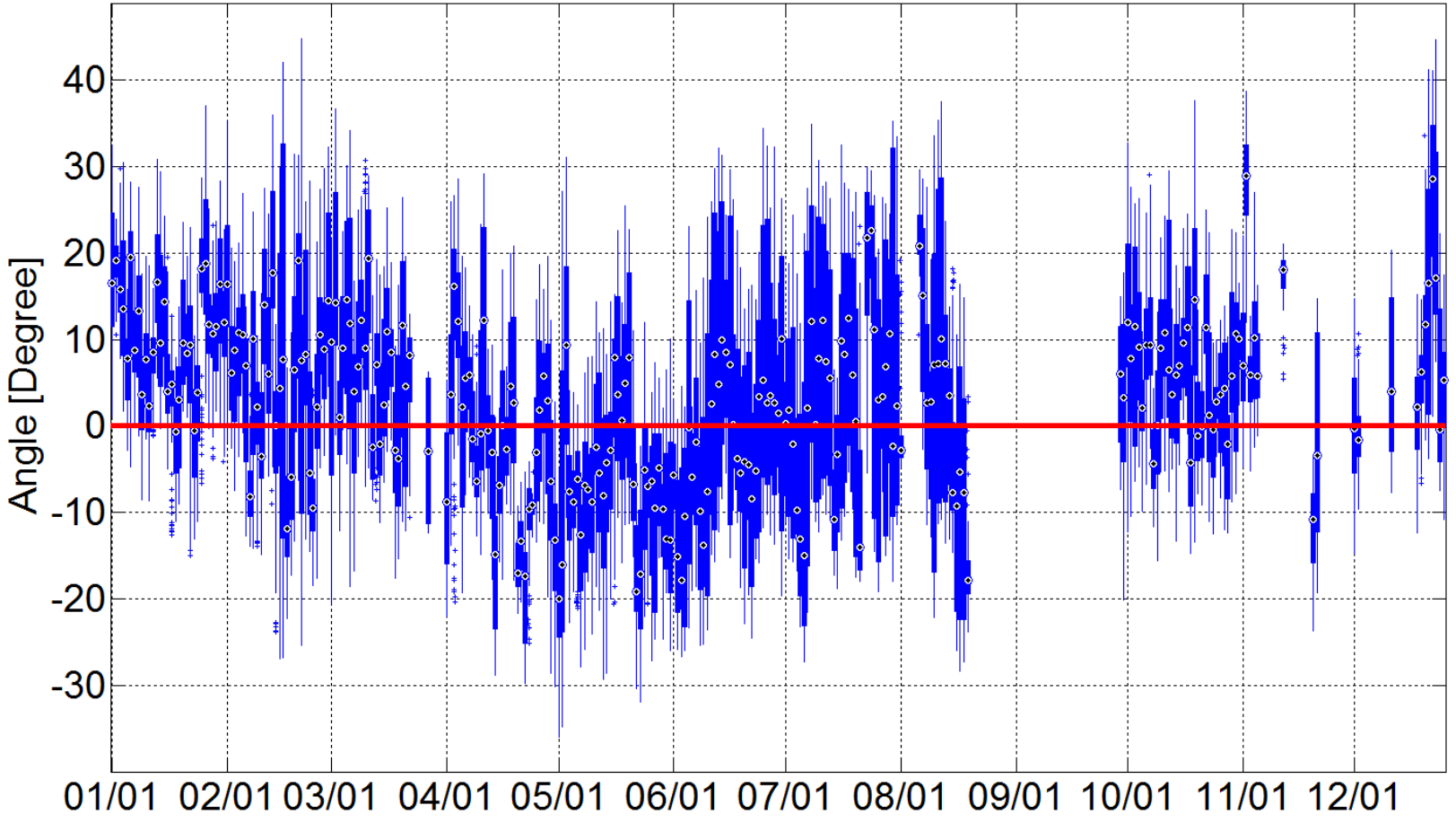

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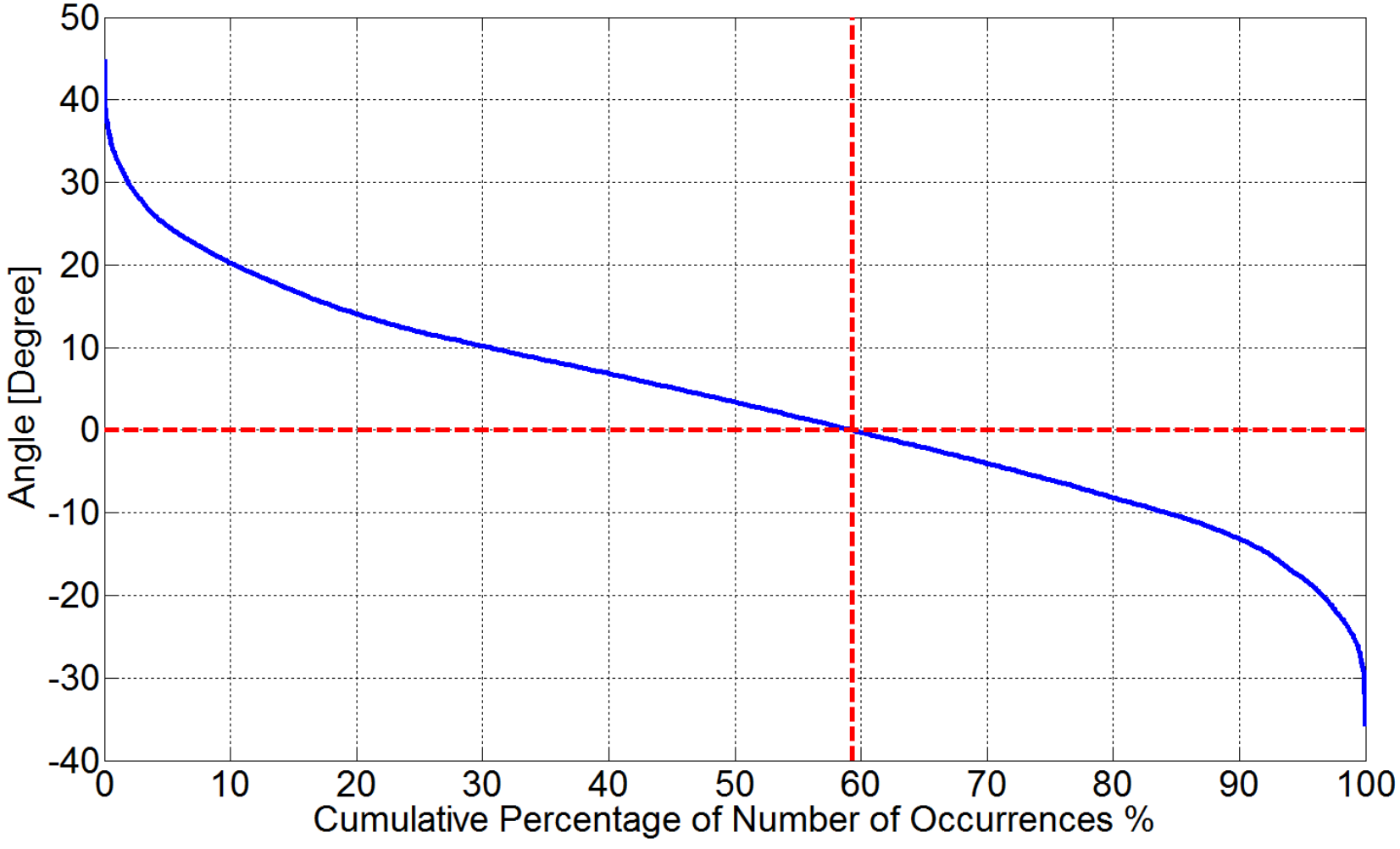

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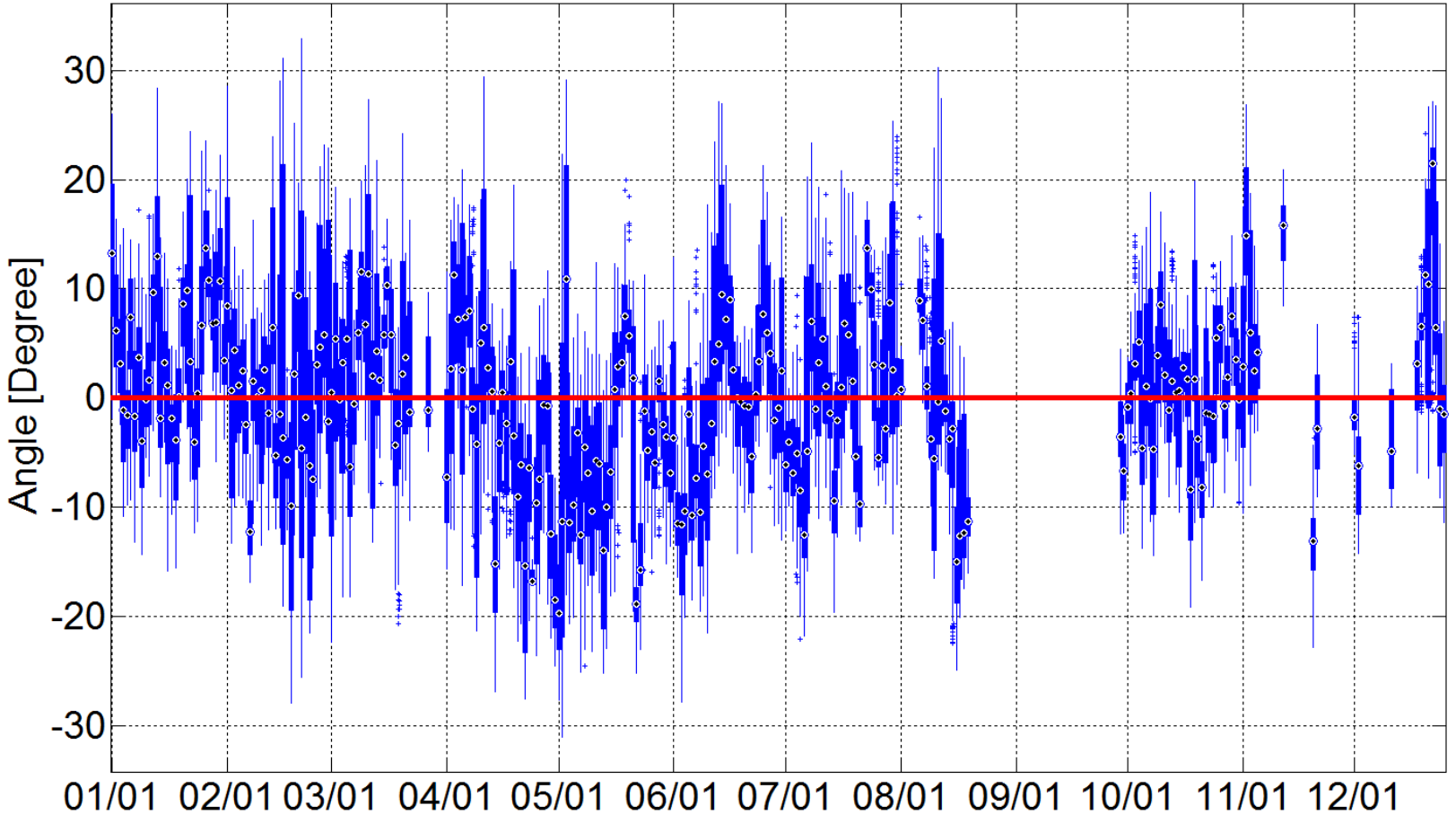

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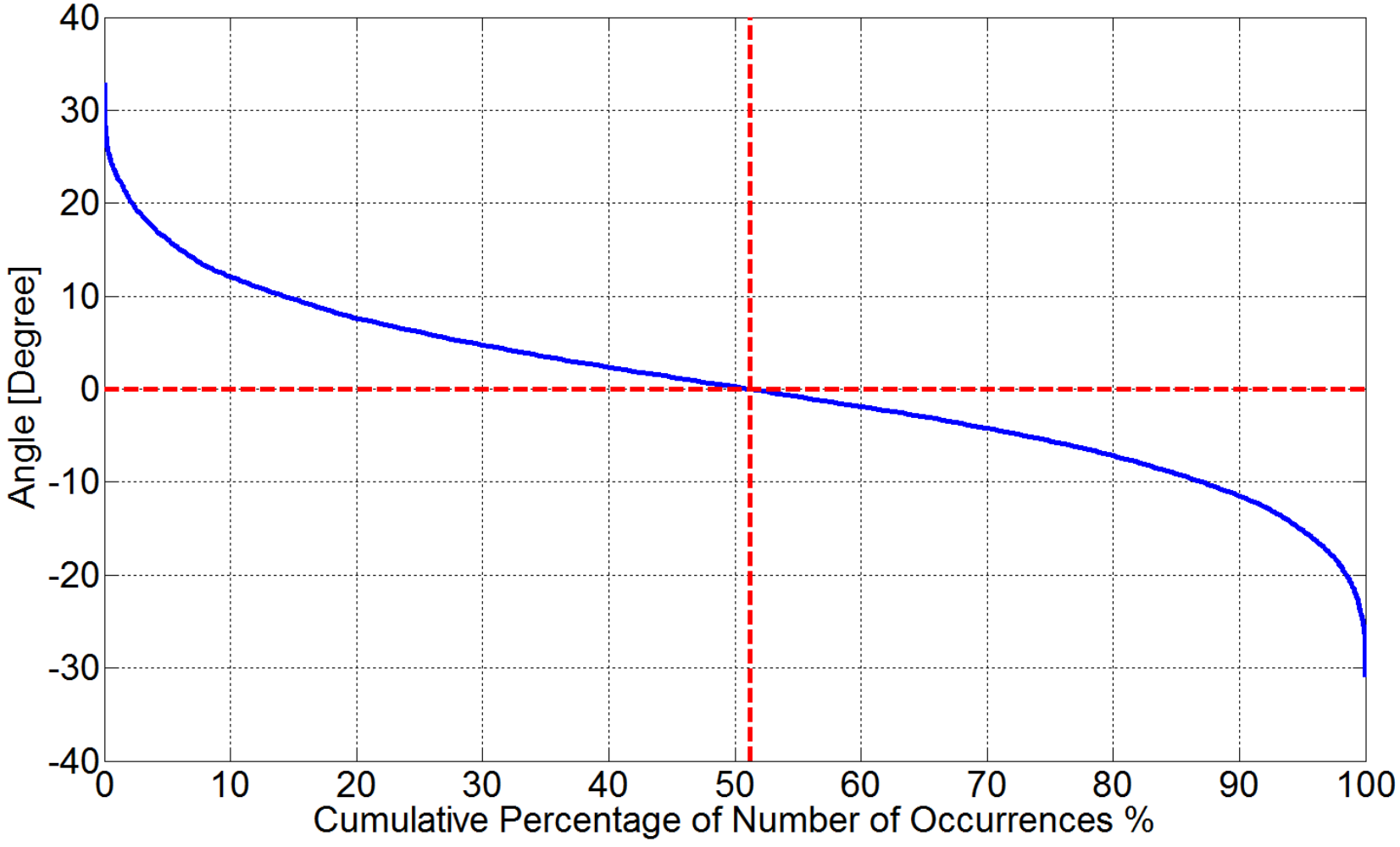

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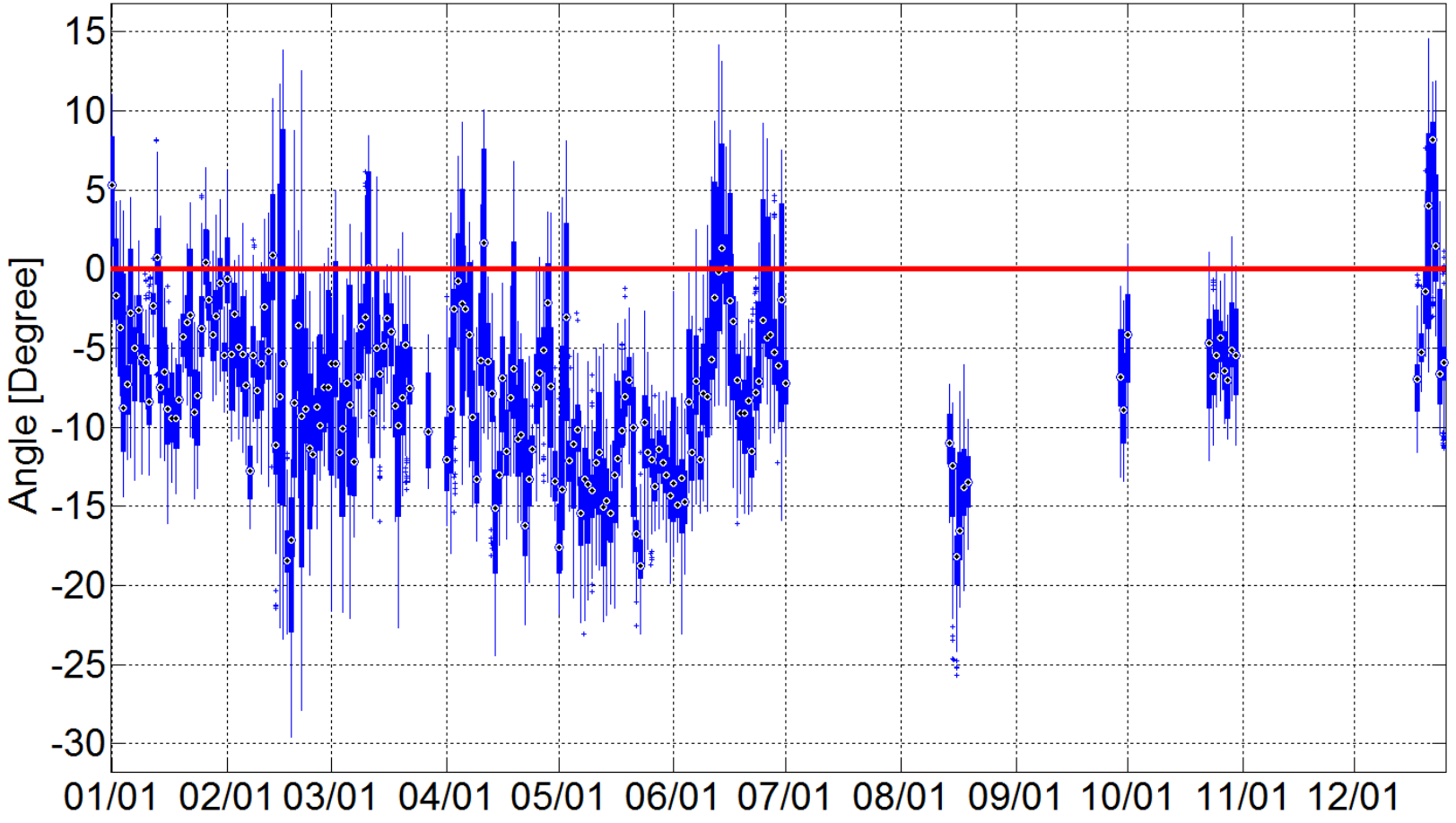

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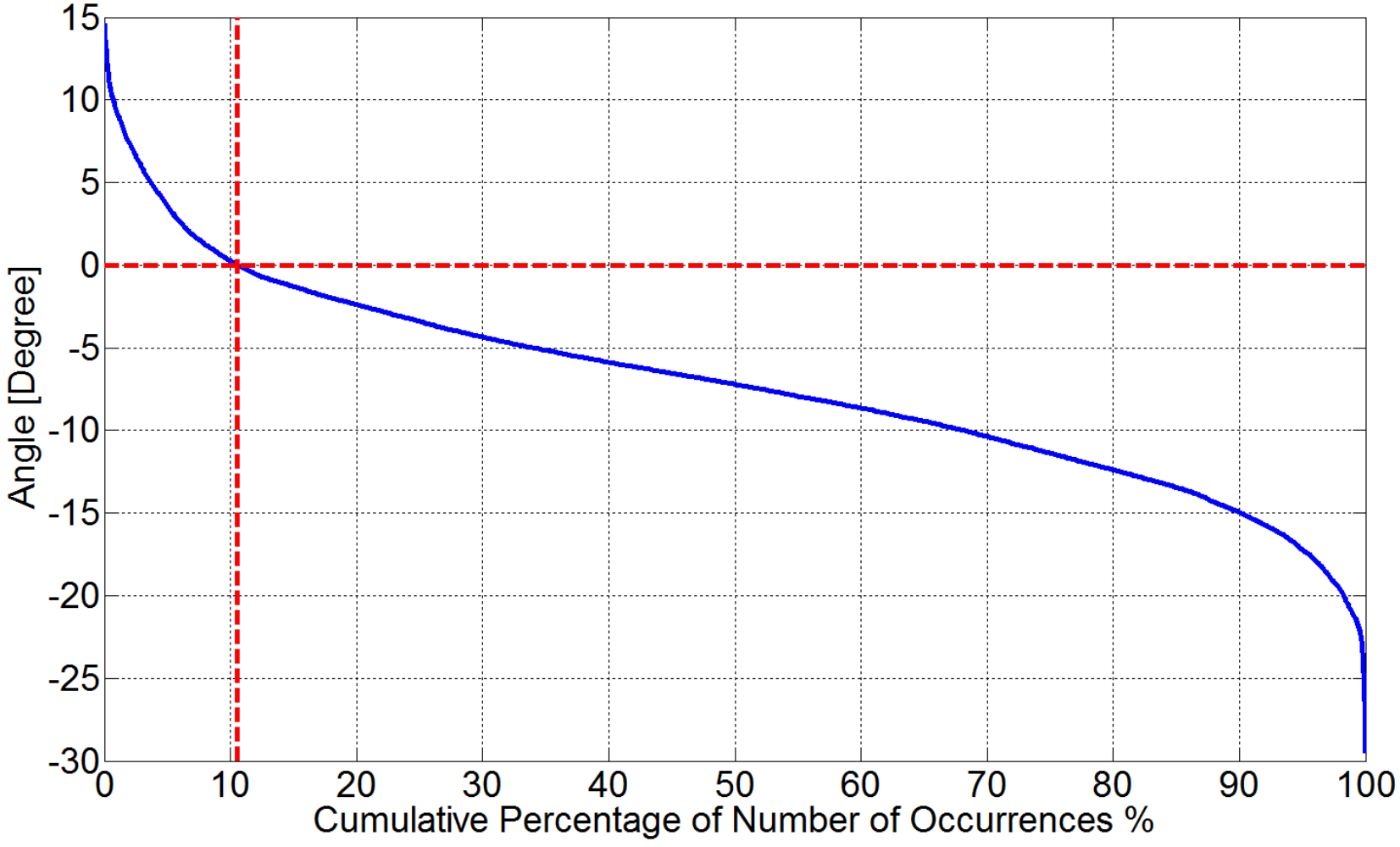

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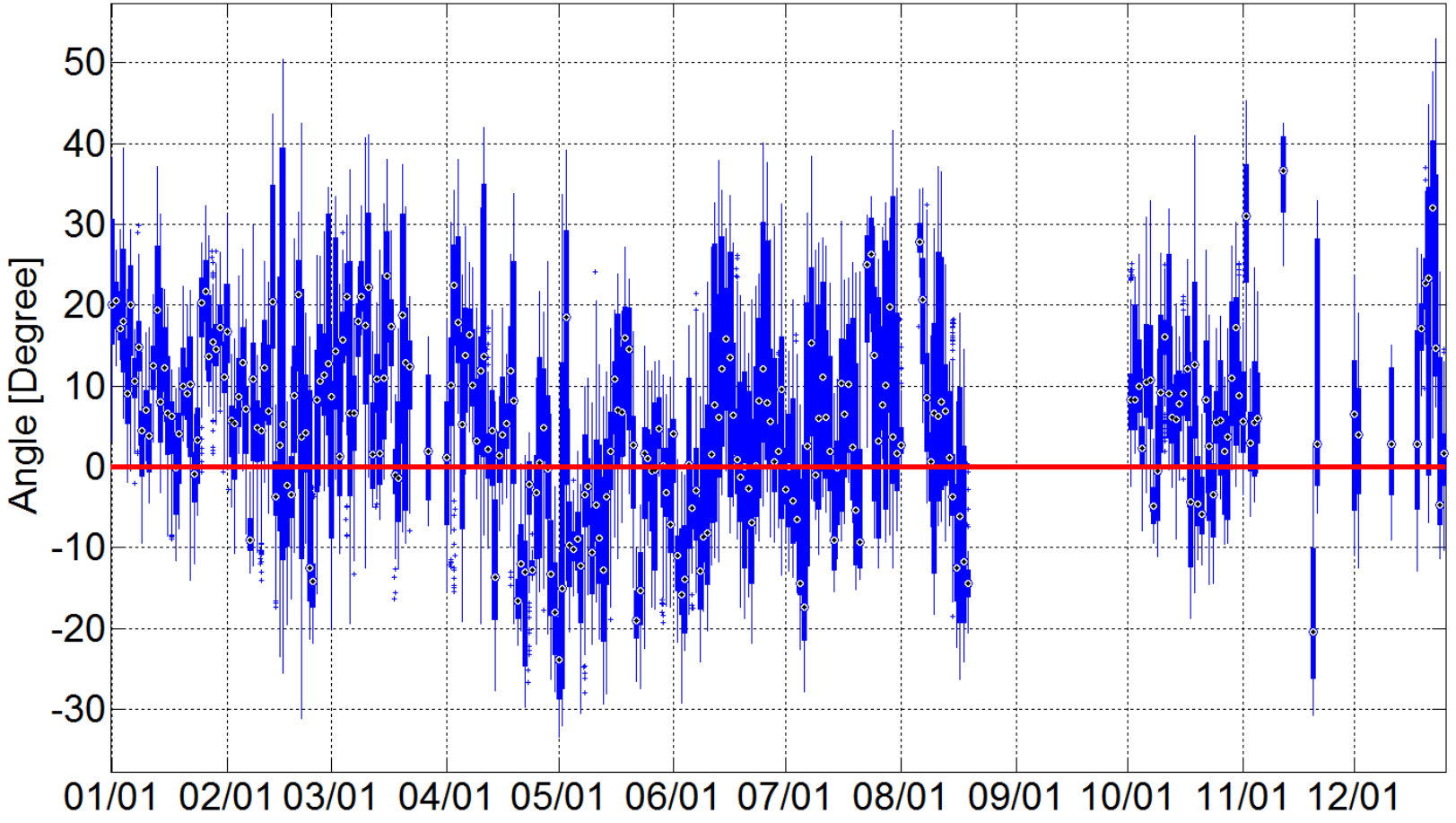

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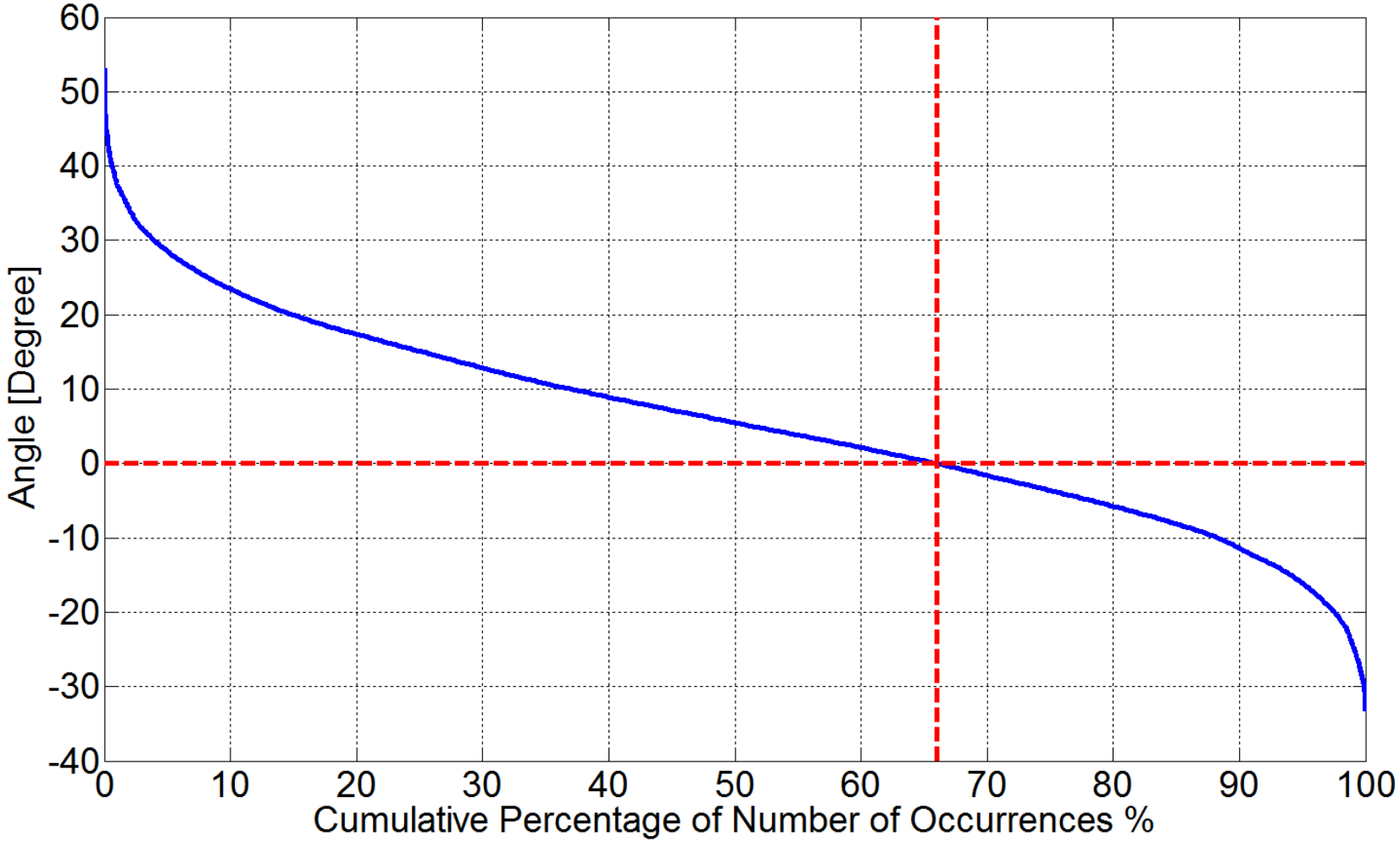

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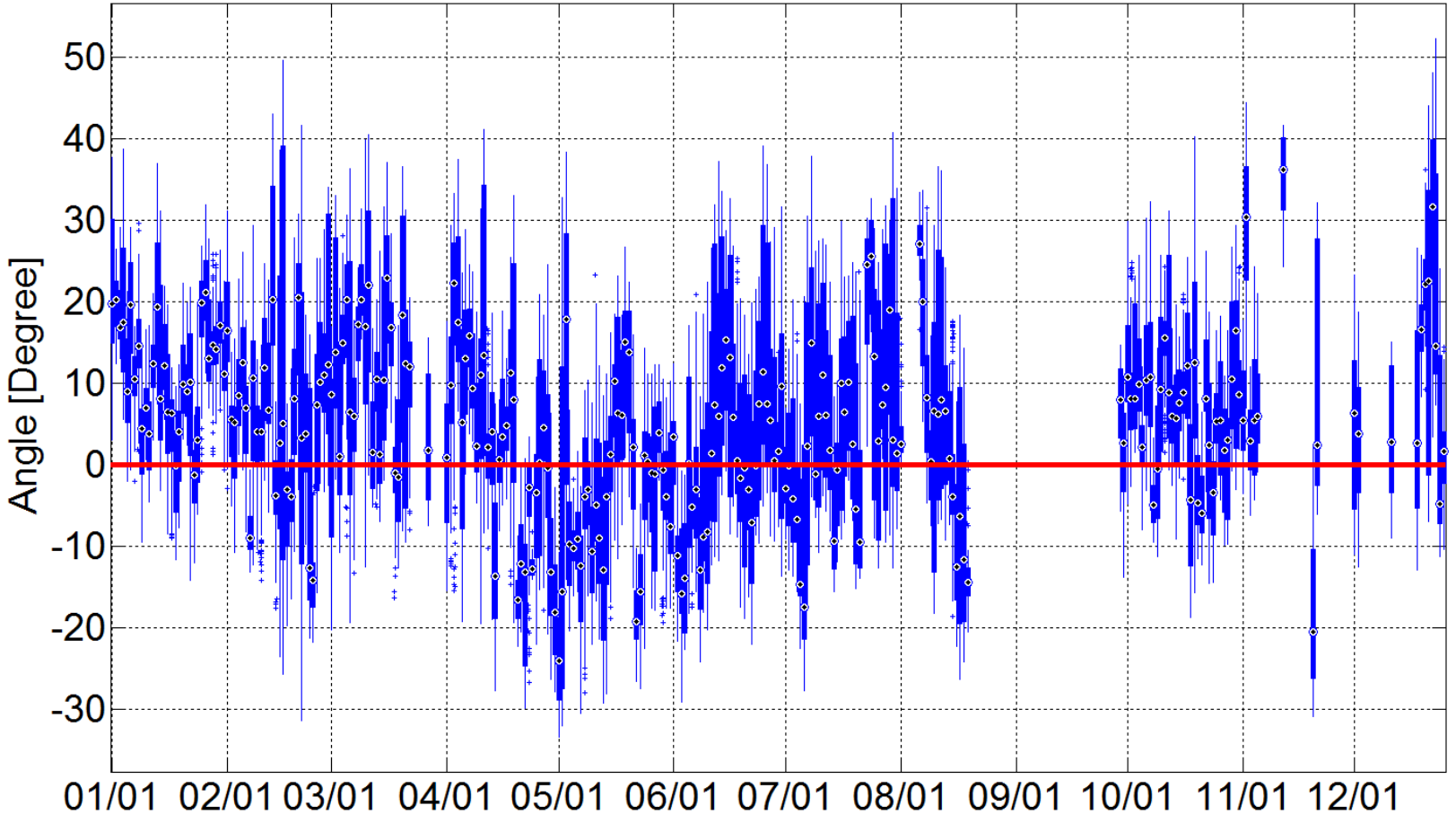

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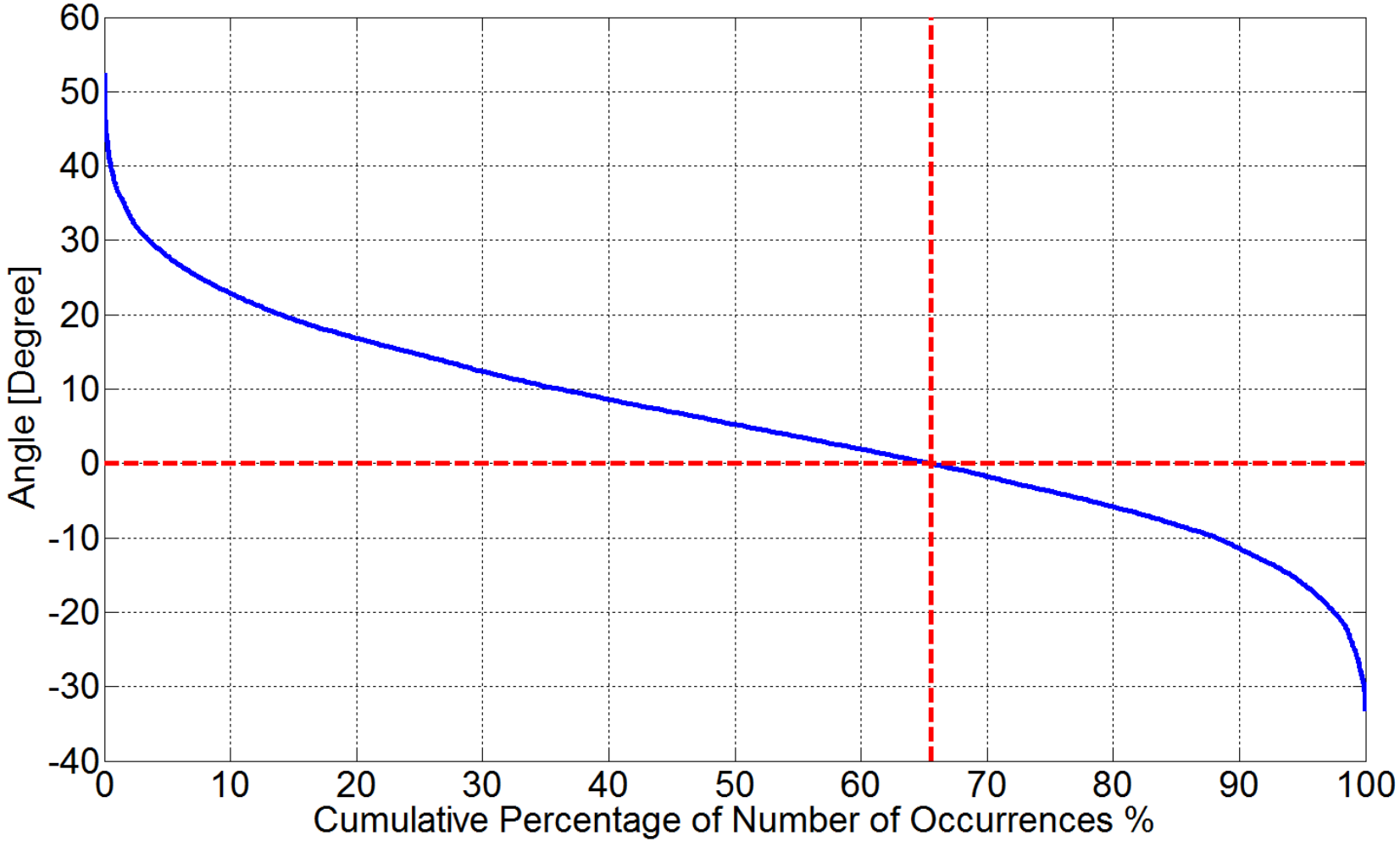

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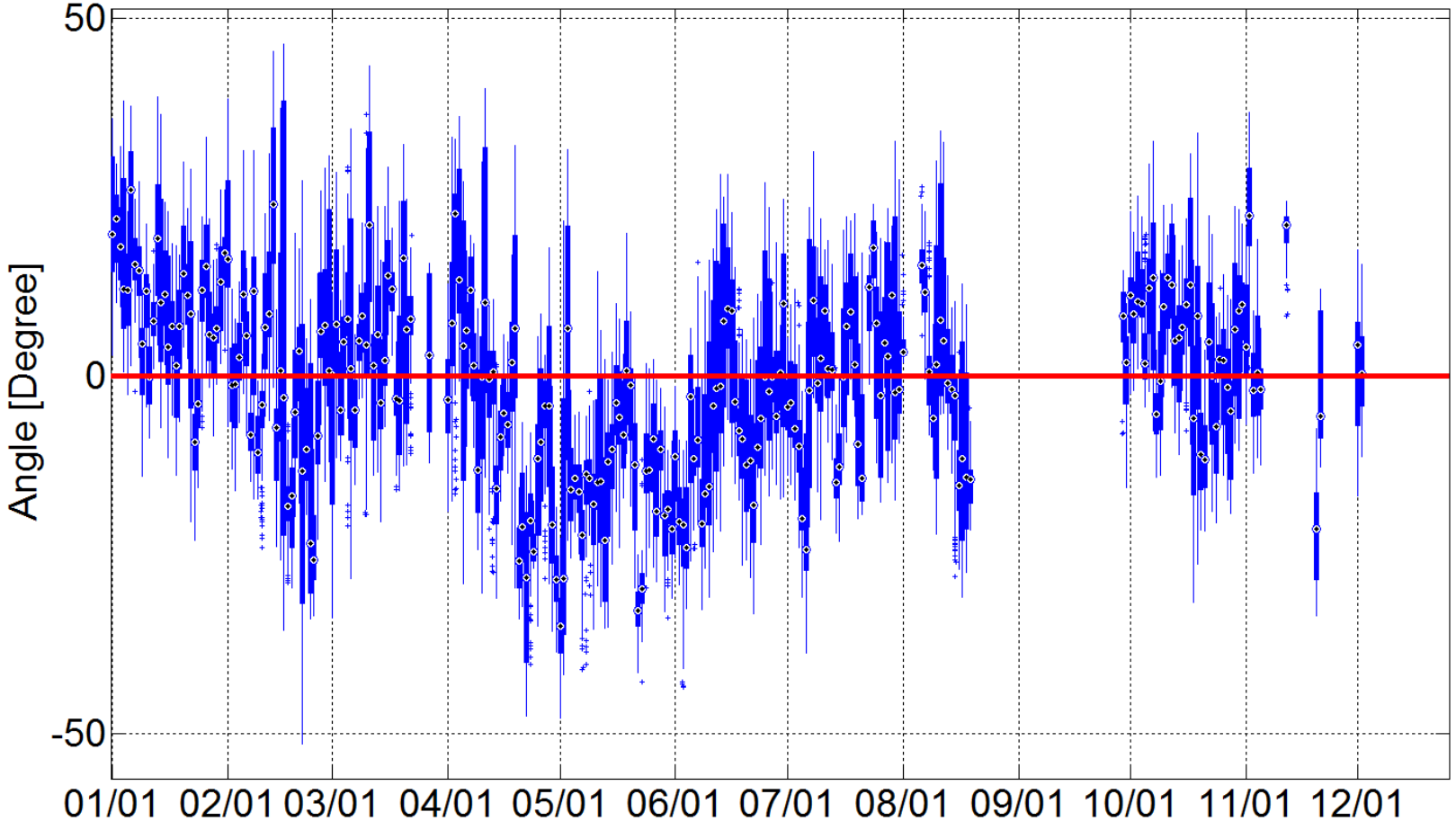

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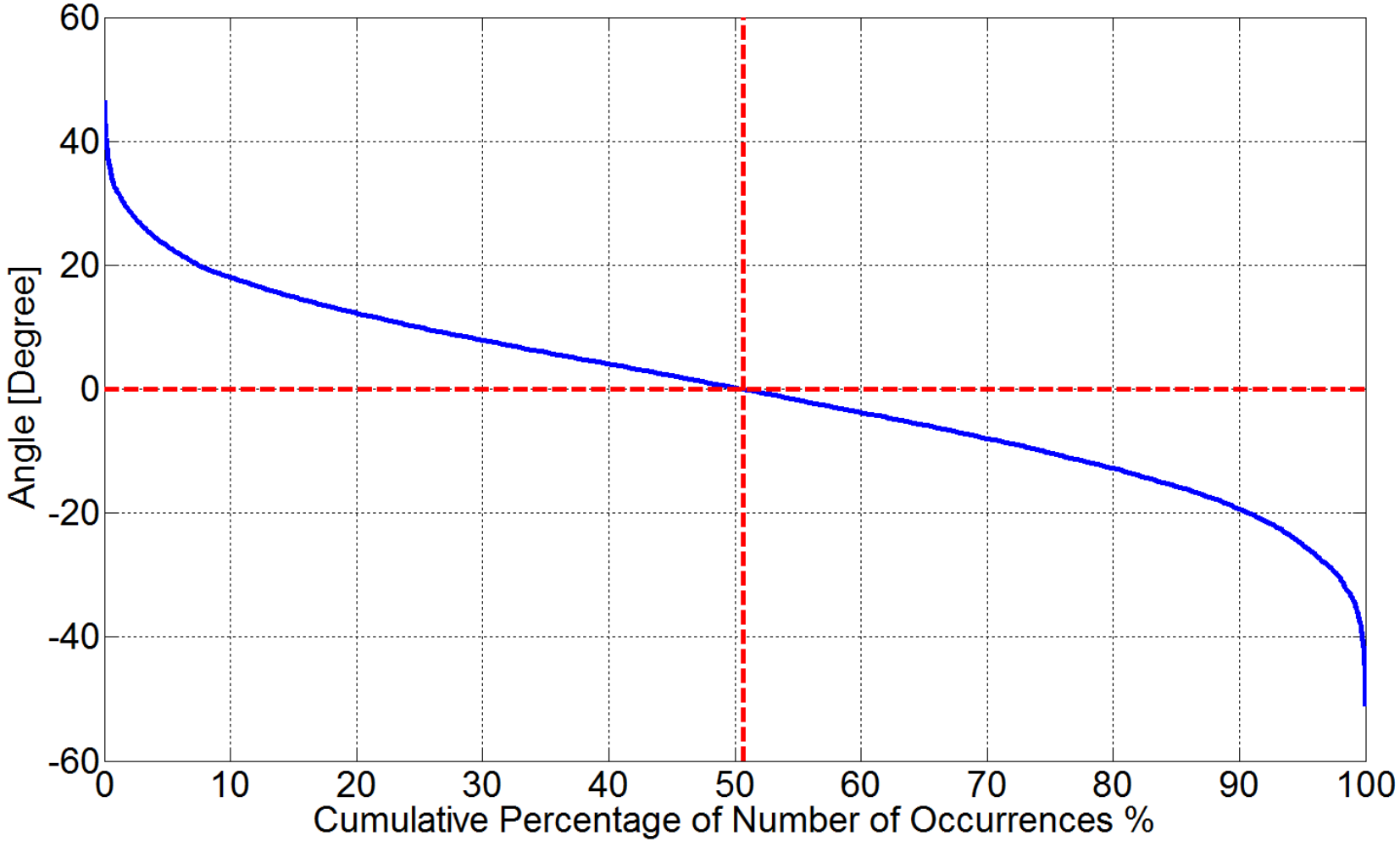

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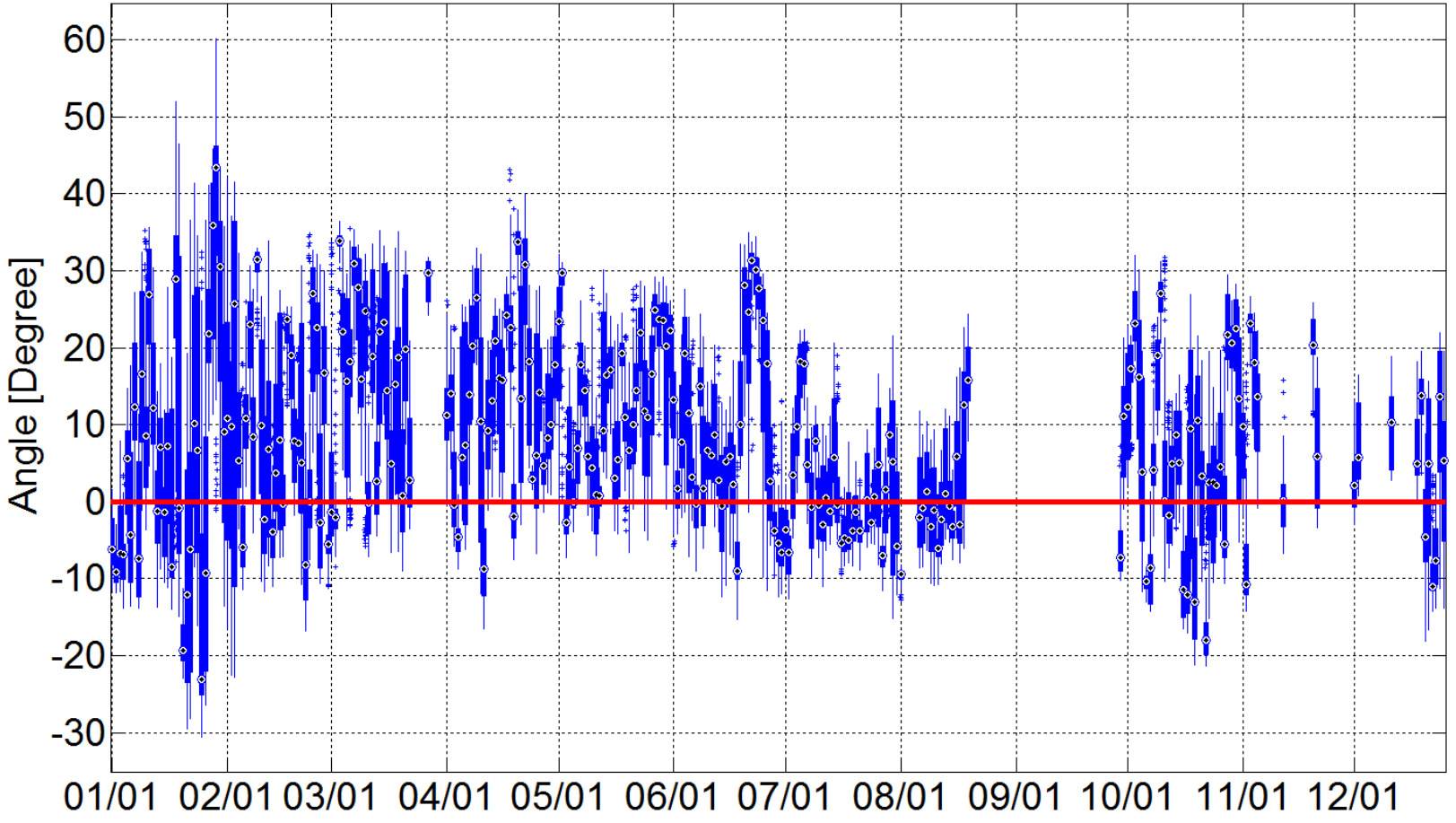

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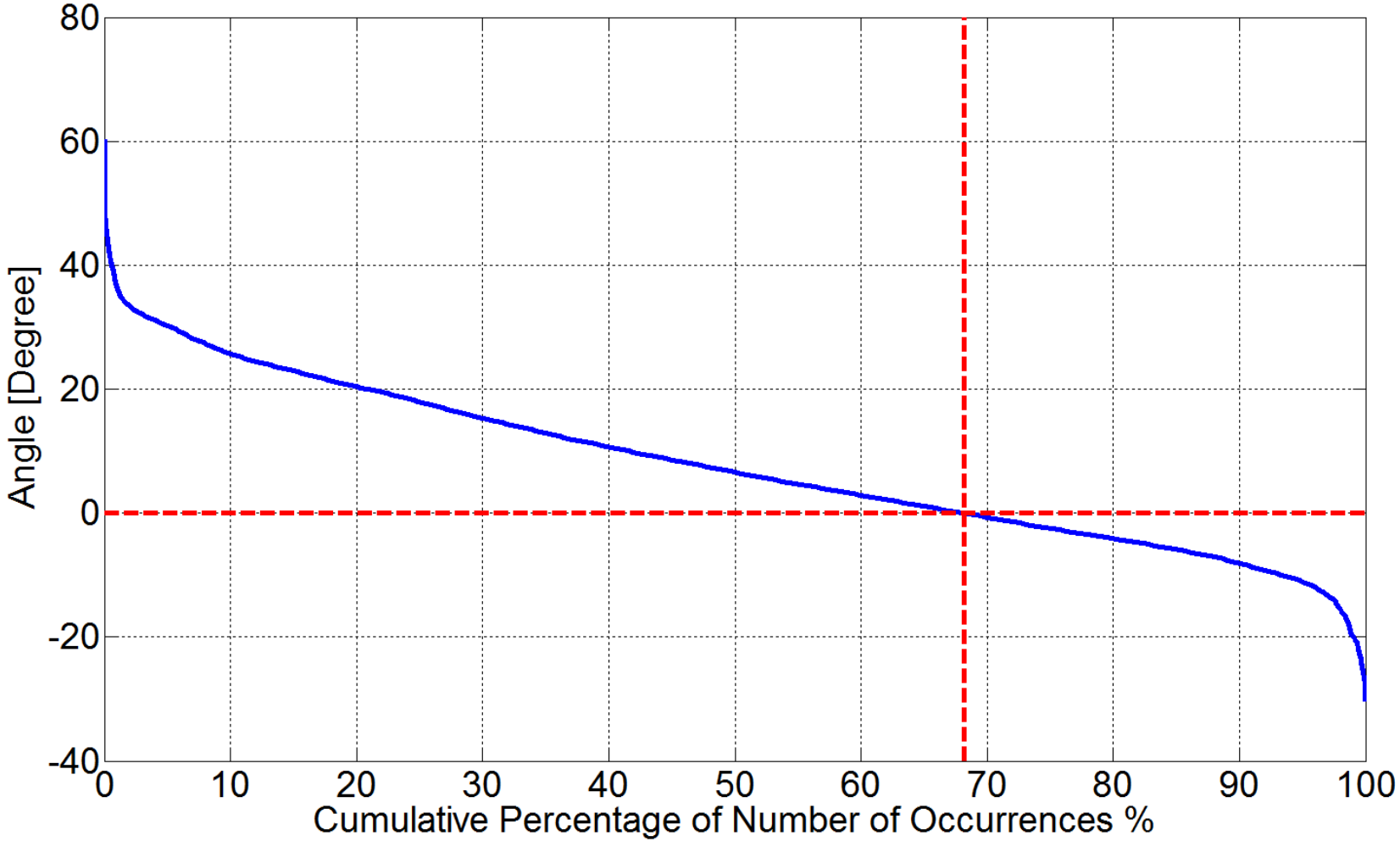

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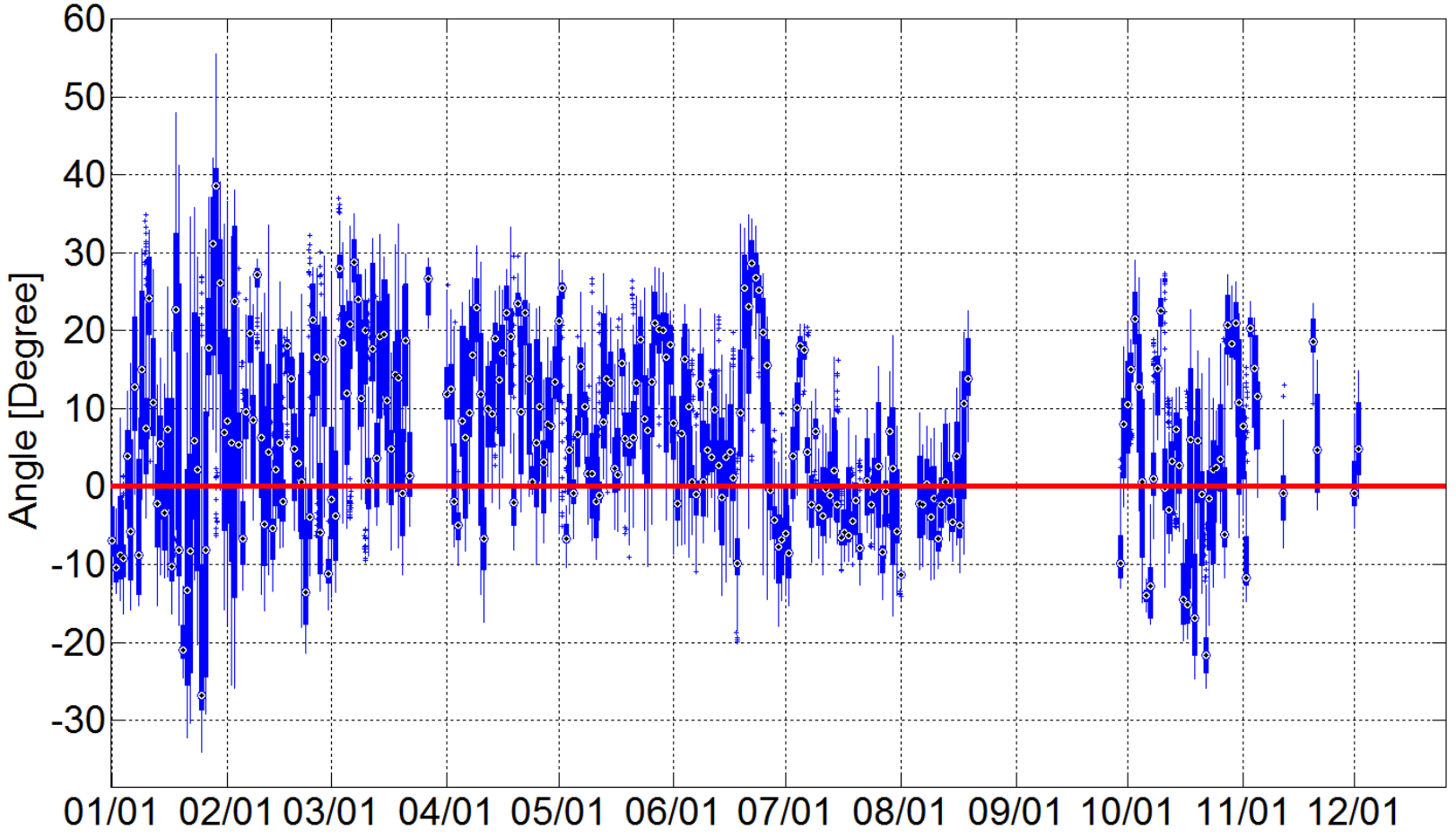

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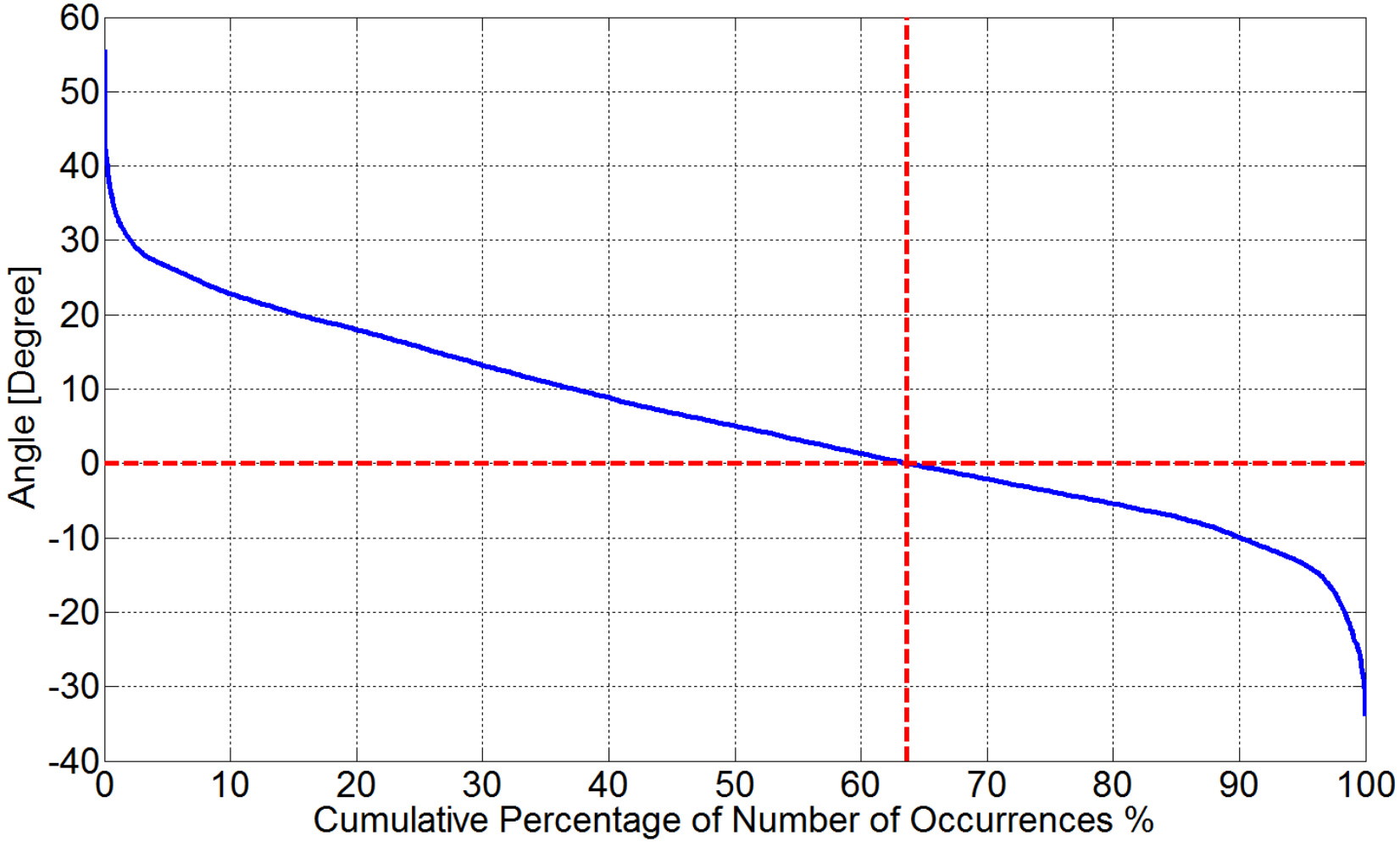

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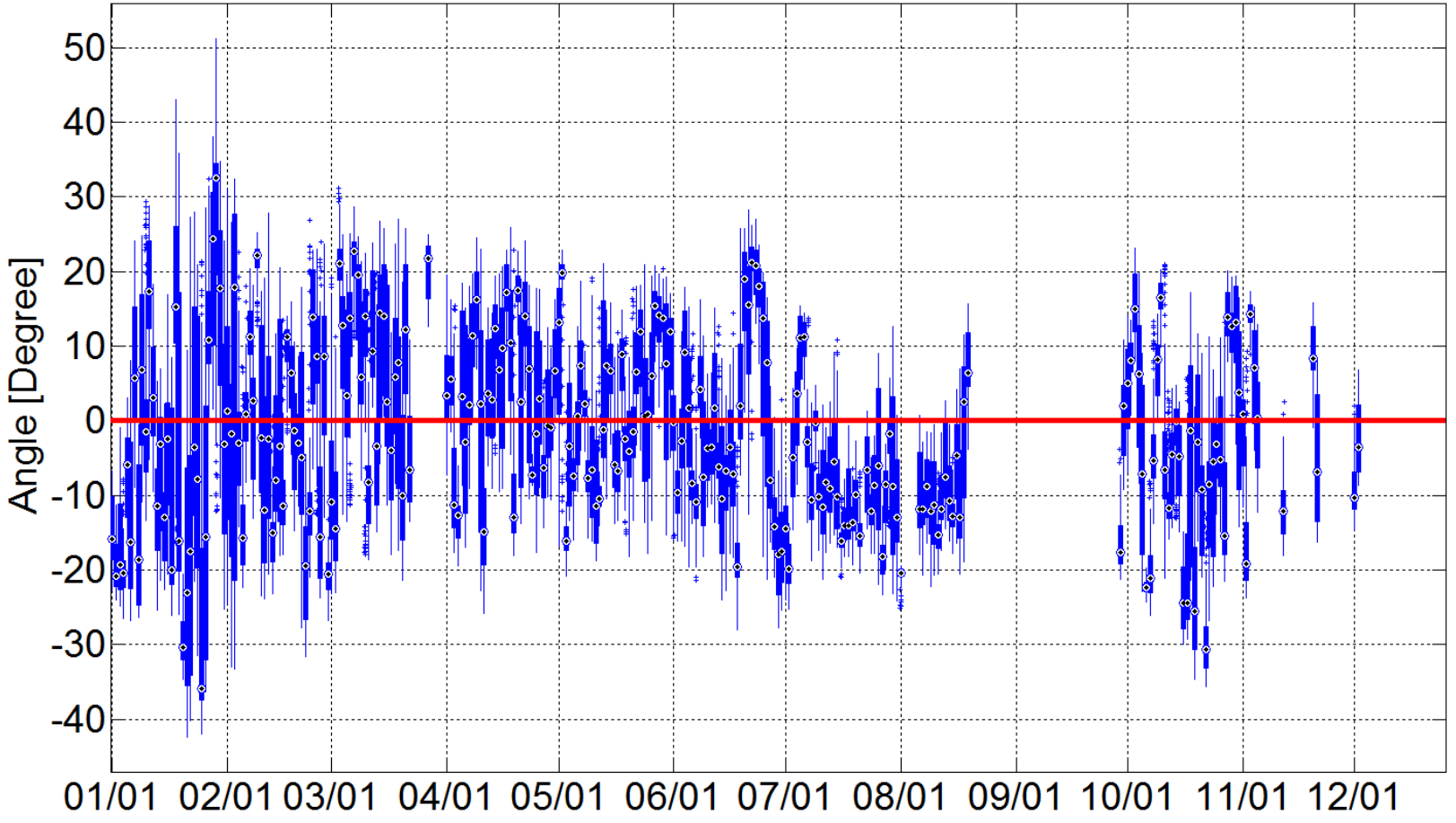

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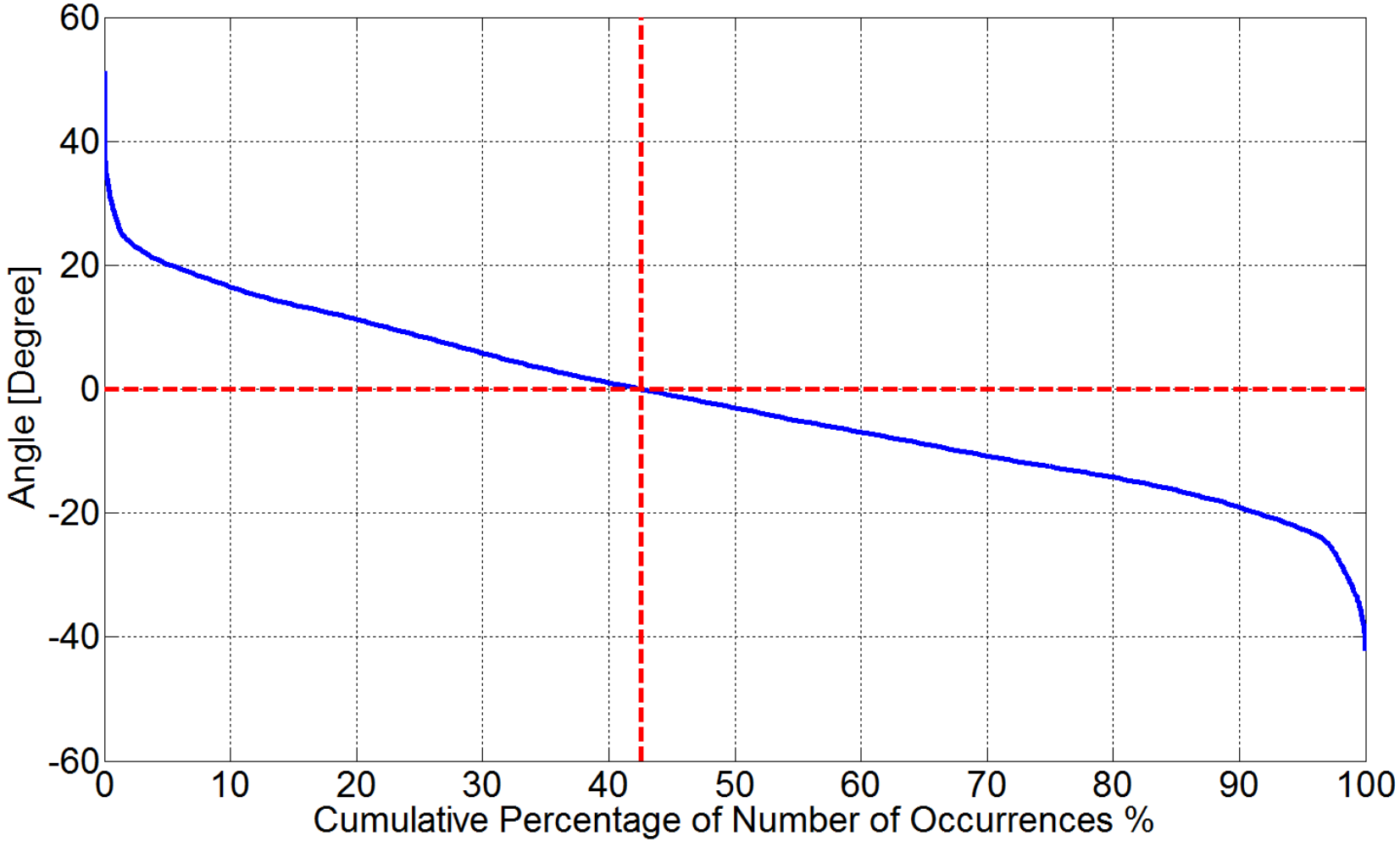
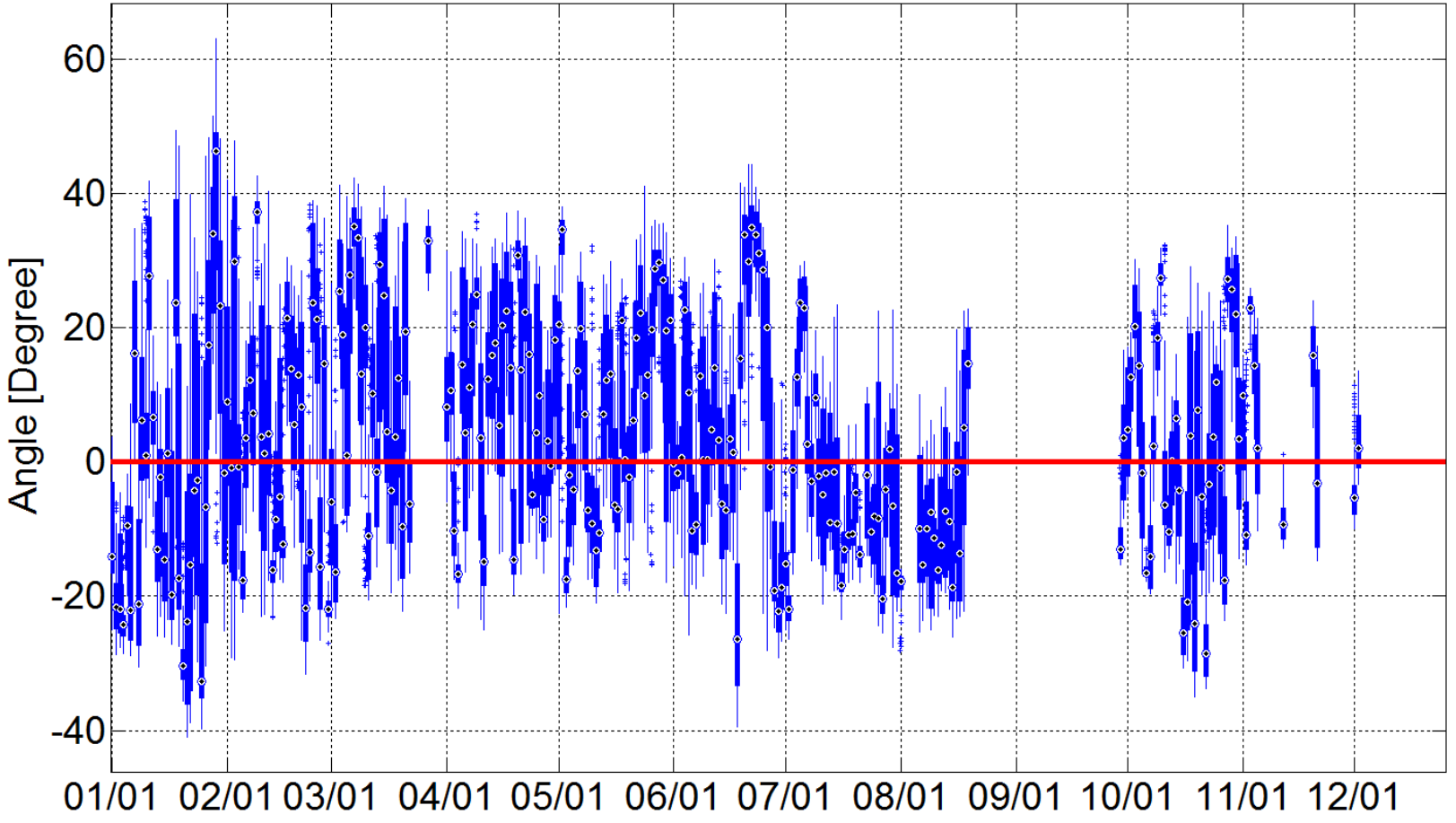


FarWest 9-North 7



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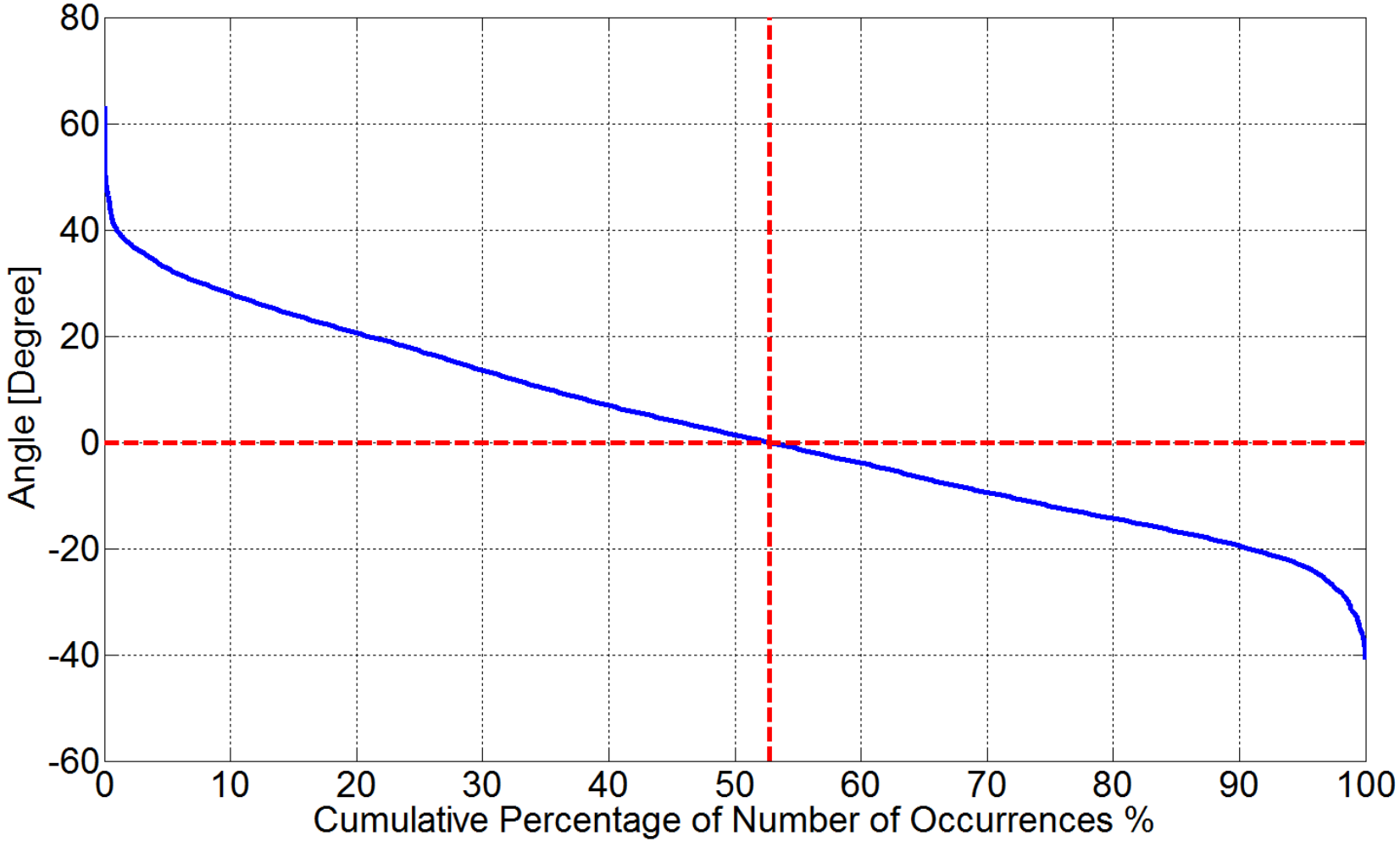

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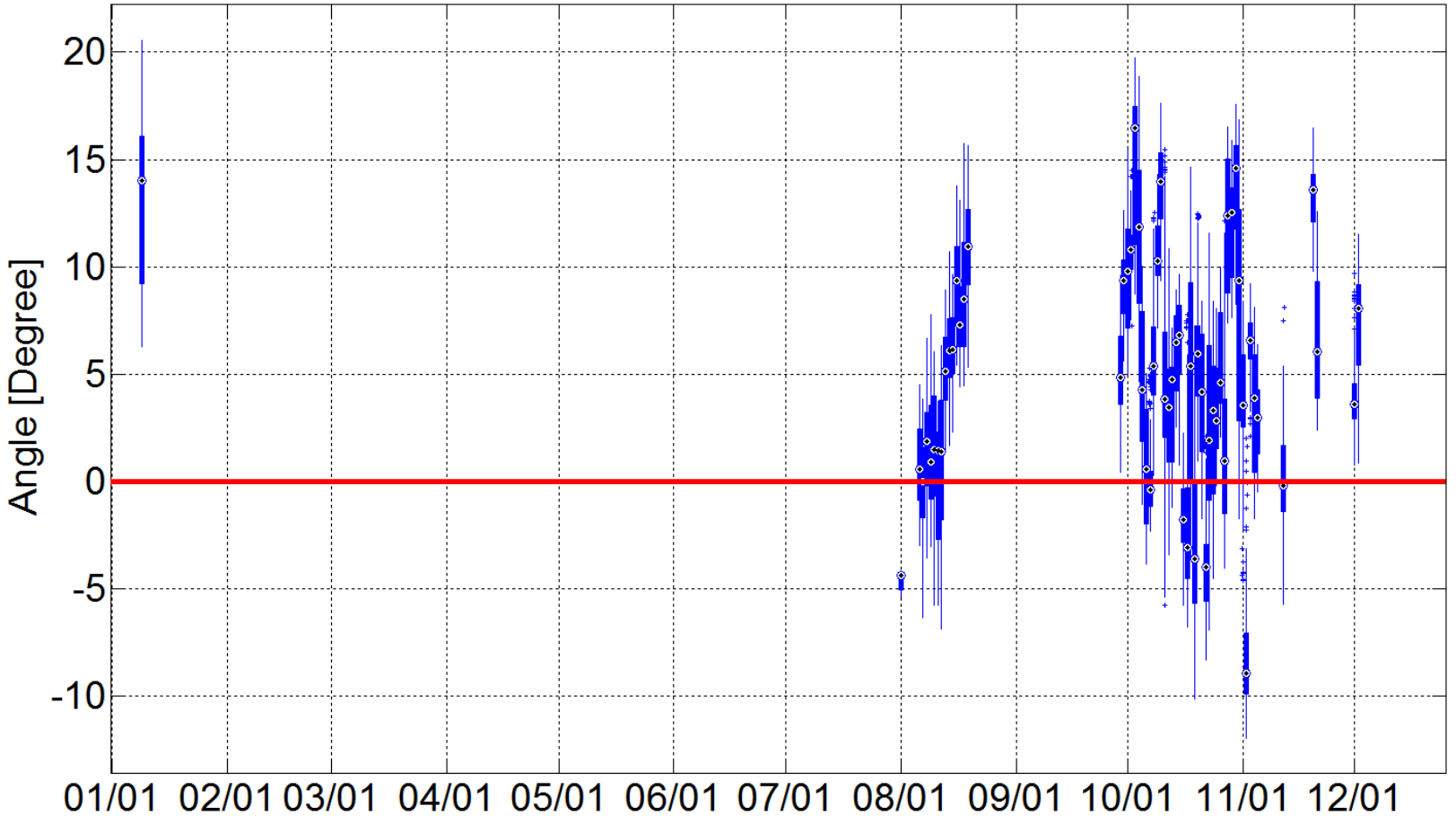

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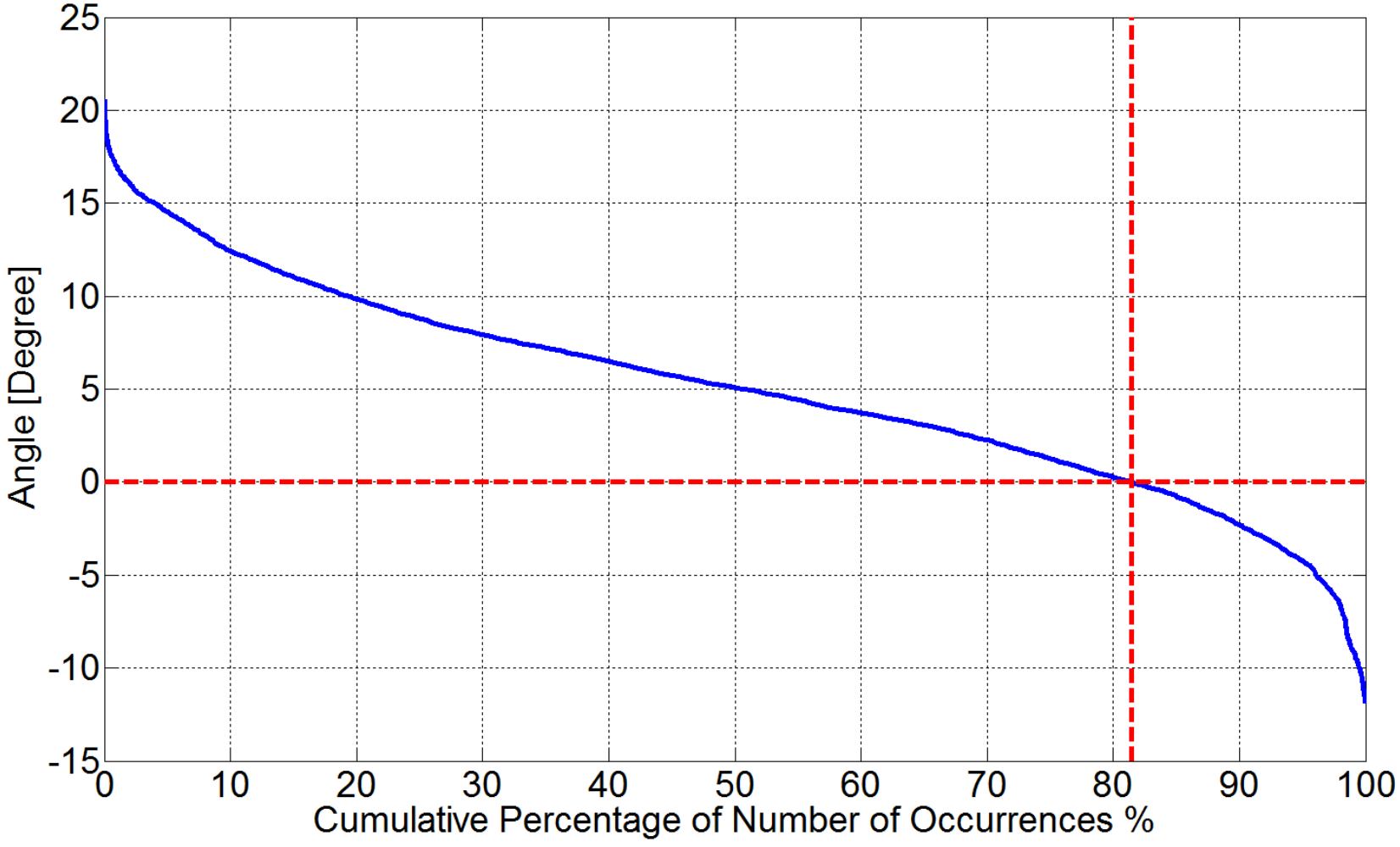

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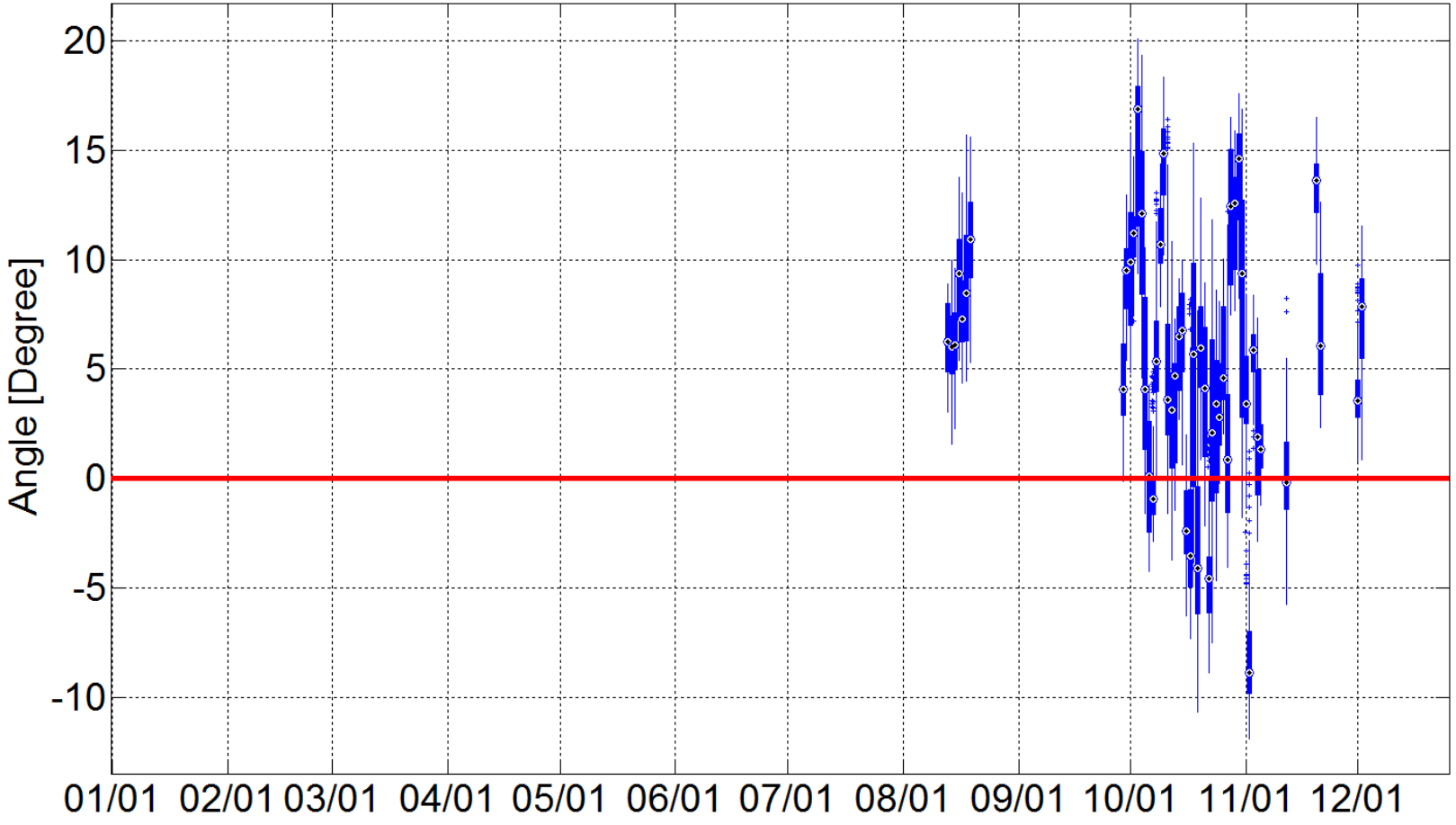

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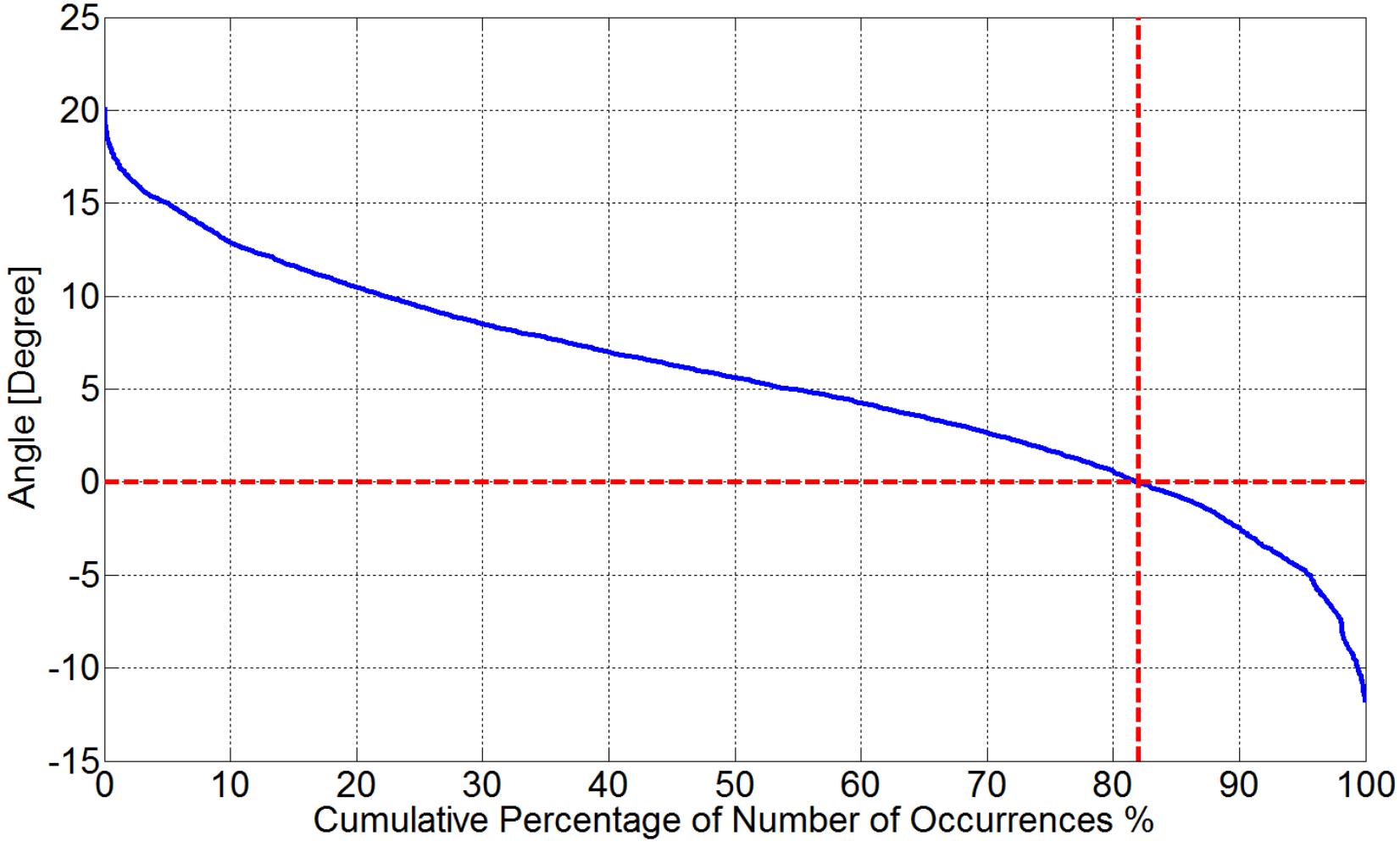

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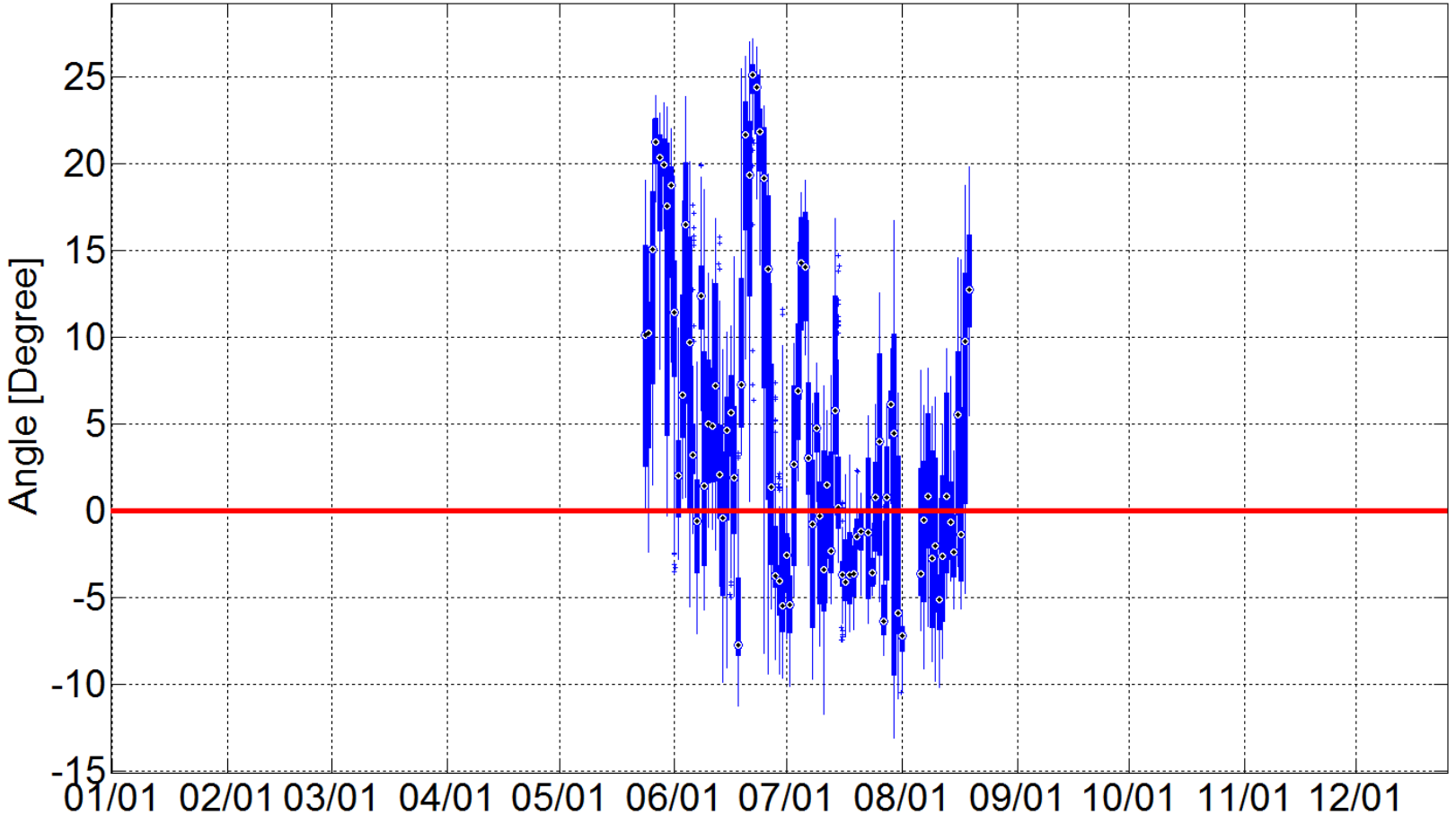

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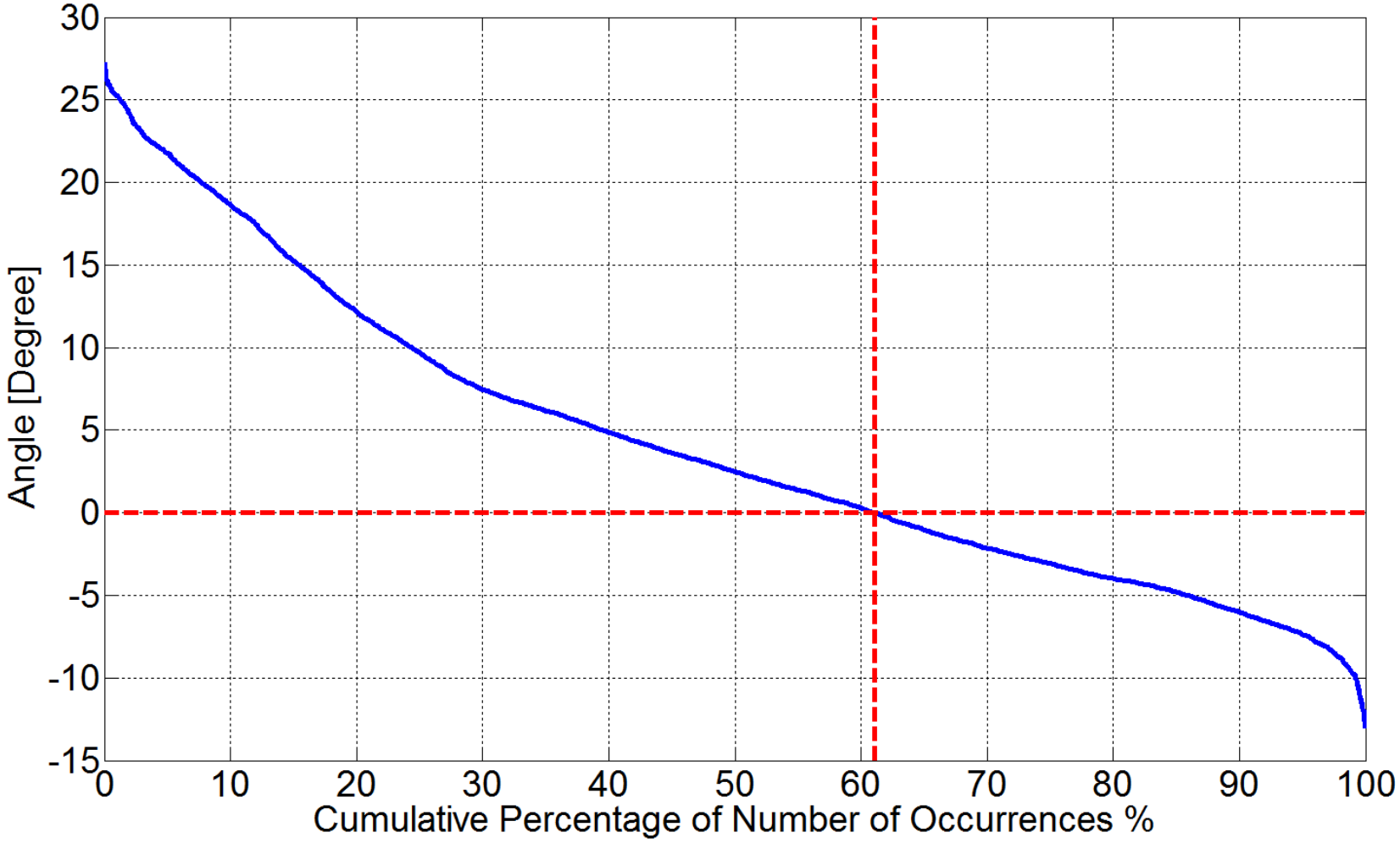

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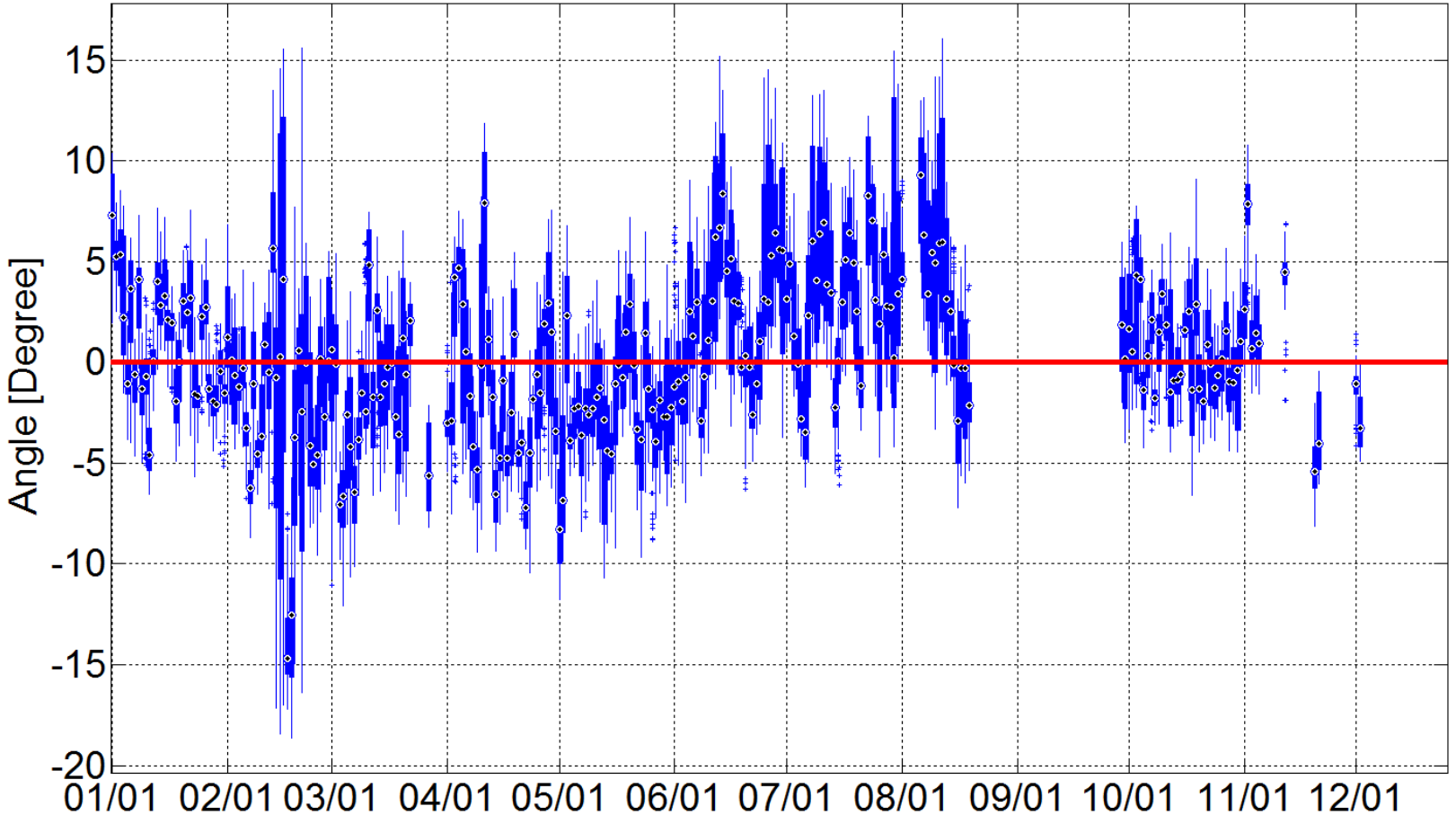

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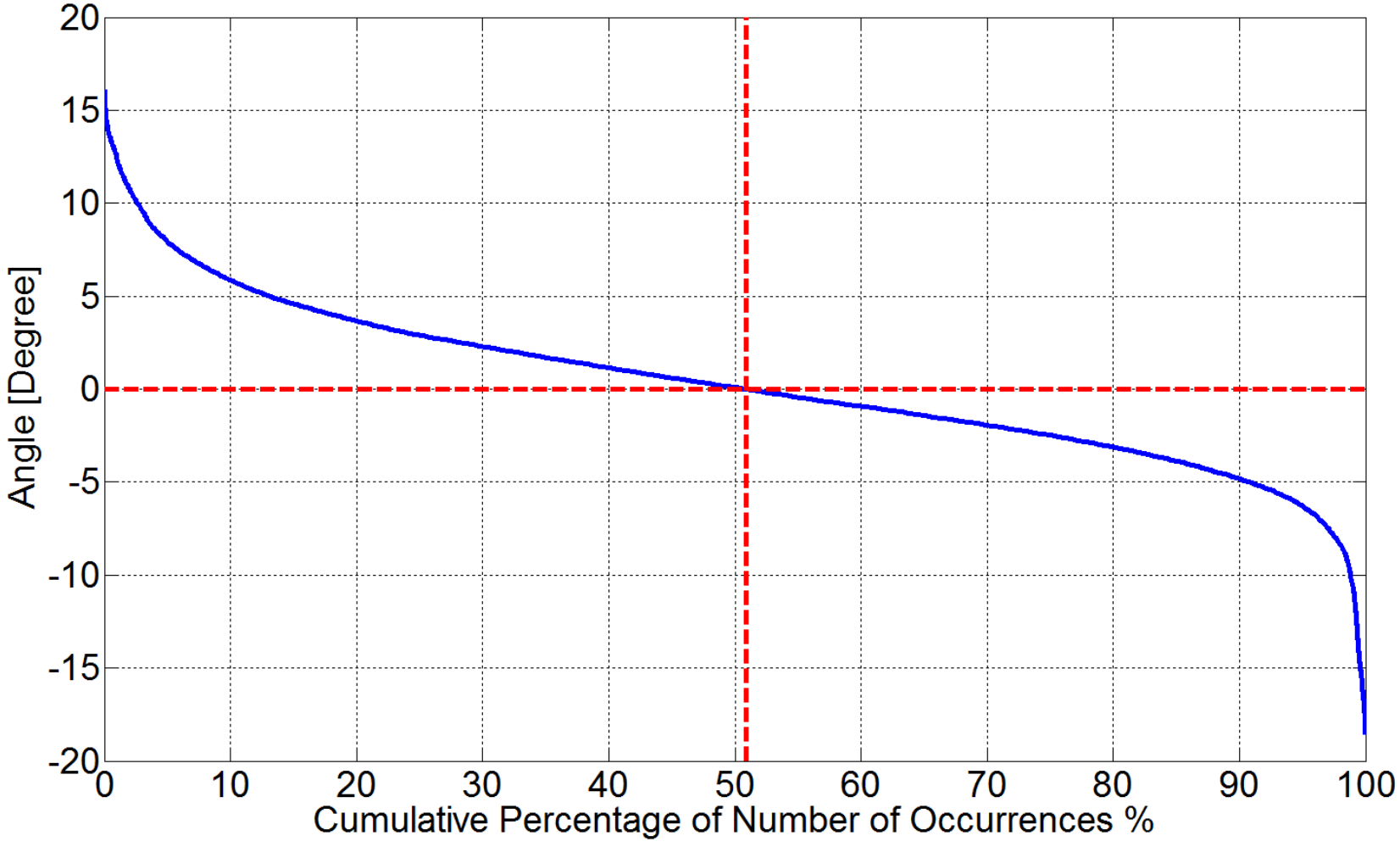

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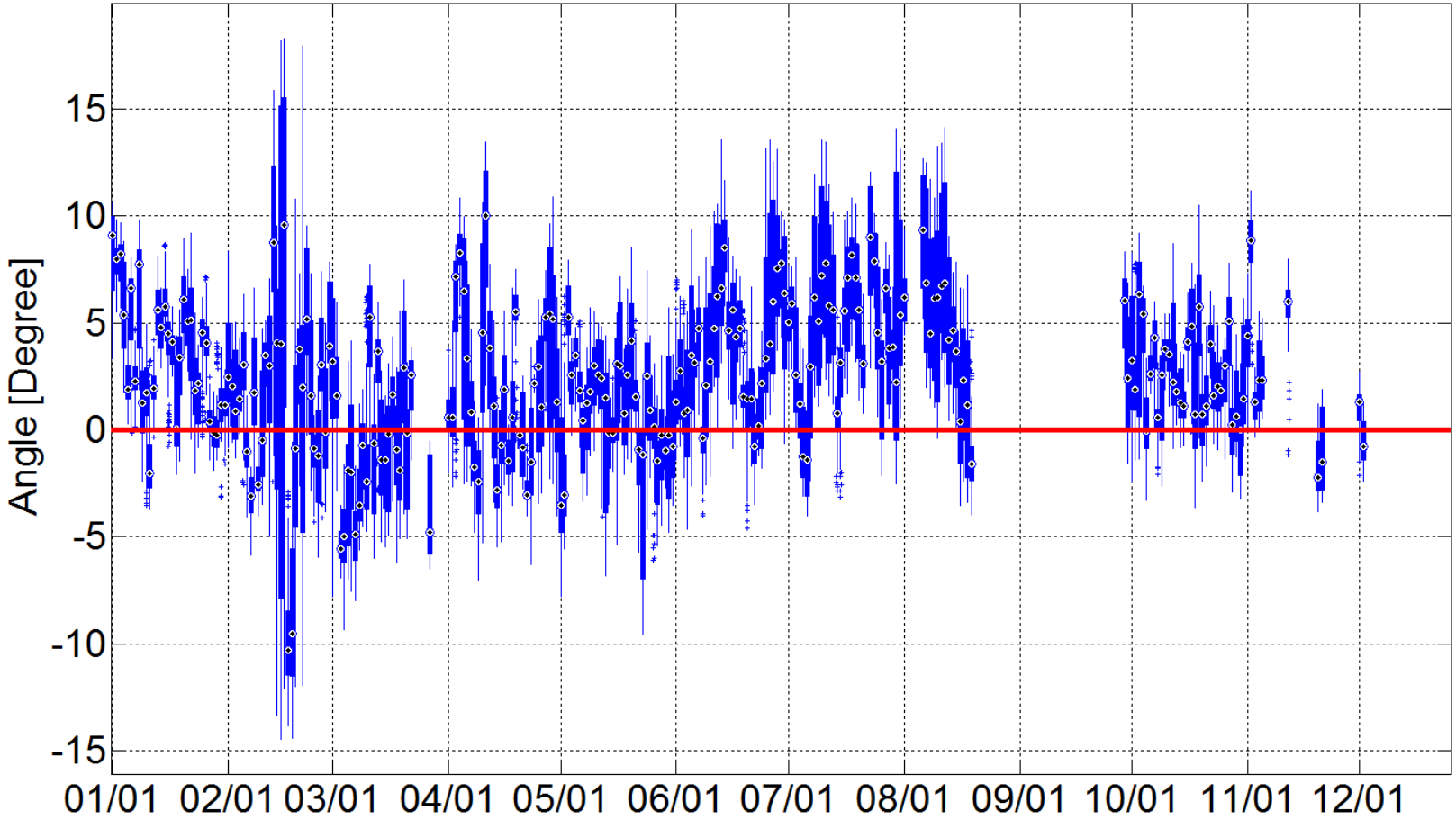

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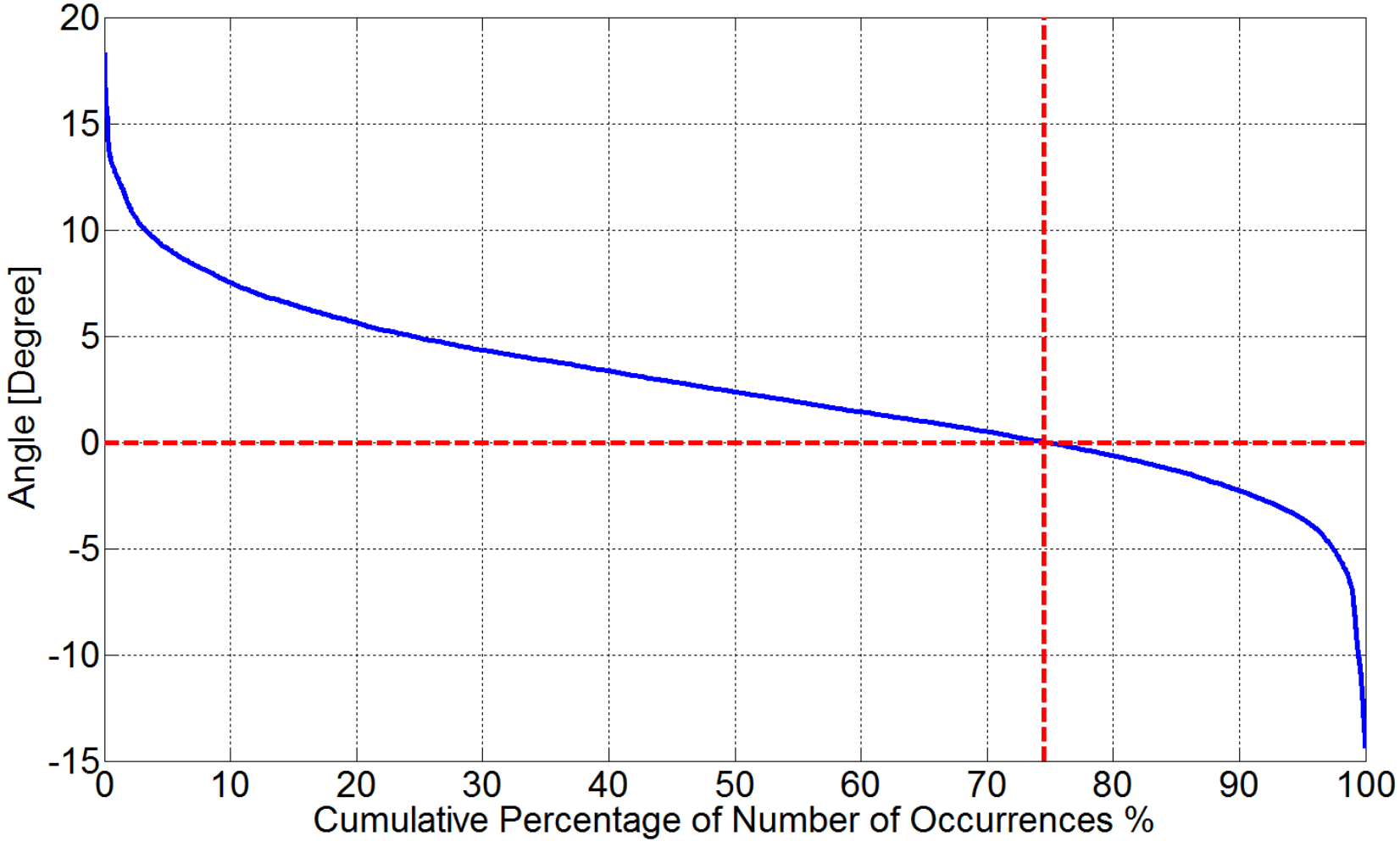

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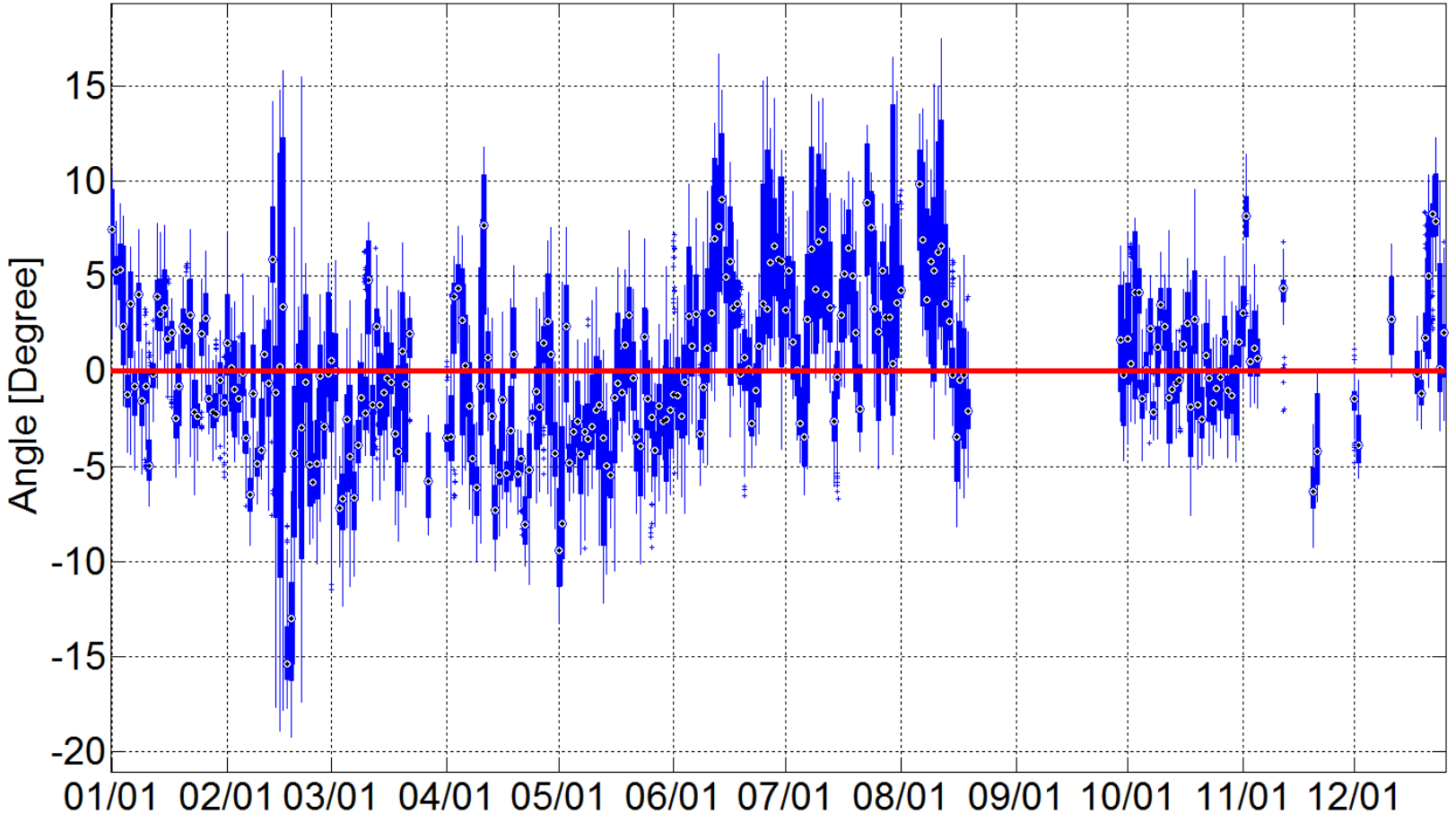

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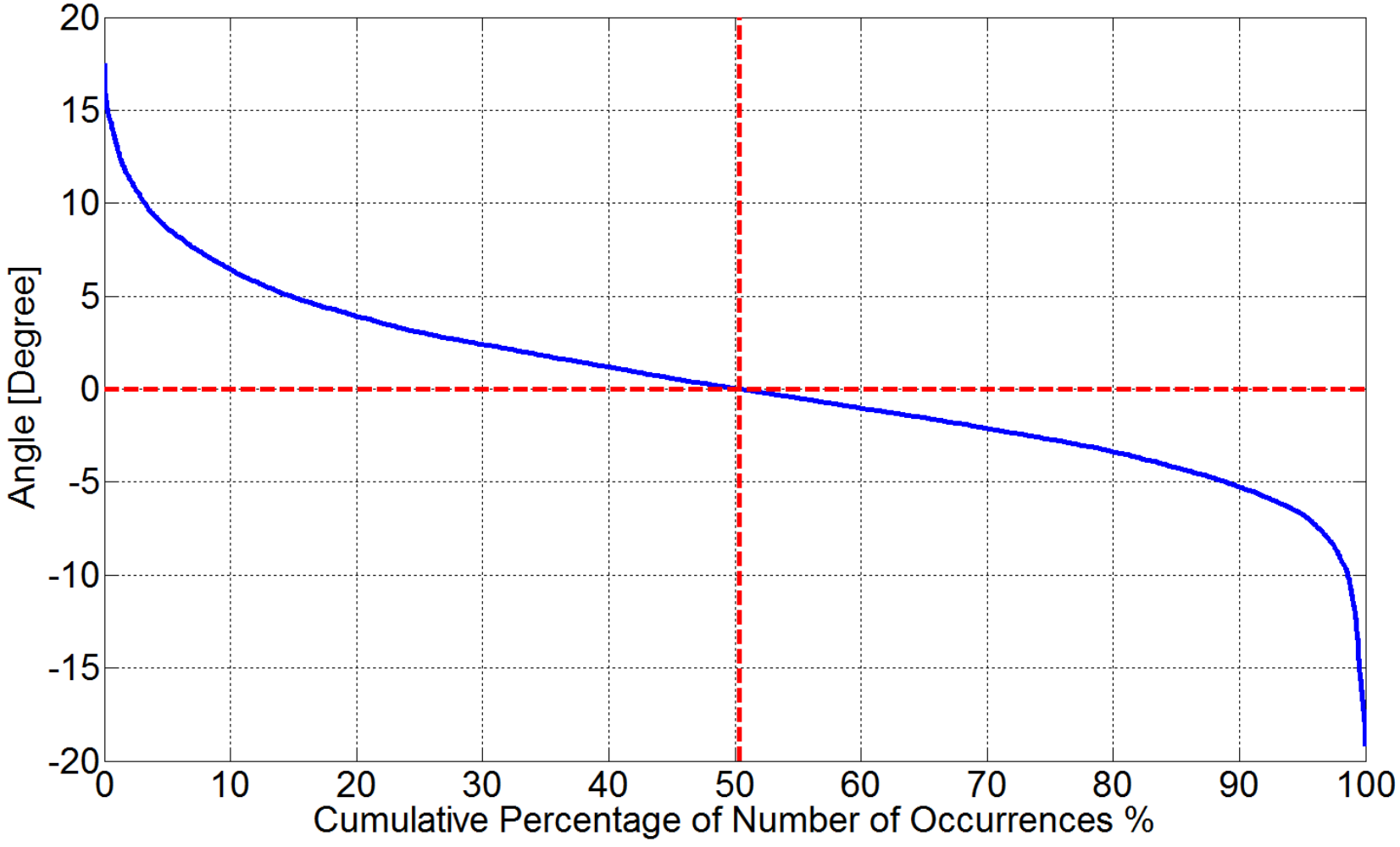
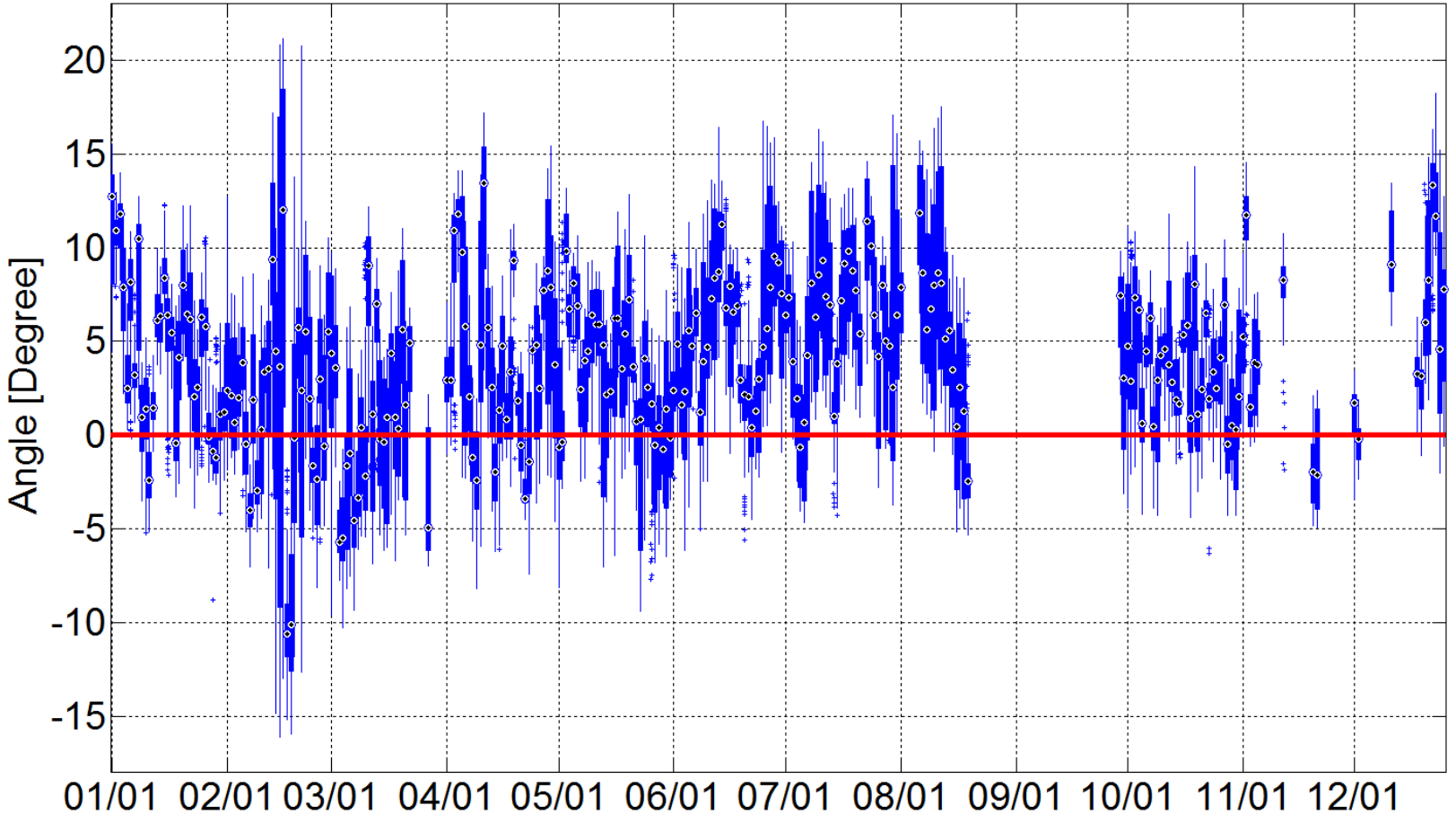


South 7-North 7



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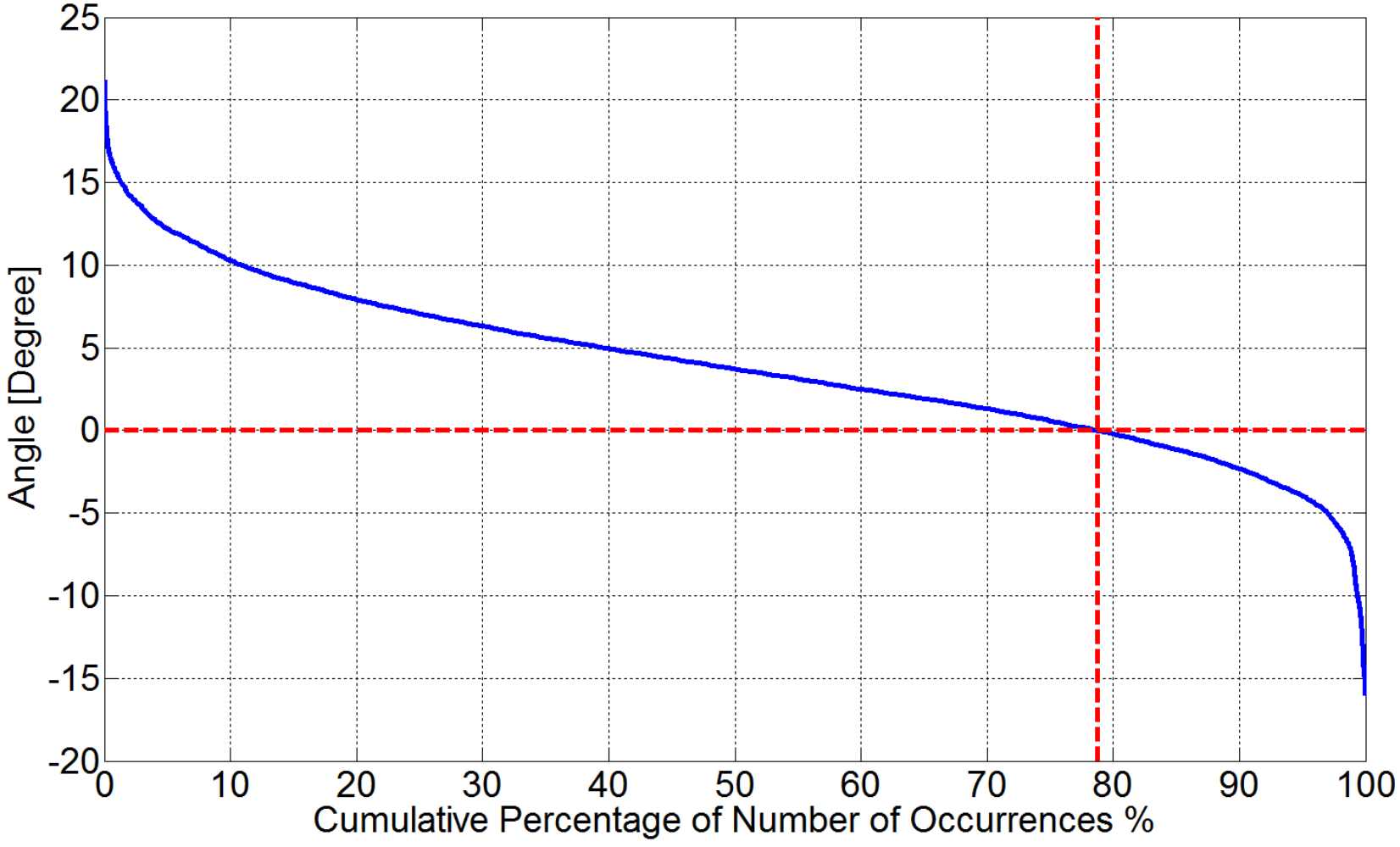
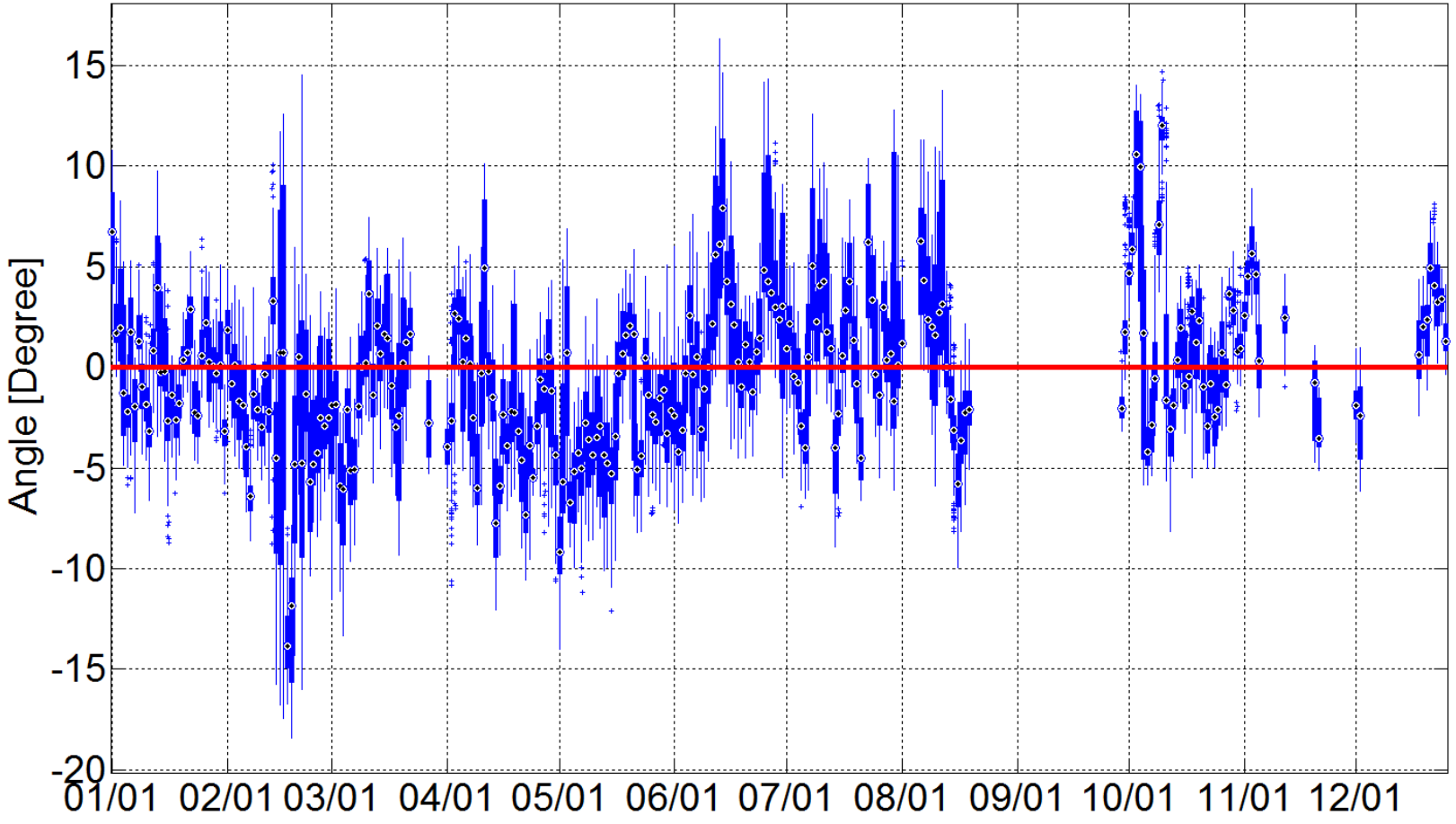


South 9-North 7



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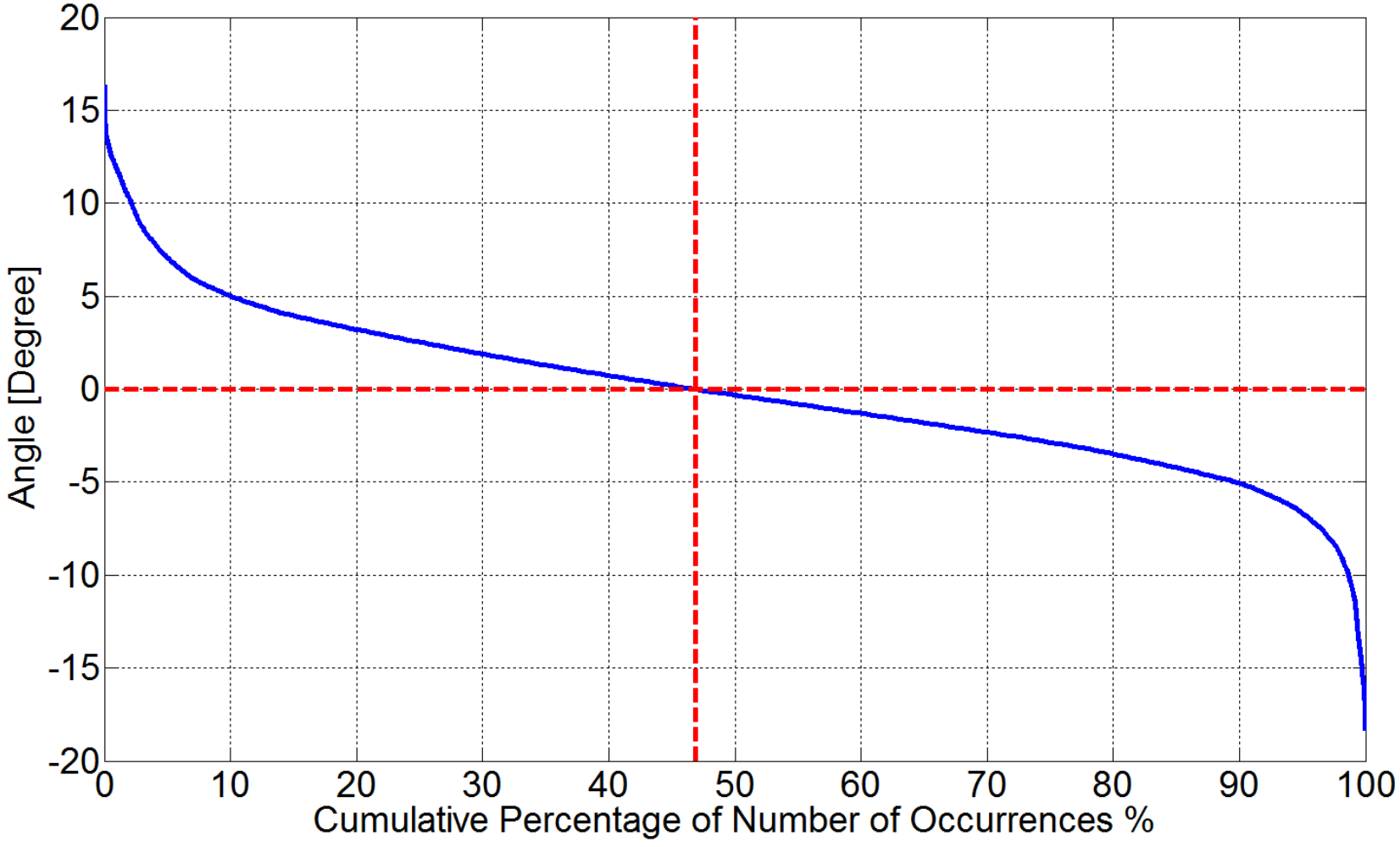
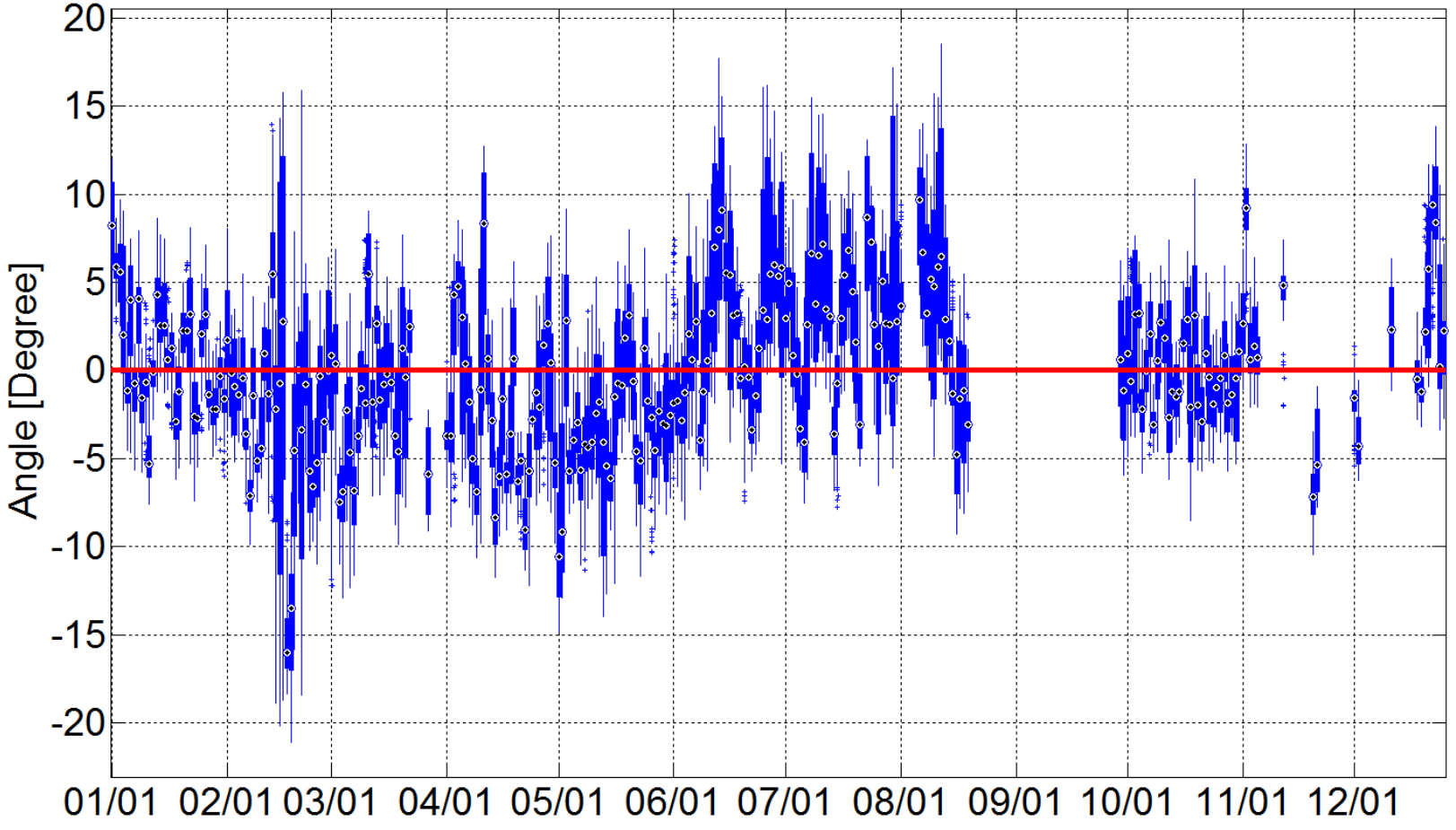


South 11-North 7



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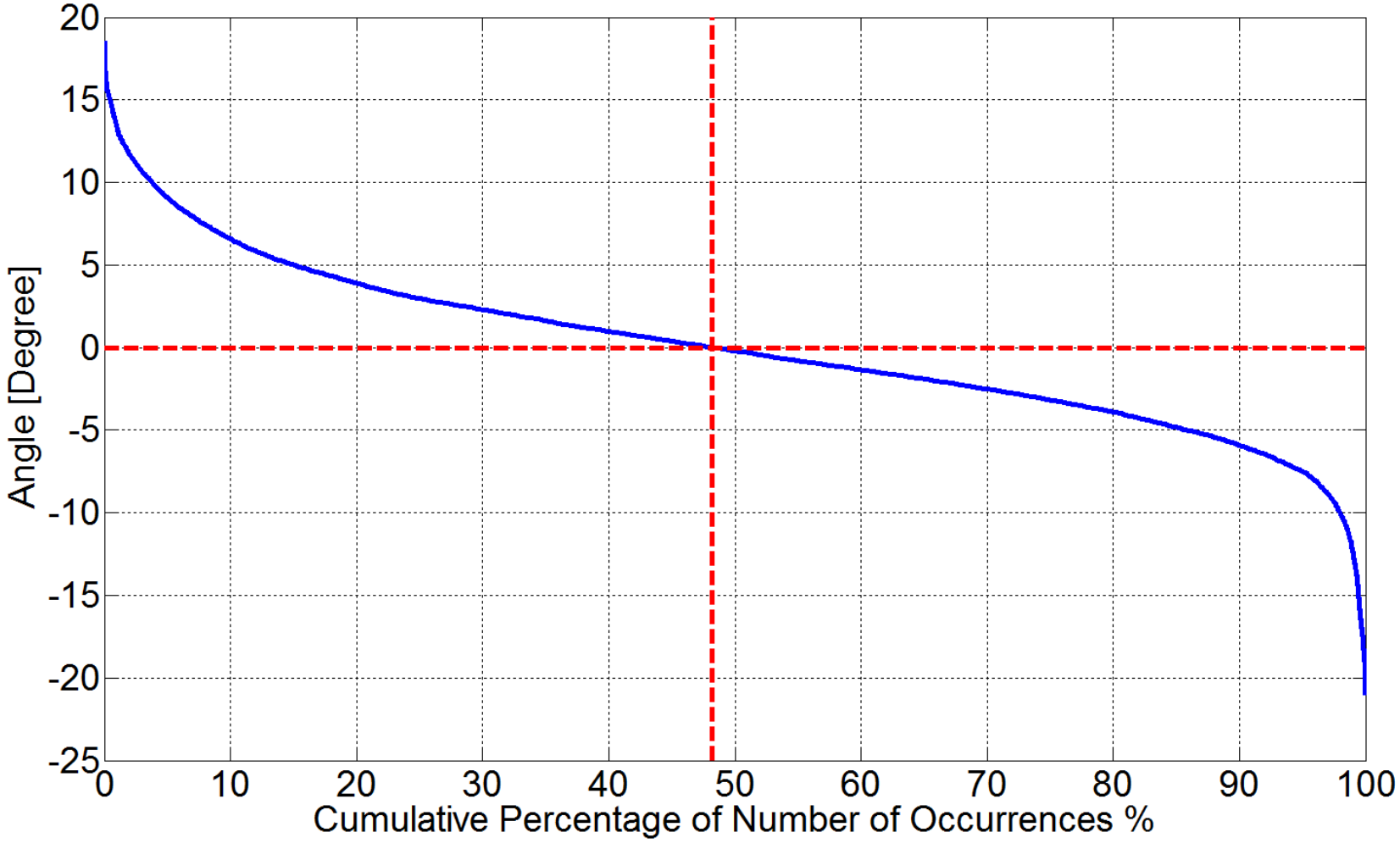

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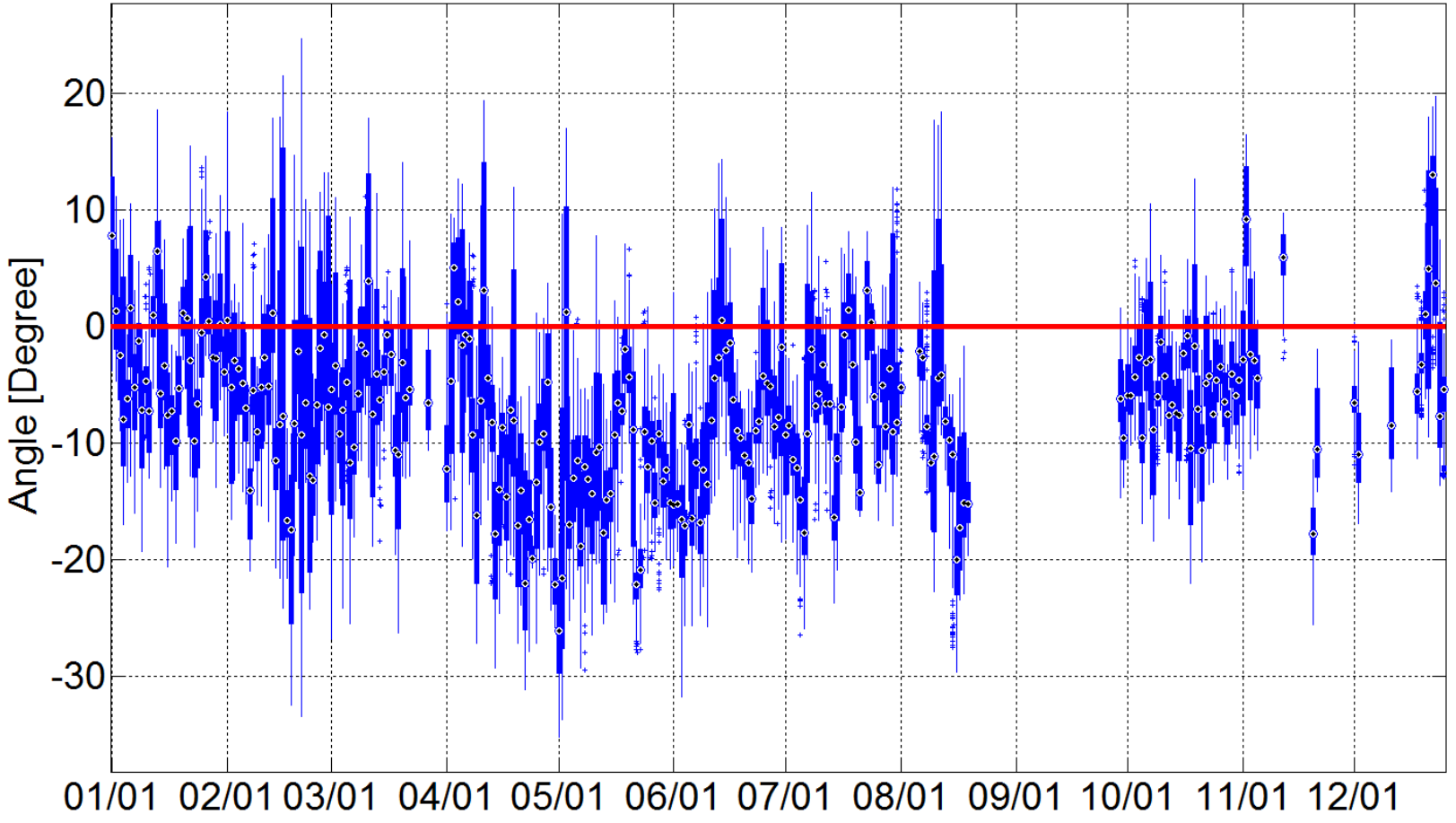

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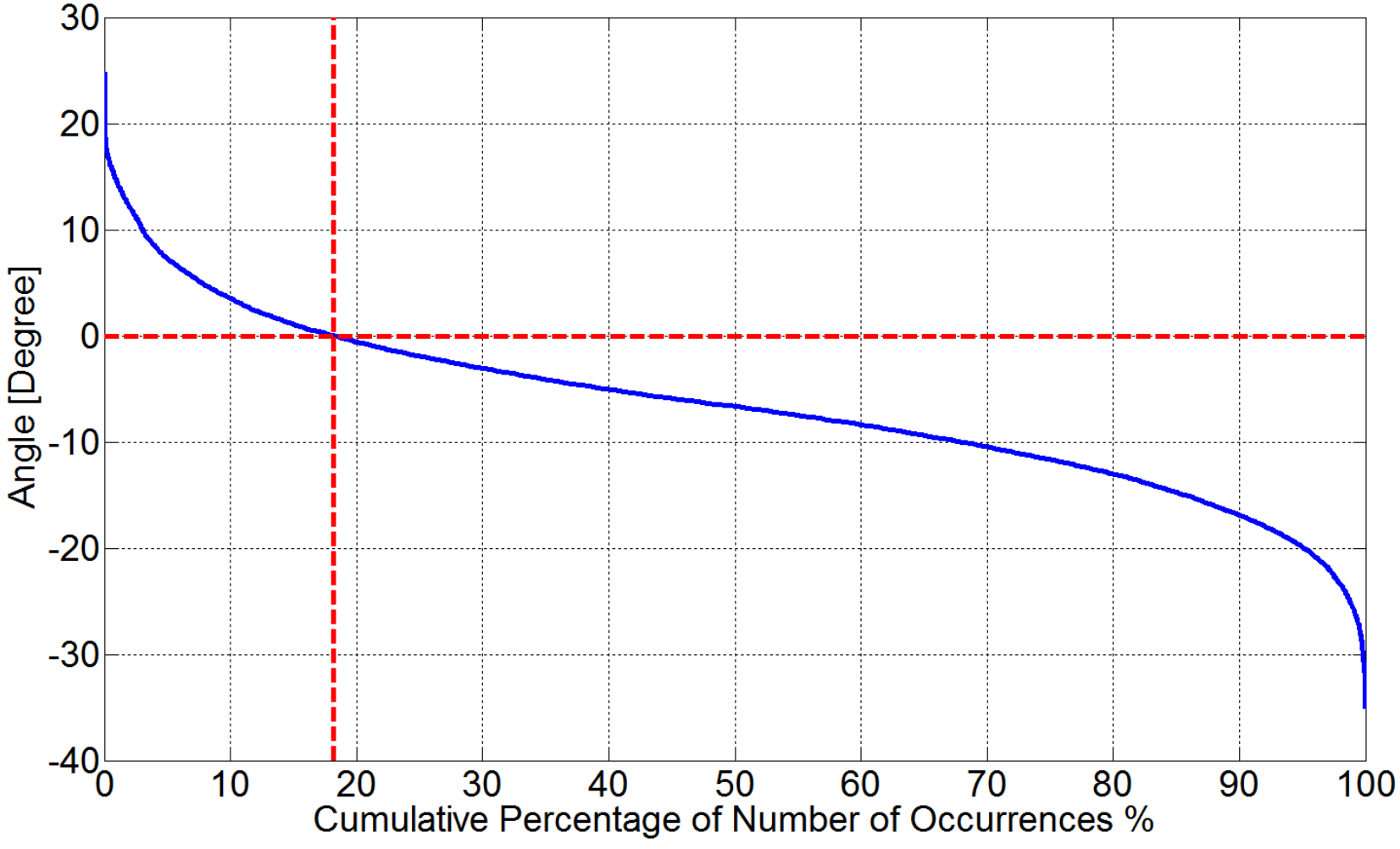
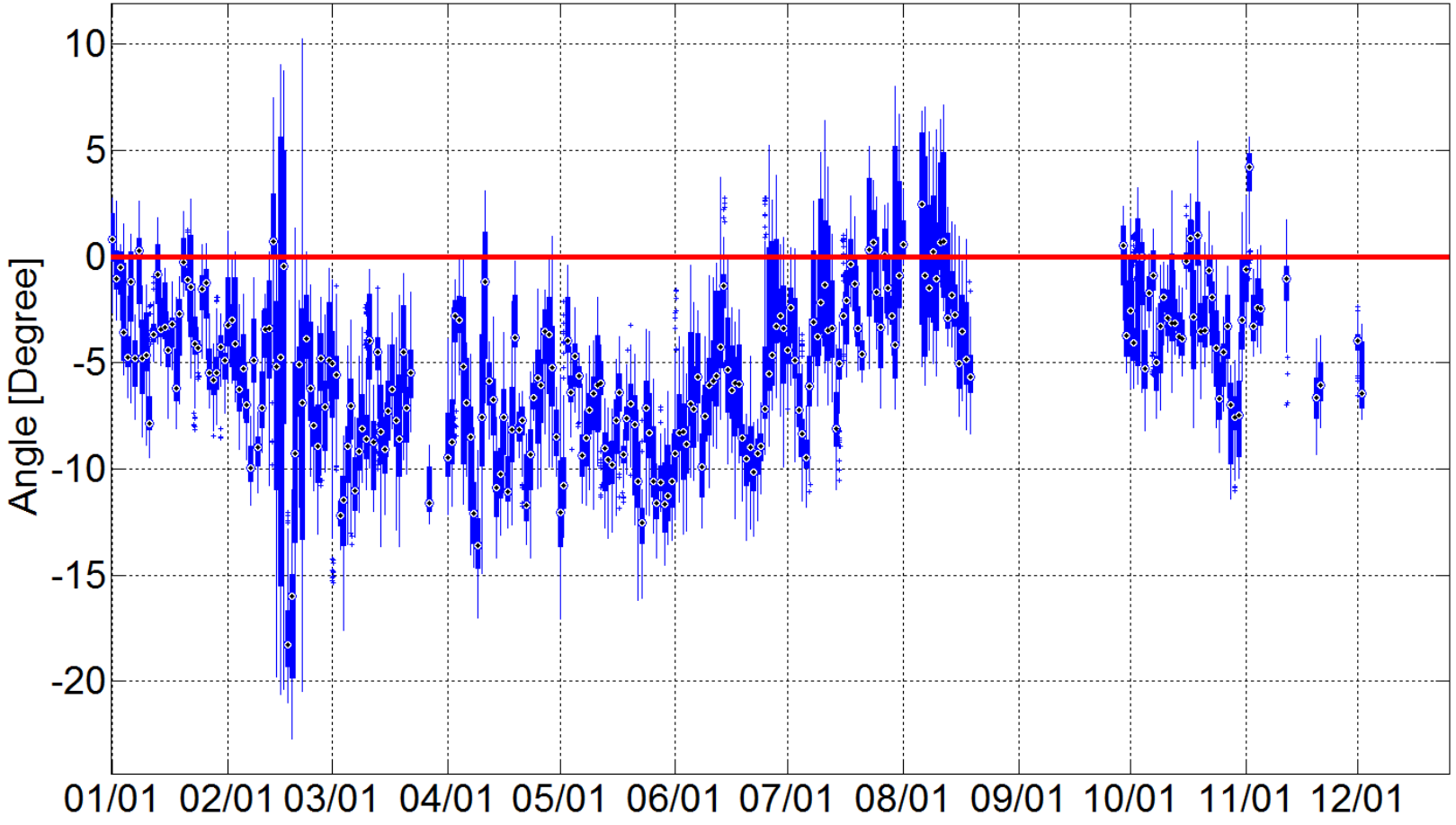
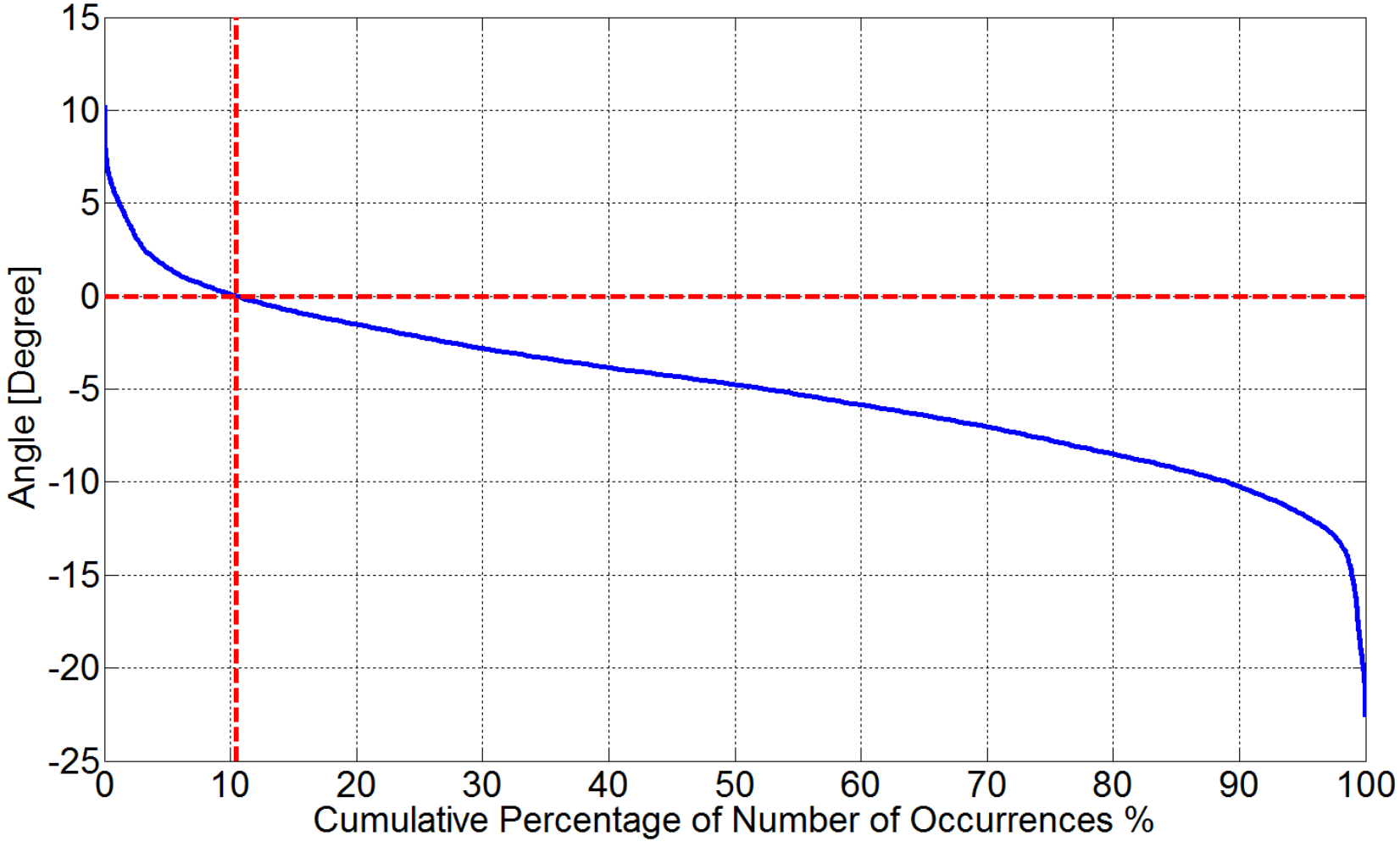


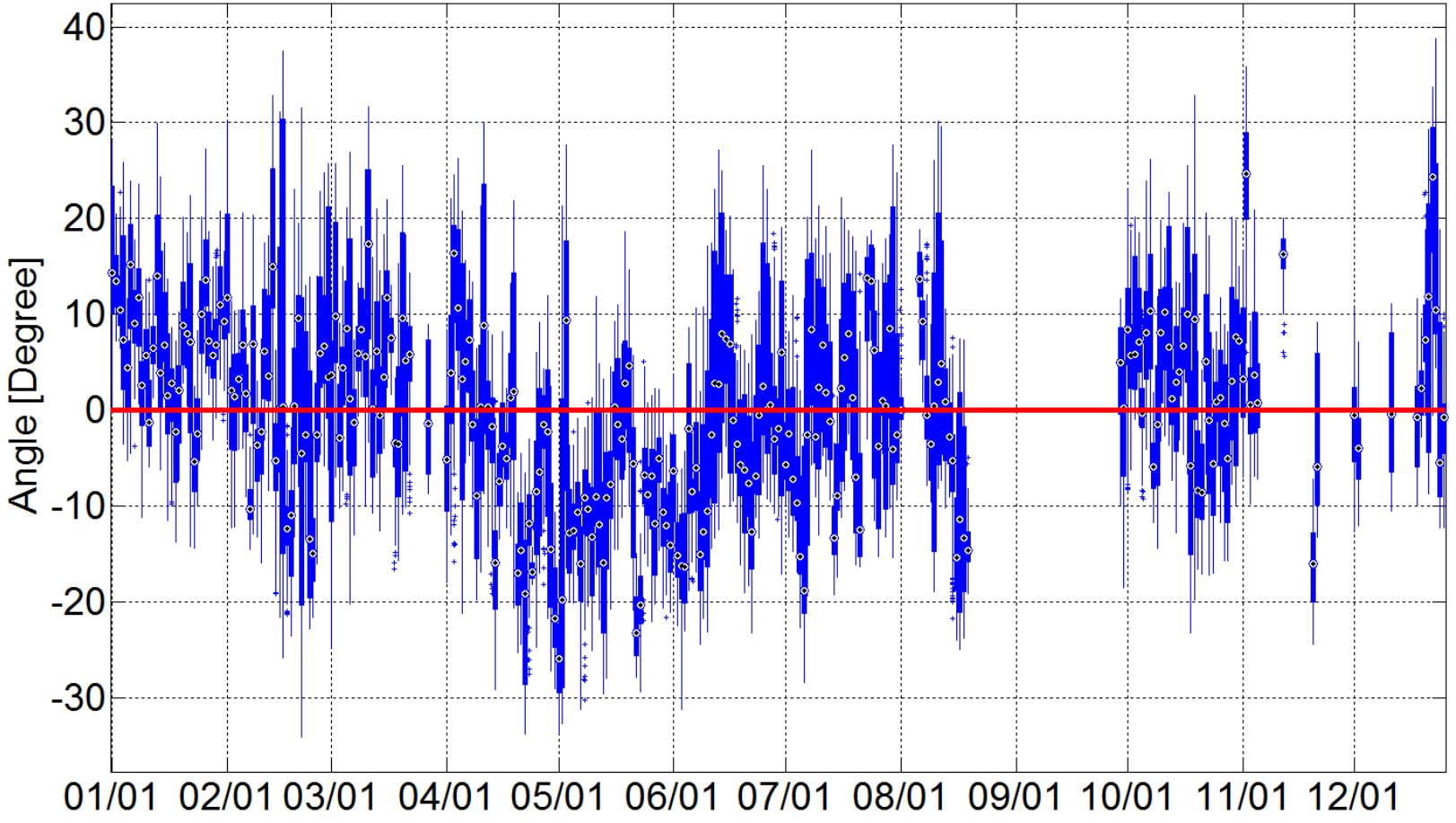
North 2-North 7



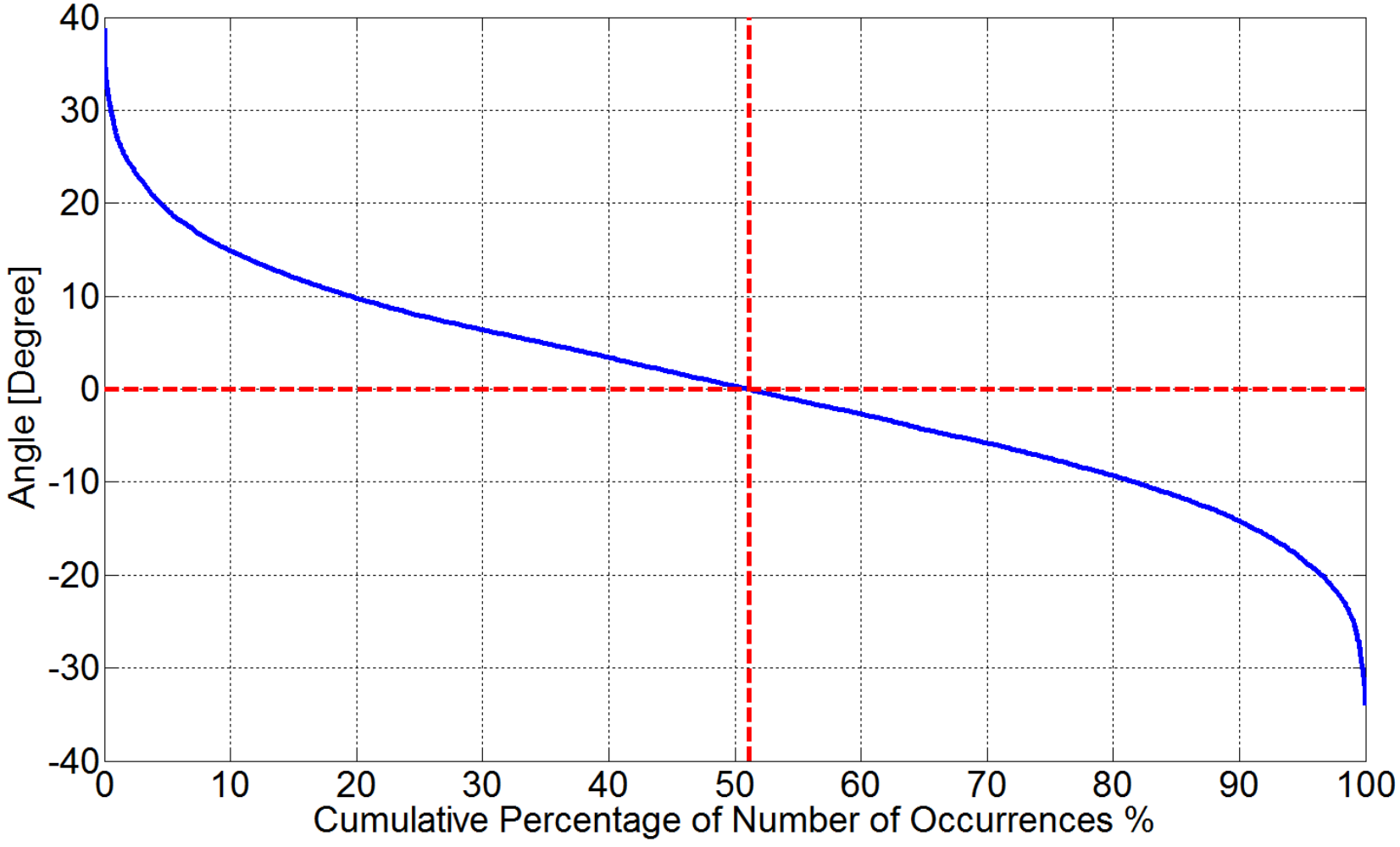
North 2-North 7



South 6-North 7



South 6-North 7



Appendix B – Part 2
CCET Discovery Across Texas project

Baseline Analysis Update - Voltage Angles (Reference: North 7)

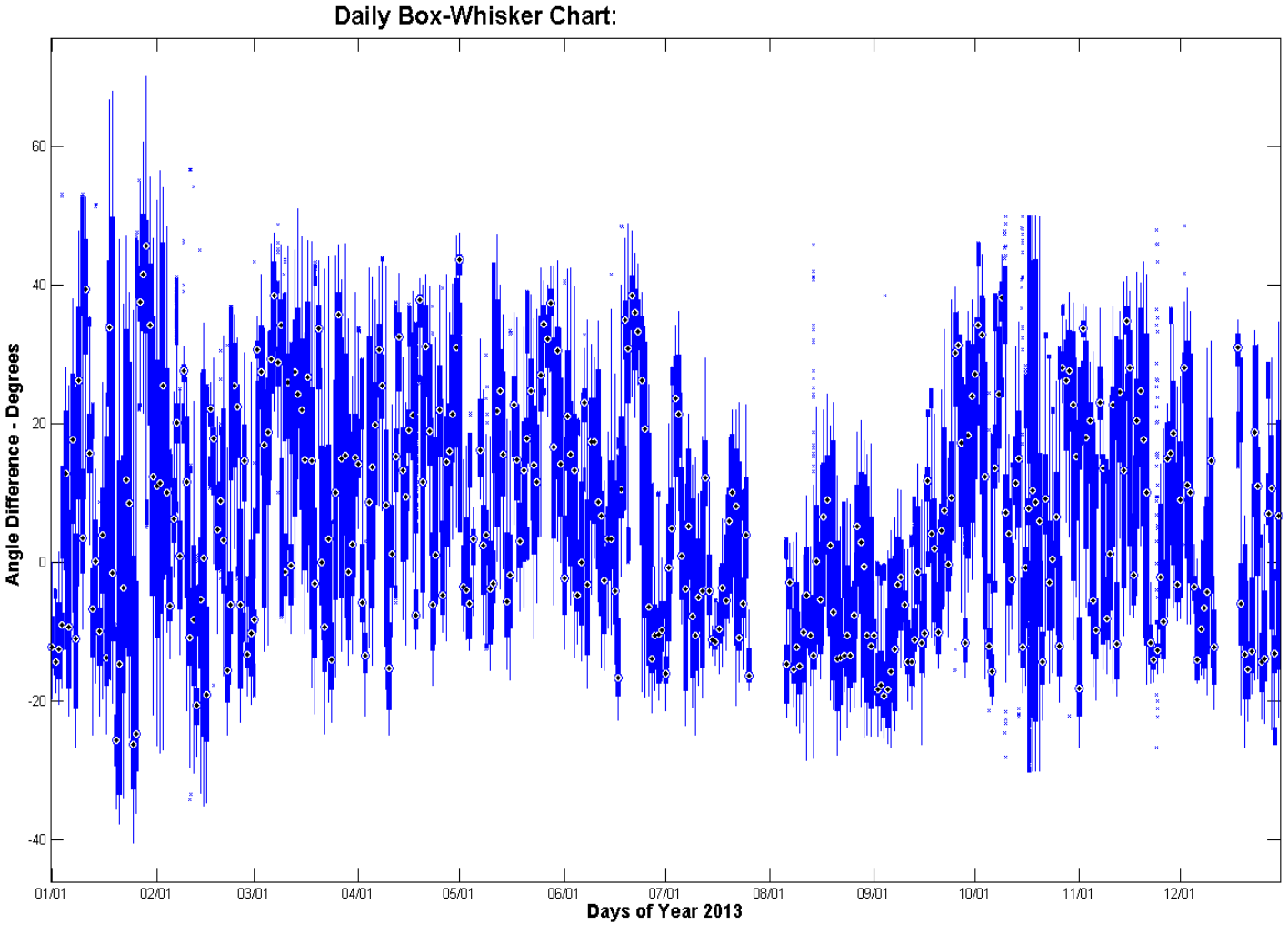
Phasor Data: January to December 2013
Box-Whisker Plots and Time Duration Curves

Electric Power Group

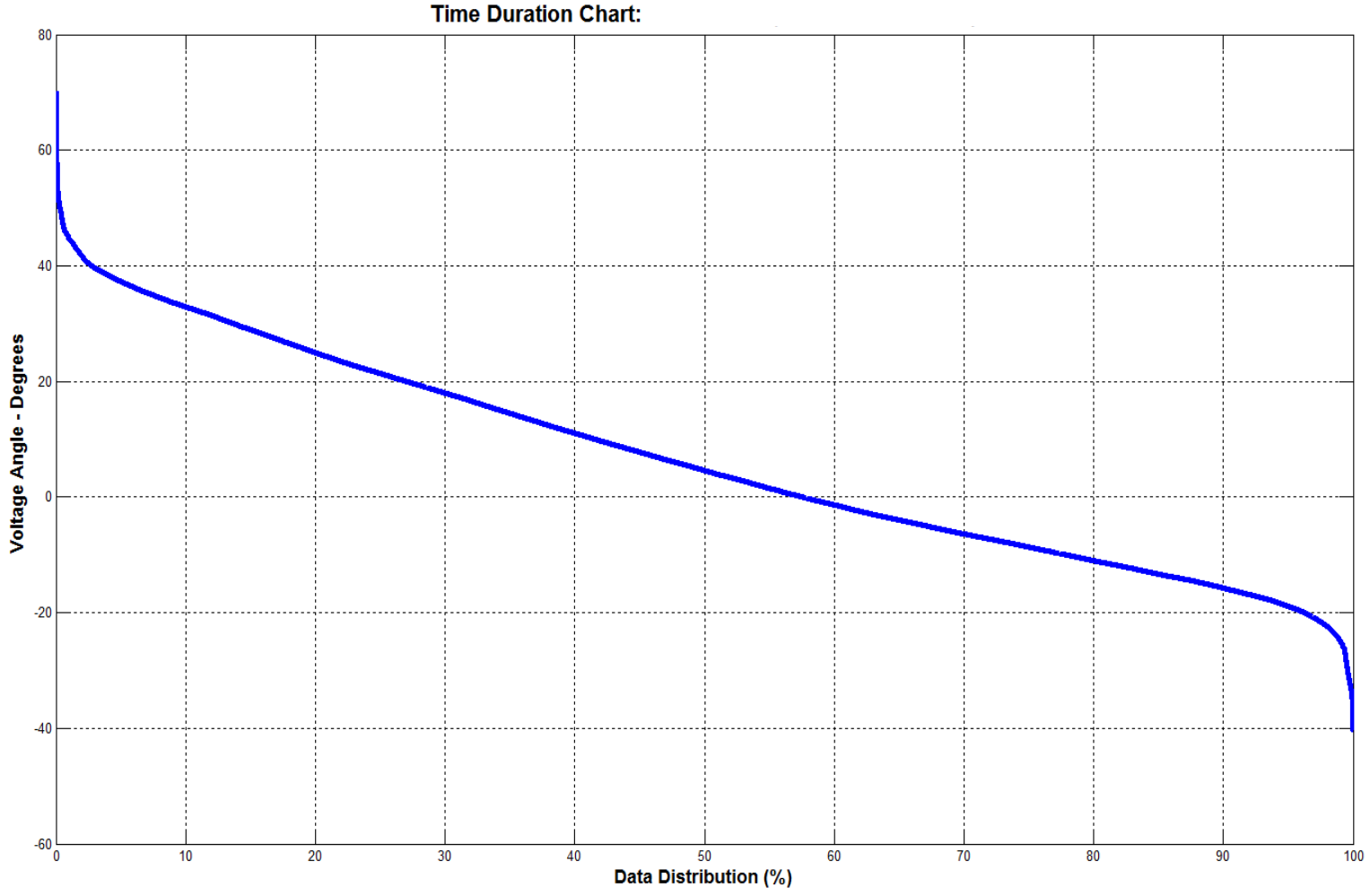
CCET

ERCOT

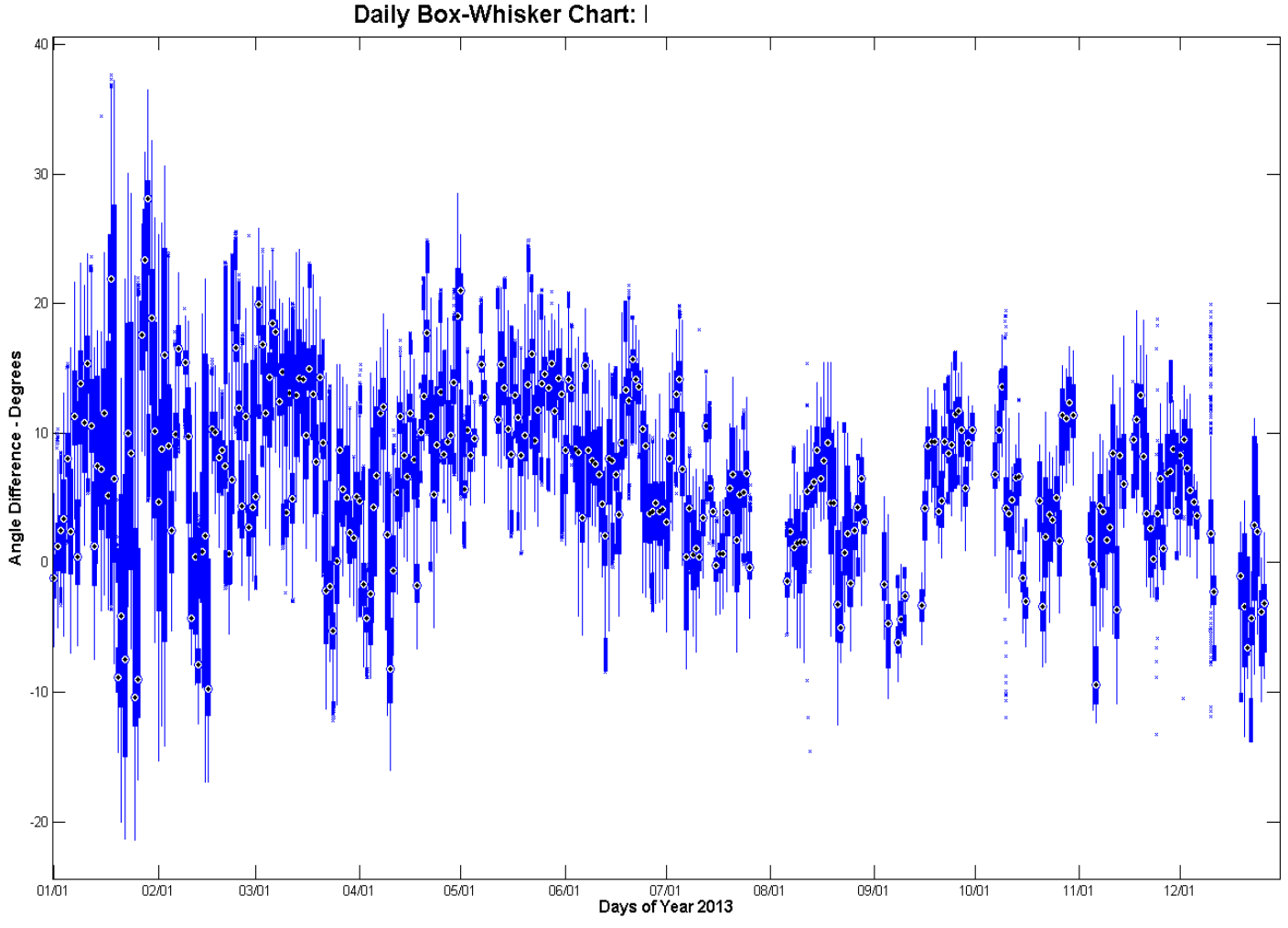
West 10


Daily Box-Whisker Chart:
Angle Difference - Degrees
60
40
20
0
-20
-40
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

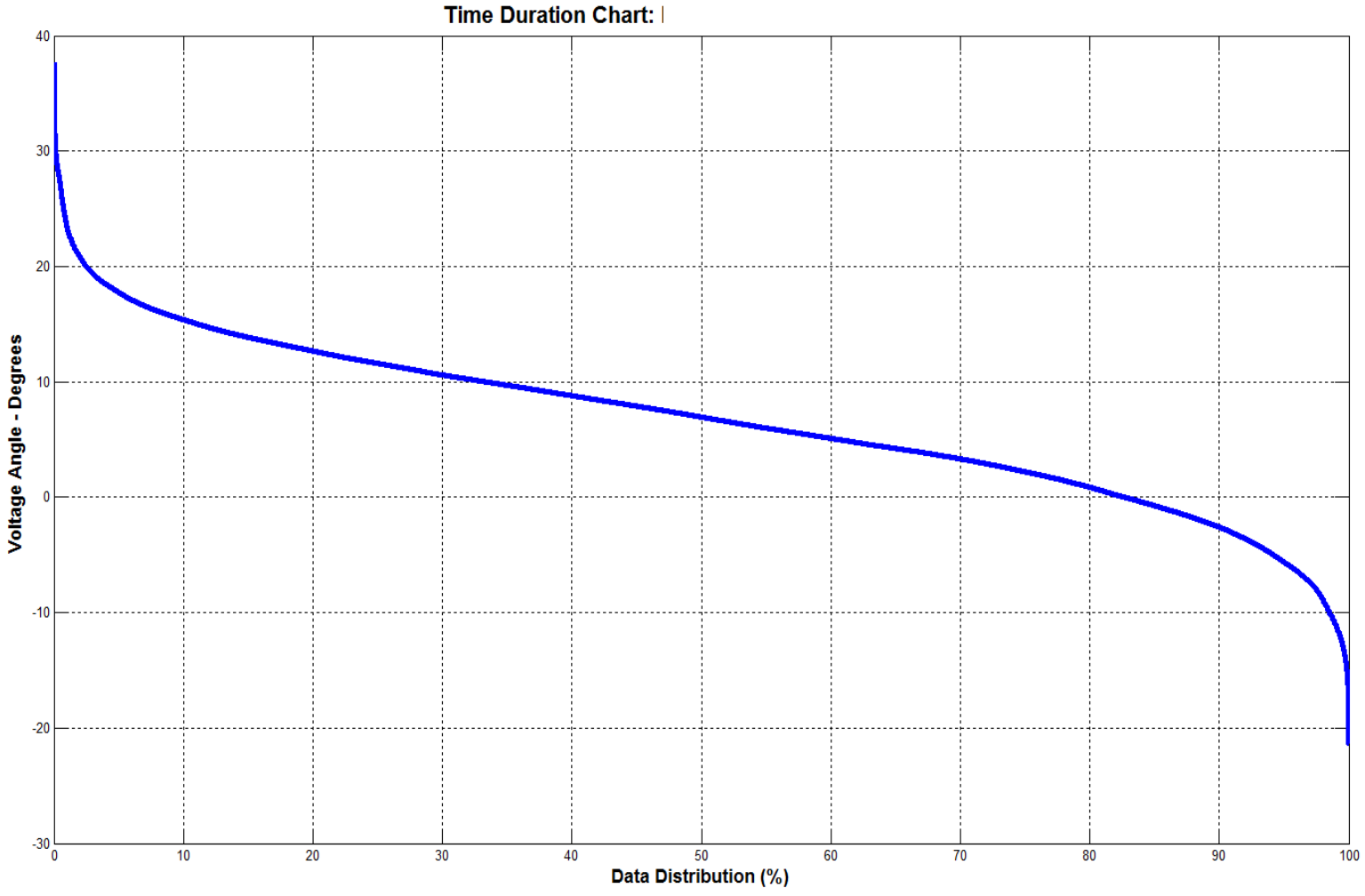
West 10


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
80
60
40
20
0
-20
-40
-60
0
10
20
30
40
50
60
70
80
90
100

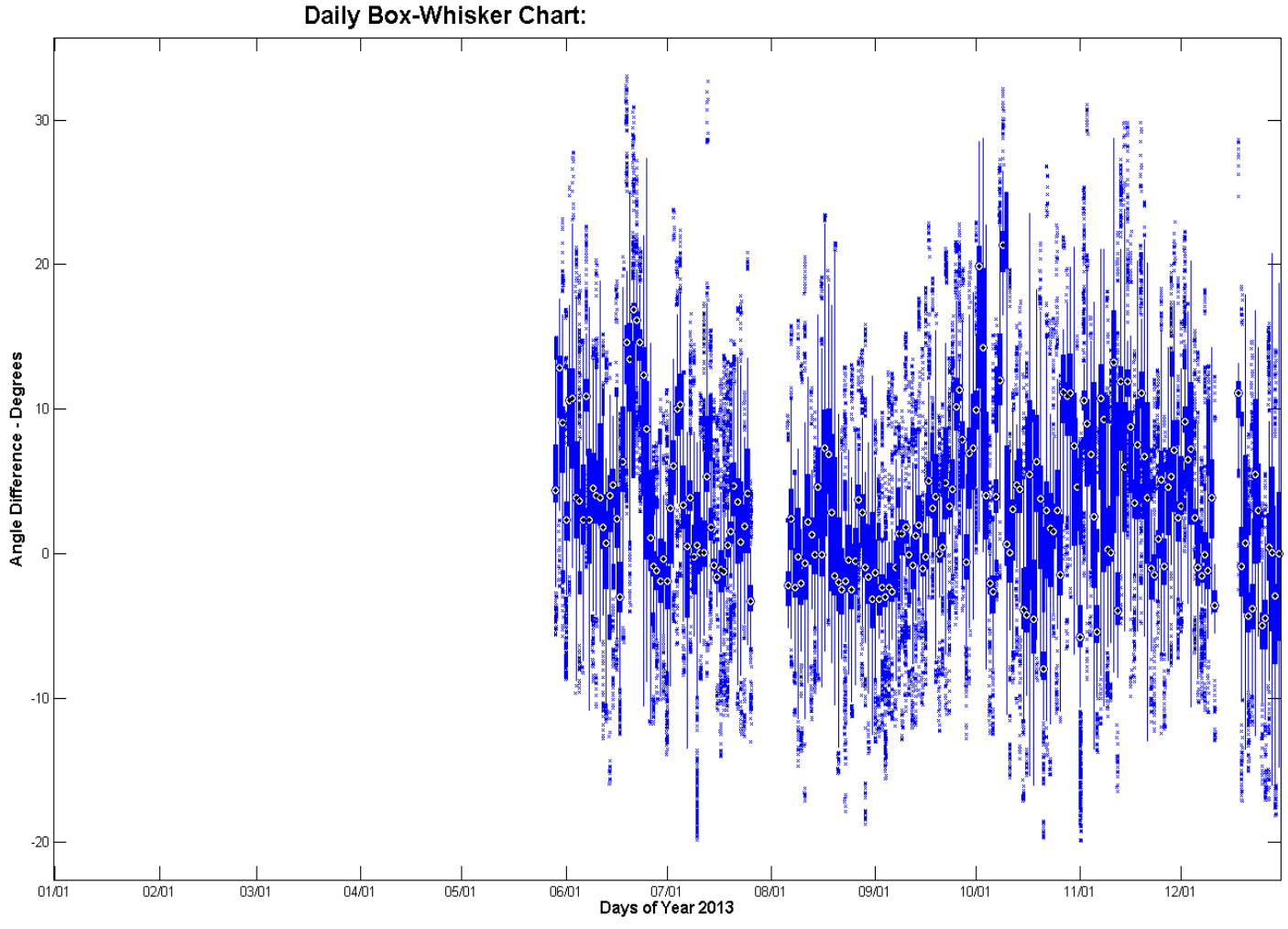
West 14


Daily Box-Whisker Chart: I
Angle Difference - Degrees
40
30
20
10
0
-10
-20
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

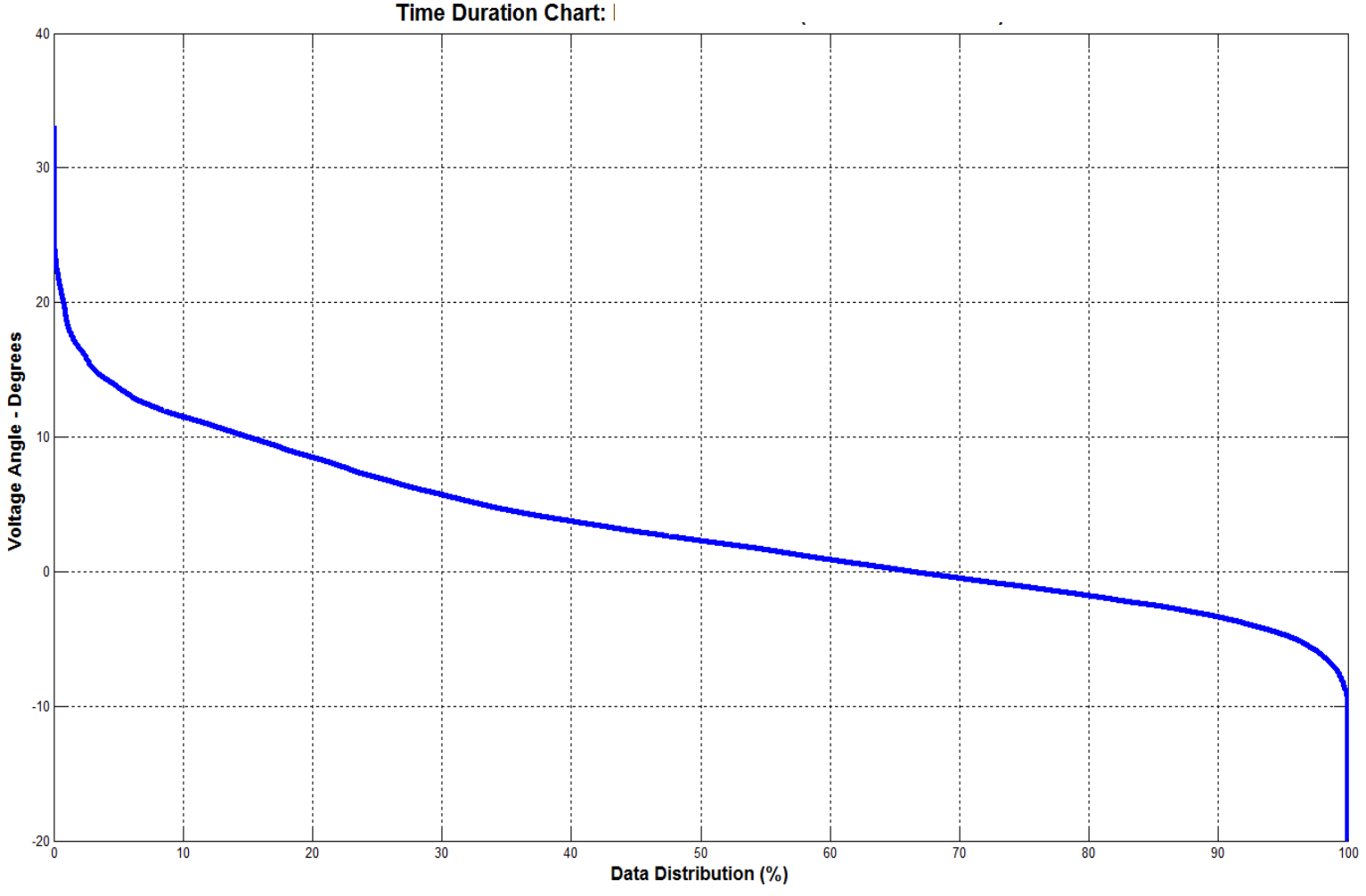
West 14


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
40
30
20
10
0
-10
-20
-30
0
10
20
30
40
50
60
70
80
90
100

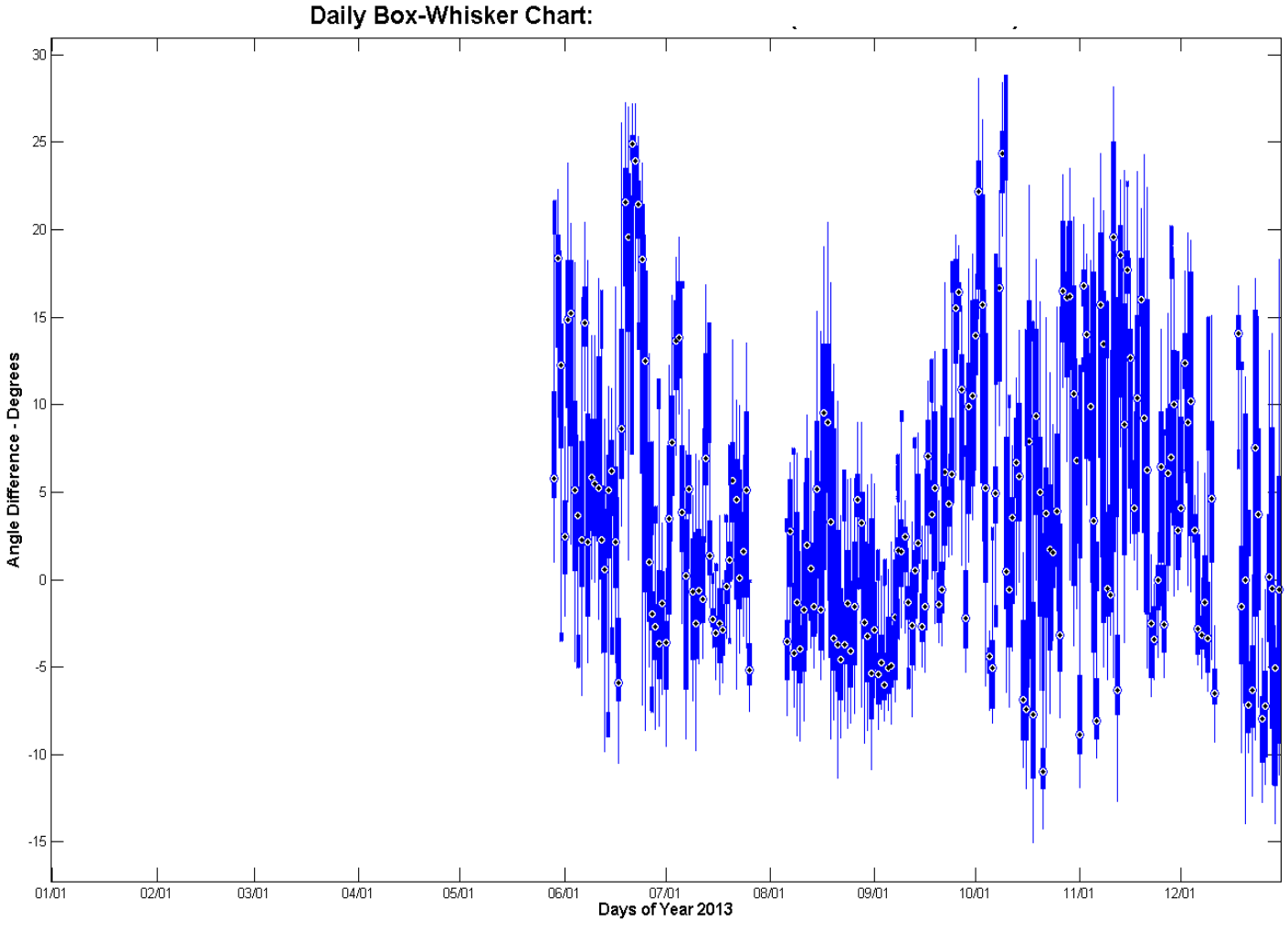
West 1


Daily Box-Whisker Chart:
Angle Difference - Degrees
30
20
10
0
-10
-20
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

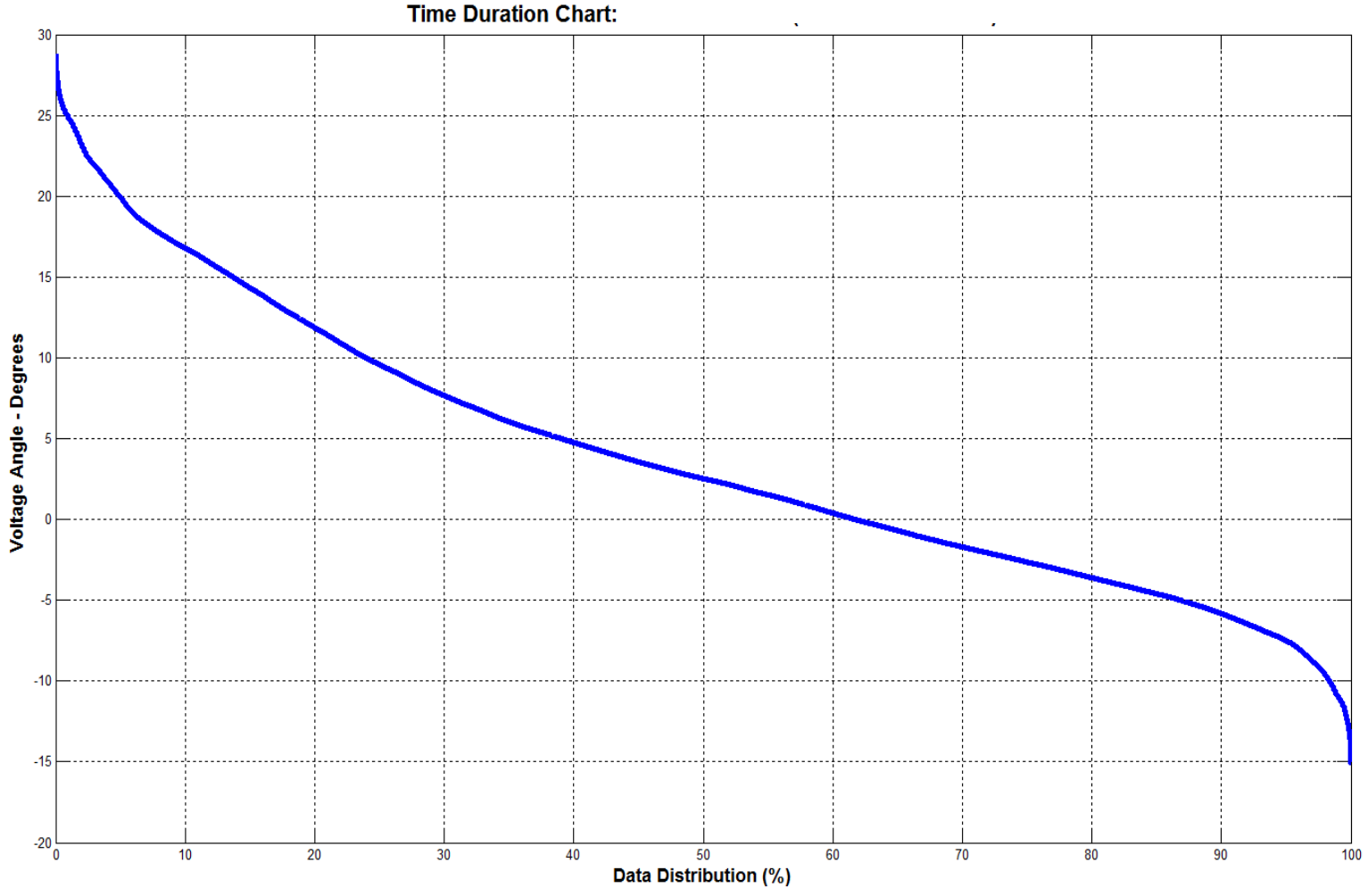
West 1


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
40
30
20
10
0
-10
-20
0
10
20
30
40
50
60
70
80
90
100

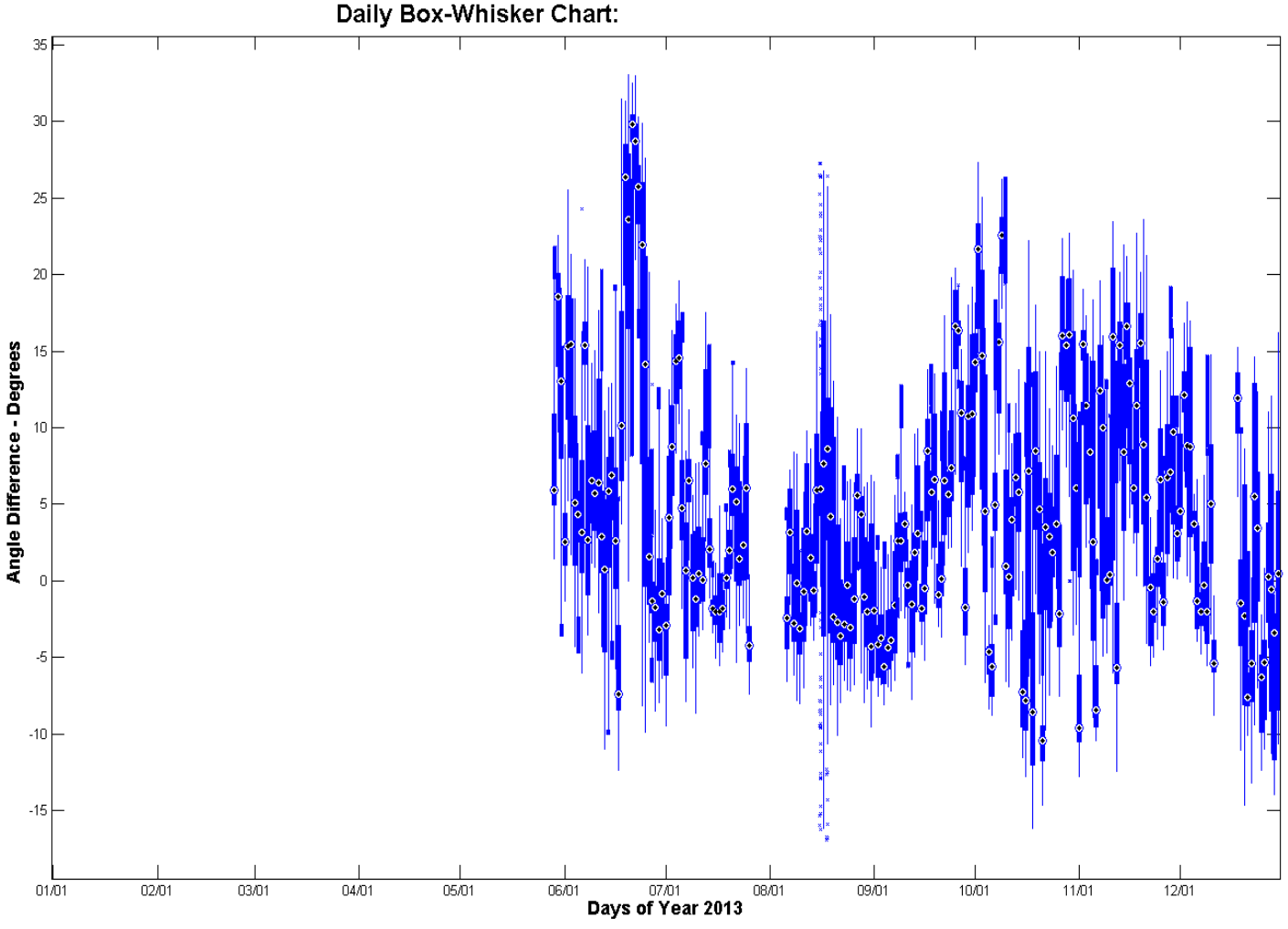
West 2


Daily Box-Whisker Chart:
Angle Difference - Degrees
30
25
20
15
10
5
0
-5
-10
-15
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

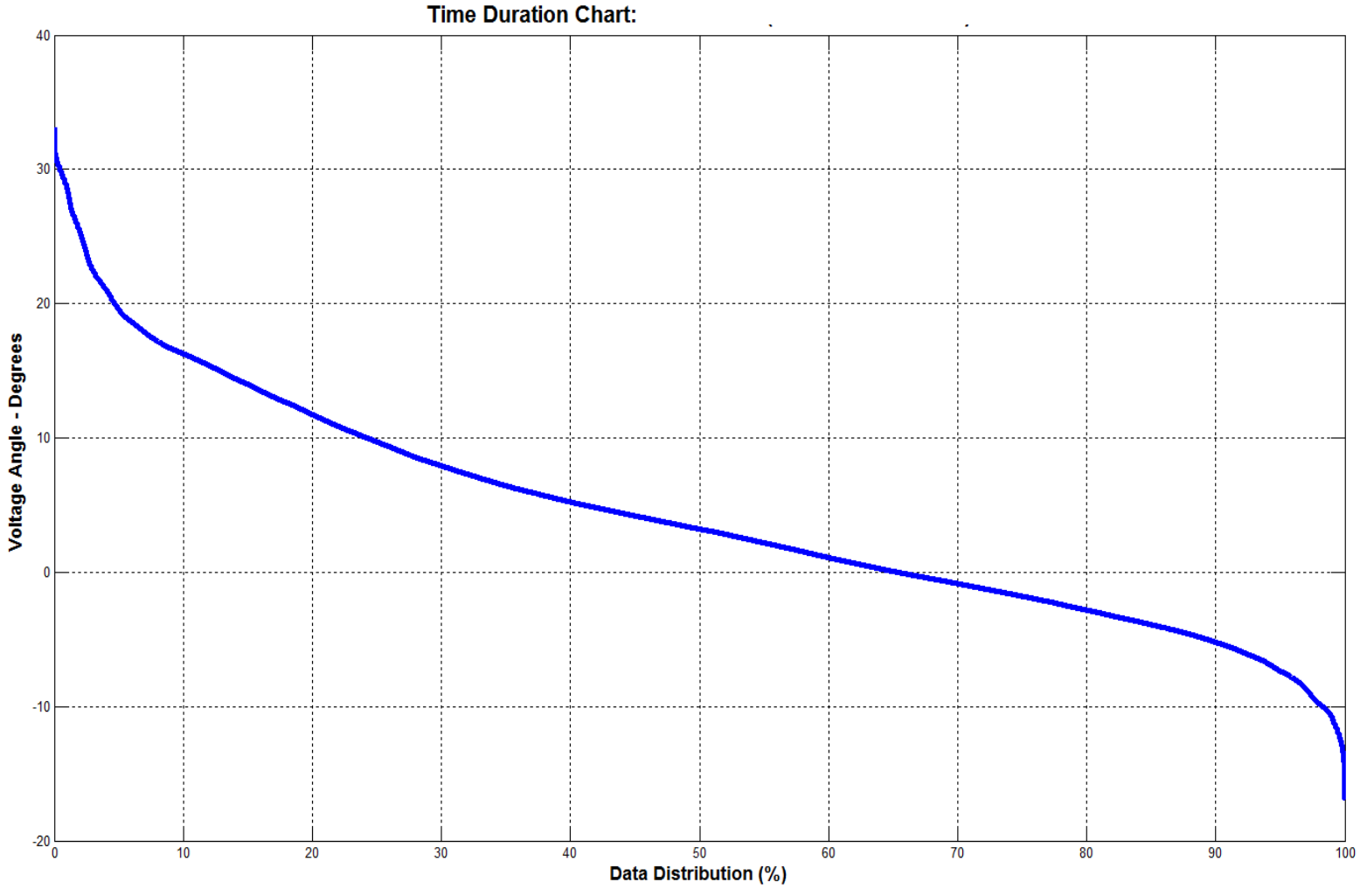
West 2


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
30
25
20
15
10
5
0
-5
-10
-15
-20
0
10
20
30
40
50
60
70
80
90
100

West 9


Daily Box-Whisker Chart:
Angle Difference - Degrees
35
30
25
20
15
10
5
0
-5
-10
-15
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

West 9


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
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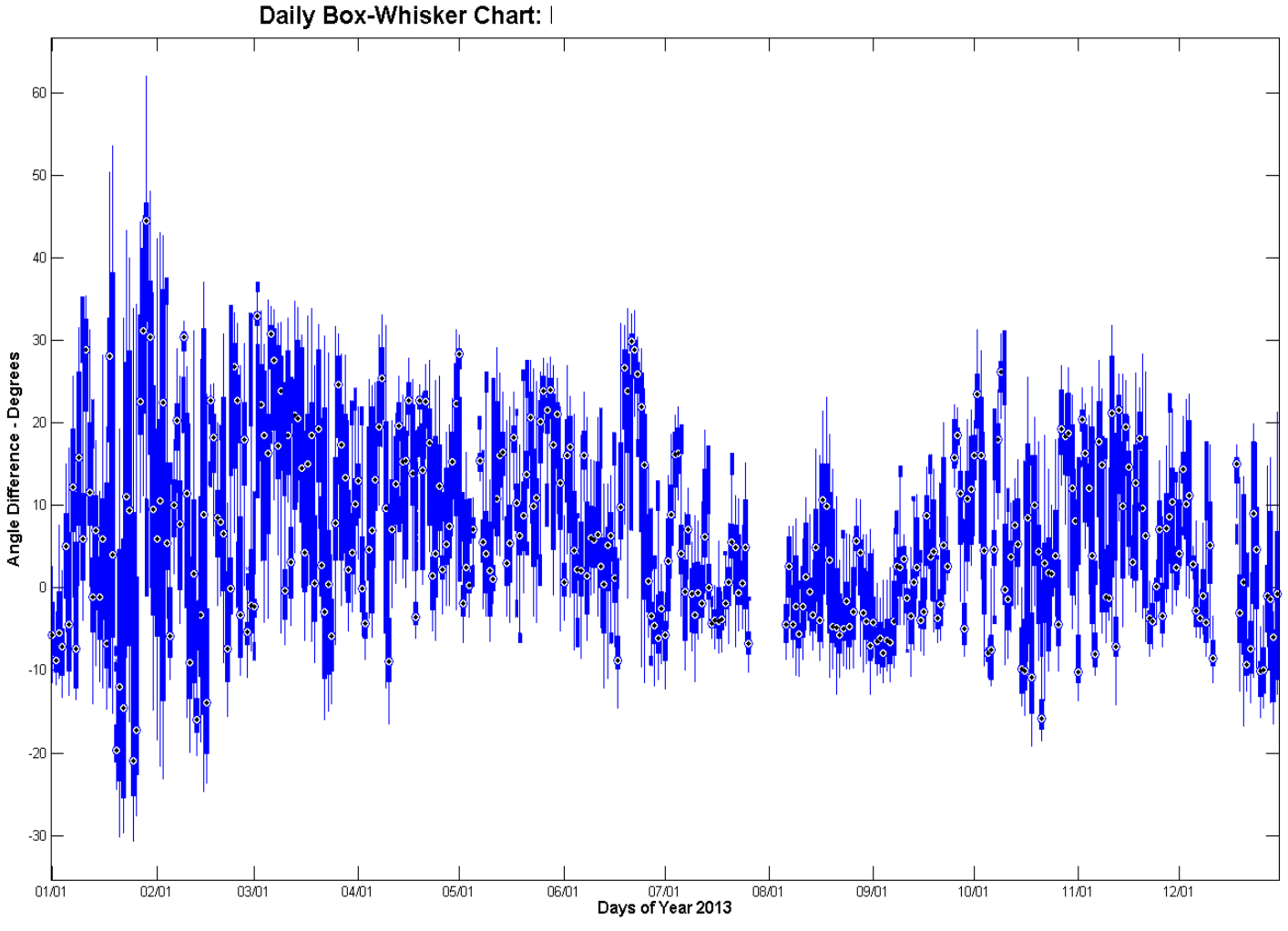
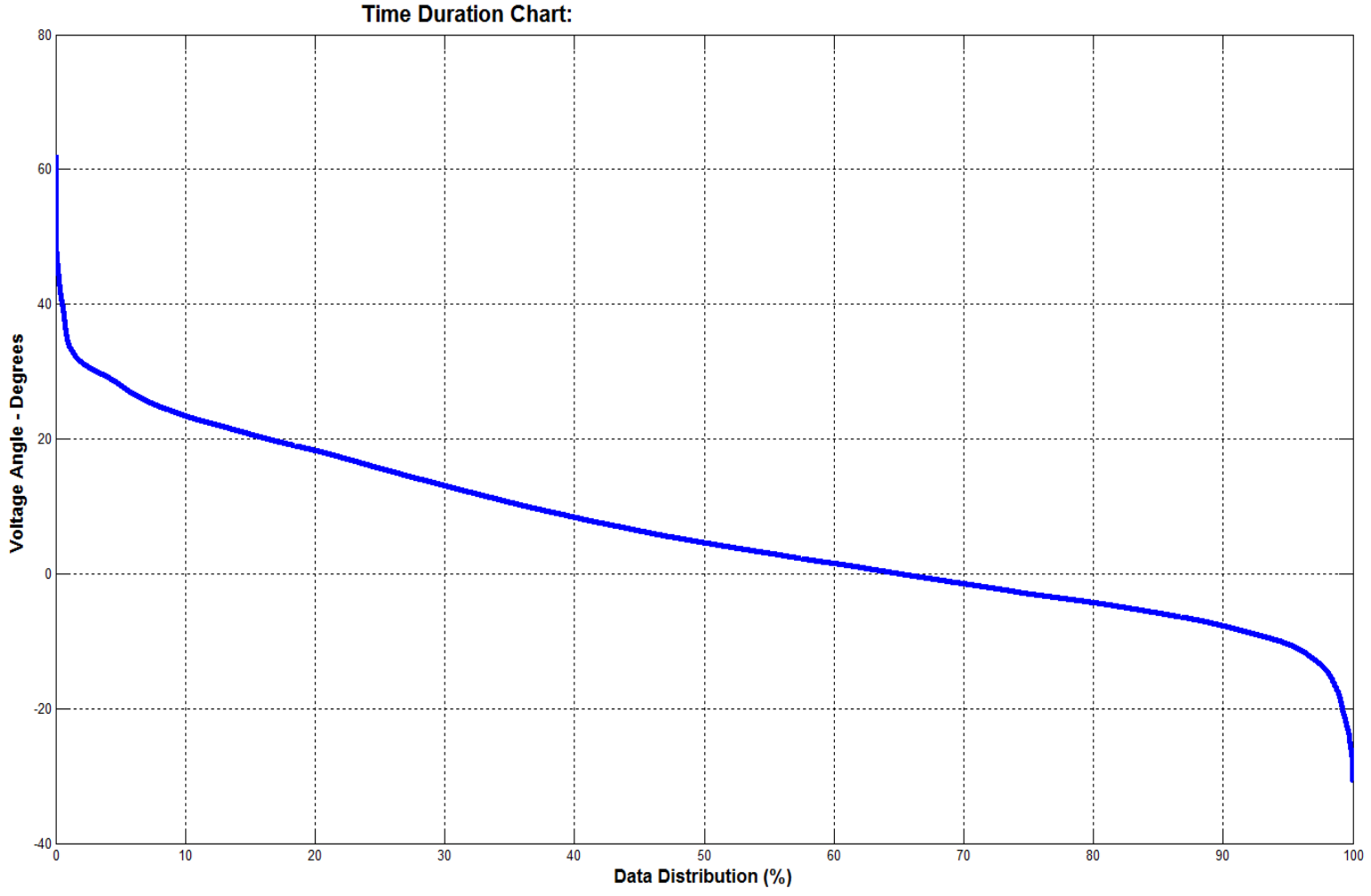
30
20
10
0
-10
-20
0
10
20
30
40
50
60
70
80
90
100

West 11


Daily Box-Whisker Chart:
Angle Difference - Degrees
60
50
40
30
20
10
0
-10
-20
-30
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

West 11


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
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60
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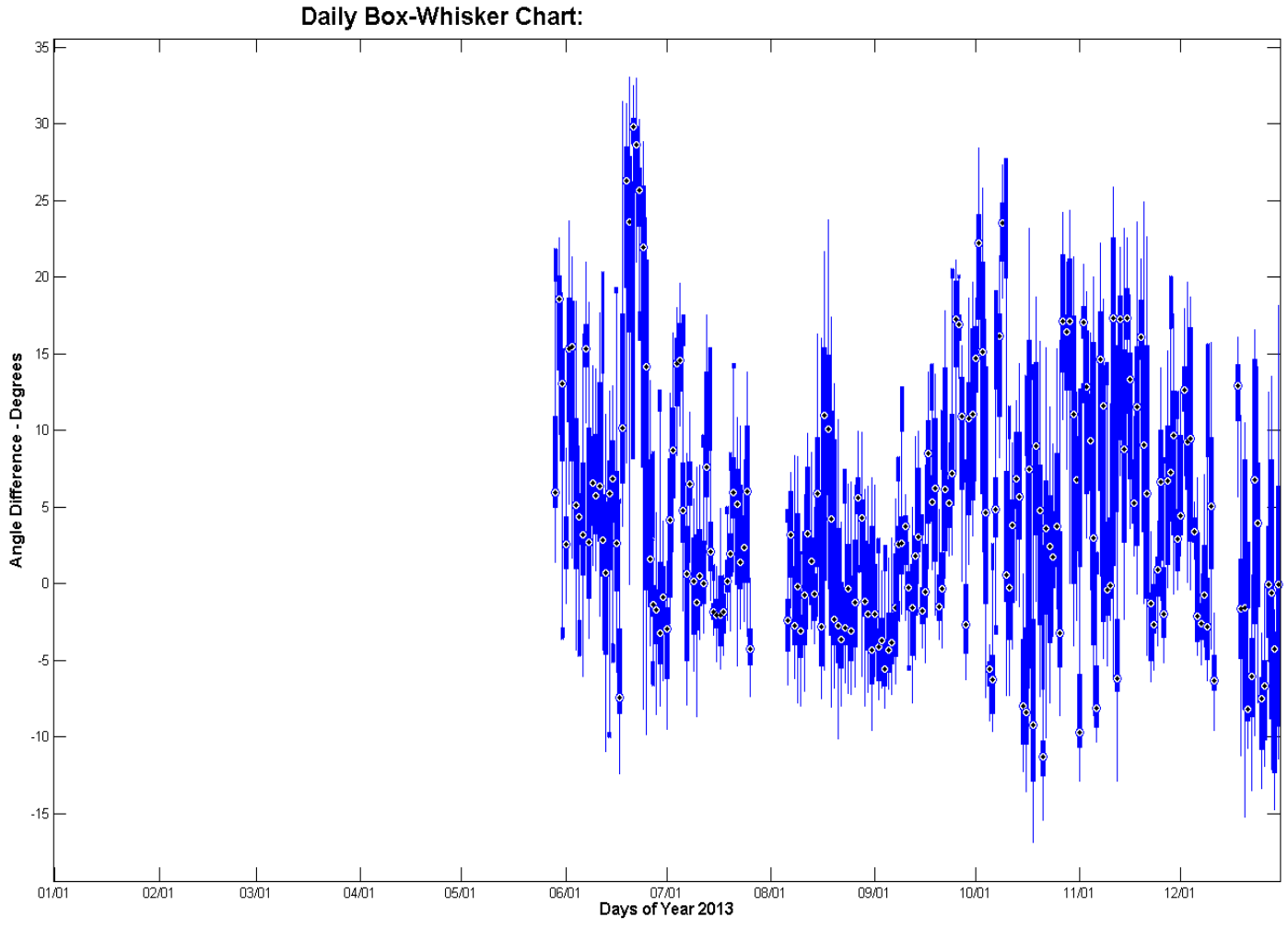
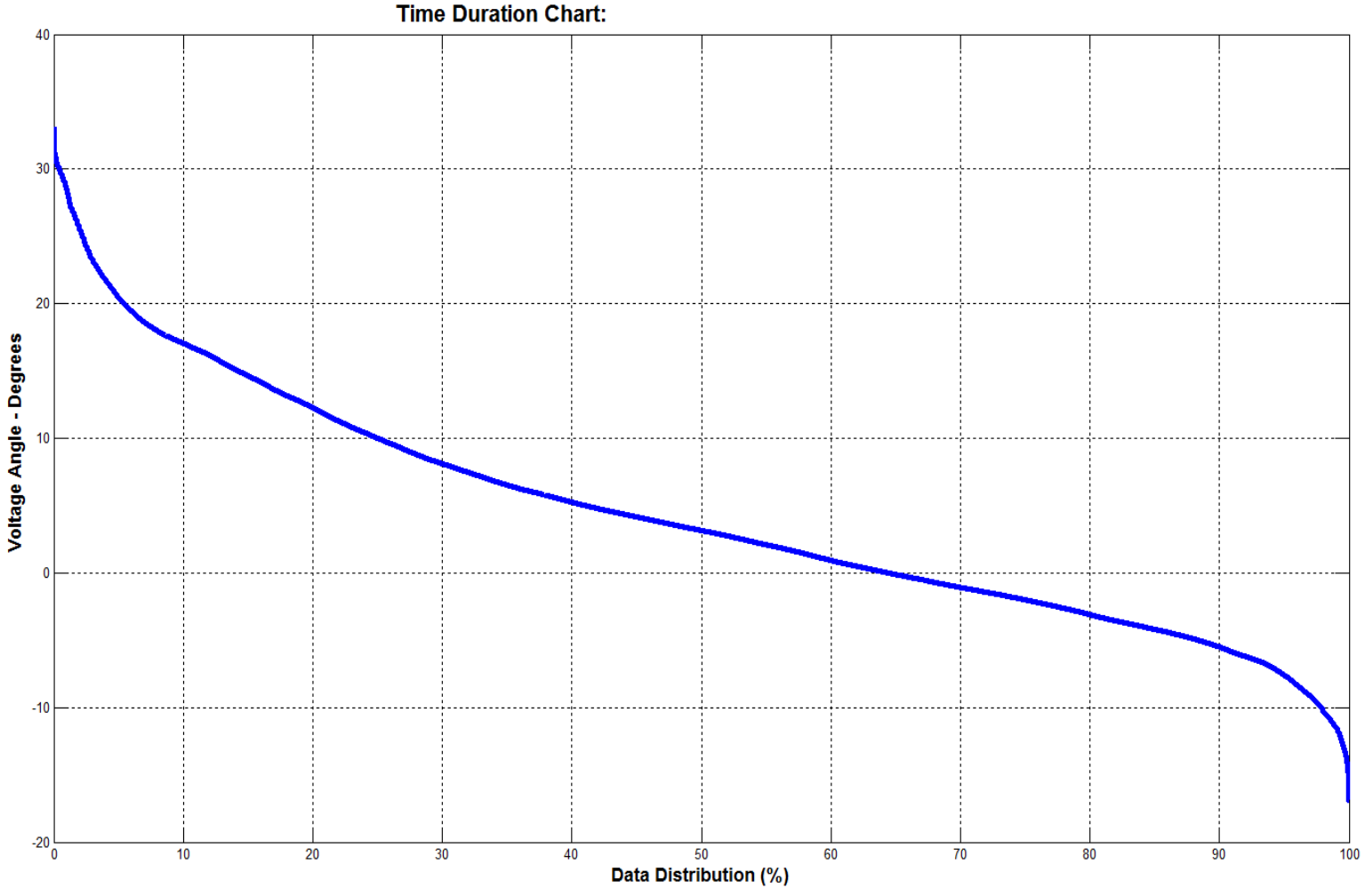
0
-20
-40
0
10
20
30
40
50
60
70
80
90
100

West 12


Daily Box-Whisker Chart:
Angle Difference - Degrees
35
30
25
20
15
10
5
0
-5
-10
-15
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

West 12


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
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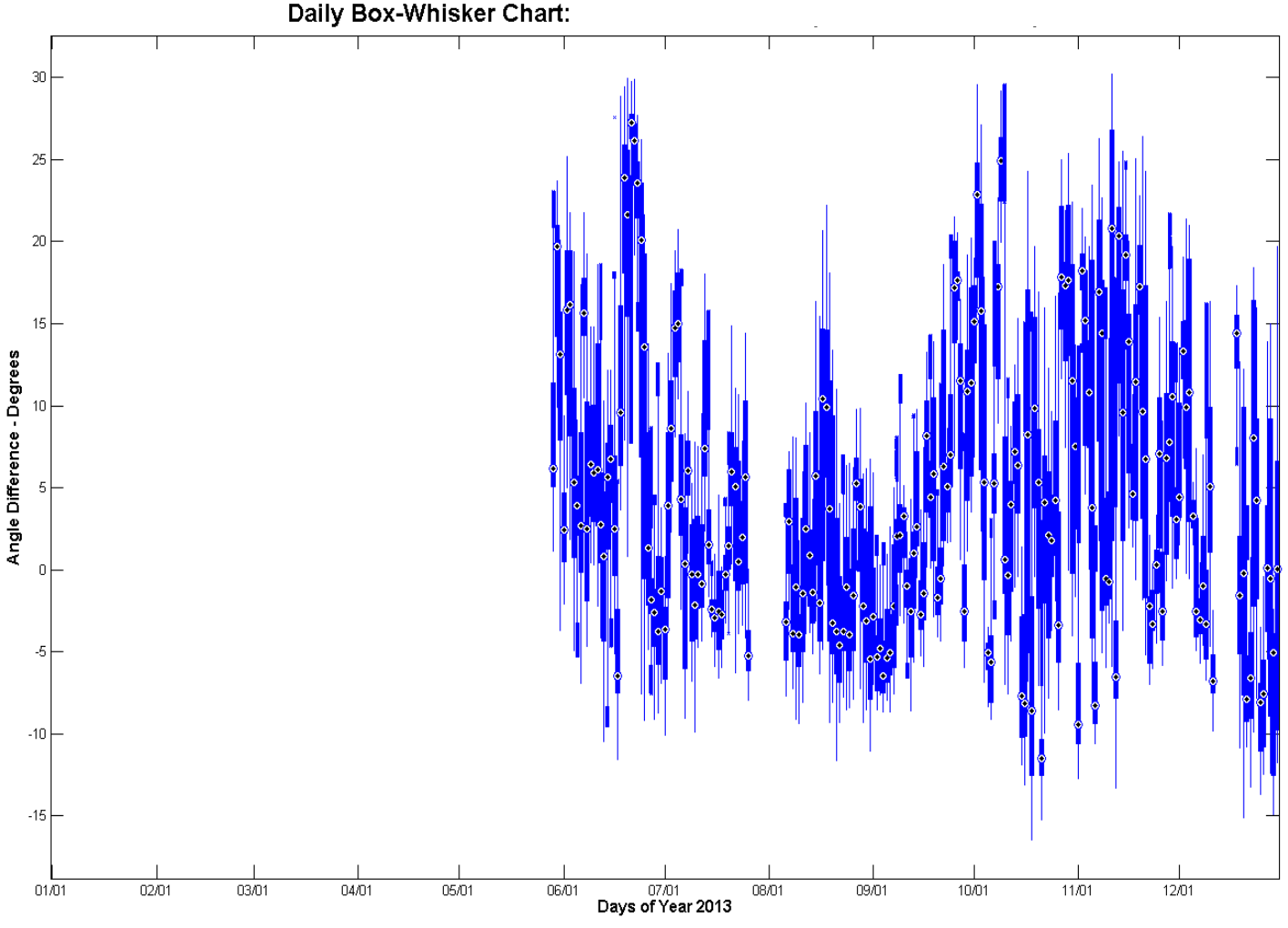
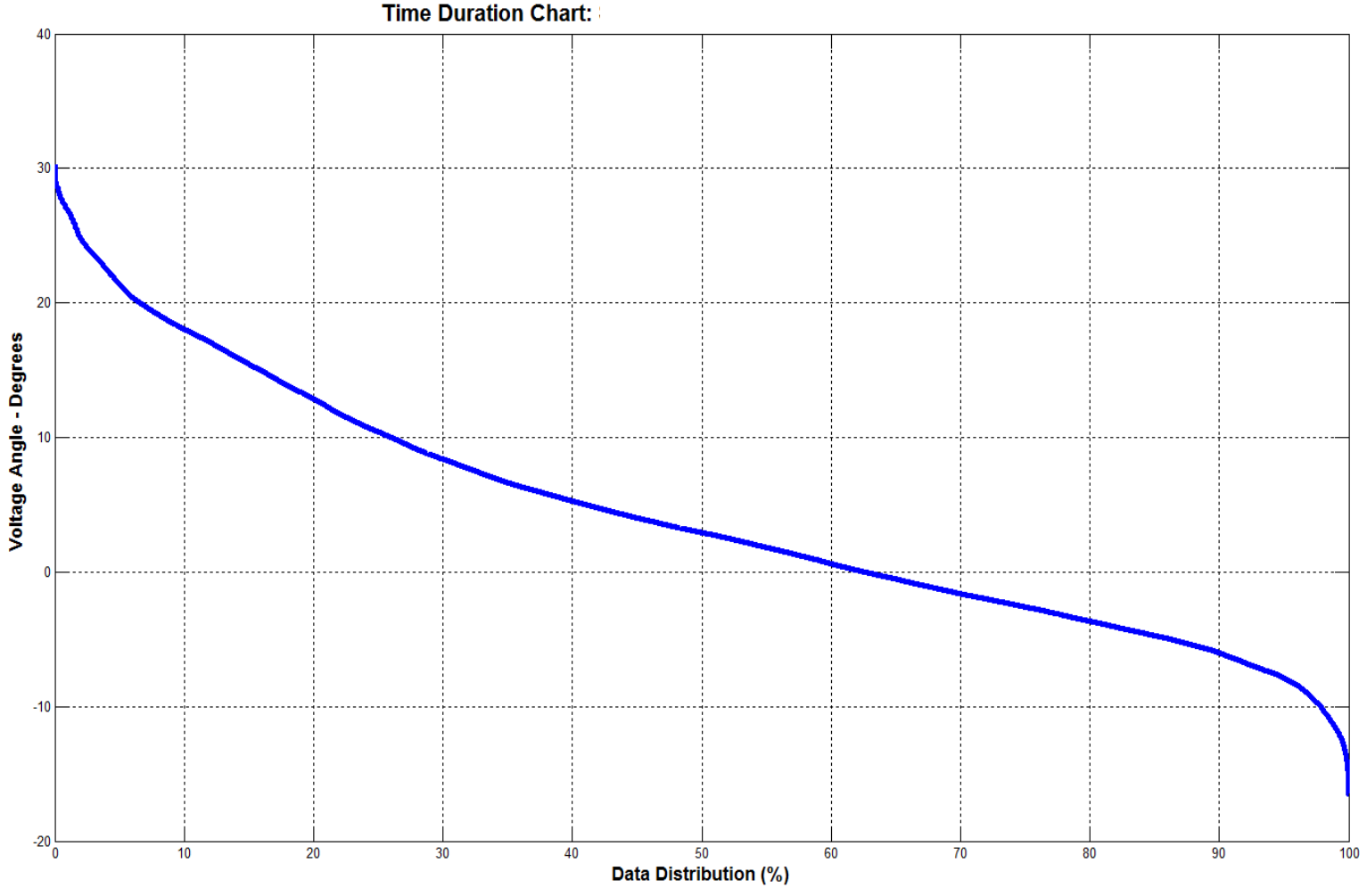
30
20
10
0
-10
-20
0
10
20
30
40
50
60
70
80
90
100

West 5


Daily Box-Whisker Chart:
Angle Difference - Degrees
30
25
20
15
10
5
0
-5
-10
-15
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

West 5


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
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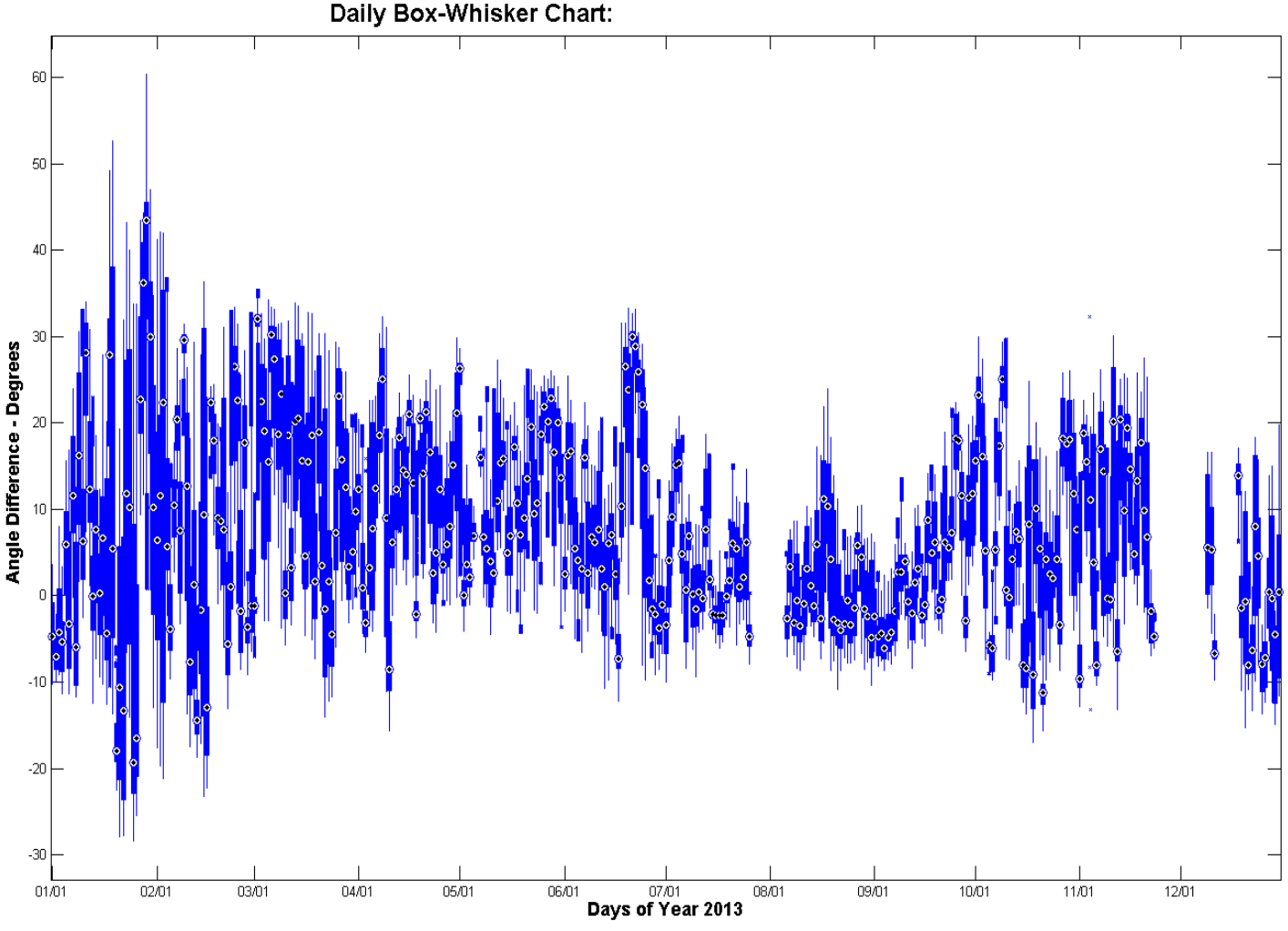
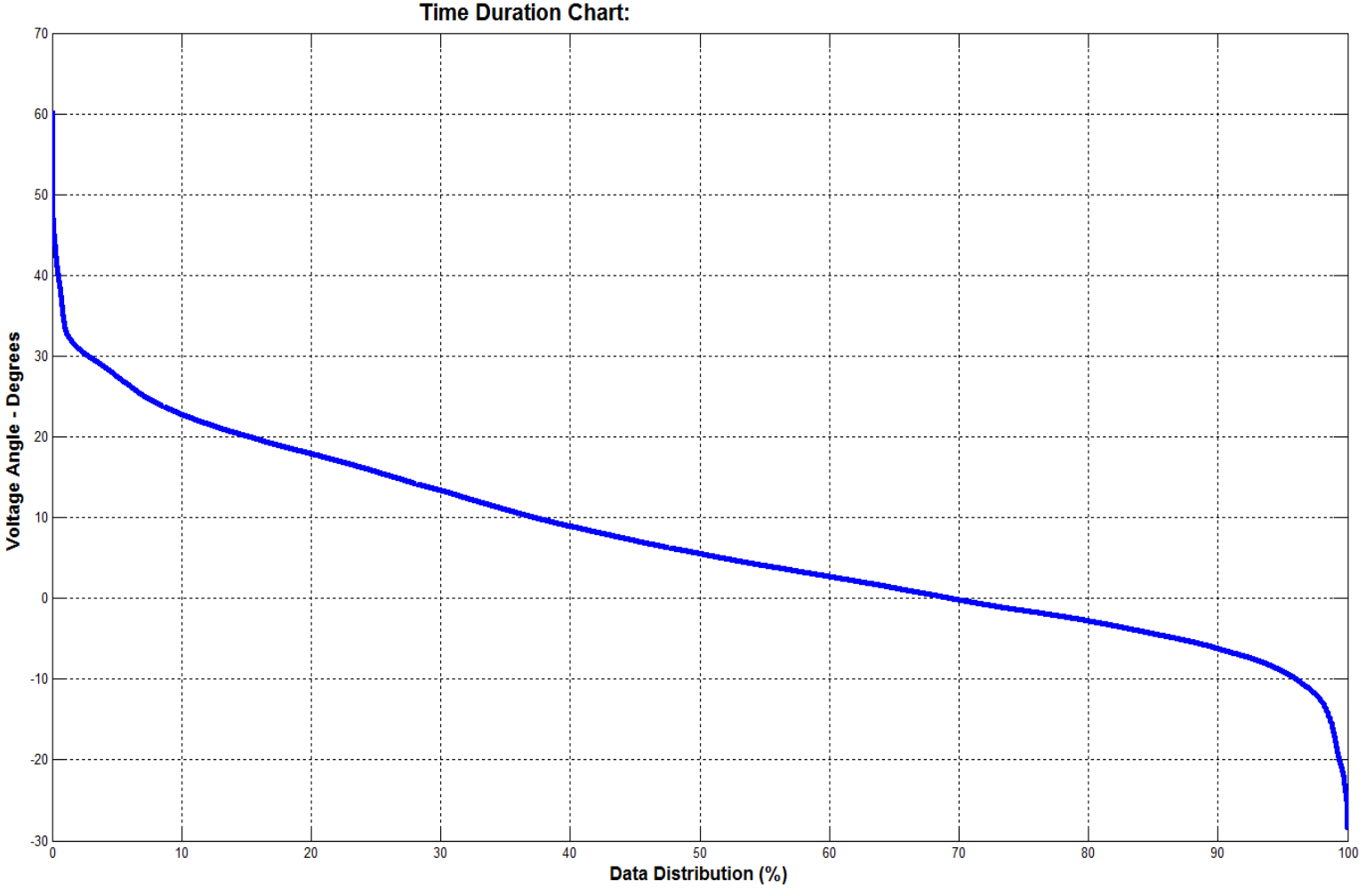
30
20
10
0
-10
-20
0
10
20
30
40
50
60
70
80
90
100

West 6


Daily Box-Whisker Chart:
Angle Difference - Degrees
60
50
40
30
20
10
0
-10
-20
-30
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

West 6


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
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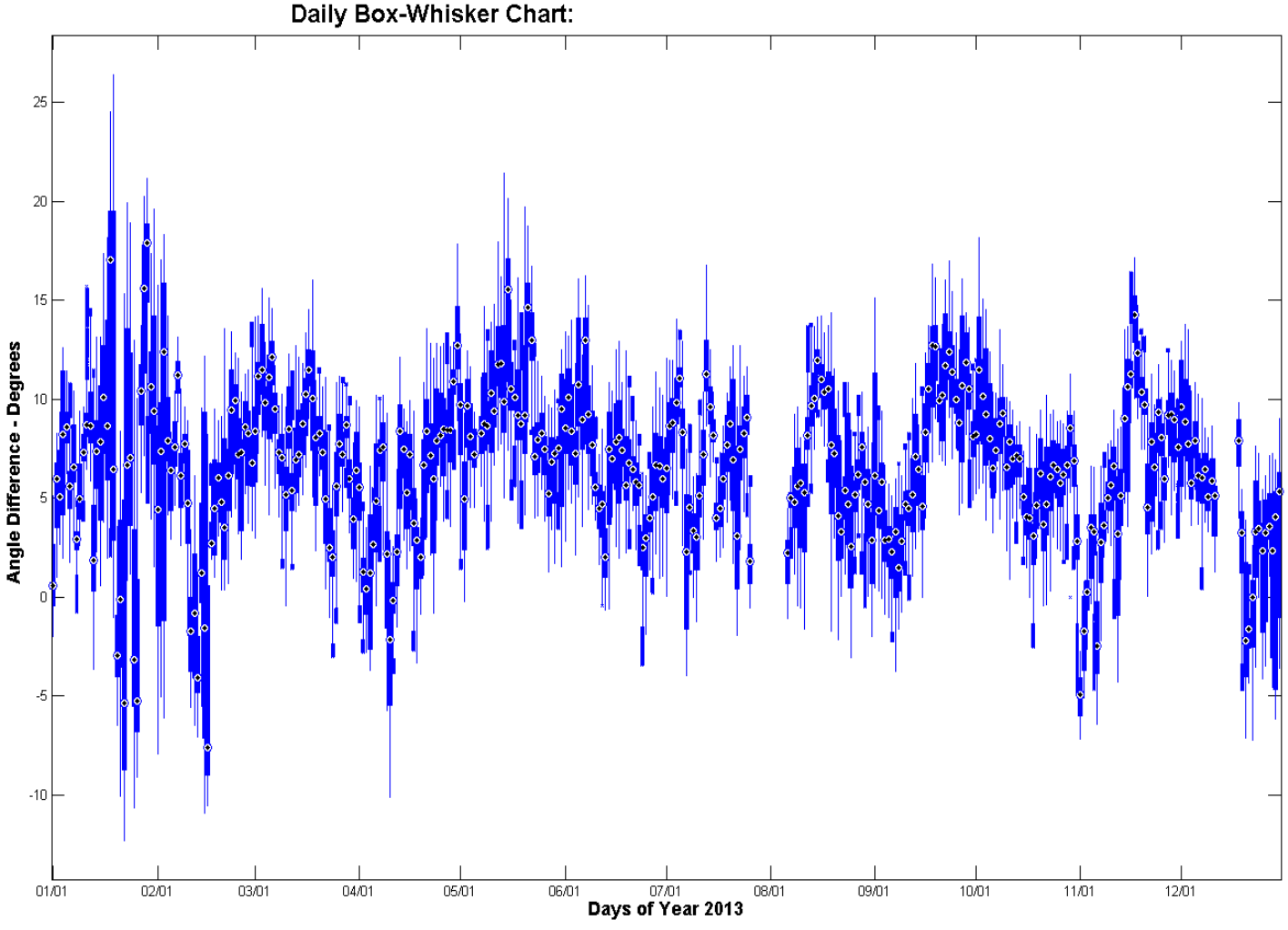
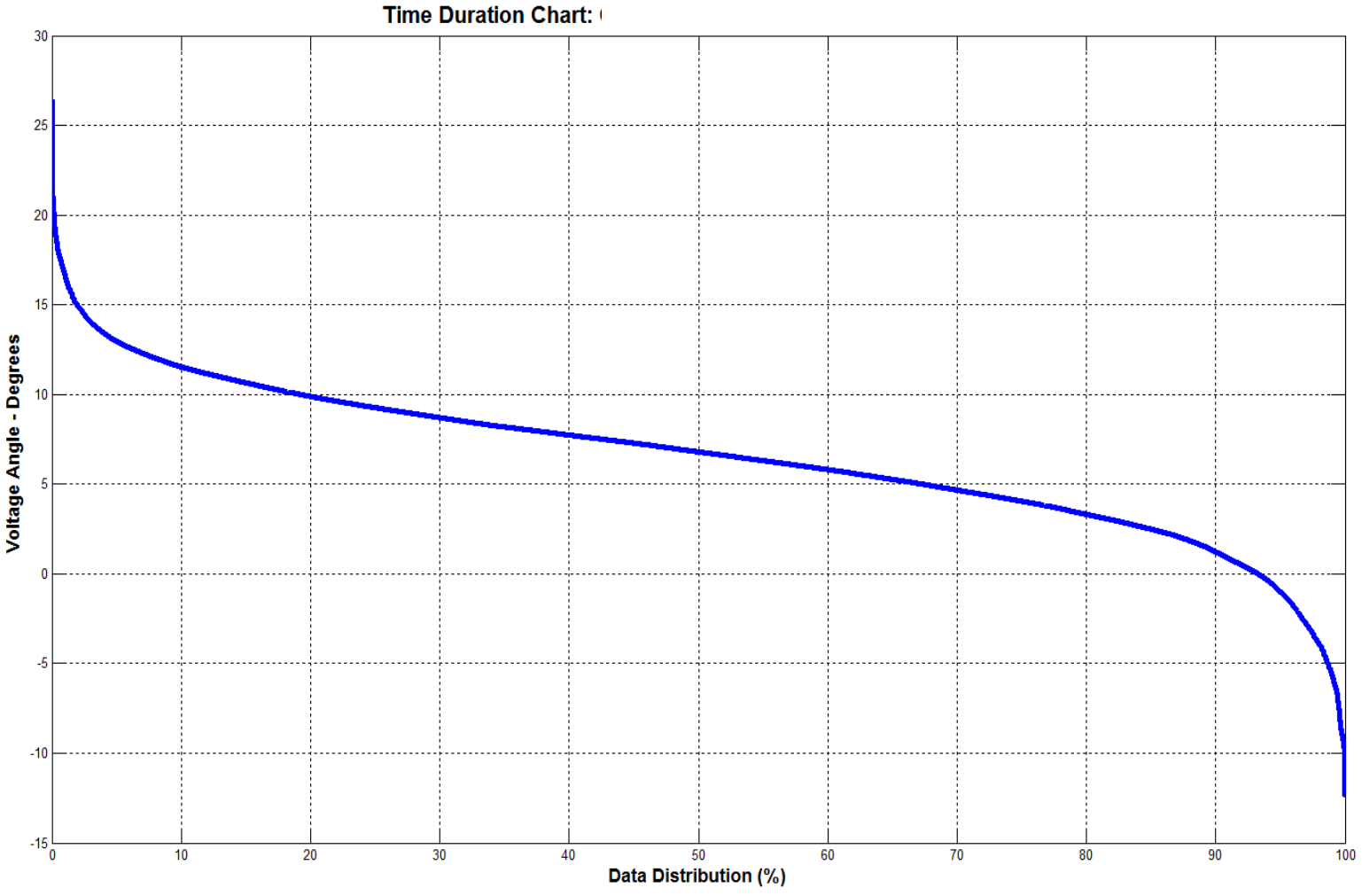
60
50
40
30
20
10
0
-10
-20
-30
0
10
20
30
40
50
60
70
80
90
100

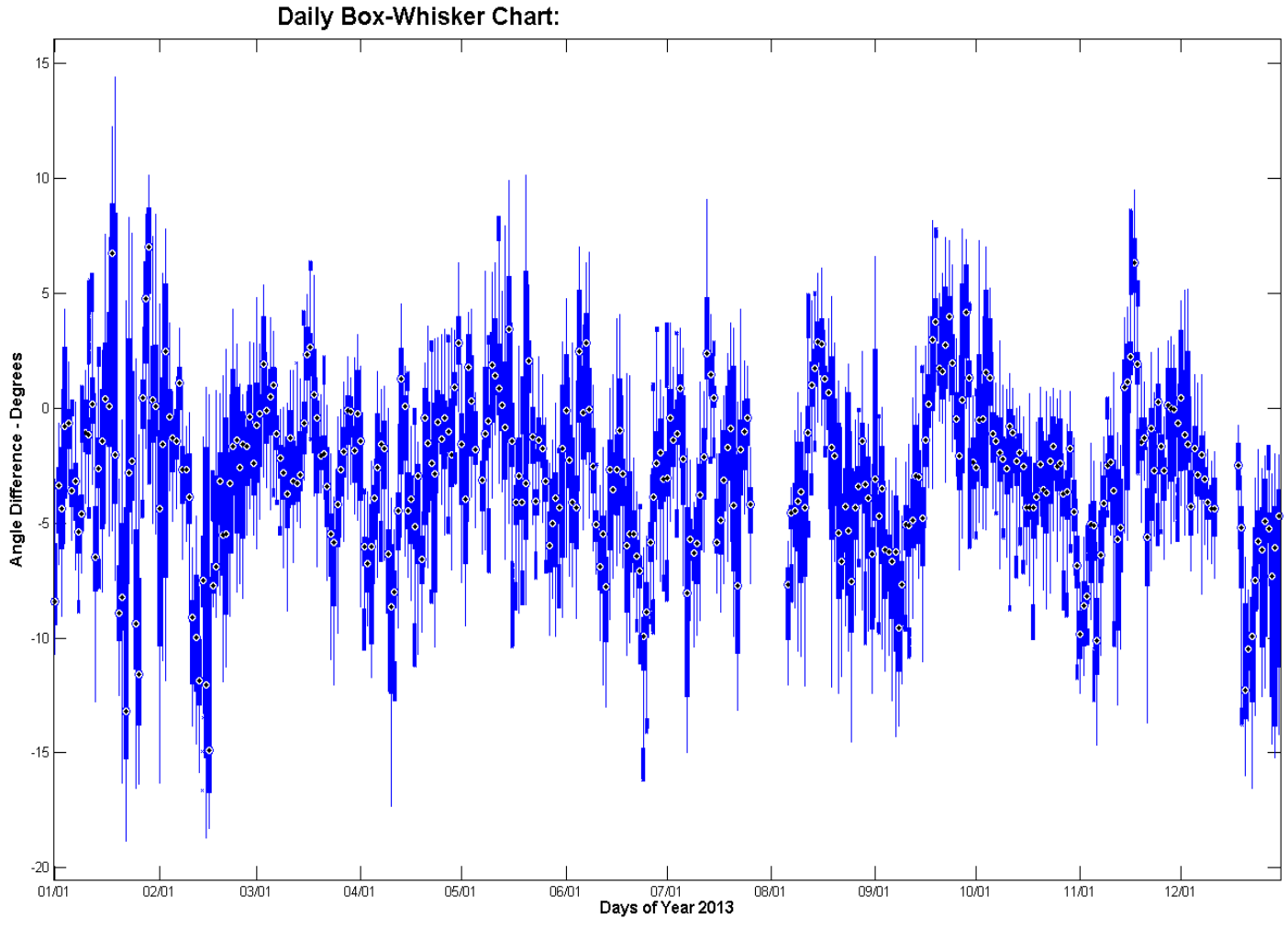
North 1


Daily Box-Whisker Chart:
Angle Difference - Degrees
25
20
15
10
5
0
-5
-10
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

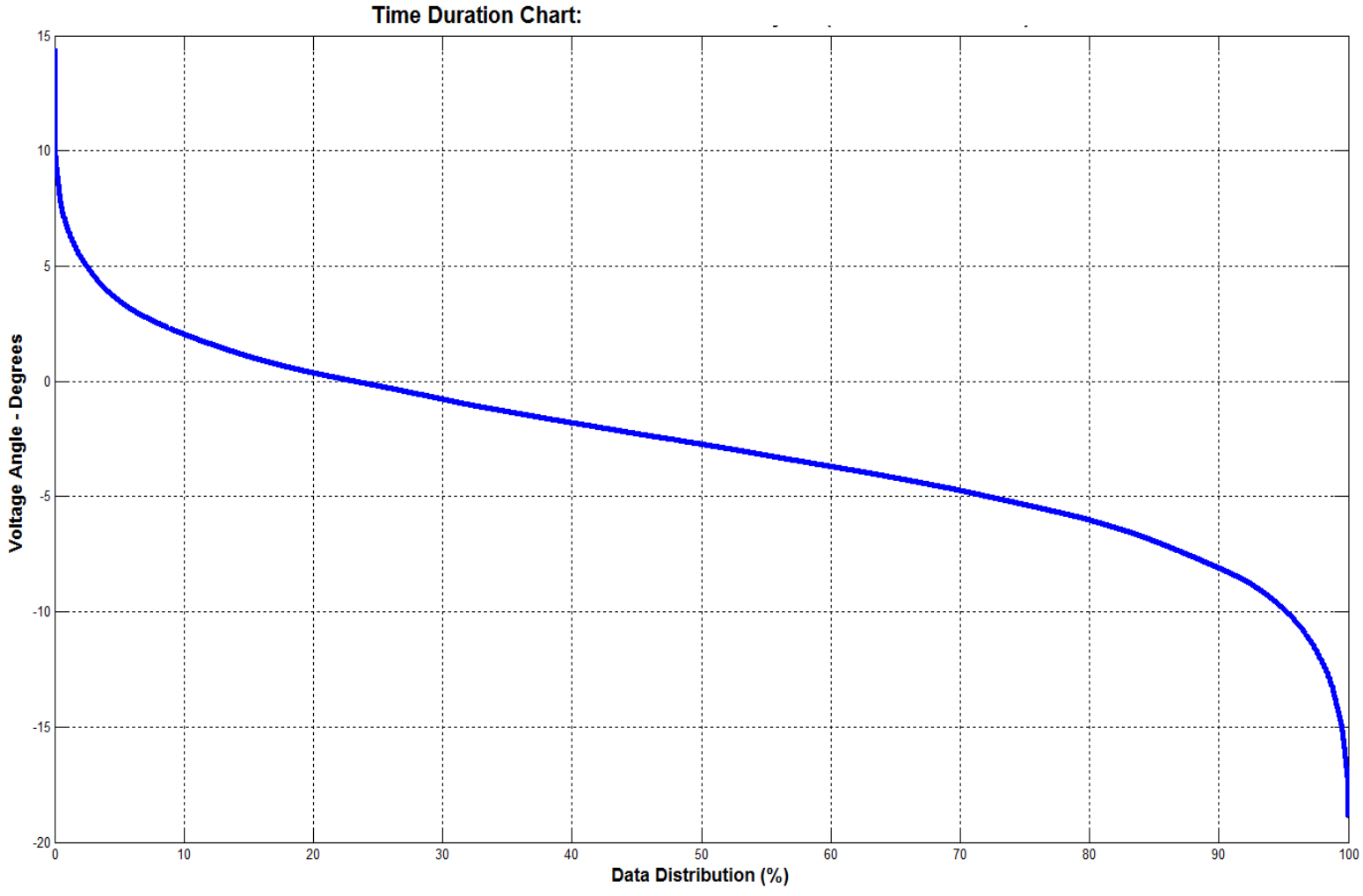
North 1


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
30
25
20
15
10
5
0
-5
-10
-15
0
10
20
30
40
50
60
70
80
90
100

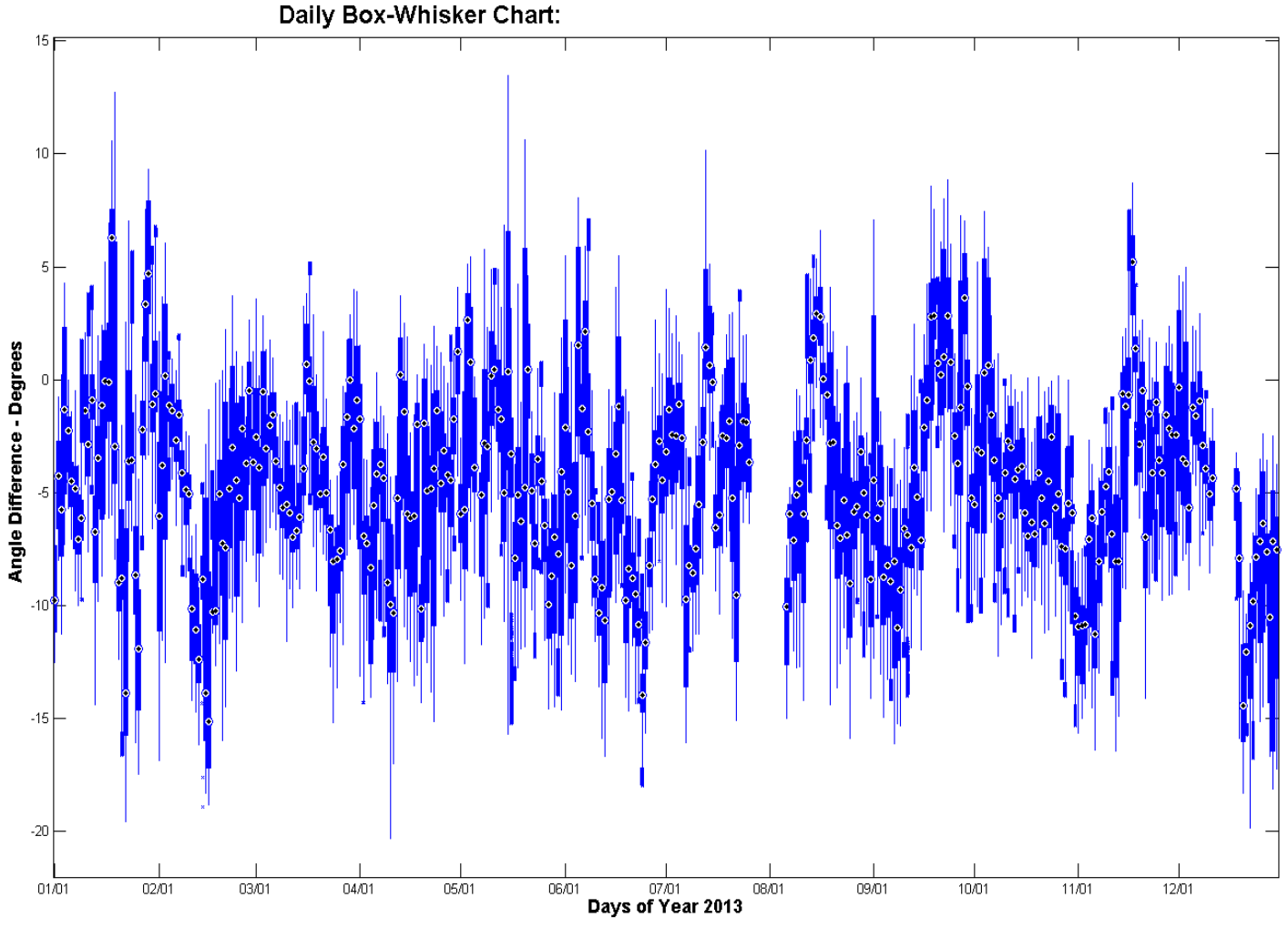
North 4


Daily Box-Whisker Chart:
Angle Difference - Degrees
15
10
5
0
-5
-10
-15
-20
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

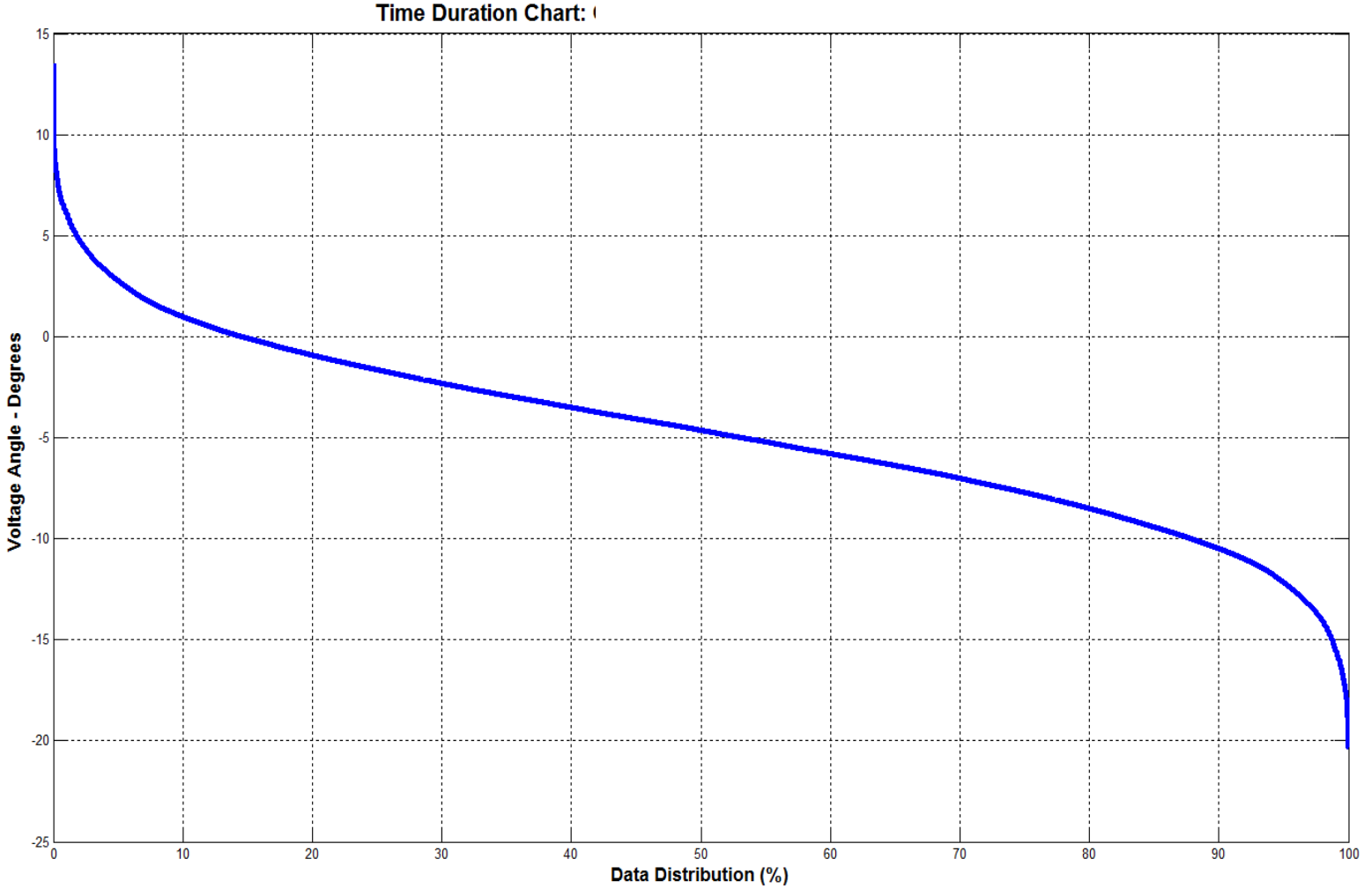
North 4


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
15
10
5
0
-5
-10
-15
-20
0
10
20
30
40
50
60
70
80
90
100

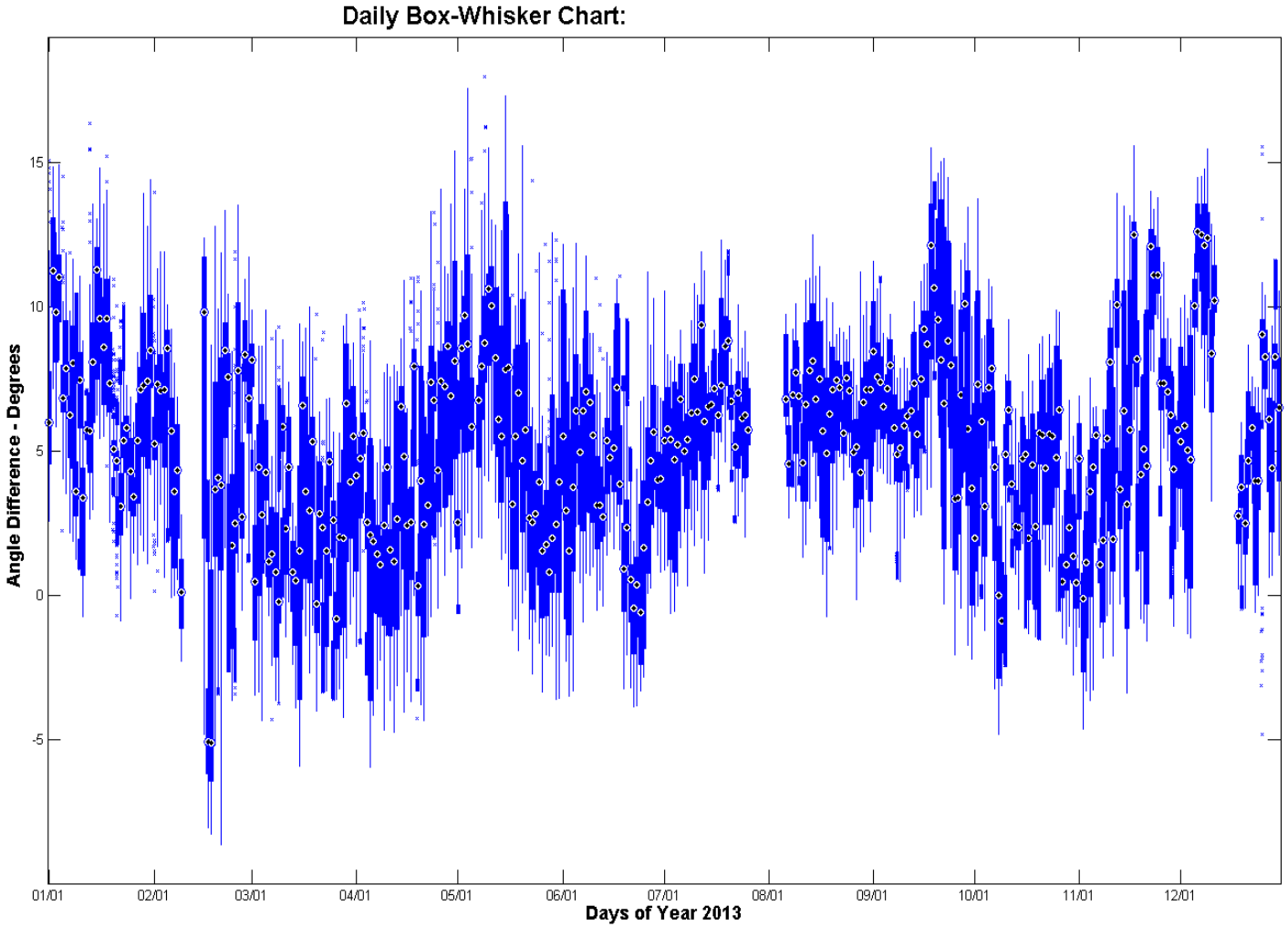
North 5


Daily Box-Whisker Chart:
Angle Difference - Degrees
15
10
5
0
-5
-10
-15
-20
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

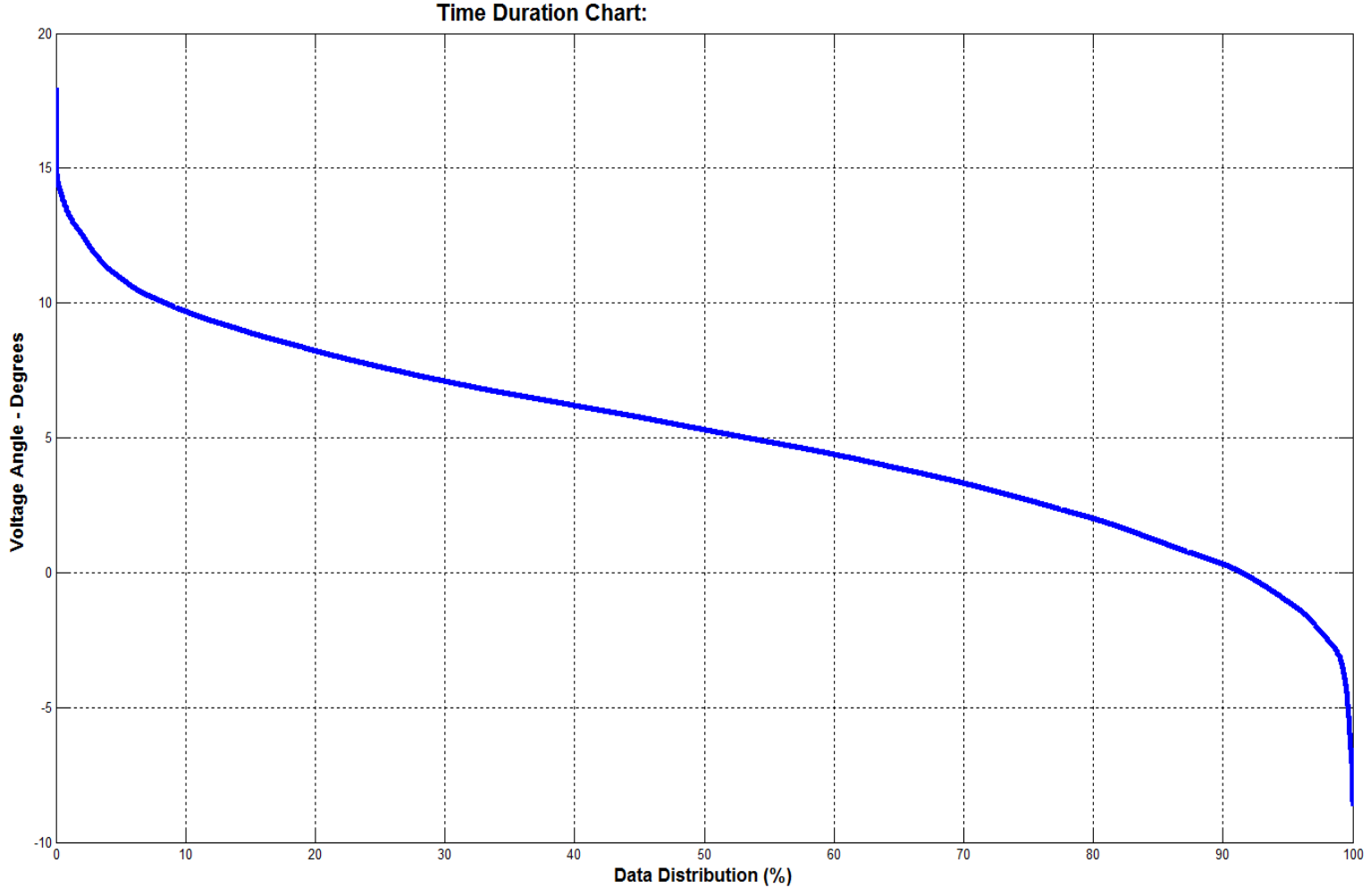
North 5


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
15
10
5
0
-5
-10
-15
-20
-25
0
10
20
30
40
50
60
70
80
90
100

North 6


Daily Box-Whisker Chart:
Angle Difference - Degrees
15
10
5
0
-5
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

North 6


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
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15
10
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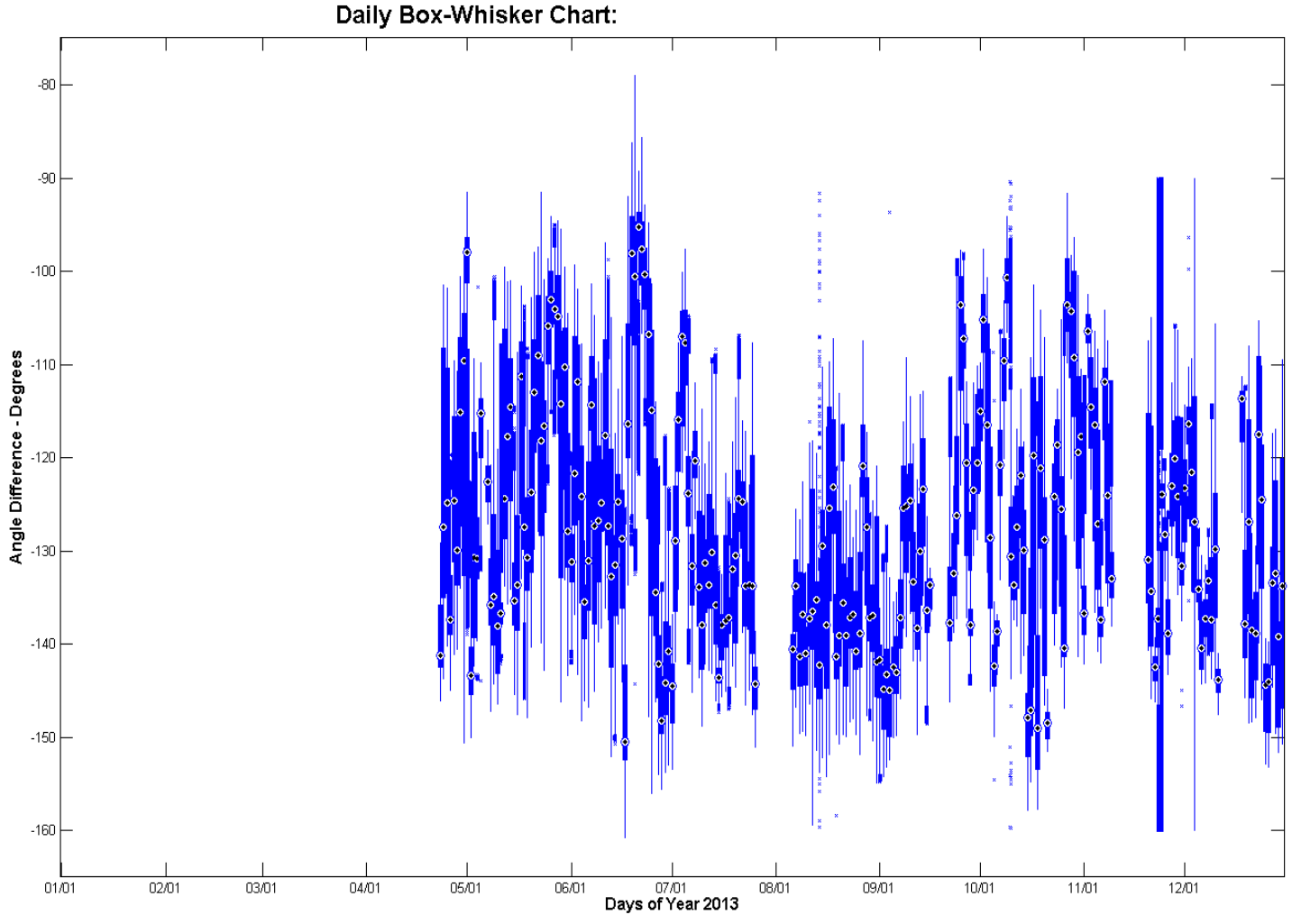
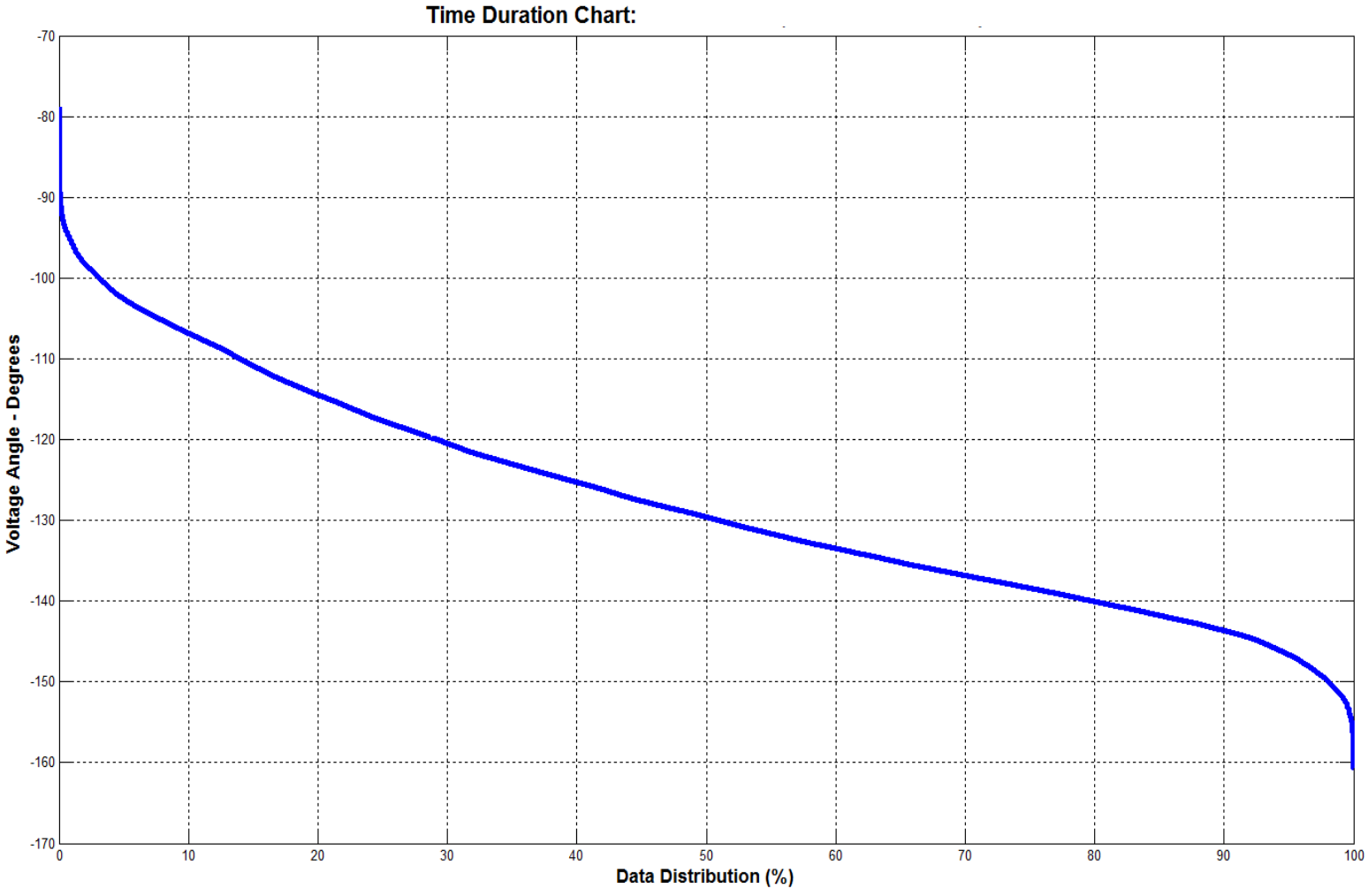
0
-5
-10
0
10
20
30
40
50
60
70
80
90
100

FarWest 2


Daily Box-Whisker Chart:
Angle Difference - Degrees
-80
-90
-100
-110
-120
-130
-140
-150
-160
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

FarWest 2


Time Duration Chart:
Voltage Angle - Degrees
-70
-80
-90
-100
-110
-120
-130
-140
-150
-160
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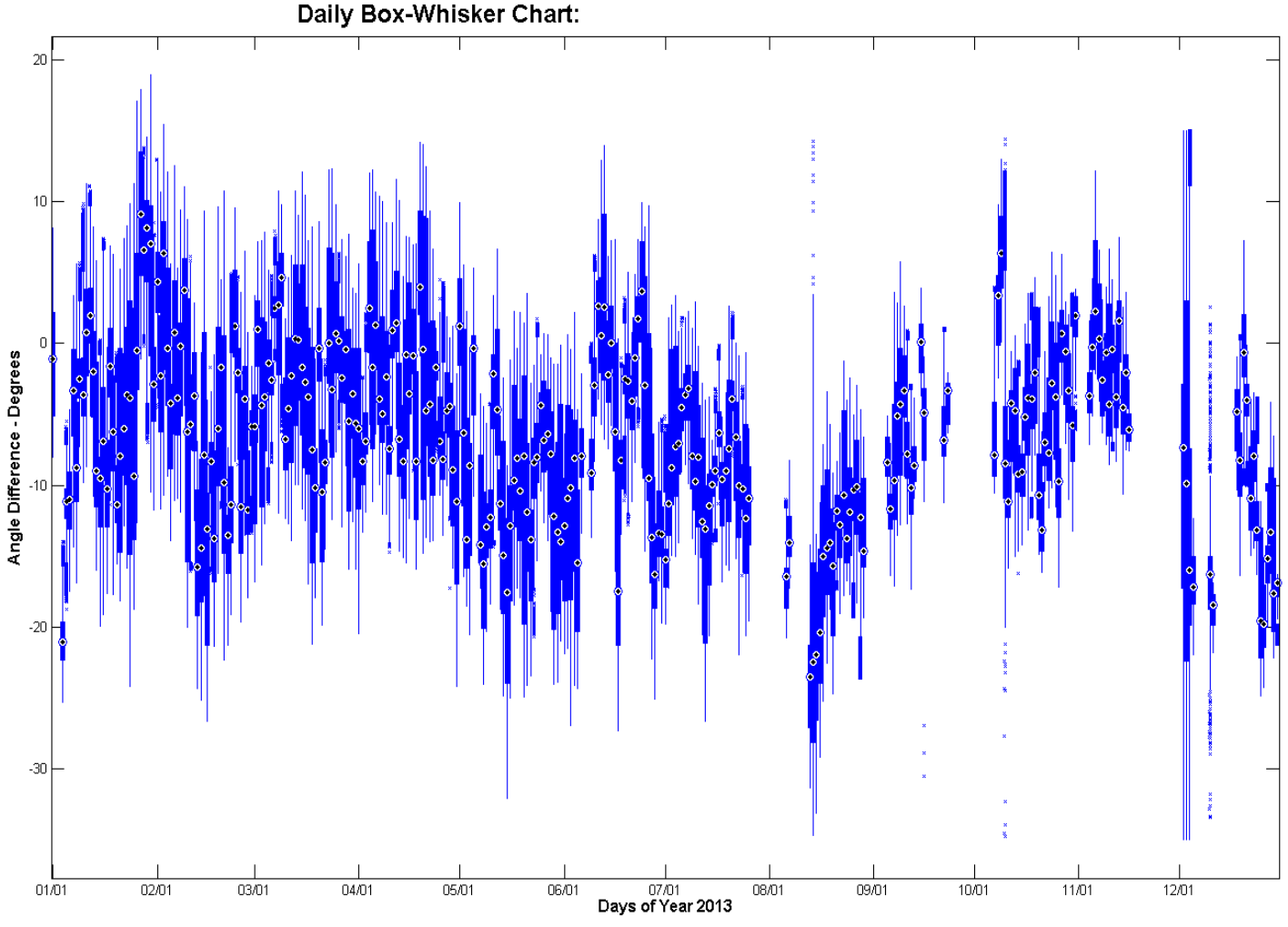
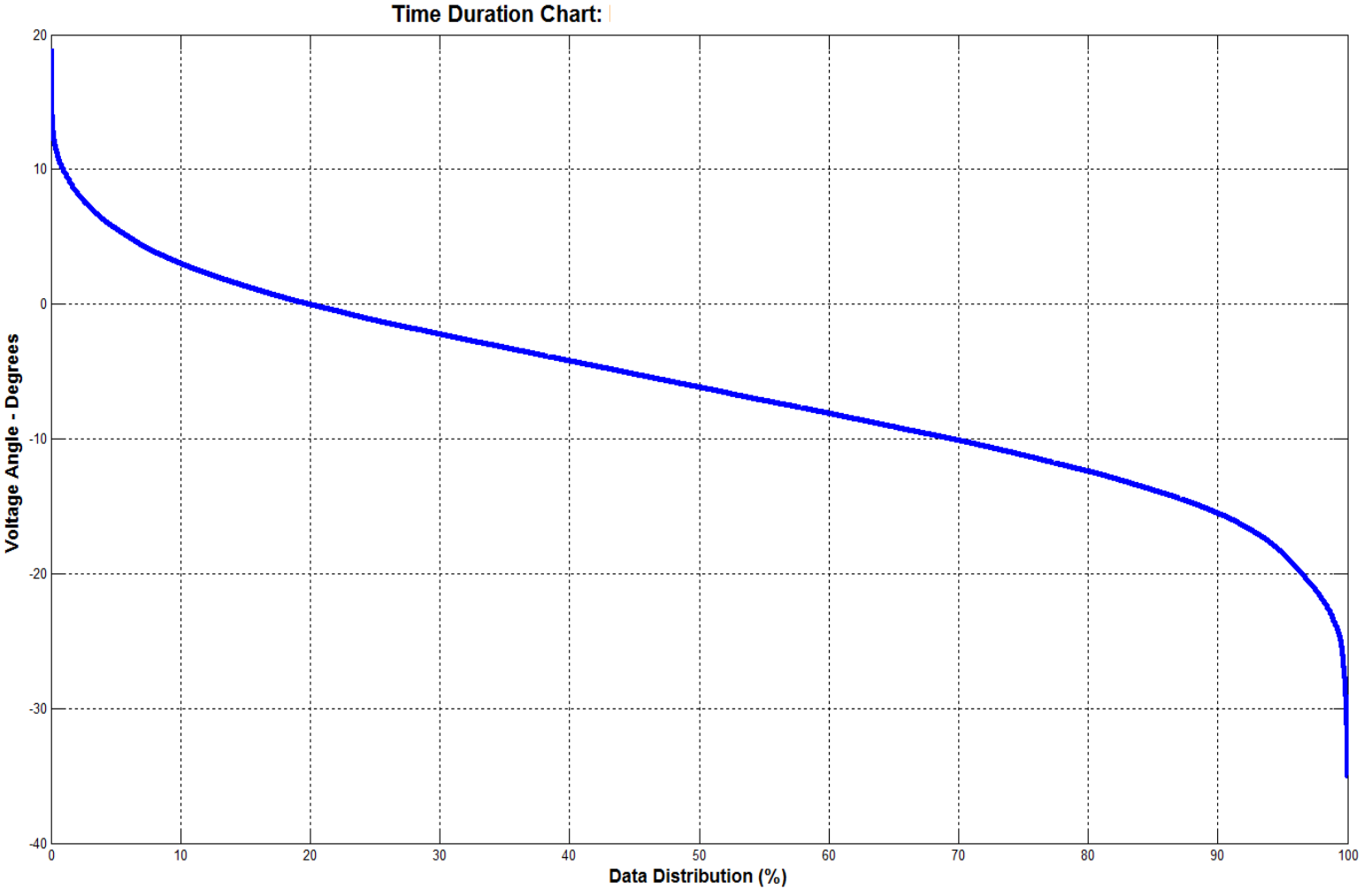
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

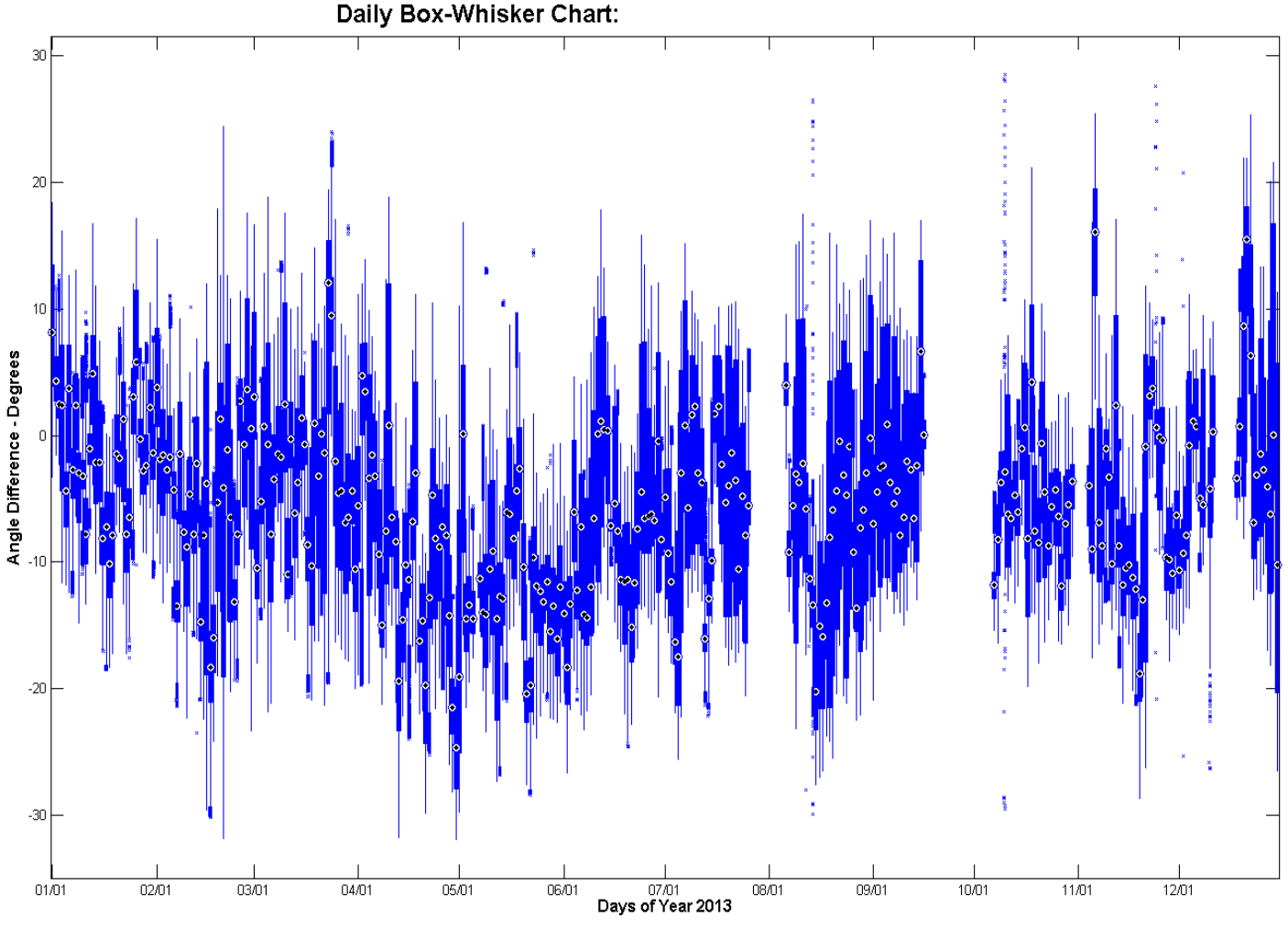
West 4


Daily Box-Whisker Chart:
Angle Difference - Degrees
20
10
0
-10
-20
-30
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

