Final Report

August 2013

DYNAMIC LINE RATING

Oncor Electric Delivery Smart Grid Program

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Acknowledgment & Disclaimer

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EXECUTIVE SUMMARY

Electric transmission lines are the lifeline of the electric utility industry, delivering its product from source to consumer. This critical infrastructure is often constrained such that there is inadequate capacity on existing transmission lines to efficiently deliver the power to meet demand in certain areas or to transport energy from high-generation areas to high-consumption regions. When this happens, the cost of the energy rises; more costly sources of power are used to meet the demand or the system operates less reliably. These economic impacts are known as congestion, and they can amount to substantial dollars for any time frame of reference: hour, day or year.

There are several solutions to the transmission constraint problem, including: construction of new generation, construction of new transmission facilities, rebuilding and reconductoring of existing transmission assets, and Dynamic Line Rating (DLR). All of these options except DLR are capital intensive, have long lead times and often experience strong public and regulatory opposition. The Smart Grid Demonstration Program (SGDP) project co-funded by the Department of Energy (DOE) and Oncor Electric Delivery Company developed and deployed the most extensive and advanced DLR installation to demonstrate that DLR technology is capable of resolving many transmission capacity constraint problems with a system that is reliable, safe and very cost competitive.

The SGDP DLR deployment is the first application of DLR technology to feed transmission line real-time dynamic ratings directly into the system operation's State Estimator and load dispatch program, which optimizes the matching of generation with load demand on a security, reliability and economic basis. The integrated Dynamic Line Rating (iDLR)[1] collects transmission line parameters at remote locations on the lines, calculates the real-time line rating based on the equivalent conductor temperature, ambient temperature and influence of wind and solar radiation on the stringing section, transmits the data to the Transmission Energy Management System, validates its integrity and passes it on to Oncor and ERCOT (Electric Reliability Council of Texas) respective system operations. The iDLR system is automatic and transparent to ERCOT System Operations, i.e., it operates in parallel with all other system status telemetry collected through Supervisory Control and Data Acquisition (SCADA) employed across the company.

[1] The terms iDLR (integrated Dynamic Line Rating), Conductor Monitored rating (CMR) and DLR (Dynamic Line Rating) are referenced frequently in this report. iDLR is Oncor's designation for real time ratings that account for the full impact of ambient temperature, solar radiation, and wind variations; and integrating the data into the system's status telemetry for operations. CMR refers to a rating system that continuously monitors the line parameters and ambient conditions. DLR refers to the determination of a line rating based on real-time parameters. In addition, AAR is Oncor's designation for real time ratings that account only for ambient temperature variation.

The SGDP project assessed the DLR technology and its application in the following ways with indicated successful results:

Increased line capacity. The cumulative probability of increased capacity over the course of the project validated that DLR provided capacity above the Ambient Temperature-Adjusted Ratings (AAR) 6 to 14% for 345 kV and 8 to 12% for 138 kV transmission lines. The availability of that added capacity ranged from 83.5% to 90.5% of the time.

DLR system accuracy. The statistics show that the segments were instrumented to be within 1 or 2 ^{o}C average conductor temperature accuracy.

DLR system reliability. The systems installed provided 24/7 functionality.

Streaming of DLR. For the first time, DLR was seamlessly and transparently delivered through Oncor's EMS (Energy Management System) to ERCOT's EMS, where it was automatically applied to Security-Constrained Economic Dispatch (SCED) and the wholesale market system.

Congestion volatility. Congestion was found to be very volatile and sporadic. While the impact on Oncor transmission lines was $145,000,000 to $197,000,000 annually, the lines that were congested changed throughout the project period. Not one of the 180 lines that experienced congestion during the study had continuous congestion.

Congestion mitigation. Study results show that congestion mitigation can be obtained with as little as a 5 to 10% increase in capacity over the currently used ambient-adjusted line ratings. The effective congestion mitigation can be in the range of 60 to 100% on the lines monitored.

Cybersecurity and Interoperability. Cybersecurity assessments and Interoperability integration into transmission system operating functions was achieved showing minimal risk or difficulty.

Planning applications. DLR will be a successful tool to enable transmission planners to mitigate congestion, increase system reliability and make capital investments to its most efficient uses through a least regrets strategy.[2]

Extensibility of the technology. The SGDP project validated the application of DLR on a large-scale project and identified a protocol for extending the benefits of DLR across a larger segment of Oncor's, ERCOT's and the industry-wide existing transmission infrastructure. The project also verified that any deployed DLR technology must be capable of continuously capturing both the spatial and temporal variability of weather (especially wind) along the transmission line. For any instant in time, each line section associated to one monitoring device had a unique characteristic that was not duplicated anywhere else on that line or across the project's lines. The minimum number of monitoring devices required to safely establish the DLR for any transmission line was established.

The SGDP Project has been a complete success, having demonstrated that Dynamic Line Ratings are a practical and efficient tool to increase the capacity of a transmission line, which will enable transmission

[2] "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," Chang, Pfeifenberger and Hagerty, The Brattle Group, July 2013.

providers and system operators to mitigate congestion, increase system reliability and redeploy capital to its most efficient uses through a least regrets strategy.

As evidence of the extensibility of DLR technology, Oncor has deployed an additional twelve (12) DLR devices in the Odessa-Midland region of Texas and incorporated them in the iDLR system operating telemetry feed. The Odessa-Midland area has experienced extensive growth over the past several years as the petroleum industry has applied need recovery technologies to existing plays. The growth created congestion issues and the need for added capacity on several lines in the region. The iDLR deployment addressed capacity needs on five additional transmission circuits. The project need was initially discussed in January 2013, and the West Texas iDLR was placed in service June 17, 2013.

1. Scope

This document represents the Final Report for the Oncor Electric Delivery Smart Grid Development Program (SGDP). The SGDP Project applies real-time sensing instrumentation that will monitor the line conductor tension from several transmission lines. This information through an algorithm is used to calculate the Dynamic Line Rating (DLR), which represents the maximum line capacity, i.e., maximum power transfer capacity of the transmission line, based on ambient weather conditions and the physical location of the transmission lines. This information when incorporated into a utility's transmission management system is used to dynamically rate transmission circuits and supplement their transfer capacities. This project is designed to demonstrate the effective use of Dynamic Line Ratings to reduce transmission grid congestion and estimate the dollar benefit to the wholesale electricity market based on data collected during the project.

Oncor is the sixth largest transmission and distribution (T&D) utility in the U.S. and the largest in Texas with approximately three million points of delivery in a service area covering north central, eastern and western parts of the state. Oncor is a transmission service provider (TSP) within the transmission region controlled by the Electric Reliability Council of Texas (ERCOT). Within ERCOT there are numerous transmission paths that are at times considered to have Commercially Significant Constraint (CSC), i.e., there is insufficient transmission capacity along the given path to efficiently transmit the power between generation source and load demand locations.

Oncor installed and commissioned the DLR technology to provide dynamic ratings and perform utility studies on eight transmission circuits on its system. Those eight circuits are located in Bell, Bosque, Falls, Hill, McLennan and Williamson counties in Central Texas and are part of the north-to-south CSC path as designated by ERCOT in the 2008-2009 time frame.

The following sets forth the objectives, benefits, key asset deployment milestones, associated data collection, aggregation and analysis methods, monetary investments, baseline data, marketplace innovation and collaboration/interaction with the Department of Energy (DOE) necessary to accomplish Oncor's fully integrated Smart Grid Project.

1.1 Introduction to Oncor Electric Delivery Company

Oncor is located within the ERCOT region in which retail competition for customers of investor-owned utilities was implemented January 1, 2002. The ERCOT market structure required vertically integrated utilities to separate their business functions into three companies: a power generation company, a T&D utility and a retail electric provider (REP). T&D utilities remain fully regulated by the Public Utility Commission of Texas (PUCT), with rates set on a cost-of-service basis and open access to all buyers and sellers of electricity. The rates of power generation companies and REPs are not regulated. Oncor provides T&D delivery to REPs, who bundle the commodity and T&D costs in their customer invoices. Oncor provides electricity delivery and measurement services and does not sell electricity.

As a T&D utility within ERCOT, Oncor delivers energy to REPs, who have direct relations with the end-use customers. Another facet of this three-part electric provider system in ERCOT is that the actual costs of the transmission congestion constraint and relief are not defined or maintained by Oncor. As an open access provider, Oncor's role is strictly to efficiently and reliably provide energy delivery between any generation entity, wholesaler and any authorized power retail service within Texas. Oncor is compensated by a regulated return based on its overall capability to deliver electricity.

Oncor's service territory is illustrated in Figure 1. One can envision the context of Oncor's service area as part of ERCOT by comparing Figure 1 and Figure 2. The size and extent of Oncor's service territory and operating statistics are provided in **Table 1**.

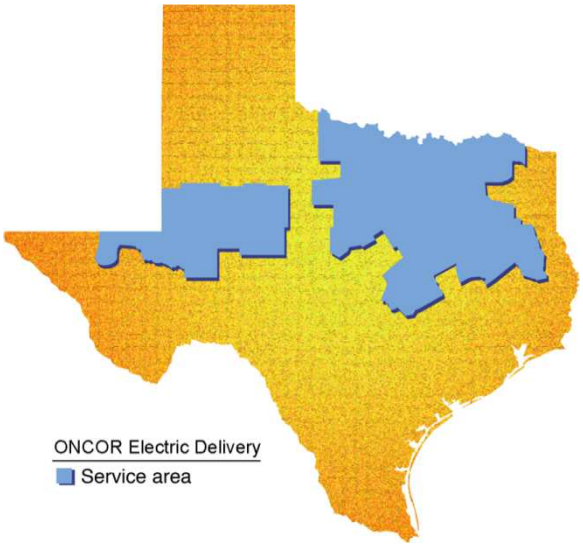


Figure 1 - Oncor Service Area

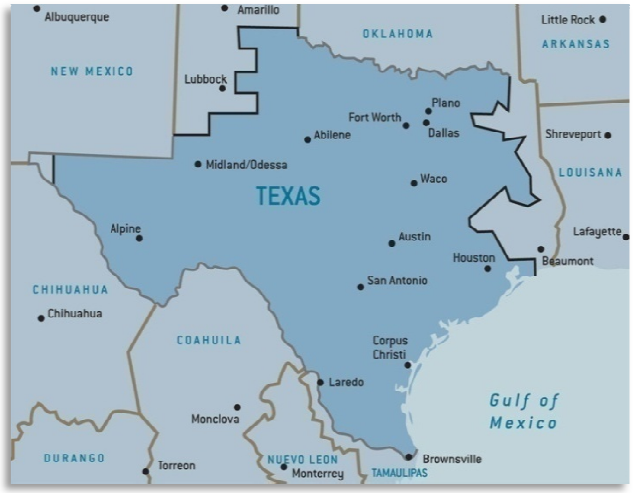


Figure 2 - ERCOT Region

Table 1 - Oncor Electric Delivery Service Territory Operating Facts

Oncor's Service Territory as of 12/2011	
Total number of customers:	
Residential, Commercial & Industrial	3,189,751
Peak load:	
Summer	25,564 MW
Total MWh sales	
Residential, Commercial & Industrial	113,836,638 MWh
Total number of substations	707
Total number of distribution feeders	103,437
Total miles of distribution line	96,827
Total number of transmission substations	288
Total number of transmission circuits	747
Total miles of transmission line	15,342

1.2 Project Overview

Oncor's Smart Grid regional demonstration project includes the instrumentation of eight transmission lines in a section of the system grid where CSCs existed when the project was proposed (Figure 3). The CSCs inhibit transfer of electric power from the generation sources to the area of load demand. Transmission lines are operated at a line rating that reflects the allowable transfer capacity across a given line segment, based on mandated vertical clearances to ground and other objects for safety and

operating considerations. When the required transfer capacity across a path exceeds this limit or there is a risk of exceeding this limit with the outage of a generation source or another grid asset, system operators must redispatch the generation mix such that the allowable transfer capacity across the grid does not exceed the posted allowable ratings. The risk associated with exceeding line ratings if another outage or operating event occurs is known in the industry as planning/operating for an N-1 contingency.

The project will install instrumentation that monitors the tension of the conductors in real time. The sensing technology and associated algorithms translate the line tension into the available line rating that can be safely maintained in the line section being monitored. This rating is provided to the system operator's console and the system State Estimator model. The real-time Dynamic Line Rating provides increased capacity 90 to 99% of the time and has the potential for reducing transmission line congestion and allowing the system to operate at optimum levels for a greater proportion of the time. The line capacity is established as a line rating correlating conductor type and size with ambient wind speeds, temperature and solar radiation.

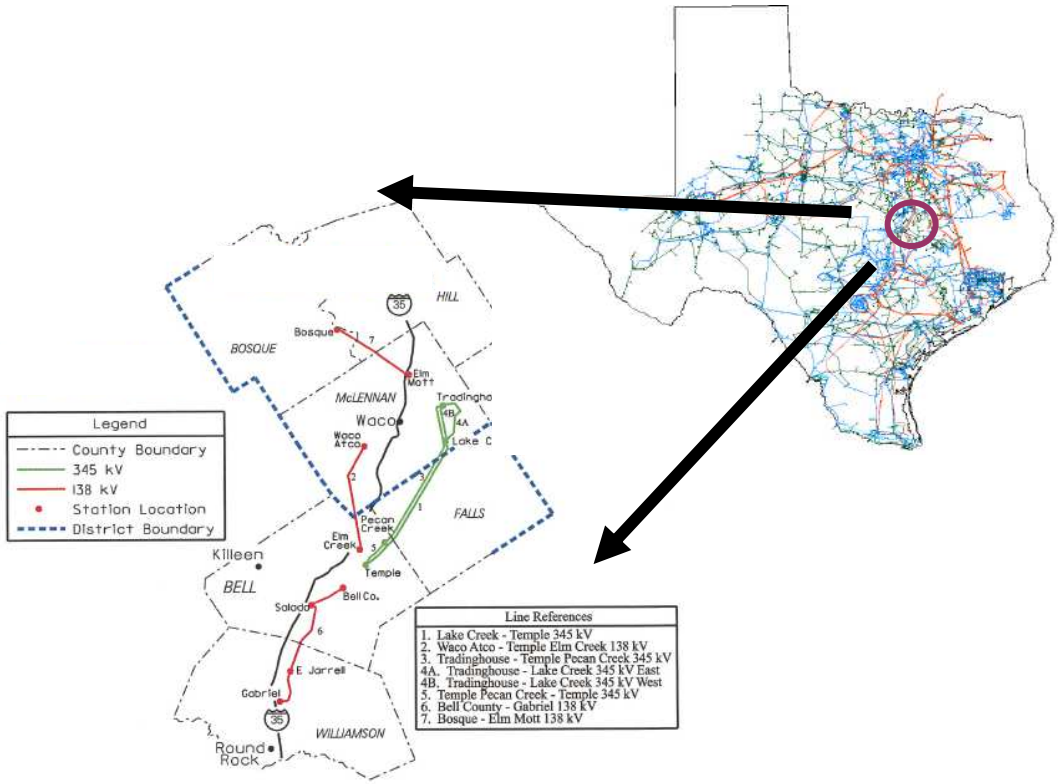


Figure 3 - SGDP Project Map Showing Test Line Locations

During line operation, the conductor transfers current from source to load sink. The line current creates heat within the conductor from joule heating. As Figure 4 illustrates, there is a thermal environment around the conductor that develops heat balance forces, increasing the heat of the conductor or removing heat. Heat accumulation within the conductor is caused through the joule heating from the current and absorption of radiant heat from the sun. Countering the influx of heat is the radiation of

heat from the conductor and the convection of heat away from the conductor as wind blows past the conductor. The heat balance takes into consideration the emissivity of the conductor surface, ambient temperature, solar radiation level and wind speed and direction to drive the conductor to its operating temperature.

Traditionally, a fixed set of ambient parameters with a prescribed probability of occurrence was established as the base rating case for planning and emergency line ratings. ERCOT has allowed its associated transmission providers to utilize an adjusted rating, taking into account the ambient temperature. When the ambient temperature is lower than the assumed static rating ambient temperature, a higher line rating can be applied. However, when the ambient temperature is above the static rating base temperature, the allowable equipment ratings will be lower than the static rating.

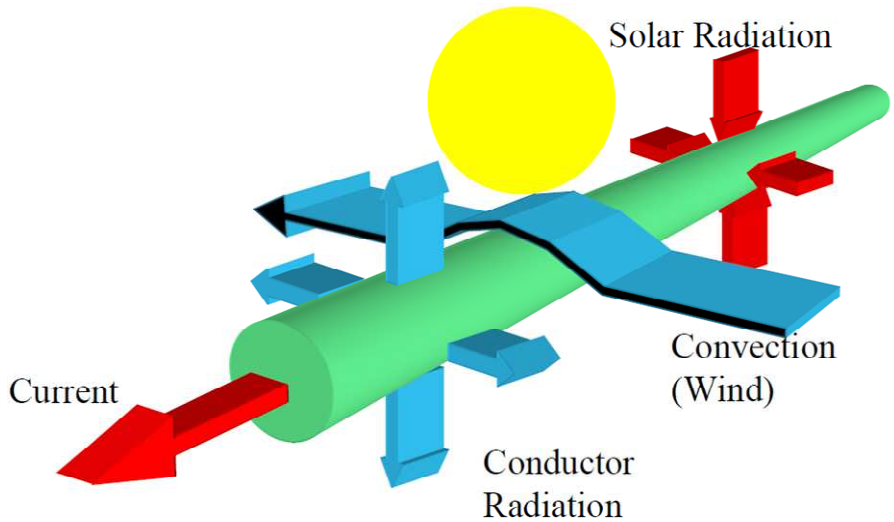


Figure 4 - Conductor Line Rating Thermal Characterization

The thermal relationship between the conductor, power flow and ambient conditions is defined and applied through the publication of Standards by the IEEE and CIGRÉ, which provide the mathematical models defining the thermal behavior of the conductor:

> IEEE Standard 738-2006, IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors, 2006. [IEEE 738]
>
> CIGRÉ Technical Brochure 207, Thermal Behavior of Overhead Conductors, Working Group 22.12, 2002. [CIGRÉ 207]

The DLR Project is designed to take into account ambient temperature, the wind blowing across the conductor to cool it and the ambient solar radiation to model the heat balance effect on the conductor. By dynamically adjusting the line ratings, the transmission capacity will provide more opportunities for optimal utilization of the transmission grid and optimized economic dispatch of the generation.

As Figure 3 illustrates, the project is concentrated on a small portion of the Oncor transmission grid and an even smaller portion of the ERCOT system. The deployment strategy of the DLR instrumentation and analysis package is an important aspect of determining the accuracy of the dynamic rating model and critical to an accurate prediction of available transmission capacity. The DLR Project will analyze the data obtained during peak winter and summer season monitoring periods to develop an appropriate protocol to guide future application of the DLR technology to other locations where CSCs exist.

1.3 Project Objectives

The project will install a dense array of instrumentation on the noted transmission line segments to collect the necessary real-time data. The SGDP will assess the data recorded and line rating calculations to determine the optimum location for sensing devices to achieve the accurate real-time ratings required for optimal application of DLR technology for system operation. This protocol will be project deliverable for application by future DLR projects throughout the U.S. transmission grid.

The economic impact of the reduction in CSCs will also be computed throughout the project period to demonstrate the economic benefits of implementing the DLR protocol. Combined, the protocol and the benefits of congestion relief will be a valuable package for other utilities to optimize their transmission systems and make the grids more efficient.

Commercially Significant Constraints Reduction Objectives

- Clearly demonstrate that DLR technology is reliable by operating the system using real-time dynamic ratings over the course of several critical peak operating seasons.
- That utility planners understand the cost structure and benefits and can quantify the increased line capacity for planning and operating the system more efficiently;
- Show interoperability with Utility Transmission Management Systems by incorporating the dynamic rating functionality into the system control center's operating protocols so it is transparent to the operators. Assure the integrity and accuracy of the data through Cybersecurity assessment.

Economic Objectives

- Quantify economic value of released transmission capacity to market.
- Estimate the savings associated with deferral of rebuilding, reconductoring or building new circuits to meet transmission requirements.
- Quantify the total costs of implementing an effective DLR program.

Operational Objectives

- Relieve congestion and transmission constraints.
- Gain operational knowledge of DLRs for wide-scale deployment.
- Ensure that safety code clearances are not impacted.
- Demonstrate that multiple monitoring units can be integrated into operations.
- Identify/quantify other operational limits that may impact ability to raise ratings.

Demonstration Objectives

- Extrapolate the impact of DLRs on the study's transfer path to entire ERCOT region.
- Determine a methodology to release day-ahead ratings.
- Develop user-friendly tools for the operator to manage improved Wide Area Situational Awareness (WASA).

1.4 Project Milestones and Schedule

The project had two phases:

- First, the installation and deployment of the DLR instrumentation and validation hardware into the field, development of the software interfaces and modifications to the Oncor EMS, and the calibration of the systems to bring them online to stream DLR data to the operating environment.
- Second, the application of the DLR data in the operating environment and the technical assessment of the impact of DLR on the availability of transmission line capacity, the accuracy and optimization of the DLR deployment protocol, an assessment of the Interoperability And Cybersecurity capabilities, and the impact on congestion relief from economic and environmental aspects.

With regard to the installation, deployment and commissioning of the DLR systems, the primary DLR instrumentation packages were scheduled for fall 2010. The software enhancements to the Oncor EMS to integrate the DLR ratings into the operating environment were scheduled for spring 2011. Installation of secondary line status hardware to validate the accuracy and reliability of the primary DLR systems was scheduled for spring 2011. Go-Live DLR system streaming of DLR data to the Oncor and ERCOT operating environment was scheduled for the summer of 2011. Refer to Table 2 for a summary of the completion of the milestones. Most notably, all equipment was installed in the field by the spring of 2011. Outage requirements prevented a sooner completion date.

An issue with degradation of the DLR signal wires exposed to high-voltage field levels required the replacement of some loadcells and signal wires, which was completed in August 2011. The EMS upgrade to accommodate acceptance of the DLR streaming data and perform quality checks on the data was completed in April 2012. With its completion, the Go-Live date for streaming data to ERCOT for operations was May 1, 2012.

The Interoperability and Cybersecurity Plan was completed in spring 2011, and the study to fully assess the DLR technology for I&CS was scheduled for execution through 2011 and completed in January 2012.

The quantification of the accuracy, reliability and economic potential impacts of the DLR technology was scheduled to initiate after the system is operating through the completion of the SGDP Project operating window ending December 2012. The results of these studies are addressed throughout this final report.

Table 2 - Project Milestones and Schedule

Date	Milestone	Completion Date & Comments
04/30/2010	Initial DLR Installation	04/30/2010 – Initial DLR hardware installation completed on a couple of 138 kV lines before outage issues prevented further installations.
09/16/2010	Design Installation Plan/Material Procurement	09/16/2010
01/31/2011	Terminal Upgrades	01/31/2011
03/25/2011	Complete DLR Installation	03/25/2011 – All DLR installation complete 08/31/2011 – Modified the 345 kV installations due to signal-wire issues at high voltage 05/01/2012 – System Go-Live with ERCOT operations
03/25/2011	Installation of Sag Monitors	6/30/2011 - Sagometers and Promethean RT-TLMS systems installed
03/28/2013	Project Studies: Reported Quarterly • Analysis of DLR real-time constraint release • Sag studies – alternative DLR technology confirmation • Economic Trade Space Analysis • Cybersecurity Study • Technology Deployment protocol	01/20/2012 - Interoperability and Cybersecurity Study completed All other studies completed with submission of the Final Report
06/28/2013	Complete Project Documentation	08/02/2013 Document submitted for DOE Comment

1.5 Project Benefits

Oncor's economic benefits from this project are summarized as:

- Improvements to the management of the transmission grid
- Future deployment methods of the DLR technology
- Economies of a real-time rating system
- Advancements made through DLR technologies
- Stakeholder interest and involvement
- Interoperability and security of Smart Grid data

1.6 Improved Management of Transmission Lines

The Oncor DLR demonstration is significant when compared to current practices because it will allow future utilities faced with constrained or heavily loaded transmission lines to better manage those lines, i.e., increase the transfer capacity of the line based on real-time conditions rather than static contingent parameters, and increase system awareness of the status of the lines that have DLR monitoring devices installed. In the current operating environment, utilities have the ability to accurately measure their load in real time, but they have limited means to know the capacity, in real time, of one of their most valuable assets – the transmission grid.

Since that transmission capacity depends not only on the physical characteristics of the conductors and structures supporting them but also on the ambient conditions of temperature, wind speed and direction and solar radiation, the transmission line capacity is truly dynamic and difficult to characterize without knowing the actual ambient conditions. Real-time monitoring of the line parameters and calculating the real dynamic rating of the line increases system awareness and allows the grid to more fully utilize its asset capabilities while maintaining reliability and safe operations.

The industry breakthrough associated with the SGDP Project is that this will be the first worldwide application where real-time Dynamic Line Ratings are fed through telemetry to the State Estimator that is used to model the real-time characterization of the system to maintain reliable operating parameters of load flow, frequency and voltage while maintaining an optimized economical dispatch. Prior to this project, dynamic ratings may have been introduced to the control room environment, where they were posted on an operator's console. The control room operator would need to look at these ratings and decide whether to use them in his operating decisions.

By streaming the data into the State Estimator program, the actual ratings are used to optimize the operations of the grid and optimize the dispatch of generation and transmission capabilities to meet load demand in real time.

1.7 Enable Further Deployment of DLR Technology

One of the deliverables of this project is "best practices" documentation for deploying and operating a DLR system so that other utilities can more efficiently develop and deploy their own DLR systems.

Oncor will document the findings from the project and make this knowledge available for wider deployment within Oncor's transmission system, the ERCOT region and throughout the nation as part of the national Smart Grid initiative.

Through this project, the DLR technology will be demonstrated on the selected region and set of transmission circuits. The following key parameters will be demonstrated and documented in order to ensure easier and wider deployment at the regional and national level:

- Using procedures that demonstrate how installation can be streamlined, including potential improvements on the assembly itself or the installation practices and methodology.
- Optimizing the number of monitors required to accurately rate the transmission line, depending on deadend and insulator type.
- Training for installation crews on effective installation practices.
- Establishing guidelines for the introduction of DLR into the grid operations environment and facilitating the real-time streaming of the data to the grid management system while maintaining reliability, security and economic dispatch.
- Developing a best practices manual for future installations.
- Evaluating current calibration techniques with a view to improving productivity while maintaining and improving accuracy.

Viability and practicality will be two of the key objectives. More specifically, the viability of "knowing" one's true transmission capacity in real time is almost axiomatic. The project will demonstrate this concept.

More importantly, the project will demonstrate and quantify the benefits of having this additional and deterministic knowledge of the true circuit capacity and how it can be utilized to optimize the entire transmission system for energy delivery. For instance, Oncor anticipates that Dynamic Line Ratings will expose the next operational limit on the grid. Oncor will then be in a much better position to perform economic analysis as to the next optimum investment.

1.8 Economic Value of Capacity Released by Dynamic Line Ratings

The transmission grid is made up of multiple paths for delivering power from sources to locations of demand or load. Each path consists of multiple transmission circuits that are described as constrained or congested when the amount of power that the market wishes to move from resource to load is greater than the power transfer capacity (rating) of the path. That transfer capacity (rating) has traditionally been limited to a fixed (static) value based on worst case weather assumptions (high ambient temperature, full solar radiation, zero or very little wind) designed to protect individual transmission circuits from overheating and sagging too close to the ground.

The worst case weather assumptions rarely occur, and thus the transmission circuits are limited to an artificially low capacity without better insight into actual ambient conditions along the transmission lines. DLR technologies account for the actual weather conditions and release the true capacity of the transmission circuits and the path for operation.

When the transmission grid's capacity is unconstrained and consumers have full access to the lowest-cost generation sources, a competitive market determines the price of electricity. When the grid's capacity is constrained (congested), access to the lowest-cost power is limited and retail electric providers must pay for power from higher-cost generation sources that have access to transmission line capacity to deliver the power to the load location and incur congestion costs.

The cost of congestion can be high. Over the past two years within the Oncor system, several lines have experienced congestion rents in excess of $1,000,000 for a given day with maximum values as high as $6,000,000. During that period, 180 lines experienced congestion exceeding $349,000,000 and a daily average of almost $250,000 per line.

Projecting an exact economic value associated with a reduction in congestion costs that will be achieved with Dynamic Line Ratings is difficult since future meteorological conditions and load flows will not be known with certainty until they occur. However, a sound estimate can be made by examining the economic impact of congestion events that occurred and an adjusted line performance with increased line capacity through DLR and its ability to mitigate the congestion cost. Examining these mitigated costs for several time periods in different seasons and grid conditions will provide an overall estimate for congestion relief through DLR.

Additional economic benefits can be realized through the deferment of capital expenditures when DLR increased capacity and response to ambient conditions provides a sufficient margin to safely and economically operate transmission lines. Lines that exceed their static design capacity during planning studies to address load growth, voltage stability and reliability will be analyzed to determine the economic advantages of various upgrade alternatives versus DLR capacity that could be realized through real-time monitoring.

1.9 Technology Advancements of Dynamic Line Ratings

The technical benefits of this SGDP project have direct correlation to the interoperability and cybersecurity issues addressed in this document, including to:

- Validate the technical accuracy and capability of DLR to provide the grid operators with timely and accurate conditional data and capabilities of the transmission line elements.
- Provide the documentation of consistency, security and accuracy of the real-time data to allow decisions to be made to optimize the grid operations and reduce operating and delivery costs of energy.
- Provide documentation outlining the protocol that can be applied by Oncor, ERCOT and other transmission grid systems to implement additional DLR technologies to mitigate transmission congestion and provide a more open, dynamic and secure grid.

Reliable Dynamic Line Ratings provide the means to know the true transfer capacity of grid transmission elements in real time. The system conditions or state required to make these adjustments is derived from real-time data measured at remote locations on the transmission line away from the control center or substation measurement environment. That data must be transmitted to some entry point into the grid management system for delivery to an algorithm-processing server and then fed to grid operating systems and personnel for application in the operating displays and technology employed by the grid's system operator. Figure 5 illustrates the DLR system configuration identifying the three zones of activity: Remote (Transmission Line), Utility Entre (Substation) and Grid Operations (Control Center).

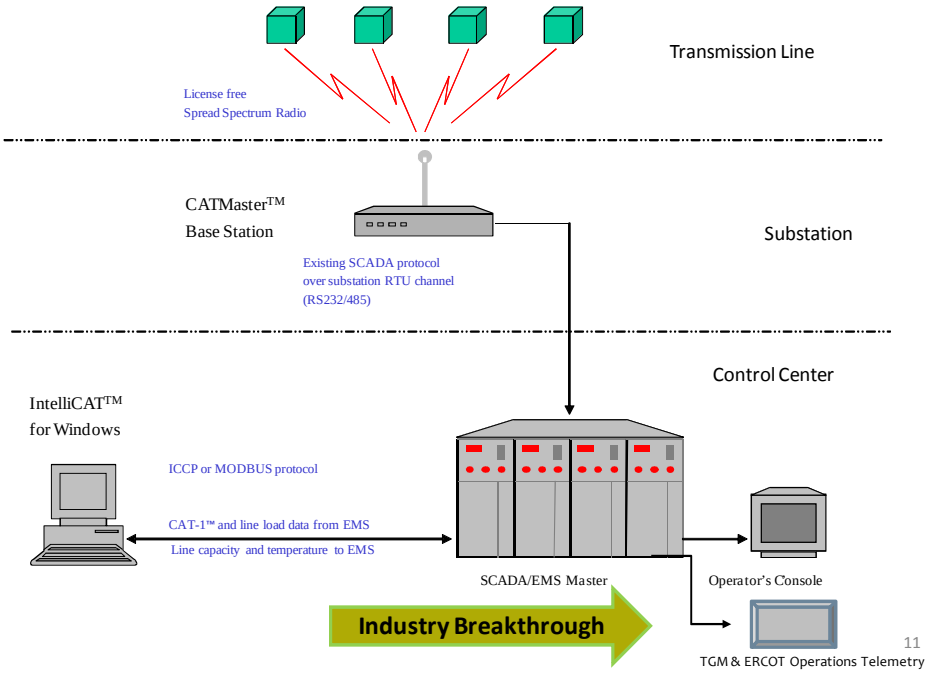


Figure 5 - DLR System Description

The primary DLR equipment applied during the SGDP was the CAT-1™ systems offered by The Valley Group, a Nexans company.

System state conditional data is obtained at the CAT-1remote monitors located on structures on the transmission line. That data is transmitted via radio frequency to a substation location equipped with a CATMaster™ unit. The data is then routed through the utility Remote Terminal Unit (RTU) and Supervisory Control and Data Acquisition (SCADA) system to the control center's EMS/SCADA master unit and the IntelliCAT™ server. The IntelliCAT server is where the data is processed using proprietary software to calculate the real-time dynamic rating. The rating is then transmitted back to the EMS where it is posted for operations. The I&CS Plan addresses the CAT-1 systems, the CATMaster and the interface between them. The SCADA system, its interface and the EMS reside within the Oncor security network and will not be assessed as part of the SGDP Project.

The EMS in most applications in the past made the ratings available on an operator's console that required pulling the data up on the screen and assessing its value and deciding whether to use the rating. The SGDP Project automated this process, making the DLR ratings available to the State Estimator tool at Oncor and at ERCOT, where the data is pulled into the Security Constrained Economic Dispatch (SCED) tool, which optimizes the grid to economically and reliably dispatch resources to meet current demand requirements and reliability criteria. This automated, near-transparent application of the DLR data is an industry breakthrough that provides increased system-wide awareness and more reliable operations.

1.10 Stakeholder Interaction During Project

Several Oncor internal and external stakeholders have interest in the SGDP Project from a commitment of participation basis and from realizing beneficial impacts. Their involvement will be maintained and encouraged as the project evolves.

For example, previous discussions identified the need to develop a relationship with ERCOT to open a line of communication and information exchange that will provide the project with specific event information, including where and when congestion occurs on the Oncor lines, what is the level of congestion, and the economic impact of congestion events. This relationship is necessary due to the de-regulated electric utility model within the United States whereby the TSP (Oncor in this case) is only a delivery service providing open access to all generation resources in the region and all energy-marketing entities that sell energy to customers.

Internal to Oncor, System Operations is a user of the DLR data stream, and its application needs and understanding are critical to project success. System Planning is also a stakeholder relative to how DLR increased capacity can be used to optimize the planning process and provide guidance for project definition, project prioritization and capital management. DLR may provide sufficient capacity on an instrumented line to defer its upgrade for several years or longer or defer the construction of a new line altogether. ERCOT has a parallel interest in the planning application of DLR as it is responsible for seeing that the grid it manages remains reliable, secure and optimally functioning to deliver power to the ultimate users.

1.11 Interoperability and Cybersecurity Approach

Reliable Dynamic Line Ratings provide the means to know the true transfer capacity of the grid in real time. The system conditions or state required to make these adjustments is derived from real-time data measured at remote locations on the transmission line away from the control center or substation measurement environment. That data must be transmitted to some entry point into the grid management system for delivery to an algorithm-processing server and then fed to grid operating systems and personnel for application in the operating displays and technology employed by the grid's system operator. Figure 5 illustrates the DLR system configuration identifying the three zones of activity: Remote (Transmission Line), Utility Entre (Substation) and Grid Operations (Control Center).

System state conditional data is obtained at the CAT-1™ remote monitors located on structures of the transmission line. That data is transmitted via radio frequency to a substation location equipped with a CATMaster™ unit. The data is then routed through the utility RTU and SCADA system to the control center's EMS/SCADA master unit and the IntelliCAT™ server. The IntelliCAT™ server is where the data is processed using proprietary software to calculate the real-time dynamic rating. The rating is then transmitted back to the EMS where it is posted for operations. The I&CS Plan will address the CAT-1™ systems, the CATMaster™ and the interface between them. The SCADA system, its interface and the EMS reside within the Oncor security network and will not be assessed.

Specific Smart Grid requirements supported by Oncor's DLR Project and aligned with DOE Interoperability and Cybersecurity are addressed in the following pages.

1.11.1 Interoperability

The Oncor DLR demonstration project is significant when compared to current practices because it will allow utilities faced with constrained or heavily loaded transmission lines better manage those lines, i.e., increase the transfer capacity of the line and improve system reliability based on real-time conditions rather than static contingent parameters. In the current operating environment, utilities have the ability to very accurately measure their load in real time, but they have limited means to know the real-time capacity (line rating) of one of their most valuable assets – the transmission grid.

The real-time monitoring system and processors must be designed to meet interoperability issues on a broad spectrum of system interfaces that while not unique are open to many application variations of industry standard interfaces and protocols. The technical approach to the interoperability issues of the I&CS Plan include a summary of:

- The interfaces for information exchange and communication of the real-time data to a point inside the utility's secure information zone.
- Whether the project technology is open and capable of interfacing with its own components and the legacy systems of the utility.
- Mitigation strategy to manage equipment changes and updating and to prevent system failures.
- How the project will support the pertinent emerging NIST protocols.

1.11.2 Cybersecurity

Cybersecurity is critical to the success of the SGDP Project, as the accuracy of the data is critical to the viability of the transmission grid and the numerous interfaces involved in the collecting of remote real-time data and its delivery to a secure utility network. The risks include but are not limited to damaging, interrupting or superimposing false data into the data recovery stream, interfering or sabotaging the data reduction, or using the DLR system as an entree into the main grid information and control system to compromise security and operational issues.

Since this is a demonstration project with a service life of two years, the life cycle aspect is fairly limited in duration. The work performed during this task will, however, provide a strong foundation for future

enhancements to the DLR technology and to the protocol that future utility applications can use to guide their DLR projects. As such, it will strengthen the Cybersecurity base of the technology by identifying any current issues and developing mitigation actions to correct and address them.

As part of the proof of concept deliverable, the thorough execution of this Interoperability and Cybersecurity assessment is intended to complete the requirements and document the optimum implementation and application strategy for DLR projects of the future.

The technical approach to Cybersecurity will include a summary of:

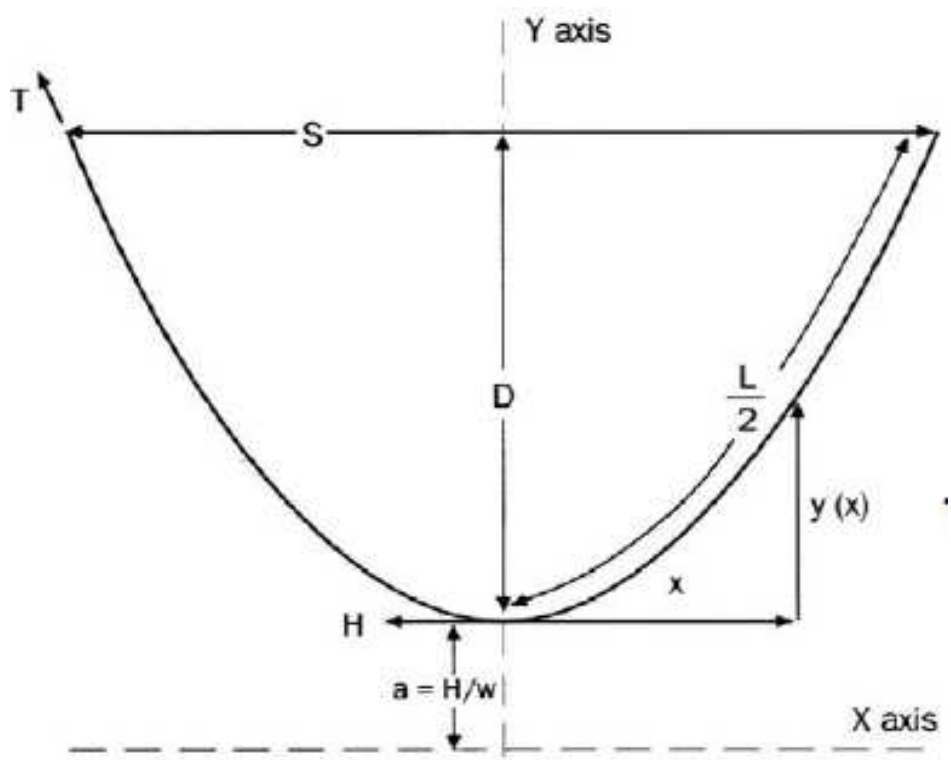
- The risks, threats and vulnerabilities that the system faces or will face in service life and mitigation strategies.
- The standards and best practices employed for Cybersecurity relevant to the technologies and interfaces applied in the project.
- How this project will support future applications and development of future DLR installations.

As previously mentioned, the project is intended to provide a “Best Practices” guide for future deployment of DLR by other utilities. With regard to Interoperability and Cybersecurity, the documentation will discuss issues that require addressing during the life cycle of a DLR installation, from design and procurement through operation and retirement for the operating utility. These concerns may require the attention of the vendor of the equipment and other stakeholders in the design, manufacturing and operation of DLR equipment.

2. Technical Approach

2.1 Conductor Ratings – Heat and Tension

Conductor is suspended in the air according to the physics and mathematics of the catenary curve, which defines the relationship between the conductor's characteristics, the shape of the conductor curve and the tension in the conductor (Figure 6). Transmission lines are designed according to a number of anticipated mechanical loading conditions, from bare wire on cold ambient-temperature days to ice and wind-loaded cold days, and the high-temperature maximum current (electrical load) carrying conditions.



$$y(x) = \frac{H}{w}\left[cosh\left(\frac{wx}{H}\right) - 1\right]$$

Figure 6 - Catenary Curve

Figure 7 illustrates a set of typical sag curves for a span of conductor. The DLR Project is focused on the **"Sag @ Max Electrical Load – Tmax"** curve. This curve is directly associated with the Minimum Electrical Clearance, which must be maintained at all times to be in compliance with the National Electrical Safety Code (NESC). The maximum electric capacity of a transmission line is based on the minimum clearance to ground, which dictates the maximum sag allowable in the span to provide adequate safety and operating clearance. That sag is then related to a maximum operating temperature of the conductor.

The maximum operating temperature is set by the utility and is typically 75 °C, 90 °C or 125 °C. Knowing the maximum sag allowed, the maximum electrical operating load can be determined based on the specific conductor and ambient climatic conditions at the time of electrical loading using either IEEE 738 or CIGRÉ TB 207 referenced previously.

Traditionally, the climatic conditions for minimum clearance were assumed to be a worst case scenario of minimum wind speed, high ambient temperature and full solar radiation, e.g., 2 fps wind, full sun and ambient temperature of 104 °F (40 °C). Other ambient conditions can be used for this calculation, but the aforementioned values are predominant in the United States. They represent a typical maximum ambient temperature for the service area, a typical minimum effective wind speed and full solar exposure. Note: The utility is generally the responsible party for selecting the ambient conditions and conductor rating model used to establish operating criteria. The utility is required to guarantee that the minimum clearance will be maintained under these conditions and that the rating associated with that condition is used for operating limits.

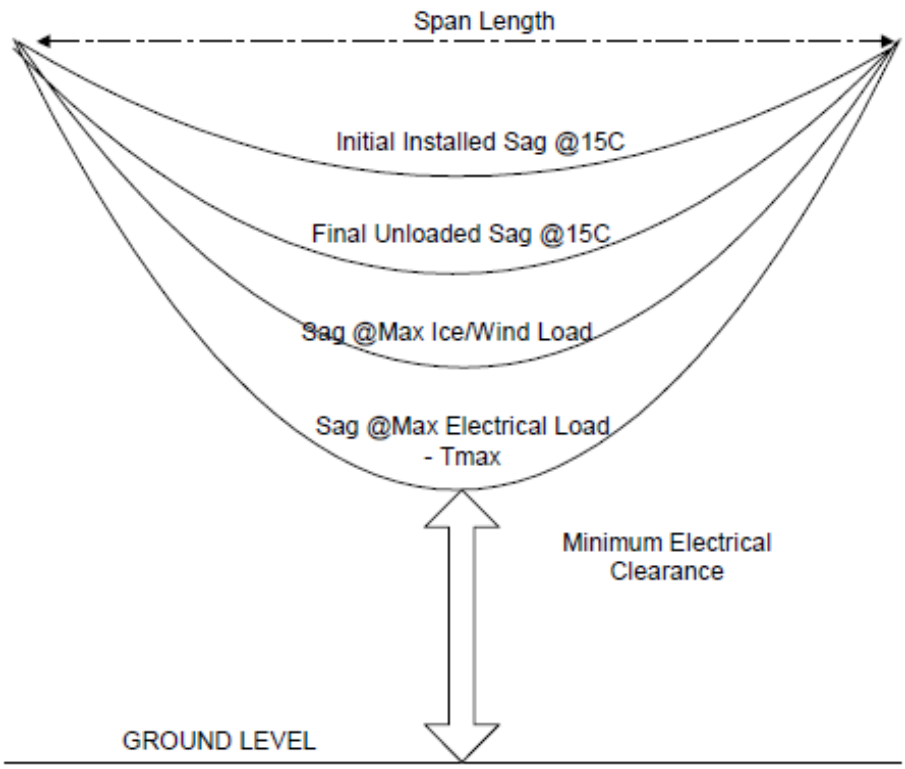


Figure 7 - Typical set of sag curves for a span

The DLR Project recognizes that the assumed ambient conditions that Static Line Ratings are based on have a low probability of occurrence concurrent with the period that the maximum load current is required to be carried by the conductors. The project is designed to determine the actual ambient and conductor parameters along the line at the given time to allow the maximum load current to be increased to the point where the Minimum Electrical Clearance is maintained while the current flow is maximized.

In operations, the State Estimator model is run and constrained under the assumption that the transmission grid will experience the N-1 contingency and that the system will maintain its service and reliability levels under those conditions. So the operation is not based on the combined probability of an event occurring, the system is operated under the criteria that both events occur simultaneously.

The monitoring of the line can be done by measuring the sag or clearance in a span or by measuring the tension in the conductor. From the catenary curve relationship in Figure 6, we know that the sag/clearance and tension of the conductor are directly correlated and that measuring the tension or sag/clearance in the span can be used to directly calculate the operating parameters in a real-time manner such that the current can be increased to a point where the Minimum Electrical Clearance will not be violated.

The DLR Project's primary monitoring system measures the tension in a span section of the transmission line as illustrated in Figure 8. A four-span section is illustrated, but the physics apply to any number of spans between deadended structures of the line. The conductor sag and tension are a characteristic of the span section between deadended structures. The intermediate insulator strings swing in either direction along the line to allow the span section to reach equilibrium where the horizontal tension along the span section is uniform. By monitoring this tension at the endpoints of the span section, the characteristics of the span section can be monitored rather than a single span or point along the line. This is important from a Dynamic Line Rating standpoint.

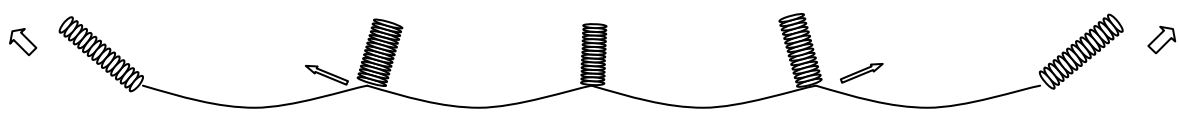


Figure 8 - Tension Monitoring CAT-1 system measures more than one span

The conductor performance characteristics are driven by the electrical loading in the line, i.e., the current, the ambient temperature, the solar radiation and wind blowing past the conductor. Since the latter three variables are spatial in content, i.e., they vary with location along the transmission line, the dynamic rating of the line is difficult to measure with a single point reference, i.e., the direct measurement of the temperature of the conductor in one span.

One of the concerns about using a point reference as the basis for a dynamic rating is whether one can be sure the worst conditions leading to the minimum clearance exist in the monitored span. By measuring the tension or sag/clearance of a section of the line between two deadends, the characteristics of that line section are more accurately determined and a more accurate line rating can be calculated for the ambient conditions.

The following Metrics Derivation shows how the measured line tension is used to obtain the various measureable quantities that define the benefits derived from Dynamic Line Rating. By knowing the line tension we can determine the conductor tension and ambient conditions, which then enables us to calculate the allowable increased transmission line capacity above the traditional static rating or the

currently applied ERCOT temperature-adjusted line ratings that can be transferred and maintain adequate ground clearance.

The increased line capacity is determined in megawatts and then megawatt hours depending on the duration of the increased capacity. By correlating that increased capacity and power transfer, the incremental cost in congestion can be derived by looking at the transfer change multiplied by the Shadow Price to derive the potential impact on congestion.

Metrics Derivation

Real-time Measurements:	**Line Tension**	
	↓	
Real-time Parameters Derived:	**Conductor Temperature → Sag → Real-time Ground Clearance**	
	↓	
Real-time Line Rating:	**MW**	**[Load to Match Minimum Clearance]**
Constraint:	**Baseline Rating exceeded by actual loading or N-1 contingency load**	
Transmission Constraint Relief:	**MW -**	**Real-time Rating – Baseline Rating**
	t -	Duration of increased capacity
	Mw-hr -	Mw x t
	↓	
Economic Relief	**$**[1]	**Mw-hrs x Congestion Shadow Price**

[1] Requires Congestion Shadow Price Cost Data from ERCOT

2.2 Project Development

When preparing the submission to DOE for this project, Oncor looked at its transmission grid system and operating characteristics and identified a corridor that was experiencing CSCs due to transmission congestion. At the time, ERCOT, the independent region transmission grid that Oncor operates within, was operated as a Zonal managed system. Figure 9 identifies the four zones within ERCOT and the

significant paths in which CSCs were currently identified. Effectively, Commercially Significant Constraints are when a number of transmission paths experience sufficient congestion that they constrain economic dispatch of the generation to serve the identified load. For example, the figure shows CSCs between the West and North zones in both directions depending on generation availability and load requirements and an export constraint between the South zone and the North zone. This South-North CSC was selected for the DLR instrumentation and validation project. The South-North zonal congestion historically contributed to the $40,000,000 of incurred congestion costs by the ratepayers per year.

Figure 9 - ERCOT Zonal Layout and Commercially Significant Constraints

The South-North corridor is shown as part of the Oncor grid in Figure 10. This corridor has a main backbone of two circuits of 345 kV transmission and several parallel paths of 138 and 69 kV serving the communities along the I35 corridor between Dallas and Austin.

Five 345 kV circuit sections and three 138 kV transmission lines were selected for instrumentation.

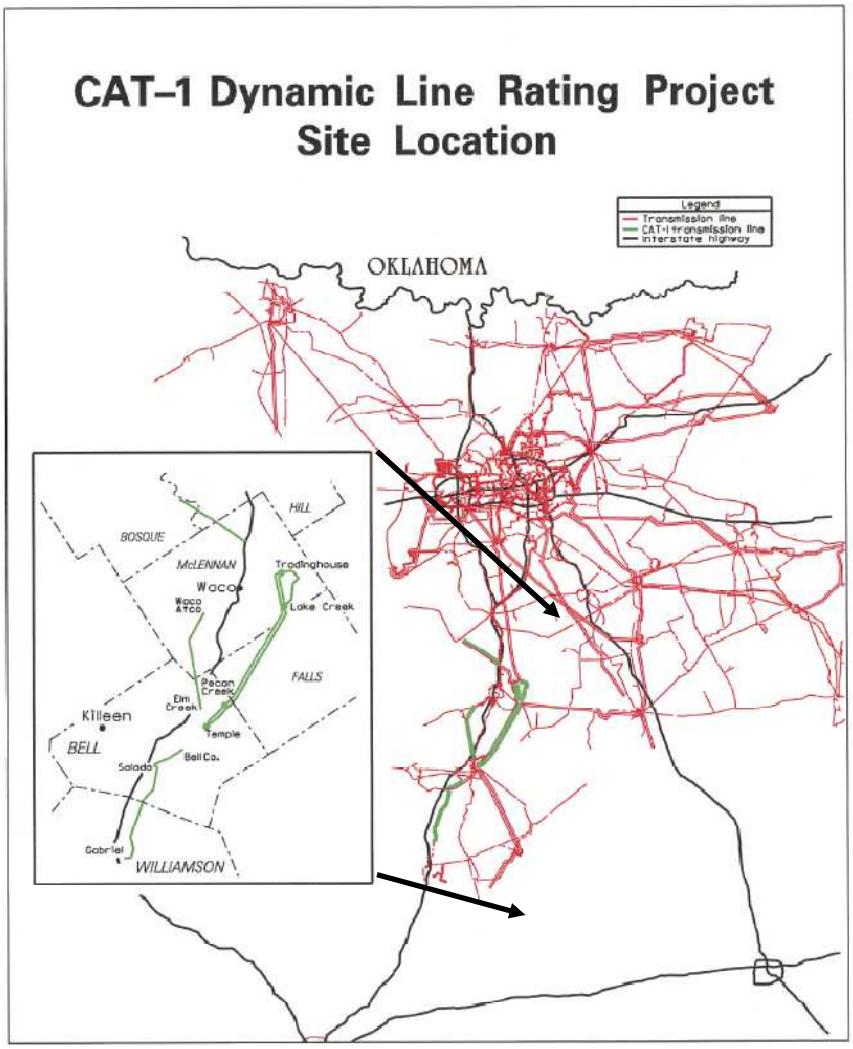


Figure 10 - DLR Project Area Showing Lines Selected for Instrumentation

2.3 Nodal versus Zonal Operation

When the project submission was made, accepted and approved, ERCOT was operating as a zonal market. Effective December 1, 2010, ERCOT transitioned to a Nodal Market, which significantly changed the way the grid was operated and the way in which congestion was identified and quantified. The zones identified in Figure 9 were supplemented by more than 3,000 nodes associated with each generation unit and every substation and transmission delivery point within ERCOT providing a network shown in simplified terms in Figure 11. ERCOT continues to consider the more global zone transfers but increased its system awareness of congestion through quantifying the grid performance on a nodal basis.

Grid operations changed with this new environment as well, taking advantage of the increased granularity of the system to manage the power flow and generation dispatch node by node, unit by unit, to provide optimal generation to load matching and system reliability. In the Zonal environment, ERCOT identified generation needs and placed a request for generation within the zone to meet demand. The

generation providers within that zone selected the generation unit(s) to produce and deliver the requested energy. The resulting energy costs and congestion impacts were socialized across each zone.

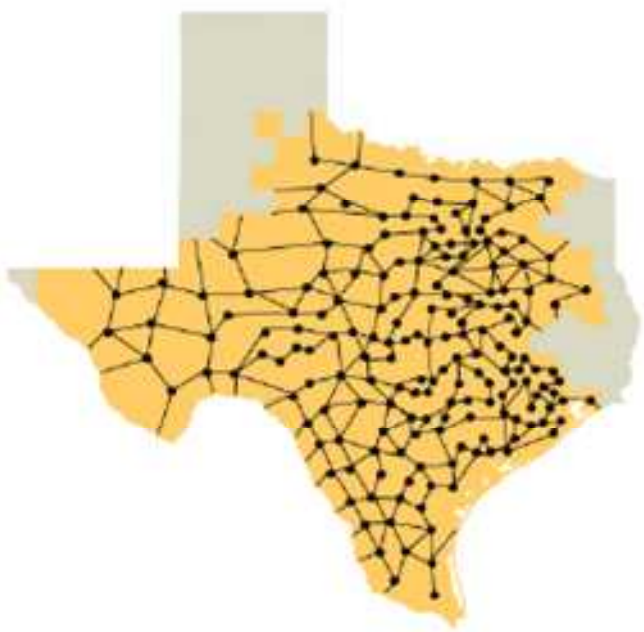


Figure 11 - ERCOT Nodal Configuration

The Nodal Market, however, manages the dispatch of generation at the unit level specifying the amount of energy to be generated and the cost to be paid based on the Day-Ahead Market Energy Offer Curves of the generation unit.

Each day before the Nodal Market's operation, the Day-Ahead Market (DAM) accepts Energy Bids for buying energy at a settlement point and Day-Ahead Energy Offers from energy resources. The offers are three-part and the entity can make the offer as any combination of parts up to a full three-part offer, identifying start-up costs, a minimum energy offer and an Energy Offer Curve (cost/amount of energy). Using the grid model, a co-optimized solution is calculated that matches generation with load, considering capacities and availabilities of the transmission elements and generation offers.

During the operating day, a SCED run is executed every five minutes during real-time operation to determine the most economic and reliable generation dispatch to meet load demand and transmission grid status, i.e., consider generation availability, transmission element ratings and transmission element outages. The SCED solution is an optimized calculation of the available transmission delivery system modeled in the Transmission State Estimator to dispatch energy from resources to demand on a node-by-node basis. The energy offered is based on the Day-Ahead Energy Offers, which identify the available sources of energy and the Energy-Offer Curves, essentially their cost curve. The State Estimator model may change at any time due to the real-time telemetry that identifies when transmission elements are not available due to a forced or planned outage for maintenance and for energy resources that may be on a forced or planned outage.

Congestion occurs when a transmission grid element, i.e., a line segment or piece of equipment in a substation on the path, cannot deliver the power from the desired (lowest-cost provider) node to the load sink node.

The congestion can be the result of an actual load flow limitation where the current would cause the line to operate at a temperature such that the minimum clearance would not be maintained (Figure 7). More than likely the congestion is due to an N-1 contingency limitation where the next outage of a plant, piece of transmission equipment or transmission line would cause a given line segment to exceed its maximum operating temperature with post-contingency loading. In either case, SCED may be able to manage the congestion event or the grid operator may be required to redispatch generation to meet the load demand. The Nodal Market adjusts the Locational Margin Price (LMP) for electric power at each node based on the economic dispatch and congestion costs to produce and deliver the power.

The Nodal Market provides much greater control over the grid operations, allowing the Independent System Operator (ISO) to manage generation unit by unit to meet the load demand on the system. By posting an LMP for each node, the actual cost to deliver energy at any given node can be determined. Costs for generation and energy delivery can be directly assigned to the responsible parties. When congestion occurs, it is specifically assigned to the cause of the congestion and the nodal prices reflect that cost and the market settles financially on a node-by-node basis.

If DLR capability was available on the line(s) that experience congestion and the ambient weather conditions were favorable, the line rating would most likely be higher than the static rating or ambient temperature-adjusted rating. With the increased DLR rating, the congestion event may have been mitigated or avoided and congestion costs averted.

In the ERCOT system, the market prices are established in the Day-Ahead Market where the generation providers identify their availability to generate and their cost of generation delivery curve. ERCOT identifies which resources and providers are required for the next day's operation to meet load forecasts and auxiliary energy services. A day-ahead Reliability Utility Commitment (RUC) system analysis is performed to establish an initial dispatch commitment for the resources.

As the day moves into and through real time, a RUC is performed every five minutes as part of the Security-Constrained Economic Dispatch cycle. Based on real-time conditions, the generation resources are given dispatch commitment signals to operate the system as close to optimum as possible. Forced outages of generation and/or transmission equipment may result in congested delivery paths that SCED resolves to avoid N-1 contingency and stability concerns. The resulting operating signals dispatched at the end of the SCED run include the LMP for each node for the next time interval. If congestion remains on any of the node-to-node paths, the LMP reflects the cost of congestion. The cost is equivalent to the LMP Shadow Price multiplied by the MW of power delivered.

2.4 DLR Instrumentation Design and Deployment

The primary DLR instrumentation deployed during the SGDP is based on a tension monitoring system developed by The Valley Group, a component of Nexans. The CAT-1 system incorporates a loadcell into the deadend insulator assembly at the end of each stringing section of conductor (Figure 12). The loadcell measures the tension of the conductor and sends a signal to a local processor at the structure. The tension data, ambient temperature and data on the solar radiation affecting the conductor are sent to a nearby substation via radio transmission. At the substation the data is streamed via the RTU and SCADA system of the utility to the system's Energy Management System (EMS) (Figure 5).

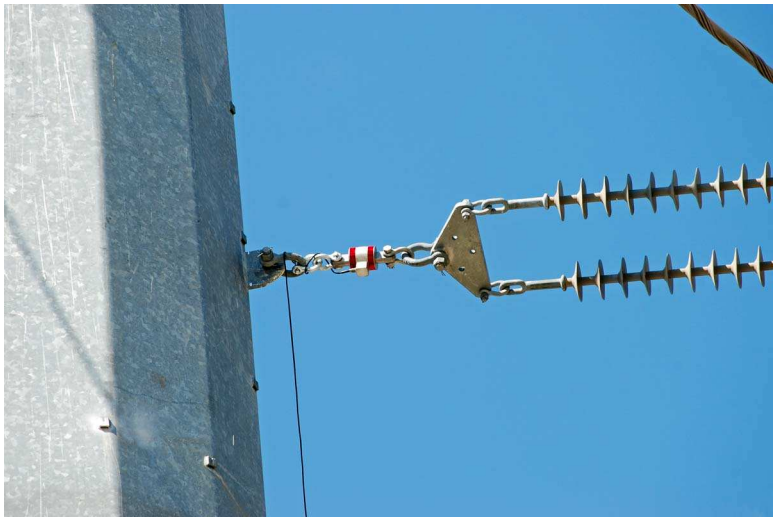


Figure 12 - Loadcell in Deadend Assembly

Through the Nexans algorithms, the data is transformed into a conductor temperature representative of the line section the loadcell is monitoring. From that information, the effective ambient conditions are measured and calculated. Then the algorithm calculates what the maximum current capacity would be before the conductor would reach the minimum clearance – maximum sag condition. This revised allowable current is the Dynamic Line Rating for the line section. By monitoring multiple sections of a transmission line to account for different line orientations, stringing conditions or terrain, the minimum dynamic rating can be identified and used for optimum operation of the transmission line.

As mentioned in the technical review of the line rating technology, the tension or sag of the conductor/conductor position can be utilized to characterize the line section's line rating behavior. The tension monitoring system was selected for the primary line monitoring technology for this project. The tension monitoring equipment and systems have been deployed by utilities for years in a variety of line applications. This SGDP deployment is the largest and most aggressive to be installed to bring real-time data to the control room operating environment.

One of the issues associated with deployment of a DLR system is the selection of location(s) for monitoring from both a geographic and quantity perspective. For example,

Figure 13 illustrates a simple transmission line layout. The majority of the structures are tangent structures with suspension attachment points. Deadend structures are located at each end of the line, possibly at a substation. A deadend is a location where the conductors are terminated on the structure or the direction of the line is sufficiently different such that the conductor is terminated in each direction and attached to a stronger structure to withstand the loads created by the line angle. In Figure 13, the line is broken down into six sections, A-F. Deadend structures are located at the triangular intersection of line orientations that have an angle of intersection greater than 17°. The angle structures between sections B-C and C-D are smaller than 17° and may or may not have deadends at the two intersection points.

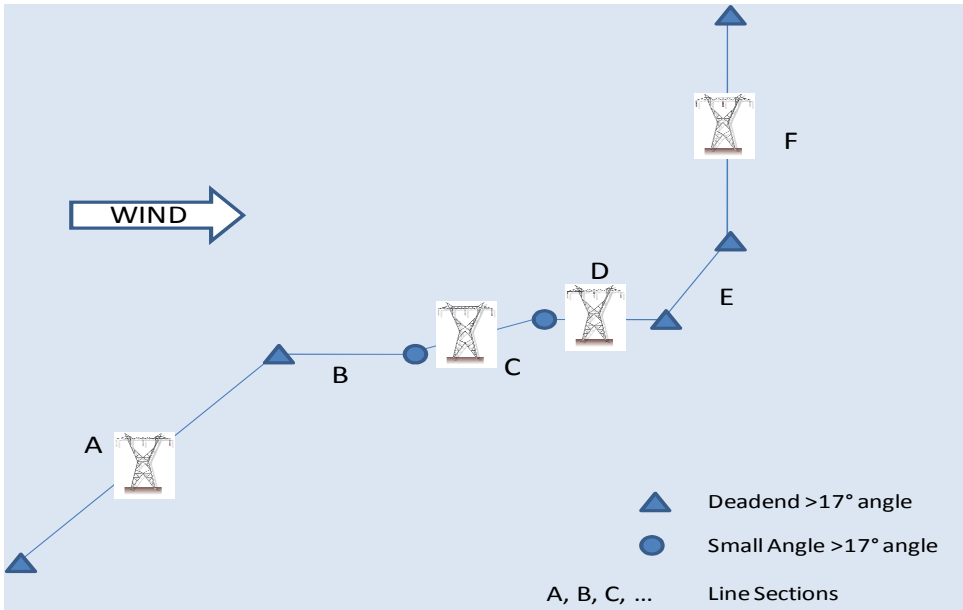


Figure 13 - Simple Transmission Line Layout

The DLR is very dependent on the wind speed and direction; and while the wind does not always blow from one direction, this layout shows several exposures to the wind direction indicated. Sections A, E and F will see the most cooling from wind as indicated by the direction in this figure. Due to different orientations and possibly different terrain covers, it will be desirable to capture the line rating in each of these sections. The wind is nearly parallel to Sections B, C and D. With this wind orientation there will be minimal cooling from the wind and thus these sections will run the “hottest” and be of most concern in the ratings. As the prevailing wind direction changes, the impact on the different sections also changes, so instrumentation will be needed on every section. Sections B, C and D may be considered one section depending on section lengths and terrain features. That predominant wind direction is further complicated by the fact that low wind speeds, of prime importance in the conductor rating scenario, seldom maintain a consistent direction and are greatly influenced by terrain and terrain cover, e.g., shielding of the line by trees and/or buildings.

Sections A and F may require several monitoring locations, depending again on length and terrain features. As part of this project, an Optimization Study was carried out on the data collected from the monitors deployed to provide guidance on optimum location and quantity of monitors required.

For deadend structures, the conductor is referred to as being deadended or terminated and attached directly to the structure with an insulator string (Figure 14).

In this picture, the conductor can be seen terminating directly to the shaft of the steel pole through an insulator string. The loadcell, which measures the tension of the conductor, is between the insulator assembly and the pole, as shown in Figure 12.

Figure 14 - Deadend Structure

The second type of structure identified is a small-angle structure. Note that at these locations, there is a difference in line orientation but the line angle may be small enough to allow what is called a “running-angle” configuration. This is an attachment similar to but stronger than a suspension point to withstand

the increased loads due to the conductor loads associated with the angle in the line. Between these two types of structures, many tangent structures support the conductor off the ground in what is called a suspension attachment (Figure 15).

In this illustration, the conductor is supported at the ends of the two insulator assemblies below the arm, which is attached to the pole. The suspension attachment is not fixed in position as the deadend position in Figure 14. A suspension insulator can swing longitudinally along the line as the tension of the conductor changes or swing in line with forces imposed on the conductor by wind.

Figure 15 - Suspension Structure

The Nexans recommendation has customarily been that a single loadcell has a reach of six to 10 spans in either direction from the device when both sides of a deadend structure are instrumented and no significant angles, i.e., greater than 17°, are encountered before reaching another deadend location. Depending on structure type and line construction, the “reach” will vary; typically, it’s six to 10 spans in each direction and as many as 15 or more spans on lines with longer insulator strings and span lengths.

This is one of the questions that could be answered by the Optimize Number of Devices Study and the Sag Verification Study. An objective of this project is to identify a best practices protocol for deploying DLR. So the line sections being monitored have more instrumented locations on them than traditionally applied. An optimization study will be conducted to determine the optimum number of loadcells required to develop accurate line characterization. A sensitivity study of varying combinations of instruments on each line will identify the minimum instrumentation requirement for accurate DLR projections.

Several of the transmission lines monitored for this DLR SGDP are 345 kV lines with lattice towers and no deadend structures between the substations. The preferred location is a deadend where the conductor assembly is already in a position to accommodate the loadcell to monitor tension. However, in the case of the 345 kV circuits being monitored, there were no angle structures with deadend assemblies. On the structures selected for instrumentation, “floating deadends” were installed on the lower outboard phase of each circuit. Figure 16 depicts the typical 345 kV CAT-1 DLR installation on a tangent structure for this Project. The full structure view of the tangent tower on the left in Figure 16 shows suspension attachments for the conductor. The two outboard phases were converted to “floating deadends”.

The top two insets of Figure 16 show a close-up of the floating deadend and the yoke plate assemblies with the loadcell in the left side of the hardware assembly. The vertical insulator is left on the structure and the suspension clamps at the base are replaced with a yoke plate to which the two deadend assemblies for the conductor bundle are attached. The jumper loops below the insulator assemblies and the yoke plate carry the current through the floating deadend assembly.

The mid-lower inset shows the CAT-1 control and communications cabinets with solar panels for charging the batteries.

For the 138 kV installations, several structures were converted from tangent - suspension framing to tangent - deadend configurations to accommodate the loadcell placement. Figure 17 shows the structure framing and details of the deadend with the loadcell and the instrumentation package mounted on the wood pole.

Along the eight circuits, 19 loadcells were installed on the 345 kV lines and 26 on the 138 kV circuits.

As noted previously, various combinations of loadcells for a given line will be used to predict the Dynamic Line Rating for the transmission lines. For every combination, the lowest calculated Dynamic Line Rating is used to rate the line. By doing a statistical analysis of the data for various loadcell installations, a guide for selecting the optimum deployment of instrumentation will be derived.

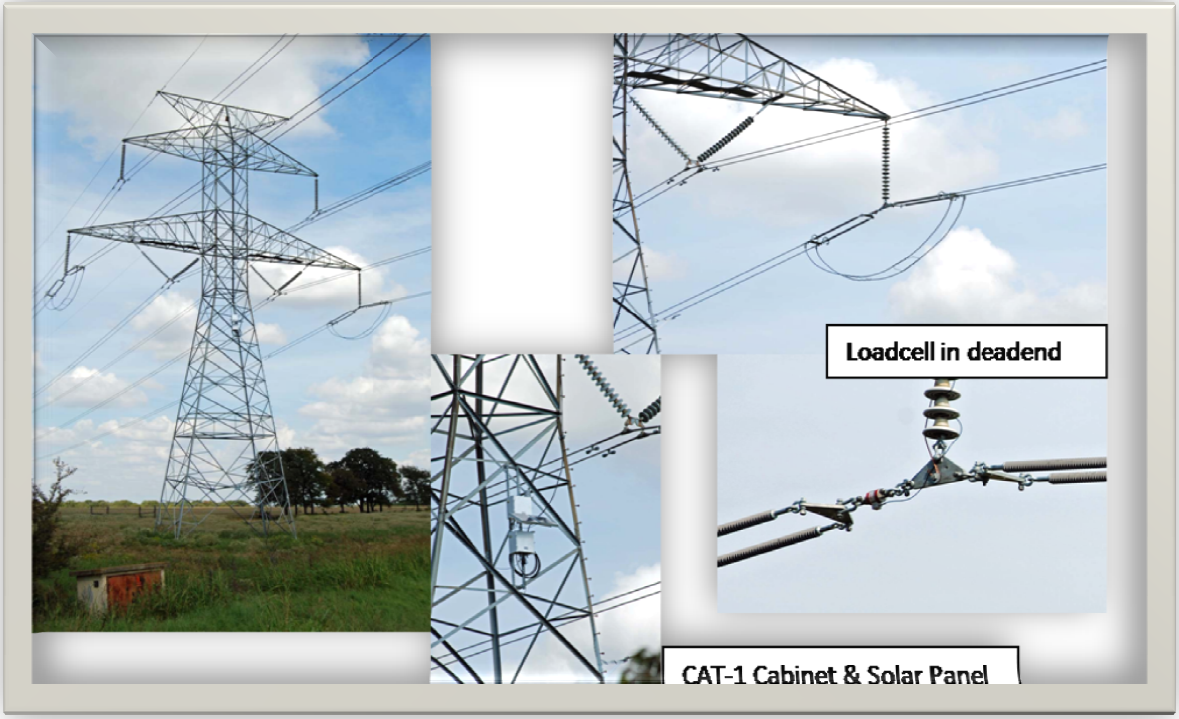


Figure 16 - 345 kV CAT-1 Installation

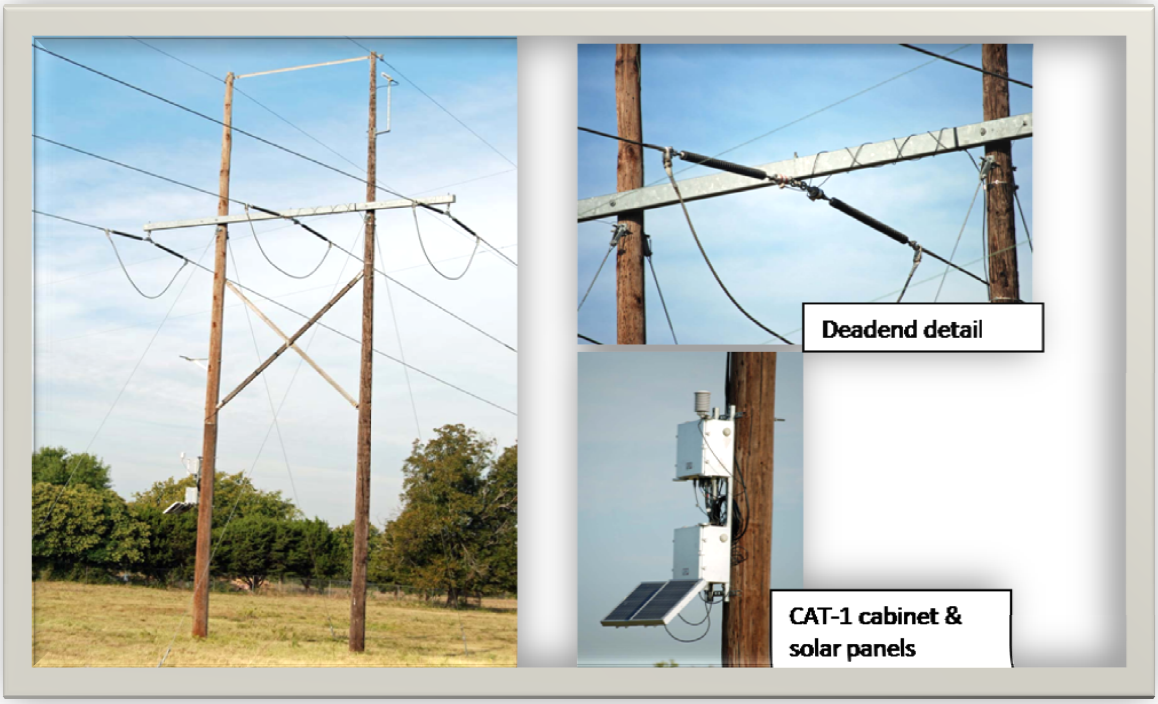


Figure 17 - 138 kV CAT-1 Installation

For each CAT-1 installation, a radio path was identified to locations where a CATMaster data aggregator could be installed to collect data from several CAT-1 sites and import that data through DNP protocol into the Oncor SCADA system via an RTU at designated substations. For the deployment on this project, eight CATMasters were located to aggregate the data and provide to the system via SCADA (Figure 5).

In some cases radio repeaters were required to connect the CAT-1 locations to the CATMaster due to terrain, topography and other line-of-sight communication issues.

2.5 Line Ratings

Several designations are used to define the level or type of line ratings. The following paragraphs will help delineate the classifications by showing the basis for each.

Static Line Rating (SLR). The Static Line Rating is a line rating associated with a specific set of ambient conditions. The specifics are not prescribed across the industry but are set by individual transmission entities. Oncor's SLR is based on an ambient temperature of 104 °F (40 °C), with a perpendicular wind speed of 2 feet per second (0.6 m/s, 1.364 miles/hour) and full sun. IEEE Standard 738 is used to calculate the rating for a given conductor based on a desired maximum operating temperature.

Ambient Temperature Adjusted and Dynamic (AAR or ATR). The Ambient-Adjusted Rating takes into account the change in ambient air temperature away from the temperature used in the Static Rating. If the air is cooler than 104 °F, the rating is increased according to the IEEE 738 equation, holding all other parameters the same. If the temperature is higher than 104 °F, the line rating is decreased.

The Oncor system is divided into seven areas, with ambient air temperature data derived from one National Weather Service station in each area. The lines are associated with one of the seven areas.

Some entities also refer to the Ambient-Adjusted Rating as Ambient Temperature Rating (ATR).

Dynamic Line Rating (DLR). The Dynamic Line Rating refers to any rating based on time-sensitive parameters that characterize the conditions at the time of the observation. This does not include the current loading but may reflect an ambient temperature, solar level or wind blowing across the conductor. Based on that time-sensitive set of parameters, the rating is adjusted.

Dynamic Line Rating in the SGDP is the line rating derived from the real-time monitoring system described in this report, which takes into account all of the ambient condition variables to derive the allowable line rating to arrive at a given maximum operating temperature.

There is a nomenclature issue in that many refer to the AAR as a Dynamic Line Rating, which it is, but it's not as dynamic as the real-time sensing system used in the SGDP. Therefore we are introducing two new references for DLR as described in the SGDP project.

Conductor-Monitored Rating (CMR). The Conductor-Monitored Rating incorporates the full measurement in real time of the ambient temperature, the contribution to the thermal equation due to solar radiation, the current loading on the line and the effective wind speed cooling the line. These conductor-monitored attributes are used to determine the line rating available that maintains the prescribed line clearance.

integrated Dynamic Line Rating (iDLR). The iDLR integrates the CMR data real time in the EMS telemetry that uses system-state values to perform its State Estimator reliability calculations.

Table 3 provides a comparison of the line rating formats. The more actual real-time data is available for the rating determination, the greater the opportunity will be to optimize the capacity of the assets in service. The Static Line Ratings are in fact very static; they do not change with time or operating conditions, but reflect what is considered a near-worst case condition for operations that the utility expects. Figure 18 shows that the Static Line Rating is fixed.

The AAR as Oncor applies it has one variable – the ambient temperature in the zone of the transmission line. Each line is assigned to a nearby weather station from which temperature values are received at some interval, and the rating is revised to reflect that ambient temperature, holding all other parameters at the same level as the SLR. Figure 18 illustrates that AAR exceeds SLR a large proportion of the time. It is less than SLR when the ambient temperature and effective wind speed are less than the SLR prescription.

A caveat of AAR is that when the ambient temperature is at or above the SLR temperature AND the effective wind speed is calm, the ratings are less than the AAR curve. In Figure 18 this is exemplified by the CIGRÉ curve. CIGRÉ Technical Brochure 299[3] requires that the deterministic prescribed wind speed be reduced when the ambient temperature is the only variable adjusted in the rating calculations. In essence, TB 299 does not allow taking full advantage of the 2 fps (0.6 m/s) wind speed if you also take advantage of a cooler temperature when you do not have a means to measure the effective wind speed on the conductor spans.

CMR has the potential to exceed all of the previous ratings a good proportion of the time. The only time it is exceeded by AAR and SLR is when the ambient temperature is high and there is no wind, since both SLR and AAR assume a 2 fps (0.6 m/s) wind.

Finally in reference to Table 3, the application of the ratings is different between the various formats. Currently, all system operators have the ability to apply SLRs in their automated State Estimator model to perform system security/reliability assessments for optimizing the generation resources.

Some entities like Oncor, in the ERCOT ISO system, stream AAR for operations. The application of AAR is not mandated in any jurisdictions and is not a widely applied technology across the utility industry.

[3] "Guide for Selection of Weather Parameters for Bare Overhead Conductor Ratings," CIGRÉ Technical Brochure 299, WG B2.12, 2006

The last two columns develop the same ratings based on line monitoring of the ambient conditions and transmission line performance from which accurate line ratings can be determined for the actual line conditions. Their method of application differs.

In the DLR or CMR application, the line ratings may be displayed in the control room for the instrumented lines. The data can be called up on a console screen and reviewed by the system operator. A decision may be made whether to take advantage of the real-time ratings. The iDLR format automatically provides the real-time ratings via its streaming system telemetry to the ISO operating environment where it is used as the lines' characteristic parameters for economic dispatch and system security modeling. The application of iDLR within this SGDP is an industry breakthrough for operations.

Table 3 - Line Rating Schema for Various Formats

Rating Designation	Static Rating	Ambient Adjusted Rating	Dynamic Line Rating	Conductor Monitored Rating	integrated Dynamic Line Rating
Considerations	**SLR**	**AAR or ATR**	**DLR**	**CMR**	**iDLR**
Conductor Properties, i.e, resistance and area	F	F	F	F	F
Ambient Temperature	D	V	V	R	R
Solar Radiation	D	D	V	R	R
Wind Speed (effective)	D	D	V	R	R
Line Loading (amps)			R	R	R
Real-time Measured Values			✓	✓	✓
Operations Display	A	A	A	A	A
Streamed to State Estimator in Real-time					✓

F: Fixed Based on Conductor Properties

D : Deterministic - 1 predetermined value

V : Variable to zonal value

A : Available

R : Real-time Monitored

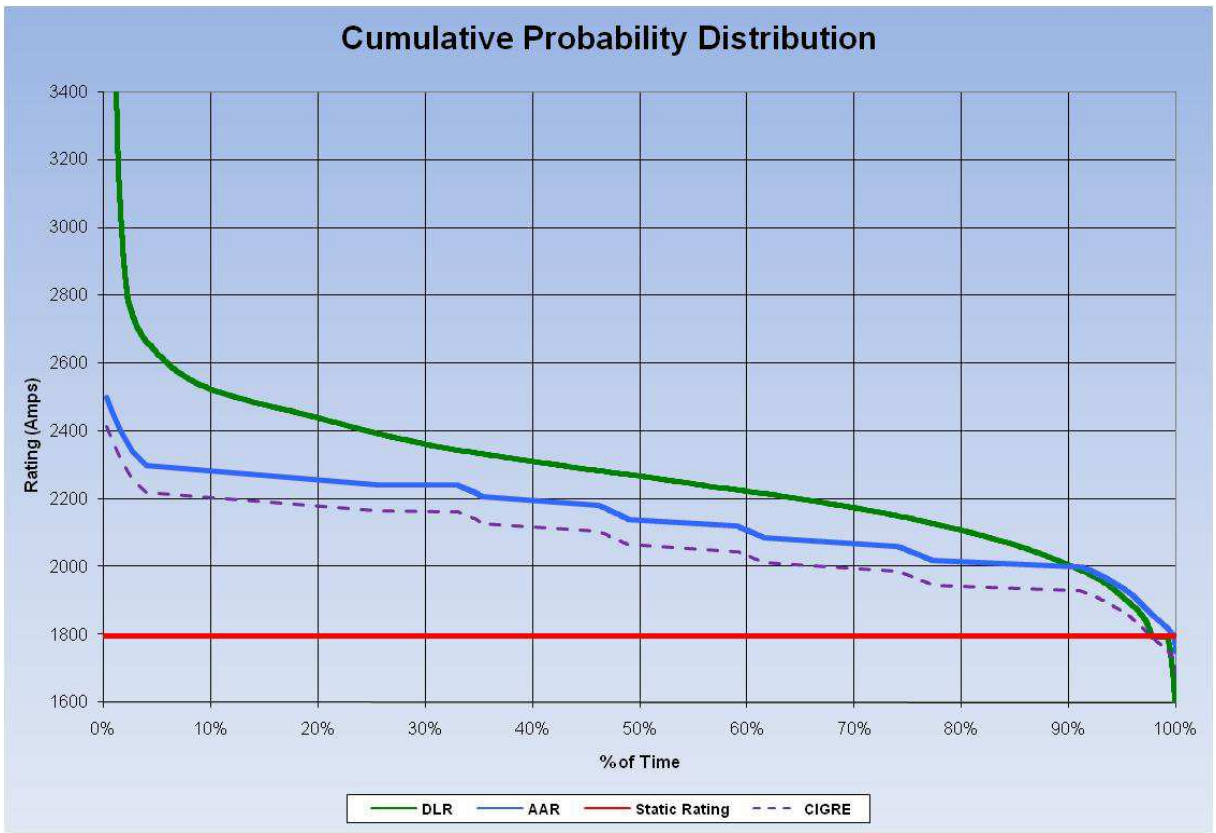


Figure 18 - Comparative Line Ratings Illustration

Figure 19 is an example of the variation in the ratings for a three-day period of data.

The red line is SLR, which does not change throughout the period. The blue line is the Ambient-Adjusted Rating (AAR), which reflects the change in the rating due to ambient temperature. Note the diurnal pattern reflecting the change in ambient temperature throughout the days. In this case the data was from August and the rating dipped below or was equal to the SLR two afternoons. This reflects that the temperature was probably higher than the SLR base of 104 °F.

The green line represents the Dynamic Line Rating (DLR) based on the remote monitoring of the line tension and determining the actual line rating. Note in this case we are using CMR data from a project line. The majority of the time DLR exceeds both SLR and AAR. There are times, however, where DLR is lower. This occurs when the wind and ambient temperature combination result in the line rating being lower due to either the ambient temperature being higher, conditions with less than 2 fps wind or a combination of both.

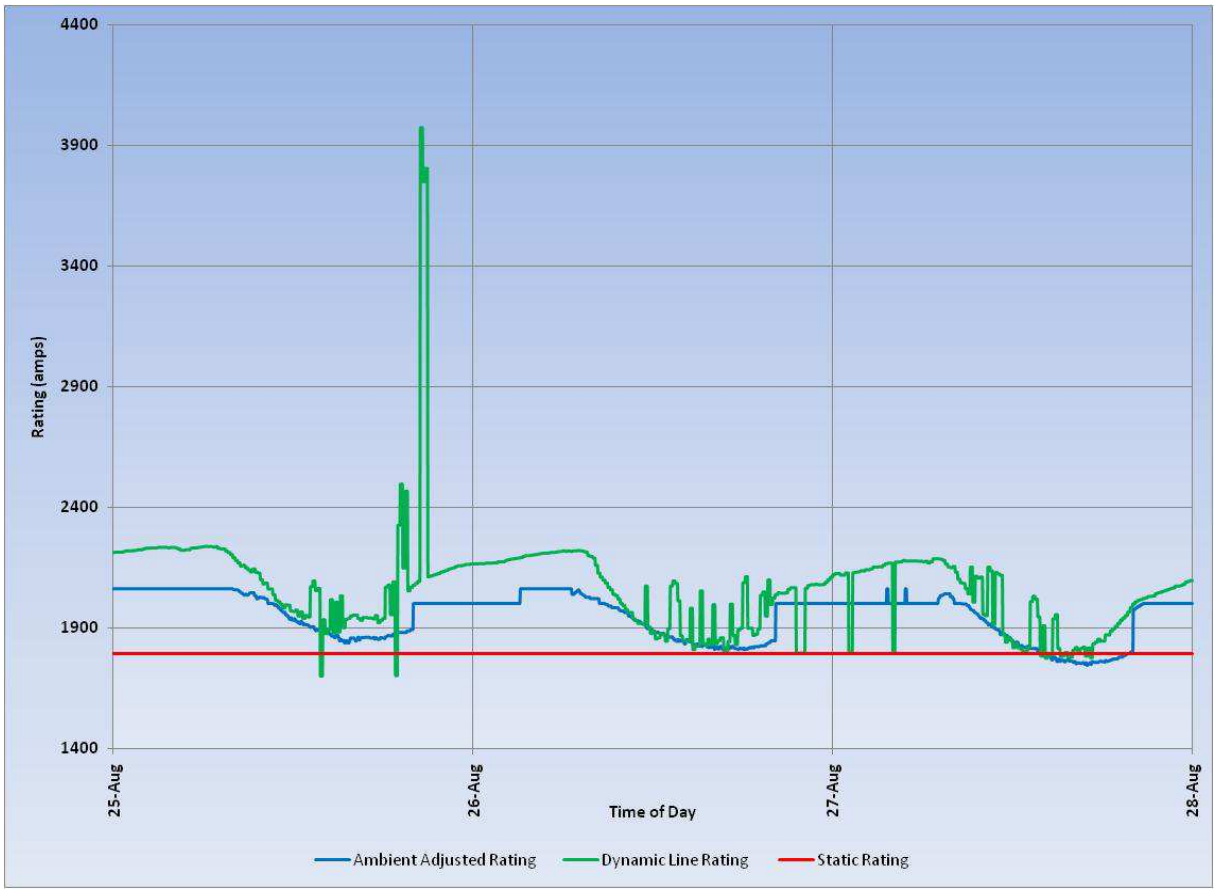


Figure 19 - Line Rating Comparison - Static, Ambient-Adjusted and Dynamic Line

Later in the report we will discuss the cumulative times that the ratings differ and present the capacity available as a percent of time. This is valuable information for applying DLRs for planning purposes.

From an operations standpoint, since the system is monitoring the ratings in real time and the ISO Operations are assessing and managing the system performance based on the real-time data being streamed to them, the SCED runs and system-awareness provided by DLR enable reliable operation of the grid to continue across the time period.

2.6 Energy Management System

As noted in the previous section, there are two ways DLR data can be applied in the operating environment: responsive or real-time operations.

In the case of a responsive mode, the DLR data is available to the grid operations staff on a console. The operator can consult the console to see the available ratings if the need arises. For example, a line is going to be loaded to an elevated level due to prescribed flows or anticipated through a possible contingency event. The operator could check the DLR on a console and decide if there is sufficient capacity to respond to pending needs.

This has been the traditional application of DLR in real-time operations for years. System Operations consults the DLR on an as-needed basis.

The SGDP Project applied the DLR system in a real-time automated operations mode. The EMS was programmed to insert the DLR into the data telemetry used by Oncor's operating system and State Estimator program and in the data stream posted for ERCOT's use in running the real-time SCED system. Thus we are referring to the technology as iDLR.

This is a breakthrough in DLR application. Operations applies the iDLR in an automatic-transparent mode, which accepts the iDLR rating after quality checks are performed and automatically uses it within the operations scheme of the EMS at Oncor and ERCOT. The processing of data as exemplified in Figure 5 proceeds from collection of the tension at multiple remote locations; it is sent to several collection centers and introduced to the Oncor system through RTUs and SCADA.

On the IntelliCAT server, the ratings are calculated, quality checks made, alert flags set and minimum ratings for line sections posted to the EMS server. EMS inserts the data into the grid telemetry if all flags pass logic checks. If the quality checks detect an issue with the data, the ratings revert to the Ambient Temperature Adjusted Rating used by Oncor and an alert notification is sent to specific Operations desks for technical support.

ERCOT polls the Oncor EMS on a regular basis for application in the SCED analysis. The iDLR are now used to establish the capacity of the monitored line sections. It has been Oncor's practice to limit AARs to no more than 125% of the line's Static Rating, and for the SGDP that cap has also been applied to the iDLRs. The cap setting is applied for two reasons. First, many of the next-limiting elements of the system are approximately 133% of the Static Line Rating, so the 125% keeps a small buffer for those elements. Second, the DLR Project is operating as a new protocol in respect to the autonomous-transparent nature, and it was decided to maintain some restraint on the degree of additional capacity introduced to the system.

The autonomous-transparent mode requires a large level of confidence in the iDLR system by System Operations. However, if we reflect on the data provided in Figure 19, we see that the iDLR has both increased capacity the majority of the time and system awareness of the grid performance all of the time, which provides increased reliability.

Prior to this project, the operations environment has been reluctant to adopt the near-transparent mode of streaming DLR to the automated operating environment. In fact it has been very difficult to get the responsive mode where the dynamic rating is available on a console. The operations environment must have confidence in the rating system from several aspects:

- Accuracy. Is the dynamic rating an accurate rating that the operators can depend on? They need faith in the technology, the calculation validity and the accuracy of the ambient temperature, solar and wind effect characterization to develop the ratings.
- Reliability. Is the dynamic rating system reliable in that it does not go offline due to technical and mechanical issues?

- Technical knowledge. Do operators understand what the ratings represent and the basis for their variability?

The operators who use the ratings to manage the grid must have high confidence that the dynamic ratings are correct and available for them to apply. Since the ratings typically represent additional capacity and their application could be considered an additional risk to system reliability, the operators must trust the line rating system and its data.

Another aspect of the ratings that has been an operator concern is the apparent variability of the ratings and their constant fluctuation. The fluctuation that can be seen in plots like Figure 19 seem too volatile to the operator for operation confidence, i.e., they fluctuate too much and too fast to be able to depend on that capacity being available.

The iDLR application addresses all of these issues. From an accuracy and availability aspect, the EMS has been revised to include a series of checks and validations that ensure that the data being received from the remote monitors is within an acceptable range, that the data is available in consistent data captures, and that it has not been interrupted or contaminated. Once a sufficient number of monitors have reported reliable data, ratings are determined for each line section, applying the lowest rating as the defining rating for the section. That is to say, due to line orientation and sheltering, each line sections will have a different rating from the next. We use the minimum rating as the overall line rating. That rating is passed through EMS and posted for operations.

The volatility of the conductor temperature and rating is inherently managed by the conductor itself and its time-constant, referring to the time it takes for the conductor to reach a stable temperature due to a load flow change, an ambient temperature change or an effective wind speed change that would alter the thermal performance of the conductor. Since the time constant is on the order of 15 minutes for most transmission-size conductors, the volatility is basically controlled by the time constant. An ambient condition change must be in effect for a sufficient length of time to impact the conductor; the line length also comes into play in this case.

If any concerns are raised about the quality, availability or consistency of the data, the system reverts to the base system rating, which for Oncor is the AAR. An alert is sent to an appropriate desk in the operations environment for resolution of the cause for the iDLR interruption. That desk performs appropriate analysis of the problem and has any repairs or appropriate action taken to bring iDLR back online. The system continues to operate without interruption.

The iDLR technology as applied in the SGDP does not introduce additional workload or training on operations personnel. They understand that the iDLR is being applied and that appropriate checks maintain the systems viability and continuous ratings offering for operations. Because the iDLR system is continuously monitoring the condition of the transmission grid where monitors are installed, there is an increased system awareness of how that portion of the grid is performing, and that awareness is applied to the grid's benefit in real time.

2.7 Alternative DLR Technologies

The SGDP Project has applied several alternative DLR technologies currently available in the marketplace. As we mentioned, the determination of the conductor position via tension monitoring or by monitoring the sag/clearance distances is the preferred methodology to characterize the spatial aspect of the conductor on a transmission line. Devices are available that take direct measurement of the conductor temperature, but as previously discussed, they provide no insight into the spatial context of that temperature.

Several position monitoring devices are offered for DLR and more are in development. The project used two of the systems for the collection of data to be used in validating the spatial aspect of the DLR monitoring systems described in the next section.

The Sagometer® monitors the sag of a span by automatically determining the movement of a target attached to the conductor within view of a camera attached to one of the transmission structures. Through catenary mathematics the position of the target is interpolated to the point of interest, e.g., the low point of sag, the sag at a minimum clearance location on the span, etc. The data can be stored within the device or collected via external communications and presented in real time on a server. http://www.edmlink.com/line-rating.html

The Promethean Real-Time - Transmission Line Monitoring System (RT-TLMS) monitors the magnetic field around a conductor. The field strength is proportionate to the level of current flowing through the line, and the magnetic field strength degradation is proportionate to the distance squared. By monitoring the phase currents of a transmission line and performing calculations of the installation geometry, the conductor position, i.e., clearance to the sensors/ground, can be monitored and again displayed on a server via external communications. http://www.prometheandevices.com/

The Sagometer and Promethean RT-TLMS systems were deployed on the project to collect positional data to be used in the Technology Validation tasks.

Another collection of monitoring equipment is deployed with direct attachment to the conductor at prescribed locations on the span. Many use the slope of the conductor, measured by an inclinometer within the device attached in the span on the conductor to characterize the catenary curve and revert back to the conductor positional algorithms.

Other systems measure the natural frequency of the conductor to characterize its catenary curve, similar to the tension on a guitar string and its frequency. A number of the devices also include telemetry to measure the conductor temperature, the distance to the ground using Lidar and ambient conditions. Equipment in this category includes but is not limited to (additional systems are under development worldwide):

- Ampacimon – Ampacimon Monitor http://www.ampacimon.com/
- Lindsey Manufacturing – TLM Device http://www.lindsey-usa.com/

2.8 Validation Technologies

As part of the project, a validation and accuracy assessment of the CRM technology is being conducted. This task has two objectives: first, to validate that the tension monitoring and CRM algorithm properly characterize the conductor by properly estimating the conductor position and temperature for the stringing section the CAT-1 loadcell is mounted on; and second, to validate the spatial capability of the CAT-1 device relative to its "reach" and the variability in span characterization within the monitored spans' length. For example, do small line angles, short versus long span in a stringing section, or the distance from a DLR device have a significant impact on the system's ability to characterize the conductor position and temperature under real-time climatic conditions?

To facilitate this validation assessment, secondary monitoring systems are being installed on a variety of spans relative to the primary CAT-1 systems. The secondary monitors use two technologies to monitor the conductor position in specific spans. The first system, known as the Sagometer, is a camera mounted on a transmission structure monitoring a target attached to the conductor a short distance into the span (Figure 20). By correlating the target position with the full span behavior, the Sagometer can capture the conductor position at any given time. In Figure 20, the camera (in the inset at the left) is mounted on the structure below the conductor positions. The target is visible on the closest phase near the left side of the picture as a round dot hanging from the conductor. The Sagometer was developed by the Electric Power Research Institute and sponsoring utilities. It is marketed by Avistar, Inc.

Figure 20 - Sagometer Installation on 138 kV Wood H-frame

The second technology used for system validation task is the Real-Time - Transmission Line Monitoring System (RT-TLMS) by Promethean Devices, Inc. The RT-TLMS is located on the ground under the transmission line. The sensors detect the magnetic field associated with the level of current flowing through the conductor. As Figure 21 illustrates, the multiple sensors detect the magnetic field strength and through their algorithm calculates the position of the conductors by triangulating the field strength associated with each phase.

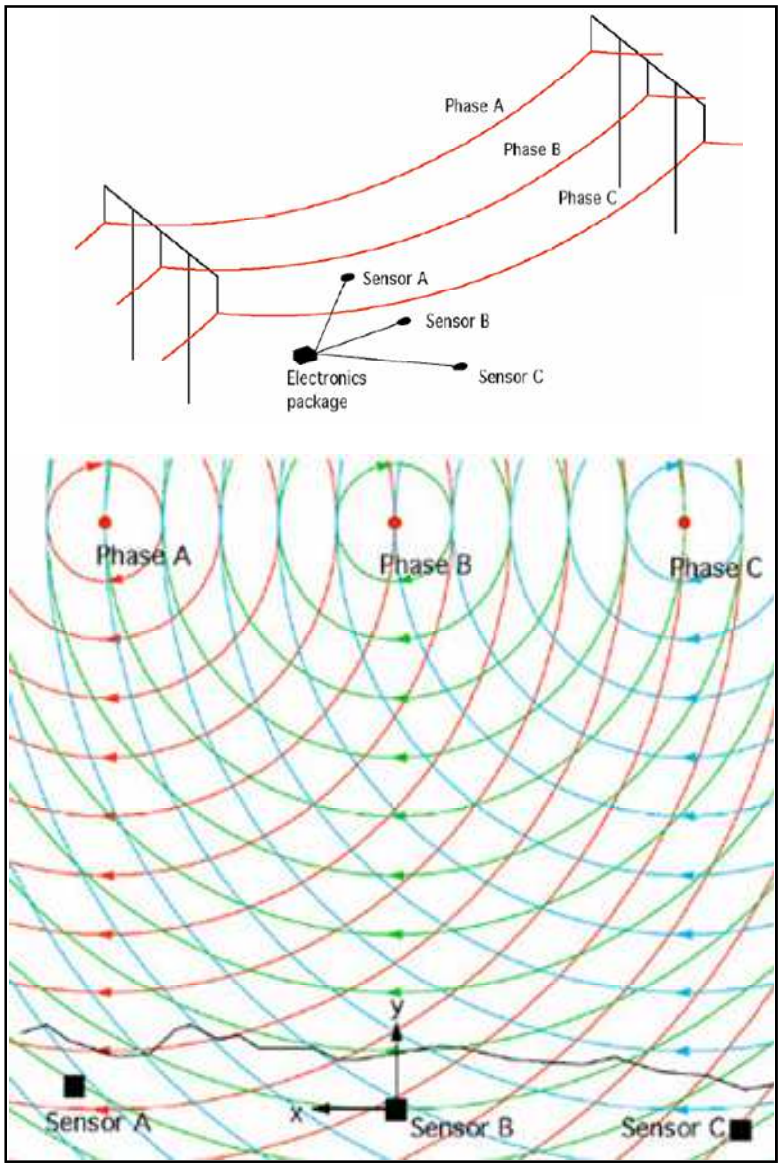


Figure 21 - RT-TLMS Technology Overview

Figure 22 is a picture of the double circuit installation under a 345 kV line. The six phase sensors are located inside the faux-rock structures and connected via signal cables to the processor in the cabinet under the solar panels in the background. The white stakes are referenced points and not part of the instrumentation. This configuration could also be buried on the right-of-way for a lengthier application.

Both the Sagometer and RT-TLMS are designed to provide streaming real-time data to a control room in similar fashion to the primary CAT-1 systems. The systems also have their respective algorithms to determine the dynamic rating of the line. For SGDP, they are not streaming data real time to a control room but providing a time-stamped data set of conductor position that can be correlated to synchronized time frame data of the CAT-1 system. The sag position of the systems will be used to validate the accuracy and capability of the CAT-1 system to characterize a multi-span section of transmission line. Effectively, this validation process will calibrate and validate the overall DLR spatial accuracy to characterize transmission line operations.

Figure 22 - RT-TLMS Double Circuit Installation Under 345 kV Line

2.9 Analyses

2.9.1 Capacity Above Static or AAR

The basic capacity study is to evaluate what percentage of time the DLR exceeds both the SLR and the ERCOT Ambient-Adjusted Rating (AAR). For the more traditional operating environment where the static ratings are based on a fixed ambient temperature and wind speed, the availability of dynamic ratings will show a cumulative value above the static level similar to the plot shown in Figure 23 where the

ambient temperature has a very low probability of exceeding the static rating ambient temperature base. For example, 104 °F (40 °C) is typically set as the ambient temperature for line ratings. If the utility is in the northern half of the country, the probability of having many days at or above this temperature is very low. Coupled with the simultaneous occurrence of a 2 fps wind, the probability of occurrence is likely less than 1-2%.

In the ERCOT region where Oncor operates, the probability of an ambient temperature higher than this static rating target is much greater. For example, the 2011 summer season experienced record numbers of days over 100 °F across the state. The Oncor service territory exceeded 100 °F 80 days during the 2011 summer.

The statistical capacity availability analysis will evaluate the magnitude and statistical availability of increased capacity for Oncor's service area and also take into consideration the Ambient-Adjusted Rating.

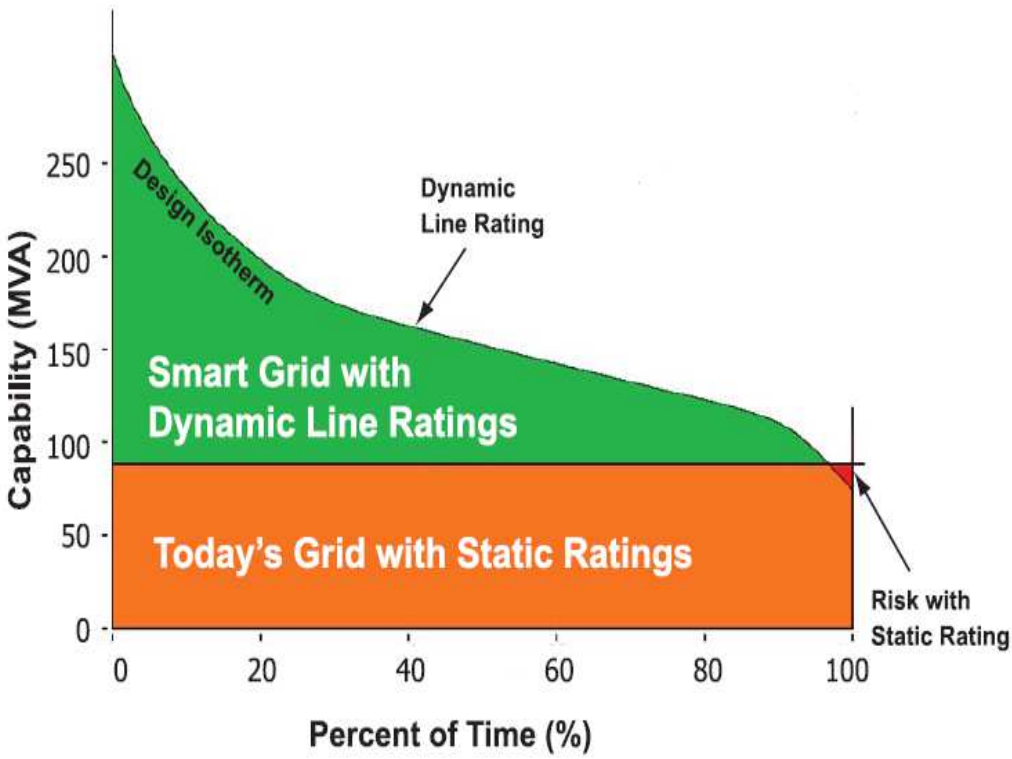


Figure 23 - DLR Availability vs. Static Ratings

2.9.2 Persistence

One of the concerns about using dynamic ratings is how long a time frame an increased line capacity is available on a transmission line. This concept is referred to as Persistence. Will the increased capacity be available for the next five minutes, 15 minutes, one hour, two hours or longer? If the capacity is only available for short durations, its peak value may not be the value of interest; a lower level of capacity

available for a longer period may be more valuable. Conversely, if the persistence characteristic is of a longer duration, more of the DLR capacity may be depended upon. One of the studies being undertaken as part of the SGDP is such a persistence study.

Consideration about persistence also has to be given to periods of high temperature and limited wind (< 2 fps) when the conductor rating will be less than static due to the lack of wind. If that condition persists for too long a period, lines will need to be derated.

The rating persistence is important from an application perspective when the system operators need to depend on the DLR increased capacity and in the cases when new generation must be dispatched to resolve a congestion problem. Generation units have different start-up times between the dispatch request and when the energy is available on the grid. There is an integrated correlation between the persistence of dynamic ratings and its solution to various system energy demands and dispatch coordination.

2.9.3 Capacity Availability for Planning

The availability of increased capacity through DLR can also be applied by System Planning when considering deferring capital investments. If the capacity released by DLR has an appropriate level of availability when N-1 contingency demands and peak loading events occur, DLR can be used to provide the capacity required. This would allow deferring physical construction and upgrading lines, thus deferring capital investments and optimizing operating costs.

In the long term it would be a goal that an appropriate planning tool would be built around the proven capacity identified and provided by a Dynamic Line Rating system as correlated to specific weather forecasts and the anticipated weather for some future time frame, perhaps next hour, several hours, next day or next week.

This study will identify patterns in ratings that can be used to forecast dynamic transmission capacity. Based on those patterns, a methodology will be defined that provides a practical and easily implemented forecast of capacity. It is anticipated that the data will justify a methodology that raises the static limits presently employed in transmission system planning. However, that is not a foregone conclusion and other techniques remain open to exploration.

There is always uncertainty in any forecasting technique. The degree of uncertainty that is acceptable and the impact of that uncertainty on planning and operations will be assessed.

Also to be assessed is whether a given methodology is universally applicable or if it needs to be tuned for a specific set of conditions such as voltage class, size of conductor, length of line and surrounding terrain.

In summary, there are a variety of parameters and their relationships that will require study to move the planning and forecasting tools forward:

- What historical dynamic ratings need to be correlated to ambient climatic conditions to be used as a statistical basis for analysis?
- How global is the forecast relationship relative to line location, line geometry, conductor loading and terrain? Will the statistical analysis be required for every line application individually?
- How does climatic event development affect the rating characterization? Does a period of windy weather after a long, dry, calm spell have different behavior than long, moderate days, etc.?
- Is it possible to capture sufficient data over some period of time to be able to forecast behavior without monitoring but using forecast information?
- Will monitoring the line on a continuous basis be required versus data capture, algorithm modeling and forecasting tools?

2.9.4 Capacity Released by DLR

A major phase of the SGDP Project involves the reduction of the real-time data and the DLR forecasts to identify the opportunities for congestion relief during the monitoring periods following the derivation noted above. The Capacity Released Study will work through the real-time data and ratings algorithm to develop a methodology to harvest events of congestion relief opportunity from the ERCOT data. Once these events are identified, their constraint relief will be identified by MW and duration. The Economic Trade Space Analysis Study evaluating the economic impact will depend on developing a relationship with ERCOT to determine the cost impact of the specific congestion relief.

If a transmission corridor is constrained such that the system would like to transfer more electricity along the corridor than is possible, the ISO will have to redispatch generation to meet load demand at a specific location. This may create an incremental cost increase for the energy due to the need to secure the additional energy from an incrementally more expensive generation source.

As Figure 24 illustrates, Oncor is the portion of the electric power delivery system within the red circle. As mandated by FERC and administered by ERCOT, Oncor Electric Delivery is strictly a transport and delivery service within the system, a TSP. By regulation, Oncor is not allowed to know the incremental cost of generation that is impacted by congestion and congestion relief on its transmission lines. Nor is Oncor involved with the retail business of selling the power to a customer. Oncor is paid on a PUCT regulated basis for each MW delivered between point A and point B, regardless of the owner of the power or buyer of the power. The economic benefits that the Dynamic Line Rating protocol can create are reflected in the development of the cost of power at the delivery node.

Note: While ERCOT and Oncor are used as the basis for this discussion, similar relationships and operating criteria exist among the other ISOs in the country and the TSPs within them. The specific terminology used at each ISO may be different, but equivalent operating protocols are used in all situations.

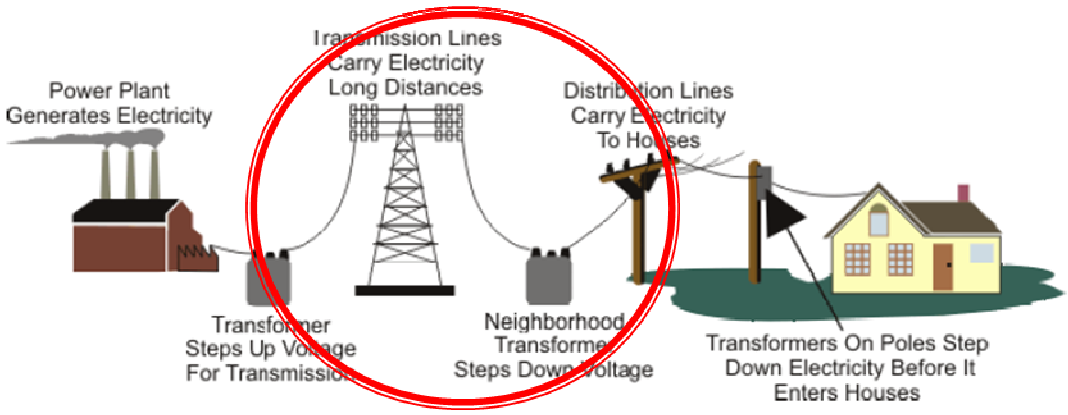


Figure 24 - Oncor Electric Delivery - The Power Delivery Portion of the Electric Business

Oncor has been working with ERCOT to identify a process to quantify the economic benefits of DLR in the operation of the ERCOT grid. As noted, ERCOT has been operating under a nodal basis since December 1, 2010. The ERCOT Nodal Market is divided into three time-oriented segments:

Day-Ahead Market. The DAM is a planning stage where the generation entities identify and quote their proposed offering for the next day to sell energy on the market as energy or an ancillary service (power used to help maintain reliability and stability on the grid). A deliverable of the DAM is a list of potential congestion constraints based on the available transmission elements, forecast load and offered generation known as the DAM Shadow Prices. The DAM Shadow Prices list the constrained transmission elements, including line segments and transformers and their respective shadow price-effective congestion cost.

Real-time operations. During real time, ERCOT runs SCED analysis that models the generation and transmission elements to match the load demand. SCED is run at a minimum of every five minutes, and its result is generation dispatch commitment signals to every generator. The SCED Shadow Prices and Binding Transmission Constraints is a published list of active congestion constraints on the ERCOT grid, again listing the transmission element and the effective cost of congestion across that element. When the SCED analysis is not able to solve a congestion issue, the system operators are alerted and they make specific decisions about redispatching generation to resolve an issue. Their decision is largely based on their experience with the grid and its operating characteristics. Their experience plays into knowing that selecting a specific transmission path and redispatch order may resolve several issues.

Settlement period. Every 15 minutes, ERCOT creates a settlement entry that averages the cost of energy generated and delivered for 500 settlement point nodes. The load-serving entities that bought the energy are invoiced based on these settlement points. The generation resources are paid based on their DAM offers and the amount of energy they provided.

Because the iDLR ratings to Oncor EMS and ERCOT are transparent, it is not possible to know when congestion events would be avoided by increased capacity from DLR. The added capacity is integrated into the SCED run, and if that capacity resolved a transfer capacity need due to high loads or an N-1

contingency the event or impact of the specific DLR differential rating would not be known. The only time that the DLR capacity would be recognized is if we could look at the SCED analysis with and without the DLR component.

In order for the DLR SGDP to quantify the impact of the increased ratings on operations, ERCOT and Oncor developed a strategy to use the DAM analysis to provide an indication of the impact Dynamic Line Ratings have on congestion relief. The DAM analysis models the day in one-hour blocks and identifies where congestion events will arise due to load demands and the generation resource availability/cost profile. By executing a DAM analysis based on the traditional ambient-adjusted temperature ratings and a DAM analysis using potential DLR in a post-processing analysis, a comparison of the impact of DLR can be achieved.

By rerunning the DAM analysis for several days and using several adjusted DLR, a matrix analysis of the impact of DLR on congestion can be developed. Lines that are congested will be selected for the study and various adjusted ratings applied to the same base DAM model. Rerunning DAM is a time-consuming task that cannot interfere with normal ERCOT operations. So a limited number of days were chosen for the assessment.

The results of the DAM assessment will provide a template for congestion mitigation relief that can be expected for the n-target lines and then extrapolated to Oncor-wide and ERCOT-wide impacts.

2.10 Reliability

System reliability is the No. 1 goal of ERCOT, Oncor and all electric operating entities. Increasing the capacity of target lines through the use of DLR provides the potential for increased reliability. Increased capacity provides some flexibility and margin in the operating environment not present when the system is running tight and near the edge. The reality is that the system will take added capacity and raise the bar, operating at the higher level, but that is still at a level where the system is stronger.

In real time ERCOT receives telemetry from all the grid participants that relates information about voltage, loading on equipment, current flows, etc. DLR instrumentation is additional data that can be introduced to the data stream and as such improves ERCOT’s ability to characterize grid status and operate more efficiently and reliably.

DLR provides a higher state of awareness of the system performance through the real-time monitoring of the transmission operation state at the remote DLR sites.

3. Project Results

3.1 Installation and Deployment

Deployment of the DLR equipment was completed effective per the following stages:

- Thirty-seven loadcell CAT-1 devices were installed on eight line segments.
- Eighteen were installed on 345 kV steel tower lines.
- Nineteen were installed on 138 kV wood H-frame lines.
- Eight CATMasters were installed in substations to route the data into the Oncor SCADA system.
- An IntelliCAT server was installed at the Transmission Grid Management.
- EMS system was upgraded to manage DLR data incorporation in ERCOT telemetry.
- Five Sagometers were installed for the Sag Verification Study.
- Two RT-TLMS systems were installed, one for 138 kV monitoring and one for double-circuit 345 kV monitoring.

3.2 Primary DLR Remote Sensing Equipment – CAT-1s

Installation completed October 2010

Loadcell replacements. After several months of operation, degradation in the loadcell signal from the loadcell to the CAT-1 motherboard was identified on the 345 kV installations associated with the floating deadends. Upon examination, it was found that spark discharges from individual insulator caps to the signal wire were causing the wire sheath to break down; moisture ingress and signal attenuation resulted. The loadcells and their signal wires were replaced, and the insulator assemblies had each insulator cap and pin grounded and the signal wire routed through a piece of PVC conduit attached to the insulator string to mitigate any electrical charge discharges from the insulator metal parts. This was completed July 2011.

3.3 EMS Upgrade

Programming in the Energy Management System to feed the DLR ratings through to the operating control rooms at Oncor and ERCOT was completed June 2011. The build was not incorporated into the EMS until May 2012 due to other EMS activities outside the SGDP.

The EMS upgrade included the validation checks that assessed whether the ratings calculated in real time were appropriate, i.e., within an acceptable range, and whether sufficient numbers of instruments reported ratings data. If the rating passed these tests, the rating was posted to the online telemetry that Oncor maintains for all equipment operating on the transmission system, which ERCOT queries to perform its Security-Constrained Economic Dispatch on five-minute intervals.

3.4 System Go-Live

The go-live for the system, i.e., actually streaming CRM ratings to the ERCOT control room and SCED analysis, was delayed due to several issues that developed during the project execution. The actual go-live date was May 1, 2012.

As mentioned above, the upgrades to the EMS were developed and coded fairly early in the project, but the build with that software upgrade was not accomplished due to delays in associated software enhancements by other Oncor needs being incorporated in that specific build. Late in the first quarter of 2012 (calendar), we investigated modifying the IntelliCAT software to perform the validation functionality that was built into the EMS and found that the solution could be implemented in a timely manner. Just prior to moving in that direction, the EMS build was installed and, with checkouts complete, the DLR system went live.

An Operator's Guide for the Oncor control room was prepared by the System Operations. The EMS has been programmed with appropriate logic to switch the ratings from DLR to the Ambient-Adjusted Rating if the DLR data becomes suspect or out of range. Alerts are transmitted to an operator's desk for corrective action to identify the problem. The system, as noted, reverts to traditional ratings without operator intervention.

Bringing DLR data into the control room and making operating decisions based on the data is a very sensitive issue. In fact, many utilities have deployed various DLR systems in the past without bringing data into the control room or using it for operating decisions. The system operators are very concerned about introducing new operating issues, especially any that might affect reliability and system availability.

Accuracy and reliability are paramount to the willingness to accept the real-time data for operating decisions. That is why the Validation task outlined in our project is important to verifying the validity and accuracy of the data as well as its availability. If DLR projections are accurate about the latent capacity of the system that has always been there above the static rating, the operators are concerned about taking some of that buffer of operating capacity from the system and using it for operations. Effectively they are reducing their operation margin of error, and again the reliability and accuracy of the data is critical to their being comfortable using it.

Presenting DLR data in a control room and applying it to operations is not an easily accepted model. Reliability is the primary concern of the System Operations, and confidence in the capabilities and accuracy of DLR values is a difficult threshold to cross. Lack of experience with the technology and limited track record of application combine to create a reluctance to fully apply the technology. This acceptance threshold must be crossed before DLR can be utilized; once that happens, the tolerance for issues with the availability, accuracy and reliability of DLR ratings is very low and unforgiving. If a problem arises and the DLR system must be shut down for adjustments, repairs or other accommodations, the threshold for acceptance back to operating environment has a significant step increase in difficulty.

These issues are understandable from the operations perspective. They are gauged on their accurate and reliable operation of the system. Any technical capability that is not reliable to operating procedures is suspect and seldom applied. In essence, acceptance and application of DLR in the individual operating departments of utilities has a single opportunity with little tolerance from fully compliant operation.

Fortunately, Oncor System Operations was agreeable to allowing the DLR data to be applied in real time. This acceptance was further offered in the automatic near-transparent flow of the data into the real-time telemetry Oncor maintains for ERCOT's access for the Nodal Market operations. Thus the SGDP Project has the most extensive deployment of DLR equipment in history and the first that was applied real time in Nodal Market operations. This is especially valuable in the validation of Smart Grid technology application in the transmission grid.

3.5 Capacity Released Study

Transmission lines are designed to operate at a maximum safe conductor temperature to ensure that the energized conductor does not sag dangerously close to the public and also to protect the integrity of the conductor itself. The rating of a transmission line is defined as the amount of current that can be carried by a conductor without exceeding its maximum safe temperature. There are several recognized methods for determining the relationship between the current passing through a conductor, the weather conditions surrounding the conductor, and the conductor's temperature (example: IEEE Standard 738-2006 for Calculating the Current-Temperature of Bare Overhead Conductors). Each of these methods looks at a thermodynamic heat balance driven by:

- the ambient air temperature surrounding the conductor (the starting temperature)
- heat added to the conductor by the electrical current passing through it
- heat added to the conductor by solar radiation impinging on it
- heat removed from the conductor by natural radiation or by convection (wind)

This study compares the amount of current that can be safely carried by a transmission line under two rating methods: AAR and DLR.

It is to be noted that most utilities use Static Line Ratings, which are typically more conservative than Ambient Adjusted Ratings because they are based on assumed worst case conditions of ambient temperature, solar radiation, wind speed and direction. Hence, for utilities using Static Line Ratings, the capacity gains over SLR will be substantially higher on average than the capacity gains over AAR which are presented in this report.

Ambient Adjusted Ratings vary only with the monitored ambient air temperature surrounding the conductor. Wind and solar radiation are assumed to be unchanging over all ambient temperature ranges. For safety and the economic life of the conductor, the worst case weather conditions expected during the year are assigned to all ambient temperatures, namely full mid-summer sun to heat the conductor and low wind speeds to cool the conductor.

Dynamic Line Ratings vary with the monitored ambient air temperature, monitored solar radiation, and monitored wind. Monitoring all three weather parameters has the advantage of generally higher ratings (more safely released capacity) since actual weather conditions are generally more favorable than the assumed worst case solar and wind assumptions associated with Ambient Adjusted Ratings.

A comparison of the DLR capacity and that of the existing AAR was performed for each month for each transmission line segment at 2 minute intervals. The purpose of the comparison identifies the added benefit of DLR technology beyond what is provided by AAR. To visualize the benefit, the data was processed into the following charts:

- Chart of the DLR and the AAR on a monthly basis as a timeline.
- Chart of the difference between the DLR and the AAR on a monthly basis as a percent of time probability distribution.
- Chart of the DLR and the AAR on a monthly basis as a daily distribution.

Additional data sets and charts were also produced to support other studies performed by Oncor and Southwest Research Institute (SwRI) within the scope of the demonstration project.

The ONCOR team wanted to know the capacity released by Net Radiation Temperature (NRT) based ratings over AAR since NRT based ratings were occurring on average 21% to 70% of time as a result of loads at 20% or less of the Static Line Rating. The analysis was revised to include cumulative probability distributions of NRT based ratings and Ambient Adjusted Ratings for each segment for each month of the study.

The analysis also addressed the 15-minute transient DLR also commonly called Short Term Emergency (STE) ratings.

Figure 25 through Figure 27 are examples of the charts produced for each line segment for each month. Charts shown in the figures are for a 345 kV segment during September 2011.

Because September 2011 was relatively warm and had moderately elevated loads, it was chosen as a month representative of a moderately loaded circuit during summer. The maximum ambient temperature was 104 ^{o}F (40.1 ^{o}C) with the average temperature being 83 ^{o}F (28.4 ^{o}C). Forty-four percent of the month's ambient temperatures were above 86 ^{o}F (30 ^{o}C).

How the time series of ratings, Figure 25, were developed:

- Data was recorded every two minutes (30 ratings per hour).
- The ratings for each two-minute interval were plotted.

Each plot shows the SLR, AAR and DLR. Depending on the ambient temperature, the AAR varies relative to the SLR. The DLR contains both the ambient temperature influence and the solar radiation component and effects of wind cooling as experienced along the line section. When the temperature is at or above the SLR base temperature and the wind velocity is below 2 fps, the DLR will be below the SLR. The DLR can also be below the AAR when the wind velocity is below 2 fps because the AAR always

assumes a 2 fps wind. Typical of many of the segments, capacity released by DLR is normally above AAR and does exhibit more variation, including periods well above AAR and periods at or below the SLR.

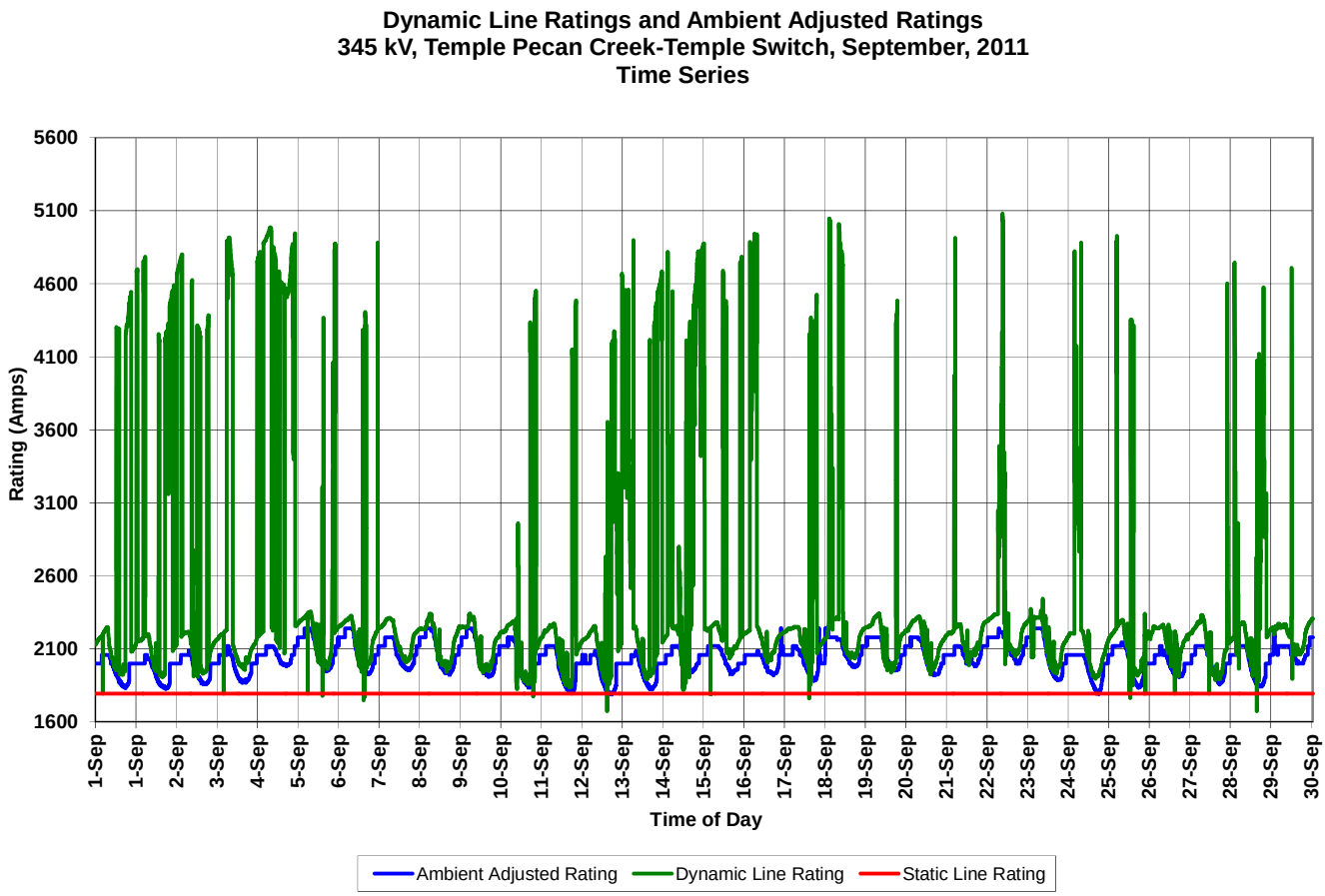


Figure 25 - Time series showing Ambient-Adjusted (AAR) and Dynamic Line Rating (DLR)

The cumulative distribution is a summary of the percent of time that the rating provided by DLR is available. It can be compared to the AAR or SLR to reveal the amount of additional capacity potential there is from DLR.

How the cumulative distributions of the difference between DLR and AAR were calculated for Figure 26 and Figure 27:

1. Data was recorded every two minutes (30 ratings per hour).
2. For each two-minute interval in the month, the AAR was subtracted from the DLR (DLR_AAR_Delta).
3. DLR_AAR_Delta was plotted as a standard cumulative probability chart.
4. When the rating increase (DLR_AAR_Delta) is above zero, DLR is greater than AAR.

The example for the 345 kV segments during months with moderate loads shows DLR typically delivers an increased capacity above AAR 80-95% of the time. This specific example delivered increased capacity 95.6% of the time.

How the cumulative distributions of the difference in DLR and SLR were calculated in Figure 27:

1. Data was recorded every two minutes (30 ratings per hour).
2. For each two-minute interval in the month, the SLR was subtracted from the DLR (DLR_SLR_Delta).
3. DLR_SLR_Delta was plotted as a standard cumulative probability chart.
4. When the rating increase (DLR_SLR_Delta) is above zero, DLR is greater than the SLR.

For most transmission lines, DLR typically delivers an increased capacity above the SLR 97-99% of the time. This specific example in Figure 27 had increased capacity 99.8% of the time above the SLR.

This type of analysis was performed for each line monthly and on a cumulative annual basis.

3.5.1 Capacity Released Results

This project demonstrated that DLRs release significant additional capacity over that released by AAR and SLR.

Table 4 summarizes the increased capacity released by DLR over AAR on the 345 kV lines. When filtering out months where comparison was difficult due to data anomalies, DLR provided a median capacity increase over AAR 92.2% of the time and an average increase 90.5% of the time.

Primary and secondary Dynamic Line Rating technologies were deployed at the outset of the SGDP Project. The primary DLR technology is referred to as tension based and accounts for the combined effects of actual wind, actual solar and actual ambient temperature. The secondary DLR technology is referred to as NRT and accounts for actual ambient temperature and actual solar radiation, but it assumes a constant fixed low wind speed. Unless otherwise noted in this report, all references to DLR include the combined results of both the primary tension-based technology and the secondary NRT-based technology. It is possible [see below] to extract the relative impact of DLRs primary and secondary technologies from the total DLR rating.

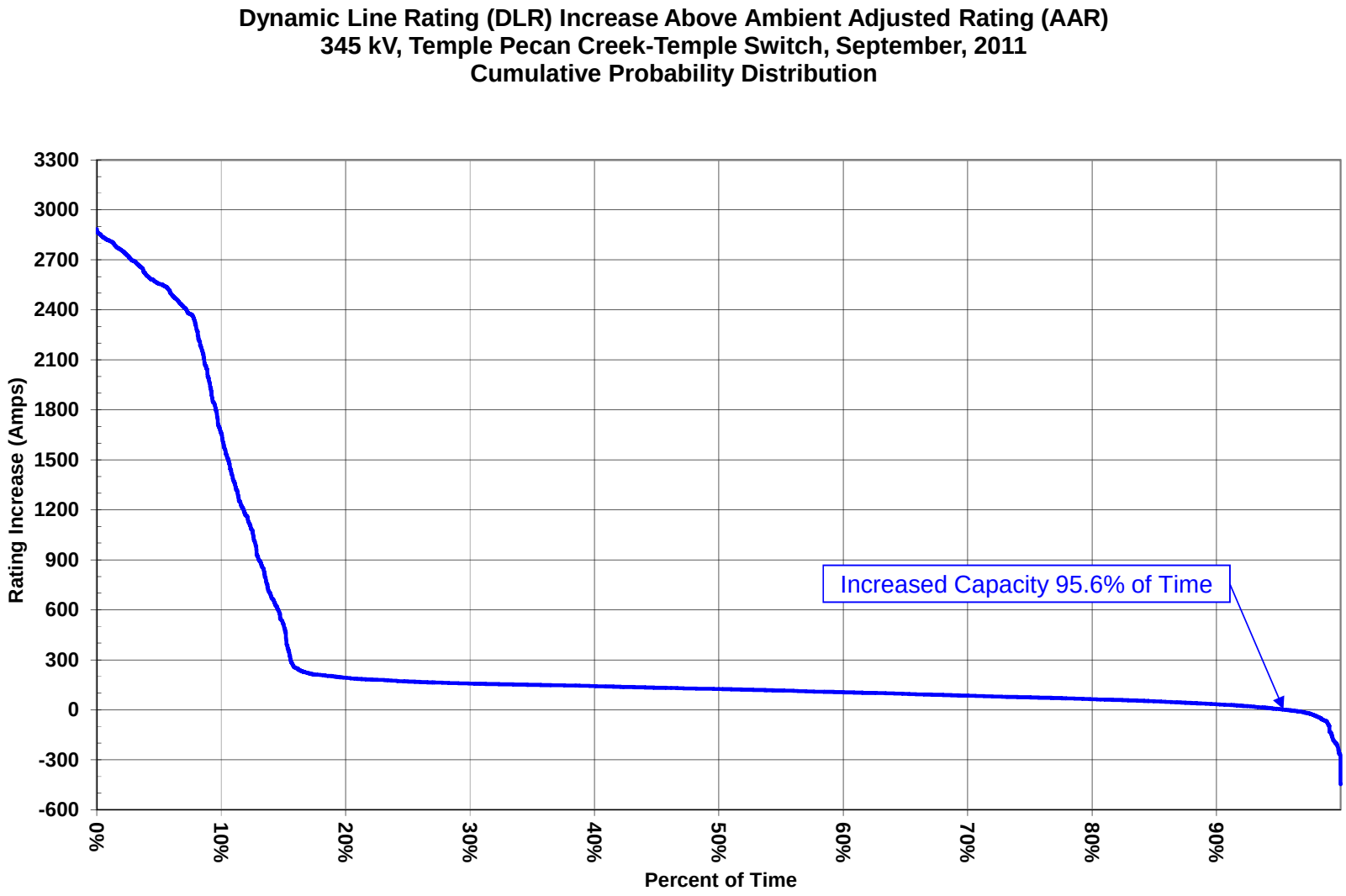


Figure 26 - Cumulative probability distribution showing the increased capacity delivered by the Dynamic Line Rating above the Ambient-Adjusted Rating

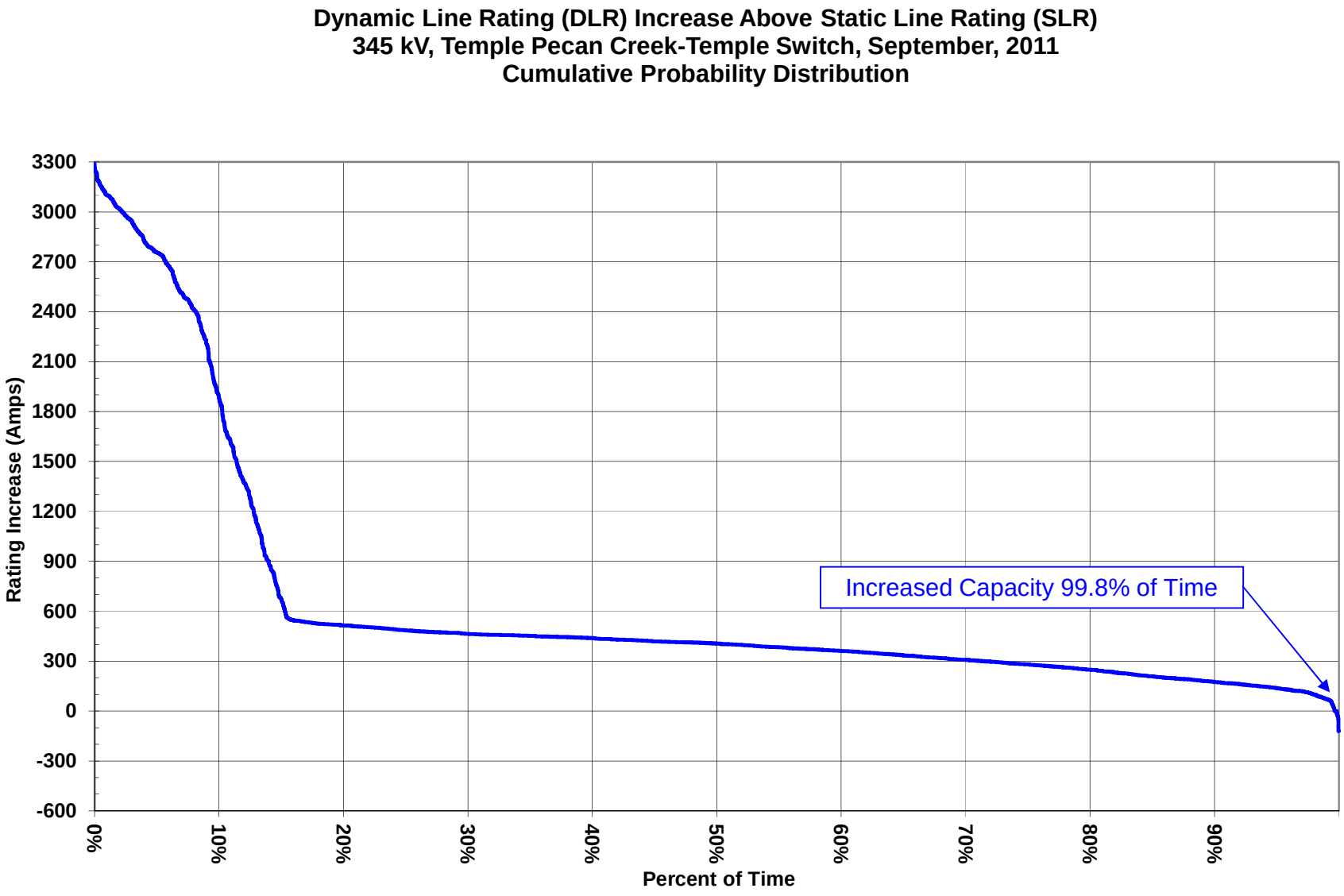


Figure 27 - Cumulative probability distribution showing the increased capacity delivered by the Dynamic Line Rating above the Static Line Rating

Table 4 - Statistical Summary of Additional Capacity Released by DLR Compared to Ambient-Adjusted Ratings

Summary of Capacity Released on all 345 kV Lines Percent of Time Dynamic Line Ratings Exceeded Ambient-Adjusted Ratings				
	Median	**Max**	**Min**	**Average**
Months free of data anomalies	92.2%	97.7%	73.5%	90.5%
Months with up to 10% of data missing or DLR defaulted to the Static Line Rating because of data anomalies	90.5%	97.7%	65.9%	89.1%
All Months	89.1%	97.7%	6.5%	83.5%

Line loads on a monthly average were less than the threshold required for a tension-based DLR 21 to 70% of the time. Under those very low load conditions (less than 20% of the SLR); the DLR was calculated using an NRT-based DLR. During periods of NRT-adjusted ratings, the ratings provided increased capacity over AAR.

When line loads are above 20% of the SLR, the primary tension technology dominates the DLR by adding the full impact of wind, including its spatial variability, to the rating.

Figure 29 and Figure 30 show the capacity gained under all load conditions and when loads are greater than 20% of the SLR on one of the 345 kV lines and on all monitored 345 kV lines, respectively. Note that the increased capacity revealed for loads above 20% of SLR is always there, it simply can't be accessed without a DLR technology that captures the full spatial impact of wind.

The data was examined for indications of seasonality by dividing the August 2011 through July 2012 data set into quarters.

While quarterly results vary, the increased capacity delivered by Dynamic Line Ratings over Ambient-Adjusted Ratings was on average 6 to14% for 345 kV and 8 to 12% for 138 kV, shown in Figure 31 and Figure 32. During March-June 2012, the lowest loads and the greatest number of load anomalies occurred on the 138 kV segments, forcing the Dynamic Line Rating to default to the Static Line Rating, which accounts for the very low gains in second-quarter 2012 (Figure 32). Despite the load issues and reported lower gains, the yearly averages for the 138 kV voltage class were between 8% and 12%.

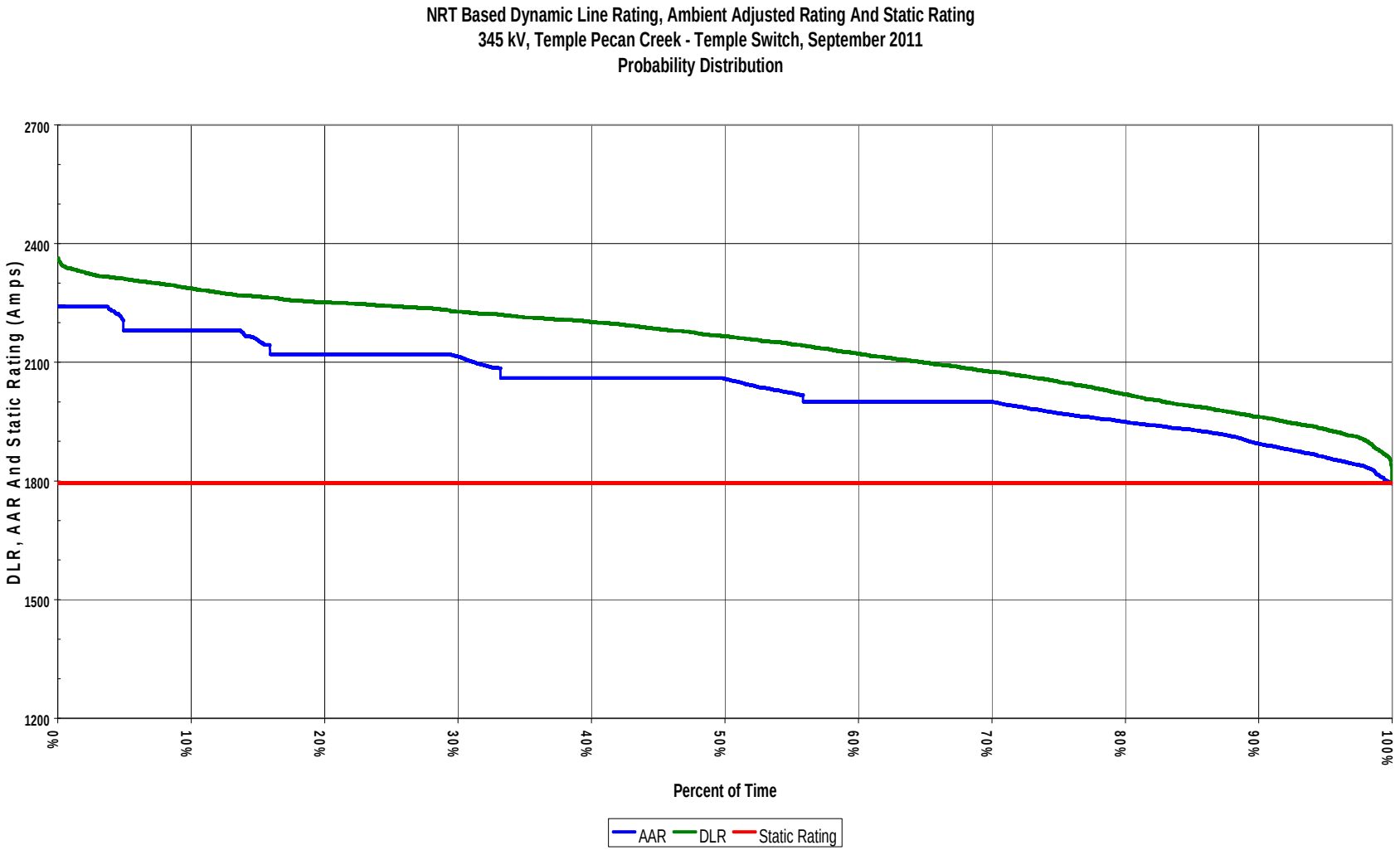


Figure 28- Cumulative Probability Distribution Showing Side-By-Side Comparison of NRT Based DLR and AAR as a Function of Percentage of Time

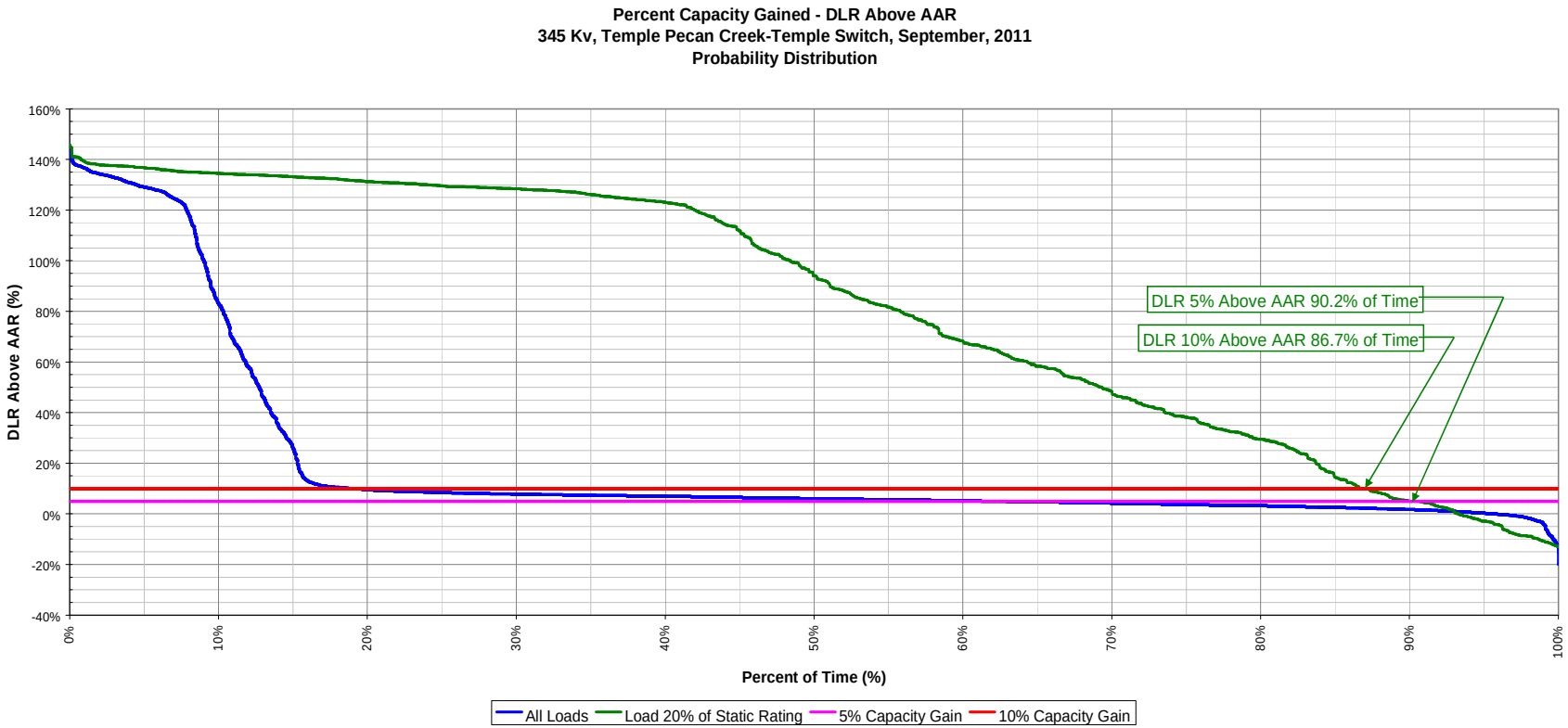


Figure 29 - Cumulative Probability Distribution Showing the Increased Capacity Delivered by the Dynamic Line Rating Above the Ambient-Adjusted Rating for All Load Conditions

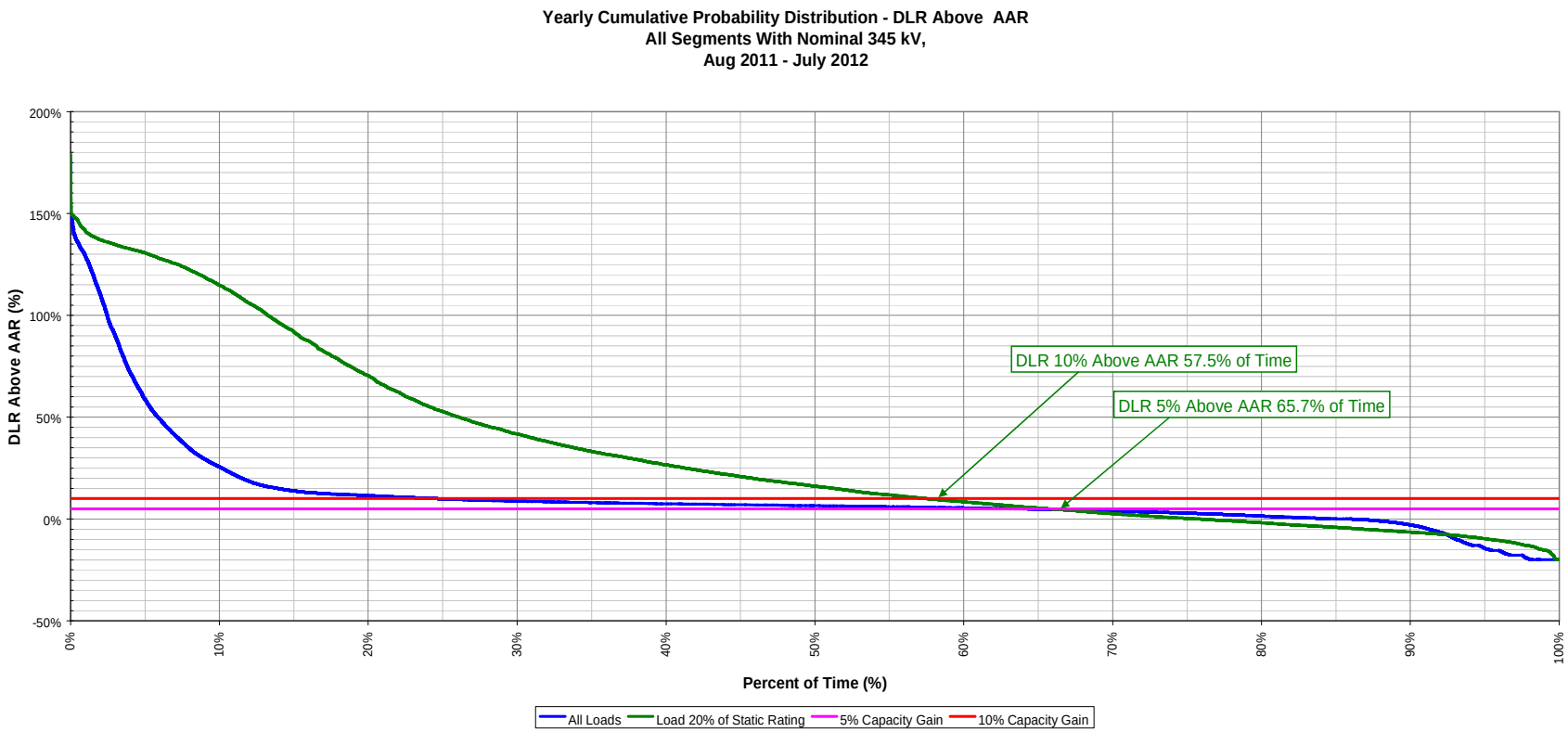


Figure 30 - Cumulative Probability Distribution Showing the Increased Capacity Delivered by the Dynamic Line Rating Above the Ambient-Adjusted Rating for All Load Conditions – All Lines

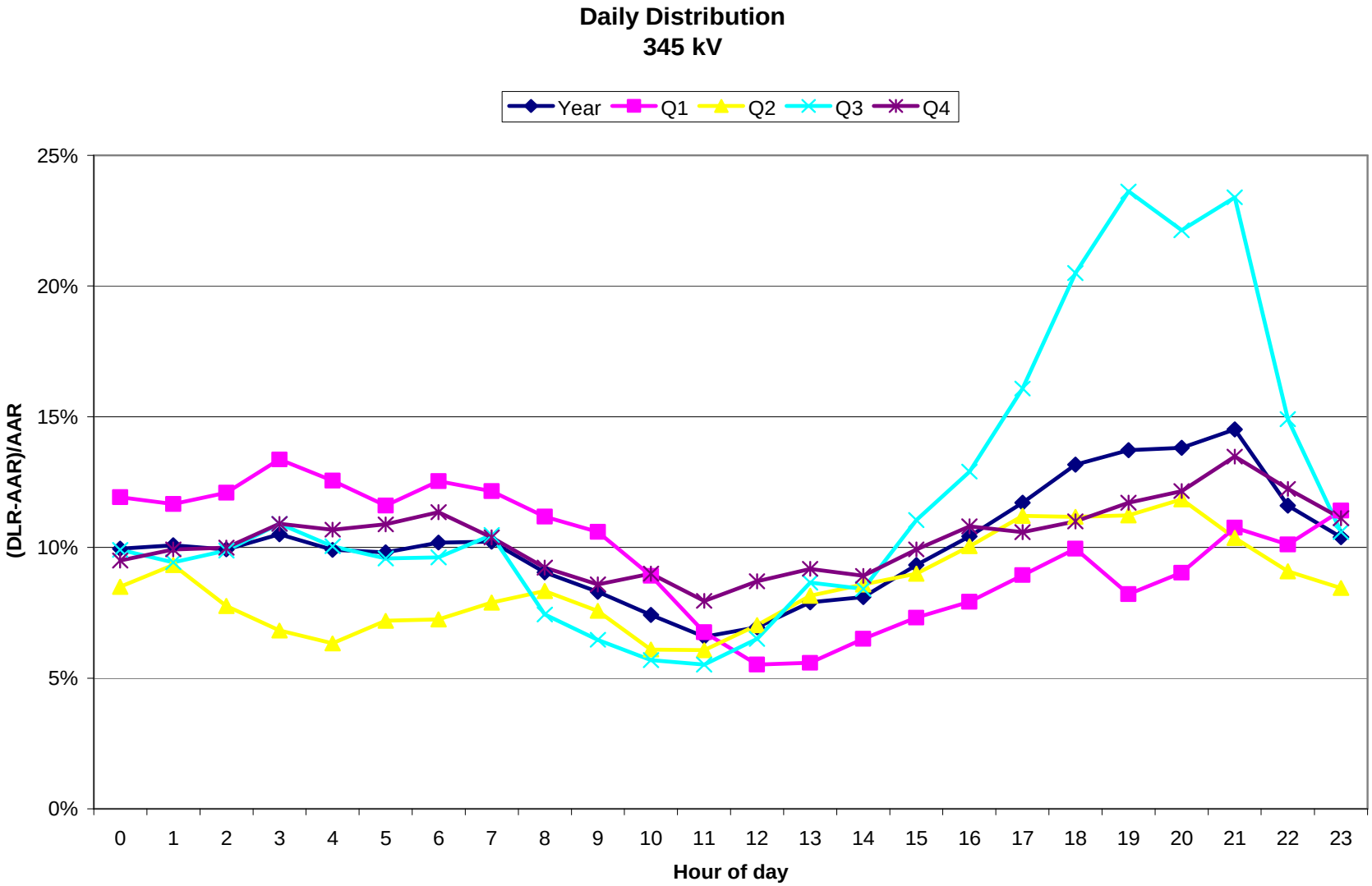


Figure 31 - Yearly and Quarterly Average Increased Capacity Delivered by the Line Rating Above the Ambient-Adjusted Rating for All 345 kV Lines

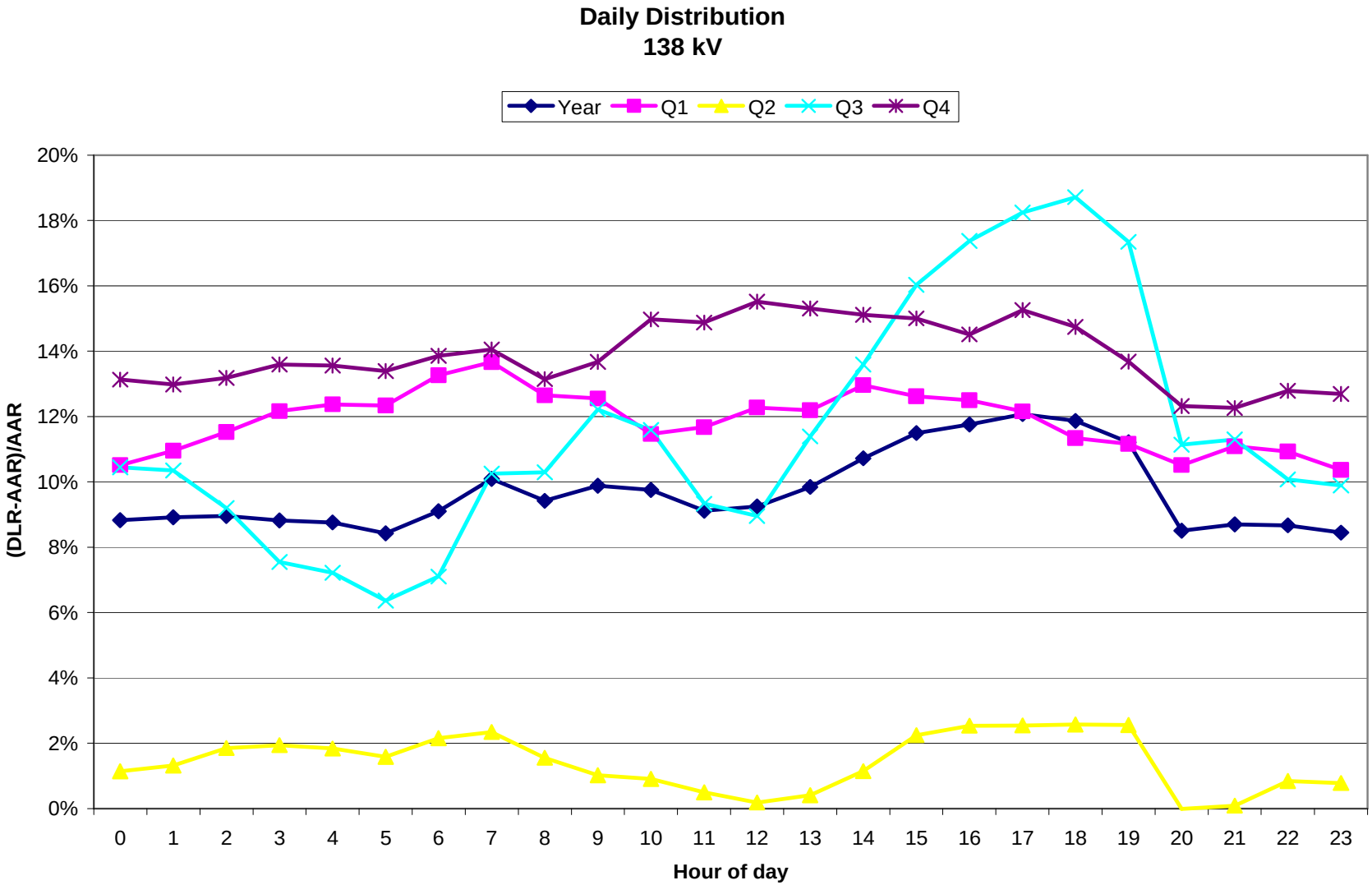


Figure 32 - Yearly and Quarterly Average Increased Capacity Delivered by the Dynamic Line Rating Above the Ambient-Adjusted Rating for All Load Conditions for All 138 kV Lines

As noted above, the ability to calculate a Dynamic Line Rating is impacted by the load level on the line. If the line is lightly loaded, i.e., below 20 to 30% of capacity, the conductor temperature will not be elevated above the natural temperature due to ambient temperature and net solar radiation impact. When this condition is the state of operations, the effective wind speed on the line section cannot be determined and therefore the projection of the full dynamic capacity of the line is less accurate.