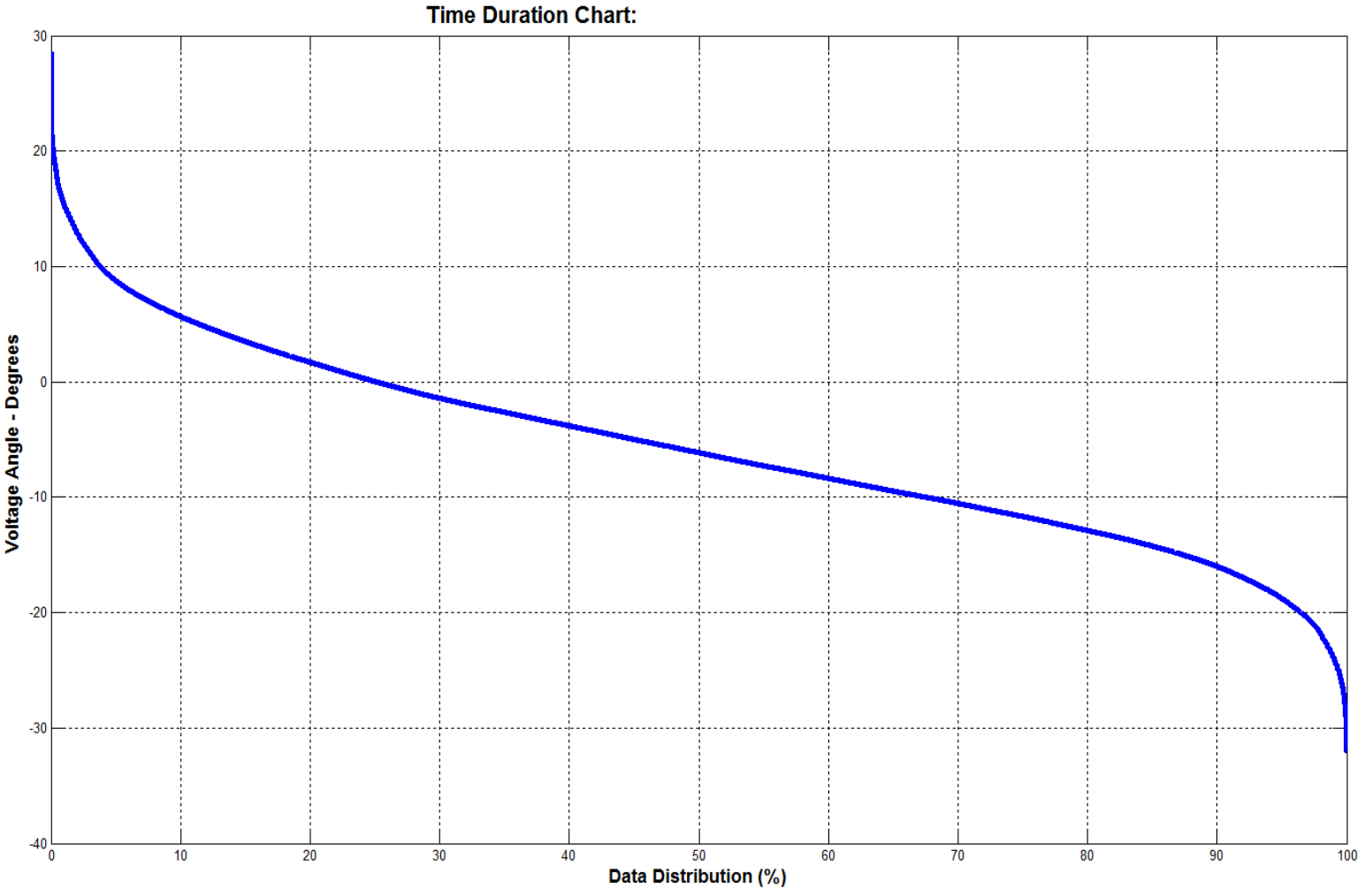
West 4


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
20
10
0
-10
-20
-30
-40
0
10
20
30
40
50
60
70
80
90
100

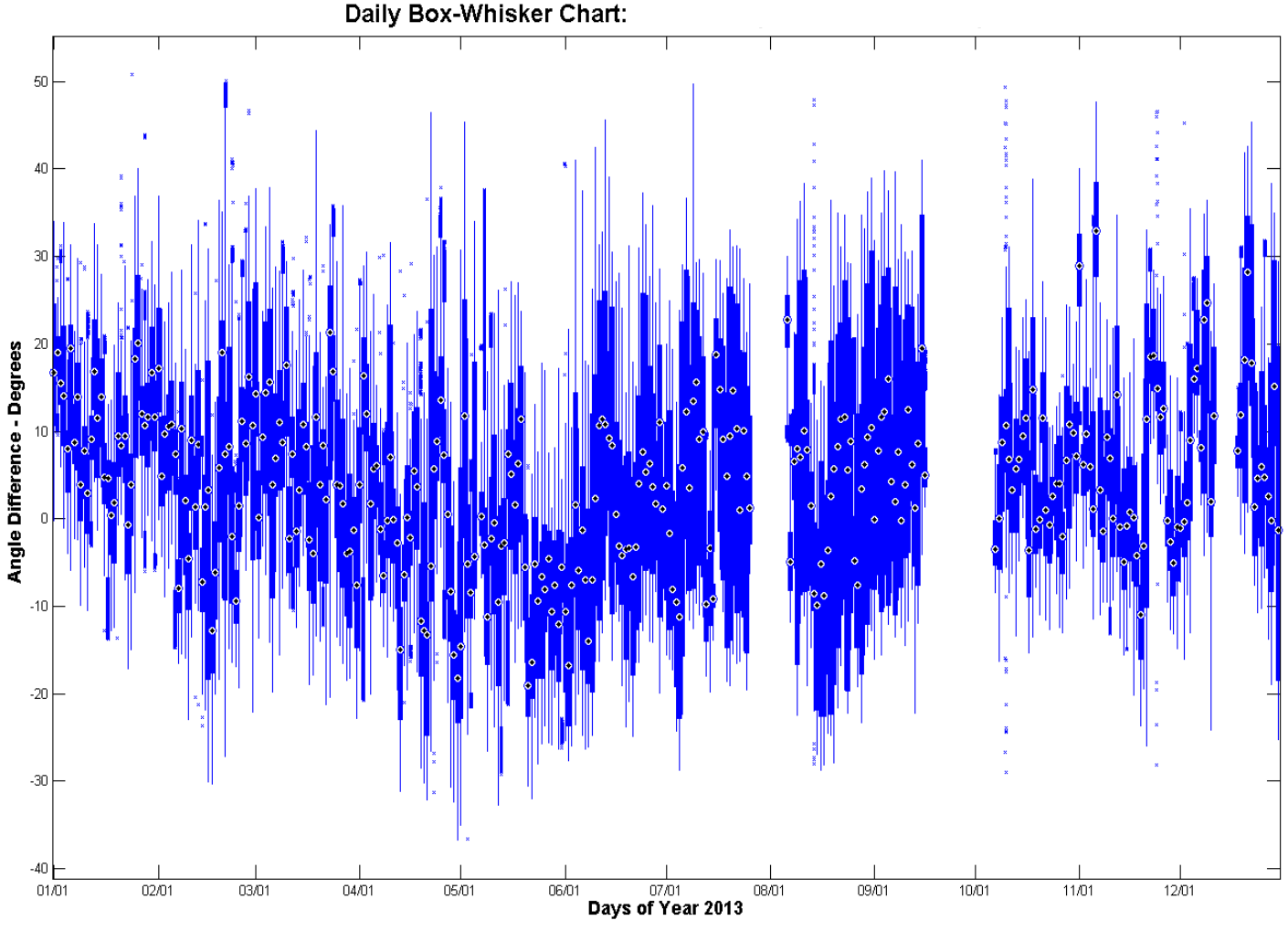
Coast 2


Daily Box-Whisker Chart:
Angle Difference - Degrees
30
20
10
0
-10
-20
-30
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

Coast 2


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
30
20
10
0
-10
-20
-30
-40
0
10
20
30
40
50
60
70
80
90
100

Coast 1


Daily Box-Whisker Chart:
Angle Difference - Degrees
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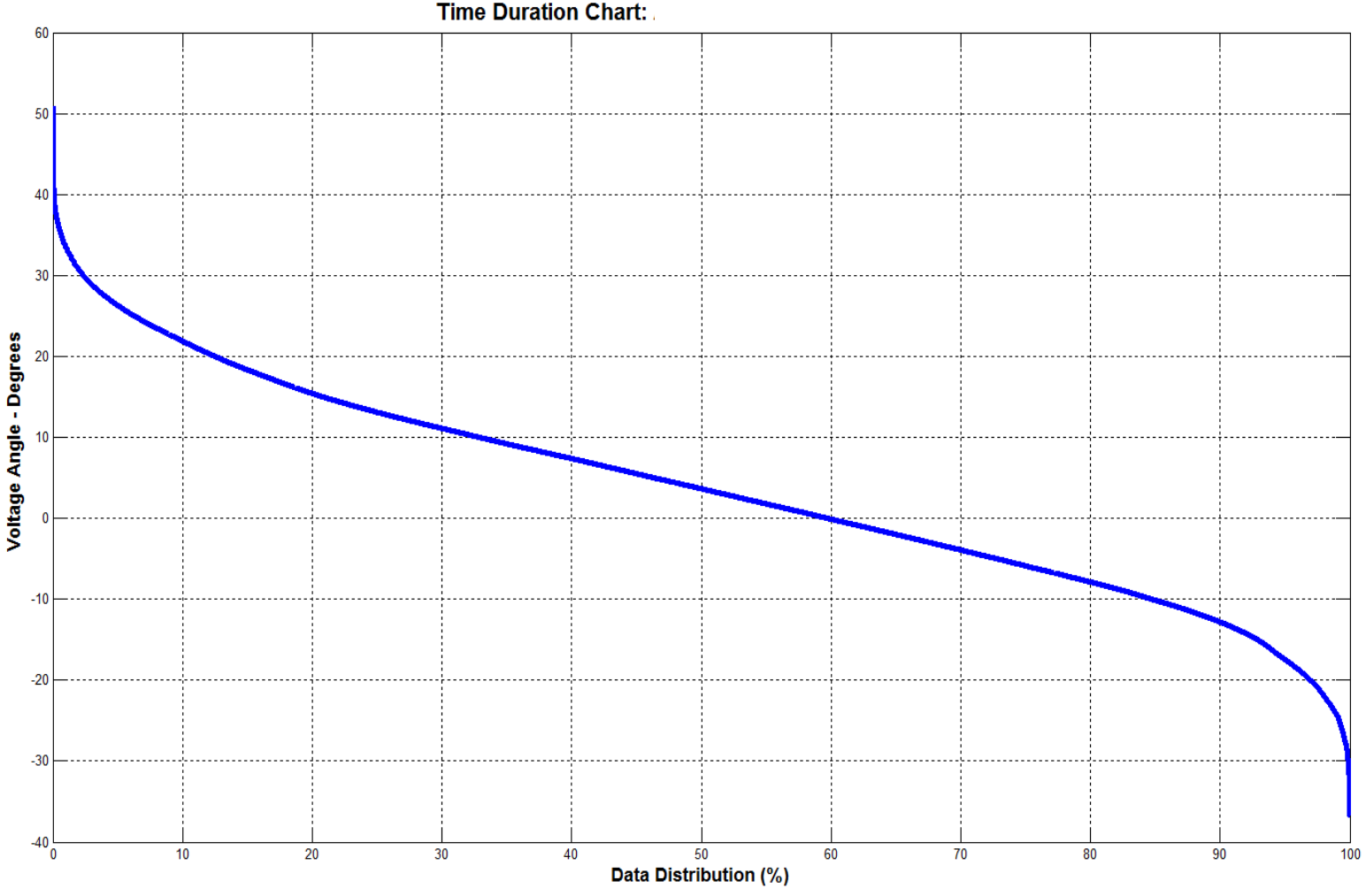
40
30
20
10
0
-10
-20
-30
-40
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

Coast 1


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
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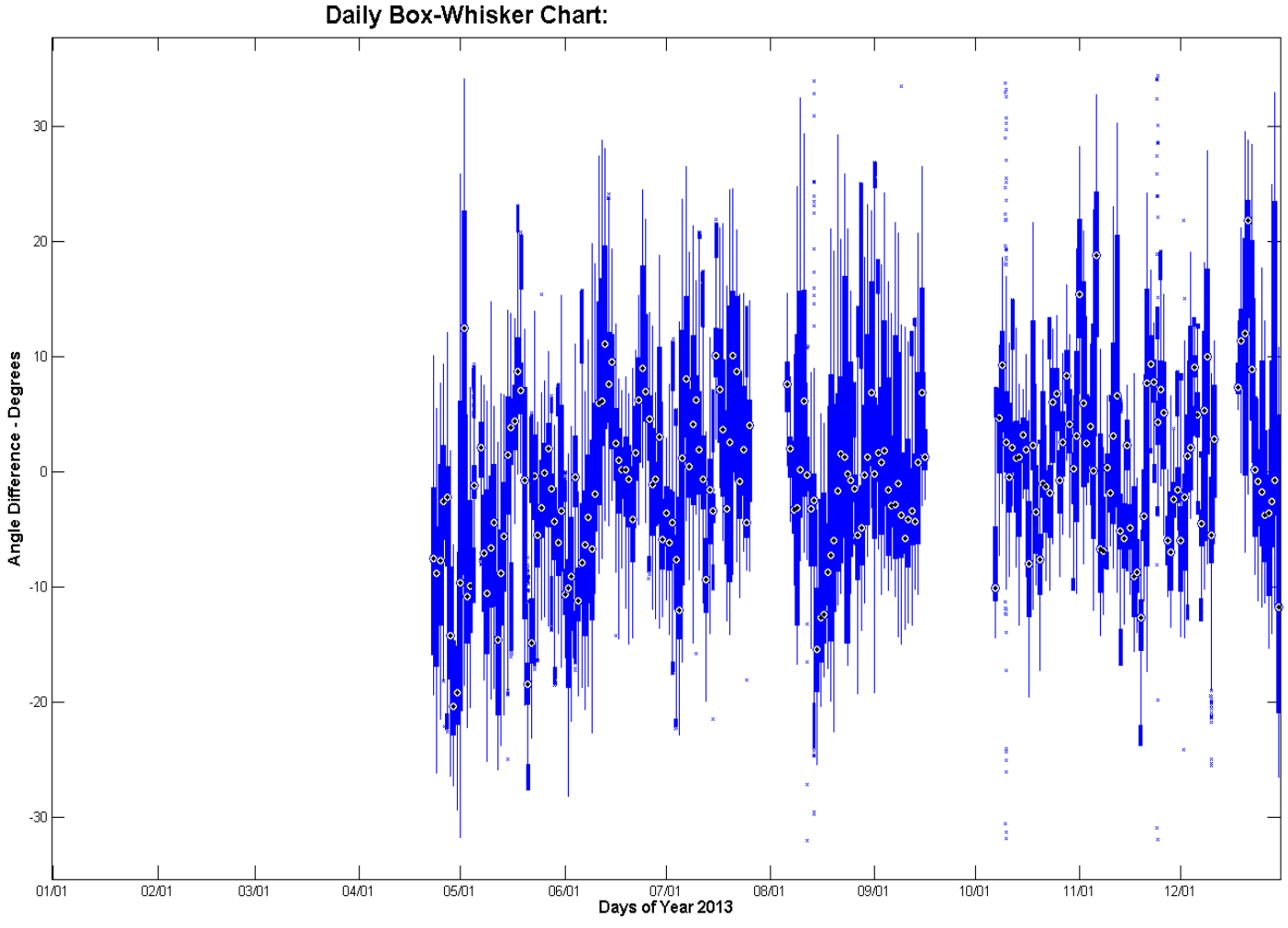
50
40
30
20
10
0
-10
-20
-30
-40
0
10
20
30
40
50
60
70
80
90
100

South 3


Daily Box-Whisker Chart:
Angle Difference - Degrees
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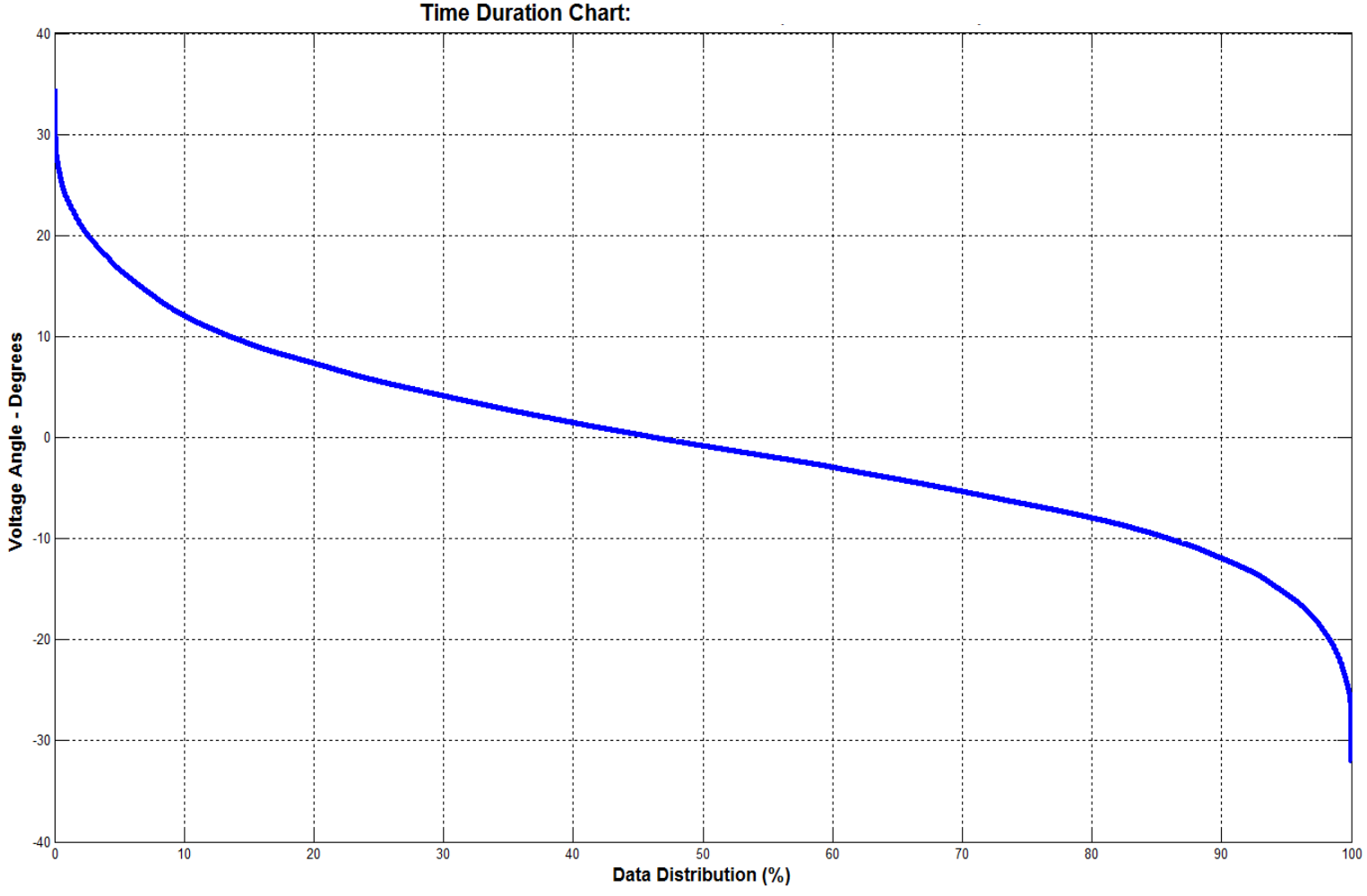
20
10
0
-10
-20
-30
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

South 3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Voltage Angle - Degrees
Data Distribution (%)
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30
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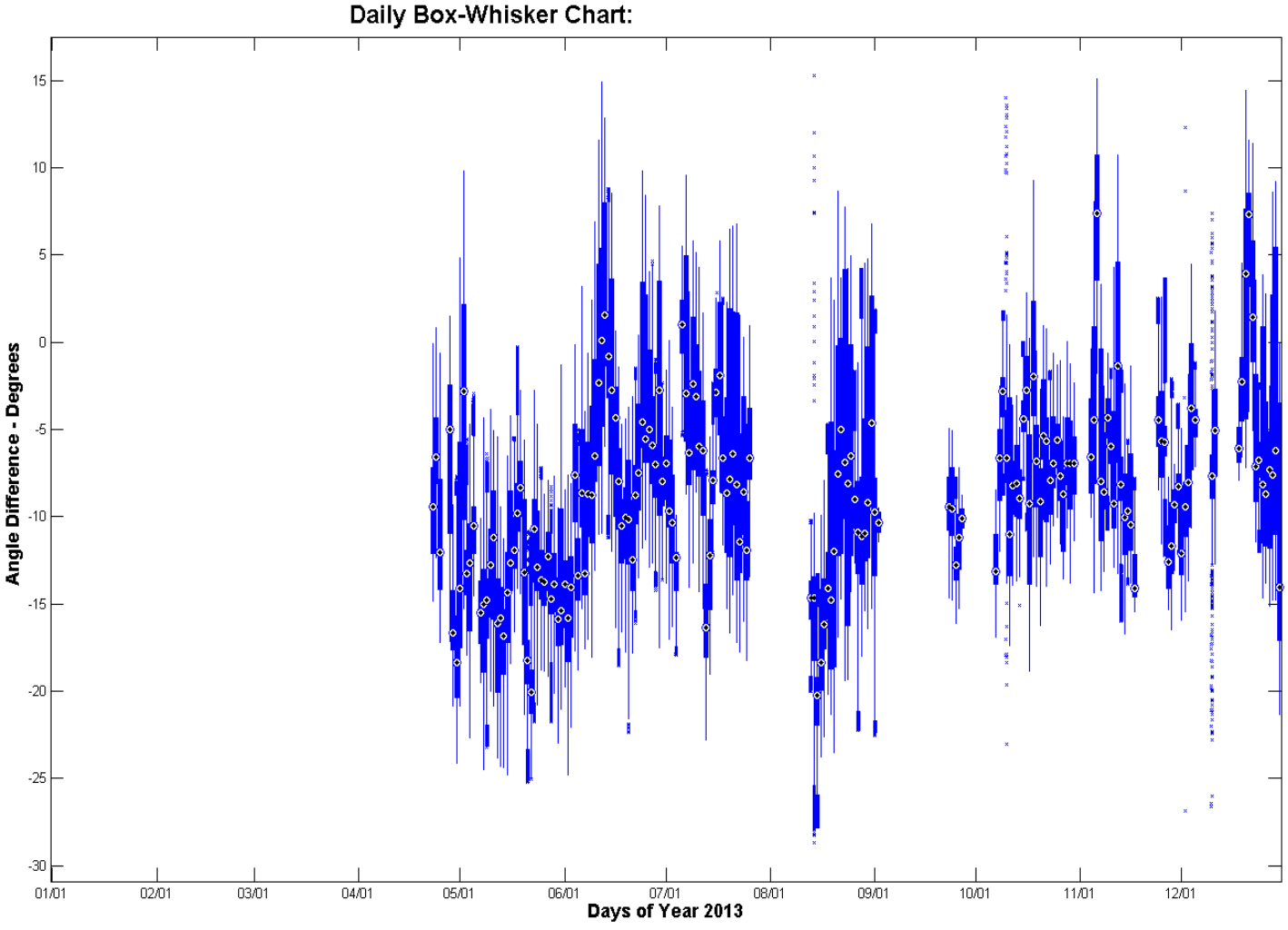
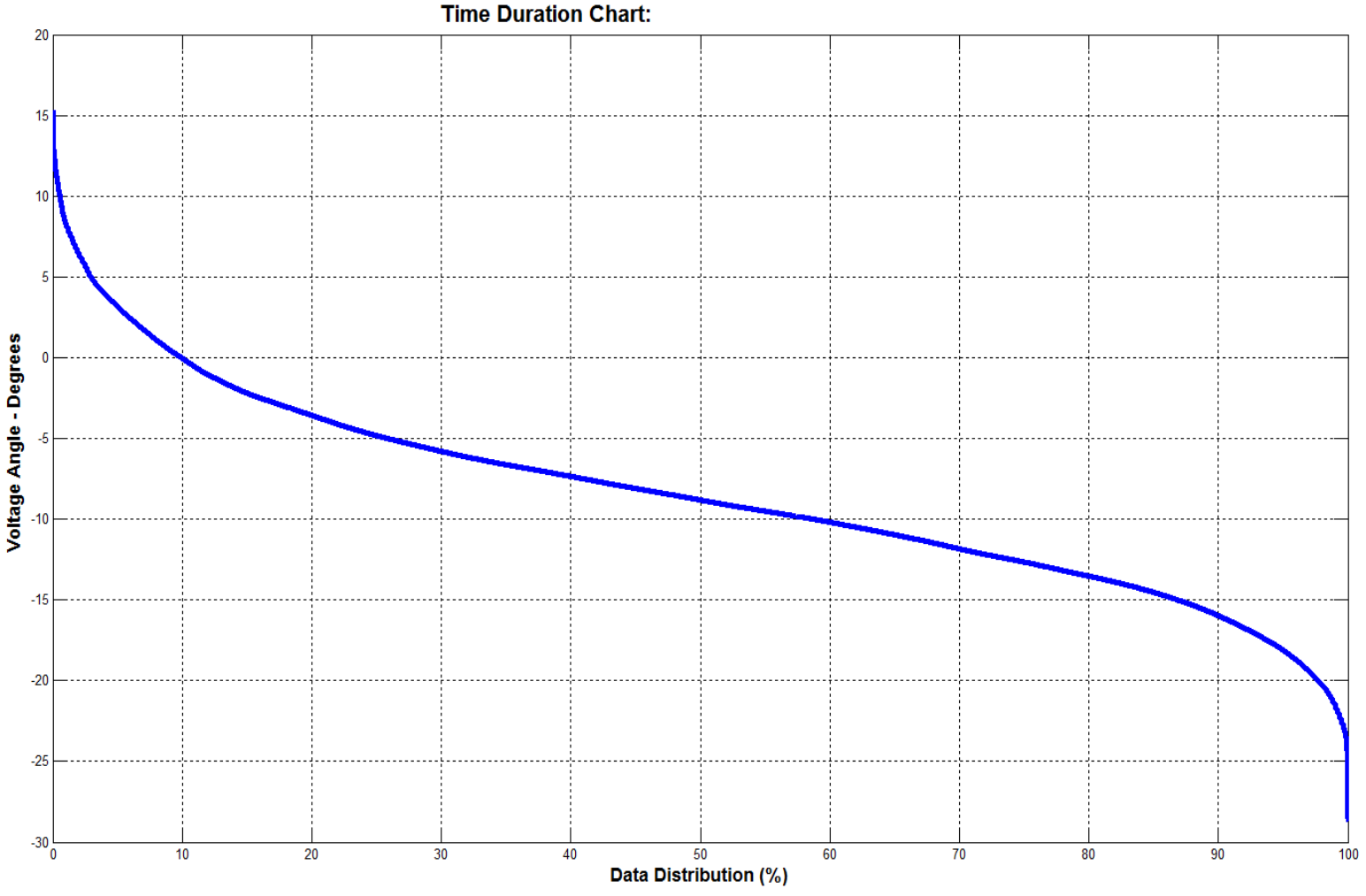
-20
-30
-40
0
10
20
30
40
50
60
70
80
90
100

South 5


Daily Box-Whisker Chart:
Angle Difference - Degrees
15
10
5
0
-5
-10
-15
-20
-25
-30
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

South 5


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
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15
10
5
0
-5
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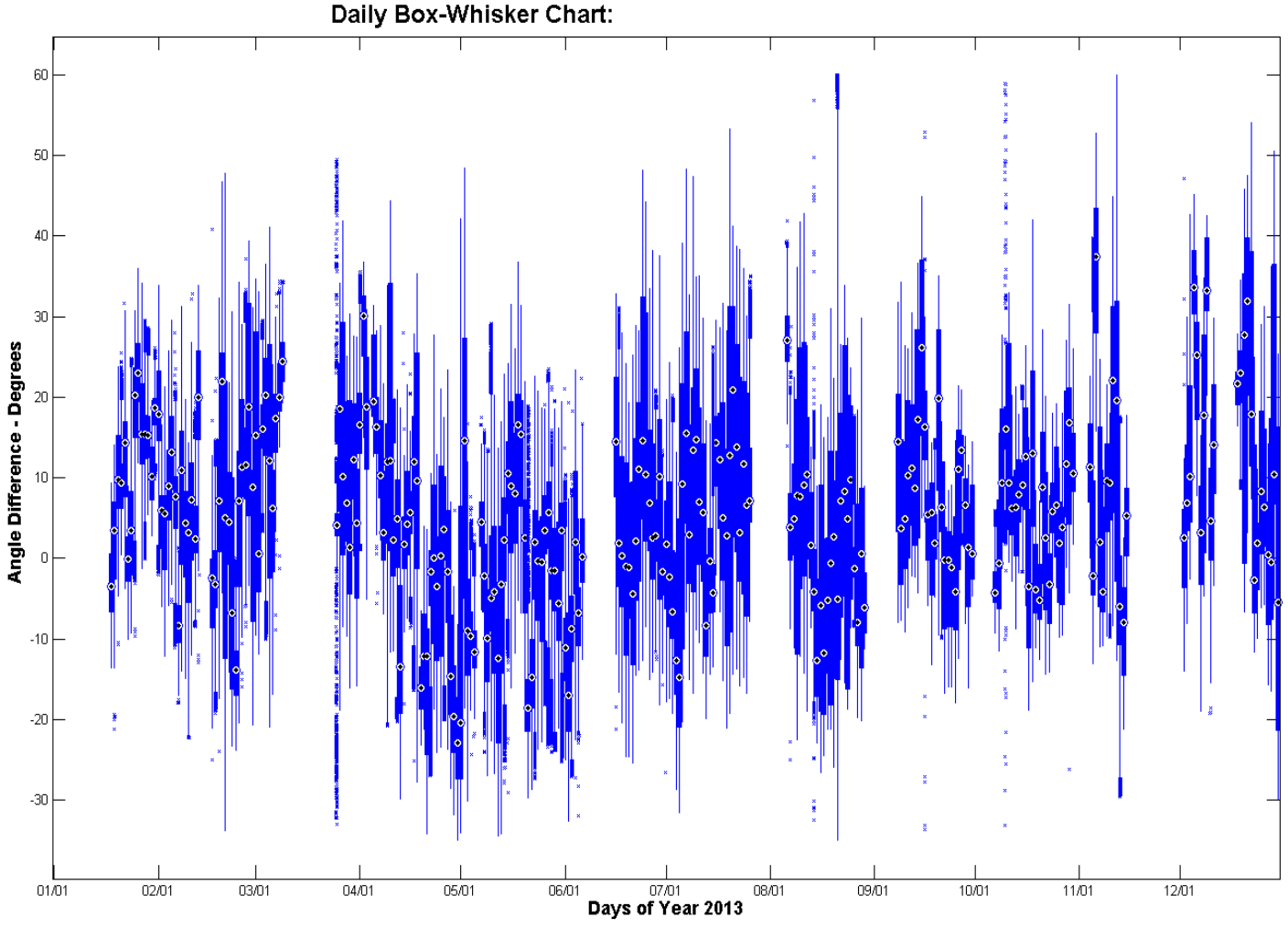
-20
-25
-30
0
10
20
30
40
50
60
70
80
90
100

Coast 4


Daily Box-Whisker Chart:
Angle Difference - Degrees
60
50
40
30
20
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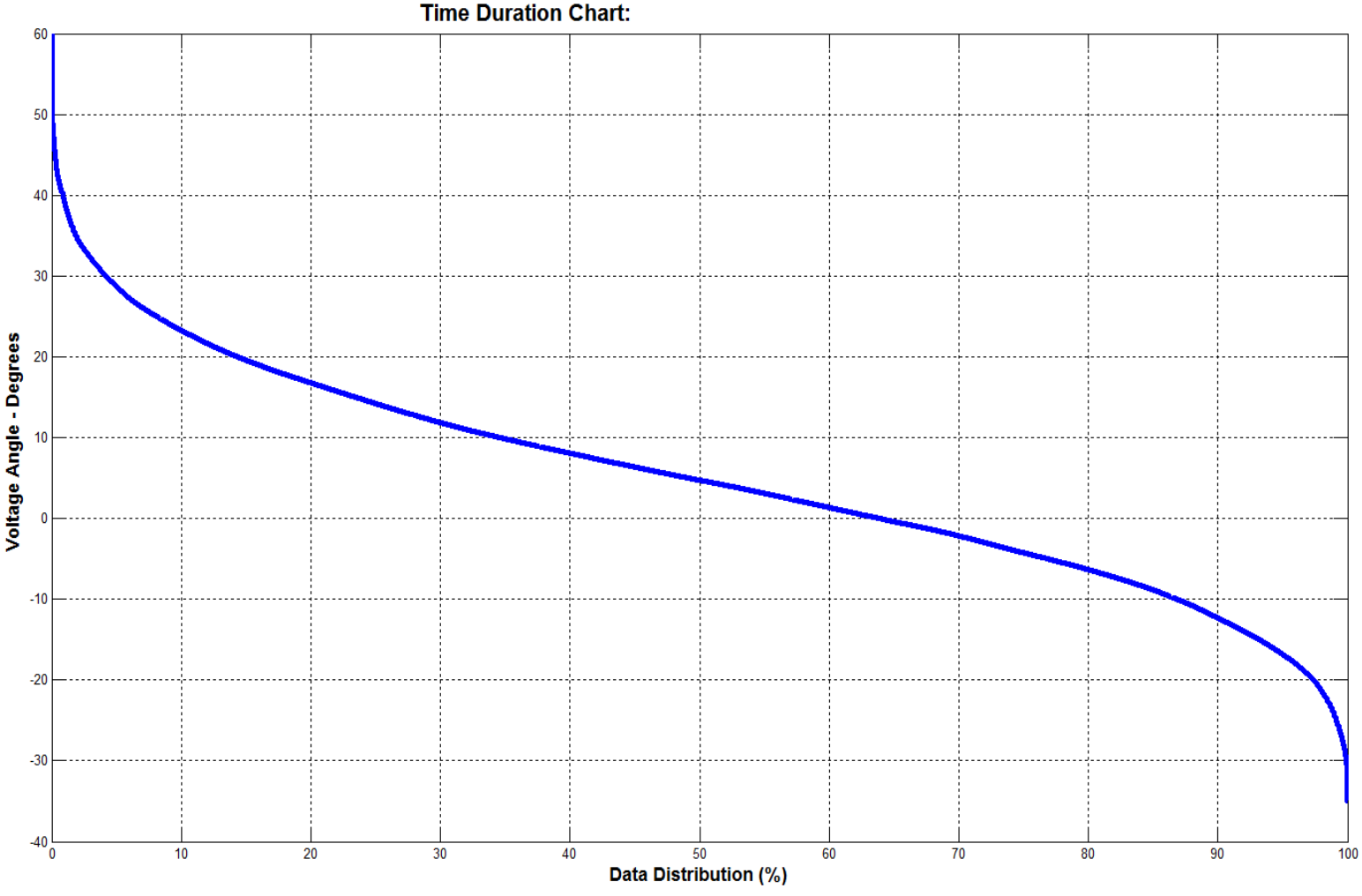
0
-10
-20
-30
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

Coast 4


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
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50
40
30
20
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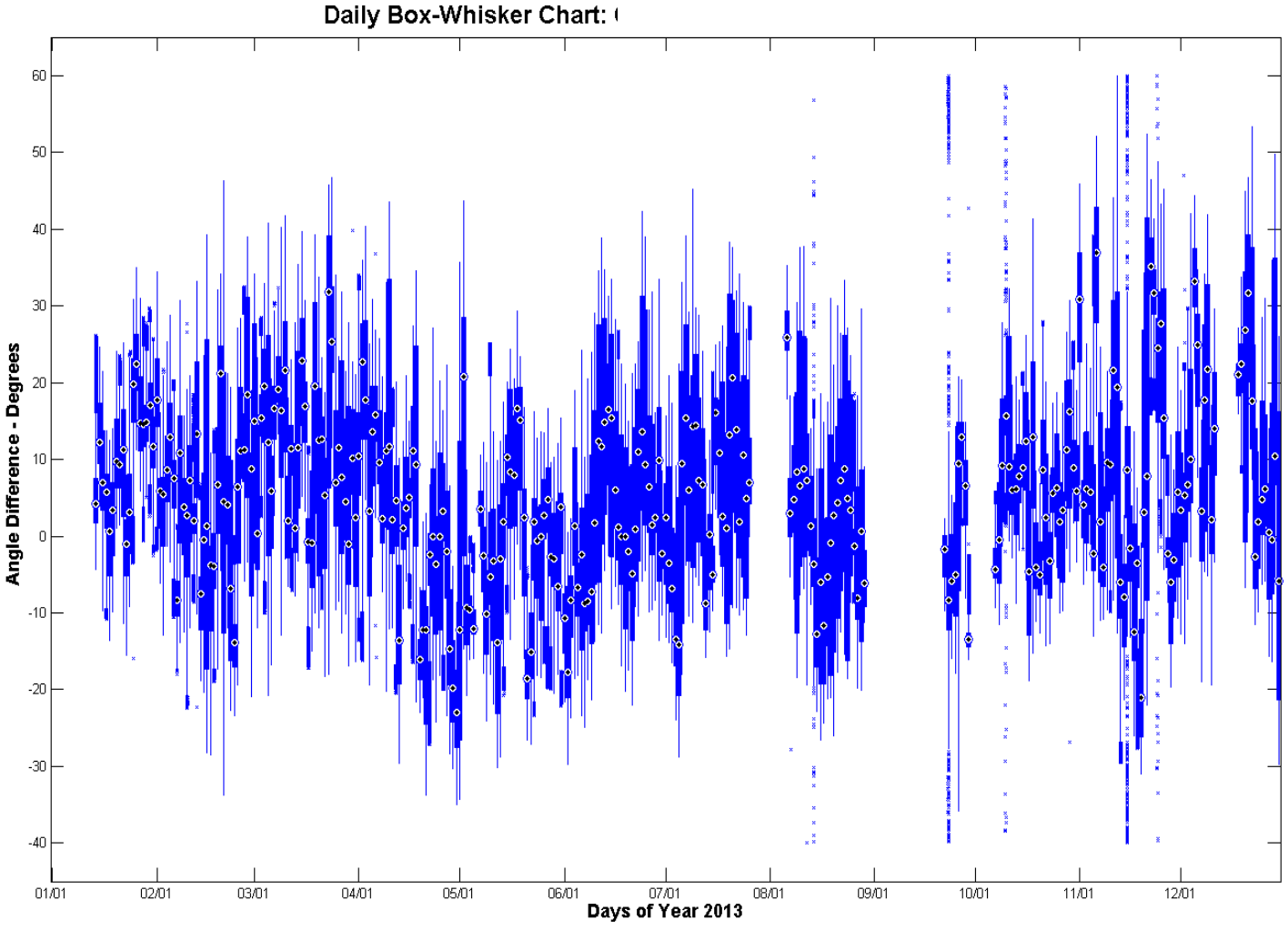
-20
-30
-40
0
10
20
30
40
50
60
70
80
90
100

Coast 3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Angle Difference - Degrees
60
50
40
30
20
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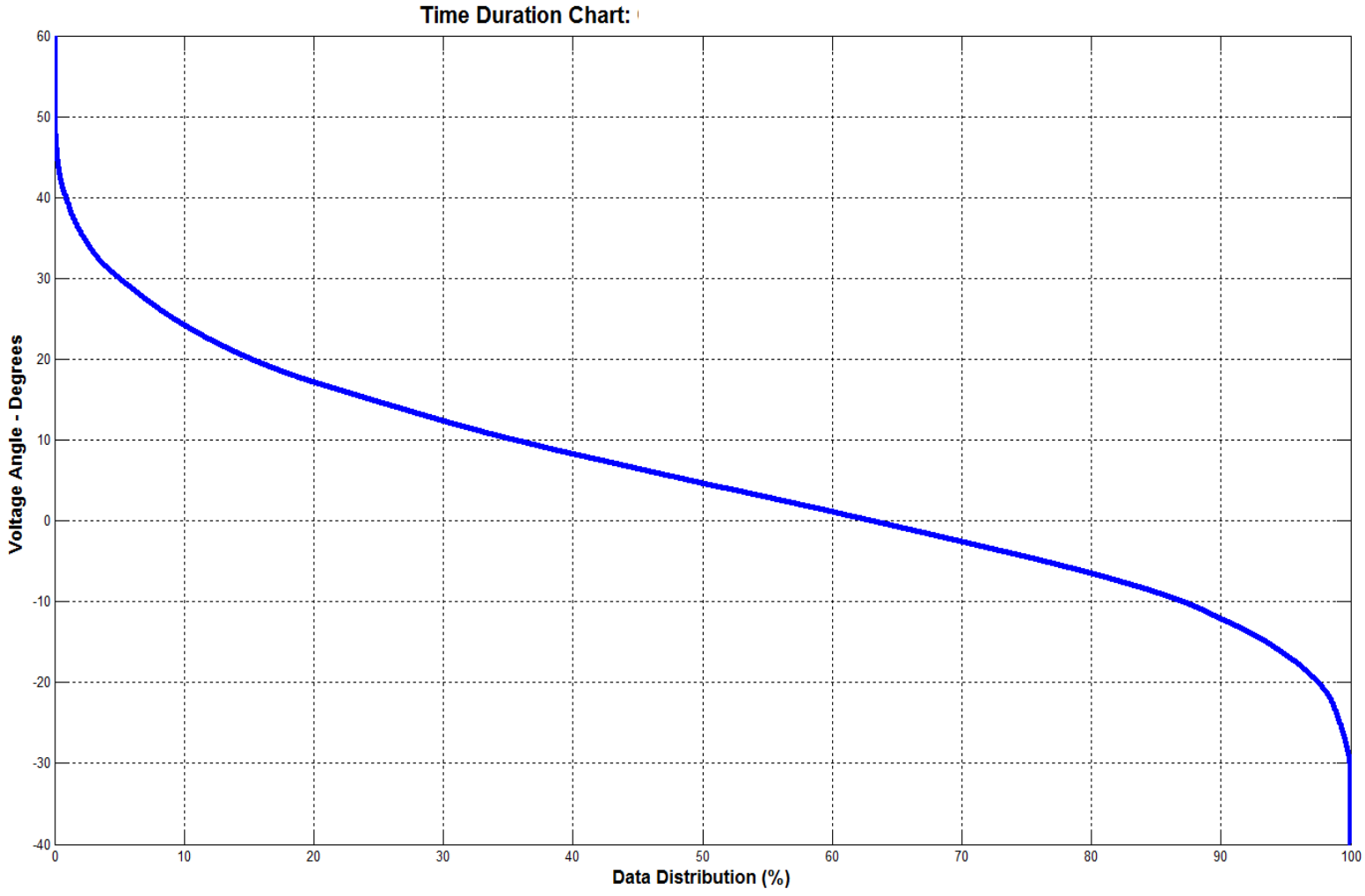
0
-10
-20
-30
-40
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

Coast 3


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
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50
40
30
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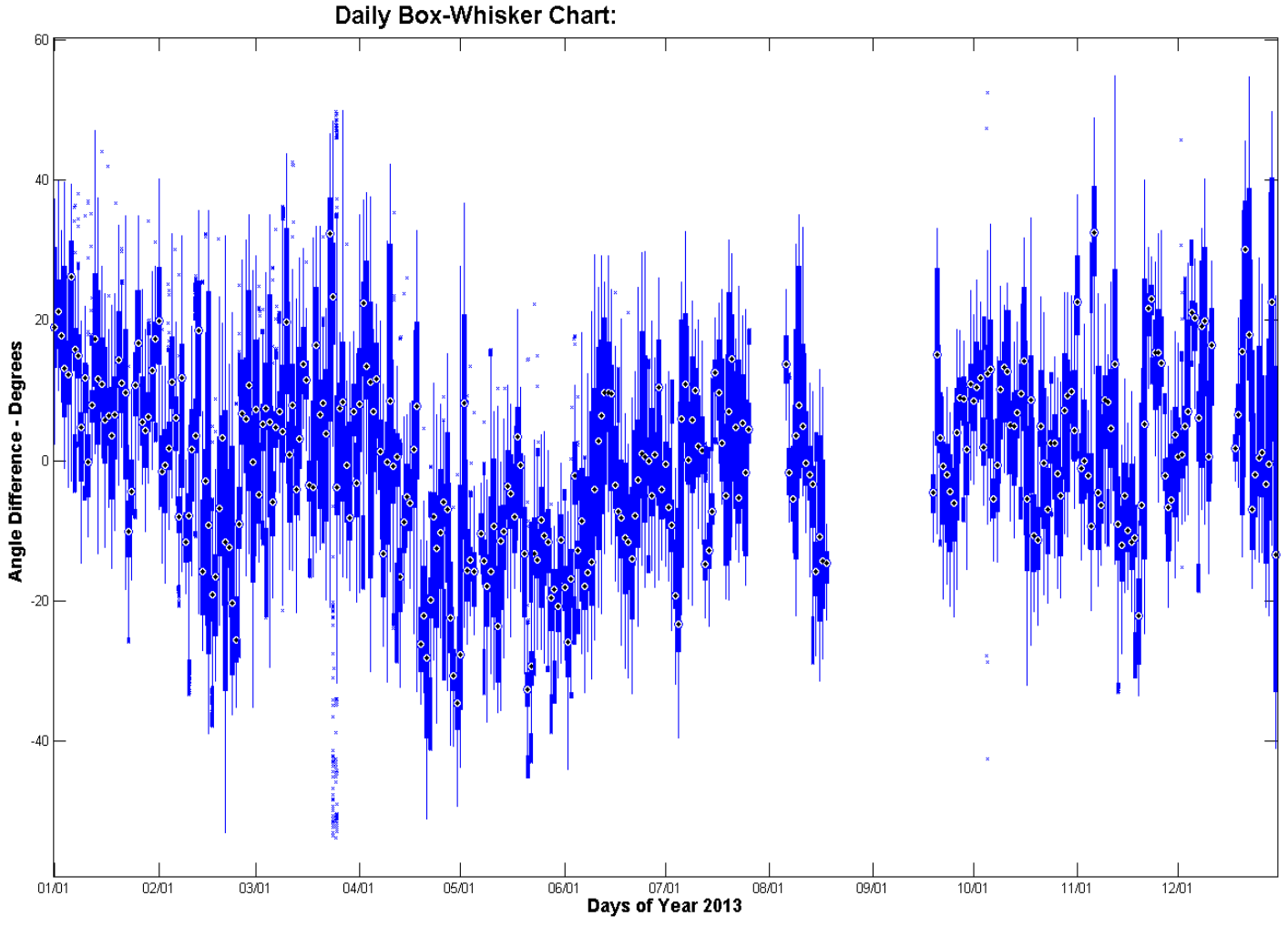
-40
0
10
20
30
40
50
60
70
80
90
100

South 13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Angle Difference - Degrees
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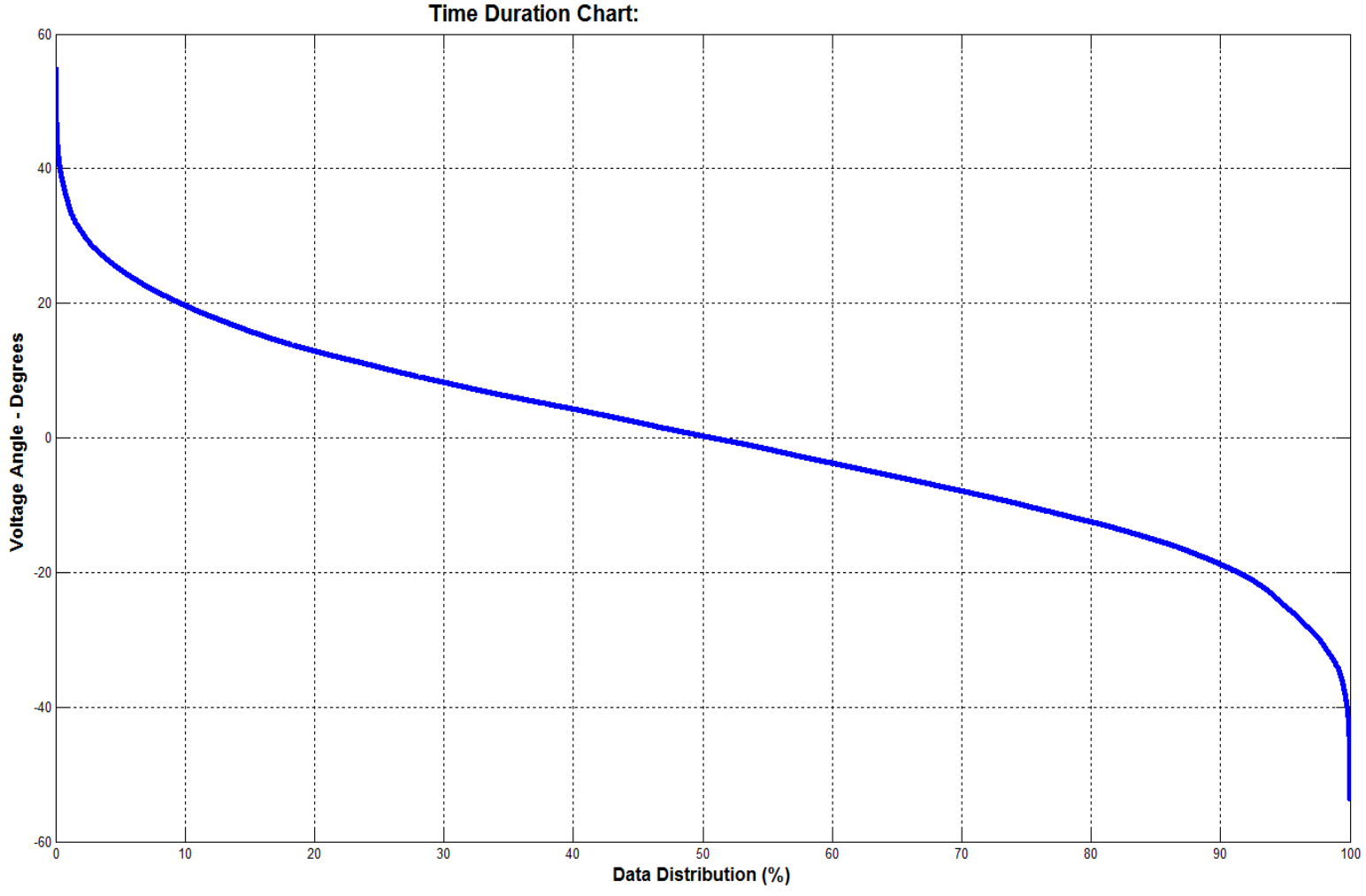
20
0
-20
-40
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

South 13


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
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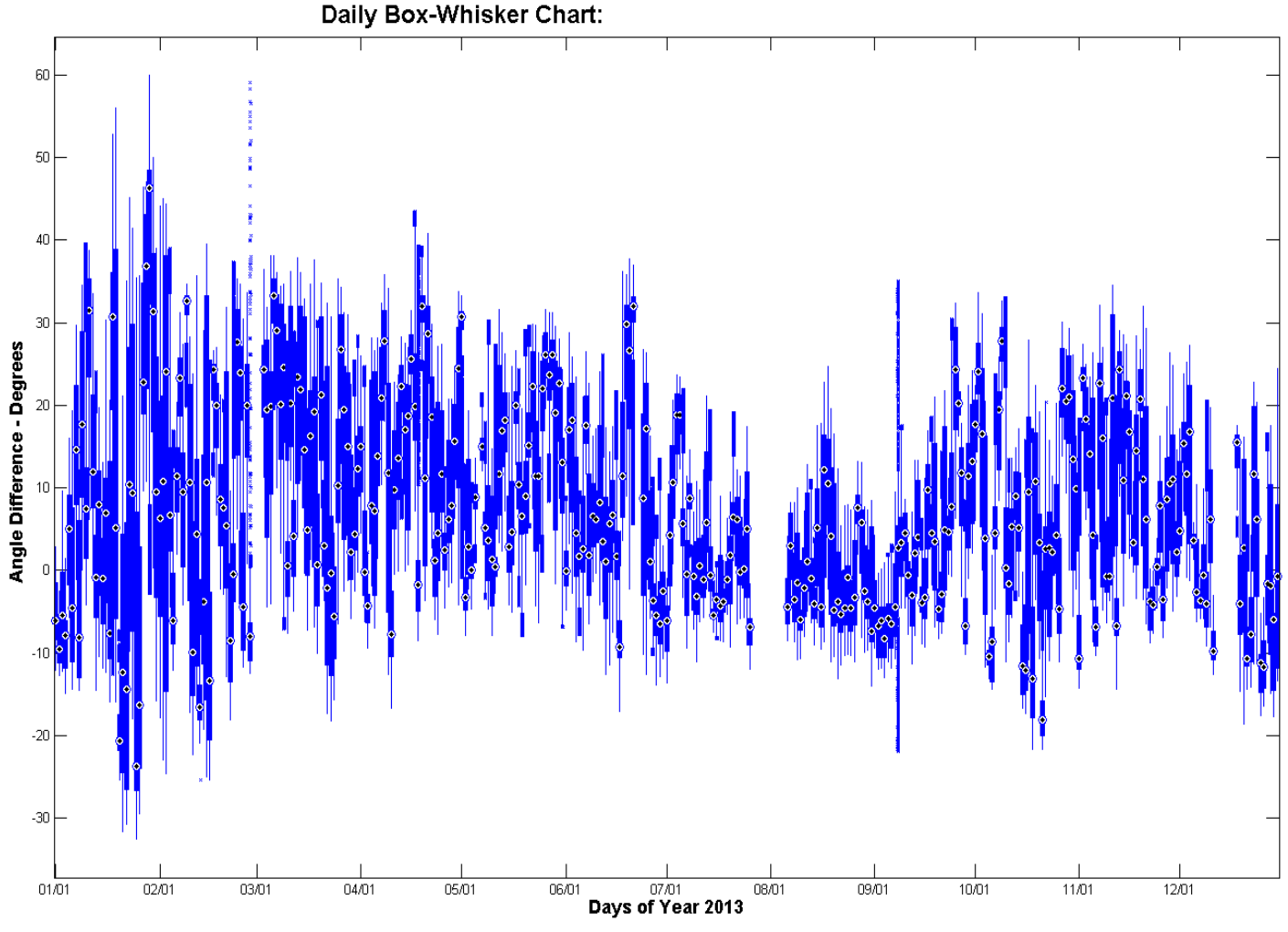
-20
-40
-60
0
10
20
30
40
50
60
70
80
90
100

FarWest 4


Daily Box-Whisker Chart:
Angle Difference - Degrees
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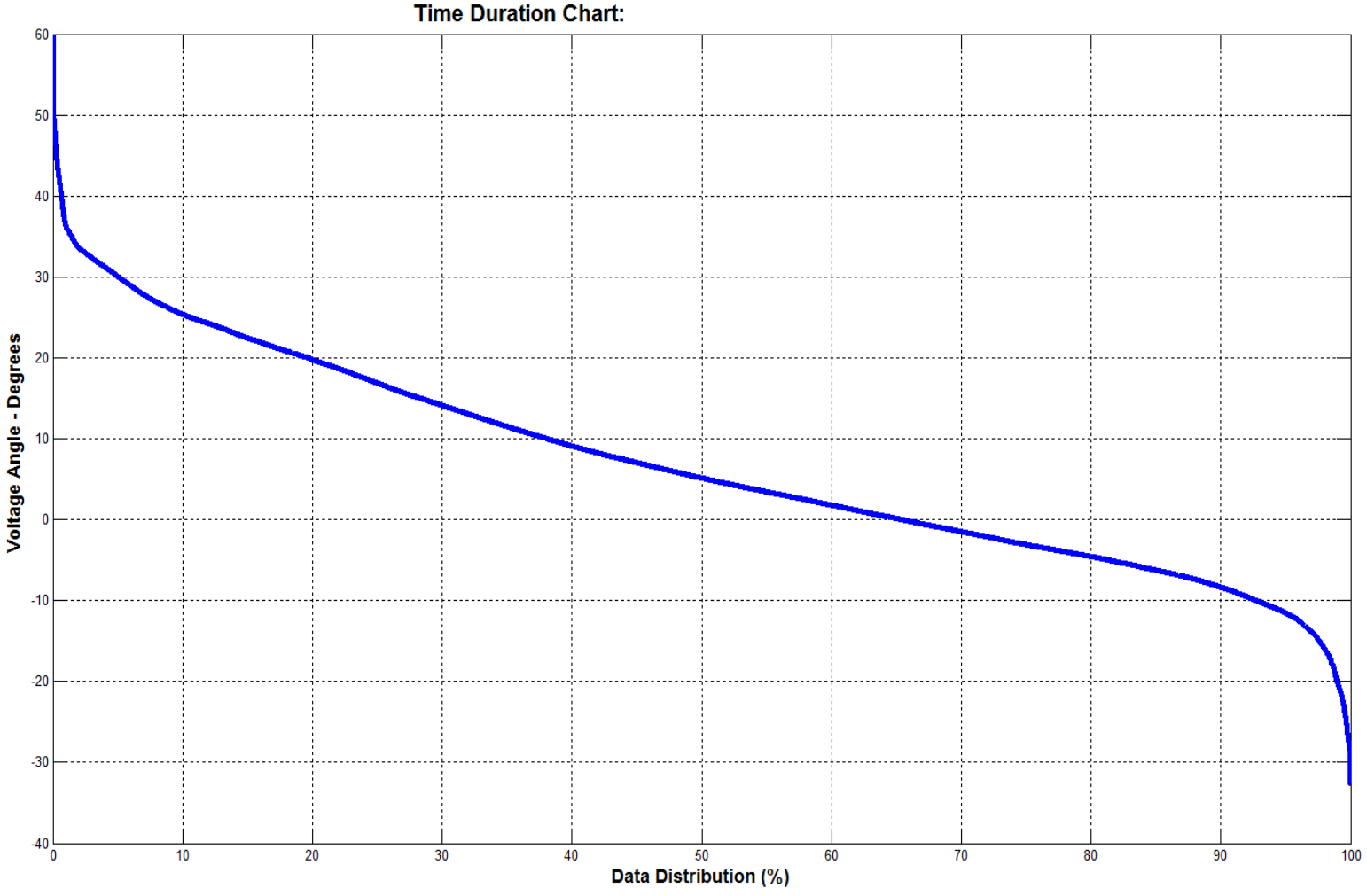
40
30
20
10
0
-10
-20
-30
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

FarWest 4


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
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50
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30
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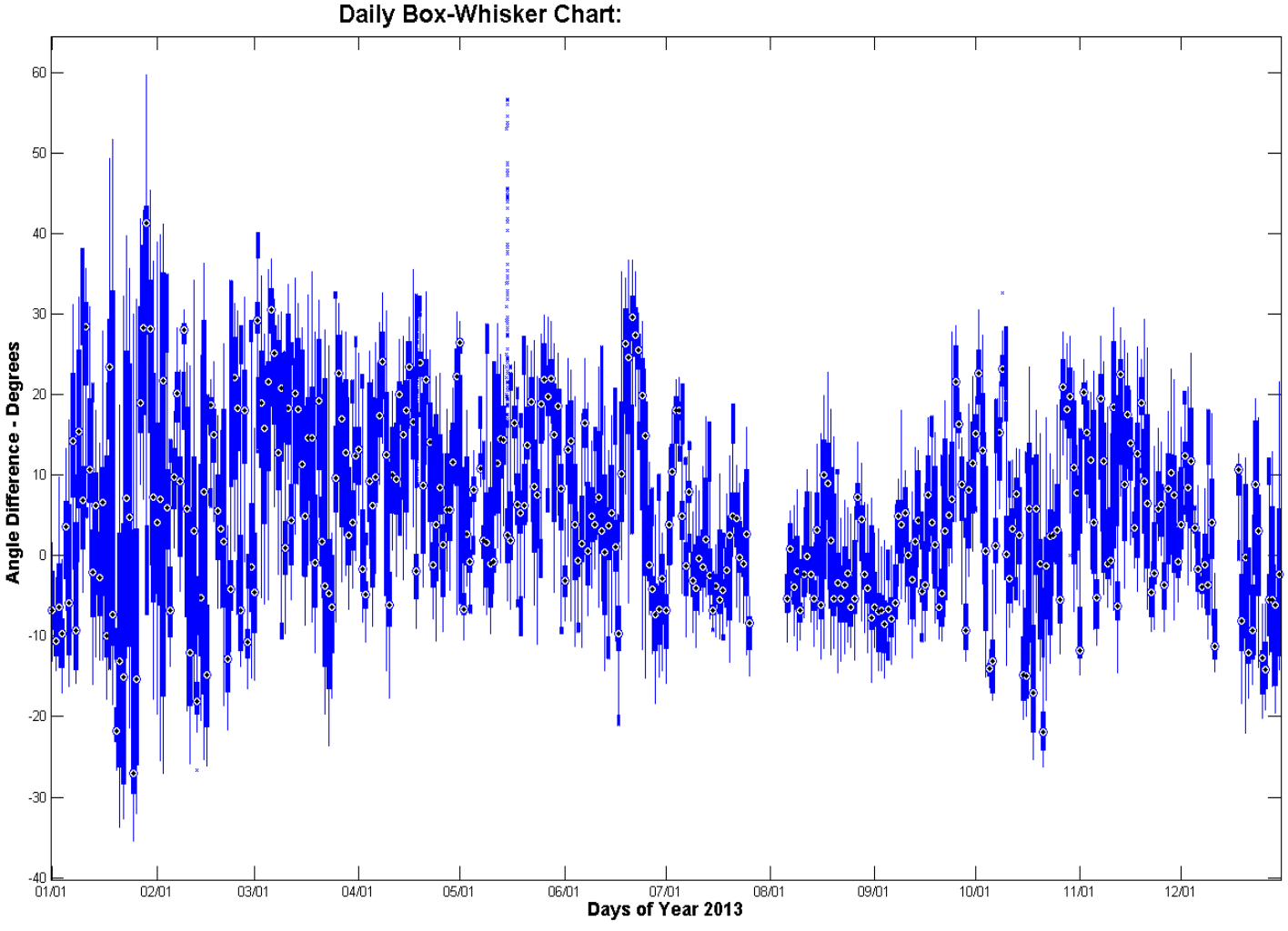
0
-10
-20
-30
-40
0
10
20
30
40
50
60
70
80
90
100

FarWest 7


Daily Box-Whisker Chart:
Angle Difference - Degrees
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30
20
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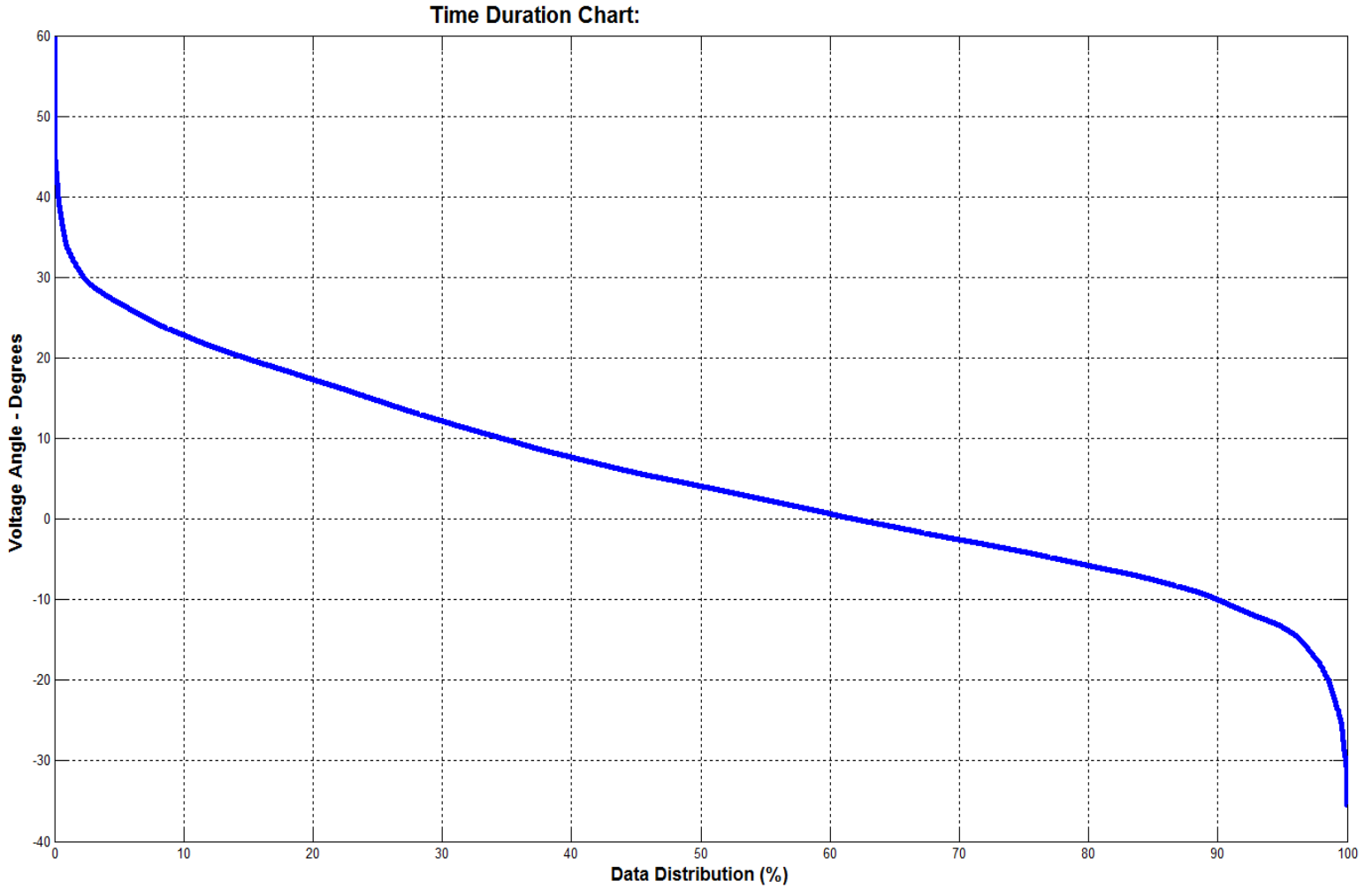
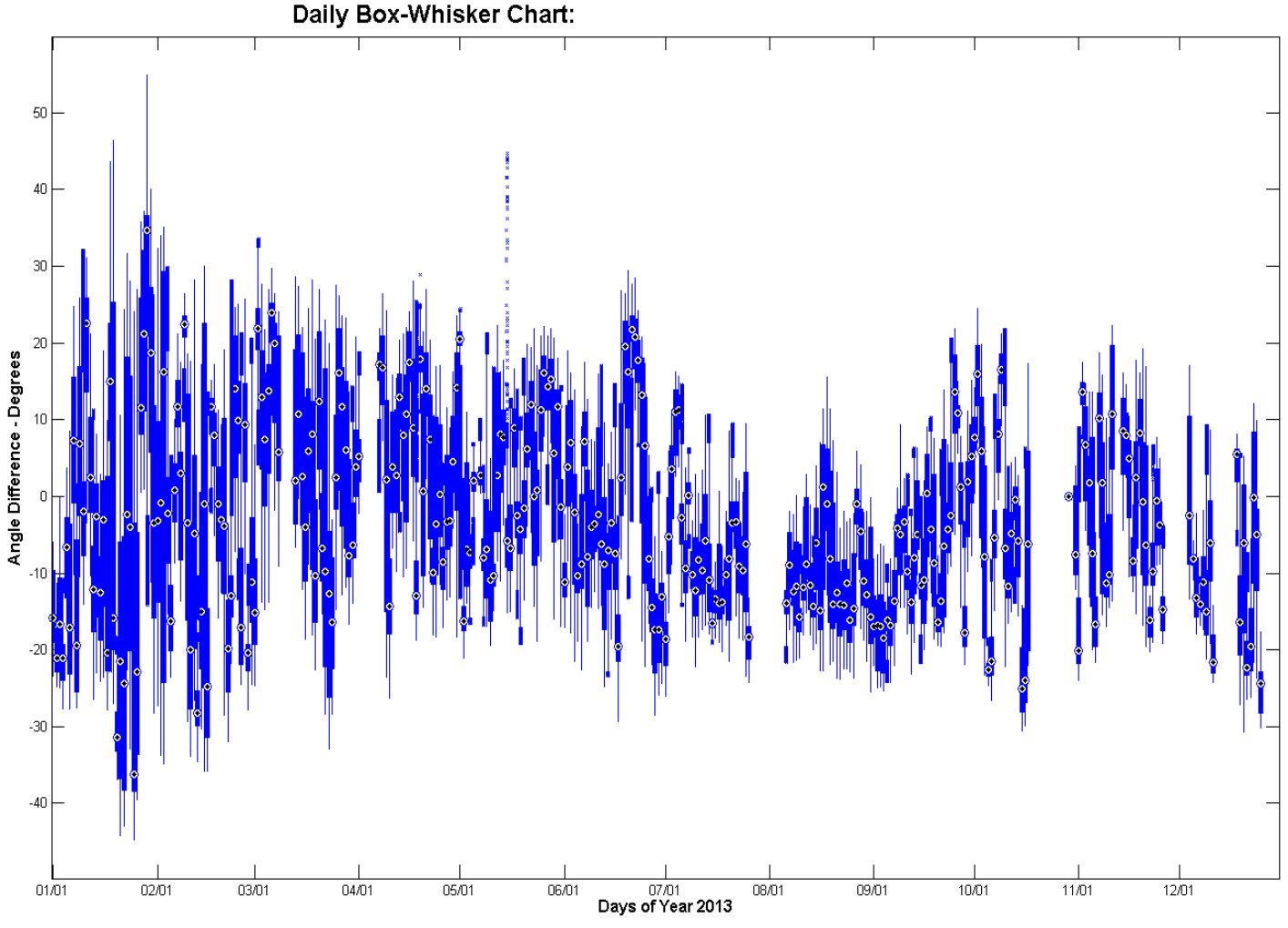
0
-10
-20
-30
-40
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

FarWest 7


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
60
50
40
30
20
10
0
-10
-20
-30
-40
0
10
20
30
40
50
60
70
80
90
100

FarWest 8


Daily Box-Whisker Chart:
Angle Difference - Degrees
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30
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10
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-10
-20
-30
-40
01/01
02/01
03/01
04/01
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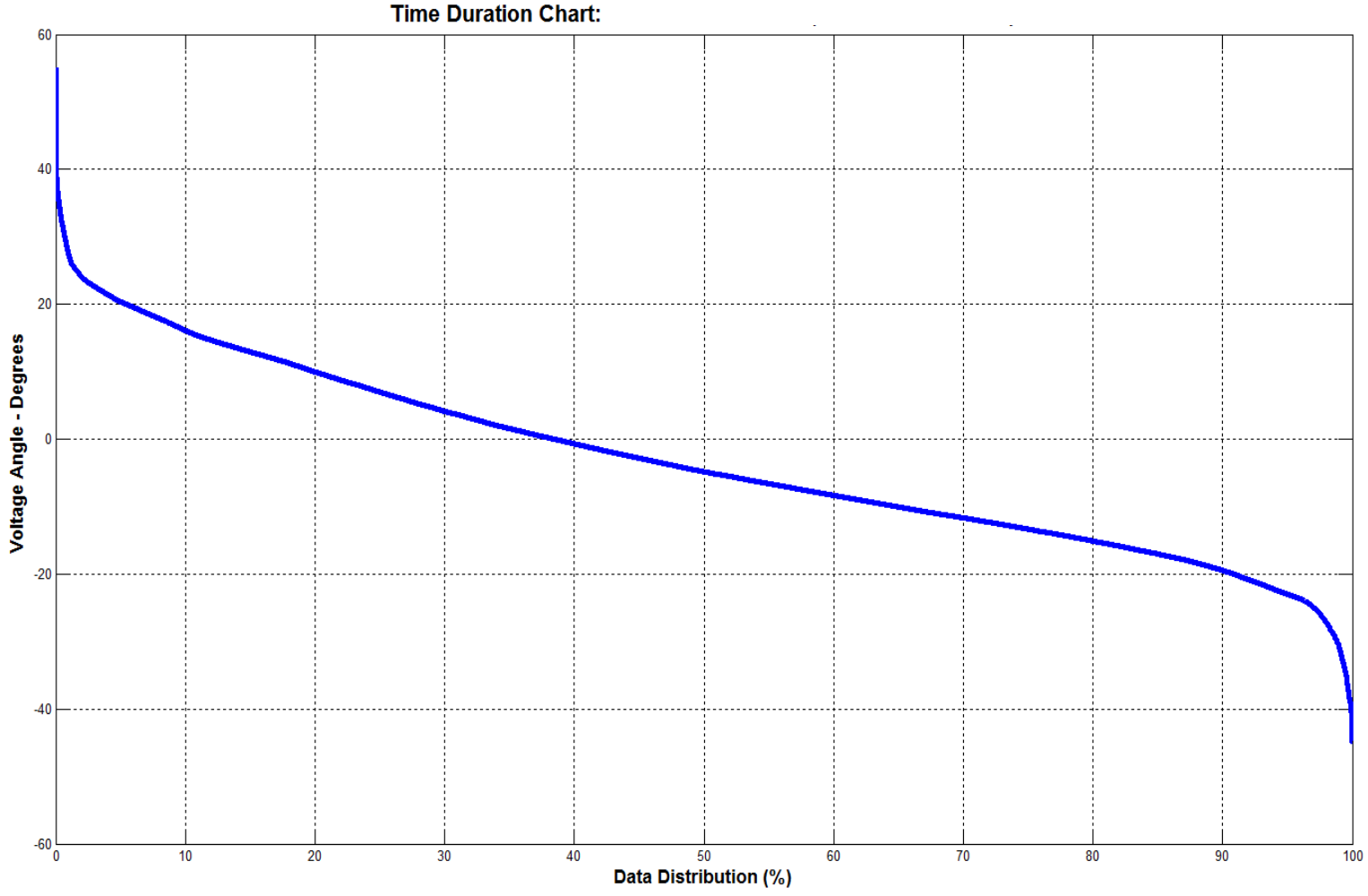
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

FarWest 8


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
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40
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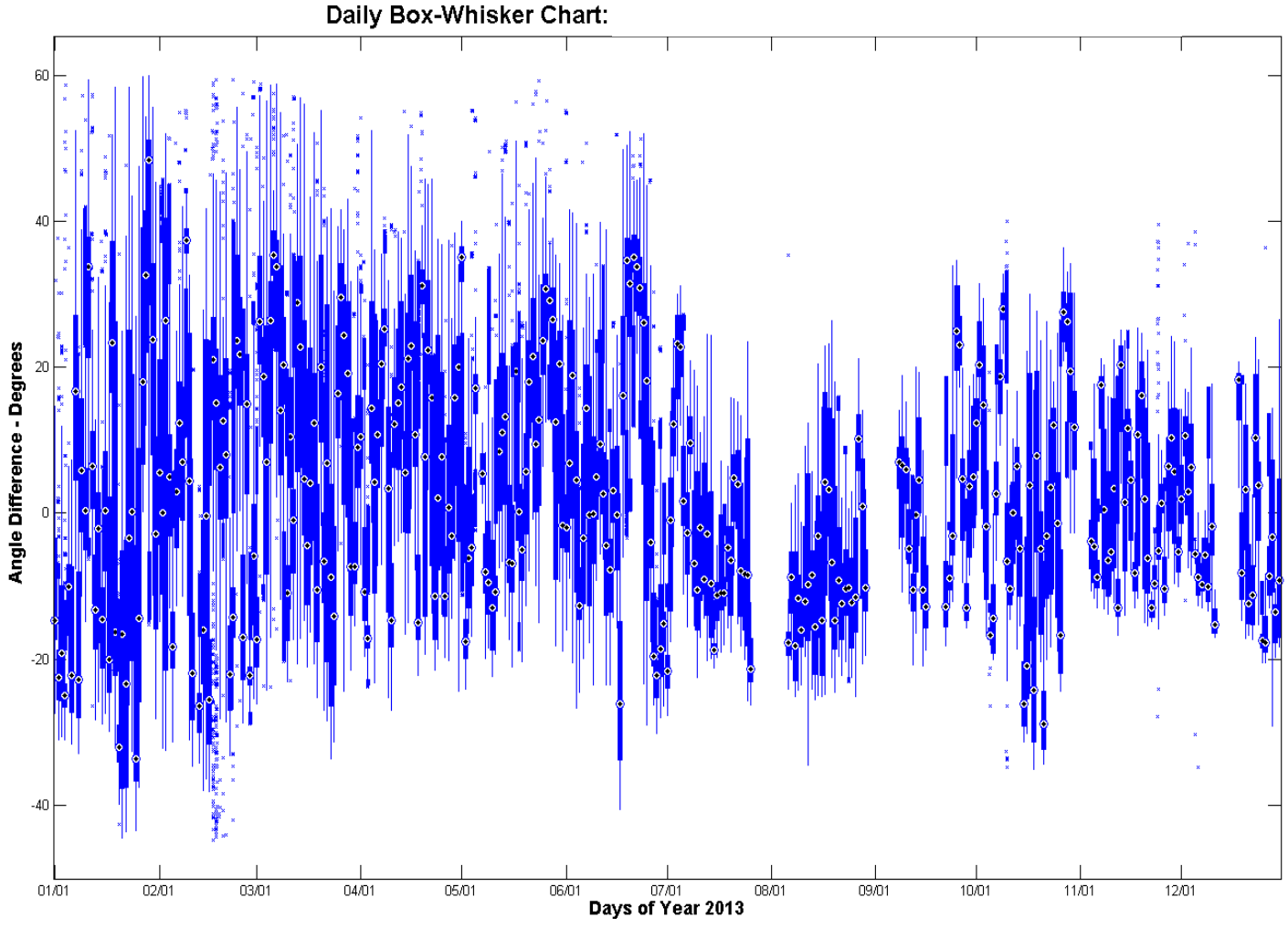
-20
-40
-60
0
10
20
30
40
50
60
70
80
90
100

FarWest 9


Daily Box-Whisker Chart:
Angle Difference - Degrees
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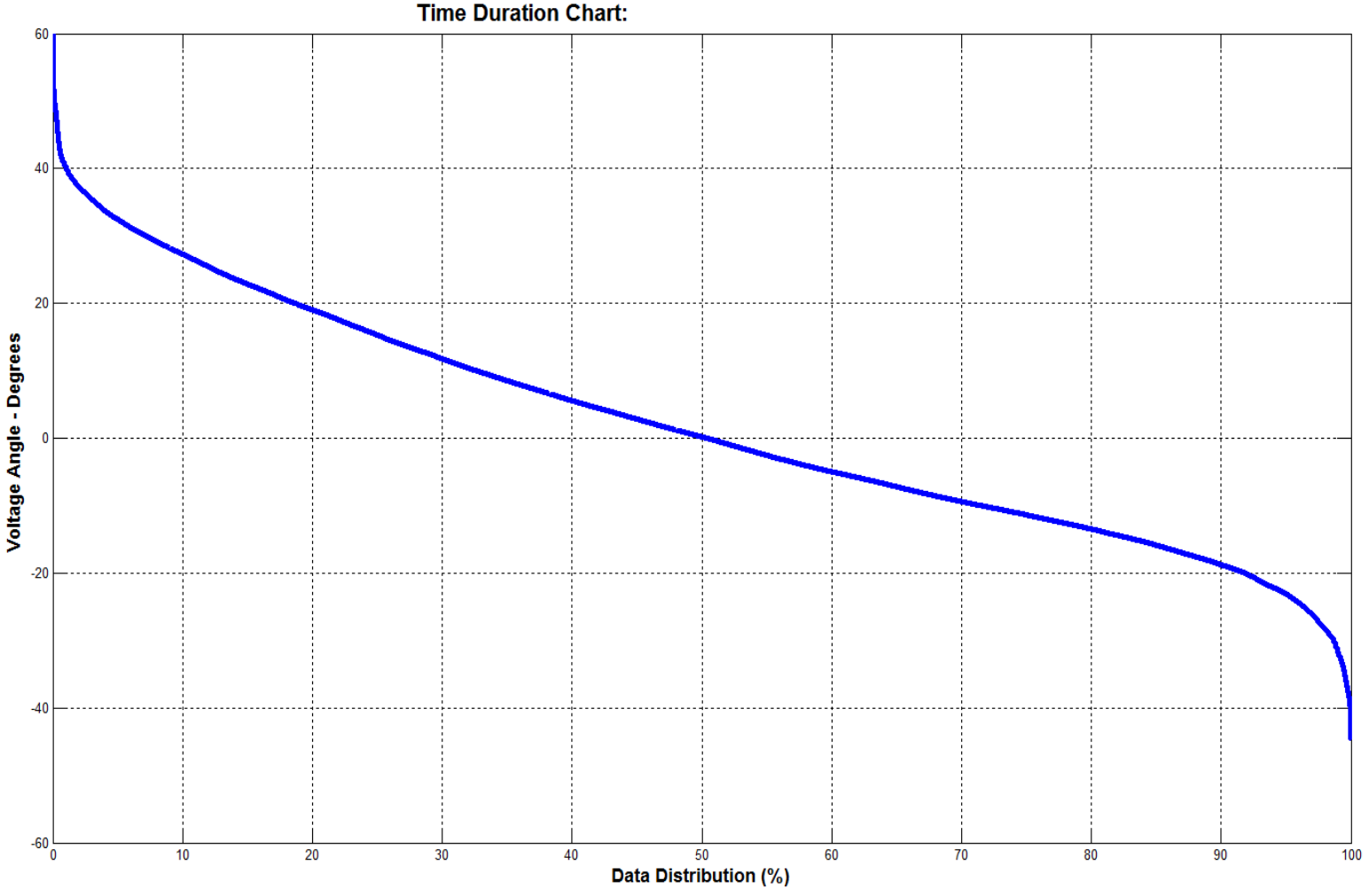
20
0
-20
-40
01/01
02/01
03/01
04/01
05/01
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

FarWest 9


Time Duration Chart:
Voltage Angle - Degrees
60
40
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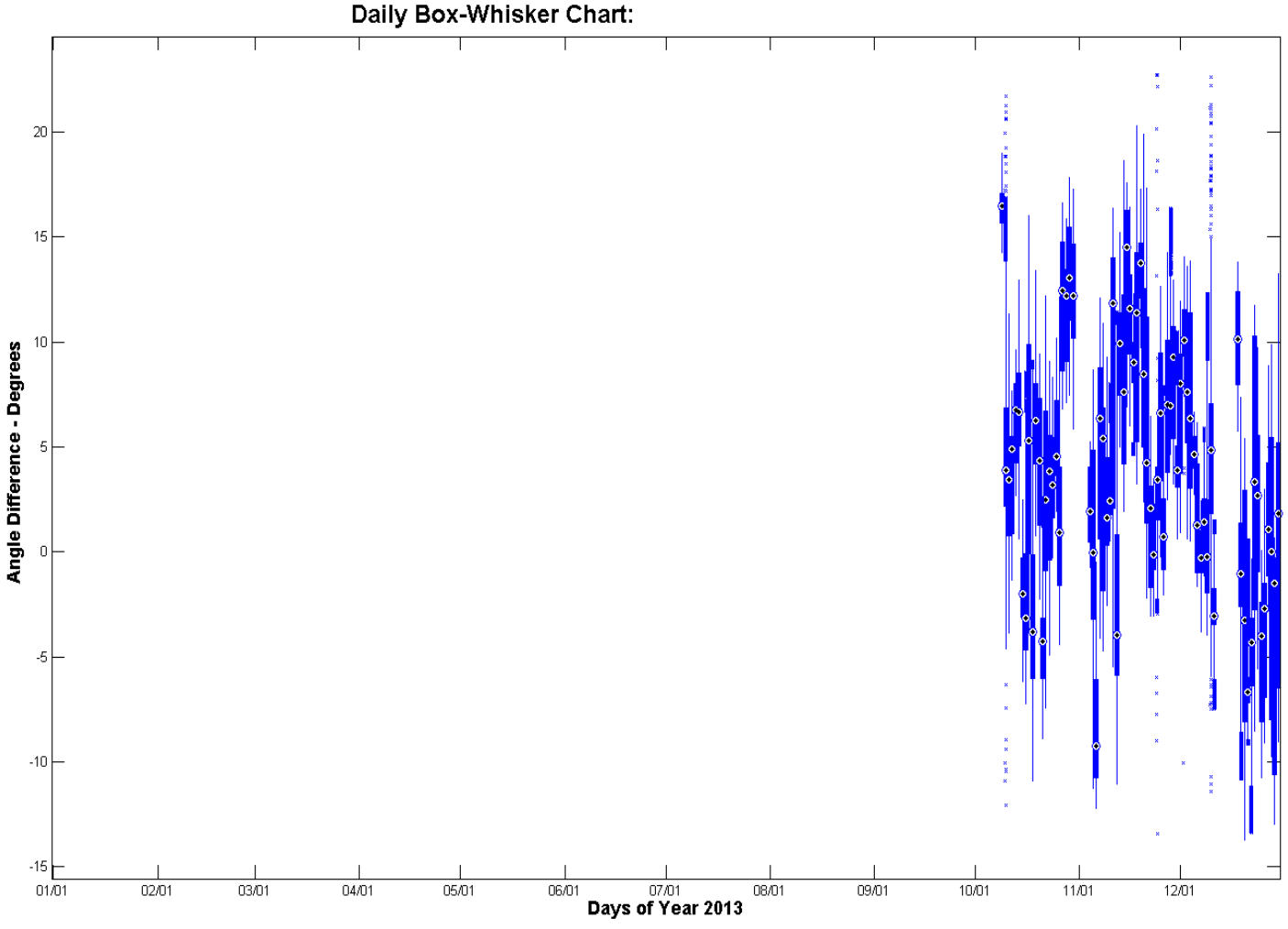
-20
-40
-60
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (%)

West 15


Daily Box-Whisker Chart:
Angle Difference - Degrees
20
15
10
5
0
-5
-10
-15
01/01
02/01
03/01
04/01
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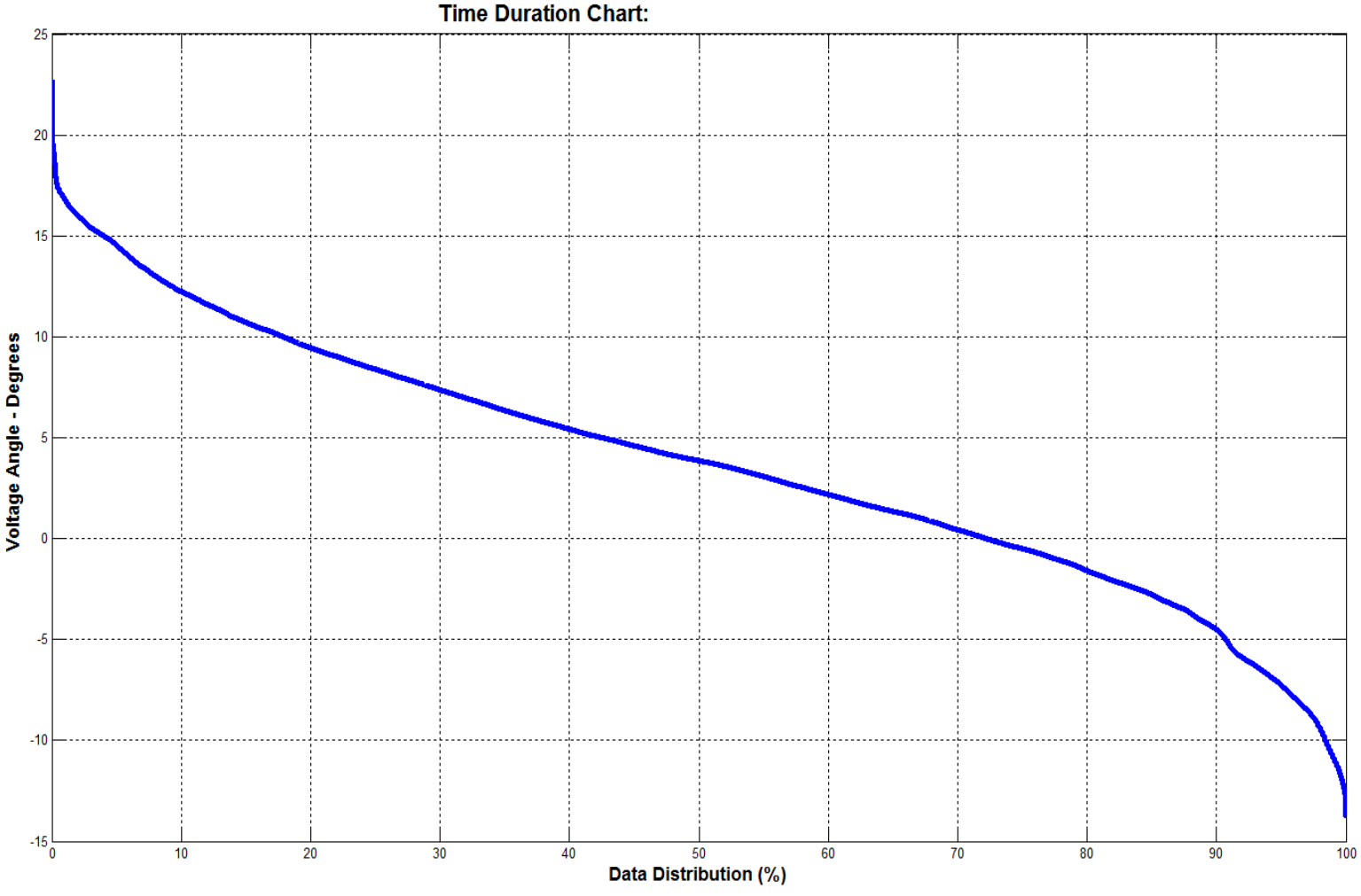
06/01
07/01
08/01
09/01
10/01
11/01
12/01
Days of Year 2013

West 15


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (%)
25
20
15
10
5
0
-5
-10
-15
0
10
20
30
40
50
60
70
80
90
100

Appendix C – Part 1
CCET Discovery Across Texas project

Baseline Analysis Update – Angle Differences

State Estimator Data: January to December 2013

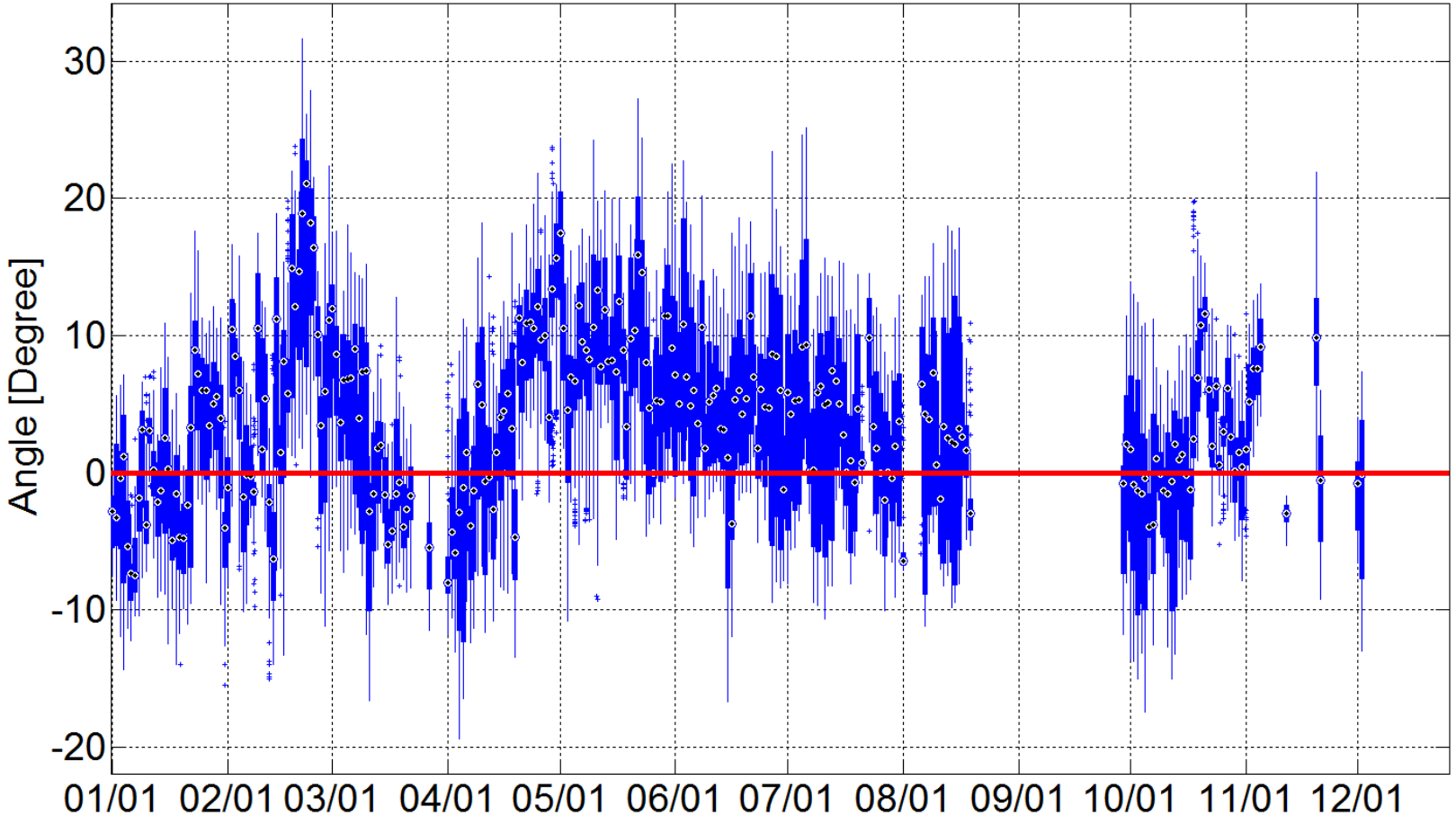
Box-Whisker Plots and Time Duration Curves

Electric Power Group

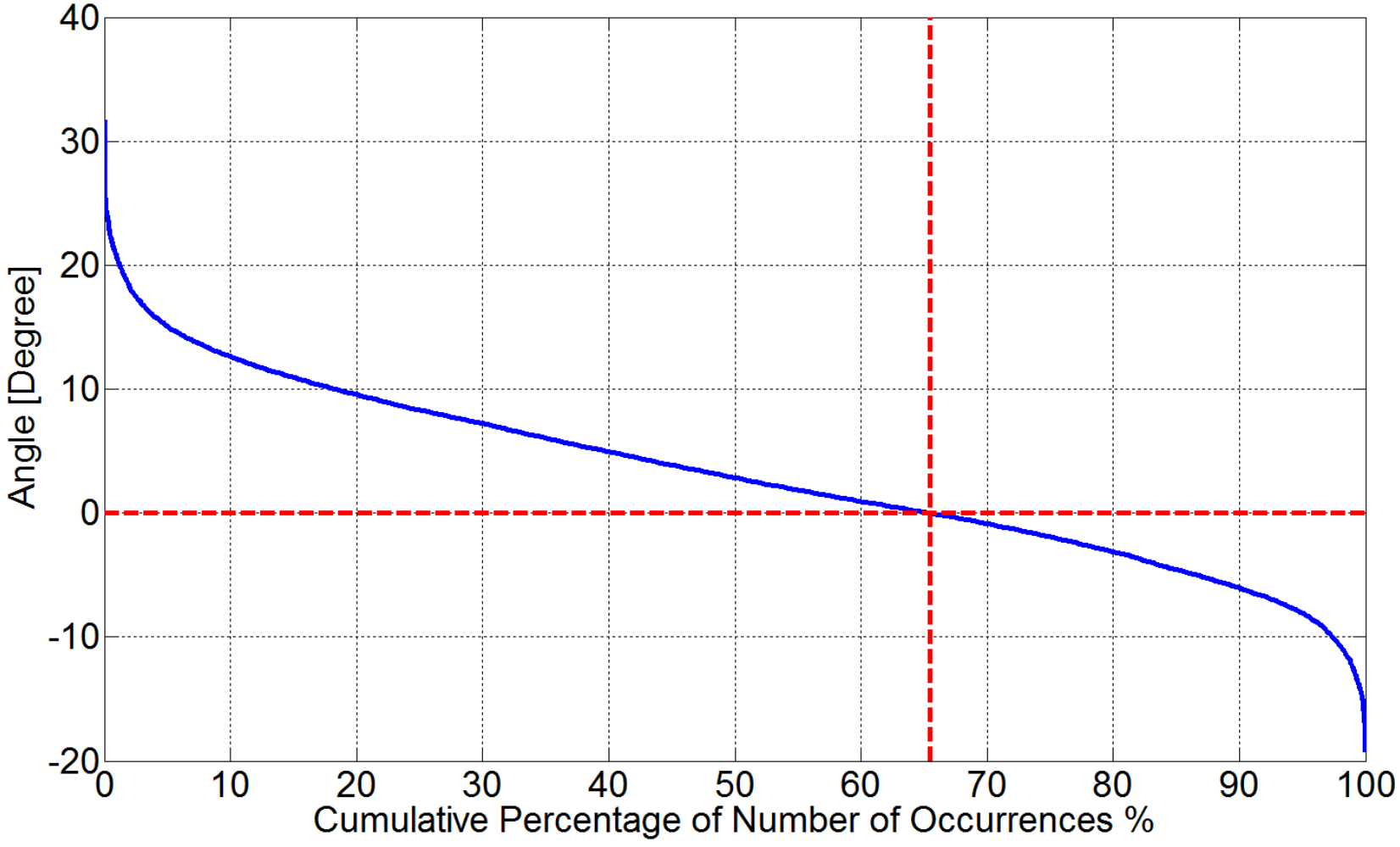
CCET

ERCOT

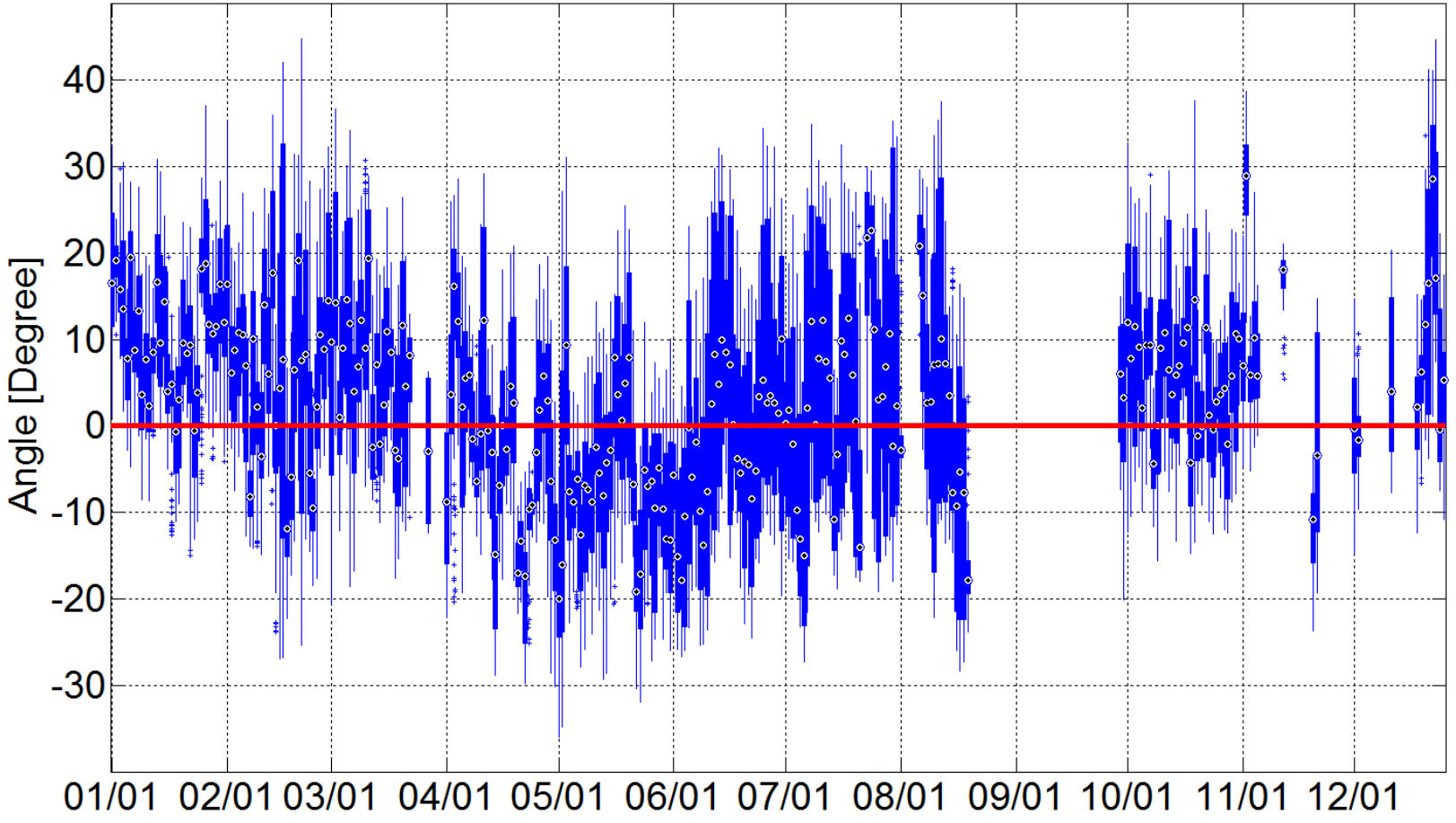
Coast 1-South 13



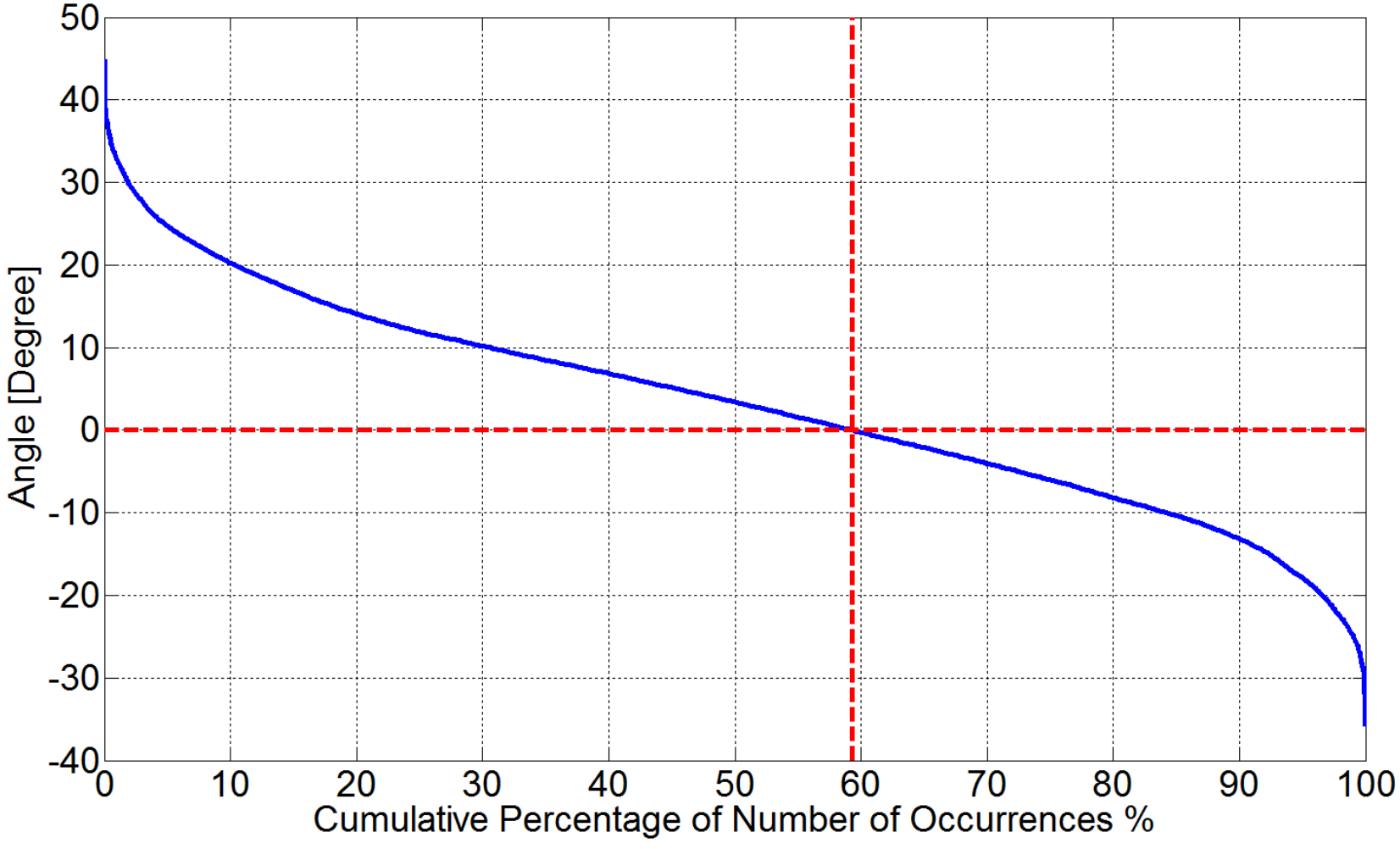
Coast 1-South 13



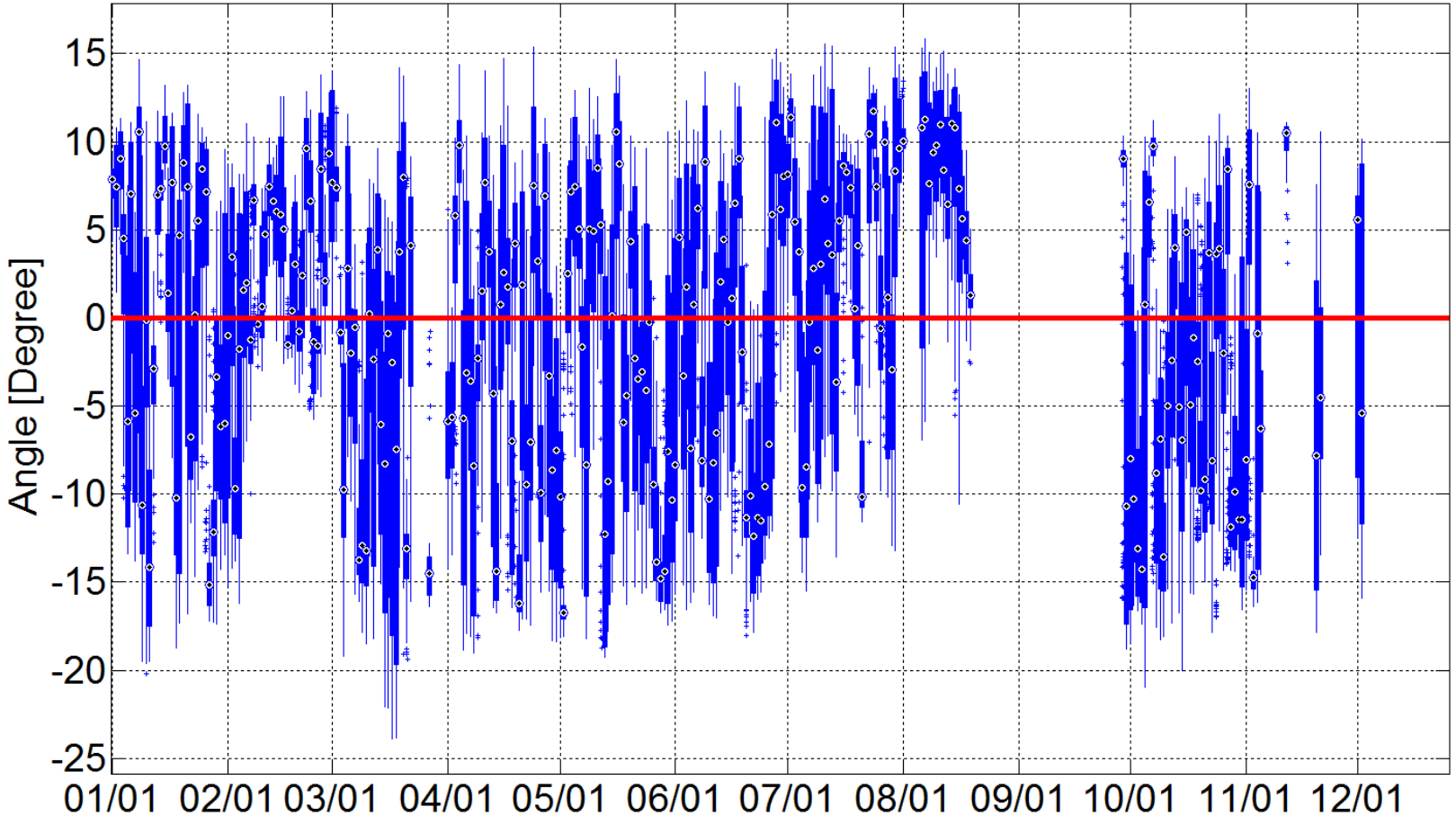
Coast 1-North 7



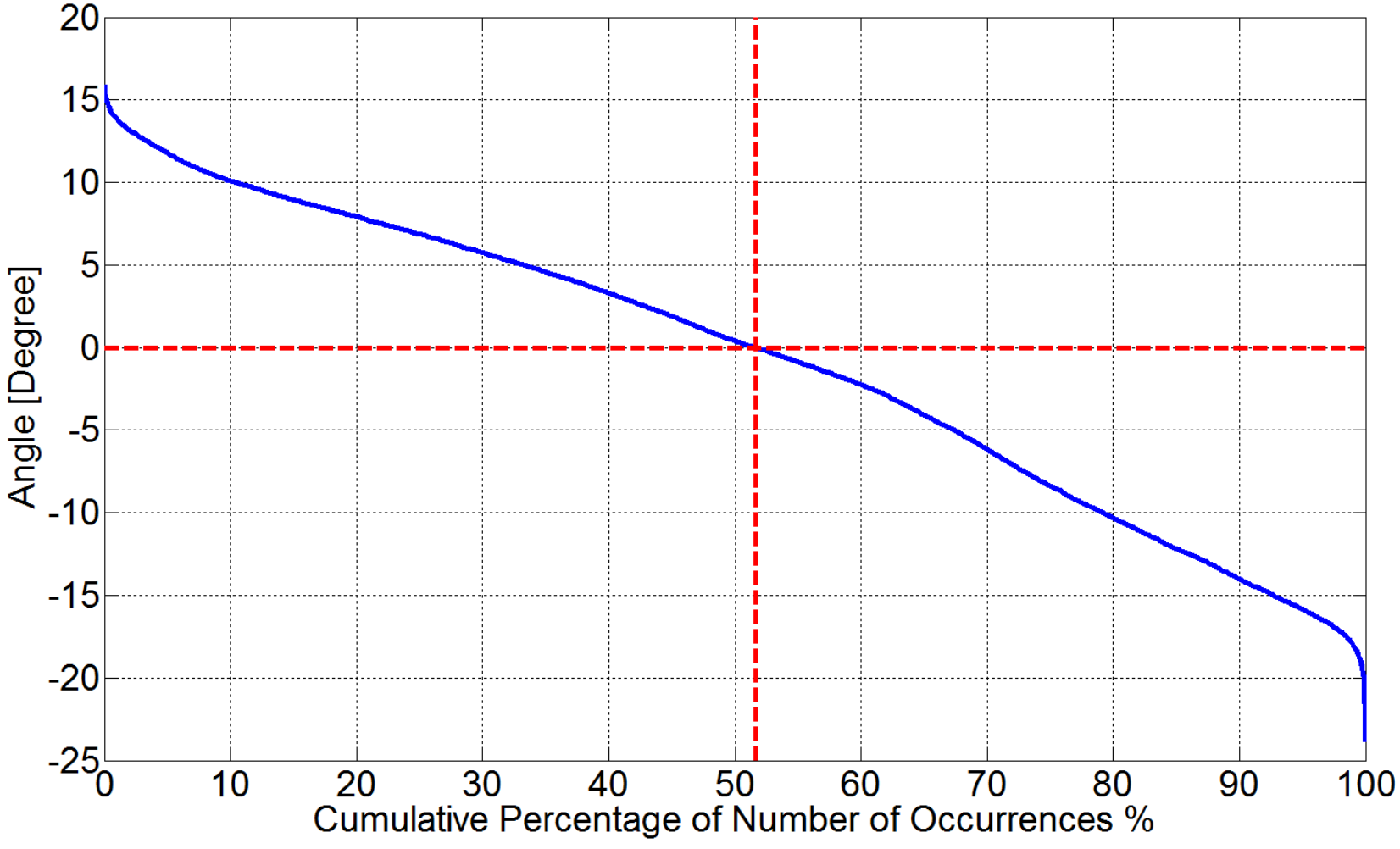
Coast 1-North 7



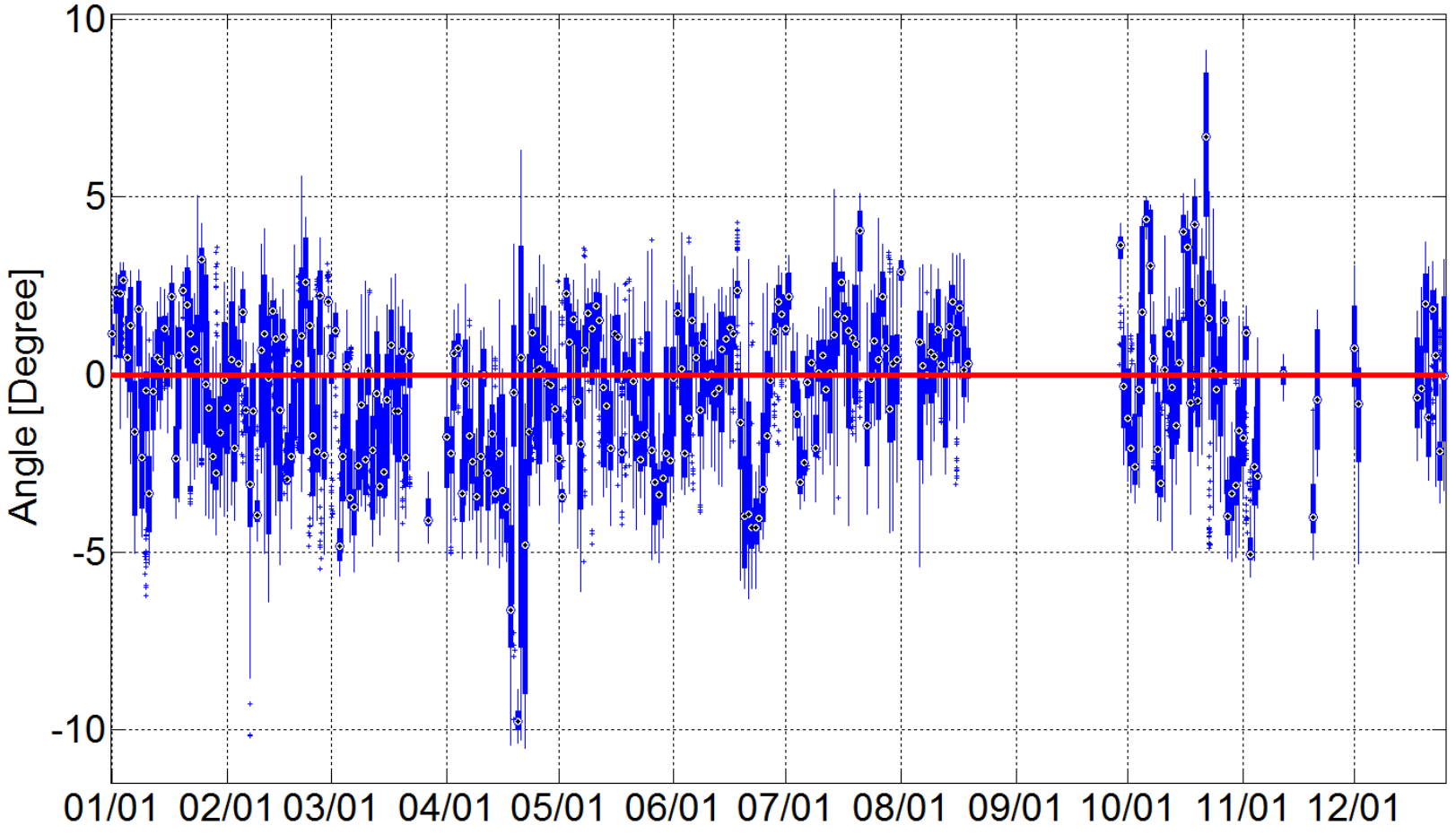
West 5-West 10



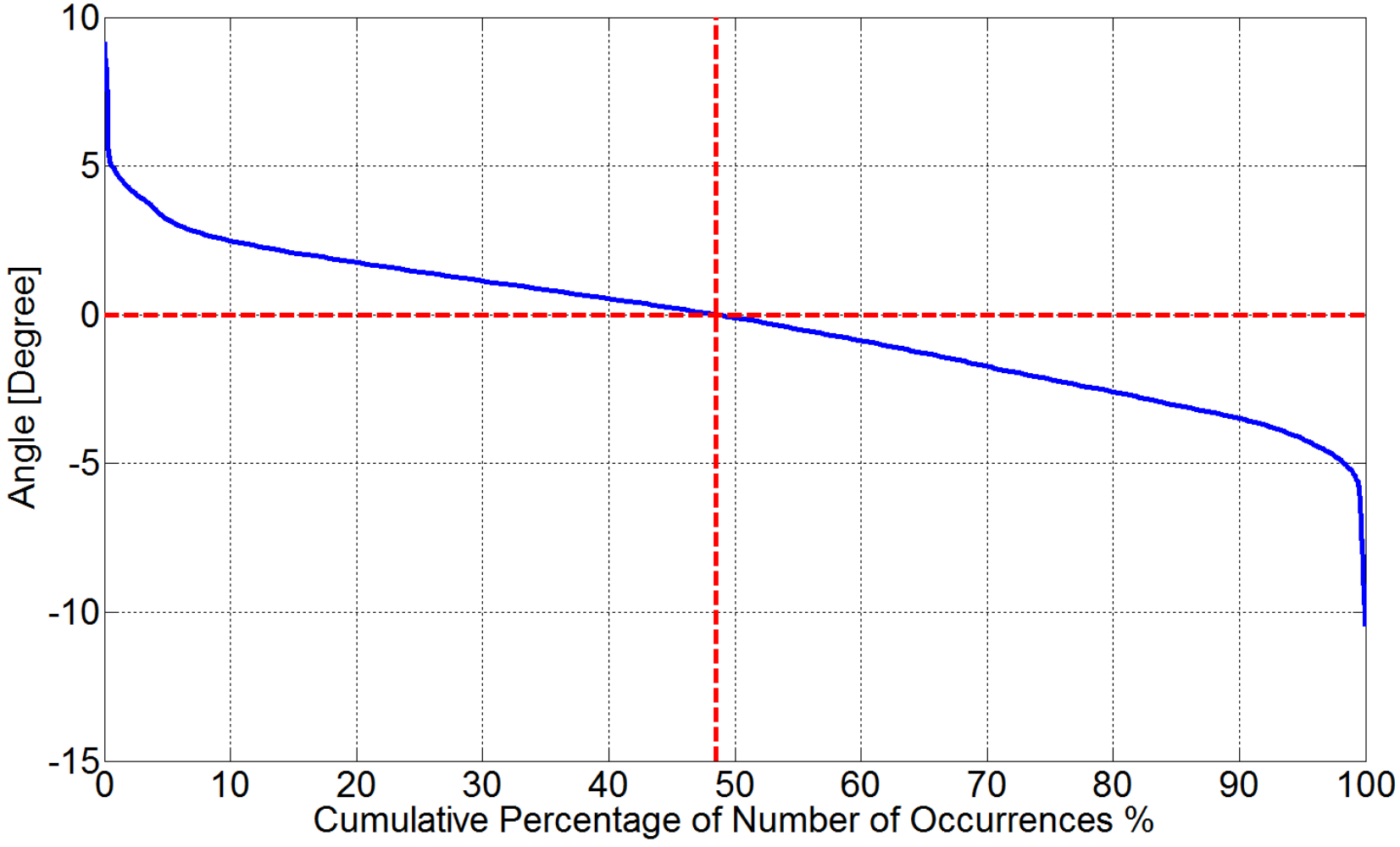
West 5-West 10



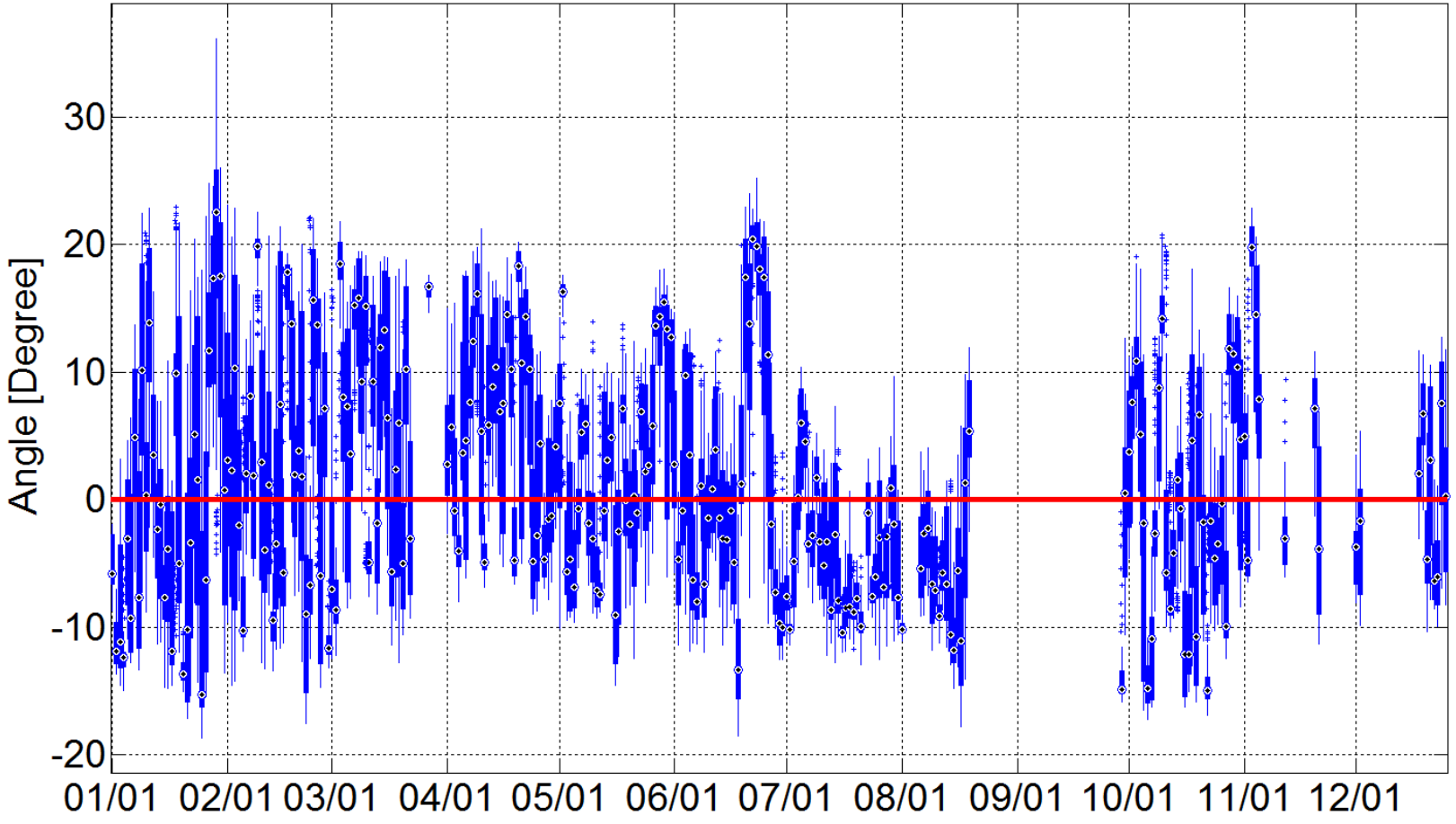
West 5-FarWest 4



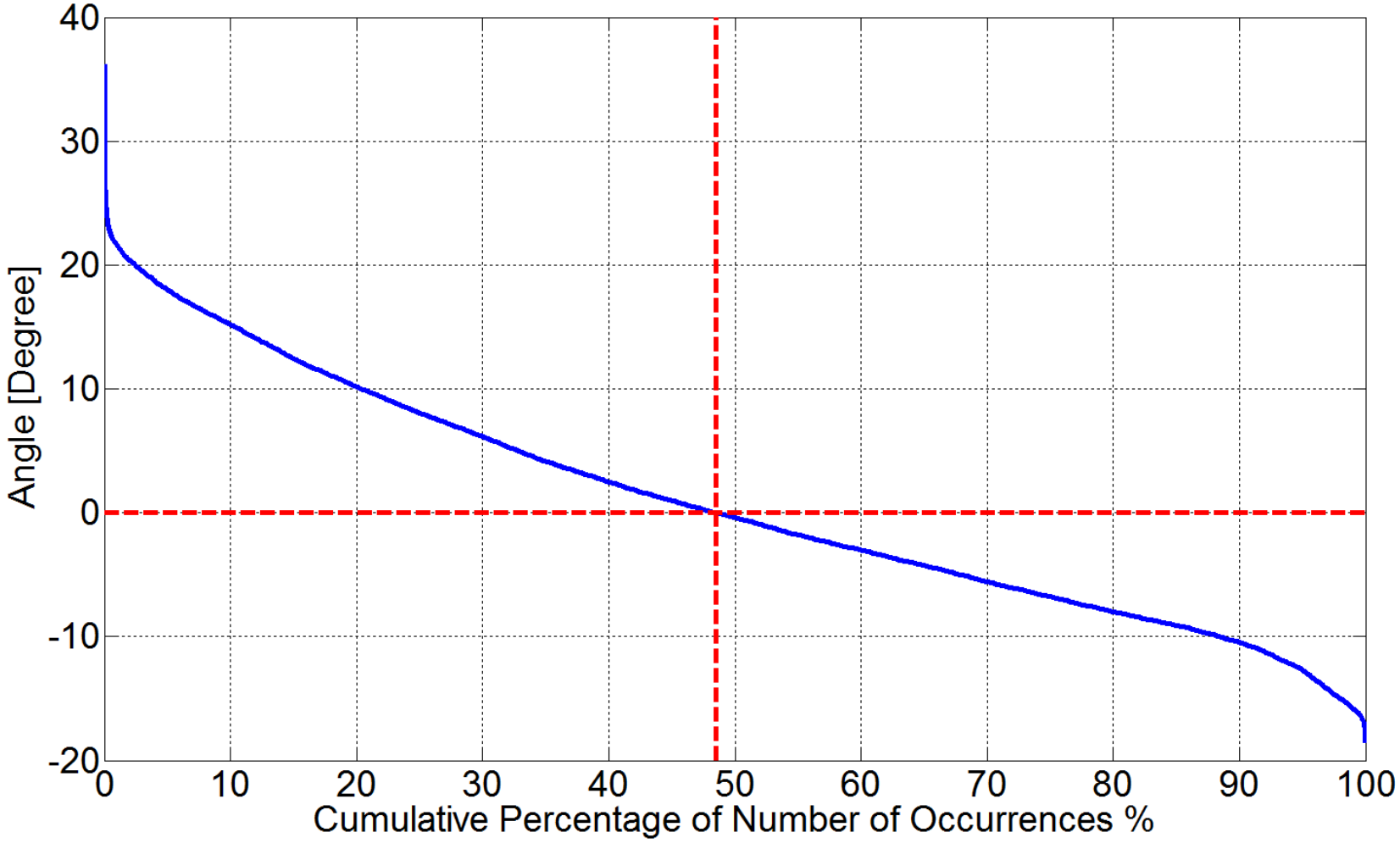
West 5-FarWest 4



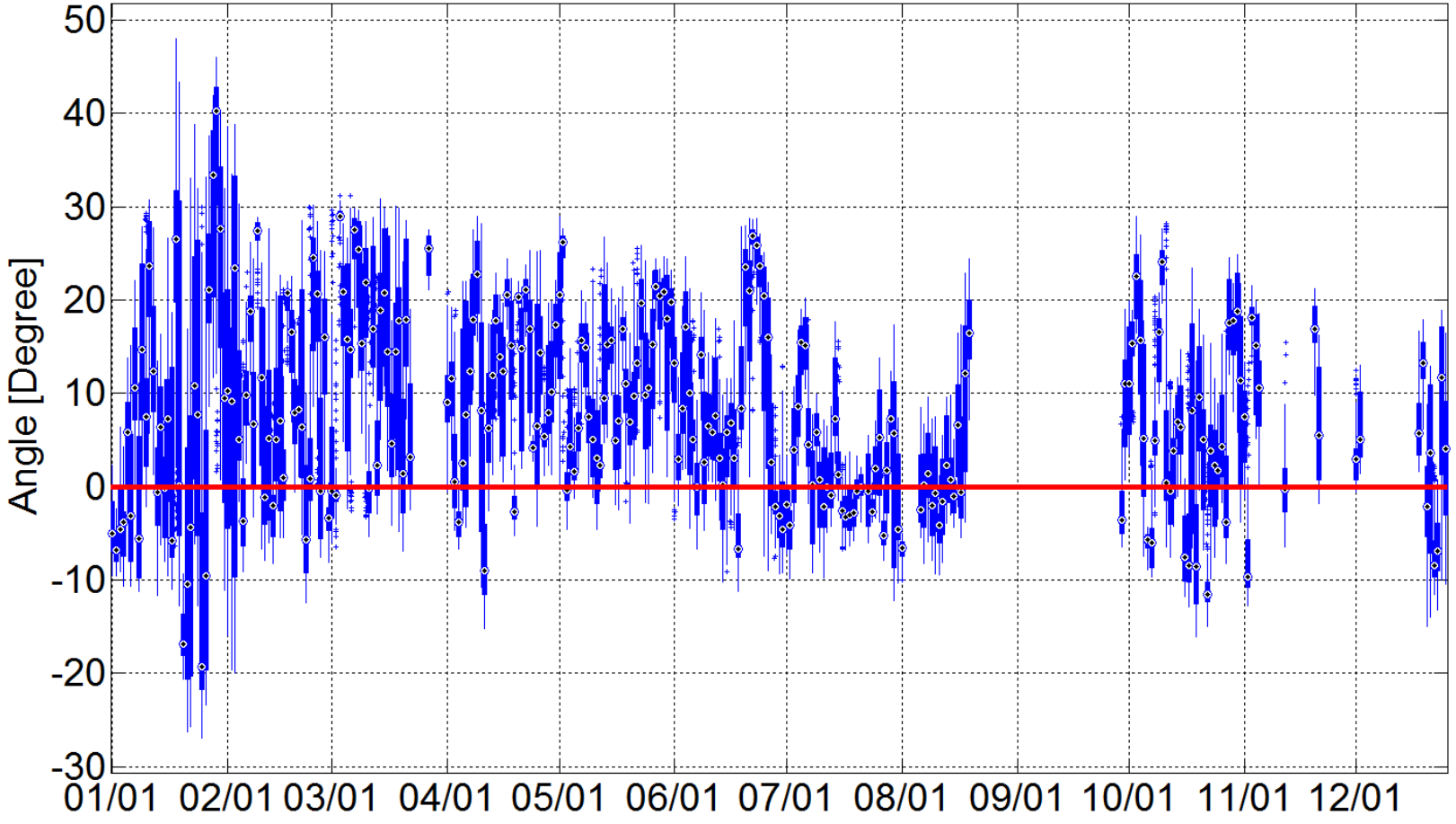
West 5-North 1



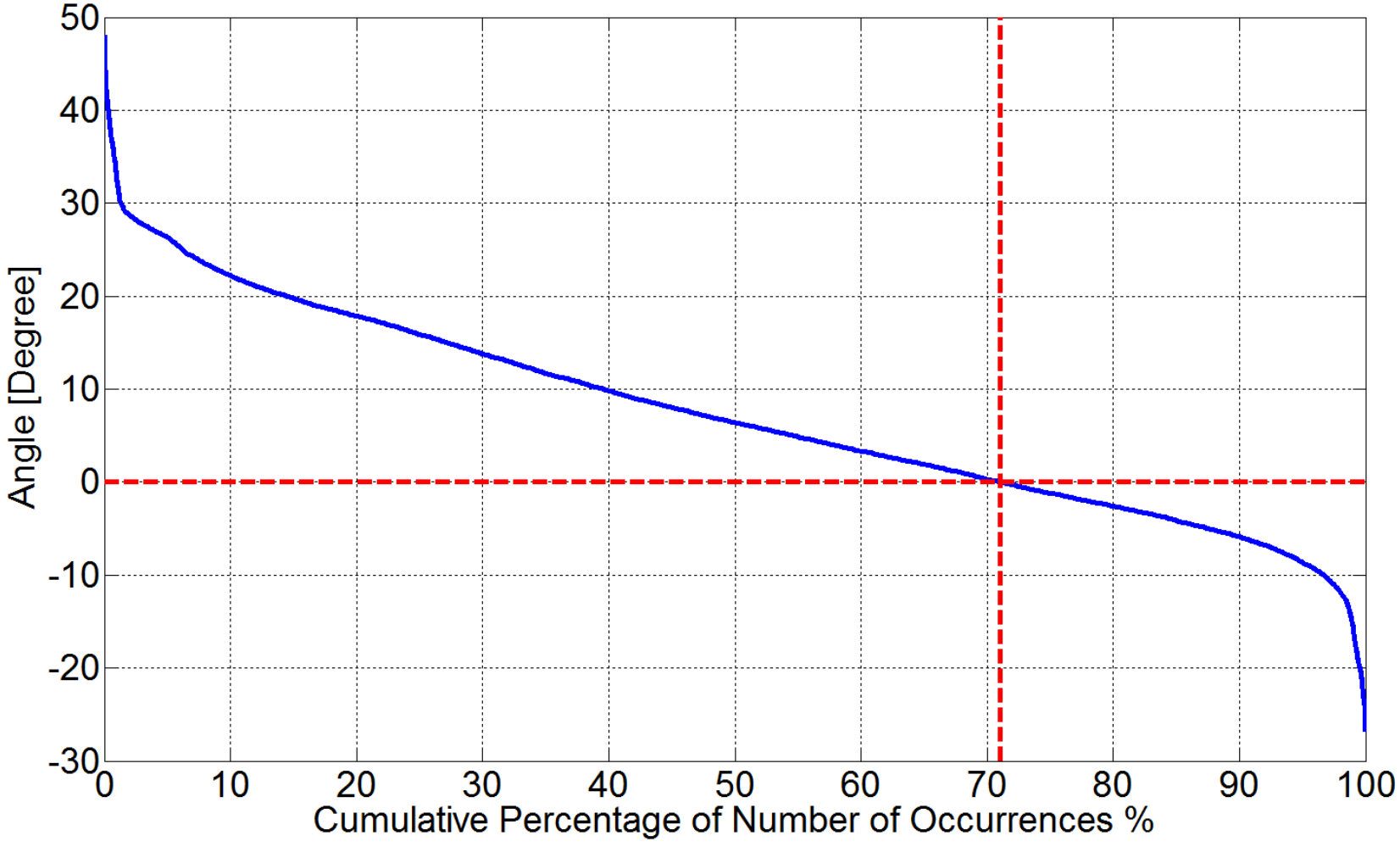
West 5-North 1



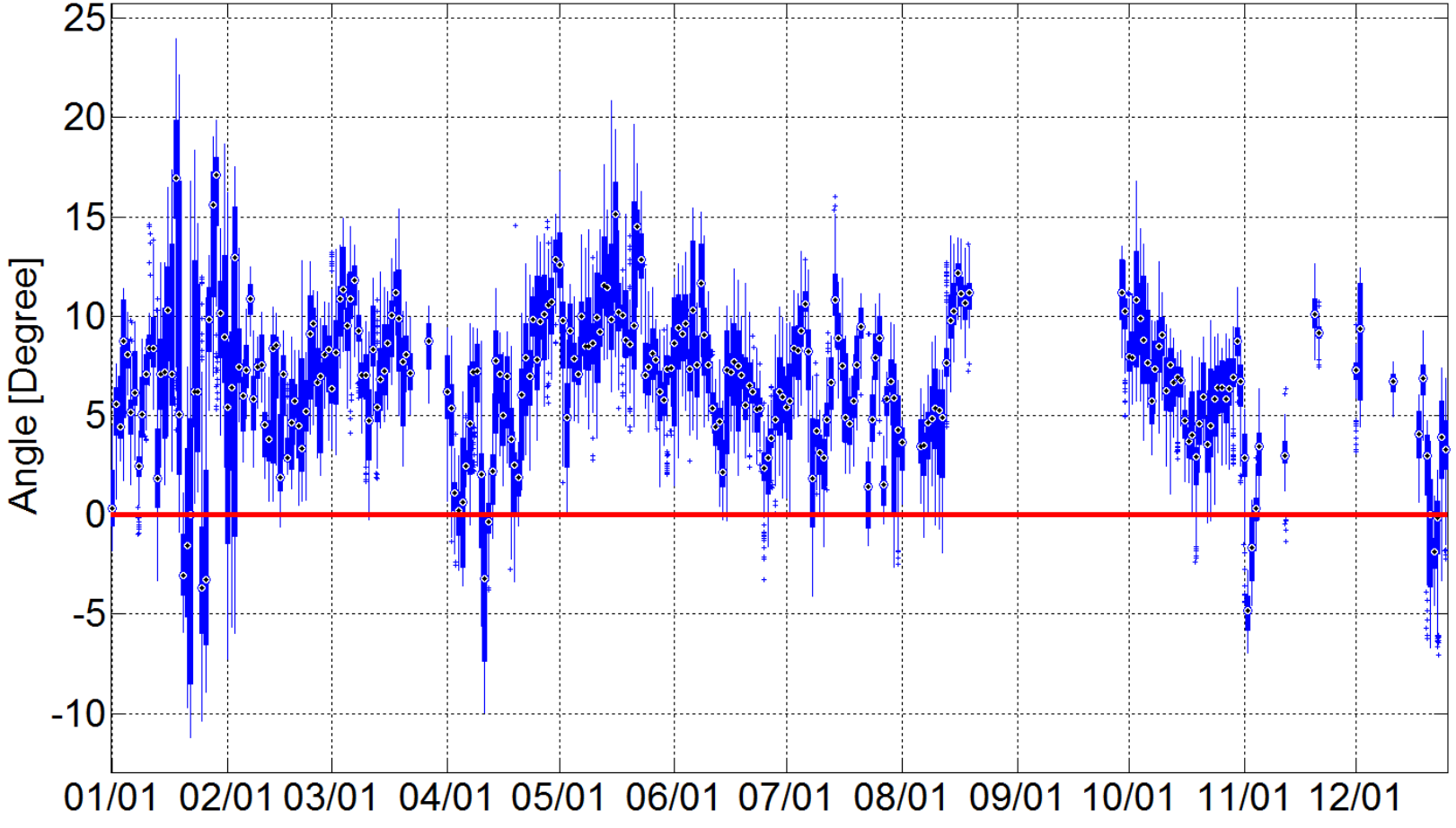
West 5-North 7



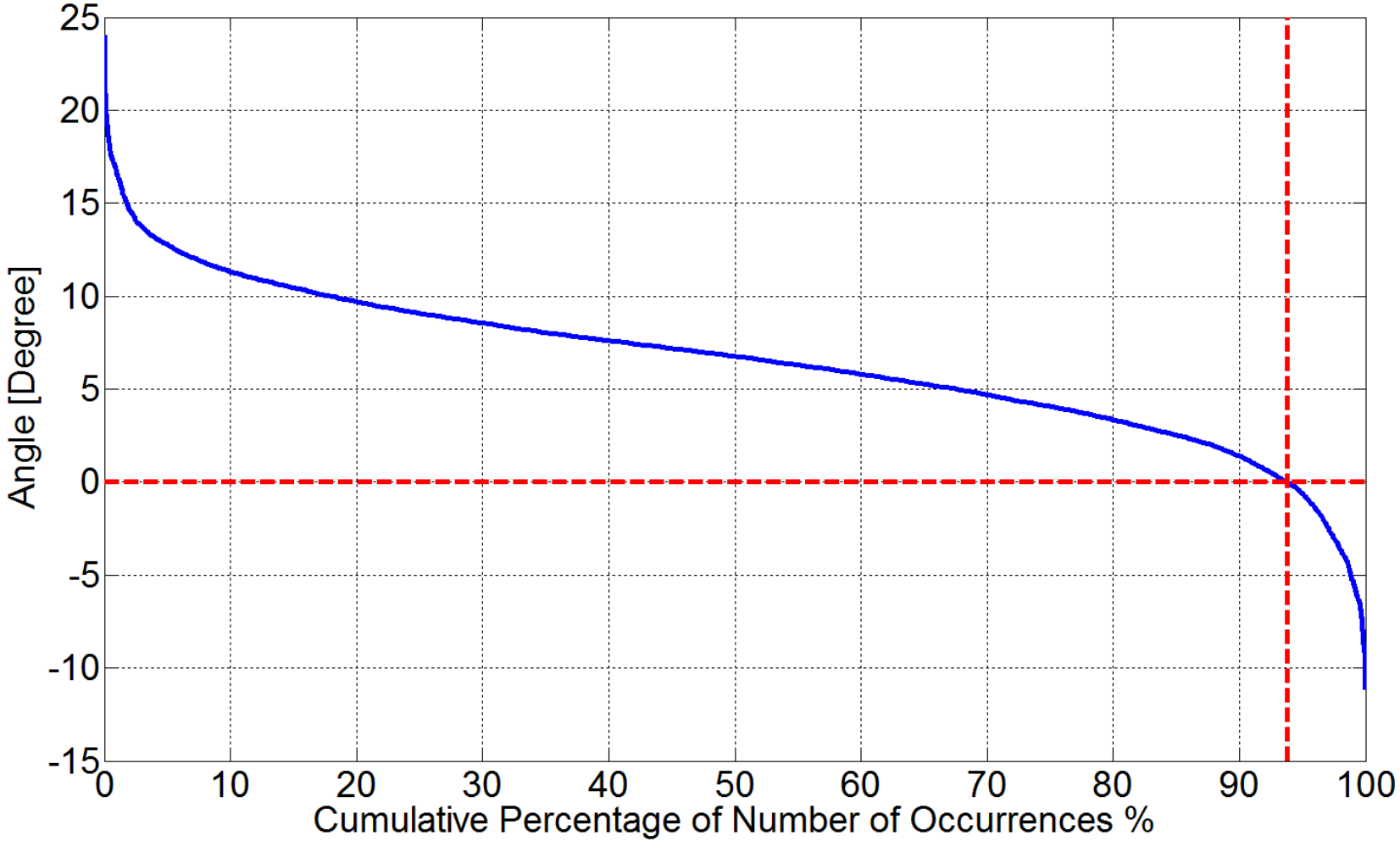
West 5-North 7



North 1-North 7



North 1-North 7



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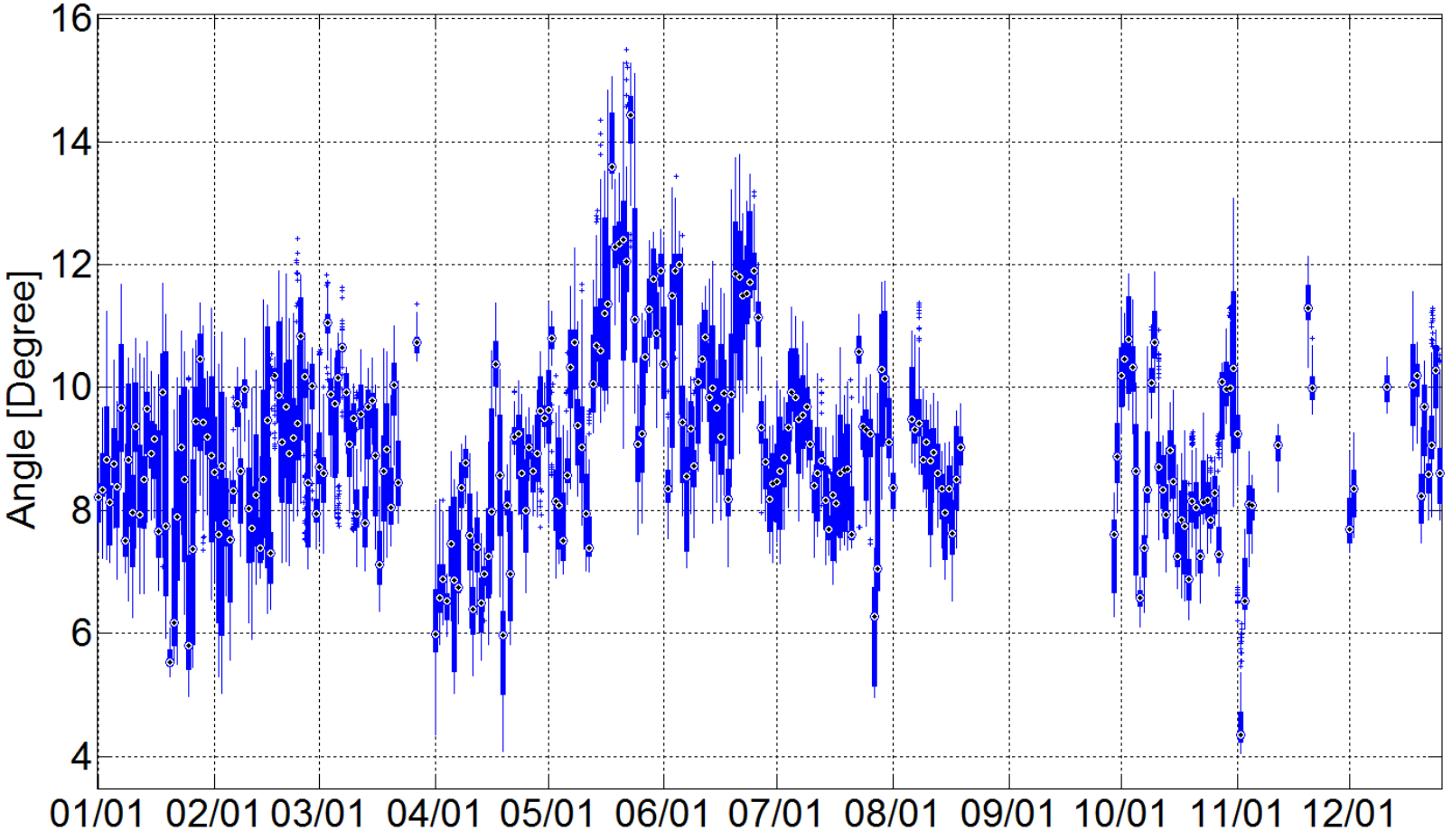
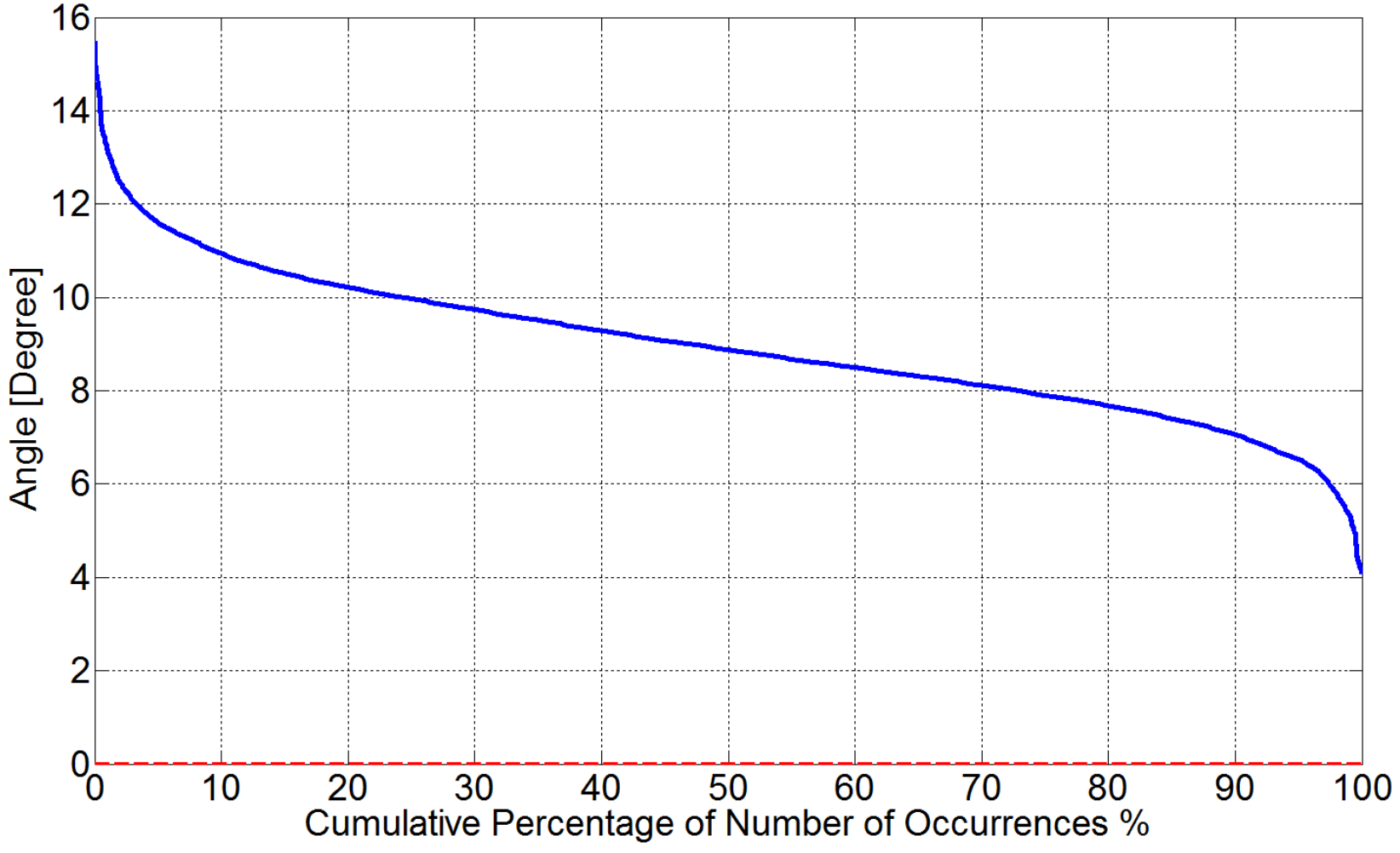
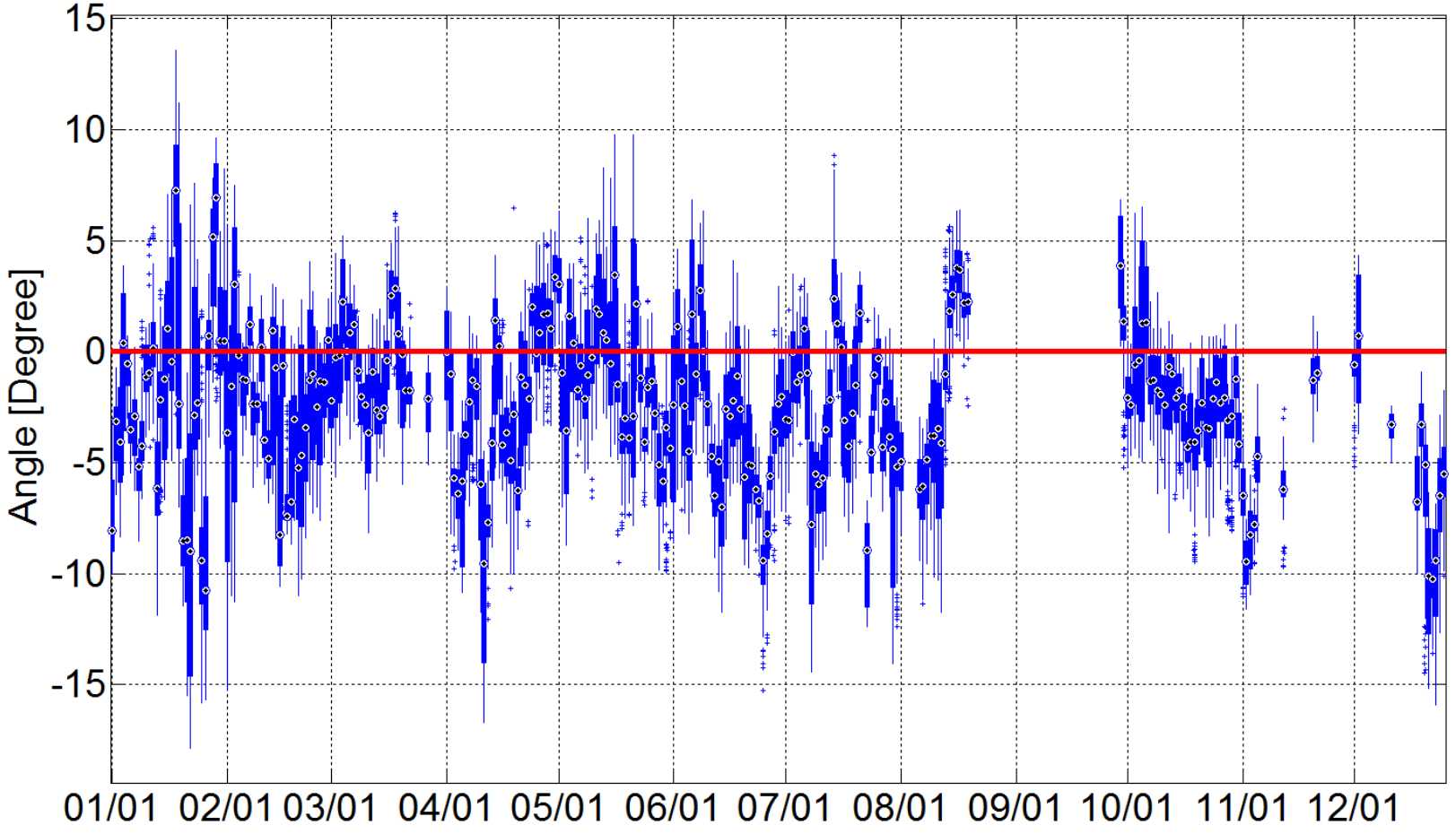


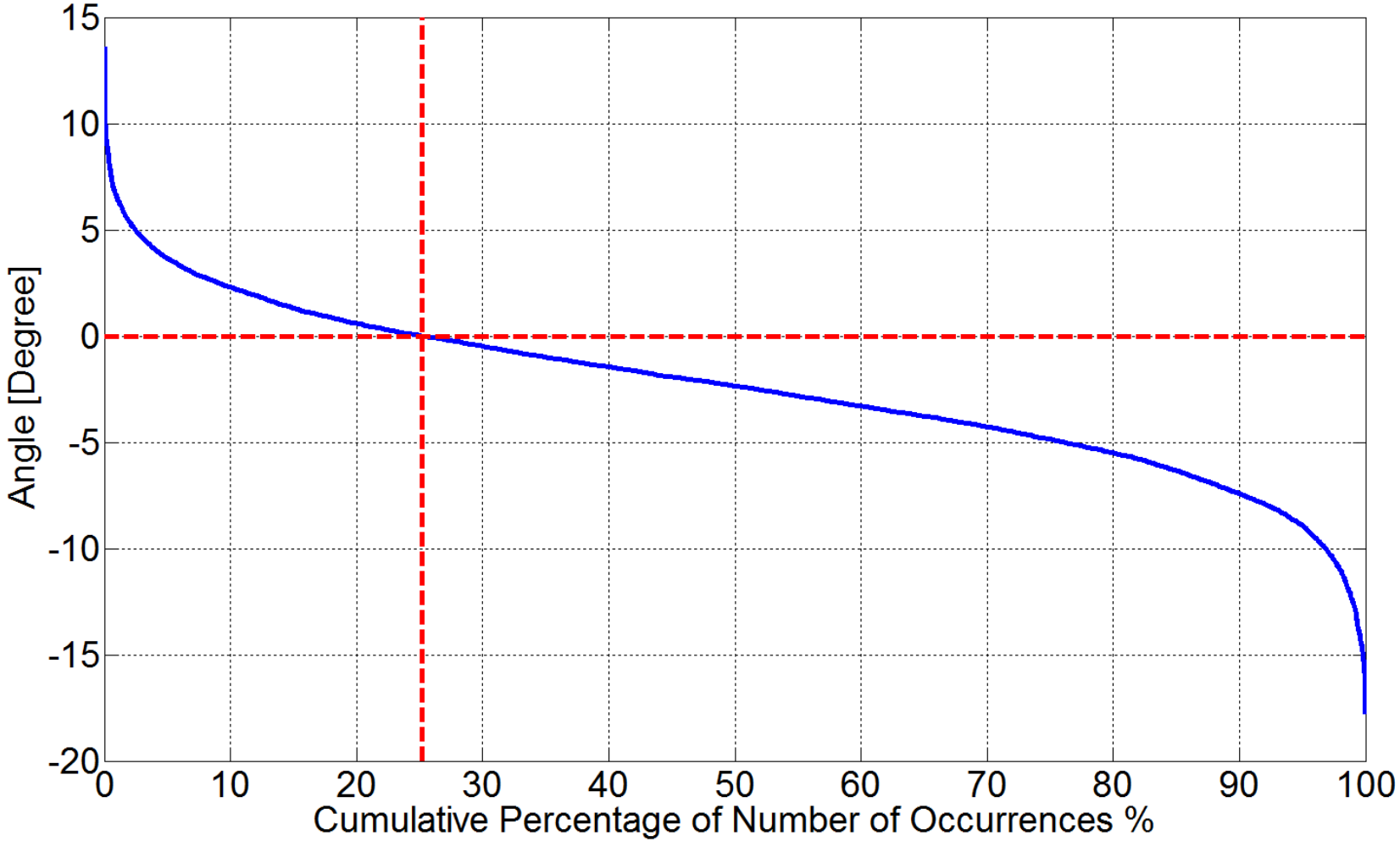
North 1-North 4



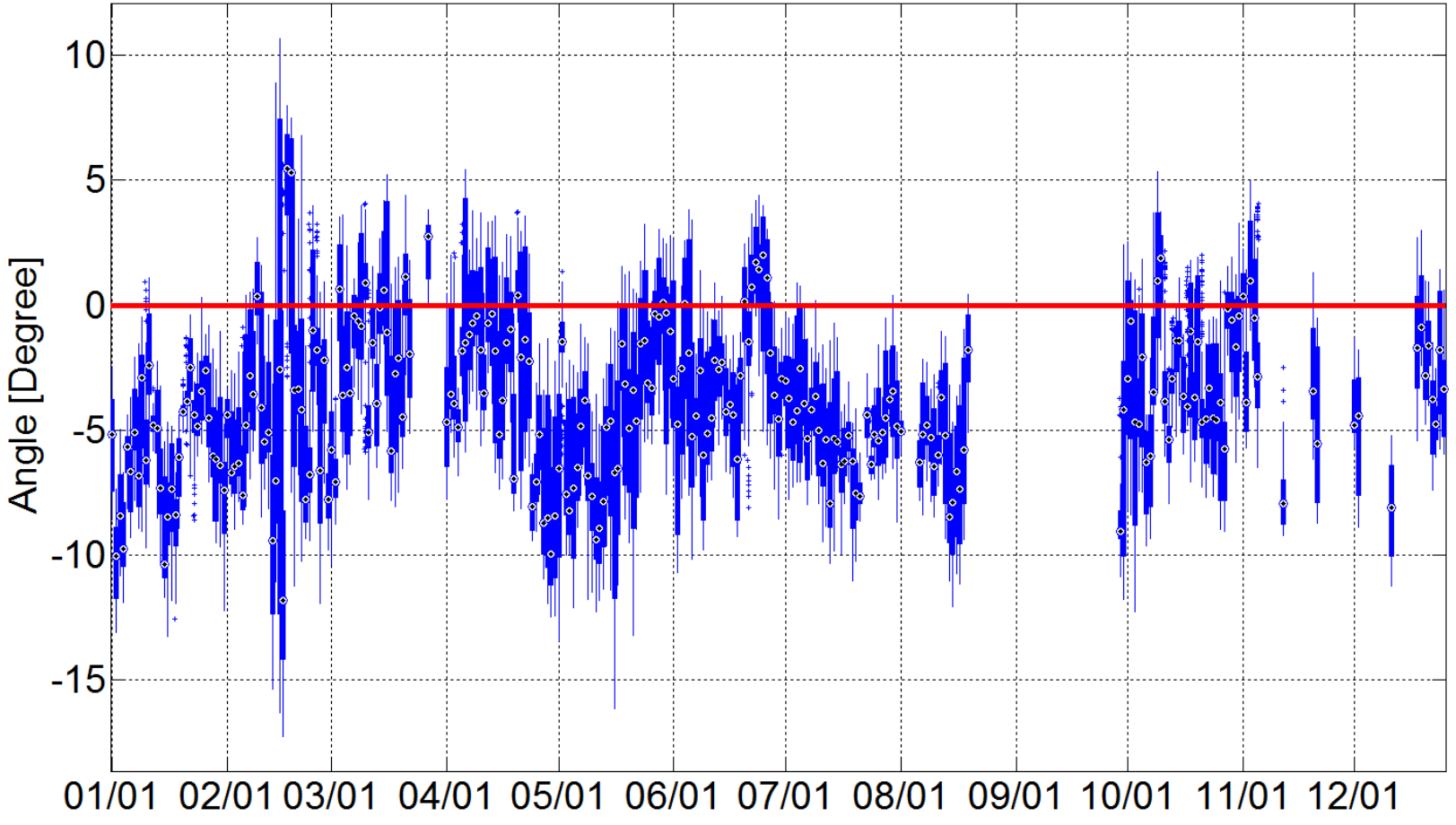
North 4-North 7



North 4-North 7



North 7-North 6



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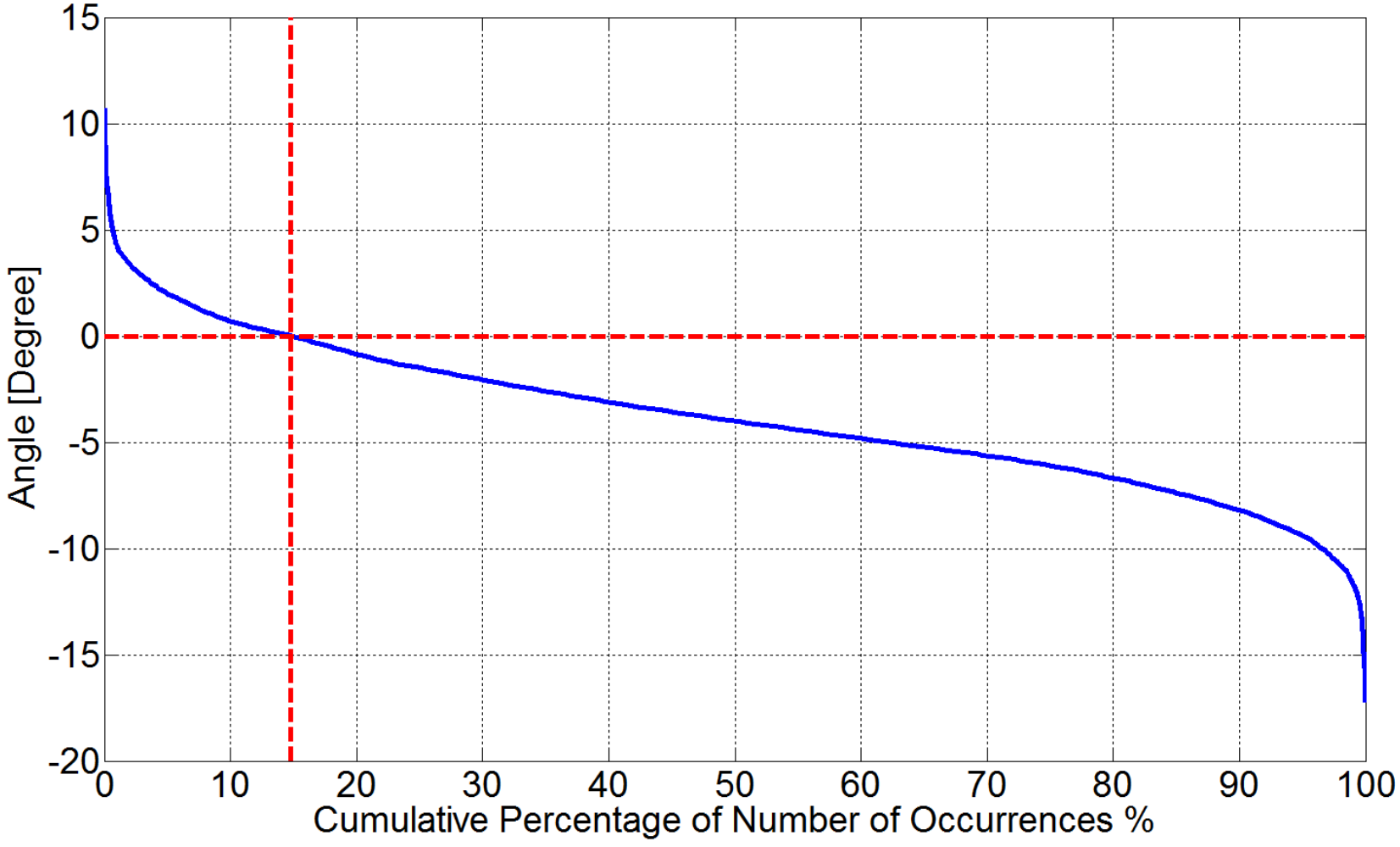

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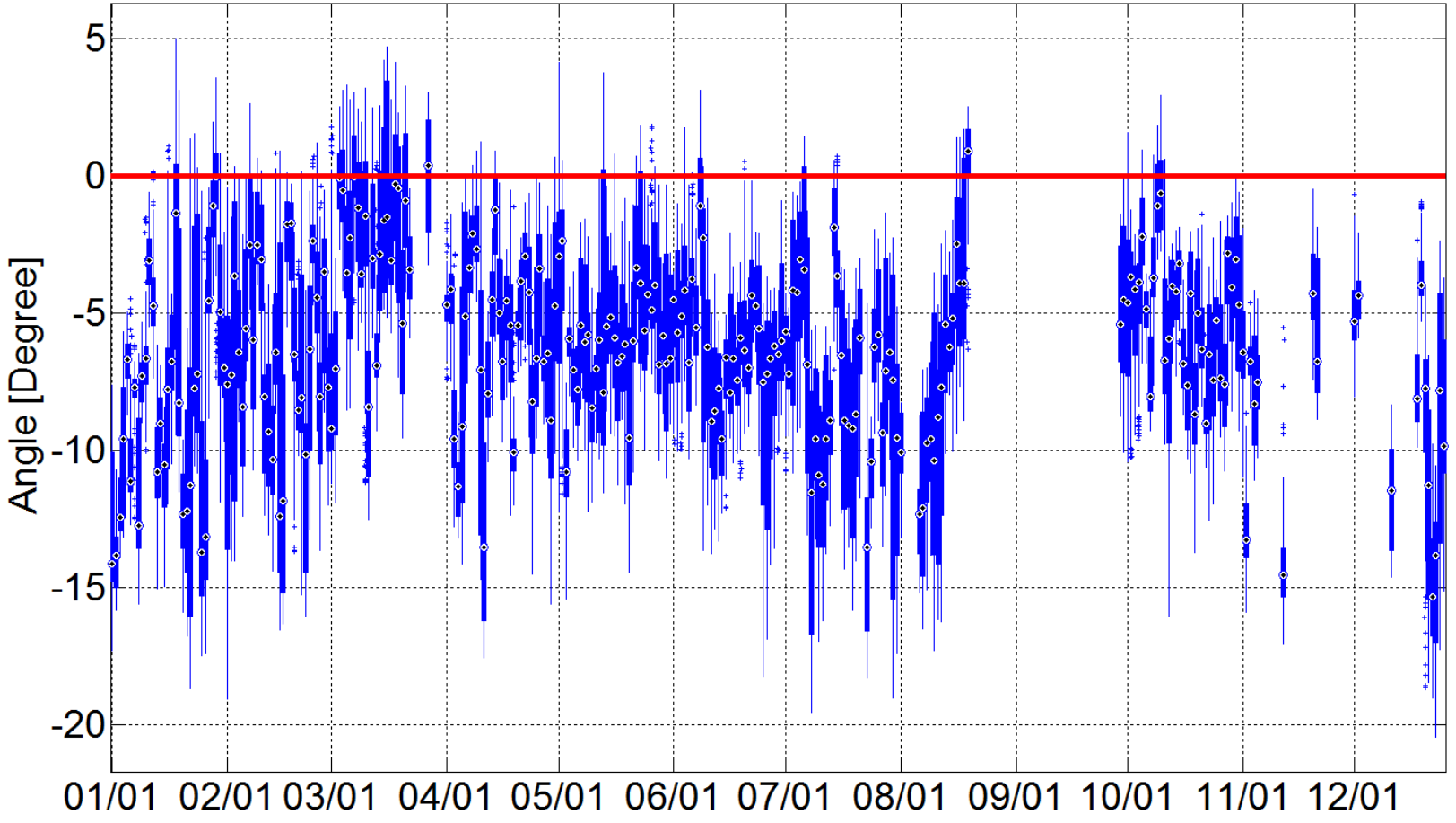

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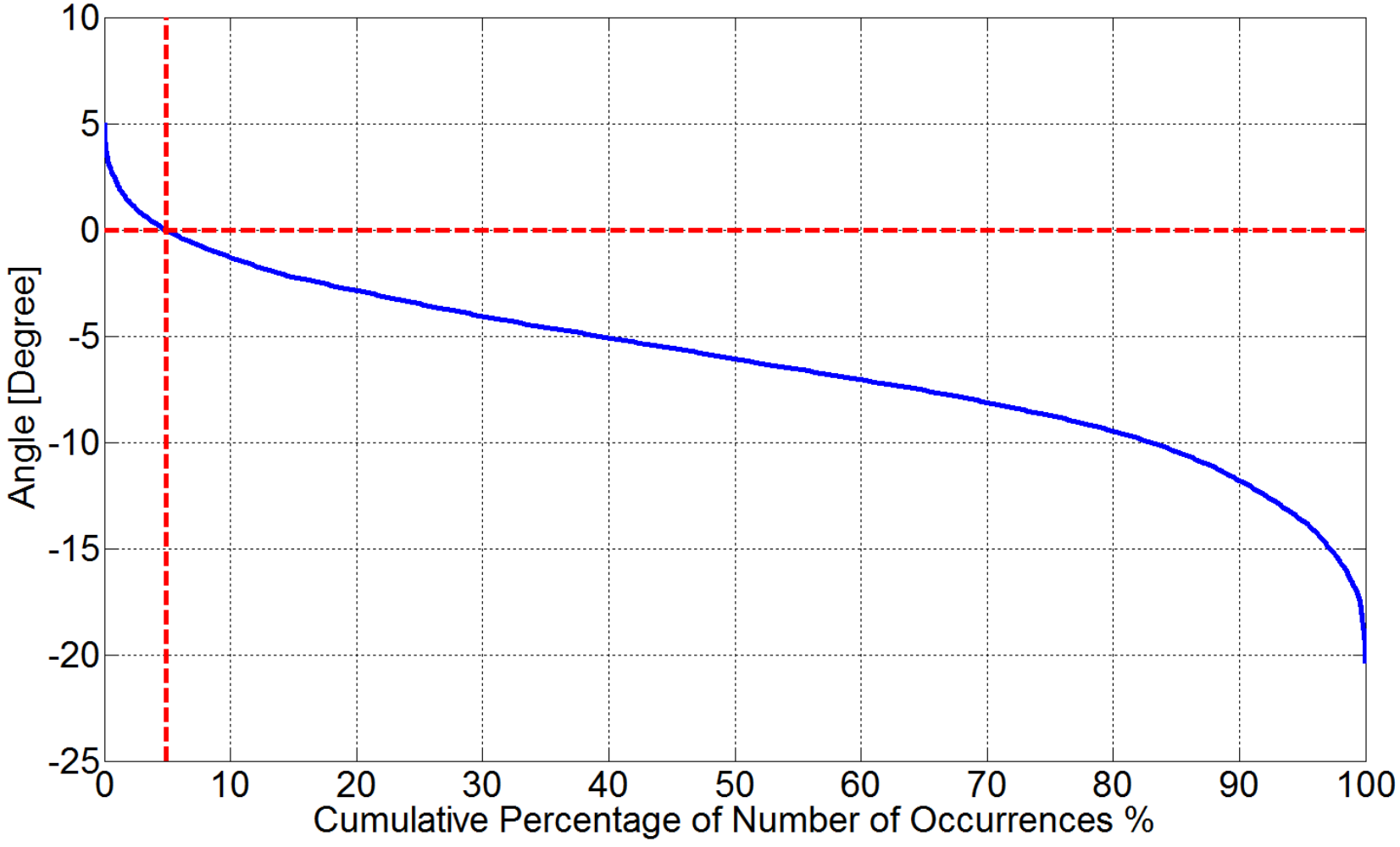

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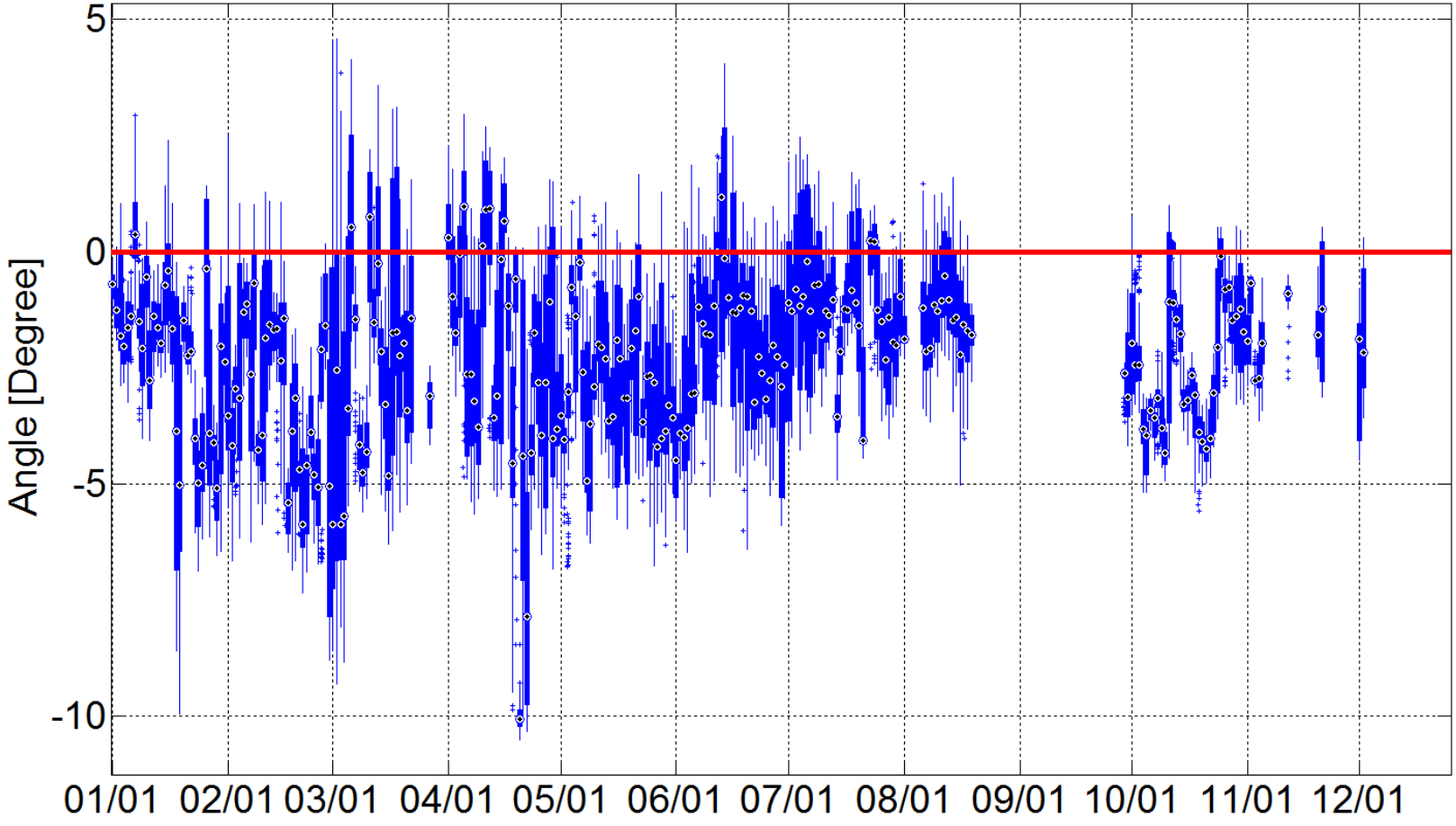

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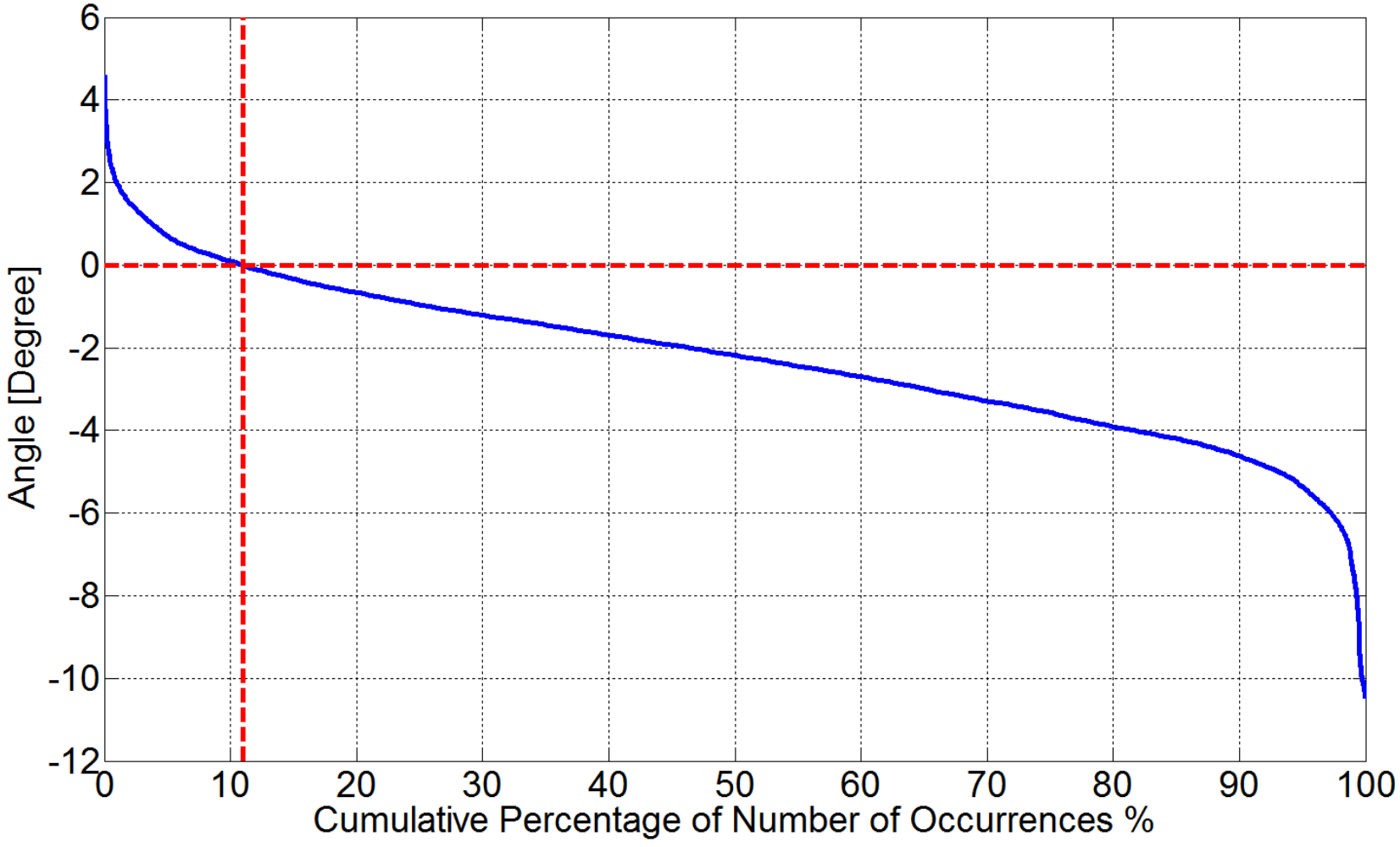

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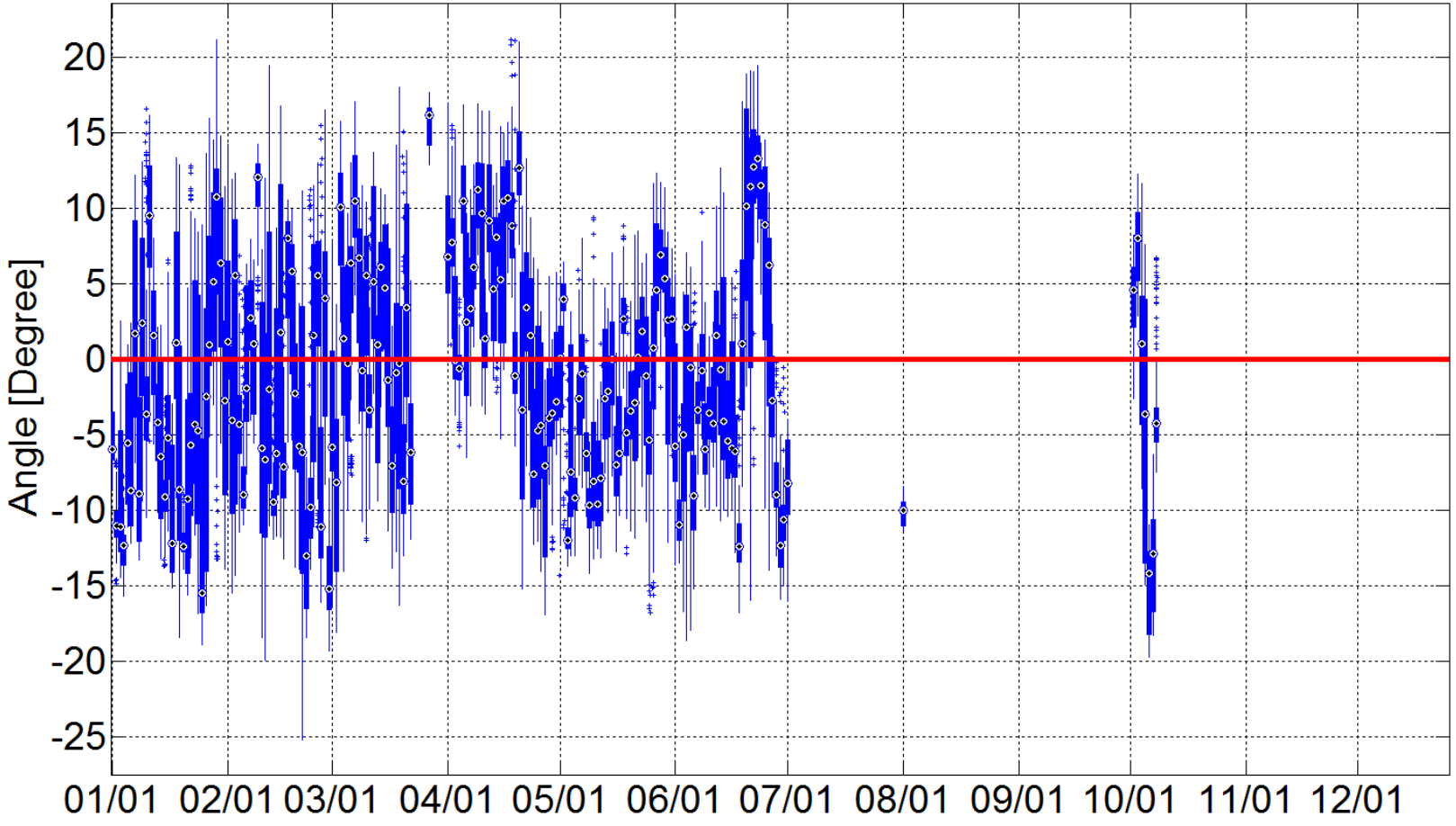
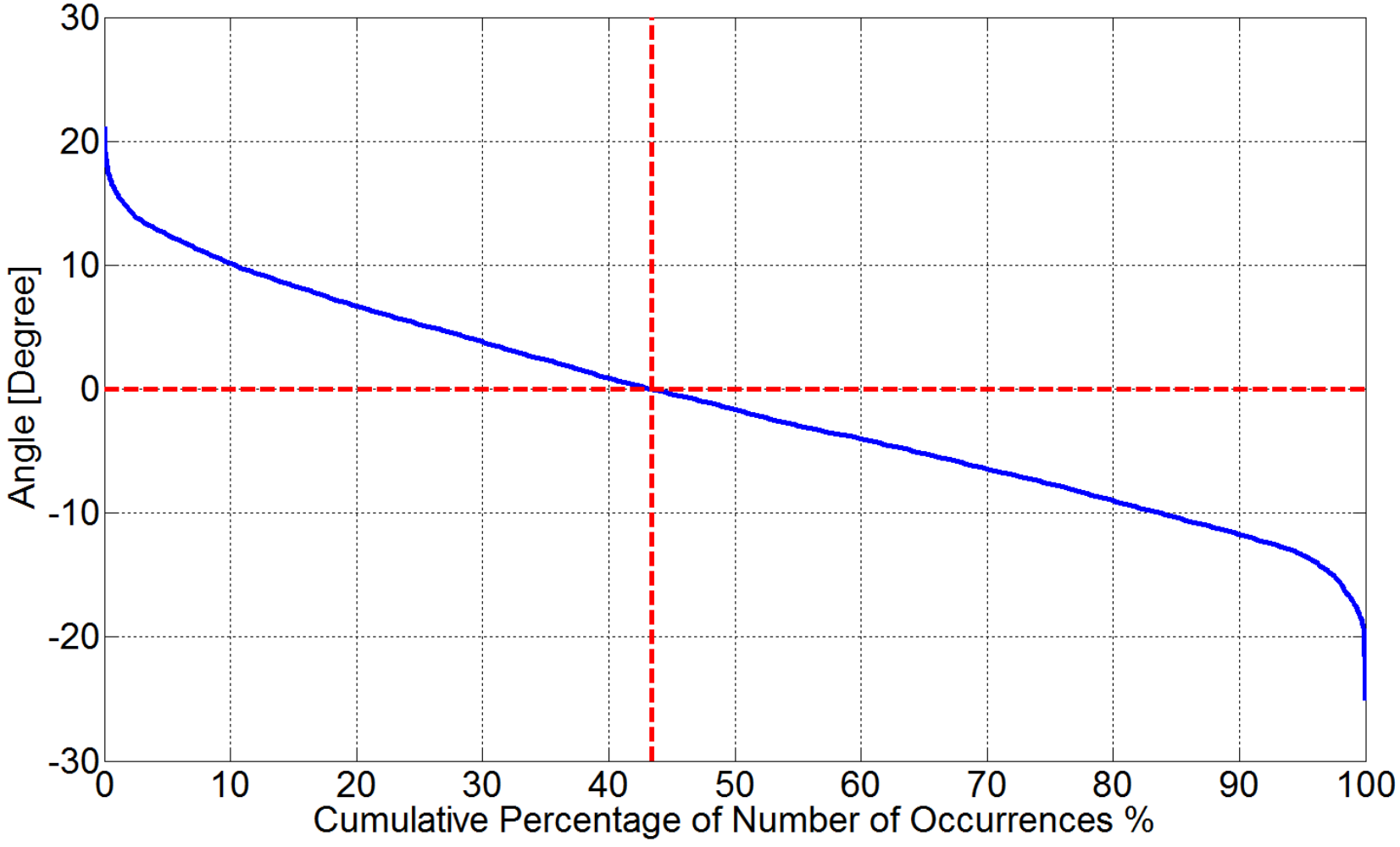


FarWest 7-West 14



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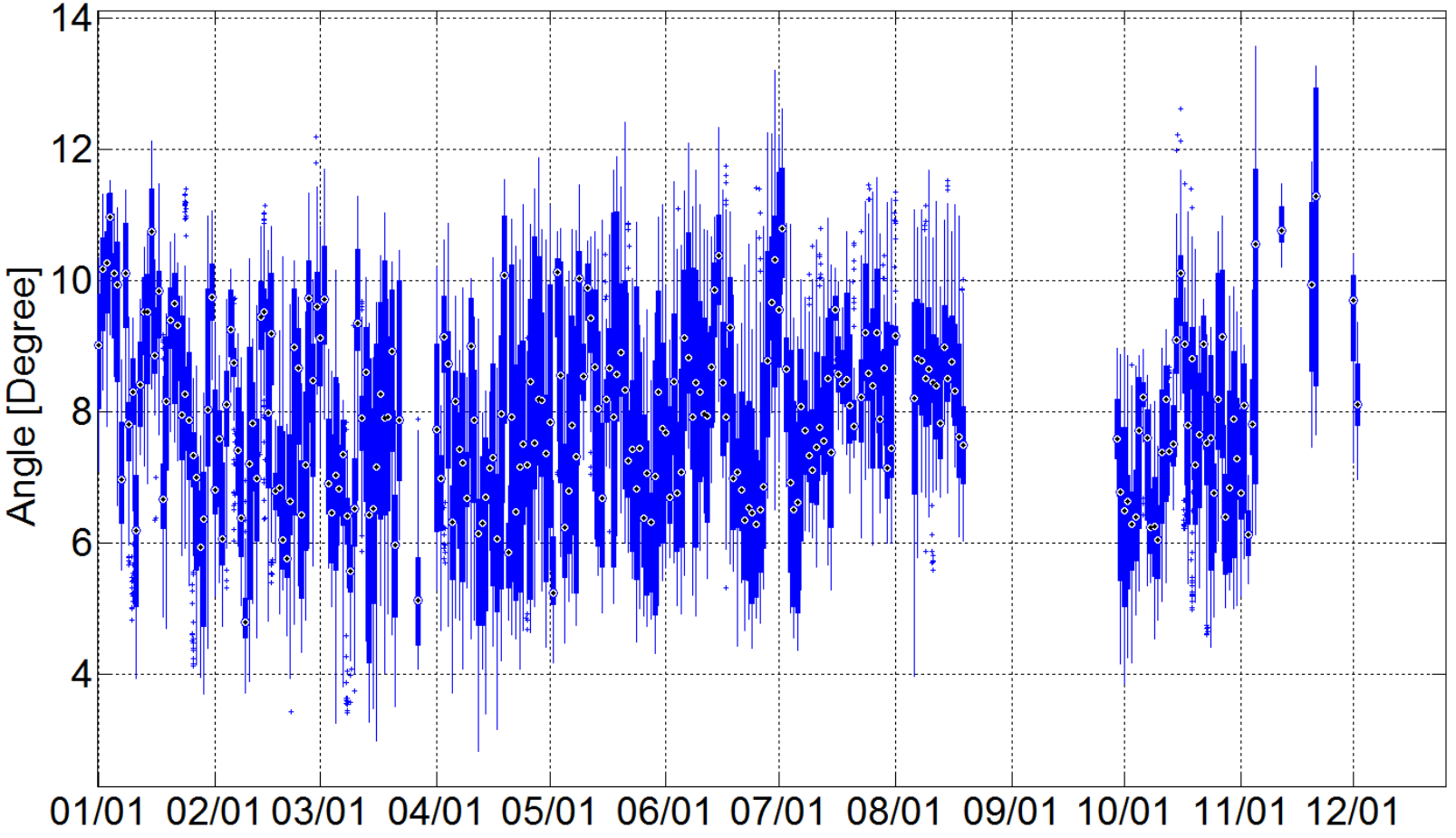

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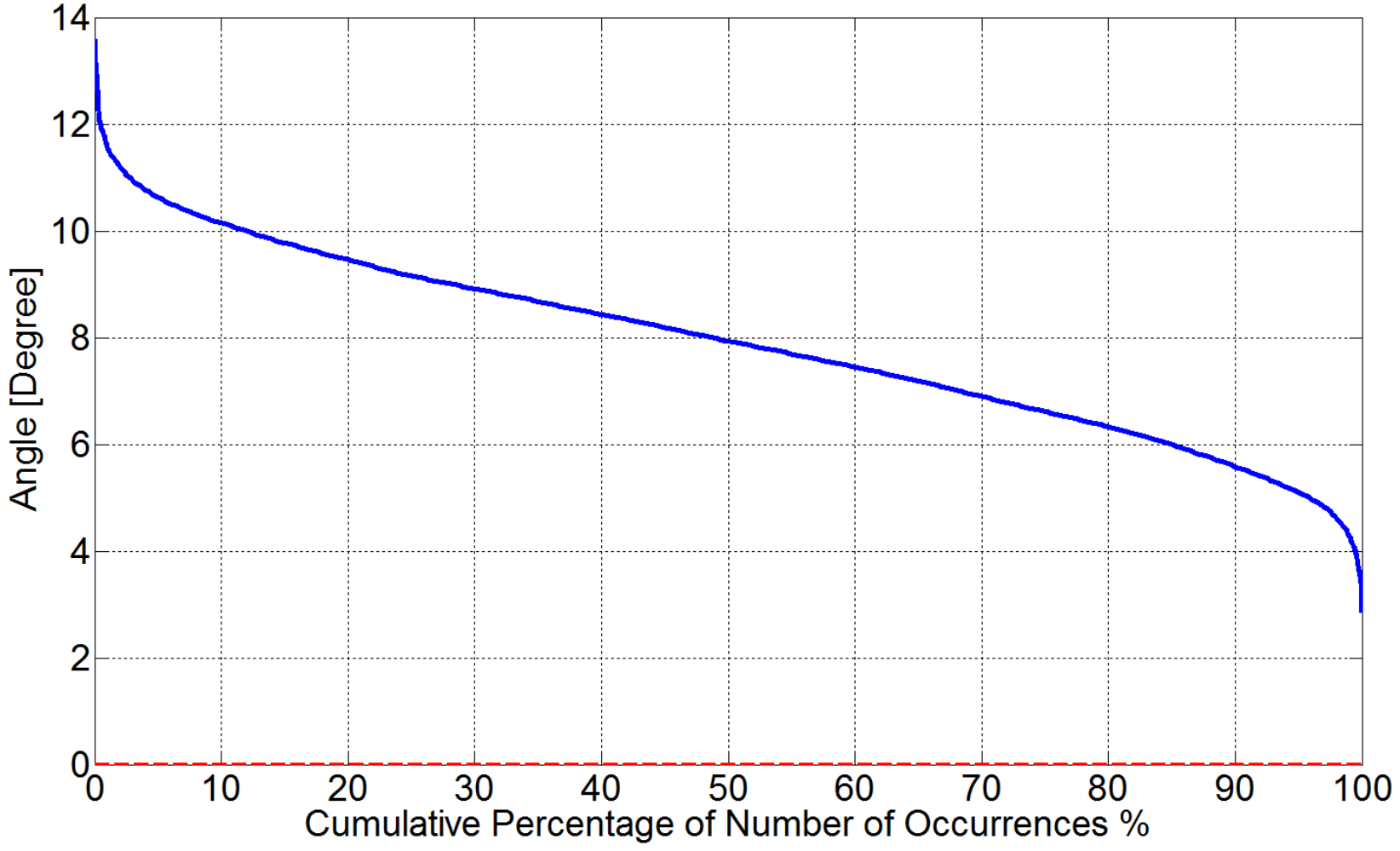

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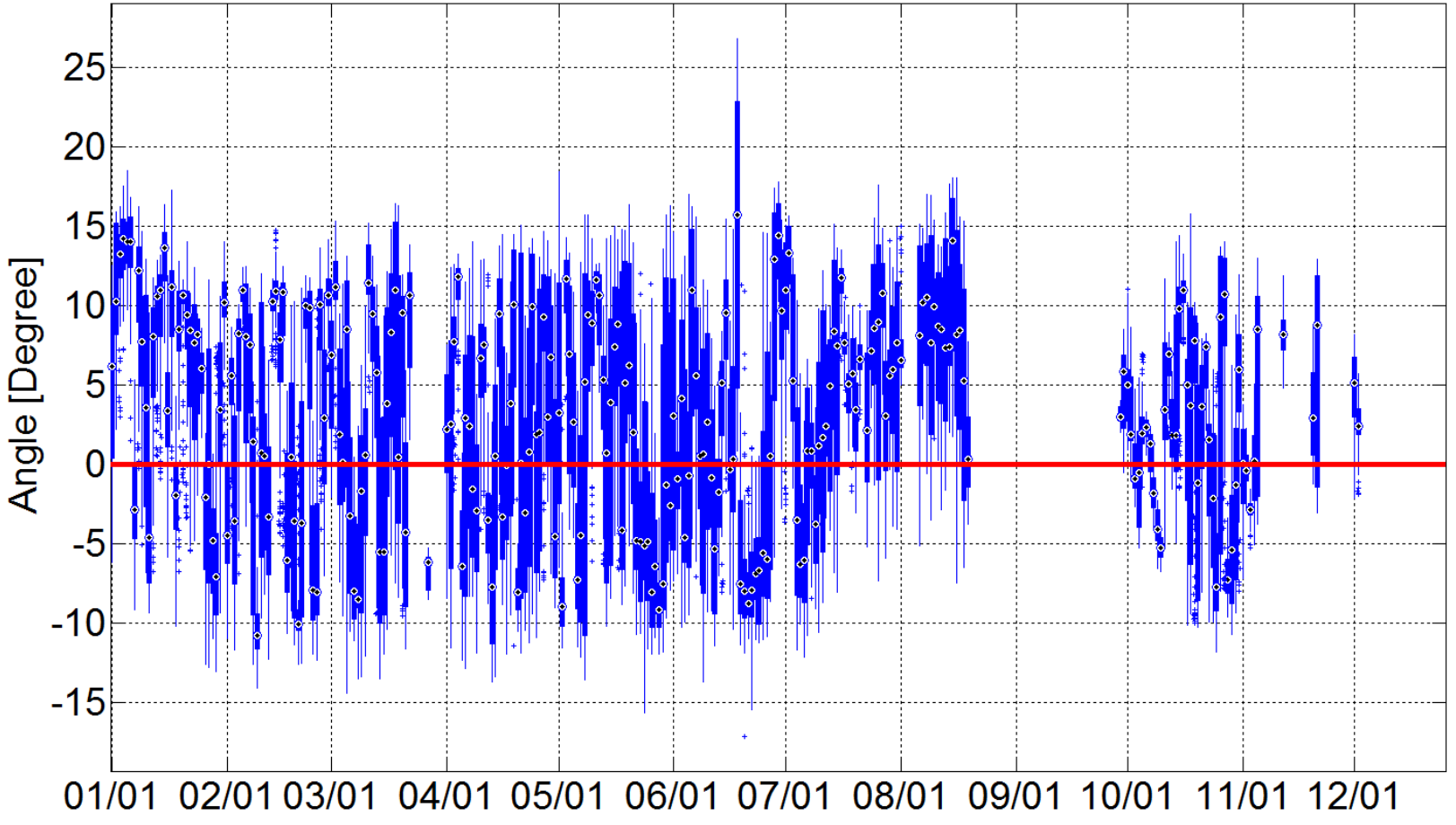

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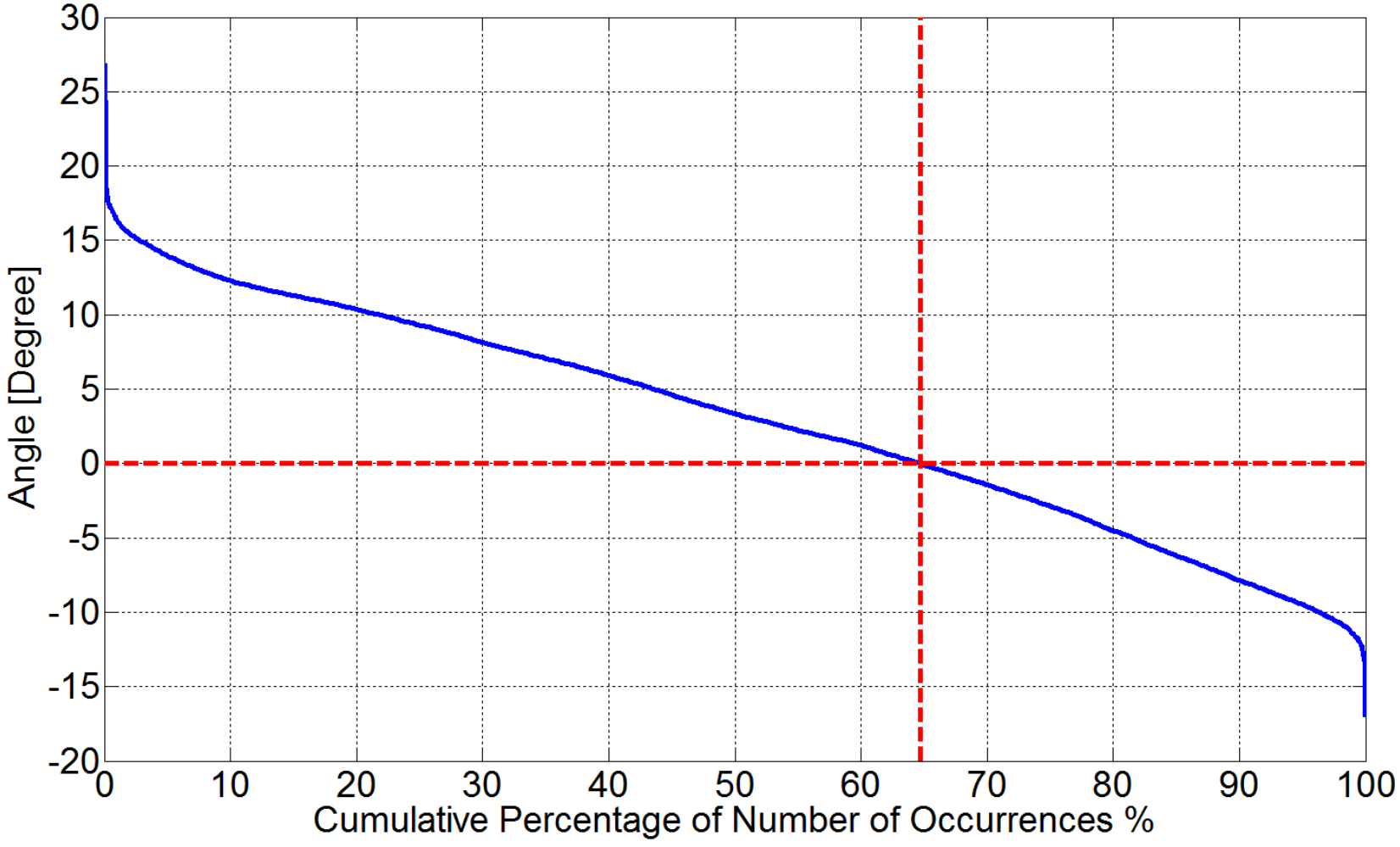

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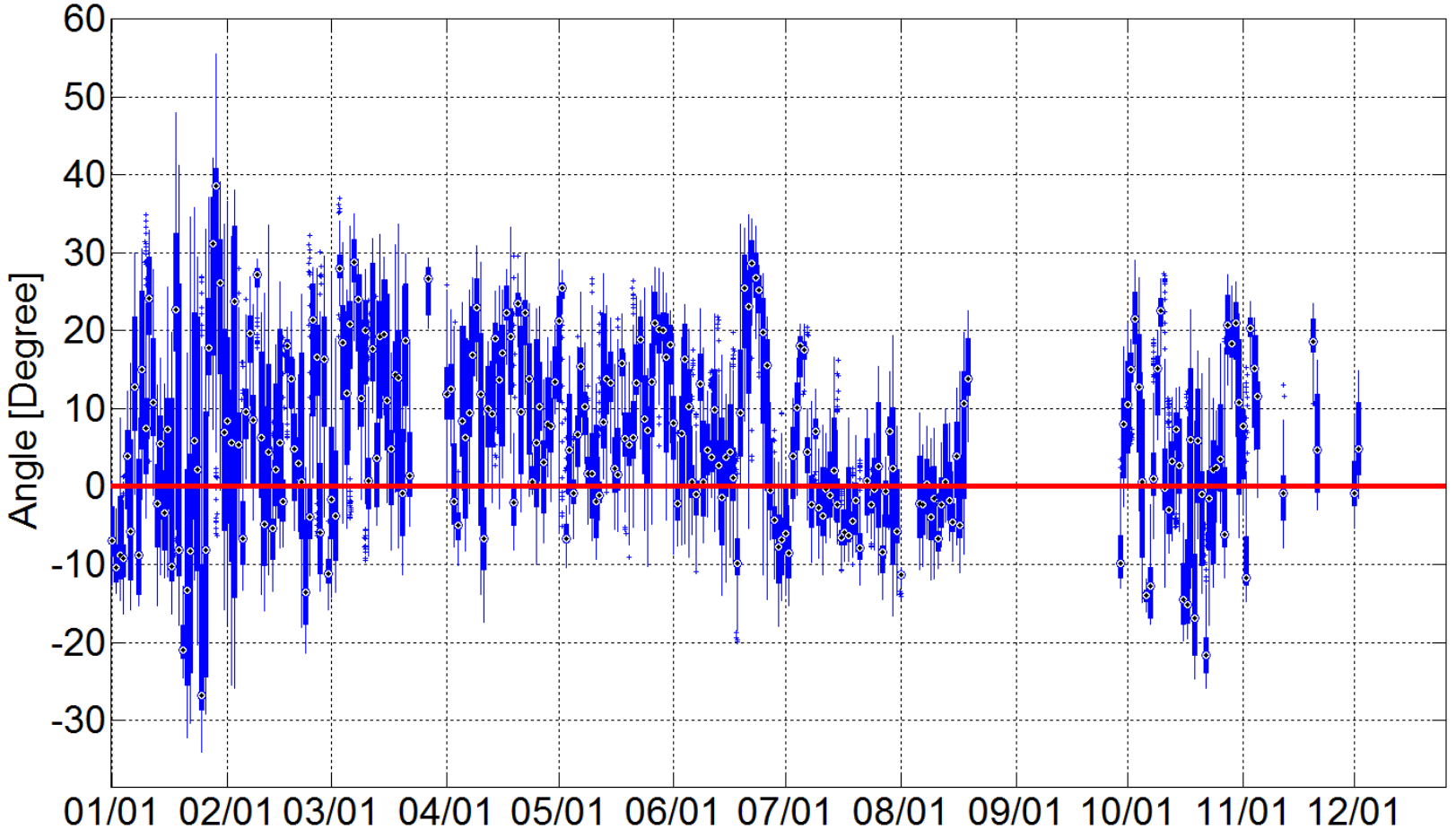
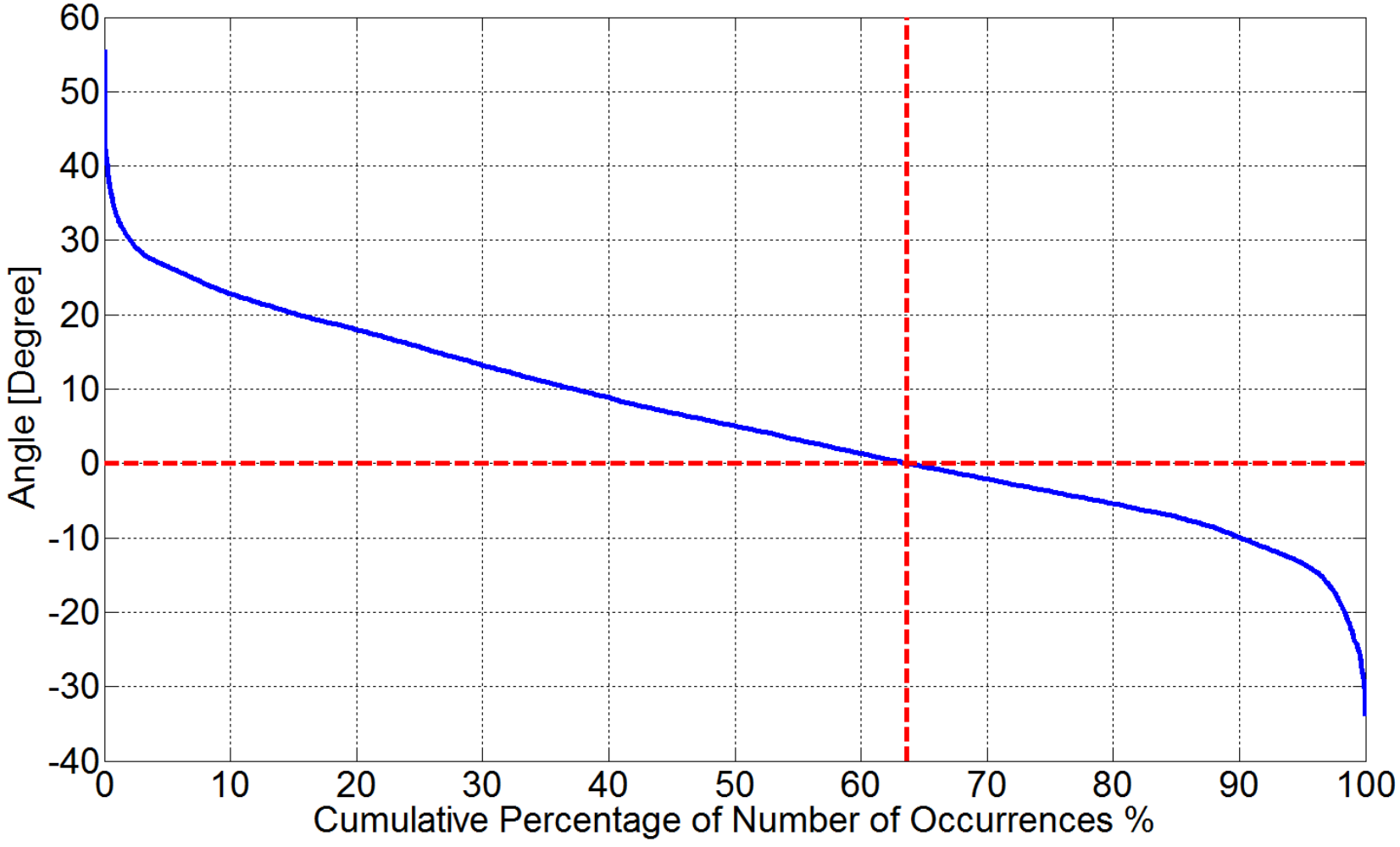
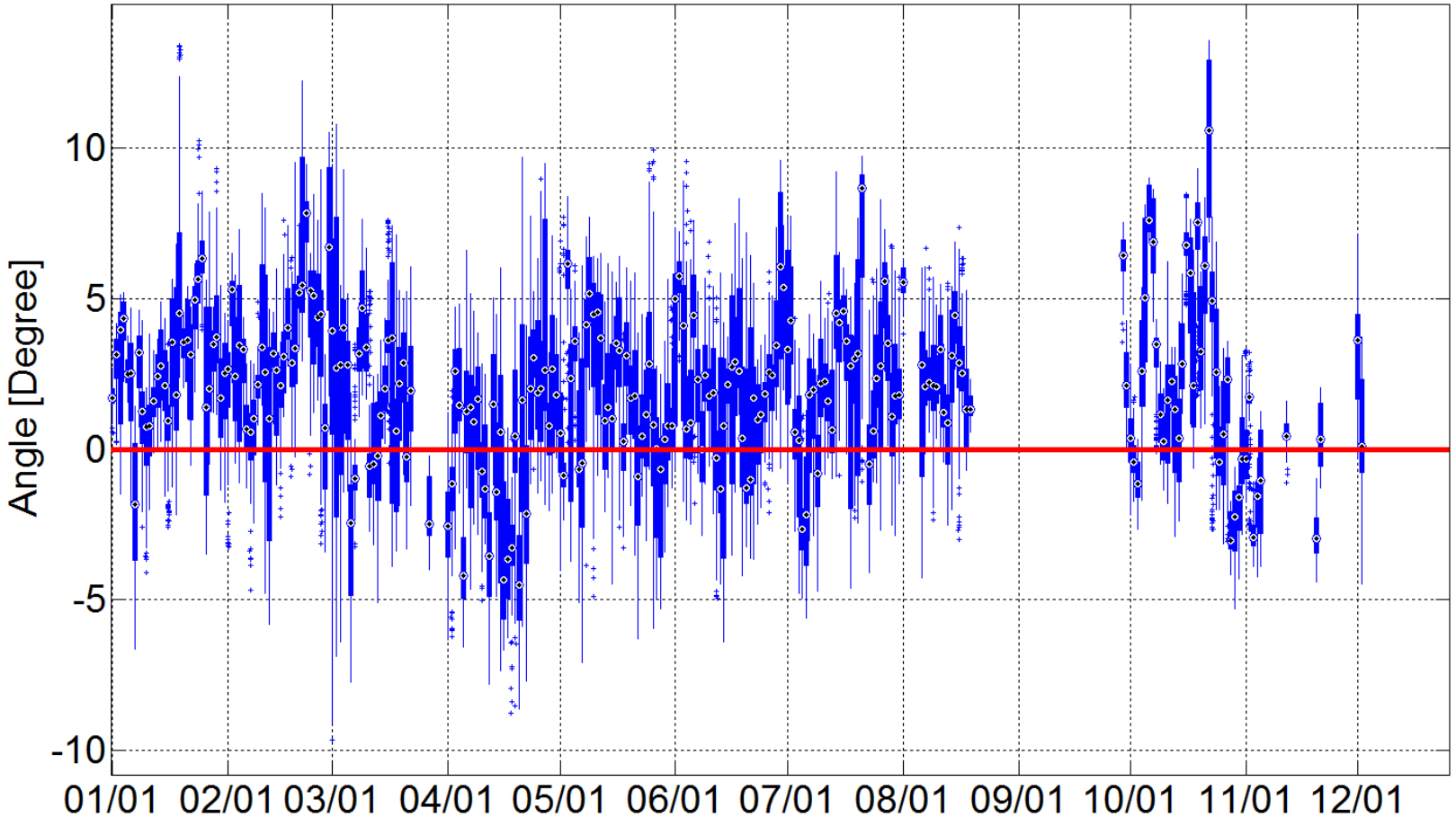


FarWest 7-North 7



West 12-FarWest 7



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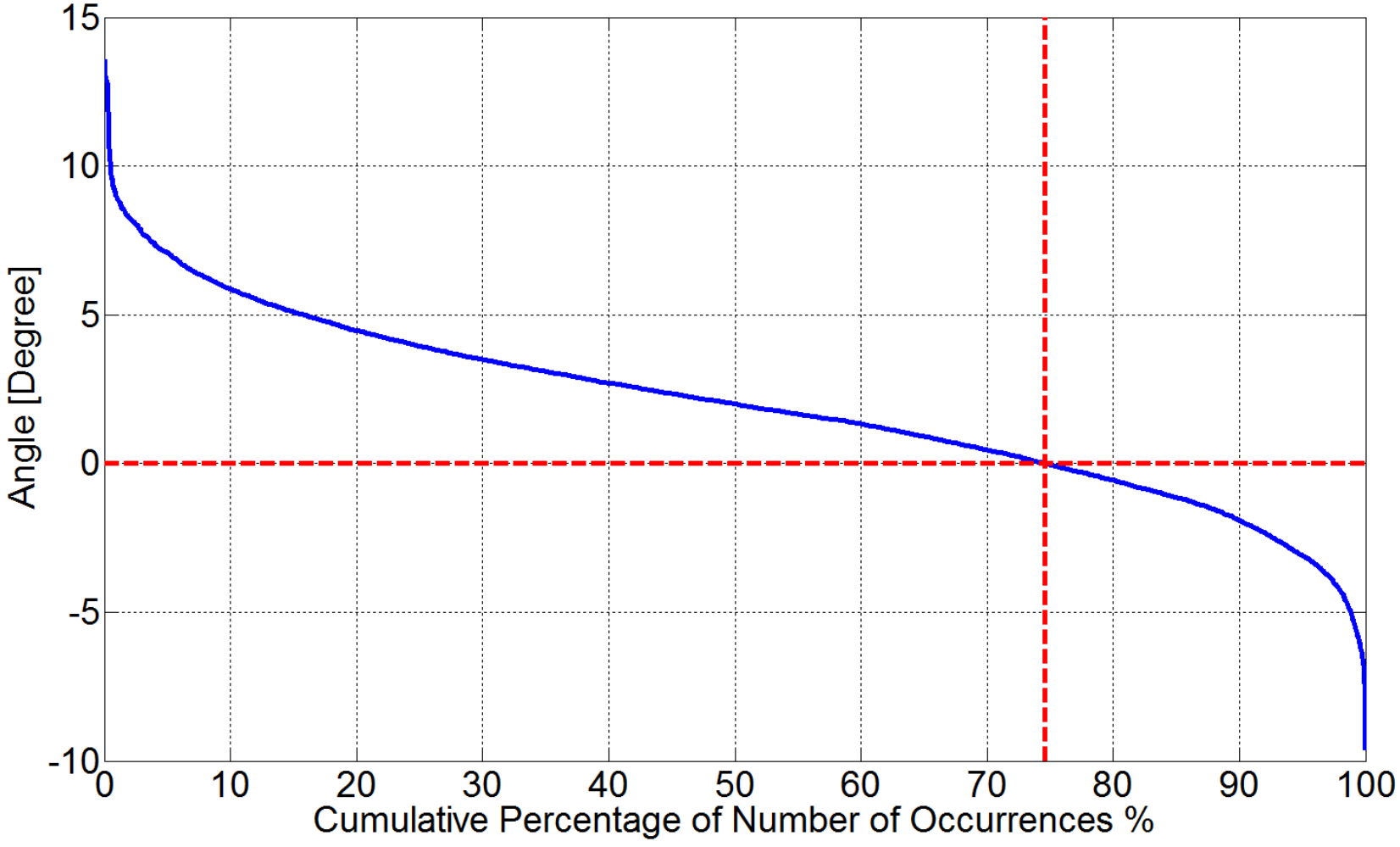

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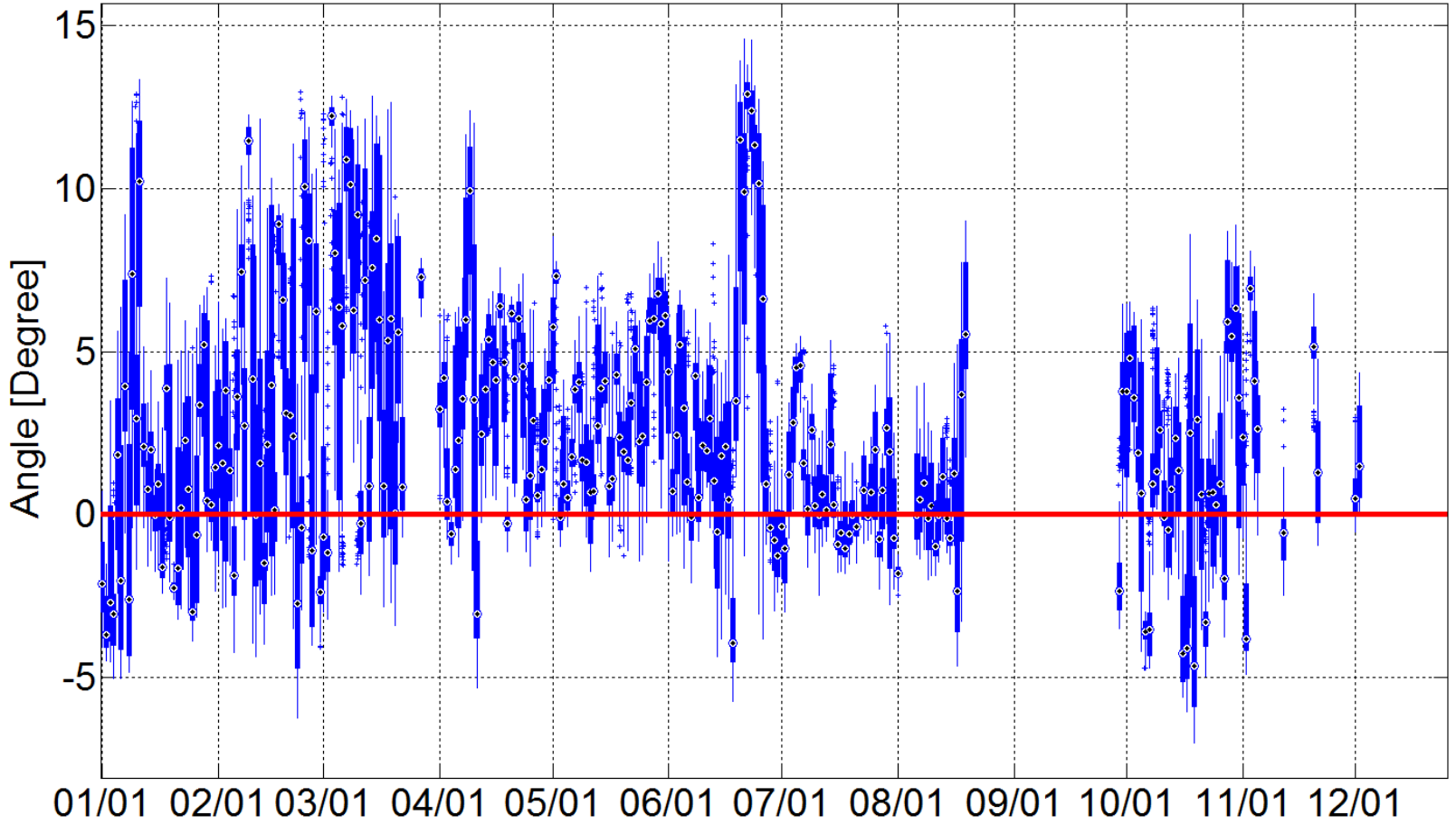

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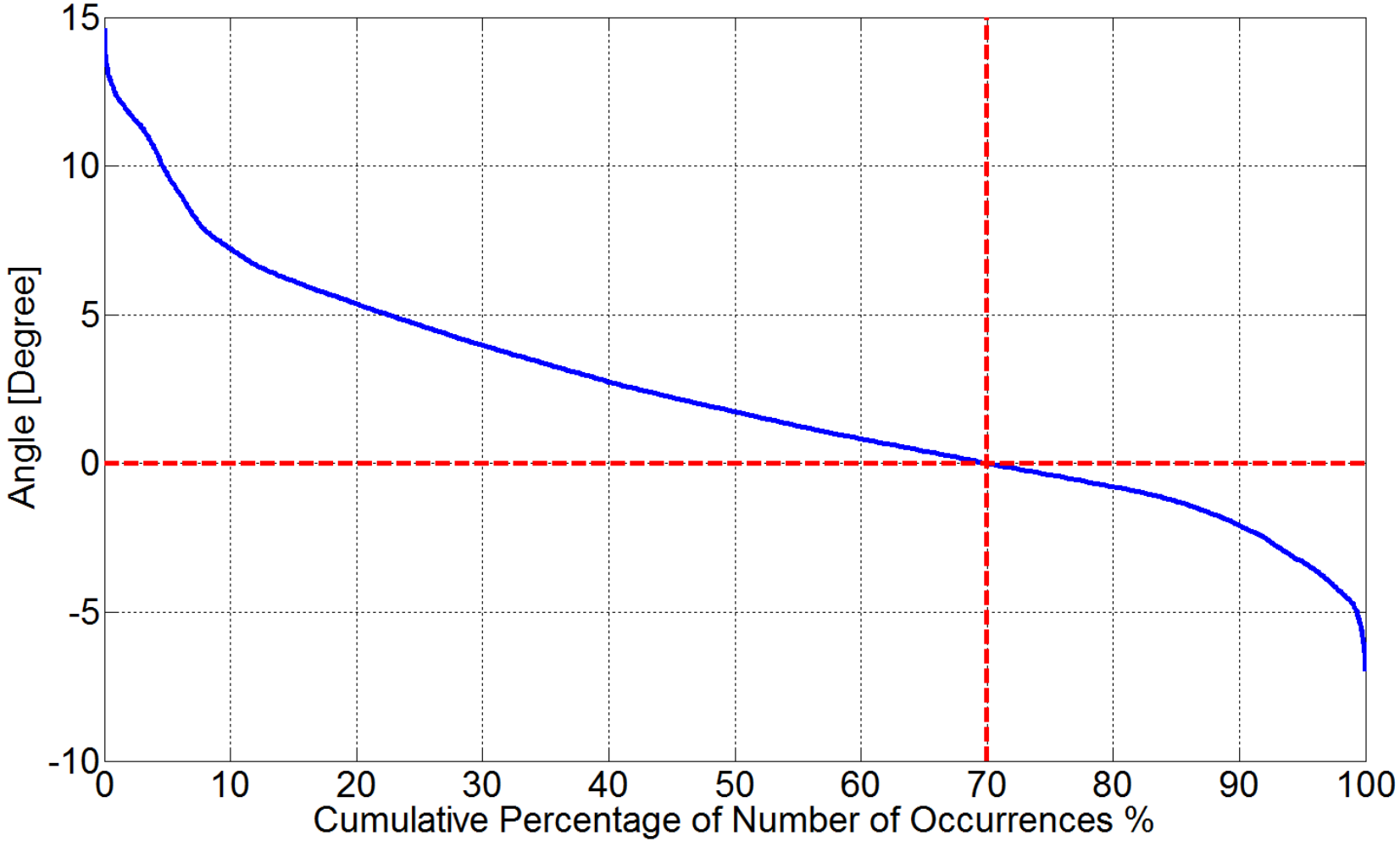

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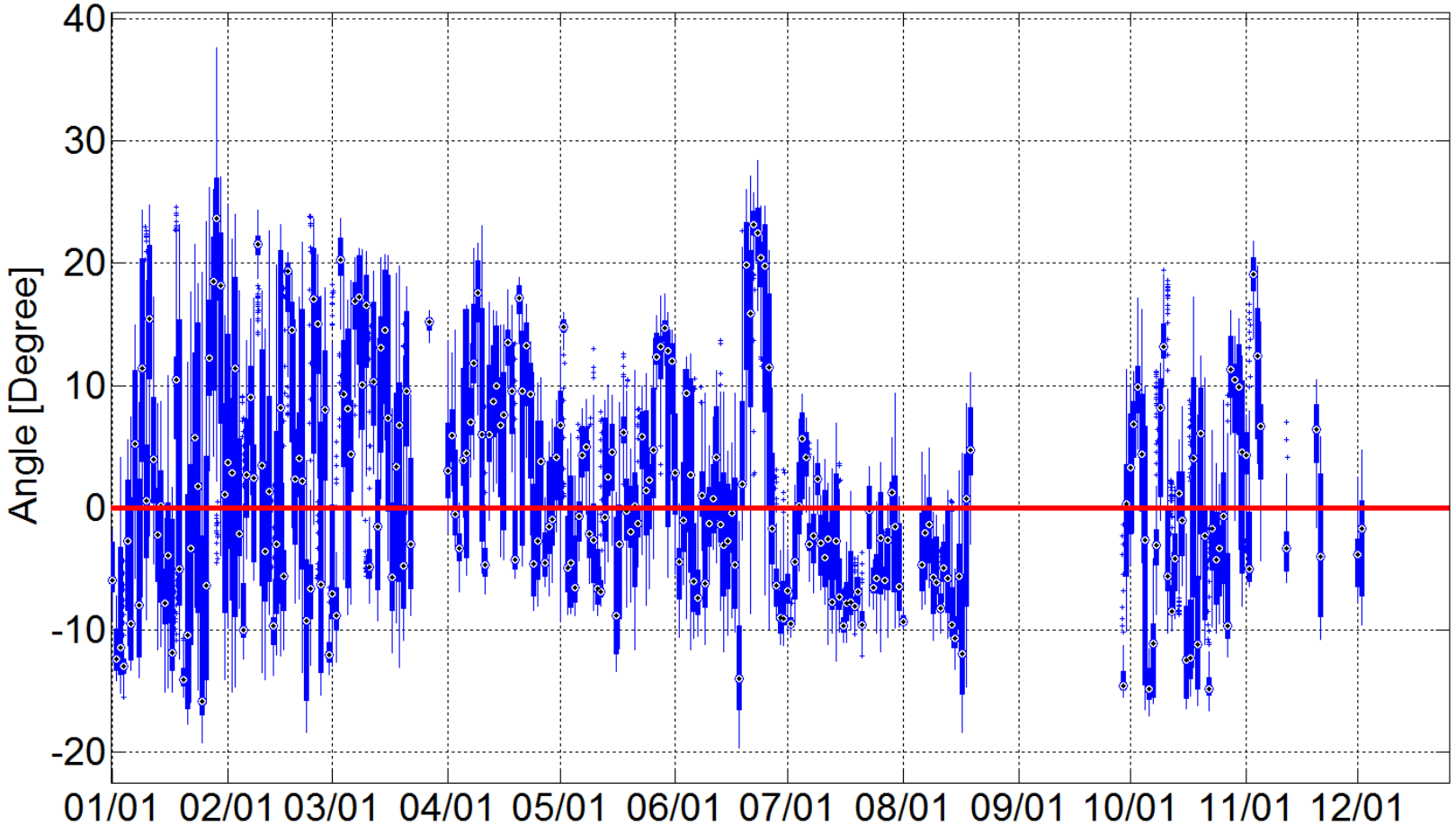

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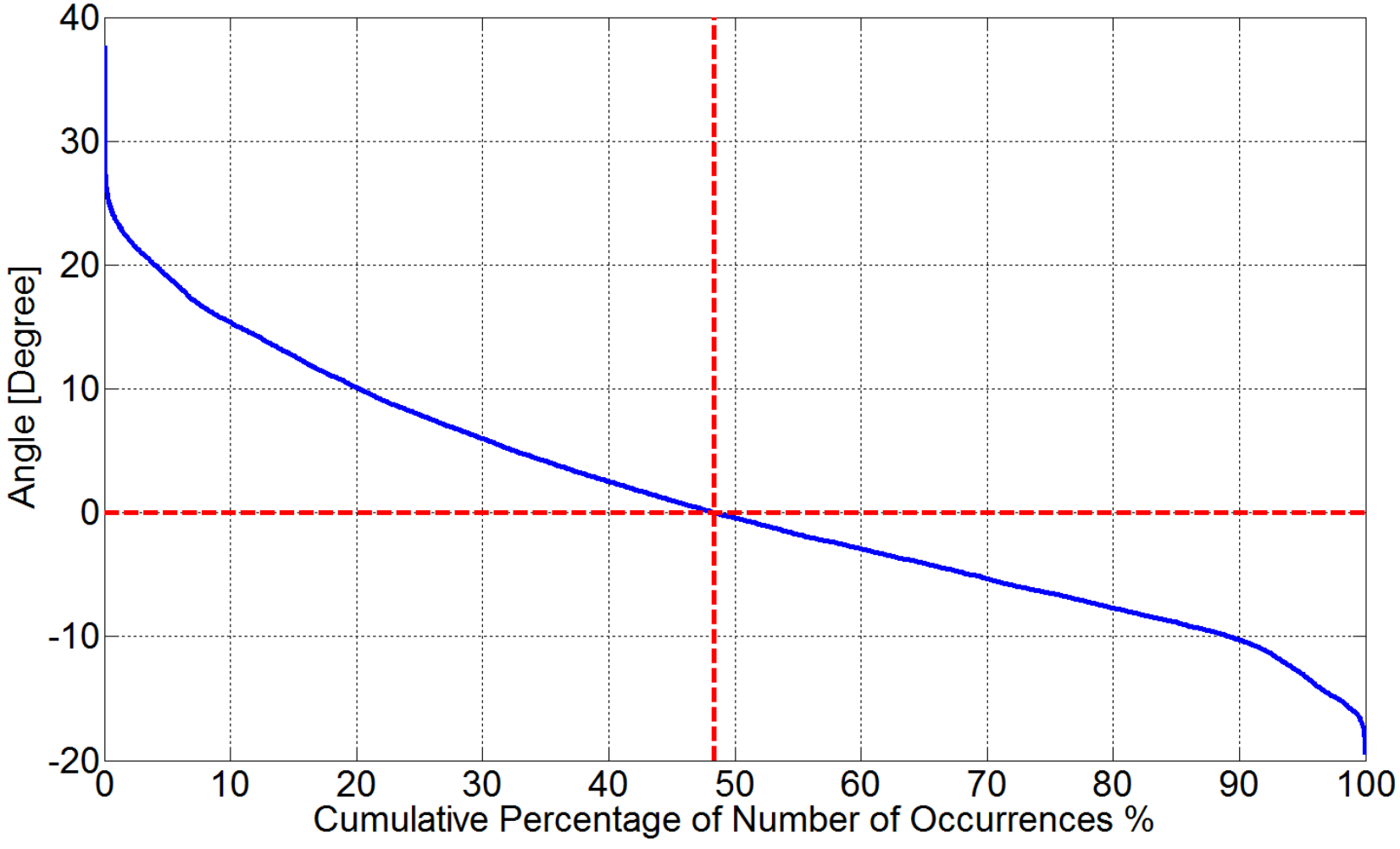

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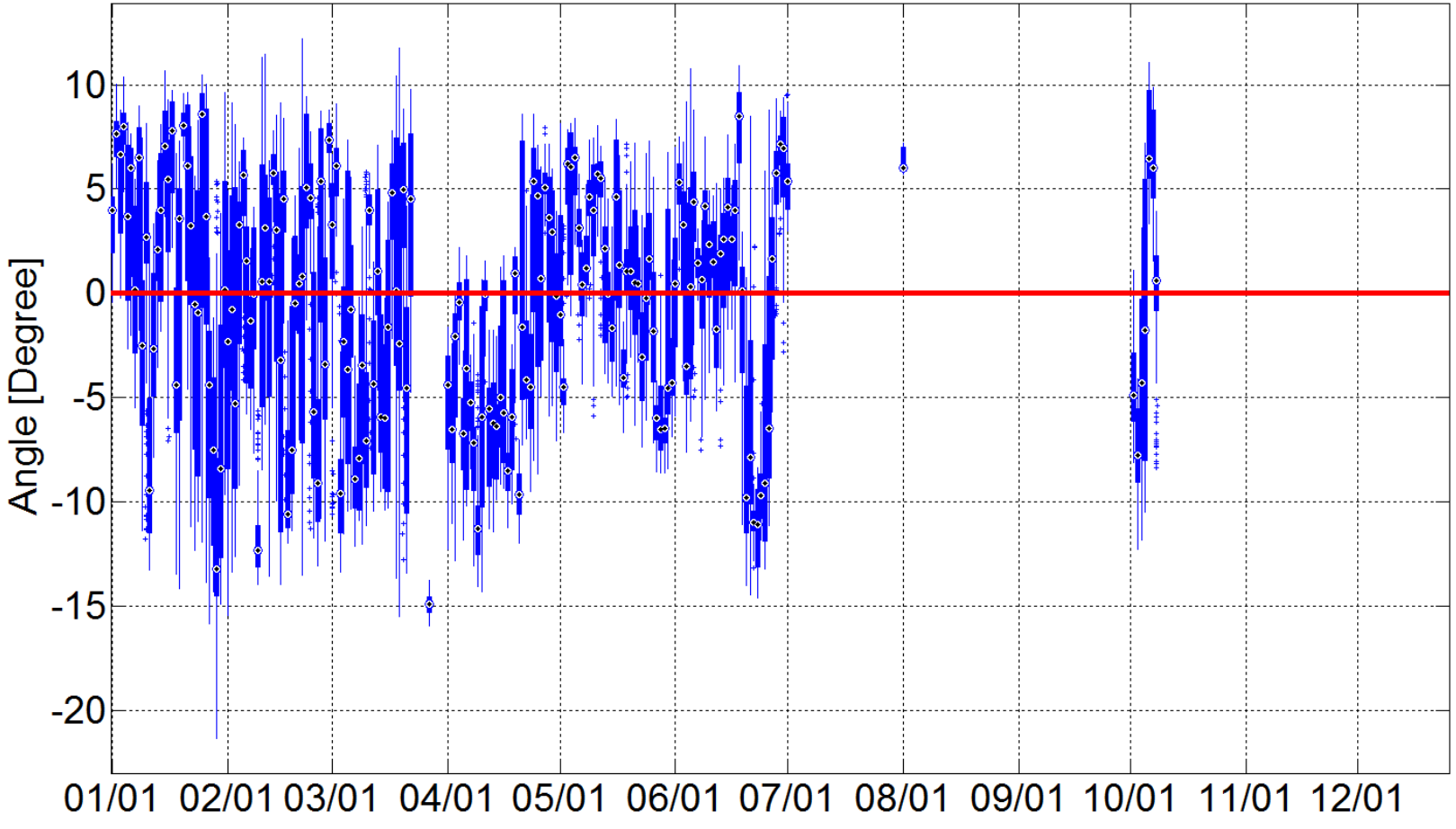

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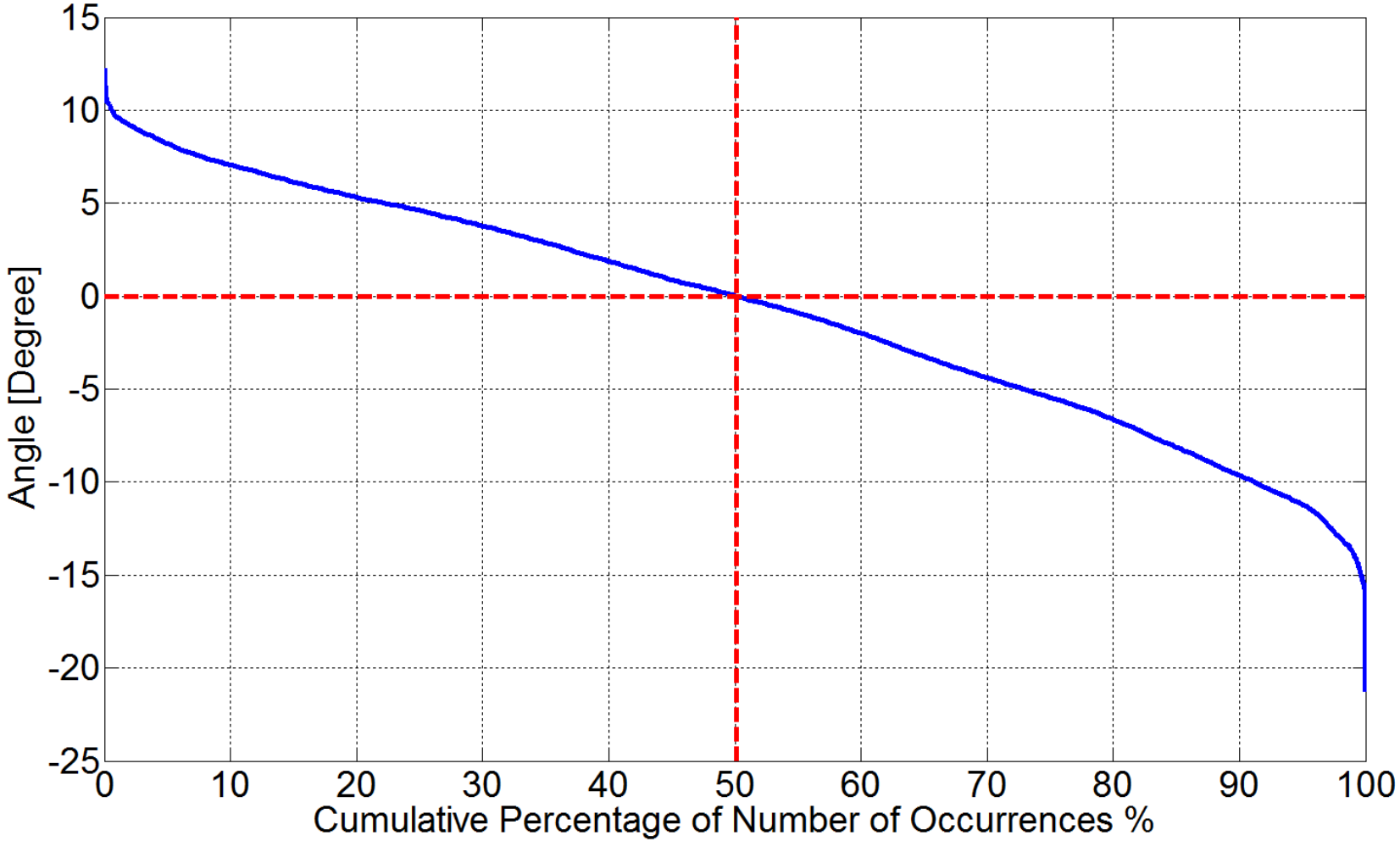

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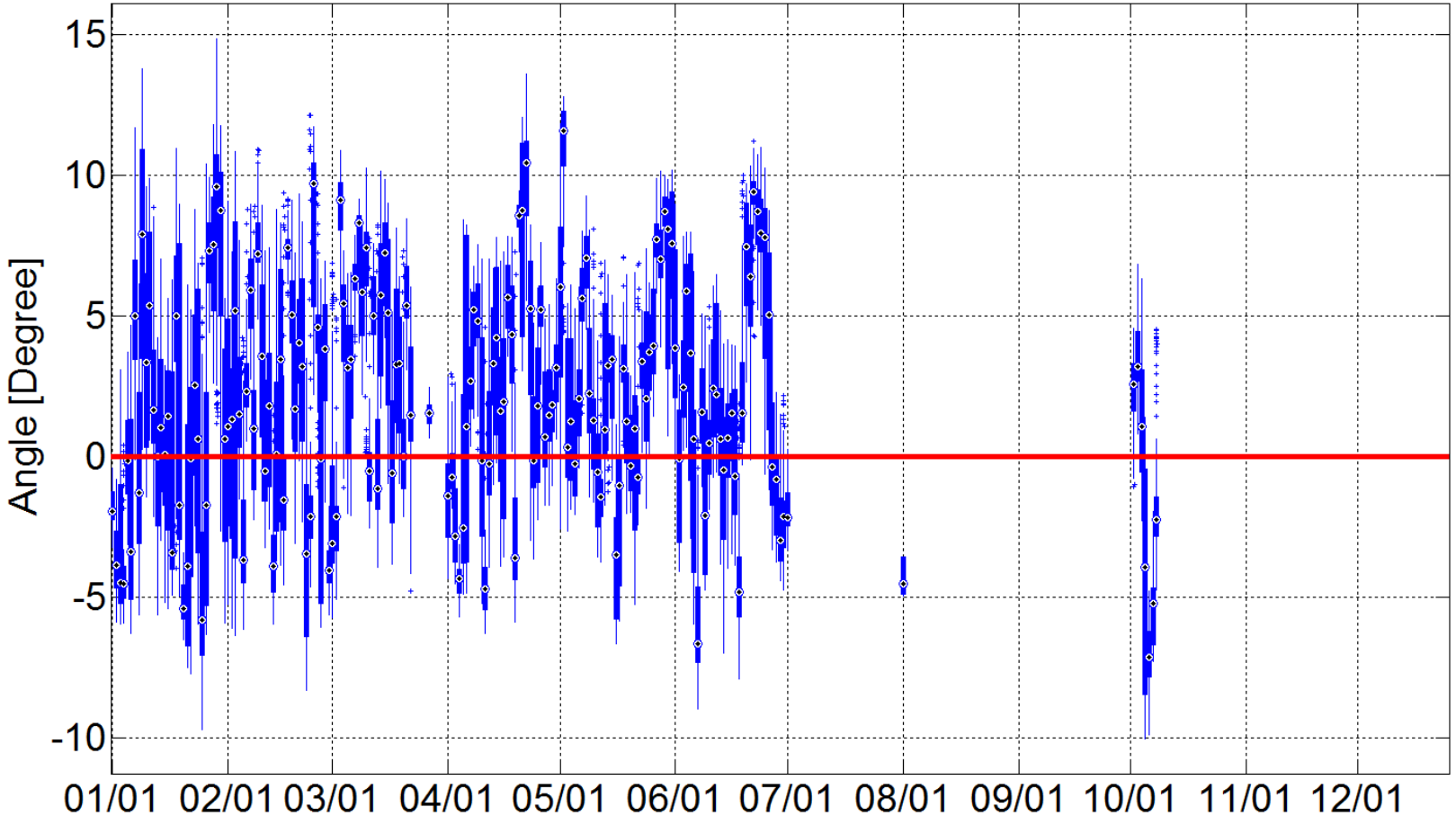

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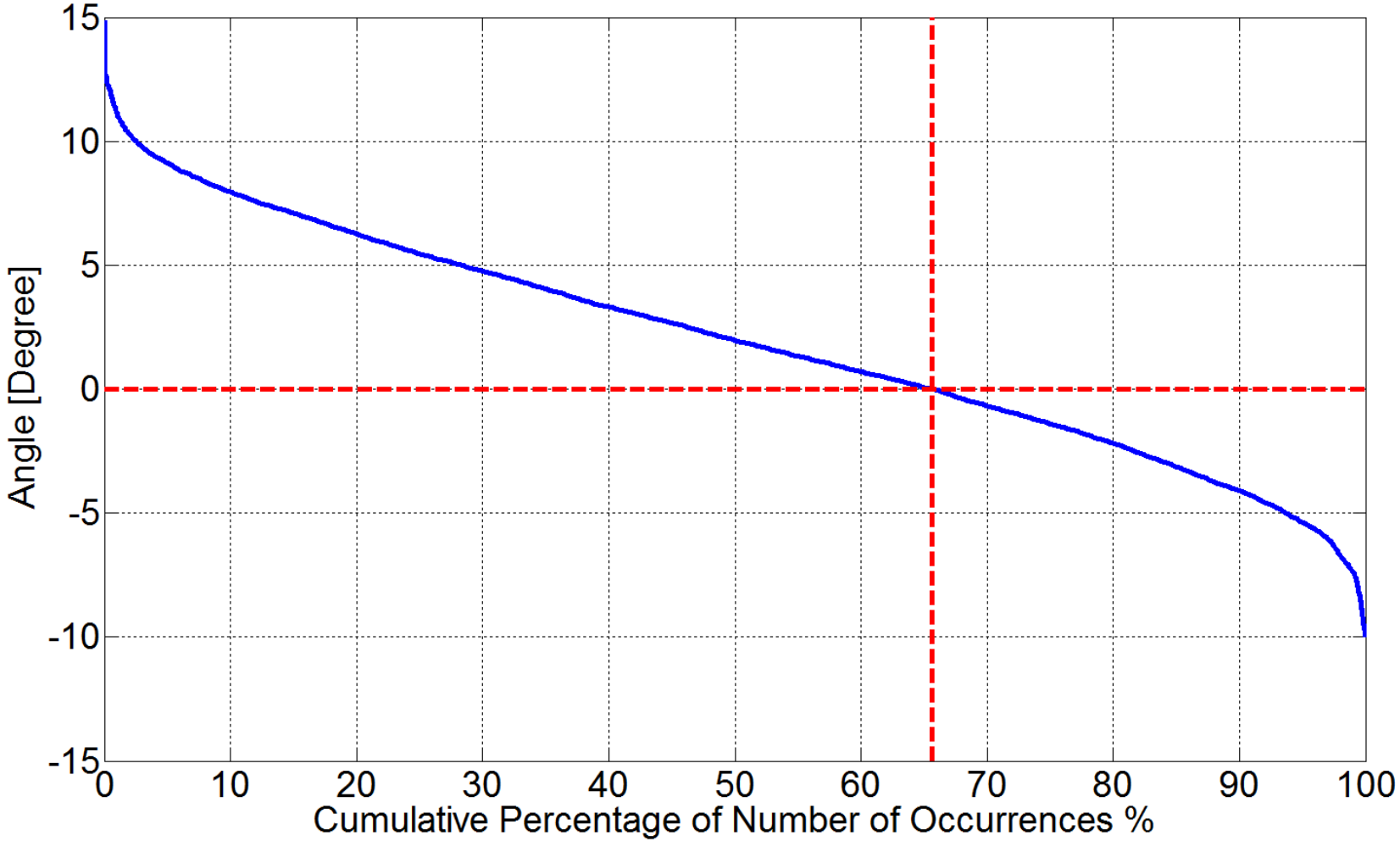

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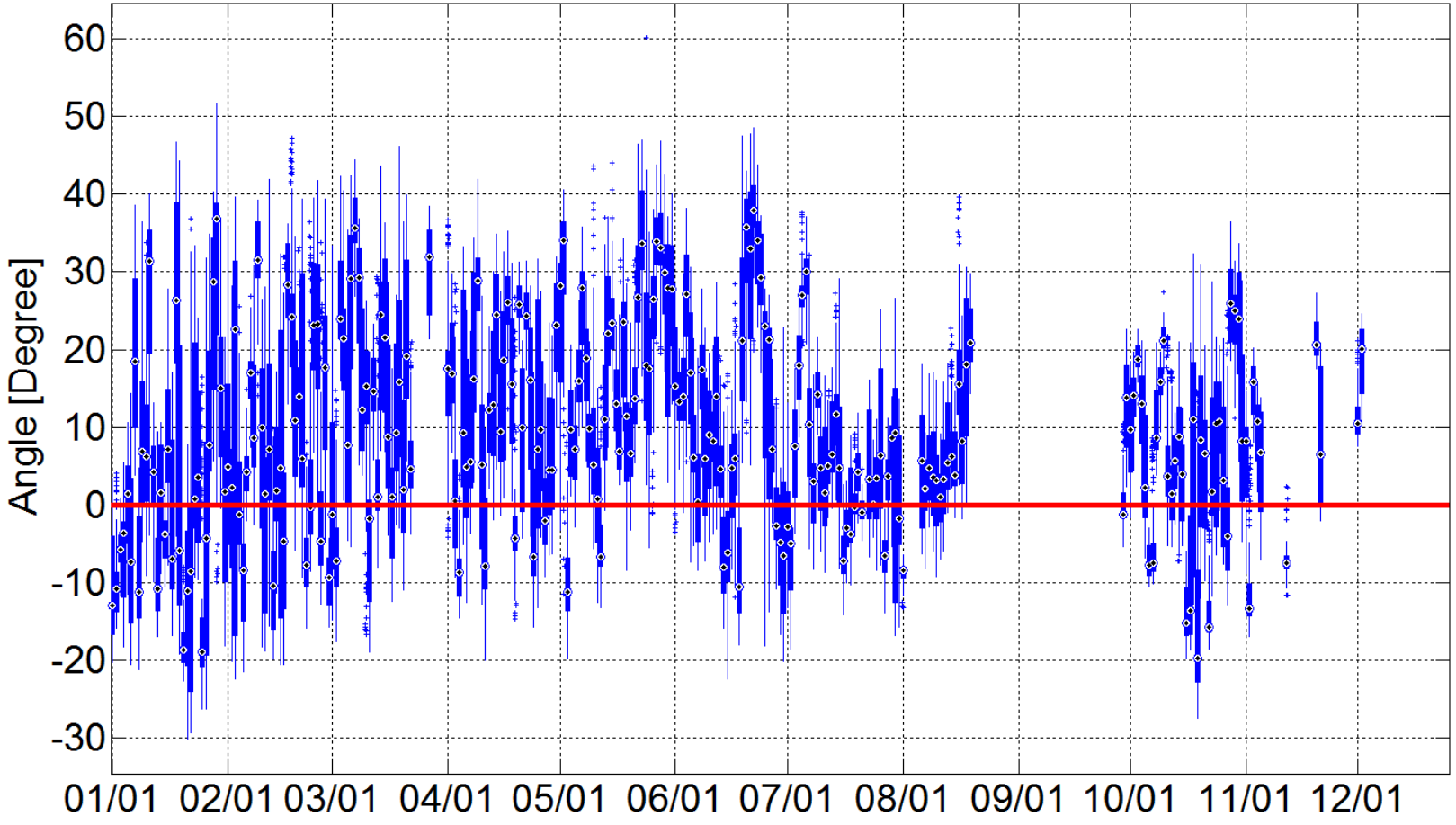

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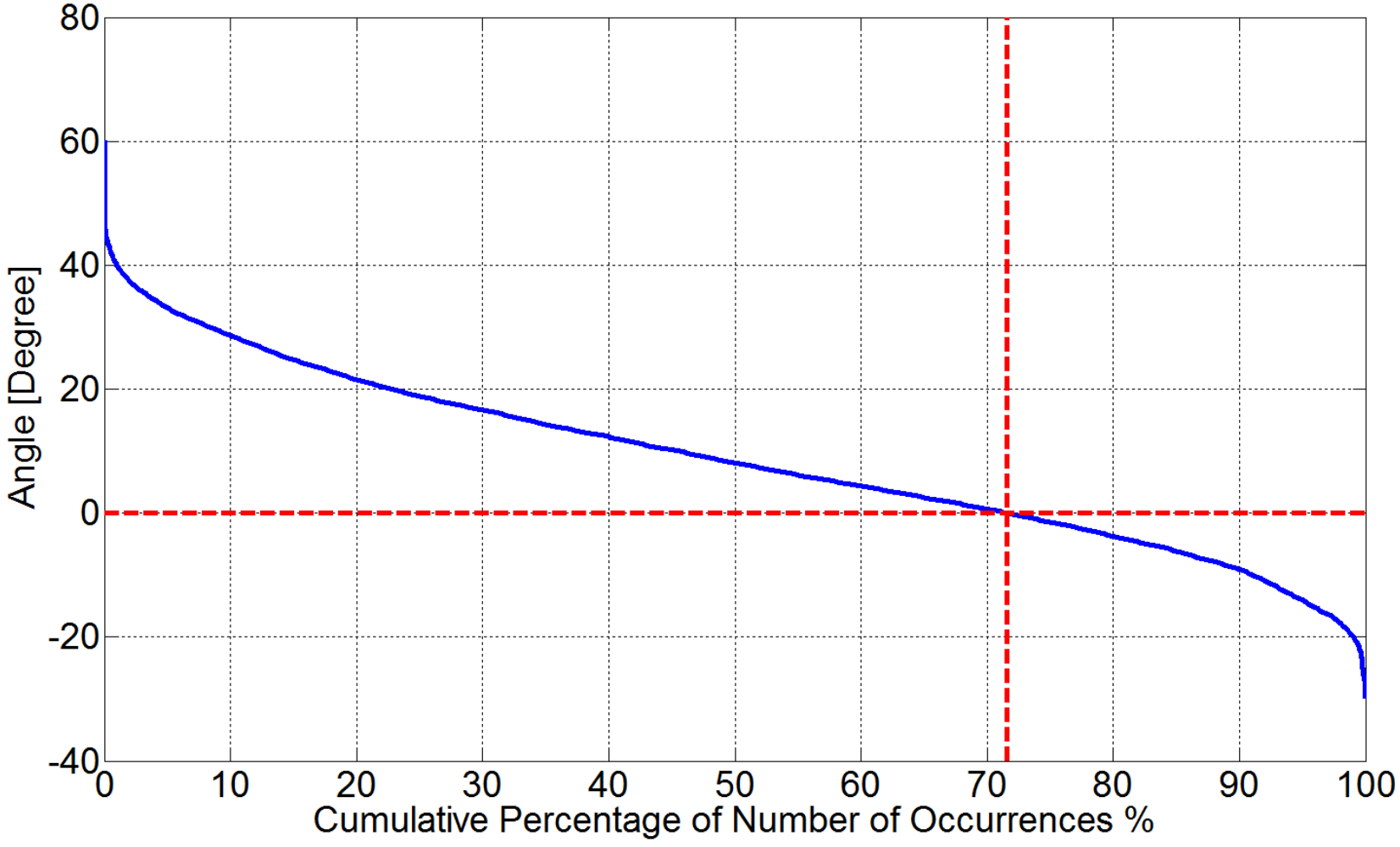

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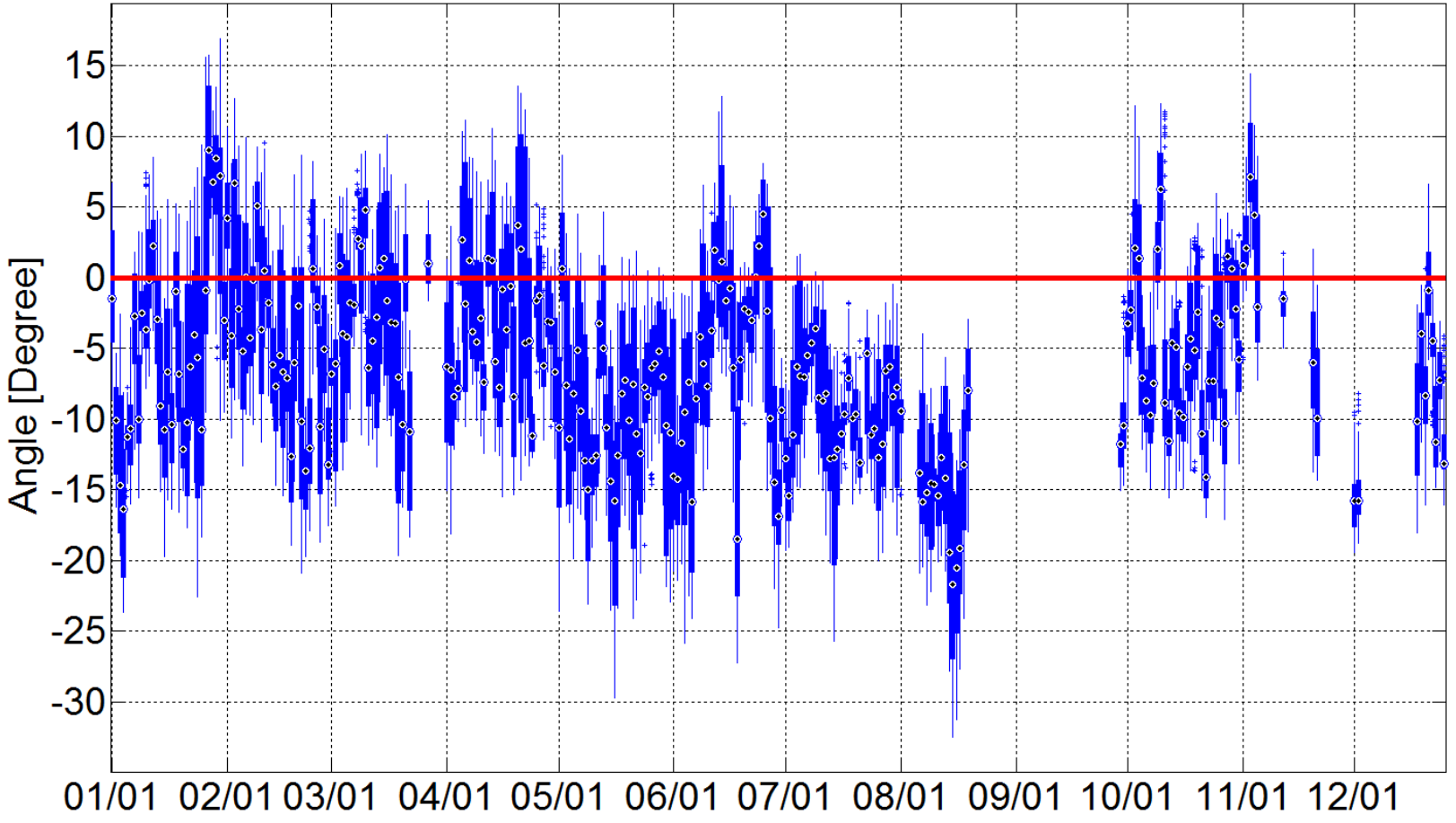

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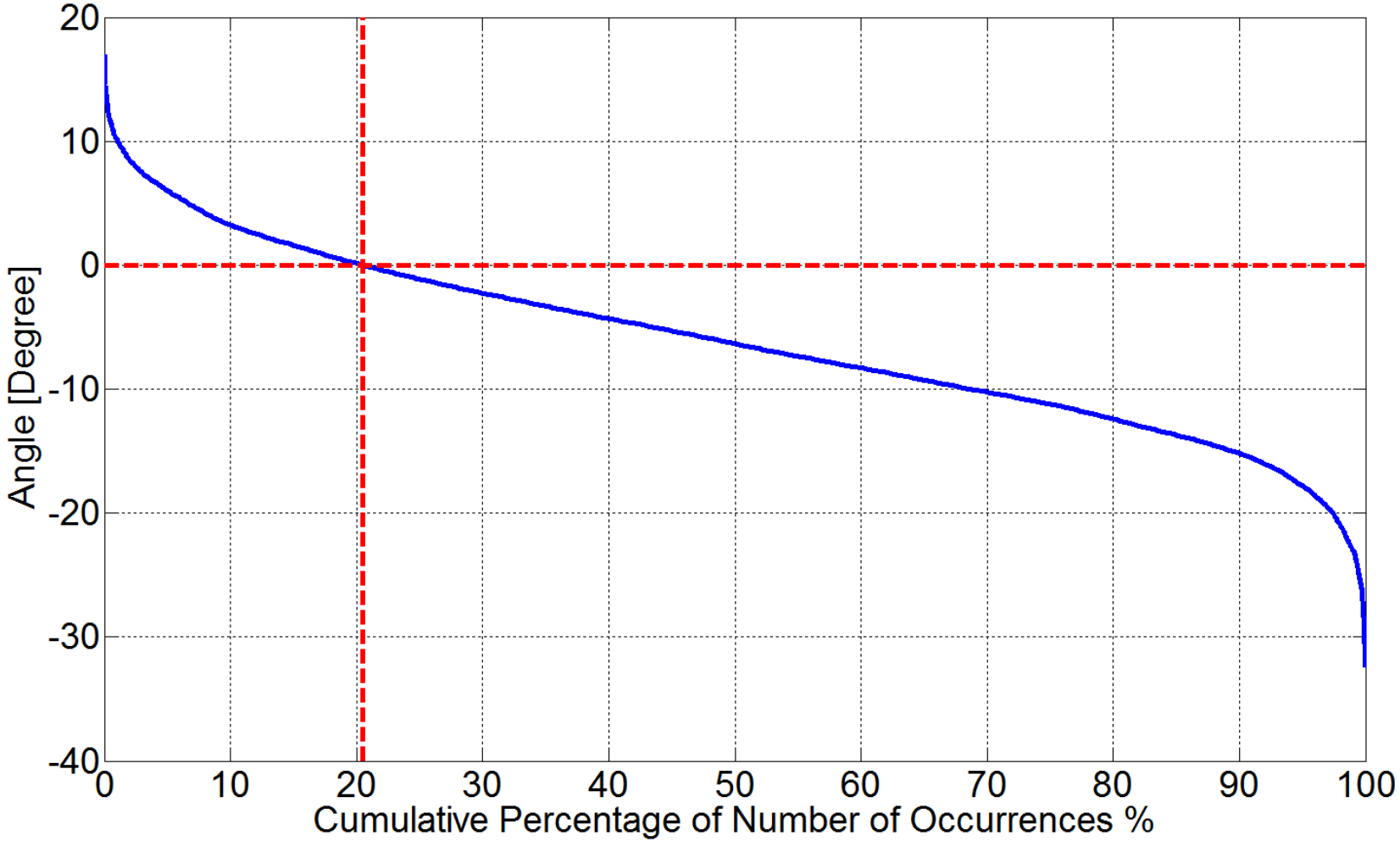

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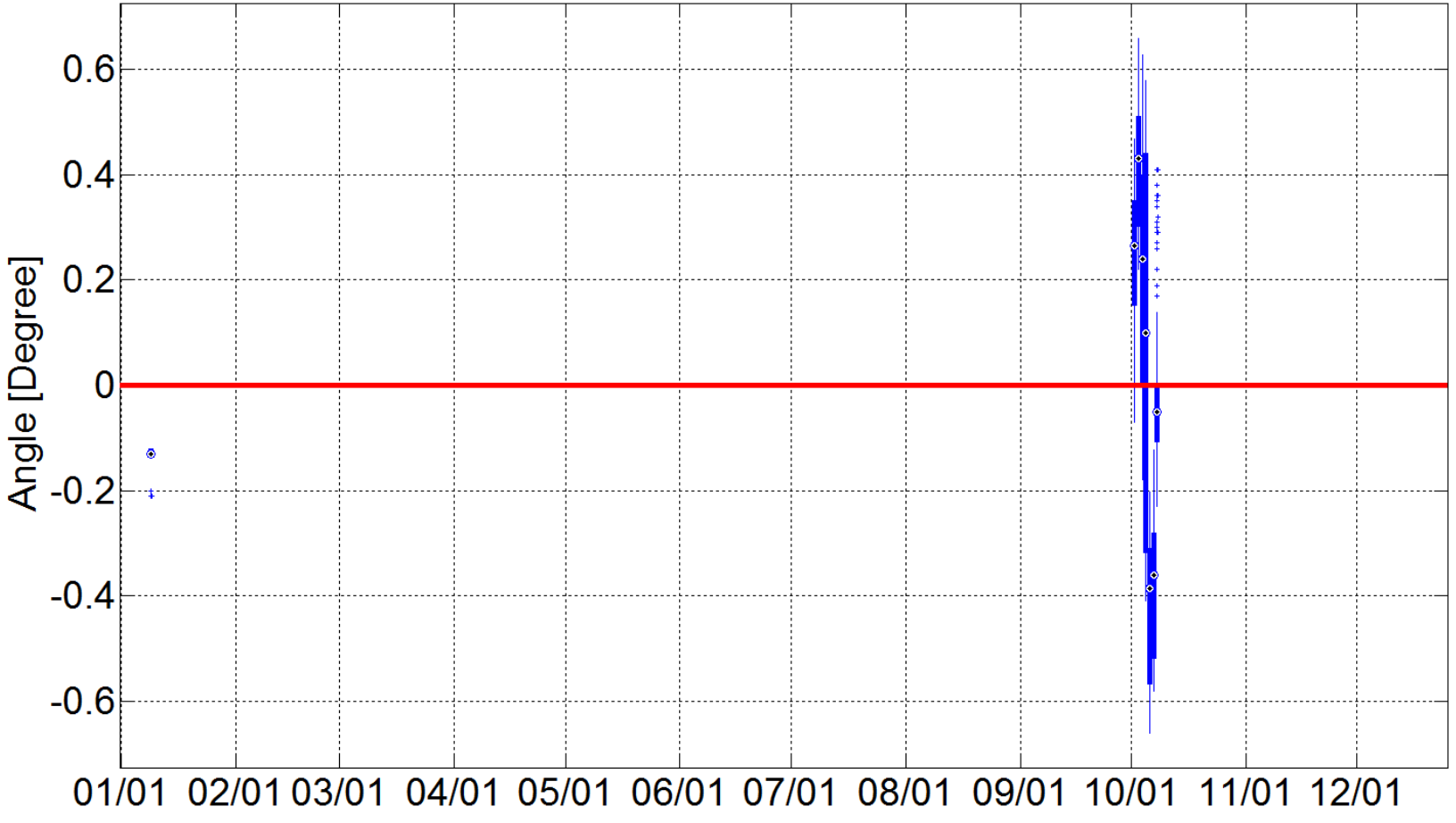

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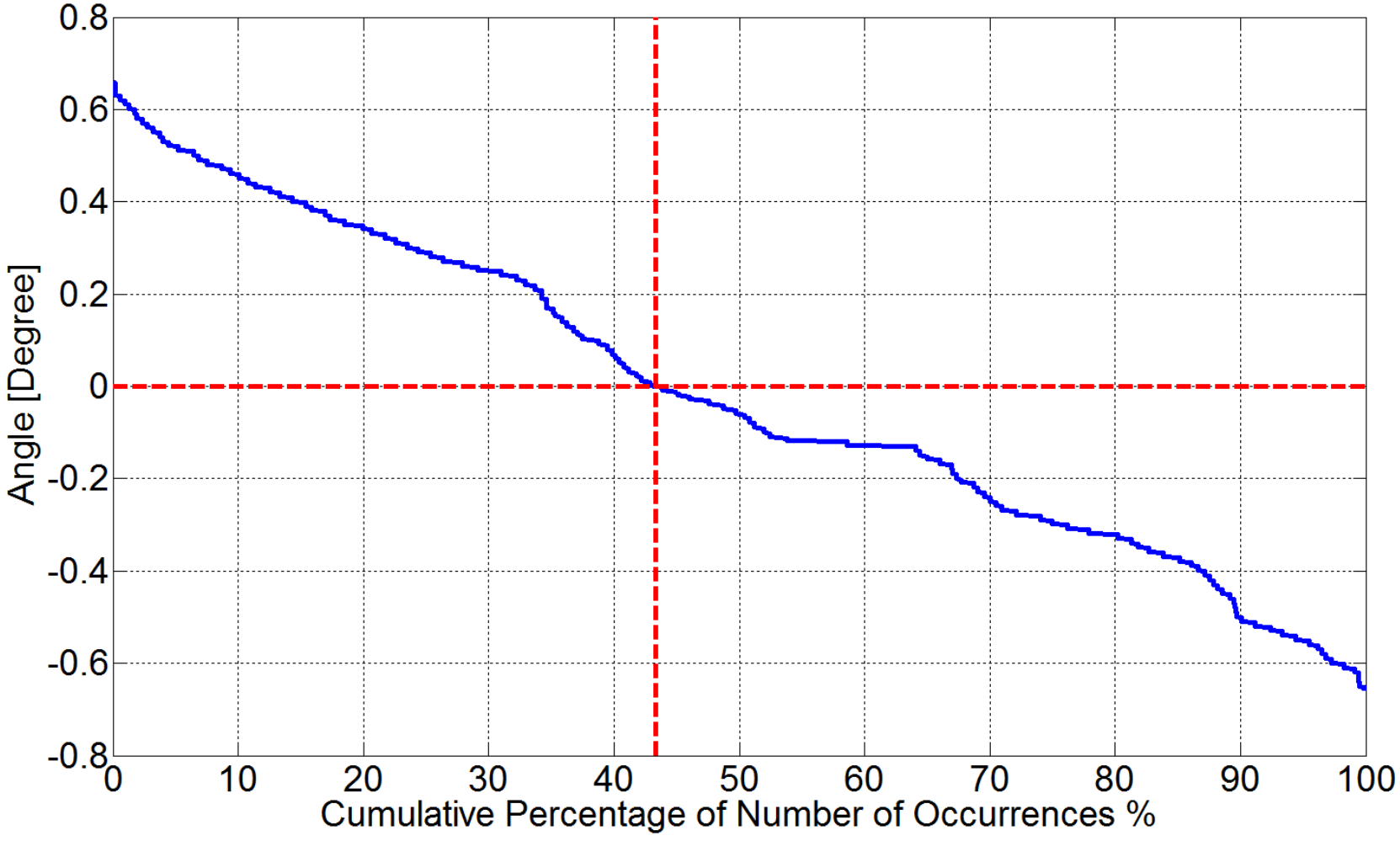

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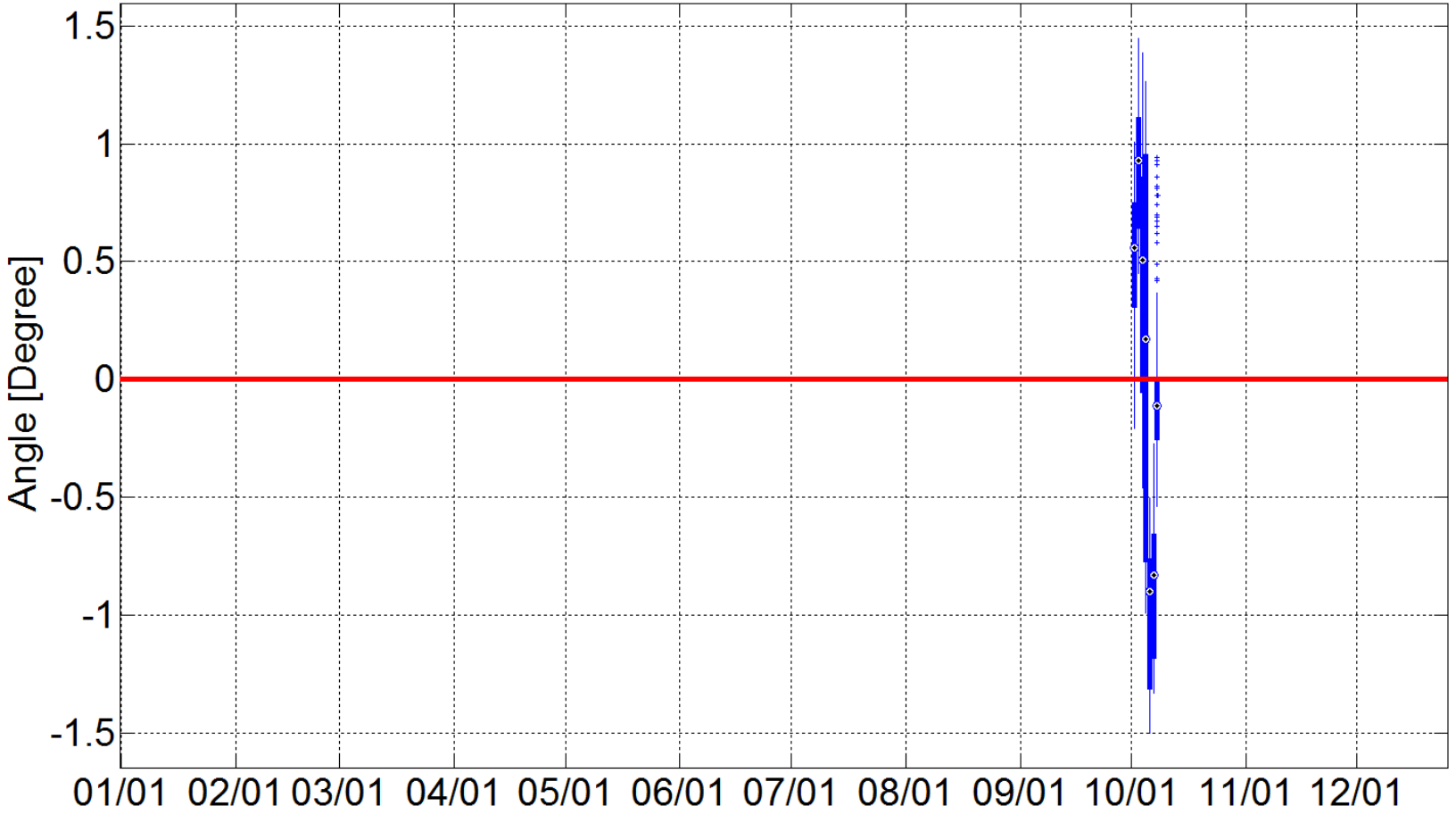

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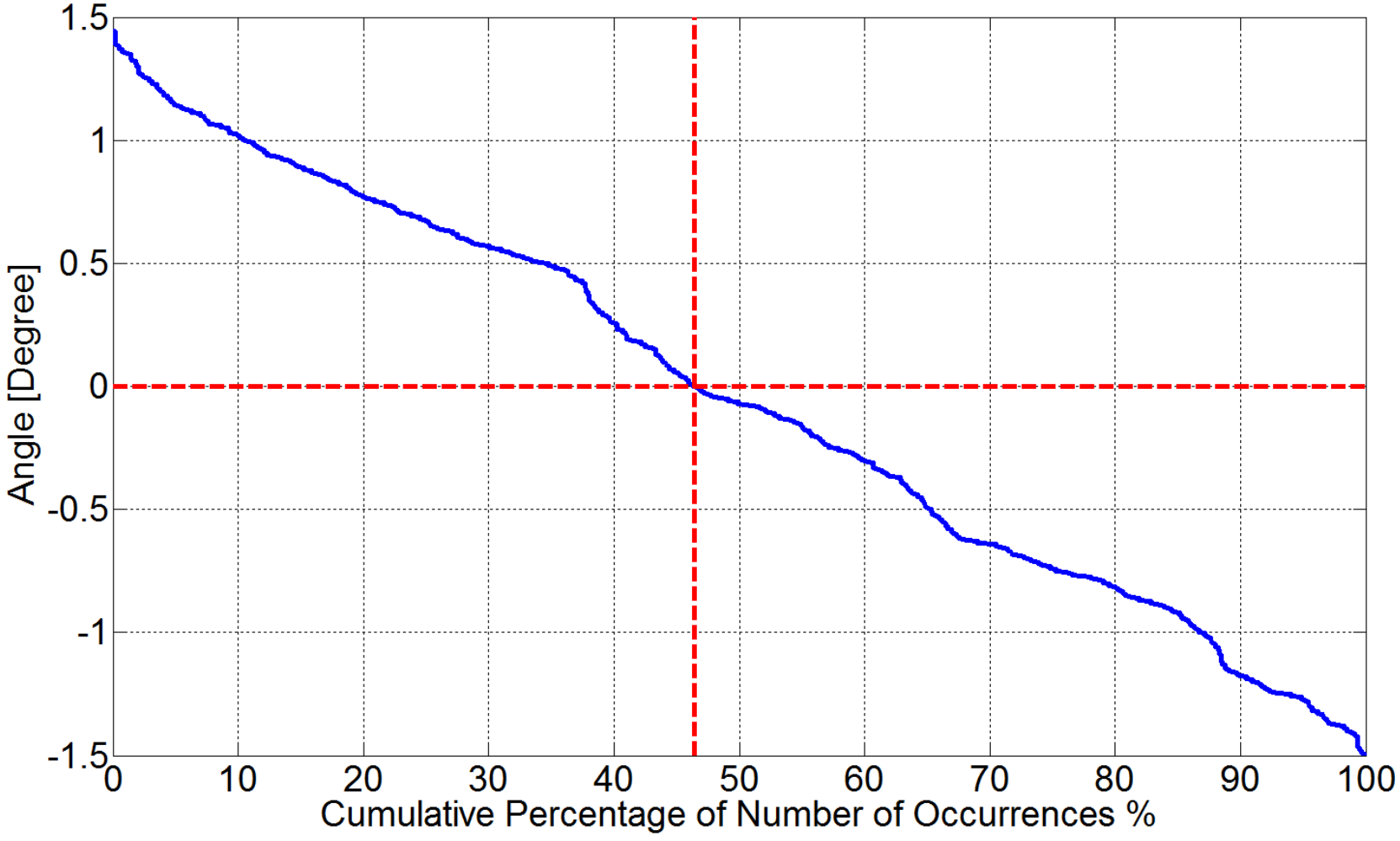
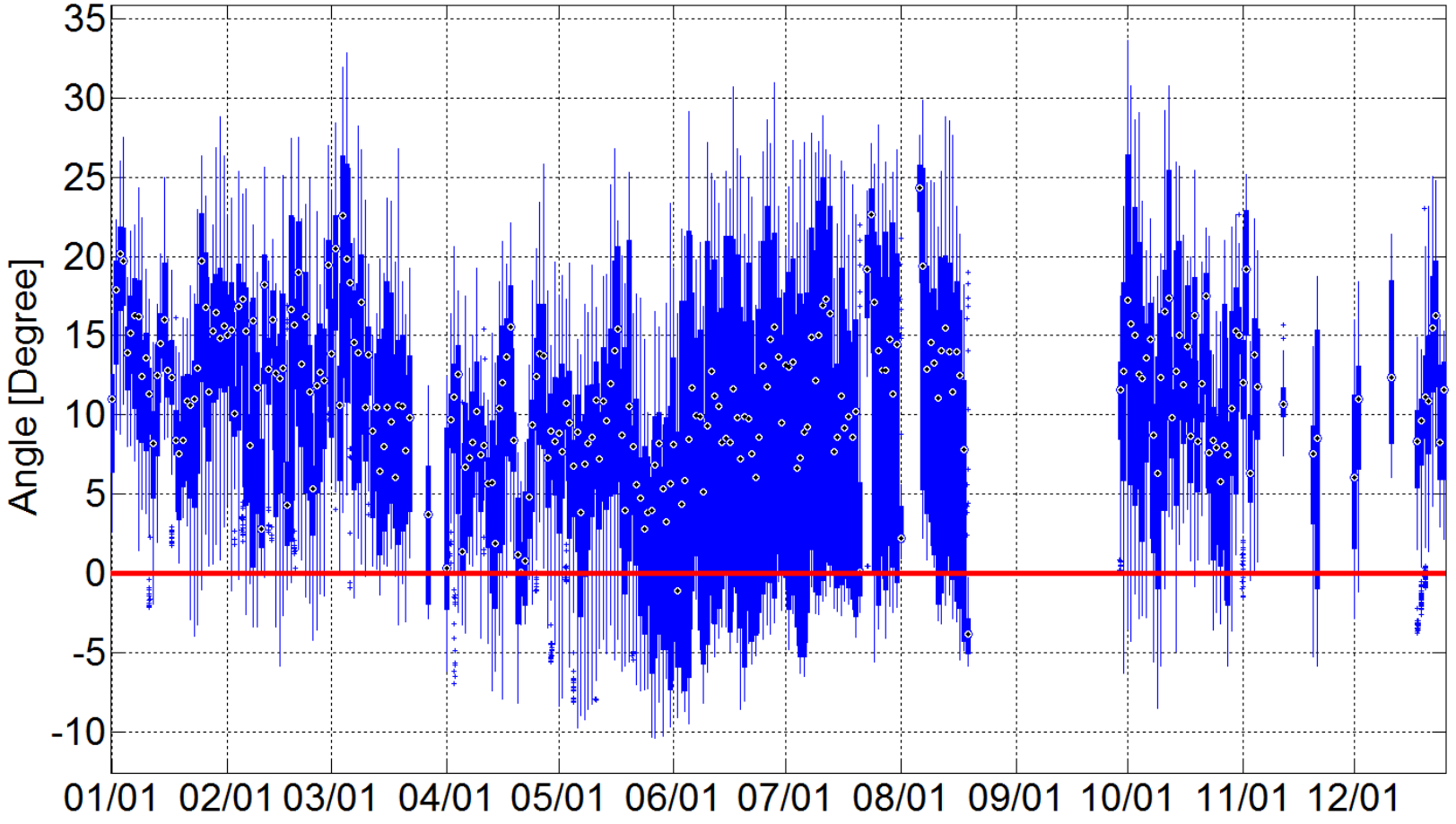
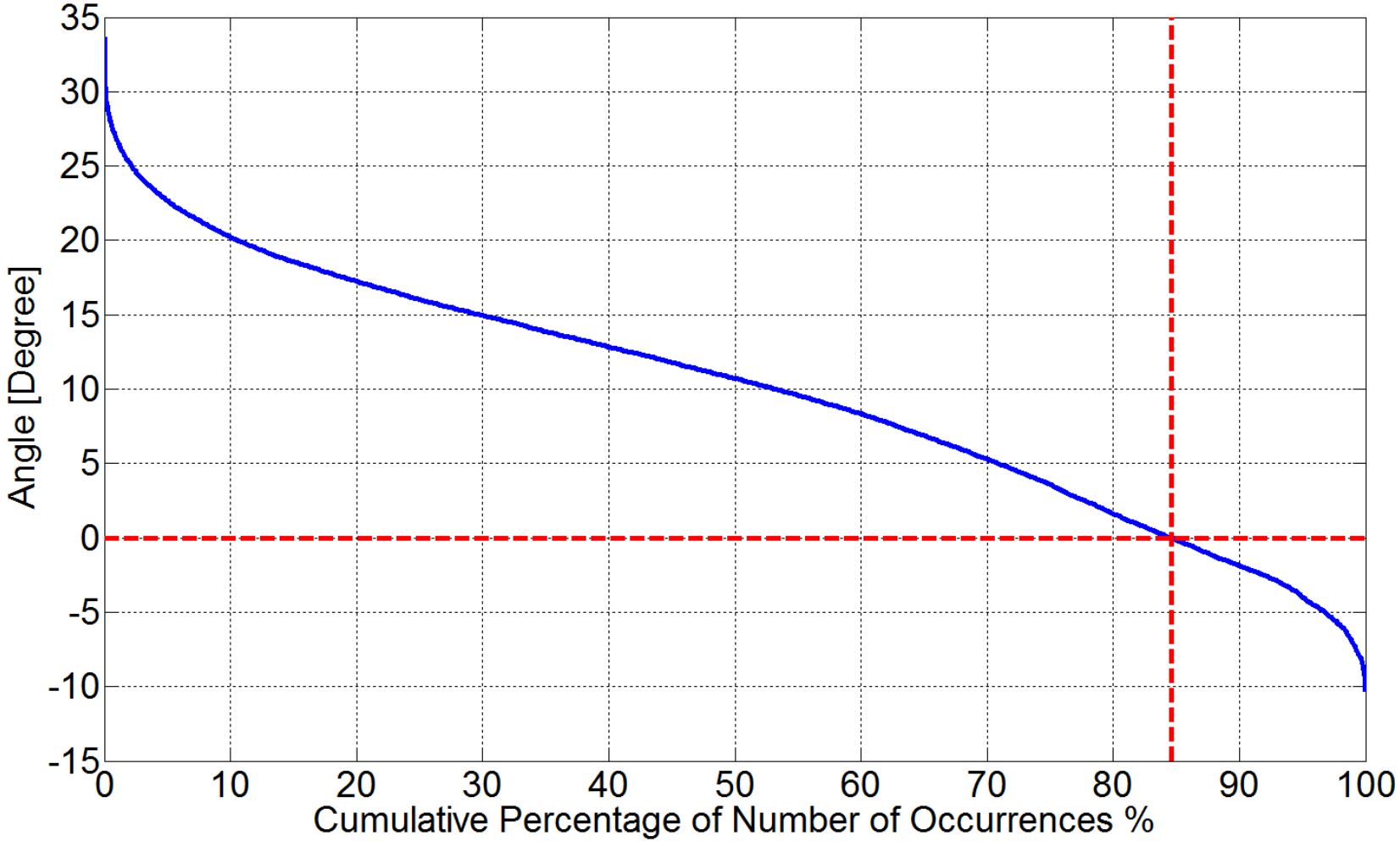


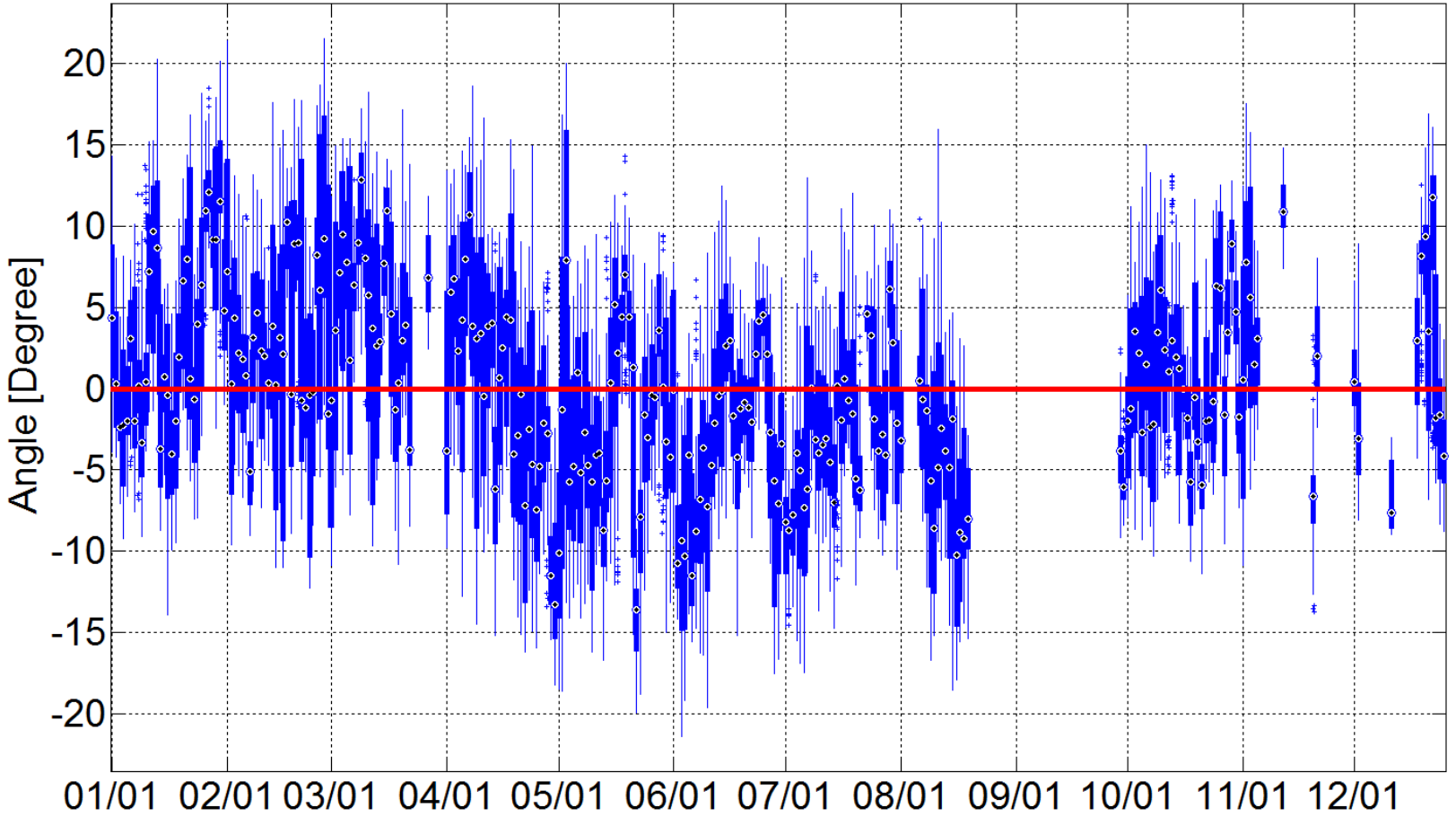
Coast 1-South 10*



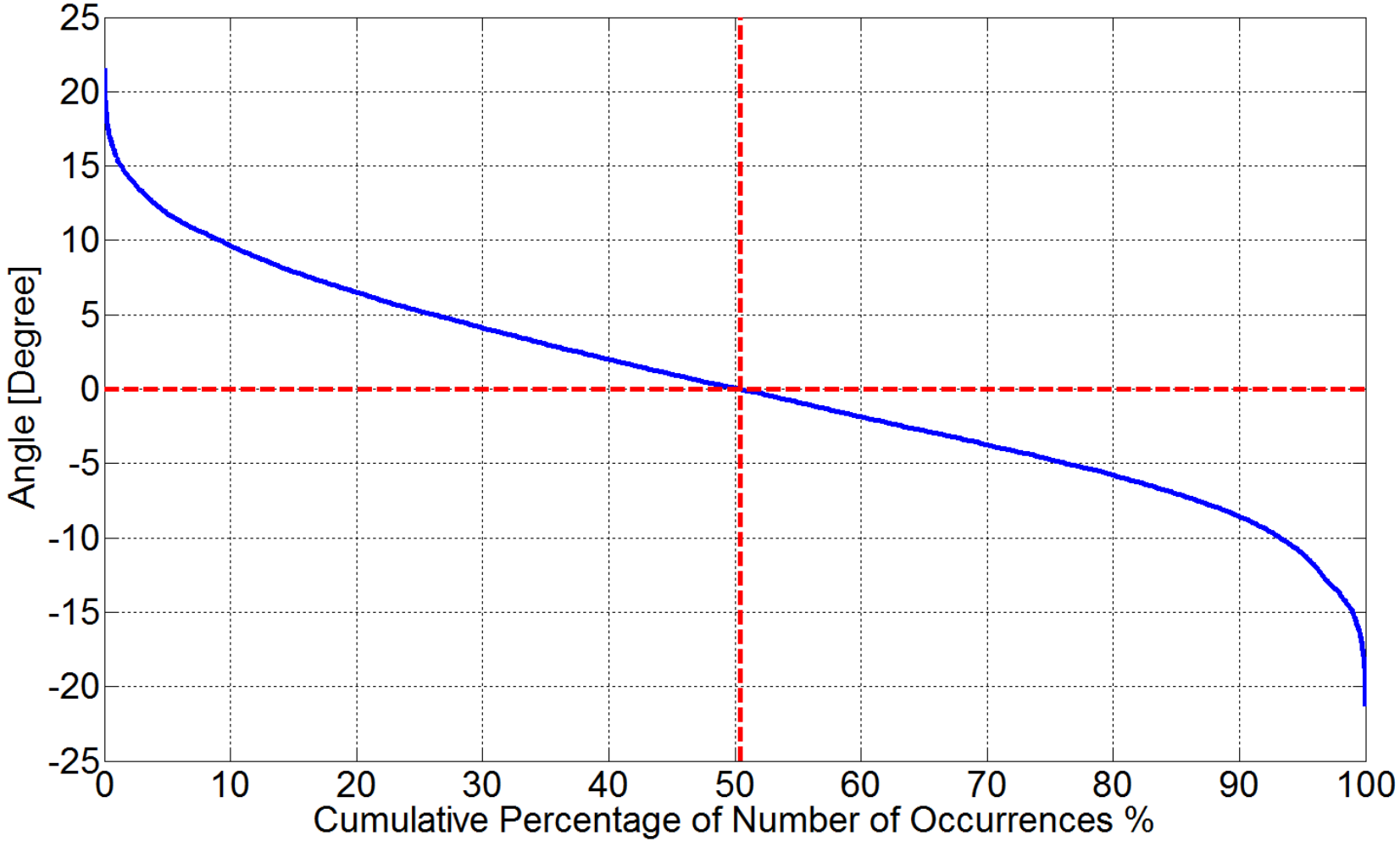
Coast 1-South 10*



South 3*-South 11*



South 3*-South 11*



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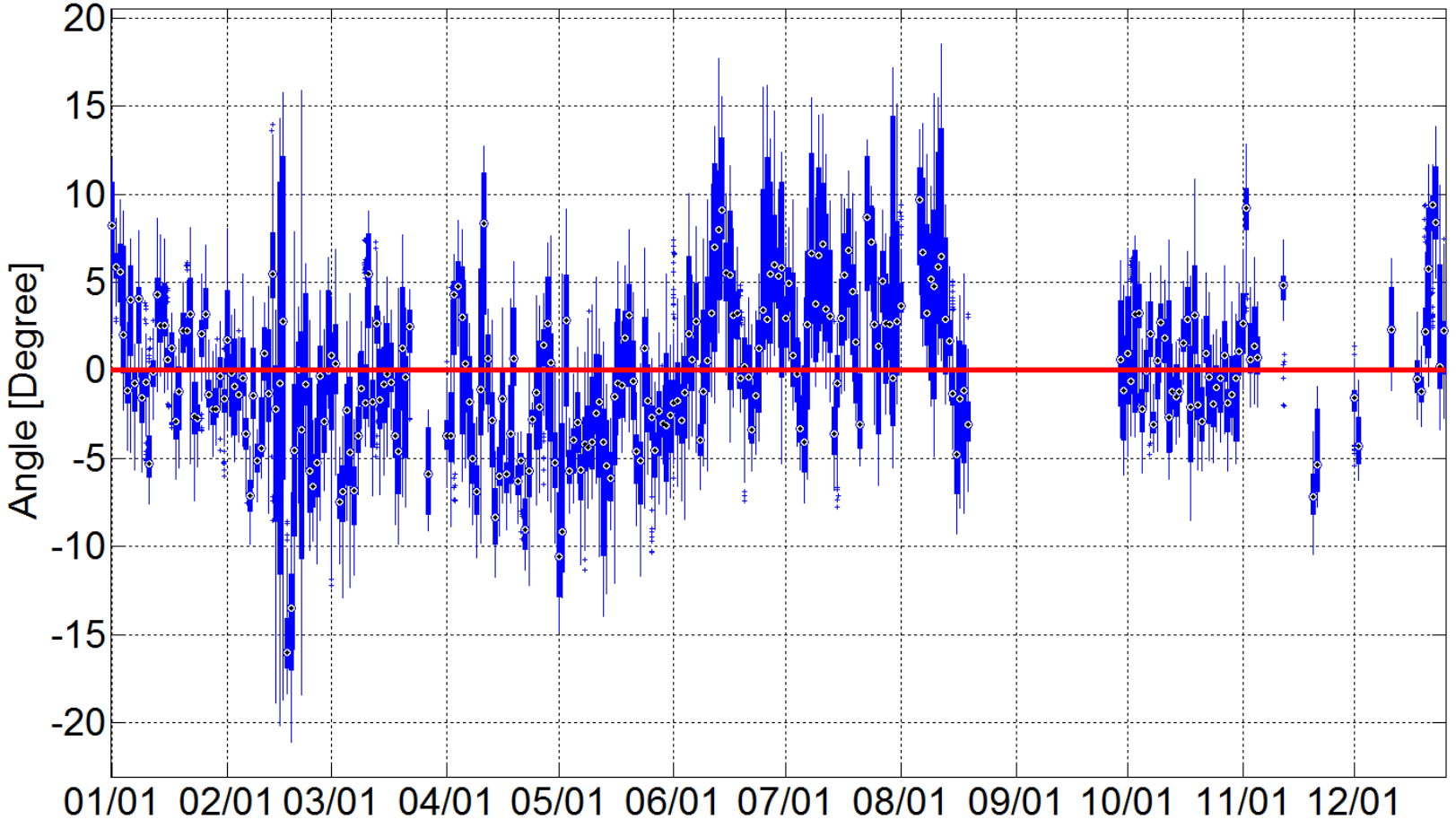

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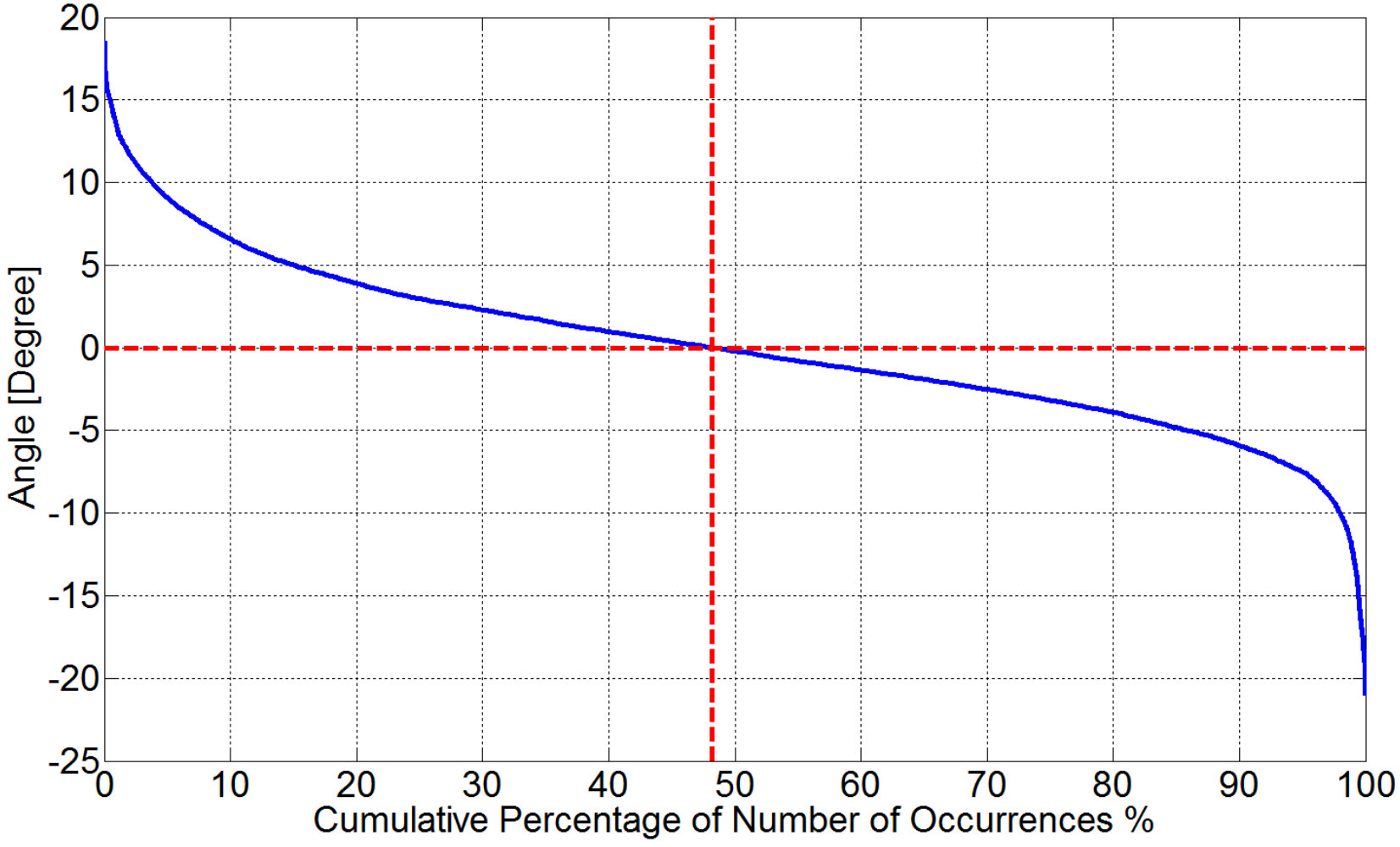

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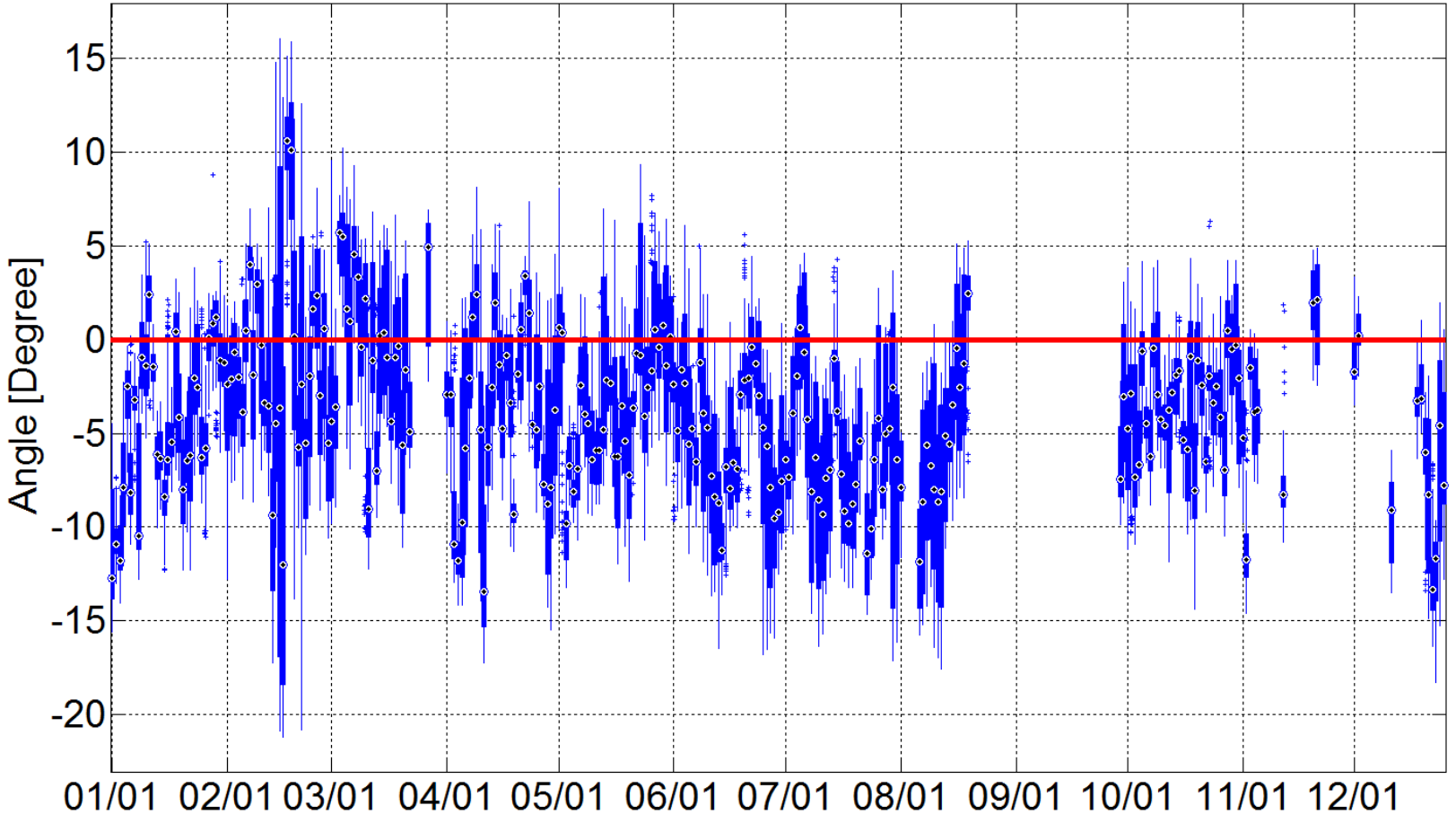

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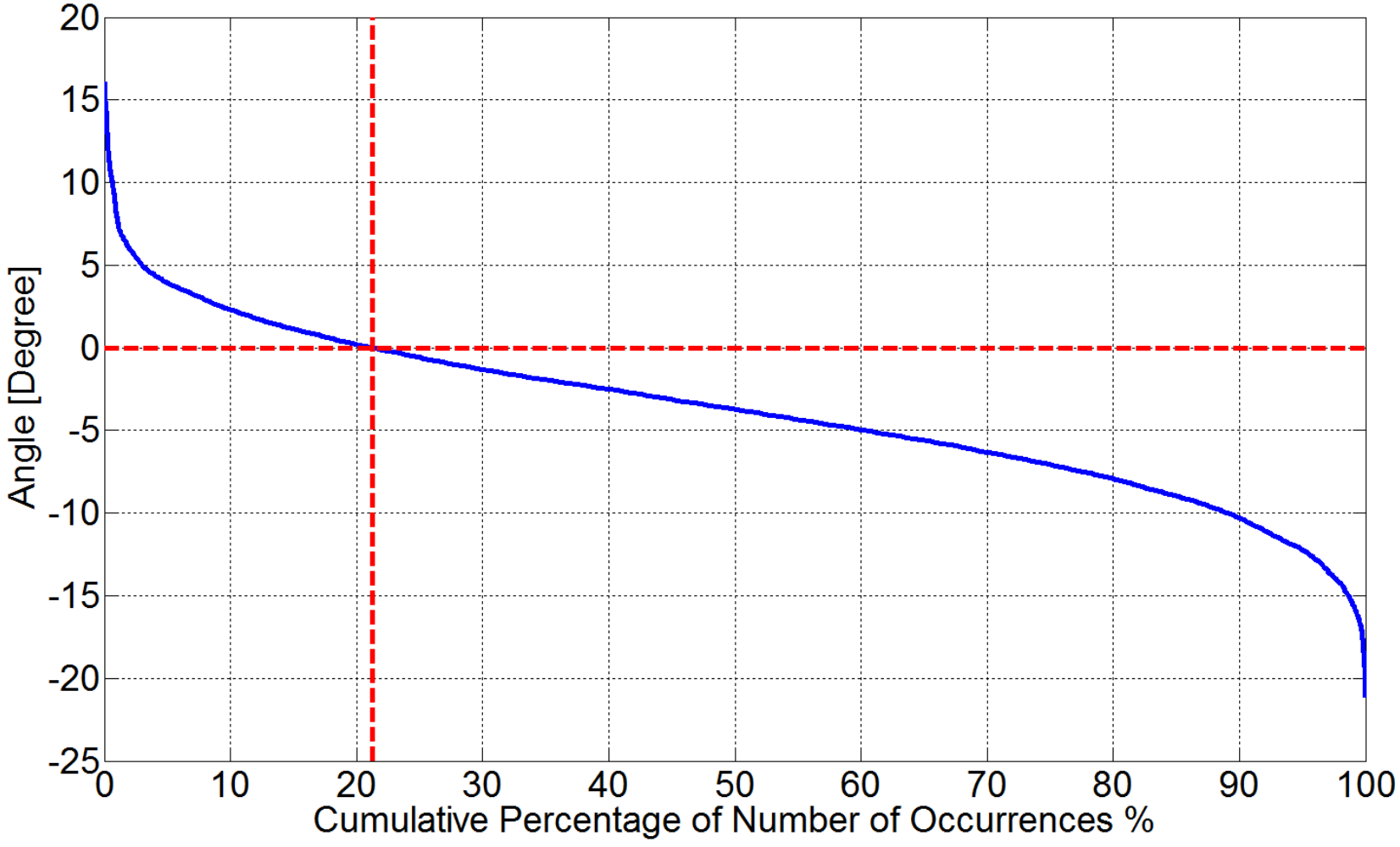

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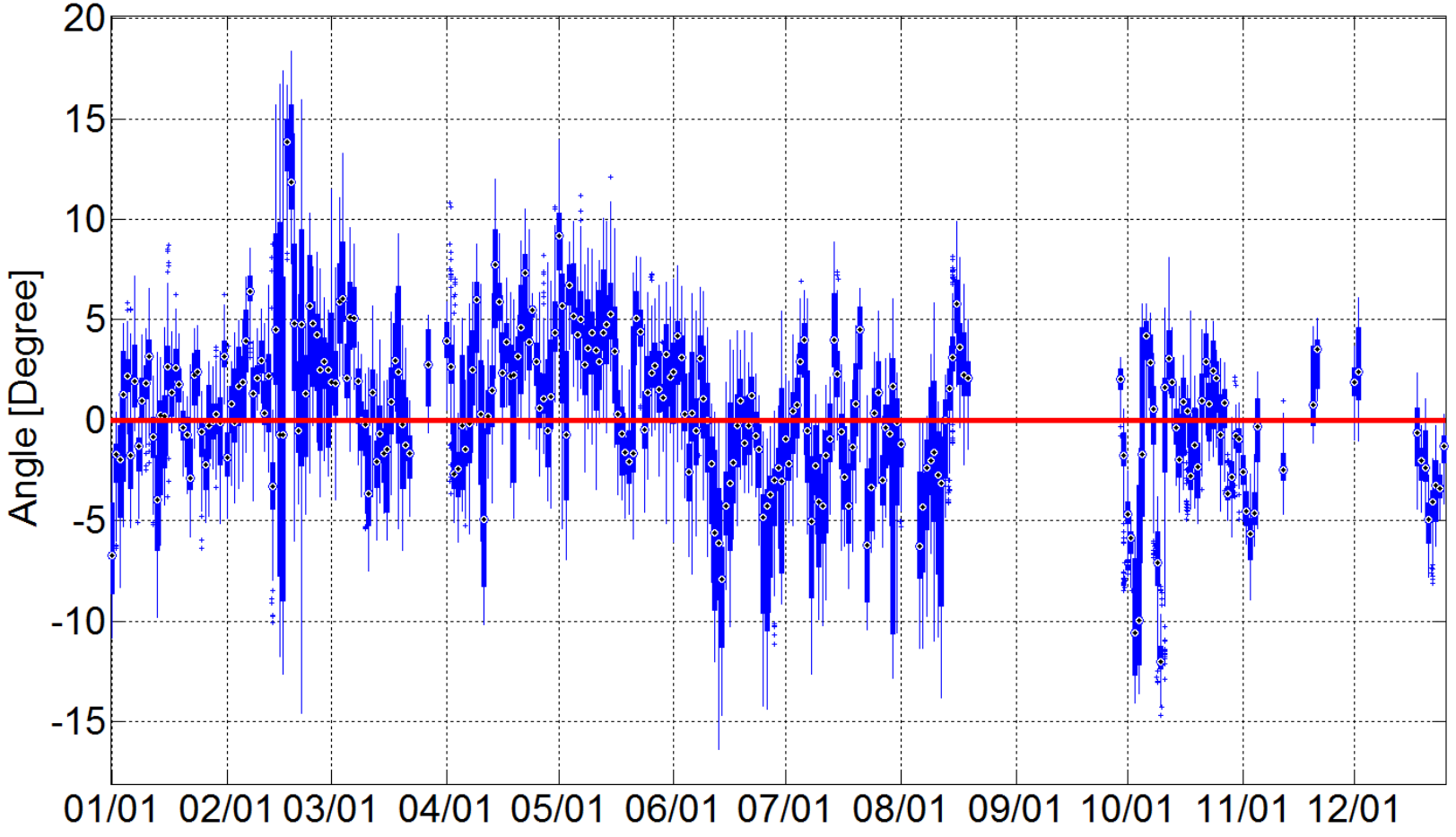

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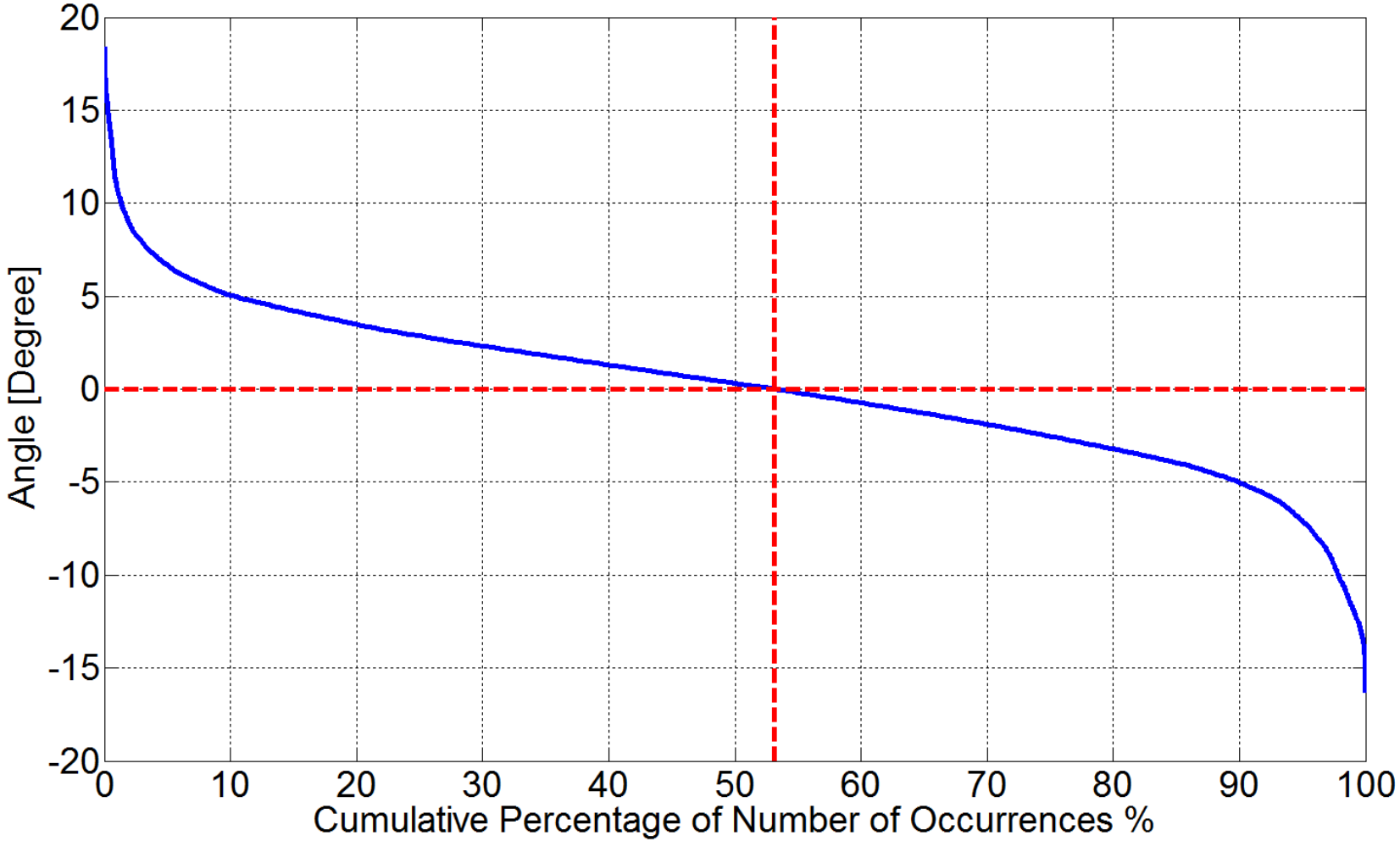

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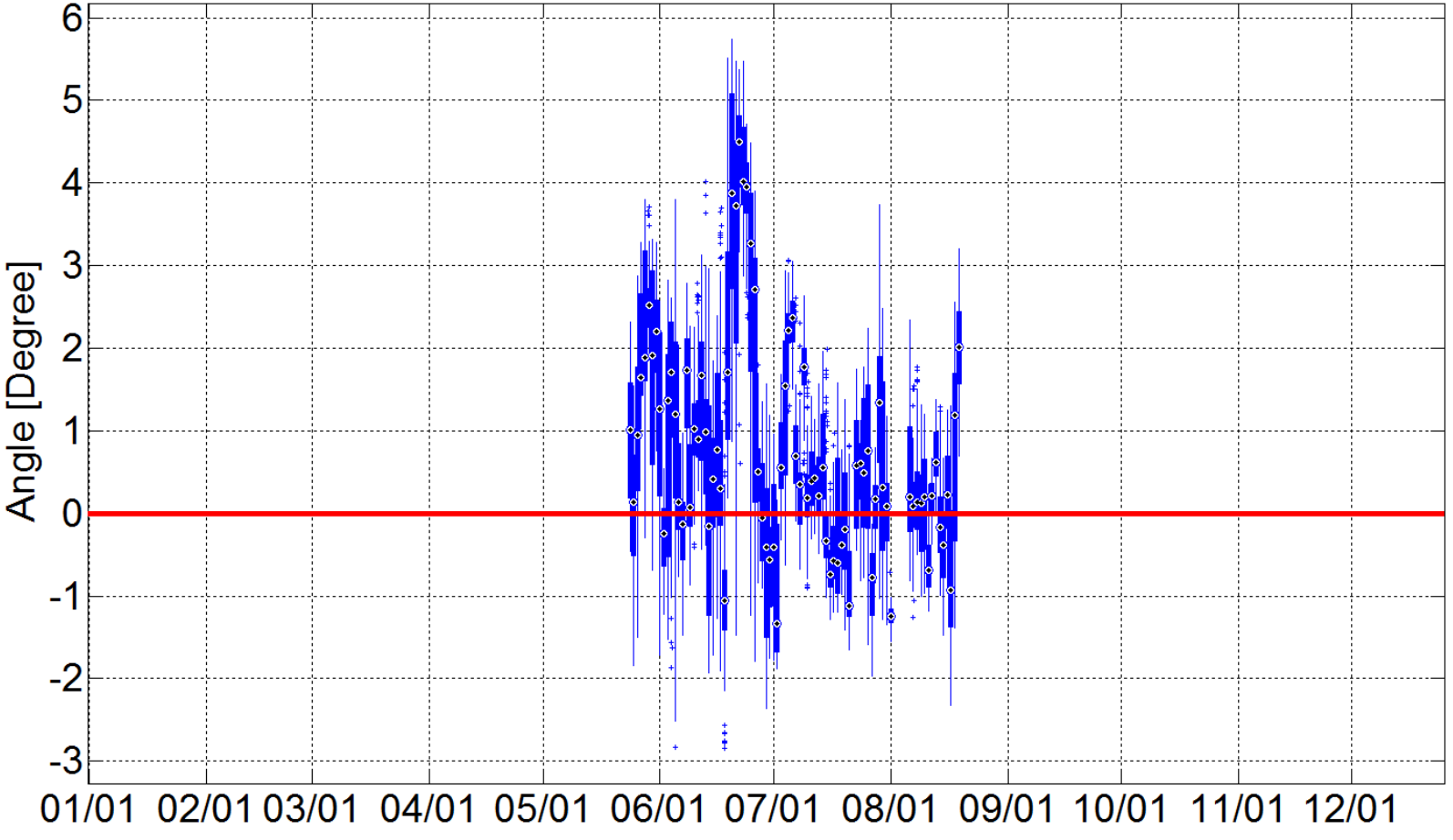

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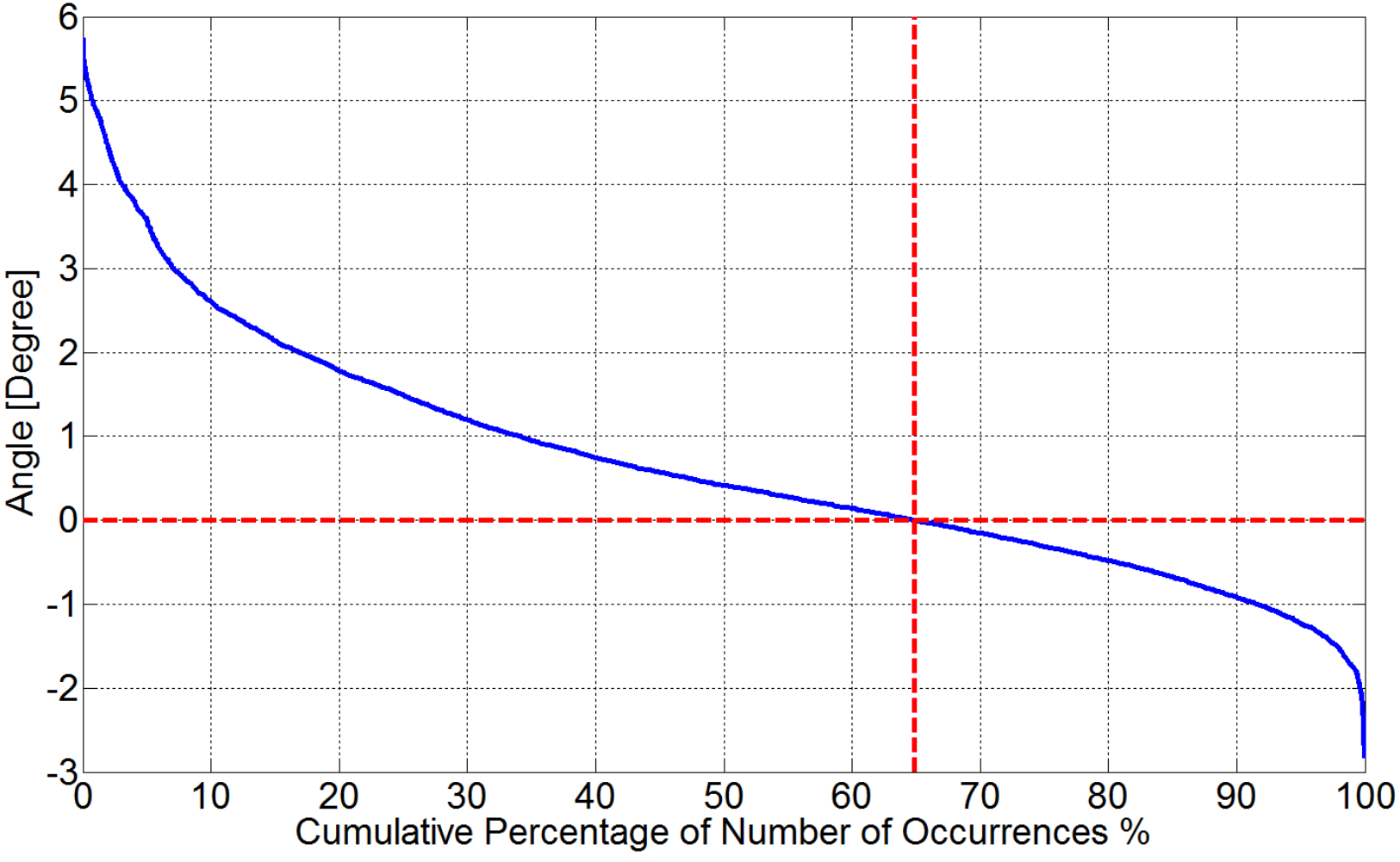

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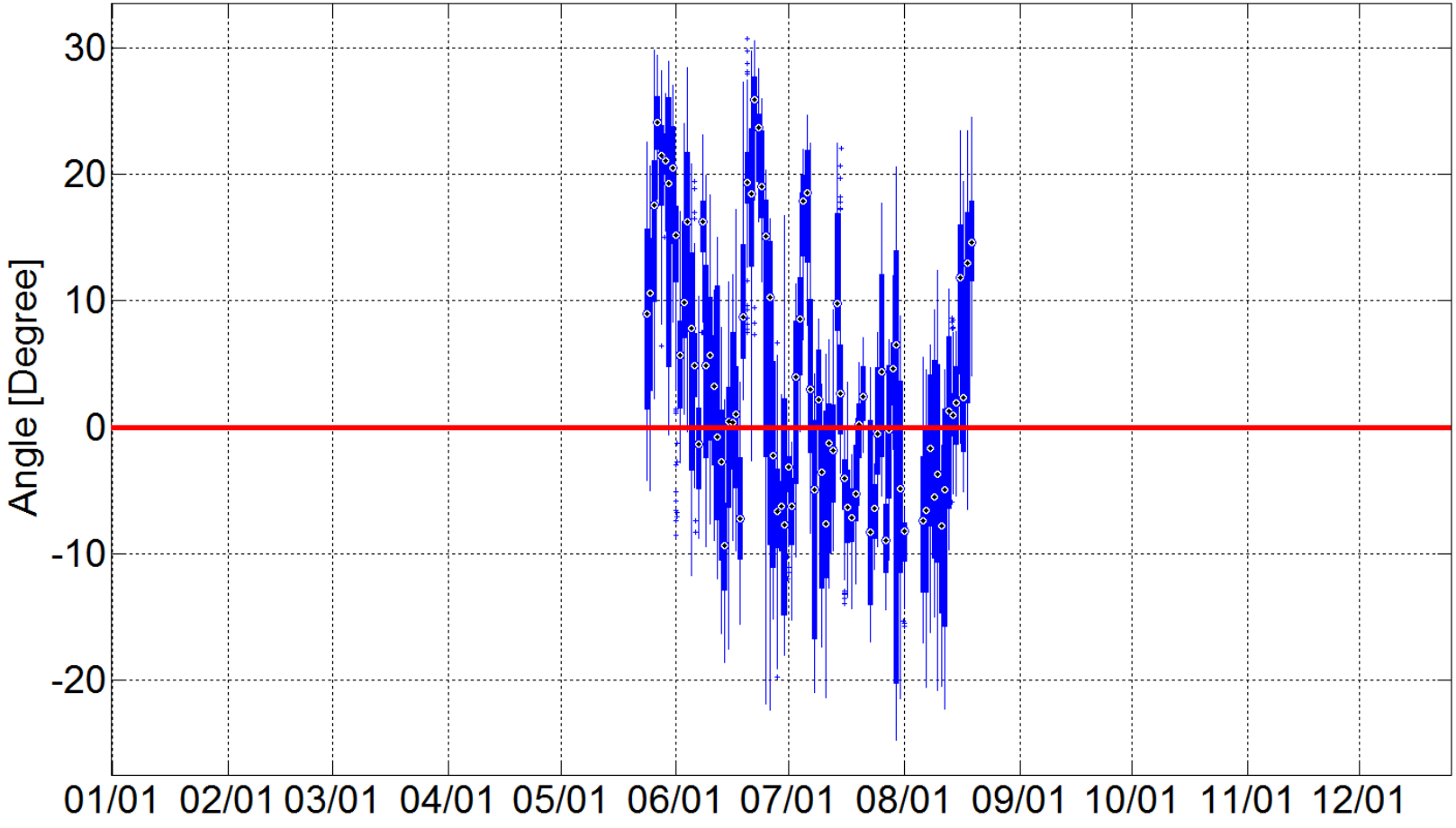

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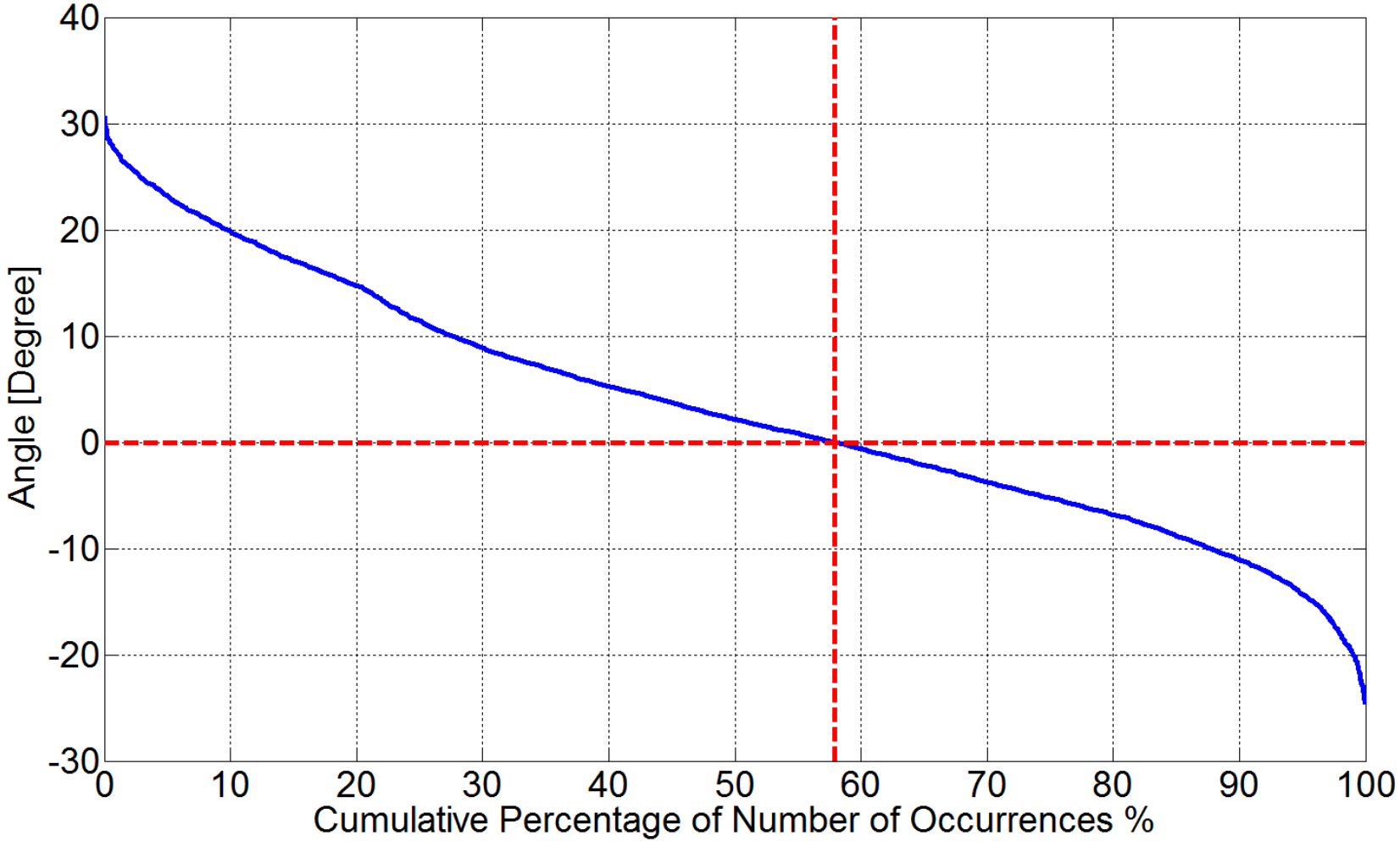
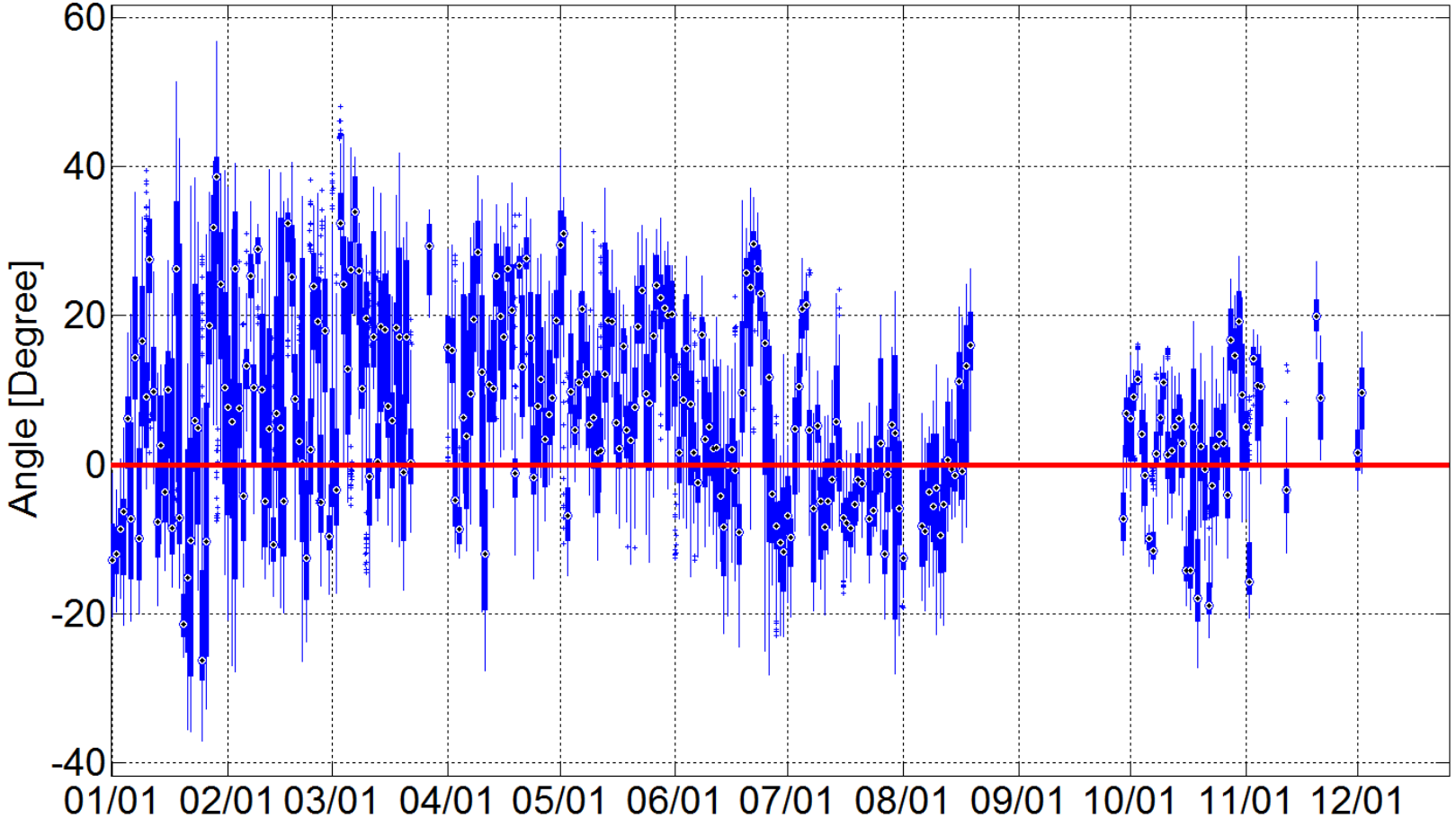


FarWest 7-South 9*



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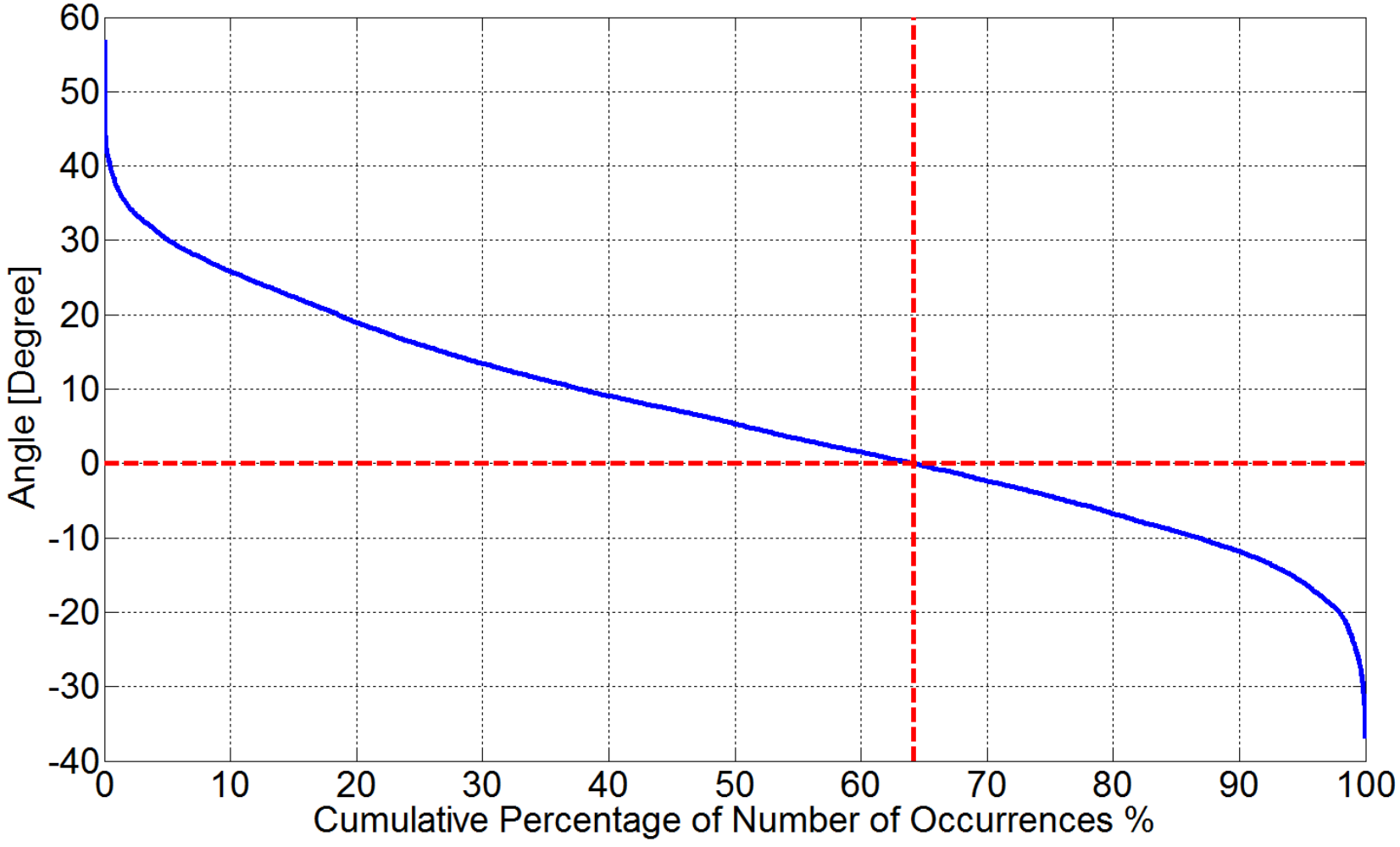

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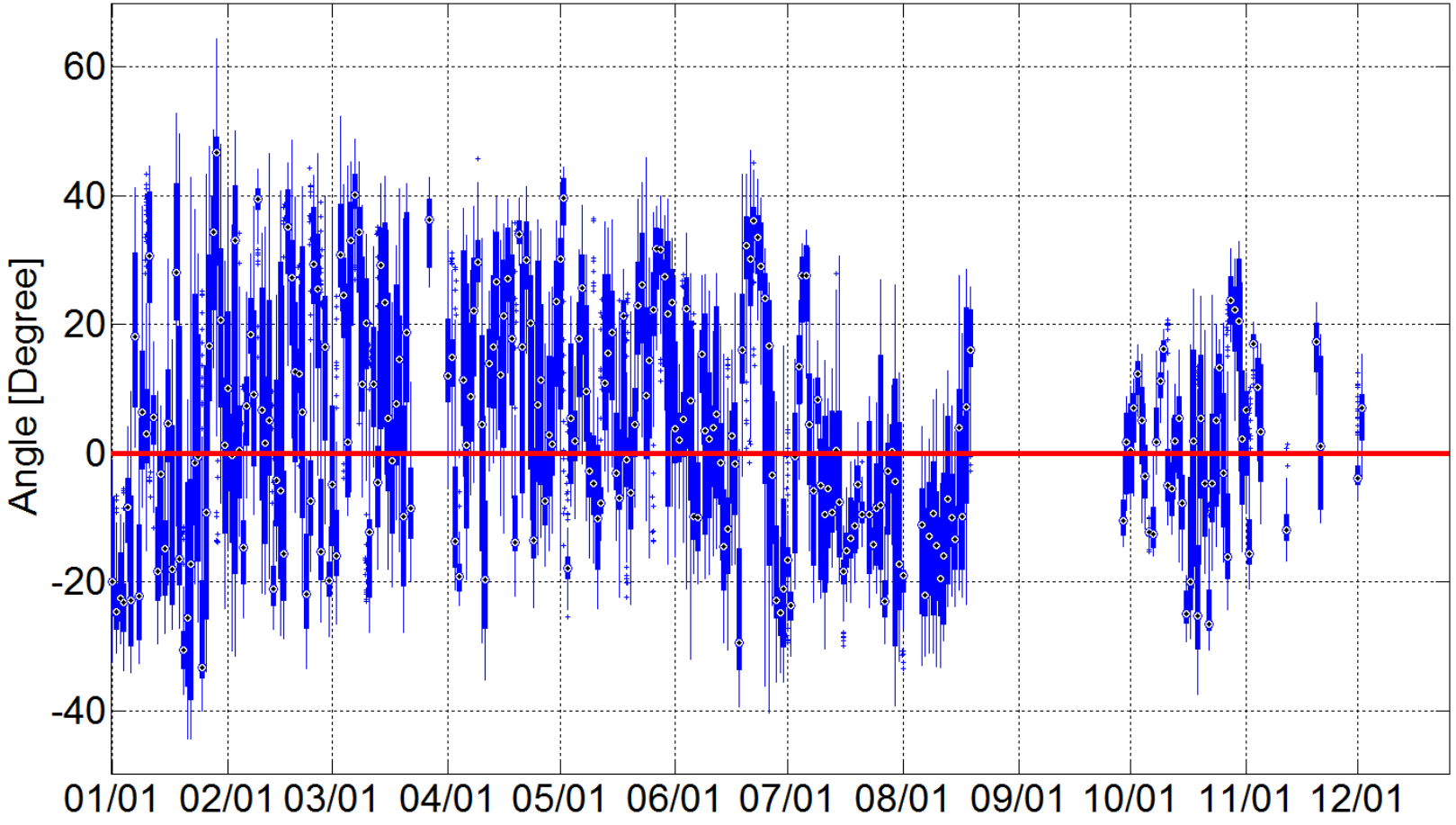

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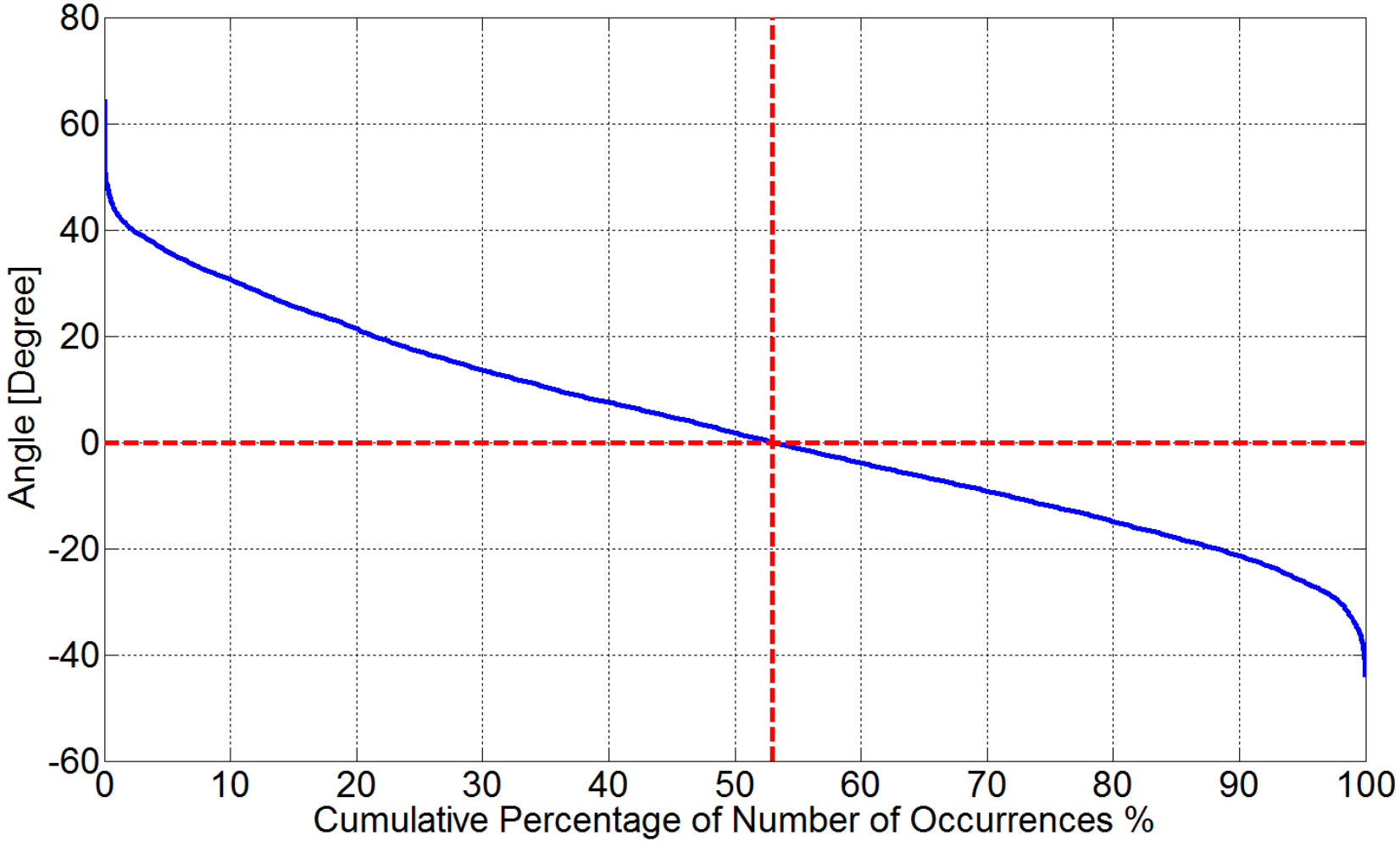


Appendix C – Part 2
CCET Discovery Across Texas project

Baseline Analysis Update – Angle Differences

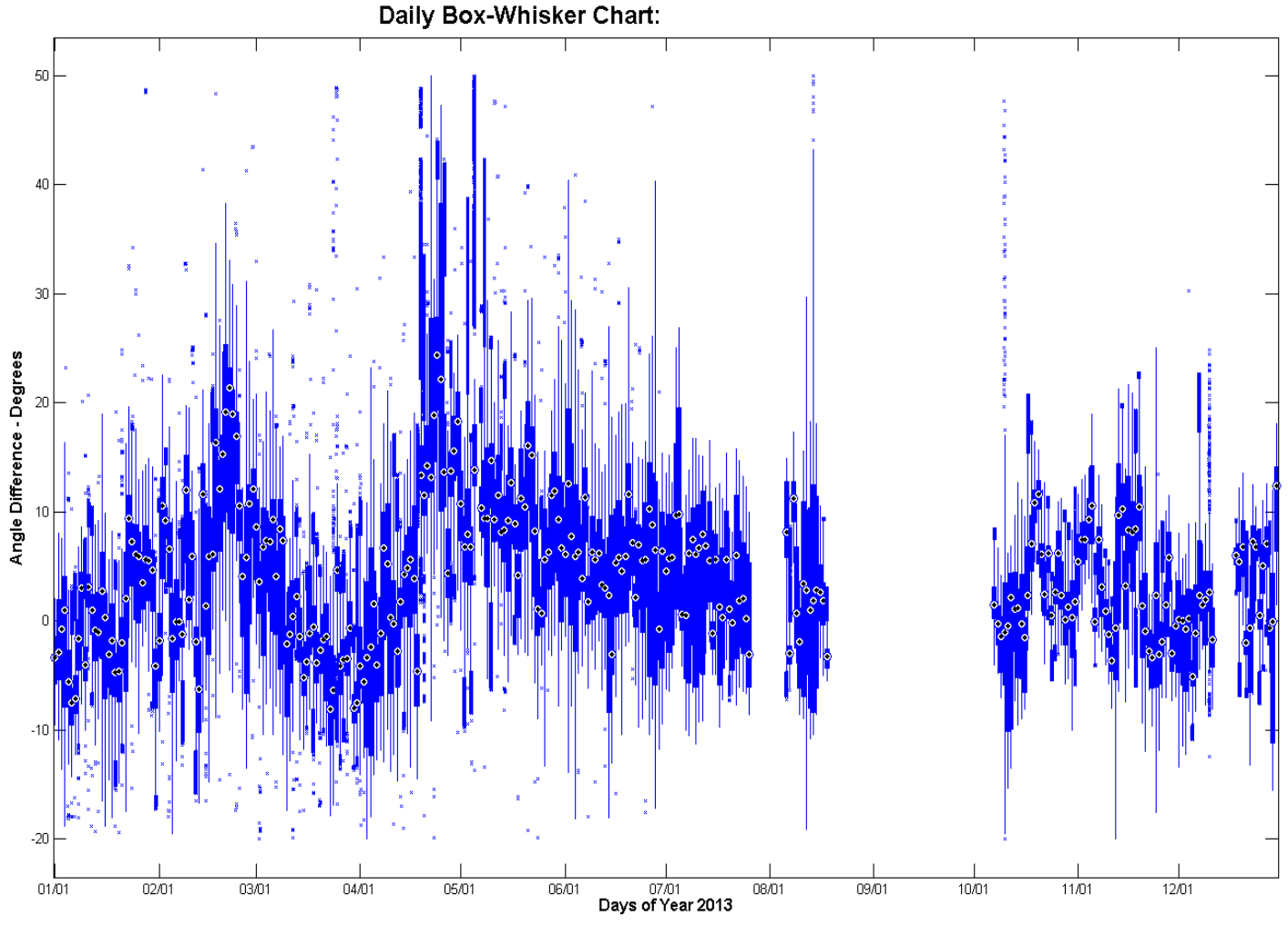
Phasor Data: January to December 2013
Box-Whisker Plots and Time Duration Curves

Electric Power Group

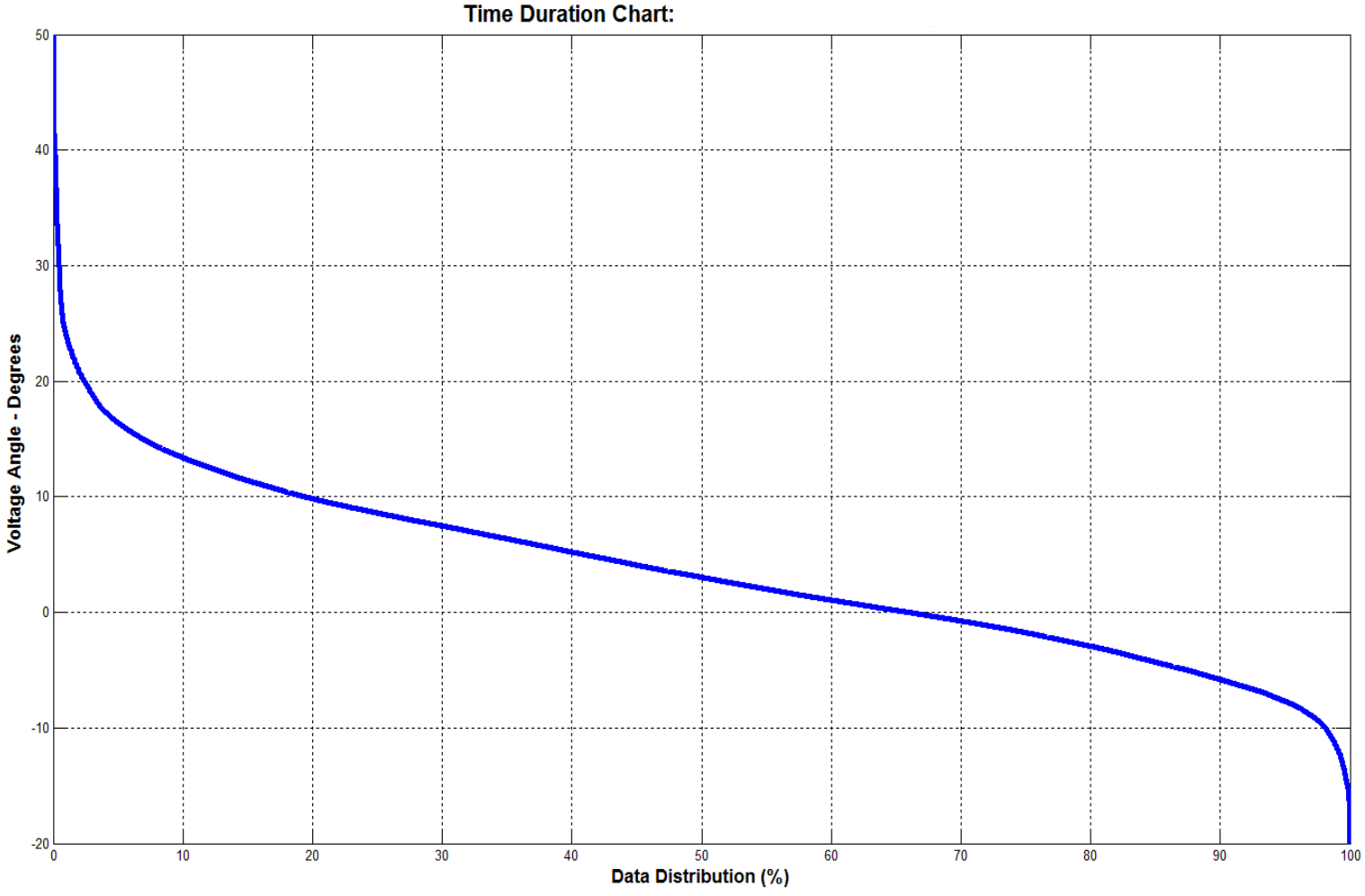
CCET

ERCOT

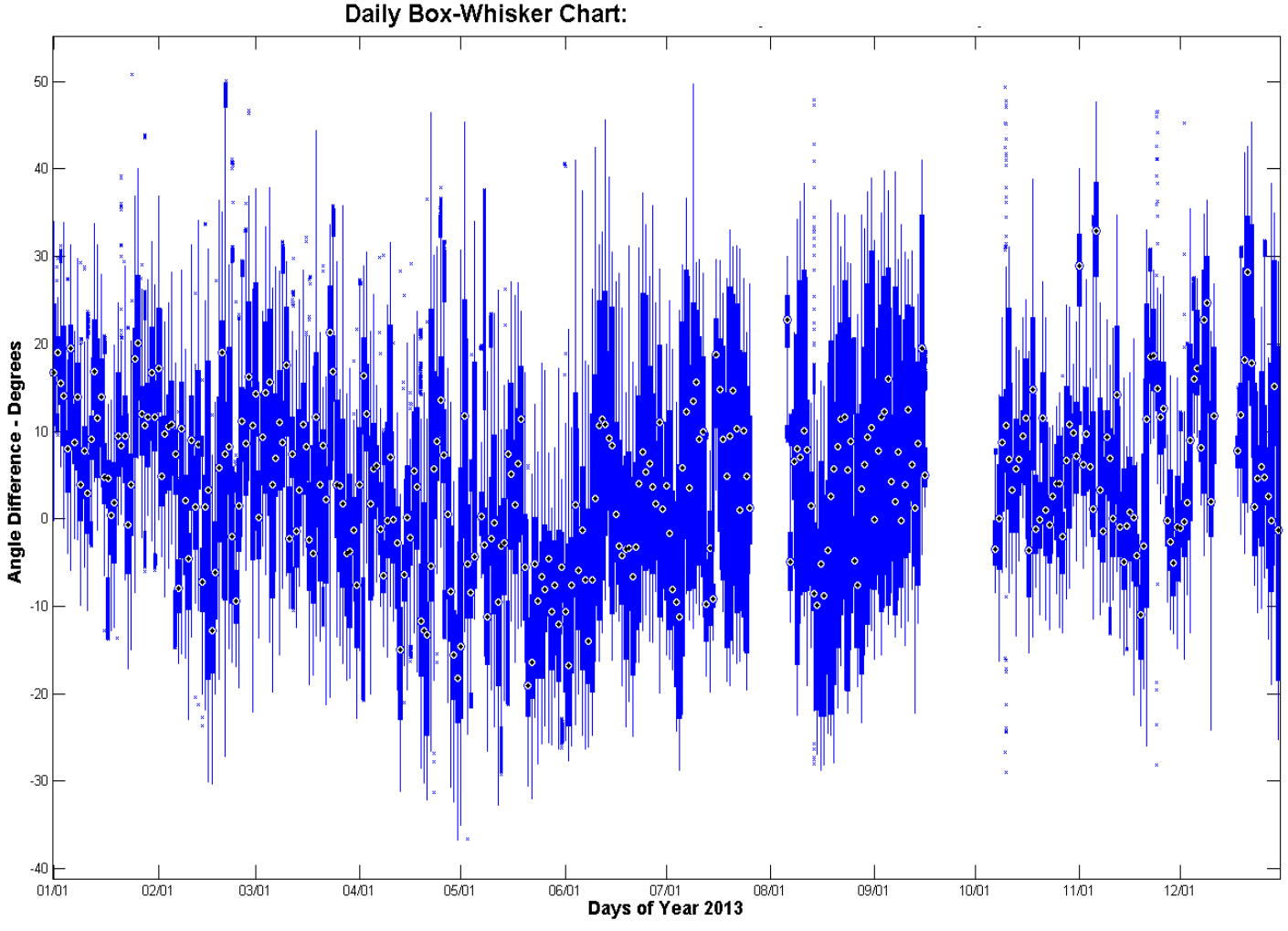
Coast 1-South 13



Coast 1-South 13



Coast 1-North 7



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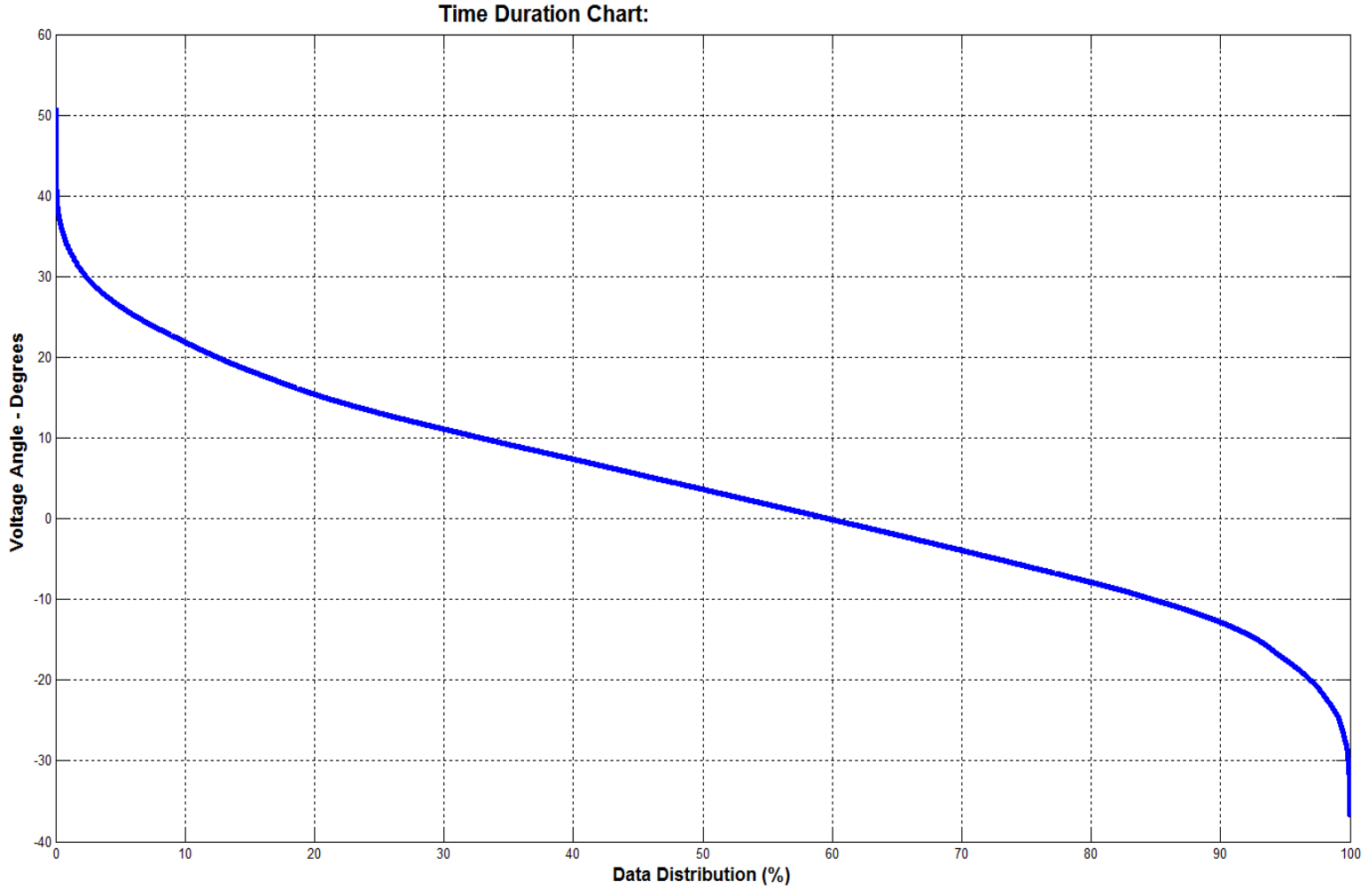

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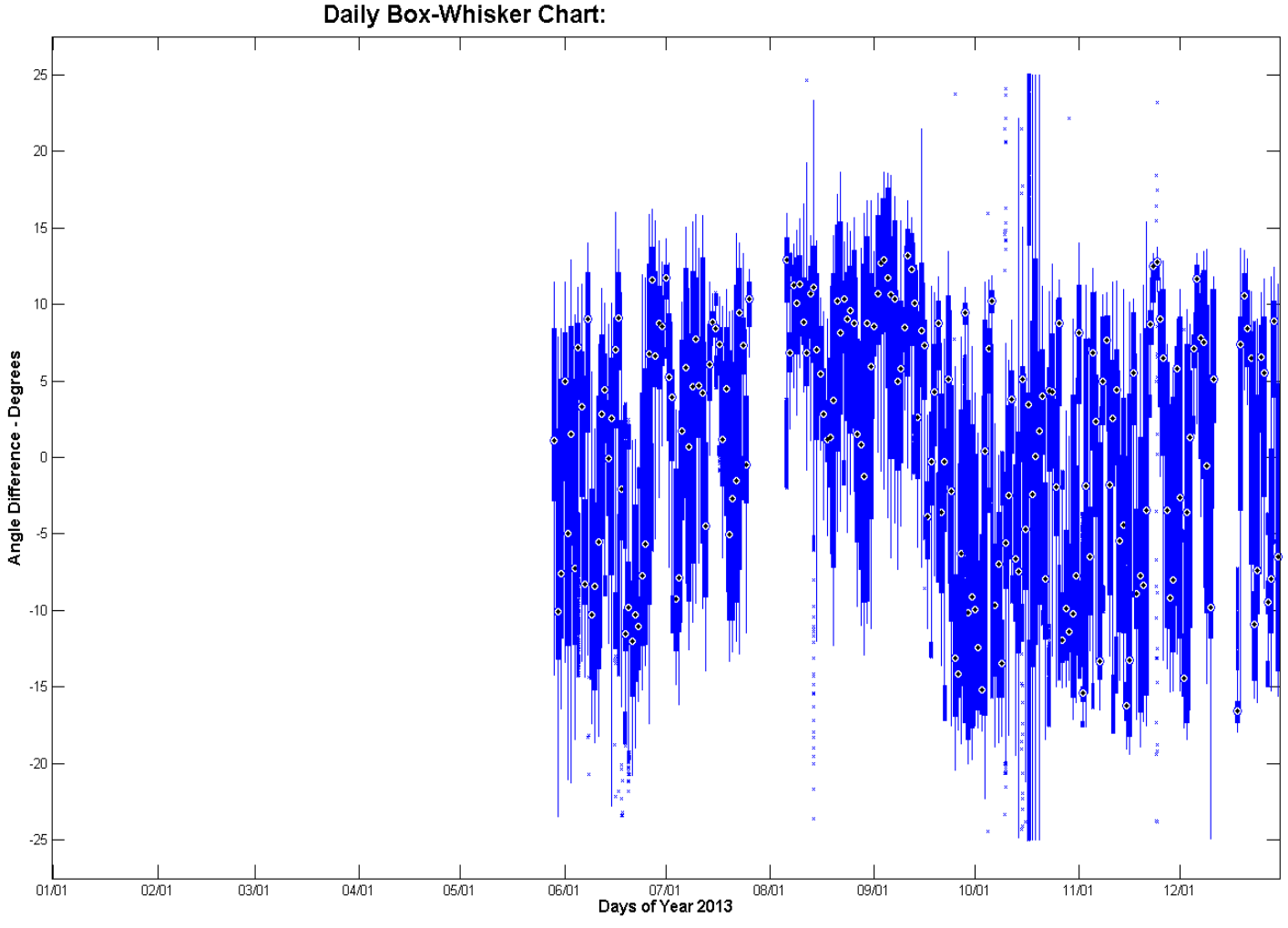

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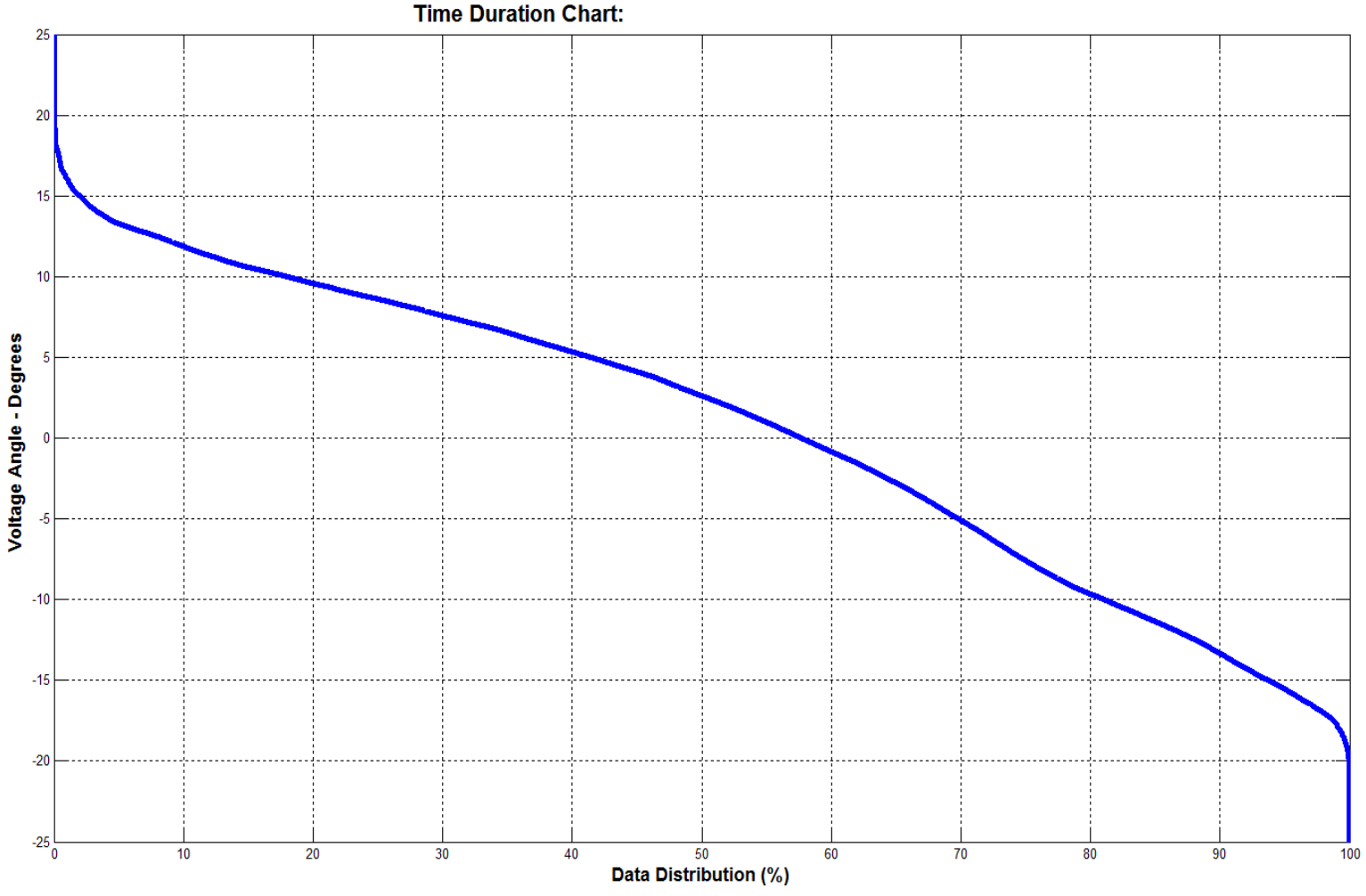

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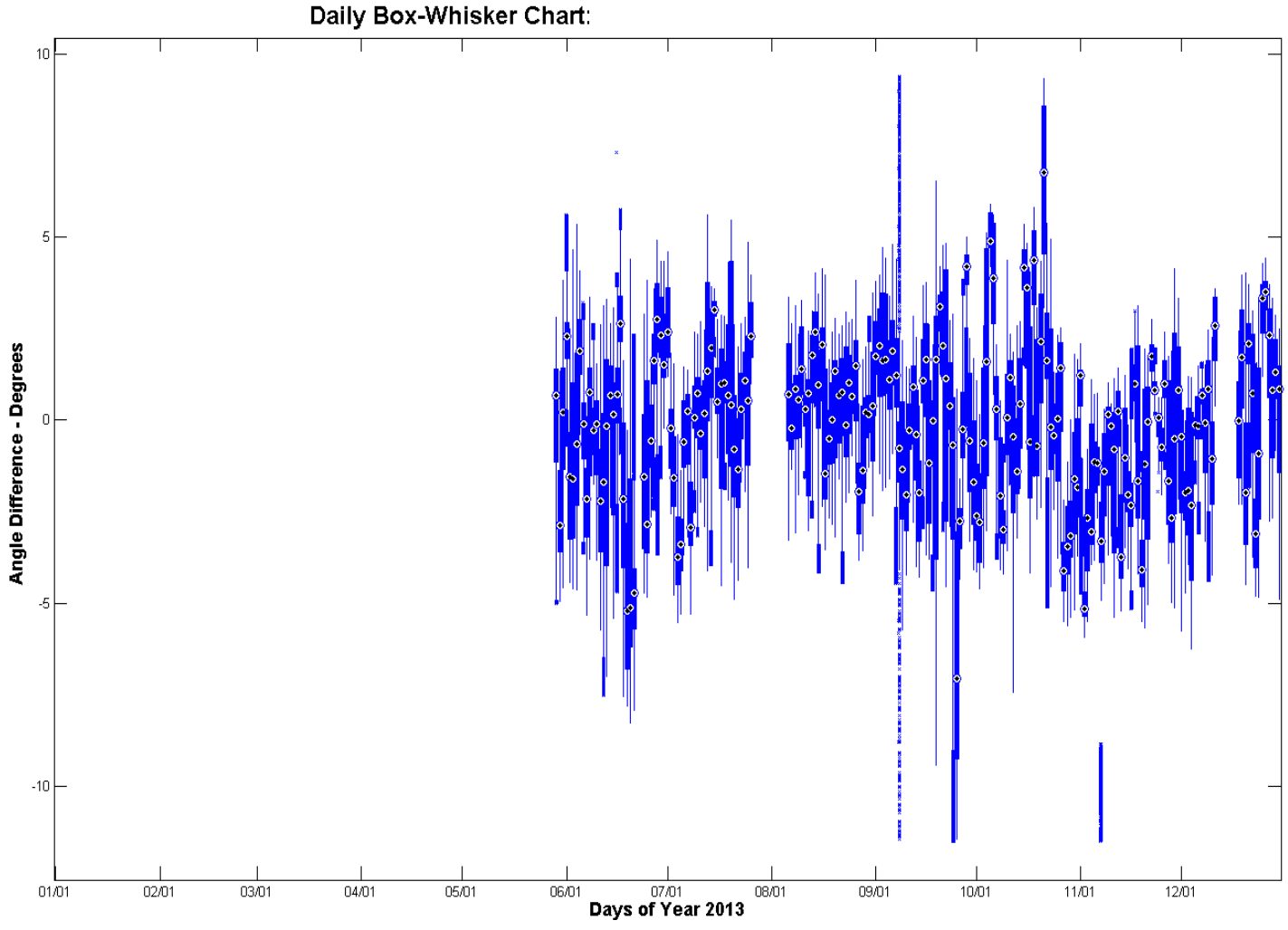

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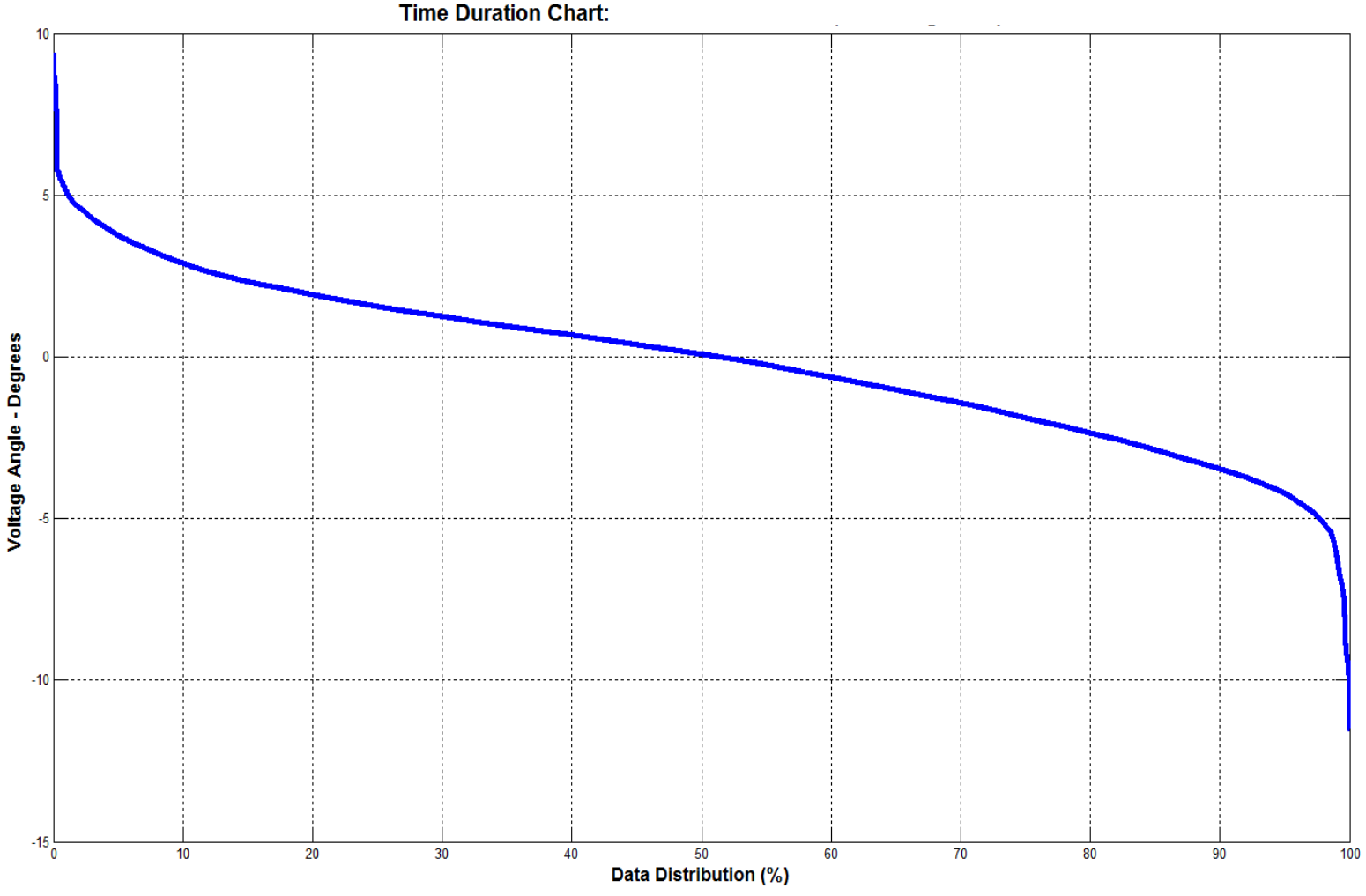

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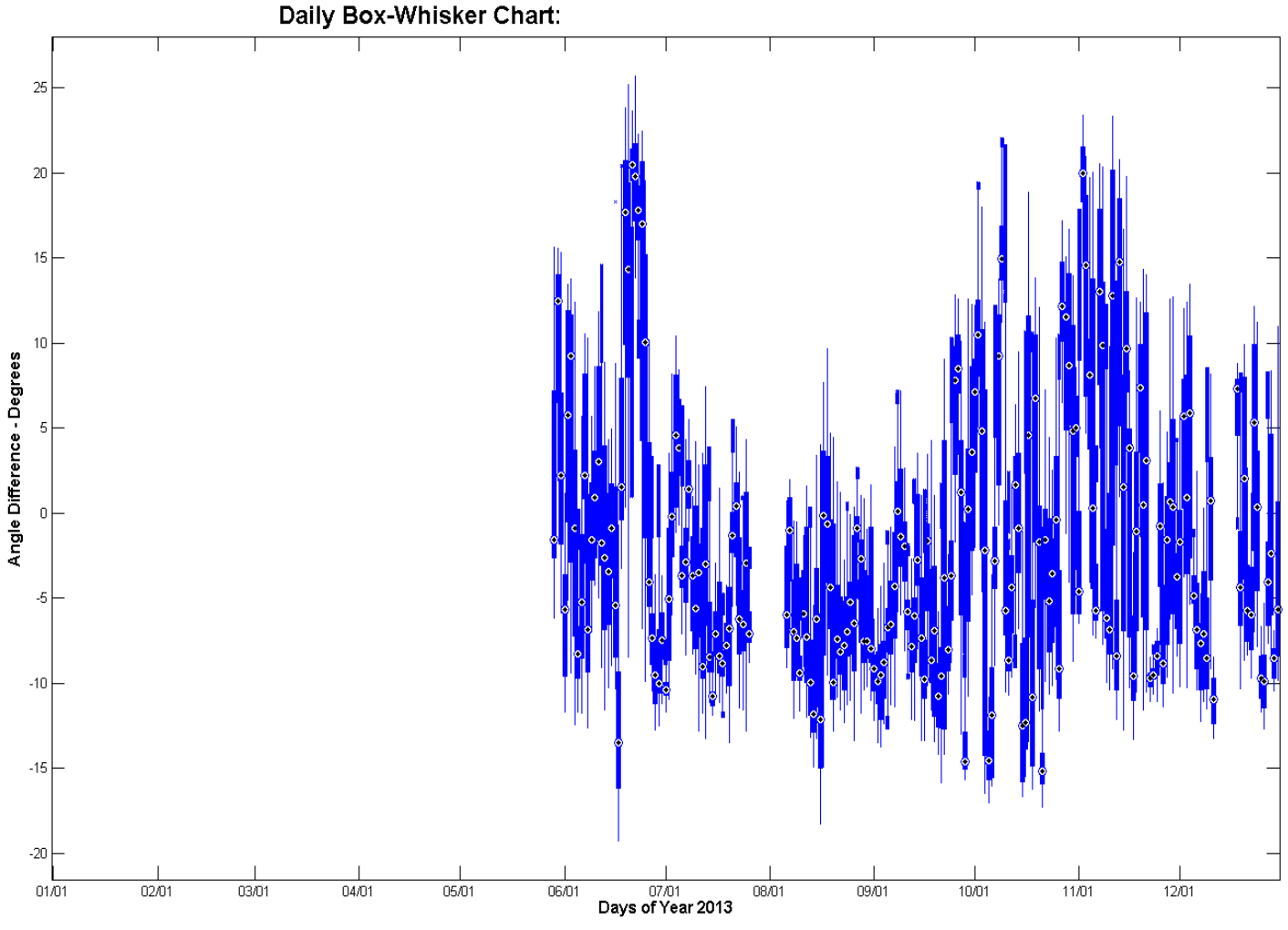

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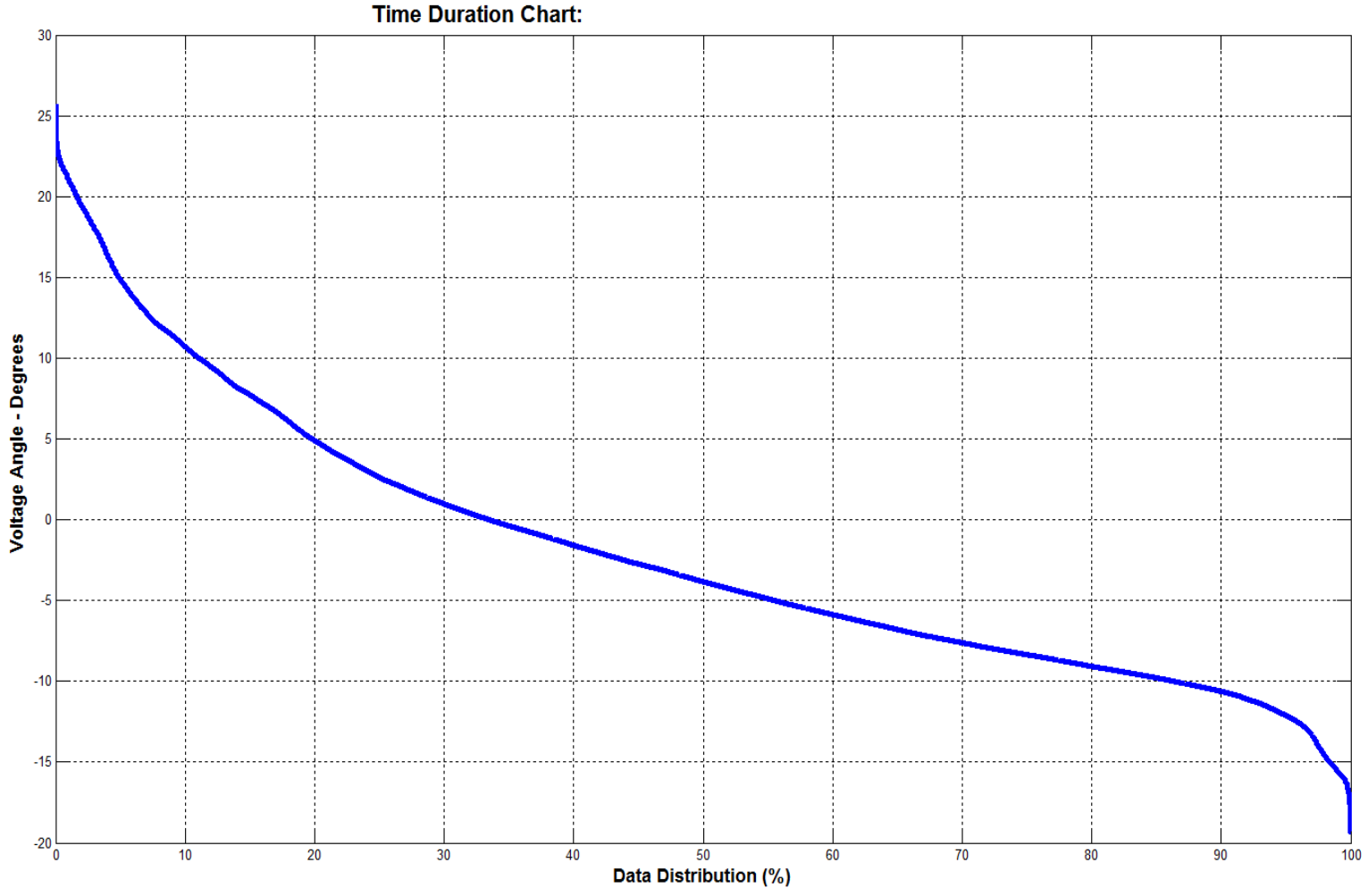

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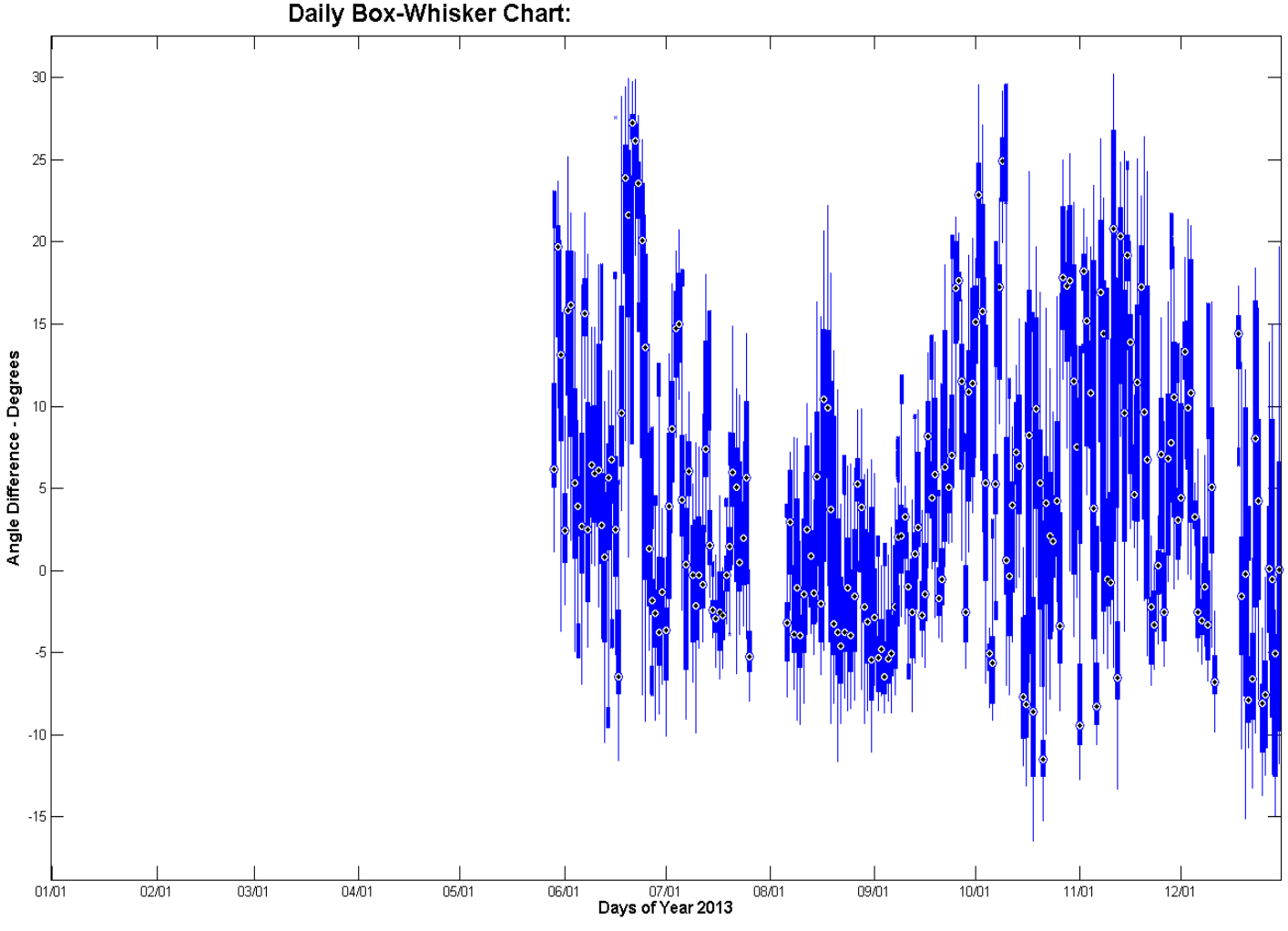

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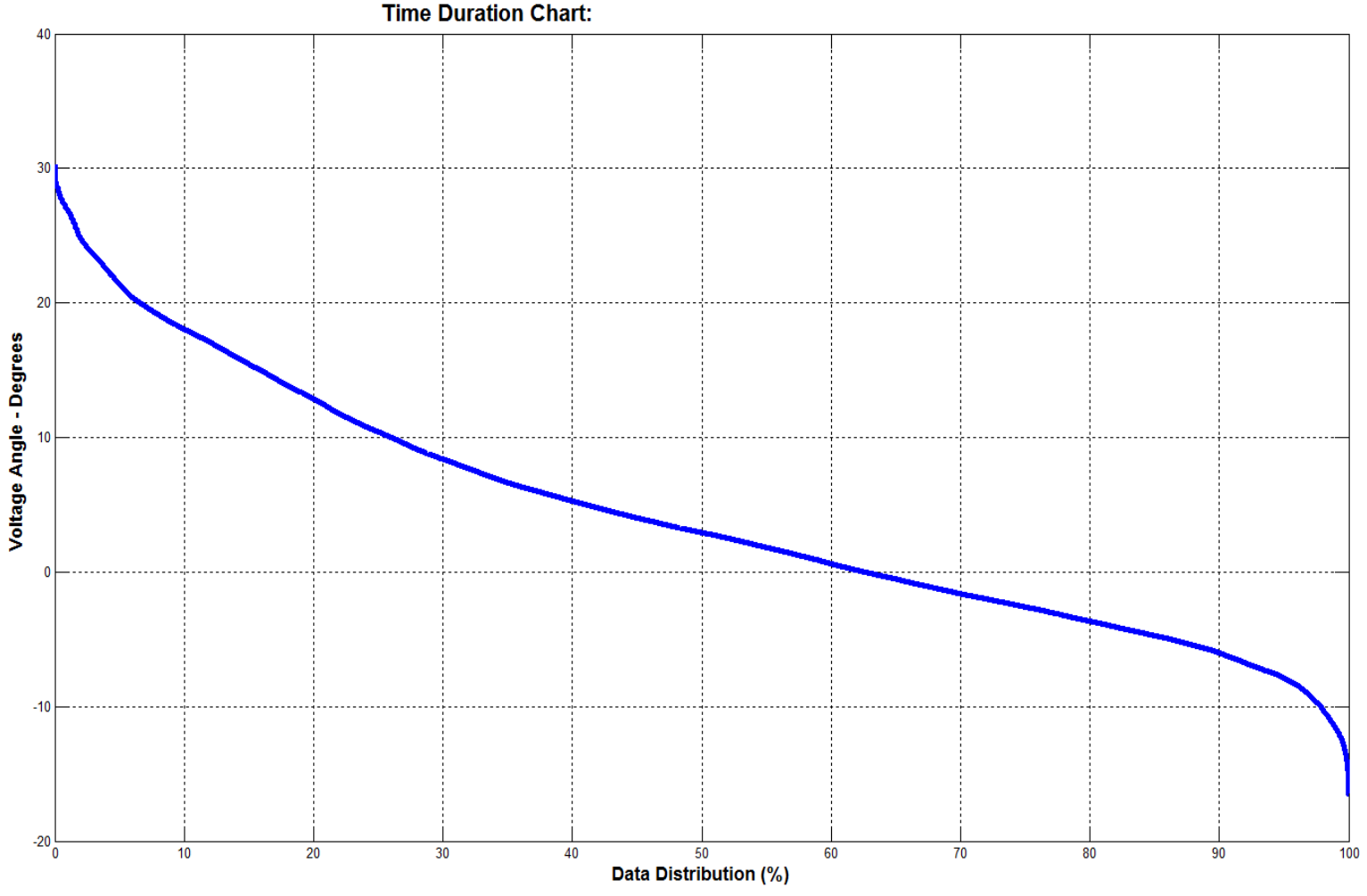

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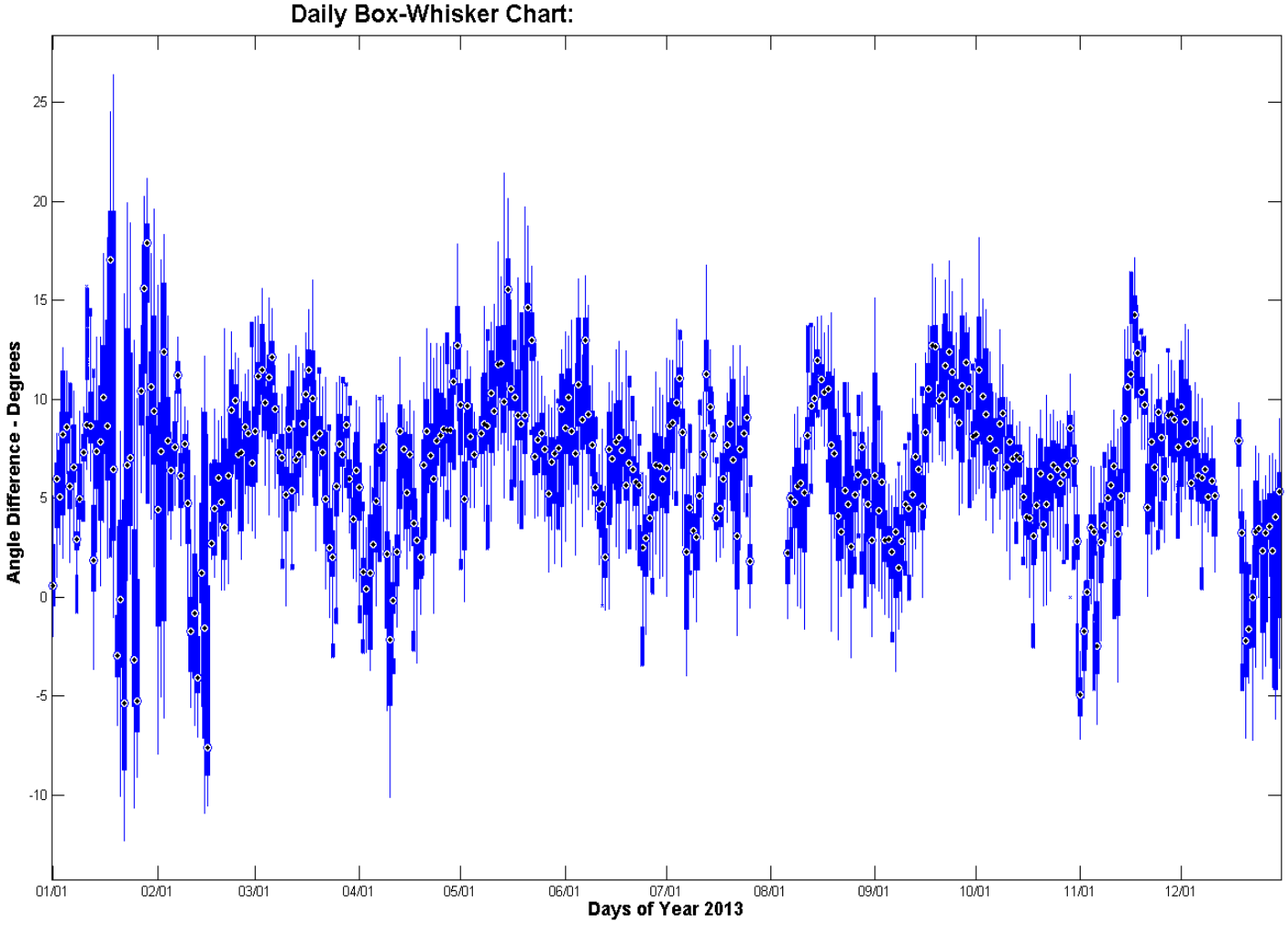

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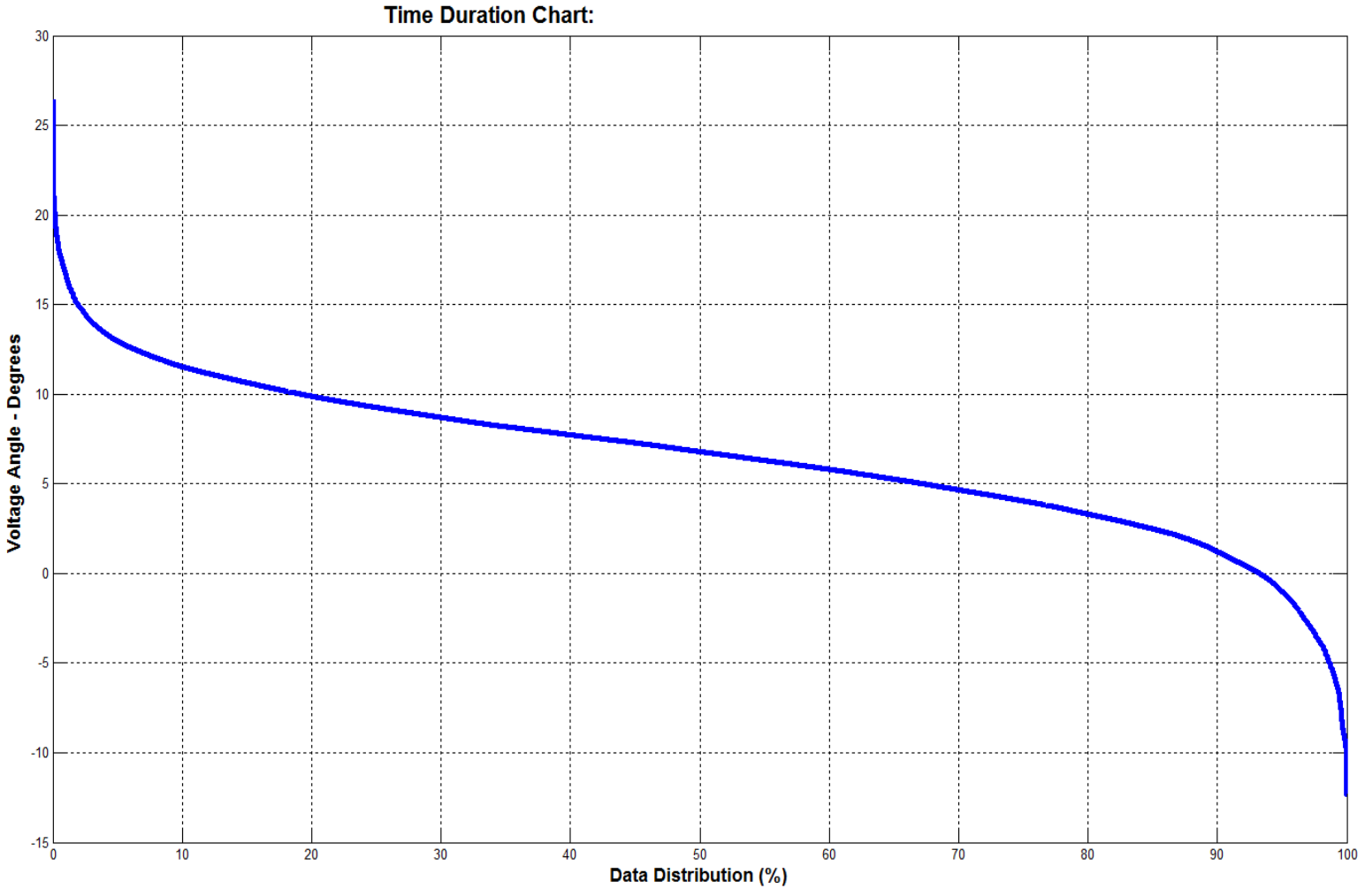

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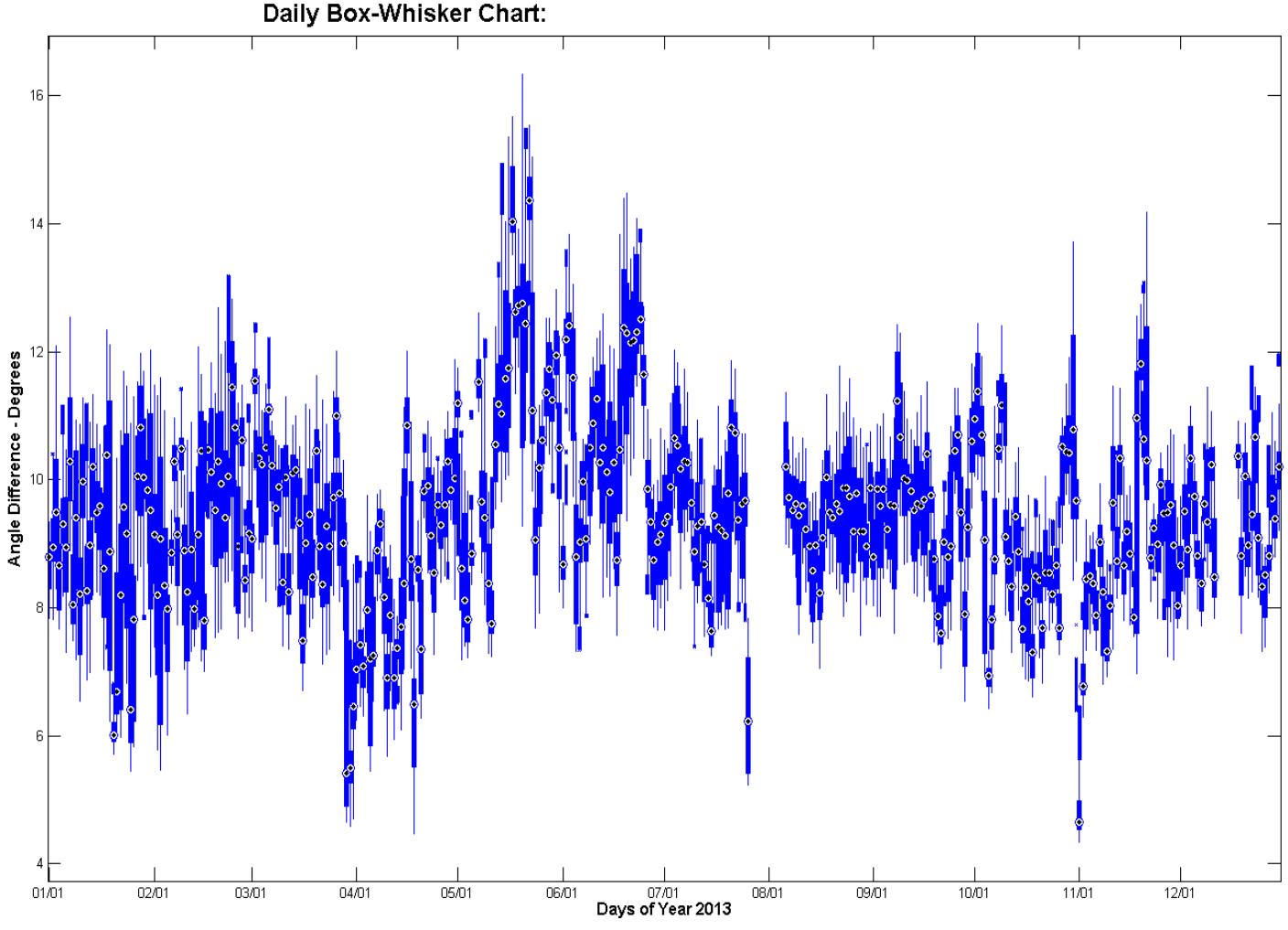

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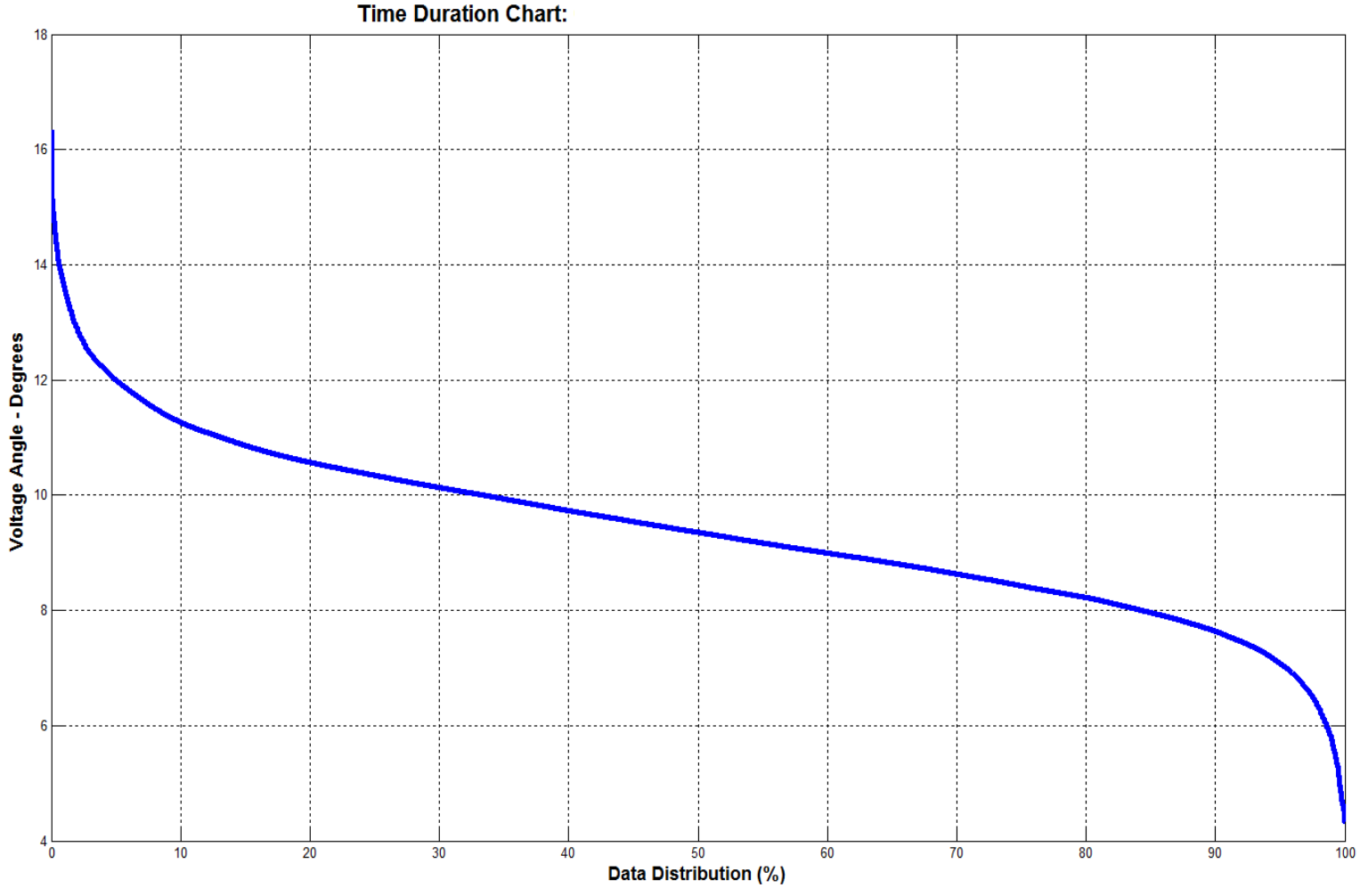

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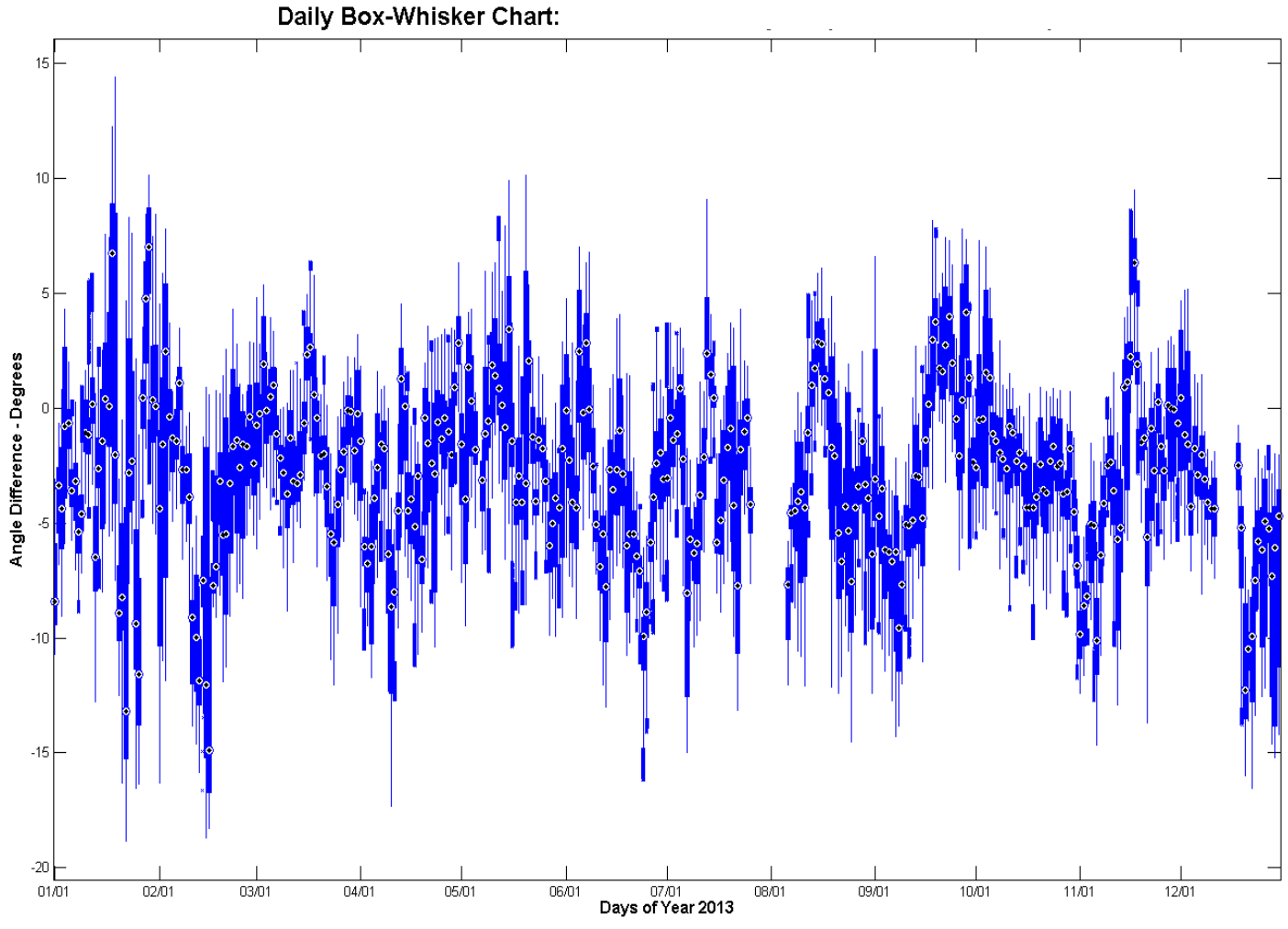

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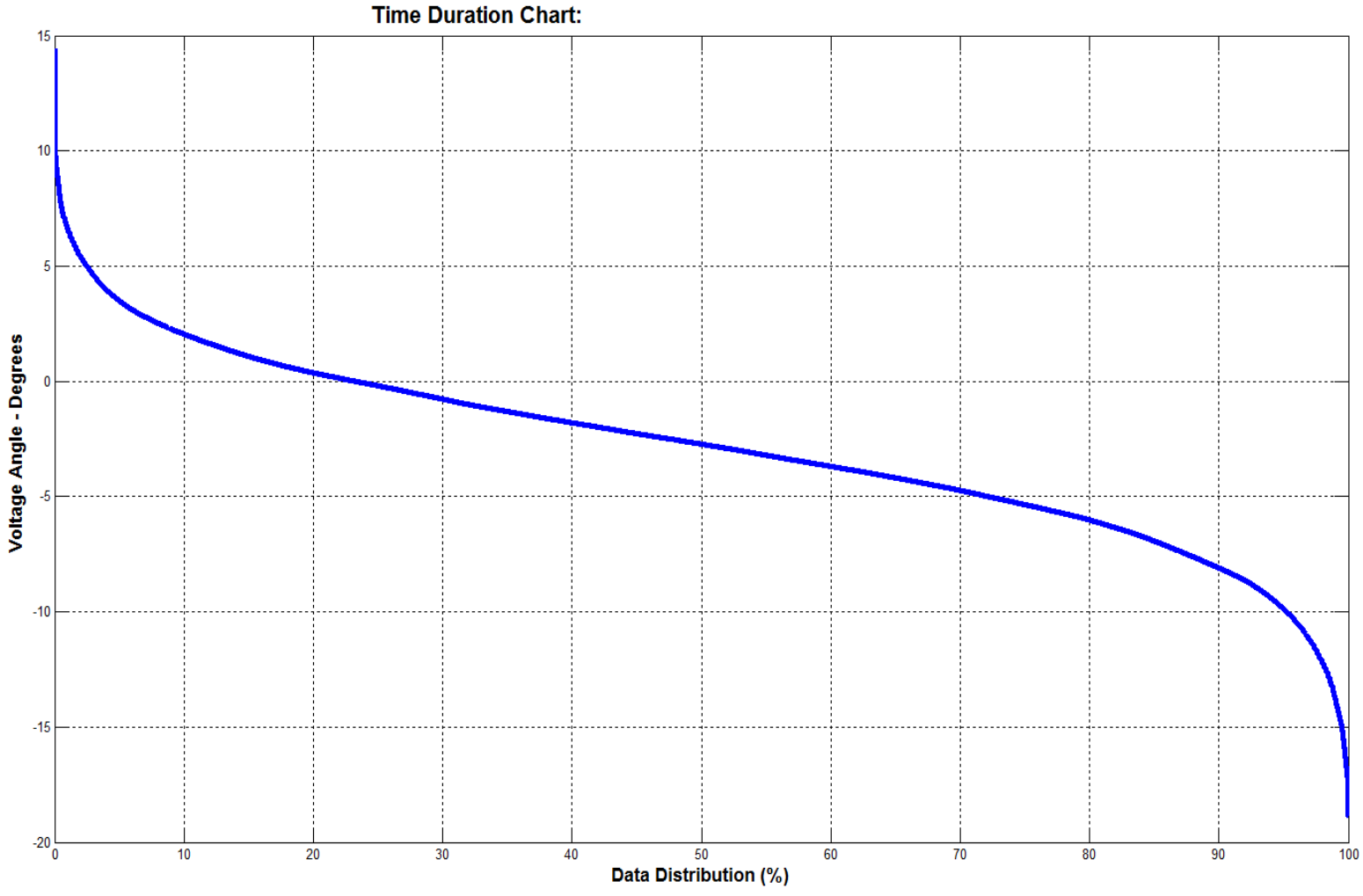

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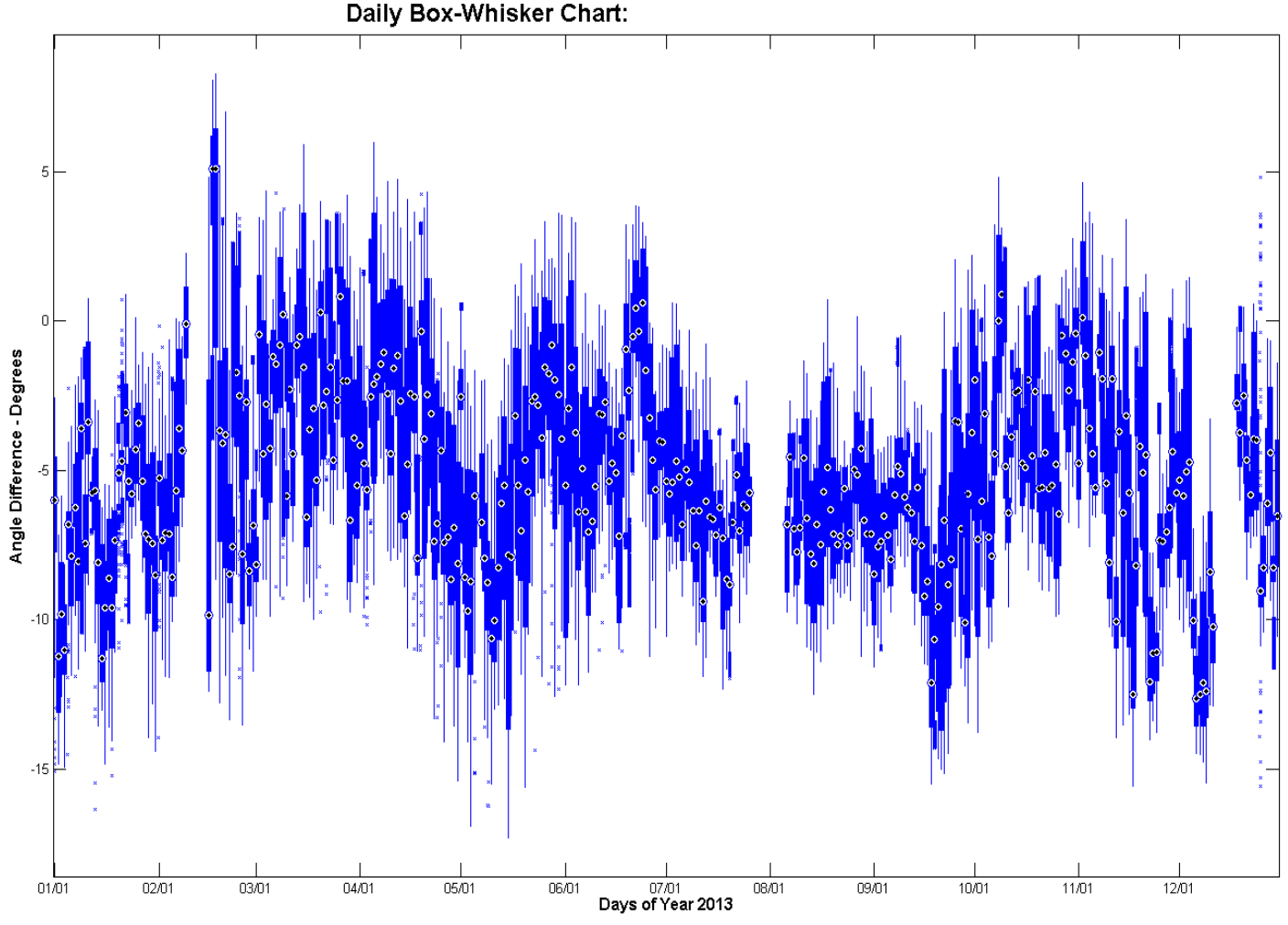

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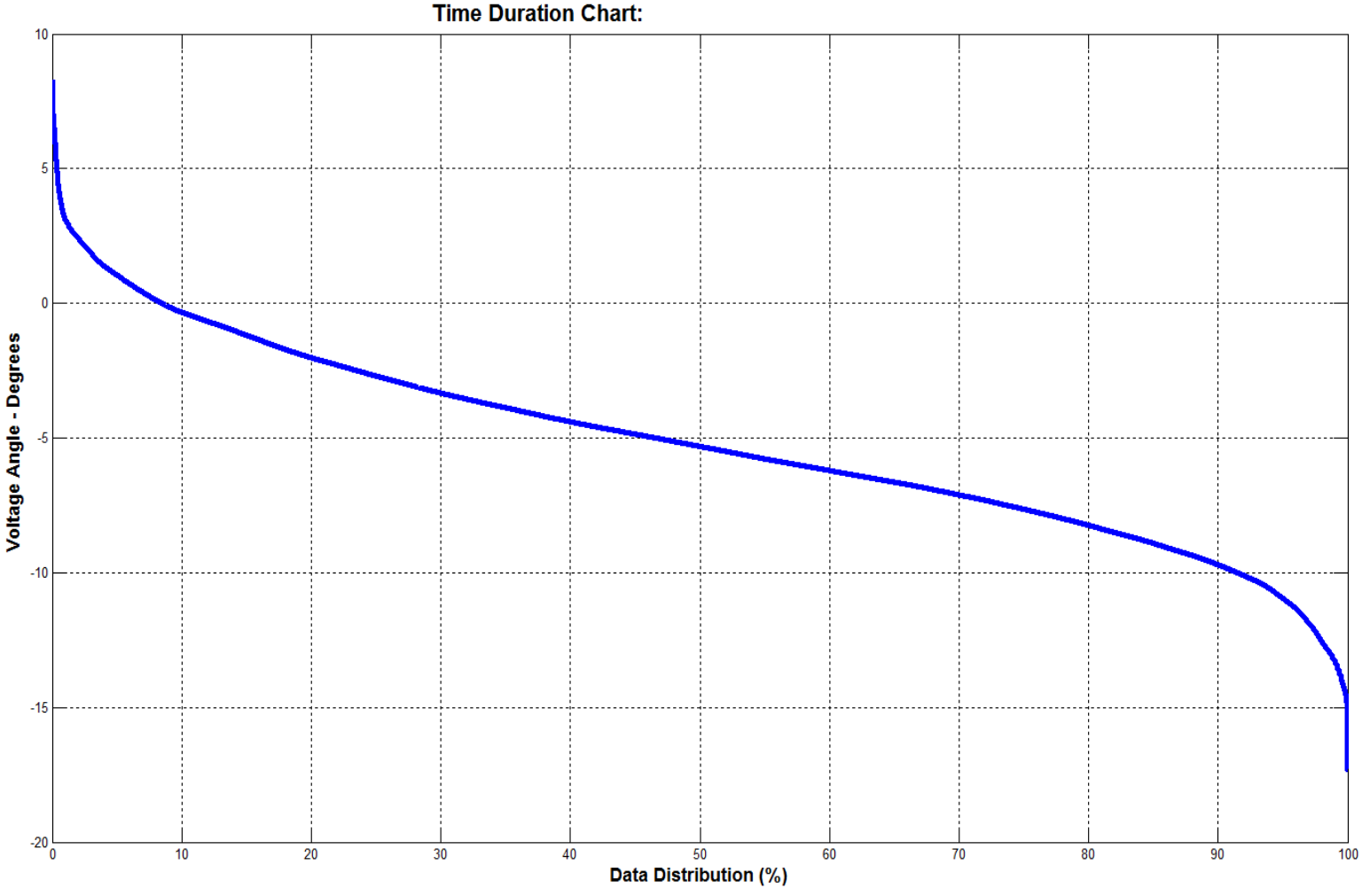

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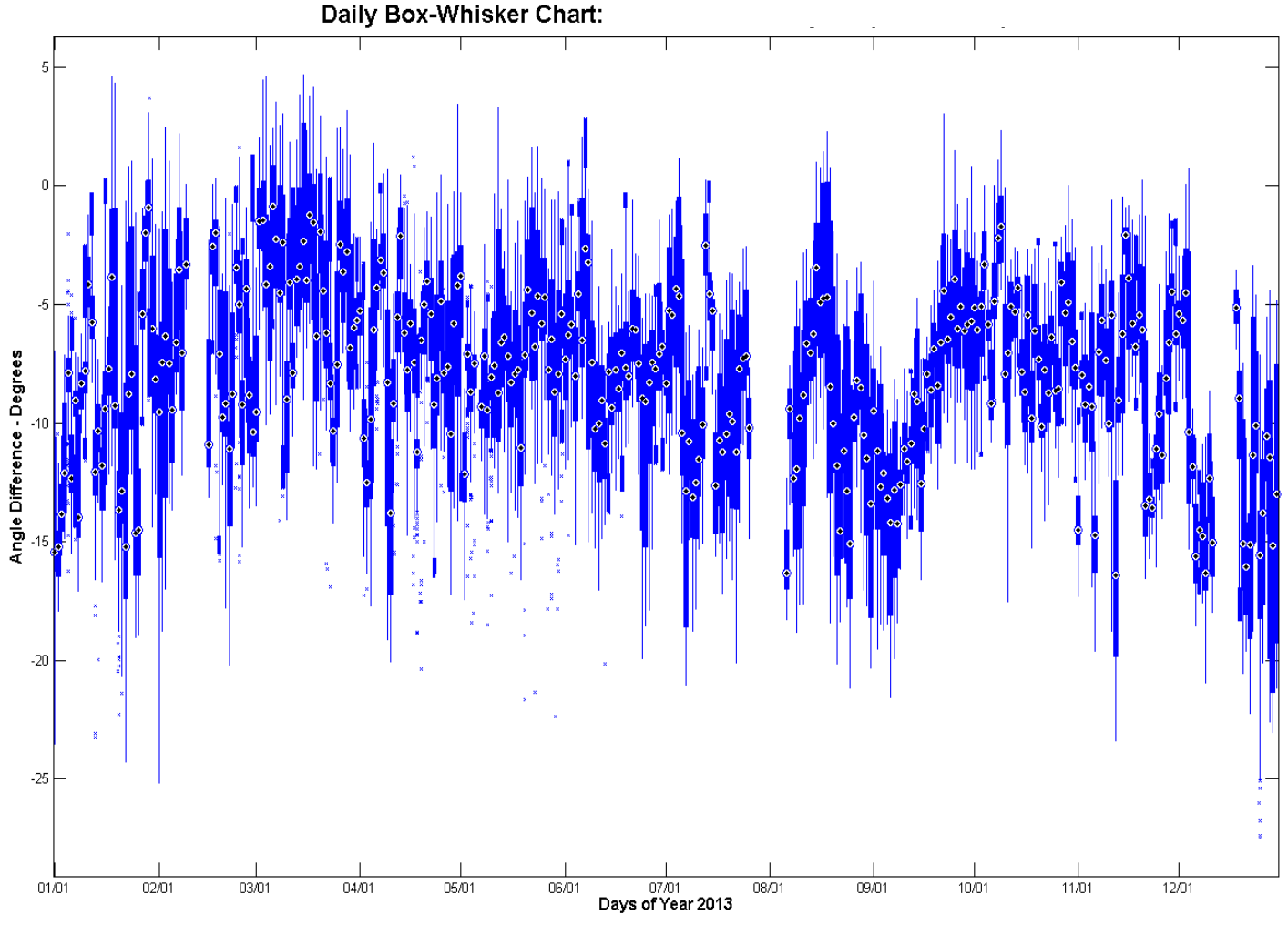

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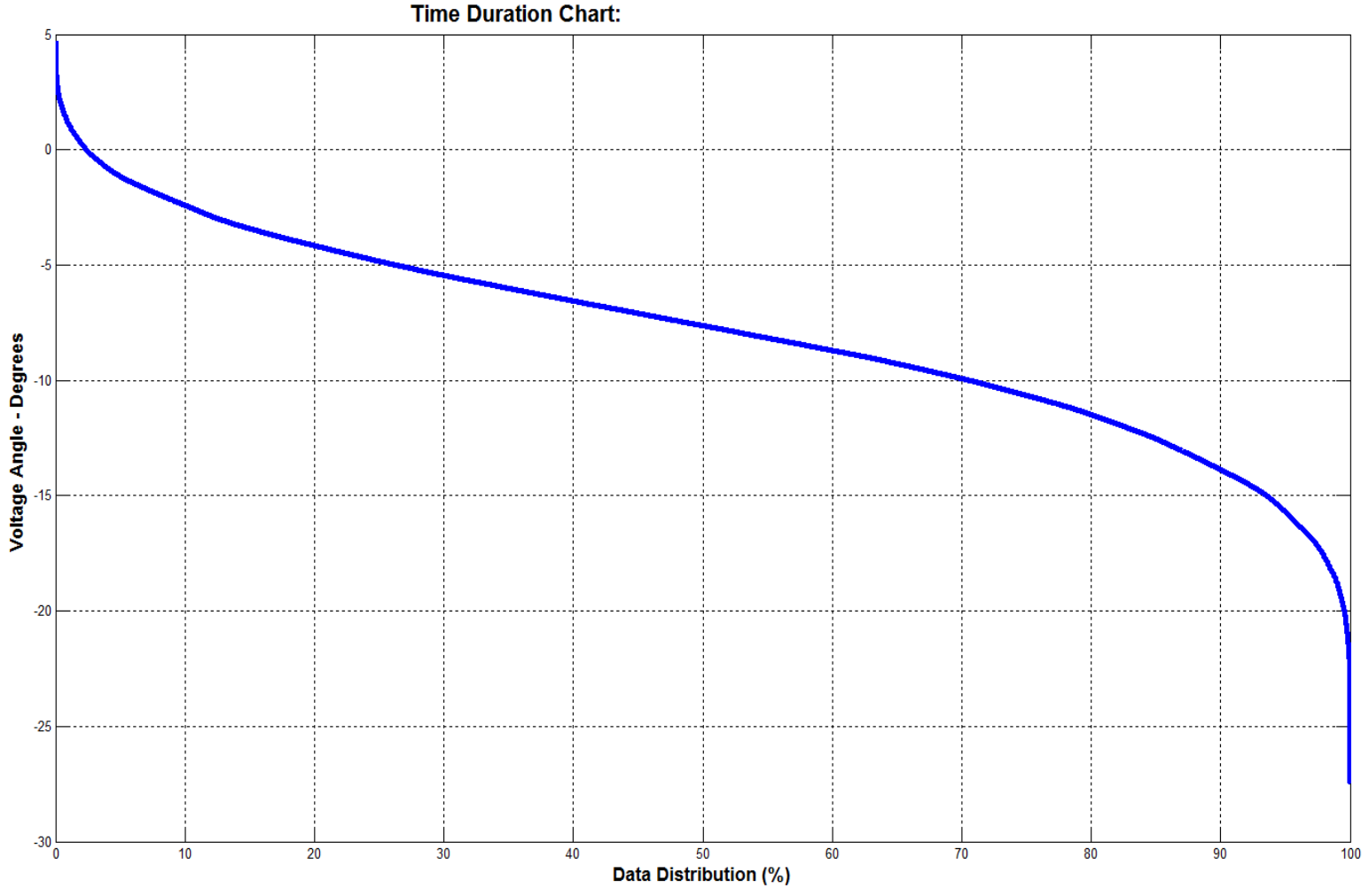

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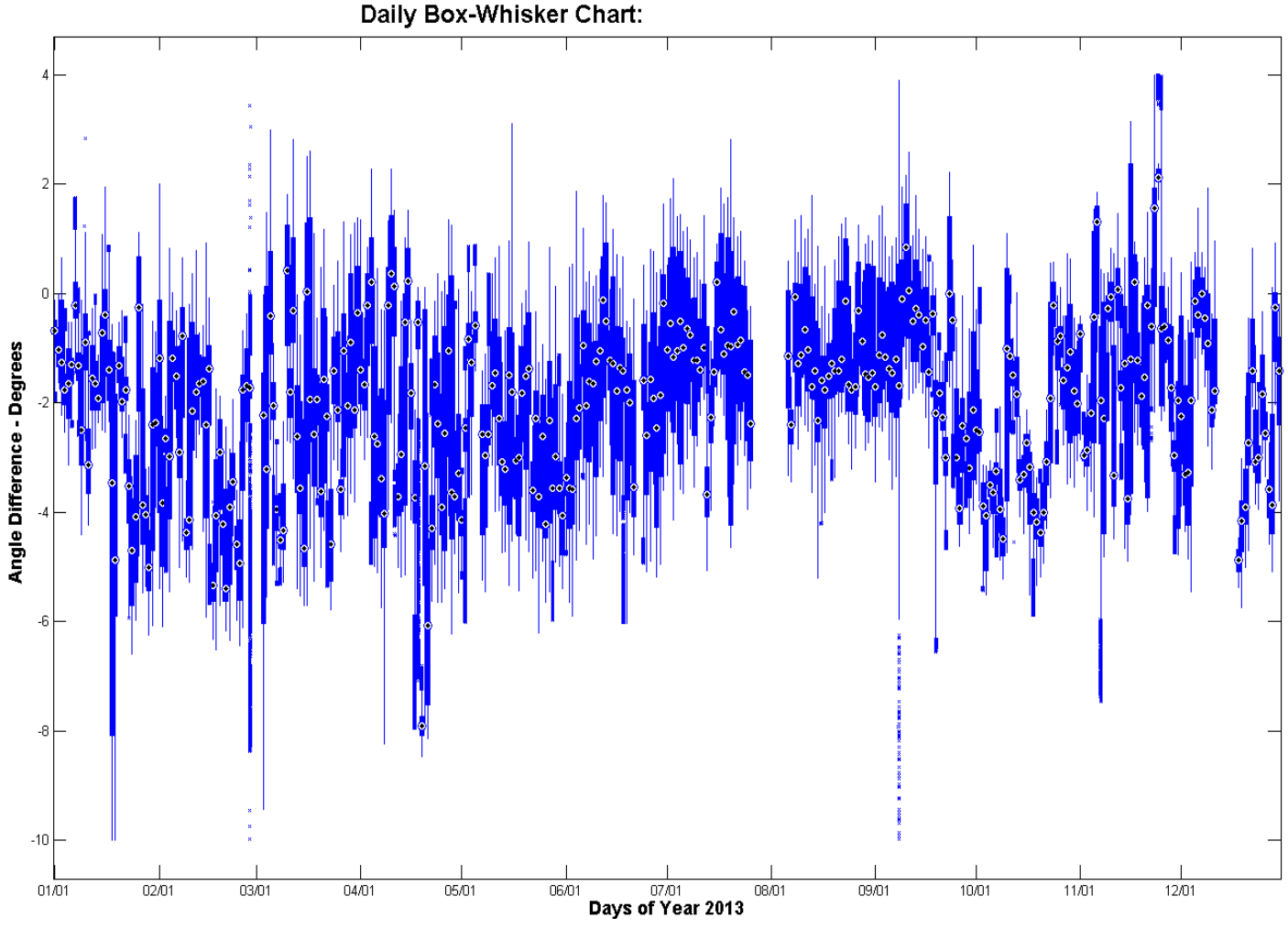

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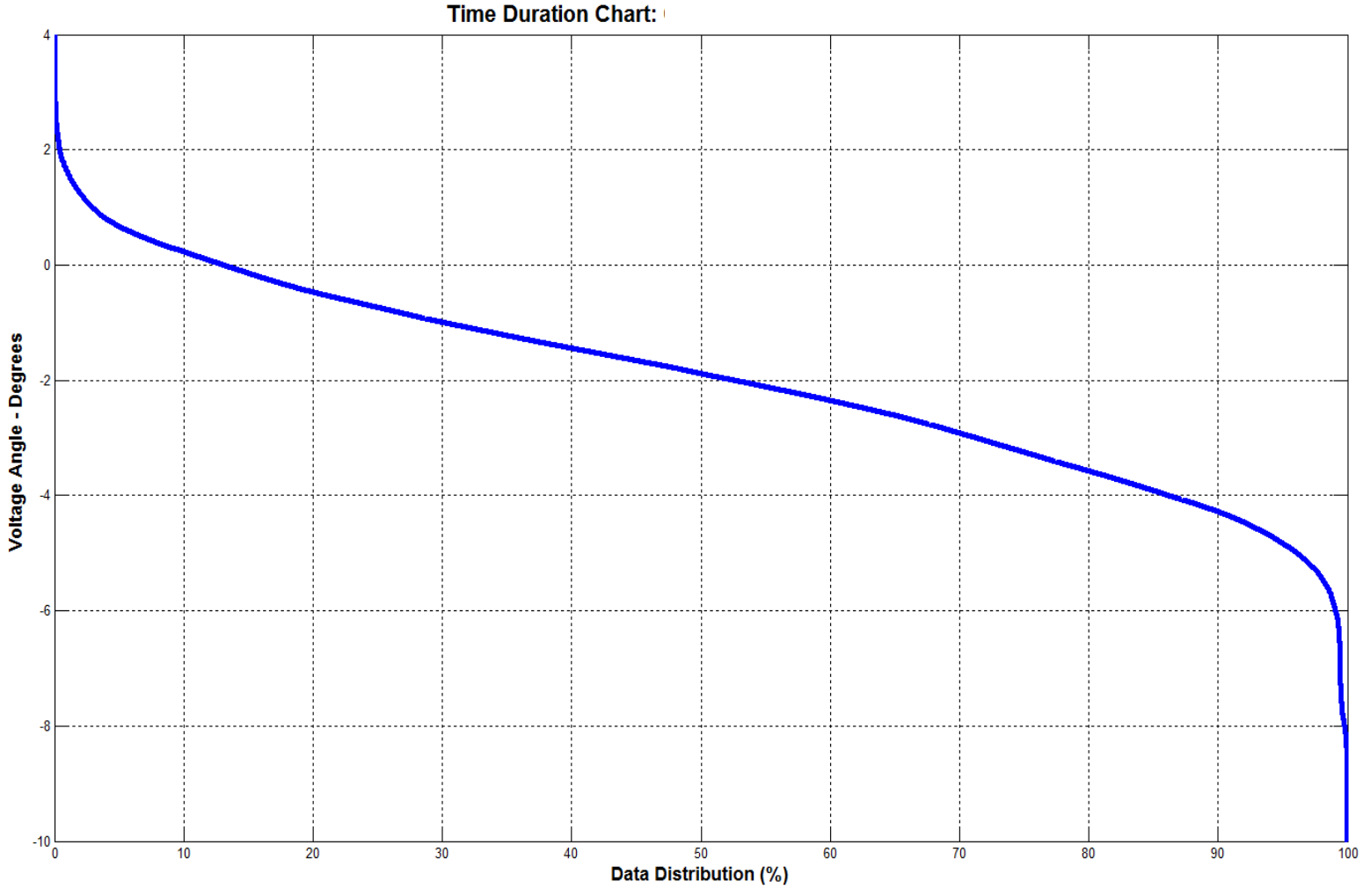

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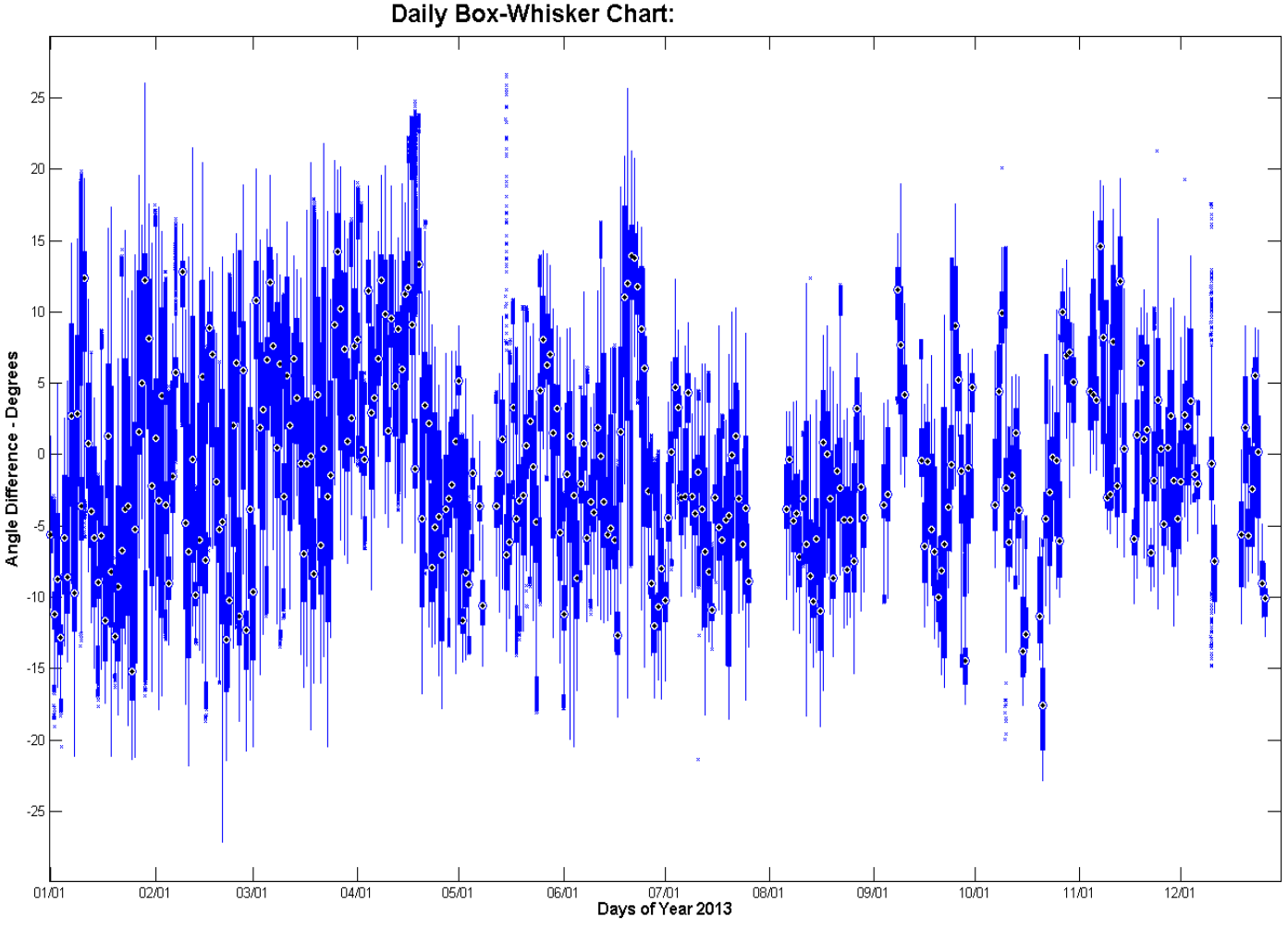

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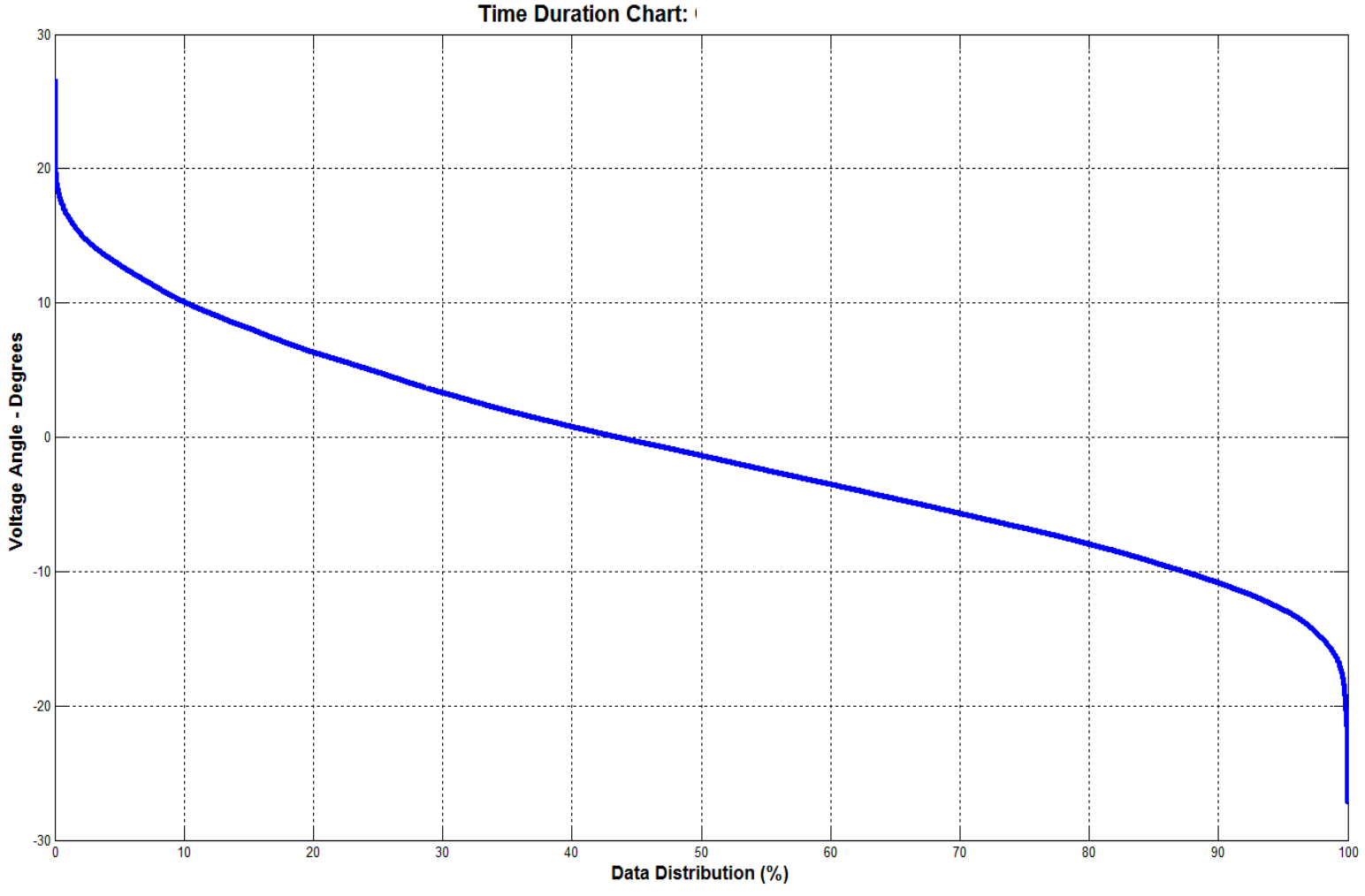

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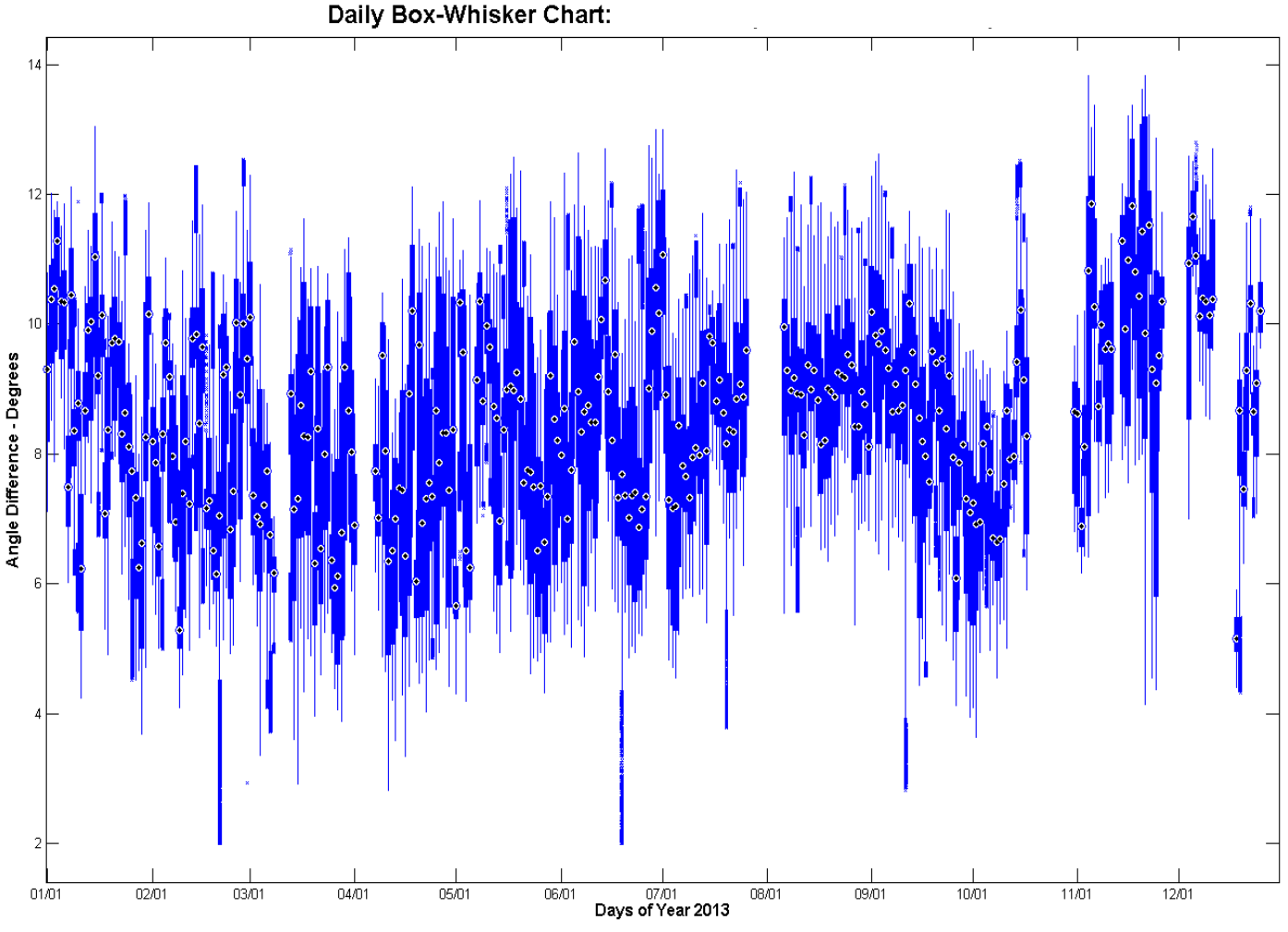

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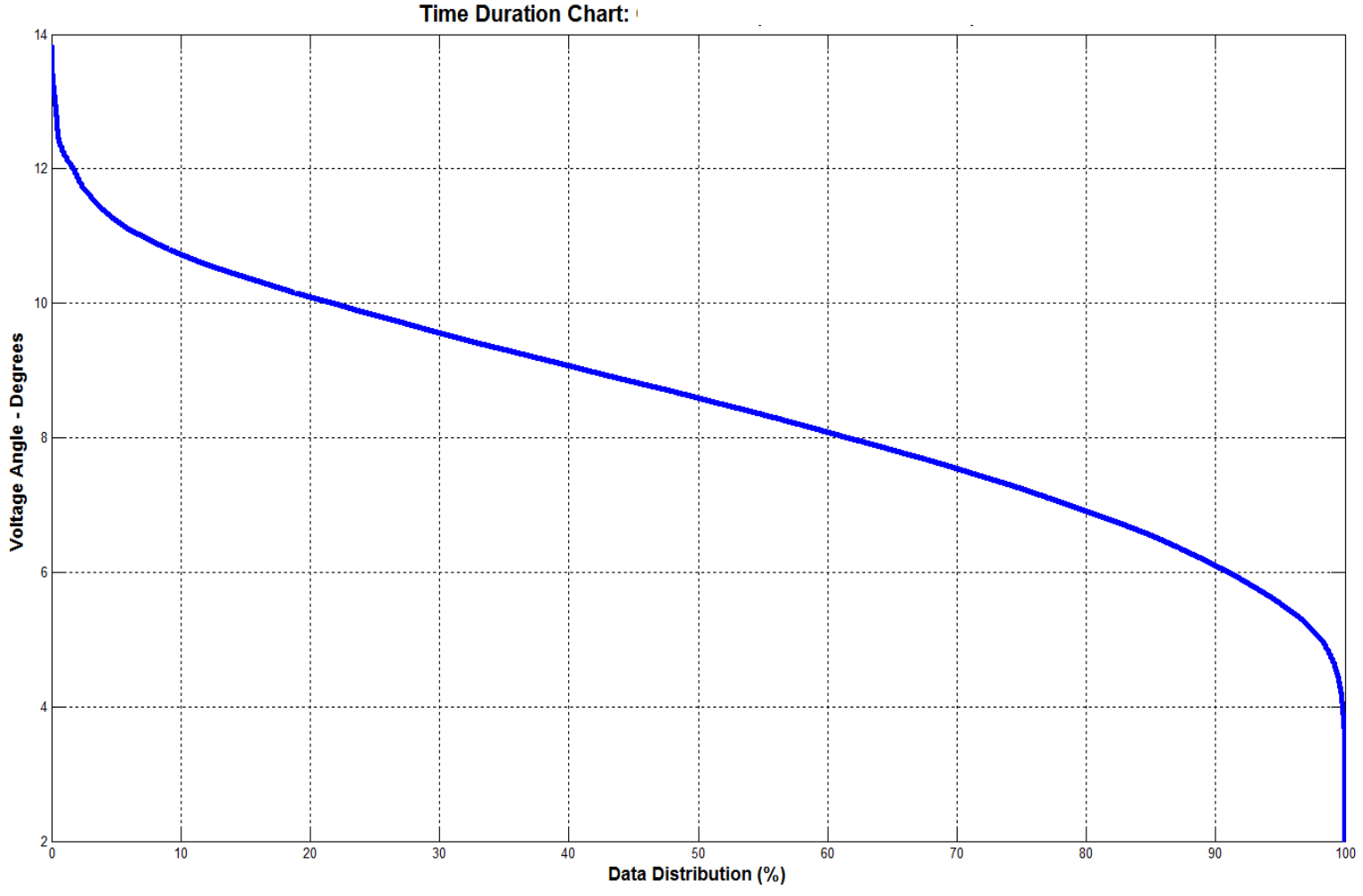

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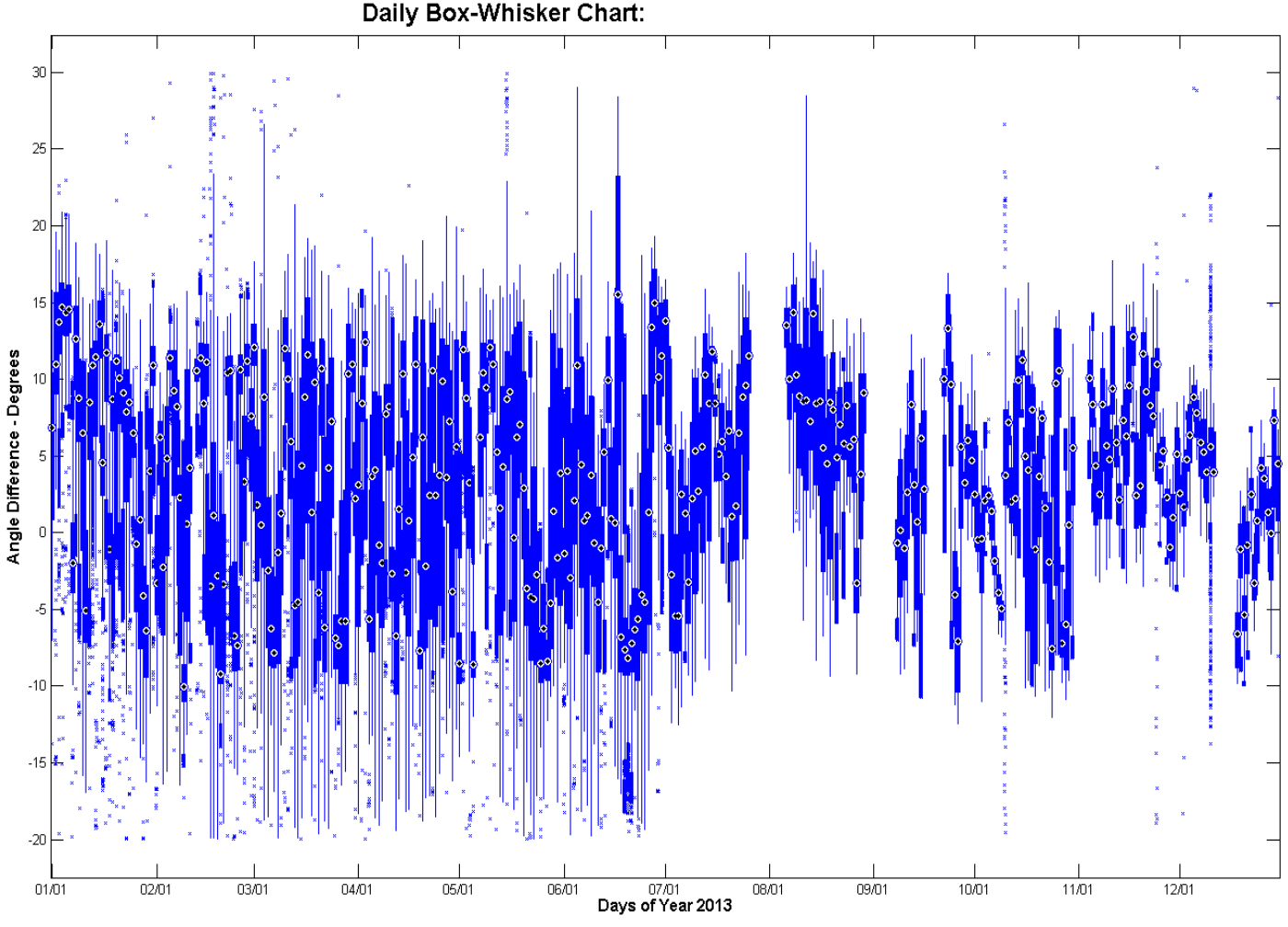

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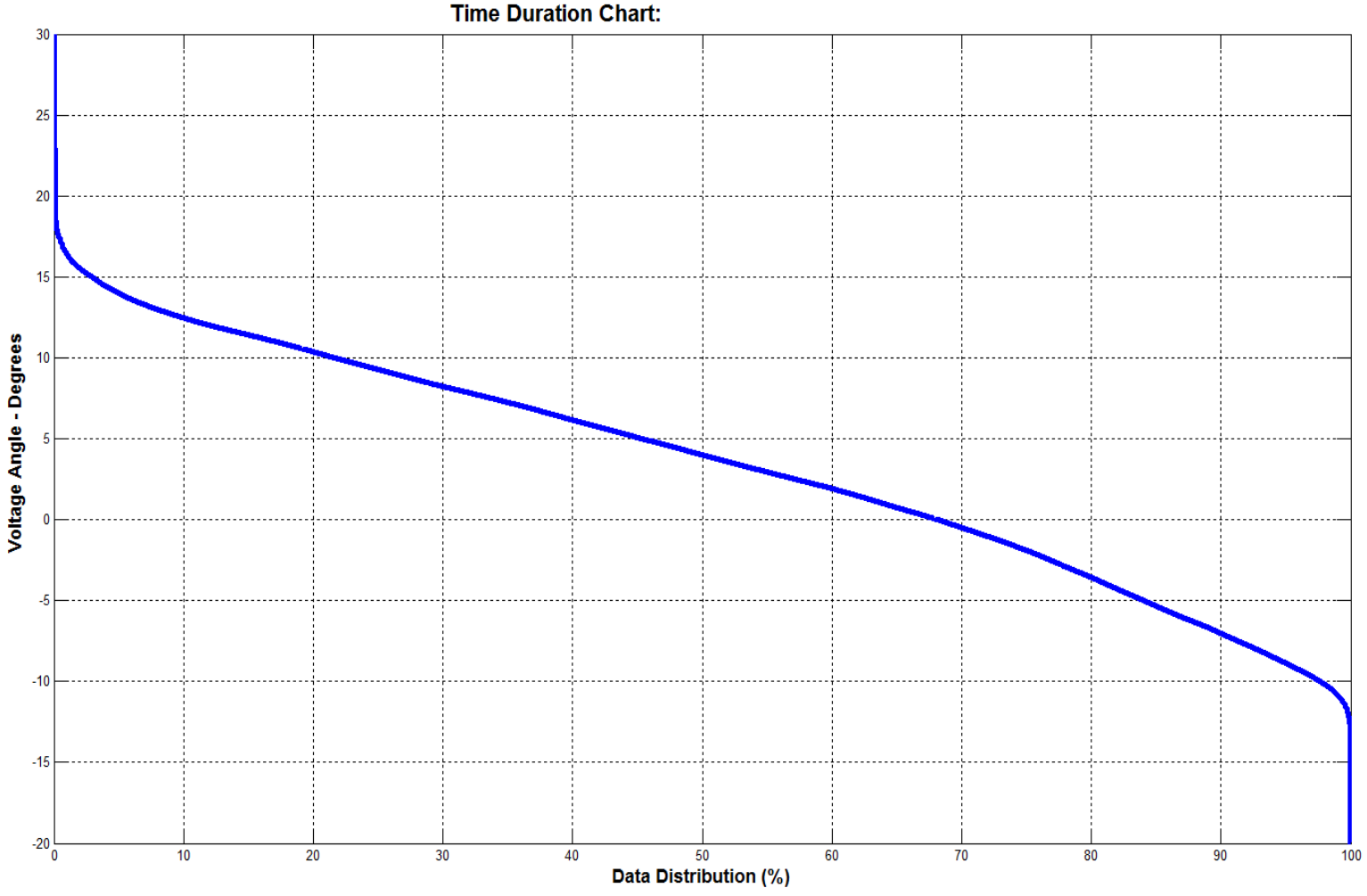

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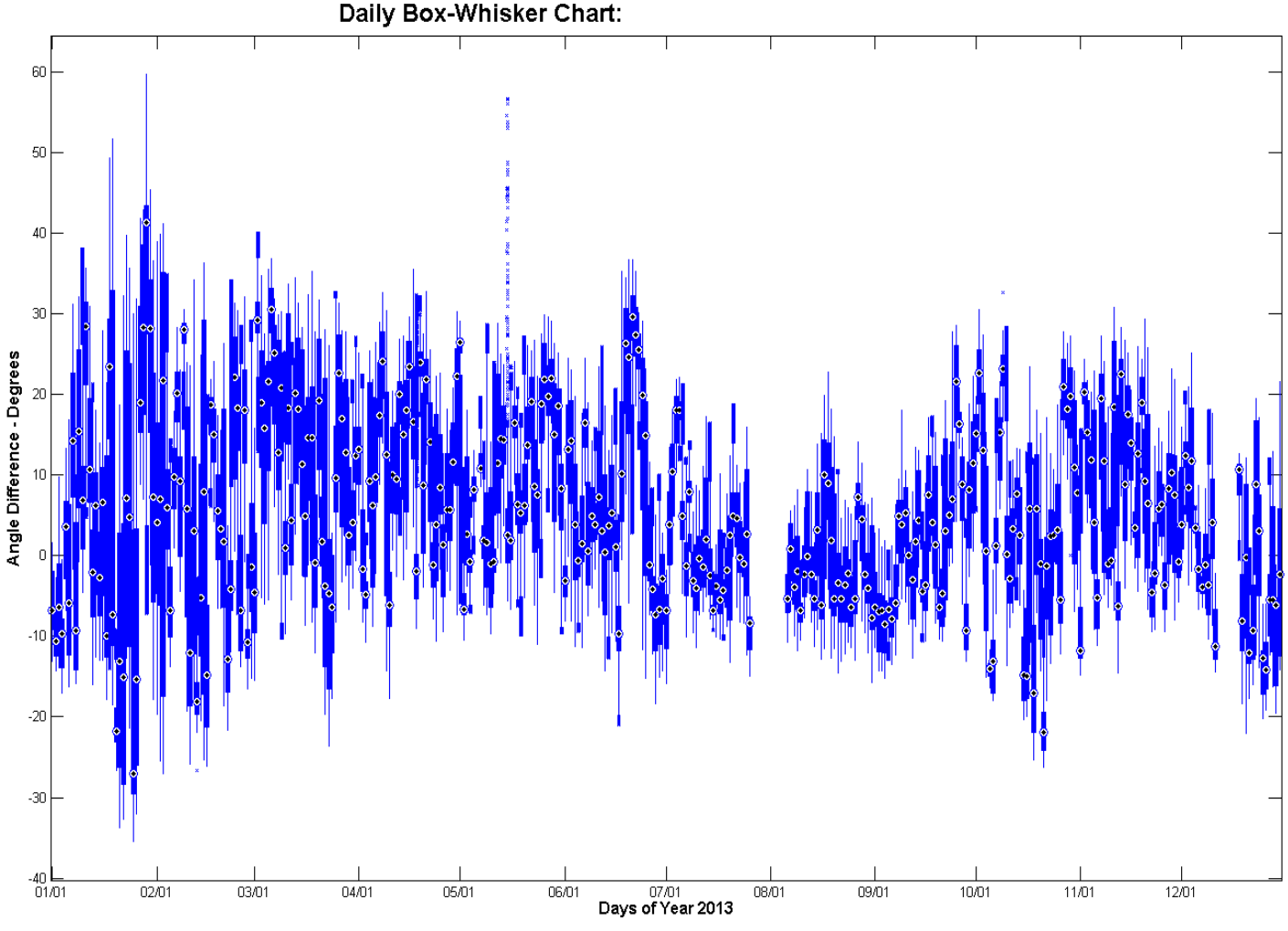

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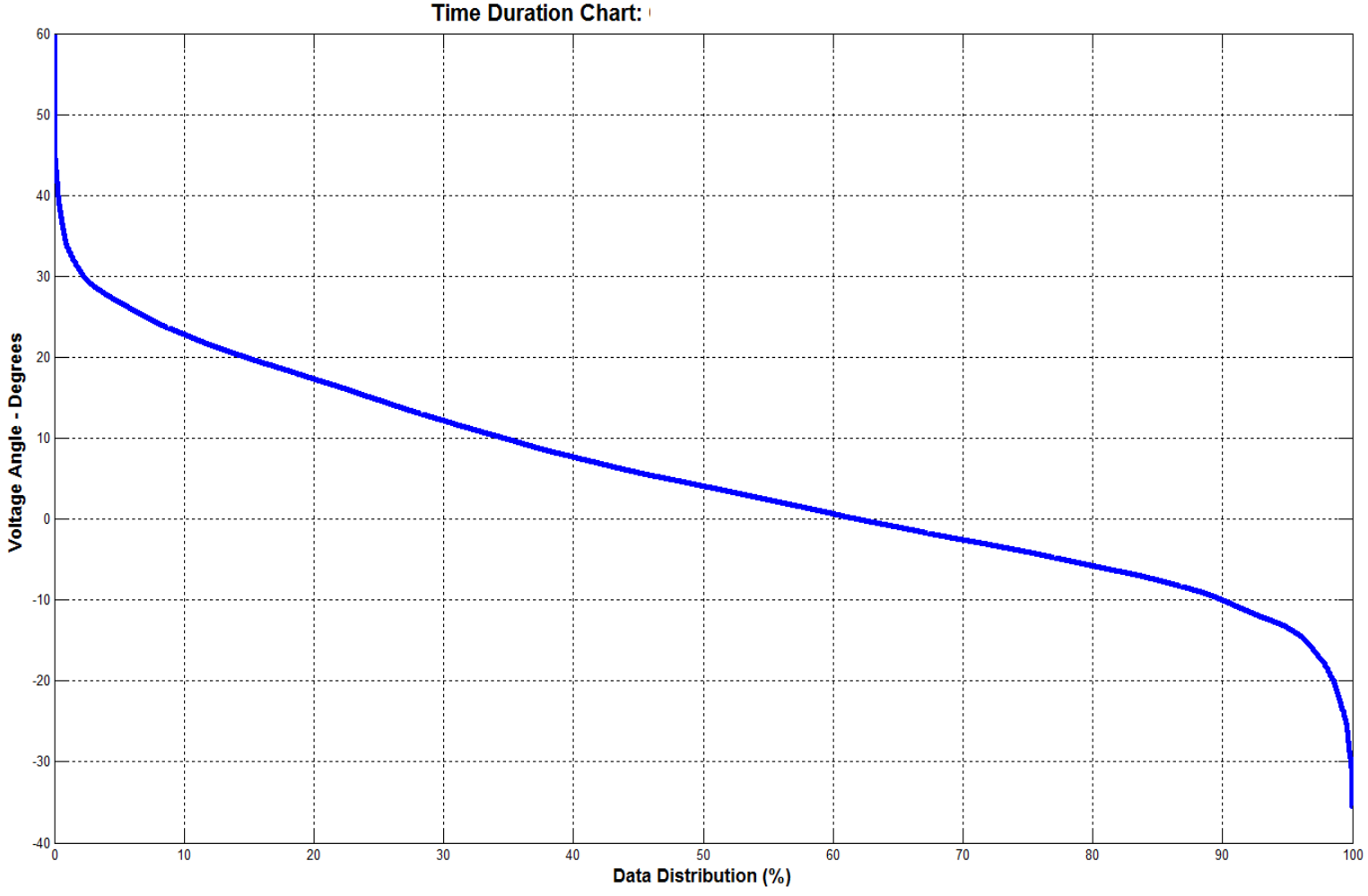

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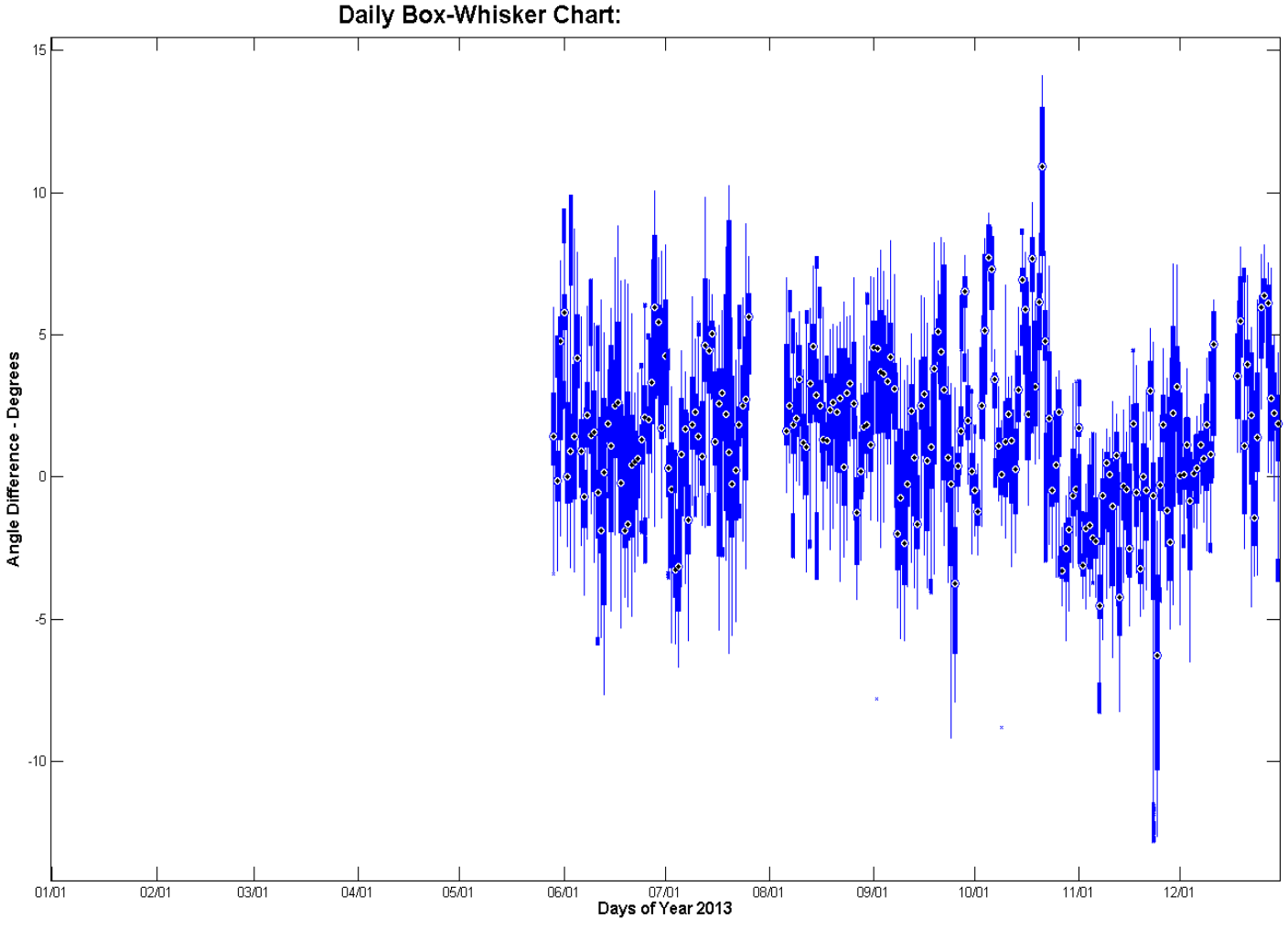

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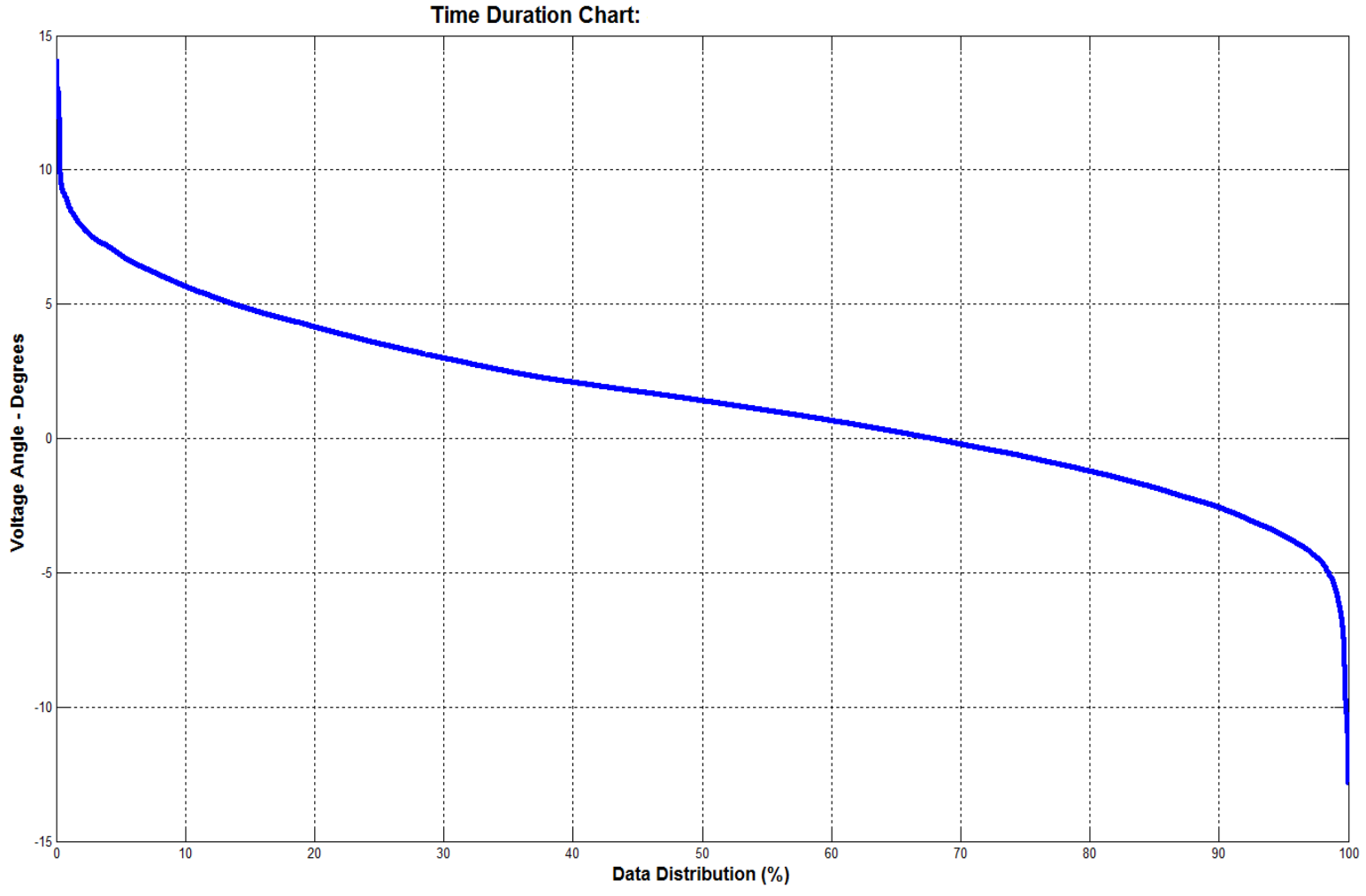

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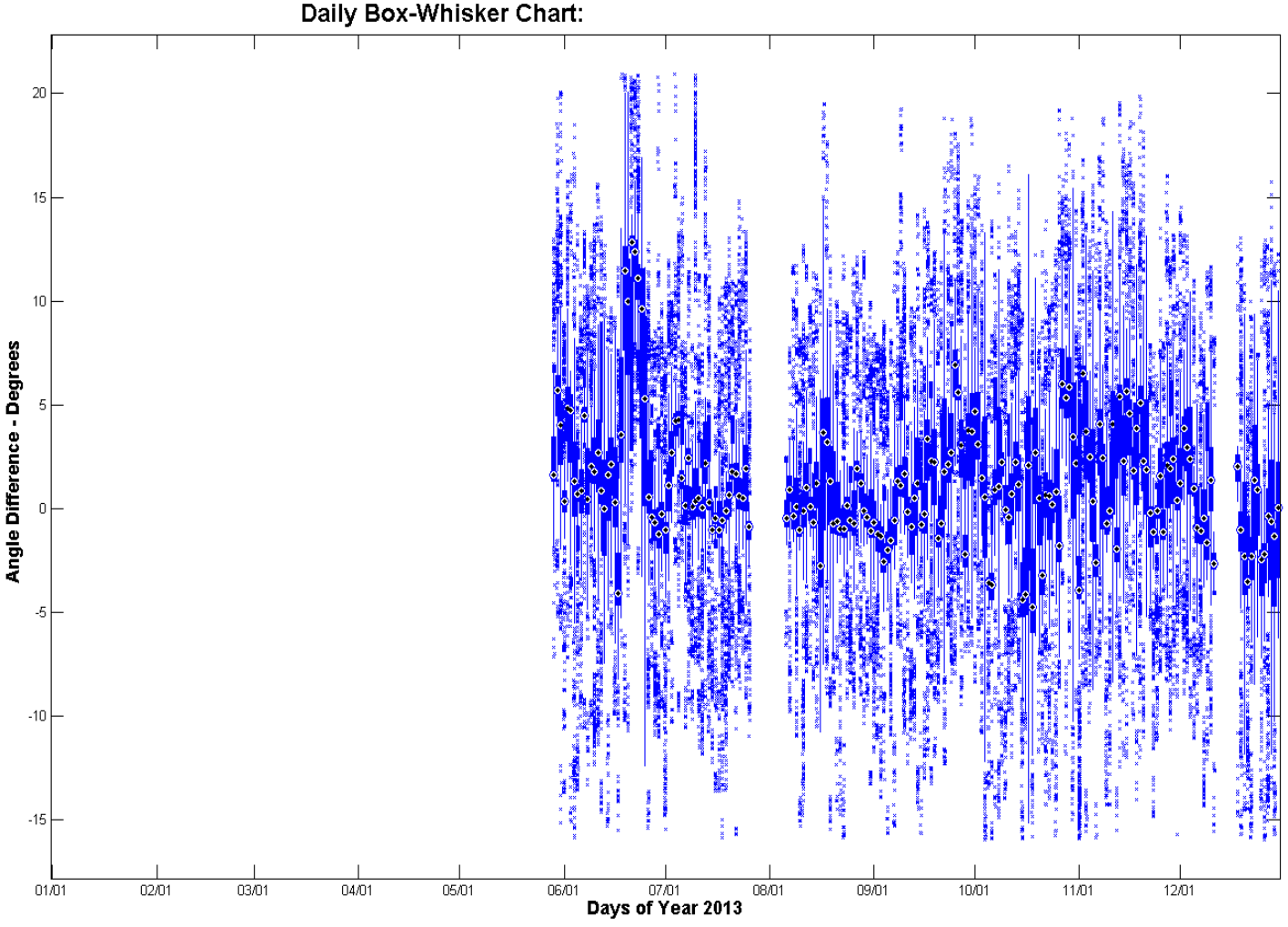

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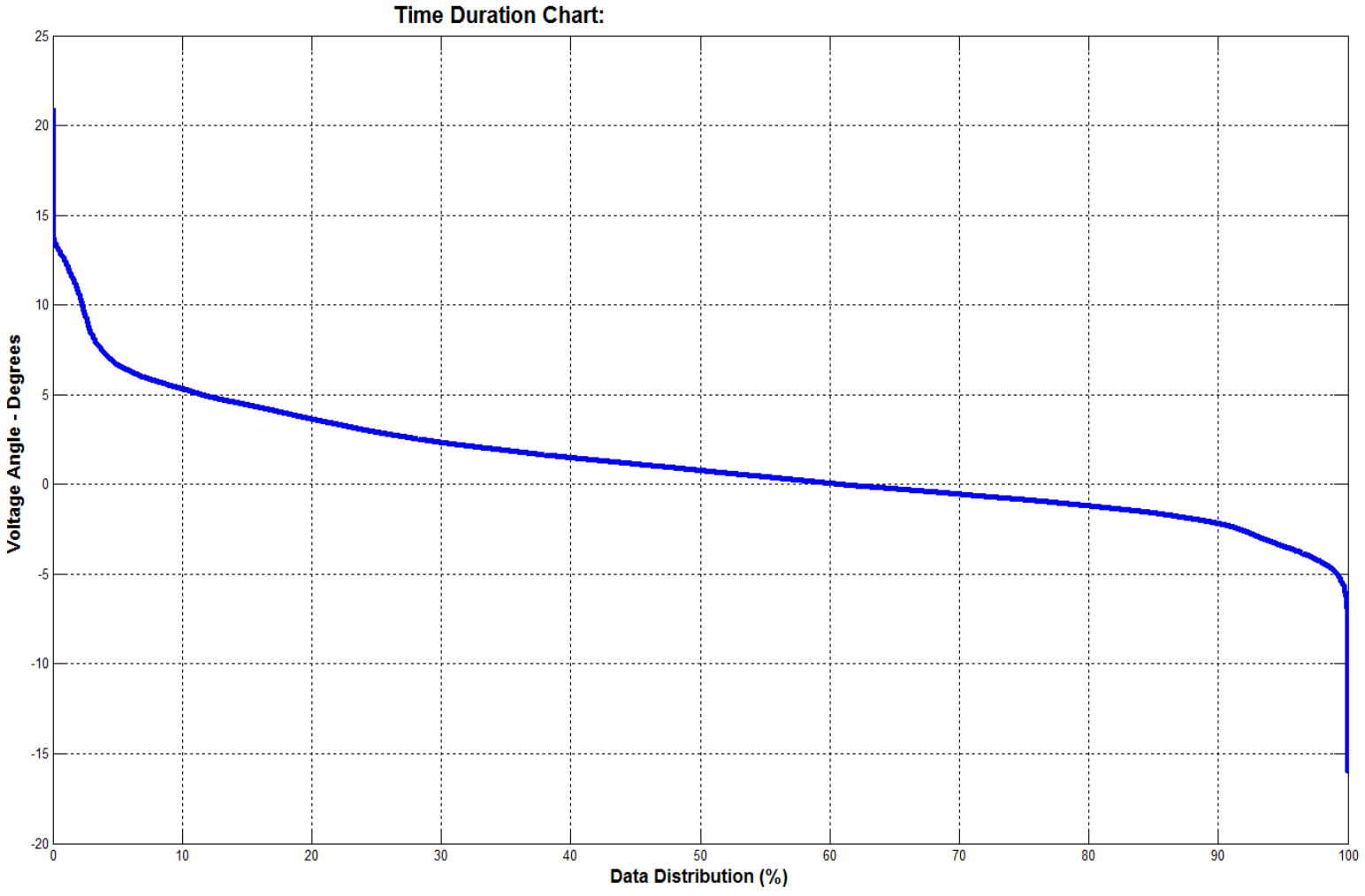

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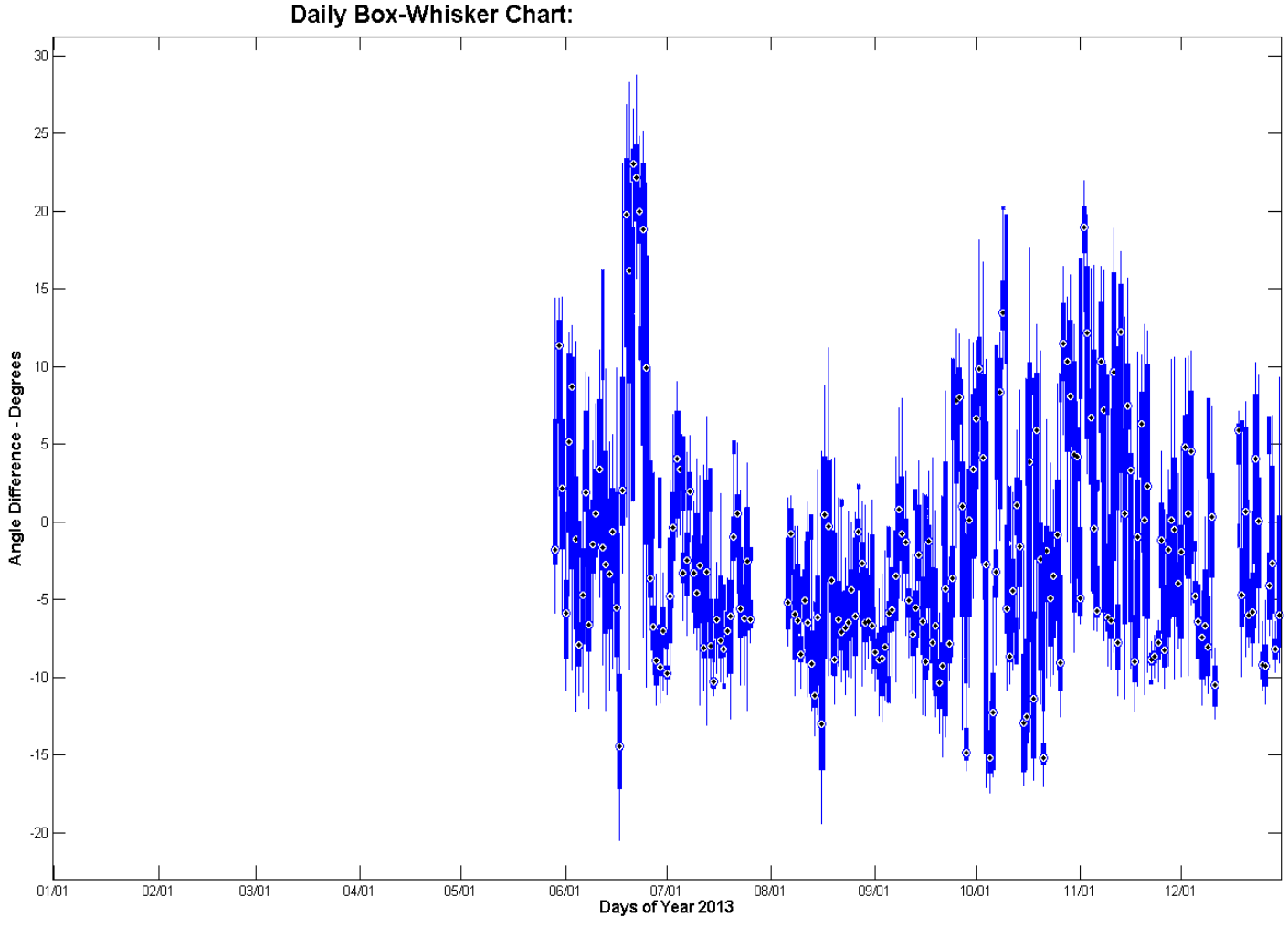

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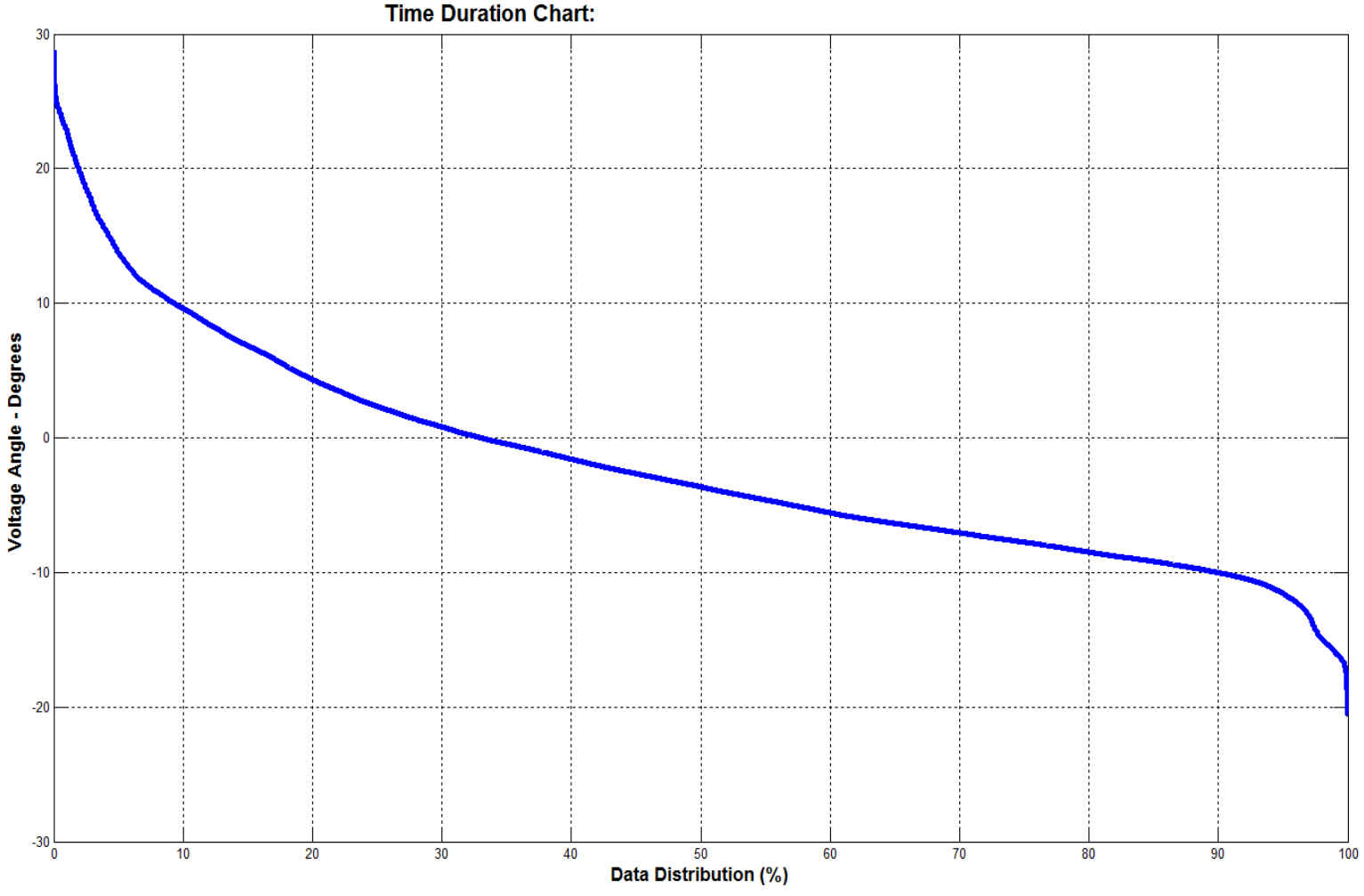

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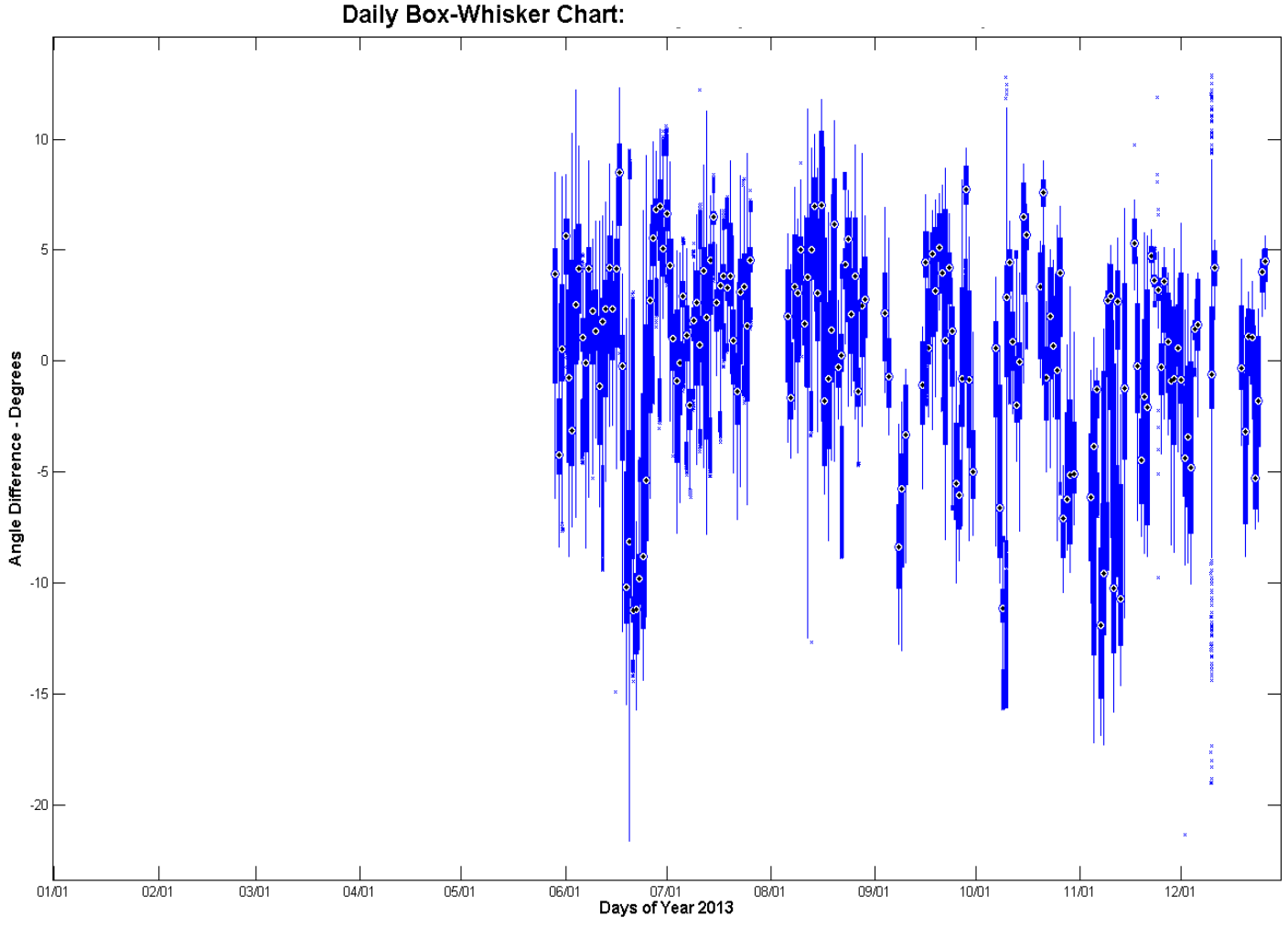

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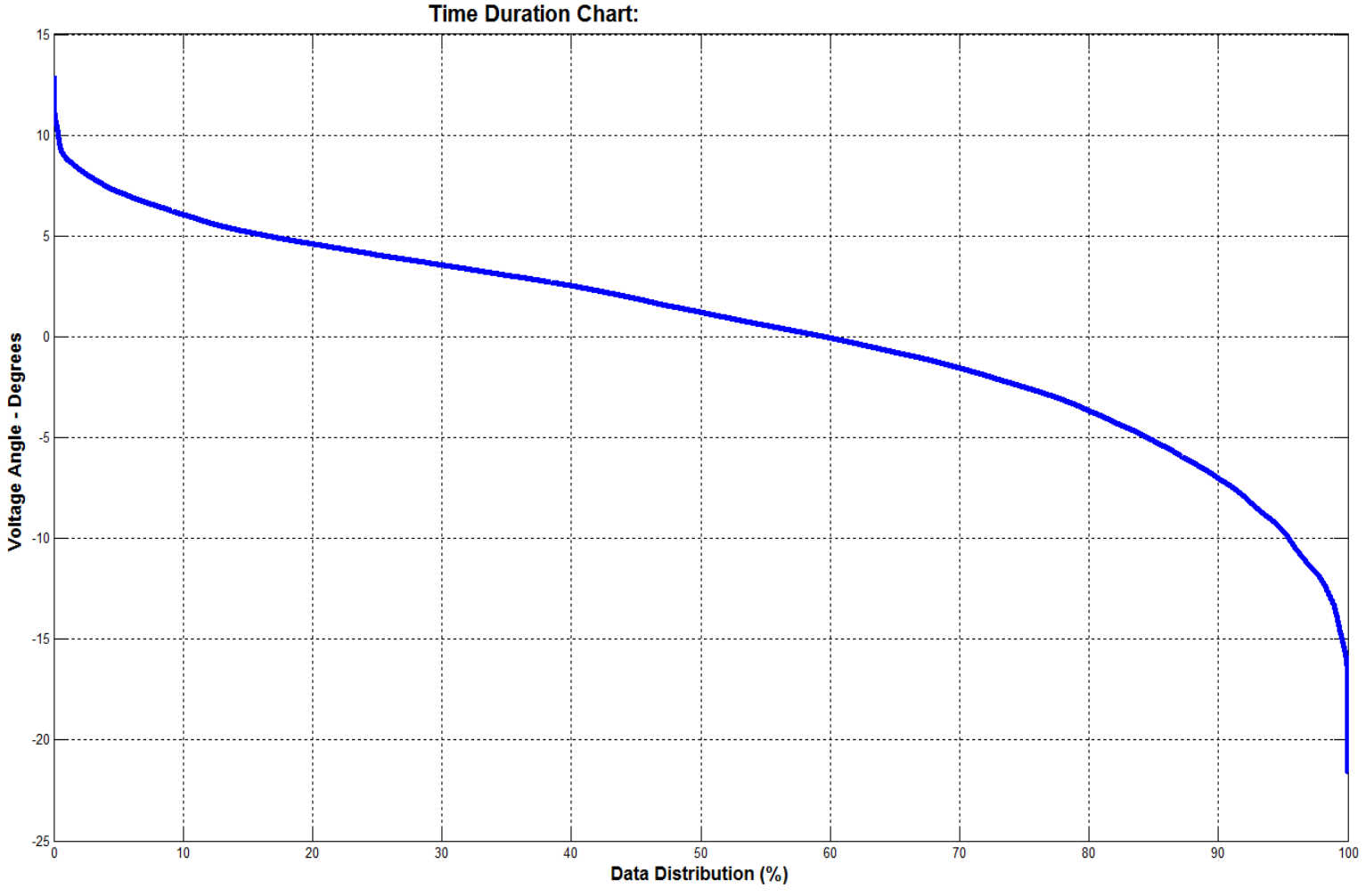

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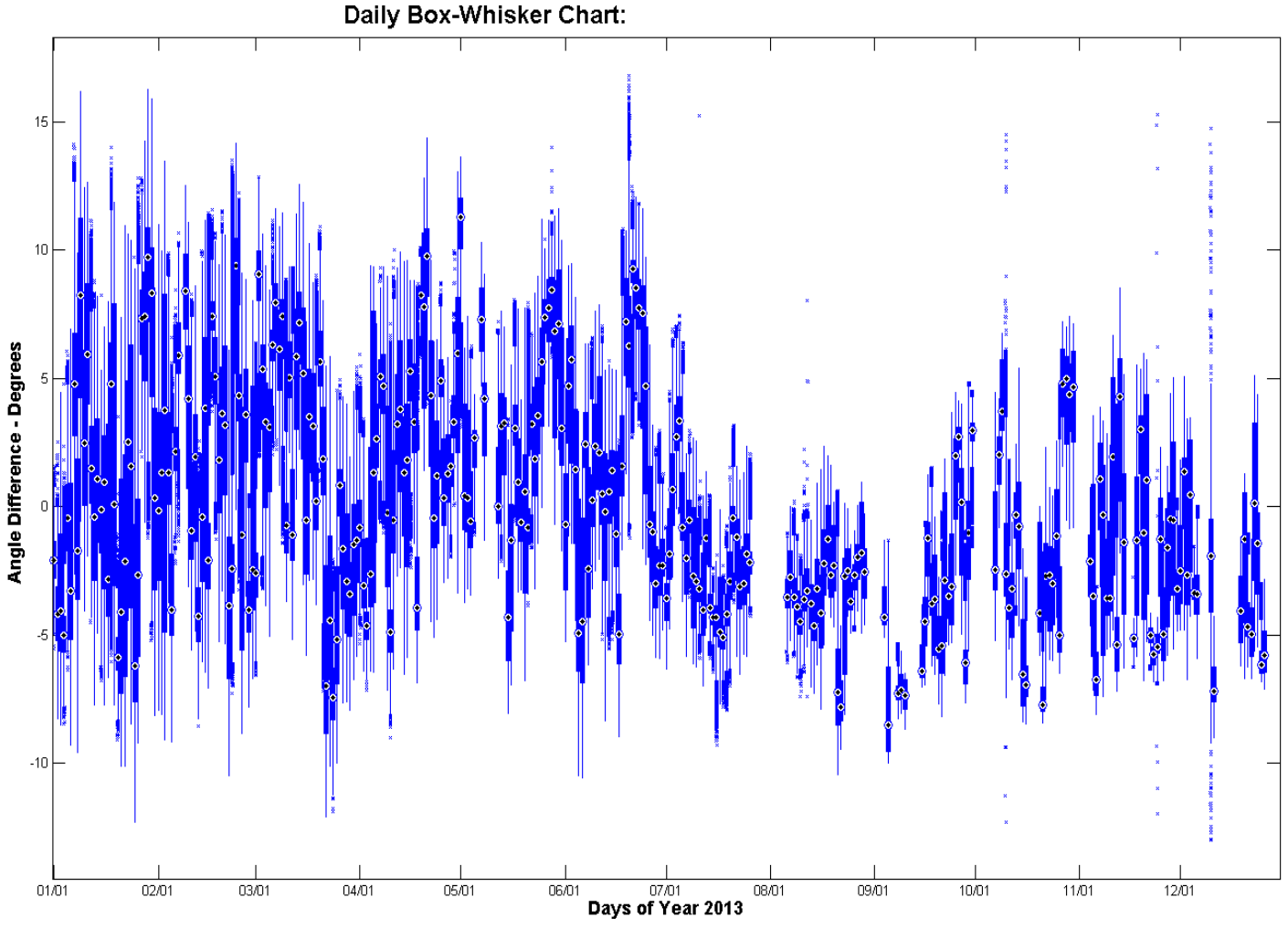

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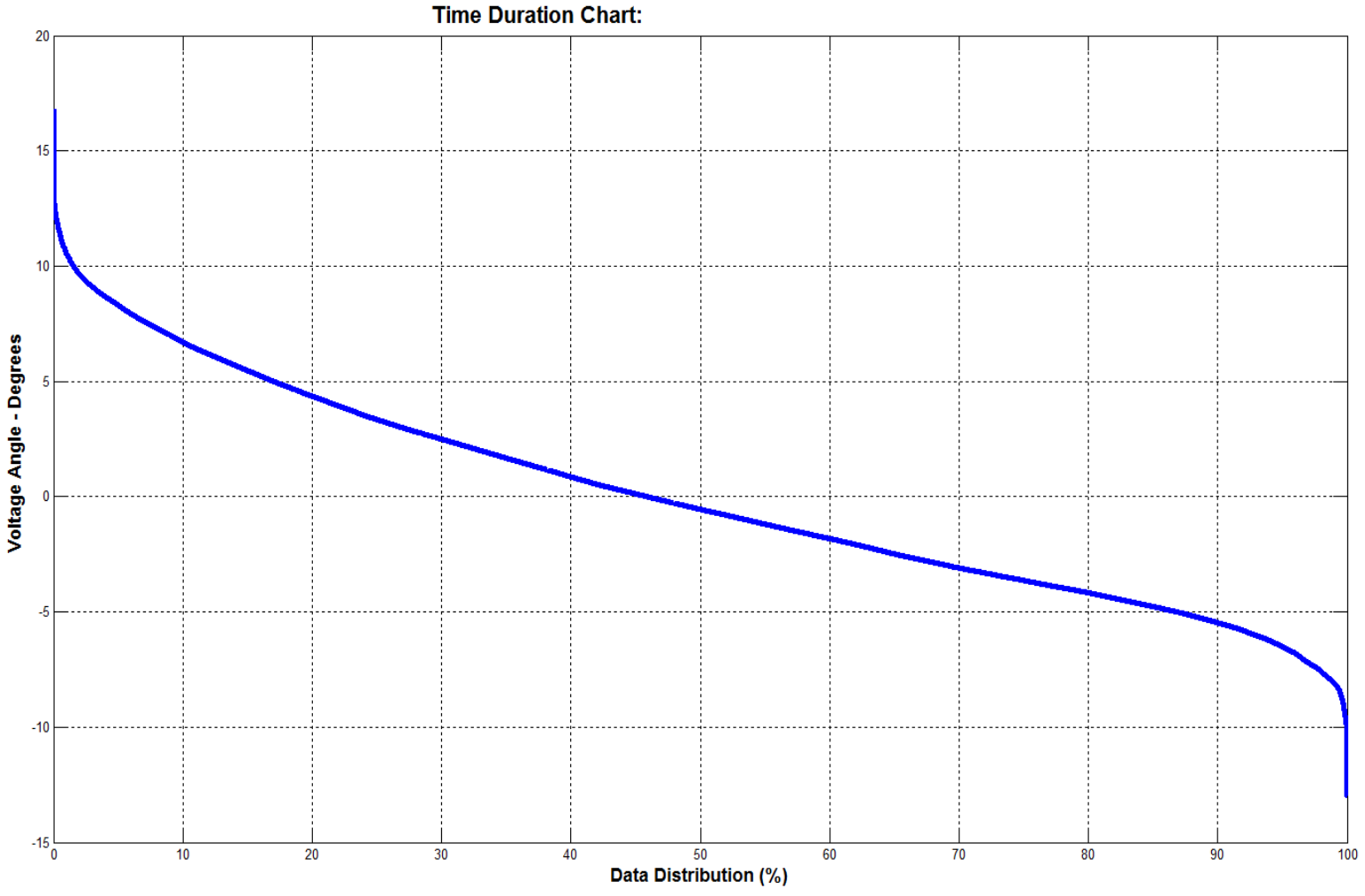

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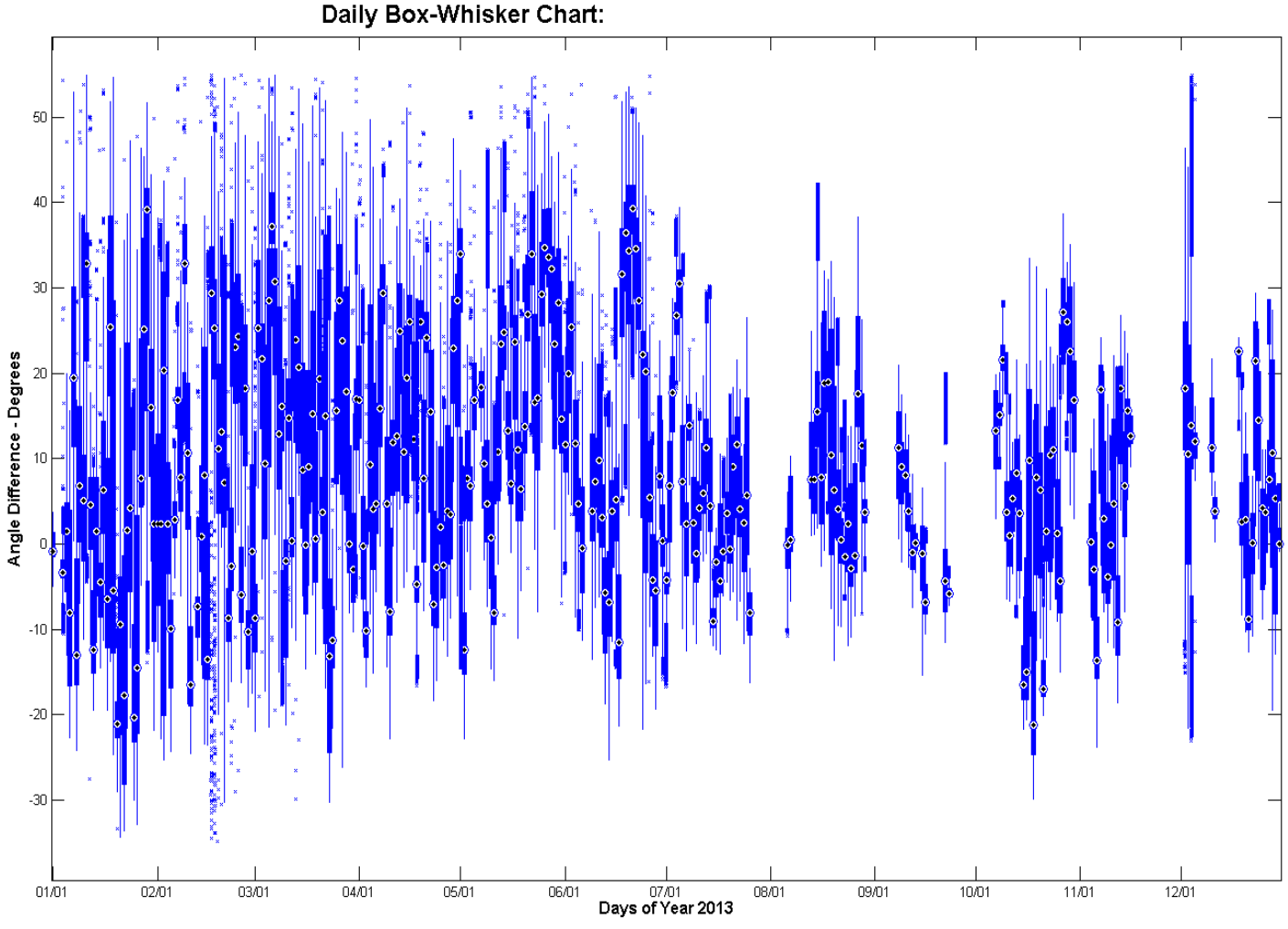

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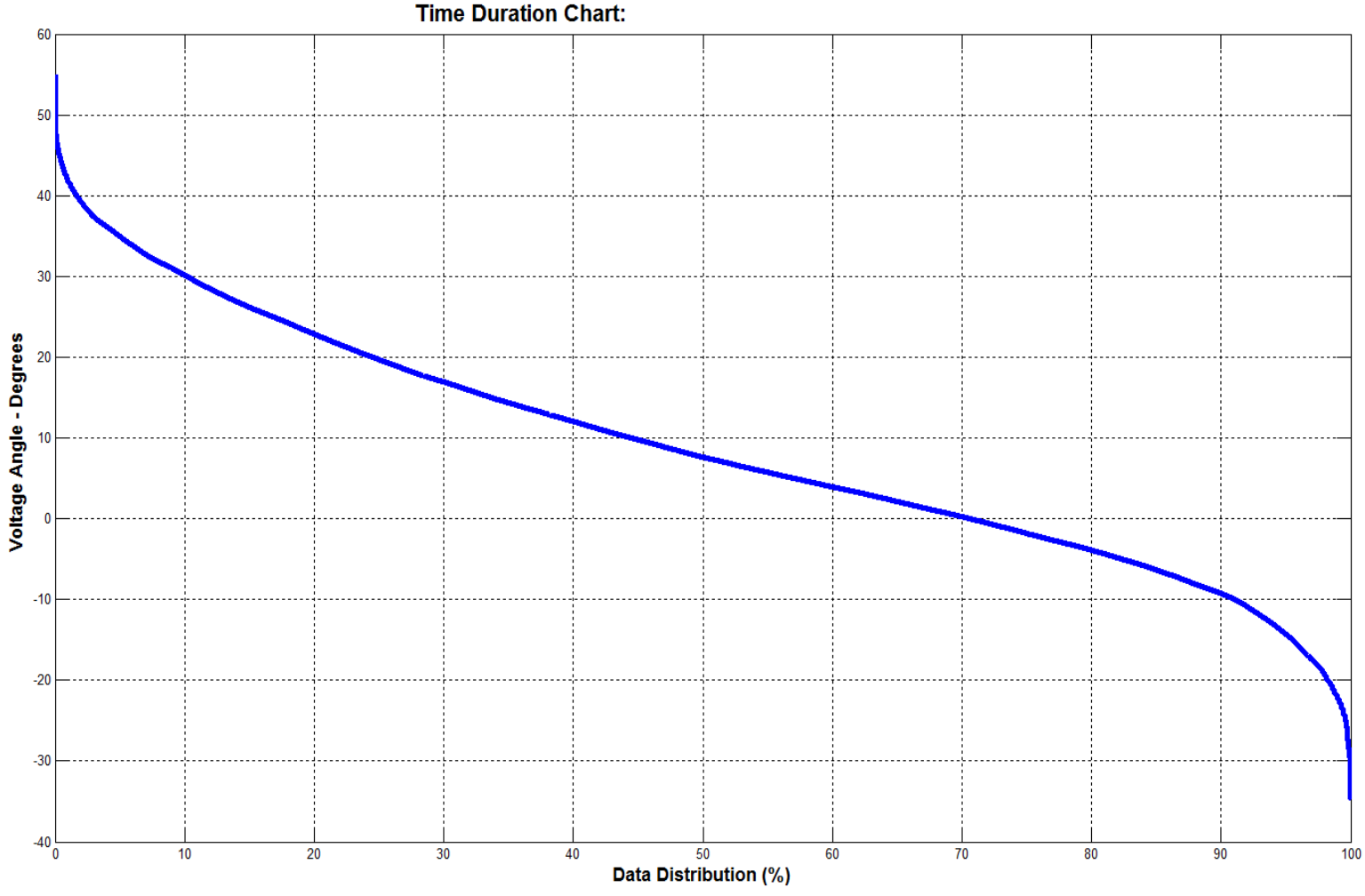

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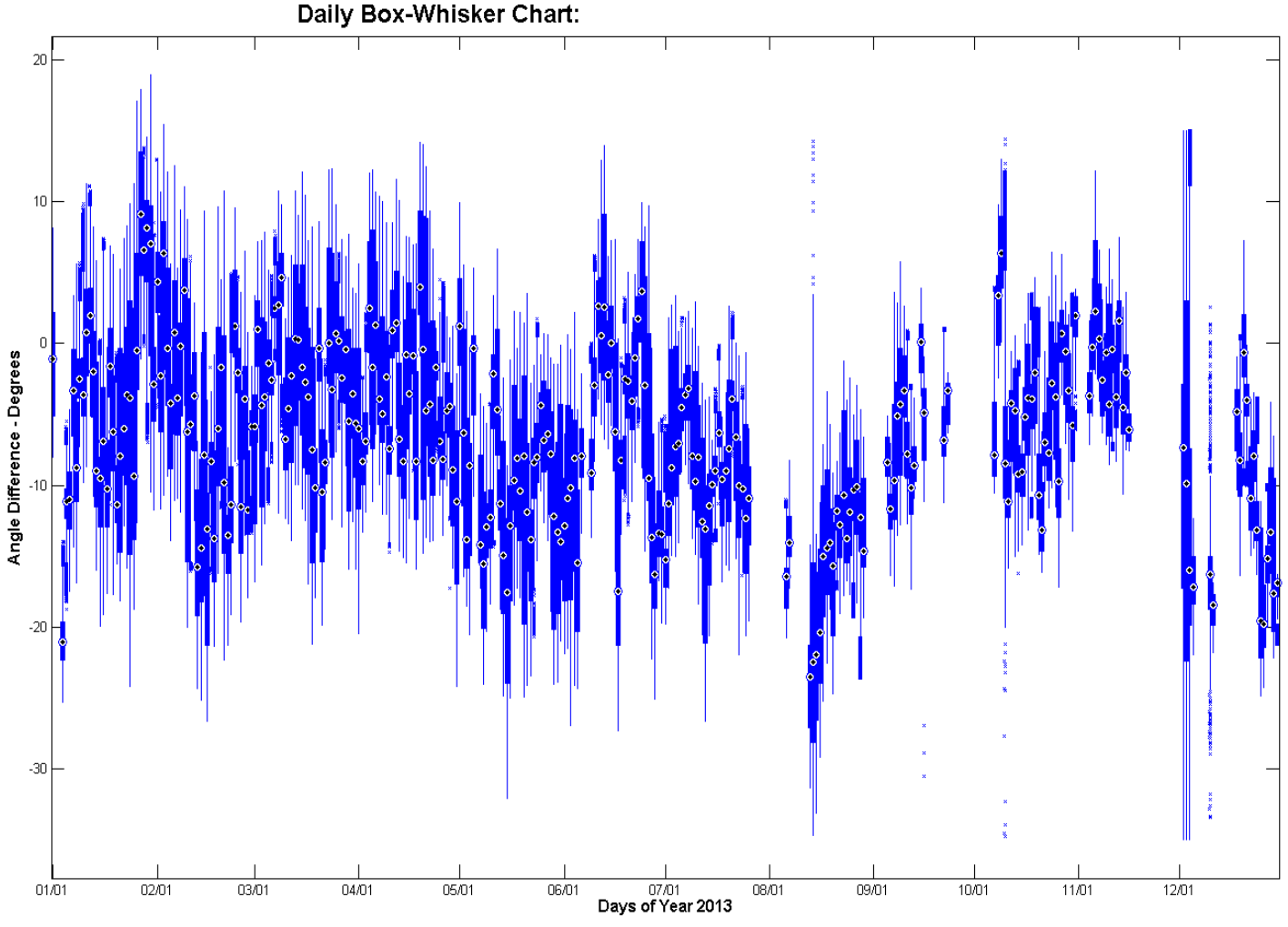

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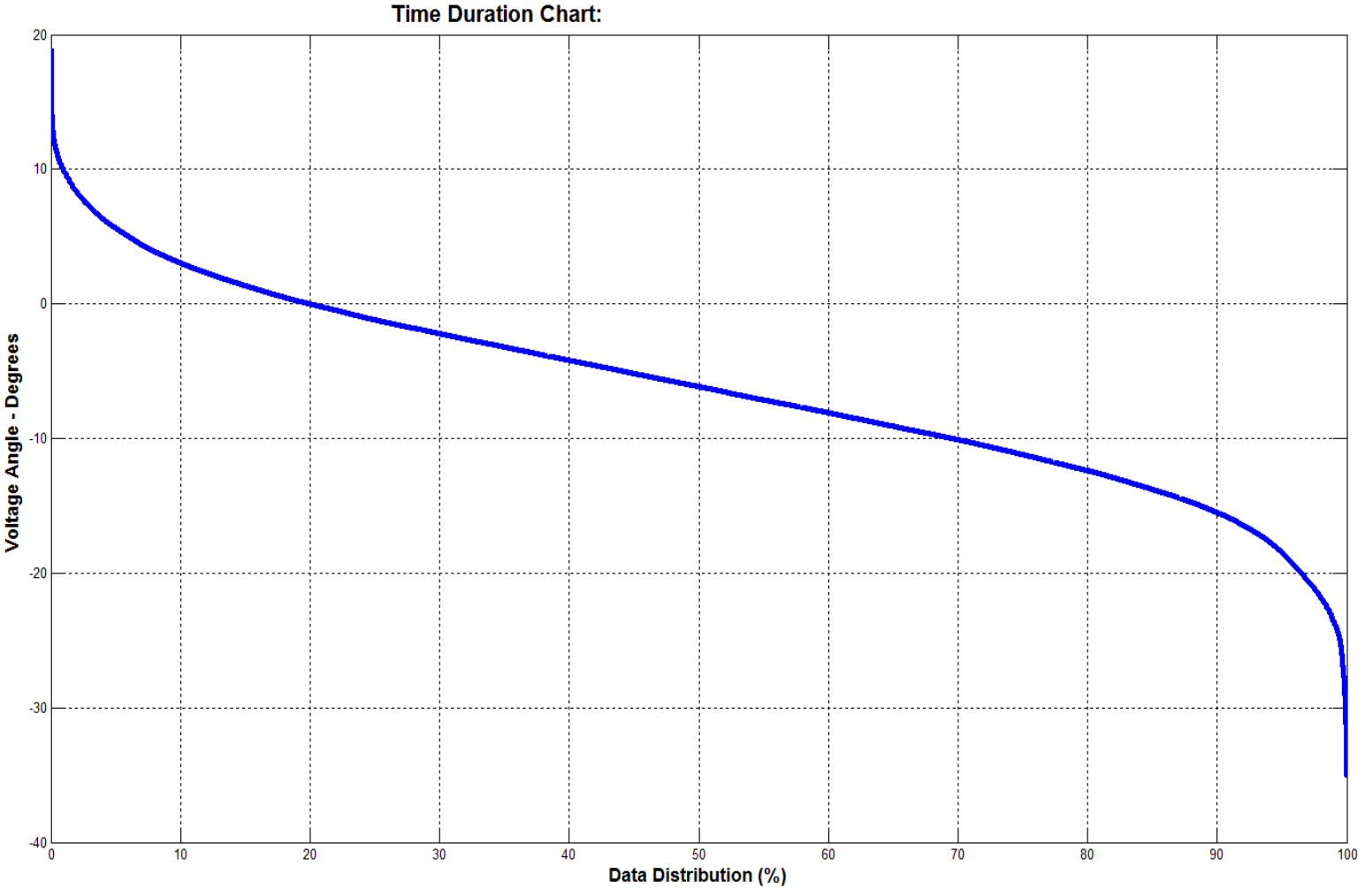

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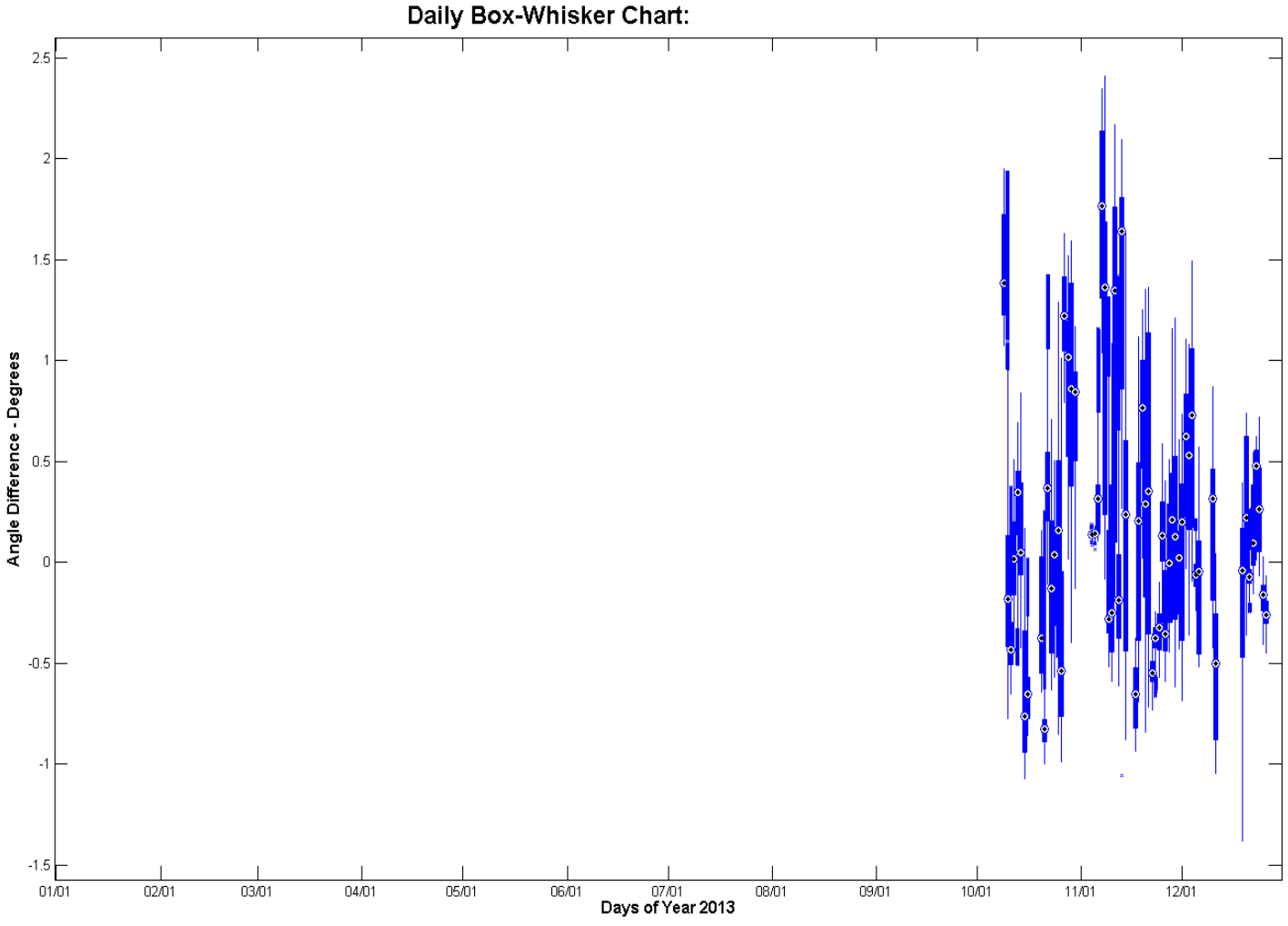

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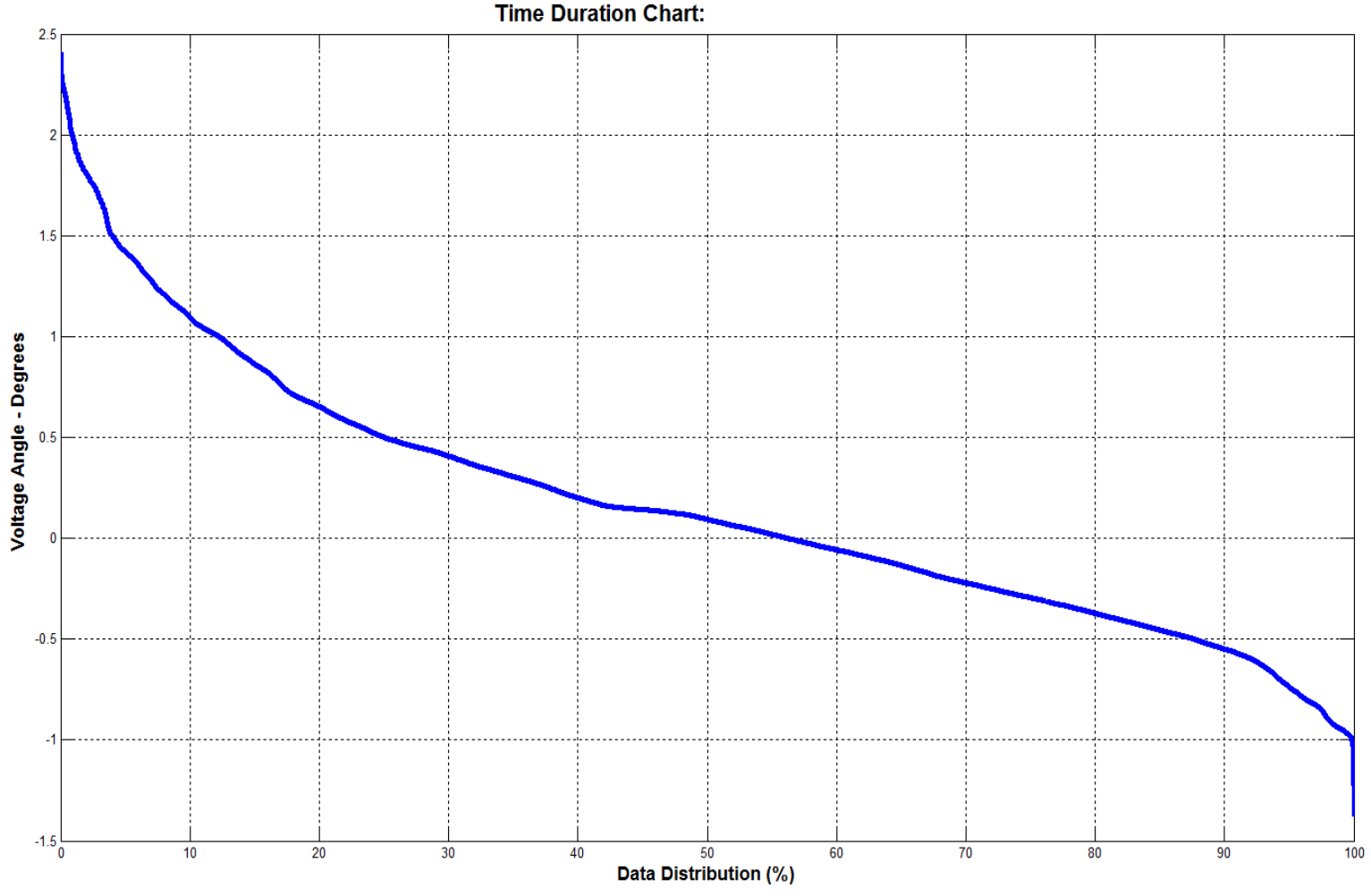

Attachment 5. Updated Baselining Study #3 for 2013 and First Half of 2014

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

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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 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. 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. The 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 that report. However those alarm limits were expected to change because they were based on 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 the ERCOT grid using State Estimator data, plus phasor data, for the February to July 2014 period, to identify normal and abnormal voltage 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 2014. Activities performed as part of this Update 3:

1. Extracted key metric information (i.e., angles and angle differences).
2. Analyzed extracted data and developed baseline understanding of voltage phase angle, and angle difference patterns, for key pairs of substations similar to those used in Update 2.
3. Monitored angle differences (pairs), and developed 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. Prepared 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. Developed a comparison table to show the difference in results for voltages and angle differences using 2012, 2013, and the 6-months of 2014 data.
6. Prepared 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 System[1] (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 after March 2014, and the angle difference ranges should be more stable, resulting in a more current and accurate set of alarm limits.

[1] ® Electric Power Group. Built upon GRID-3P platform, US Patent 7,233,843, US Patent 8,060259, and US Patent 8,401,710.

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 with 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 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 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 substations 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)				
	FROM	TO	VOLTAGE	IN-SERVICE DATES
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 over 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 inTable 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, 2013, and 2014 (six months):

2014

<20%	**20% to 60%**	**61% to 90%**	**>90%**
Coast 2	None	Coast 1	West 10
FarWest 2		West 4	West 11
		West 14	South 3
		Coast 4	South 5
		Coast 3	West 1
		South 13	West 2
		FarWest 9	West 9
		West 16	West 12
		West 3	West 5
		West 15	West 6
			North 1
			North 4
			North 5
			North 6
			FarWest 4
			FarWest 7
			FarWest 8
			North 7

2013

<20%	**20% to 60%**	**61% to 80%**	**>80%**
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

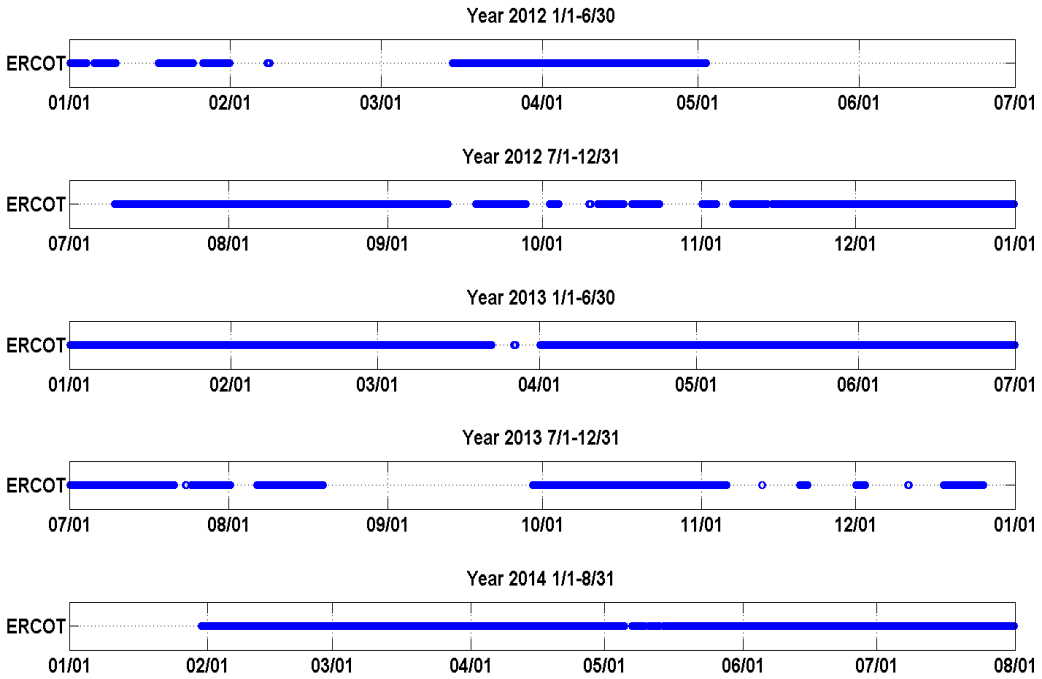
2012

<40%	**41% to 60%**	**61% to 80%**	**>80%**
	West 4	West 11	West 10
West 14			
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

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-whisker 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. Obtained and processed phasor data and state estimator data.
2. Identified the substations for which phasor data is available and for which PMUs are planned.
3. Selected angle pairs of interest to ERCOT and the synchrophasor team members by choosing substations that have, or soon will have, PMUs installed.
4. Extracted information to identify max, min, and average values from these data sources. Prepared summary tables for the selected pairs showing results of all data, including data saved during events.
5. Developed statistical charts, including time duration curve and box-whisker graphs, for voltage angle pairs.
6. Identified 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 as normal operating limits.
7. Performed statistical analyses to identify angle differences limits for the selected pairs under all conditions. Summarized angle difference limits.
   - Established limits for normal operation based on the criteria described in the corresponding methodology. Summarized 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. Analyzed results, identified limits, and reported 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, and 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 (Reference: 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		

B. Summary of Results - All Data Included

The voltage angle results obtained from 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 were 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 Min	Max	Average	Percent Positive	Max-Min Spread	% Data Availabl e	State Estimator Data - 2/1/2014 to 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 ERCOTb July 31, 2014; 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-whisker 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)

Table A-2 - CCET DISCOVERY ACROSS TEXAS- BASELINING ANALYSIS - VOLTAGE ANGLES - NORMAL CONDITIONS (Reference: 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 noted with a * have no phasor data available.

D. Observations – Normal Conditions

1. 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 was 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 spreads 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 degree 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 (Reference: 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

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 5 below.

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 5 below.

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:

i. 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 monthly angle median.

ii. Nine pairs, all located in either 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.

iii. 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.

iv. The North 5 and West 4 to North 7 pairs had their voltage angle go more negative; North 5 and West 4 appear to be drawing power from North 7 more often.

v. On the other hand, the voltage angle median for 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.

vi. The South 13 to North 7 pair had their voltage angle go less negative; South 13 appears to be drawing less power from North 7.

F. Conclusions

i. The voltage angles for substations in west Texas and the Panhandle area 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

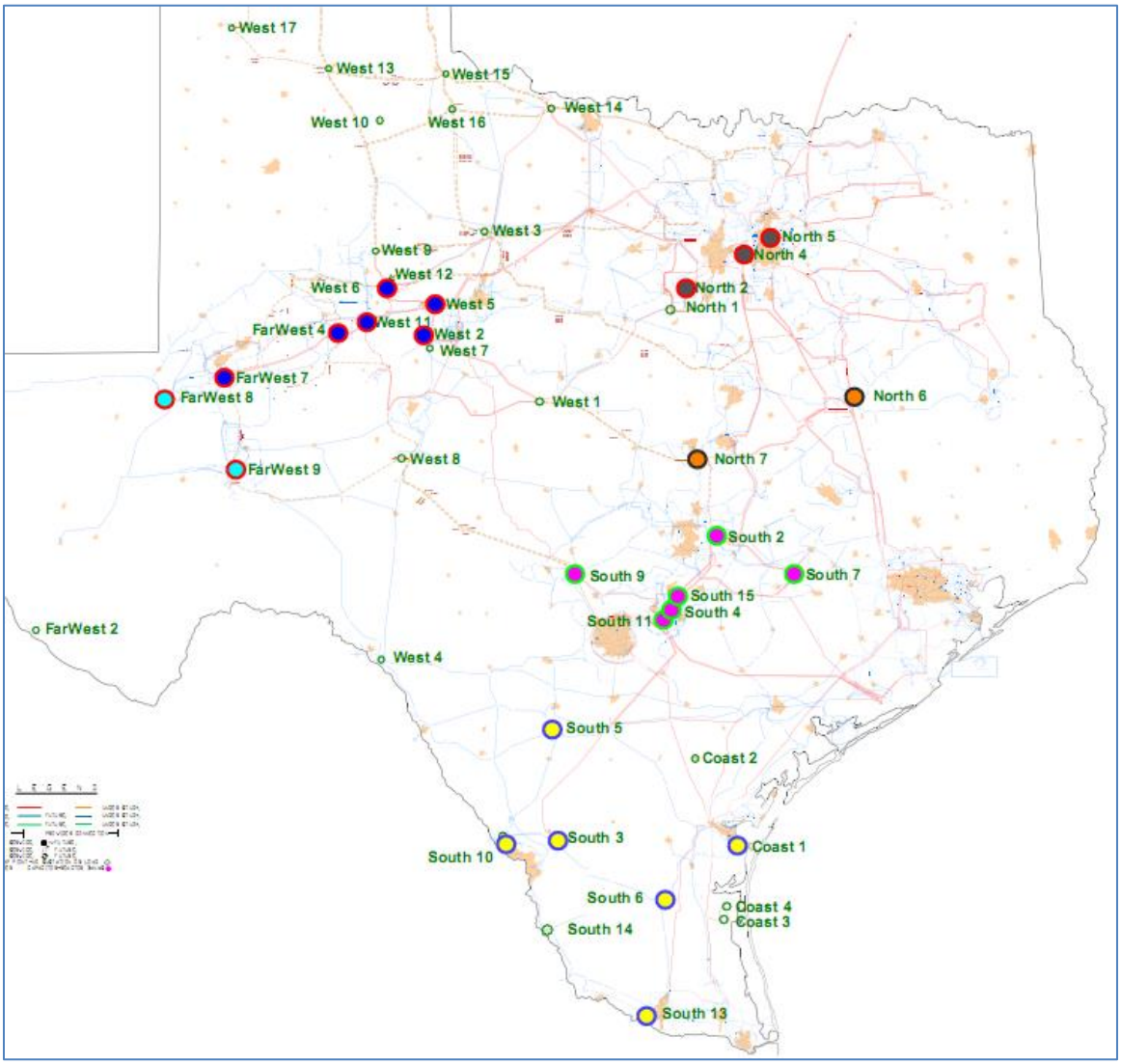
The following pairs of substations were selected to perform analysis of angle difference (also see map below):

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 of 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 others 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 spreads 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 maximum 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 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 represents 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)															
				Phasor Data				State Estimator Data									SE Data		
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	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.

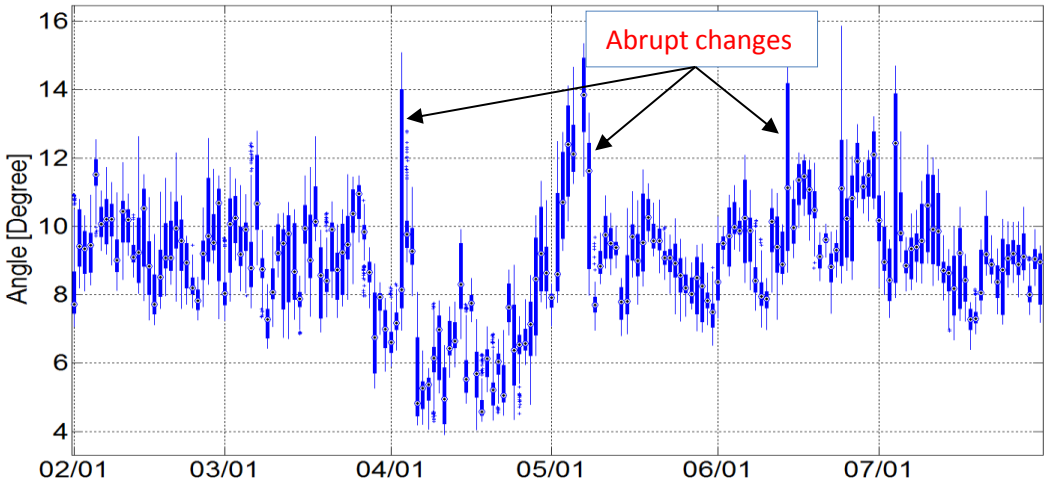
E. Observations from Table B-2:

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%).