In addition to these phenomena, SGDP Project studies have shown that the line sections monitored by each DLR device are different time stamp to time stamp due to variations in the influence of ambient temperature, solar radiation, wind and the effective ruling span of the monitored section. Transmission lines add extremely large spatial context to these variables; thus a line's overall state at any given time is different section to section, and that variance is further reflected in the cumulative probability of occurrence of the dynamic ratings.

The cumulative probability curves for all of the 345 kV transmission lines monitored during the project for a year are shown in Figure 33. The variation in performance for the line sections is evident by looking at the curves. The 0% line represents when the DLR equals the AAR. The five curves cross this line at different probabilities ranging from 55% up to 88% of the time.

Two additional ratings levels are shown: 5% and 10% above AAR. Again the ratings probability curves cross these capacity levels at different probabilities. Note that the curves become closer and more similar as the probability level increases and that all have approximately the same capacity 90% of the time. But the real variance is at higher capacities, which reflect variation in exposure to wind due to line routing, terrain, natural cover and sheltering.

Many utilities do not apply AAR, so their interest would be in comparing the DLR to the traditional SLR (Figure 34). Note that the DLR curves are the same in both figures. The SLR (0% level), 5% increase and 10% increase are shown. Again line variation is evident, reflecting the spatial context of a transmission line and the impact various ambient conditions will have on the dynamic ratings.

3.5.2 Conclusions – Capacity Released

DLR consistently released additional grid capacity compared to AAR. While quarterly results varied, the average increased capacity delivered by DLR over AAR was 6 to 14% for 345 kV and 8 to 12% for 138 kV transmission lines. The availability of that added capacity ranged from 83.5 % of the time under all operating conditions to 90.5% of the time when outages and other events were excluded from the data.

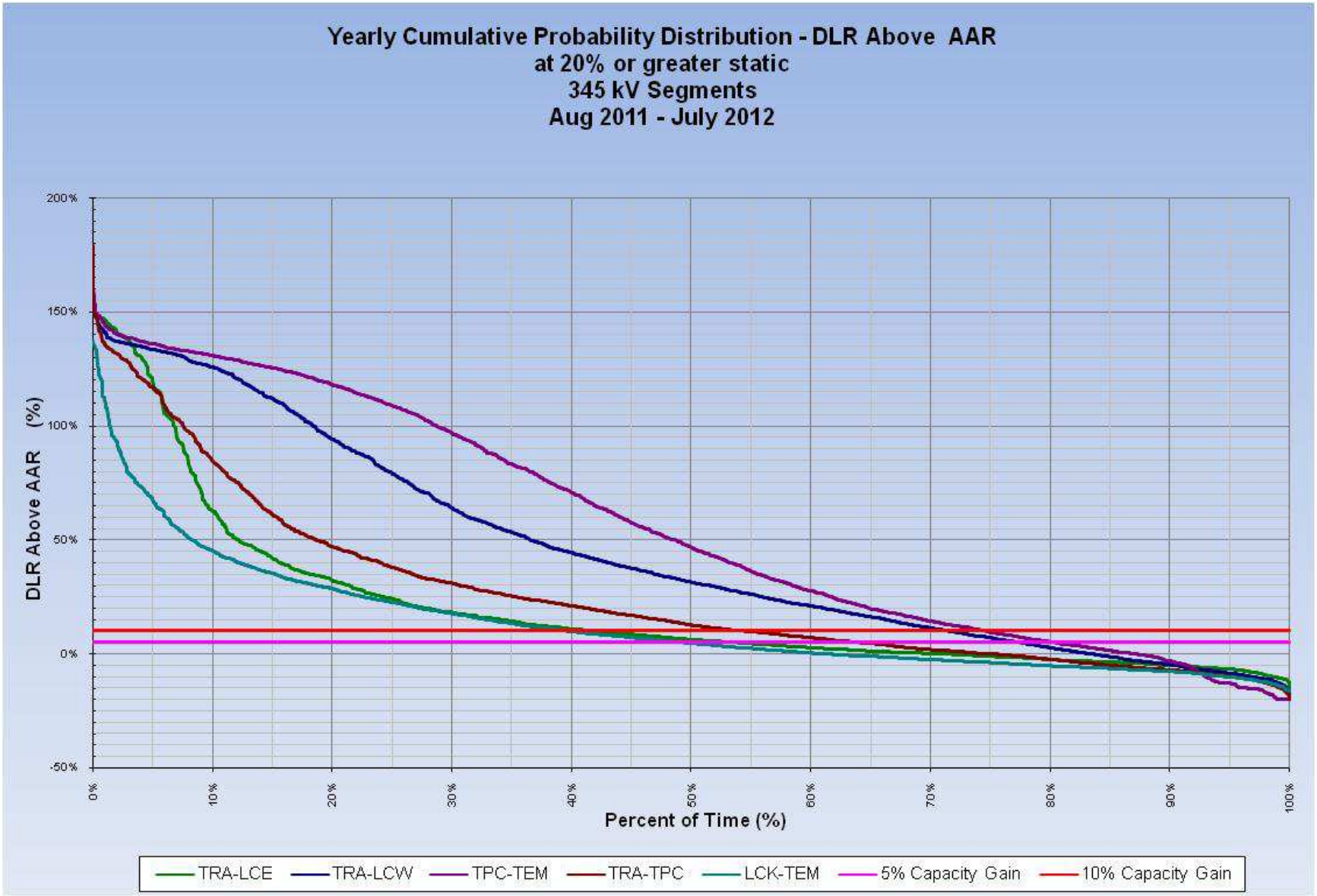


Figure 33 - Capacity Released Cumulative Probability Curve Above Ambient-Adjusted Rating - 345 kV

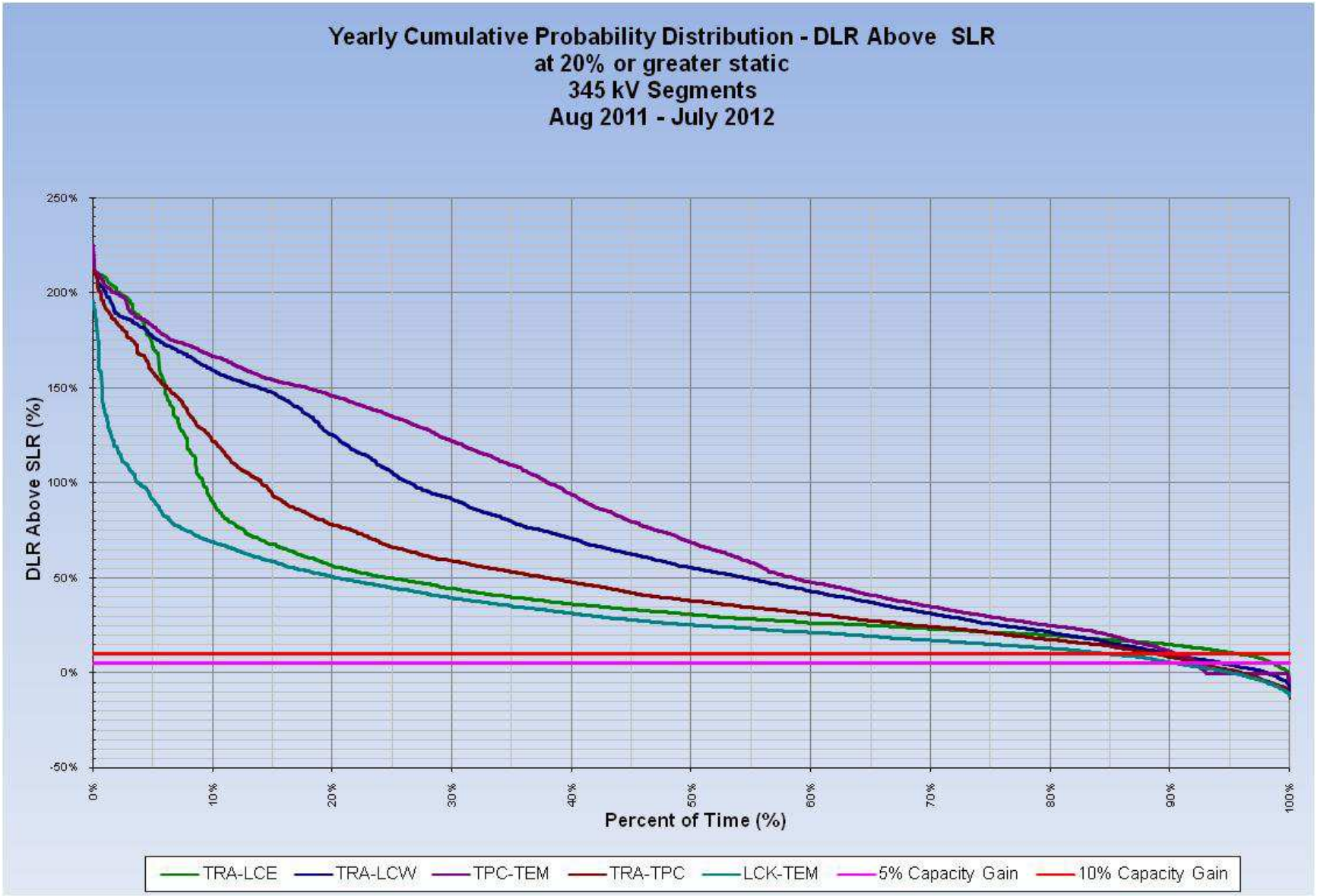


Figure 34 - Capacity Released Cumulative Probability Curve Above Static Line Rating - 345 kV

3.6 Short-term Emergency Ratings

For contingency management and for electricity markets that are sufficiently advanced to be operating at 15-minute intervals, even greater grid capacity gains can be safely tapped by 15-minute Dynamic Line Ratings, alternately known as transient ratings or STE ratings.

In the process of establishing the DLR of a transmission line, the average temperature of the conductor is determined. That temperature is a prerequisite to determining the real-time transient response of the conductor to a change in load. Two forms of the transient response are useful in contingency management: one before the event, and one after the event.

Figure 35 is an example of pre-contingency transient analysis. Here the conductor is not permitted to exceed a design temperature of 100 °C. Both the load on the line and the conductor's temperature are known at time zero. A DLR system will answer the question: How large a step in load will cause the conductor to reach its 100 °C design temperature in 15 minutes, but not before? The answer is the real-time 15-minute STE rating. In practice, an operator can dispatch the system to the STE rating, knowing that should a contingency event occur, he will have a full 15 minutes to respond. After 15 minutes, load must be reduced to the real-time continuous rating.

Figure 36 is an example of post-contingency transient analysis where the conductor has just been subjected to a large step current. The question answered by the DLR system is: How many minutes until the conductor reaches its 100 °C design temperature? In this example, it's 8.5 minutes. In practice, the operator must reduce load on the line to the real-time continuous rating before 8.5 minutes elapse.

The time available to take corrective actions is valuable information to the operator. If time is short, quick but expensive actions may be required. If a longer time is available, more economical or less disruptive actions may be taken.

Figure 37 and **Figure 38** show the increased capacity above AAR that is released by the 15-minute rating. For all 345 kV lines, at least 10% above AAR is available 93% of the time under all load conditions and 98% of the time under moderate load conditions (load greater than 20% of the Static Line Rating). Those increased capacities can be safely deployed within a market structure while ensuring lines will always be operated within their limits.

3.6.1 Conclusions – Short-term Emergency

For contingency management and for energy markets that clear on a 15-minute basis, the study demonstrated that at least 10% above the Ambient-Adjusted Rating was available 93% of the time under all load conditions and 98% of the time under moderate load conditions (load greater than 20% of the Static Line Rating). Those increased capacities can be safely deployed within a market structure while ensuring lines will always be operated within their limits.

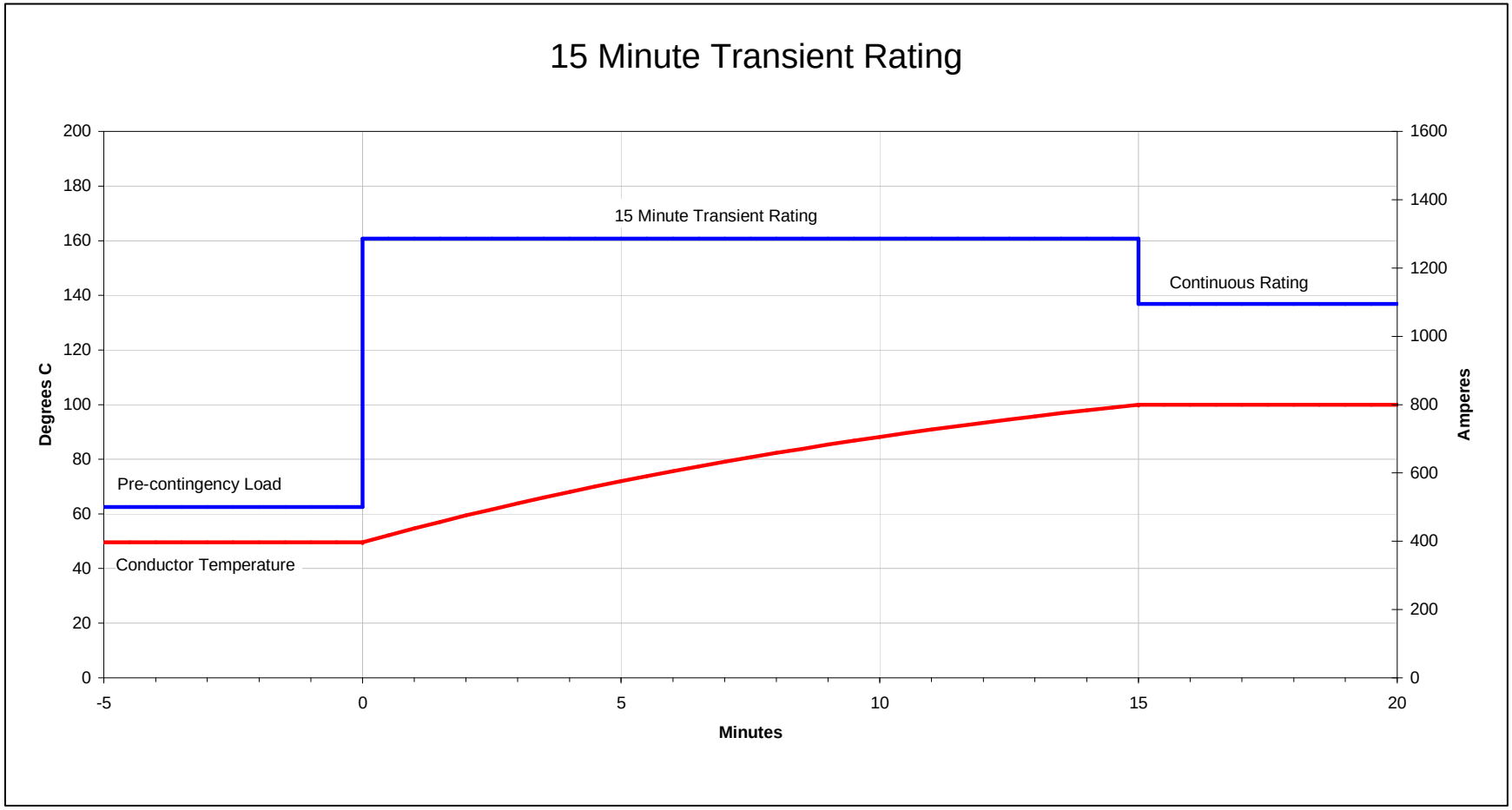


Figure 35 - Pre-contingency Transient Response Analysis

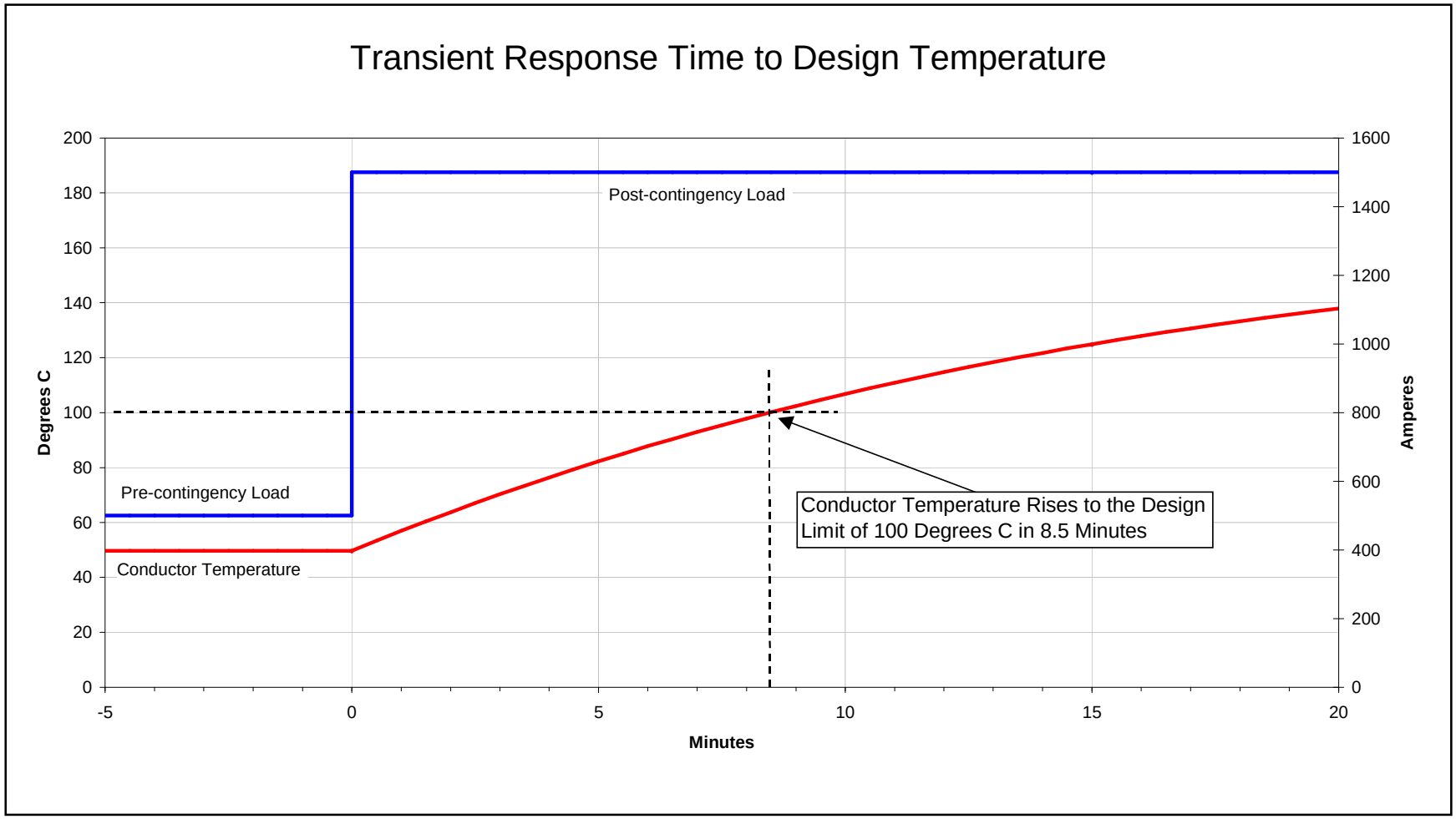


Figure 36 – Post-contingency Transient Response Analysis

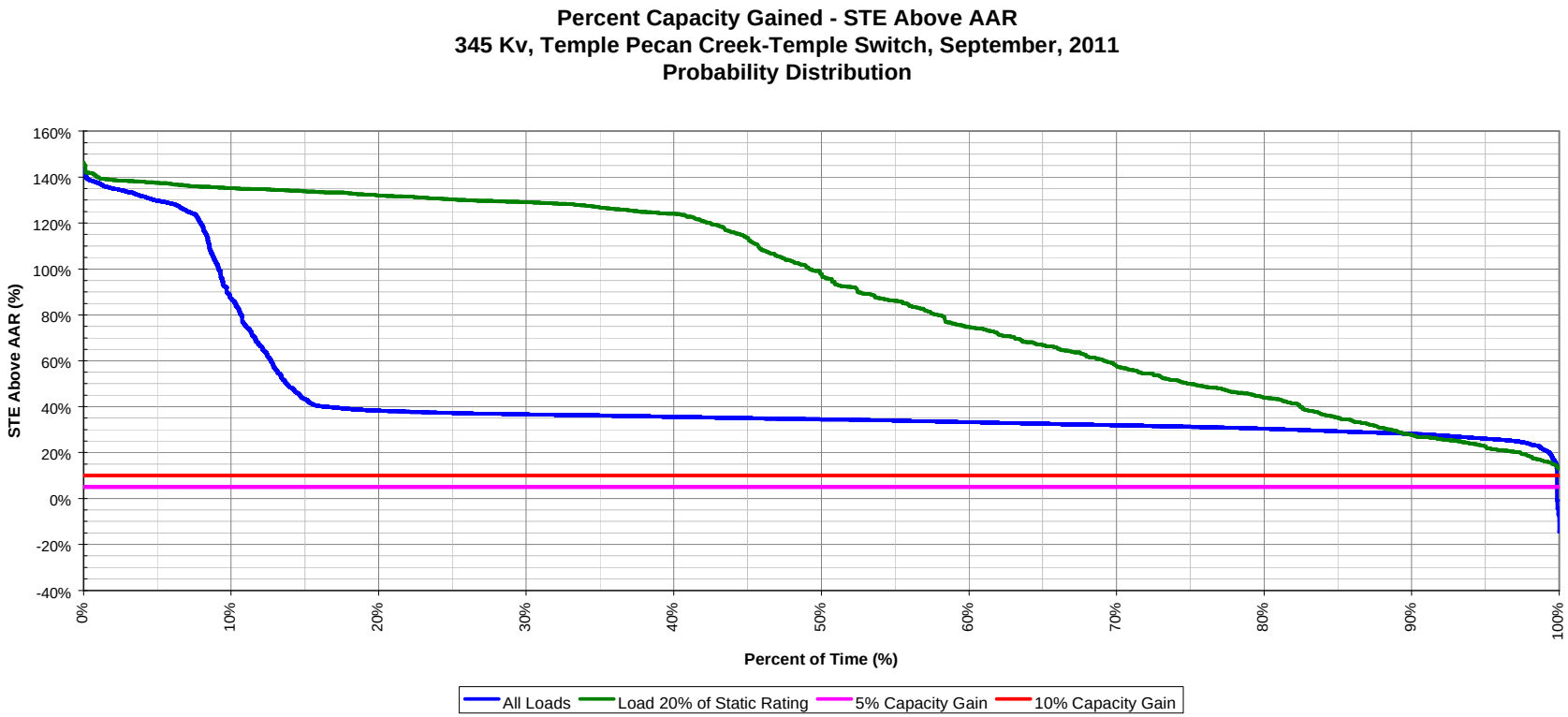


Figure 37 - Cumulative Probability Distribution as a Function of Percentage of Time Showing Side by Side

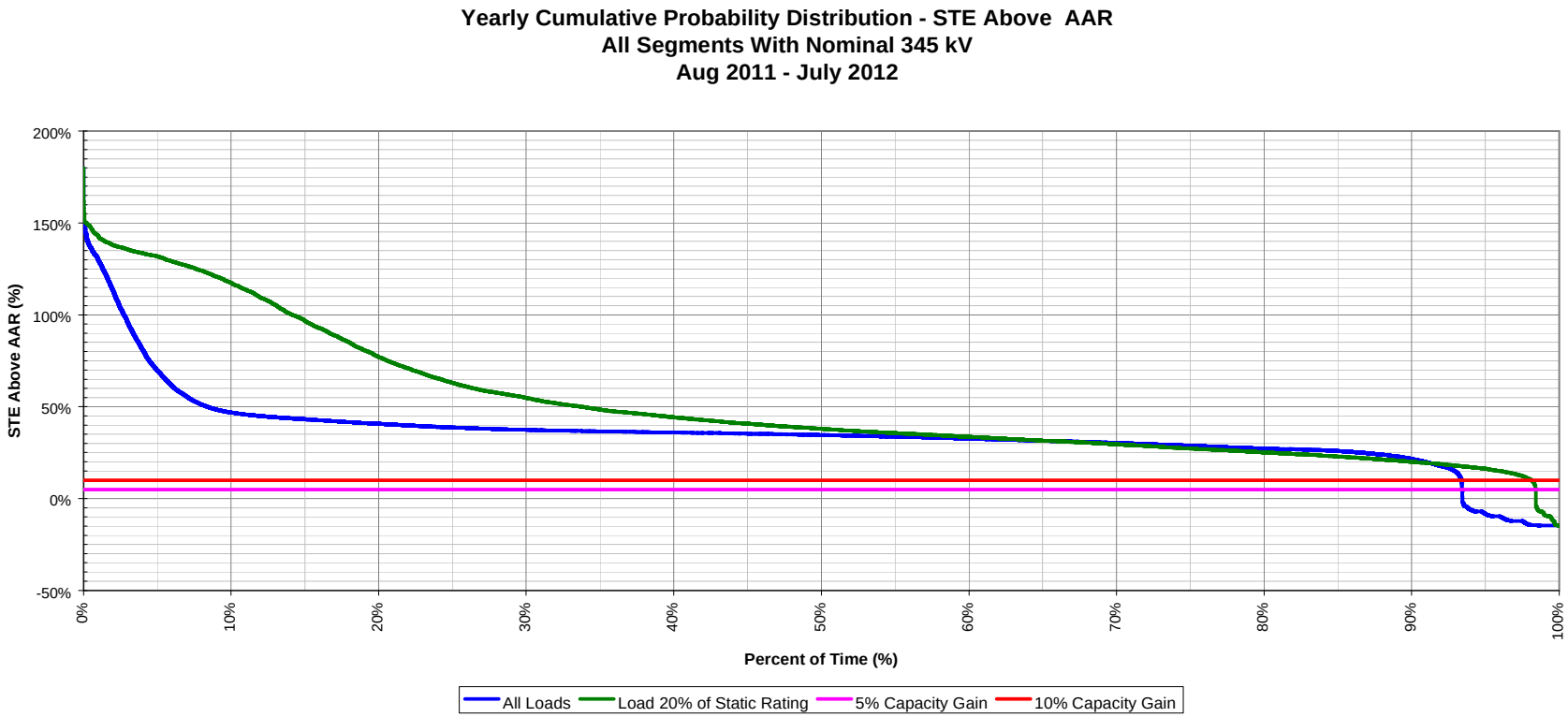


Figure 38 - Comparison of the Gain Above AAR Using 15-Minute Ratings (STE) – Single 345 kV Line Example

3.7 Cybersecurity

Five key aspects of real-time data acquisition and processing were the focus of Cybersecurity issues:

Confidentiality – prevention of unauthorized access to the information

Integrity – prevention of the theft, unauthorized insertion or modification of information

Availability – consistency of data stream availability to secure users and prevention of access by unauthorized entities

Accountability – clear documentation of any event, its time, source and purpose

Life cycle – Cybersecurity must be an element of the DLR system over its entire life cycle, from design and manufacture of the equipment through implementation, operation, maintenance and retirement.

The AMI Risk Assessment document prepared by the Advanced Metering Infrastructure Security Task Force (AMI-SEC) was used as a starting point for the test plan. DLR is similar to other advanced metering of infrastructure in that it monitors real-time system status, metering the tension on the transmission line. The methodology outlined in the document was developed by the AMI-SEC working group within the OpenSG users group. This document has since been passed to the NIST Cybersecurity Working Group to be integrated into documents it is producing.

Appendix B.3 of the AMI-SEC document presents an exhaustive list of threats that a potential AMI system could face. While the system being tested here is not an AMI, the threats described are still applicable to the DLR system and can be utilized for test plan development. Using this list as a starting point, it was first reduced to only include threats that were applicable to the system and within the scope of testing.

Platform Communication Vulnerabilities

- Integrity Checking
- Authentication (Users, Data or Devices)
- Encryption
- Replay
- Protocol Usage
- Cross-Domain Injection
- Unnecessary Services

Physical Vulnerabilities

- Platform Hardware Vulnerabilities
- Chips/Exposed Ports
- Component Protection
- Tampering/Injection/Eavesdropping

- Platform Configuration Vulnerabilities
- Storage of Information
- Password Security/Permission Levels
- Audit Logs
- Platform Software Vulnerabilities
- Packet Floods
- Handling of Malformed Data
- Code Protection

System-level Vulnerabilities

- End-to-End Encryption
- Denial of Service (Handling, Recovery)
- Replay Attacks
- Endpoint Spoofing
- Audit Logs (Manipulation, Generation)
- Physical Tamper Detection
- Firmware Update (Verification, Process, Integrity Checking)

Next, for each threat that remained, a test case will be designed to determine if the system is vulnerable to that threat. Finally, an initial risk rating for each test case was assigned in order to help with test prioritization. The priority of testing is developed through an assignment of the severity of the vulnerability/threat and the likelihood of the threat occurring.

The flowchart of the process is laid out in Figure 39.

Severity of impact addresses the degree of impact in two ways: breadth, i.e., number of units impacted or the reach into the network and grid; and relative to the economic/security/reliability/safety aspect of the impact (Table 5).

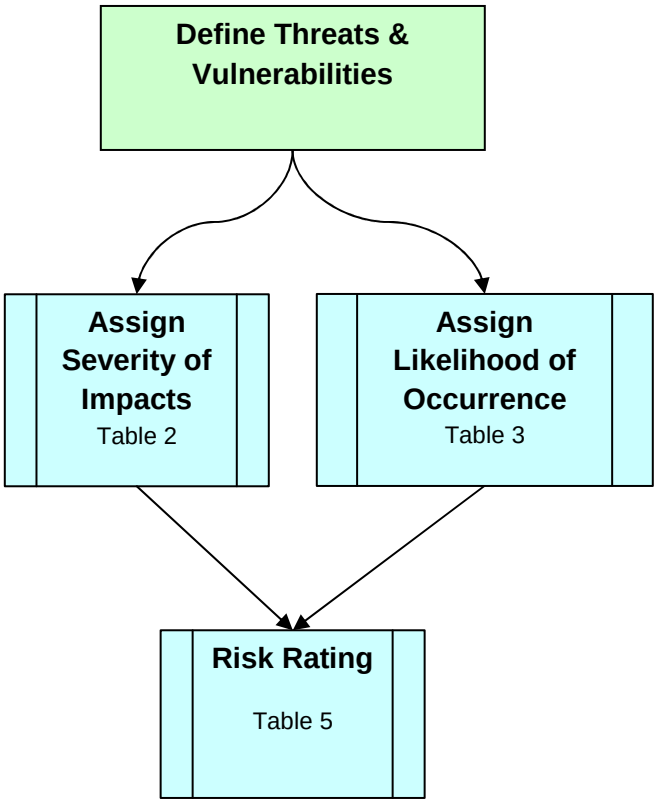


Figure 39 - Cybersecurity Assessment Flowchart

Table 5 - Severity of Impact Ratings

Severity			
1	Negligible	Low	Effects limited to single unit Minimal e/s/r/s impacts
2	Moderate	Medium	Effects limited to units in a single cell (NAN) Moderate e/s/r/s impacts
3	Severe	High	Effects beyond a single cell (System/WAN) Severe e/s/r/s impacts

The likelihood that a threat will occur or vulnerability be exposed is measured according to the descriptions in Table 6.

Table 6 - Likelihood of Occurrence Rating

Likelihood / Threat			
A	Rare	Low	Exceptional circumstances only
B	Unlikely	Low	Not expected to occur
C	Possible	Medium	Could occur at some time
D	Likely	High	Will probably occur in most circumstances
E	Almost Certain	Critical	Expected in most circumstances

Once the vulnerabilities and threats have been reviewed relative to severity and likelihood of occurrence, their product probability defines a Risk Rating as shown in Table 7 and Table 8. The Risk Rating guides the assessment on the most efficient path to address the issues of highest concern and impact.

Table 7 - Risk Rating

Risk Rating				
Likelihood		Severity		
		Negligible	Moderate	Severe
		1	2	3
E	Almost Certain	M	H	E
D	Likely	M	H	E
C	Possible	L	M	E
B	Unlikely	L	M	H
A	Rare	L	M	H

Table 8 - Risk Levels

E	Extreme risk
H	High risk
M	Moderate risk
L	Low risk

Figure 40 illustrates the risk-prioritization rankings established in the review of the vulnerability and threats previously discussed. This type of information is beneficial in establishing which Cybersecurity issues will be investigated further based on overall ranking. The High-risk category represents approximately 35% of the issues. Approximately half of the concerns are rated Moderate-risk. The Cybersecurity analysis will drill down through these issues and identify a subset that will be completely assessed, while other issues will be shown of lesser risk and insufficient impact to fully investigate at this time. Interestingly, no Extreme-risks were identified.

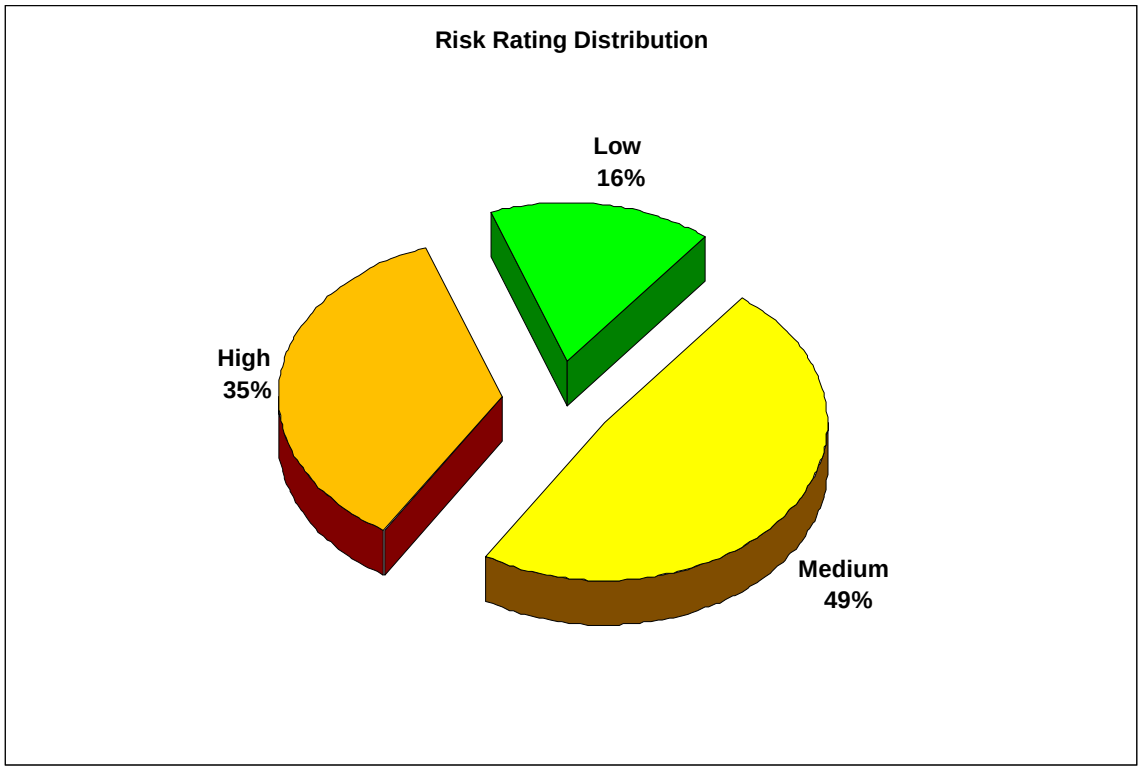


Figure 40 - Risk Rating Distribution Capacity Above Static or AAR

3.8 Line Sag Measurement Verification (LSMV) Study

The DLR technology deployed for the SGDP Project measures the tension of the conductor across a stringing section of the transmission line, i.e., the tension of the conductor between two deadend positions; all support assemblies being suspended in a tangent section or a swinging angle of less than 15° to 18°. The optimum case is for the conductors to be supported by unconstrained suspension assemblies. Braced post and line post insulator assemblies provide a degree of longitudinal constraint to the movement of the conductor attachment point, which may prevent the conductor from reaching a horizontal equilibrium tension. In these cases, an assessment of conductor system flexibility may be required prior to DLR application.

The LSMV Study is designed to analyze two aspects of the ratings monitoring system. The primary objective is to validate that the monitoring device accurately represents the behavior of the conductor at different thermal loadings, i.e., that the monitoring calculates the position of the conductor relative to its governing constraint, ground clearance. The tension monitoring system equates the tension to a conductor temperature and compares that to the maximum allowable conductor temperature for operations and design. Other technologies monitor the conductor position and correlate that to the design case allowable position.

Next, the task addresses the length of the tangent stringing section, the “reach” that a DLR device is capable of accurately representing. The DLR device could measure tension or conductor position as long as the conductor is supported in insulator assemblies that are free to swing in a longitudinal direction to allow equilibrium horizontal tension to represent that section of the line.

To facilitate this task, secondary DLR equipment was installed in the target transmission lines at various distances from the primary CAT-1 DLR devices. By statistically comparing the conductor characteristics, tension and sag position in the spans at various times for the same record time stamp, the accuracy of the DLR system to model the conductor and the reach of the DLR device can be quantified. Along with the CAT-1 Layout Optimization Study, the optimum deployment of DLR devices by location and quantity can be defined.

Sagometers and Promethean RT-TLMS units were selected for the LSMV data acquisition. Both are designed to define the conductor position within a span that can be correlated to the sag or clearance of the line, which can then be correlated to the tension reading of the CAT-1s.

The LSMV devices were installed at varying distances from CAT-1 devices as shown in Table 9. The distances varied from the adjacent span, which was either 640 or 1,075 feet away to as far as 107,113 feet (over 20 miles). Sixty-two percent of the test reaches were over two miles; 80% were up to seven miles from the DLR device. For example, RT-TLMS 1-1 was a site on a 138 kV line with two CAT-1 devices in the same stringing section. One CAT-1 device was 8,420 feet from the RT-TLMS site, and one was 30,291 feet in the other direction. Similar combinations are shown in Table 9.

Table 9 - Line Sag Measurement Validation – "Reach" Matrix

Line	Device	Reach (ft)	Reach (ft)	Reach (ft)	Reach (ft)	Reach (ft)
A 138 kV	RTTLMS 1-1	30,291	8,420			
A 138 kV	RTTLMS 1-2	640	10,156	27,915	38,071	
A 138 kV	RTTLMS 1-3	10,156	27,915			
B 345 kV	RTTLMS 2-1	1,075	9,491			
B 345 kV	RTTLMS 2-2*	14,646	7,110			
B 345 kV	RTTLMS 2-3*	21,146	13,610			
C 345 kV	Sagometer 1	15,640	21,620	44,422	65,001	93,654
D 345 kV	Sagometer 2	3,507	7,694			
D 345 kV	Sagometer 3*	3,495	30,963	41,071	78,331	107,113
E 138 kV	Sagometer 4*	11,150	15,690			
F 345 kV	Sagometer 5	6,400				

* - Data from these devices was suspect and not used in the analysis

For each site comparison the time-stamped records for the different monitoring systems were matched so that the record from each set representing the same time frame was compared. From the CAT-1 systems, the line tension was recorded as the direct measure. From the conductor position monitors, the line clearance or the sag were recorded for each matching time stamp. When the RT-TLMS system data was used, the clearance was converted to sag by subtracting the clearance from the attachment point heights on the structures.

The LSMV analysis compared the conductor position recorded for time-correlated records between one or more devices according to the plan in Table 9. The two devices are a CAT-1 device at the end of the stringing section and a conductor position monitoring device, i.e., a Sagometer or an RT-TLMS, at different distances in the same stringing section.

The CAT-1 devices monitor the tension of the conductor and have a calibrated algorithm to convert that value to a conductor temperature and sag. The tension record is posted every 10 minutes according to the Oncor RTU clock.

The Sagometer system monitors the conductor position approximately 150 feet (45 meters) from the structure. Using catenary equations and field survey of the span, the sag and clearance at specific points in the span can be calculated from the Sagometer data. The Sagometer data is recorded every 10 minutes according to the communications satellite time signal used in the system hardware. The Sagometers were installed and left in their position for the Project duration. The RT-TLMS systems were moved twice during the project so that additional distances could be assessed during the LSMV Study.

The RT-TLMS system measures the clearance to the conductor at the location of the sensors (mid-span). The RT-TLMS system provides a record every minute with a time stamp fixed to Coordinated Universal Time (UTC). The RT-TLMS systems because of their non-contact style of installation were moved several times during the Project to increase the size of the span length comparison needed for the Sag Validation study.

All three measured values – CAT-1 tension, Sagometer sag and RT-TLMS clearance – can be related to a conductor position for the same time stamp. Independently, each of the vendor systems has been

proven and calibrated by direct measurements of conductor position in the monitored span of conductor. The vendors do this as a step in their system development and as validation of the accuracy of their system. The LSMV exercise is to extend that validation process to see how far the monitored DLR measurement can be considered accurate and representative of the span section it is monitoring. If this reach was determined to be on the order of several hundred to a couple thousand feet, a DLR monitor would be needed at multiple locations along a stringing tangent section. If the reach is extended and validated to a mile or several miles, the number of DLR devices required is greatly reduced.

The CAT-1 data has discrete tension levels at which the loadcells provide results, i.e., the loadcell load class has minimum discernible differences in load. Therefore the data is provided in a continuous series of buckets of data associated with the discernible tension changes the loadcell provides. The buckets may be in ~5 lb to ~20 lb increments. All of the data from that loadcell will be reported in the series of discrete tension valued buckets.

The vertical component of the conductor position monitoring data is of primary interest to the SGDP Project. But due to wind and other vibrations, the position of the conductor has some horizontal component. As the conductor swings, the distance measured for each record may not be the absolute vertical projection. So the association of data must be reviewed to handle the vertical projection of the conductor.

The time stamp correlation links the CAT-1 tension with the associated conductor position. The vertical component is derived by analyzing the records associated with each tension-valued bucket of data. The desired correlation is a tension with the conductor vertical projection. From sag and tension behavior, we know that a bare conductor will have the same tension to position correlation. For each tension bucket the data was analyzed to determine the average position and the mode position of the conductor. The average value is simply the average of the position arguments. The mode value is the conductor position with the highest number of occurrences within that tension bucket. The mode value can be associated with the true vertical position associated with that tension because with all movement away from that position due to wind or vibration, the conductor will spend the majority of its time at the dead-vertical position. If the wind is sufficient to blow the wire out of the vertical plane, there is sufficient wind blowing across the conductor to provide more cooling than dynamic ratings will need. At very low wind speeds, of critical interest in dynamic ratings, the deflection will be minimal if measurable.

The correlated average or mean value of sag associated with each tension is plotted. These sag-tension pairs should match the catenary curve relationship of the conductor's sag-tension behavior. From Table 9 we see that Sagometer 1 can be correlated with tensions monitored at five CAT-1 locations at varying distances from 15,640 feet up to 93,654 feet. The comparison of this data is shown in Figure 41. The comparison for each CAT and the Sagometer combination is made with the catenary sag-tension curve for the CAT-1 device curve plotted and the associated tension value of the Sagometer data. The better the accuracy of the CAT-1 device representation of the line performance, the closer the Sagometer values will be to the catenary curve data. There are several interesting points in the graphic. First note

that all five calibrated sag-tension curves for the CAT-1 devices fall right on top of each other. This indicates that the conductors between these five locations behave consistently with each other and represent a long stringing span section.

The sag values measured by the Sagometer have a fair correlation to the sag-tension curve; the data is consistent in that it is well behaved along a figurative correlation line with little dispersion. The data for CATs at structures 8/4, 15/5 and 23/5 have very good correlation with the sag-tension curve from the 5200 lb to 5800 lb range. This is the critical area of concern to ratings – low tension due to elevated conductor temperature operation. The data for CATs at 2/4 and 29/5 are not as well correlated to the sag-tension curve. Distance from the CAT, i.e., reach, may be responsible for this, even though the data for 23/5, a distance between the 2/4 and 29/5 reaches, seems well correlated.

One issue of interest in this evaluation is the overall number of records in each tension-bucket. Many of the buckets have only one or two records, and in all cases the buckets only contained 1-2% of the number of records. An analysis of the Sagometer 1 data when we concentrate our comparison on the more populated tension-buckets was performed and is illustrated in Figure 42. In this plot only the tension-sag correlations with 1% or more of the data are shown. A trendline for this overall population is shown as the Poly. (Sagometer1) curve, using a second-order polynomial fit. Note the “slope” variance from the sag-tension calibrated curves.

The Sagometer sag validation exercise demonstrated that the data is well behaved for both the CAT-1 system and Sagometer technologies. The correlation has a well-defined relationship with limited variance in the data, evident from the limited variance away from a well-defined correlation, i.e., not many outliers. The variance that is noted is the lack of correlation between the orientations of the slopes of the sag-tension curves from the measured sag data. This dispersion may be attributed to the accuracy of the calibration of the Sagometer system.

The Sagometer system is calibrated by taking a field survey of the span that the Sagometer is installed in. The attachment points, Sagometer target and multiple points along the span are surveyed. A catenary curve approximation is made for the survey data to provide the sag to target correlation used by the Sagometer to report each records position aspect. The target position reported by the Sagometer is correlated to the time of survey. The accuracy of this correlation is reflected in the overall accuracy of the ability to track the conductor movement and sag-tension relationship.

Similar analysis was performed on data recorded by Sagometers 2 and 5, which were located on two different lines from Sagometer 1. All three lines are of similar construction and conductor size and design sag-tension criteria. In this plot, Figure 43, we see that the three sag-tension calibrated curves for the CAT-1 devices are different. Note that in this case the correlation between the Sagometers and CATs was very good for Sagometer 5 and Sagometer 2 with one of the CATs on that line. The other CAT-Sagometer correlation was consistent but showed an offset that is probably related to a Sagometer calibration issue.

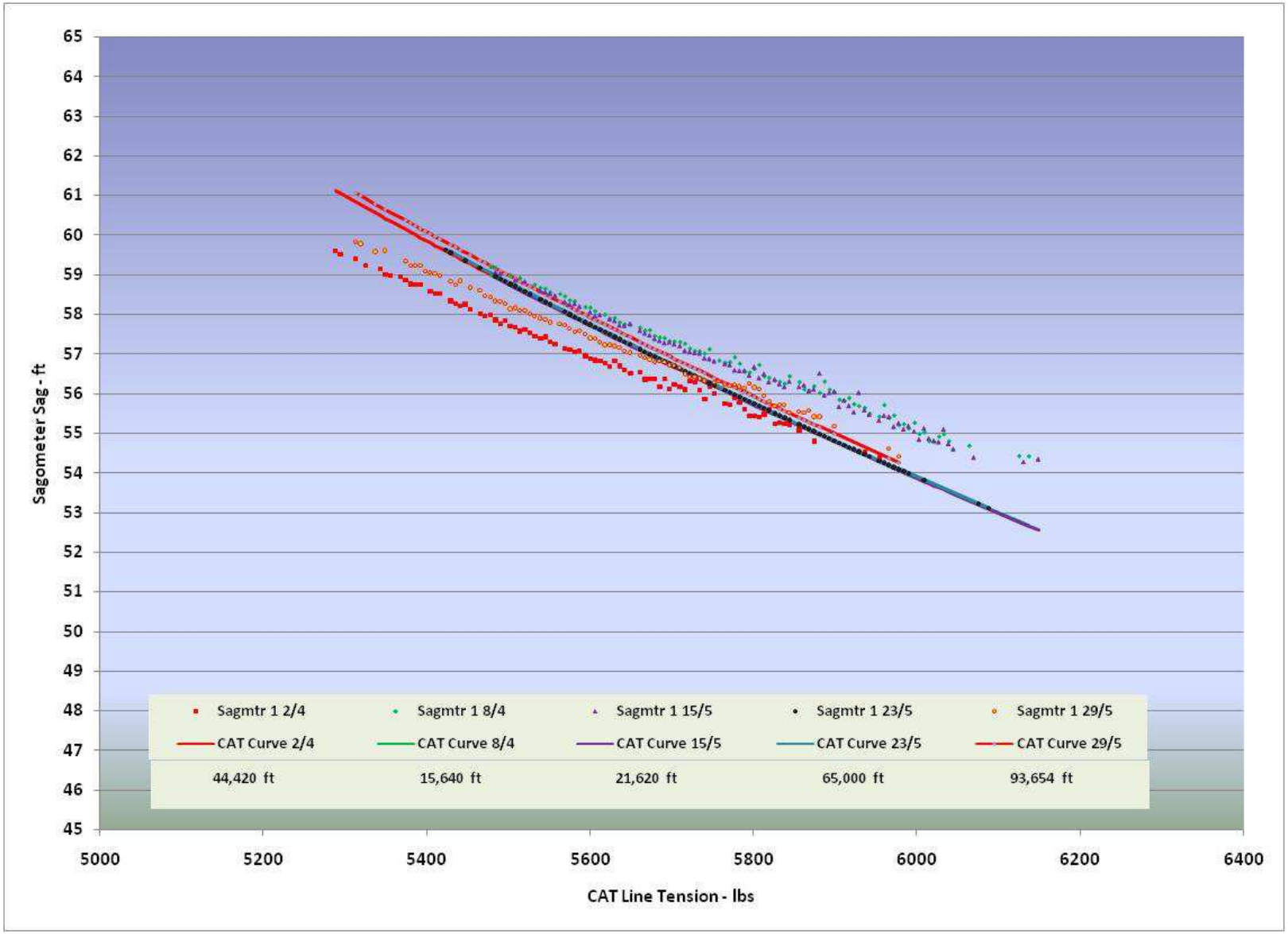


Figure 41 - Sagometer Sag Validation – Sagometer 1

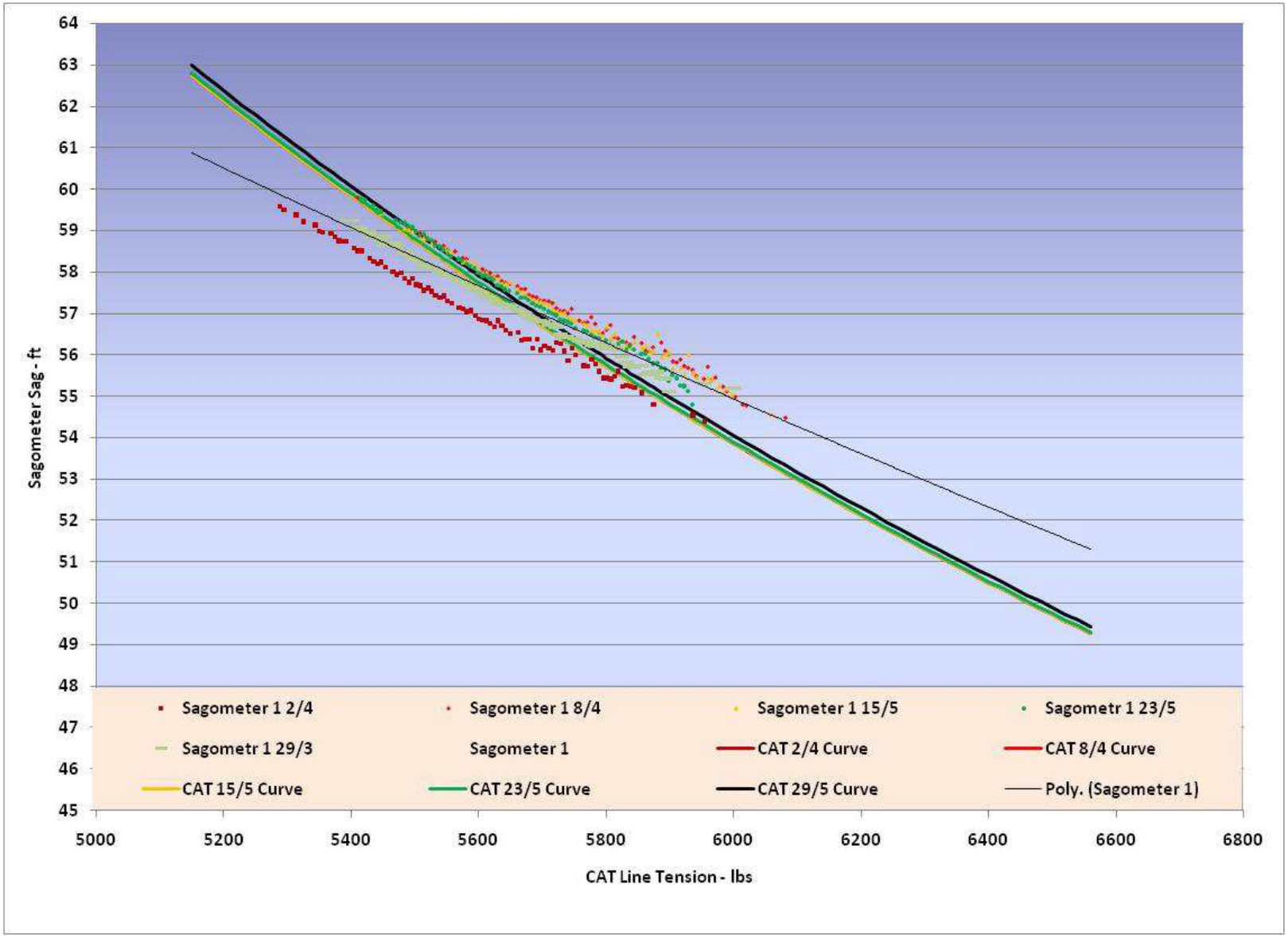


Figure 42 - Sagometer Sag Validation – Sagometer 1 – More Frequently Populated Tension-Bucket

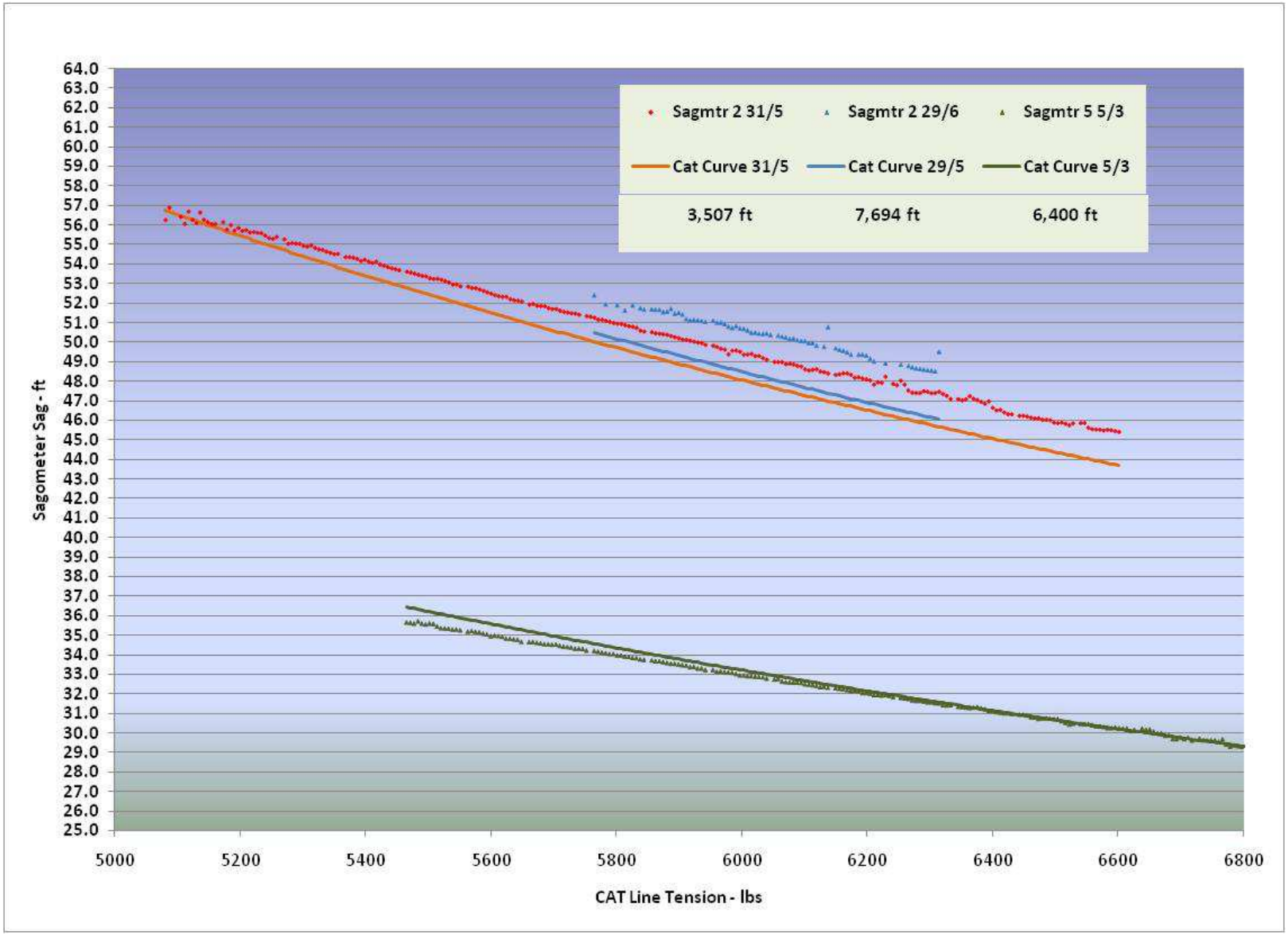


Figure 43 - Sagometer Sag Validation – Sagometers 2 & 5

The RT-TLMS technology was deployed for a similar sag validation task. The RT-TLMS was deployed at three locations under the 138 kV wood H-frame line. Data was collected for four to six months at each location. All three locations were situated between two CAT-1 devices. The locations are designated in Table 9 as RT-TLMS 1-1, 1-2 and 1-3. This provided six comparisons (Figure 44). There are two catenary sag-tension curves for the CAT-1s at Str 19/2 and 26/7. The RT-TLMS monitors were in spans from 640 feet to 38,071 feet from the CATs.

The RT-TLMS units measure the distance from the monitor (near-ground) and the conductor for each phase. As noted above, there is a horizontal component included in these distance measurements that is taken out of the analysis by looking at the average distance in each tension-bucket. That distance is designated the conductor clearance and the sag for the record is calculated by subtracting the clearance from the span's attachment point height.

The data plotted demonstrates excellent correlation between the sag-tension curves of the CATs and the measured data from the RT-TLMS devices. There is some dispersion evident in the Site 1-3 data for both comparisons to the CATs. Overall, the difference between the curves is less than a foot all the time.

Similar to the Sagometer analysis, when we analyze the buckets that contain 1% of the data (no bucket has more than 1%); most tension-buckets have limited numbers of records, especially at the tails of the data population (Figure 45). In addition to the RT-TLMS data for the frequent tension-sag data points, a trendline was fit to each of the CAT-associated records. These plots demonstrate excellent accuracy and correlation between the CAT-1 monitoring devices and the measured clearance or sag along the stringing section.

Additional statistical analysis of the Line Sag Measurement Verification (LSMV) Study is found in Appendix D. The study discusses the margin of error found in the direct measured conductor position and the behavior revealed through the tension-monitoring CAT-1 devices.

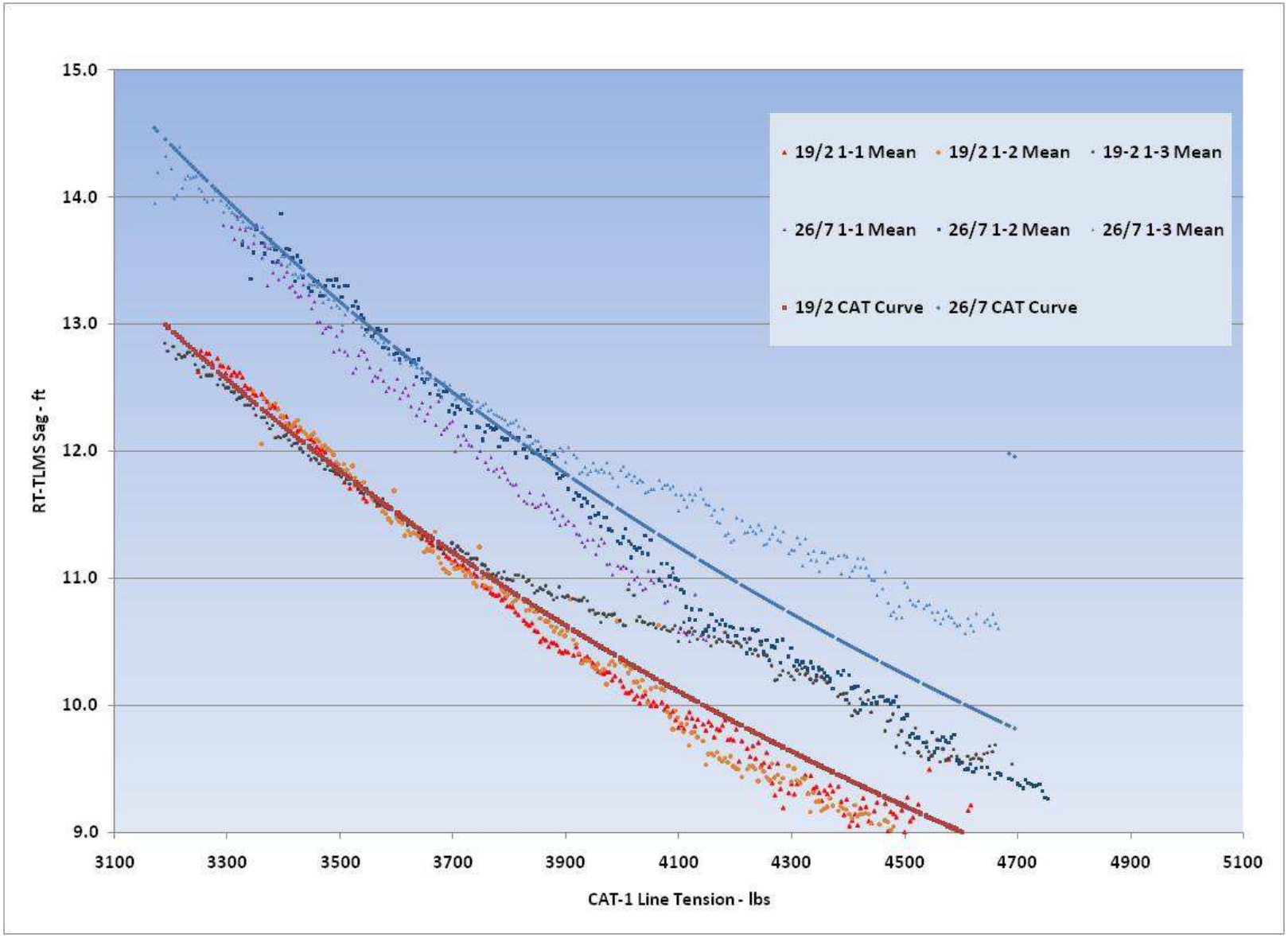


Figure 44 - Sag Validation Results for RT-TLMS Data

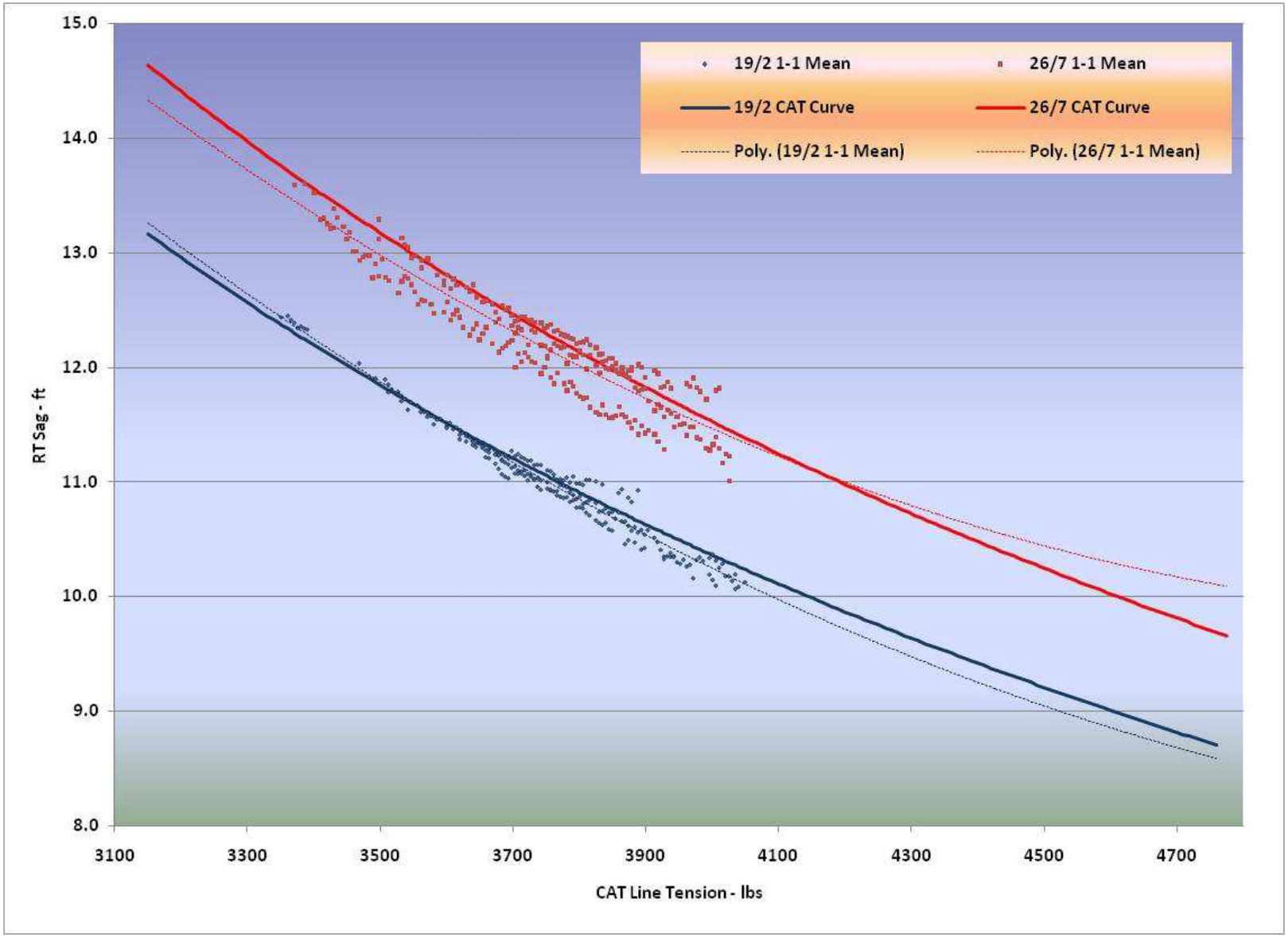


Figure 45 – RT-TLMS Sag Validation – More Frequently Populated Tension-Buckets

3.8.1 Accuracy Sensitivity

The sensitivity of the dynamic ratings system is contingent upon the sag-tension-temperature relationship for any given transmission line section. What is the impact on the other stringing parameters and operations for a small variation in the tension or the conductor temperature?

For example, if the tension changes 20 lbs, the sag of the conductor changes over a range of 0 to 0.1 feet for 138 kV construction and 0.1 to 0.2 feet for 345 kV. With a 100 lb. change in tension the sag range is 0.1 ft to 0.5 ft for 138 kV and .05 ft to 0.7 ft at 345 kV.

The conductor temperature change ranges are 0.5 to 1.7 °C for a 20 lb. tension change at 138 kV and 1.0 to 1.3 degrees at 345 kV. If the tension changes 100 lbs, the conductor temperature changes 2.5 degrees to 8.2 °C for the 138 kV lines and 4.5 to 6.3 degrees on the 345 kV lines.

The ranges depend on the actual ruling span sections that each loadcell of the DLR monitors is measuring tension in. While the design of the lines may be based on one or more ruling spans, the conductors and suspension system develop their own effective ruling span. That effective ruling span causes each specific loadcell to see slightly different behavior over the length of line it is monitoring.

Figure 46 and Figure 47 show how conductor temperature and sag vary for each of the equivalent ruling spans that the Project loadcells monitor for 138 kV and 345 kV lines, respectively. The data is shown as the delta temperature or sag for a 20 lb. or 200 lb. change in monitored tension from the loadcell data.

The gradient changes in the temperature and sag show that the accuracy of the DLR equipment as described in the LSMV Study is well within the change created by 100 lbs. or less change in tension.

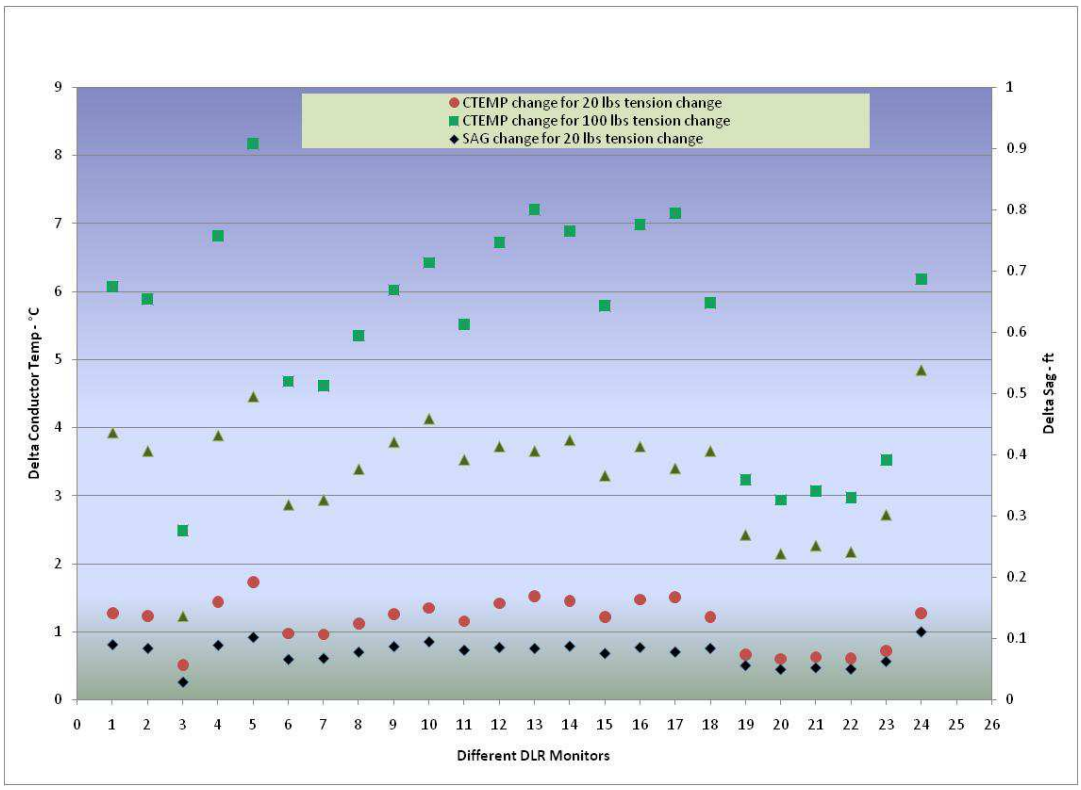


Figure 46 - DLR Parameter Sensitivity – 138 kV Stringing Sections

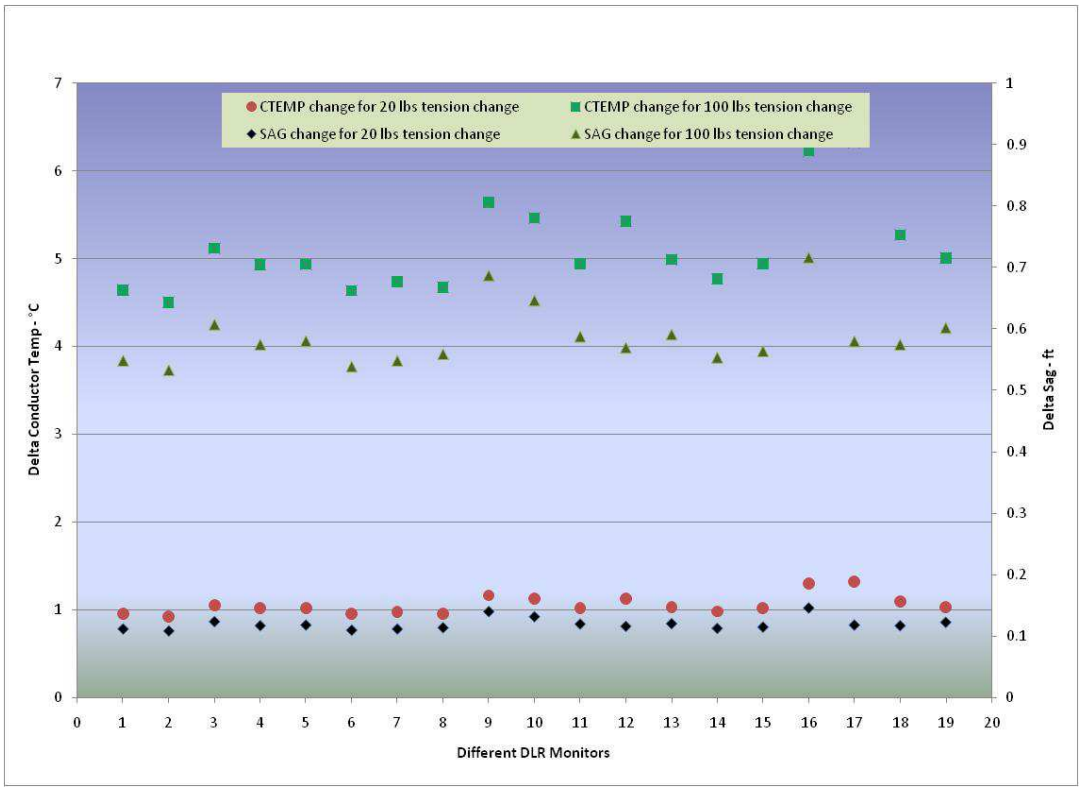


Figure 47 - DLR Parameter Sensitivity – 345 kV Stringing Sections

3.8.2 Conclusions – Line Sag Measurement Verification

The objective of the LSMV was to validate the accuracy of the CAT-1 DLR device to characterize the conductor performance; specifically, that the tension monitored and reported in each record from a CAT-1 device accurately represents the conductor behavior in that stringing section. Since DLR is contingent on an accurate determination of the real-time characteristics of the transmission line conductor, the tension must represent the direct-correlated position of the conductor, its tension and its temperature.

Because a bare conductor is in a strict tension-sag-temperature relationship, knowing one of these variables allows you to calculate the remaining variables with a calibrated sag and tension relationship. The LSMV results demonstrate that the tension monitoring technology is very accurate in portraying the real-time state of the conductor system.

Further, the accuracy extends along a continuous stringing section for a distance in excess of 50,000 feet. This finding complements the results of the DLR Layout Optimization in the next section.

From the LSMV Study we can define these conclusions for different perspectives:

- DLR can support decision-making.
    - The conductor parameters measured, i.e., tension, sag and clearance, agree with accepted models for tension-sag-temperature correlations.
    - There is low risk of erroneous measurements.
    - Measurements are consistent among alternative DLR technologies.
    - There are viable alternative DLR technologies.
- DLR provides System Planning's capacity characterization.
    - DLR characterizes the performance of a transmission line with respect to time, distance and rating.
    - There are predictable confidence intervals for the measurements.
- DLR supports System Operations in providing reliable service.
    - Measurements are reliable and available for performing operations.
    - Measurements are accurate and portray actual line status.
    - Streaming data to the State Estimator enables seamless incorporation of DLR technology to the operating arena.

3.9 DLR Layout Optimization

3.9.1 Background

Transmission lines are designed to operate at a safe maximum conductor temperature to ensure that the energized conductor does not sag dangerously close to the public and also to protect the integrity of the conductor itself. The conductor's temperature is the net result of the heat added by electrical current losses, solar radiation and the ambient air temperature minus the cooling effects of wind. Note that it is the average temperature of the conductor, not the spot temperature at any single point on the conductor, which controls the sag and clearance to ground. Thus, all DLR systems must accurately capture the average conductor temperature for all spans within all sections and segments of a transmission line to ensure safe and reliable operation.

The average temperature of the conductor has both cross-sectional (axial) and longitudinal components. The cross-sectional temperature gradient from the core to outer surface can be significant for an alternating current system. The gradient varies with the size of the conductor, the electrical load and weather conditions; the gradient is especially pronounced under high loads and low wind. Variation in the longitudinal temperature of the conductor is primarily driven by wind speed and direction, which have been extensively documented to vary randomly, substantially and continuously within sub-span distances. This random wind behavior is even more pronounced at low wind speeds, which provide the least cooling and consequently higher conductor temperatures.

Two technologies are available to capture the conductor's average temperature: point measurements and distributed measurements.

Since wind speed and direction can vary significantly and spatially along the corridor and over sub-span distances, accurately capturing the average temperature of the conductor would require a large number of point measurement devices, each recording the temperature at one spot on the conductor's surface. Optimization of point measurement devices was not attempted in this study since: (1) Deployment of the large number of required point measurement devices has not been shown to be economically viable. (2) Given that the reliability for any system is partially a function of the number of the devices, the overall reliability of a DLR system based on point measurements might compromise the accuracy and reliability of the output. (3) Point measurement devices will not account for the temperature gradient across the conductor's cross-section, making determination of the true average temperature impossible.

Distributed measurement technologies alleviate this problem by providing a measurement that captures both the cross-sectional and longitudinal components of the conductor's average temperature over multiple spans without requiring a large number of sensors. The term distributed measurement means that a single measured parameter represents the average temperature of the entire universe of discreet

temperatures along multiple spans of a transmission line. The mechanical tension of the conductor is one such parameter.[4]

Variations in construction types, line geometry, line hardware, etc., all play a role in determining the length of line that a tension measurement will represent. Proper selection of tension measurement sites must capture predominant line directions, elevations and, most importantly, the distribution of wind speeds and directions along the line. The allocation and location of tension measuring equipment (loadcells) must be sufficient to capture the variability of weather conditions along the line. Practice has dictated that approximately four loadcells per 20 miles will provide accurate results in most cases. (Note: An unusually large number of line angles and/or deadend structures on a line will increase the number of loadcells required.) For the present project, measuring equipment deployment was based on a 50% increase in sensor count above prior practice. This was done to provide enough additional data points to determine how many individual loadcell measurements could be removed while still preserving the desired accuracy.

3.9.2 Scope

The original scope of the study included determining the minimum number of sensors required to dynamically rate a transmission conductor. The original scope was extended to also consider the percentage of time that individual loadcells were the limiting element in maintaining the 1 ^{o}C and 2 ^{o}C accuracies to determine if individual loadcells dominated the results. Both objectives were met.

The temperature accuracies of 1 ^{o}C and 2 ^{o}C were chosen based on the following:

- The minimum temperature accuracy is a function of the measurement accuracy of the device being used to determine the average conductor temperature (averaged longitudinally and axially) and the geometry of the line being measured. All DLR devices will have some degree of measurement error. As stated in CIGRÉ TB 498, “In practice, the best possible accuracy from existing devices is about 1 to 1.5 ^{o}C.” While some DLR devices and methods will yield poorer temperature accuracies than this, data collected in this Project found that tension-based measurements typically fall in this best-of-class range.
- A range between 1 ^{o}C and 2 ^{o}C temperature accuracy corresponds to approximately a one-inch sag error on a typical ruling span at maximum operating temperature. For example, a ruling span of Drake double-bundle conductor at 90 ^{o}C, which corresponds to the 345 kV voltage class in the study, has a sag error of 0.72 inches at 1 ^{o}C and 1.44 inches at 2 ^{o}C.

Optimizing loadcell placement with a goal of minimizing average conductor temperature error to between 1 ^{o}C and 2 ^{o}C makes the best use of the individual sensor’s (loadcell) accuracy as well as minimizes the potential sag error.

[4] Stephan 2012, “Guide for application of Direct Real-time monitoring systems.” CIGRÉ Technical Brochure N° 498. Working Group Committee B2.36.

Overall, the statistics gathered in this study on the number of sensing points (loadcells) required shows that previously developed guidelines of approximately four sensing points per 20 miles were correct. More specifically, this study demonstrated that for segments greater than nine miles long, one loadcell per five miles was required to provide a 2 ^{o}C or less error. In segments that were less than nine miles, a minimum of two loadcells was required for a 2 ^{o}C or less error. In all cases, the statistics show that segments were over-instrumented or correctly instrumented, rather than under-instrumented.

The data was examined for evidence of one loadcell consistently limiting the overall rating of the line. Ten of the 14 monitored segments showed little or no evidence of a particular loadcell consistently limiting the line. All four segments where one loadcell significantly dominated the results were short with only two loadcells deployed. Except for one loadcell on a 138 kV line, none of the individual loadcells always limited a line. Because the limiting loadcells in the majority of the segments were well distributed and/or not always limiting, the concept of monitoring a “critical span” was not supported in this real world demonstration project.

Seasonal and system drift effects were investigated over the 15 months of collected data on a segment basis (see graphs in Appendix E, “Seasonal Trends”). Seasonal influence on the minimum required number of loadcells was limited and difficult to discern from the data with the average number of loadcells needed within a year typically not varying by more than 10 to 15%. Future deployment of loadcells only needs to consider the seasonal and monthly variation as a secondary influence on specifying the minimum number of loadcells deployed.

3.9.3 Task Execution

Temperature Accuracy as a Function of Sag Error

The temperature accuracies of 1 ^{o}C and 2 ^{o}C were chosen as optimization targets.

A sag error analysis for the three types of conductors deployed on the Project lines shows that an approximate one-inch sag error results in the range of 1 ^{o}C and 2 ^{o}C temperature accuracy. Table 10, Table 11 and Table 12 show the results of this analysis.

Table 10- Calculated Sag Errors for 345 kV Sections (Drake with a 1,086-ft Ruling Span at 90 ^{o}C Maximum Operating Temperature)

Temperature Error (^{o}C)	Sag Error (in)
1	0.72
-1	-0.6
2	1.44
-2	-1.32

Table 11 - Calculated Sag Errors for 138 kV Sections (Drake with a 582-ft Ruling Span at 90 ^{0}C Maximum Operating Temperature)

Temperature Error (^{o}C)	Sag Error (in)
1	0.48
-1	-0.48
2	0.96
-2	-1

Table 12 - Calculated Sag Errors on the 138 kV Line (Grosbeak with a 537-ft Ruling Span at 90 ^{0}C Maximum Operating Temperature)

Temperature Error (^{o}C)	Sag Error (in)
1	0.36
-1	-0.48
2	0.84
-2	-0.84

Development Tools, Data Collection and Processing

A software program was developed to extract raw 10-minute-interval data and organize the conductor temperature data for each monitored conductor by loadcell. These data were collated per segment by month for conductor temperature accuracy levels of 1 ^{o}C and 2 ^{o}C.

From this data the following parameters were calculated by the program: Maximum Conductor Temperature (MaxCT), Temperature Target Range (TargetRange), Number of Loadcells within range of accuracy (WithinRange) and Number of Loadcells Needed (LCNeeded). In addition, the ranking of loadcell temperature measurements was added to be able to investigate whether specific loadcells were dominating the results. Table 13 shows an example of data extracted and calculated by the program. The next section explains how these parameters are used in analysis.

Table 13 - Example of Extracted and Calculated Data from Raw 10-Minute-Interval Data for a Segment

DATE_TIME	LC 1 CT	LC 2 CT	LC 3 CT	LC 4 CT	MaxCT	TargetRange	WithinRange	LCNeeded	LC 1 Rank	LC 2 Rank	LC 3 Rank	LC 4 Rank
8/1/2011 0:00	29.6	34.1	30.2	33.0	34.1	32.1	2	3	4	1	3	2
8/1/2011 0:10	29.3	31.2	30.7	30.7	31.2	29.2	4	1	4	1	3	2
8/1/2011 0:20	28.8	30.9	30.2	30.6	30.9	28.9	3	2	4	1	3	2
8/1/2011 0:30	28.7	30.8	29.9	30.0	30.8	28.8	3	2	4	1	3	2
8/1/2011 0:40	28.4	30.4	29.6	30.6	30.6	28.6	3	2	4	2	3	1
8/1/2011 0:50	28.4	30.4	29.6	30.9	30.9	28.9	3	2	4	2	3	1
8/1/2011 1:00	28.3	30.4	29.6	30.7	30.7	28.7	3	2	4	2	3	1
8/1/2011 1:10	28.3	30.2	29.3	30.4	30.4	28.4	3	2	4	2	3	1
8/1/2011 1:20	28.1	30.0	29.2	30.0	30.0	28.0	4	1	4	1	3	2
8/1/2011 1:30	28.1	29.9	28.9	30.0	30.0	28.0	4	1	4	2	3	1
8/1/2011 1:40	27.8	29.8	28.8	30.0	30.0	28.0	3	2	4	2	3	1
8/1/2011 1:50	27.8	29.5	28.6	29.7	29.7	27.7	4	1	4	2	3	1
8/1/2011 2:00	27.7	29.6	28.6	29.6	29.6	27.6	4	1	4	1	3	2
8/1/2011 2:10	27.6	29.6	28.6	29.4	29.6	27.6	3	2	4	1	3	2
8/1/2011 2:20	27.6	29.5	28.5	29.4	29.5	27.5	4	1	4	1	3	2

Analysis

To determine the number of loadcells needed for specific temperature accuracy, the calculated conductor temperatures from each loadcell were ranked from coldest to hottest. After ranking, the number of loadcells was counted until the calculated conductor temperature was within the specified temperature accuracy Target Range (Table 4). Target Range was determined by using the maximum conductor temperature for each time stamp minus the temperature accuracy of 1 ^{o}C and 2 ^{o}C.

For example, as shown in Figure 1 and the highlighted row in Table 13, the temperature measurements from lowest to highest were 29.6 ^{o}C at LC 1, 30.2 ^{o}C at LC 3, 33.0 ^{o}C at LC 4, and 34.1 ^{o}C at LC 2. The maximum conductor temperature measurement was 34.1 ^{o}C at LC 2, and thus for a 2 ^{o}C accuracy the first measurement that fell above the 32.1^{o}C threshold determined the number of loadcells needed (LCNeeded in Table 13). The measurement at LC 4 is the first loadcell that falls above the threshold and is the third loadcell in the ranked list (LC 3 Rank, Table 13). Therefore, the number of loadcells needed (LCNeeded) is 3. This calculation was done for each 10-minute time stamp for the duration of the study.

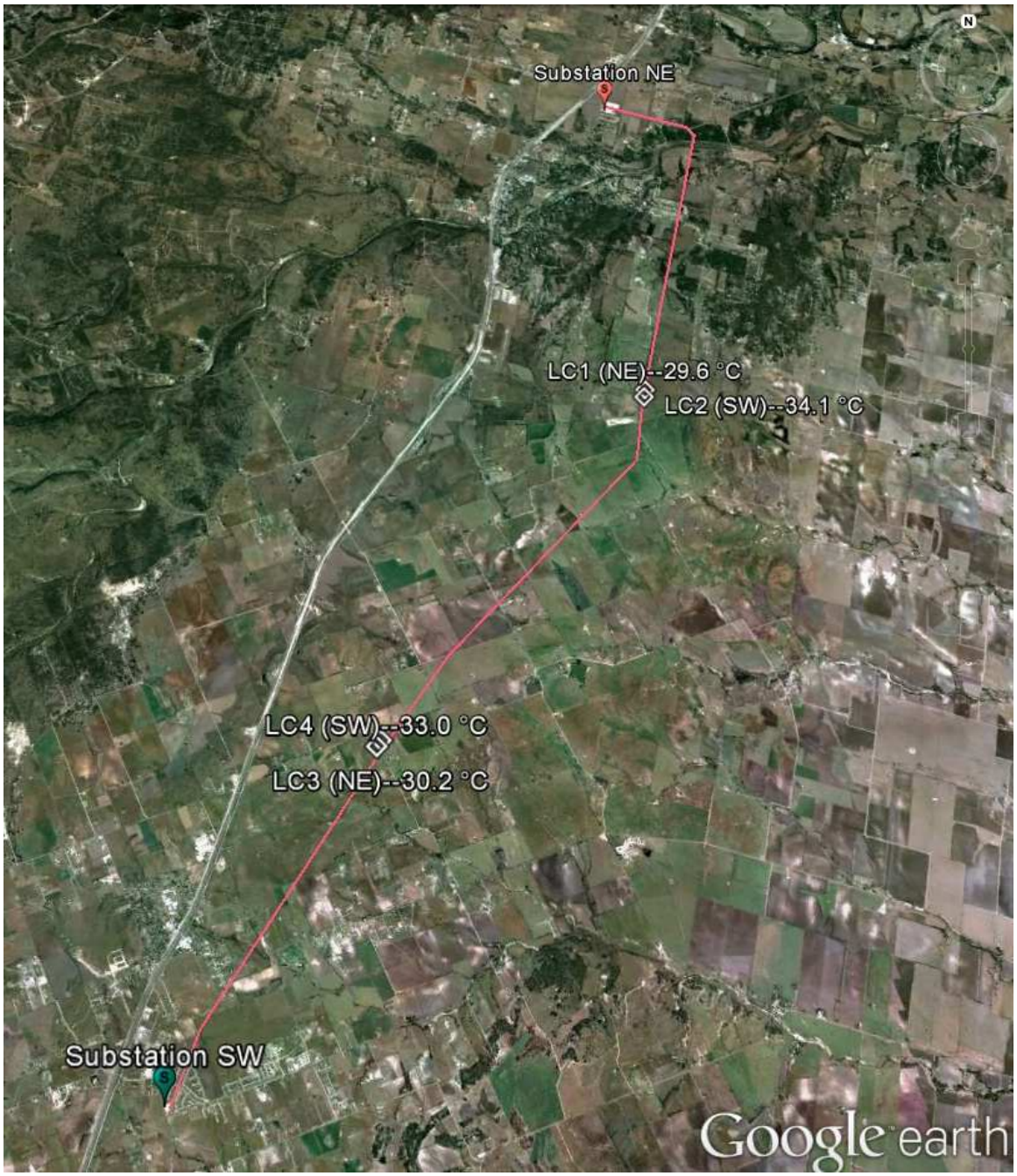


Figure 48 - Configuration of a Four Loadcell Segment with Corresponding Conductor Temperature Measurements

Figure 48 shows a demonstration of a computer program that was developed to compile and calculate additional statistics from raw data. The statistics were compiled monthly per segment for August 2011 through October 2012 using the temperature accuracy levels of 1 ^{o}C and 2 ^{o}C.

Monthly analysis was chosen for two reasons. The data was received as monthly files, and a monthly level of granularity provided enough information to see seasonal influences and other long-term trends.

Data was filtered out if any of the loadcells of a segment had invalid tension readings since tension is used to calculate conductor temperature.

An example of monthly collated statistics based on the number of loadcells needed (LCNeeded) is shown in Table 14. Statistics include: Count (COUNT), Average Fractional Number of Loadcells Needed (Ave), Standard Deviation (STDP), Maximum Loadcells Needed (MAX) and Minimum Loadcells Needed (MIN). In addition, the monthly Miles per Average Number of Loadcells (Miles/LC) was calculated by taking the Average and dividing by the Segment Length.

Table 14 - Example of Monthly Collated Statistics

Segment	SAL_SON		
Voltage Class	138 kV		
Total LC	4		
Segment Length	14.45	mi	
Threshold		**1C**	**2C**
Month	**Statistics**	**LCNeeded**	**LCNeeded**
201108	**COUNT**	4460	4460
	AVE	2.54	1.57
	STDP	0.86	0.79
	Miles/LC	5.69	9.21
	MAX	4	4
	MIN	1	1
201109	**COUNT**	4303	4303
	AVE	2.507088078	1.62561004
	STDP	1.011154821	0.885740285
	Miles/LC	5.76	8.89
	MAX	4	4
	MIN	1	1
201110	**COUNT**	4464	4464
	AVE	2.238575269	1.369175627
	STDP	1.008134182	0.712408984
	Miles/LC	6.45	10.55
	MAX	4	4
	MIN	1	1
201111	**COUNT**	4284	4284
	AVE	2.202614379	1.362044818
	STDP	0.986620428	0.670066347
	Miles/LC	6.56	10.61
	MAX	4	4
	MIN	1	1

3.9.4 Layout Optimization Results

Overall collated statistics are shown in Table 15 and Table 16 for 1 ^{o}C and 2 ^{o}C resolutions, respectively. Statistics include fractional number of loadcells, number of loadcells needed and percentage that a study segment is over-instrumented. The tables group statistics by voltage class, in order of the number of monitored loadcells. The fractional numbers of loadcells needed (LCs Needed) were rounded up to the nearest integer to represent the physical reality in deploying loadcells.

Table 15 - Collated statistics of Loadcells Required for each segment at 1 ^{0}C accuracy

Voltage Class	Segment	Fractional loadcells needed	Load cells needed *
345 kV	Tradinghouse-Temple Pecan Creek	4.4	5
	Lake Creek-Temple	3.9	4
	Tradinghouse-Lake Creek East	2.3	3
	Tradinghouse-Lake Creek West	1.2	2
	Temple Pecan Creek-Temple	1.7	2
138 kV	McGregor Phillips Tap-Temple Elm Creek	4.1	5
	Salado-Sonterra	2.4	3
	Bosque-Rogers Hill	2.8	3
	Jarrell East-Gabriel	2.3	3
	Bell County-Salado	2.0	2
	Roger Hill-Elm Mott	1.5	2
	Waco Atco-Cottonbelt Tap	1.4	2
	Cottonbelt Tap-Spring Valley Tap	1.6	2
	Spring Valley Tap-McGregor Phillips Tap	1.8	2

Table 16 - Collated statistics of Loadcells Required for each segment at 2 ^{0}C accuracy

Voltage Class	Segment	Fractional loadcells needed	Load cells needed *
345 kV	Tradinghouse-Temple Pecan Creek	2.6	3
	Lake Creek-Temple	2.3	3
	Tradinghouse-Lake Creek East	1.9	2
	Tradinghouse-Lake Creek West	1.0	2
	Temple Pecan Creek-Temple	1.4	2
138 kV	McGregor Phillips Tap-Temple Elm Creek	2.9	3
	Salado-Sonterra	1.5	2
	Bosque-Rogers Hill	1.7	2
	Jarrell East-Gabriel	1.7	2
	Bell County-Salado	1.9	2
	Roger Hill-Elm Mott	1.2	2
	Waco Atco-Cottonbelt Tap	1.1	2
	Cottonbelt Tap-Spring Valley Tap	1.3	2
	Spring Valley Tap-McGregor Phillips Tap	1.5	2

The results show a consistent trend in segments where more than two loadcells were present. In the 345 kV voltage class, over-instrumentation on segments with three or more loadcells ranged from 22% to 34% for 1 ^{o}C resolution and 37% to 61% for 2 ^{o}C resolution. Miles per loadcell for the same segments ranged from 4.0 to 8.4 miles for the 1 ^{o}C resolution and 5.0 to 14.2 miles for 2 ^{o}C resolution.

In the 138 kV voltage class, over-instrumentation on segments with three or more loadcells ranged from 18% to 39% for the 1 ^{o}C resolution and 42% to 63% for the 2 ^{o}C resolution. Miles per average number of loadcell for the same segments ranged from 4.2 to 5.9 miles for 1 ^{o}C resolution and 5.9 to 9.6 miles for 2 ^{o}C resolution.

Over-instrumentation and miles per loadcell varied more for shorter segments that had only two loadcells. In the 345 kV voltage class, over-instrumentation on the two segments with two loadcells were 14% and 41% for 1 ^{o}C resolution and 32% and 49% for the 2 ^{o}C resolution. Miles per loadcell for

the same segments were 2.6 miles and 6.8 miles for 1 ^{o}C resolution and 3.3 miles and 7.8 miles for 2 ^{o}C resolution.

In the 138 kV voltage class for segments with only two loadcells, over-instrumentation ranged from 0% to 32% for 1 ^{o}C resolution and from 5% to 44% for 2 ^{o}C resolution. Miles per loadcell for the same segments ranged from 1.3 to 4.1 miles for 1 ^{o}C resolution and from 1.6 to 4.9 miles for 2 ^{o}C resolution.

Overall, the statistics show that previous guidelines to approximate the number of loadcells required were correct. Of all the segments that were at least 10 miles long with three or more loadcells, one loadcell per five miles provided accuracy within 2 ^{o}C of maximum conductor temperature. In all cases, the statistics show that the segments were over-instrumented rather than under-instrumented.

In all cases, the statistics show that the segments were over-instrumented or correctly instrumented to be within 1 or 2 ^{o}C average conductor temperature accuracy.

Percentage of Time Loadcells Were the Limiting Element

Ideally, given that wind (especially), temperature and solar radiation vary along a line, over time each loadcell will have an approximately equal contribution in providing the limiting conductor temperature measurement within the 1 ^{o}C or 2 ^{o}C temperature accuracy. Table 17, Table 18 and Table 19 summarize the results of the percentage of time that each loadcell is the limiting element for 1 ^{o}C and 2 ^{o}C, respectively. As can be discerned from the tables, the majority of segments show that no single loadcell governs all the time. Of the 14 monitored segments, 10 had well-distributed percentages of time that loadcells were the limiting element. The four exceptions were on segments that were less than five miles and only had two loadcells. These shorter segments all required two loadcells to provide a 1 ^{o}C and 2 ^{o}C temperature accuracy. While these shorter segments may be viewed by some to support the concept of a “critical span,” because the majority of the segments had close to equal or some distribution in loadcells being the limiting element, the concept of critical span does not seem to exist in this real world demonstration. In addition, a well-engineered system requires some redundancy. Therefore, to meet conductor temperature measuring accuracy requirements with little support for the concept of critical span, and for redundancy reasons, two loadcells are recommended on straight segments nine miles or less.

Table 17 - Percentage of time each loadcell contributes to being the limiting element (based on loadcells needed) for 138 kV segments

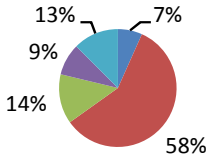
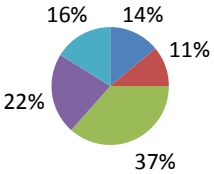
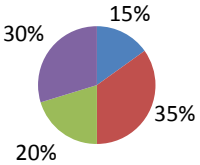
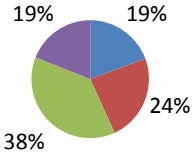
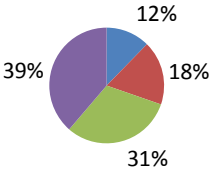
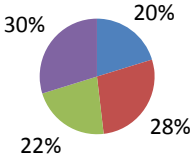
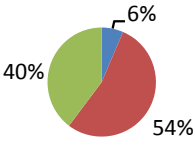
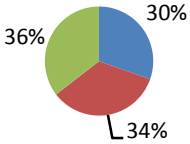
Segment	1 °C		2 °C	
	Limiting Element position	Percentage of time each load cell is in the limiting element position.	Limiting Element position	Percentage of time each load cell is in the limiting element position.
McGregor Phillips Tap-Temple Elm Creek	5		3	
Salado-Sonterra	3		2	
Bosque-Rogers Hill	3		2	
Jarrell East-Gabriel	3		2	

Table 18 - Percentage of time each loadcell contributes to being the limiting element (based on loadcells needed) for 138 kV segments with three or more loadcells

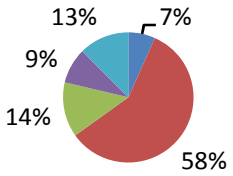
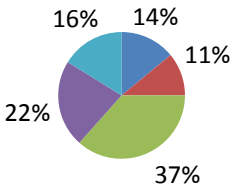
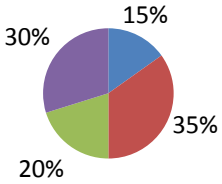
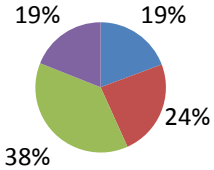
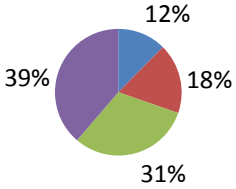
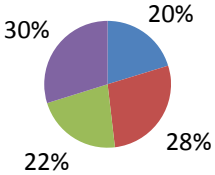
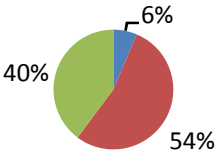
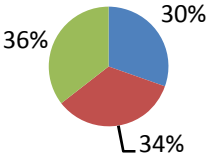
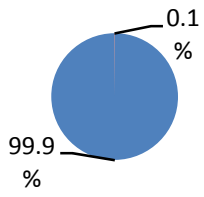
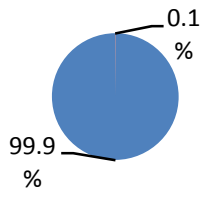
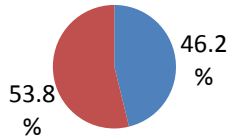
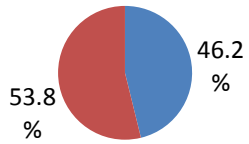
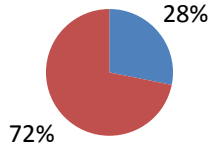
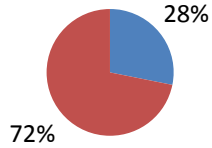
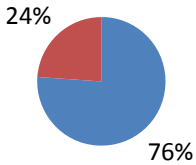
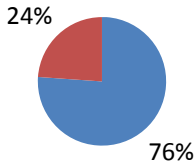
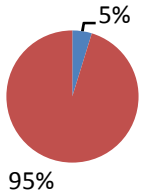
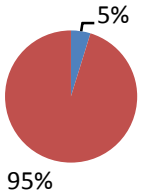
Segment	1 °C		2 °C	
	Limiting Element position	Percentage of time each loadcell is in the limiting element position.	Limiting Element position	Percentage of time each loadcell is in the limiting element position.
McGregor Phillips Tap-Temple Elm Creek	5		3	
Salado-Sonterra	3		2	
Bosque-Rogers Hill	3		2	
Jarrell East-Gabriel	3		2	

Table 19 - Percentage of time each loadcell contributes to being the limiting element (based on loadcells needed) for 138 kV segments with two loadcells

Segment	1 °C		2 °C	
	Limiting Element position	Percentage of time each loadcell is in the limiting element position.	Limiting Element position	Percentage of time each loadcell is in the limiting element position.
Bell County-Salado	2		2	
Roger Hill-Elm Mott	2		2	
Waco Atco-Cottonbelt Tap	2		2	
Cottonbelt Tap-Spring Valley Tap	2		2	
Spring Valley Tap-McGregor Phillips Tap	2		2	

Seasonal Trends

Monthly trends for each segment were compiled for the two accuracies (1 ^{o}C and 2 ^{o}C). There are two types of analysis:

1. Monthly trend of the Fractional Average Number of loadcells required with standard deviation (2-sigma). Included in the analysis is the count, which represents the number of 10-minute data records available during the month. The count is useful to know in case there were few data values available for a particular month, which could explain why the average and standard deviation would be different from other months.

2. Monthly trend of the Miles per Average Number of loadcells. These trends show the number of miles that each loadcell covers on average.

Both seasonal influences and system changes may affect monthly trends. Most segments with two loadcells and a few with more than two loadcells showed no seasonal variation. On segments with three or more loadcells, the data show slightly more loadcells are required during the warmer months and fewer during the cooler months. One segment showed the opposite trend with the cooler seasons having a slightly higher number of loadcells needed.

Typically the variation among monthly averages of the number of loadcells required and the miles per loadcell was approximately ±10 to 15% on segments with three or more loadcells. However, two segments had a monthly variation exceeding ±20%. On segments with two loadcells the monthly range was more variable and varied from near zero to over ±20%.

Future determination of the number of loadcells for a segment should consider monthly variation as a secondary concern. The results do not indicate any clear seasonal trends.

3.9.5 Conclusions – Layout Optimization

The study makes a case that a 1 ^{o}C and 2 ^{o}C temperature accuracy for conductor measurements by tension monitoring equipment is an acceptable temperature accuracy based on two factors: conductor temperature accuracy and minimizing a rating error. Overall, the statistics on the number of loadcells needed show that previous guidelines of approximately four loadcells per 20 miles were correct. More specifically, in segments that were longer than nine miles with three or more deployed loadcells, one loadcell per five miles was required to provide a 2 ^{o}C or less error. In segments that were less than nine miles, a minimum of two loadcells were required to provide a 2 ^{o}C or less error. In all cases, the statistics show that the segments were over-instrumented or correctly instrumented to be within 1 or 2 ^{o}C average conductor temperature accuracy.

Of the 14 monitored segments, 10 had well-distributed percentages of time that a loadcell was the limiting element in meeting temperature accuracy. Thus the majority of segments could not be monitored using a critical span for temperature accuracy. The four exceptions were on short segments

with only two loadcells. Having more duplication of tension measuring equipment seems to reduce the risk of bias.

Seasonal and system drift was limited and difficult to discern from the data. However, the average number of loadcells within a year typically didn't vary more than ±10 to 15% from month to month. Results indicate that future applications of loadcells may consider seasonal and monthly variation as a secondary influence on the minimum number of loadcells needed for deployment.

3.9.6 References

[1] Stephan 2012, "Guide for Application of Direct Real-time Monitoring Systems." CIGRÉ Technical Brochure N° 498. Working Group Committee B2.36.

3.10 Persistence Study

Persistence is defined as the range of future real-time ratings as a function of current rating, time and probability. The objective of Persistence-Based Ratings is to predict the probability of available capacity above the static book ratings and to reduce the load curtailment probability to less than 1%. Note that the future ratings have the ability to increase or decrease from their current value. However, the greatest concern is for the ratings going lower than their current value.

As a research and development exercise, the challenges and outcomes of the SGDP Project were uncertain. In the project plan, it was assumed that the line currents would be relatively high and that occasional load curtailments would be necessary because of contingency limits. Those curtailments would have provided a real world laboratory that allowed development of real-time Persistence-Based Rating algorithms for operational purposes.

Unfortunately, the loads of all circuits were quite low. This resulted in only four circuits with load levels sufficient for statistical evaluation of the potential benefits of Persistence-Based Rating, and even in these circuits only for only a few months of the data collection period. Nonetheless, based on these statistics alone, the study demonstrates that a fully automated application of Persistence-Based Ratings would allow operation of the lines at 105-125% of static ratings, at less than 1% risk of load curtailment.

The operational trial of persistence slated for this study was not able to be completed. The low line loads prevalent throughout this project precluded a meaningful trial and validation of the preliminary results reported here.

3.10.1 Background

For effective operational use of dynamic ratings, the system's operators need to have information about the persistence of the observed ratings, i.e., knowledge of the possible change of ratings during the next

15 to 60 minutes. Studies, especially a recent one in California[5], have shown that rating conditions can have substantial short-term persistence. The California investigation showed that for the selected relatively short time periods and during summer conditions, persistence information offered a feasible approach for more effective utilization of transmission capabilities. The short extent of the study did not verify the application for other climates or for weather conditions throughout the year, nor did it study the most effective use of such information.

3.10.2 Scope

This study originally consisted of three phases, which are described below. Different layers of challenges, which required changes in the task, were uncovered as the project proceeded. The second and third phases were dependent on having sufficient load levels a significant amount of time to capture a data set large enough to develop algorithms and software. Because the load levels on the project's lines were much lower than anticipated, the original scope of the second and third phases could not be implemented. The scope was modified to substitute an analytical study demonstrating one practical application based on the limited amount of historical data that came out of Phase 1. This demonstration application may be useful for future studies and operations.

Phase 1. Validation of concept and estimation of benefits

Data from the five separate line corridors is collected and evaluated statistically, to identify the persistence and its dependence on localities, seasons and other external variables (line length, conductor's thermal time constant, etc.) This data is used to estimate the potential benefits and risks. It will also provide the data for bench-testing algorithms and software to be developed in Phase 2.

Task Changes to Phase 1

Because load levels over 12 months for the eight project lines were low, there was insufficient data to identify persistence trends based on seasons, localities and other external variables. Instead, benefits and risks were assessed based on a few months of data at four segments where load levels were sufficient.

Phase 2. Development of algorithms and software

Based on data from Phase 1, algorithms and software, which automatically calculate in real time the risk level for different rating levels, were to be developed and bench-tested against collected historical data.

Task Changes to Phase 2

Load levels in the majority of the months over a 12-month period for the eight lines through most corridors were below those required to support persistence. Those low load levels were projected to continue into Phase 3 where they would preclude successful operational trials. Therefore, Phase 2's slated development of algorithms and automated software for use in Phase 3 was canceled. Instead, a

[5] Attachment D for Multi-Area Real-Time Transmission Line Rating Study, CIEE Award C-05032, WA 121, Under CEC/CIEE Prime Contract 500-99-013.

historical analysis of available data was conducted. One of two persistence methods was chosen and applied to the available data to gauge potential benefits and risks.

Phase 3. Operational trials and final report

Operational trials are conducted with the developed software. Oncor will establish a small team of at least one person from Operations and one from Planning. This team will evaluate the persistence data collected over six months and compare it to operational records. The purpose is to identify operating actions, especially contingencies, that could have been managed differently based on persistence information. The economic consequences of such alternative actions are estimated and summarized. A final report is produced.

Task Changes to Phase 3

As noted under Phase 2's task changes, the loads required to support persistence were generally not available on the eight lines scheduled for operational trials. Blindly proceeding with the trials made no sense and they were canceled. This final report provides analytical results on a few segments, each with a few months of sufficient data. The report includes potential benefits, risks and an application of one persistence method based on historical statistical analysis.

3.10.3 Task Execution

Sufficient Load for Persistence Calculations

Two conditions are required to calculate persistence ratings: (1) a sufficient conductor temperature rise (delta T) above the no load temperature[6] to enable calculating a dynamic rating based on the effective wind along a section of line using empirically calibrated state change equations and IEEE algorithms, and (2) the presence of a sufficient delta T for at least three consecutive 10-minute sample intervals. To ensure that both conditions were met, a 350 amp per conductor load threshold was chosen with which to filter the data set.

As discussed in the scope section above, load levels in most of the line-corridors were below the 350 amp thresholds. In addition, other system errors required removing data from the analysis. These system errors included periods of maintenance and known issues uncovered from careful evaluation of system data. The process of load and system error filtering is discussed in the next section.

[6] The no load temperature of each line segment in this project was measured by a device called a Net Radiation Sensor (NRS). The device determines the conductor temperature if the conductor is carrying zero current.

Data Filtering

Load filtering

Four segments were identified that had sufficient loads. A segment was determined to have sufficient loads if 10% or more of the load data during a month was at or above 350 A. In choosing segments that met sufficient load levels, the individual loadcells in the segment needed to have simultaneous sufficient load levels. This was usually not an issue since a segment usually shares similar loads.

Shadow Filtering

To remove error due to shadow effects on Net Radiation Sensors (NRS) a procedure was developed to filter out periods of shadowing. This second level of filtering was performed after load filtering and selecting candidate segments as discussed in the previous section.

The process involved calculating the actual and ideal daily Net Radiation Gain curves for each loadcell for each month and looking for periods of time of reduced measured Net Radiation values.

Net Radiation Gain (NRG) is the difference between the measured ambient temperature and net radiation temperature at each loadcell. An NRG value for each 10-minute interval was averaged over a month and compared to the calculated NRG curve using IEEE steady-state thermal calculations. If the difference between actual and ideal NRG was more than 1.75 °C, the period of time was flagged as a significant shadowing event and was removed from the data set.

RateKit was run in batch mode to calculate daily hourly NRG on a day in the middle of each month of the study. Assumptions included: ambient temperature of 20 °C, wind speed 3 fps normal to the conductor, and 0.65 emissivity and absorptivity. Conductor orientation was adjusted based on the line orientation near each loadcell.

System Health Filtering

The final set of filtering occurred by reviewing system health reports for outages or other problems that may have affected the raw data.

Monthly system health reports were created by running a program that tabulated statistical data on the raw data. These reports were then scanned for anomalous data, and a monthly health report was written to summarize outages.

3.10.4 Persistence Data Analysis

Principle and Application of Persistence Method

Static ratings assume that the most unfavorable solar, wind and ambient temperature conditions all happen concurrently. Real-time rating systems determine the transmission line's capacity under the present actual solar, wind and ambient conditions. Real-time ratings generally exceed static ratings 99% of the time since actual weather conditions rarely approach the worst case weather conditions upon which static ratings are based. Real-time ratings can be used to safely increase the available transfer capacity of lines, as long as the operators are willing to act within a short time if contingencies occur.

The objective of the Persistence Method is to provide useful information about the probability of future, 15 to 60 minutes, line capacities. One important application is when real-time weather conditions are actually unfavorable and the real-time capacity of the transmission line is low and thus critical.

The Persistence Principle

The Persistence Principle is based on the following:

- The median real-time rating is typically 135 to 145% of the static rating, based on CIGRÉ TB 299. The ratings close to static ratings have very low probability of occurrence.
- Lowest observed real-time ratings occur invariably during the time periods when effective wind speeds are low, generally less than 2 fps. Such wind speeds seldom persist for more than 20 minutes during daytime conditions.[7]
- The likelihood that a low real-time rating is followed by other low ratings for 30 to 40 minutes is very low. On the other hand, at low wind speeds the time constant of the conductor is higher. For example, a Drake ACSR requires 30+ minutes to reach 90 to 95% of its final temperature rise. Thus a low real-time rating does not imply a high likelihood that a conductor will reach its limiting temperature in the near future.[8]
- Ratings can remain low for a prolonged time only if effective wind speeds remain depressed for an extended period. These generally happen only when the ambient temperatures are moderate and the solar radiation is low – typically when weather fronts become stagnant and temperatures are moderate. These conditions are rare but not impossible, as shown by the conditions prior to the 2003 blackout.[9] These are seldom relevant if ratings are based on CIGRÉ 299 guidelines.
- Typically, the 30-minute average persistence rating is 5 to 15% higher than the real-time rating. Thus, judicious application of persistence ratings can significantly reduce operator interventions.

[7] T. Seppa, E. Cromer, W. Whitlatch: Summer Thermal Capabilities of Transmission Lines in Northern California Based on a Comprehensive Study of Wind Conditions, IEEE Trans. Power Delivery, Vol. 8, No. 3, pp. 1551-1561, 1992.

[8] For ACSR "Drake," the end temperature after 40 minutes of transient change is 90% if wind speed is 1 fps, 95% if wind speed is 2 fps, 97% if wind speed is 3 fps.

[9] Tapani O. Seppa; Fried Wire? Public Utilities Fortnightly, pp. 39-42 (December 2003).

Persistence Application Methods

There are two methods in applying persistence to operational applications.

a) Continuous analysis of ratings in which the statistical distribution of persistence ratings would be calculated continuously, and the persistence limit would be set based on a selected confidence level (e.g. 2-sigma) based on the statistical distribution of the most recent one to two hours observation. This would require prolonged periods of moderate currents (over 350 A in the case of Drake) and is not feasible for present operating conditions of the studied lines.
b) Analyze ratings from historical data sets where conductor currents are greater than 350 A per conductor. This allows selection of statistical persistence boundaries as functions of the present real-time rating. For example, if the statistics show that the 2-sigma level of the persistence rating is 75 A higher than the present real-time rating at 1000 A, the operators could set the load curtailment levels at 1075 A when the real-time rating is 1000 A.

As already discussed, Method (b) was chosen due to lack of high load data on many of the segments.

Calculating Persistence Values

For Method (b), the procedure for calculating persistence used the following steps:

1. Filter out loadcell data for each 10-minute measurement using load, shadowing and system health filters as discussed above.
2. Ensure that the next 30 minutes beyond the current time stamp do not have filter flags due to load levels, shadowing or system health reasons. If there were no flags, then this provided a full 30 minutes of data to calculate persistence ratings.
3. Find the minimum present and persistence ratings for each loadcell to represent the present and persistence segment rating.
4. Calculate persistence ratings as the average of the next 30 minutes of ratings at the segment level. This provided the historical persistence data set.

An example of the results of Method (b) calculation can be seen in Figure 49. The present line rating is shown on the horizontal axis, and the associated persistence rating based on the average rating on the next 30 minutes is located on the vertical axis. The data point shows the persistence rating referenced to the present rating. If the rating goes up in the next 30 minutes, the data point will be plotted above the equivalency line. If the average rating decreases over the next 30 minutes, the data point is below the equivalency line. The variation in the scatter plot is indicative of the fact that ratings statistically have ample opportunity to decrease and increase on average in the next 30 minutes. The dispersion and tendency in one direction or another is different for different lines. Of particular note is that persistence ratings tend to go up when the present rating is low. For example, in Figure 49 this is apparent for present ratings below 1050 A. The majority of persistence ratings are above the equivalency line at present ratings 1050 A or below.

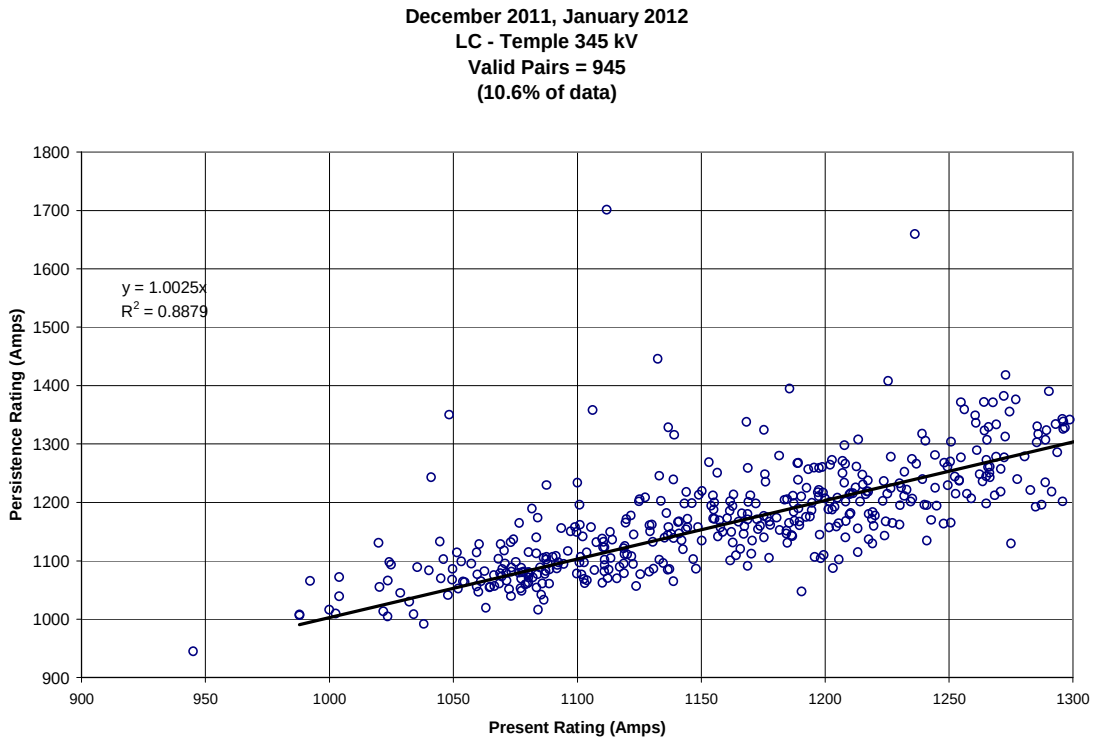


Figure 49 – Scatter Plot of Present Rating to Persistence - Next 30-Minute Average Rating

Figure 50 shows an example of the cumulative probability functions of real-time ratings, Persistence Based Ratings and "persistence step" ratings for one of the four circuits studied. The curves are based on 100 A bins and provide insight into the benefits and risk of using persistence Method (b); 100 A bins were used (instead of 50 A or 25 A) because of the limited number of data points due to load levels.

A persistence step can be used by an operator as a simple and conservative way to gain capacity. Because the study only had a limited number of months on a few segments, a continuous calculation of persistence based on a 2-sigma variance was not available. Instead, the persistence step method is a logical way to gain benefit. It provides less benefit than the continuous persistence method, but with less risk.

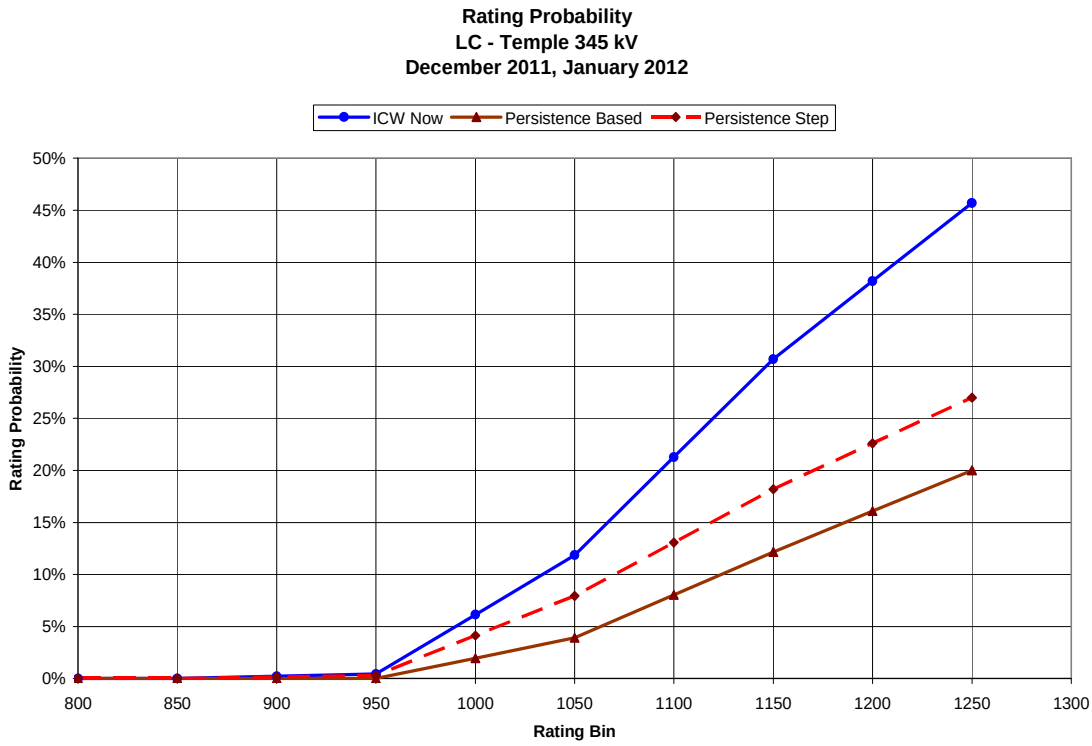


Figure 50 - Cumulative Probability Functions for Real-Time Rating, Persistence and "Persistence Step" Using 100 Amp Bins

To apply a persistence step, the persistence data in each bin has a flat buffer applied to it to reduce the uncertainty of the persistence rating in the next 30 minutes. For example, in Figure 50 the real-time rating risk level for 1050 A is about 11.9%. Using persistence data alone would provide 1150 A for the next 30 minutes at the same risk level. However, using the persistence step method, the increase is about 40% of the gain of persistence alone or about 1090 A for the next 30 minutes. With this gain, the risk level according to the persistence curve alone is approximately 7%.

The persistence steps used for all segments were 50 A for present ratings that fall into the 900-1000 A bin, 25 A for present ratings in the 1000 to 1100 A bin, 12.5 A for present ratings in 1100 to 1200 A bin, and 6.25 A for present ratings in the 1200 to 1300 A bin. With more months of data, persistence steps could be refined for each segment.

3.10.5 Conclusions - – Persistence Study

In each case, real-time ratings indicate that static rating assumptions met the IEEE-CIGRÉ recommendations in TB 299, representing occurrence less than 1% of the time. Persistence values have 1% risk levels at about 1010 A per subconductor for two 345 kV segments, 1130 A per subconductor on Temple Pecan Creek-Temple (also a 345 kV segment), and 1040 A on the 138 kV segment. Based on these statistics alone, a fully automated application of PBR would allow operating the lines at 105 to

125% of static ratings, at less than 1% risk of load curtailment. Because the study only had a limited number of months on a few segments for persistence calculation purposes during the 12 months of monitoring, a continuous calculation of persistence based on a 2-sigma variance was not available. Instead, a persistence step method was developed that could allow slightly more restricted benefits, typically a 103 to 113% of the benefit gain in line capabilities over static ratings, while reducing the risks. While the reduction of risk is likely much less than 1% of the time, it was difficult to quantify given the small database, which was limited in capturing seasonal and location diversity.

A capacity forecasting engine (CFE) has now been developed that essentially replaces and enhances the concept of persistence. The CFE methodology had not been adequately conceived at the time the scope for this Smart Grid Demonstration Project was prepared. A pilot study using the CFE has demonstrated the ability to predict capacity with high accuracy. More importantly, it can predict capacity not only for the 15- to 60-minute persistence window but also for the next 24 to 48 hours for day-of and day-ahead operations and markets. It is recommended that a natural next step would be to apply the CFE principles to further optimize transmission capacity and benefits to the consumer by representing a more representative capacity state of the grid for day-of and day-ahead operations and markets.

3.11 Day Ahead Forecasting

3.11.1 Preface

Utility Operations and Regional Transmission Organization (RTO) markets are interested in not only the real-time characteristics and performance of a transmission line but also in the forecast for operating conditions, whether the future is the next 15 minutes, hour, several hours or the next day. With increased understanding of how the transmission system will operate in the future, better decisions can be made for optimizing the system's performance within each of those time frames.

The transmission capacity released by DLR (Dynamic Line Rating) is as variable as the weather over time. The key question is how much additional released capacity will be available for the next day's operations and the next year's operations. The answer has major implications for asset utilization, economy of power delivery and system reliability.

3.11.2 Scope

DLR data from the eight transmission lines will be examined to identify patterns in ratings that can be used to forecast dynamic transmission capacity. Based on those patterns, a methodology will be defined that provides a practical and easily implemented forecast of capacity. It was anticipated that the data will justify a methodology that raises the static limits presently employed in transmission system planning. However, that is not a foregone conclusion and other techniques remain open to exploration.

Any forecasting technique carries some uncertainty. The degree of uncertainty that is acceptable and the impact of that uncertainty on planning and operations will be assessed.

Also to be assessed is whether a given methodology is universally applicable or if it needs to be tuned for a given set of conditions such as voltage class, size of conductor, length of line and surrounding terrain.

The following data presentations will be required to identify and formulate an initial methodology. The data is identical to that produced under the tasks associated with defining the capacity released over current ambient only temperature dynamic approach.

- Plot of the difference between the Dynamic Line Rating and the Ambient-Adjusted Rating on a monthly basis as a probability distribution as a percent of time.
- Plot of the DLR and the AAR on a monthly basis as a daily distribution.
- Plot of the DLR, conductor temperature and ambient temperature as a time-of-day plot.

Additional data presentation formats may be required based on questions or conclusions drawn from an examination of the initial data set.

A report summarizing findings and making recommendations on future practices or studies will be written.

3.11.3 Task execution

Each month the data from the subject lines in the SGDP Project was processed to produce the different types of graphs shown below. For comparison purposes, two 345 kV transmission lines are shown side by side for the summer month of August and the winter month of December 2012. The processed data shown below is typical of all the data processed for all of the eight lines.

The monthly probability distribution graphs in Figure 51 show the percentage of time that a given Dynamic Line Rating was available during each month. The DLRs of both lines exceeded the Static Ratings by at least 95% of the time during both the summer and winter months. Note that although the lines are parallel and separated by only two to three miles, they show different probability distributions.

The monthly distribution probability graphs in Figure 52 show the percentage of time that the Dynamic Line Rating exceeded the Ambient-Adjusted Rating throughout each month. Again the same two parallel transmission lines are shown for August and December. Note that trends are similar between the lines during the same time of year. However, the trends are not similar when comparing the same line at different times of the year.

The daily distribution probability graphs in Figure 53 show the Dynamic Line Ratings available during each hour of the day during the month. Data for the Minimum Rating, Median Rating, 85th Percentile, 90th, 95th and 99th Percentiles are shown. Example: At noon during August 2012, the Dynamic Line Rating for the 345 kV line was greater than 1917 amperes 90% of the time compared to the Static Line Rating of 1794 amperes. Again, note that the variation of the data across the four panes for the two lines and the two months of data is different for each line and in each month.

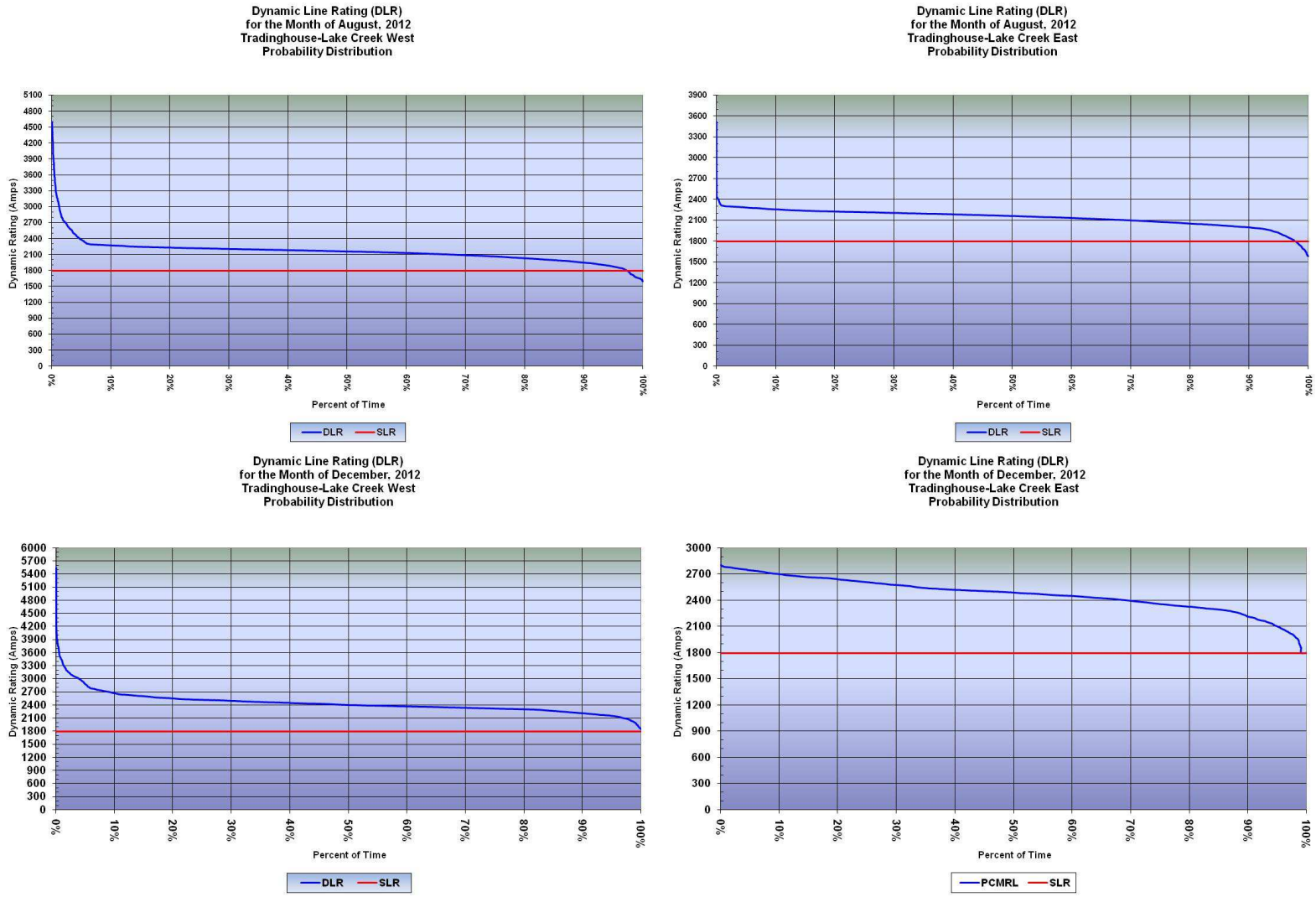


Figure 51 - DLR Probability Distribution Curve - 2 Lines - Aug & Dec

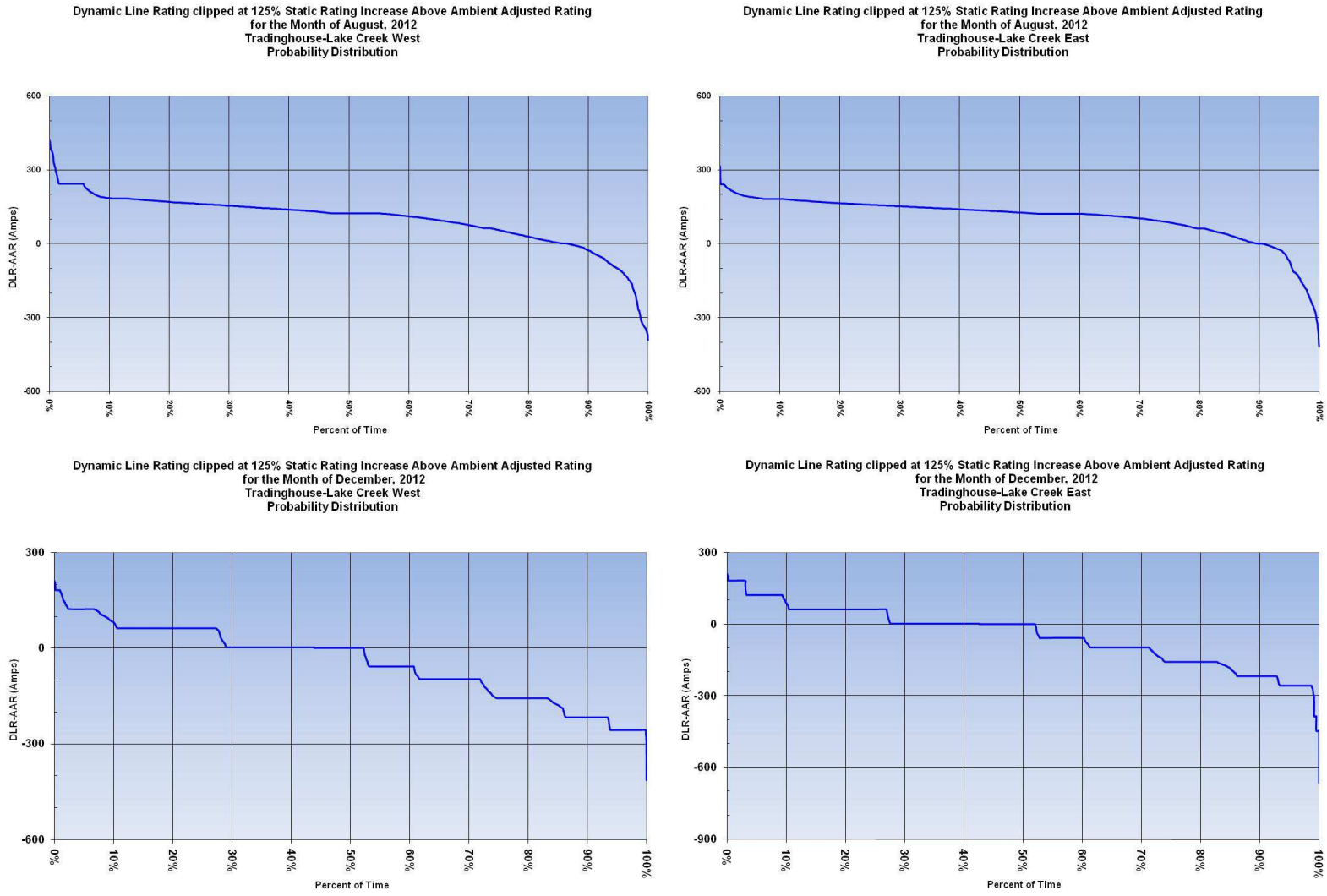


Figure 52 - DLR Increase Above AAR - 2 Lines - Aug & Dec

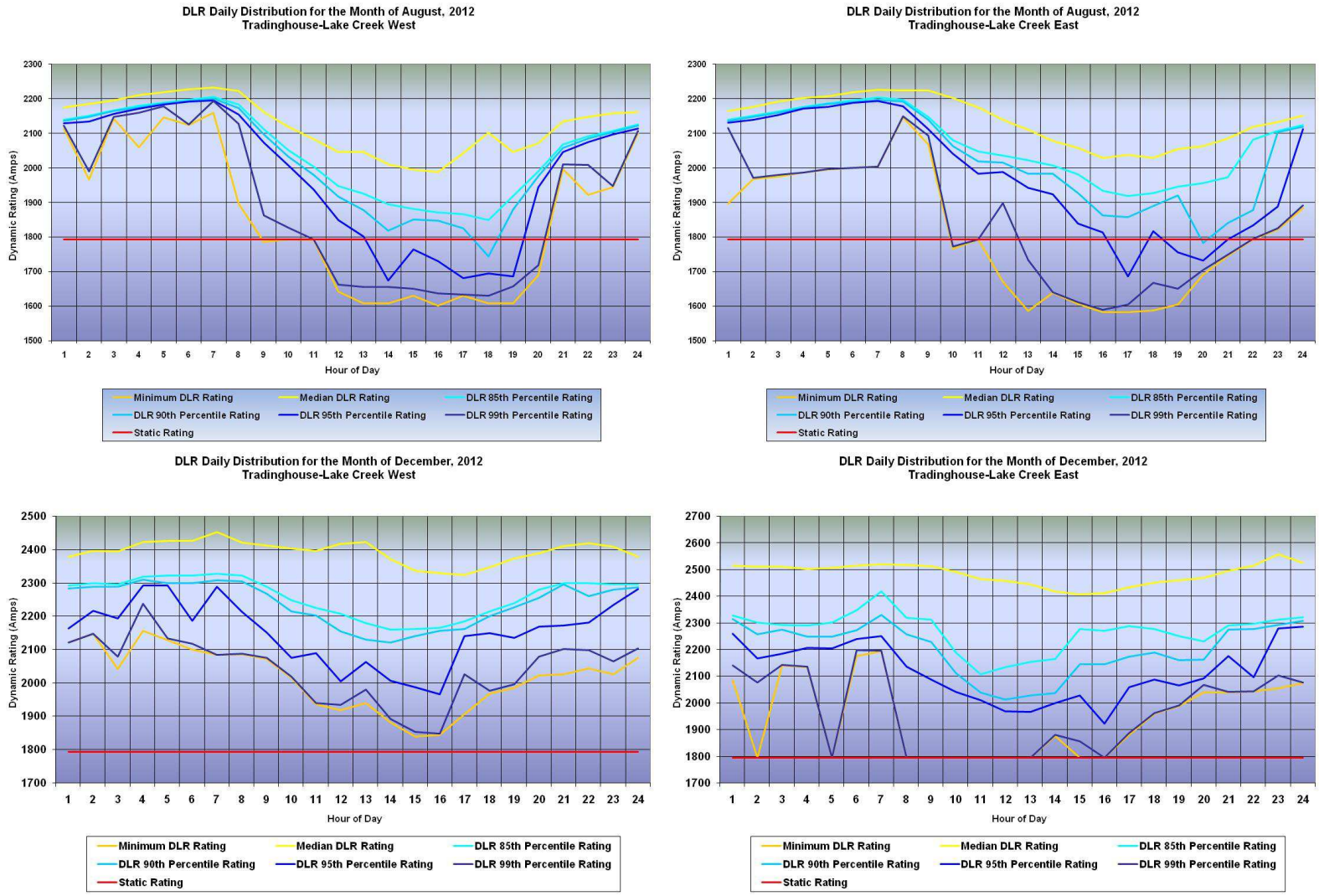


Figure 53 - DLR Availability Percentiles - 2 Lines - Aug & Dec

3.11.4 Results

As noted in the Task Execution section, the transmission capacity released by DLR is as variable as the weather over time and distance. A common denominator could not be identified that would establish a single predictor of capacity across an entire geographical region, voltage class or other criteria. The conclusion is consistent with expectations given the spatial and temporal nature of weather coupled with the differing topologies of each transmission line.

However, the data did lend itself to development of a practical methodology that provides both planning and operations functions with a usable prediction of capacity for each individual transmission line. That methodology results in the ability to safely raise the static rating limits on a transmission line while ensuring that the conductor always remains within its specified maximum operating temperature and thus its sag limits.

Figure 54 shows the 90th percentile of Dynamic Line Ratings for each month during 2012 on one of the 345 kV transmission lines. The interpretation of the graph is that for any given month, the available capacity on the transmission line was greater than the 90th percentile line on the graph. Note that for October, 90% of Dynamic Line Ratings were at least 1955 amps (the published static limit was 1794 amps).