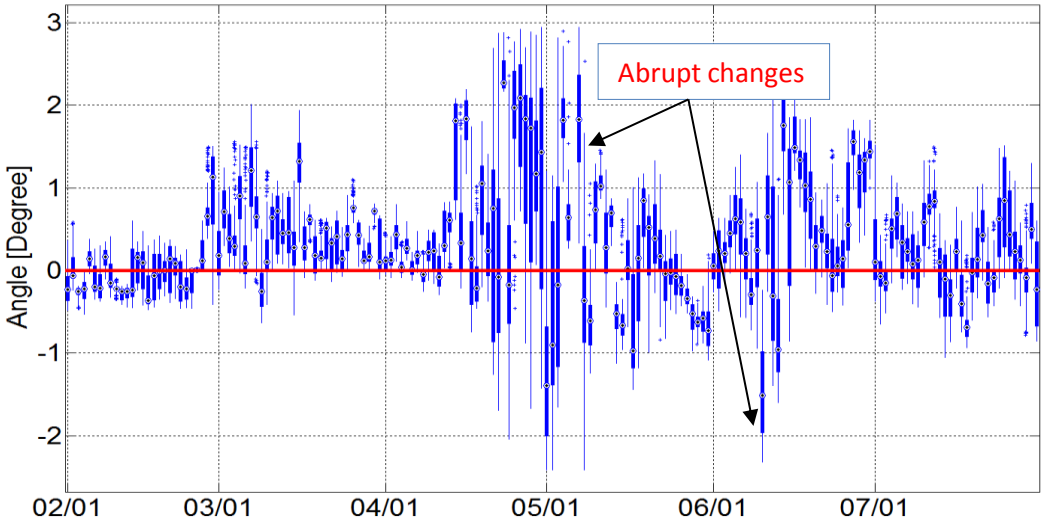
F. Observations from State Estimator Box-Whisker Plots (Appendix B - Part 1)

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 the 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 for 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 suggests 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 FROM (inbound power flow) direction and the positive values apply in the FROM to 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 Update 3 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 (Reference: 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 angle 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 spread 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 angle 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. 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. 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 three largest normal condition angles in degrees for angle differences were observed 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 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 (Reference: North 7)

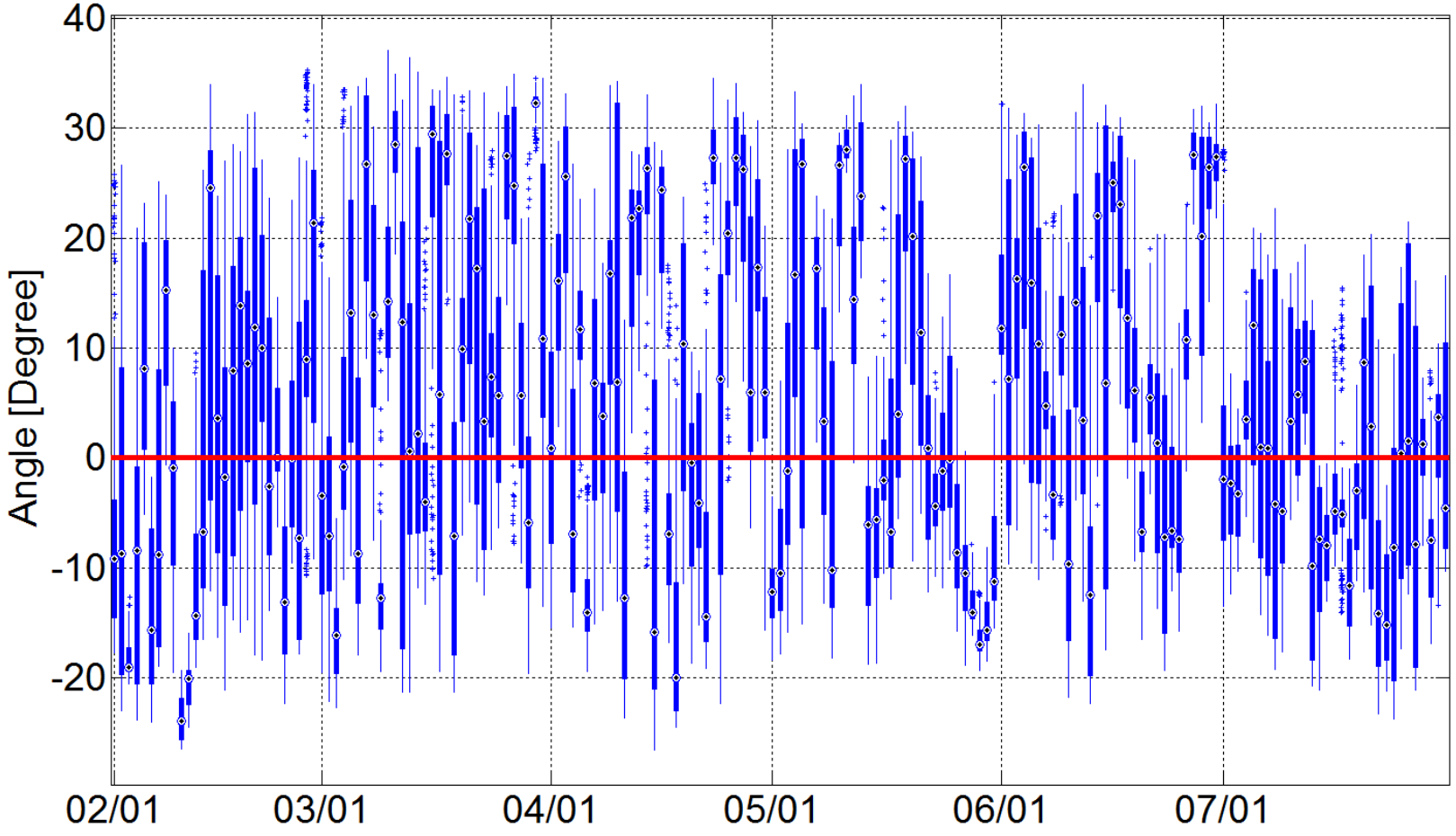
State Estimator Data: February to July 2014
Box-Whisker Plots and Time Duration Curves

Electric Power Group

CCET

ERCOT

West 10-North 7



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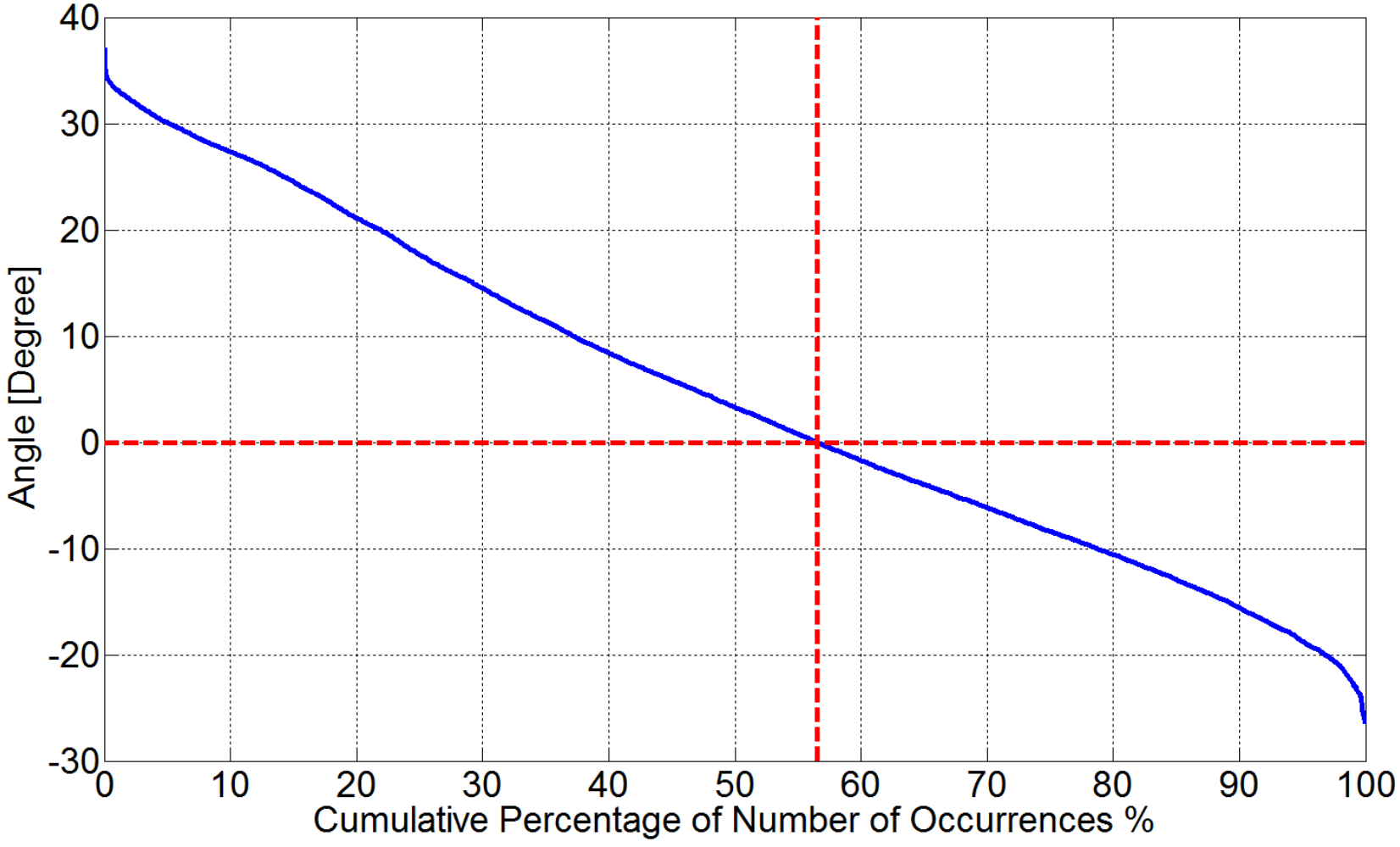

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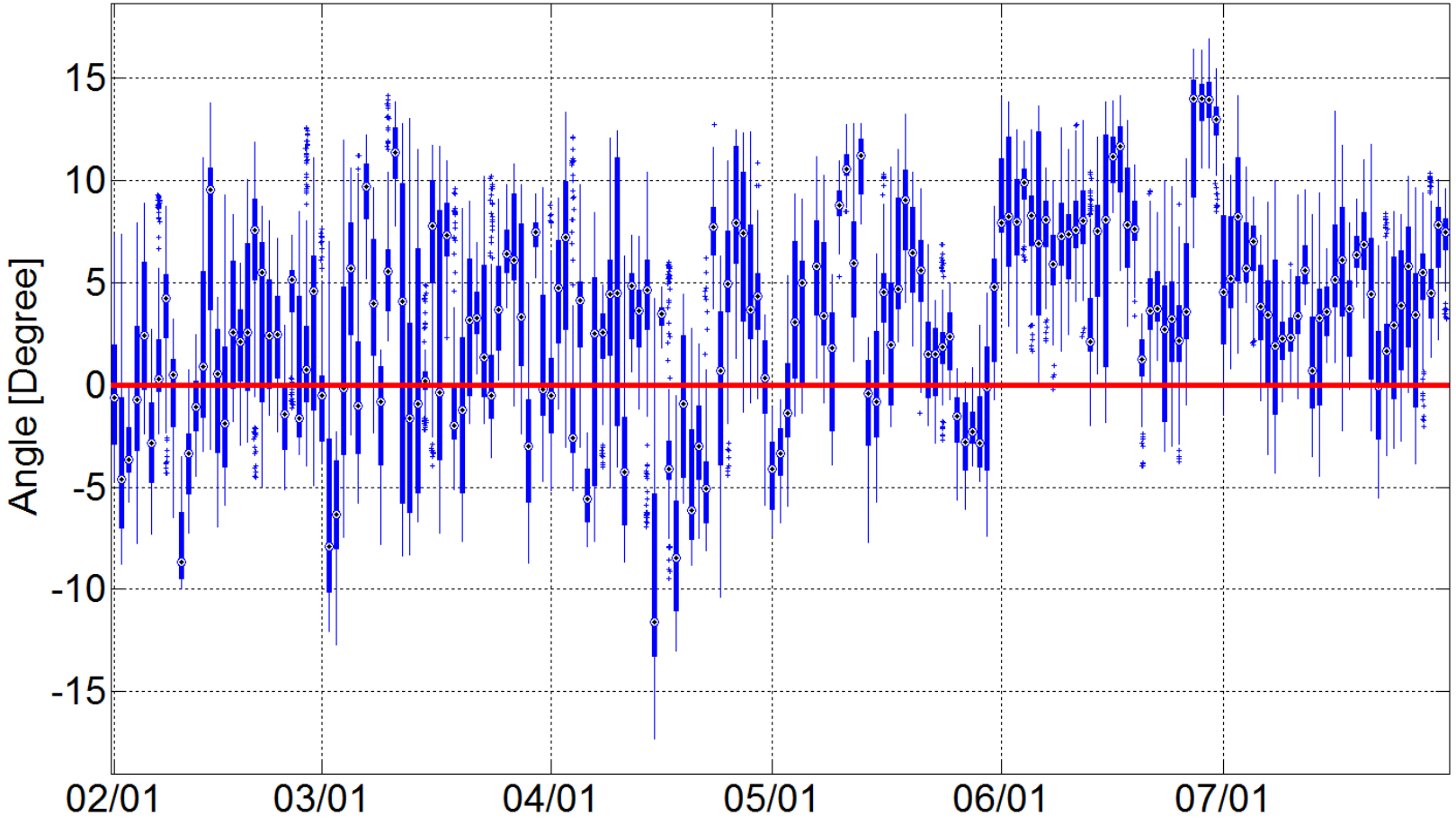

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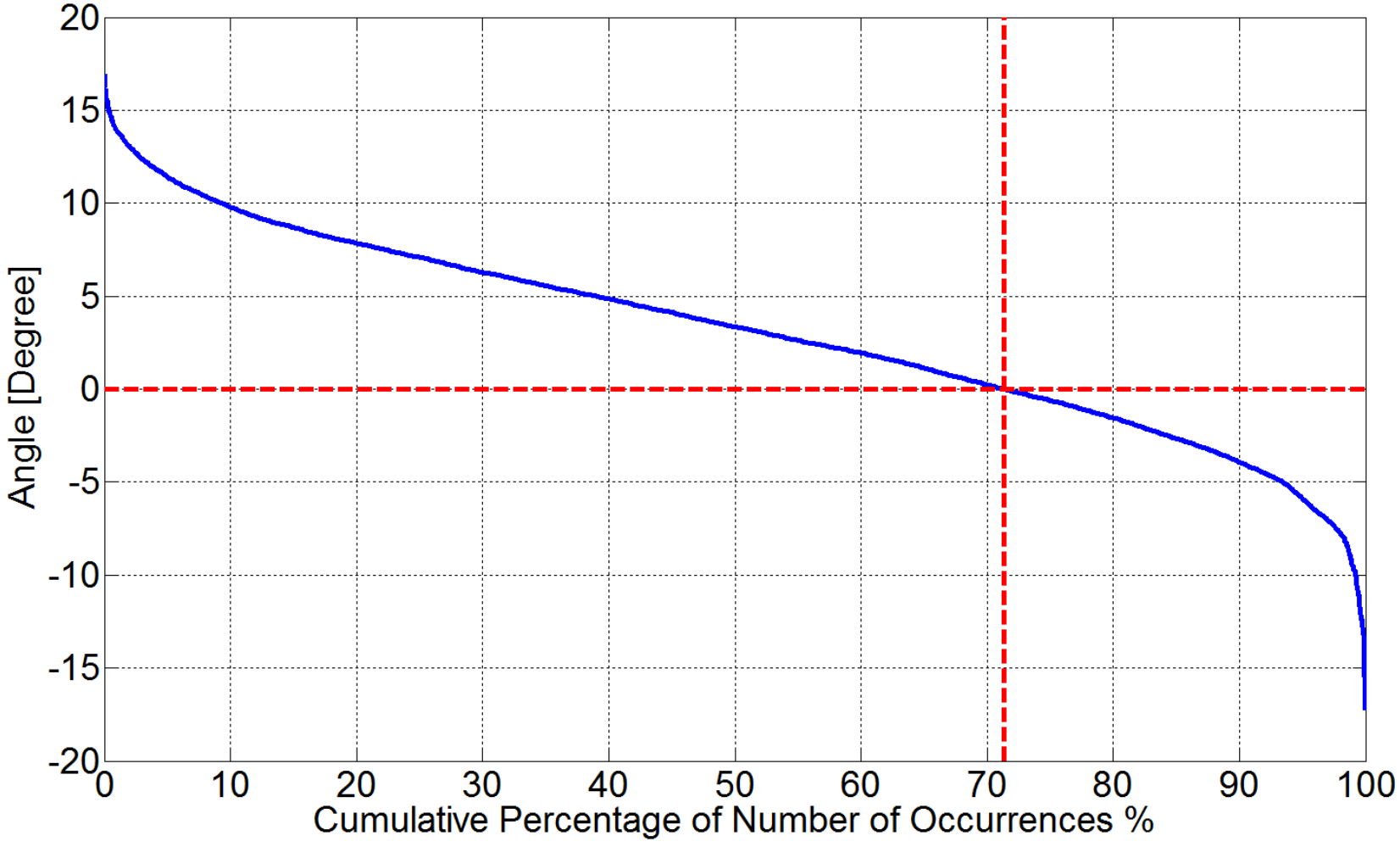

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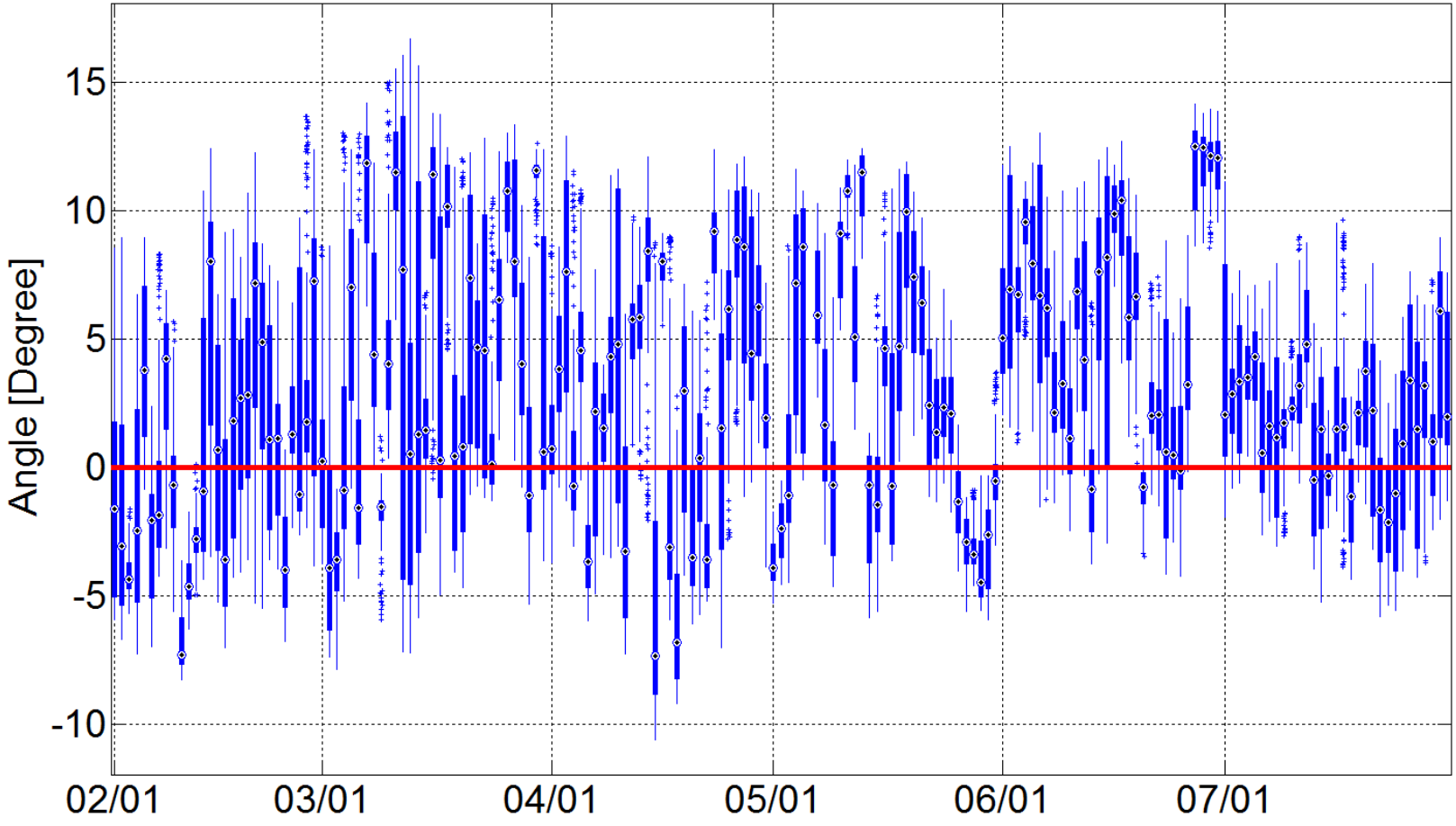

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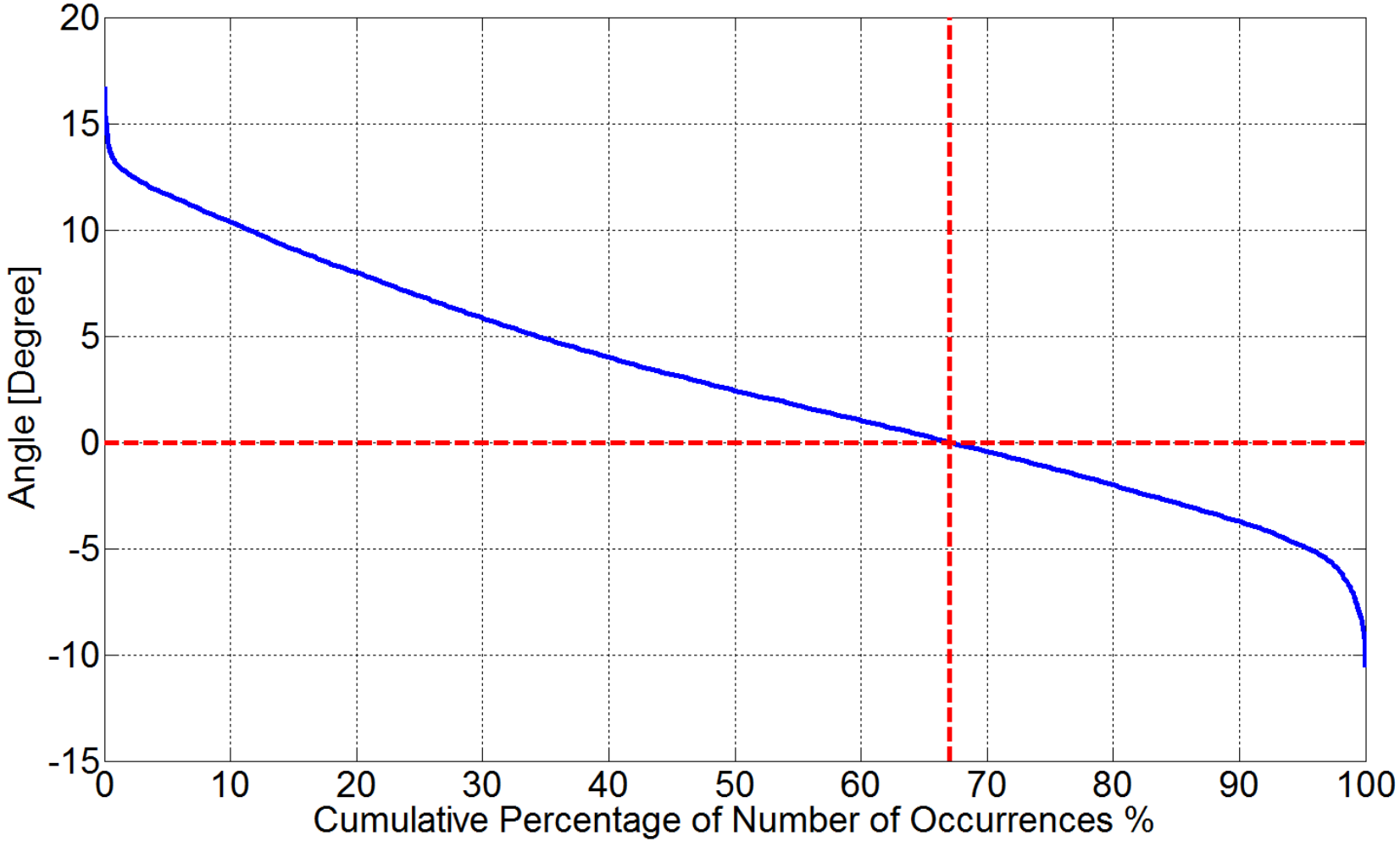

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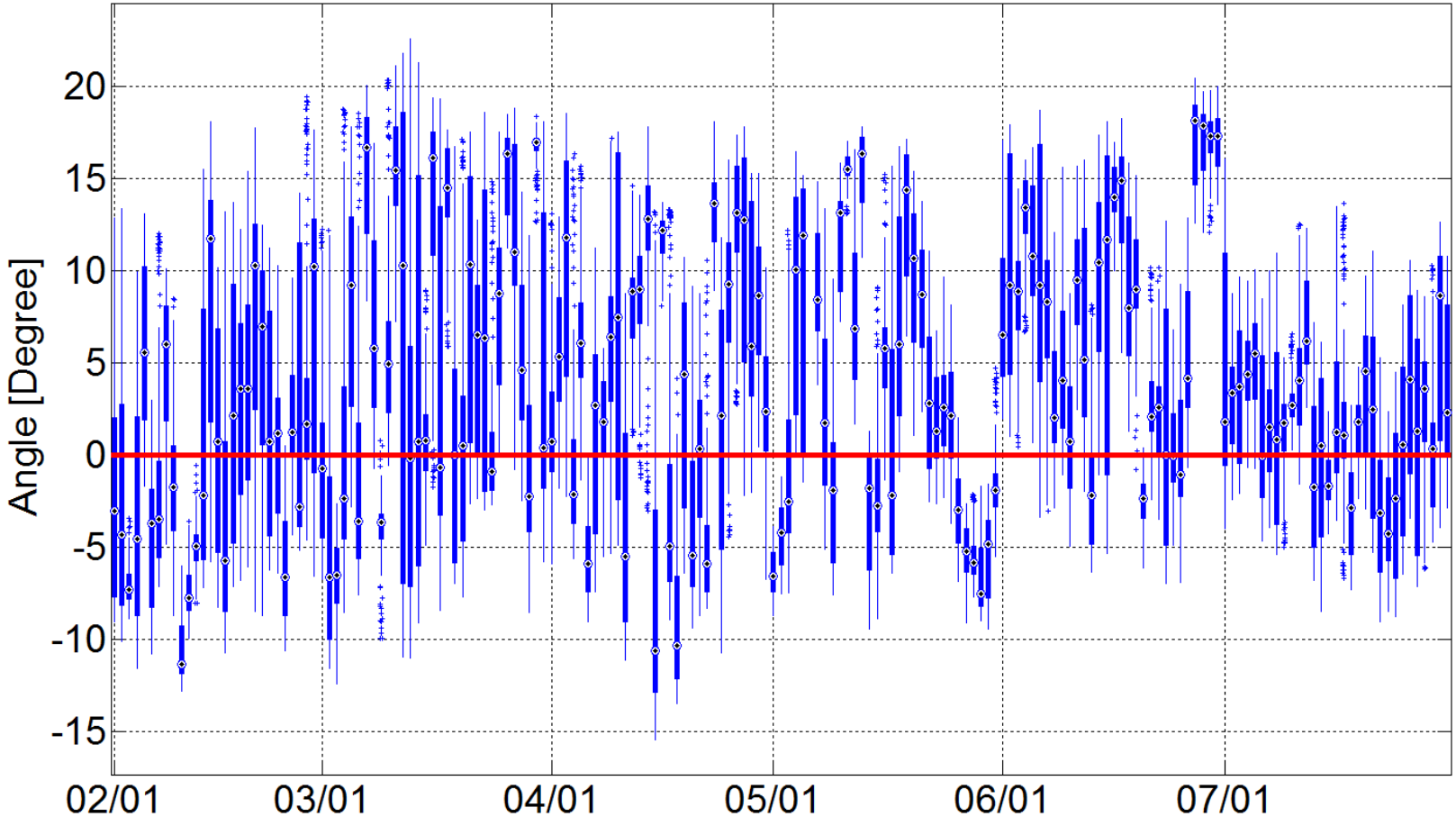

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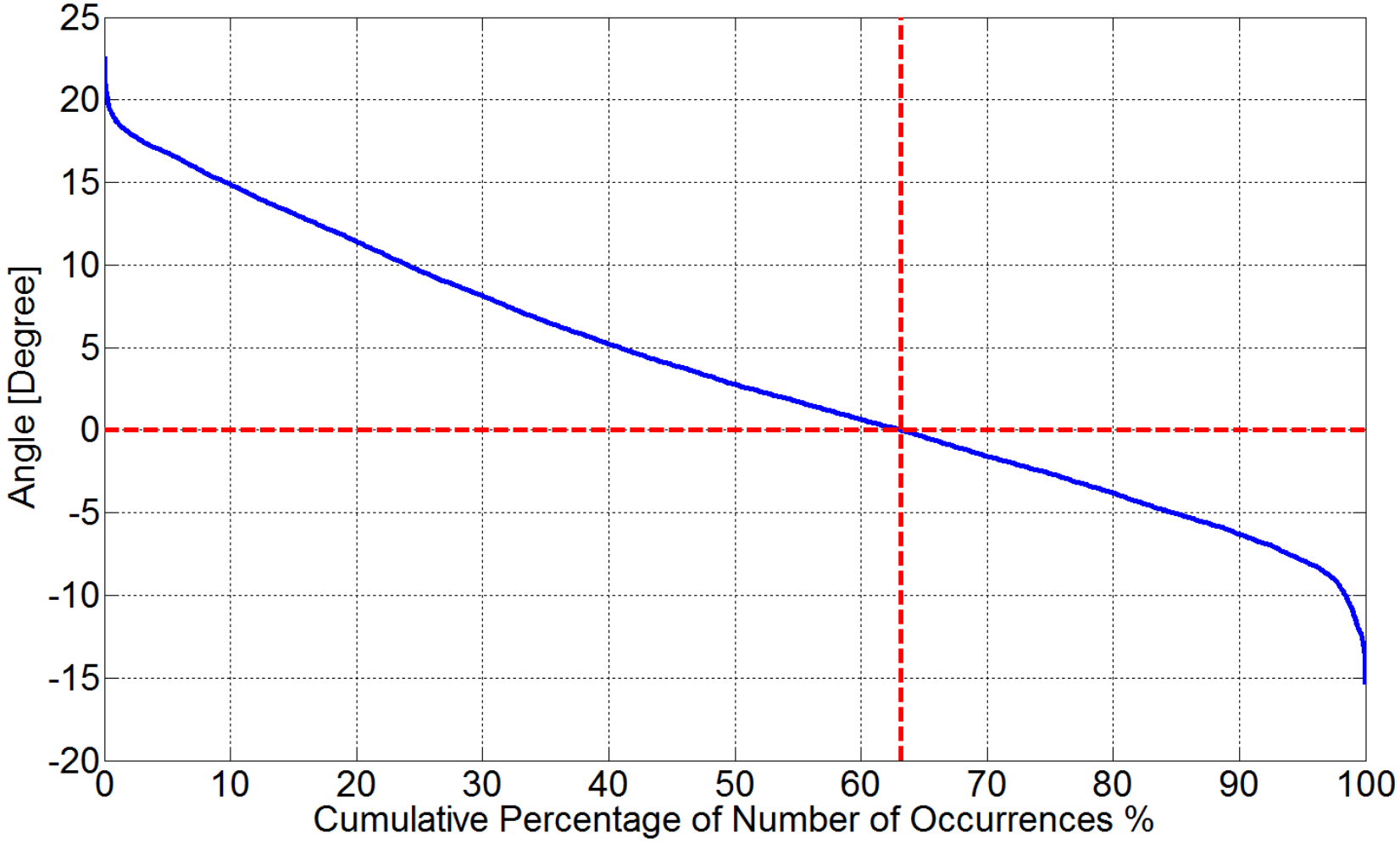

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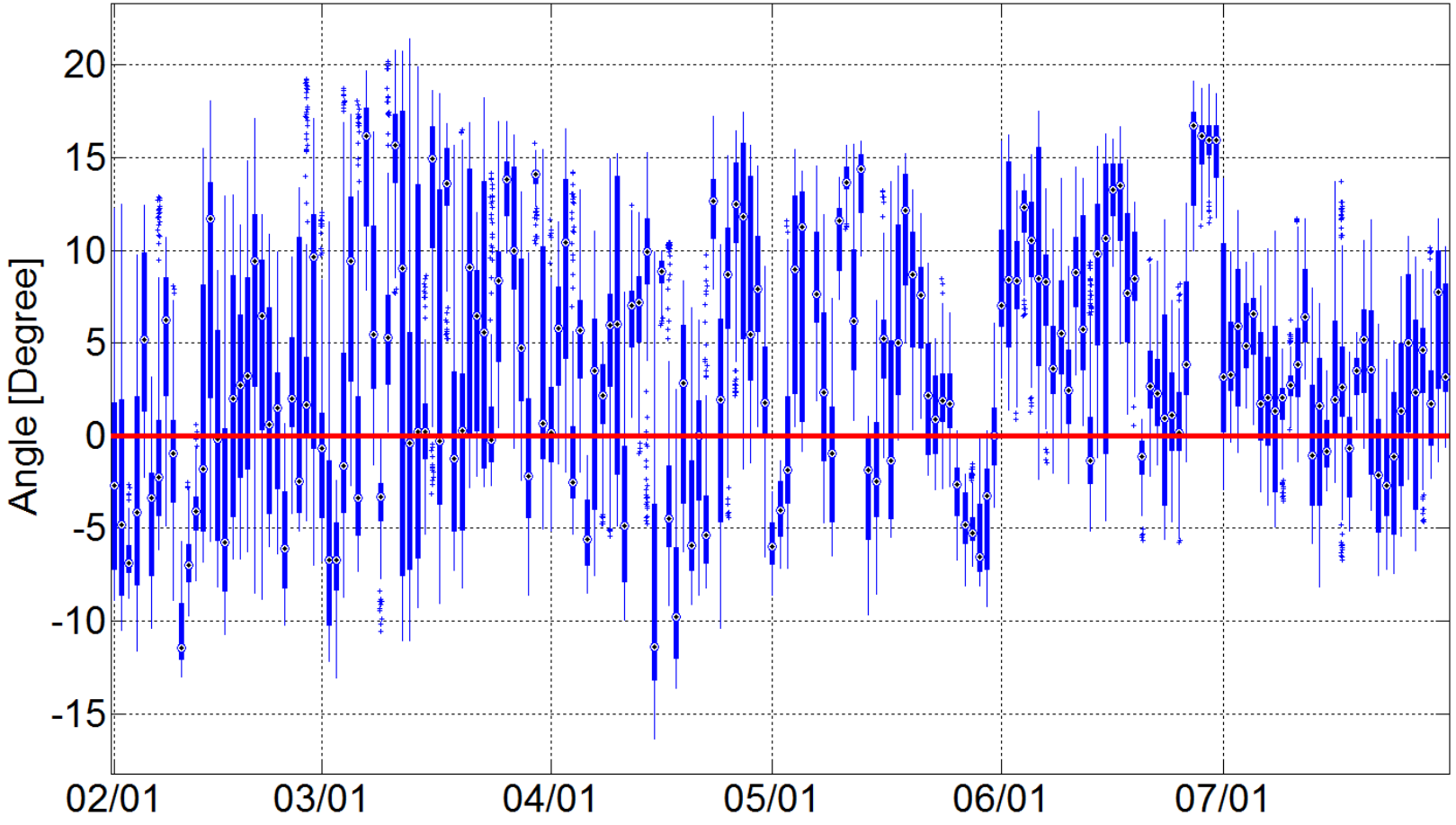

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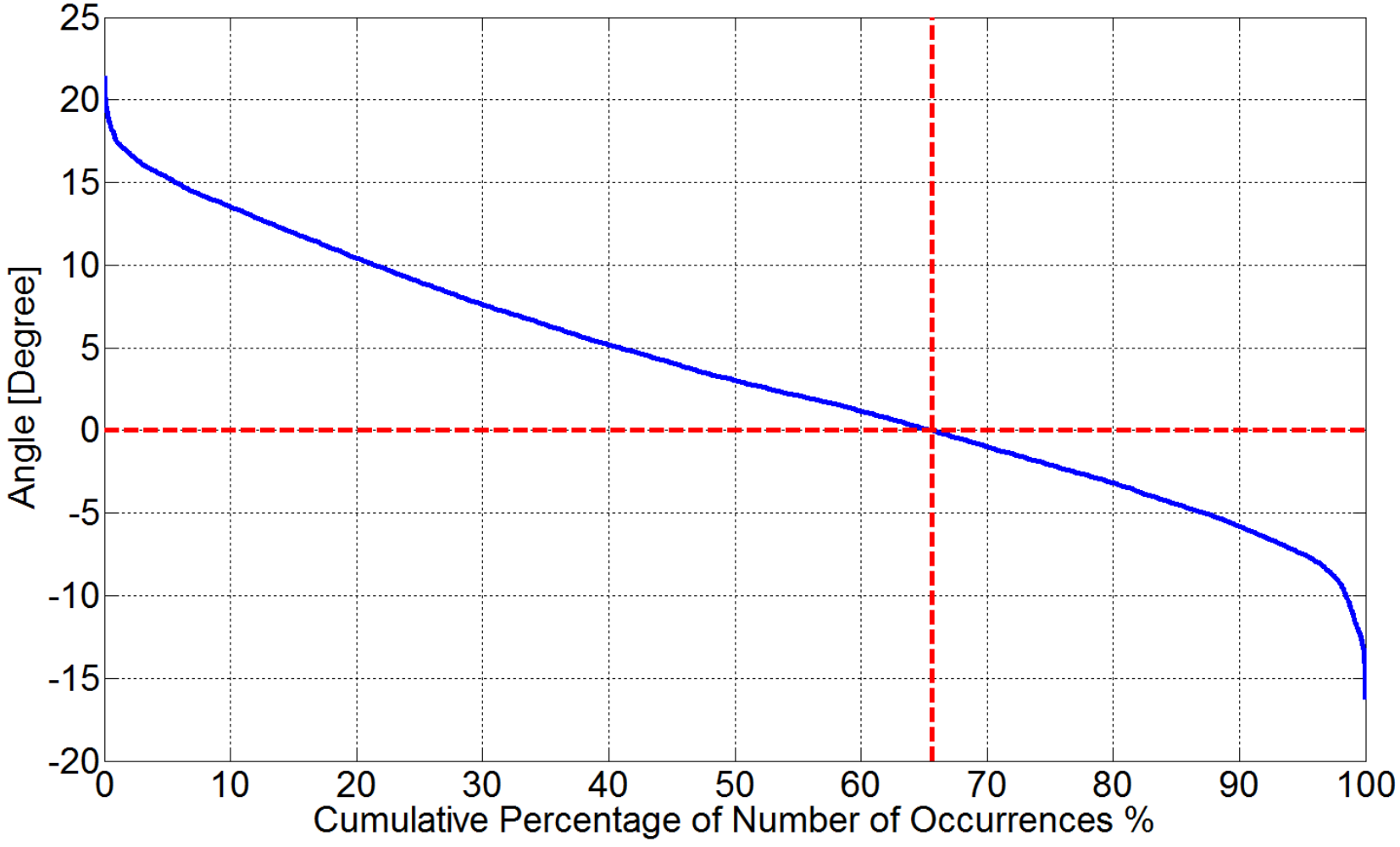

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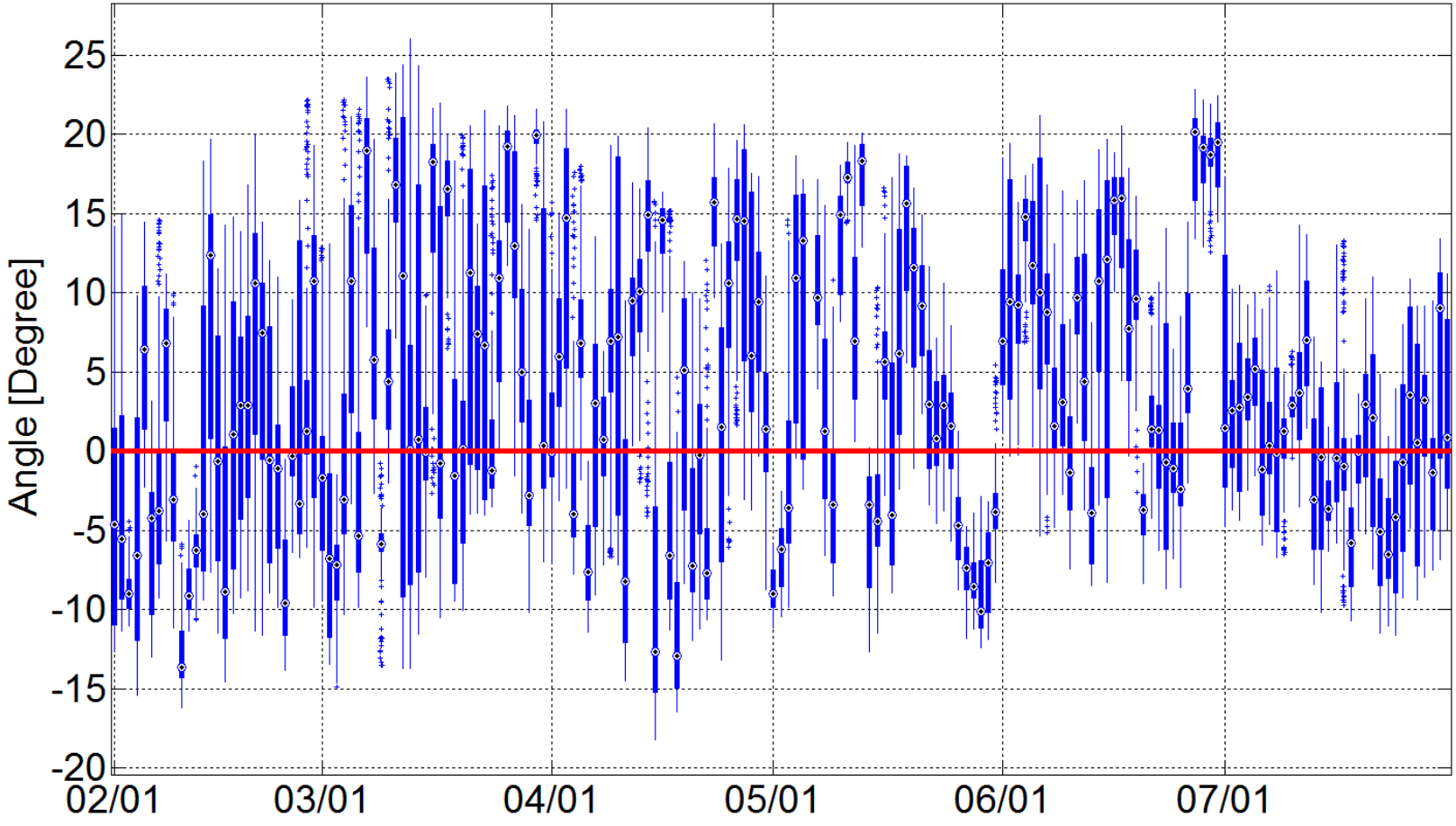

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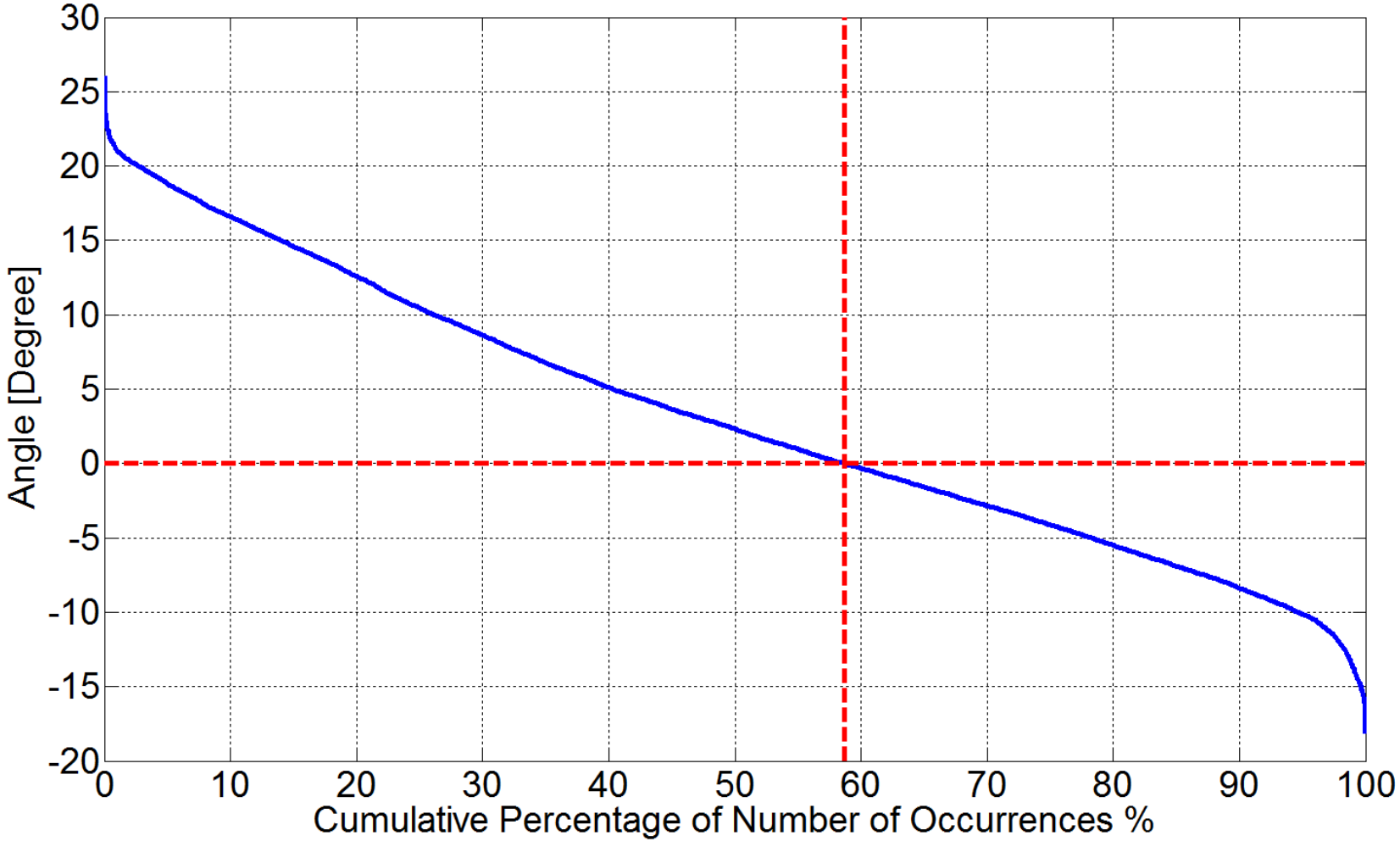

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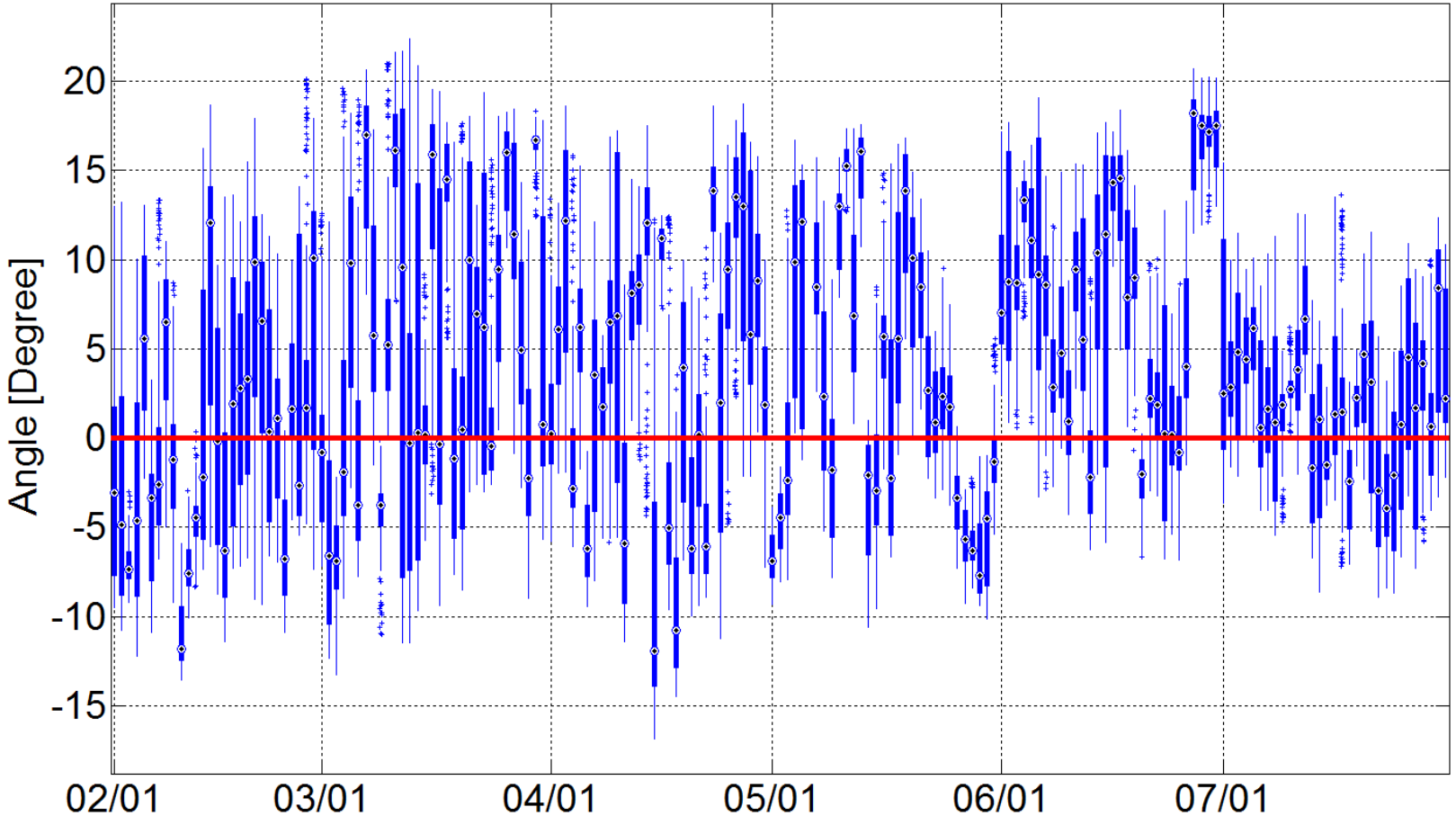

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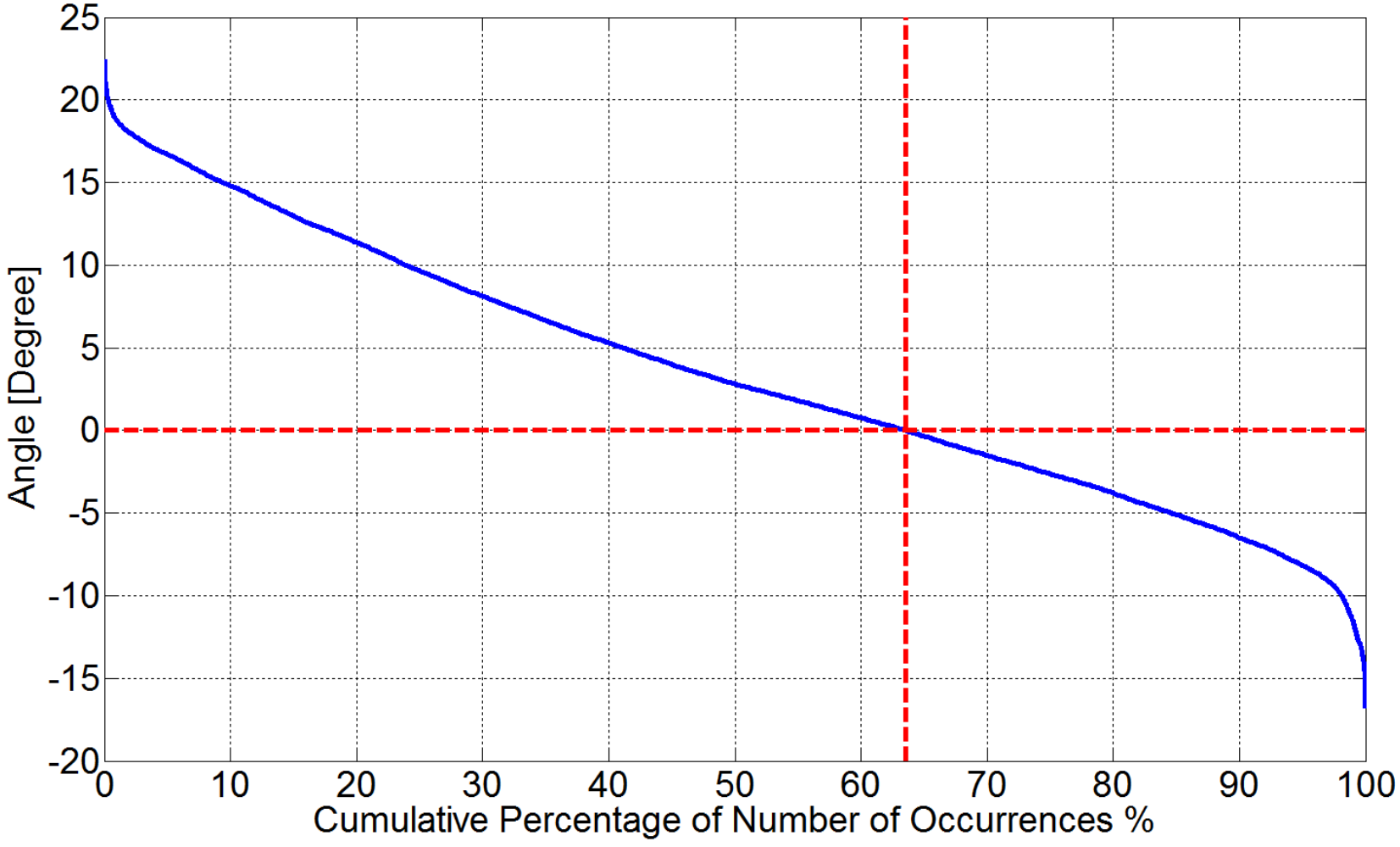

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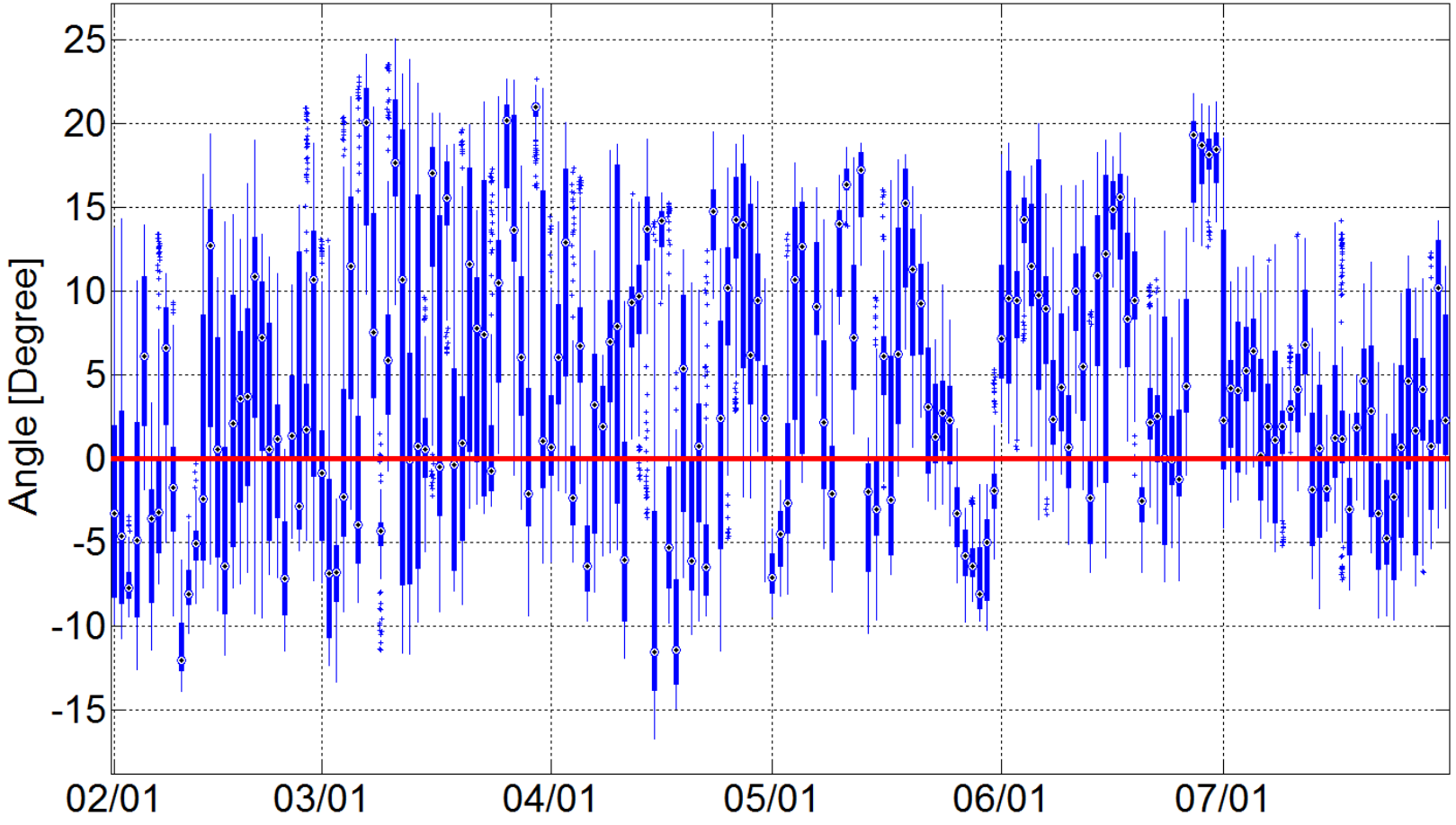

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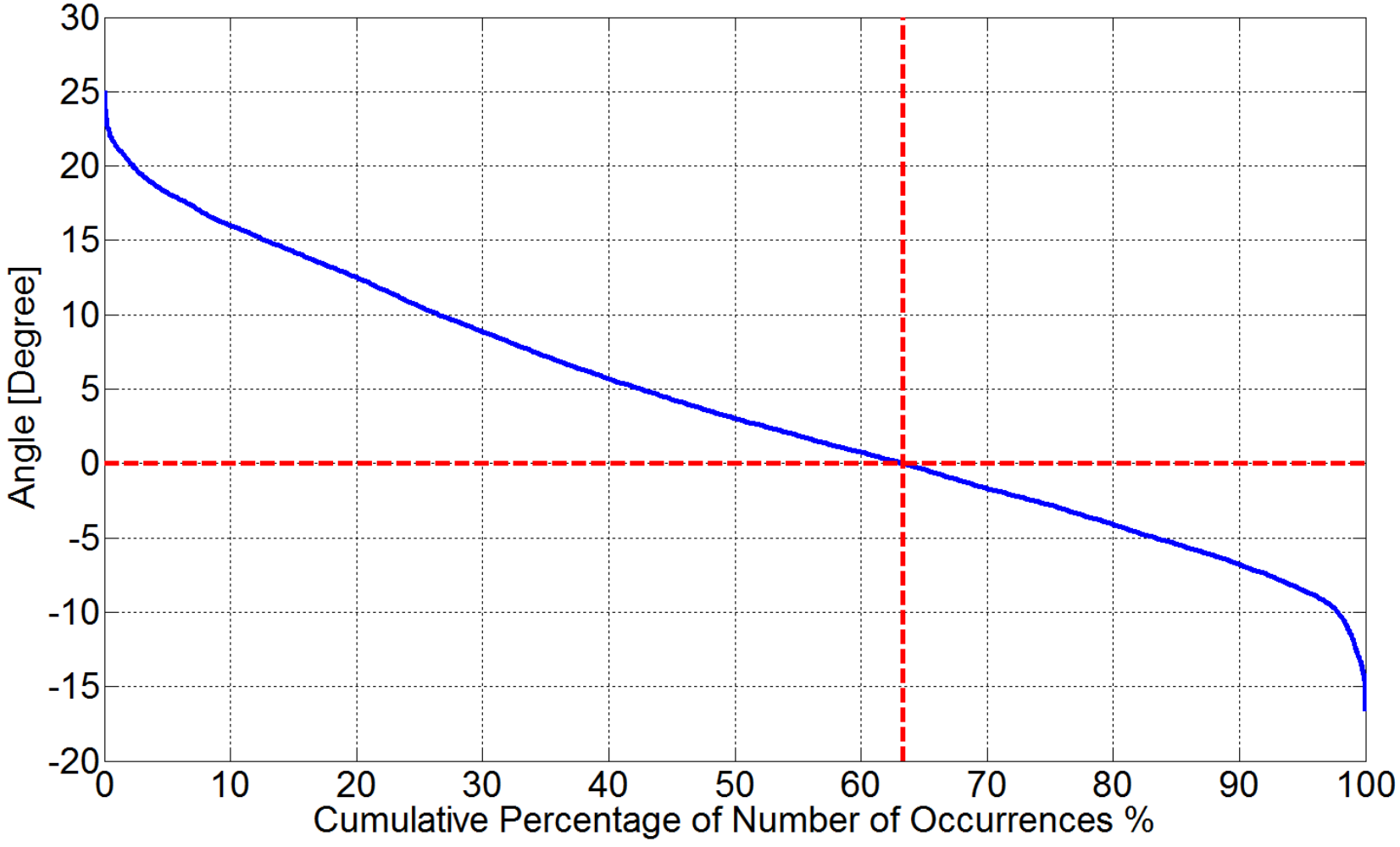

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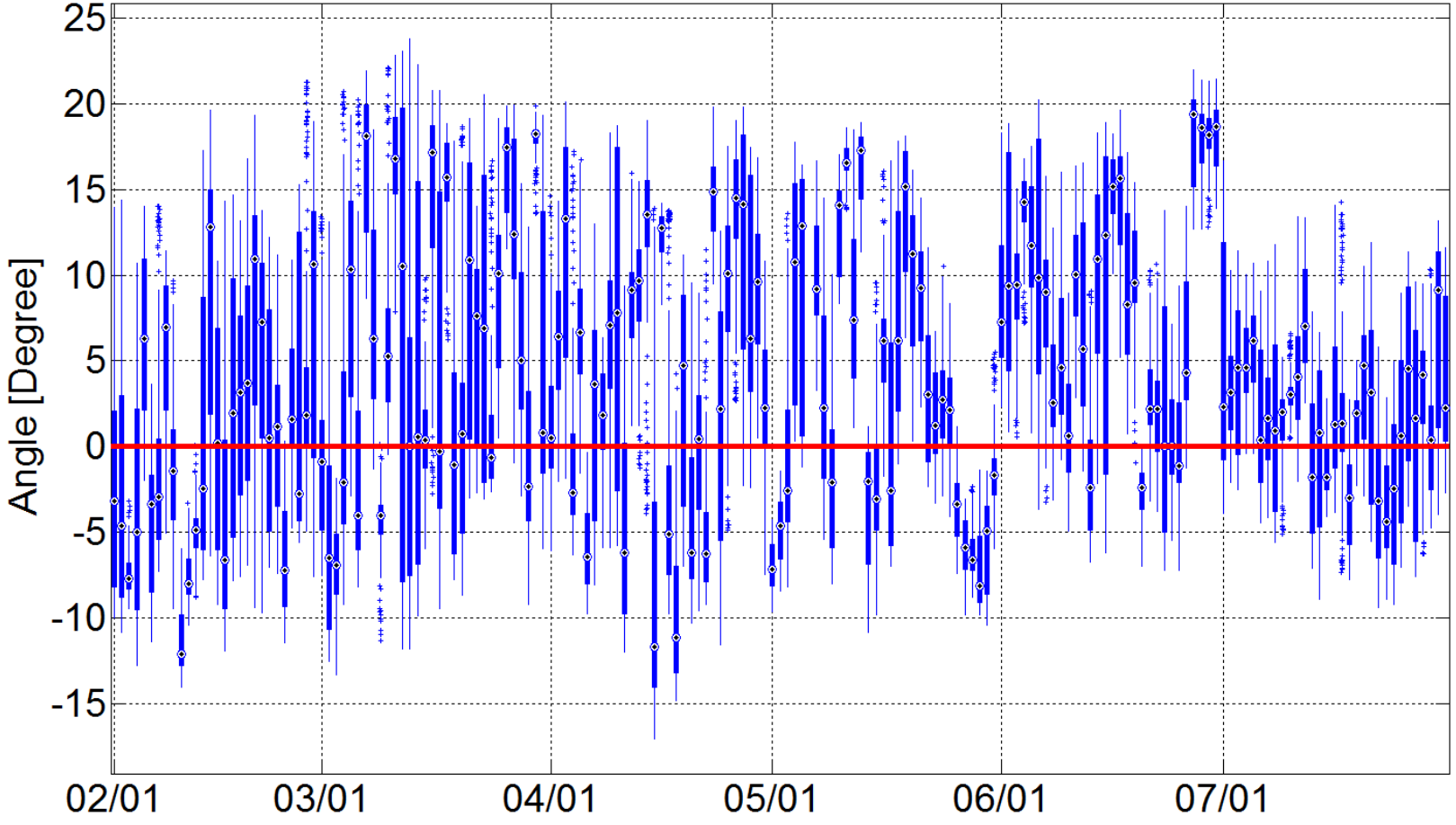

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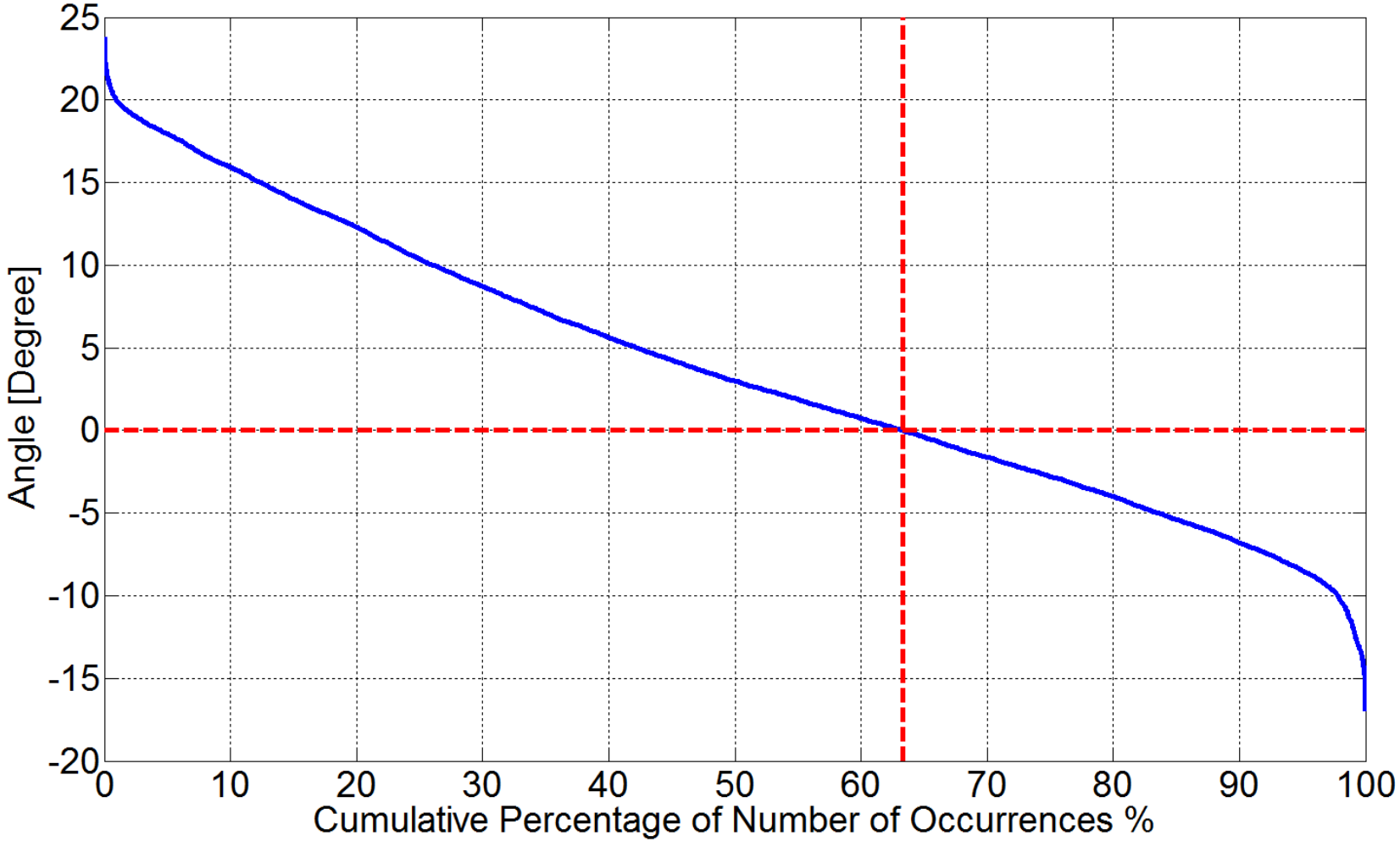

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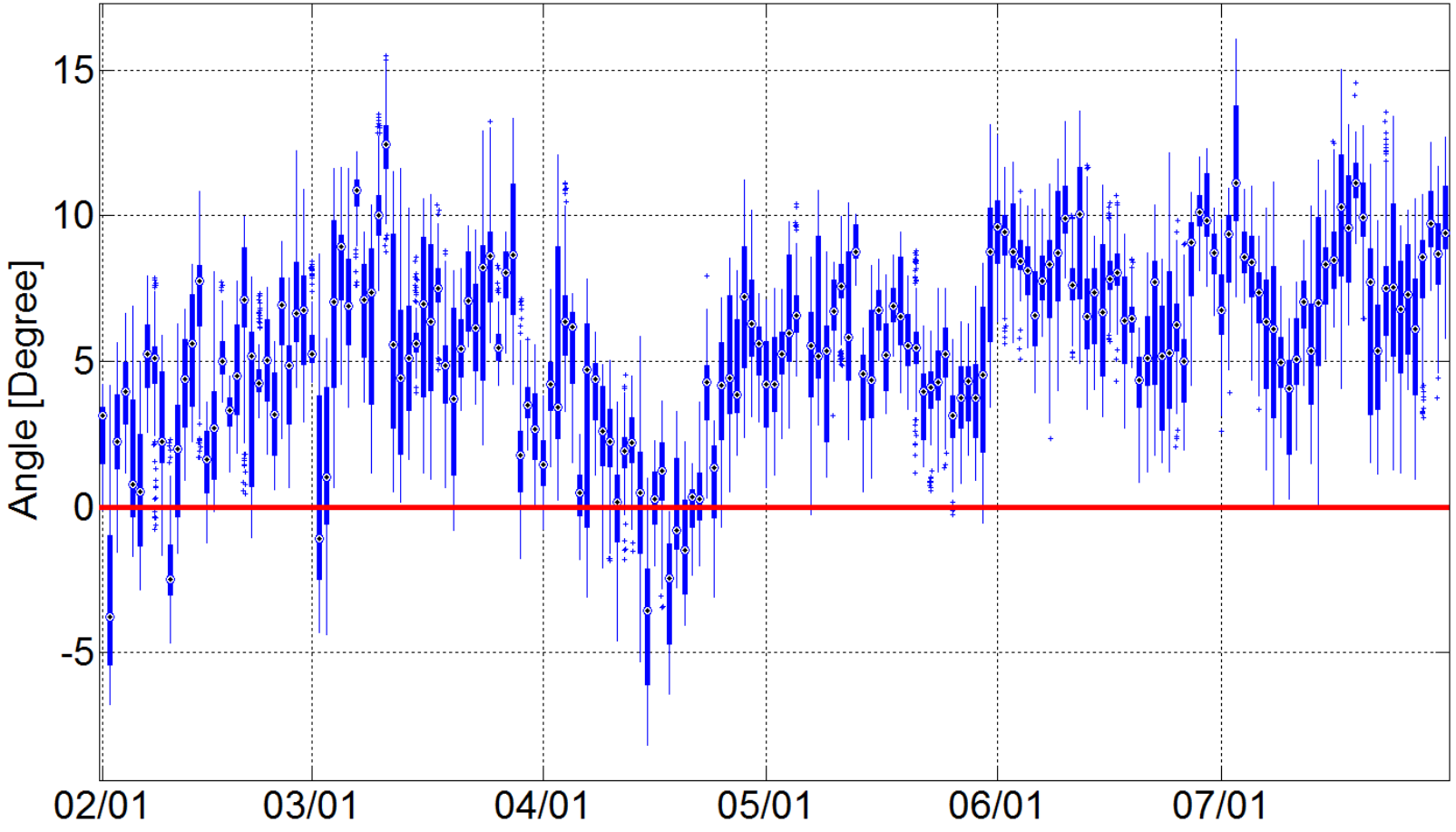

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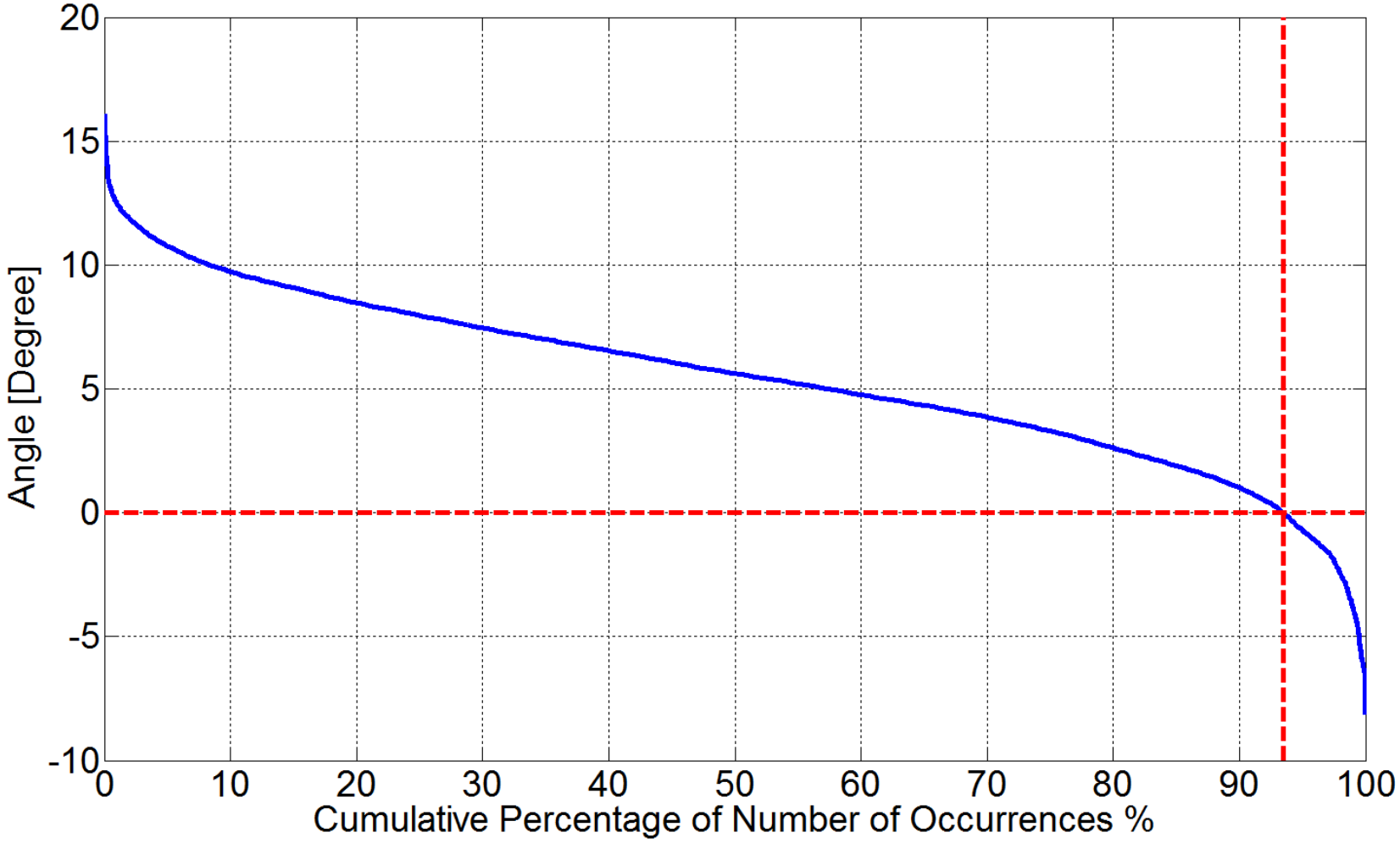

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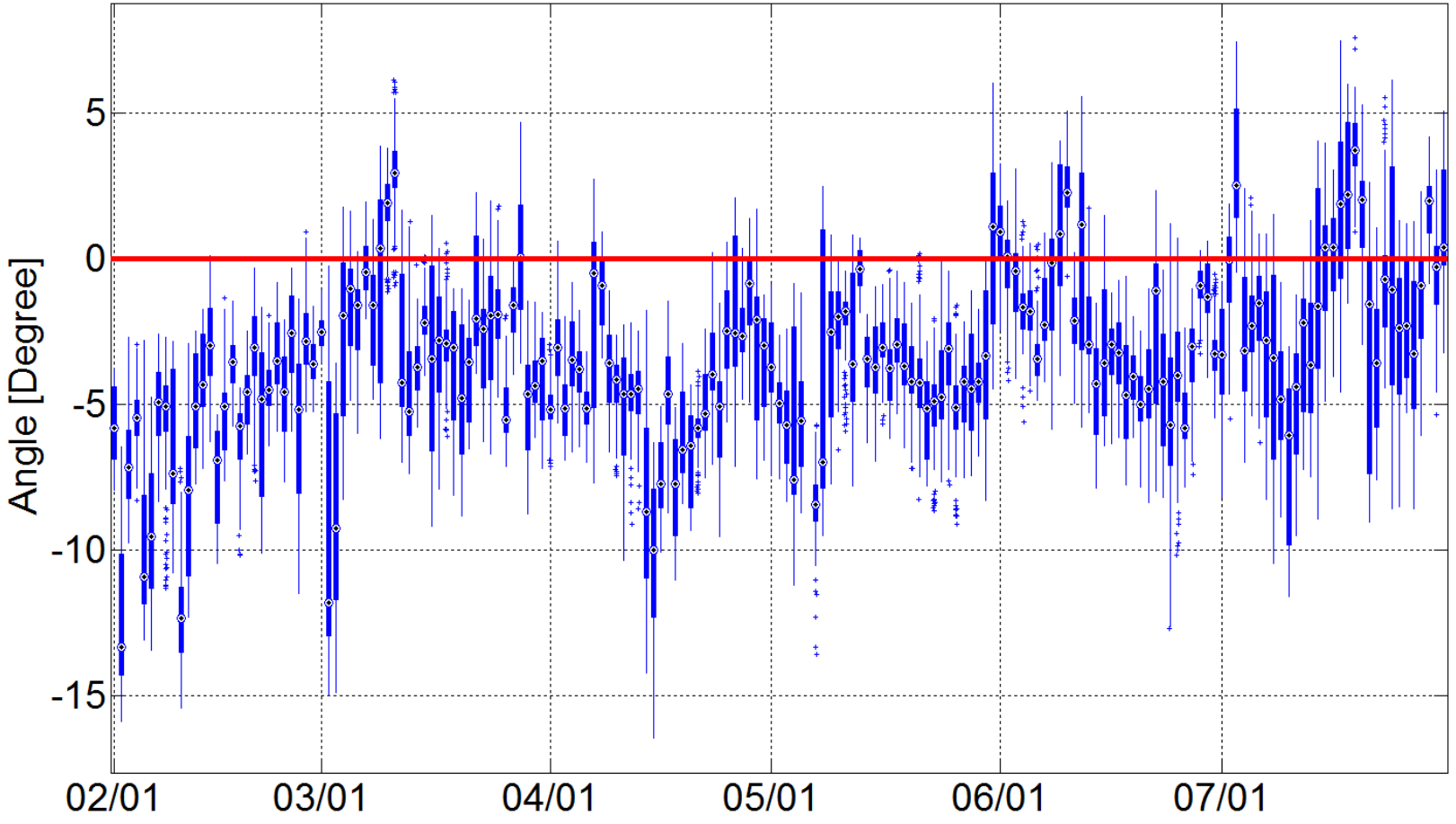

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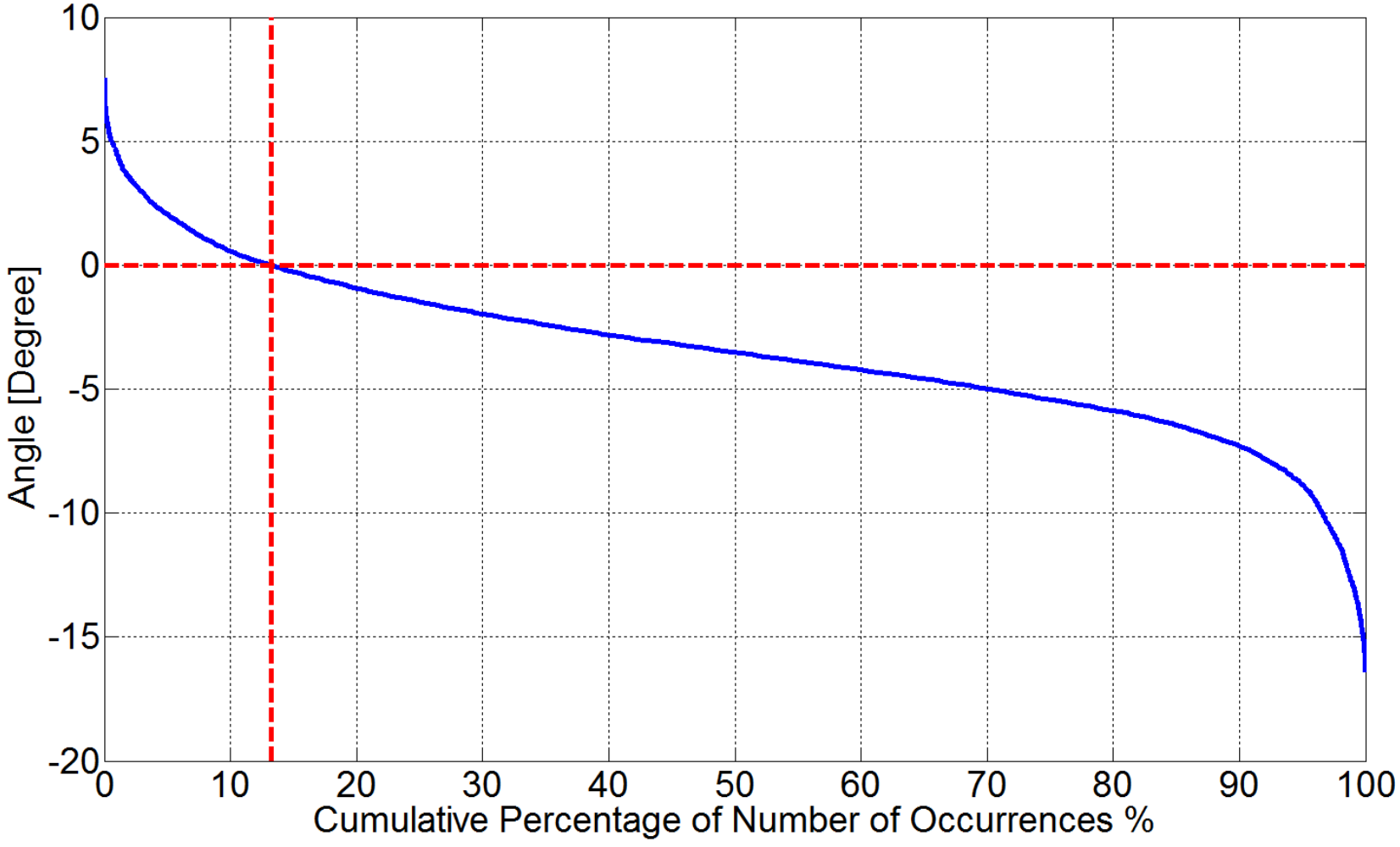

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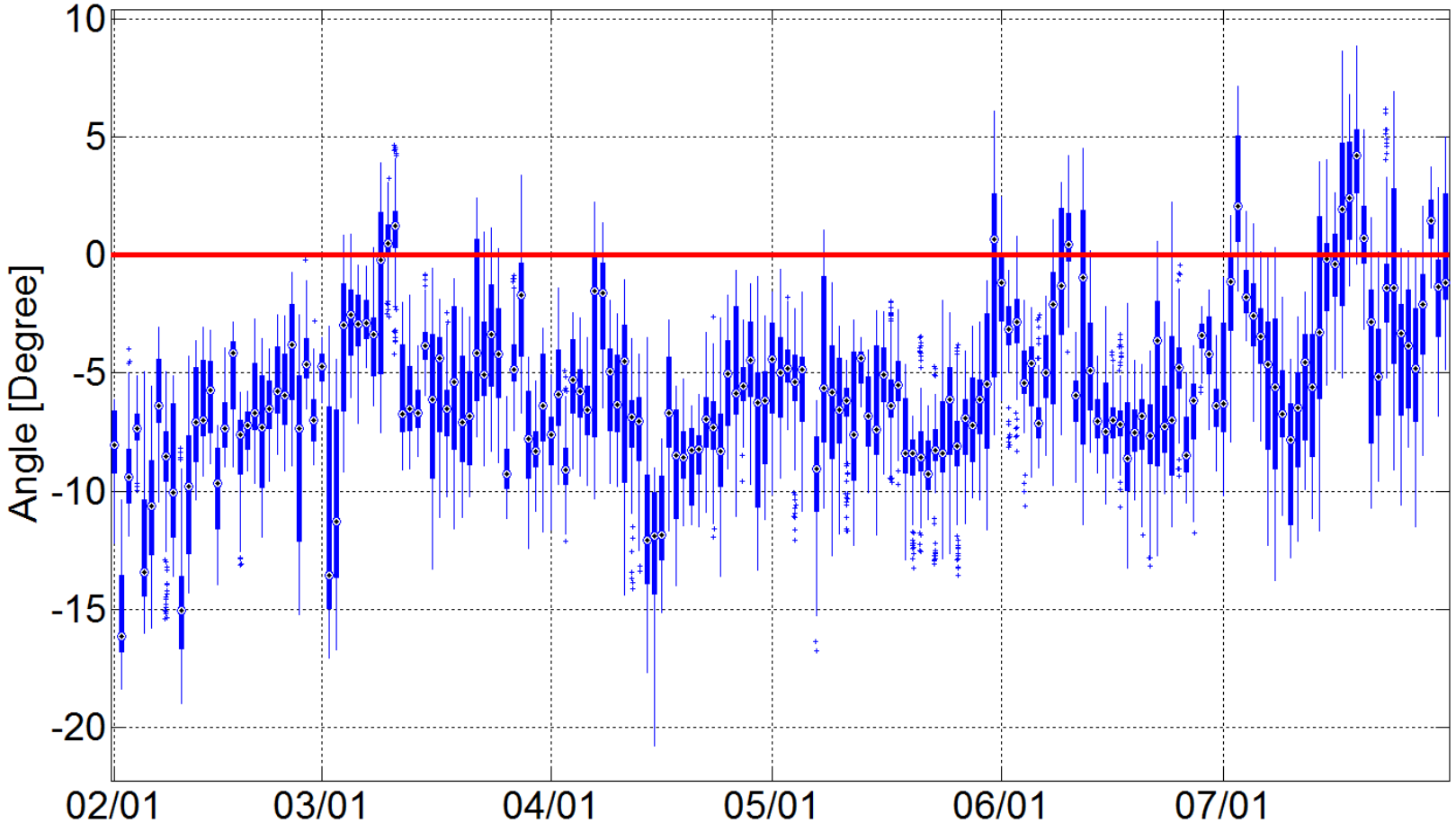

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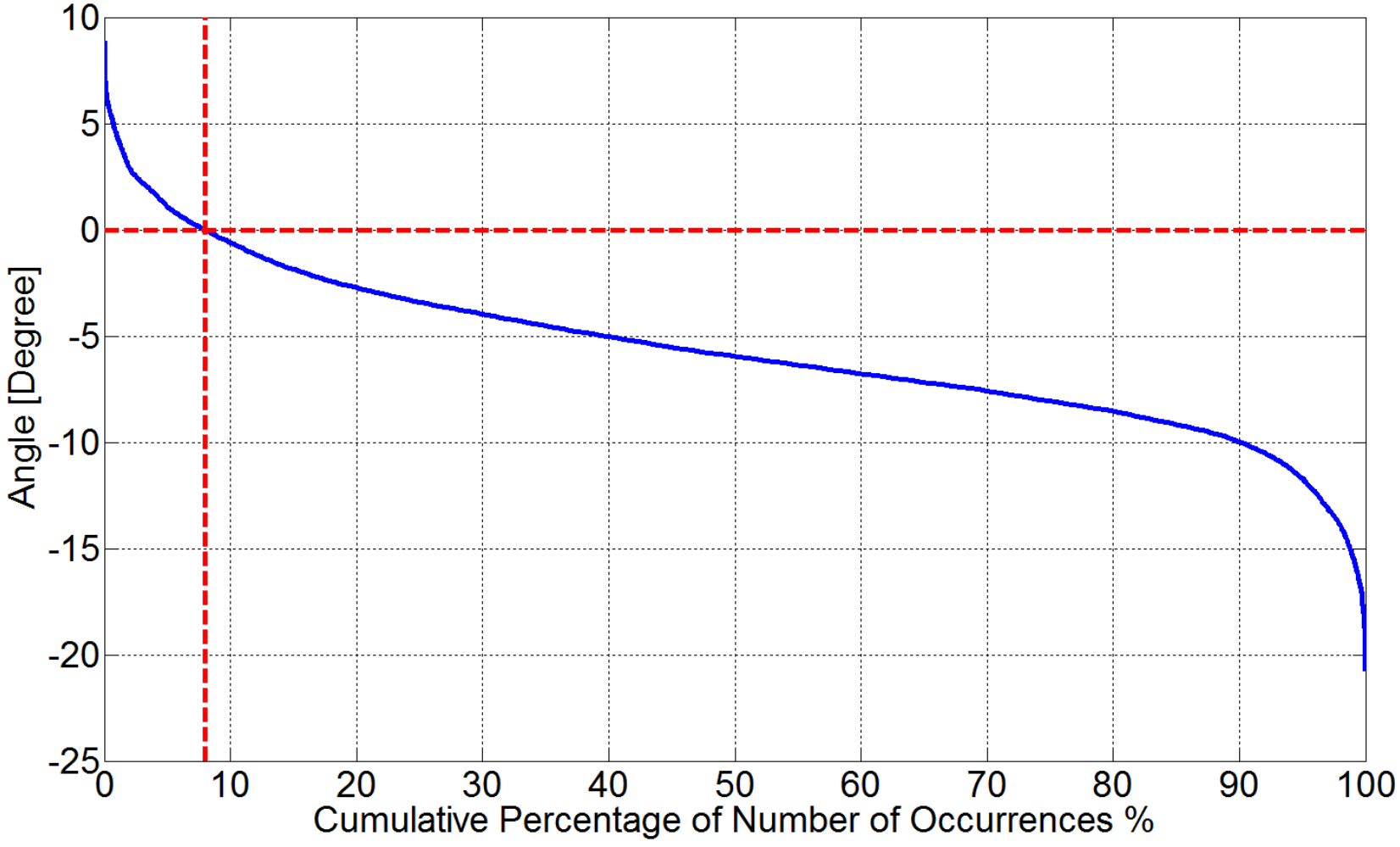

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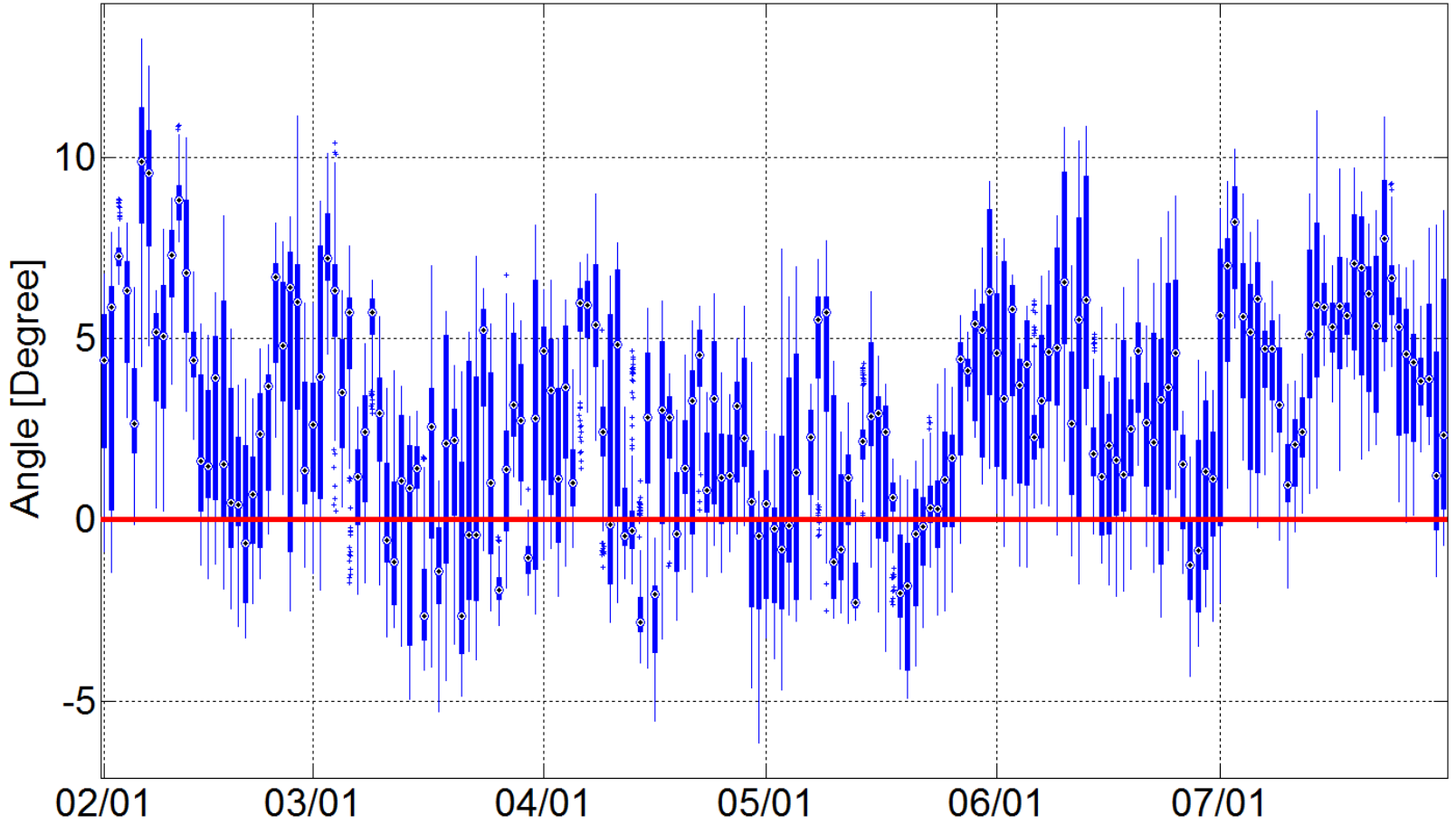

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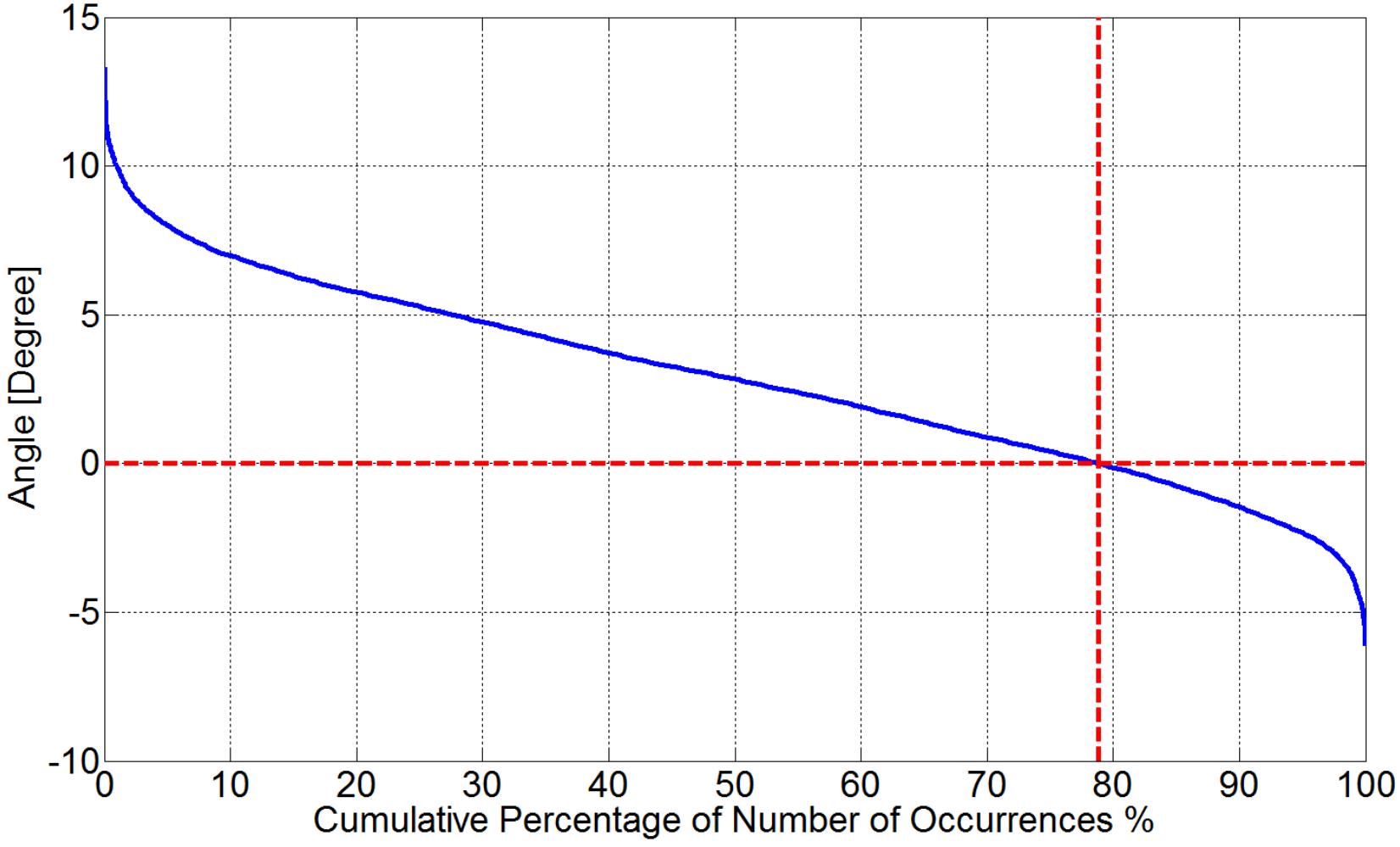

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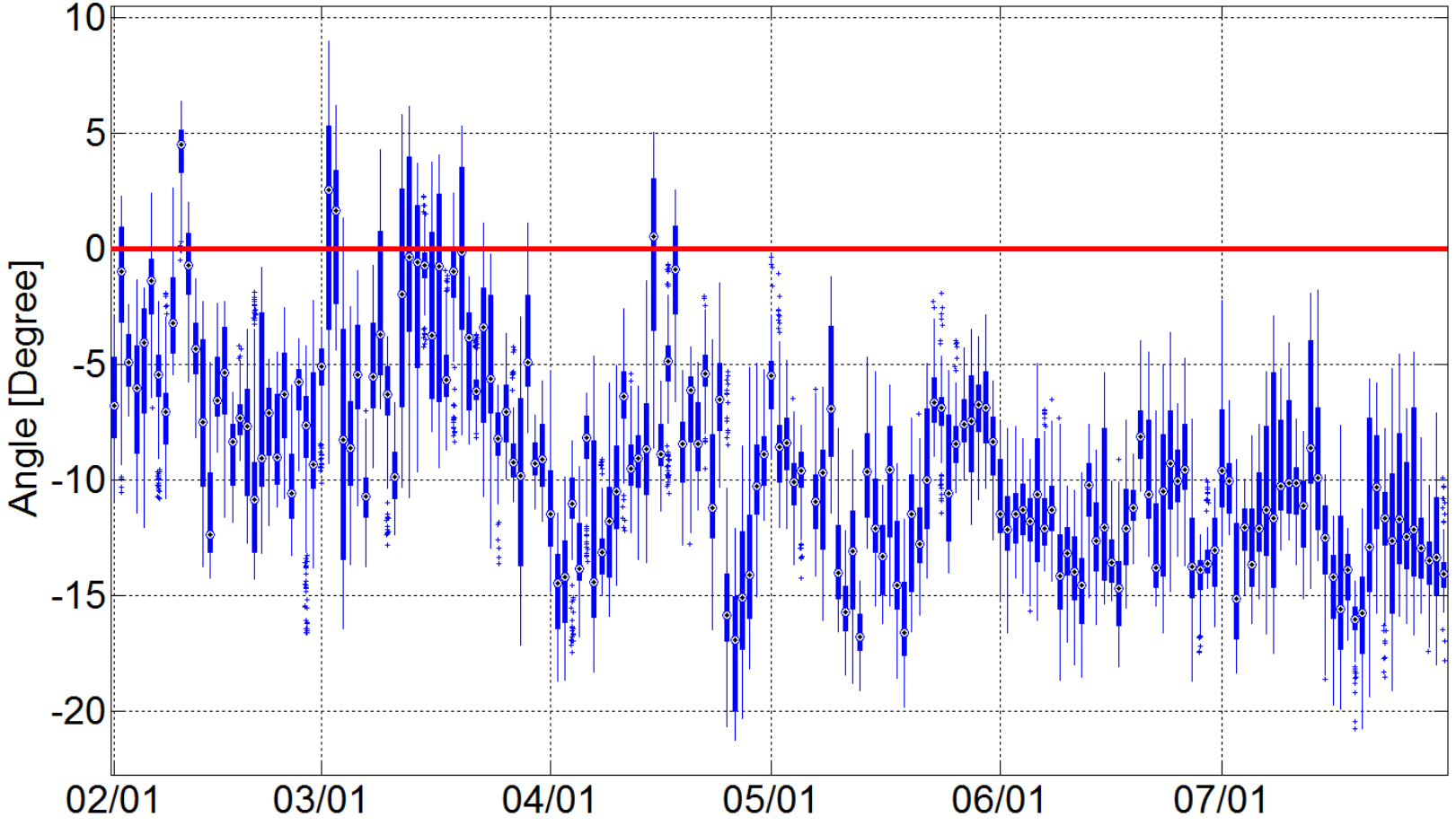

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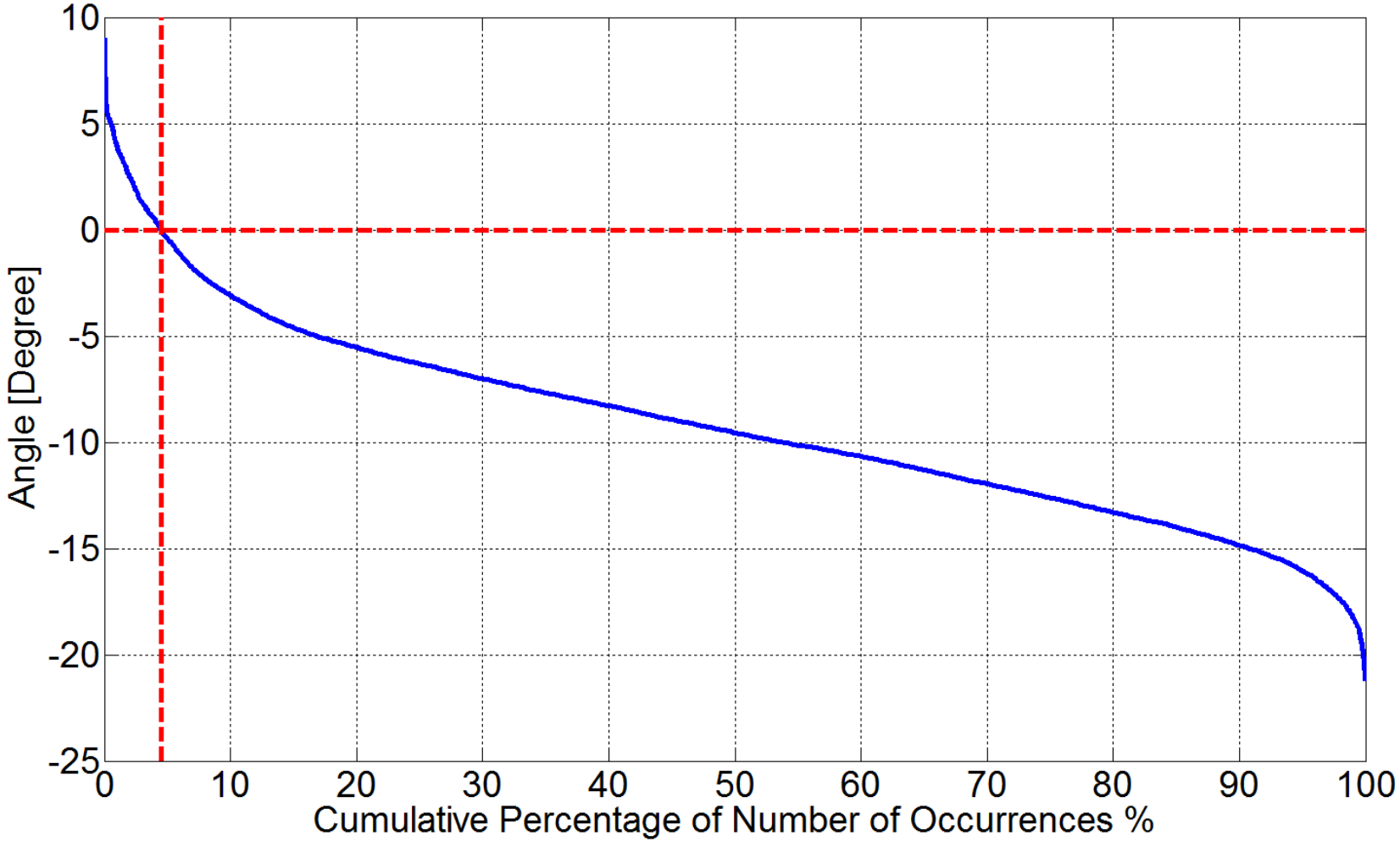

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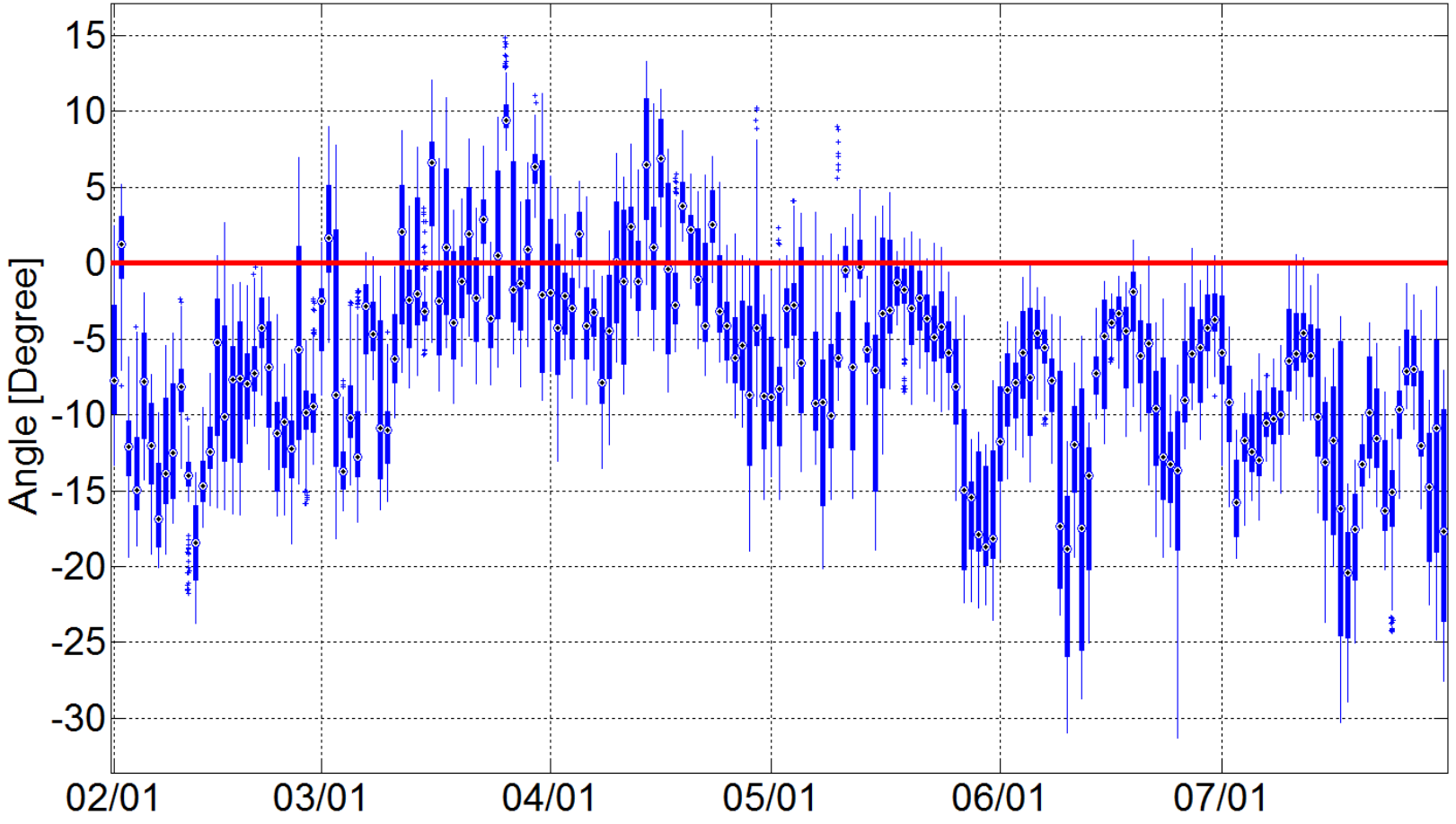

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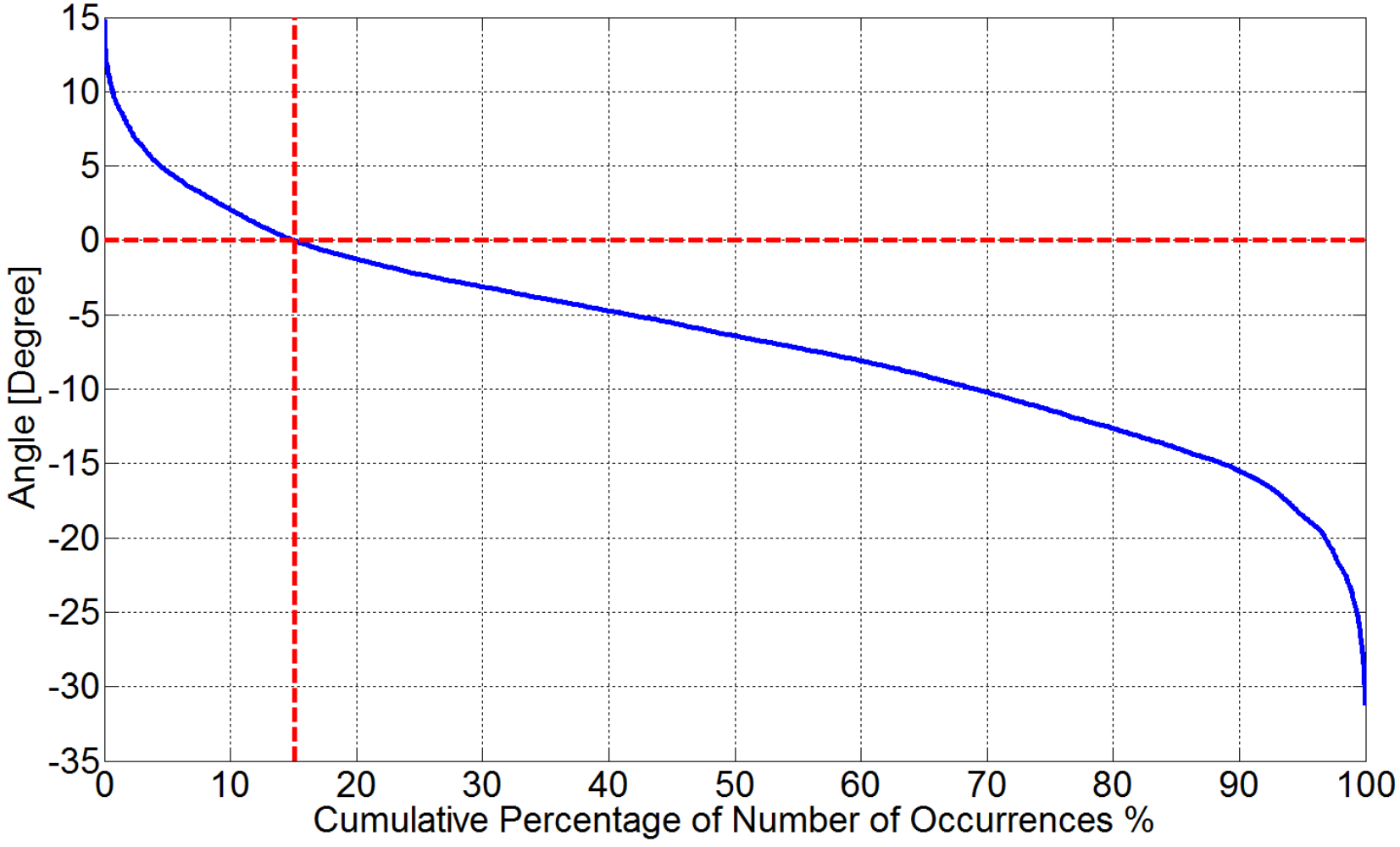

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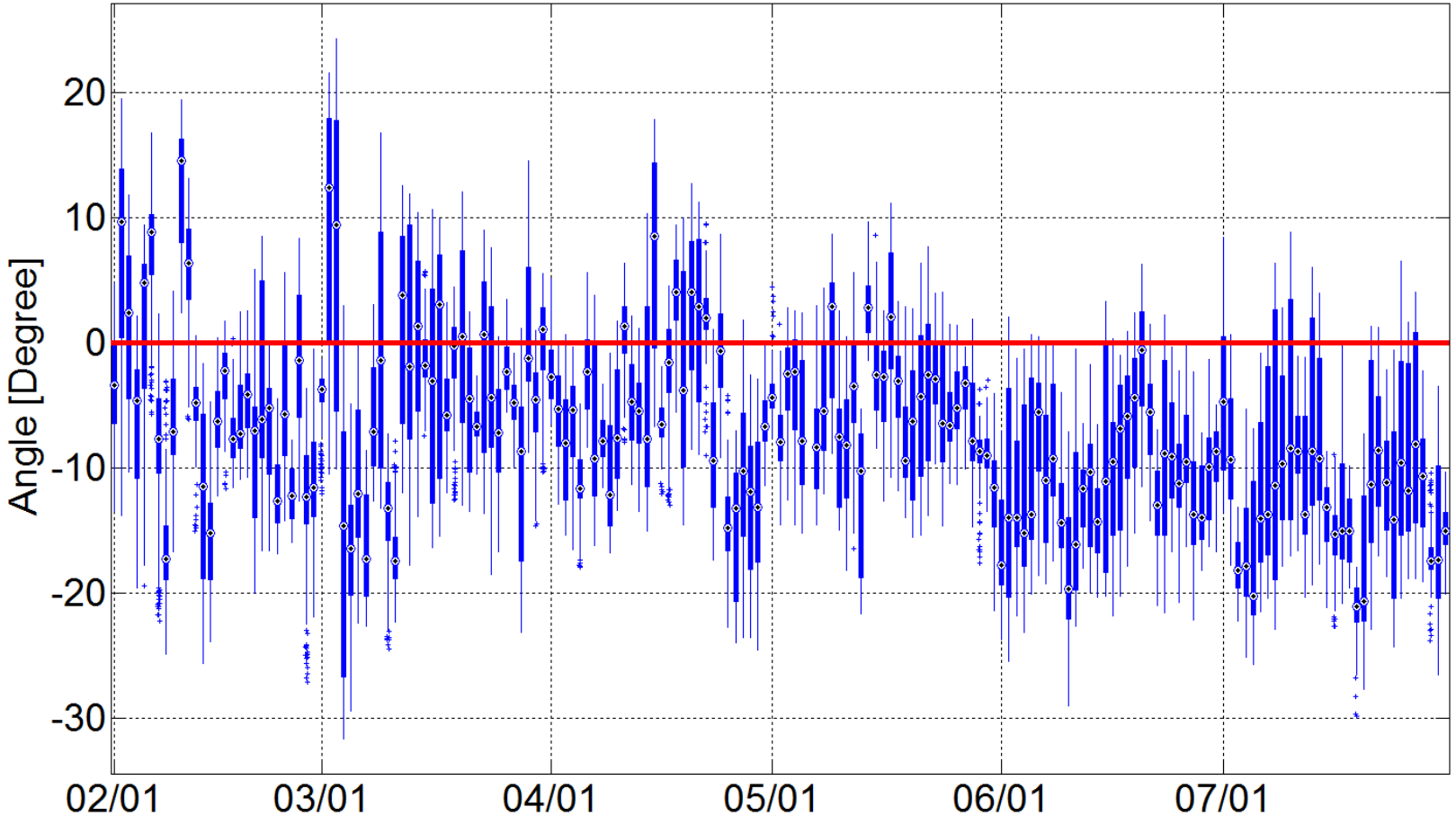

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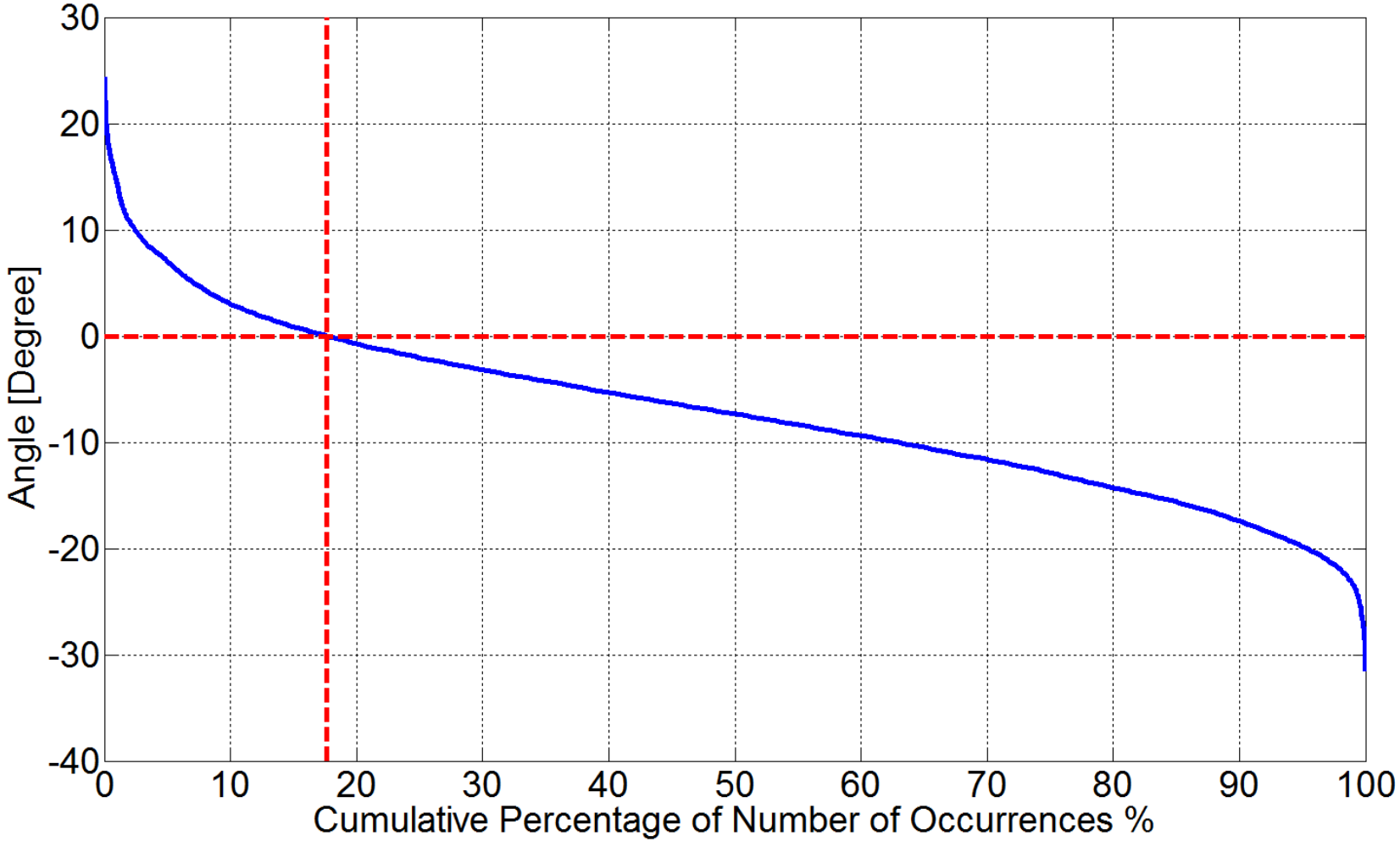

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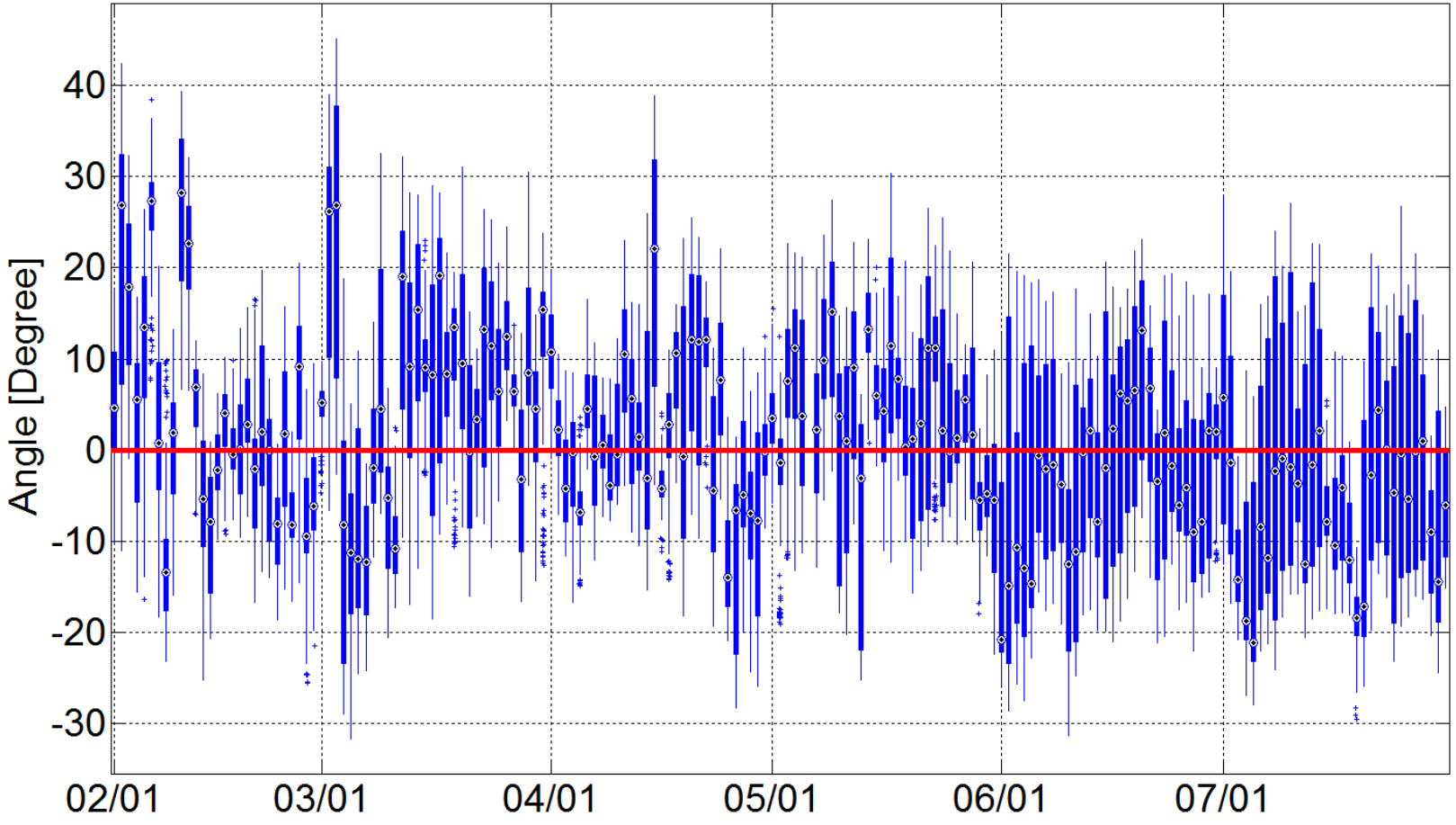

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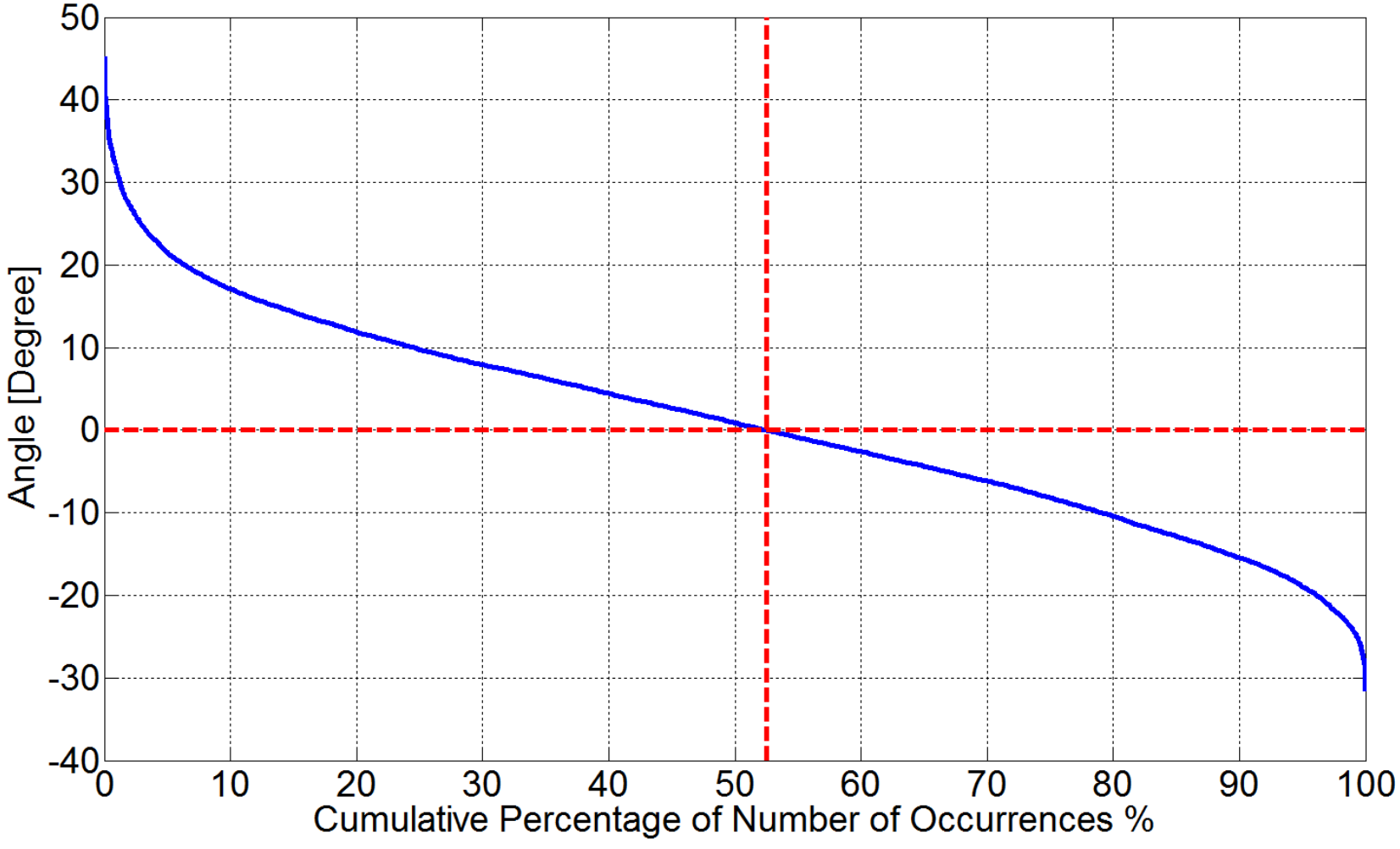

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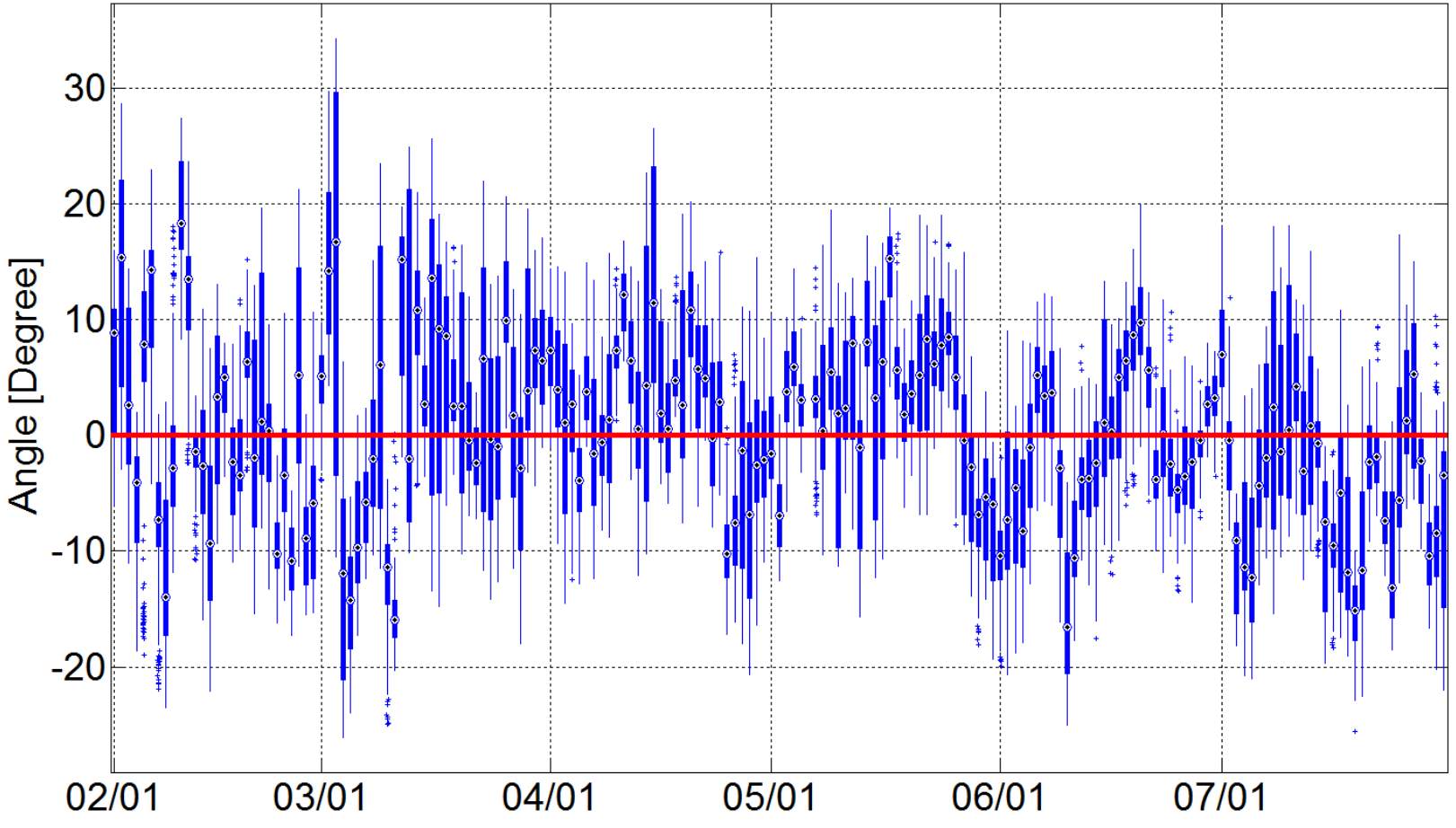

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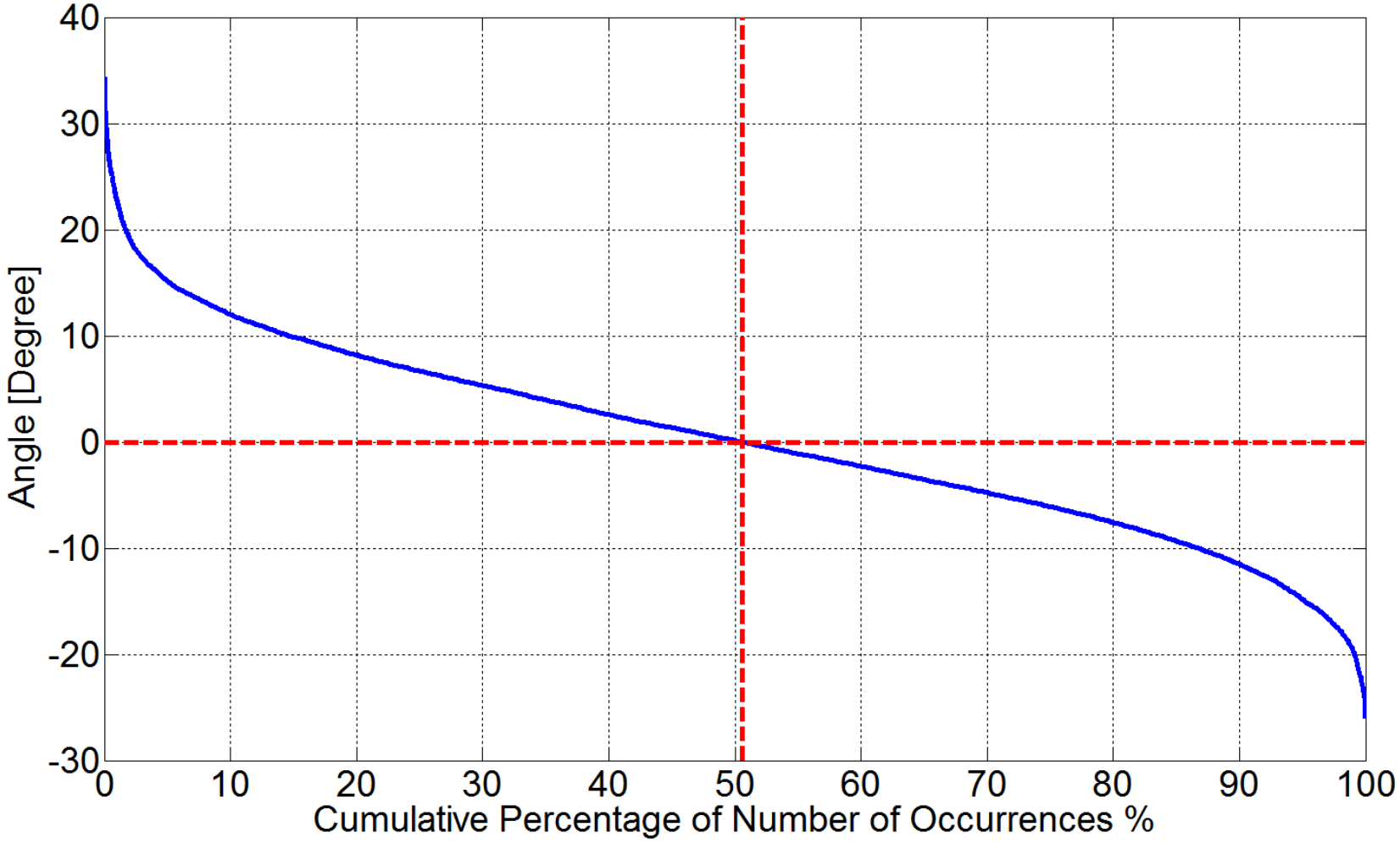

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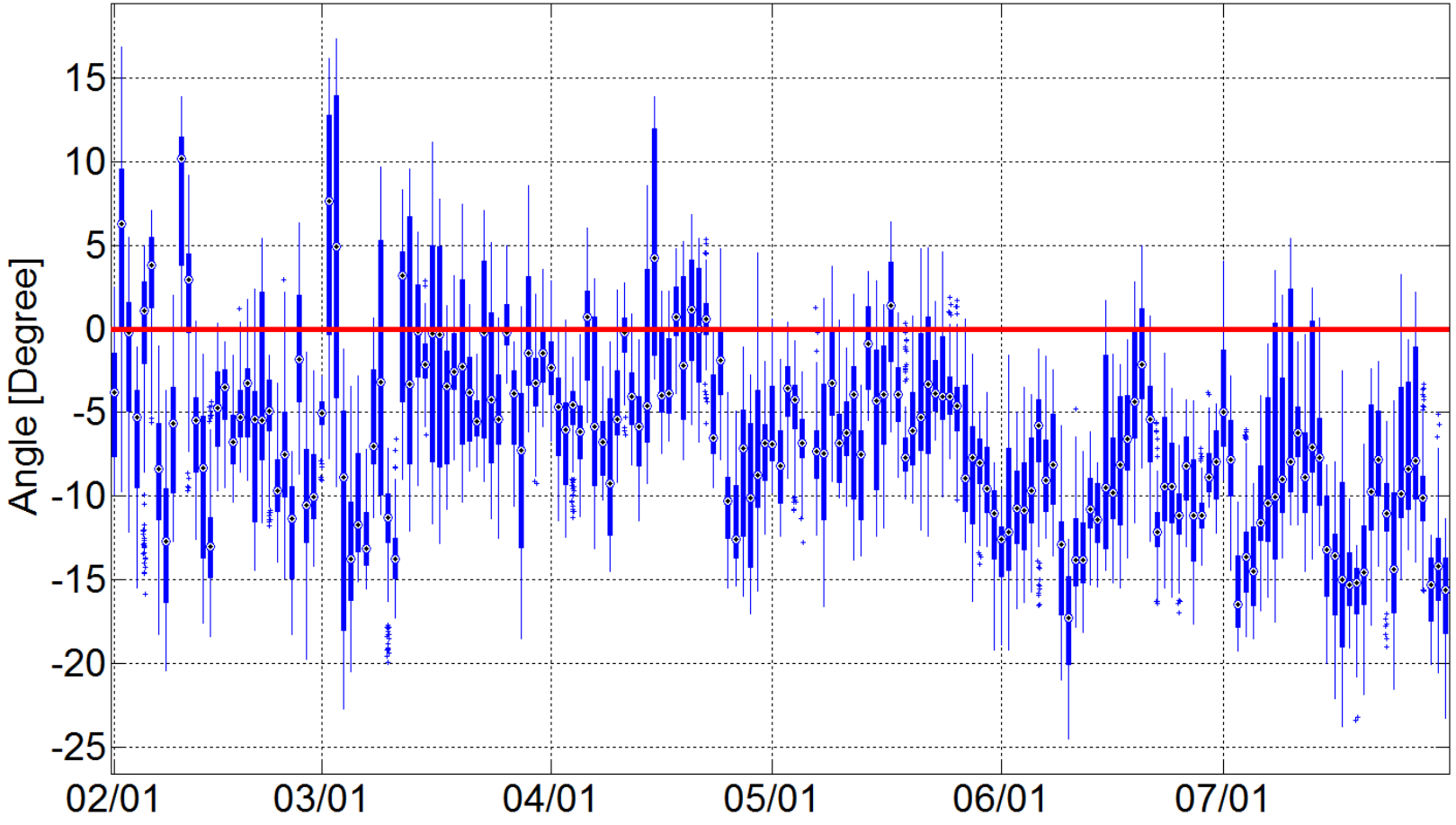

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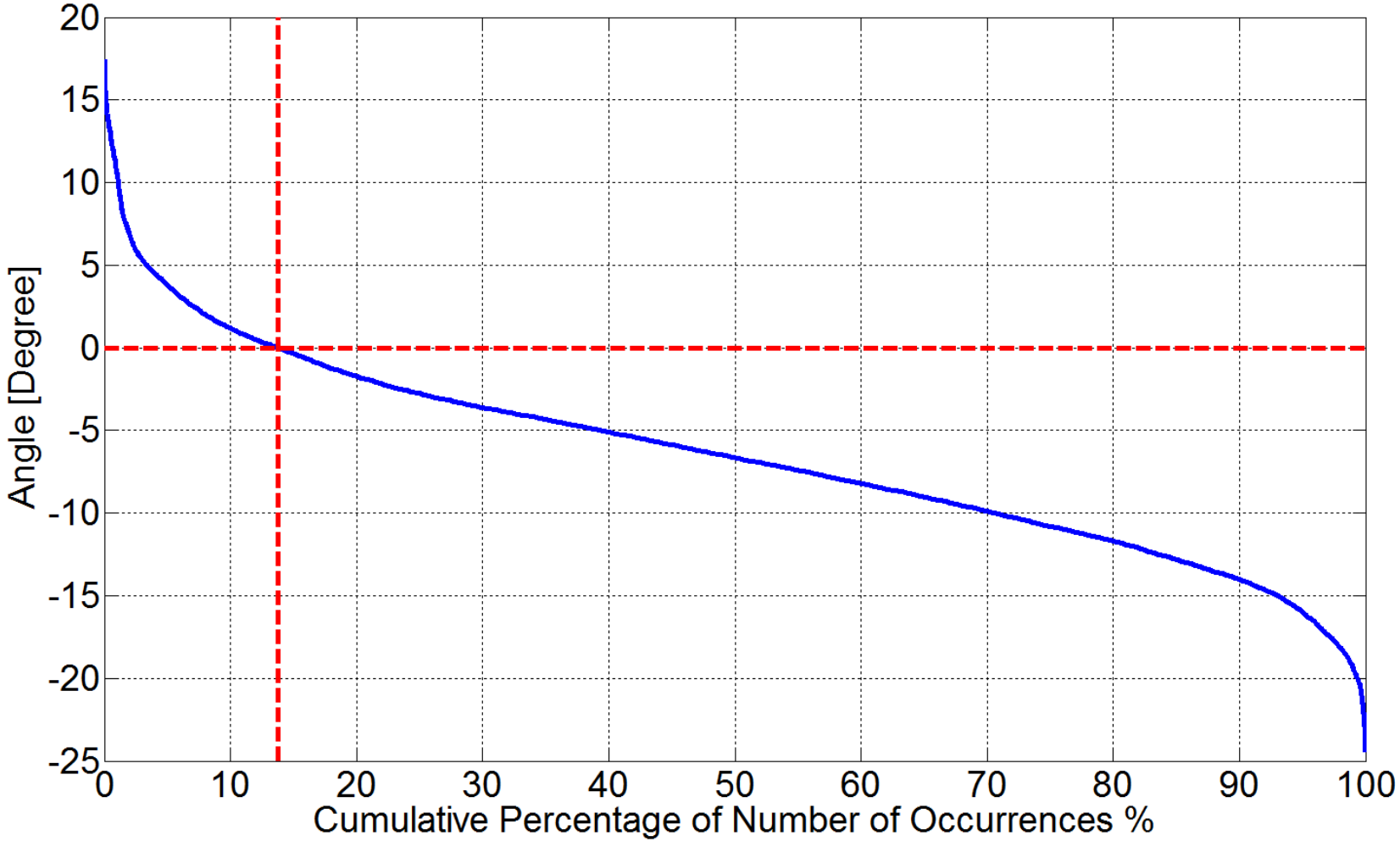

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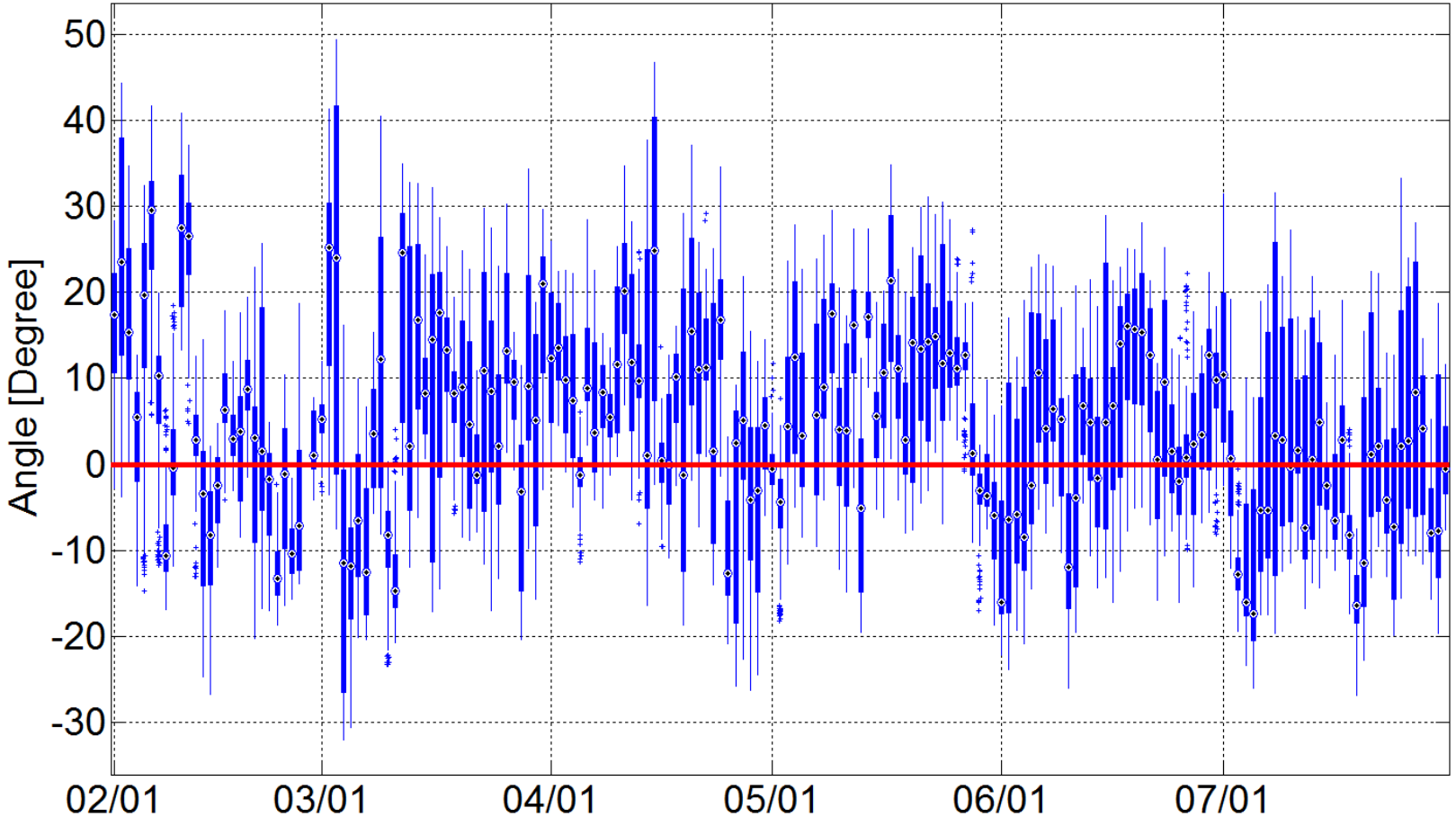

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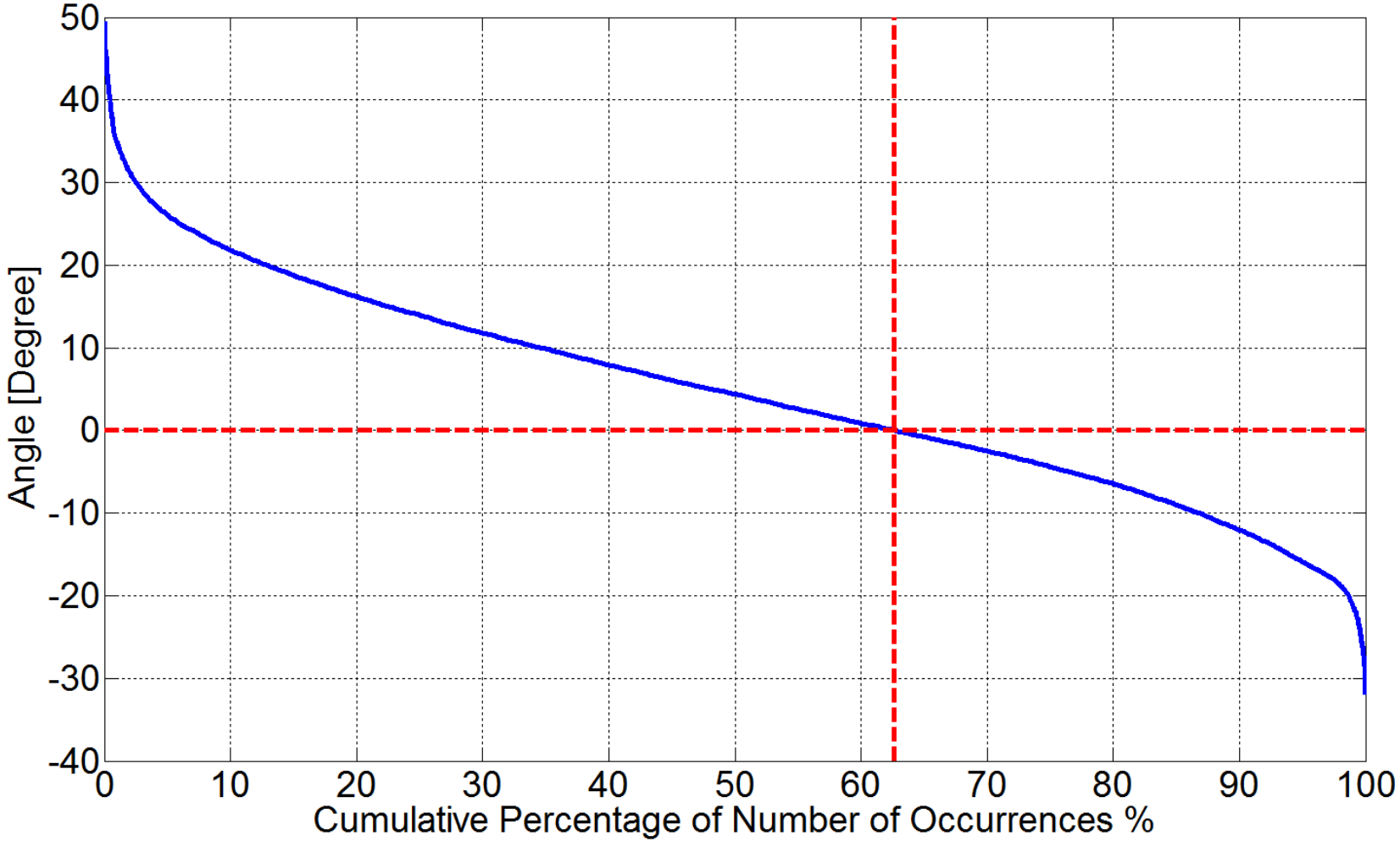

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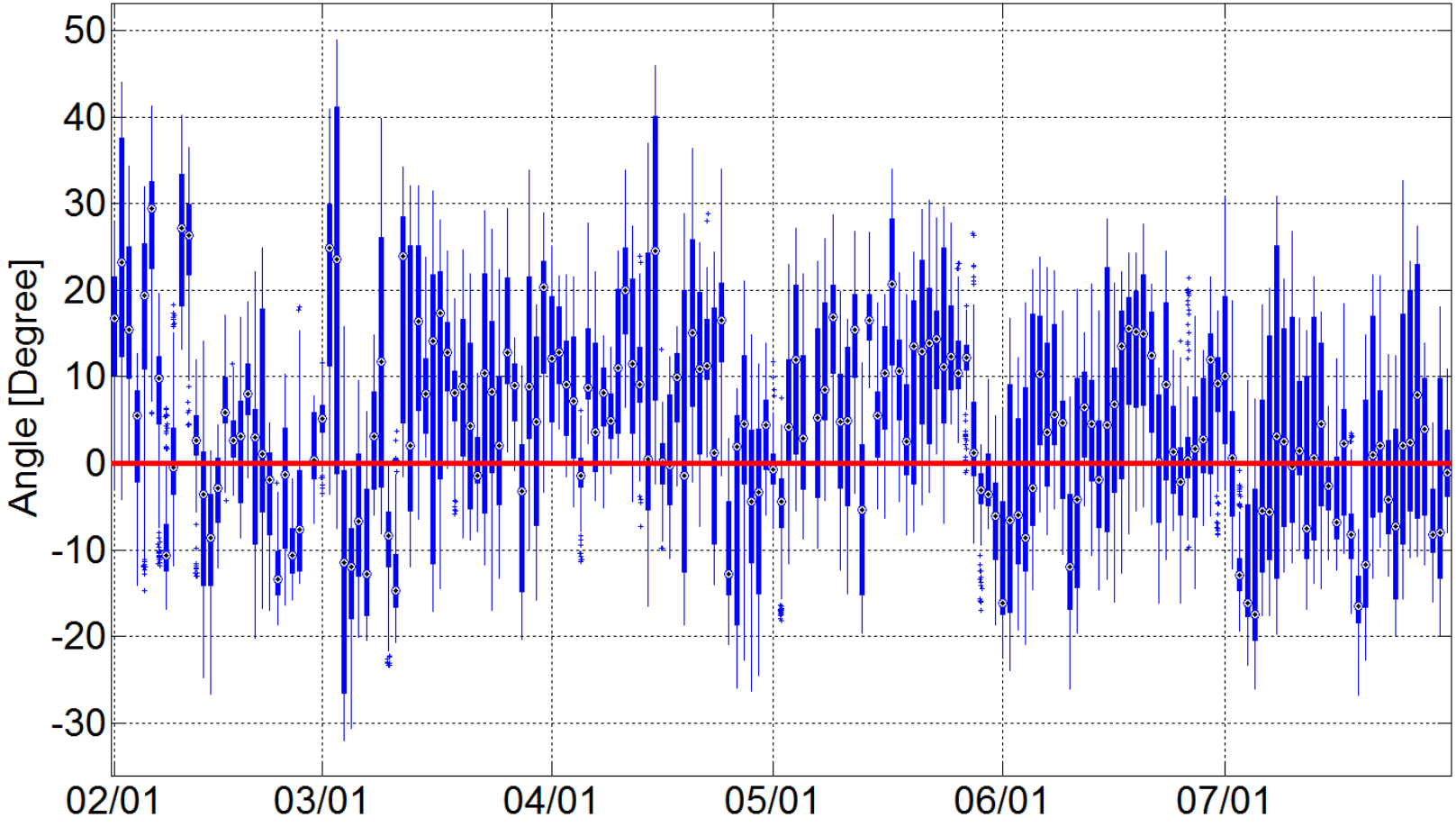

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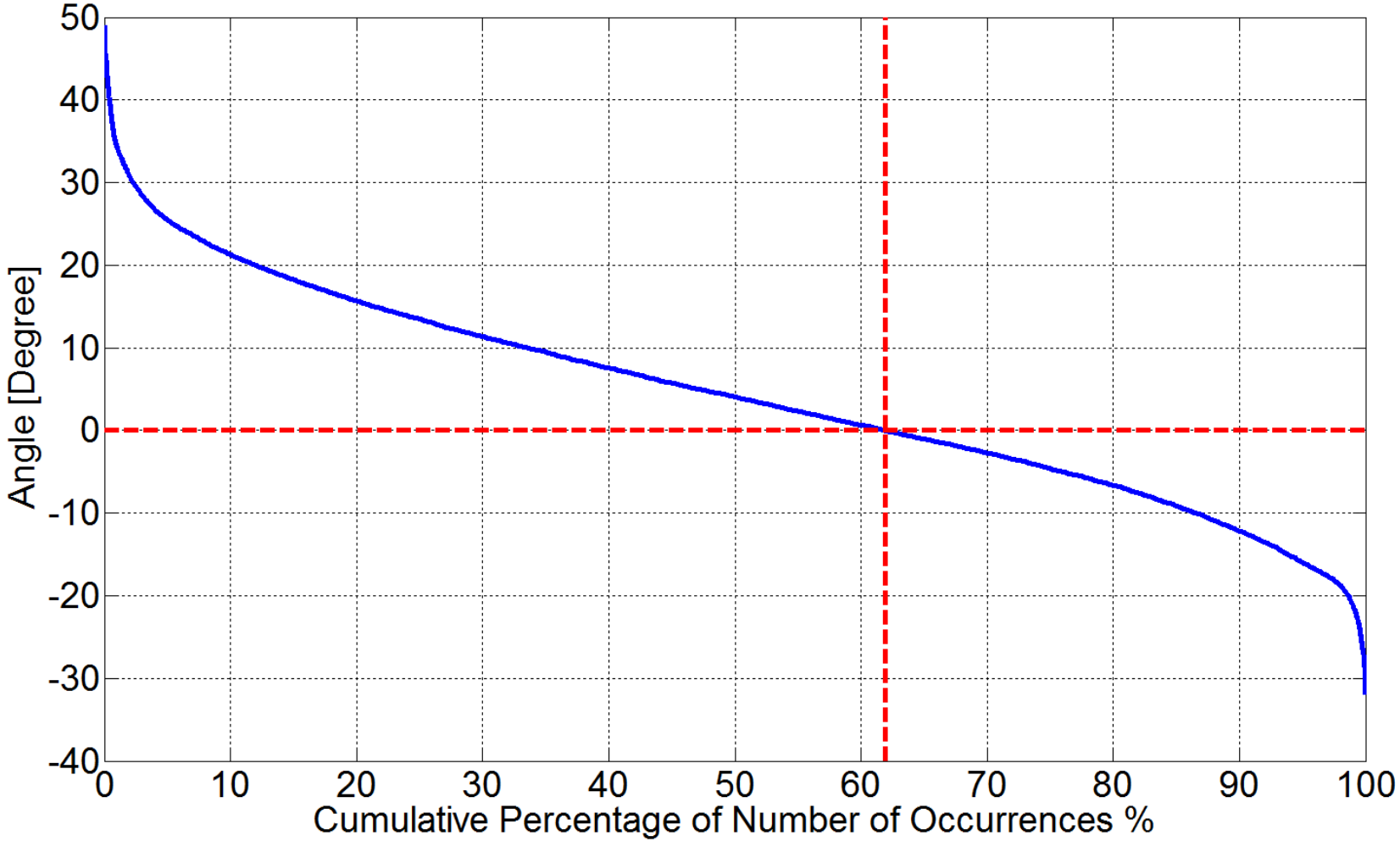

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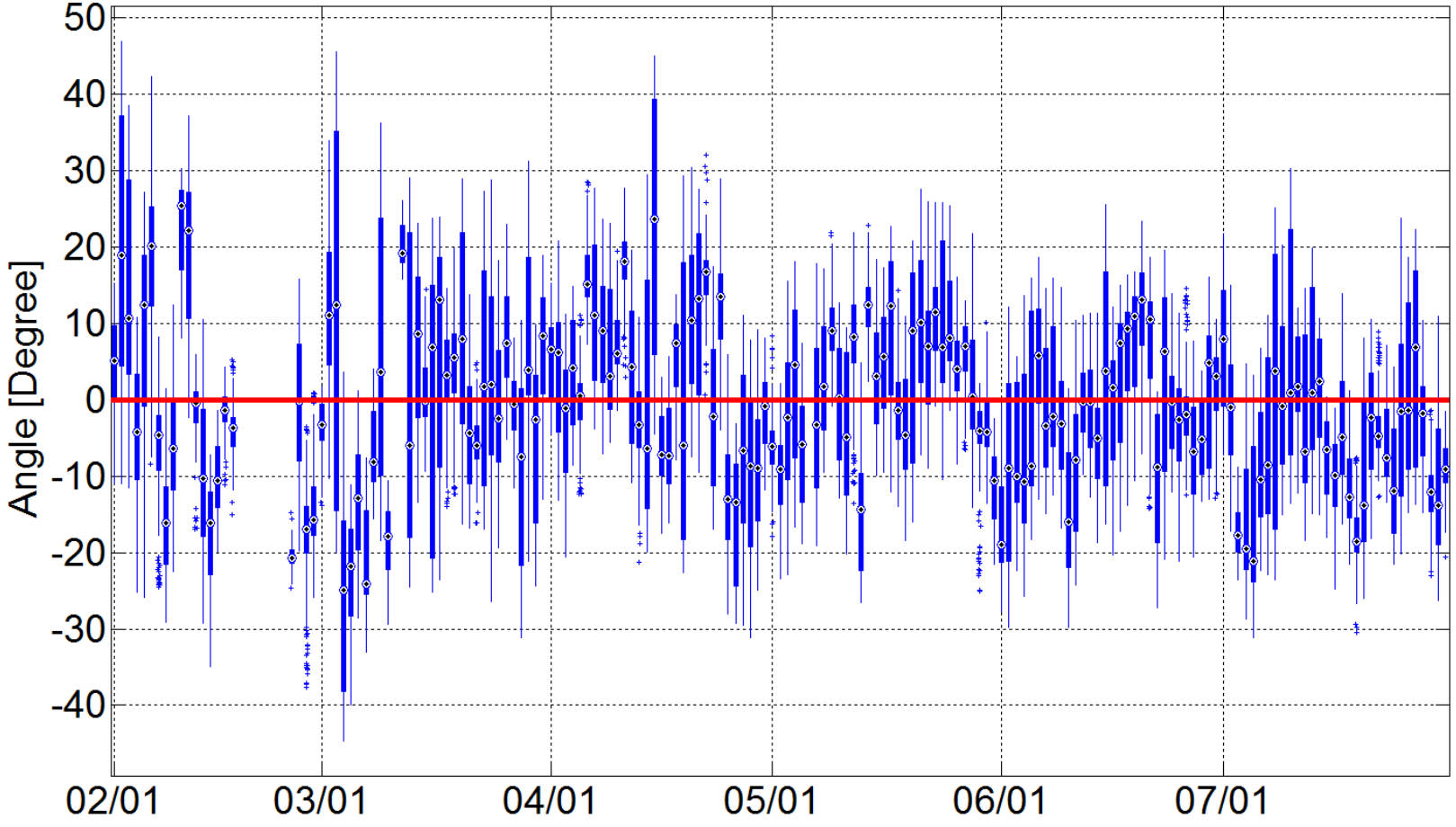

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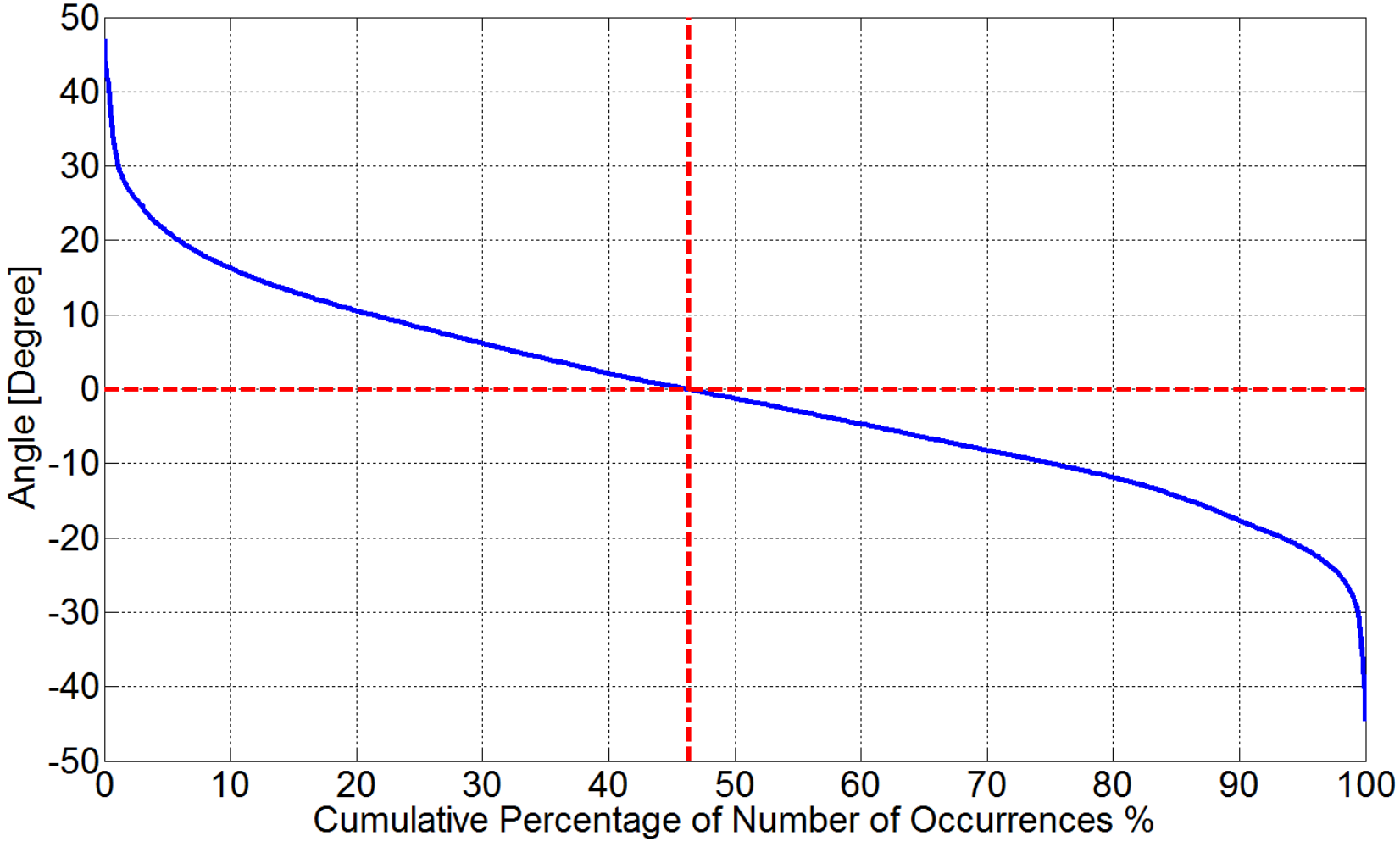

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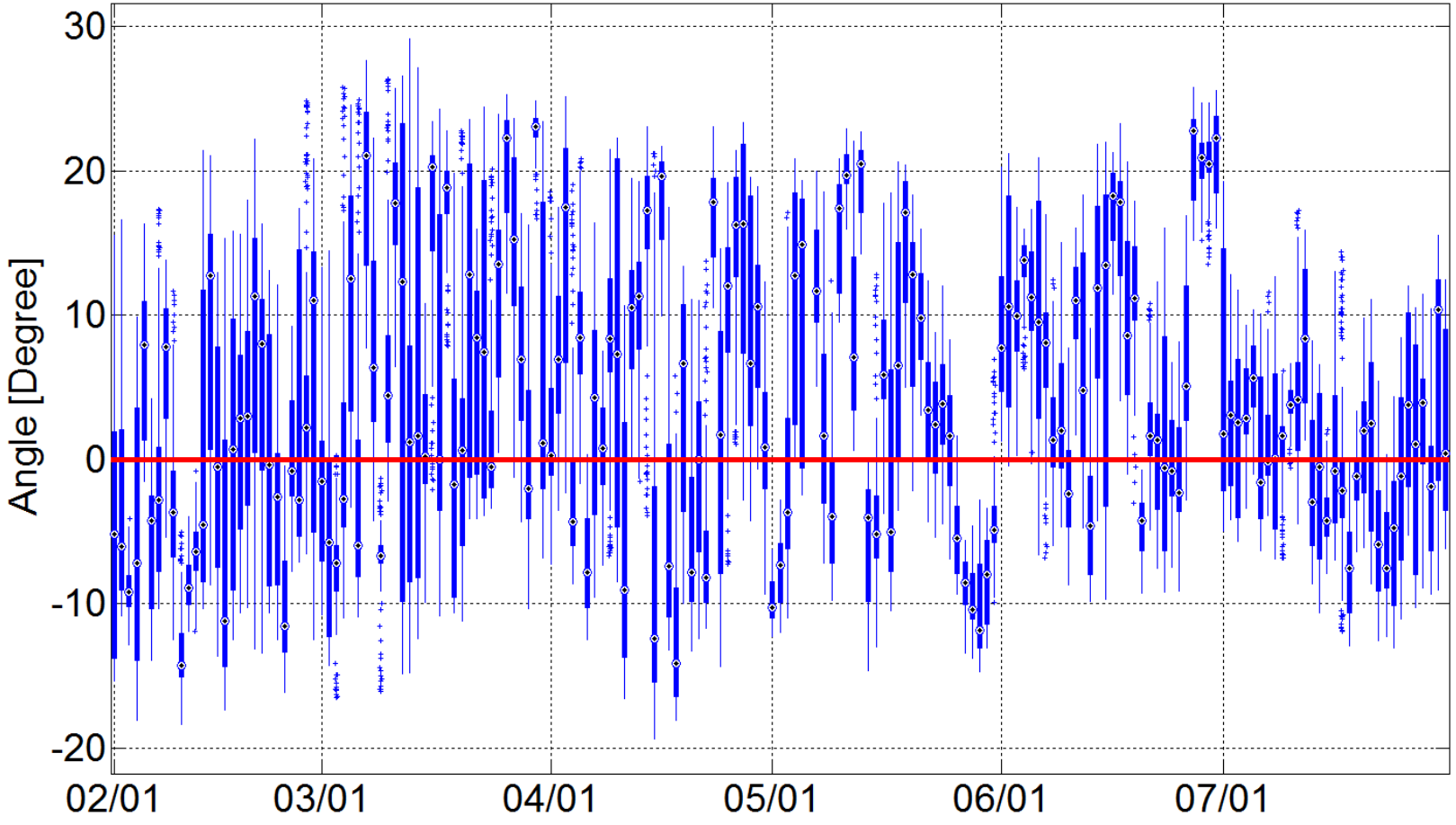

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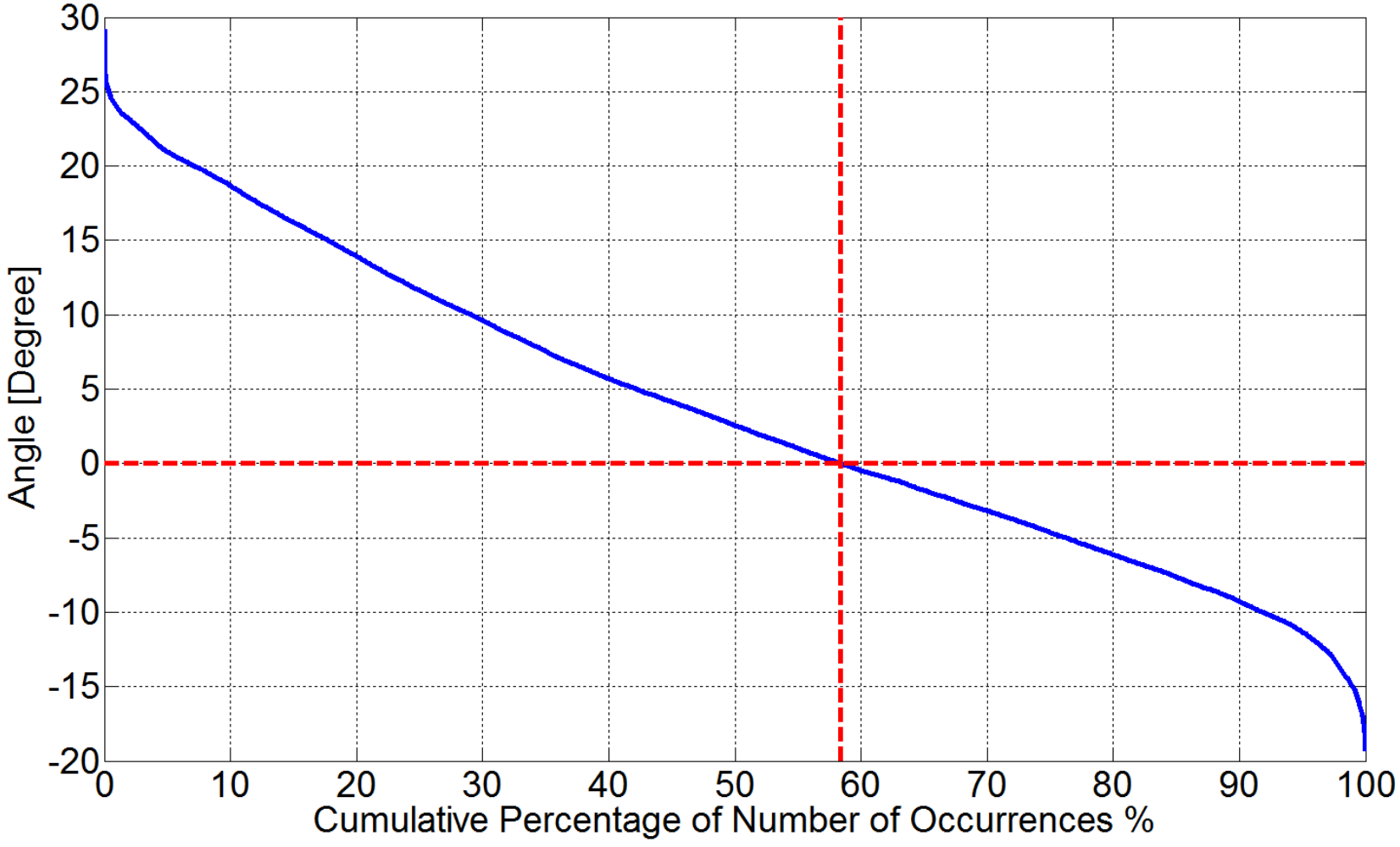

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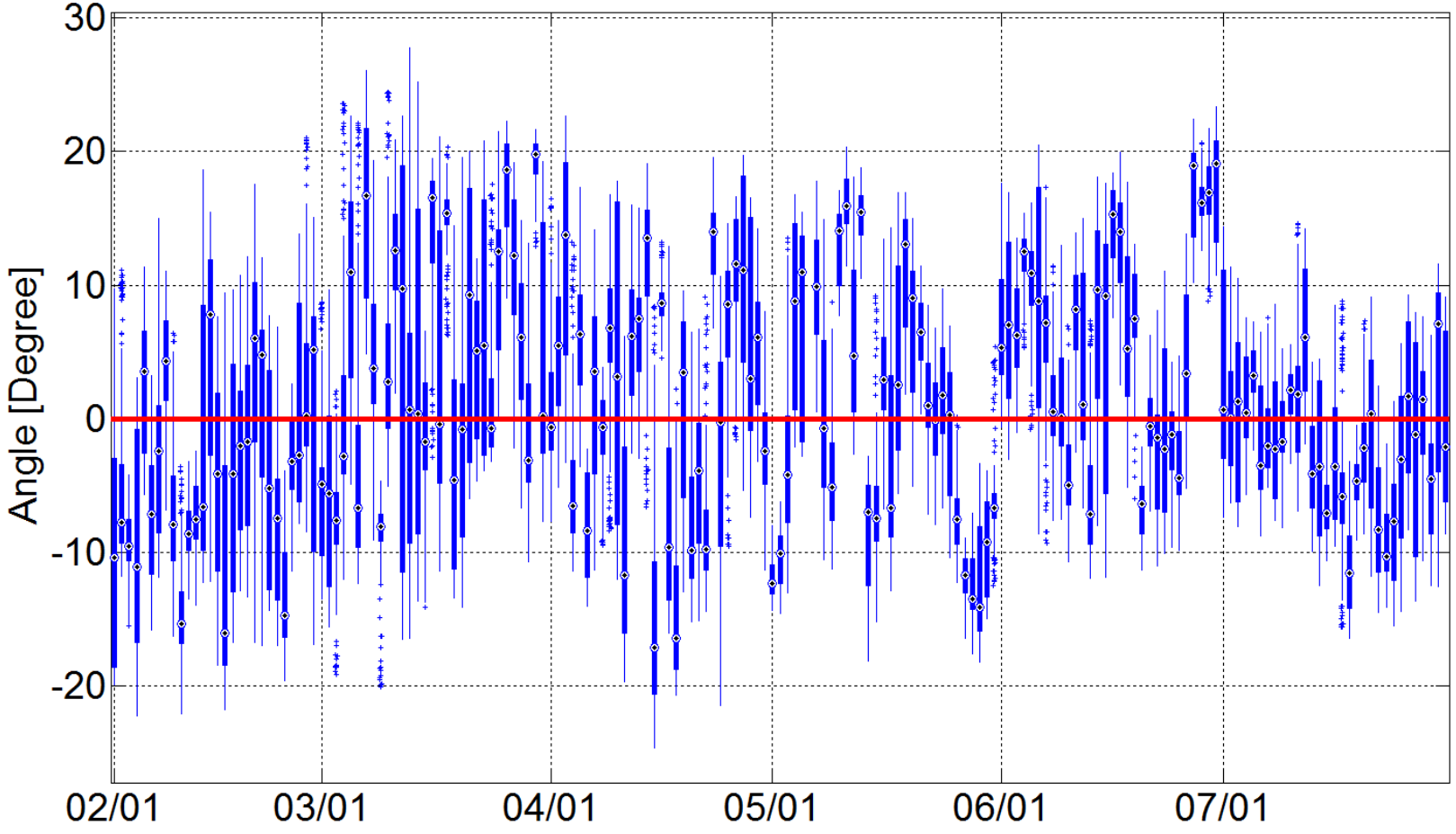
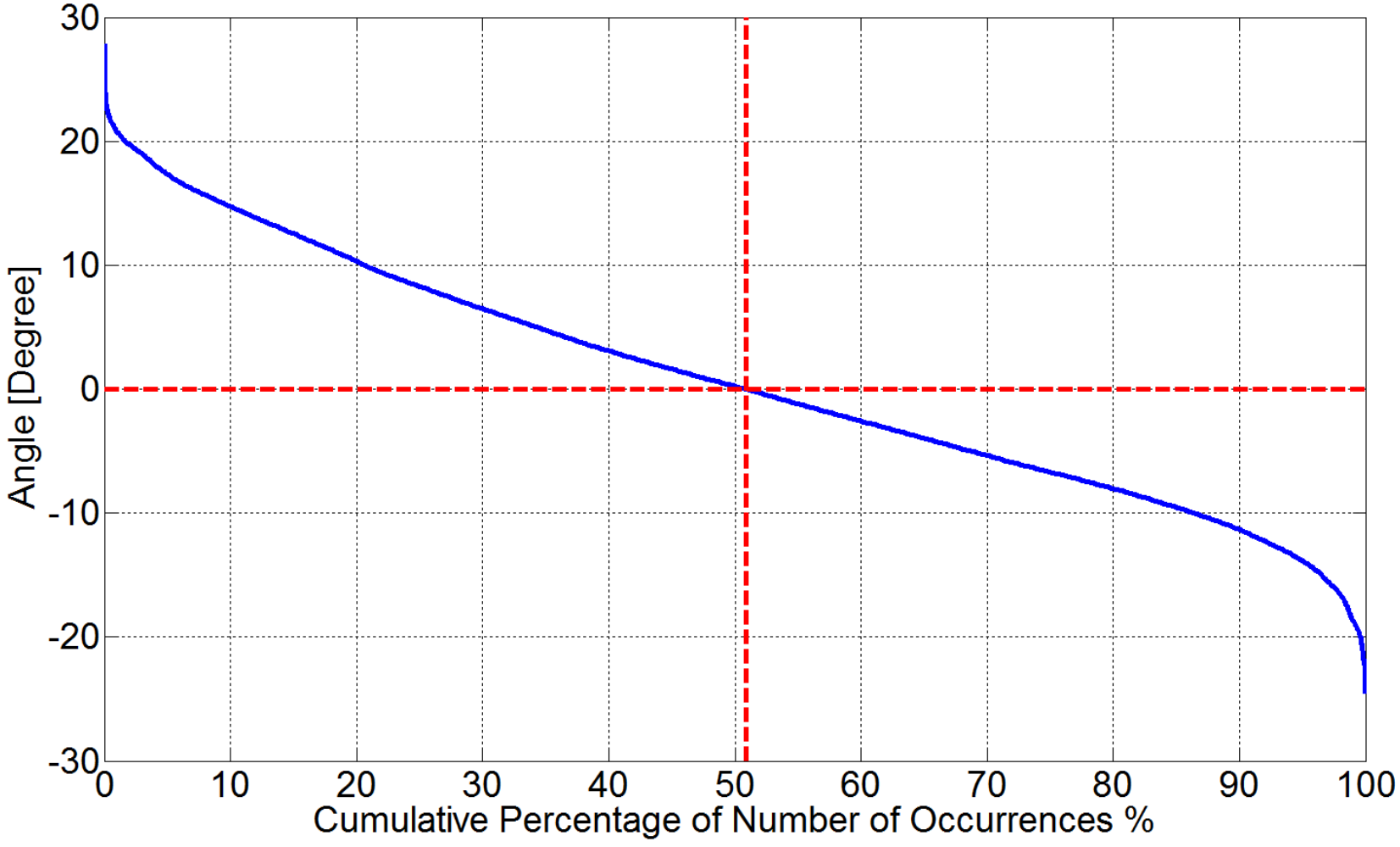
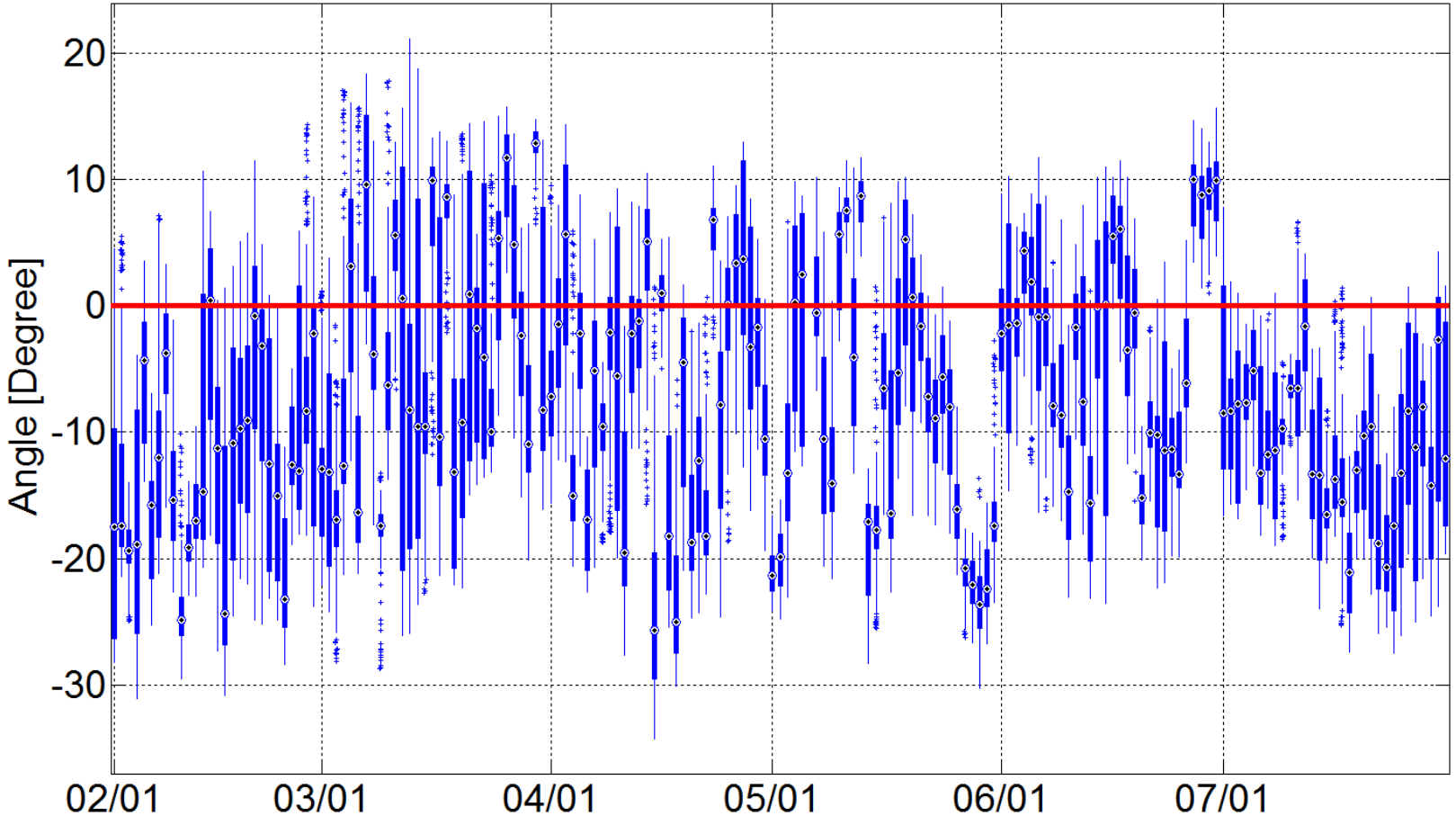


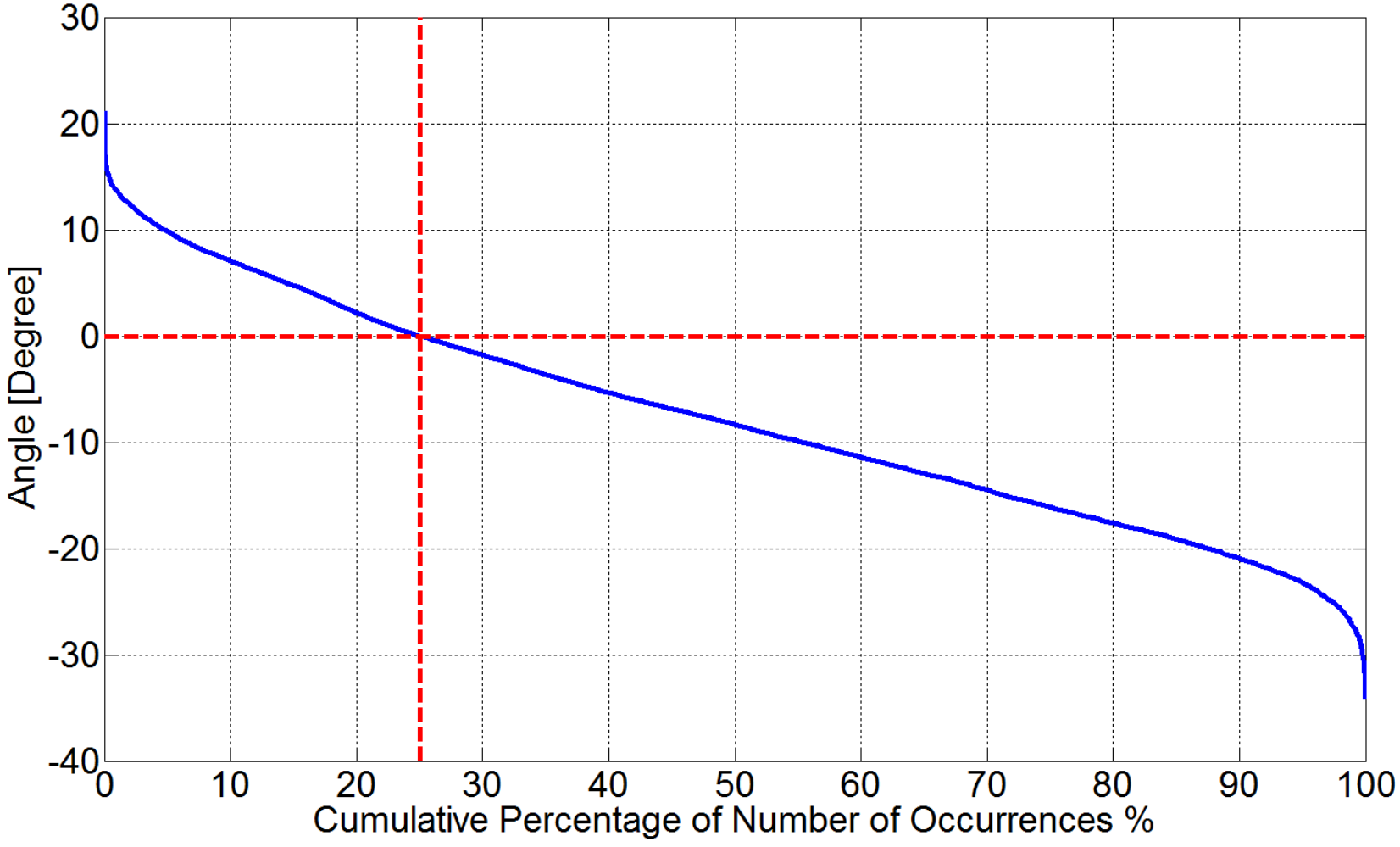
FarWest 7-North 7



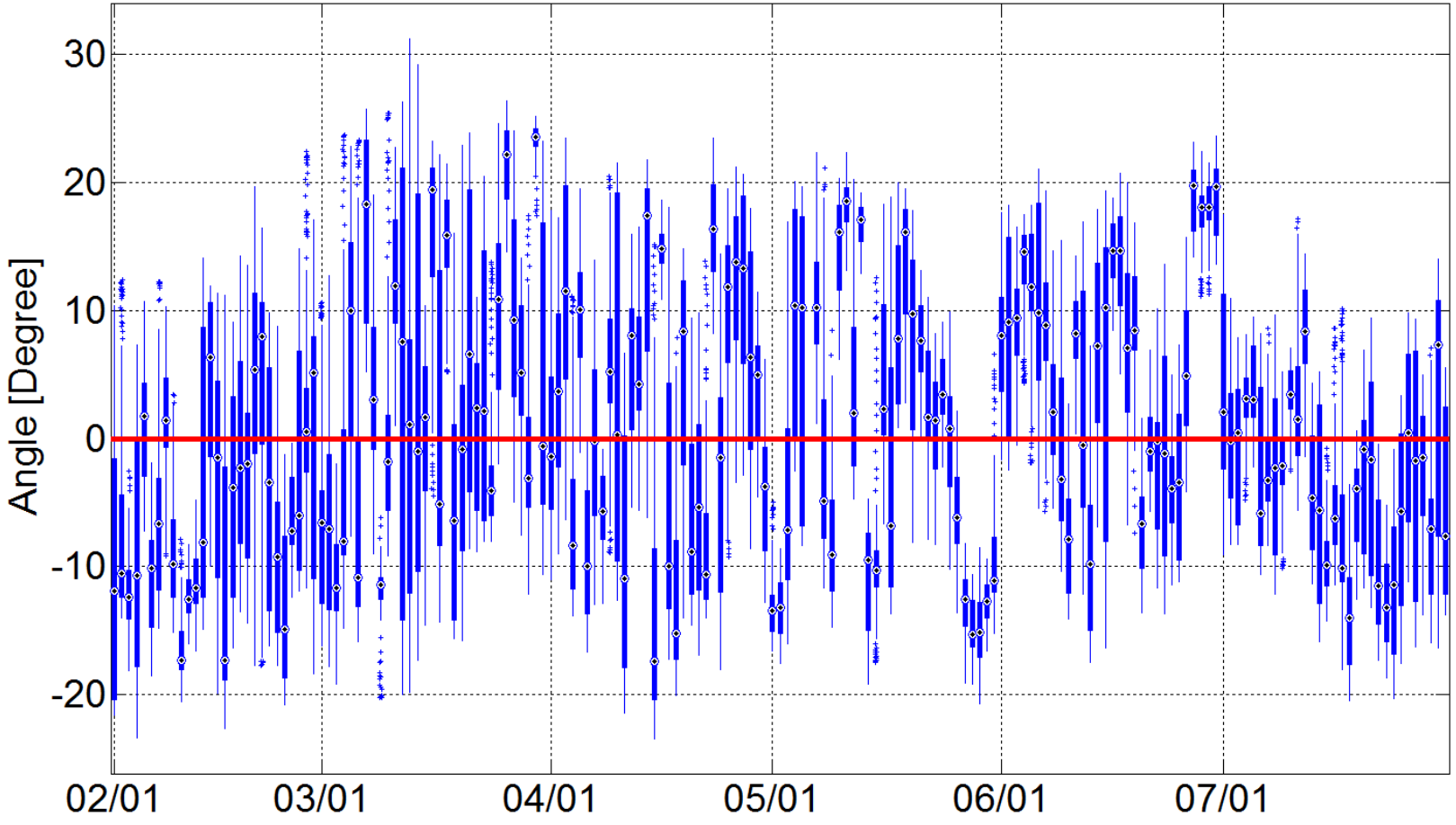
FarWest 8-North 7



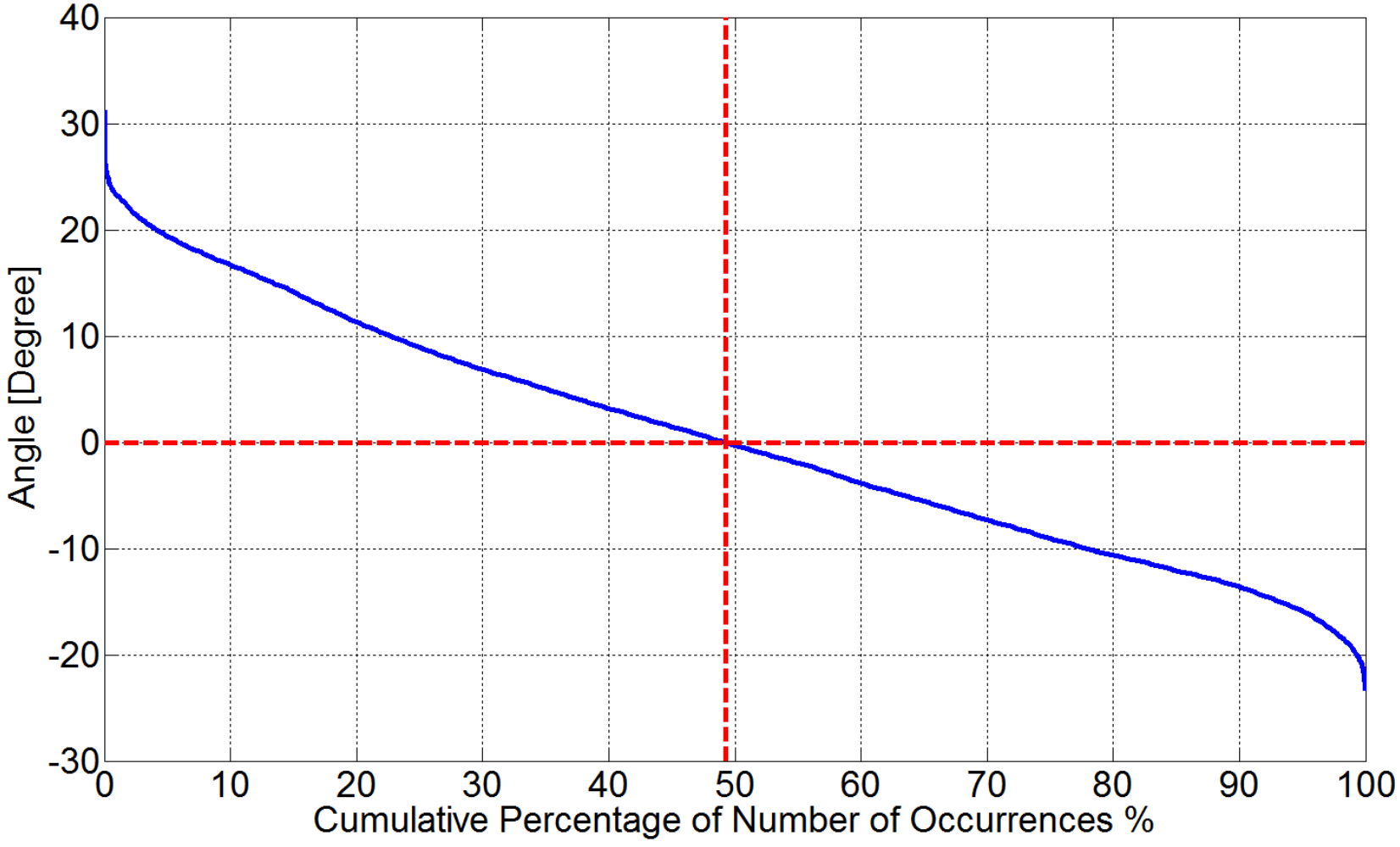
FarWest 8-North 7



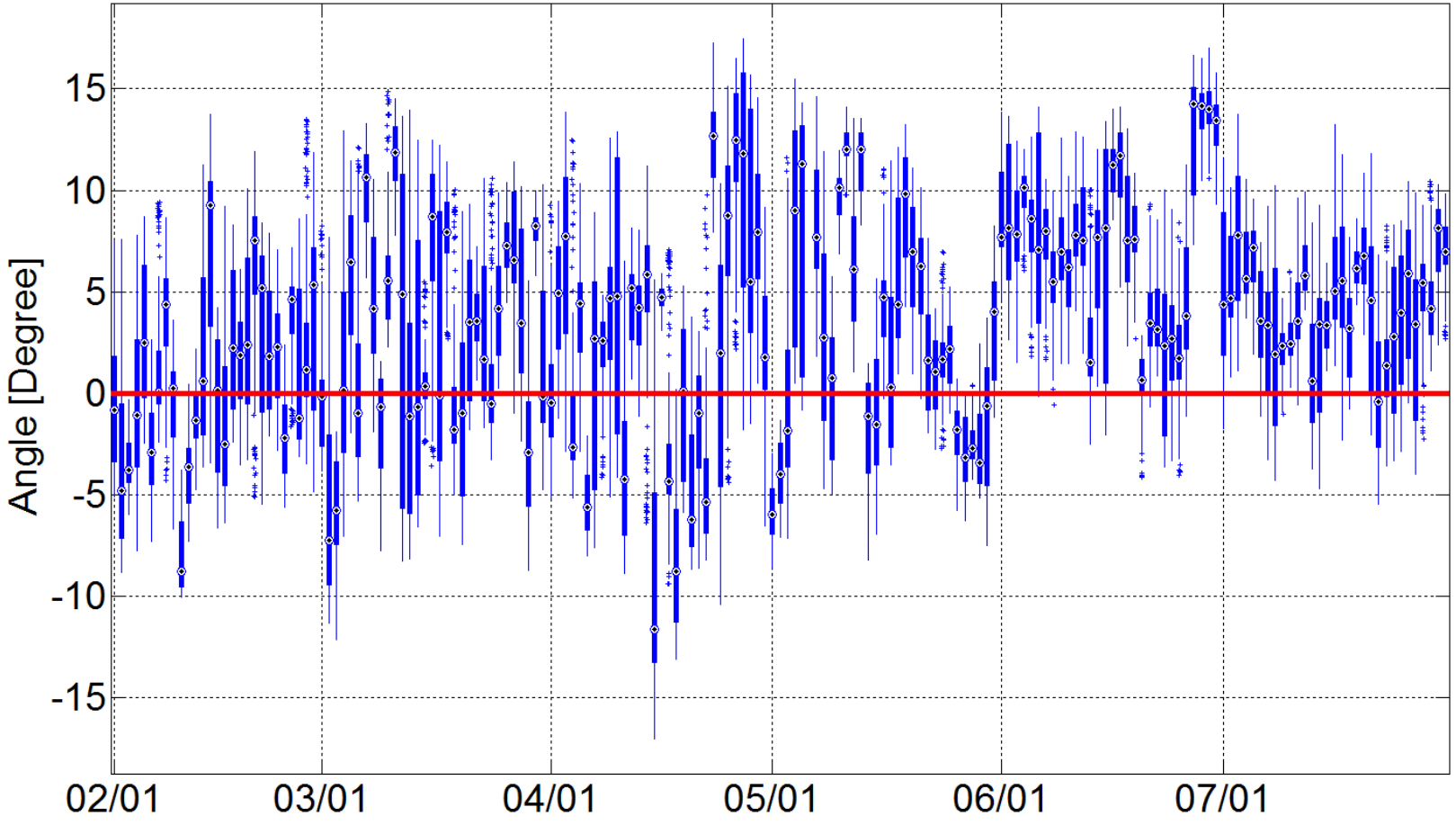
FarWest 9-North 7



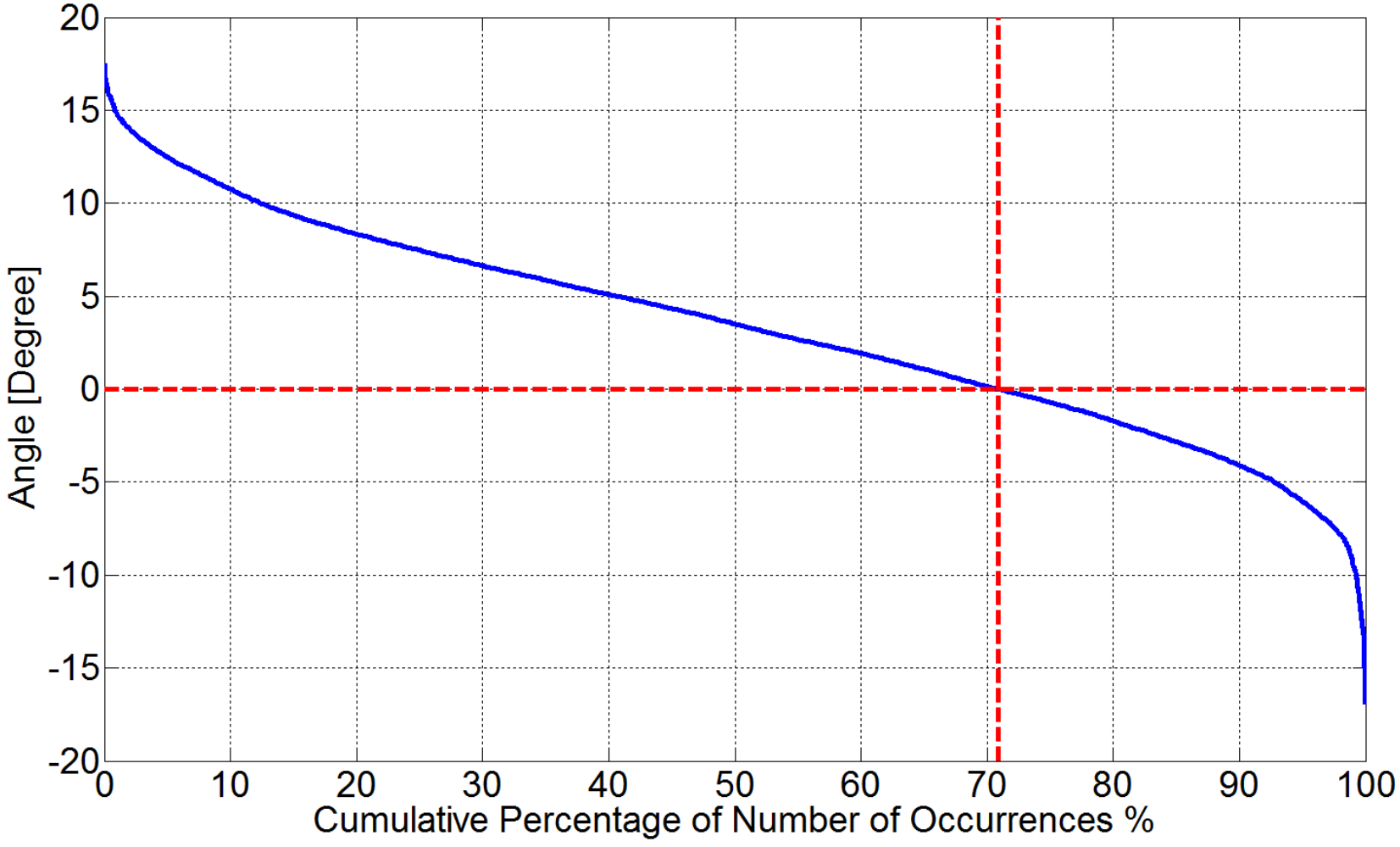
FarWest 9-North 7



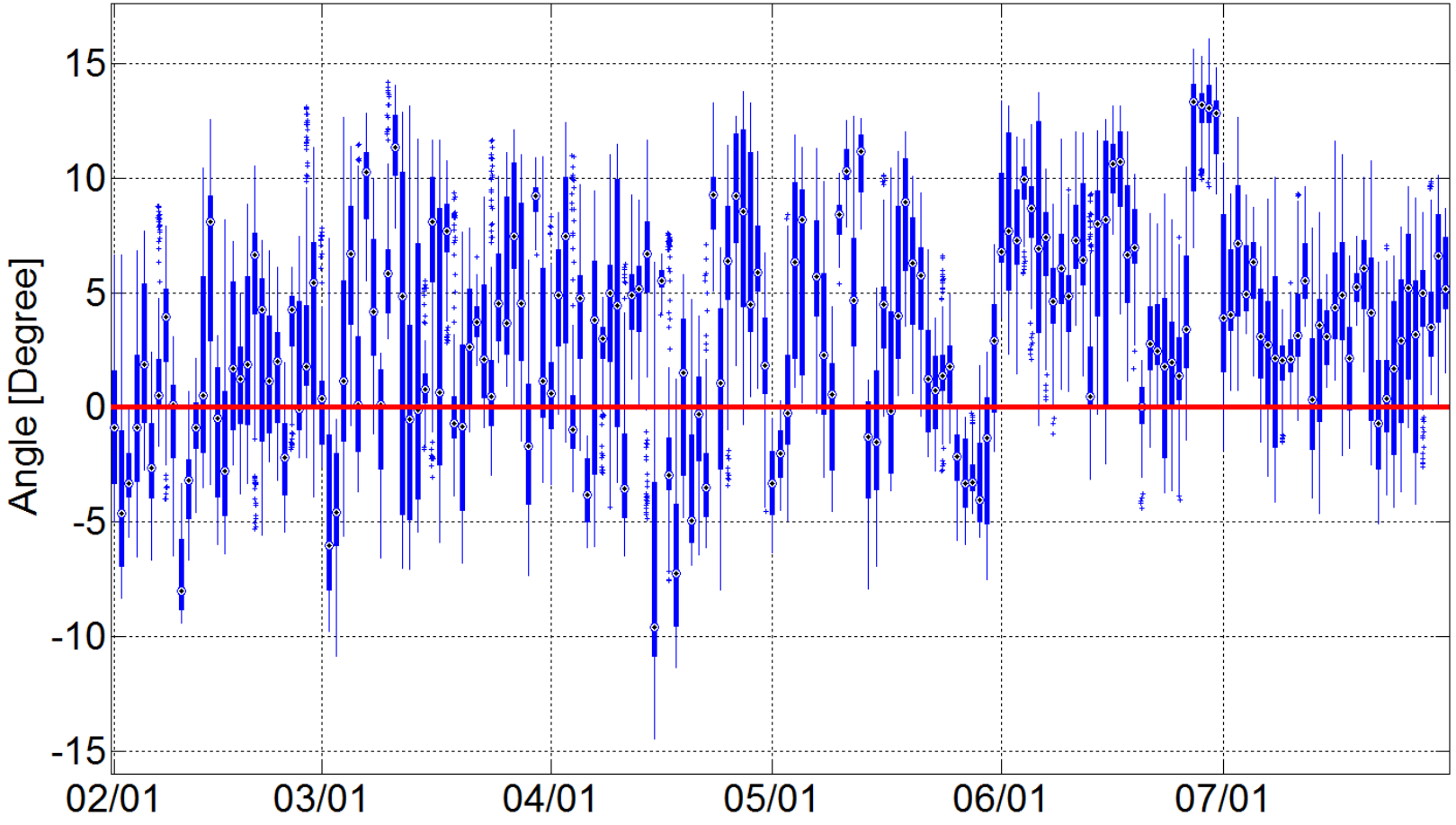
West 16-North 7



West 16-North 7



West 3*-North 7



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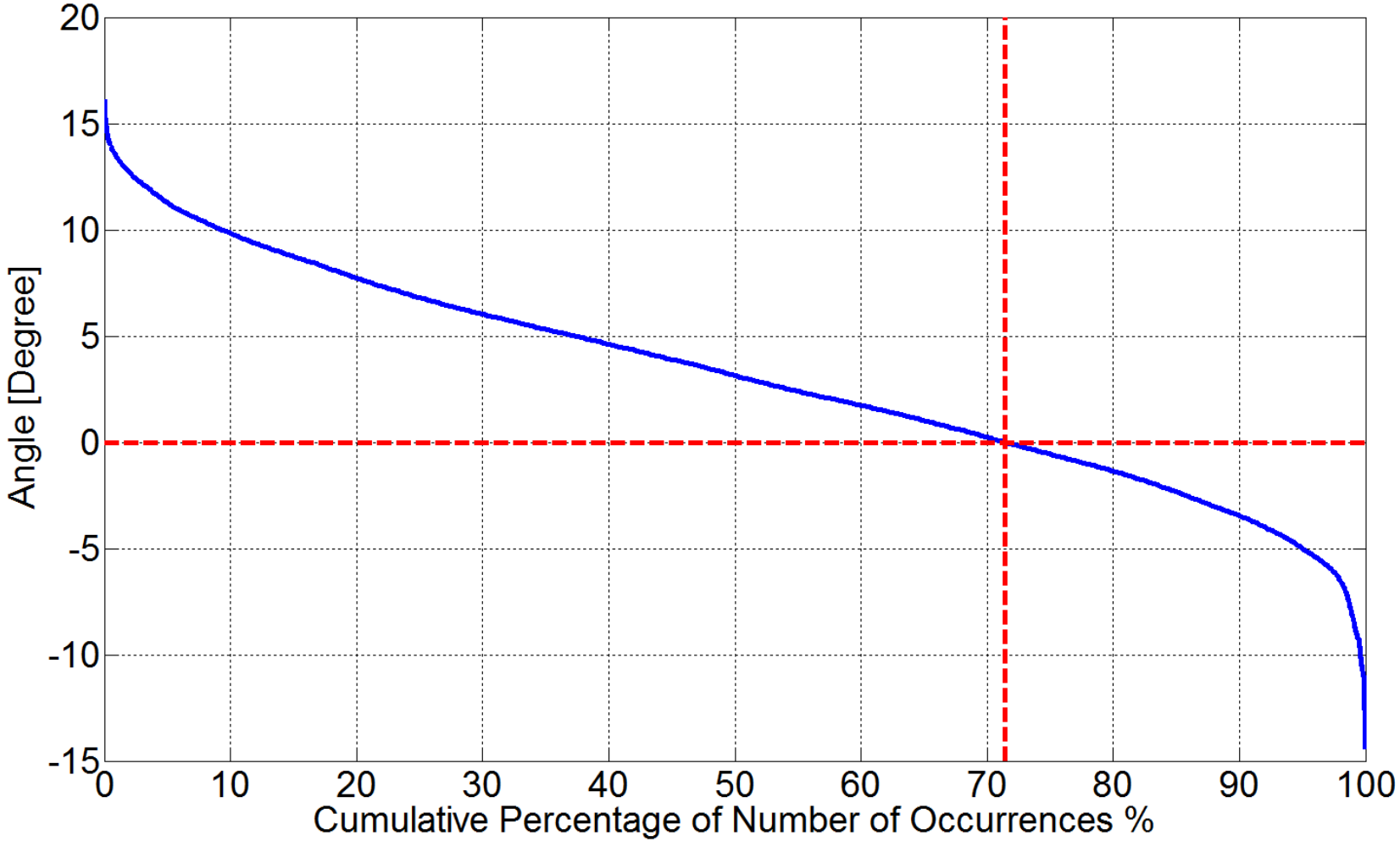
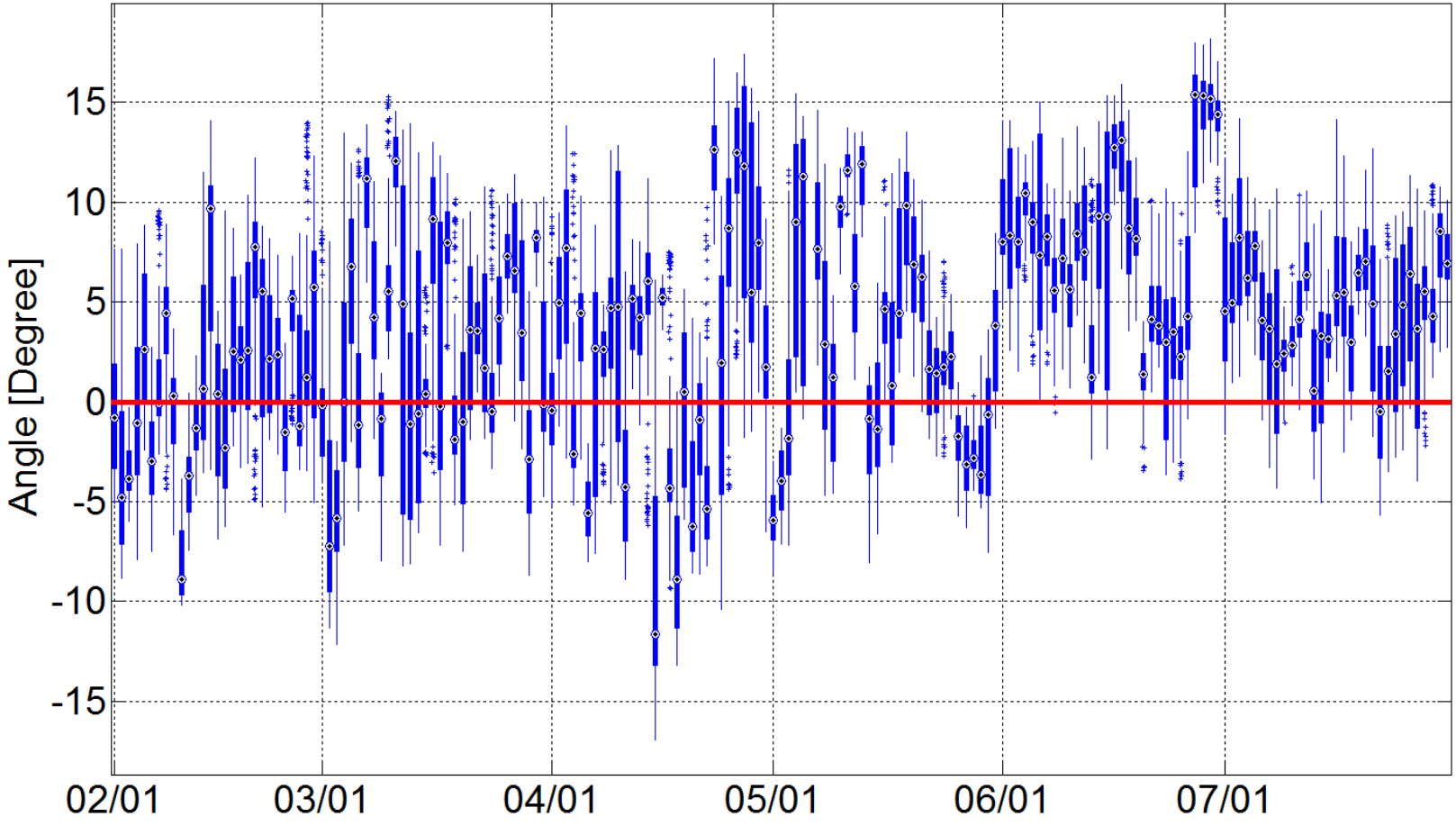
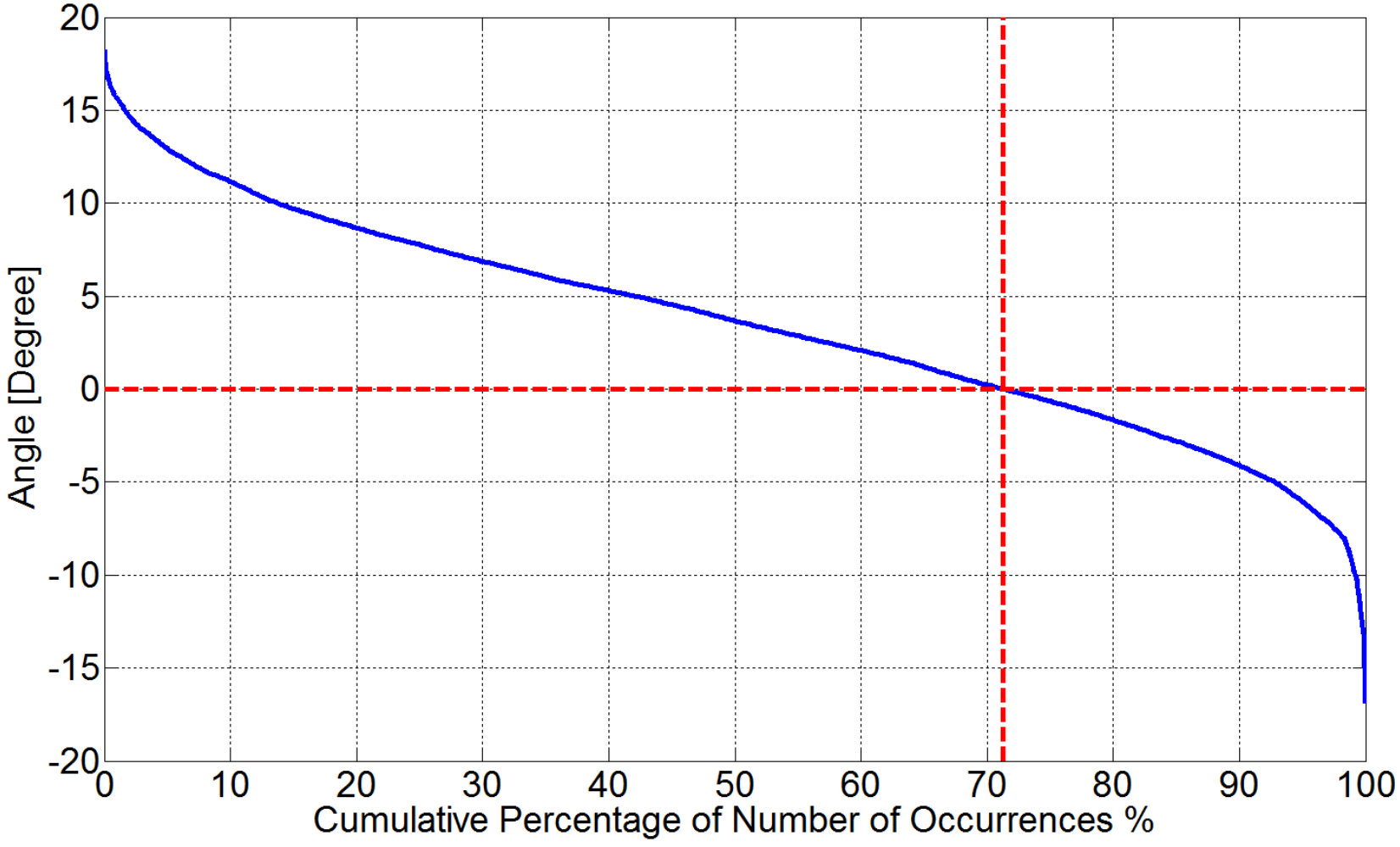


West 15-North 7



West 15-North 7



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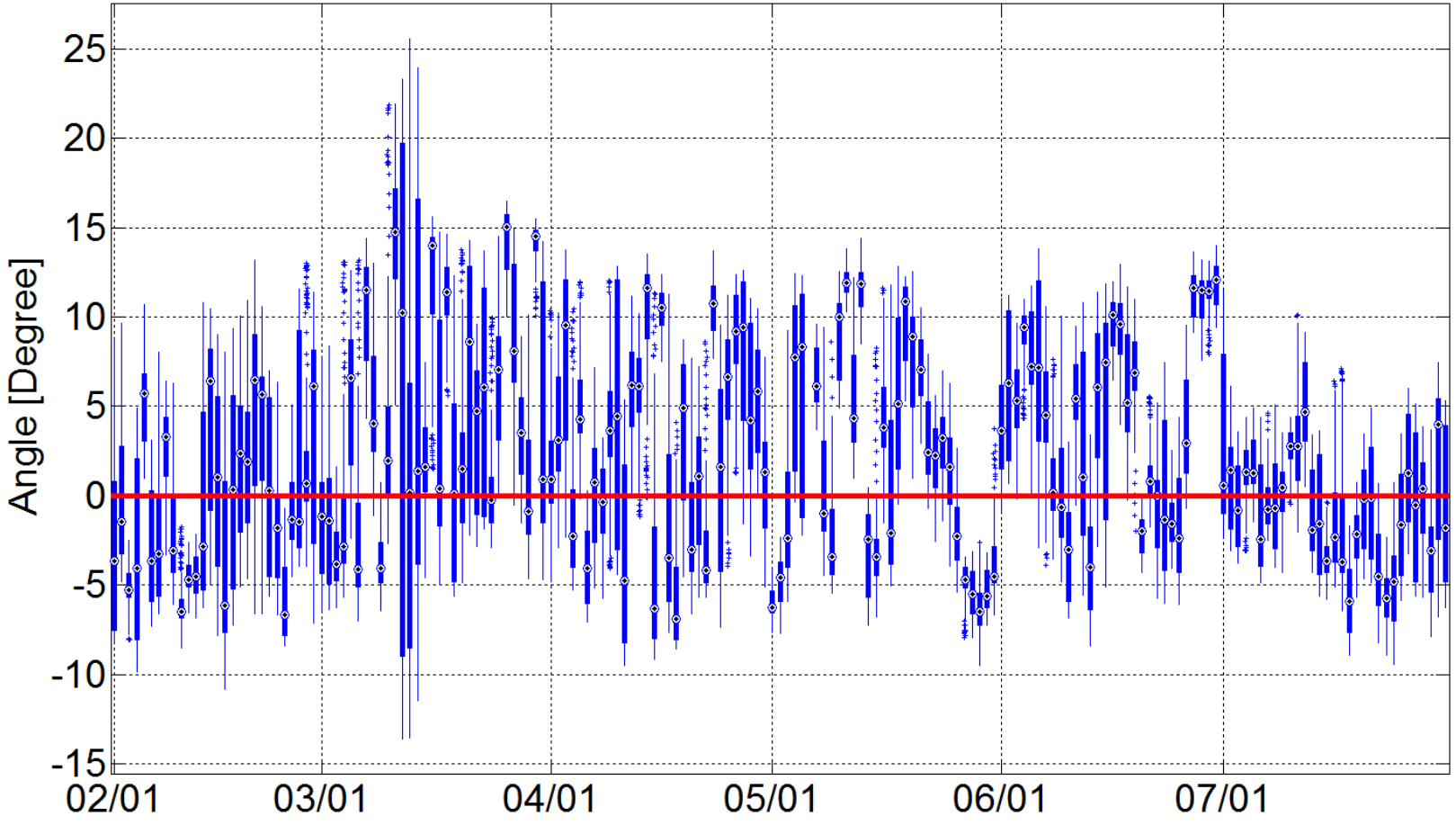

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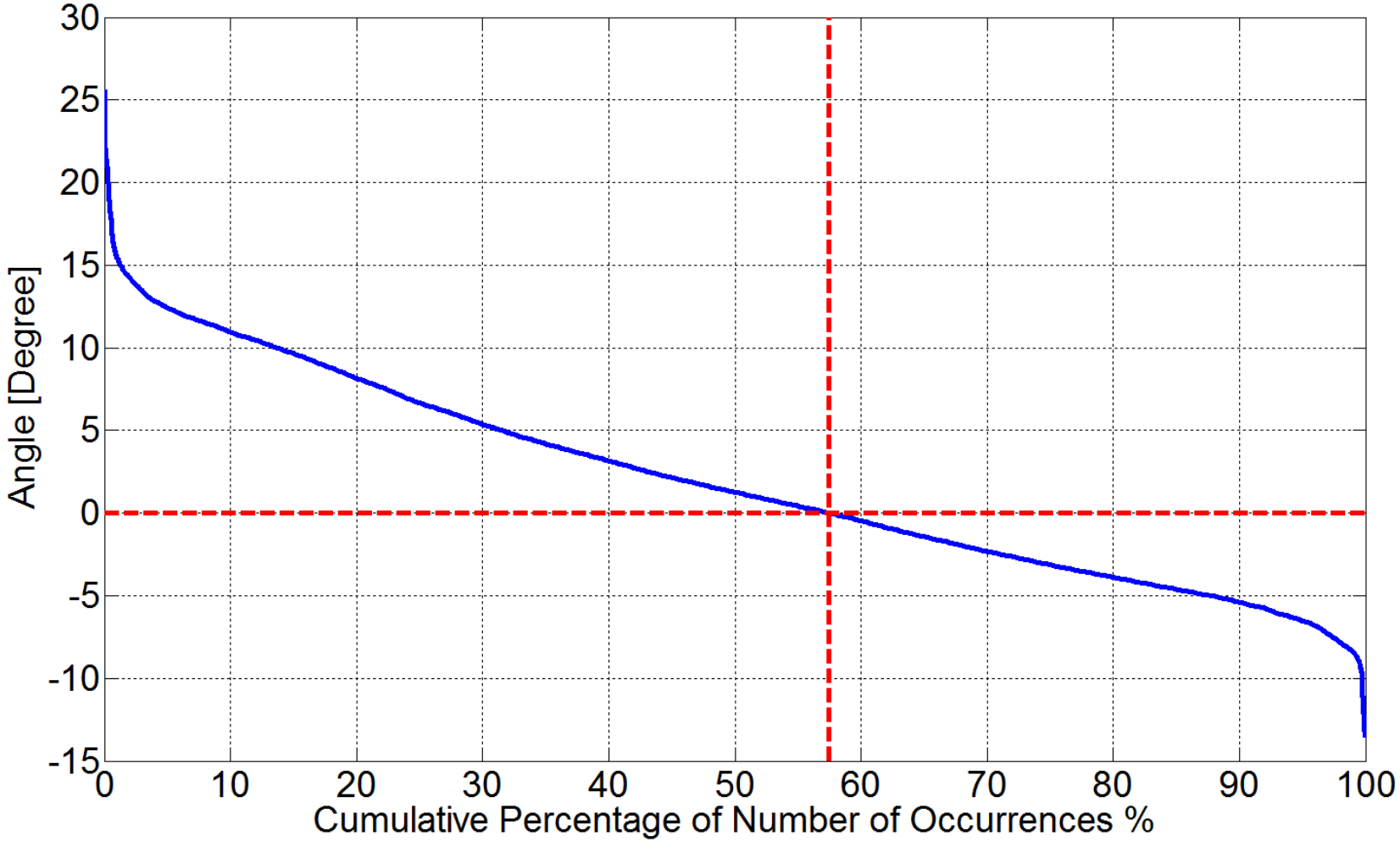

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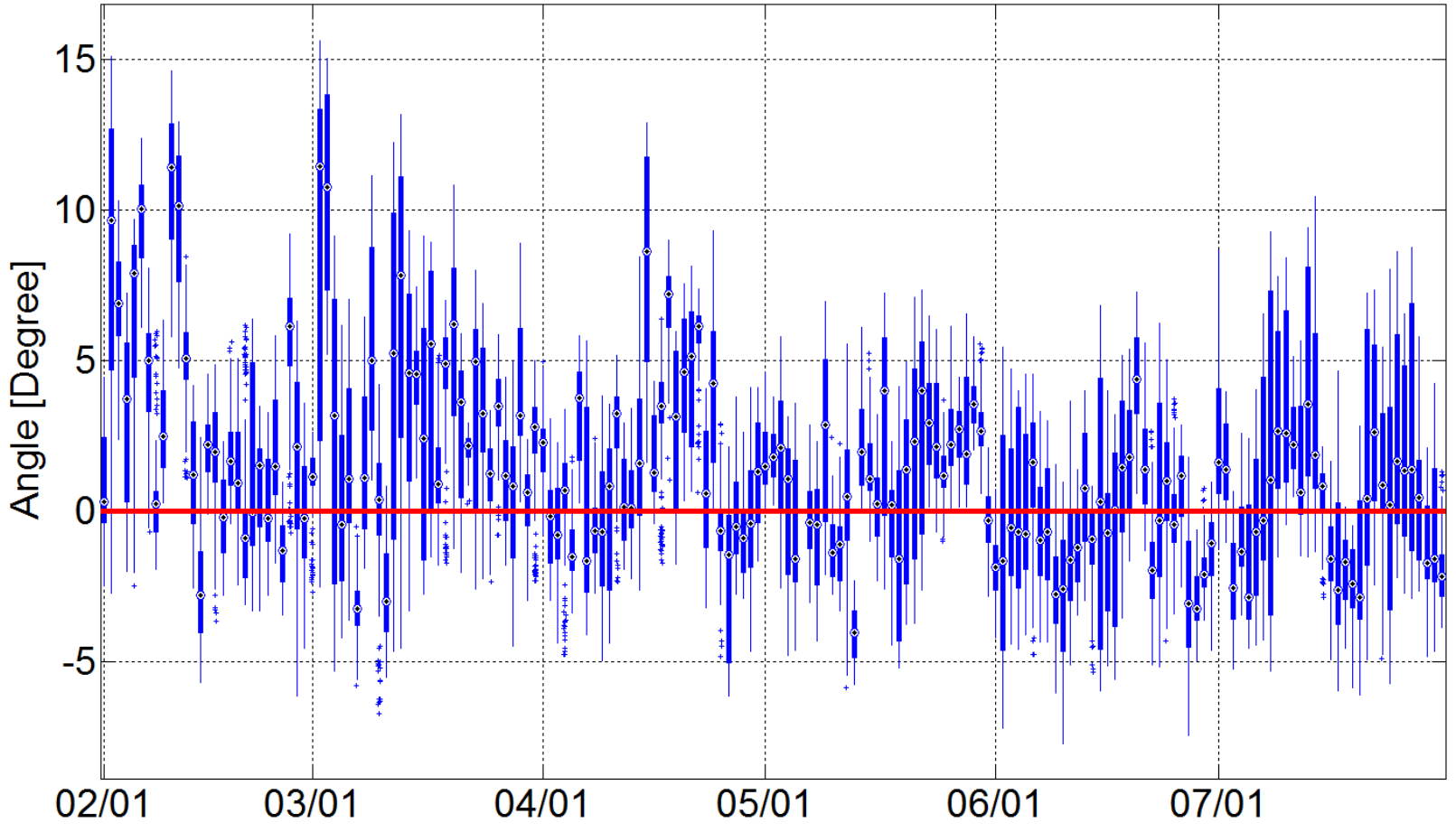
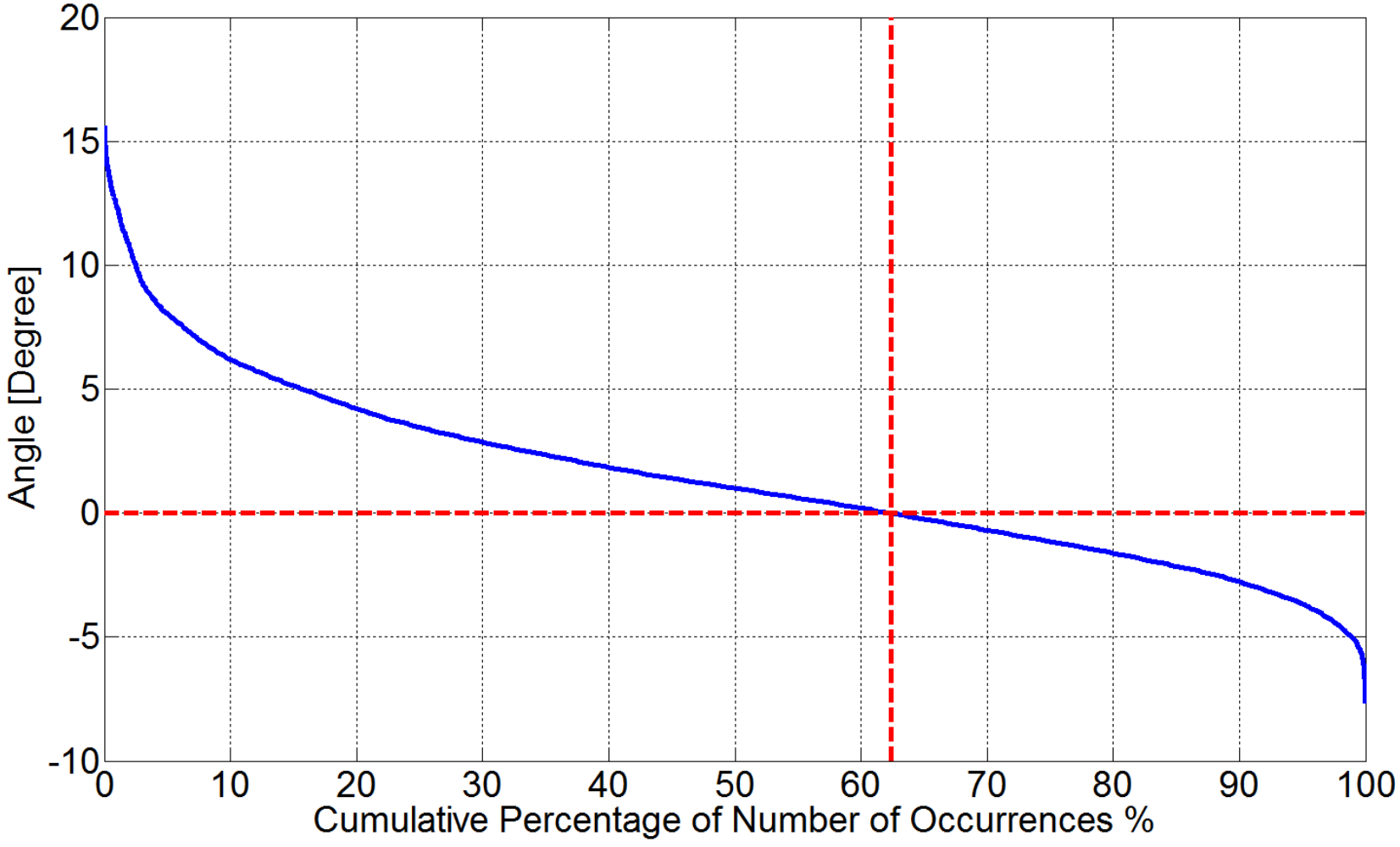


South 15*-North 7



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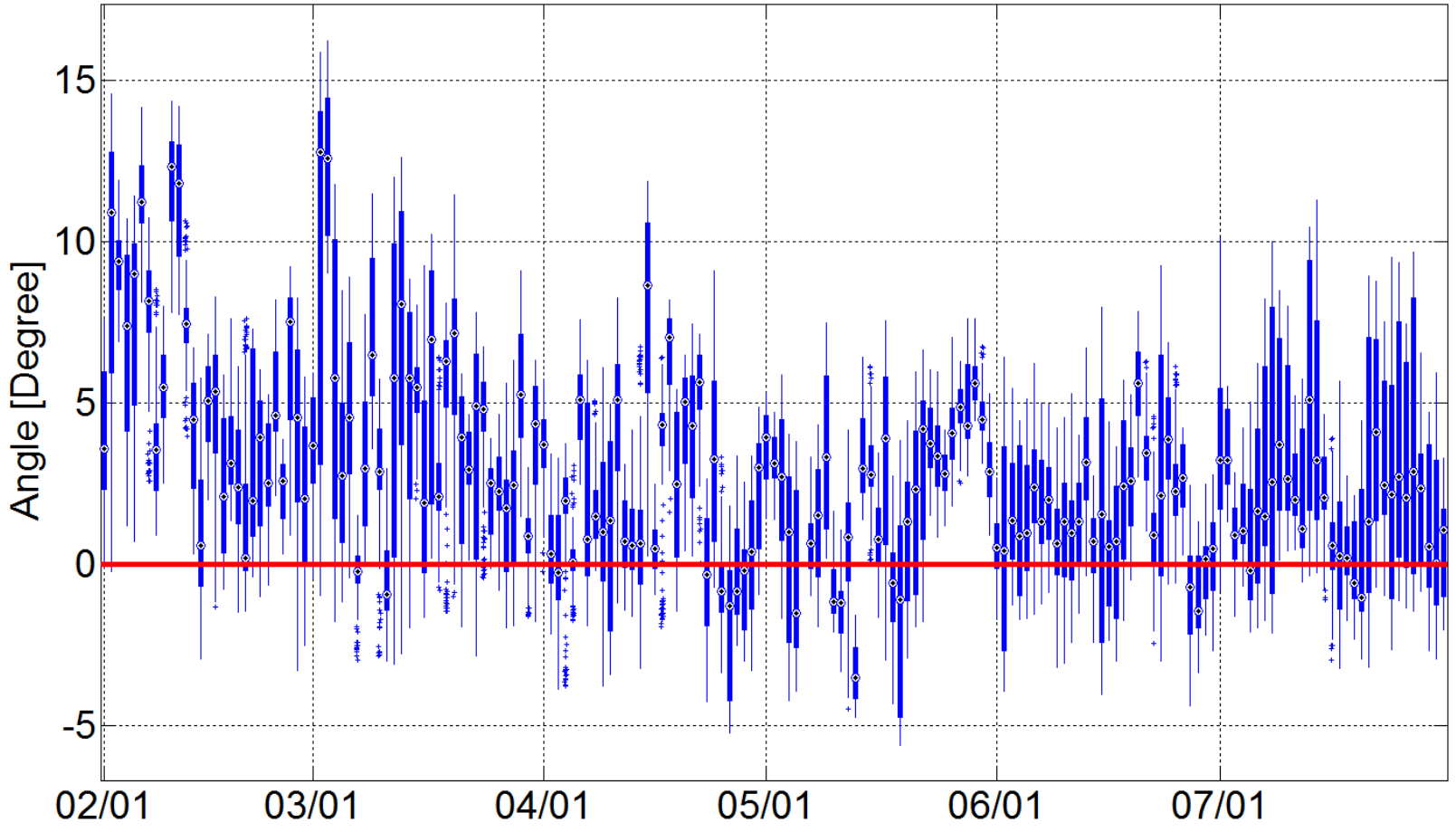

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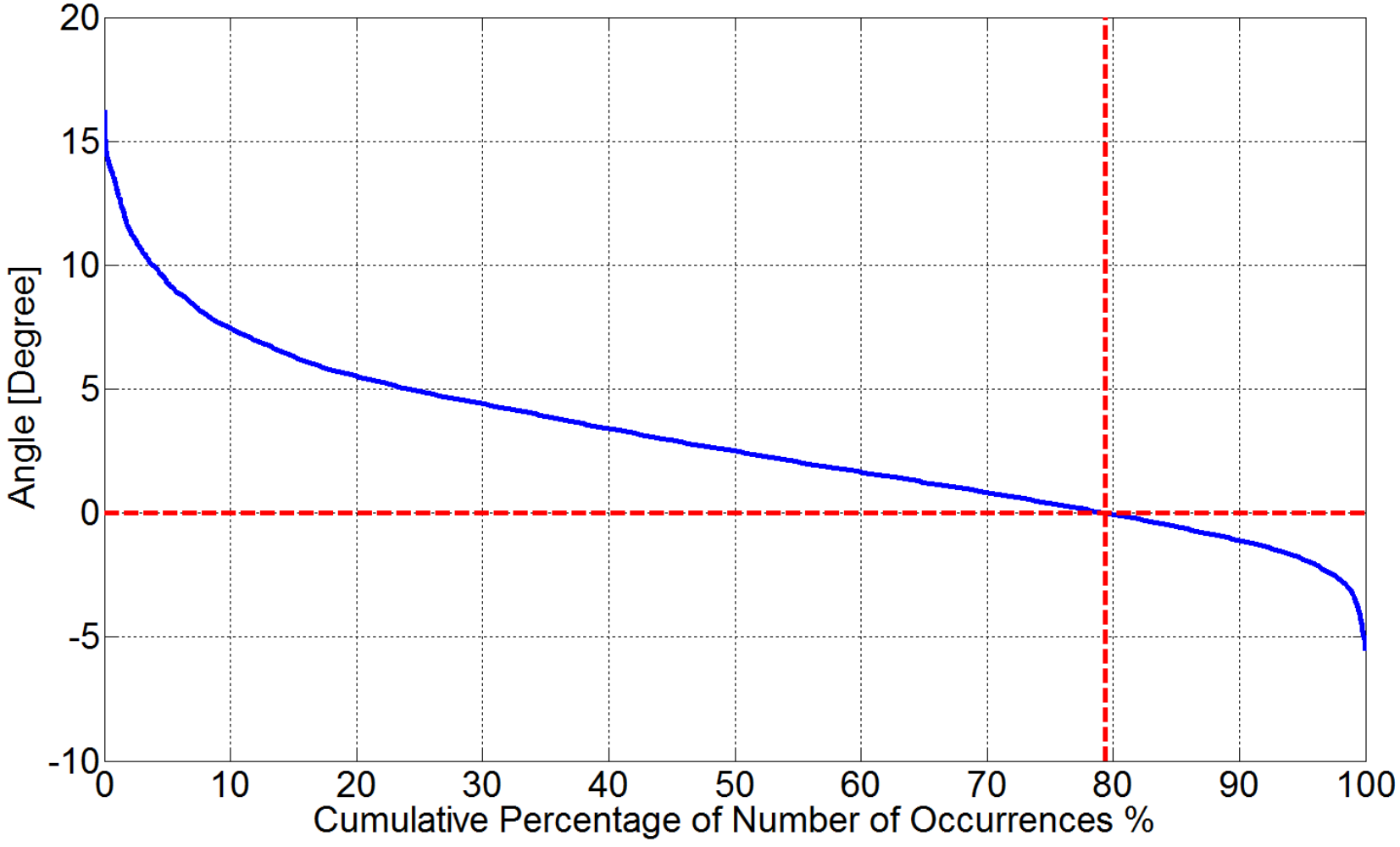

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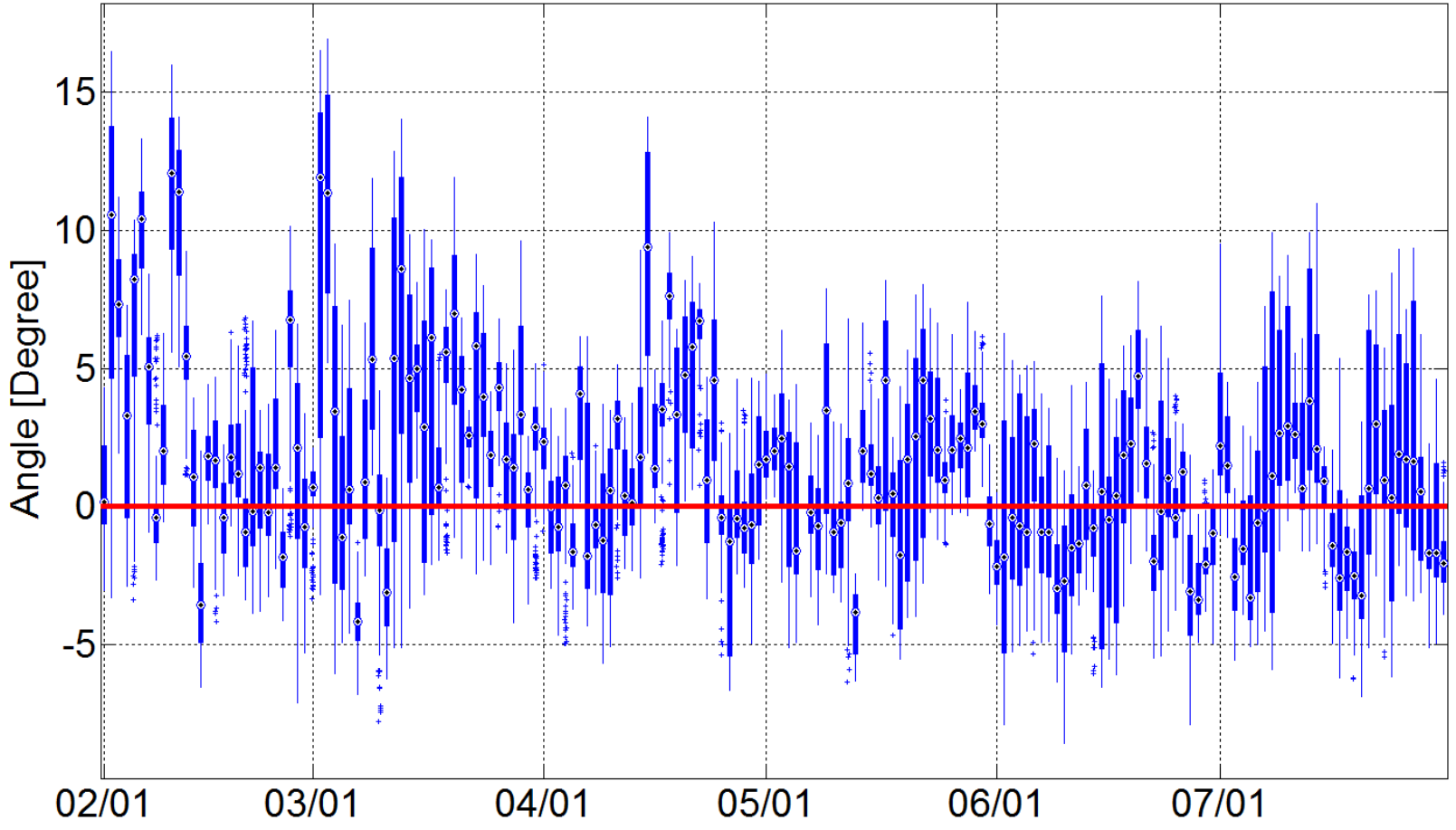

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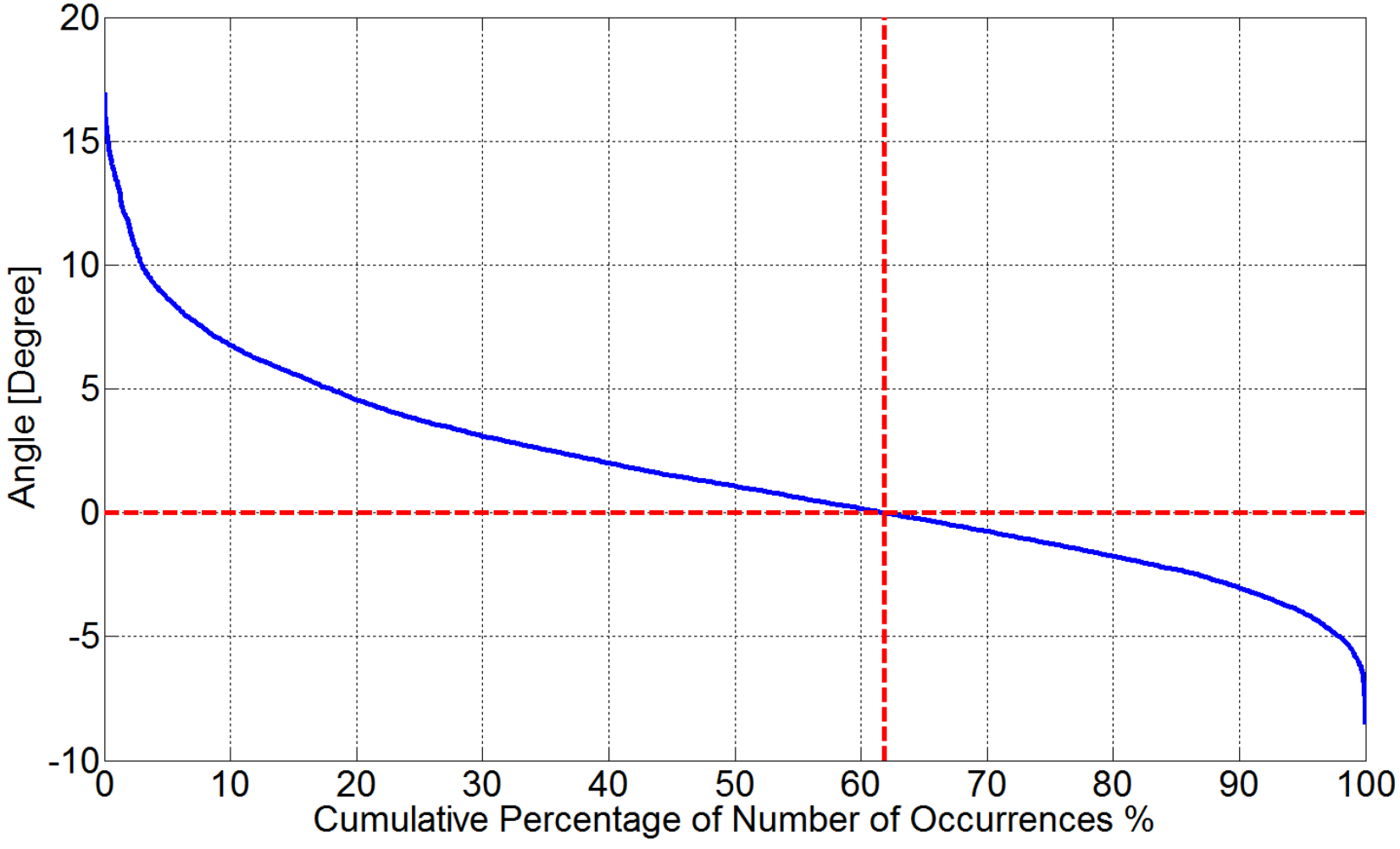

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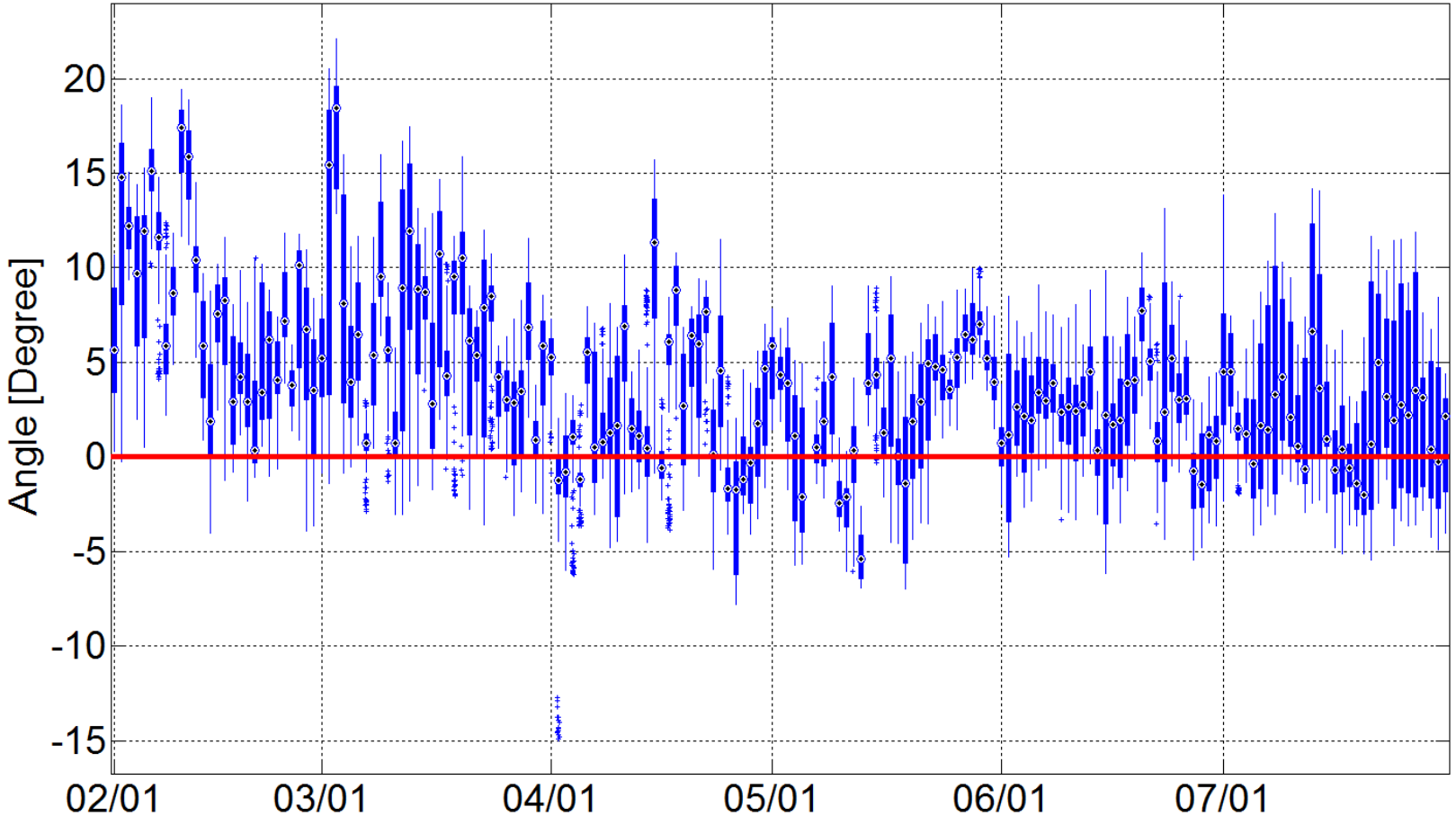

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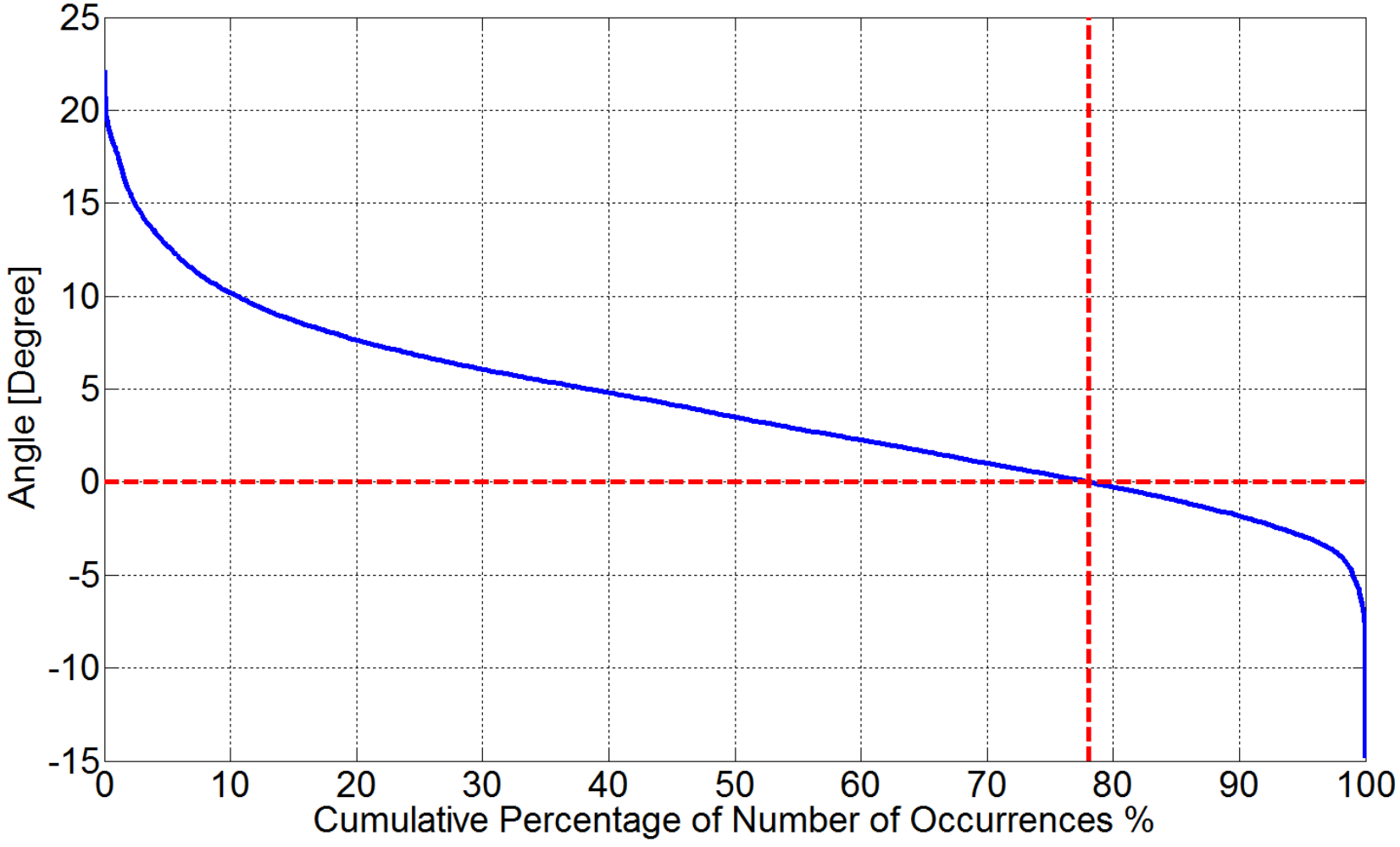

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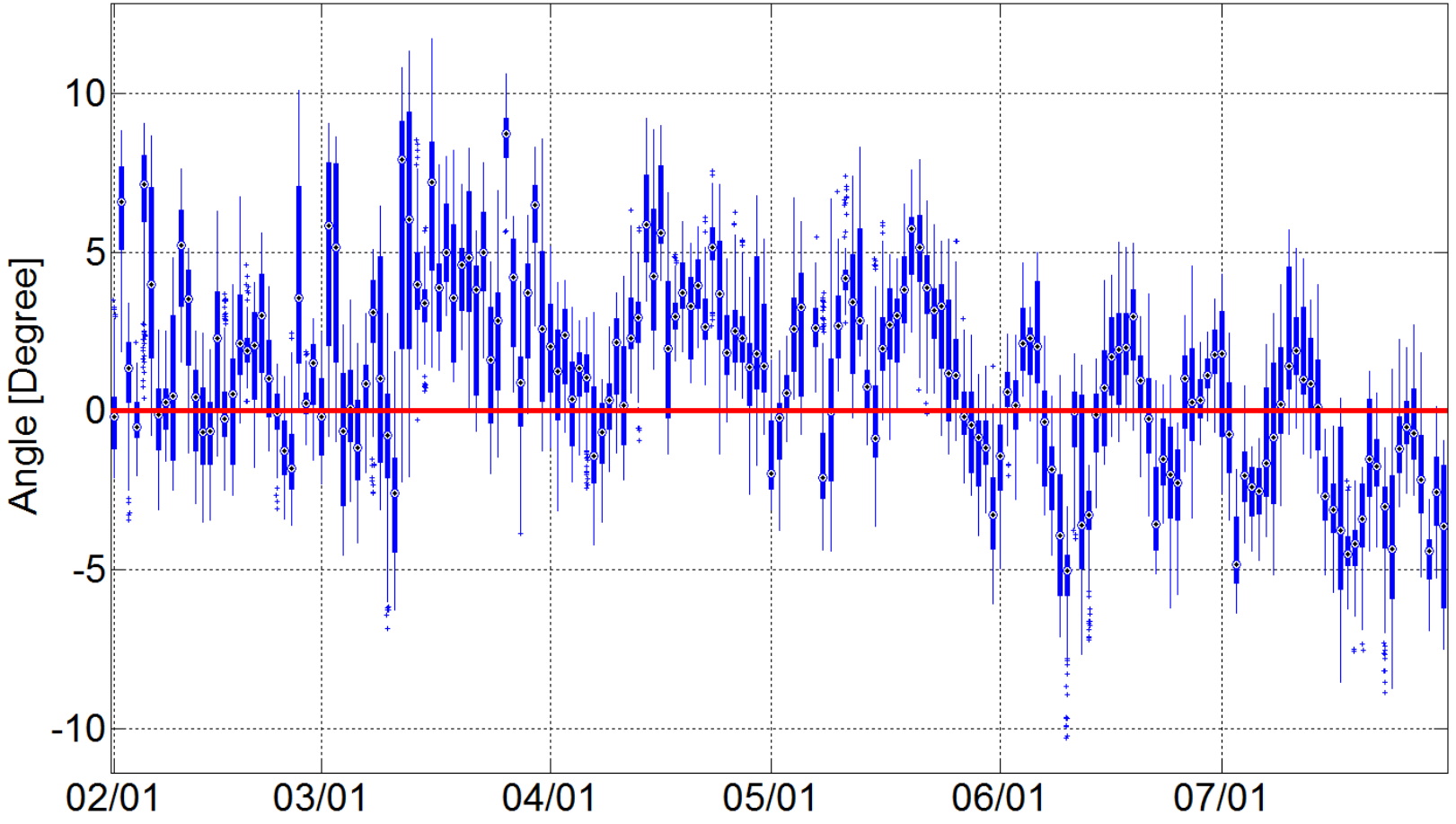

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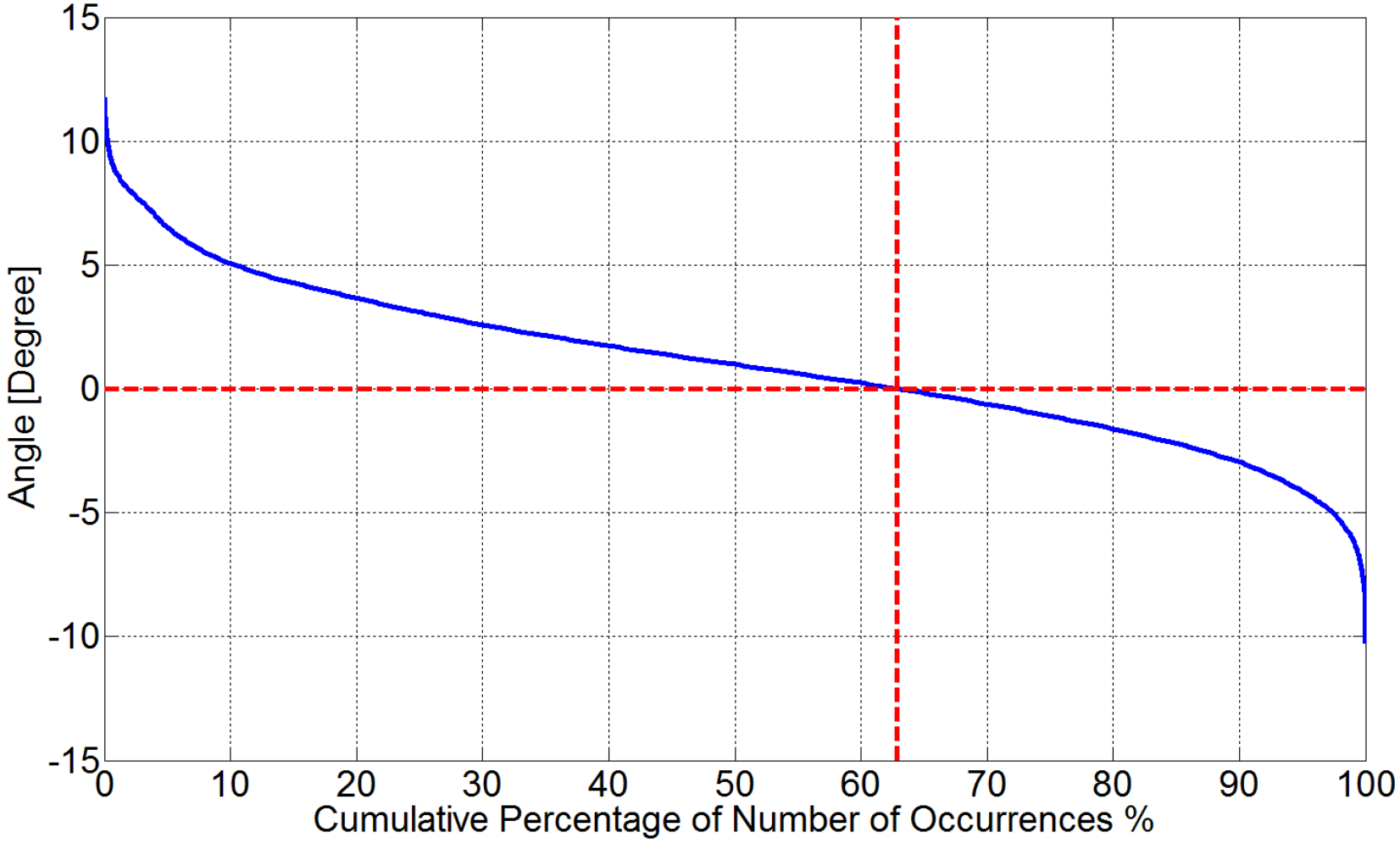

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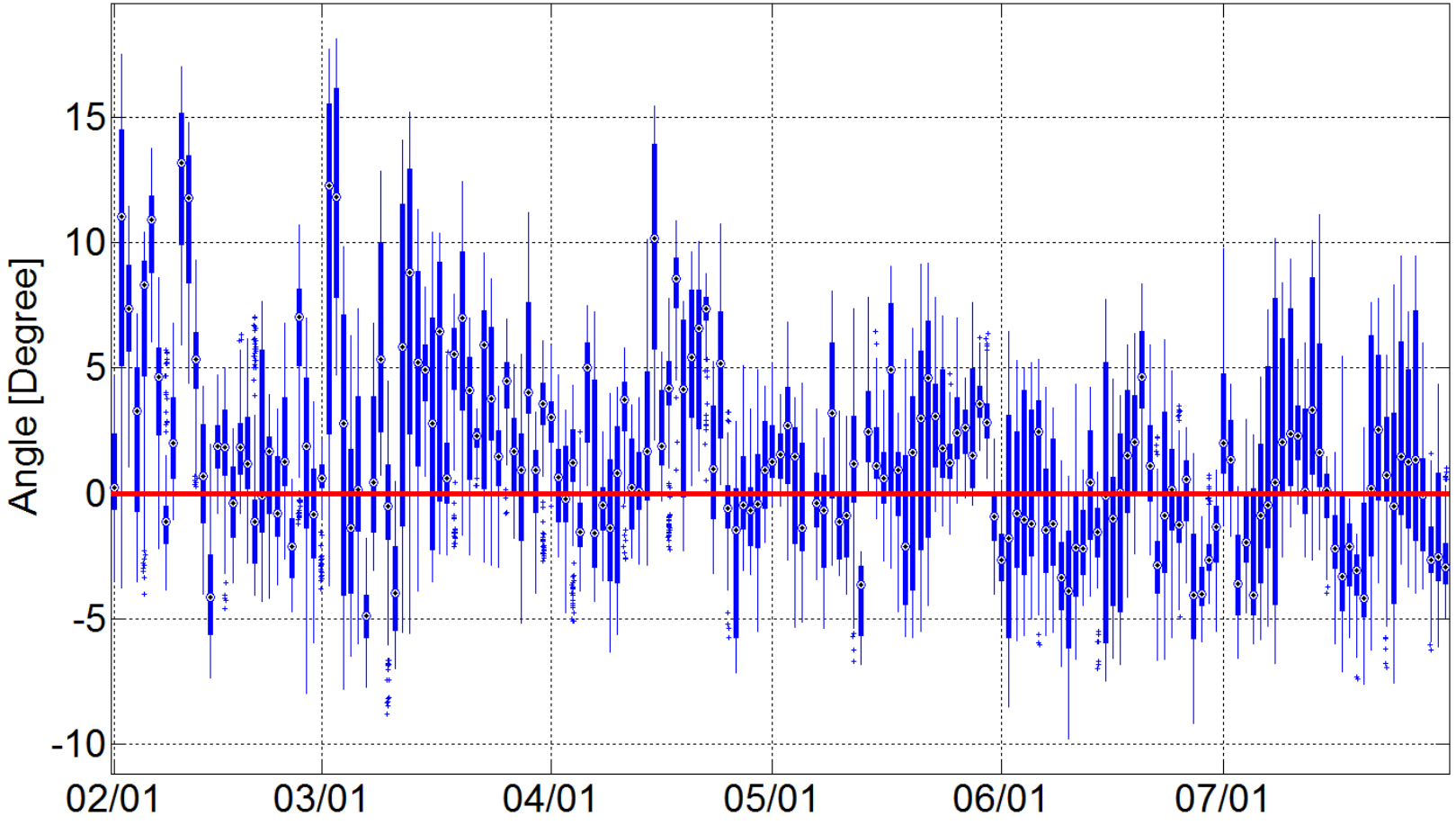

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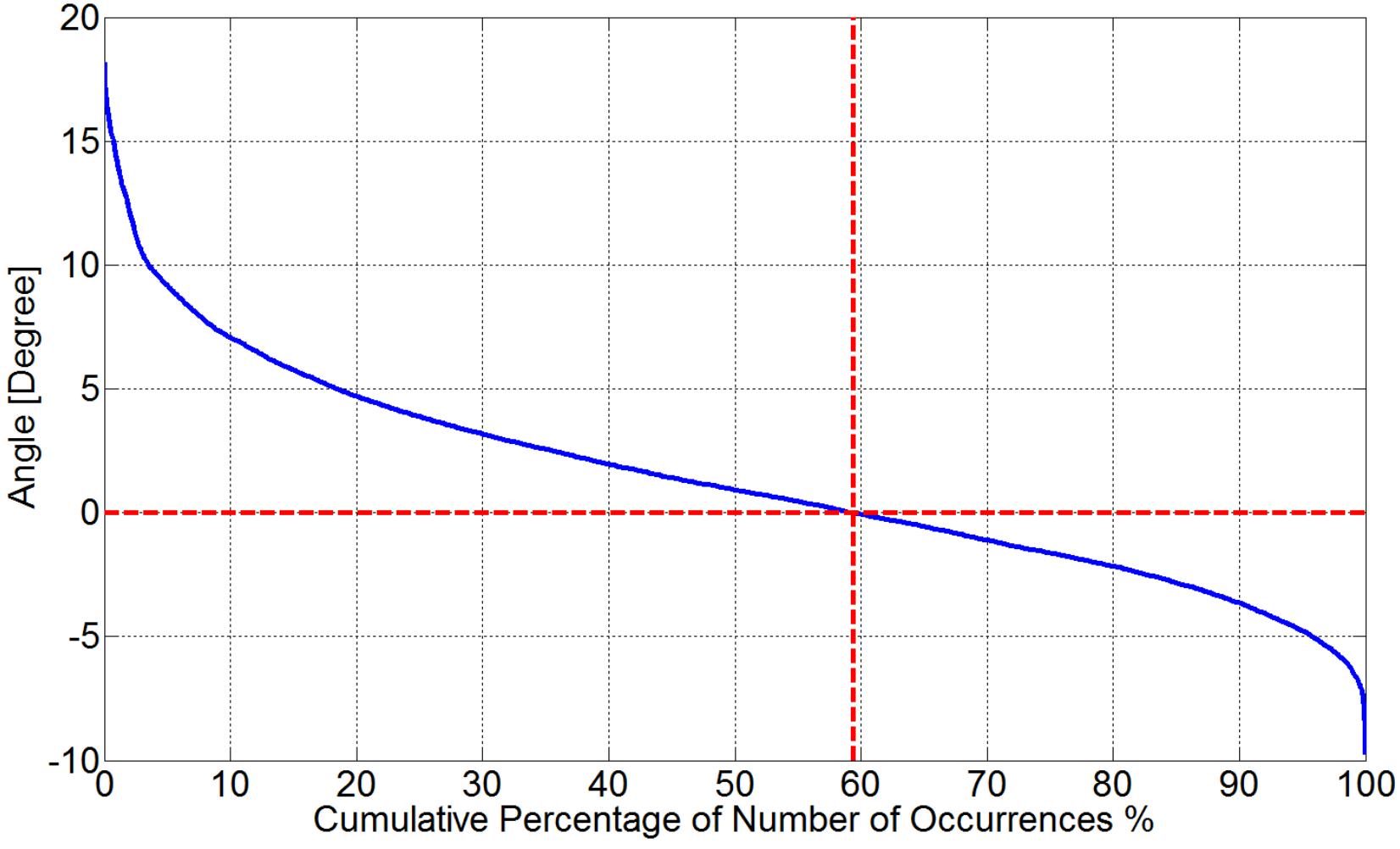

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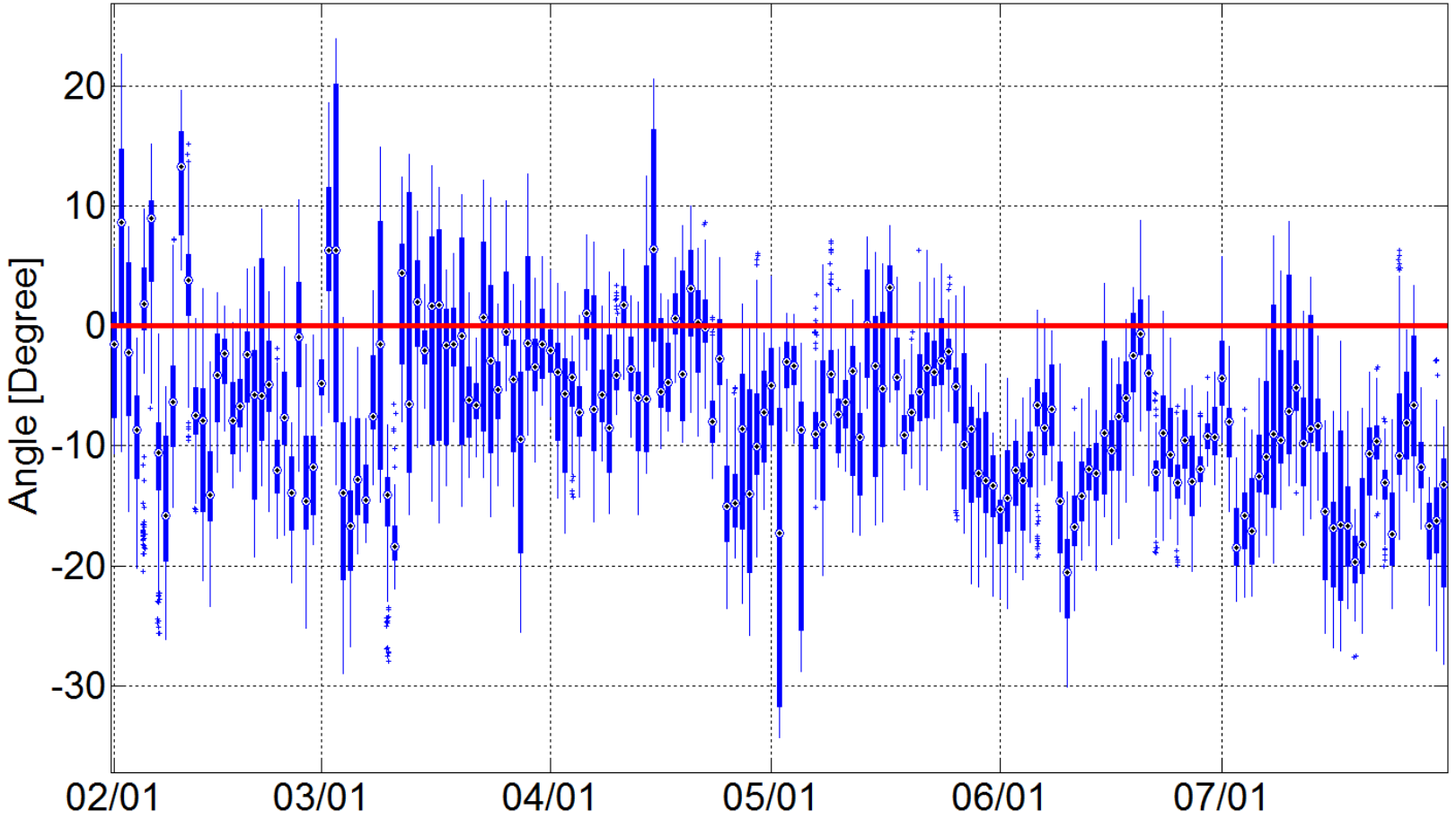

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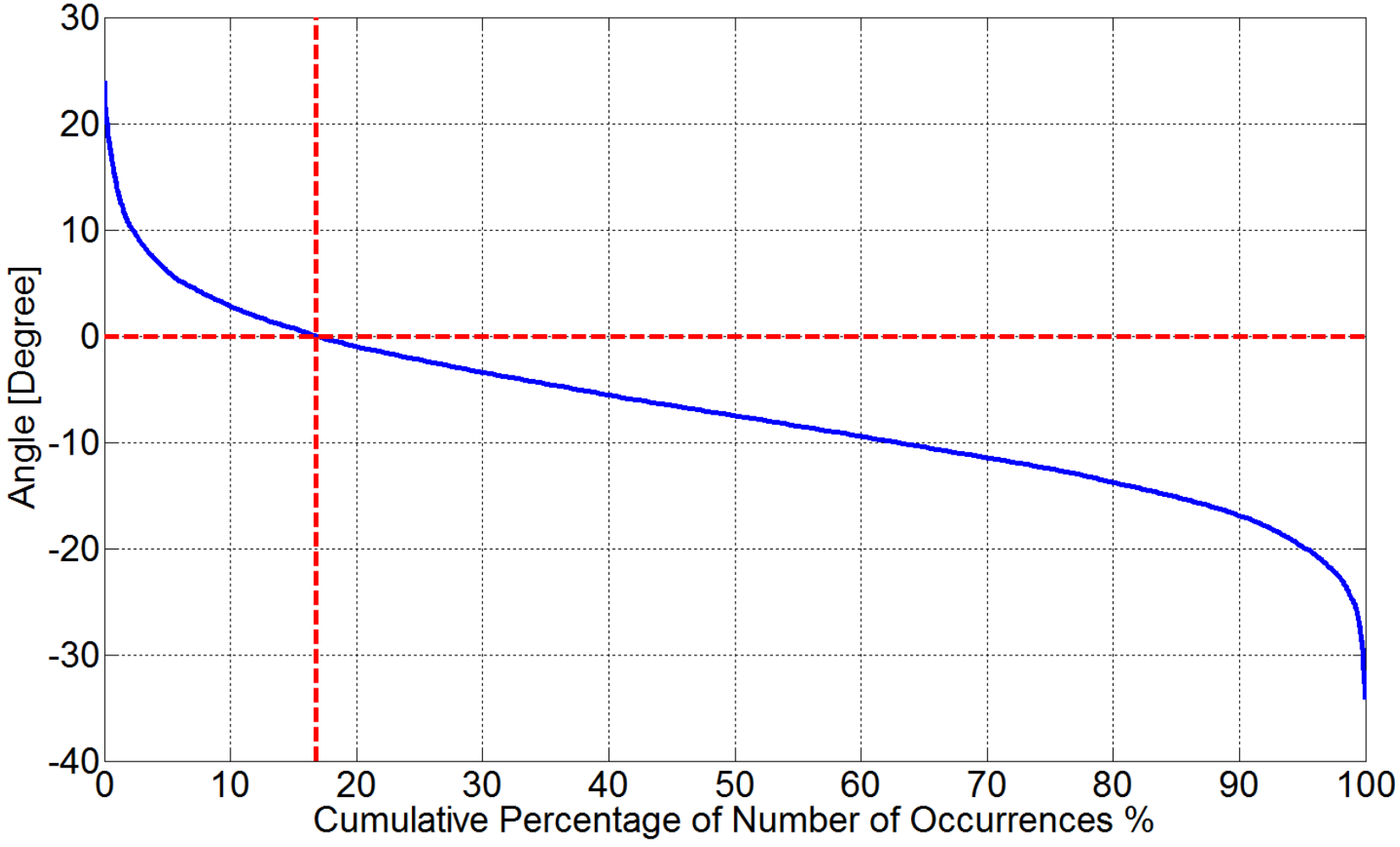

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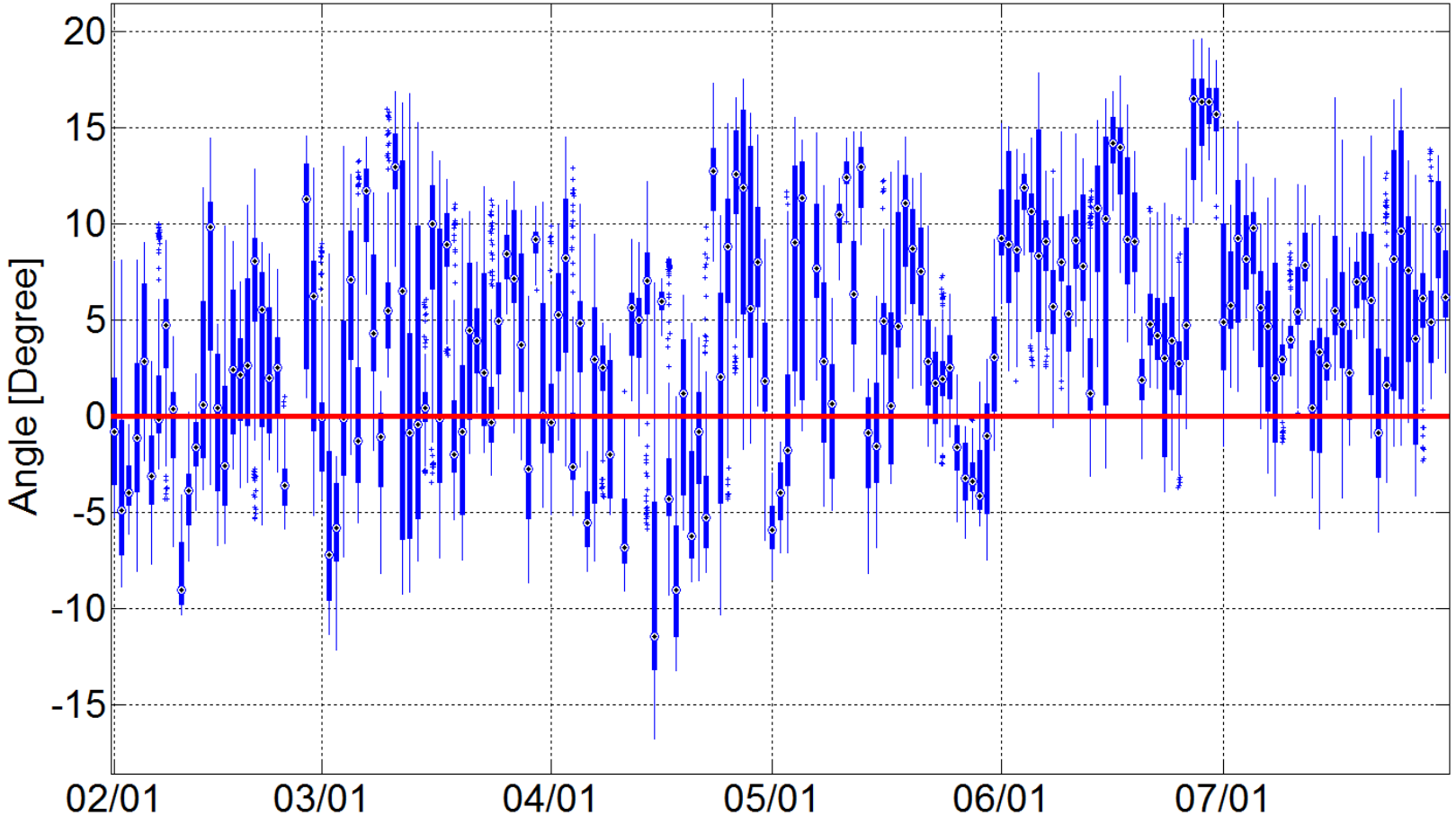

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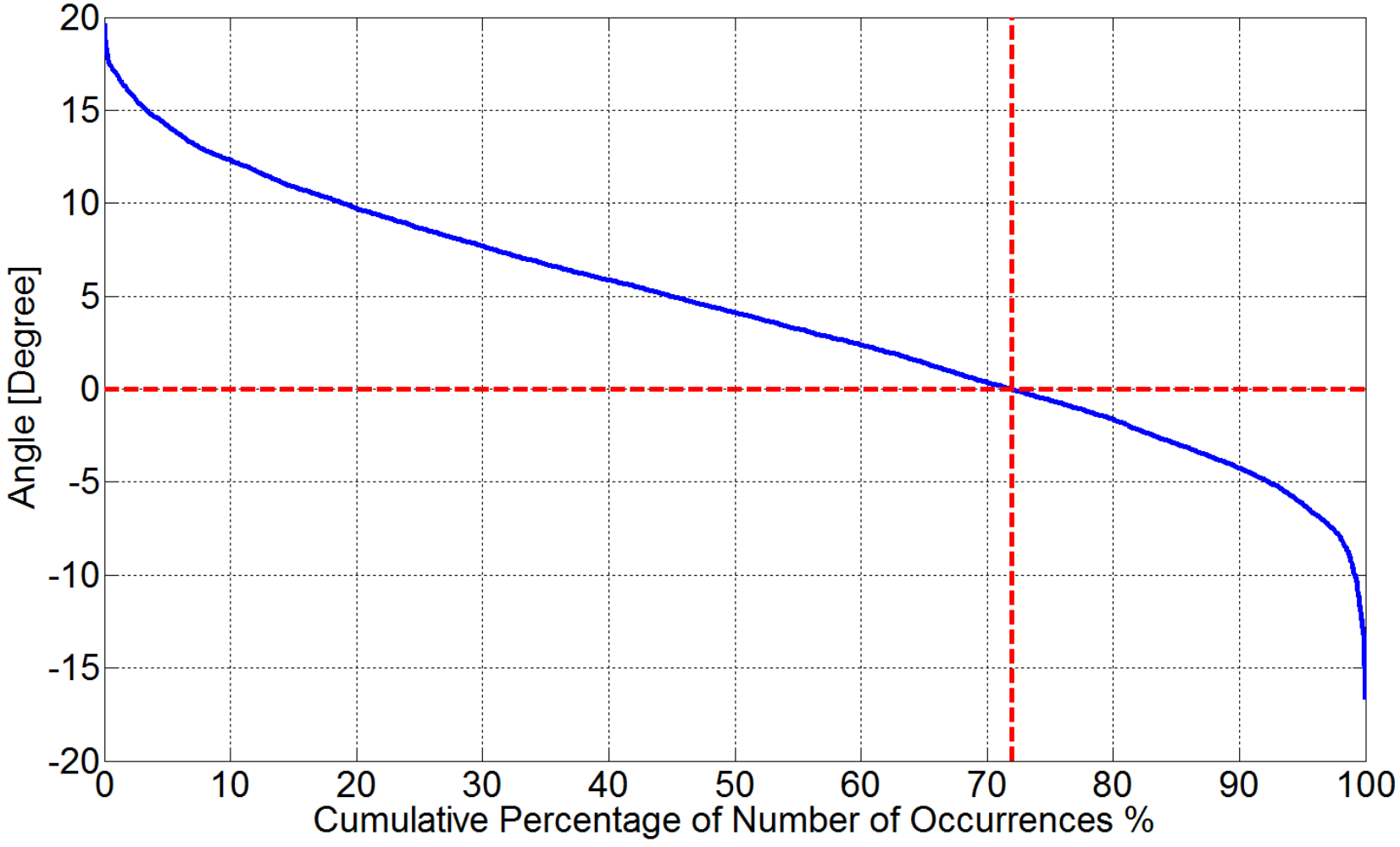
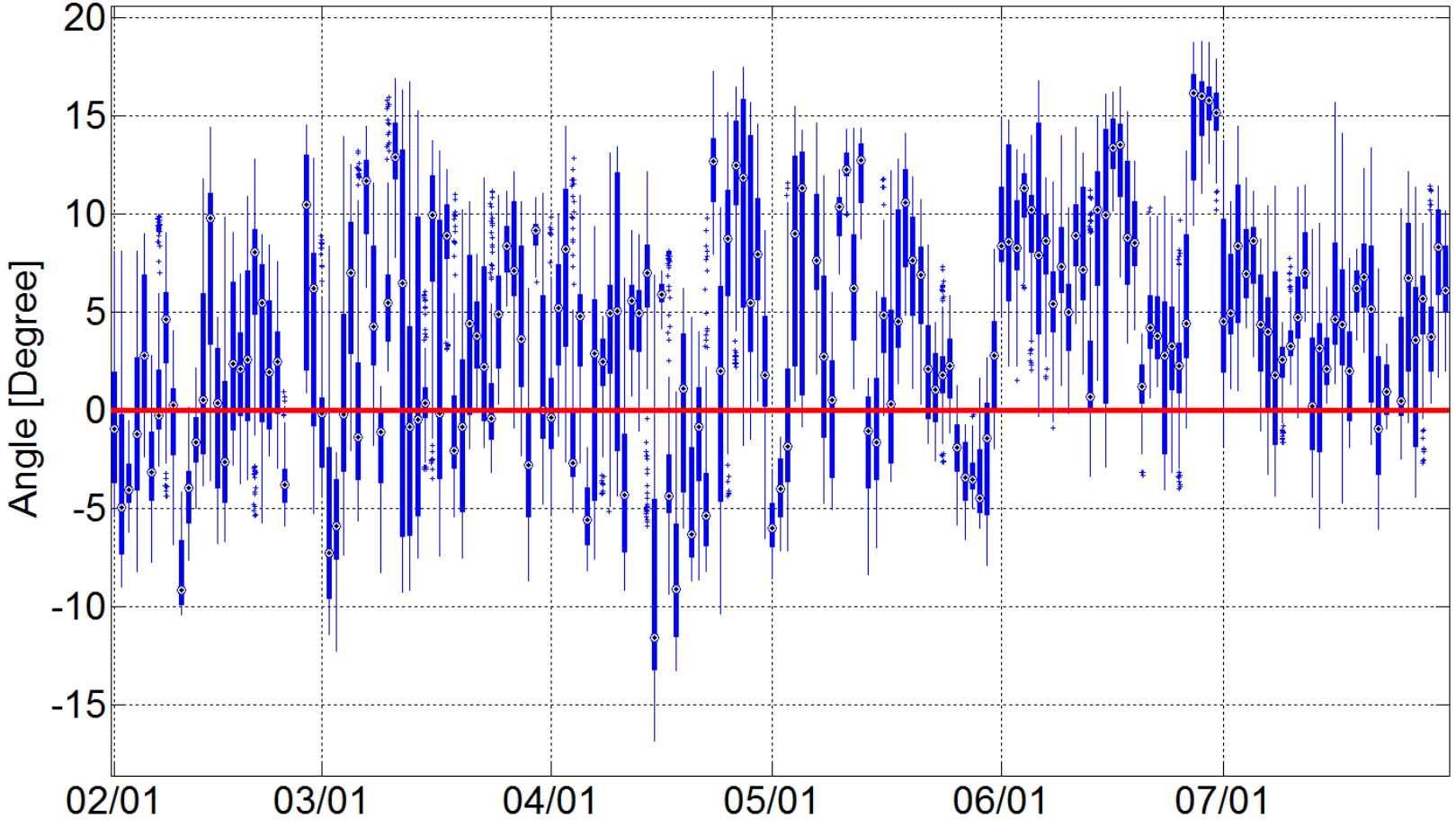


West 13*-North 7



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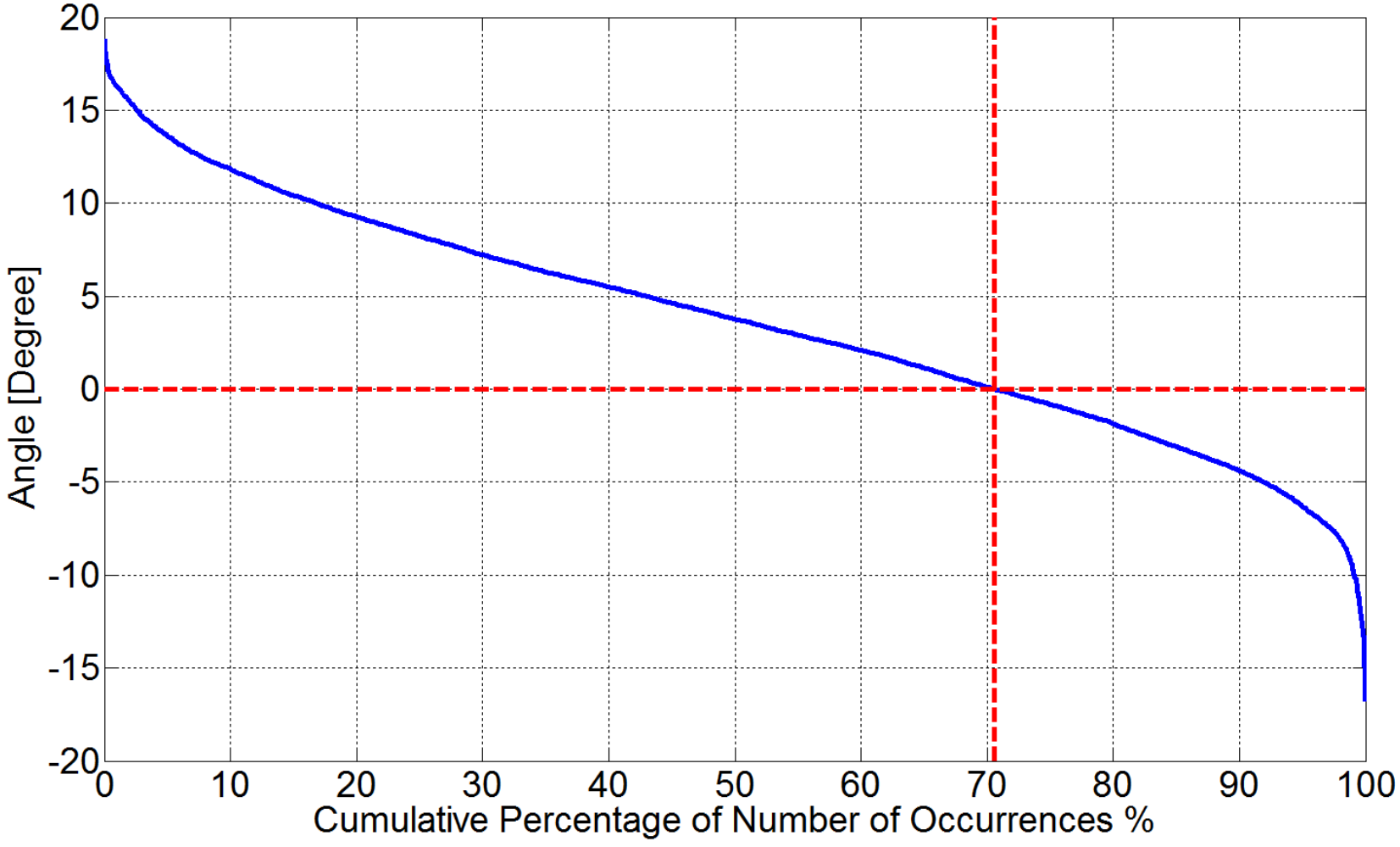
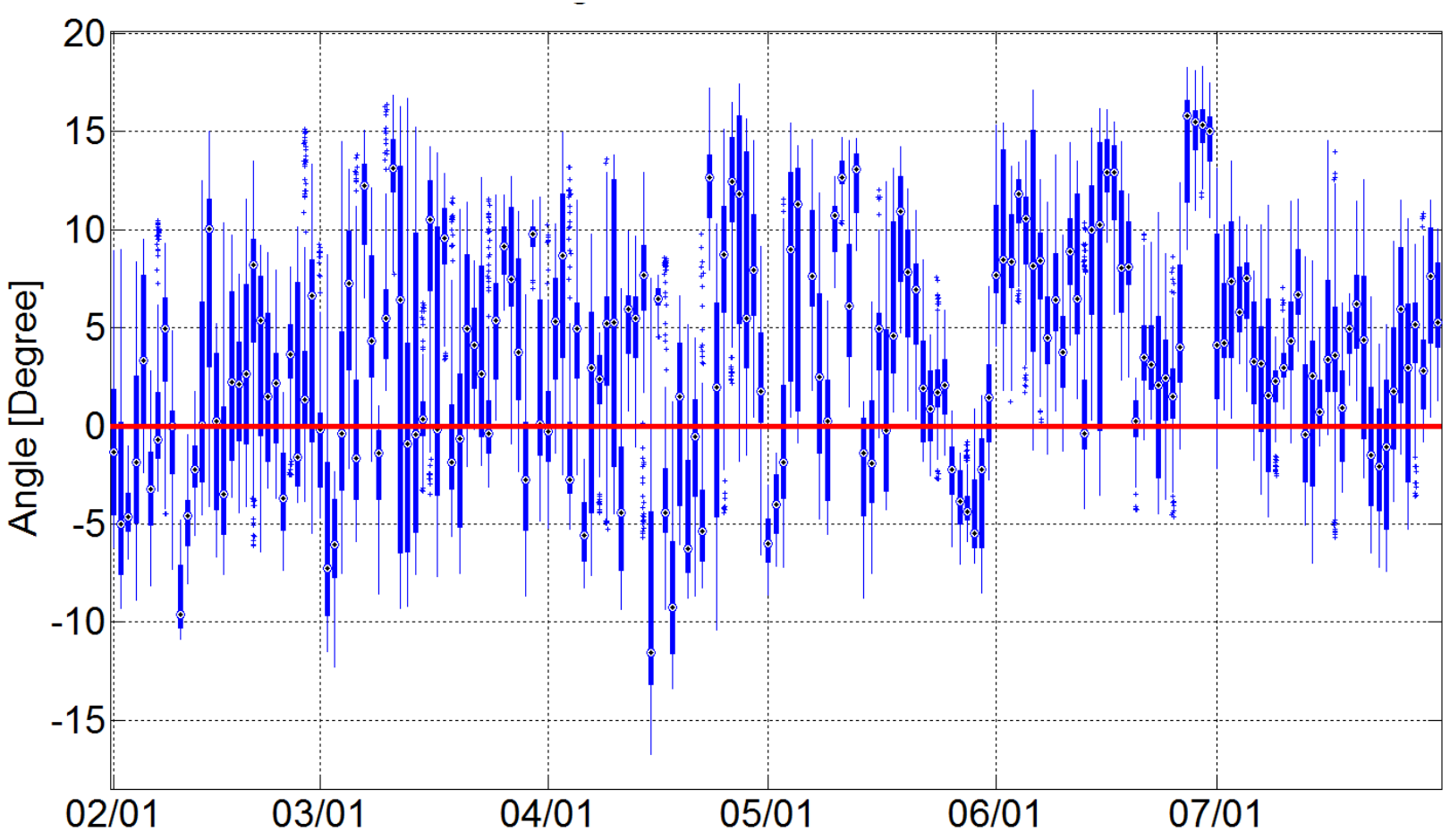
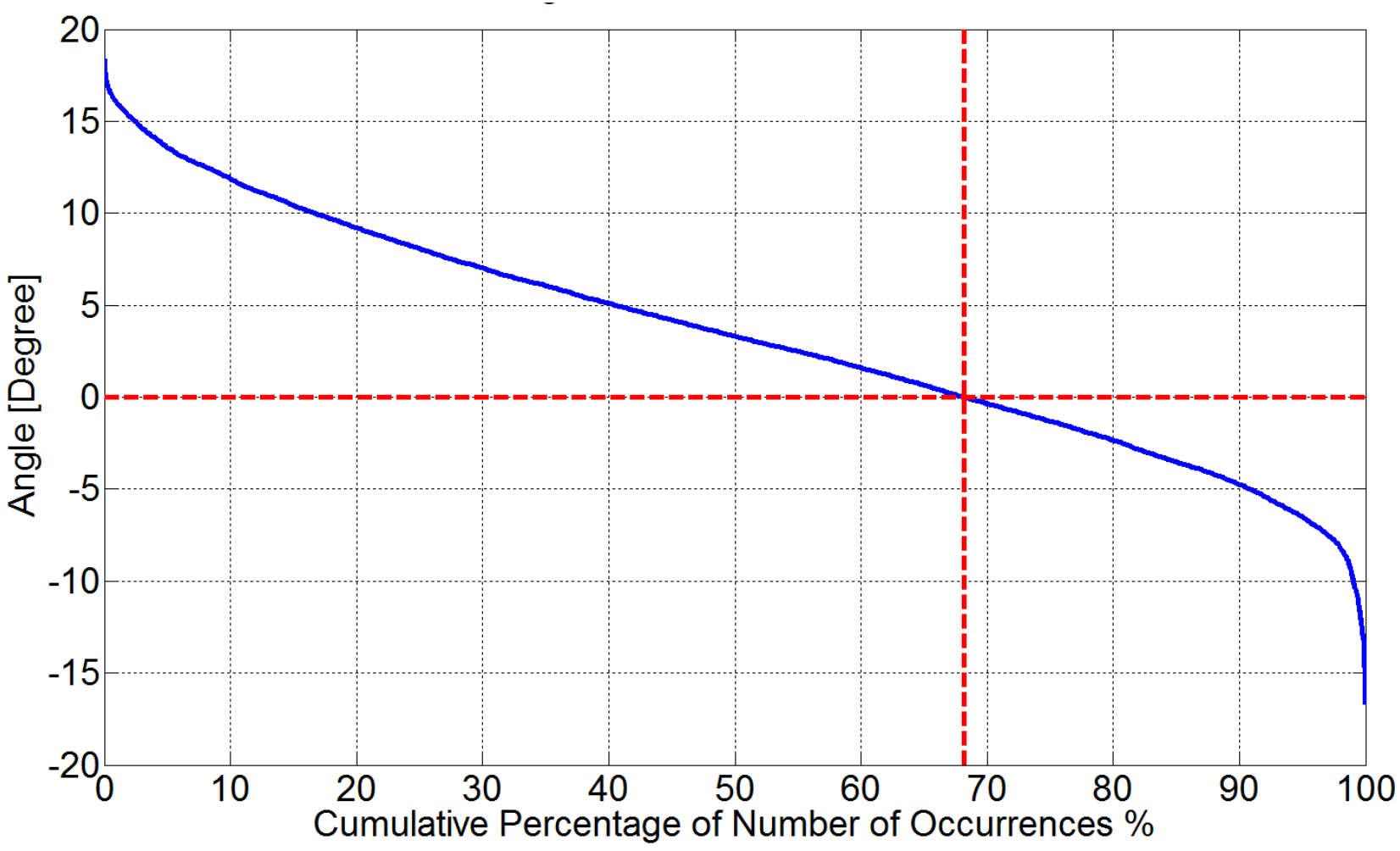


West 19-North 7



West 19-North 7



Appendix A – Part 2
CCET Discovery Across Texas project

Baseline Analysis Update - Voltage Angles (Reference: North 7)

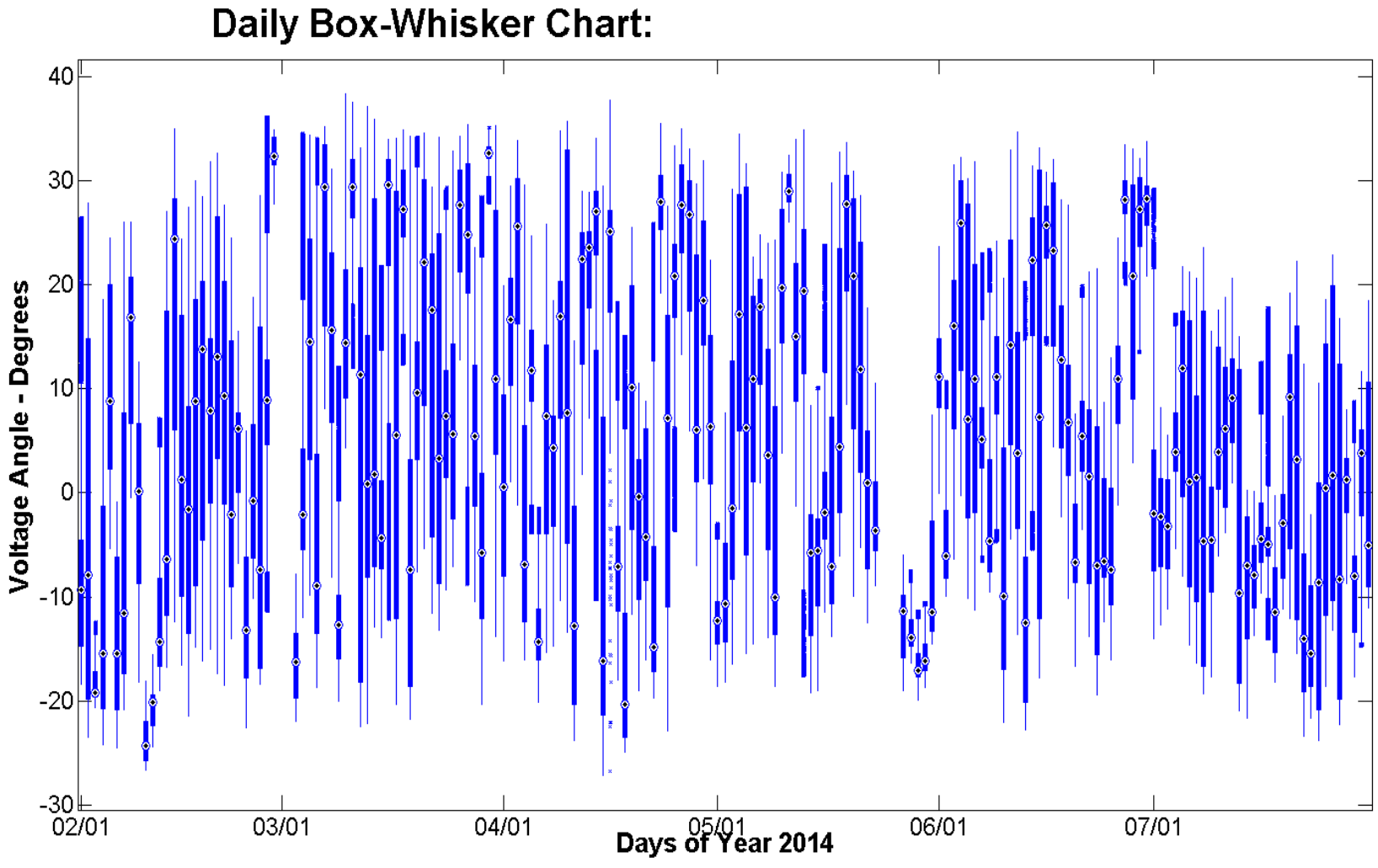
Phasor Data: February to July 2014
Box-Whisker Plots and Time Duration Curves

Electric Power Group

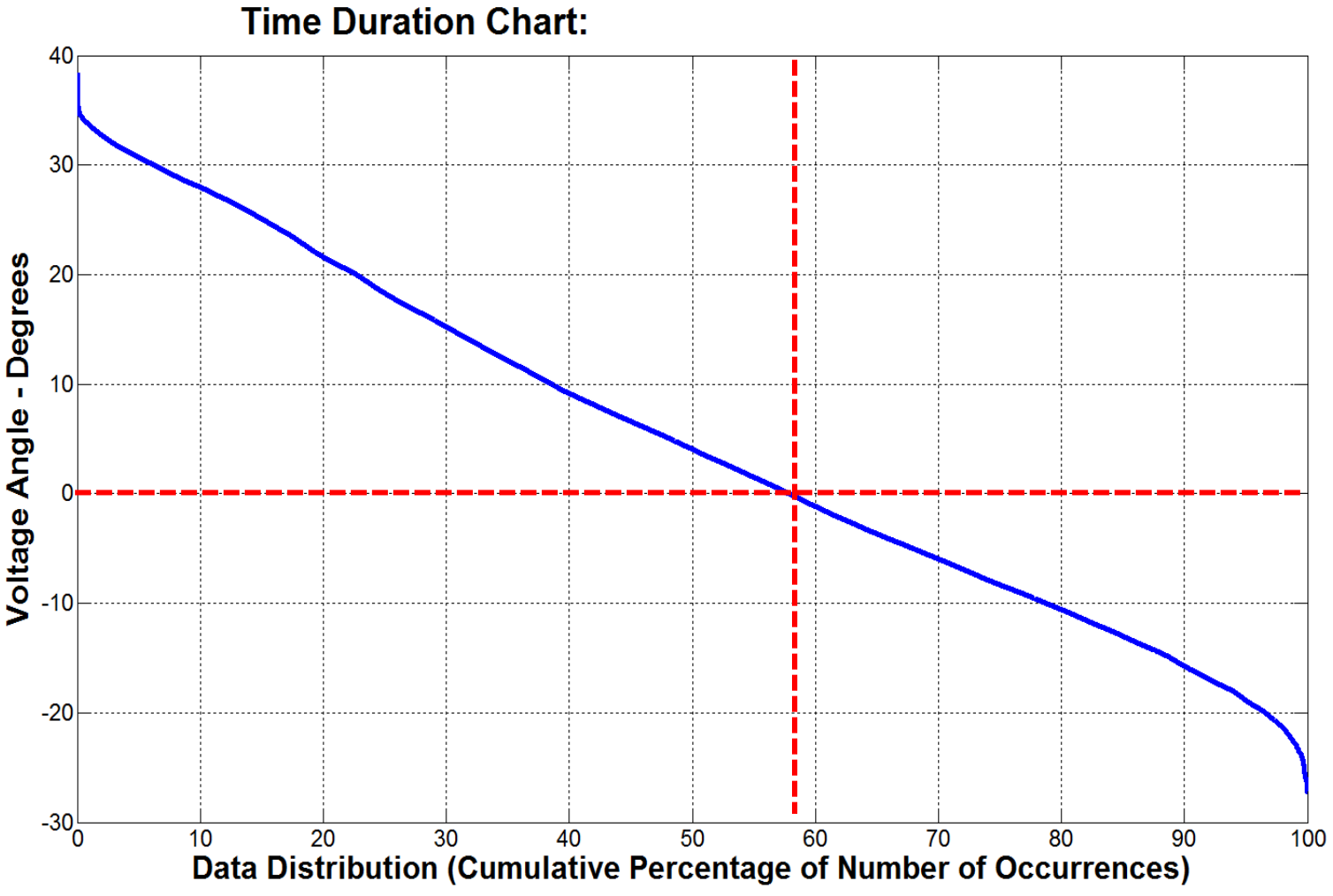
CCET

ERCOT

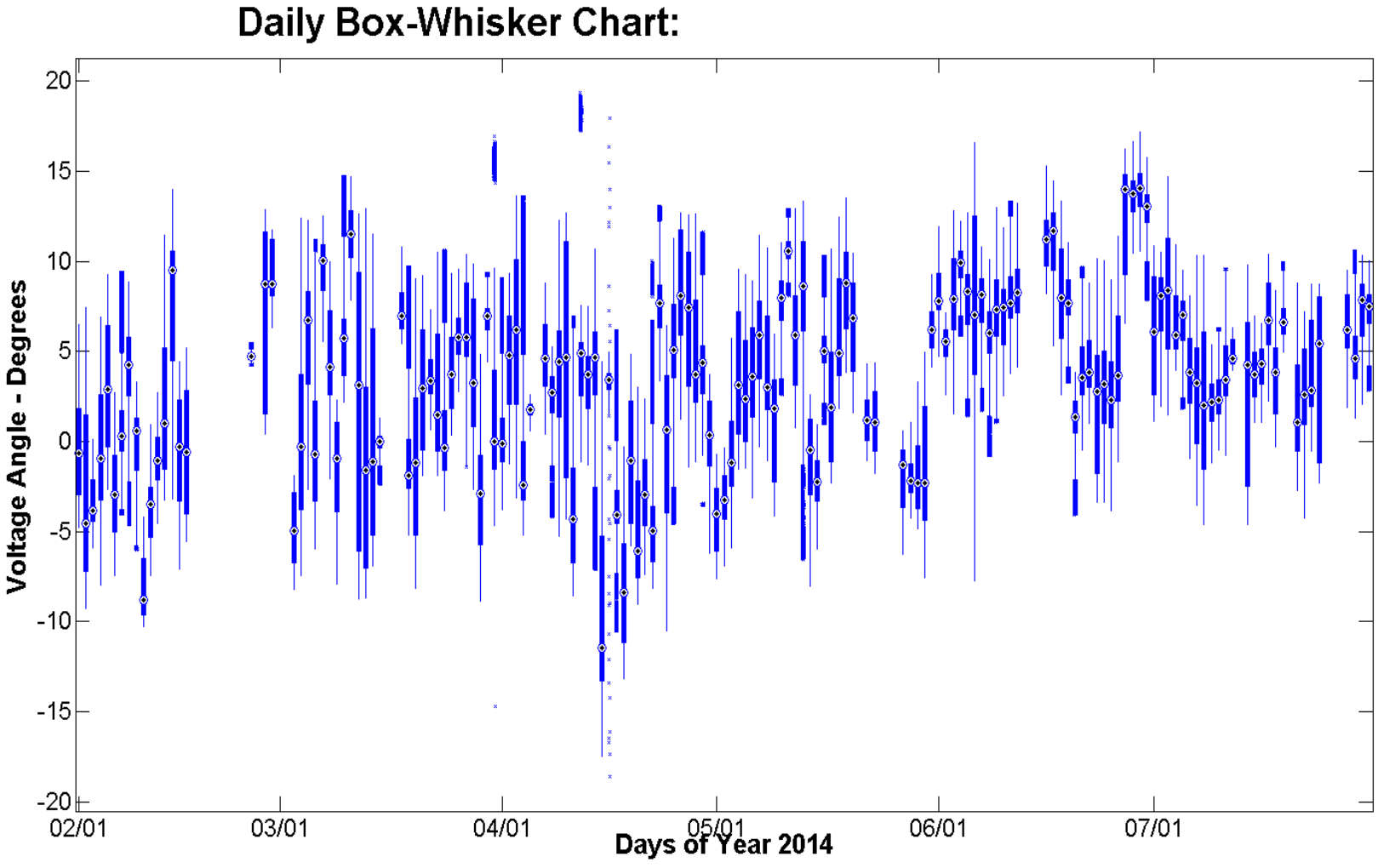
West 10


Daily Box-Whisker Chart:
Voltage Angle - Degrees
40
30
20
10
0
-10
-20
-30
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

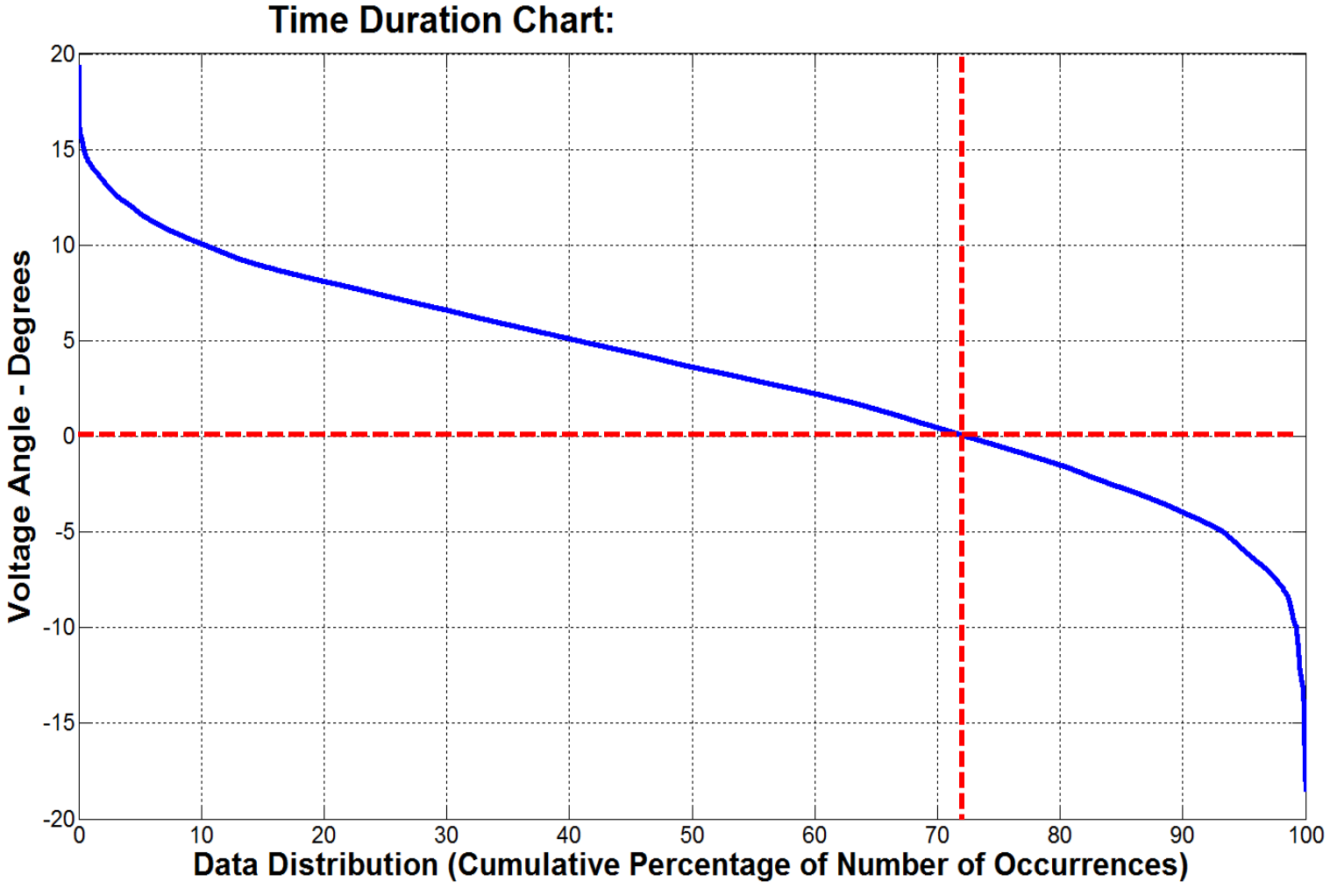
West 10


Time Duration Chart:
Voltage Angle - Degrees
40
30
20
10
0
-10
-20
-30
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

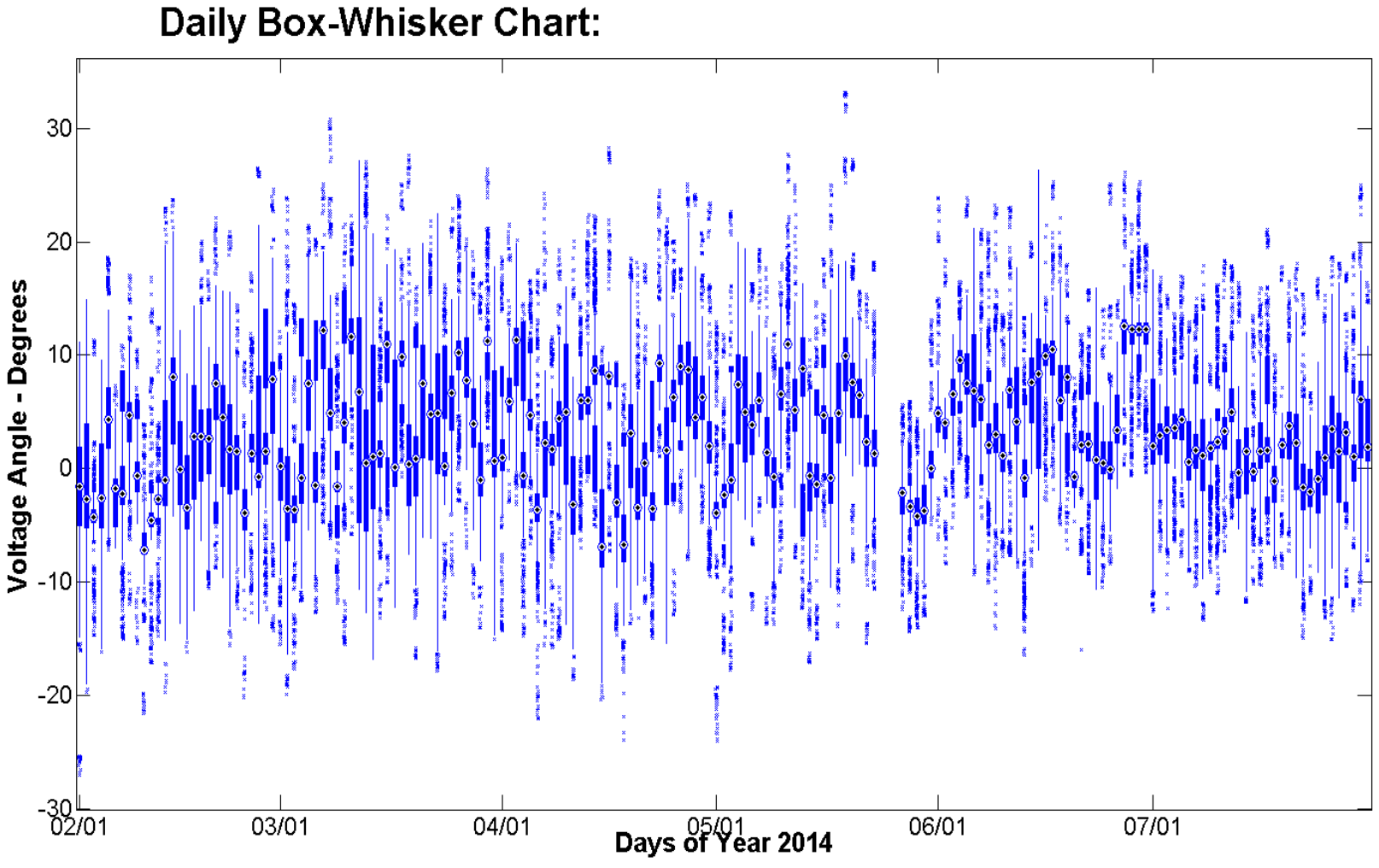
West 14


Daily Box-Whisker Chart:
Voltage Angle - Degrees
20
15
10
5
0
-5
-10
-15
-20
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

West 14

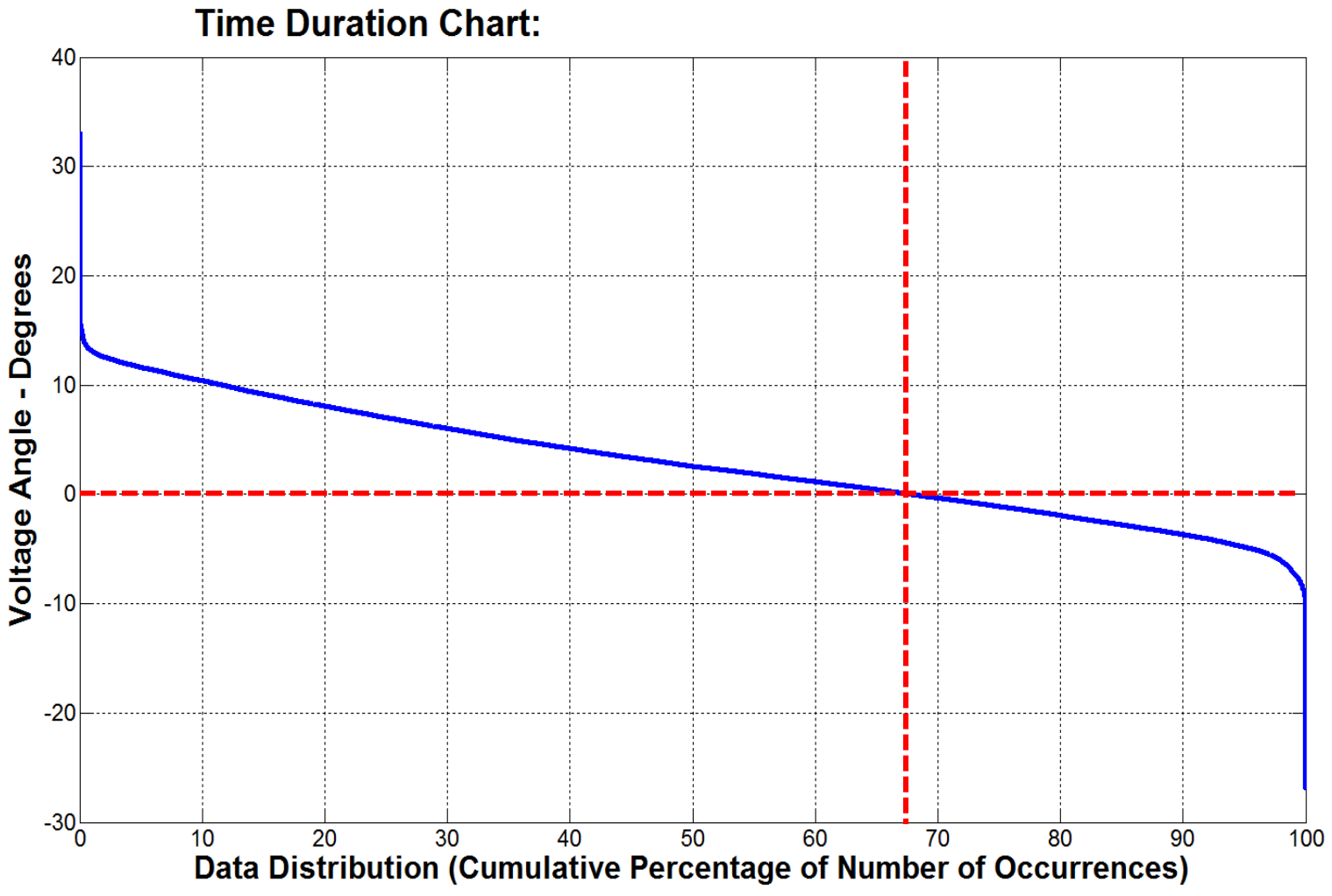

Time Duration Chart:
Voltage Angle - Degrees
20
15
10
5
0
-5
-10
-15
-20
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

West 1*

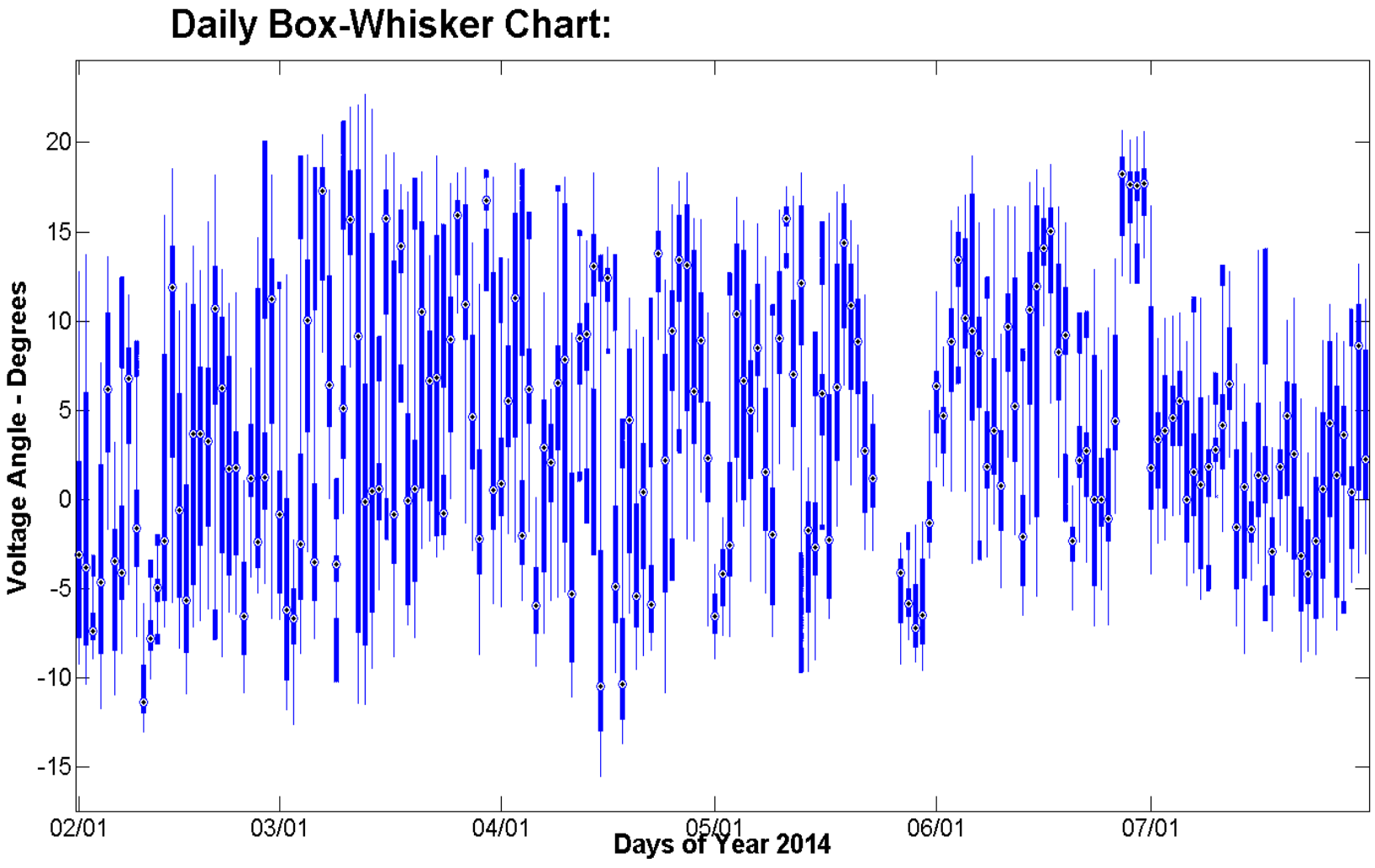


* West 1 PMU has noisy signal

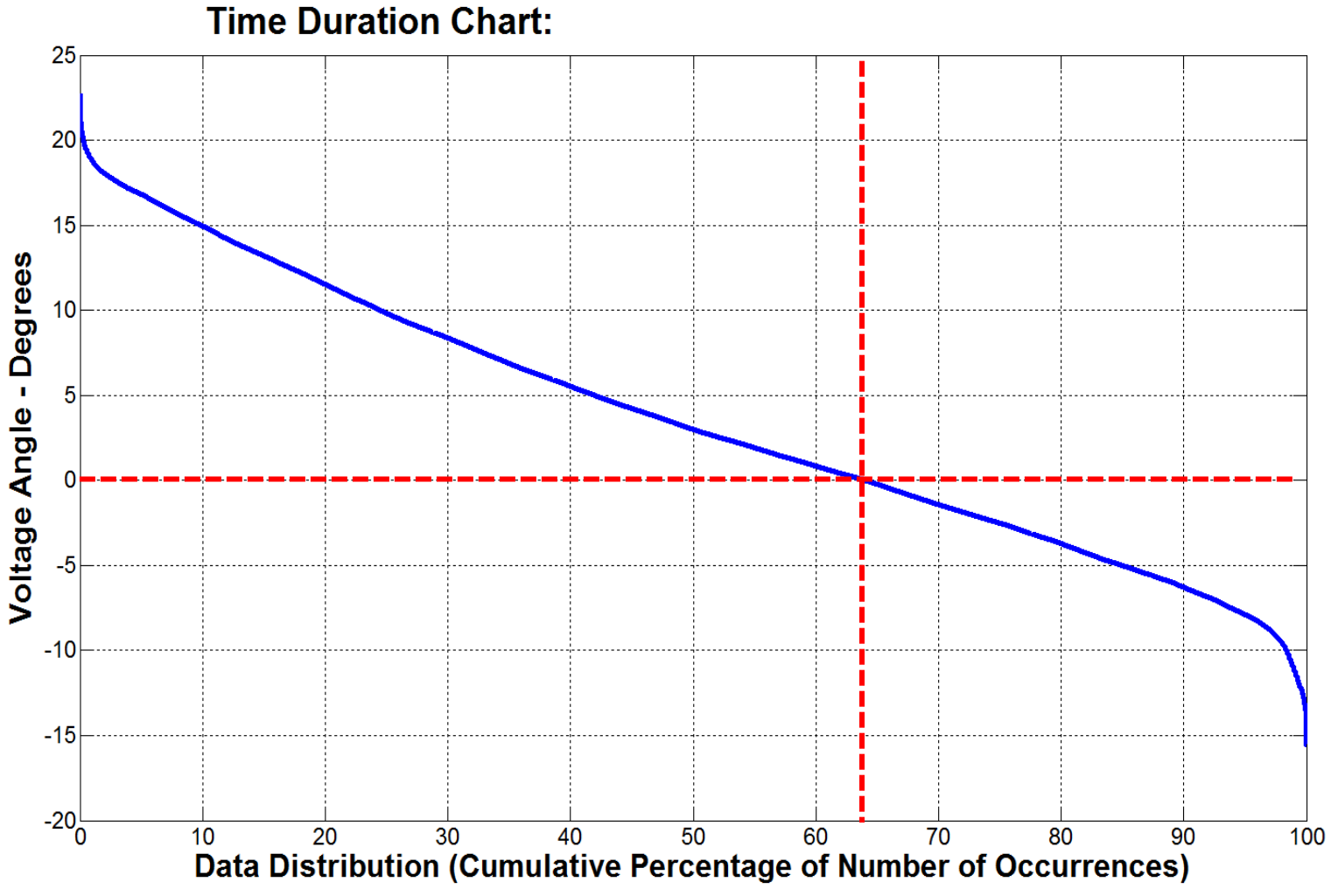
West 1


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (Cumulative Percentage of Number of Occurrences)
40
30
20
10
0
-10
-20
-30
0
10
20
30
40
50
60
70
80
90
100

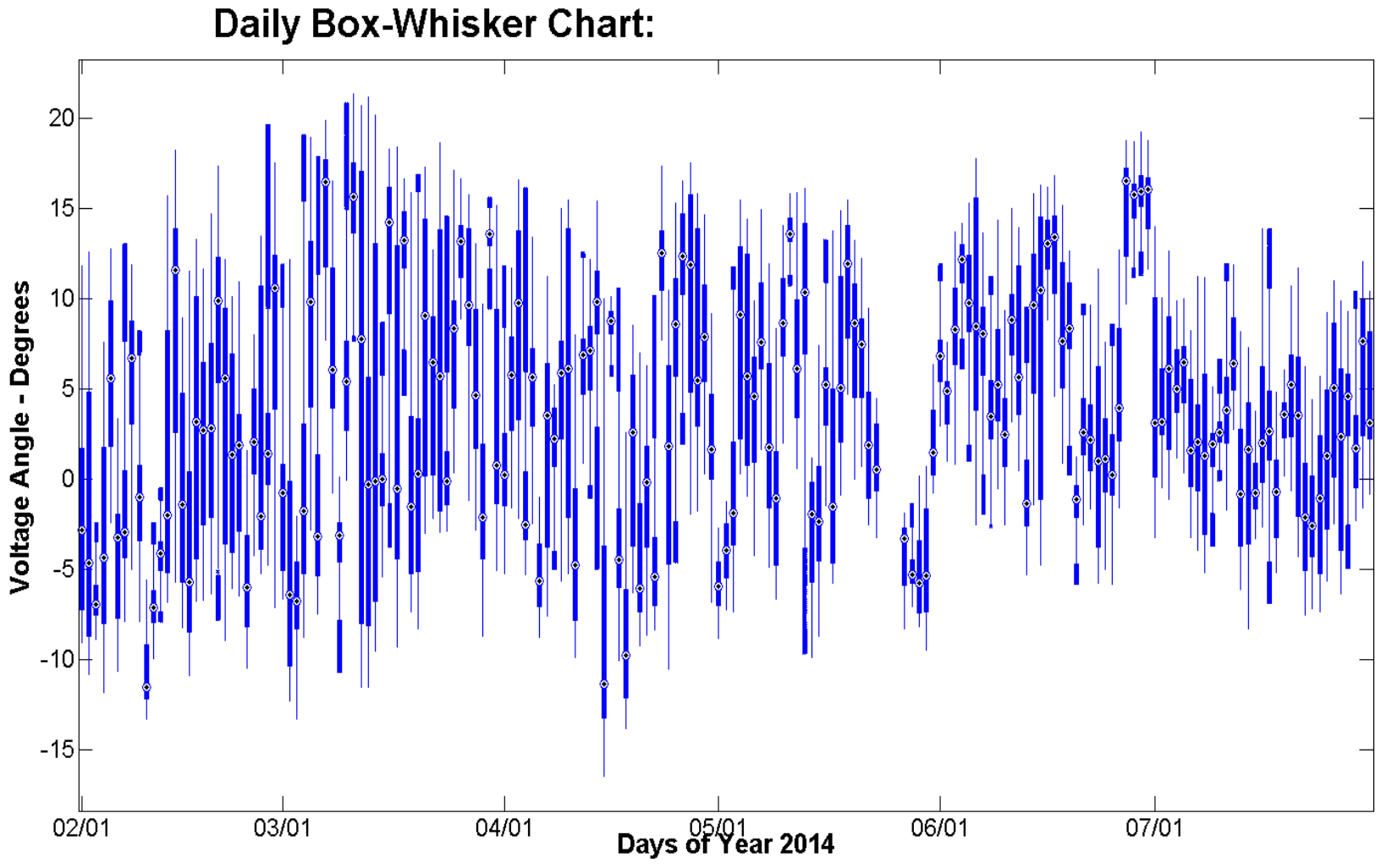
West 2


Daily Box-Whisker Chart:
Voltage Angle - Degrees
20
15
10
5
0
-5
-10
-15
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

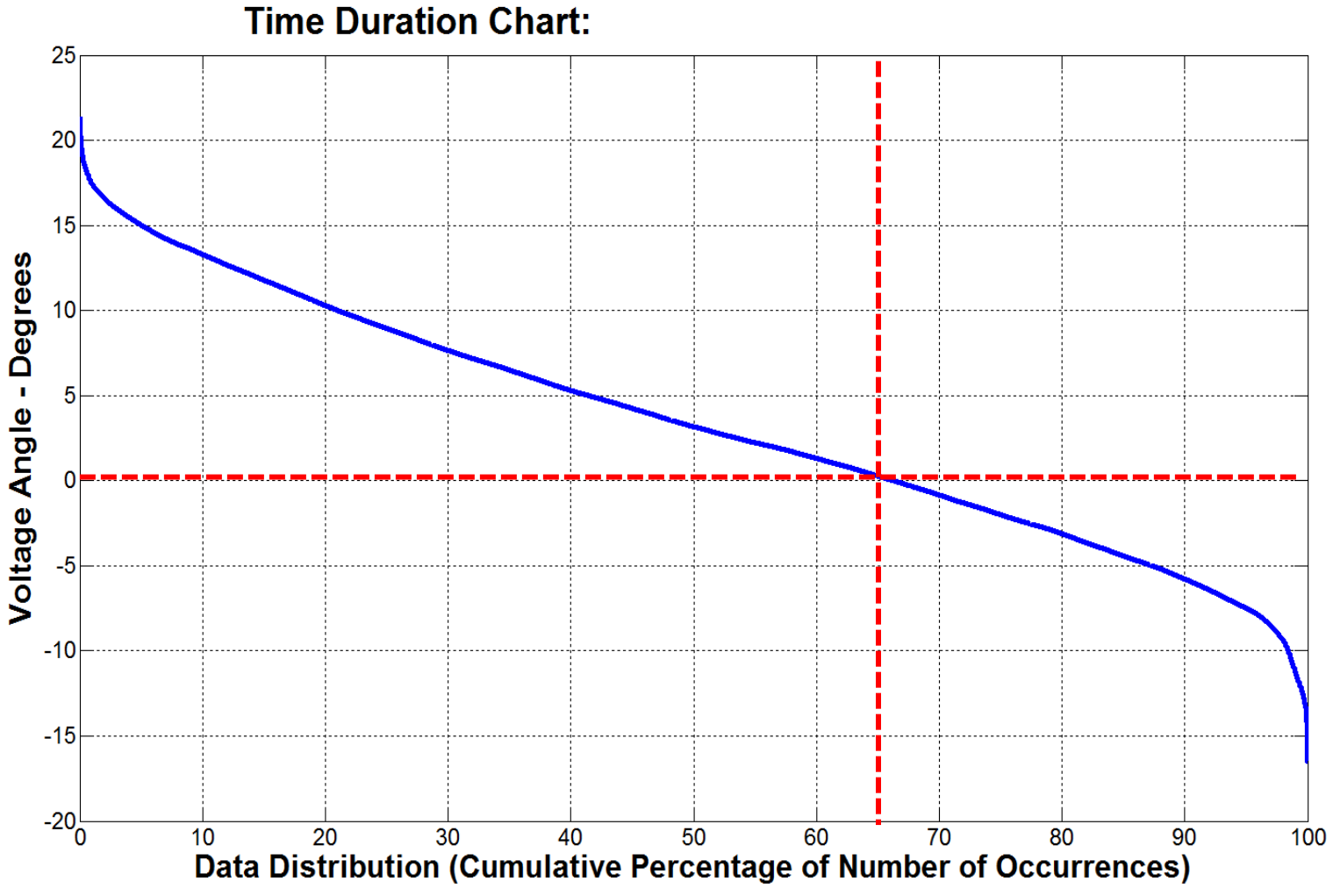
West 2


Time Duration Chart:
Voltage Angle - Degrees
25
20
15
10
5
0
-5
-10
-15
-20
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

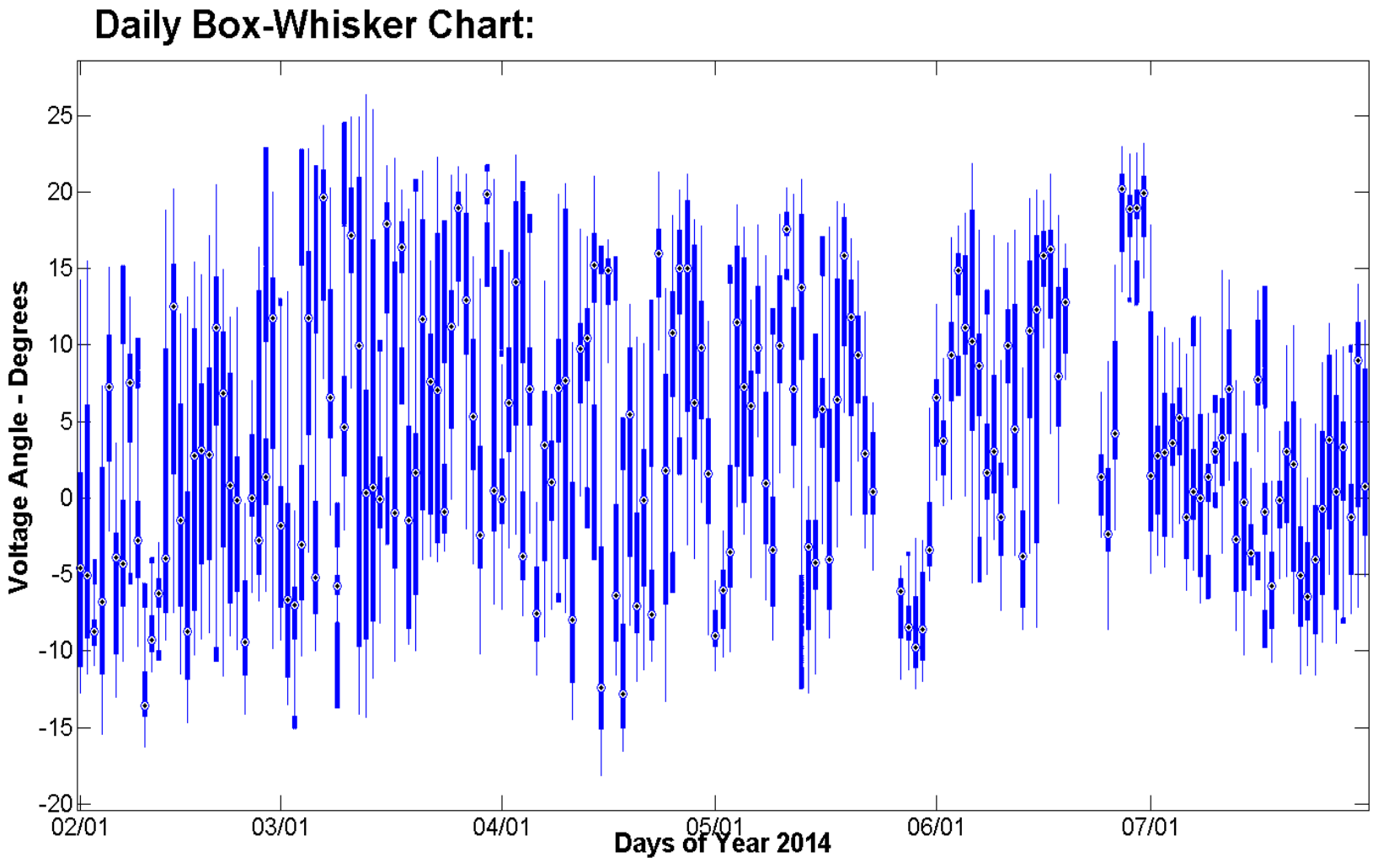
West 9


Daily Box-Whisker Chart:
Voltage Angle - Degrees
20
15
10
5
0
-5
-10
-15
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

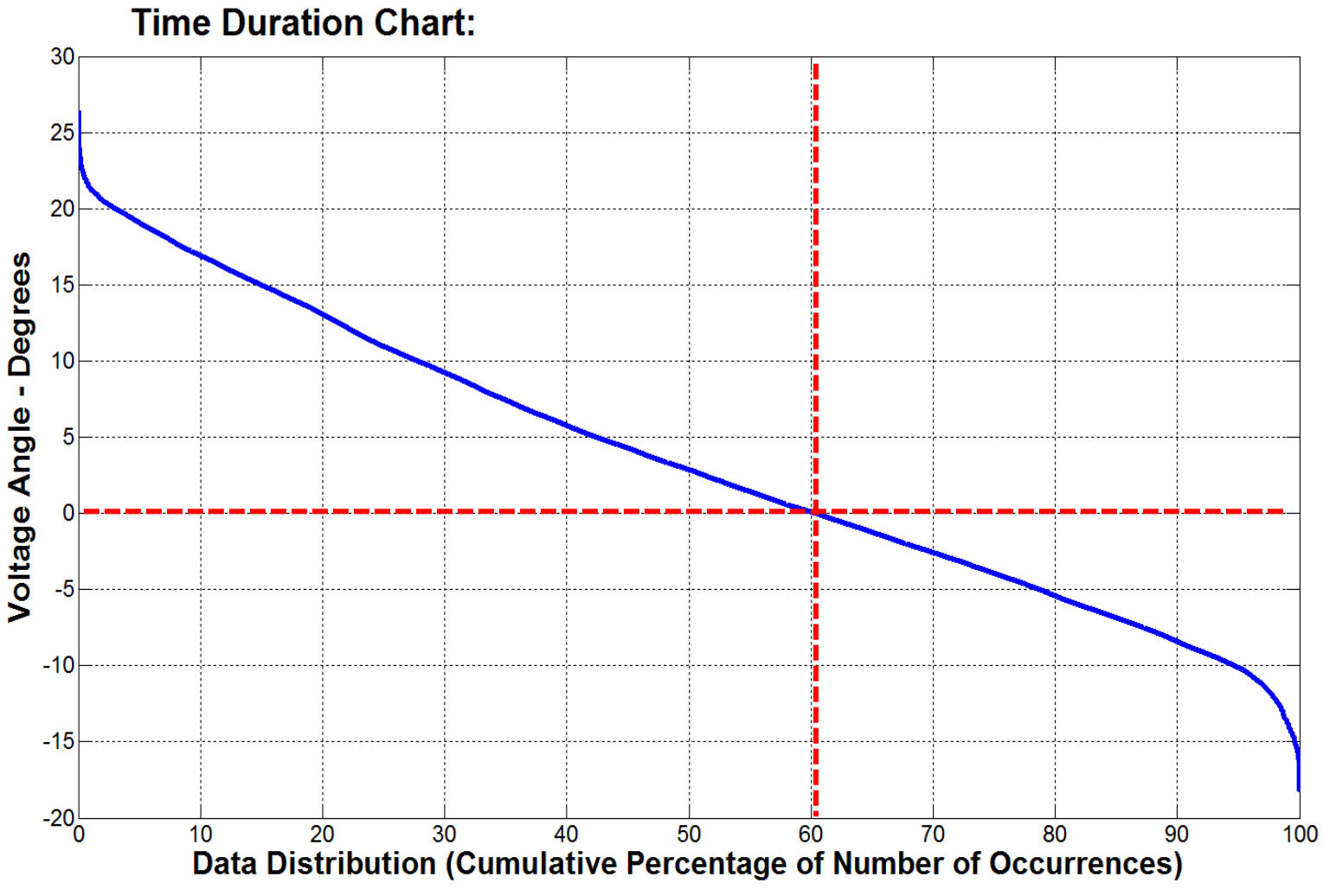
West 9


Time Duration Chart:
Voltage Angle - Degrees
25
20
15
10
5
0
-5
-10
-15
-20
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

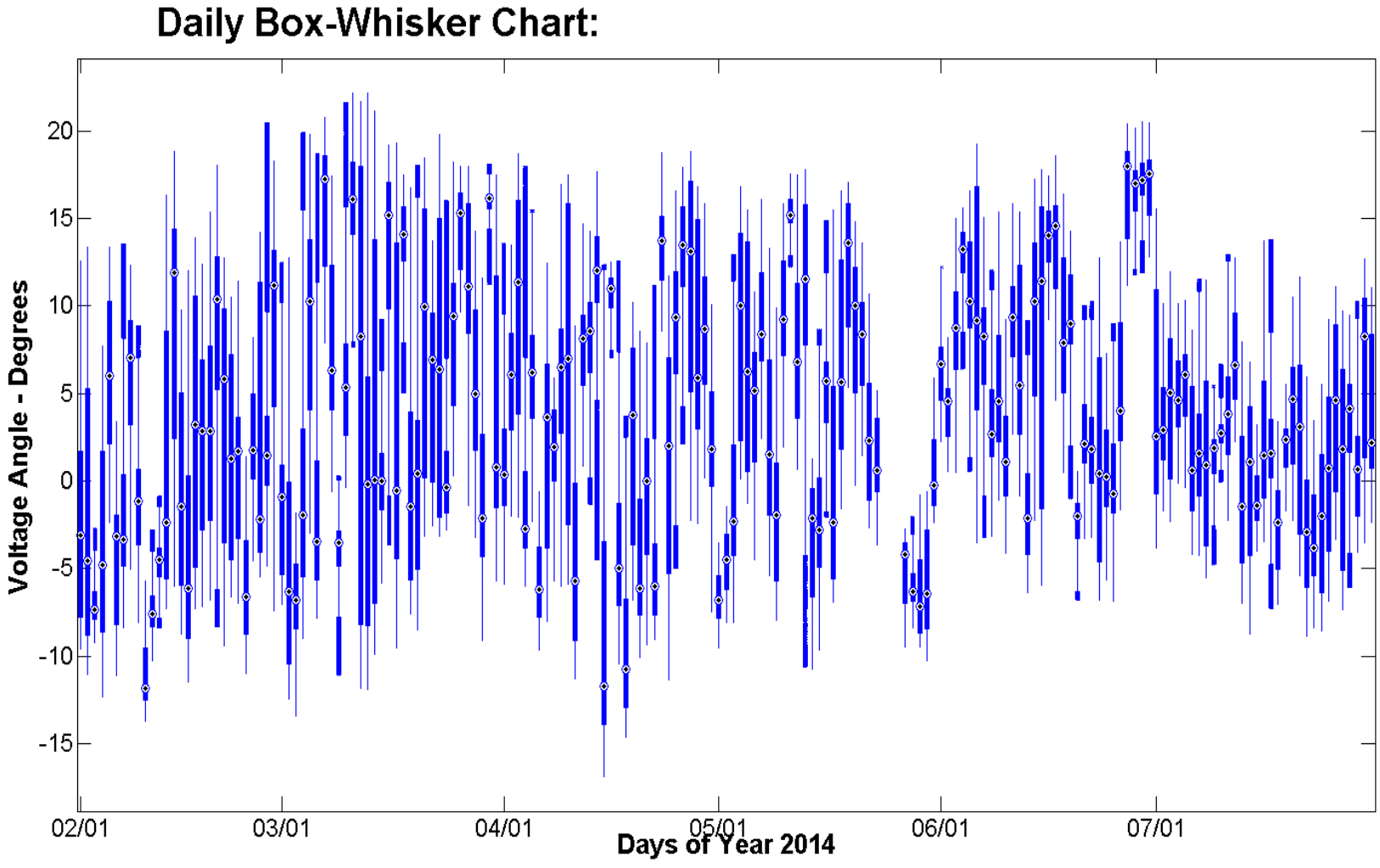
West 11


Daily Box-Whisker Chart:
Voltage Angle - Degrees
25
20
15
10
5
0
-5
-10
-15
-20
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

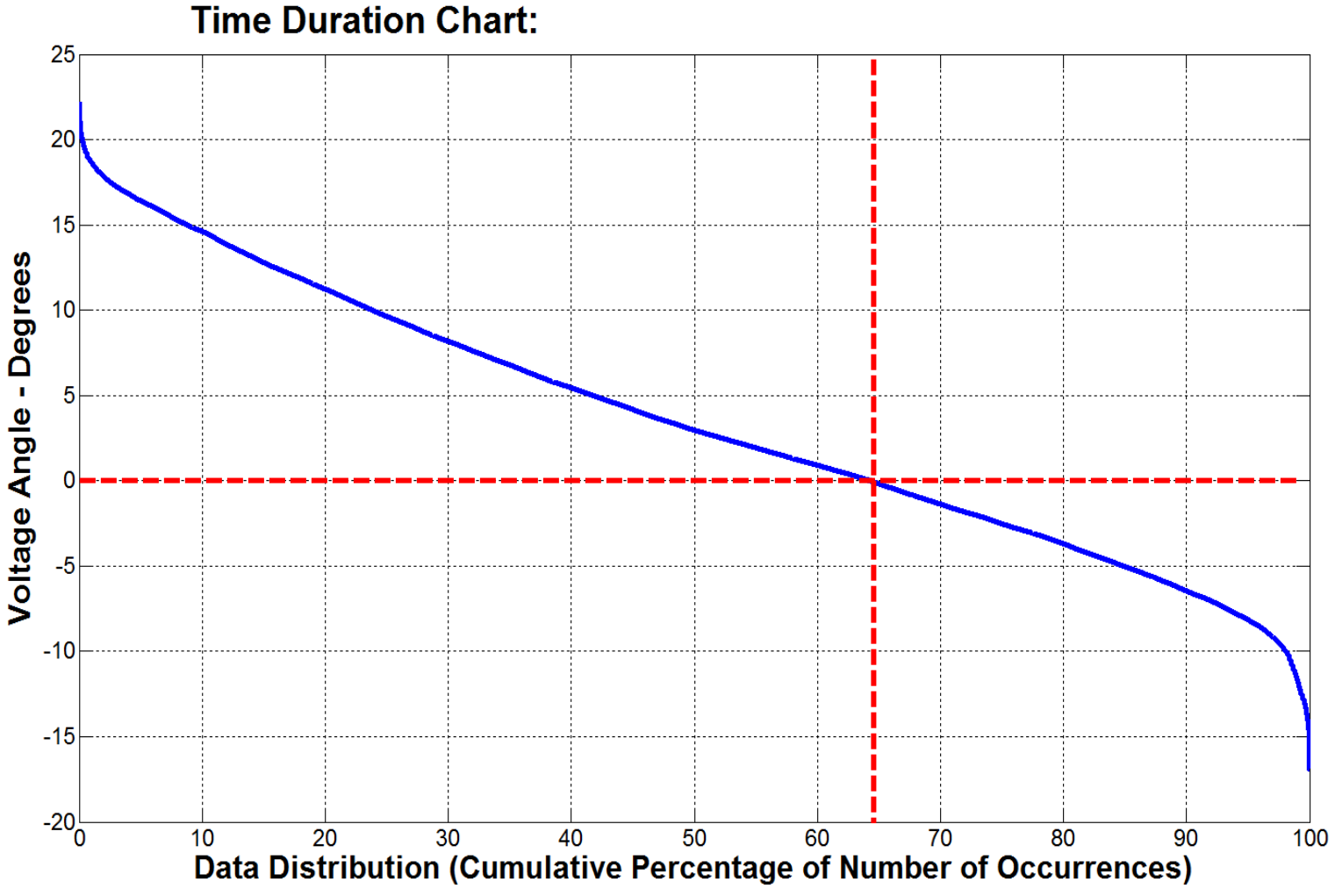
West 11


Time Duration Chart:
Voltage Angle - Degrees
30
25
20
15
10
5
0
-5
-10
-15
-20
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

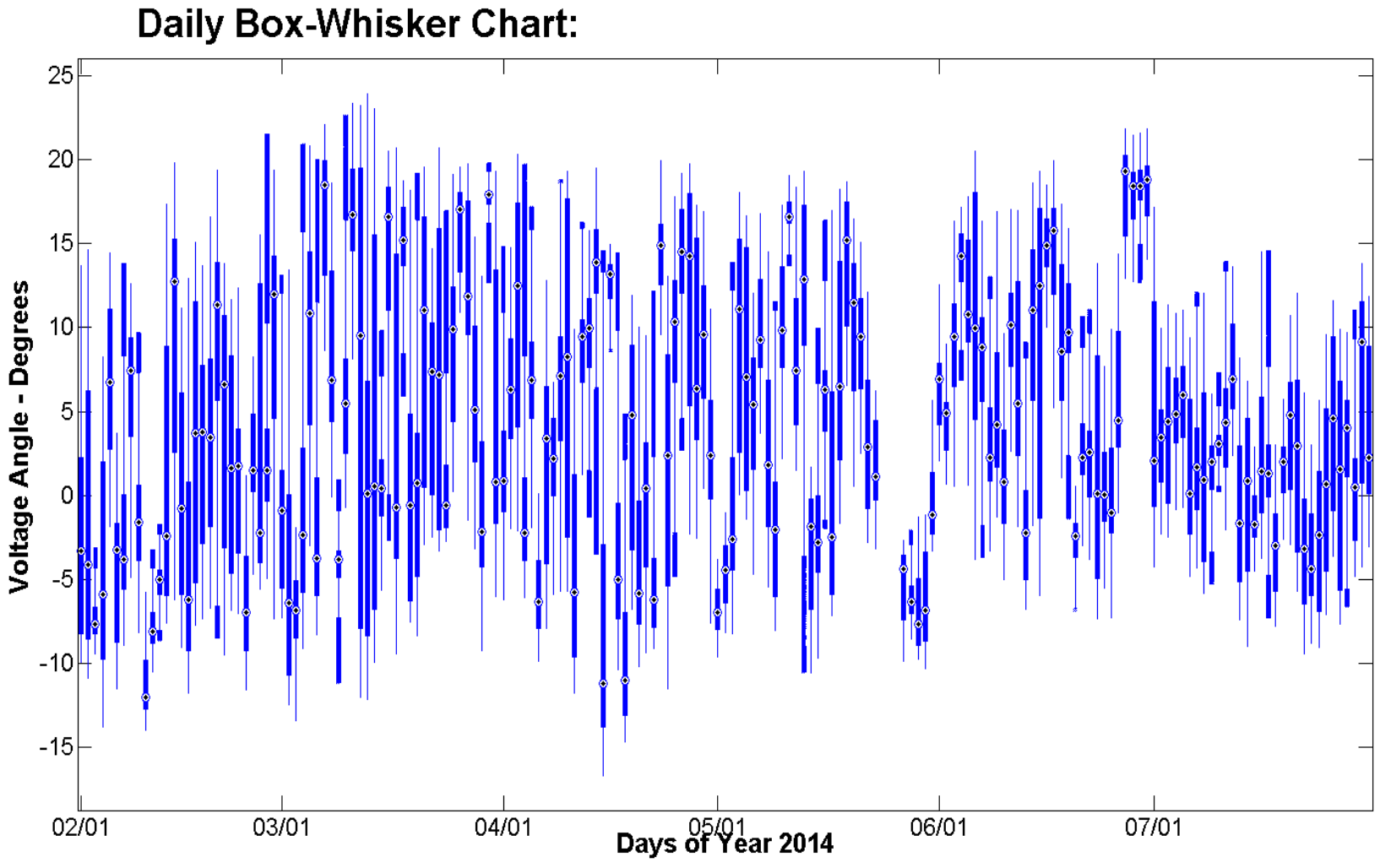
West 12


Daily Box-Whisker Chart:
Voltage Angle - Degrees
20
15
10
5
0
-5
-10
-15
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

West 12


Time Duration Chart:
Voltage Angle - Degrees
25
20
15
10
5
0
-5
-10
-15
-20
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

West 5


Daily Box-Whisker Chart:
Voltage Angle - Degrees
25
20
15
10
5
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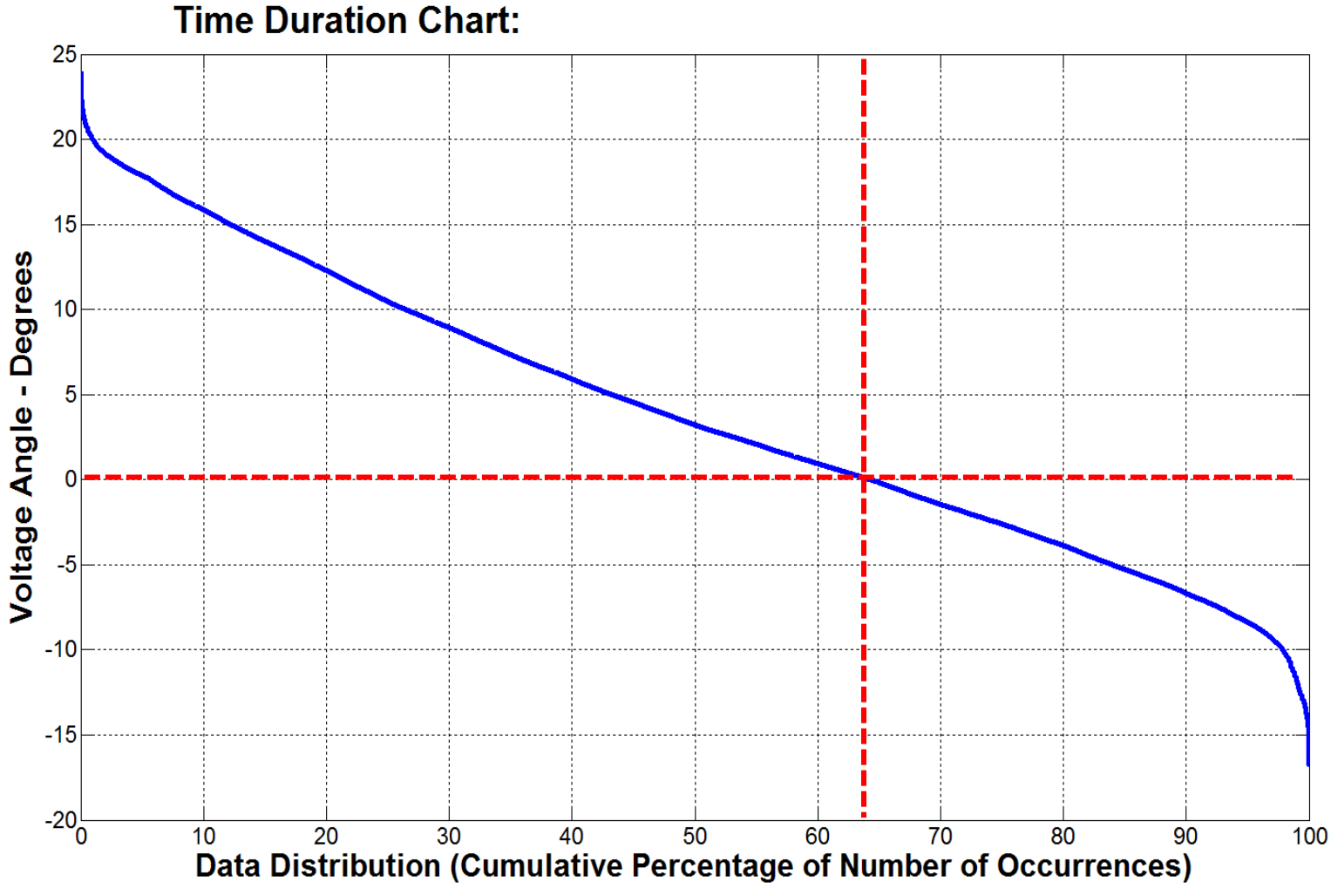
-5
-10
-15
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

West 5


Time Duration Chart:
Voltage Angle - Degrees
25
20
15
10
5
0
-5
-10
-15
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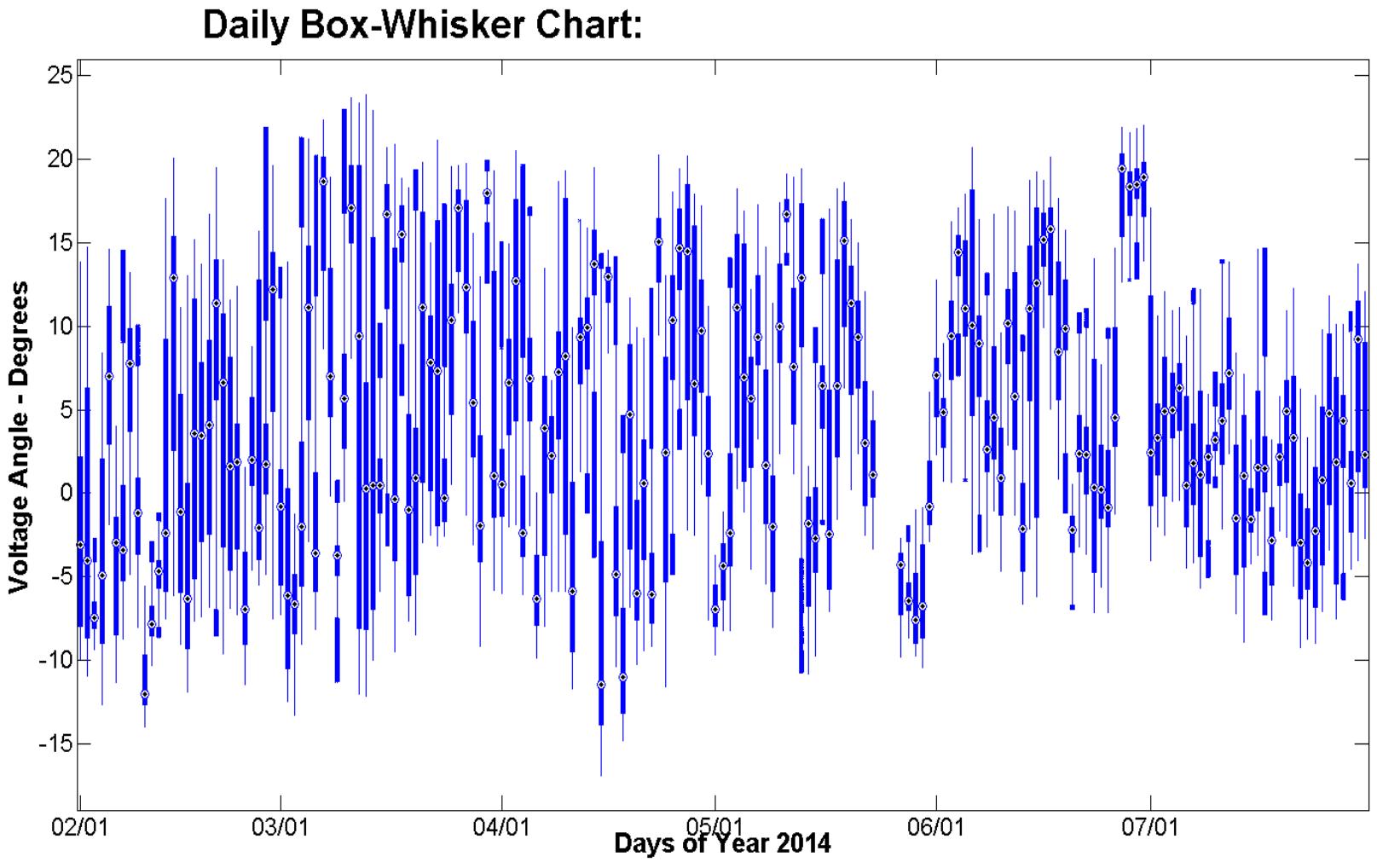
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

West 6


Daily Box-Whisker Chart:
Voltage Angle - Degrees
25
20
15
10
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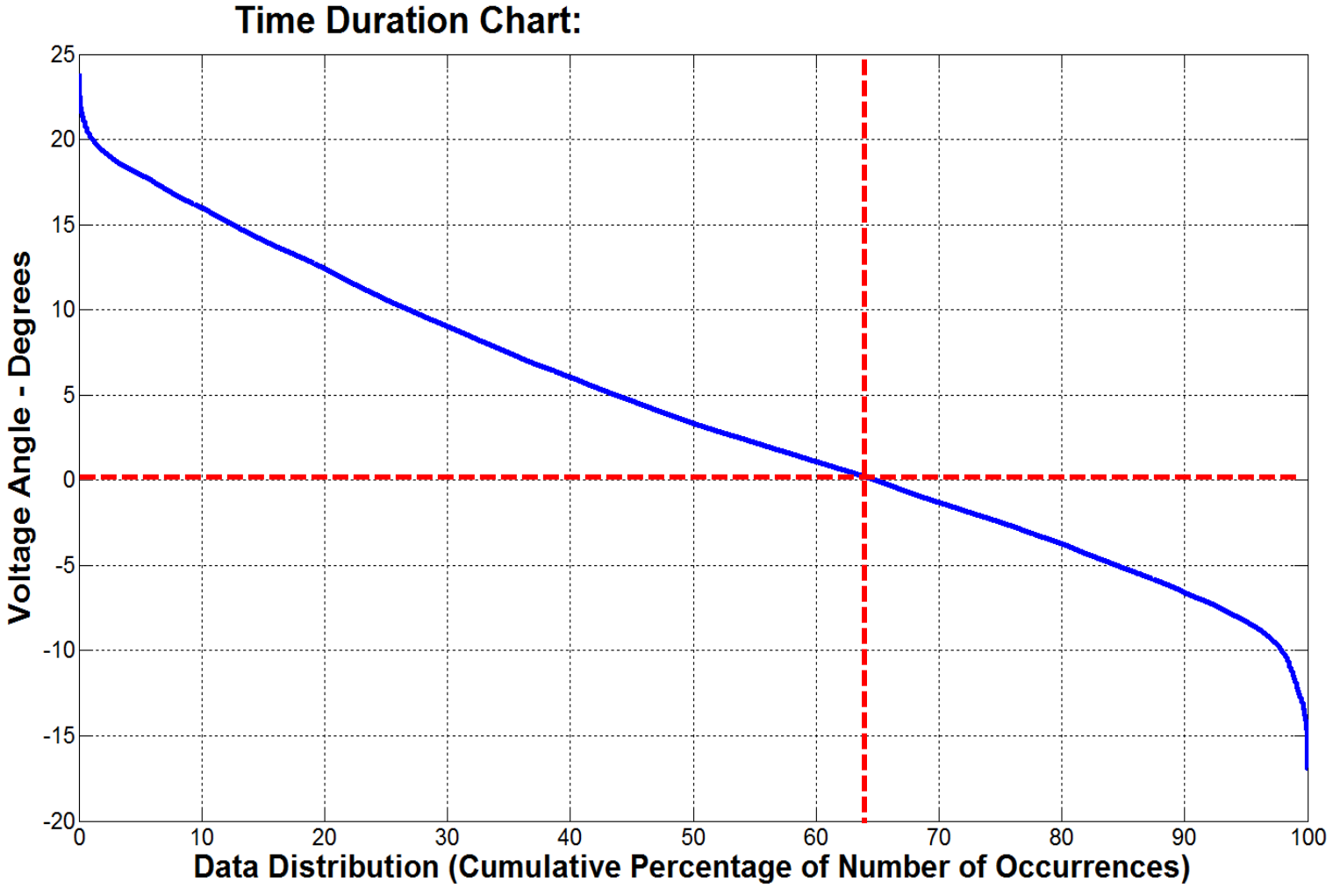
-10
-15
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

West 6


Time Duration Chart:
Voltage Angle - Degrees
25
20
15
10
5
0
-5
-10
-15
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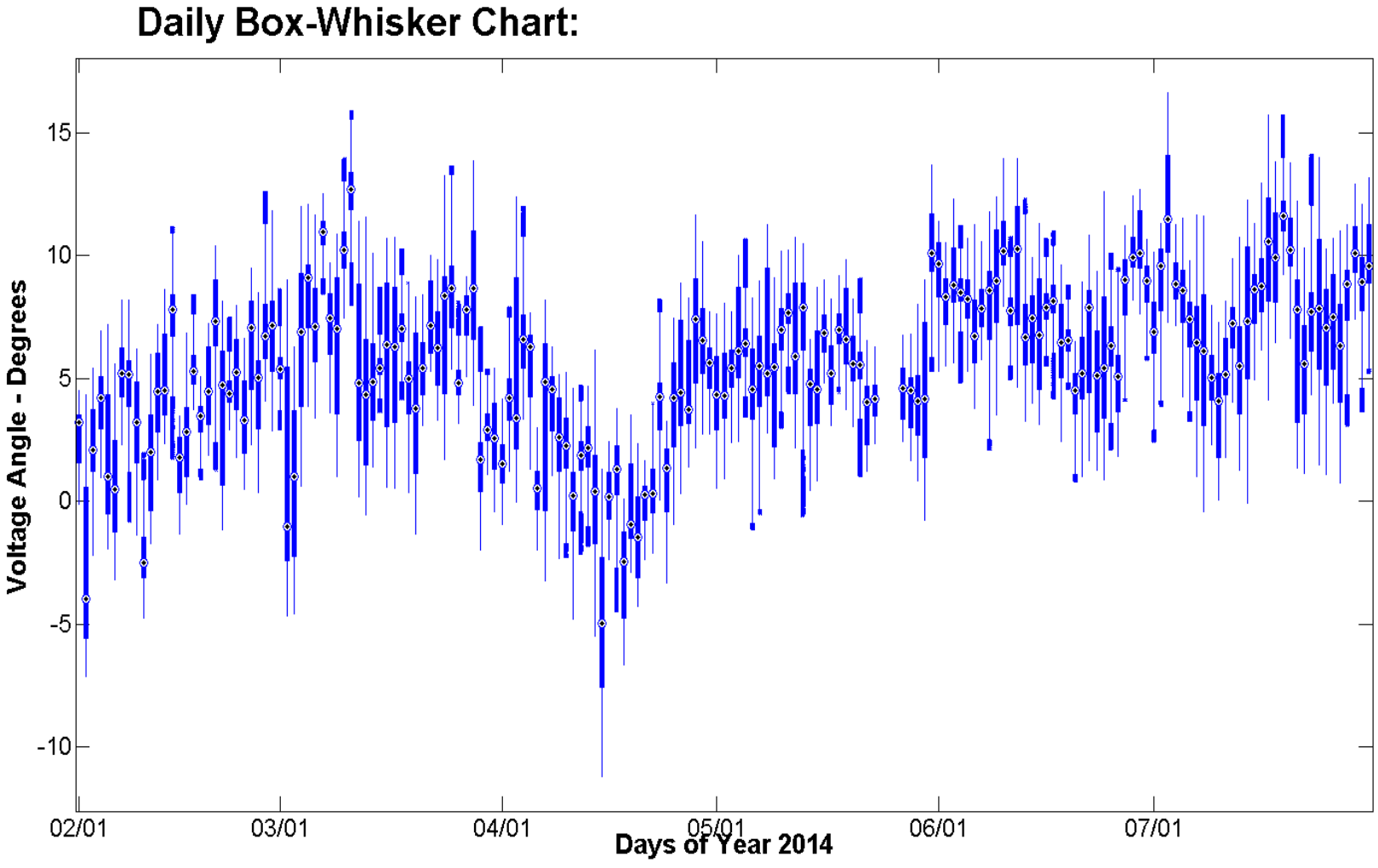
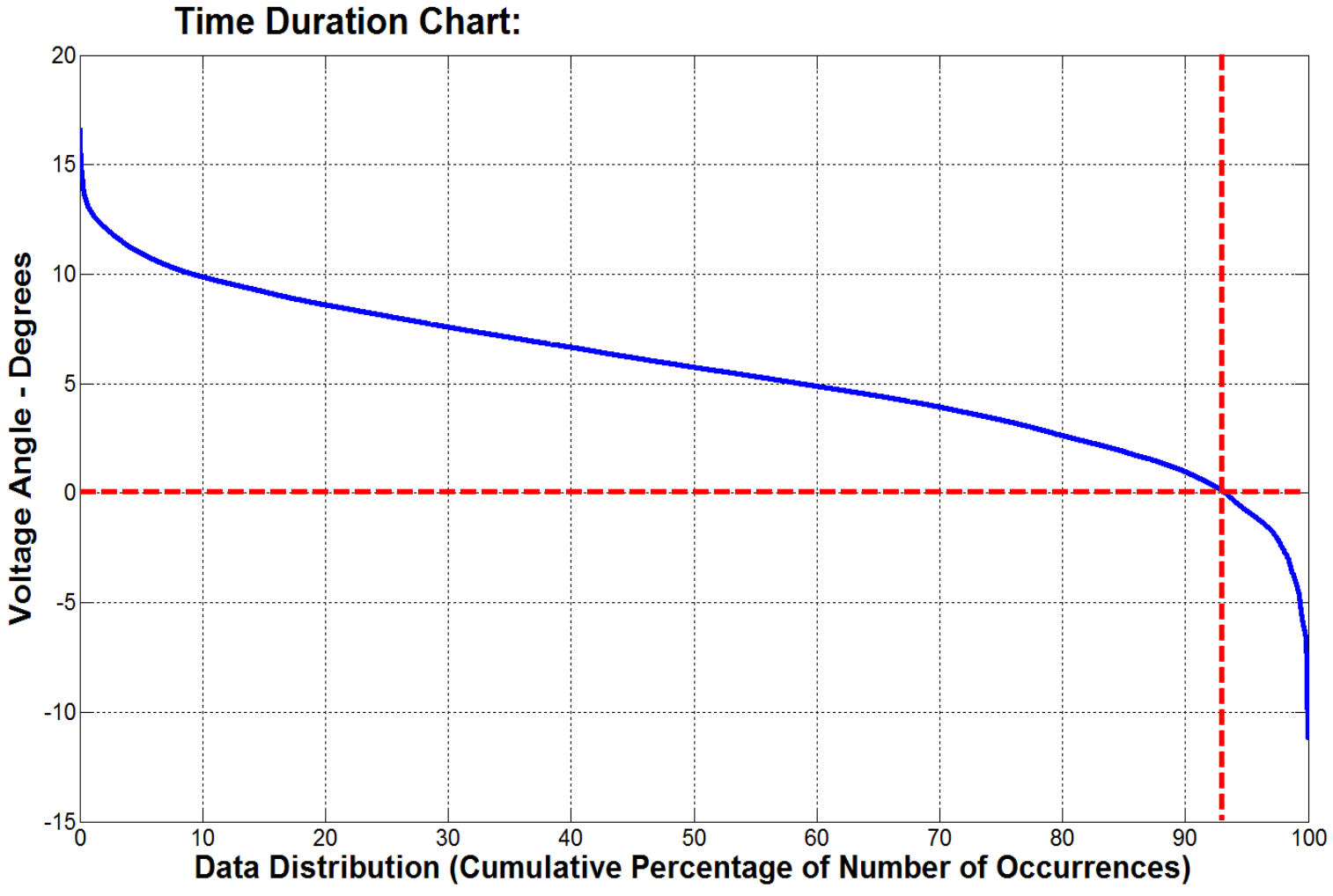
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

North 1


Daily Box-Whisker Chart:
Voltage Angle - Degrees
15
10
5
0
-5
-10
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

North 1


Time Duration Chart:
Voltage Angle - Degrees
20
15
10
5
0
-5
-10
-15
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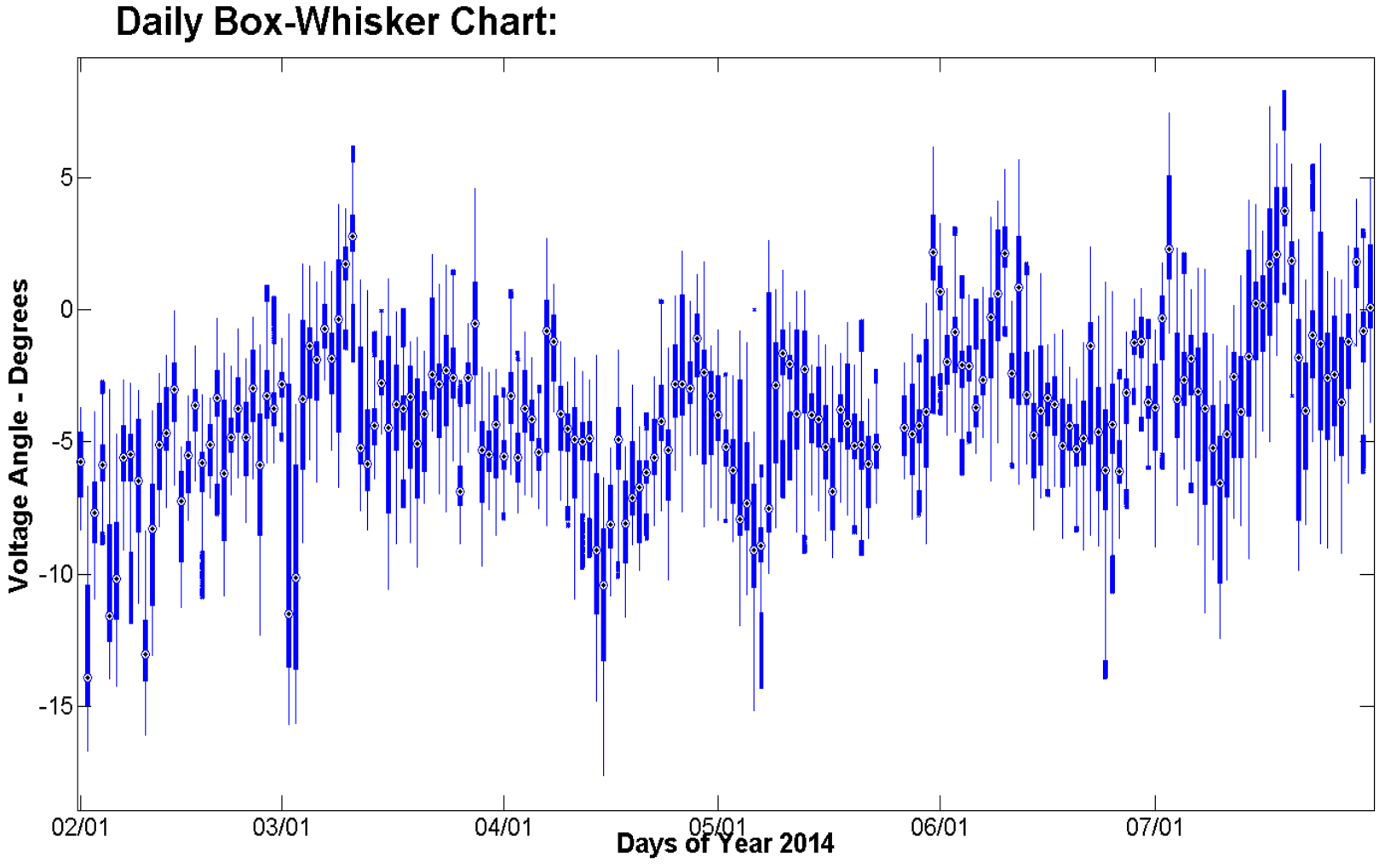
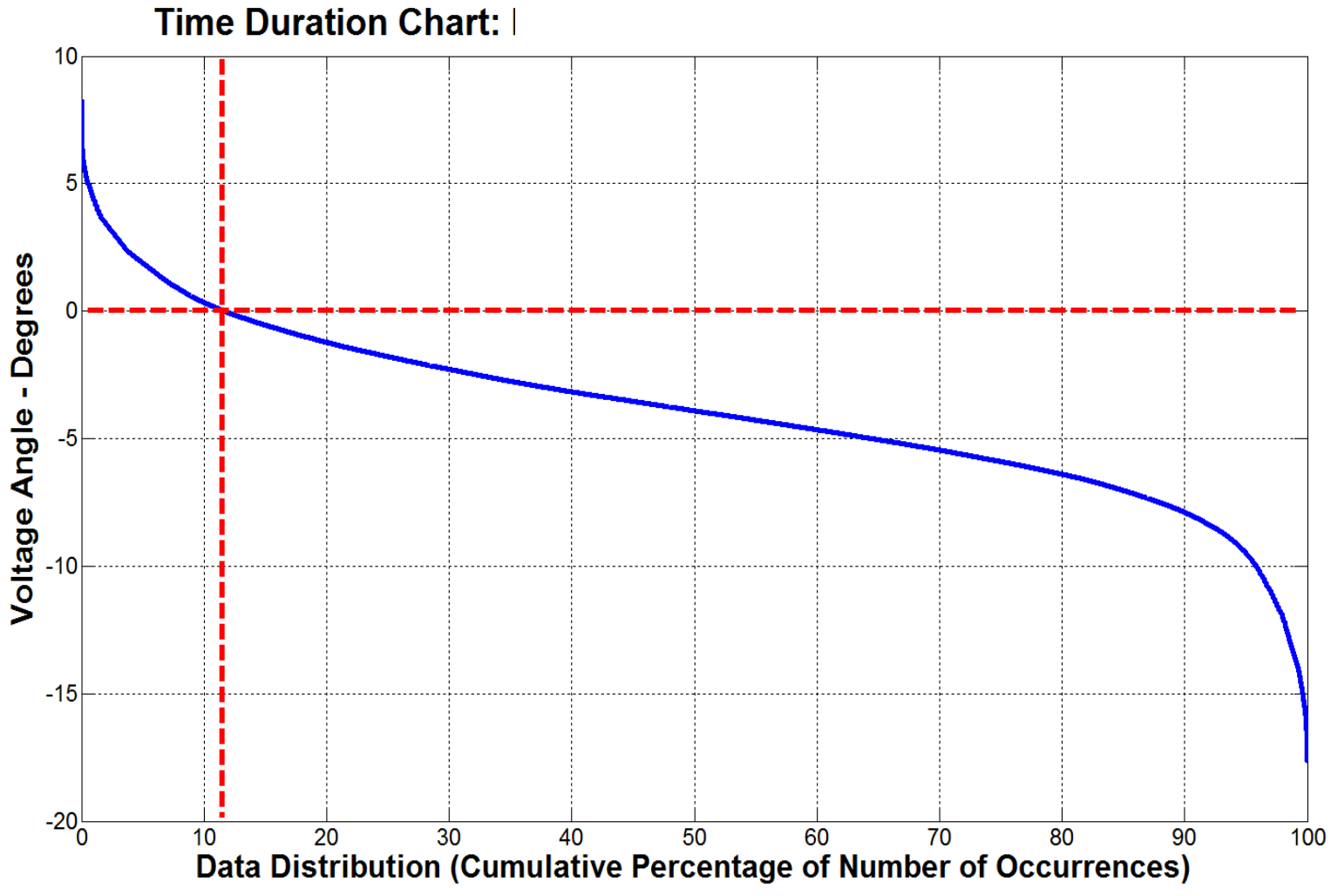
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

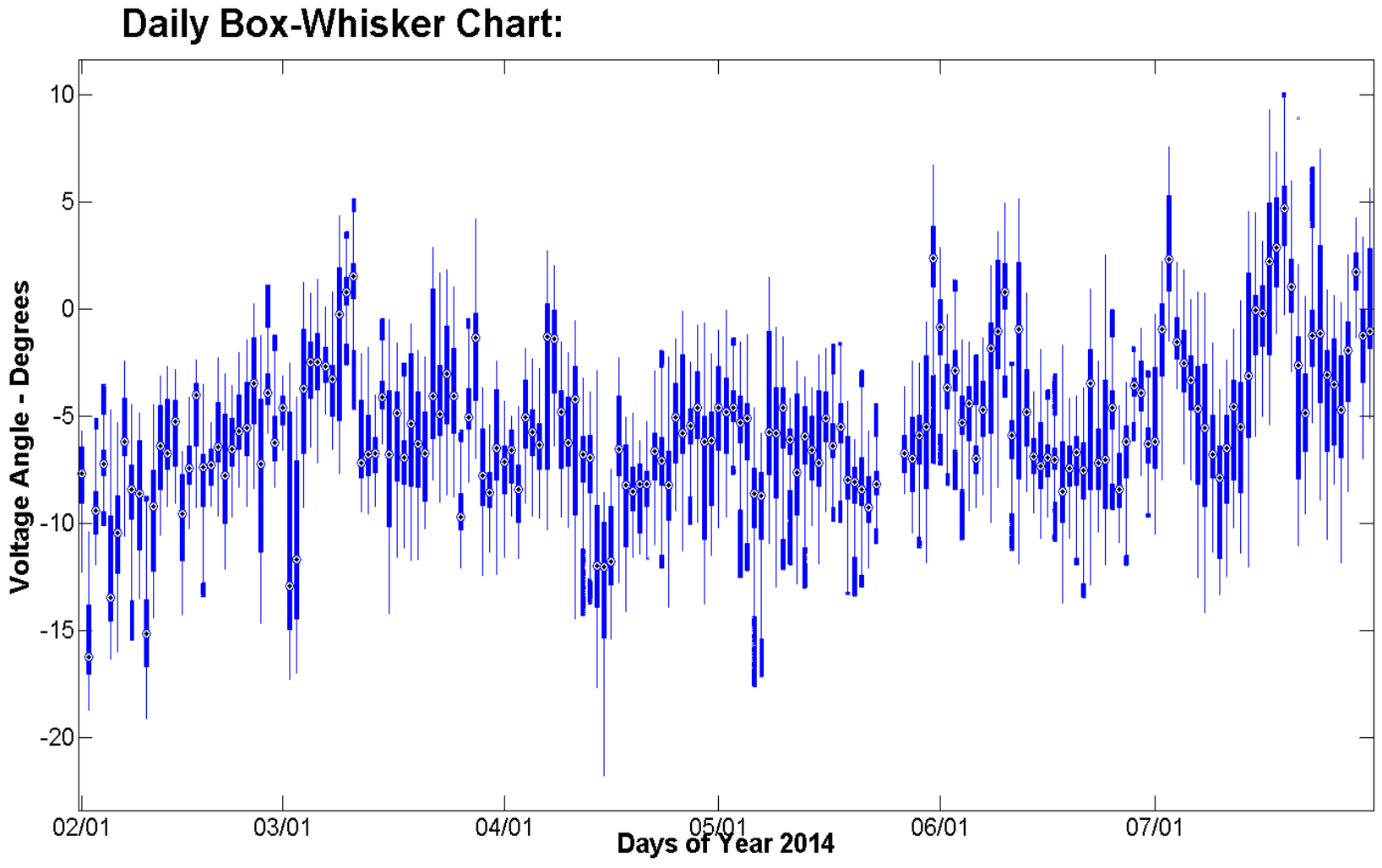
North 4


Daily Box-Whisker Chart:
Voltage Angle - Degrees
5
0
-5
-10
-15
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

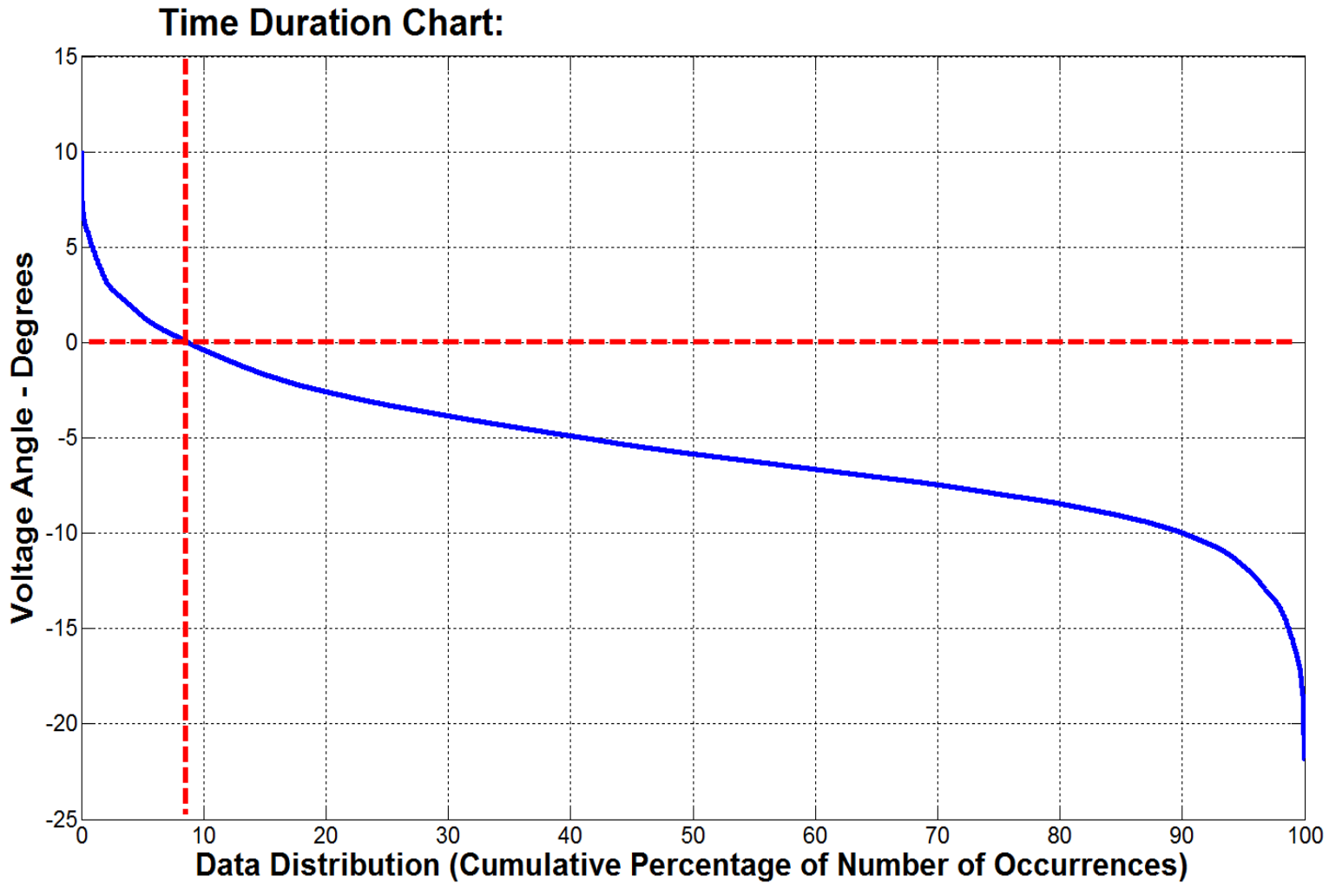
North 4


Time Duration Chart:
Voltage Angle - Degrees
10
5
0
-5
-10
-15
-20
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

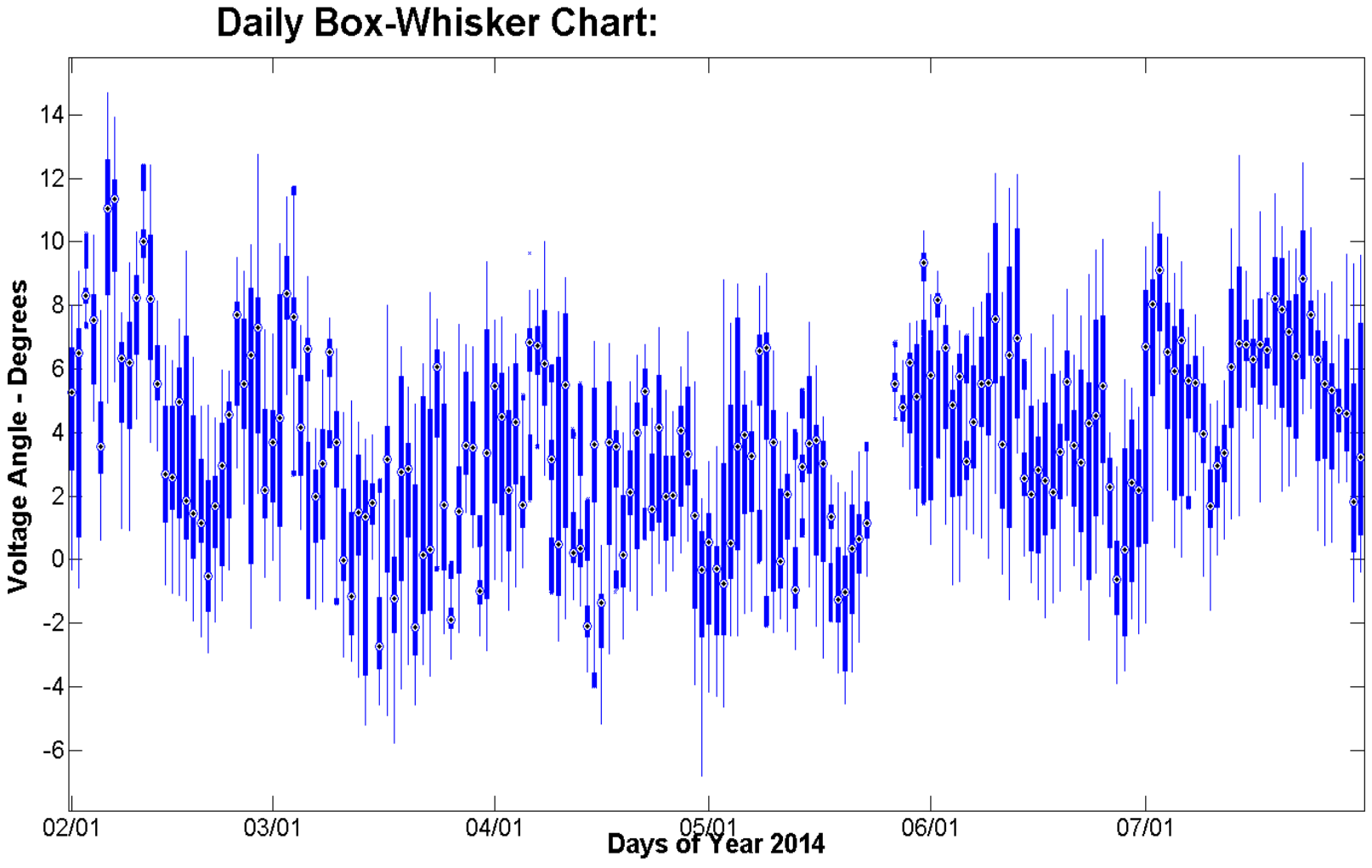
North 5


Daily Box-Whisker Chart:
Voltage Angle - Degrees
10
5
0
-5
-10
-15
-20
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

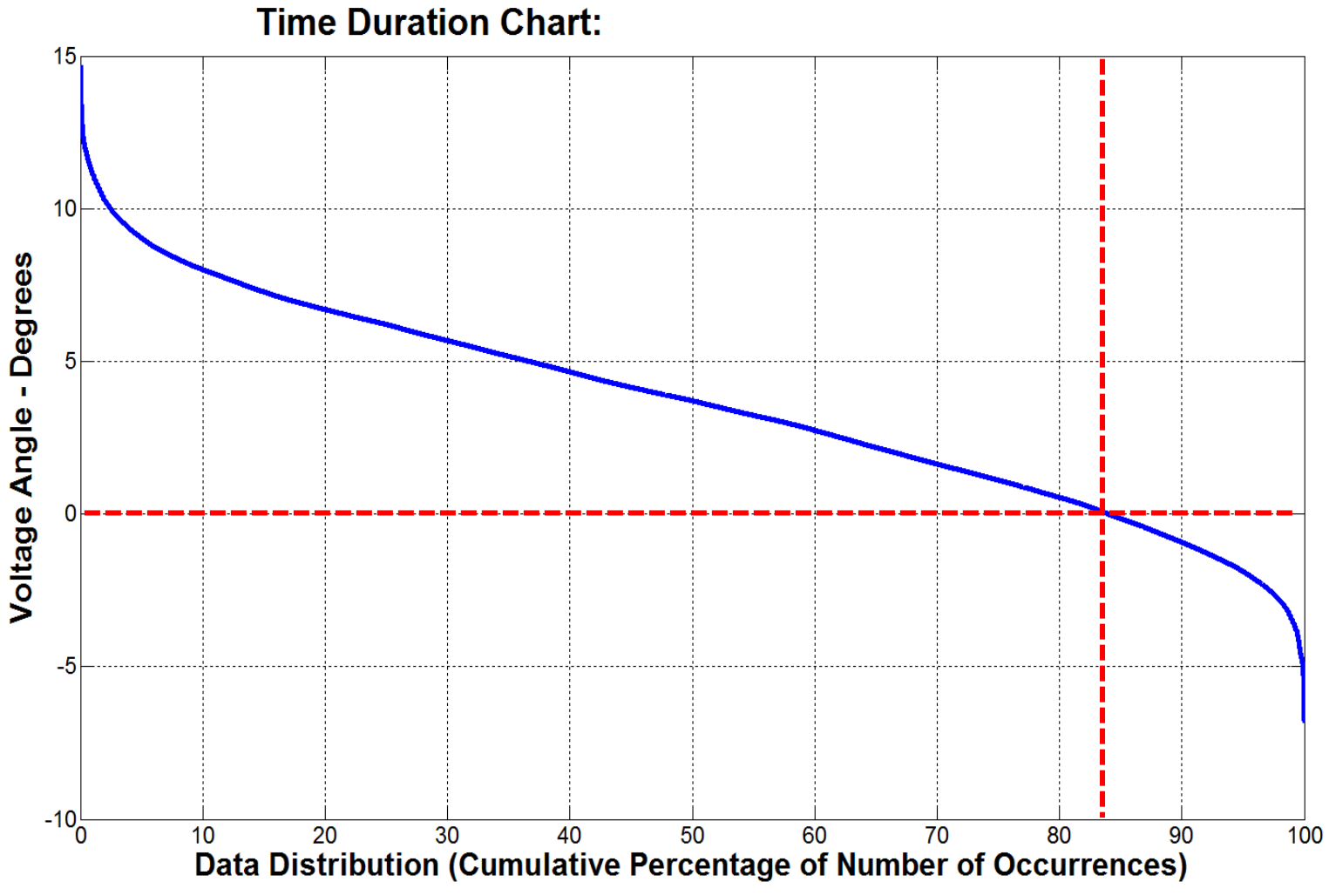
North 5


Time Duration Chart:
Voltage Angle - Degrees
15
10
5
0
-5
-10
-15
-20
-25
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

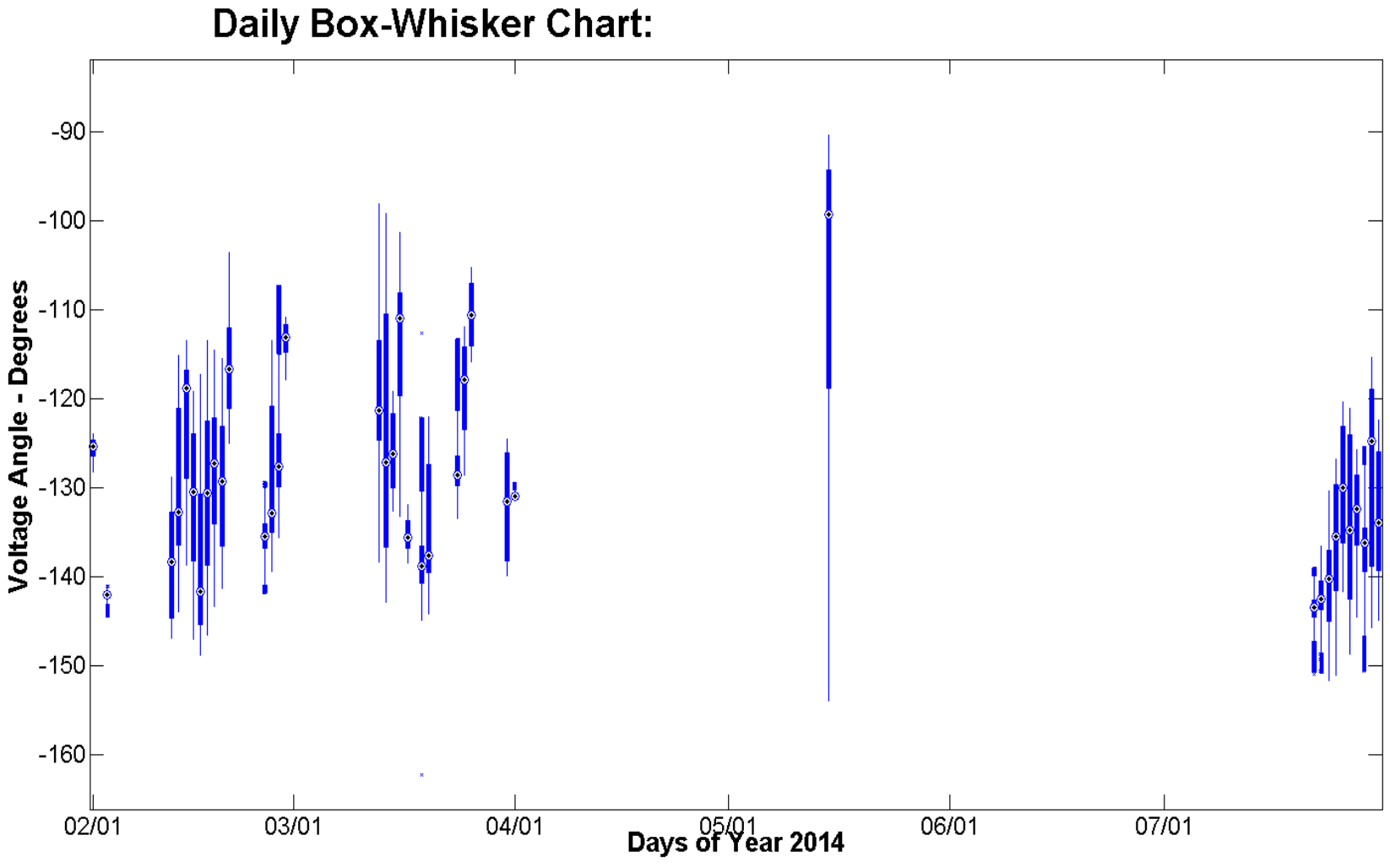
North 6


Daily Box-Whisker Chart:
Voltage Angle - Degrees
14
12
10
8
6
4
2
0
-2
-4
-6
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

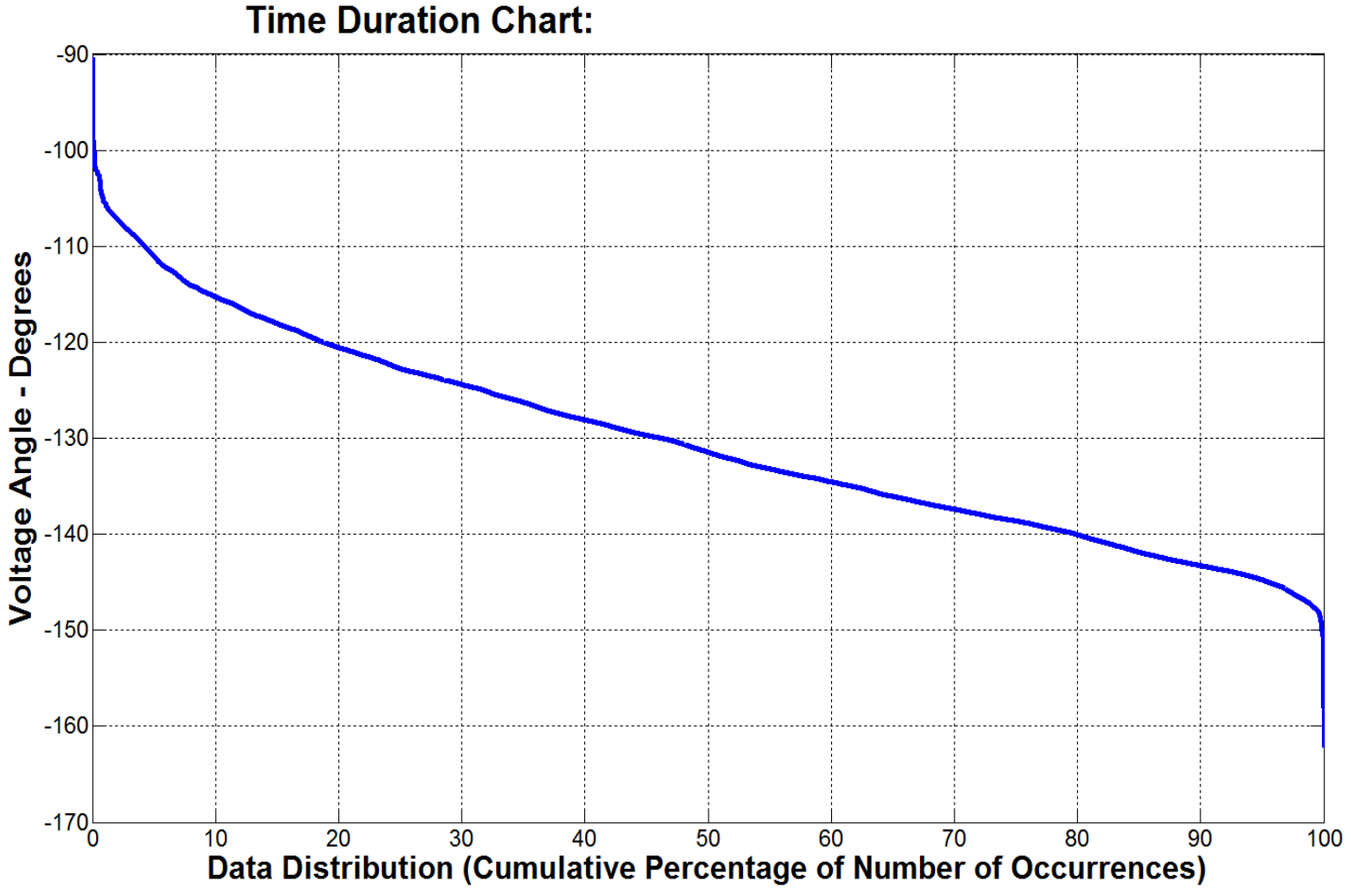
North 6


Time Duration Chart:
Voltage Angle - Degrees
15
10
5
0
-5
-10
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

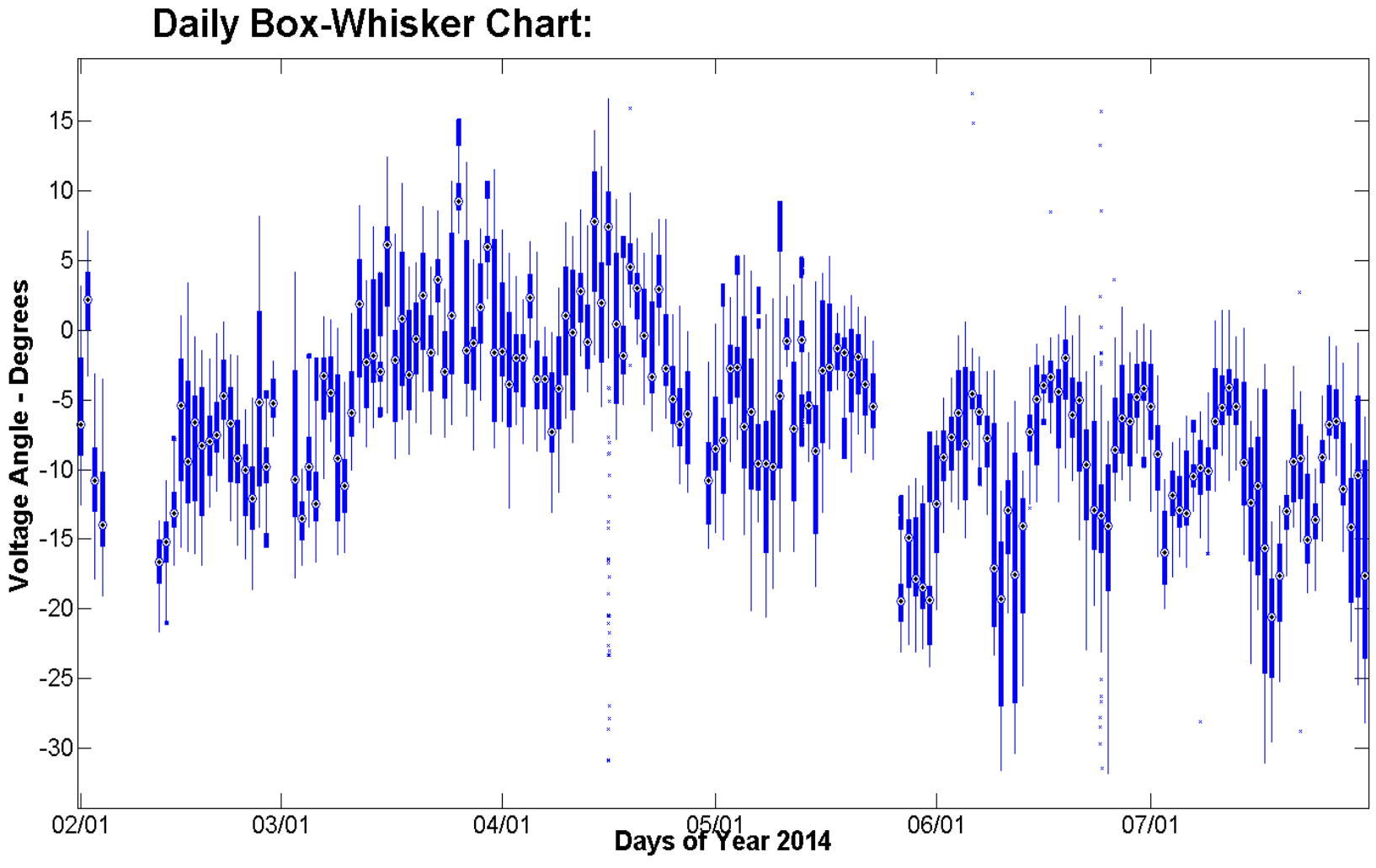
FarWest 2


Daily Box-Whisker Chart:
Voltage Angle - Degrees
-90
-100
-110
-120
-130
-140
-150
-160
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

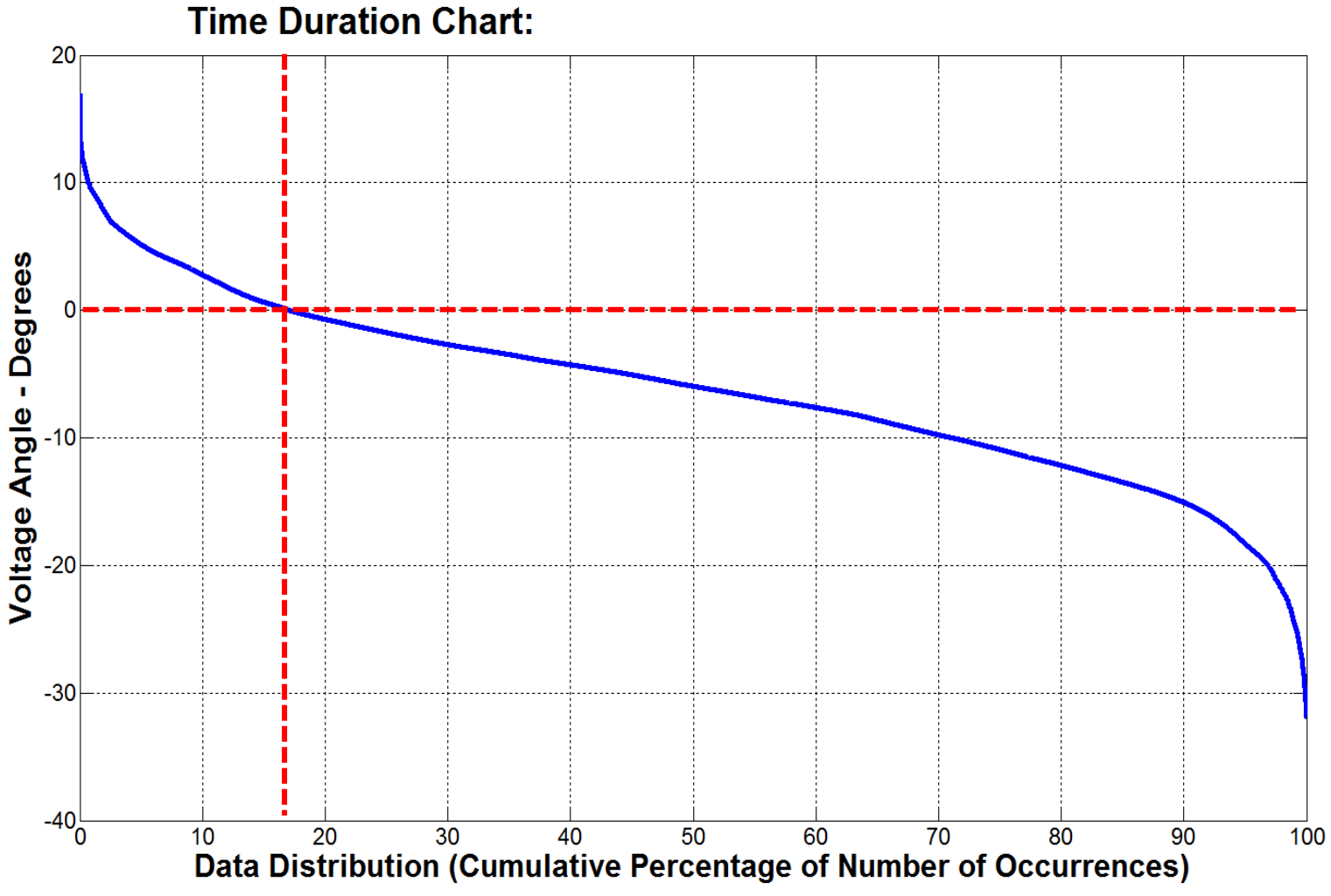
FarWest 2


Time Duration Chart:
Voltage Angle - Degrees
-90
-100
-110
-120
-130
-140
-150
-160
-170
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

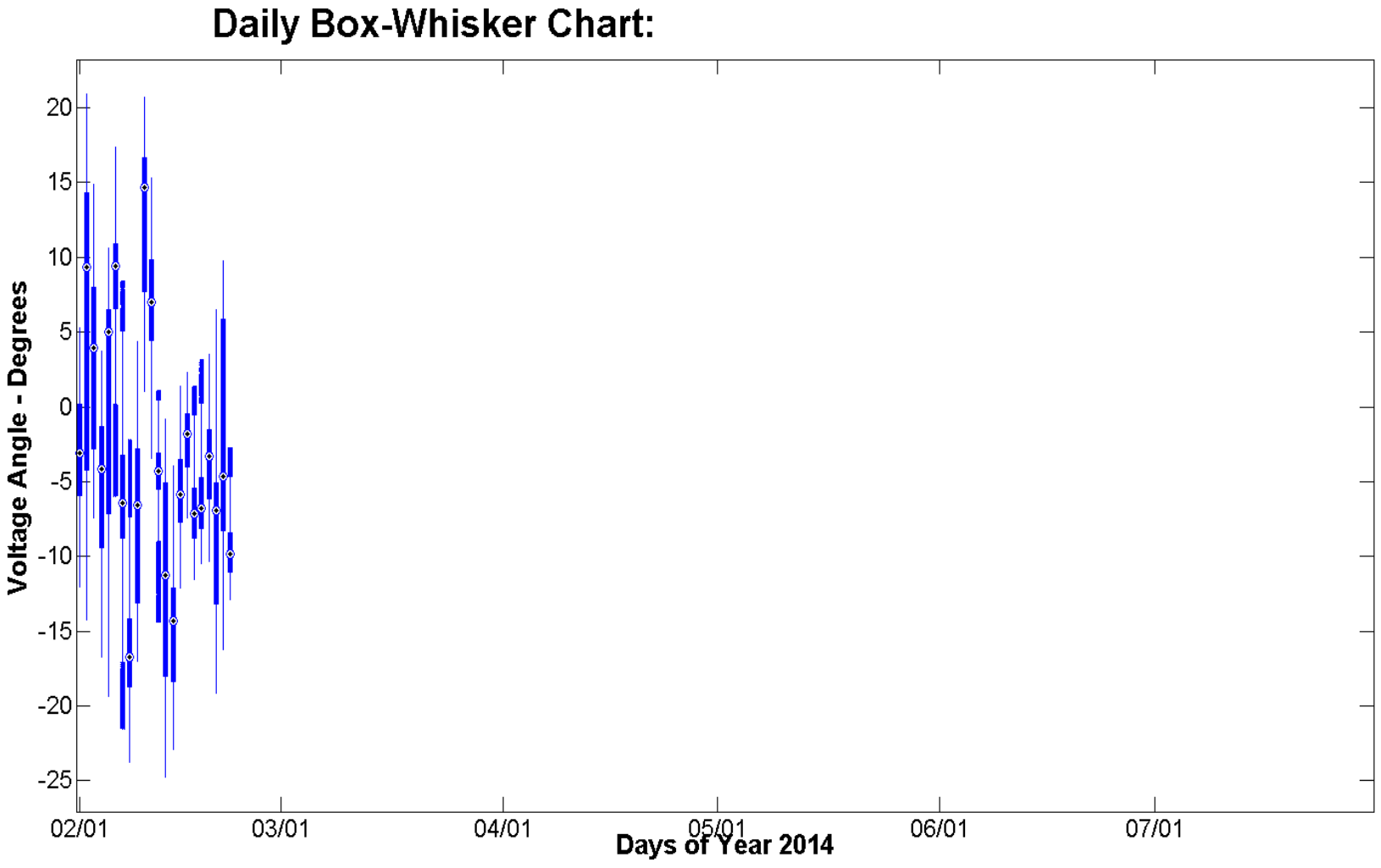
West 4


Daily Box-Whisker Chart:
Voltage Angle - Degrees
15
10
5
0
-5
-10
-15
-20
-25
-30
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

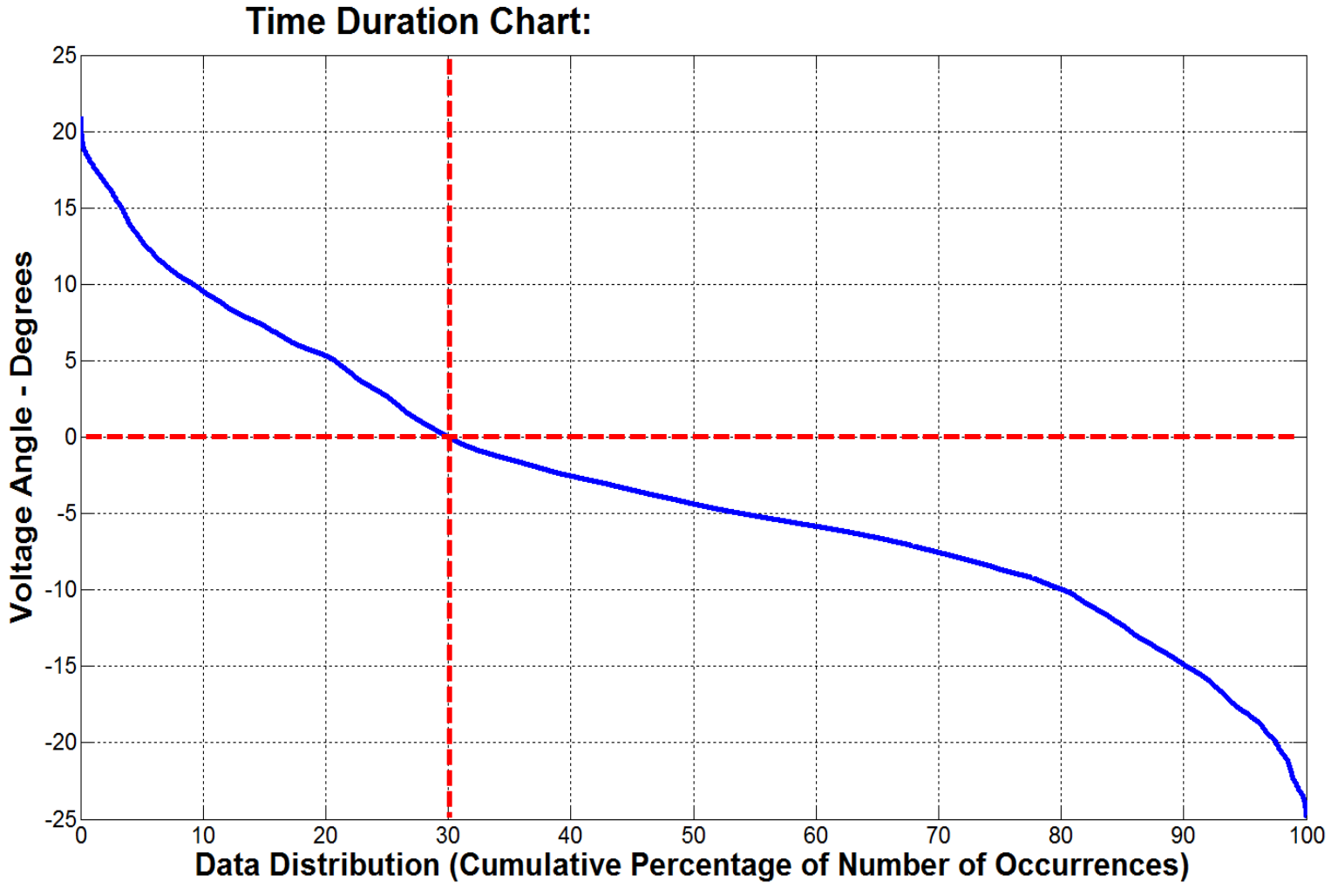
West 4


Time Duration Chart:
Voltage Angle - Degrees
20
10
0
-10
-20
-30
-40
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

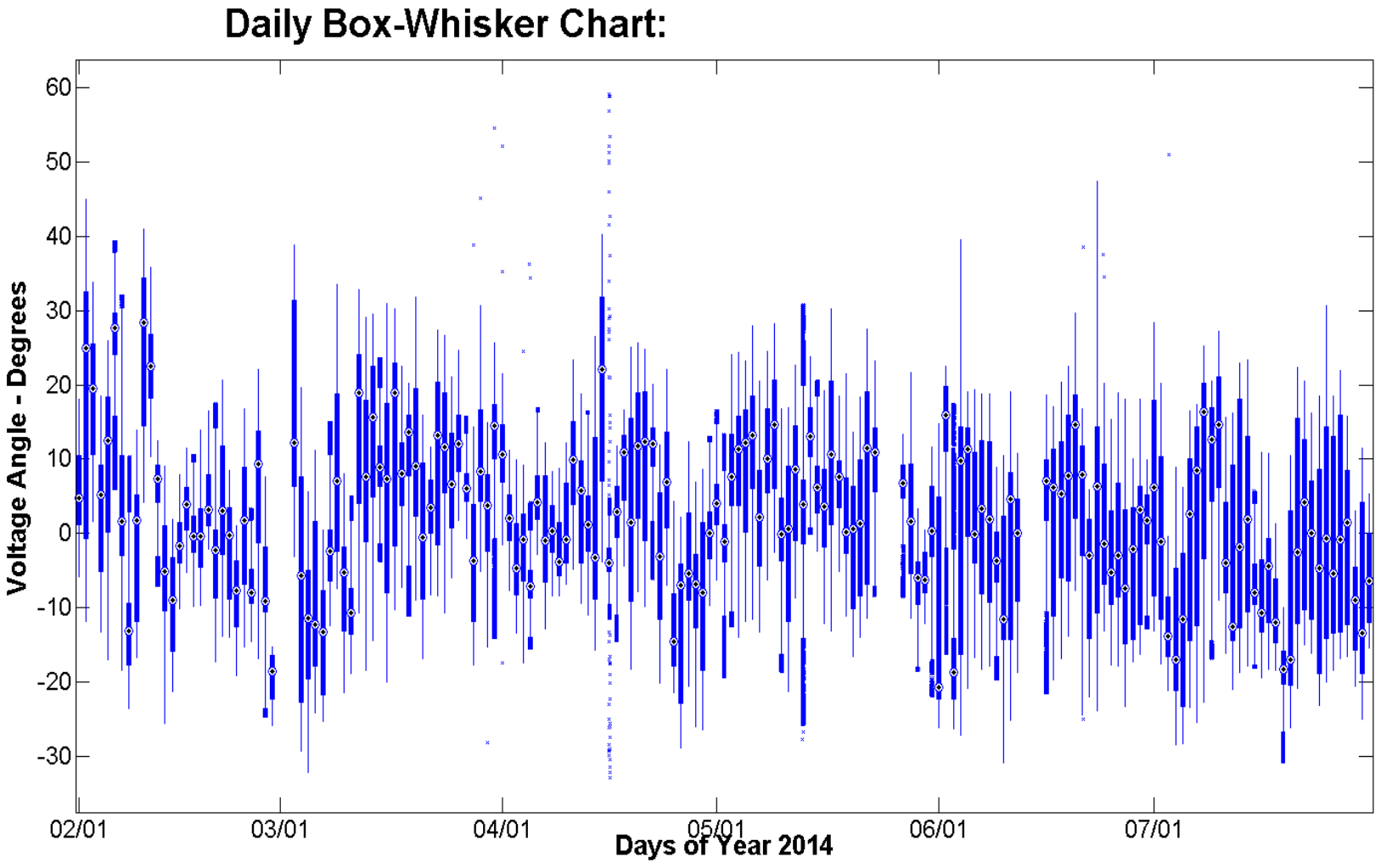
Coast 2


Daily Box-Whisker Chart:
Voltage Angle - Degrees
20
15
10
5
0
-5
-10
-15
-20
-25
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

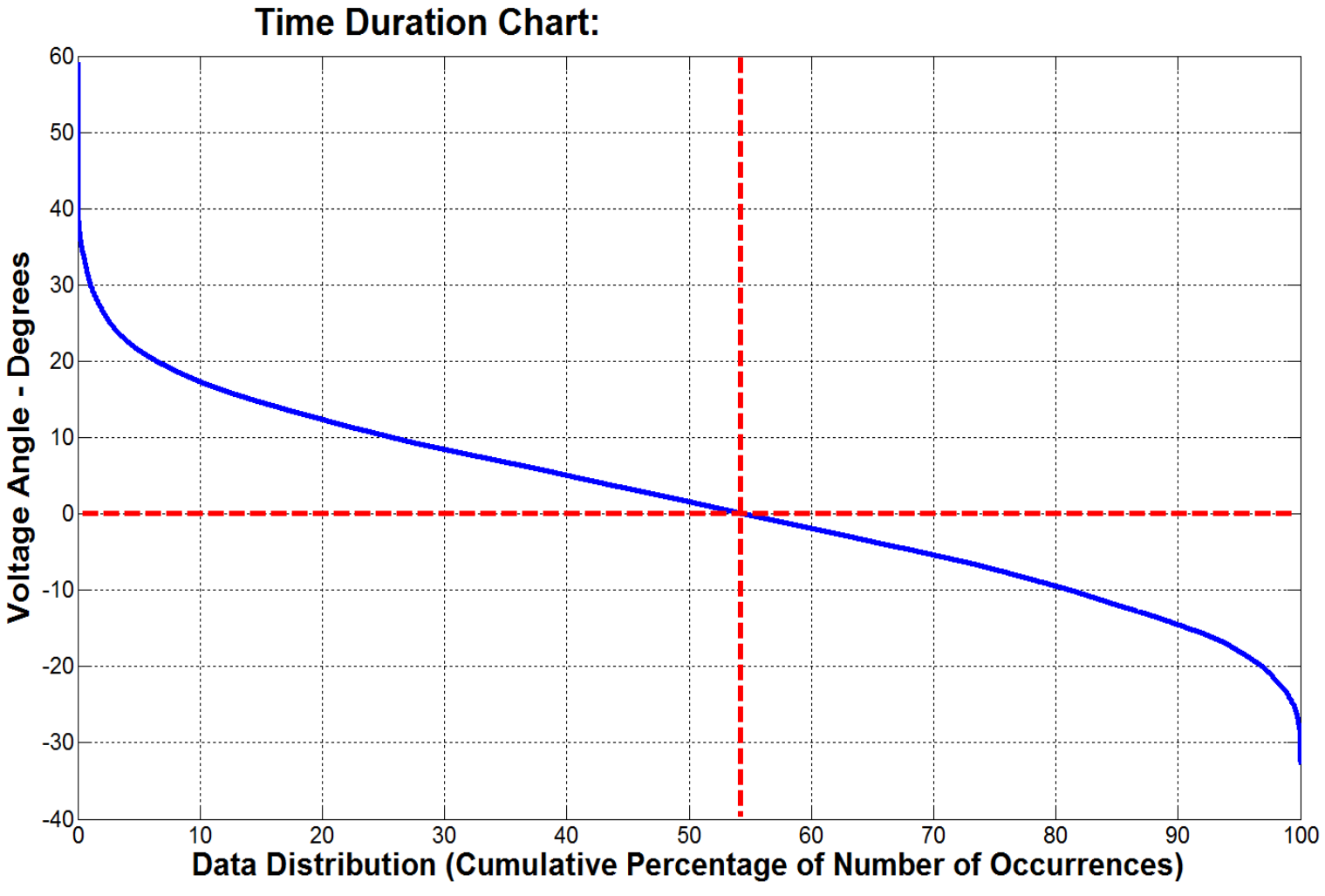
Coast 2


Time Duration Chart:
Voltage Angle - Degrees
25
20
15
10
5
0
-5
-10
-15
-20
-25
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

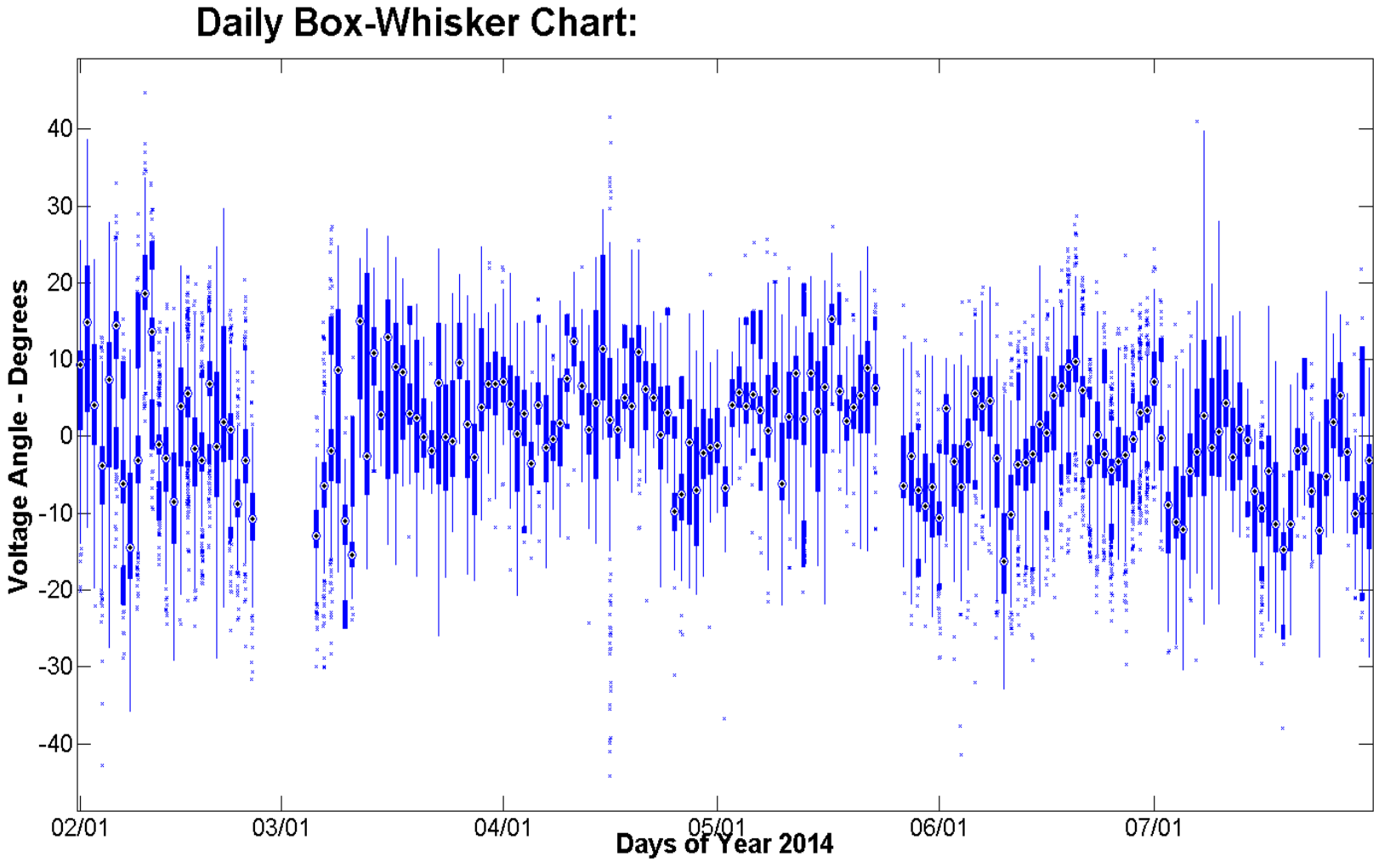
Coast 1


Daily Box-Whisker Chart:
Voltage Angle - Degrees
60
50
40
30
20
10
0
-10
-20
-30
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

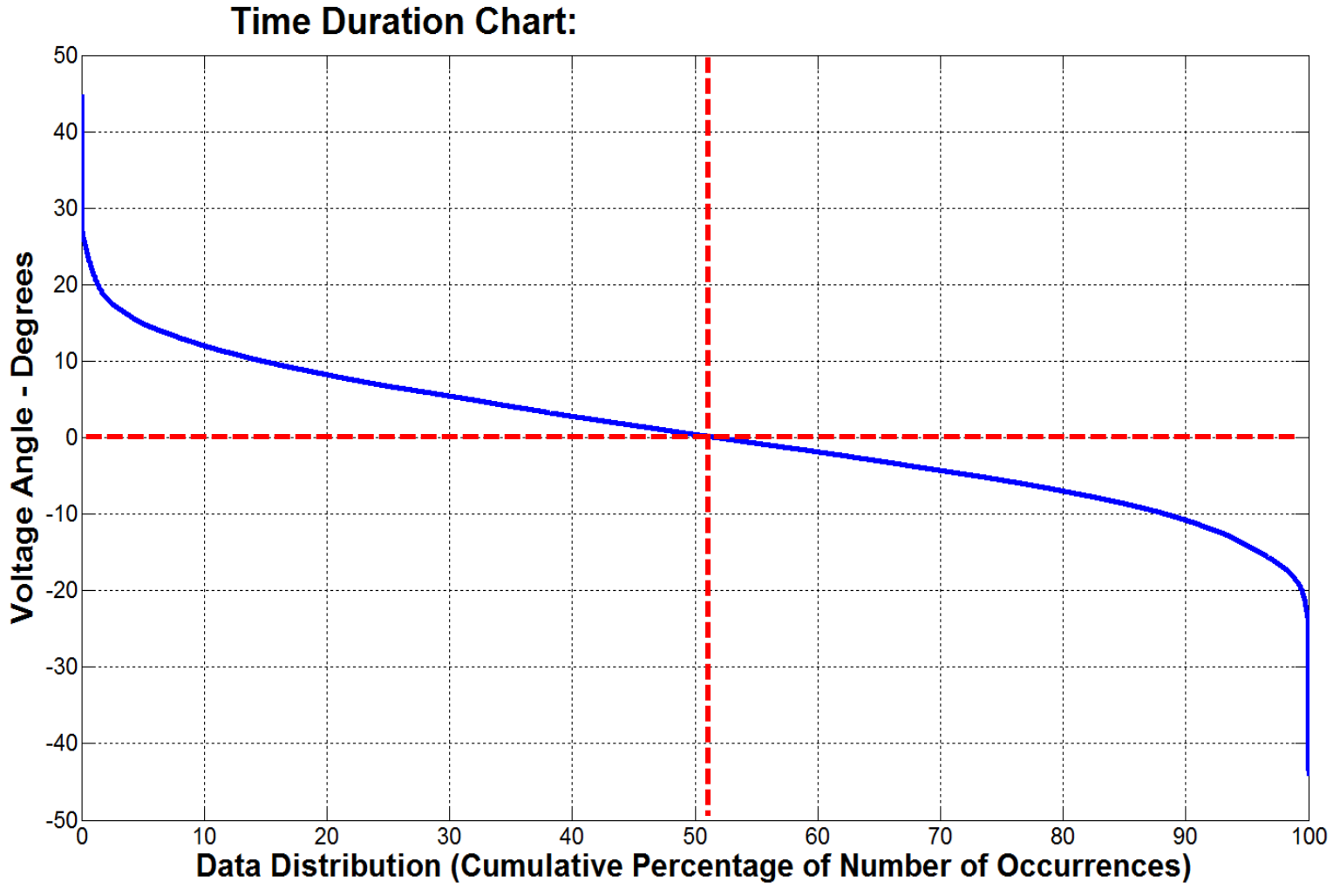
Coast 1


Time Duration Chart:
Voltage Angle - Degrees
60
50
40
30
20
10
0
-10
-20
-30
-40
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

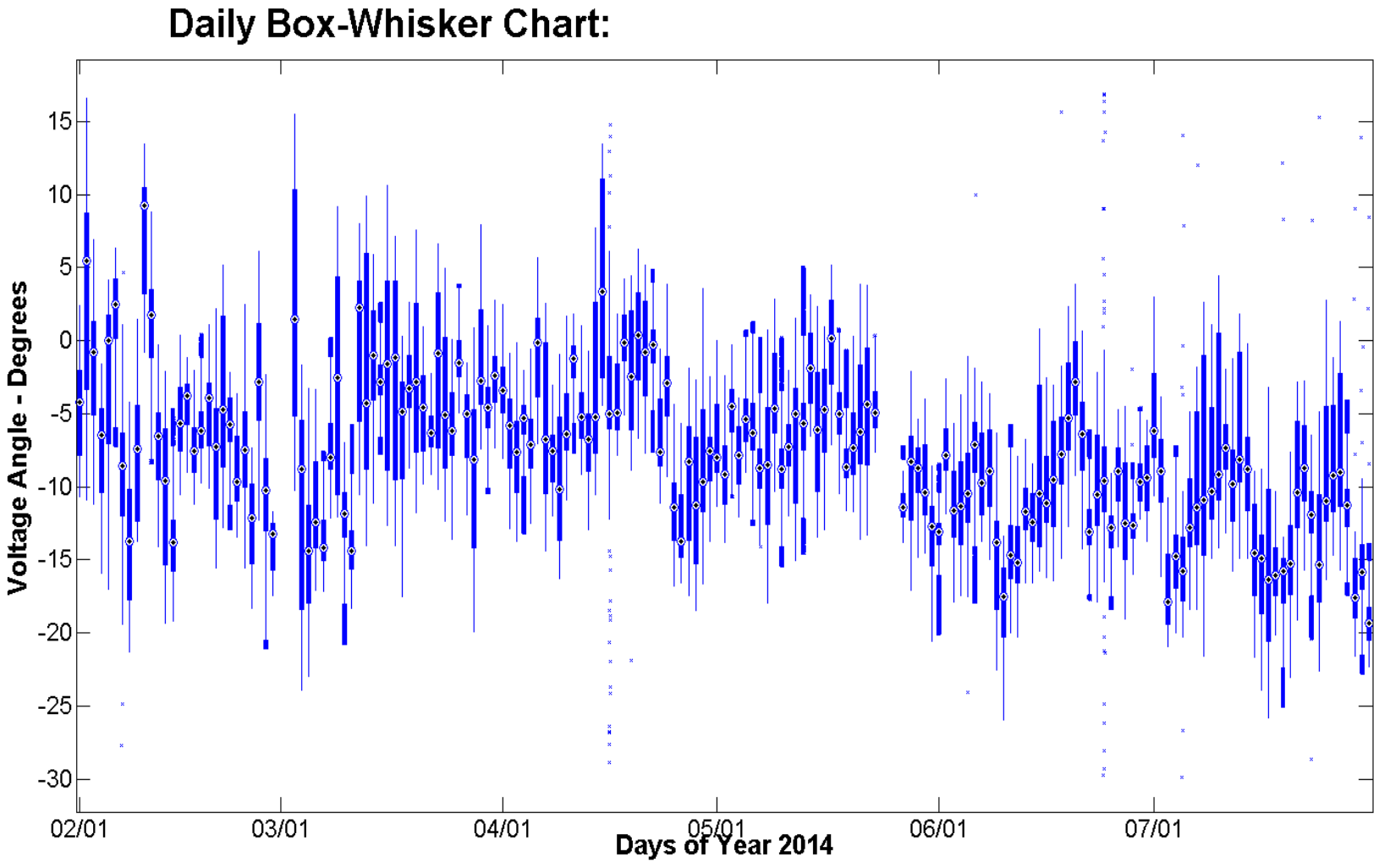
South 3


Daily Box-Whisker Chart:
Voltage Angle - Degrees
40
30
20
10
0
-10
-20
-30
-40
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

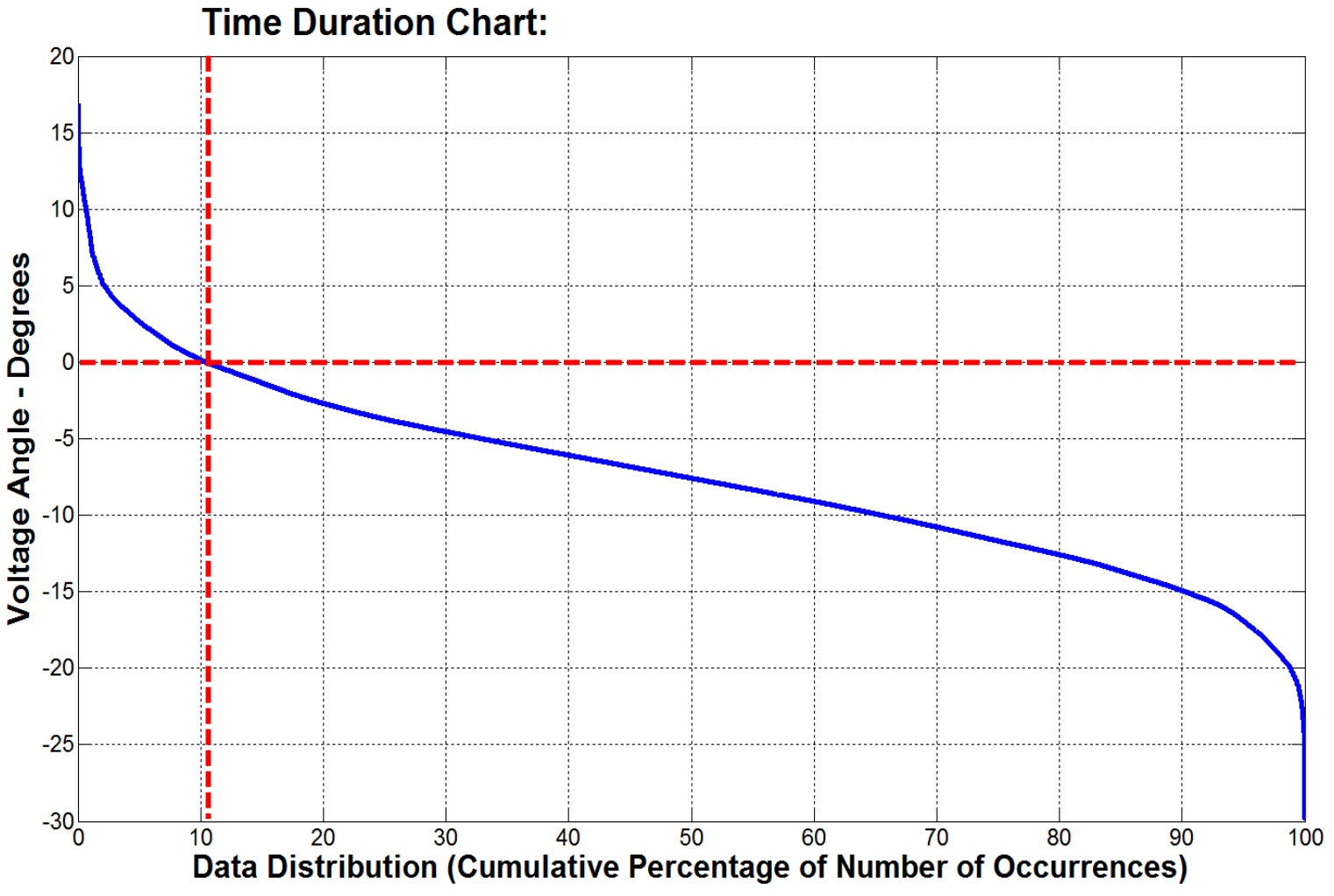
South 3


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (Cumulative Percentage of Number of Occurrences)
50
40
30
20
10
0
-10
-20
-30
-40
-50
0
10
20
30
40
50
60
70
80
90
100

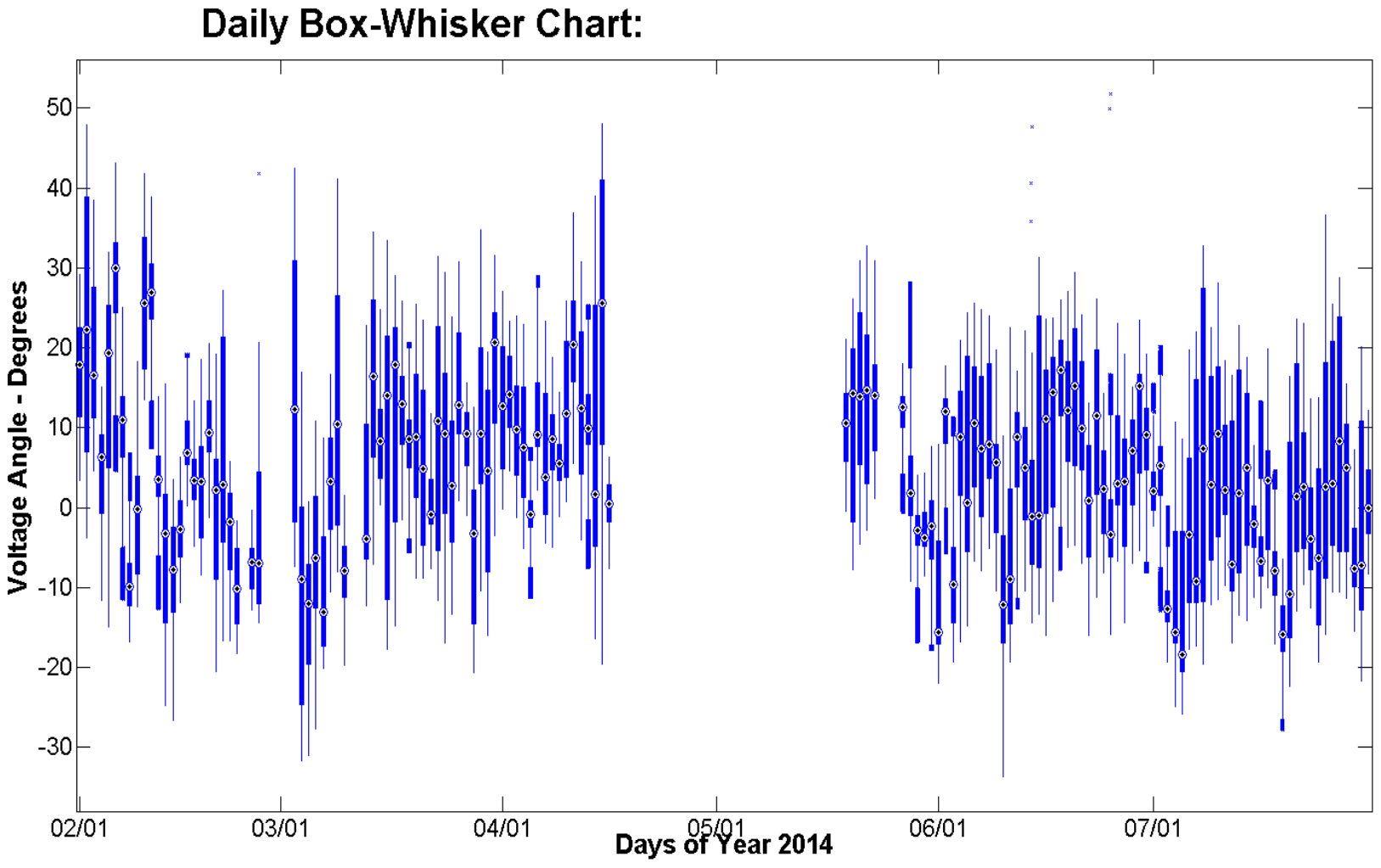
South 5


Daily Box-Whisker Chart:
Voltage Angle - Degrees
15
10
5
0
-5
-10
-15
-20
-25
-30
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

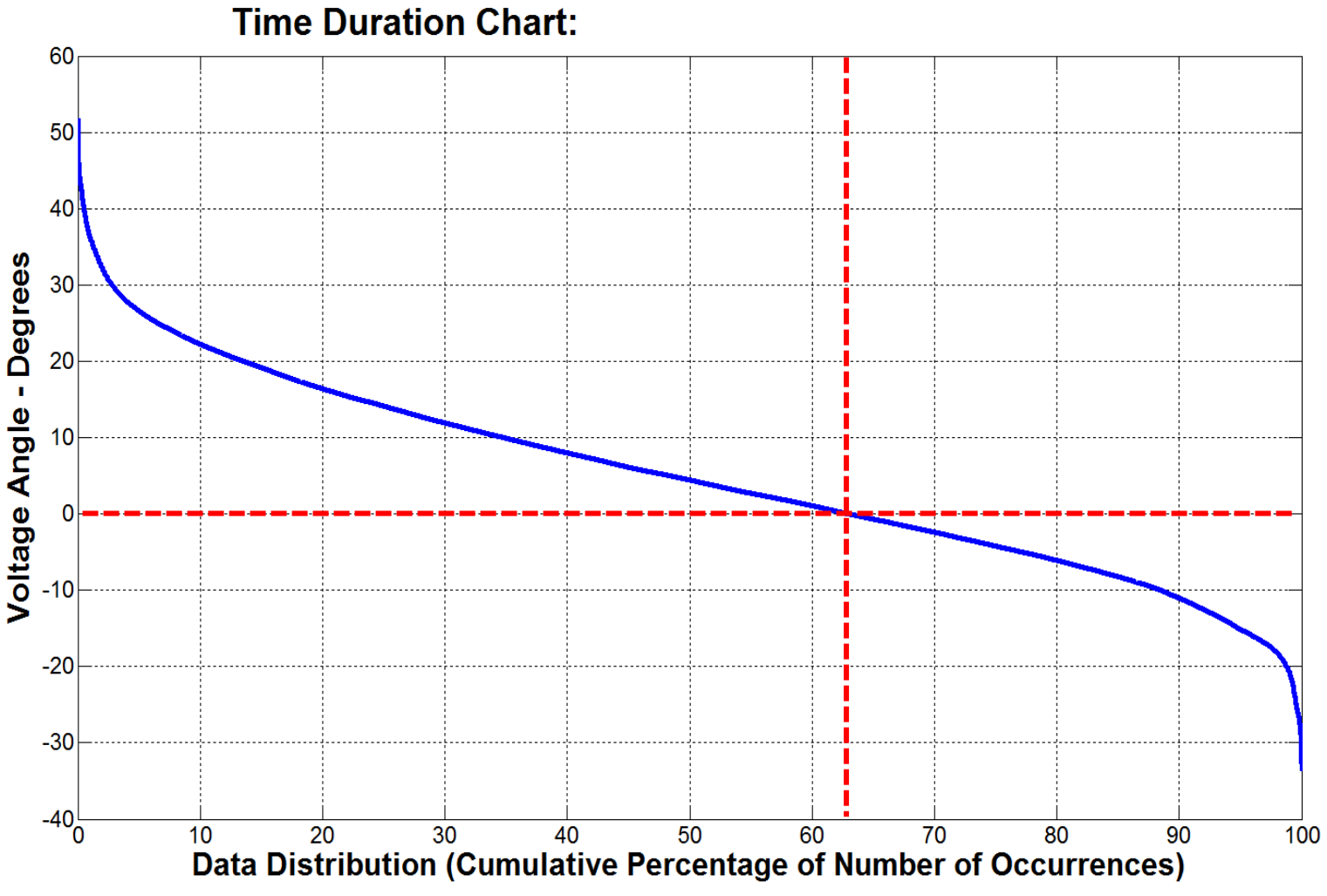
South 5


Time Duration Chart:
Voltage Angle - Degrees
20
15
10
5
0
-5
-10
-15
-20
-25
-30
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

Coast 4


Daily Box-Whisker Chart:
Voltage Angle - Degrees
50
40
30
20
10
0
-10
-20
-30
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

Coast 4


Time Duration Chart:
Voltage Angle - Degrees
60
50
40
30
20
10
0
-10
-20
-30
-40
0
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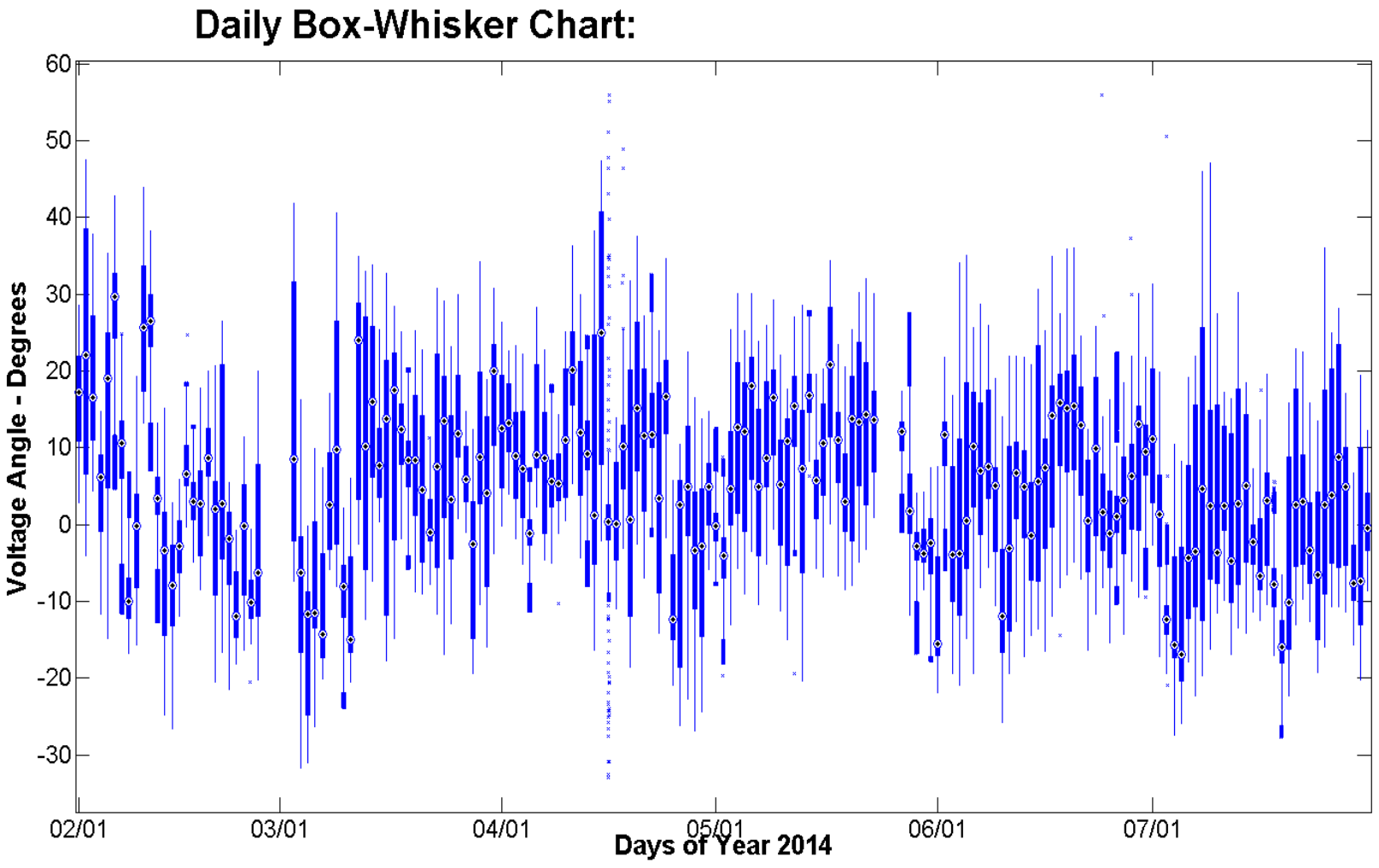
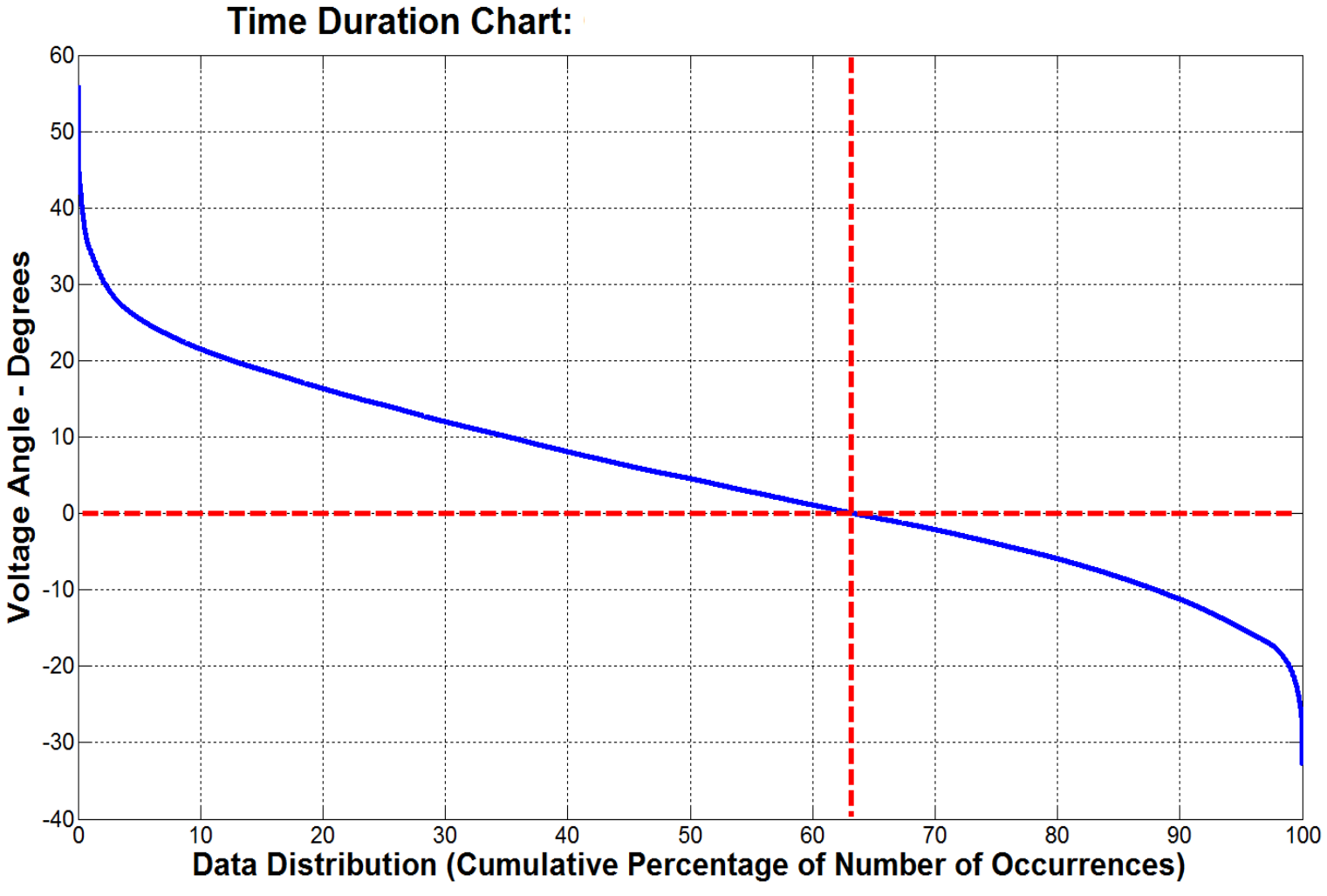
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

Coast 3


Daily Box-Whisker Chart:
Voltage Angle - Degrees
60
50
40
30
20
10
0
-10
-20
-30
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

Coast 3


Time Duration Chart:
Voltage Angle - Degrees
60
50
40
30
20
10
0
-10
-20
-30
-40
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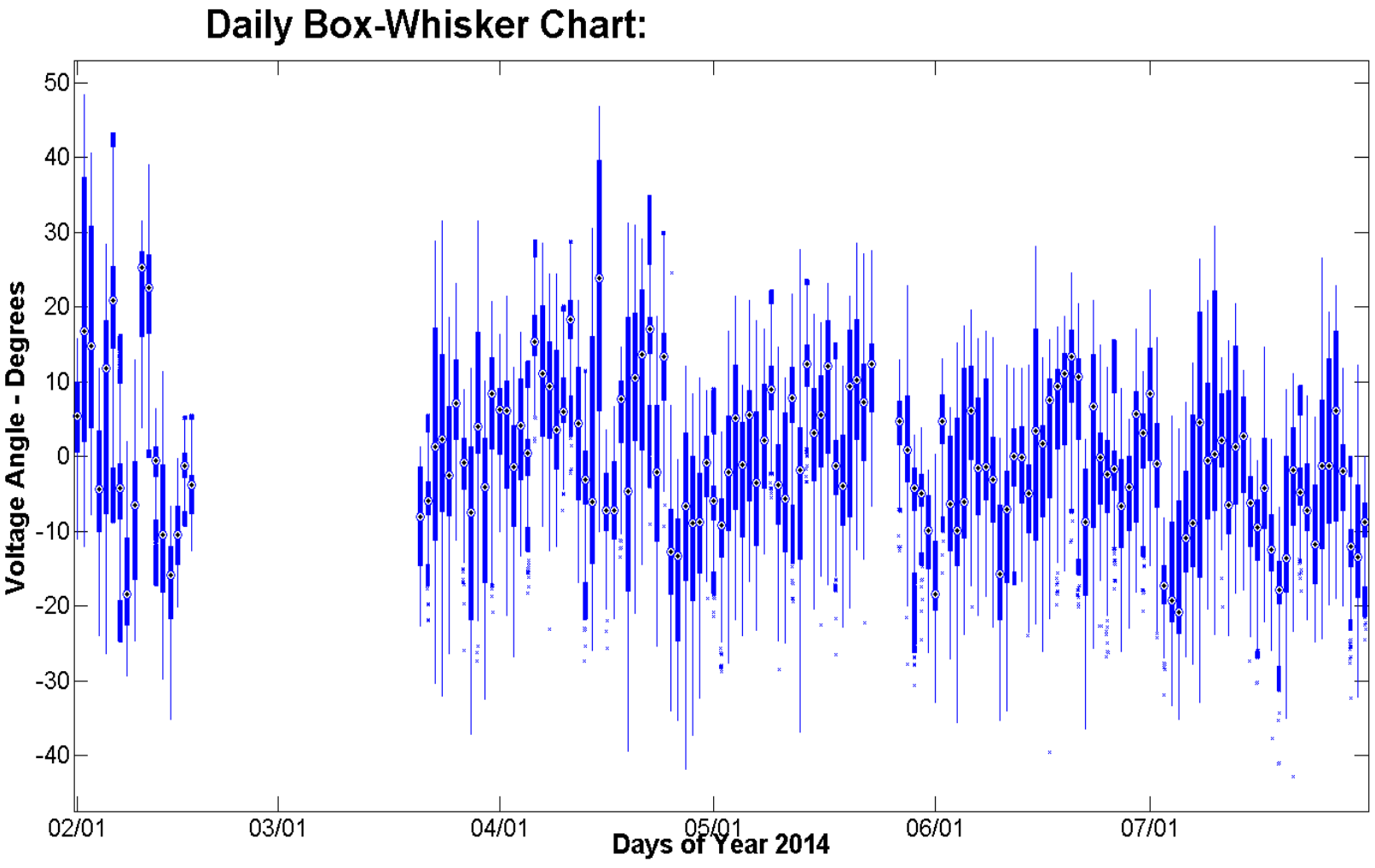
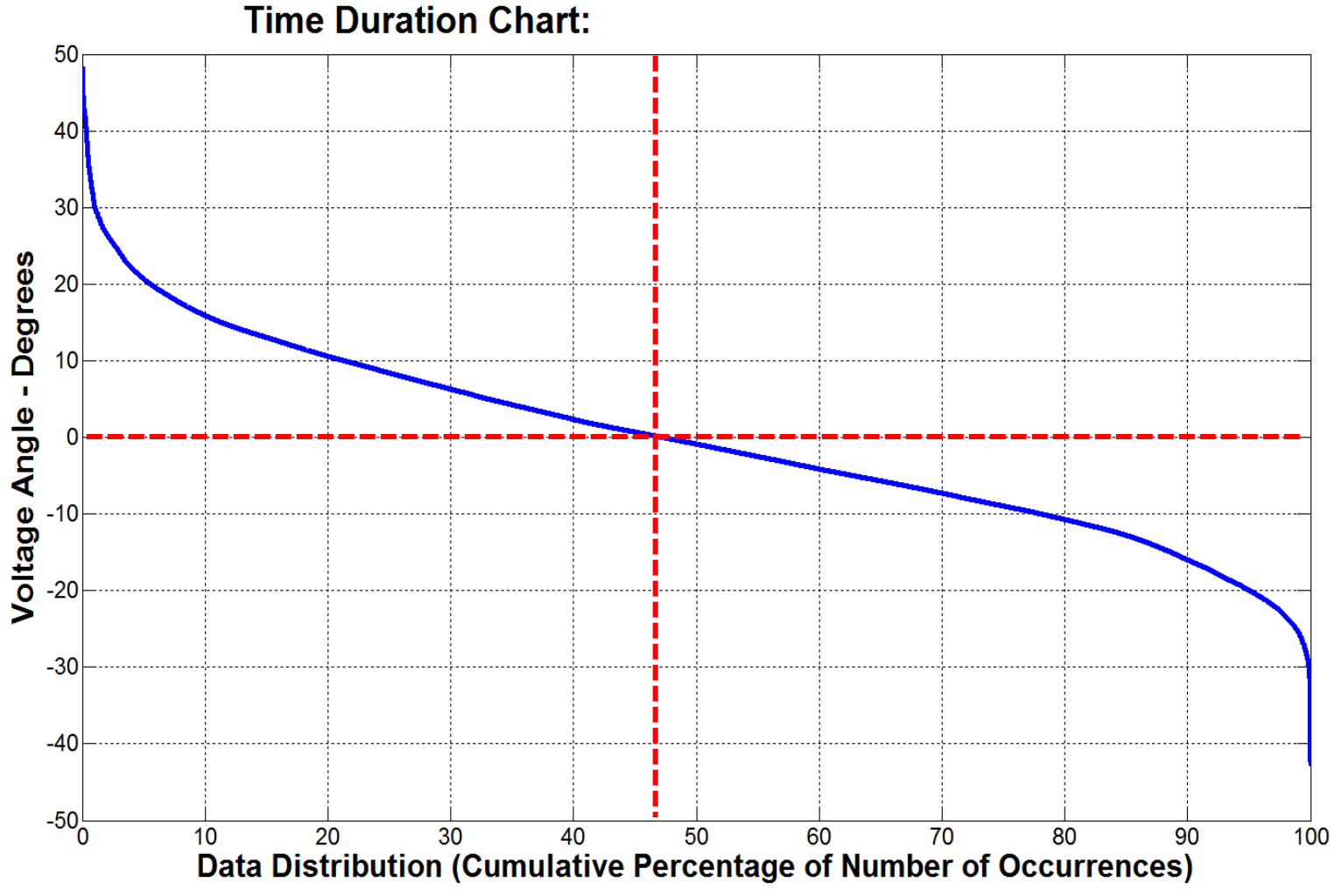
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

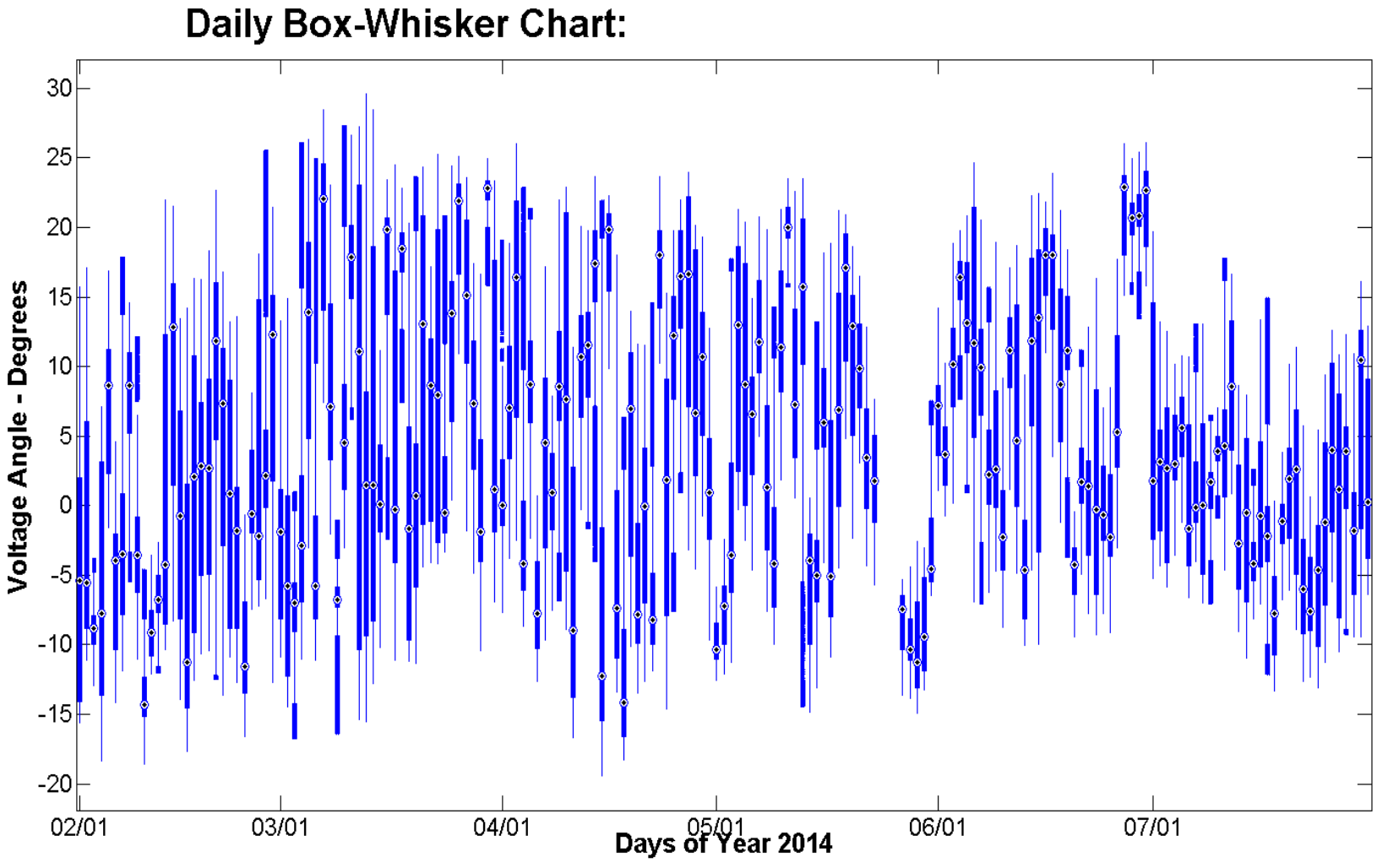
South 13


Daily Box-Whisker Chart:
Voltage Angle - Degrees
50
40
30
20
10
0
-10
-20
-30
-40
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

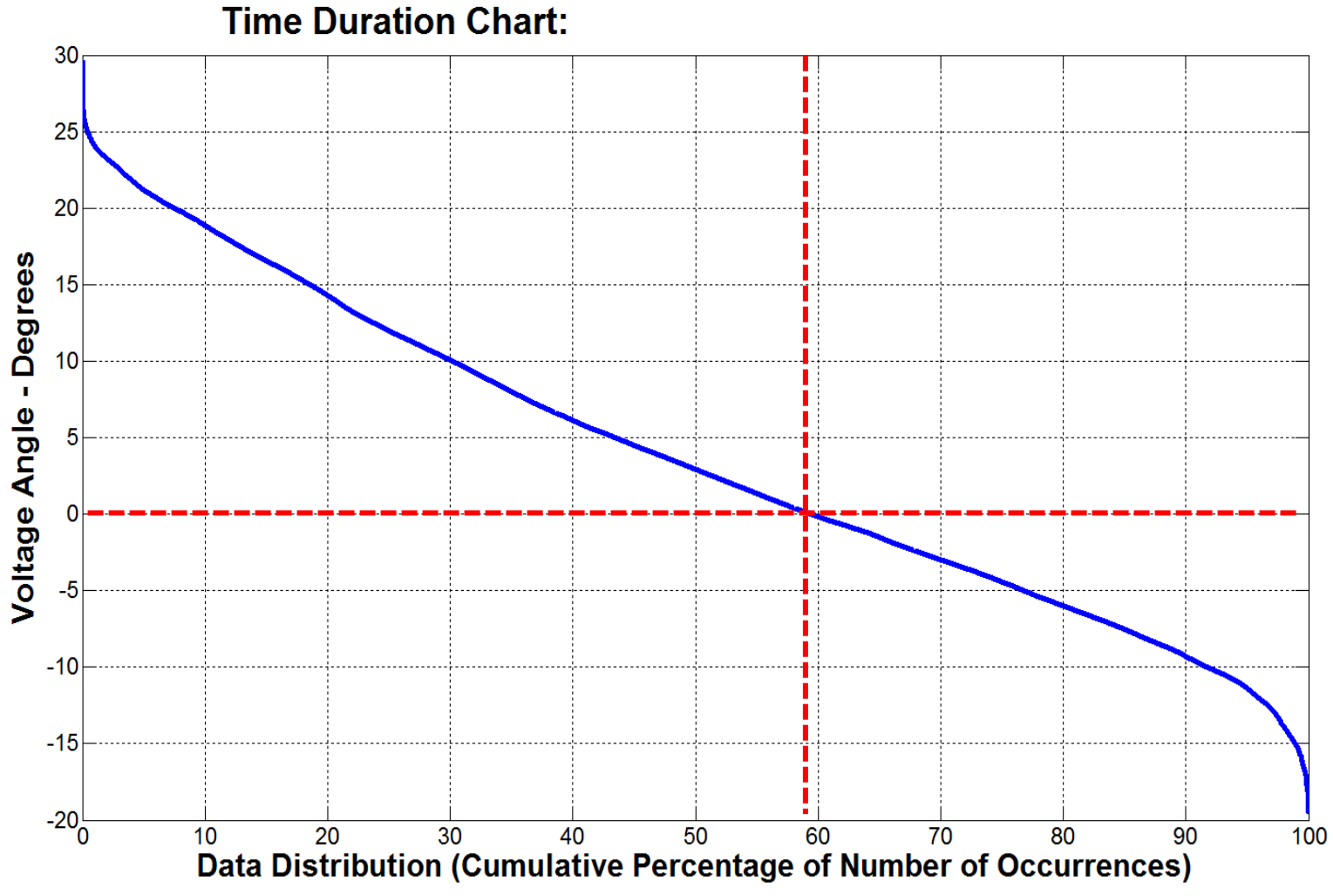
South 13


Time Duration Chart:
Voltage Angle - Degrees
50
40
30
20
10
0
-10
-20
-30
-40
-50
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

FarWest 4


Daily Box-Whisker Chart:
Voltage Angle - Degrees
30
25
20
15
10
5
0
-5
-10
-15
-20
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

FarWest 4


Time Duration Chart:
Voltage Angle - Degrees
30
25
20
15
10
5
0
-5
-10
-15
-20
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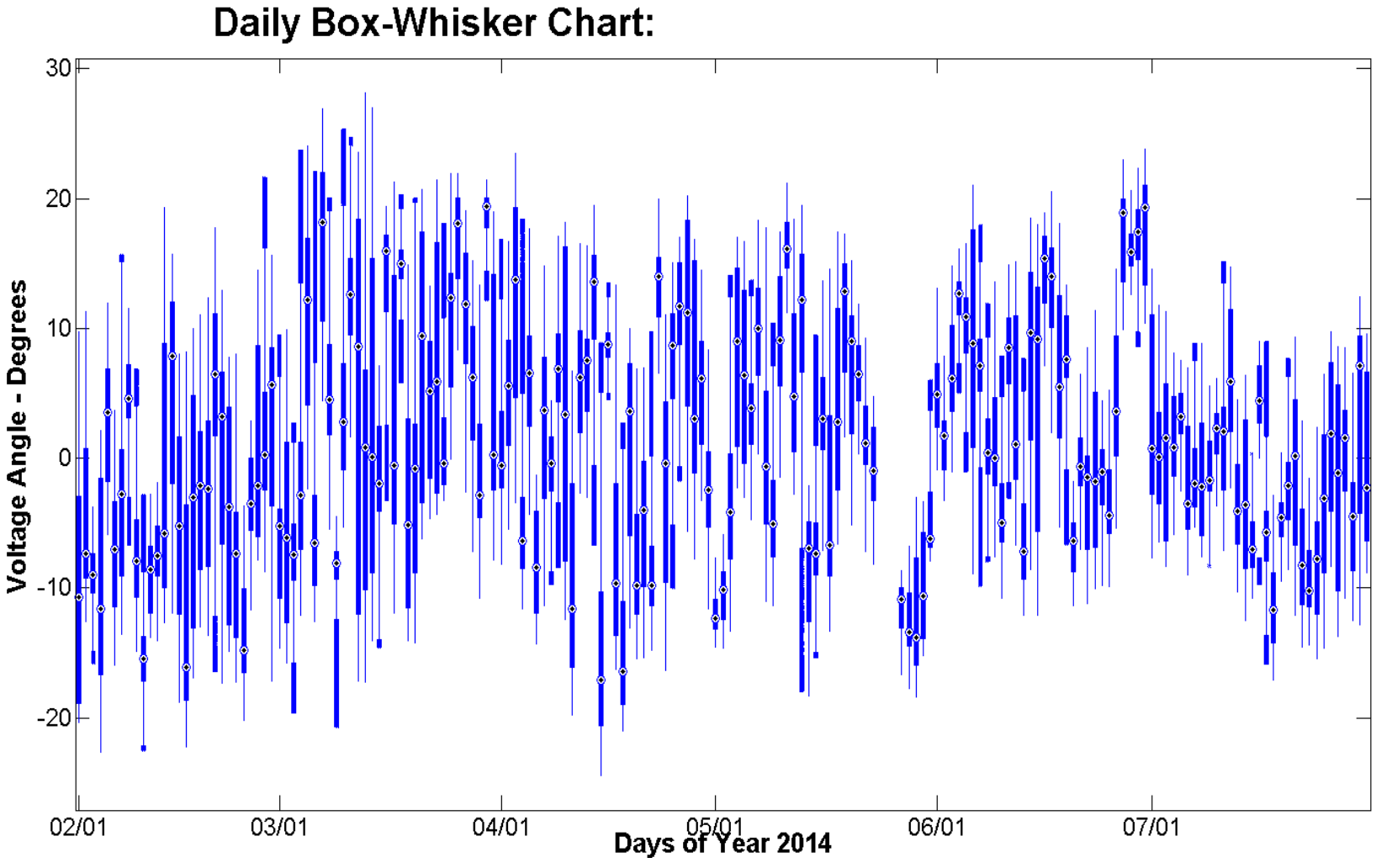
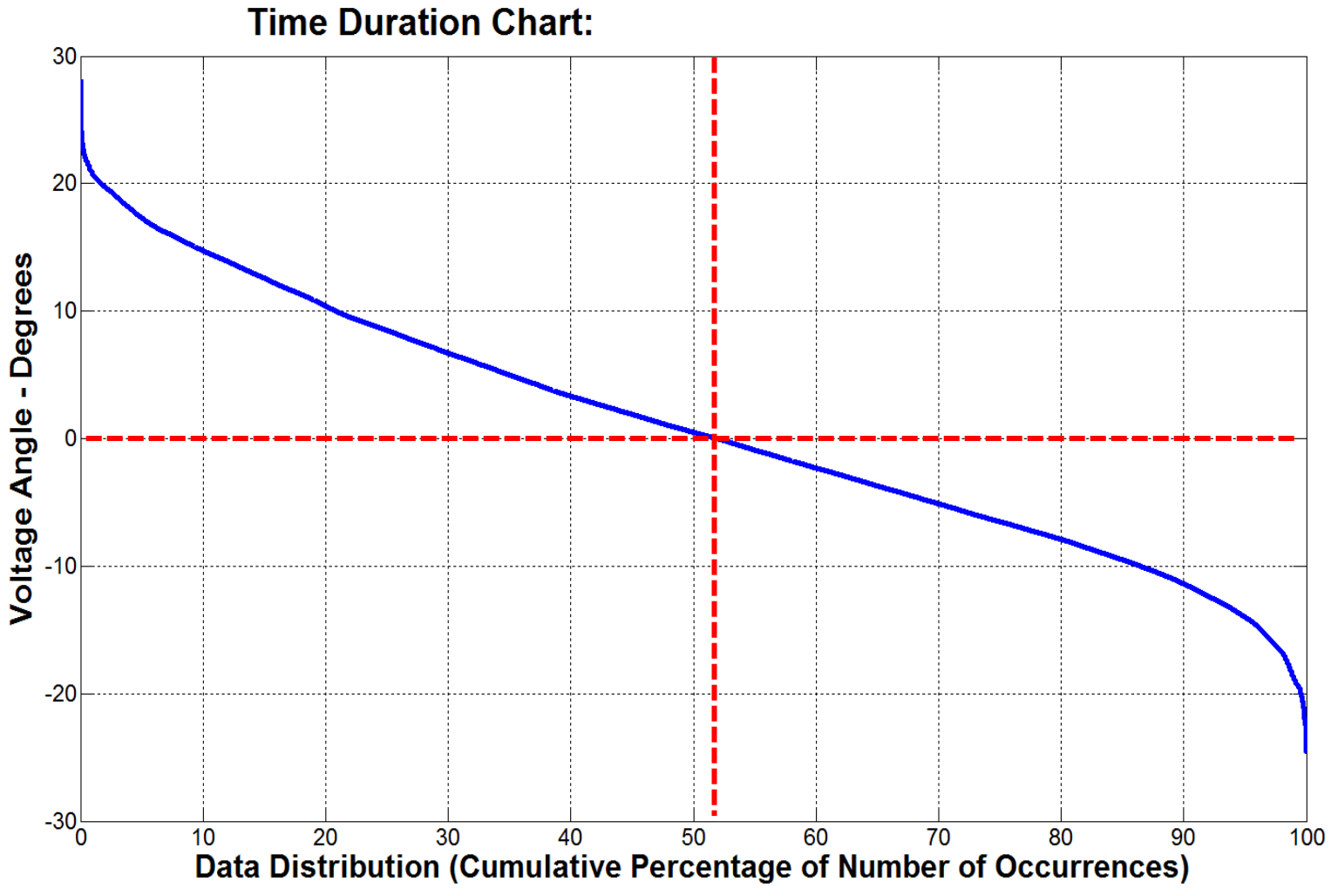
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

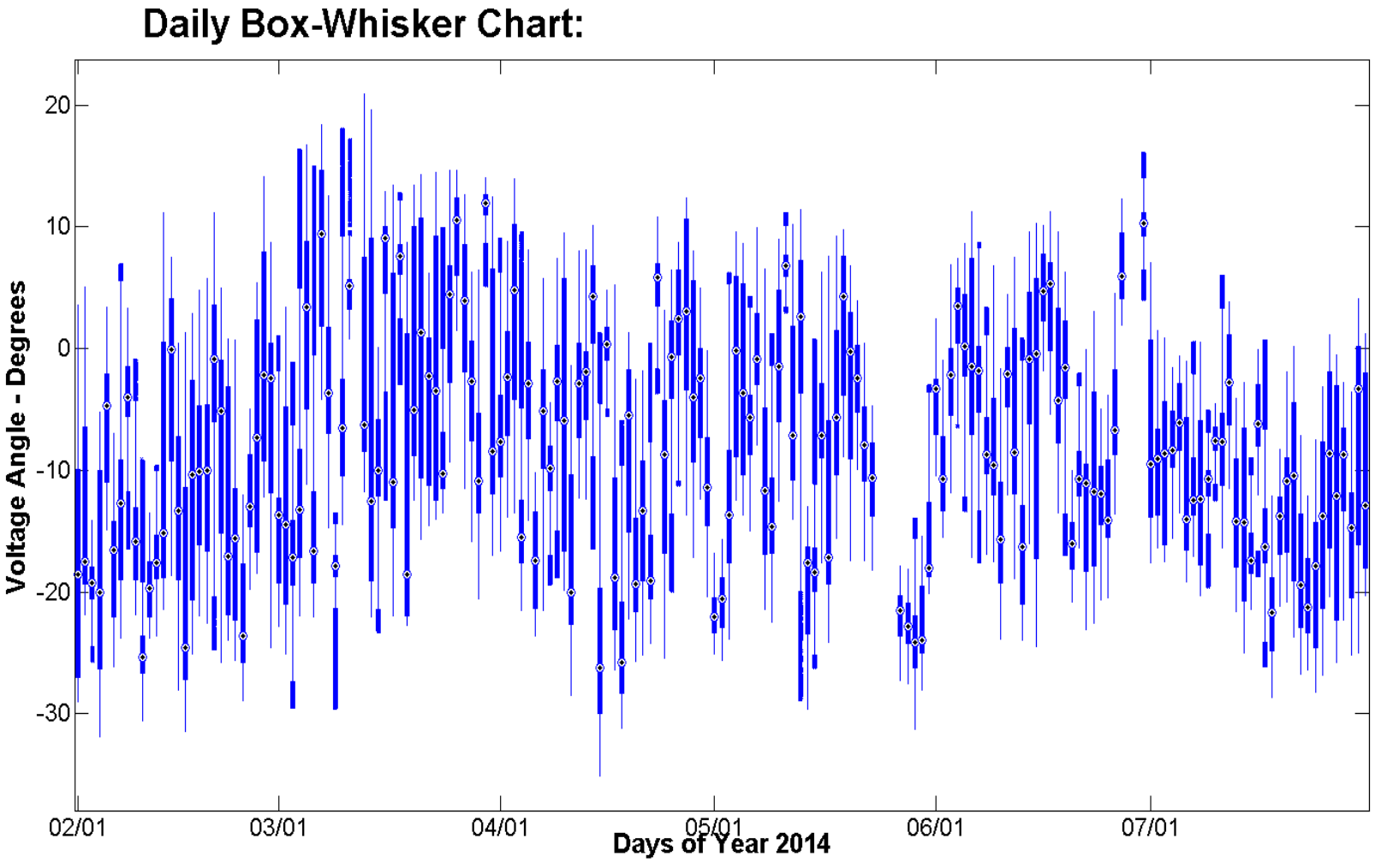
FarWest 7


Daily Box-Whisker Chart:
Voltage Angle - Degrees
30
20
10
0
-10
-20
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

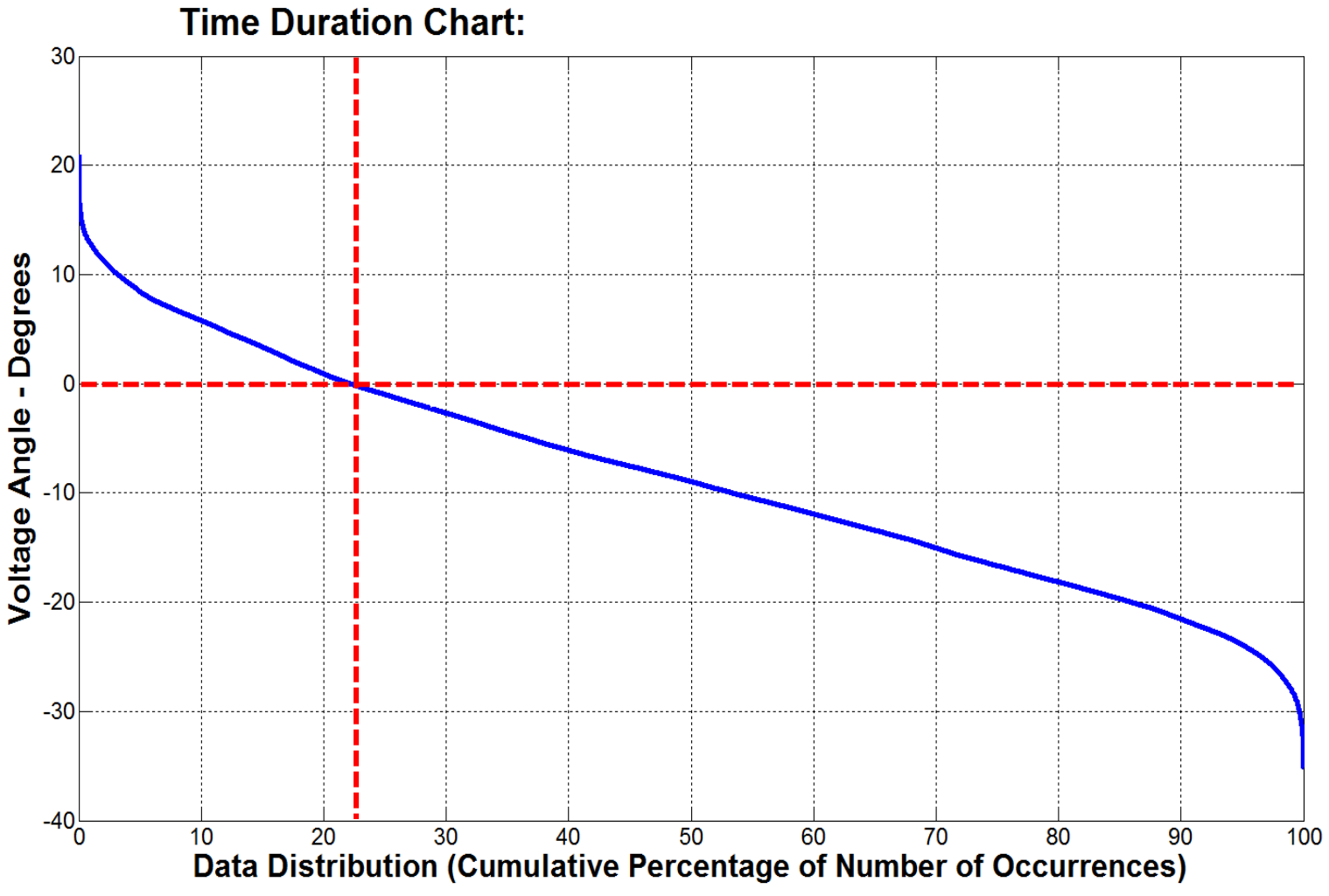
FarWest 7


Time Duration Chart:
Voltage Angle - Degrees
30
20
10
0
-10
-20
-30
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

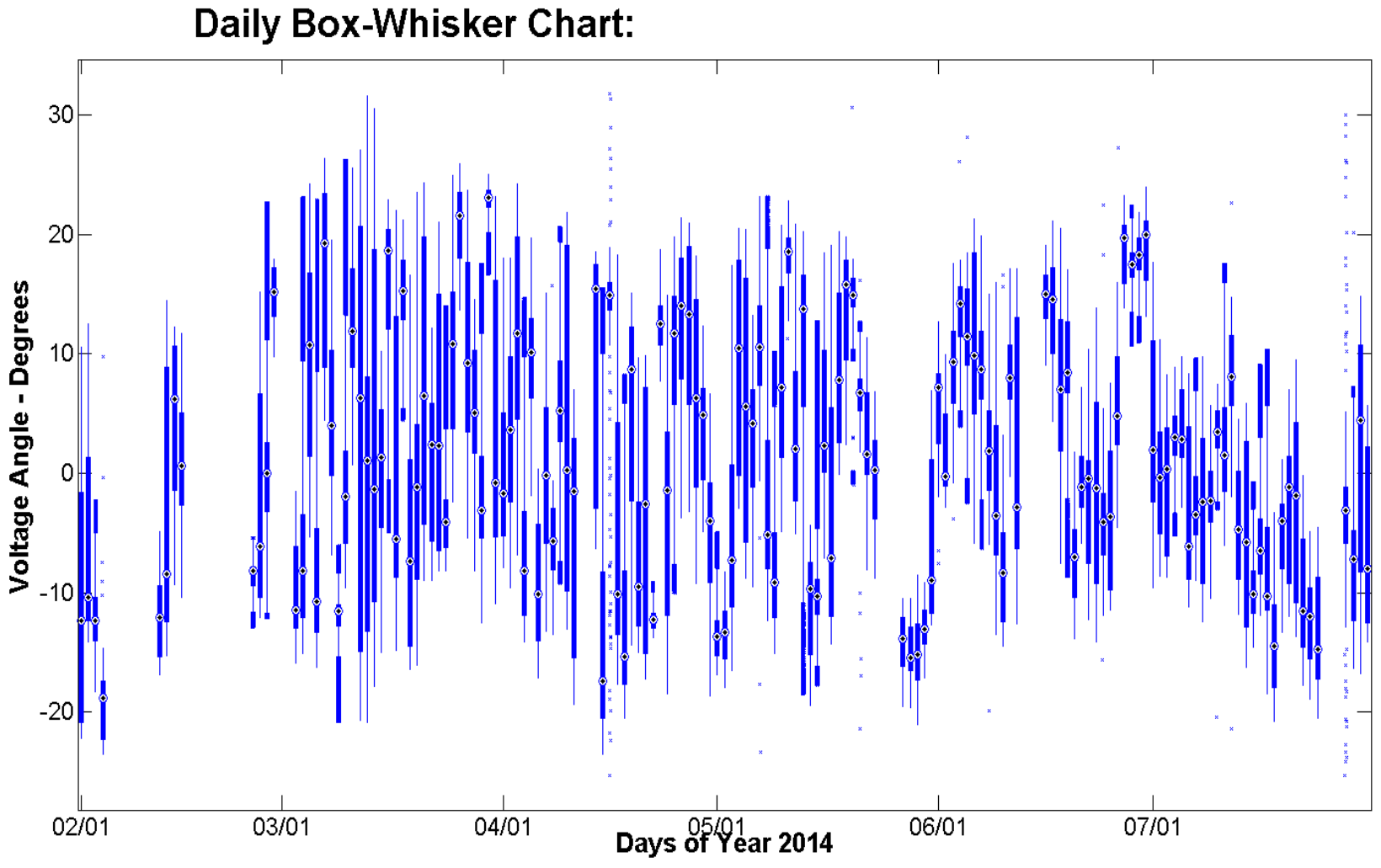
FarWest 8


Daily Box-Whisker Chart:
Voltage Angle - Degrees
20
10
0
-10
-20
-30
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

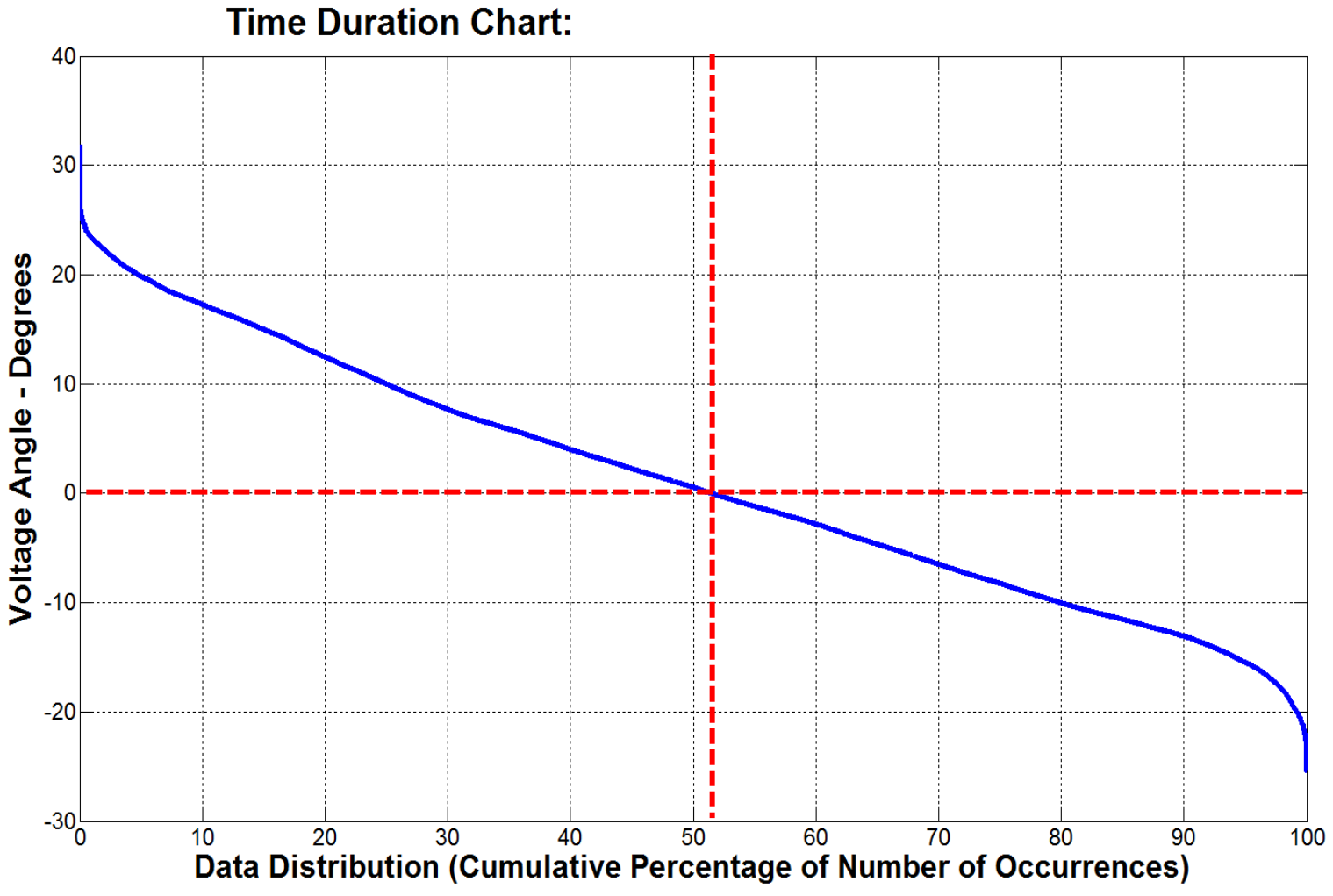
FarWest 8


Time Duration Chart:
Voltage Angle - Degrees
30
20
10
0
-10
-20
-30
-40
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

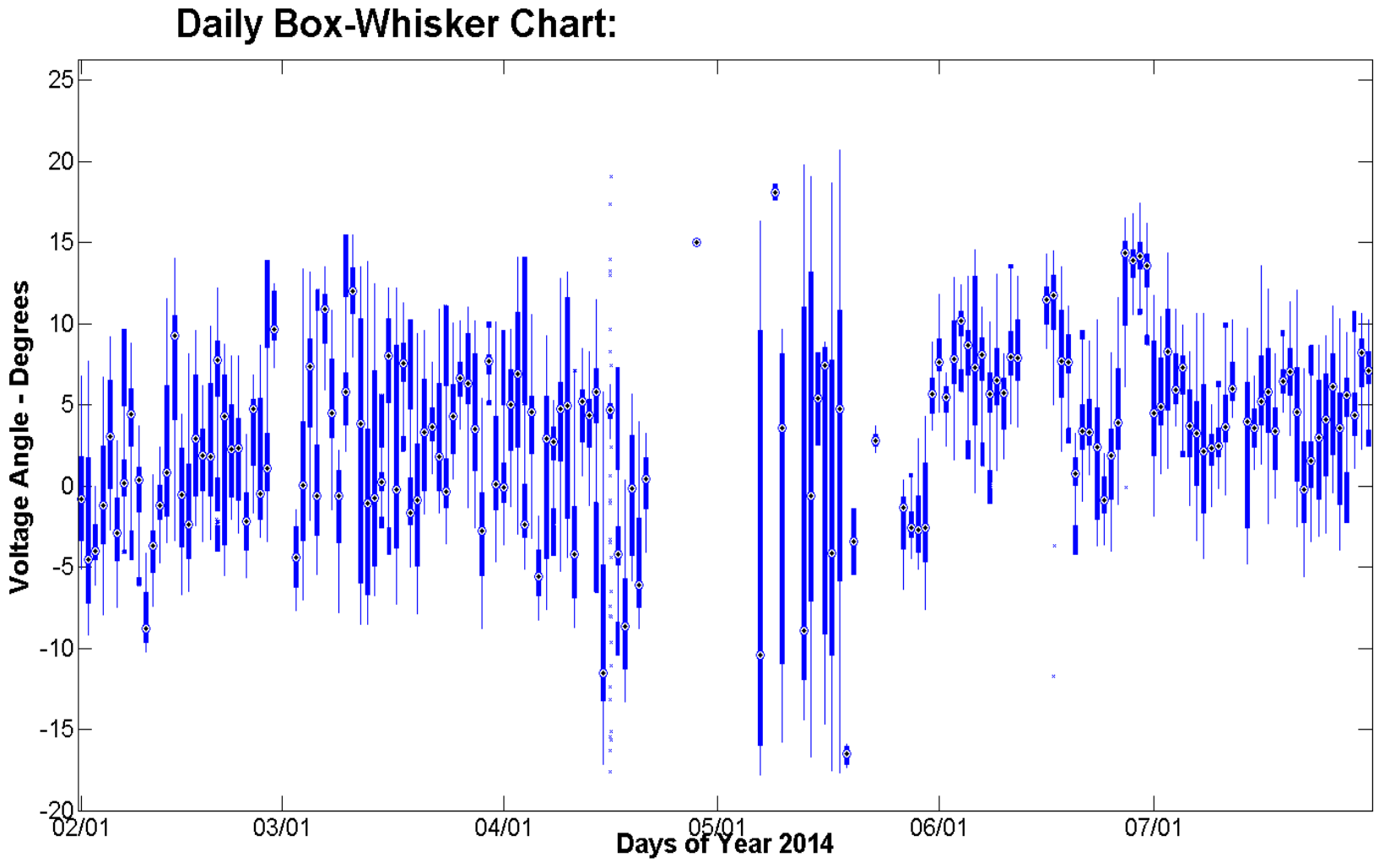
FarWest 9


Daily Box-Whisker Chart:
Voltage Angle - Degrees
30
20
10
0
-10
-20
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

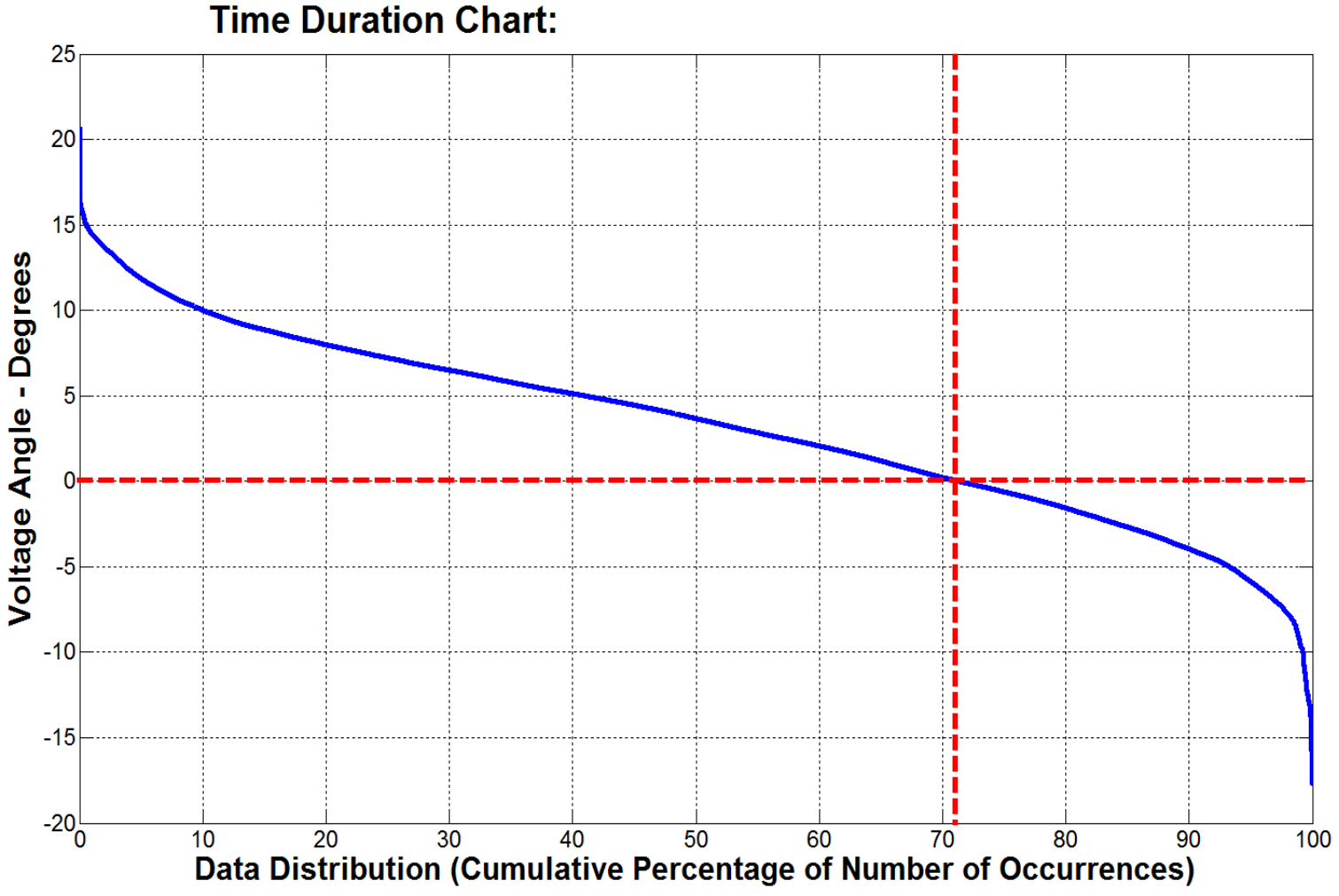
FarWest 9


Time Duration Chart:
Voltage Angle - Degrees
40
30
20
10
0
-10
-20
-30
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

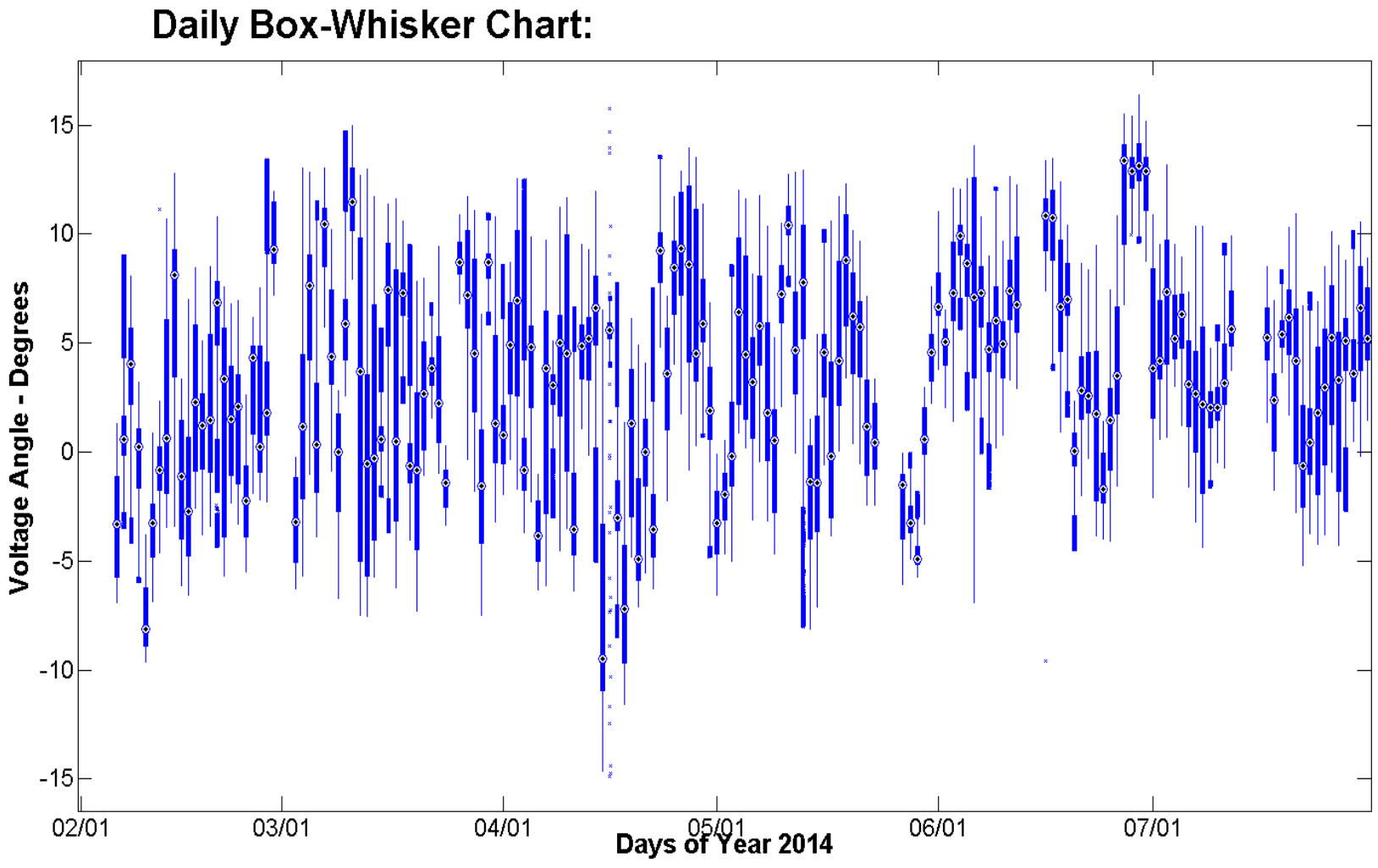
West 16


Daily Box-Whisker Chart:
Voltage Angle - Degrees
25
20
15
10
5
0
-5
-10
-15
-20
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

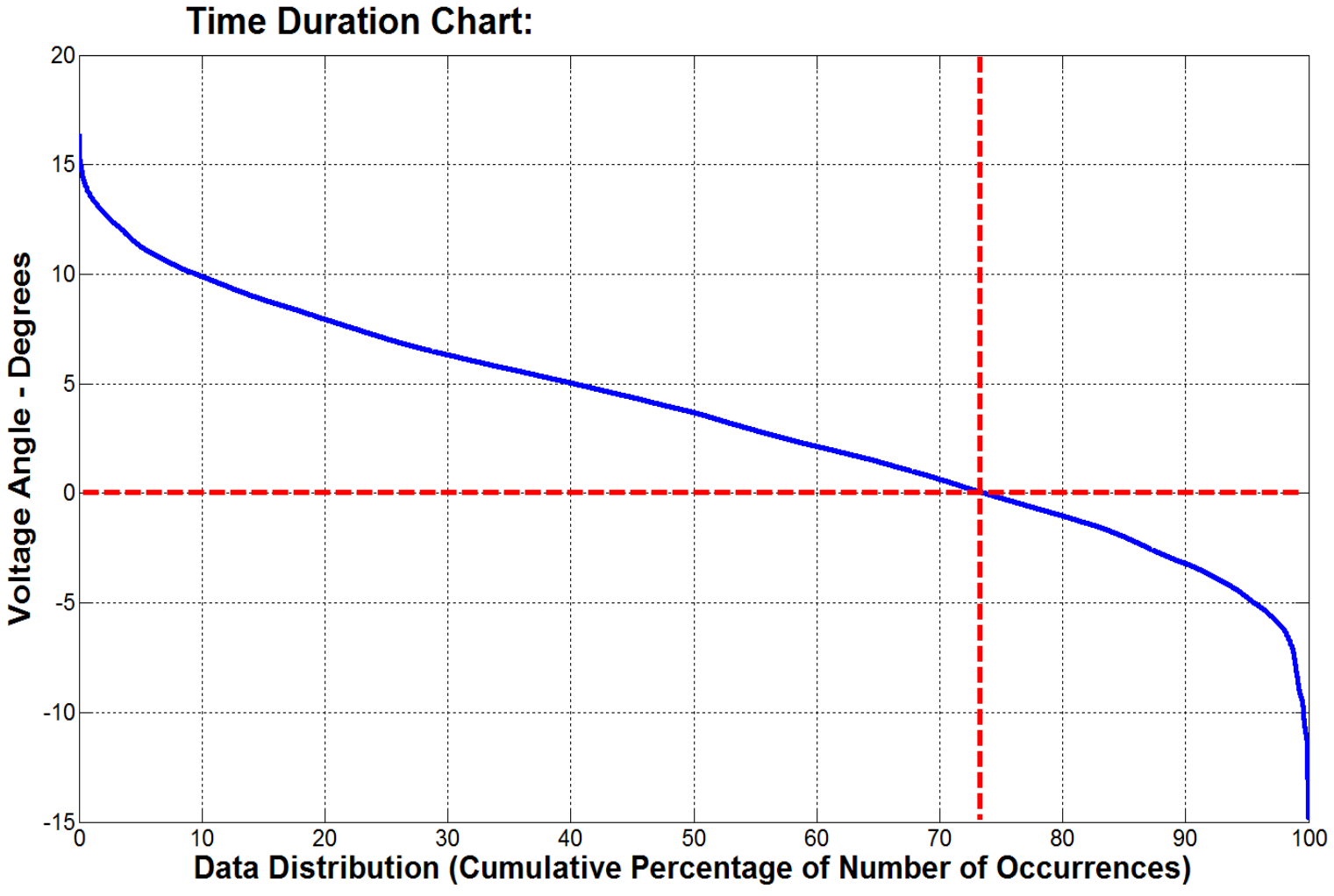
West 16


Time Duration Chart:
Voltage Angle - Degrees
25
20
15
10
5
0
-5
-10
-15
-20
0
10
20
30
40
50
60
70
80
90
100
Data Distribution (Cumulative Percentage of Number of Occurrences)

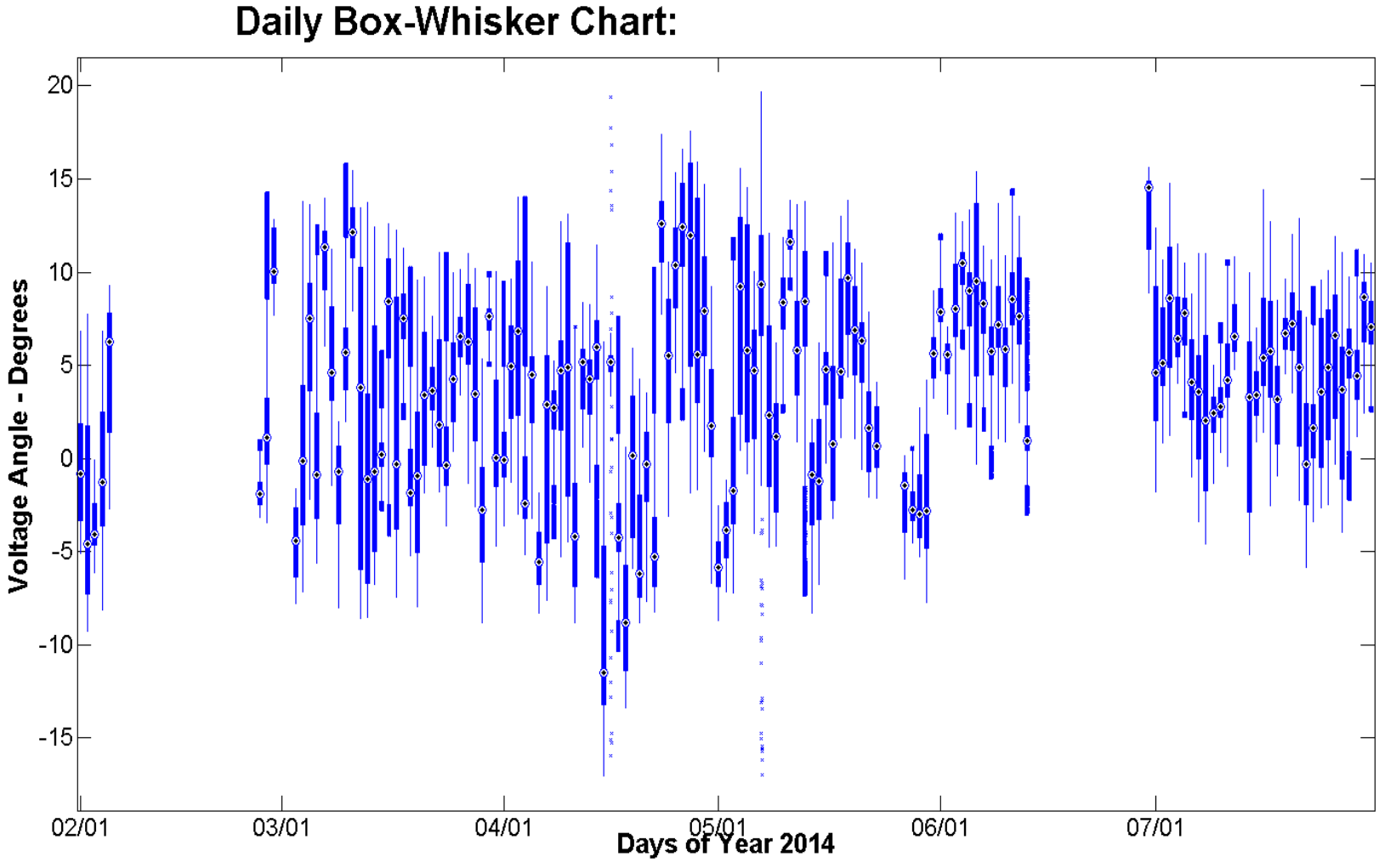
West 3


Daily Box-Whisker Chart:
Voltage Angle - Degrees
15
10
5
0
-5
-10
-15
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

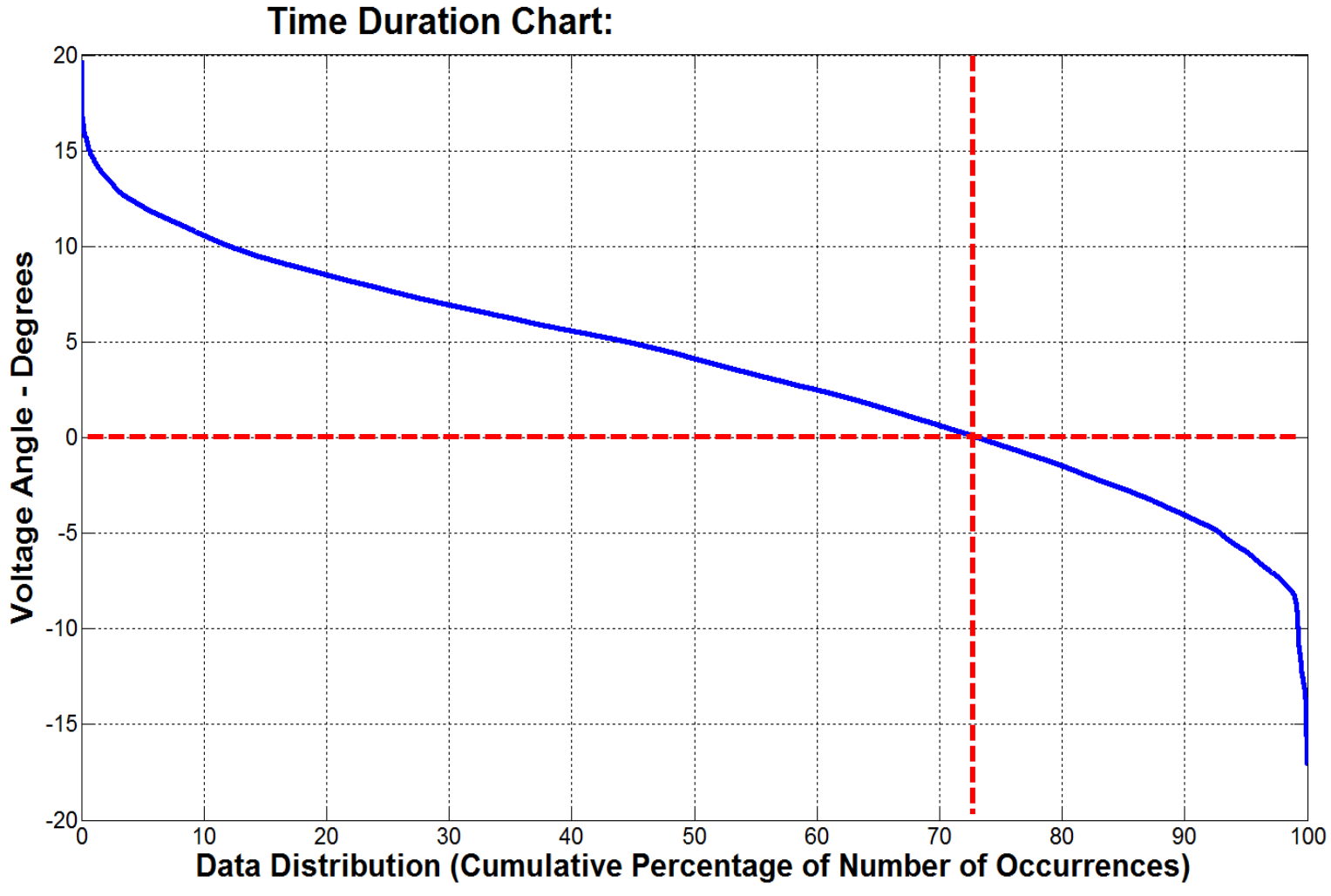
West 3


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (Cumulative Percentage of Number of Occurrences)
20
15
10
5
0
-5
-10
-15
0
10
20
30
40
50
60
70
80
90
100

West 15


Daily Box-Whisker Chart:
Voltage Angle - Degrees
20
15
10
5
0
-5
-10
-15
02/01
03/01
04/01
05/01
06/01
07/01
Days of Year 2014

West 15


Time Duration Chart:
Voltage Angle - Degrees
Data Distribution (Cumulative Percentage of Number of Occurrences)
20
15
10
5
0
-5
-10
-15
-20
0
10
20
30
40
50
60
70
80
90
100

Appendix B – Part 1
CCET Discovery Across Texas project

Baseline Analysis Update – Angle Differences

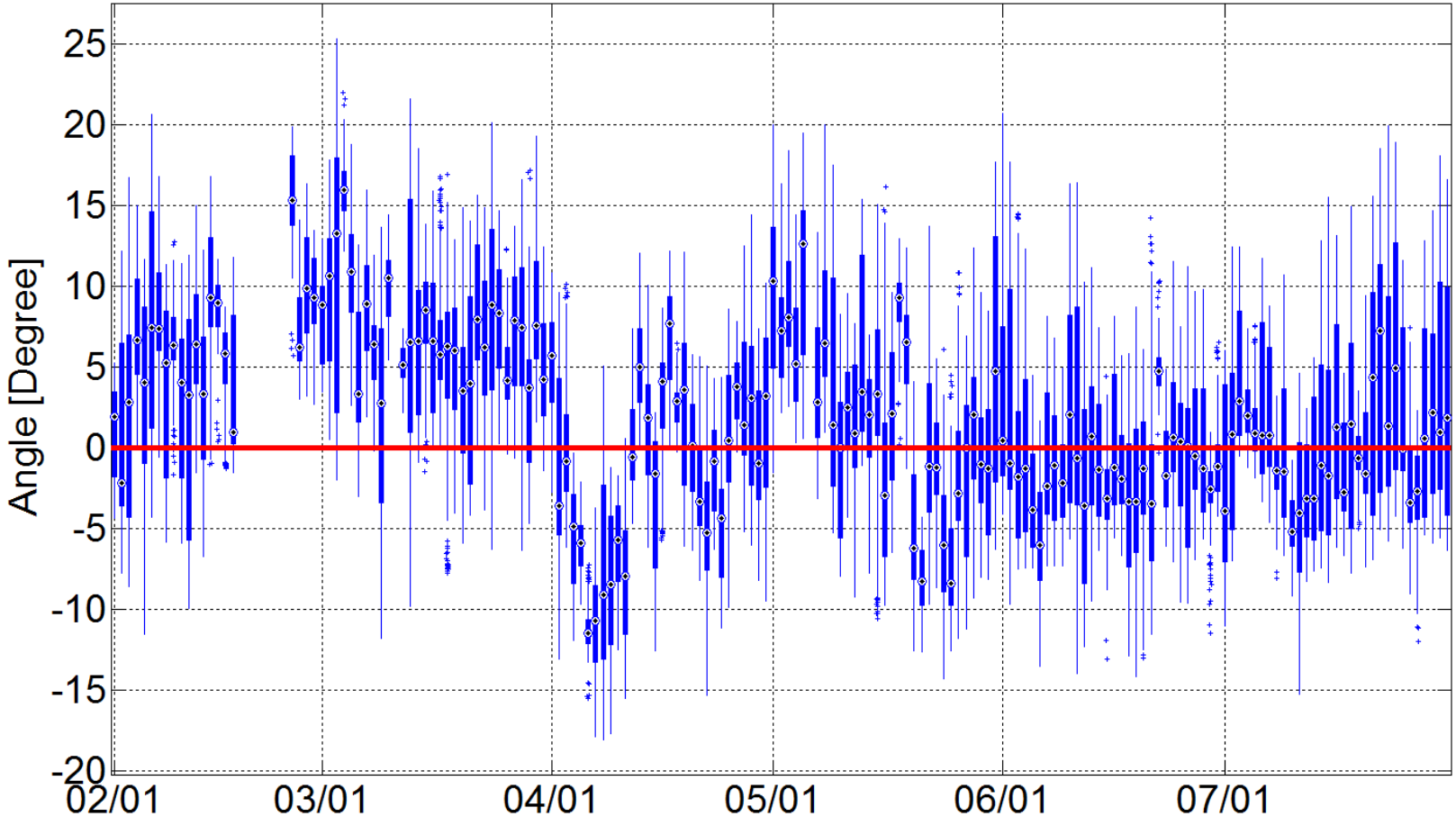
State Estimator Data: February to July 2014
Box-Whisker Plots and Time Duration Curves

Electric Power Group

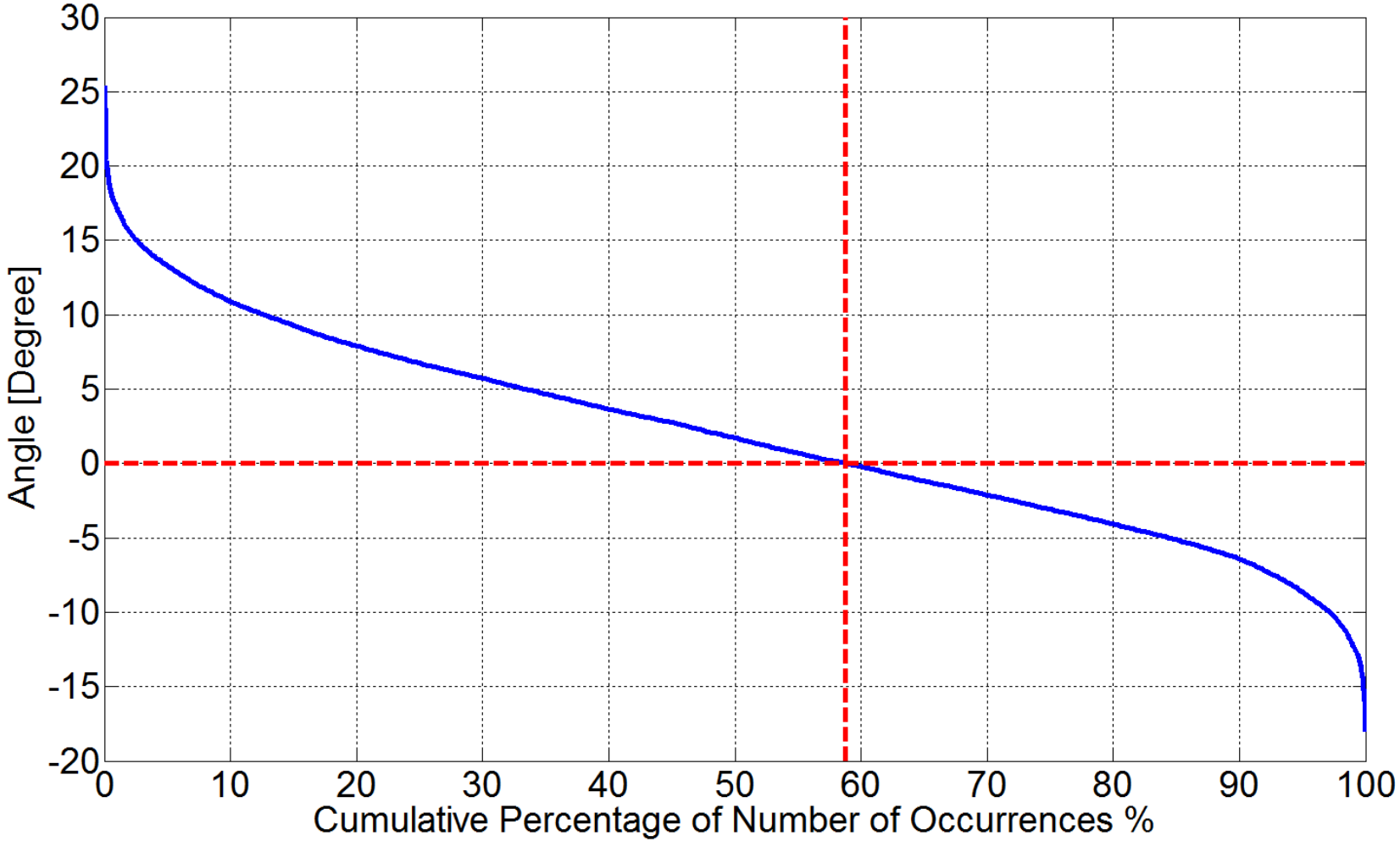
CCET

ERCOT

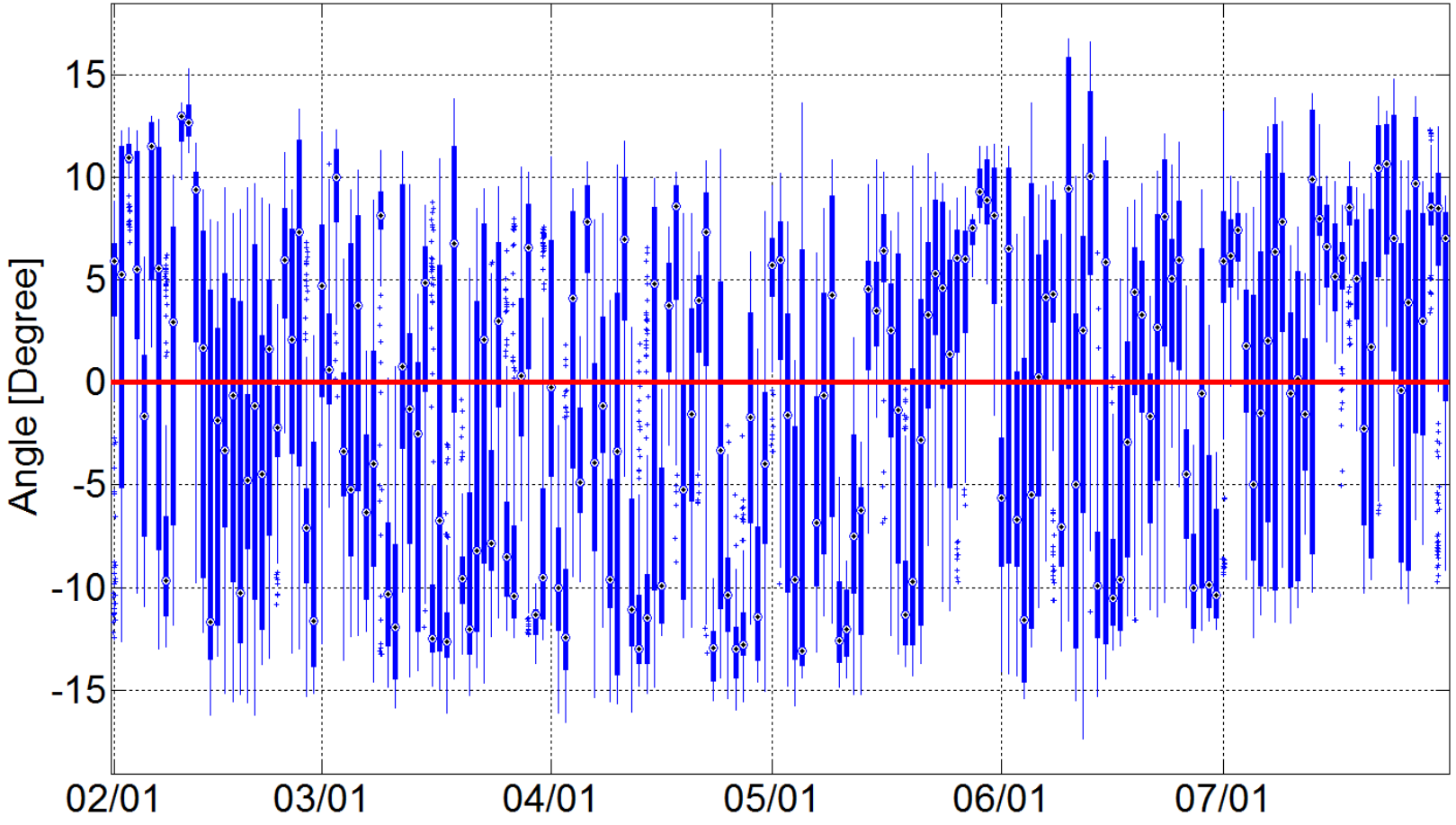
Coast 1-South 13



Coast 1-South 13



West 5-West 10



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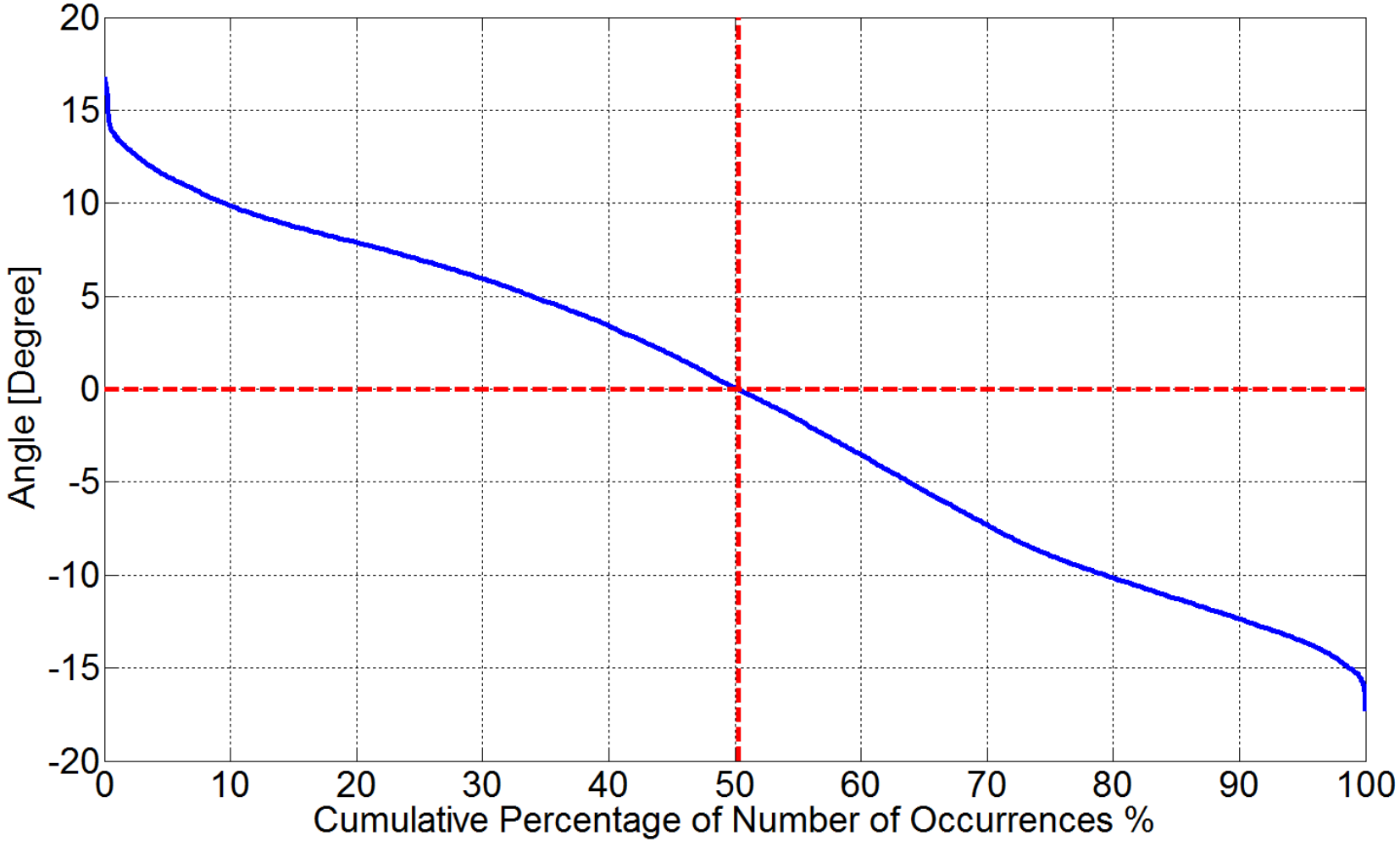
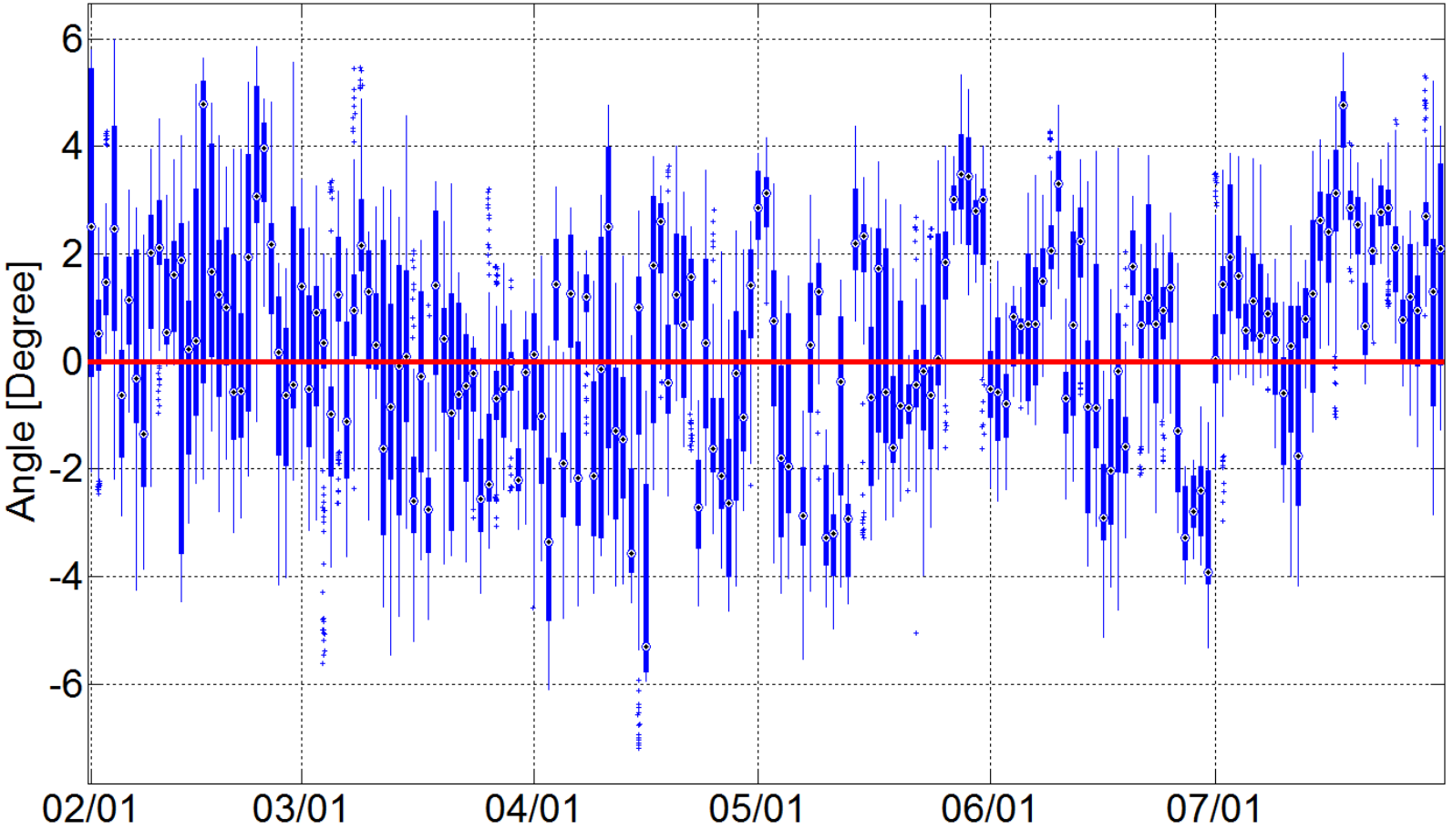
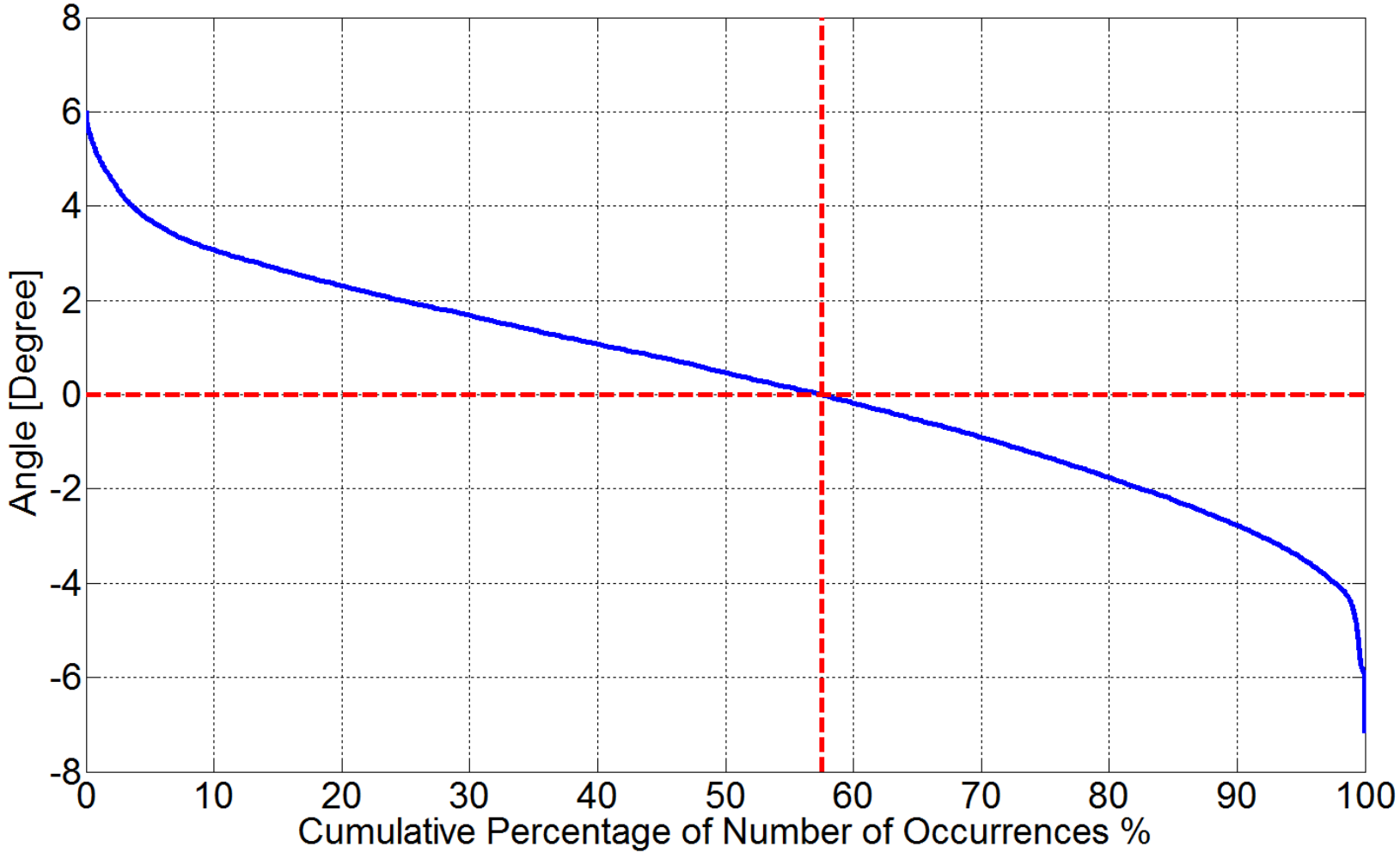


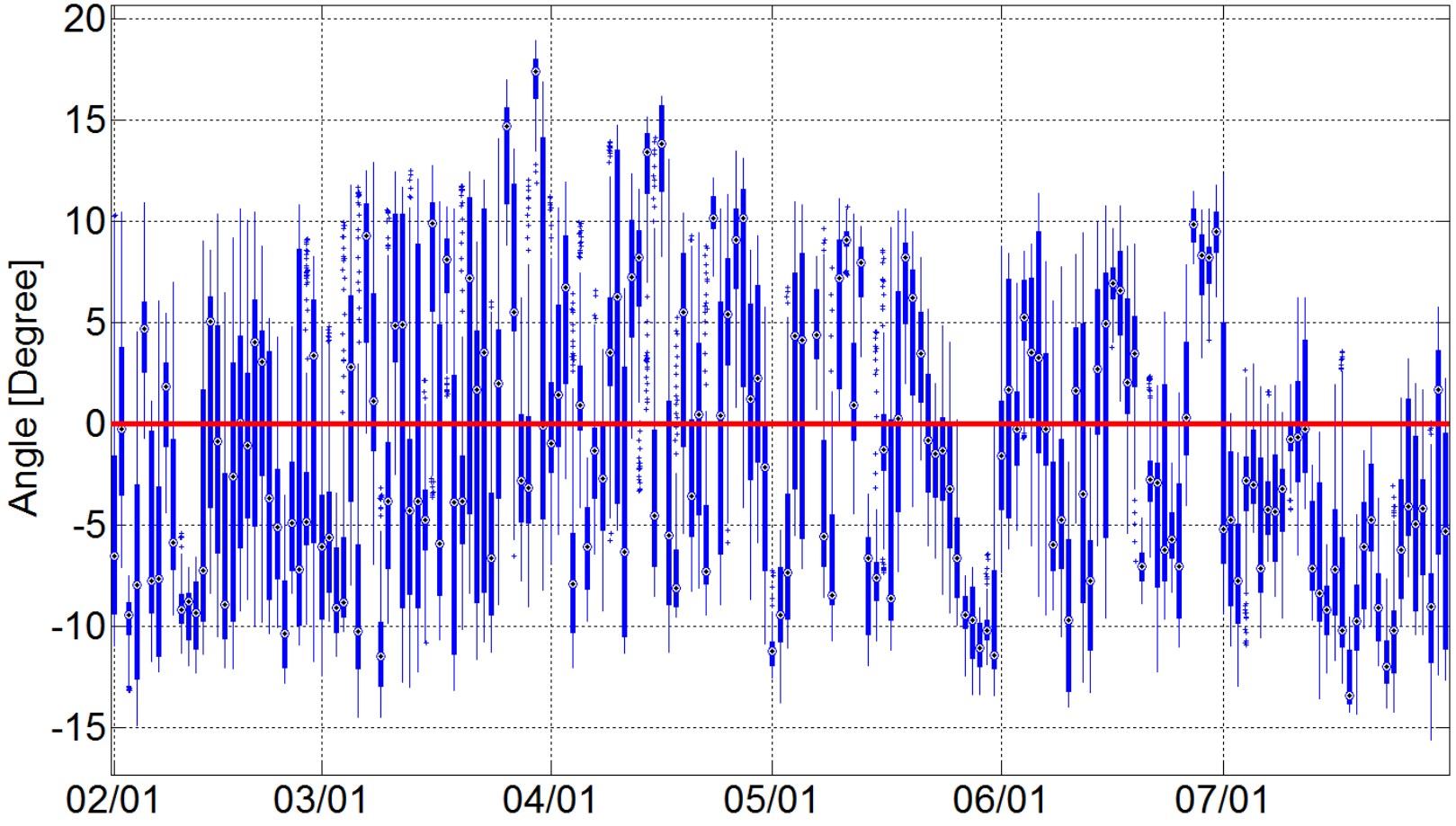
West 5-FarWest 4



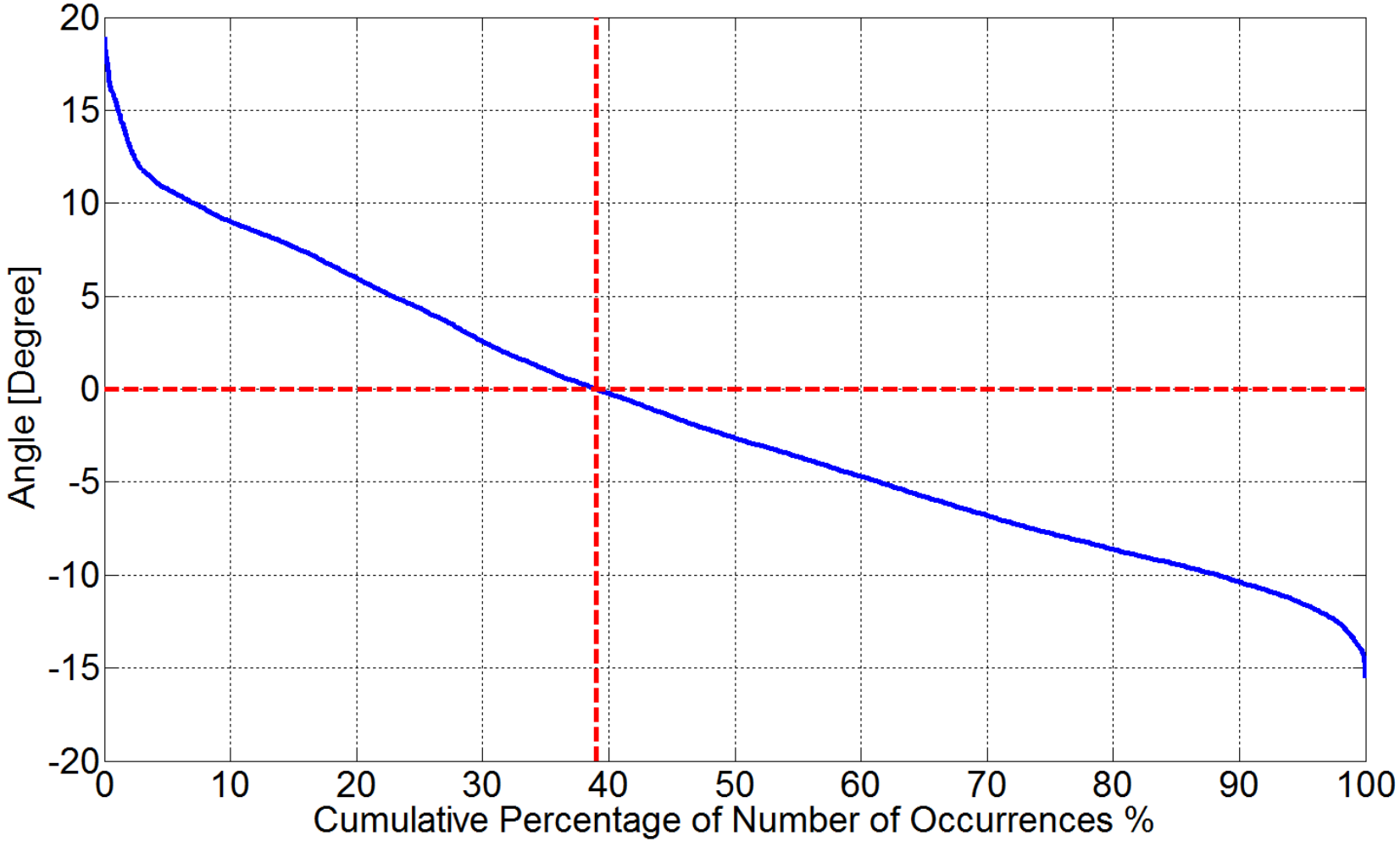
West 5-FarWest 4



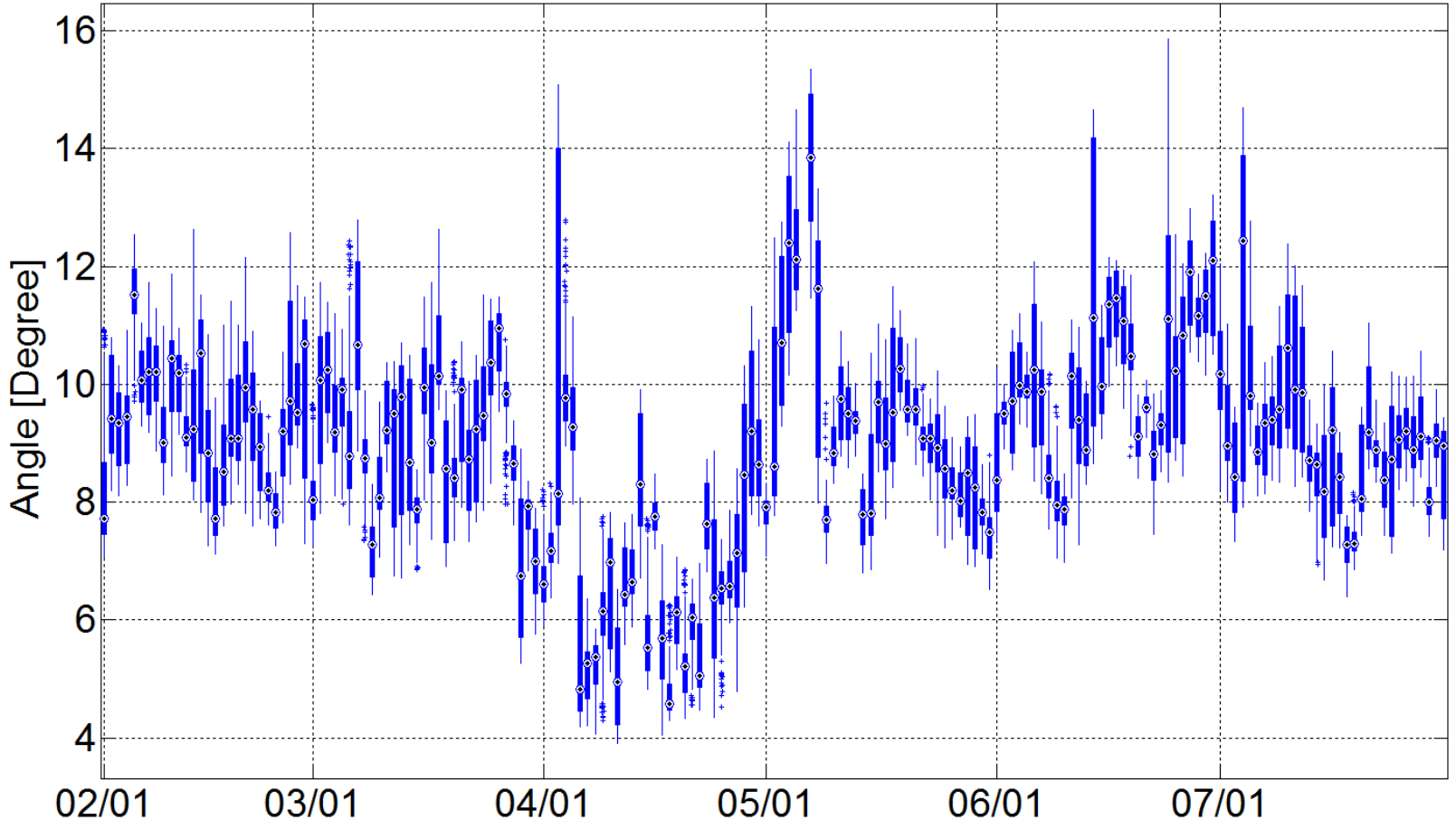
West 5-North 1



West 5-North 1



North 1-North 4



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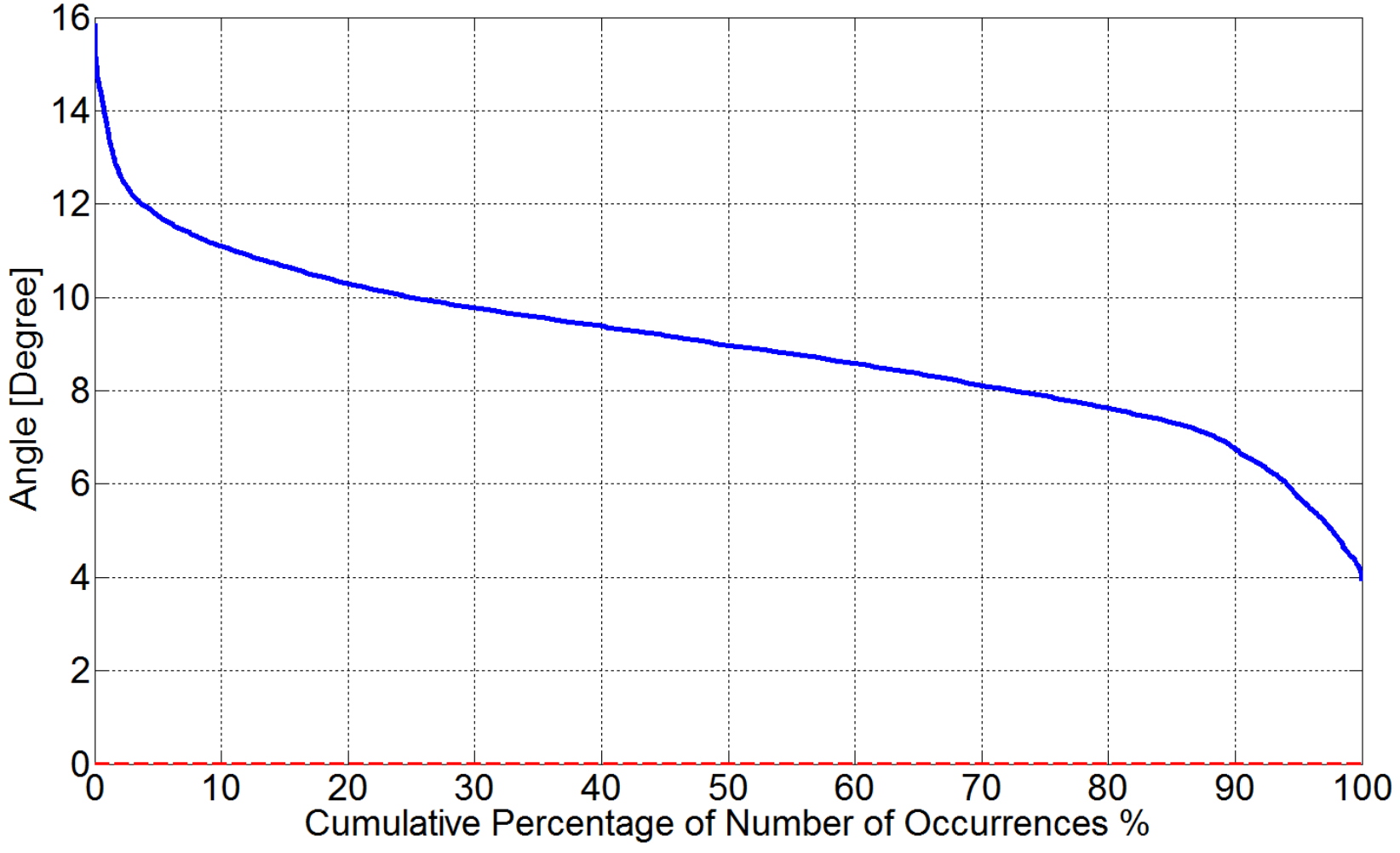
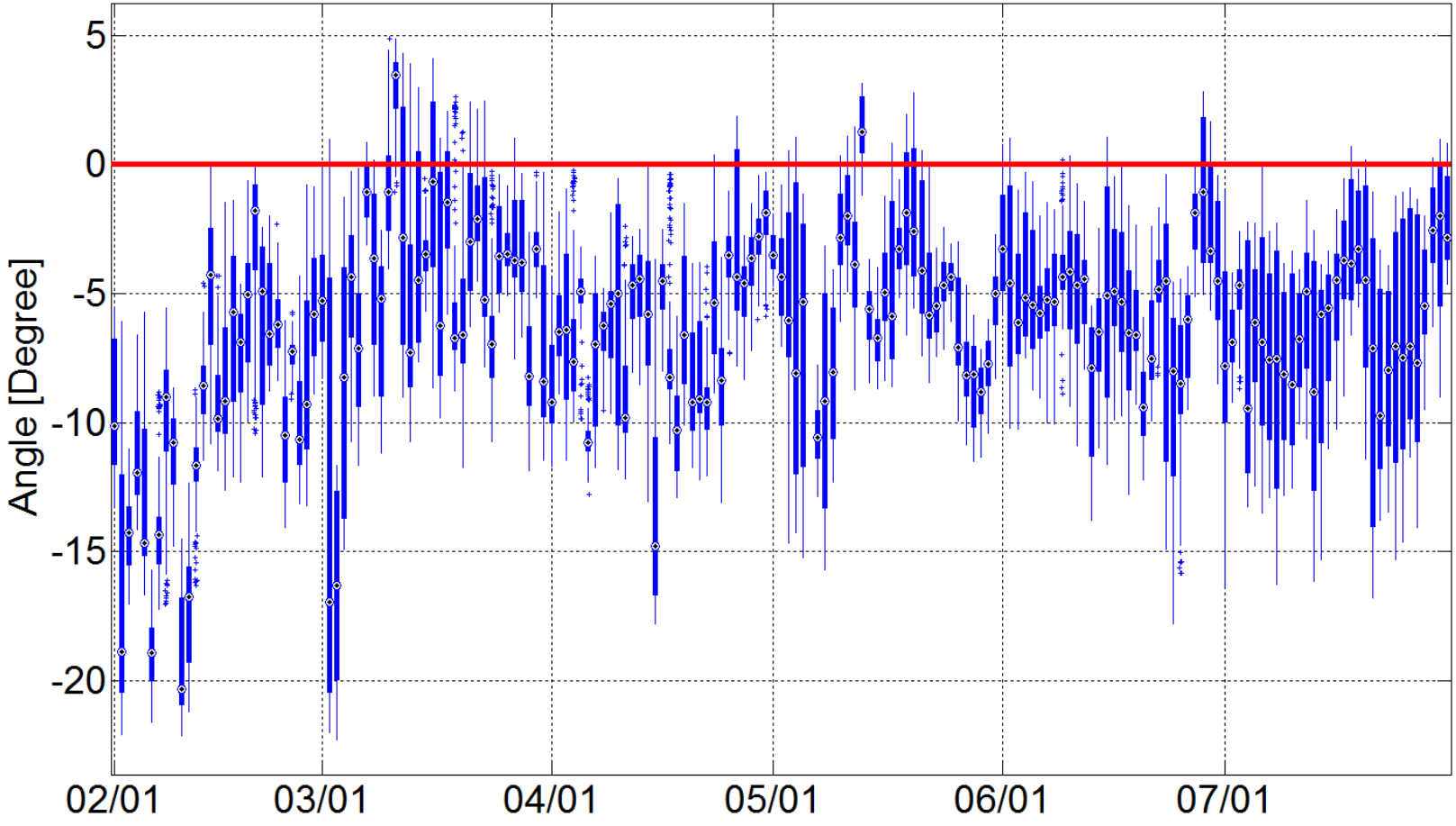
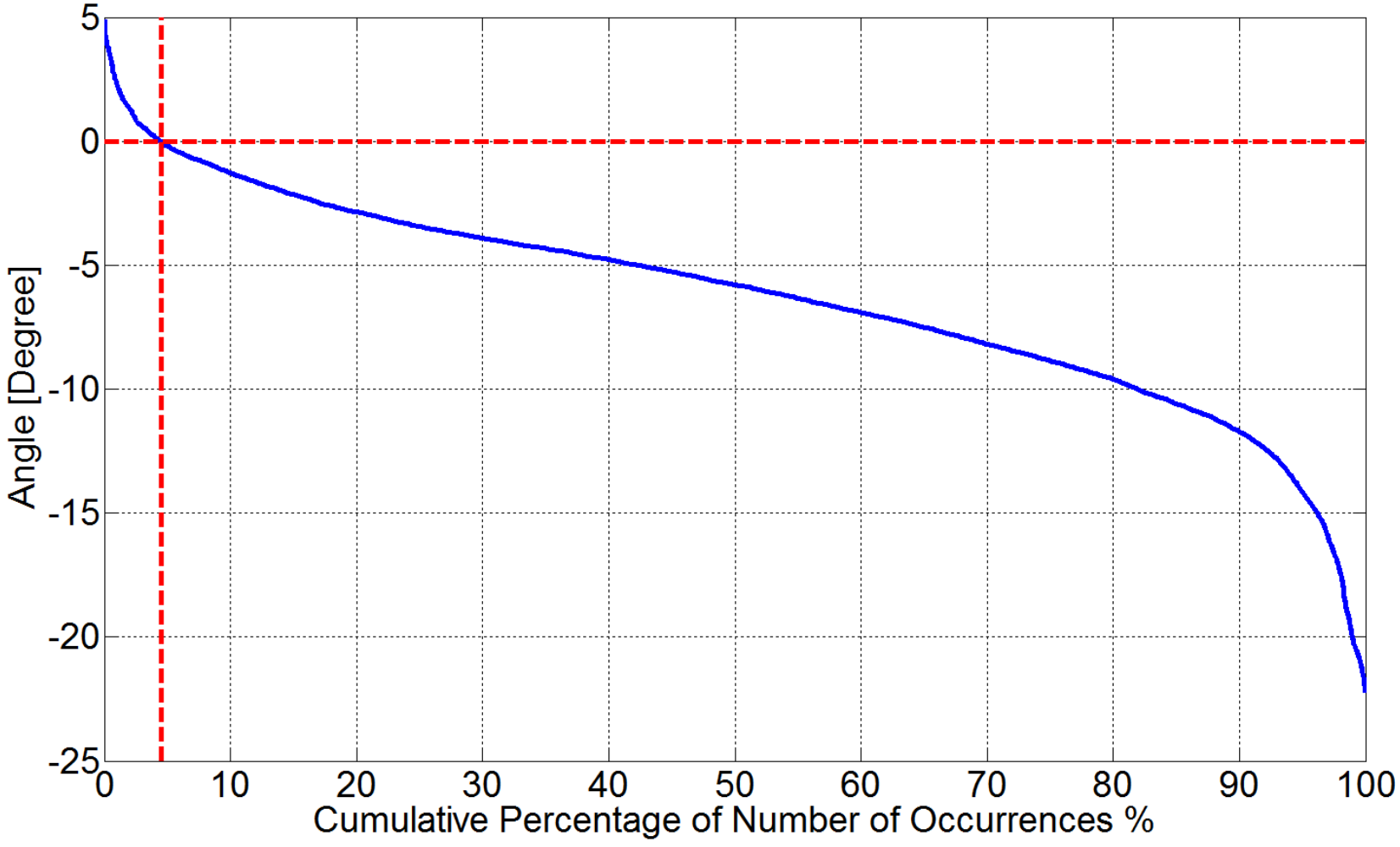


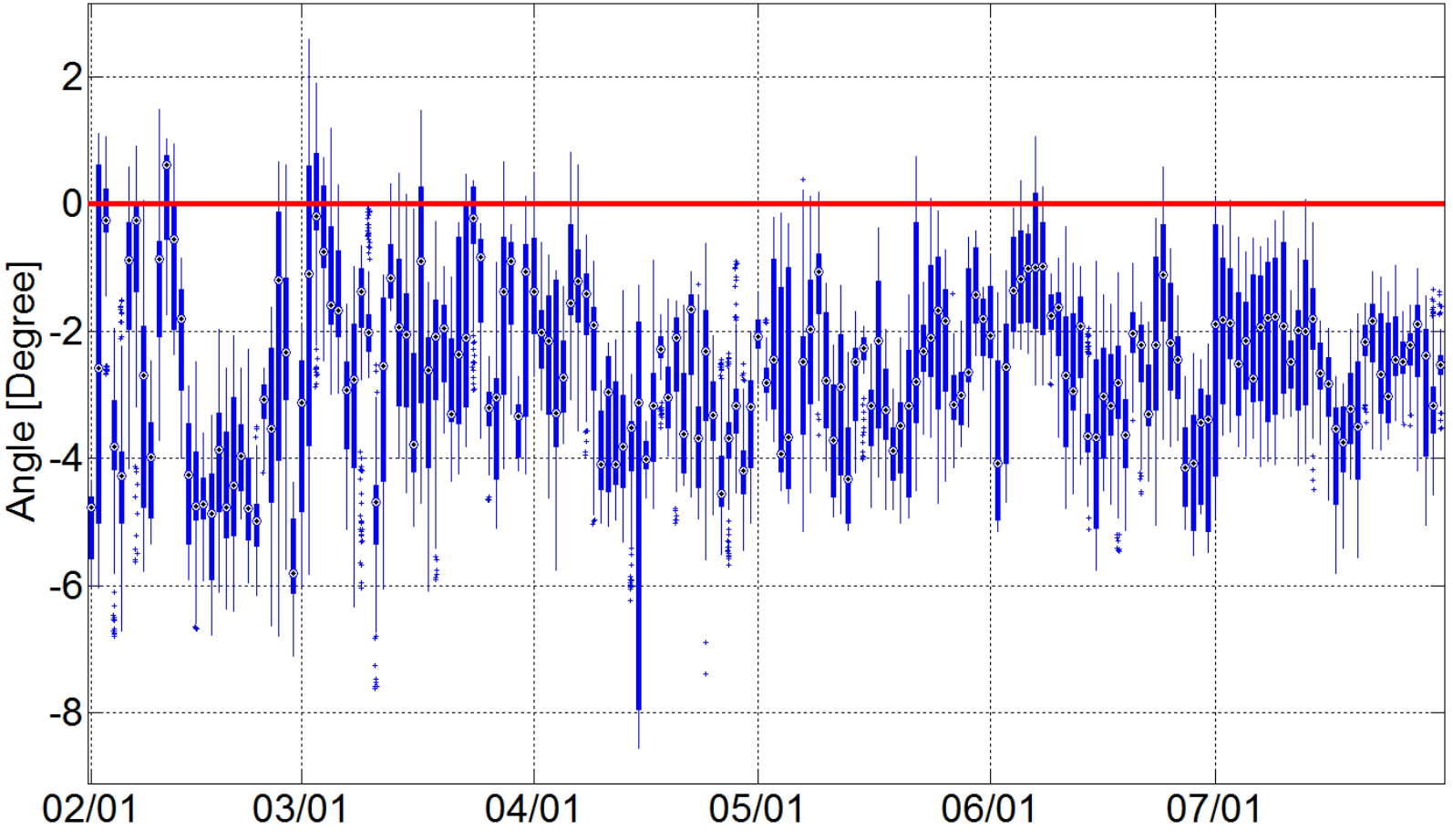
North 4-North 6



North 4-North 6



FarWest 7-FarWest 4



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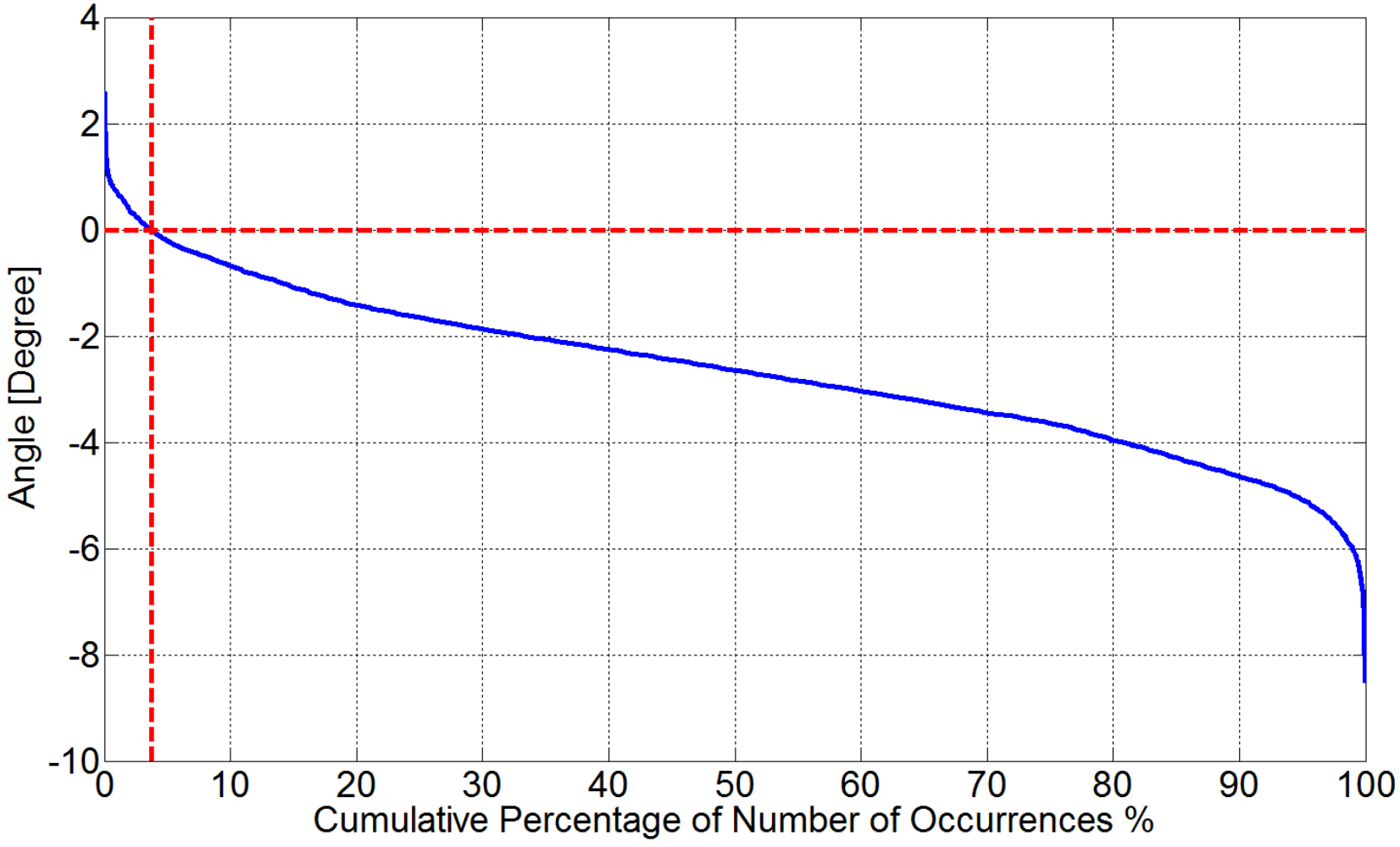

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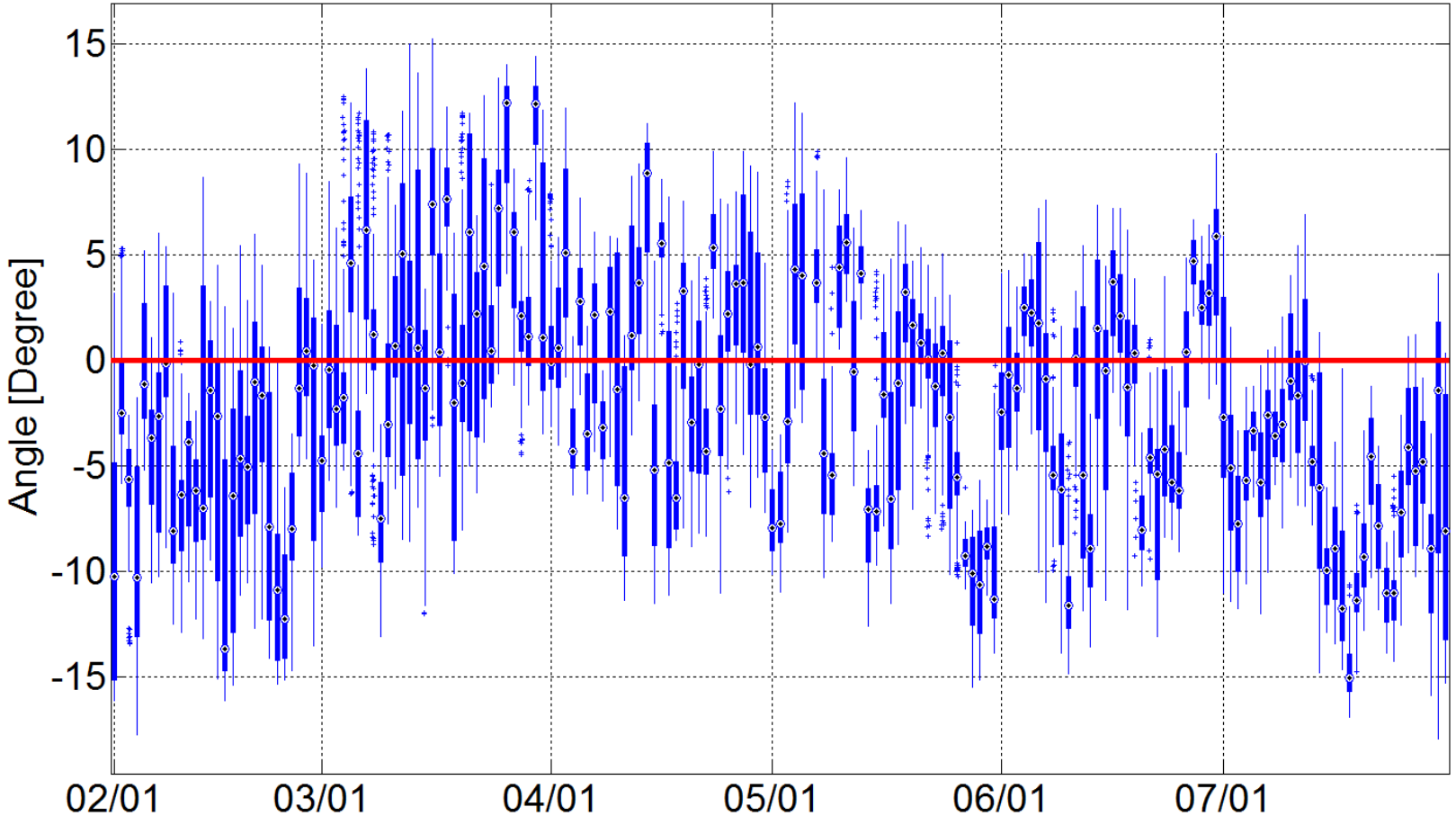
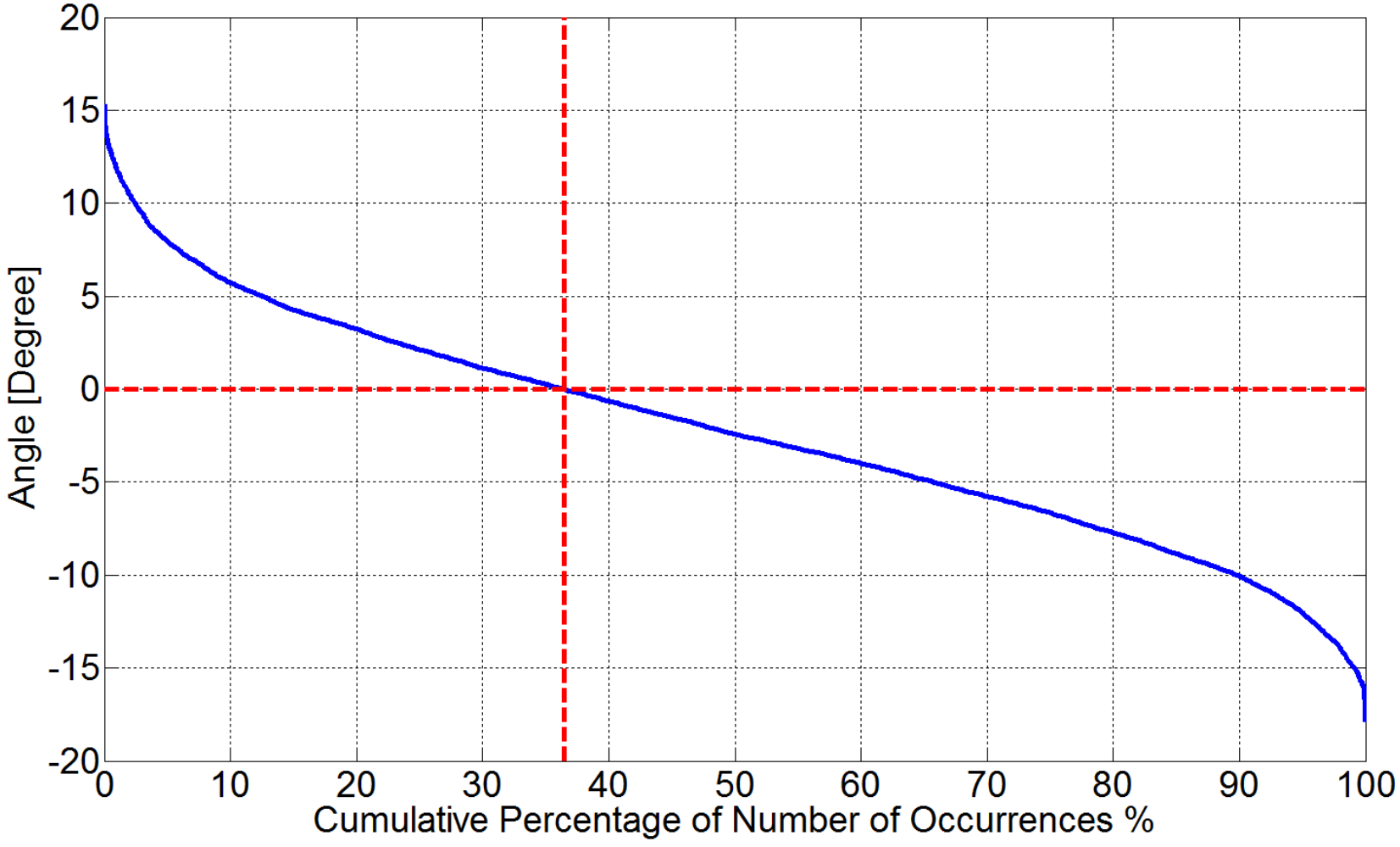


FarWest 7-West 14



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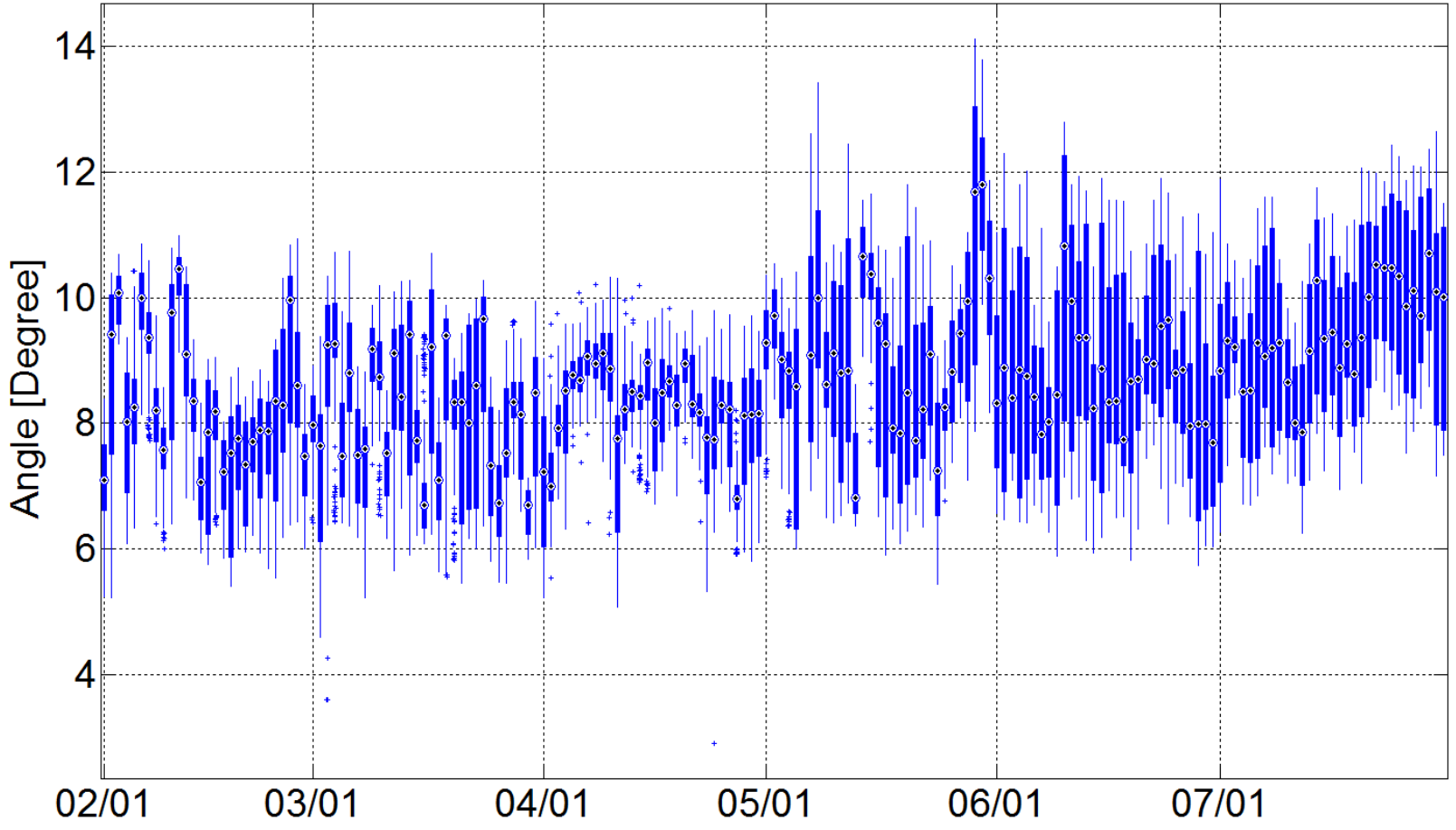

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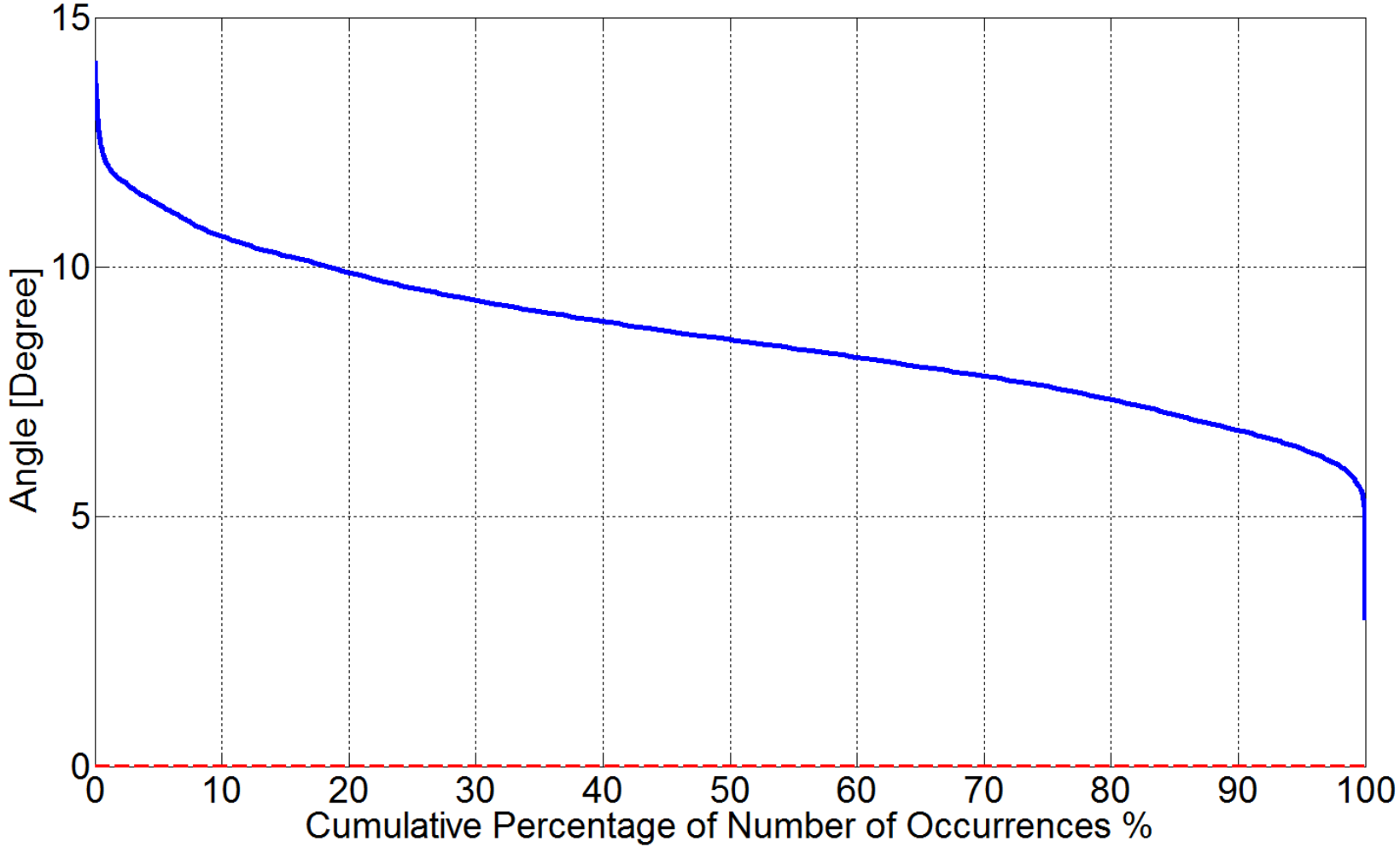

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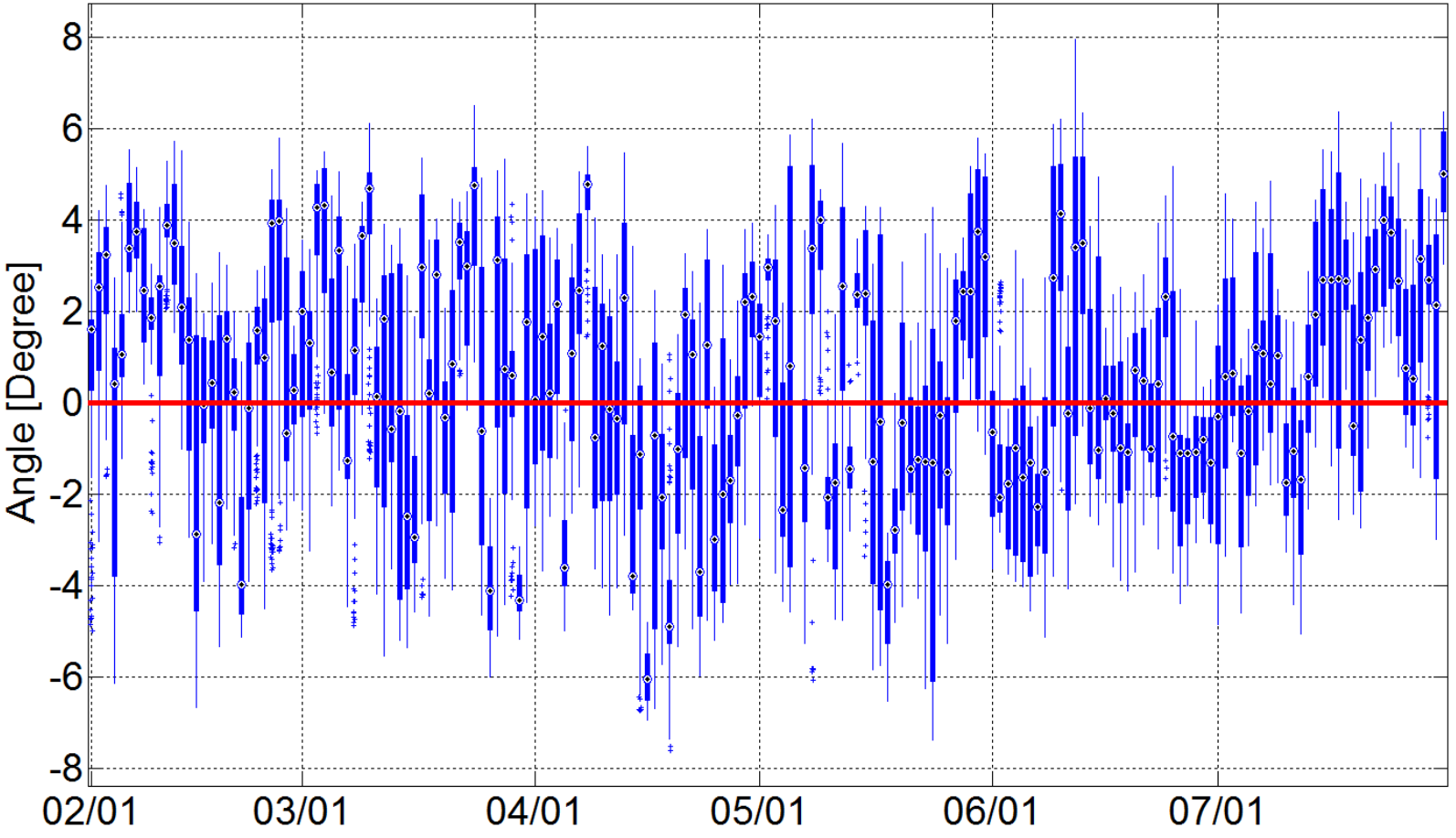

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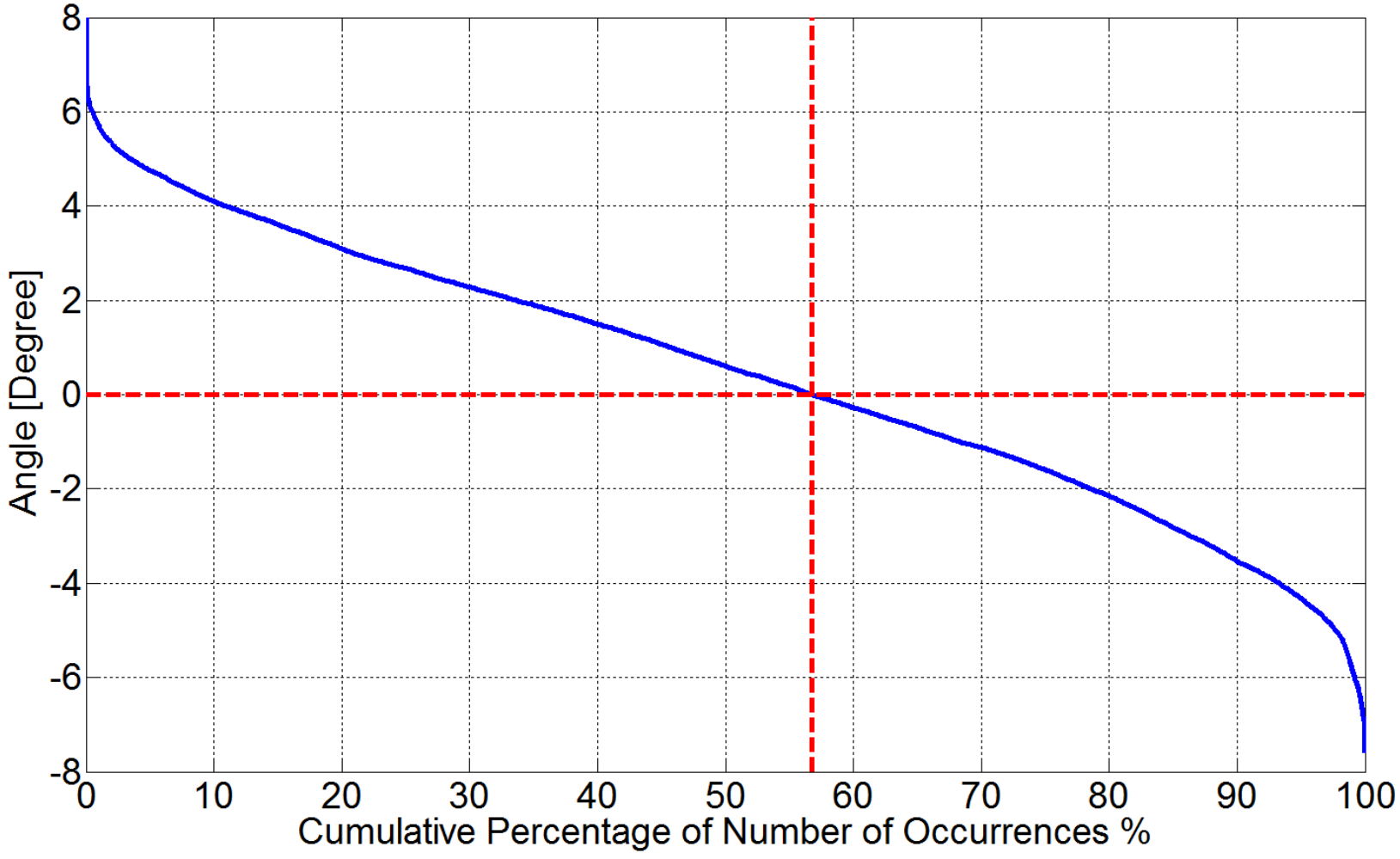
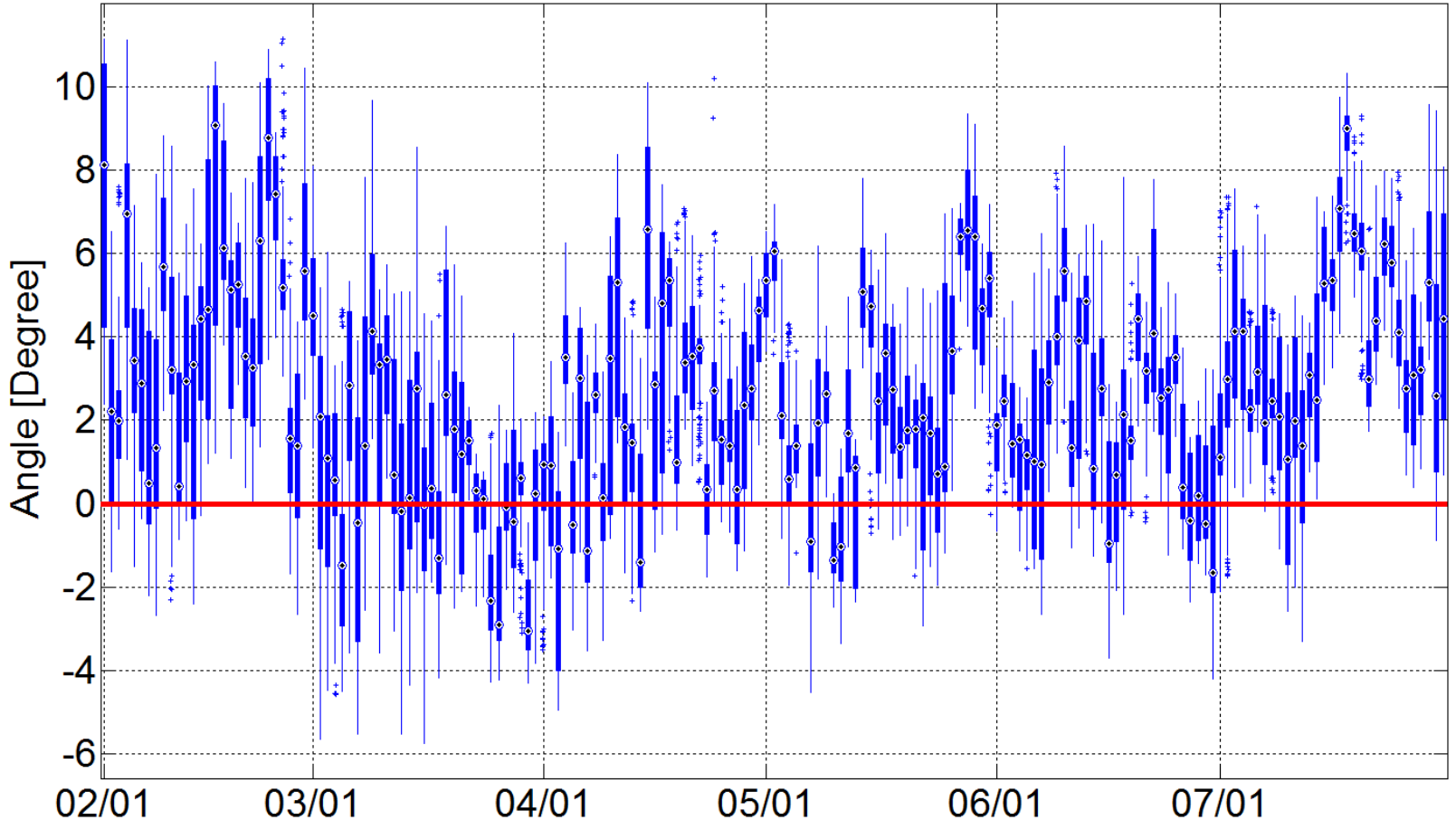


West 12-FarWest 7



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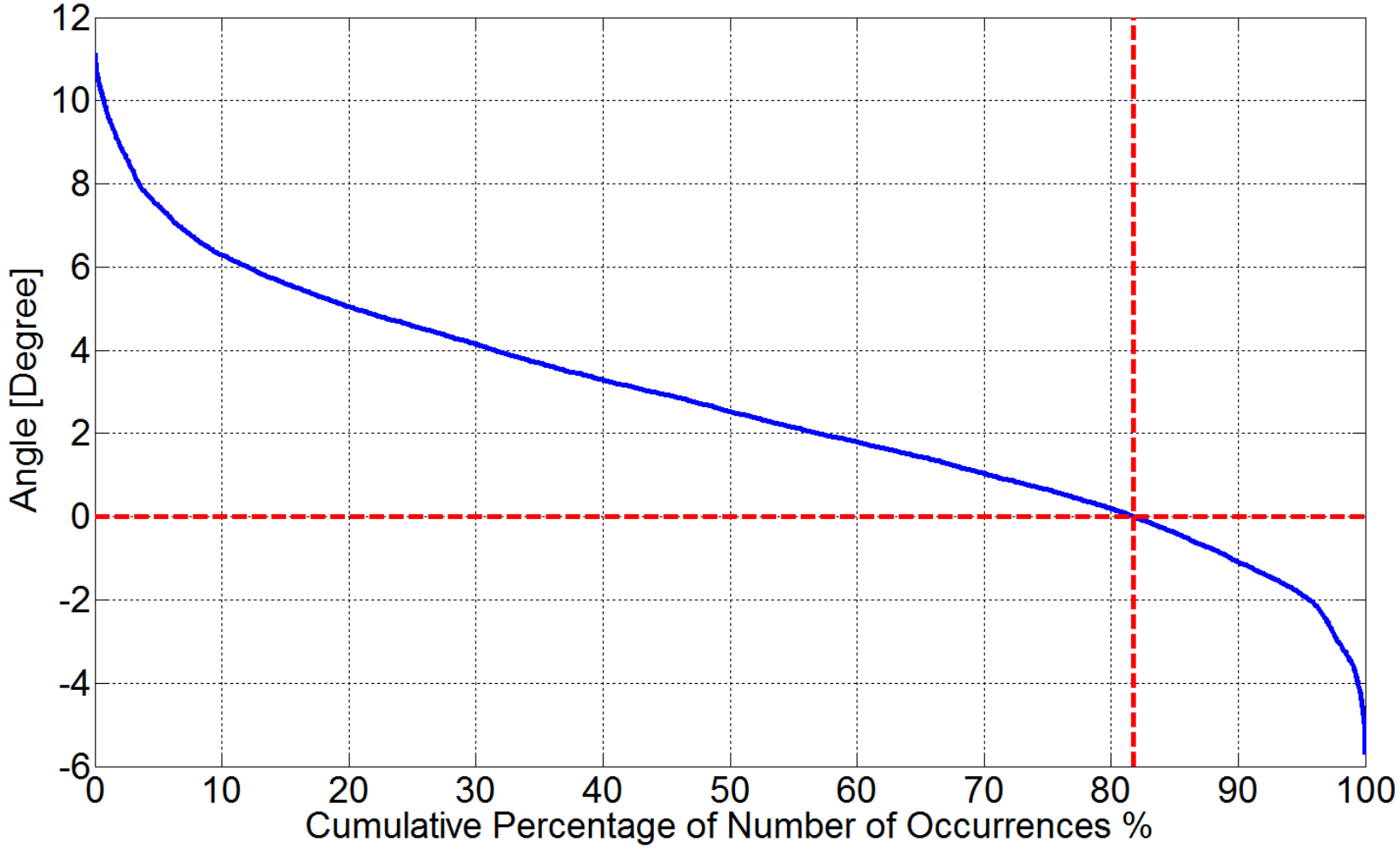
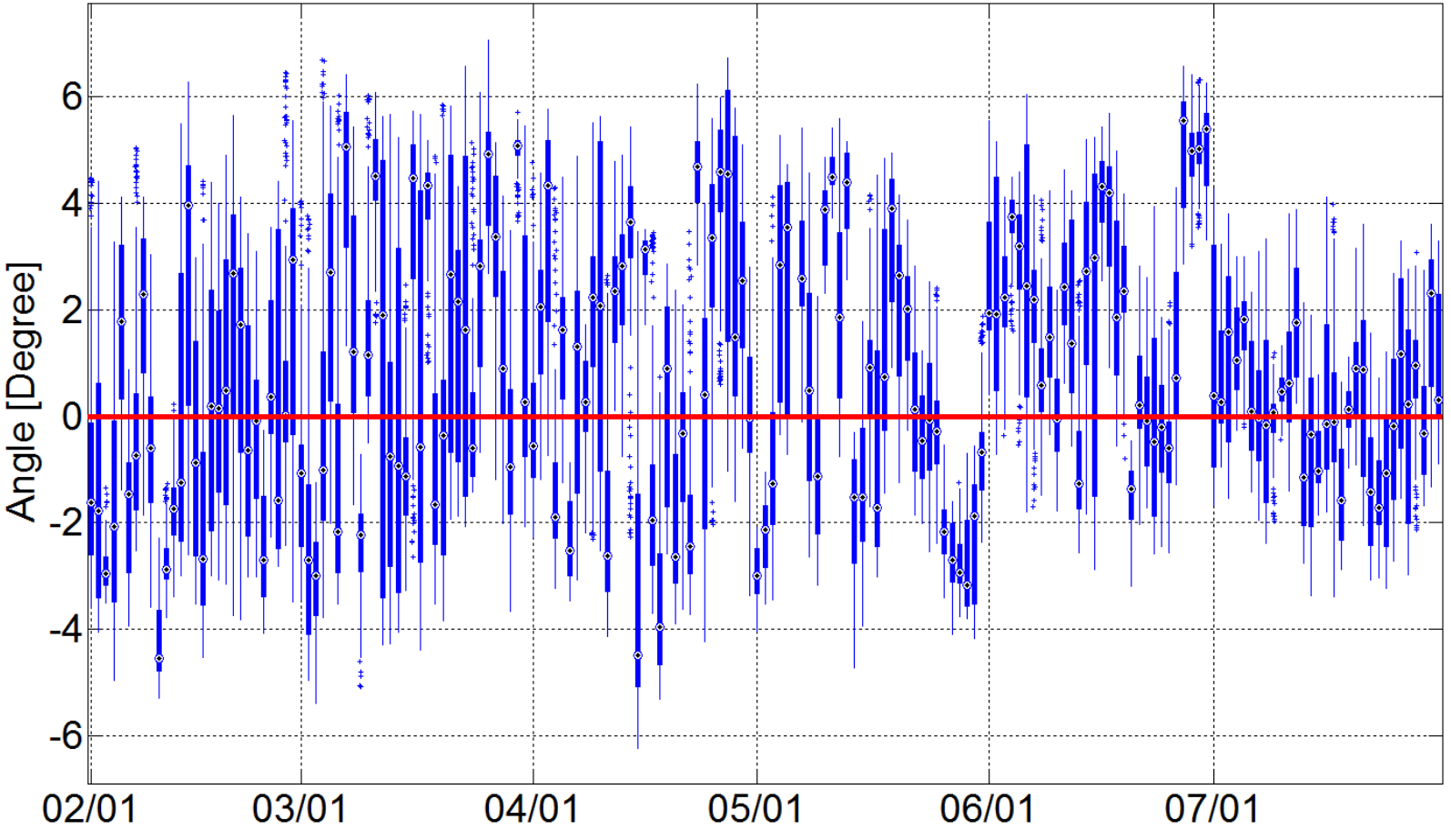
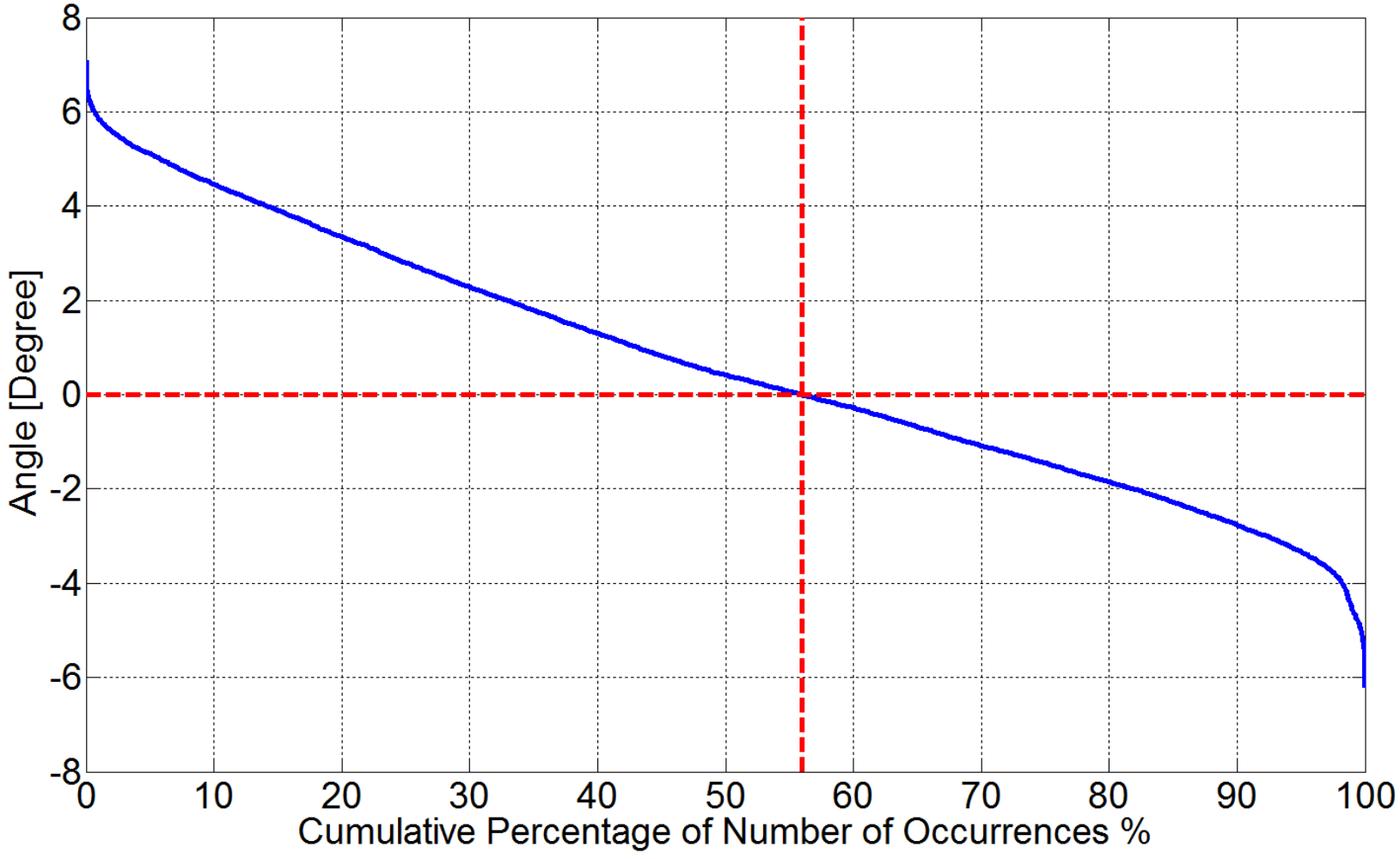