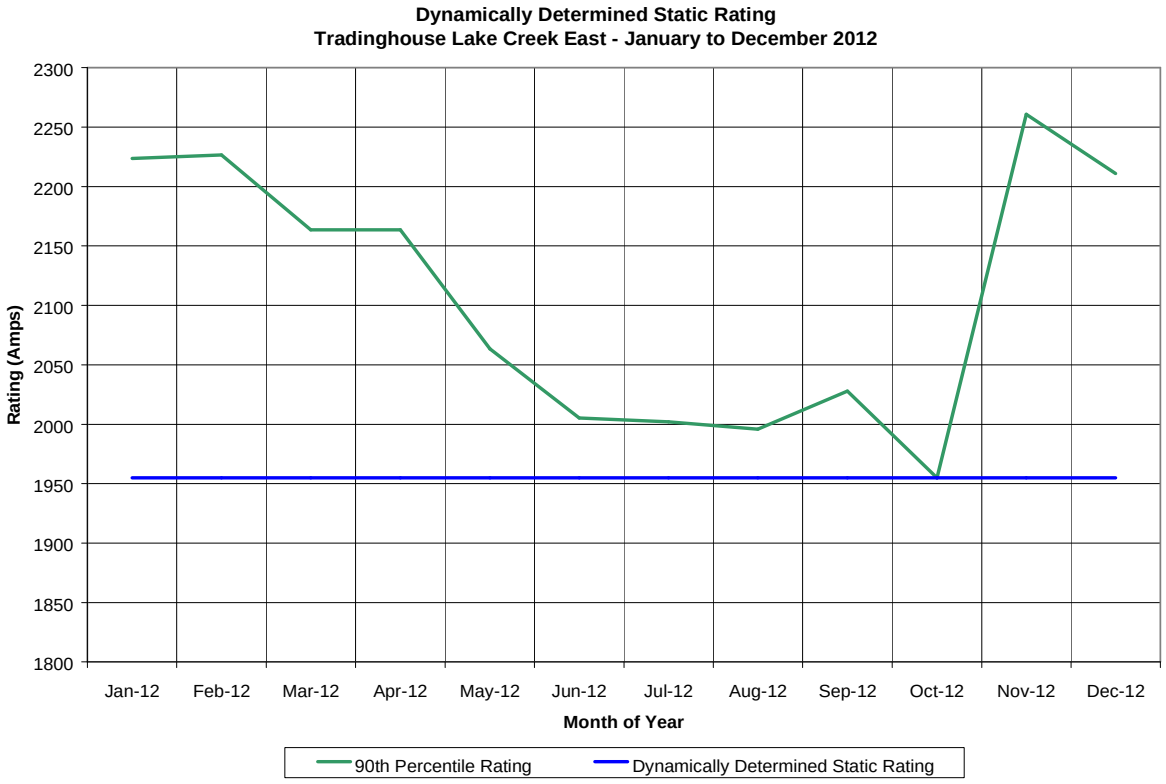


Figure 54 - 90th Percentile of Dynamic Line Ratings for Each Month During 2012 345 kV Line

Figure 55 depicts the available capacity of the 345 kV transmission line during October 2012. The present static rating for the line is 1794 amps. This line is capable of exceeding its static rating more than 97% of the time, with more than 9% additional capacity being available at least 90% of the time.

What would be the impact of raising the static rating from 1794 amps to 1955 amps (90th percentile)? The available transfer capability would go up, congestion would be relieved, and there would be more

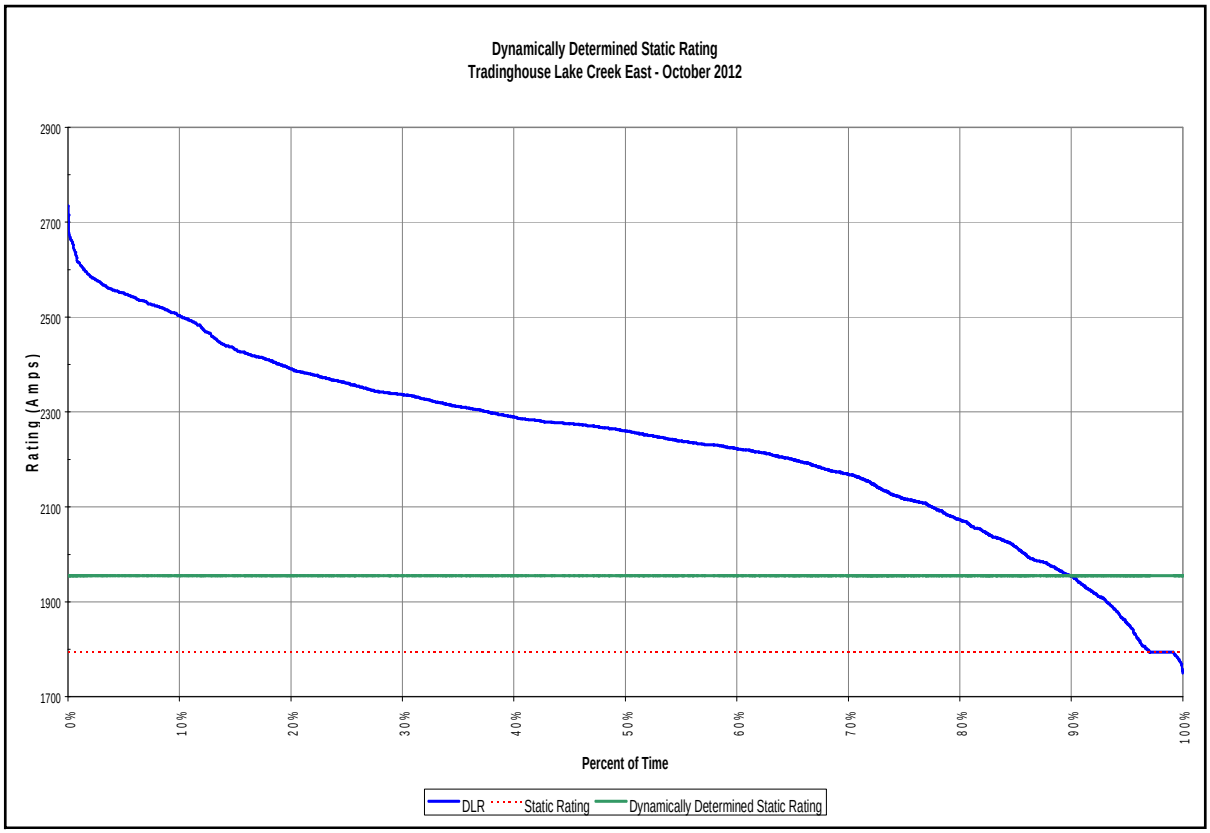


Figure 55 - Available Capacity - October 2012

room with which to ensure system reliability. Operating practices would remain unchanged since they would still be based on a fixed static rating. It would be business as usual with less congestion and more reliability.

But what would be the impact of the added risk? Most transmission lines are operated to survive a first-contingency event. The risk of a first-contingency event occurring is 0.001 to 0.005%. The risk that the 1955 amp rating will not be available is 0.10%. The combined risk of both events occurring at the same time is 0.005 x 0.10 = 0.0005%. 99.95% of the time the system operates (including first-contingency events) without operator intervention. What about the other 0.05% of the time? If a conventional DLR System is in place, the operator will receive an advance warning when the projected post-contingency load is approaching the Dynamic Line Rating. If the SGDP-demonstrated DLR technology is applied, the

system will adjust in real time as it maintains economic dispatch and reliability through the State Estimator/load dispatch operations.

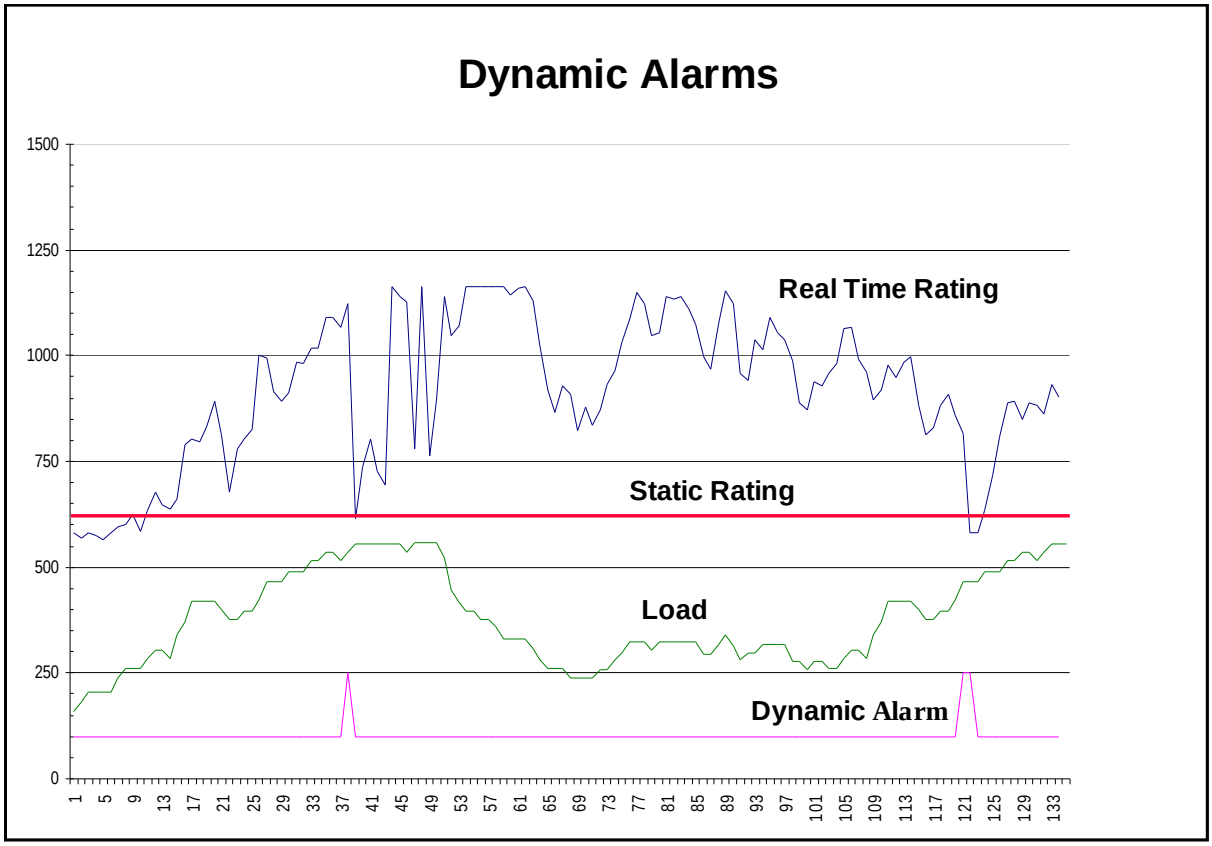


Figure 56 - Dynamic Alarms

Figure 56graphically portrays a DLR system function known as a dynamic alarm. The static rating has been increased to a higher level as described above. The load can be actual load or, more typically, the projected post-contingency load output by the EMS's security analysis. The DLR system will trend both the load and the Dynamic Line Rating. When the two trends are projected to converge in 15 minutes, an alarm is triggered. The operator may then respond as he deems appropriate. Responses might include:

- Redispatching the system to accommodate any possible contingency event.
- Taking no action but having a plan should a contingency event actually occur. Dynamic Line Ratings coupled with dynamic alarms make it possible to garner all the economic and operational benefits of a higher and more realistic static rating with complete safety.

3.11.5 Conclusion

The SGDP Project results and the methodology developed and applied to present the results are practical and effective initial steps in developing forecast criteria and methodology.

Data shows that DLR varies in both time and space along a transmission line; it also varies between lines even if the lines are in close proximity. A common denominator could not be identified that would establish a single predictor of capacity across an entire geographical region, voltage class or other criteria. The conclusion is consistent with expectations given the spatial and temporal nature of weather coupled with the differing topologies of each transmission line.

However, the data did lend itself to development of a practical methodology that provides both planning and operations functions with a usable prediction of capacity for each individual transmission line. That methodology results in the ability to safely raise the static rating limits on a transmission line while ensuring that the conductor always remains within its specified maximum operating temperature and thus its sag limits.

The developed methodology permits grid operators in the control room to comfortably, even transparently, utilize a new higher static rating with no or very minimal change to day-of and day-ahead practices.

Since the higher ratings can readily be accommodated in the control room with the developed methodology, planning functions can also safely utilize the higher static ratings in assessments for grid capacity upgrades.

Most load growth is gradual and can be foreseen a year or more in advance. Those are ideal conditions under which to capitalize on rapid (90-day) DLR deployment and extremely low capital utilization. As the need for additional capacity becomes visible on the horizon, DLR systems can be deployed on the target lines (usually 9-12 months in advance). That provides sufficient time to gain a clear picture of exactly where the new higher static rating should be set. Plans for physical upgrades to the lines can then be scheduled in keeping with the company's least regrets capital strategy.

The methodology developed by this project can be immediately utilized by both System Operations and System Planning on individual transmission lines. In order to develop a capacity forecasting tool on which multiple line behavior can be patterned and decisions made based on wide geographical areas, voltage classes or other global criteria, a greater length of time and cross-section of lines is required to formulate a statistical model of the data for capacity forecasting. In particular, a statistical database needs to be developed to capture and classify seasonal and local variations in ratings, which are influenced by the local geography, line attributes and mesoscale and microscale meteorological conditions.

The success of this project in the development of a capacity forecasting method for individual lines suggests that pursuing a forecasting method for multiple lines at once may be warranted.

3.12 Congestion Mitigation

As noted, the lines selected for monitoring and applying DLR (Figure 10) are seldom loaded above 25% of their capacity. The data shows they are seldom a constrained path even considering the N-1

contingency scenarios. It's important to note that the lines evaluated were connected to two generating facilities that have been mothballed since project inception.

Another change in grid operations was the conversion of the ERCOT system from a zonal management overview to a nodal system effective December 1, 2010. In the Zonal Market, the system was divided into four zones and congestion was managed on a zone-to-zone basis and generation dispatch was managed in a global sense within each zone. Effective with the nodal transition, the ERCOT system was defined as a grid system with more than 3,000 nodes representing generation nodes, transmission and delivery buses. Management of the nodal grids was managed unit-by-unit, node-to-node transmission element.

ERCOT runs a State Estimator program at five-minute intervals in real time to optimize the economic dispatch of generation and maintain reliable operation. The SCED system identifies transmission elements (zonal paths, transmission lines and transformers) that are constrained in the N-1 contingency security analysis. Shadow prices for each node are calculated based on source of energy and transmission congestion. The nodal prices reflect the cost of energy delivered at that node. With each SCED run the congested elements are posted with their associated shadow price. If System Operations intervention is required to resolve a congestion constraint, a cap price is assigned for the shadow price dependent on line voltage. The cap price is designed to both cap the potential proliferation of the cost due to congestion and to help identify constraints that are significant to the grid and may require capital investment in the form of additional transmission capacity or additional strategically located generation.

In order to investigate the impact of DLR on congestion mitigation, the Project assessed the amount of transmission line congestion and the potential impact DLR has to mitigate the congestion. This assessment was first made on the Oncor transmission lines. In order to accomplish this, the results of the SCED runs were filtered to list the transmission lines on the Oncor system from the entire ERCOT grid.

Congestion costs have two distinct tiers of impact. Some of the costs are associated with the settlement LMP cost between the two nodes of the source of energy and the load sink delivery point. These costs may range from the nominal $30 to $45/MWh LMP to very high LMPs over $2,000/MWH. The second impact tier is active if a specific line actually requires relief via the operator sending dispatch signals to a generation resource. In these cases, ERCOT has a penalty rate established based on voltage level such that the MWh rate applied is increased to $2,800, $3,500, $4,500 or $5,000. When these pricing structures are in play, the congestion impact escalates quickly.

The congestion rent for each event was calculated by

$$Congestion\ Rent\ =\ \ Shadow\ Price\ \times Line\ Limit\ Capacity$$

Where:

Congestion Rent	cost of congestion across this element for the reported five-minute period
Shadow Price	congestion cost for the next MWh of energy delivered to a node on the transmission system
Line Limit Capacity	posted capacity limit in MW for the transmission element, i.e., the current element rating

Figure 57 shows the posted Oncor congestion rent for 2011 and 2012. The graph depicts the large volatility in congestion experienced across the two-year period. Note that the patterns are different between 20011 and 2012. Individual days range from no congestion rent to over $11,000,000.

When the data is accumulated for each year, the cumulative numbers in Table 20 represent the magnitude of the congestion impact. Note the degree of volatility; 2012 is almost 33% greater than 2011.

Congestion can also be viewed from the perspective of minutes of congestion as illustrated in Table 21. Note that the number of minutes between the two years of data is not significantly different as compared to the dollar impacts shown in Table 20. Considering these two tables, it would appear that the 2012 events required considerably more intervention by operators to resolve constraint issues and that the Maximum Shadow Price caps were applied more frequently.

Table 20 also shows the breakdown of the congestion impact by whether the congestion is associated with an outage or is market driven. It was interesting to note that outage-driven congestion was in a range of 17 to 28% of the overall congestion cost. The outage versus market-driven ratio was not what was expected, as we anticipated that outages would be a more significant driver of the congestion impact. The comparison does show the importance of mitigating congestion from the market-driven standpoint.

Table 20 - Annual Oncor Transmission Congestion Rent

Congestion Rent	2011	2012
Outage Driven	**$ 25,839,214**	**$ 55,693,594**
69	$ 9,979,518	$ 3,221,552
138	$ 4,250,412	$ 52,472,042
345	$ 11,609,284	
Market	**$ 122,415,065**	**$ 141,161,541**
69	$ 29,772,770	$ 12,198,216
138	$ 78,768,085	$ 121,438,822
345	$ 13,874,210	$ 7,524,503
Grand Total	**$ 148,254,279**	**$ 196,855,135**

Table 21 - Annual Oncor Congestion Minutes

Congestion Minutes	2011	2012
Outage Driven	**35,170**	**33,365**
69	22,125	6,545
138	4,665	26,820
345	8,380	-
Market	**160,005**	**171,550**
69	78,940	17,790
138	65,025	144,780
345	16,040	8,980
Grand Total	**195,175**	**204,915**

The numbers indicate a heavier share of congestion being realized at the lower voltages than the 345 kV backbone transmission lines. The impact of N-1 contingency scenarios on the operating protocols drives this pattern. When contingency scenarios are run for the loss of a 345 kV line, the power must be transferred on lower-voltage lines that serve the same parallel path between generation source and load sink. If the 138 and 69 kV systems are not robust enough to carry the load, then congestion occurs and generation must be redispatched to serve the load over a different path. Granted, in some cases parallel 345 kV lines may serve this function, but the tendency is for the load to be carried by the closest transmission elements and they are typically lower-voltage lines.

Another factor that may be overlooked when considering congestion is that many of the lines that are characterized as congested by SCED may be carrying less than 40% of their capacity in real-time operation. However, depending on grid topology and operation parameters, one or more of the N-1 contingencies that must be resolved in each SCED run would result in an overload of the line if the contingency occurs. If SCED cannot automatically adjust the system performance dispatches to keep all elements out of overload, a constraint is incurred and the congestion costs are accumulated and paid for by the impacted market participants. The overload may only be a few percent, but the constraint and its penalties are incurred.

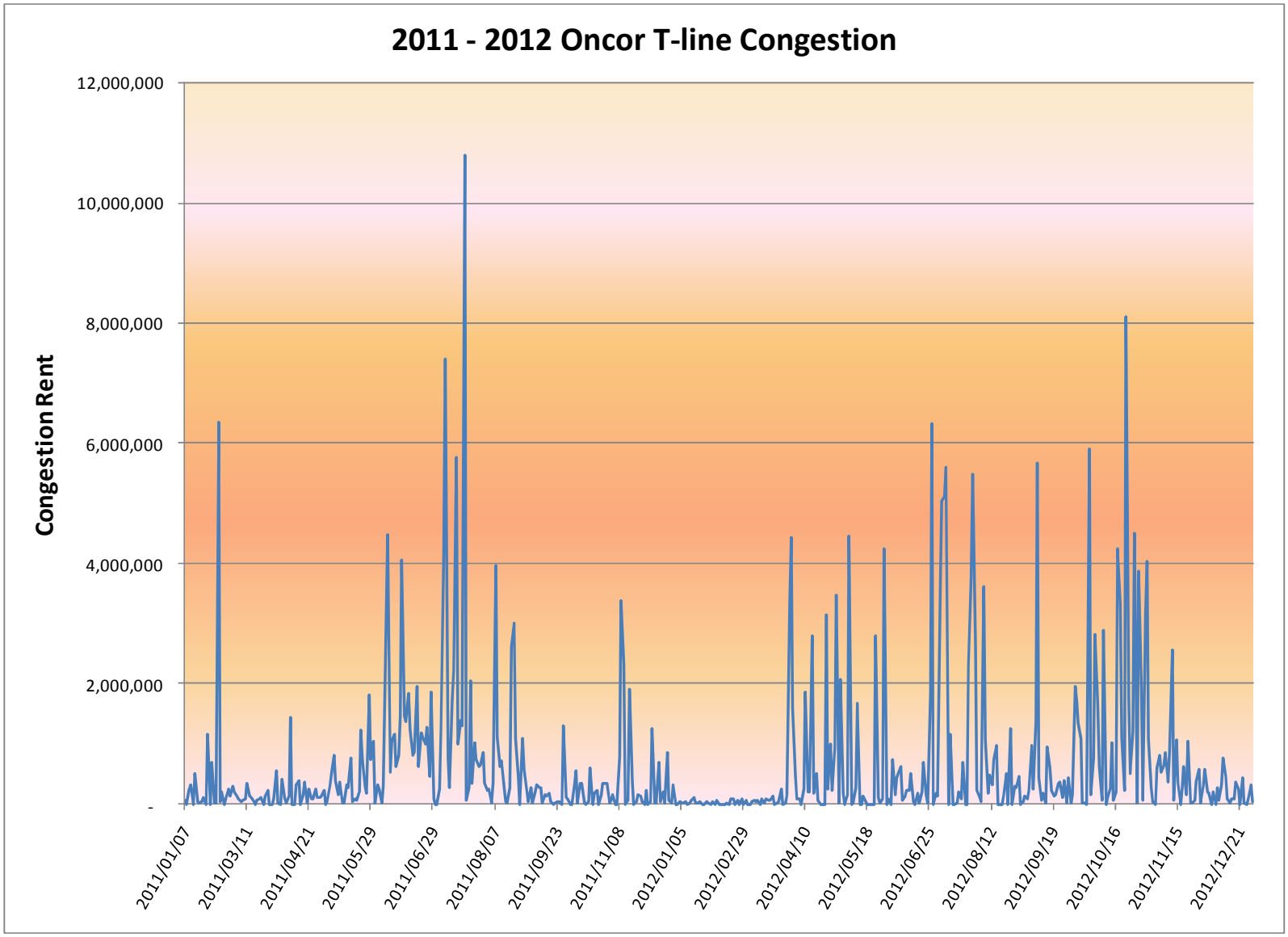


Figure 57 - Oncor Transmission Line Congestion Rent - 2011-2012

Finally, we can look at the congestion as a rent-dollars impact per minute normalization as shown in Table 22. This view illustrates that the impact of outages is more significant considering the impact per minute rate. The congestion impact from outages, originally perceived to be higher than market driven, holds true on the basis of per-minute impact. Outage-driven dollars are less than market-driven dollars, but their associated minutes of impact are less frequent than market driven.

Table 22 - Congestion Rent / Minutes of Congestion

Congestion/Minute		
Outage Driven	**735**	**1,669**
69	451	492
138	911	1,956
345	1,385	
Market	**765**	**823**
69	377	686
138	1,211	839
345	865	838
Grand Total	**760**	**961**

The number of hours of congestion and economic impact of the congestion varies widely with each operating day. This is illustrated in the following two graphs that show the DAM congestion and SCED congestion for the same summer period sorted by date and voltage. In Figure 58 the variability is displayed by the number and size of the congestion costs distributed across the daily screen. The graph shows a higher concentration of congestion events early in the period, followed by a span of sporadic events of varying frequency and financial impact. Note that the 345 kV impacts are fewer and less significant than the 69 kV and 138 kV congestion.

The previous tables indicate significant financial impacts attributed to congestion. However, that congestion is associated with a very limited portion of the operating exposure of the Oncor system. For example:

- The number of lines experiencing congestion in the last two years, 179, is 23% of Oncor's circuits.
- The minutes of impact represent 5/1,000^{ths} of a percent of the operating time of the 762 circuits per year.

These two factors indicate the scarcity of congestion events relative to the overall Oncor operation. In order to identify which lines to put the DLR on, we need to identify which lines have consistent chronic congestion. Figure 58 is a plot of the congestion rent in dollars (bar length) by line by day of record for 2011 and 2012. The daily variability in congestion by line is evident in the wide range of bar lengths representing the dollar impact

To select lines for DLR, lines with chronic behavior would be a key factor. Figure 59 is a 2D projection of the previous sparsity graph showing the lines impact by day. Chronic lines that always have congestion would appear as horizontal bands on the plot. The plot shows that only a few lines have chronic

behavior over the two-year period. Some lines have an apparent chronic behavior for three to four months and then are not active. Lines that were chronic early in the project (bottom left corner) and then disappear were lines that were upgraded in 2011 prior to the summer season. The upgrade eliminated congestion on those lines.

The emphasis of these two graphs is that congestion has not shown to be a chronic problem on specific lines. At most utilities, planning for load growth and future generation needs is performed by running multiple N-1 contingency scenarios. As lines become more heavily loaded they become highlighted in this process and move up the queue for study and upgrade potential. In essence, the line issues become chronic and support the funding criteria for actual resolution. Examples are the more chronic lines in the bottom left of the plot.

Using the congestion data accumulated from the ERCOT SCED reports and ranking the various lines by congestion rent dollars, minutes of congestion and additional considerations, it is possible to screen the lines and identify some candidates for future dynamic rating. Such a process was used to identify a set of lines for further economic impact studies.

Six lines were selected based on the congestion behavior in 2011. Four of the lines were located within a 30-mile radius in an active, growing area of the Oncor system. The other two lines were selected so that an assessment of DLR benefits to 345 kV lines on the system could be reviewed. ERCOT's assistance was sought to investigate what impact a DLR rating could have had on the congestion incurred by the lines. ERCOT was asked to support the analysis by rerunning the original analyses of the system using proposed alternative DLR ratings. ERCOT's system does not allow for rerunning a specific SCED analysis as the real-time data is not retained, only results. ERCOT was able, however, to rerun specific DAM analyses.

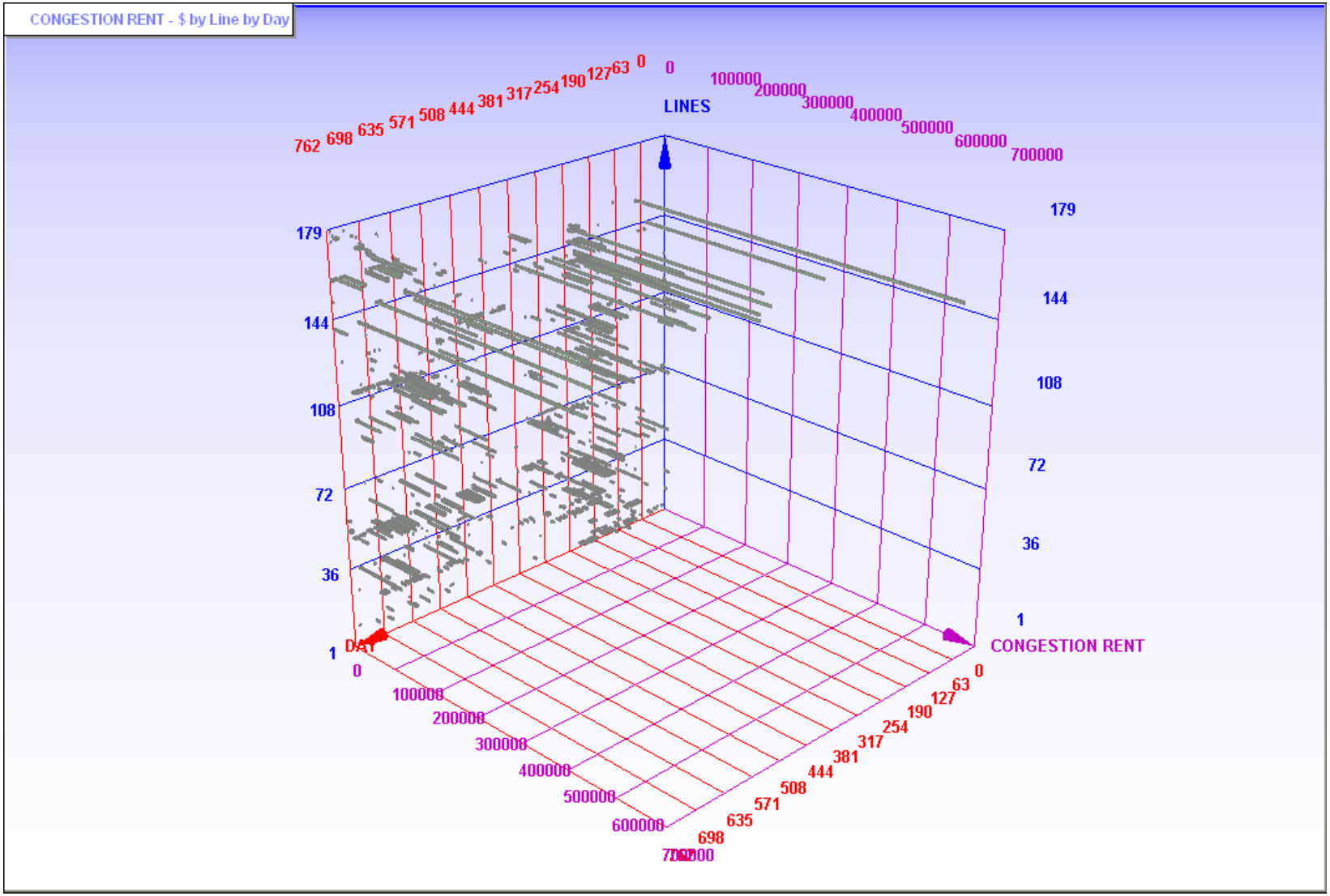


Figure 58 - Congestion Sparsity Graph

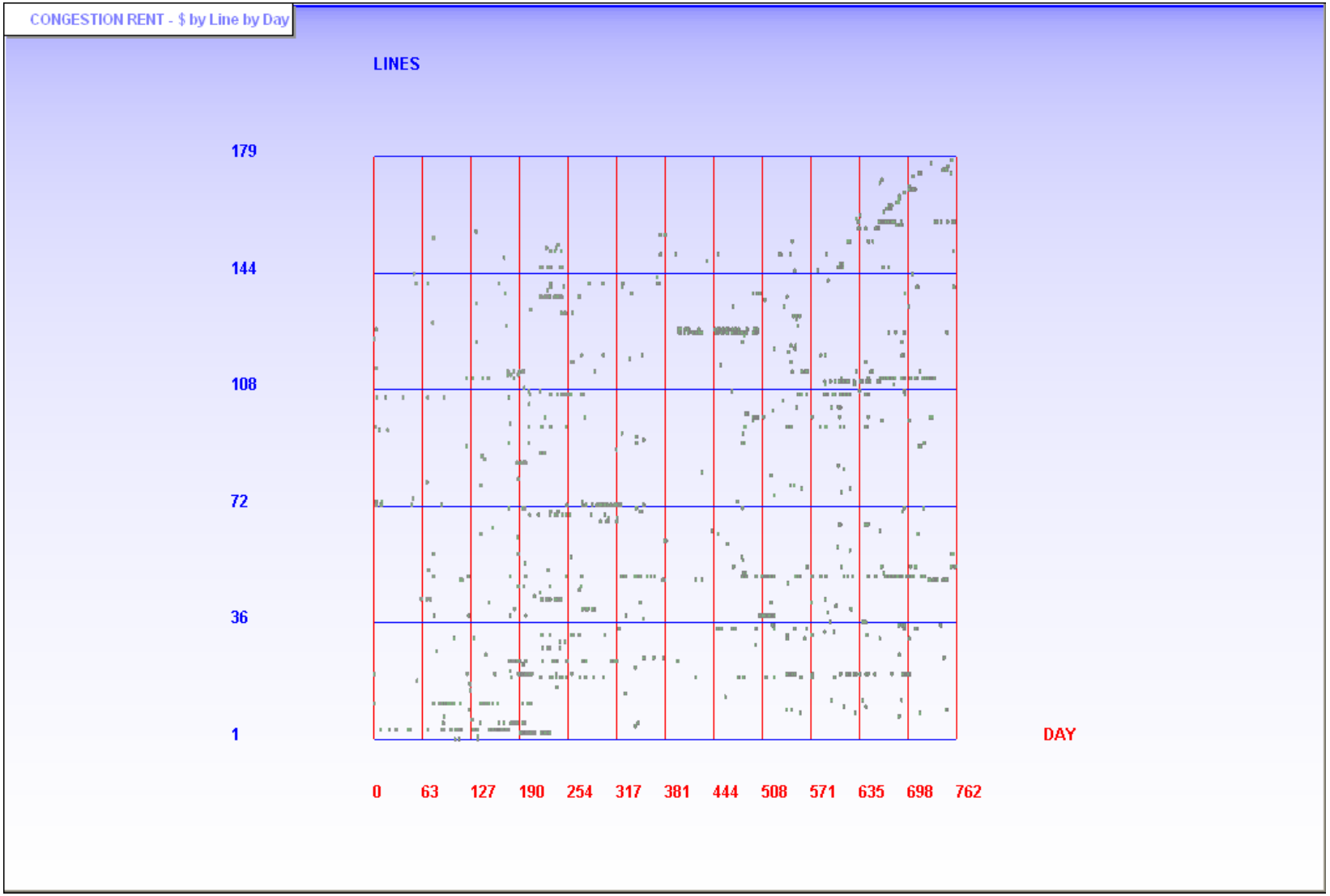


Figure 59 - Congestion Sparsity by Line by Day

As a trial run, a specific day in 2011 where congestion was identified on the six target lines was selected for the economic analysis. For each of the six target lines, the ratings used were adjusted by negative 10%, positive 5%, positive 10% and positive 25% for each hour in the DAM. Results showed that the congestion levels for the target lines increased when the ratings were reduced and improved in general for the positive rating runs. It was found that the congestion on the target lines that had been present in the base case was almost entirely eliminated with the positive 10% rating adjustment. This effort was extremely time-consuming for the ERCOT team, so a plan was devised to get a representative sample of data for a full year.

The first Tuesday of each month was selected for analysis. In addition, the peak congestion day for the target lines was selected for analysis. This sample case would provide a basis to establish the envelope of potential mitigation from a non-congested day to the worst day.

For each target line and the respective days, the target lines' ratings were increased a positive 5% and positive 10% hour by hour and the DAM analysis was rerun. The congestion identified in the DAM report was compared to the original run and the estimated DLR benefits were calculated.

The results from the DAM Congestion Mitigation Study are found in Table 23. The results for the single peak day analysis and the cumulative results for the 12 days selected from the year (one day per month) are shown separately. Data is provided for the target lines, i.e., the "direct" results, and for the lines that emanate from either substation at the end of the target lines, i.e., the "peripheral" impact.

We imagine that some additional capacity on a target line can reduce the congestion on that line, but there may be a "ripple" effect on adjacent transmission assets due to the incremental capacity increase from DLR on the target line. The effect may be positive, i.e., an additional reduction in congestion on adjacent lines, or the impact may be negative, for example, the congestion is just moved to the next restricting element. In reviewing the DAM analysis we did not see a negative impact on the target (direct) lines or the immediately adjacent peripheral lines. Additionally, there was no identifiable adjacent ripple impact from the 5% and 10% adjustments.

On a peak day, the congestion can be significantly mitigated with 5 to 10% increase in capacity through DLR. Table 23 indicates that a potential reduction of 68 to 78% is possible on the direct target lines where DLR is installed. Adjacent lines can also be mitigated if they have congestion ranging from 54% to fully-mitigated.

3.12.1 Conclusions – Congestion Mitigation

Based on the annual assessment where 12 random days were analyzed, the direct mitigation can range from 60% to 100% with a modest DLR increase in capacity, and peripheral impact could reach the mid-50% level.

Based on the DAM analysis for congestion mitigation and the results of the capacity gained studies, we can see that a 5 to 10% capacity increase has a high probability and that effective mitigation can be in the range of 60% to 100%. There are two indicators of where to locate the DLR equipment as discussed

earlier in the project – where congestion tracking showed congestion to be, even though the congestion history may be very sparse and unpredictable, and how many lines to install DLR on.

The project has not performed a statistical impact study of whether installing more and more DLR equipment could eventually impact system-wide performance. In discussion with System Planning and ERCOT personnel, we know that the increase in capacity from DLR and capital investments in the transmission grid make the system more flexible and capable of being more efficient and lower in congestion. There may be a point, however, where incremental increases raise the system performance to a new threshold where additional incremental capacity improvements through DLR may not contribute to additional congestion relief.

Table 23 - Congestion Mitigation Projections Based on DAM Analysis

Congestion Mitigation Projections		
Peak Day	**Direct**	**Peripheral**
Control	-	-
Plus 05%	68%	54%
Plus 10%	78%	100%
Annual	**Direct**	**Peripheral**
Control	-	-
Plus 05%	60%	56%
Plus 10%	100%	58%

Since most transmission grids have limited capability to manage the flow of the electricity down specific paths, the system finds its optimum operating performance. The grid operations through manual or automatic systems like SCED are actually responsive to that performance more than managerial. In each SCED cycle, the system parameters received through telemetry tell the State Estimator what the current operating schema is. SCED then adjusts the system to maintain it as reliable and optimally priced as possible. Adding capacity incrementally through DLR allows the system to adapt to the new optimum performance. These adjustments if more global in nature, i.e., trying to resolve all congestion with DLR, may just shift the congestion to different paths with successful mitigation under certain operating situations and potentially less successful mitigation at other times.

Project results show significant success in congestion mitigation, and we project a very successful mitigation on a broader basis with additional DLR installations.

3.13 Planning and Operations Application of DLR

Planning and Operations must maintain system reliability for a wide range of issues that change every day based on ambient weather conditions, load demand and market participant economic decisions. The environment that most transmission grid operators find in today's industry is far different from the vertically integrated days when utilities managed generation, delivery and sales. Today the transmission

provider is responsible only for building, operating and maintaining its delivery system so that there is reliability and capacity available to meet clients' demands.

Dynamic Line Ratings, during the project, consistently released additional grid capacity compared to Ambient-Adjusted Ratings. While quarterly results varied, the average increased capacity delivered by DLR over AAR was 6 to 14% for 345 kV and 8 to 12% for 138 kV transmission lines. The availability of that added capacity ranged from 83.5% of the time under all operating conditions to 90.5% of the time when outages and other events were excluded from the data.

In comparison, a new transmission line or reconductoring the line is generally directed toward a 100% gain in capacity. That gain comes at a significant cost and with a very long lead time. The next section will detail the cost comparisons of various major capital investment solutions compared to solutions using DLR. The cumulative probability curves in Figure 33 and Figure 34 illustrate that DLR can provide large amounts of increased capacity; however, it's not at a 100% probability, as with a new line.

Planning departments maintain a queue of projects that become defined as load growth studies and reliability studies identify specific areas and transmission lines that require reinforcement. The majority of these lines enter the queue at a low level of overload or requirement for capacity increase. When congestion constraints are included in the project definition process, the number of lines multiplies where a moderate line capacity increase is required. The increases in capacity identified in this project through DLR meet these requirements.

Each year as the budget cycle is reviewed for each project in the queue and for new projects being identified, any topology changes, actual loading history and projected load growth are incorporated into the system model and future line loadings are projected. Budget estimates for each project are updated. The new system requirements provide a prioritized list of projects that are then measured against the anticipated budget available for construction. The queue is managed from highest priority down, depending on funding available.

DLR can provide a mechanism to address many projects that do not make the funding cut yet are deemed necessary to maintain reliability, meet load growth or mitigate congestion. Most capital investment solutions for small incremental capacity increases fail the cost-to-benefit rationale. DLR is a way to extend the available funding to a broader number of projects by applying more efficient investment of the funding budget. A secondary benefit of the DLR solution is that in future years as the grid topology changes, some of these projects in the queue never mature to where the capacity requirements change the solution to a larger capital investment. In some cases, the capacity increase even decreases as topology provides different line loading patterns. In either case, DLR can be a tool to defer projects and their capital investment.

From an operations standpoint, added capacity in any form provides a more flexible and robust system to meet the transient situations that evolve across the grid. Added capacity makes maintenance and outage management more efficient and reliable. Small amounts of capacity can provide the flexibility to ride through transients that might have caused an issue in the past.

3.13.1 Conclusion – DLR as a Planning Tool

DLR can enable transmission planners to mitigate congestion, increase system reliability and redeploy capital to its most efficient uses through a least regrets strategy. We see five potential applications for DLR as a planning tool.

a) Use of DLR to prepare a more cost efficient least regrets capital transmission investment strategy
b) Use of DLR to characterize the dynamic thermal capacity of a line corridor and develop a data base for higher, yet reliable line ratings guidelines, enhancing earned ROE
c) Use of DLR to enhance operations planning
d) DLR as a bridge to accelerate and facilitate transmission build
e) Addressing the next limiting element

a) **Least regrets capital strategy**: DLR can be utilized in the planning process to enable a least regrets capital strategy, which minimizes any potential stranded investment.[10] [11] The SGDP Project demonstrated that DLR is a valuable tool to be applied during project identification and solution development. DLR can be an effective screening tool that can be used in identifying and analyzing the value of proposed transmission investments and help avoid potential capital-intensive stranded assets. DLR can be a filtering gate allowing utilities to redirect scarce capital to higher-value projects for the long term. DLR as a screening tool can enable planners to choose the highest-value project first, enabling them to better deal with the demands FERC policies place on planners.

   Specifically, DLR offers very competitive solutions for projects in the planning queue that require a few percent up to 10 to 15% or higher increased capacity. The actual released capacity depends on the topology of each transmission corridor. Typically, there are many projects of this type in the queue every year. Since all lines must be able to support one to multiple N-1 contingency events, there are frequently cases where the base loading of a line plus the N-1 contingency load exceed the line rating capacity by a few percent. These cases may stay at this level for several years during the long-term planning process, or loading may grow enough to necessitate a well-justified extensive capital expenditure. Generally these lines do not make the need/cost/benefit test to become funded during the short-term budget cycle. Projects that do have load growth in the area may ultimately clear the threshold and become funded. Other projects may drop off the queue when some other grid topology changes and the loading issue is addressed by some other solution or system change. When projects do not clear the funding threshold, the marginal overloads are dealt with in real time by System Operations, which manages the system to maintain no violations for N-1 contingencies. This leads to non-economic dispatch and line congestion costs. Instead, DLR maintains economic

[10] Duke University, "Calculating Regret Scores," presented to SEARUC, June 9, 2013.

[11] The Brattle Group, "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," July 2013

dispatch and can act as a gate in the 0% to 15% capacity need range, enabling more cost-effective long-term planning of transmission assets.

b) **More realistic and reliable transmission corridor rating**: Each transmission corridor is subject to different weather parameters, especially wind direction and speed. These parameters determine transmission capacity for a given wire size. Typically, the topology of the transmission corridor remains the same over an extended period. DLR can be used to collect historical and statistically significant data to characterize the meteorological patterns within each corridor. Analytics can then be applied that will help create a "ratings signature" for each monitored corridor, rather than using static ratings that are based on assumed weather conditions. This ratings signature can then be used for more representative ratings for all monitored transmission corridors. This will boost asset utilization and reliability.

c) **DLR for Operations Planning**: As transmission owners come under increased regulatory pressure on allowed ROE and face daily challenges to realize that allowed ROE, DLR can be used as a financial mitigation tool. Specifically, DLR enables the transmission owner to realize additional revenue, which is available with DLR-wide deployment. This is accomplished because DLR allows the transmission owner to take full advantage of the actual transmission capacity in real time, which is more than the static capacity used to plan for operations without the use of DLR. Further, DLR protects the transmission asset from overheating and ensures that transmission operations always comply with NERC and NEC phase-to-ground clearance requirements.

The SGDP Project demonstrated that the actual transfer capacity of the grid is more than the currently used capacity based on static assumptions or based on AAR for the vast majority of the time. The project also demonstrated the value of DLR as a clearance reliability tool.

d) **DLR as a Bridge to Planned Transmission Build-up**: The demand for capacity often presents itself faster than time and capital can address it. DLR can provide a bridge that immediately addresses the need while keeping system reliability intact. Planning and construction can proceed at a pace that precludes cost overruns. Capital can be scheduled to take advantage of lower costs in the marketplace, especially if the demand for capacity is steadily ramping up. Capital can also be redirected to more urgent or desirable projects. And, of course, DLR provides the least regrets option when the supposed demand fails to materialize.

e) **Addressing the next limiting element**: When DLR is deployed on a line, the true capacity of the line becomes known. The monetary value of each added unit of capacity is also then known. If that true capacity is capped by the next limiting element, it becomes a simple matter to calculate the economic benefit of upgrading the next limiting element.

3.14 Alternative Solution Comparisons

DLR can serve as a solution for several transmission system requirements, as reported in the previous sections, to increase capacity for planning applications and operations flexibility, and as a tool to mitigate congestion. The deployment of DLR on a line or several lines in an area can offer a solution that defers major capital investments for one to several years and possibly altogether as other projects change grid topology in future budget cycles. There are alternative solutions that compete with DLR for selection. The following discussion reviews several examples of how DLR can be applied and compares costs and benefits.

Most of the examples are for 138 kV lines, which are often the supporting infrastructure for larger-backbone higher-voltage lines on a transmission system. From a congestion management and contingency standpoint, these lines must be capable of serving their base requirement and a share of the contingency loads that would develop if another transmission element goes out of service. The majority of the time, this constraint is what developed the “need” for increased capacity on a line.

In these cases, the additional load requirement is in a range of a few to 10%, maybe 15% additional capacity. The project has demonstrated that additional capacity is available for contingency management and for energy markets that clear on a 15-minute basis at least 10% above the Ambient-Adjusted Rating 93% of the time under all load conditions and 98% of the time under moderate load conditions (load greater than 20% of the Static Line Rating). In many cases these constraints due to contingency modeling create congestion that has substantial financial impact. These two areas are the primary target for DLR applications. If the demand for capacity is above this range on a continuous basis, DLR is not a typical solution.

The different project scenarios include different solutions:

- iDLR – applying DLR with real-time application of monitoring the conductor state on the transmission line and feeding the dynamic rating to the ISO State Estimator and economic dispatch criteria.
- Rerating the line to a higher maximum operating temperature, requiring some structure modifications or replacements for obtaining additional clearances where needed.
- Reconductoring the line, assuming it has sufficient structural capacity and height to support a new conductor that has the required capacity and maintains minimum ground clearances.
- Rebuilding the line by replacing it with structures that provide required clearances for a larger-capacity conductor.

The examples are described in Table 24. A description of the line type of construction, voltage level and structure framing is noted. The alternative solution descriptions per the list above are noted for each alternative with information on what the new line rating would be compared to the original static rating, what work is required to achieve the solution and the estimated cost per mile for that alternative.

Table 24 - Alternative Solution Comparisons to Dynamic Line Rating – Project Descriptions

Line Type	Alternative Description	New Rating (% of Static)	Work Required	Cost Per Mile
138 kV Lattice & Wood H-frame	Reconductor ACCC	193%	Reconductor	$ 321,851
	DLR	110%	DLR	$ 56,200
138 kV Wood H-frame	Rerate 125 °C Modify Strs	130%	Modify 6 H-frames	$ 10,561
	Rerate 125 °C Replace Strs	130%	Replace 6 H-frames	$ 6,919
	Rebuild	209%	Rebuild Line	$ 750,000
	DLR	110%	DLR	$ 29,471
138 kV Wood H-frame	Rebuild	140%	Rebuild Line	$ 237,871
	DLR	110%	DLR	$ 16,767
138 kV Wood H-frame	Reconductor	212%	Reconductor	$ 750,000
	DLR	110%	DLR	$ 28,323
345 kV Lattice Tower	Raise structure heights	120%	Raise Str Heights	$ 73,600
	DLR	110%	DLR	$ 26,626

Because many utilities evaluate the financial comparison of solutions differently, the following examples are evaluated via several metrics. The comparisons are not all-inclusive. Any given utility may have a preferred economic evaluation. The comparisons do, however, show how different approaches provide different results and appreciation for a solution comparison.

Table 25 and Table 26 show the comparative costs when evaluated on different criteria as discussed below. Each column is a different evaluation. Table 25 provides the comparison of solutions in cost, while Table 26 normalizes the costs against the DLR estimate as the base. Thus you can see which solutions cost more than DLR on a percent over/under basis.

Table 25 - Alternative Solution Comparisons to Dynamic Line Rating – Solution Costs/Mile

Line Type	Alternative Description	$/% Rating Increase	$/% Rating	%DLR
138 kV Lattice & Wood H-frame	Reconductor ACCC	$ 346,127	$ 166,774	$ 292,592
	DLR	$ 562,000	$ 51,091	$ 51,091
138 kV Wood H-frame	Rerate 125 °C Modify Strs	$ 35,069	$ 8,117	$ 9,601
	Rerate 125 °C Replace Strs	$ 22,976	$ 5,318	$ 6,290
	Rebuild	$ 685,540	$ 358,161	$ 681,818
	DLR	$ 294,712	$ 26,792	$ 26,792
138 kV Wood H-frame	Rebuild	$ 213,235	$ 112,440	$ 216,246
	DLR	$ 167,669	$ 15,243	$ 15,243
138 kV Wood H-frame	Reconductor	$ 1,852,105	$ 533,829	$ 681,818
	DLR	$ 283,230	$ 25,748	$ 25,748
345 kV Lattice Tower	Raise structure heights	$ 68,038	$ 61,340	$ 66,916
	DLR	$ 266,256	$ 24,205	$ 24,205

Note: The DLR increase is capped at 110% of the static rating in these comparisons. The project has shown that higher ratings are possible a good percentage of the time. However, the type of example project we are purporting DLR to be an optimal solution for is the case where a line is marginally overloaded, no more than 10 to 15% additional capacity required. The comparison metrics are described as:

Per-mile Cost per Percent Rating Increase - $/% Rating Increase – This compares each alternative by dividing the cost per mile alternative solution by the percent ratings increase. For example, reconductoring increases the rating to 212% of the original static rating and DLR raises the ratings by 10% to 110%. Since we are comparing the incremental amount of capacity gain for each solution, the rerate options with moderate modifications and replacements favor the non-DLR option. The reconductoring with a High Temperature Conductor example also favors the physical upgrade because so much more capacity is gained over the DLR solution.

Cost Per Percent Rating - $/% Rating – This comparison looks at the cost of the solution divided by the overall line capacity after executing the solution. This solution favors DLR over rebuild but not compared

to solutions where it is possible to raise the rating with a few structure modifications and obtain more clearance to increase the maximum operating temperature of the line.

On-par DLR % Increase - %DLR – This comparison is to evaluate the cost comparison when only the 10% increase attributed to DLR is the basis for consideration. That is to say, this evaluation is only interested in meeting the requirement for 10% more capacity and not the additional capacity of a new conductor or rebuild. In this case, the extra costs are not justified. This is the example where a small incremental capacity increase will meet the planning and operating needs for the short term.

Table 26 - Alternative Solution Comparisons to Dynamic Line Rating

Line Type	Alternative Description	$/% Rating Increase	$/% Rating	$/% DLR Increase
138 kV Lattice & Wood H-frame	Reconductor ACCC	62%	326%	573%
	DLR	100%	100%	100%
138 kV Wood H-frame	Rerate 125 °C Modify Strs	12%	30%	36%
	Rerate 125 °C replace Strs	8%	20%	23%
	Rebuild	233%	1337%	2545%
	DLR	100%	100%	100%
138 kV Wood H-frame	Rebuild	127%	738%	1419%
	DLR	100%	100%	100%
138 kV Wood H-frame	Reconductor	654%	2073%	2648%
	DLR	100%	100%	100%
345 kV Lattice Tower	Raise structure heights	138%	253%	276%
	DLR	100%	100%	100%

Another benefit of applying DLR is that the technology offers great flexibility. As discussed in the Planning Application of DLR aspects of the project, many projects only require an incremental capacity increase, i.e., 5 to 15%, to meet current contingency requirements or to relieve congestion. Then the system topology changes, that need is no longer there, and the original line capacity or a small increment continues to meet load transfer requirements. The DLR technology provides that capacity at a very competitive price with a short lead time and can be removed or relocated with minimal cost. The larger cost of a capital outlay for the rebuild or reconductor solution is mitigated, and the funding is available for some other critical project.

As noted in the Planning discussion above, many projects are identified when their N-1 contingency loading approaches 100% of the line rating. As each budget cycle reviews the project queue, some of

these projects show increased loading until they reach 100% of the rating and start to exceed the rating with N-1 contingency scenario review. Depending on the system topology and load growth in the area, projects may stay at the low percentage overload level for years. DLR can offer a solution that defers the capital investment required for a larger solution, e.g., reconductoring or line rebuild. As Table 26 illustrates, DLR is a very competitive solution to meet the loading requirement.

If load growth continues and a specific project continues to grow with necessity for increased capacity above what DLR can provide, the project can move forward into more traditional capital expenditures. However, in the intervening years DLR may have provided the capacity and reliability required for the grid and successfully deferred the expenditures of more expensive solutions. Another case might be that additional grid topology changes actually eliminate the growing need for the capital investment and that the DLR solution completely fulfilled the project's necessity.

DLR cost solutions provide greater flexibility to meeting more project needs and optimizing the application of annual budgets over a broader spectrum of projects.

3.15 Economic Trade Space Analysis

The effect of DLR means different things to different market entities in the energy sector and has an impact not only on the economics of energy generation and transmission, but on the environmental aspects of said generation, especially as it relates to wind generation in Texas. This study looked at the economics as it is perceived by the different entities in energy generation, transmission and delivery within the market. It also looked at the potential for environmental benefits based on changes to the generation patterns resulting from increased capacity. Finally, the analysis looked at wind generation and how it may be impacted through DLR technology.

3.15.1 Economic Study

The purpose of this study is to determine the economic benefits that may be derived through DLR technology to provide a real-time power flow capability analysis of transmission lines in the areas of installation. To the extent possible, we attempt to extrapolate these results throughout the transmission market and the impact that DLR technology would have on reducing congestion and congestion costs. Our study takes into account multiple perspectives of the energy market: those that place power onto the market, those that pay for consumption of power, and the operator of the energy market (in this study ERCOT is the Independent System Operator, or ISO).

Department of Energy Perspective

DLR technology provides benefits in line with DOE goals to reduce congestion and reduce costs to the ratepayer by increasing throughput of transmission lines and providing greater utilization of the transmission lines' capacity by providing a real-time perspective on actual capacity based on conductor temperature rather than an overly conservative capacity model based on either a quasi-deterministic approach for static ratings or an ambient temperature-adjusted model, taking into account the ambient temperature at the line's location.

Transmission Provider Perspective

From the electric power industry perspective, the benefits of DLR technology are realized through the cost benefits derived through the buying and selling of power in the ISO energy market, the delivery of that power through the wires of the transmission and distribution companies, and ultimately the cost to the ratepayer.

While congestion resides on different elements of the transmission system, i.e., lines and transformers, there is no direct incentive to the transmission provider to reduce congestion costs and, therefore, less of an incentive for DLR application. In the current market design, the delivery of power is not by commodity unit, i.e., MWh delivered per hour on a given asset. Rather, most transmission providers are regulated and receive compensation on an overall capacity basis, as an ability to deliver power reliably. Incrementally changing the hourly delivery through a dynamic rating does not generate increased revenues and a correlated means to calculate a typical return of investment.

Market Operator Perspective

The market operator's perspective revolves primarily on the reliability of the grid, the economic efficiency of the electric grid and the satisfaction of consumer requests for power.

The primary cause of congestion is not in the actual violation of line transmission criteria (N-1 events) but in the potential for violations based on projected line capacity requirements under N-1 contingencies. The economic dispatch of generation and system estimator toolset incorporates a set of scenarios based on the bids and offers on the market to attempt to most economically and reliably meet load requirements, project congestion and relieve that congestion through the market process. For brevity of reference, this toolset is known as SCED (Security-Constrained Economic Dispatch) in the ERCOT system.

The primary benefit of DLR for the market operator is in the resolution of projected congestion in the real-time market through the improved utilization of traditionally underutilized transmission lines due to the conservative line rating models. The more that congestion is resolved in SCED through the effect of real-time DLR data streaming into the SCED system, the less probability or need that congestion will have to be resolved during the operation day through direct operator intervention. This results in fewer hands-on decisions that have to be made by the operations staff, as well as less administrative capability that has to be maintained to manage the congestion cost billing and collection.

The market operator gains additional benefit by having increased system awareness through real-time DLR data on which to base control decisions. While SCED may work with a conservative rating capacity increase, the system operators may be able to see increased capacity based on the real-time system conditions that DLR feeds. Therefore, they may be able to relieve SCED constraints without dispatch instructions, resulting in not only a reduced cost to the market but also reduced risk introduced during "human in the loop" processes where a system operator makes a dispatch change.

Retail Perspective

Ultimately, energy prices are felt by consumers through the price per kWh they pay through their retail provider. Increased congestion requires market participants to increase their costs to consumers in order to maintain profitability. Benefits to the retail provider include:

- Less risk for congestion. By increasing throughput of existing lines, there is less risk for congestion, which is ultimately paid for by the retail provider.
- Lower congestion costs. Reducing congestion provides direct impact to the retail provider by reducing congestion costs.
- Reduced Congestion Revenue Rights (CRR) buying. To hedge against congestion, market participants buy congestion revenue rights, a type of insurance that protects the CRR owner against what can be significant congestion costs. Lessening the need for CRRs reduces the overall operating costs of retail providers and effectively the ratepayer.
- Fewer insolvency risks. Significant congestion costs can place a retail provider in financial trouble during days of significant congestion. Increased purchases of CRRs can reduce that risk but at additional costs to the retail provider and ultimately the end consumer.

DLR technology, by increasing line throughput and utilizing underutilized line capacity, should help reduce congestion costs and thus be directly reflected back to the ratepayer in the form of cheaper energy.

3.15.2 Environmental Study

The scope of this study, combined with the dynamic nature of the energy market, prevents a comprehensive generator-by-generator study of the environmental reductions that may be possible through DLR technology. Our study in this area primarily focuses on the gross emission reductions noticed through the use of DLR to increase capacity of the selected lines.

3.15.3 Wind Energy Integration

The proposed impact to environmental output from electrical generation we have chosen to study is in the area of wind generation. Specifically, we focus on the amount of fossil fuel generation that could be reduced by putting as much wind generation onto the grid as possible. With Texas now the largest wind producer in the nation (with plans to make Texas the largest solar producer as well), it becomes obvious that the more renewable generation is placed onto the grid, the fewer contaminants are placed into the air from energy generation. Congestion at the bottlenecks to transmission of wind energy from West Texas to East Texas prevents wind from entering the grid, resulting in increased use of contaminant-generating electrical generation. DLR technology should provide relief to those congestion bottlenecks, allow more wind-generated energy to enter the grid, and reduce the need for fossil fuel generation.

3.15.4 Shift Factors for Security-Constrained Economic Dispatch

Shift Factors identify generation resources that would have an impact on the congestion if they were ramped up or activated in response to an SCED action and generation resources that were ramped down

or deactivated as a part of that response. ERCOT produces a report that lists these Shift Factors for every N-1 contingency event and line component, which can be correlated to constraint events to identify how generation was moved in response to an SCED action.

To determine potential environmental impacts due to congestion and the alleviation of those impacts through DLR, we analyzed the Shift Factors for the days of study to determine how DLR would have resulted in a change of generation resources from more than one level to a different level of polluting generation values based on dispatched operating signals.

3.15.5 Simulation of Day-Ahead Market with DLR Ratings

It is important to note that DLR, being a real-time telemetry system, is fed into ERCOT's real-time SCED analysis for operations every five minutes. Unfortunately, SCED cannot be rerun to assess whether an alternative rating, e.g., the DLR rating, could have provided a different congestion result. The best alternative was to seek ERCOT's assistance to rerun several DAM results with DLR to see how the economic model would change with different ratings available for operation.

Our approach to producing data for the economic study involved analyzing the impact to the DAM results if DLR were implemented in a section of lines. To this effort, we have been working with ERCOT to produce new DAM results and utilizing the results of the DLR monitoring study to evaluate the impact on congestion if additional line capacity were to be provided within the congested lines.

We analyzed DAM models where the ambient temperature ratings from the original DAM analysis rating were replaced by a percentage factor of either 5% or 10% above the base rating used, which simulates historical DLR capacity increases in the greater than 95th percentile as identified in the DLR monitoring study.

Identification of Days to Rerun

Given the transient nature of congestion within the transmission system, we were unable to identify a statistically significant set of days suitable for rerunning DAM models. Our approach was to select one day per month over the course of the year to have the data provided for study. We selected the first Tuesday of each month, with the exception of July where the 16th showed significant congestion for the study lines. This gave us 12 days of reports over one year to study. In addition, we reran the overall peak congestion day from 2011 to assess the potential "peak" impact.

ERCOT Assistance in DAM Simulations

Our team worked closely with ERCOT in identifying and selecting the new DAM reports to be generated. Several test reports were generated and provided in order to determine the best parameters for running a full-year study.

It should be noted that running the DAM model and producing the report is an intensive operation by ERCOT and we needed to limit the amount of runs that were made. ERCOT provided this data to the

study team and worked with us to ensure the DAM reports were providing the best information related to the economic study.

DAM models were run at three capacity levels: base case, 105% capacity and 110% capacity. This provided the study team with 36 DAM reports on which to conduct analysis.

3.15.6 Justification of Increased Capacity Levels

Our choice in using the 105% and 110% capacity levels for increased line ratings was based on our findings from the DLR monitoring study. This study gathered data from the six actually monitored lines over the period of one year. As shown in Figure 60, DLR resulted in an average of greater than 8% increased capacity for the 138 kV lines in the study. Figure 61 shows an average increase of greater than 5% increased capacity in the 345 kV lines for the study period.

3.15.7 Analysis of DAM Data

Analysis shows that with a conservative projection of 5%, increased capacity from DLR congestion costs can be significantly reduced within the DAM model. The data further shows that a 10% increase in capacity does not readily mean a further reduction in congestion costs.

In our initial congestion relief DAM runs, we extended the increase in capacity to 120% and 125% of the base rating used in the DAM run. When we looked at the results, we found that the 105% and 110% increase practically eliminated all of the direct congestion on a line segment when it had been there in the base case. This is consistent with the overall DAM and SCED operating environment. As each State Estimator analysis is performed, the system tries to balance itself, redispatching incremental generation values to make sure all elements of the grid remain within N-1 contingency compliance. Therefore, congestion events are almost always within several percentage points of resolution capacity. As such, the 5% and 10% increments provided sufficient incremental capacity to reduce congestion.

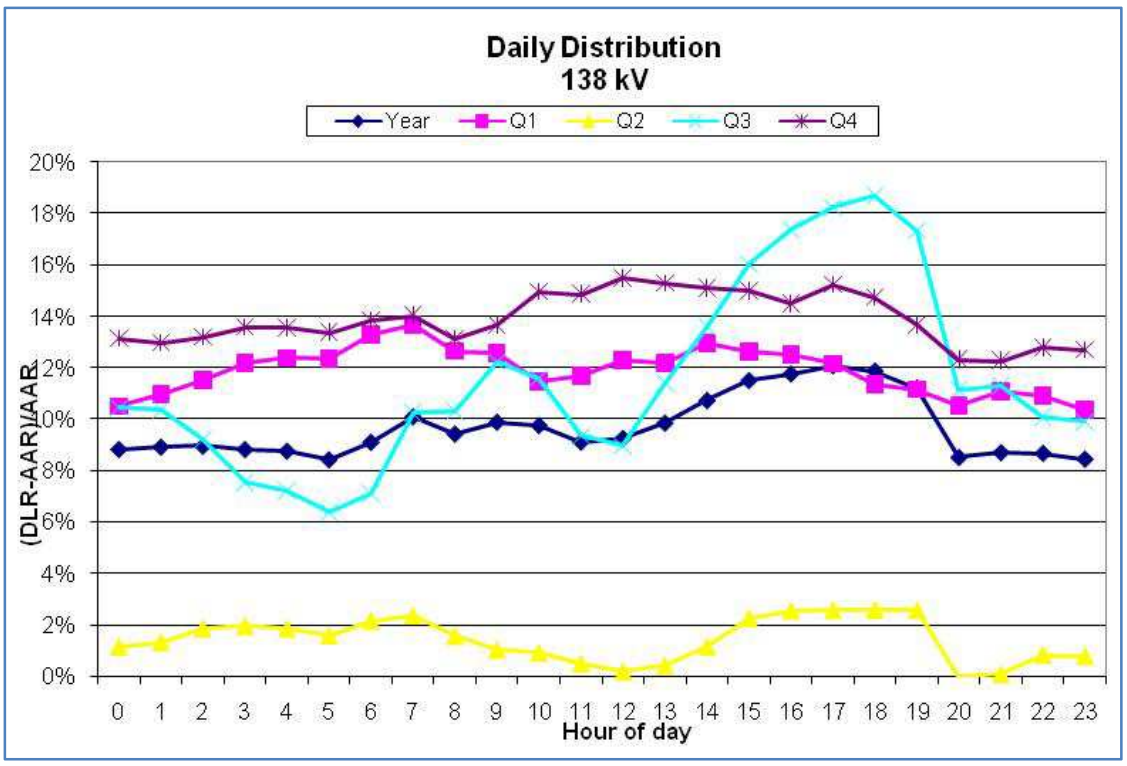


Figure 60 - Yearly Distribution Plot of DLR Increased Capacity 138 kV

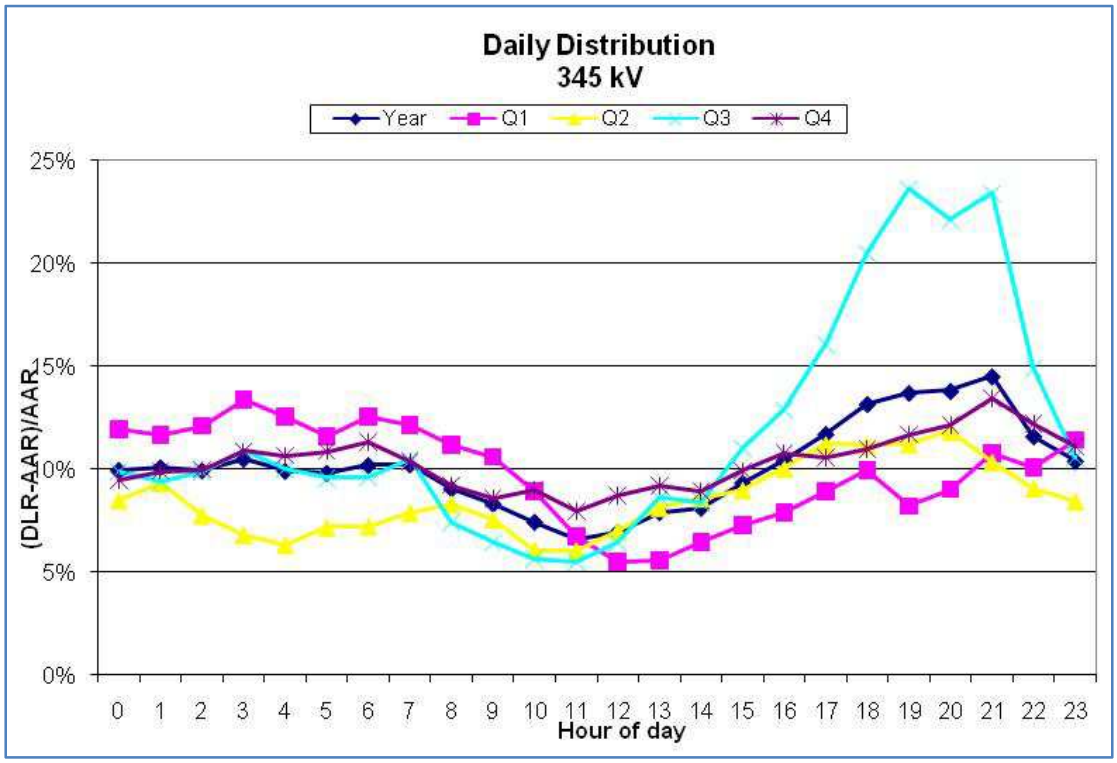


Figure 61 - Yearly Distribution Plot of DLR Increased Capacity 345 kV

Figure 62 shows the average congestion impact across the day, summarized for the study year. In this plot we see that the congestion impact is reduced in a DAM model run with 105% capacity for the six economic study lines. Notice that the 110% capacity model actually results in higher congestion costs than the 105%, although the costs are still significantly less than the base (no DLR) model.

The average savings (represented as a percent savings from the base model) over the year can be seen in **Figure 63** along with the significant increase in congestion cost savings achieved during the most heavily loaded parts of the day.

The monthly congestion impact, as a percentage of congestion savings over the base model, is shown in Figure 64. Note that each month only contains data for one day and so is subject to skewing based on weather or other generation/transmission events. In general, the results show a consistent savings that can be achieved, with a greater impact in the critical high-load summer months.

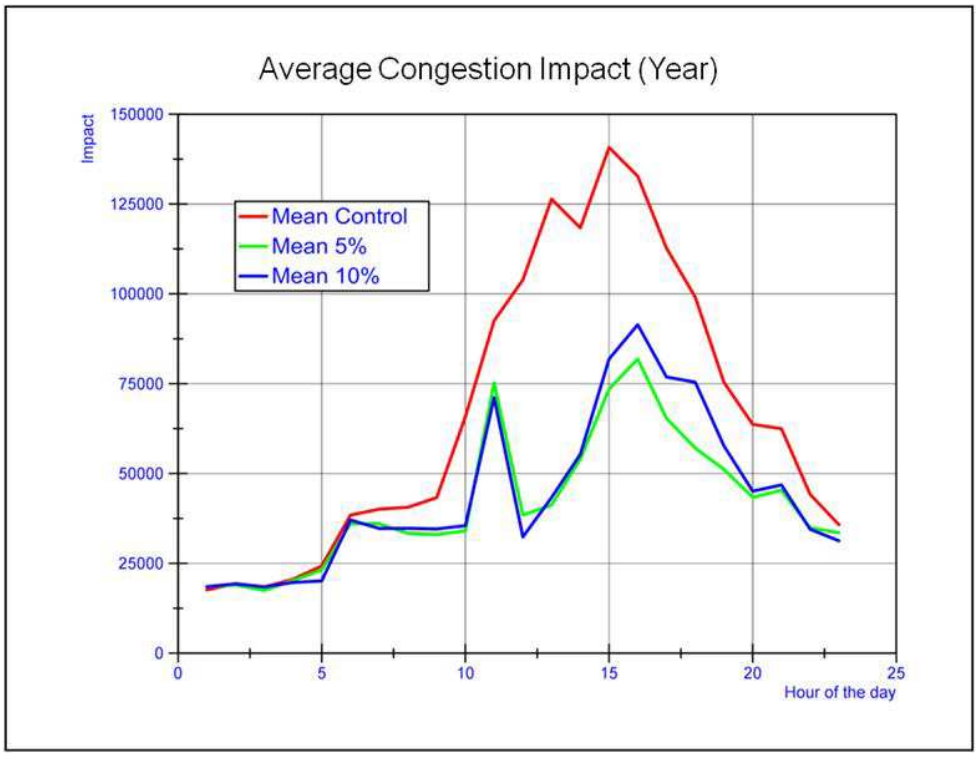


Figure 62 - Average DAM Congestion Impact (Year)

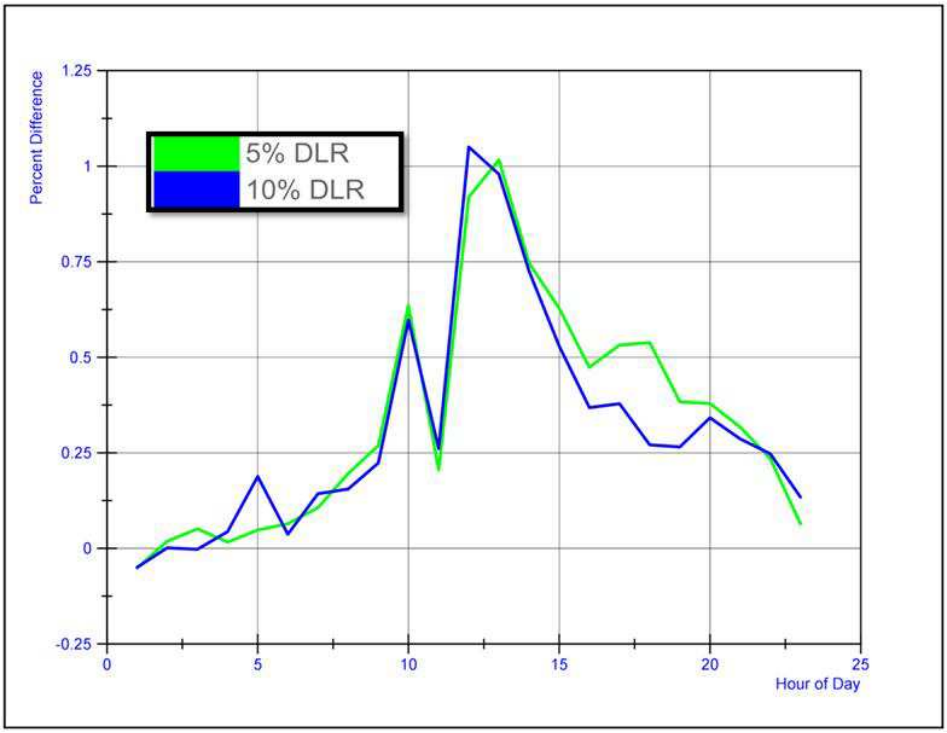


Figure 63 - Percent DAM Congestion Savings Over Static/AAR

The monthly congestion impact, as a percentage of congestion savings over the base model, is shown in Figure 64. It is important to note that each month only contains data for one day and so is subject to skewing based on weather or other generation/transmission events. In general, the results show a consistent savings that can be achieved, with a greater impact in the critical high-load summer months.

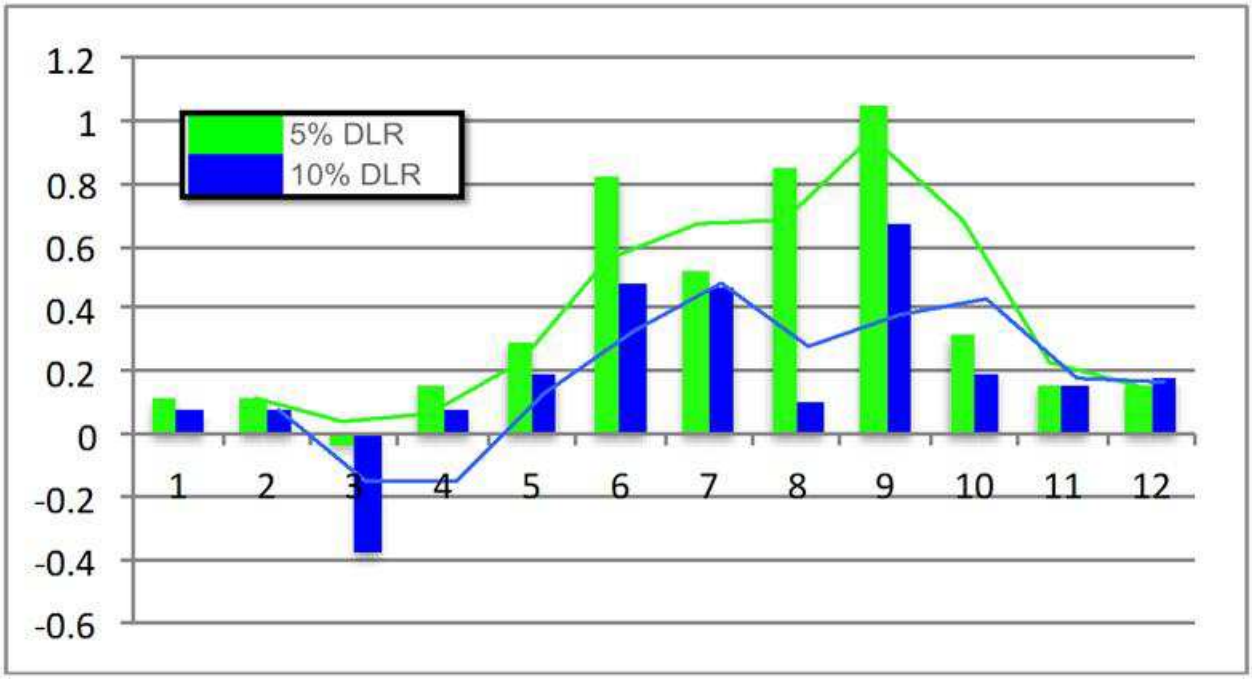


Figure 64 - Monthly Congestion Impact

The next two plots show the cost impact for one day in January (Figure 65) and July (Figure 66). The plots show an hourly impact as well as a cumulative summary for the day.

Note that in January (Figure 65), the 105% and 110% capacity lines track almost perfectly; thus, there was no quantitative difference between these two scenarios on this day's congestion relief.

In the July plot (Figure 66), we see that 110% capacity resulted in more congestion cost savings than 105% capacity.

Predictive DLR within the DAM shows that significant savings are achieved, especially during the peak hours of the day, with congestion cost savings at times over 100% of the base case congestion costs. This shows that DLR can be effective at reducing congestion during peak demand periods and thus at reducing costs across the market.

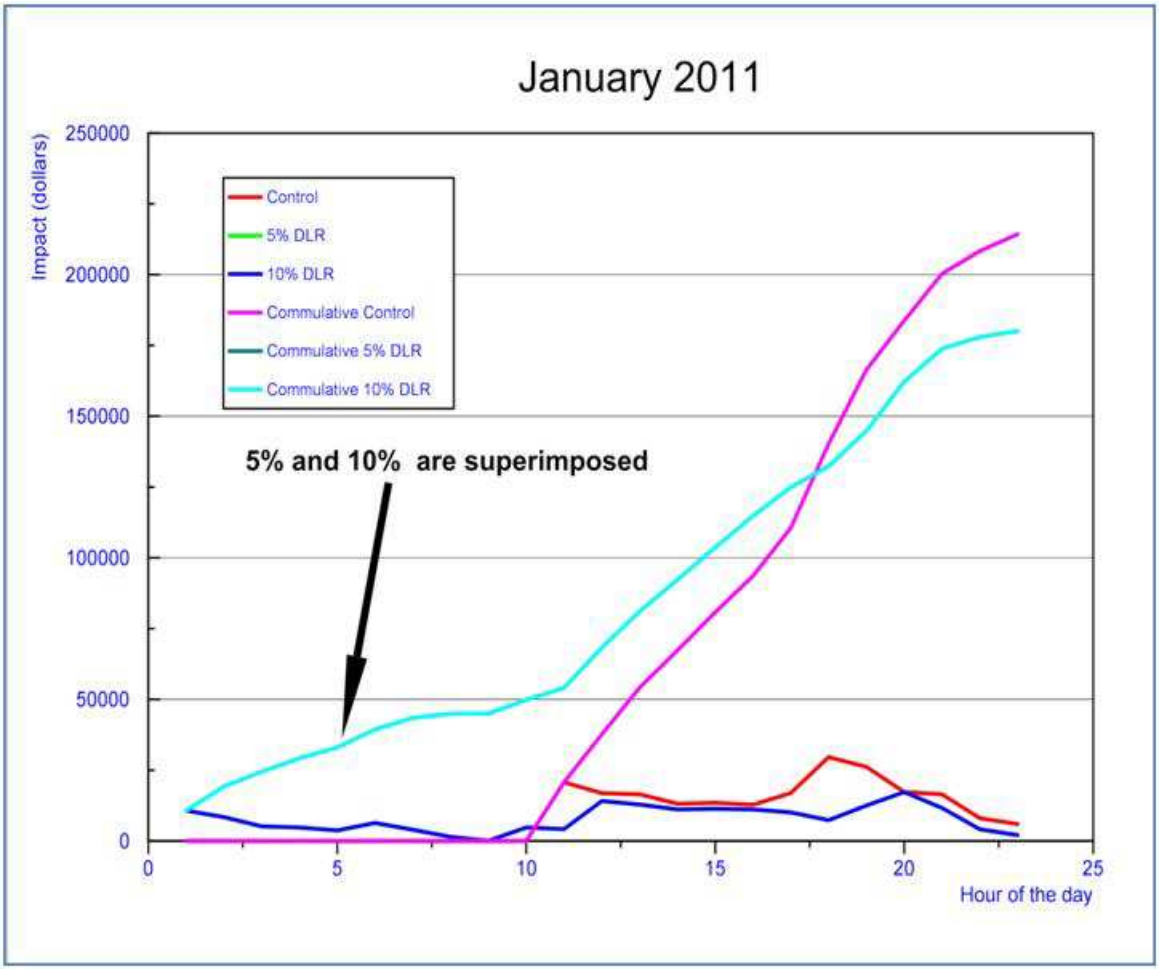


Figure 65 - January Cost Impact Hourly and Cumulative

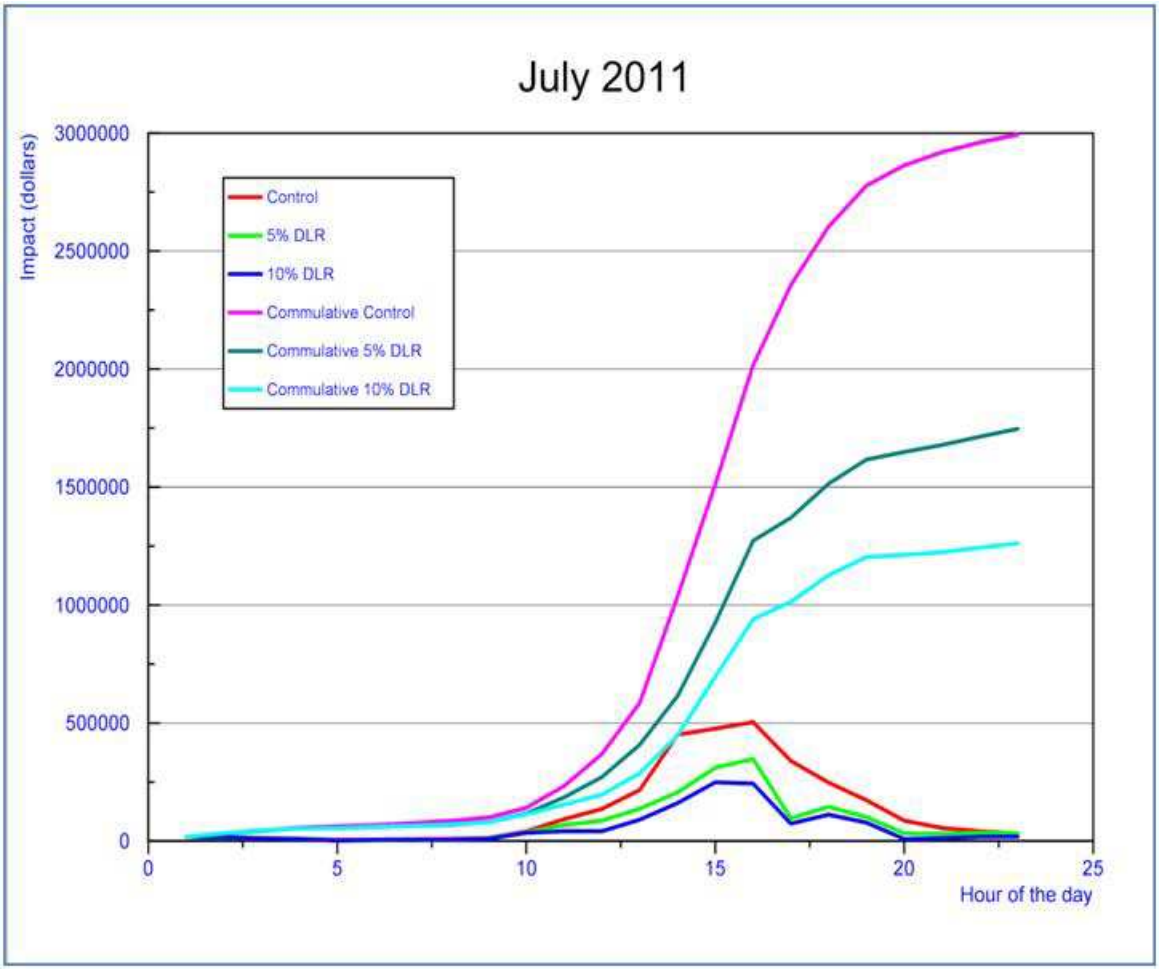


Figure 66 - July Cost Impact Hourly and Cumulative

3.15.8 Correlation of DAM Results to Real Time

Congestion in the grid costs significantly more when it is identified in the daily modeling of the system through the SCED. SCED runs every five minutes during the operational day, providing a prediction of the potential constraints in the system and alerting system operators of problems that may need human intervention through the application of generation shifting.

Having developed an understanding of how DLR can affect congestion costs through DAM modeling, we then focused on how the daily operations model (SCED) could potentially be impacted and what the potential cost impact could be through congestion mitigation.

For this correlation, we looked at the direct impact on the six lines we selected for this study and at the impact on the peripheral lines that radiate from connection points along those six lines.

Using a congestion reduction model of 75% for direct lines with DLR and 54% for peripheral lines (as averaged over 12 months), we see a congestion rent impact within the DAM as shown in Figure 67.

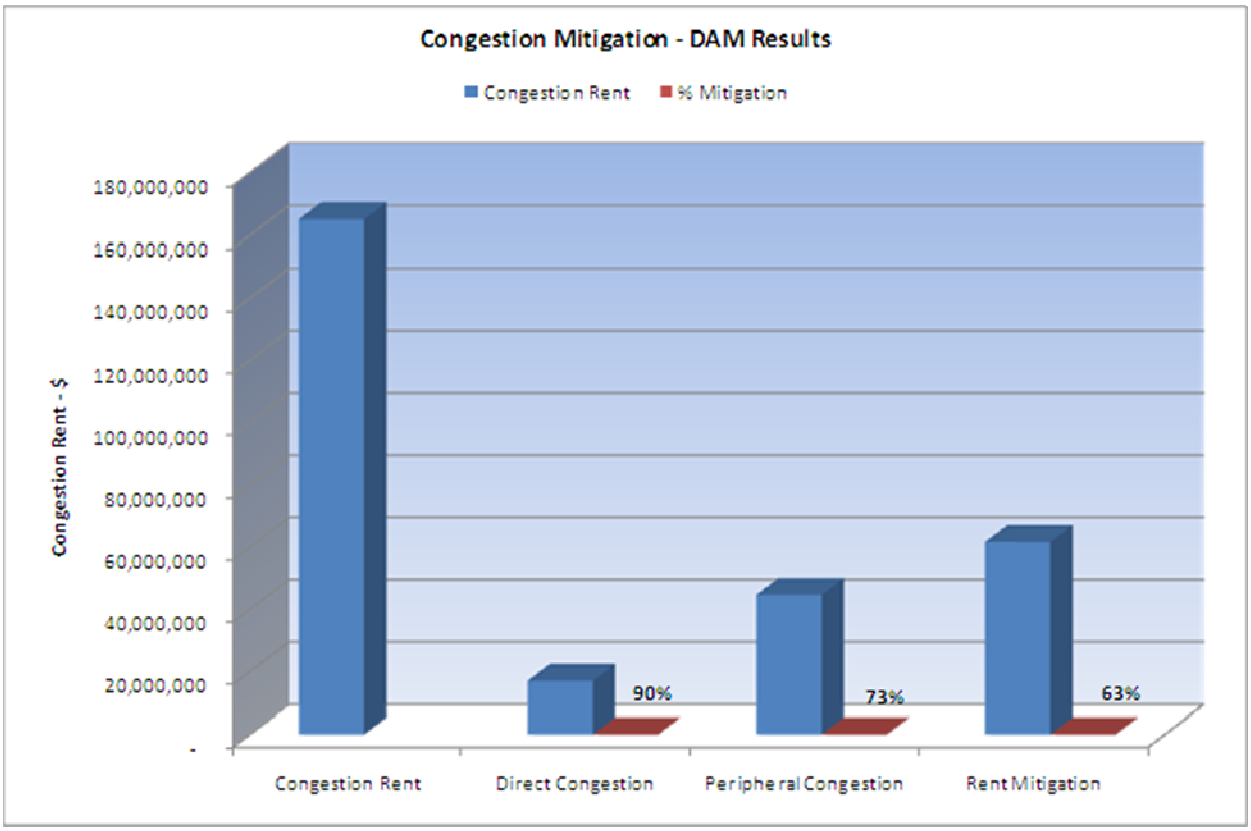


Figure 67 - Congestion Impact within DAM on Direct and Peripheral Lines

Extrapolating these results into the SCED congestion, we see the impact to congestion rent (Figure 68).

Analyzing these two views shows that for a given year on a set of target lines, DLR has the potential to reduce congestion costs by an average of 65% (63% rent mitigation in DAM, 68% in SCED).

Based on these results, we now make an assumption that DLR can reduce congestion rent by 65% on the annual congestion. Making a further assumption that DLR would not be deployed on all lines but on a percentage of them that show regular congestion, we are able to show a congestion mitigation impact within the SCED. For example, if one-sixth of the lines were directly monitored with DLR within the Oncor transmission system (30 of the 180 lines with congestion), the congestion impact savings for the past two years (2011 and 2012, Table 20) would be:

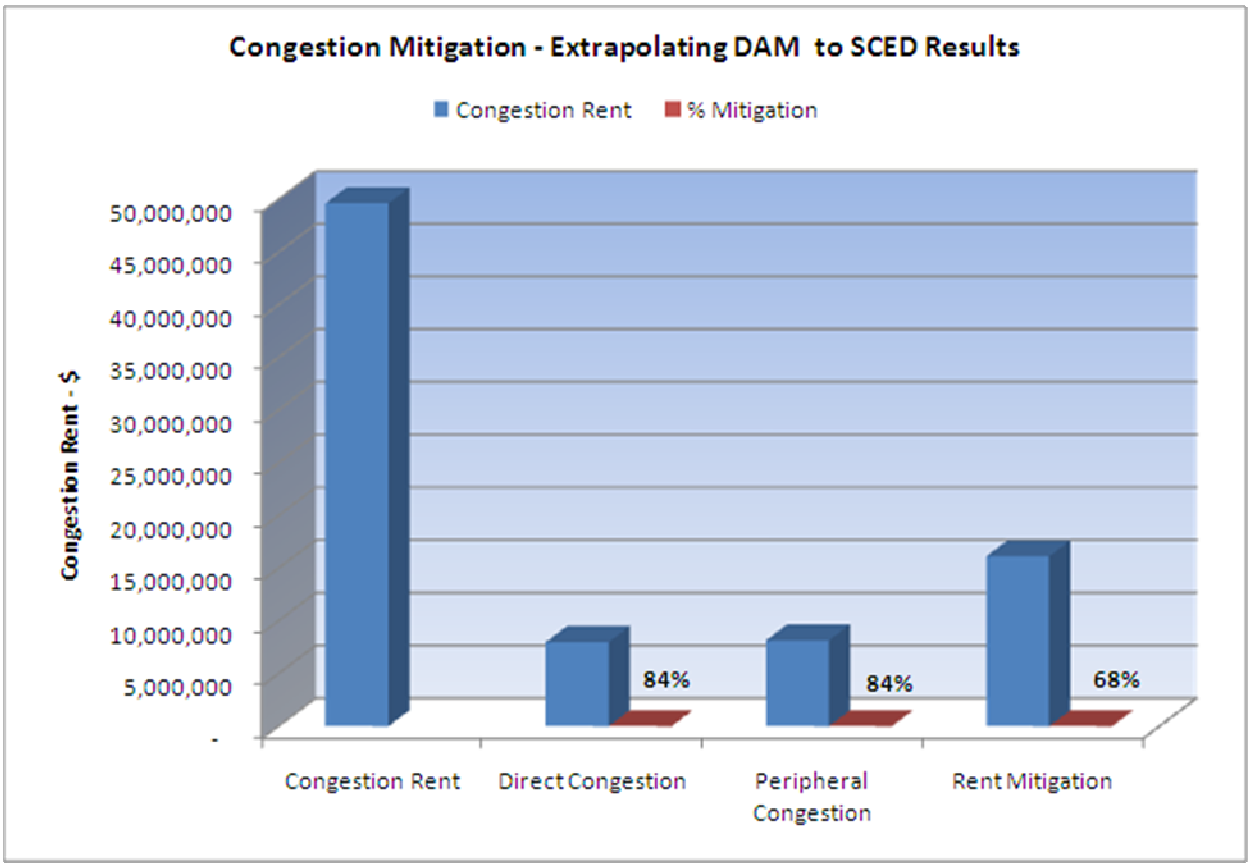


Figure 68 - Congestion Impact within SCED on Direct and Peripheral Lines

This results in a savings of approximately 11% over the two years.

Extrapolating across all of ERCOT, where 2012 SCED congestion costs were $618,908,587, and assuming that only one-twentieth of the lines were monitored, we believe that congestion impact savings would be:

As can be seen, DLR could result in a cost savings potential in this case of approximately 3% ERCOT-wide.

To help validate our assumptions and analysis, we looked at the DAM (base case, +5% DLR, +10% DLR) and SCED data from November 1, 2011. DAM congestion for that day is shown in Figure 69.

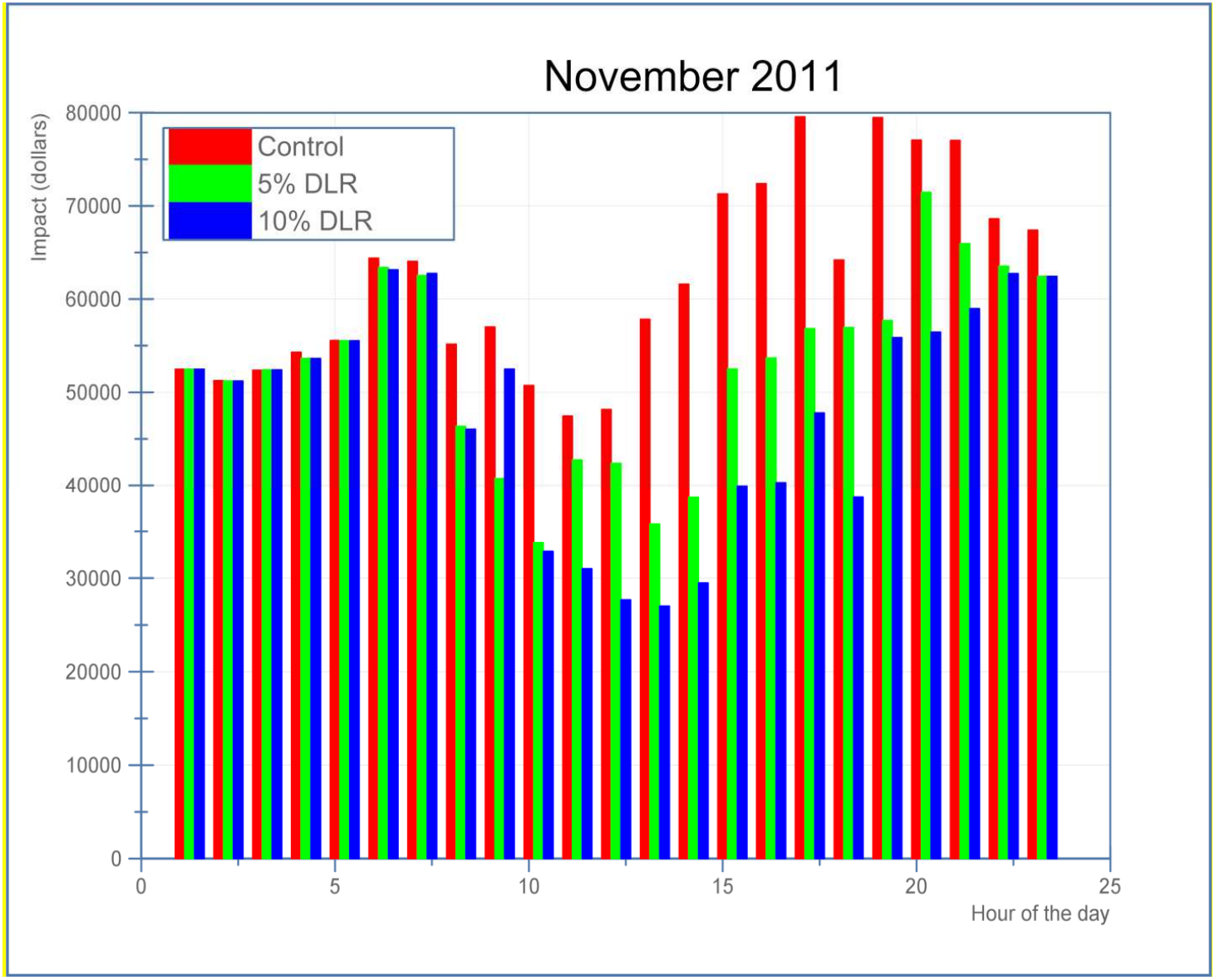


Figure 69 - DAM Hourly Congestion Costs per Hour, November 1, 2011

SCED congestion for that day is shown in Figure 70.

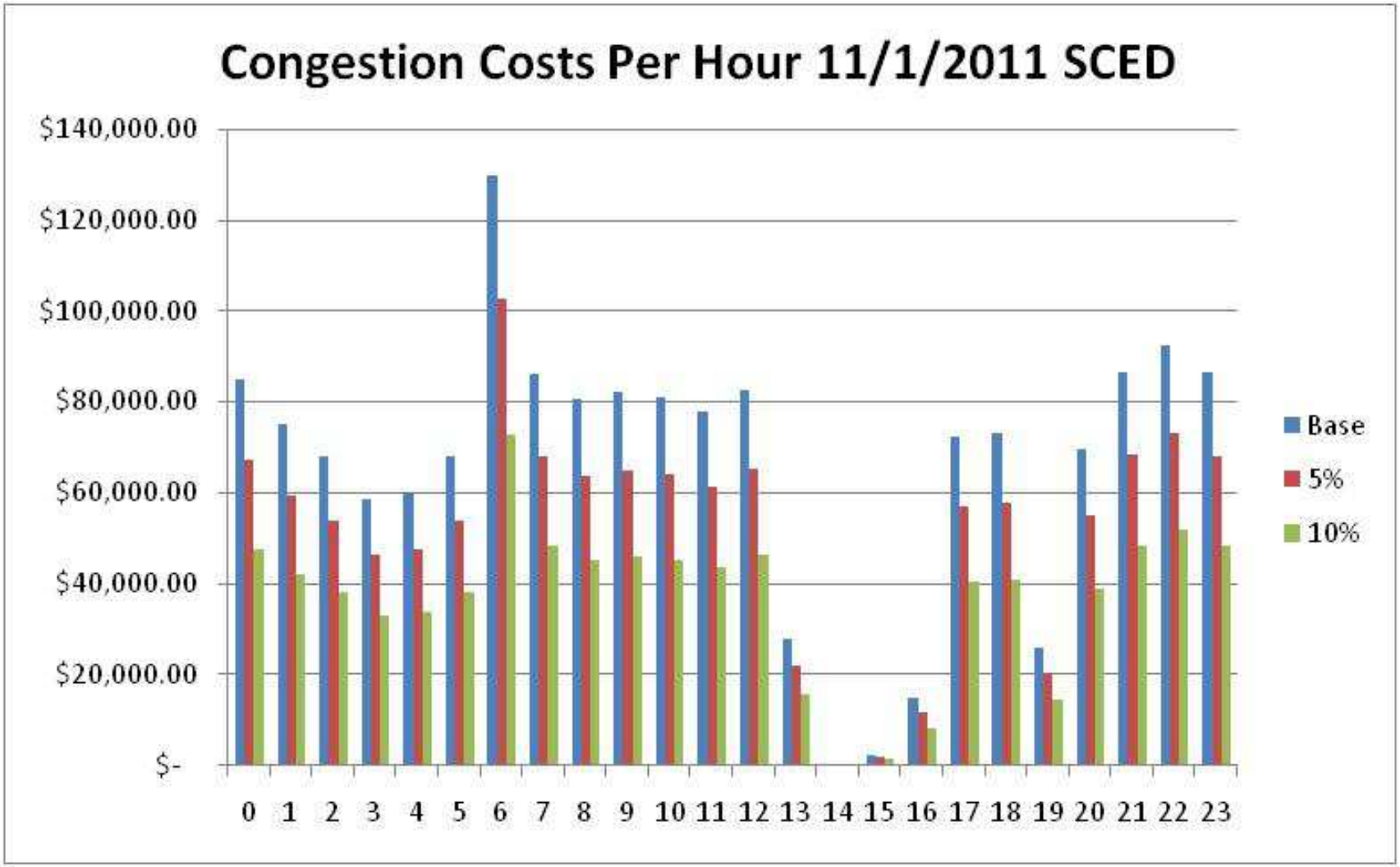


Figure 70 - SCED Congestion Costs per Hour, November 1, 2011

Utilizing the DAM data reruns analysis and doing the above calculations on the SCED data for that day, we see congestion cost reductions as shown in Figure 71

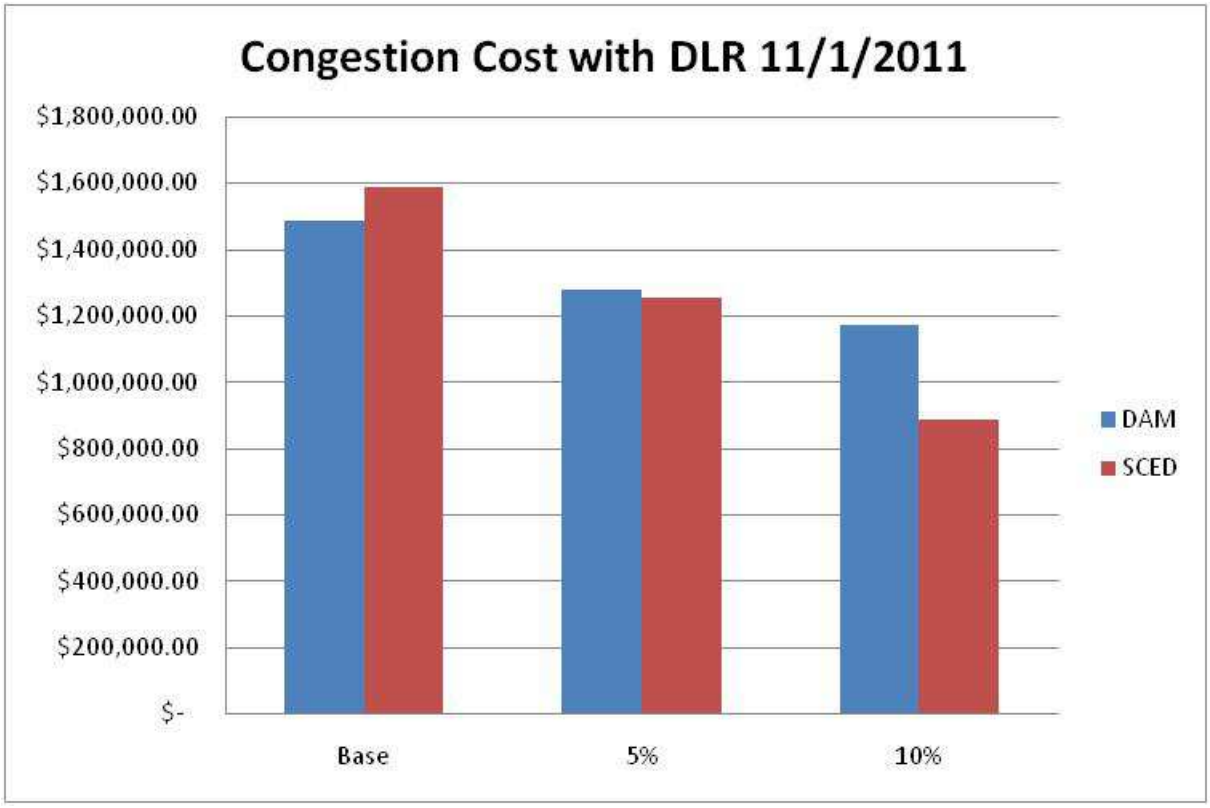


Figure 71 - DAM and SCED Congestion Relief Cost Impact for November 1, 2011

While this analysis for November 1, 2011, shows different cost reductions between DAM and SCED than our annual analysis, it does support that DLR has a positive impact to congestion rent mitigation and shows that the impact is greater to SCED, where overall congestion costs are higher. Additionally, it shows that 10% DLR has significant impact to SCED analysis, whereas it had a much smaller impact over 5% in the DAM.

The percentage congestion relief cost impact is shown in Figure 72. It is important to note that for this particular day, there is a much greater impact to SCED congestion costs than to DAM. Also, it can be seen that 10% DLR has a significant impact on SCED congestion, eliminating 44% of the congestion costs for November 1, 2011.

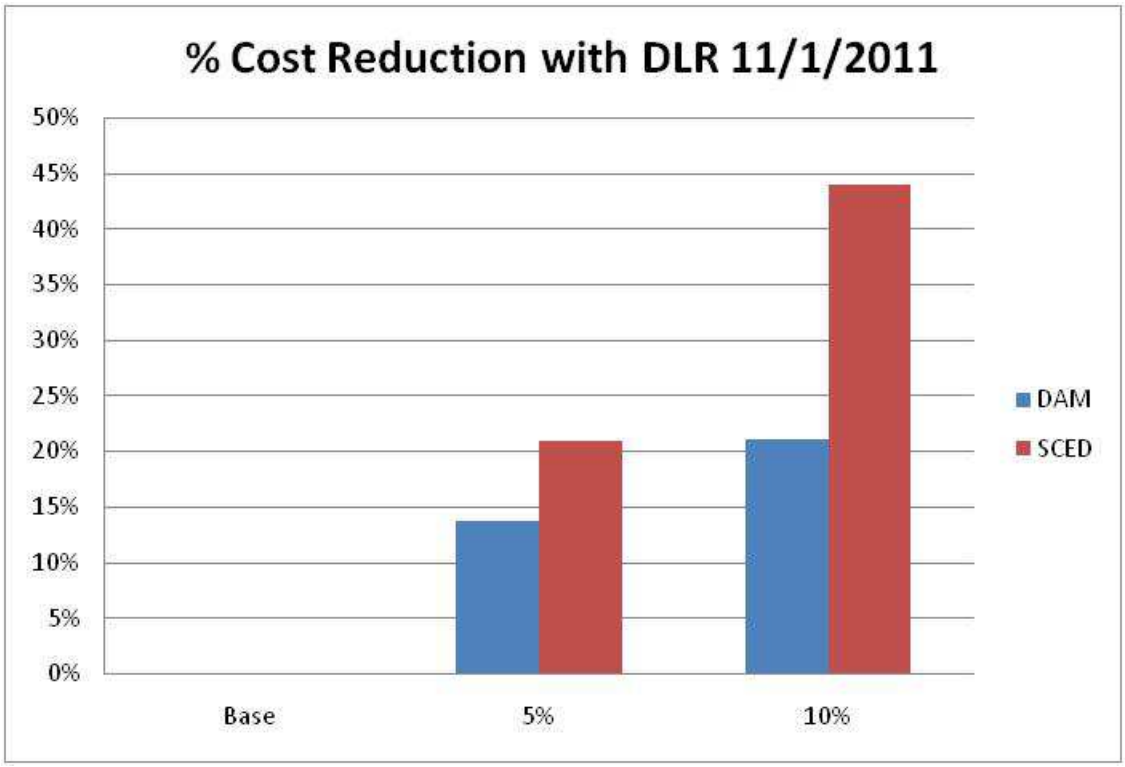


Figure 72 - Percent Cost Reduction DAM/SCED November 1, 2011

3.15.9 Environmental Analysis Based on Shift Factors in SCED

Shift Factors define a set of recommended actions for increasing or decreasing generation on each side of a constrained element in the system that will change the congestion constraint proportionately to the Shift Factor. A file is produced for every SCED run where all of the active constraints are identified along with a set of Shift Factors that can be applied to relieve the constraint. Each Shift Factor is associated with a single generator unit. Any given constraint in any given SCED run may have a few to 50 or more Shift Factors that can be applied to relieve the constraint.

The Shift Factors for a given constraint range from negative to positive, where a negative constraint represents a positive impact on the congestion constraint, i.e., a reduction in congestion, while a positive Shift Factor represents a negative impact on the congestion constraint. These Shift Factors are used by the system operators to increase generation on one side of a constrained element while decreasing generation on another unit, thus balancing out the system around the constrained element and relieving the congestion. The more negative a Shift Factor, the greater impact an incremental change in that unit's generation will have on congestion relief. Conversely, the more positive the Shift Factor, the greater impact the incremental generation has on increasing congestion.

The typical method for implementing the Shift Factors is to work inward from both directions using the most negative and most positive Shift Factors first and moving toward the middle of the list until congestion is relieved.

While the Shift Factor files provide a prioritization for change in generation through a negative or positive Shift Factor, the files do not provide information on incremental change in magnitude of the power output of the generator or what the power output result would be when the Shift Factor is implemented. Because of this, we were not able to determine results in terms of megawatts of power changed and effectively direct environmental change. Our approach then was to determine unit-less change, or the delta in emissions output, between base and DLR cases.

Our approach to analyzing the environmental impact of DLR technology involves analysis of the Shift Factors as they relate to a change in generation pattern due to system constraints. We did this by identifying the differences in SCED constraints between the base and normal case and in a system where DLR was in effect for the six lines identified for the economic analysis.

ERCOT provided Shift Factor files for our 12 study days. For each day, we produced a base case file, a DLR file where capacity was increased by 5% on our six lines, and a DLR file where capacity was increased by 10%. This resulted in the creation of 36 files, three per month.

3.15.10 Nature of Primary Generation in the ERCOT System

The nature of primary electricity generation in Texas has changed several times over the past 50 years. Starting in the early 1950s, natural gas plants were the primary additions to the generation fleet. This changed to coal in the mid- to late 1970s due to a perceived shortage in natural gas deposits and associated increase in market price. Nuclear plants sprang up in the late 1980s and early 1990s. With the discovery of new natural gas deposits and the emergence of hydraulic fracturing technology, natural gas has again become the dominant fuel to generate electricity in Texas, although in the past decade wind has made significant impact on the electricity market.

According to the Texas Comptroller of Public Accounts Office, natural gas generation in 2006 accounted for 49% of all Texas electricity generation, followed by coal at 36.5% and nuclear at 10.3%, with renewables, other gases, petroleum and hydro making up the remaining 4.2%. The picture, however, is changing.

In 2006 Texas had 2,739 MW of installed wind production[12]. By 2010 that number increased to more than 10,000 MW of installed capacity[13]. Another 6,500 MW have been announced for construction over the next five years.

In looking at generation plants completed since 1995, natural gas leads by accounting for around 75% of all energy generation. Wind is the second largest new generation contributor, accounting for an

[12] Report: Annual Report on U.W. Wind Power Installation, Cost, and Performance Trends: 2006; U.S. Department of Energy Office of Energy Efficiency and Renewable Energy, http://www.windpoweringamerica.gov/pdfs/2006_annual_wind_market_report.pdf

[13] Wind Powering America: Installed Wind Capacity; U.S. Department of Energy Office of Energy Efficiency and Renewable Energy, http://www.windpoweringamerica.gov/wind_installed_capacity.asp

additional 20%, with coal, nuclear, solar and biomass making up the other 5% in new generation capability.

3.15.11 Use of DOE eGRID Database for Environmental Outputs

Emissions data was taken from the Department of Energy eGrid 2010 Version 1-1, which provides the emissions output of generation plants from the year 2007. A mapping file was created to match Texas generation plant names with the eGrid identified plant names. Two files from ERCOT, a generator units file and a generator sites file, were used to provide the mapping from a generator key name in the Shift Factor files to the plant name within eGrid.

For this study, which focused on the difference in emissions output when DLR is applied to a part of the transmission system, only plant-level emissions data was used. This means that where the Shift Factor files identified a particular generator within a plant, that generator was mapped to the plant rather than to the generator unit. This decision was made because an analysis of the Shift Factor files showed that when a Shift Factor was applied for a given constraint, there was typically a Shift Factor identified for each generator within a plant, and it was usually the same Shift Factor. For example, if a generation plant has five boilers, the Shift Factor file usually contained a Shift Factor entry for each boiler for the same constraint for the same hour.

For each plant, we utilized the following eGrid data fields for emissions output:

- Plant annual NOx total output emission rate (lb/MWh)
- Plant annual SO2 total output emission rate (lb/MWh)
- Plant annual CO2 total output emission rate (lb/MWh)
- Plant annual CH4 total output emission rate (lb/GWh)
- Plant annual N2O total output emission rate (lb/GWh)

To properly weigh the emissions outputs for each Shift Factor, we multiplied the Shift Factor by the lb/MWh rate to produce a weighted emissions rate. Our analysis shows the difference in emissions output from base versus DLR in unit-less form.

3.15.12 Analysis Methodology

Since the Shift Factor files do not provide a picture of what actually happened, only what could happen, our approach had to be one of what-ifs. While DLR was implemented on only six lines within the system, our analysis encompasses the entire ERCOT grid, looking at total system emissions change. Our first step was to determine what differences would be the subject of focus between the base and DLR files.

Identification of Constraint Differences

Since our study area encompassed the implementation of DLR on only six lines in the system, many of the constraints and their identified Shift Factors remained the same across the files. To reduce the data set, we conducted a union across the three files (base, +5% DLR, +10% DLR) to identify where the

constraint cases differed. Our study then focused on those changes. Changes were identified by one of three factors: the number of times a given constraint appeared in any one file was greater than in another file, was less than in another file, or the constraint appeared in any one file and not in one of the others. Table 27 provides an example of this.

Table 27 - Example Constraint Difference from August Data Set

10% DLR	Count	5% DLR	Count	Base	Count	B-5	B-10	5-10
CUELCA_THOMAS1_1	4791	CUELCA_THOMAS1_1	4791	CUELCA_THOMAS1_1	4791	0	0	0
				DOW_RISN_1	960	960	960	0
DRSY_SANA_T1_1	1040	DRSY_SANA_T1_1	1040	DRSY_SANA_T1_1	1040	0	0	0
FALFUR_69A1	126	FALFUR_69A1	126	FALFUR_69A1	126	0	0	0
FDR_OZN_1	5280	FDR_OZN_1	5280	FDR_OZN_1	5280	0	0	0
GBY_AT2	1608	GBY_AT2	1608	GBY_AT2	1608	0	0	0
GBY_AT2L	1608	GBY_AT2L	1608	GBY_AT2L	1608	0	0	0
GIL_PHM_1	10184	GIL_PHM_1	10184	GIL_PHM_1	10184	0	0	0
		HAMILT_PICACH1_1	4	HAMILT_PICACH1_1	4	0	4	4
HIC_LOCU_1	6384	HIC_LOCU_1	6384	HIC_LOCU_1	6384	0	0	0
HILLCTRY_MR4H	6375	HILLCTRY_MR4H	6375	HILLCTRY_MR4H	6375	0	0	0
HILLCTRY_MR4L	6375	HILLCTRY_MR4L	6375	HILLCTRY_MR4L	6375	0	0	0

In this example taken from the August data, a count of the number of times a constraint occurs in each file is compared to determine where changes to the generation pattern could occur when DLR is implemented. In this case, the DOW_RISN_1 and HAMILT_PICACH1_1 constraint cases differed. In the case of DOW_RISN_1, constraints identified in the base case did not appear in the DLR cases, while in the HAMILT_PICACH1_1 constraint case, the constraint did not appear in the 10% DLR case.

To verify this methodology of identifying change, spot checks were done on some of the zero-change cases. In 100% of those checks, it was verified that there was no change in the Shift Factors across the three files.

Analysis of Selected Constraint Cases ('All' Method)

As stated previously, the Shift Factor files are a set of recommended or potential shifts in generation that could be executed to relieve a given constraint in a given interval. No data was available to determine which, if any, of these Shift Factors were actually implemented or the scope of those shifts for a given constraint. Since this information was not available, our first approach was to look at the Shift Factor changes *en masse* to determine the potential change in emissions. This approach makes the hypothesis that if all Shift Factors were executed as specified in each file, a change in generation emissions output could be equally compared between the base and the DLR cases.

Initial analysis of the reduced data sets showed that there was little to no change between the +5% DLR and +10% DLR files. We decided to only focus on the differences between the base and +5% DLR cases.

To determine the emissions output for a set of Shift Factors from a given file, summation method of emissions output as described in the equation below was used.

$$Emissions = P_{case} = \sum_{1}^{c} E_{Type} * SF_{case}$$

Where:

SF = Shift Factor

Case = base or +5% DLR

E = emission

Type = emission data type (NOx, SO2, CO2, CH4, or N2O)

C = number of constraint rows to be analyzed for a given constraint

Once the emissions were computed for the base and DLR cases, the following equation was used to calculate the differences:

$$Change\ with\ 5\%\ DLR = \Delta_{DLR} = \frac{P_{DLR} - P_{Base}}{Abs(P_{Base})}$$

Where:

DLR = Shift Factor file with DLR

Base = Shift Factor file without DLR

This resulted in a set of data elements, by emissions type, showing the percent difference in emissions output in the +5% DLR Shift Factor recommendations versus in the base case.

The data shown in Figure 73 shows that for seven of the 12 months of the year DLR resulted in a positive net reduction of emissions output throughout the grid. This was especially true during the winter months (January-April). During the core summer months (June-August), there was minimal emissions impact, while during the fall (October-December) there was a net increase in emissions with DLR.

While the data shows a net positive impact with DLR, it is not definitive and warrants further study. Since the data only represents one day within each month, it is subject to skewing due to unknown anomalous events, such as a significant weather event or a major generation plant problem. For example, the October data was taken from only a few data points since there were only two differing constraints in the October Shift Factor files, resulting in only 11 data points that could be analyzed. While the SO2 emissions difference for October looks significant, in reality it had minimum impact on the system-total SO2 emissions for the day.

The following graphs show more detail of the net effect of DLR on a particular emission throughout the year. Note that the y-axis scales are the reduction in pollutant from the base model in pounds per MW or pounds per G, but the total values are unit-less since the actual affected MW/GW were unreported in the data. Thus, these charts show relative change only.

Figure 74 shows the cumulative change in emission rates throughout the year. We can see there is a general reduction in emissions output during the winter months, relatively little change during the summer and a steep increase in emissions during the fall. The remaining emissions graphs reflect similar trends (see Figure 75, Figure 76 and Figure 77).

The results of this study methodology show that there is an impact to emissions outputs when lines are monitored in real time using DLR. The net effect for the year is a 10 to 25% reduction in emissions output with DLR over the normal ambient-adjusted line rating method predominant with the ERCOT transmission network.

Further research should be conducted to quantify this emissions impact. If it were possible to know exactly what the pre- and post-redispatch notices were, we could quantify the actual unit loading change and calculate the environmental impact in actual tonnage.

Factors such as expanding the number of DLR lines could show even greater reduction. Placement of DLR was not factored into this study but could be used to show impact such as increased wind, solar or hydro generation (all of which have zero emissions). Furthermore, analysis could be conducted to study why emissions output showed significant increase in May, November and December. We hypothesize this may be related to planned plant maintenance in preparation for a peak season: May in preparation for the heavy summer season and November-December in preparation for the winter heating season.

Additionally, as pointed out previously, our study data only represents one day per month and is subject to event skewing (which was not determinable through the data). Correlation between the types of primary generation and shifted generation could identify how DLR might benefit the environment by allowing more environmentally efficient generators to put more power onto the grid. Finally, a study that could match Shift Factor recommendations with actual actions taken by the system operators could provide a much more definitive answer to emissions impact.

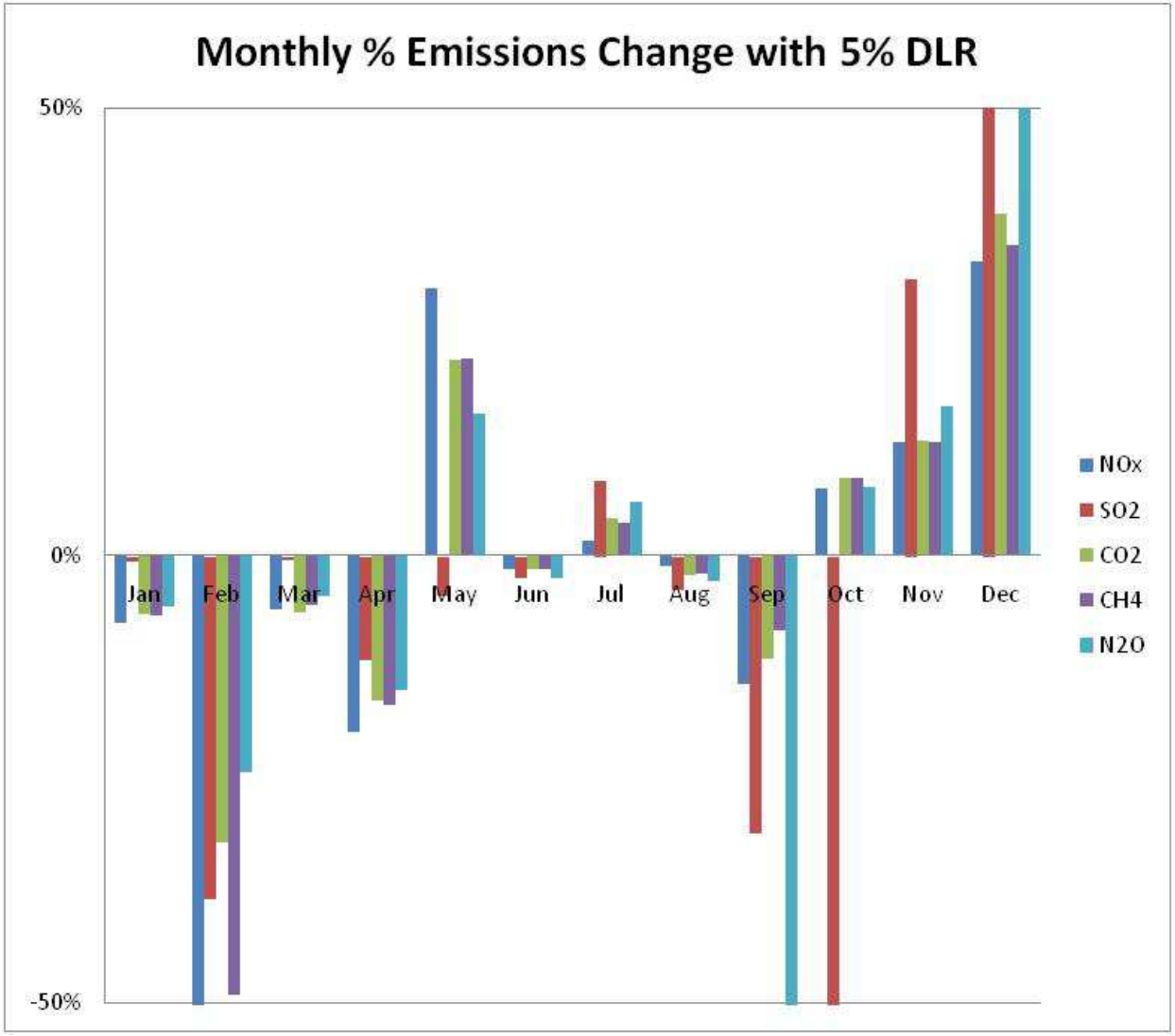


Figure 73 - Net Emissions Difference using +5% DLR on Six Lines within the ERCOT Grid

*Note: y-axis scale reduced to +/- 50% to enhance view-ability of the data.

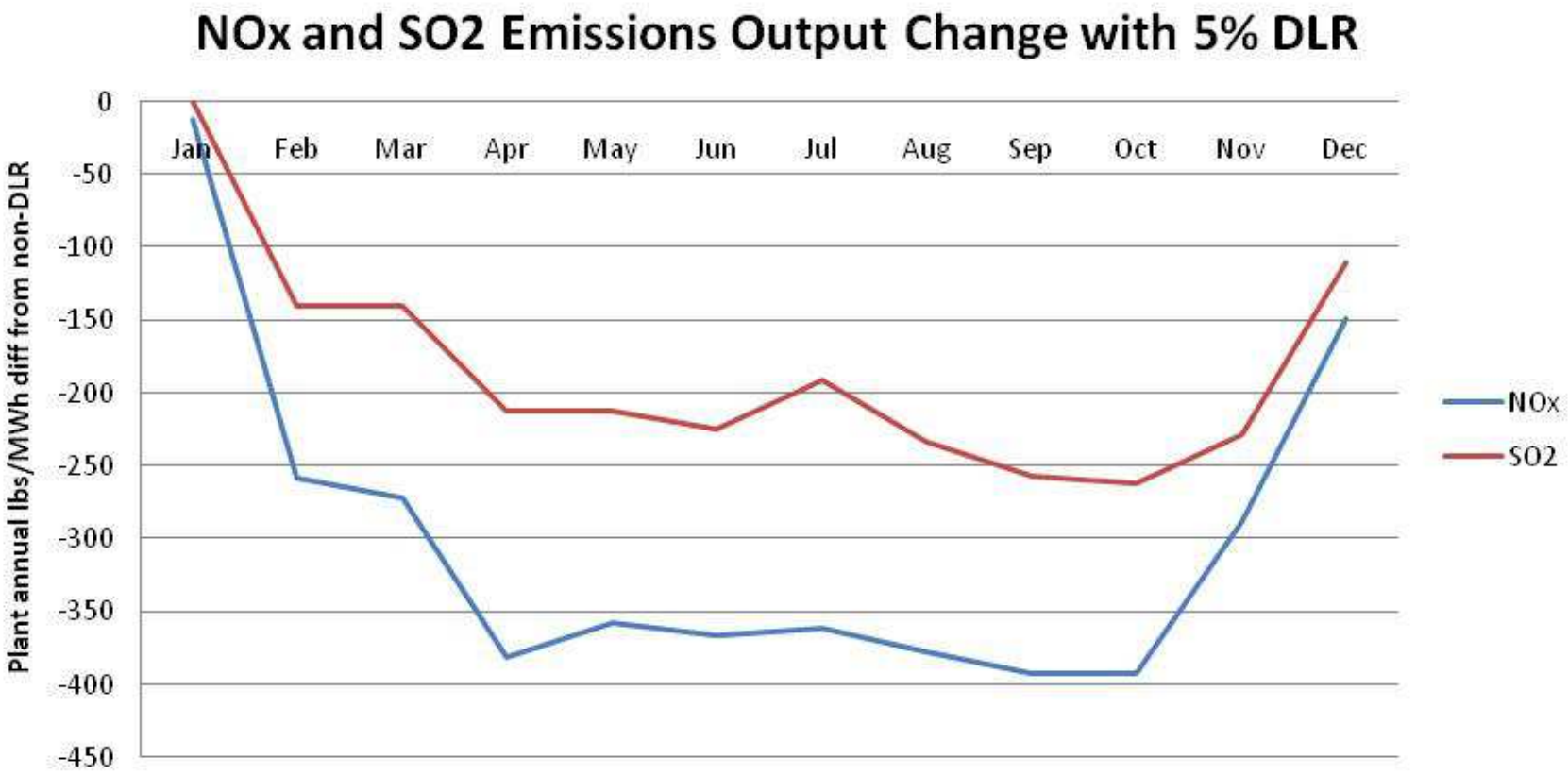


Figure 74 - NOx and SO2 Emissions Output

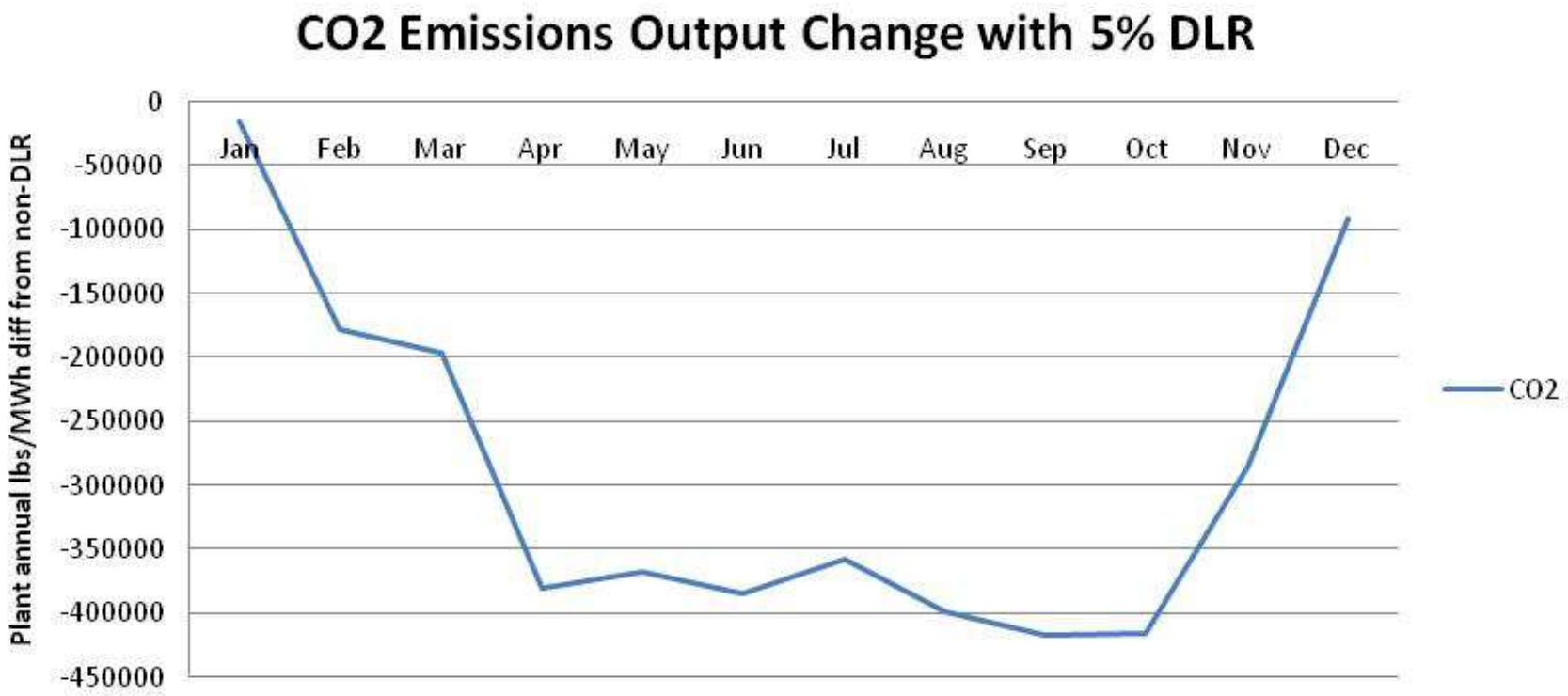


Figure 75 - CO2 Emissions Output

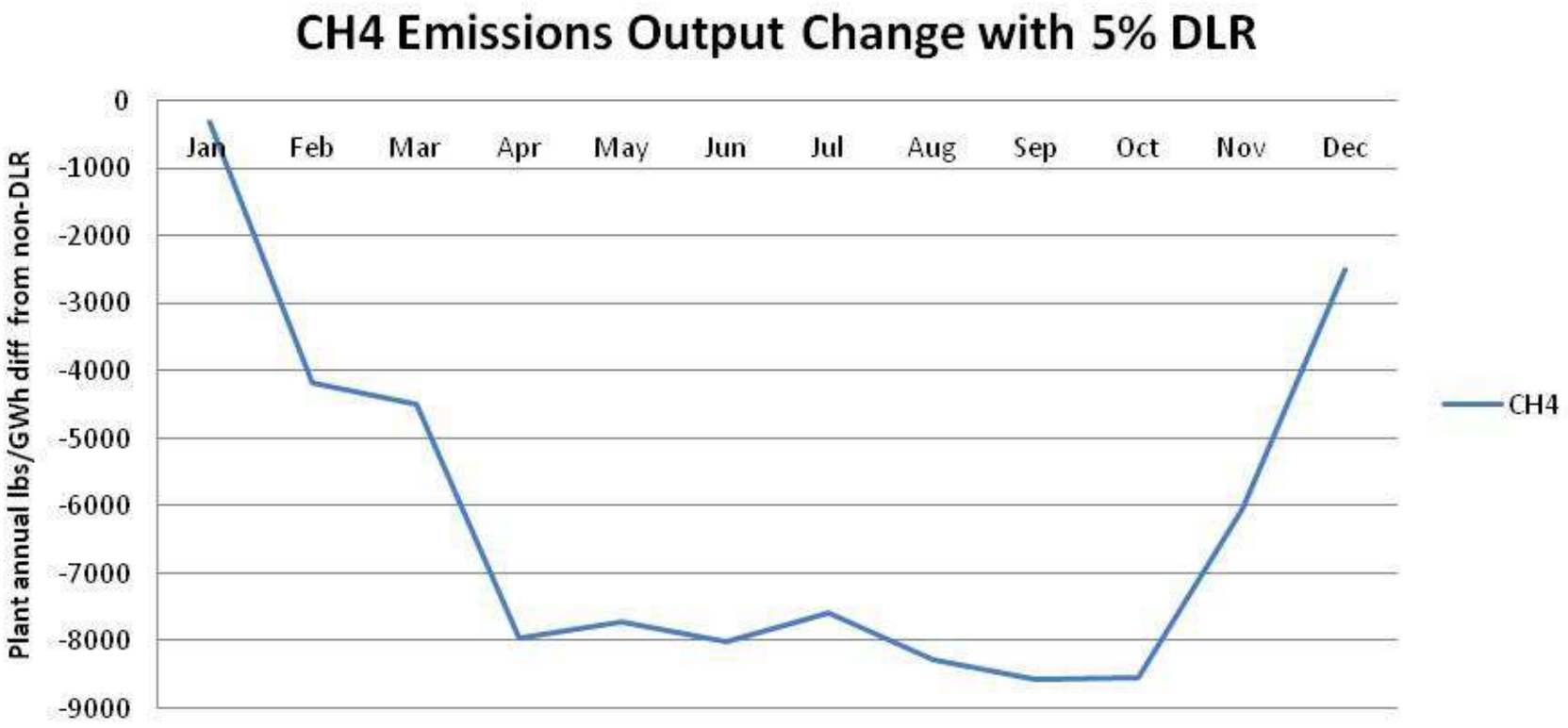


Figure 76 - CH4 Emissions Output

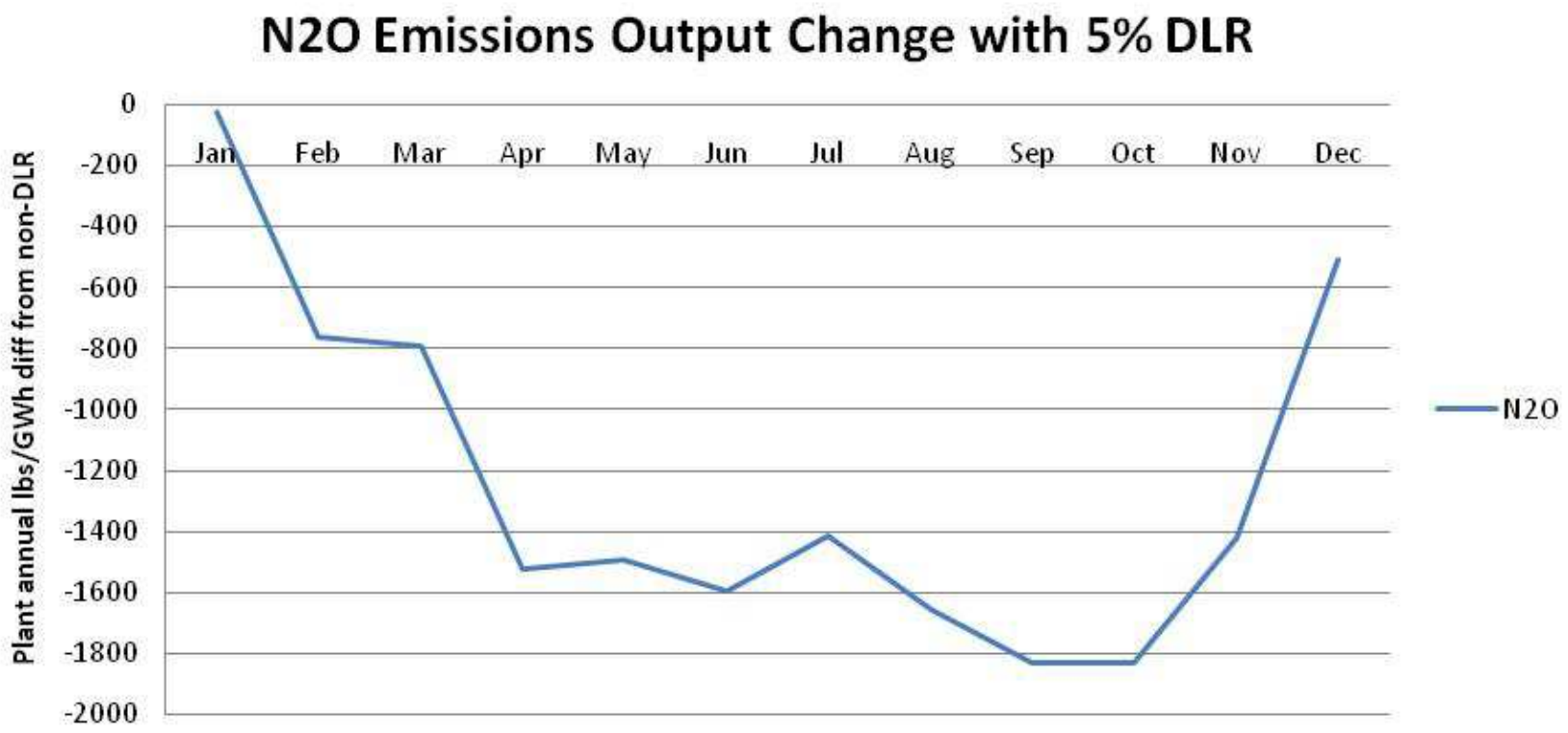


Figure 77 - N2O Emissions Output

Analysis of Selected Constraints (Hourly Top Five Method)

Our previous analysis looked at the system Shift Factors as a whole, doing a comparison of all the Shift Factors for a given constraint. Thus the Shift Factors file is a set of recommendations for all possible constraints as identified in the specific SCED run. The reality is that not all constraints actually happen, and when they do happen, the system operators will only shift generation as needed to relieve the constraint. We were unable to gain knowledge on the exact methodology for exercising Shift Factors; however, in discussions with ERCOT officials and through our own team knowledge, we developed an additional hypothesis for analysis, i.e., when a given constraint occurs, system operators will execute the most negative and most positive Shift Factors, working their way toward the middle until congestion is relieved.

To conduct this analysis, we selected the top five distinct negative and positive Shift Factors for a given constraint within the same event. Our analysis was done to reflect a shift of generation at up to five units at both extremes of the Shift Factor priority list. In general, when a shift is defined, a Shift Factor is assigned to each generator at a generation plant; thus our choice in top five resulted in five to 25 individual rows of shift per negative and positive Shift Factor. The net result was approximately 50 total shifts, negative and positive, per constraint. This is in contrast to the “All” method, where anywhere from a few hundred to a few thousand shifts per constraint were analyzed. We then analyzed the resulting data set using the same equations as in the "All" method.

Because of the difficulty in extracting data using this method, only January was fully analyzed (Figure 78). A few of the constraints from August were also analyzed. This method shows a greater impact on emissions output when DLR is implemented.

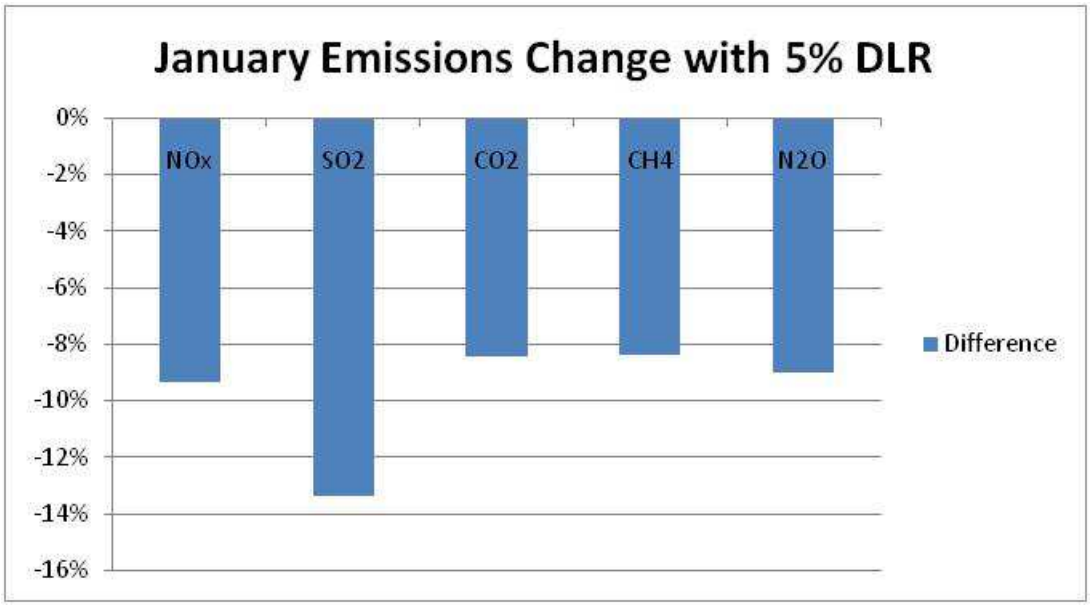


Figure 78 - January Emissions Difference Using the Top Five Method

3.15.13 Economics of DLR Technology

This section discusses DLR and the economics of the energy market. It discusses the impact of the lines directly monitored (lines where DLR has been installed); peripheral lines that radiate out from the monitored lines, and the grid as a whole.

Direct Impact on Monitored Lines

As a part of this study to further understand the impact of DLR to the relief of congestion, analysis was conducted on the economic impact to the lines directly monitored by DLR, that is, the lines on which the DLR equipment is installed. As stated before, the lines used for the economic study were not actually monitored; however, using the data from the capacity study that resulted from monitoring the actual test lines, we were able to simulate the effect of DLR on the six lines chosen for the economic study.

This study used the same DAM runs with adjusted DLR as before but focused only on the six target lines. To further understand the impact of DLR on congestion, the congestion rent was distributed into three summations: base case constraints, transformer constraints and line constraints. Base cases are defined as operations scenarios where large blocks of power transfer are modeled as compared to individual N-1 contingency-constrained element analyses (such as a west-to-north zonal transfer of a block of wind generation energy being there in one instant and not there in the next). This type of constraint has actually happened as a weather front passed west to east and no wind pockets were embedded in the front or quickly followed the front when wind generation had been high and then nonexistent.

Transformer cases are constraints related to a transformer capacity being insufficient to meet load at the other voltage (such as from a 138 kV to a 69 kV line). Line cases are constraints related to line capacity.

Figure 79 shows the impact of DLR on the six directly targeted lines. Congestion rent decreases significantly when 5% DLR is added into the DAM for the six lines and is completely eliminated at +10% DLR.

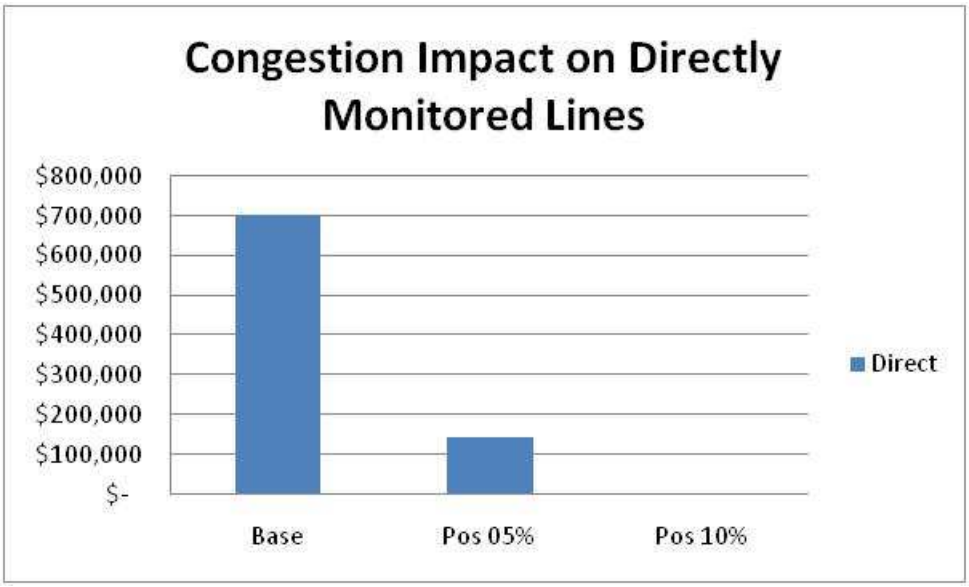


Figure 79 - Oncor Line and Transformer Congestion Data

Direct Impact on Peripheral Lines

This part of the study looked at the lines that radiate out from the actual monitored lines to see the scope of the economic impact. The vision of DLR is not to monitor each and every line within a transmission system; rather, it is to monitor critical lines where congestion is prevalent as an alternative to near-term capital improvements or system upgrades.

For purposes of this study, a peripheral line is a transmission line that is adjacent to a directly monitored line, either feeding into it or being fed from one of the monitored lines through a connection point, such as a transmission substation.

Our results show a significant reduction in peripheral line congestion around DLR-monitored lines. As can be seen in Table 28, peripheral line congestion was reduced by 42% when directly monitored line capacity was increased to 105% and by 44% at 110% capacity. We can see that the cost impact begins to decrease as you move away from the directly monitored lines but it's still significant. We also notice that while 10% DLR has significant impact over 5% DLR on the directly monitored lines, it has negligible impact on peripheral lines, here showing only a 2% increased benefit. This is a trend that continues as we look at the system-wide impact.

Table 28 - Congestion Comparison between Direct and Peripheral Lines

	Direct	Peripheral	Grand Total
Control	$ 704,535	$ 1,096,893	$ 1,801,428
Pos 05%	$ 146,668	$ 632,967	$ 779,635
Pos 10%		$ 609,873	$ 609,873

Percent Reduction in Congestion

% Reduction	Direct	Peripheral	Grand Total
Control			
Pos 05%	79%	42%	57%
Pos 10%	100%	44%	66%

3.15.14 Extrapolated Impact on Utility Transmission System

As discussed previously, the direct monitoring of only a few lines with DLR can result in a significant economic benefit across the entire energy market. The benefit of +5% DLR on chronically congested lines ripples through the system, resulting in less congestion cost not only at the monitored lines but in other areas. Our thoughts on this relate to the maturity and efficiency of the SCED program to mitigate congestion through the decisions on bids and offers. By providing improved line capacity based on real world conditions (especially when factoring in wind cooling), better line capacity data is provided to the SCED, which is then able to resolve more of the congestion than when static or ambient temperature-adjusted ratings were used.

3.15.15 Market Impact on ISO System

An analysis of the DAM models with increased throughput of +5% and +10% shows a significant impact on the energy market. During the hours and days studied in the DAM analysis, congestion cost savings within the DAM on those lines were better than 20%, with peak savings exceeding 100%, i.e., congestion was fully mitigated on the target line. It is clear from the study data that an ability to increase line capacity within the SCED yields a clear economic impact based on reduced congestion costs.

Another important note is that increasing line capacity does not always mean a reduction in congestion savings. Time of day, season, events within the transmission system – all have an effect on congestion that cannot be guaranteed to be relieved through increased line capacity. However, the trend and the annual summary show that DLR does have a congestion cost impact potential across the energy market and is especially significant during peak load periods of the day and peak demand months of the year.

3.15.16 Capital Deferment of New Transmission Investments

One of the goals for using DLR technology is to defer capital improvements or system upgrades to relieve congestion. Static and AAR methods do not provide a true picture of line capacity, resulting in congestion being identified on lines where they may in fact have the additional capacity available. When a line is proven to be chronically congested, it is typically scheduled for some sort of capital improvement to permanently relieve the congestion. We believe through our study that not all lines identified for capital improvement actually need it. DLR technology can be used to accurately measure line capacity in real time, potentially relieving congestion through an increased line rating.

3.15.17 Environmental Impacts of DLR

This section focuses on the impact of DLR as it relates to wind generation, a significantly growing energy resource within the ERCOT grid.

Integration of Wind Energy

As part of this study, we wanted to know whether DLR made an impact on wind generation entering the grid. Since wind is a zero-emission resource, the more that can enter the grid, the less overall generation emissions will be. In Texas the majority of wind generation is in sparsely populated West Texas, and the energy generated must traverse half the width of the state to reach the more densely populated areas. While the lines we picked for the economic study were selected with wind in mind, our primary focus was on congestion no matter the source.

For the 12 days of data provided to us for the year, we extracted the Shift Factors that were directed strictly at wind generation, identified in the eGrid database as having a primary fuel type of WND, and the resulting zeros in the emissions columns. To resolve the fact that a large amount of wind generation had been added in Texas since the last update to eGrid (2007), our custom mapping file matched new wind generation plants to an existing wind plant in eGrid since the emissions values would remain the same (i.e., zero).

The net result of our analysis shows that there was an increase in generator shift toward wind generators when DLR was applied to our target lines.

The net increase in wind was 3% for the year (encompassing data for one day of each month). The average difference in wind generation is shown in Figure 80, which is a running cumulative shift in wind generation pattern when 5% DLR is applied. Note that only three of our six study lines are in the wind zone, which makes this potential increase significant.

The method used to calculate this impact was to summarize all of the negative Shift Factor options (where a change in generation has a positive impact on congestion), summarize all of the positive Shift Factors (options where a change in generation has a negative impact on congestion), and then compute the difference to determine a net negative or positive shift. This was done for the base case (no DLR) and the 5% DLR case, and then the percent difference between these two cases was computed.