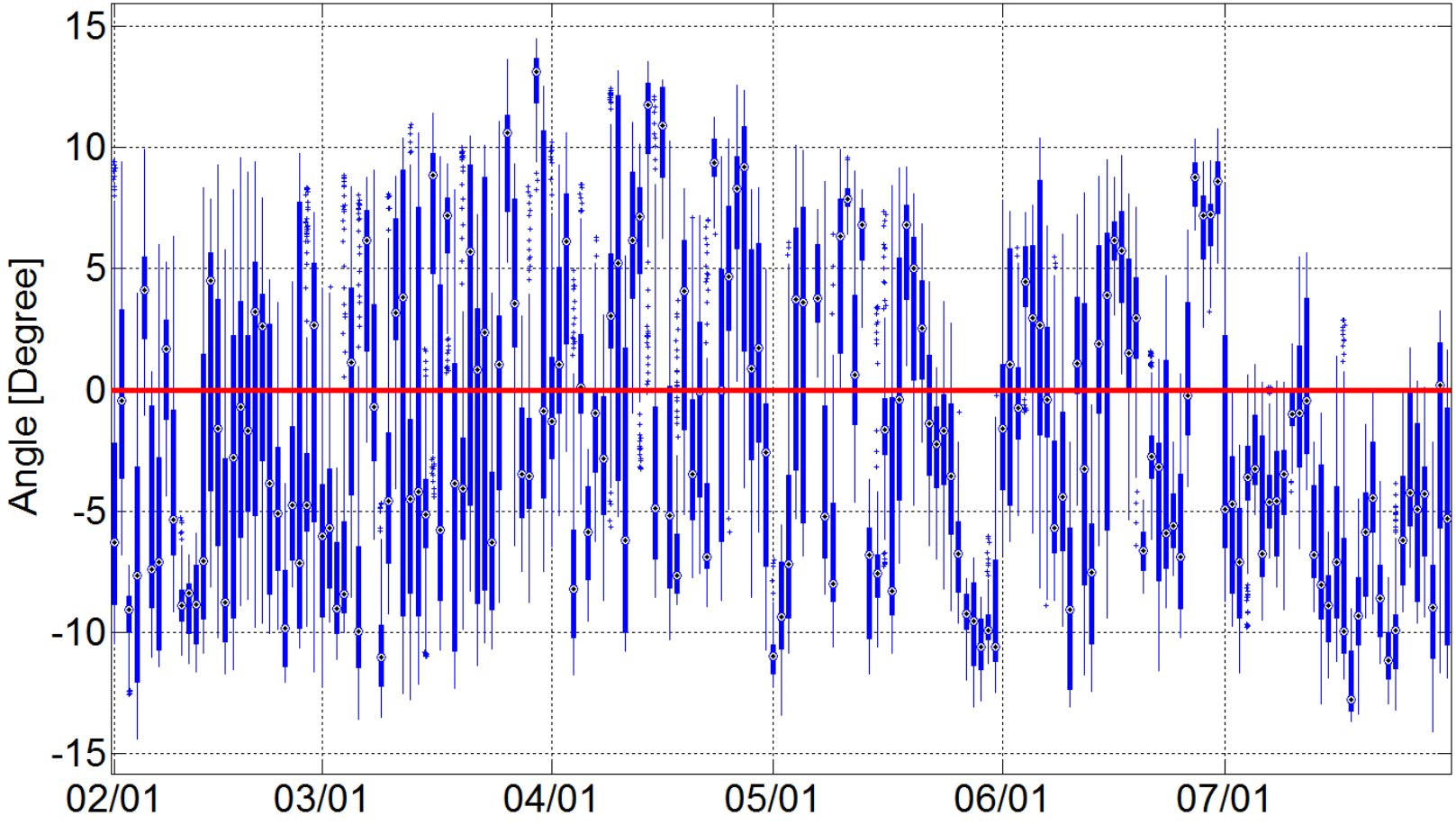
West 12-West 1



West 12-West 1



West 12-North 1



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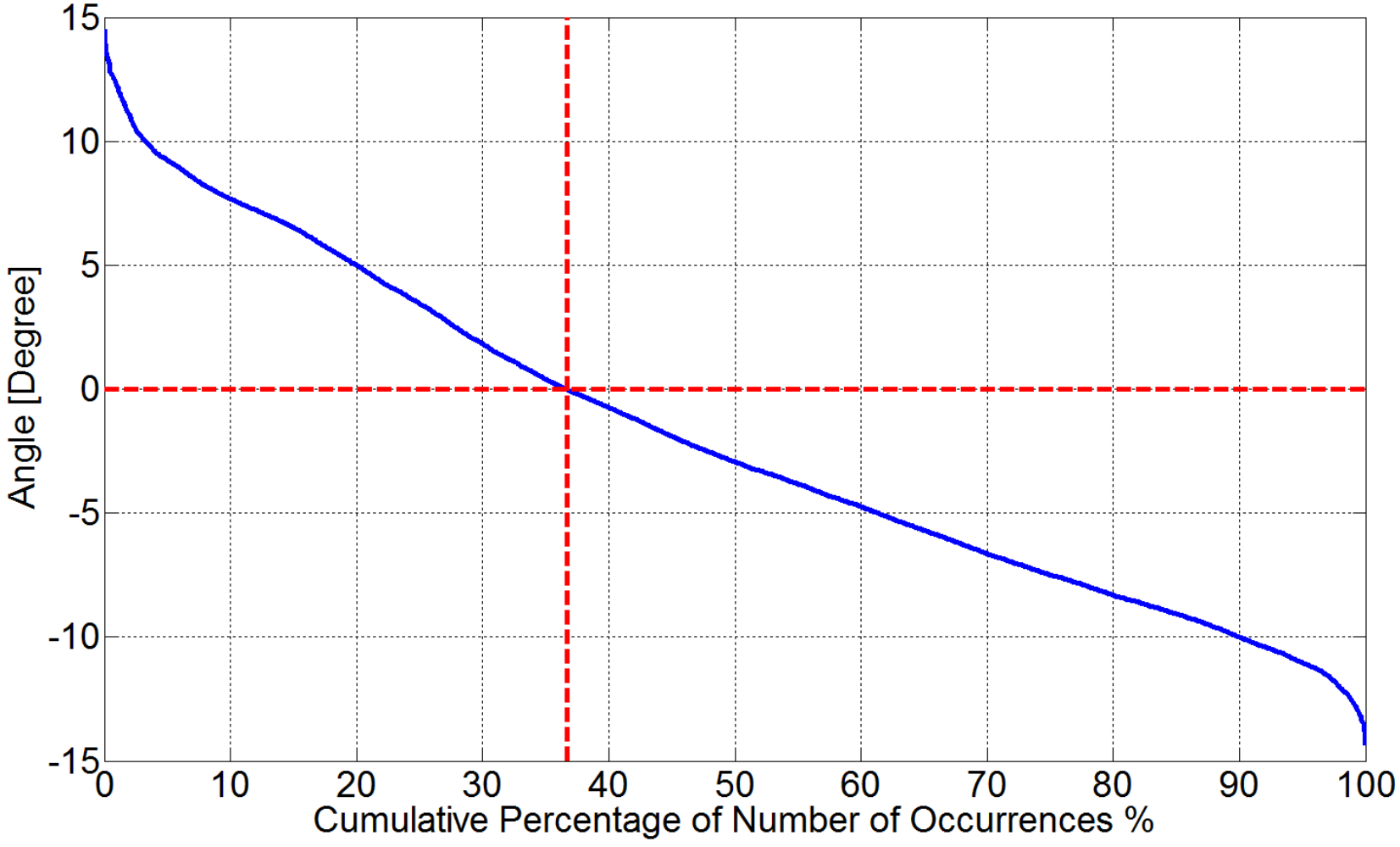

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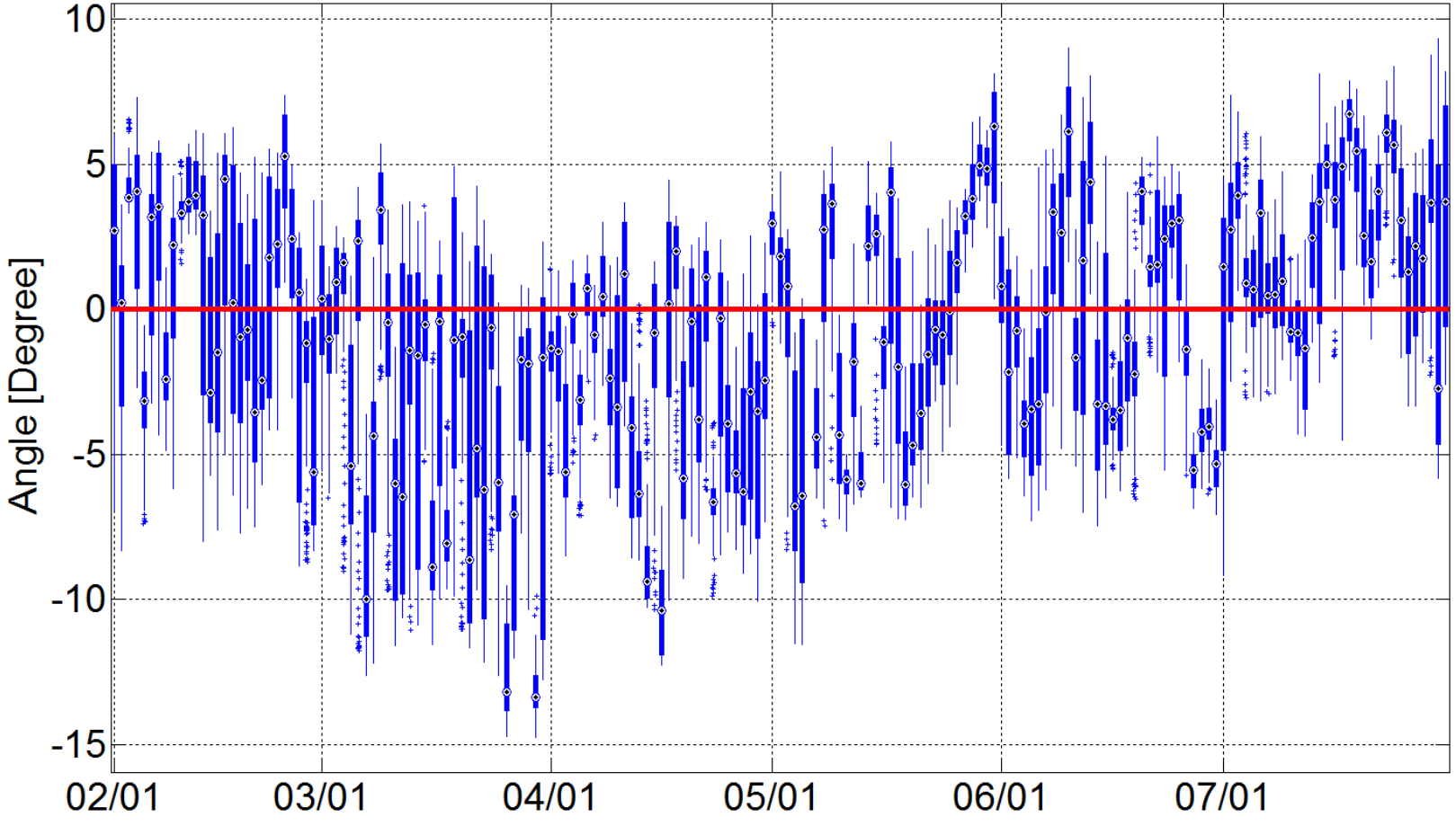

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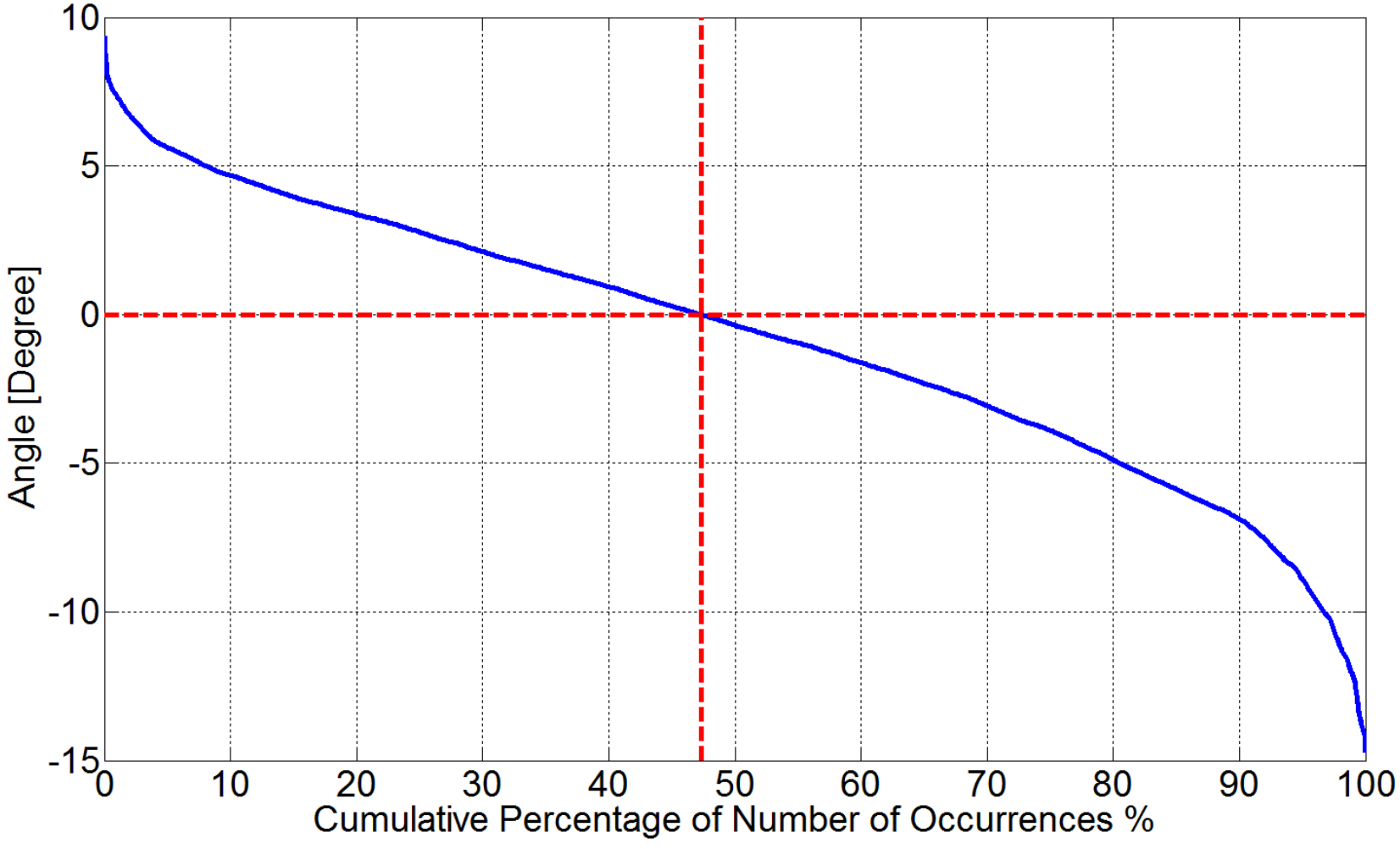

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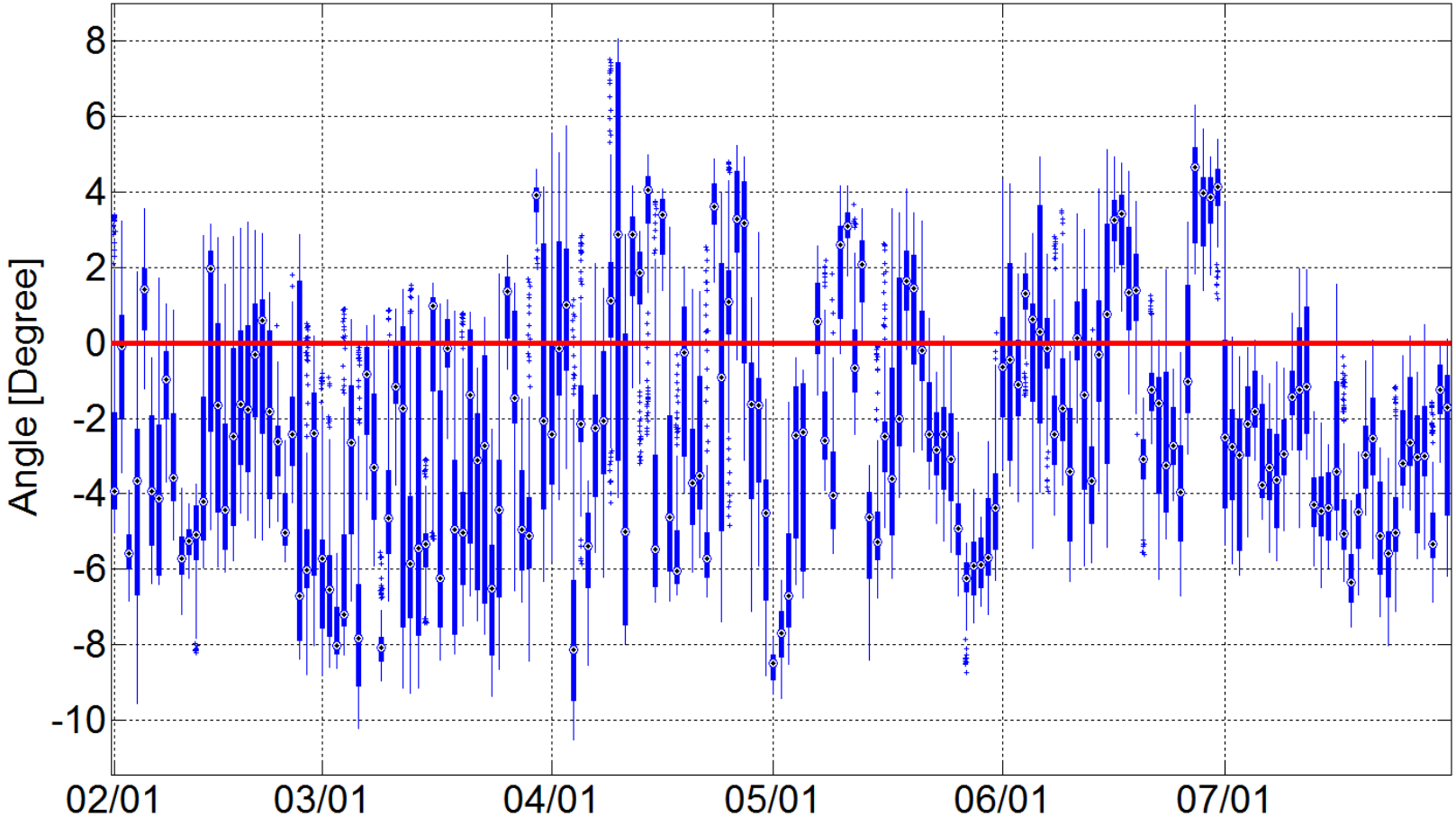

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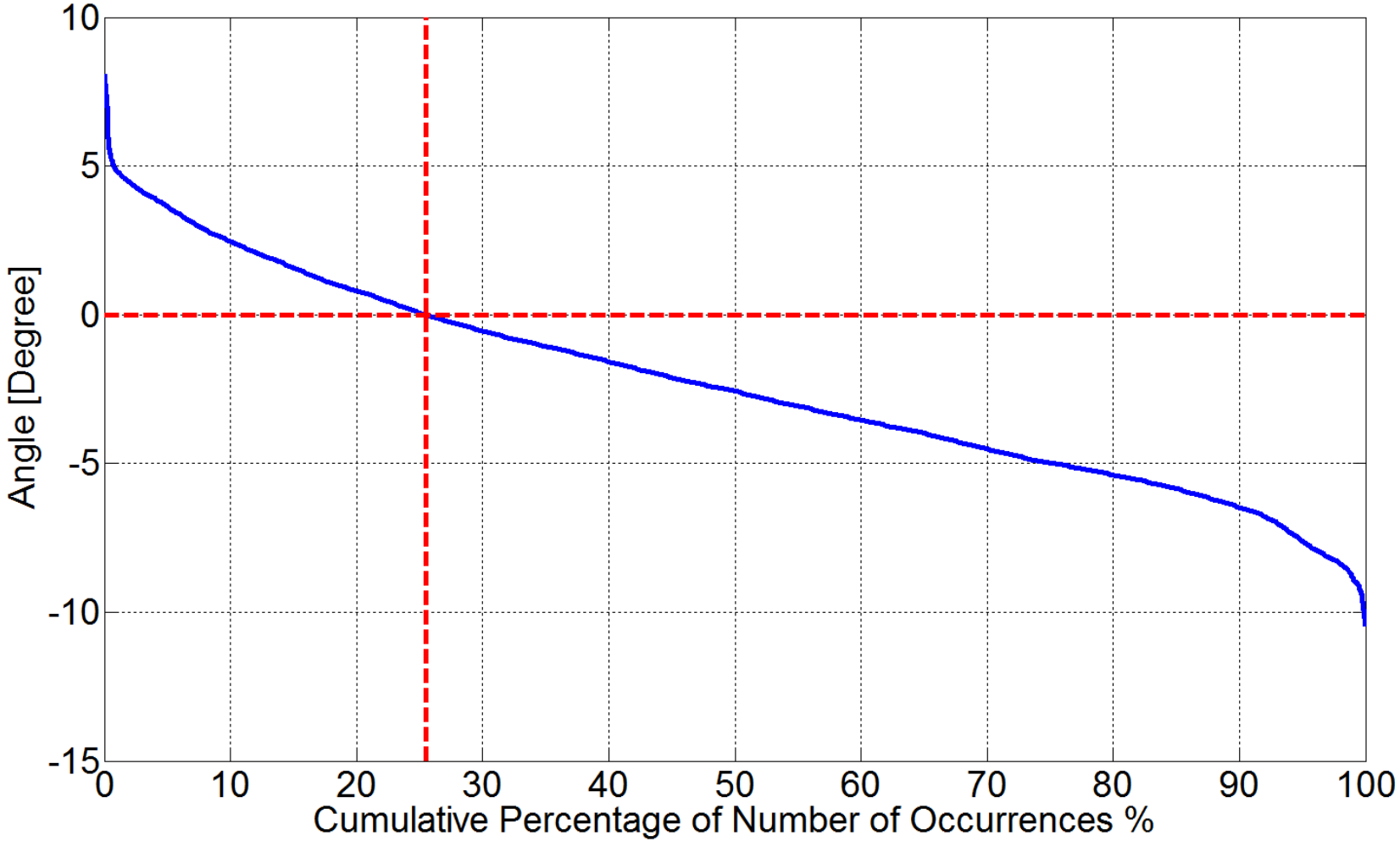
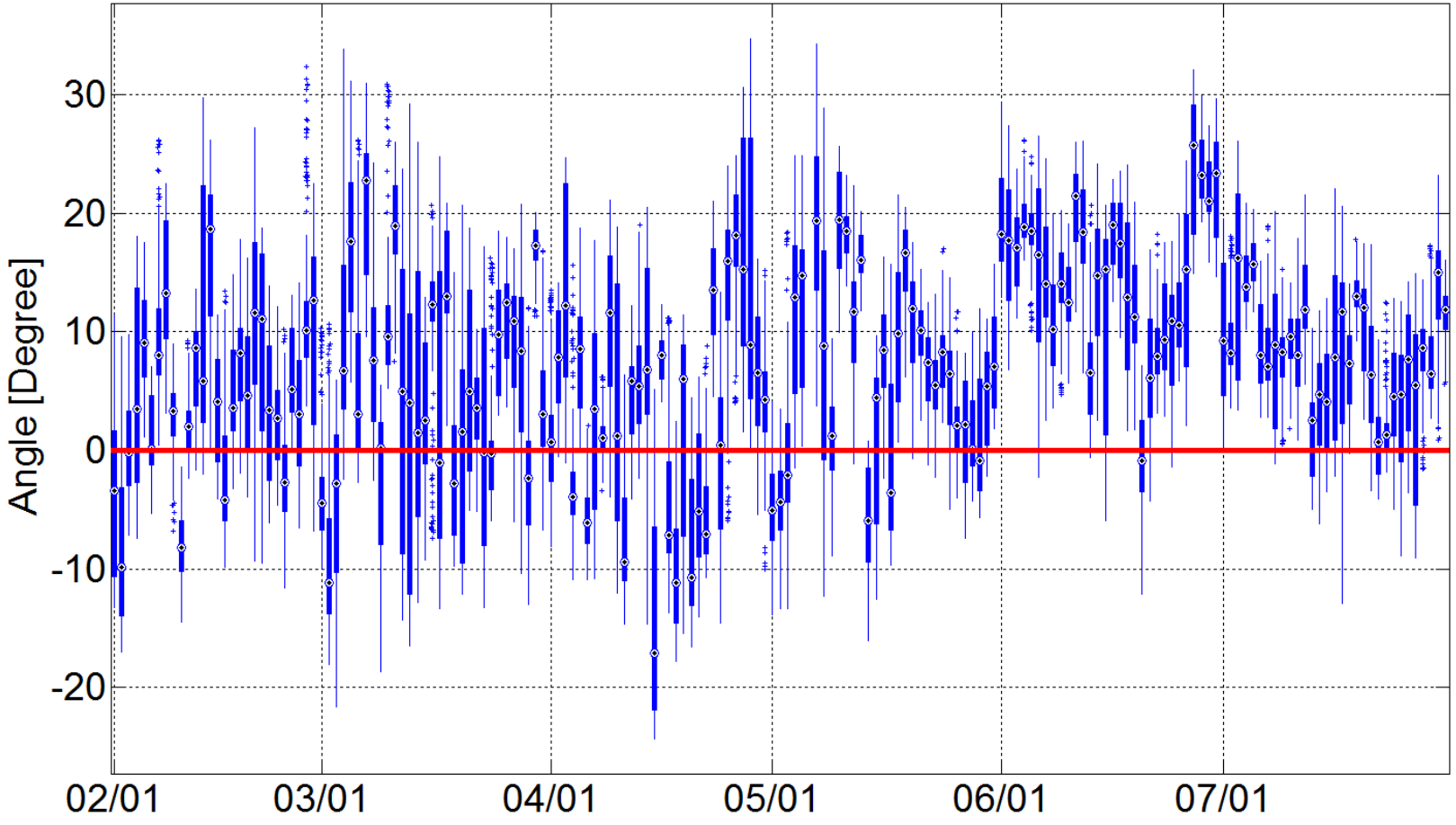
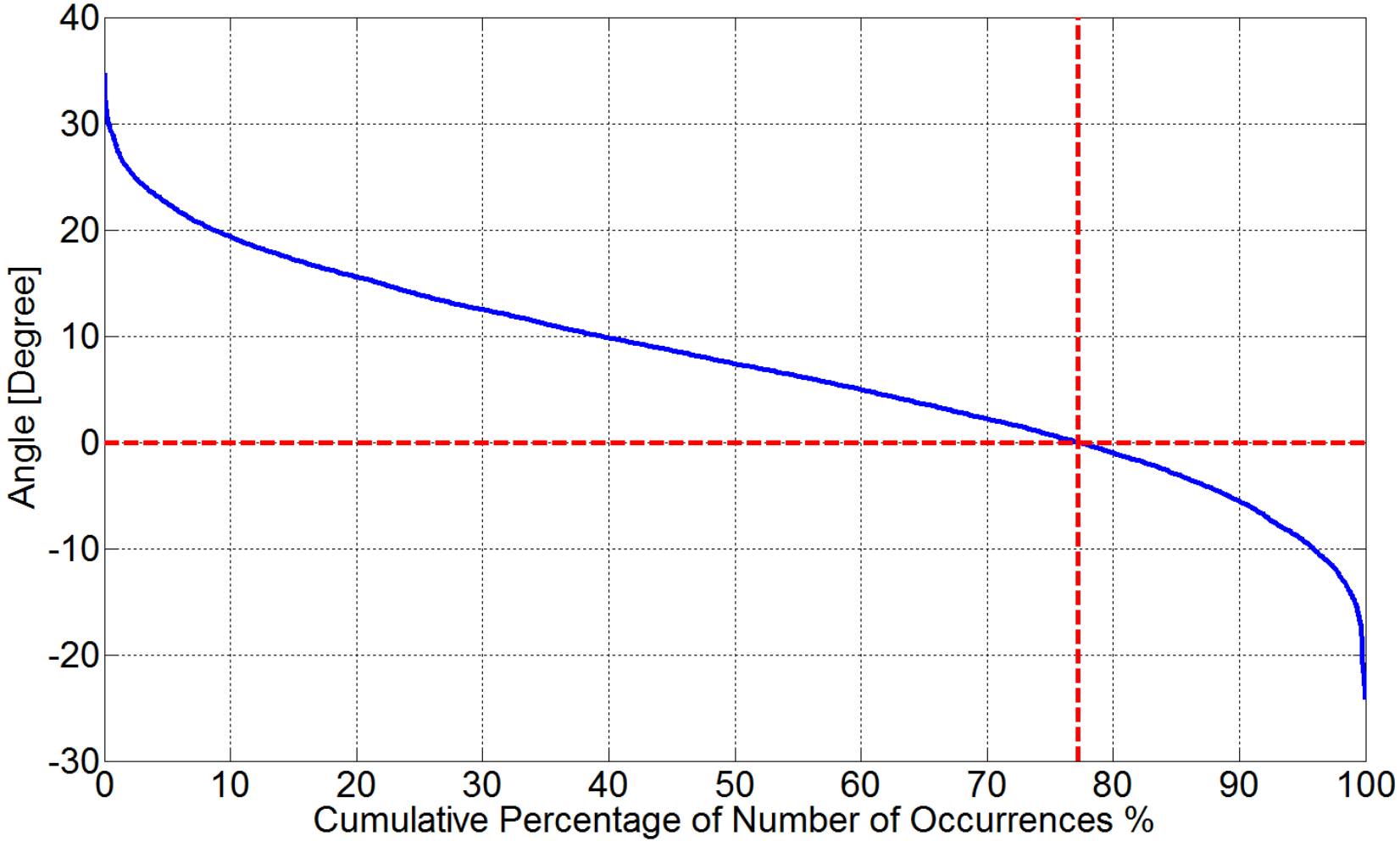


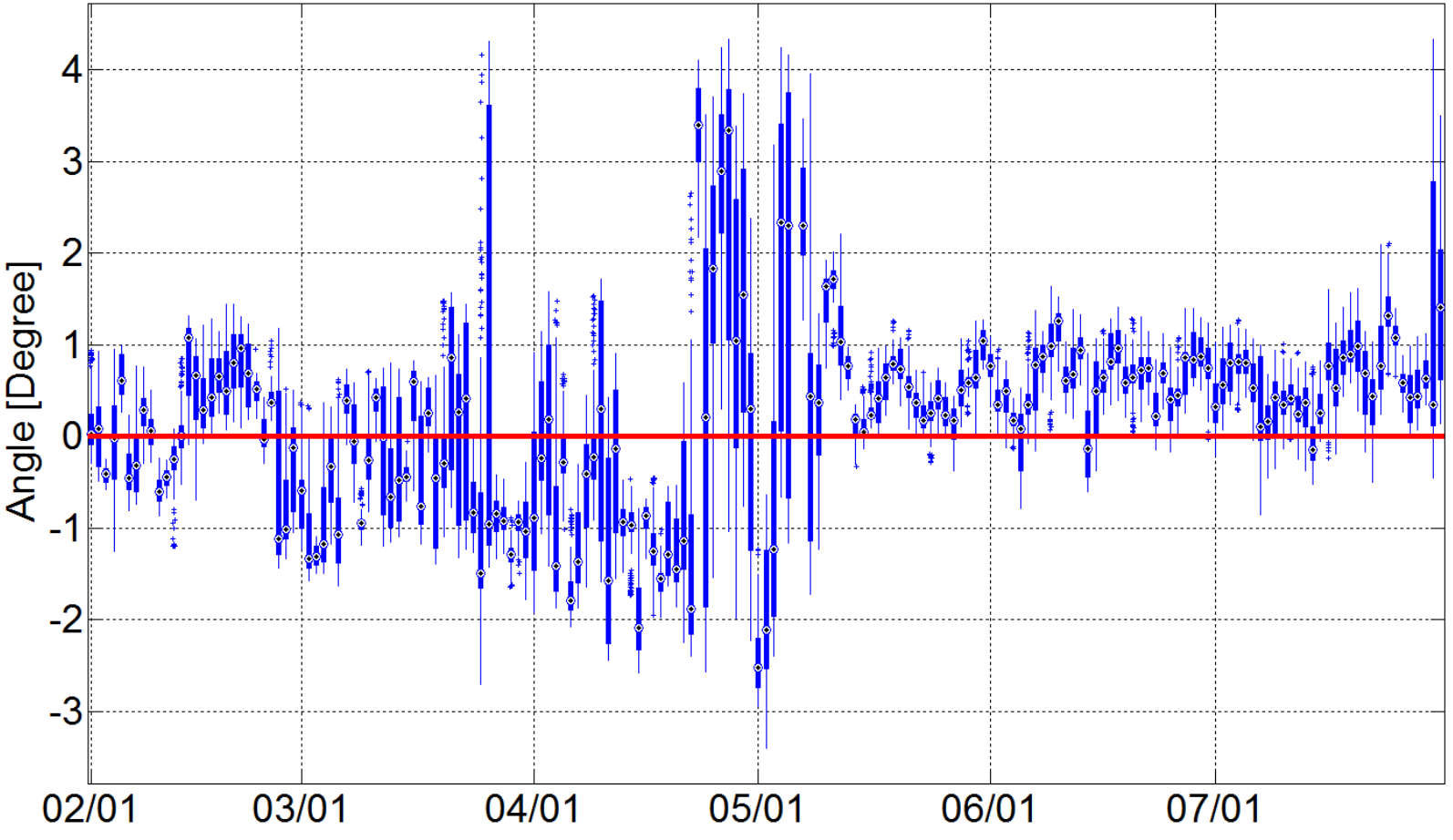
FarWest 9-West 4



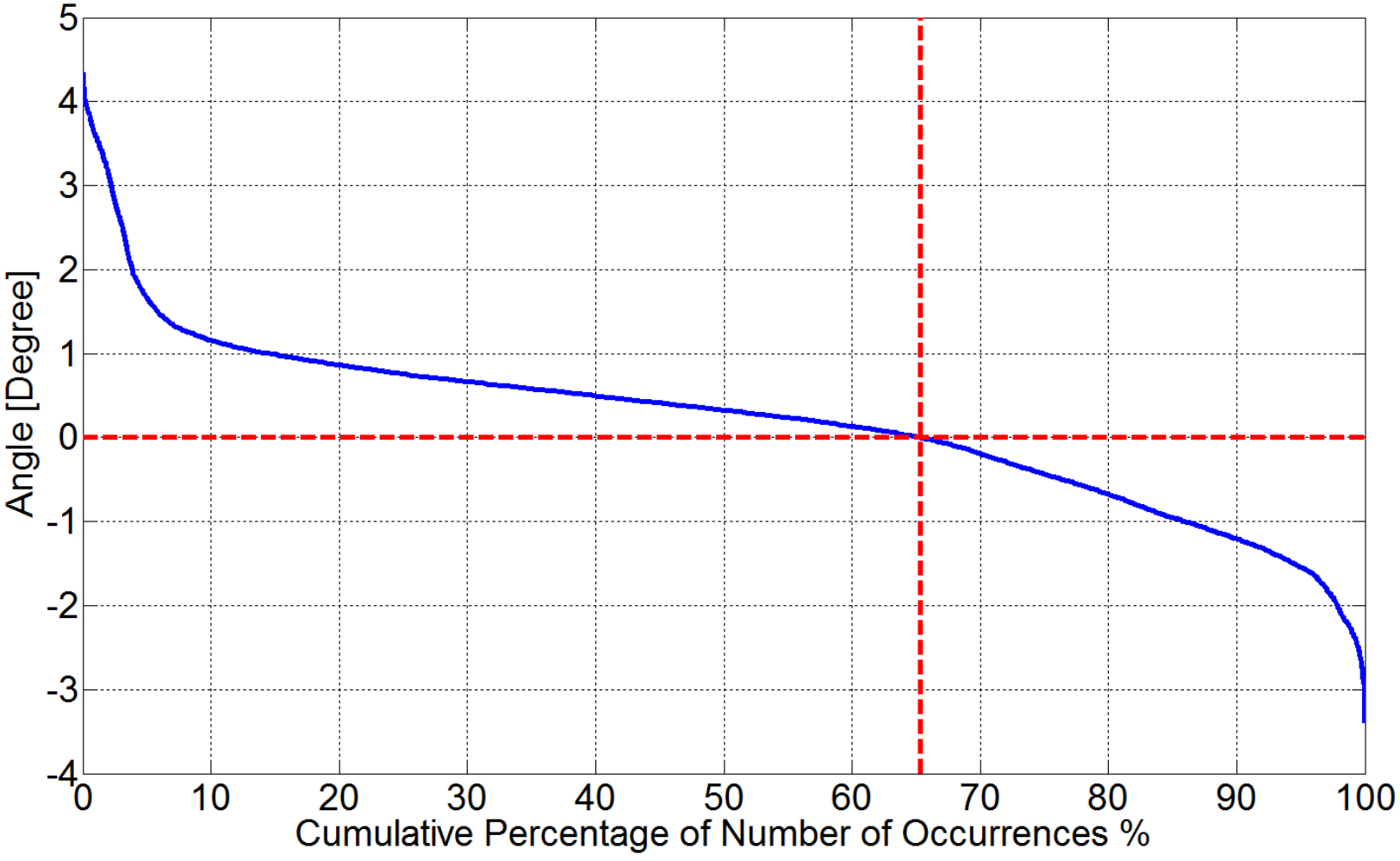
FarWest 9-West 4



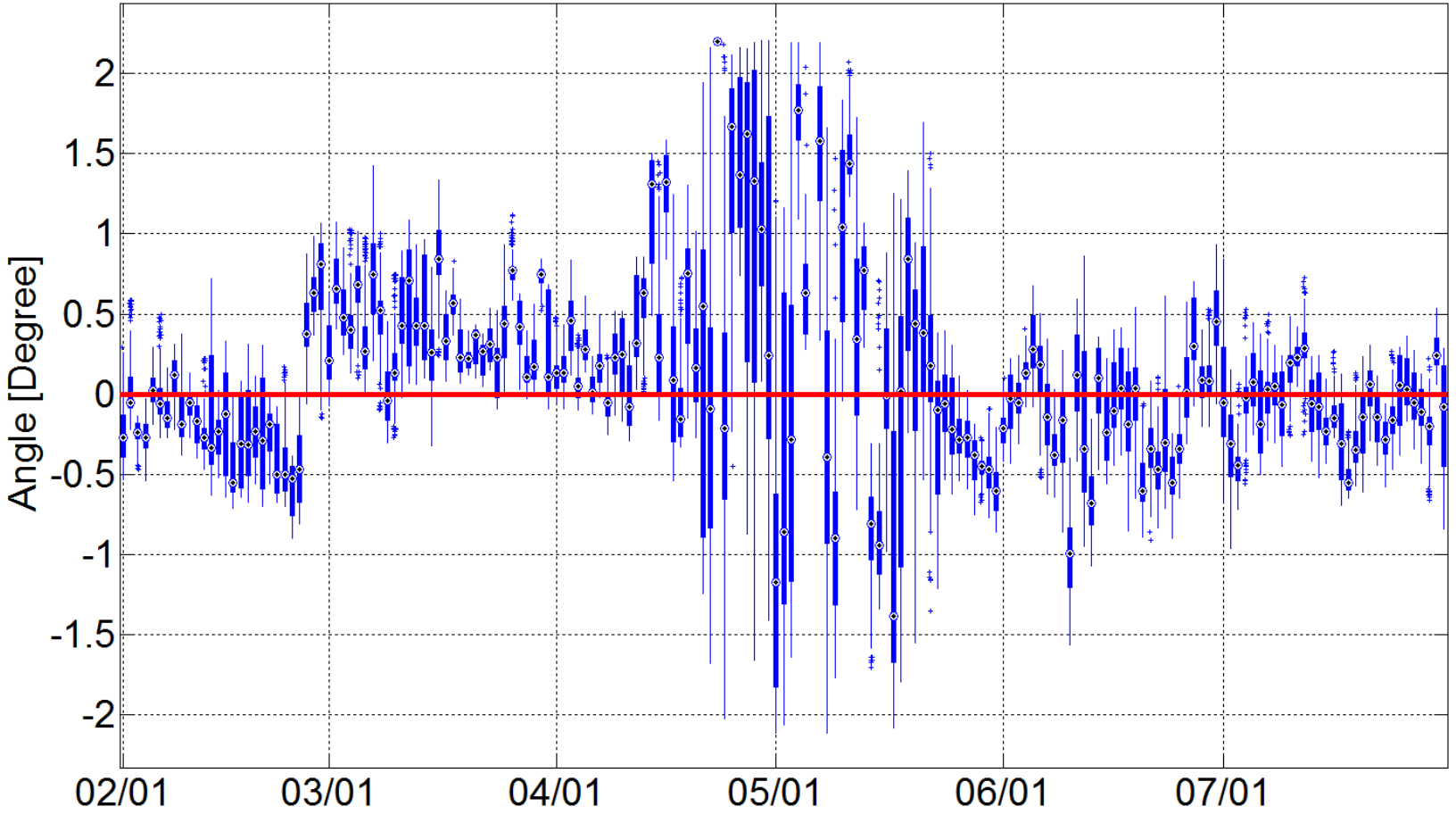
West 16-West 3



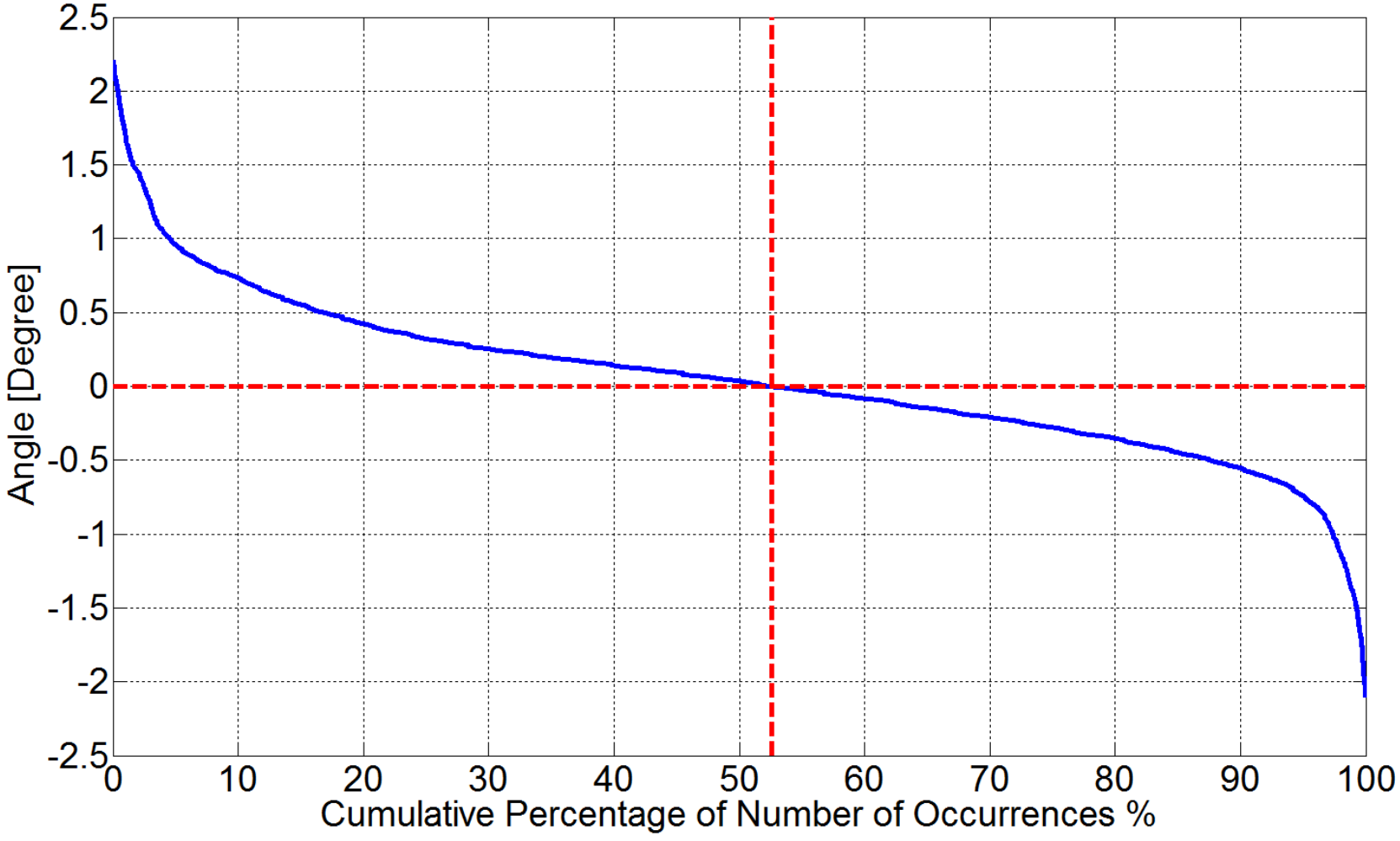
West 16-West 3



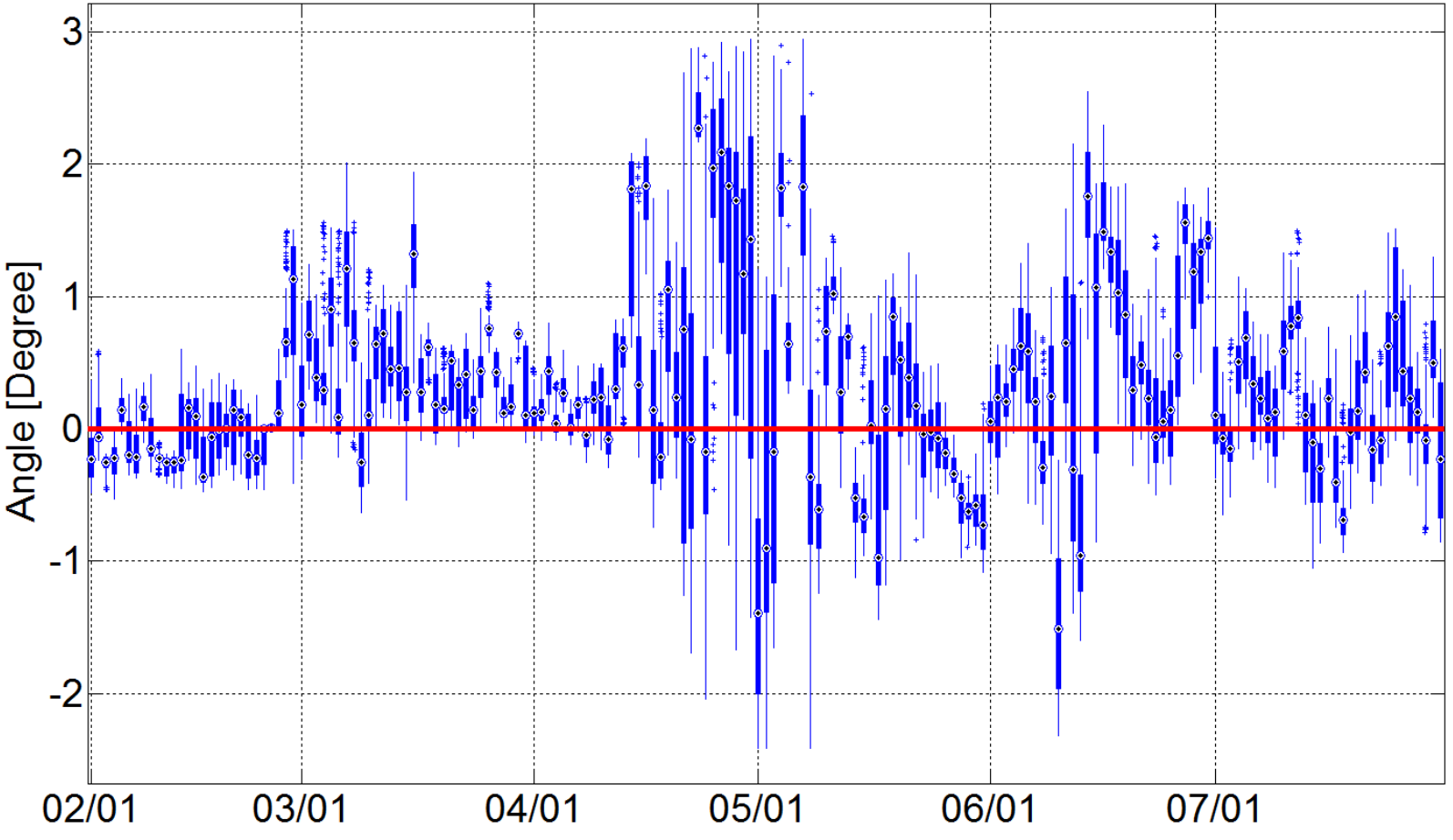
West 16-West 14



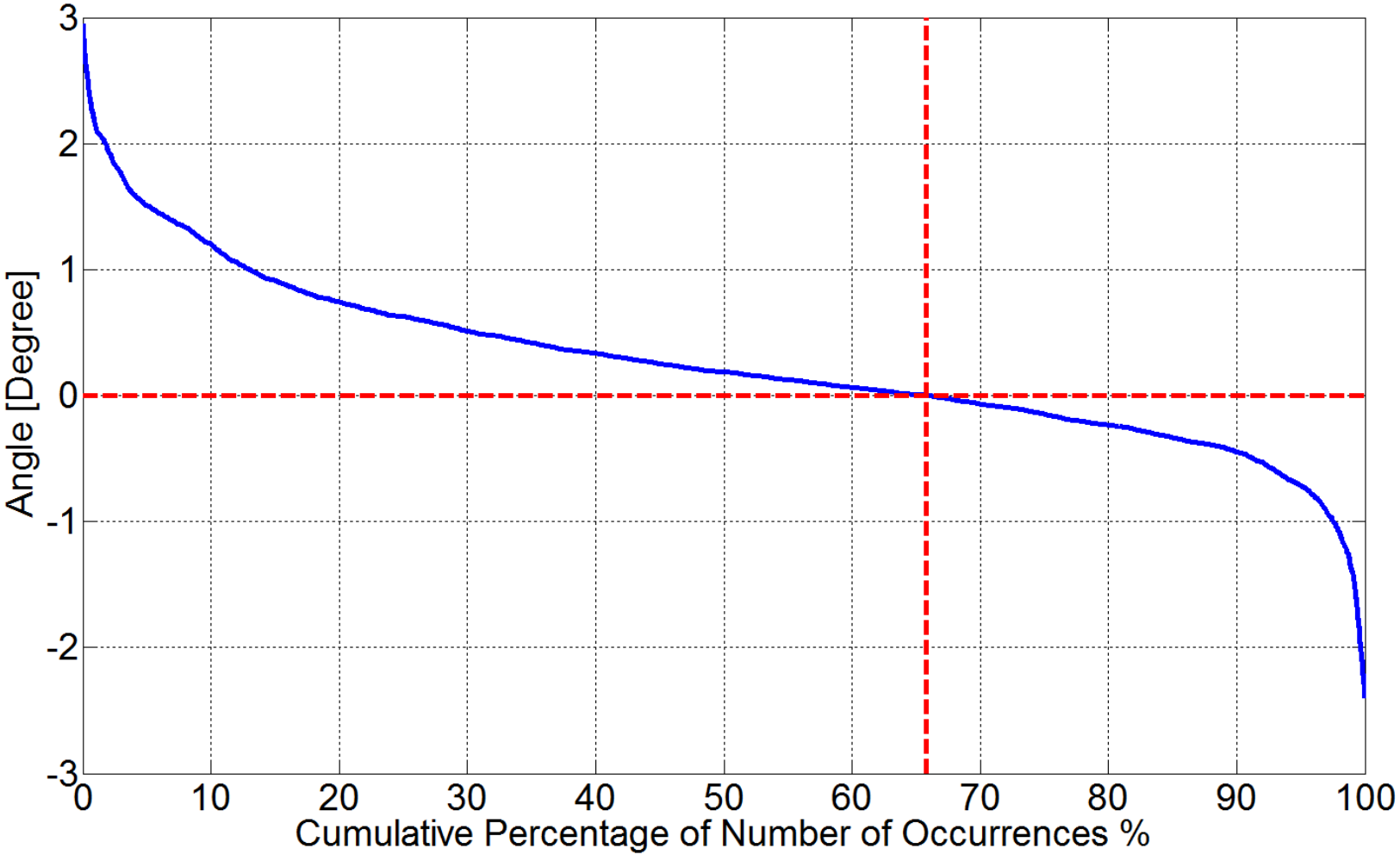
West 16-West 14



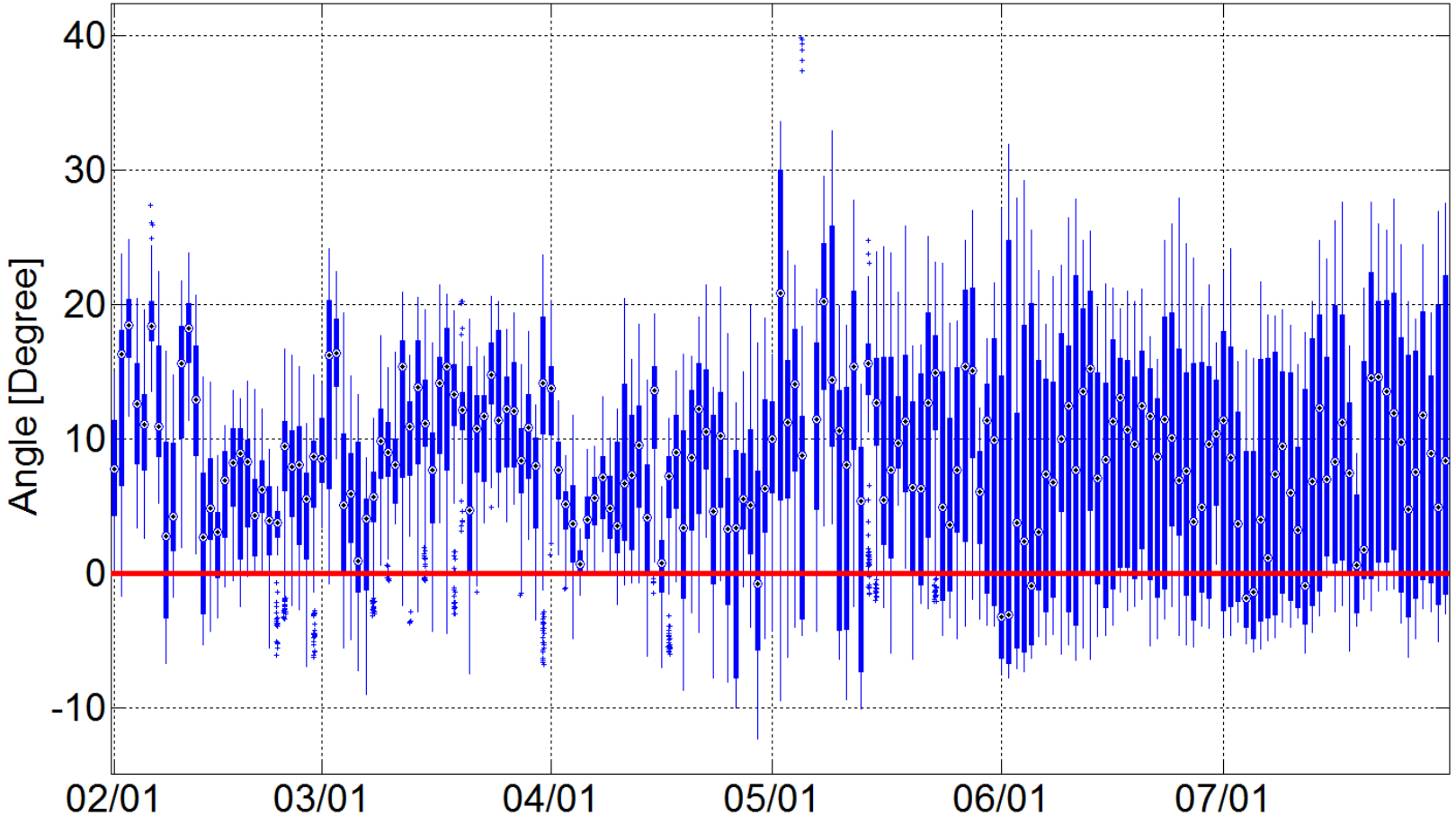
West 15-West 14



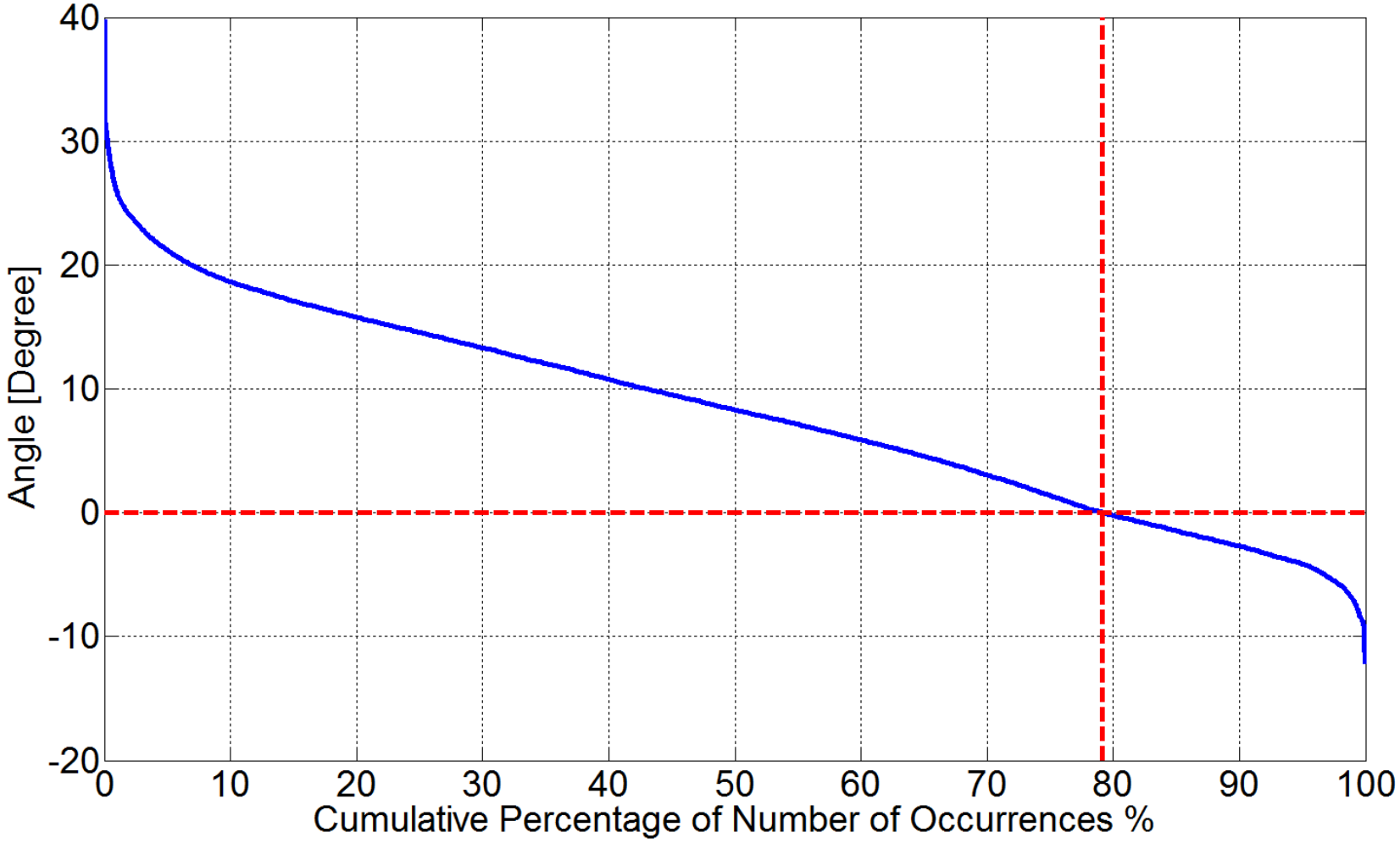
West 15-West 14



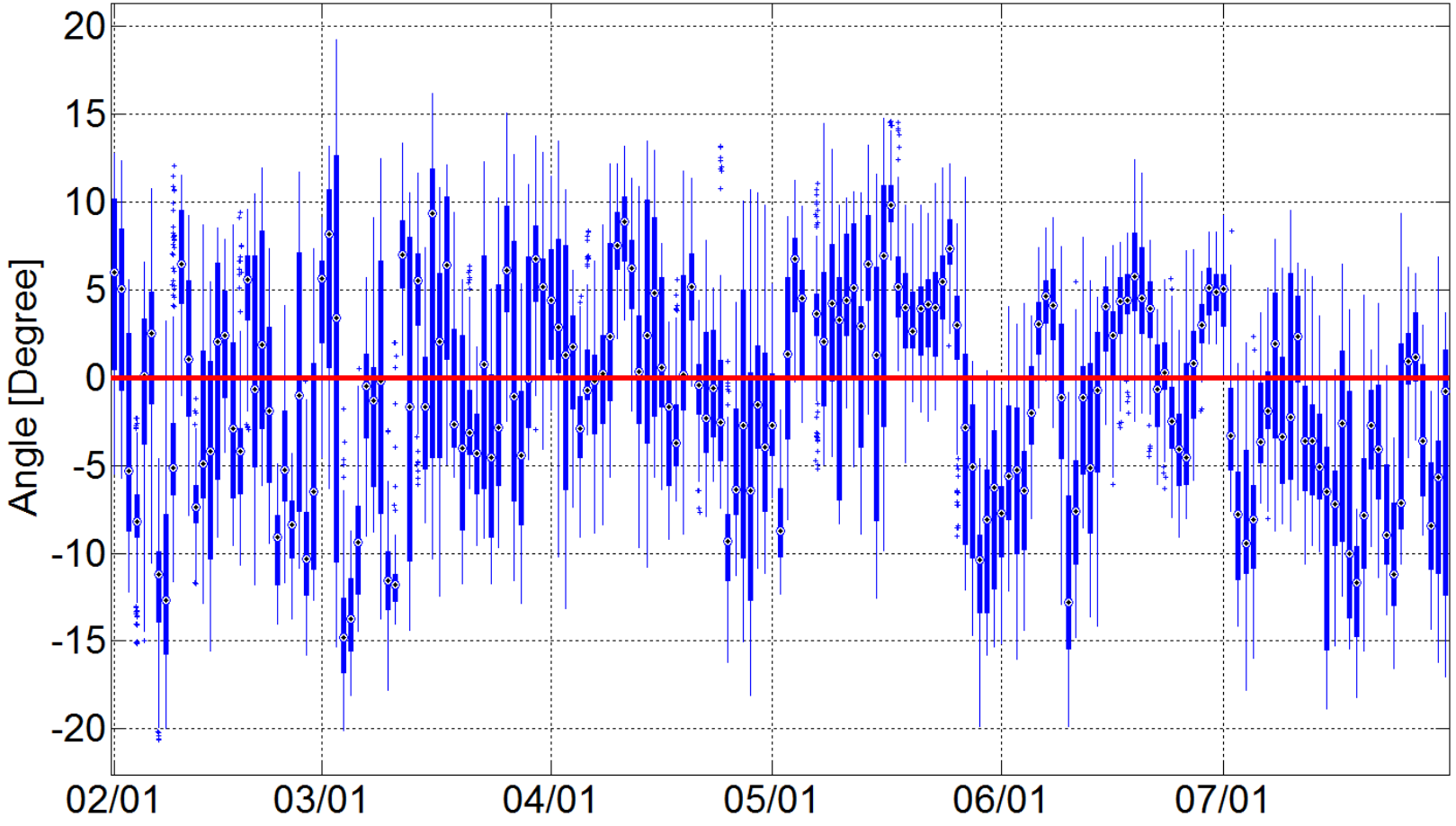
Coast 1-South 10*



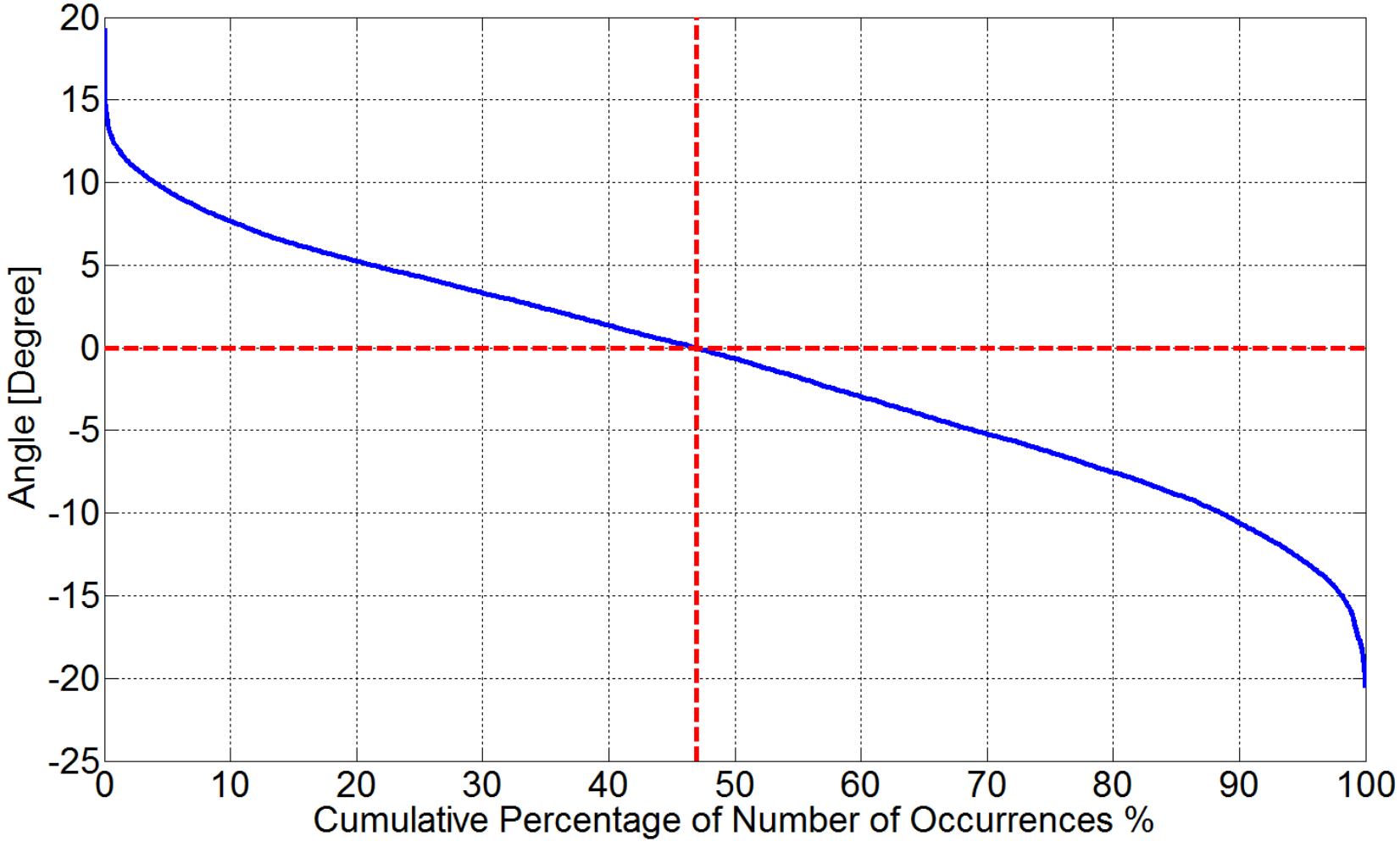
Coast 1-South 10*



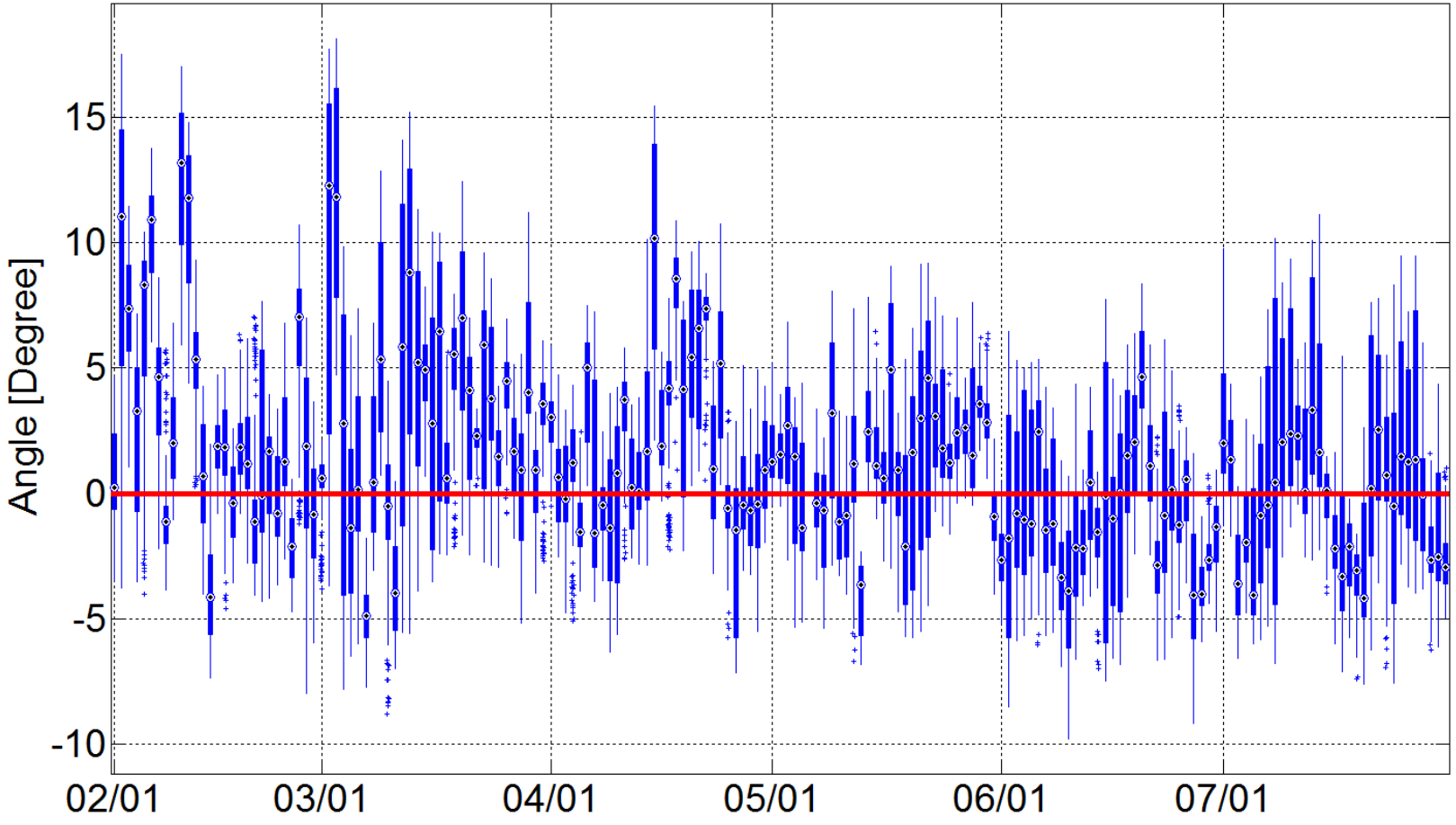
South 3*-South 11*



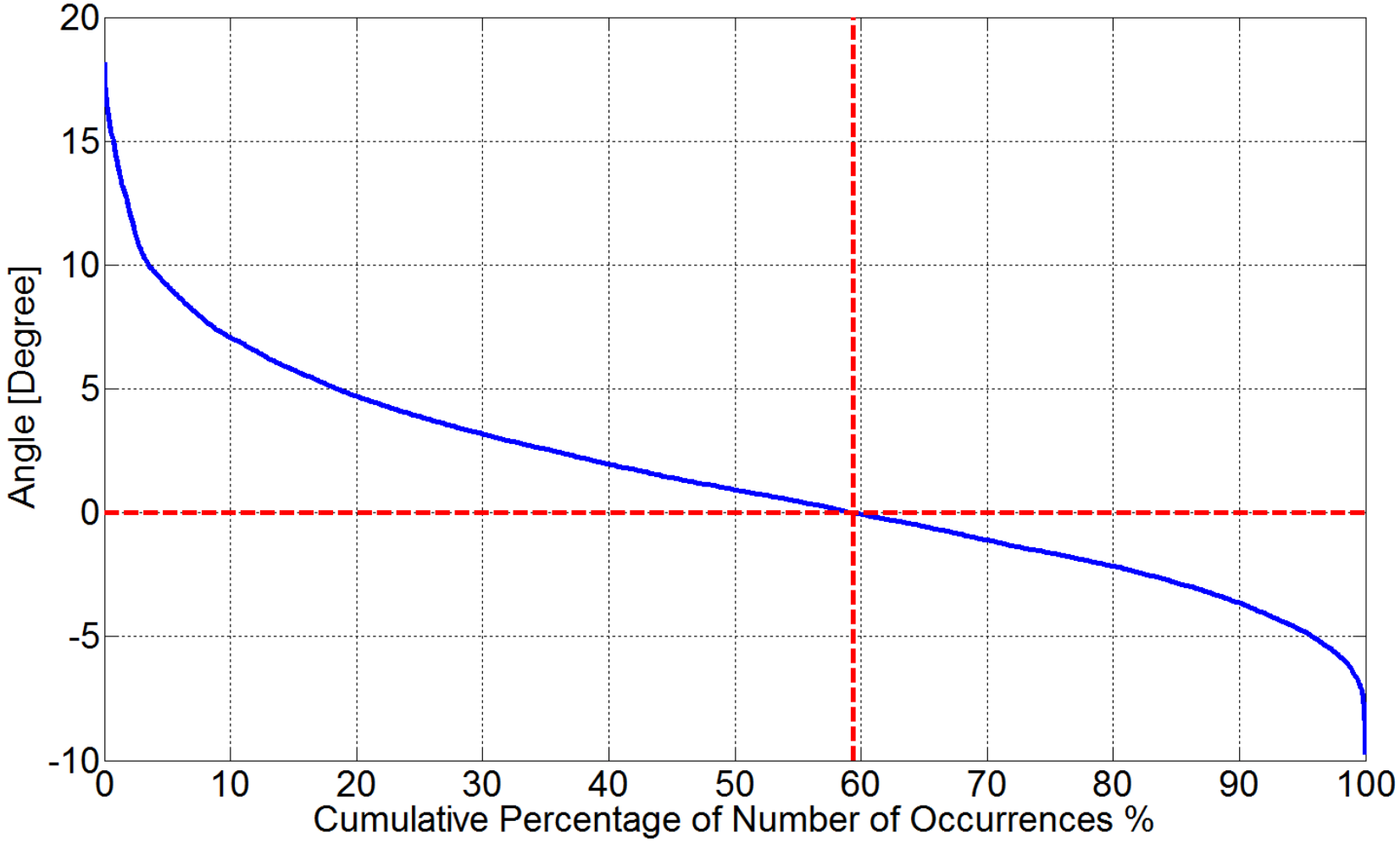
South 3*-South 11*



South 11*-North 7



South 11*-North 7



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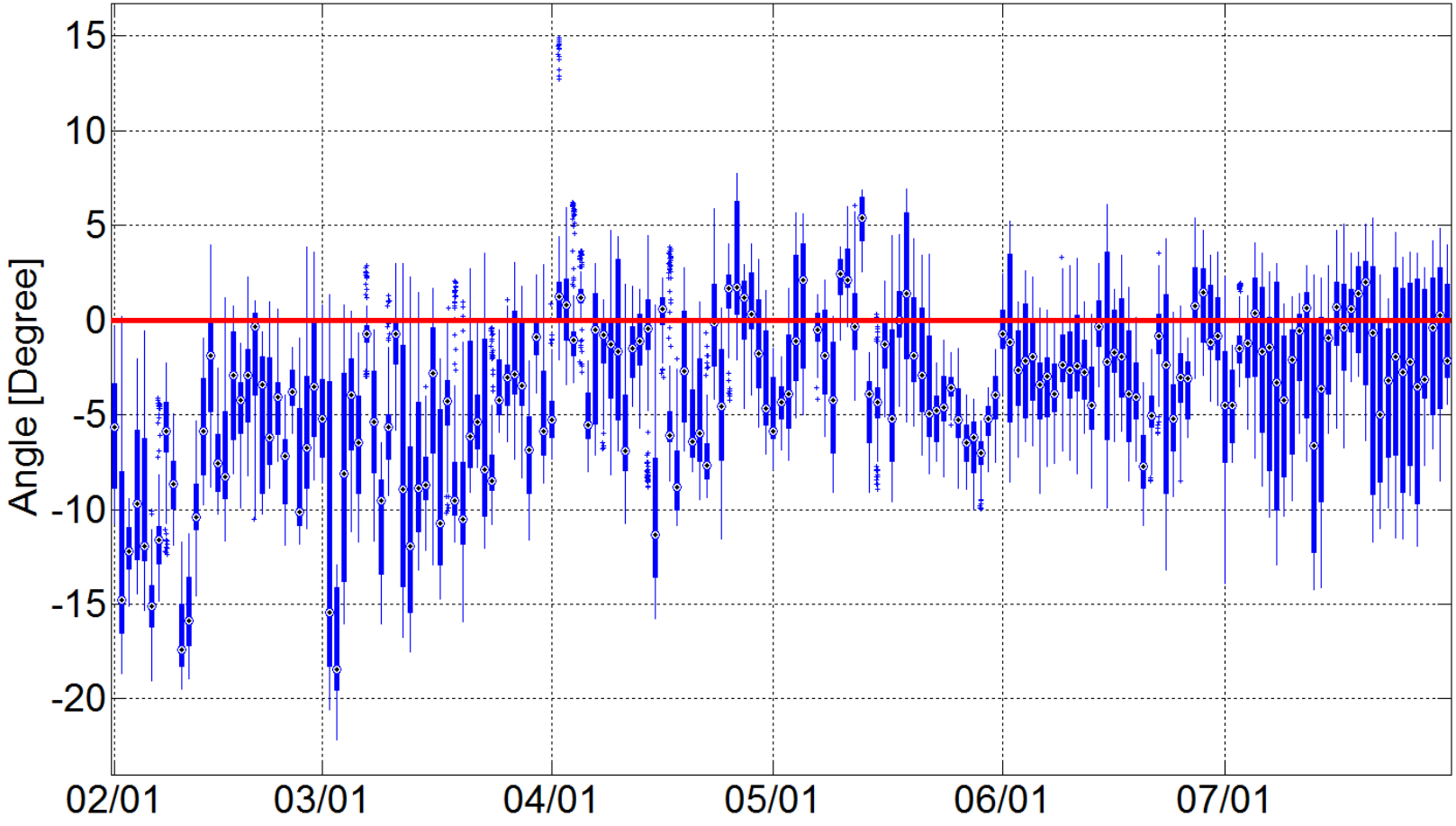

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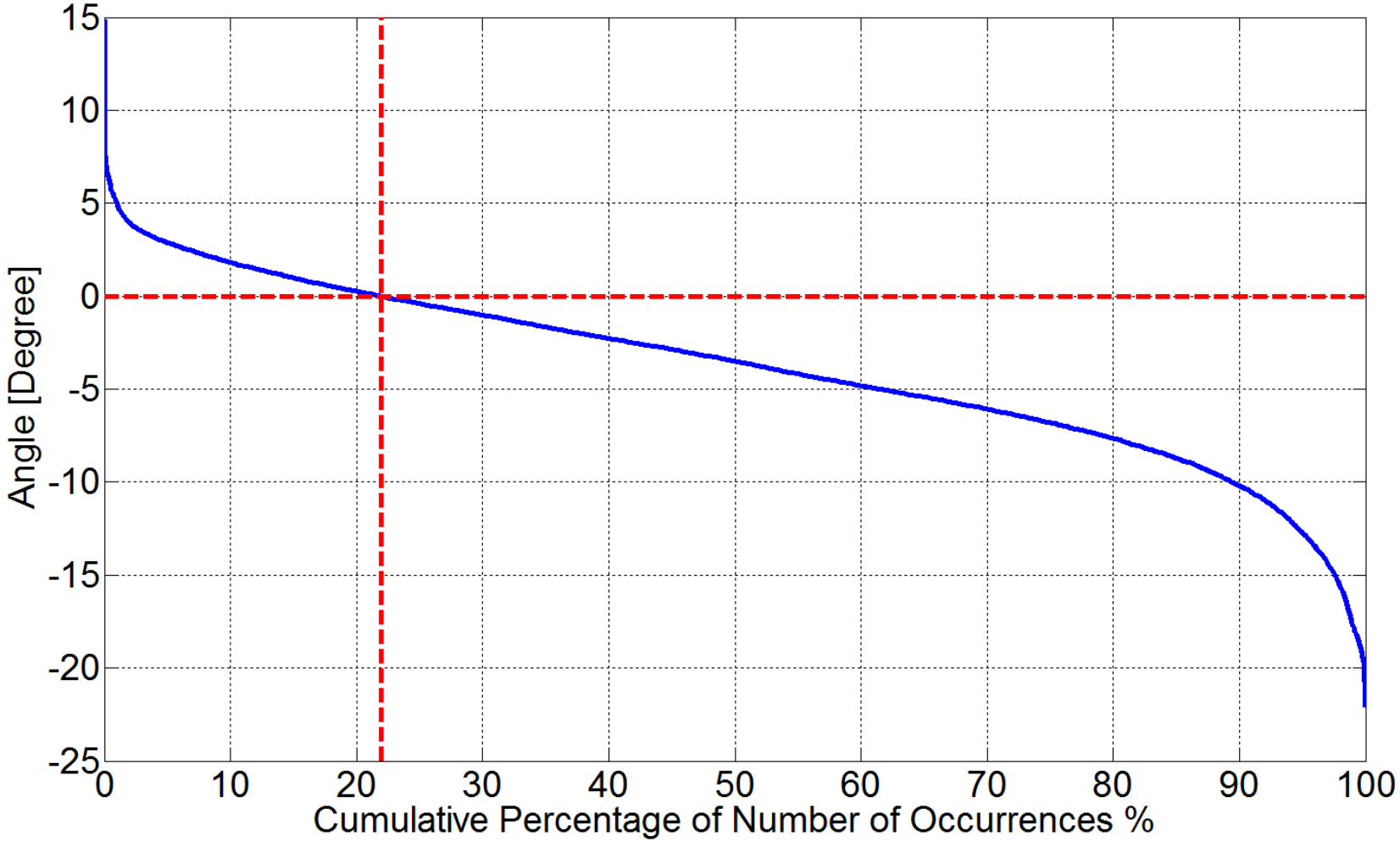

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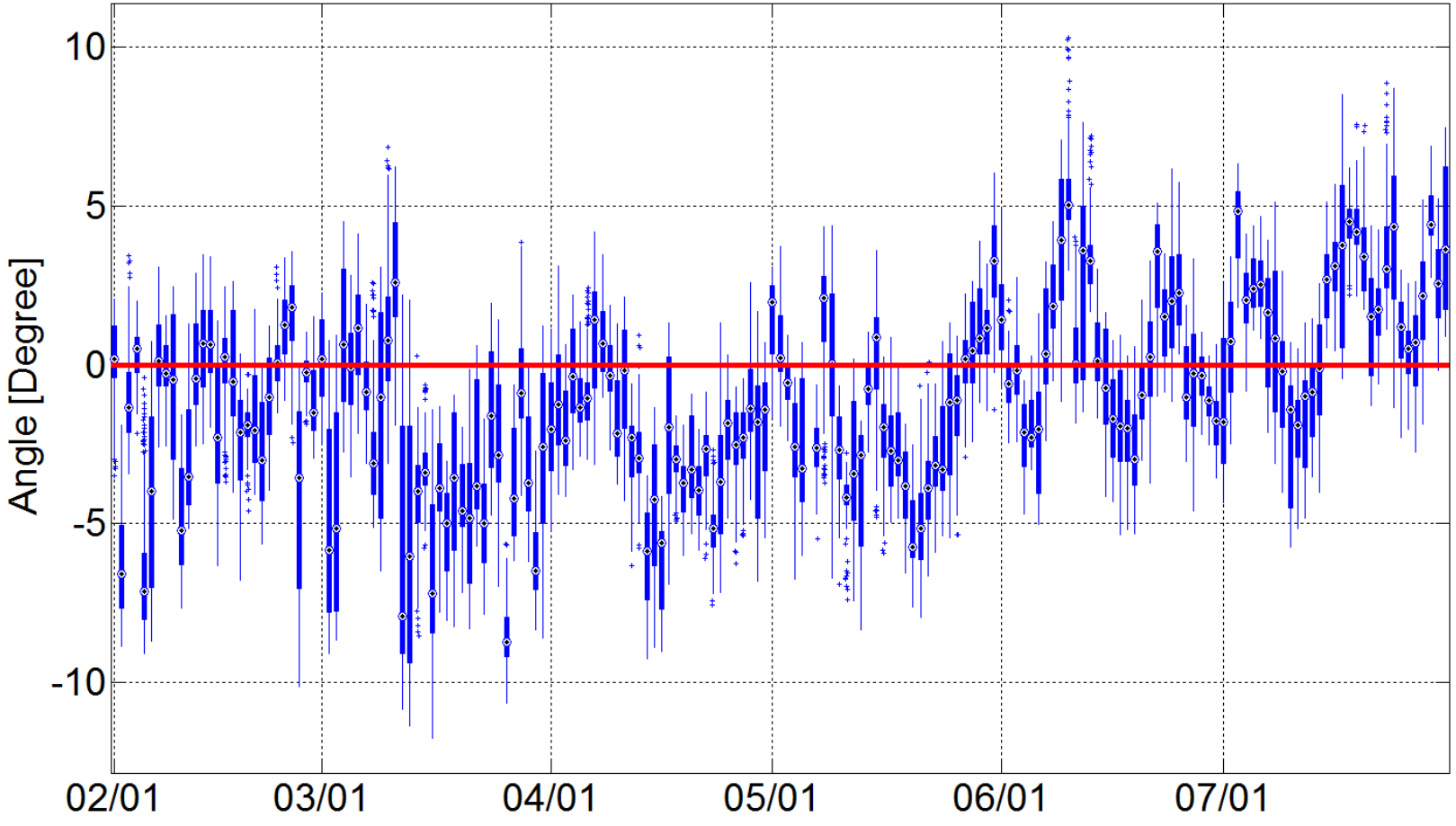

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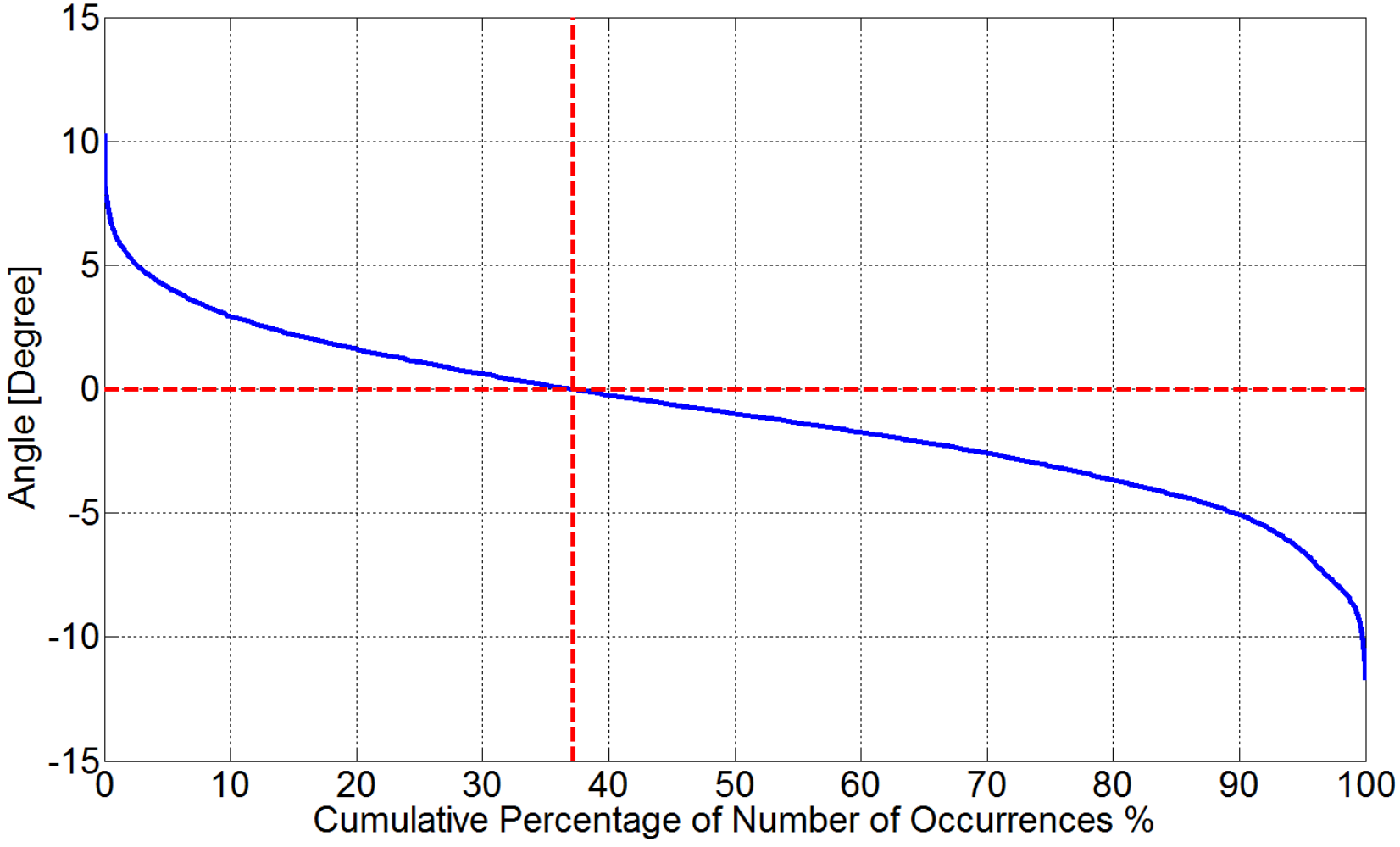

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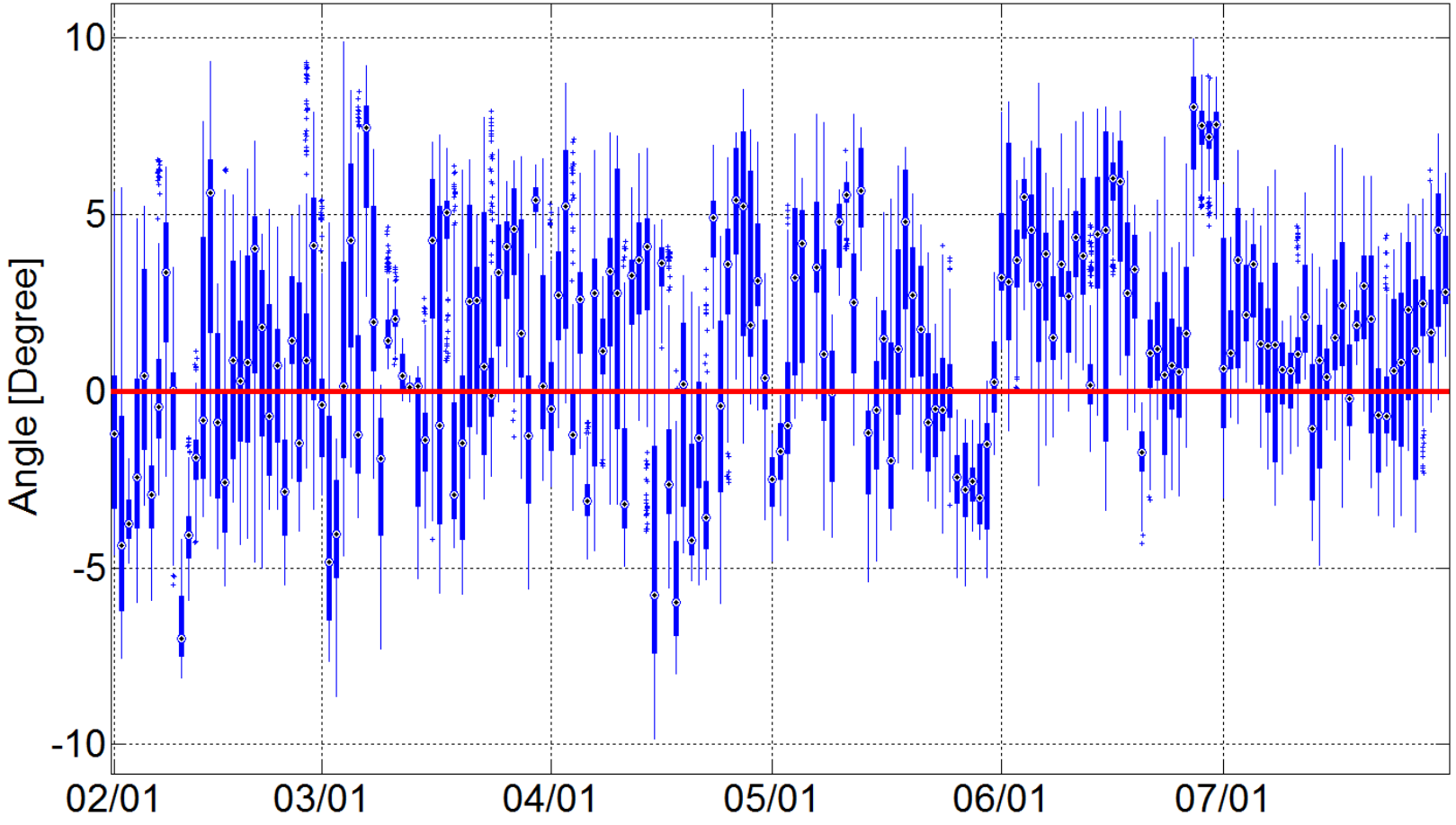

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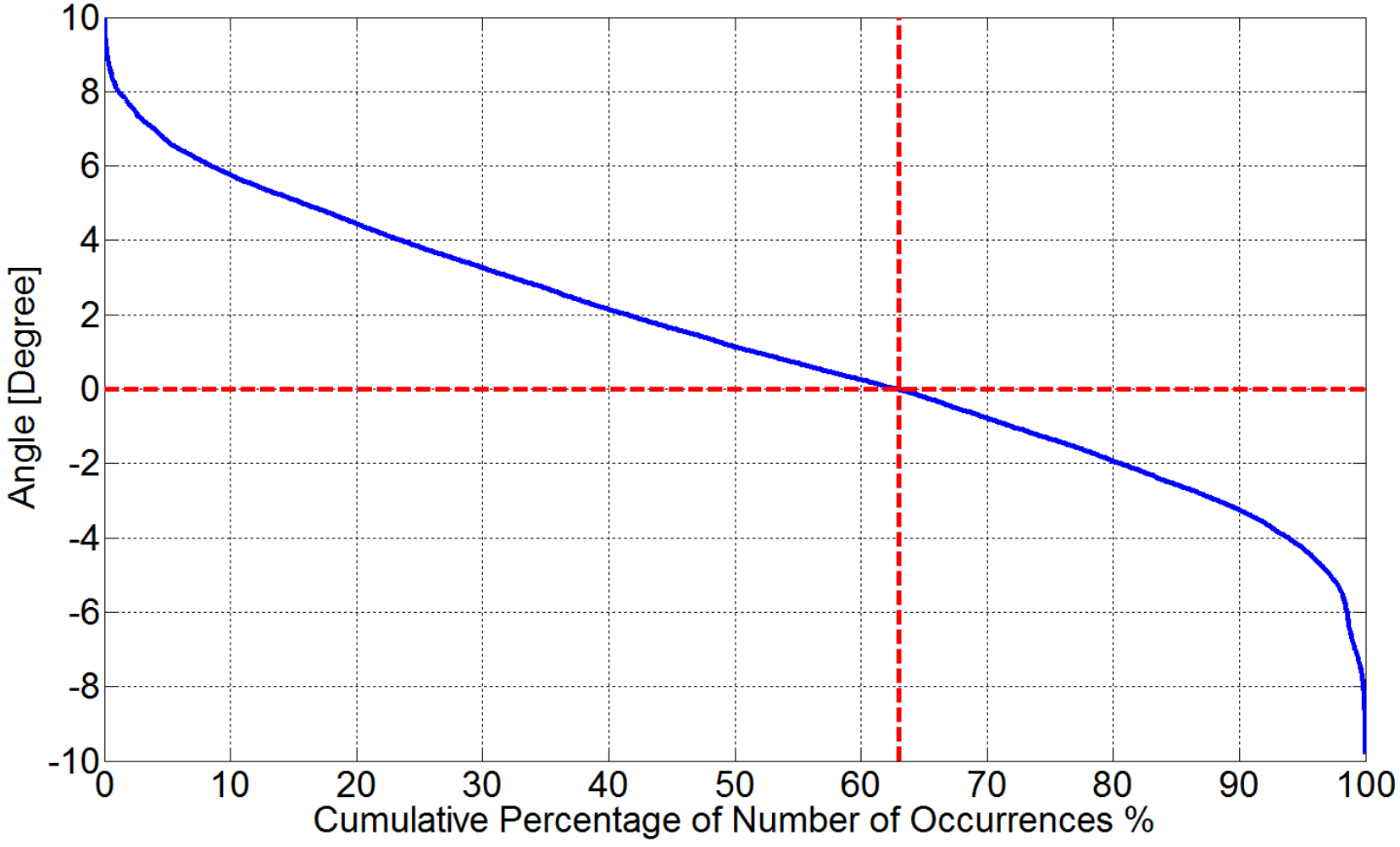

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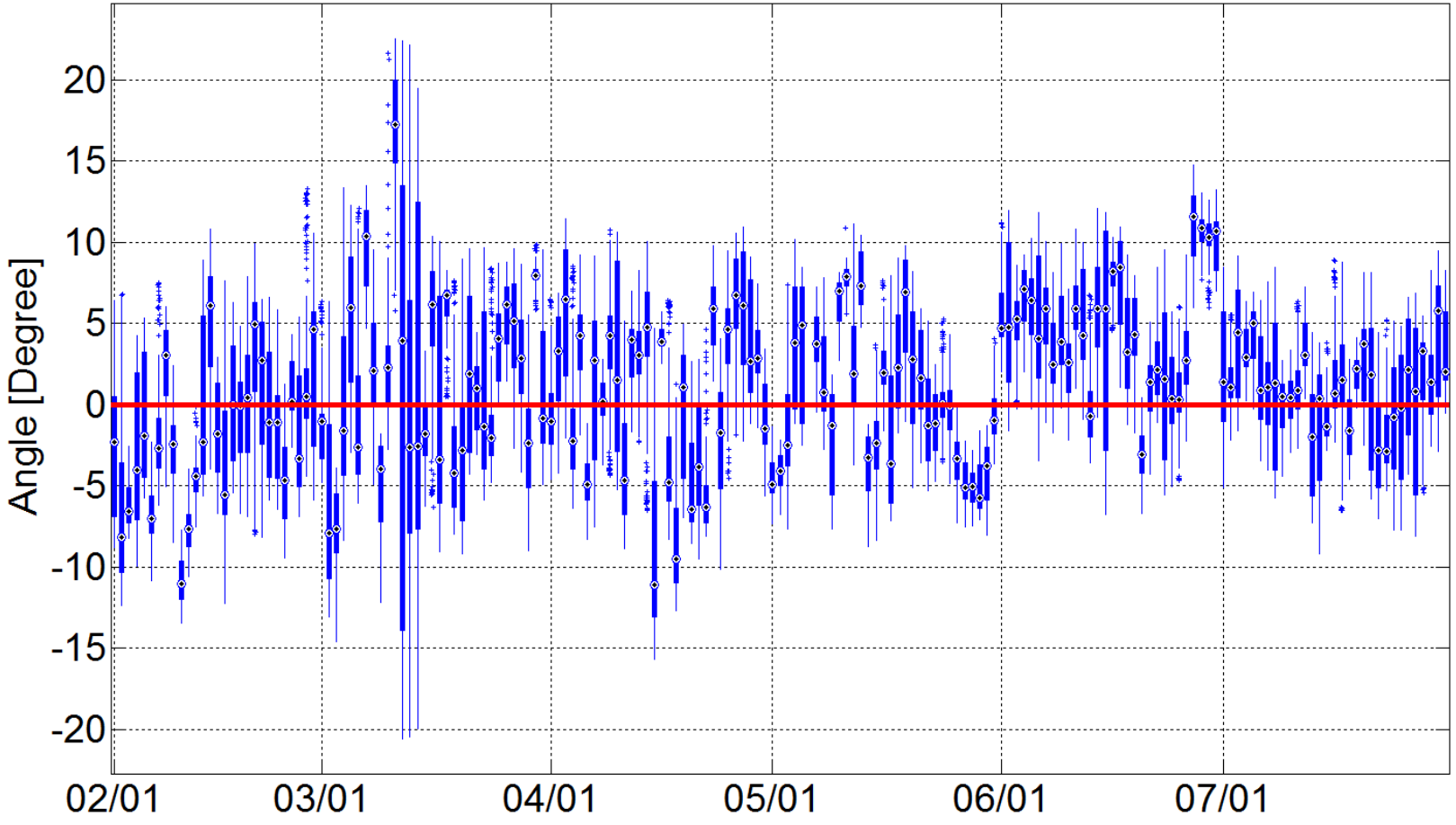

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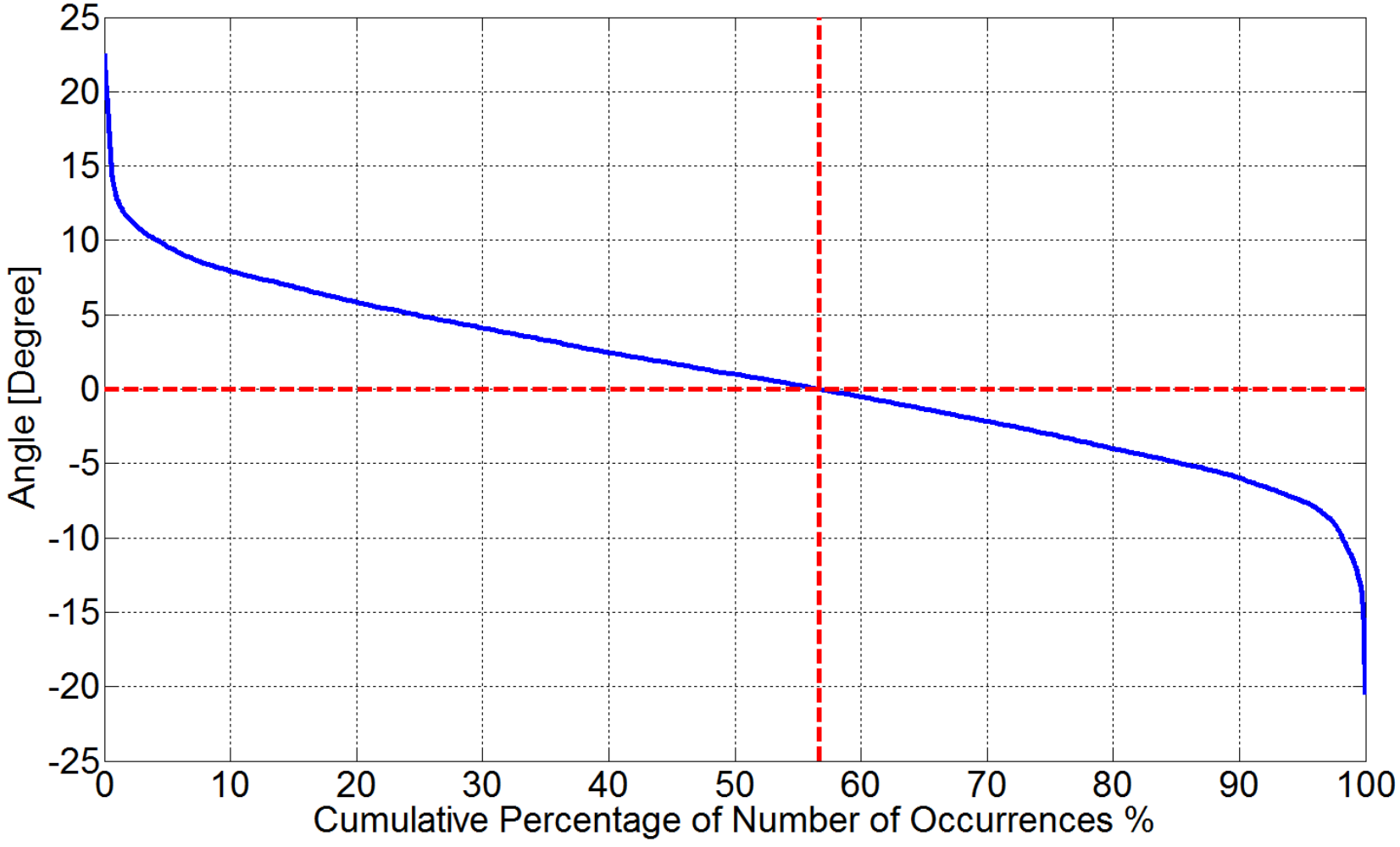

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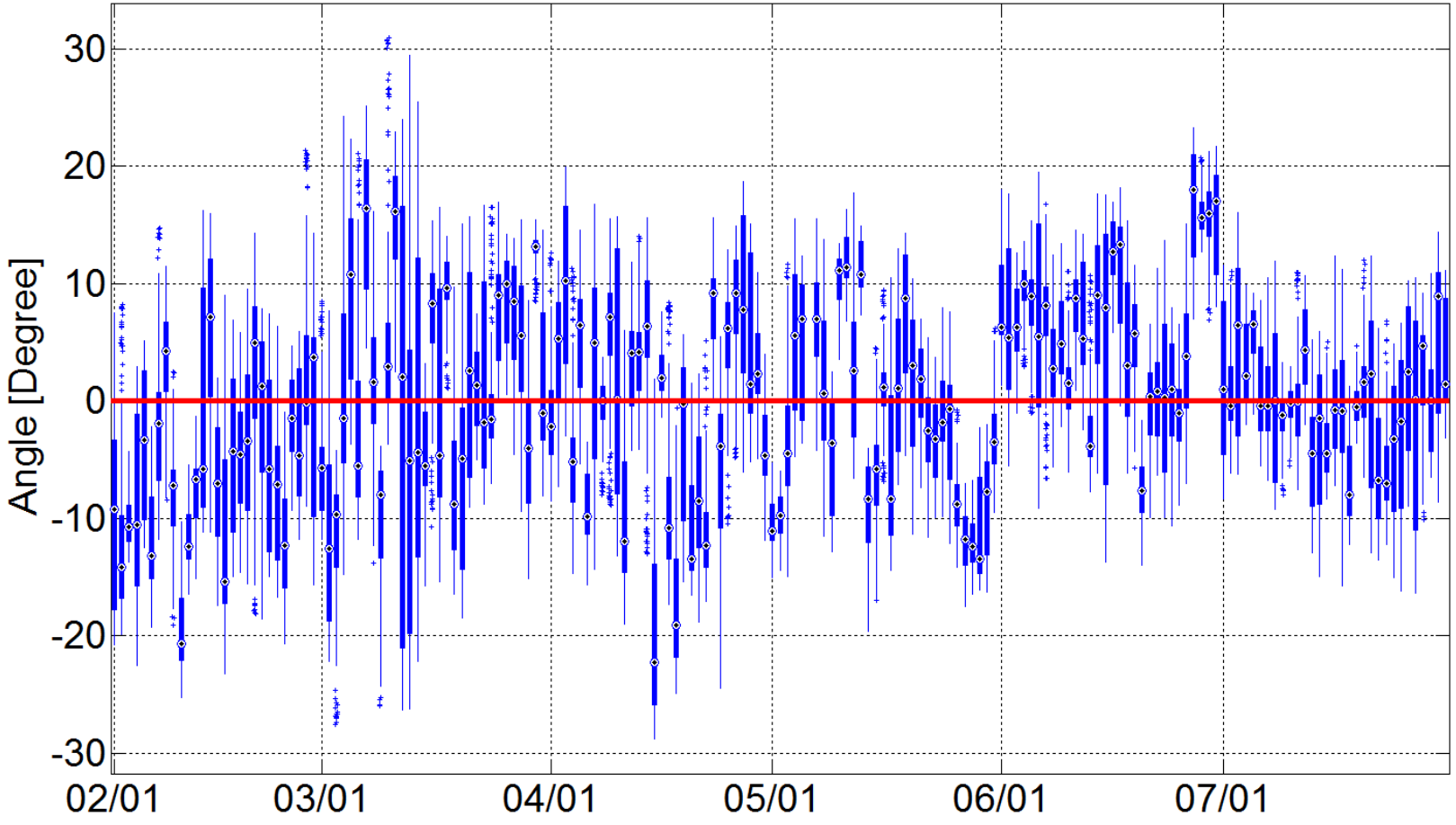

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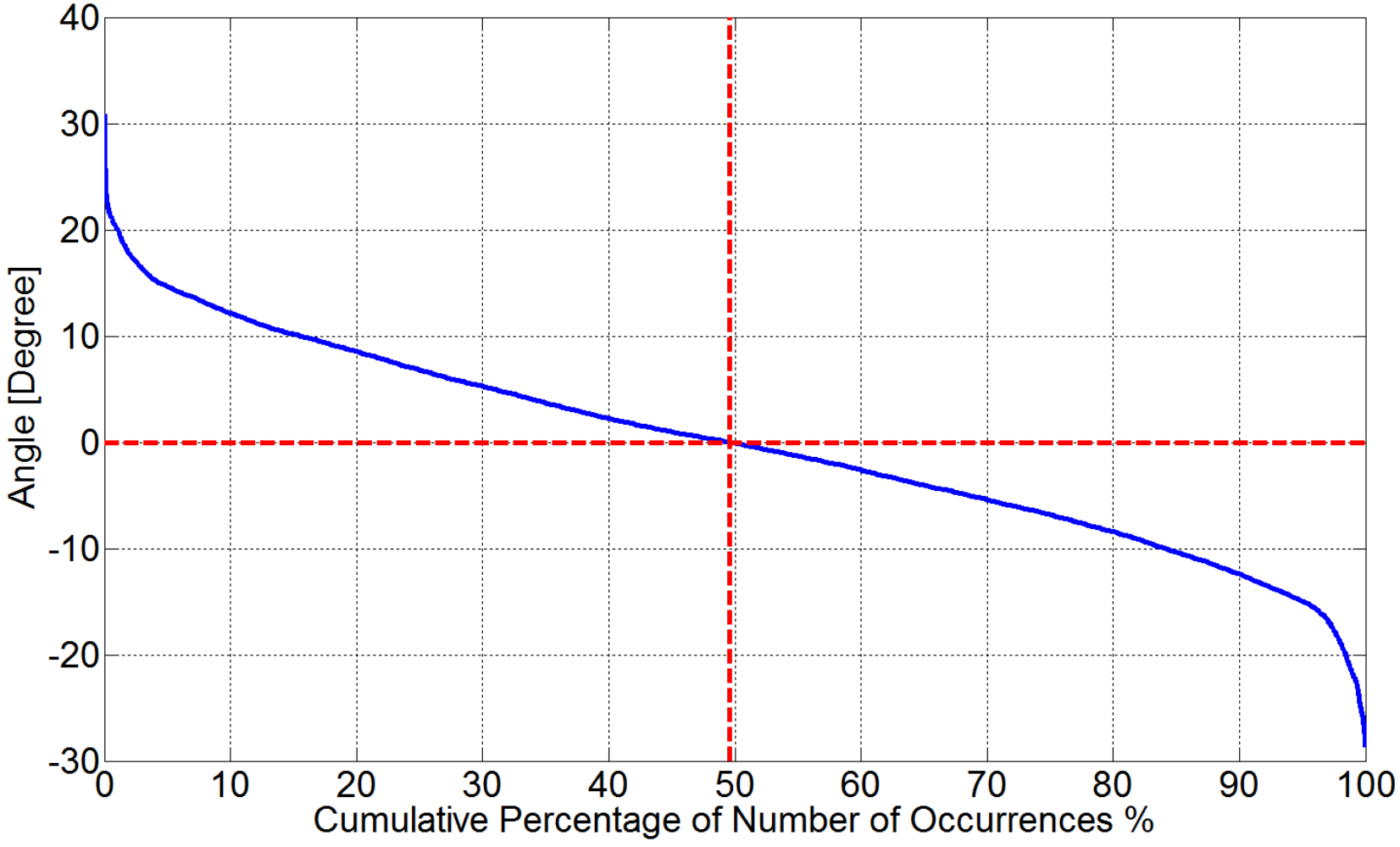
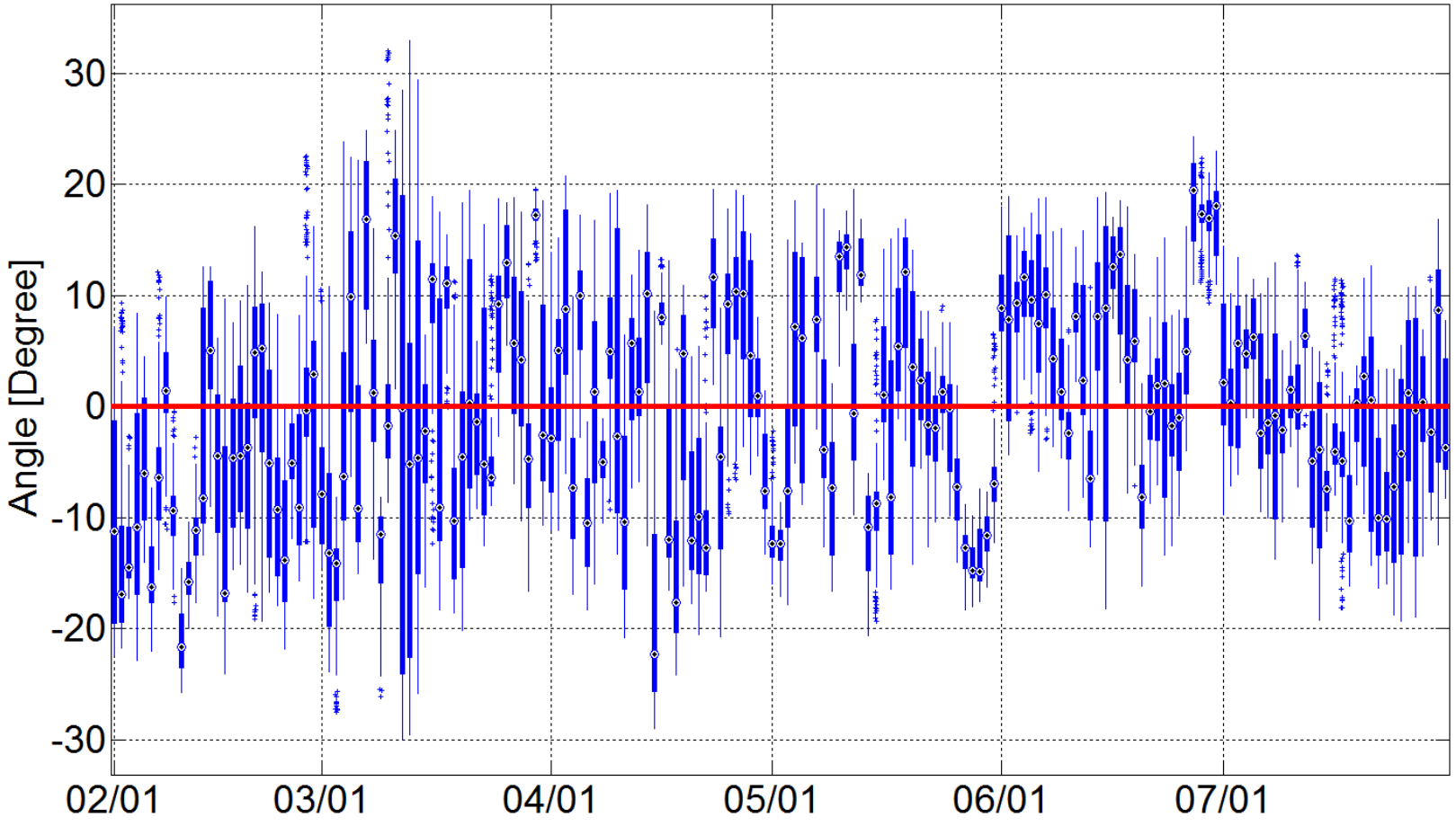


FarWest 9-South 9*



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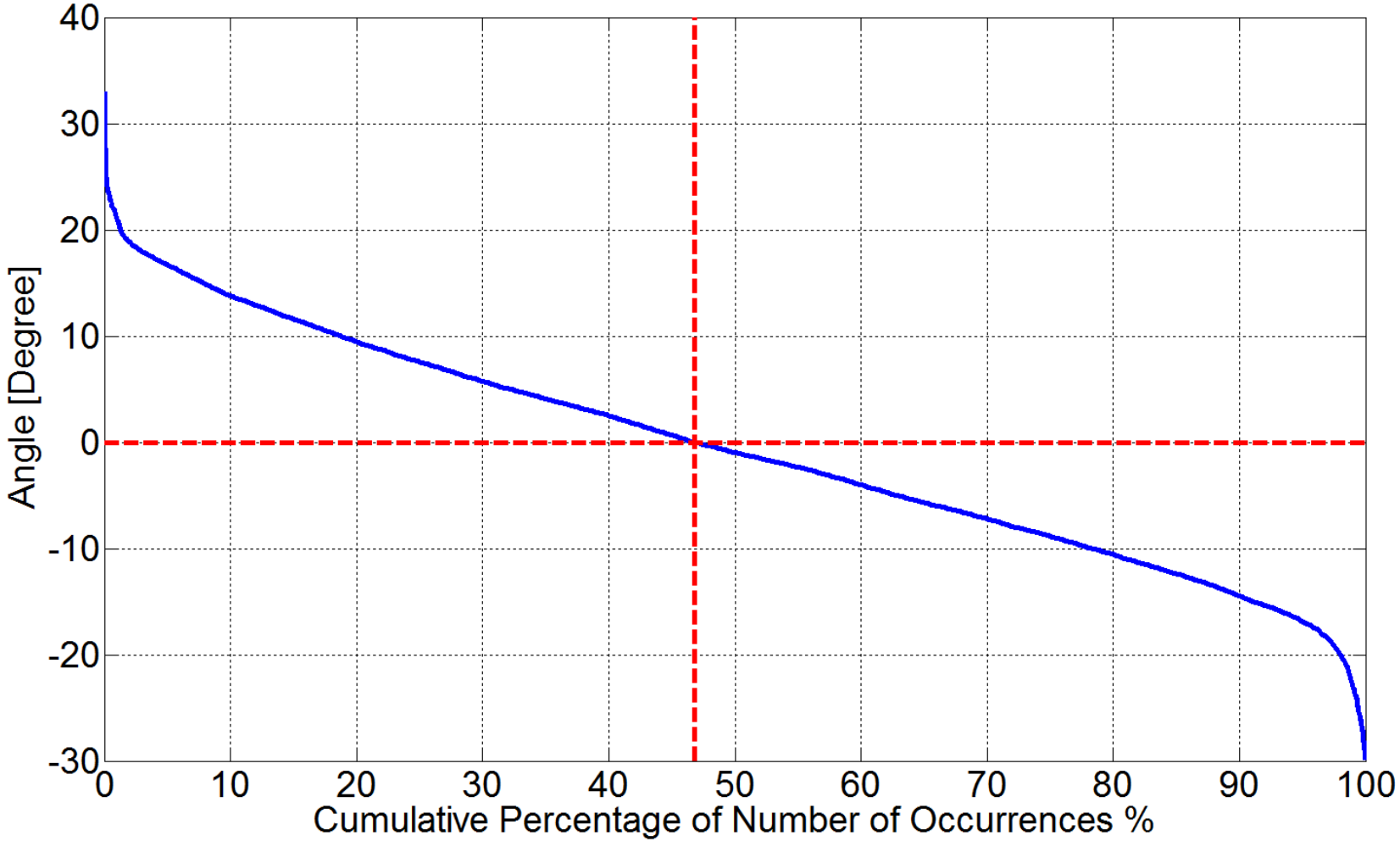
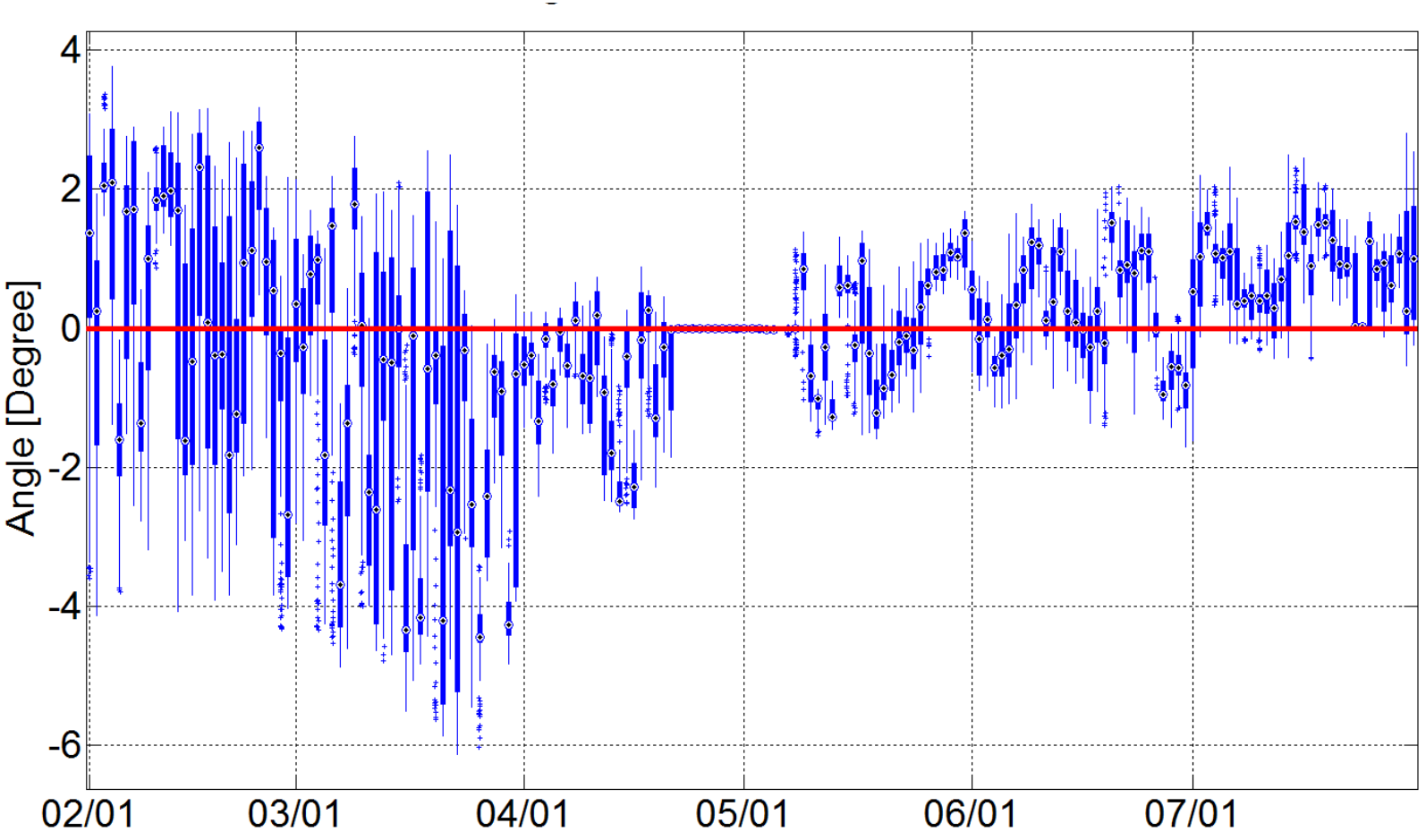
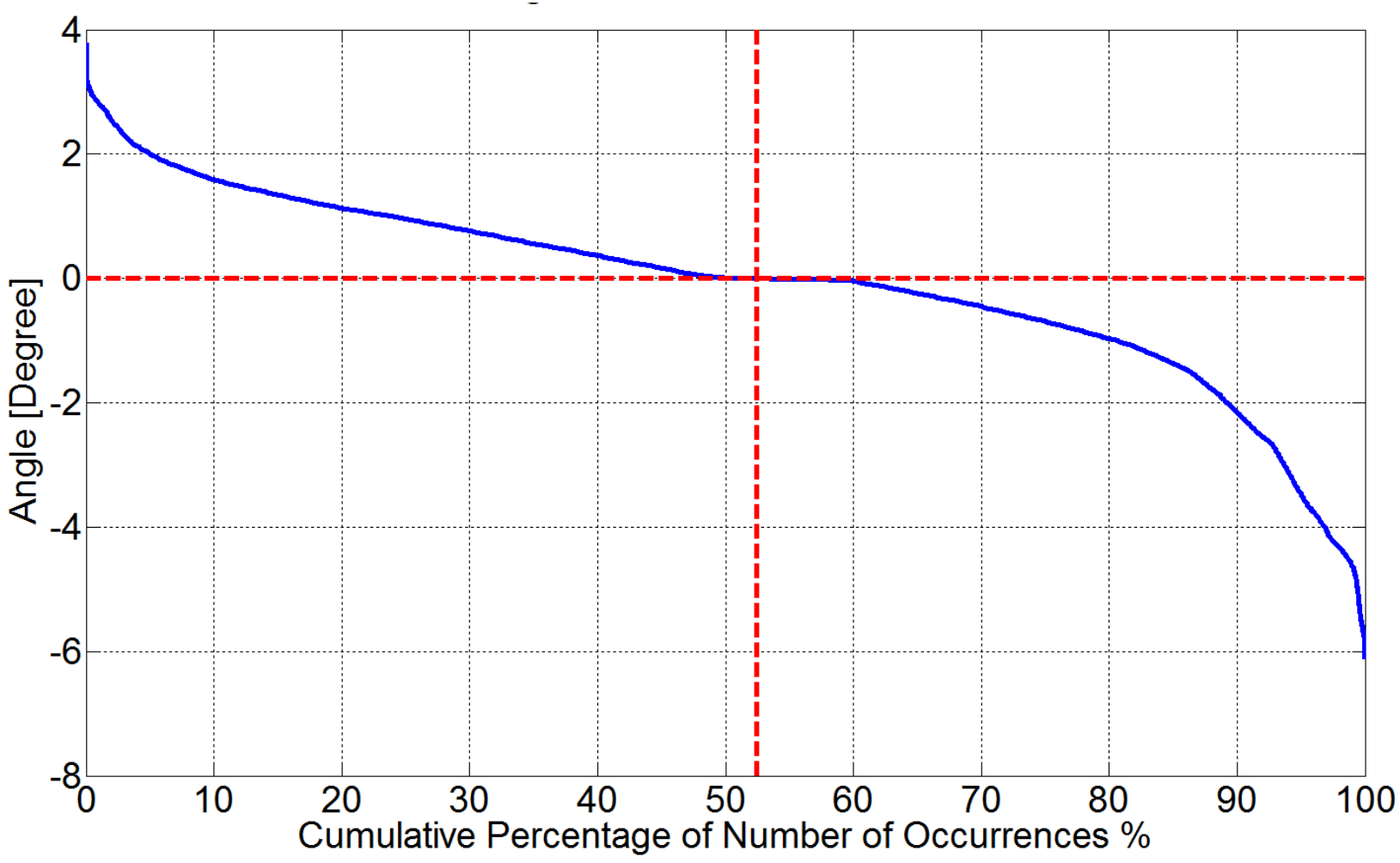


West 19*-West 9



West 19*-West 9



Appendix B – Part 2
CCET Discovery Across Texas project

Baseline Analysis Update – Angle Differences

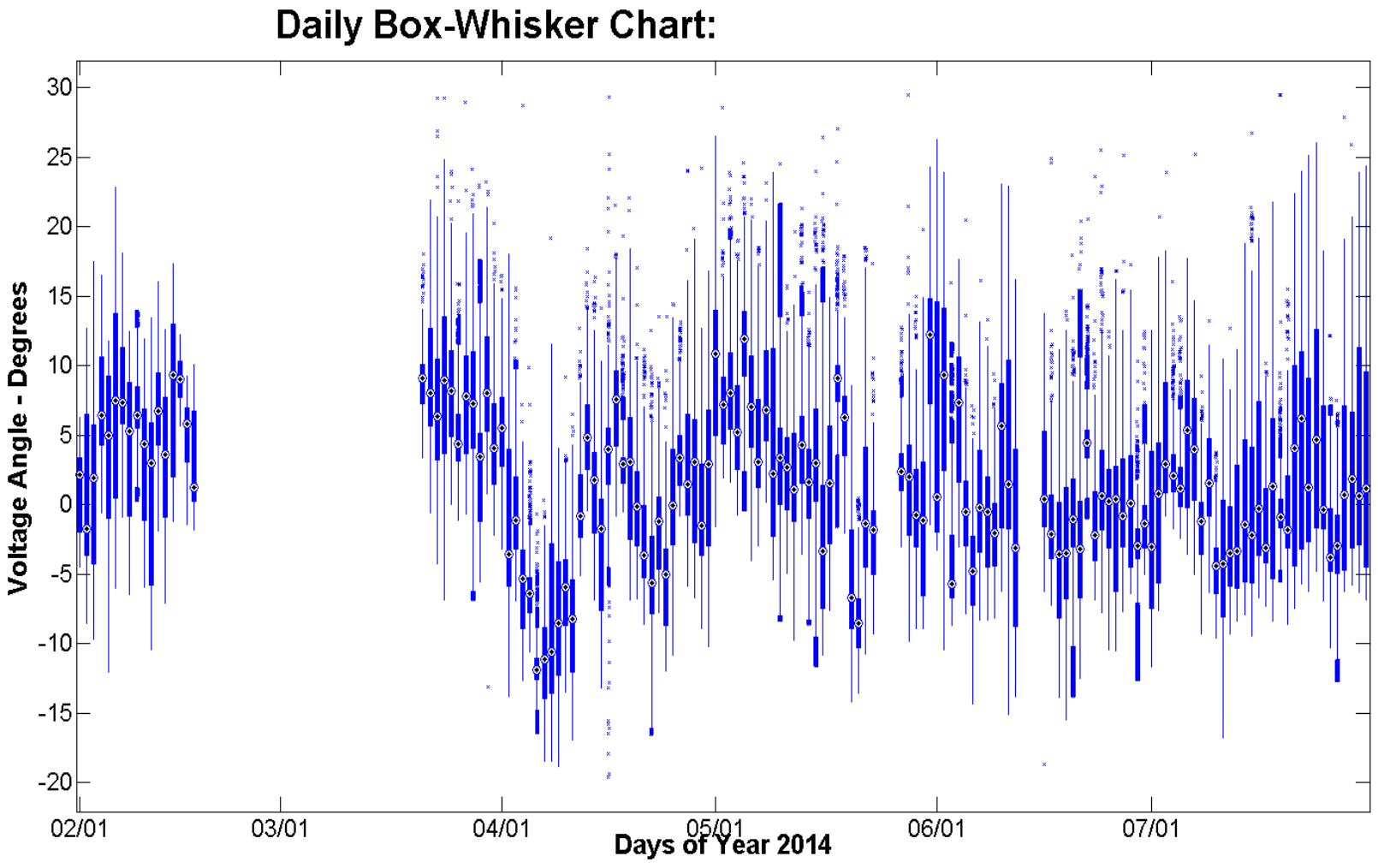
Phasor Data: February to July 2014
Box-Whisker Plots and Time Duration Curves

Electric Power Group

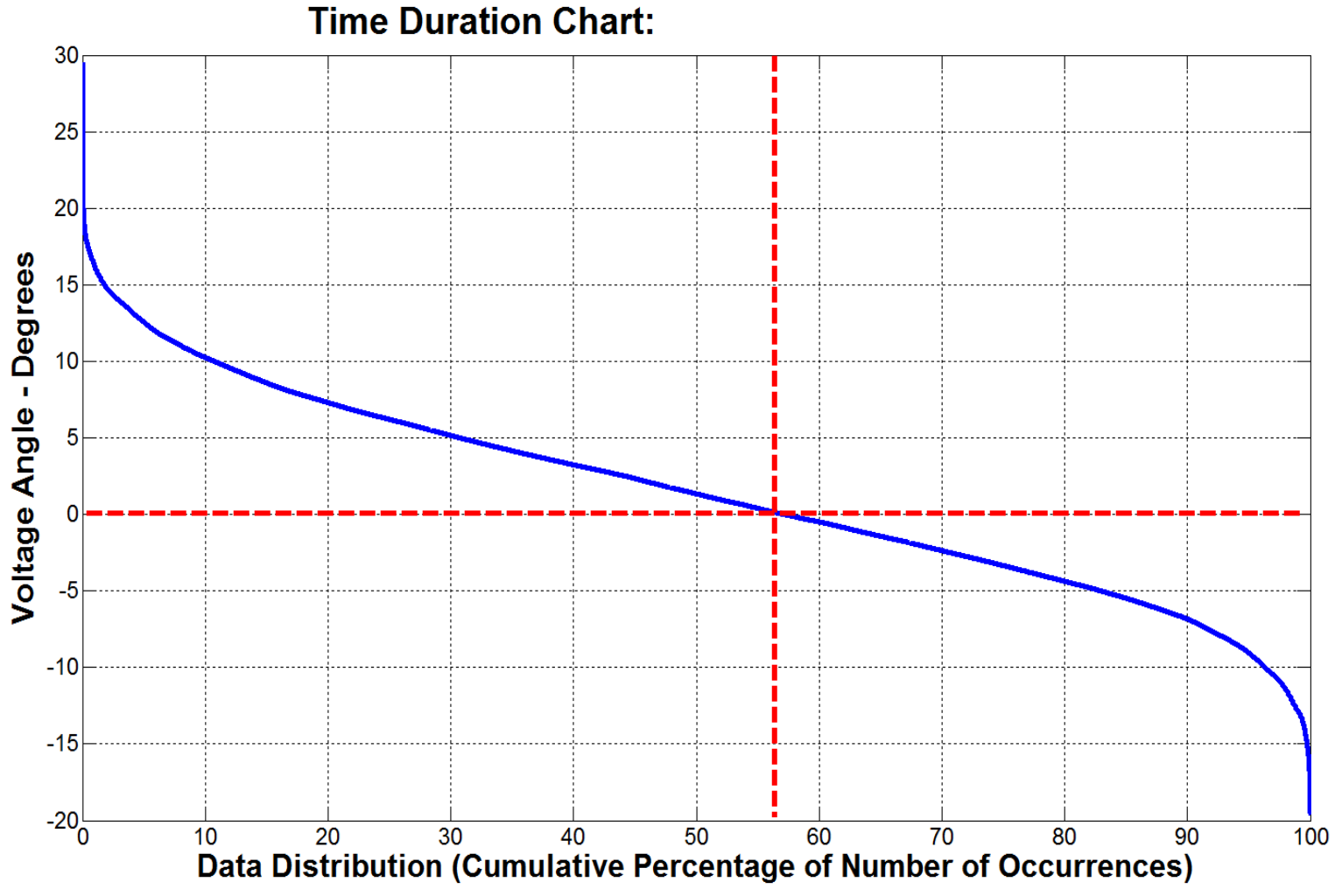
CCET

ERCOT

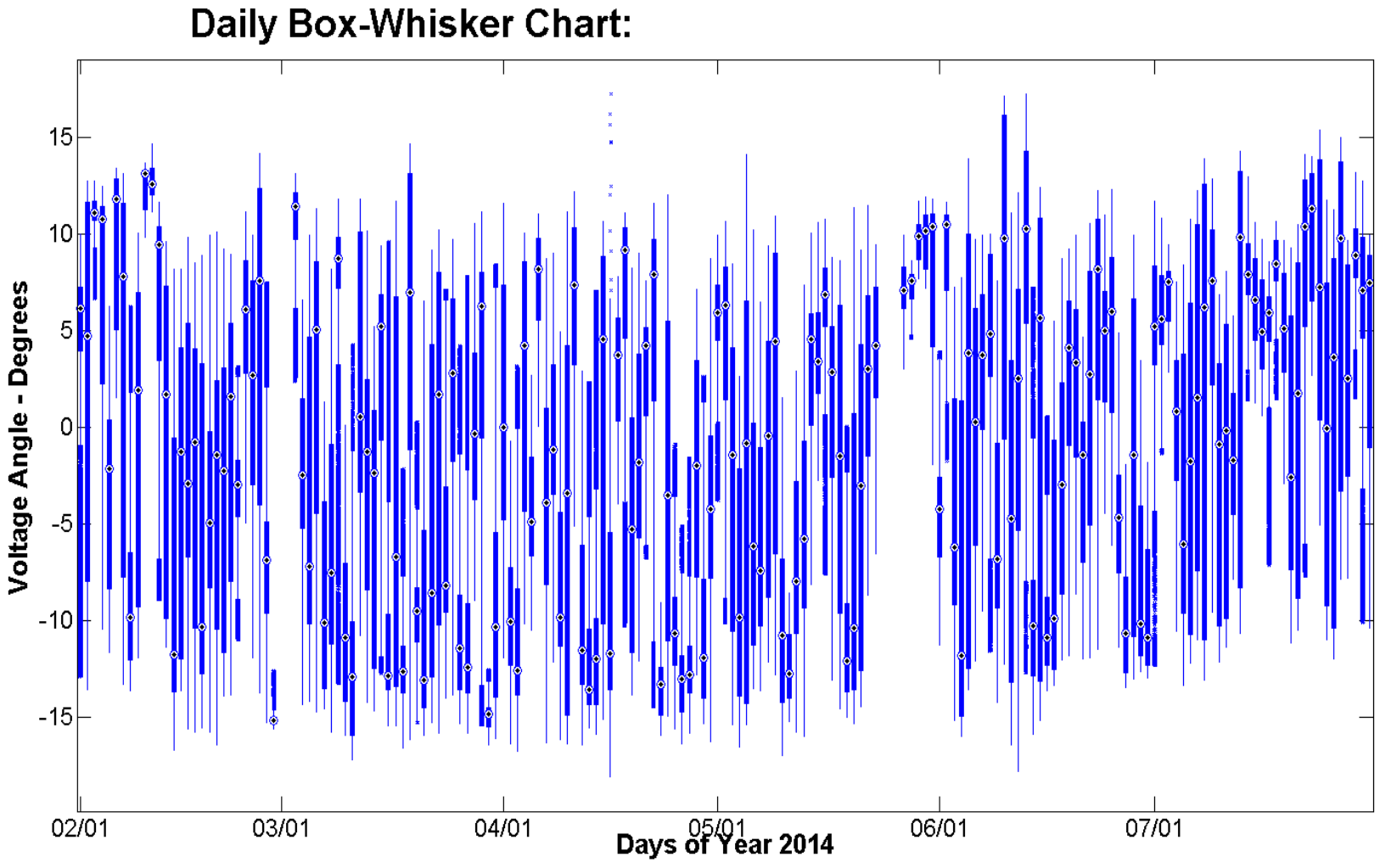
Coast 1 - South 13



Coast 1 - South 13



West 5 – West 10



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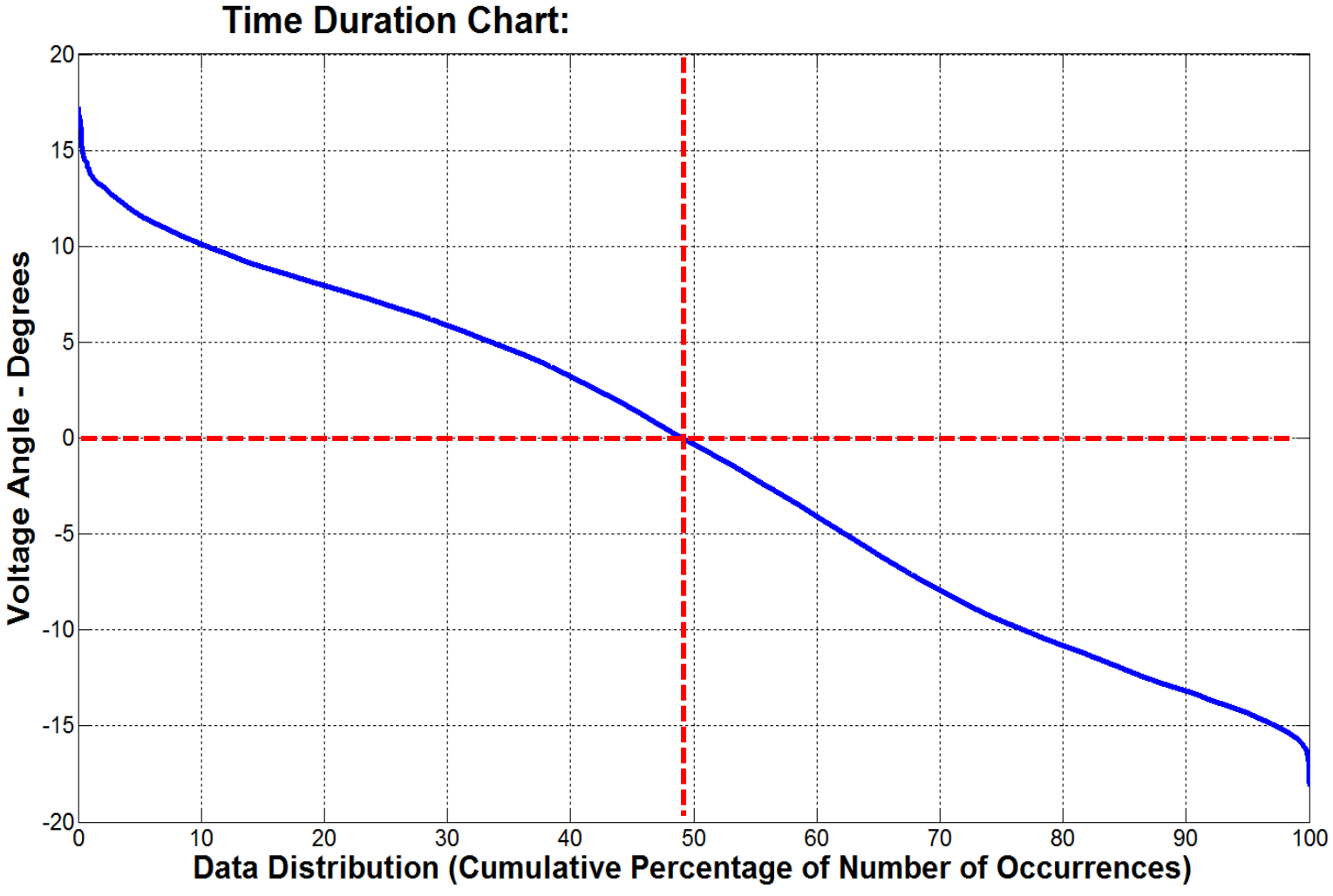
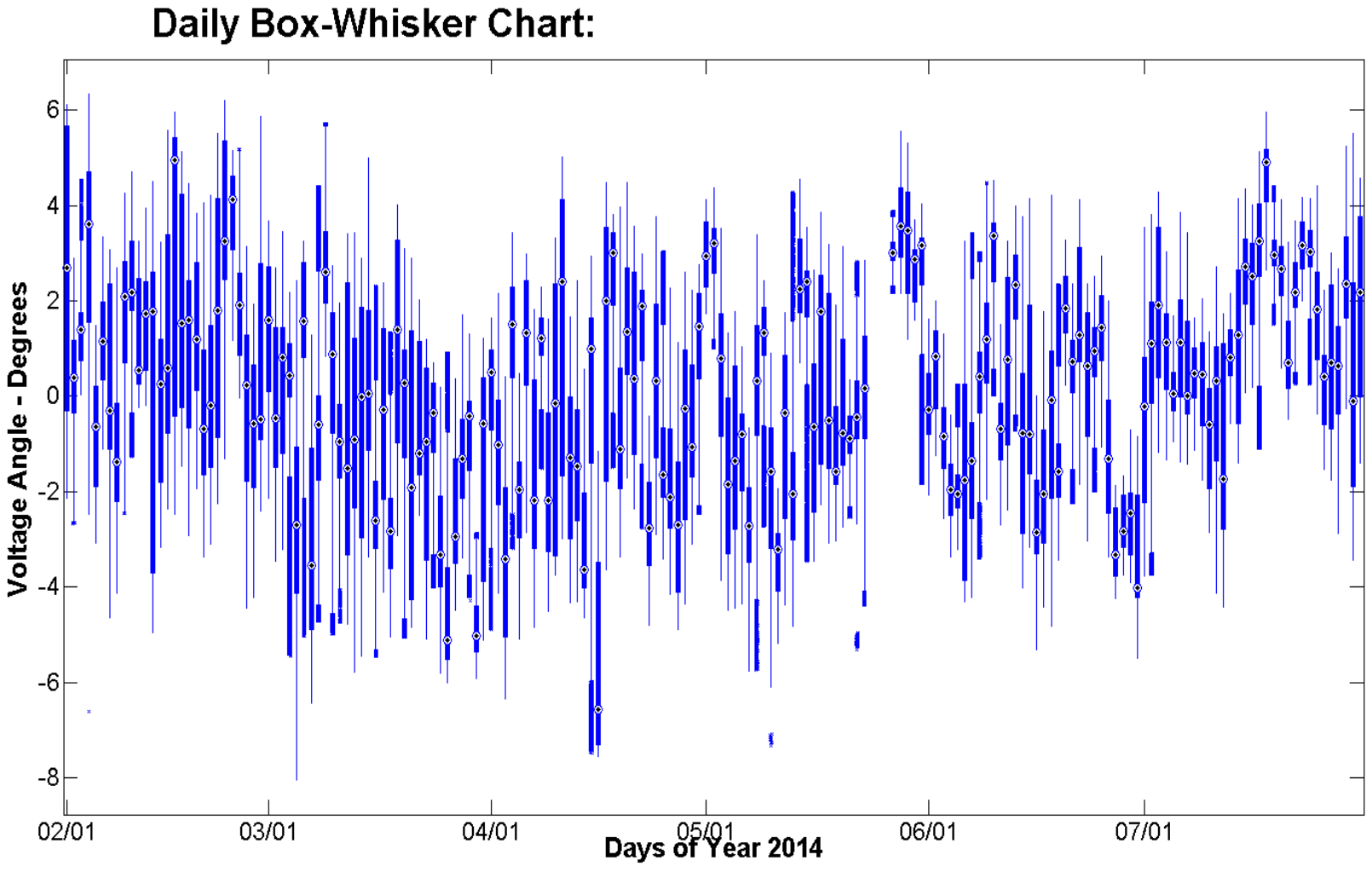


West 5 – FarWest 4



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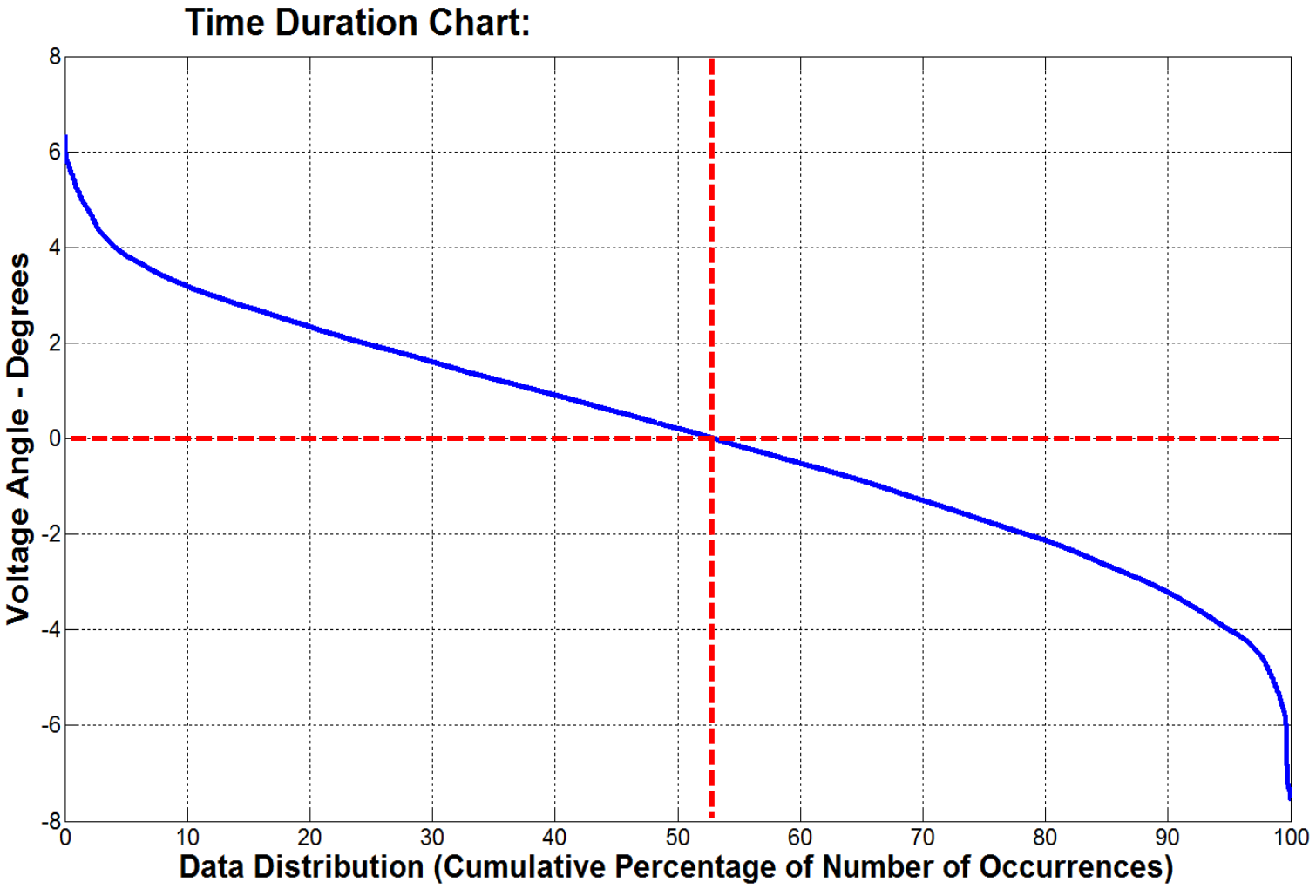
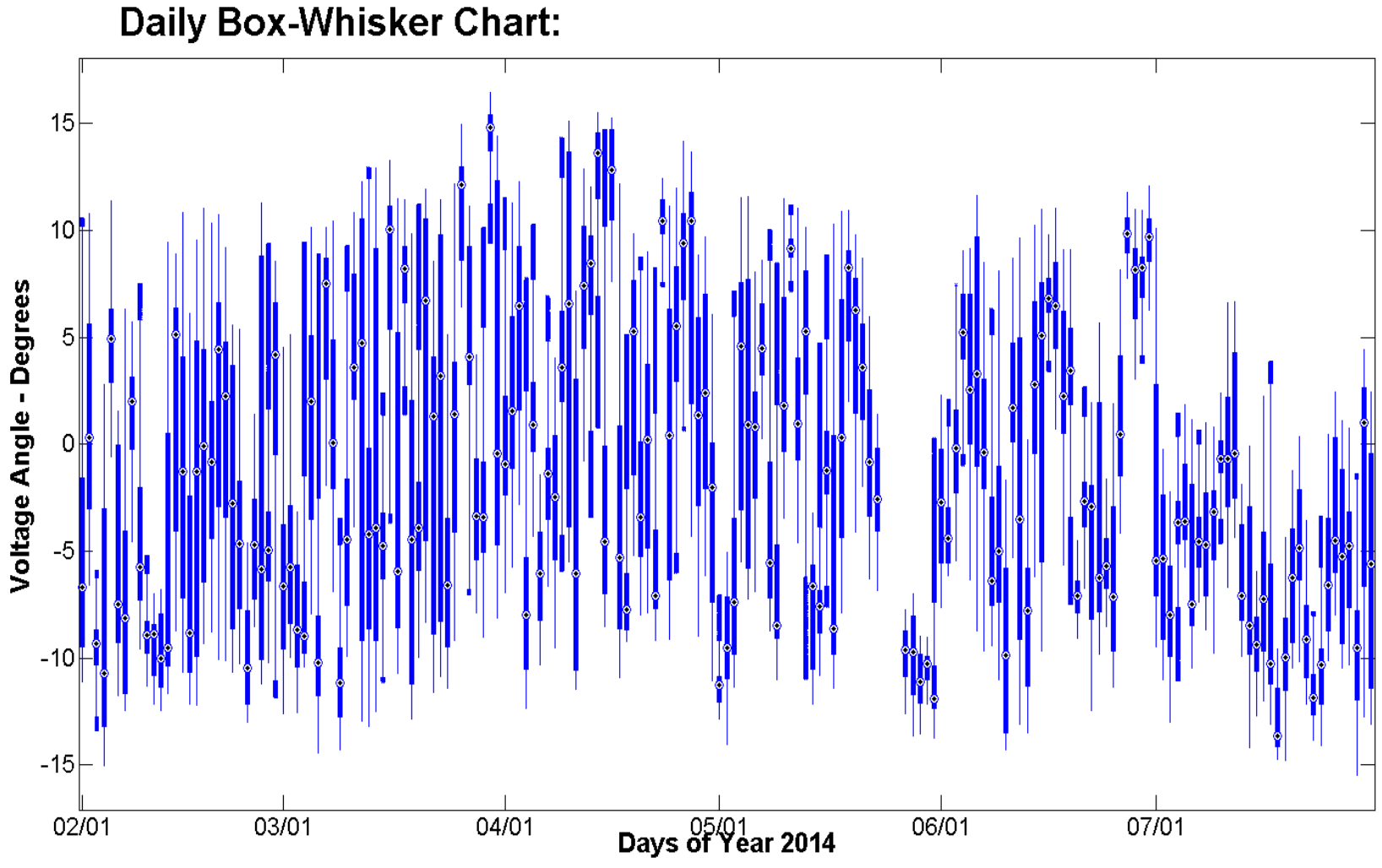
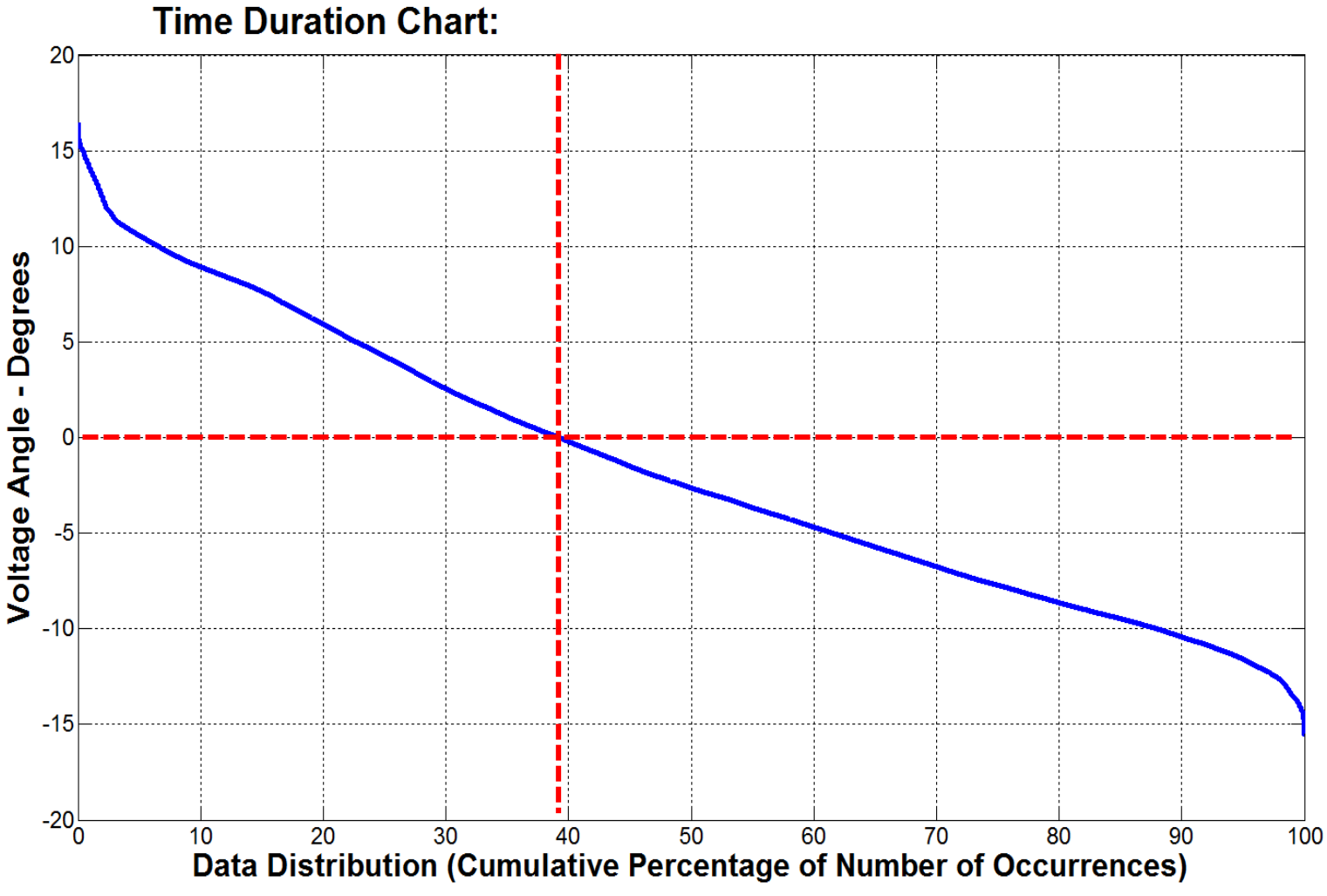


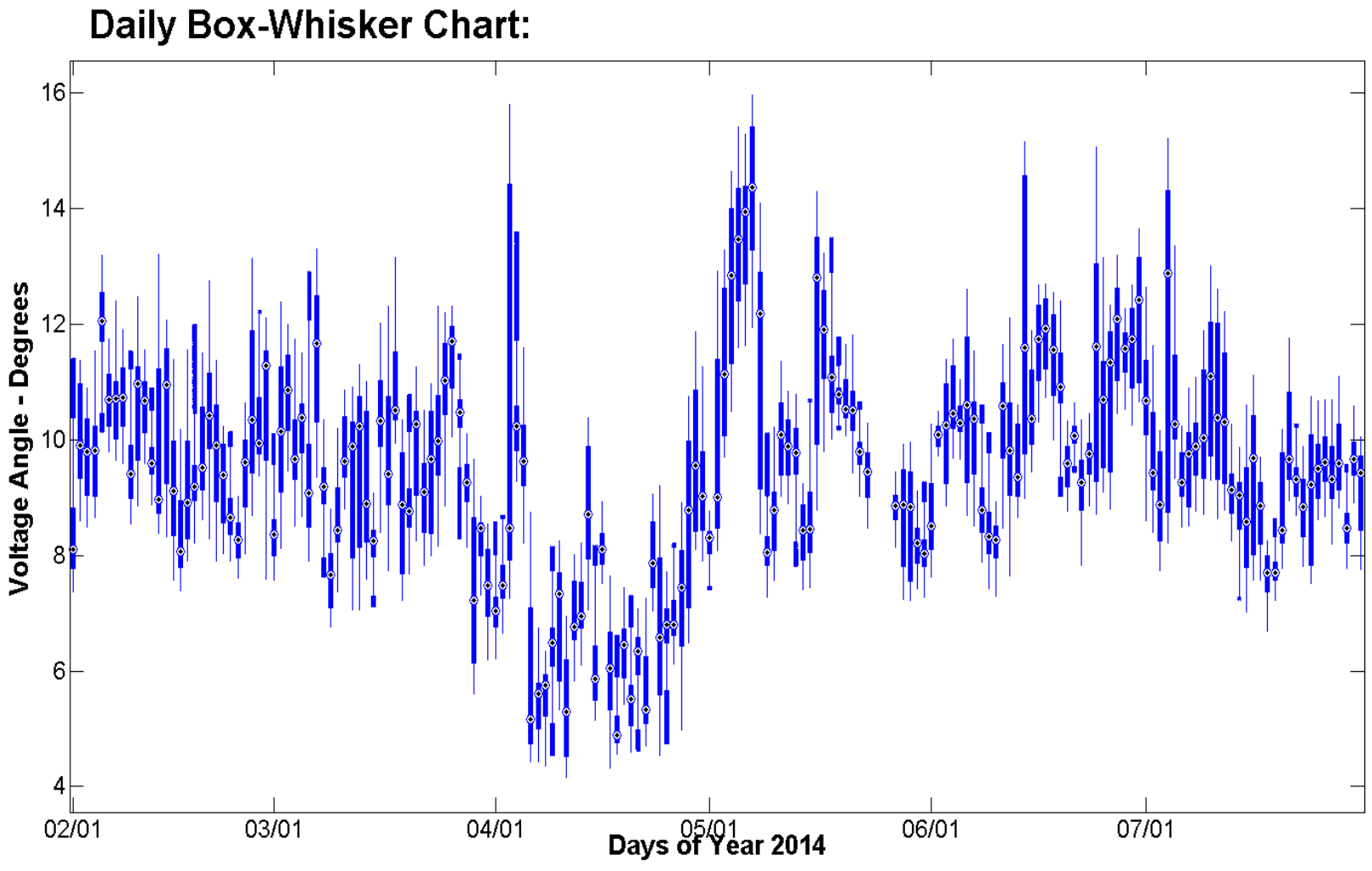
West 5 – North 1



West 5 – North 1



North 1 – North 4



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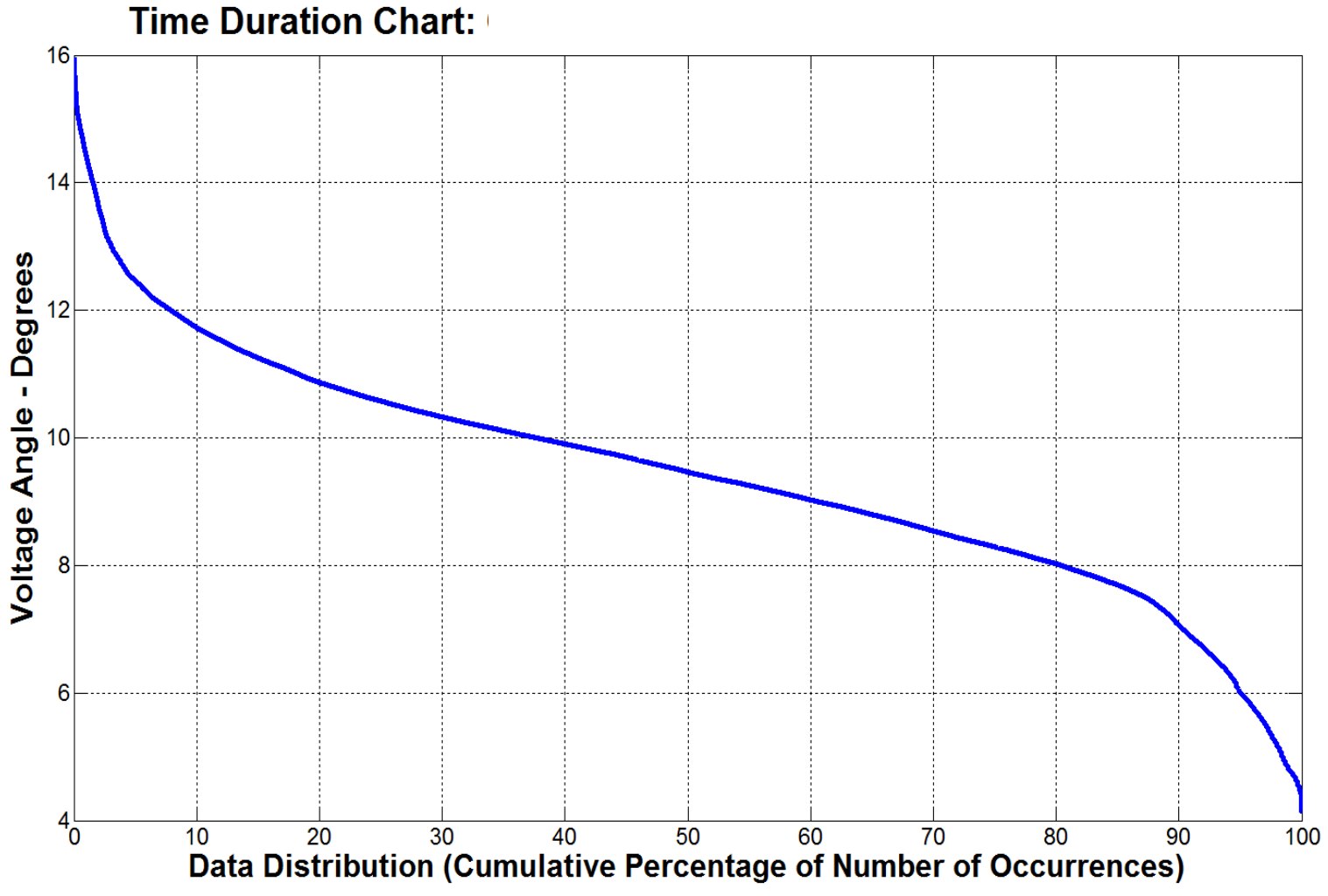

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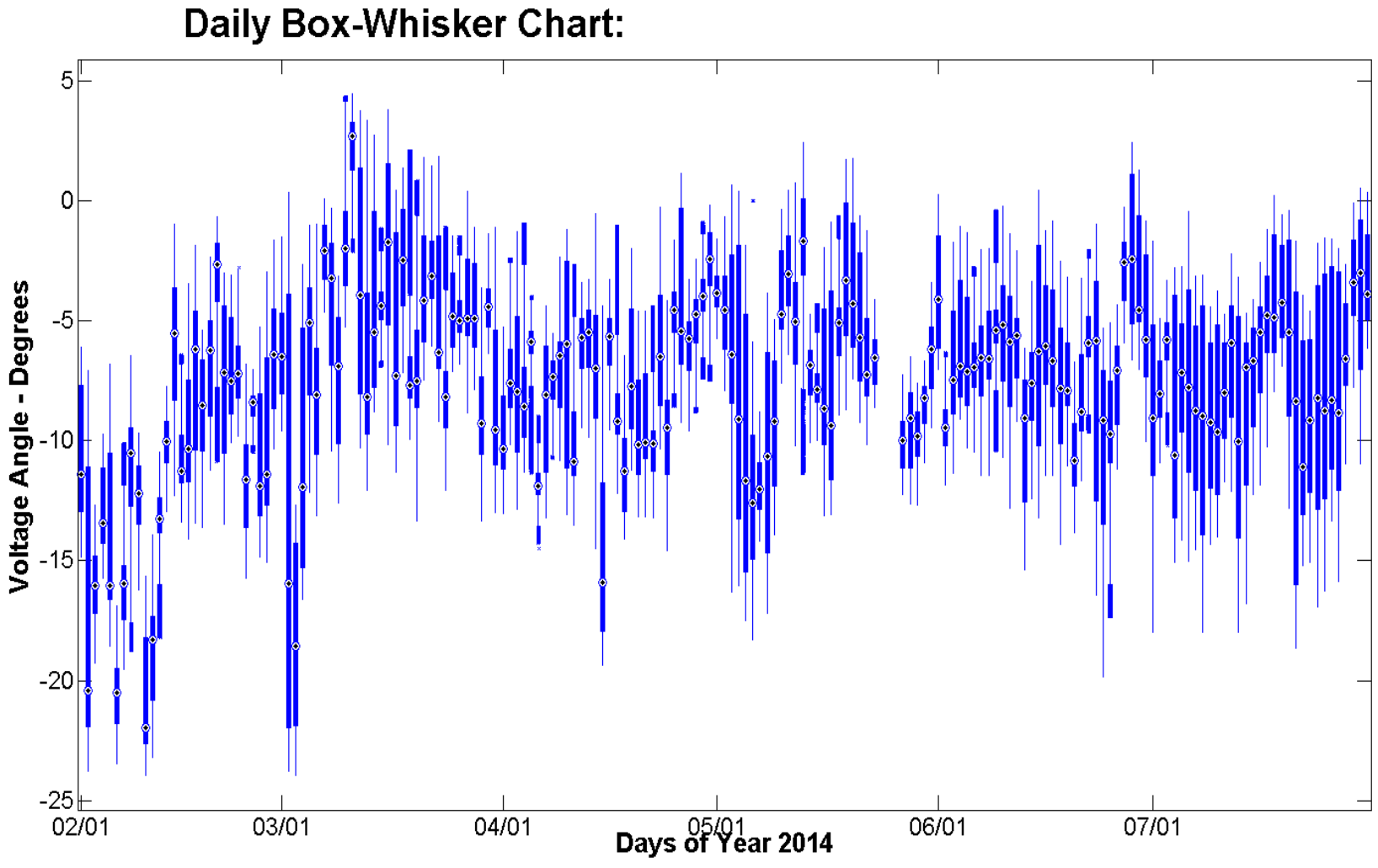
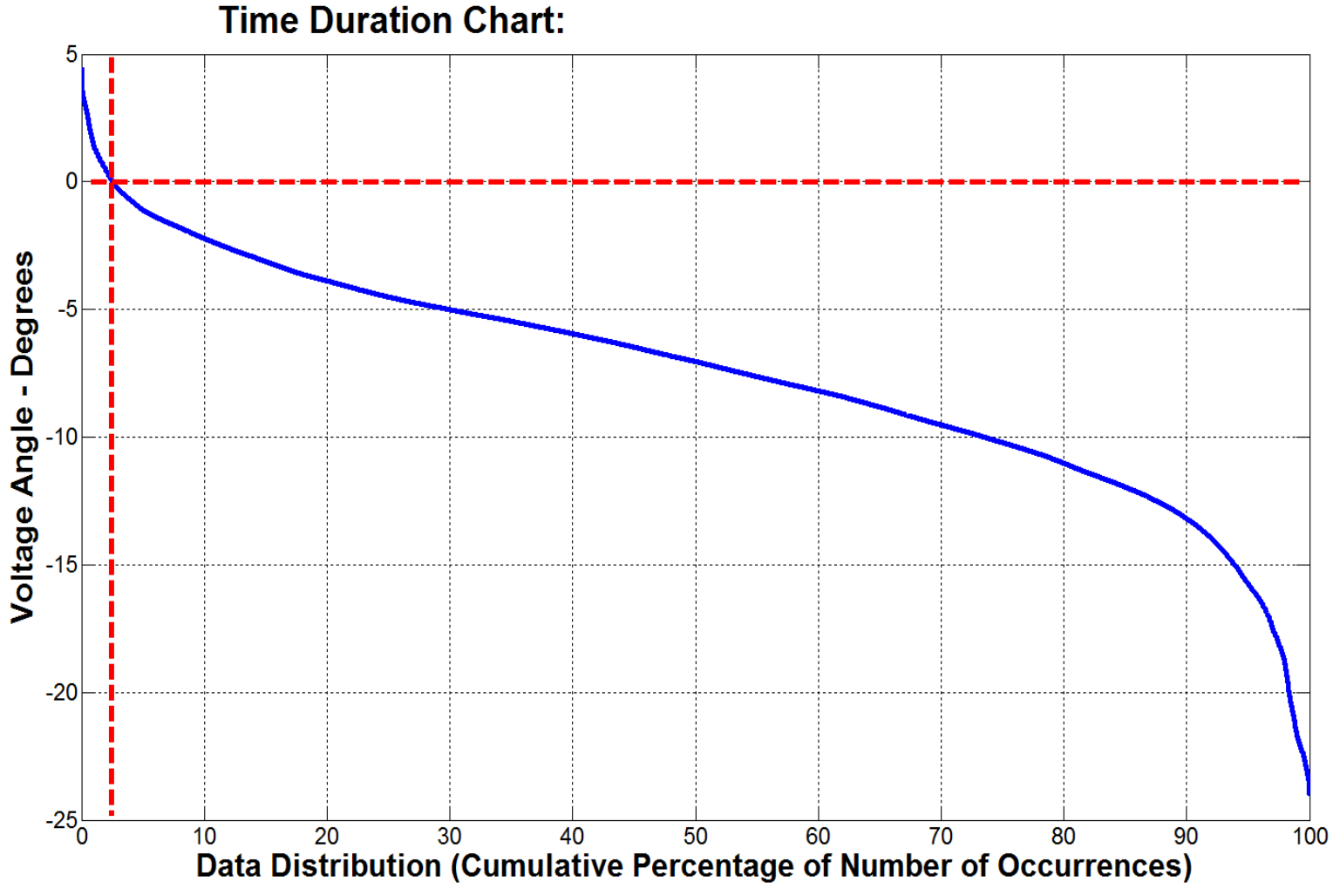
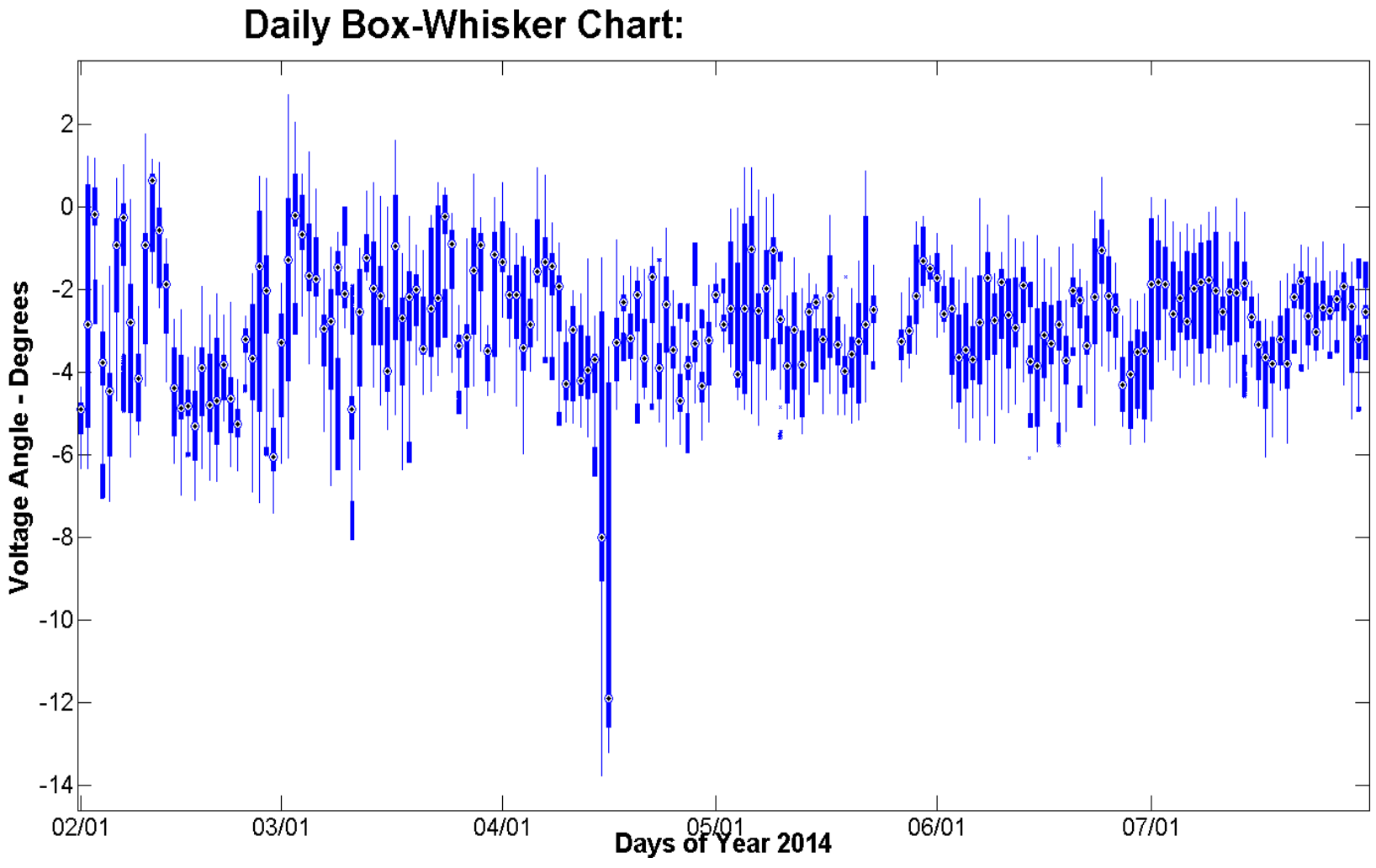


North 4 – North 6



FarWest 7 – FarWest 4



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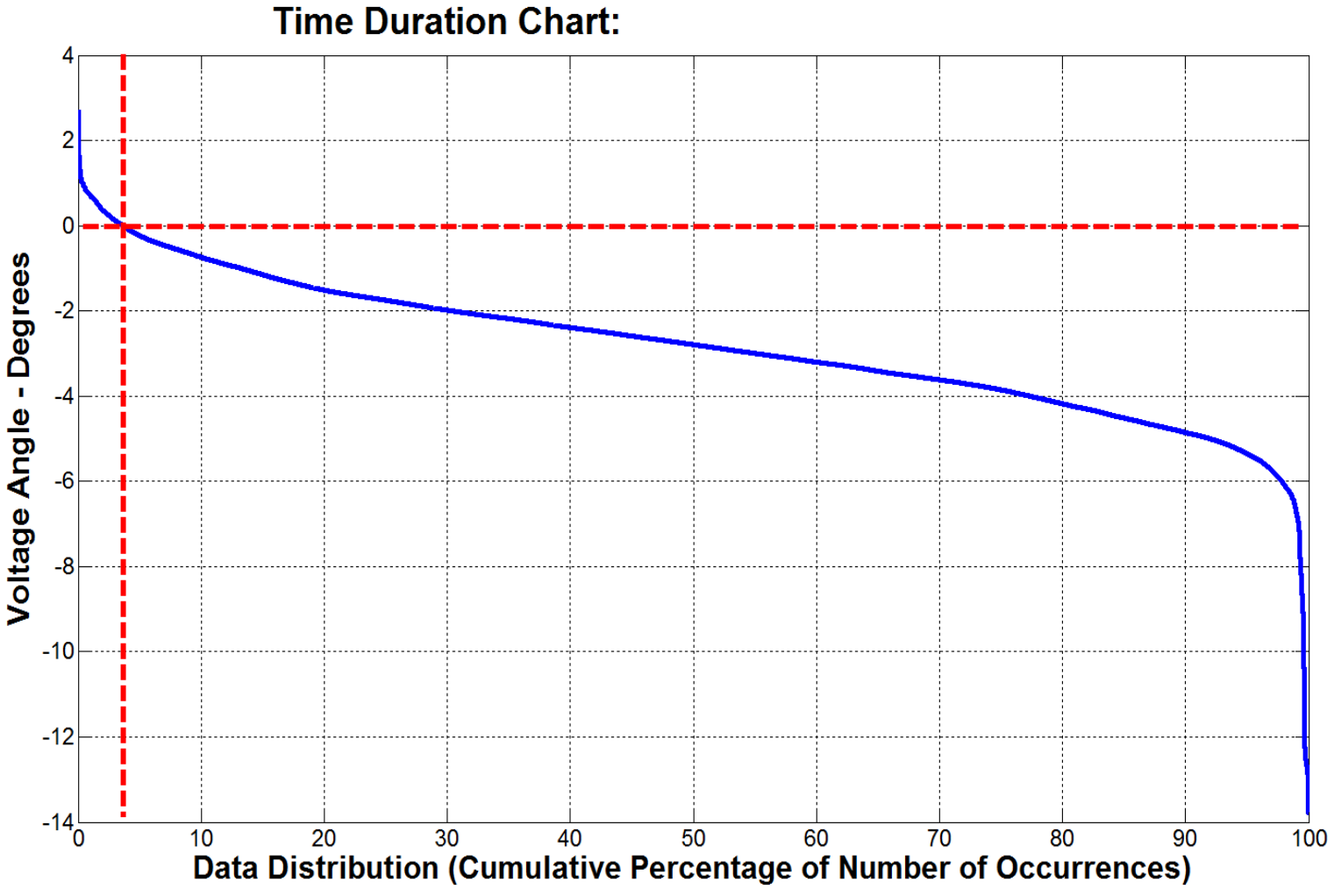
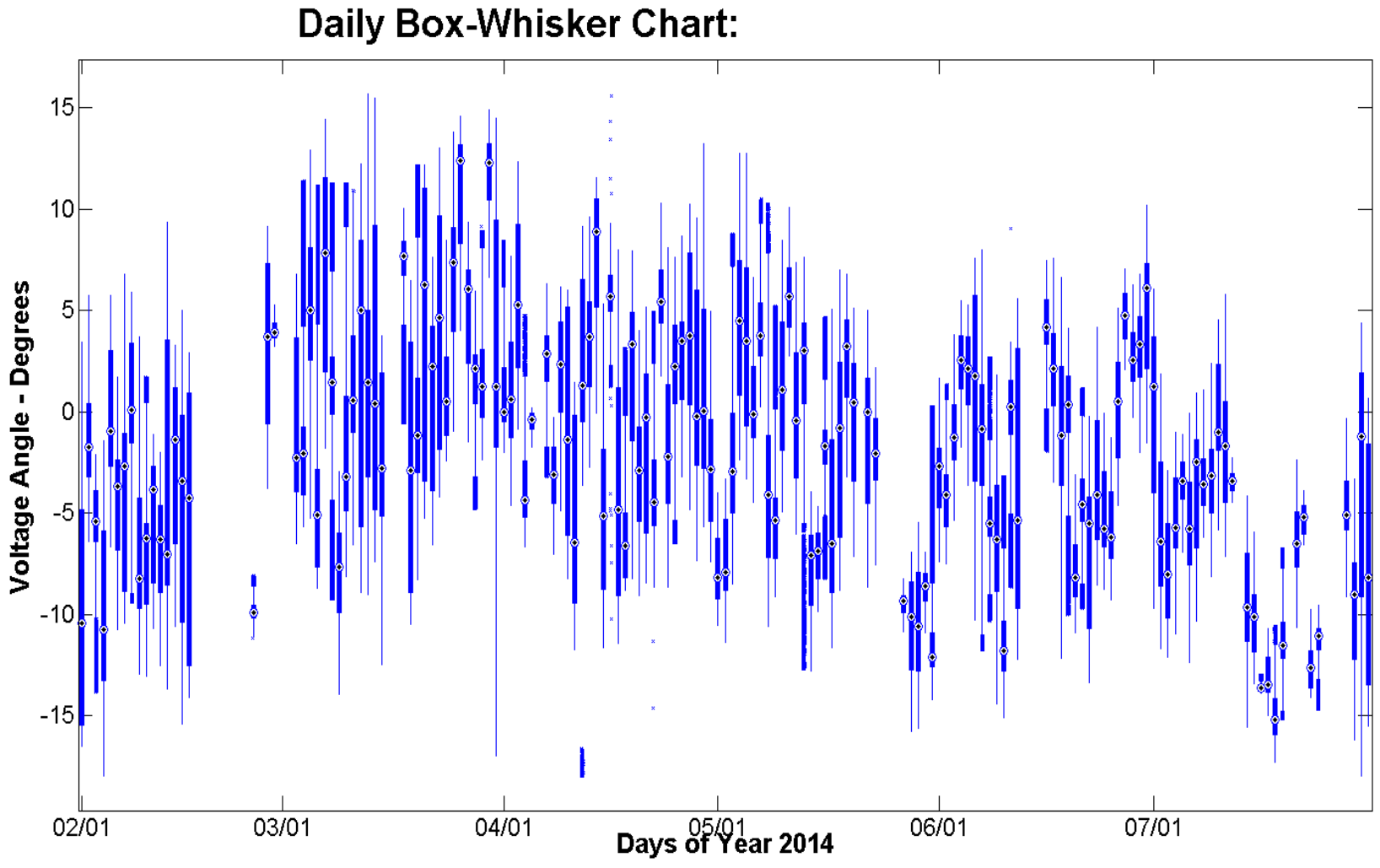
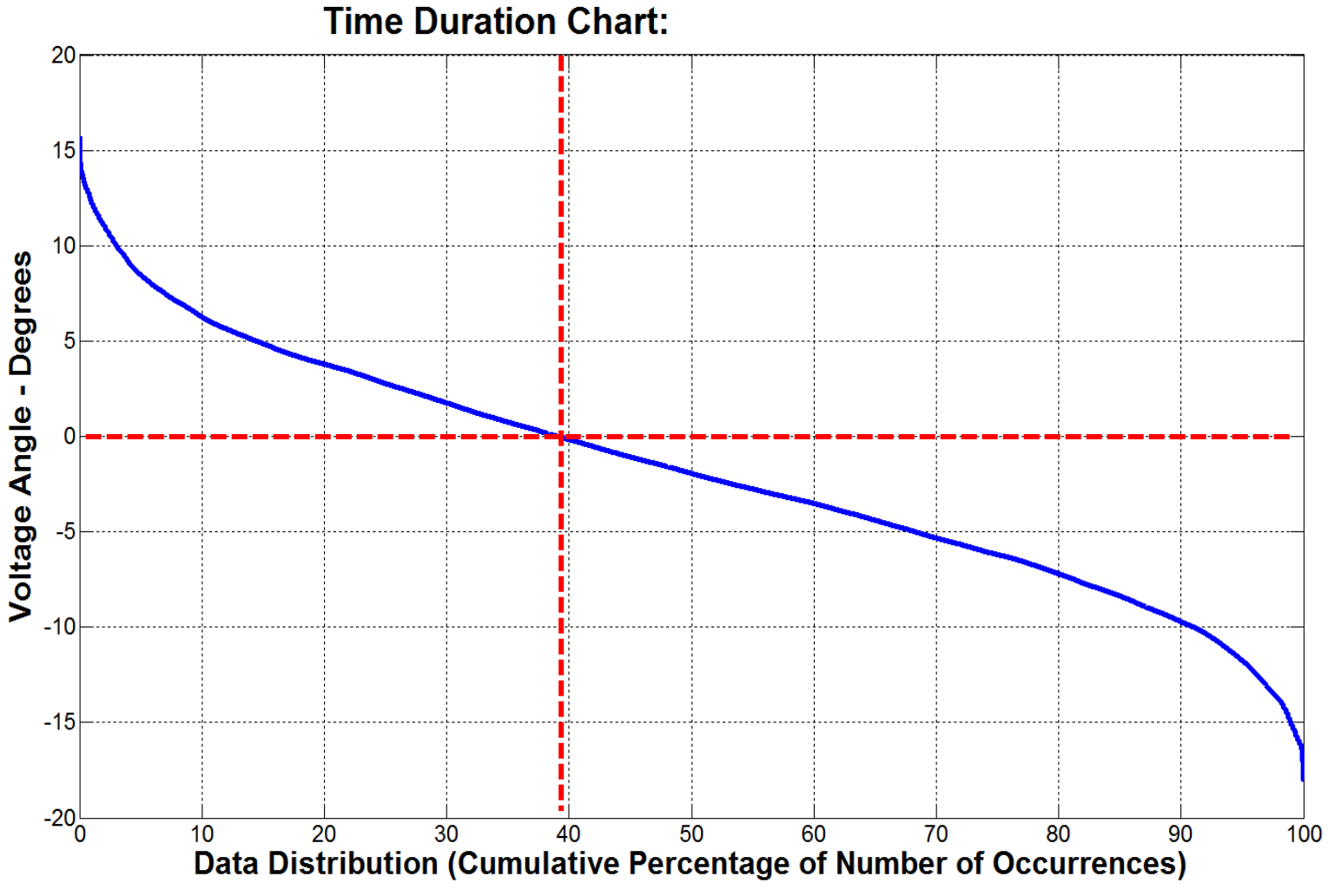


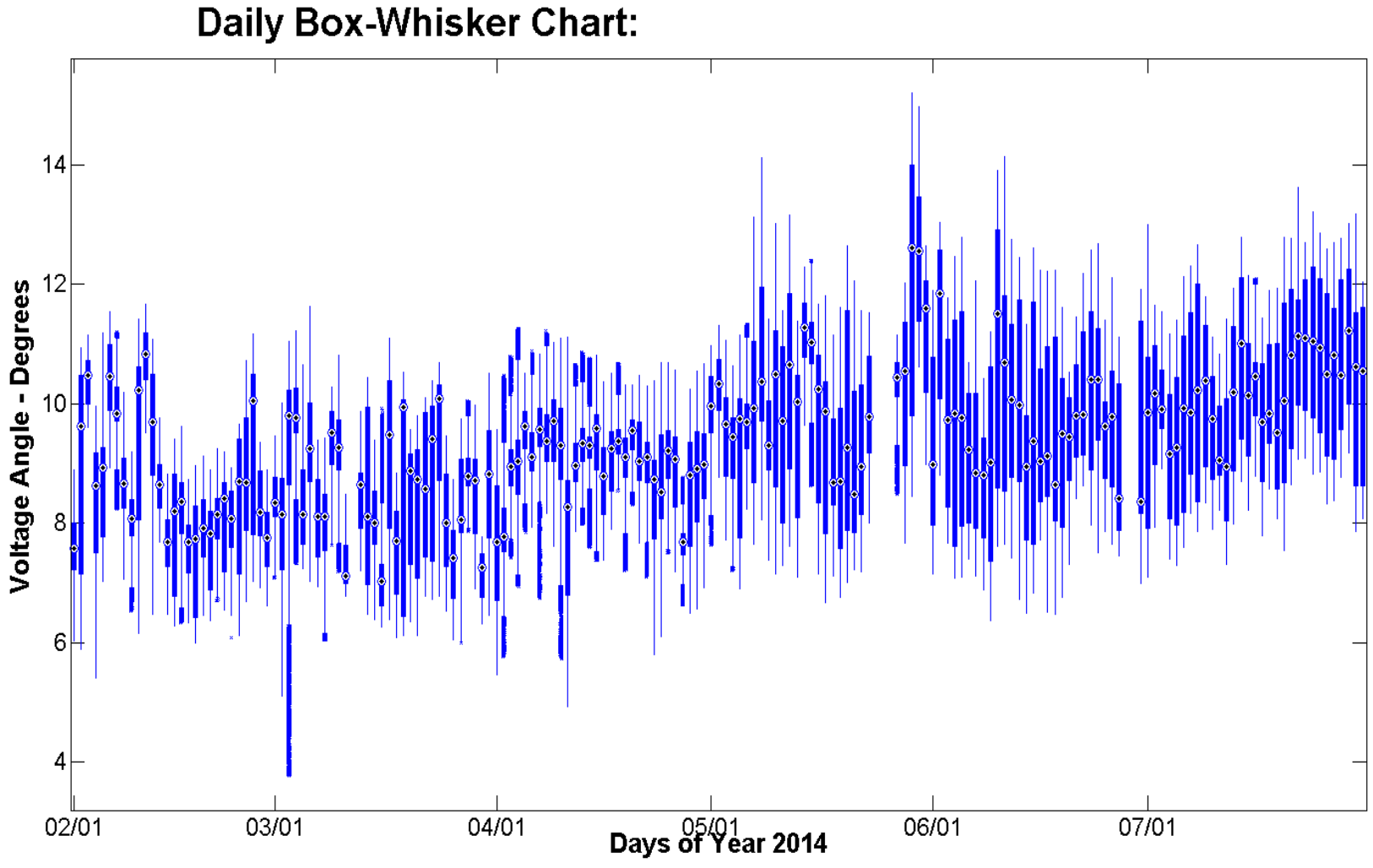
FarWest 7 – West 14



FarWest 7 – West 14



FarWest 7 – FarWest 8



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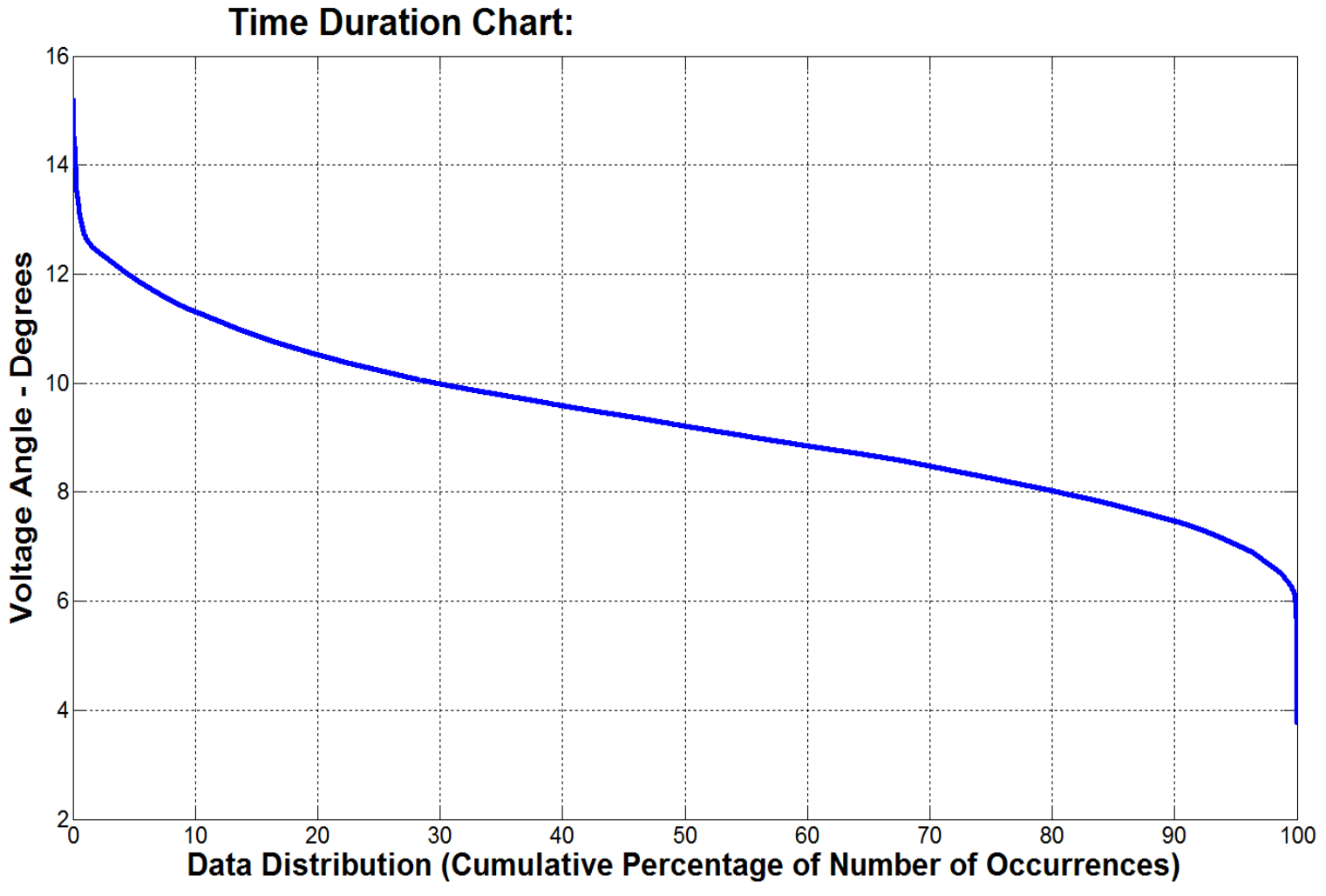
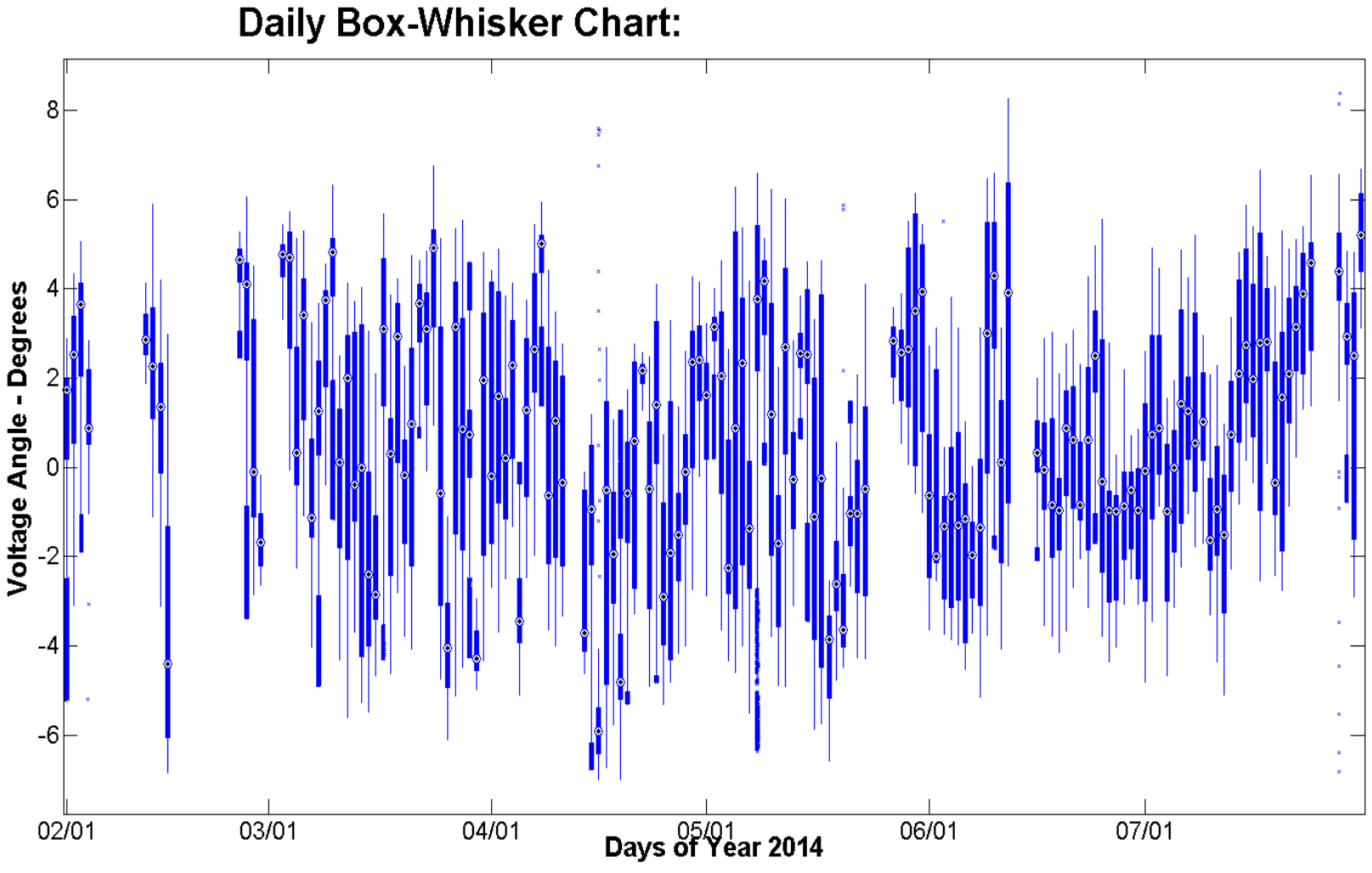
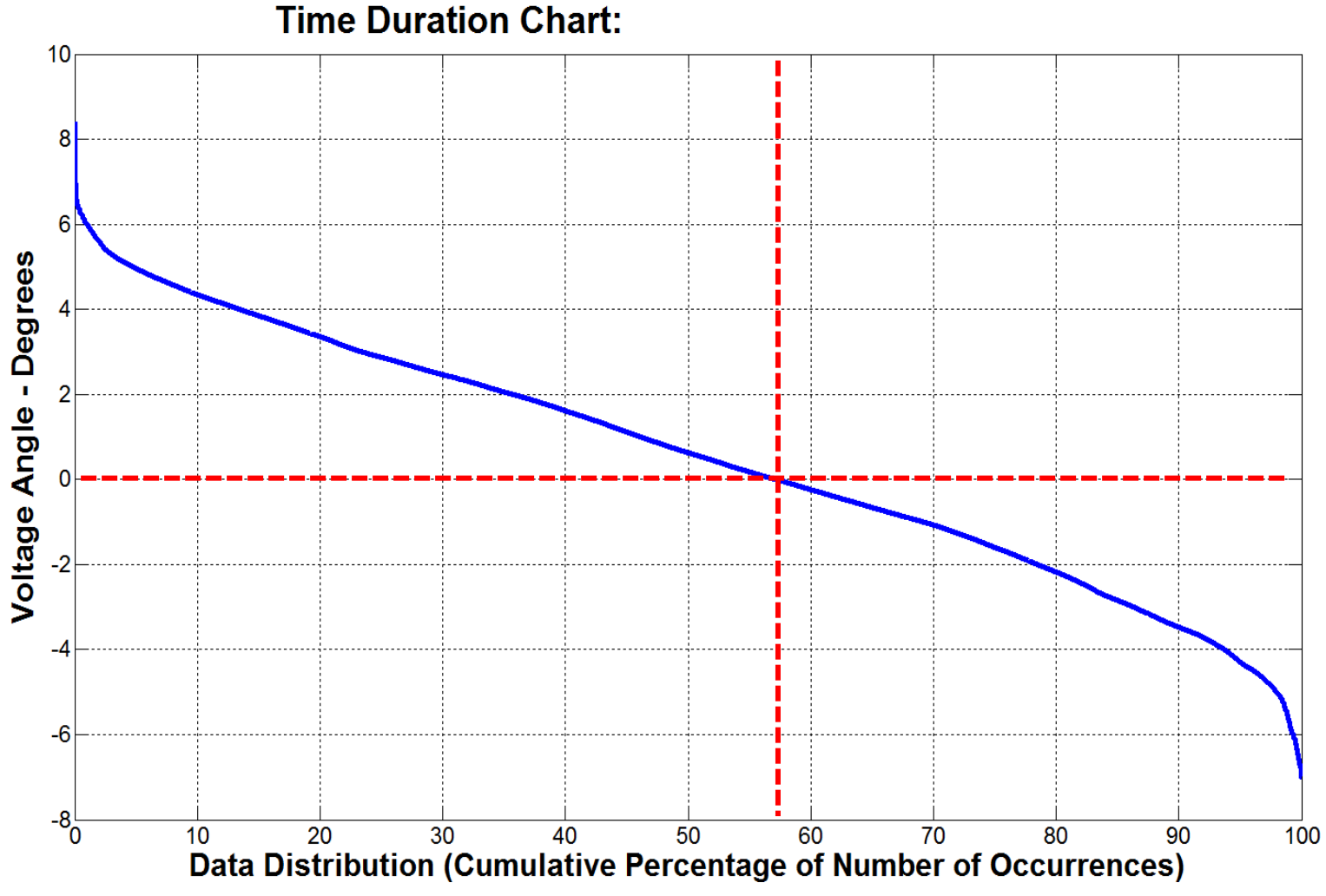


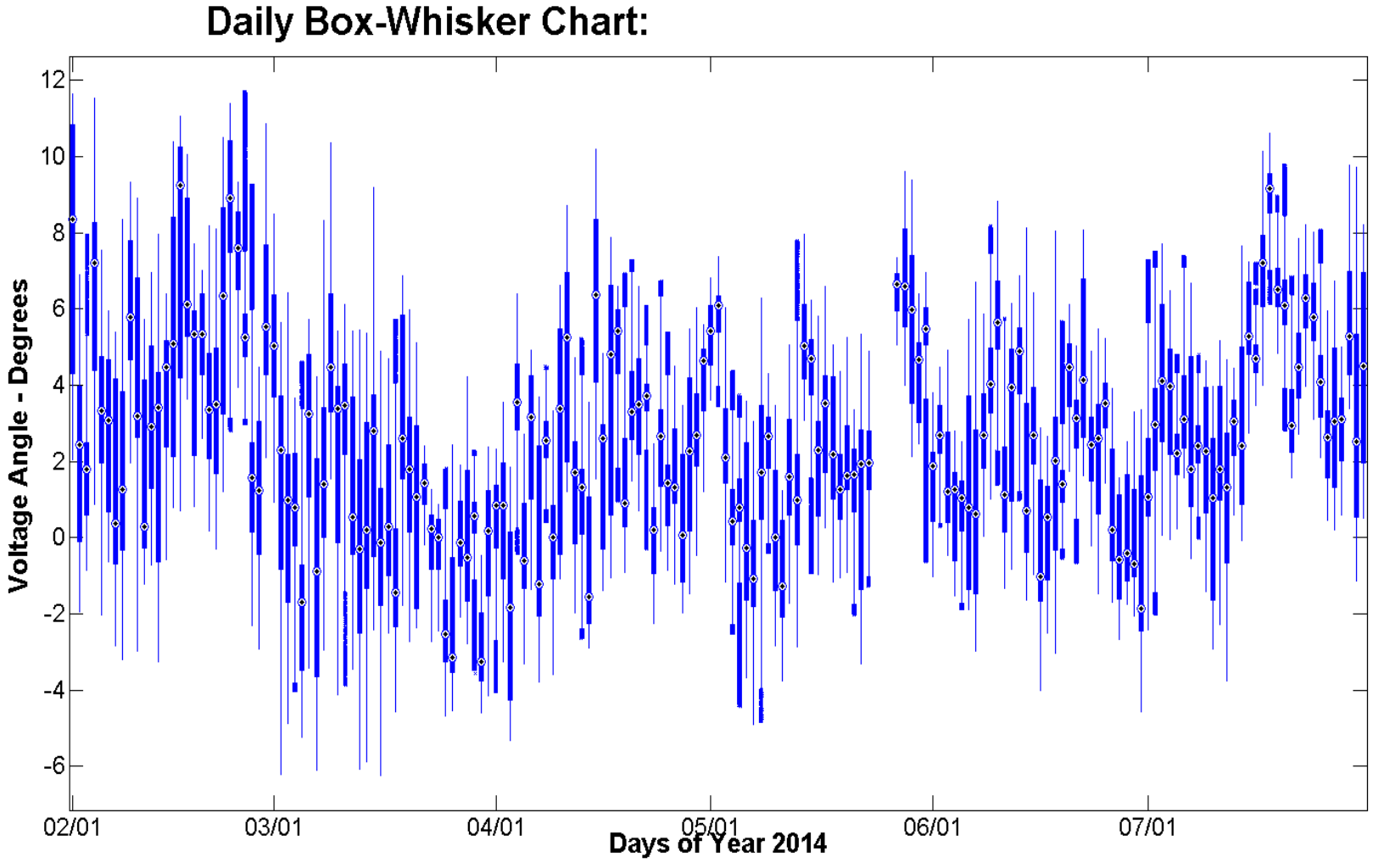
FarWest 7 – FarWest 9



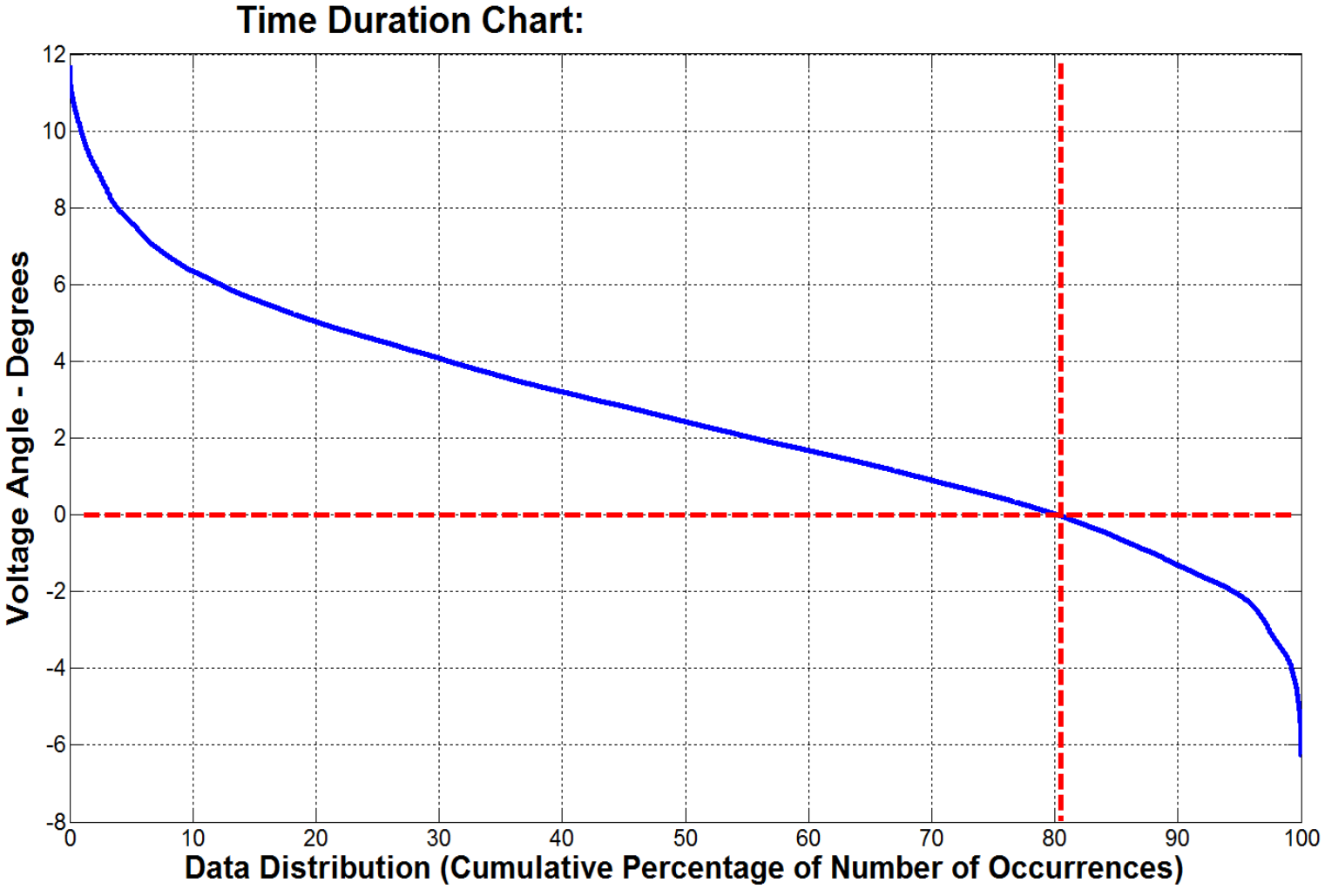
FarWest 7 – FarWest 9



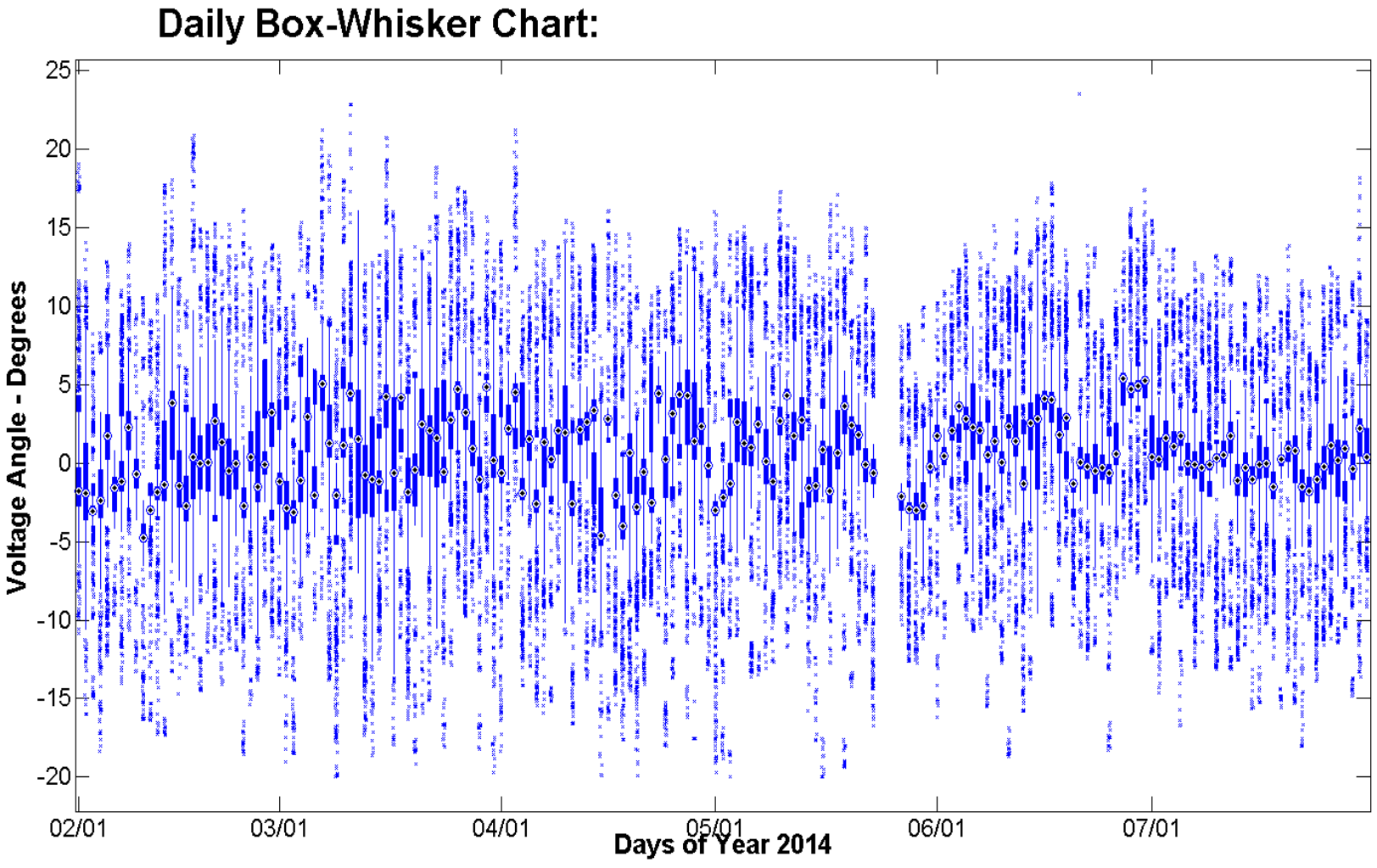
West 12 – FarWest 7



West 12 – FarWest 7

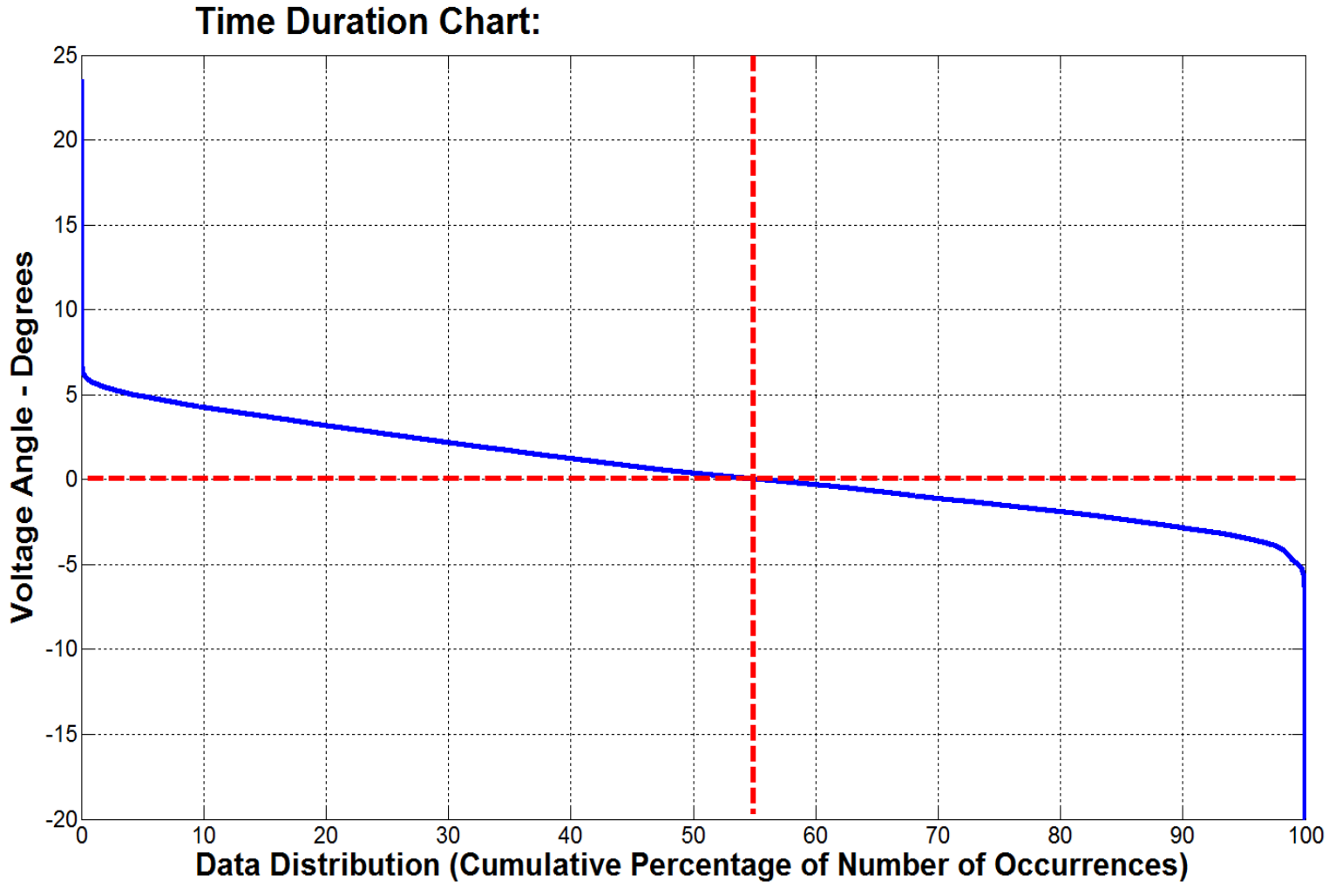


West 12 – West 1*

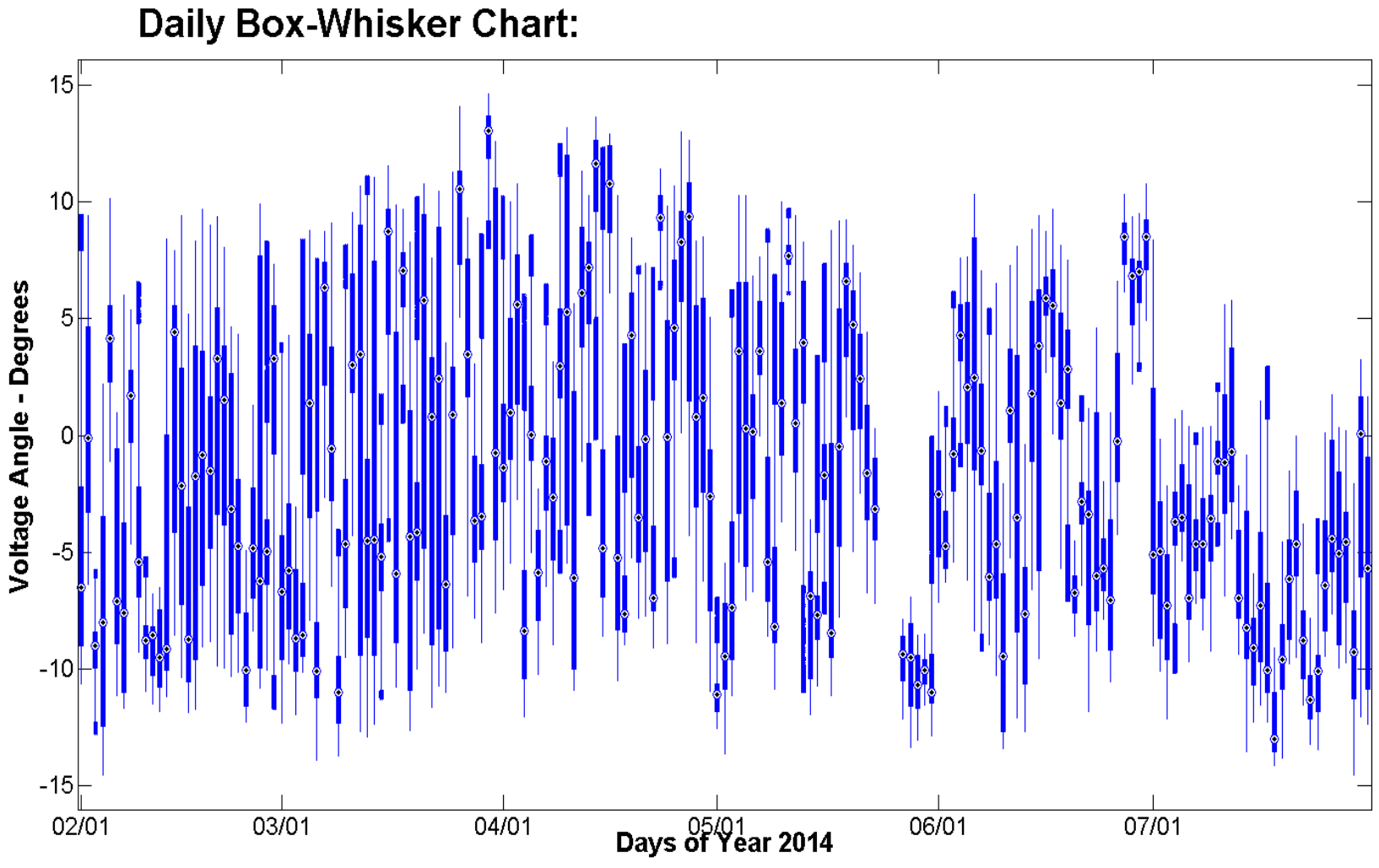


* West 1 PMU has noisy signal

West 12 – West 1



West 12 – North 1



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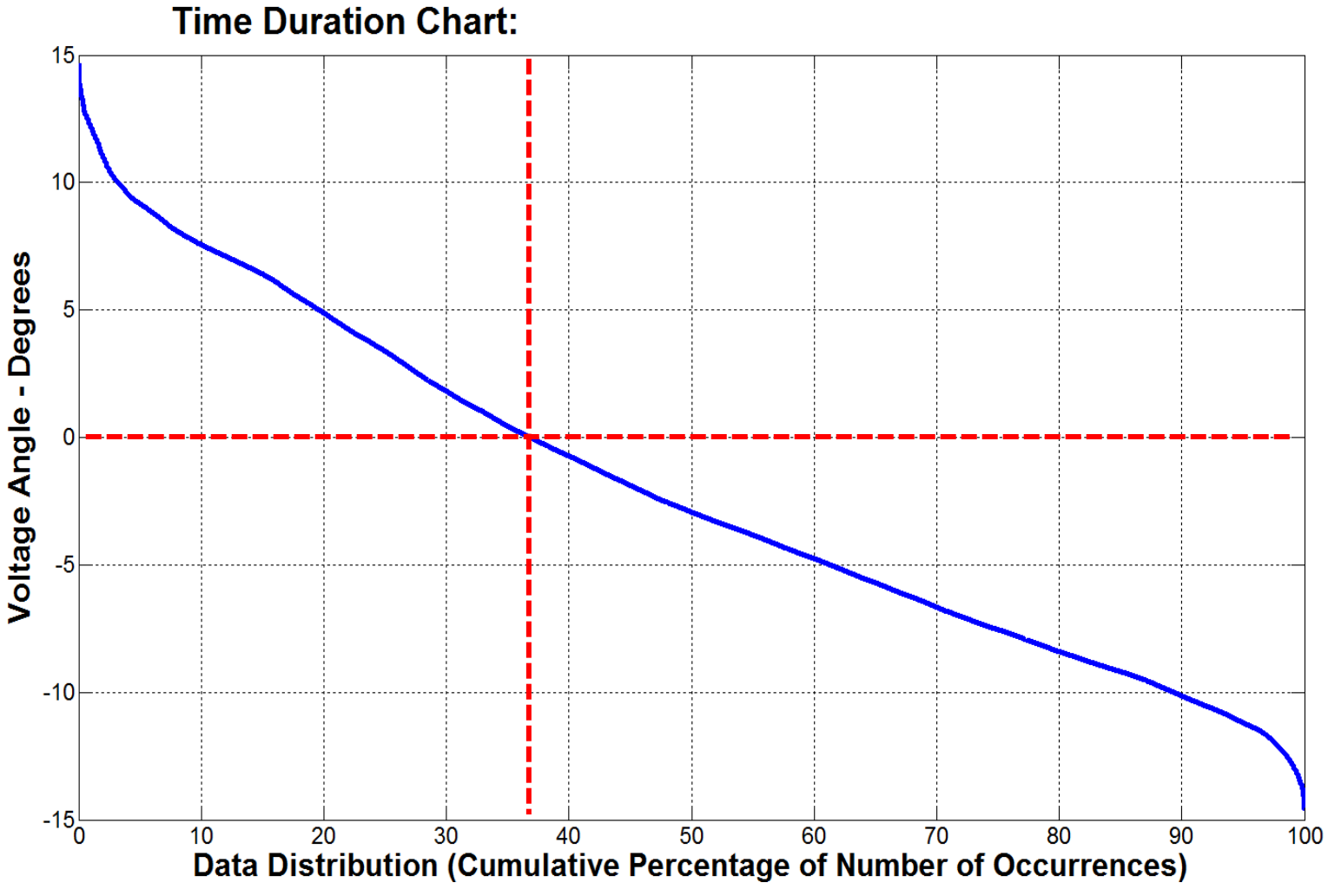
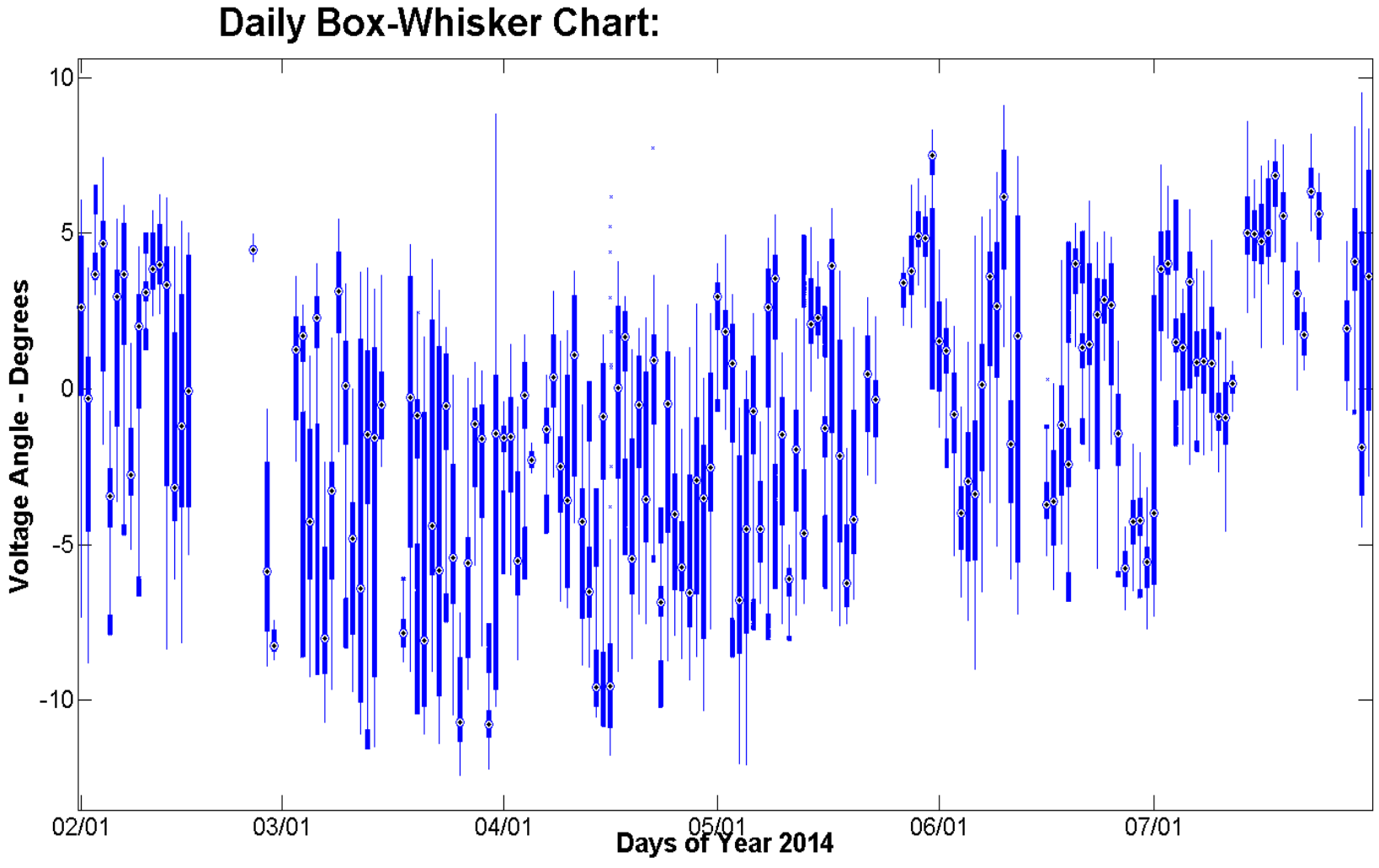


West 14 – West 5



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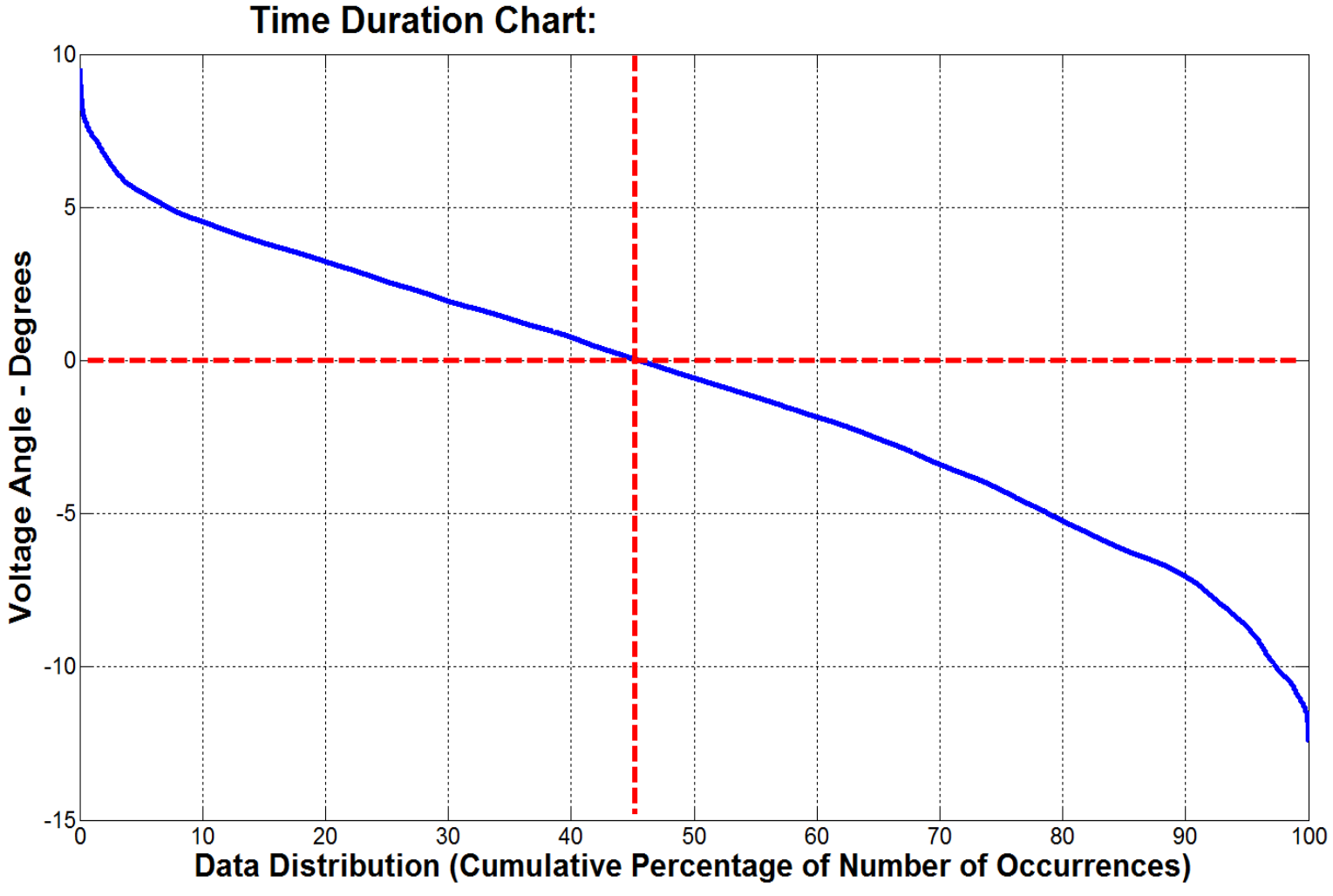

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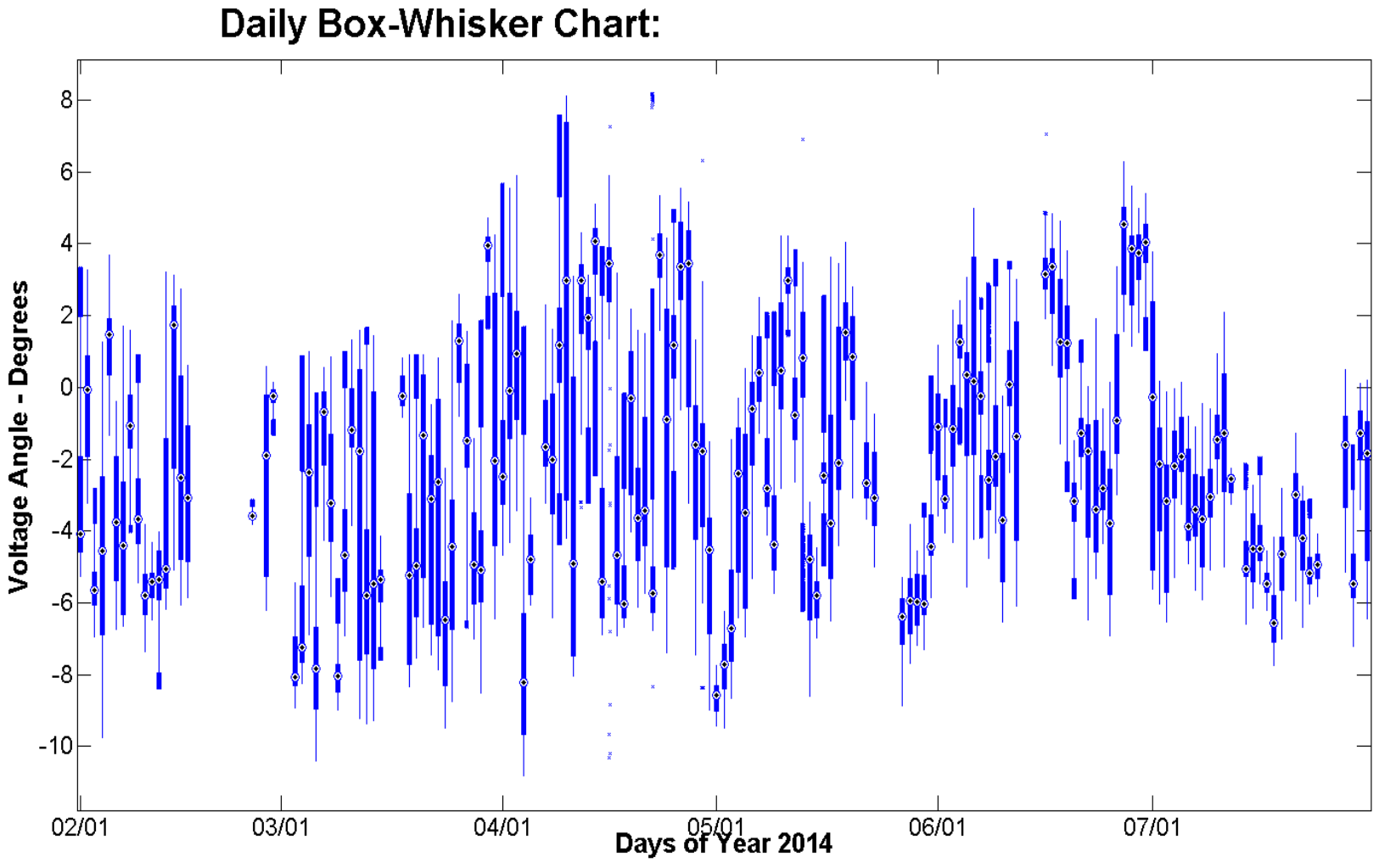
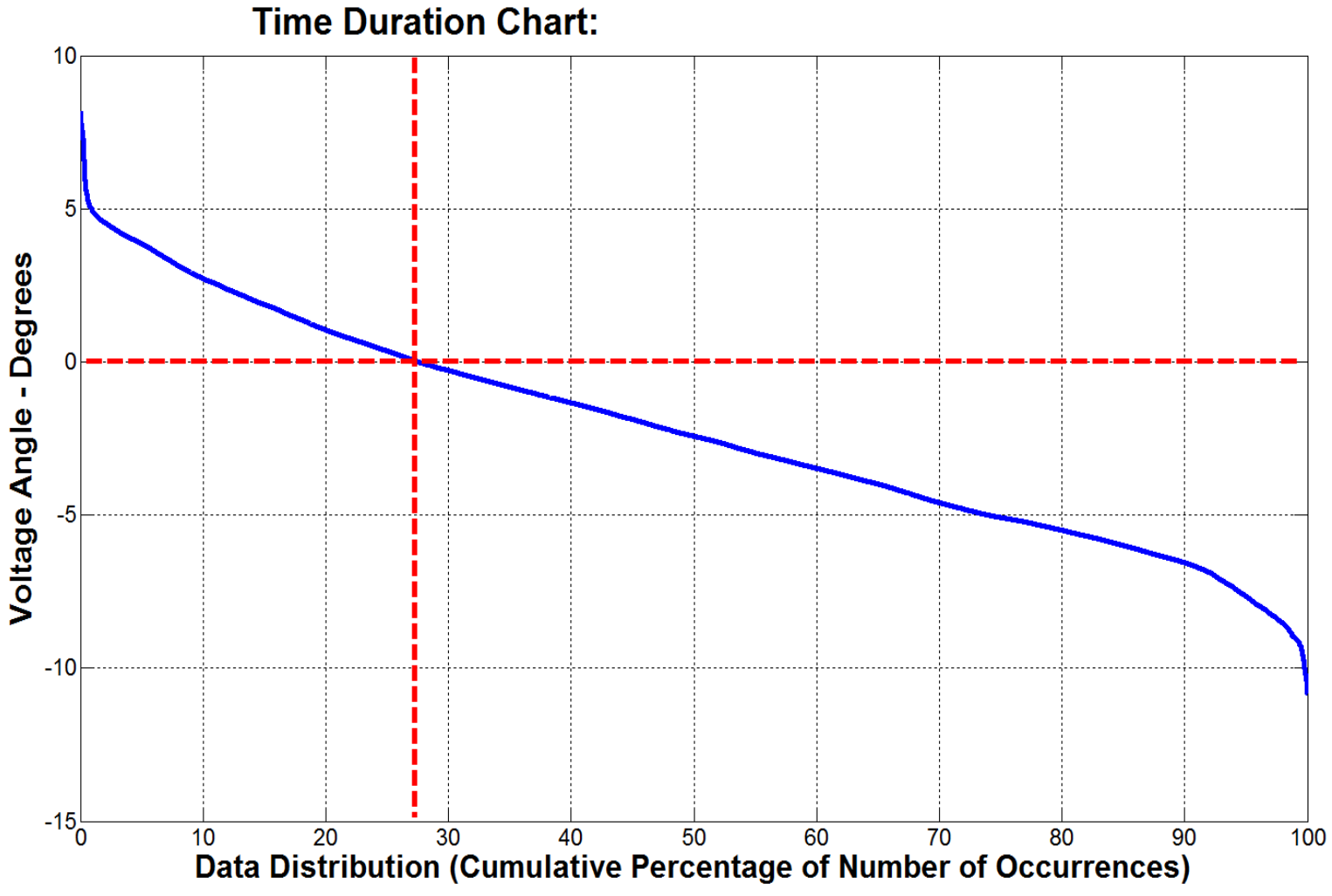
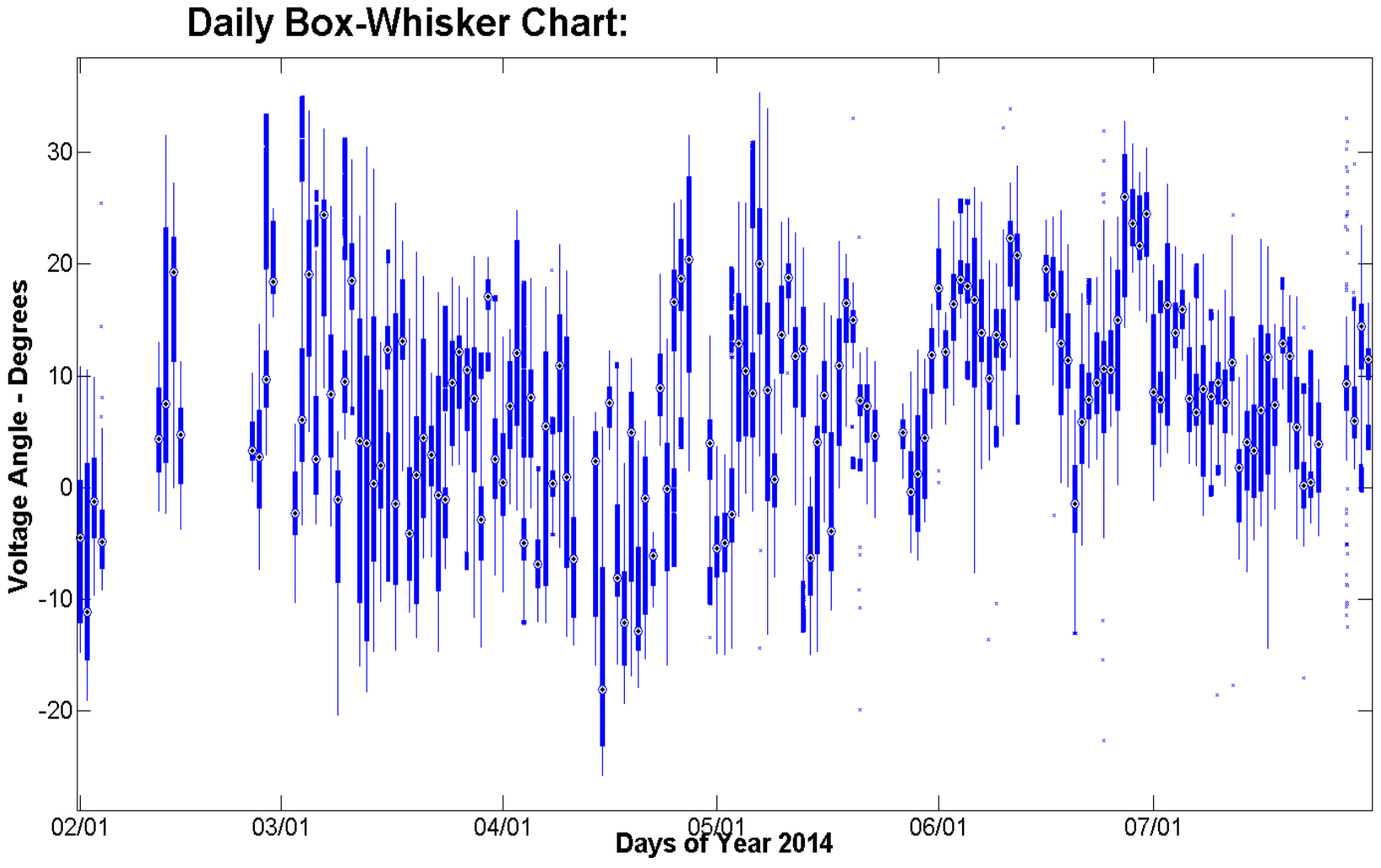


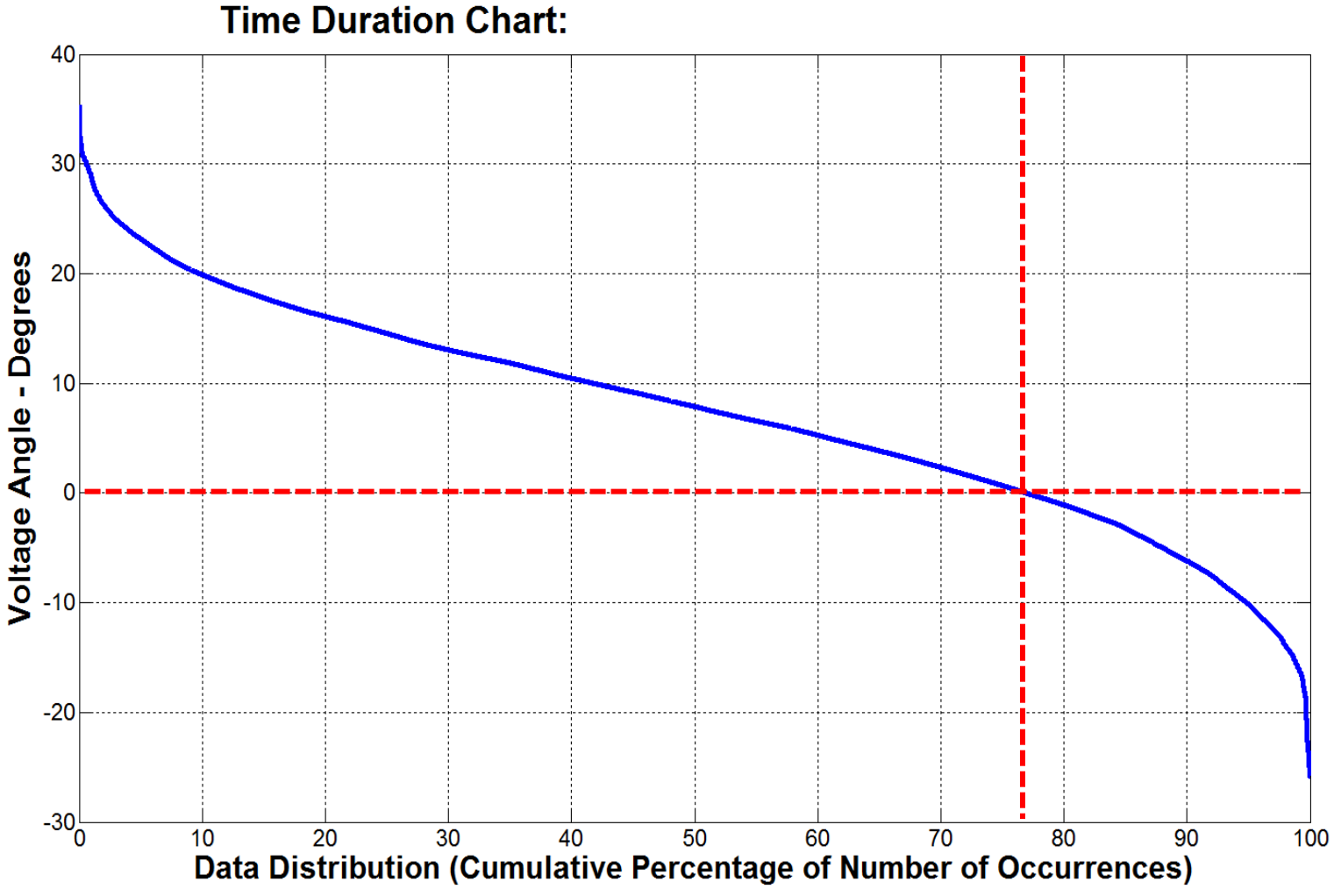
West 14 – North 1



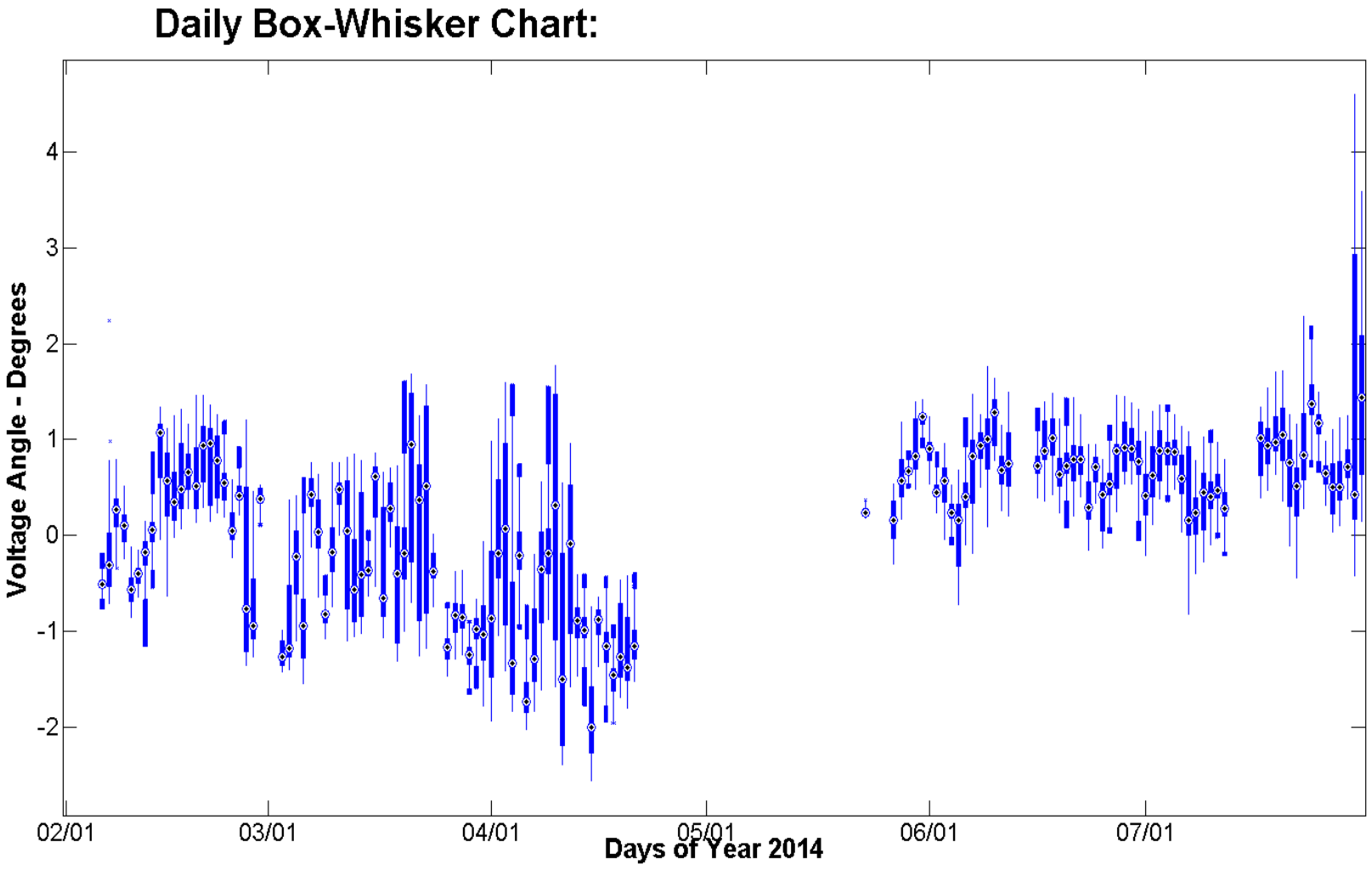
FarWest 9 – West 4



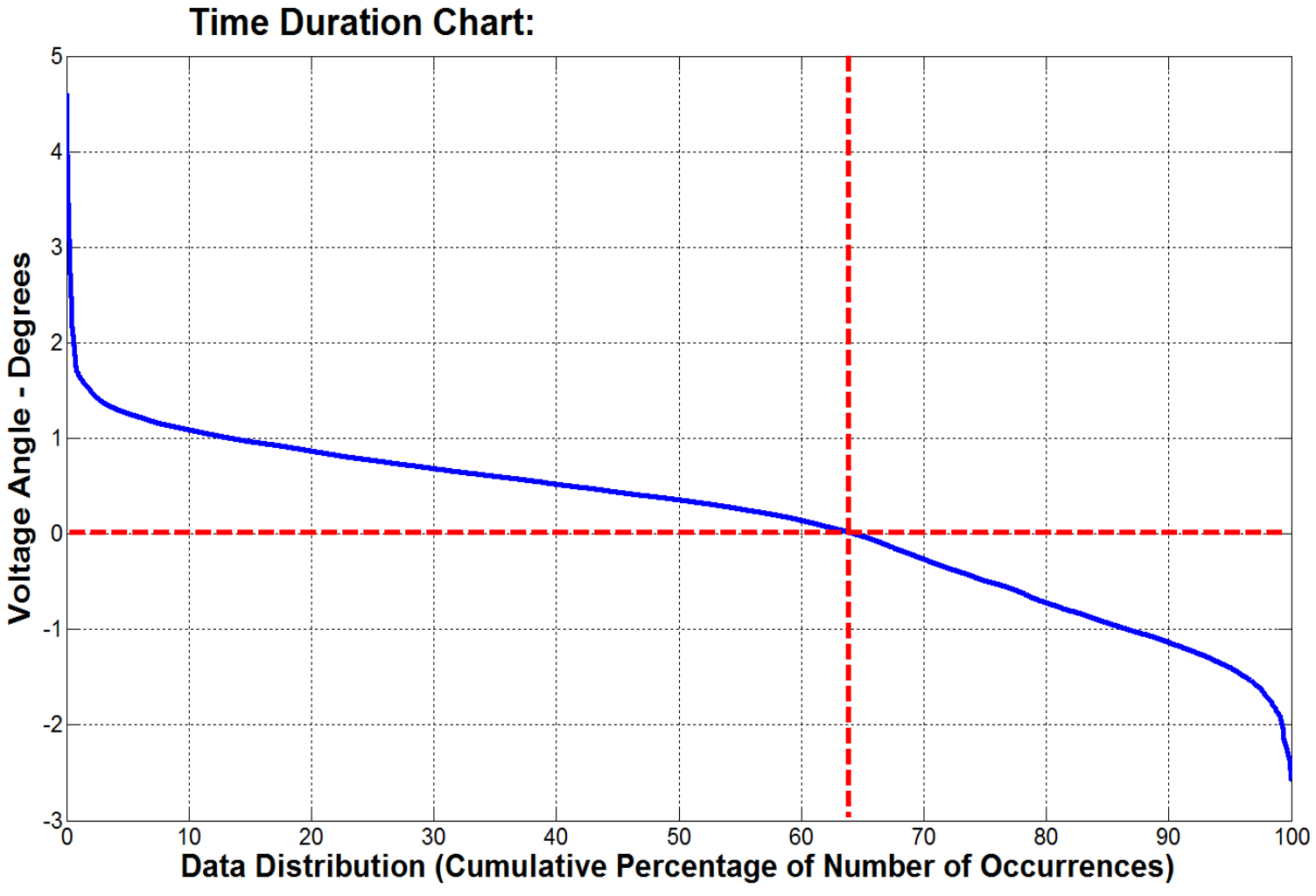
FarWest 9 – West 4



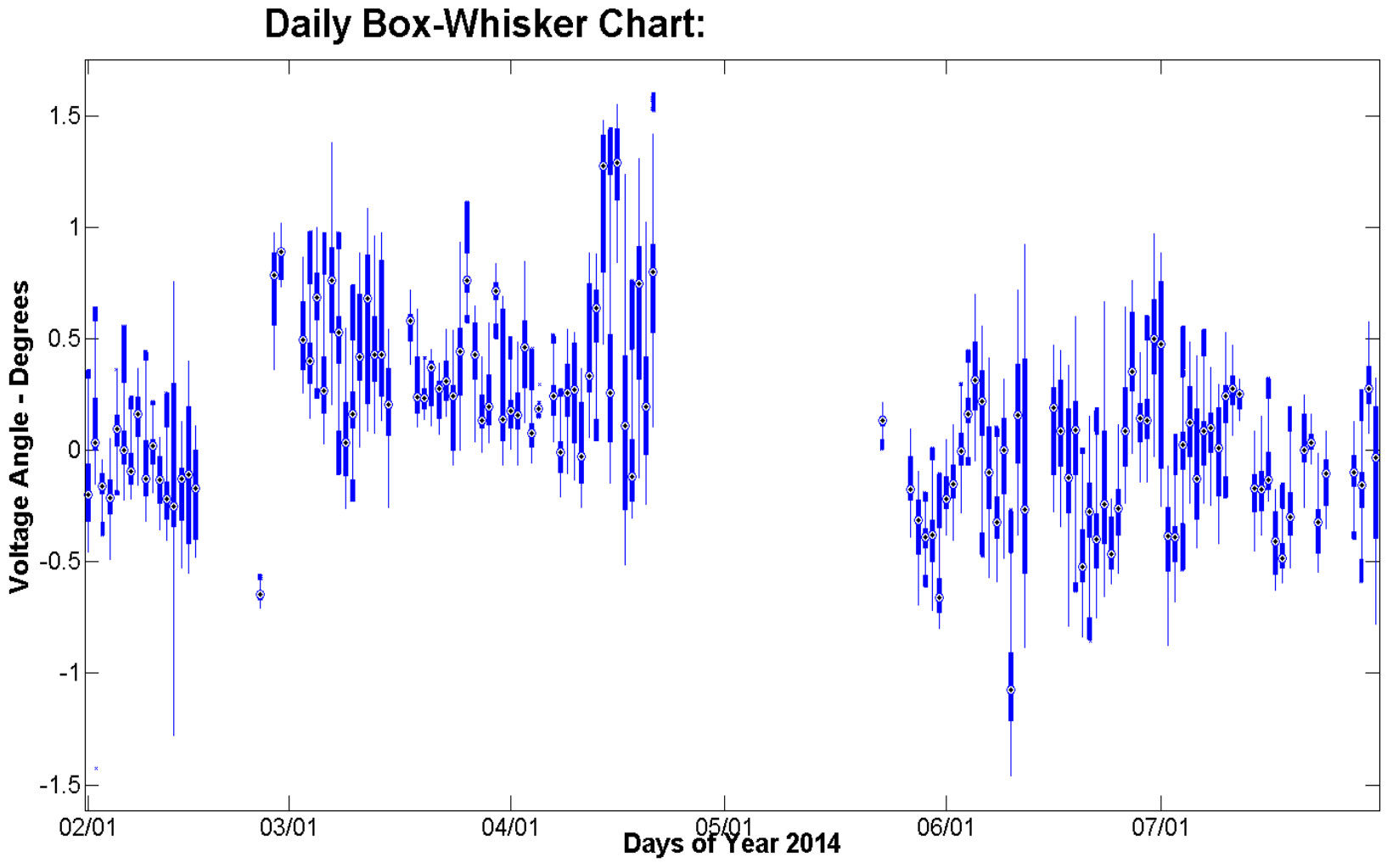
West 16 – West 3



West 16 – West 3



West 16 – West 14



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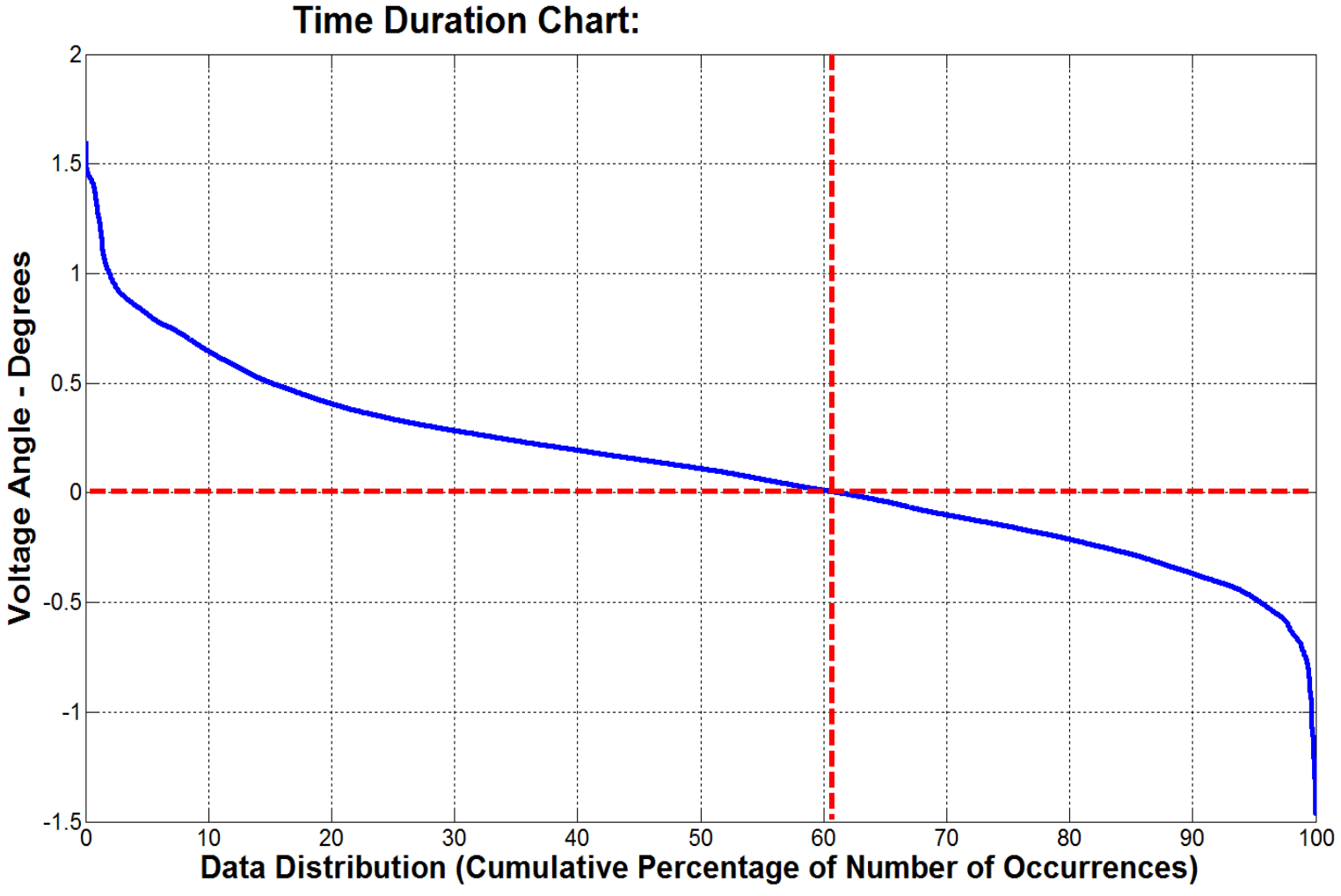

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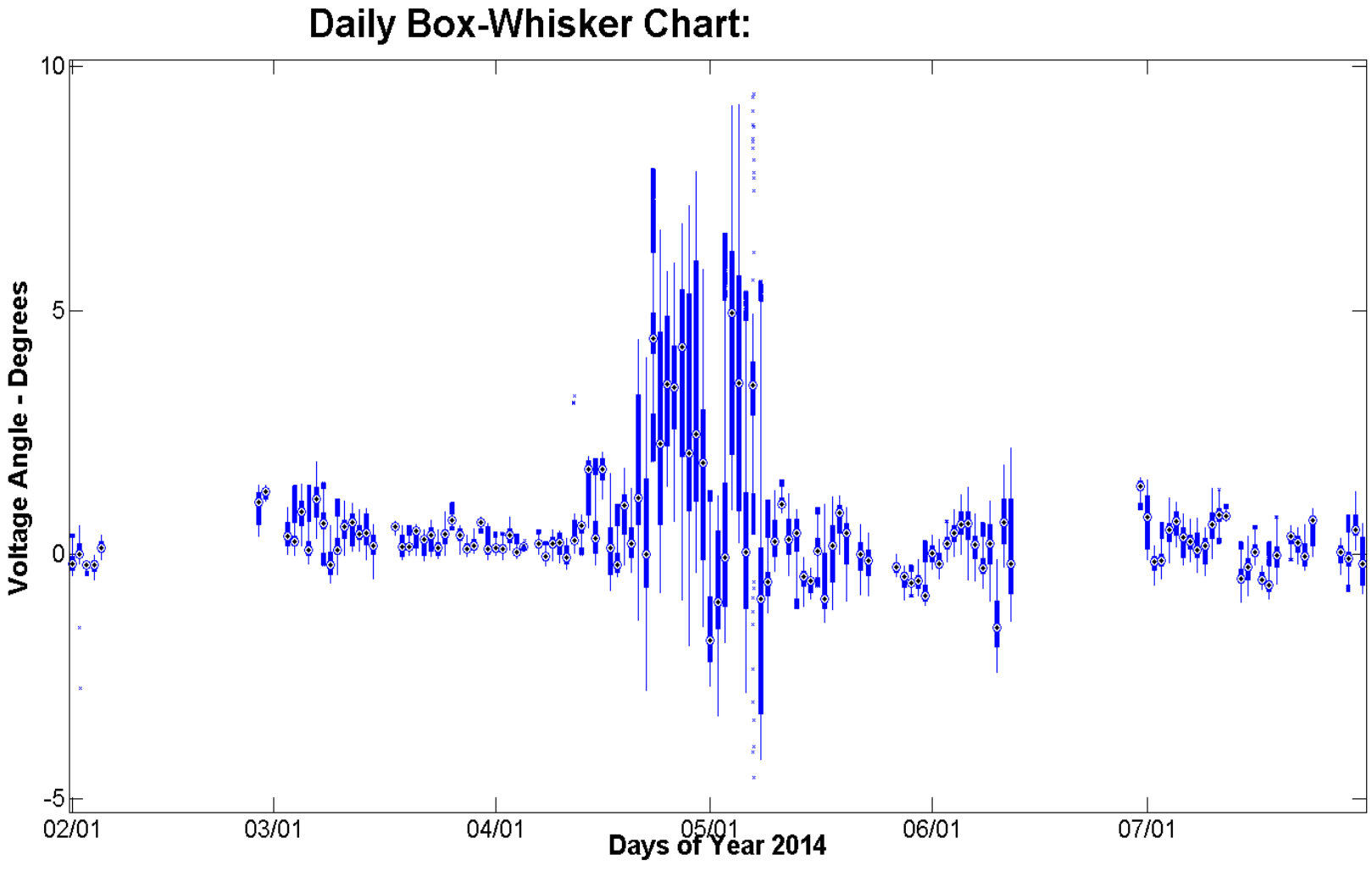

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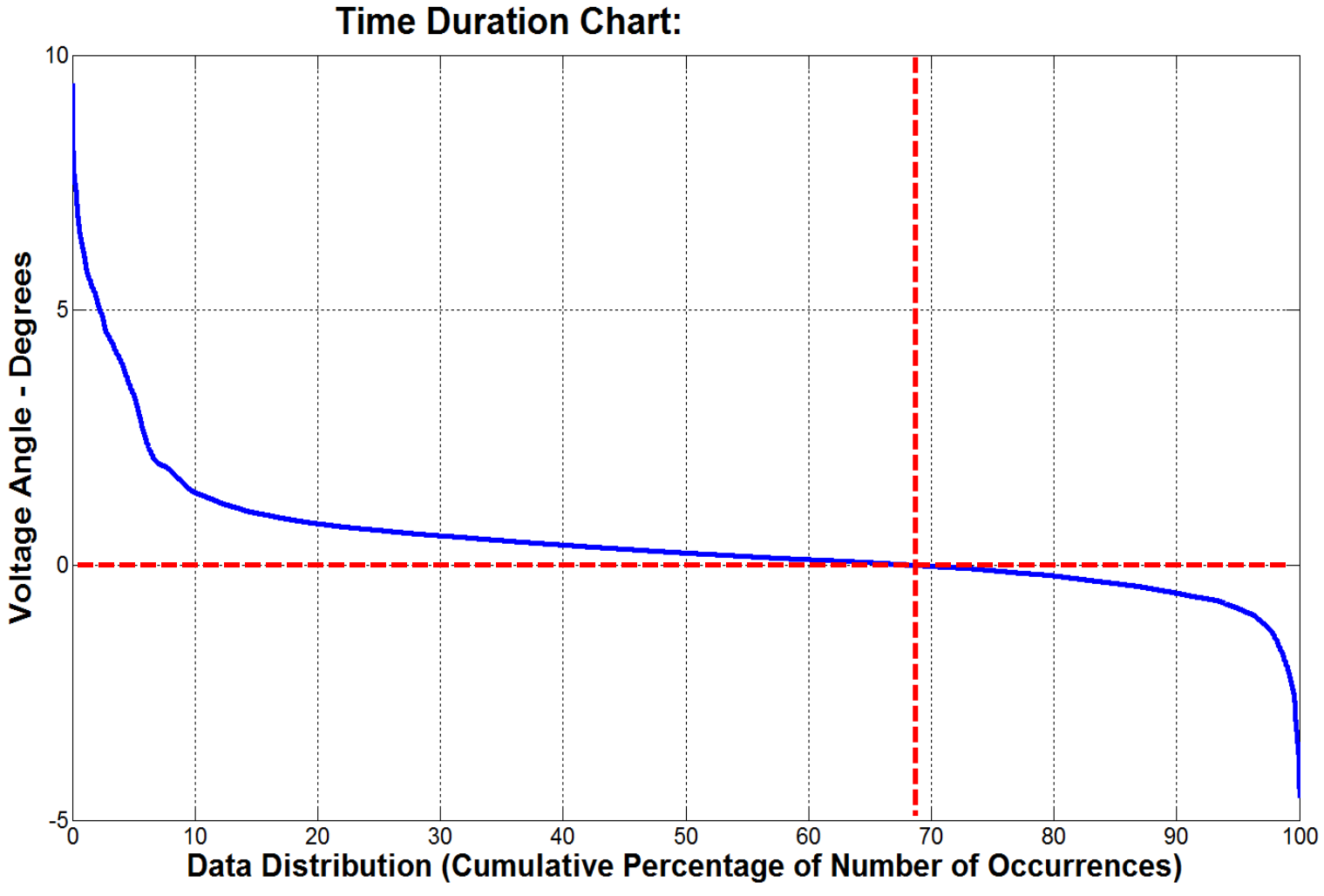

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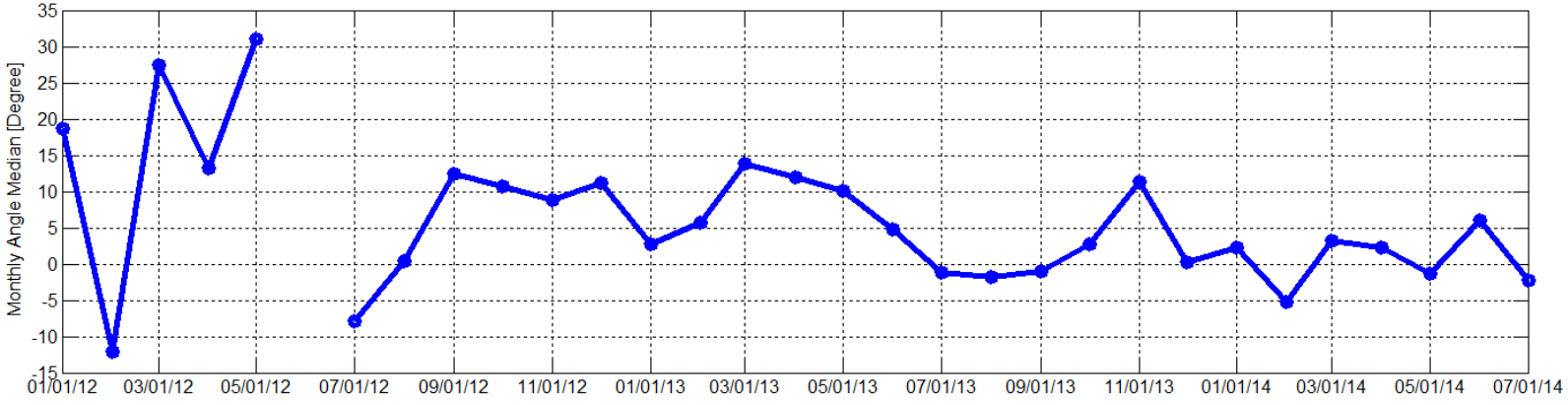

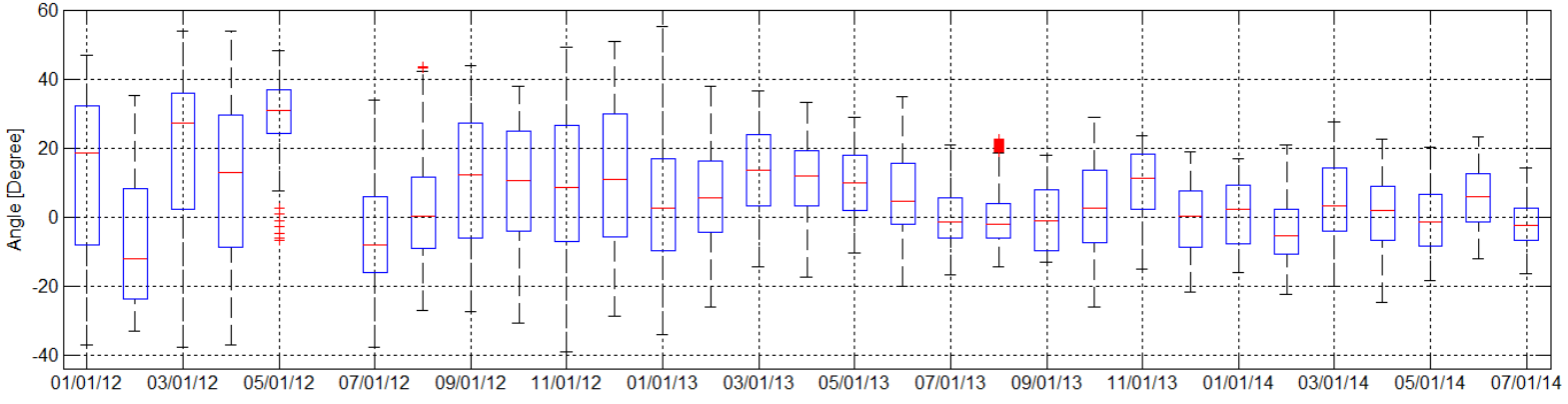

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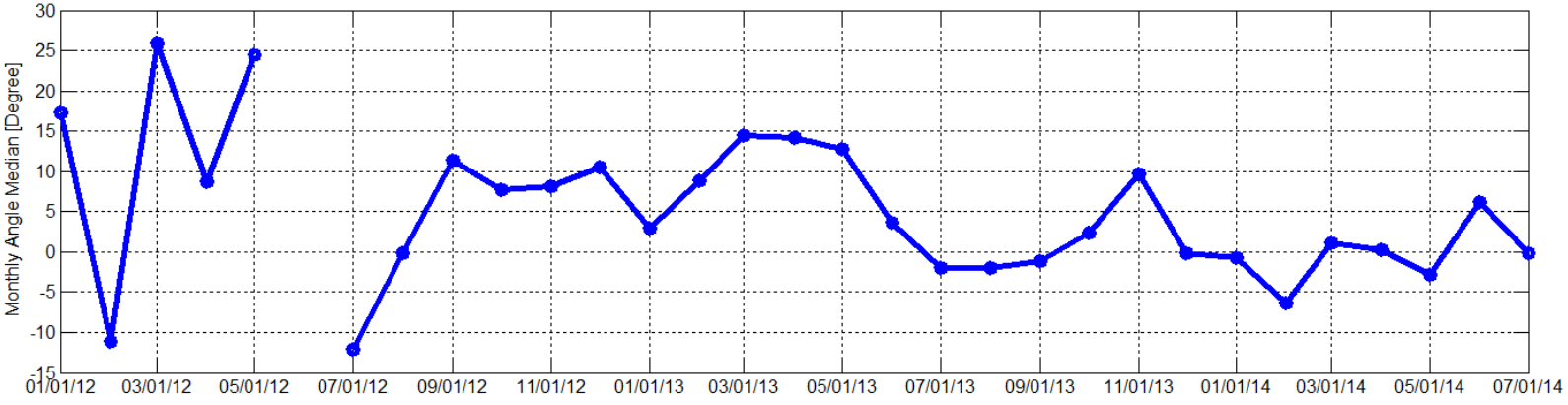
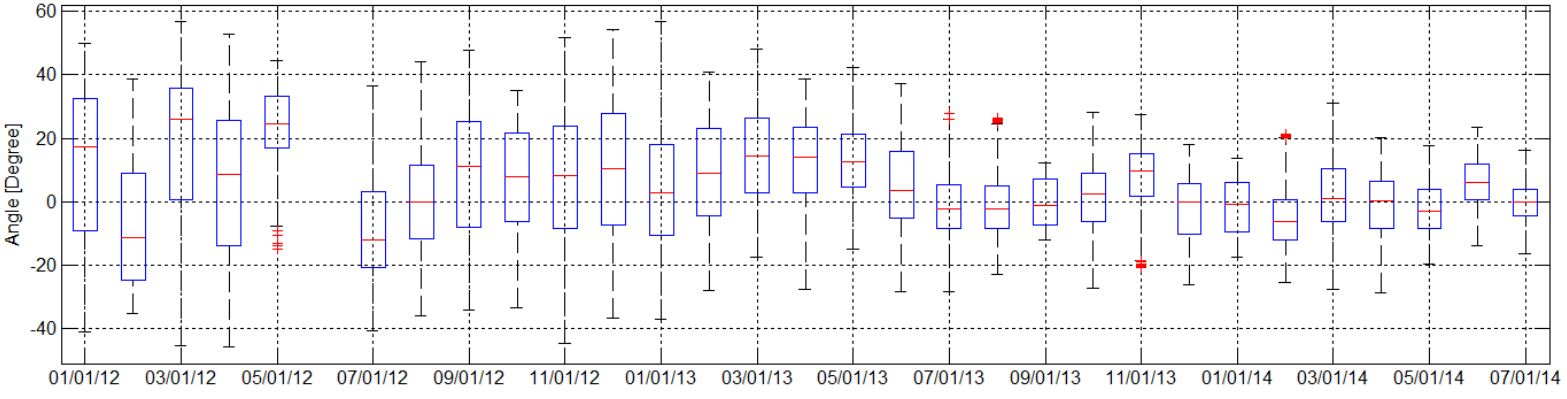
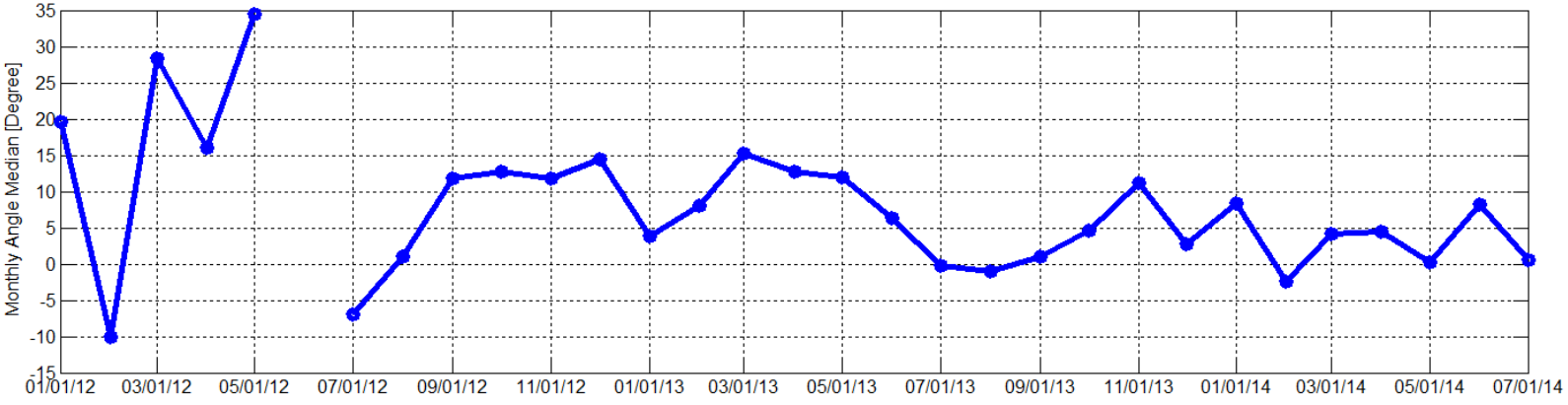
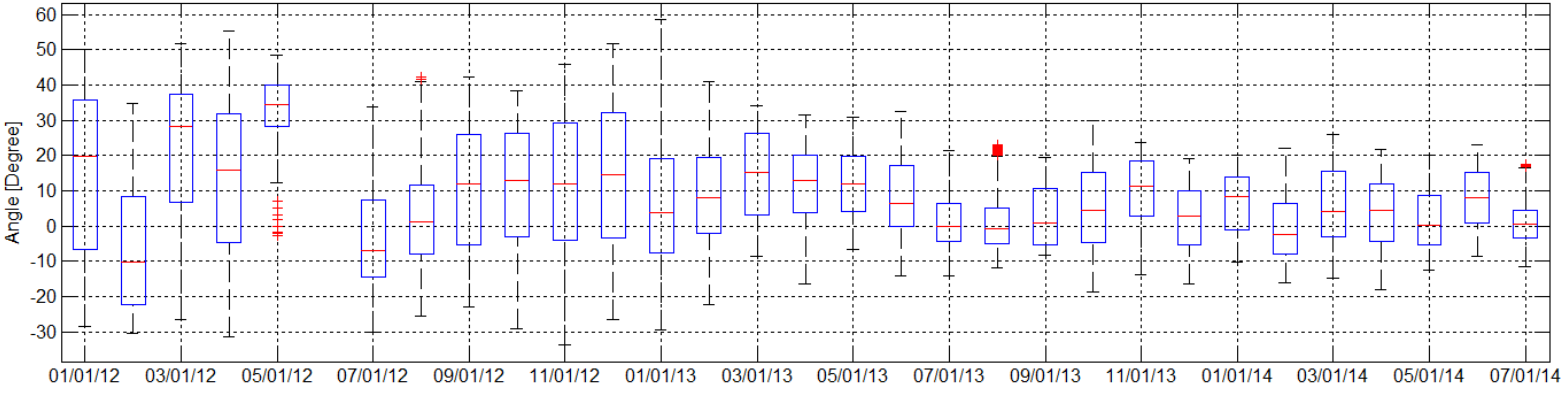


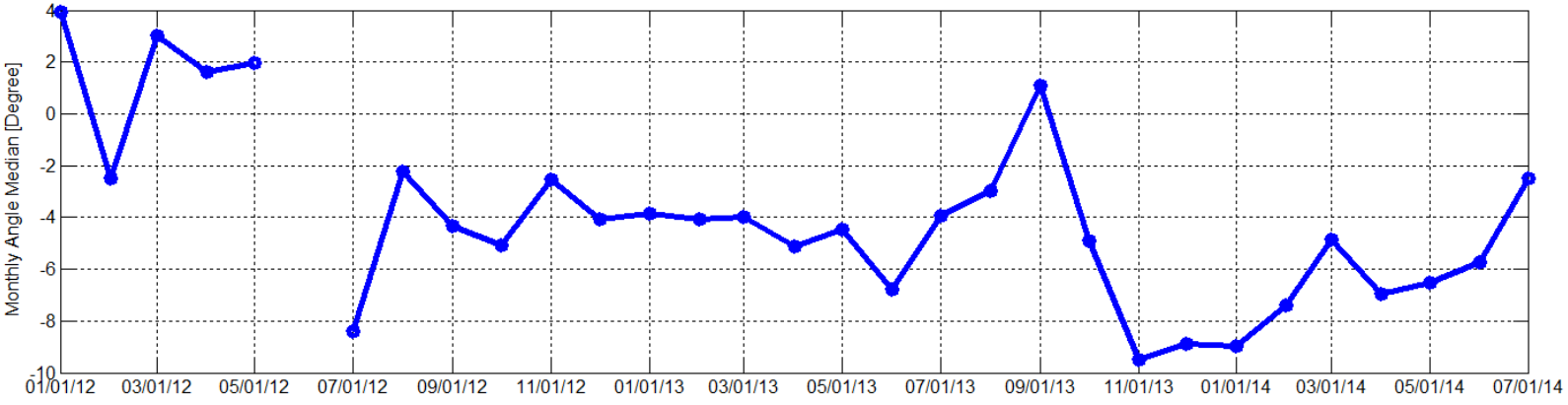


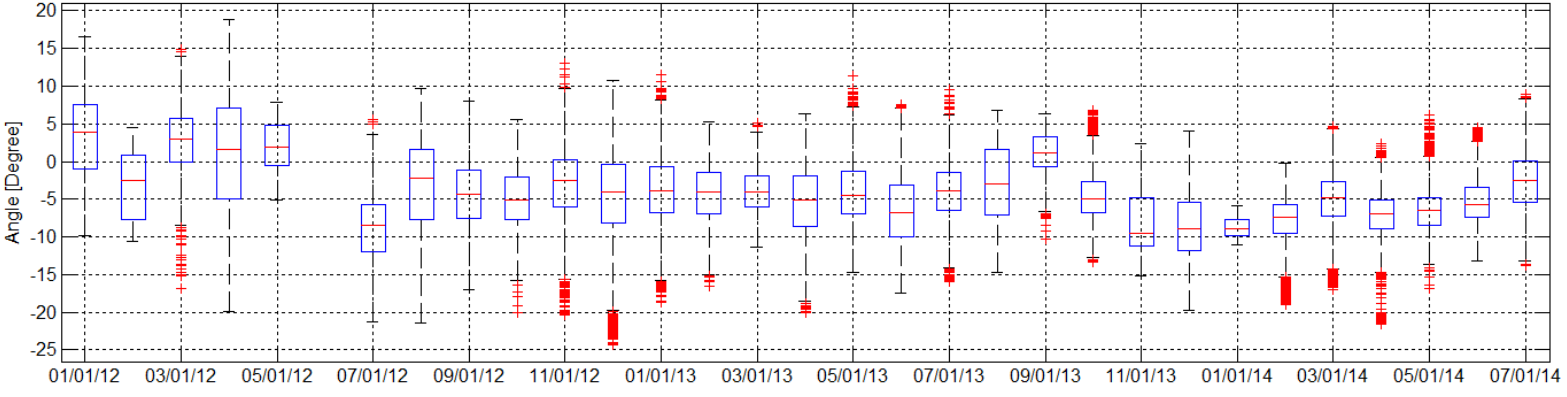
West 11-North 7





North 5-North 7





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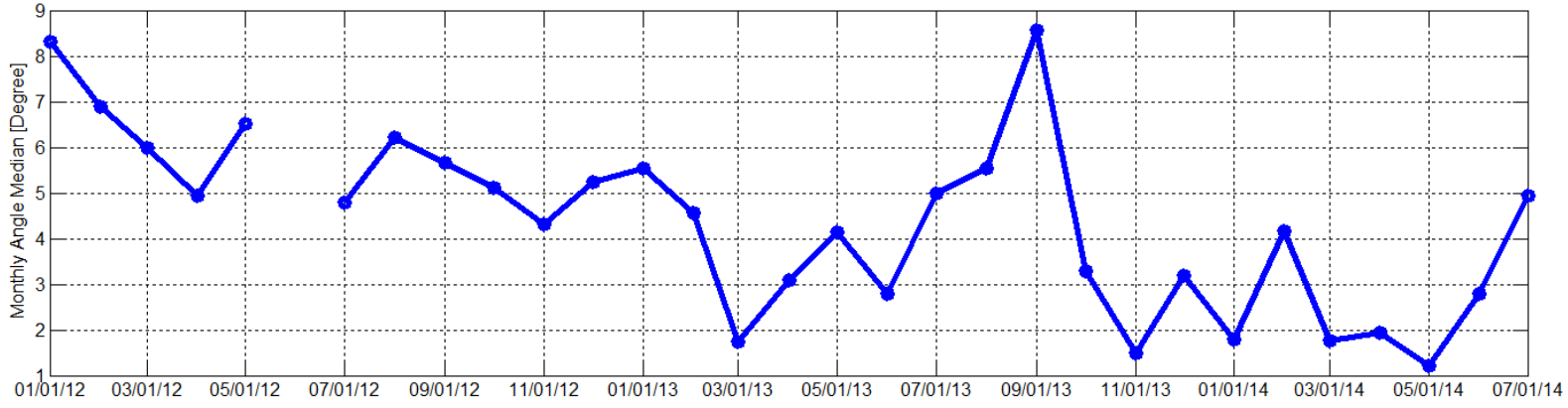
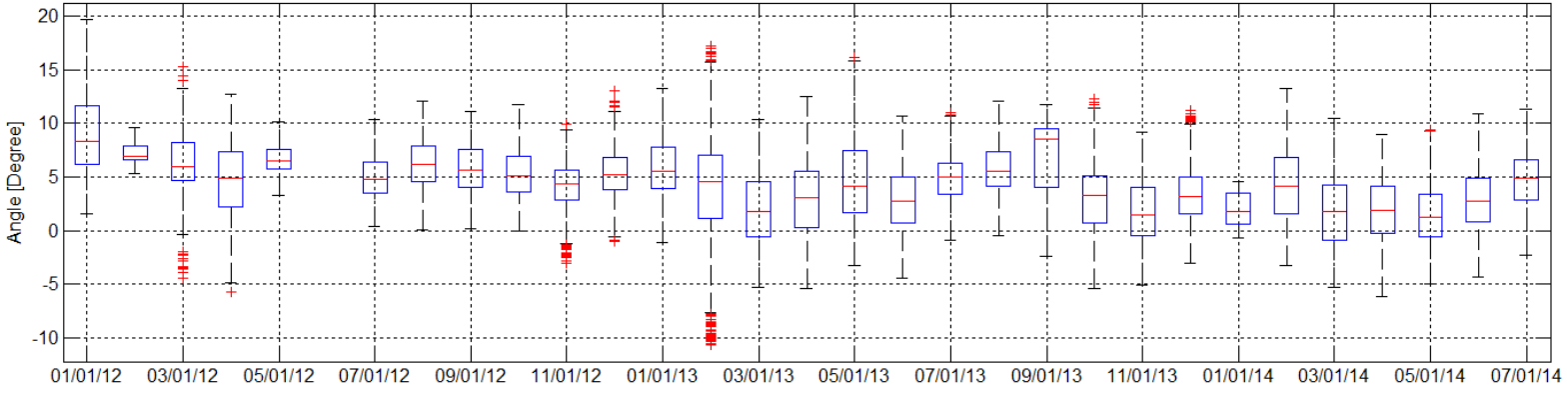
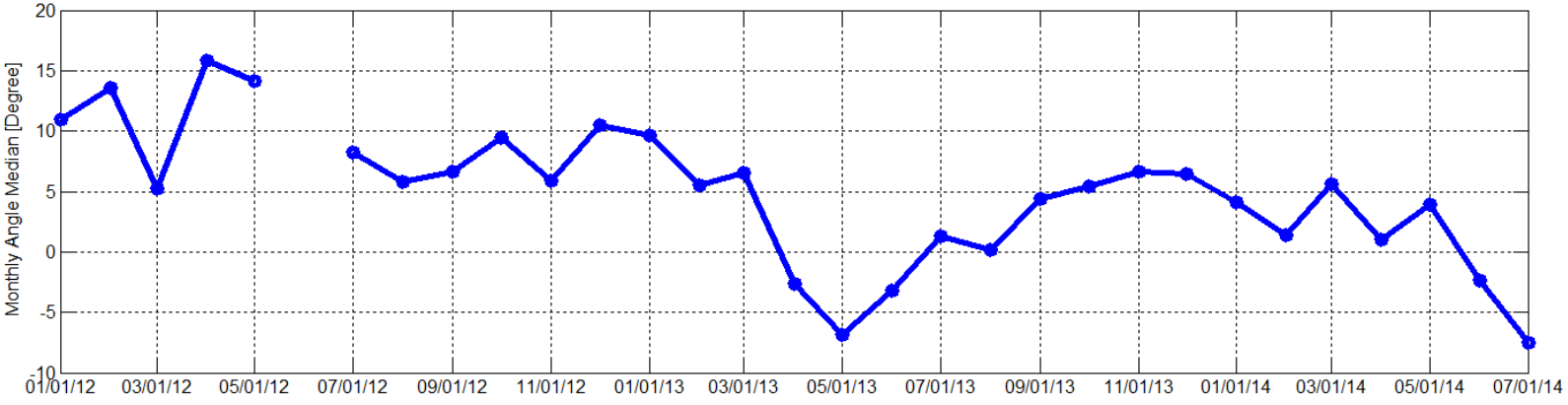
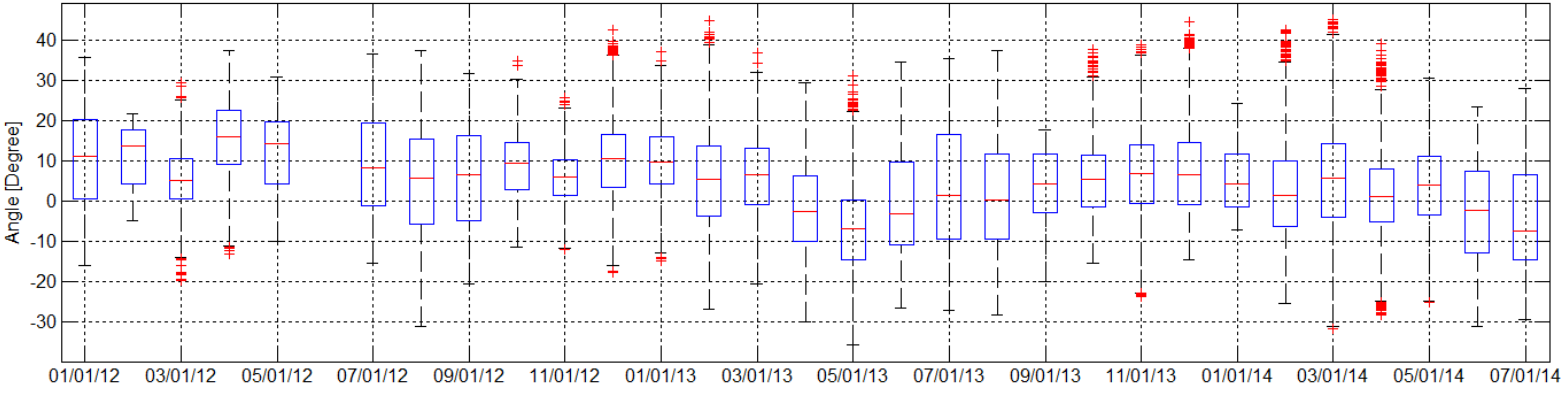


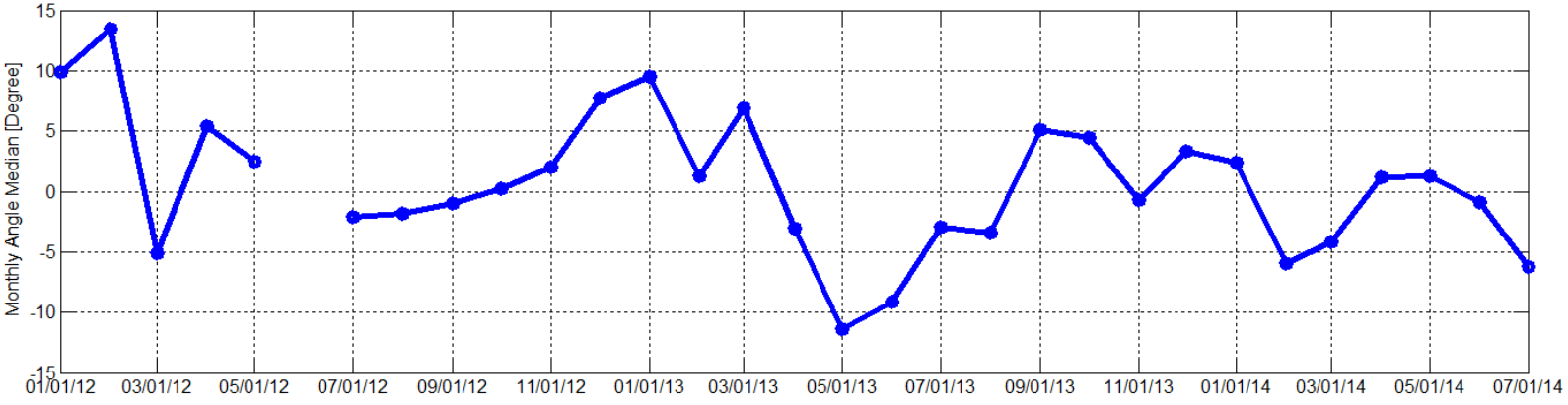


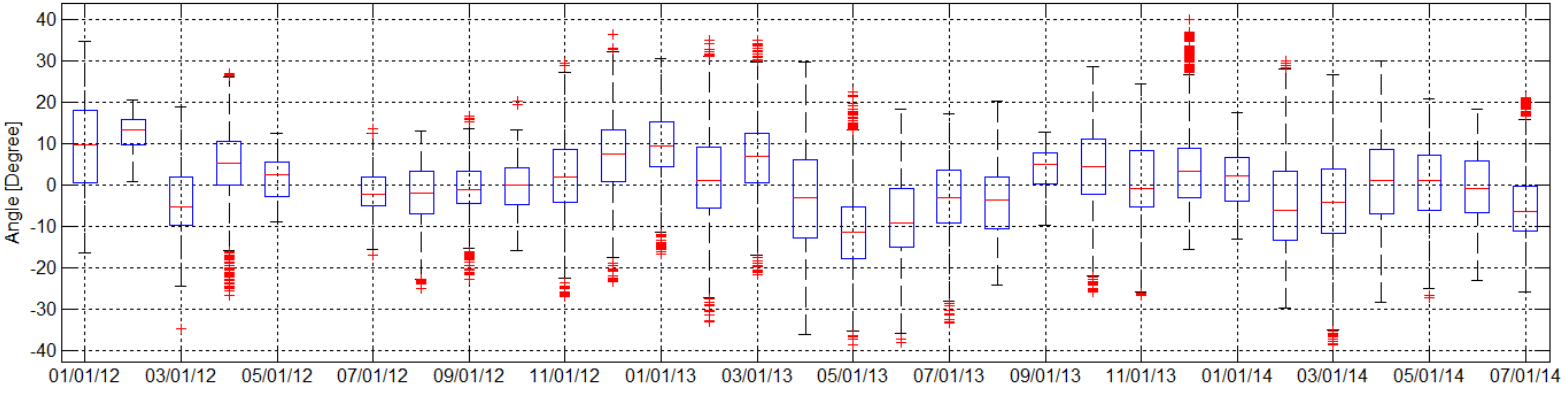
Coast 1-North 7





South 13-South 11*





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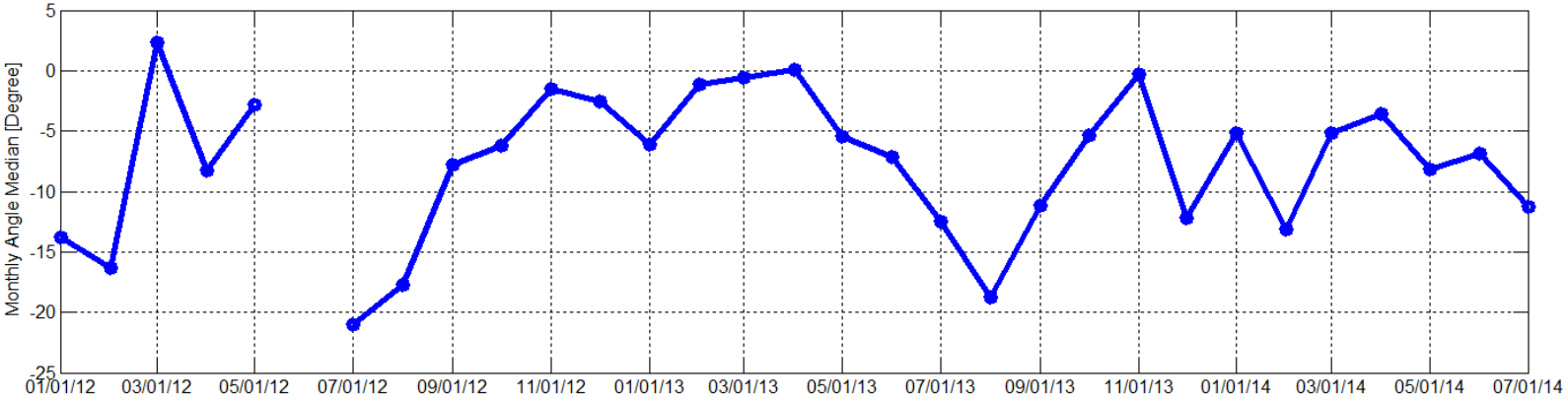
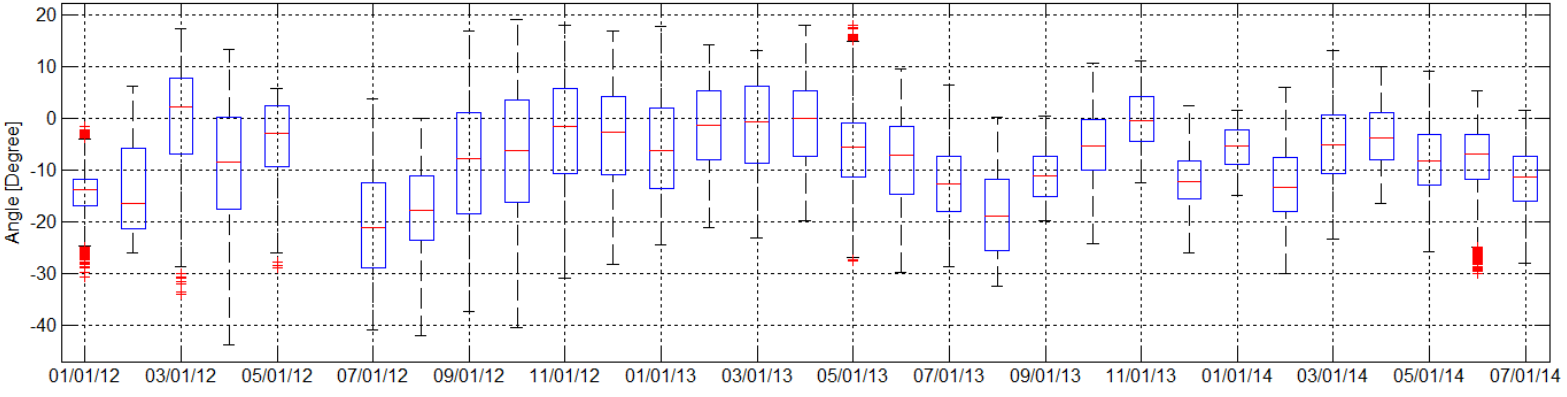
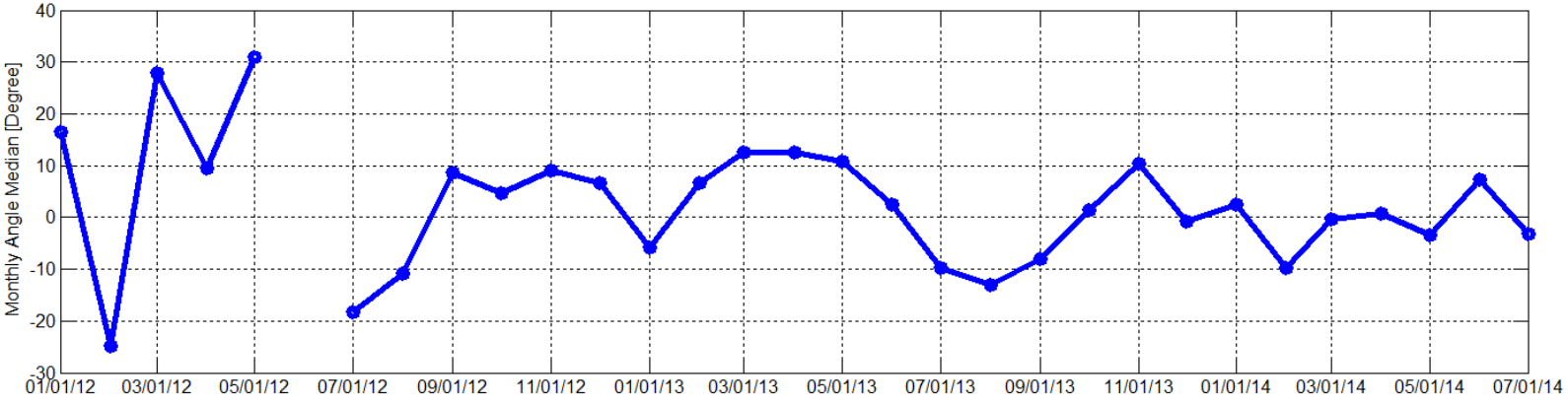
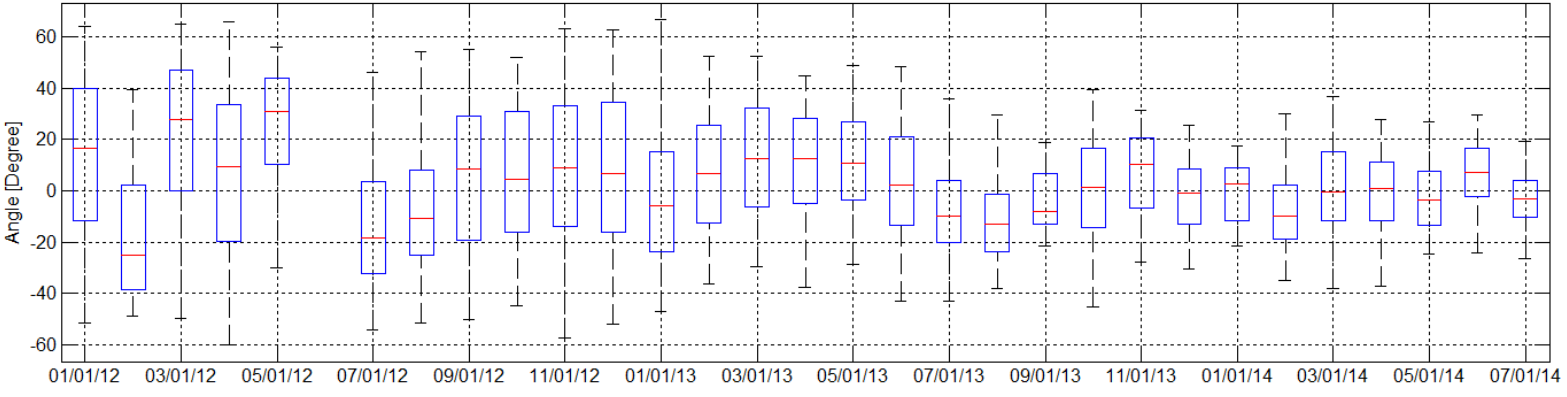


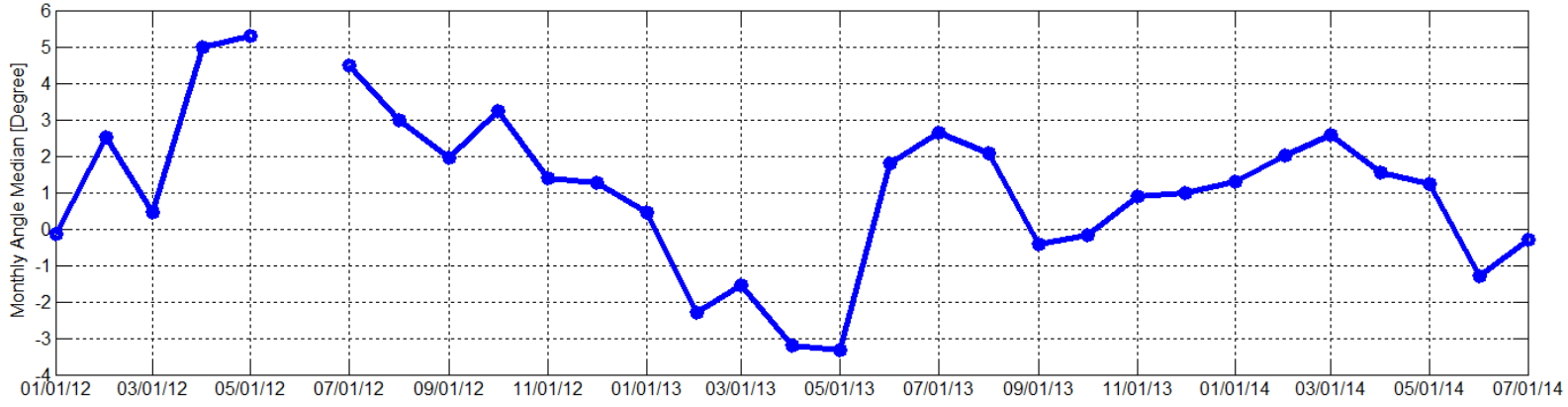


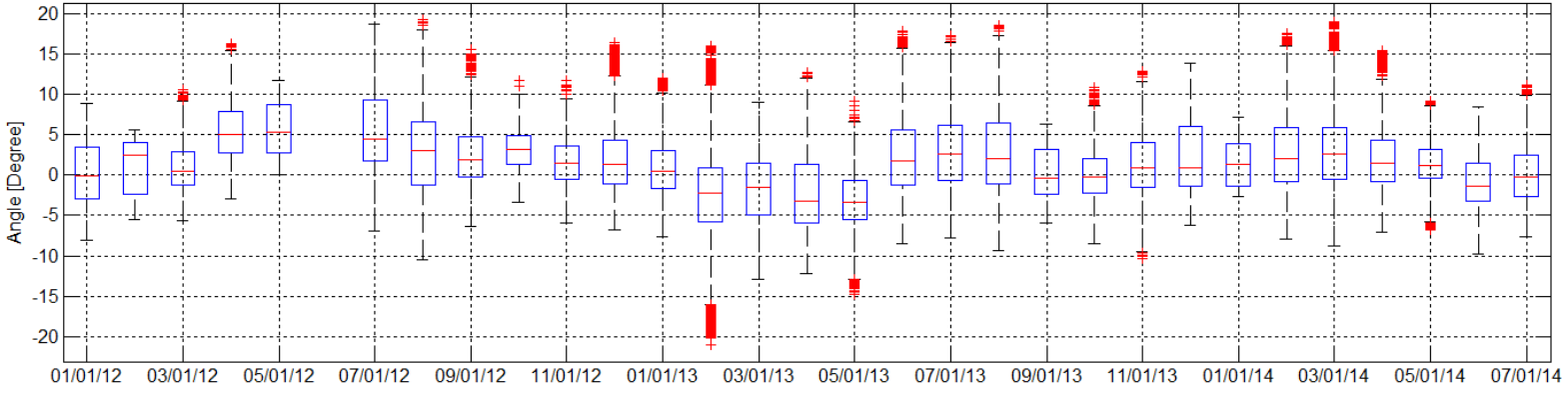
FarWest 9-South 11*





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

Electric Power Group

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 System[1] (RTDMS®)server and database. 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® database 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 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.
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 the identified data availability problems.

The 2012 and 2013 Baselining 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.

3. PHASOR DATA NETWORK

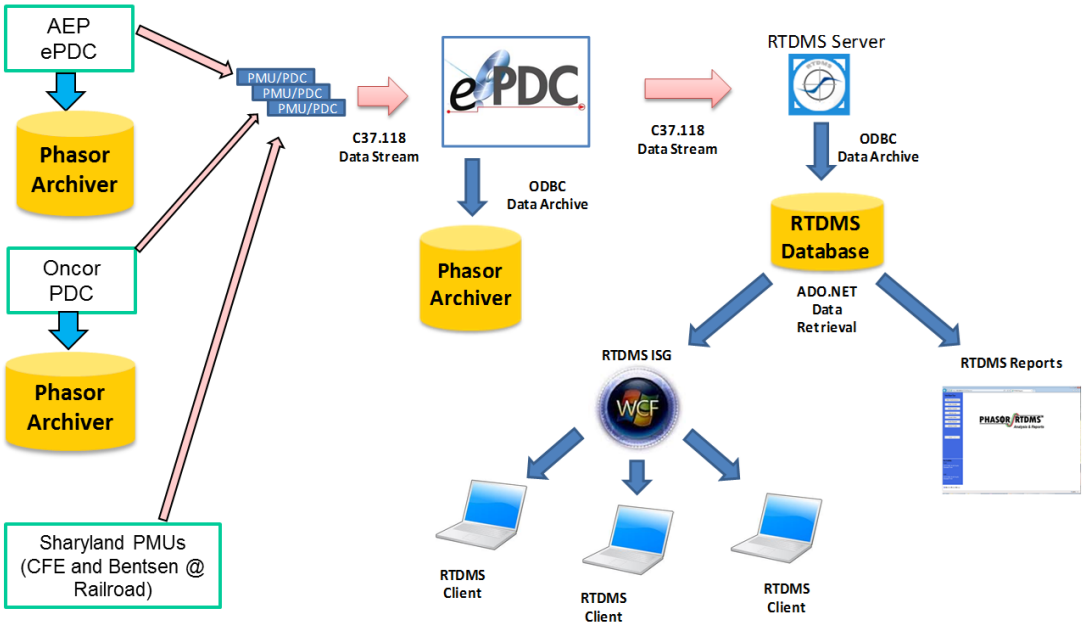
The ERCOT Synchrophasor Network was originally implemented beginning in 2006. With the development of the CCET Discovery Across Texas Regional Demonstration Project, the three participating Transmission Owners, AEP, Oncor, and Sharyland, committed to install PMUs in their respective transmission networks, 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 the *e*PDC Management Tool showed major dropouts (60-99%) in real-time data streams.
- Observation of the *e*PDC and RTDMS performance logs showed the presence of missing samples as dropouts for past streams.
- Data availability checks performed on the RTDMS® and *e*PDC database confirmed the presence of data dropouts.
- Examination of one-second and one-minute tables in the 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.
- *e*PDC to RTDMS® server interface problems.
- *e*PDC input and/or output configuration problems.
- Problems on the outbound *e*PDC stream to *e*PDC database.
- Problems on the inbound *e*PDC 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 errors, time errors, received samples, good samples, and missing samples using the status flag information embedded in the PMU status signals. These performance metrics provided hourly statistics of the database for all the available signals.

The performance metrics, such as data dropouts, data invalid, GPS sync errors, and time errors, 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 *e*PDC and RTDMS® performance log
  - Identify differences in missing samples

A comparative check on the signal headers was also performed between the ERCOT *e*PDC 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 *e*PDC and RTDMS® databases at ERCOT, and between the *e*PDC databases at AEP, Oncor, Sharyland, and ERCOT.

Analysis was conducted separately on each of the three companies' data delivery 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 being sent from the (AEP, Oncor ,and Sharyland) PDCs to ERCOT with the data reported as received by the ERCOT PDC, and also with the data reported as received by the ERCOT RTDMS® database. The study initially (for the AEP data) focused on two recent days (26-hours of data over two different days was used to avoid any time synchronization issues).

The two identified study dates were:

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

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

1. ERCOT RTDMS® Database (Central Time).
2. ERCOT *e*PDC Phasor Archiver Database (Central Time).

3. AEP *e*PDC Phasor Archiver Database (Eastern Time) – the stream is currently sent to ERCOT.

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

1. January 9, 2014 (10-11 a.m. UTC).
2. January 17, 2014 (midnight-1 a.m. UTC), (1-2 a.m. UTC).

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

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

The identified study date for Sharyland was:

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

The data provided includes PMU2 & PMU3 from the 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 Database (UTC) – Collected at EPG.
2. Sharyland PDC Database (UTC) – the stream is currently sent to ERCOT.

6. OBSERVATIONS

6.1 Phase 1 – Investigation of ERCOT and AEP Data

6.1.1 AEP ePDC Database Recurring and Non-Recurring Missing Samples

During the study, it was found that there were missing samples in the local AEP *e*PDC 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 – 1,800 plus additional	14th hour missing additional 336 samples at 5th minute	Received most of the samples.	3rd hour missing additional 412 samples at 54th minute	**Log shows missing 469 samples at same hour.**
Non-recurring – 1,800 plus additional	15th hour missing additional 332 samples at 30th minute	Received most of the samples.	16th hour missing additional 307 samples at 32nd and 33rd 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 *e*PDC stream to its local database. And the likely cause for samples missing in both the ERCOT performance log and AEP database could be a problem on the inbound stream of the AEP *e*PDC receiving the data from the PMUs.

Resolution:

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

The table below shows the results. 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	*e*PDC Database Tool
Non-recurring	9th hour missing 93,600 samples after 8th 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 *e*PDC 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 *e*PDC database client tool.
- Batch size duration issue in the *e*PDC 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 the 6th minute until the 10th second of 15th minute, equivalent to 16,230 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 = 18,360 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	10th Hour missing 16,230 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
*e*PDC	3.1.1
*e*PDC Phasor Archiver (MySQL)	3.1.1
*e*PDC 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 server and single user laptop)	2.0.0.350

Starting July 9, 2013, until present, the data availability is 24 hours. No dropouts in the 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 *e*PDC database. Additionally, there were 56 additional RTDMS® non-pseudo signal headers which were not found in the *e*PDC 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 database.

On the other hand, there were 58 *e*PDC 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.Frequency.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 *e*PDC database also had both old and new headers.

Resolution:

The signal name changes and duplicate names between the *e*PDC and RTDMS® database can be corrected.

- *e*PDC can be corrected to set the output configuration for the phasor identification method to be same as the input name for a input stream.
- For each PMU under an input stream, the PMU output system configuration can be set the same as the input system configuration.
- *e*PDC sends data to the RTDMS® server and *e*PDC database. The above two steps can be corrected to both output streams from the *e*PDC.

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

- RTDMS® server output to the RTDMS® database can be configured to output the same as the *e*PDC output to the *e*PDC database.
- After *e*PDC 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 stream their data directly to the ERCOT *e*PDC, and were logged as separate streams in the ERCOT *e*PDC performance log. In the table below,

for 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 *e*PDC database. The possible reason behind the positive difference in missing samples is progressive forward padding.

The current version of *e*PDC 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 *e*PDC 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 the Line_1@South13 PMU stream.

Input Name	Hour	Checkword 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 *e*PDC 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, but 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 *e*PDC performance log and the database.

It was likely that the *e*PDC marked them as data dropouts due to:

- Errors in the timestamps.
- Duplicate timestamps.

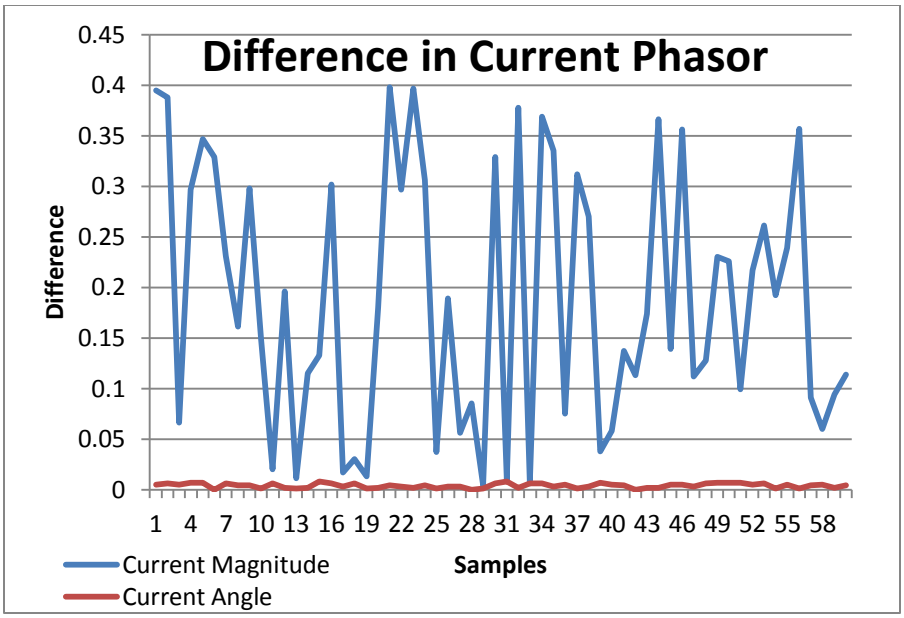
Input Name	Hour	Checkword Error	Format Error	Time Error	GPS UnSync	Good	Received	Missing	Data Dropout - ERCOT ePDC Databa	Difference
SHARYLAND1	1/28/2013 7:00	0	0	0	0	107375	107375	625	0	625
SHARYLAND1	1/28/2013 16:00	0	0	0	0	105447	105447	2553	2547	6
SHARYLAND1	1/28/2013 19:00	0	0	0	0	107154	107154	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

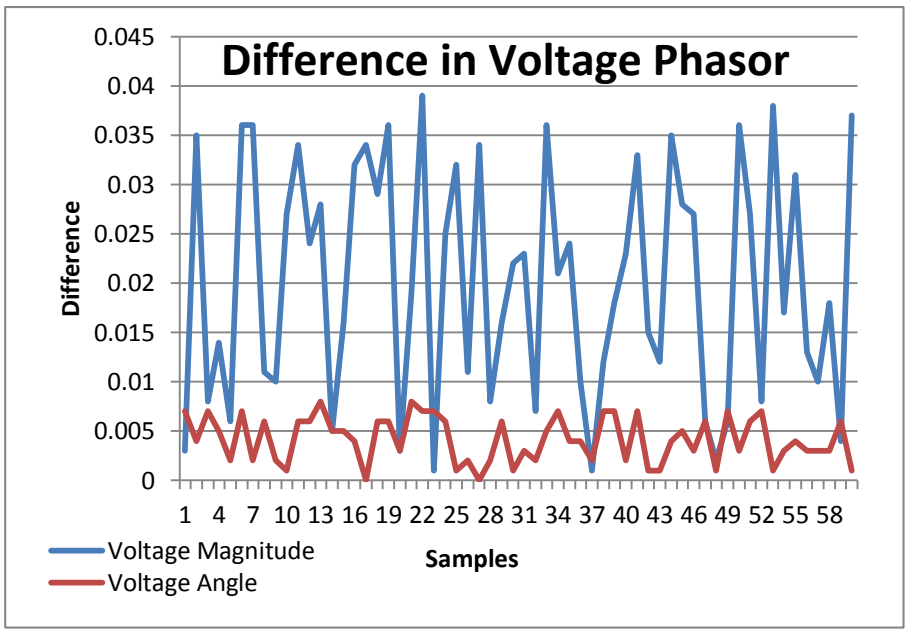
No difference in missing samples between the ERCOT *e*PDC performance log and database.

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 *e*PDC 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.

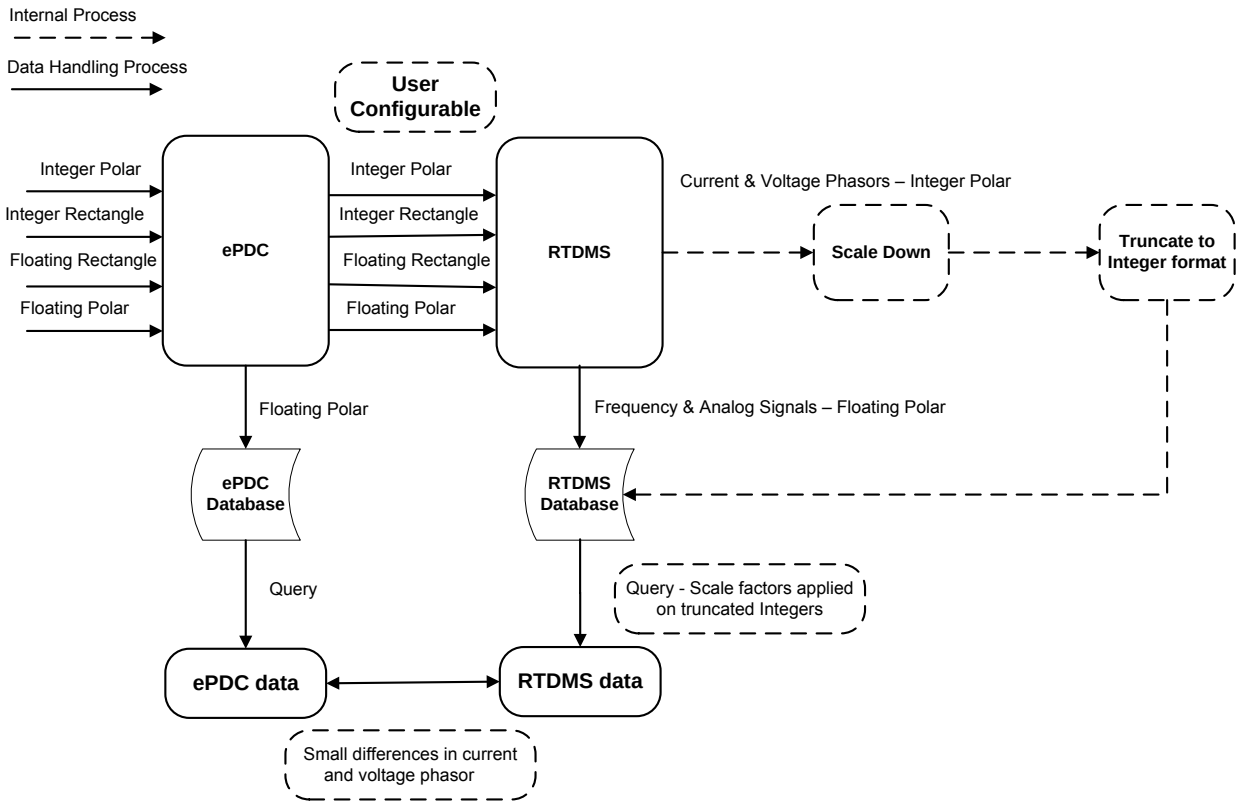
6.1.3 Accuracy of Decimal Digits between ERCOT ePDC and RTDMS® Database – Jan 24, 2013, 23rd Hour

RTDMS® data was observed to be stored and extracted at a slightly lower accuracy than the *e*PDC. 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 the RTDMS® database. The graphs below show differences in current phasor and voltage phasor. (Difference = *e*PDC data – RTDMS® data).





These small differences in accuracy between *e*PDC and RTDMS ®database can be explained.



The diagram above illustrates the data handling process. The *e*PDC 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®. The 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 84,773 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 compliment 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

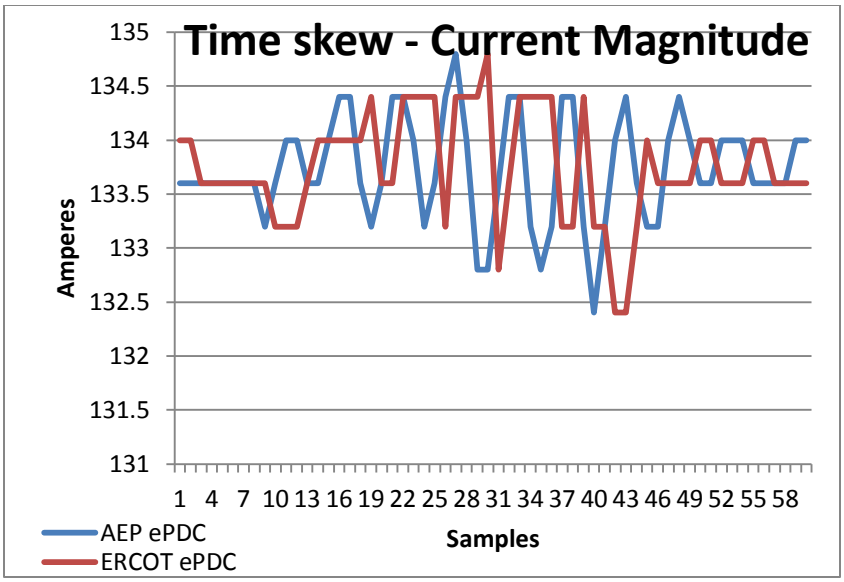
The following describes how the data is scaled down and stored in the RTDMS® database:

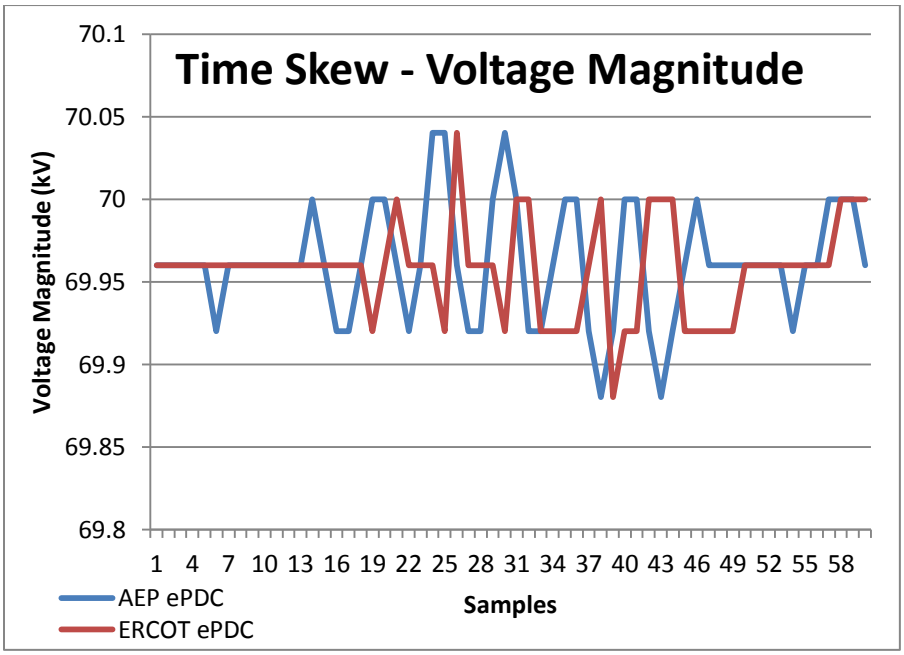
- Scale Up - For those metrics that require a conversion, and need to be stored as integer/polar data format, the value of each part of the phasor (magnitude and angle) with the entire resolution (all fractional part of the mantissa) is divided by its corresponding scale factor.
- The scaled up value 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 *e*PDC.
- 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 *e*PDC and RTDMS® database as the values are stored in floating point.
  - The order of resolution is current magnitude < voltage magnitude < vngle < 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 *e*PDC data extracted appears to be time skewed from the AEP *e*PDC data. When the ERCOT *e*PDC 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 *e*PDC data. The plots below show comparison between AEP *e*PDC data and ERCOT *e*PDC data for current magnitude and voltage magnitude.



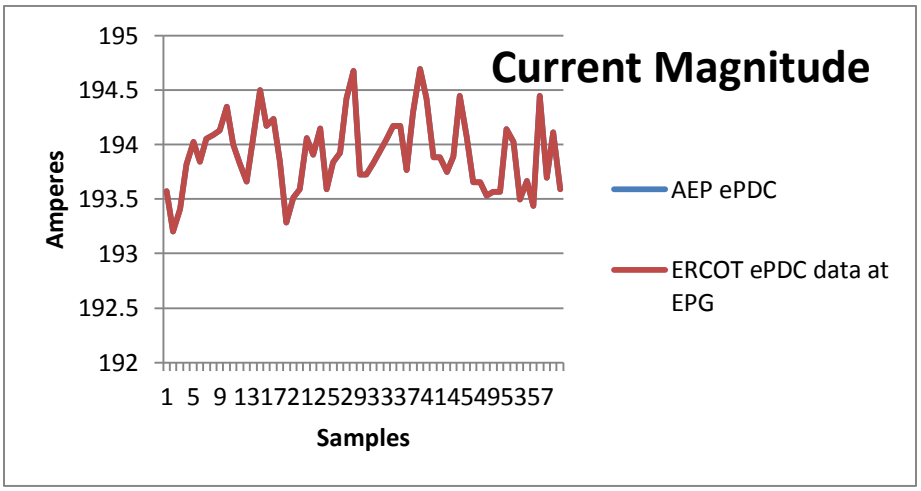


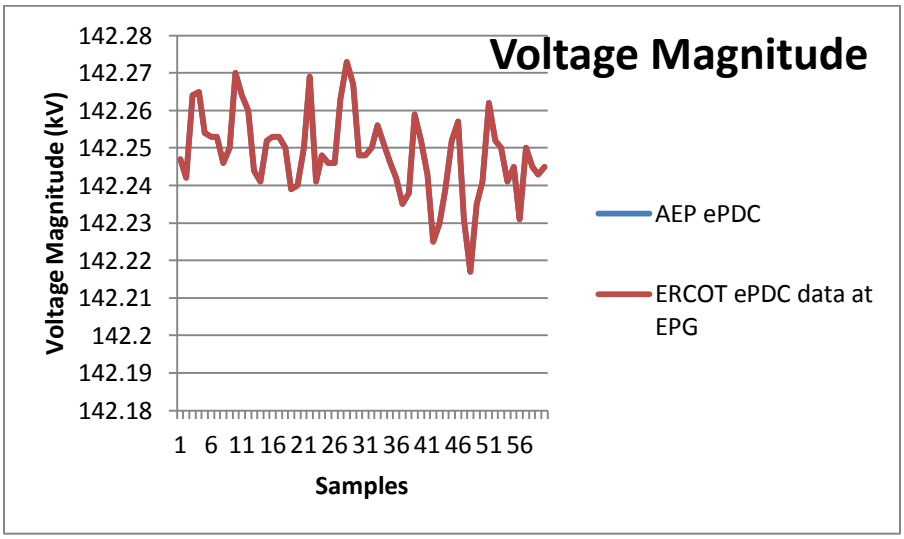
Resolution:

The time skew issue was related to user-defined *e*PDC minimum output latency, and the use of progressive forward padding. To resolve this issue, the *e*PDC 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 *e*PDC v3.1.1 with missing data padding disabled.

Following a configuration change to the AEP *e*PDC, an extract was obtained for 30 minutes, starting 27 August ,2013 11 a.m. 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 a.m. UTC).
2. January 17, 2014 (midnight-1 a.m. UTC), (1-2 a.m. UTC).

A matching set of data was extracted from the ERCOT *e*PDC Phasor Archiver Database (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 – 1,716	59th Minute Start to miss from 3rd second until 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 (midnight-1 a.m. UTC) reveals that there is a higher count of bad data flags in the ERCOT *e*PDC database than in the Oncor database. There are only four PMUs in the 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 p.m. UTC).

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

A matching set of data was extracted from the ERCOT *e*PDC Phasor Archiver Database (which is replicated at EPG for this project).

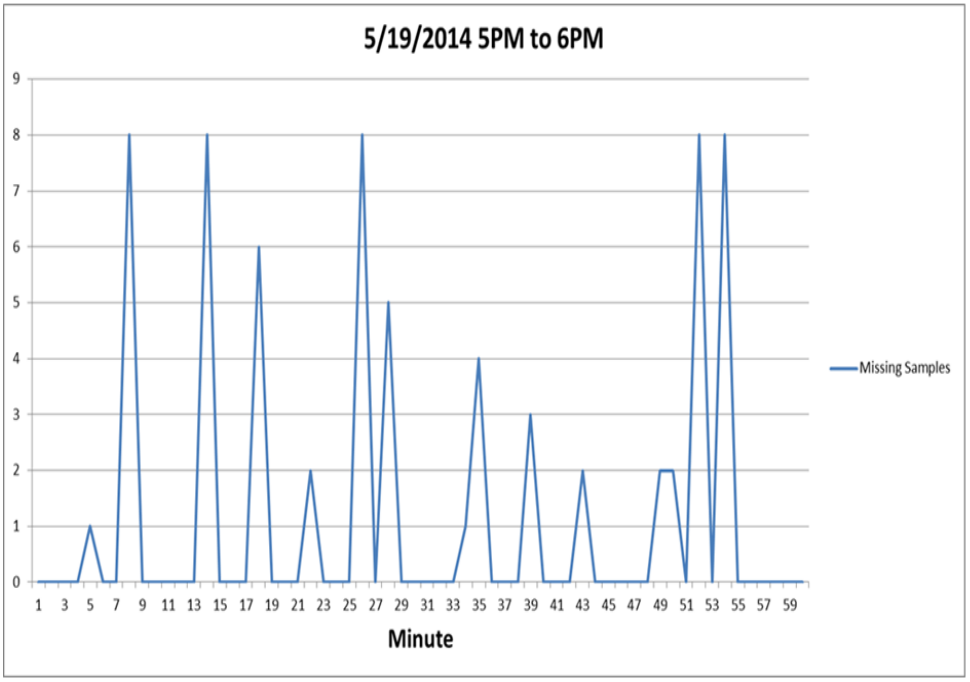
6.3.1 Dropouts in Sharyland Database Extracts

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

Missing samples means no record of data found in the 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	9th & 10th	8
13	49th & 50th	8
25	19th & 20th	8
51	10th	8
53	9th & 10th	8
4	10th	1
21	0th	2
42	0th	2
48	40th	2
49	20th	2
34	10th	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 database than in the Sharyland database. ‘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 versus 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

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 30 samples per second, then the count of samples expected for duration of 1 hour is equal to 108000 samples.

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)

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

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

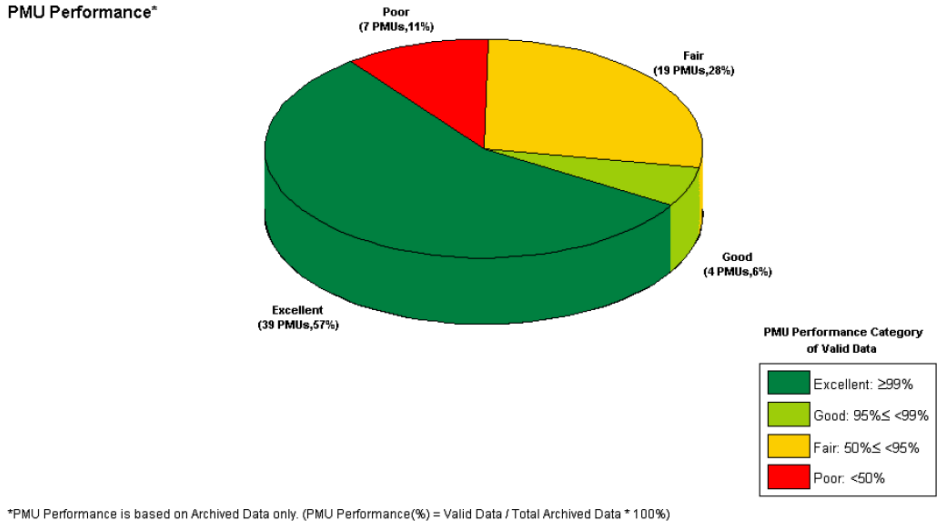
5.2 RTDMS PMU Performance Test

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 Chart – RTDMS Daily Report

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

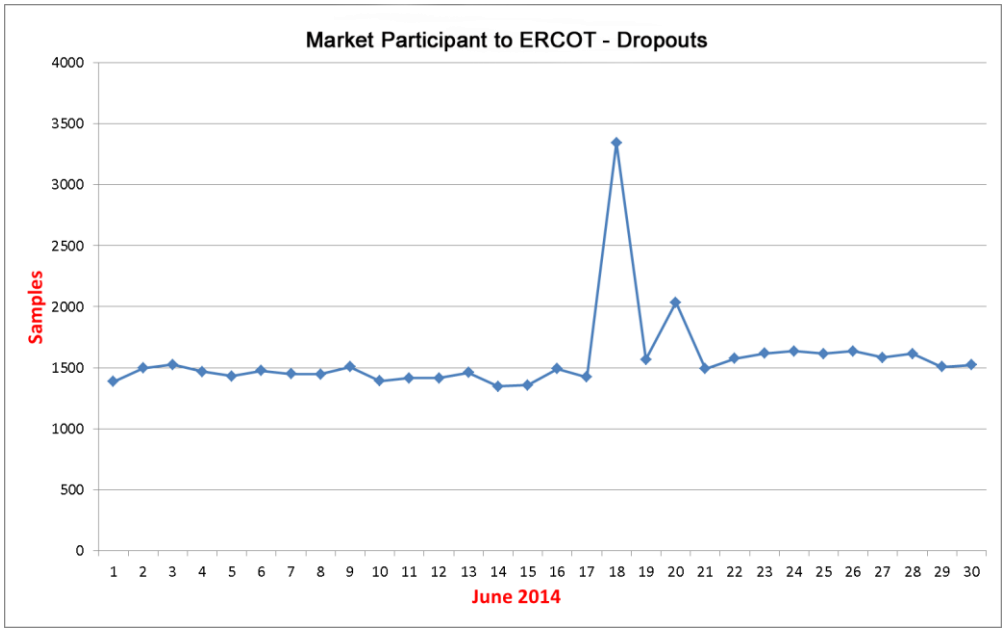
Daily Dropouts between MPs and ERCOT

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

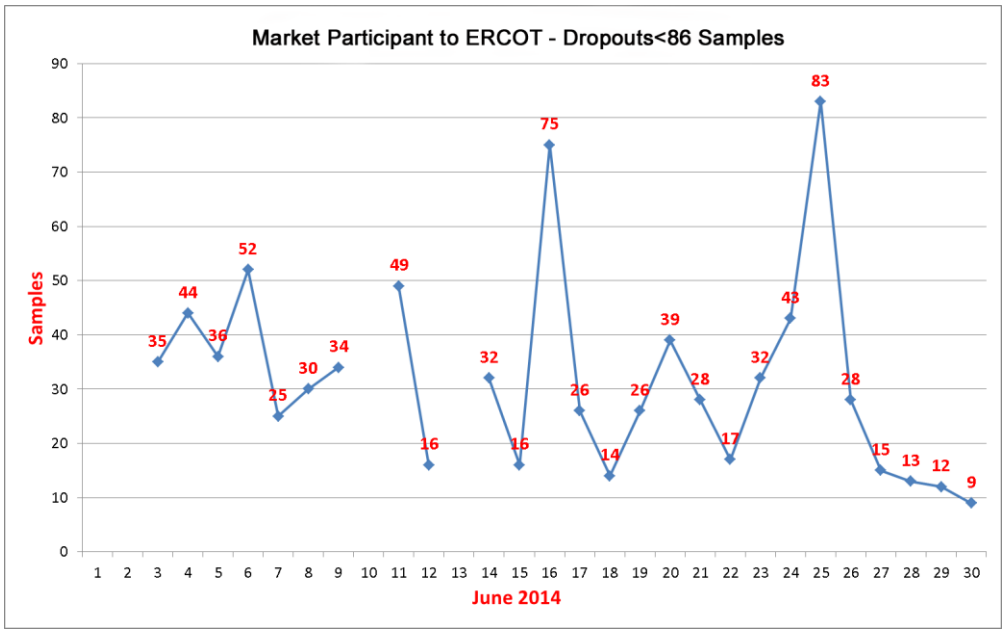
Daily Consistent Dropouts for entire stream from MP

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.



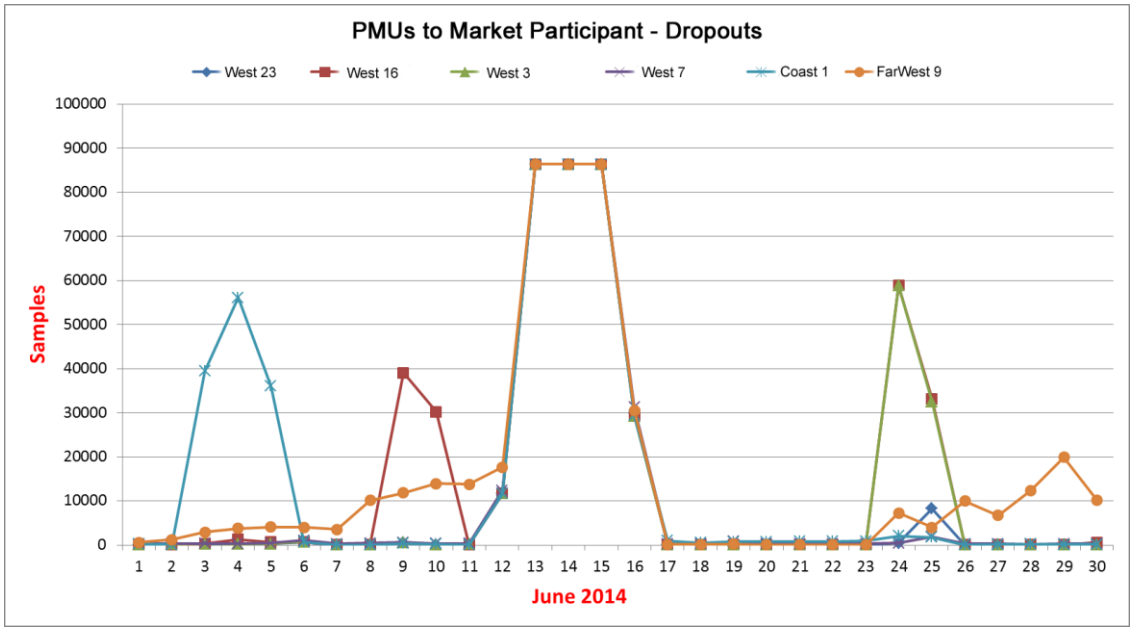
Daily Irregular Dropouts for entire stream from MP

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



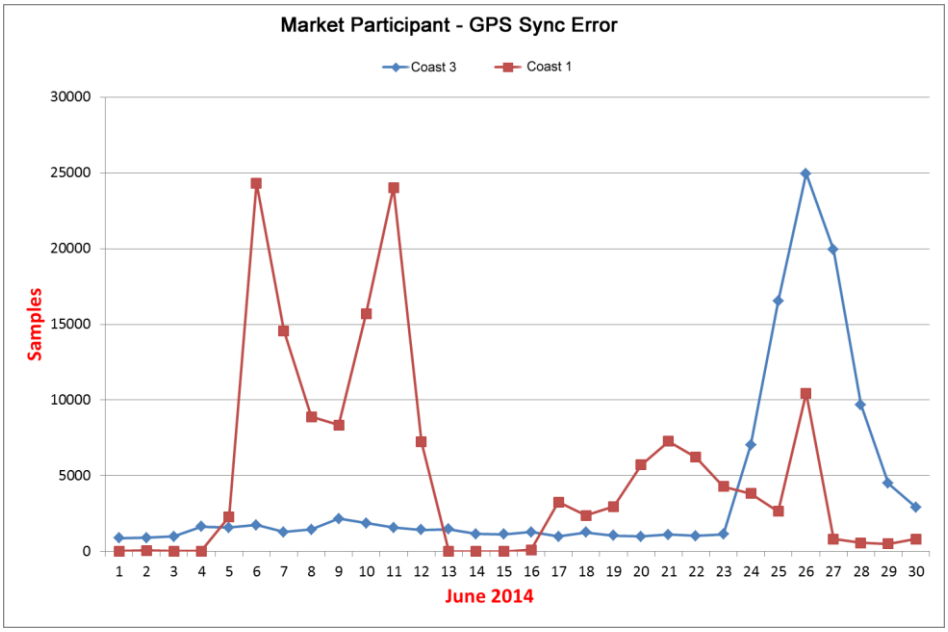
Daily Dropouts between Specific PMUs and MPs

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

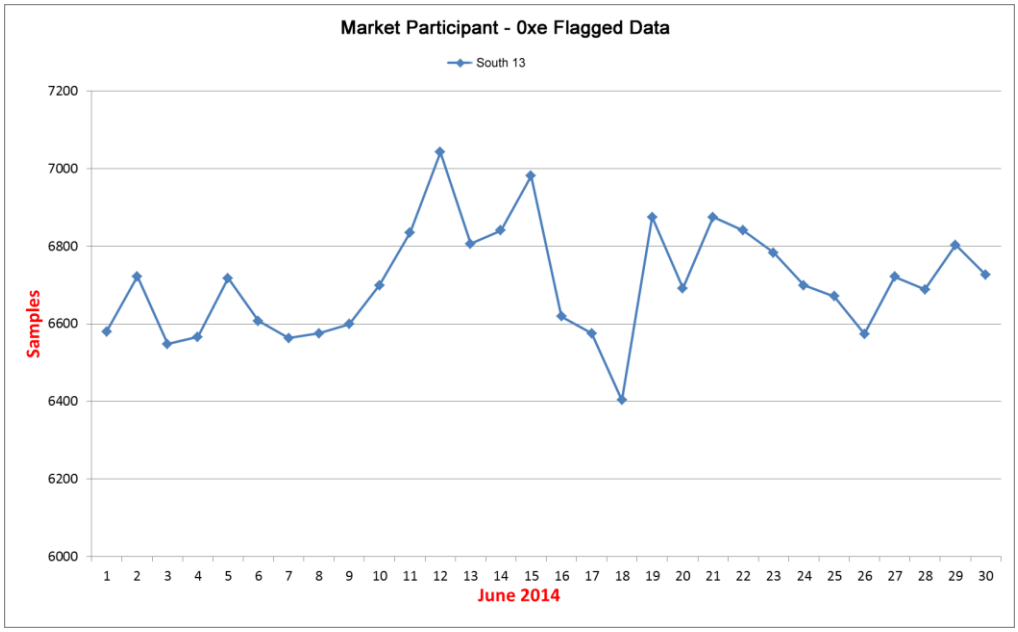
ERCOT might notice data samples from specific PMUs that are flagged bad as '0xE', most likely set by the MP's PDC and sent to ERCOT. It was found that those flagged data samples were flagged and archived as good at the MP database. It was observed that ERCOT was receiving a greater count of flagged data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

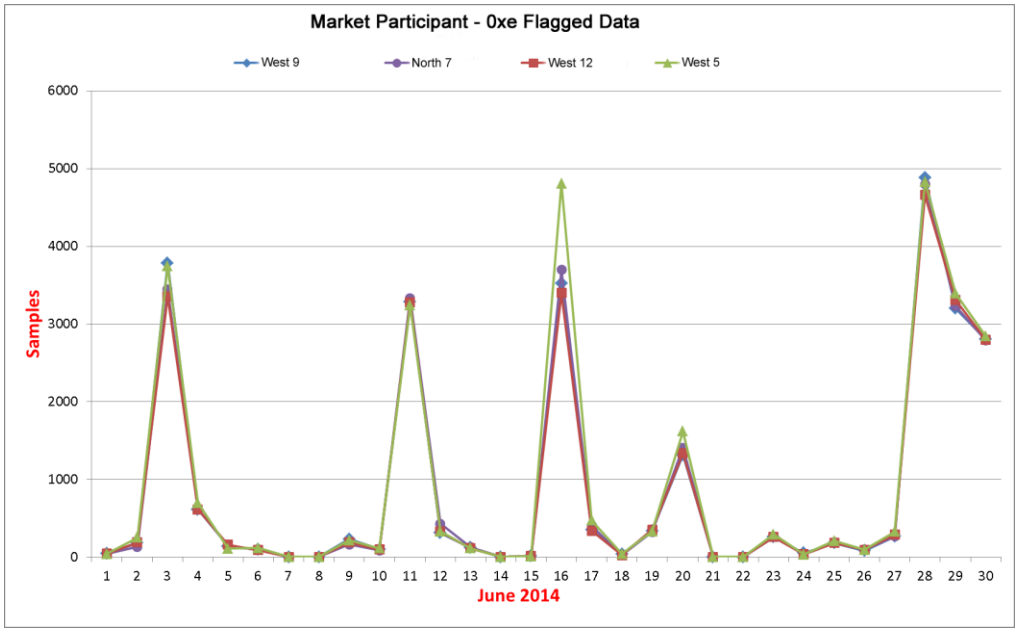
Daily Consistent Pattern from specific group of PMUs

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.



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 10, 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 Figure 1, ERCOT looked at the generation at the Wind Farm unit close to Wind Farm PMU. It was generating about 56 MW (Figure 2). 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 Figure 3 and Figure 4. It was found that oscillations were present in the system since 6:15 p.m. of January 9, 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 Figures 5 and 6. The voltage oscillations were having magnitude of about 1kV, as shown in Figure 7. The oscillations were present till the next morning. Figures 7 and 8 show the oscillations present in the morning of January 10, 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 9, 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.

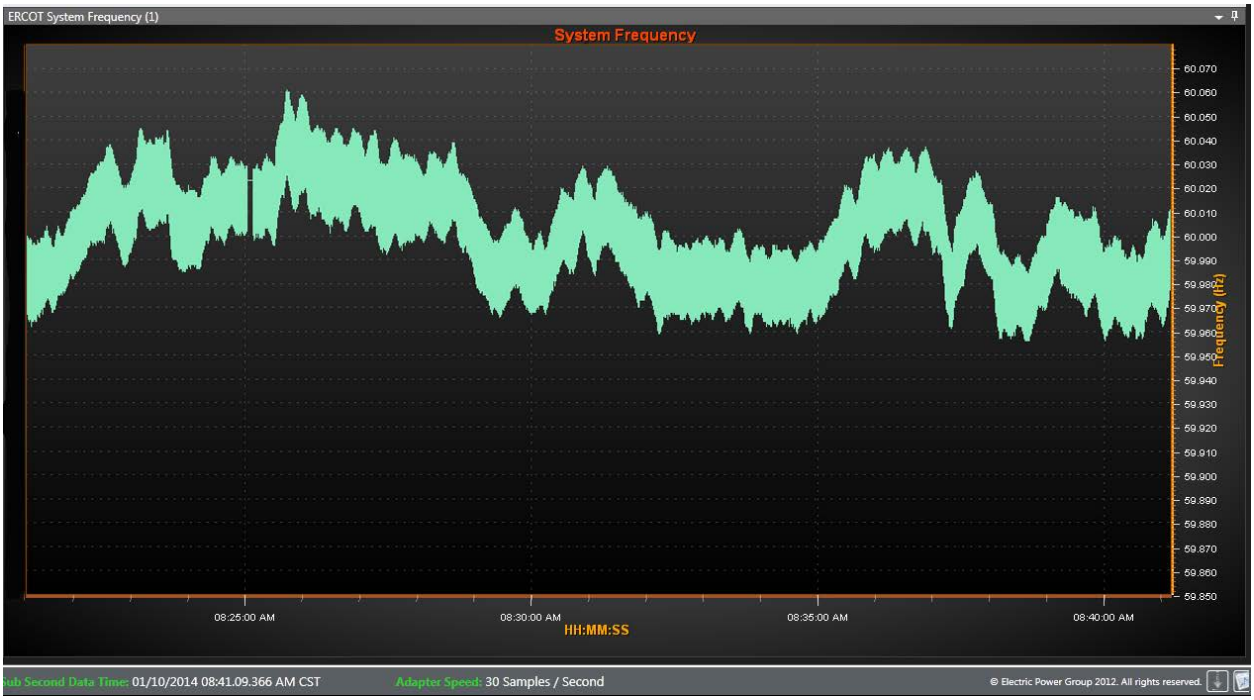


Figure 1. Frequency at Wind Farm PMU on RTDMS System on 10 January 2014.

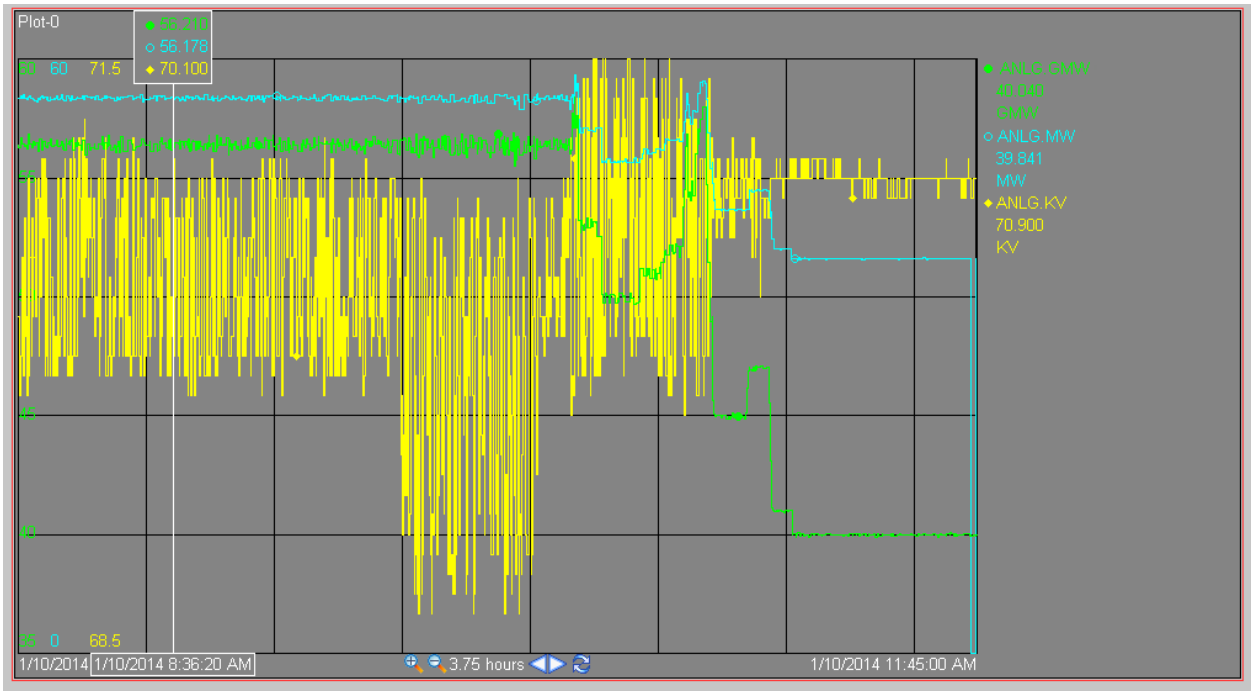


Figure 2: EMS Trend for Generation at the Wind Farm on 10 January 2014.

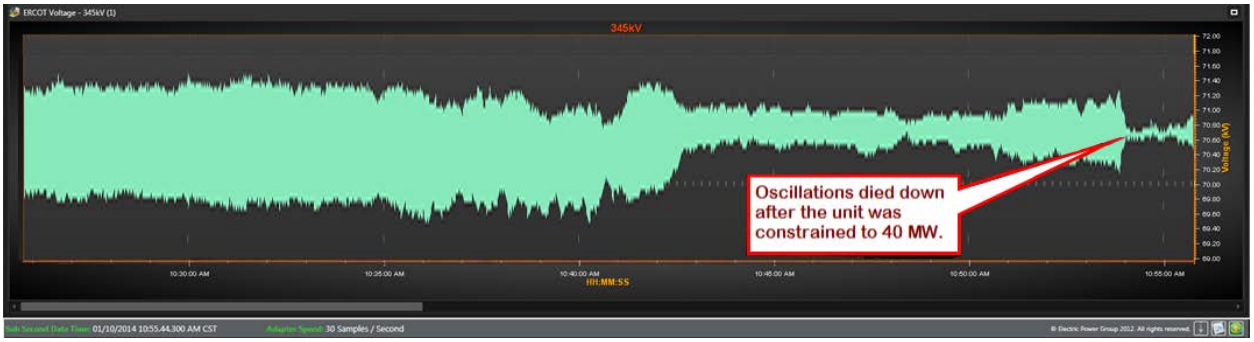


Figure 3: Reduction of Oscillations after Constraining the Plant to 40 MW on 10 January 2014.

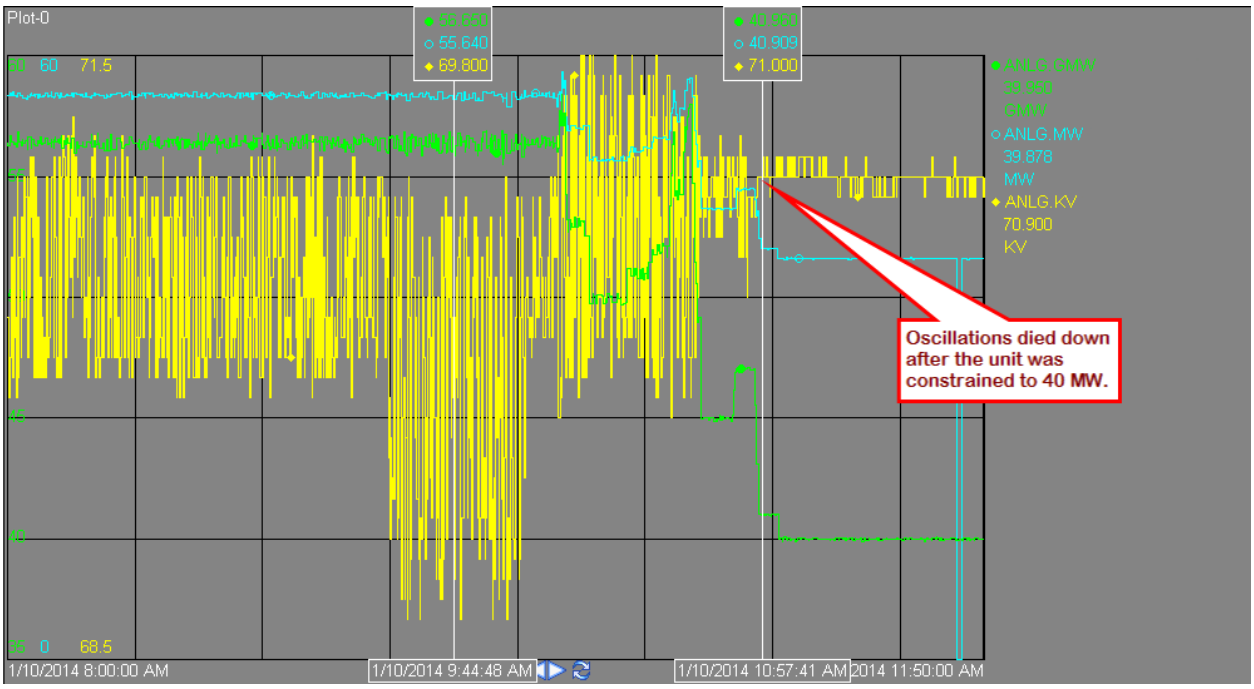


Figure 4: EMS Trend for Generation at the Wind Farm on 10 January 2014.

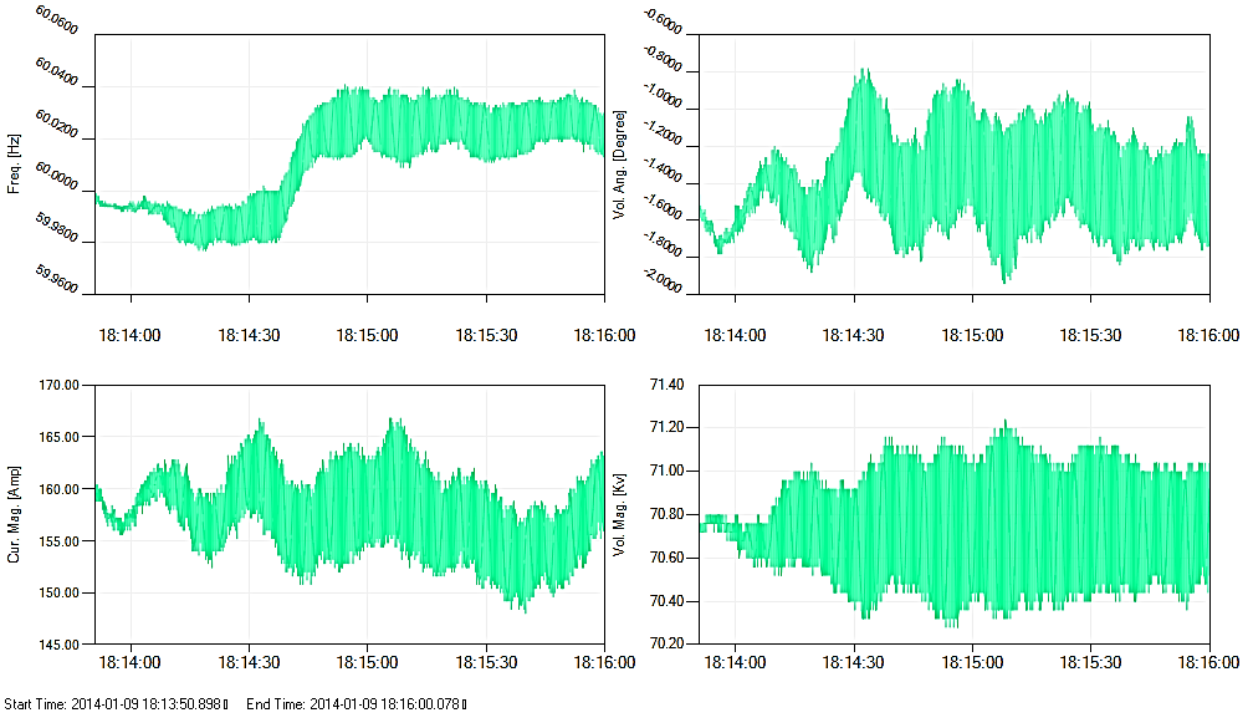


Figure 5: The Frequency, Voltage and Current Captured by the Wind Farm PMU on 9 January 2014

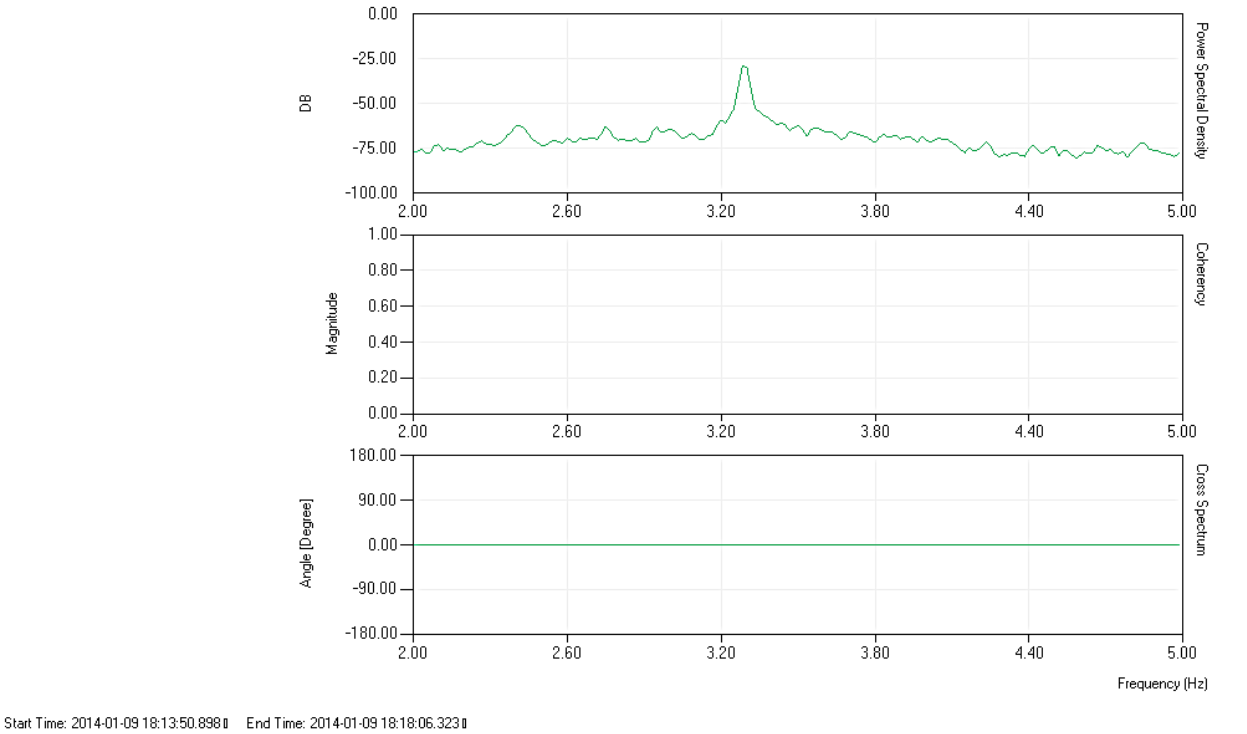


Figure 6a: Modal Analysis of the Frequency Data using PGDA on 9 January 2014.

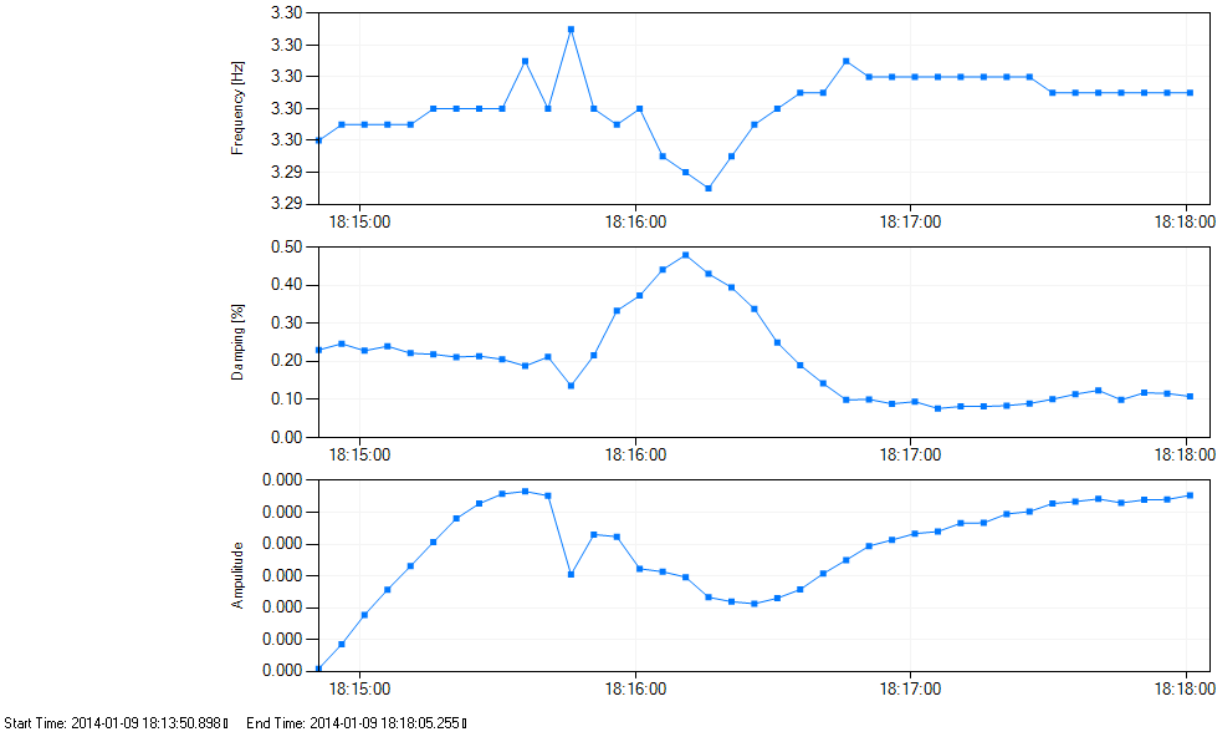


Figure 6b: Modal Analysis of the Frequency Data using PGDA on 9 January 2014.

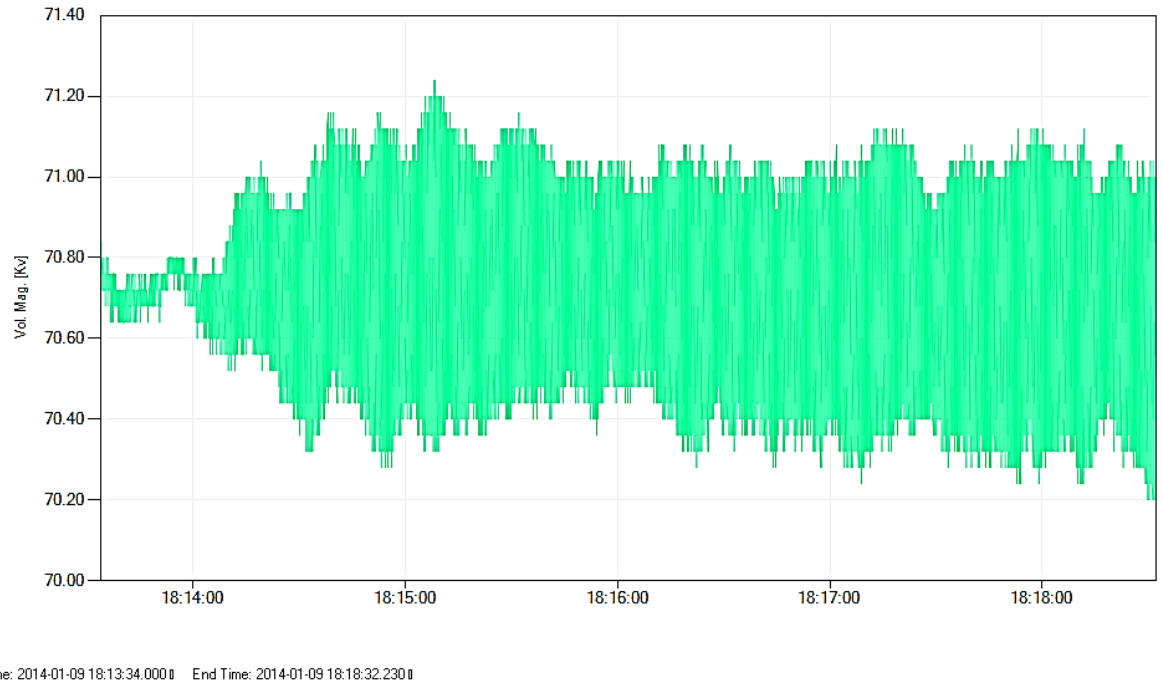


Figure 7: Voltage Oscillations at Wind Farm

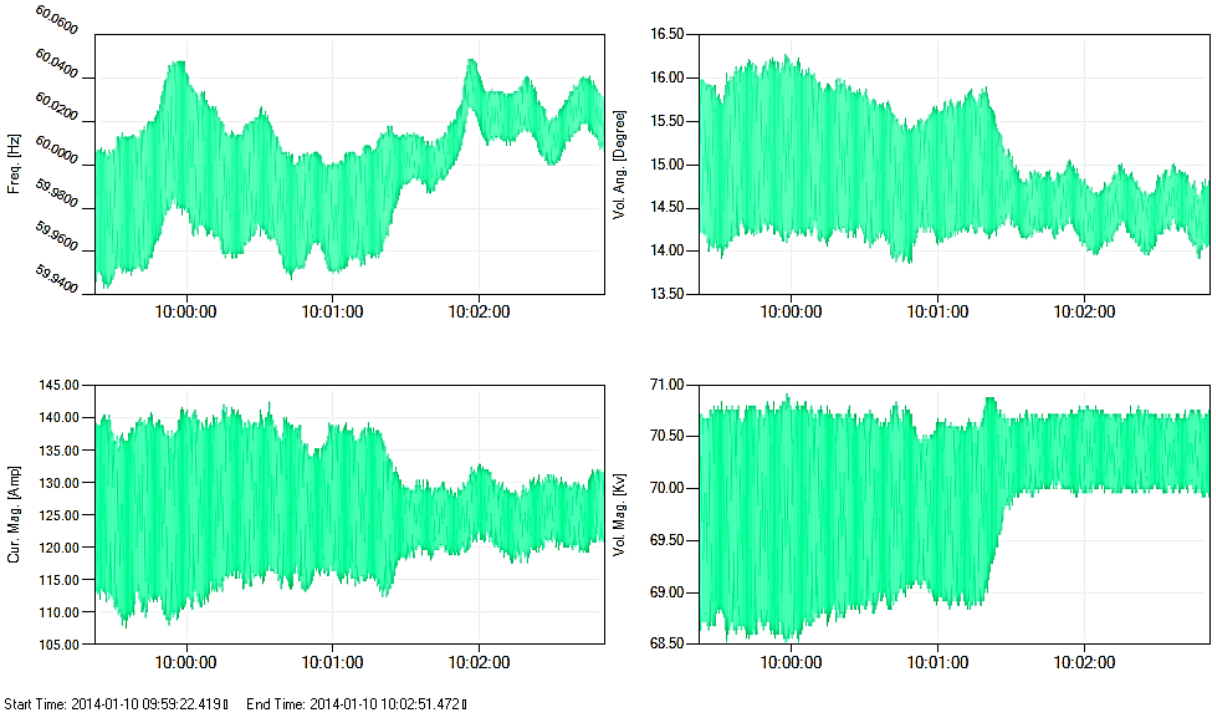


Figure.8: The Frequency, Voltage and Current Captured by the Wind Farm PMU on 10 January 2014

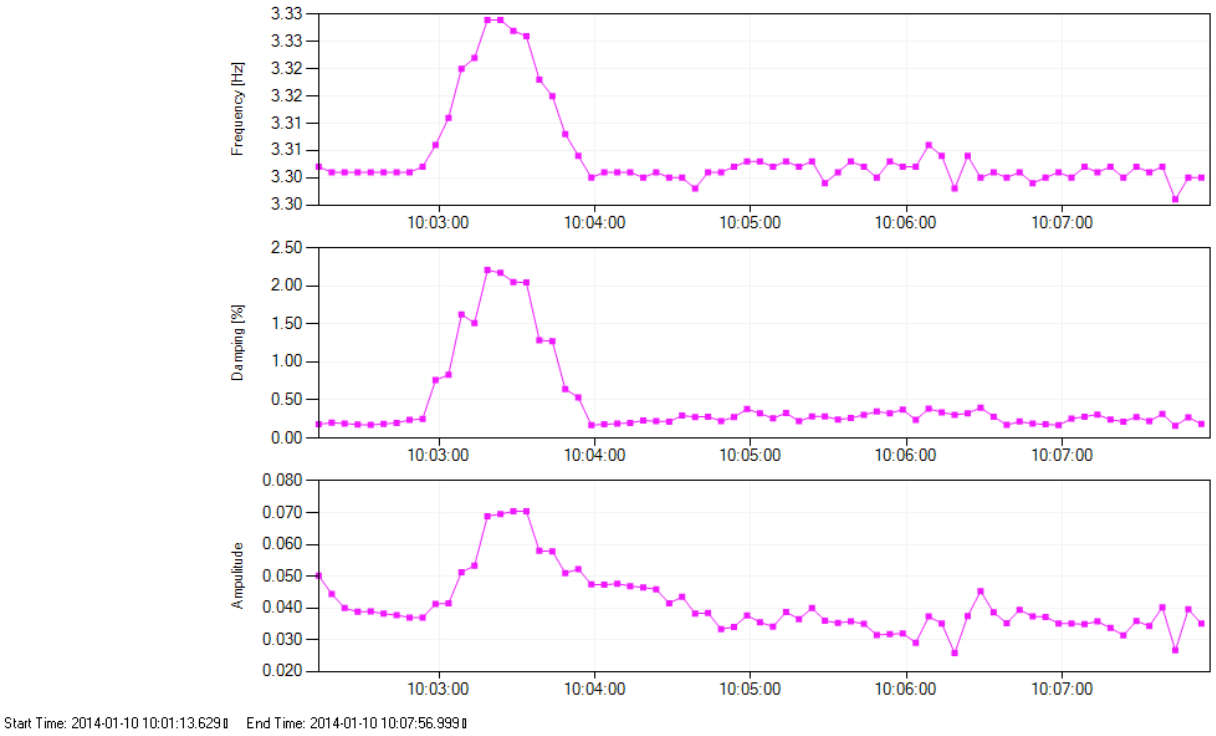


Figure 9: Modal Analysis of the Frequency Data using PGDA on 10 January 2014.

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 Figures 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.

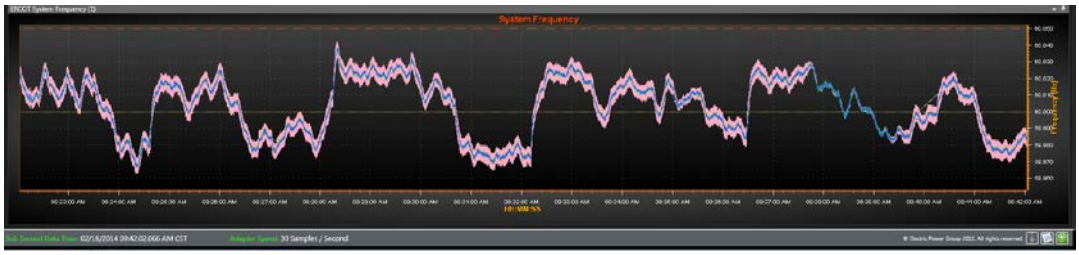


Figure 1: Frequency Oscillations on RTDMS System on February 18th, 2014.

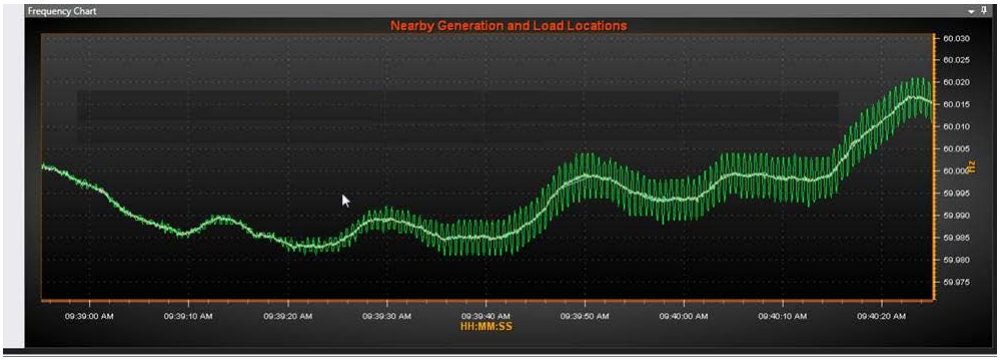


Figure 2a: Frequency Oscillations in West 4 PMU on February 18th, 2014.

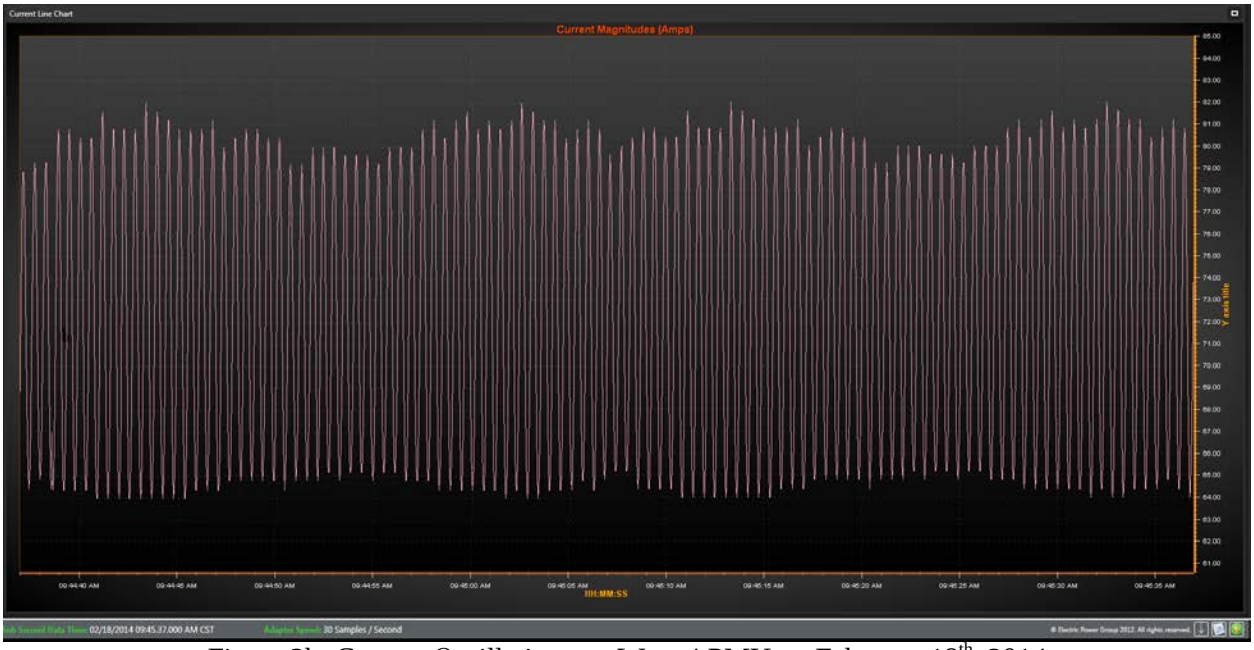


Figure 2b: Current Oscillations on West 4 PMU on February 18th, 2014.

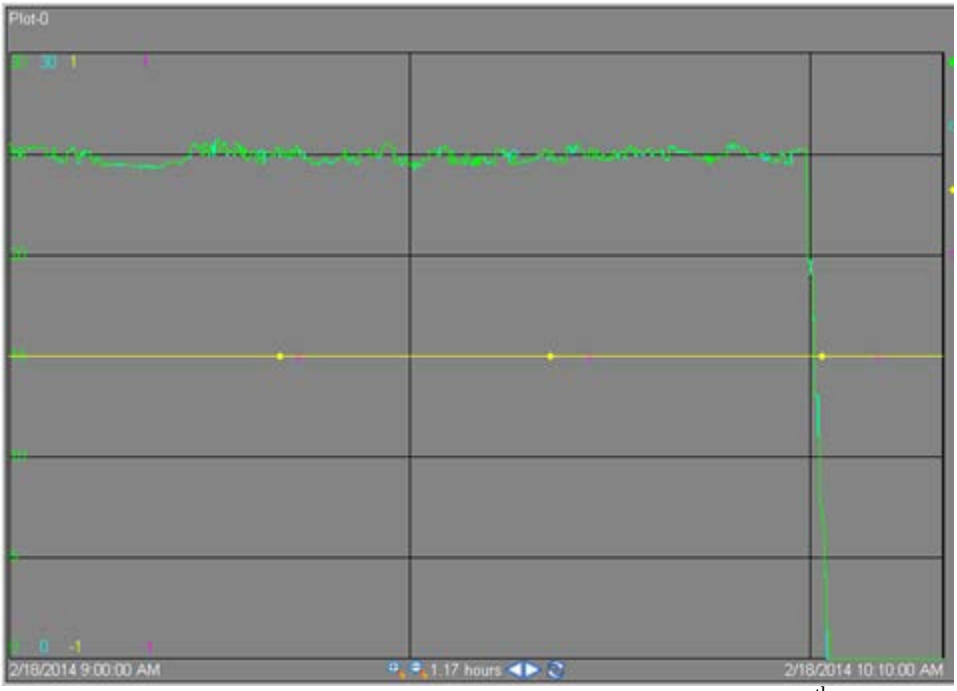


Figure 3: EMS Trend for Generation at the Power Plant on February 18th, 2014 at 10:00 a.m.

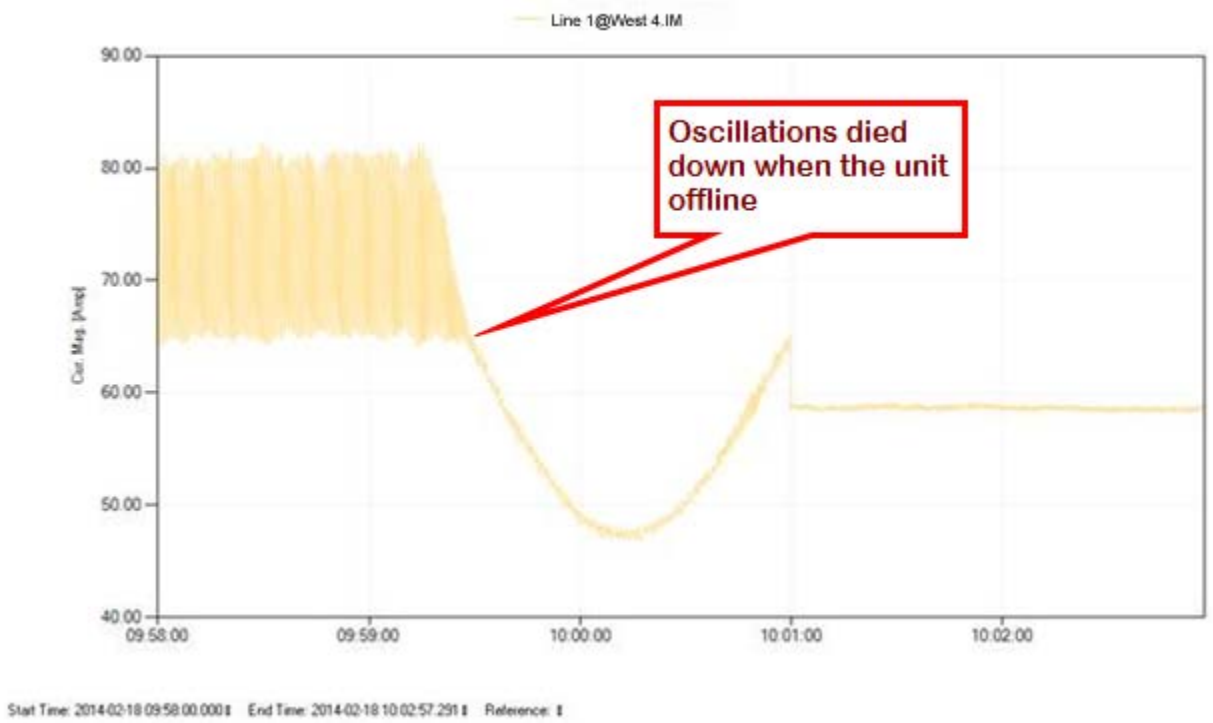


Figure 4: Current Oscillations when the Unit Went Offline on February 18th, 2014 at 10:00 a.m.

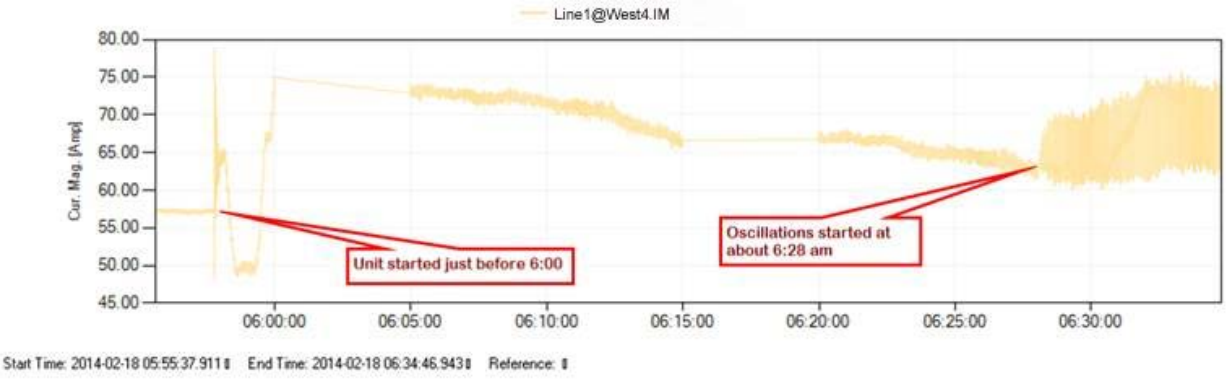


Figure 5a: Oscillations on February 27th, 2014

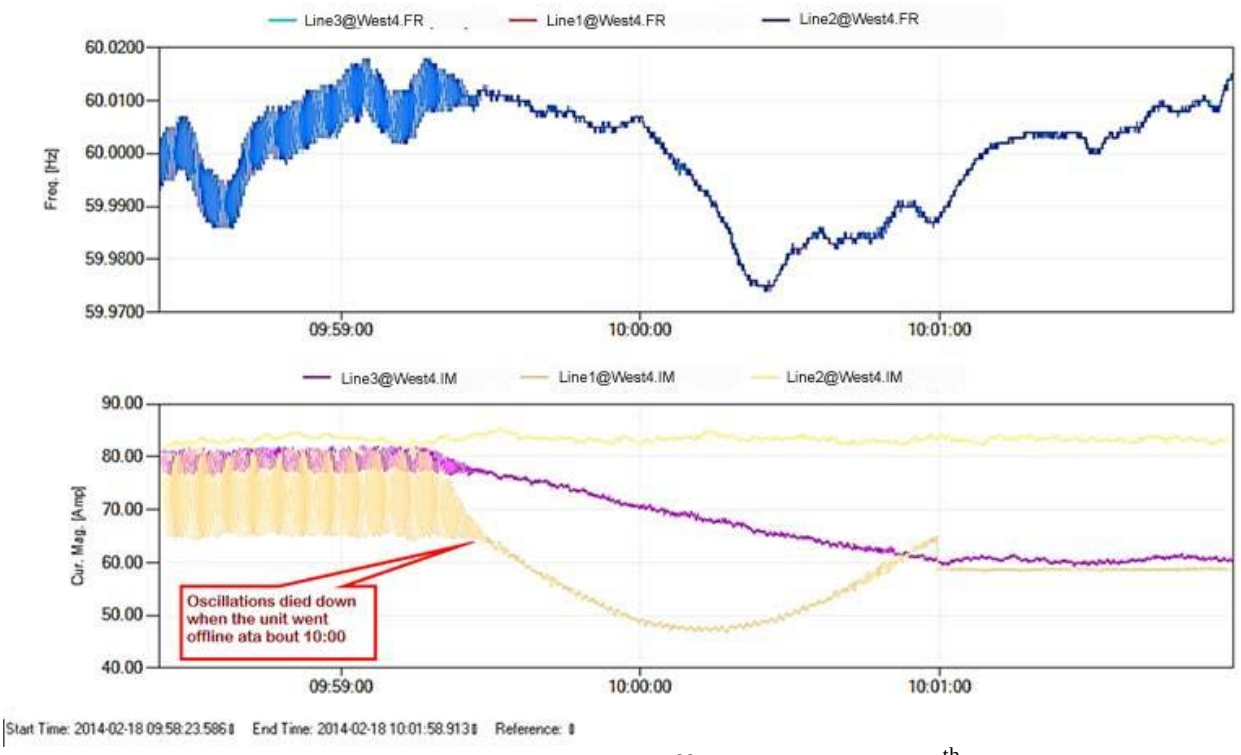


Figure 5b: Oscillations when the Unit Went Offline on February 27th, 2014 at 9:59 a.m.

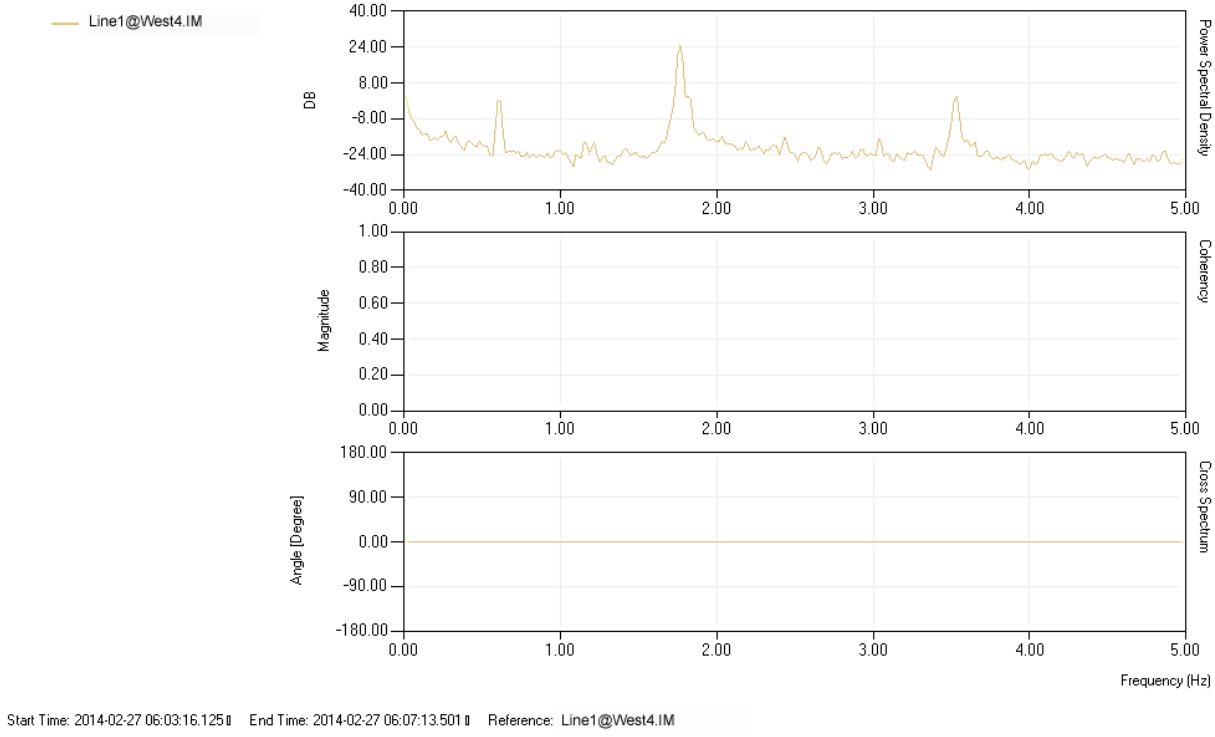


Figure 6a: Modal Analysis of the Current Data using PGDA on February 27th, 2014.

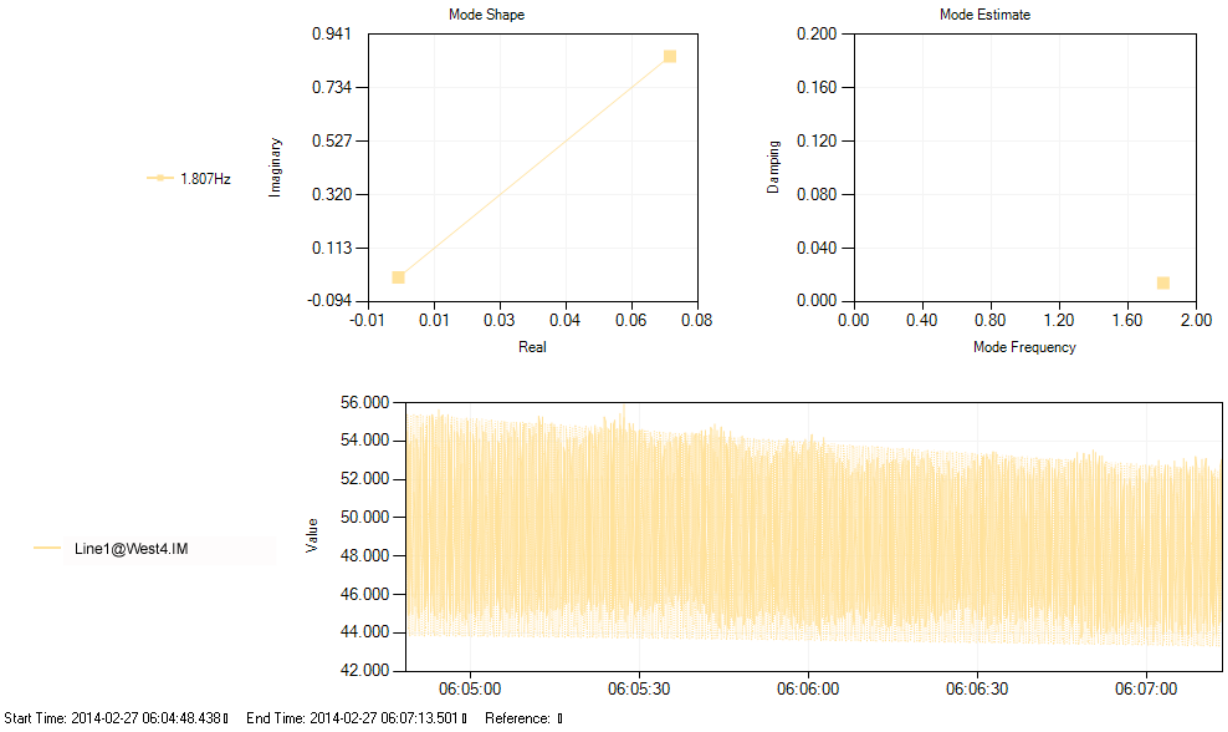


Figure 6b: Modal Analysis of the Current Data using PGDA on February 27th, 2014.

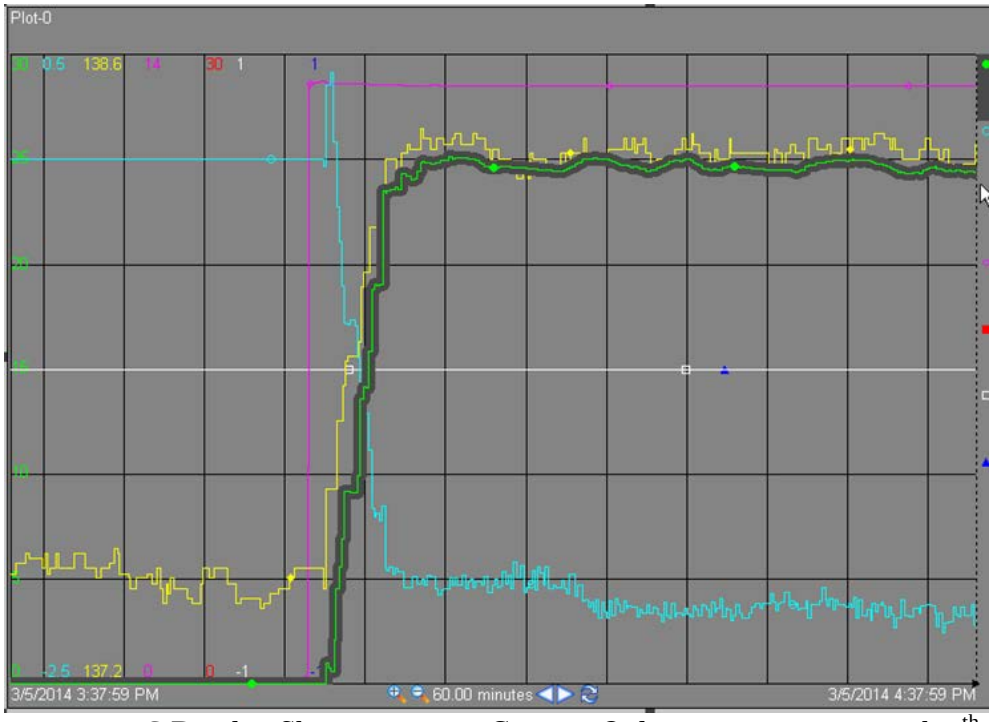


Figure 7: EMS Display Showing Unit 1 Coming Online at 4 p.m. on March 5th, 2014

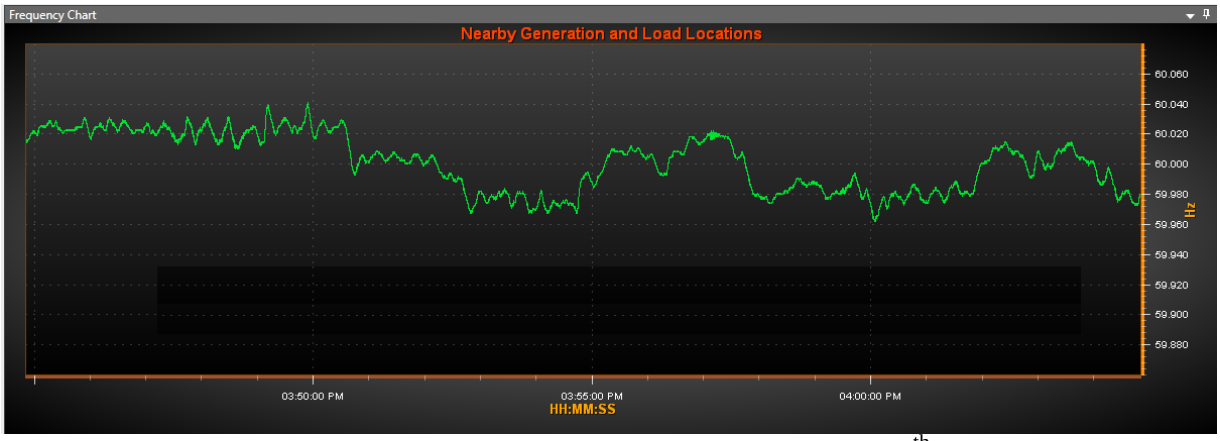


Figure 8a : Frequency Display on RTDMS on March 5th, 2014

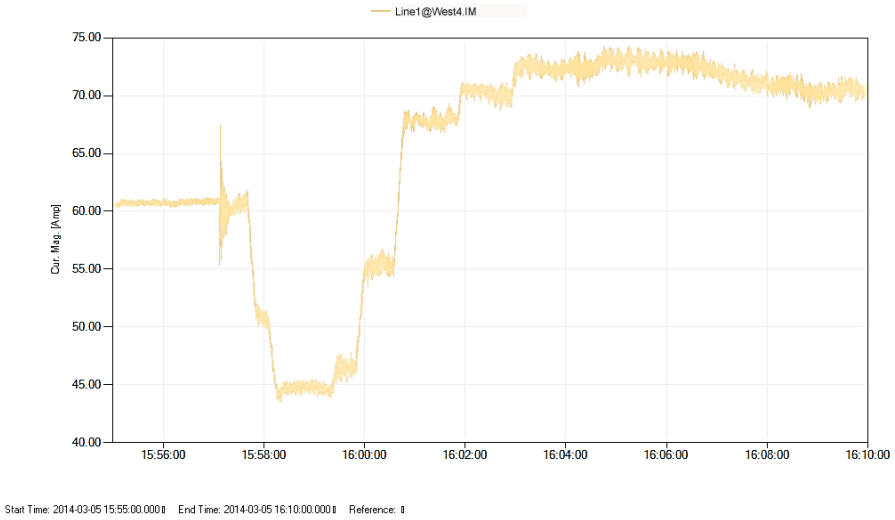


Figure 7b: Current Display on PGDA on March 5th, 2014

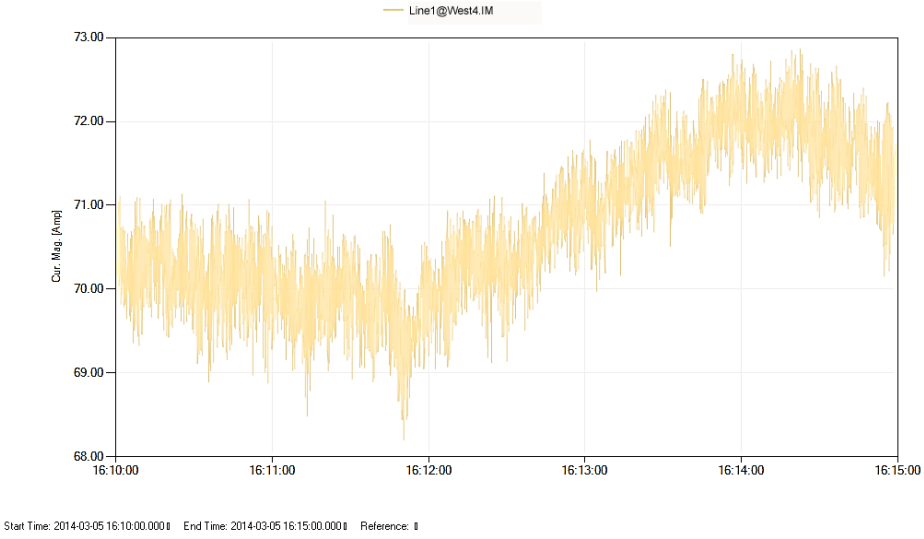


Figure 7c: Current Display on PGDA on March 5th, 2014

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
Milton Holloway, Ph.D.
mholloway@electrictechnologycenter.com

Prepared by:

Electric Power Group

John W. Ballance
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 online 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 the 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 online 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 online in the nation, and attains a new wind production level every year. With increasing amounts 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 fesponse 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 online had a strong positive correlation, suggesting inertia is proportional to non-wind generation.

3. The generation trip events, which showed 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 and 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 and derive metrics needed for the study.

Step 7 Conduct analysis to achieve the goals for this study.

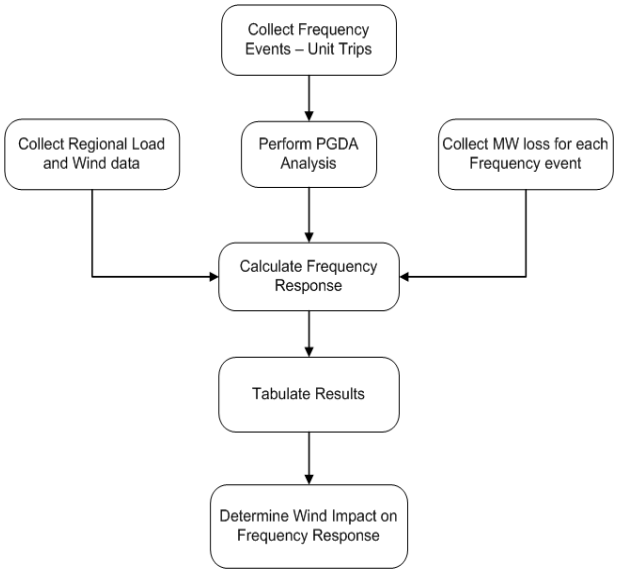


Figure 1. Analysis Workflow

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)
   ERCOT Load = Coast + East + Far West + North + North Central + Southern + Southern Central + 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 and 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 online during each event.

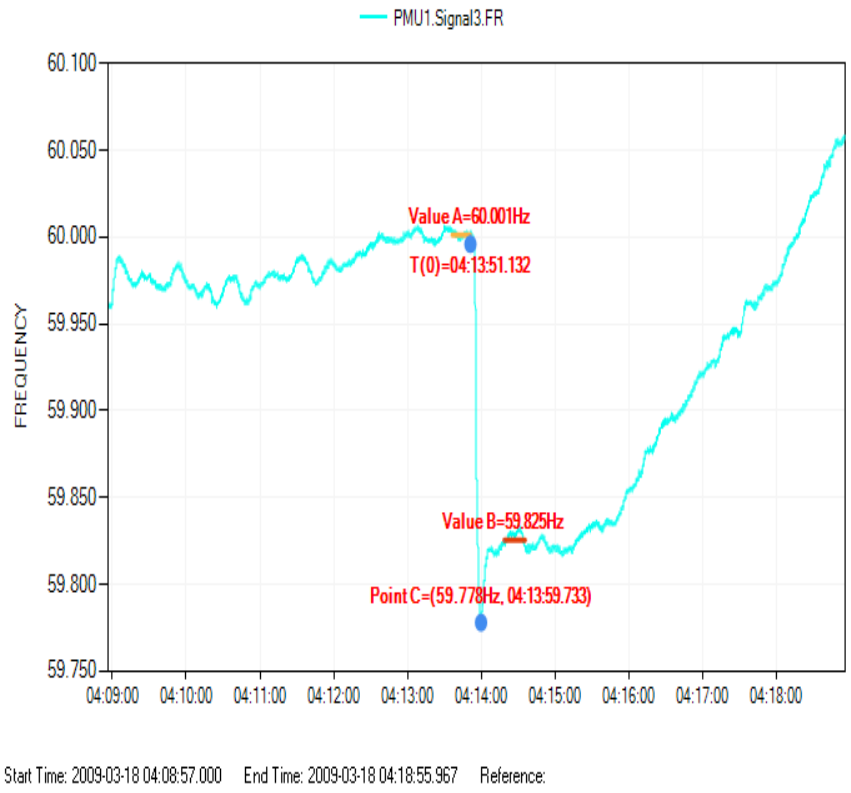


Figure 2. PGDA Event Analysis Plot

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 and A-2 in the Appendix show the estimation of inertial frequency response for 2012 and 2013, respectively.

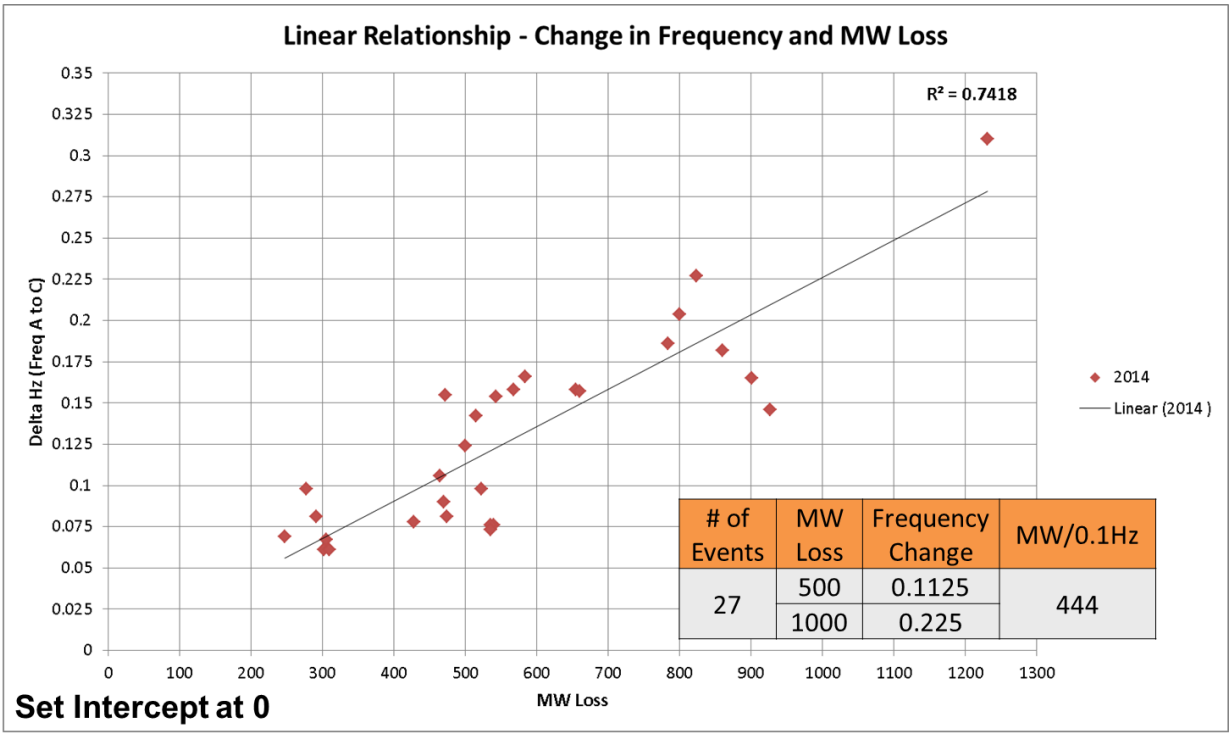


Figure 3. Estimation of Inertial Frequency Response – 2014

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 online generation) without filtering on different load conditions. The two levels of wind penetration chosen were:

1. <= 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.

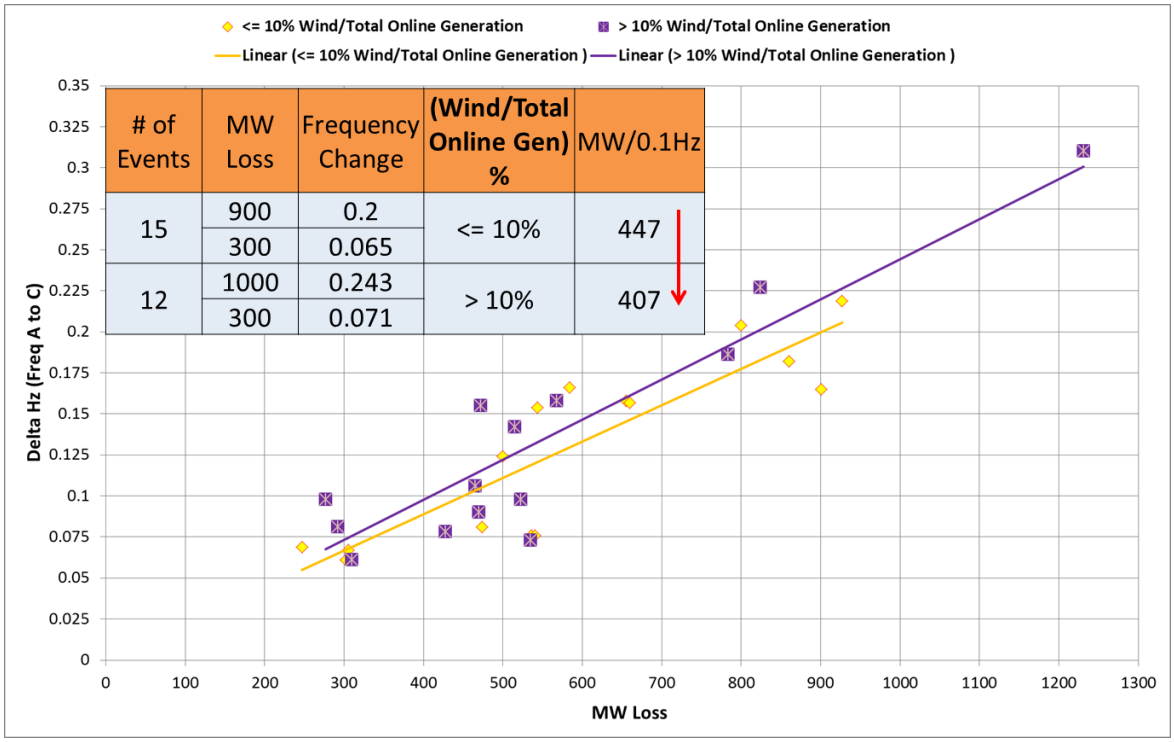


Figure 4. Estimation of Inertial Frequency Response (Two Wind Levels & No Load Levels) – 2014

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 versus 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.

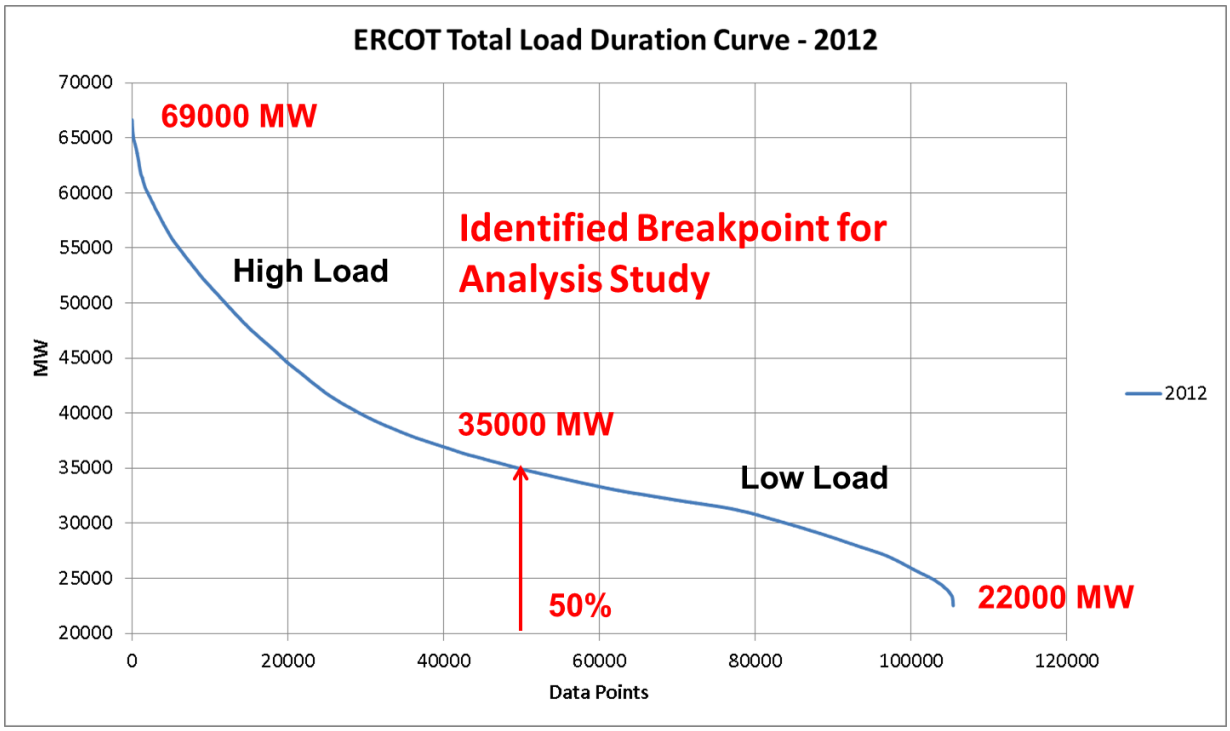


Figure 5a. Load Duration Curve – 2012

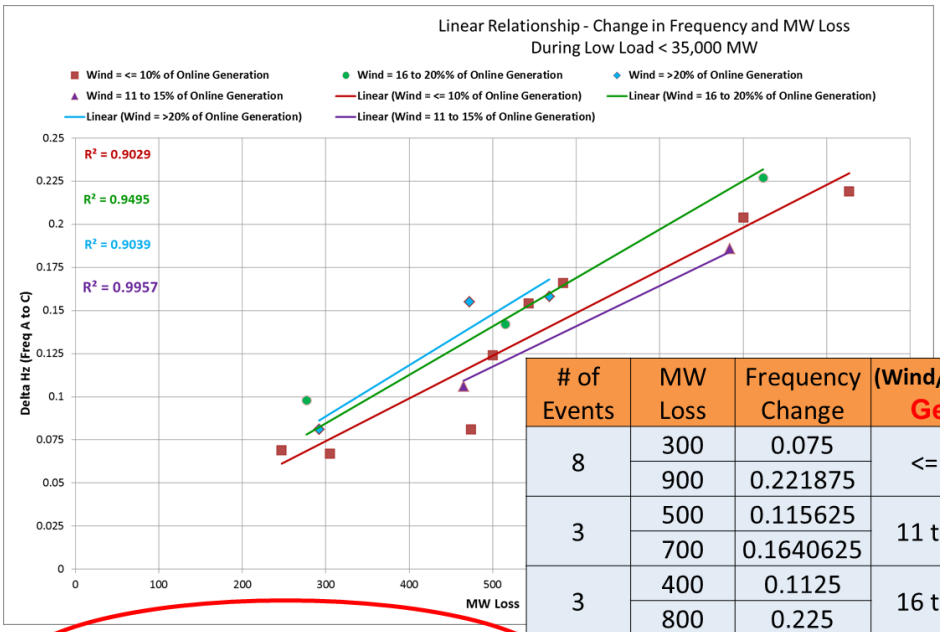
Figure 5b shows an example of estimating inertial frequency response for 2014, with load less than 35 GW using four different levels of wind generation. The events for this case were divided into four different levels of wind generation, and using the linear relationship between generation and frequency 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. It 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 contain estimations of inertial frequency response under different loading conditions, and different levels of wind generation, for 2012, 2013 & 2014.



Decline in Inertia with increasing levels of wind resources

Increase in Inertia with increasing levels of wind resources

# of Events	MW Loss	Frequency Change	(Wind/Online Gen) %	MW/0.1Hz
8	300	0.075	<= 10%	408.5
	900	0.221875		
3	500	0.115625	11 to 15%	412.9
	700	0.1640625		
3	400	0.1125	16 to 20%	355.5
	800	0.225		
2	400	0.11875	> 20%	355.5
	500	0.146875		

Same Inertia, at Different Levels of Wind Impact

Figure 5b. Estimation of Inertial Frequency Response (Four Wind Levels & Load < 35GW) – 2014

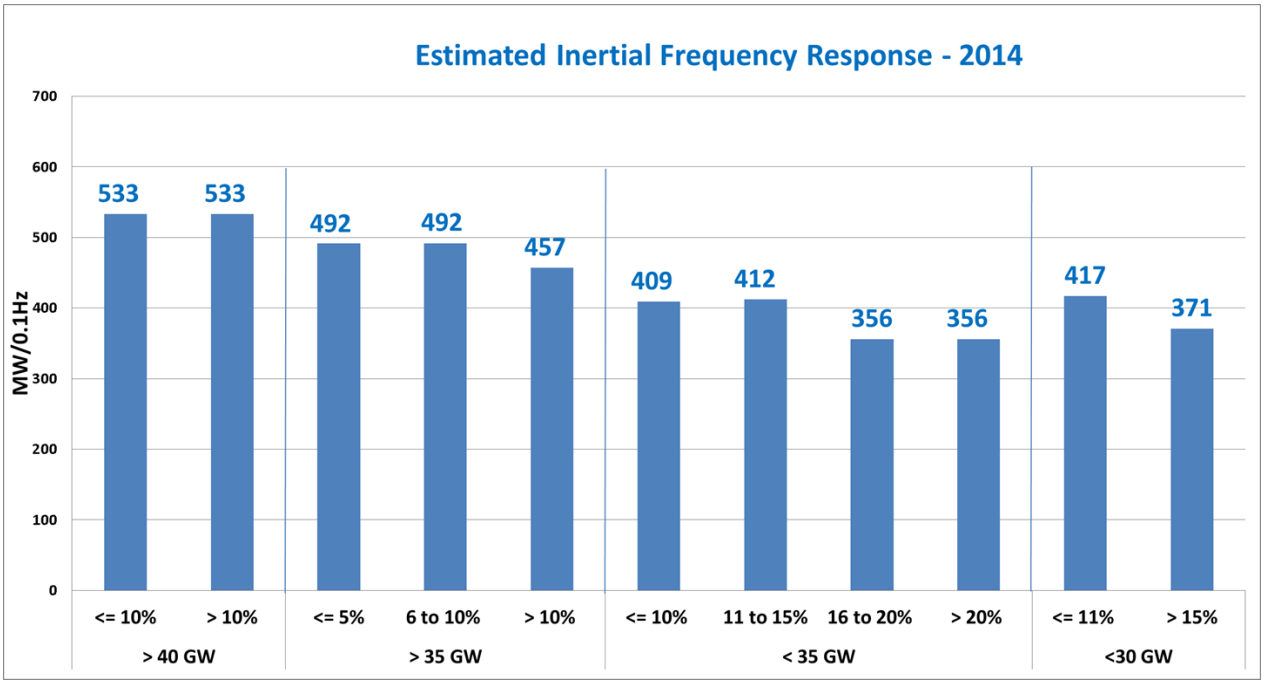


Figure 6. Estimation of Inertial Frequency Response (Different Wind Levels & Load Levels) – 2014

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 Online.
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 were compared to examine the relationship between them. Figures 7, 8, and 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.

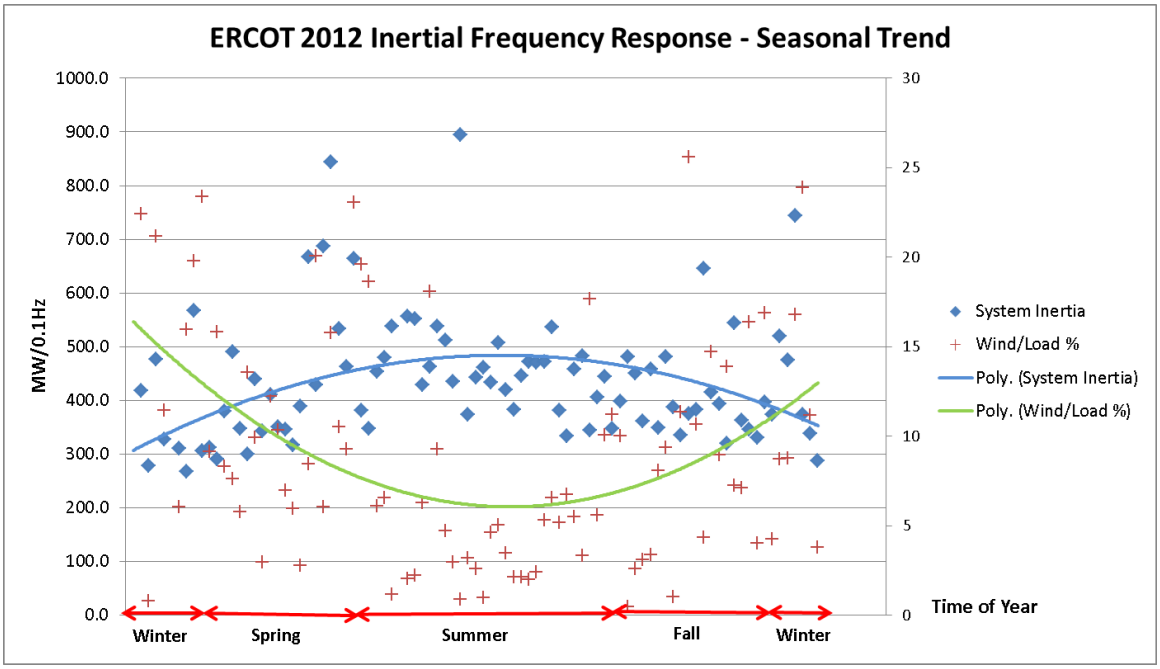


Figure 7. Seasonal Trend of ERCOT Inertial Frequency Response & Percentage of Wind Generation – 2012

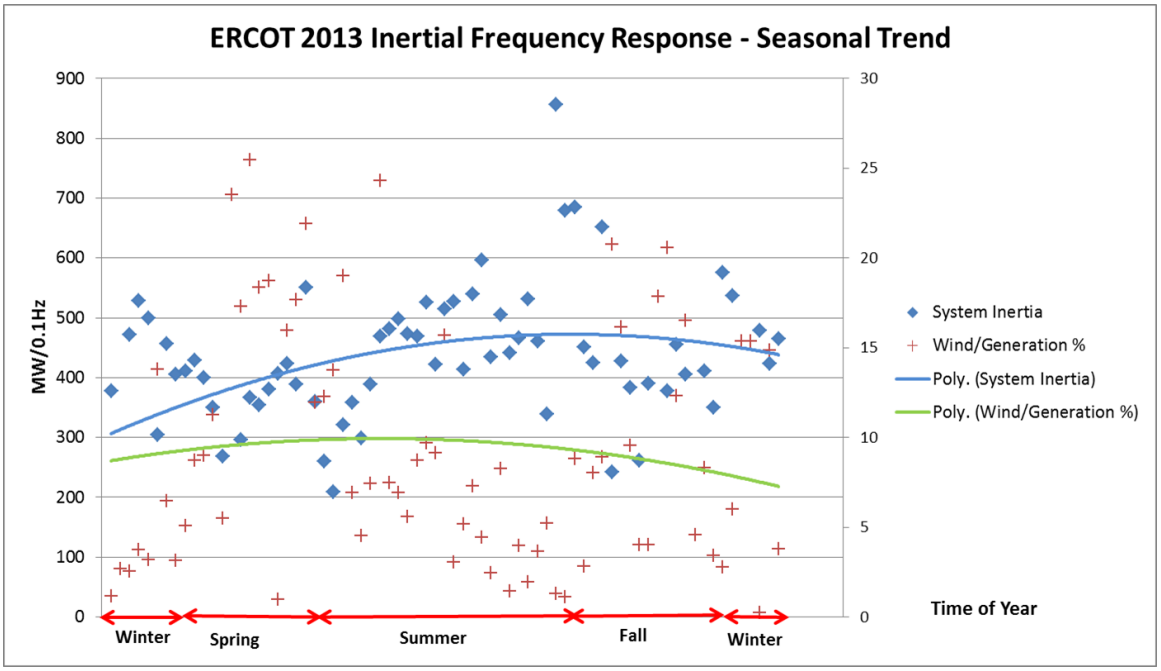


Figure 8. Seasonal Trend of ERCOT Inertial Frequency Response & Percentage of Wind Generation – 2013

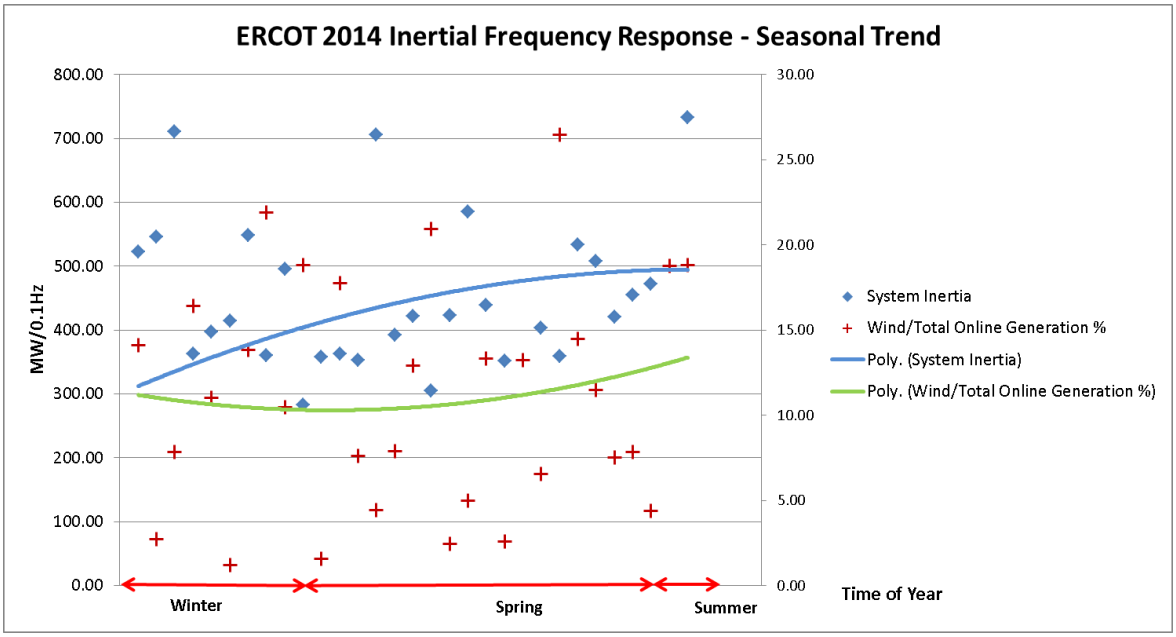


Figure 9. Seasonal Trend of ERCOT Inertial Frequency Response & Percentage of Wind Generation – 2014

2. Inertial Frequency Response vs. Non-Wind Generation Online

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 online is both linear and positively correlated, suggesting a strong relationship. The non-wind generation online is the sum of total ERCOT generation plus spinning reserves minus wind gseneration. 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.

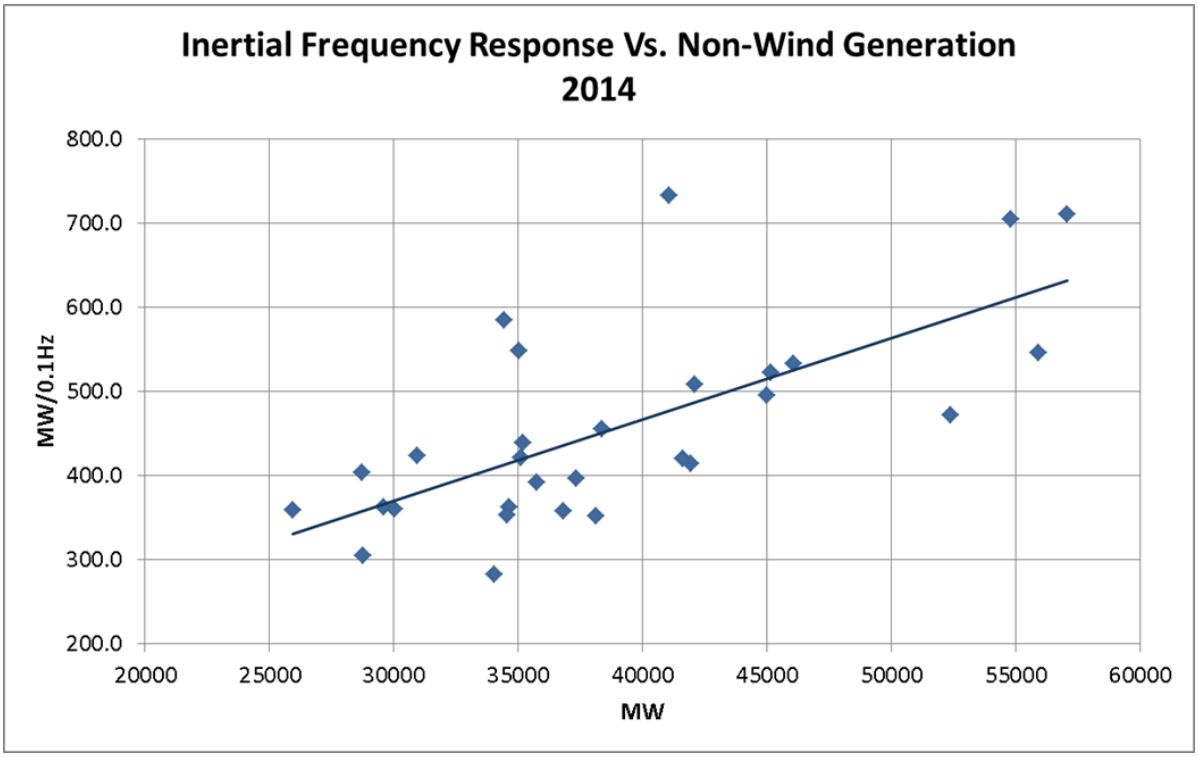


Figure 10. Linear Relationship (Inertia Proportional to Non-Wind Generation) – 2014

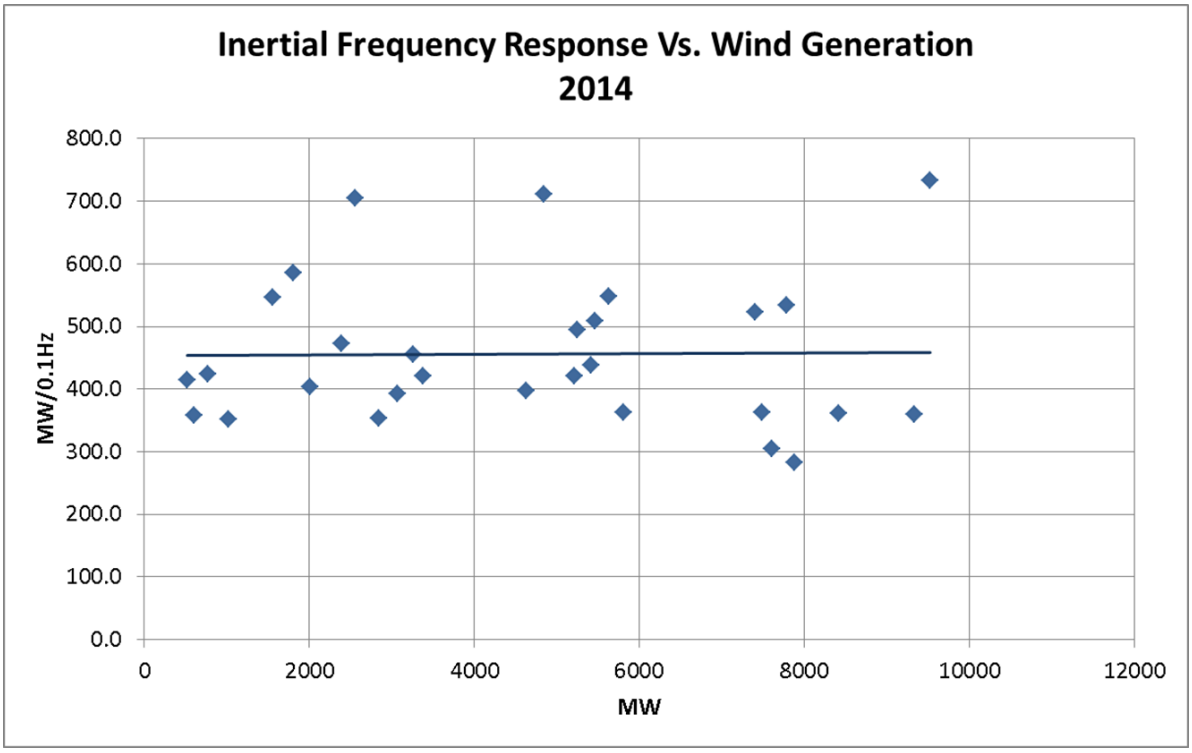


Figure 11. Wind Generation Showing No Contribution to Inertial Frequency Response – 2014

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 shown previously in Figure 6. The different levels of wind generation were determined based on the availability and occurrence of actual generator loss events.

There is partially 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 online (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 (MW-seconds per MW) than do hydro units. The mix of non-wind generation online 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 data from PMUs 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, and West 6.

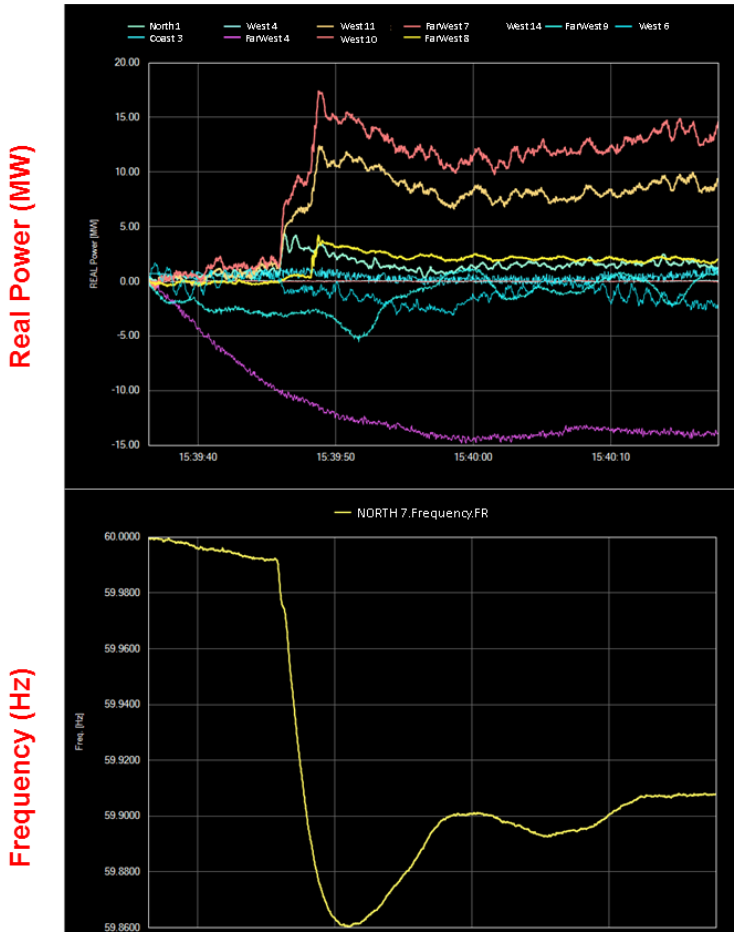


Figure 14. Example of No Inertia from Wind Plants Using PGDA – Wind Output vs. Frequency Range (PMU data)

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 from 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 data from PMUs located near wind units were collected and analyzed to understand the variation and trends 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 the 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

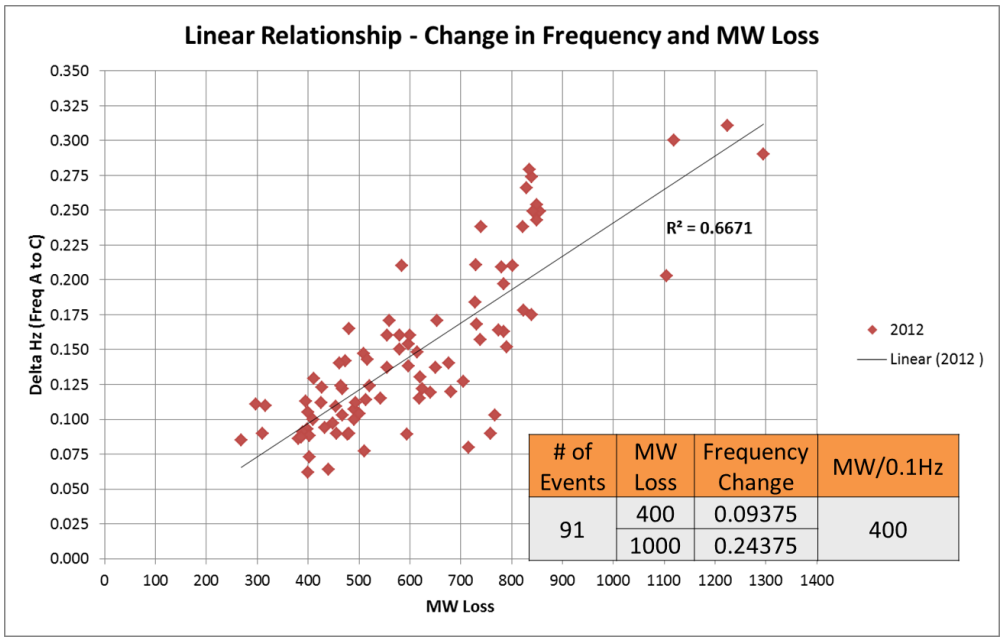


Figure A-1. Estimation of Inertial Frequency Response – 2012

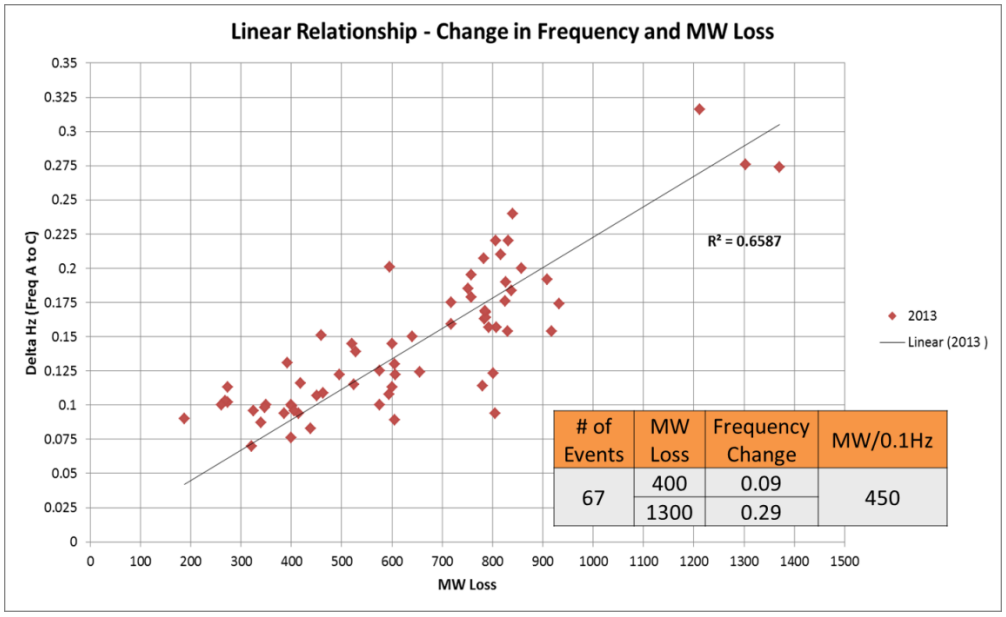


Figure A-2. Estimation of Inertial Frequency Response – 2013

Hypothesis – Decline in Inertial Frequency Response

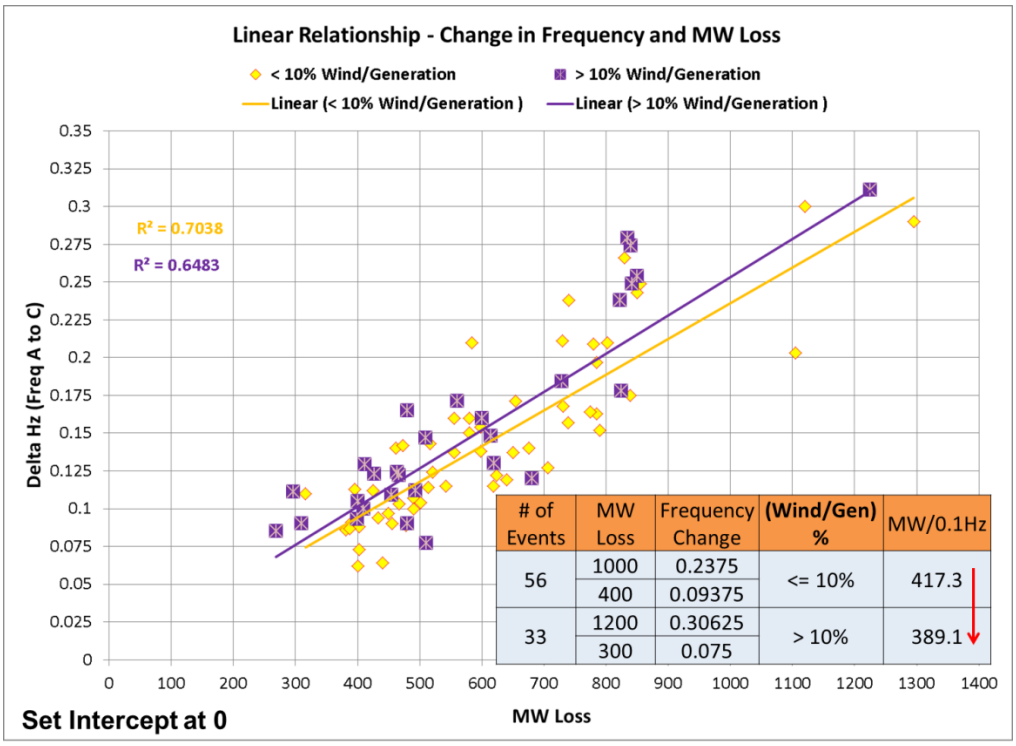


Figure A-3. Estimation of Inertial Frequency Response (Two Wind Levels & No Load Levels) – 2012

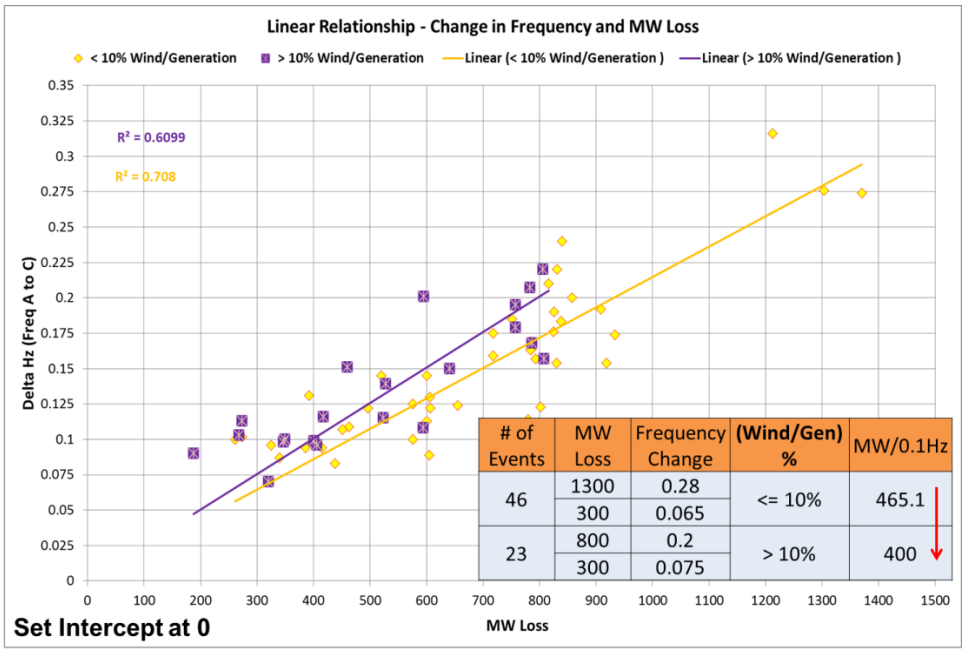
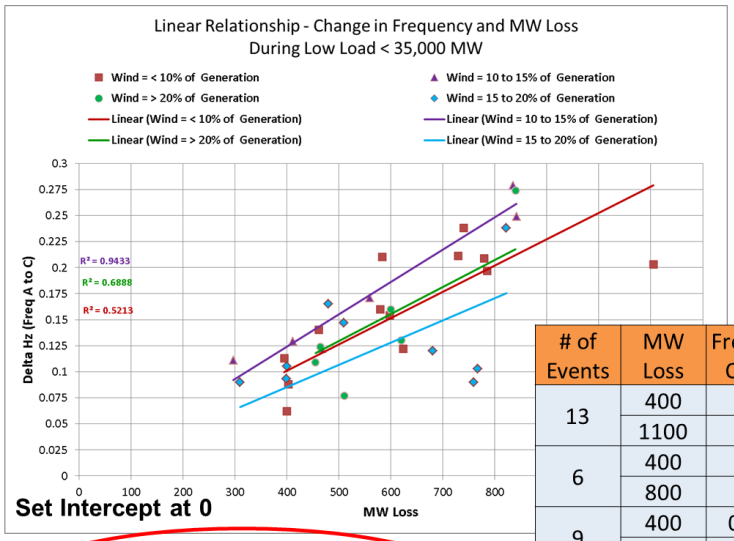


Figure A-4. Estimation of Inertial Frequency Response (Two Wind Levels & No Load Levels) – 2013



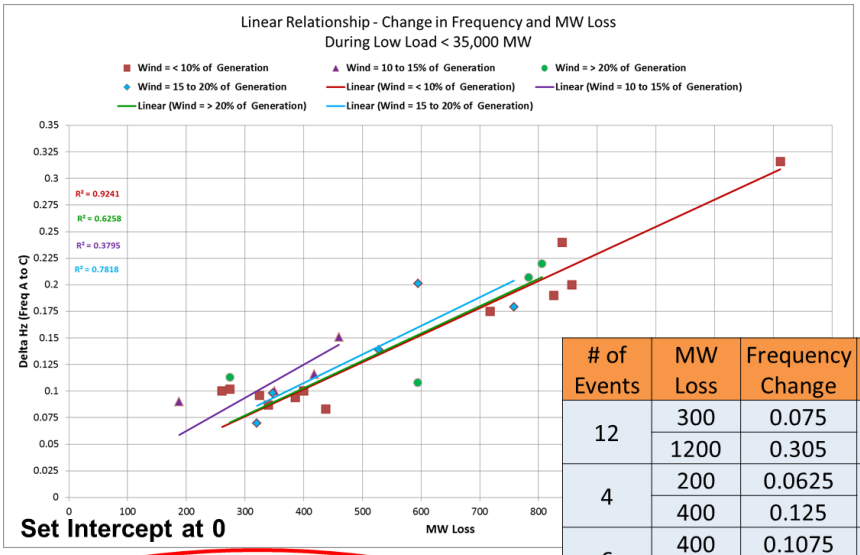
Decline in Inertia with increasing levels of wind resources

Increase in Inertia with increasing levels of wind resources

# of Events	MW Loss	Frequency Change	(Wind/Gen) %	MW/0.1Hz
13	400	0.1	<= 10%	400
	1100	0.275		
6	400	0.125	11 to 15%	320
	800	0.25		
9	400	0.0875	16 to 20%	492.3
	800	0.16875		
6	500	0.13125	> 20%	400
	800	0.20625		

Same Inertia, at Different Levels of Wind Impact

Figure A-5. Estimation of Inertial Frequency Response (Four Wind Levels & Load <35 GW) – 2012



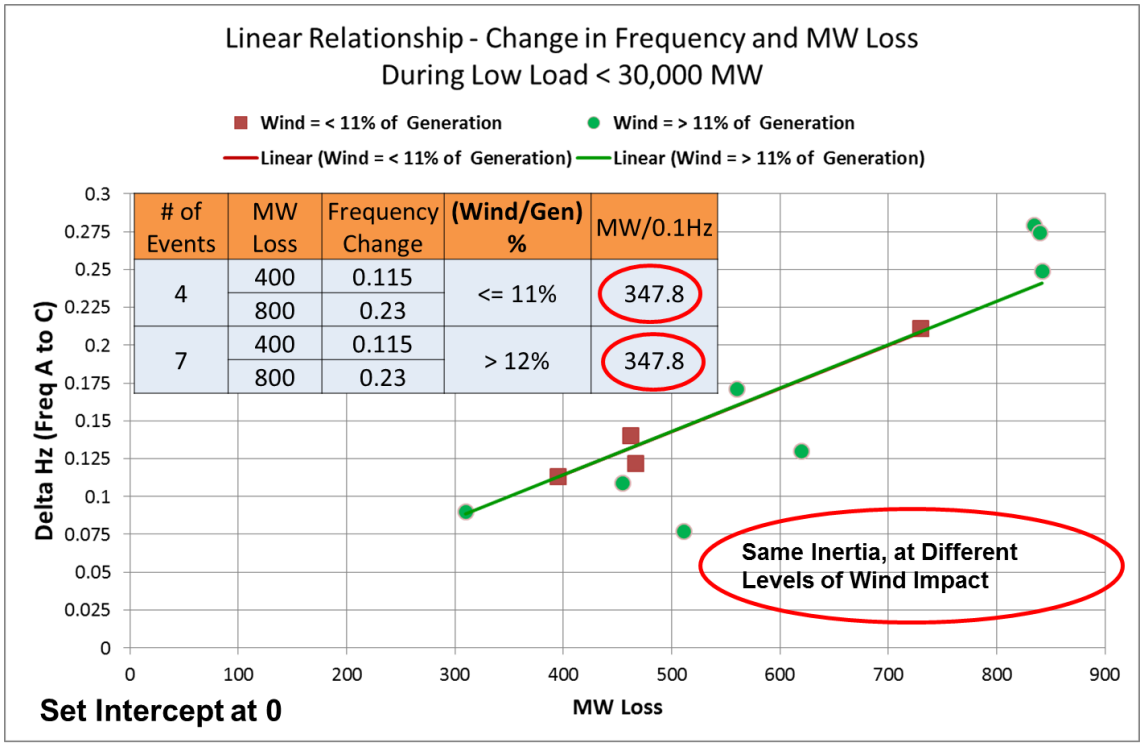
Decline in Inertia with increasing levels of wind resources

Increase in Inertia with increasing levels of wind resources

# of Events	MW Loss	Frequency Change	(Wind/Gen) %	MW/0.1Hz
12	300	0.075	<= 10%	391.3
	1200	0.305		
4	200	0.0625	11 to 15%	320
	400	0.125		
6	400	0.1075	16 to 20%	375
	700	0.1875		
3	300	0.0775	> 20%	392.1
	800	0.205		

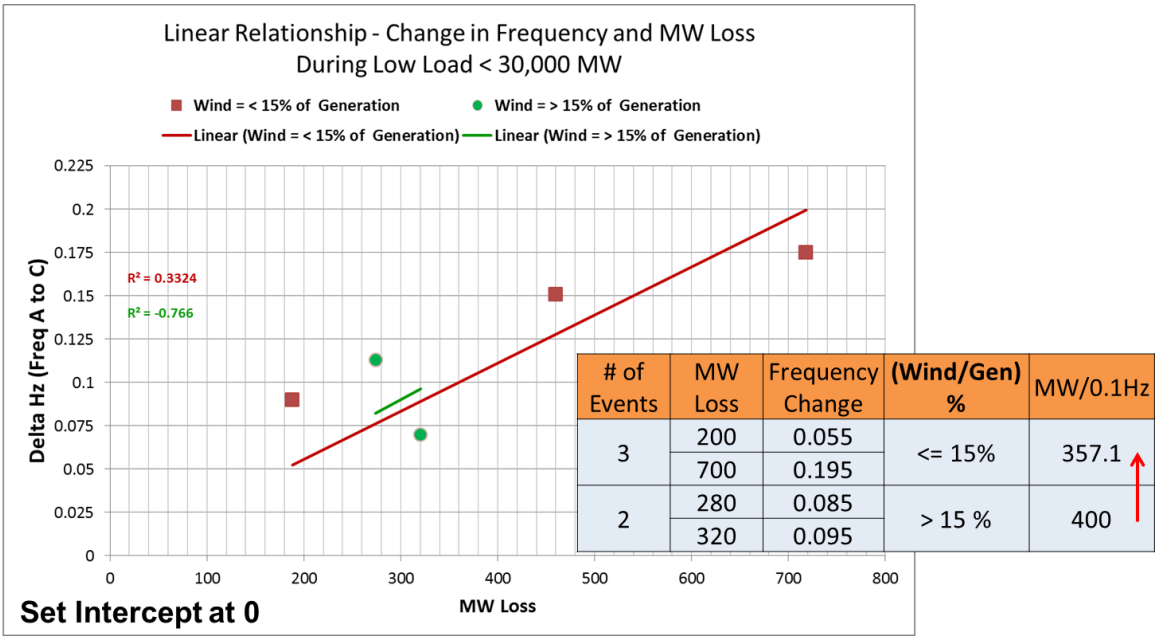
Same Inertia, at Different Levels of Wind Impact

Figure A-6. Estimation of Inertial Frequency Response (Four Wind Levels & Load <35 GW) – 2013



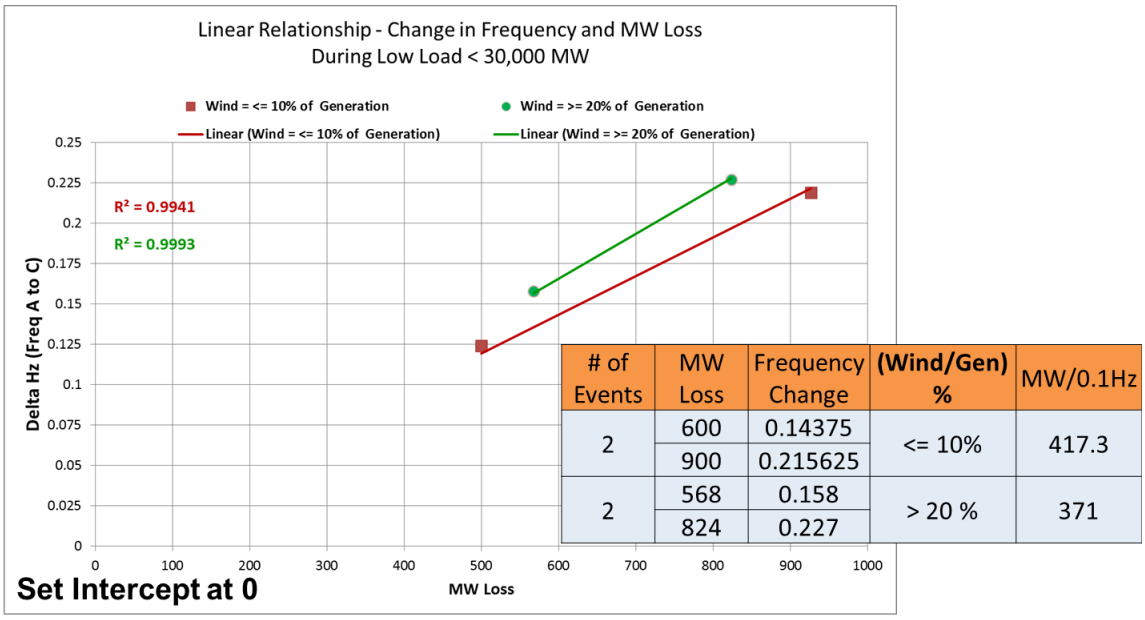
# of Events	MW Loss	Frequency Change	(Wind/Gen) %	MW/0.1Hz
4	400	0.115	<= 11%	347.8
	800	0.23		
7	400	0.115	> 12%	347.8
	800	0.23		

Figure A-7. Estimation of Inertial Frequency Response (Two Wind Levels & Load <30 GW) – 2012



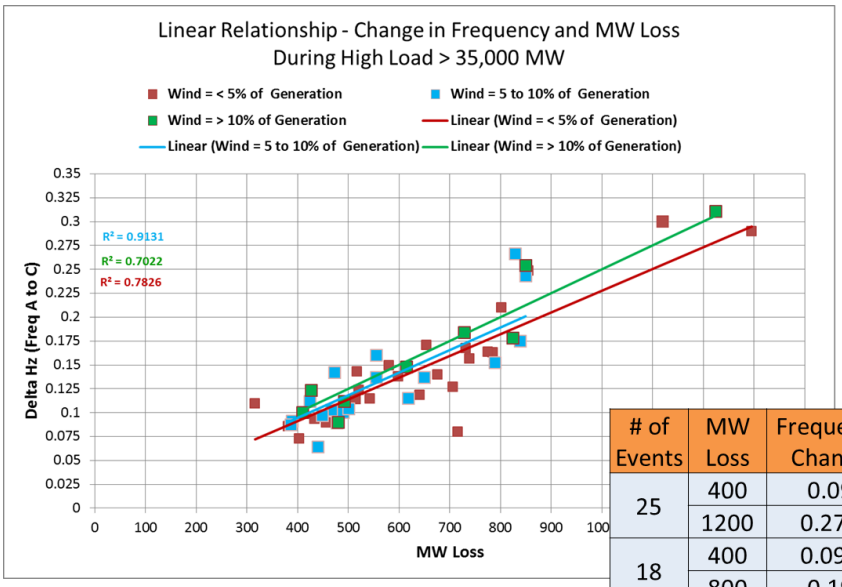
# of Events	MW Loss	Frequency Change	(Wind/Gen) %	MW/0.1Hz
3	200	0.055	<= 15%	357.1
	700	0.195		
2	280	0.085	> 15 %	400
	320	0.095		

Figure A-8. Estimation of Inertial Frequency Response (Two Wind Levels & Load <30 GW) – 2013



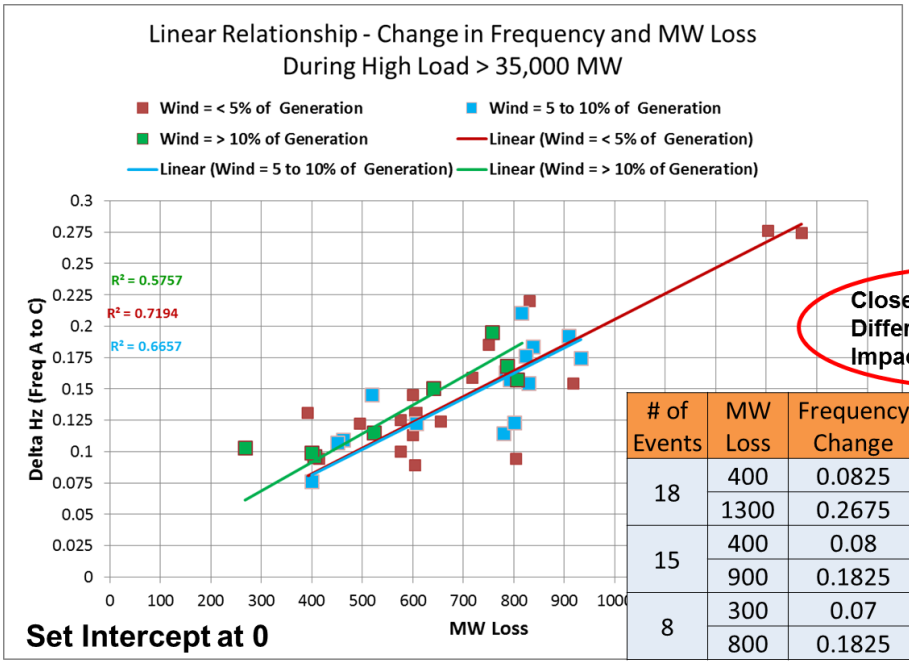
# of Events	MW Loss	Frequency Change	(Wind/Gen) %	MW/0.1Hz
2	600	0.14375	<= 10%	417.3
	900	0.215625		
2	568	0.158	> 20 %	371
	824	0.227		

Figure A-9. Estimation of Inertial Frequency Response (Two Wind Levels & Load <30 GW) – 2014



# of Events	MW Loss	Frequency Change	(Wind/Gen) %	MW/0.1Hz
25	400	0.09	<= 5%	432.4
	1200	0.275		
18	400	0.095	6 to 10%	421
	800	0.19		
9	500	0.125	> 10%	400
	1200	0.3		

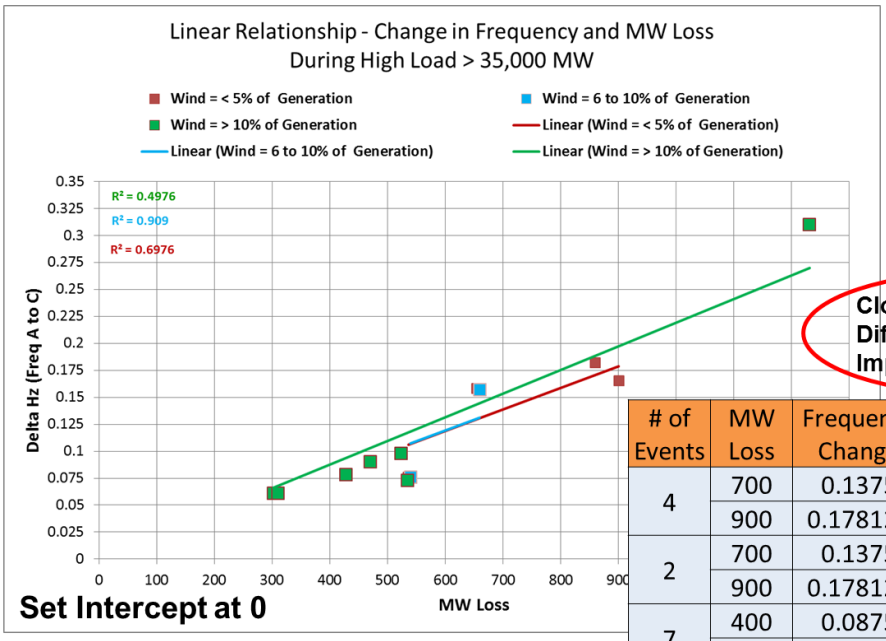
Figure A-10. Estimation of Inertial Frequency Response (Three Wind Levels & Load >35 GW) – 2012



Close to same Inertia, at Different Levels of Wind Impact

# of Events	MW Loss	Frequency Change	(Wind/Gen) %	MW/0.1Hz
18	400	0.0825	<= 5%	486.4
	1300	0.2675		
15	400	0.08	6 to 10%	487.8
	900	0.1825		
8	300	0.07	> 10%	444.4
	800	0.1825		

Figure A-11. Estimation of Inertial Frequency Response (Three Wind Levels & Load >35 GW) – 2013



Close to same Inertia, at Different Levels of Wind Impact

# of Events	MW Loss	Frequency Change	(Wind/Gen) %	MW/0.1Hz
4	700	0.1375	<= 5%	492.3
	900	0.178125		
2	700	0.1375	6 to 10%	492.3
	900	0.178125		
7	400	0.0875	> 10%	457.1
	1200	0.2625		

Figure A-12. Estimation of Inertial Frequency Response (Three Wind Levels & Load >35 GW) – 2014

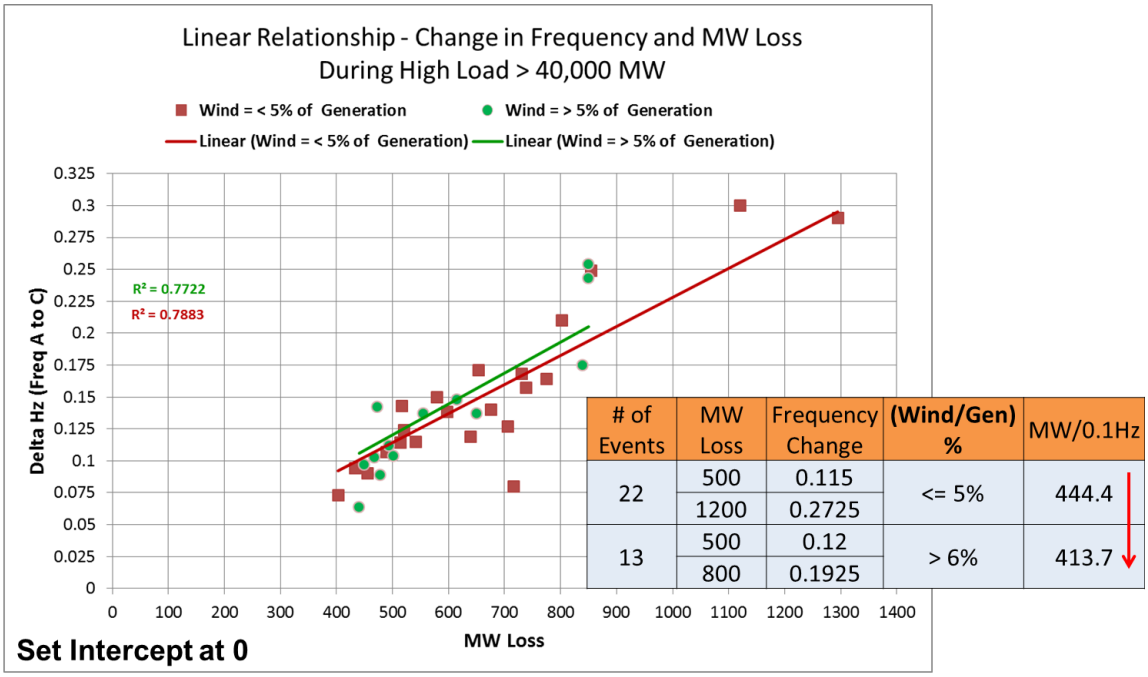


Figure A-13. Estimation of Inertial Frequency Response (Two Wind Levels & Load >40 GW) – 2012

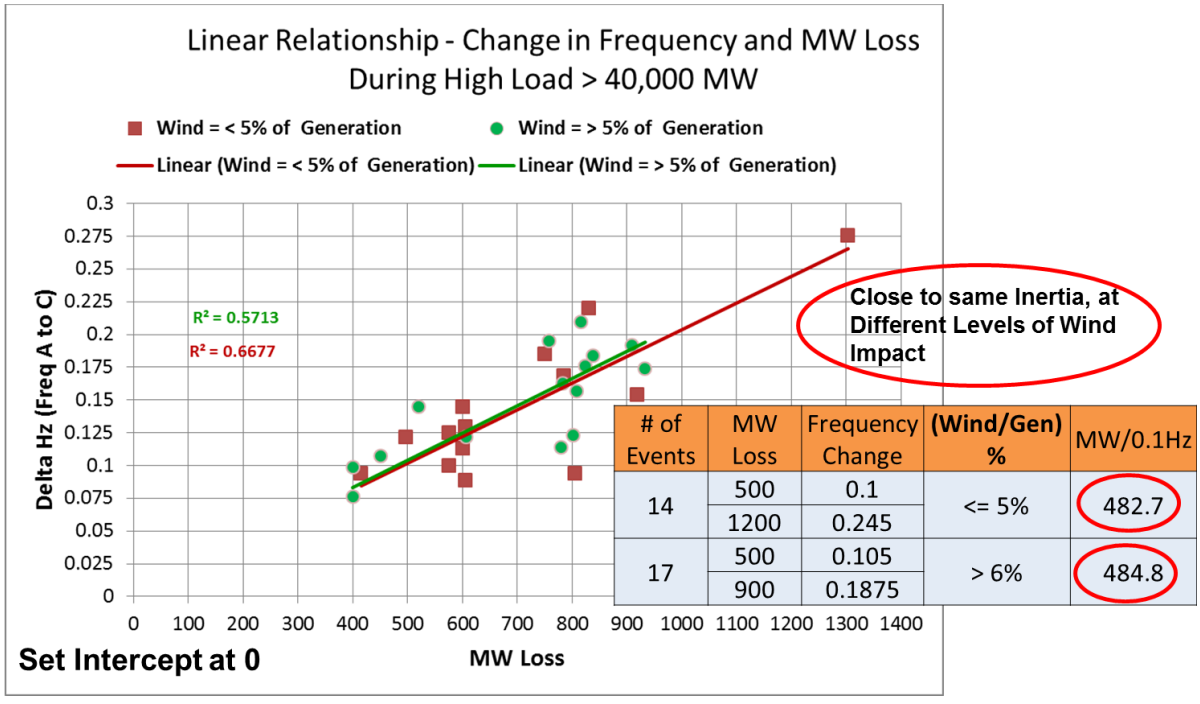
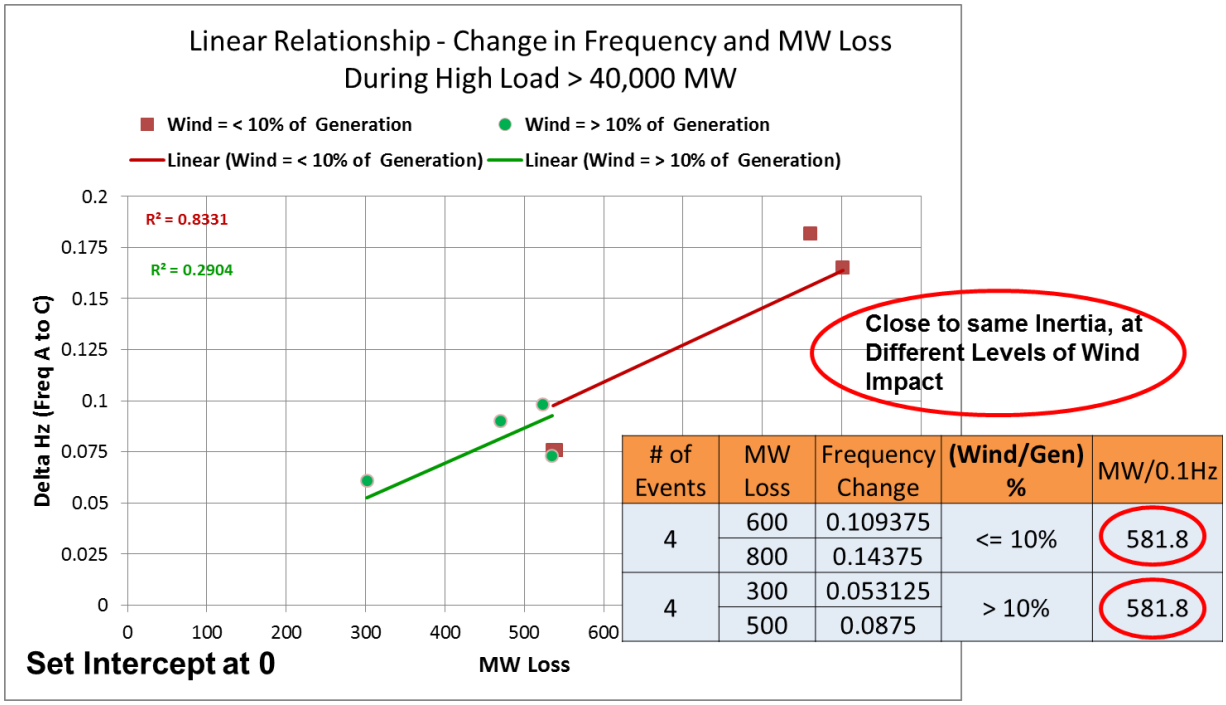


Figure A-14. Estimation of Inertial Frequency Response (Two Wind Levels & Load >40 GW) – 2013



# of Events	MW Loss	Frequency Change	(Wind/Gen) %	MW/0.1Hz
4	600	0.109375	<= 10%	581.8
	800	0.14375		
4	300	0.053125	> 10%	581.8
	500	0.0875		

Figure A-15. Estimation of Inertial Frequency Response (Two Wind Levels & Load >40 GW) – 2014

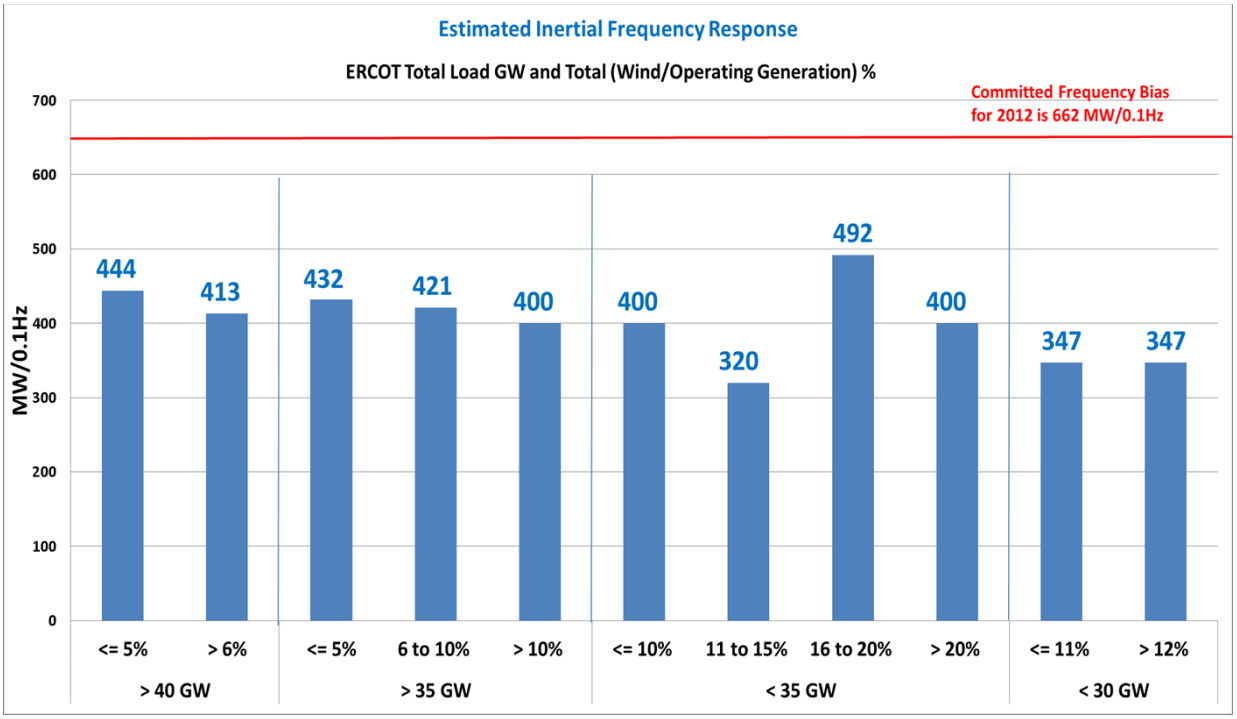


Figure A-16. Estimation of Inertial Frequency Response (Different Wind Levels & Load Levels) – 2012

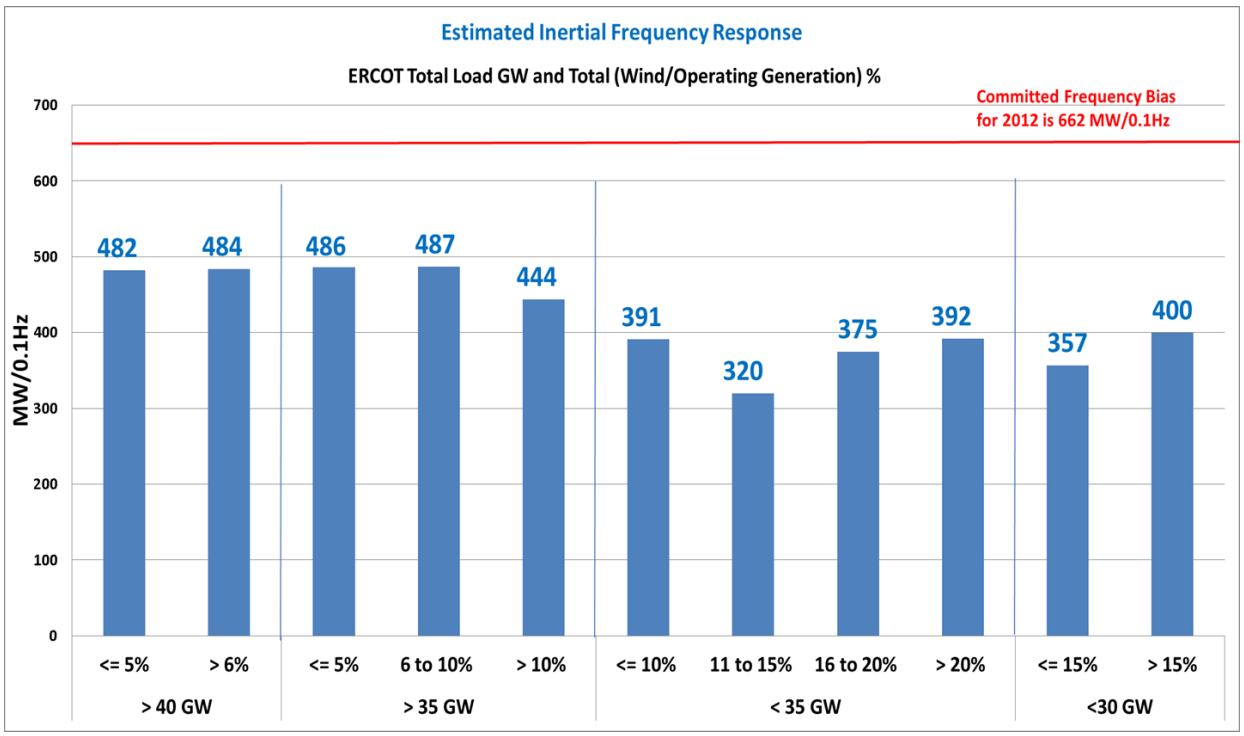


Figure A-17. Estimation of Inertial Frequency Response (Different Wind Levels & Load Levels) – 2013

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

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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 online 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. 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 online 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 PMU locations measuring grid metric samples at 30 frames per second.

Hence, this study was proposed to investigate:

1. Other unknown oscillations from wind generators.
2. 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, spanning three years, was done using EPG's Phasor Data Mining Tool. The tool enabled automatic scanning of the data in periodic intervals, and it 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 near 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 0.1 Hz to 15 Hz. 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 set 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 and 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 changes 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 – 0.9 Hz (West 6) & 2.7 Hz (FarWest 4).
3. The occurrence of 4 modes appear to be related to control system settings changes – 1.5 Hz (Coast 3), 1.7 Hz (FarWest 7), 2 Hz (Coast 3), and 3.2 Hz (West 10).
4. The occurrence of 3 modes appear to be related to the presence of wind generation and control systems - 5.0 Hz (Coast 3),5.4 Hz (West 10 & FarWest 4), and 6.0 Hz (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 – 0.6 Hz (West 10).

This study concludes that four modes appeared consistently for three years, and are still present. There are four other modes that appeared intermittently with high energy. There are another 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 System[1] (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 near 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 and energy values.
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 the 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.

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 Set up 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 Parse the CSV file containing results for all PMU measurements for post processing in MATLAB.
Step 5 Write MATLAB script 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.

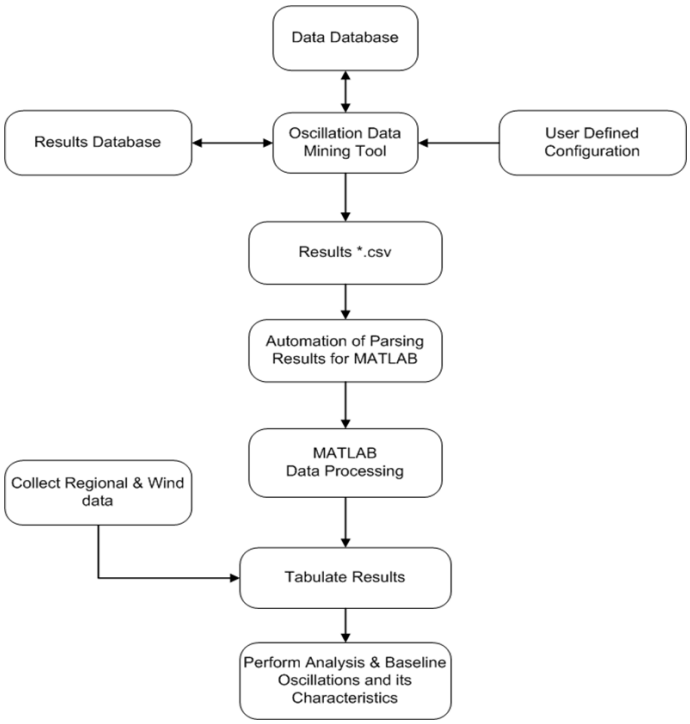


Figure 1. Analysis Workflow

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 were:

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 were:

1. Monthly mode occurrence (%) = (count of minutes having mode/total number of reported minutes) * 100 (e.g. 0.9 Hz appeared 42% of the time in April 2012)
2. Monthly highest energy = maximum energy of an oscillatory mode each month

Other information extracted along with monthly statistics was:

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 near wind generators, but do not directly monitor the output of individual wind farms. They 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 were as follows:

1. Frequency.
2. Voltage phasor (voltage magnitude and voltage angle).
3. Current magnitude.

The mining tool was configured to look for oscillatory modes within one frequency band, from 0.1 Hz to 15 Hz. Bad data in the phasor measurements were removed before scanning for oscillations using the flags set in the status signal embedded with PMU measurements in C37.118 format. The algorithm settings to scan for oscillations were set in such a way that the output results were 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 – 0.1 Hz.
5. Maximum frequency – 15 Hz.

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 processing 1 hour, 1 day, and 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

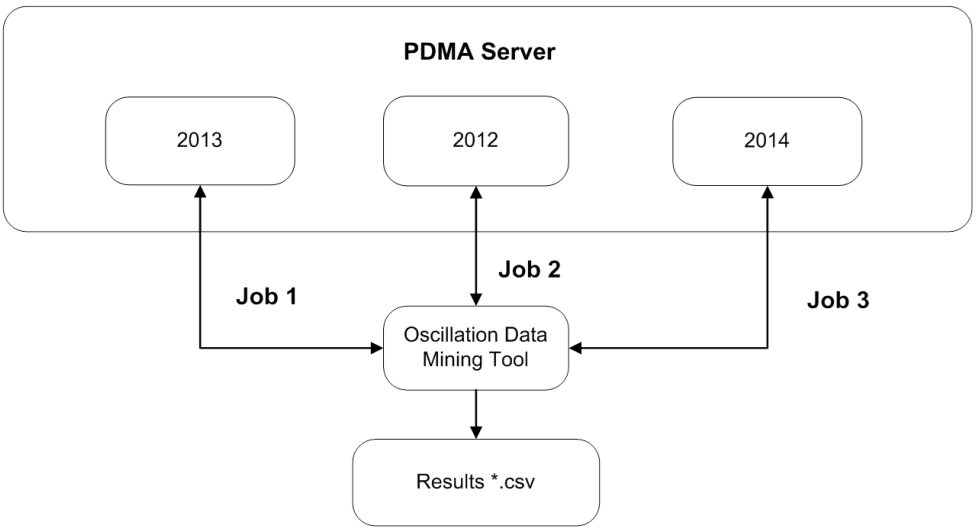


Figure 3. Analysis Work flow

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. This reduced the overall processing time to that of one year instead of three years. 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 in order 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 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 and timestamp fields are associated with each other.

8. Summary of Identified ERCOT Oscillatory Modes

Figure 4 shows a quick summary of the 10 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 (0.9 Hz, 5.0 Hz, 5.4 Hz, and 6.0 Hz) that are consistent in occurrence during the three years, and continue to be present. The rest of the modes appear to fall into two categories of intermittency. The 0.6 Hz and 2.7 Hz 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 intermittent oscillations showed high energy when they occurred. These modes need additional monitoring to identify their nature and initiating factors. The 1.7 Hz, 1.5 Hz, 3.2 Hz, and 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 10 oscillatory modes with the nearby location of wind generators that saw the highest occurrence of each mode. The 0.9 Hz and 2.7 Hz 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 5.0 Hz, 5.4 Hz and 6.0 Hz modes remained flat, and didn't appear to vary in relationship with changing levels of regional wind production, except for the 6.0 Hz 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 changes in control systems, 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 another 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 – 0.9 Hz (West 6) and 2.7 Hz (FarWest 4).
2. The occurrence of 4 modes appears to be related to control system settings changes – 1.5 Hz (Coast 3), 1.7 Hz (FarWest 7), 2 Hz (Coast 3), and 3.2 Hz (West 10).
3. The occurrence of 3 modes appears to be related to the presence of wind generation and related to wind generation control systems - 5.0 Hz (Coast 3), 5.4 Hz (West 10 & FarWest 4), and 6.0 Hz (West 10).
4. The occurrence of 1 mode appears to be a local oscillation due to a topology change or tuning of wind generators – 0.6 Hz (West 10).

Mode 2: 0.9 Hz

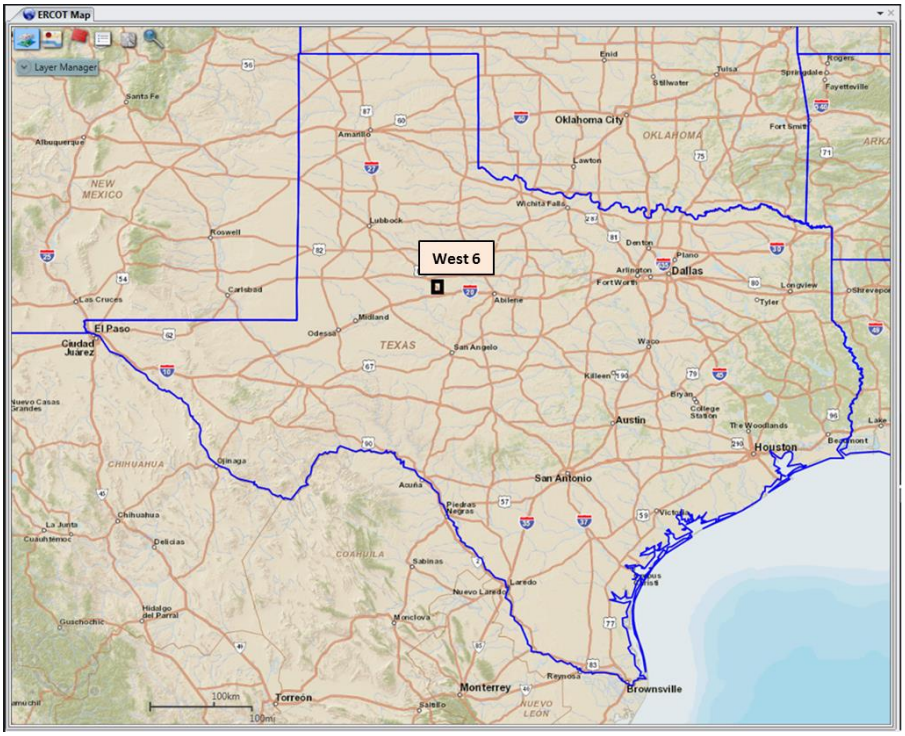


Figure 6. Mode 2 – PMU Location

Figure 6 shows the PMU location in ERCOT that had consistent occurrence of the 0.9 Hz mode spanning 3-years, and which continues to be present. The mode showed up in the current magnitude signal measurement for the West 6 substation which is located near wind generators

including WestGen1, WestGen2, WestGen3, and WestGen4. Figure 8 shows the trend of the 0.9 Hz mode occurrence in the West 6 current magnitude signal over the 3 years. The maximum occurrence of the 0.9 Hz mode appeared 53% of the time in June 2014, and the minimum occurrence of the same mode appeared 22% of the time in December 2013. The average occurrence over all 3 years is about 42% of the time each month. Figure 7 shows the comparison between the mode occurrence of 0.9 Hz and the monthly average west wind production in MW from January 2012 to April 2013. The trend of mode occurrence and average west wind has similar patterns and provides a first indication that 0.9 Hz is likely related to wind production. The mode occurrence reduced from 40% to 30% when the average wind production showed reduction from 3,000 MW to 1,600 MW in August 2012, suggesting that mode 0.9 Hz is related to wind production. This relationship is based on west wind generation (an aggregation of wind production), since 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 3,500 MW in the same month.

This mode appears to be related to wind production, 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). Figure 8 shows the comparison of the mode occurrence to the highest energy of the mode during each month spanning the three 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 = 0.85 Hz.
- Maximum frequency = 1.2 Hz.
- Minimum energy = 2.
- Damping = 8%.

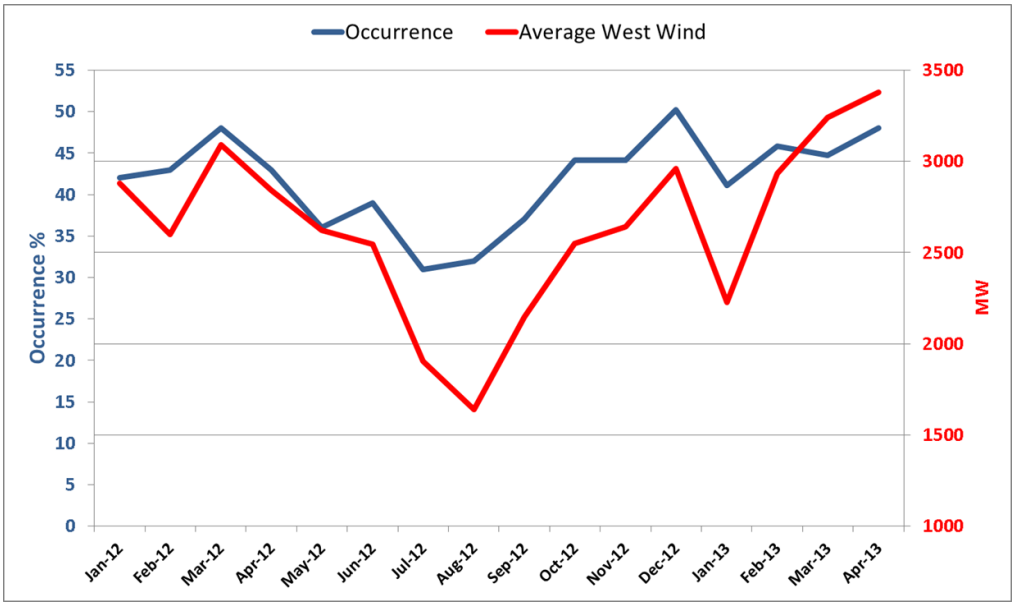


Figure 7. Mode 2 – Mode Occurrence vs. Regional West Wind

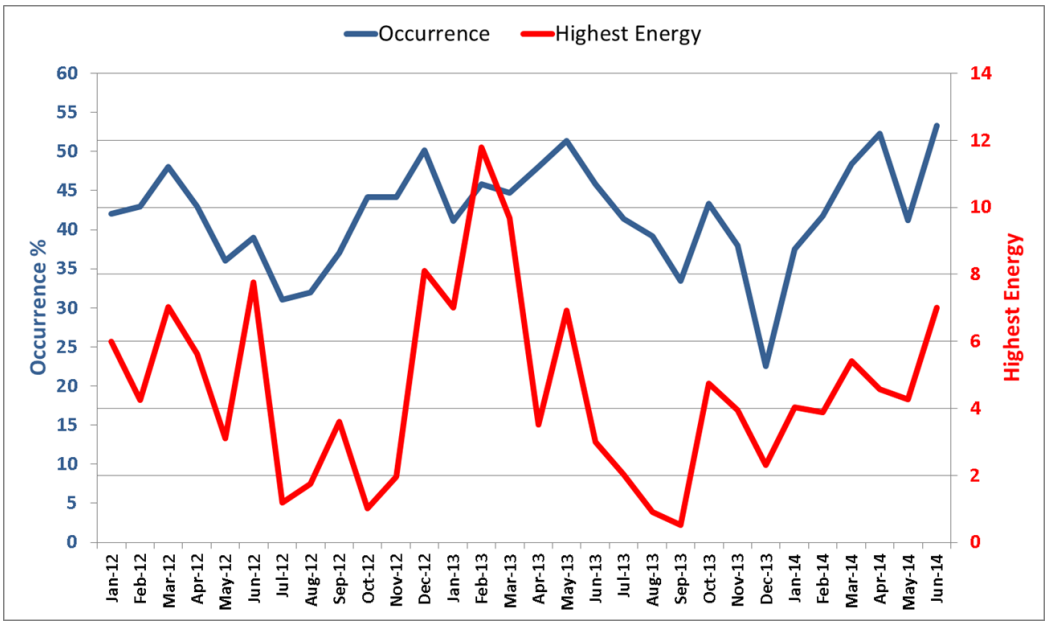


Figure 8. Mode 2 – Mode Occurrence vs. Highest Energy

Mode 6: 2.7Hz

Similar to 0.9 Hz, the study discovered another mode at 2.7 Hz related to wind production. Figure 9 shows the PMU location in the ERCOT Interconnection that had the most consistent occurrence of the 2.7 Hz mode. The mode showed up in the current magnitude signal measurement in the FarWest 4 substation, located near generators, including FarWestGen4.

Figure 11 shows the trend of this 2.7 Hz mode occurrence in the FarWest 4 current magnitude signal over 2 years, and then suddenly disappearing starting January of 2014. The maximum occurrence of the 2.7 Hz mode appeared for 34% of the time in May 2013, and the minimum occurrence of the same mode appeared 9% of the time in July 2013. The average occurrence in the first 2 years is approximately 20% of the time each month. Figure 10 shows the comparison between mode occurrence of 2.7 Hz and the monthly average west wind production in MW from January 2012 to April 2013. The trends of mode occurrence and average west wind have similar patterns, and provide a first indication that the 2.7 Hz 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 0.9 Hz. 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.

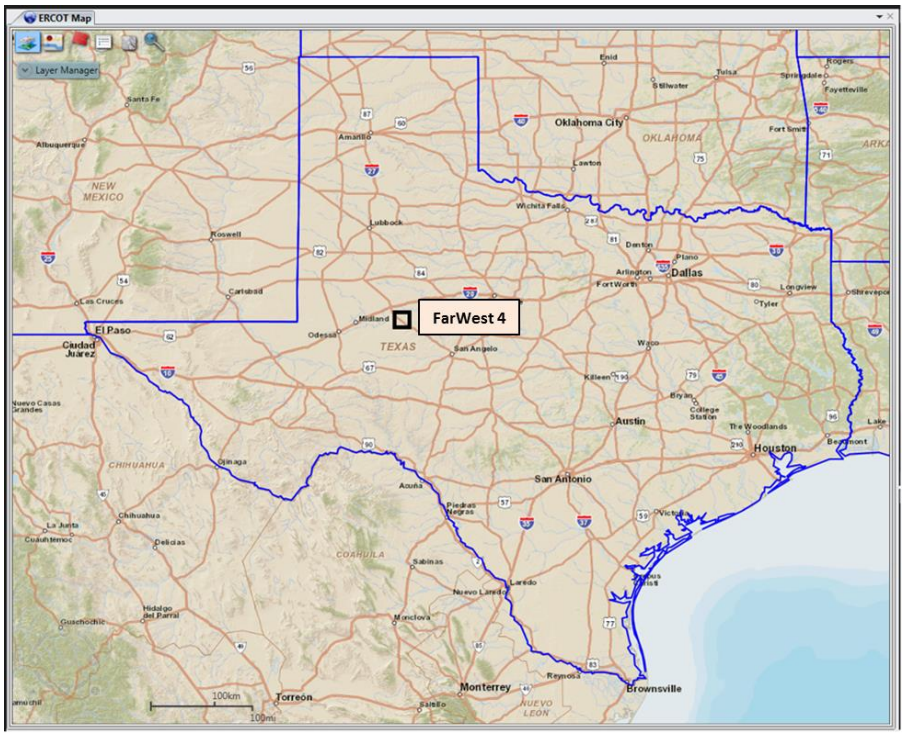


Figure 9. Mode 6 – PMU Location

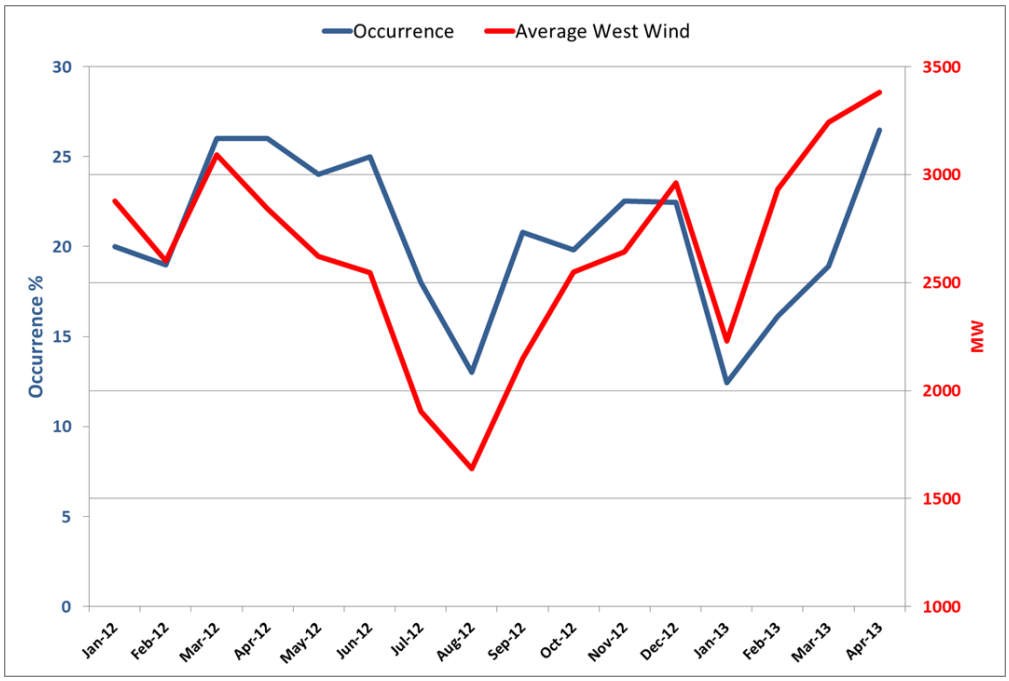


Figure 10. Mode 6 – Mode Occurrence vs. Regional West Wind

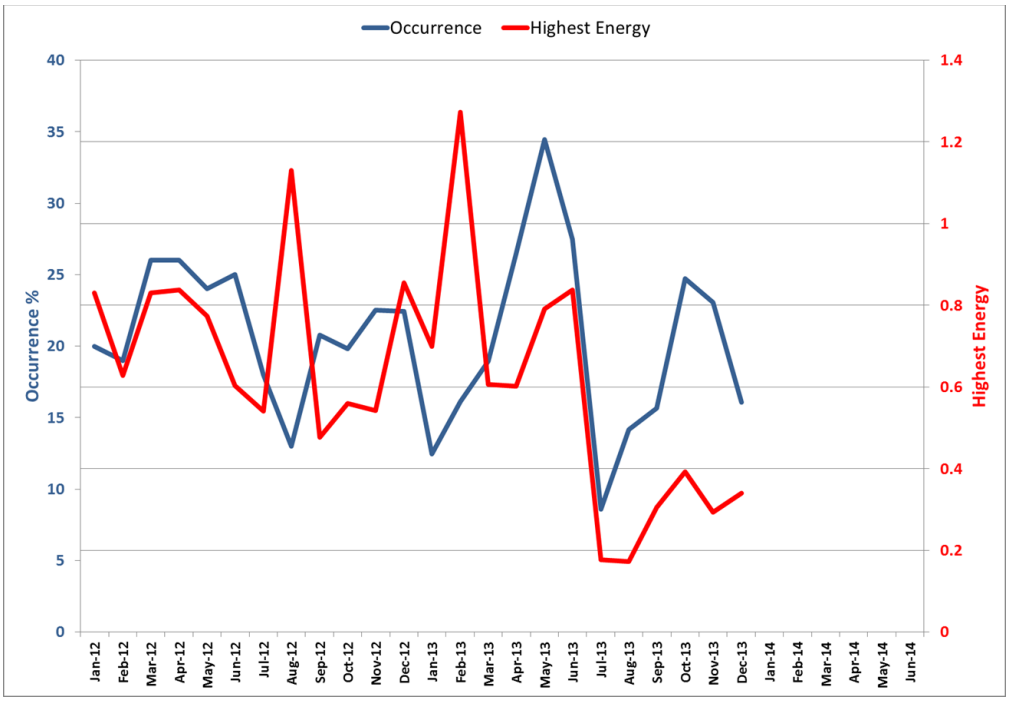


Figure 11. Mode 6 – Mode Occurrence vs. Highest Energy

Mode 8: 5.0 Hz

Figure 12 shows the six different PMU locations in ERCOT that showed the occurrence of the 5.0 Hz mode. Of these six locations, Coast 3 and 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 and frequency signal measurements in the Coast 3 and Coast 4 substations, both of which are located near wind generators. Figure 14 shows the trend of the 5.0 Hz mode occurrence in the Coast 3 voltage magnitude signal over 3 years. The mode appeared every month in all three years, except the first three months of 2012 and the month of March 2013. The maximum occurrence of the 5.0 Hz 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 5.0 Hz 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 patterns 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 5.0 Hz 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 online) 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 its minimum highest monthly energy, in December 2012, was approximately 0.00015.
It is recommended that ERCOT review this 5.0 Hz oscillation with wind owners to determine the root cause, and to evaluate the need for additional monitoring and possible mitigation.

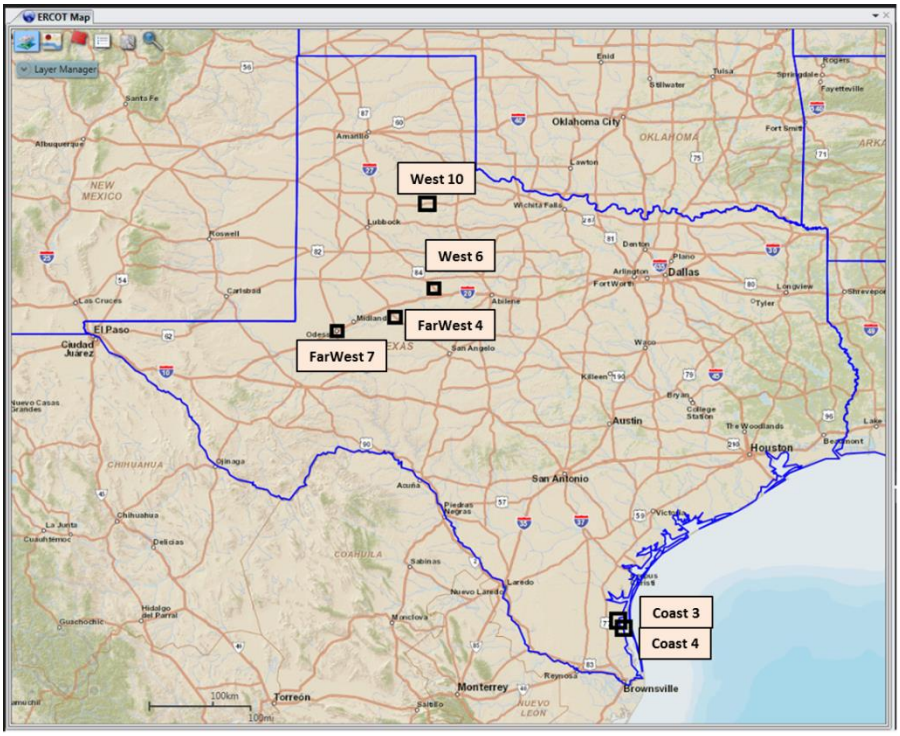


Figure 12. Mode 8 – PMU locations

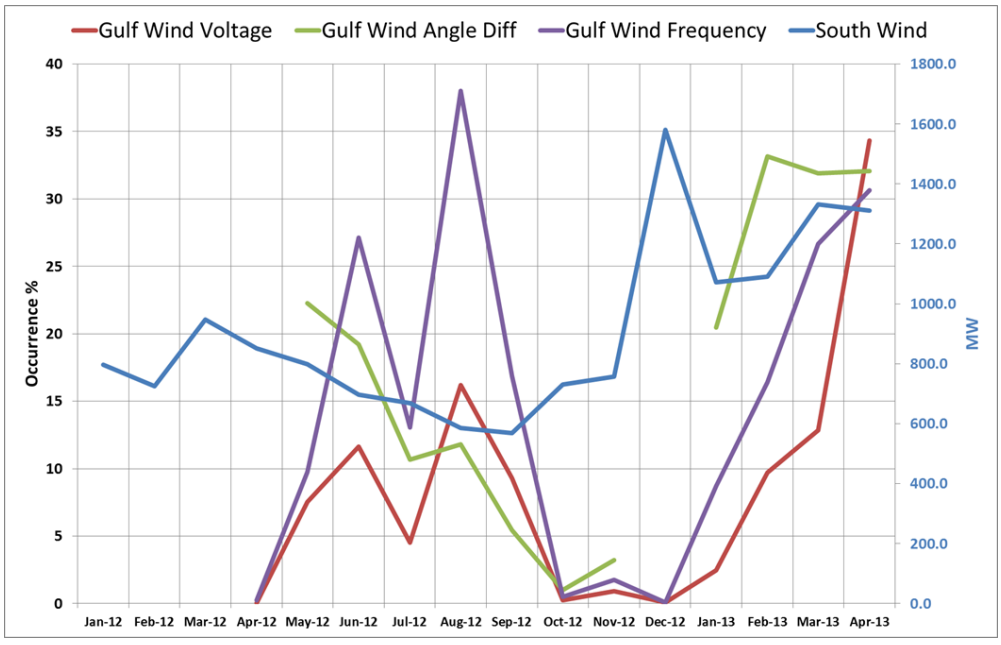


Figure 13. Mode 8 – Mode Occurrence vs. Regional South Wind

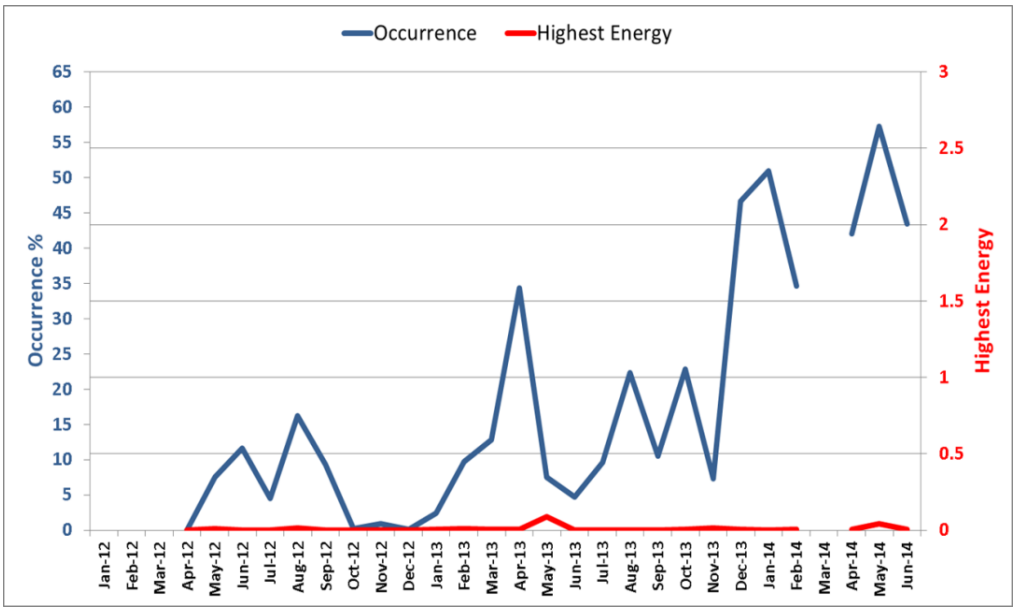


Figure 14. Mode 8 – Mode Occurrence vs. Highest Energy

Mode 9: 5.4 Hz

Similar to the 5.0 Hz mode, the study discovered another mode at 5.4 Hz, 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 5.4 Hz mode occurrence. The voltage magnitude signal measurement at FarWest 4 substation 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 5.4 Hz at West 10 and FarWest 4, indicating that the 5.4 Hz mode has different drivers in the two regions. Hence, FarWest 4 in west Texas and West 10 in the Panhandle were identified as critical locations to monitor the 5.4 Hz mode.

Similar to the 5.0 Hz mode at Coast 3 and Coast 4, the 5.4 Hz 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 5.0 Hz were obtained using figures 16 and 17. Figure 16 shows the comparison between the mode occurrence of 5.4 Hz 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 5.4 Hz mode. The same relationship appears to be true for this 5.4 Hz mode at FarWest 4, as shown in figures 18 and 19. The highest energy level trend of the 5.4 Hz 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 5.4 Hz

oscillation with wind owners to determine the root cause, and to evaluate the need for additional monitoring and possible mitigation.

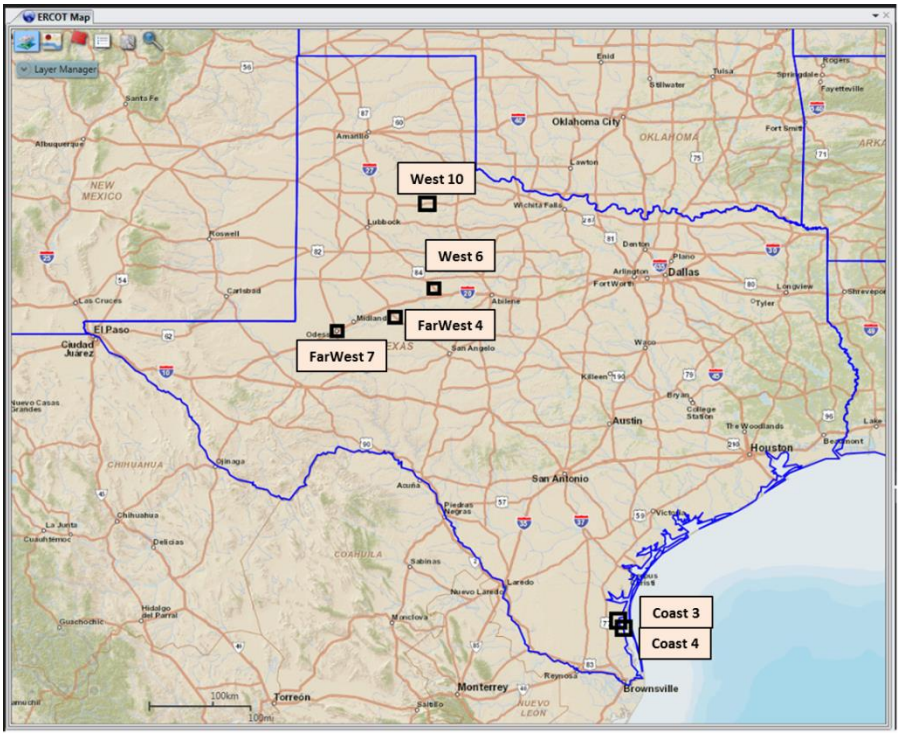


Figure 15. Mode 9 – PMU Locations

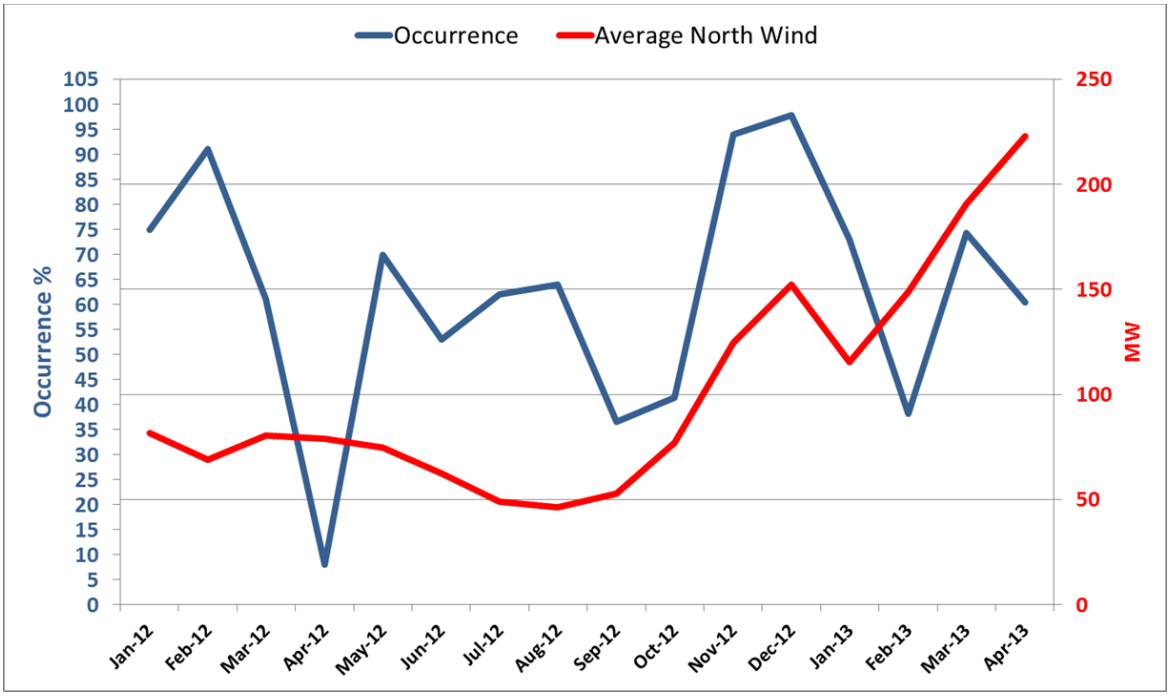


Figure 16. Mode 9 at West 10 – Mode Occurrence vs. Regional North Wind

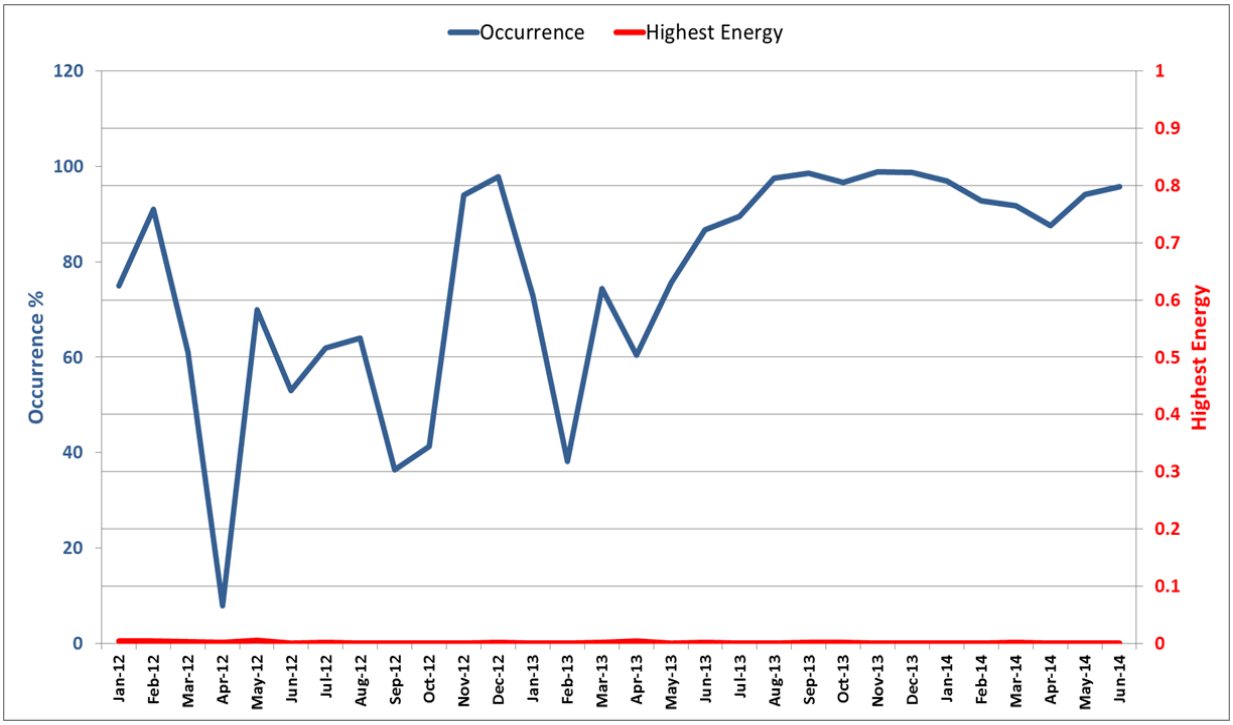


Figure 17. Mode 9 at West 10 – Mode Occurrence vs. Highest Energy

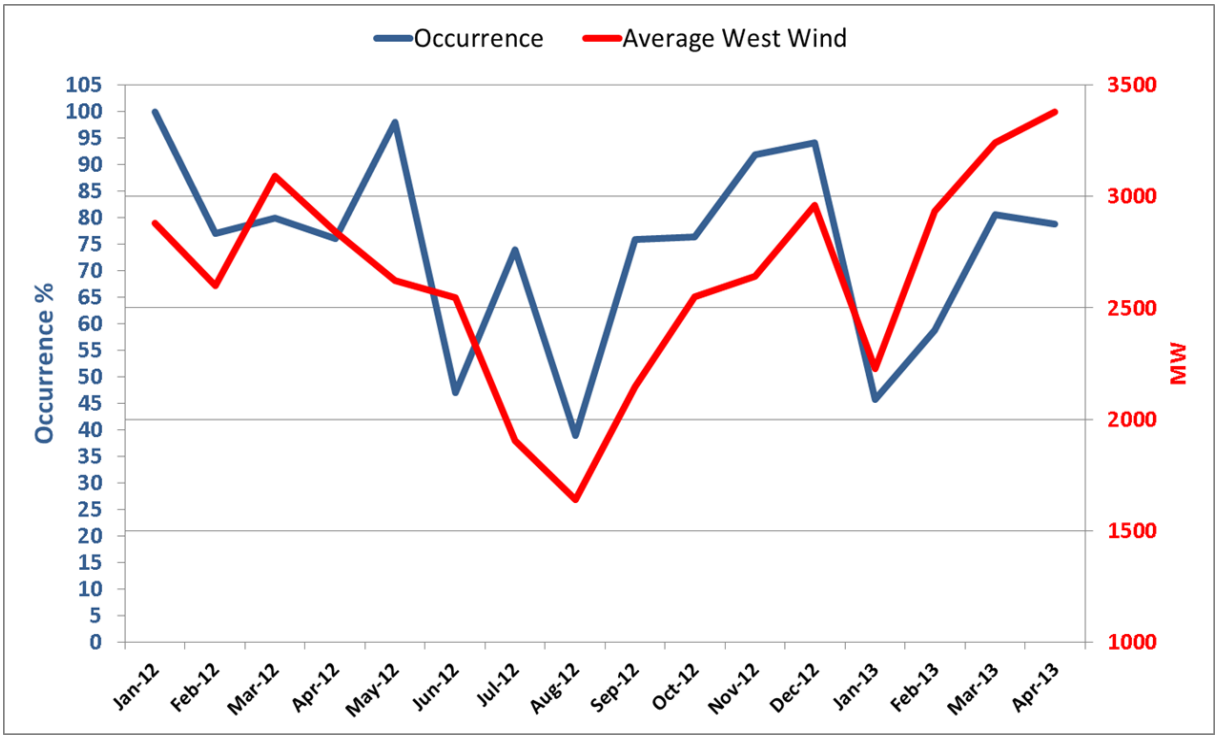


Figure 18. Mode 9 at FarWest 4 – Mode Occurrence vs. Regional West Wind

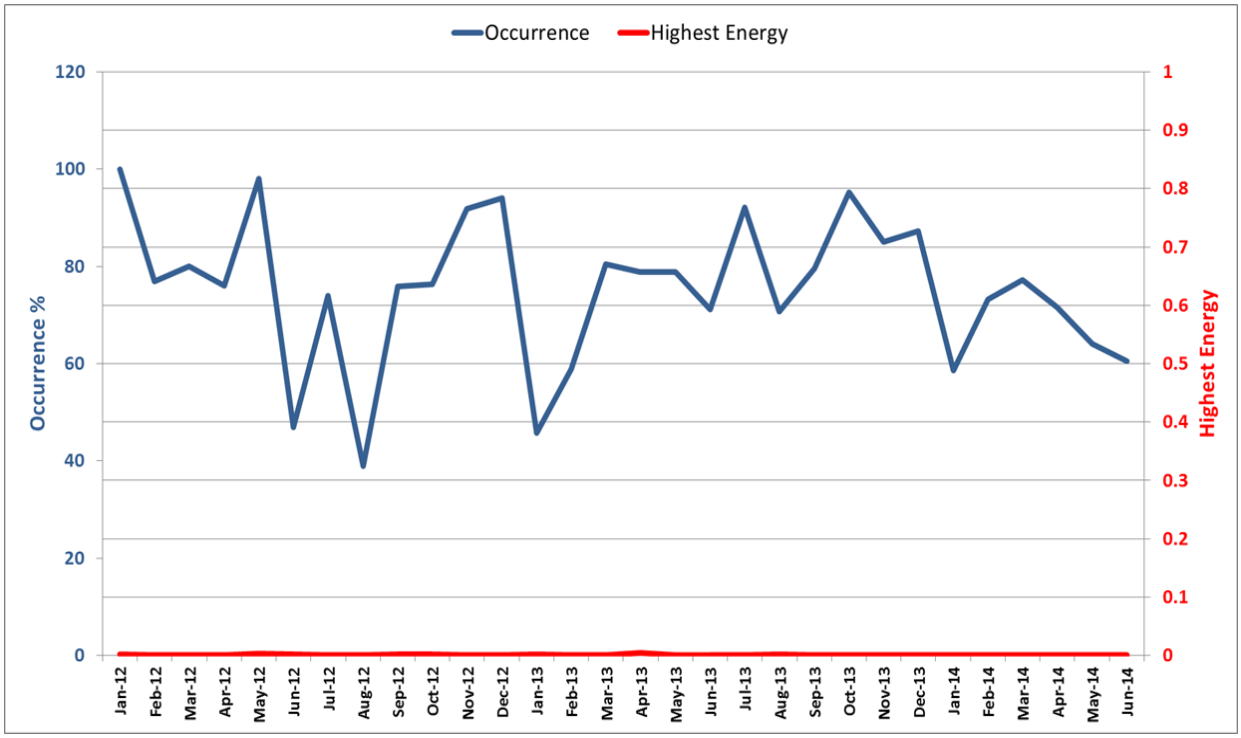


Figure 19. Mode 9 at FarWest 4 – Mode Occurrence vs. Highest Energy

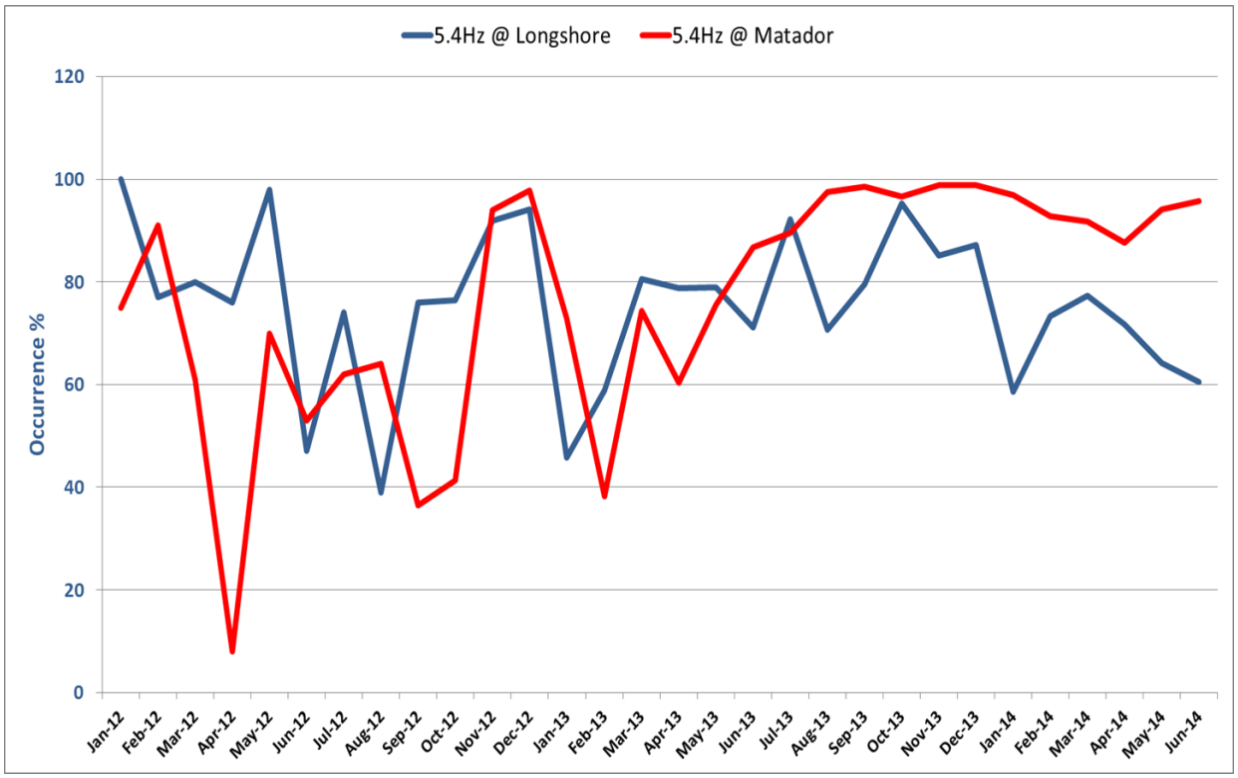


Figure 20. Mode 9 – West 10 vs. FarWest 4

Mode 10: 6.0 Hz

Similar to the 5.0 Hz and 5.4 Hz modes, the study discovered another mode at 6.0 Hz, 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 6.0 Hz 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 January to March and in 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 6.0 Hz 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 = 5.5 Hz.
- Maximum frequency = 6.5 Hz.
- Minimum energy = 5.
- Damping = 8%.

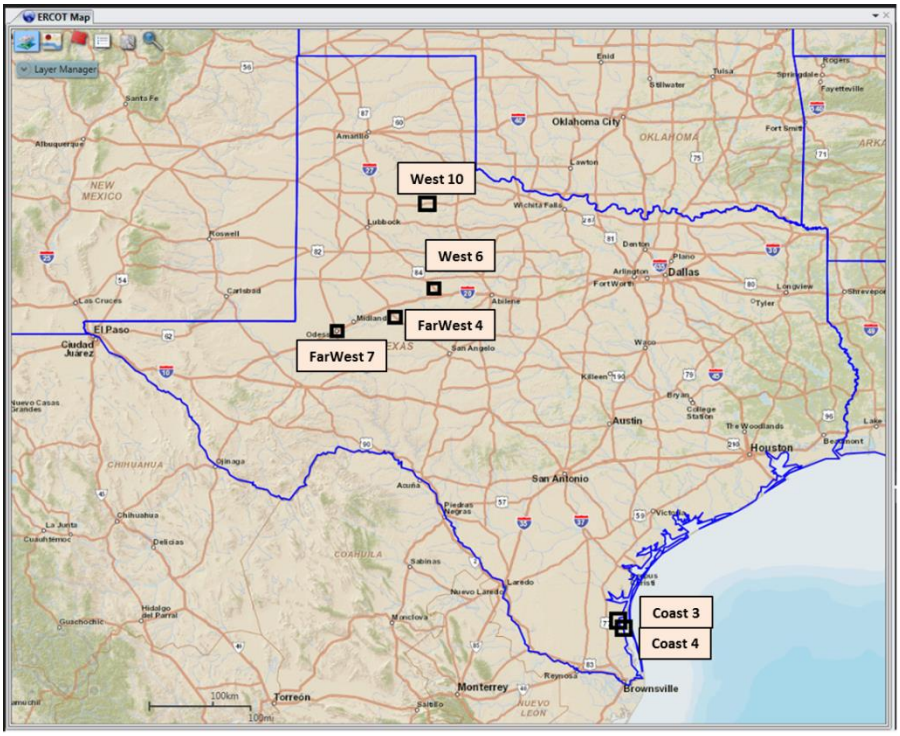


Figure 21. Mode 10 – PMU Location

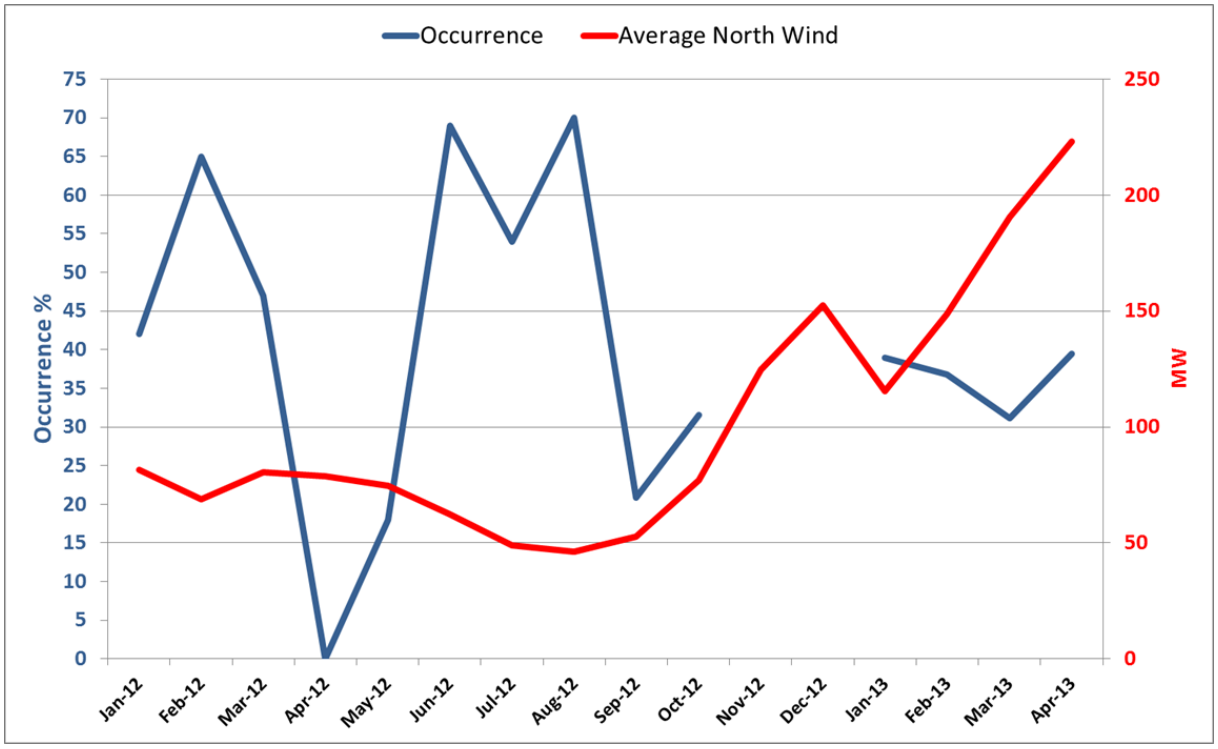


Figure 22. Mode 10 – Mode Occurrence vs. Regional North Wind

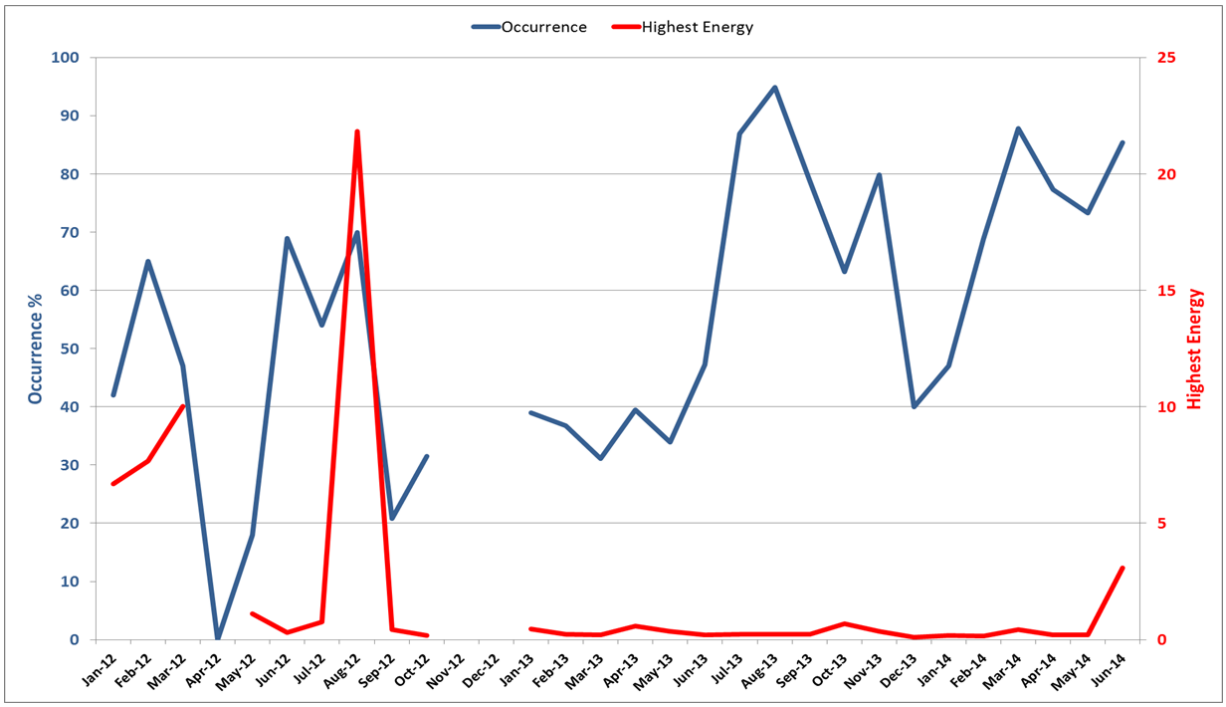


Figure 23. Mode 10 – Mode Occurrence vs. Highest Energy

West 10 appears to have two strong modes at 6.0 Hz and 5.4 Hz, both driven by the control systems of the nearby wind generators. Figure 24 shows the mode occurrence of 5.4 Hz at West 10 measured from current magnitude signal spanning 3 years. The mode occurrence at 5.4 Hz shows consistently higher persistence than the 6.0 Hz trend, but never showed the high energy levels which were recorded for the 6.0 Hz mode.

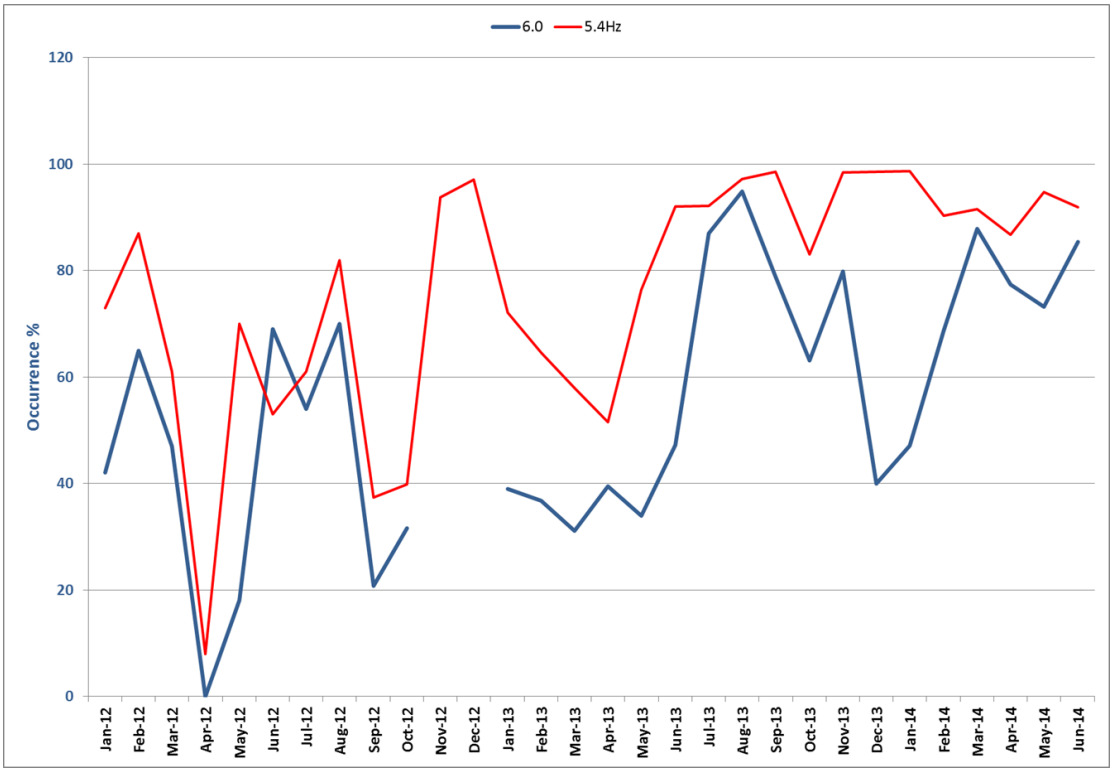


Figure 24. Mode 10 at West 10 – 5.4 Hz vs. 6.0 Hz

Mode 7: 3.2 Hz

Figure 25 shows the PMU location in the ERCOT Interconnection that had observed a 3.2 Hz mode. This mode showed up in the current magnitude signal measurement in the West 10 substation. Figure 27 shows the trend of the 3.2 Hz mode occurrence in the West 10 current magnitude signal over 3 years. The mode does not appear to be consistent ,such as 5.0 Hz, 5.4 Hz and 6.0 Hz, 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 the 3.2 Hz mode appeared for 20% of the time in January 2014, and the minimum occurrence of the same mode appeared 10% of the time in March 2013. Figure 26 shows the comparison between the mode occurrence of 3.2 Hz 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 by 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 = 2.6 Hz.
- Maximum frequency = 3.8 Hz.
- Minimum energy = 50.
- Damping = 8%.

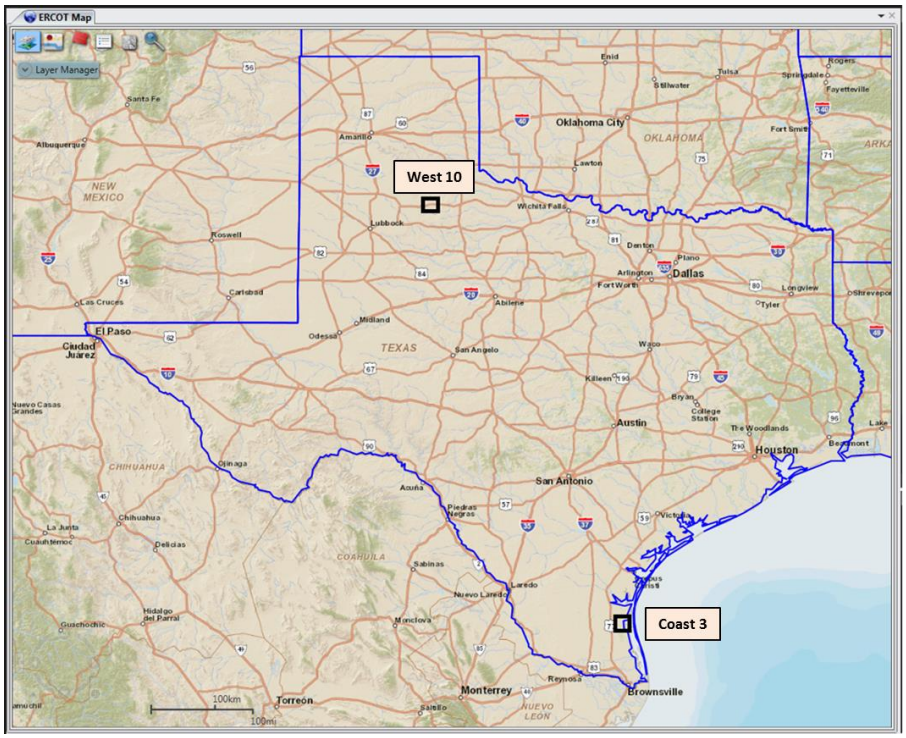


Figure 25. Mode 7 – PMU Locations

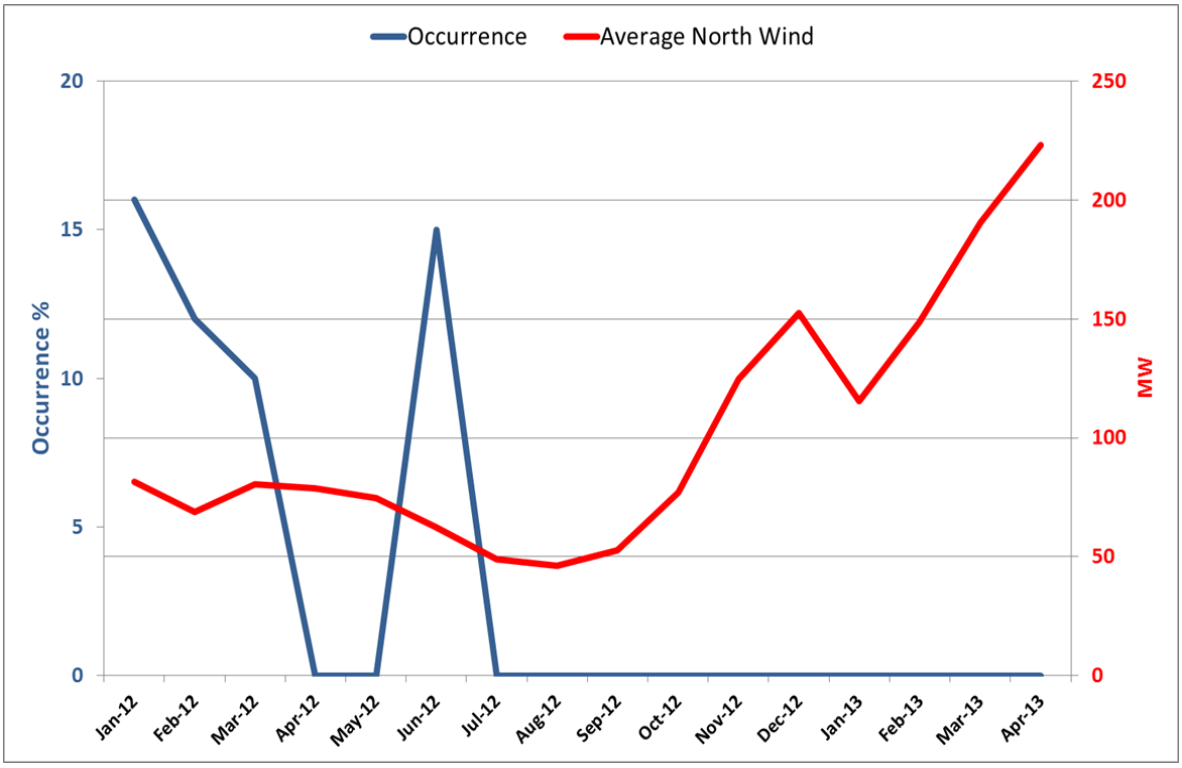


Figure 26. Mode 7 – Mode Occurrence vs. Regional North Wind

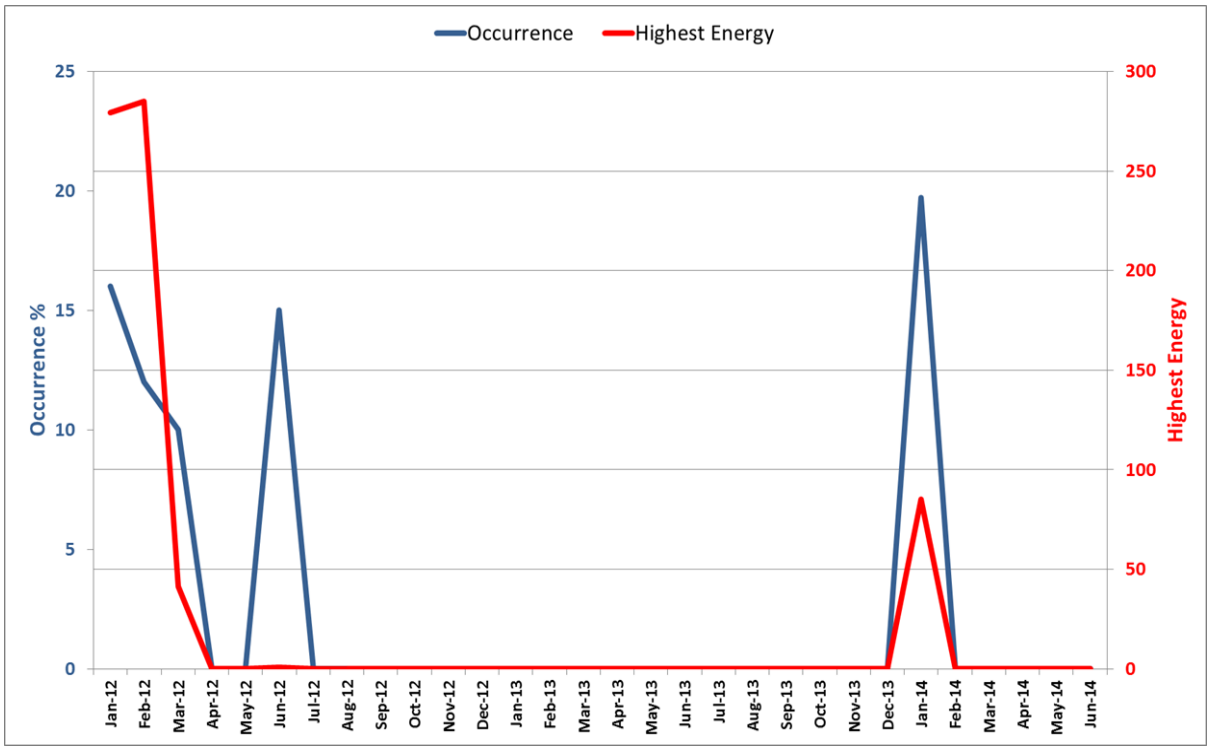


Figure 27. Mode 7 – Mode Occurrence vs. Highest Energy Level

The study also discovered other modes (1.5 Hz, 1.7 Hz, and 2 Hz) similar to 3.2 Hz 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: 1.5 Hz

The study discovered a mode at 1.5 Hz, at Coast 3 in the Valley region, as shown in Figure 28. This mode occurred only in April 2012, for 0.04% of the 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 = 1.0 Hz.
- Maximum frequency = 2.0 Hz.
- Minimum energy = 0.1.

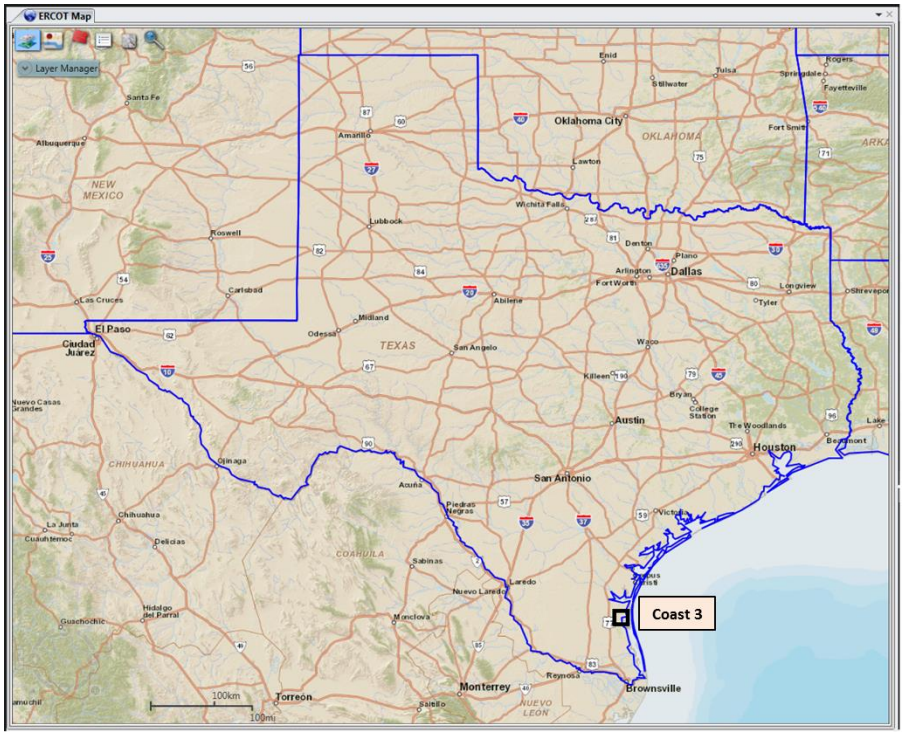


Figure 28. Mode 3 – PMU Location

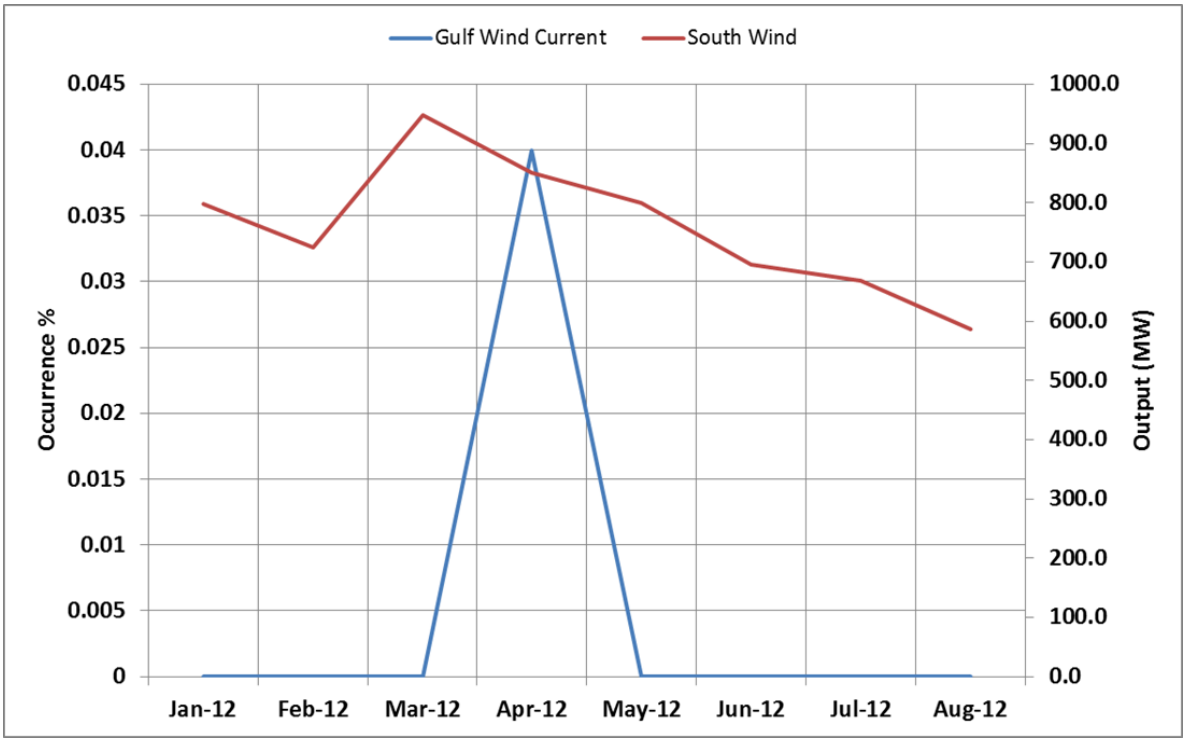


Figure 29. Mode 3 – Mode Occurrence vs. Regional South Wind

Mode 4: 1.7 Hz

The study also discovered a mode at 1.7 Hz, at FarWest 7 in the 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 and 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.

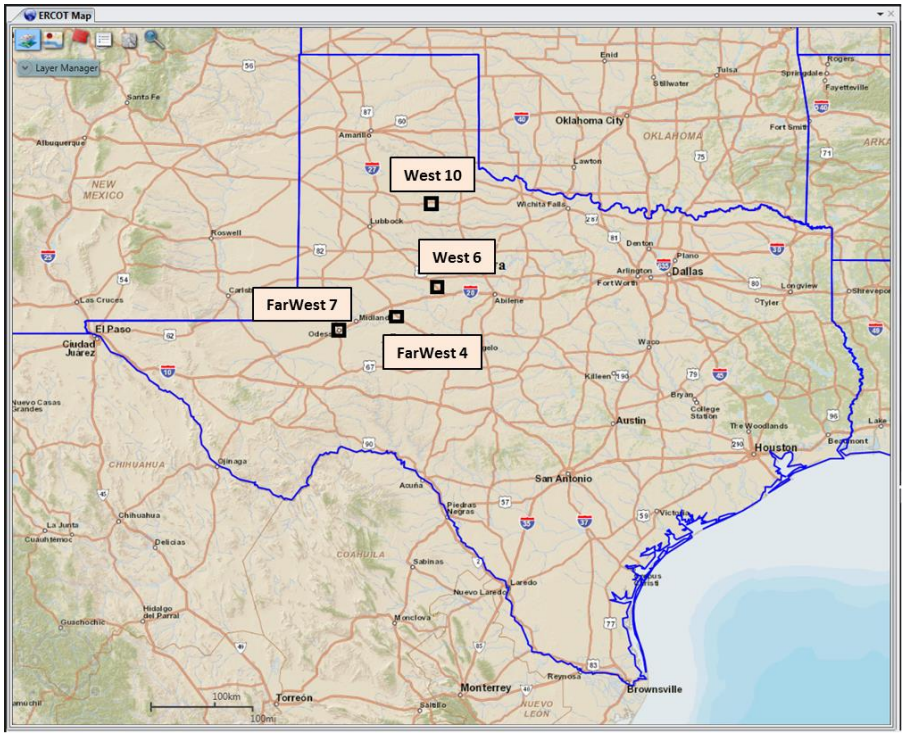


Figure 30. Mode 4 – PMU Location

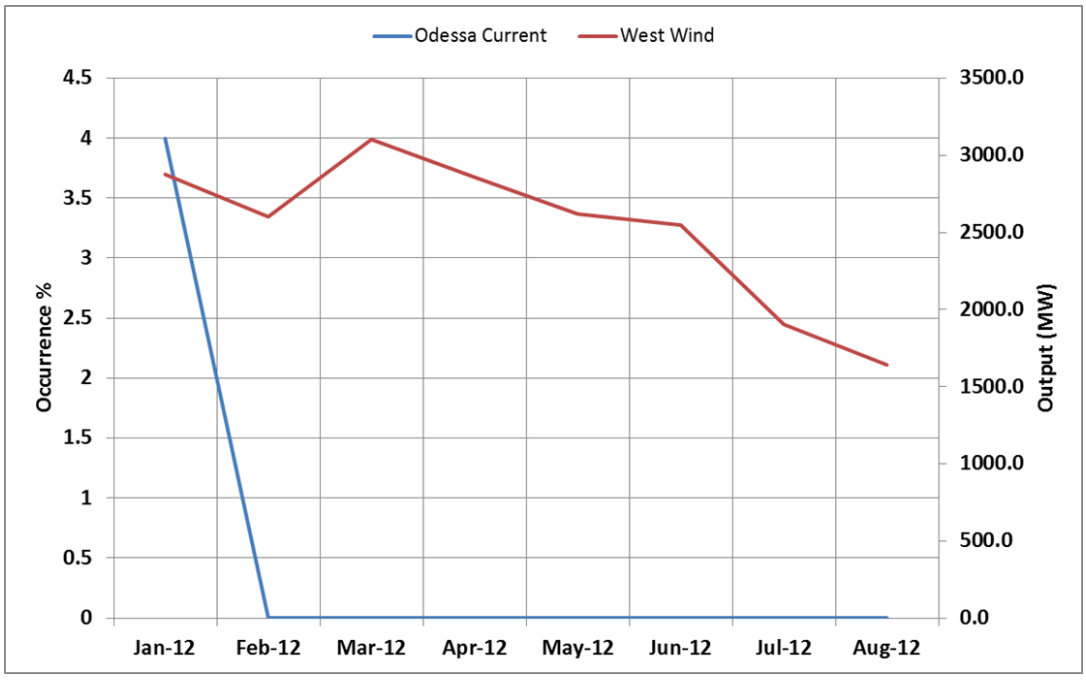


Figure 31. Mode 4 – Mode Occurrence vs. Regional West Wind

Mode 5: 2.0 Hz

The study also discovered another mode at 2.0 Hz at Coast 3 (voltage magnitude signal measurement) in the 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, which has nearby wind generators such as CoastGen3, CoastGen4, and CoastGen5. It is recommended that ERCOT do additional monitoring of the mode with the following configuration.

- Minimum frequency = 1.5 Hz.
- Maximum frequency = 2.5 Hz.
- Minimum energy = 0.1.

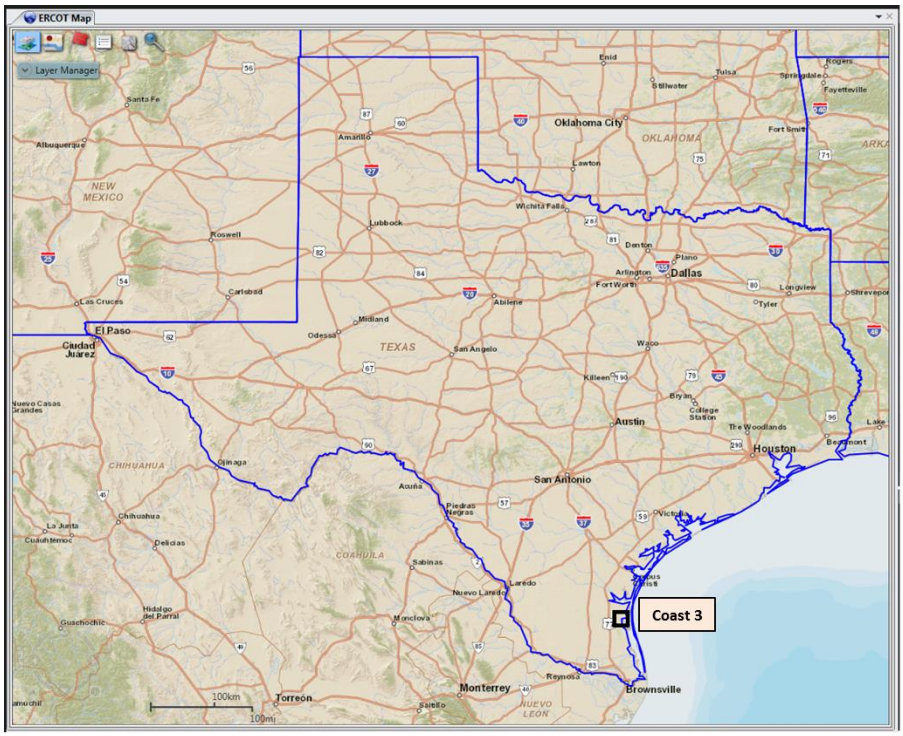


Figure 32. Mode 5 – PMU Location

Mode 1: 0.6 Hz

The study uncovered a mode at 0.6 Hz, 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 the 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 0.6 Hz 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.