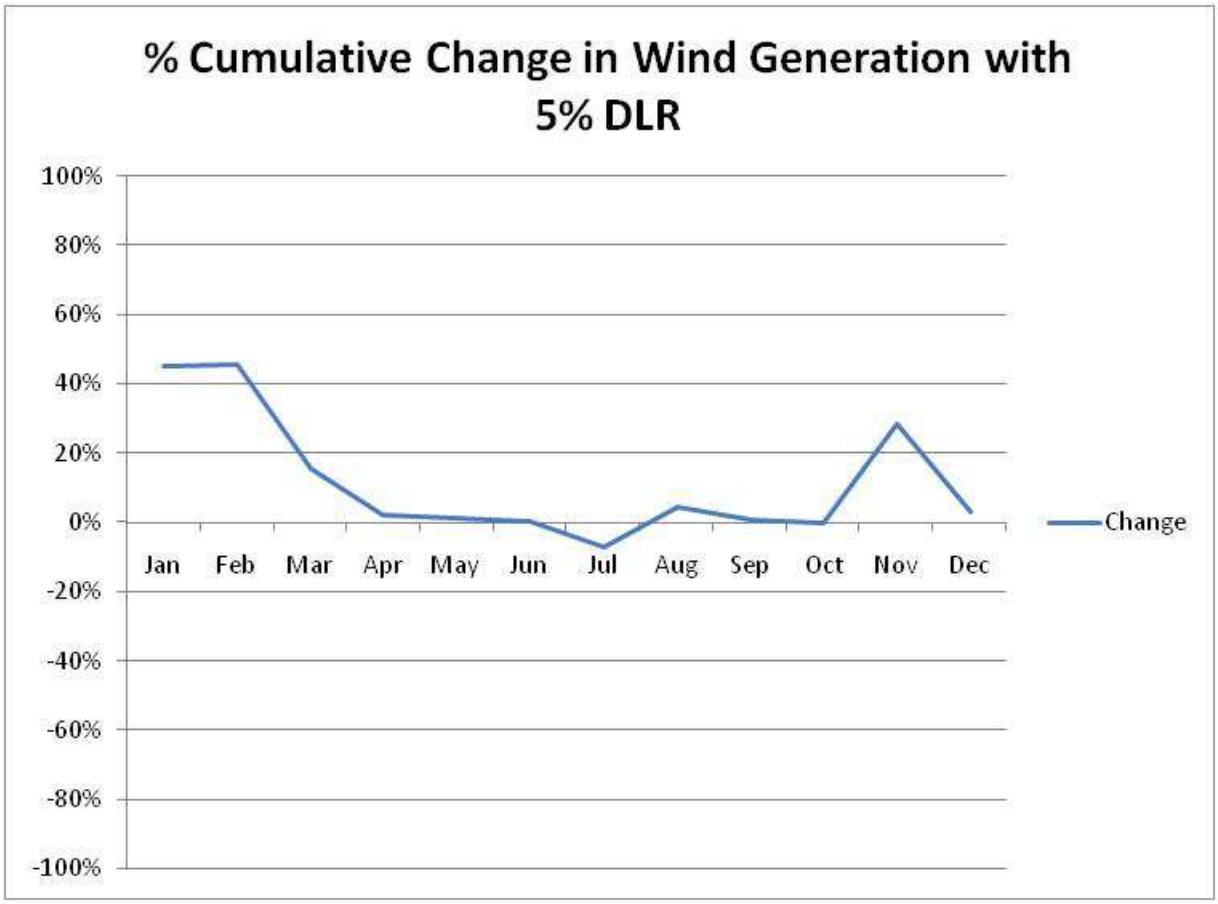


Figure 80 - Running Average Shift Factor to Wind Generation with DLR

While this data is not definitive due to the limited amount of data, it is significant in that SCED events analyzed appear to be utilizing the increased line capacity to recommend generation shifts to more wind production. A more thorough study, one that analyzes distinct lines involved in wind generation input to the grid and contains more days of data, could provide a more definitive answer. As the data exists now, we do see a potential increase in wind generation; as a result, we would expect a reduction in emissions from generation that could be achieved through DLR technology.

Note the lack of a systemic change from April through October (Figure 80). This is indicative of the lack of wind available for generation in these months. The units are not in the Shift Factor list because the wind is not there for generation, especially during peak periods of the day.

Changes in Generation Patterns to Relieve Congestion

Our study shows that the addition of DLR produces a change in the generation pattern within the grid. This change results in a positive impact to congestion cost as well as a reduction in emissions output. Additionally, our results show a potential increase in wind generation within the ERCOT system.

3.15.18 Conclusions and Recommendations for Future Economic Trade Space Studies

Presented here are our summary conclusions as well as recommendations for further study.

Economics of DLR on the Energy Market

Our study shows that DLR technology can have an impact on the price of energy within the transmission grid, reducing congestion costs associated directly with line constraints and indirectly with transformer constraints. The study results show that congestion mitigation can be obtained with as little as a 5 to 10% increase in capacity over the current line ratings using DLR.

Emissions Impact of DLR

The results of the study show a positive impact on emissions outputs from generation plants across the system grid when DLR is able to increase capacity. This impact is shown through a change in generation shift patterns in response to N-1 and other contingency cases. The quantification of this impact in tonnage was not possible here and should be the subject of a more in-depth study focused on emissions outputs. The missing factor was the actual incremental generation-dispatch changes in response to congestion constraints on the grid (data of which was not publicly available).

Our hypothesis in this study was that DLR would enable a reduction in shift patterns, allowing more generation to occur as scheduled in the SCED where more efficient generators could be selected (efficient being defined as generators offering energy at levels where their plants run most efficiently) and would reduce the shift to less environmentally efficient generation. While efficiency levels of individual generators were not a focus of this study, the data seems to validate our hypothesis; a more detailed study could potentially provide proof. Additionally, we have shown that with DLR there is an increase in the SCED to provide shifts that increase wind generation, a zero-emission resource, when it is available.

3.15.19 References

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3.16 Stakeholder Feedback

Oncor has had several interaction opportunities with stakeholders within ERCOT, other independent System Operators (ISO) and peer transmission service providers to discuss the project objectives.

Most notably, the project team met with ERCOT staff to review the results of the DLR-DAM assessments that ERCOT supported. We met with the planning, operations and Nodal Market staff. The results of the mitigation projections were reviewed, as was capacity availability from a planning perspective. Interest in both aspects was expressed and further discussions led to a 2013 DLR project to be executed by Oncor to install DLR on five additional lines in the Odessa area to help mitigate ongoing load growth and congestion issues. The deployment of DLR instrumentation was initiated late in January 2013 and went into service in mid-June 2013. The Odessa deployment performs in identical fashion to the SGDP Project operation, streaming real-time data to ERCOT for its nodal SCED application.

A brief summary of the project scope, activities and results was shared with several other ISOs to gauge the potential interest in applying similar DLR programs in their systems. None of the ISOs have equivalent DLR systems. They run a similar SCED analysis to ERCOT's for real-time operation. They have expressed interest in the DLR program. ISOs contacted include PJM, California ISO, New York ISO, ISO-New England and Southwest Power Pool.

Presentations have been made at numerous technical conferences, including:

GridWeek 2010. The project objectives and strategy for accomplishing the objectives were shared with conference participants. Since the project was just beginning deployment of equipment there were no results available at the time.

Texas Reliability Entity (TRE). In spring 2011, TRE held its annual programs for recertification of all regional operators of transmission and generation assets in the ERCOT system. Oncor's representative

on the board of the TRE training committee proposed that an overview of the DLR SGDP be given to all of the operators. A one-hour presentation on line ratings, dynamic ratings and their importance to system operation was prepared, including a discussion of the DLR project. The training session was provided to more than 800 attendees over seven weeks. The reception was mixed, perking up the ears of attendees associated with generation (DLR could increase the capacity of outlet lines from power plants at a very low cost) but finding only moderate interest in grid operators who would see the streaming line ratings and make decisions upon them. Their interest was directed toward the reliability, dependability and accuracy of the data.

A similar presentation was made to more than 400 transmission line engineers at the 2011 University of Texas at Arlington Transmission and Substation Design and Operations Symposium, and In September 2011 to 30 college engineering students associated with ASME at Texas Christian University.

A presentation was made at the Carnegie Mellon University Data-Driven Sustainable Energy Systems Conference in March 2012. More than 100 attendees discussed the various aspects of real-time data collection, management and application related to Smart Grid activities.

A presentation was made to the IEEE PES Fort Worth group in May 2012, to approximately 50 attendees at the EEI Transmission Section meeting in October 2012, and to the Southwire Western Transmission Seminar in November 2012.

A presentation was made at the 2013 Distributech conference during a DLR panel session.

The project results were shared with ERCOT staff to deliver the results of the project and to acknowledge their contributions towards developing the economic impact of DLR on congestion. An outcome of this meeting was the consideration and eventual deployment of additional DLR sensors on five lines in West TX.

IEEE Overhead Lines and ESMOL Subcommittees. In July 2013, a presentation of the project and its results were shared with the IEEE Subcommittees

A paper describing the Project and its successes has been accepted for the CIGRÉ 2014 General Session for Study Committee B2 Overhead Lines. A presentation is scheduled for Distributech 2014.

Stakeholder feedback has been extremely supportive, with considerable interested in the progress and technical deliverables to date.

Forecasting is a topic of significant interest for both the System Operations perspective, i.e., persistence, and from a market perspective, i.e., what will tomorrow’s ratings be, taking into consideration both wind and ambient temperature.

3.17 Lessons Learned

The project as part of the Smart Grid Demonstration Program (SGDP) addressed both the development of technology and the application of that technology in a real world application. Many lessons were

learned that can be used to immediately address issues with deploying the technology; they are also valuable for extensions of the technology to a broader spectrum of users and applications. The lessons learned documentation provides a list and explanation of the knowledge gained to help guide future users.

Appendix I contains complete documentation concerning the Lessons Learned while executing the project. Specific sections address different aspects, including Project Planning, Installation Planning, Equipment Planning, Installation, Calibration, Integration into SCADA, and Integration into the EMS.

Some of the lessons learned, taken from the appendix.

- First, system characteristics are not static. The lines originally selected, identified for their significant congestion, demonstrated minimal congestion during the course of the project. System changes altered the flow of energy across the grid. New lines, line upgrades, load demand differences and generation availability all made changes to the grid operation in the project area. The point to note is this: DLR can be a responsive tool to resolve a situation that has a time reference of unknown length but likely is shorter rather than longer term (past three to four years). Refer to the variability of congestion in Section 3.11.4.

- The CAT-1 system requires an accurate real-time data feed of the line current in each CAT-1 location. Without this data, the algorithm cannot be accurately referenced to the line's state. This situation arose on several of the 138 kV lines where some of the substation terminals were owned by neighboring utilities and not Oncor. The access to the real-time data is not timely enough to satisfy the algorithm needs. In another case, there are several unmetered taps off of the transmission line, which prevents access to the accurate load flow in adjacent line sections. The takeaway is that an incorporated line-current sensing device or additional line metering is needed to completely utilize the DLR capability.

- The timeliness of deployment and bringing a DLR system online is important. In response to a previous note, the identification of a congestion issue and its life span makes response time of a DLR deployment critical. Deployment, calibration and validation of the DLR rating need to be achieved in a timely manner so that data can go online more quickly.

- Control room acceptance of DLR data and the operators' decision to apply the data remains a critical issue. The system operators' responsibility is reliability. Reducing congestion is not high on their critical list. Applying DLR, in their viewpoint, takes some of their working buffer away from them and uses it in actual operation. It is imperative that when data goes to the control room it is reliable and accurate. It is critical that no false steps of go-live and then pulling it back are taken. Confidence erosion is damaging if not fatal to DLR deployment success.

- Quantifying the benefits of DLR to mitigating congestion will be difficult to compute directly in most cases. Congestion is identified in real time during the operation of the grid by the system operator,

typically an ISO using State Estimator and grid optimization modeling, e.g., Security-Constrained Economic Dispatch (SCED) at ERCOT. SCED does not have the ability to be run with and without a DLR rating in place of the traditional rating. Without that ability you cannot specifically quantify the difference in operations. You are able to see what the increase in capacity was from applying DLR but it is uncertain the specific impact on congestion. As this project showed by performing what-if scenarios using the Day-Ahead Model, congestion relief is possible with DLR and its range of impact measurable.

- As-built characteristics of the transmission line can be significantly different from the construction plan. Actual structure locations, structure framing, ground-line profile and the exact stringing parameters of the conductor when it is tensioned and clipped-in all impact the true catenary characteristics of the conductor. The most important aspect of this characterization is the direct association of the sag-tension-temperature correlation of the conductor. This relationship is set at stringing. Generally it is only modeled by computer, whether using the original design layout by template or computer tool like PLS-CADD or after construction with technology like Lidar. The assignment of the conductor temperature to a specific sag and tension is critical to all modeling and monitoring of the conductor behavior.

4. SGDP DLR Project Conclusions

Electric transmission lines deliver electric energy generated at power plants – coal-fired, gas-fired, solar, wind energy, hydroelectric, bio fuel, nuclear, etc., – to the consumer safely with high reliability, high availability and at optimum cost. The infrastructure that has been built to serve this function is designed to carry the power at different voltages through conductors supported in the air on structures. To maintain safe operating conditions for reliability and public safety, the transmission lines are required to maintain a minimum clearance to the ground and from other objects. Typically this clearance is based on a worst case combination of high operating load, i.e., maximum power flow on the conductor, and constricting ambient conditions, i.e., high ambient temperature, full sun on the conductor and minimal wind. These extreme conditions create a constraint that limits the amount of power a transmission line can carry. Since the criteria are worst case, there is additional capacity in the conductor that could be utilized if the transmission operator knows what the current conductor state is and what the ambient conditions along the line are in real time. Unfortunately, the conductor performance is constrained because the conductor is so sensitive to the wind speed blowing by it, and the wind speed is so variable along the extent of the transmission line, that it is not possible to model the performance in real time without having real-time temperature, solar and wind levels along with the current state of the transmission line.

This constraint limits the capacity of a transmission line and has several economic and operating impacts on the electric power industry. Transmission constraints create the need for upgrading existing transmission lines and adding more lines to address load growth and the changes in power generation associated with many economic drivers, including the desire to increase renewable energy resources. Transmission constraints also limit the optimum operation of the electric grid, preventing optimum-cost power to be efficiently delivered at all demand sites; this constraint is known as congestion, and it has an economic impact on the consumer.

If the real-time ambient conditions and conductor state are known along a transmission line, that information could be used to accurately define the real-time capacity of a given transmission line and enable delivery of that increased capacity. Dynamic Line Rating (DLR) is the technology to provide this correlation of conductor capabilities and the real-time environment. The SGDP Project was completed to:

- Demonstrate that DLR technology is mature and reliable.
- Demonstrate the economic benefits and costs of deploying DLR systems.
- Demonstrate that DLR can reliably interoperate with a utility Energy Management System (EMS).

The SGDP Project installed 46 tension-monitoring devices on eight transmission lines in a corridor in Central Texas. The real-time data, conductor tension, ambient temperature and net impact of solar radiation on the conductor were transmitted by radio to eight substations. At the substations, the data was introduced to the utility Supervisory Control and Data Acquisition (SCADA) system, and then forwarded to the EMS where the dynamic ratings were calculated for each transmission line. Quality

validation was performed before posting the real-time ratings to the Oncor telemetry stream that is used in-house and at ERCOT (Electric Reliability Council of Texas). Both Oncor and ERCOT used the real-time dynamic ratings in system modeling tools to operate the transmission grid reliably and economically.

Introduction of the real-time ratings into the data telemetry being used to operate the system is a unique worldwide breakthrough for DLR technology delivered by the SGDP. The "streaming" data requires no operator monitoring or decision-making before it is applied transparently to the real-time grid. In the past, if real-time ratings were applied, an operator would have to toggle a computer display to access the ratings and make a decision on whether to apply a rating for operating a line. The SGDP Project took that task and automated it, making the system more efficient and available for economic benefits. To differentiate this automated rating technology from past DLR system applications, the technology is being referred to as **integrated Dynamic Line Ratings** (iDLR) to reflect that the ratings being applied are due directly to the real-time monitoring of the conductor performance.

The success in deploying the iDLR system to a section of the Oncor system, incorporating the real-time data stream into the operating telemetry, and making it available to ERCOT for nodal operations demonstrates the maturity of the technology and its interoperability with broader systems. A Cybersecurity assessment of the iDLR technology was performed to test its vulnerability to a broad spectrum of attacks. Recommendations for additional security measures to maintain changing compliance needs were identified and forwarded to the vendors to improve future systems. The risk assessment identified different ways the system might be tested and prioritized the risk and potential for attack.

One of the aspects of DLR technology currently available on the market is that each system is unique, measuring different parameters of the transmission line and deriving a dynamic rating. Each has unique interfaces to measure line state, report data, collect and visualize the data. DLR technologies are not a commodity market product where different components are plug and play or interchangeable between vendors. So the interoperability of various systems is different yet conformable to be adapted to provide equivalent information to a user for the same function. The Cybersecurity and Interoperability aspects of the project demonstrated that while different paths and technologies are applied, all can develop the appropriate ratings information and provide a system that can be incorporated into any utility operations.

From an economics assessment, there were two primary application objectives of the SGDP Project: First, there is wide interest in using DLR to mitigate congestion on transmission lines. Transmission congestion accrues extremely large charges that must be paid in the course of generating, delivering and using electricity. For example, congestion on the Oncor transmission lines in 2011 and 2012 cost more than $148,000,000 and $197,000,000, respectively. Similar impacts are experienced across the industry.

With such financial impact, it would be expected that the source of these charges, i.e., identifying the specific lines that cause congestion, would be easy. The SGDP studies on the economics associated with mitigating congestion identified the following key points:

- Congestion is widely variable, sporadic and always changing. Many more lines contribute significantly to congestion than expected. The movement of congestion from line to line is dependent on the grid topology and market influences.
- N-1 contingency resolution governs system operations and planning project development. So in many cases, transmission lines are not that heavily loaded with current in real time, yet they are considered congested because they must be able to carry the load for one or more anticipated contingencies.
- Annual, seasonal and market influences change the congestion patterns.
- For the actual data analyzed, outages drive only 25% of the congestion events/costs while the market drives the remaining 75%. The previous expectation was that outages were the drivers, especially when the variability was observed.
- Congestion constraints and their impacts on a transmission line can be effectively mitigated with DLR. It is hard for a transmission provider to determine which lines are good candidates for mitigation since congestion depends on many operating and market parameters that are not part of the transmission providers' responsibilities. Most lines are not consistently congested. They might be congested for a couple of weeks, and then grid topology or operations change and the transmission flows will be different, resulting in little or no congestion.
- Minimum changes in capacity available through DLR can have dramatic impact on congestion if the DLR monitoring is installed on the appropriate lines. In our analysis of congestion mitigation, 5% additional capacity could relieve congestion by up to 60% on the target lines with DLR installed, while 10% additional capacity would practically eliminate all congestion on the target lines.

The second economic benefit of DLR is focused on the planning process and funding of transmission projects where DLR enables a least regrets capital strategy, which minimizes any potential loss of investment value due to future volatility of the need or benefit of the solution to the grid. The SGDP demonstrated that DLR is a valuable tool to be applied during project identification and solution development. DLR offers very competitive solutions for projects in the planning queue that require a few percent up to 10 to 15% increased capacity. There are many projects of this type in the queue every year. Since all lines must be able to support one to multiple N-1 contingencies, there are frequently cases where the base-loading of a line plus the N-1 contingency load exceed the line rating capacity by a few percent. These cases may stay at this level for several years or loading may grow. Generally these lines do not make the need-cost-benefit test to become funded during the budget cycle. Projects that do have load growth in the area may ultimately clear the threshold and become funded. Other projects may drop off the queue when some other grid topology changes and the load is addressed by some other solution or system change. When projects do not clear the threshold for funding, the marginal overloads are dealt with in real time by System Operations to maintain no violations for N-1 contingencies. This leads to non-economic dispatch and line congestion costs.

DLR can address many of these cases by providing the needed capacity through real-time monitoring and calculation of the true dynamic rating of the line. Using iDLR, the data flows directly to operations and the capacity is available for operations and mitigation of N-1 contingency issues. iDLR also provides

increased Wide Area System Awareness (WASA) through its real-time monitoring capabilities and introducing actual line parameters into the operating environment. As System Operations performs its security/reliability and economic dispatch analyses on regular time intervals (several times an hour), the system is constantly monitoring and adjusting to maintain reliable operation at optimal cost.

The SGDP Project demonstrated that DLR can meet the objectives outlined in the development of the project scope and objectives. The project also validated that taking snapshots of line performance and trying to expand that characterization to a broader set of lines and a time frame longer than the monitoring period is not prudent. From a ratings perspective, the project showed that every line section, i.e., each section of line with a monitoring device, had different behavior than the rest of the system. The difference was identified sample to sample, i.e., every 10 minutes, daily, monthly and on an annual basis; the difference was stringing section to stringing section and line to line even though the lines were of similar age, conductor and construction. Continuous monitoring and applying the dynamic ratings using iDLR technology is necessary to achieve the benefits from WASA and the increased capacity the DLR technology identifies.

There are two challenges, however, that many utilities will experience in assessing the deployment of DLR for their transmission grid.

The biggest challenge is verifying the actual real-time financial benefits of DLR. The capacity gained can be quantified, the reliability of the technology and instrumentation measured, but the economic benefit is more difficult to assess, especially related to congestion mitigation. During day-of operations, the streamed DLR capacity is automatically integrated into the ISO's State Estimator and load dispatch program and the capacity is applied and utilized. But, there is presently no capability to perform real-time "what-if" scenarios of economic benefit with and without DLR.

Transmission line congestion is so volatile and transient that it is difficult to compare today's operations with yesterday's or last year's, etc. The SGDP Project showed that congestion makes it difficult to predict grid behavior for real-time assessment of benefits. The project was able to approximate the with-DLR and without-DLR scenarios by running comparative models in the Day-Ahead Market (DAM) analysis with the assistance of ERCOT, our ISO.

The secondary challenge will be verifying the actual DLR financial benefits to the transmission owner. The standard return on equity (ROE) for a DLR investment could be minimal since the reduction in congestion cost is not directly shared by the transmission company. If DLR is used to solve a capacity problem when needed, the benefit is difficult to quantify if the only avenue for cost recovery is through a rate proceeding. Of course, deferred capital investment can be calculated if DLR serves for that solution.

In addition, if a transmission owner is not collecting its full allowed ROE due to reasons such as regulatory lag[14] or unanticipated derates; DLR can provide an avenue to restore the missing ROE. Finally, FERC recently contemplated the use of DLR as a consideration for incentive ROEs.[15]

The next area that DLR needs to progress toward is deployment across more lines and the analyzing of historical line performance characterization that can be created from the DLR data in order to improve forecast capabilities. The future might be 15 minutes up to one or several days. Capacity forecasting will enable all market participants from generation to wholesale/retail-qualified providers and transmission companies to better operate the system and make it more efficient, reliable and economic. The SGDP Project investigated this area through its Day-Ahead Forecast and Persistence work. The persistence window of 15 to 60 minutes is potentially usable in an hour-ahead reliability unit commitment process, allowing the operator to address any unexpected, near-real-time events. Additional cost savings could be realized if transmission capacity could be predicted with reasonable accuracy on the day-ahead unit commitment process, or 12 to 48 hours in advance.

The processes have been identified to address these areas. Processing data for additional lines and DLR applications will help frame these technologies and move the industry forward to providing enhanced capabilities in capacity forecasting.

In the years since commencement of the SGDP study, a new capacity forecasting engine (CFE) has appeared in the marketplace that can extend out to 48 hours the predicted capacity from the persistence window of 15 to 60 minutes. A proof of concept study (separate from this SGDP) using CFE has demonstrated the ability to predict capacity with high accuracy. A natural next step would be to apply CFE principles to further optimize grid dispatch by enabling both day-ahead and real-time markets to utilize the incremental DLR capacity.

The SGDP Project has been a success, demonstrating that Dynamic Line Ratings are a valuable tool to increase the capacity of a transmission line, which will enable transmission providers and system operators to mitigate congestion, increase system reliability and redeploy capital to its most efficient uses through a least regrets strategy.

Additional deployments of iDLR have been made in the Odessa-Midland region of Oncor's service territory. Load growth due to an active application of new technologies in the recovery of petroleum products from long-operating play has created congestion issues and capacity needs. Planning has proceeded with capital expenditures to add lines and reconductor existing lines. Since the lead times for these projects extended beyond the summer 2013 high-load period, the application of CMR as a

[14] EEI, "2012 Financial Highlights," February 6, 2013: "[Regulatory] lag obstructs utilities' ability to earn their allowed return when costs are rising and can ultimately increase their borrowing costs. Electric utilities often fall short of achieving their allowed return due to regulatory lag." DLR can allow a utility to maintain reliability compliance while awaiting rate case approval for new capital investments.

[15] 141 FERC ¶ 61,129, "Promoting Transmission Investment Through Pricing Reform," November 15, 2012, at p. 21

solution for several lines was discussed in January 2013. A decision was made to install iDLR on five additional lines. The approach laid out in the Best Practices Guide was followed and 12 DLR monitors were designated to monitor these five lines. Because the iDLR protocol had already been established as part of the SGDP Project, it was possible to bring the new monitors online by June 17, 2013. Two of the lines on which iDLR was added are listed in the top 10 congestion rent-impacted lines in ERCOT.

Additional lines for iDLR deployment are under assessment based on planning needs and congestion exposure for 2013.

5. Best Practices Guide

As part of the documentation for the project, the following section contains a Best Practices Guide for developing and executing a plan to deploy Conductor-Monitored Ratings (CMR) and the integrated Dynamic Line Rating (iDLR) technology for a transmission system. Combined with the Lessons Learned documentation, the guide will provide future engineering groups a roadmap for picking lines for DLR, developing a deployment plan and incorporating the DLR results in transmission system operations. The need for DLR can be developed with System Planning, System Operations or at the request of an ISO to provide increased capacity on a given line for reliability improvement or congestion relief.

CR not only includes the calculation of a dynamic rating for the line segment considering the ambient temperature, solar radiation and effective wind cooling, but it also includes the automatic incorporation of this data into the transmission grid telemetry passed to the State Estimator performing reliability assessments associated with N-1 contingencies as part of the ISO entomic dispatch of generation and reliability management of the grid.

The best solution is to install an appropriate number of real-time monitors on a given circuit, analyze the data, forecast the available dynamic rating for the next selected time period, e.g., five minutes to one hour, and post the data for System Operations to apply in its standard procedures.

Operations can deploy the DLR in one of two formats. In both cases, real-time monitoring as outlined above is deployed and fed to the system. In option one, the dynamic rating is posted to the desk monitors where the operator can access the data, identify the dynamic rating of the line and decide whether to accept that rating and use it for operations.

The second option is to collect the dynamic rating in real time and feed that automatically into whatever system is managing the system through the periodic runs of the State Estimator, which then uses the results to make operation decisions and dispatch orders. For example, the system deployed in the DOE-ONCOR SGDP streamed the dynamic ratings for eight transmission circuits through utility grid management system and posted it to ERCOT for operations in real time in the Security-Constrained Economic Dispatch (SCED) system that dispatched generation throughout ERCOT to maintain grid reliability at the most economic conditions.

The system has logic built into its EMS that validates the accuracy and authenticity of the DLR before passing it to operations. If there are concerns about the DLR for any reason, the system reverts to the standard rating methodology and sends an alert to a manned desk for assessment and corrective actions. Streaming DLR is now the operating norm for these lines and their incremental capacity is utilized.

There is a secondary benefit of streaming DLR in the form of increased system awareness. By operating on the data automatically, the SCED environment takes advantage of the actual ratings available and adjusts to the rating automatically every SCED system. If anything happens on the lines with DLR equipment, the system is automatically aware of it and adjusts to accommodate that change automatically.

DLR has been available for 20 to 25 years. The DLR vendors have been striving to get streaming DLR into the operating environment. The quasi-real-time versions where DLR numbers are posted on operation consoles was the furthest the technology had advanced until the DOE-Oncor SGDP project. Operations is focused on system availability and system reliability. Streaming data requires full confidence in the DLR equipment. Any question about the DLR system raises concerns on the operator's part; once a system falters, it is almost impossible to go real time again.

The SGDP Project as deployed the past 18 months validates the streaming DLR process and offers System Operations a validated tool to add to its operating environment that is reliable, accurate and full of potential benefits.

Some DLR proponents recommend an installation that is quasi-real-time. They seek to install some DLR equipment and record data for a certain length of time, ranging from a peak season to a year to several loading cycles/seasons. They then analyze the data and establish incremental DLR capacity based on the snapshot of historical data. They may couple their projects with some weather characterization, which may include scaling the rating to a given ambient temperature or some wind speed from a weather station.

This solution has several deficiencies compared to the DLR model proposed here:

- Lead time. This method requires data collection and analysis before a rating can be suggested.
- Quasi-real time. This model removes the user from the actual real-time application and requires some approximation between the current ambient conditions and the model's characterization.
- Loss of WASA. Without the actual real-time aspect of iDLR, the situational awareness of the real-time ratings is lost and the DLR will not be responsive to operating perturbations.

5.1 Selecting Projects for Dynamic Line Rating

DLR is a tool that can be used on any transmission system to increase the capacity of a given transmission circuit, taking advantage of the cooling effect of wind and ambient temperatures to more fully utilize the capacity of conductors already installed on the transmission line.

5.2 Meeting Incremental Load Growth

The need for increased capacity may be created during the course of System Planning's annual process of evaluating load growth and system changes while identifying projects for evaluation and ranking for funding authorization. Frequently, these projects start to show up in constraint analysis when an N-1 contingency creates an overload. These lines show steady increase in loading, and each funding cycle sees a ratcheting up of the overload percentage until the lines reach enough need to pass the threshold to being funded and authorized for capital improvement.

The ratcheting process may be slow and lengthy. In these cases, the priority and need may not create enough return on investment for capital authorization, and a project remains in queue rather than proceed to funding and construction. In some cases, these small percentage overloads may be

associated with other reliability or operating issues that are less quantifiable in financial terms that would allow the project to proceed to funding and construction.

The need may be the result of some new generation source being placed on the grid that requires all or some portion of the capacity of an existing transmission path. While the added capacity is typically higher for this type of project, the closer the generation source is coupled to a given circuit, the more likely an existing circuit is a supporting line or redundant path for N-1 contingencies. Under many of these cases, the contingency constraints may be small percentages of increased capacity above the SLR or AAR rather than significant capacity increase requirements.

Congestion constraints can also be a driving force for creating a need for increased capacity. In many cases, these incremental capacity needs are in the 5 to 10% increase range. As in the case of the planning queue, these projects are difficult to push forward as their justification on financial terms is not easily justified for return on investment.

So there are several scenarios for projects that need some incremental capacity improvement but lack the ROI justification to advance. These projects may be favorable candidates for DLR. DLR offers several advantages that can help solve these issues:

- DLR can reliably provide incremental capacity improvements with high probability of availability at minimum costs per percent increase in capacity compared to traditional solutions of upgrades, rebuilds or additional transmission lines, especially when incremental need is no more than 10-20% additional capacity.
- DLR systems are flexible. If the need for capacity is reduced by a system topology change, the DLR equipment can be removed and installed on another line that needs incremental capacity at that time. This minimizes the investment of capital dollars.
- Lead time for DLR deployment from conception to deployment and operating can be very short, typically months, depending on DLR equipment availability and type of system being deployed. Compare this to lead times for new lines or upgrade projects.
- DLR is very economical with high benefit-to-installed cost ratios.

Line ratings are driven by the current being carried in the conductor, the size and characteristics of the conductor and the ambient conditions that the line is operating in, specifically the ambient temperature of the air, the amount of wind blowing across the conductor and accounting for any solar radiation that adds to heating the conductor. Because a transmission line runs for miles, across a variety of terrains and at different headings, the spatial context of the transmission line causes the dynamic rating of a transmission line to also be extremely spatial in context. The wind and temperature influence on a conductor is constantly variable as the temperature and effective wind speed change with distance along the line and time.

5.3 Solutions for Derated Lines

Another application for DLR may be in resolving issues with lines that were derated as a result of addressing the reporting requirements of the NERC Alert, “Consideration of Actual Field Conditions in

Determination of Facility Ratings." Many utilities identified line sections with clearances where the design and construction of a transmission line did not meet the NESC clearance requirements or where subsequent changes, such as landslides, construction activities, etc., reduced the design clearances. The resolution to regain full line capacity may be obtained by traditional capital investments such as increasing structure heights or rebuilding/reconductoring the line. Many resolutions may require substantial investments or extended lead time to secure additional permissions to complete the modifications, e.g., new easements, permits or outage time.

Some DLR vendors market their products more like an alarm system that notifies the line manager if an operation constraint will be imposed due to a clearance restriction. Such an alarm system requires several steps, including detection, notification, acknowledgment and a corrective action decision.

DLR, on the other hand, mitigates the constraint via an automated WASA that provides System Operations with a quasi-continuous update of the available capacity of the line section. The State Estimator uses the real-time data as efficiently as possible. If a constraint develops due to ambient weather conditions or increased loading in the area or on the line, the DLR maintains system awareness and the EMS automatically adjusts and optimizes the system on a continuing basis. There is no abrupt change in system characteristics that must be addressed. The Static Line Rating remains at the derated level, i.e., maximum operating temperature based on the available line clearance. By installing DLR, the line can be operated at the full available capacity of the line based on real-time operating and ambient conditions.

The key aspect in this application is the continuous stream of data to System Operations and its ability to work an optimum solution for real-time grid conditions. An alarm-type system requires a more drastic response. A iDLR system maintains grid reliability automatically and allows the system to adjust to whatever transfer capacity the real-time parameters allow.

5.4 Operations Implementation

iDLR requires acceptance from System Operations at both the utility and the ISO. Operations must have confidence in the iDLR system to provide accurate ratings with high reliability and availability (minimal interruption of CMR). iDLR must also be inherently simple to apply, intrinsic to the operations model. These criteria are met in the following ways:

Accuracy. The rating model and algorithms must provide accurate assessment of the ambient conditions along a transmission line and their impact. The predicted full capacity of the line must also be accurate so that System Operations' dependence on their value is reliable and an accurate assessment of the line's performance. DLR is the most accurate means of calculating the spatial context of a transmission line's rating. The effective ambient temperature and wind cooling effect of the many spans of the transmission section are incorporated into the characterization of the current status of the line and how increased power transfer will affect the conductor sag and respective clearances.

Reliability. Beyond the accuracy of the calculated rating, the reliability of the system in terms of confidence in the value is critical to acceptance. The iDLR system has a series of sanity checks that address these criteria:

- Rating within acceptable range.
- Sufficient number of monitors available for predicting the line section's performance.
- Cybersecurity concerns addressed from an intrusion or spoofing aspect.

Availability. The dynamic rating system must have a high level of availability and reliability of performance. If there are frequent interruptions to the monitoring system and ratings calculation, System Operations will not be able to depend on having a consistent forecast of the true line capacity.

Minimal impact on operating protocol. The introduction of the CRM system and its real-time operations must not impose additional burden on the staff.

Real-time streaming of DLR within the telemetry and system status data stream achieve these intrinsic characteristics. Operations staff does not have to take additional steps to assess the availability or status of the dynamic rating, as the system has incorporated the DLR in the real-time system status after performing an appropriate level of quality checks. The system automatically reverts to the traditional rating model if any sanity checks performed within the iDLR system determine that the rating is suspect in accuracy or availability. No operator intervention is required.

The DLR may be above the static rating when it is windy or cooler than the static governing temperature (104 °F typically). The DLR may also be less than the static rating when it is a hot day (over 104 °F, 40°C) with no wind.

As part of the standard protocols within the operating environment, a streaming rating incorporated in the transmission telemetry and operated on at the standard nodal protocol economic dispatch and reliability modeling, the iDLR and its impact on the operations are constantly being reviewed, and adjusted for. Most security dispatch modeling is performed on a two-minute to five-minute basis. The typical time constant for transmission class conductors is over 15 minutes. Any changes that occur are melded within the nodal operation protocol.

The increased system awareness from providing real-time monitored conductor characteristics and incorporating that telemetry in nodal operations creates additional reliability and accuracy of the grid operations as the system verifies itself every nodal modeling cycle. By monitoring multiple spans of the transmission line with each iDLR monitor, the spatial context of the transmission line is characterized in the rating system and the transient nature associated with point reference measurements of an ambient temperature, a wind speed or possibly a conductor temperature from a sensor is eliminated.

By using the DLR technology and protocol as applied in the SGDP Project, this model does not require additional training of the operations staff. The protocol is built into the EMS such that the introduction of the real-time dynamic rating is fully transparent. The validity and accuracy logic checks built into the EMS provide alerts to a specific operations desk, which is informed if there is an issue with any

component of the iDLR system from communications to accuracy and Cybersecurity issues detected. The notified desk has a protocol that directs it in how to address the alarm and resolve any issues.

The EMS reverts the rating to the traditional rating system, typically a static rating or an ambient-adjusted temperature rating. The nodal protocol continues to operate and uses that rating for the next economic dispatch and reliability nodal assessment; no operations intervention or decision-making is required. When the alert is cleared, the DLR is reintroduced to the operations telemetry.

5.5 Technology Selection

Several alternative DLR technologies are available in the marketplace. The biggest factor in selecting a technology is the realization that a transmission line is defined by its spatial context in regards to the area it traverses and the ambient environment conditions it is exposed to. The spatial context and behavior of the conductor, insulator systems and structures responding to all of the external influences that affect the dynamic rating performance of the system require a spatially sensitive monitoring system.

Some of the DLR technologies are point-monitoring devices, e.g., temperature sensors that measure the conductor temperature at one point on the wire. These are divided into contact sensors and non-contact devices. Unfortunately, they have no spatial context and can only reflect the performance of the wire over a very limited length, perhaps one foot. Even applying multiple devices along the line gives very limited spatial context of the line's behavior.

The determination of the conductor position via tension monitoring or by monitoring the sag/clearance distances characterizes the spatial aspect of the conductor and the supporting structural systems on a transmission line.

Several position-monitoring devices are currently offered for DLR and more are in development. The SGDP Project used three of the systems for the collection of data to be used in validating the spatial aspect of the DLR monitoring systems described in the next section.

The Avistar, Inc. Sagometer® monitors the sag of a span by automatically determining the movement of a target attached to the conductor within the plane of view of a camera attached to one of the transmission structures. Through catenary mathematics the position of the target is interpolated to the point of interest, e.g., the low point of sag, the sag at a minimum clearance location on the span, etc. The data can be stored within the device or collected via external communications. http://www.edmlink.com/line-rating.html

Promethean Devices' Real-Time - Transmission Line Monitoring System (RT-TLMS) monitors the magnetic field around a conductor. The field strength is proportionate to the level of current flowing through the line and distance from the conductor. The magnetic field strength degradation is proportionate to the distance squared. By monitoring the phase currents of a transmission line and performing calculations of the installation geometry, the conductor position, i.e., clearance to the sensors/ground can be monitored. http://www.prometheandevices.com/

The Sagometer and Promethean RT-TLMS systems were deployed on the project to collect positional data to be used in the technology validation tasks.

Other types of monitoring equipment are deployed with direct attachment to the conductor at prescribed locations on the span. Many use the slope of the conductor, measured by an inclinometer within the device attached to the conductor to characterize the catenary curve and revert back to the conductor positional algorithms.

Other systems measure the natural frequency of the conductor to characterize its catenary curve, similar to the tension on a guitar string and its frequency. A number of the devices also include telemetry to measure the conductor temperature, the distance to the ground using Lidar and ambient conditions. Equipment in this category includes but is not limited to (additional systems are under development worldwide):

- Ampacimon – Ampacimon Monitor: http://www.ampacimon.com/
- Lindsey Manufacturing – TLM Device: http://www.lindsey-usa.com/

5.6 DLR System Design/Layout

Once the target lines are identified for DLR, the layout of the DLR monitors and selection of technologies can proceed.

The spatial context of a transmission line as outlined previously requires the installation of DLR equipment that can monitor the conductor behavior of a stringing section, not a point characterization or a system of multi-point monitoring. The SGDP Project used three systems that monitor the tension or the position of the conductor in real time and calculate the dynamic rating for that section of the line of tangent-suspension spans in the stringing section where the DLR monitor resides. The rating of the line is the minimum rating of the monitors installed along the length of the line.

DLR is influenced most by the wind speed blowing past the conductor. The closer the incident angle of the wind is to the perpendicular to the conductor, the greater its impact on the line rating. So line orientation is critical to deployment design. Change in line orientation greater than 15 degrees to the next section constitutes a different section of line that may need monitoring. Sheltering from ground cover or terrain can also have a big influence on the wind effect on the conductor temperature. So transmission line alignment is the first order of assessment for locating sensors.

The deadend structures at the end of line sections with different orientation are primary candidates for DLR installations monitoring tension. If the line angle is moderate, the structure may use a side-tension construction. When the orientation changes by 15 degrees or more, it is recommended that this creates two line sections. One of the phases could be modified to a deadend configuration for installation of a tension-monitoring device. If sag/clearance monitoring technology is applied, these locations define the endpoints of sections that define separate monitoring requirements.

Additional DLR locations are dependent on defining the actual ruling span breakdown of the line. Changes in ruling span lengths of various line sections are also subsets that may need independent

monitoring from other sections. While the line designer did not install deadend structures between these ruling span sections, the DLR system depends on the equalization of the conductor horizontal tension over many spans, i.e., insulator swing. Physics dictates that the spans reach that equilibrium based on span lengths and attachment heights, developing their own “as-built” ruling spans. DLR wants to acknowledge when these ruling spans have significant difference such that the equalization due to insulator swing in the spans would be different section by section.

Once the stringing sections are identified, the overall lengths of the different sections are reviewed for how long a distance each monitoring site might have to cover. The project identified very consistent characterization of the stringing section when the DLR monitors were as far as five miles apart and the terrain was no more than rolling hills. The long stringing sections should be evaluated for length and changes in sheltering of the line, such that a sufficient number of monitors are placed to address each of the changes and maintain the “reach” of each monitor at a reasonable length.

If the positional or in-span monitors are being applied, they can be spaced at appropriate locations to monitor each of these sections of line identified. In the case of the tension-monitoring systems, if the length of a stringing section becomes so long that intermediate monitors are needed in a tangent suspension length of line, conversion of one or more structures from tangent to deadend may be required. Some applications of floating deadends have been applied where a deadend was not available. It is preferred, however, to have a full deadend structure. Perhaps a running angle could be converted efficiently.

Running angles up to 15 to 18 degrees typically can be considered part of a stringing section. Above that angle, the wire tension on the angle makes insulator swing and therefore horizontal tension equilibrium difficult to achieve past that structure. The larger angles will define changes in stringing sections and thus a section break in defining the ratings of the line.

Braced-post and horizontal lineposts do not provide for as much longitudinal displacement as a suspension insulator string to effectively create horizontal tension equilibrium. Discussions should be held with DLR vendors on their experience in dealing with this type of transmission framing and their system’s response. In some cases, enough longitudinal flexibility is provided to create a long stringing section. In other cases, the flexibility will be limited and additional monitoring locations required.

With these considerations, a sufficient number of monitoring sites should be identified. It is a goal to minimize the number of instrument deployments, but it’s also necessary to capture each subsection characterization, where a different horizontal equilibrium and thus effective DLR would characterize the line performance.

Some DLR proponents use the critical span focus for deploying instrumentation. They analyze the line for those spans with minimal clearance and start the deployment at these locations. Perhaps that is the only location they monitor because it is the critical span.

Unfortunately, the critical span is only the critical span for a specific set of operating and environmental parameters. Mother Nature is far too unpredictable to say the span is "*the* span". A properly deployed DLR system monitors the full length of the transmission line.

There is delineation in application between an installation of equipment to generate reliable accurate dynamic ratings and an alert system that is basically monitoring the condition of a line to avoid a clearance restriction. DLR is intended to monitor the transmission line's operational performance and as-built capabilities in real time. To focus on a few point sources of data for a multi-mile transmission line and its spatial context does not provide an accurate definition of the line's capacity in real time. That is why a thoroughly designed deployment plan is required.

As the real-time data is accumulated for each monitor along a transmission line, the ratings for each section are calculated and checked for reasonable values. For the transmission line section, the minimum rating calculated based on the data collected is applied for the entire section as its limiting element value. This rating is then passed to Operations.

5.7 Interoperability and Cybersecurity

The accumulation and security of the real-time data is dependent on the technology used for DLR and the transmission operations and IT environment.

Certain DLR technologies use communication technology to send their ratings to local accumulators at the local substation where it is inserted into the SCADA system through an RTU. Once in SCADA the data is brought to System Operations for processing, quality and integrity checks and introduction to real-time operations.

Other DLR technologies are based on cellular communication. This may require a dedicated server at the transmission office where the DLR processing and quality checks are performed and then the data is introduced to the operating environment. Some utility IT and CyberSecurity requirements may require the server outside the firewall first and then introduced to System Operations. Other utilities may allow the raw data to come across the firewall.

The point is that the utility must coordinate with the DLR technology vendor for the specific protocol to bring the data into System Operations purview. All of the systems will have some form similar to that depicted in Figure 81. One vendor or more may be involved in the remote monitoring systems on the transmission line and then parallel paths transcend to the juncture with the EMS, which coordinates the introduction of the ratings into the system telemetry.

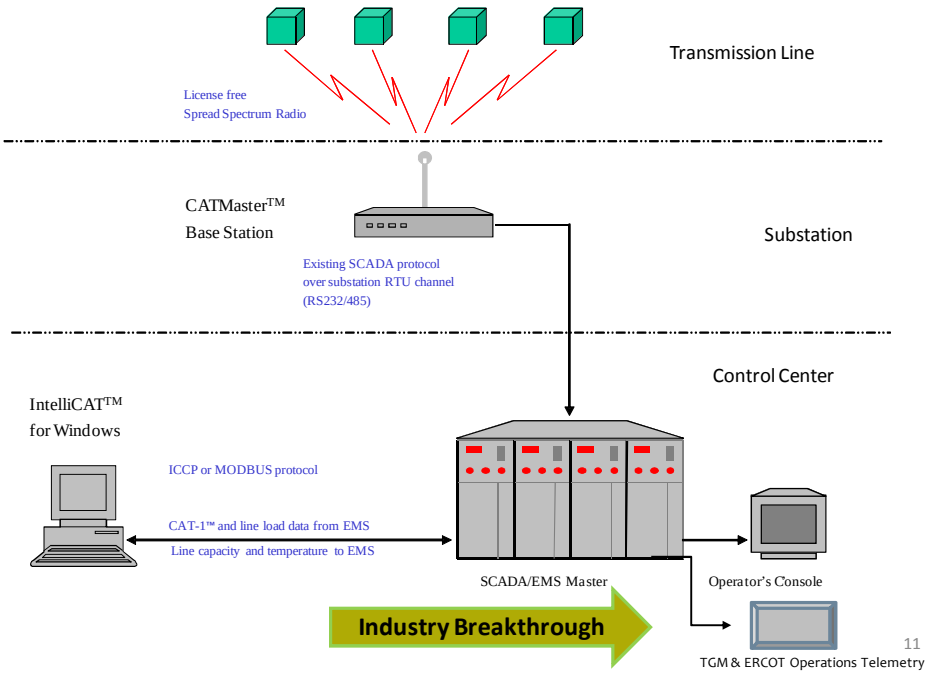

Figure 81 - Interoperability of iDLR Installation

Interoperability of the DLR systems defines their ability to perform certain functions remotely and independently of the utility IT environment while transparently interfacing with the utility EMS environment. The vendors of DLR equipment communicate across this interface in a number of ways, and it is important that the utility and vendor have an open commitment to bridge the gap. It is in the vendors' interest to be accommodating of the network and protocols used by the utility, and the utility needs to work with the vendor to make the communication as efficient and reliable as possible.

DLR is not a commodity market where multiple vendors make interchangeable components that can interface seamlessly into the application. For example, DLR hardware and technology is not equivalent to a compression deadend used in an insulator assembly. The components are made by several vendors and are basically identical in form and function. DLR technologies are not interchangeable from a hardware perspective, but they need to be from a communications and interoperability standpoint to the utility EMS environment.

Cybersecurity (CS) is a life cycle commitment for DLR technology that must begin with vendor approval and be carried through deployment and updating to stay within compliance.

Procurement of DLR equipment must require the vendor to address CS at the equipment level as well all subsystems that may be incorporated into the system. CS addresses intrusion protection on-site, in the communications paths and links, data manipulation and at the hardware level.

CS shall address the protection of the equipment in the field such that any attempts to break into the equipment and associated facilities are identified, logged and communicated to a system awareness location. CS shall be designed to identify if there is any intrusion in the data communications path

between remote data acquisition site and the eventual data delivery point at the utility. Surveillance and alarms shall be applied for intrusions in the data path where market participants or the environment in general attempt to alter, append, replace, etc. the DLR data collection, transmission and processing.

The CS concerns shall be from equipment conception through development, installation, operations and maintenance for the life cycle of the instrumentation. System modifications and updates shall be made to ensure the DLR system is current with the technology environment.

5.8 Next Limiting Element

The transmission line is not the only element that can constrain the capacity of a line. Switches, circuit breakers, wave traps and transformers on equipment all have ratings that cannot be exceeded in terms of real loading and for N-1 contingency. Once a line has been selected for DLR, all of the elements on the path or monitoring the load flow on the path must be checked to ensure that their rating exceeds the anticipated increase in capacity being gained by the DLR equipment.

Some utilities use adjustable ratings on these elements similar to the adjustment they are making on their lines. A line that is being rated with temperature-based adjusted ratings typically may have its associated equipment ratings adjusted for ambient temperature. Some utilities adjust the lines and not the terminal equipment.

In designing a DLR deployment, the associated equipment ratings must also be considered. The lowest rating assigned to the line section or the equipment dictates that line's rating.

Another area that requires review is relay settings. If the allowable ratings change is over a range broader than the relay settings are governing, they must also be addressed to accommodate whatever range is allowed with the DLR. One way to manage this is to cap the maximum ratings increase allowed with DLR at 125% or another value of the Static Rating. This contains the ratings swing and makes settings tasks easier.

When these elements are identified for upgrading, they need to be coordinated with the DLR deployment so they also have the appropriate ratings range to accommodate the conductor rating's adjustment and are completed prior to going live with the DLR equipment.

5.9 Going Live

Once the equipment is installed, individual technologies have their own specific calibration needs. The calibration process is required to associate the measured quantity, whether tension, sag or clearance, with the equivalent conductor temperature of the monitored line section. Line ratings are dependent on an accurate correlation of the measured quantity to the equivalent conductor temperature and the four variables that drive the thermal performance of the conductor, i.e., the current flowing in the line (amps), the ambient temperature (°C or °F), the solar absorption of the conductor and the effective wind speed (fps). Knowing these parameters allows the calculation of the maximum operating temperature associated with the clearance constraint of the line design.

The calibration process defines the "as-built" sag-tension-temperature characteristics of the ruling span section and thus its thermal behavior. As mentioned, each technology and vendor has a calibration process that needs to be followed to set the forecasting product of DLR. Many require a line outage of several hours longer than the conductor size's time constant.

5.10 Example Project

As a template, the following installation of tension-monitoring DLR can show how a system is designed and deployed.

Line identification. System Planning selected five lines for dynamic ratings.

Determine number and location of monitors. For each line, the plan and profile or section maps are reviewed for a breakdown of the line topography searching for tangent sections that run in the same direction. The sections are compared for length, compass bearing, topography and terrain. Any wire size changes, different stringing sections and configurations are identified. Many lines have all identical characteristics except compass bearing of several line sections. For those sections with the same bearing, the need to monitor each is dependent on the distance between them and any terrain changes.

The primary consideration for laying out the monitor locations is how different can the effective wind be on each section of conductor. If their orientation or distance from each other or sheltering differs, they need monitoring. The focus is the minimum "maximum dynamic rating" for the line. If one section can be different from another, the DLR must be designed to capture that difference.

From the SGDP Project, it has been shown that monitoring devices on a stringing section have a "reach" of several miles, say five, and that their accuracy in predicting the conductor temperature can be 1 to 2 °C in that same reach.

If these patterns are followed, no additional monitors are needed. The prescribed monitors will provide sufficient redundancy to accurately characterize the line's dynamic rating.

Once the monitor locations are chosen, then the means of communicating the information back to the EMS facilities must be identified, the protocol set to assess the validity of the data, and the assignment of the lines' DLR executed. As an example, if the remote systems require a line-of-sight radio system to bring the data to the EMS, an evaluation of practical RTU sites for interfacing with the remotes must be considered. This involves determining if the RTU capabilities match the interoperability requirements of the DLR equipment, whether the line-of-sight radio paths require repeater stations, etc.

If a cellular retrieval system is used, then the proper equipment and software at the firewall to the EMS must be established to meet the utility IT and CS requirements.

In either case, the remote data is brought inside the firewall at some point where the data is evaluated for compliance with acceptable ranges, validity and ratings calculated. The prescribed DLR is then posted to the system's real-time status telemetry and applied in all operations tasks.

5.11 Lessons Learned

The lessons learned during the DOE SGDP in Appendix I comprise a quick checklist that addresses a variety of deployment issues that may or may not arise for any given project.

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APPENDIX A. CAPACITY RELEASED

Quantify the Capacity Released Over Current Ambient-Only Temperature Dynamic Approach

1. Preface

The following is essential to understanding the subsequent sections about the SGDP Project's results and benefits.

Transmission lines are designed to operate at a maximum safe conductor temperature to ensure that the energized conductor does not sag dangerously close to the public and also to protect the integrity of the conductor itself. The rating of a transmission line is defined as the amount of current that can be carried by a conductor without exceeding its maximum safe temperature. There are several recognized methods for determining the relationship between the current passing through a conductor, the weather conditions surrounding the conductor, and the conductor's temperature (example: IEEE Standard 738-2006 for Calculating the Current-Temperature of Bare Overhead Conductors). Each of these methods looks at a thermodynamic heat balance driven by:

1. The ambient air temperature surrounding the conductor (the "starting temperature").
2. Heat added to the conductor by electrical current passing through it.
3. Heat added to the conductor by solar radiation impinging on it.
4. Heat removed from the conductor by natural radiation or by convection (wind).

This study compares the amount of current that can be safely carried by a transmission line under two rating methods: Ambient-Adjusted Rating (AAR) and Dynamic Line Rating (DLR).

Ambient-Adjusted Ratings vary only with the monitored ambient air temperature surrounding the conductor. Wind and solar radiation are assumed to be unchanging over all ambient temperature ranges. For safety and the economic life of the conductor, the worst case weather conditions expected during the year are assigned to all ambient temperatures, namely full mid-summer sun to heat the conductor and low wind speeds to cool the conductor.

Dynamic Line Ratings vary with the monitored ambient air temperature, monitored solar radiation and monitored wind. Monitoring all three weather parameters has the advantage of generally higher ratings (more safely released capacity) since actual weather conditions are generally more favorable than the assumed worst case solar and wind assumptions associated with Ambient-Adjusted Ratings.

It is to be noted that most utilities use what are called Static Line Ratings (SLR). Static Line Ratings are typically more conservative than Ambient-Adjusted Ratings because they are based on assumed worst case conditions of ambient temperature, solar radiation, wind speed and direction. Hence, for utilities using Static Ratings, the capacity gains over SLR will be substantially higher on average than the capacity gains over AAR which are presented in this report.

2. Scope

The initial scope of this study included (1) distilling large amounts of raw AAR and DLR data into formats conducive to practical use by other studies, and (2) quantifying the capacity gained by using the DLR method versus the AAR method.

A comparison of the Dynamic Line Rating capacity and that of the existing Ambient-Adjusted Rating was performed for each month for each transmission line segment at two-minute intervals. The purpose of the comparison identifies the added benefit of Dynamic Line Rating technology beyond what is provided by Ambient-Adjusted Ratings. To visualize the benefit, the data was processed into the following charts:

- Chart of the Dynamic Line Rating and the Ambient-Adjusted Rating on a monthly basis as a timeline.
- Chart of the difference between the Dynamic Line Rating and the Ambient-Adjusted Rating on a monthly basis as a percent of time probability distribution.
- Chart of the Dynamic Line Rating and the Ambient-Adjusted Rating on a monthly basis as a daily distribution.

Additional data sets and charts were also produced to support other studies performed by Oncor and SwRI within the scope of the demonstration project.

In reviewing results at a final draft report meeting in December 2012, the ONCOR team wanted to know the capacity released by Net Radiation Temperature (NRT)-based ratings over Ambient-Adjusted Ratings since NRT-based ratings were occurring on average 21% to 70% of the time as a result of loads at 20% or less of the Static Line Rating. The scope was revised to include cumulative probability distributions of NRT-based ratings and Ambient-Adjusted Ratings for each segment for each month of the study.

The scope was also revised to include 15-minute transient dynamic ratings commonly referred to as Short Term Emergency (STE) ratings.

Reports containing processed data and charts were posted to an FTP site the second Friday of each month.

3. Task Execution

At the end of each month, log files containing all segment ratings for the month were extracted from the ICW Dynamic Line Rating computer located in Oncor's Transmission Management System's control center.

A Visual Basic (VB.NET) program was developed to extract raw data from the log files, perform comparison calculations as needed, organize data and results into time stamped Excel files, and generate the charts described in the task scope above.

Reports containing processed data and charts were posted to an FTP site the second Friday of each month.

As each month's data became available, it was examined for anomalies. Identified anomalies were

investigated and traced to their root causes.

Identified data anomalies, their root cause, and the impact on task results:

- The instruments that monitor the transmission conductor are installed at deadend towers. Since standard full deadend towers were not located where needed on some transmission lines, floating deadend towers were created to accomplish the mission. Because the floating deadend towers constituted a new installation technique for DLR, unforeseen corona damage occurred to the instruments located at the floating deadend towers. This damage corrupted the data collected prior to August 2011 when the corona problem was remediated.

  Impact on task results: All data prior to repair of the sensors was discarded, resulting in 17 rather than the anticipated 24 months of collected data.

- Generally low load levels on all segments prevented the calculation of a true DLR based on all three rating elements of wind, solar and ambient temperature approximately 21% to 70% of the time. All DLR technologies that utilize the transmission conductor to capture the spatial variability of wind require a temperature rise on the conductor in order to perform a heat balance calculation from which the true average effective wind speed can be calculated. The threshold temperature rise for that calculation occurs at approximately 20% of the line's static rating. When loads fell below the 20% threshold, a variant of DLR, referred to as a Net Radiation Temperature (NRT)-adjusted rating, was calculated; the NRT rating was entered as the DLR rating in the logs and databases. An NRT-adjusted DLR is based on actual ambient temperature, actual solar radiation and an assumed low wind speed consistent with IEEE/CIGRÉ guidelines.

  Impact on task results: NRT-based ratings are generally higher than AAR but lower than a full DLR. The widespread application of NRT ratings necessitated by widespread low load conditions significantly depressed the statistics on DLR gain above AAR.

- SCADA RTU outages occurred, which prevented the transmission line monitor data from reaching the EMS. During these outages, the Dynamic Line Rating associated with the affected monitors was defaulted to the Static Line Rating. SLRs are consistently lower than AARs.

  Impact on task results: SCADA RTU outages depressed the statistics on DLR gain above AAR.

- Lack of substation metering necessitated calculating load levels on many of the 138 kV segments. The calculated load values were subsequently identified as being erroneously low. Invalid load input to the rating algorithm results in artificially low calculated effective winds and correspondingly low ratings. Invalid load metering occurred on five of the 138 kV segments. The following line sections were significantly impacted: Waco Atco-Cottonbelt Tap, Cottonbelt Tap-Spring Valley Tap, Spring Valley Tap-McGregor Phillips Tap, Salado-Sonterra and Jarrell East-Gabriel.

  Impact on task results: Line loads reported as erroneously low depressed the statistics on DLR gain above AAR.

- Shadowing of NRS sensors at some installation sites resulted in calculation of abnormally low effective wind speeds. This also led to artificially low ratings. Field correction of the four worst shadowing sites was completed in April 2012. Refer to the appendices for a list of the segments and CAT-1 locations most impacted by shadowing.

  Impact on task results: Shadowing of NRS sensors depressed the statistics on DLR gain above AAR.

- Extended line outages on certain segments prevented calculation of ratings. During these outage periods ratings were defaulted to the Static Line Ratings (SLR). SLR is consistently lower than AAR.

  Impact on task results: Extended line outages depressed the statistics on DLR gain above AAR.

4. Results

Figures A-1 through A-3 are examples of the charts produced for each line segment for each month. Charts shown in the figures are for Temple Pecan Creek-Temple Switch (345 kV segment) during September 2011.

Because September 2011 was relatively warm and had moderately elevated loads, it was chosen as a month representative of a moderately loaded circuit during summer. The maximum ambient temperature was 104 ^{o}F (40.1 ^{o}C) with the average temperature being 83 ^{o}F (28.4 ^{o}C). Forty-four percent of the month's ambient temperatures were above 86 ^{o}F (30 ^{o}C).

How the time series of ratings were developed:

1. Data was recorded every two minutes (30 ratings per hour).
2. The rating for each two-minute interval was plotted.

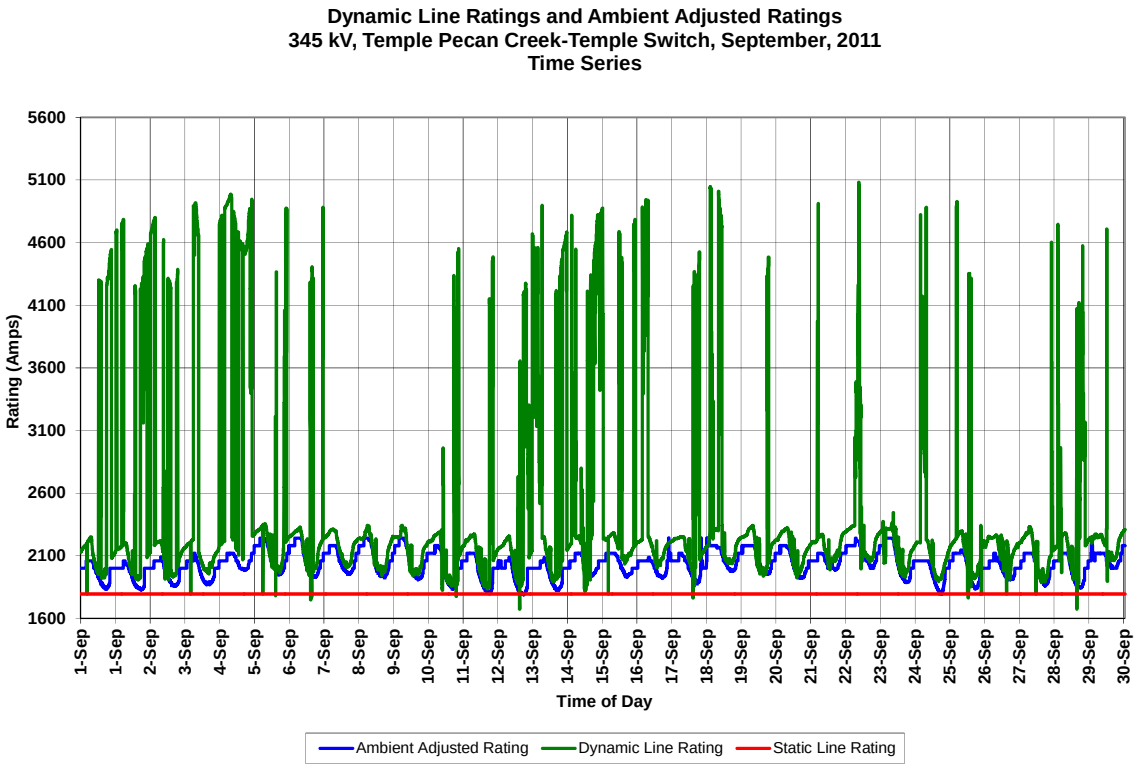

Figure A-1: Time series showing Ambient-Adjusted (AAR) and Dynamic Line Rating (DLR). The example is for Temple Pecan Creek-Temple Switch (345 kV) during September 2011. Typical of many of the segments, capacity released by DLR is normally above AAR and does exhibit more variation, including periods well above AAR and periods at or below the Static Line Rating.

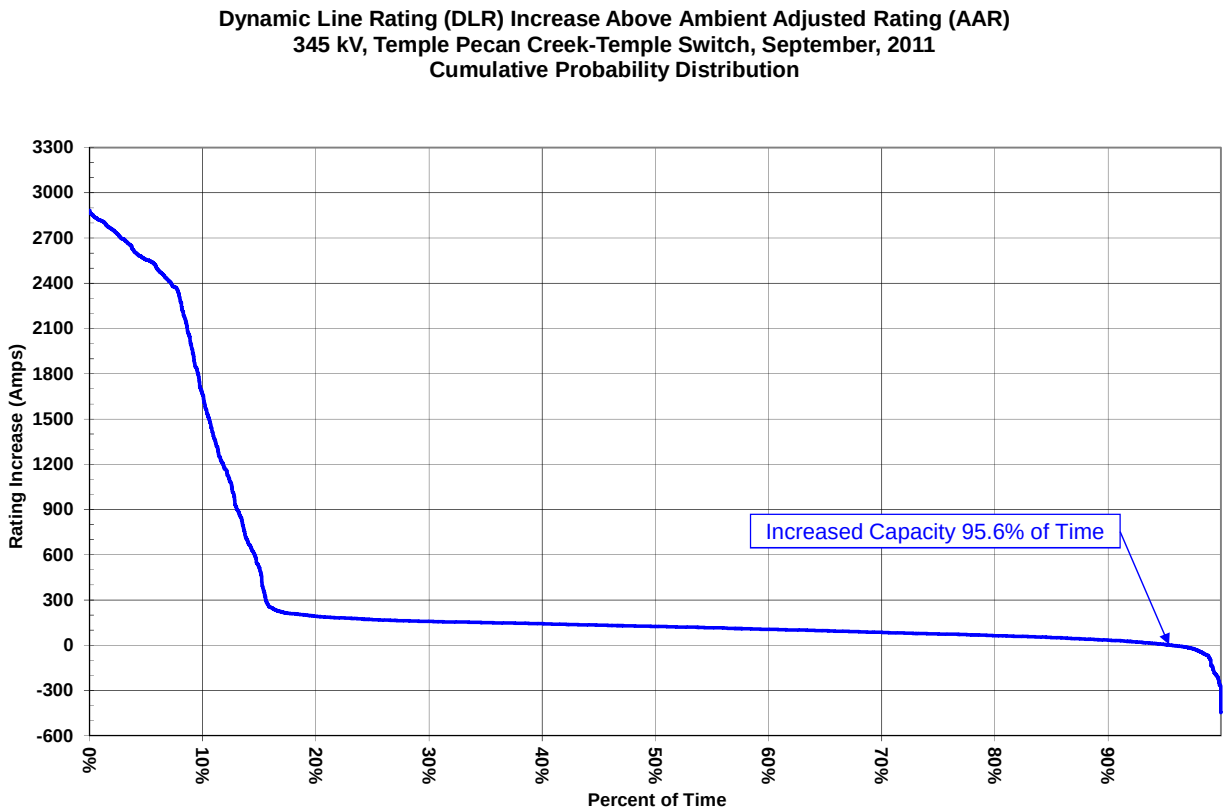

Figure A-2: Cumulative probability distribution showing the increased capacity delivered by the Dynamic Line Rating above the Ambient-Adjusted Rating as a function of percentage of time. The example is for Temple Pecan Creek-Temple Switch (345 kV) during September 2011. For 345 kV segments during months with moderate loads, DLR typically delivers an increased capacity above AAR 80-95% of the time. This specific example delivered increased capacity 95.6% of the time.

How the cumulative distributions of the difference between DLR and AAR were calculated:

1. Data was recorded every two minutes (30 ratings per hour).
2. For each two-minute interval in the month, the AAR was subtracted from the DLR (DLR_AAR_Delta).
3. DLR_AAR_Delta was plotted as a standard cumulative probability chart.
4. When the rating increase (DLR_AAR_Delta) is above zero, DLR is greater than AAR.

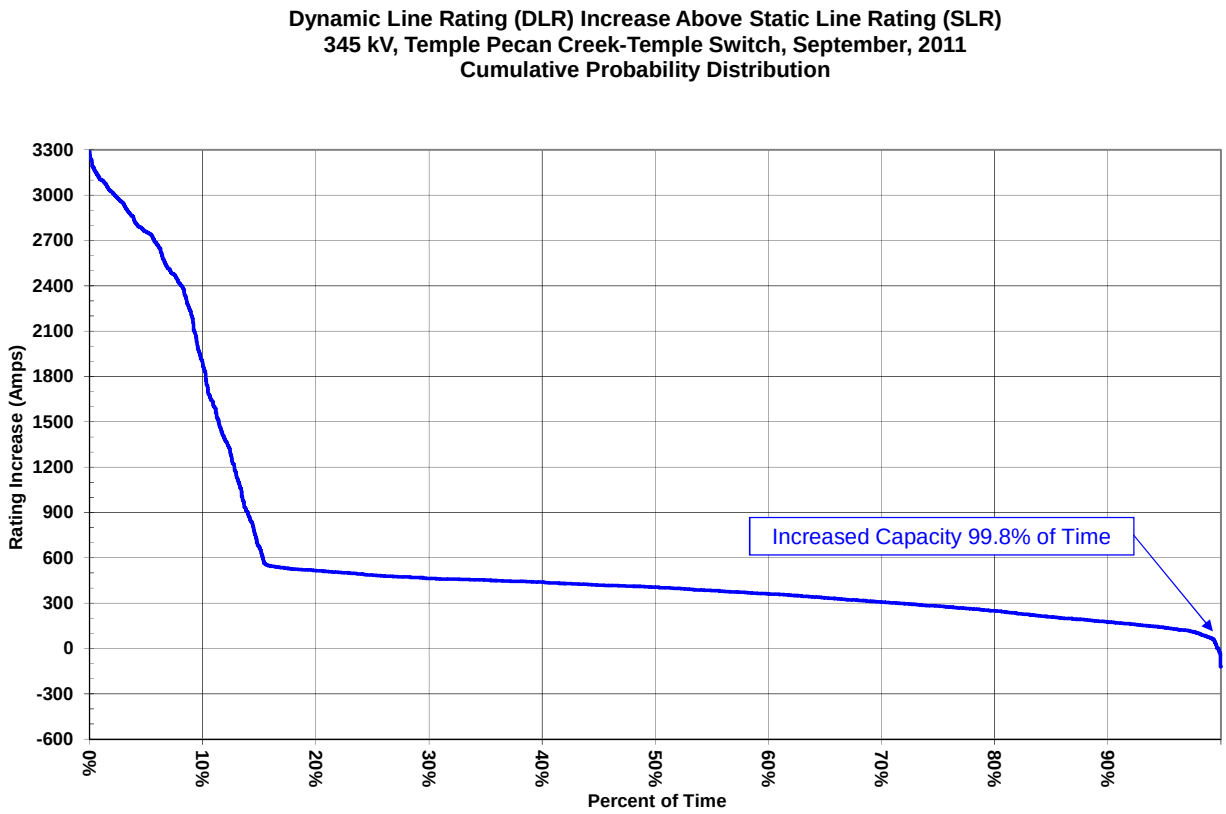

Figure A-3: Cumulative probability distribution showing the increased capacity delivered by the Dynamic Line Rating above the Static Line Rating as a function of percentage of time. The example is for Temple Pecan Creek-Temple Switch (345 kV) during September 2011. For most transmission lines, Dynamic Line Rating typically delivers an increased capacity above the Static Line Rating 97-99% of the time. This specific example had increased capacity 99.8% of the time.

How the cumulative distributions of the difference in DLR and SLR (Static Line Rating) were calculated:

1. Data was recorded every two minutes (30 ratings per hour).
2. For each two-minute interval in the month, the SLR was subtracted from the DLR (DLR_SLR_Delta).
3. DLR_SLR_Delta was plotted as a standard cumulative probability chart.
4. When the rating increase (DLR_SLR_Delta) is above zero, DLR is greater than the Static Line Rating (SLR).

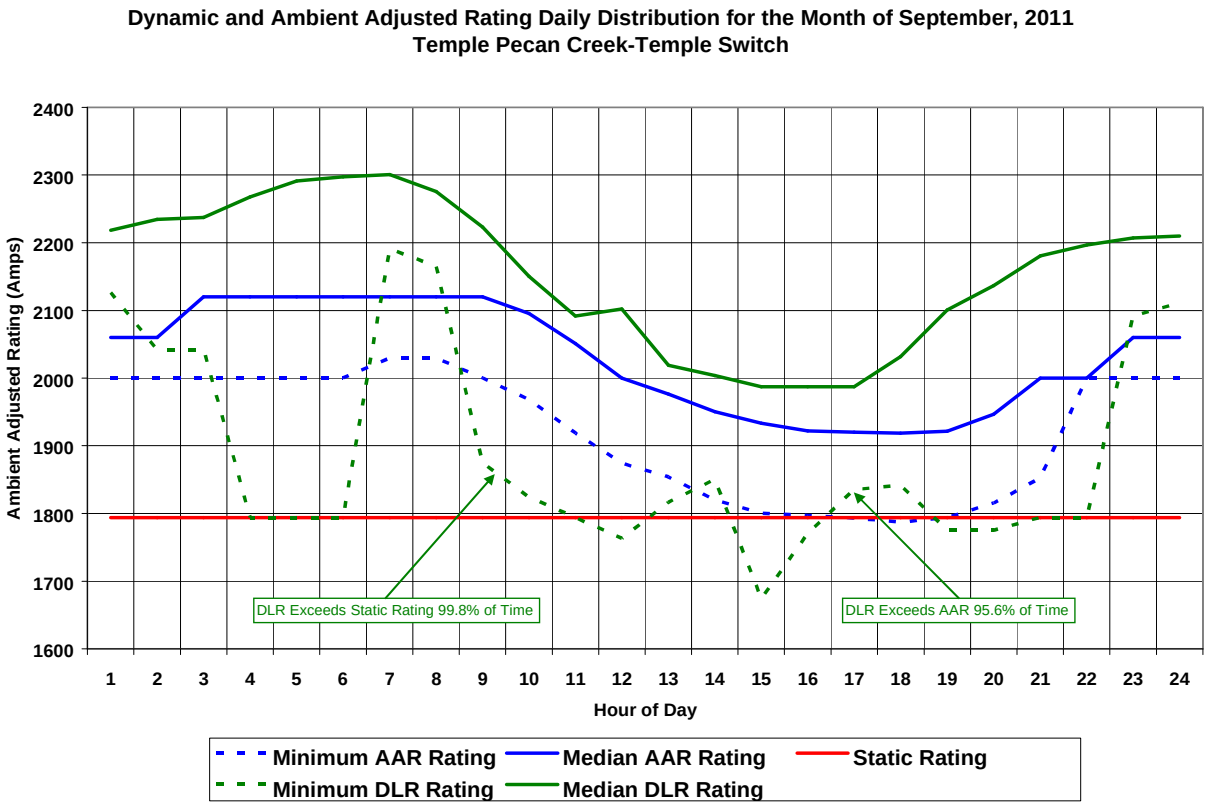

Figure A-4: Daily distribution of ratings showing median and minimum Ambient-Adjusted (AAR) and Dynamic Line Rating (DLR). The example is for Temple Pecan Creek-Temple Switch (345 kV) during September 2011. Note that the median Dynamic Line Rating (DLR) is significantly above the median Ambient-Adjusted Rating (AAR). Minimum ratings in each hour represent 0.1% of the total ratings recorded for that hour during the entire month. The variability in DLR and AAR minimum values is a direct result of DLR accurately reflecting the actual wind, solar, and ambient temperature while AAR reflects actual ambient temperature but assumes a constant wind speed and solar radiation.

Referring back to Figures A-2 and A-3, DLR was above AAR 95.6% of the time and above the Static Line Rating 99.8% of the time.

How the daily distributions of DLR and AAR were calculated:

1. Data was recorded every two minutes (30 ratings per hour).
2. The data was binned for each hour of each day in the month (30 ratings per hour times 30 days = 900 ratings per month per hour).
3. The lowest of the total hourly ratings becomes the minimum rating for the month (minimum = 1 ÷ 900 ratings = 0.1% of ratings).
4. Medians are standard statistical medians.

5. Benefits

This project demonstrated that Dynamic Line Ratings release significant additional capacity over and above that released by Ambient-Adjusted Ratings and Static Line Ratings.

Table A-1 summarizes the increased capacity released by DLR over AAR on all 345 kV lines. When filtering out months where comparison was difficult due to data anomalies, DLR provided a median capacity increase over AAR 92.2% of the time and an average increase 90.5% of the time.

Summary of Capacity Released on all 345 kV Lines Percent of Time Dynamic Line Ratings Exceeded Ambient-Adjusted Ratings				
	Median	**Max**	**Min**	**Average**
Months free of data anomalies	92.2%	97.7%	73.5%	90.5%
Months with up to 10% of data missing or DLR defaulted to the Static Line Rating because of data anomalies	90.5%	97.7%	65.9%	89.1%
All Months	89.1%	97.7%	6.5%	83.5%

Table A-1: Statistical Summary of Additional Capacity Released by Dynamic Line Ratings Compared to Ambient-Adjusted Ratings.

A primary and a secondary Dynamic Line Rating technology were deployed at the outset of the demonstration project. The primary DLR technology is referred to as tension based and accounts for the combined effects of actual wind, actual solar and actual ambient temperature. The secondary DLR technology is referred to as Net Radiation Temperature (NRT) based and accounts for actual ambient temperature and actual solar radiation, but it assumes a constant fixed low wind speed. Unless otherwise noted in this report, all references to Dynamic Line Rating or DLR include the combined results of both the primary tension-based technology and the secondary NRT-based technology. It is possible [see below] to extract the relative impact of DLR primary and secondary technologies from the total DLR.

Line loads on a monthly average were less than the threshold required for a tension-based Dynamic Line Rating 21 to 70% of the time. Under those very low load conditions (less than 20% of the Static Line Rating); the Dynamic Line Ratings were calculated using a NRT-based DLR. During periods of NRT-adjusted ratings, the ratings provided increased capacity over AAR. Figure A-5 is an example of a cumulative probability distribution for Temple Pecan Creek—Temple Switch during September 2011 demonstrating the typical gain seen by NRT-adjusted ratings over AAR.

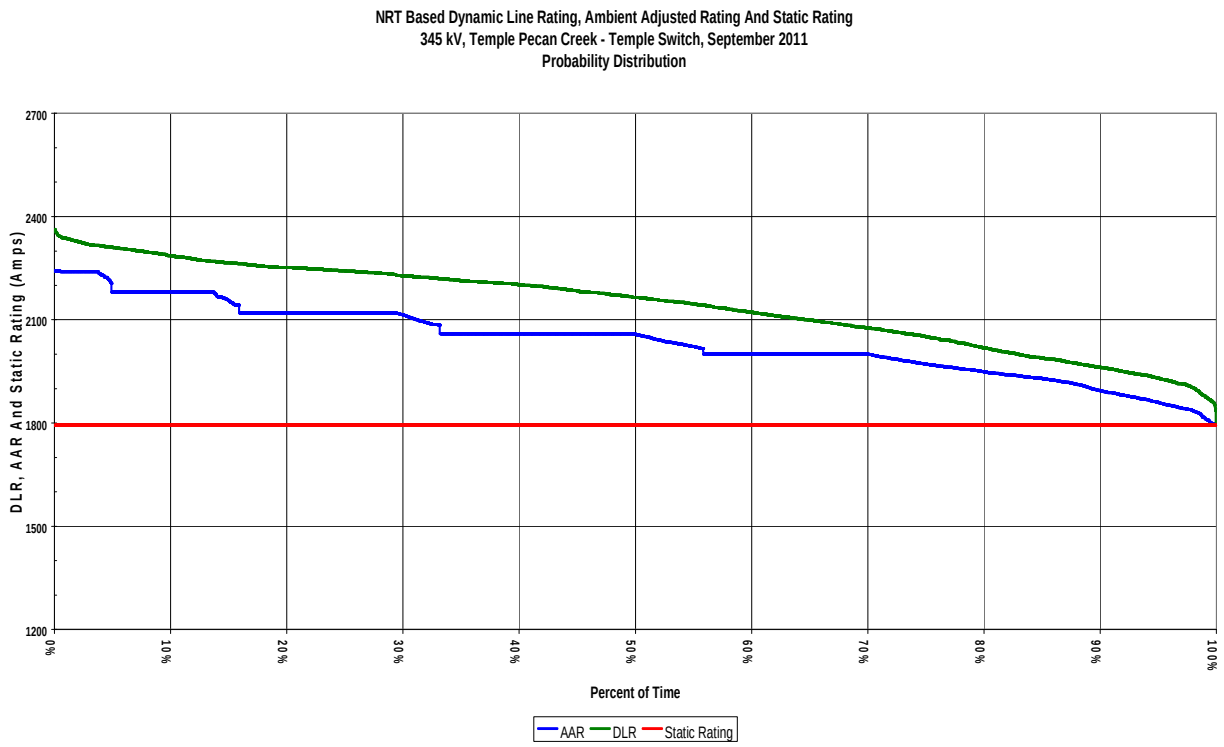

Figure A-5: Cumulative probability distribution showing side-by-side comparison of NRT-based DLR and AAR as a function of percentage of time. Typical of the 345 kV segments during most of the months, NRT-based DLR demonstrates increased capacity above AAR.

When line loads are above 20% of the SLR, the primary tension technology dominates the DLR by adding the full impact of wind, including its spatial variability, to the rating. Figures A-6 and A-7 show the capacity gained under all load conditions and when loads exceed 20% of the Static Rating (SLR). Note that the increased capacity revealed for loads above 20% of SLR is always there. However, the increased capacity simply can't be accessed without a DLR technology that captures the full spatial impact of wind.

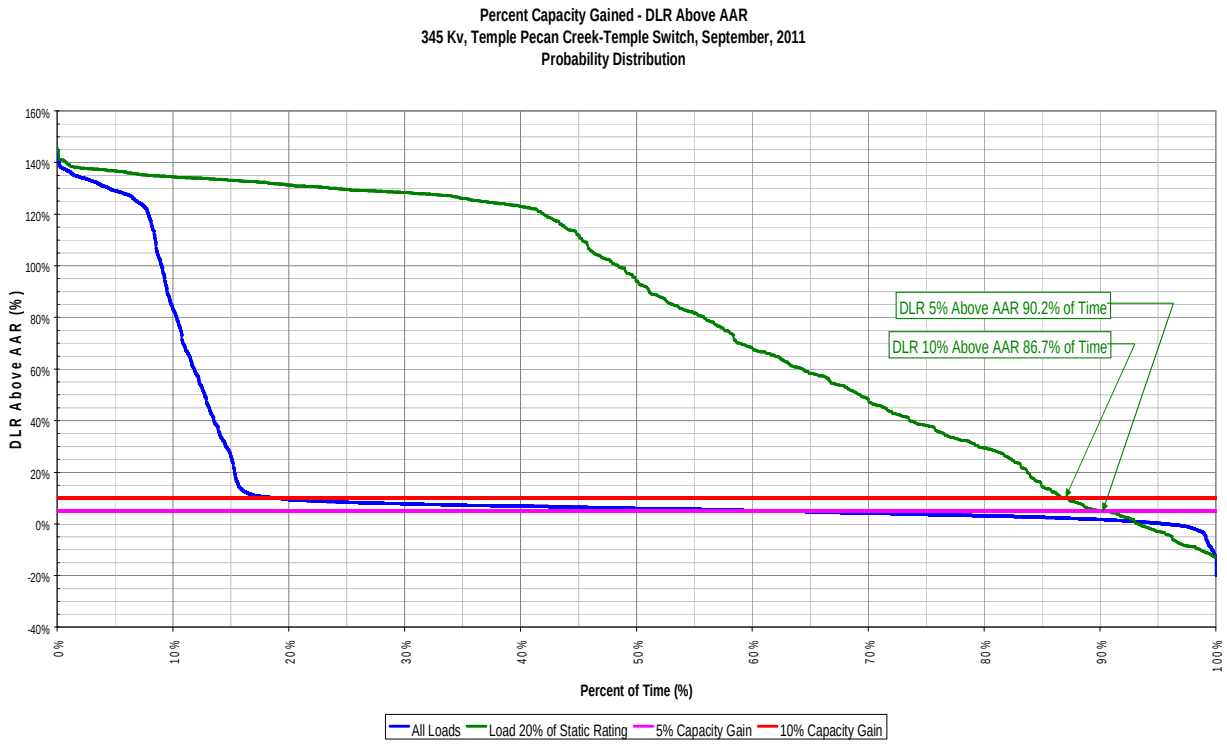

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Figure A-6: Cumulative probability distribution showing the increased capacity delivered by the Dynamic Line Rating above the Ambient-Adjusted Rating for all load conditions and for loads greater than 20% of Static Line Rating for Temple Pecan Creek-Temple Switch (345 kV) during September 2011.

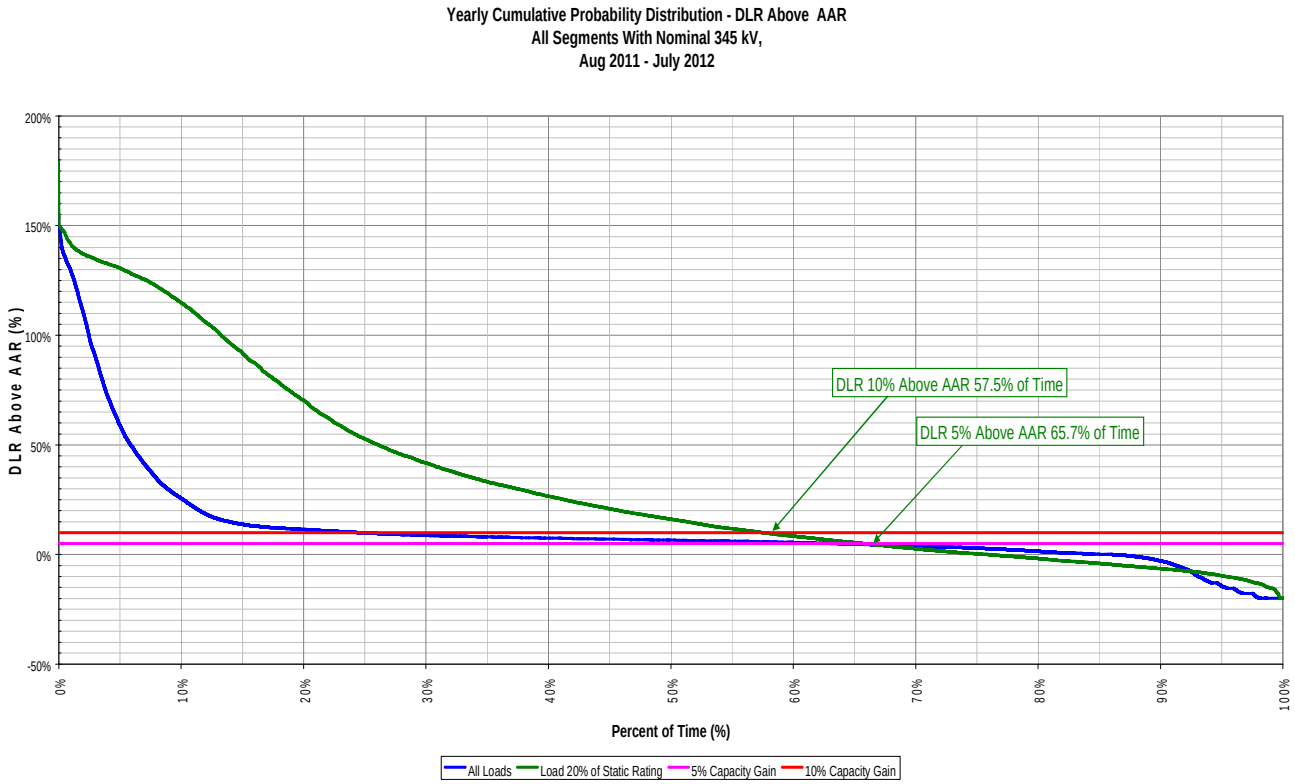

Figure A-7: Cumulative probability distribution showing the increased capacity delivered by the Dynamic Line Rating above the Ambient-Adjusted Rating for all load conditions and for loads greater than 20% of Static Line Rating for all 345 kV lines August 2011 through July 2012.

The data was examined for indications of seasonality by dividing the August 2011 through July 2012 data set into quarters.

While quarterly results vary, the increased capacity delivered by Dynamic Line Ratings over Ambient-Adjusted Ratings was on average 6-14% for 345 kV and 8-12% for 138 kV (Figures A-8 and A-9). During March-June 2012, the lowest loads and the greatest number of load anomalies occurred on the 138 kV segments, forcing the Dynamic Line Rating to default to the Static Line Rating, which accounts for the very low gains during the second quarter of 2012 (Figure A-9). Despite the load issues and reported lower gains, the yearly averages for the 138 kV voltage class centered around 10% (between 8% and 12%).

Discounting the second quarter of 2012's data because of the load anomalies, only nominal seasonal variation is evident in this study.

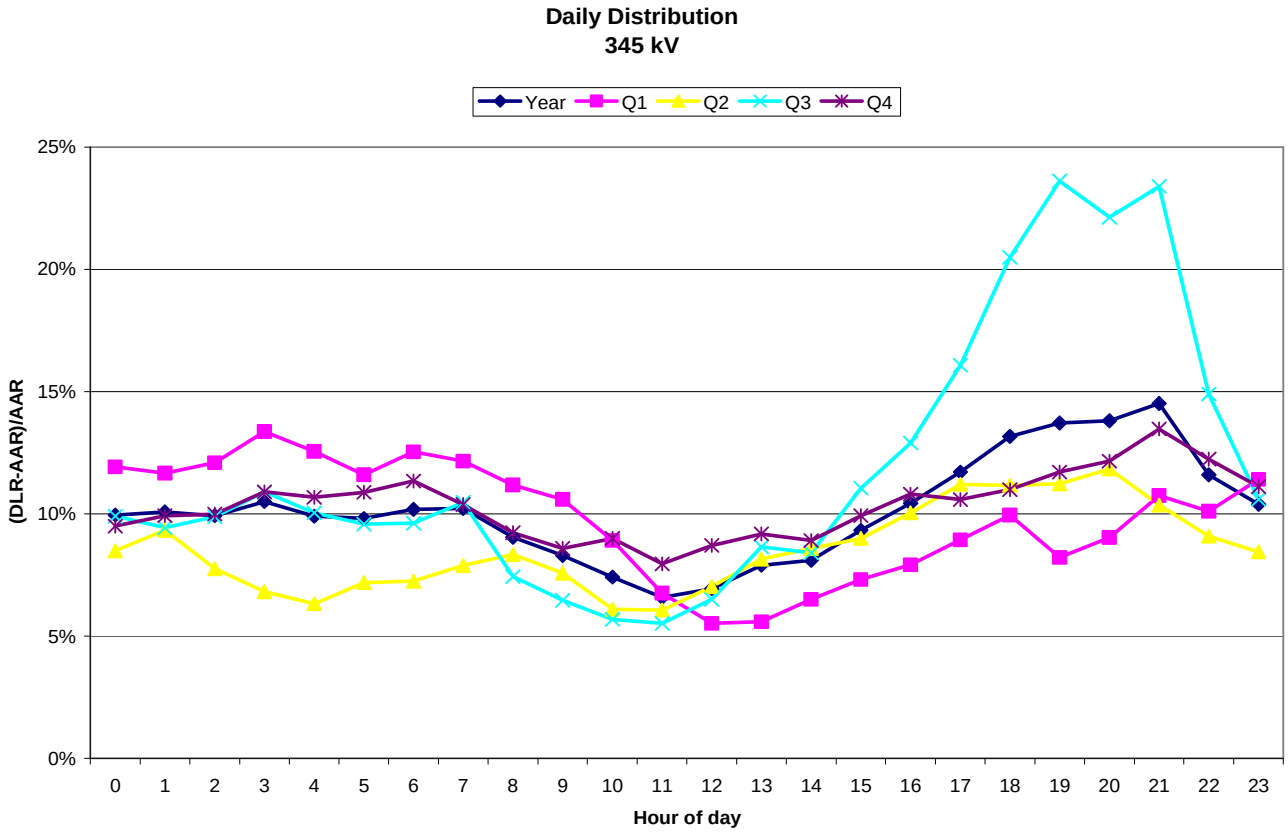

Figure A-8: Yearly and quarterly average increased capacity delivered by the Dynamic Line Rating above the Ambient-Adjusted Rating for all load conditions for all 345 kV lines August 2011 through July 2012.

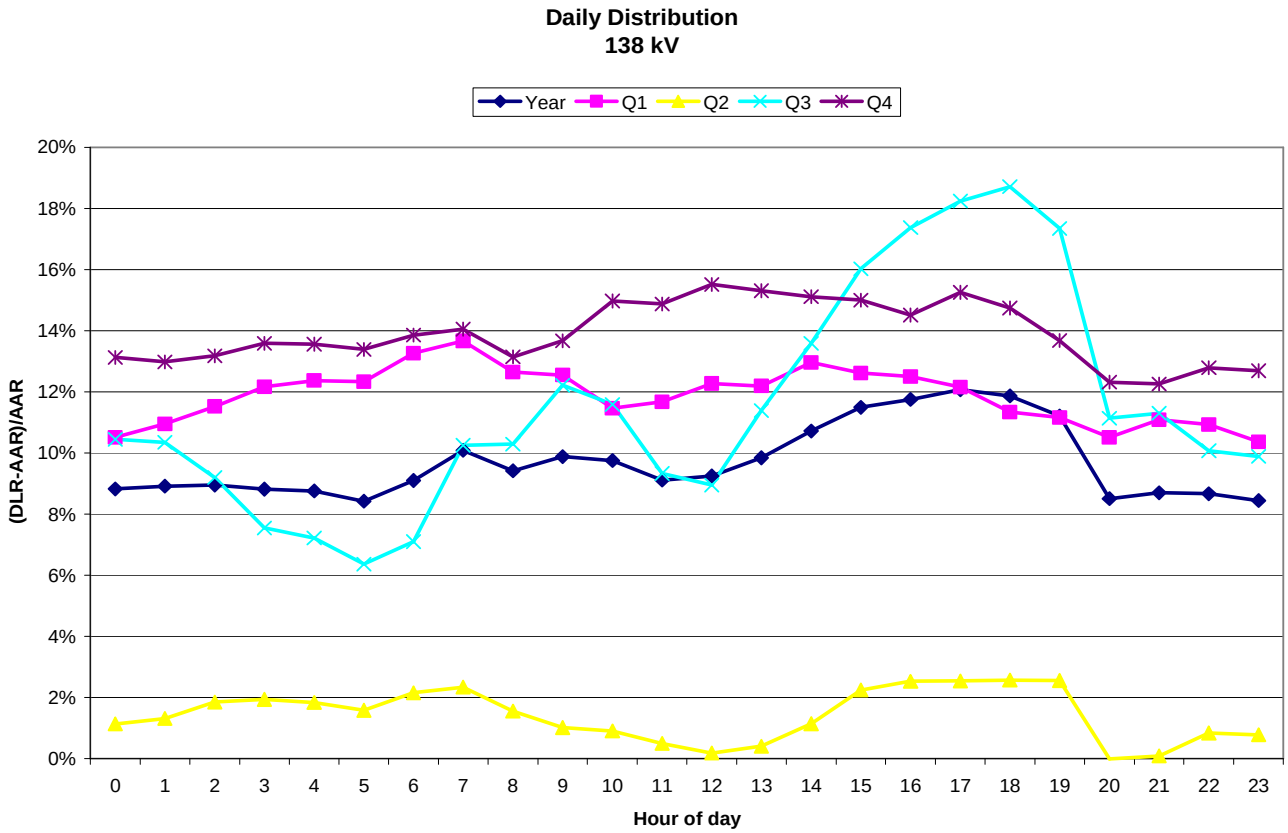

Figure A-9: Yearly and quarterly average increased capacity delivered by the Dynamic Line Rating above the Ambient-Adjusted Rating for all load conditions for all 138 kV lines August 2011 through July 2012.

For contingency management and for electricity markets that are sufficiently advanced to be operating at 15-minute intervals, even greater grid capacity gains can be safely tapped by 15-minute Dynamic Line Ratings alternately known as transient ratings or Short Term Emergency (STE) ratings.

In the process of establishing the Dynamic Line Rating of a transmission line, the average temperature of the conductor is determined. That temperature is a prerequisite to determining the real-time transient response of the conductor to a change in load. Two forms of the transient response are very useful in contingency management: one before the event, and one after the event.

Figure A-10 is an example of pre-contingency transient analysis. In this example, the conductor is not permitted to exceed a design temperature of 100 ^{o}C. Both the load on the line and the conductor's temperature are known as time zero. A Dynamic Line Rating system continuously calculates a 15-minute short term emergency (STE) rating that identifies how large a step in load will cause the conductor to reach its 100 ^{o}C design temperature in 15 minutes, but not before. In practice, an operator can dispatch the system to the STE rating, knowing that should a contingency event occur, he will have a full 15 minutes to respond. After 15 minutes, load must be reduced to the real-time continuous rating.

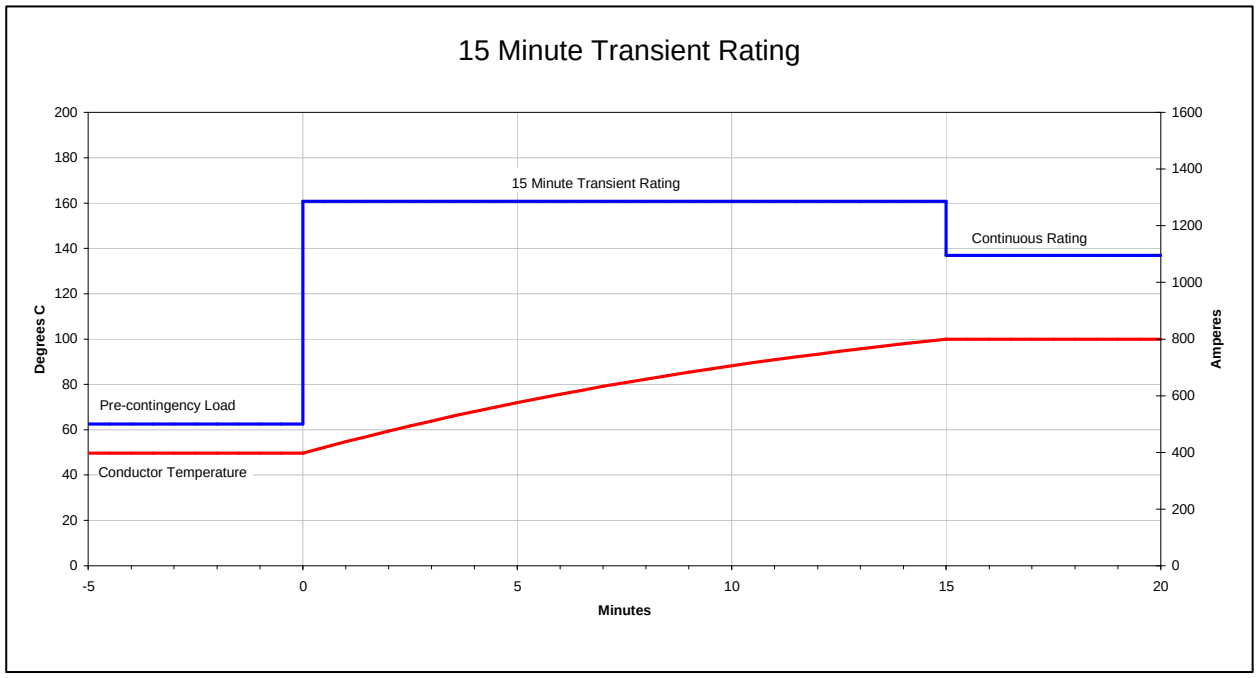

Figure A-10 – Pre-contingency Transient Response Analysis

Figure A-11 is an example of post-contingency transient analysis where the conductor has just been subjected to a large step current. A DLR system continuously calculates how many minutes will elapse before the conductor reaches its 100 ^{o}C design temperature for any step in current. In this example, the time is 8.5 minutes. In practice, the operator must reduce load on the line to the real-time continuous rating before 8.5 minutes elapse.

The time available to take corrective actions is valuable information to the operator. If time is short, quick but expensive actions may be required. If a longer time is available, more economical or less disruptive actions may be taken.

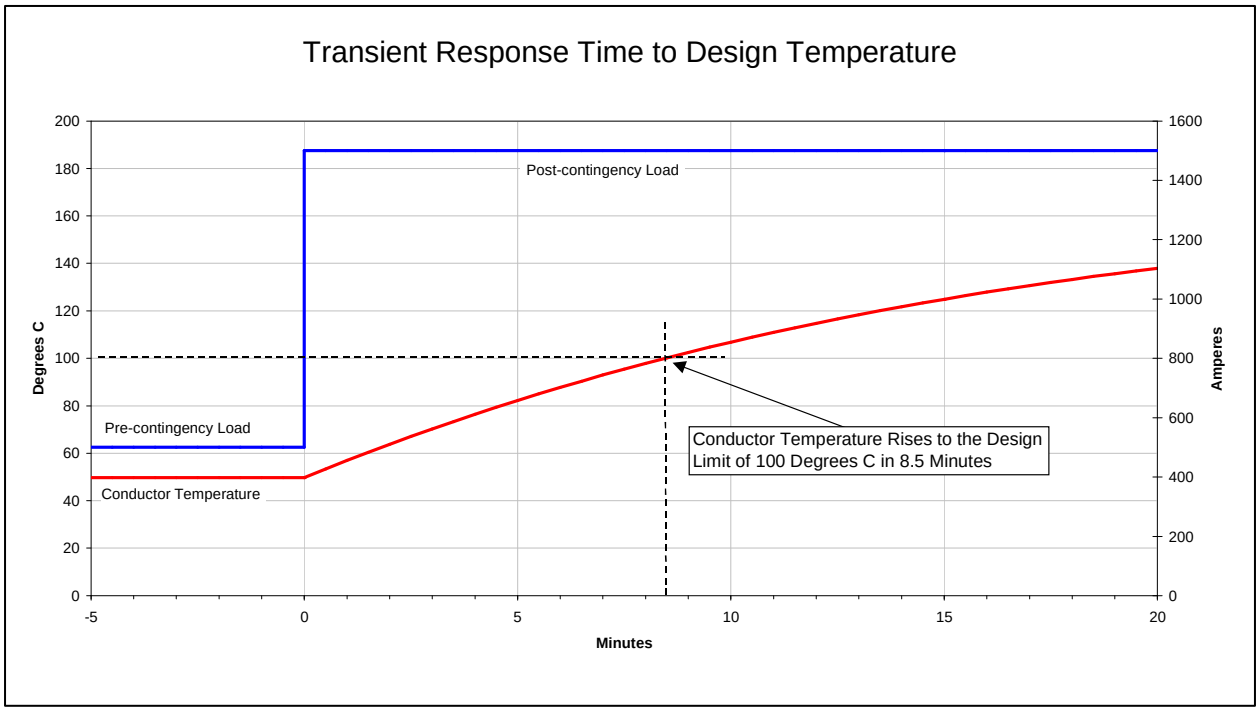

Figure A-11 – Post–contingency Transient Response Analysis

Figures A-12 and A-13 show the increased capacity above AAR that is released by the 15-minute rating (STE). For all 345 kV lines, at least 10% above AAR is available 93% of the time under all load conditions and 98% of the time under moderate load conditions (load greater than 20% of the Static Line Rating). Those increased capacities can be safely deployed within a market structure while ensuring that lines will always be operated within their limits.

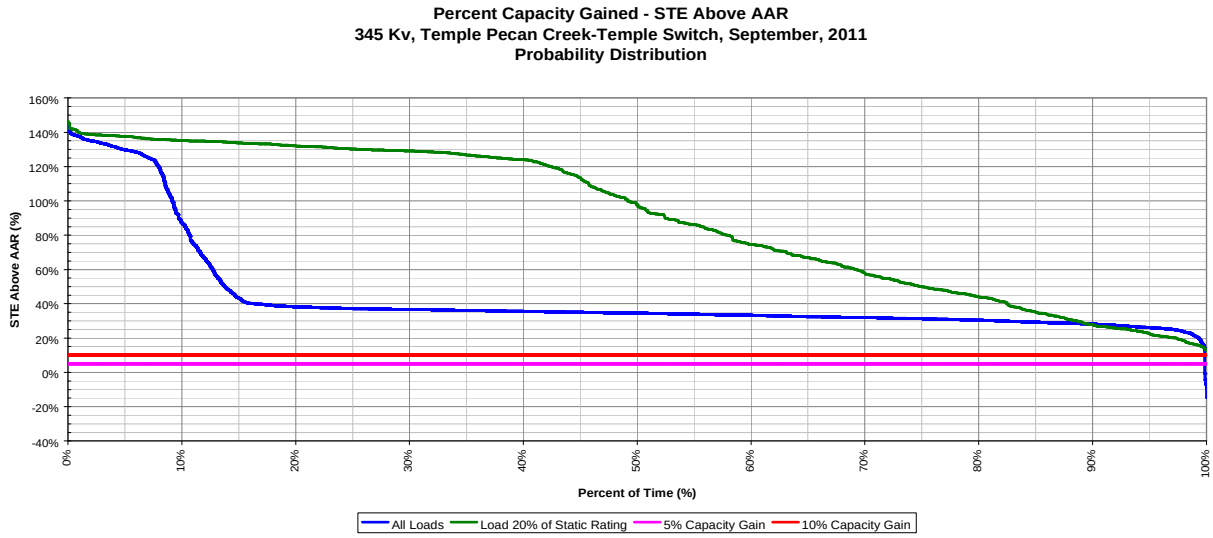

Figure A-12: Cumulative Probability distribution as a function of percentage of time showing side-by-side comparison of the gain above AAR using 15-minute ratings (STE) for all load conditions and for loads greater than

20% of Static Line Rating for Temple Pecan Creek – Temple Switch September, 2011.

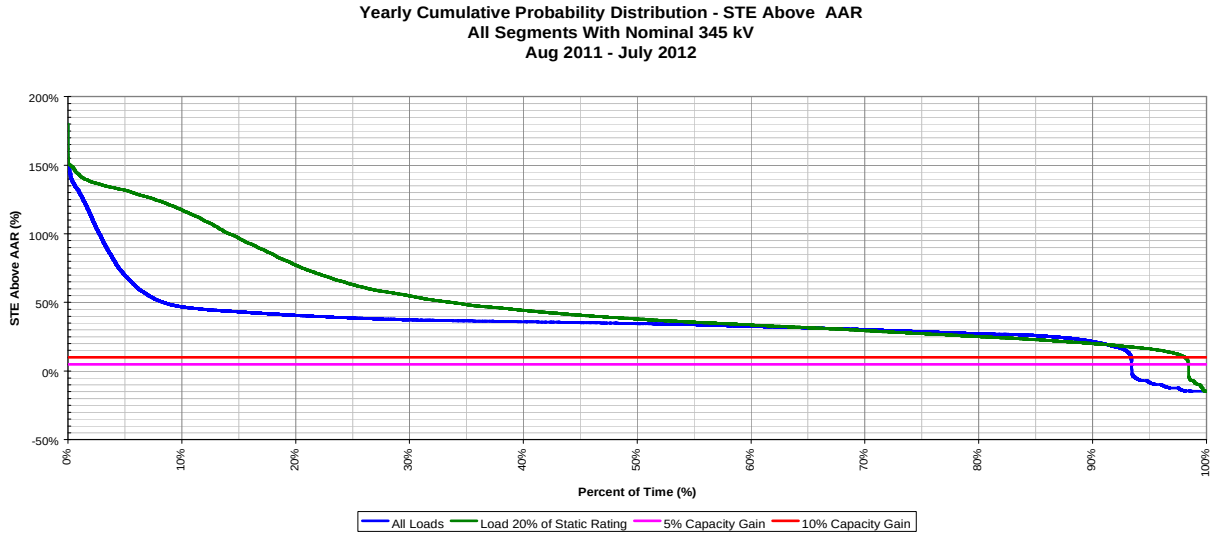

Figure A-13: Cumulative Probability distribution as a function of percentage of time showing side-by-side comparison of the gain above AAR using 15-minute ratings (STE) for all load conditions and for loads greater than 20% of Static Line Rating for all 345 kV lines August 2011 through July 2012.

6. Conclusions – Capacity Released

Dynamic Line Ratings consistently released additional grid capacity compared to Ambient-Adjusted Ratings. While quarterly results varied, the average increased capacity delivered by Dynamic Line Ratings over Ambient-Adjusted Ratings was 6 to 14% for 345 kV and 8 to 12% for 138 kV transmission lines. The availability of that added capacity ranged from 83.5% of the time under all operating conditions to 90.5% of the time when outages and other events were excluded from the data.

For contingency management and for energy markets that clear on a 15-minute basis, the study demonstrated that at least 10% above the Ambient-Adjusted Rating was available 93% of the time under all load conditions and 98% of the time under moderate load conditions (load greater than 20% of the Static Line Rating). Those increased capacities can be safely deployed within a market structure while ensuring lines will always be operated within their limits.

7. Appendices

Appendix I - Identified Net Radiation Sensors and locations where significant shadowing occurred.

Segment	Serial and Port Number	Structure	Shadowing times	Date Corrected
Lake Creek – Temple	SN 4005 – port 1	2/4	9:00 – 12:00	Not Corrected due to site access issue
Lake Creek – Temple	SN 4006 – port 1	8/4	10:00 – 12:00	April 19, 2012
Tradinghouse – Temple Pecan Creek	SN 4005 – port 2	2/4	9:00 – 12:00	Not Corrected due to site access issue
Trading house – Temple Pecan Creek	SN 4006 – port 2	8/4	10:00 – 12:00	April 19, 2012
Cottonbelt Tap – Spring Valley Tap	SN 4016 – port 1	12/9	8:00 am – 11:00	Not Corrected due to site access issue
Cottonbelt Tap – Spring Valley Tap	SN 4016 – port 2	12/9	8:00 – 11:00	Not Corrected due to site access issue
Bell County – Salado	SN 4024 – port 1	13/2	10:00 – 13:00	April 20, 2012
Jarrell East – Gabriel	SN 4027 – port 1	20/1	16:00 – 18:00	April 18, 2012

8. References

[1] Stephan 2012, “Guide for application of Direct Real-time monitoring systems.” CIGRÉ Technical Brochure No. 498. Working Group Committee B2.36.

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APPENDIX B. INTEROPERABILITY AND CYBERSECURITY ASSESSMENT

FINAL REPORT

for

DYNAMIC LINE RATING CYBERSECURITY ASSESSMENT

Version 0.3

February 28, 2013

SwRI® Project No. 10.16404

Prepared for

Oncor Electric Delivery
115 West Seventh Street, Suite 505
Fort Worth, Texas 76102

Prepared by
Joseph G. Loomis

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FINAL REPORT

for

DYNAMIC LINE RATING CYBER SECURITY ASSESSMENT

Version 0.3

February 28, 2013

SwRI® Project No. 10.16404

Prepared by: _____ Date: 2/27/13
Joseph G. Loomis, Technical Lead

Prepared by: _____ Date: 2/28/2013
Gary L. Ragsdale, Ph.D., Project Manager

Approved by: _____ Date: 2/27/2013
Mark E. Moczygemba, P.E., Assistant Director
Communications and Embedded Systems Department

REVISION NOTICE

Version Identifier	Date of Issue	Summary of Changes
0.1	November 30, 2011	Initial issue.
0.2	January 20, 2012	Draft final version.
0.3	February 28, 2013	Final version.

This document contains information that is as complete as possible. Where final numerical values or specification references are not available, best estimates are given and noted TBR (To Be Reviewed). Items that are not yet defined are noted TBD (To Be Determined).

1. EXECUTIVE SUMMARY

The principal objective of the Cybersecurity Assessment (CSA) task was to assess and validate that the proposed demonstration technology does not create an increased Cybersecurity risk for the systems in which it will operate. The CSA is part of the published and accepted Interoperability and Cybersecurity Plan (I&CS) to perform a "proof of concept" demonstration project whereby a standalone measurement technology is adapted to provide real-time operating characteristics in a transmission grid control room environment. The CSA task was mainly performed as an integral part of the development of the demonstration project, not to evaluate the security of the devices adapted for the demonstration project. To evaluate the system's Cybersecurity posture, Oncor requested that SwRI perform a penetration testing exercise on a representative system to identify security vulnerabilities that exist in the Dynamic Line Rating (DLR) CAT-1 unit. SwRI focused testing on the individual components and the communication channel used by the CAT-1 system. This report describes the process used to create the penetration test plan and the test environment. For security reasons, the results of penetration testing, such as discovered vulnerabilities and configurations recommendations, if any, are not documented as part of this report.

2. INTEROPERABILITY

Nexans technology is fully compliant with the requirements set forth in the amendments to Section 1306 in Title XIII (Smart Grid) of the Energy Independence and Security Act of 2007 by the American Recovery and Reinvestment Act of 2009. Oncor supports and makes use of open protocols and standards at all points within Oncor's CAT-1 DLR system, from CAT-1 to IntelliCAT for Windows (ICW). A breakdown of those communications interfaces:

- CAT-1 to CATMaster – DNP 3.0 Protocol (Distributed Network Protocol). This protocol is an open, standards-based protocol maintained by the DNP3 Users Group. It is a widely used Supervisory Control and Data Acquisition (SCADA) protocol in the U.S. and to a lesser degree in Europe. It is referenced in IEEE 1379-2000 and is compliant with IEC 62351-5.
- CATMaster to Energy Management System (EMS) – Standard EMS/Remote Terminal Unit (RTU) protocols are supported; however, individual project implementations can use whatever protocol a utility may have deployed, which does include proprietary, non-standards-based protocols. Standard protocols supported would include DNP 3.0 and IEC 870-5-101/104. Also supported is MODBUS, which has become a de facto standard in the industry.
- ICW to EMS – The standard offering makes use of two standard protocols: OLE for Process Control (OPC) (an open standard) and Inter Control Center Protocol (ICCP) (also known as IEC 60870-6/TASE.2 which is also an open standard). Oncor can also support DNP 3.0, MODBUS and IEC 870-5-101/104 in lieu of ICCP. ICW always communicates via OPC.
- The implementation of the core ICW DLR algorithm functionality as an OPC client-based Windows service ensures a smooth integration path into virtually any EMS system. It also provides for a future proof solution which can easily be adapted to meet any future Smart Grid interoperability standards which may develop.

Interoperability is provided at three key interface points: structure instrumentation (CAT-1), EMS/RTU interface (CATMaster) and the Dynamic Line Rating engine (ICW). A utility has the option of inserting its own or third-party devices at any of the interfaces.

3. CYBERSECURITY

4. Scope

The goal of the project was to perform a security assessment of a representative configuration of the DLR CAT-1 component. As such, the following pieces were in scope for the testing effort:

- CAT-1 unit
  - Physical testing of the board and microcontrollers.
  - Evaluation of the radios being utilized.
- RF Communications
  - Examination of frequency hopping and radio configurations.
  - Analysis of traffic being transmitted across the RF link.

The CATMaster, IntelliCAT and the existing SCADA network that provide substation-to-utility communication were all out of scope for this effort.

5. Risk Assessment and Test Plan Development

The AMI Risk Assessment document prepared by the Advanced Metering Infrastructure Security Task Force (AMI-SEC) was used as a starting point for the test plan. DLR is similar to other advanced metering of infrastructure in that we are monitoring the real-time status, metering the tension on the transmission line. The methodology outlined in the document was developed by the AMI-SEC working group within the OpenSG users group. This document has since been passed to the National Institute of Standards and Technology (NIST) Cybersecurity Working Group to be integrated into documents that they are currently producing.

Four key aspects of real-time data acquisition and processing are the focus of Cybersecurity issues:

- Confidentiality – prevention of unauthorized access to the information.
- Integrity – prevention of the theft, unauthorized insertion, or modification of information.
- Availability – consistency of data stream availability to secure users and prevention of access by unauthorized entities.
- Accountability – clear documentation of any event, its time, source, and purpose.

Appendix B.3 of the AMI-SEC document is an exhaustive list of threats that a potential AMI system could face. While the system being tested is not an AMI system, the threats described are still applicable to the DLR system and can be utilized for test plan development. Using this threat list as a starting point, the list was first pruned down to only include threats that were applicable to the system and that were within the scope of testing. Next, for each threat that remained a test case was designed to determine if the system was vulnerable to that threat or not. Finally, an initial risk rating for each test case was assigned in order to help with test prioritization. The priority of testing is developed through an assignment of the severity of the vulnerability/threat and the likelihood of the threat occurring.

The flowchart of the process just reviewed is laid out in Figure B-1.

Severity of impact addresses the degree of impact in two ways: the breadth of the impact, i.e., number of units impacted or the reach into the network and grid; and relative to the economic/security/reliability/safety aspect of the impact (see Table B-1).

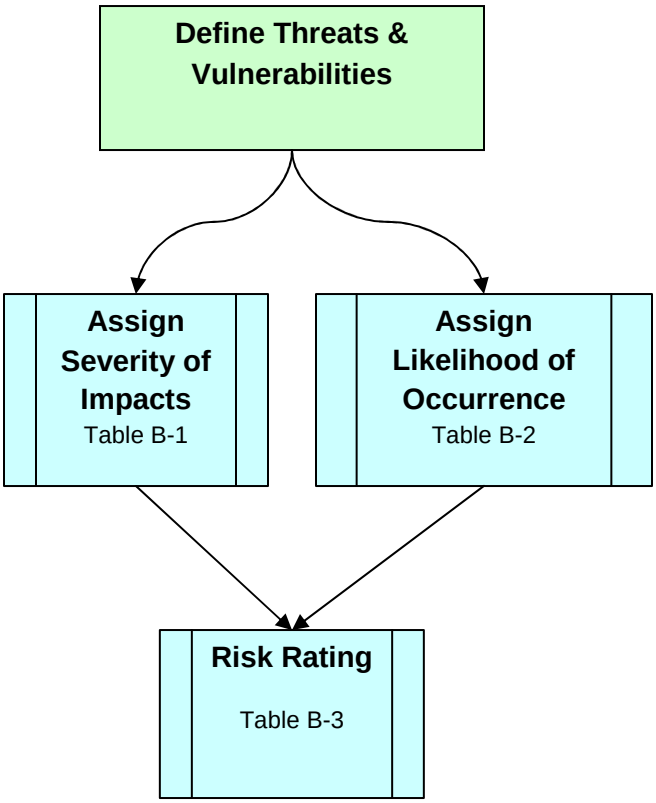

Figure B-1 - Cybersecurity Assessment Flowchart

Table B-1 - Severity of Impact Ratings

Severity			
1	Negligible	Low	Effects limited to single unit / Minimal e/s/r/s impacts
2	Moderate	Medium	Effects limited to units in a single cell (NAN) / Moderate e/s/r/s impacts
3	Severe	High	Effects beyond a single cell (System/WAN) / Severe e/s/r/s impacts

The likelihood that a threat will occur or vulnerability be exposed is measured according to the descriptions in Table B-2.

Table B-2 - Likelihood of Occurrence Rating

Likelihood / Threat			
A	Rare	Low	Exceptional circumstances only
B	Unlikely	Low	Not expected to occur
C	Possible	Medium	Could occur at some time
D	Likely	High	Will probably occur in most circumstances
E	Almost Certain	Critical	Expected in most circumstances

Once the vulnerabilities and threats have been reviewed relative to Severity and Likelihood of occurrence, their product probability defines a Risk Rating as shown in Table B-3 and Table B-4. The Risk Rating guides the Cybersecurity assessment to perform its assessment on the most efficient path to address the issues of highest concern and impact.

Table B-3 - Risk Rating

Risk Rating			
Likelihood	**Severity**		
	Negligible	Moderate	Severe
	1	2	3

E	Almost Certain	M	H	E
D	Likely	M	H	E
C	Possible	L	M	E
B	Unlikely	L	M	H
A	Rare	L	M	H

Table B-4 - Risk Levels

E	Extreme risk
H	High risk
M	Moderate risk
L	Low risk

A test plan was developed using this methodology, and it was used to perform penetration testing of the representative system.

6. Testing Environment

Figure B-2 shows an example of what the test lab configuration is intended to simulate and how the individual components communicate. The test environment included one actual CAT-1 remote unit with three additional devices being simulated in the software. The CAT-1 devices communicated to the CATMaster using the typical radios used in production. The CATMaster and IntelliCAT were connected using a serial cable to transmit data and simulate the remaining SCADA network.

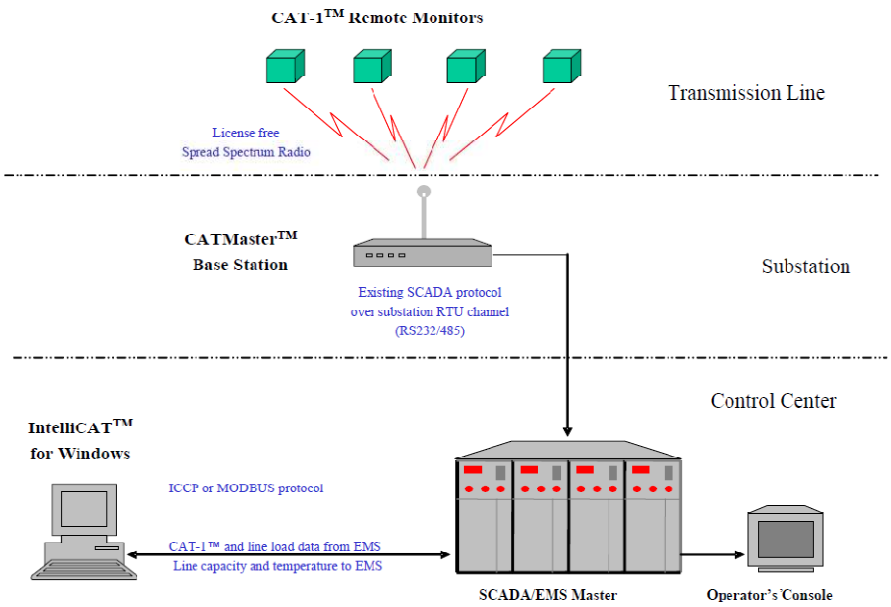

Figure B-2 - Sample Test Lab Configuration

7. CONCLUSION

To evaluate the DLR system's Cybersecurity posture, Oncor requested that SwRI perform a penetration testing exercise on a representative system to identify security vulnerabilities that may exist in the DLR CAT-1 unit. As part of this effort, SwRI developed a penetration test plan and test environment using the process described in this report. Penetration testing focused on the individual components and the communication channel used by the CAT-1 system. This CSA task was performed to assess and validate that the proposed demonstration technology does not create an increased Cybersecurity risk for the systems in which it will operate. The CSA task was mainly performed as an integral part of the development of the demonstration project, not to evaluate the security of the devices adapted for the demonstration project.

APPENDIX A

ACRONYM LIST

ACRONYM LIST

AMI-SEC	Advanced Metering Infrastructure Security Task Force
CSA	Cybersecurity Assessment
DLR	Dynamic Line Rating
DNP	Distributed Network Protocol
EMS	Energy Management System
I&CS	Interoperability and Cybersecurity Plan
ICCP	Inter Control Center Protocol
ICW	IntelliCAT for Windows
NIST	National Institute of Standards and Technology
OPC	OLE for Process Control
RF	Radio Frequency
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SwRI	Southwest Research Institute
TBD	To Be Determined
TBR	To Be Reviewed

APPENDIX C. LIFE CYCLE DESIGN FOR CYBERSECURITY

LIFE CYCLE DESIGN

for

DYNAMIC LINE RATING CYBERSECURITY ASSESSMENT

Version 0.1

February 28, 2013

SwRI® Project No. 10.16404

Prepared for

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LIFECYCLE DESIGN

for

DYNAMIC LINE RATING CYBER SECURITY ASSESSMENT

Version 0.1

February 28, 2013

SwRI® Project No. 10.16404

Prepared by: _____ Date: 2/28/13
Joseph G. Loomis, Technical Lead

Prepared by: _____ Date: 2/28/2013
Gary L. Ragsdale, Ph.D., Project Manager

Approved by: _____ Date: 2/28/2013
Mark E. Moczygemba, P.E., Assistant Director
Communications and Embedded Systems Department

REVISION NOTICE

Version Identifier	Date of Issue	Summary of Changes
0.1	February 28, 2013	Initial issue.

This document contains information that is as complete as possible. Where final numerical values or specification references are not available, best estimates are given and noted To Be Reviewed (TBR). Items which are not yet defined are noted To Be Determined (TBD).

1. Lifecycle Design

Lifecycle design of a secure system can be divided into four main steps: procurement, installation, operation, and retirement. This document emphasizes the important issues when developing a secure system for long-term operation. Some adaptation of the process is expected since each system has unique operational and risk considerations. Finally, for any system to be secure, it is necessary to consider security at each step of the lifecycle and to periodically verify the security of the complete system so that it is consistent with risk management. A list of resources is provided to assist in lifecycle security.

The process of designing a secure system involves a number of key personnel. Each party is listed below with an explanation of their role in creating and maintaining a secure system.

- Information Technology (IT) Department – Standard bearer for company security and provides technical expertise.
- Vendor – Provides secure configuration information for products. Notifies customer whenever possible of known security issues.
- Operations – Supervisory Control and Data Acquisition (SCADA) and Energy Management System (EMS) specialists responsible for maintaining data quality and distribution.
- Supply Chain – Manages quality control of purchased products and ensures security compliance during the purchase process.
- Maintenance – End-system owner responsible for ongoing compliance of the system.
- Management – Ensures that all parties have the necessary resources to perform their jobs and oversee security compliance and risk management.

The list below highlights some of the items to consider when installing the Dynamic Line Rating (DLR) into an existing secure utility. Although many of the recommendations made in this document are valid for a system that extends beyond the DLR, the outline provided focuses on the DLR system and its interface with the utility.

- Procurement
  - Perform risk assessment
    - Identify potential threats to the system and assign likelihoods and impacts
    - Determine controls necessary to mitigate those threats [feeds into Request for Proposal (RFP) requirements]
  - Include security requirements in the RFP
    - Require confidentiality of data, integrity of communications, and authentication of users
    - Require physical security of components in the system
    - Establish a secure way to change keys and, possibly, encryption algorithms
    - Mandate that security requirements “flow-down” to suppliers of suppliers
    - Mandate that all third-party communication links are secure
    - Establish a standard for the components that references external standards, compliance requirements, and terms

  - Perform validation of vendor security mechanisms, typically performed by an independent third party, which in itself may require a separate procurement standard and protocol
    - Ensure all security requirements are being met
    - Verify the proposed system does not contain vulnerabilities
    - Provide documentation of assets and utilized encryption algorithms and technologies
  - Maintain evidence of security practices and risk management through proper documentation
- Installation
  - Establish a secure method for installation of device-specific security keys
  - Establish an approach for verifying that the system is configured and deployed securely
  - Establish an alerts and alarms response plan to ensure secure operation
  - Train users and operators on new system and security processes
  - Maintain evidence of security practices and risk management through proper documentation
- Operations
  - Establish a routine security review of the deployed system, security processes, users, and operators [this may be part of annual North American Electric Reliability Corporation (NERC) Compliance]
  - Rotate keys (in a secure fashion) periodically to prevent possible cryptographic attacks
  - Update systems with patches that fix potential security flaws as released by vendor
  - Maintain a test system to verify patches and the security of the system before implementation on the production system
  - Perform regression testing on new software and firmware
  - Investigate all suspected security events as per established response plan
  - Perform configuration management and maintain accurate and up-to-date system documentation
  - Ensure that utilized security technology is not past recommended end of life
  - Identify vendors for replacement components and/or obtain spares for critical system devices
  - Provide a way to train users and operators on the system and security [this may be covered in annual NERC Critical Infrastructure Protection (CIP) compliance training]
  - Log and audit information relevant to security
  - Proactively assess system requirements and actively pursue and manage mitigation activities
  - Maintain evidence of security practices and risk management through proper documentation
- Retirement
  - Establish a procedure for disposing of devices in a secure fashion (clearing memory of passwords, keys and other sensitive information)
  - Change passwords and keys as necessary for personnel once access is no longer required
  - Ensure that out-of-date documentation is disposed of properly
  - Monitor device failures for possible trends in failure modes
  - Maintain evidence of security practices and risk management through proper documentation

2. References

The list below provides references for lifecycle security.

1. U.S. Department of Commerce, National Institute of Standards and Technology, Security Considerations in the System Development Life Cycle, Special Publication 800-64, Revision 1.
2. U.S. Department of Homeland Security, Catalog of Control Systems Security: Recommendations for Standards Developers, September 2009.
3. U.S. Department of Commerce, National Institute of Standards and Technology, Guide for Conducting Risk Assessments, Special Publication 800-30, Revision 1.
4. U.S. Department of Commerce, National Institute of Standards and Technology, Guide to Selecting Information Technology Security Products, Conducting Risk Assessments, Special Publication 800-36, Revision 1.
5. U.S. Department of Commerce, National Institute of Standards and Technology, Computer Security Incident Handling Guide, Special Publication 800-61, Revision 2.

APPENDIX A

ACRONYM LIST

ACRONYM LIST

CIP	Critical Infrastructure Protection
DLR	Dynamic Line Rating
EMS	Energy Management System
IT	Information Technology
NERC	North American Electric Reliability Corporation
SCADA	Supervisory Control and Data Acquisition
SwRI	Southwest Research Institute
TBD	To Be Determined
TBR	To Be Reviewed

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APPENDIX D. LINE SAG MEASUREMENT VERIFICATION (LSMV) STUDY REPORT

LINE SAG MEASUREMENT VERIFICATION (LSMV) STUDY REPORT

for the

ELECTRIC TRANSMISSION SYSTEM DYNAMIC LINE RATING SYSTEMS

Document No. 10-16404-DLR-LSMV

Version 1.1

May 3, 2013

SwRI® Project No. 10.16404.06

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LINE SAG MEASUREMENT VERIFICATION (LSMV) STUDY REPORT

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Document No. 10-16404-DLR-LSMV

Version 1.1

May 3, 2013

SwRI® Project No. 10.16404.06

Prepared by: Gary L. Ragsdale Date: 5/3/2013
Gary L. Ragsdale, Ph.D., Staff Engineer

Approved by: Mark E. Moczygemba Date: 5/3/2013
Mark E. Moczygemba, P.E., Assistant Director
Communications and Embedded Systems Department

REVISION NOTICE

Version Identifier	Date of Issue	Summary of Changes
-	February 15, 2013	Rough Draft
1.0	March 15, 2013	Draft – Formatting and review with additional content.
1.1	April 30, 2013	SwRI Final Report

This document contains information that is as complete as possible. Where final numerical values or specification references are not available, best estimates are given and noted To Be Reviewed (**TBR**). Items which are not yet defined are noted To Be Determined (**TBD**). The following table summarizes the TBD/TBR items in this revision of the document, and supplements the revision notice above.

Section	Description

EXECUTIVE SUMMARY

LINE SAG MEASUREMENT VERIFICATION STUDY

Actionable Conclusions

The Nexan CAT-1 system produces reliable tension measurements useful for the computation of other transmission line parameters, specifically line sag estimates. Southwest Research Institute (SwRI) reached the following conclusion regarding the CAT-1 sag estimates using a series of statistical techniques.

- Differences in the observed and tension-based sag estimates are small for properly calibrated Dynamic Line Rating (DLR) systems.
- All of the sag estimates reported the same line sag behavior for any given observation time or tension.
- The sag estimates produced reliable estimates in a variety of 138 kV and 345 kV line section configurations.
- The sag estimates can be reliably reproduced.
- Observed sag and observed tension are complementarily correlated.
- Observed sag and the catenary sag given observed tension is directly correlated.
- The rate of change of observed sag and the rate of change in the catenary sag given an observed tension is directly correlated.
- The correlated behaviors are insensitive to the distance separating the observed span and the structure where tension is observed.
- The differences in the observed sag and the catenary sag given an observed tension are small and have small standard deviations.

Methodology

The study compared sag estimates produced independently for an “observed span” chosen within a selected line section span using DLR systems placed along the line section. Oncor placed CAT-1 systems at structure connection points along a line section for study. The “observed span” within the same line section was instrumented with a Sagometer or a Real-Time - Transmission Line Monitoring System (RT-TLMS) DLR system. Oncor collected sag estimates produced by Sagometer or Promethean RT-TLMS DLR systems and tension estimates from the CAT-1 DLR systems. SwRI created custom software to process observed span sag estimates taken from the Sagometer or RT-TLMS. The software computed tension-based catenary sag estimates for the observed span using the catenary sag equation and CAT-1 tension measurements. The software referenced all sag comparisons to the observed span by using the observed span length and conductor weight. Statistical techniques compared the differences in the sag reported by the independent systems for the observed span. Statistical inference techniques used in clinical trials verified and validated the similarity of the reported sag behavior for given time intervals, ranges of tension, distances and rates of sag change.

Executive Management Key Takeaways

- The Nexan CAT-1 DLR system produces tension measurements sufficient for reliable line section sag estimates.
- The tension-based sag estimates were distance insensitive for distances up to 93,460 feet within the line sections examined by the study.
- The estimates are repeatable and are not coincidental.

Engineering Takeaways

- The accuracy of tension-based sag estimates is dependent on the accuracy of the as-built span connection point separation distance, referred to hereafter as the "span length." Span length errors of a few feet cause a constant bias in the tension-based sag estimates.
- The accuracy of tension-based sag estimates is dependent on the accuracy of the CAT-1 tension measurement calibration. Tension calibration errors can cause a constant bias in the tension-based sag estimates.
- The accuracy of CAT-1 tension measurements is dependent on proper configuration of the CAT-1 and Supervisory Control and Data Acquisition (SCADA) data acquisition systems. Misconfiguration of systems can cause large tension quantization errors as evidenced by measurements taken during the study.
- Tension measurements within a given line section are distance insensitive for the sections studied by SwRI. The maximum distance separating a CAT-1 system and a corresponding observed span was 93,460 feet.

Planning Takeaways

- Accurate clock synchronization among the CAT-1 systems is necessary for high-fidelity measurement studies. Tension measurements may not correlate if separated in time by more than a minute.
- The accuracy and functionality of CAT-1 tension measurements can be improved by increasing the measurement reporting rate from one report per 10 minutes to one report per minute.
- Appropriate statistical analytics are required to reduce the measurements to meaningful sag estimates. Tension measurements are randomly varying values due to random line vibration and aerodynamic motion. Data omissions were common during the study. The analytics should detect and compensate for data omission.
- Sag estimates are reliable within statistically defined confidence intervals.

Operations Takeaways

- Reliable communications should be maintained with CAT-1 systems for measurement reliability and accuracy.
- Measurement omissions are disruptive to sag or other line parametric estimates.

Other Conclusions and Notations

The disqualifications of measurements, as noted in the study, were all attributable to known conditions. The primary causes for measurement disqualification were misalignment of time stamps and discontinuities in the measurement collection.

SwRI observed that the RT-TLMS provided greater detail and opportunities for complex testing due to its higher, one sample/minute observation rate. SwRI recommends a cost-benefit analysis be applied to the idea of increasing the observation rate on the CAT-1 systems.

The study was successfully completed in large part due to the diligent leadership of Tip Goodwin and the Oncor Energy Delivery staff. Our compliments also go to The Valley Group for staff support, especially to Robert Mohr. The author of this document and Southwest Research Institute were honored to conduct the Line Sag Measurement Verification (LSMV) Study on behalf of Oncor Energy Delivery and the Department of Energy.

1. Introduction

This document describes the purpose, approach, results and conclusions of an independent verification and validation (IV&V) study conducted by Southwest Research Institute (SwRI) on Dynamic Line Rating (DLR) measurements supplied by Oncor Energy Delivery. The study was funded by Oncor Energy Delivery and by a Department of Energy demonstration grant.

The study applies a statistical inference methodology to reach a set of conclusions regarding the efficacy of the DLR measurements. The statistical inference methodology tests two competing hypotheses. The first hypothesis contends that measurements of transmission line conductor operating characteristic behavior produced by two or more independent DLR line parametric measurement devices are verifiable as a correlated relationship. The second hypothesis validates the correlation by showing that the measurement correlation is not a random result, i.e., the relationship exists and is repeatable.

The study performs a series of tests for the purpose of assigning a quantifiable degree of confidence to DLR measurements in a manner that is logically and mathematically rigorous. The test philosophy relies on the following requirements:

- Independent measurements of line parametric behavior (e.g., sag) should have a strong correlation (agree) under the same conditions within a chosen span, hereafter referred to as the "observed span."
- Line parametric measurements should be distinguishable from random events unrelated to line behavior, i.e., there should be no ambiguity or deception within the measurements.
- Line behavior measurements should corroborate well-known and proven models for line behavior (e.g., the catenary sag equation).
- Differences in observed span behavior should be small and fall within reasonable confidence intervals.

The Line Sag Measurement Verification Report contained herein documents the measurement results against specific DLR objectives:

- CAT-1 tension observation sensitivity to line parameter characterization as a function of distance.
- Correlation of observed span parametric behavior among CAT-1, Real-Time - Transmission Line Monitoring System (RT-TLMS) and Sagometer measurements.
- Correlation of observed span parameter behavior with the catenary sag equation and the equation's first derivative, i.e., the predicted behavior rate of change.
- Calculation of differences in observed span sag estimates, variations in the differences and sag estimate difference confidence intervals.

2. Line Sag Measurement Verification Study Scope of Work

The following sections describe the Line Sag Measurement Verification (LSMV) Study, hereafter referred to as the LSMV Study or simply the study.

2.1 Objective

The primary goal of the Line Sag Measurement Verification task is to verify and validate the line parametric measurements collected by the Nexan CAT-1 DLR system. The measurements are verified and validated if the following statements can be shown to be true:

- Independent measurements of line parametric behavior (e.g., sag) should have a strong correlation (agree) under the same conditions.
- Line parametric measurements should be distinguishable from random events unrelated to line behavior, i.e., there should be no ambiguity or deception within the measurements.
- Line behavior measurements should corroborate well-known and proven models for line behavior (e.g., the catenary sag equation).
- Differences in behavior should be small and fall within reasonable confidence intervals.

2.2 Background

The study tests line parametric data collected from more than one source for the same snapshot of time. The tests determine the reliability of the prime sensing and rating algorithm of the DLR technology of the project. As such, valid and consistent updates of the actual sag (vs. that of the dynamic rating estimator) are needed. Representative spans of the monitored lines distributed across hundreds of miles need to be monitored. While parameter measurements could be done manually, it would be quite expensive to provide a large quantity of these values over the two-year period of desired measurements. Additionally, modeling and estimation efforts can be greatly enhanced when more input data (i.e., data sampled more often) is utilized. The task implements an automated approach to measuring line parameters.

DLRs measure line behavior parameters as a means to infer the conductor's electrical characteristics and associated line sag. The DLR measurements must provide accurate representation of spans traversing miles of conductors.

DLR uses several technologies to measure a variety of parameters that represent the operating characteristics of the conductor. Ultimately, transmission lines are designed to maintain a minimum ground clearance at a prescribed maximum operating condition. Therefore, the position of the conductor is of primary interest relative to the ground. Clearance is proportional to the sag of the conductor below the attachment points to the supporting structures. Sag can be characterized by mathematical equations that include the following parameters: conductor type, weight, tension of the conductor, load (current) flowing through the conductor, ambient temperature, wind direction and speed, and solar conditions. Many of these parameters are set at the time of installation. Others vary with time and operating conditions. The catenary equation for a suspended cable is the mathematical model that provides a direct correlation between the parameters. It is possible to solve the mathematical relationship such that the conductor's operating characteristics can be determined knowing the majority of the parameters enabling the measurement of the conductor position, i.e., its sag below supports or clearance to ground or its tension, and resolving the other characteristics.

This project used the CAT-1 system as a primary measurement technology, measuring the tension of the conductor, and two secondary technologies measuring positional characteristics of sag or clearance. The study correlates the line parametric measurements from all three technologies as a test of the CAT-1 DLR system measurement integrity.

The study verified conductor sag measurements over many spans of the instrumented transmission lines. The sag information was used to assess the effectiveness and reliability of an observed span representation of the transmission system. This validation is important to the DLR validation process and future acceptance of the protocols used in the project.

2.3 Data Reduction

SwRI performed a comparative analysis between the CAT-1 tension-sensing technology results and the equivalent time-stamped conductor position characteristics for the observed spans monitored by Sagometers and RT-TLMS devices. The analysis determined the degree of variability between the parametric measurements. It presents a critical evaluation of the root cause for variability and recommendations to enhance the monitoring systems to improve correlation and effective DLR predictions.

2.4 Data Reduction

Deliverables included test metrics and documentation, as well as consulting on field deployment and data collection requirements. At the conclusion of the field data collection, SwRI prepared a final report, contained herein, detailing the analysis and correlation between CAT-1 measurements and the Sagometer or RT-TLMS measurements.

3. Definition of Terms and Abbreviations

The following definitions appear in the study and are provided for reference and clarification.

Transmission line, also simply referred to as a line – One or more conductors suspended from two or more transmission towers. See Figure D - 1.

SN.Port – CAT-1 tension observation sensors are individually identified by a serial number (SN) and port number (Port). For example, a CAT-1 sensor may have the designation CAT-1 SN.Port 4011.1 or simply CAT-1 4011.1. CAT-1 sensors were attached to observed spans and were stationary during the study.

RT-TLMS X-Y – RT-TLMS clearance observation sensors are individually identified by sensor number X and a sensor site location number Y. For example, an RT-TLMS sensor appearing in this study is RT-TLMS 1-3, meaning sensor number one located at site number three. RT-TLMS sensor number 1 was relocated to three different sites during the study.

Sagometer X – Sagometer sag observation sensors are individually identified by a sensor number X. For example, Sagometer 5 appears in this study. Sagometers were attached to observed spans and stationary during the study.

Span – The portion of a line connecting two adjoining transmission structures (Figure D- 1). The span is identified by the structures at its connection points (e.g., span 11/3 - 11/4 is a conductor suspended between structures 11/3 and 11/4).

Observation – A data element consisting of one or more behavior data values (tension, clearance, sag) related to one or more condition values (date and time of the observation, line description, tension).

Measurement – A set containing two or more observation data elements represented by the expression $observation \in \{measurement\}$. Each element of the set is an observation. The "measurements" within this study are sets of independent observations of transmission line behavior recorded under the same given conditions.

Metric – A value that quantifies the result of a test.

Valid – A hypothesis is "valid" if the hypothesis metrics and confidence intervals indicate an expected behavior observed by two or more independent observers (sensors).

Verify – A hypothesis is "verified" if it is improbable that a behavior other than the expected behavior produced the metric.

Correlate – "Either of two things so related that one directly implies or is complementary to the other (as husband and wife)" [Merriam Webster Dictionary – http://www.merriam-webster.com/dictionary/correlated]. "Things" are observed transmission line parametric behaviors within the context of the LSMV Study.

Correlation coefficient ρ – A metric between -1.0 and 1.0 indicating the similarity of two independent measurements of a behavior under the same given conditions. The value of ρ is the null hypothesis metric of behavioral similarity. Section 8.2.

Given condition (noted as "behavior | condition") – A control variable used as a basis of observation comparison (e.g., time and tension are given conditions for comparing DLR line measurements as denoted by "sag | time" and "sag | tension", respectively).

Figure D - 1 Transmission Line Towers, Lines, Spans and Conductors

Cross-correlation function – A statistical function described in [18] and symbolized by the operator "⇔" (e.g., ρ | (time, line) = RT-TLMS sag ⇔ $Sag[CAT1\ tension\ \xi]$| (line,time).

Null hypothesis (H_0) – The expected outcome of a behavioral test (e.g., the$-1.0 \leq \rho \leq -0.8$ or $0.8 \leq \rho \leq 1.0$). The correlation of two independent DLR observations under the same given conditions is the null hypothesis adopted within the study. Specifically, measurements taken by two independent devices given the same conditions are strongly correlated if $\mathrm{H}_0 \xrightarrow{\text{yields}} 0.8 \leq |\rho| \leq 1.0$). See Section 8.2 for information specific to this study.

p-value (ϕ) - The alternative hypothesis test metric expressed as positive number between 0 and 1 that quantifies the uncertainty of a null hypothesis metric. (e.g., the correlation coefficient computed for two DLR observations). A sufficiently large value of ϕ indicates the sag correlation coefficient could be the coincidental result of random events. Note that a measurement set correlated with itself always has a unity p-value, $\phi = 1.0$, because all sets, including random noise, correlate perfectly with themselves and, therefore, are indistinguishable from other correlation events. Section 8.2.

Alternative hypothesis (H_a) – The alternative outcome of a test (e.g., the correlation may be a random coincidence, i.e., $\mathrm{H_a} \xrightarrow{\text{yields}} \phi > 0.1$. See Section 8 for additional metrics information specific to

this study. The study evaluates the metric ρ as a test of the null hypothesis. The success of the H_0 test is verified if H_a test demonstrates that ρ is the unlikely result of coincident random events.

Sag – The vertical distance from the transmission tower conductor attachment points to the lowest point in the conductor connected to two adjoining towers, i.e., a span. The analysis assumes that the tower conductor attachment points are at the same altitude.

Tension ξ – The force expressed in "pounds – force" and measured between the suspended conductor and its tower attachment point. Tension can be further expressed as the combination of its horizontal and vertical tension components, i.e., "horizontal tension" and "vertical tension." Hence forward, all references here to "tension" are implicitly horizontal tension ξ unless otherwise specified.

Catenary sag equation $\mathrm{Sag}[\xi]$ – A function that estimates the sag of a span given the horizontal tension (lbs – force), span length (ft), and the conductor weight (lbs/ft). Span length and conductor weight are constants conditioned by the given line as documented in Tables D - 1 and D - 2. See Section 8.1 for more information regarding the catenary sag equation. All catenary sag estimates used in the study are the observed span length and conductor weight, thereby producing an estimate of sag in the observed span.

Clearance – The vertical distance between the lowest point in a conductor attached between two towers and a surface immediately below the conductor.

Observed span – A span instrumented to produce sag measurements using a Sagometer or an RT-TLMS. All catenary sag estimates are referenced to observed span using $\mathrm{Sag}[\xi]$ and the observed span length and conductor weight. In other words, all catenary sag estimates employ the $\mathrm{Sag}[\xi]$, CAT-1 tension measurements, the observed span length and the observed span conductor weight.

4. Research Objectives

The study conducts tests to verify and validate transmission line parametric measurements as reliable representations of line behavior. Measurement verification conducts comparisons of independent measurements of transmission line behavior as representations of the same behavior under the same given measurement conditions, i.e., the measurements are correlated. The conditions of verification are met if the verification test metric is within a selected test metric confidence interval. The conditions for test validation are met when validation test shows that the relationship between independent measurements, i.e., measurement correlation, is not the result of random events. The study defines verification and validation tests as successful if the measurements of line behavior have a strong correlation as deemed by a verification metric value bounded within the metric confidence interval, and if it can also be shown that the strong correlation is not the result of coincidental random events. The study's objectives:

- Produce evidence of line parametric behavior similarity under varying given conditions.
  - Line parametric behavior similarity as a function of distance between observations.
  - Similarity as a function of differences in observation time.
  - Similarity to theoretical or design predictions of line sag behavior.
  - Similarity during changes in line parametric behavior.
- Verify similarity through independent observations.
- Distinguish between coincidental random behavior and correlated behavior.
- Validate the similarity by disqualifying alternative possibilities from the test results.
- Validate and verify the correlation of measurements and the predictions of line behavior models.

5. Problem Description

The study must verify and validate the relationship of multiple measurements of transmission line sag behavior collected by independent devices in a logical and methodical fashion. The study method must qualify the line behavior interrelationship and validate the relationship as real, i.e., the relationship must not be the result of coincident, random events. The following bullets describe important aspects of the study environment.

- "Sag" refers to the vertical displacement of a conductor within a 2D space.
  - Transmission lines move horizontally and vertically.
  - Verification is only in the vertical dimension.
- Two or more measurement methods are required for a relationship comparison.
  - There must be sufficient observations within measurements for a sound behavioral comparison.
    - Independent observations must be related via some common ("given") observation context (condition) (time, frequency, tension, statistics, temperature).
- Behavioral similarity may be masked by measurement conditions.
  - Behavior may be separated in time.
  - Behavior may be attenuated by distance.
  - Behavior may be masked by random external processes (noise).
- Measurement methods have constraints and limitations.

- Manual measurement methods are not practical.
- Error is resident in all measurement methods.

6. Research Context

The CAT-1 system produced by The Valley Group, a subsidiary of Nexans, was the primary DLR system deployed within the scope of a larger demonstration project plan. Two additional technologies were also deployed in support of the LSMV Study –The additional technologies were the Sagometer®, produced by EDM International, and the RT-TLMS, produced by Promethean Devices, Inc.

The CAT-1 system collected real-time line characteristics measurements, which were used to calculate the actual allowable dynamic rating of the transmission line for operations and for the LSMV Study. The Sagometer and RT-TLMS systems were secondary systems deployed to provide comparative measurements used by the LSMV Study as described herein.

Oncor installed CAT-1s, Sagometers, and RT-TLMS systems at observation points, denoted as "observed spans," on selected lines as shown in Table D - 1. Sagometers or RT-TLMS were placed in the observed spans to provide a varied sample of data representing different distances from the CAT-1 installations and in different topography (groundcover and terrain). The "Reach (ft)" columns give the estimated transmission line corridor distances from the Sagometer or RT-TLMS to a corresponding CAT-1.

The line conductor specifications are given in Table D - 2. All of the selected lines use Drake conductors. The transmission lines use single conductors per phase and bundles of two conductors for each phase denoted as "2X-Drake." All catenary sag calculations assume the Drake conductor weight, i.e., 1.094 lbs./ft. for both types of Drake conductors.

Table D – 3 lists the tension observation points equipped with Nexan CAT-1 systems. By design, CAT-1 measurements are compared with observed span sag measurements collected by an RT-TLMS or a Sagometer. Tension measurements from CAT-1s can be compared one against another if more than one CAT-1 observes tension in the same line.

Table D - 1 Instrumented Lines and Associated DLR Observation Points

DLR Validation Study
Secondary Span Sites
Sag, Clearance and Tension Data

Line	Span From Str.	Span To Str.	Device	Span To Set	Span To Ph.	Span (ft)	Δh (ft)	Cond Temp °C	Max. Tens. (lbs)	Hori. Tens. (lbs)	Max Ten %UL	Cond Constant C (ft)	Midspan Chord Sag (ft)	Clearance (ft)	CAT @	Reach (ft)	CAT @	Reach (ft)	CAT @	Reach (ft)	CAT @	Reach (ft)	CAT @	Reach (ft)	CAT @	Reach (ft)
															29° Angle at Str 6/9, Side Tension											
Bell County - Gabriel 138 kV	8/3	8/4	Sagometer 4	2	1	555	0	0		4517			9.33	39.38	6/2	11,150	11/4	15690								
Lake - Creek - Temple 345 kV	11/3	11/4	Sagometer 1	2	1	1535	22	0	7791	7732	25	7067	41.19	33.65	8/4	15,640	2/4	44,422	15/5	21620	23/5	65,001	***29/3A***	93,654		
Waco Atco - Temple ELM Creek 138 kV	19/4	19/5	RT-TLMS 1-2	5	1	640	3	0	5068	5054	16	4620	11	48.78	19/3	640	26/7	38,071								
Waco Atco - Temple ELM Creek 138 kV	21/3	21/4	RT-TLMS 1-3	5	1	640	3	85	3164	3142	10	2872	17.67	42.11	19/3	10,156	26/7	27,915								
Waco Atco - Temple ELM Creek 138 kV	25/1	25/2	RT-TLMS 1-1	5	1	640	3	0	5073	5059	16	4625	10.96	46.67	19/3	30,291	26/7	8,420								
Temple Pecan Creek - Temple 345 kV	31/1	31/2	Sagometer 2	2	1	1450	22	0	6386	6324	20	5780	45.49	34.58	31/5	3,490	***29/5B***	7677								
Tradinghouse - Lake Creek East 345 kV	4/1	4/2	Sagometer 5	3	1	1200	5	0	6602	6569	21	6004	29.57	49.8	5/3	6,400										
Tradinghouse - Lake Creek West 345 kV	3/1	3/2	RT-TLMS 2-1	4	1	1153	1	0	6593	6562	21	5999	27.79	38.2	3/3	1075	5/1	9491								
Tradinghouse - Lake Creek West 345 kV	6/2	6/3	RT-TLMS 2-2	4	1	880	7	0	6562	6540	21	5978	16.13	37.21	3/3	14,646	5/1	7,110								
Tradinghouse - Lake Creek West 345 kV	7/3	7/4	RT-TLMS 2-3	4	1	880	7	85	4608	4579	15	4185	23.04	30.3	3/3	21,146	5/1	13,610								
Tradinghouse - Temple Pecan Creek 345 kV	23/3	23/4	Sagometer 3	2	1	1200	20	0	7518	7476	24	6834	26.33	39.2	8/4	78,331	2/4	107,113	15/5	41,071.00	23/5	3,495	29/3B	30,963		

Table D - 2 Line Conductor Specifications

Line Segment	Conductor	Max Operating Temperature	Static Rating
Rogers Hill – Elm Mott 138 kV	GROSBEAK	90C	780 A
Bosque – Rogers Hill 138 kV	GROSBEAK	90C	780 A
Lake Creek – Temple Switch 345 kV	2X DRAKE	90C	1794 A
Tradinghouse – Temple Pecan Creek 345 kV	2X DRAKE	90C	1794 A
Temple Pecan Creek – Temple Switch 345 kV	2X DRAKE	90C	1794 A
Tradinghouse – Lake Creek West 345 kV	2X DRAKE	90C	1794 A
Tradinghouse – Lake Creek East 345 kV	2X DRAKE	90C	1794 A
Waco Atco – Cottonbelt Tap 138 kV	DRAKE	90C	897 A
Cottonbelt Tap – Spring Valley Tap 138 kV	DRAKE	90C	897 A
Spring Valley Tap – McGregor Phillips Tap 138 kV	DRAKE	90C	897 A
McGregor Phillips Tap – Temple Elm Creek 138 kV	DRAKE	90C	897 A
Bell County – Salado 138 kV	DRAKE	100C	990 A
Salado – Sonterra 138 kV	DRAKE	90C	897 A
Jarrell East – Gabriel 138 kV	DRAKE	90C	897 A

Table D - 3 Nexan CAT-1 Observation Points by CAT-1 Serial Number (SN) and Port Number

CAT S	Po	Line	Line	Segment	Structu	Type/Direction
4005	1	300_A	Lake Creek-Temple 345 kV	Lake Creek-Temple 345 kV	2/4	FDE
4005	2	490_A	Tradinghouse - Temple Pecan Creek 345 kV	Tradinghouse - Temple Pecan Creek 345 kV	2/4	FDE
4006	1	300_A	Lake Creek-Temple 345 kV	Lake Creek-Temple 345 kV	8/4	FDE
4006	2	490_A	Tradinghouse - Temple Pecan Creek 345 kV	Tradinghouse - Temple Pecan Creek 345 kV	8/4	FDE
4007	1	300_A	Lake Creek-Temple 345 kV	Lake Creek-Temple 345 kV	15/5	FDE
4007	2	490_A	Tradinghouse - Temple Pecan Creek 345 kV	Tradinghouse - Temple Pecan Creek 345 kV	15/5	FDE
4008	2	280_A	Tradinghouse - Lake Creek West 345 kV	Tradinghouse - Lake Creek West 345 kV	5/1	FDE
4008	1	490_A	Tradinghouse - Temple Pecan Creek 345 kV	Tradinghouse - Temple Pecan Creek 345 kV	5/1	FDE
4009	1	300_A	Lake Creek-Temple 345 kV	Lake Creek-Temple 345 kV	23/5	FDE
4009	2	490_A	Tradinghouse - Temple Pecan Creek 345 kV	Tradinghouse - Temple Pecan Creek 345 kV	23/5	FDE
4010	1	300_A	Lake Creek-Temple 345 kV	Lake Creek-Temple 345 kV	29/3A	DE - North to Lake Creek
4010	2	490_A	Tradinghouse - Temple Pecan Creek 345 kV	Tradinghouse - Temple Pecan Creek 345 kV	29/3B	DE - North to Tradinghouse
4011	1	1830_C	Waco Atco - Temple ELM Creek 138 kV	McGregor Philips - Temple Elm Creek	26/7	DE - South to TEC
4011	2	1830_C	Waco Atco - Temple ELM Creek 138 kV	McGregor Philips - Temple Elm Creek	26/7	DE - North to McGregor Philips
4012	1	315_A	Temple Pecan Creek-Temple 345 kV	Temple Pecan Creek-Temple 345 kV	31/5	FDE
4013	1	300_A	Lake Creek-Temple 345 kV	Lake Creek-Temple 345 kV	29/5A	DE - South to Temple
4013	2	315_A	Temple Pecan Creek-Temple 345 kV	Temple Pecan Creek-Temple 345 kV	29/5B	DE - South to Temple
4014	1	1830_C	Waco Atco - Temple ELM Creek 138 kV	McGregor Philips - Temple Elm Creek	33/11	DE - North to McGregor Philips
4015	1	1830_F	Waco Atco - Temple ELM Creek 138 kV	Waco Atco - Cottonbelt	8/5	DE - South to Cottonbelt
4015	2	1830_F	Waco Atco - Temple ELM Creek 138 kV	Waco Atco - Cottonbelt	8/5	DE - North to Waco Atco
4016	1	1830_E	Waco Atco - Temple ELM Creek 138 kV	Cottonbelt - Spring Valley	12/9	DE - South to Spring Valley
4016	2	1830_E	Waco Atco - Temple ELM Creek 138 kV	Cottonbelt - Spring Valley	12/9	DE - North to Cottonbelt
4017	1	1830_B	Waco Atco - Temple ELM Creek 138 kV	Spring Valley - McGregor Philips	15/7	DE - South to McGregor Philips
4017	2	1830_B	Waco Atco - Temple ELM Creek 138 kV	Spring Valley - McGregor Philips	15/7	DE - North to Spring Valley
4018	1	1830_C	Waco Atco - Temple ELM Creek 138 kV	McGregor Philips - Temple Elm Creek	19/3	DE - South to TEC
4018	2	1830_C	Waco Atco - Temple ELM Creek 138 kV	McGregor Philips - Temple Elm Creek	19/3	DE - North to McGregor Philips
4019	1	290_A	Tradinghouse-Lake Creek East 345 kV	Tradinghouse-Lake Creek East 345 kV	2/3	FDE
4020	1	290_A	Tradinghouse-Lake Creek East 345 kV	Tradinghouse-Lake Creek East 345 kV	5/3	FDE
4021	1	290_A	Tradinghouse-Lake Creek East 345 kV	Tradinghouse-Lake Creek East 345 kV	8/5	FDE
4022	1	280_A	Tradinghouse - Lake Creek West 345 kV	Tradinghouse - Lake Creek West 345 kV	3/3	FDE
4023	1	1710_A	Bell County - Gabriel 138 kV	Salado-Sonterra	6/2	DE - North to Salado
4023	2	1710_A	Bell County - Gabriel 138 kV	Salado-Sonterra	6/2	DE - West to Sonterra
4024	1	1710_C	Bell County - Gabriel 138 kV	Bell County-Salado	13/2	FDE
4025	1	1710_C	Bell County - Gabriel 138 kV	Bell County-Salado	11/4	FDE
4026	1	1710_A	Bell County - Gabriel 138 kV	Salado-Sonterra	11/4	DE - North to Salado
4026	2	1710_A	Bell County - Gabriel 138 kV	Salado-Sonterra	11/4	DE - South to Sonterra
4027	1	1710_D	Bell County - Gabriel 138 kV	Jarrell East - Gabriel	20/1	DE - North to Jarrell East
4027	2	1710_D	Bell County - Gabriel 138 kV	Jarrell East - Gabriel	20/1	DE - South to Gabriel
4028	1	1710_D	Bell County - Gabriel 138 kV	Jarrell East - Gabriel	20/1	DE - North to Jarrell East
4029	1	1030_A	Bosque-Elm Mott 139 kV	Rogers Hill - Elm Mott	21/10	DE - West to Rogers Hill
4029	2	1030_A	Bosque-Elm Mott 139 kV	Rogers Hill - Elm Mott	21/10	DE - East to Elm Mott
4030	1	1030_B	Bosque-Elm Mott 139 kV	Bosque - Rogers Hill	28/6	DE - West to Bosque
4030	2	1030_B	Bosque-Elm Mott 139 kV	Bosque - Rogers Hill	28/6	DE - East to Rogers Hill
4031	1	1030_B	Bosque-Elm Mott 139 kV	Bosque - Rogers Hill	33/3	DE - West to Bosque
4031	2	1030_B	Bosque-Elm Mott 139 kV	Bosque - Rogers Hill	33/3	DE - East to Rogers Hill

7. Telemetry Acquisition

The study compares line parametric measurements taken from one or more CAT-1s and an RT-TLMS or a Sagometer all attached to different spans of a given line. The measurements are independent and have different characteristics.

CAT-1

CAT-1s measure tension logged on 10-minute intervals. The measurements are transmitted from the span to the Oncor Energy Management System (EMS) control center via the Oncor Supervisory Control and Data Acquisition (SCADA) system. The measurements carry a time stamp synchronized to the Oncor SCADA clock. Time synchronization among the CAT-1s is closely maintained. That said, the CAT-1 measurement time stamps are not precisely aligned, i.e., they are not observed at the same second within a given 10-minute interval. The lack of precise time synchronization of the CAT-1 measurements limits correlation of CAT-1 $\text{tension} \mid \text{time}$ to the nearest 10-minute interval. The 10-minute time ambiguity implies that the tension relationship may need to persist for up to five minutes. If not, the CAT-1 tension | time observations will decorrelate if comparable observations occur at too great a time difference. Telemetry time synchronization is essential to line rating analysis in the time domain, i.e., when time is the given condition. The line behavior decorrelates as the telemetry time separation increases.

The tension from the CAT-1 systems is transformed into a sag estimate for the test span using the catenary equation and the calibrated results of the tension, sag and conductor temperature relationship. The sag positional aspect of the conductor was used for correlation to the secondary systems, which directly measured either the sag of the conductor or the conductor clearance to the ground.

Sagometers

The Sagometer uses smart camera technology to take pictures at regular intervals of a target suspended from the observed span conductor. The smart camera calculates the X and Y coordinates of the target and converts the coordinates into span sag observations. The camera transmits the measurements to a data recording and communication system mounted on the tower or pole. The communication system connects to the Internet through the local cellular phone system. The communications system facilitates the remote measurement retrieval.

The Sagometer records a sag observation on 10-minute intervals at times not synchronized with the CAT-1 telemetry clock. SwRI aligned the Sagometer measurements in time to the 10-minute boundary nearest to a corresponding CAT-1 measurement. Consequently, there can be several minutes separating the actual recording time of the Sagometer and CAT-1 observations. The lack of precise time synchronization affects the correlation metric when time is the given condition.

RT-TLMS

The RT-TLMS monitors the magnetic field level beneath an observed span and, using algorithms, calculates the position of the conductors. The calculations effectively determine the distance from the RT-TLMS sensor to the conductor, an estimate of the line clearance. The observations are stored on the local recording system and are available for download via cellular telephone networks. The RT-TLMS sensors were moved periodically to new spans to collect data from different vantage points. The magnetic field measurements were verified by direct sag measurements for a short time using a high-definition laser distance device.

The RT-TLMS records clearance observations on one-minute intervals at times not synchronized with the CAT-1 telemetry clock. Clearance measurements were converted to sag estimates using an estimate of the conductor attachment height.

SwRI aligned RT-TLMS observations in time to the 10-minute interval boundary nearest to a corresponding CAT-1 measurement. Consequently, there can be up to 30 seconds separating the recording times of the RT-TLMS and CAT-1 measurements. The lack of precise time synchronization affects the correlation metric when time is the given condition.

8. Research Study Plan and Results Summary

The verification and validation study adopts a combination of statistical metrics, confidence intervals and hypothesis testing methods. The study is executed with two opposing test hypotheses:

- a null hypothesis (H_0), "Line sag behavior can be reliably verified if two or more independent observation methods yield strongly correlated measurements of the sag behavior under the same observation conditions" and
- the alternative hypothesis (H_a) – "Line sag behavior is uncorrelated and the appearance of sag correlation is actually the result of coincidental random events."

The study declares a correlation of line behaviors to be "validated and verified" if the null hypothesis is shown to be true and the alternative hypothesis is shown to be improbable.

Therefore, the null hypothesis test result, called the "correlation coefficient," is expressed as a quantifiable metric of the interrelationship. The null hypothesis correlation coefficient must fall within the bounds of a null hypothesis confidence interval defined by the study to be a strong indicator of the interrelationship.

The alternative hypothesis test verifies the integrity of the null hypothesis metric, i.e., the null hypothesis relationship is tested against the probability of a random event. An alternative hypothesis metric, called the "p-value," quantifies the probability of a random measurement correlation. A confidence interval bounds the p-value metric. The alternative hypothesis tests for a possible false validation indication by the null hypothesis.

Measures of line parametric behavior are declared as valid if the correlation coefficient falls within the strong correlation confidence interval. The correlation is verified if the p-value of the correlation coefficient falls within the random event confidence interval defined to be an "improbable random event."

The null hypothesis and alternative hypothesis tests are applied to relationships of several sets of behavior measurements under several sets of given conditions. Behavior measurements examined include the interrelationship of CAT-1 tension measurements to Sagometer sag measurements, RT-TLMS clearance measurements, and catenary sag equation predictions.

8.1 Catenary Sag Equations

The study employs the catenary sag equation, $Sag[tension\ \xi]$, to convert CAT-1 horizontal tension measurements into span sag estimates [15].

$$\mathrm{Sag[HorizontalTension, LineWeight, SpanLength]} = \frac{\mathrm{HorizontalTension}}{\mathrm{LineWeight}} * \left(\mathrm{Cosh}\left[\frac{\mathrm{LineWeight} * \mathrm{SpanLength}}{2 * \mathrm{HorizontalTension}}\right] - 1\right),$$

<u>Note</u>: Cosh[] – hyperbolic cosine function

The "LineWeight" and "SpanLength" parameters are implicitly specified by the given line condition (e.g., the given line = "Waco Atco – Temple Elm Creek 138 kV line"). It is essential that the parameters be accurately specified for good predictions of sag. See Section 8.3 for examples of sag estimate bias introduced by relatively small errors in the span length parameter.

Use of the catenary equation implicitly assumes an ideal observed span, i.e., connection points are at identical heights. The conductor tension must not be altered by mechanical structure or terrain, i.e., the conductors must be free to equalize tension on either side of a floating connection points. Towers must be rigid, i.e., the tower structure must not move at the conductor connection point.

The "small angle" catenary sag equation saSag[] is a simplification of Sag[].

$$\mathrm{saSag[HorizontalTension, LineWeight, SpanLength]} := \frac{\mathrm{LineWeight} * \mathrm{SpanLength}^2}{8 * \mathrm{HorizontalTension}}$$

It can be shown that saSag[] approximates Sag[] under the condition that the conductor attachment angle is much less than one radian. The conductor attachment angle is formed at the intersection of the conductor and a horizontal line drawn through the tower connection point. saSag[] is included here for completeness but is not used in the analysis that follows.

8.2 Metrics Definition

The correlation coefficient (ρ) is the chosen verification metric of relationships between two sets of line behavior measurements [18]. The values of ρ describe the correlation as a signed, fractional number. The sign specifies the relationship as being either "direct" or "complementary." For example, temperature measurements observed in degrees Fahrenheit and in degrees Celsius have direct correlation, i.e., they are either both increasing or decreasing values for a given temperature change. It is well known and will be confirmed later in this study that conductor tension and sag have a complementary relationship, i.e., tension decreases as sag increases. Thus the correlation coefficient computed for sag and tension measurements for a given line (e.g., time, tension) should be a negative number between -1.0 and 0.

The study verification step computes the correlation coefficient (ρ) for two or more estimates of behavior within the observed span under the same given condition. The study assigns a correlation "strength" weighting as defined by a confidence interval set. Table D - 4 lists the study's adopted ρ confidence intervals as proposed by [18]. Recall that the null hypothesis, as defined above, requires a "strong correlation," i.e., $-1.0 \leq \rho \leq -0.8$ or $0.8 \leq \rho \leq 1.0$.

Table D - 4 – Correlation Coefficient Metrics and Confidence Intervals

Correlation Coefficient (ρ)	Correlation Strength	Relationship
$-1.0 \leq \rho \leq -0.8$	Strong correlation	Complementary
$-0.8 < \rho < -0.5$	Moderate correlation	Complementary
$-0.5 \leq \rho < 0$	Weak correlation	Complementary
$0 \leq \rho \leq 0.5$	Weak correlation	Direct
$0.5 < \rho < 0.8$	Moderate correlation	Direct
$0.8 \leq \rho \leq 1.0$	Strong correlation	Direct

The study validates each behavior correlation metric by testing the null hypothesis with an alternative hypothesis test. Under the dual hypothesis test, the correlation coefficient must show strong correlation, whether direct or complementary, and the alternative hypothesis must not be probable.

The study employs p-value metric as the alternative hypothesis metric. The p-value assesses the randomness in the measurements producing ρ. See [18] for an explanation of the p-value and its computation.

SwRI bounded the alternative hypothesis test specifying a p-value confidence interval, p-value $\phi > 0.1$. The alternative hypothesis is probable if there is a 1% or greater probability that ρ is the product of random events. The null hypothesis is invalid if the alternative hypothesis is improbable, i.e., $\phi \leq 0.1$.

The possible reasons for a large p-value or a lack of correlation are many:

1. Alternative hypothesis is probable, implying that the measurements are not related, i.e., the different DLR systems produce unrelated or random sag estimates (H_a is always true, and H_0 is always false).
2. The measurements lack sufficient statistical significance due to omissions or errors in the data.
3. The measurements are affected by random external influences (e.g., wind deflection and line aerodynamic lift).
4. The measurements lack adequate precision (e.g., substantial quantizing error, equipment malfunctions).
5. The observed behavior is obscured under ambiguous given conditions (e.g., poor time alignment, mechanical attenuation due to separation distance or tension equalization interference).

See Section 8.3 for a more detailed discussion of telemetry acquisition factors.

A null hypothesis H_0 failure does not necessarily prove that the alternative hypothesis H_a is true. H_0 may fail due to the effects described in Section 8.3. This study identifies the conditions, if any, under which H_0 verifies or H_a validates the correlation of two independent measurements. The remaining

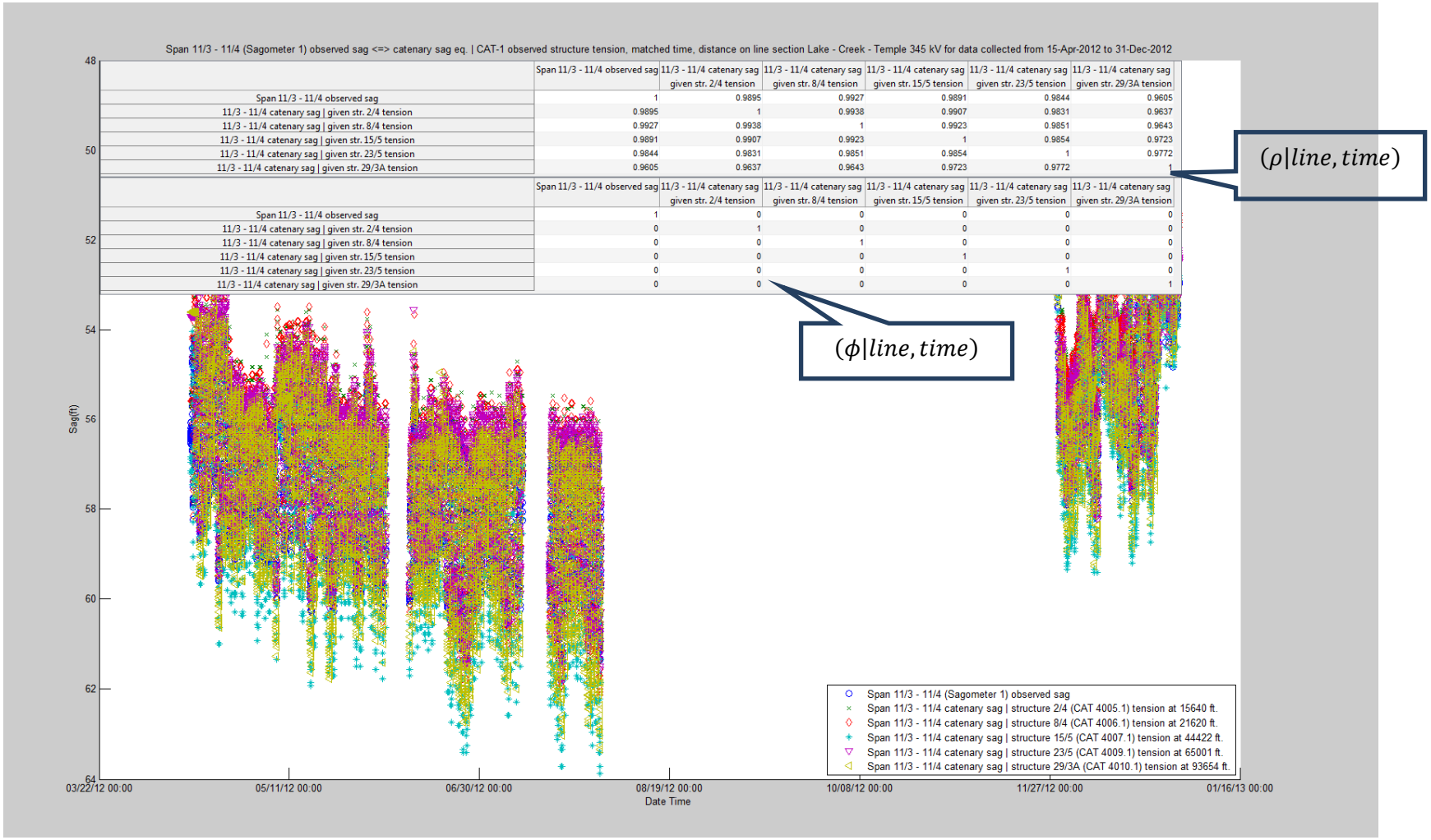
sections are devoted to the analysis and its interpretation of the hypothesis test metrics, i.e., ρ and ϕ. . Table D – 5 summarizes the criteria for validating and verifying test results.

Table D - 5 – DLR Line Measurement Validation and Verification Criteria

Test names	Null hypothesis test H_0 (validation)		
Alternative hypothesis test H_a (verification)	Test metrics	$0.8 \leq \lvert\rho\rvert \leq 1.0$	$0.0 \leq \lvert\rho\rvert < 0.8$
	$\phi \leq 0.01$	Validated and verified	Invalidated, but verified
	$\phi > 0.01$	Validated, but unverified	Invalidated and unverified

For example, Figure D - 2 displays correlation coefficients $\rho|line, time$ and p-values $\phi|line, time$ among the Sagometer-observed span 11/3 – 11/4 and CAT-1 systems located on structures comprising line section Lake Creek – Temple. Each table entry compares the sag estimates for observed span 11/3 – 11/4 produced by a pair of systems. For example, a comparison of the Sagometer in the observed span and a CAT-1 located on structure 23/5 produced $\rho|line, time = 0.9844$ and $\phi|line, time = 0$.

All of the table entries in Figure D – 2 satisfy the criteria in Table D – 1 for validating and verifying the observed behavior within line section Lake Creek – Temple. All of the catenary sag estimates $Sag[\xi]|CAT - 1\ tension\ \xi$ correlate strongly with the observed sag measurements. Furthermore, the table shows that all of the catenary sag estimates $Sag[\xi]|CAT - 1\ tension\ \xi$ correlate strongly with one another. The p-values ϕ are zero indicating that the cross correlation behavior is real and not a random event.



	Span 11/3 - 11/4 observed sag	11/3 - 11/4 catenary sag given str. 2/4 tension	11/3 - 11/4 catenary sag given str. 8/4 tension	11/3 - 11/4 catenary sag given str. 15/5 tension	11/3 - 11/4 catenary sag given str. 23/5 tension	11/3 - 11/4 catenary sag given str. 29/3A tension
Span 11/3 - 11/4 observed sag	1	0.9895	0.9927	0.9891	0.9844	0.9605
11/3 - 11/4 catenary sag | given str. 2/4 tension	0.9895	1	0.9938	0.9907	0.9831	0.9637
11/3 - 11/4 catenary sag | given str. 8/4 tension	0.9927	0.9938	1	0.9923	0.9851	0.9643
11/3 - 11/4 catenary sag | given str. 15/5 tension	0.9891	0.9907	0.9923	1	0.9854	0.9723
11/3 - 11/4 catenary sag | given str. 23/5 tension	0.9844	0.9831	0.9851	0.9854	1	0.9772
11/3 - 11/4 catenary sag | given str. 29/3A tension	0.9605	0.9637	0.9643	0.9723	0.9772	1

	Span 11/3 - 11/4 observed sag	11/3 - 11/4 catenary sag given str. 2/4 tension	11/3 - 11/4 catenary sag given str. 8/4 tension	11/3 - 11/4 catenary sag given str. 15/5 tension	11/3 - 11/4 catenary sag given str. 23/5 tension	11/3 - 11/4 catenary sag given str. 29/3A tension
Span 11/3 - 11/4 observed sag	1	0	0	0	0	0
11/3 - 11/4 catenary sag | given str. 2/4 tension	0	1	0	0	0	0
11/3 - 11/4 catenary sag | given str. 8/4 tension	0	0	1	0	0	0
11/3 - 11/4 catenary sag | given str. 15/5 tension	0	0	0	1	0	0
11/3 - 11/4 catenary sag | given str. 23/5 tension	0	0	0	0	1	0
11/3 - 11/4 catenary sag | given str. 29/3A tension	0	0	0	0	0	1

Figure D - 1 Line Section Lake Creek –Temple 345 KV Sag | Time Correlation between Span 11/3 – 11/4 (Sagometer 1) Sag Observations and Catenary Sag Estimates | CAT-1 Tension Observations

8.3 DLR Constraints, Errors, Omissions and Other External Factors

The next few subsections provide a summary of factors affecting the verification and validation of DLR sag estimates. In general, all of the DLR systems convert analog measurements to digital representations with the attendant introduction of quantizing error. Quantizing error is reported in the following paragraphs to the extent that it is known to SwRI. Calibration error may also exist within any of the DLR line parametric systems. A lack of clock synchronization can decorrelate otherwise related measurements.

The catenary sag equation $Sag[tension\ \xi]$ is caveated with certain assumptions that, if not satisfied, may introduce errors in its calculations. Some of the effects that could introduce error:

- The observed design parameters such as the distance between structures, called “span length,” may not be precisely known.
- Conductor attachment points may not be at the same elevation.
- Tower design constraints at conductor attachment points may alter line tension equilibrium.
- Towers may flex under changing line tensions.

The remainder of this section discusses factors potentially affecting results specific to the DLR line parametric measurement systems.

8.3.1 CAT-1 Tension Measurement Factors

CAT-1 DLR sensors are time synchronized to the Oncor SCADA clock and record tension observations. Each tension observation is sampled at a time value called “RTime” and officially time stamped with a the date and time of the next 10-minute interval as specified in the “Date” and “Time” fields, respectively. The value of RTime is not precisely synchronized, i.e., the CAT-1s have different values of RTime within the same 10-minute interval. The lack of exact time synchronization for the observations contributes in varying degrees to a reduction of correlation amongst CAT-1s making observations on the line. The CAT-1 “Date” and “Time” fields produced better time alignment with Sagometer and RT-TLMS measurements and were used to align CAT-1 tension observations with Sagometer sag and RT-TLMS clearance observations.

There were occasional lapses in CAT-1 logging due to various operational or installation problems. The Oncor DLR Lessons Learned Report [16] provides details regarding some of the problems. The absence of data at any given time constrained SwRI from performing correlation analysis for the affected times and lines. The following analysis will cite specific instances of missing or erroneous CAT-1 data when the omissions or errors are potentially significant to the analysis.

CAT-1 sensors quantize continuous analog tension observations into binary tension values using Analog-to-Digital Converters (ADCs). The CAT-1 ADCs have a quantizing resolution (α) of 12 lbs. - force/bit. The presence of ADCs introduces quantizing noise in the tension measurements. The quantizing noise statistics are zero mean and have a standard deviation of [17].

$$\sigma_{ADC} = \sqrt{{\alpha_{ADC}}^2/_{12}} \xrightarrow{yields} \sigma_{ADC} = 3.464\ lbs - force$$

The corresponding random change in the catenary sag estimate, while small in relation to the large values of tension observed by the CAT-1, contributes to the decorrelation of CAT-1 measurements.

Misconfiguration of CAT-1s (Table D - 6) decreased the quantizing resolution (α) to 60 lbs. - force/bit. The quantizing noise standard deviation increased to $\sigma_{ADC} = 17.32$ lbs – force. The decrease in quantizing resolution may impact measurement correlation.

Table D - 6 CAT-1 Serial Numbers and Port Numbers Exhibiting Decreased Quantizing Resolution

Line Section	Line Structure	CAT-1 Serial Number (SN)	CAT-1 Port Number
Lake Creek – Temple 345 kV	8/4	4006	1
Lake Creek – Temple 345 kV	15/5	4007	1
Temple Pecan Creek – Temple 345 kV	31/5	4012	1
Tradinghouse – Lake Creek East 345 kV	5/3	4020	1

The CAT-1 tension measurements are converted to sag estimates using the sag catenary equation described in Section 8.1. It is possible to assume that the slope angle of the conductor at the tower attachment point is much less than one radian. A simpler, less computationally expensive "small angle" version of the sag catenary equation can then be applied to the CAT-1 tension measurements. The "small angle" sag catenary equation was not used in this analysis in deference to greater computational accuracy.

8.3.2 RT-TLMS Clearance Measurement Factors

RT-TLMS DLR sensors record the distance from the sensor to the conductor. The measurement is reported as "Clearance." In reality, the distance may be slightly greater than the actual clearance if the wind deflects the cable. Figure D - 3 gives evidence that the wind deflection contributes to a random behavior in the RT-TLMS measurements.

"Clearance" is observed on one-minute intervals and recorded with date-time value in the measurement "Time" field. The value of Time is not synchronized with the Oncor SCADA clocks or the CAT-1 "Date" and "Time" values. The lack of exact time synchronization for the observations contributes in varying degrees to a reduction of RT-TLMS ⇔ CAT-1 correlation for a given line.

RT-TLMS clearance measurements were converted to sag estimates prior to the analysis. Lacking a verifiable value, SwRI used a sample mean estimate of the RT-TLMS tower connection height to convert RT-TLMS "Clearance" measurements to RT-TLMS sag estimates. The tower height estimate is computed as

$$\overline{Connection\ Height\ Estimate} = mean[RTTLMS\ Clearance(i) + Sag[CAT\ \xi(i)], i \in \{0,1,..N-1\}].$$

The variable N is a number of sag-tension observation pairs for which RT-TLMS clearance and CAT-1 tension have been observed at time $t = i * 10\ minutes + T_0$, where T_0 is the date time of the first RT-TLMS ⇔ CAT-1 sag measurement pair, i.e., $i = 0$. The height estimate is the sample mean of the sum of two random variables. There is some random error in the resulting RT-TLMS sag estimate

$$RTTLMS\ Sag\ Estimate(i) = \overline{Connection\ Height\ Estimate} - RTTLMS\ Clearance(i).$$

RT-TLMS sensors quantize distance measurements into binary clearance values using ADCs. The ADC quantizing specifications and the resulting quantizing noise statistics are unknown to SwRI. That said, the quantization noise exists and affects the distance calculation to some degree.

The sag measurement distribution for a given tension and line, $f_s(sag|(tension, line))$, reflects the combined effects of wind aerodynamics, ADC quantizing noise and the RT-TLMS observation time synchronization error $\tau(i)|(tension, line)$. For example, the RT-TLMS 1-1 measurement standard deviation is typically $\sigma = 0.5\ ft$ for the observed span 25/1 – 25/2 in the Waco Atco – Temple Elm Creek 138 kV line, as shown in Figure D - 4. The mean sag estimate $|(tension, line)$, as indicated by the legend in Figure D - 4, is of particular interest to the analysis appearing in subsequent sections.

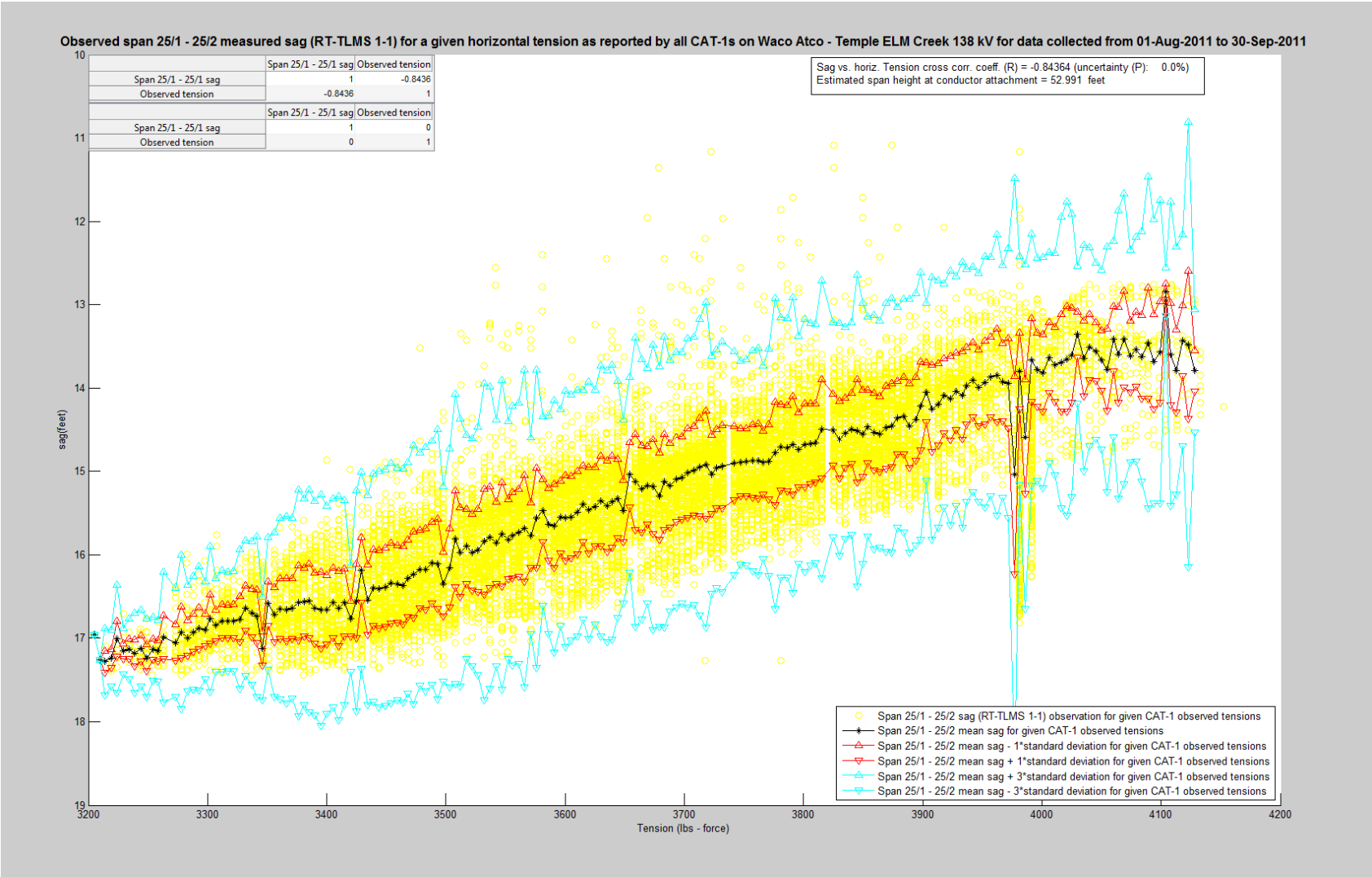


Figure D - 3 Span 25/1 -25/2 Observed Sag Distribution | (Observed Tension, Waco Atco – Temple Elm Creek 138 kV)

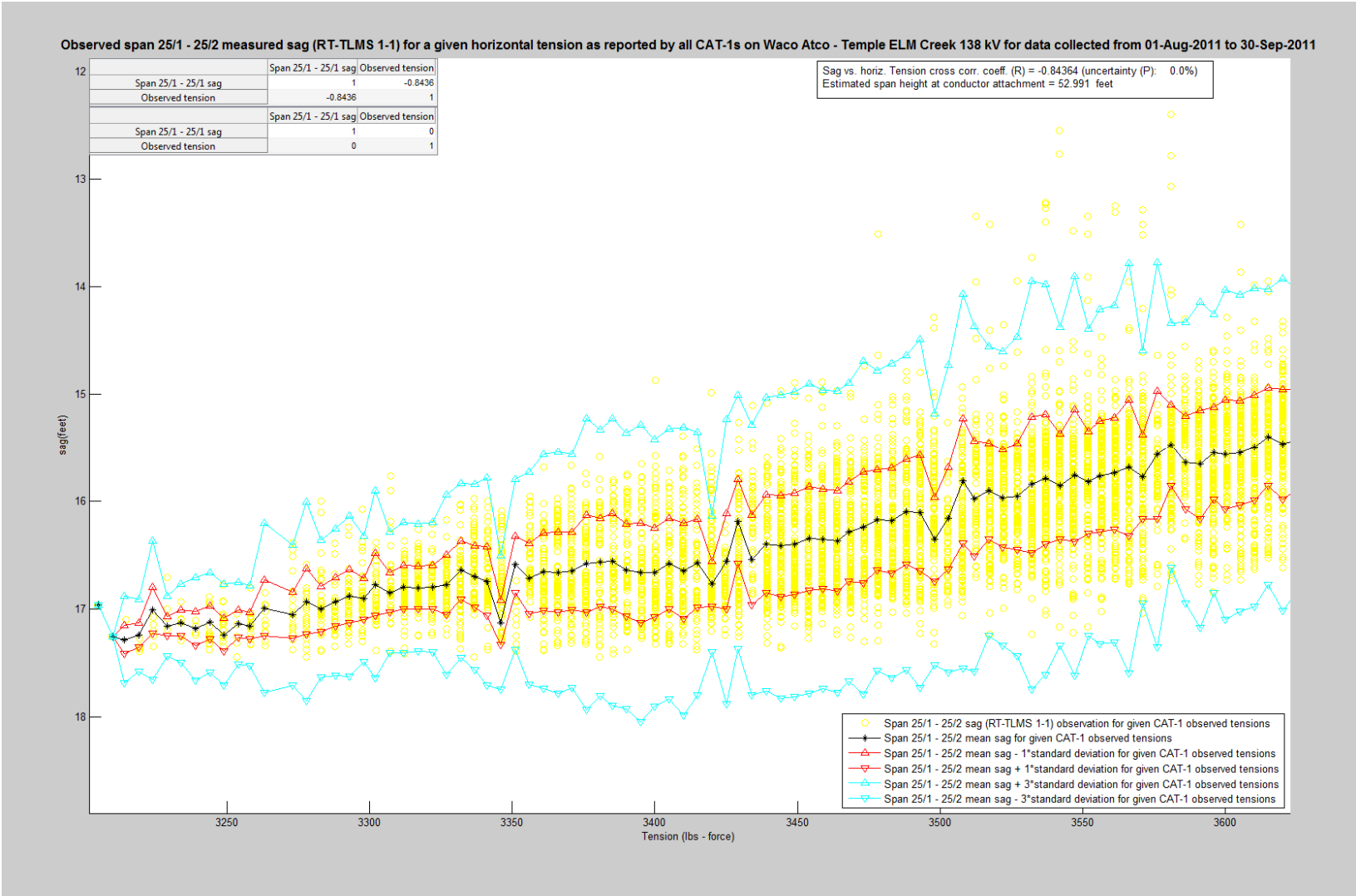


Figure D - 2 Observed Span 25/1 -25/2 Sag Standard Deviation σ | (CAT-1 Tension, Waco Atco – Temple Elm Creek 138 kV)

8.3.3 Sagometer Tension Measurement Factors

Sagometer DLR sensors observe the location of the conductor in a plane perpendicular to an observed span conductor. Sag estimates derived from the observations are reported in the "Sag at Mid-Span" column of the measurement record. In reality, the Sagometer records the position of a target and reports its vertical position relative to the conductor attachment point. The target moves in a plane perpendicular to the conductor sag. The observed span sag observation will vary about the actual sag clearance if wind horizontally deflects the cable. Figure D - 5 gives evidence that the wind deflection contributes to a random behavior in the Sagometer measurements.

Sag is observed on 10-minute intervals and recorded with a date-time value in the measurement "Time" field. The Sagometer's value of Time is not synchronized with the Oncor SCADA clocks or the CAT-1 RTime values. The lack of exact time synchronization for the observations contributes in varying degrees to a reduction of Sagometer ⇔ CAT-1 correlation for a given line.

Sagometer sensors quantize target location into binary coordinate values using analog to digital converters (ADCs). The ADC quantizing specifications and the resulting quantizing noise statistics are unknown to SwRI. That said, the quantization noise exists and affects the sag calculation to some degree.

The sag measurement distribution for a given tension and line, $f_s(sag|(tension, line))$, reflects the combined effect of wind aerodynamics, ADC quantizing noise, and Sagometer observation time synchronization error $\tau(i)|(tension, line)$. For example, the standard deviation of Sagometer 5 measurements is typically $\sigma = 0.10\ ft$ for the Tradinghouse – Lake Creek East 345 kV line as shown in Figure D - 6. The mean sag estimate $|(tension, line)$, as indicated by the legend in Figure D - 6, is also of interest to the study analysis appearing in subsequent sections.

8.4 Study Methodology

The study compared sag estimates produced independently for an "observed span" chosen within a selected line section span. Oncor placed CAT-1 systems at structure connection points along a selected line section for study. The observed span within the same line section was instrumented using a Sagometer or an RT-TLMS sag system. Oncor collected sag measurements produced by Sagometer or Promethean RT-TLMS DLR systems and tension measurements from the CAT-1 DLR systems. SwRI created custom software to process observed span sag measurements taken from the Sagometer or RT-TLMS. The software computed tension-based sag estimates for the observed span using the catenary sag equation, CAT-1 tension measurements, and the observed span design parameters. The software referenced all sag comparisons to the observed span, i.e., the observed span length and conductor weight were used on all catenary sag calculations as described in Section 8.1. SwRI used statistical techniques to compare the differences in the sag reported by the independent systems for the observed span. Statistical inference techniques used in clinical trials verified and validated the similarity of the reported sag behavior for given time intervals, ranges of tension, distances and rates of sag change.

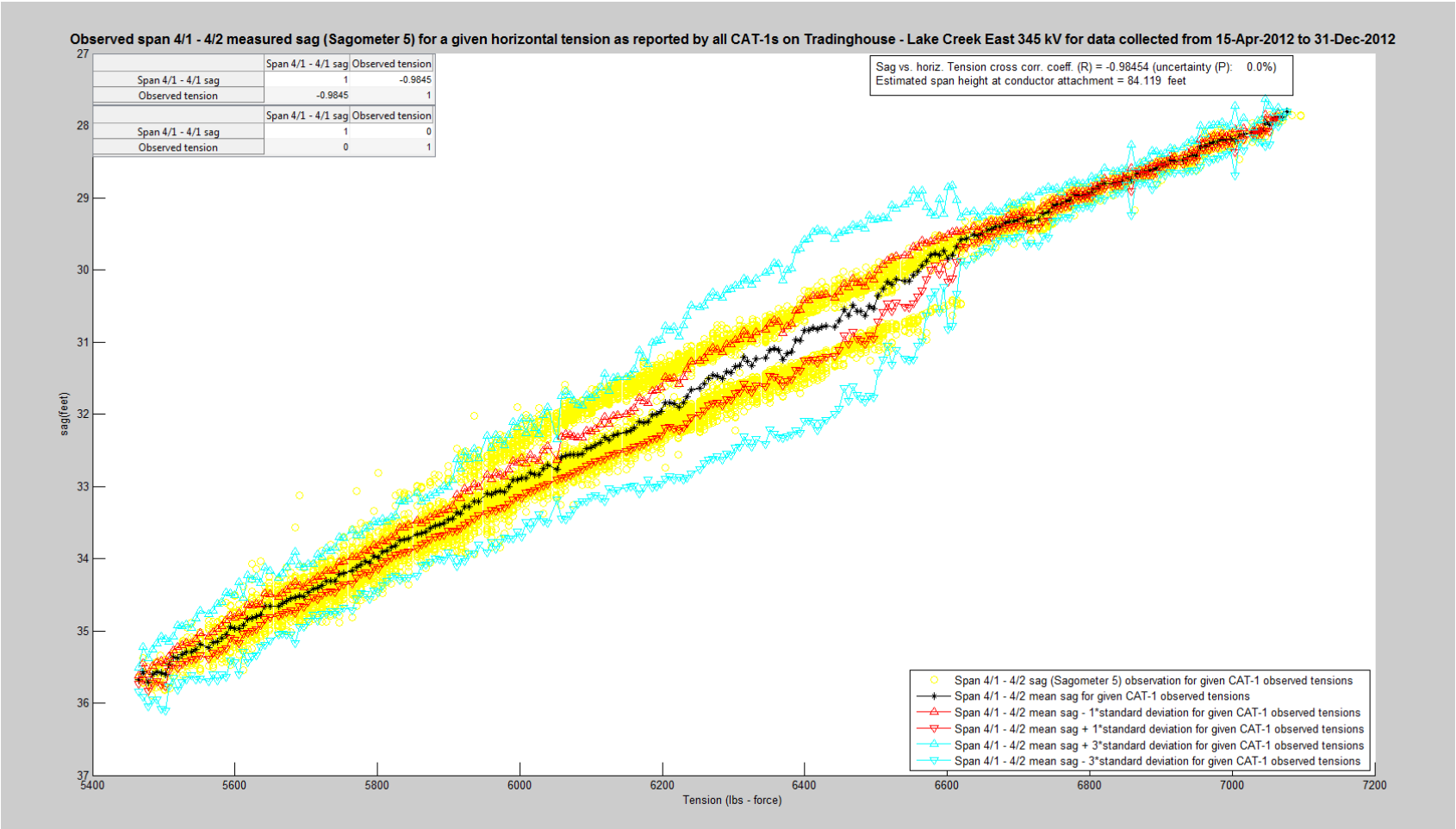


Figure D - 3 Observed Span 4/1 – 4/2 Sag Distribution | (CAT-1 Observed Tension, Tradinghouse – Lake Creek East 345 kV)

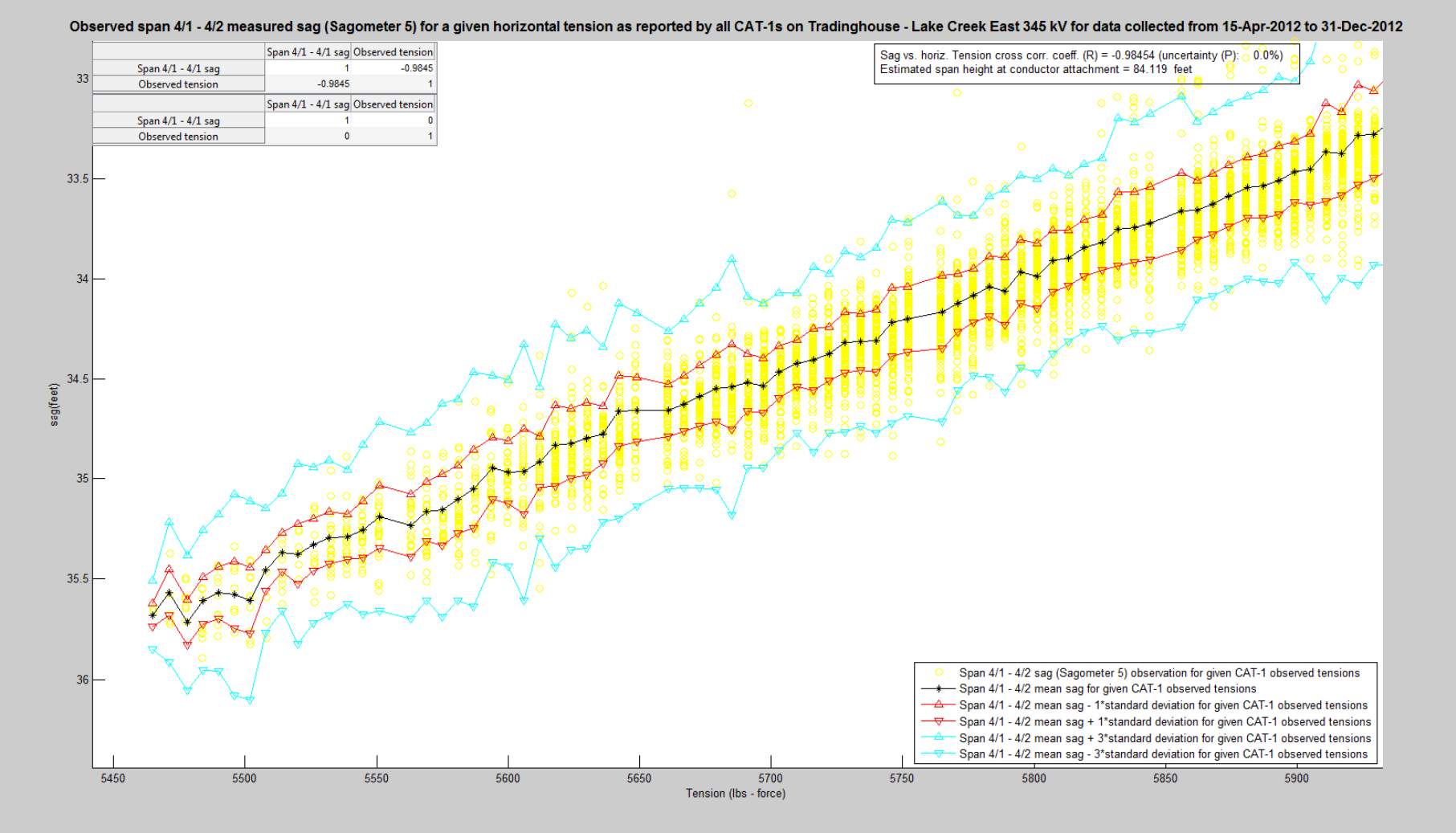


Figure D - 4 Observed Span 4/1 – 4/2 Sag Standard Deviation σ | (CAT-1 Observed Tension, Tradinghouse – Lake Creek East 345 kV)

8.5 Selected Line Section Configurations and Study Results Summary

The following section contains descriptions of six line sections and observed spans selected for the purpose of this study. Each description consists of a figure and set of descriptive bullets describing the configuration of DLR systems within the line section. The table that follows the description summarizes the results of study comparisons performed on the line section. The table contains the mean and standard deviation for the difference between the observed span sag and CAT-1 catenary sag estimates taken at specified distances from the observed span. The figures following each table illustrate the collected sag estimates and associated results summarized in the table.

8.5.1 Line Section Lake Creek – Temple 345 kV with Observed Span 11/3-11/4

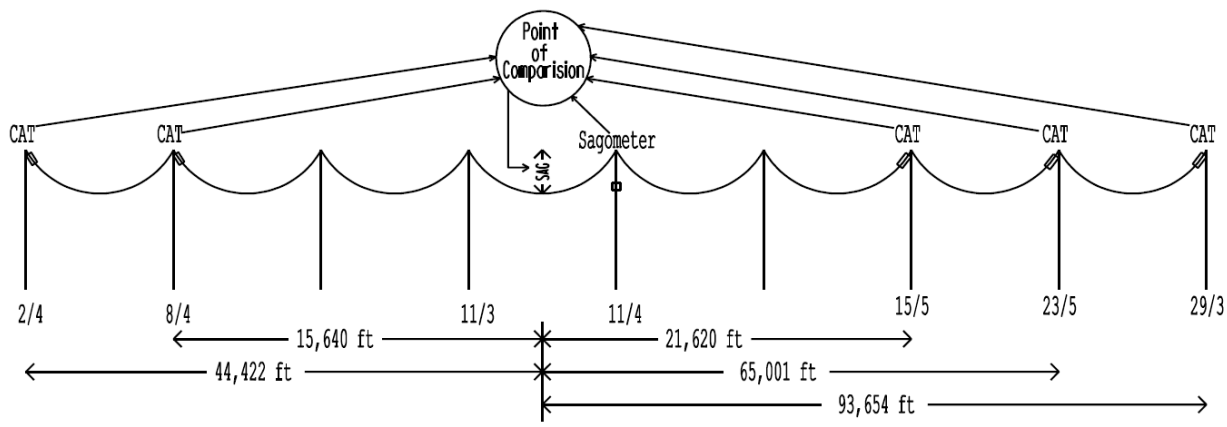


Figure D - 5 Line Section Lake Creek –Temple 345 kV with Observed Span 11/3-11/4

- CAT devices are mounted on structures 2/4, 8/4, 15/5, 23/5 and 29/3.
- Sagometer 1 is on the conductor in observed span 11/3 – 11/4.
- SwRI software uses Sagometer sag and CAT tension measurements to evaluate sag estimates for the observed span 11/3 - 11/4.
- Calculated differences in sag vary with the statistics shown in Table D - 7.
- Correlation of sag estimates for span 11/3 – 11/4 for a given time and for a given tension are also provided in Table D - 7.
- The calculations and associated measurements are illustrated in Figures D – 8 to D - 10, which follow Table D - 7.

Table D - 7 Line Section Lake Creek –Temple 345 kV Sag Difference Statistics and Correlation between Observed Span 11/3 – 11/4 (Sagometer 1) Sag Observations and CAT-1 Catenary Sag Estimates

Device	Distance from Sagometer at span 11/3 - 11/4 and a given CAT (in feet)	Calculated average sag difference between Sagometer on span 11/3 - 11/4 (in feet)	Calculated sag difference standard deviation between Sagometer on span 11/3 - 11/4 and a given CAT (in feet)	Calculated correlation coefficient $\rho \mid time$ between a Sagometer on span 11/3 - 11/4 and a given CAT (metric: $\lvert\rho\rvert \geq 0.8$)	Calculated sag p-value $\phi \mid time$ between a Sagometer on span 11/3 - 11/4 and a given CAT (metric: $\phi \leq 0.01$)	Calculated correlation coefficient $\rho \mid tension\ \xi$ between a Sagometer on span 11/3 - 11/4 and a given CAT (metric: $\lvert\rho\rvert \geq 0.8$)	Calculated sag p-value $\phi \mid tension\ \xi$ between a Sagometer on span 11/3 - 11/4 and a given CAT (metric: $\phi \leq 0.01$)
CAT on 2/4	15640	-0.749	0.611	0.9895	0	0.9991	0
CAT on 8/4	21620	0.754	0.469	0.9938	0	0.9993	0
CAT on 15/5	44422	0.664	0.522	0.9591	0	0.9993	0
CAT on 23/5	65001	0.442	0.395	0.9844	0	0.9987	0
CAT on 29/3A	93654	-0.158	0.742	0.9605	0	0.9975	0

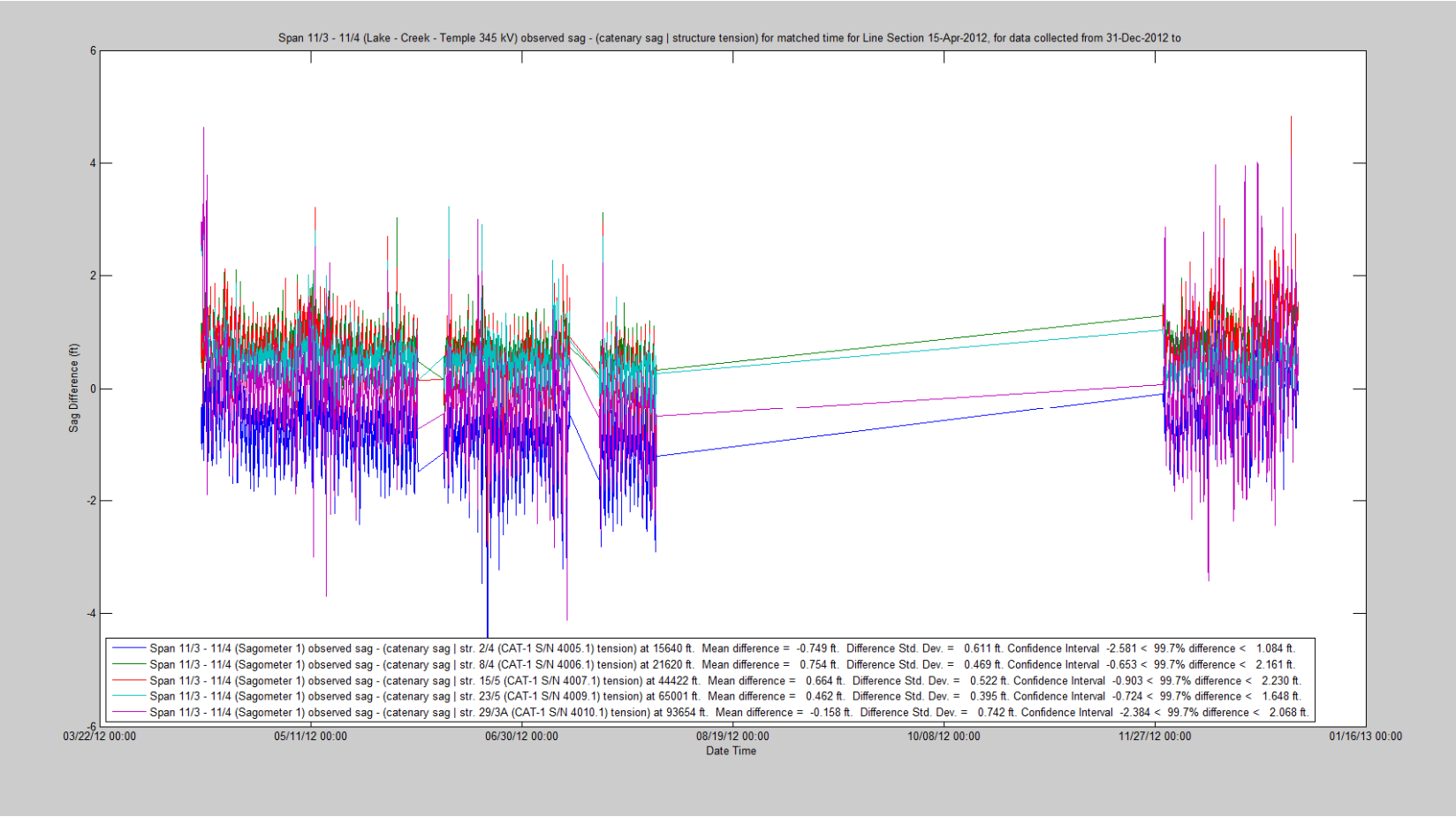
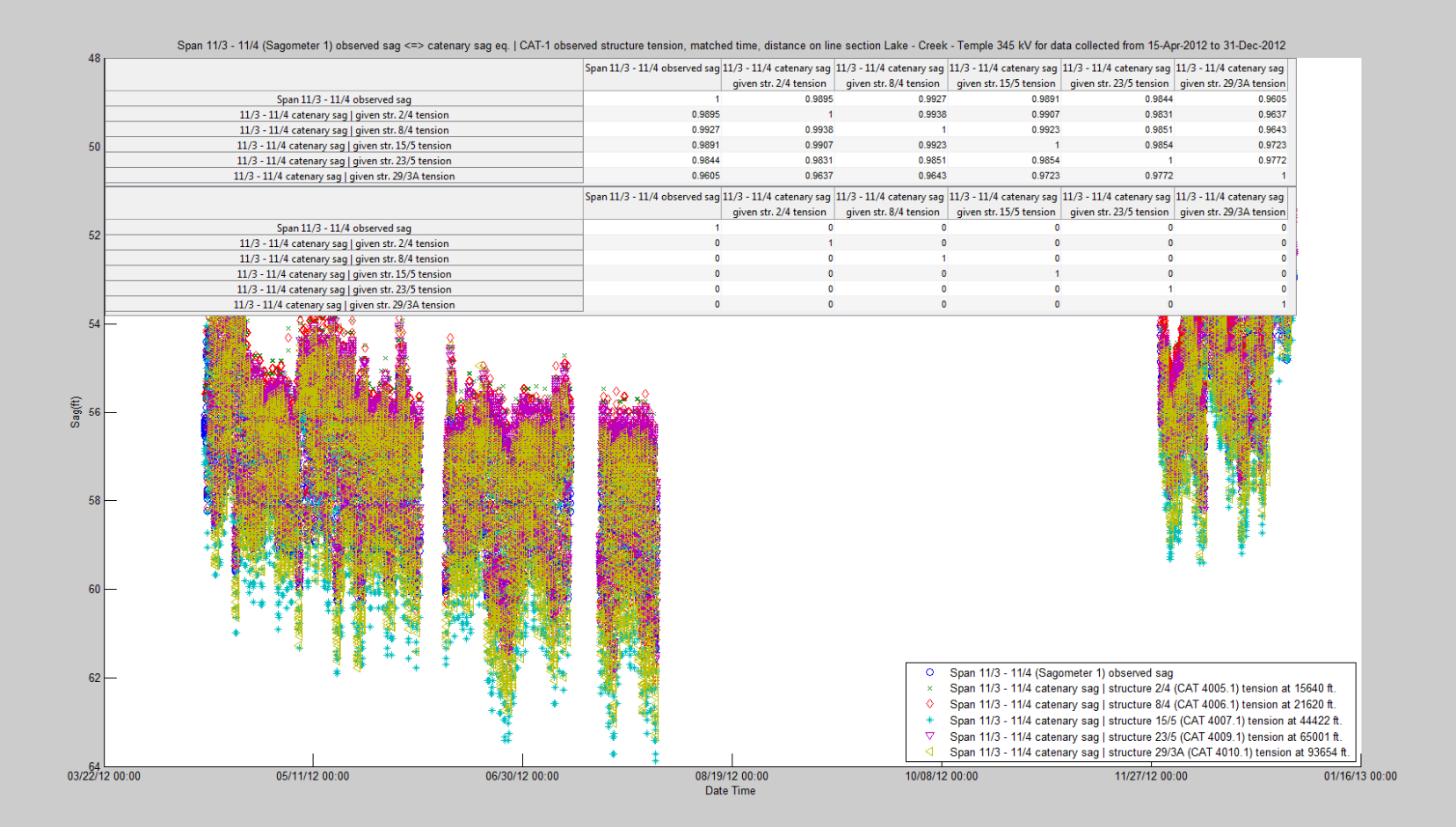


Figure D - 6 Line Section Lake Creek –Temple 345 kV Sag Difference Statistics between Observed Span 11/3 – 11/4 (Sagometer 1) Sag Observations and CAT-1 Tension-Based Catenary Sag Estimates



	Span 11/3 - 11/4 observed sag	11/3 - 11/4 catenary sag given str. 2/4 tension	11/3 - 11/4 catenary sag given str. 8/4 tension	11/3 - 11/4 catenary sag given str. 15/5 tension	11/3 - 11/4 catenary sag given str. 23/5 tension	11/3 - 11/4 catenary sag given str. 29/3A tension
Span 11/3 - 11/4 observed sag	1	0.9895	0.9927	0.9891	0.9844	0.9605
11/3 - 11/4 catenary sag | given str. 2/4 tension	0.9895	1	0.9938	0.9907	0.9831	0.9637
11/3 - 11/4 catenary sag | given str. 8/4 tension	0.9927	0.9938	1	0.9923	0.9851	0.9643
11/3 - 11/4 catenary sag | given str. 15/5 tension	0.9891	0.9907	0.9923	1	0.9854	0.9723
11/3 - 11/4 catenary sag | given str. 23/5 tension	0.9844	0.9831	0.9851	0.9854	1	0.9772
11/3 - 11/4 catenary sag | given str. 29/3A tension	0.9605	0.9637	0.9643	0.9723	0.9772	1

	Span 11/3 - 11/4 observed sag	11/3 - 11/4 catenary sag given str. 2/4 tension	11/3 - 11/4 catenary sag given str. 8/4 tension	11/3 - 11/4 catenary sag given str. 15/5 tension	11/3 - 11/4 catenary sag given str. 23/5 tension	11/3 - 11/4 catenary sag given str. 29/3A tension
Span 11/3 - 11/4 observed sag	1	0	0	0	0	0
11/3 - 11/4 catenary sag | given str. 2/4 tension	0	1	0	0	0	0
11/3 - 11/4 catenary sag | given str. 8/4 tension	0	0	1	0	0	0
11/3 - 11/4 catenary sag | given str. 15/5 tension	0	0	0	1	0	0
11/3 - 11/4 catenary sag | given str. 23/5 tension	0	0	0	0	1	0
11/3 - 11/4 catenary sag | given str. 29/3A tension	0	0	0	0	0	1

Figure D - 7 Line Section Lake Creek –Temple 345 kV Sag | Time Correlation between Span 11/3 – 11/4 (Sagometer 1) Sag Observations and CAT-1 Catenary Sag Estimates

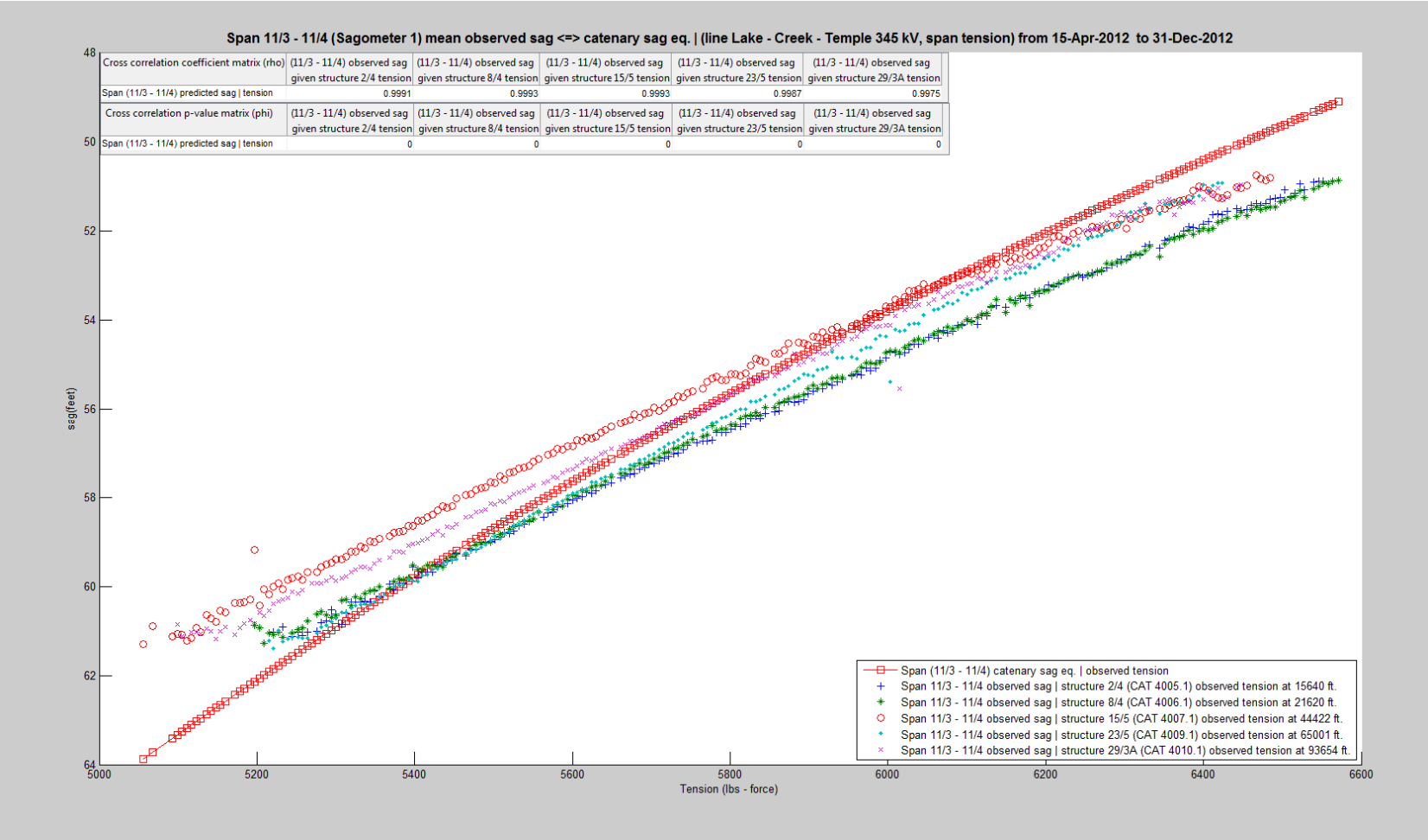


Figure D - 8 Line Section Lake Creek –Temple 345 kV Sag | Tension Correlation between Span 11/3 – 11/4 (Sagometer 1) Sag Observations and CAT-1 Catenary Sag Estimates

8.5.2 Line Section Waco Atco – Temple Elm Creek 138 kV with Observed Span 19/4 – 19/5

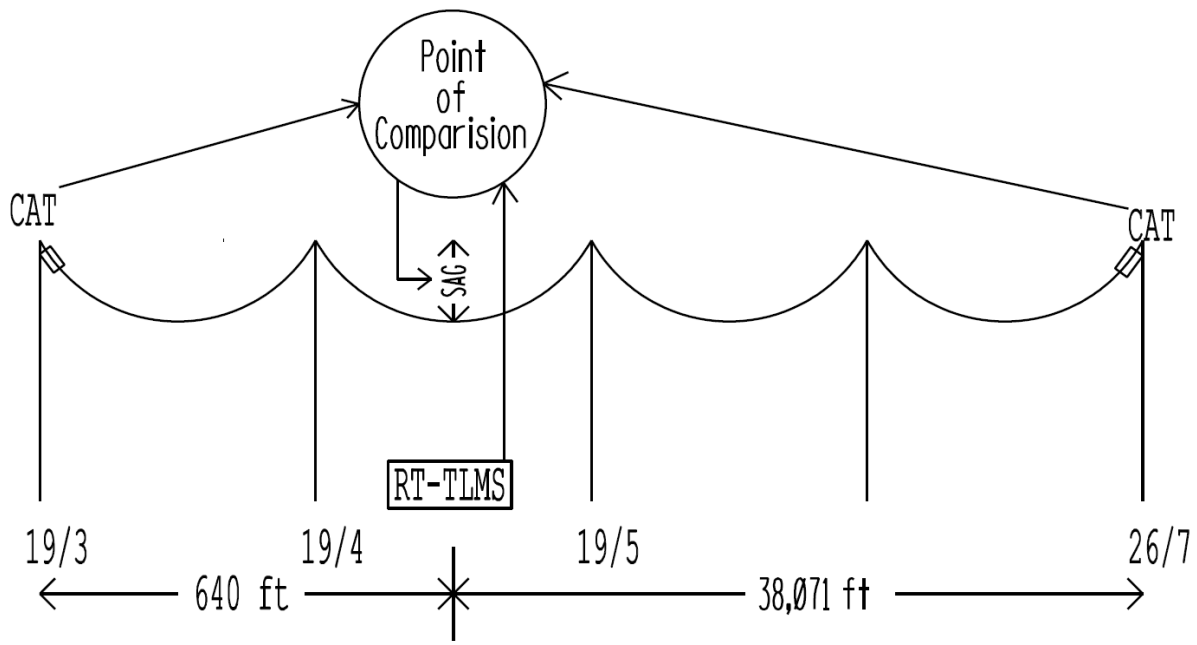


Figure D - 9 Line Section Waco Atco - Temple Elm Creek 138 kV with Observed Span 19/4 – 19/5

- CAT devices are mounted on structures 19/3 and 26/7.
- Device RT-TLMS 1-2 is positioned under the observed span between structures 19/4 and 19/5.
- SwRI software uses RT-TLMS clearance and CAT tension measurements to evaluate sag estimates for the observed span 19/4 - 19/5.
- The difference in sag calculations varies with the statistics shown in Table D - 8.
- Correlation of sag estimates for span 19/4 - 19/5 for a given time and for a given tension are also provided in Table D - 8.
- The calculations and associated measurements are illustrated in Figures 12 to 14, which follow Table D - 8.

Table D - 8 Line Section Waco Atco - Temple Elm Creek 138 kV Sag Difference Statistics and Correlation between Span 19/4 – 19/5 (RT-TLMS 1-2) Sag Observations and CAT-1 Sag Estimates

Device	Distance a RT-TLMS at span 19/4 - 19/5 and a given CAT (in feet)	Calculated average sag difference between RT-TLMS at span 19/4 - 19/5 and a given CAT (in feet)	Calculated sag difference standard deviation between a RT-TLMS at span 19/4 - 19/5 and a given CAT (in feet)	Calculated correlation coefficient $\rho \mid time$ between a RT-TLMS span 19/4 - 19/5 and a given CAT (metric: $\lvert\rho\rvert \geq 0.8$)	Calculated sag p-value $\phi \mid time$ between a RT-TLMS at span 19/4 - 19/5 and a given CAT (metric: $\phi \leq 0.01$)	Calculated correlation coefficient $\rho \mid tension\ \xi$ between a RT-TLMS at span 19/4 - 19/5 and a given CAT (metric: $\lvert\rho\rvert \geq 0.8$)	Calculated sag p-value $\phi \mid tension\ \xi$ between a RT-TLMS at structures span 19/4 - 19/5 and a given CAT (metric: $\phi \leq 0.01$)
CAT on 19/3	640	0.082	0.202	0.9721	0	0.9885	0
CAT on 26/7	38071	0.138	0.215	0.9685	0	0.9851	0

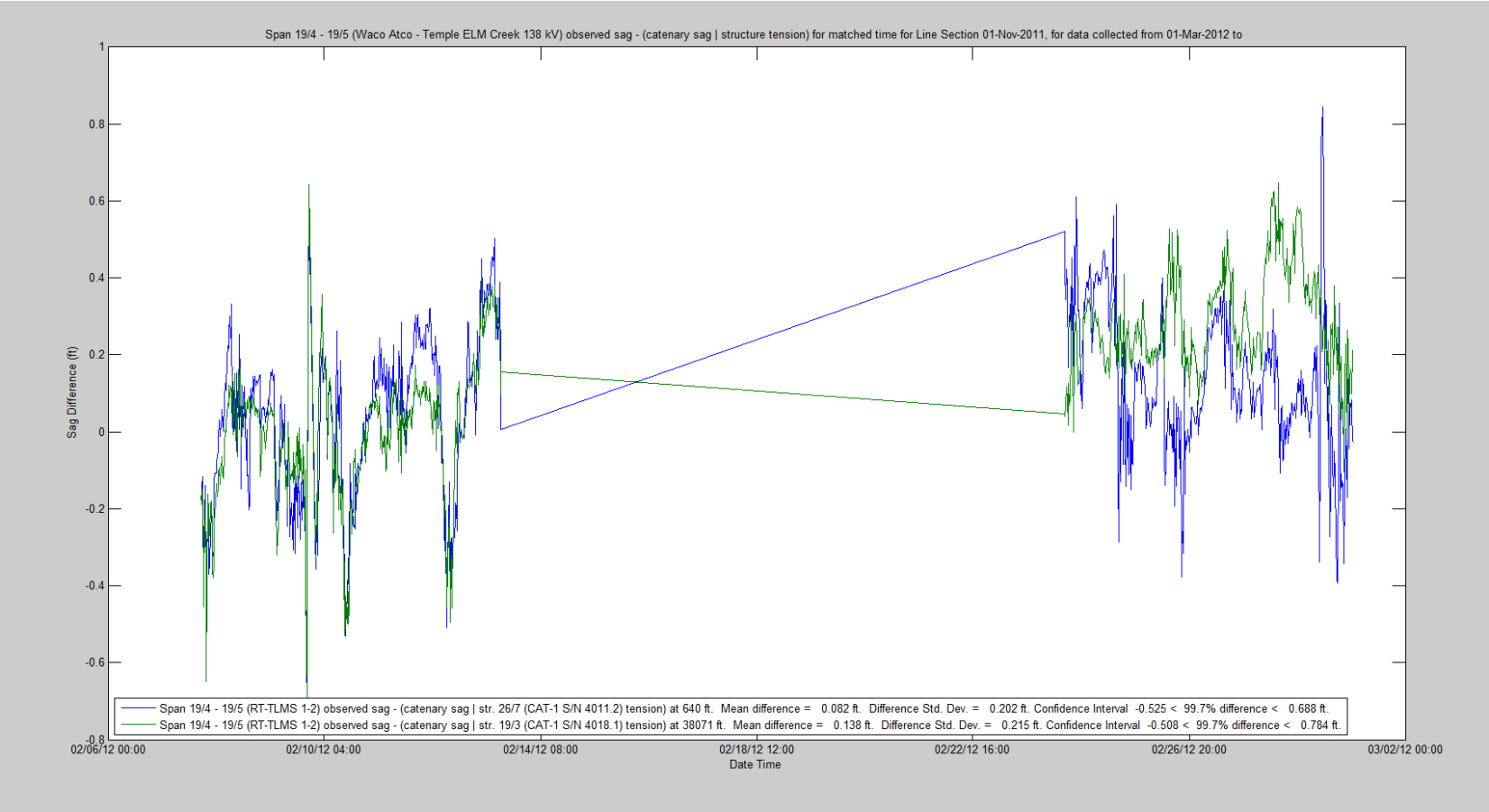
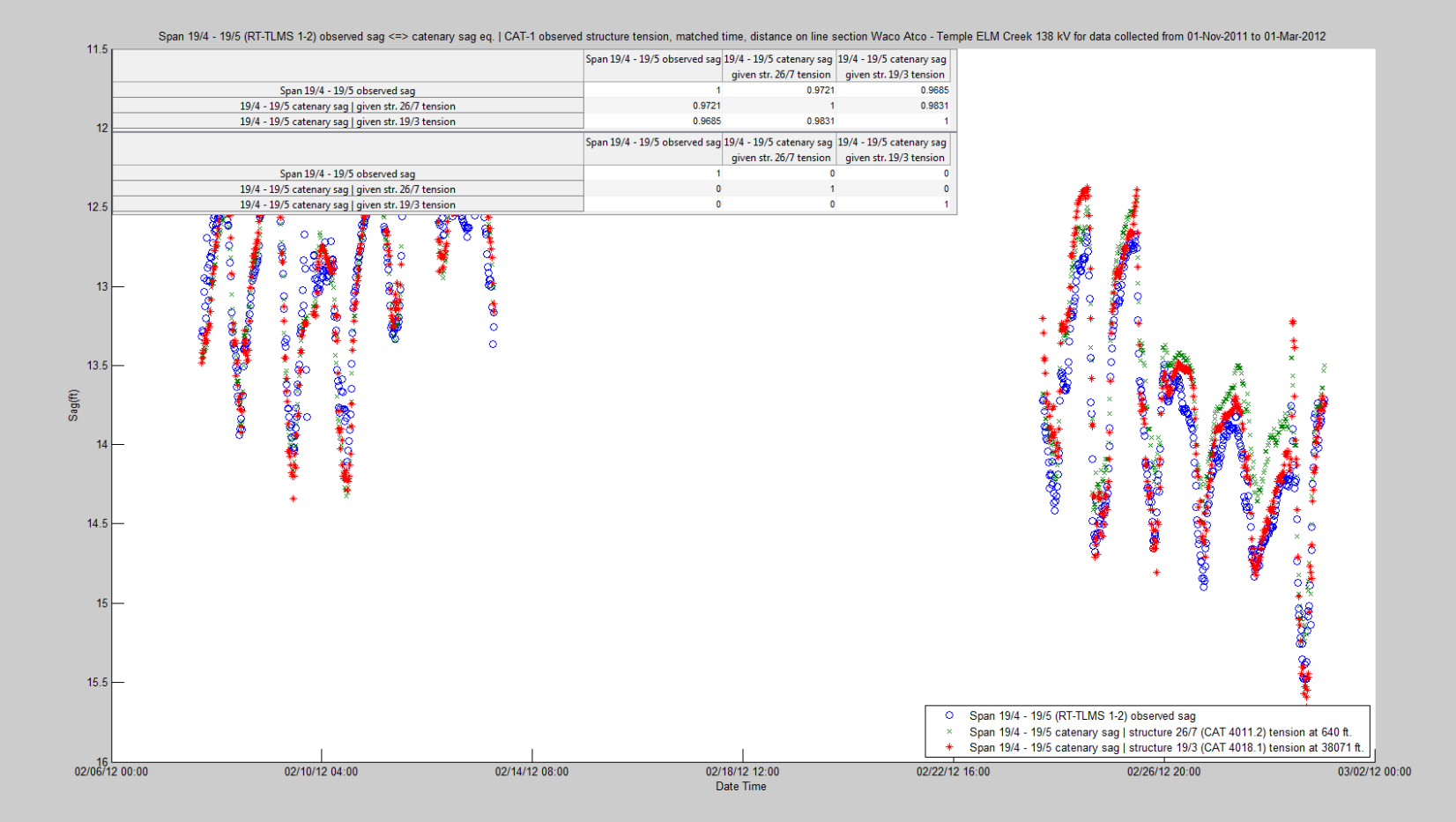


Figure D - 10 Line Section Waco Atco – Temple Elm Creek 138 kV Sag Difference Statistics between RT-TLMS 1-2 Observations and CAT-1 Sag Estimates



	Span 19/4 - 19/5 observed sag	19/4 - 19/5 catenary sag given str. 26/7 tension	19/4 - 19/5 catenary sag given str. 19/3 tension
Span 19/4 - 19/5 observed sag	1	0.9721	0.9685
19/4 - 19/5 catenary sag | given str. 26/7 tension	0.9721	1	0.9831
19/4 - 19/5 catenary sag | given str. 19/3 tension	0.9685	0.9831	1

	Span 19/4 - 19/5 observed sag	19/4 - 19/5 catenary sag given str. 26/7 tension	19/4 - 19/5 catenary sag given str. 19/3 tension
Span 19/4 - 19/5 observed sag	1	0	0
19/4 - 19/5 catenary sag | given str. 26/7 tension	0	1	0
19/4 - 19/5 catenary sag | given str. 19/3 tension	0	0	1

Figure D - 11 Line Section Waco Atco - Temple Elm Creek 138 kV Sag | Time Correlation between Span 19/4 – 19/5 (RT-TLMS 1-2) Sag Observations and CAT-1 Sag Estimates

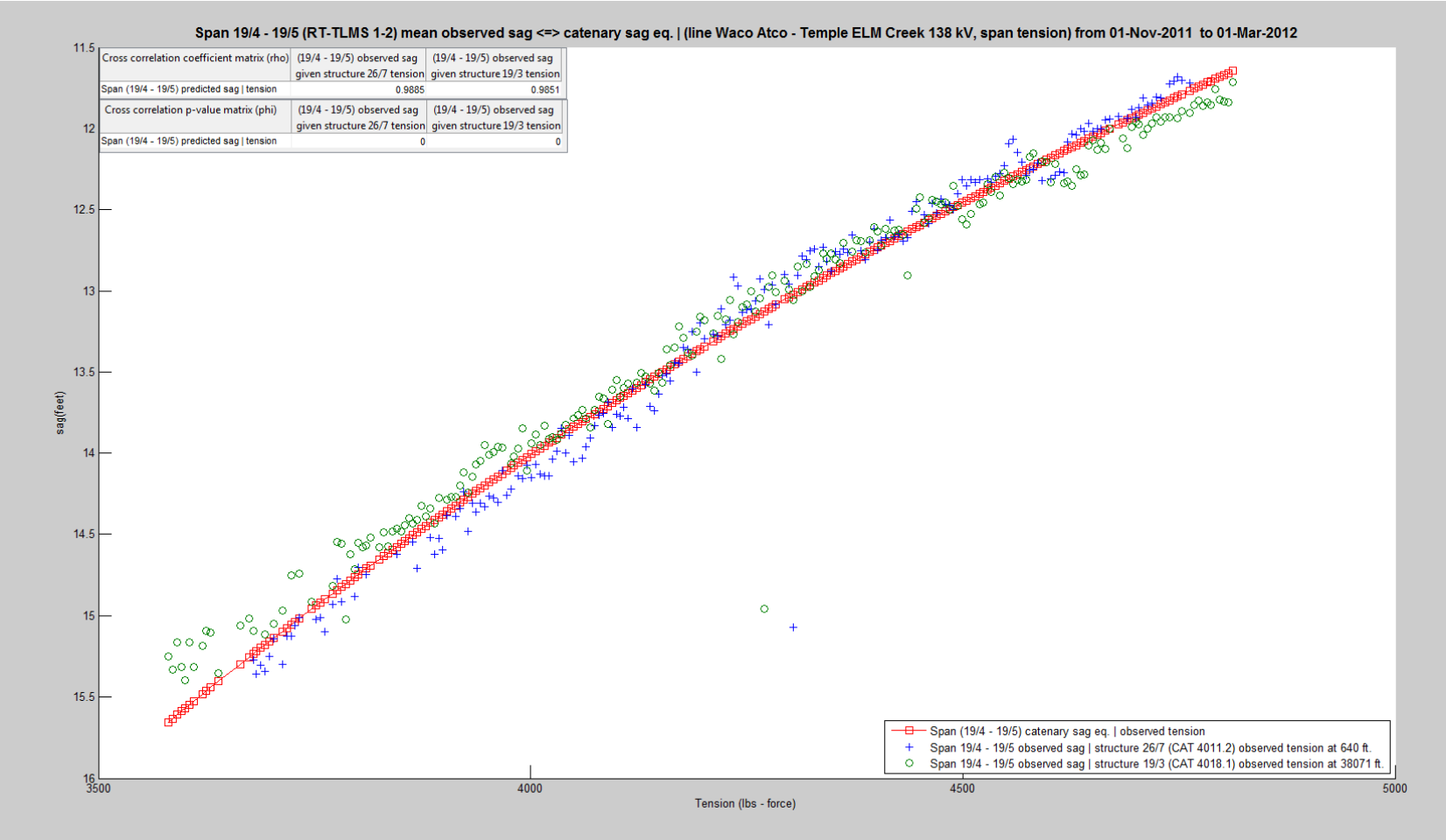


Figure D - 12 Line Section Waco Atco - Temple Elm Creek 138 kV Sag | Tension Correlation between Span 19/4 – 19/5 (RT-TLMS 1-2) Sag Observations and CAT-1 Sag Estimates

8.5.3 Line Section Waco Atco - Temple Elm Creek 138 kV with Observed Span 21/3 – 21/4

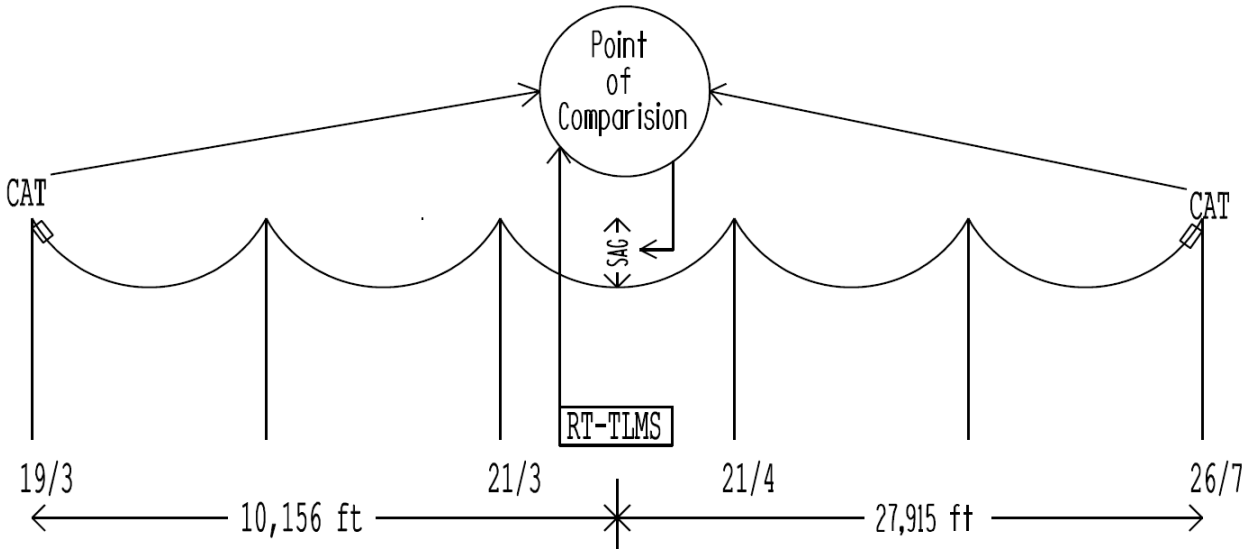


Figure D - 13 Line Section Waco Atco - Temple Elm Creek 138 kV with Observed Span 21/3 – 21/

- CAT devices are mounted on structures 19/3 and 26/7.
- Device RT-TLMS 1-3 is placed under the observed span between structures 21/3 and 21/4.
- SwRI software uses RT-TLMS clearance and CAT tension measurements to evaluate sag estimates for the observed span 21/3 - 21/4.
- The difference in sag calculations varies with the statistics shown in Table D - 9.
- Correlation of sag estimates for span 21/3 - 21/4 for a given time and for a given tension are also provided in Table D - 9.
- The calculations and associated measurements are illustrated in Figures D – 16 to D - 18, which follow Table D- 9.

Table D - 9 Line Section Waco Atco - Temple Elm Creek 138 kV Sag Difference Statistics and Correlation between Span 21/3 - 21/4 (RT-TLMS 1-3) Sag Observations and CAT-1 Sag Estimates

Device	Distance from the RT-TLMS in span 21/3 - 21/4 and a given CAT (in feet)	Calculated average sag difference between RT-TLMS in span 21/3 - 21/4 and a given CAT (in feet)	Calculated sag difference standard deviation between RT-TLMS in span 21/3 - 21/4 and a given CAT (in feet)	Calculated correlation coefficient $\rho \mid time$ between a RT-TLMS at span 21/3 - 21/4 and a given CAT (metric: $|\rho| \geq 0.8$)	Calculated sag p-value $\phi \mid time$ between a RT-TLMS at span 21/3 - 21/4 and a given CAT (metric: $\phi \leq 0.01$)	Calculated correlation coefficient $\rho \mid tension\ \xi$ between a RT-TLMS a span 21/3 - 21/4 and a given CAT (metric: $|\rho| \geq 0.8$)	Calculated sag p-value $\phi \mid tension\ \xi$ between a RT-TLMS at span 21/3 - 21/4 and a given CAT (metric: $\phi \leq 0.01$)
CAT on 19/3	10156	-0.3062	0.467	0.8399	0	0.9885	0
CAT on 26/7	27915	0.047	0.361	0.8627	0	0.9897	0

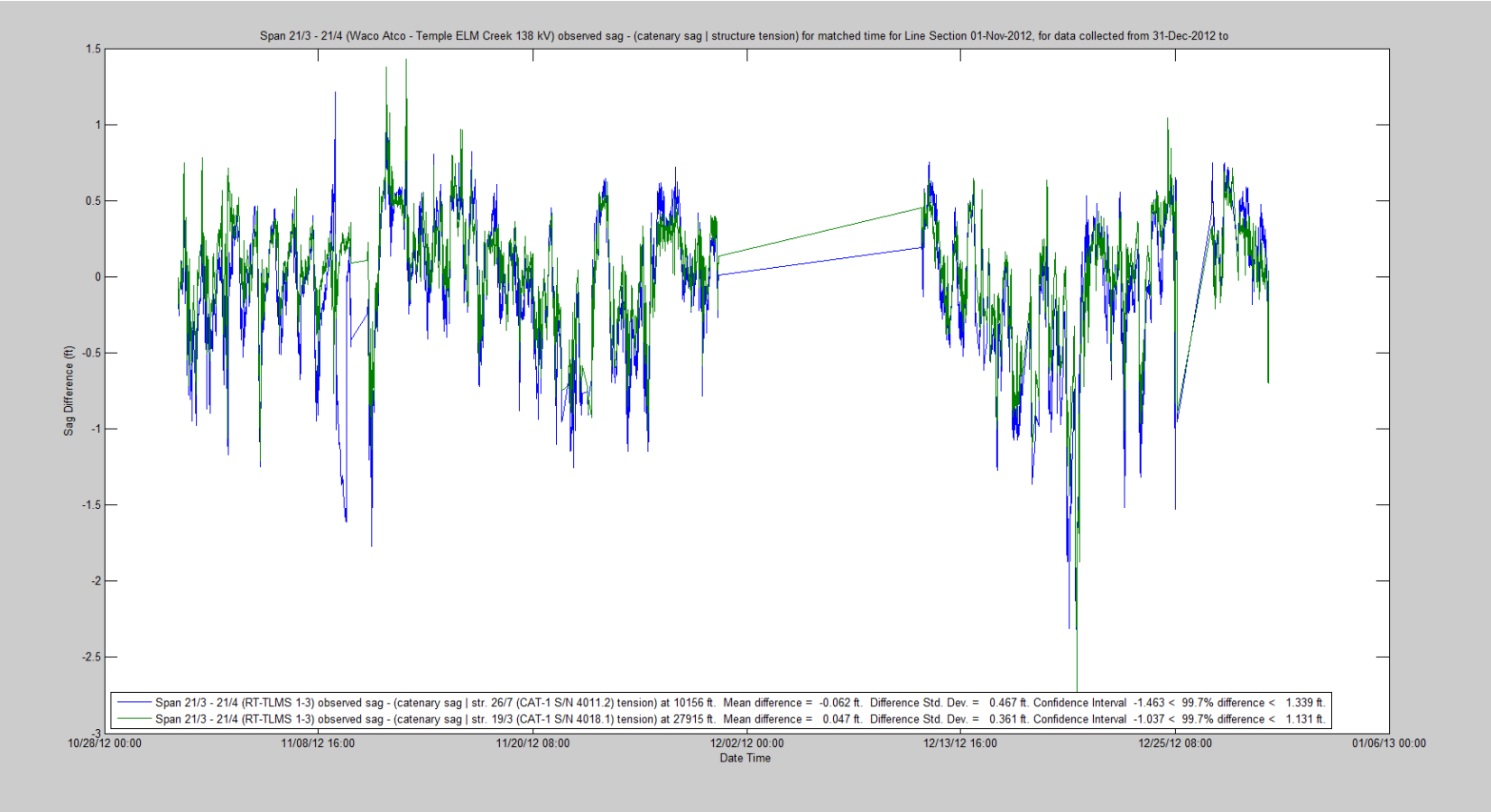


Figure D - 14 Line Section Waco Atco - Temple Elm Creek 138 kV Sag Difference Statistics between Span 21/3 - 21/4 (RT-TLMS 1-3) Sag Observations and CAT-1 Sag Estimates

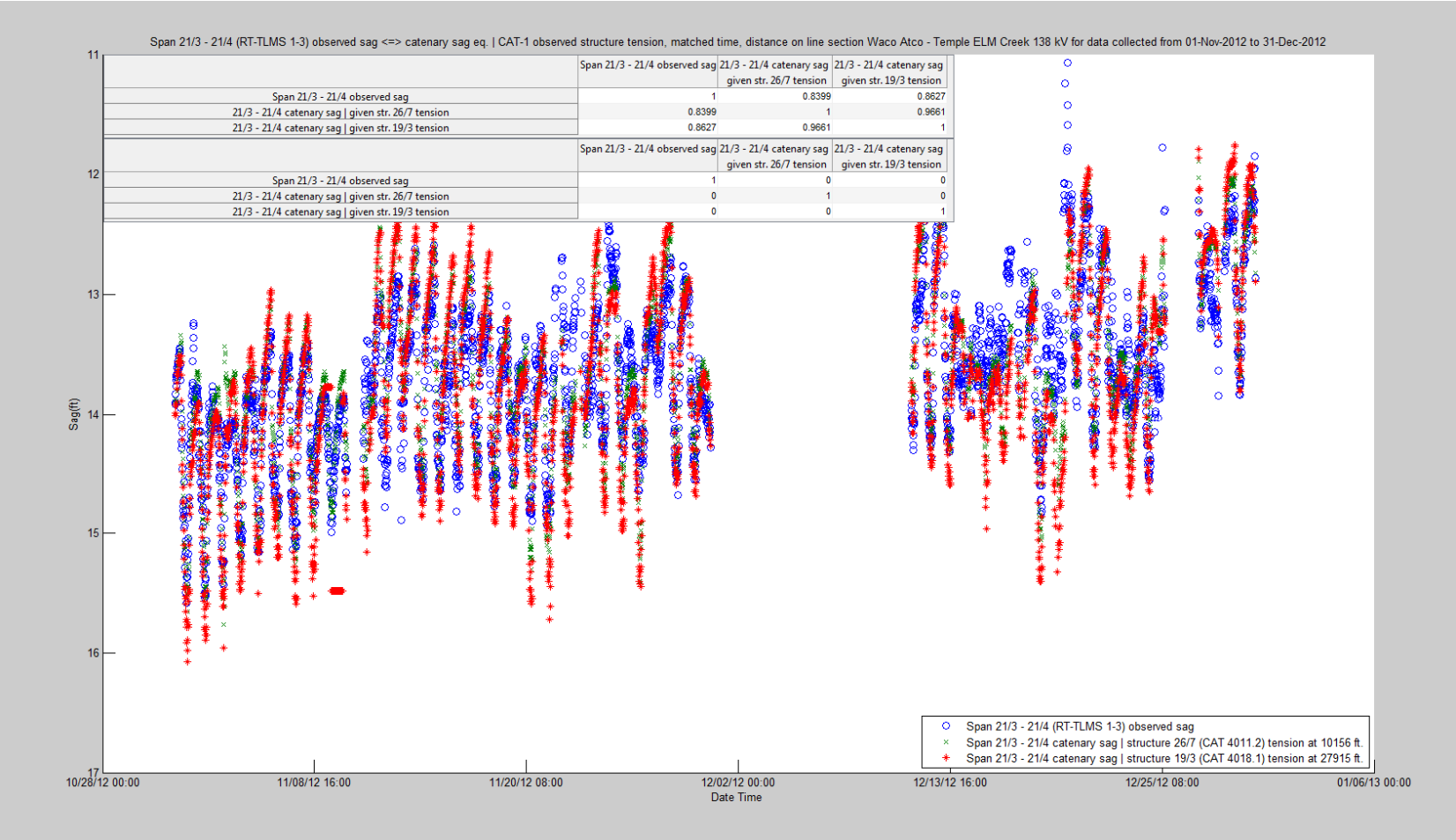


Figure D - 15 Line Section Waco Atco - Temple Elm Creek 138 kV Sag Correlation | Time between Span 21/3 - 21/4 (RT-TLMS 1-3) Sag Observations and CAT-1 Sag Estimates

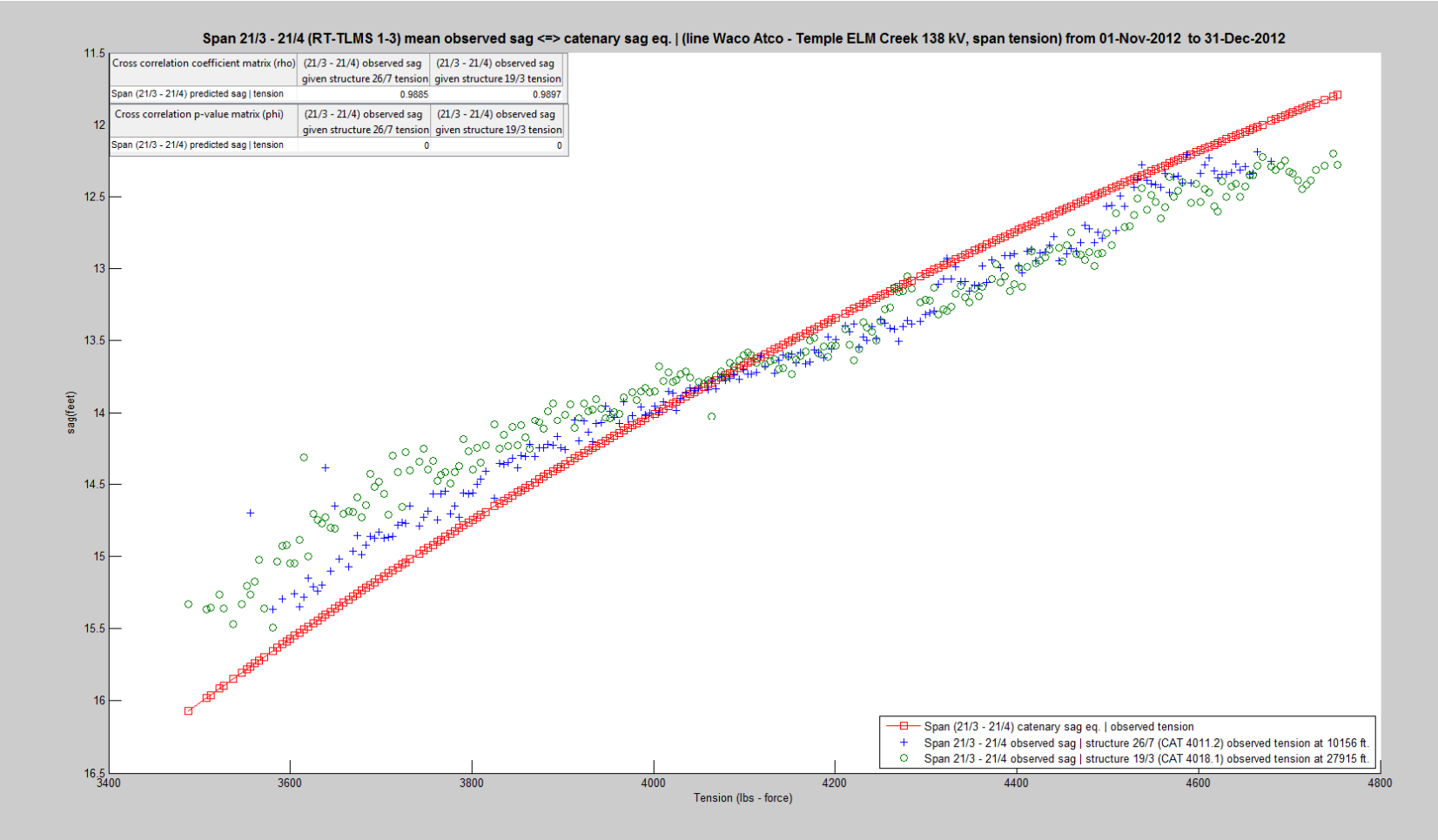


Figure D - 16 Line Section Waco Atco - Temple Elm Creek 138 kV Sag Correlation | Tension between Span 21/3 - 21/4 (RT-TLMS 1-3) Sag Observations and CAT-1 Sag Estimates

8.5.4 Line Section Waco Atco - Temple Elm Creek 138 kV with Observed Span 25/1 – 25/2

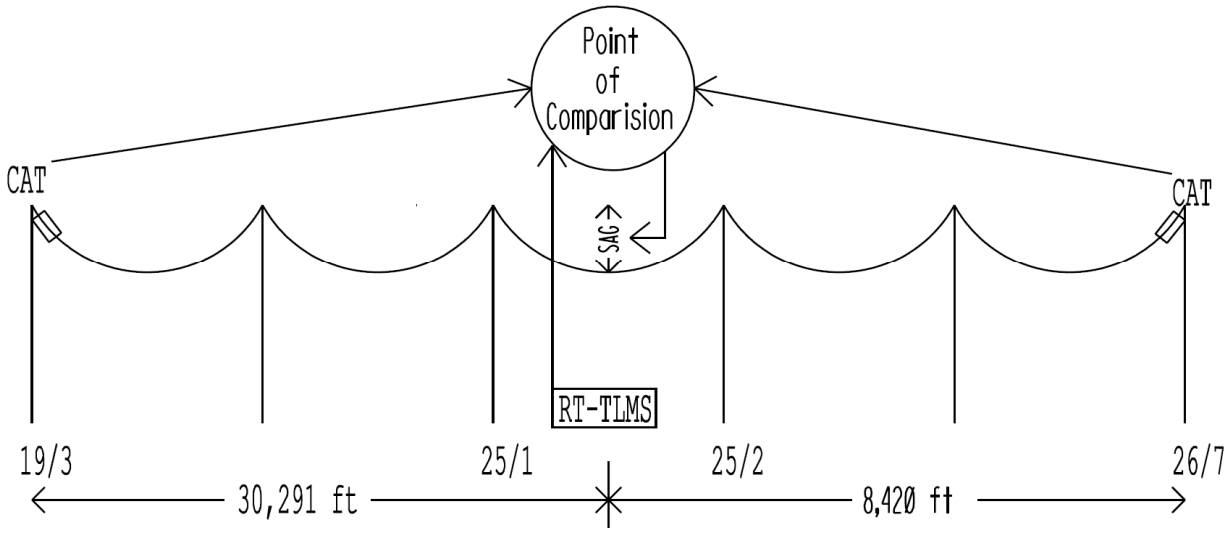


Figure D - 17 Line Section Waco Atco - Temple Elm Creek 138 kV with Observed Span 25/1 – 25/2

- CAT devices are mounted on structures 19/3 and 26/7.
- Device RT-TLMS 1-1 is placed under the observed span between structures 25/1 and 25/2.
- SwRI software uses RT-TLMS clearance and CAT tension measurements to evaluate sag estimates for the observed span 25/1 - 25/2.
- The difference in sag calculations varies with the statistics shown in Table D - 10.
- Correlation of sag estimates for span 25/1 – 25/2 for a given time and for a given tension are also provided in Table D - 10.
- The calculations and associated measurements are illustrated in Figures D – 20 to D - 22, which follow Table D - 10.

Table D – 10 Line Section Waco Atco - Temple Elm Creek 138 kV Sag Difference Statistics and Correlation in Span 25/1 - 25/2 (RT-TLMS 1-1) Sag Observations and CAT-1 Sag Estimates

Device	Distance from the RT-TLMS at span 25/1 and 25/2 and a given CAT (in feet)	Calculated average sag difference between RT-TLMS at span 25/1 and 25/2 and a given CAT (in feet)	Calculated sag difference standard deviation between RT-TLMS at span 25/1 and 25/2 and a given CAT (in feet)	Calculated correlation coefficient $\rho \mid time$ between a RT-TLMS at span 25/1 and 25/2 and a given CAT (metric: $\lvert\rho\rvert \geq 0.8$)	Calculated sag p-value $\phi \mid time$ between a RT-TLMS at span 25/1 and 25/2 and a given CAT (metric: $\phi \leq 0.01$)	Calculated correlation coefficient $\rho \mid tension\ \xi$ between a RT-TLMS at span 25/1 and 25/2 and a given CAT (metric: $\lvert\rho\rvert \geq 0.8$)	Calculated sag p-value $\phi \mid tension\ \xi$ between a RT-TLMS at span 25/1 and 25/2 and a given CAT (metric: $\phi \leq 0.01$)
CAT on 19/3	8420	-0.156	0.527	0.8483	0	0.9889	0
CAT on 26/7	30921	0.161	0.484	0.8866	0	0.9947	0

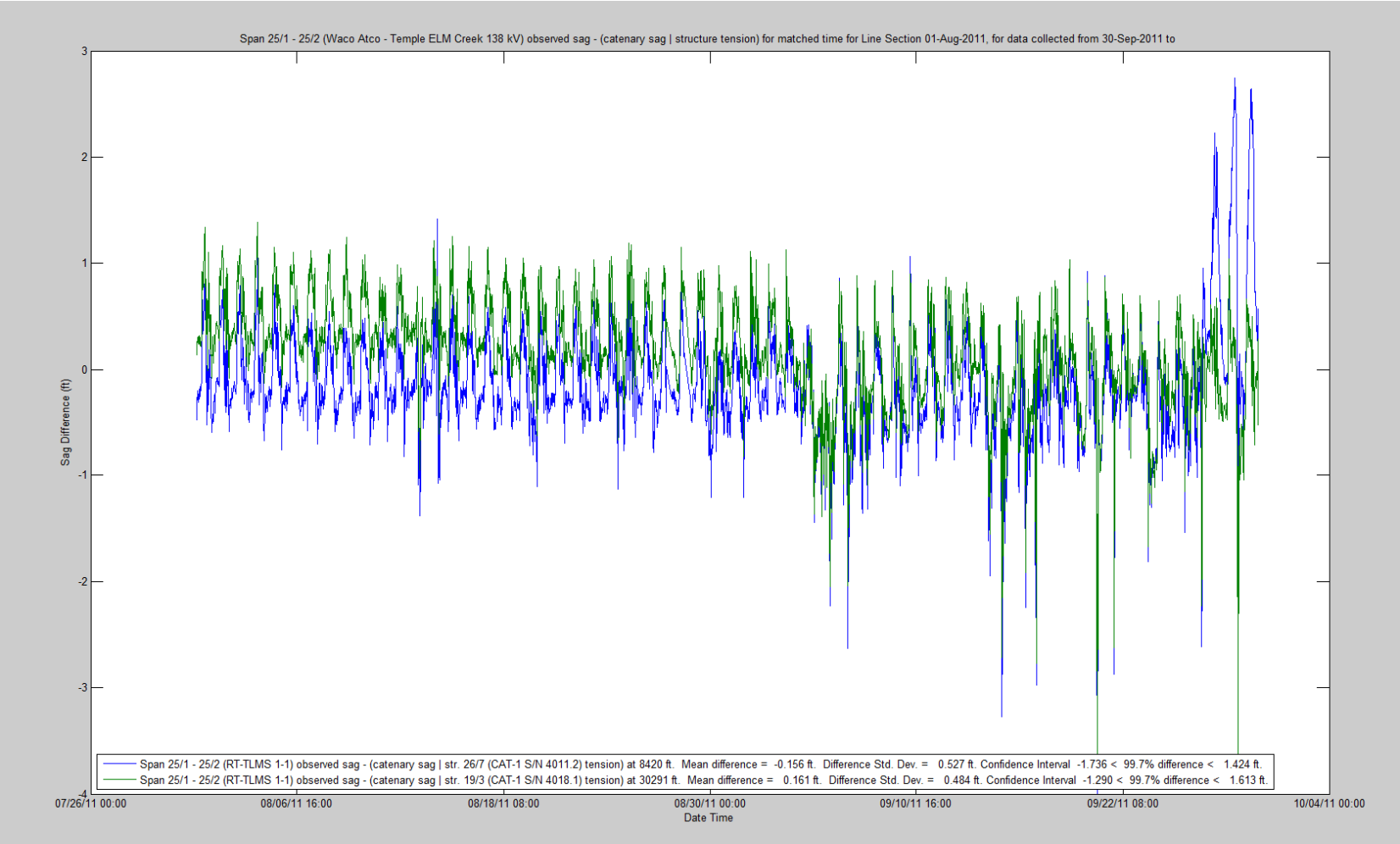
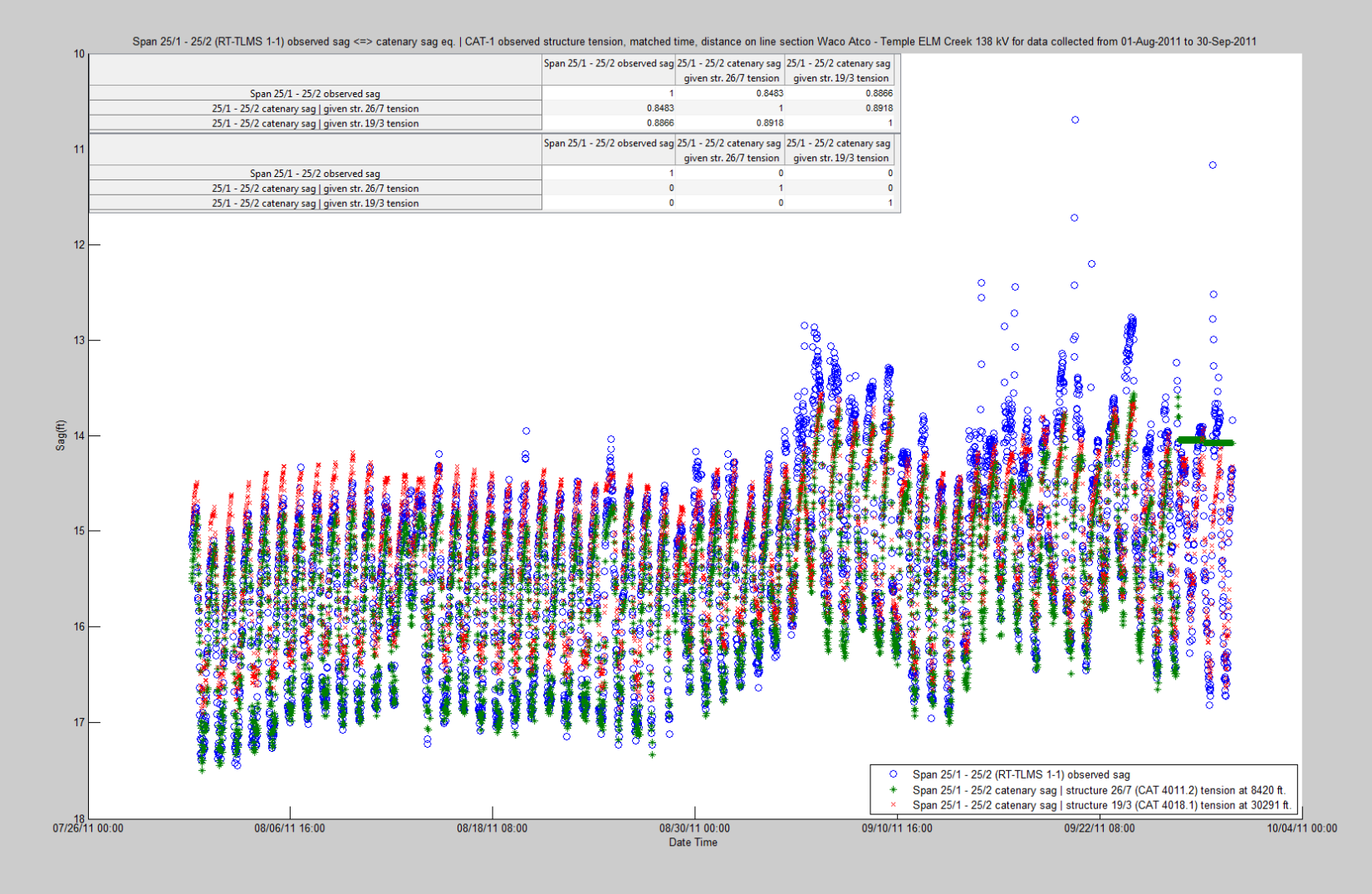


Figure D - 18 Line Section Waco Atco - Temple Elm Creek 138 kV Sag Difference between Span 25/1 and 25/2 (RT-TLMS 1-1) Sag Observations and CAT-1 Sag Estimates



	Span 25/1 - 25/2 observed sag	25/1 - 25/2 catenary sag given str. 26/7 tension	25/1 - 25/2 catenary sag given str. 19/3 tension
Span 25/1 - 25/2 observed sag	1	0.8483	0.8866
25/1 - 25/2 catenary sag | given str. 26/7 tension	0.8483	1	0.8918
25/1 - 25/2 catenary sag | given str. 19/3 tension	0.8866	0.8918	1

	Span 25/1 - 25/2 observed sag	25/1 - 25/2 catenary sag given str. 26/7 tension	25/1 - 25/2 catenary sag given str. 19/3 tension
Span 25/1 - 25/2 observed sag	1	0	0
25/1 - 25/2 catenary sag | given str. 26/7 tension	0	1	0
25/1 - 25/2 catenary sag | given str. 19/3 tension	0	0	1

Figure D - 19 Line Section Waco Atco - Temple Elm Creek 138 kV Sag Correlation | Time between Span 25/1 and 25/2 (RT-TLMS 1-1) Sag Observations and CAT-1 Sag

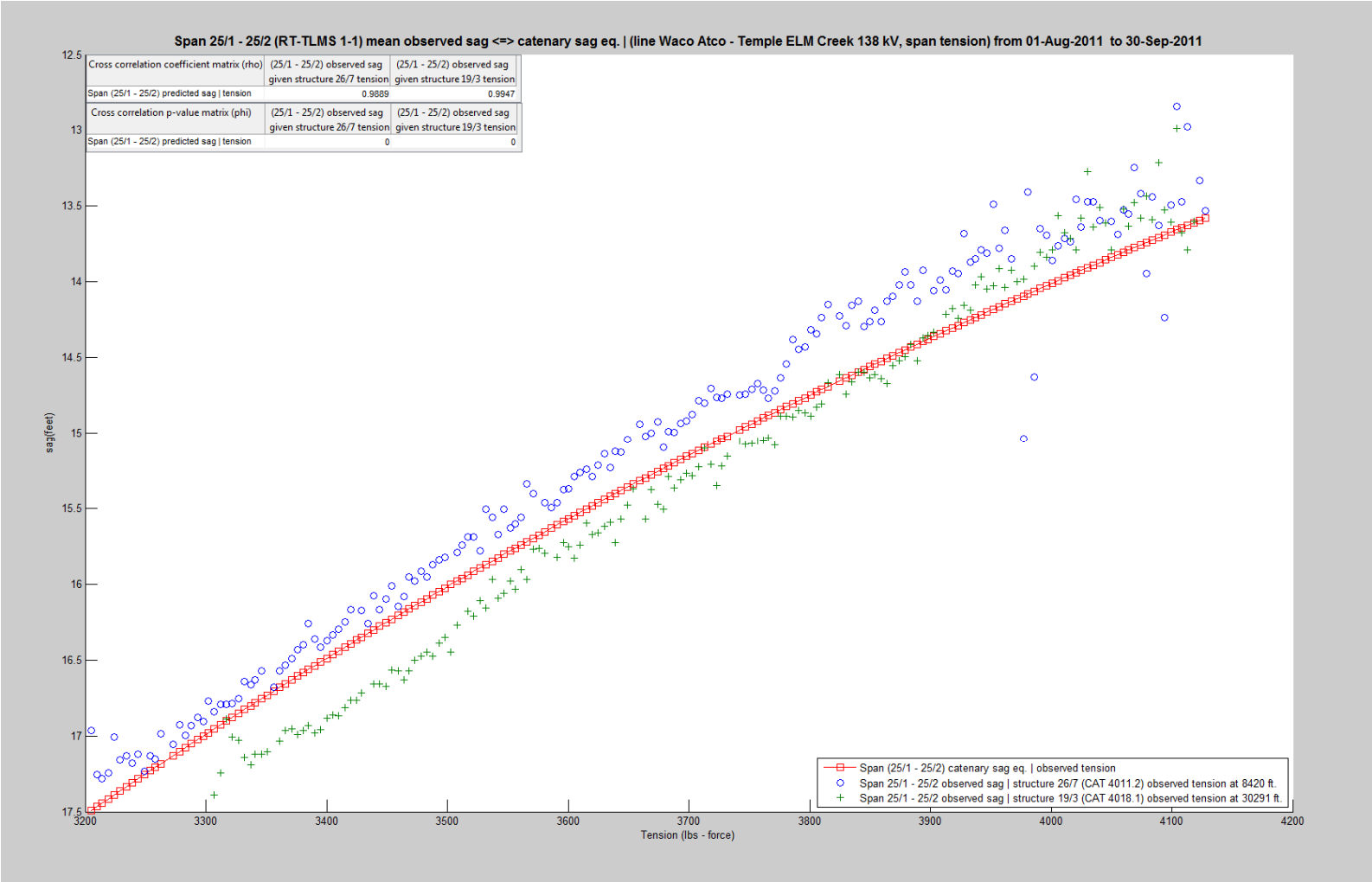


Figure D - 20 Line Section Waco Atco - Temple Elm Creek 138 kV Correlation | Tension between Span 25/1 and 25/2 (RT-TLMS 1-1) Sag Observations and CAT-1 Sag Estimates

8.5.5 Line Section Temple Pecan Creek - Temple 345 kV with Observed Span 31/1 – 31/2

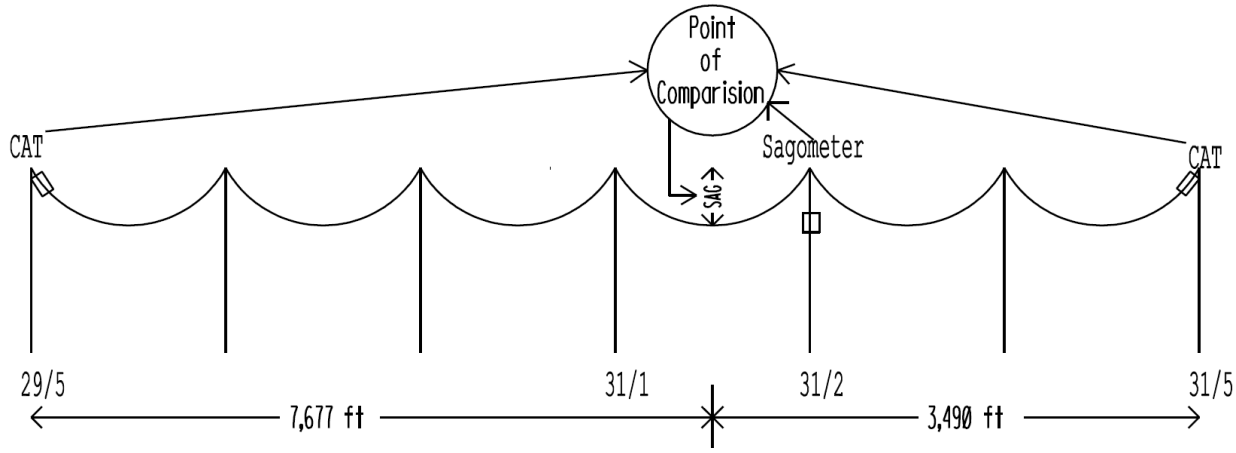


Figure D - 21 Line Section Temple Pecan Creek - Temple 345 kV with Observed Span 31/1 – 31/2

- CAT devices are mounted on structures 29/5 and 31/5.
- Sagometer 2 is mounted on the observed span 31/1 - 31/2.
- SwRI software uses Sagometer sag and CAT tension measurements to evaluate sag estimates for the observed span 31/1 - 31/2.
- The difference in sag calculations varies with the statistics shown in Table D - 11.
- Correlation of sag estimates for span 31/1 – 31/2 for a given time and for a given tension are also provided in Table D - 11.
- The calculations and associated measurements are illustrated in Figures D – 24 to D - 26, which follow Table D - 11.

Table D - 11 Line Section Temple Pecan Creek - Temple 345 kV Sag Difference Statistics and Correlation between Span 31/1 and 31/2 (Sagometer 2) Sag Observations and CAT-1 Sag Estimates

Device	Distance from the Sagometer in span 31/1 - 31/2 and a given CAT (in feet)	Calculated average sag difference for Sagometer in span 31/1 - 31/2 and a given CAT (in feet)	Calculated sag difference standard deviation for Sagometer span 31/1 - 31/2 and a given CAT (in feet)	Calculated correlation coefficient $\rho \mid time$ between a Sagometer span 31/1 - 31/2 and a given CAT (metric: $|\rho| \geq 0.8$)	Calculated sag p-value $\phi \mid time$ between a Sagometer span 31/1 - 31/2 and a given CAT (metric: $\phi \leq 0.01$)	Calculated correlation coefficient $\rho \mid tension\ \xi$ between a Sagometer span 31/1 - 31/2 and a given CAT (metric: $|\rho| \geq 0.8$)	Calculated sag p-value $\phi \mid tension\ \xi$ between a Sagometer span 31/1 - 31/2 and a given CAT (metric: $\phi \leq 0.01$)
CAT on 29/5	8420	No data	No data	No data	No data	No data	No data
CAT on 31/5	30921	1.296	0.315	0.9848	0	0.9983	0

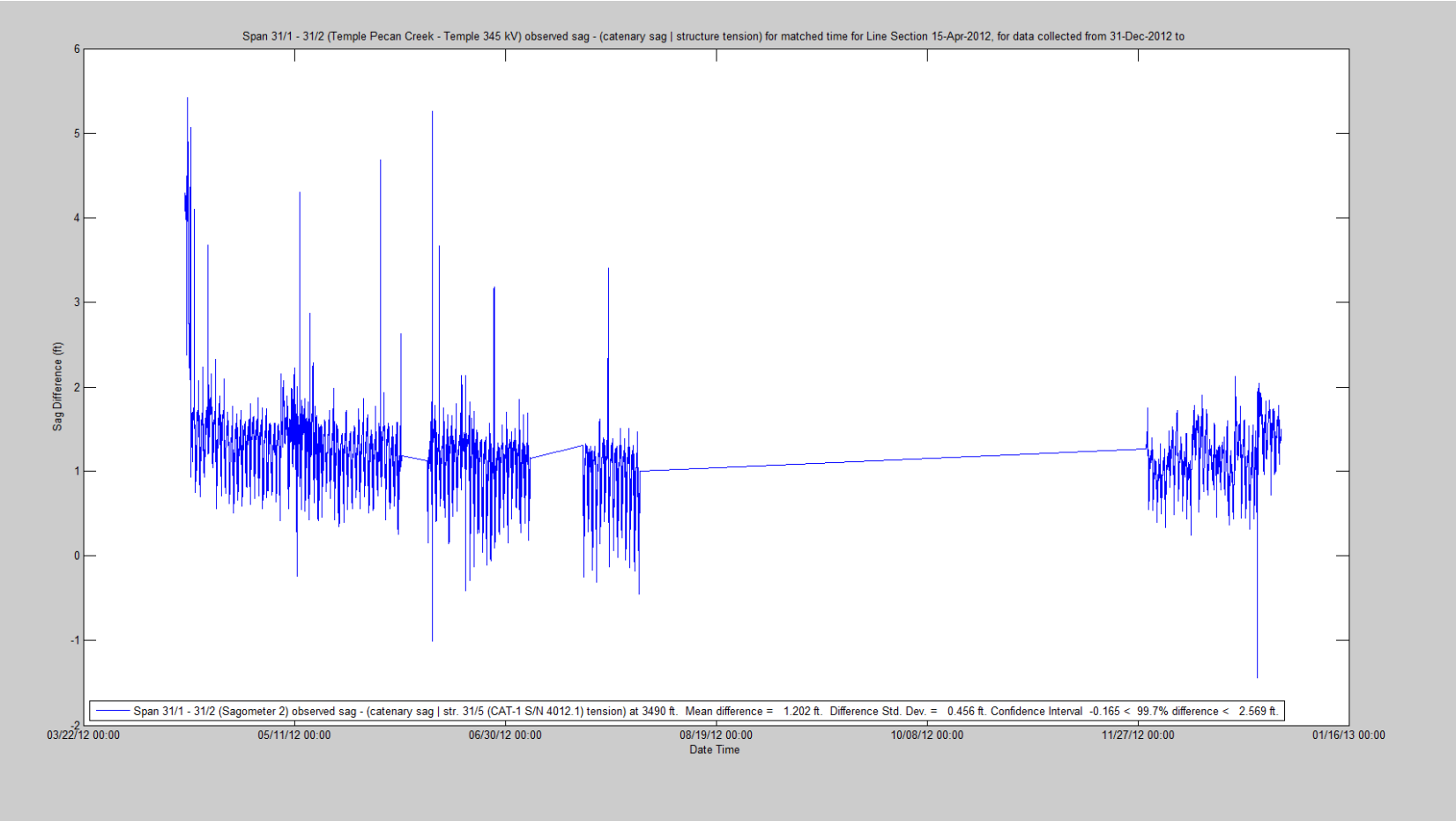


Figure D - 22 Line Section Temple Pecan Creek - Temple 345 kV Sag Difference Statistics between Span 31/1 and 31/2 (Sagometer 2) Sag Observations and CAT-1 Sag Estimates

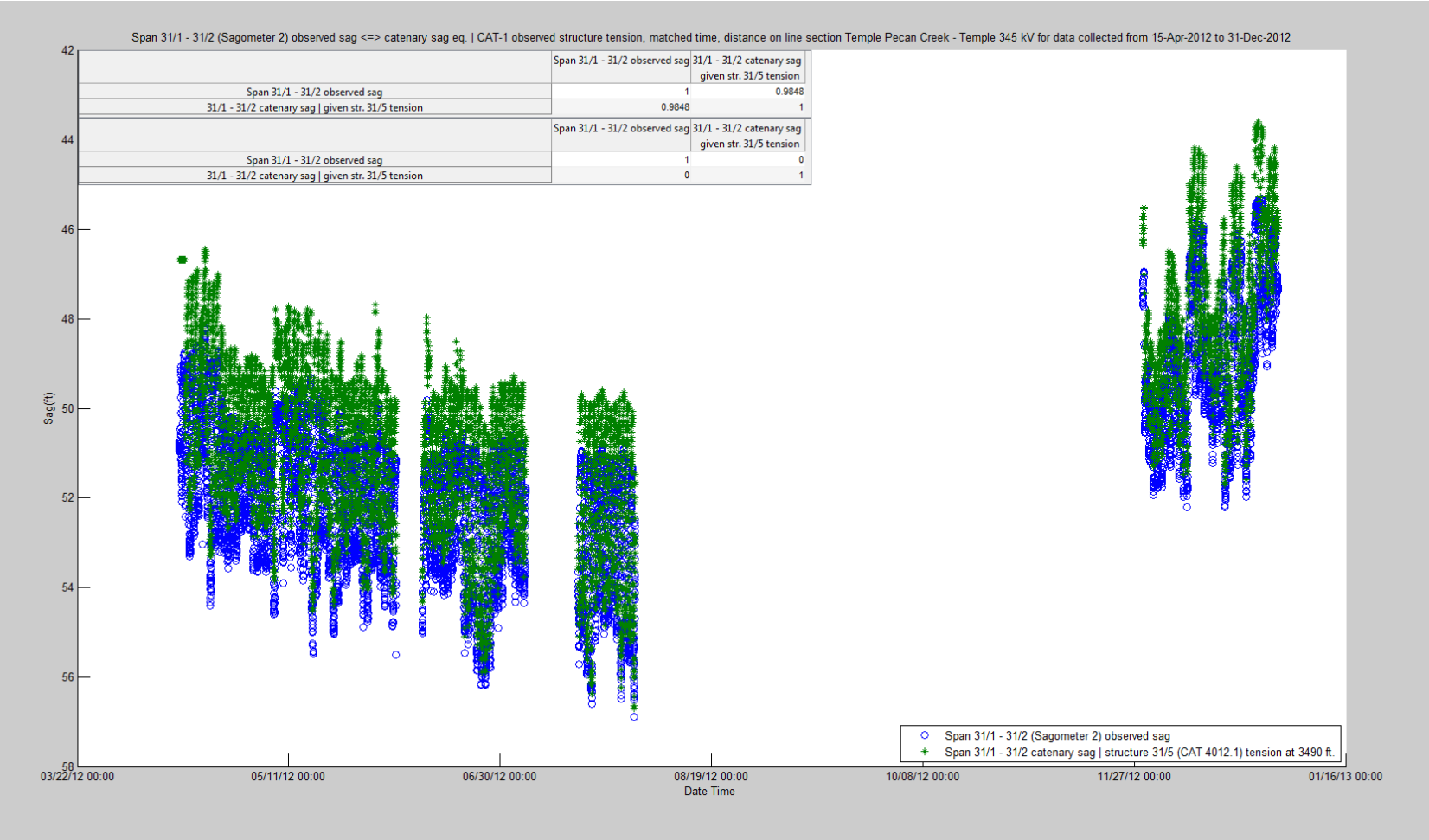


Figure D - 23 Line Section Temple Pecan Creek - Temple 345 kV Sag Correlation | Time between Span 31/1 and 31/2 (Sagometer 2) Sag Observations and CAT-1 Sag Estimates

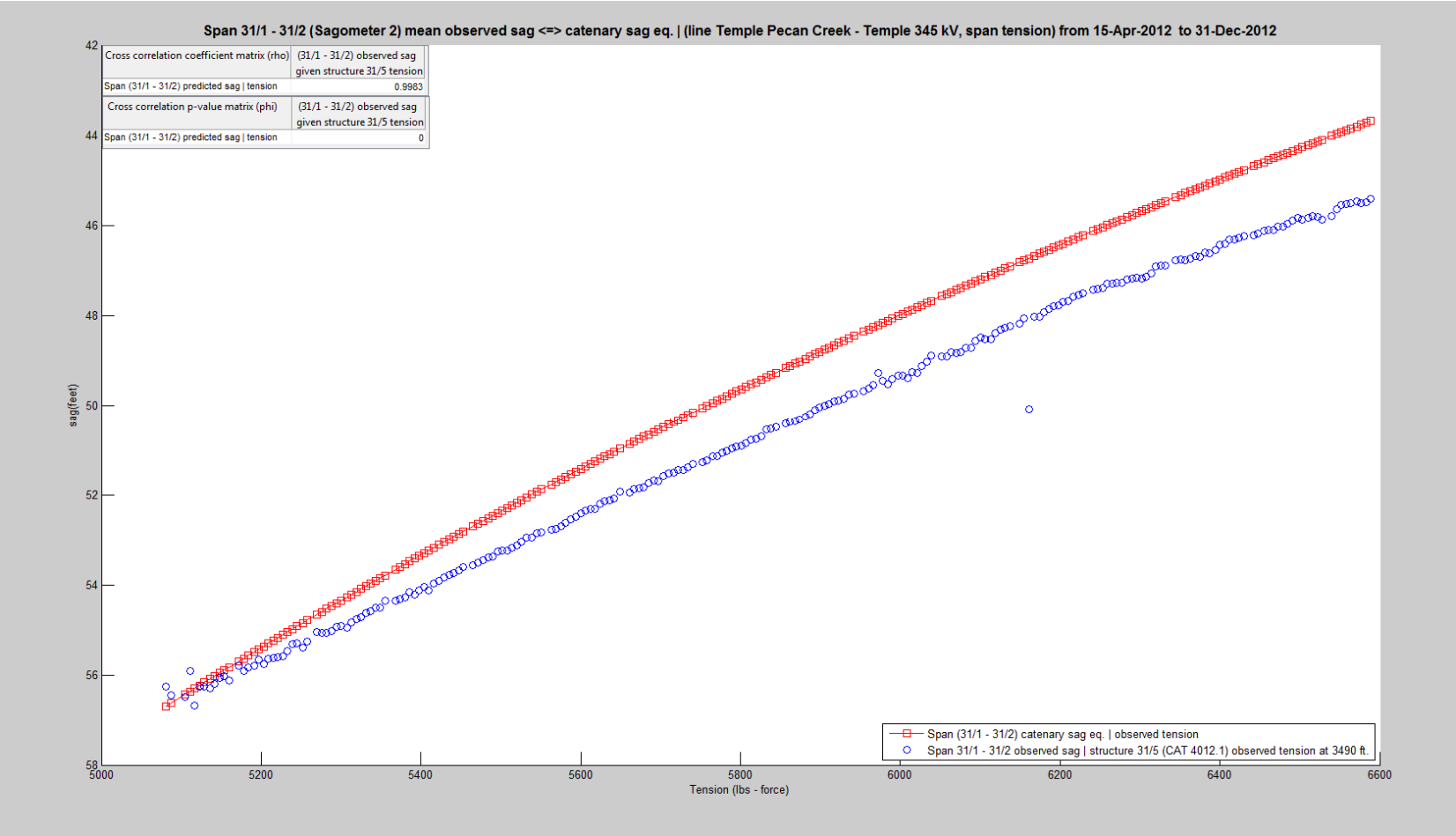


Figure D - 24 Line Section Temple Pecan Creek - Temple 345 kV Correlation | Time between Span 31/1 and 31/2 (Sagometer 2) Sag Observations and CAT-1 Sag Estimates

8.5.6 Line Section Tradinghouse - Lake Creek 345 kV with Observed Span 4/1 - 4/2

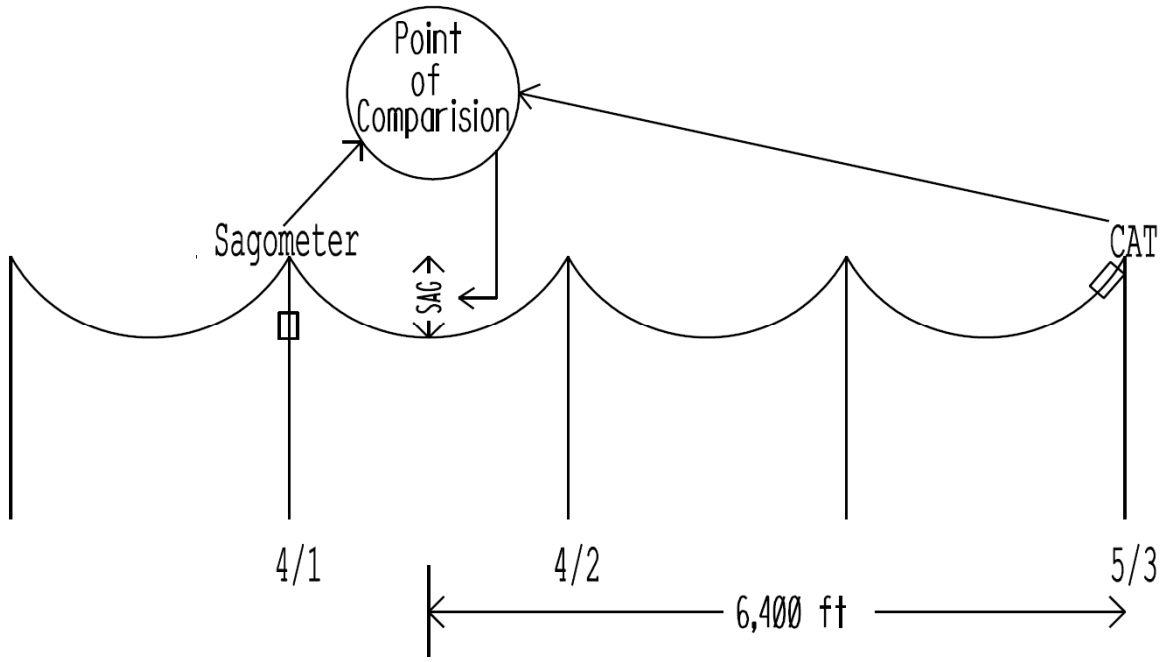


Figure D - 25 Line Section Tradinghouse - Lake Creek 345 kV with Observed Span 4/1 - 4/2

- CAT device is mounted on structure 5/3.
- Sagometer 5 is mounted on the span between structure 4/1 and 4/2.
- Sagometer and each CAT are calculating span sag between structures 4/1 and 4/2.
- The difference in sag calculations varies with the statistics shown in Table D - 12.
- Correlation of sag estimates for span 4/1 – 4/2 for a given time and for a given tension are also provided in Table D - 12.
- The calculations and associated measurements are illustrated in Figures D – 28 to D - 30, which follow Table D - 12.

Table D - 12 Line Section Tradinghouse - Lake Creek 345 kV Sag Difference Statistics and Correlation between Span 4/1 - 4/2 (Sagometer 5) Sag Observations and CAT-1 Sag Estimates

Device	Distance from the Sagometer in span 4/1 - 4/2 and a given CAT (in feet)	Calculated average sag difference for a Sagometer in span 4/1 - 4/2 and a given CAT (in feet)	Calculated sag difference standard deviation for a Sagometer in span 4/1 - 4/2 and a given CAT (in feet)	Calculated correlation coefficient $\rho \mid time$ between a Sagometer in span 4/1 - 4/2 and a given CAT (metric: $\lvert\rho\rvert \geq 0.8$)	Calculated sag p-value $\phi \mid time$ between a Sagometer in span 4/1 - 4/2 and a given CAT (metric: $\phi \leq 0.01$)	Calculated correlation coefficient $\rho \mid tension\ \xi$ between a Sagometer in span 4/1 - 4/2 and a given CAT (metric: $\lvert\rho\rvert \geq 0.8$)	Calculated sag p-value $\phi \mid tension\ \xi$ between a RT-TLMS a Sagometer in span 4/1 - 4/2 and a given CAT (metric: $\phi \leq 0.01$)
CAT on 5/3	6400	0.080	0. 287	0.9831	0	0.9984	0

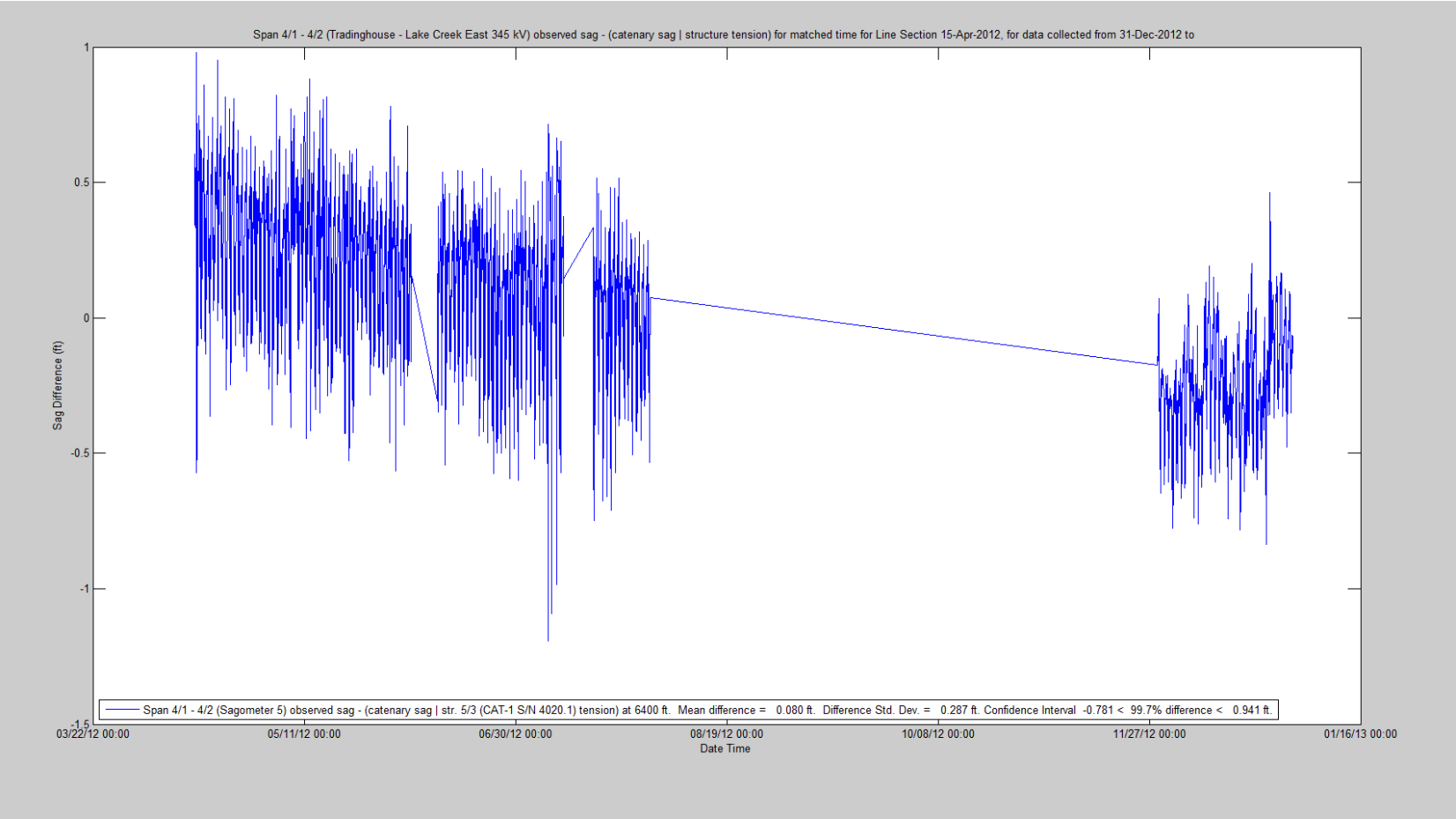


Figure D - 26 Line Section Tradinghouse - Lake Creek 345 kV Sag Difference Statistics Span 4/1 - 4/2 (Sagometer 5) Sag Observations and CAT-1 Sag Estimates

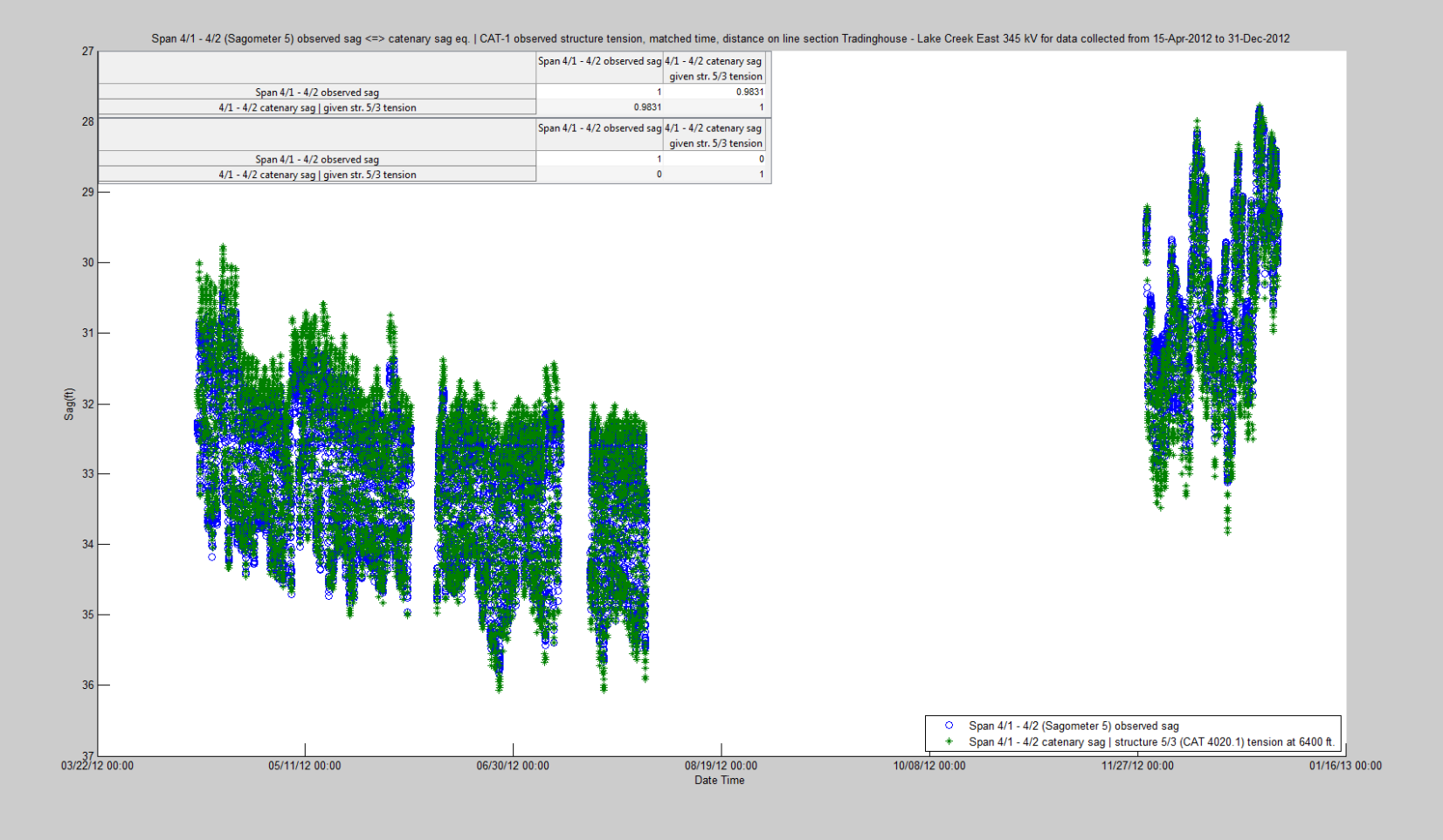


Figure D - 27 Line Section Tradinghouse - Lake Creek 345 kV Correlation | Time between Span 4/1 - 4/2 (Sagometer 5) Sag Observations and CAT-1 Sag Estimates

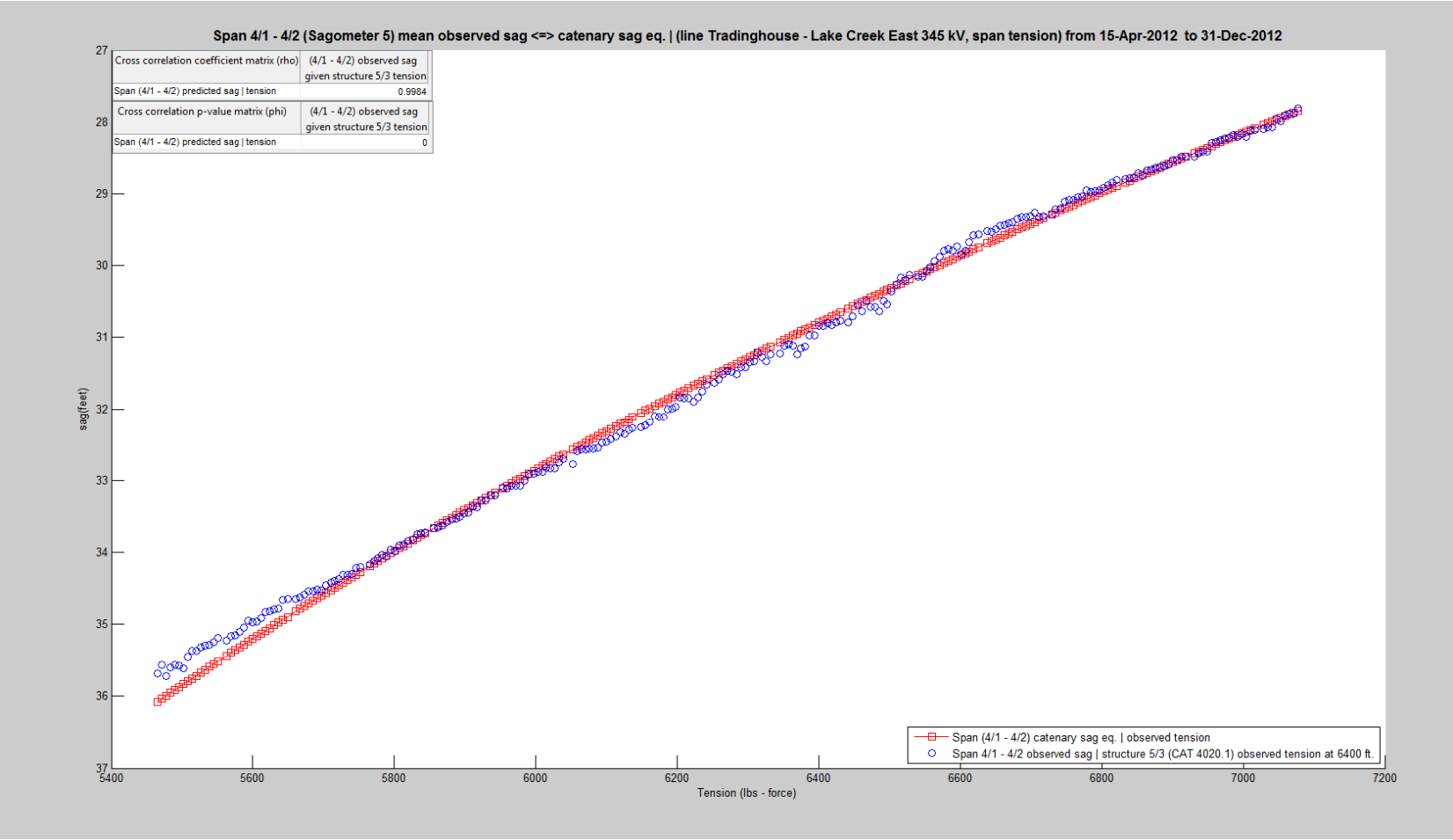


Figure D - 28 Line Section Tradinghouse - Lake Creek 345 kV Sag Correlation | Time between Span 4/1 - 4/2 (Sagometer 5) Sag Observations and CAT-1 Sag Estimates

9. Explanation of Measurement Analysis and Results

The following sections describe line behavior measurement tests conducted under different given conditions. The sections also contain the test results.