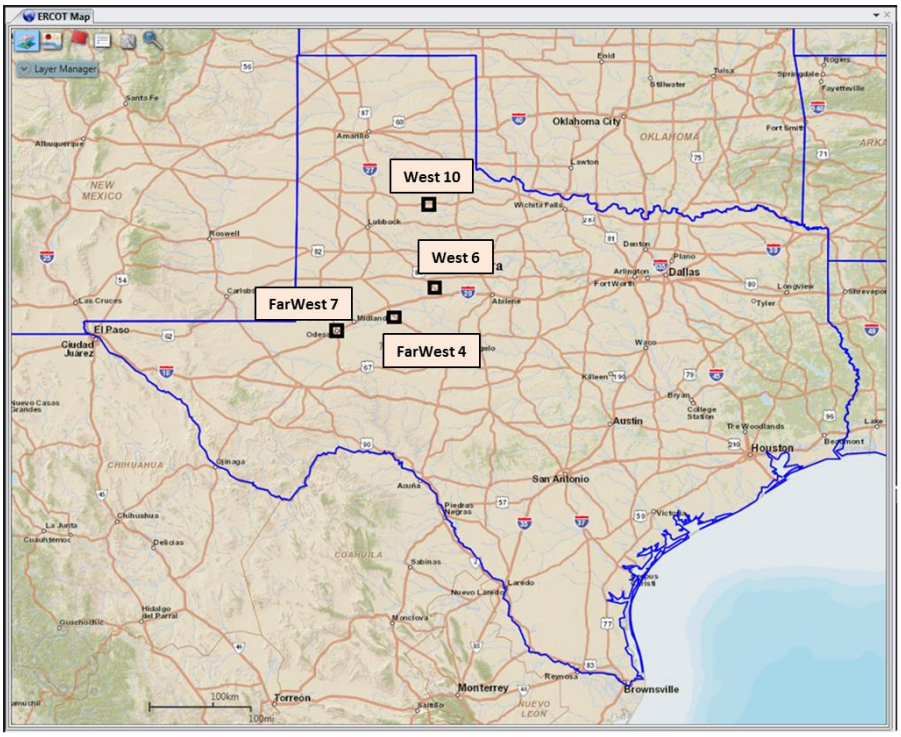


Figure 33. Mode 1 – PMU Location

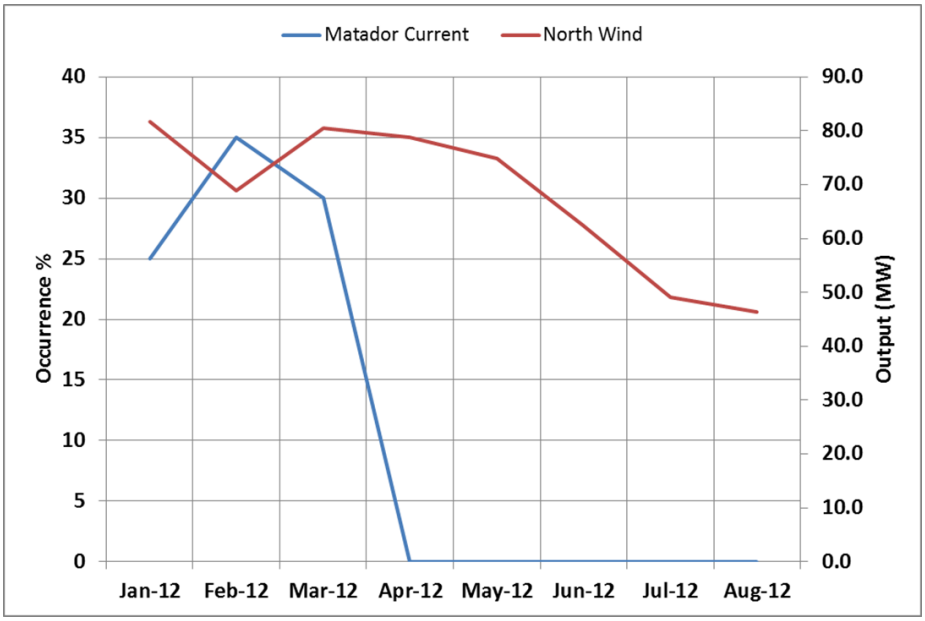


Figure 34. Mode 1 – Mode Occurrence vs. Regional North Wind

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 near 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 0.1 Hz to 15 Hz. 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 used 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 changes 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 – 0.9 Hz (West 6) and 2.7 Hz (FarWest 4).
3. The occurrence of 4 modes appear to be related to control system settings changes – 1.5 Hz (Coast 3), 1.7 Hz (FarWest 7), 2 Hz (Coast 3), and 3.2 Hz (West 10).
4. Three modes appear to be related to the presence of wind generation and control systems - 5.0 Hz (Coast 3), 5.4 Hz (West 10 & FarWest 4), and 6.0 Hz (West 10).
5. The occurrence of 1 mode appears to be a local oscillation due to a topology change or tuning of wind generators – 0.6 Hz (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 Power Group

PUBLIC VERSION

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

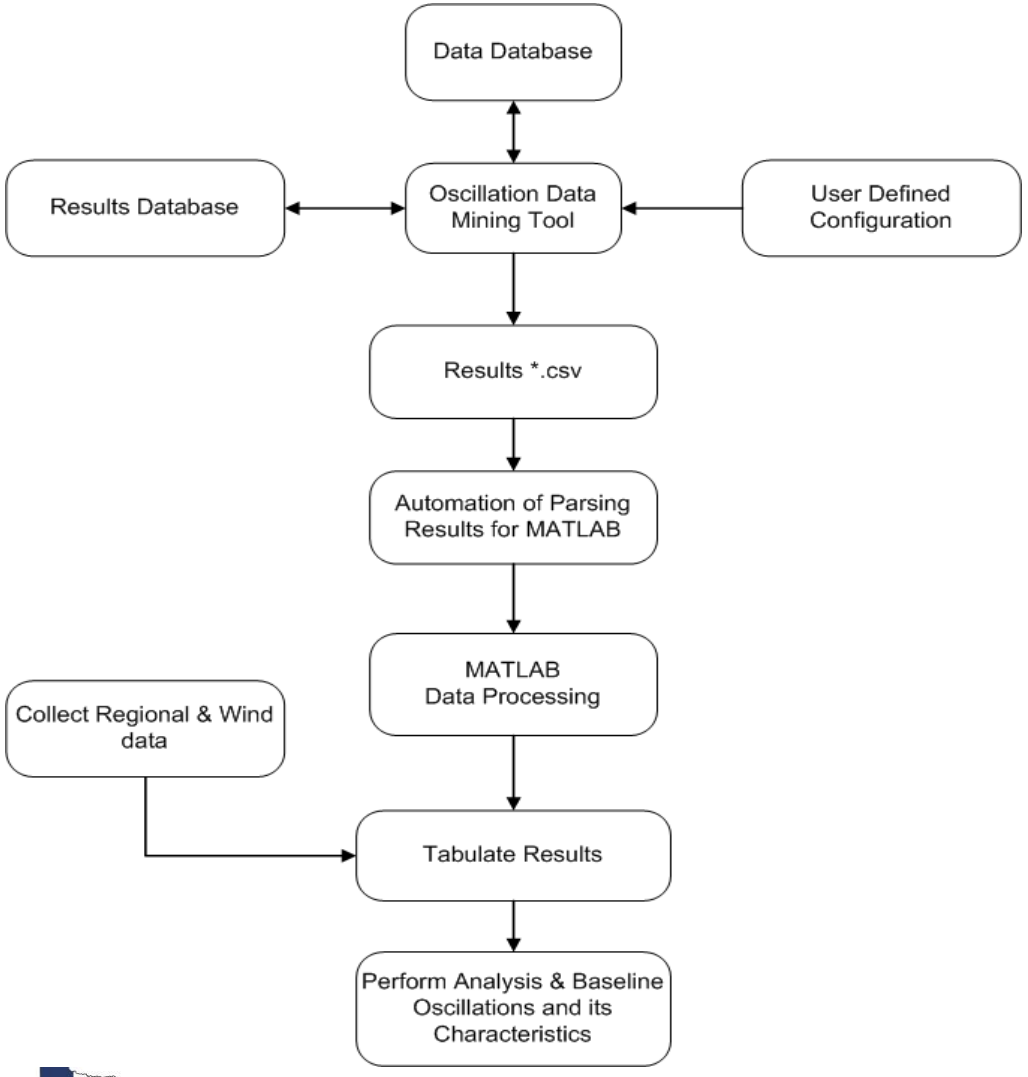
- Texas has the greatest amount of wind generation online in the nation, and set a new wind production record each year
- Early detection and mitigation of oscillations prevents system vulnerability and customer complaints
- These oscillations can possibly grow at high energy with increasing levels of 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 the 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 and 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, and 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

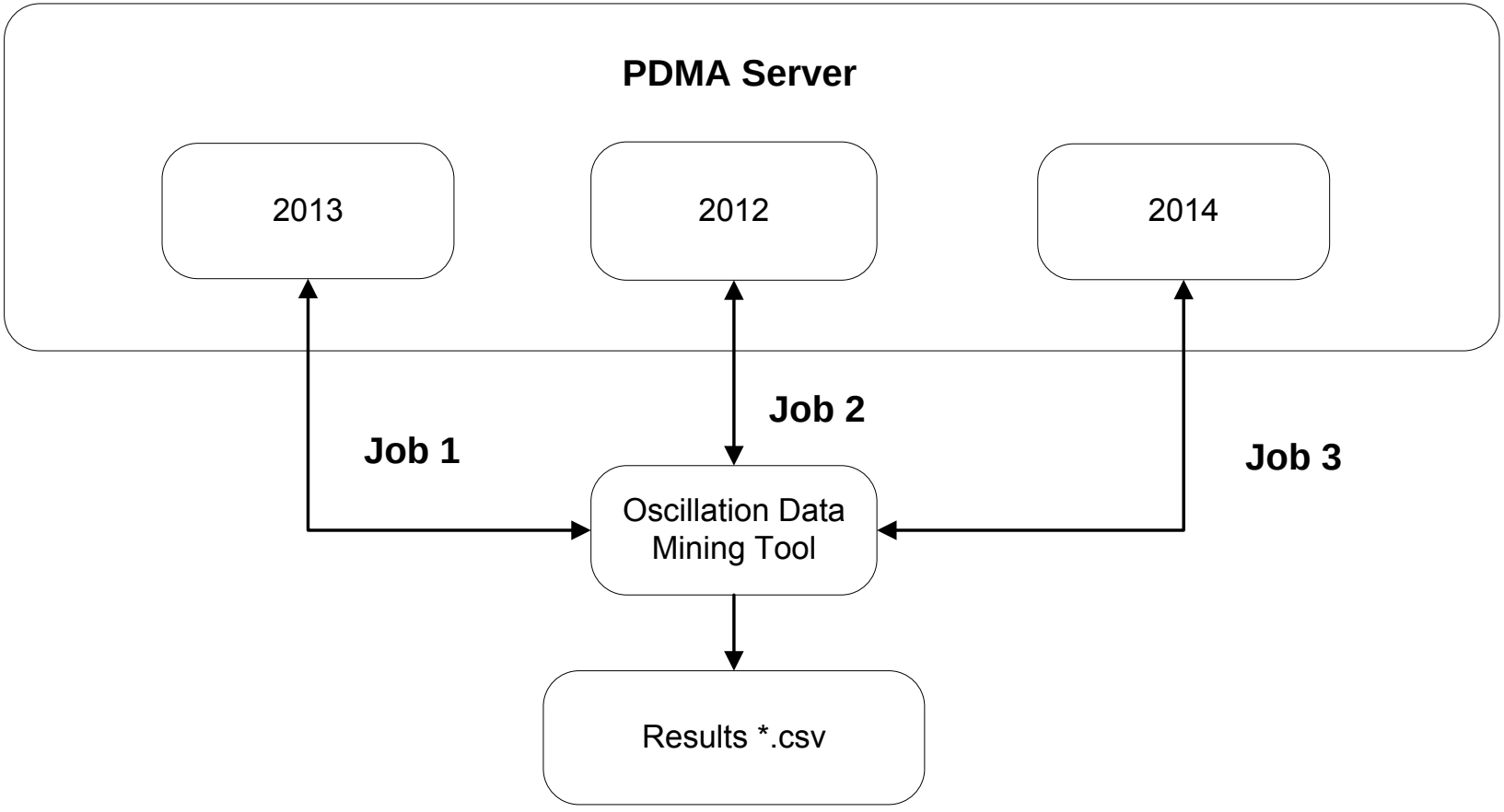
Identification of Significant Oscillations – MATLAB Post Processing

- Oscillation Data Mining Tool outputs **all calculated modes** every minute for all configured signals
- Planners and Operators need to focus on “modes” that:
  - Occur most of the time (high occurrence)
  - Occur with high energy (high magnitude)
- MATLAB code was written to identify such critical “modes” whose:
  - Existence is “>=“ 20% of highest occurrence
  - Magnitude is “>=“ 20% of highest energy
- Intelligence is included in code to count only distinct modes

Oscillations Data Mining Performance

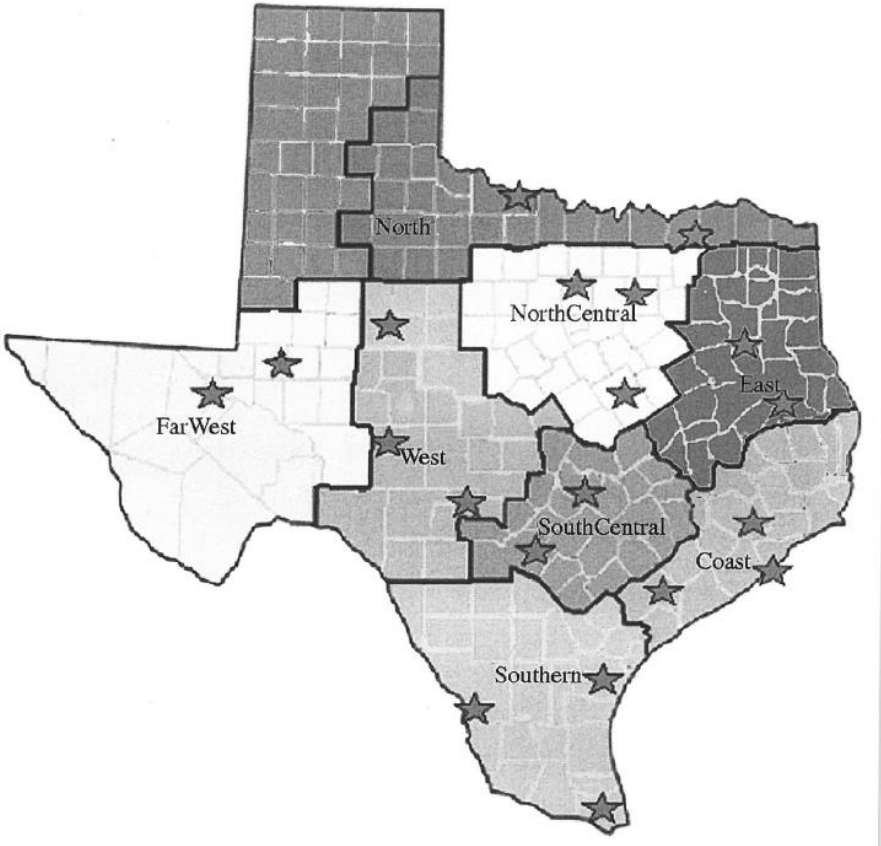
Task	Time
Data Loading (1 minute of data, All PMU signals)	3 sec
Data Filtering Mode Solving Result Exporting	1 sec
Total **(All Frequency Bands)**	**4 sec**
Ideal Example	
1 Hour	4 Min
1 Day	1.6 Hours
1 Week	11.2 Hours
1 Month (31 days)	**2.06 Days**

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

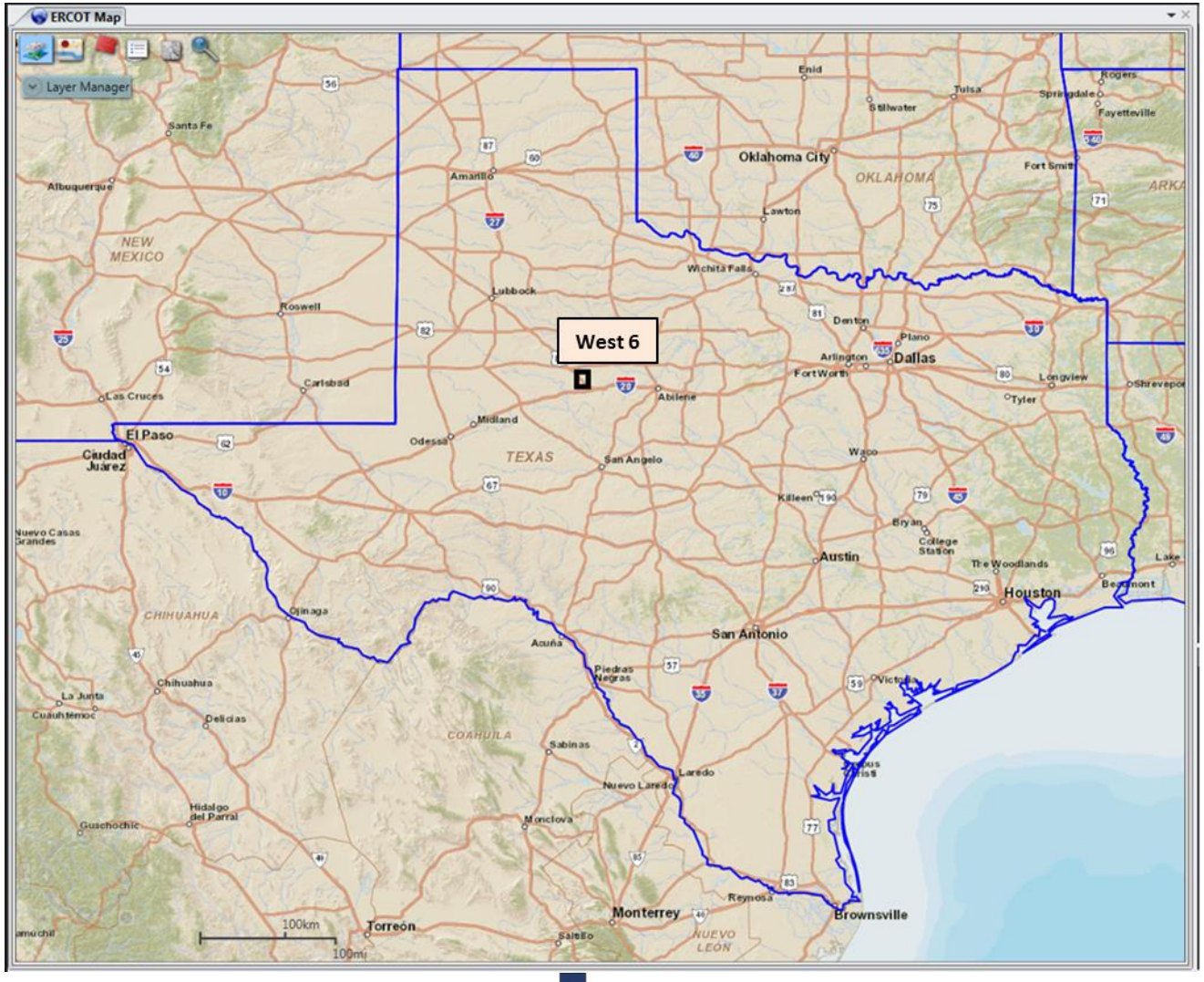
Identified 10 ERCOT Oscillatory Modes

#	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

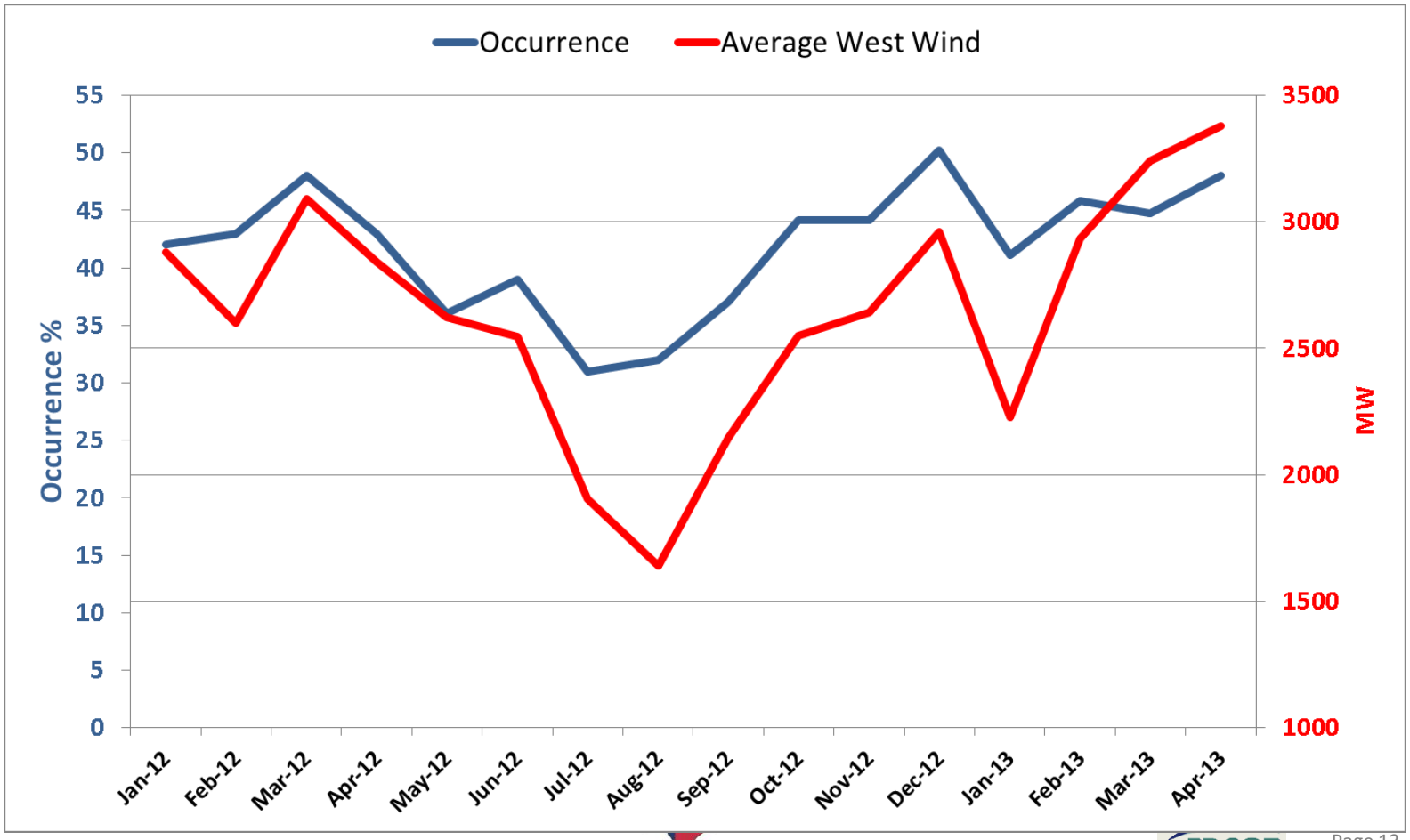
#	Mode (Hz)	Nearest PMU	Related to Wind Production	Highest Energy Level
1	**0.6**	West 10	No	Low Energy & Flat
2	**0.9**	West 6	Yes	High Energy & Tracking Occurrence
3	**1.5**	Coast 3	No	Low Energy
4	**1.7**	FarWest 7	No	High Energy
5	**2.0**	Coast 3	No	Low Energy
6	**2.7**	FarWest 4	Yes	High Energy & 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



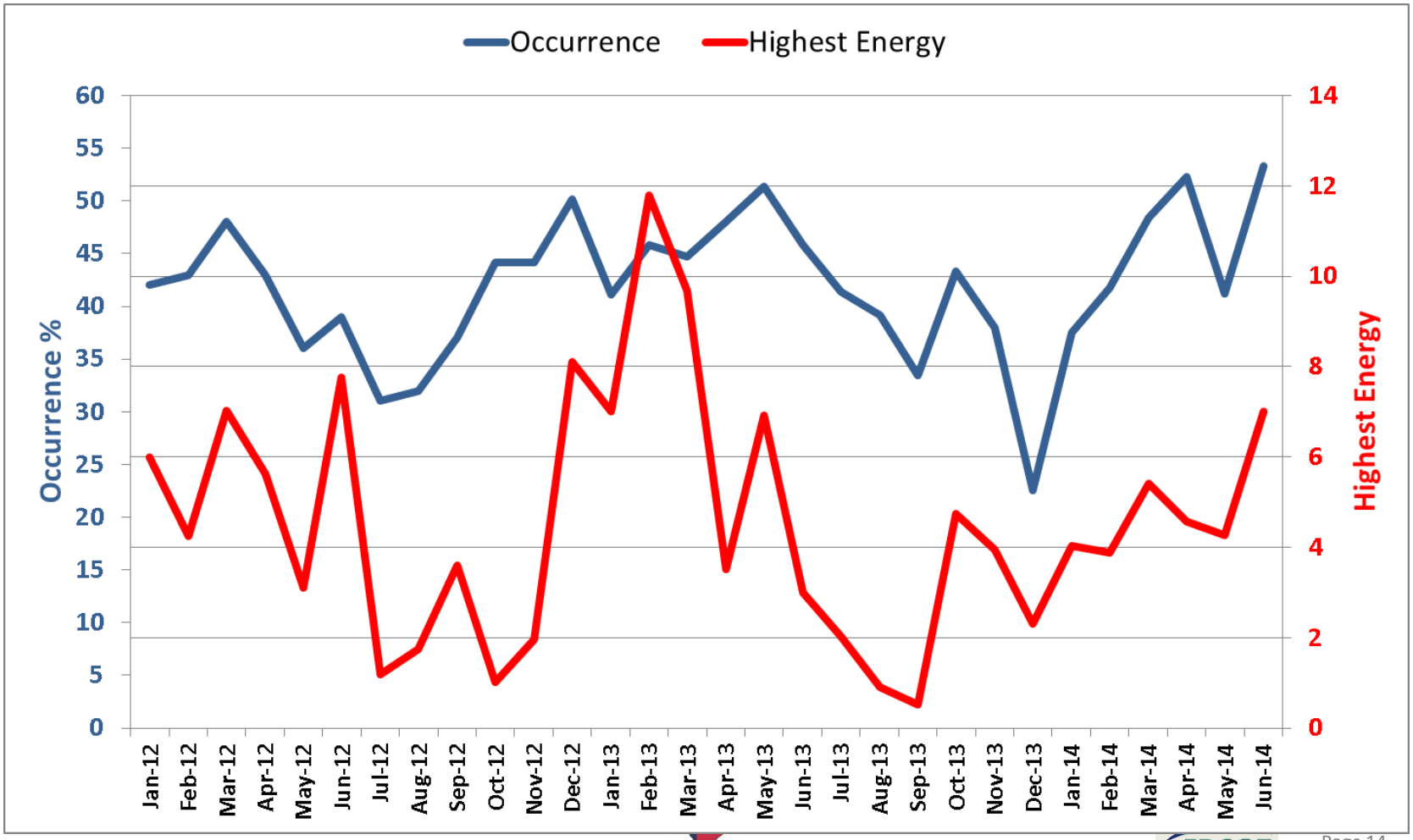
Mode #2 – 0.9 Hz @ West 6

The trend of mode occurrence & average west wind have similar pattern and provides first indication that 0.9 Hz is more likely related to wind production



Mode #2 – 0.9 Hz @ West 6

The peaks & valleys of mode occurrence & highest energy matched very well to provide second indication that 0.9 Hz is more likely related to wind production near West 6



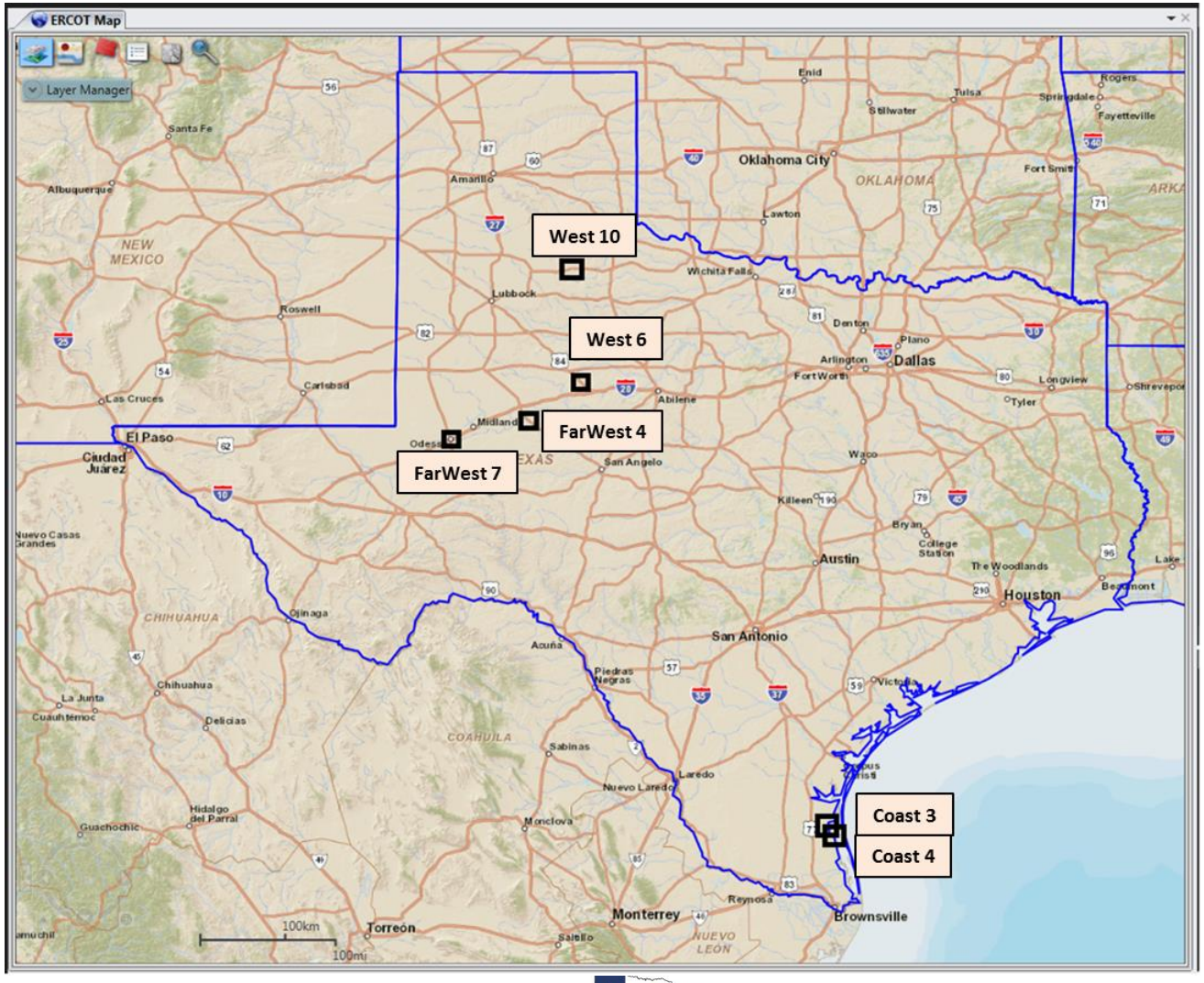
Mode #2 – 0.9 Hz @ West 6

- 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 – 0.9 Hz @ West 6

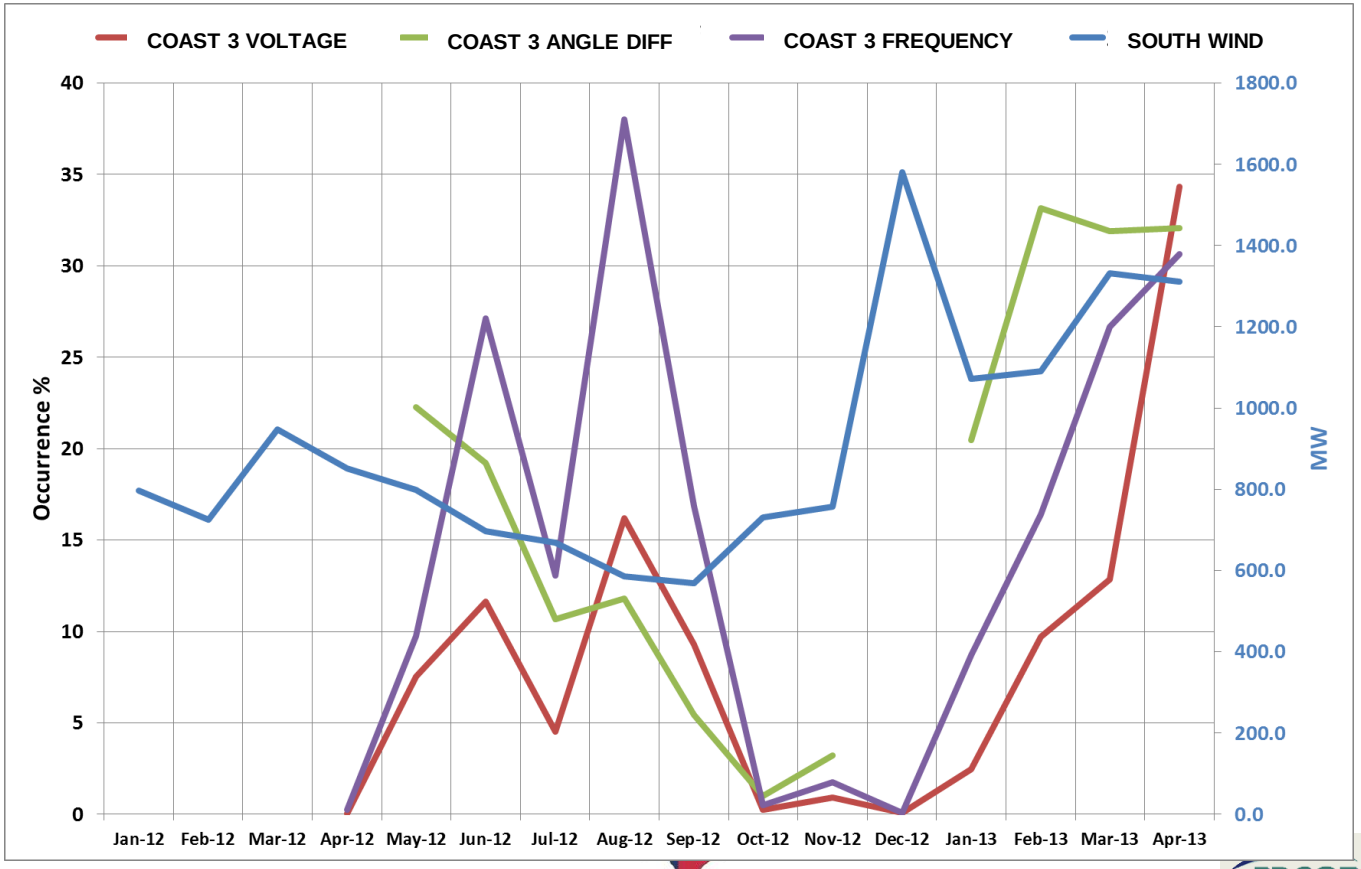
- Highest energy: Represents the highest energy of the mode during each month
  - Maximum highest energy in Feb 2013 and energy was 12
  - Minimum highest energy in Sep 2013 and energy was 0.5
- **ERCOT should monitor in real time with the following configuration**
  - West 6 current magnitude
  - Minimum frequency = 0.85 Hz
  - Maximum frequency = 1.2 Hz
  - Minimum energy = 2
  - Damping = 8%

Mode #8 – 5.0 Hz @ 6 Locations



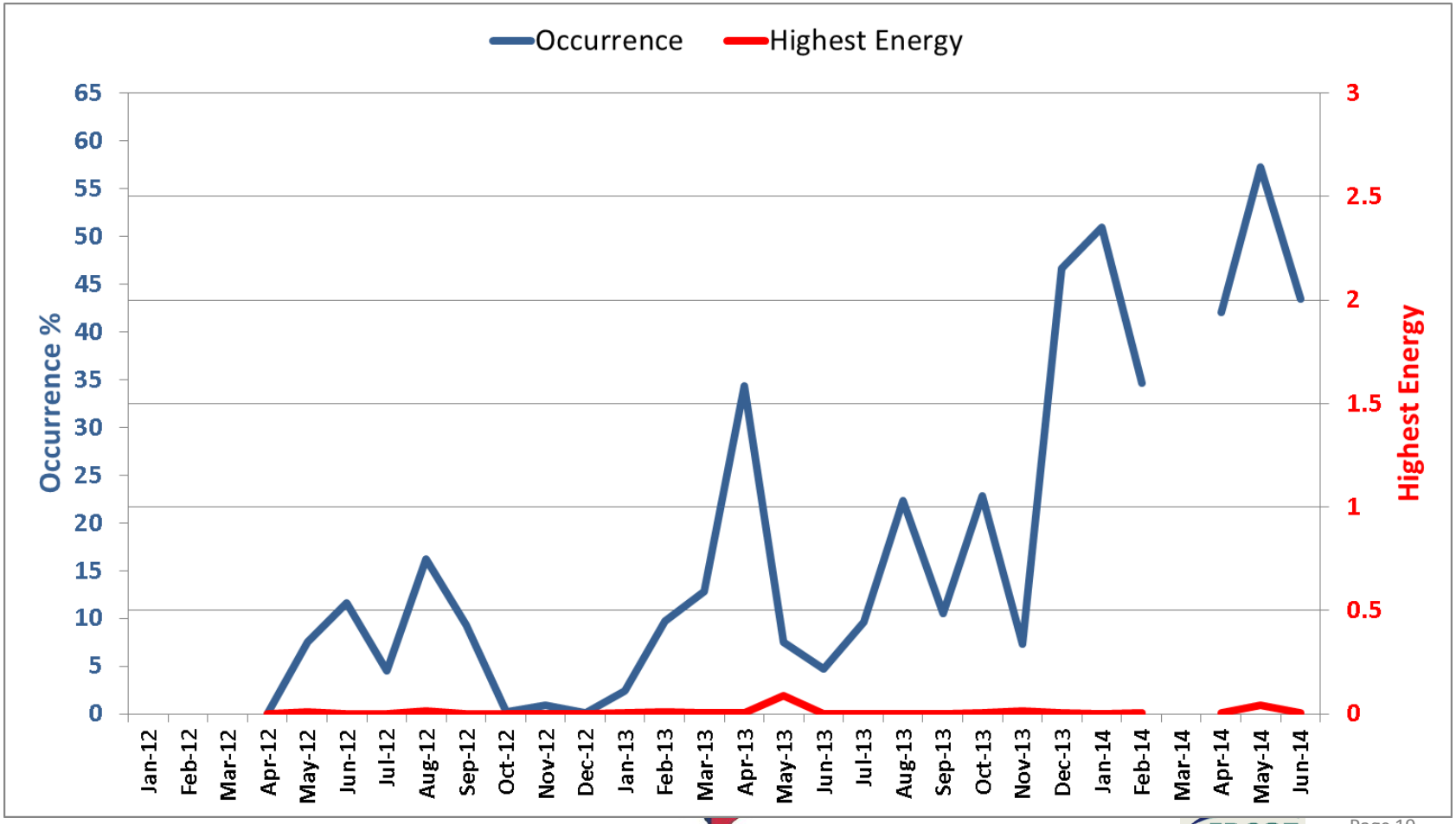
Mode #8 – 5.0 Hz (May Not be Wind Related)

- 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 – 5.0 Hz (Local Control Systems)

- The energy of the mode remained fairly flat at low levels (< 0.01) indicating no relationship with changing wind production
- These oscillations are more likely driven by control systems at the local wind generators



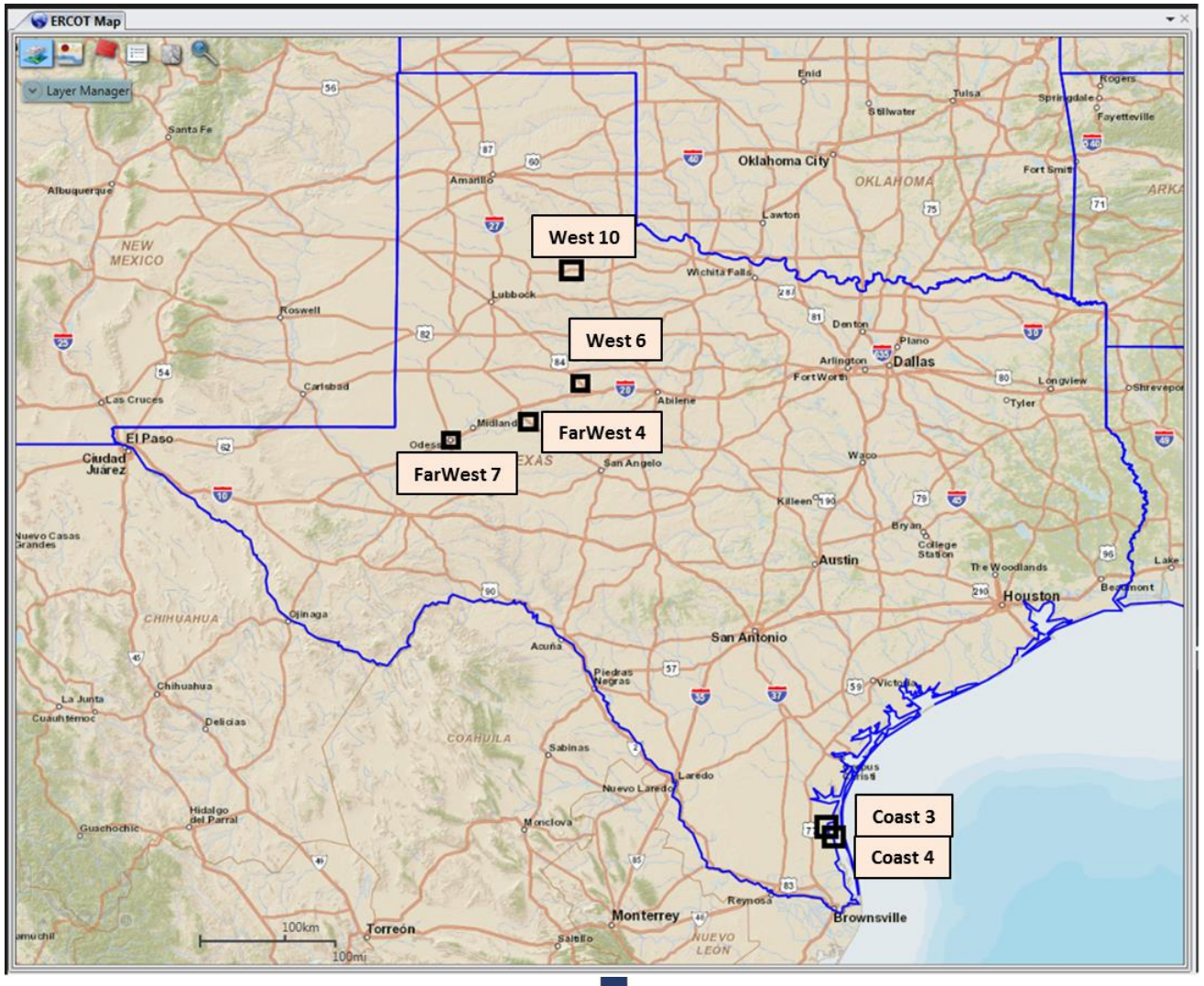
Mode #8 – 5.0 Hz @ Coast 3

- 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 and in 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 – 5.0 Hz @ Coast 3

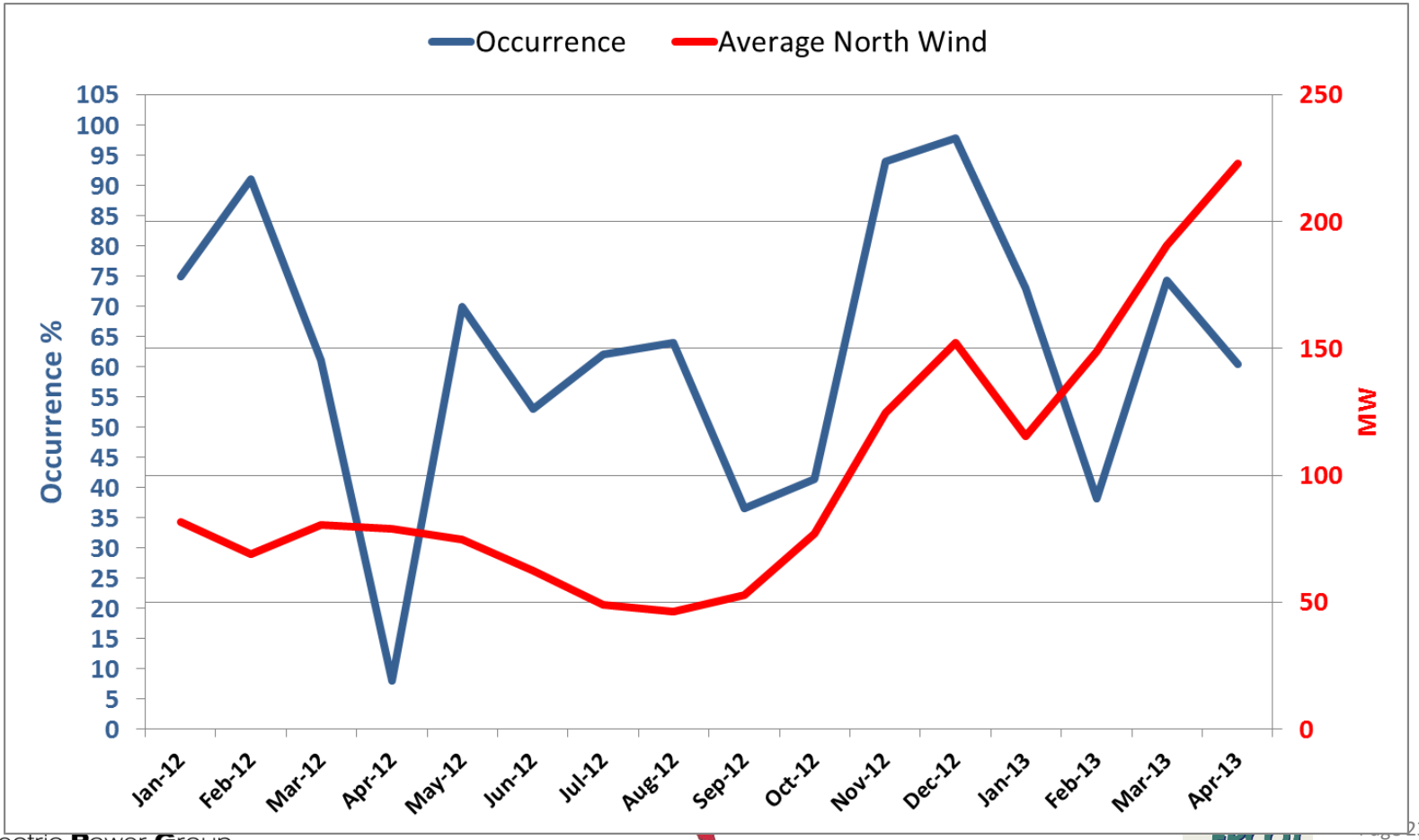
- Highest energy: represents the highest energy of the mode during each month (no significant event with high energy)
  - Maximum highest energy in May 2013 and energy was 0.09 (low)
  - Minimum highest energy in Dec 2012 and energy was 0.00015 (very low)
- **ERCOT should review 5.0 Hz oscillation with wind owners for possible mitigation, and determine root cause to evaluate need for additional monitoring**

Mode #9 – 5.4 Hz @ 6 Locations



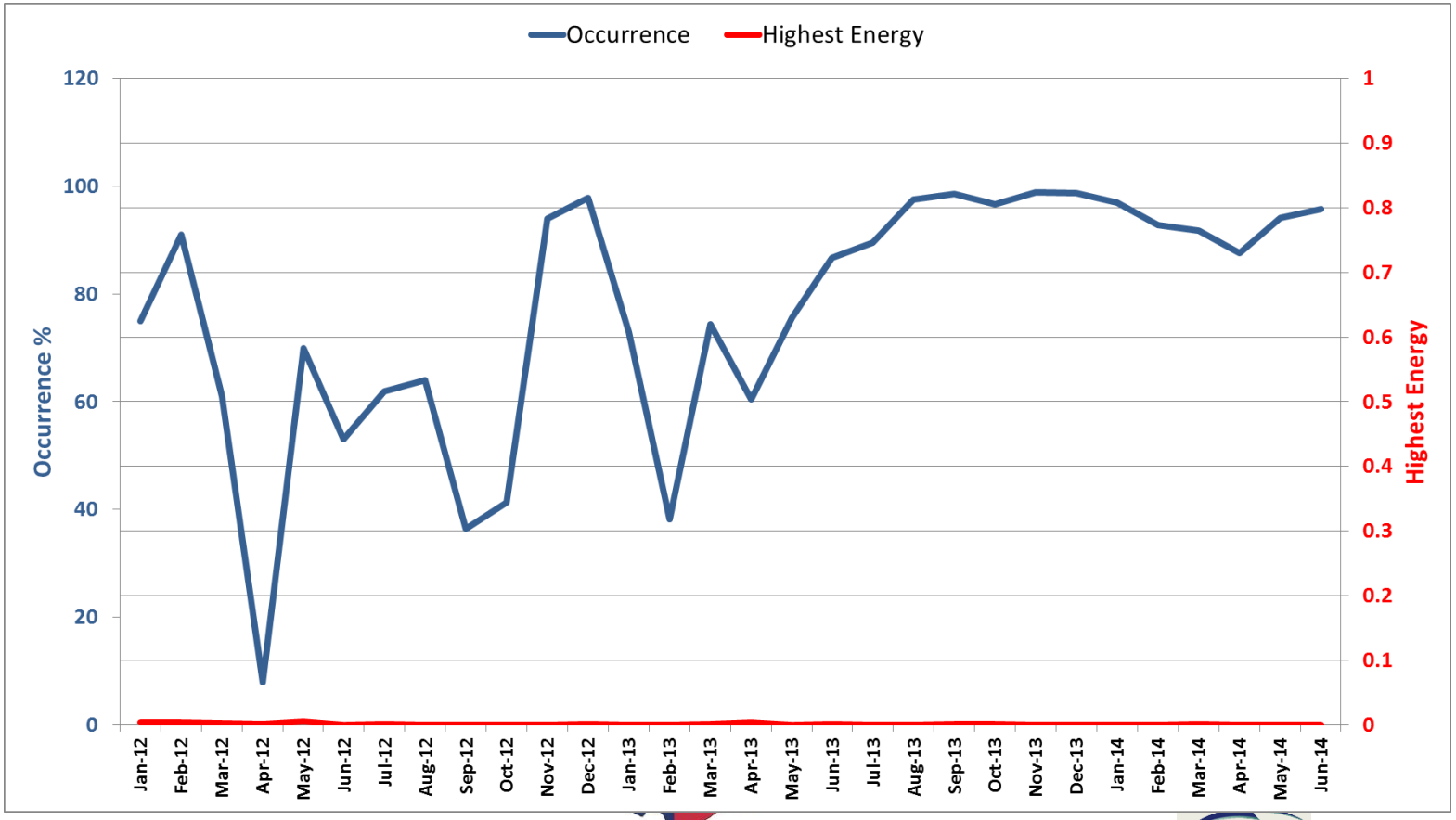
Mode #9 – 5.4 Hz @ West 10

- 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



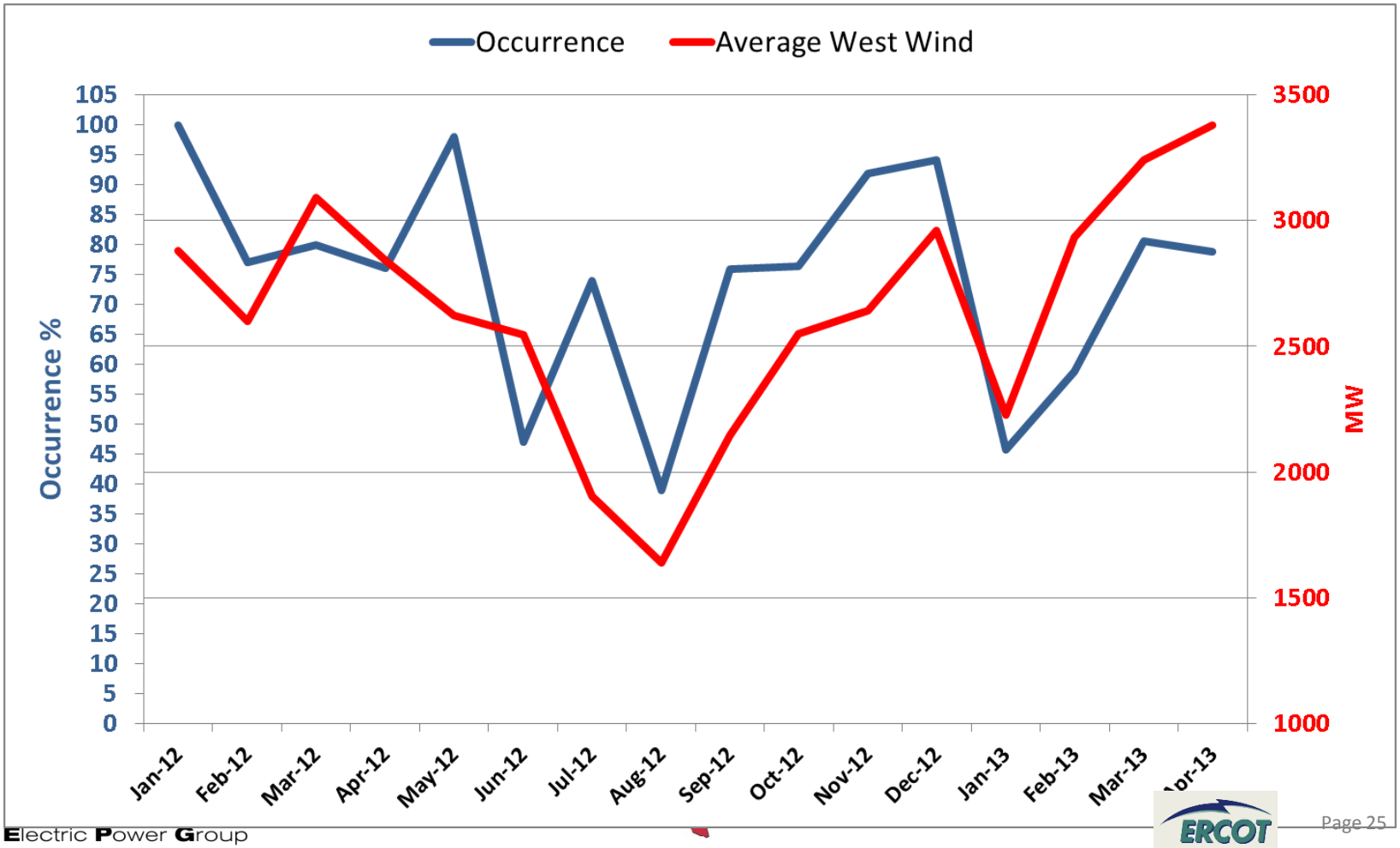
Mode #9 – 5.4 Hz @ West 10 (Local Control Systems)

- 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



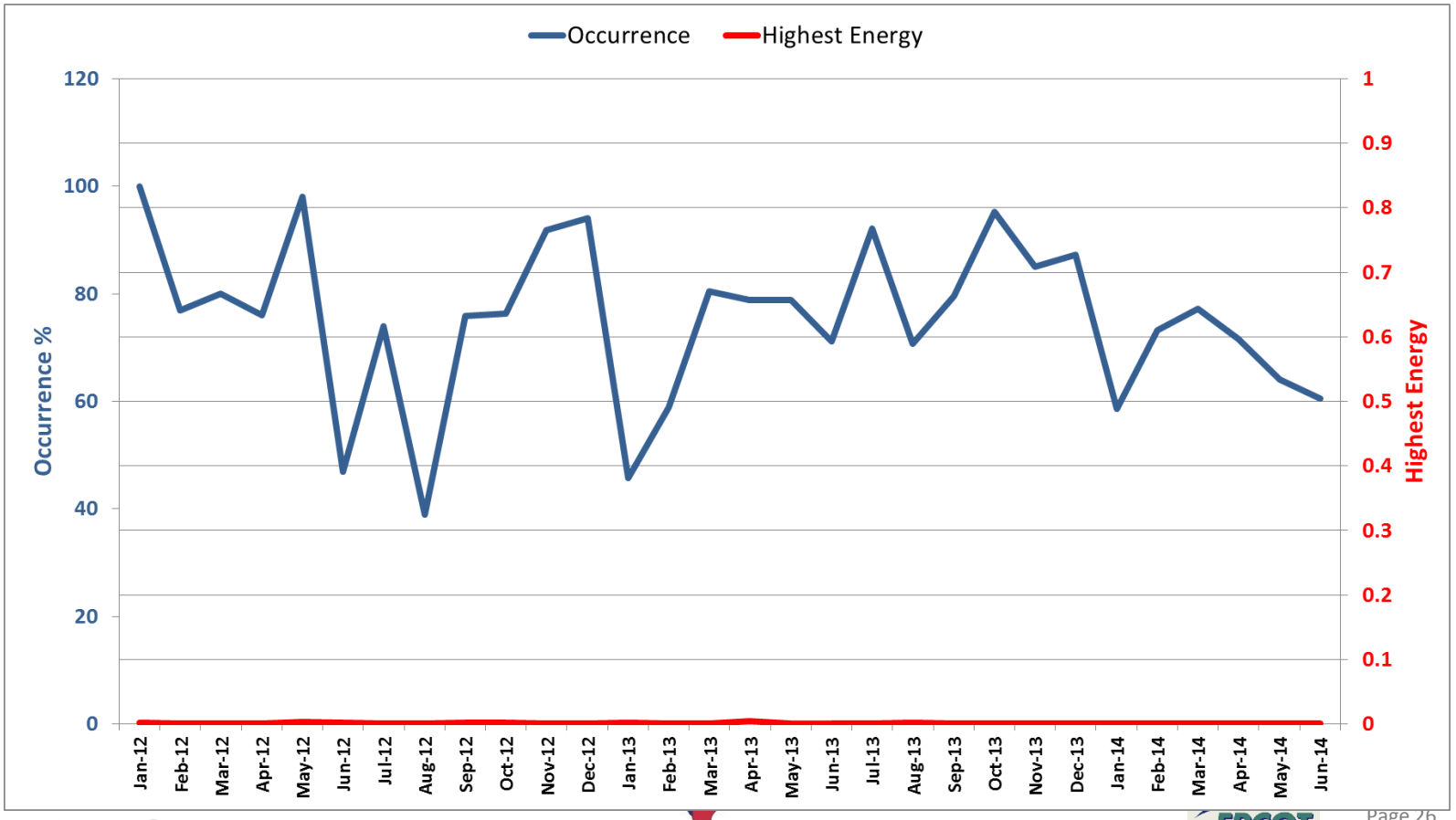
Mode #9 – 5.4 Hz @ FarWest 4

The trend of mode occurrence and average west wind have similar pattern, and provides first indication that 5.4 Hz may be related to wind production

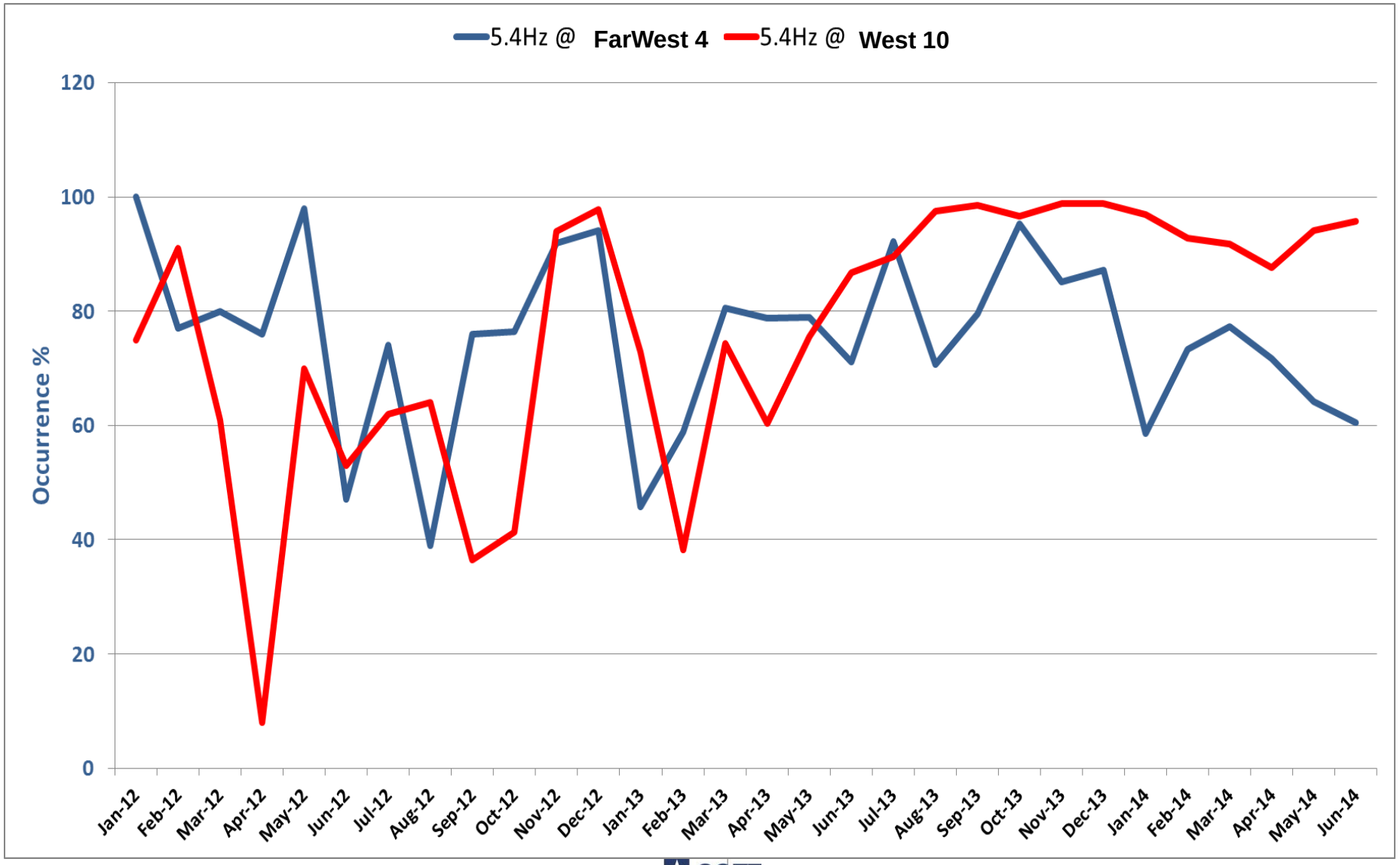


Mode #9 – 5.4 Hz @ FarWest 4 (Local Control Systems)

- 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



5.4 Hz Mode Pattern – FarWest 4 Vs. West 10



Mode #9 – 5.4 Hz @ West Texas & Panhandle

- Source: Panhandle (West 10), West (FarWest 4, FarWest 7, West 6) – most occurrence
- PMU: West 10 and 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 and 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 and FarWestGen4

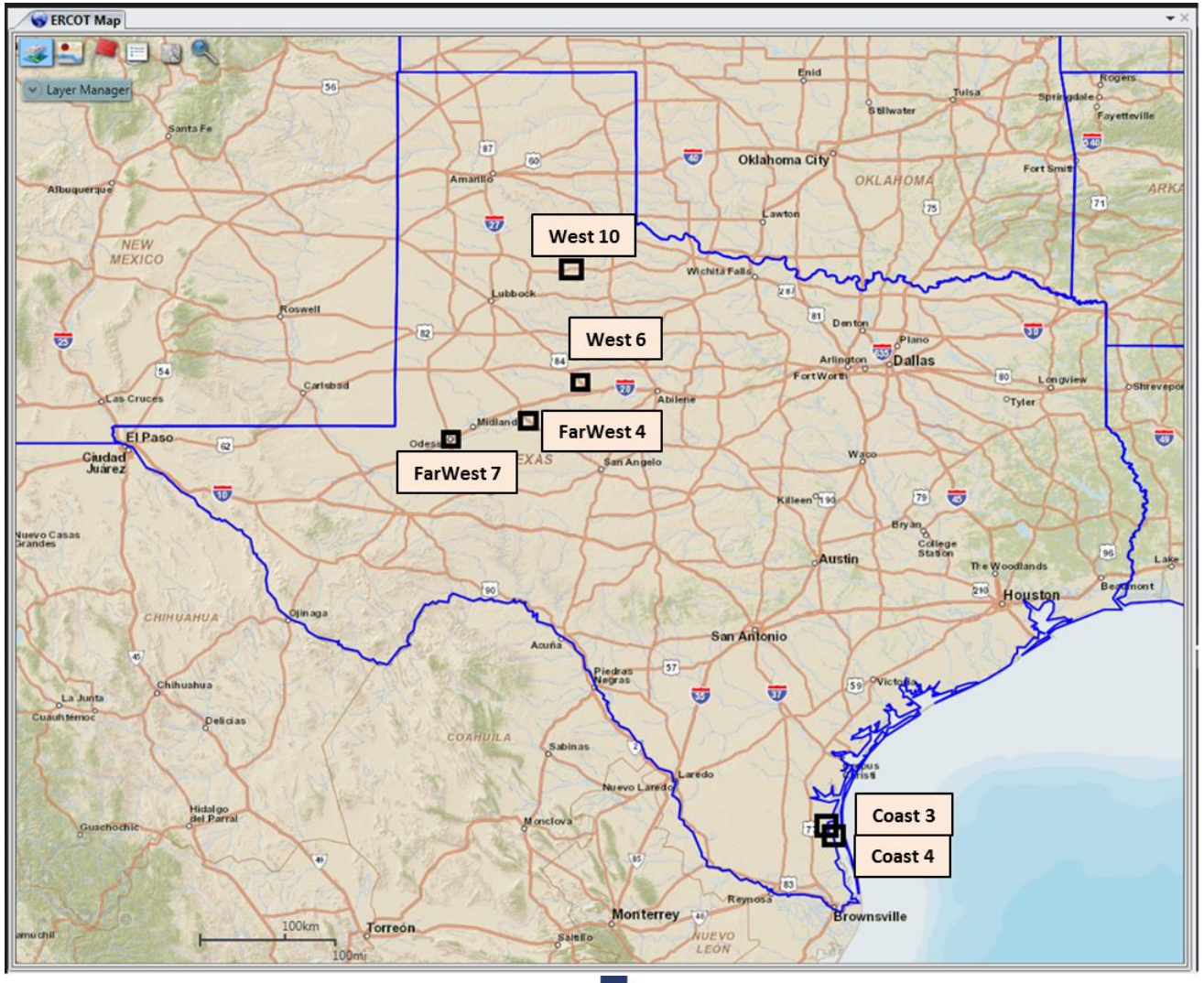
Mode #9 – 5.4 Hz @ West 10

- 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, and Dec 2013, and appeared for 99% of time (all the time)
- **ERCOT should review 5.4 Hz oscillation with wind owners for possible mitigation, and determine the root cause to evaluate need for additional monitoring**

Mode #9 – 5.4 Hz @ FarWest 4

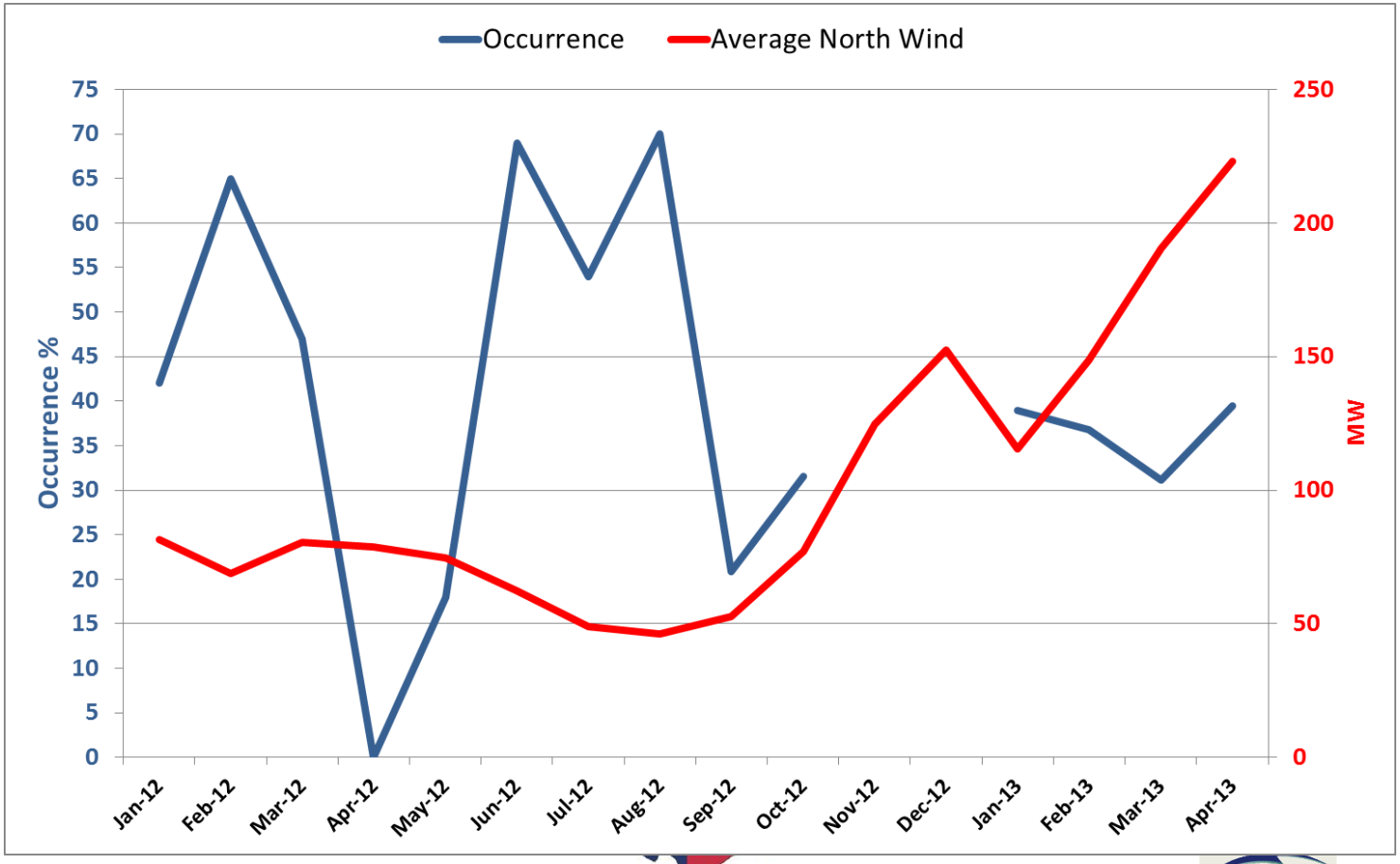
- Occurrence: appeared every month in all three years
  - Minimum occurrence in August 2012, and appeared for 39% of time (12 Days)
  - Maximum occurrence in Jan 2012, and appeared all the time
- **ERCOT should review 5.4 Hz oscillation with wind owners for possible mitigation, and determine the root cause to evaluate need for additional monitoring**

Mode #10 – 6.0 Hz @ 6 Locations



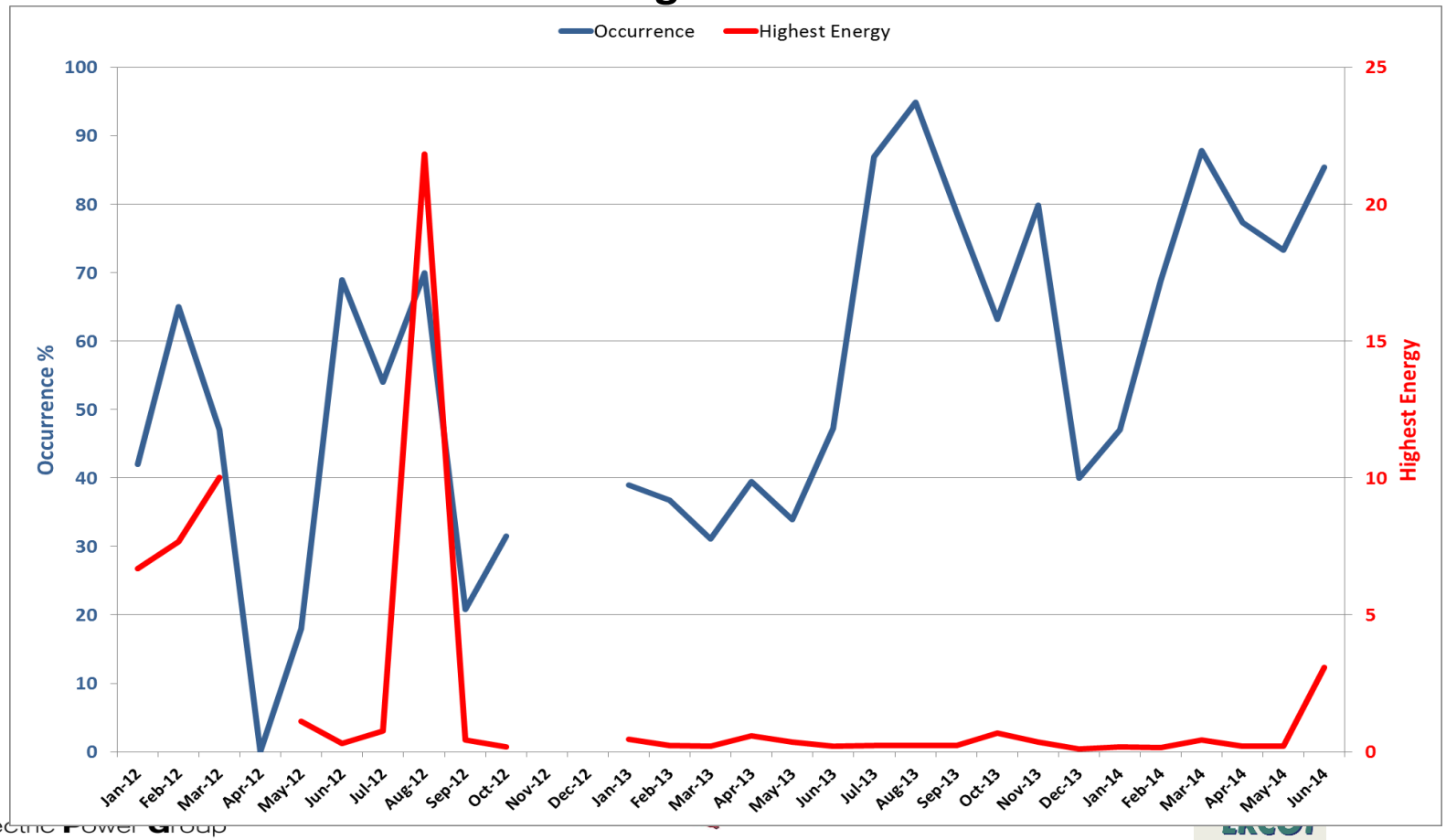
Mode #10 – 6.0 Hz @ West 10

- 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 – 6.0 Hz @ West 10 (Local Control Systems)

- The energy of the mode remained fairly flat at low levels (< 0.01) except in January-March & August 2012, indicating oscillations driven by control systems at the local wind generators can also reach high energy levels and needs additional monitoring



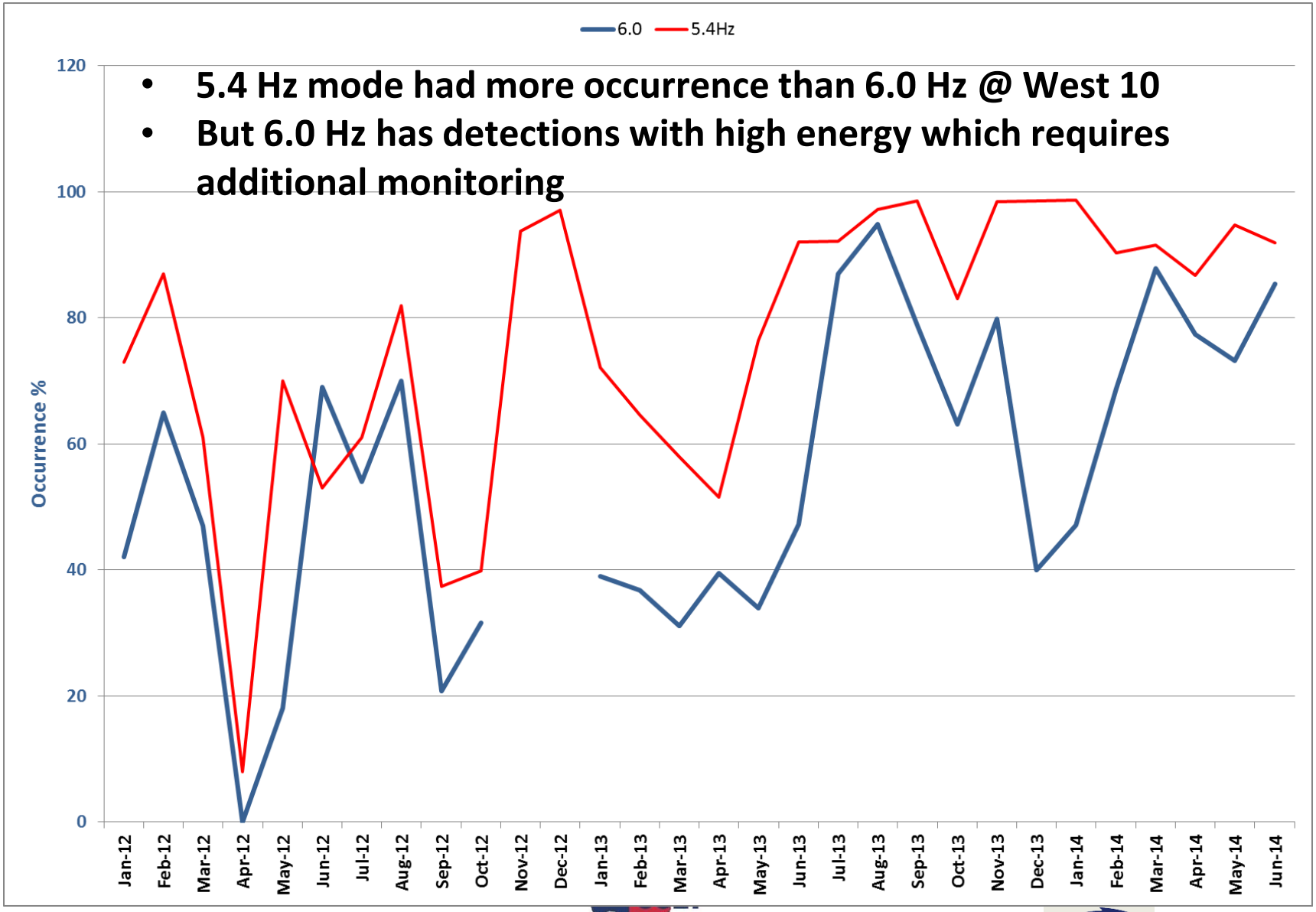
Mode #10 – 6.0 Hz @ West Texas & Panhandle

- 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 – 6.0 Hz @ West 10

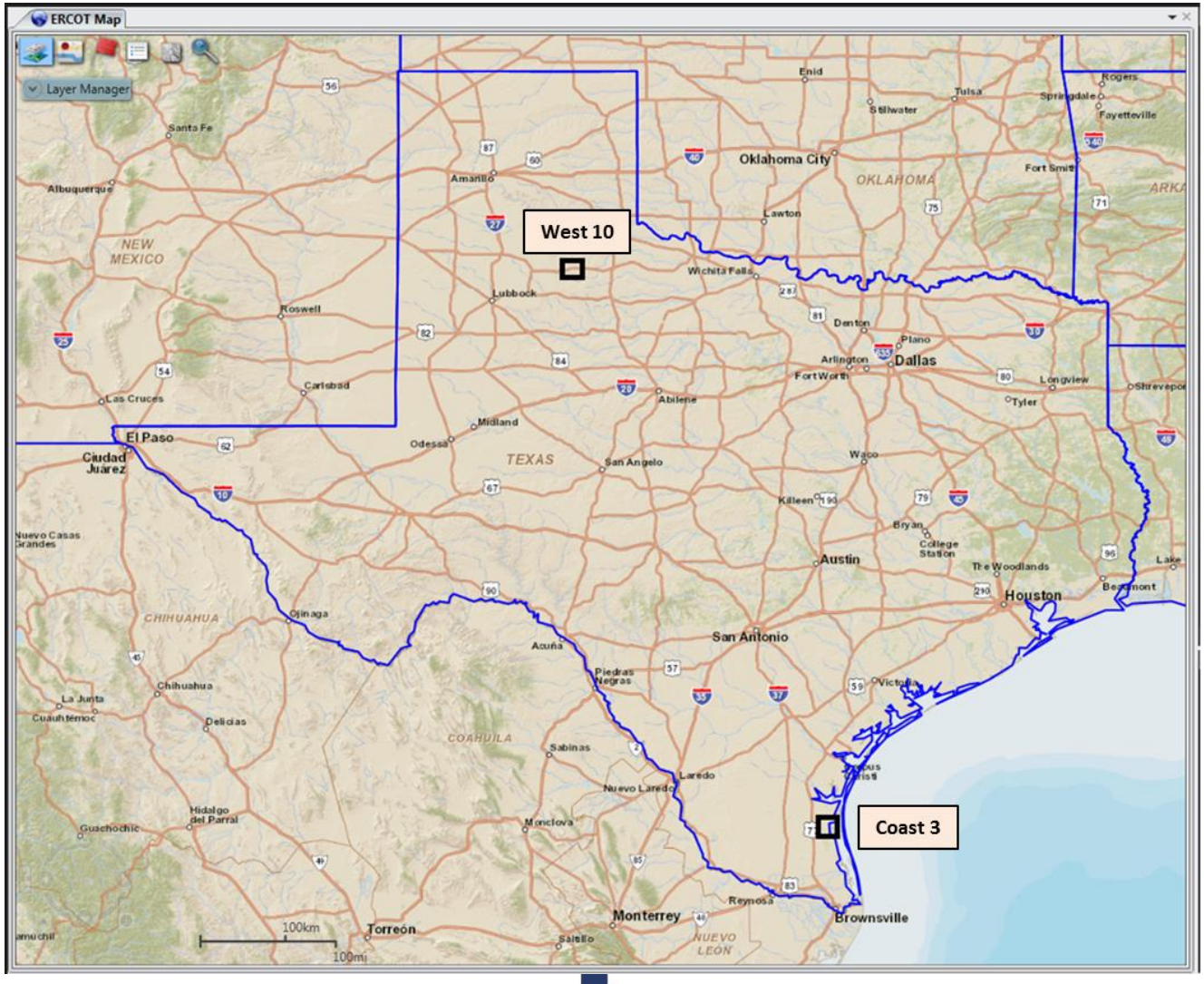
- Occurrence: appeared every month in all three years except April 2012
  - Minimum occurrence in May 2012, and appeared for 18% of time
  - Maximum occurrence in Aug 2013, and appeared 95% of time
- **ERCOT should review 6.0 Hz oscillation with wind owners for possible mitigation and also monitor with following configuration**
  - West 10 current magnitude
  - Minimum frequency = 5.5 Hz
  - Maximum frequency = 6.5 Hz
  - Minimum energy = 5
  - Damping = 8%

West 10 – 5.4 Hz vs. 6.0 Hz



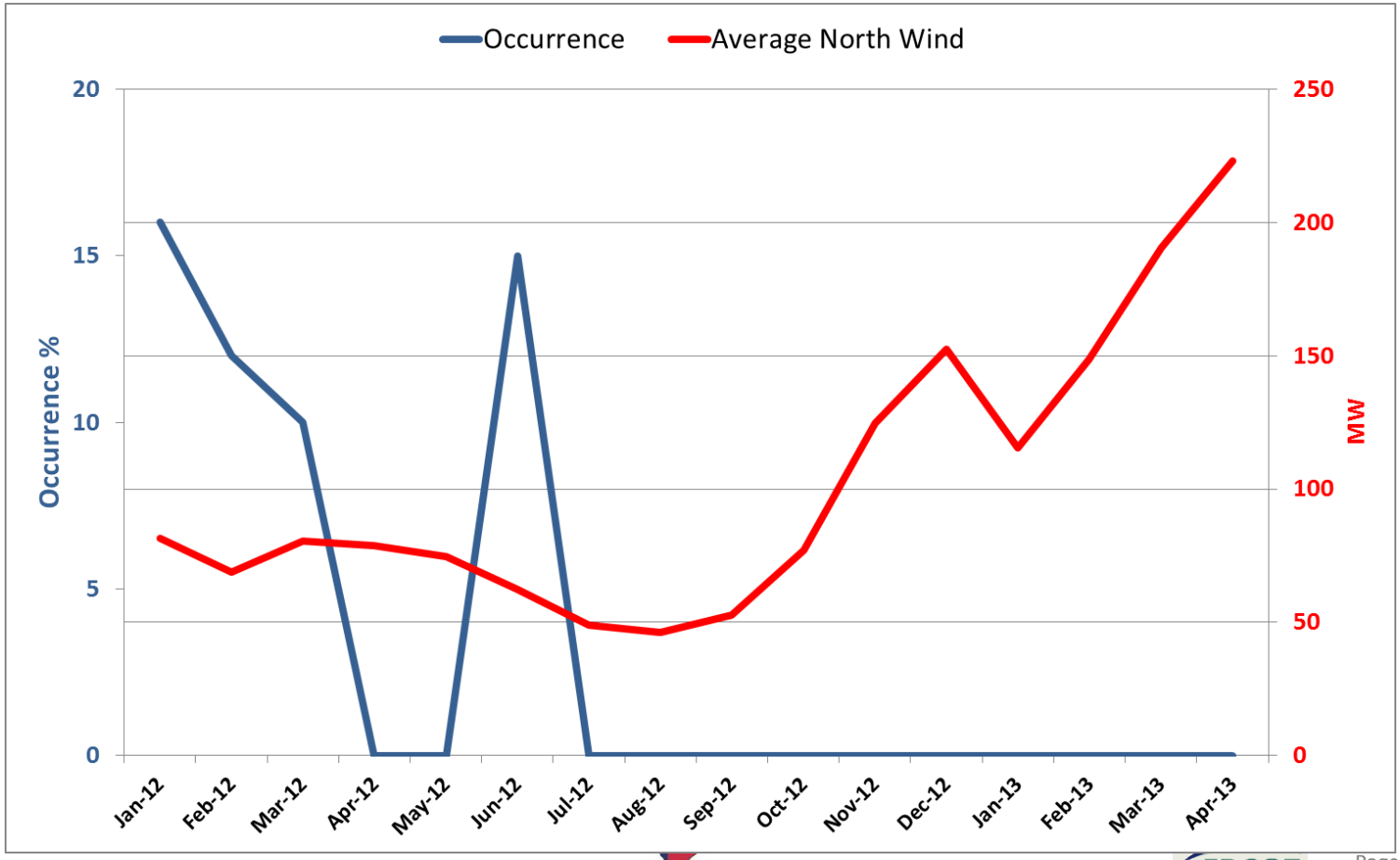
- 5.4 Hz mode had more occurrence than 6.0 Hz @ West 10
- But 6.0 Hz has detections with high energy which requires additional monitoring

Mode #7 – 3.2 Hz @ West 10



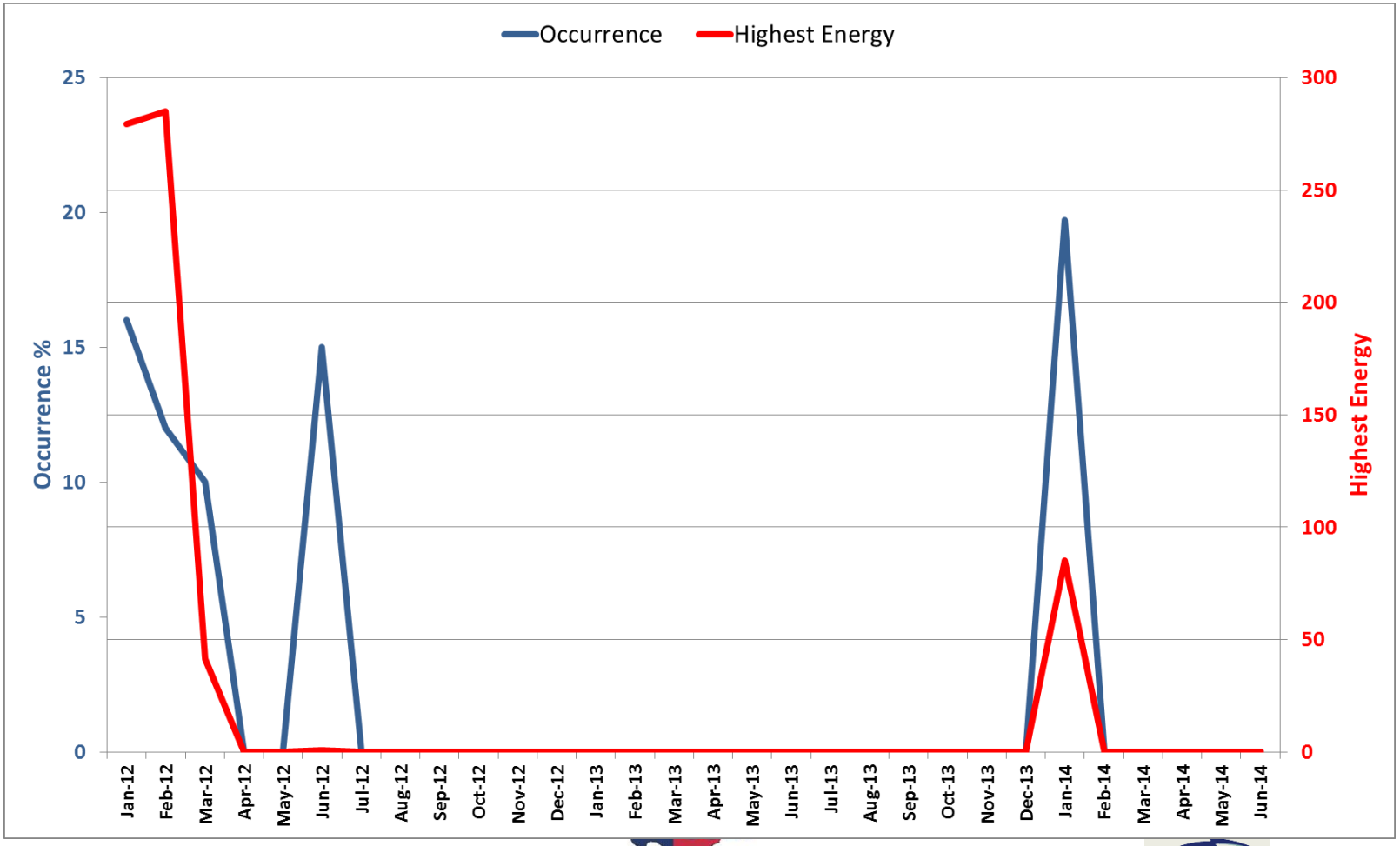
Mode #7 – 3.2 Hz @ West 10

- Mode occurrence @ West 10 does not follow north wind pattern & does not appear to be consistent as 5.4 Hz 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 – 3.2 Hz @ West 10

- **The occurrence of 3.2 Hz mode appears to be intermittent, and energy is high during the occurrence. Would require additional monitoring to detect occurrence of same mode at West 10**



Mode #7 – 3.2 Hz @ West 10

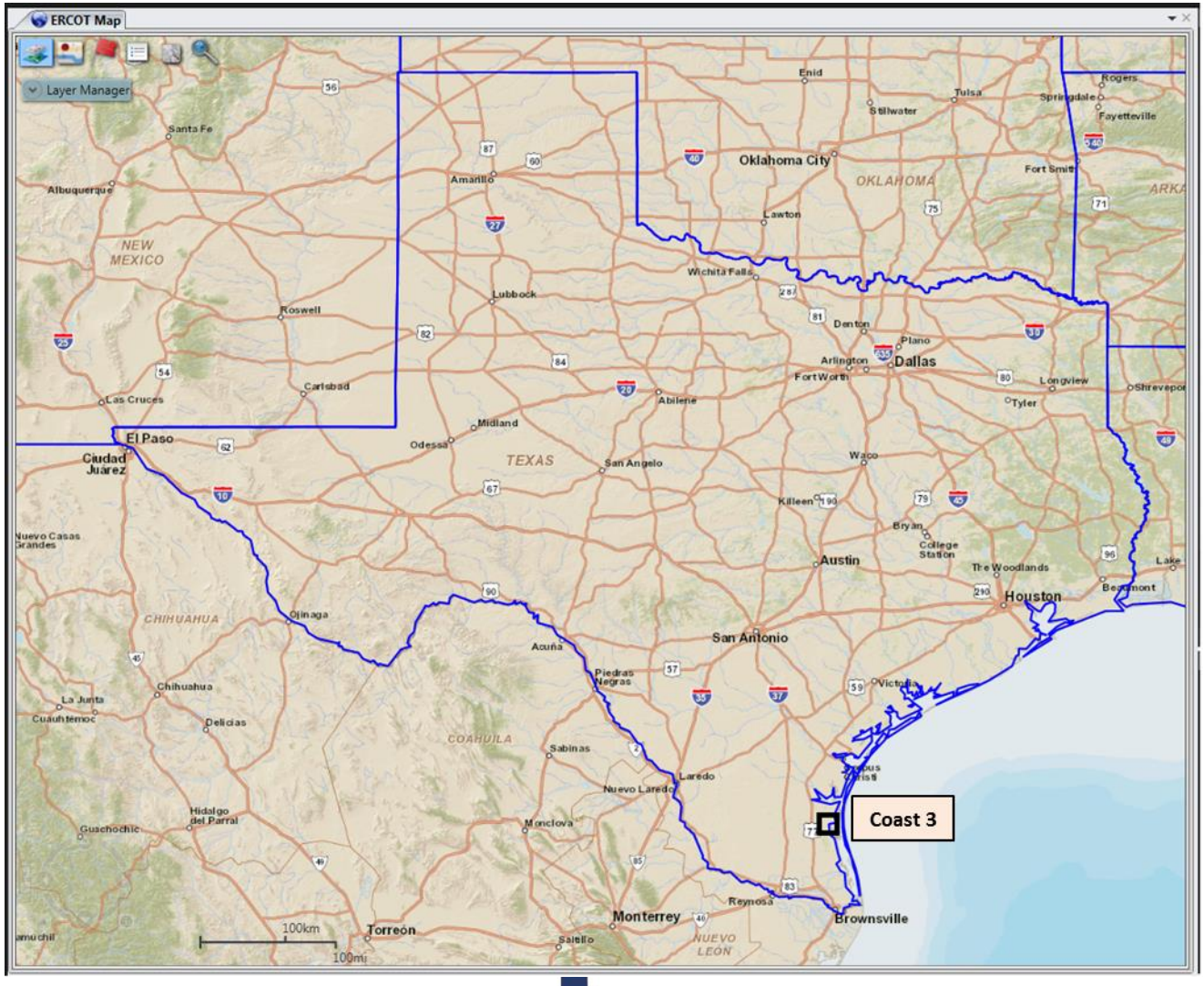
- Source: West 10
- Signal type: current magnitude
- Oscillation type: wind generator control systems setting change
- Generators nearby: WestGen10
- Occurrence:
  - Appeared in first 3 months & June of 2012, Jan of 2014
  - Minimum occurrence in Mar 2013, and appeared for 10% of time
  - Maximum occurrence in Jan 2014, and appeared for 20% of time

Mode #7 – 3.2 Hz @ West 10

- The mode 3.2 Hz is driven by control systems settings change and needs additional monitoring at West 10

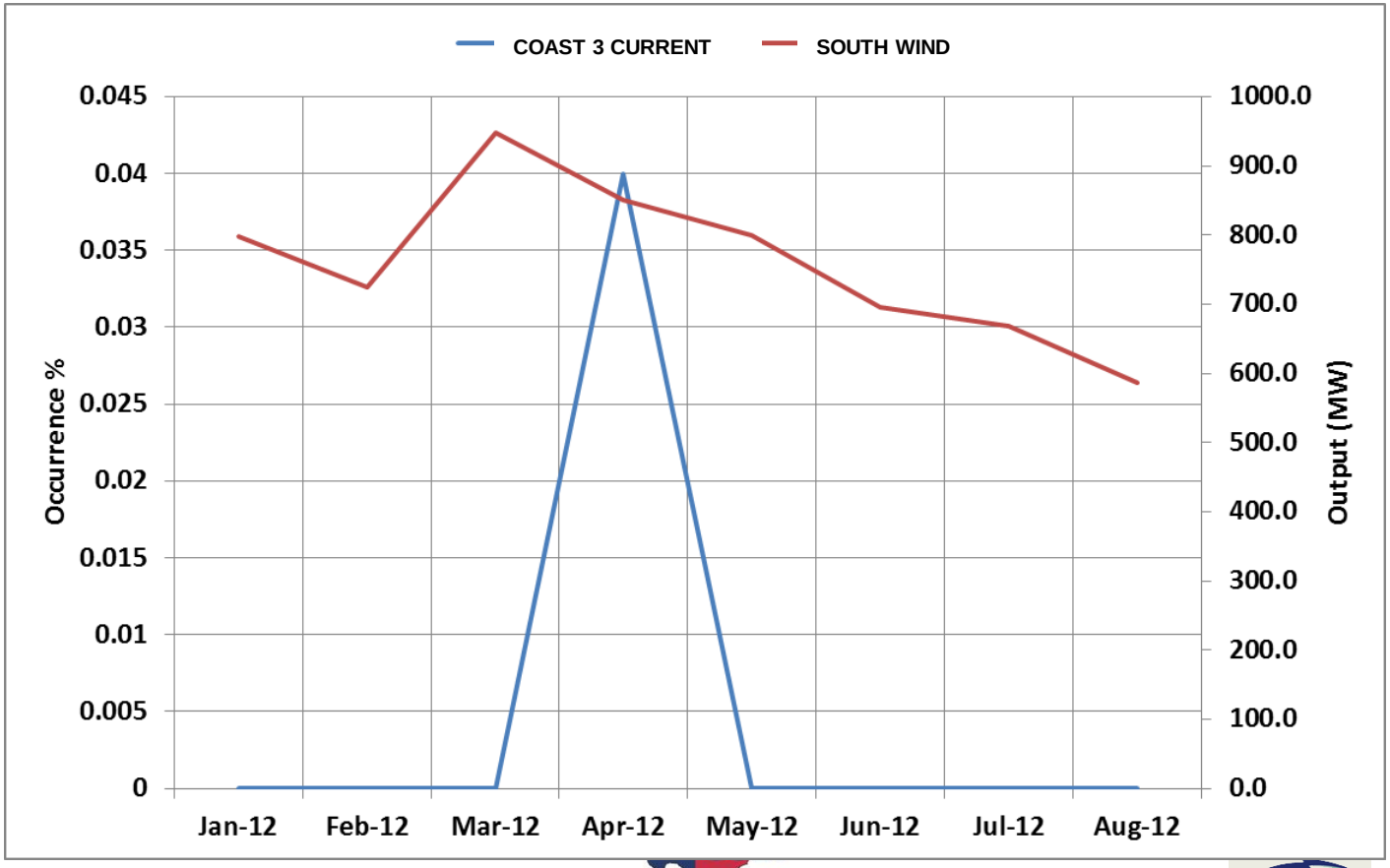
- **ERCOT should do additional monitoring of the mode with the following configuration**
  - Signal: West 10 current magnitude
  - Minimum frequency = 2.6 Hz
  - Maximum frequency = 3.8 Hz
  - Minimum energy = 50
  - Damping = 8%

Mode #3 – 1.5 Hz @ Coast 3



Mode #3 – 1.5 Hz @ Coast 3

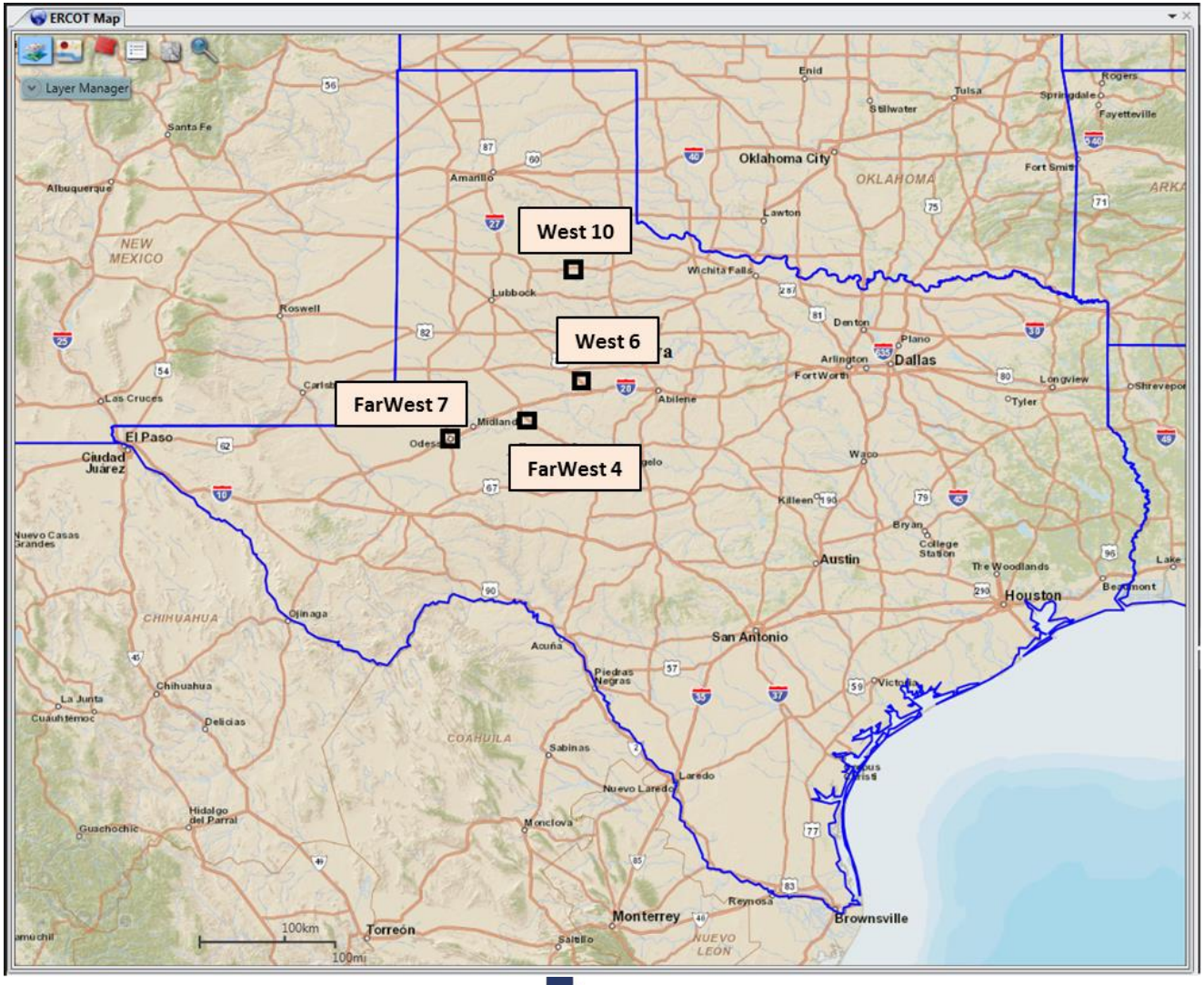
- Mode occurrence @ Coast 3 does not follow south wind pattern & does not appear to be consistent as 5.4 Hz or 6.0 Hz, rather occurred once
- But these oscillations are observed more strongly near wind generators, and appear to be driven by “settings change in the control systems”



Mode #3 – 1.5 Hz @ Coast 3

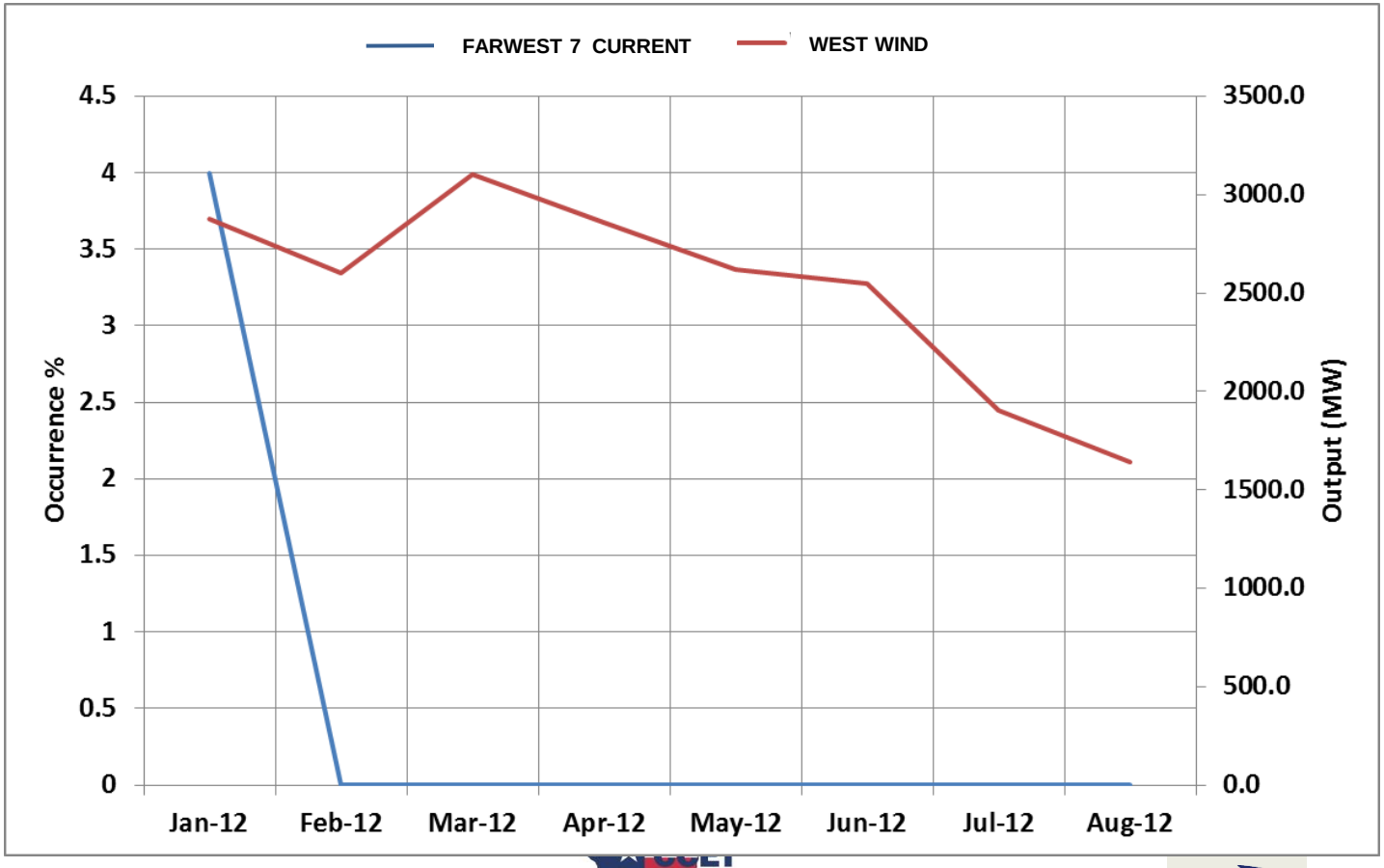
- Source: Valley (Coast 3)
- Oscillation type: wind generator control systems setting change
- Wind generators nearby: CoastGen3 & CoastGen4
- Occurrence:
  - Appeared only in April 2012 for 0.04% of time
- Energy – within the period of occurrence
  - Highest energy was about 0.02
- Occurred for a short period of time with low energy

Mode #4 – 1.7 Hz @ 4 Locations



Mode #4 – 1.7 Hz Mode Occurrence

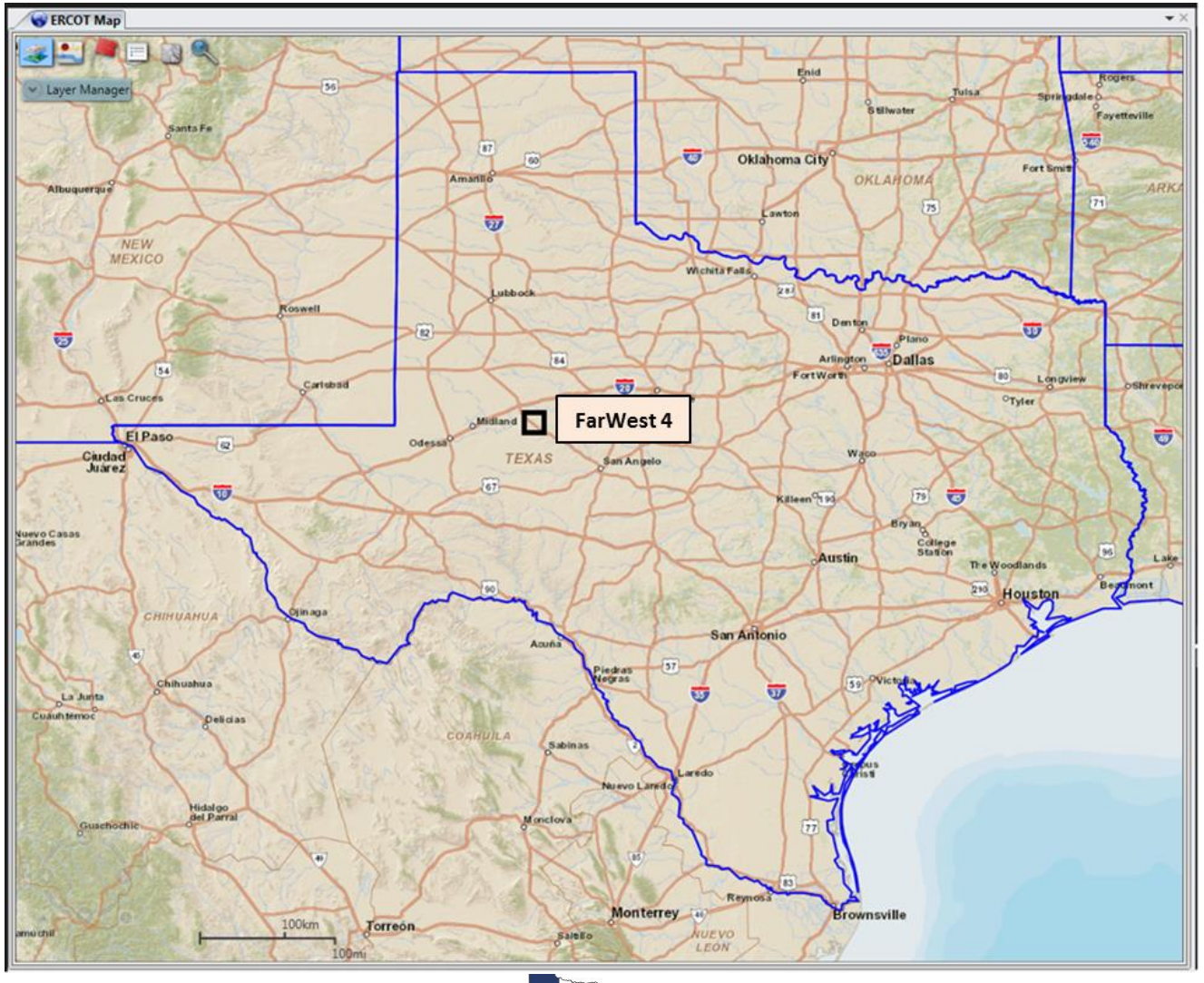
- Mode occurrence @ FarWest 7 does not follow west wind pattern & does not appear to be consistent as 5.4 Hz or 6.0 Hz, rather occurred once
- But these oscillations were observed more strongly near combined cycle unit with total capacity of 1,135 MW (6 Units)



Mode #4 – 1.7 Hz @ FarWest 7

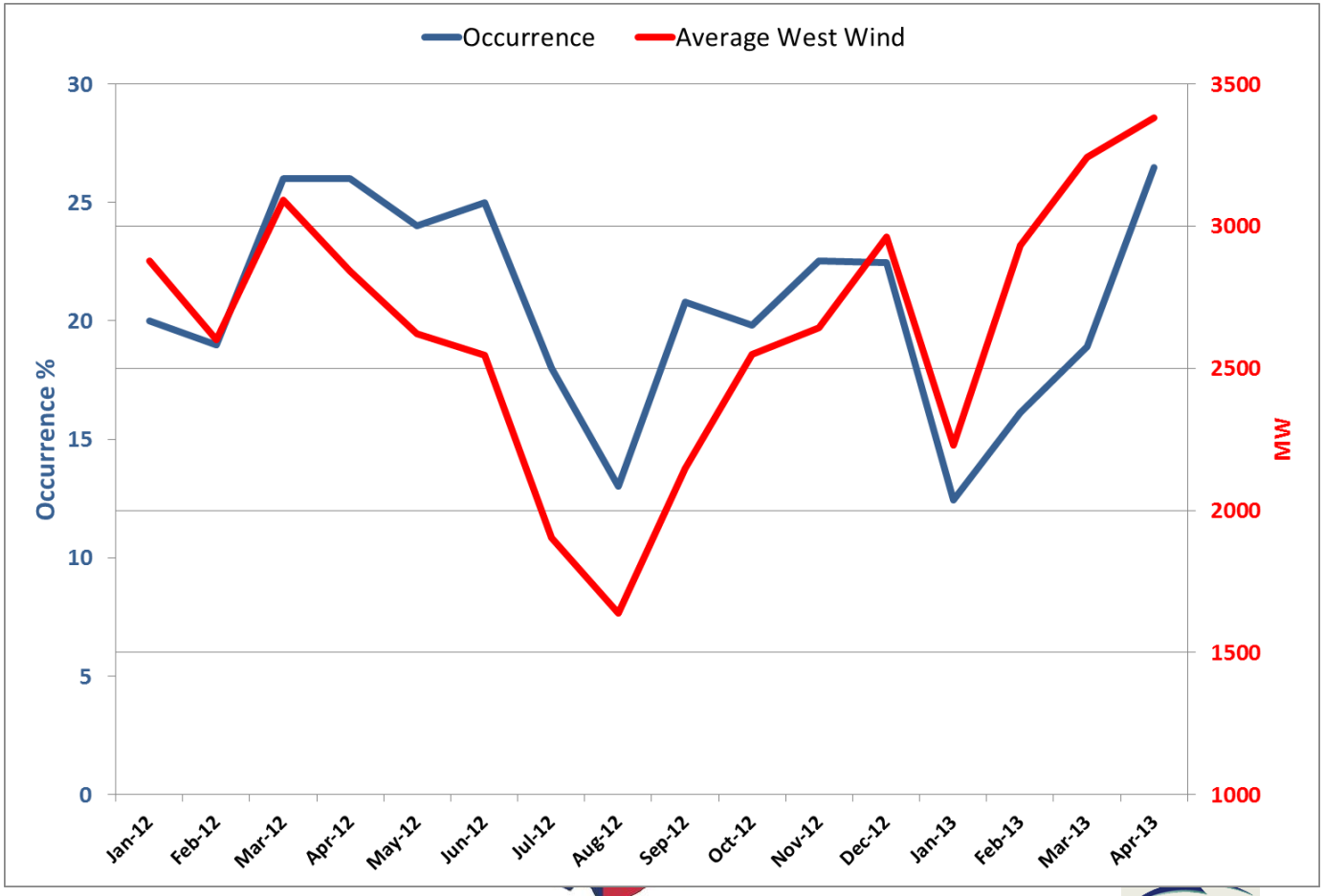
- Source: west Texas (FarWest 7)
- Oscillation type: local
- Other generators nearby: FarWestGen7 & FarWestGen8
- Occurrence:
  - Appeared only in Jan of 2012
- Highest energy – within the period of occurrence
  - Highest value was about 36
- **Appears to be a local issue & ERCOT needs to review the appearance of the mode with plant owners and determine the root cause to evaluate the need for additional monitoring**

Mode #6 – 2.7 Hz @ FarWest 4

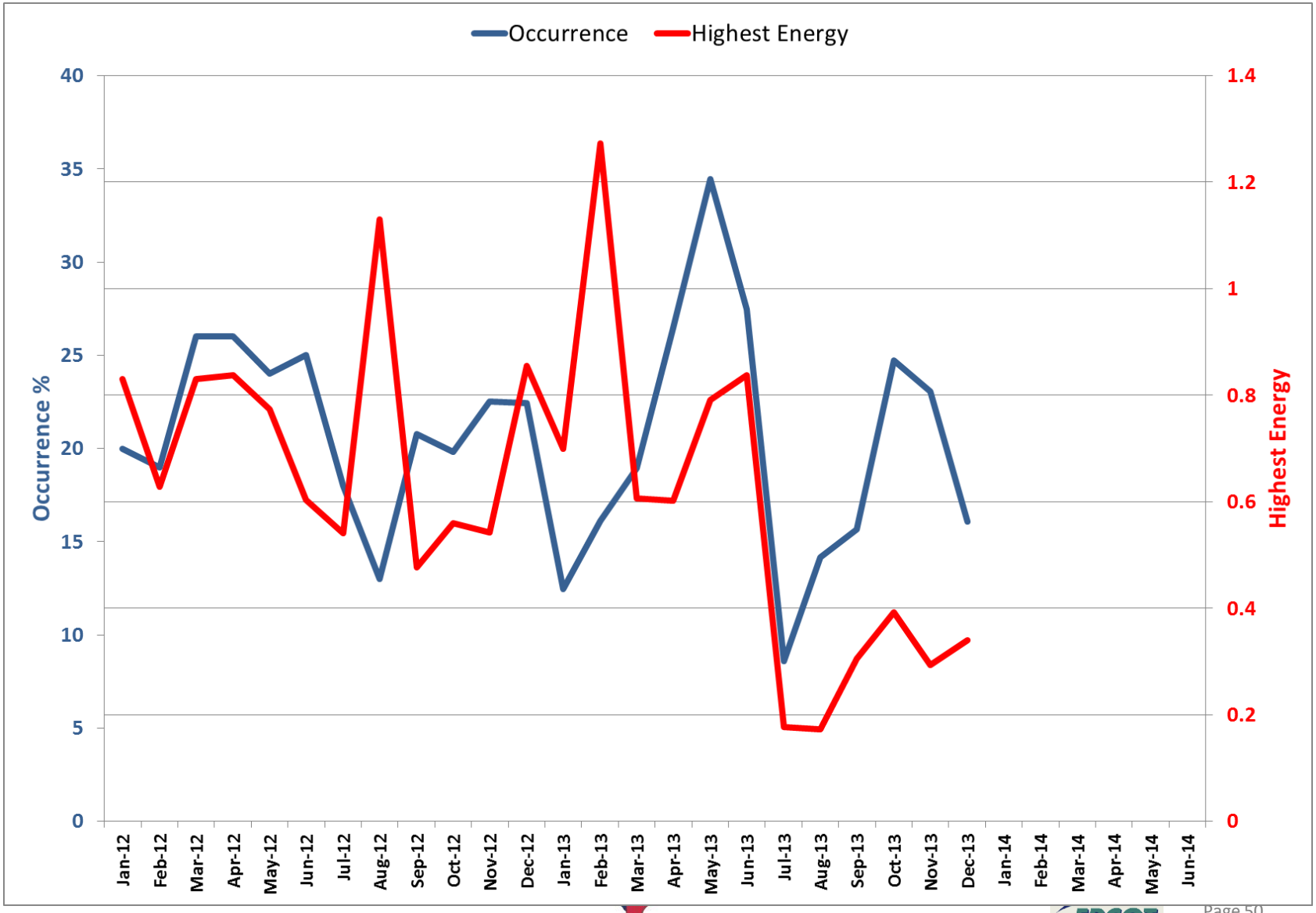


Mode #6 – 2.7 Hz @ FarWest 4

The trend of mode occurrence & average west wind have similar pattern, and provides first indication that 2.7 Hz is more likely related to wind production



Mode #6 – 2.7 Hz @ FarWest 4



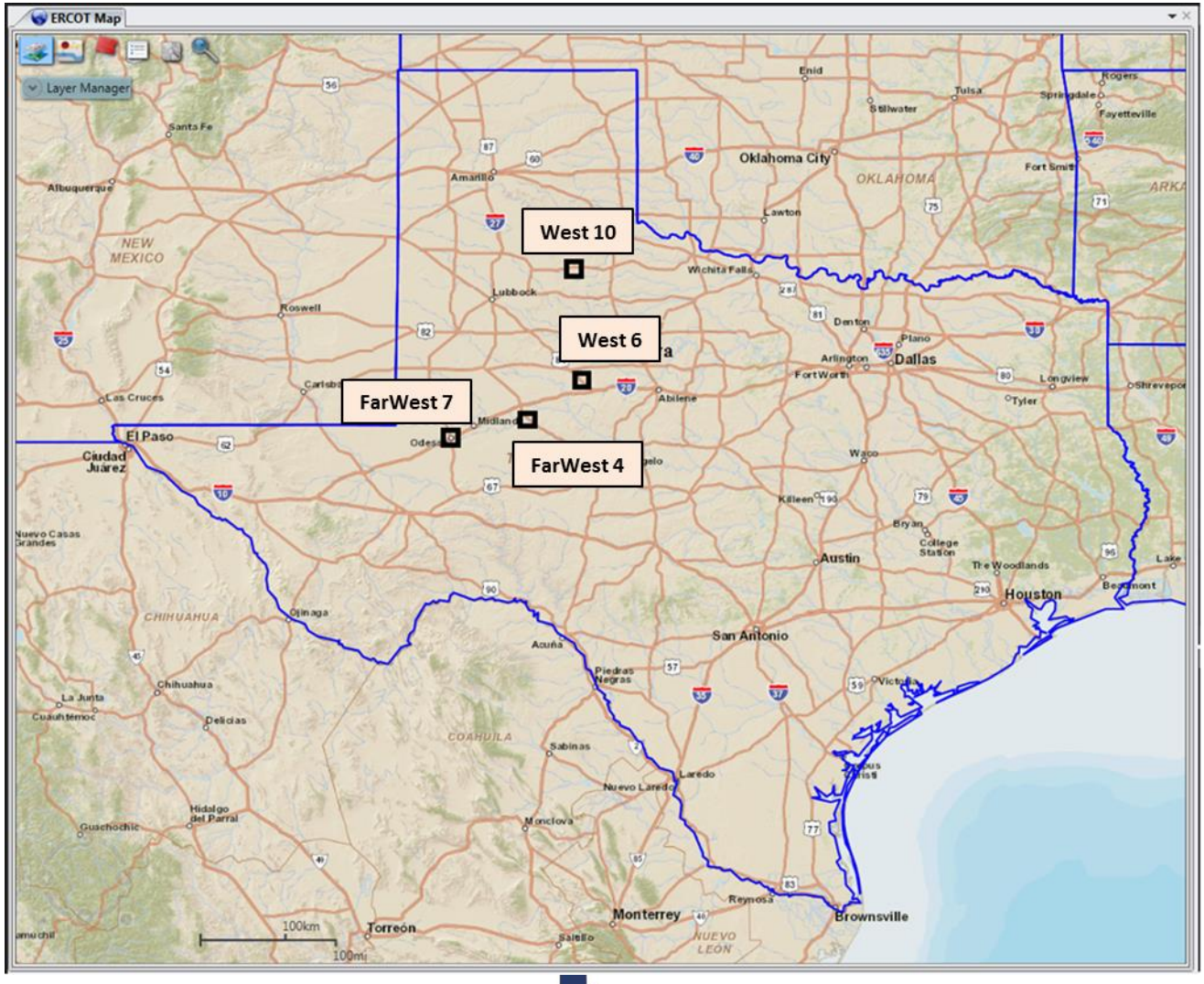
Mode #6 – 2.7 Hz @ FarWest 4

- 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 – 2.7 Hz @ FarWest 4

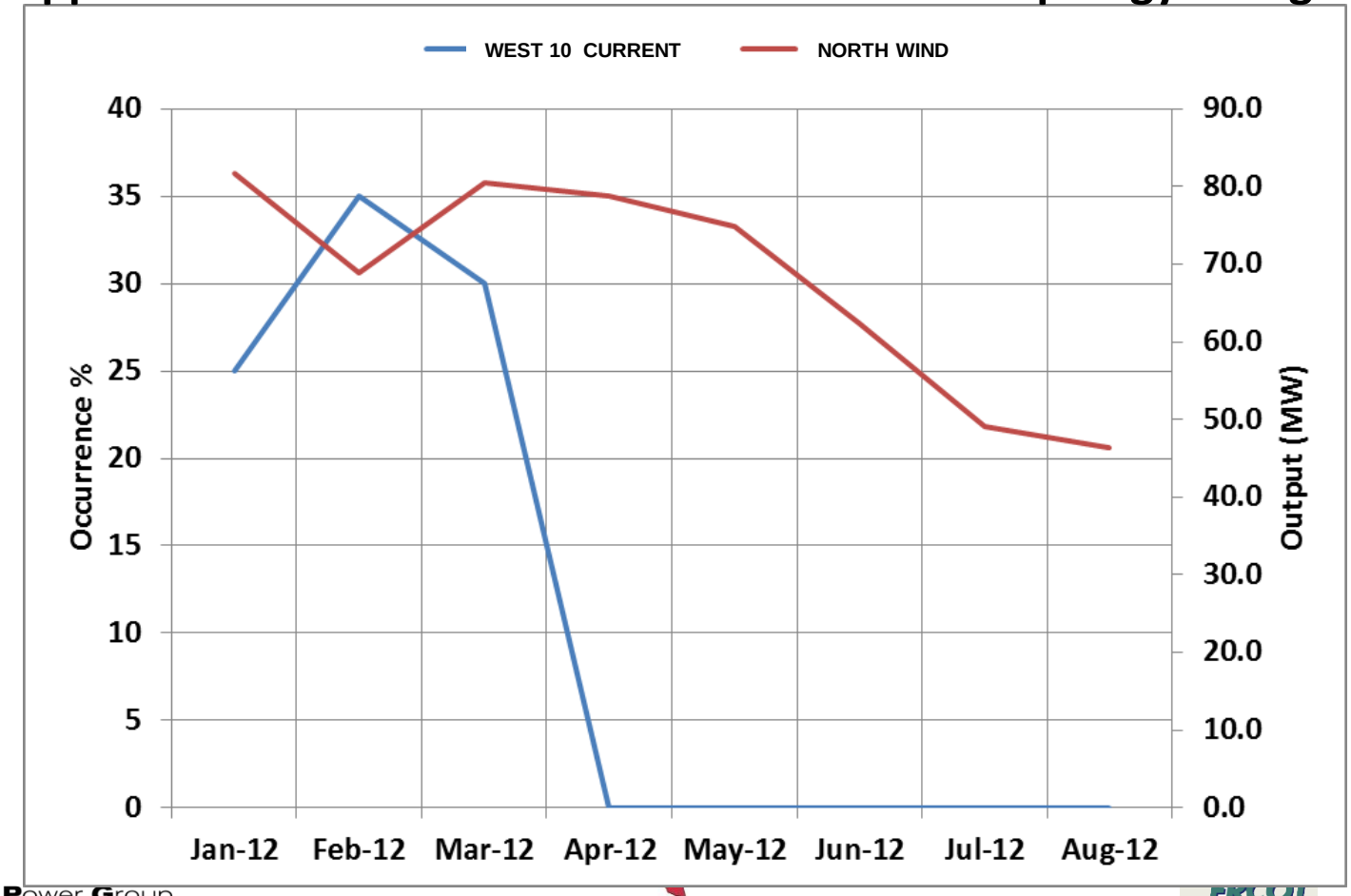
- Occurrence:
  - Mode disappears at beginning of 2014
- Disappearance of 2.7 Hz mode may be related to addition of new CREZ transmission lines near FarWest 7, running down to West 29 and West 8 on Jan 3, 2014, or any tuning of control systems @ FarWestGen4
- **ERCOT should review the disappearance of the mode with wind owners and determine the root cause to evaluate the need for additional monitoring**

Mode #1 – 0.6 Hz @ 4 Locations



Mode #1 – 0.6 Hz @ West 10

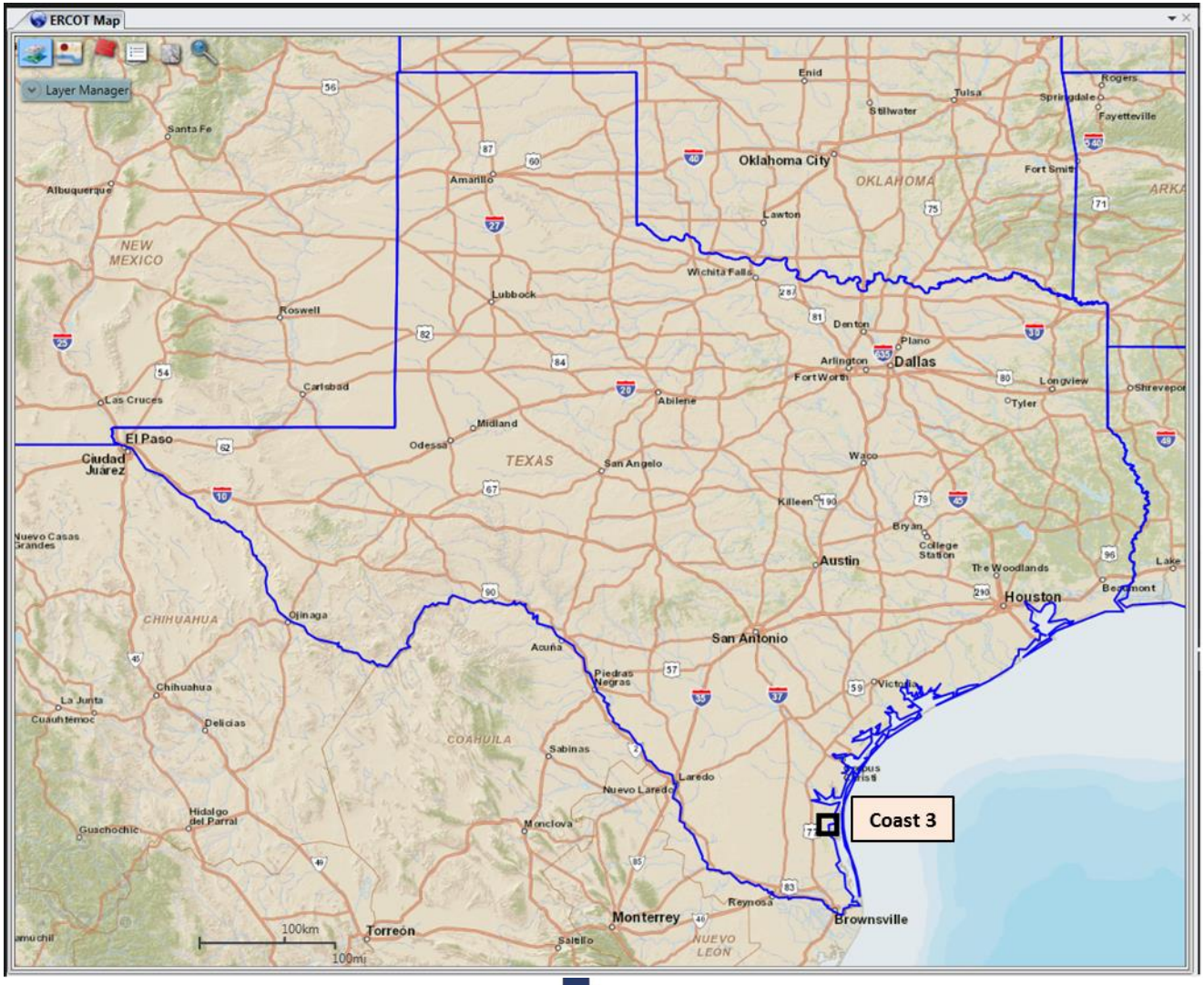
- Mode occurrence @ West 10 does not follow north wind pattern & does not appear to be consistent as 3.2 Hz, rather disappeared after March 2012
- But these oscillations were observed more strongly near wind generators, and appear to be related to local oscillation due to topology change



Mode #1 – 0.6 Hz @ 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 – 2 Hz @ Coast 3



Mode # – 2 Hz @ 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 – 0.9 Hz (ongoing) & 2.7 Hz (no longer present)
- Occurrence of some modes appear to be related to control system changes –1.5 Hz (Coast 3), 1.7 Hz (FarWest 7), 2 Hz (Coast 3), 3.2 Hz (West 10)
  - Appear with significant energy for a short period of time and disappear
- Occurrence of some modes (5.0 Hz, 5.4 Hz, and 6.0Hz) appear to be related to the presence of wind generation, but not to production
- 0.6 Hz from West 10 – local oscillation (no longer present)
- 0.9 Hz from West 6 (ongoing)
- 5.0 Hz from Coast 3 (ongoing)
- 5.4 Hz from west wind & Panhandle (ongoing)
- 6.0 Hz 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, and 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 tabs 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 question and answer 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 information 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 too quick
- At times it got too technical, to the engineer level, so 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 improve 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 algorithms 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 of how the RTDMS will be integrated using SCADA, SE, and RTCA
- Make more displays/profiles
- Follow an 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 practice
- 3 - Somewhat
- Limited to moderate. We do not have this application at my company
- No, but not just because of presenter, but because 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 case 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 baselining. 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 information 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 information 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 improve 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's 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 practice
- 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 identity 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:

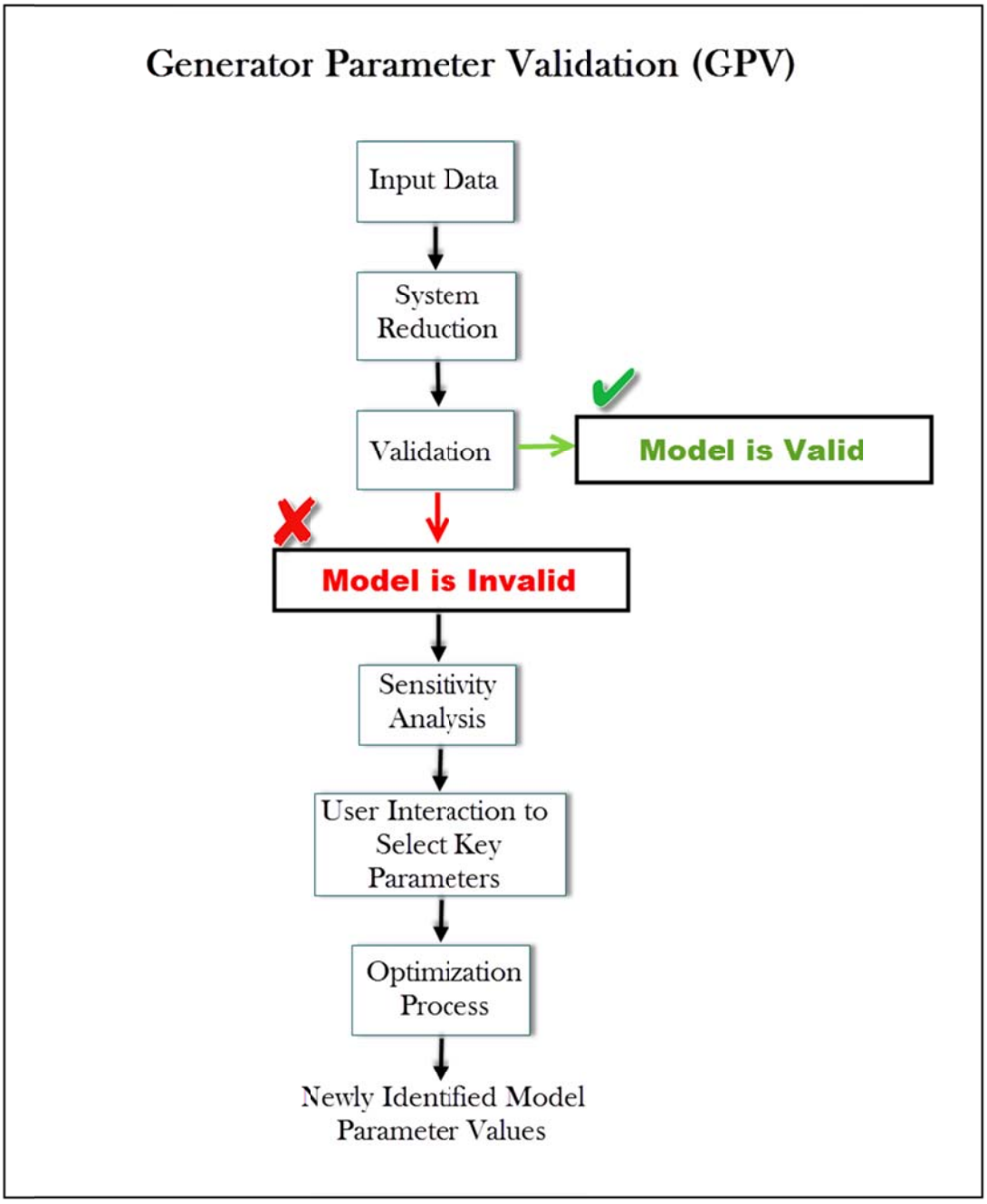


Figure 1. Generator Parameter Validation Process Workflow

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 identity 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.

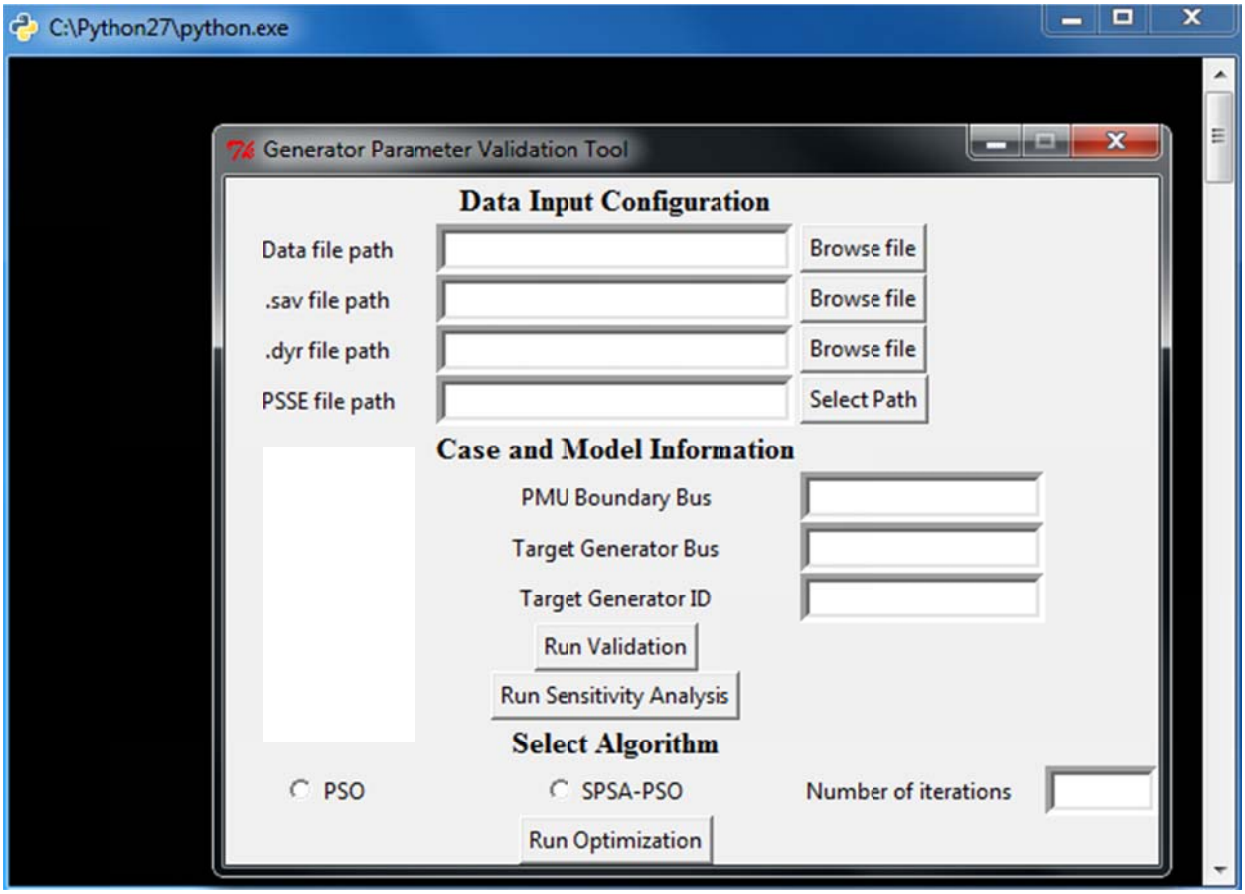


Figure 2. GPV tool user interface

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.

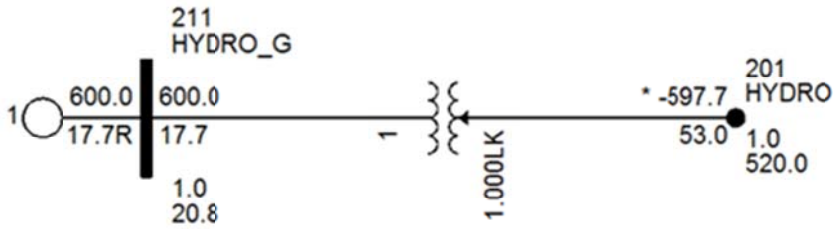


Figure 3. One-line diagram view of the target generator

The results from the validation process are shown in figures 4 and 5 below.

Active Power (P)

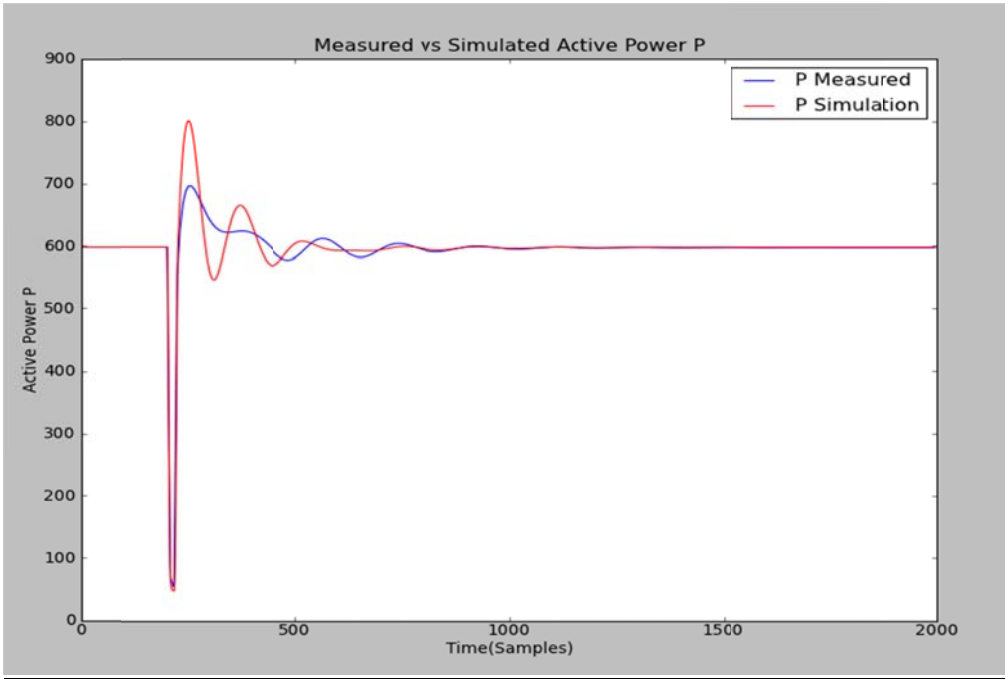


Figure 4. Validation Plots for active power (P)

Reactive Power (Q)

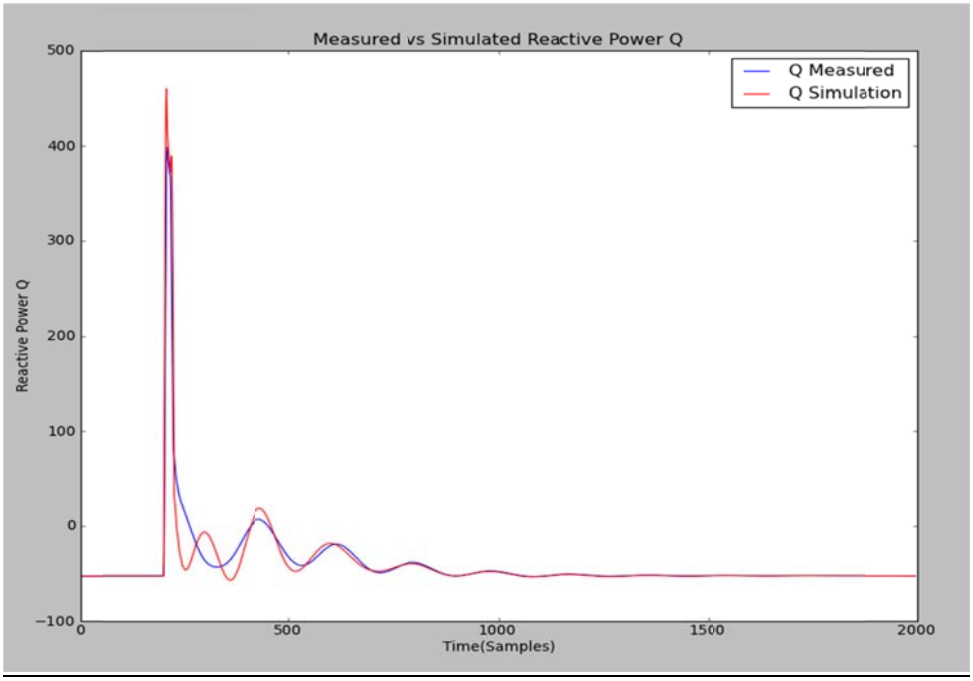
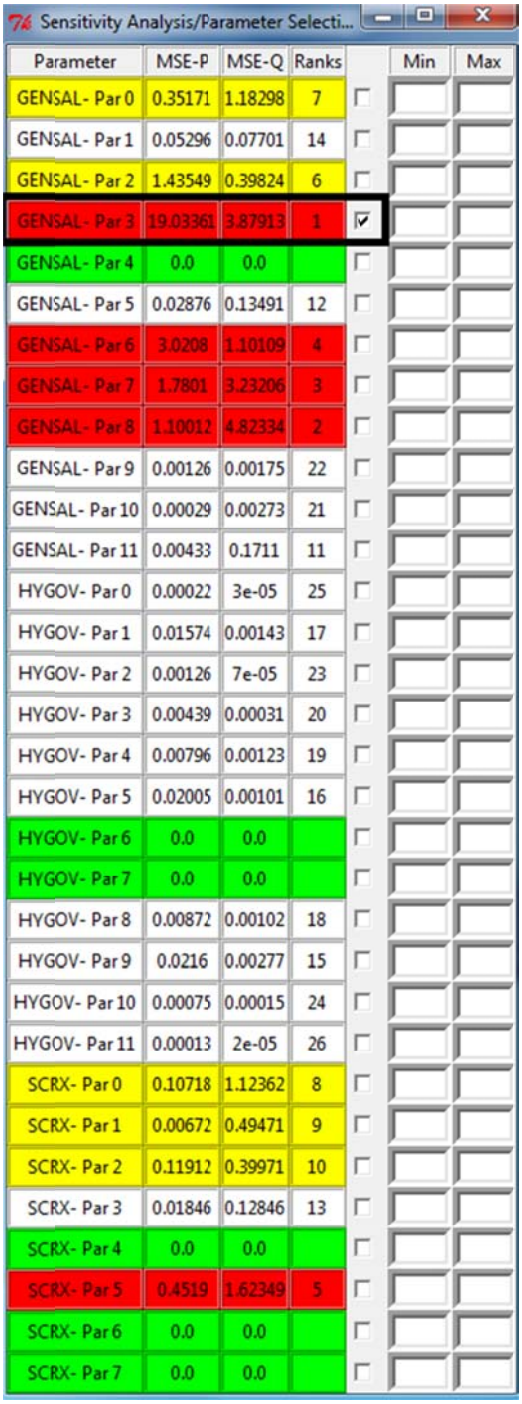


Figure 5. Validation plots for reactive power (Q)

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	☐		
GENSAL- Par 1	0.05296	0.07701	14	☐		
GENSAL- Par 2	1.43549	0.39824	6	☐		
GENSAL- Par 3	19.03361	3.87913	1	☑		
GENSAL- Par 4	0.0	0.0		☐		
GENSAL- Par 5	0.02876	0.13491	12	☐		
GENSAL- Par 6	3.0208	1.10109	4	☐		
GENSAL- Par 7	1.7801	3.23206	3	☐		
GENSAL- Par 8	1.10012	4.82334	2	☐		
GENSAL- Par 9	0.00126	0.00175	22	☐		
GENSAL- Par 10	0.00029	0.00273	21	☐		
GENSAL- Par 11	0.00433	0.1711	11	☐		
HYGOV- Par 0	0.00022	3e-05	25	☐		
HYGOV- Par 1	0.01574	0.00143	17	☐		
HYGOV- Par 2	0.00126	7e-05	23	☐		
HYGOV- Par 3	0.00439	0.00031	20	☐		
HYGOV- Par 4	0.00796	0.00123	19	☐		
HYGOV- Par 5	0.02005	0.00101	16	☐		
HYGOV- Par 6	0.0	0.0		☐		
HYGOV- Par 7	0.0	0.0		☐		
HYGOV- Par 8	0.00872	0.00102	18	☐		
HYGOV- Par 9	0.0216	0.00277	15	☐		
HYGOV- Par 10	0.00075	0.00015	24	☐		
HYGOV- Par 11	0.00013	2e-05	26	☐		
SCRX- Par 0	0.10718	1.12362	8	☐		
SCRX- Par 1	0.00672	0.49471	9	☐		
SCRX- Par 2	0.11912	0.39971	10	☐		
SCRX- Par 3	0.01846	0.12846	13	☐		
SCRX- Par 4	0.0	0.0		☐		
SCRX- Par 5	0.4519	1.62349	5	☐		
SCRX- Par 6	0.0	0.0		☐		
SCRX- Par 7	0.0	0.0		☐		

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)

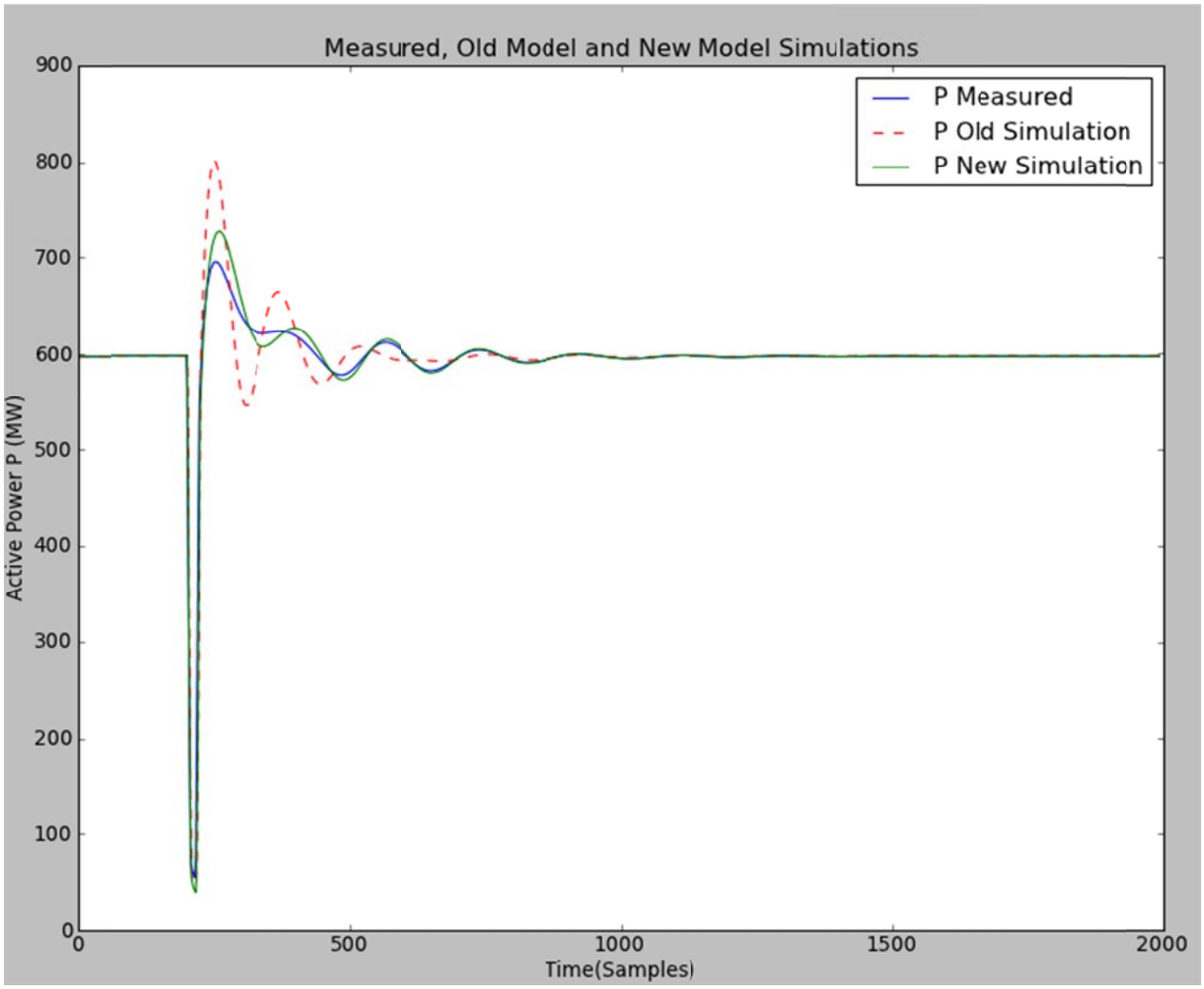


Figure 7. Active power plots after the optimization process

Reactive Power (Q)

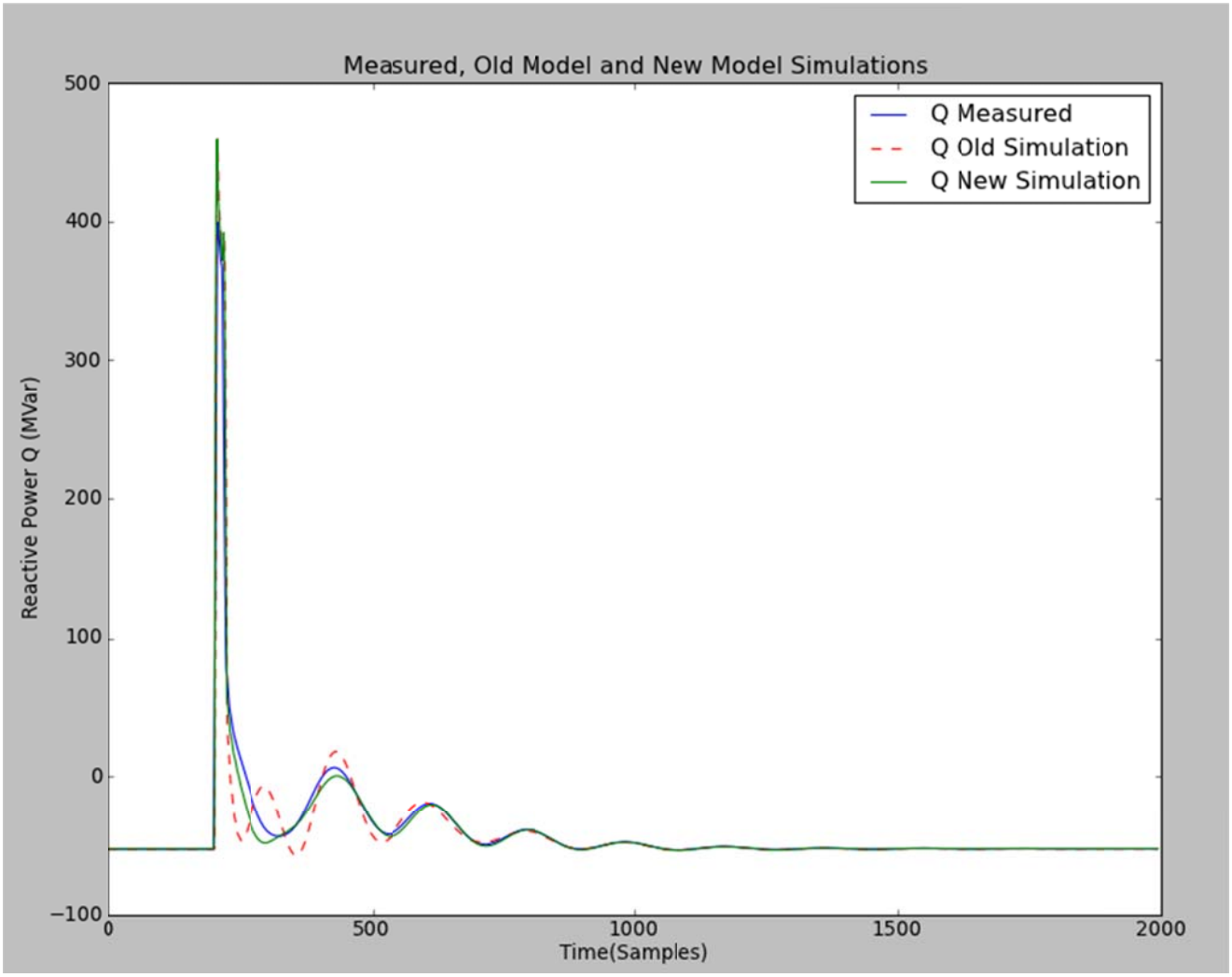


Figure 8. Reactive power plots after the optimization process

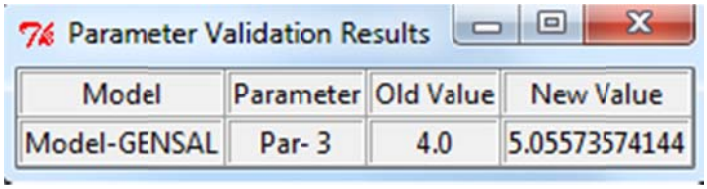


Figure 9. Parameter validation results – new identified parameter values

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.

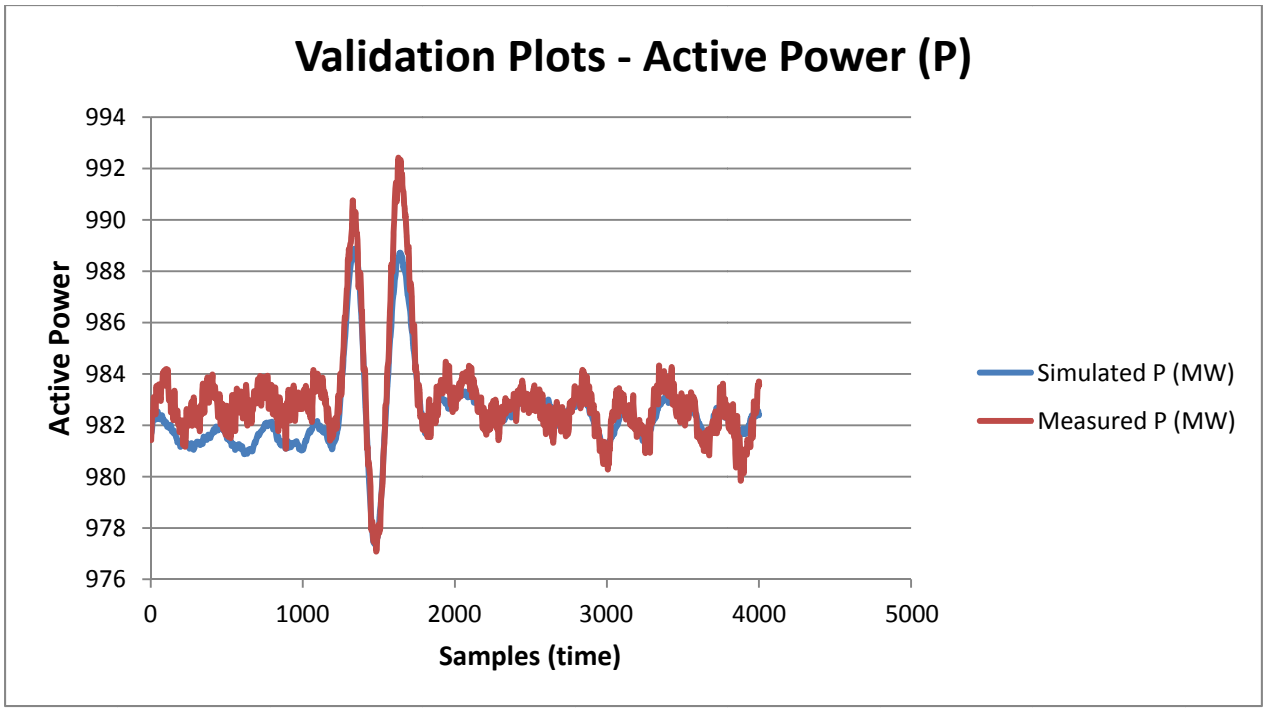


Figure 10. Validation plots for active power (P)

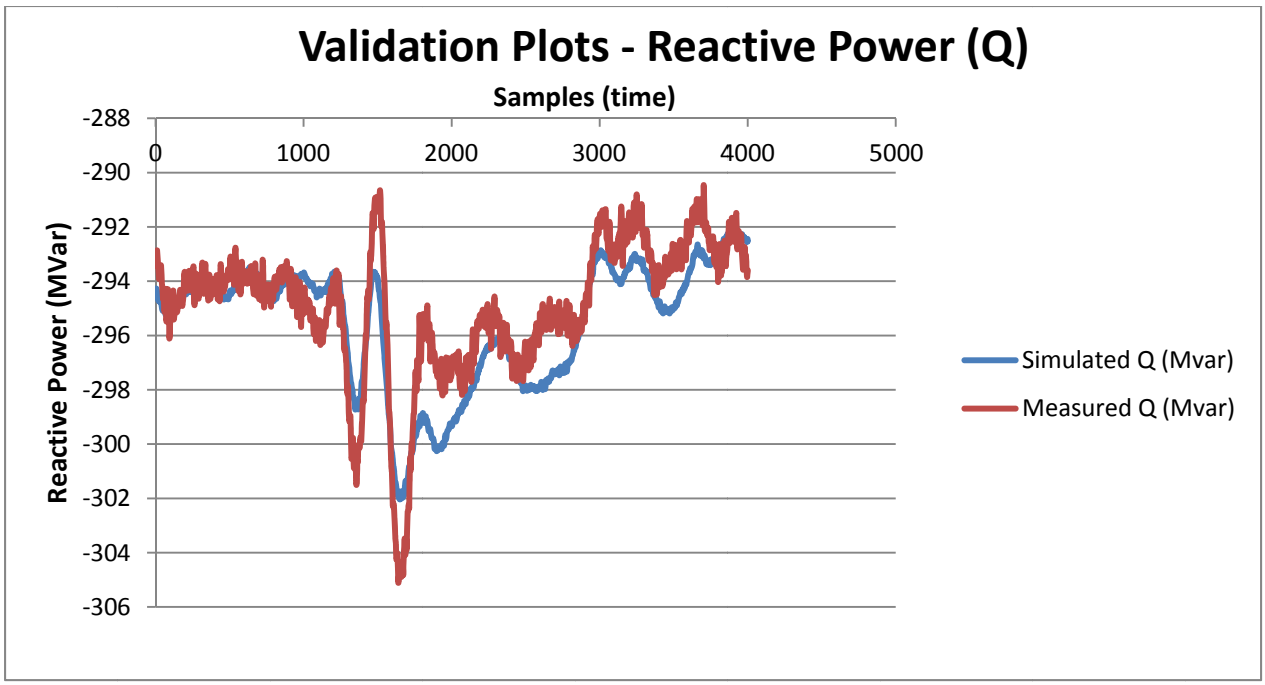


Figure 11. Validation plots for reactive power (Q)

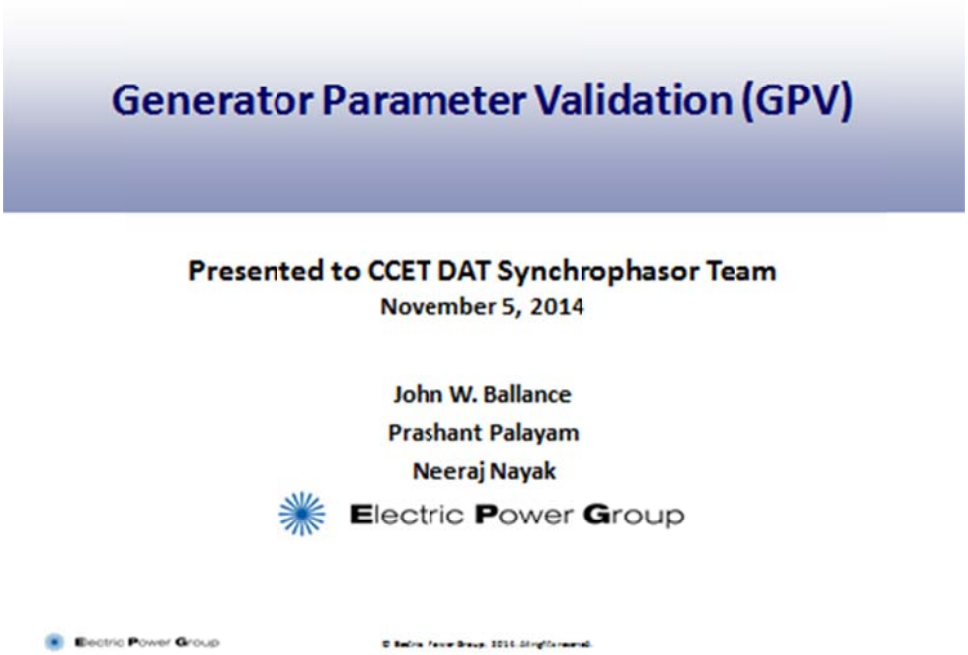
We can see from the plots above that the model simulation results reasonably match that of the measured data. It is important to remember that models are an approximation of the real system and some error due to the use of a reduced system is inevitable.

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 Power Group

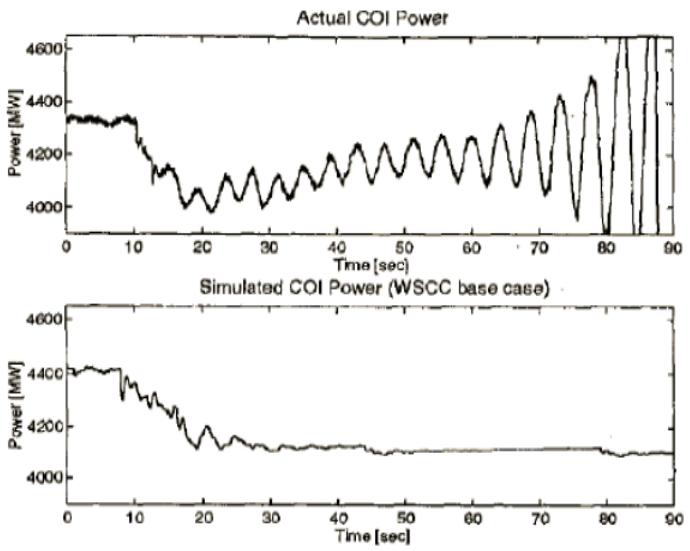
November 5, 2014

Presented to CCET DAT Synchrophasor Team

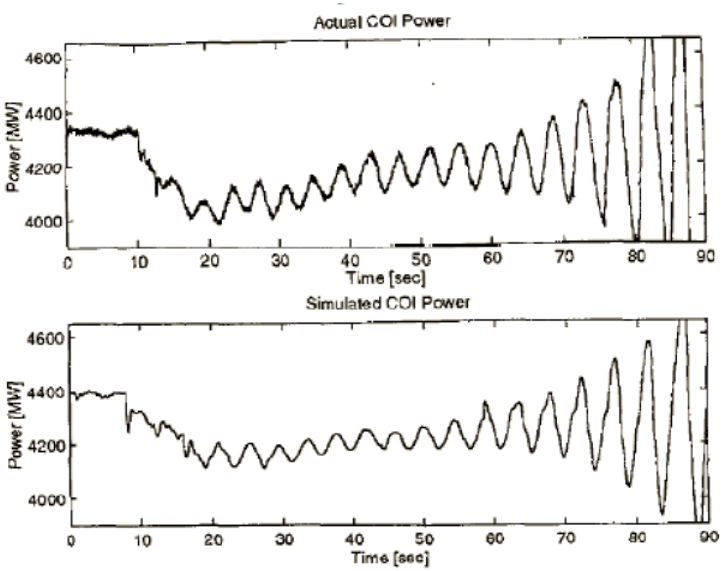
Outline

- Background and purpose
- Introduction
- Generator parameter validation process
- Example
- Testing on real data
- Best practices
- Limitations and areas of smprovement
- 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

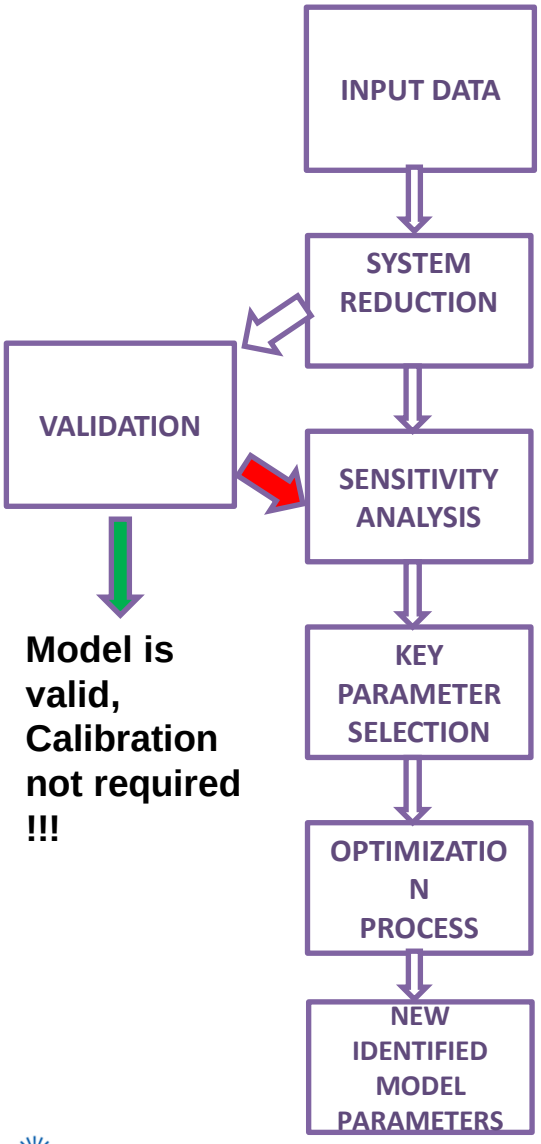
- Dr. Wei-Jen Lee (UT Arlington) et. al proposed and developed a PMU-based parameter identification method
- The purpose of the GPV tool is to validate generator models and calibrate the models to identify correct parameter values
- An initial first phase development of GPV method as a tool that was 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 PSSE 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

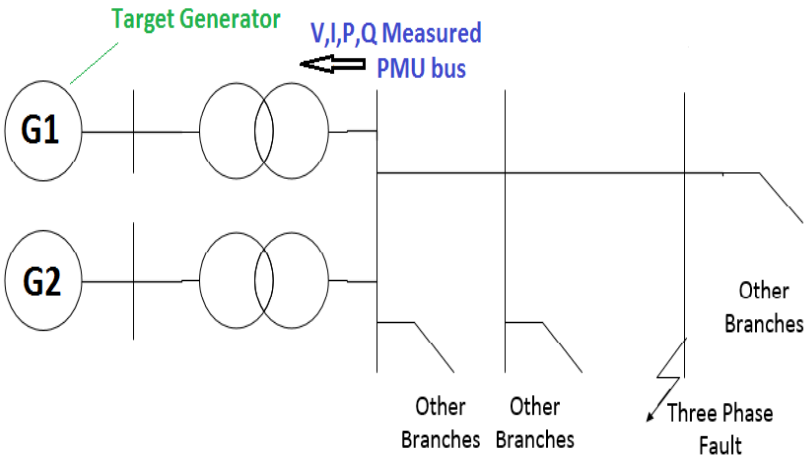
4. Trajectory Sensitivity Analysis – Compute sensitivities of P and Q flows to parameter change
   - Tabulate results
   - Plot results

5. Key Parameter Selection
   - User interaction to select key parameters from the sensitivity analysis for the optimization Pprocess

6. Optimization Process – Run the optimization process with the selected key parameters to identify the new model parameters
   - Tabulate results
   - Plot results

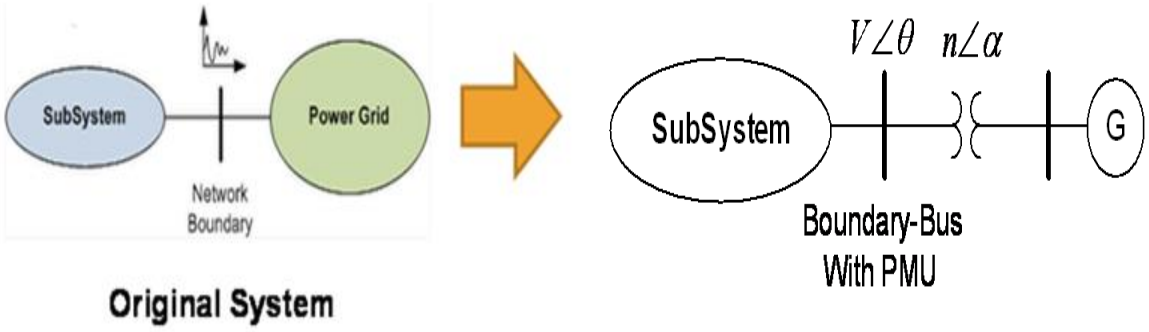
Input Data

- 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

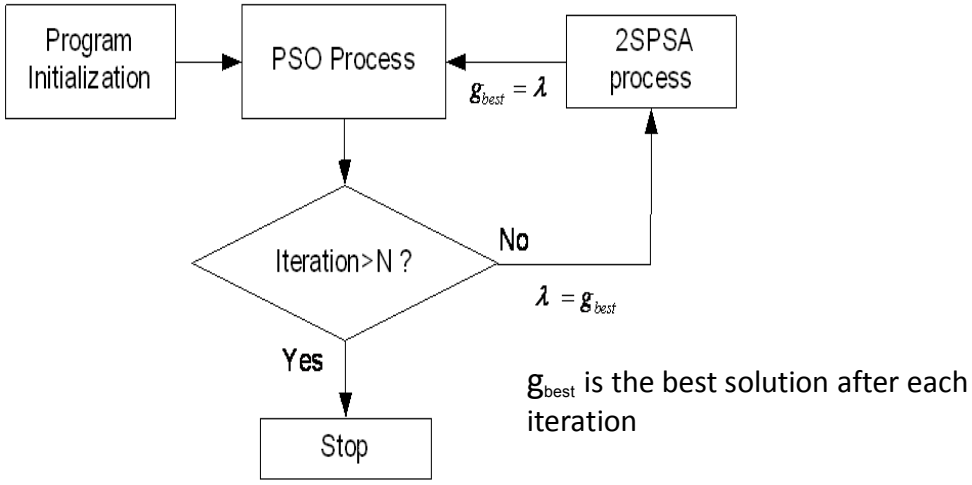
- The objective of sensitivity analysis is to identify the key parameters to be chosen for the validation process
- There are several parameters in generator unit's models, each parameter has a different influence on system response.
- The trajectory sensitivity analysis is carried out to understand 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

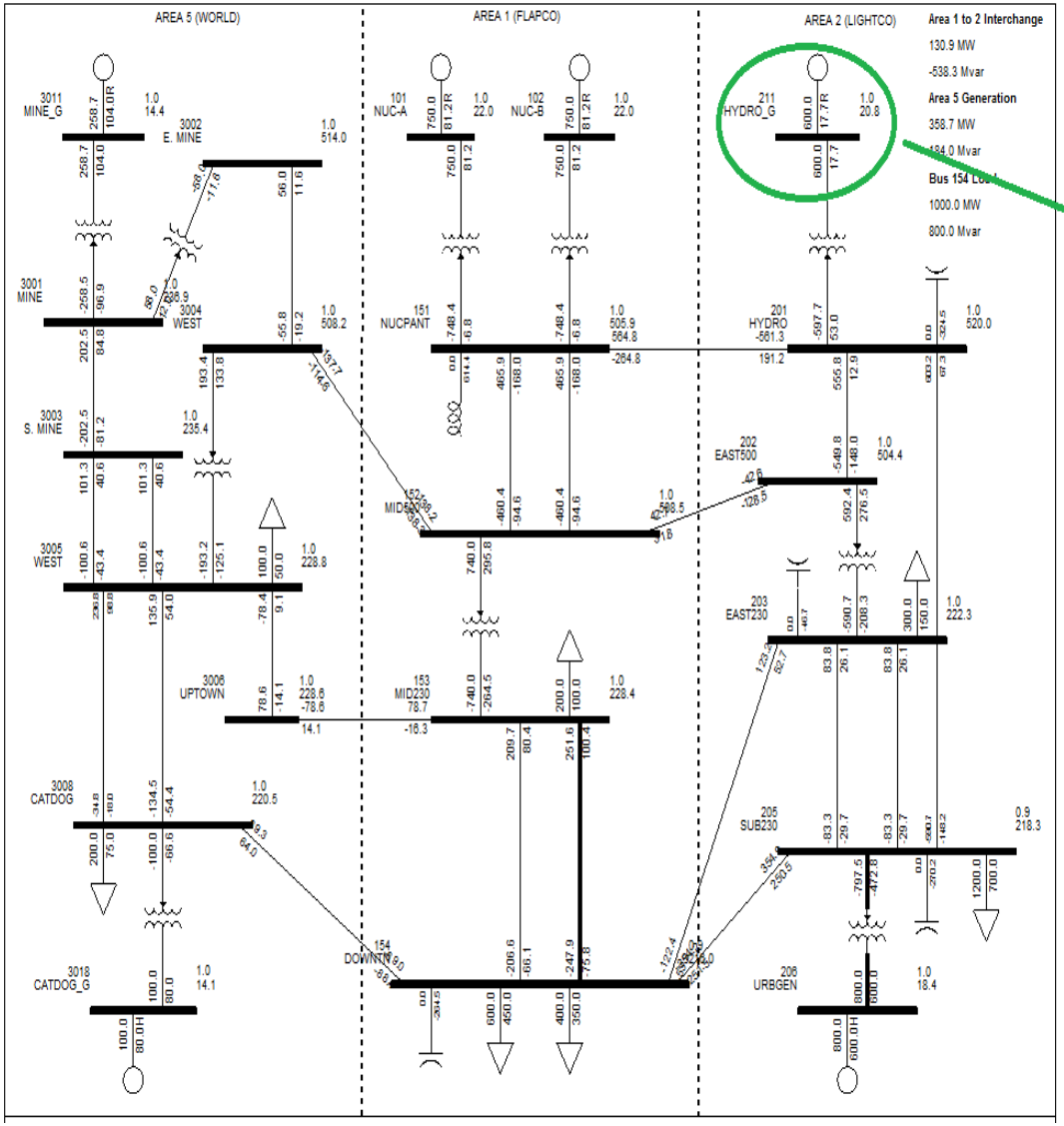
- Optimization objective is to fit the simulation curves with the measured curves by adjusting the model parameters and identify the new model parameter values
- Two algorithms are used for the optimization process:
  - Particle Swarm Optimization (PSO)
  - Simultaneous Perturbation Stochastic Approximation (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.



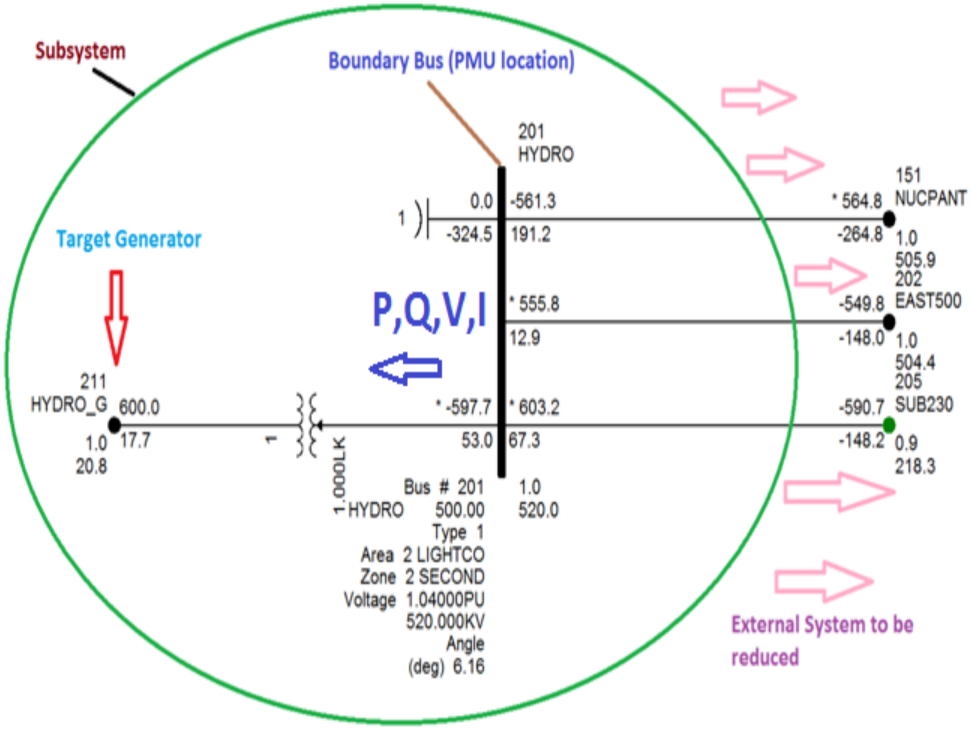
g_{best} is the best solution after each iteration

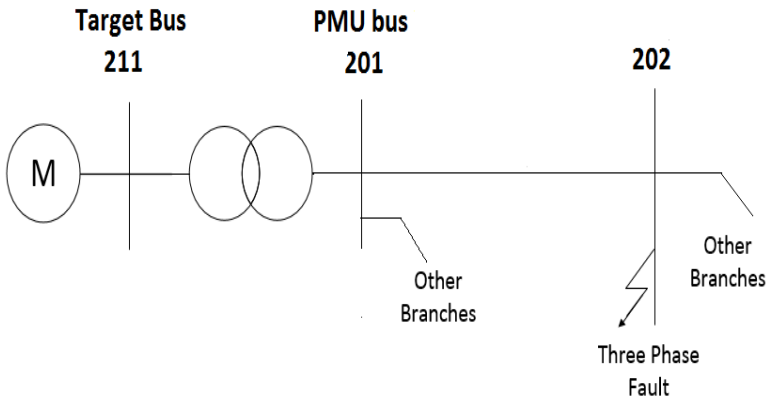
EXAMPLE

PSSE Example Case savnw.sav



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

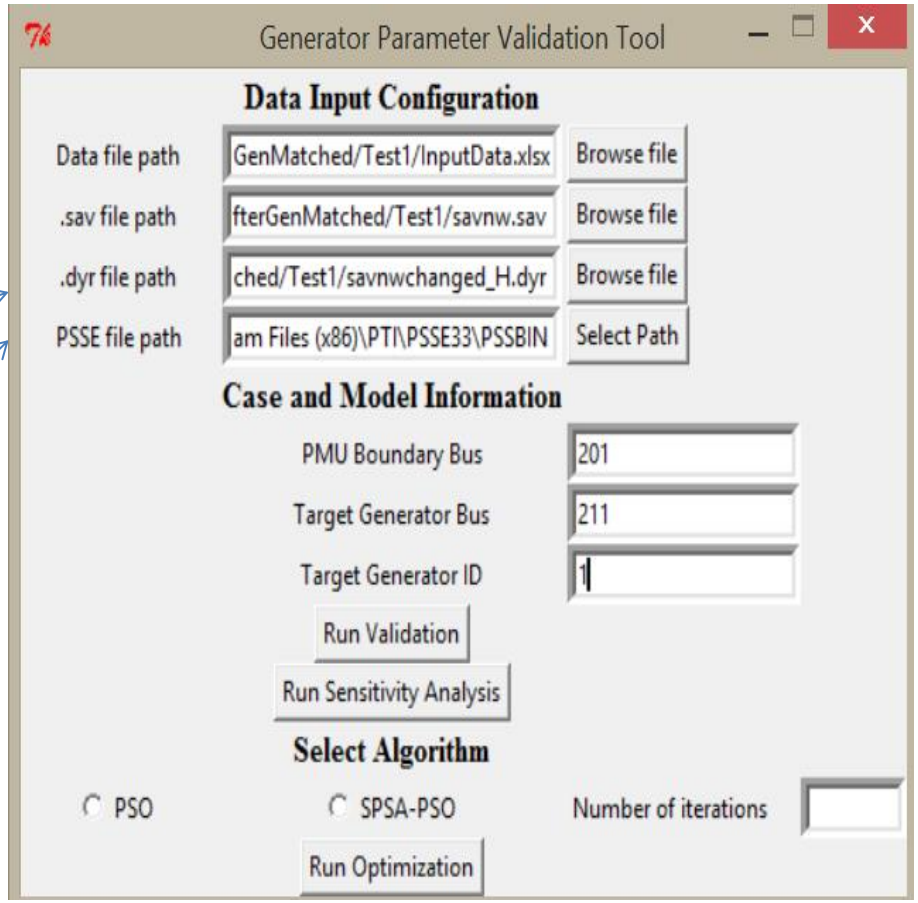
Run GPV Tool

Input data file (.xlsx)

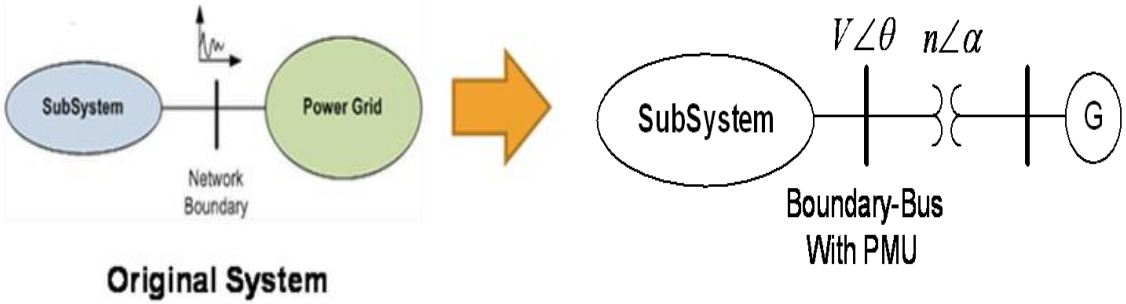
PSSE case file (.sav)

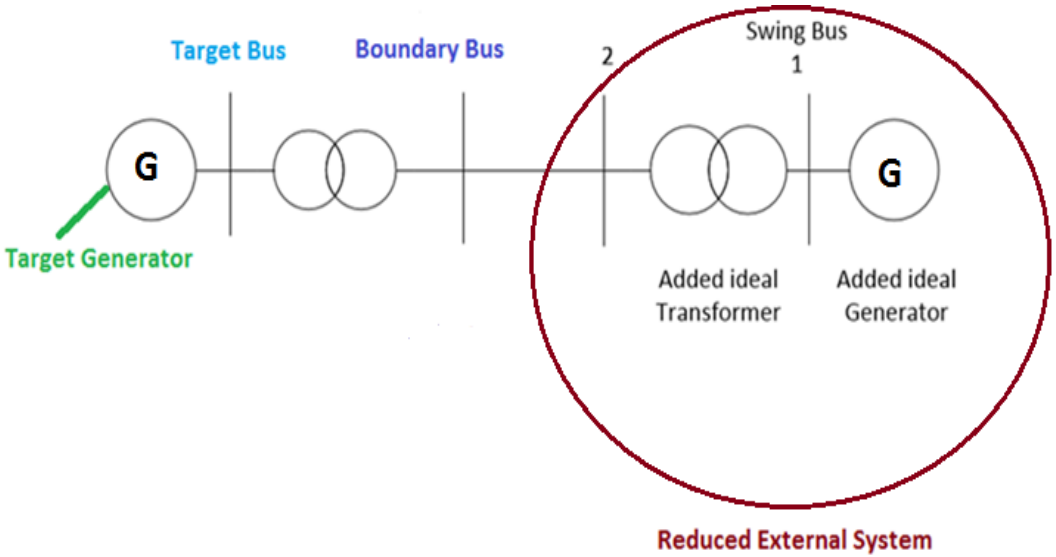
PSSE dynamics file(.dyr)

Path to PSSE PSSBIN folder containing python modules

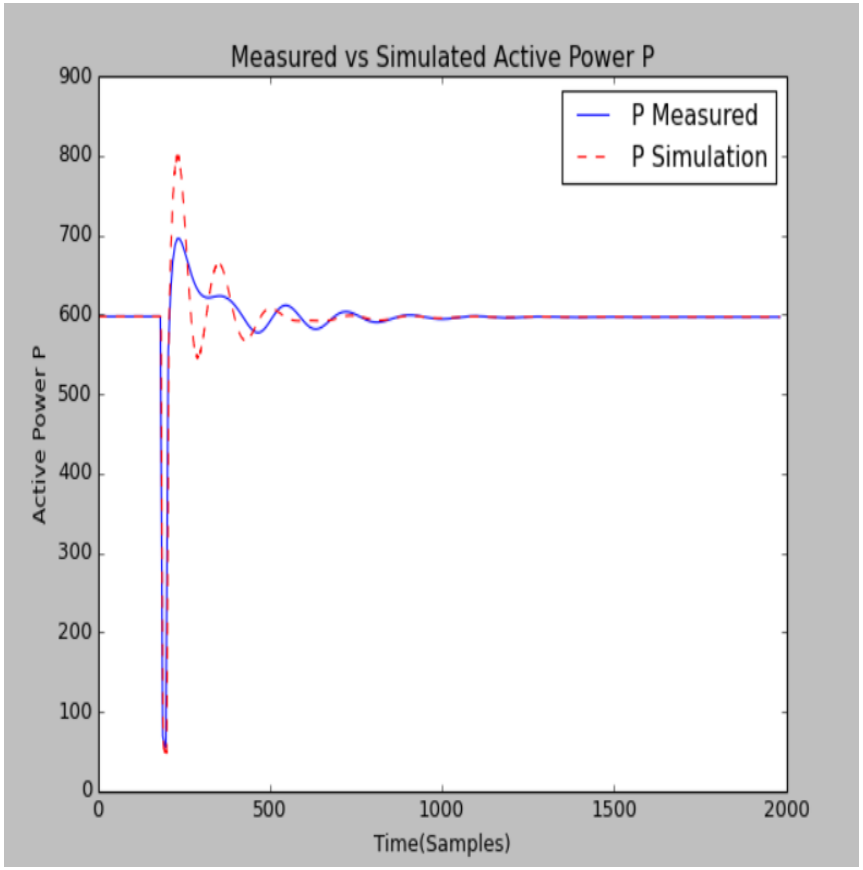


Automated System Reduction

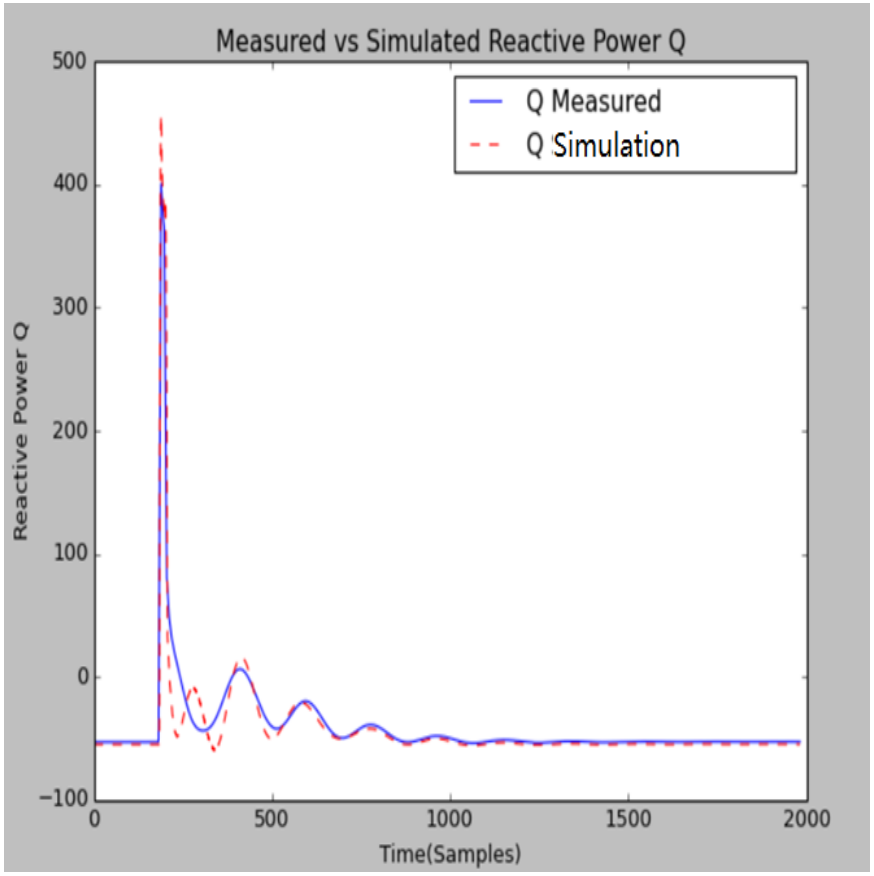




Validation Plots



Active Power (P)

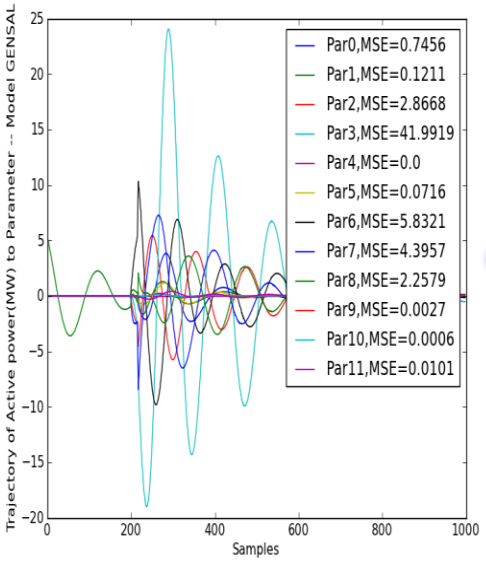


Reactive Power (Q)

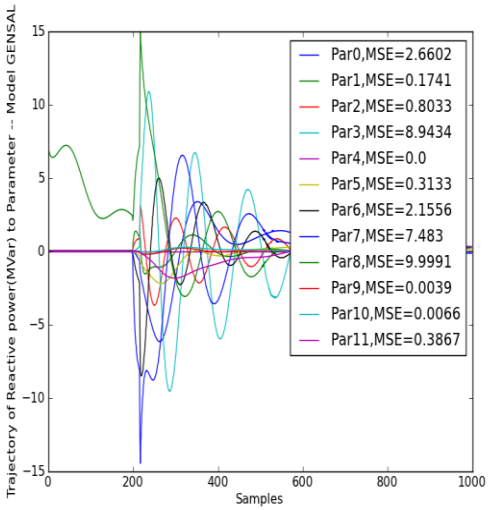
Sensitivity Analysis- Identify Key Parameters

Sensitivity Analysis/Parameter Selecti...

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	19.1313	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

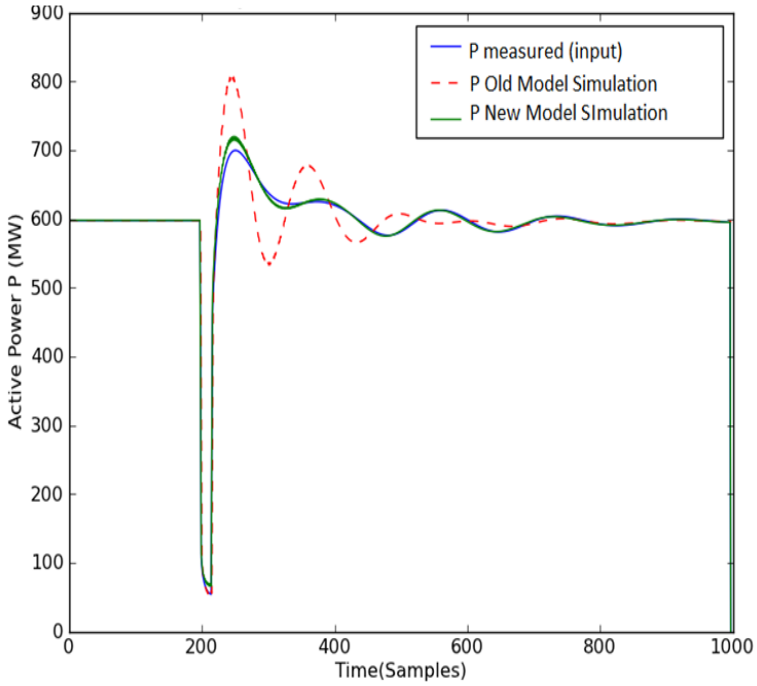
Note:
Pnew = Active Power flow for original model parameter value
Qnew = Reactive Power flow for original model parameter value
Pold/Qold = Active Power/Reactive Power flow for a 5% increase in the corresponding parameter value
*Key Parameter column based on a sensitivity threshold of 0.01

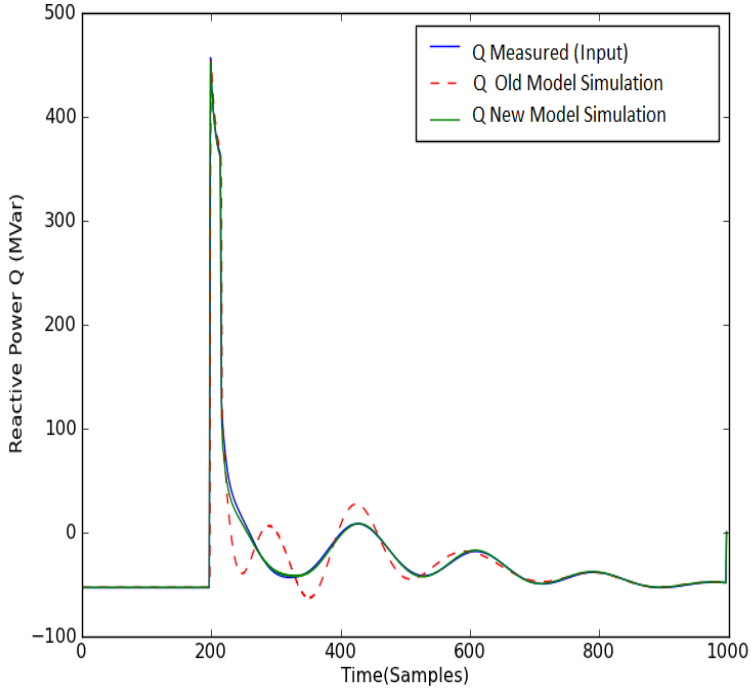
Optimization Results - Identified Parameter Values

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''qo (sec)
GENSAL Parameter 3	H, Inertia

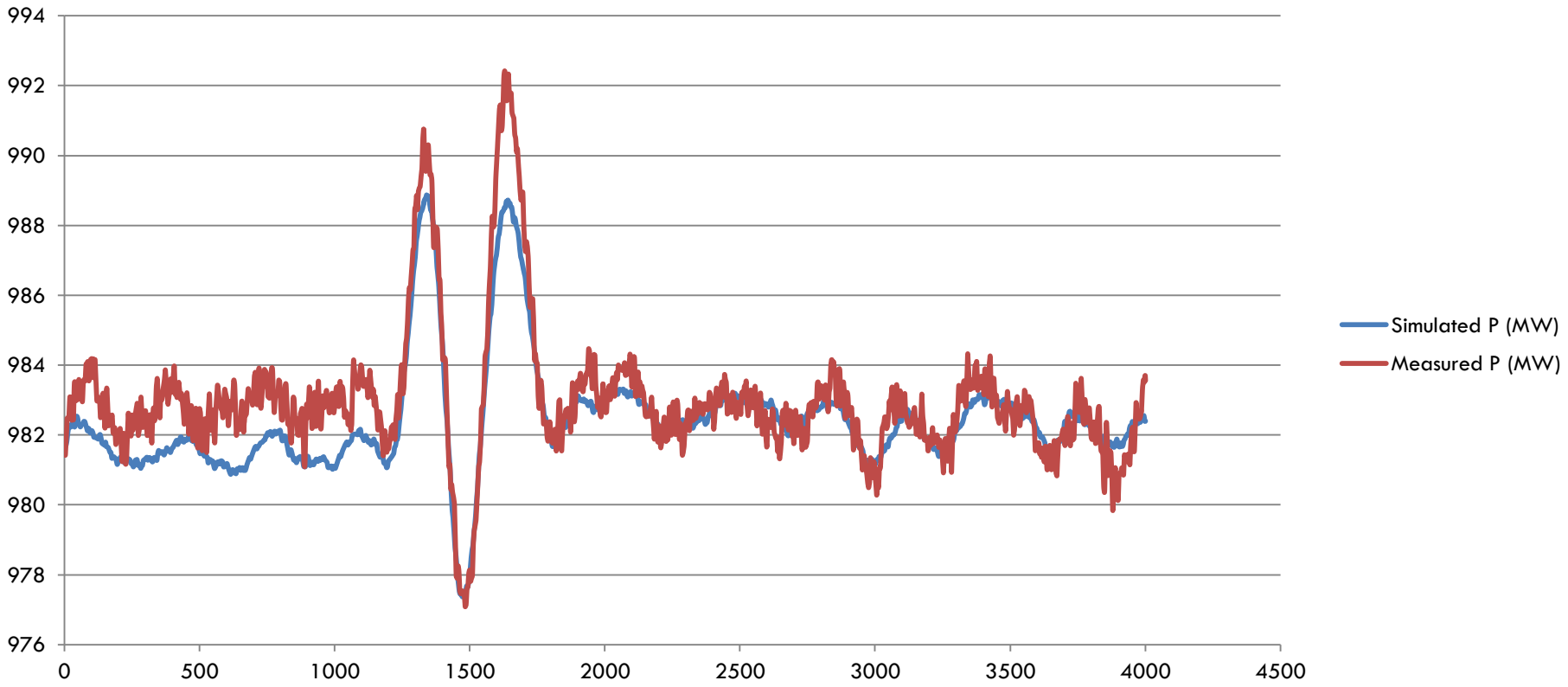




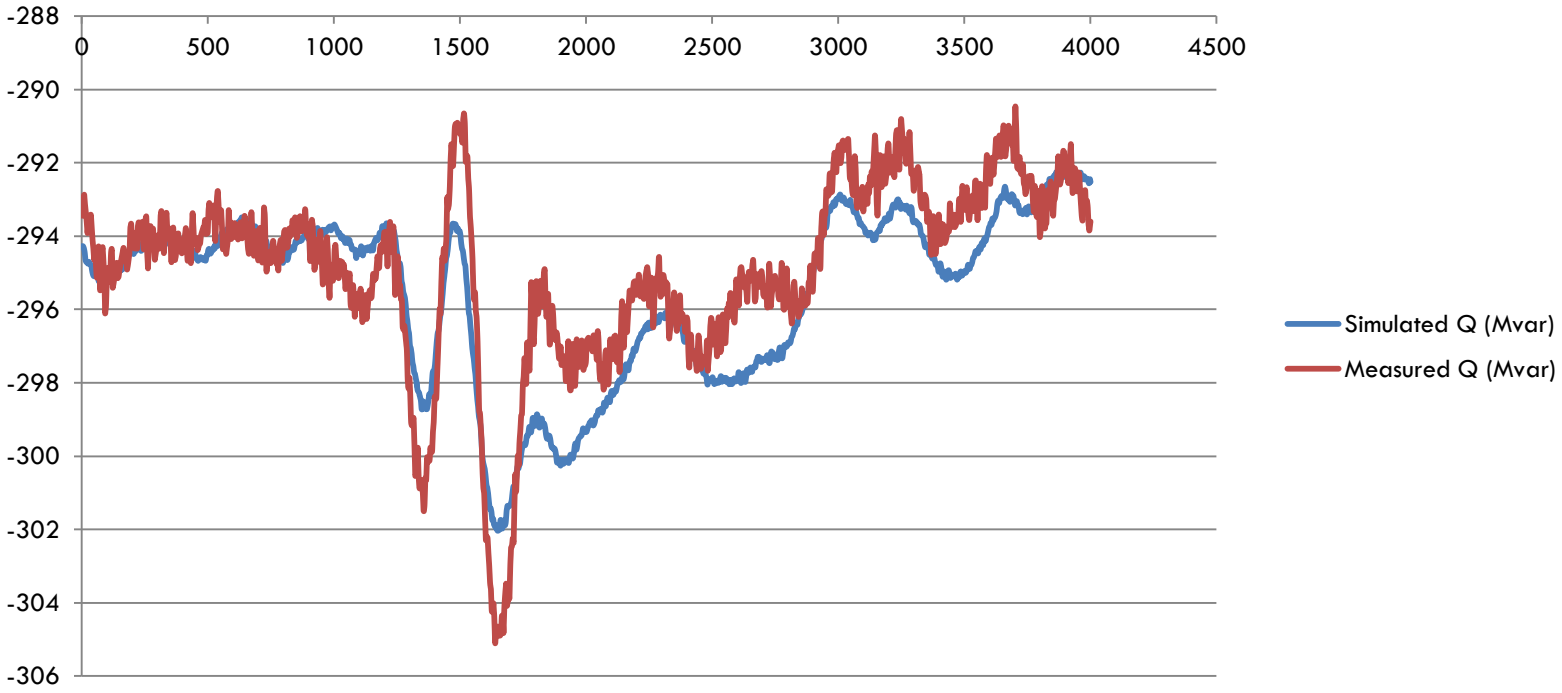
Testing on Real Data

- 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 snalysis 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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Electric Power Group

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

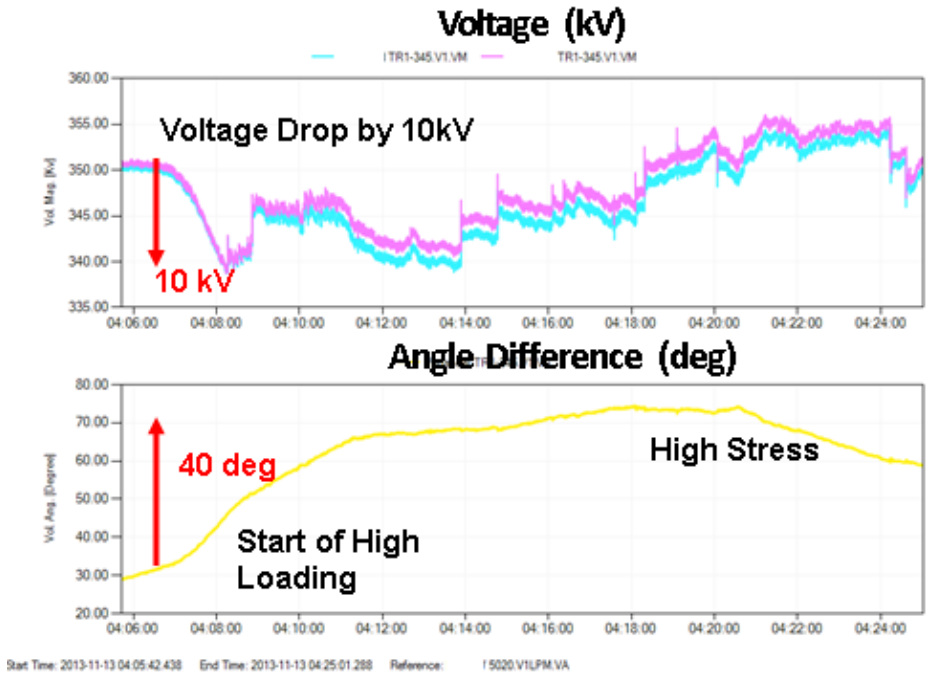
Use Case Overview

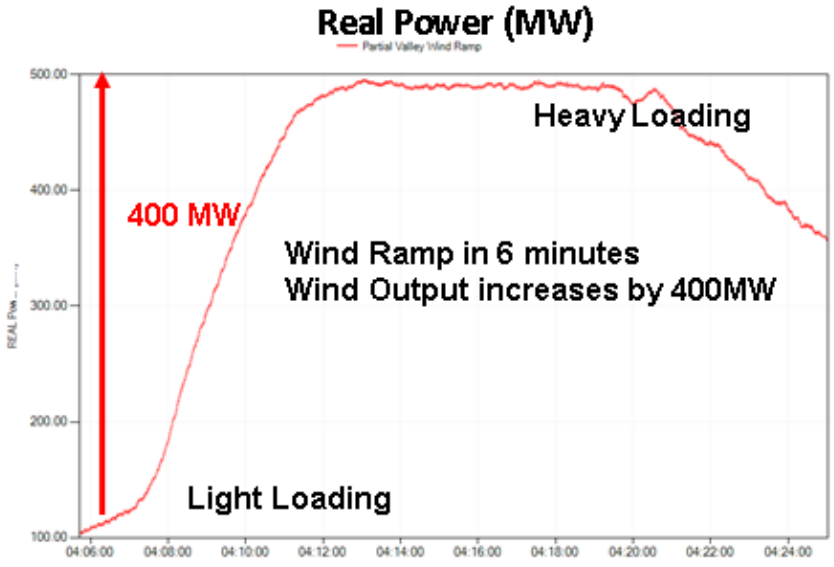
Use Case	Grid Scope	Streaming 30 samples/sec	Slow Speed 3 samples/min	Local Event Capture	Example of Application on ERCOT Grid
High Stress Across System (High Phase Angle) Observed	Wide Area	Yes	Yes		High Phase Angle from Valley - November 13, 2013
Small Signal Stability – Damping is Low	Wide Area	Yes			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



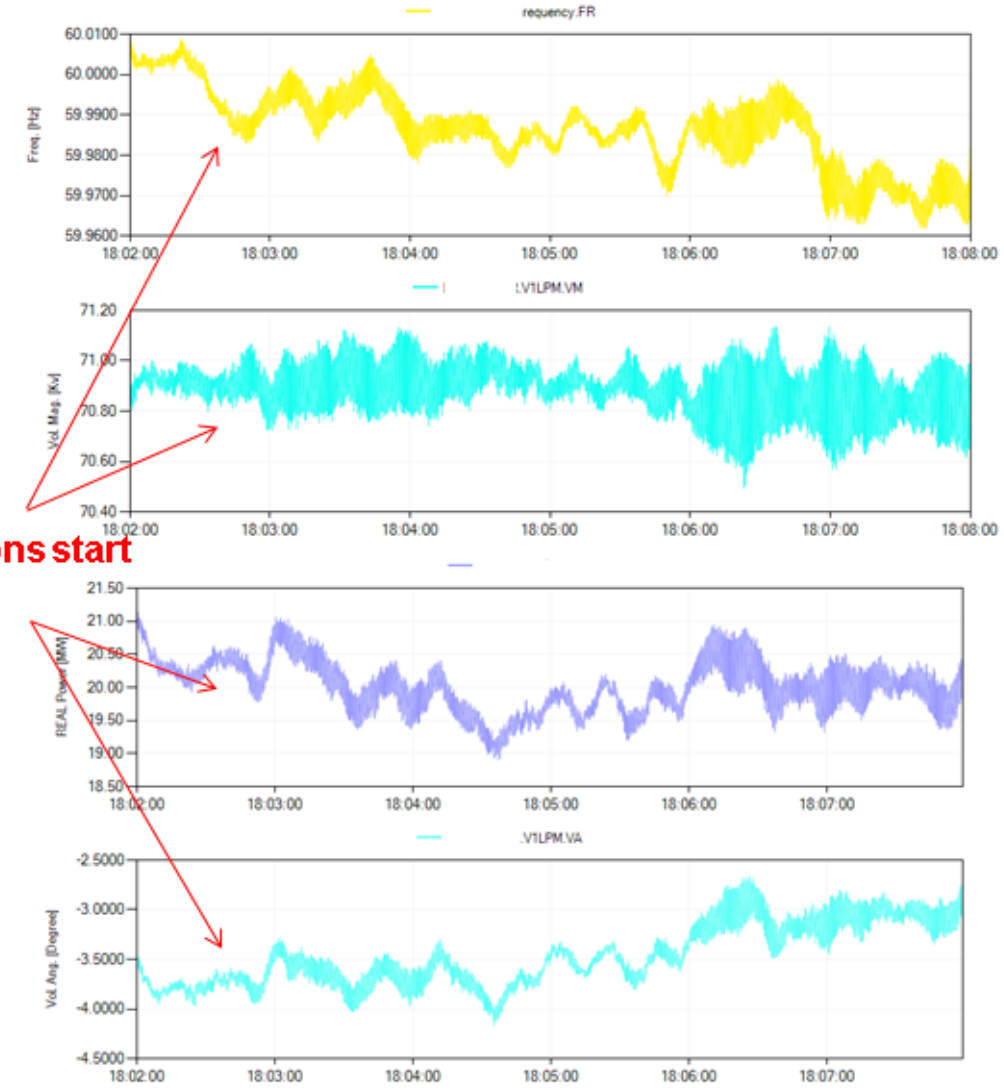


Reference Angle: North 7

Use Case - Small Signal Stability – Low Damping

- **Need:** PMU data can advise the Shift Engineer about both known and 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 and restore output

PMU Data Illustrates Oscillation With Low Damping



Oscillations start sharply

Frequency (Hz)

Voltage (kV)

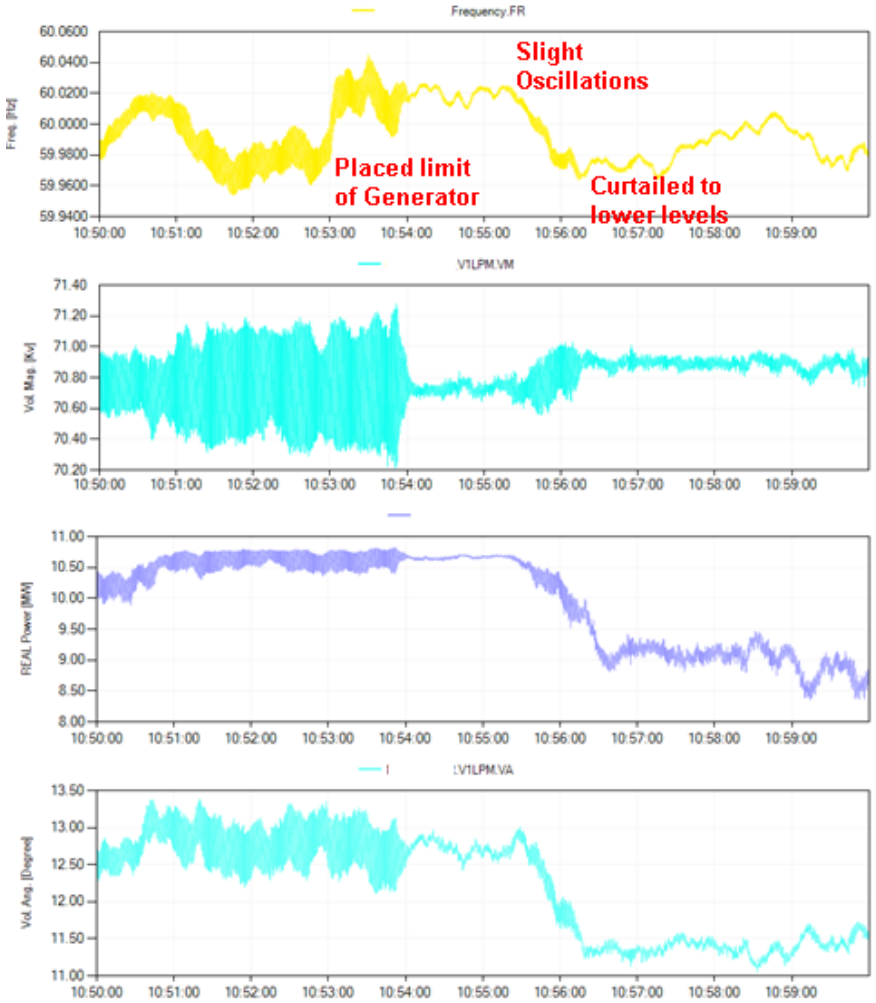
Real Power MW)

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)

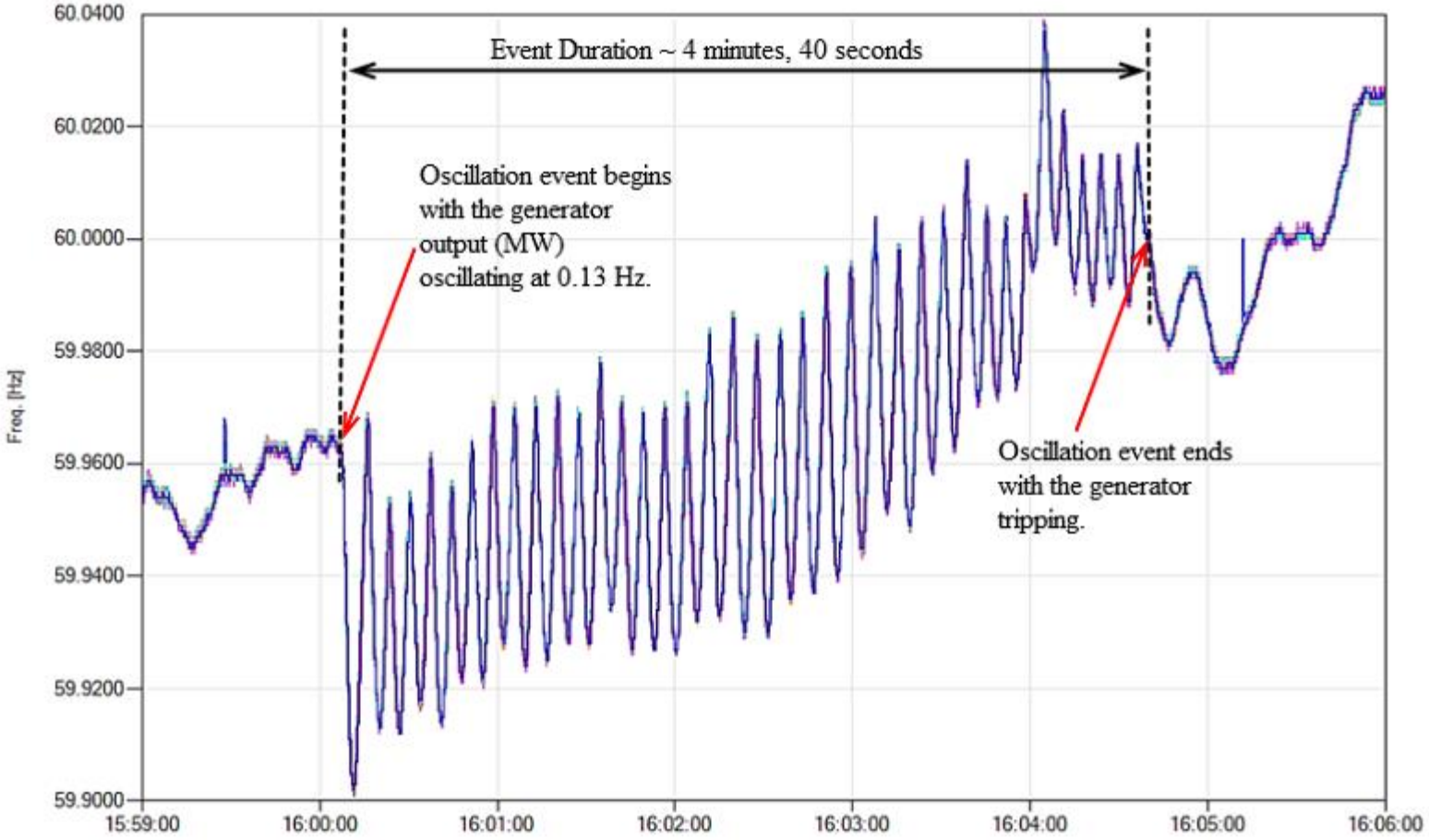
Reference Angle: North 7

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 and 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)

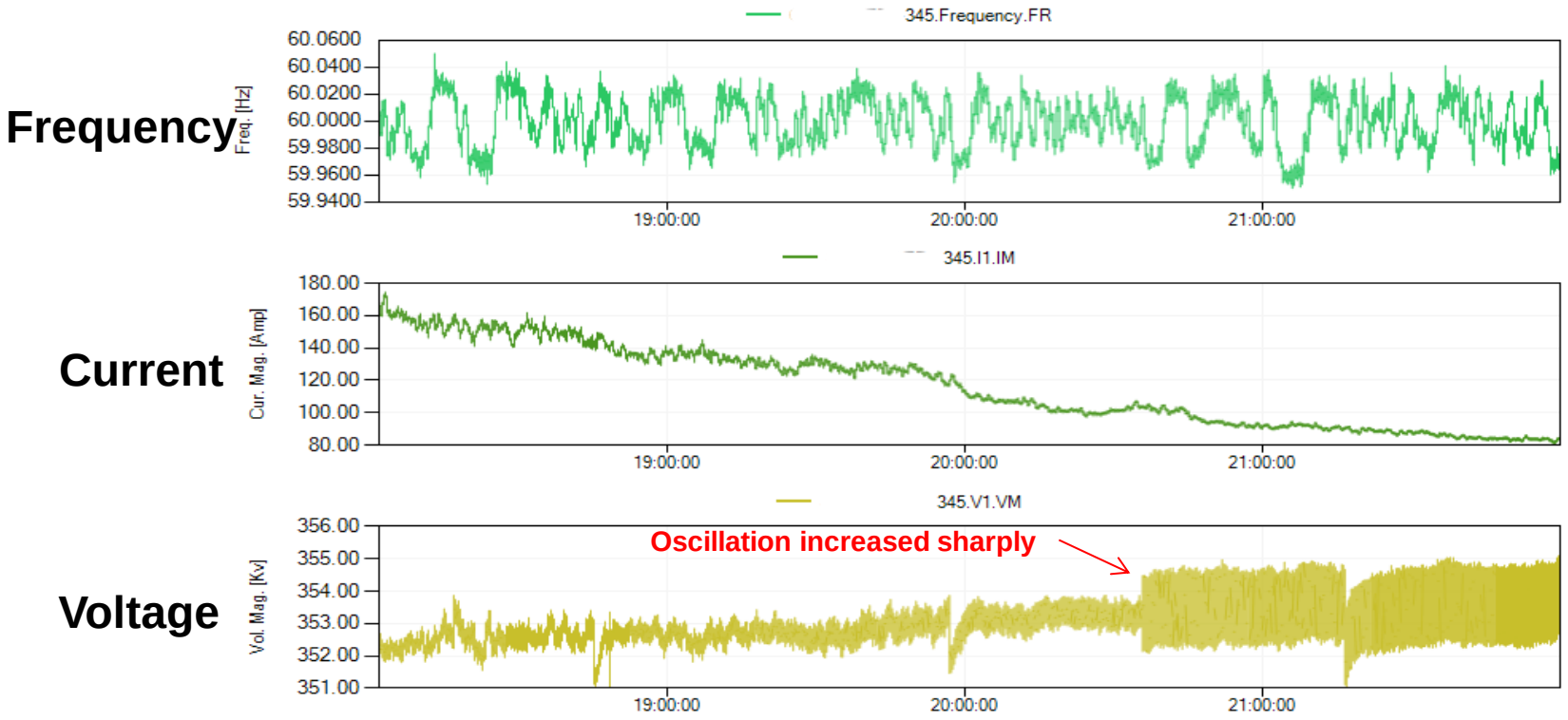
PMU Data Illustrates Emerging Oscillation



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

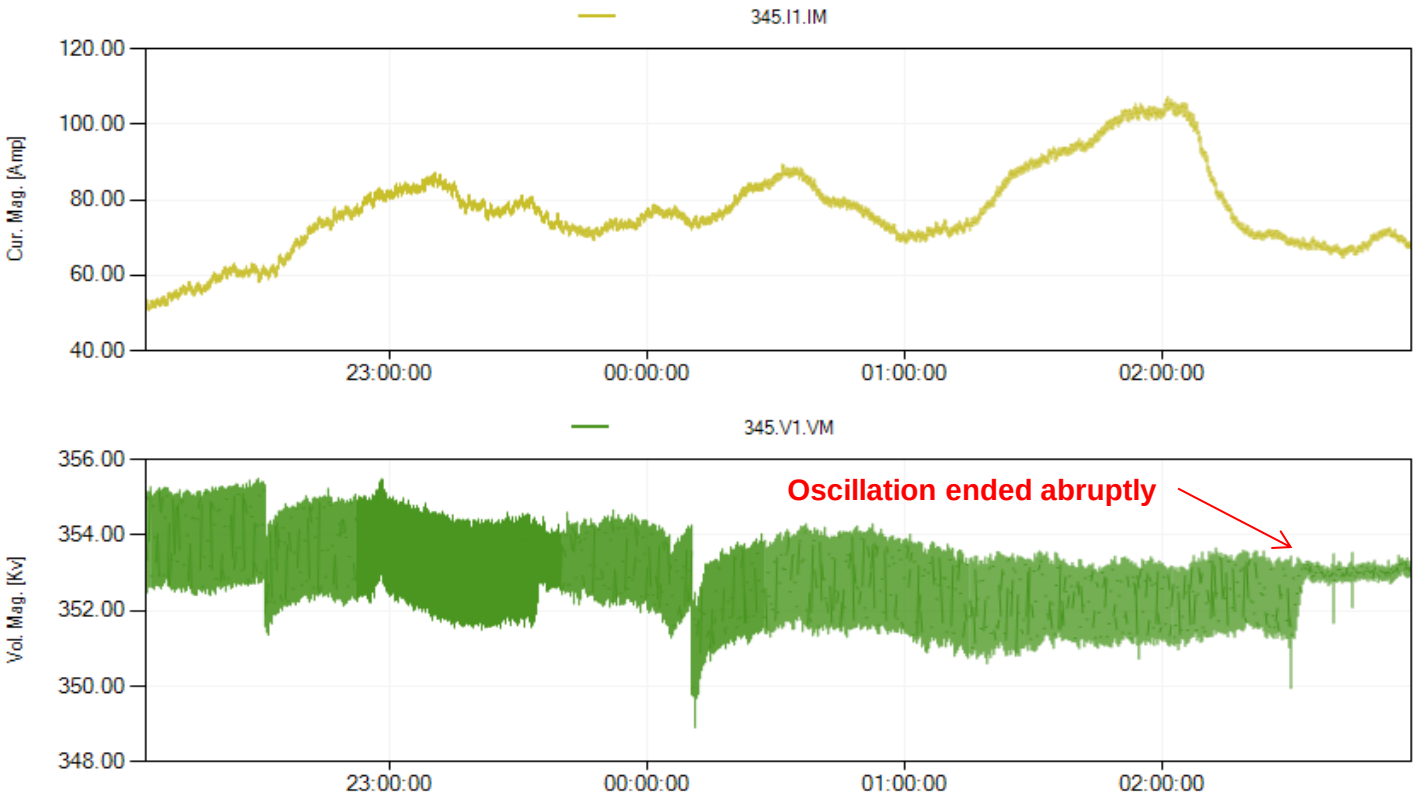


Screenshot of PGDA (Phasor Grid Dynamics Analyzer)

Nearby PMU Detects Voltage Oscillation

Current

Voltage



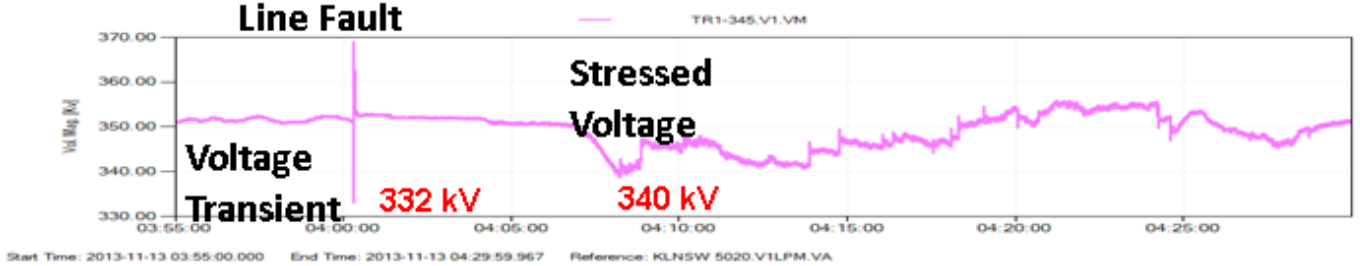
Screenshot of PGDA (Phasor Grid Dynamics Analyzer)

Use Case - Voltage Instability Monitoring (P-V, Q-V)

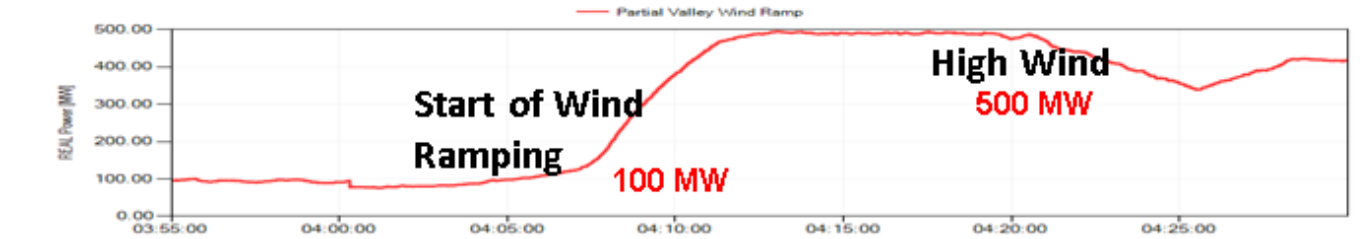
- **Need:** PMU data (real, reactive power and voltage) can advise the Shift Engineer indirectly on high grid stress under low voltage deteriorating conditions
- **EXAMPLE: HIGH PHASE ANGLE AT COAST 3 (VALLEY) – NOV 13, 2013**
- **Possible Action:**
- Shift Engineer reviews P-V performance, compares 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

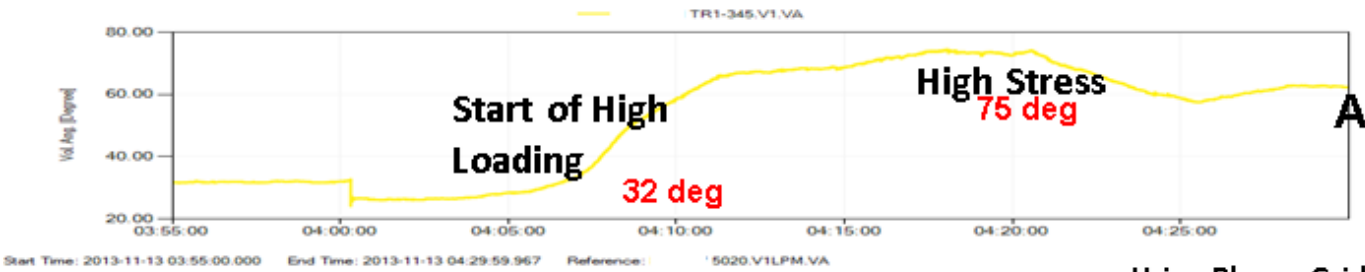
Frequency (Hz)



Voltage (kV)



Real Power MW)



Angle Difference (deg)

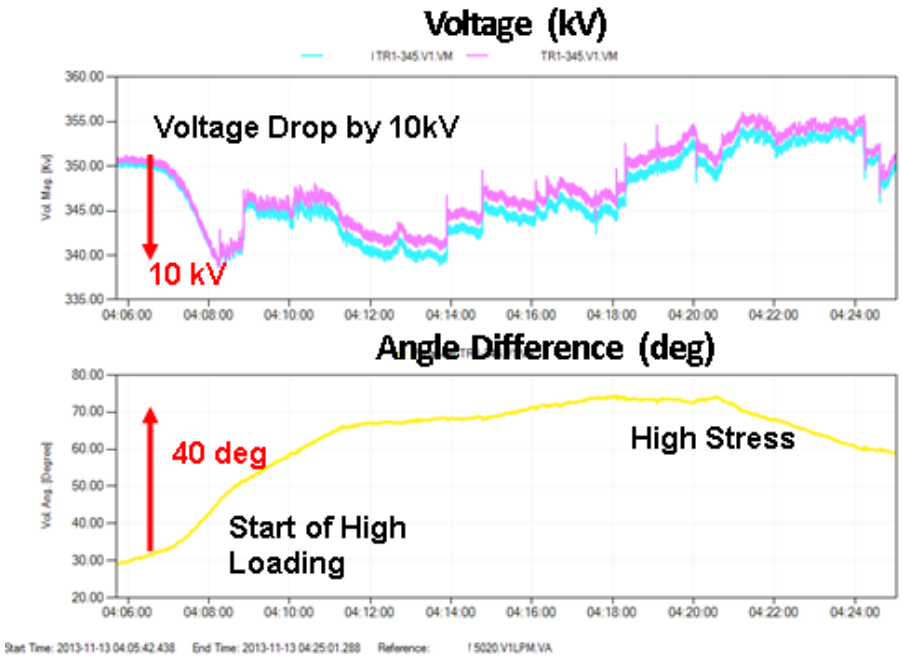
Start Time: 2013-11-13 03:55:00.000 End Time: 2013-11-13 04:29:59.967 Reference: KLNSW 5020.V1LPM.VA

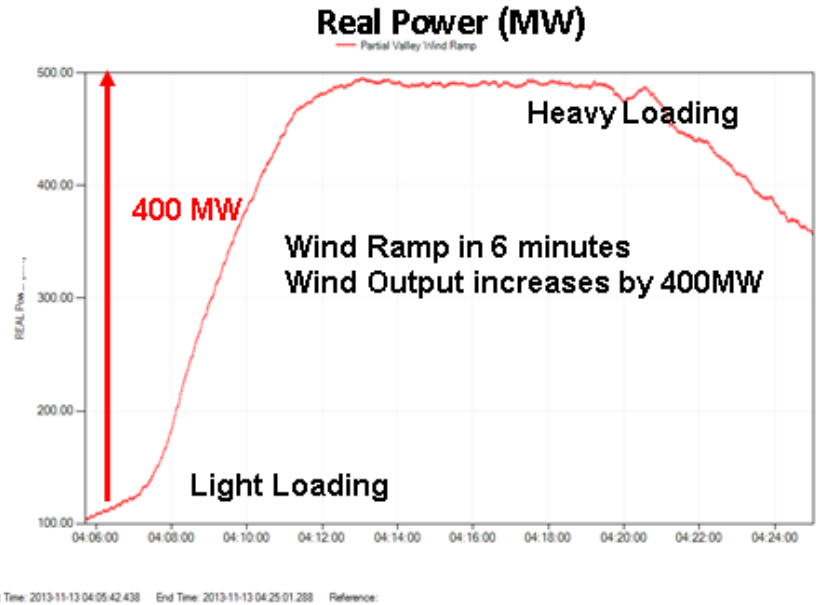
Start Time: 2013-11-13 03:55:00.000 End Time: 2013-11-13 04:29:59.967 Reference: 5020.V1LPM.VA

Reference Angle: North 7

Using Phasor Grid Dynamic Analyzer (PGDA) plots

PMU Data Illustrates Voltage Stress During Power Ramp





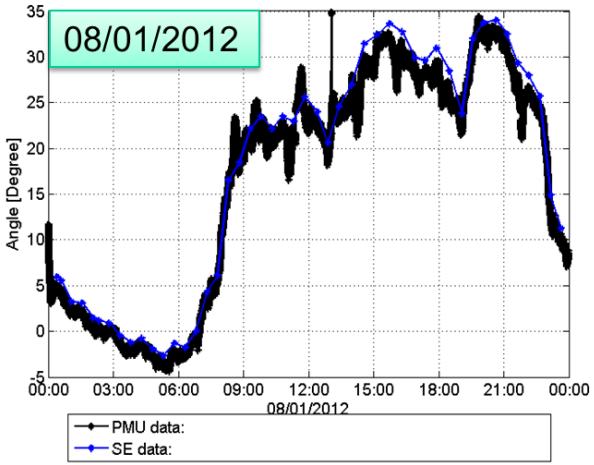
Reference Angle: North 7

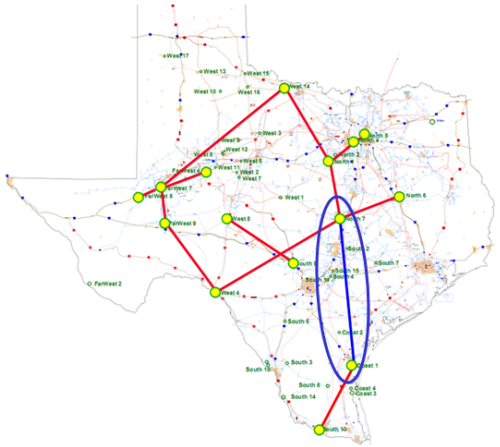
Use Case - Validate State Estimator Results Used in Control Rooms

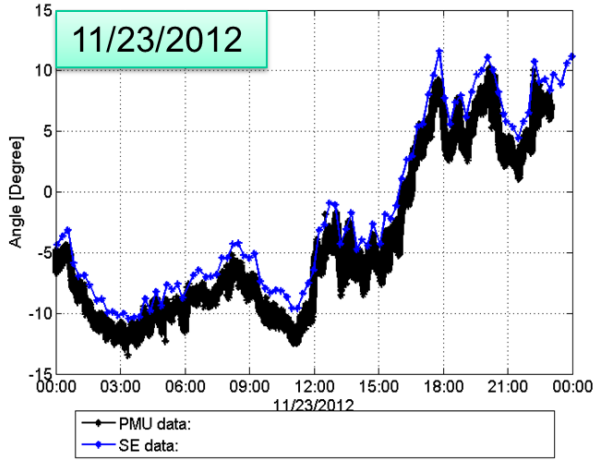
- **Need:** PMU phase angles can be used to validate the state estimator results used in control rooms (locate differences which reflect anomalies in models used for state estimation)
- **EXAMPLE: BASELINING STUDIES**
- Possible Action:
  - Identify the root cause for the mismatch and update models

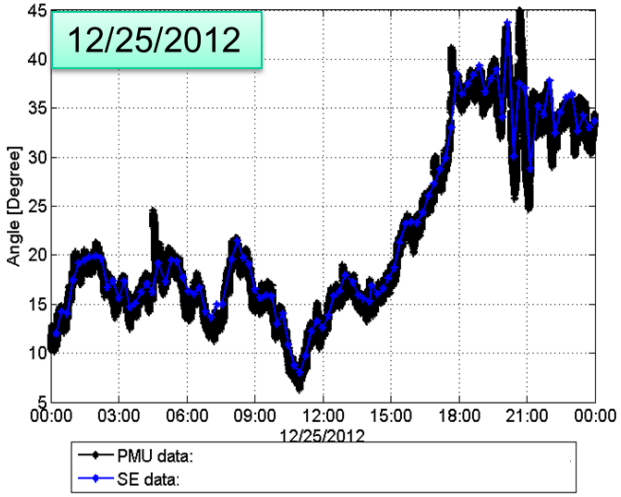
PMU Data vs SE Data Comparison

Coast 1-North 7









Use Case - System Disturbance – Cause & Interpretation

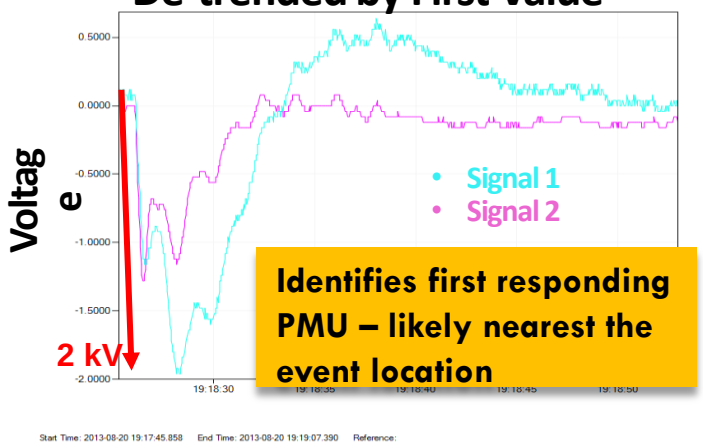
- **Need:** PMU data is useful for event analysis and determine root cause of the event and its location.
- **EXAMPLE: EVENT SIGNATURES OF GENERATION TRIP, LINE TRIP & OSCILLATIONS**
- **Possible Action:**
  - Shift Engineer reviews network performance, including frequency dip and recovery, voltage dip 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

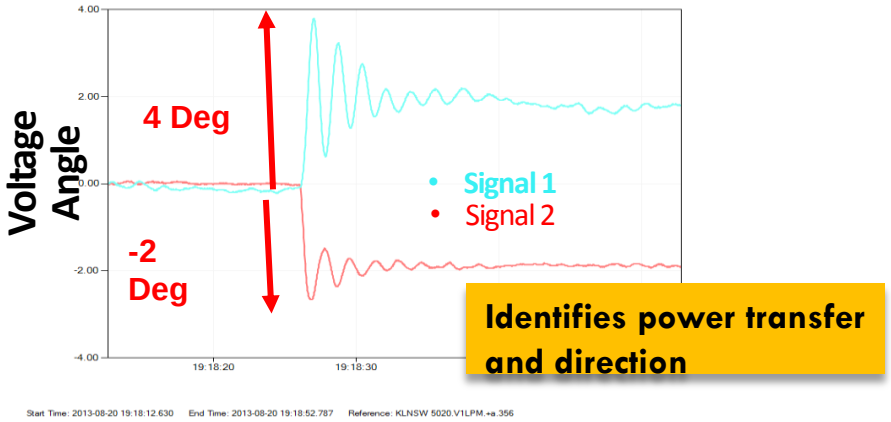
NERC-defined A, B and C Frequency
A – 60.004 Hz
B – 59.924 Hz
C – 59.893 Hz

De-trended by First Value



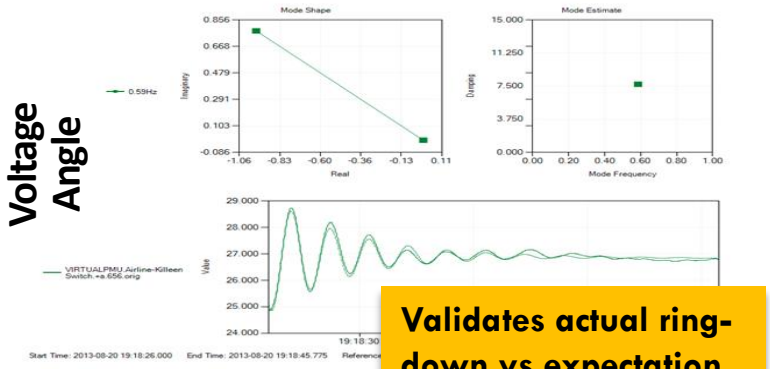
Identifies first responding PMU – likely nearest the event location

De-trended by First Value



Identifies power transfer and direction

Ringdown Analysis



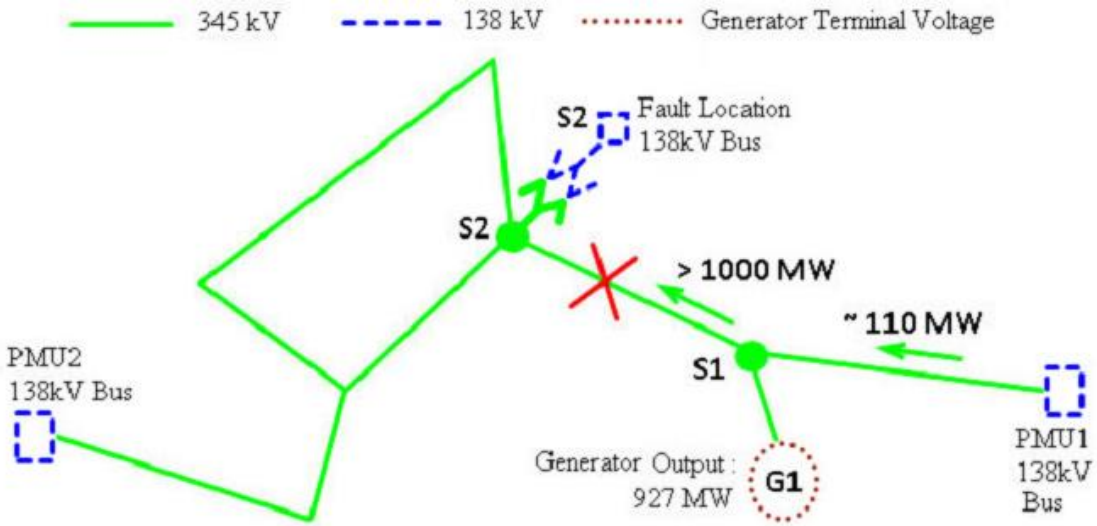
Validates actual ring-down vs expectation

PGDA used for analysis

PMU Data Enables Effective Post-Event Analysis – Power Load Unbalance Circuit Example

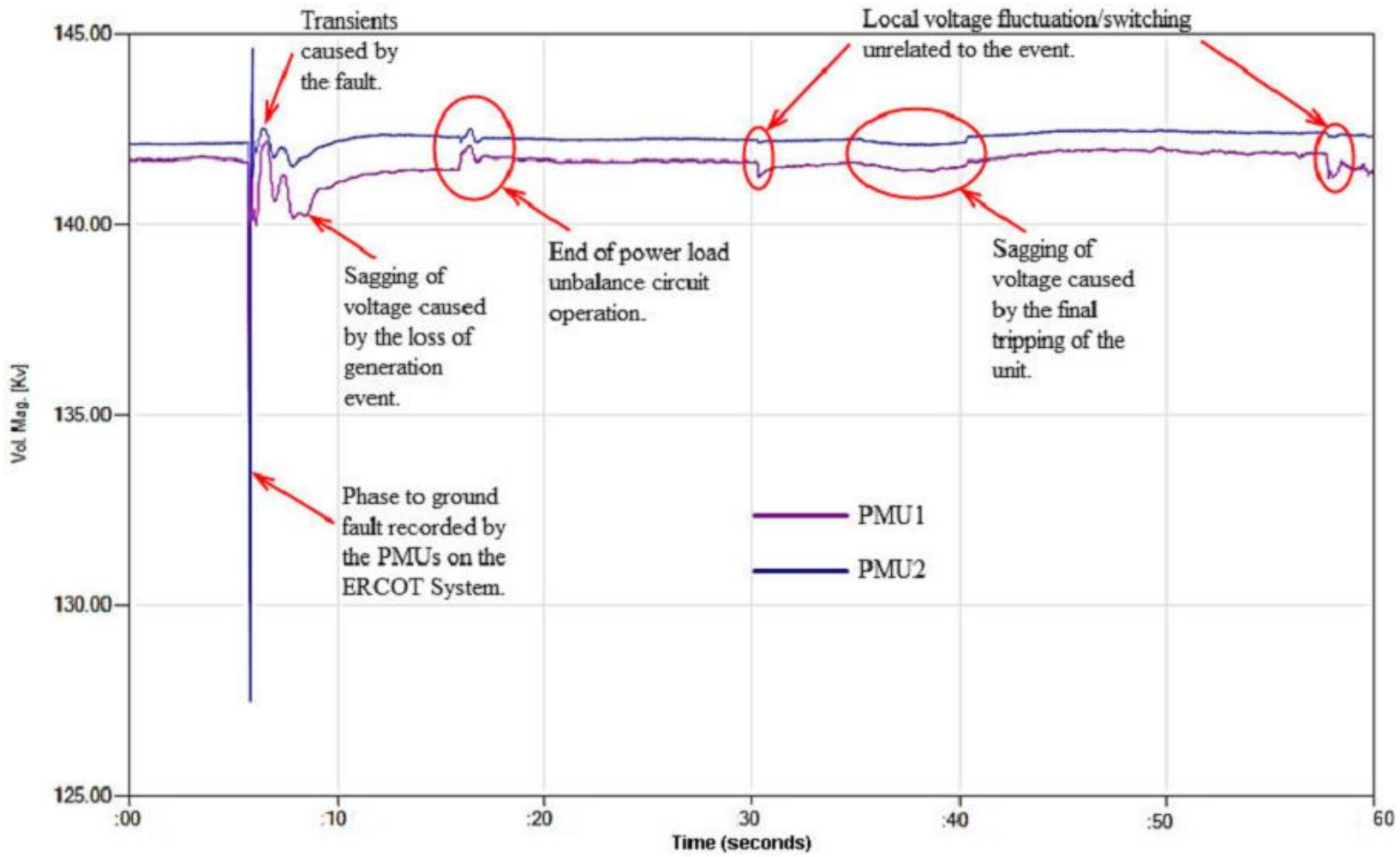
- **Predictive relaying**
  - Protection against possible over-speed of generator/turbine
- **Designed to rapidly close control/intercept valves under load imbalance conditions**
- **Relay checks for two conditions –**
  - Difference in mechanical and electrical loading
    - operates if the difference 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



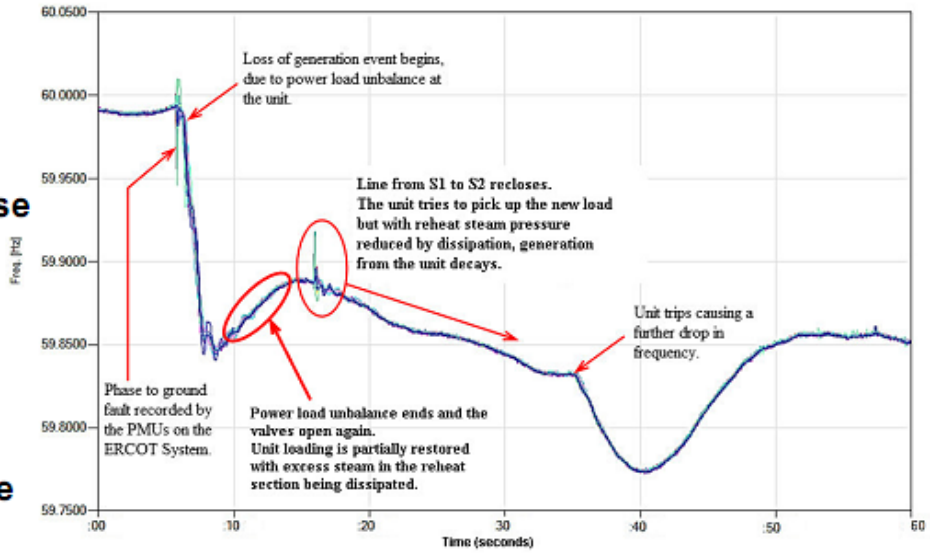
- **Generator 'G1' close to full output.**
- **Fault on 138kV bus section at sub-station 'S2'**
  - Fault cleared in ~5 cycles
  - Three 138kV circuits tripped as part of the fault clearing.
- **Fault detection and mis-operation of relay at substation 'S1'**
  - Line from 'S1' to 'S2' tripped due to 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'**



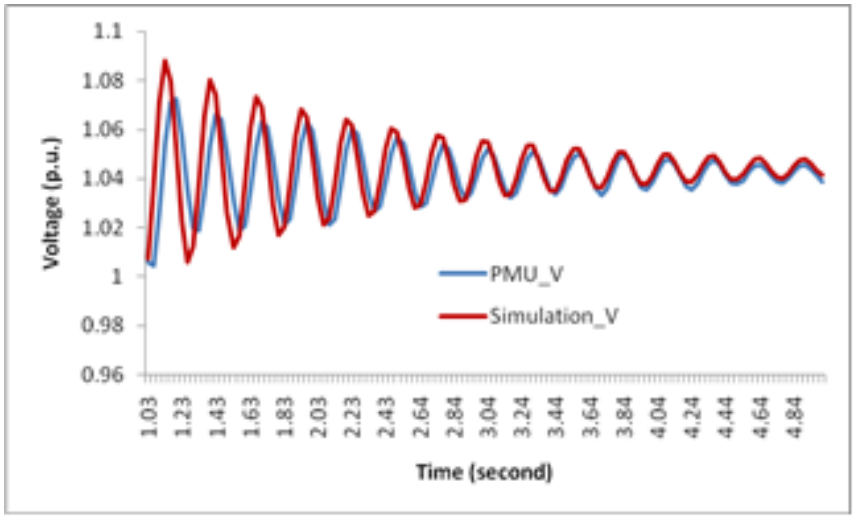
Event Analysis - Lessons Learned

- **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.

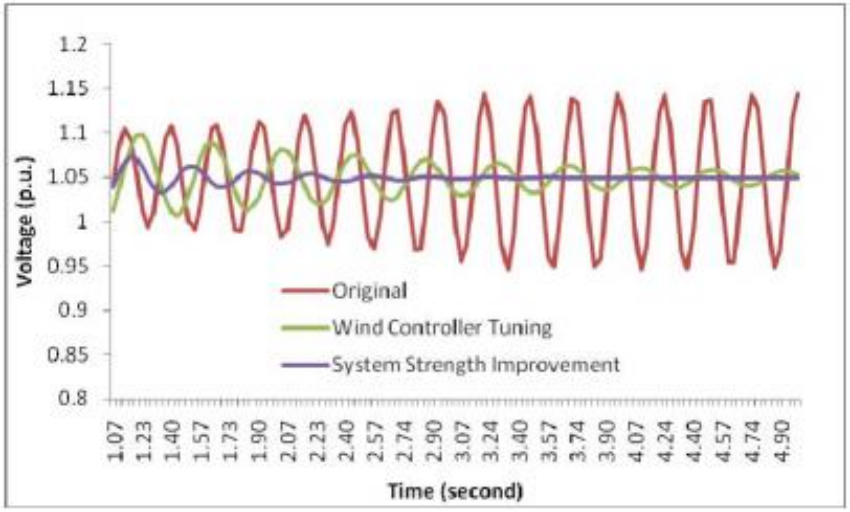
Use Case - Generator Parameter Determination

- **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:**
- Advanced 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



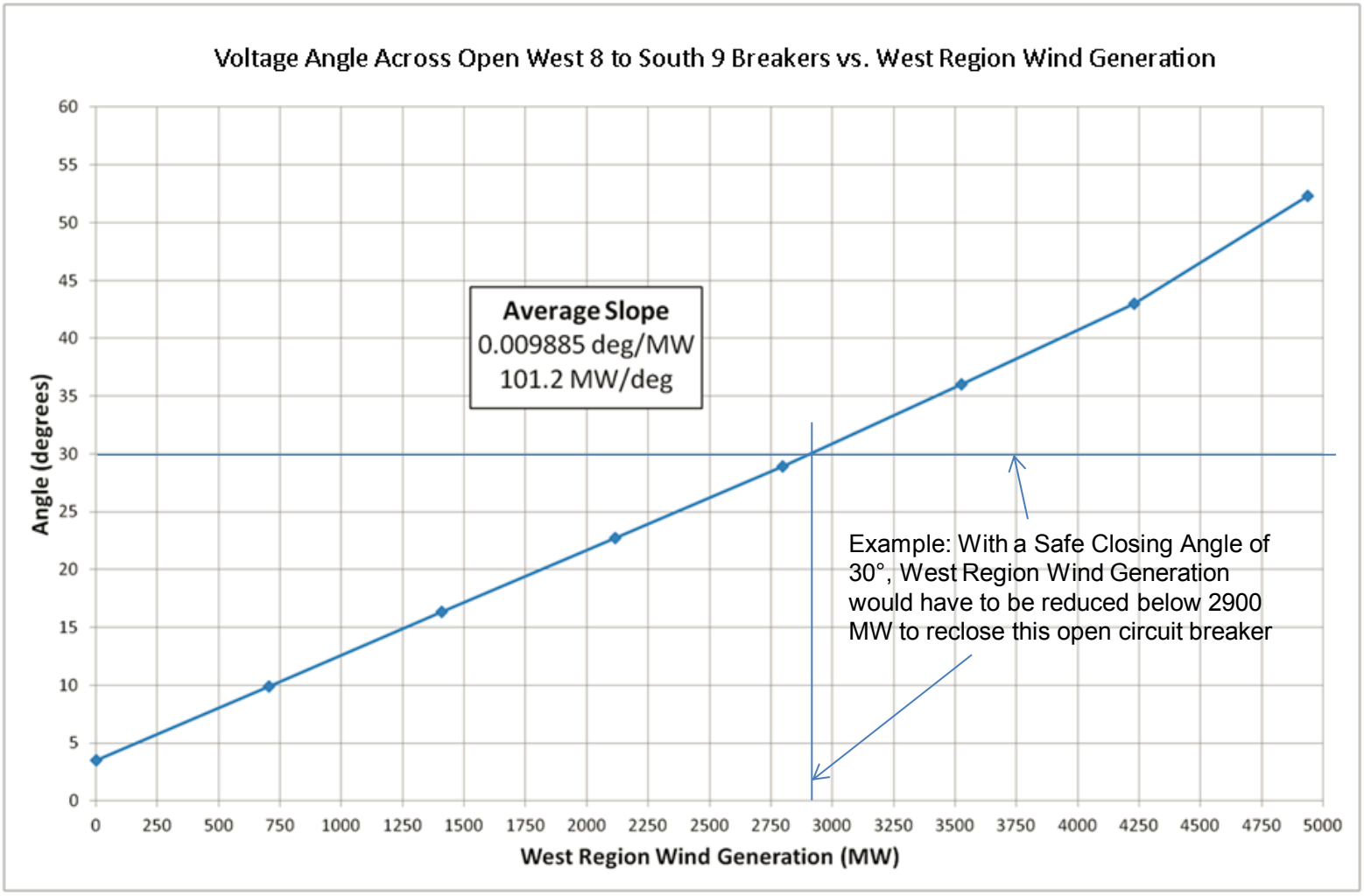
Recorded vs Simulated Voltage Response at Wind Power Plant – High Power Output – Improved performance after tuning wind controller settings

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 *e*PDC 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.

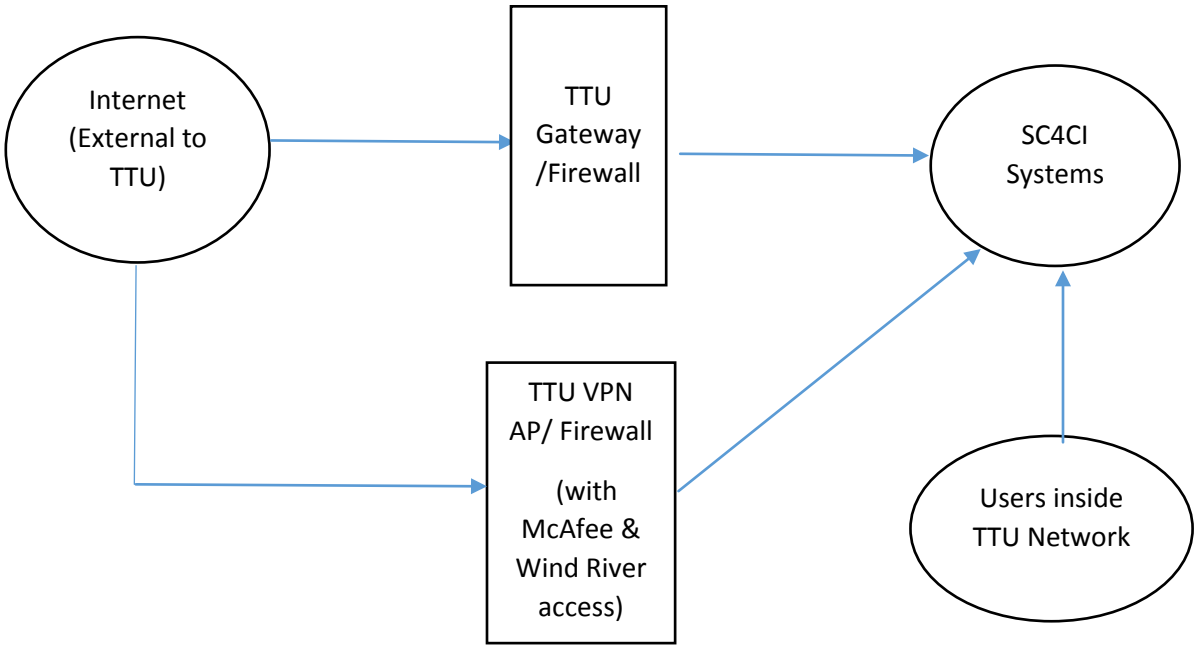
This forensics report describes the analysis of unauthorized attempts to access the SC4CI devices installed at TTU during the time period December 2013 through February 2014. The variety of intrusion attempts demonstrates the need to provide active protection and monitoring of critical infrastructure 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 logon attempts since the last successful login.

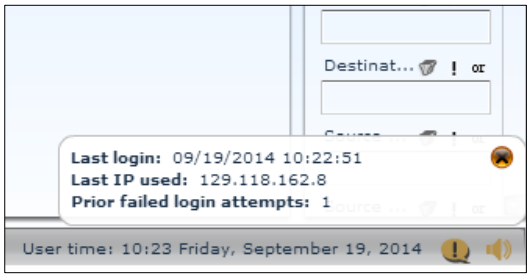


Figure 1. Message notification after successful logon from ESM.

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.

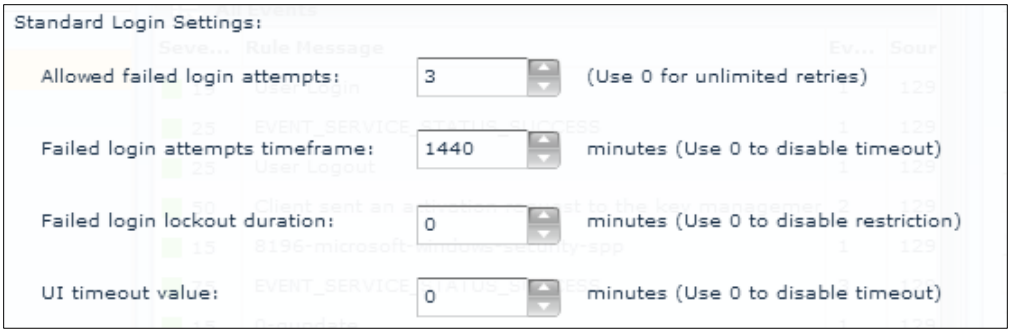


Figure 2. Part of Login Security property from ESM component.

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.

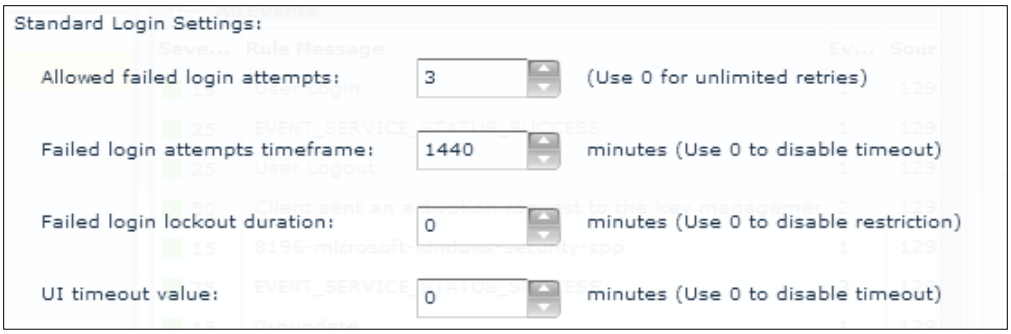


Figure 4. Part of Login Security property from ESM component.

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.

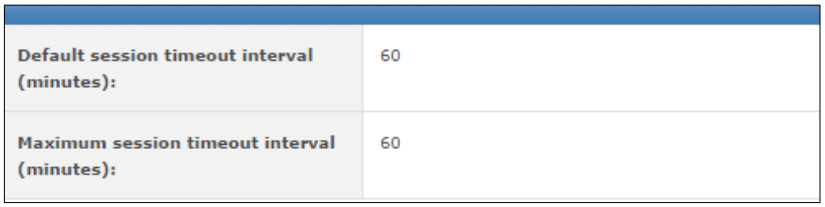


Figure 5. Current Setting of session timeout interval from ePO web component.

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.

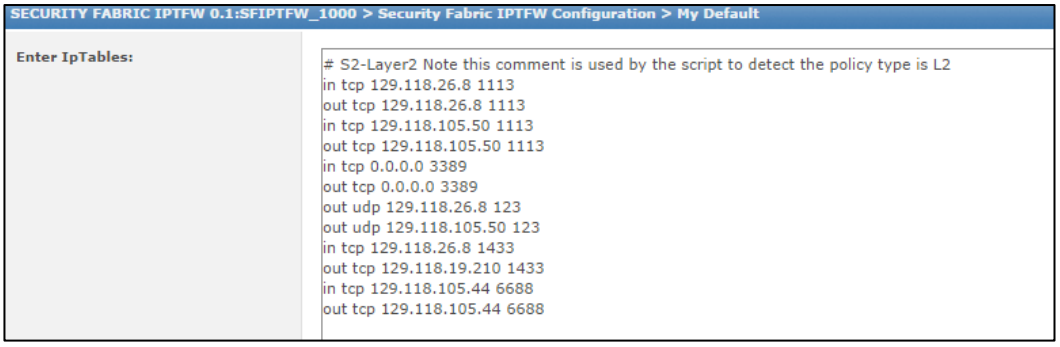


Figure 6. IP Table Firewall rule in ePO policy.

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.

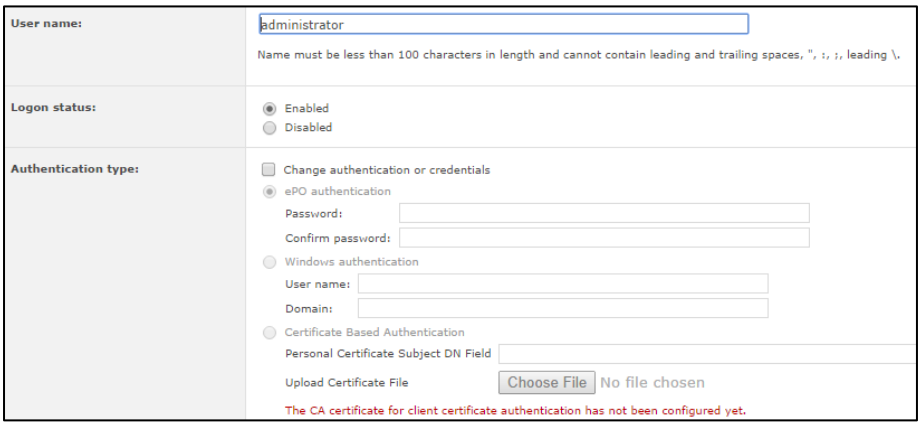


Figure 7. Password Policy for each user in ePO system.

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.

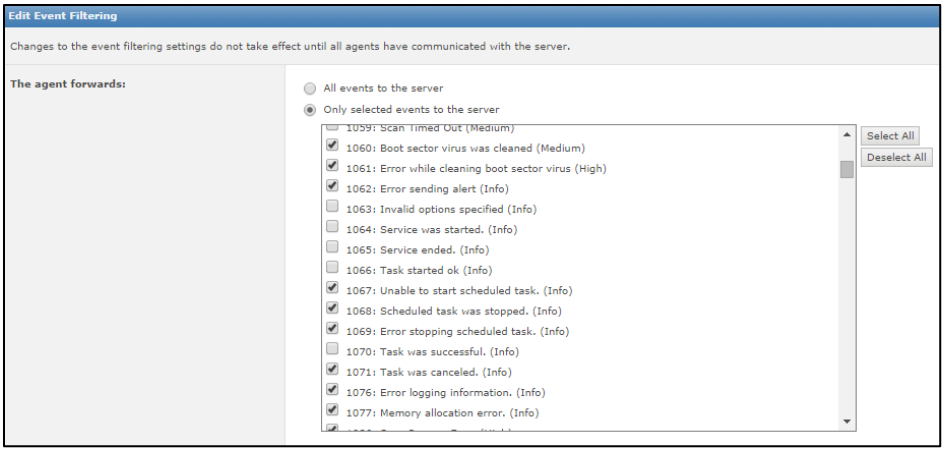


Figure 8. Event Filtering in ePO system.

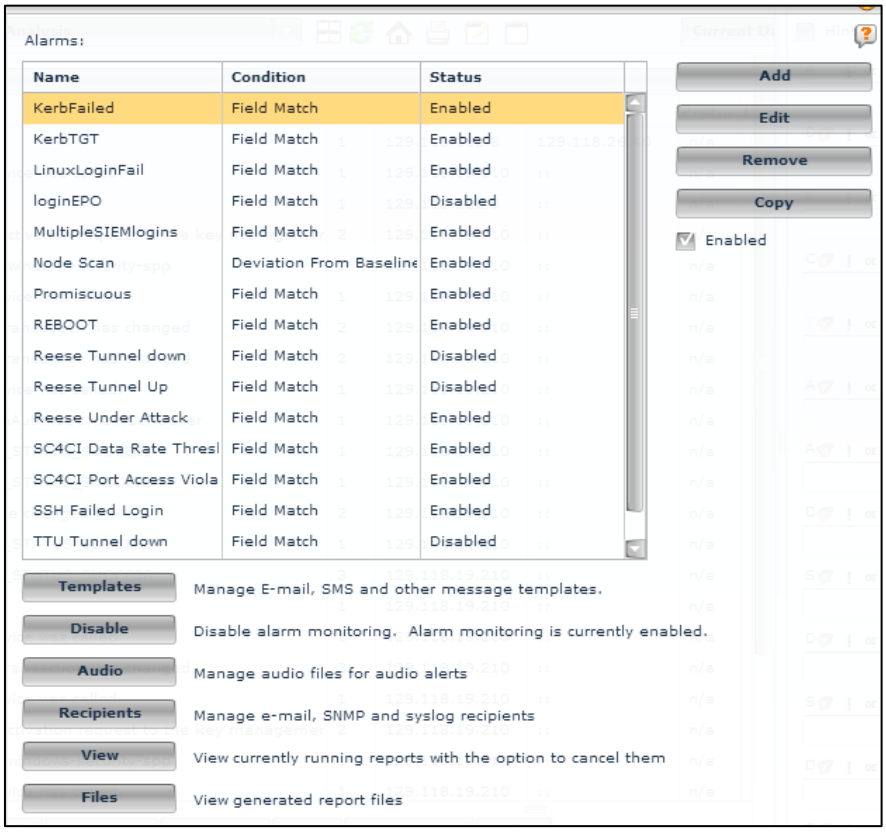


Figure 9. Event Editor and Filtering in ESM system.

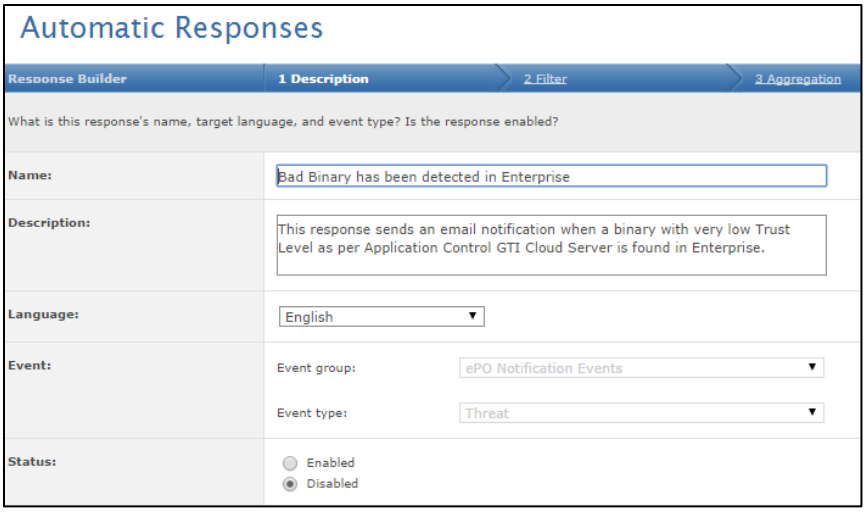
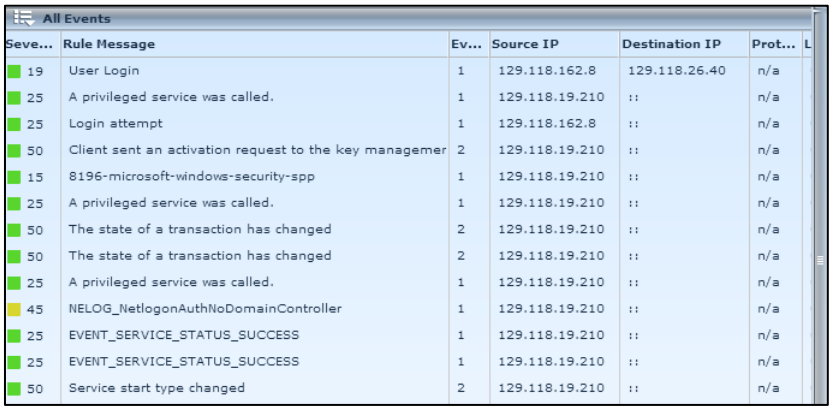


Figure 10. Automatic Responses for specific events in ePO system.



Seve...	Rule Message	Ev...	Source IP	Destination IP	Prot...
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 managemer	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 Addres
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

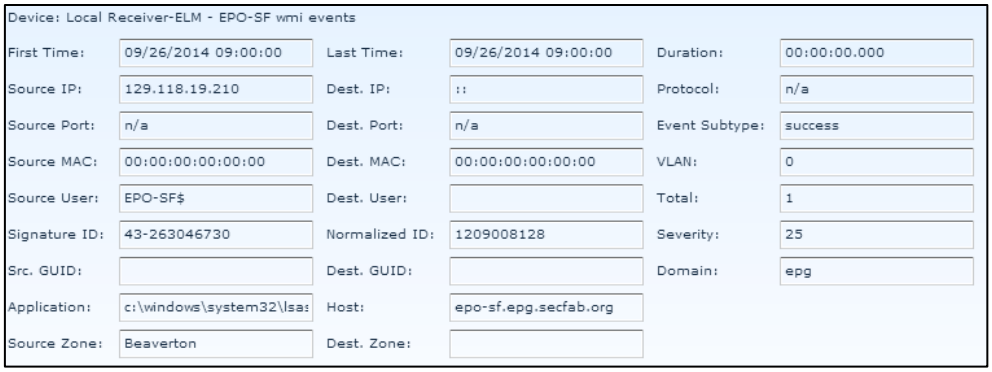
Specification

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\lsa:	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.

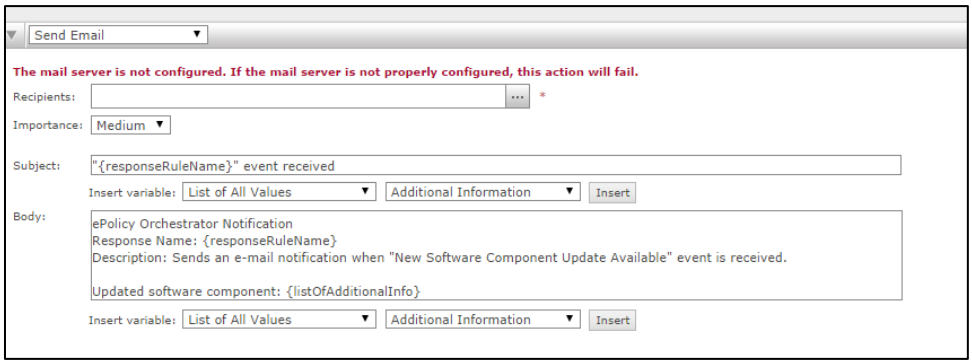


Figure 14. Alerting mechanism in ePO system.

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.

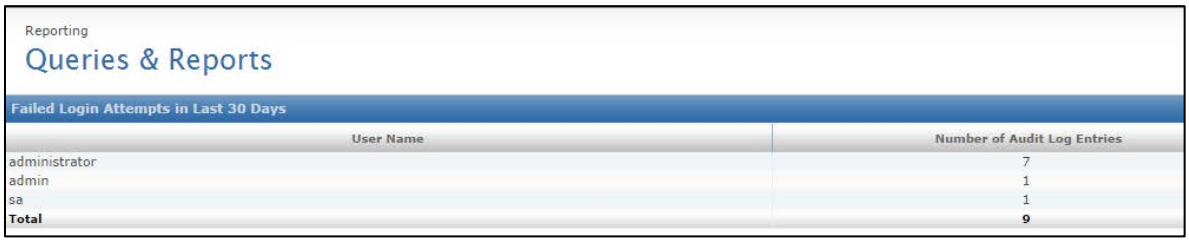


Figure 15. Report generation from ePO system.

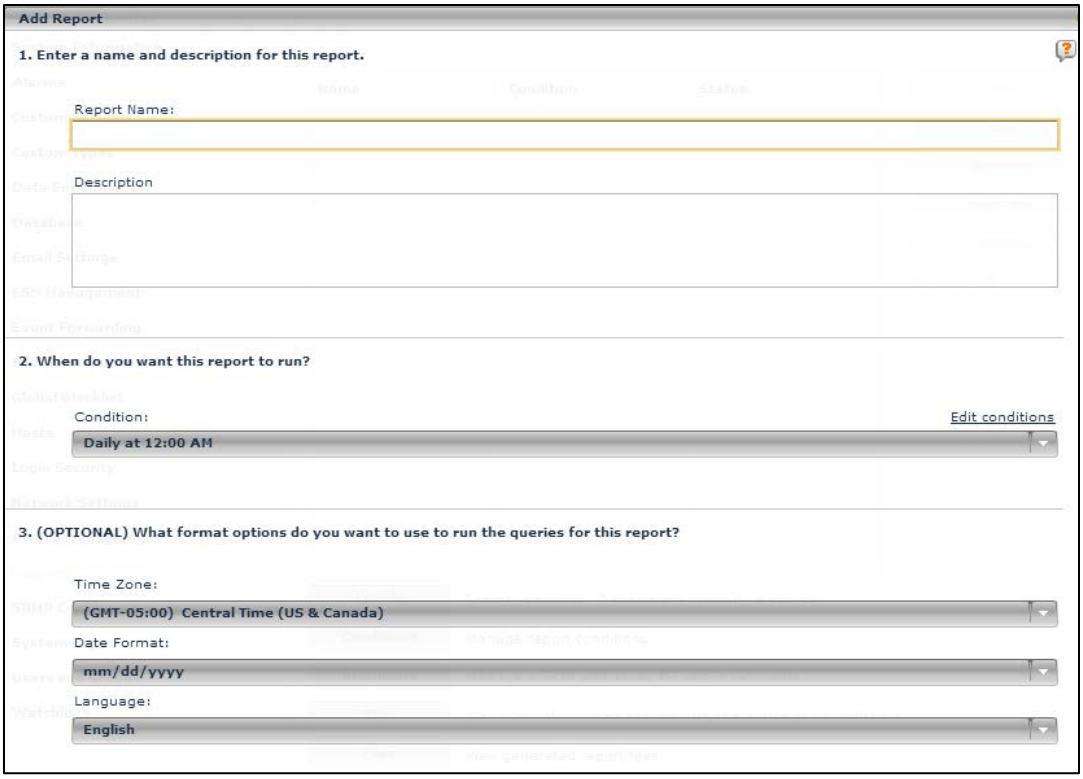


Figure 16. Report generation in ESM.

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.

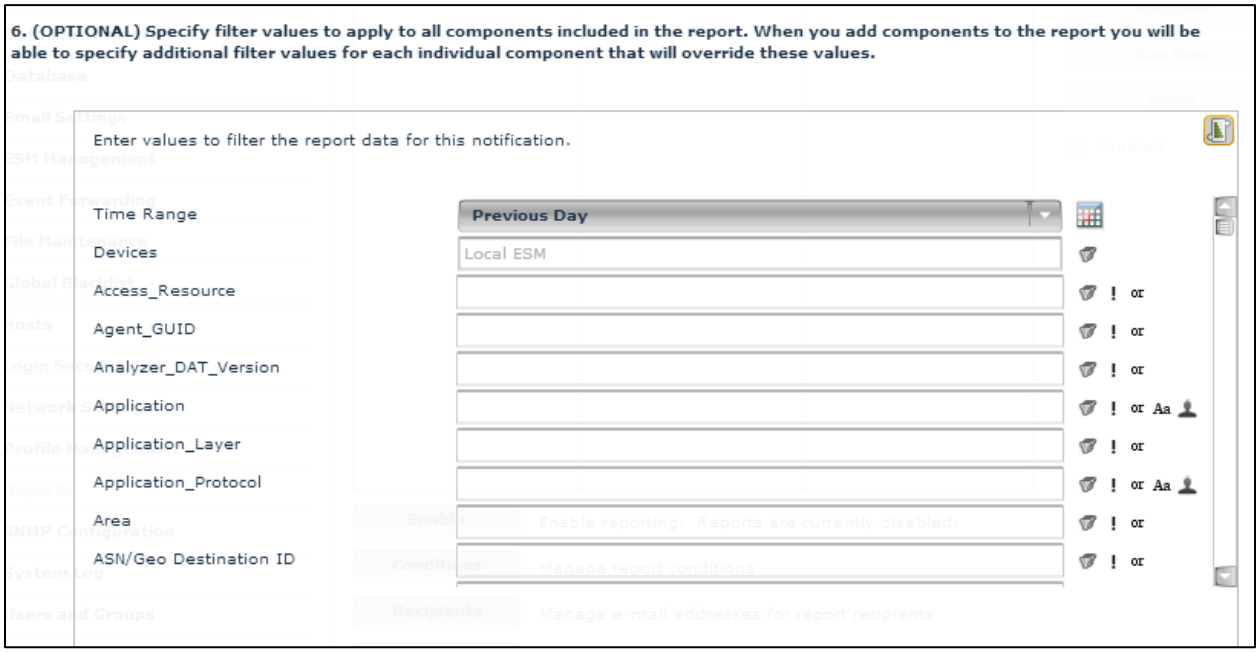


Figure 17. Event filtering in report generation from ESM.

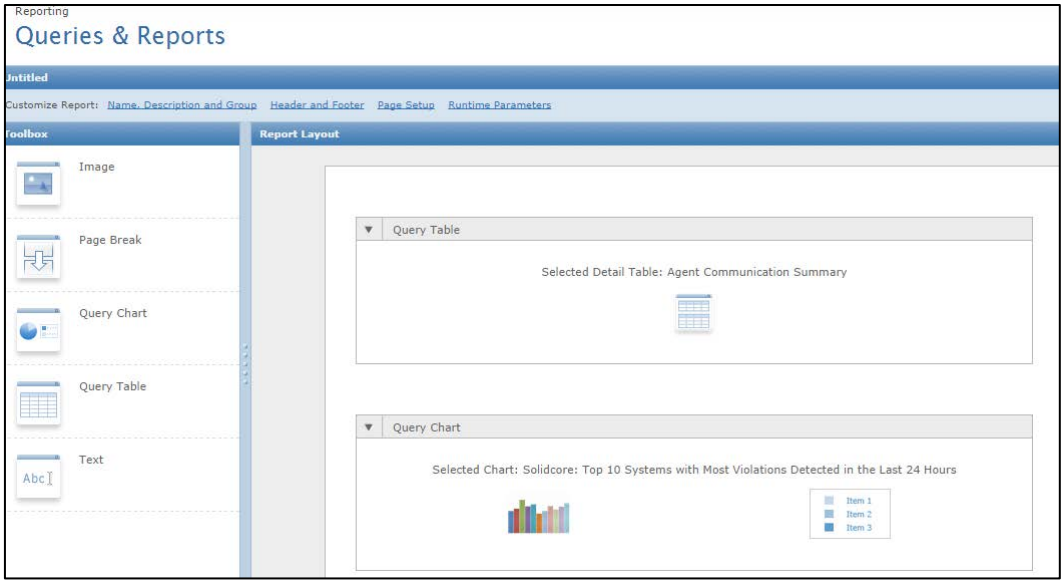


Figure 18. Event filtering in report generation from ePO.

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.

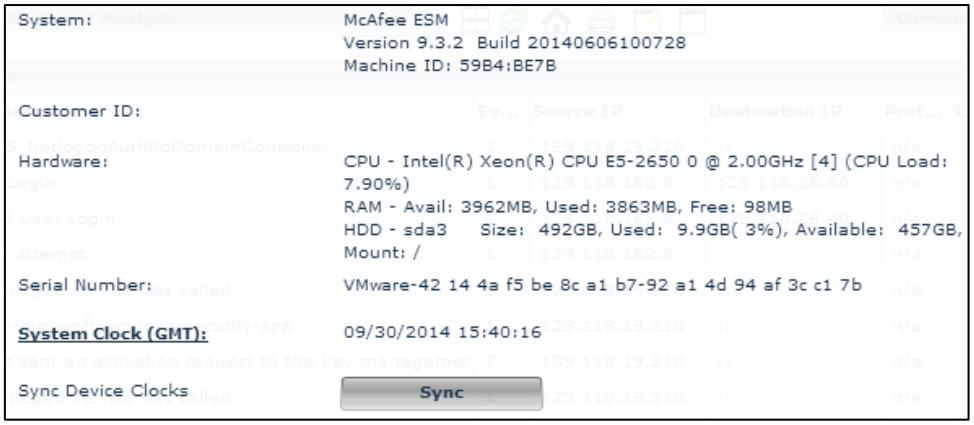


Figure 19. ESM system clock configuration.

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 conducts the audition based on their defined frequency to access 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.

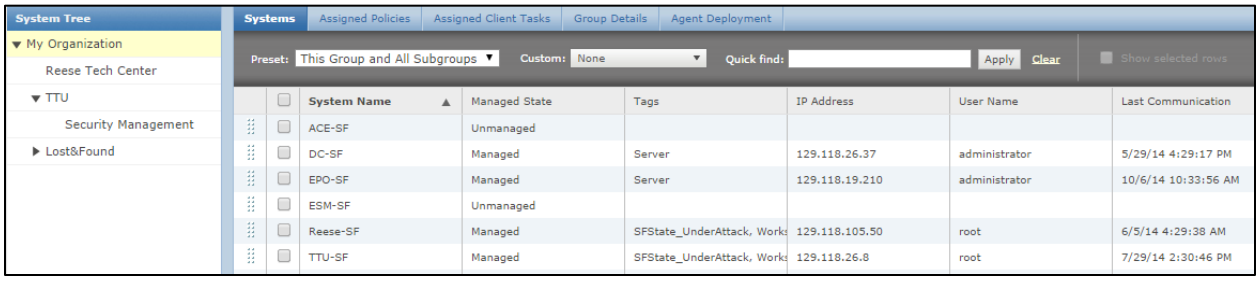
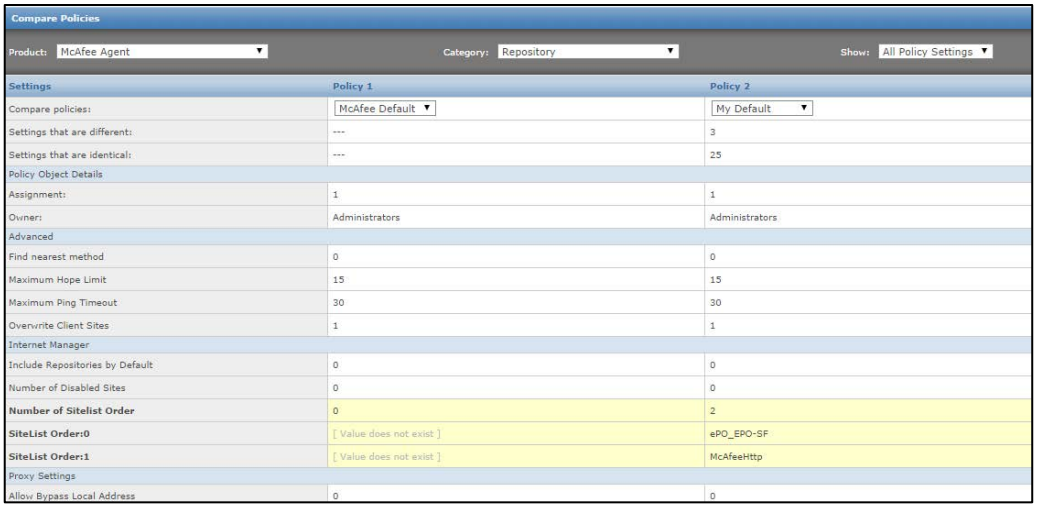


Figure 20. Components controlled by Security Fabric Environment.



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 Hope Limit	15	15
Maximum Ping Timeout	30	30
Overwrite 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 devise 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.

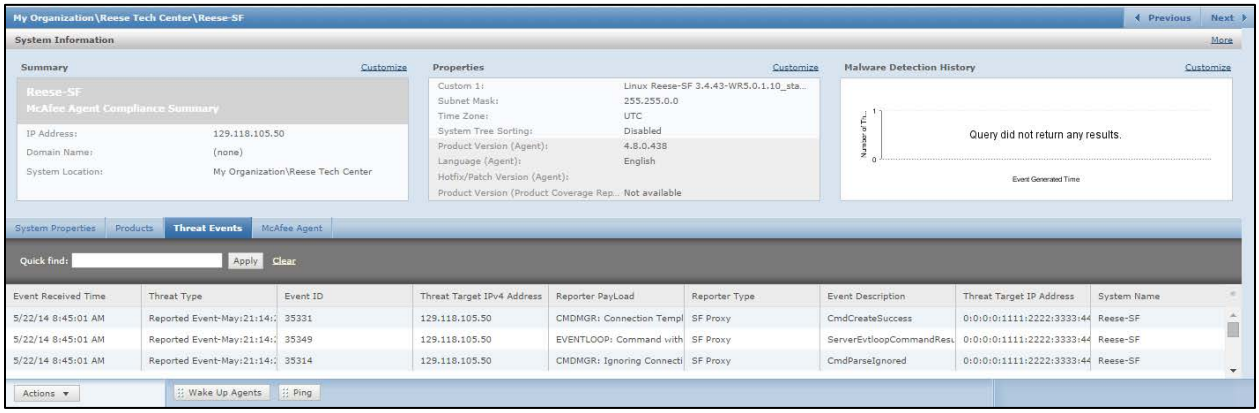


Figure 22. Status of controlled agent in ePO system.

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 A***c***cess 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.

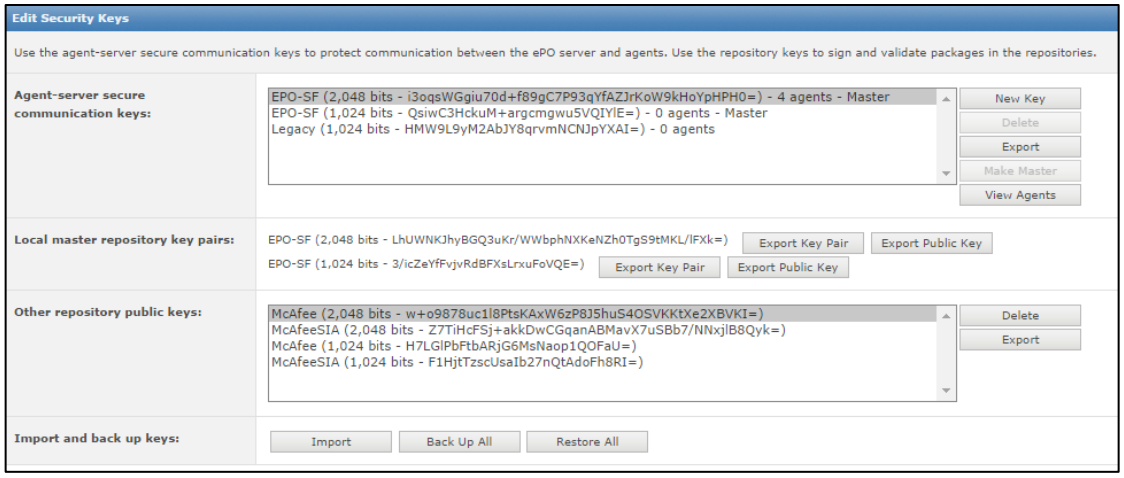


Figure 23. Device-to-Device Key Management in ePO.

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.

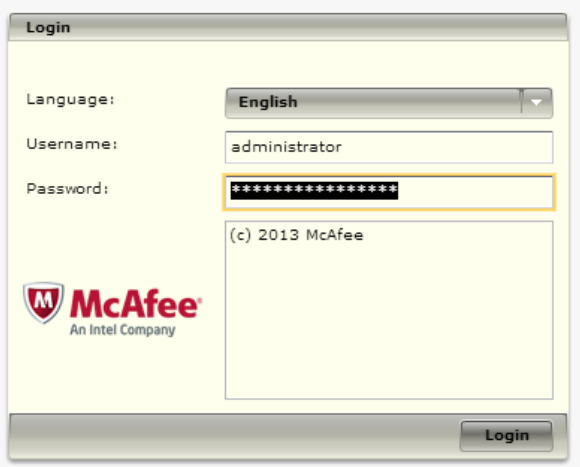


Figure 25. Masked password in ESM system.

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-gird 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 Hypervisor[1].

[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 document[2] 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 instance

   System 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 in 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 Guide[3], 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"?).

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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 much 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 Guide[4], 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

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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 systems[5]).

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 hypervisor[6] 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 Reponses 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 exploitable 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 crypto-analytical 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 exploitable 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)

  [!]             Certificate 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 cprt01-v162.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 cprt01-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 cprt01-v162.ttu.edu (129.118.163.254)

   2   0.35 ms  eewrb001.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 cprt01-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 cprt01-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-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

   |_sslv2: 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 cprt01-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
```