9.1 Sag Correlation for a Given Line, Time and Distance [sag ⇔sag|(line, time, distance)]

In this section, the study poses the question, "Do CAT-1, RT-TLMS, Sagometer and the catenary sag equation strongly correlate (agree) on line parametric behavior when observing a given line, during a given time span, and at given separation distances?" The null hypothesis, the measurement correlation coefficient and the strong correlation confidence interval are used to verify the measurement correlation. The alternative hypothesis test, the correlation coefficient p-value and the random event confidence interval validate the correlation coefficient.

SwRI followed the steps listed below to test the correlation of line behavior measurements for the given conditions of line, time and separation distance (reach).

1. Qualify coincident CAT-1 and RT-TLMS or Sagometer measurements within time range for a given line.
2. Align RT-TLMS clearance observations to the nearest minute interval.
3. Convert RT-TLMS clearance measurements to sag estimates.
4. Align Sagometer sag observations to the nearest 10-minute interval.
5. Align CAT-1 tension measurements to the nearest 10-minute interval.
6. Select measurements for the given line that intersect at the nearest 10-minute interval.
    a. Discard all measurements that do not intersect.
7. Correlate CAT-1 ⇔ CAT-1 catenary sags | (time, line, distance), ρ.
8. Compute the p-values ϕ for CAT-1 ⇔ CAT-1 catenary sags | (time, line, distance), ρ.
9. Correlate (CAT-1 sag ⇔RT-TLMS or Sagometer sag) | (time, line, distance), ρ.
10. Compute the p-values ϕ for (CAT-1 sag ⇔RT-TLMS or Sagometer sag) | (time, line, distance), ρ.
11. Compute conditional statistics (mean and standard deviation).
12. Evaluate the values of ρ and ϕ using the hypothesis test criteria in Table D - 5.

9.1.1 Measurement Conversion and Qualification

SwRI evaluated the lists of line configurations in Section 6 for combinations of two or more devices providing independent observations of the line parametric behavior. A detailed graph of measurements, like the one shown in Figure D - 31, provided a visual method for qualifying the measurements within time spans containing few measurement omissions or errors. The remaining sections and the appendices provide an analysis for those lines with sufficient coincident observations to provide meaningful results.

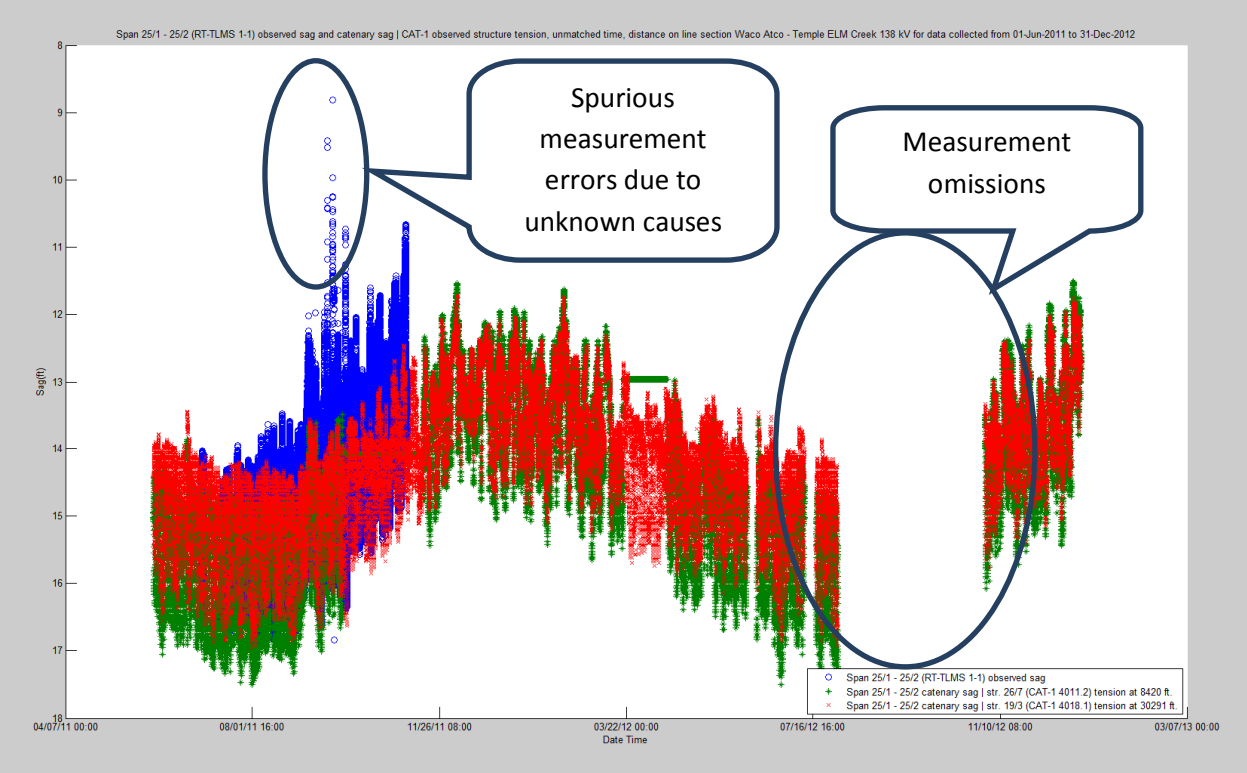


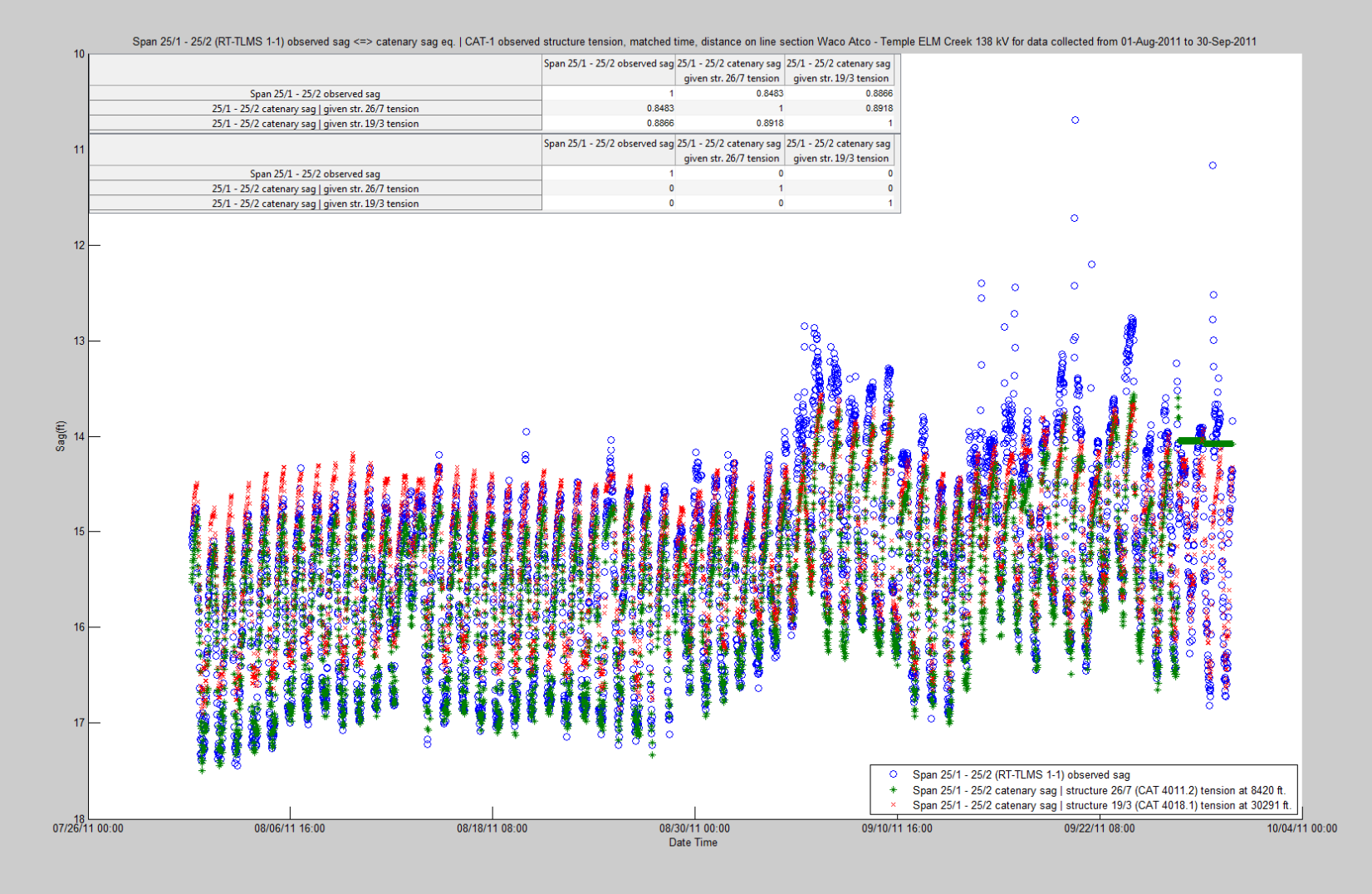
Figure D - 29 Measurement Errors and Omissions in Waco Atco - Temple Elm Creek 138 kV Line, 7/1/2011 through 6/30/2012

Figure D - 32 gives an example of a selected time span for the Waco Atco Temple Elm Creek 138 kV line observed by RT-TLMS 1-1, CAT-1 SN.Port 4011.1 and CAT-1 SN.Port 4018.1.

Figure D - 33 shows the distinct measurements for each of the devices named in the legend. The legend also gives the distance separating the devices referenced to the observed span 25/1 – 25/2. There are obvious similarities between the measurements, but further time alignment and qualification is required before ρ and p-value metrics can be calculated.

9.1.2 Time Alignment, Intersection and Hypothesis Test Results for a Given Line and Time

SwRI aligned the observation time stamps to the nearest minute and further qualified the observations that occurred in the same one-minute time interval. Having measurements that intersect in time, it was then possible to compute the correlation coefficients ρ for the null hypothesis and the p-values for the alternative hypothesis.



	Span 25/1 - 25/2 observed sag	25/1 - 25/2 catenary sag given str. 26/7 tension	25/1 - 25/2 catenary sag given str. 19/3 tension
Span 25/1 - 25/2 observed sag	1	0.8483	0.8866
25/1 - 25/2 catenary sag | given str. 26/7 tension	0.8483	1	0.8918
25/1 - 25/2 catenary sag | given str. 19/3 tension	0.8866	0.8918	1

	Span 25/1 - 25/2 observed sag	25/1 - 25/2 catenary sag given str. 26/7 tension	25/1 - 25/2 catenary sag given str. 19/3 tension
Span 25/1 - 25/2 observed sag	1	0	0
25/1 - 25/2 catenary sag | given str. 26/7 tension	0	1	0
25/1 - 25/2 catenary sag | given str. 19/3 tension	0	0	1

Figure D - 30 Sag | Waco Atco - Temple Elm Creek 138 kV Line, Time, Distance

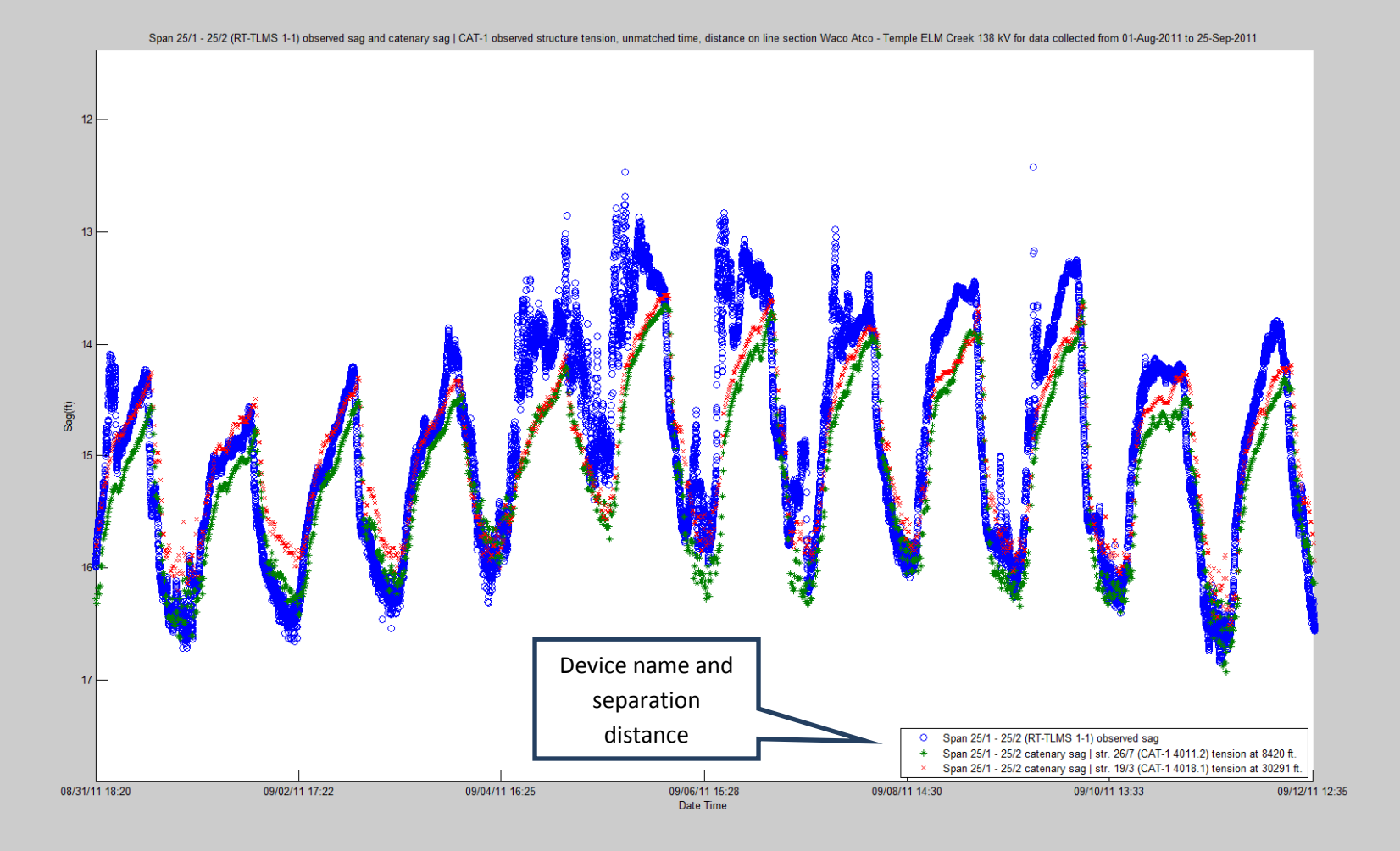


Figure D - 31 Sag | Waco Atco - Temple Elm Creek 138 kV Line, Time, Distance (Expanded View)

9.1.3 Hypothesis Tests for a Given Line and Time Range

Figure D - 34 illustrates the observations that intersect in time. The tables in the figure's upper left corner give the conditional values for ρ and the p-values ϕ. In this example, the values of ρ indicate strong correlation among the DLR devices observing sag behavior on the given line during the given time span. The p-values give no indication of a random coincidental occurrence of correlated behavior. The conclusion for this example evaluated by the criteria in Table D - 5 is that the measurements are valid and are verified for the given line and time span.

The relationship of $(\rho|line, time, distance)$ to distance is highlighted in Figures D – 34 and D- 35. The strong correlation coefficient confidence interval is satisfied between observed span 25/1 - 25/2 (RT-TLMS 1-1), structure 26/7 (CAT-1 4011.2) and structure 29/3 (CAT-1 4012.1) at distances exceeding 30,000 feet. For all measurements, the correlations satisfy the following confidence interval.

$$|(\rho|Lake - Creek - Temple\ 345\ \ kV\ Line, 1\ August\ 2011 - 30\ September\ 2011, distance)| \geq 0.8$$

The strong correlation confidence interval is satisfied in Figure D - 35 for distances separating Sagometer 1 and associated CAT-1s SN4006.1 through CAT-1 SN4010.1 at distances exceeding 93,000 feet.

$$|(\rho|Lake - Creek - Temple\ 345kV\ Line, 15\ April\ 2012 - 3\ June\ 2012, distance)| \geq 0.8$$

The relationships are verified and validated for independent observations of line parametric behavior for the given lines during a given time range. The preceding analysis was repeated for all of the line sections described in Section 8.5.

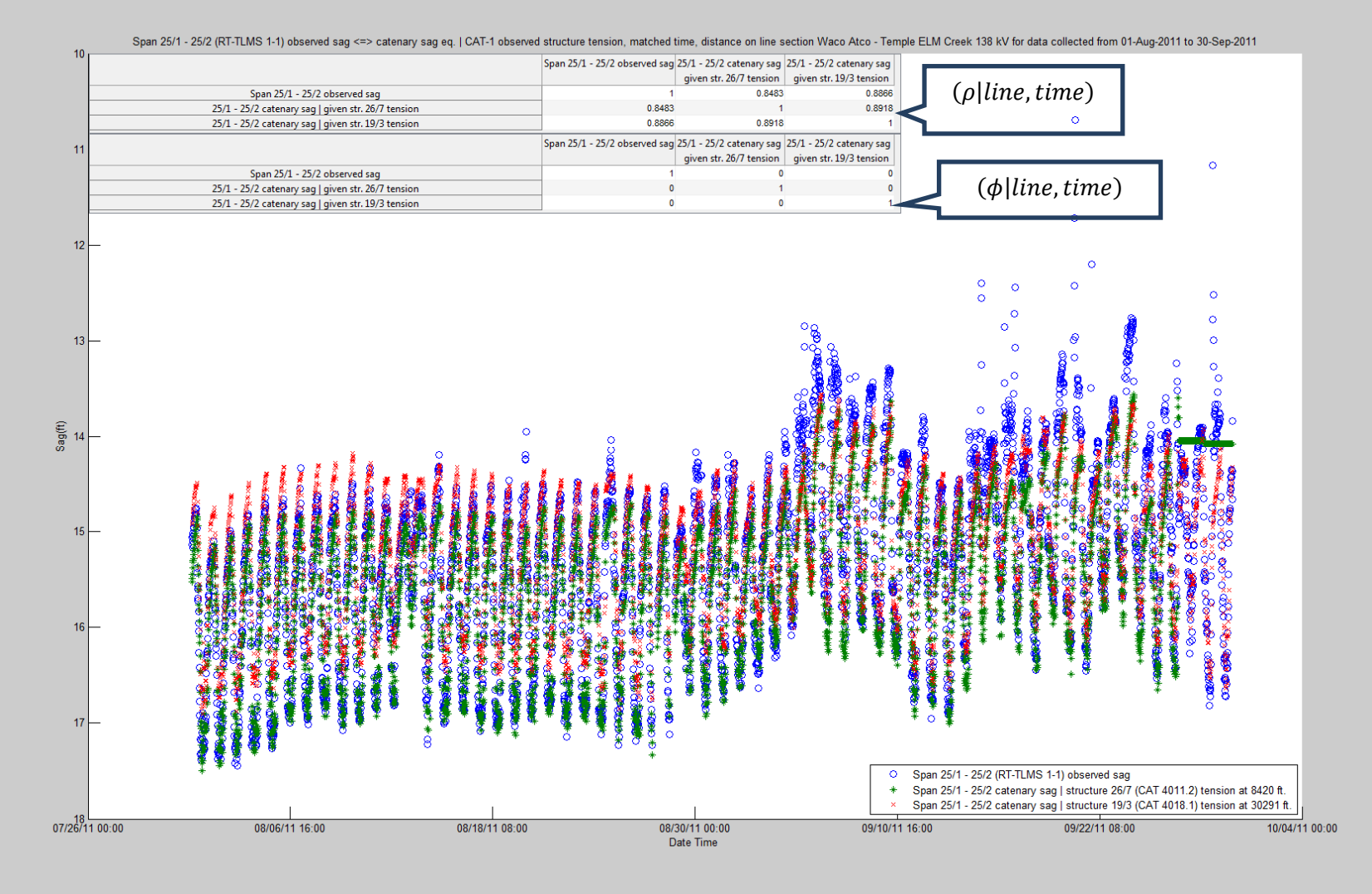
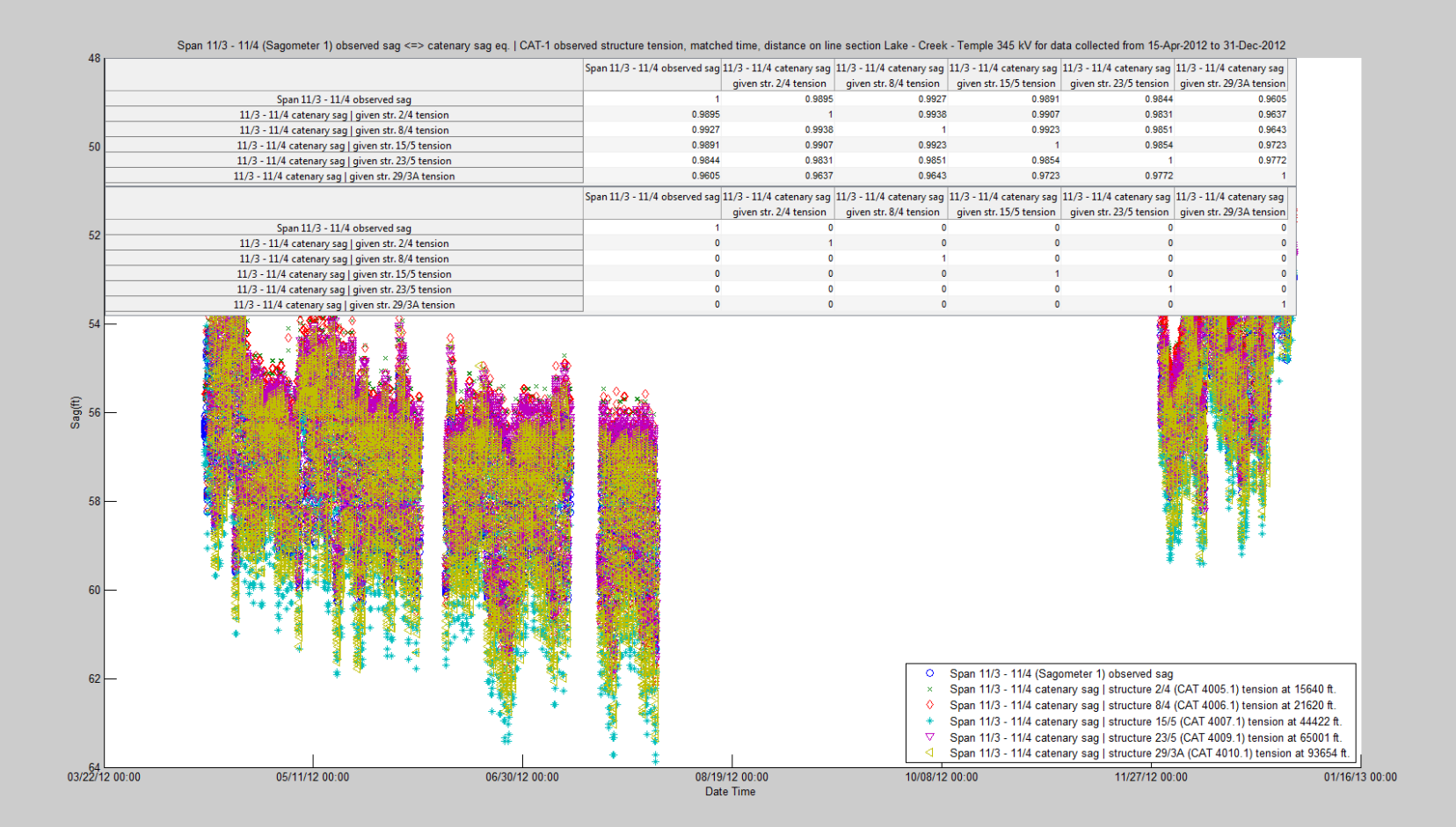


Figure D - 32– Sag | (Waco Atco - Temple Elm Creek 138KV Line, Time, Distance)



	Span 11/3 - 11/4 observed sag	11/3 - 11/4 catenary sag given str. 2/4 tension	11/3 - 11/4 catenary sag given str. 8/4 tension	11/3 - 11/4 catenary sag given str. 15/5 tension	11/3 - 11/4 catenary sag given str. 23/5 tension	11/3 - 11/4 catenary sag given str. 29/3A tension
Span 11/3 - 11/4 observed sag	1	0.9895	0.9927	0.9891	0.9844	0.9605
11/3 - 11/4 catenary sag | given str. 2/4 tension	0.9895	1	0.9938	0.9907	0.9831	0.9637
11/3 - 11/4 catenary sag | given str. 8/4 tension	0.9927	0.9938	1	0.9923	0.9851	0.9643
11/3 - 11/4 catenary sag | given str. 15/5 tension	0.9891	0.9907	0.9923	1	0.9854	0.9723
11/3 - 11/4 catenary sag | given str. 23/5 tension	0.9844	0.9831	0.9851	0.9854	1	0.9772
11/3 - 11/4 catenary sag | given str. 29/3A tension	0.9605	0.9637	0.9643	0.9723	0.9772	1

	Span 11/3 - 11/4 observed sag	11/3 - 11/4 catenary sag given str. 2/4 tension	11/3 - 11/4 catenary sag given str. 8/4 tension	11/3 - 11/4 catenary sag given str. 15/5 tension	11/3 - 11/4 catenary sag given str. 23/5 tension	11/3 - 11/4 catenary sag given str. 29/3A tension
Span 11/3 - 11/4 observed sag	1	0	0	0	0	0
11/3 - 11/4 catenary sag | given str. 2/4 tension	0	1	0	0	0	0
11/3 - 11/4 catenary sag | given str. 8/4 tension	0	0	1	0	0	0
11/3 - 11/4 catenary sag | given str. 15/5 tension	0	0	0	1	0	0
11/3 - 11/4 catenary sag | given str. 23/5 tension	0	0	0	0	1	0
11/3 - 11/4 catenary sag | given str. 29/3A tension	0	0	0	0	0	1

Figure D - 33 Span 11/3 -11/4 Observed Sag Catenary Sag | (Lake-Creek-Temple 345kV Line, Time, CAT-1 Observed Tension, Distance)

The behavior relationship is insensitive to the distance separating the CAT-1 tension observed span and the observed span. There is very little indication of correlation attenuation due to separation distance. Any lack of correlation appears to be caused by time stamp misalignment, measurement errors, omissions, or other external factors as mentioned in Section 8.3.

Appendix A contains the test results for several lines, time ranges, and distances. The null hypothesis metric values $(\rho|line, time, distance)$ indicate strong correlation giving consistent proof that H_0 is valid for all of the qualified measurements. The alternative hypothesis p-values are all $\phi \ll 0.1$ implying that H_a validates H_0 for all selected measurements, i.e., the $(\rho|line, time, distance)$ are actual relationships and not random events.

Thus, the hypothesis tests H_0 and H_a validated and verified for the qualified measurements for the given lines, time ranges, and distances considered within the study. Furthermore, the measurements are insensitive to distance. SwRI concludes that a CAT-1 tension measurement taken on one span can be used to accurately estimate tension in any other span under the conditions of tension equilibrium within a given line.

The broader question that will be examined in this and subsequent sections is, "Do DLR measurements satisfy the criteria in Table D - 5 under more general given conditions?" The study conducts additional tests in the following sections under alternative conditions in search for more evidence upon which to base additional conclusions.

9.1.4 Sag Estimate Differences and Statistics for a Given Line and Time Span

The sag estimate difference mean $\mu_\delta|(line, time, distance)$ and standard deviation $\sigma_\delta|(line, time, distance)$ give further insight into the behavior similarity.

$$\mu_\delta(j)|\big(line, time, distance(j)\big) = \frac{1}{N}\sum_{i=1}^{N}\left(sag_{\substack{RTTLMS\ or\\ Sagometer}}(i) - sag_{CAT1}(i,j)\right)|line, time, distance(j)$$

$$\sigma_\delta(j)|\big(line, time, distance(j)\big) = \left(\sqrt{\frac{\sum_{i=1}^{N}\left(sag_{\substack{RTTLMS\ or\\ Sagometer}}(i) - sag_{CAT1}(i,j)\right)^2}{N} - (\mu_\delta(j))^2}\right)|\big(line, time, distance(j)\big)$$

The variable N is the number of coincident observations of sag along a given line for a given distance(j), where j denotes the distance separating the jth CAT-1 and observed span for the given line during the

given measurement time range. The variable $i \in \{1 \ldots N\}$ is the ith coincident observation for a set of observations.

Ideally, $\mu_\delta(j) = 0$ and $\sigma_\delta(j) = 0$ for any given line and distance j, but external factors described in Section 8.3 add randomly to the observed behavior. The time-matched (intersecting) measurements in Figure D - 34 are subtracted to compute differences between the observed span and each of the CAT-1 system-equipped structure on the given line "Waco Atco – Temple Elm Creek 138 kV." The measurement differences are shown in Figure D - 36. The statistics for the differences are provided in the lower left corner of the figure. The example shows that the structure 26/7 (CAT-1 4011.2) sag mean difference is $\mu_\delta = 0.082$ feet and the standard deviation is $\sigma_\delta 0.202$ feet. Structure 26/7 sag differences observed for behavior in Figure D - 36 fall within a 99.7% confidence interval of $-0.525 \leq difference \leq 0.688\ ft.$ Structure 19/3 (CAT-1 4018.1) sag differences fall within a 99.7% confidence interval of $-0.508 \leq difference \leq 0.784\ ft.$ . . Figure D - 37 shows the difference statistics to be insensitive to observation separation distance for examined distances of up to 93,654 feet. Appendix B contains the measurement difference and difference statistics for a number of given lines, time ranges and distances.

The study observed a DLR sag difference mean $|\mu_\delta| \leq 1.3\ ft$ for all of the observations. A value $\mu_\delta \neq 0$ indicates a constant bias in one or more line parametric observations. The bias could be due to tension calibration error in one or more of the CAT-1 systems or error in the values assumed for the line span length for the spans containing an RT-TLMS or Sagometer. For example, a sag difference mean $|\mu_\delta| \leq 1.3\ ft$ could be caused by a tension calibration error ≤ 255 lbs – force or a span length error $\leq 24\ feet$ on the Waco Atco - Temple Elm Creek 138 kV line with observed tension of 3,200 lb – force and assumed span length of 640 feet. In another example, a $\mu_\delta \leq 1.3\ ft.$ indicates an observed tension error $\leq\ 124$ lbs –force or span length error ≤ 17 feet on the Lake - Creek - Temple 345 kV line with an observed tension of 5,500 lbs – force and an assumed span length of 1,535 feet.

The standard deviation σ_δ and a 99.7% confidence interval are highly sensitive to measurement omissions and error. There was insufficient time to further qualify the measurements and draw detailed conclusions regarding the 99.7% confidence interval.

Similar results are found in Appendix B. The consistency of the observation difference statistics gives further evidence that measurement correlation exists among the observed behaviors. SwRI continued the hypothesis tests under different conditions, specifically for a given line and tension.

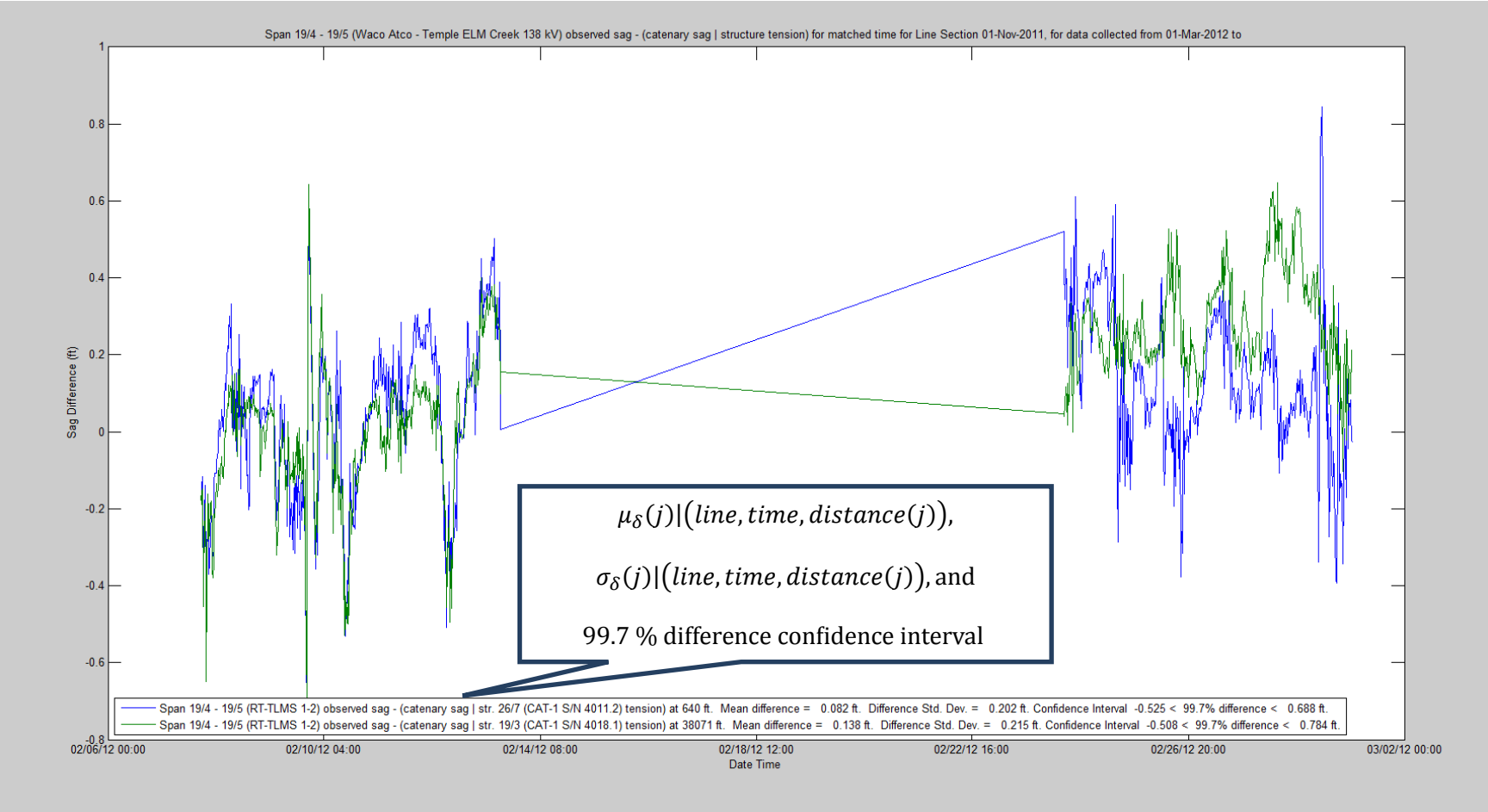


Figure D - 34 Sag Differences | (Waco Atco - Temple Elm Creek 138 kV Line, Time, Distance) with Statistics

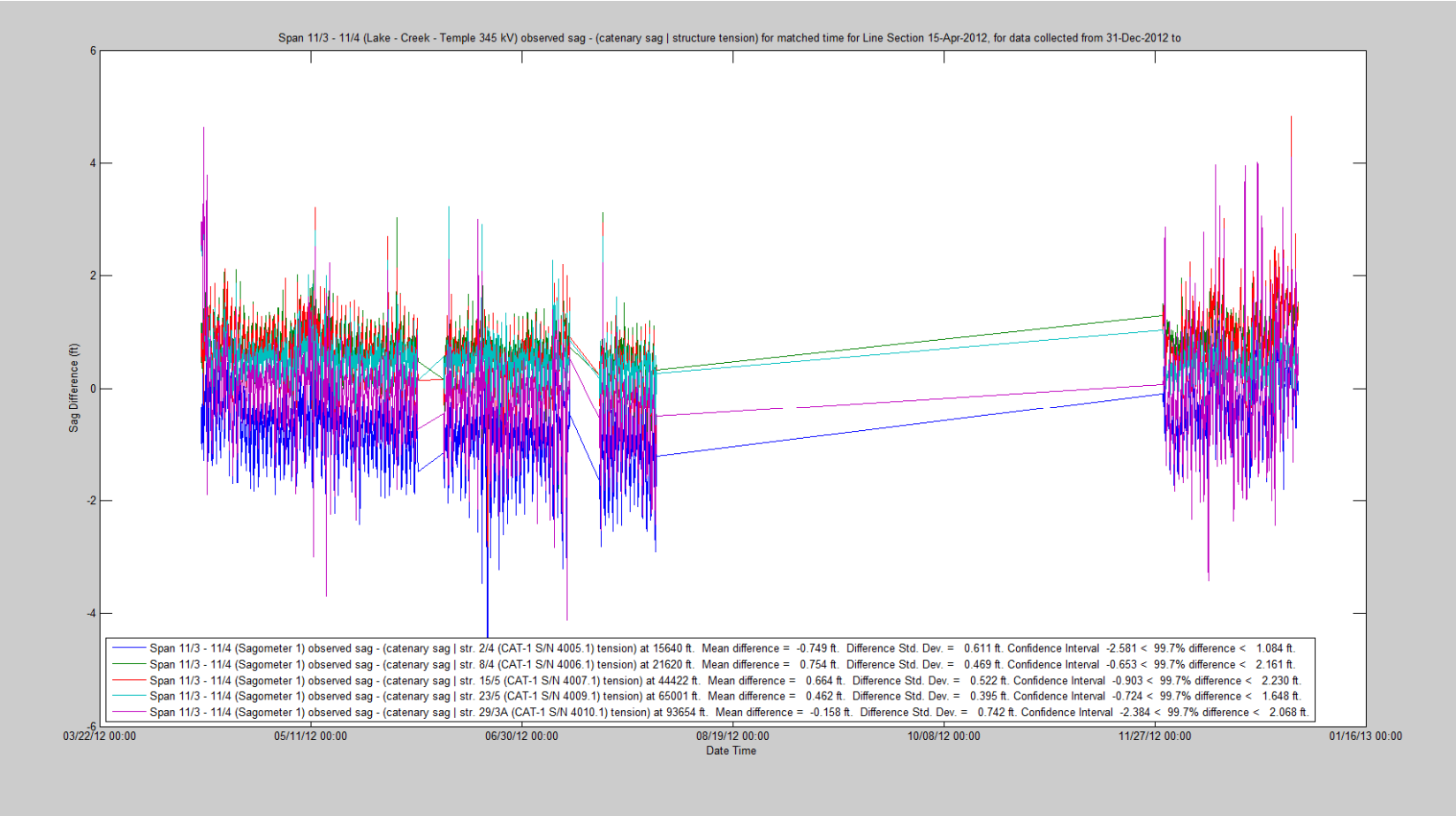


Figure D - 35 Sag Differences | (Lake Creek – Temple 345 kV Line, Time, Distance) and Statistics

9.2 Sag for a Given Line and Tension (sag|line, tension)

Section 9.1 produced some interesting conclusions. For any given time and line in tension equilibrium, CAT-1 tension measurements produce strongly correlated estimates of sag along a line regardless of the distance separating the observed span and the span of interest. The conclusion raises a more general question: "Do observed sag measurements correlate strongly with CAT-1 tension measurements and resulting catenary sag equation predictions independent of time or separation distance?" The question suggests that all observed sag and observed tension measurements should correlate regardless of where or when the observations were made along a given line and given the same operational conditions.

The second part of the study attempts to show correlation between tension and sag behaviors for a given line. Objectives also include examining the sag rate of change correlation for sag observations and for the sag catenary equation $Sag[]$.

Taking time and distance out of consideration creates a more general view of the line behavior. It also presents new analytic challenges. External influences like line aerodynamics, varying wind velocities and the resulting line motion may decorrelate CAT-1, RT-TLMS and Sagometer measurements if the measurement observations are taken at significantly different times and distances.

SwRI theorized that the quantizing error, observation omissions, observation errors, time synchronization variations and other variable external influences added a random variable ϵ to observed sag values. The conductor sag value and the random influences create a distribution of sag values for any given observation of tension. The distribution of the randomized observations is illustrated in Figure D - 3. The most likely value of sag within the distribution is represented by the mean sag μ_s, depicted as a jagged black line in Figure D - 3. The sag standard deviation σ_s defines the confidence interval of μ_s if the distribution is a normal distribution. Upon examination of Figure D - 3, SwRI concluded the normal distribution to be a reasonable assumption.

Tension is independent of distance and time under the assumption that equilibrium is maintained among the floating span connections comprising a given line. All tension measurements along the line can be correlated to observed span sag measurements taken at any point along the same line provided that the observations are of the same line behavior. It will be shown that the "same line behavior" constraint can be met if the tension and associated sag observations are taken at nearly the same time.

The catenary sag equation Sag[] is not a function of time [15]. A given tension observation along a line can be related to sag using the catenary equation Sag[]. In theory, the observations can be taken at different times provided that the observations are under the same operational and external conditions.

That said, it was not practical to obtain detailed information regarding the external conditions prevalent at the instant that a tension or sag observation was made. Instead, SwRI aligned combinations of sag and tension observations recorded within the same one-minute interval into sets of sag and tension for a given line and time, $\{sag, CAT\ tension(s)\}|(line, time)$. For example, an observation set selected

from Figure D - 35 contains one Sagometer sag observation and five CAT-1 tension ξ observations all recorded within the same one-minute interval. Note that theoretically all of the CAT-1 observations within a given set are of the same tension value, but there is no requirement that the tension values be the same.

SwRI then sorted all sag observations sets into members, using tension as the sort criteria. Each member is a conditional sag distribution $f_s(sag|line, CAT\ tension(j))$ comprised of all observed span sag observations for an observed CAT-1 $tension(j)$. A given sag observation may appear in more than one member if the tension observations within any set differ in value.

The sag observations within a tension member are taken from different time intervals and are no longer conditional on time. The member is conditioned on one observed CAT-1 tension(j) that may be observed by multiple CAT-1s at different times and different separation distances. Thus, the sag observations are no longer conditioned by distance or time. The collection of conditional sag distribution members for a given line is an ensemble of conditional sag distributions $\left\{\bigcup_{j=1}^{M} f_s(sag|line, CAT1\ tension(j))\right\}|line$. Each member represents the sag observations for one value of observed tension $\xi(j)$.

The remainder of the study assumes that sag observations for any given tension observation have a normal probability distribution $f_s(sag|line, CAT\ tension)$, conditional observation mean and conditional observation standard deviation described respectively by

$$f_s(sag|line, CAT1\ tension(j)) = \left(\frac{1}{\sqrt{2\pi\sigma_s{}^2}} e^{-(sag-\mu_s)/2\sigma_s{}^2}\right)|(line, CAT1\ tension(j))$$

$$\mu_s|(line, CAT1\ tension(j)) = \left(\frac{\sum_{i=1}^{N} sag(i)|line, tension(j)}{N}\right)|(line, CAT1\ tension(j))$$

$$\sigma_s\big|\big(line, CAT1\ tension(j)\big) = \sigma_e\big|\big(line, CAT1\ tension(j)\big)$$
$$= \sqrt{\frac{\sum_{i=1}^{N}\big(sag(i)\big|line, CAT1\ tension(j)\big)^2}{N} - (\mu_s|(line, CAT1\ tension(j)))^2}$$

The variable N is the number of sag observations within member(j) for a given line and the jth tension. The variable $i \in \{1 \dots N\}$ is the ith observation for a given line and CAT-1 tension $\xi(j)$.

The probability distribution $f_s(sag|line, CAT1\ tension)$ is an ensemble of conditional distributions having M member functions $f_s(sag|line, CAT1\ tension(j)), j \in \{1 \dots M\}$. Each functional member of the ensemble has its own statistics $\mu_s|(line, CAT1\ tension(j))$ and $\sigma_s|(line, CAT1\ tension(j))$. Each of the vertical columns of observations shown in Figure D - 38 is a member $f_s(sag|line, CAT1\ tension(j))$ of the ensemble of distributions as shown in Figure D - 39.

$$f_s(sag|line, CAT\ tension\ \xi) = \left\{\bigcup_{j=1}^{M} f_s(sag|line, CAT1\ tension\ \xi(j))\right\}|line$$

Thus, $\mu_s|(line, CAT1\ tension)$ and $\sigma_s|(line, CAT1\ tension)$ are vectors of statistics corresponding to a vector of observed line tensions ξ and the corresponding ensemble of conditional sag distributions $f_s(sag|line, CAT\ tension)$.

A tension-based analysis tests the relationship between sag observations and tension observations without consideration for the time or separation distance. It tests the relationship of the conditional sag observation mean $\mu_s|(line, CAT1\ tension\ \xi)$ to the sag cantenary equation $Sag[\xi]|(line, CAT1\ tension\ \xi\ )$ for the given line and observed tensions. It also tests the relationship of the mean sag rate of change $\frac{d\mu_s}{d\xi}|(line, CAT1\ tension\ \xi)$ and the rate of change in sag catenary equation predictions $\frac{dSag[\xi]}{d\xi}|(line, CAT1\ tension\ \xi)$.

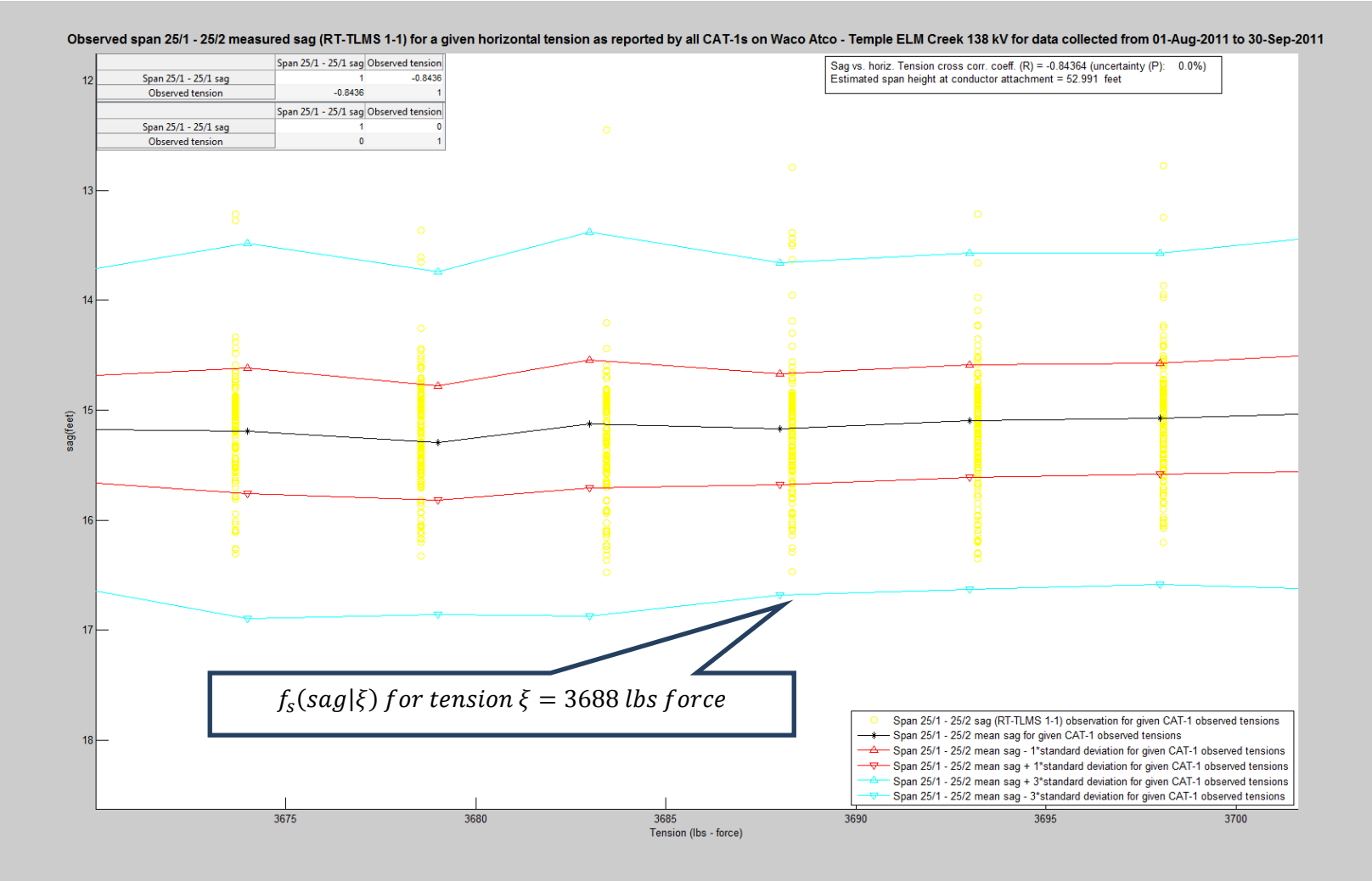


Figure D - 36 RT-TLMS1-1 Sag Distribution and Statistics | (Waco Atco – Temple Elm Creek 138 kV, CAT-1 Tension) - Expand

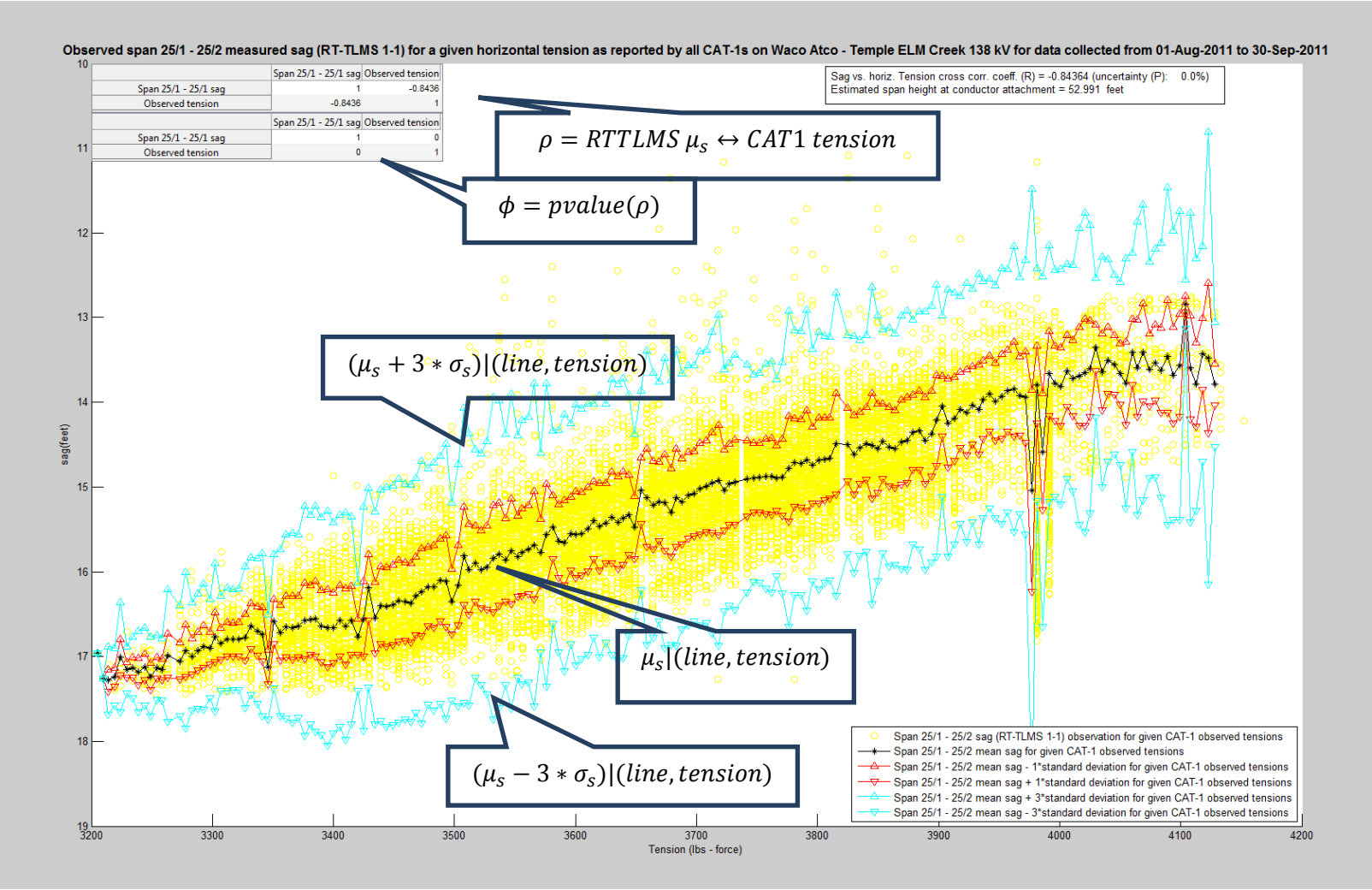


Figure D - 37 Observed Span 25/1 - 25/2 (RT-TLMS1-1) Sag Distribution and Statistics | (Waco Atco – Temple Elm Creek 138 kV, CAT-1 Tension

The preceding test approach was performed by SwRI applying the following steps:

1. Select the measurements for a given line.
2. Qualify the measurements to time ranges that minimize omissions and other external effects.
3. Align all sag observations with CAT-1 tension observations to the nearest minute interval.
4. Select sets of sag and tension observations that intersect at the same minute interval.
   a. Ignore all observations that do not intersect.
5. Reorganize sets of sag into members. A member contains all sag observations coincident with given tension observation.
6. Compute the RT-TLMS or Sagometer sag conditional mean $\mu_s|(line, CAT1\ tension\ \xi)$ and standard deviation $\left(\sigma_s\middle|(line, CAT1\ tension)\right)$ for each member.
7. Correlate observed RT-TLMS or Sagometer sag mean μ_s ⇔ observed CAT-1 tensions ξ | line, ρ.
8. Compute the p-value ϕ for the μ_s ⇔ observed CAT-1 tensions ξ | line, ρ.
9. Correlate (RT-TLMS or Sagometer μ_s⇔Sag[ξ])| (line, CAT1 tension ξ), ρ.
10. Compute the p-values ϕ for μ_s⇔Sag[ξ])| (line, CAT1 tension ξ), ρ.
11. Compute the rate of change (1st derivative) of sag estimates.
    a. Formulate 2nd order, polynomial-fit equation $P_2[\xi]|line, CAT1\ tension$ that approximates the sag conditional mean $\mu_s|(line, CAT1\ tension\ \xi)$, i.e.,
    $P_2[\xi]|(line, CAT1\ tension) \cong \mu_s|(line, CAT1\ tension\ \xi)$.
    b. Use a $\frac{dP_2[\xi]}{d\xi}|(line, CAT1\ tension\ \xi)$ as an approximation of $\frac{d\mu_s}{d\xi}|(line, CAT1\ tension\ \xi)$.
    c. Correlate $\frac{dP_2[\xi]}{d\xi}|(line, CAT1\ tension\ \xi)$⇔ $\frac{dSag[\xi]}{d\xi}|(line, CAT1\ tension\ \xi)$, ρ.
    d. Compute the p-values ϕ for $\frac{dP_2[\xi]}{d\xi}|(line, CAT1\ tension\ \xi)$⇔ $\frac{dSag[\xi]}{d\xi}|(line, CAT1\ tension\ \xi)$, ρ.
12. Produce figures containing graphs and tables of the results.
13. Evaluate the values of ρ and ϕ using the hypothesis test criteria in Table D - 5.

9.2.1 Measurement Conversion, Time Alignment and Qualification

As in Section 9.1.1, SwRI evaluated the lists of line configurations in Section 6 for combinations of two or more devices providing independent observations of the line parametric behavior. A detailed graph of measurements, like the one shown in Figure D - 31, provides a visual method for qualifying measurements within time spans having few measurement omissions. The following hypothesis tests are conducted in the same time ranges as those used in Section 9.1.2.

9.2.2 Time Intersection for Related Behavior Statistics

SwRI aligned the observation time stamps to the nearest minute and grouped the sag and tension observations into sets that occur in the same one-minute time interval. The grouping assumes that the observations are within a set. Figure D - 34 gives an example of sag and tension observations that intersect in time. Each column of observations in the figure represents a set of observations. The sets

were reorganized into sag distribution members as illustrated in Figure D - 38. The collection of members for a given line form a distribution ensemble as described in Section 9.2.1 and illustrated in Figure D - 39.

9.2.3 Sag Mean μ_s ⇔Tension|(Line, Tension) Hypothesis Tests

Having appropriately qualified and organized the sag observations into members conditioned on CAT-1 tension observations, it is then possible to compute the correlation coefficients $\rho = \mu_s$⇔CAT-1 tensions ξ | (line, tension ξ) for the null hypothesis. It is also possible to compute the p-values ϕ for the alternative hypothesis for the line and tension as given conditions. The tables in the upper left corner of Figure D - 39 give the values for ρ and the corresponding ϕ for observed span 25/1 - 25/2 in the Waco Atco – Temple Elm Creek 138 kV line. In this example, the values of ρ indicate strong, complementary correlation among the observed span 25/1 - 25/2 sag mean μ_s and the CAT-1s observed tension ξ on the Waco Atco – Temple Elm Creek 138 kV line during the indicated time range. There is no significant indication by ϕ of a random coincidental occurrence of correlated behavior. The conclusion drawn for this example is that the null hypothesis validates and the alternative hypothesis verifies μ_s⇔CAT-1 tensions ξ | (line, tension ξ) for the given Waco Atco – Temple Elm Creek 138 kV line.

Figures D – 38 and D - 39 also illustrate the random distribution of sag observations for any given tension. The mean sag $\mu_s|(Watco\ Atco - Elm\ Creek\ 138kV\ Line, tension)$ represents the most likely value of the sag under the given conditions. The figures document the μ_s and σ_s for each of the given tension values.

The Central Limit Theorem states that the sample mean of a random distribution is a random number [18]. The random mean $\mu_s|(Watco\ Atco - Elm\ Creek\ 138kV\ Line, tension)$ is clearly indicated by the jaggedness of the black line connecting the member $\mu_s(j)$ for each given tension $\xi(j)$ in Figures D – 38 and D - 39.

The confidence intervals of $(\mu_s \pm \sigma_s)|(Watco\ Atco - Elm\ Creek\ 138kV\ Line, tension)$ and $(\mu_s \pm 3 * \sigma_s)|(\ Watco\ Atco - Elm\ Creek\ 138kV\ Line$, tension) are also shown in the figures. The 99.7% confidence intervals for the example in Figure D - 38 are within the $3 * \sigma_s = 1.1\ ft$ for a typical $\mu_s|line, tension$. The $3 * \sigma_s$ in Figure D - 38 is in good agreement with the typical $3 * \sigma_\delta = 1.4\ ft$.

Appendix C contains the μ_s⇔tension|(line, tension) hypothesis test cases for the selected lines and observed spans during time periods when there were few observations, omissions or distortions. The null hypothesis verifies a strong, complementary μ_s⇔tension correlation, and the alternative hypothesis validates the correlation in all of the qualified cases. SwRI concludes that there is a strong complementary correlation between μ_s and tension within the measurements submitted for study.

9.2.4 $(\mu_s$ ⇔ $Sag[\xi])|(line, tension\ \xi)$ Hypothesis Tests

As mentioned earlier, the conditional mean sag $\mu_s|(line, CAT1\ tension\ \xi)$ is the most likely value of observed sag for any given tension ξ observed by a CAT-1 attached at an equilibrium point along the

same line. It follows from the conclusions of Section 9.2.3 that a direct correlation should exist between the observed span mean sag and the catenary sag estimate ($\mu_s \Leftrightarrow$ Sag[ξ])|(line, CAT1 tension ξ) as shown in the following figure.

$$\rho = (\mu_s \Leftrightarrow \text{Sag}[\xi])|(\text{line, CAT1 tension } \xi) \geq 0.8$$

$$\phi = pvalue\big(\rho = (\mu_s \Leftrightarrow \text{Sag}[\xi])|(\text{line, CAT1 tension } \xi)\big) \leq 0.1$$

SwRI tested the ($\mu_s \Leftrightarrow$ Sag[ξ])|(line, CAT1 tension ξ) cases shown in Appendix D. All of the test cases show that the null hypothesis is valid, is verified by the alternative hypothesis and that the correlation is a direct.

The observed span mean sag is directly and strongly correlated to values of sag computed using the catenary sag equation $Sag[\xi]$ and values of tension ξ observed by one or more CAT-1s along the same line.

9.2.5 $(\frac{d\mu_s}{d\xi} \Leftrightarrow \frac{dSag[\xi]}{d\xi})|(line, tension\ \xi)$ Hypothesis Tests

SwRI attempted to test the correlation of the first derivatives of the conditional mean sag and the catenary sag equation,

$$(\frac{d\mu_s}{d\xi} \Leftrightarrow \frac{\text{dSag}[\xi]}{d\xi})|(\text{line, tension } \xi)$$

The rates of change $\frac{\text{dSag}[\xi]}{d\xi}|(\text{line, tension } \xi)$ can be clearly seen in Figure D - 40.

The first derivative of a random number is also a random number. The first derivative $\frac{d\mu_s}{d\xi}|(line, tension\ \xi)$ is randomly distributed around $\frac{\text{dSag}[\xi]}{d\xi}|(\text{line, tension } \xi)$ in Figure D - 40. The null hypothesis fails for lack of a strong correlation, and the alternative hypothesis invalidates the correlation due to the similarity $\frac{d\mu_s}{d\xi}|(\text{line, tension } \xi)$ to a random vector of unrelated values.

A better way of analyzing $\frac{d\mu_s}{d\xi}|(\text{line, CAT1 tension } \xi)$ is required before a practical test of sag rate change correlation can be conducted. First, an understanding of $\frac{d\mu_s}{d\xi}|(\text{line, tension } \xi)$ behavior is required.

9.2.6 $\left(\frac{dP_2[\xi]}{d\xi} \Leftrightarrow \frac{dSag[\xi]}{d\xi}\right)|(line, CAT1\ tension\ \xi)$ Hypothesis Tests

The Central Limit Theorem also states that observed sag mean $\mu_s|(line, CAT1\ tension\ \xi)$ approaches the true mean sag $\overline{\mu_s}|(line, CAT1\ tension\ \xi)$, a vector of constant values, as the number of observations N becomes sufficiently large.

$$\overline{\mu_s}|(line, CAT1\ tension\ \xi) = \lim_{N\to\infty}\mu_s|(line, CAT1\ tension\ \xi) = \lim_{N\to\infty}\frac{\sum_{i=1}^{N} sag(i)|line, CAT1\ tension\ \xi)}{N}$$

SwRI hypothesized that each set of observations is affected by additive random external influences collectively represented by an independent random variable ϵ having a mean μ_ϵ and standard deviationσ_ϵ. Furthermore, the results of Section 9.2.3 indicate that the mean external effect $\mu_\epsilon \neq 0$ is a consequence of equipment calibration, span length or conductor height error. The variation in the observations for a given tension were attributed entirely to the random external influences ϵ with standard deviation $\sigma_\epsilon \geq 0$. If true, then the mean value of the observed sag $\mu_s = \overline{\mu_s}|(line, CAT1\ tension\ \xi) +\ \mu_e$. It follows then that

$$\frac{d\mu_s}{d\xi}|(line, CAT1\ tension\ \xi) = \left(\frac{d\overline{\mu_s}}{d\xi} + \frac{d\mu_e}{d\xi}\right)|(line, CAT1\ tension\ \xi)$$

Recall that $\overline{\mu_s}$ from the Central Limit Theorem is a contant. Therefore,

$$\frac{d\mu_s}{d\xi}|(line, CAT1\ tension\ \xi) = \left(\frac{d\mu_e}{d\xi}\right)|(line, CAT1\ tension\ \xi)$$

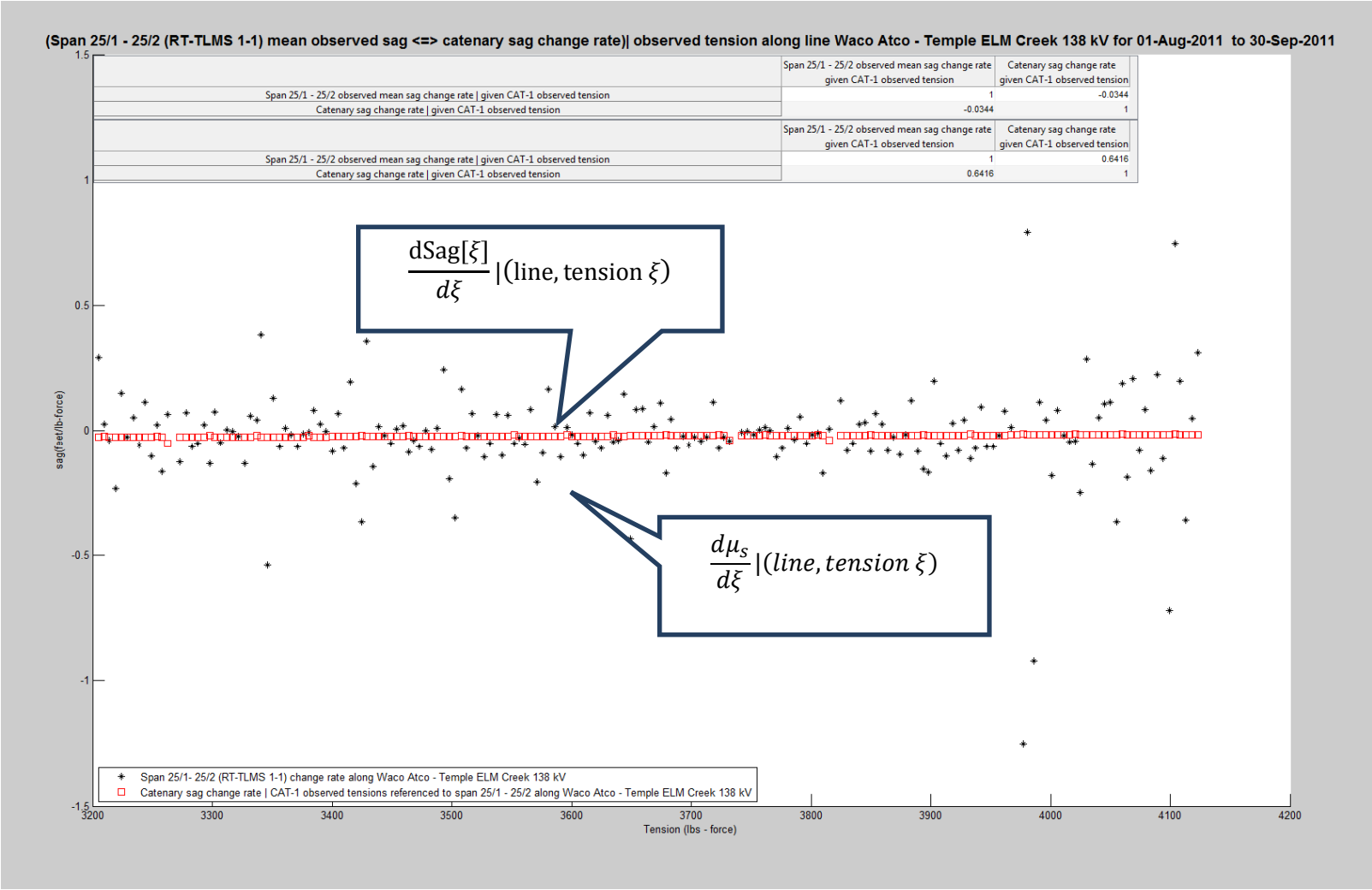


Figure D - 38 Observed Span 25/1 - 25/2 (RT-TLMS1-1) Sag Distribution and Statistics | (Waco Atco – Temple Elm Creek 138 kV, CAT-1 Tension

The p-values ϕ for $(\frac{d\mu_s}{d\xi} \Leftrightarrow \frac{\mathrm{dSag}[\xi]}{d\xi})|(\mathrm{line, tension}\ \xi)$ =$(\frac{d\epsilon}{d\xi} \Leftrightarrow \frac{\mathrm{dSag}[\xi]}{d\xi})|(\mathrm{line, tension}\ \xi)$, but μ_e is a random variable independent of ξ or $\frac{\mathrm{dSag}[\xi]}{d\xi}$. Therefore, ϕ detects a random event to be the likely cause of any correlation indicated by ρ. The $|\rho| = \left|(\frac{d\mu_s}{d\xi} \Leftrightarrow \frac{\mathrm{dSag}[\xi]}{d\xi})|(\mathrm{line, tension}\ \xi)\right| \ll 0.8$ confirms the ϕ random event indication by showing a lack of correlation between the derivatives.

SwRI hypothesized that a polynomial equation of sufficient order could be formulated from $\mu_s|(line, CAT1\ tension\ \xi)$ and used as an approximation of $\overline{\mu_s}|(line, CAT1\ tension\ \xi)$.

With some experimentation, SwRI formulated a second-order polynomial $P_2[\xi]|(line, CAT1\ tension\ \xi)$ using the vector $\mu_s|(line, CAT1\ tension\ \xi)$ as the datapoints for the polynomial fit. The null and alternative hypothesis tests were applied to the correlation as a way of verifying and validating $P_2[\xi]|(line, CAT1\ tension\ \xi)$ as shown in Figure D - 41.

$\boldsymbol{\rho} = (\boldsymbol{\mu_s} \Leftrightarrow \boldsymbol{Sag}[\boldsymbol{\xi}] \Leftrightarrow \boldsymbol{P_2}[\boldsymbol{\xi}])$ | (line, CAT1 Tension $\boldsymbol{\xi}$)

$$\phi = pvalue\big(\rho = (\mu_s \Leftrightarrow \mathrm{Sag}[\xi] \Leftrightarrow P_2[\xi])|(\mathrm{line, CAT1\ tension}\ \xi)\big)$$

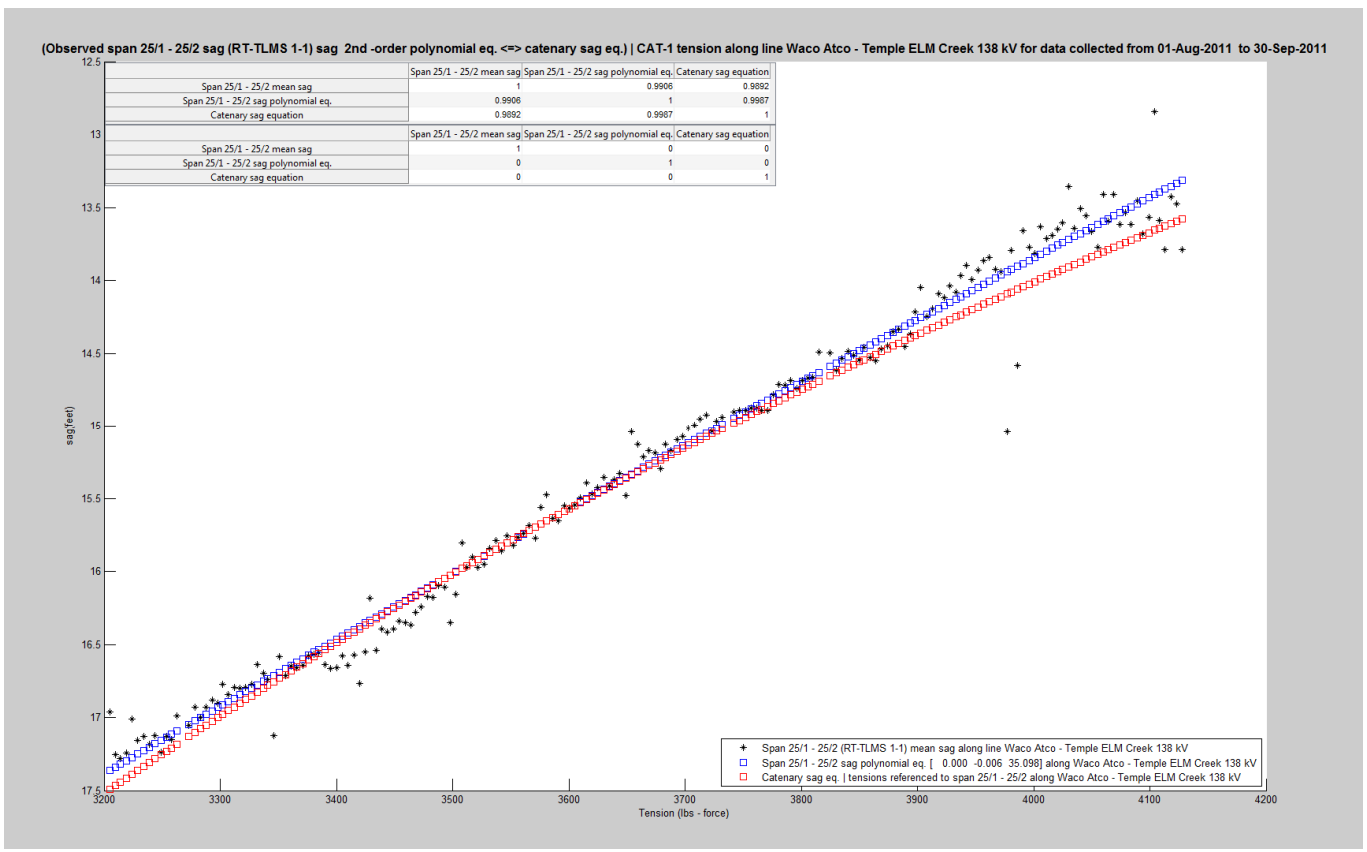


Figure D - 39 Line Section Waco Atco - Temple Elm Creek 138kV $(\boldsymbol{\mu_s} \Leftrightarrow \boldsymbol{Sag}[\boldsymbol{\xi}] \Leftrightarrow \boldsymbol{P_2}[\boldsymbol{\xi}])$ | (line, CAT1 Tension $\boldsymbol{\xi}$)

Figure D - 41 and Appendix E illustrate the correlation and the test results. The figure and the appendix show a strong correlation among the sag mean, the catenary sag equation and the polynomial $P_2[\xi]$, i.e., the null hypothesis verifies the correlation. The alternative hypothesis validates the correlation for all of the test cases.

The deterministic approximation $P_2[\xi] \cong \overline{\mu_s}|(line, CAT1\ tension\ \xi)$ provides a well-behaved basis for testing the correlation of sag rate change.

$$\rho = \left(\frac{dP_2[\xi]}{d\xi} \Leftrightarrow \frac{\mathrm{dSag}[\xi]}{d\xi}\right)|(\mathrm{line}, \mathrm{CAT1\ tension}\ \xi)$$

Figure D - 42 gives an example of the observed span sag rate of change correlation ρ for the Waco Atco – Temple Elm Creek 138 kV line. The example and all of the test cases in Appendix F show that the null hypothesis is valid and is verified by the alternative hypothesis test. The tests show that the sag rate of change and the rate of change predicted by the catenary sag equation are directly and strongly correlated.

9.2.7 $(\mu_s \Leftrightarrow Sag[\xi])|(line, tension\ \xi, distance)$ Hypothesis Tests

The last set of test cases evaluates the correlation of sag behavior given tension and distance. Section 9.2.3 validated and verified $(\mu_s \Leftrightarrow \mathrm{Sag}[\xi])|(\mathrm{line}, \mathrm{tension}\ \xi)$ hypothesis tests without regard to the distance separating the observed span and a tension observation. The tension measurements used to calculate $(\mu_s)|(\mathrm{line}, \mathrm{tension}\ \xi)$ and $(S\mathrm{ag}[\xi])|(\mathrm{line}, \mathrm{tension}\ \xi)$ include tension observations from all CAT-1 systems along the given line section. Distance can be added as a test given condition if the distances correspond to the location of the CAT-1 systems observing tension relative to the observed span.

The resulting $(\mu_s \Leftrightarrow \mathrm{Sag}[\xi])|(\mathrm{line}, \mathrm{tension}\ \xi, \boldsymbol{distance})$ null and alternative hypotheses evaluate the sag correlation of the observed span sag measurements with catenary sag estimates produced by referencing a CAT-1 tension meaurements taken at a given distance from the observed span, i.e., using the observed span length and conductor weight parameters to compute the catenary sag. Figure D - 43 illustrates the correlation $\rho|(\mathrm{line}, \mathrm{tension}\ \xi, \boldsymbol{distance})$ and p-values $\phi|(\mathrm{line}, \mathrm{tension}\ \xi, \boldsymbol{distance})$ for observed span 11/3 – 11/4 in line section Lake - Creek – Temple 345 kV. The metrics satisfy the confidence intervals for validated and verified correlation of sag estimates at distances exceeding 93,000 feet. As in other test cases, the results in Figure D 43 and in Appendix H show a lack of sensitivity to distance along the line sections included in this study.

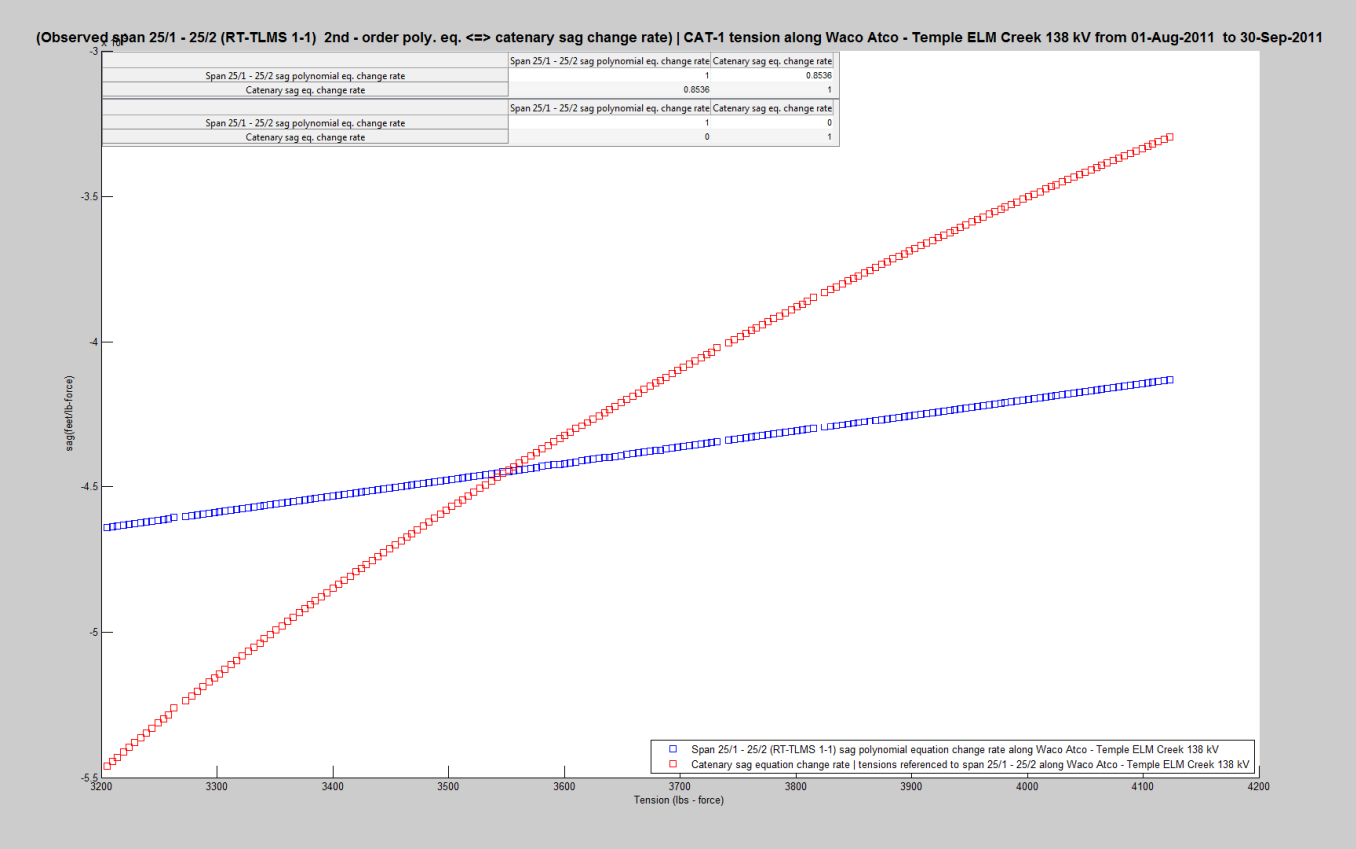


Figure D - 40 $\left(\frac{dP_2[\xi]}{d\xi} \Leftrightarrow \frac{\mathrm{dSag}[\xi]}{d\xi}\right)\Big|\left(\mathbf{Watco\ Atco - Temple\ Elm\ Creek\ 138KV, CAT - 1\ Tension}\ \xi\right)$

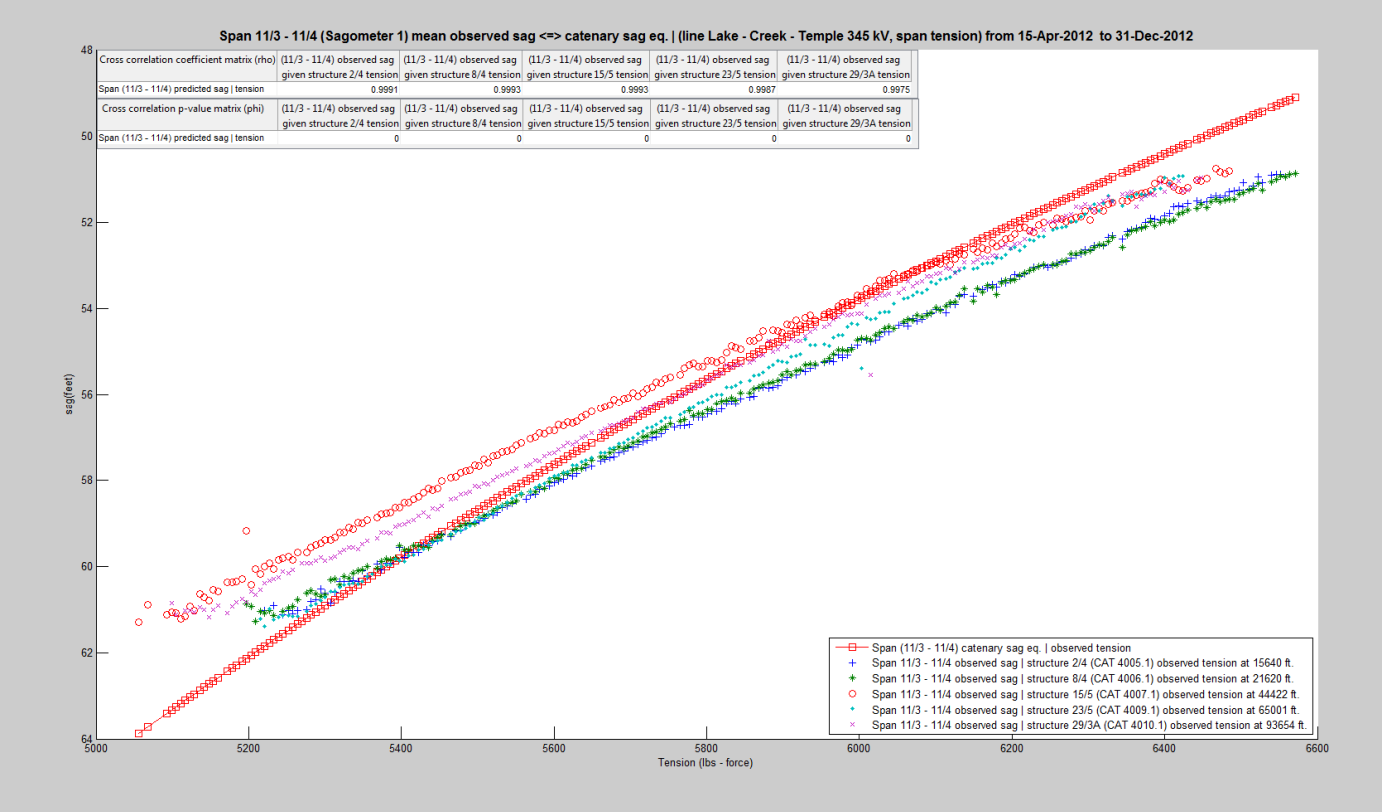


Figure D - 41 (μ_s Sag[ξ]) | (Waco Atco – Temple Elm Creek, CAT1 Tension ξ,Distance)

10. Conclusions and Recommendations

SwRI concludes that the qualified DLR line parametric measurements gathered for the observed lines are valid, verifiable and in agreement with the accepted models for line sag behavior. The measurements were tested in a mathematically and logically rigorous fashion.

The tests show that if the measurements of the same line behavior are strongly correlated with one another and with the catenary sag equation regardless of the separation distance or the time differences between DLR line parametric system observations. Moreover, the correlation is verifiable and not the product of coincident random events. Specifically, the tests show:

- Observed sag and observed tension are complementarily correlated.
- Observed sag and the catenary sag given observed tension is directly correlated.
- The rate of change of observed sag and the rate of change in the catenary sag given an observed tension is directly correlated.
- The correlated behaviors are insensitive to the distance separating the observed span and the structure where tension is observed.
- The differences in the observed sag and the catenary sag given an observed tension are small and have small standard deviations.

The differences in line parametric measurements evaluate to a typical mean sag difference $|\mu_\delta| \leq 1.3$ feet and a difference standard deviation $\sigma_\delta \leq 0.315$ feet. The difference statistics μ_δ and σ_δ were independent of separation distance between DLR systems. Given the distance insensitivity, SwRI theorizes that μ_δ is a manifestation of measurement bias. The measurement bias could have been introduced by error in DLR system calibration, span length design estimates or other constant error. The difference standard deviation σ_δ is largely attributable to measurement omissions and spurious measurement excursions like those seen in Figure D - 31. Variations in time stamp synchronization accuracy could also have contributed to σ_δ.

There is need for precision when installing and operating the CAT-1 system. Errors in the estimated span length will cause a constant bias in the sag estimates produced by the catenary sag equation and the CAT-1 tension values. Likewise, significant differences in CAT-1 sag estimates can be caused by relatively small differences in tension measurements caused by poor calibration or by differences in tension observation time stamps. See Section 8.3 for more details regarding differences in sag estimates.

The disqualification of measurements was attributable to known conditions. The primary causes for measurement disqualification were misalignment of time stamps and omissions in the data. External effects decorrelate measurements within minutes or even seconds of the observation times. Synchronization of clocks used to assign time stamps to the observations is essential for the comparison and testing of line behavior.

Omissions of measurements appear primarily to be related to the operational rigor of the observing DLR system. See Figure D - 31 for an illustration of measurement errors and omissions. The Nexan CAT-1

produced measurements in the most reliable and consistent fashion owing in part to its integration with the SCADA system and all of the operational rigor that accompanies a utility EMS. The Sagometers and RT-TLMS were not integrated with the SCADA operation and were somewhat less reliable due to the lessened operational oversight. Still, all of the DLR systems produced results in sufficient quantity and quality to be meaningful.

SwRI observed that the RT-TLMS provided greater detail and opportunities for complex testing due to its higher, one sample/minute observation rate. SwRI recommends a cost-benefit analysis be applied to the idea of increasing the observation rate on the CAT-1 systems.

11. List of References

14. Wikimedia Commons. Released under the terms of the GNU Free Documentation License and the Creative Commons Attribution ShareAlike License.

15. The Mechanics of Overhead Distribution Line Conductors, Bulletin 1724E-152, United States Department of Agriculture, Rural Utilities Service, July 30, 2003.

16. Installation and Commissioning of Dynamic Line Rating Technology within the Oncor Transmission Grid for the Lessons Learned Dynamic Line Rating Project, Version 2.1, April 30, 2013.

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18. Jay L. Devore, Probability & Statistics for Engineering and the Sciences, 1982, ISBN 0-8185-0514-1.

APPENDIX A

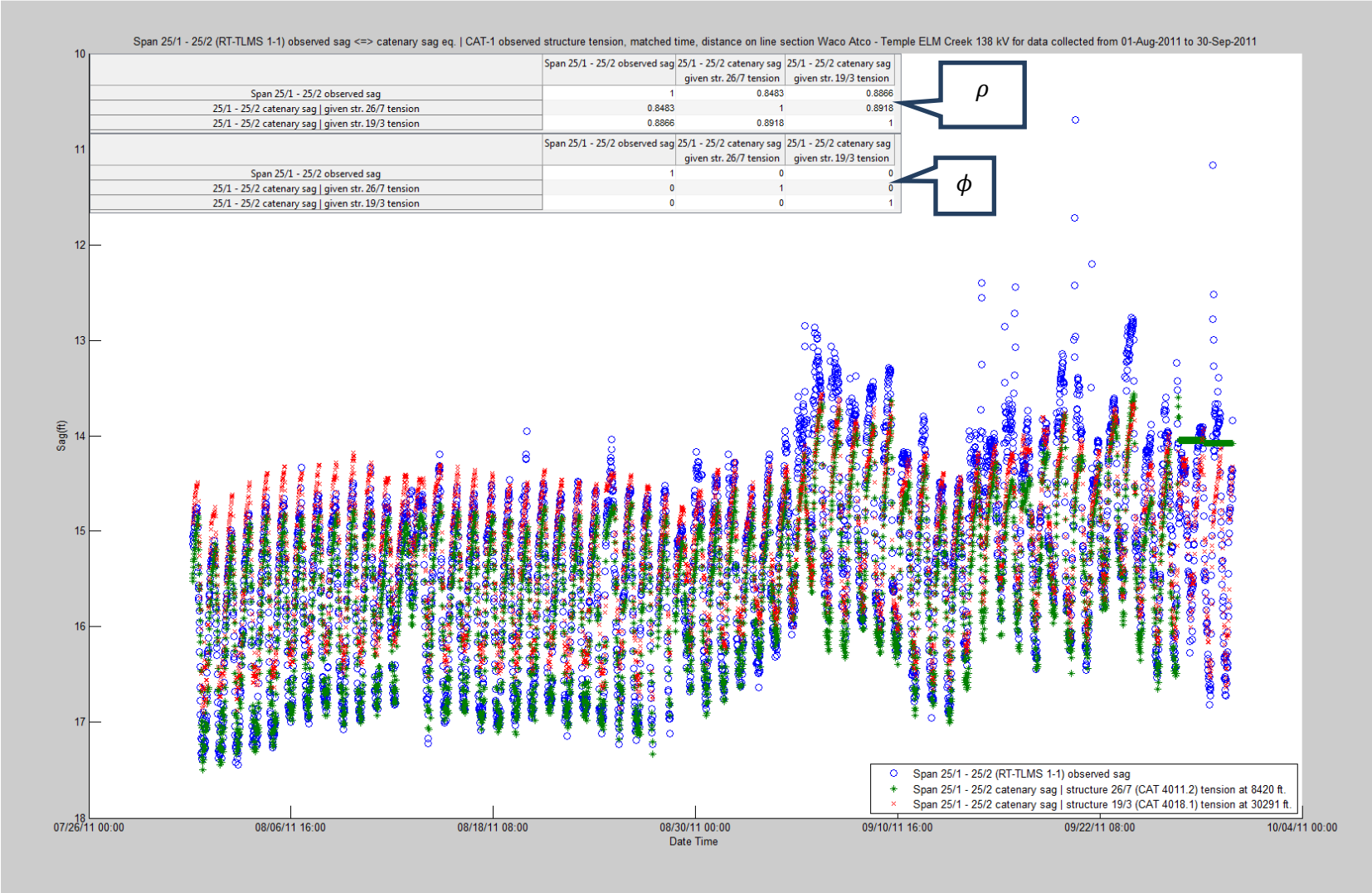
LIST OF ACRONYMS

LIST OF ACRONYMS

ADC	Analog-to-Digital Converter
DLR	Dynamic Line Rating
EMS	Energy Management System
IV&V	Independent Verification and Validation
LSMV	Line Sag Measurement Verification
RT-TLMS	Real Time - Transmission Line Monitoring System
SCADA	Supervisory Control and Data Acquisition
SN	Serial Number
SwRI	Southwest Research Institute
TBD	To Be Determined
TBR	To Be Reviewed

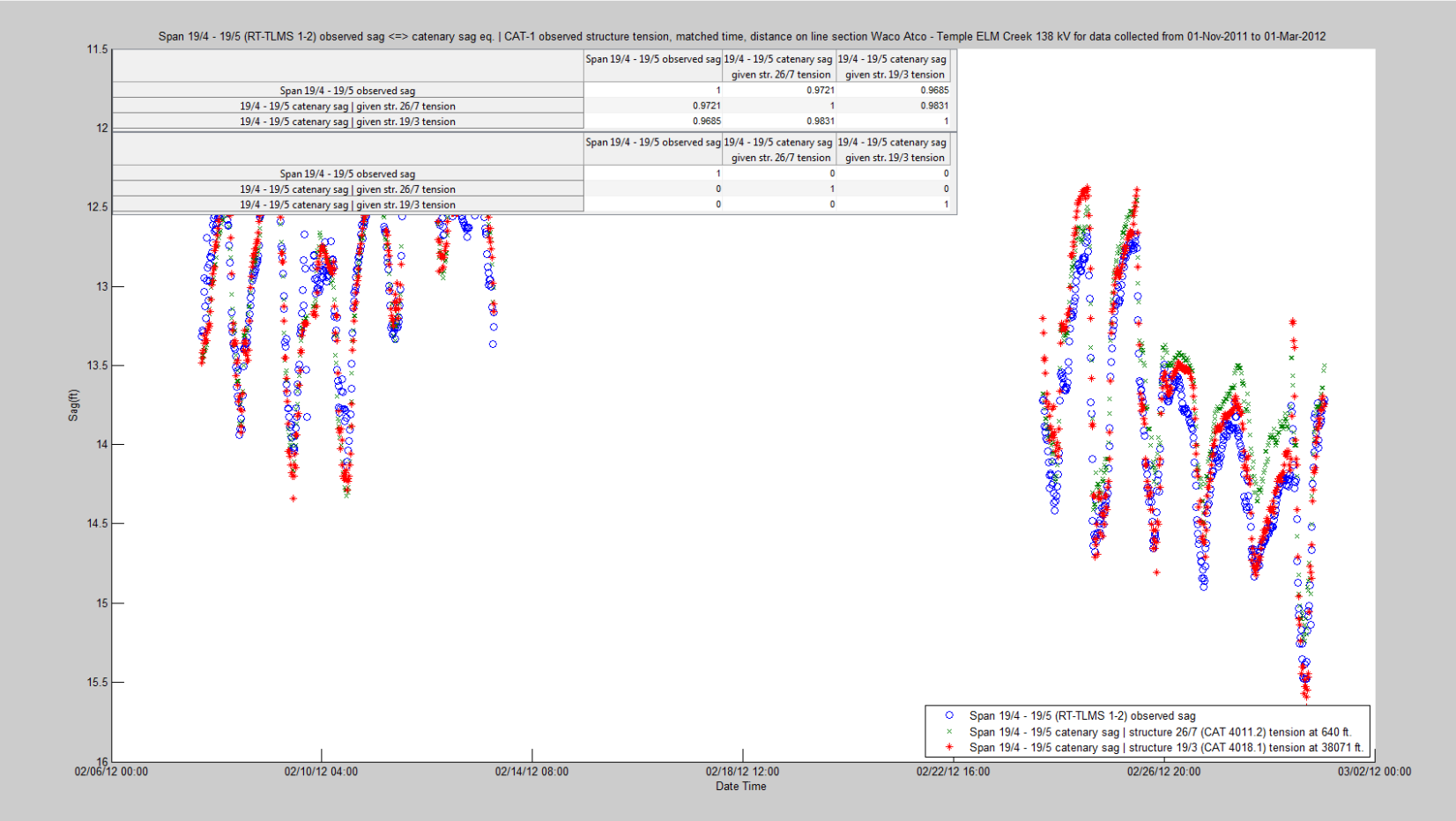
APPENDIX B

SAG AND $Sag[CAT1\ tension\ \xi]$| (LINE, TIME)



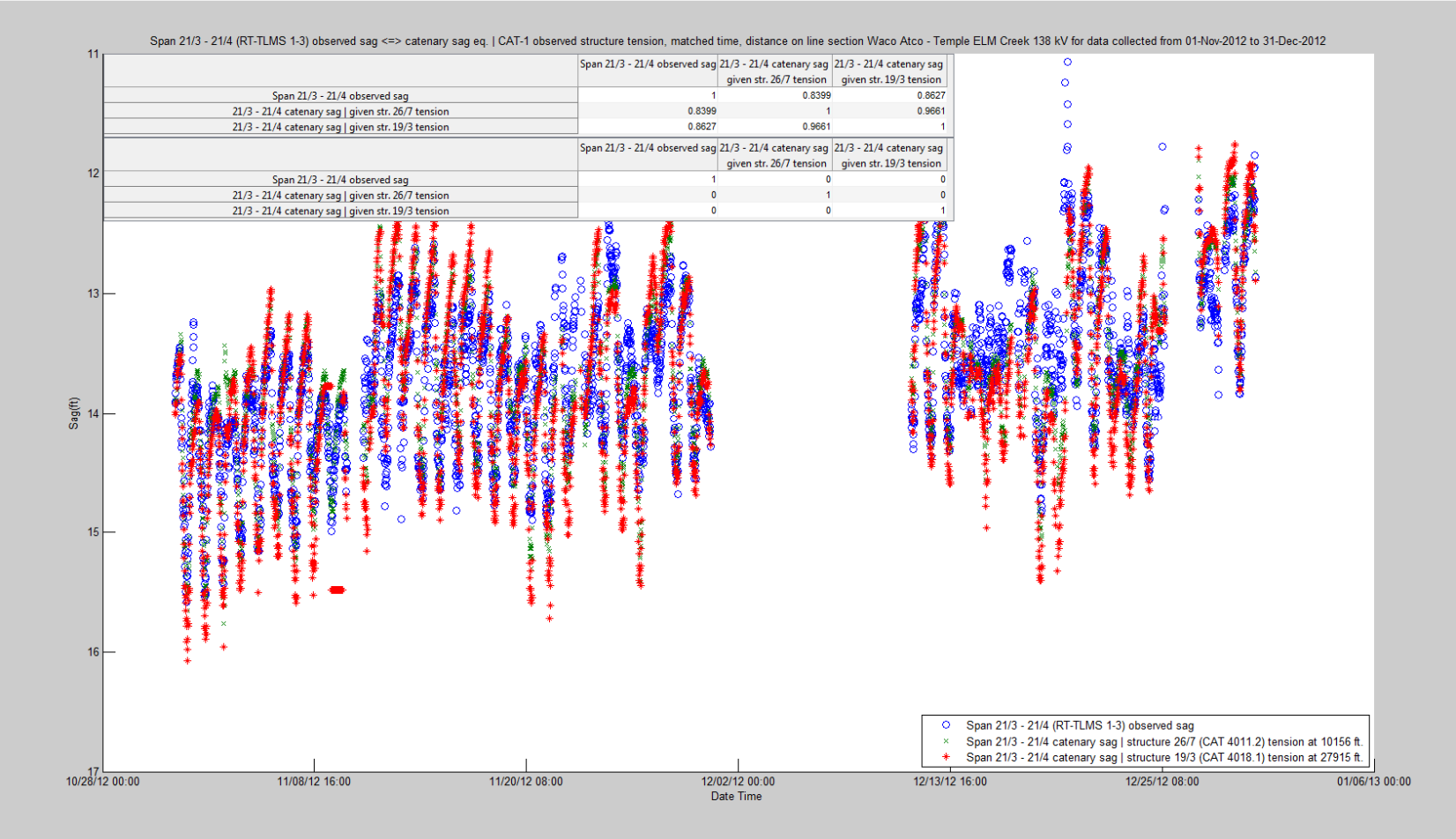
	Span 25/1 - 25/2 observed sag	25/1 - 25/2 catenary sag given str. 26/7 tension	25/1 - 25/2 catenary sag given str. 19/3 tension
Span 25/1 - 25/2 observed sag	1	0.8483	0.8866
25/1 - 25/2 catenary sag | given str. 26/7 tension	0.8483	1	0.8918
25/1 - 25/2 catenary sag | given str. 19/3 tension	0.8866	0.8918	1

	Span 25/1 - 25/2 observed sag	25/1 - 25/2 catenary sag given str. 26/7 tension	25/1 - 25/2 catenary sag given str. 19/3 tension
Span 25/1 - 25/2 observed sag	1	0	0
25/1 - 25/2 catenary sag | given str. 26/7 tension	0	1	0
25/1 - 25/2 catenary sag | given str. 19/3 tension	0	0	1



	Span 19/4 - 19/5 observed sag	19/4 - 19/5 catenary sag given str. 26/7 tension	19/4 - 19/5 catenary sag given str. 19/3 tension
Span 19/4 - 19/5 observed sag	1	0.9721	0.9685
19/4 - 19/5 catenary sag | given str. 26/7 tension	0.9721	1	0.9831
19/4 - 19/5 catenary sag | given str. 19/3 tension	0.9685	0.9831	1

	Span 19/4 - 19/5 observed sag	19/4 - 19/5 catenary sag given str. 26/7 tension	19/4 - 19/5 catenary sag given str. 19/3 tension
Span 19/4 - 19/5 observed sag	1	0	0
19/4 - 19/5 catenary sag | given str. 26/7 tension	0	1	0
19/4 - 19/5 catenary sag | given str. 19/3 tension	0	0	1

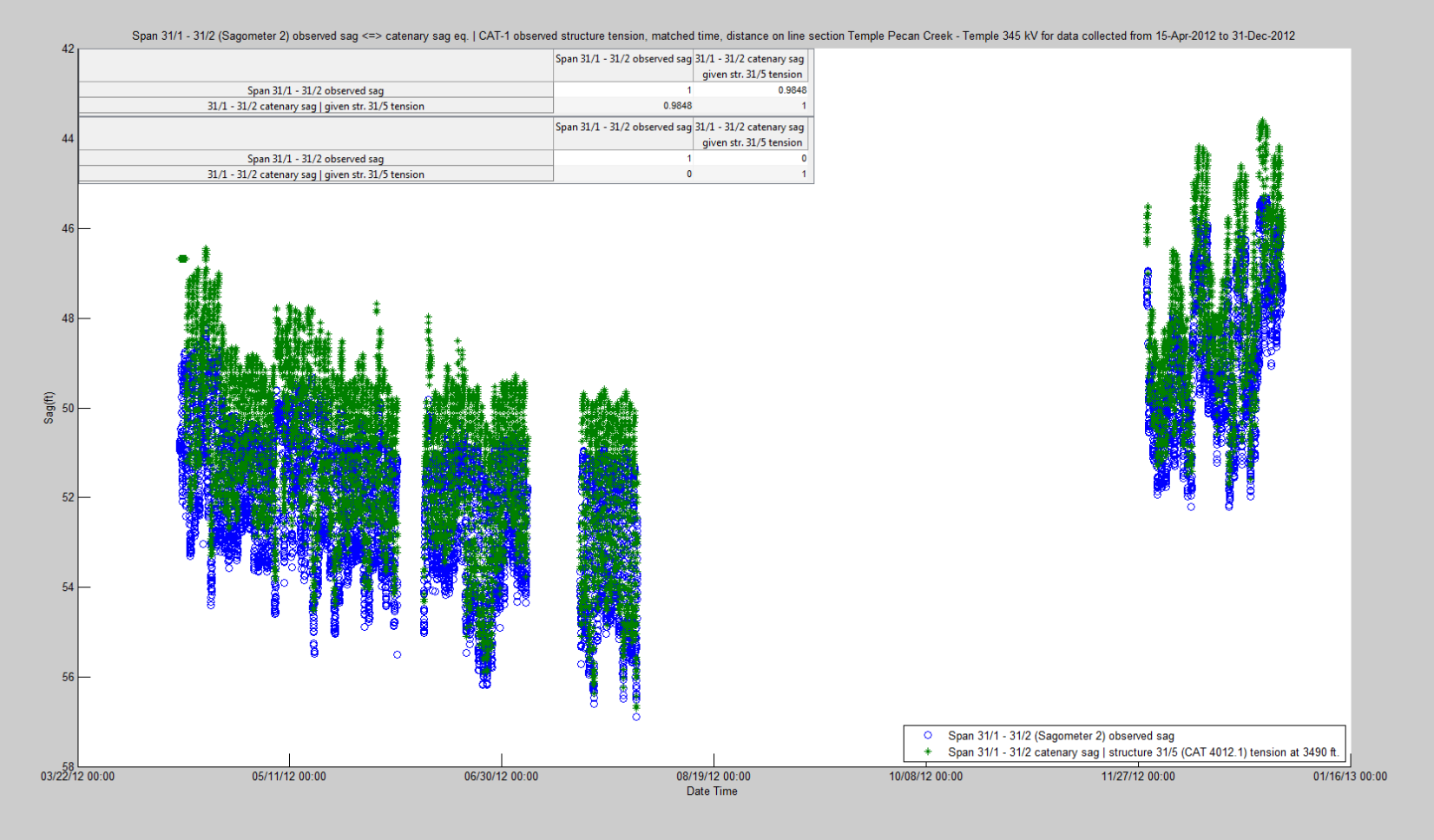


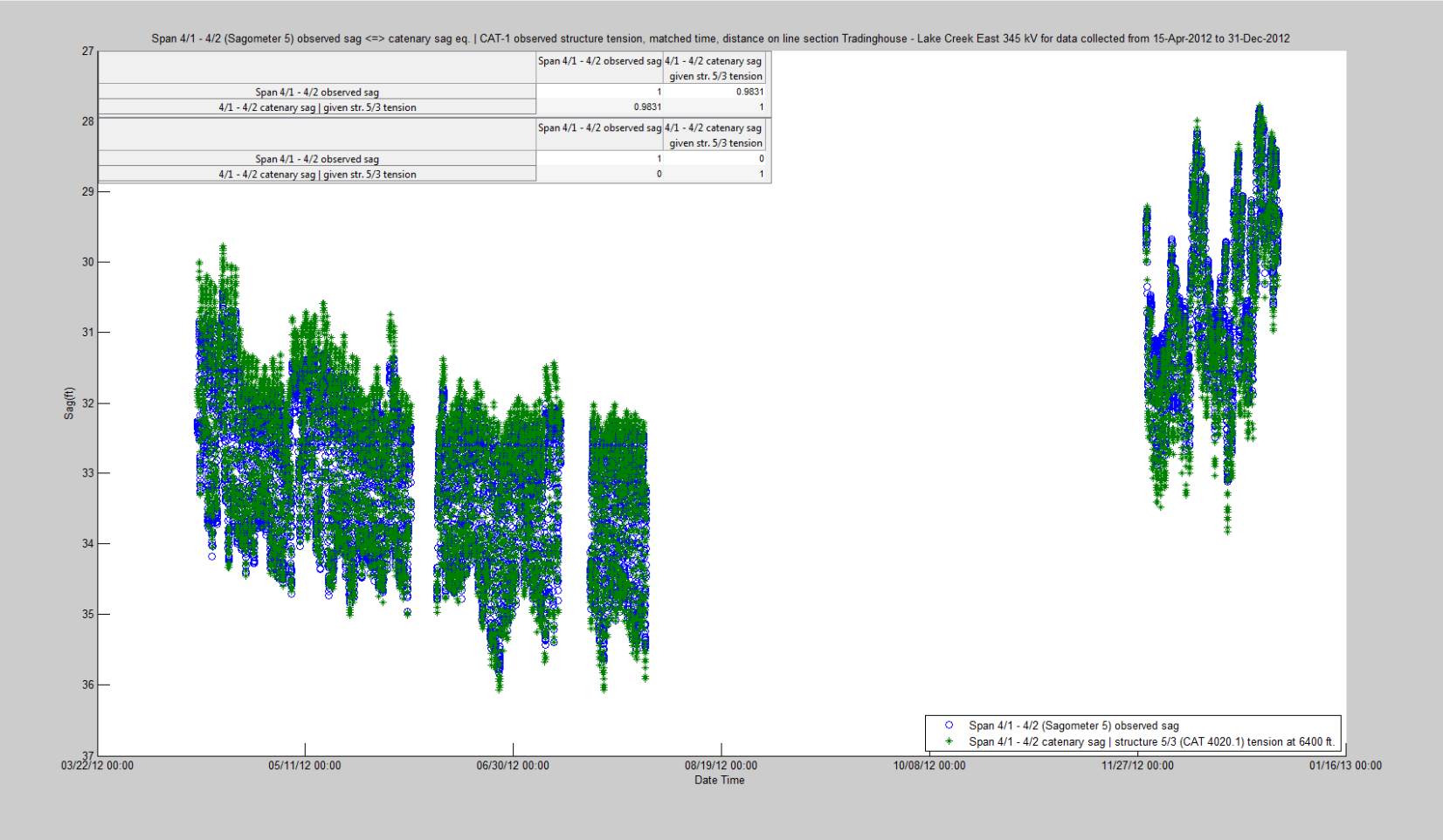
	Span 21/3 - 21/4 observed sag	21/3 - 21/4 catenary sag given str. 26/7 tension	21/3 - 21/4 catenary sag given str. 19/3 tension
Span 21/3 - 21/4 observed sag	1	0.8399	0.8627
21/3 - 21/4 catenary sag | given str. 26/7 tension	0.8399	1	0.9661
21/3 - 21/4 catenary sag | given str. 19/3 tension	0.8627	0.9661	1

	Span 21/3 - 21/4 observed sag	21/3 - 21/4 catenary sag given str. 26/7 tension	21/3 - 21/4 catenary sag given str. 19/3 tension
Span 21/3 - 21/4 observed sag	1	0	0
21/3 - 21/4 catenary sag | given str. 26/7 tension	0	1	0
21/3 - 21/4 catenary sag | given str. 19/3 tension	0	0	1

	Span 11/3 - 11/4 observed sag	11/3 - 11/4 catenary sag given str. 2/4 tension	11/3 - 11/4 catenary sag given str. 8/4 tension	11/3 - 11/4 catenary sag given str. 15/5 tension	11/3 - 11/4 catenary sag given str. 23/5 tension	11/3 - 11/4 catenary sag given str. 29/3A tension
Span 11/3 - 11/4 observed sag	1	0.9895	0.9927	0.9891	0.9844	0.9605
11/3 - 11/4 catenary sag | given str. 2/4 tension	0.9895	1	0.9938	0.9907	0.9831	0.9637
11/3 - 11/4 catenary sag | given str. 8/4 tension	0.9927	0.9938	1	0.9923	0.9851	0.9643
11/3 - 11/4 catenary sag | given str. 15/5 tension	0.9891	0.9907	0.9923	1	0.9854	0.9723
11/3 - 11/4 catenary sag | given str. 23/5 tension	0.9844	0.9831	0.9851	0.9854	1	0.9772
11/3 - 11/4 catenary sag | given str. 29/3A tension	0.9605	0.9637	0.9643	0.9723	0.9772	1

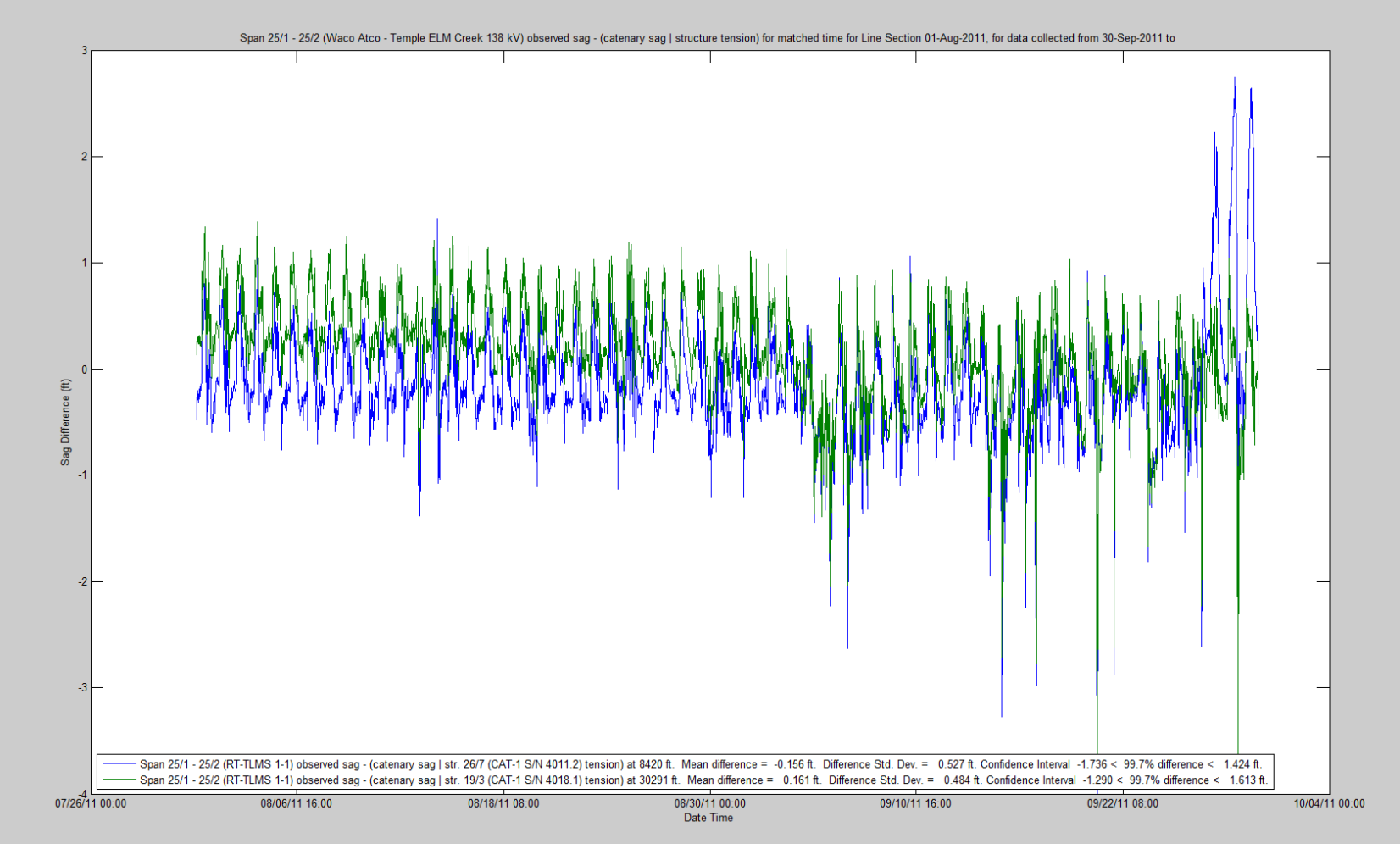
	Span 11/3 - 11/4 observed sag	11/3 - 11/4 catenary sag given str. 2/4 tension	11/3 - 11/4 catenary sag given str. 8/4 tension	11/3 - 11/4 catenary sag given str. 15/5 tension	11/3 - 11/4 catenary sag given str. 23/5 tension	11/3 - 11/4 catenary sag given str. 29/3A tension
Span 11/3 - 11/4 observed sag	1	0	0	0	0	0
11/3 - 11/4 catenary sag | given str. 2/4 tension	0	1	0	0	0	0
11/3 - 11/4 catenary sag | given str. 8/4 tension	0	0	1	0	0	0
11/3 - 11/4 catenary sag | given str. 15/5 tension	0	0	0	1	0	0
11/3 - 11/4 catenary sag | given str. 23/5 tension	0	0	0	0	1	0
11/3 - 11/4 catenary sag | given str. 29/3A tension	0	0	0	0	0	1

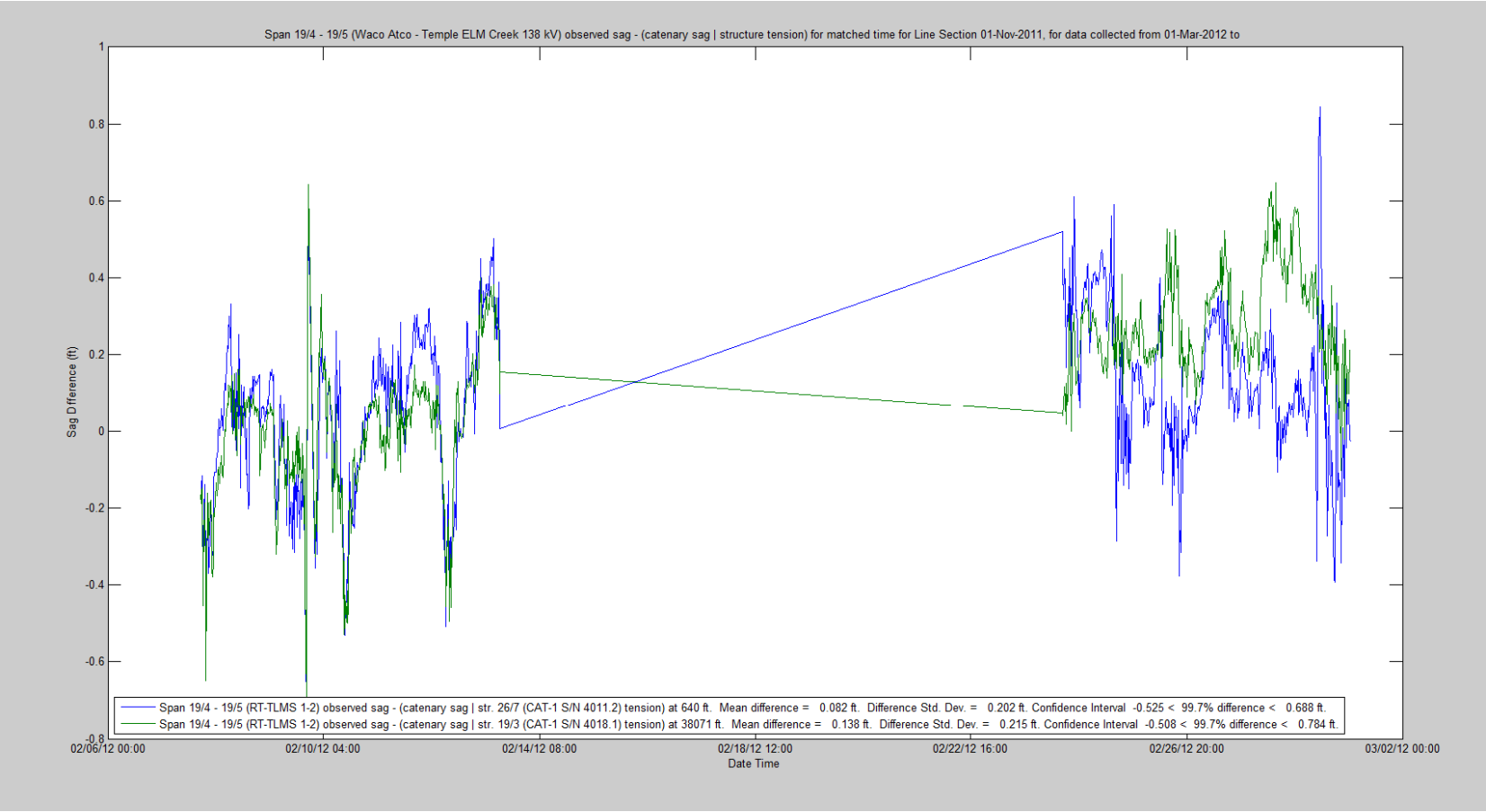

Span 31/1 - 31/2 (Sagometer 2) observed sag <=> catenary sag eq. | CAT-1 observed structure tension, matched time, distance on line section Temple Pecan Creek - Temple 345 kV for data collected from 15-Apr-2012 to 31-Dec-2012
Span 31/1 - 31/2 observed sag
31/1 - 31/2 catenary sag | given str. 31/5 tension
1
0.9848
0.9848
1
1
0
0
1
Sag(ft)
42
44
46
48
50
52
54
56
58
03/22/12 00:00
05/11/12 00:00
06/30/12 00:00
08/19/12 00:00
10/08/12 00:00
11/27/12 00:00
01/16/13 00:00
Date Time
Span 31/1 - 31/2 (Sagometer 2) observed sag
Span 31/1 - 31/2 catenary sag | structure 31/5 (CAT 4012.1) tension at 3490 ft.

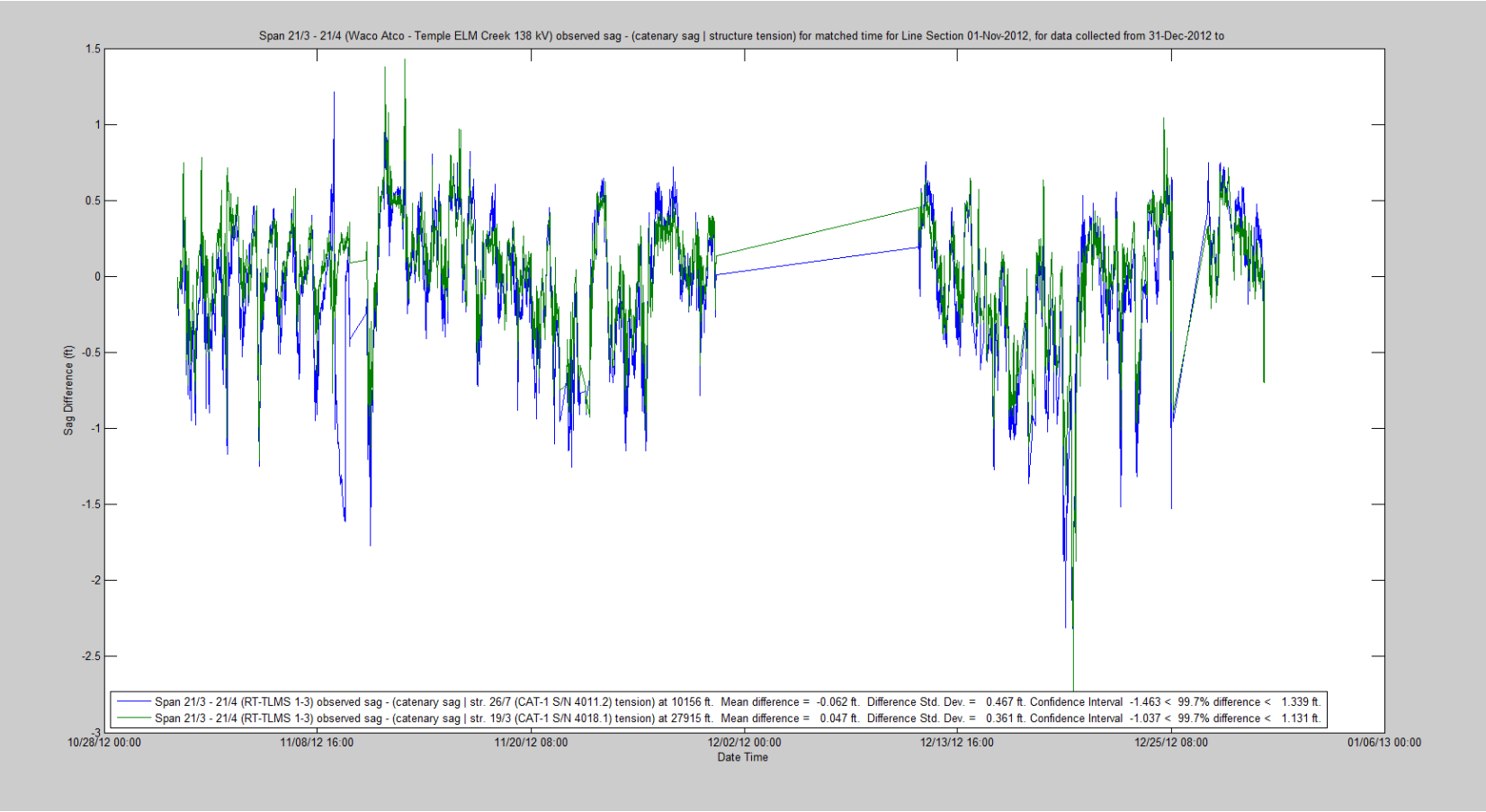

Span 4/1 - 4/2 (Sagometer 5) observed sag <=> catenary sag eq. | CAT-1 observed structure tension, matched time, distance on line section Tradinghouse - Lake Creek East 345 kV for data collected from 15-Apr-2012 to 31-Dec-2012
Span 4/1 - 4/2 observed sag
4/1 - 4/2 catenary sag | given str. 5/3 tension
1
0.9831
0.9831
1
Span 4/1 - 4/2 observed sag
4/1 - 4/2 catenary sag | given str. 5/3 tension
1
0
0
1
Sag(ft)
27
28
29
30
31
32
33
34
35
36
37
03/22/12 00:00
05/11/12 00:00
06/30/12 00:00
08/19/12 00:00
10/08/12 00:00
11/27/12 00:00
01/16/13 00:00
Date Time
Span 4/1 - 4/2 (Sagometer 5) observed sag
Span 4/1 - 4/2 catenary sag | structure 5/3 (CAT 4020.1) tension at 6400 ft.

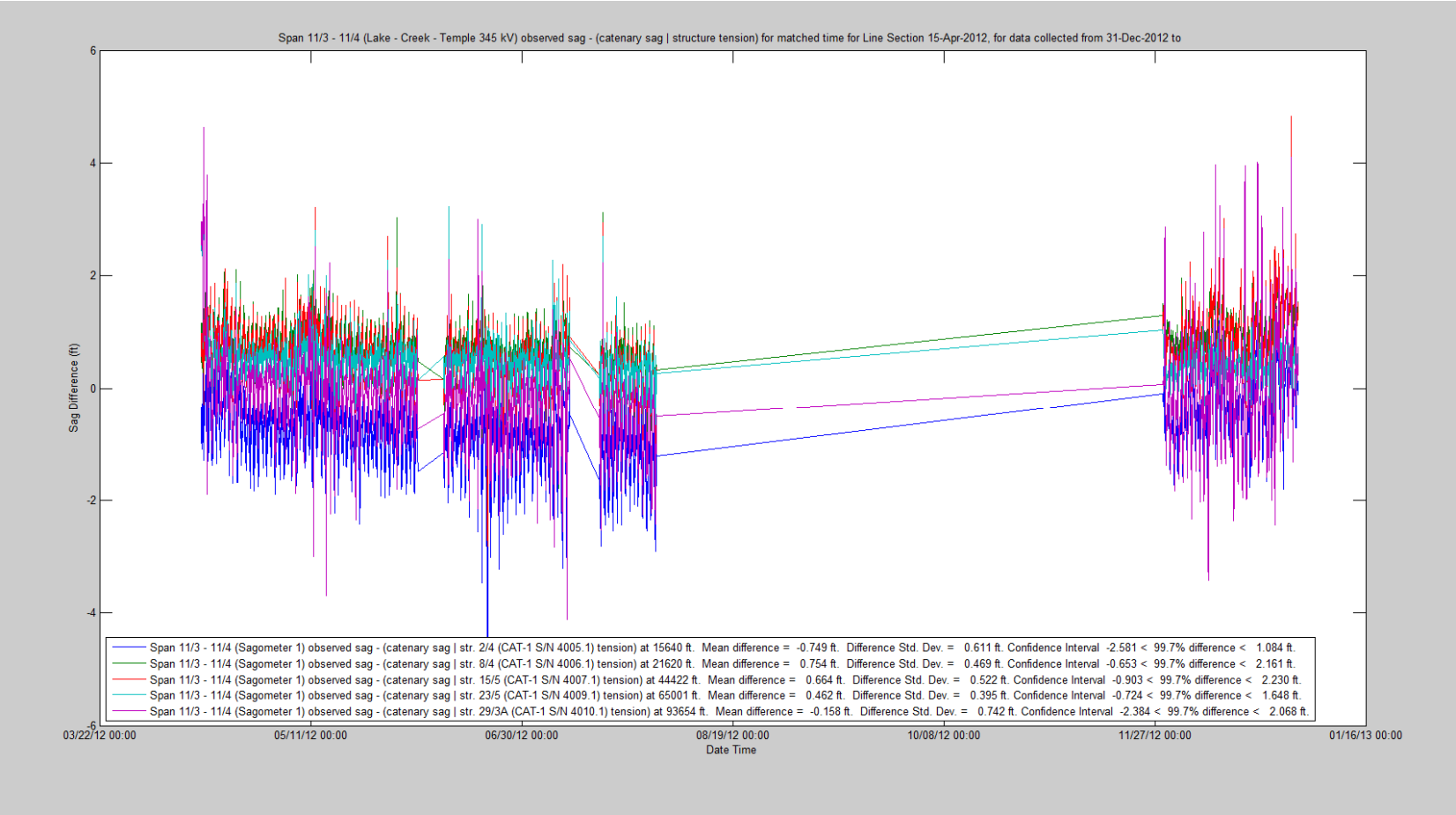
APPENDIX C

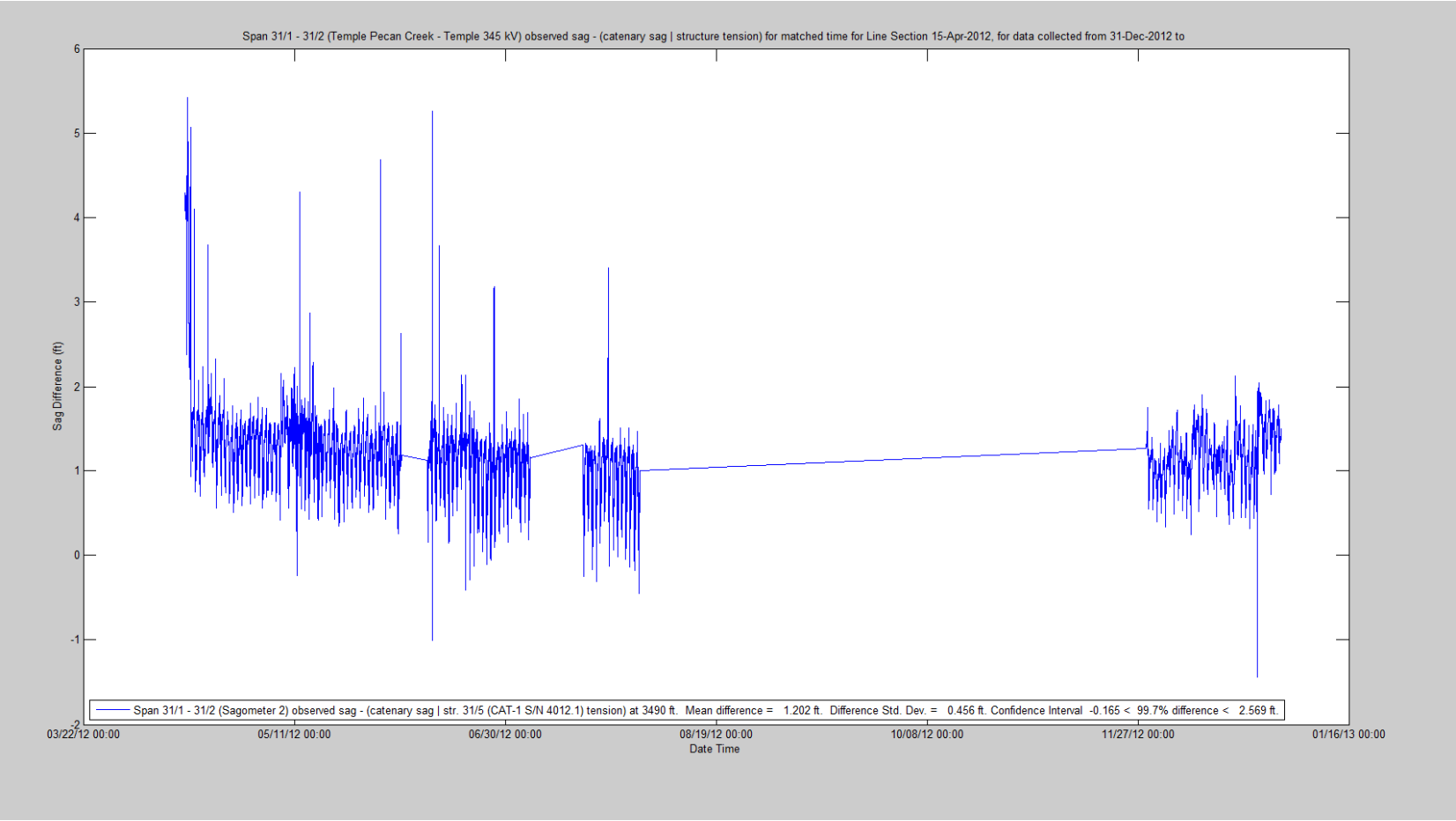
SAG ESTIMATE DIFFERENCE | (LINE, TIME)

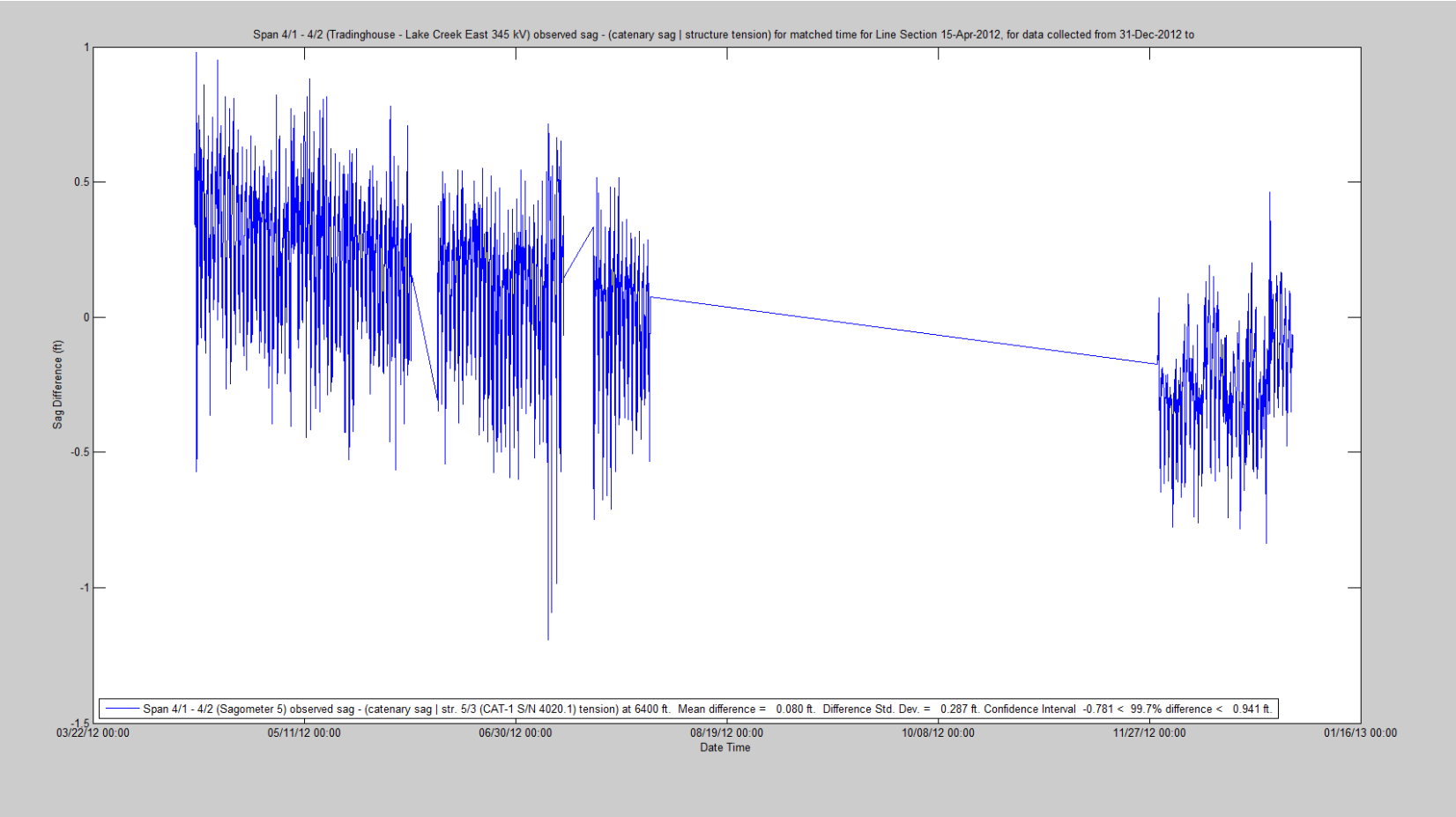

Span 25/1 - 25/2 (Waco Atco - Temple ELM Creek 138 kV) observed sag - (catenary sag | structure tension) for matched time for Line Section 01-Aug-2011, for data collected from 30-Sep-2011 to
Sag Difference (ft)
3
2
1
0
-1
-2
-3
-4
07/26/11 00:00
08/06/11 16:00
08/18/11 08:00
08/30/11 00:00
09/10/11 16:00
09/22/11 08:00
10/04/11 00:00
Date Time
Span 25/1 - 25/2 (RT-TLMS 1-1) observed sag - (catenary sag | str. 26/7 (CAT-1 S/N 4011.2) tension) at 8420 ft. Mean difference = -0.156 ft. Difference Std. Dev. = 0.527 ft. Confidence Interval -1.736 < 99.7% difference < 1.424 ft.
Span 25/1 - 25/2 (RT-TLMS 1-1) observed sag - (catenary sag | str. 19/3 (CAT-1 S/N 4018.1) tension) at 30291 ft. Mean difference = 0.161 ft. Difference Std. Dev. = 0.484 ft. Confidence Interval -1.290 < 99.7% difference < 1.613 ft.


Span 19/4 - 19/5 (Waco Atco - Temple ELM Creek 138 kV) observed sag - (catenary sag | structure tension) for matched time for Line Section 01-Nov-2011, for data collected from 01-Mar-2012 to
Sag Difference (ft)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
02/06/12 00:00
02/10/12 04:00
02/14/12 08:00
02/18/12 12:00
02/22/12 16:00
02/26/12 20:00
03/02/12 00:00
Date Time
Span 19/4 - 19/5 (RT-TLMS 1-2) observed sag - (catenary sag | str. 26/7 (CAT-1 S/N 4011.2) tension) at 640 ft. Mean difference = 0.082 ft. Difference Std. Dev. = 0.202 ft. Confidence Interval -0.525 < 99.7% difference < 0.688 ft.
Span 19/4 - 19/5 (RT-TLMS 1-2) observed sag - (catenary sag | str. 19/3 (CAT-1 S/N 4018.1) tension) at 38071 ft. Mean difference = 0.138 ft. Difference Std. Dev. = 0.215 ft. Confidence Interval -0.508 < 99.7% difference < 0.784 ft.


Span 21/3 - 21/4 (Waco Atco - Temple ELM Creek 138 kV) observed sag - (catenary sag | structure tension) for matched time for Line Section 01-Nov-2012, for data collected from 31-Dec-2012 to
Sag Difference (ft)
1.5
1
0.5
0
-0.5
-1
-1.5
-2
-2.5
-3
10/28/12 00:00
11/08/12 16:00
11/20/12 08:00
12/02/12 00:00
12/13/12 16:00
12/25/12 08:00
01/06/13 00:00
Date Time
Span 21/3 - 21/4 (RT-TLMS 1-3) observed sag - (catenary sag | str. 26/7 (CAT-1 S/N 4011.2) tension) at 10156 ft. Mean difference = -0.062 ft. Difference Std. Dev. = 0.467 ft. Confidence Interval -1.463 < 99.7% difference < 1.339 ft.
Span 21/3 - 21/4 (RT-TLMS 1-3) observed sag - (catenary sag | str. 19/3 (CAT-1 S/N 4018.1) tension) at 27915 ft. Mean difference = 0.047 ft. Difference Std. Dev. = 0.361 ft. Confidence Interval -1.037 < 99.7% difference < 1.131 ft.

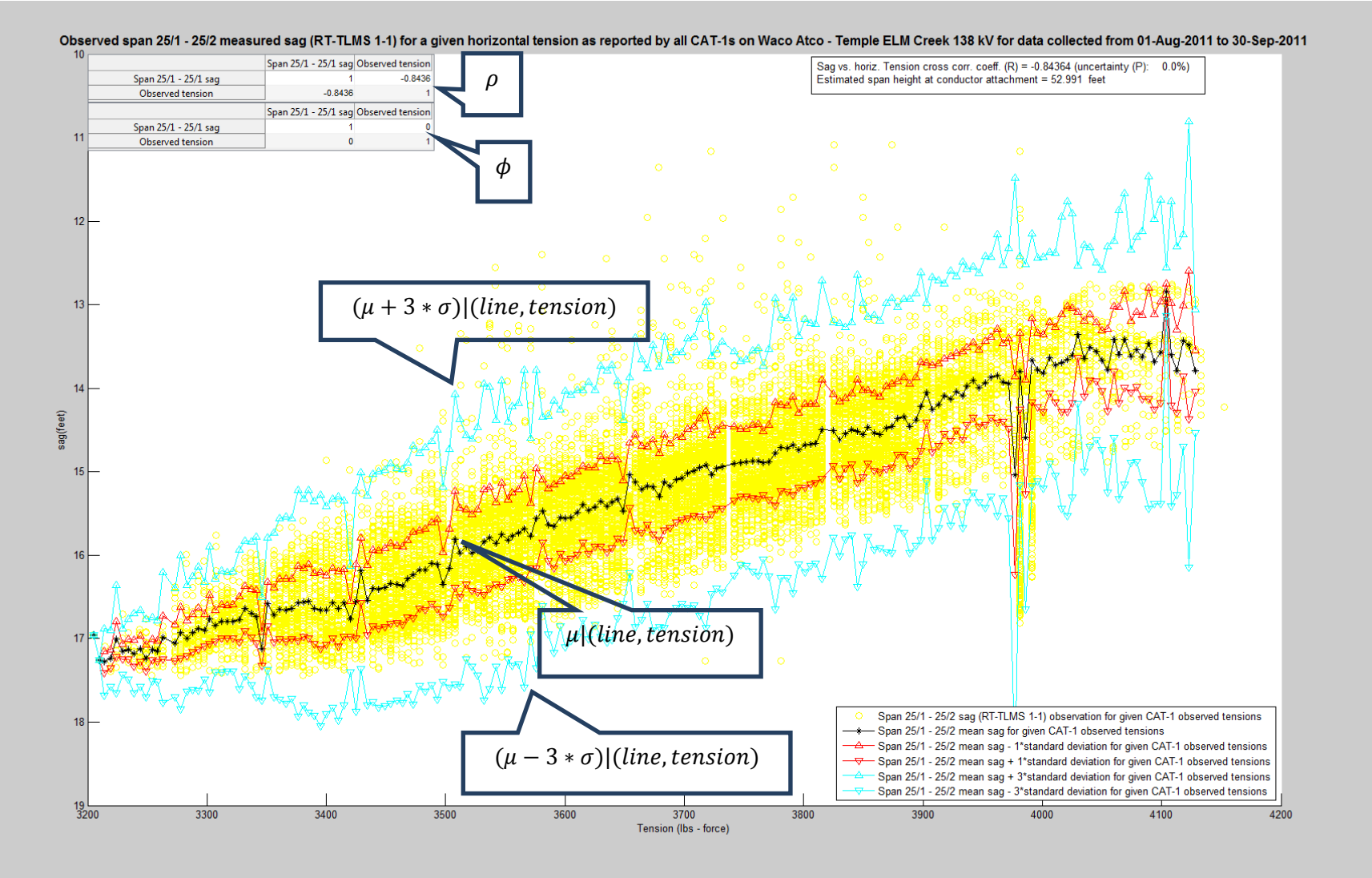

Span 11/3 - 11/4 (Lake - Creek - Temple 345 kV) observed sag - (catenary sag | structure tension) for matched time for Line Section 15-Apr-2012, for data collected from 31-Dec-2012 to
Sag Difference (ft)
6
4
2
0
-2
-4
-6
03/22/12 00:00
05/11/12 00:00
06/30/12 00:00
08/19/12 00:00
10/08/12 00:00
11/27/12 00:00
01/16/13 00:00
Date Time
Span 11/3 - 11/4 (Sagometer 1) observed sag - (catenary sag | str. 2/4 (CAT-1 S/N 4005.1) tension) at 15640 ft. Mean difference = -0.749 ft. Difference Std. Dev. = 0.611 ft. Confidence Interval -2.581 < 99.7% difference < 1.084 ft.
Span 11/3 - 11/4 (Sagometer 1) observed sag - (catenary sag | str. 8/4 (CAT-1 S/N 4006.1) tension) at 21620 ft. Mean difference = 0.754 ft. Difference Std. Dev. = 0.469 ft. Confidence Interval -0.653 < 99.7% difference < 2.161 ft.
Span 11/3 - 11/4 (Sagometer 1) observed sag - (catenary sag | str. 15/5 (CAT-1 S/N 4007.1) tension) at 44422 ft. Mean difference = 0.664 ft. Difference Std. Dev. = 0.522 ft. Confidence Interval -0.903 < 99.7% difference < 2.230 ft.
Span 11/3 - 11/4 (Sagometer 1) observed sag - (catenary sag | str. 23/5 (CAT-1 S/N 4009.1) tension) at 65001 ft. Mean difference = 0.462 ft. Difference Std. Dev. = 0.395 ft. Confidence Interval -0.724 < 99.7% difference < 1.648 ft.
Span 11/3 - 11/4 (Sagometer 1) observed sag - (catenary sag | str. 29/3A (CAT-1 S/N 4010.1) tension) at 93654 ft. Mean difference = -0.158 ft. Difference Std. Dev. = 0.742 ft. Confidence Interval -2.384 < 99.7% difference < 2.068 ft.

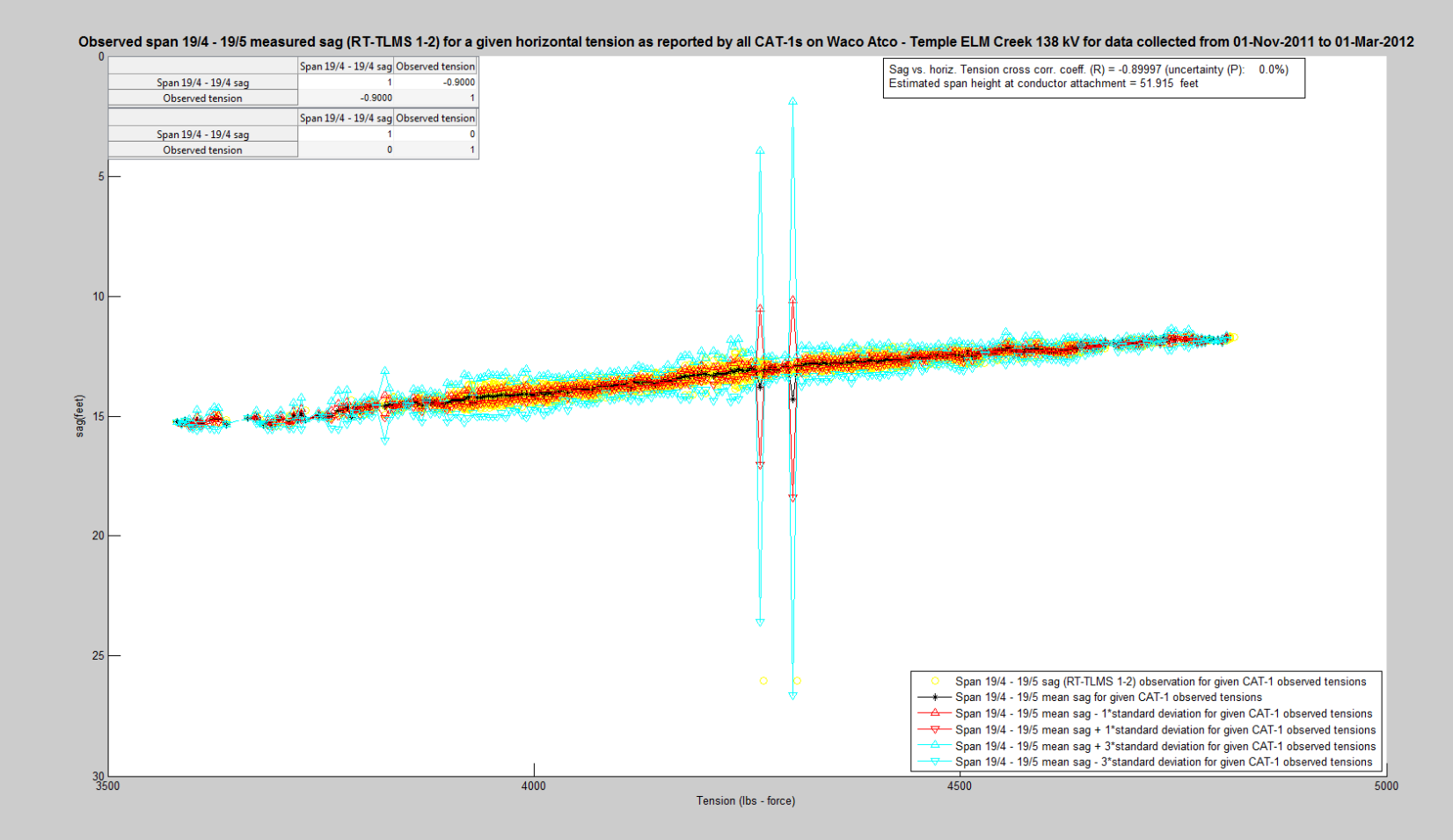

Span 31/1 - 31/2 (Temple Pecan Creek - Temple 345 kV) observed sag - (catenary sag | structure tension) for matched time for Line Section 15-Apr-2012, for data collected from 31-Dec-2012 to
Sag Difference (ft)
6
5
4
3
2
1
0
-1
-2
Span 31/1 - 31/2 (Sagometer 2) observed sag - (catenary sag | str. 31/5 (CAT-1 S/N 4012.1) tension) at 3490 ft. Mean difference = 1.202 ft. Difference Std. Dev. = 0.456 ft. Confidence Interval -0.165 < 99.7% difference < 2.569 ft.
03/22/12 00:00
05/11/12 00:00
06/30/12 00:00
08/19/12 00:00
10/08/12 00:00
11/27/12 00:00
01/16/13 00:00
Date Time

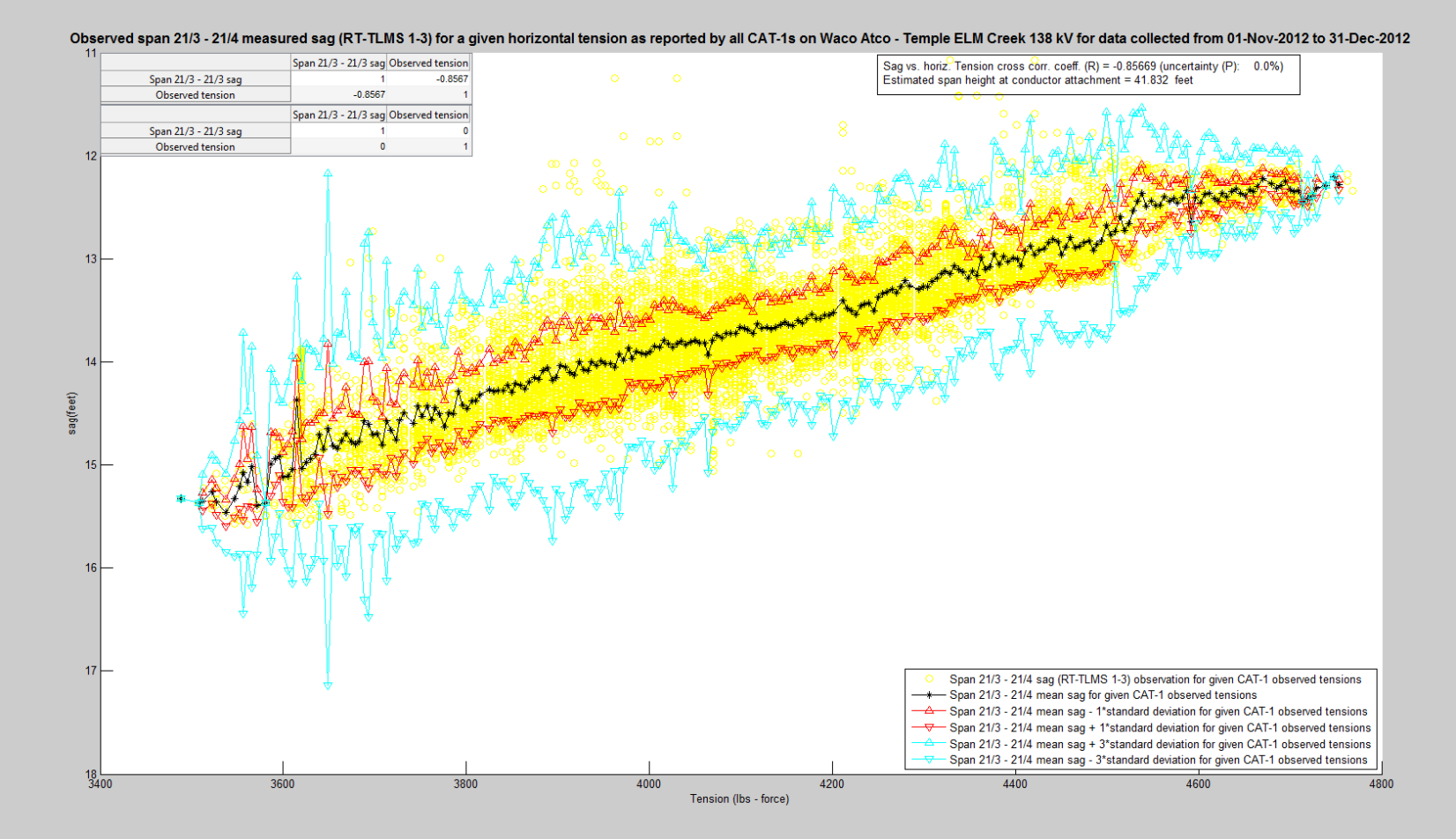

Span 4/1 - 4/2 (Tradinghouse - Lake Creek East 345 kV) observed sag - (catenary sag | structure tension) for matched time for Line Section 15-Apr-2012, for data collected from 31-Dec-2012 to
Sag Difference (ft)
1
0.5
0
-0.5
-1
-1.5
Span 4/1 - 4/2 (Sagometer 5) observed sag - (catenary sag | str. 5/3 (CAT-1 S/N 4020.1) tension) at 6400 ft. Mean difference = 0.080 ft. Difference Std. Dev. = 0.287 ft. Confidence Interval -0.781 < 99.7% difference < 0.941 ft.
03/22/12 00:00
05/11/12 00:00
06/30/12 00:00
08/19/12 00:00
10/08/12 00:00
11/27/12 00:00
01/16/13 00:00
Date Time

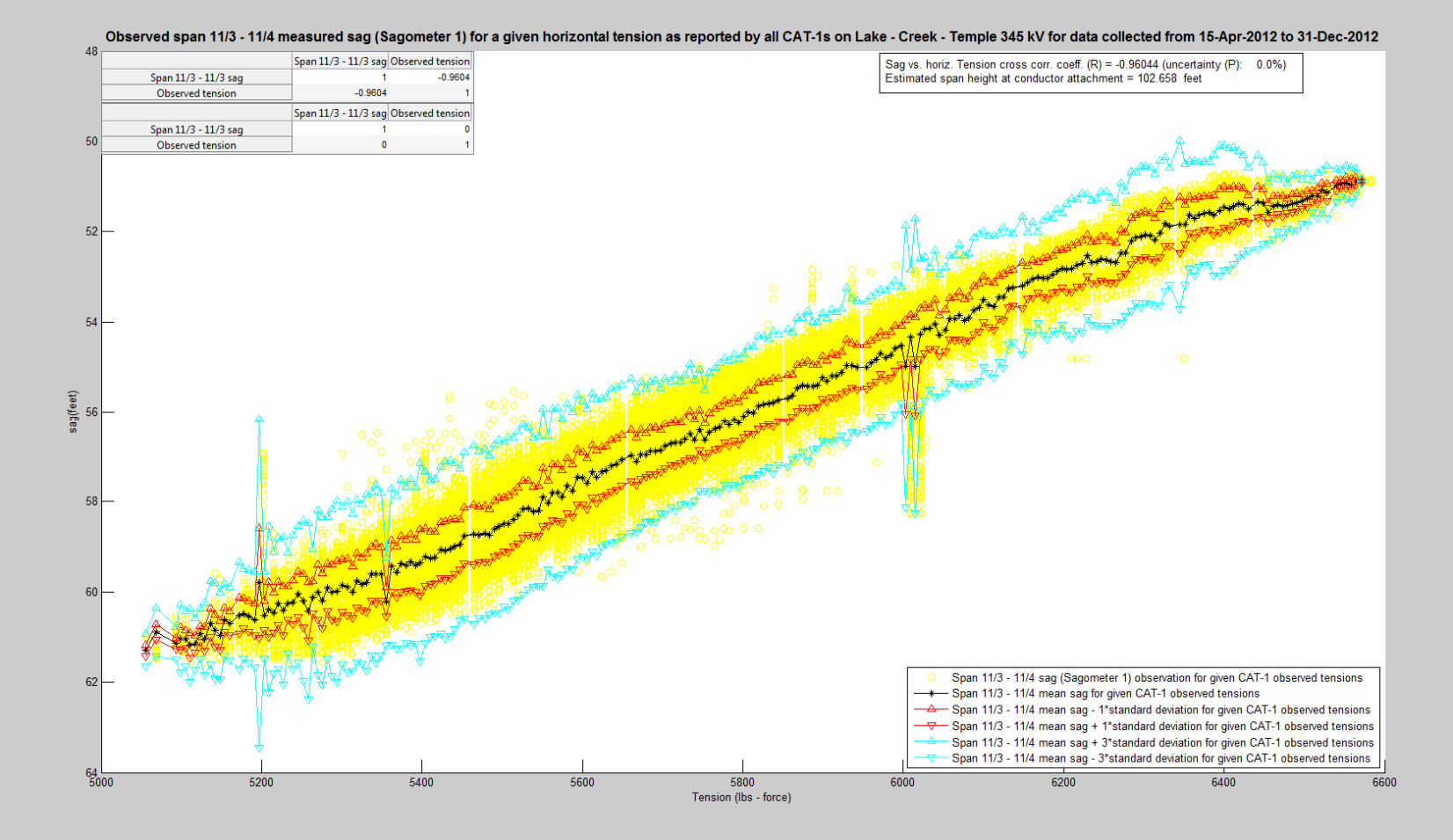
APPENDIX D

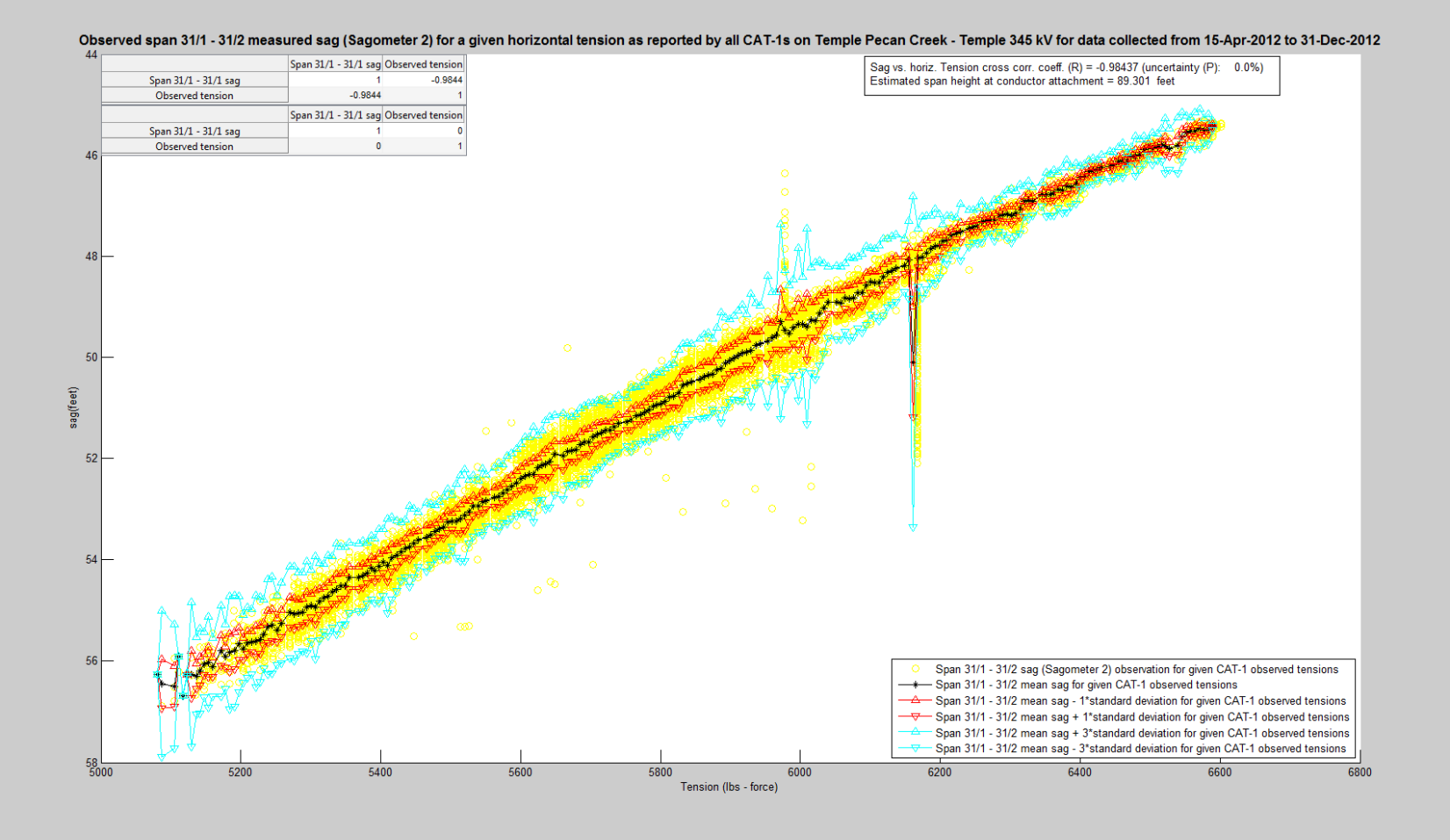
SAG MEAN μ_s⇔TENSION | (LINE, TENSION)

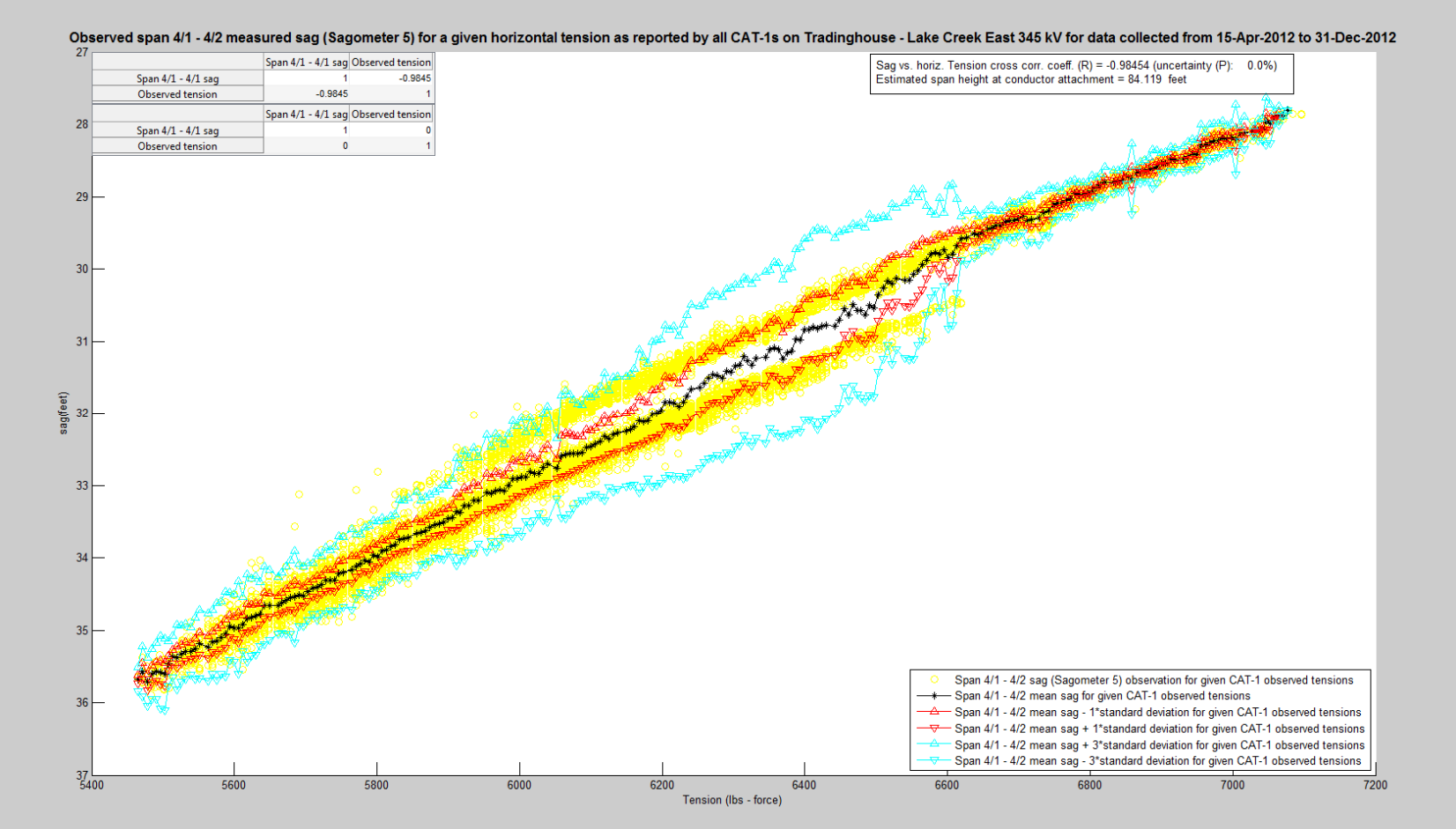

Observed span 25/1 - 25/2 measured sag (RT-TLMS 1-1) for a given horizontal tension as reported by all CAT-1s on Waco Atco - Temple ELM Creek 138 kV for data collected from 01-Aug-2011 to 30-Sep-2011
Span 25/1 - 25/1 sag
Observed tension
1
-0.8436
-0.8436
1
0
0
1
ρ
ϕ
Sag vs. horiz. Tension cross corr. coeff. (R) = -0.84364 (uncertainty (P): 0.0%)
Estimated span height at conductor attachment = 52.991 feet
$(\mu + 3 * \sigma)|(line, tension)$
$\mu|(line, tension)$
$(\mu - 3 * \sigma)|(line, tension)$
Span 25/1 - 25/2 sag (RT-TLMS 1-1) observation for given CAT-1 observed tensions
Span 25/1 - 25/2 mean sag for given CAT-1 observed tensions
Span 25/1 - 25/2 mean sag - 1*standard deviation for given CAT-1 observed tensions
Span 25/1 - 25/2 mean sag + 1*standard deviation for given CAT-1 observed tensions
Span 25/1 - 25/2 mean sag + 3*standard deviation for given CAT-1 observed tensions
Span 25/1 - 25/2 mean sag - 3*standard deviation for given CAT-1 observed tensions
sag(feet)
Tension (lbs - force)


Observed span 19/4 - 19/5 measured sag (RT-TLMS 1-2) for a given horizontal tension as reported by all CAT-1s on Waco Atco - Temple ELM Creek 138 kV for data collected from 01-Nov-2011 to 01-Mar-2012
Span 19/4 - 19/4 sag
Observed tension
1
-0.9000
-0.9000
1
Span 19/4 - 19/4 sag
Observed tension
1
0
0
1
Sag vs. horiz. Tension cross corr. coeff. (R) = -0.89997 (uncertainty (P): 0.0%)
Estimated span height at conductor attachment = 51.915 feet
sag(feet)
Tension (lbs - force)
Span 19/4 - 19/5 sag (RT-TLMS 1-2) observation for given CAT-1 observed tensions
Span 19/4 - 19/5 mean sag for given CAT-1 observed tensions
Span 19/4 - 19/5 mean sag - 1*standard deviation for given CAT-1 observed tensions
Span 19/4 - 19/5 mean sag + 1*standard deviation for given CAT-1 observed tensions
Span 19/4 - 19/5 mean sag + 3*standard deviation for given CAT-1 observed tensions
Span 19/4 - 19/5 mean sag - 3*standard deviation for given CAT-1 observed tensions


Observed span 21/3 - 21/4 measured sag (RT-TLMS 1-3) for a given horizontal tension as reported by all CAT-1s on Waco Atco - Temple ELM Creek 138 kV for data collected from 01-Nov-2012 to 31-Dec-2012
Span 21/3 - 21/3 sag
Observed tension
1
-0.8567
-0.8567
1
0
0
1
Sag vs. horiz. Tension cross corr. coeff. (R) = -0.85669 (uncertainty (P): 0.0%)
Estimated span height at conductor attachment = 41.832 feet
sag(feet)
Tension (lbs - force)
Span 21/3 - 21/4 sag (RT-TLMS 1-3) observation for given CAT-1 observed tensions
Span 21/3 - 21/4 mean sag for given CAT-1 observed tensions
Span 21/3 - 21/4 mean sag - 1*standard deviation for given CAT-1 observed tensions
Span 21/3 - 21/4 mean sag + 1*standard deviation for given CAT-1 observed tensions
Span 21/3 - 21/4 mean sag + 3*standard deviation for given CAT-1 observed tensions
Span 21/3 - 21/4 mean sag - 3*standard deviation for given CAT-1 observed tensions

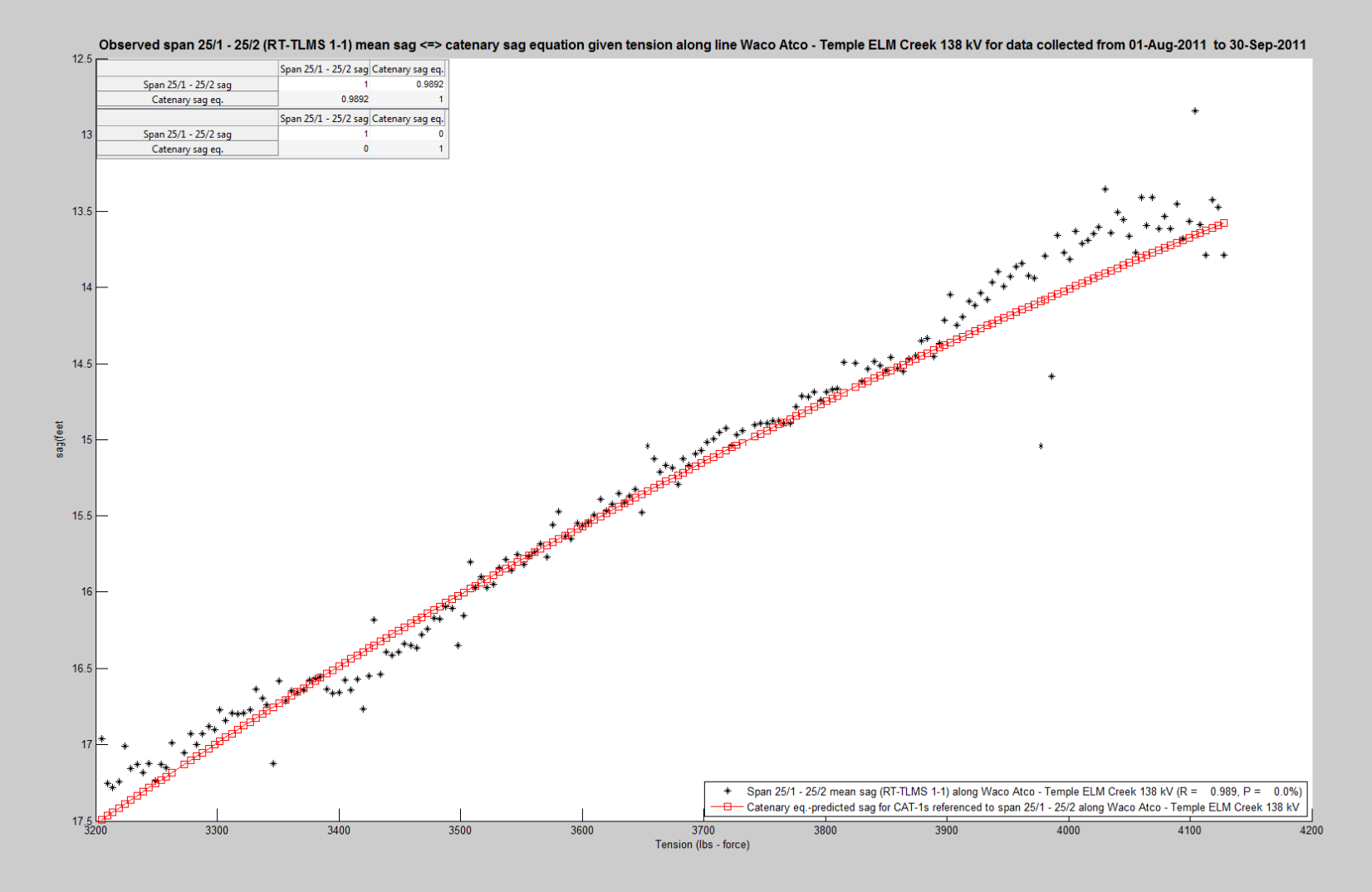

Observed span 11/3 - 11/4 measured sag (Sagometer 1) for a given horizontal tension as reported by all CAT-1s on Lake - Creek - Temple 345 kV for data collected from 15-Apr-2012 to 31-Dec-2012
Span 11/3 - 11/3 sag
Observed tension
1
-0.9604
-0.9604
1
Span 11/3 - 11/3 sag
Observed tension
1
0
0
1
Sag vs. horiz. Tension cross corr. coeff. (R) = -0.96044 (uncertainty (P): 0.0%)
Estimated span height at conductor attachment = 102.658 feet
Span 11/3 - 11/4 sag (Sagometer 1) observation for given CAT-1 observed tensions
Span 11/3 - 11/4 mean sag for given CAT-1 observed tensions
Span 11/3 - 11/4 mean sag - 1*standard deviation for given CAT-1 observed tensions
Span 11/3 - 11/4 mean sag + 1*standard deviation for given CAT-1 observed tensions
Span 11/3 - 11/4 mean sag + 3*standard deviation for given CAT-1 observed tensions
Span 11/3 - 11/4 mean sag - 3*standard deviation for given CAT-1 observed tensions
sag(feet)
Tension (lbs - force)
48
50
52
54
56
58
60
62
64
5000
5200
5400
5600
5800
6000
6200
6400
6600

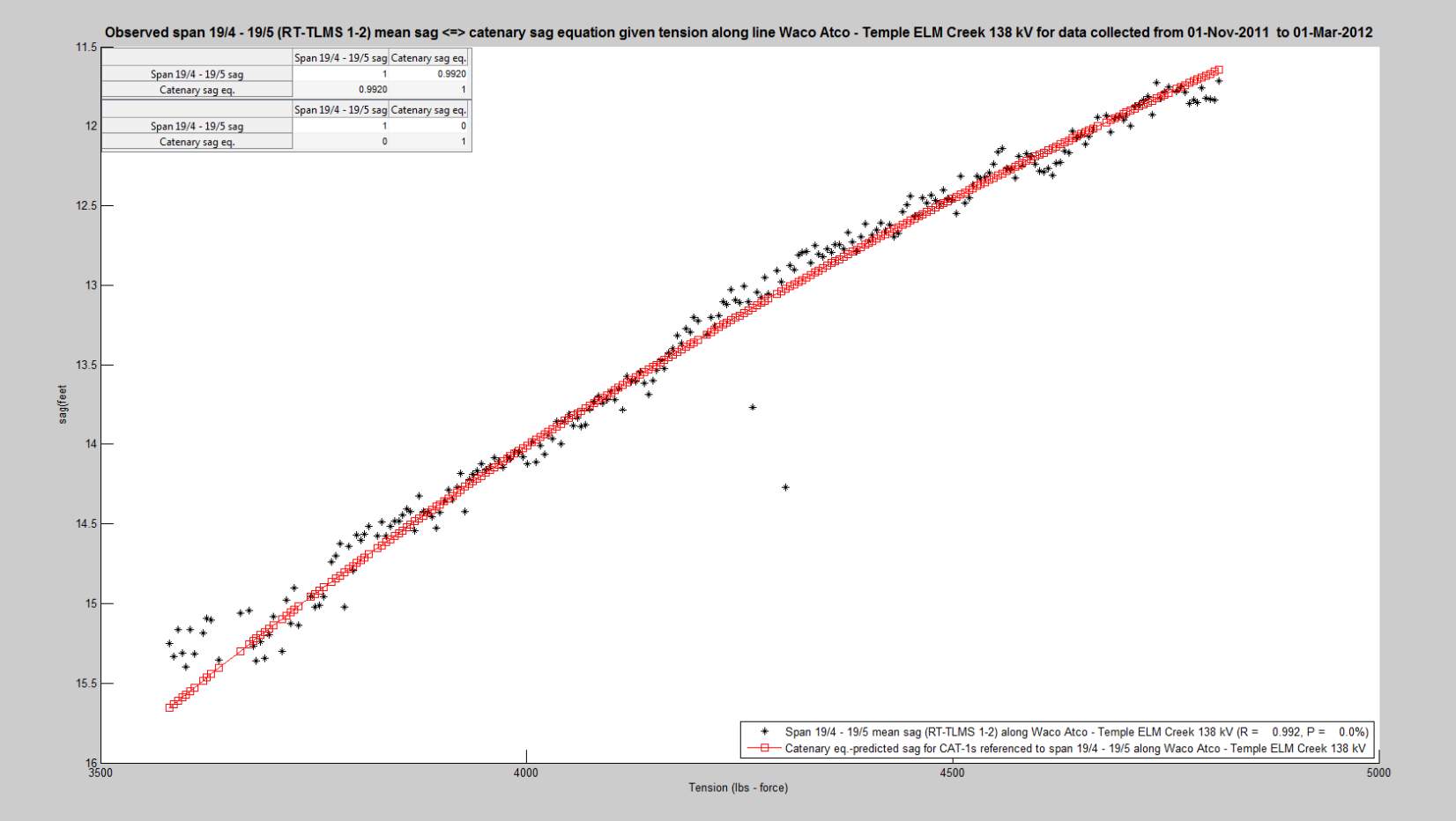

Observed span 31/1 - 31/2 measured sag (Sagometer 2) for a given horizontal tension as reported by all CAT-1s on Temple Pecan Creek - Temple 345 kV for data collected from 15-Apr-2012 to 31-Dec-2012
Span 31/1 - 31/1 sag
Observed tension
1
-0.9844
-0.9844
1
Span 31/1 - 31/1 sag
Observed tension
1
0
0
1
Sag vs. horiz. Tension cross corr. coeff. (R) = -0.98437 (uncertainty (P): 0.0%)
Estimated span height at conductor attachment = 89.301 feet
Span 31/1 - 31/2 sag (Sagometer 2) observation for given CAT-1 observed tensions
Span 31/1 - 31/2 mean sag for given CAT-1 observed tensions
Span 31/1 - 31/2 mean sag - 1*standard deviation for given CAT-1 observed tensions
Span 31/1 - 31/2 mean sag + 1*standard deviation for given CAT-1 observed tensions
Span 31/1 - 31/2 mean sag + 3*standard deviation for given CAT-1 observed tensions
Span 31/1 - 31/2 mean sag - 3*standard deviation for given CAT-1 observed tensions
sag(feet)
Tension (lbs - force)

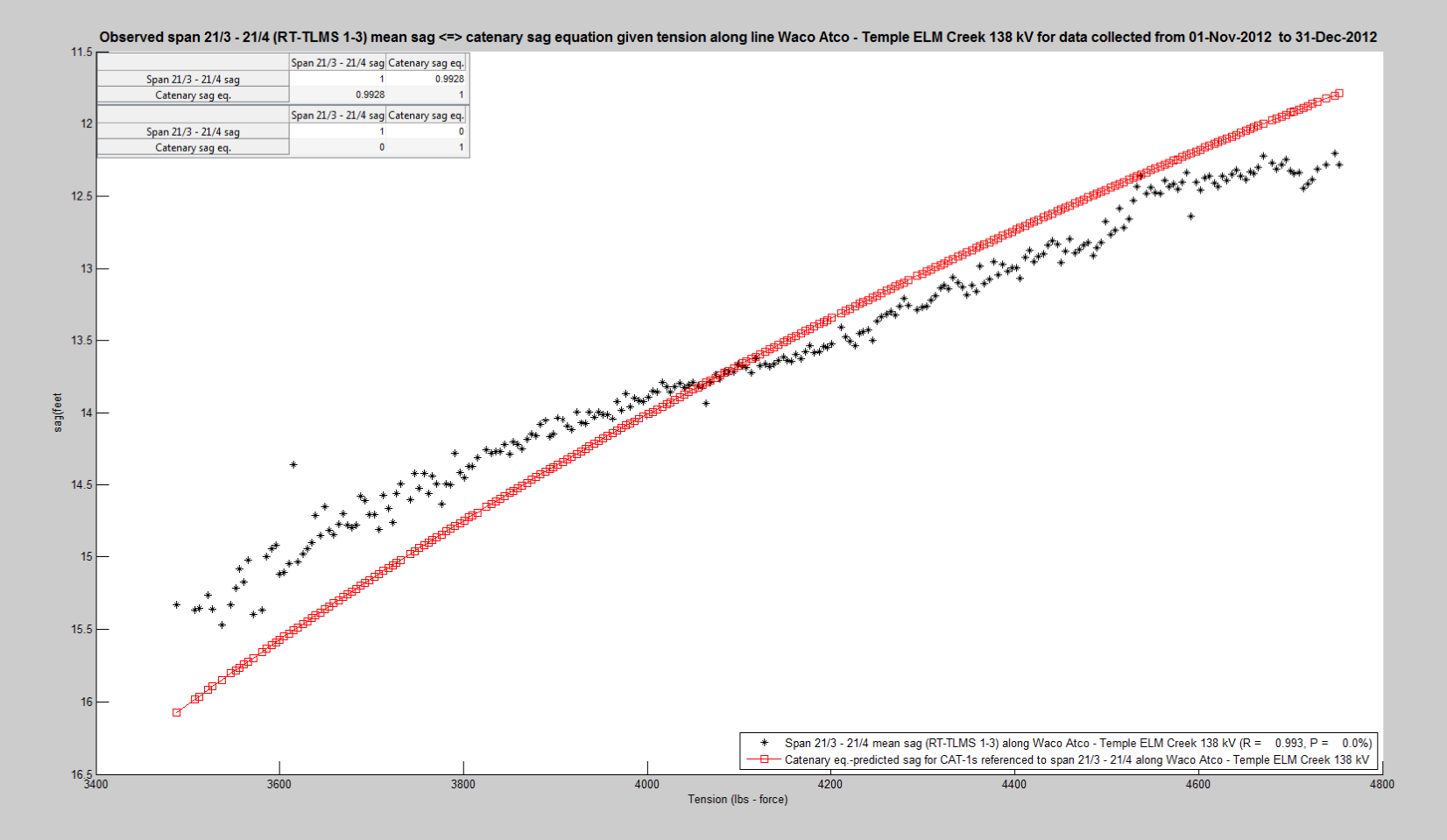

Observed span 4/1 - 4/2 measured sag (Sagometer 5) for a given horizontal tension as reported by all CAT-1s on Tradinghouse - Lake Creek East 345 kV for data collected from 15-Apr-2012 to 31-Dec-2012
Span 4/1 - 4/1 sag
Observed tension
1
-0.9845
-0.9845
1
0
1
0
1
Sag vs. horiz. Tension cross corr. coeff. (R) = -0.98454 (uncertainty (P): 0.0%)
Estimated span height at conductor attachment = 84.119 feet
Span 4/1 - 4/2 sag (Sagometer 5) observation for given CAT-1 observed tensions
Span 4/1 - 4/2 mean sag for given CAT-1 observed tensions
Span 4/1 - 4/2 mean sag - 1*standard deviation for given CAT-1 observed tensions
Span 4/1 - 4/2 mean sag + 1*standard deviation for given CAT-1 observed tensions
Span 4/1 - 4/2 mean sag + 3*standard deviation for given CAT-1 observed tensions
Span 4/1 - 4/2 mean sag - 3*standard deviation for given CAT-1 observed tensions
sag(feet)
Tension (lbs - force)
27
28
29
30
31
32
33
34
35
36
37
5400
5600
5800
6000
6200
6400
6600
6800
7000
7200

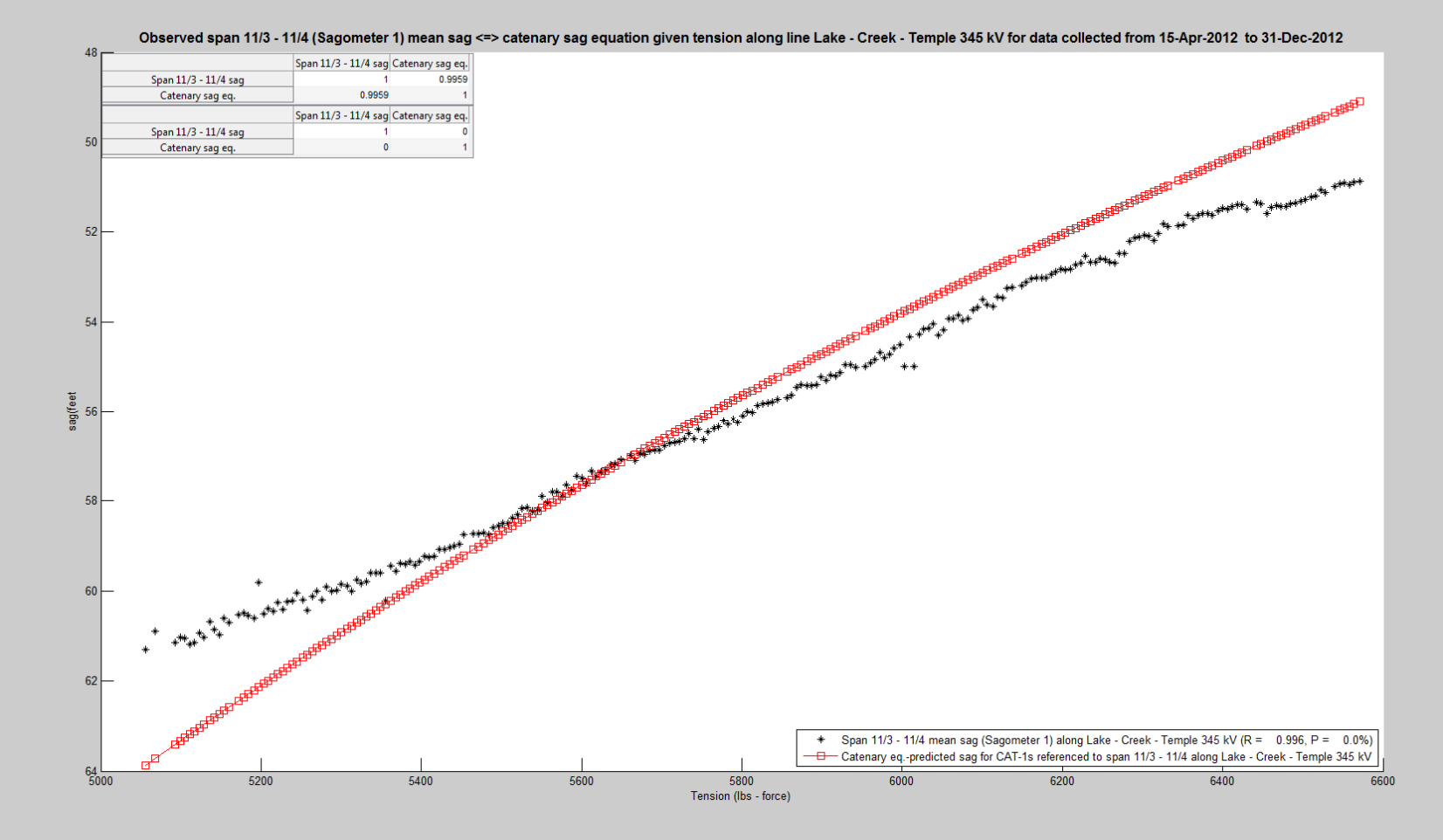
APPENDIX E

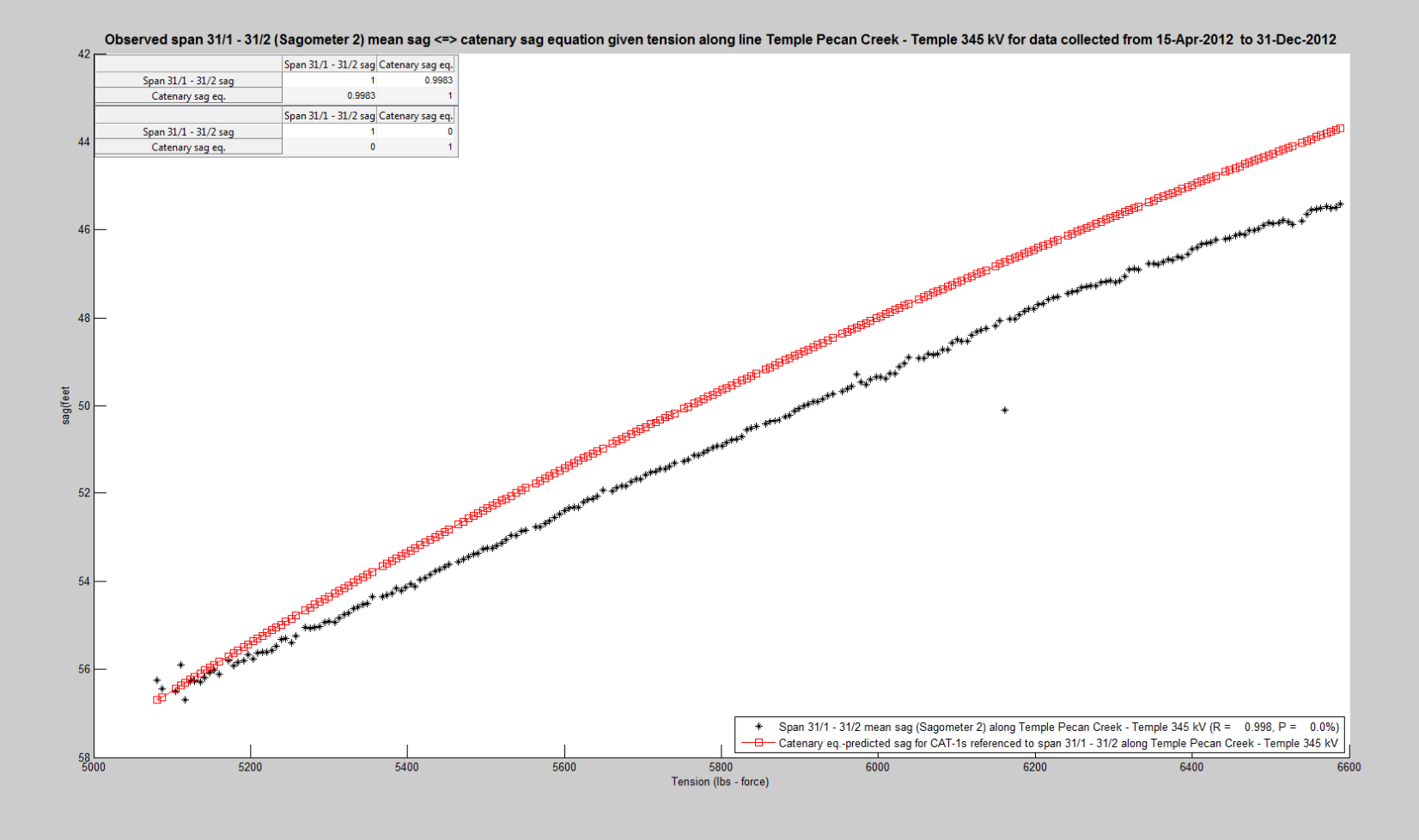
(μ_s⇔SAG[ξ])|(LINE, TENSION ξ) HYPOTHESIS TEST CASES

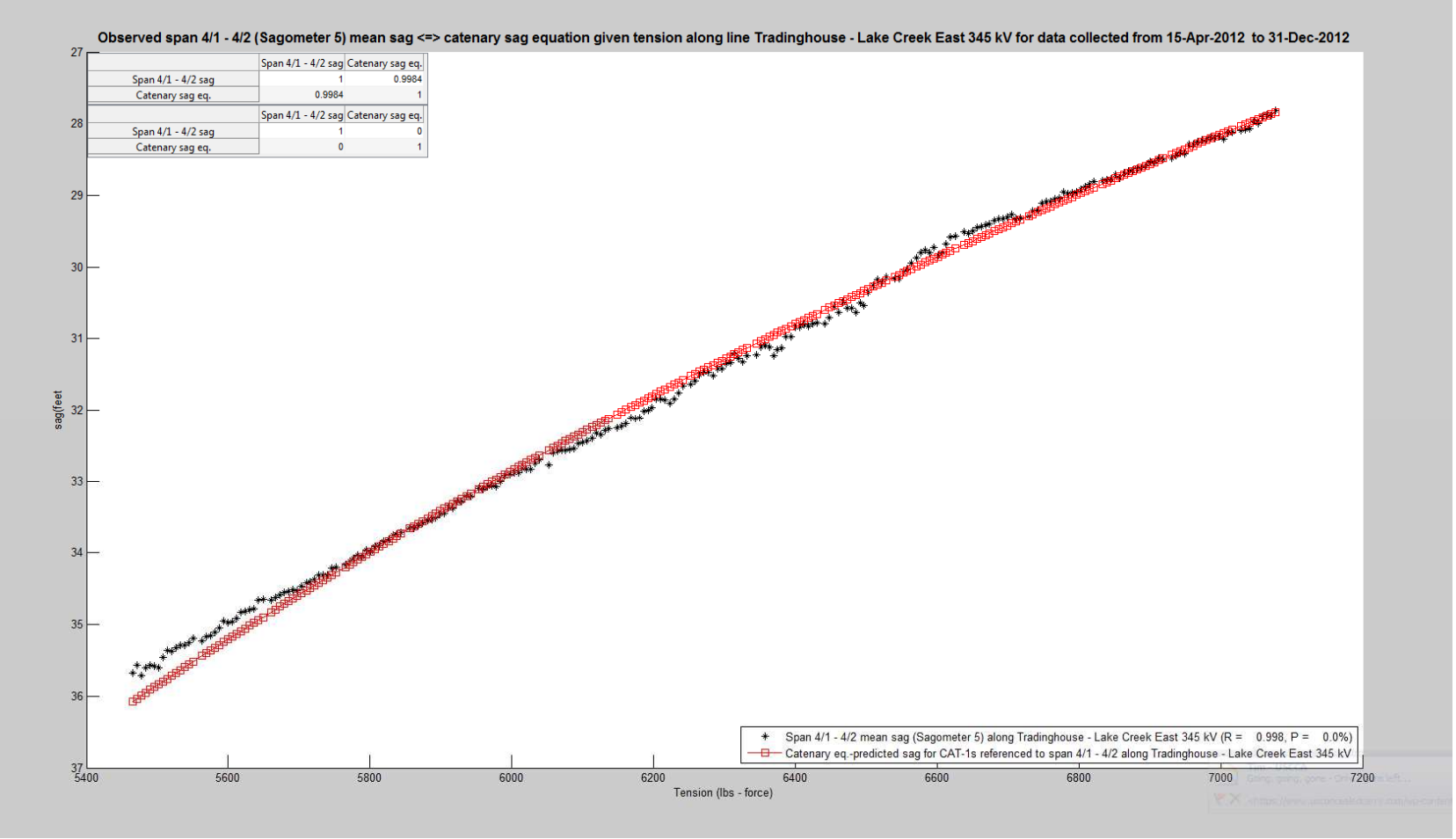

Observed span 25/1 - 25/2 (RT-TLMS 1-1) mean sag <=> catenary sag equation given tension along line Waco Atco - Temple ELM Creek 138 kV for data collected from 01-Aug-2011 to 30-Sep-2011
Span 25/1 - 25/2 sag
Catenary sag eq.
1
0.9892
0.9892
1
1
0
0
1
sag(feet
Tension (lbs - force)
Span 25/1 - 25/2 mean sag (RT-TLMS 1-1) along Waco Atco - Temple ELM Creek 138 kV (R = 0.989, P = 0.0%)
Catenary eq.-predicted sag for CAT-1s referenced to span 25/1 - 25/2 along Waco Atco - Temple ELM Creek 138 kV


Observed span 19/4 - 19/5 (RT-TLMS 1-2) mean sag <=> catenary sag equation given tension along line Waco Atco - Temple ELM Creek 138 kV for data collected from 01-Nov-2011 to 01-Mar-2012
Span 19/4 - 19/5 sag
Catenary sag eq.
1
0.9920
0.9920
1
1
0
0
1
sag(feet
11.5
12
12.5
13
13.5
14
14.5
15
15.5
16
3500
4000
4500
5000
Tension (lbs - force)
Span 19/4 - 19/5 mean sag (RT-TLMS 1-2) along Waco Atco - Temple ELM Creek 138 kV (R = 0.992, P = 0.0%)
Catenary eq.-predicted sag for CAT-1s referenced to span 19/4 - 19/5 along Waco Atco - Temple ELM Creek 138 kV


Observed span 21/3 - 21/4 (RT-TLMS 1-3) mean sag <=> catenary sag equation given tension along line Waco Atco - Temple ELM Creek 138 kV for data collected from 01-Nov-2012 to 31-Dec-2012
Span 21/3 - 21/4 sag
Catenary sag eq.
1
0.9928
0.9928
1
1
0
0
1
sag(feet
Tension (lbs - force)
Span 21/3 - 21/4 mean sag (RT-TLMS 1-3) along Waco Atco - Temple ELM Creek 138 kV (R = 0.993, P = 0.0%)
Catenary eq.-predicted sag for CAT-1s referenced to span 21/3 - 21/4 along Waco Atco - Temple ELM Creek 138 kV

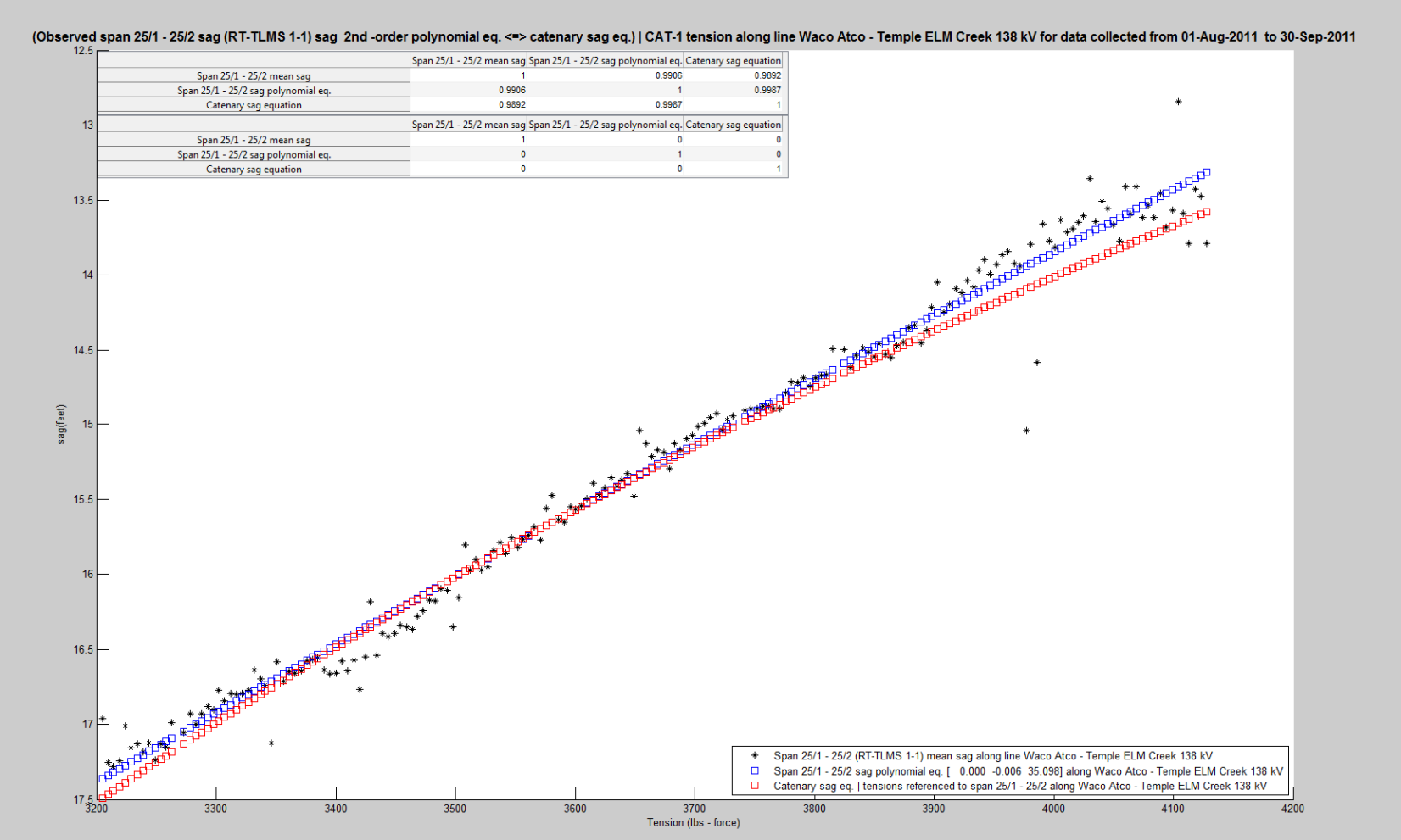

Observed span 11/3 - 11/4 (Sagometer 1) mean sag <=> catenary sag equation given tension along line Lake - Creek - Temple 345 kV for data collected from 15-Apr-2012 to 31-Dec-2012
Span 11/3 - 11/4 sag
Catenary sag eq.
1
0.9959
0.9959
1
1
0
0
1
sag(feet
Tension (lbs - force)
Span 11/3 - 11/4 mean sag (Sagometer 1) along Lake - Creek - Temple 345 kV (R = 0.996, P = 0.0%)
Catenary eq.-predicted sag for CAT-1s referenced to span 11/3 - 11/4 along Lake - Creek - Temple 345 kV


Observed span 31/1 - 31/2 (Sagometer 2) mean sag <=> catenary sag equation given tension along line Temple Pecan Creek - Temple 345 kV for data collected from 15-Apr-2012 to 31-Dec-2012
Span 31/1 - 31/2 sag
Catenary sag eq.
1
0.9983
0.9983
1
Span 31/1 - 31/2 sag
Catenary sag eq.
1
0
0
1
sag(feet
42
44
46
48
50
52
54
56
58
5000
5200
5400
5600
5800
6000
6200
6400
6600
Tension (lbs - force)
Span 31/1 - 31/2 mean sag (Sagometer 2) along Temple Pecan Creek - Temple 345 kV (R = 0.998, P = 0.0%)
Catenary eq.-predicted sag for CAT-1s referenced to span 31/1 - 31/2 along Temple Pecan Creek - Temple 345 kV


Observed span 4/1 - 4/2 (Sagometer 5) mean sag <=> catenary sag equation given tension along line Tradinghouse - Lake Creek East 345 kV for data collected from 15-Apr-2012 to 31-Dec-2012
Span 4/1 - 4/2 sag
Catenary sag eq.
1
0.9984
0.9984
1
1
0
0
1
sag(feet)
Tension (lbs - force)
Span 4/1 - 4/2 mean sag (Sagometer 5) along Tradinghouse - Lake Creek East 345 kV (R = 0.998, P = 0.0%)
Catenary eq.-predicted sag for CAT-1s referenced to span 4/1 - 4/2 along Tradinghouse - Lake Creek East 345 kV

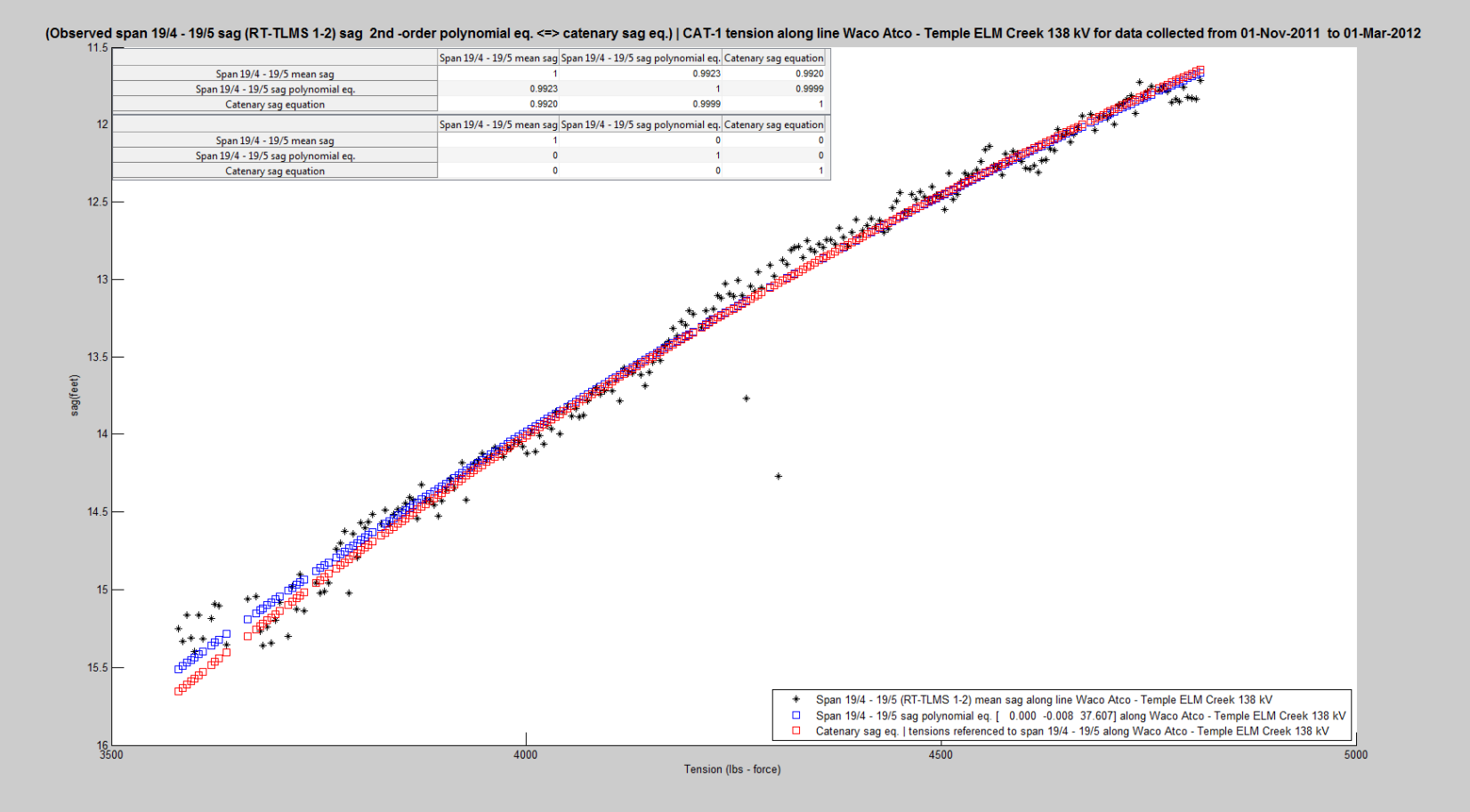
APPENDIX F

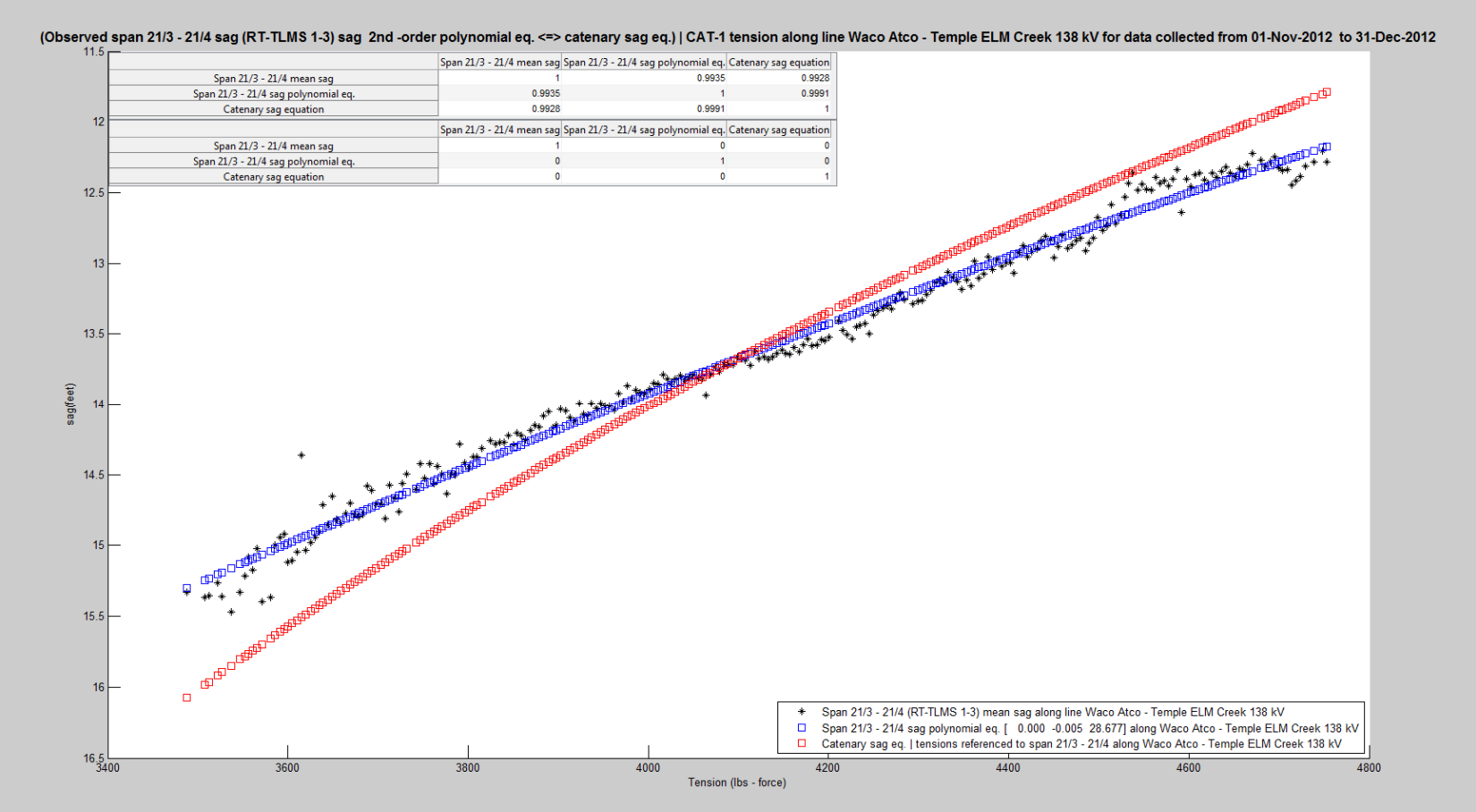
$$\boldsymbol{\mu_s \Leftrightarrow P_2(CAT1\ tension\ \xi) \Leftrightarrow Sag[CAT1\ tension\ \xi]}\ \mathbf{|}$$
$$\mathbf{(LINE,}\boldsymbol{CAT1\ tension\ \xi}\ \mathbf{)}$$

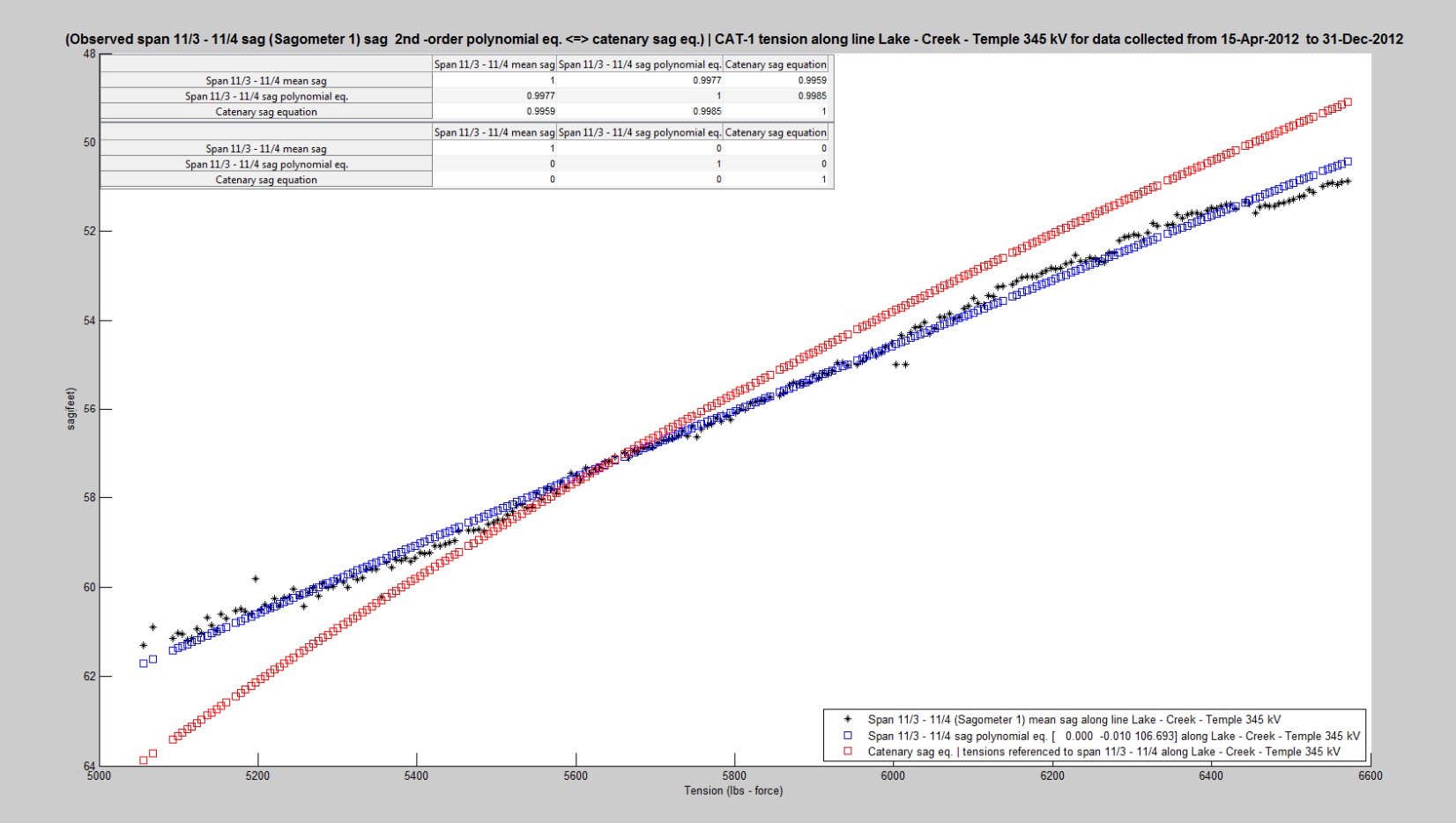


	Span 25/1 - 25/2 mean sag	Span 25/1 - 25/2 sag polynomial eq.	Catenary sag equation
Span 25/1 - 25/2 mean sag	1	0.9906	0.9892
Span 25/1 - 25/2 sag polynomial eq.	0.9906	1	0.9987
Catenary sag equation	0.9892	0.9987	1

	Span 25/1 - 25/2 mean sag	Span 25/1 - 25/2 sag polynomial eq.	Catenary sag equation
Span 25/1 - 25/2 mean sag	1	0	0
Span 25/1 - 25/2 sag polynomial eq.	0	1	0
Catenary sag equation	0	0	1

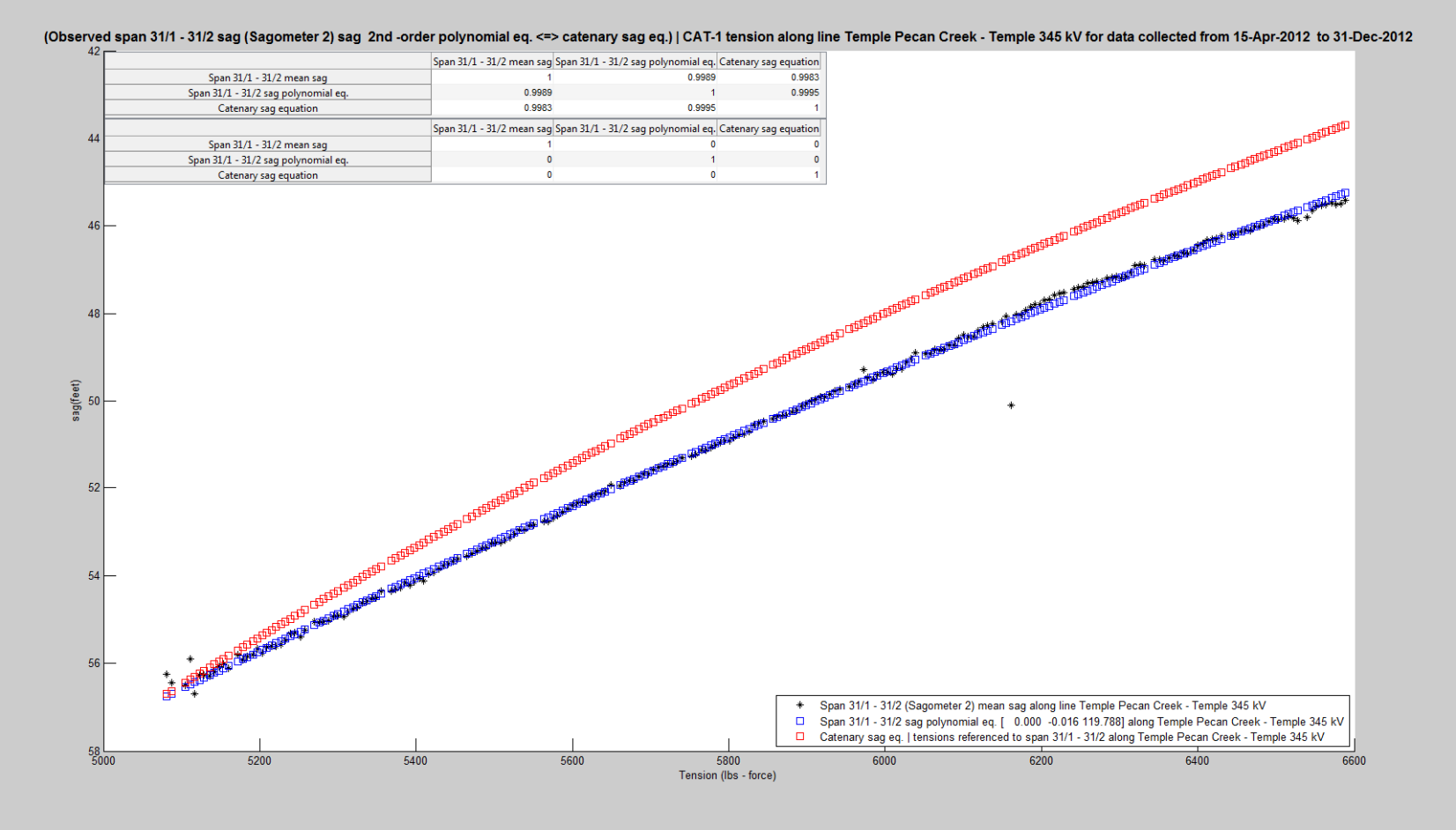

(Observed span 19/4 - 19/5 sag (RT-TLMS 1-2) sag 2nd -order polynomial eq. <=> catenary sag eq.) | CAT-1 tension along line Waco Atco - Temple ELM Creek 138 kV for data collected from 01-Nov-2011 to 01-Mar-2012
Span 19/4 - 19/5 mean sag
Span 19/4 - 19/5 sag polynomial eq.
Catenary sag equation
1 0.9923 0.9920
0.9923 1 0.9999
0.9920 0.9999 1
1 0 0
0 1 0
0 0 1
sag(feet)
Tension (lbs - force)
Span 19/4 - 19/5 (RT-TLMS 1-2) mean sag along line Waco Atco - Temple ELM Creek 138 kV
Span 19/4 - 19/5 sag polynomial eq. [0.000 -0.008 37.607] along Waco Atco - Temple ELM Creek 138 kV
Catenary sag eq. | tensions referenced to span 19/4 - 19/5 along Waco Atco - Temple ELM Creek 138 kV


(Observed span 21/3 - 21/4 sag (RT-TLMS 1-3) sag 2nd -order polynomial eq. <=> catenary sag eq.) | CAT-1 tension along line Waco Atco - Temple ELM Creek 138 kV for data collected from 01-Nov-2012 to 31-Dec-2012
Span 21/3 - 21/4 mean sag
Span 21/3 - 21/4 sag polynomial eq.
Catenary sag equation
1 0.9935 0.9928
0.9935 1 0.9991
0.9928 0.9991 1
1 0 0
0 1 0
0 0 1
sag(feet)
Tension (lbs - force)
Span 21/3 - 21/4 (RT-TLMS 1-3) mean sag along line Waco Atco - Temple ELM Creek 138 kV
Span 21/3 - 21/4 sag polynomial eq. [0.000 -0.005 28.677] along Waco Atco - Temple ELM Creek 138 kV
Catenary sag eq. | tensions referenced to span 21/3 - 21/4 along Waco Atco - Temple ELM Creek 138 kV



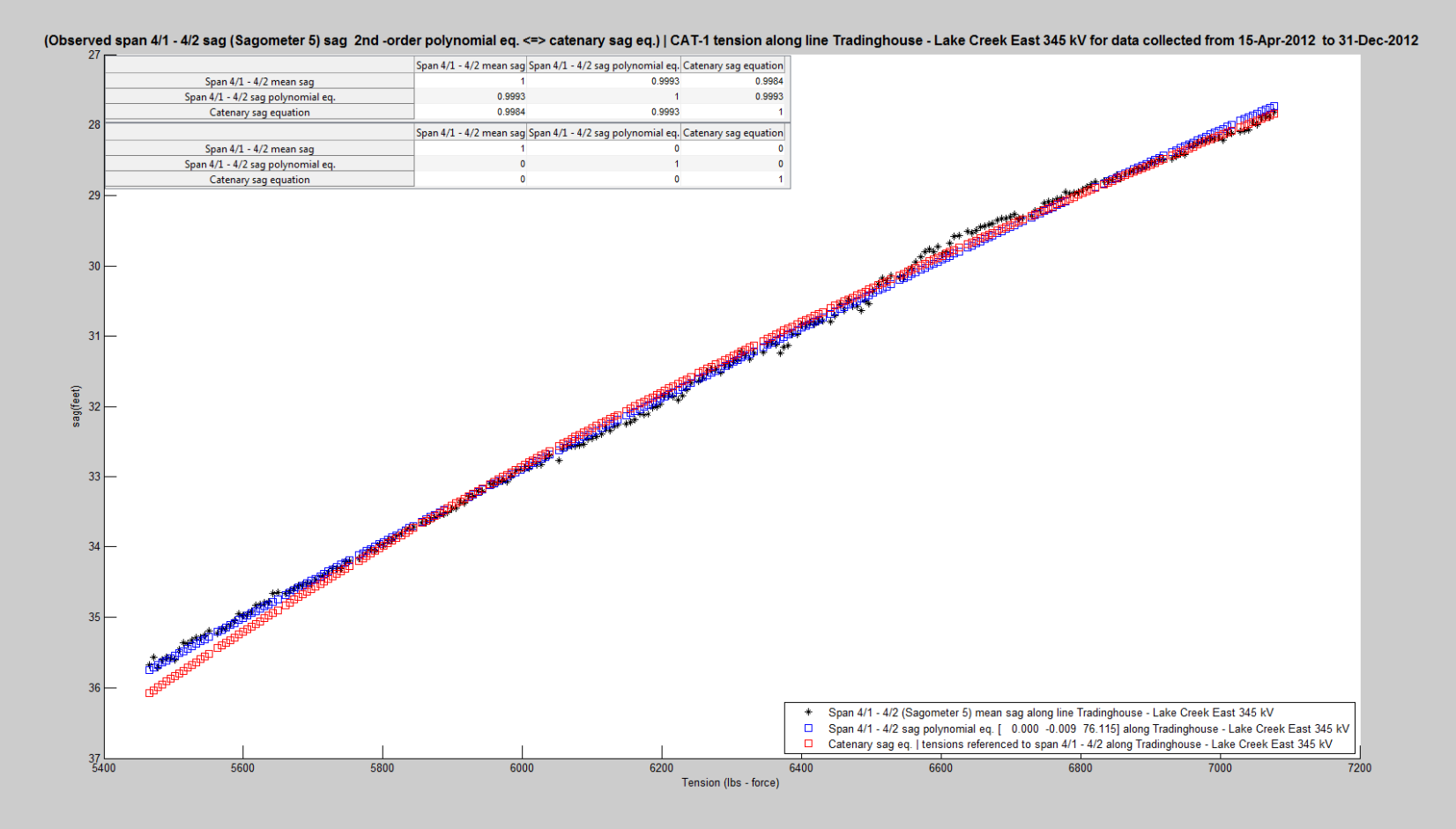
	Span 11/3 - 11/4 mean sag	Span 11/3 - 11/4 sag polynomial eq.	Catenary sag equation
Span 11/3 - 11/4 mean sag	1	0.9977	0.9959
Span 11/3 - 11/4 sag polynomial eq.	0.9977	1	0.9985
Catenary sag equation	0.9959	0.9985	1

	Span 11/3 - 11/4 mean sag	Span 11/3 - 11/4 sag polynomial eq.	Catenary sag equation
Span 11/3 - 11/4 mean sag	1	0	0
Span 11/3 - 11/4 sag polynomial eq.	0	1	0
Catenary sag equation	0	0	1



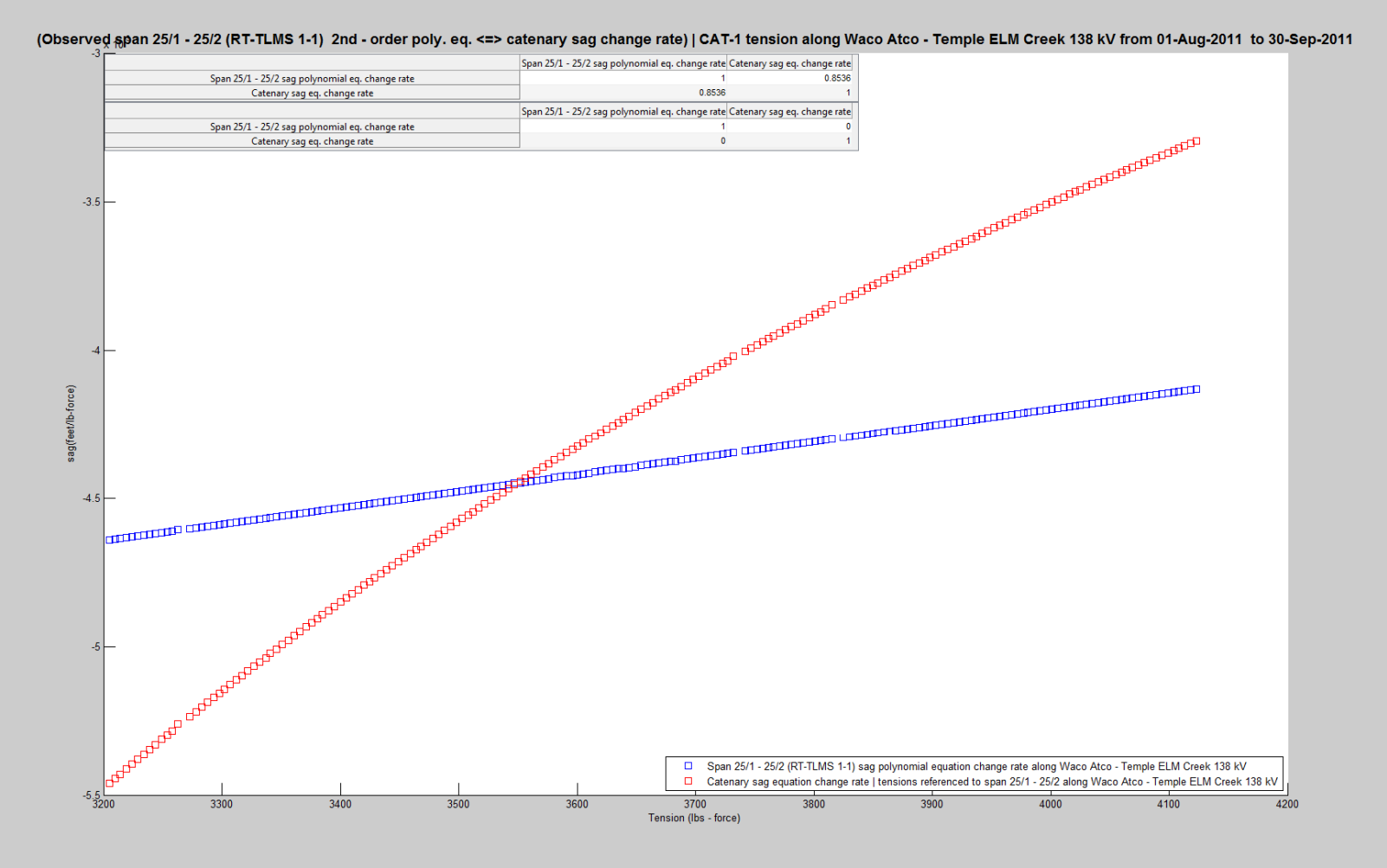
	Span 31/1 - 31/2 mean sag	Span 31/1 - 31/2 sag polynomial eq.	Catenary sag equation
Span 31/1 - 31/2 mean sag	1	0.9989	0.9983
Span 31/1 - 31/2 sag polynomial eq.	0.9989	1	0.9995
Catenary sag equation	0.9983	0.9995	1

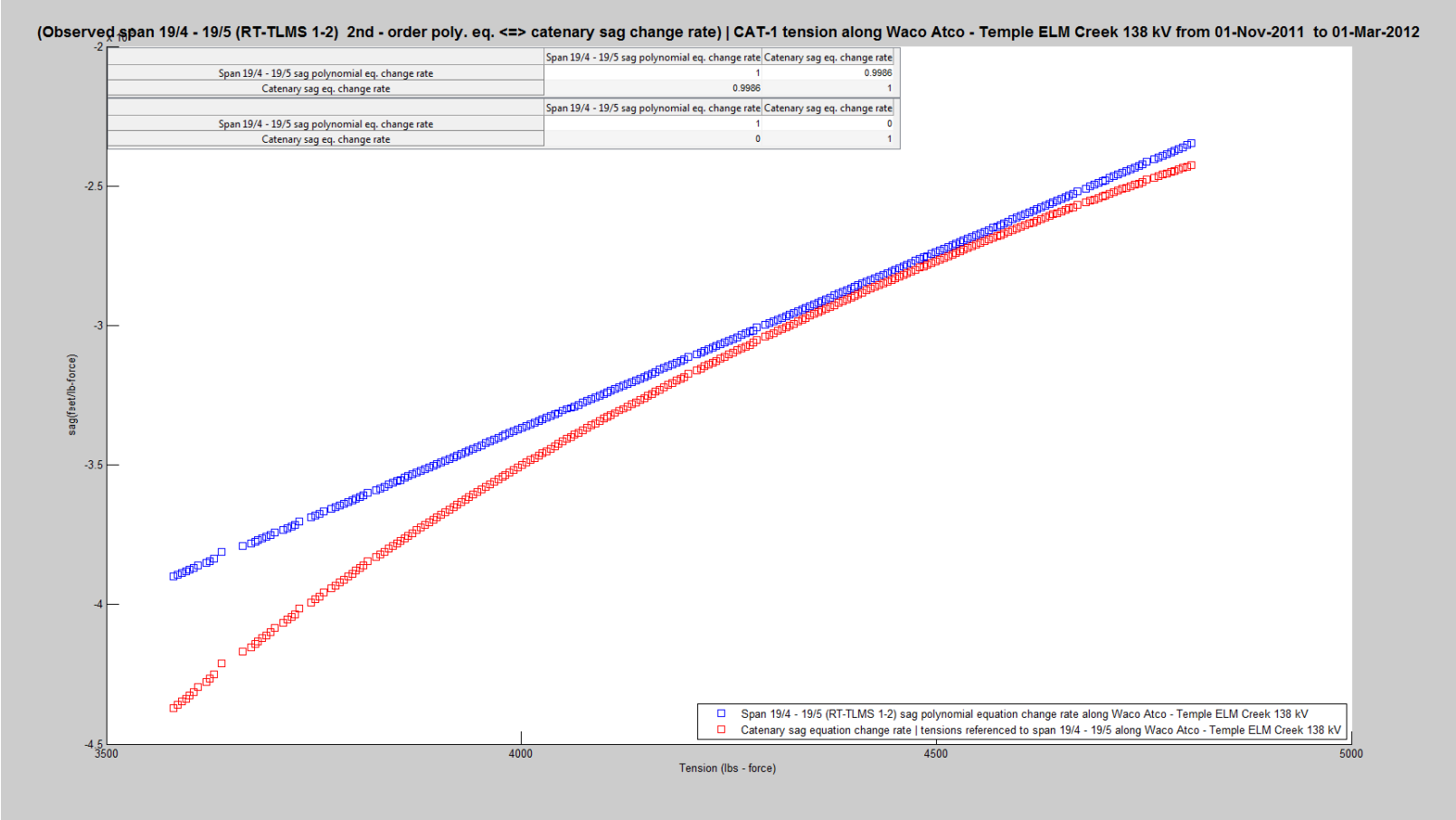
	Span 31/1 - 31/2 mean sag	Span 31/1 - 31/2 sag polynomial eq.	Catenary sag equation
Span 31/1 - 31/2 mean sag	1	0	0
Span 31/1 - 31/2 sag polynomial eq.	0	1	0
Catenary sag equation	0	0	1

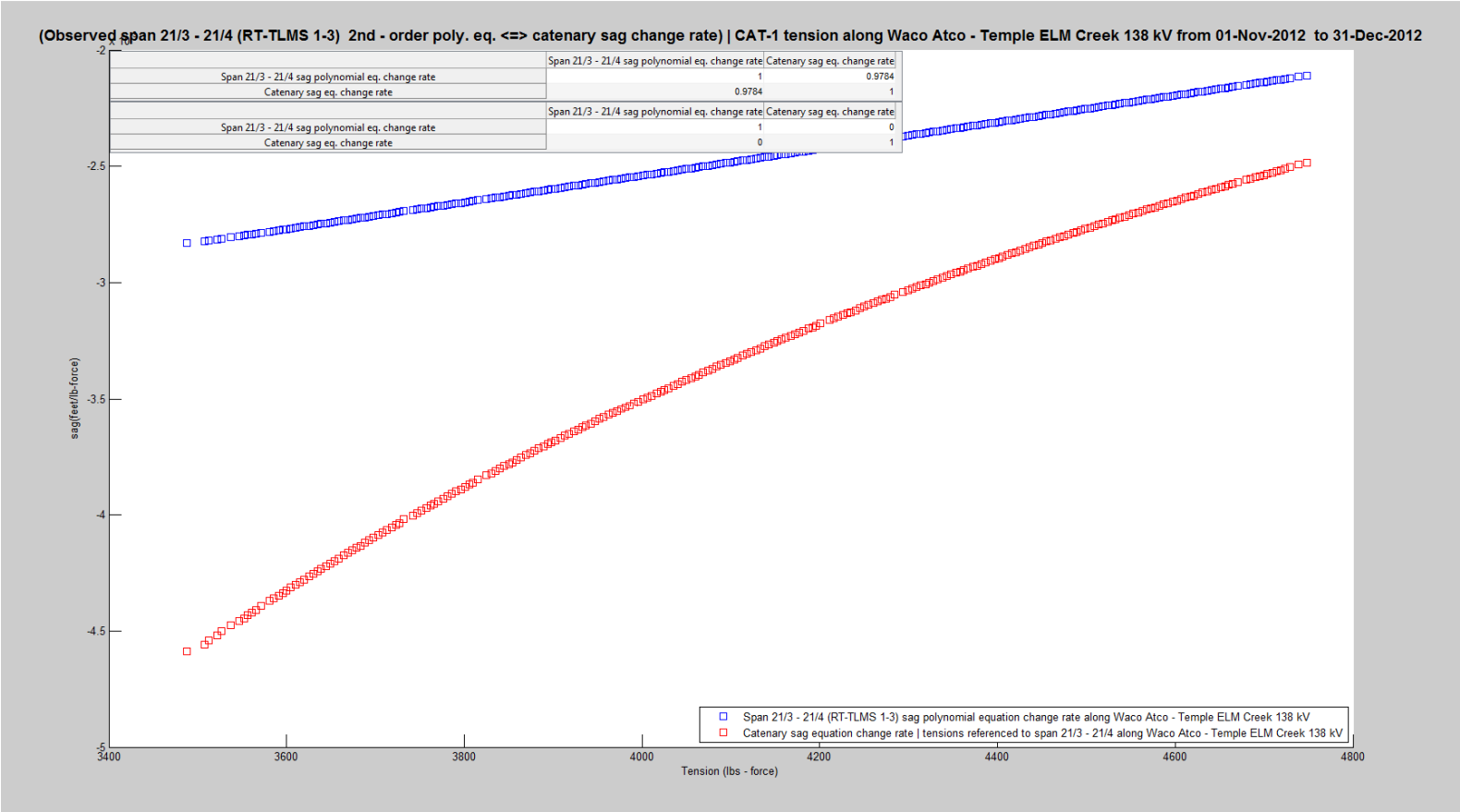

(Observed span 4/1 - 4/2 sag (Sagometer 5) sag 2nd -order polynomial eq. <=> catenary sag eq.) | CAT-1 tension along line Tradinghouse - Lake Creek East 345 kV for data collected from 15-Apr-2012 to 31-Dec-2012
Span 4/1 - 4/2 mean sag
Span 4/1 - 4/2 sag polynomial eq.
Catenary sag equation
1 0.9993 0.9984
0.9993 1 0.9993
0.9984 0.9993 1
1 0 0
0 1 0
0 0 1
sag(feet)
Tension (lbs - force)
Span 4/1 - 4/2 (Sagometer 5) mean sag along line Tradinghouse - Lake Creek East 345 kV
Span 4/1 - 4/2 sag polynomial eq. [0.000 -0.009 76.115] along Tradinghouse - Lake Creek East 345 kV
Catenary sag eq. | tensions referenced to span 4/1 - 4/2 along Tradinghouse - Lake Creek East 345 kV

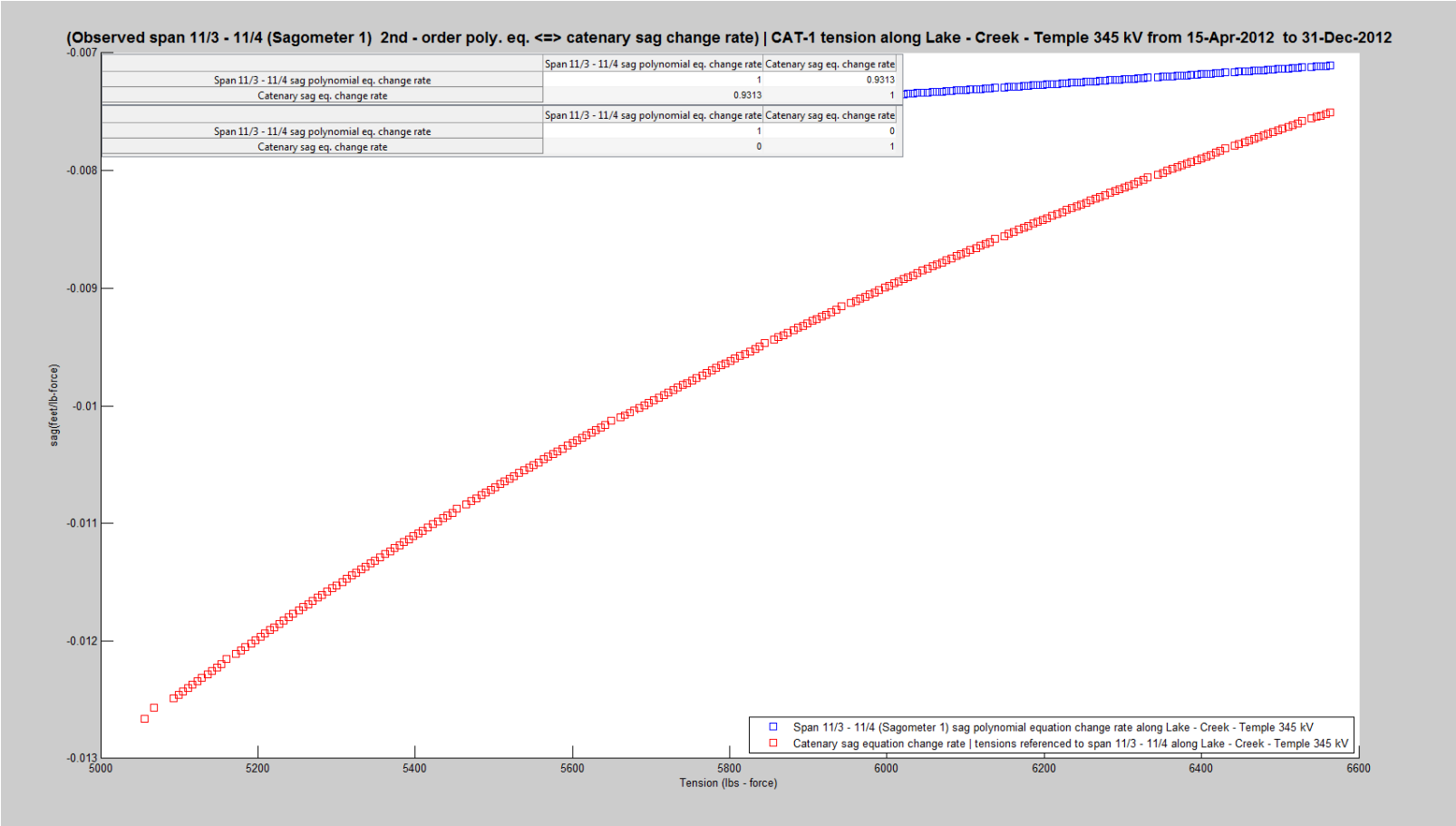
APPENDIX G

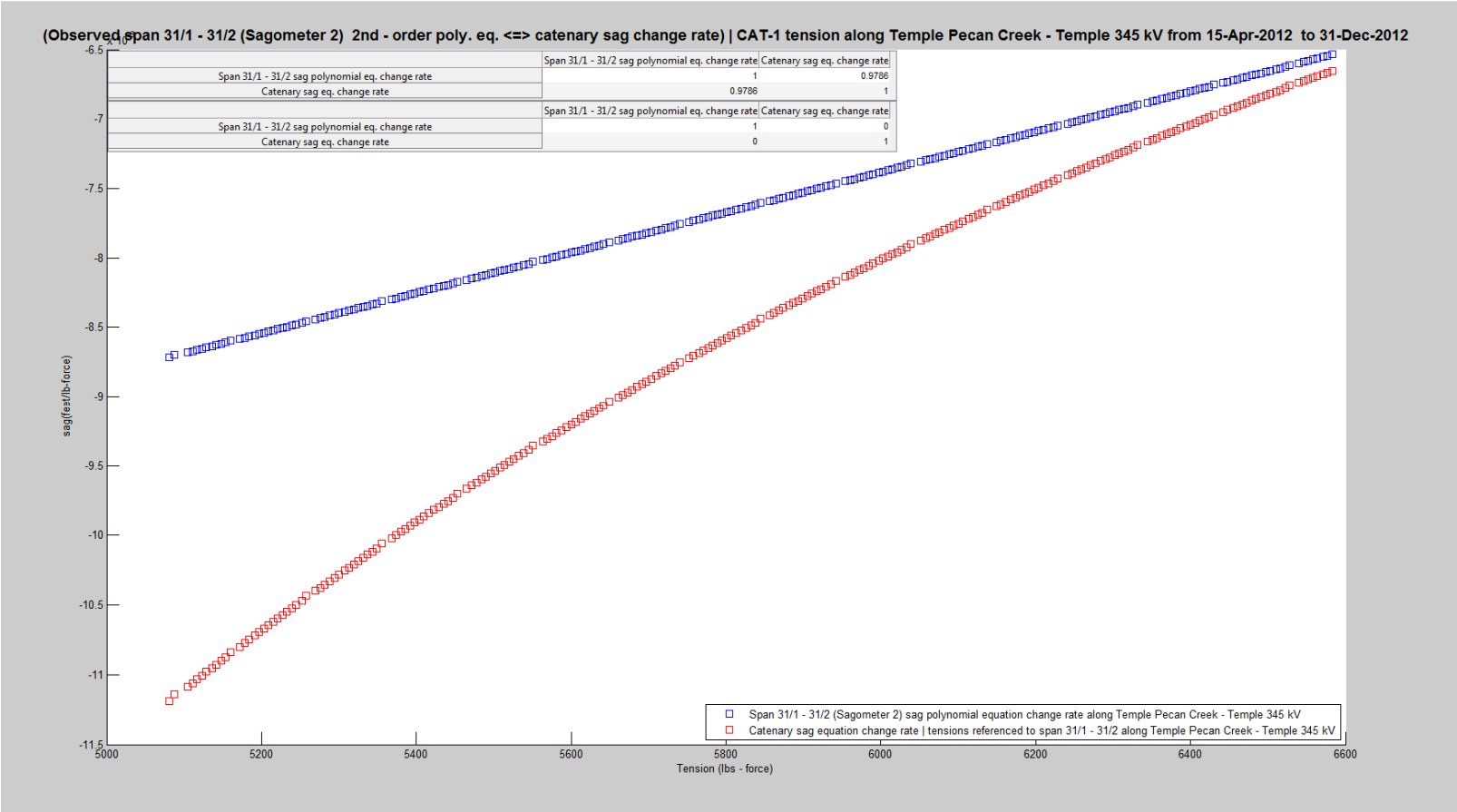
OBSERVED SAG MEAN ⇔ SAG[] CHANGE RATE| (LINE, TENSION)

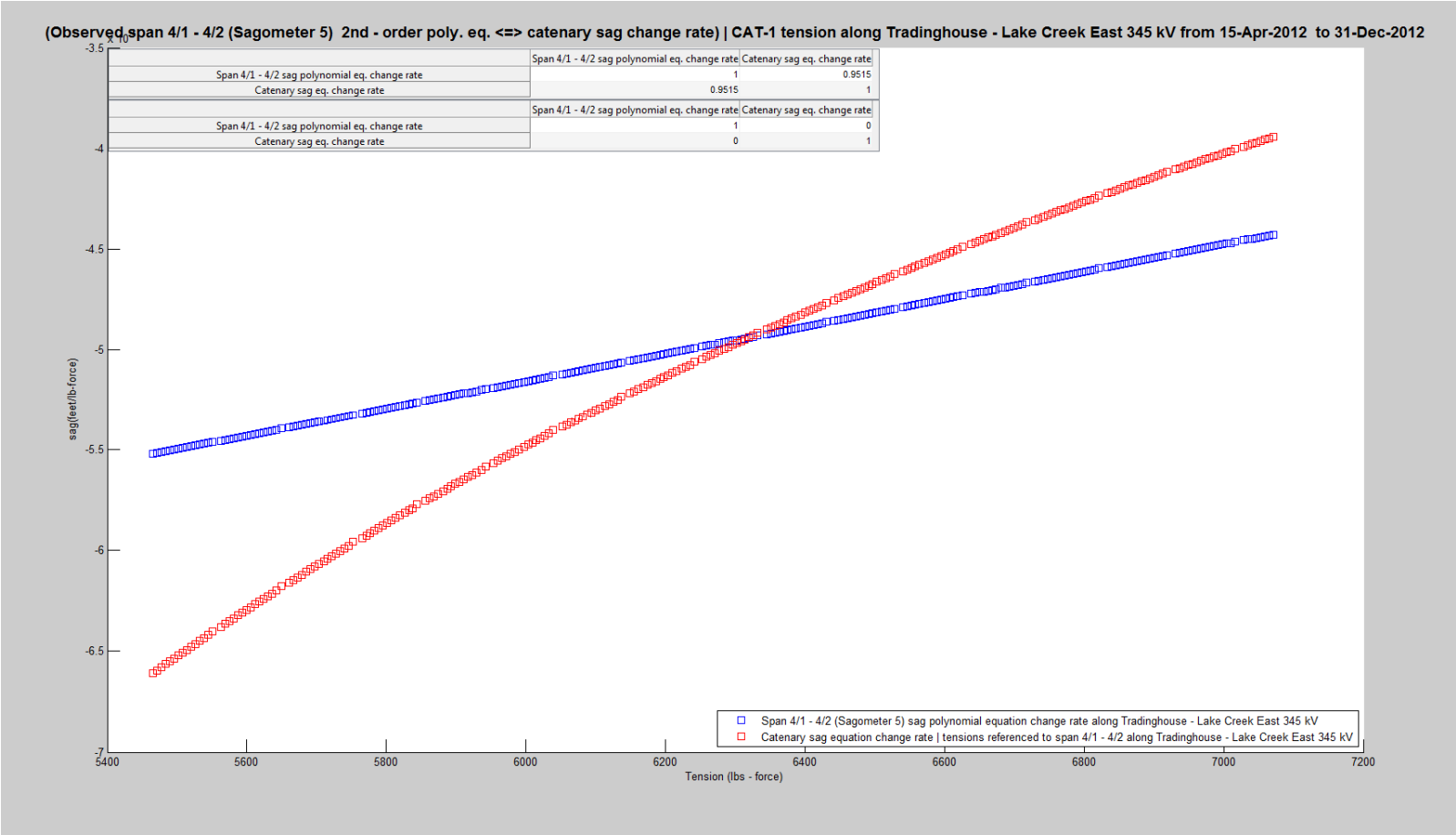

(Observed span 25/1 - 25/2 (RT-TLMS 1-1) 2nd - order poly. eq. <=> catenary sag change rate) | CAT-1 tension along Waco Atco - Temple ELM Creek 138 kV from 01-Aug-2011 to 30-Sep-2011
Span 25/1 - 25/2 sag polynomial eq. change rate
Catenary sag eq. change rate
1
0.8536
0.8536
1
1
0
0
1
sag(feet/lb-force)
-3
-3.5
-4
-4.5
-5
-5.5
3200
3300
3400
3500
3600
3700
3800
3900
4000
4100
4200
Tension (lbs - force)
Span 25/1 - 25/2 (RT-TLMS 1-1) sag polynomial equation change rate along Waco Atco - Temple ELM Creek 138 kV
Catenary sag equation change rate | tensions referenced to span 25/1 - 25/2 along Waco Atco - Temple ELM Creek 138 kV


(Observed span 19/4 - 19/5 (RT-TLMS 1-2) 2nd - order poly. eq. <=> catenary sag change rate) | CAT-1 tension along Waco Atco - Temple ELM Creek 138 kV from 01-Nov-2011 to 01-Mar-2012
Span 19/4 - 19/5 sag polynomial eq. change rate
Catenary sag eq. change rate
1
0.9986
0.9986
1
1
0
0
1
sag(feet/lb-force)
Tension (lbs - force)
-2
-2.5
-3
-3.5
-4
-4.5
3500
4000
4500
5000
Span 19/4 - 19/5 (RT-TLMS 1-2) sag polynomial equation change rate along Waco Atco - Temple ELM Creek 138 kV
Catenary sag equation change rate | tensions referenced to span 19/4 - 19/5 along Waco Atco - Temple ELM Creek 138 kV


(Observed span 21/3 - 21/4 (RT-TLMS 1-3) 2nd - order poly. eq. <=> catenary sag change rate) | CAT-1 tension along Waco Atco - Temple ELM Creek 138 kV from 01-Nov-2012 to 31-Dec-2012
Span 21/3 - 21/4 sag polynomial eq. change rate
Catenary sag eq. change rate
1
0.9784
0.9784
1
1
0
0
1
sag(feet/lb-force)
Tension (lbs - force)
Span 21/3 - 21/4 (RT-TLMS 1-3) sag polynomial equation change rate along Waco Atco - Temple ELM Creek 138 kV
Catenary sag equation change rate | tensions referenced to span 21/3 - 21/4 along Waco Atco - Temple ELM Creek 138 kV

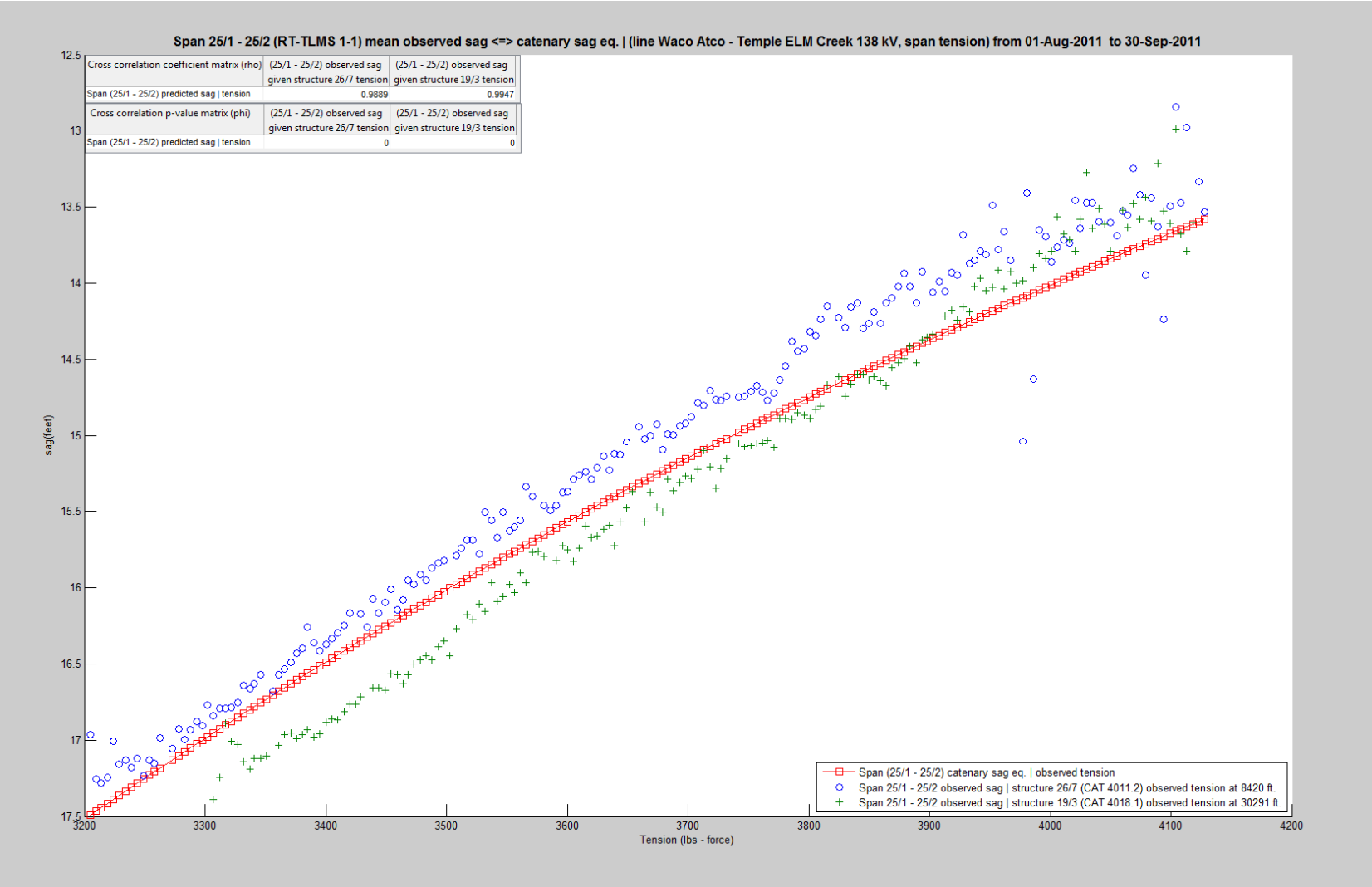

(Observed span 11/3 - 11/4 (Sagometer 1) 2nd - order poly. eq. <=> catenary sag change rate) | CAT-1 tension along Lake - Creek - Temple 345 kV from 15-Apr-2012 to 31-Dec-2012
Span 11/3 - 11/4 sag polynomial eq. change rate
Catenary sag eq. change rate
1
0.9313
0.9313
1
Span 11/3 - 11/4 sag polynomial eq. change rate
Catenary sag eq. change rate
1
0
0
1
-0.007
-0.008
-0.009
-0.01
-0.011
-0.012
-0.013
sag(feet/lb-force)
5000
5200
5400
5600
5800
6000
6200
6400
6600
Tension (lbs - force)
Span 11/3 - 11/4 (Sagometer 1) sag polynomial equation change rate along Lake - Creek - Temple 345 kV
Catenary sag equation change rate | tensions referenced to span 11/3 - 11/4 along Lake - Creek - Temple 345 kV

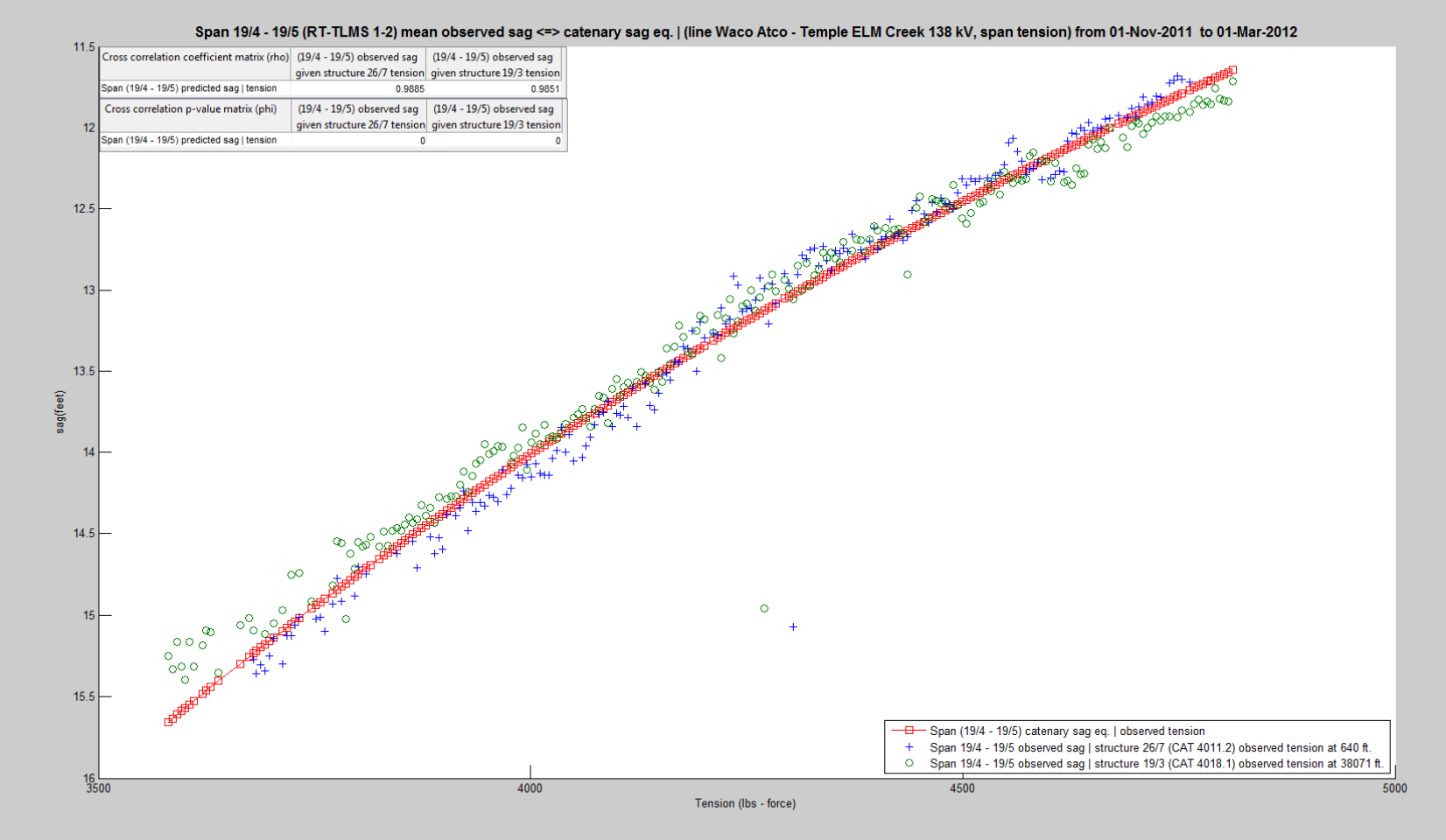

(Observed span 31/1 - 31/2 (Sagometer 2) 2nd - order poly. eq. <=> catenary sag change rate) | CAT-1 tension along Temple Pecan Creek - Temple 345 kV from 15-Apr-2012 to 31-Dec-2012
Span 31/1 - 31/2 sag polynomial eq. change rate
Catenary sag eq. change rate
1
0.9786
0.9786
1
Span 31/1 - 31/2 sag polynomial eq. change rate
Catenary sag eq. change rate
1
0
0
1
sag(feet/lb-force)
Tension (lbs - force)
Span 31/1 - 31/2 (Sagometer 2) sag polynomial equation change rate along Temple Pecan Creek - Temple 345 kV
Catenary sag equation change rate | tensions referenced to span 31/1 - 31/2 along Temple Pecan Creek - Temple 345 kV

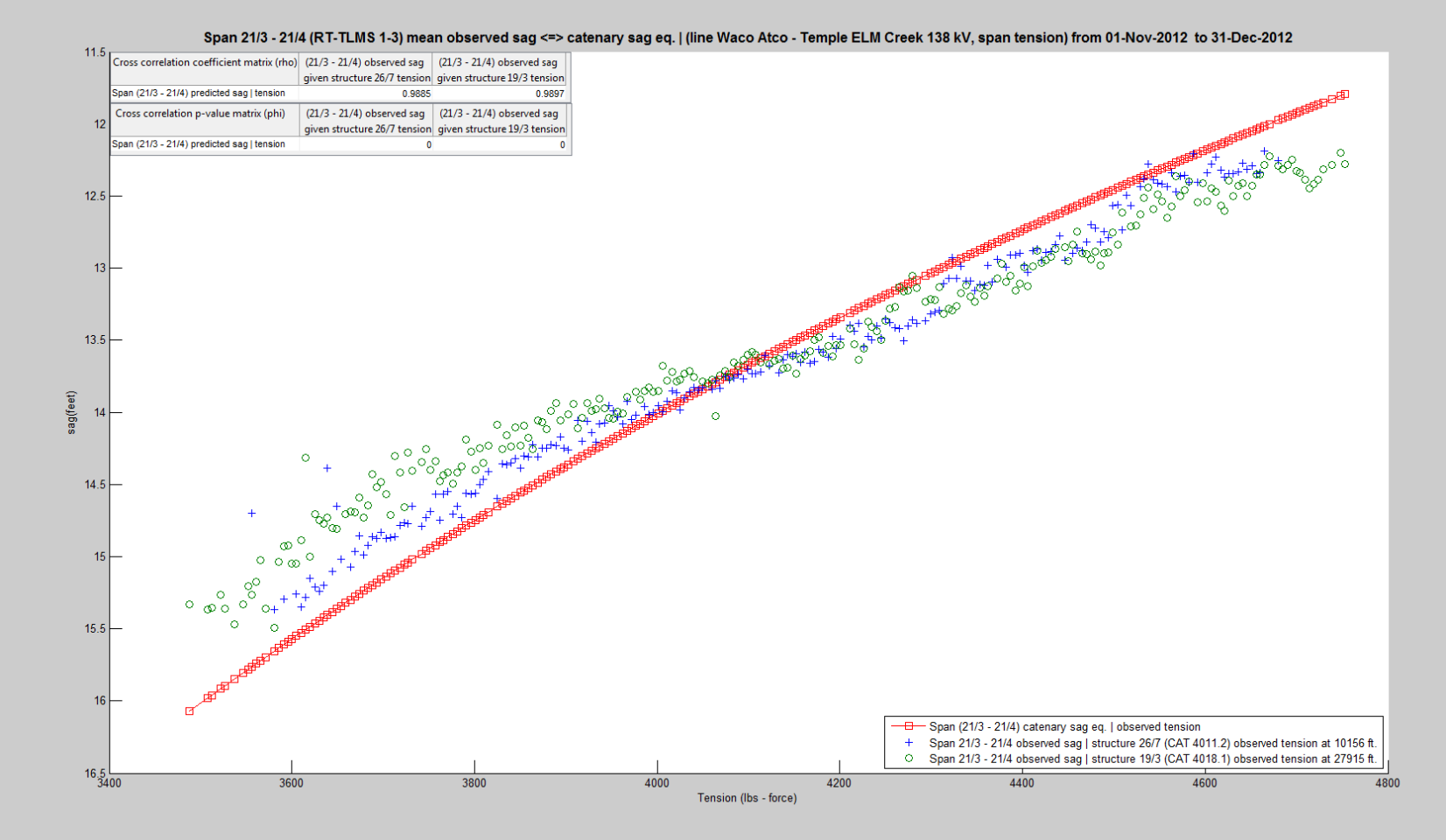

(Observed span 4/1 - 4/2 (Sagometer 5) 2nd - order poly. eq. <=> catenary sag change rate) | CAT-1 tension along Tradinghouse - Lake Creek East 345 kV from 15-Apr-2012 to 31-Dec-2012
Span 4/1 - 4/2 sag polynomial eq. change rate
Catenary sag eq. change rate
1
0.9515
0.9515
1
1
0
0
1
sag(feet/lb-force)
Tension (lbs - force)
Span 4/1 - 4/2 (Sagometer 5) sag polynomial equation change rate along Tradinghouse - Lake Creek East 345 kV
Catenary sag equation change rate | tensions referenced to span 4/1 - 4/2 along Tradinghouse - Lake Creek East 345 kV

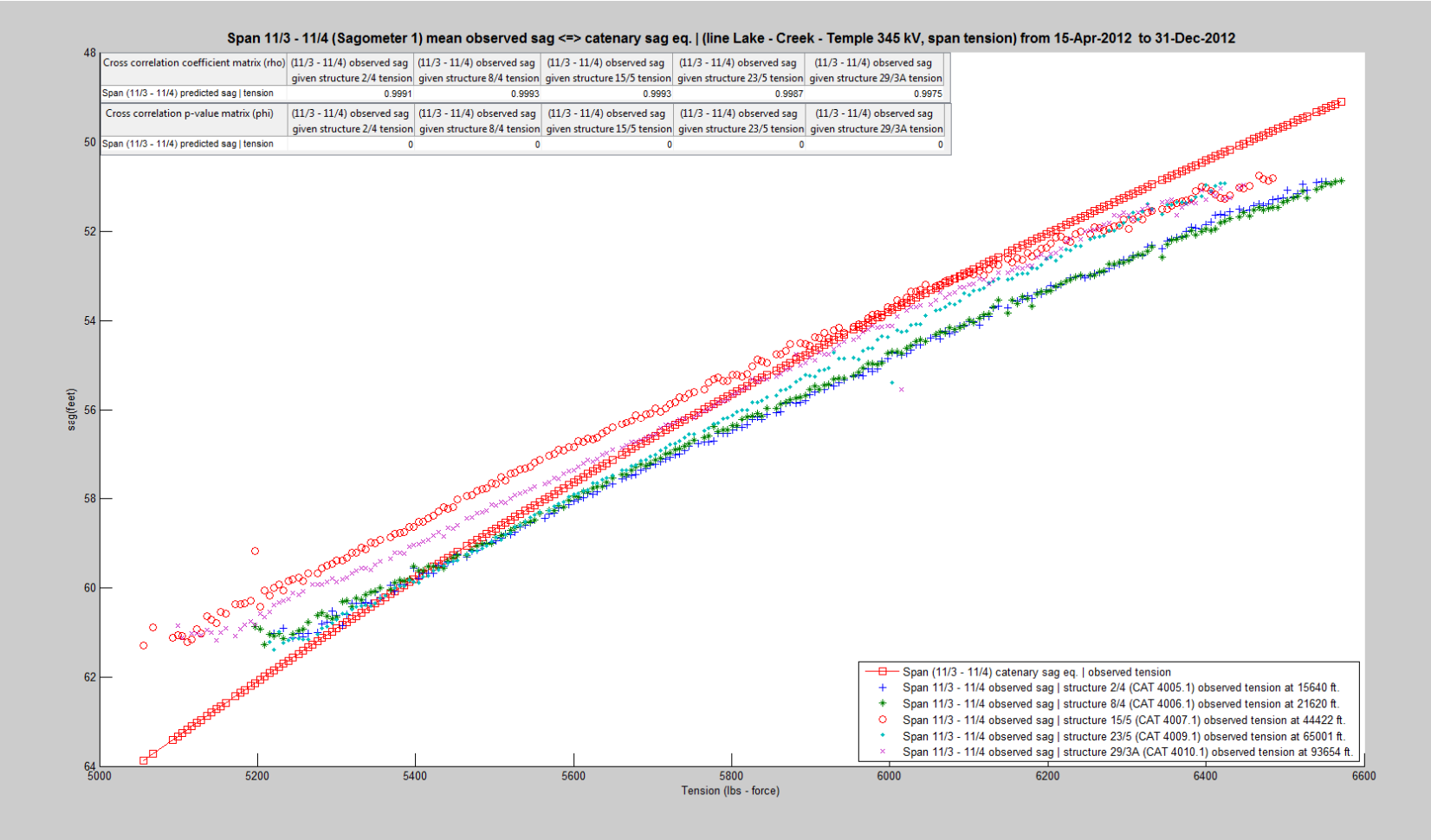
APPENDIX H

OBSERVED SAG MEAN ⇔ CATENARY SAG | (LINE, TENSION, DISTANCE)


Span 25/1 - 25/2 (RT-TLMS 1-1) mean observed sag <=> catenary sag eq. | (line Waco Atco - Temple ELM Creek 138 kV, span tension) from 01-Aug-2011 to 30-Sep-2011
Cross correlation coefficient matrix (rho)
(25/1 - 25/2) observed sag given structure 26/7 tension
(25/1 - 25/2) observed sag given structure 19/3 tension
Span (25/1 - 25/2) predicted sag | tension
0.9889
0.9947
Cross correlation p-value matrix (phi)
(25/1 - 25/2) observed sag given structure 26/7 tension
(25/1 - 25/2) observed sag given structure 19/3 tension
Span (25/1 - 25/2) predicted sag | tension
0
0
sag(feet)
Tension (lbs - force)
Span (25/1 - 25/2) catenary sag eq. | observed tension
Span 25/1 - 25/2 observed sag | structure 26/7 (CAT 4011.2) observed tension at 8420 ft.
Span 25/1 - 25/2 observed sag | structure 19/3 (CAT 4018.1) observed tension at 30291 ft.

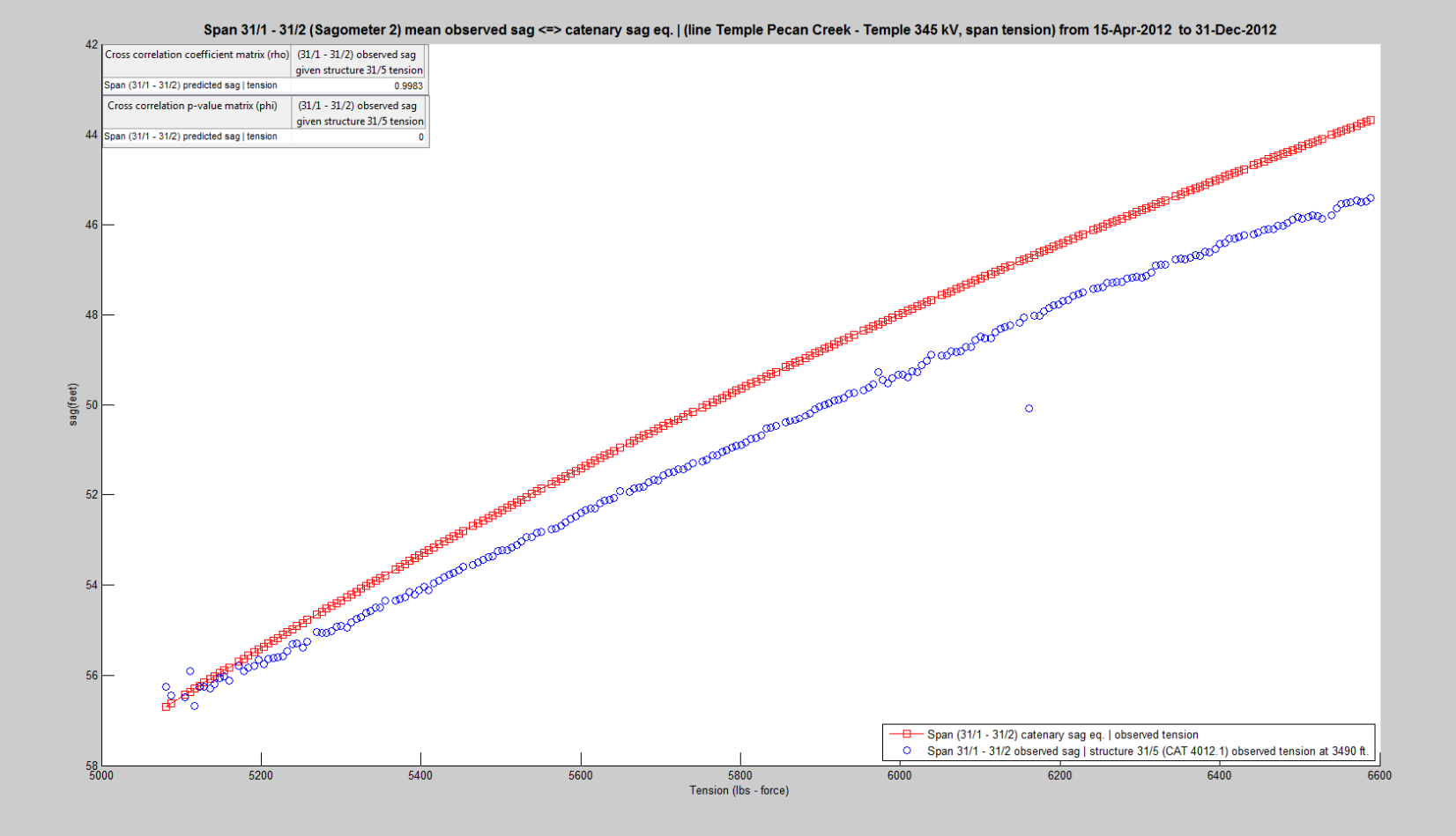

Span 19/4 - 19/5 (RT-TLMS 1-2) mean observed sag <=> catenary sag eq. | (line Waco Atco - Temple ELM Creek 138 kV, span tension) from 01-Nov-2011 to 01-Mar-2012
Cross correlation coefficient matrix (rho)
(19/4 - 19/5) observed sag given structure 26/7 tension
(19/4 - 19/5) observed sag given structure 19/3 tension
Span (19/4 - 19/5) predicted sag | tension
0.9885
0.9851
Cross correlation p-value matrix (phi)
(19/4 - 19/5) observed sag given structure 26/7 tension
(19/4 - 19/5) observed sag given structure 19/3 tension
Span (19/4 - 19/5) predicted sag | tension
0
0
sag(feet)
Tension (lbs - force)
Span (19/4 - 19/5) catenary sag eq. | observed tension
Span 19/4 - 19/5 observed sag | structure 26/7 (CAT 4011.2) observed tension at 640 ft.
Span 19/4 - 19/5 observed sag | structure 19/3 (CAT 4018.1) observed tension at 38071 ft.

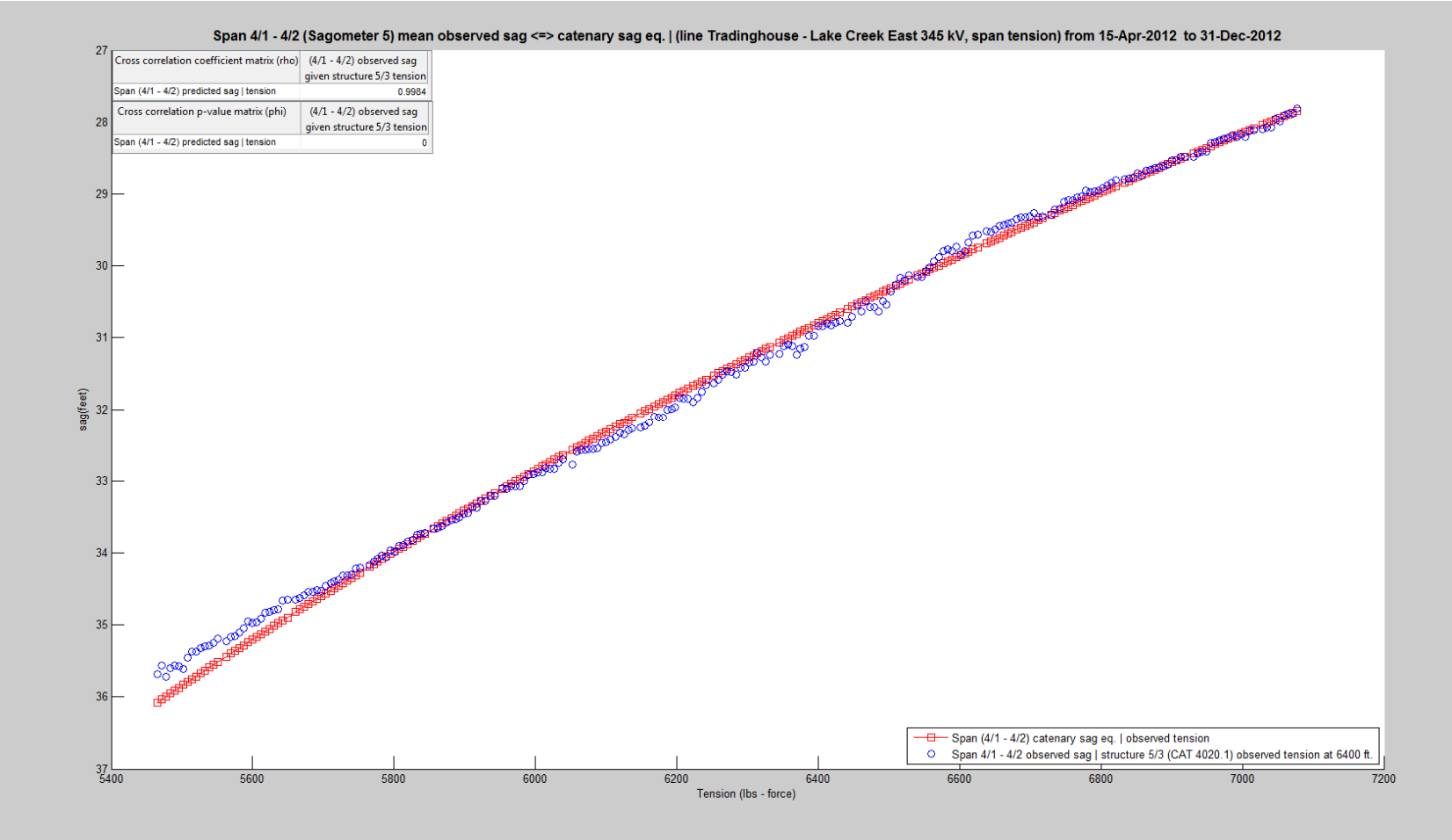

Span 21/3 - 21/4 (RT-TLMS 1-3) mean observed sag <=> catenary sag eq. | (line Waco Atco - Temple ELM Creek 138 kV, span tension) from 01-Nov-2012 to 31-Dec-2012
Cross correlation coefficient matrix (rho)
(21/3 - 21/4) observed sag given structure 26/7 tension
(21/3 - 21/4) observed sag given structure 19/3 tension
Span (21/3 - 21/4) predicted sag | tension
0.9885
0.9897
Cross correlation p-value matrix (phi)
(21/3 - 21/4) observed sag given structure 26/7 tension
(21/3 - 21/4) observed sag given structure 19/3 tension
Span (21/3 - 21/4) predicted sag | tension
0
0
sag(feet)
Tension (lbs - force)
Span (21/3 - 21/4) catenary sag eq. | observed tension
Span 21/3 - 21/4 observed sag | structure 26/7 (CAT 4011.2) observed tension at 10156 ft.
Span 21/3 - 21/4 observed sag | structure 19/3 (CAT 4018.1) observed tension at 27915 ft.



Cross correlation coefficient matrix (rho)	(11/3 - 11/4) observed sag given structure 2/4 tension	(11/3 - 11/4) observed sag given structure 8/4 tension	(11/3 - 11/4) observed sag given structure 15/5 tension	(11/3 - 11/4) observed sag given structure 23/5 tension	(11/3 - 11/4) observed sag given structure 29/3A tension
Span (11/3 - 11/4) predicted sag | tension	0.9991	0.9993	0.9993	0.9987	0.9975

Cross correlation p-value matrix (phi)	(11/3 - 11/4) observed sag given structure 2/4 tension	(11/3 - 11/4) observed sag given structure 8/4 tension	(11/3 - 11/4) observed sag given structure 15/5 tension	(11/3 - 11/4) observed sag given structure 23/5 tension	(11/3 - 11/4) observed sag given structure 29/3A tension
Span (11/3 - 11/4) predicted sag | tension	0	0	0	0	0


Span 31/1 - 31/2 (Sagometer 2) mean observed sag <=> catenary sag eq. | (line Temple Pecan Creek - Temple 345 kV, span tension) from 15-Apr-2012 to 31-Dec-2012
Cross correlation coefficient matrix (rho)
(31/1 - 31/2) observed sag given structure 31/5 tension
Span (31/1 - 31/2) predicted sag | tension
0.9983
Cross correlation p-value matrix (phi)
(31/1 - 31/2) observed sag given structure 31/5 tension
Span (31/1 - 31/2) predicted sag | tension
0
sag(feet)
42
44
46
48
50
52
54
56
58
5000
5200
5400
5600
5800
6000
6200
6400
6600
Tension (lbs - force)
Span (31/1 - 31/2) catenary sag eq. | observed tension
Span 31/1 - 31/2 observed sag | structure 31/5 (CAT 4012.1) observed tension at 3490 ft.


Span 4/1 - 4/2 (Sagometer 5) mean observed sag <=> catenary sag eq. | (line Tradinghouse - Lake Creek East 345 kV, span tension) from 15-Apr-2012 to 31-Dec-2012
Cross correlation coefficient matrix (rho)
(4/1 - 4/2) observed sag given structure 5/3 tension
Span (4/1 - 4/2) predicted sag | tension
0.9984
Cross correlation p-value matrix (phi)
(4/1 - 4/2) observed sag given structure 5/3 tension
Span (4/1 - 4/2) predicted sag | tension
0
sag(feet)
27
28
29
30
31
32
33
34
35
36
37
5400
5600
5800
6000
6200
6400
6600
6800
7000
7200
Tension (lbs - force)
Span (4/1 - 4/2) catenary sag eq. | observed tension
Span 4/1 - 4/2 observed sag | structure 5/3 (CAT 4020.1) observed tension at 6400 ft.

APPENDIX E. OPTIMIZE THE NUMBER OF DEVICES FOR A LARGE SCALE INSTALLATION

1. Optimize the Number of Devices for a Large Scale Installation

1.1 Background

Transmission lines are designed to operate at a safe maximum conductor temperature to ensure that the energized conductor does not sag dangerously close to the public and also to protect the integrity of the conductor. The conductor's temperature is the net result of the heat added by electrical current losses, solar radiation and the ambient air temperature minus the cooling effects of wind. Note that it is the average temperature of the conductor, and not the spot temperature at any single point on the conductor, that controls the sag and clearance to ground. Thus, all Dynamic Line Rating systems must accurately capture the average conductor temperature for all spans within all sections and segments of a transmission line to ensure safe and reliable operation.

The average temperature of the conductor has both cross-sectional (axial) and longitudinal components. The cross-sectional temperature gradient from the core to outer surface of the conductor can be significant for an AC system. The gradient varies with the size of the conductor, the electrical load and weather conditions; the gradient is especially pronounced under high loads and low wind. Variation in the longitudinal temperature of the conductor is primarily driven by wind speed and direction, which have been extensively documented to vary randomly, substantially and continuously within sub-span distances. This random wind behavior is even more pronounced at low wind speeds, which provide the least cooling and consequently higher conductor temperatures.

There are basically two technologies available to capture the conductor's average temperature – point measurements and distributed measurements.

Since wind speed and direction can vary significantly and spatially along the corridor and over sub-span distances, accurately capturing the average temperature of the conductor would require a large number of point measurement devices, each recording the temperature at one spot on the conductor's surface. Optimization of point measurement devices was not attempted in this study since: (1) Deployment of the large number of required point measurement devices has not been shown to be economically viable. (2) Given that the reliability for any system is partially a function of the number of the devices, the overall reliability of a DLR system based on point measurements might compromise the accuracy and reliability of the output. (3) Point measurement devices will not account for the temperature gradient across the conductor's cross-section, making the determination of the true average temperature impossible.

Distributed measurement technologies alleviate this problem by providing a measurement that captures both the cross-sectional and longitudinal components of the conductor's average temperature over multiple spans without requiring a large number of sensors. The term distributed measurement means that a single measured parameter represents the average temperature of the entire universe of discreet temperatures along multiple spans of a transmission line. The mechanical tension of the conductor is one such parameter.[1]

Variations in construction types, line geometry, line hardware, etc., all play a role in determining the length of line that a measurement will represent. Proper selection of tension measurement sites must capture predominant line directions, elevations and, most importantly, the distribution of wind speeds and directions along the line. The allocation and location of tension-measuring equipment (loadcells) must be adequate to capture the variability of the weather conditions along the line. Practice has dictated that a density of approximately four loadcells per 20 miles is sufficient to provide accurate results in most cases (an unusually large number of line angles and/or deadend structures on a line will increase the number of loadcells required). For this project, measuring equipment deployment was based on approximately a 50% increase in sensor count above prior practice. This was done to provide enough additional data points to be able to determine how many individual loadcell measurements could be removed while still preserving a desired accuracy.

1.2 Results and Benefits

The original scope of the study included determining the minimum number of sensors required to dynamically rate a transmission conductor. The original scope was extended to also look at the percentage of time that individual loadcells were the limiting element in maintaining the 1 ^{o}C and 2 ^{o}C accuracies with the objective being to see if individual loadcells dominated the results. Both objectives were met.

The temperature accuracies of 1 ^{o}C and 2 ^{o}C were chosen based on the following:

- The minimum temperature accuracy is a function of the measurement accuracy of the device being used to determine the average conductor temperature (averaged longitudinally and axially) and the geometry of the line being measured. All DLR devices will have some degree of measurement error. As stated in CIGRÉ 498, the best accuracy from existing devices is about 1 to 1.5 ^{o}C. While some DLR devices and methods will yield poorer temperature accuracies, we have found tension-based measurements to fall in this best of class range.
- A range between 1 ^{o}C and 2 ^{o}C temperature accuracy corresponds to approximately a one-inch sag error on a typical ruling span at maximum operating temperature. For example, a ruling span of Drake double-bundle conductor at 90 ^{o}C, which corresponds to the 345kV voltage class in the study, has a sag error of 0.72 inches at 1 ^{o}C and 1.44 inches at 2 ^{o}C.

Optimizing loadcell placement with a goal of minimizing average conductor temperature error to between 1 ^{o}C and 2 ^{o}C makes the best use of the individual sensor's (loadcell) accuracy as well as minimizes the potential sag error.

The statistics gathered in this study on the number of sensing points (loadcells) required shows that previously developed guidelines using approximately four sensing points per 20 miles were correct. More specifically, this study demonstrated that for segments that were greater than nine miles in length, one loadcell per five miles was required to provide a 2 ^{o}C or less error. In segments that were less than nine miles in length, a minimum of two loadcells were required to provide a 2 ^{o}C or less error. In all cases, the statistics show that segments were over-instrumented or correctly instrumented, rather than under-instrumented.

The data was examined for evidence of one loadcell consistently limiting the overall rating of the line. Ten of the 14 monitored segments showed little or no evidence of a particular loadcell consistently limiting the line. All of the four segments where one loadcell significantly dominated the results were short segments with only two loadcells deployed. Except for one loadcell on the Bell County – Salado line, none of the loadcells always limited a line. Because the limiting loadcells in the majority of the segments were well distributed and/or not always limiting, the concept of monitoring a "critical span" was not supported in this real world demonstration project.

Seasonal and system drift effects were investigated over the 15 months of collected data on a segment basis (see "Seasonal Trends" graphs in the Appendix). Seasonal influence on the minimum required number of loadcells was limited and difficult to discern from the data, with the average number of loadcells needed within a year typically not varying by more than 10% to 15%. Future deployment of loadcells only needs to consider the seasonal and monthly variation as a secondary influence on specifying the minimum number of loadcells deployed.

1.3 Optimize the Number of Devices for a Large-Scale Installation

1.3.1 Scope

The scope of the study consisted of three phases, which are described below.

Phase 1. Development of tools to process raw data into data sets

Scope for Phase 1

Data was collected from eight transmission lines broken into 15 segments (two of the lines had multiple line taps). ICW software generated conductor temperature and rating calculations for each segment at 10-minute intervals for 24 months.

Each month the raw data set was processed to generate a statistical analysis of the variance of the standard deviation of conductor temperature over each of the monitored lines. In order to speed up the processing of this large amount of data, an Excel or VB application was developed that processed the data and generated a monthly data set.

Due to field collection issues, 17 months of data were collected instead of the planned 24 months.

Phase 2. Data Collection and Processing

Scope for Phase 2

The application developed in Phase 1 was used to process the raw data every month to create analysis data sets.

Phase 3. Analysis of Study Data Sets and Final Report

Scope for Phase 3

The data sets created in Phase 2 were used to determine what minimum number of loadcells would be required to maintain a given maximum delta of conductor temperatures between the limiting and next limiting loadcell. Once this minimum threshold was established, it was possible to identify how many elements could be eliminated from the system before rating accuracy was affected.

The statistics compiled on a segment-by-segment basis were then combined into averages by groups of voltage class and conductor type. That information was used to estimate the density of equipment placement required to maintain a given fault-tolerant confidence level in ratings accuracy for future Smart Grid expansions in the region, on lines of a given group class.

In looking at ways to group statistics, overall averages of months with sufficient data and a monthly trend by voltage class were investigated. The majority of conductors were Drake ACSR with only one segment, Elm Mott – Bosque, being Grosbeak ACSR. Because most of the conductors were the same conductor type, the major distinction was by voltage classification, with 138 kV being single-bundle and the 345 kV being double-bundle conductors. This report looks at the average number of required loadcells broken up by these two voltage classes.

In addition, while reviewing results at a final draft report meeting in December 2012, the Oncor team requested that the study be expanded to look at whether particular loadcell(s) dominated being the limiting element in determining the loadcells required.

1.4 Task Execution

Temperature Accuracy as a function of Sag Error

The temperature accuracies of 1 ^{o}C and 2 ^{o}C were chosen as optimization targets.

A sag error analysis for the three types of conductors deployed in the study lines shows that approximately a one-inch sag error results in the range of 1 ^{o}C and 2 ^{o}C temperature accuracy. Tables 1 to 3 show the results of this analysis.

Table 1 is based on average ruling span length for the 345 kV voltage class with Drake conductors, Table 2 is based on the average ruling span length of the 138 kV class conductors with a Drake conductor, and Table 3 is based on average ruling span length of the Elm Mott – Bosque line with a Grosbeak conductor.

Temperature Error (^oC)	Sag Error (in)
1	0.72
-1	-0.6
2	1.44
-2	-1.32

Table 1: Calculated sag errors for 345 kV sections (Drake with a 1,086-ft ruling span at 90 ^oC maximum operating temperature).

Temperature Error (^oC)	Sag Error (in)
1	0.48
-1	-0.48
2	0.96
-2	-1

Table 2: Calculated sag errors for 138 kV sections (Drake with a 582-ft ruling span at 90 ^oC maximum operating temperature).

Temperature Error (^oC)	Sag Error (in)
1	0.36
-1	-0.48
2	0.84
-2	-0.84

Table 3: Calculated sag errors on the Elm Mott – Bosque 138 kV line (Grosbeak with a 537-ft ruling span at 90 ^oC maximum operating temperature).

Development Tools, data collection and processing

A software program was developed to extract raw 10-minute-interval data and organize the conductor temperature data for each monitored conductor by loadcell. This data was collated per segment by month for conductor temperature accuracy levels of 1 ^{o}C and 2 ^{o}C.

From this data the following parameters were calculated by the program: Maximum Conductor Temperature (MaxCT), Temperature Target Range (TargetRange), Number of Loadcells within range of accuracy (WithinRange) and Number of Loadcells Needed (LCNeeded). In addition, the rankings of loadcell temperature measurements were added to be able to investigate which loadcells were dominating the results. Table 4 shows an example of data extracted and calculated by the program. The next section talks about how these parameters are used in analysis.

DATE_TIME	LC 1 CT	LC 2 CT	LC 3 CT	LC 4 CT	MaxCT	TargetRange	WithinRange	LCNeeded	LC 1 Rank	LC 2 Rank	LC 3 Rank	LC 4 Rank
8/1/2011 0:00	29.6	34.1	30.2	33.0	34.1	32.1	2	3	4	1	3	2
8/1/2011 0:10	29.3	31.2	30.7	30.7	31.2	29.2	4	1	4	1	3	2
8/1/2011 0:20	28.8	30.9	30.2	30.6	30.9	28.9	3	2	4	1	3	2
8/1/2011 0:30	28.7	30.8	29.9	30.0	30.8	28.8	3	2	4	1	3	2
8/1/2011 0:40	28.4	30.4	29.6	30.6	30.6	28.6	3	2	4	2	3	1
8/1/2011 0:50	28.4	30.4	29.6	30.9	30.9	28.9	3	2	4	2	3	1
8/1/2011 1:00	28.3	30.4	29.6	30.7	30.7	28.7	3	2	4	2	3	1
8/1/2011 1:10	28.3	30.2	29.3	30.4	30.4	28.4	3	2	4	2	3	1
8/1/2011 1:20	28.1	30.0	29.2	30.0	30.0	28.0	4	1	4	1	3	2
8/1/2011 1:30	28.1	29.9	28.9	30.0	30.0	28.0	4	1	4	2	3	1
8/1/2011 1:40	27.8	29.8	28.8	30.0	30.0	28.0	3	2	4	2	3	1
8/1/2011 1:50	27.8	29.5	28.6	29.7	29.7	27.7	4	1	4	2	3	1
8/1/2011 2:00	27.7	29.6	28.6	29.6	29.6	27.6	4	1	4	1	3	2
8/1/2011 2:10	27.6	29.6	28.6	29.4	29.6	27.6	3	2	4	1	3	2
8/1/2011 2:20	27.6	29.5	28.5	29.4	29.5	27.5	4	1	4	1	3	2

Table 4: Example of extracted and calculated data from raw 10-minute-interval data for a segment by the program developed in Phase 1.

Analysis

To determine the number of loadcells needed at a specific temperature accuracy, the calculated conductor temperatures from each loadcell were ranked from coldest to hottest. After ranking, the number of loadcells from the coldest to hottest are counted until the calculated conductor temperature is within the specified temperature accuracy Target Range as shown in Table 4. Target Range is determined by using the maximum conductor temperature for each time stamp minus the temperature accuracy of 1 ^{o}C and 2 ^{o}C.

For example, as shown in Figure 1 and the highlighted row in Table 4, the temperature measurements from lowest to highest were 29.6 ^{o}C at LC 1, 30.2 ^{o}C at LC 3, 33.0 ^{o}C at LC 4, and 34.1^{o}C at LC 2. The maximum conductor temperature measurement was 34.1 ^{o}C at LC 2, and thus for a 2 ^{o}C accuracy the first measurement that falls above the 32.1^{o}C threshold determines the number of loadcells needed ('LCNeeded' in Table 4). The measurement at LC 4 is the first loadcell that falls above the threshold and

the third loadcell in the ranked list ('LC 3 Rank' in Table 4). Therefore the number of loadcells needed (LCNeeded) is three. This calculation was done for each 10-minute time stamp for the duration of the study.

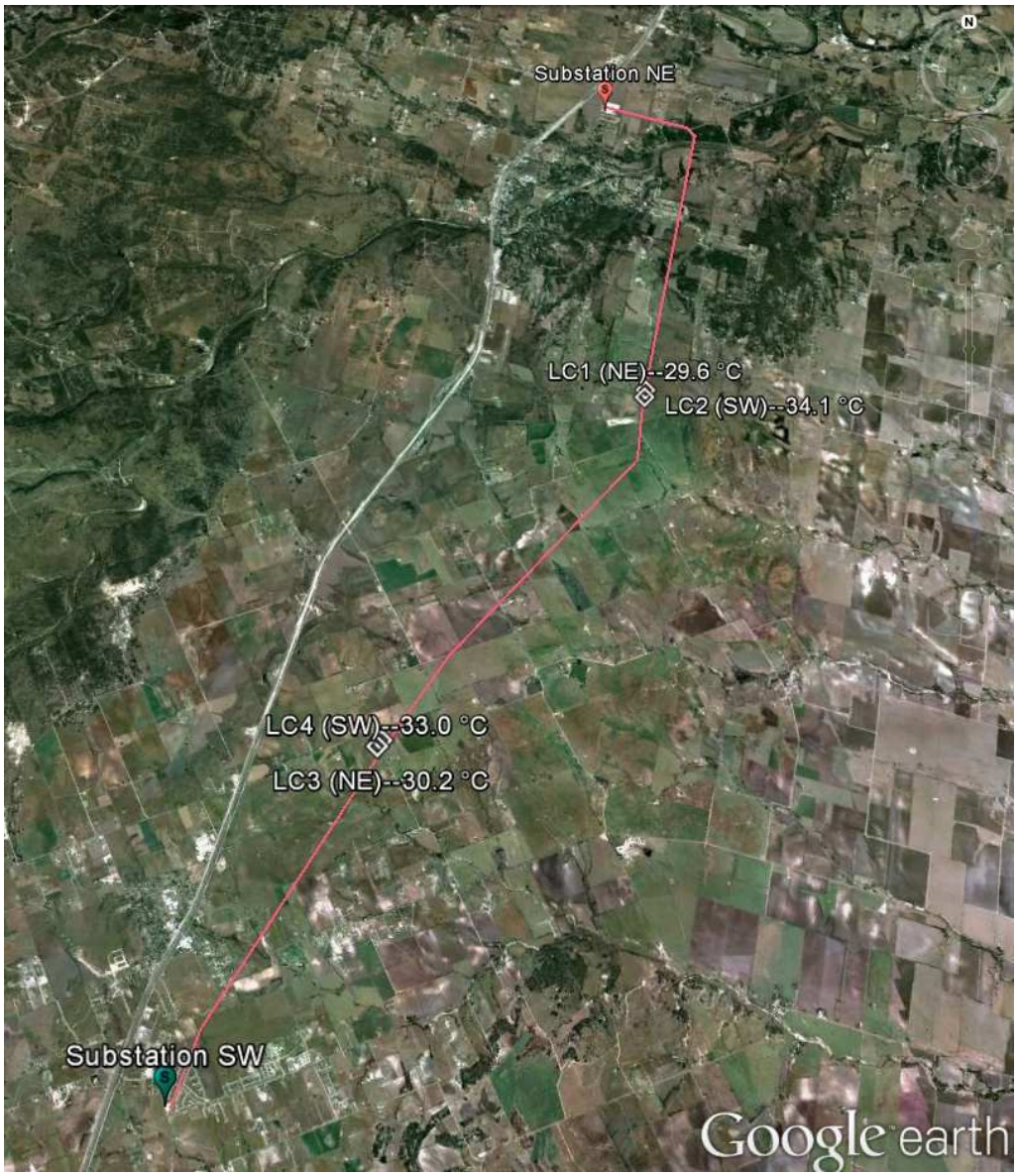


Figure 1: Configuration of a four-loadcell segment with corresponding conductor temperature measurements.

A computer program was developed to compile and calculate additional statistics from raw data output files. The statistics were compiled on a monthly basis per segment for August 2011 through October 2012 using the temperature accuracy levels of 1 ^{o}C and 2 ^{o}C.

Monthly analysis was chosen for statistics for two reasons. The data was received as monthly files, and a monthly level of granularity provided enough information to look at seasonal influences and other long-term trends. Data was filtered out if any of the loadcells of a segment had invalid tension readings, since tension is used to calculate conductor temperature.

An example of monthly collated statistics based on the number of loadcells needed (LCNeeded) is shown in Table 2. Statistics include: Count (COUNT), Average Fractional Number of Loadcells Needed (Ave), Standard Deviation (STDP), Maximum Loadcells Needed (MAX) and Minimum Loadcells Needed (MIN). In addition, the monthly Miles per Average Number of Loadcells (Miles/LC) was calculated by taking the Average and dividing by the Segment Length.

Segment	SAL_SON		
Voltage Class	138 kV		
Total LC	4		
Segment Length	14.45	mi	
Threshold		**1C**	**2C**
Month	**Statistics**	**LCNeeded**	**LCNeeded**
201108	**COUNT**	4460	4460
	AVE	2.54	1.57
	STDP	0.86	0.79
	Miles/LC	5.69	9.21
	MAX	4	4
	MIN	1	1
201109	**COUNT**	4303	4303
	AVE	2.507088078	1.62561004
	STDP	1.011154821	0.885740285
	Miles/LC	5.76	8.89
	MAX	4	4
	MIN	1	1
201110	**COUNT**	4464	4464
	AVE	2.238575269	1.369175627
	STDP	1.008134182	0.712408984
	Miles/LC	6.45	10.55
	MAX	4	4
	MIN	1	1
201111	**COUNT**	4284	4284
	AVE	2.202614379	1.362044818
	STDP	0.986620428	0.670066347
	Miles/LC	6.56	10.61
	MAX	4	4
	MIN	1	1

Table 5: Example of monthly collated statistics.

1.5 Results

1.5.1 Collated Statistics

Table 6 summarizes deployment configurations for the segments in the study and the amount of over-instrumentation based on standard practice. Included in the table are segment length, deployed number of loadcells, standard practice number of loadcells and deployment percentage of standard practice. "Deployed # of loadcells" value represents the actually number of loadcells deployed in the field during the study. "Standard practice # of loadcells" value represents the number of loadcells that would have normally been deployed based on length, line geometry and landscape. "Deployment % of standard practice" is the percentage of the actual number of loadcells deployed to standard practice deployment number of loadcells. A value of 150% represents 50% more loadcells deployed in the study than what would have been recommended. While the goal was to deploy approximately 150% of standard practice, as one can see in Table 6, for longer segments the deployment percentage of standard practice ranged from 150% to 200%. On the other hand, with shorter segments, because of the length of the segment, only two loadcells could be deployed, resulting in 100% deployment of standard practice. In other words, these shorter segments normally would have been recommended to have two loadcells deployed as standard practice.

Voltage Class	Segment	Length (mi)	Deployed # of loadcells	Standard practice # of loadcells	Deployment % of standard practice
345 kV	Tradinghouse-Temple Pecan Creek	36.49	6	4	150%
	Lake Creek-Temple	33.01	6	4	150%
	Tradinghouse-Lake Creek East	9.47	3	2	150%
	Tradinghouse-Lake Creek West	7.99	2	2	100%
	Temple Pecan Creek-Temple	4.44	2	2	100%
138 kV	McGregor Phillips Tap-Temple Elm Creek	17.23	5	3	167%
	Salado-Sonterra	14.45	4	2	200%
	Bosque-Rogers Hill	13.17	4	2	200%
	Jarrell East-Gabriel	11.25	3	2	150%
	Bell County-Salado	7.8	2	2	100%
	Roger Hill-Elm Mott	5.65	2	2	100%
	Waco Atco-Cottonbelt Tap	5.5	2	2	100%
	Cottonbelt Tap-Spring Valley Tap	2.5	2	2	100%
	Spring Valley Tap-McGregor Phillips Tap	2.4	2	2	100%

Table 6: Summary reference table of segments length, deployed number of loadcells, and deployment % of standard practice.

Resulting statistics are shown in Tables 4 and 5 for 1 ^{o}C and 2 ^{o}C accuracies, respectively. Statistics in the tables include fractional loadcells needed, loadcells needed and deployment percentage of loadcells needed.

Voltage Class	Segment	Fractional loadcells needed	Loadcells needed *	Deployment % of loadcells needed **
345 kV	Tradinghouse-Temple Pecan Creek	4.4	5	120%
	Lake Creek-Temple	3.9	4	150%
	Tradinghouse-Lake Creek East	2.3	3	100%
	Tradinghouse-Lake Creek West	1.2	2	100%
	Temple Pecan Creek-Temple	1.7	2	100%
138 kV	McGregor Phillips Tap-Temple Elm Creek	4.1	5	125%
	Salado-Sonterra	2.4	3	133%
	Bosque-Rogers Hill	2.8	3	133%
	Jarrell East-Gabriel	2.3	3	100%
	Bell County-Salado	2.0	2	100%
	Roger Hill-Elm Mott	1.5	2	100%
	Waco Atco-Cottonbelt Tap	1.4	2	100%
	Cottonbelt Tap-Spring Valley Tap	1.6	2	100%
	Spring Valley Tap-McGregor Phillips Tap	1.8	2	100%

Table 7: Collated statistics of loadcells, miles per loadcell and percent over-instrumented for each segment at 1 ^{o}C accuracy

Voltage Class	Segment	Fractional loadcells needed	Load cells needed *	Deployment % of loadcells needed **
345 kV	Tradinghouse-Temple Pecan Creek	2.6	3	200%
	Lake Creek-Temple	2.3	3	200%
	Tradinghouse-Lake Creek East	1.9	2	150%
	Tradinghouse-Lake Creek West	1.0	2	100%
	Temple Pecan Creek-Temple	1.4	2	100%
138 kV	McGregor Phillips Tap-Temple Elm Creek	2.9	3	167%
	Salado-Sonterra	1.5	2	200%
	Bosque-Rogers Hill	1.7	2	200%
	Jarrell East-Gabriel	1.7	2	150%
	Bell County-Salado	1.9	2	100%
	Roger Hill-Elm Mott	1.2	2	100%
	Waco Atco-Cottonbelt Tap	1.1	2	100%
	Cottonbelt Tap-Spring Valley Tap	1.3	2	100%
	Spring Valley Tap-McGregor Phillips Tap	1.5	2	100%

Table 8: Collated statistics of loadcells, miles per loadcell and percent over-instrumented for each segment at 2 ^{o}C accuracy.

"Fractional loadcells needed" was calculated as an average using all months of "Fractional Number of Loadcells Needed (Ave)" as shown above in Table 5. To account for the physical reality in deploying loadcells in whole increments, "Loadcells needed" values were rounded up to the nearest integer. The column "Deployment % of loadcells needed" was calculated as a percentage of the "Deployed # of loadcells" in Table 6 to "Loadcells needed." In tables 4 and 5, a value of 200% represents a result where on average twice the number of loadcells was deployed than what was needed. A value of 100% represents a result where the number of loadcells deployed matches the number needed.

Since the goal was to deploy approximately 50% or more loadcells than what was typically done in practice, a 150% deployment of loadcells needed represents a result meeting this goal. For 1 ^{o}C accuracy as shown in Table 7, the deployment configuration either met or exceeded standard practice. For 2 ^{o}C accuracy as shown in Table 8, all of the longer segments requiring three or more loadcells demonstrated

that deployment was 50% over what was required, while the shorter segments were correctly specified with two loadcells.

Overall, the statistics show that previous practices were correct in specifying four loadcells per 20 miles. In segments that were greater than nine miles in length with three or more deployed loadcells, one loadcell per five miles was required to provide a 2 ^{o}C or less error. In segments that were less than nine miles, a minimum of two loadcells were required to provide a 2 ^{o}C or less error.

In all cases, the statistics show that the segments were over-instrumented or correctly instrumented to be within 1 or 2 ^{o}C average conductor temperature accuracy.

1.5.2 Percentage of Time Loadcells were the Limiting Element

Ideally, given that wind, temperature and solar radiation vary along a line (especially wind), over time, each loadcell will have an approximately equal contribution in providing the limiting conductor temperature measurement within the 1°C or 2 ^{o}C temperature accuracy. Tables 6-8 summarize the results of the percentage of time that each loadcell is the limiting element for 1 ^{o}C and 2 ^{o}C, respectively. As can be discerned from the tables, the majority of segments show that no single loadcell governs all the time. Of the 14 monitored segments, 10 had well-distributed percentages of time that loadcells were the limiting element. The four exceptions were on segments that were less than five miles and only had two loadcells. These shorter segments all required two loadcells to provide a 1 ^{o}C and 2 ^{o}C temperature accuracy. While these shorter segments may be viewed to support the concept of a “critical span,” because the majority of the segments had close to equal or some distribution in loadcells being the limiting element, the concept of “critical span” does not seem to exist in this real world demonstration project. In addition, a well-engineered system requires some redundancy. Thus to meet conductor temperature measuring accuracy requirements, the results show little support for the concept of “critical span”, and for redundancy reasons two loadcells are recommended on straight segments nine miles in length or shorter.

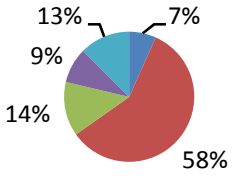
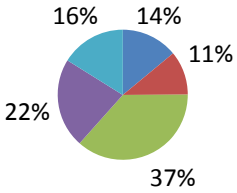
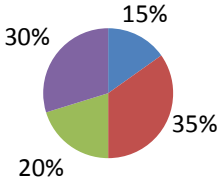
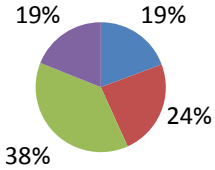
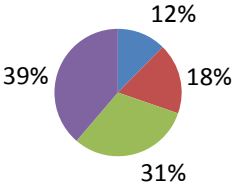
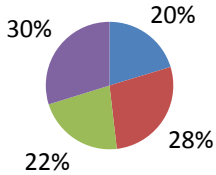
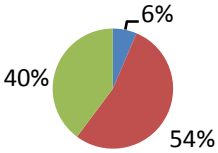
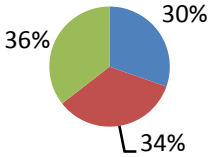
Segment	1 °C		2 °C	
	Limiting Element position	Percentage of time each load cell is in the limiting element position.	Limiting Element position	Percentage of time each load cell is in the limiting element position.
McGregor Phillips Tap-Temple Elm Creek	5		3	
Salado-Sonterra	3		2	
Bosque-Rogers Hill	3		2	
Jarrell East-Gabriel	3		2	

Table 9: Percentage of time each loadcell contributes to being the limiting element (based on loadcells needed) for 345 kV segments.

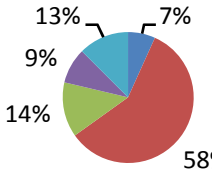
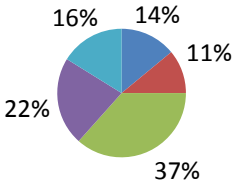
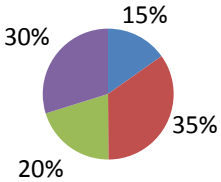
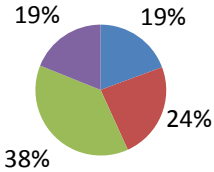
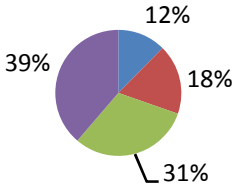
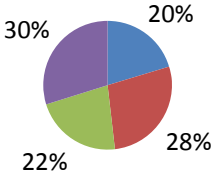
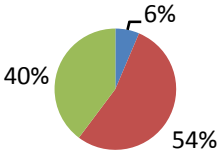
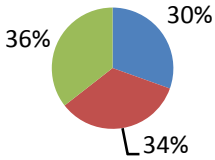
Segment	1 ºC		2 ºC	
	Limiting Element position	Percentage of time each loadcell is in the limiting element position.	Limiting Element position	Percentage of time each loadcell is in the limiting element position.
McGregor Phillips Tap-Temple Elm Creek	5		3	
Salado-Sonterra	3		2	
Bosque-Rogers Hill	3		2	
Jarrell East-Gabriel	3		2	

Table 10: Percentage of time each loadcell contributes to being the limiting element (based on loadcells needed) for 138 kV segments with three or more loadcells.

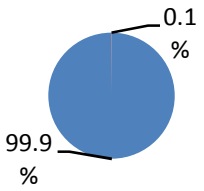
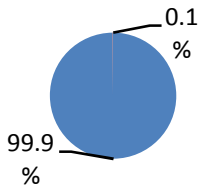
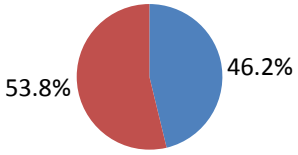
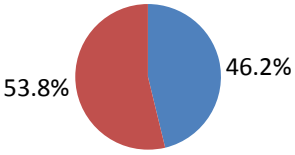
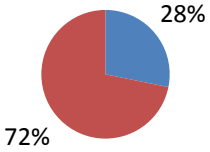
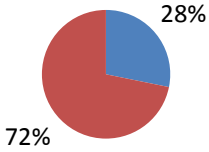
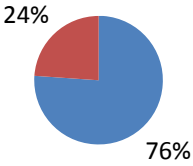
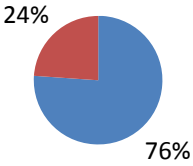
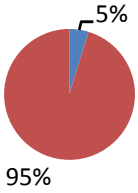
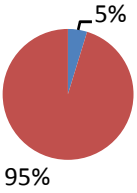
Segment	1 ºC		2 ºC	
	Limiting Element position	Percentage of time each loadcell is in the limiting element position.	Limiting Element position	Percentage of time each loadcell is in the limiting element position.
Bell County-Salado	2		2	
Roger Hill-Elm Mott	2		2	
Waco Atco-Cottonbelt Tap	2		2	
Cottonbelt Tap-Spring Valley Tap	2		2	
Spring Valley Tap-McGregor Phillips Tap	2		2	

Table 11: Percentage of time each loadcell contributes to being the limiting element (based on lolls needed) for 138 kV segments with two loadcells.

In the segments that did show one loadcell dominating the results, patterns of tree sheltering and systematic reasons were investigated and are discussed below.

Temple Pecan Creek -Temple Elm Creek (345 kV)

The cooler loadcell (SN51314) had approximately 11% of the transmission corridor lined by trees 20-40 feet high, while the warmest loadcell had less than 1% of the transmission corridor lined by trees. The higher tree-lined corridor may be creating funneling effects without sheltering, since the line is well above the trees. This funneling may be increasing local winds and thus local cooling. The loadcell SN48049 was in position 2 (hottest), 87.4% of the time.

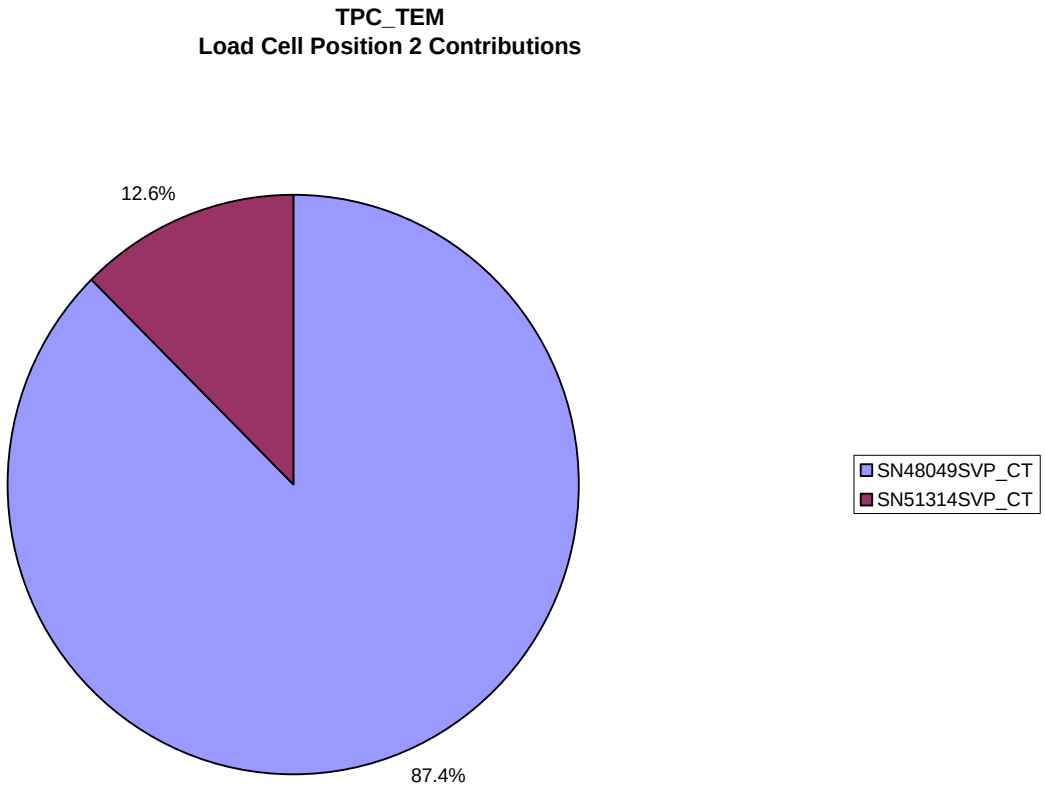


Figure 2: Temple Pecan Creek – Temple contributions of individual loadcells

Bell County - Salado (138 kV)

The cooler loadcell (SN46003) had approximately 57% of the transmission corridor lined by trees 20-40 feet high, while the warmest loadcell had 26% of the transmission corridor lined by trees. The hottest position was dominated by one loadcell 99.9% of the time, which indicates that an equipment issue may

have occurred. This loadcell was disabled from rating generation in February 2012 and may have had problems prior to being disabled, which would have biased the data. In addition, with only four months of data, a seasonal influence could have biased the data.

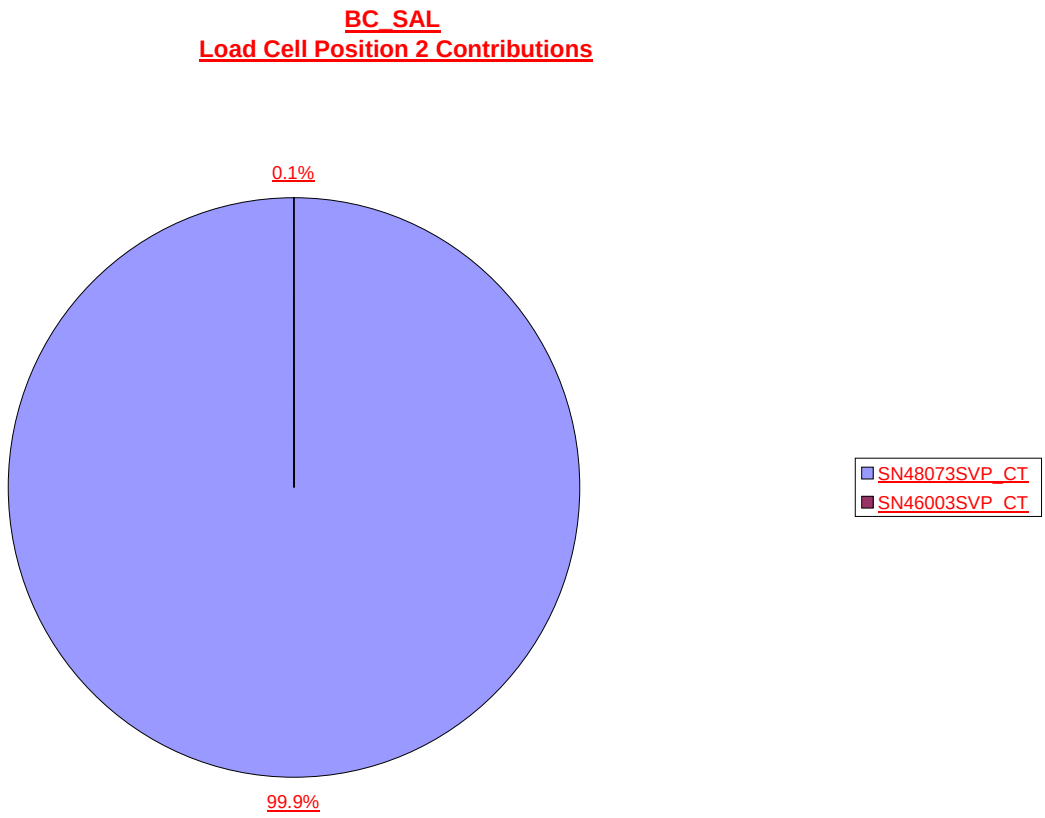


Figure 3: Bell County – Salado contributions of individual loadcells to position 2.

Cotton Belt Tap –Spring Valley Tap (138 kV)

The cooler loadcell (SN460015) had approximately 44% of the transmission corridor lined by trees 20-40 feet high, while the warmest loadcell had 61 % of the transmission corridor lined by trees. Because the sections of the transmission corridor have roughly equally amount of wooded areas, a potential explanation due to either funneling or sheltering by trees cannot fully explain the bias. The loadcell SN45238 was in position 2 (hottest) 76.1% of the time, just slightly above the bias threshold of 75%.

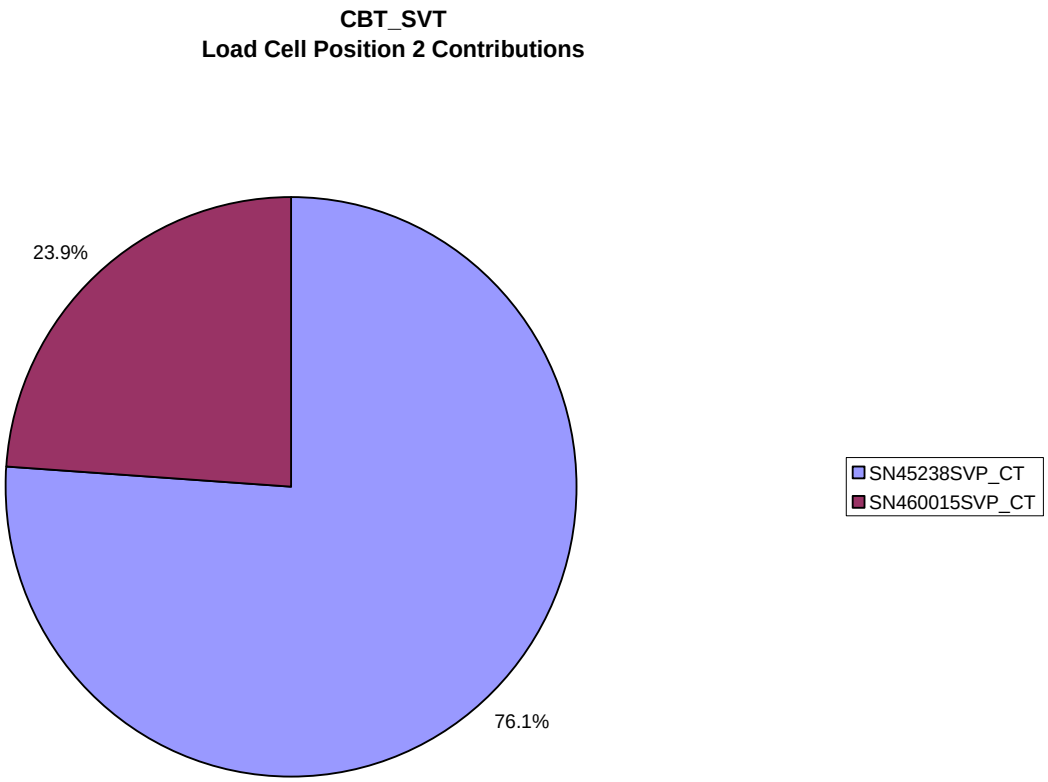


Figure 4: Cotton Belt Tap –Spring Valley Tap contributions of individual loadcells to position 2

Spring Valley Tap— McGregor Philips Tap (138 kV)

The cooler loadcell (SN460010) had approximately 65% of the transmission corridor lined by trees 20-40 feet high, while the warmest loadcell had 35% of the transmission corridor lined by trees. The higher tree-lined corridor may have had funneling effects without sheltering, since the line is generally above the tree line. This funneling may be increasing local winds and thus local cooling. The loadcell SN48076 was in position 2 (hottest) 95.3% of the time.

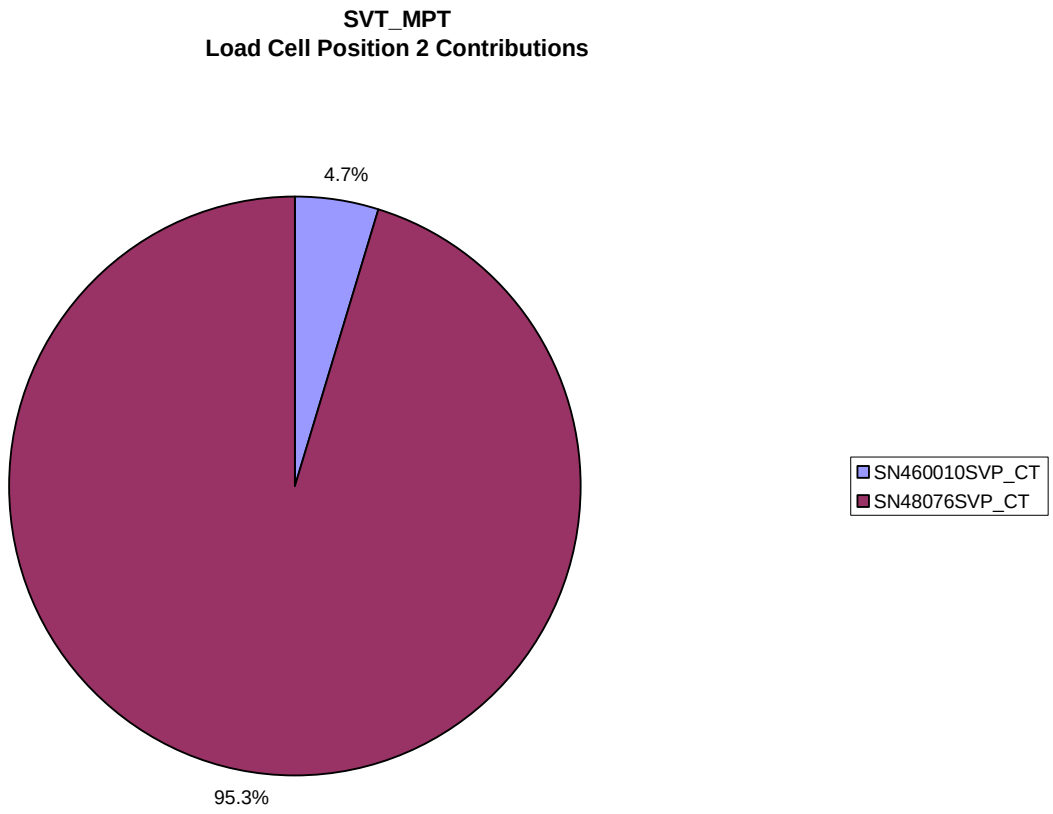


Figure 5: Spring Valley Tap — McGregor Philips Tap contributions of individual loadcells to position 2

1.5.3 Seasonal Trends

The results of monthly trends for each segment were compiled for the two accuracies (1 ^{o}C and 2 ^{o}C). There are two types of graphs:

1. Monthly trend of the Fractional Average Number of loadcells required with standard deviation (2-sigma) represented as Y error bars. Included at the top of this is the count, which represents the amount of 10-minute data available during the month. The count is useful to know in case there

were few data values available for a particular month, which could explain why the average and standard deviation would be different from other months. Figures 6 through 33 sub-charts (**a**) show the results of the monthly trends of the Average Number of loadcells. Segment Name, Voltage Class, Total Number of loadcells, Tolerance (temperature accuracy) and Segment Distance is displayed at the top of each graph.

2. Monthly trend of the Miles per Average Number of loadcells. These trends show the number of miles that each loadcell covers on average. Figures 6 through 33 sub-charts (**b**) show the results of the monthly trends of the miles per number of loadcells for each segment. Segment Name, Voltage Class, Total Number of Loadcells, Accuracy Level and Segment Distance are displayed at the top of each graph.

Both seasonal influences and system changes may affect monthly trends. Most segments with two loadcells and a few with more than two loadcells showed no seasonal variation. Segments with three or more loadcells—McGregor Phillips Tap-Temple Elm Creek, Salado-Sonterra, Jarrell East-Gabriel—show slightly more loadcells required during the warmer months and fewer during the cooler months. Bosque-Rogers Hill segment showed the opposite trend with the cooler seasons having a slightly higher number of loadcells needed. Several segments had incomplete seasonal data (Lake Creek-Temple, Tradinghouse-Temple Pecan, and Bell County-Salado), which made it difficult to assess any seasonality or system drift.

Typically the variation among monthly averages of the number of loadcells required and the miles per loadcell was approximately ±10 to 15% on segments with three or more loadcells. However, two segments had a monthly variation exceeding ±20% (McGregor Phillips Tap-Temple Elm and Bosque-Rogers Hill). On segments with two loadcells the monthly range was more variable and varied from near zero to over ±20%.

Future determination of the number of loadcells for a segment should consider monthly variation as a secondary concern. The results do not indicate any clear seasonal trends.

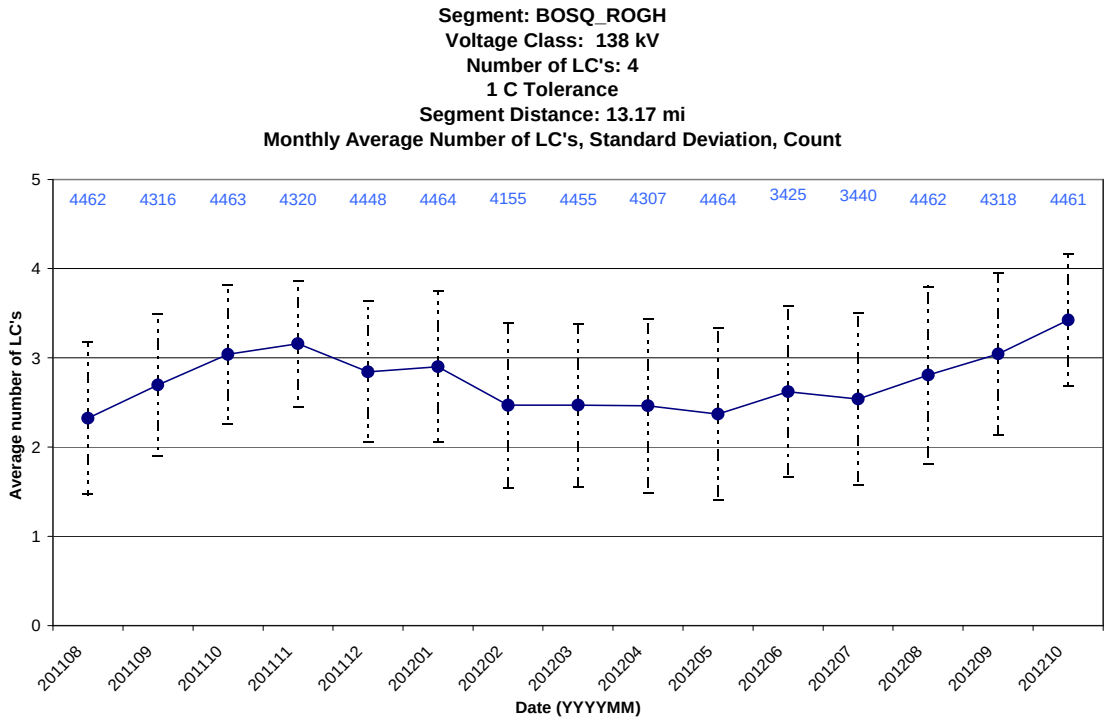


Figure 6a: Monthly Trend of number of LC's at Bosque-Rogers Hill for 1 ^{o}C accuracy.

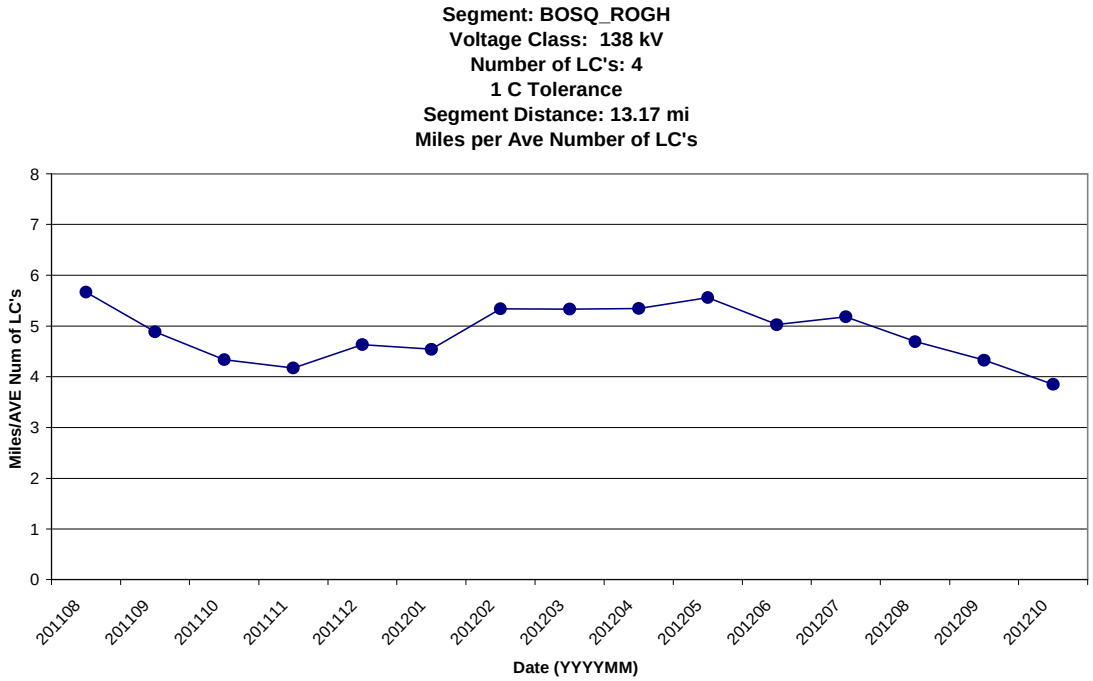


Figure 6b: Monthly Trend of Miles per average number of LC's at Bosque-Rogers Hill for 1 ^{o}C accuracy.

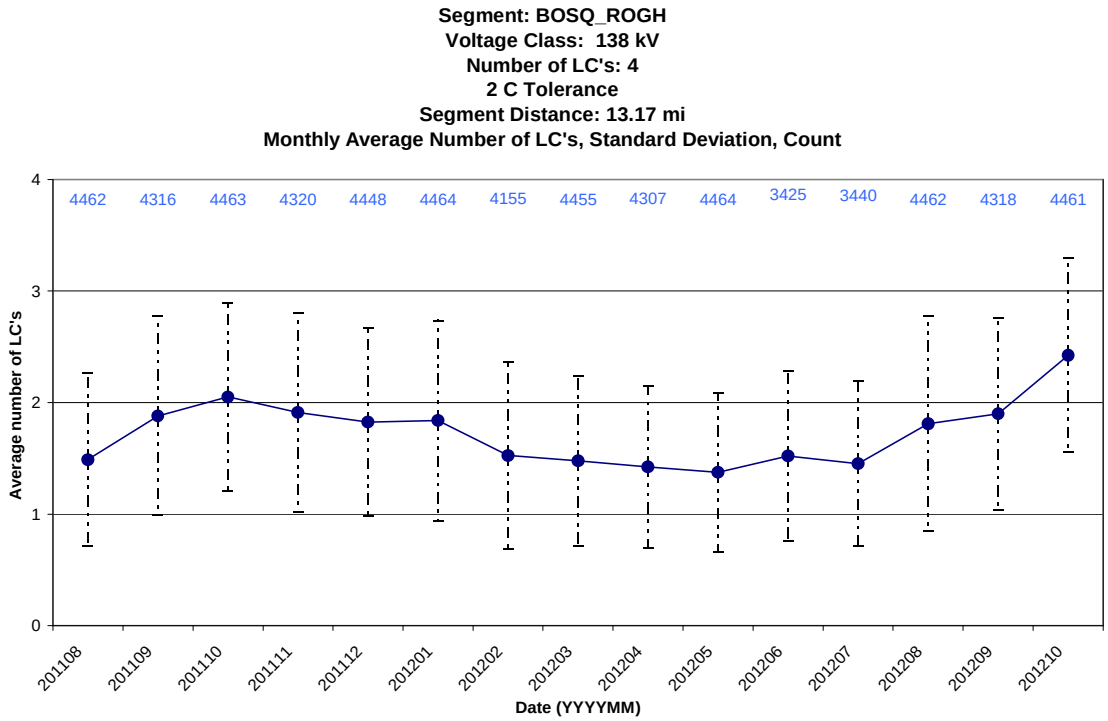


Figure 7a: Monthly Trend of number of LC's at Bosque-Rogers Hill for 2 ^{o}C accuracy.

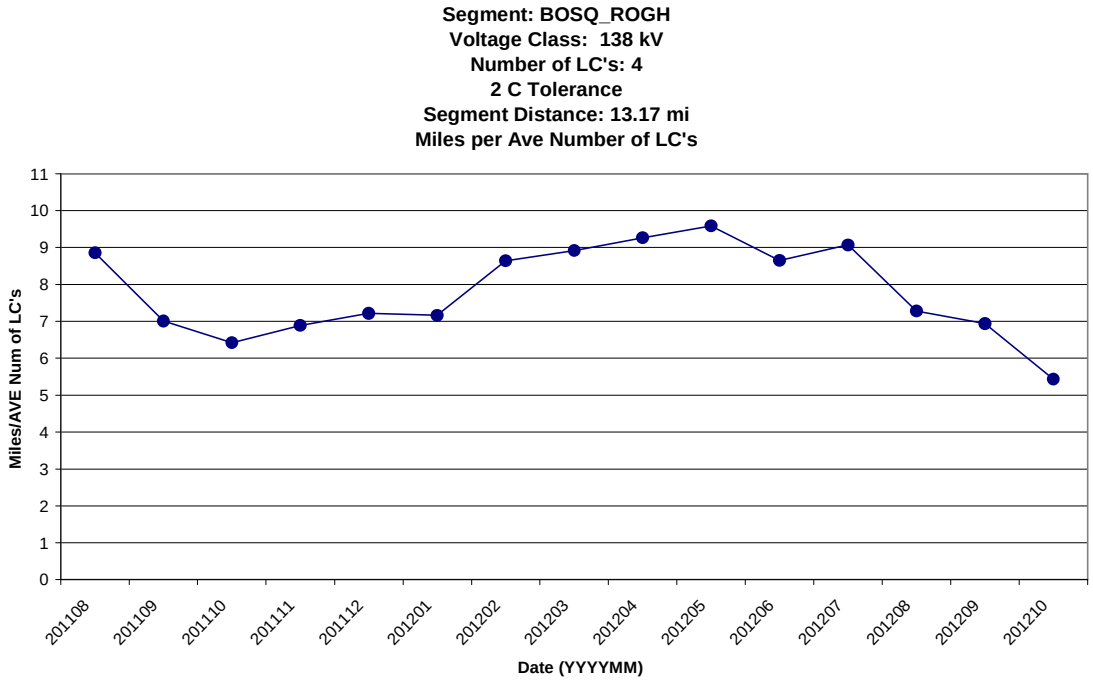


Figure 7b: Monthly Trend of Miles per average number of LC's at Bosque-Rogers Hill for 2 ^{o}C accuracy.

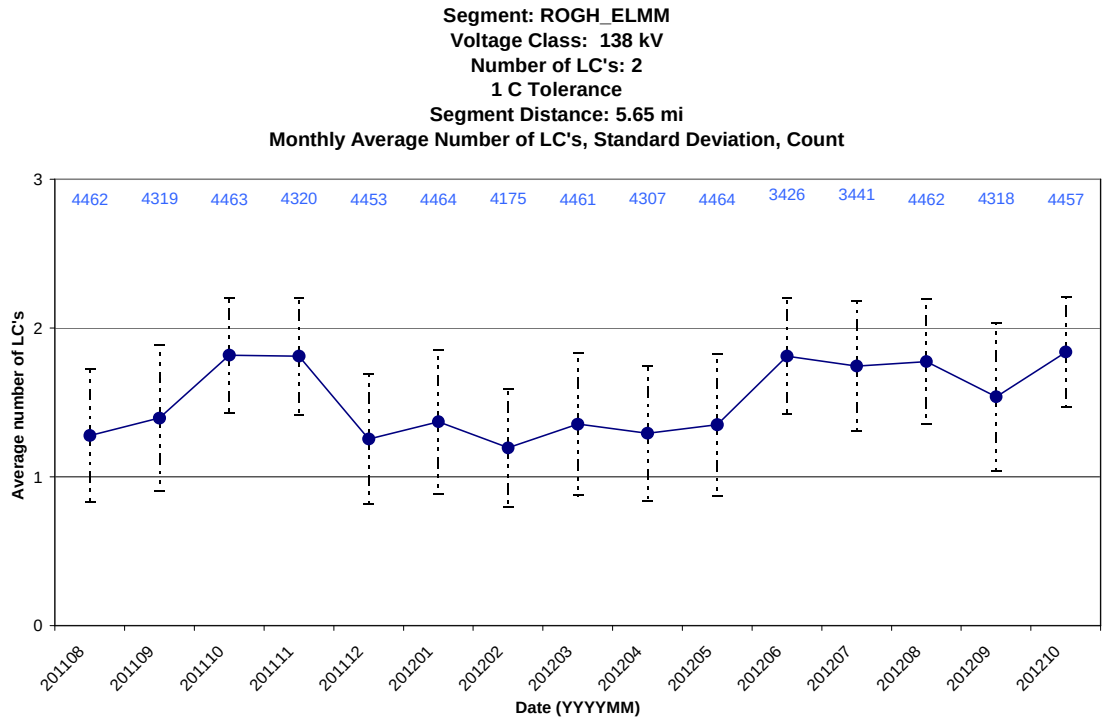


Figure 8a: Monthly Trend of number of LC's at Rogers Hill-Elm Mott for 1 ^{o}C accuracy.

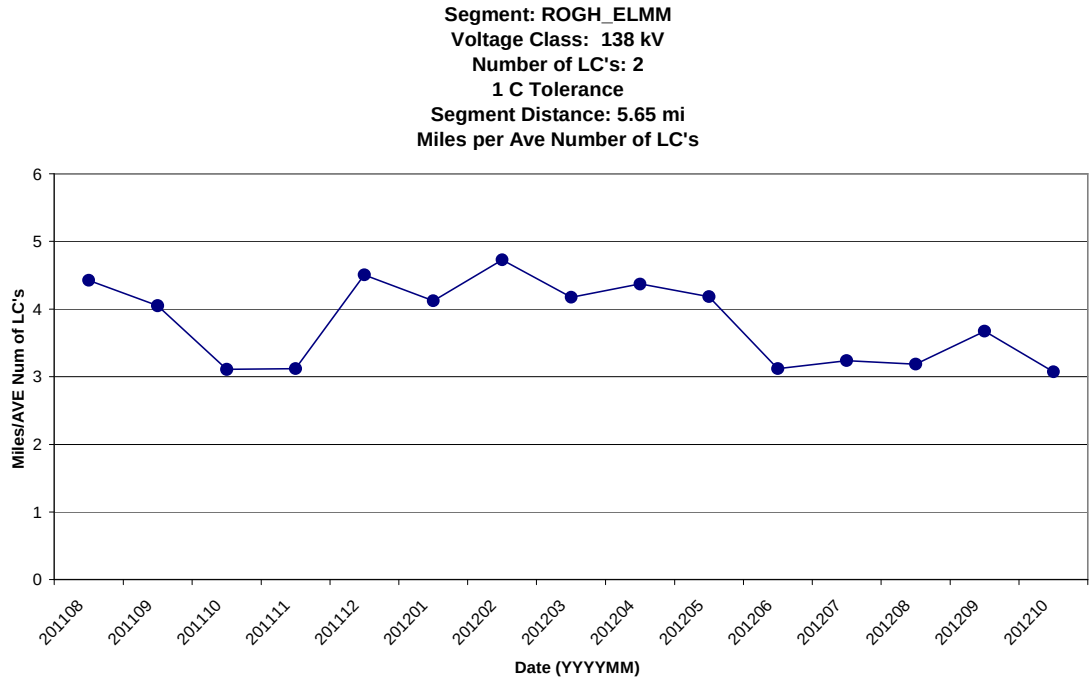


Figure 8b: Monthly Trend of Miles per average number of LC's at Rogers Hill-Elm Mott for 1 ^{o}C accuracy.

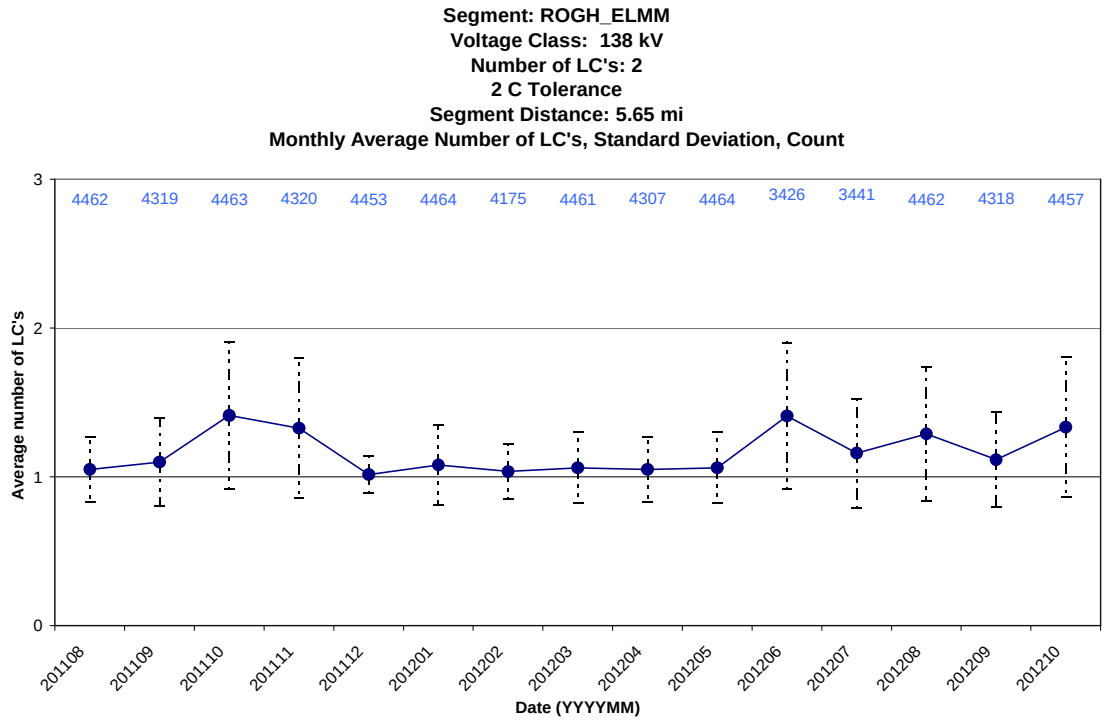


Figure 9a: Monthly Trend of number of LC's at Rogers Hill-Elm Mott for 2 ^{o}C accuracy.

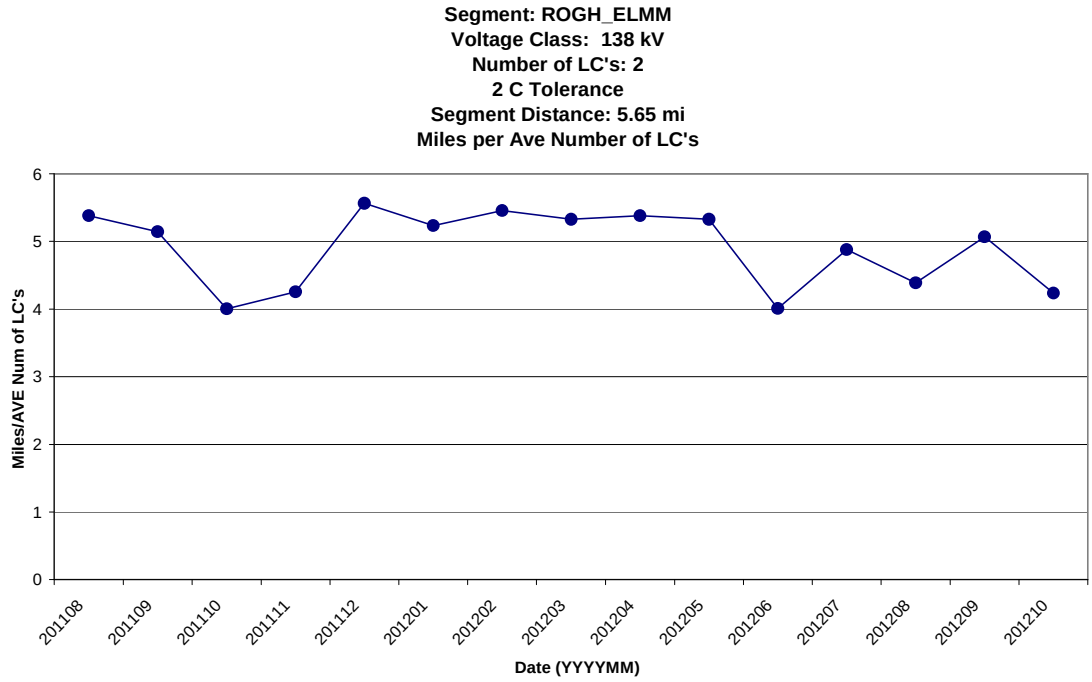


Figure 9b: Monthly Trend of Miles per average number of LC's at Rogers Hill-Elm Mott for 2 ^{o}C accuracy.

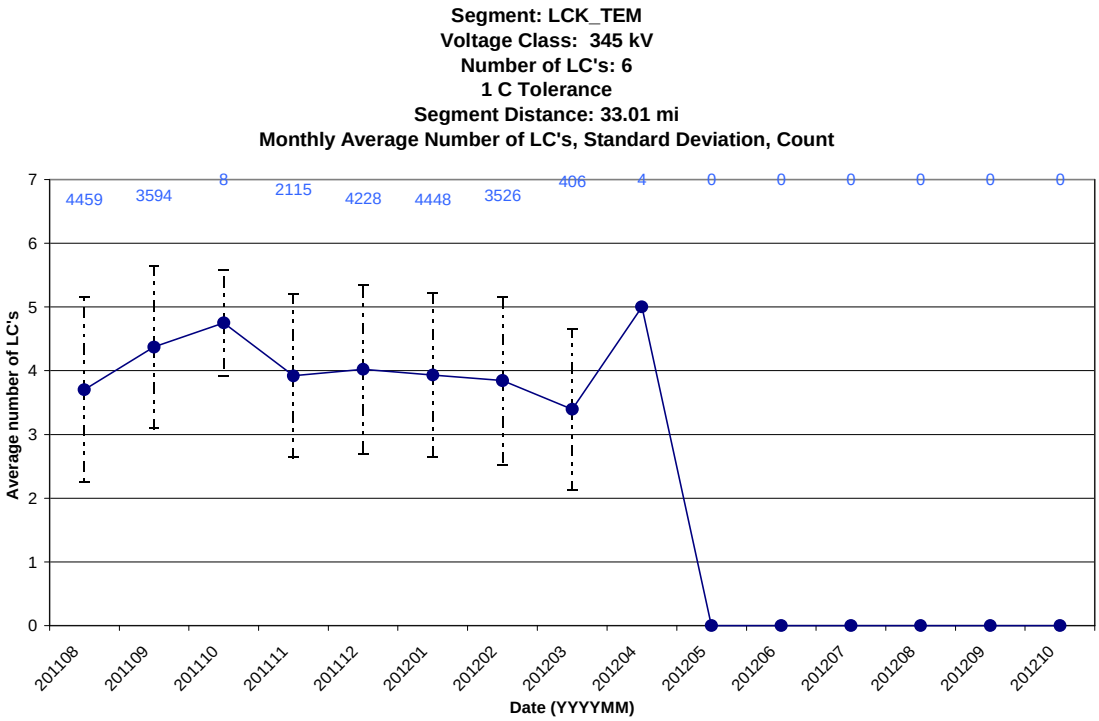
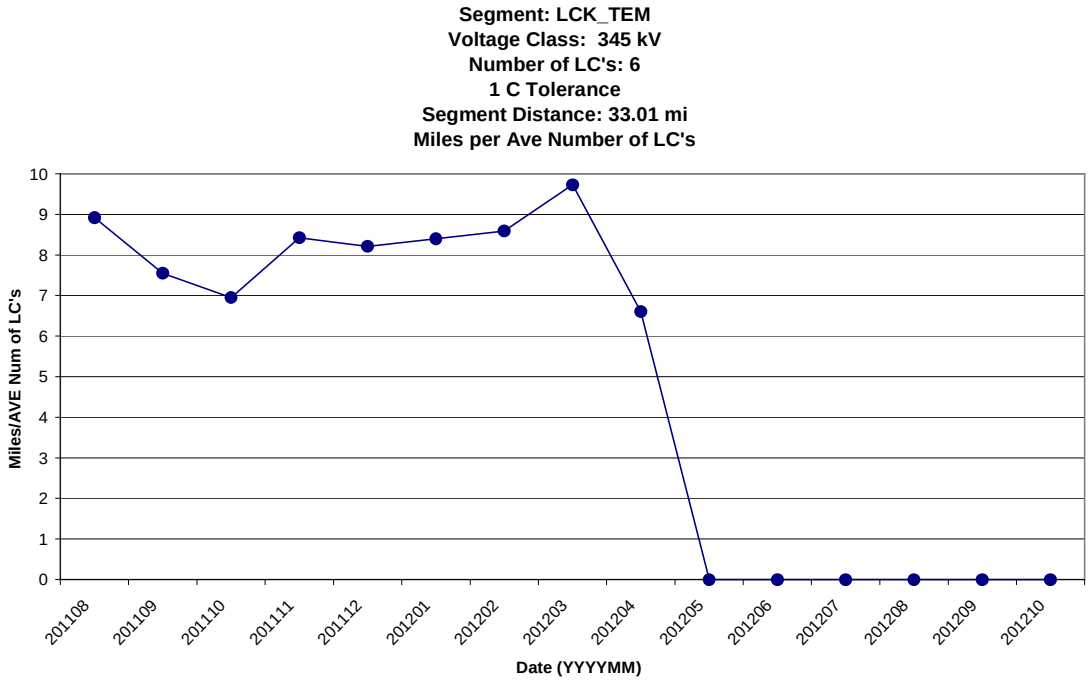


Figure 10a: Monthly Trend of number of LC's at Lake Creek-Temple for 1 ^{o}C accuracy.



Z

Figure 10b: Monthly Trend of Miles per average number of LC's at Lake Creek-Temple for 1 ^{o}C accuracy.

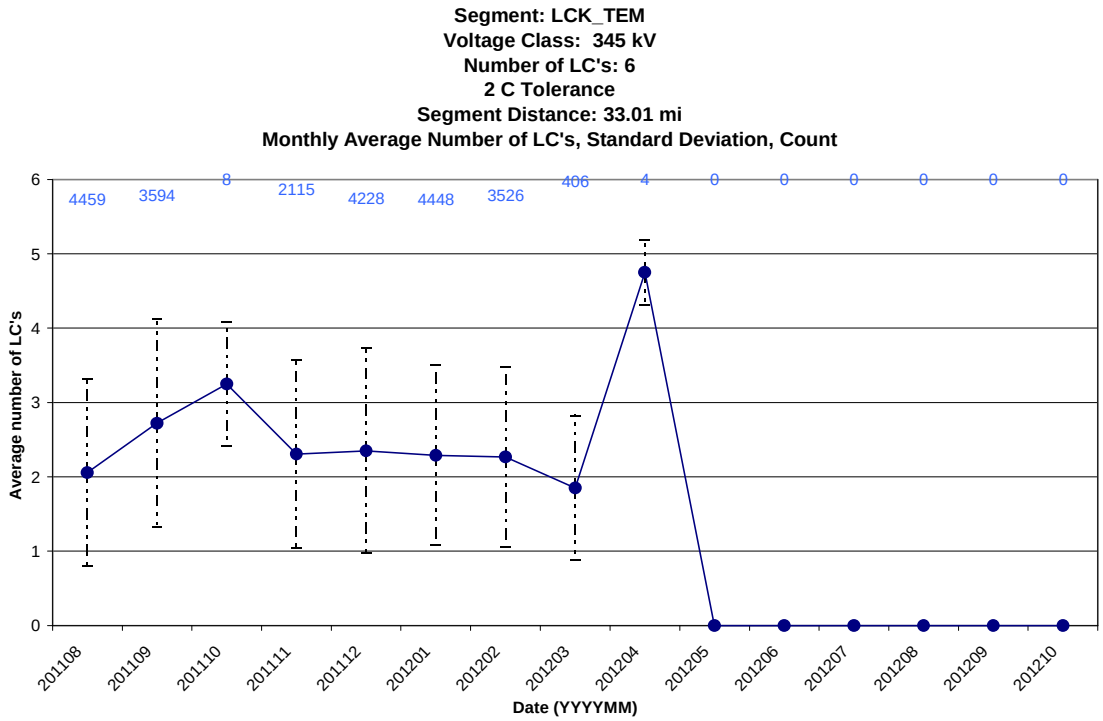


Figure 11a: Monthly Trend of number of LC's at Lake Creek-Temple for 2 ^{o}C accuracy.

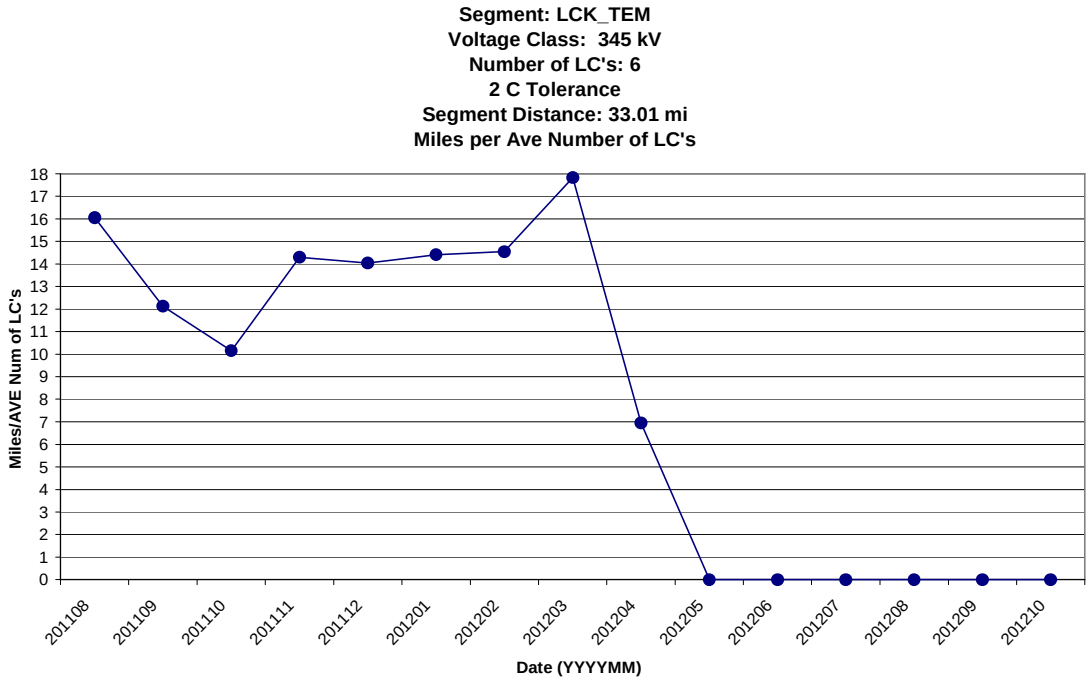


Figure 11b: Monthly Trend of Miles per average number of LC's at Lake Creek-Temple for 2 ^{o}C accuracy.

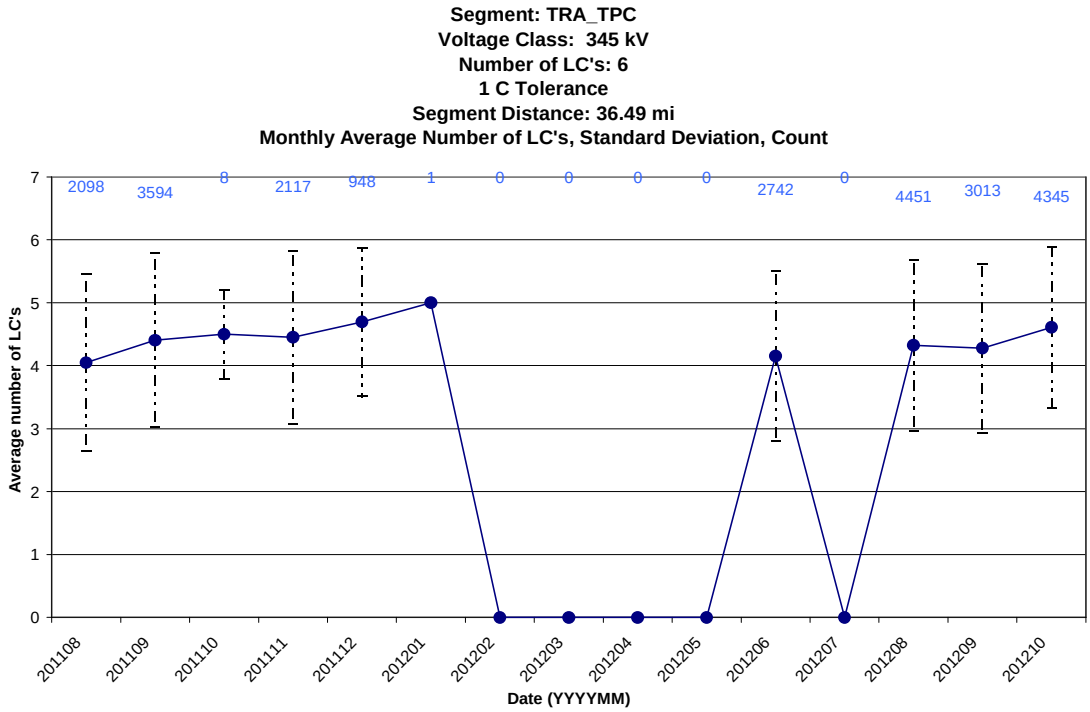


Figure 12a: Monthly Trend of number of LC's at Tradinghouse-Temple Pecan Creek for 1 °C accuracy.

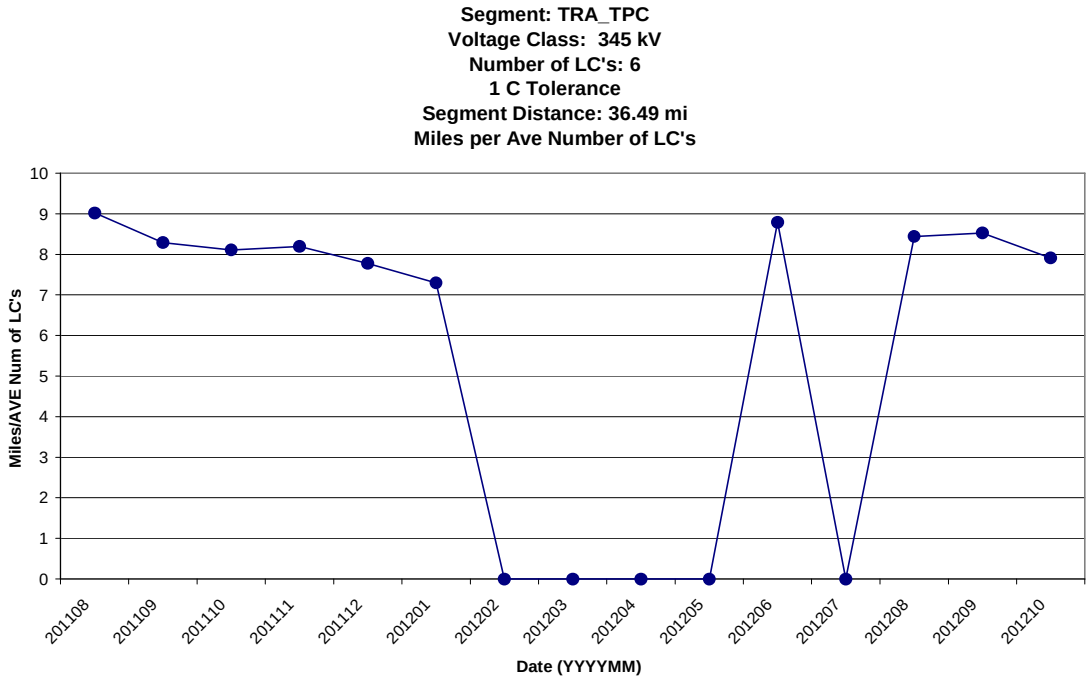


Figure 12b: Monthly Trend of Miles per average number of LC's at Tradinghouse-Temple Pecan Creek for 1 °C accuracy.

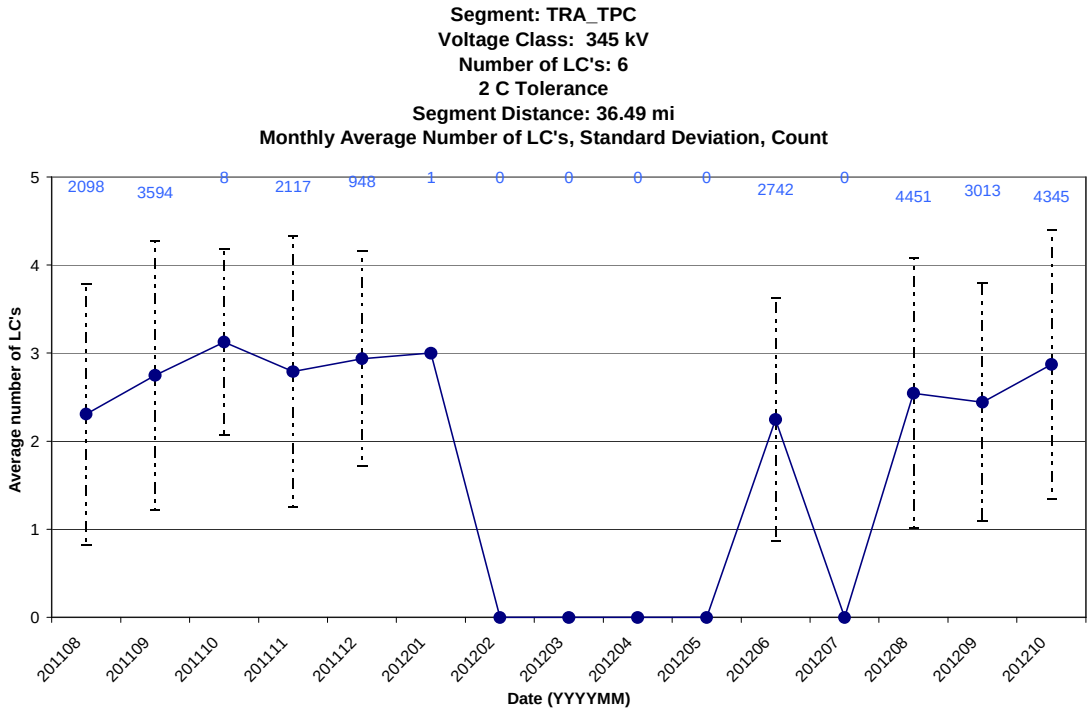


Figure 13a: Monthly Trend of number of LC's at Tradinghouse-Temple Pecan Creek for 2 ^{o}C accuracy.

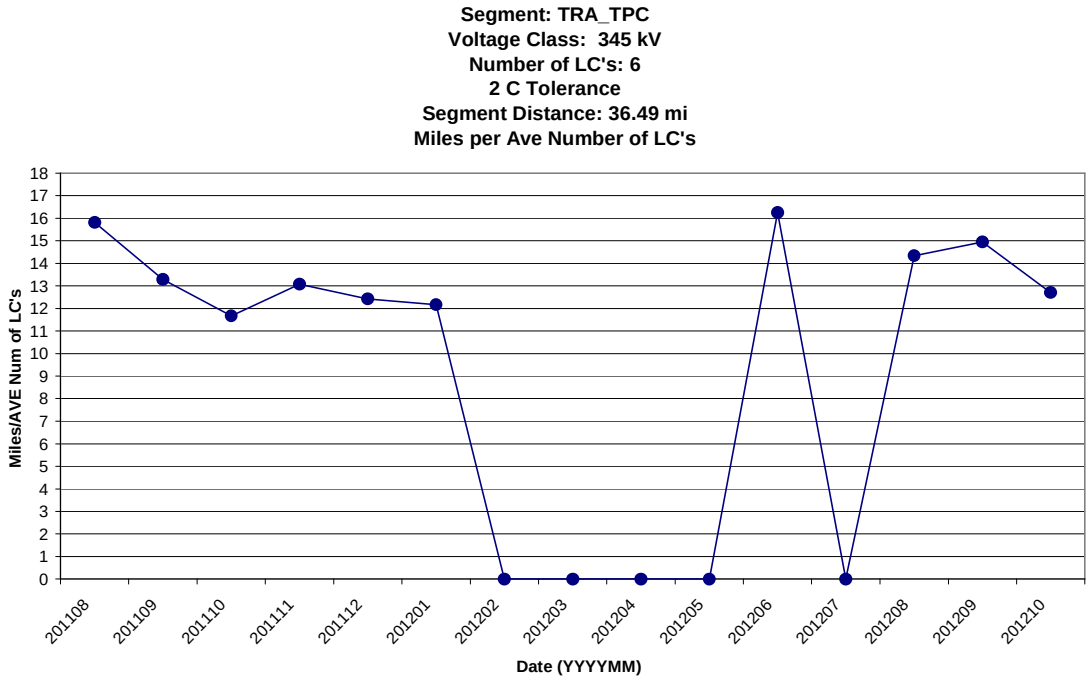


Figure 13b: Monthly Trend of Miles per average number of LC's at Tradinghouse-Temple Pecan Creek for 2 ^{o}C accuracy.

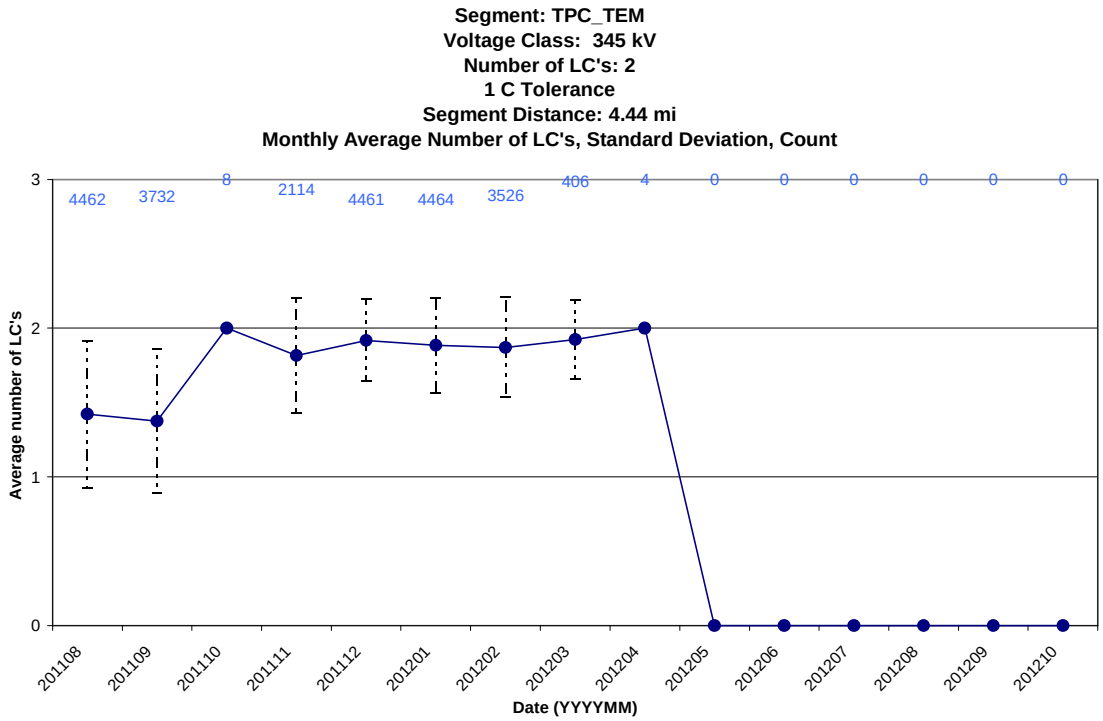


Figure 14a: Monthly Trend of number of LC's at Temple Pecan Creek-Temple for 1 ^{o}C accuracy.

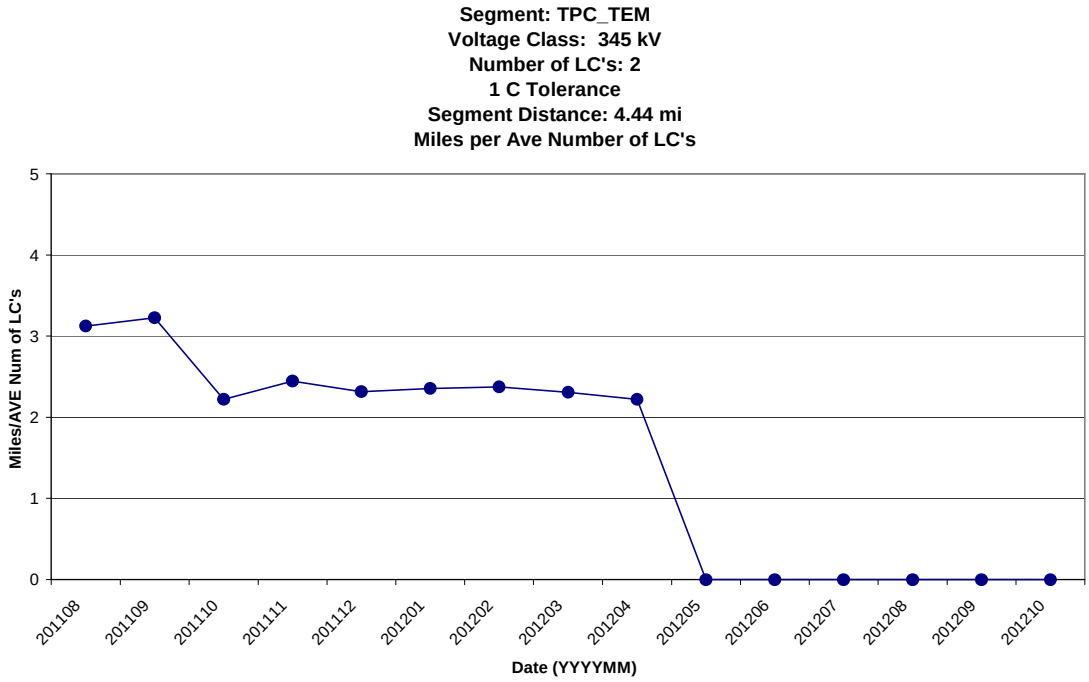


Figure 14b: Monthly Trend of Miles per average number of LC's at Temple Pecan Creek-Temple for 1 ^{o}C accuracy.

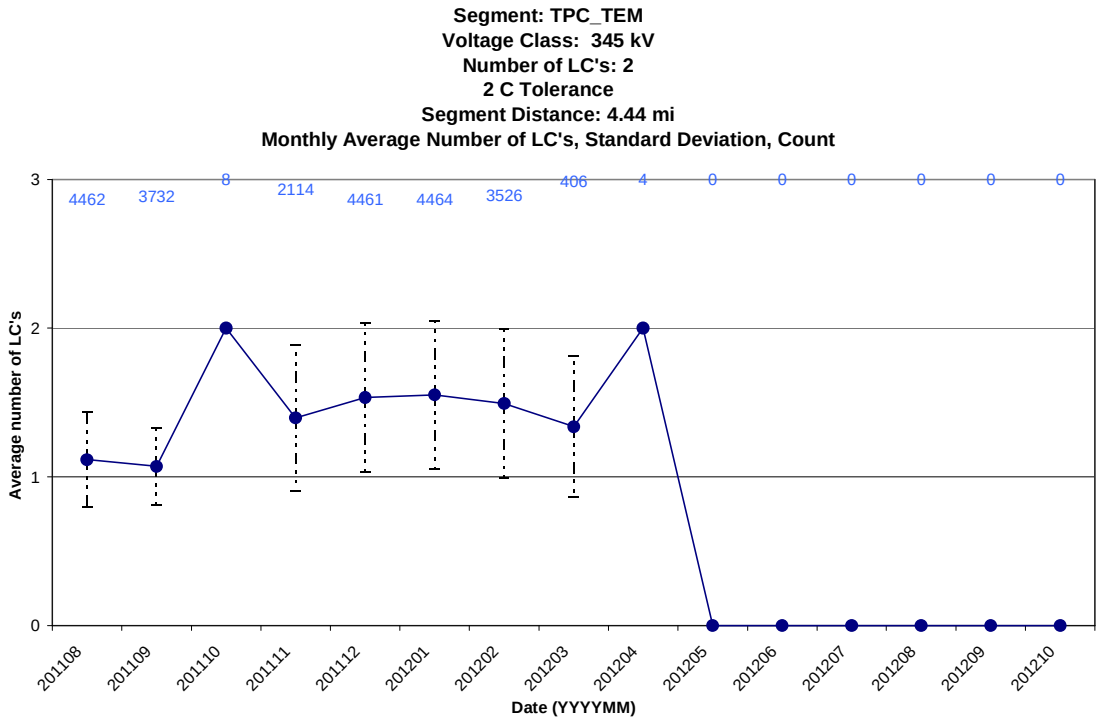


Figure 15a: Monthly Trend of number of LC's at Temple Pecan Creek-Temple for 2 ^{o}C accuracy.

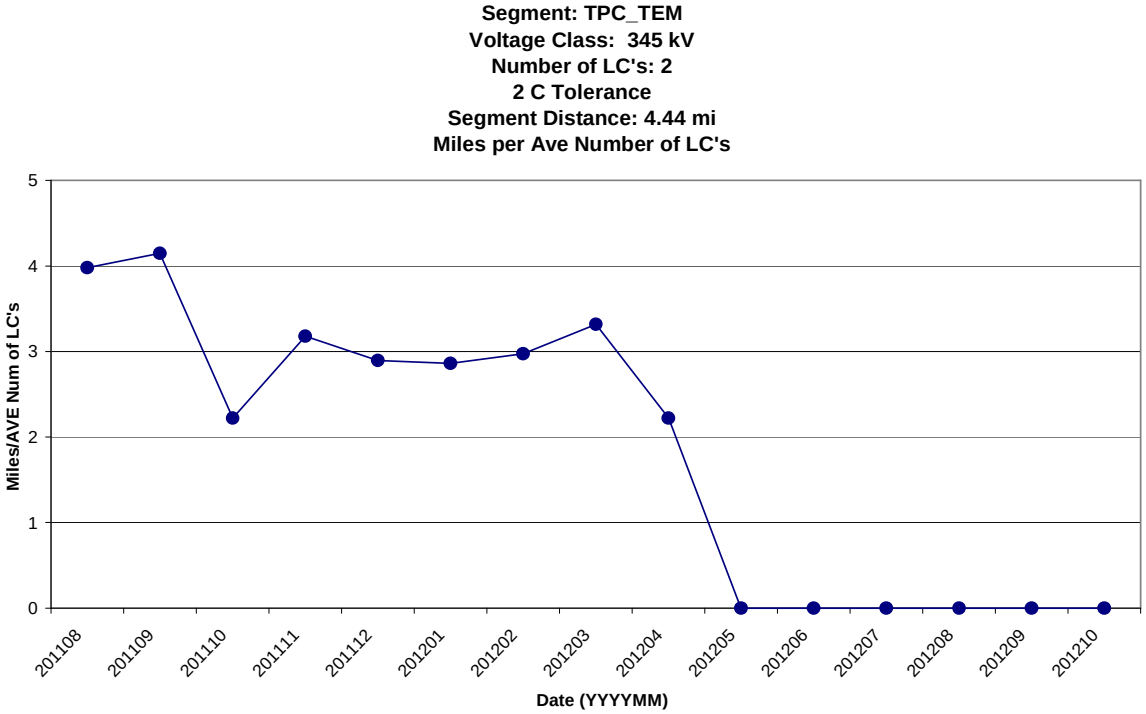


Figure 15b: Monthly Trend of Miles per average number of LC's at Temple Pecan Creek-Temple for 2 ^{o}C accuracy.

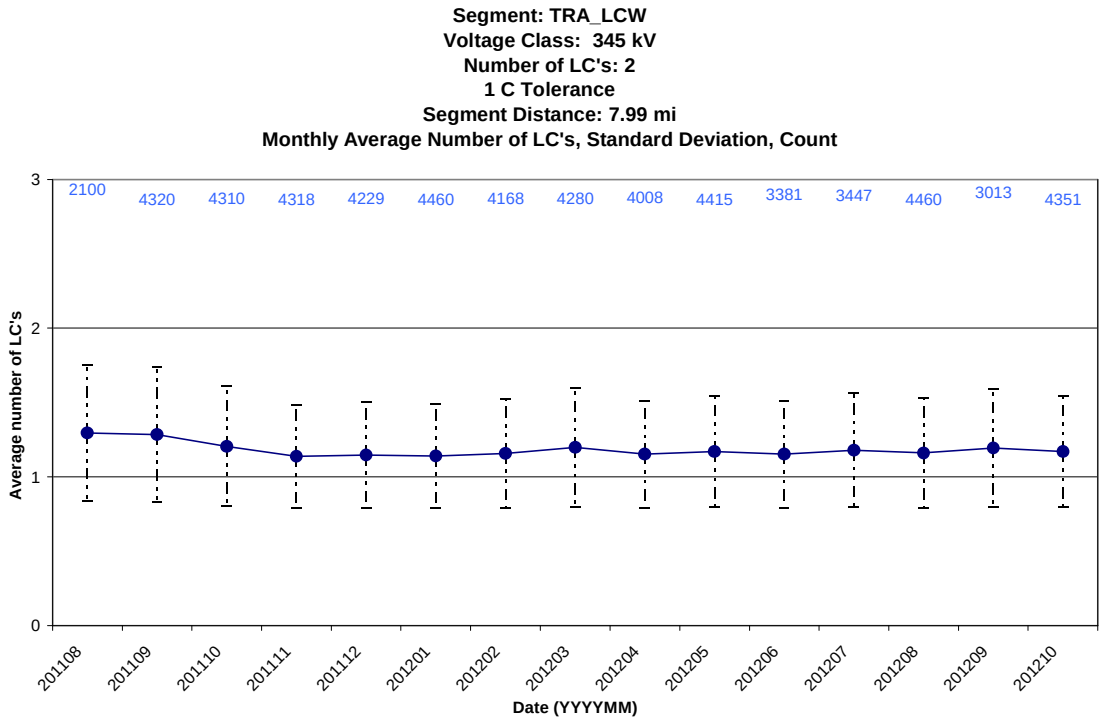


Figure 16a: Monthly Trend of number of LC's at Tradinghouse-Lake Creek West for 1 ^{o}C accuracy.

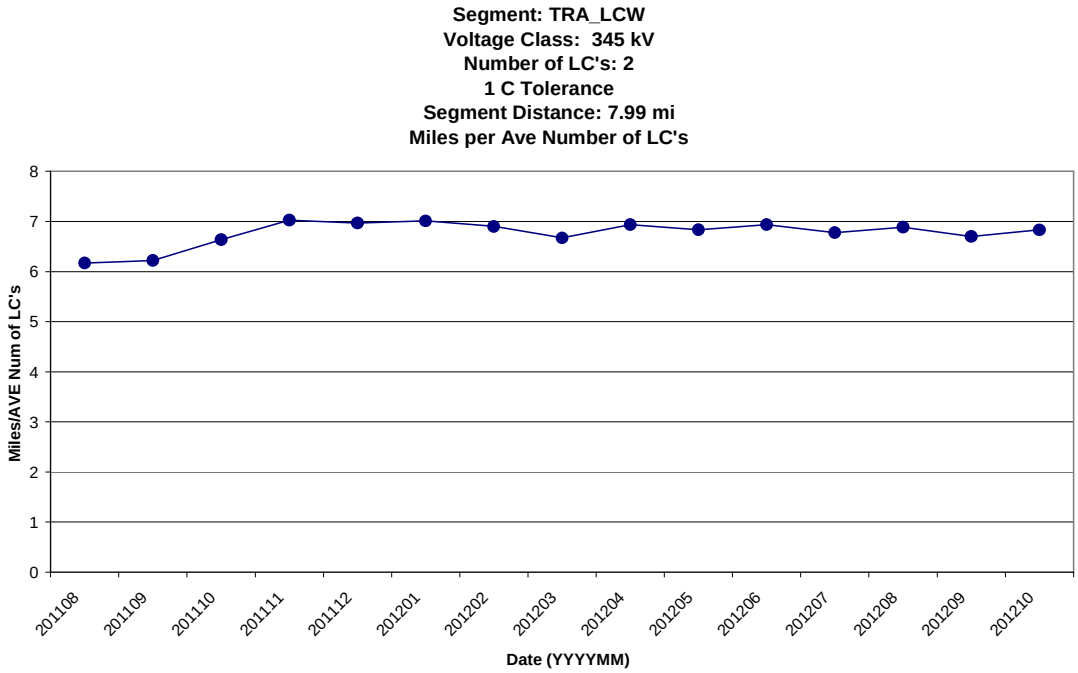


Figure 16b: Monthly Trend of Miles per average number of LC's at Tradinghouse-Lake Creek West for 1 ^{o}C accuracy.

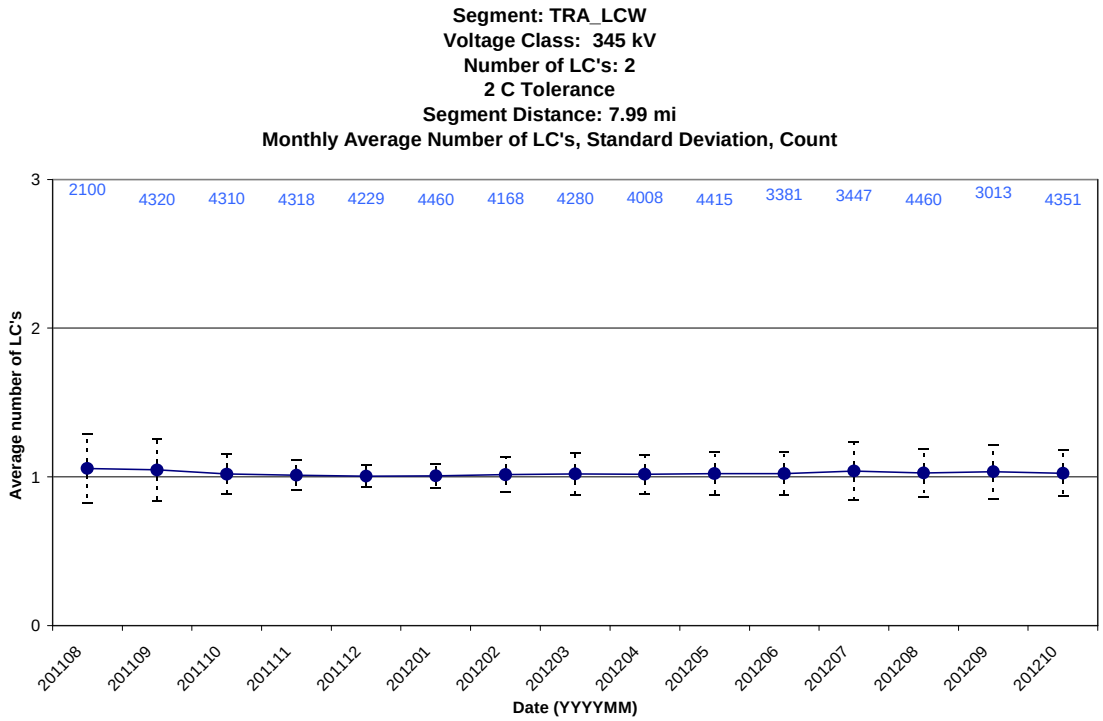


Figure 17a: Monthly Trend of number of LC's at Tradinghouse-Lake Creek West for 2 ^{o}C accuracy.

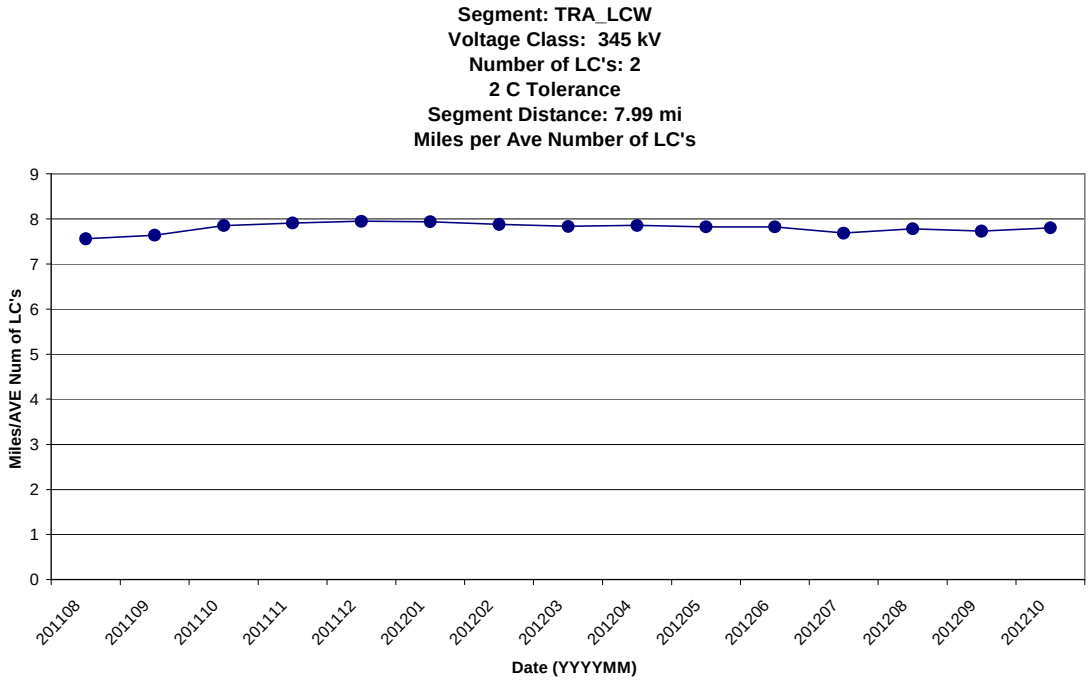


Figure 17b: Monthly trend of miles per average number of LC's at Tradinghouse-Lake Creek West for 2 ^{o}C accuracy.

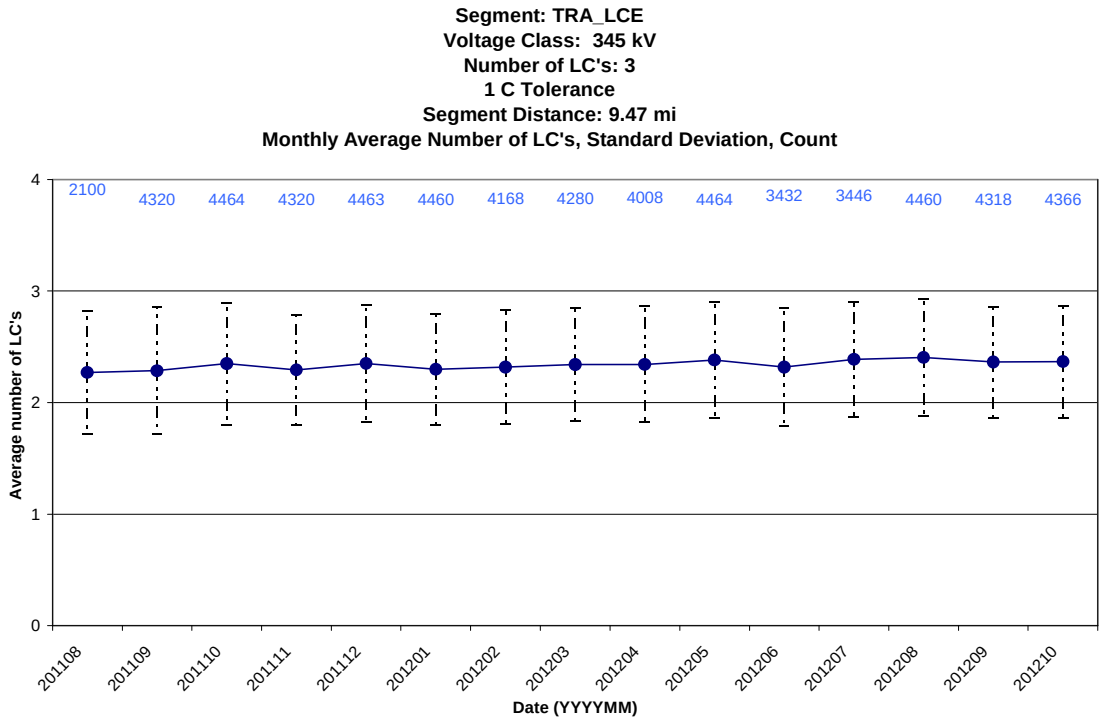


Figure 18a: Monthly Trend of number of LC's at Tradinghouse-Lake Creek East for 1 ^{o}C accuracy.

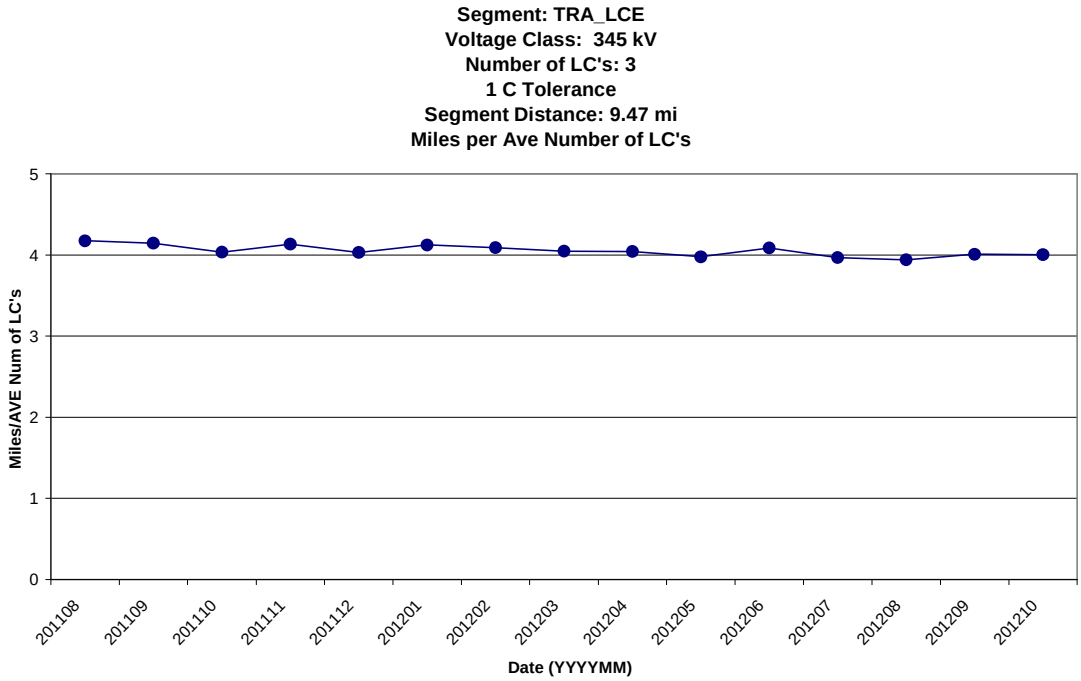


Figure 18b: Monthly Trend of Miles per average number of LC's at Tradinghouse-Lake Creek East for 1 ^{o}C accuracy.

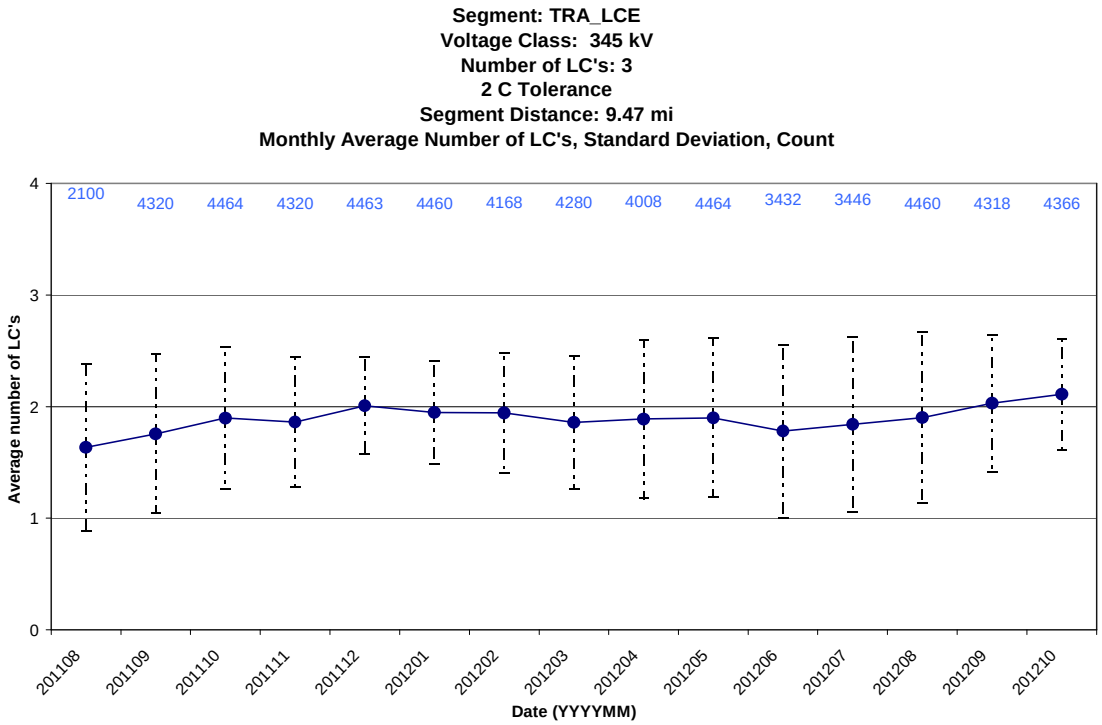


Figure 19a: Monthly Trend of number of LC's at Tradinghouse-Lake Creek East for 2 ^{o}C accuracy.

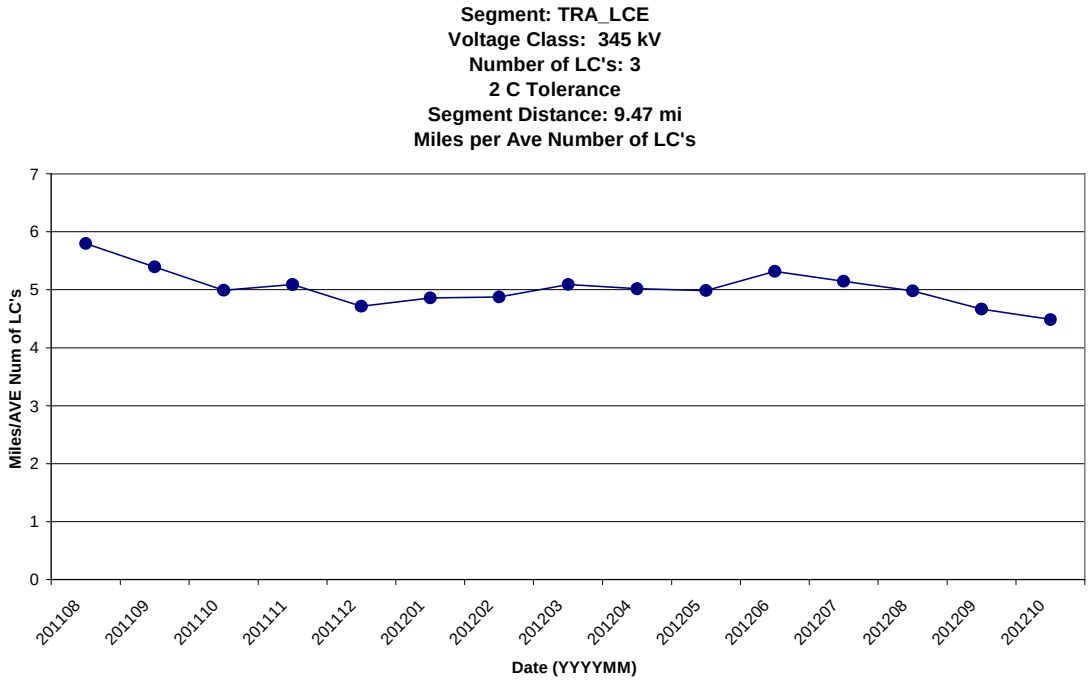


Figure 19b: Monthly Trend of Miles per average number of LC's at Tradinghouse-Lake Creek East for 2 ^{o}C accuracy.

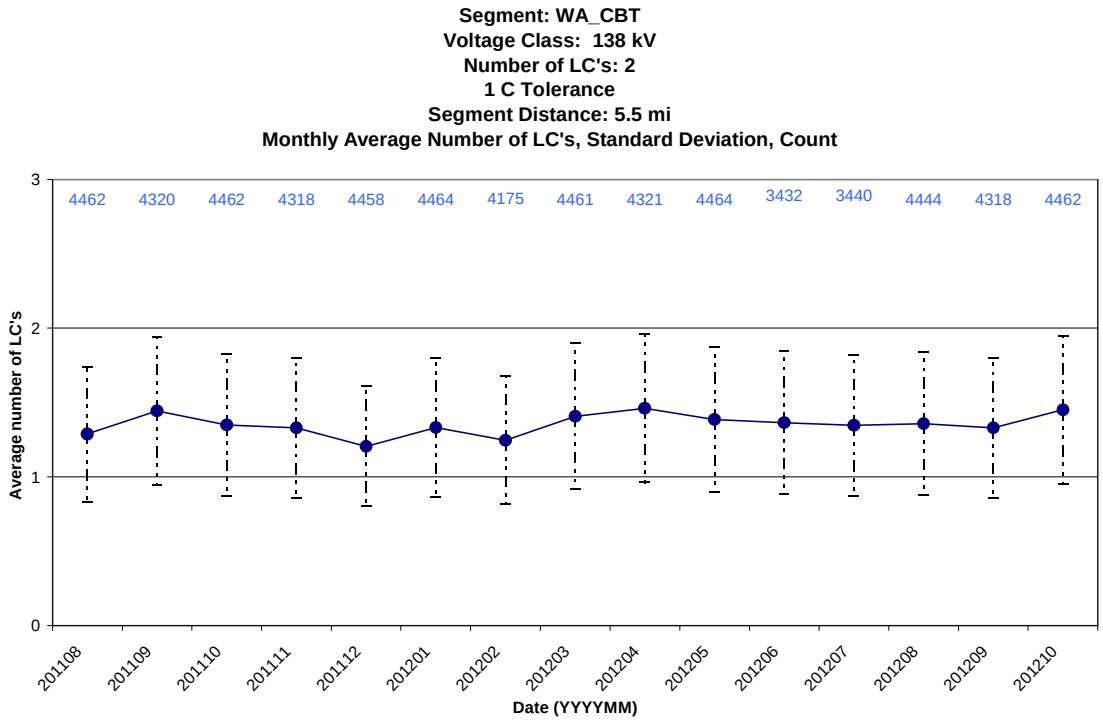


Figure 20a: Monthly Trend of number of LC's at Waco Atco-Cottonbelt Tap for 1 ^{o}C accuracy.

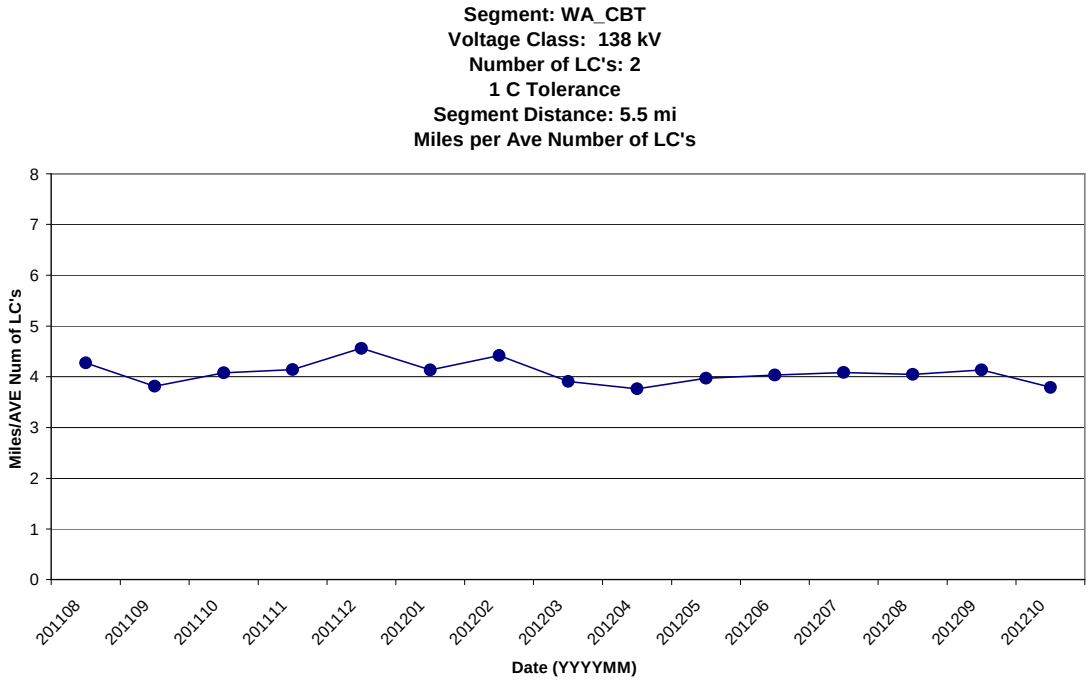


Figure 20b: Monthly trend of miles per average number of LC's at Waco Atco-Cottonbelt Tap for 1 ^{o}C accuracy.

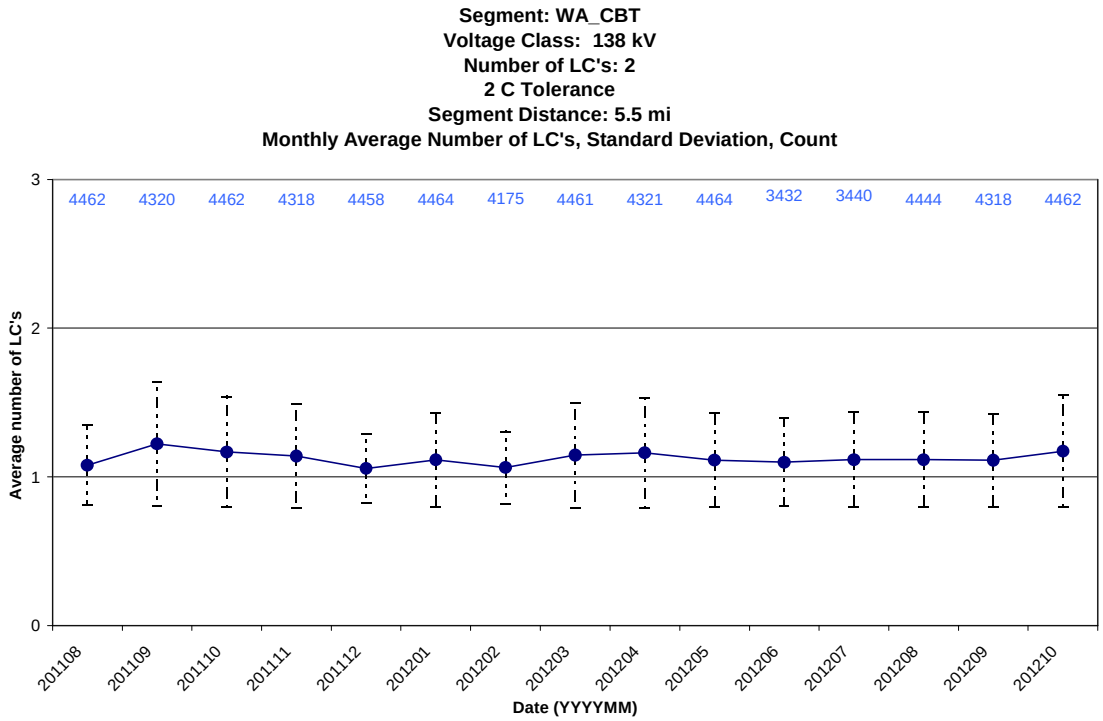


Figure 21a: Monthly Trend of number of LC's at Waco Atco-Cottonbelt Tap for 2 ^{o}C accuracy.

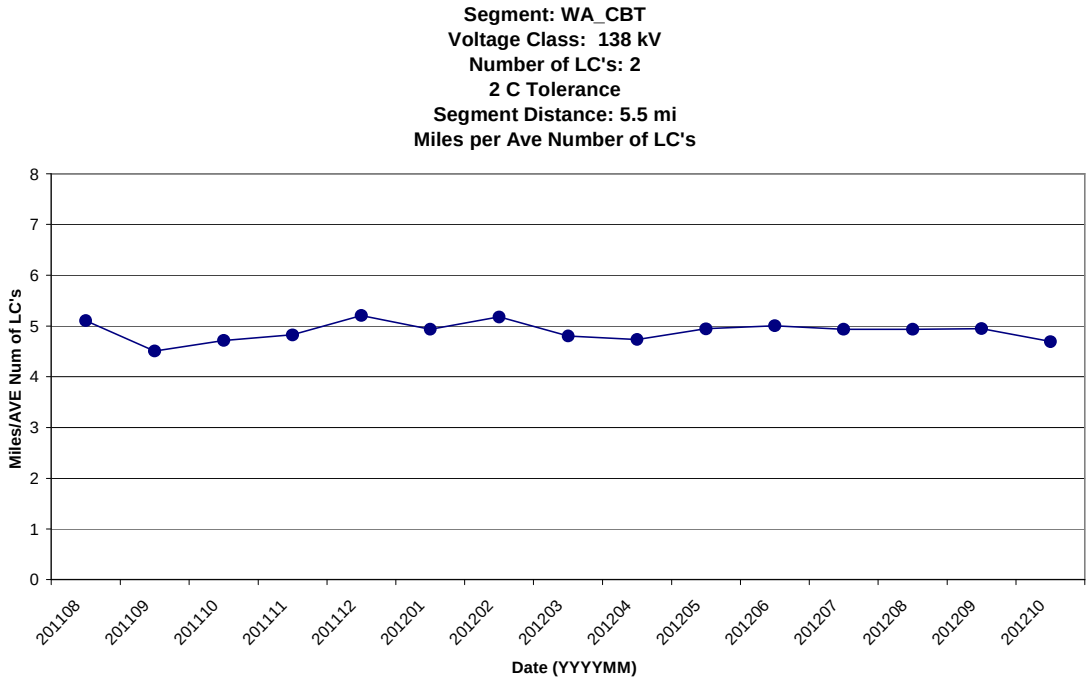


Figure 21b: Monthly trend of miles per average number of LC's at Waco Atco-Cottonbelt Tap for 2 ^{o}C accuracy.

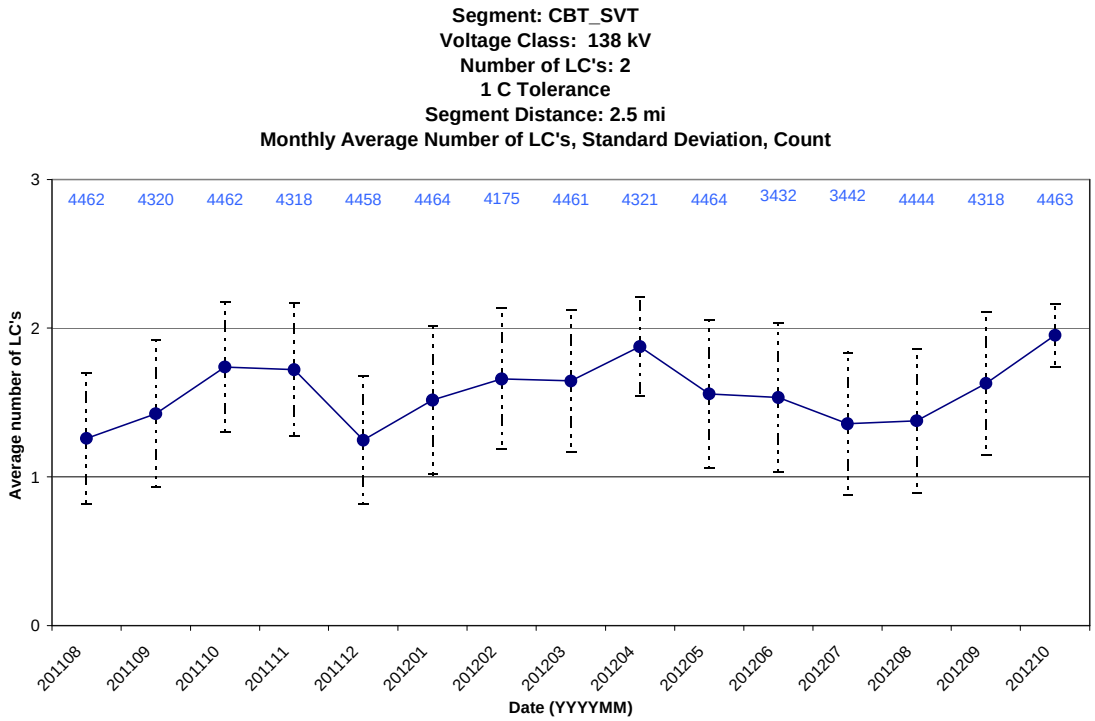


Figure 22a: Monthly Trend of number of LC's at Cottonbelt Tap-Spring Valley Tap for 1 ^{o}C accuracy.

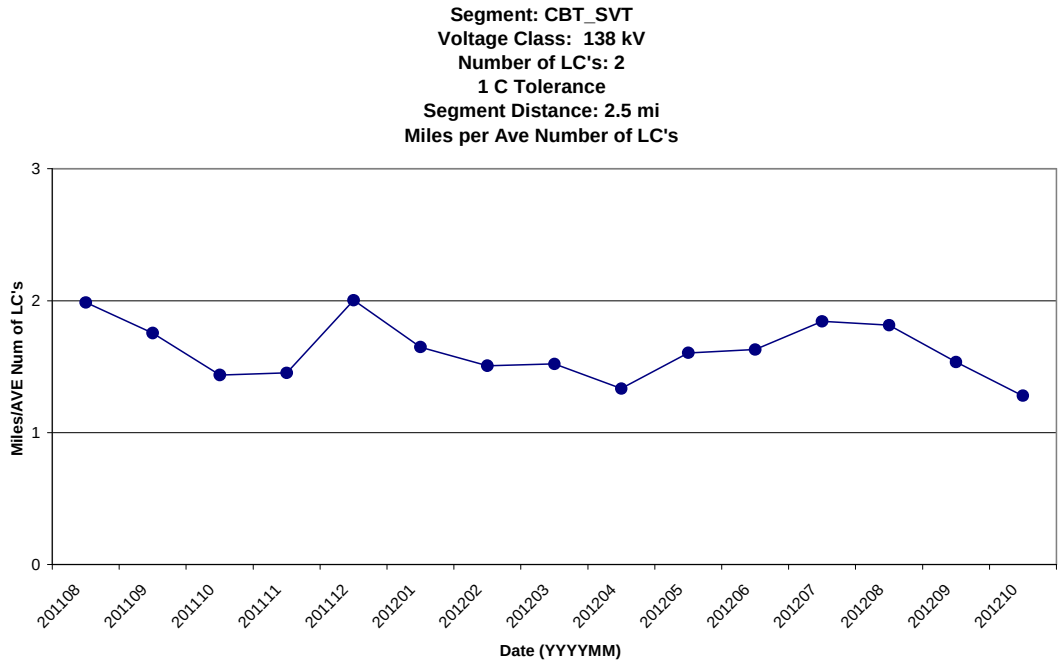


Figure 22b: Monthly trend of miles per average number of LC's at Cottonbelt Tap-Spring Valley Tap for 1 ^{o}C accuracy.

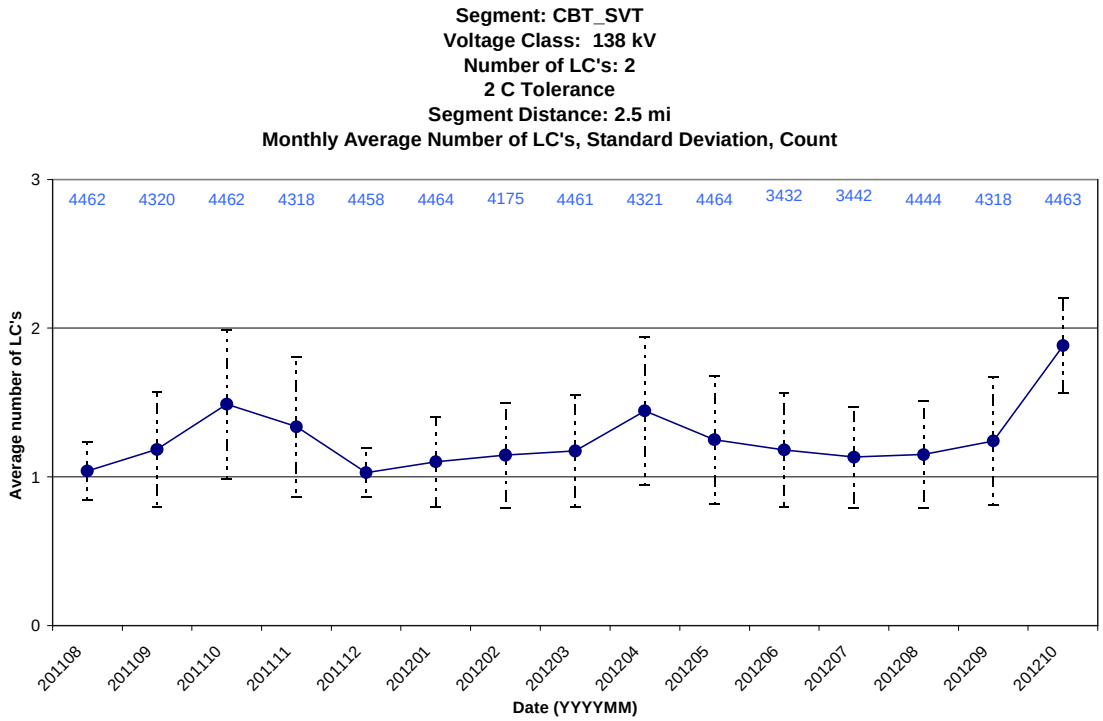


Figure 23a: Monthly Trend of number of LC's at Cottonbelt Tap-Spring Valley Tap for 2 ^{o}C accuracy.

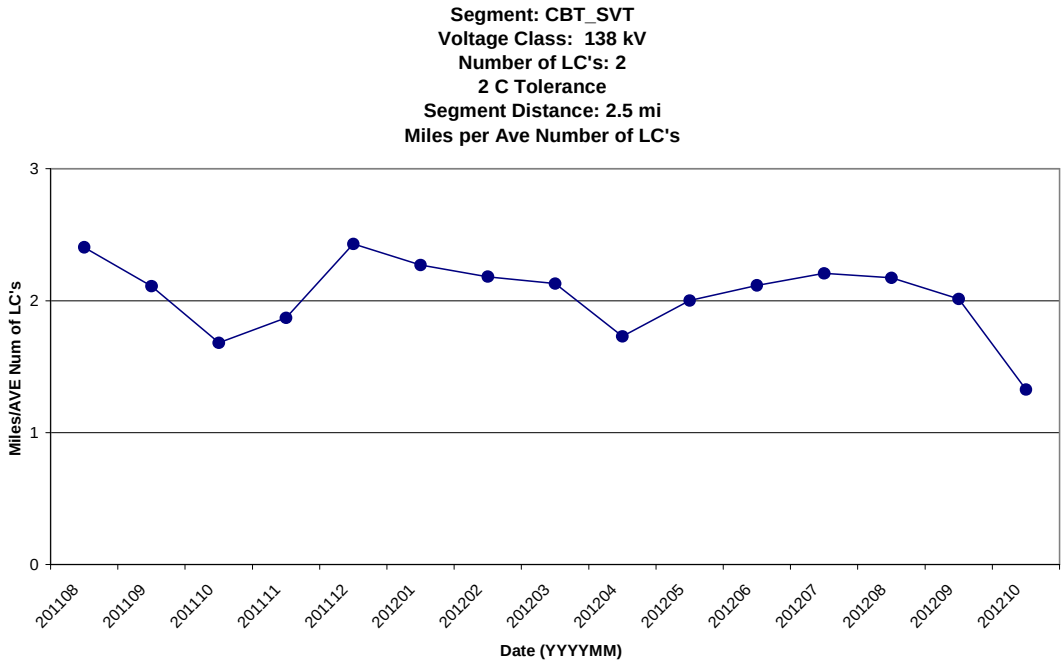


Figure 23b: Monthly trend of miles per average number of LC's at Cottonbelt Tap-Spring Valley Tap for 2 ^{o}C accuracy.

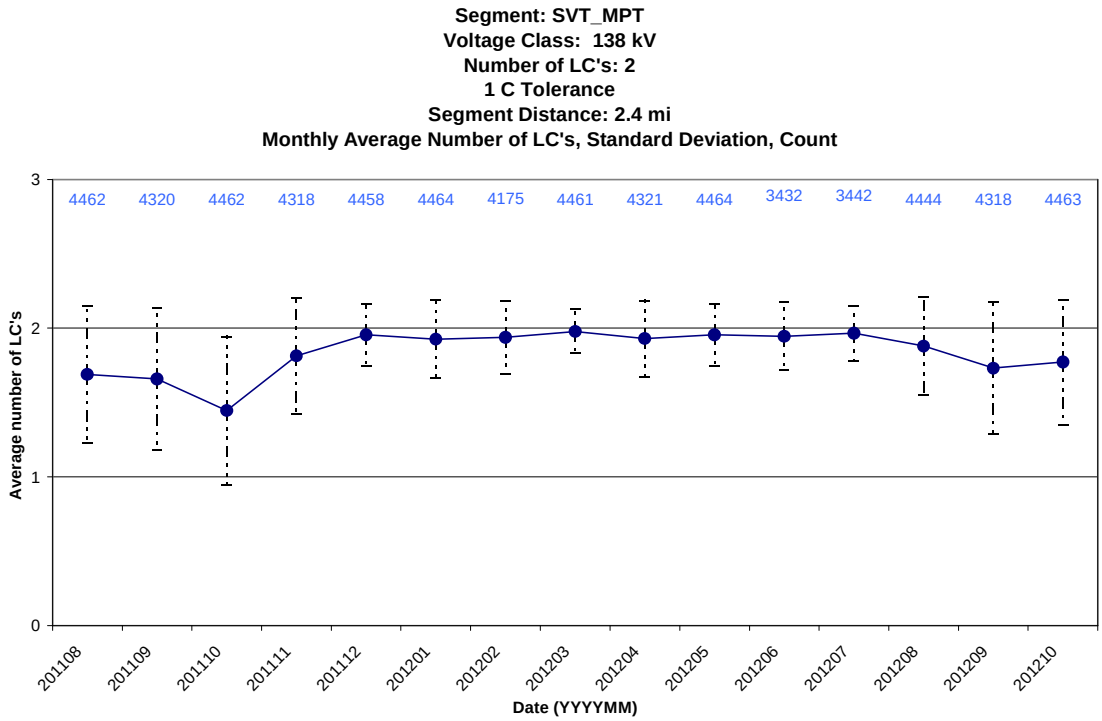


Figure 24a: Monthly Trend of number of LC's at Spring Valley Tap-McGregor Phillips Tap for 1 ^{o}C accuracy.

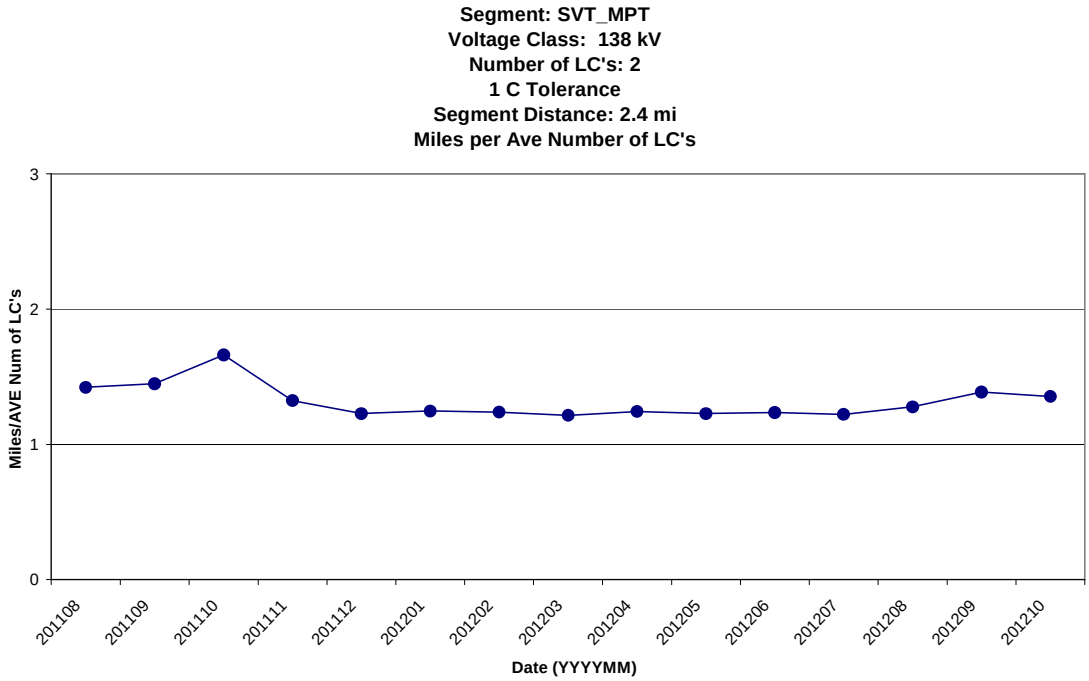


Figure 24b: Monthly trend of miles per average number of LC's at Spring Valley Tap-McGregor Phillips Tap for 1 ^{o}C.

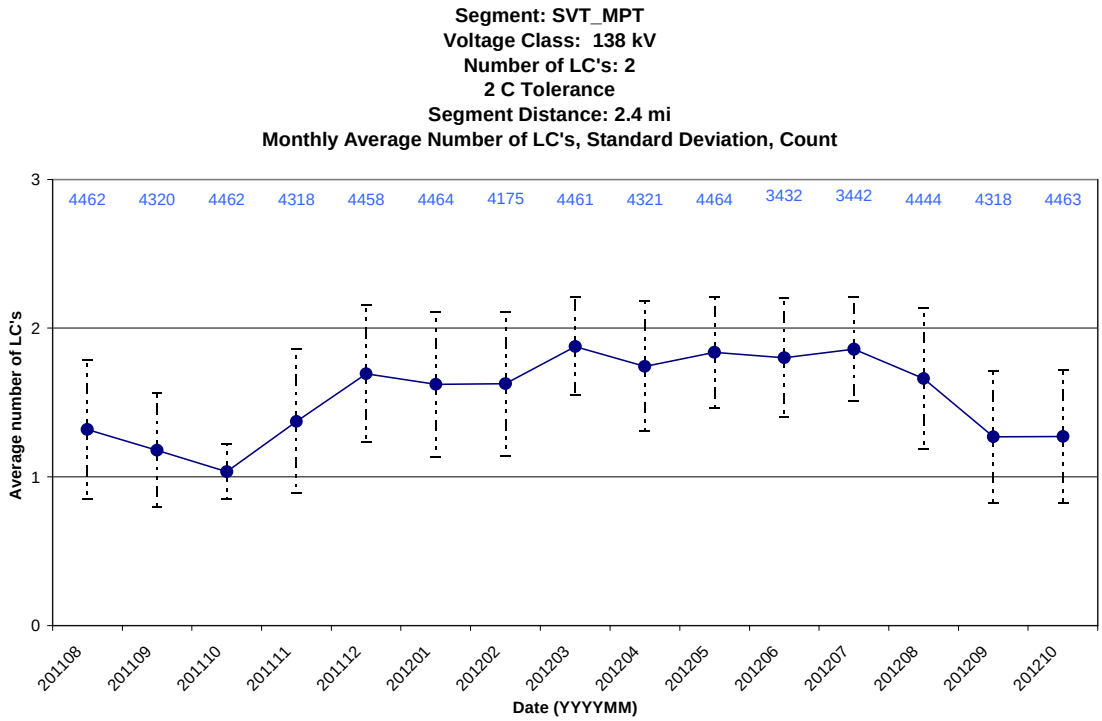


Figure 25a: Monthly Trend of number of LC's at Spring Valley Tap-McGregor Phillips Tap for 2 ^{o}C accuracy.

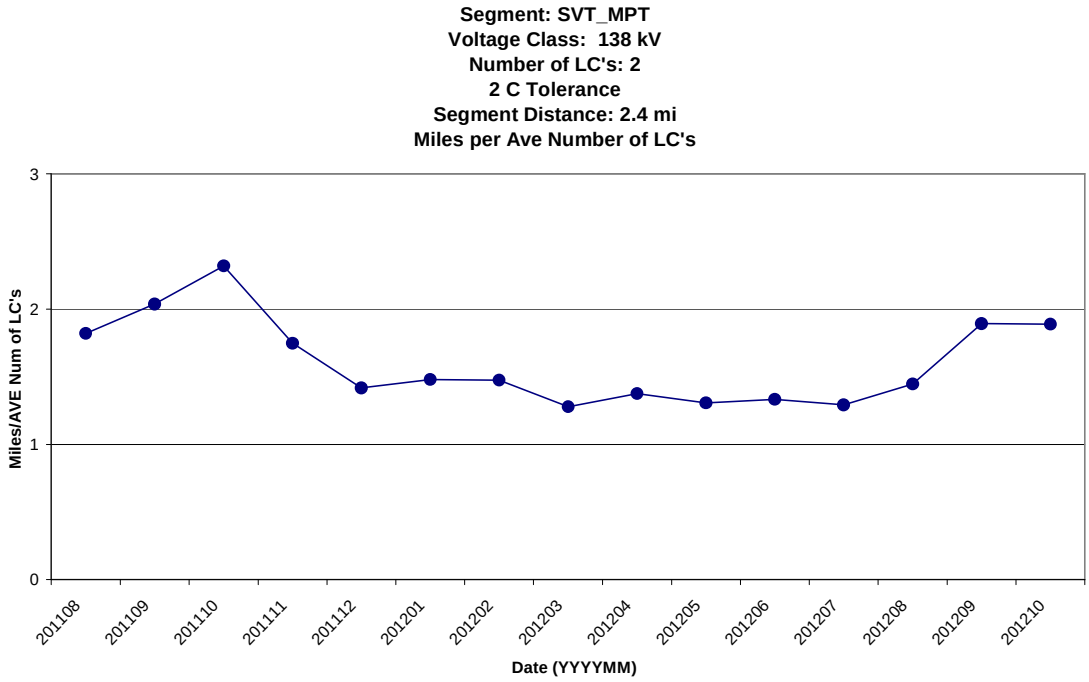


Figure 25b: Monthly trend of miles per average number of LC's at Spring Valley Tap-McGregor Phillips Tap for 2 ^{o}C.

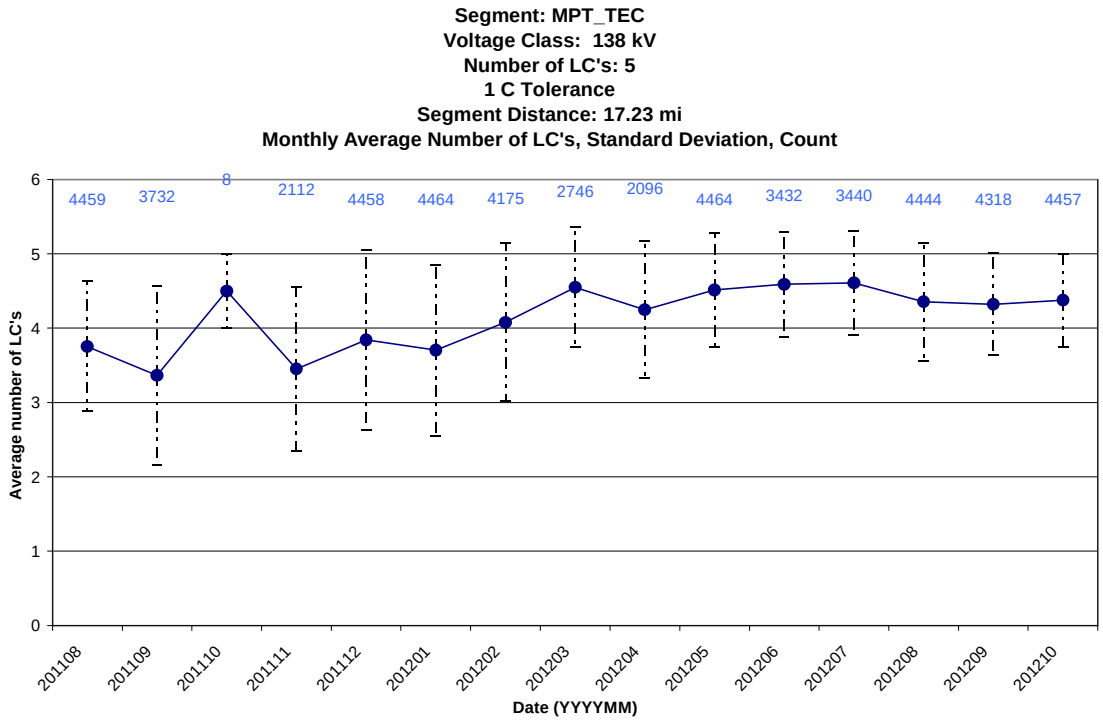


Figure 26a: Monthly Trend of number of LC's at McGregor Phillips Tap-Temple Elm Creek for 1 ^{o}C accuracy.

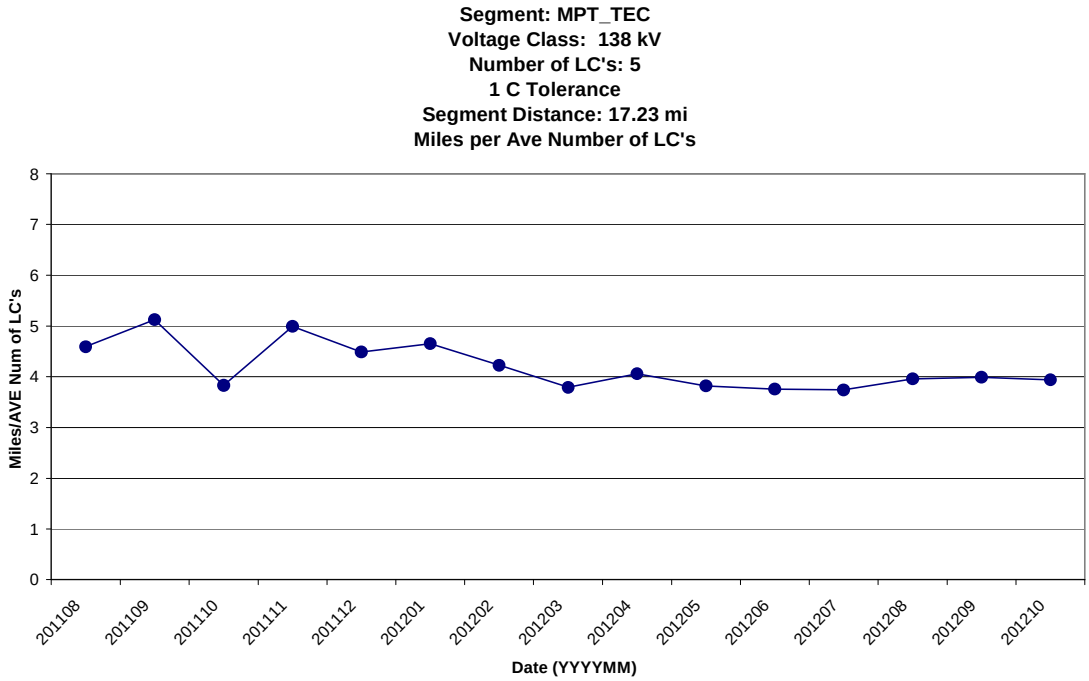


Figure 26b: Monthly trend of miles per average number of LC's at McGregor Phillips Tap-Temple Elm Creek for 1 ^{o}C.

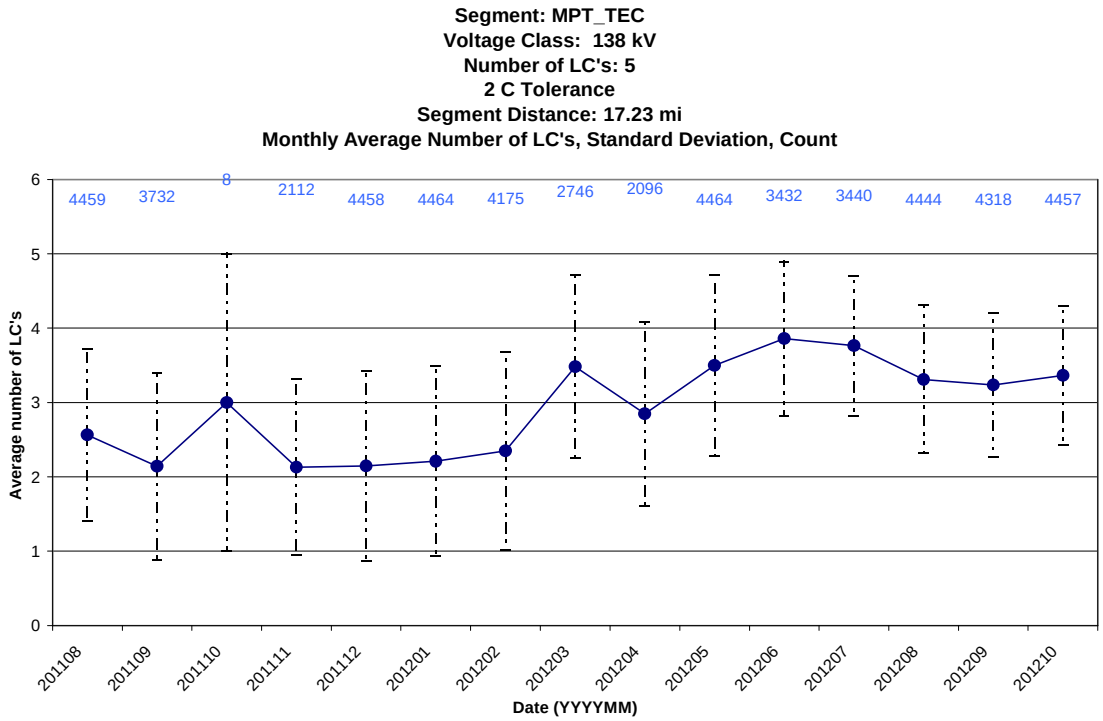


Figure 27a: Monthly Trend of number of LC's at McGregor Phillips Tap-Temple Elm Creek for 2 ^{o}C accuracy.

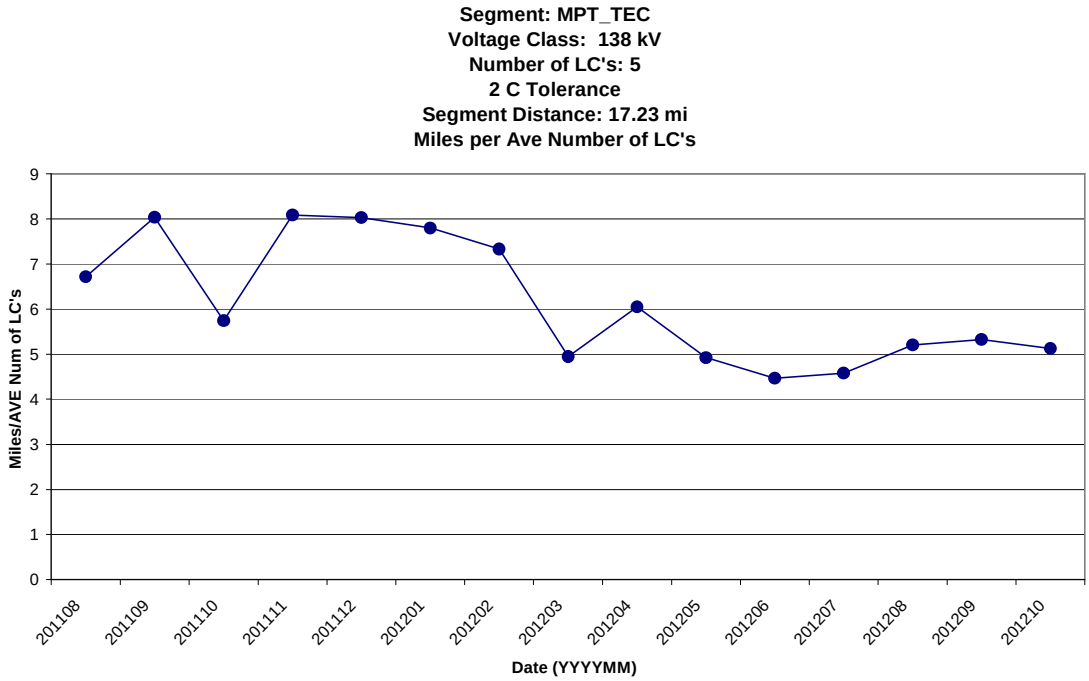


Figure 27b: Monthly trend of miles per average number of LC's at McGregor Phillips Tap-Temple Elm Creek for 2 ^{o}C.

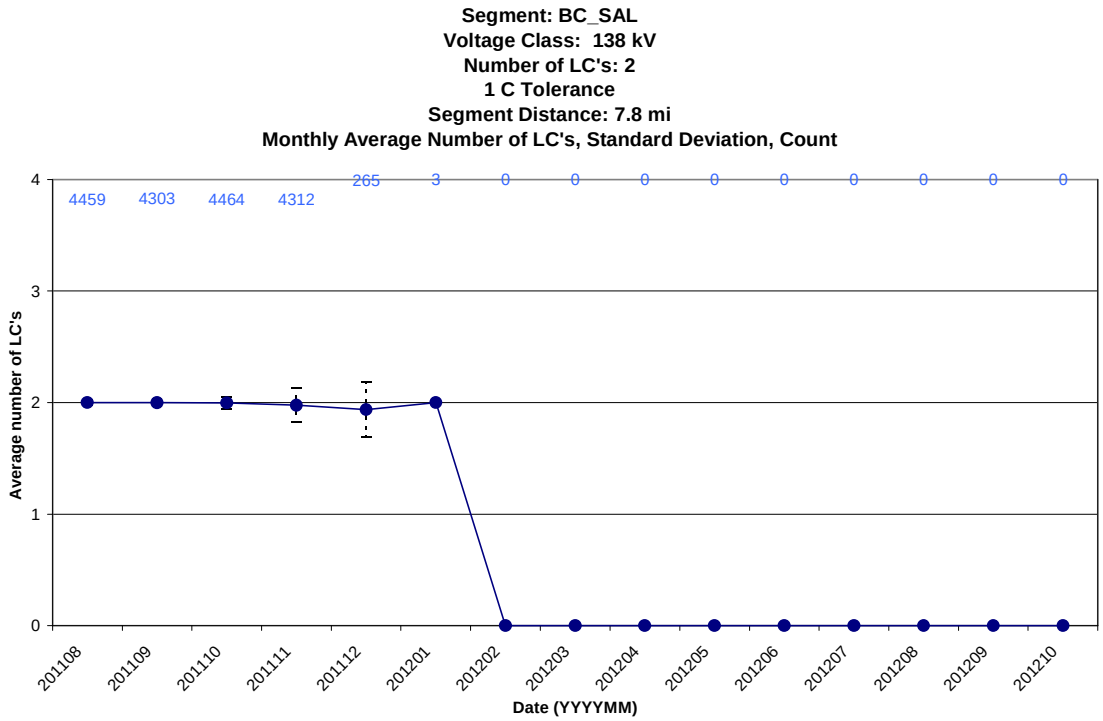


Figure 28a: Monthly Trend of number of LC's at Bell County-Salado for 1 ^{o}C accuracy.

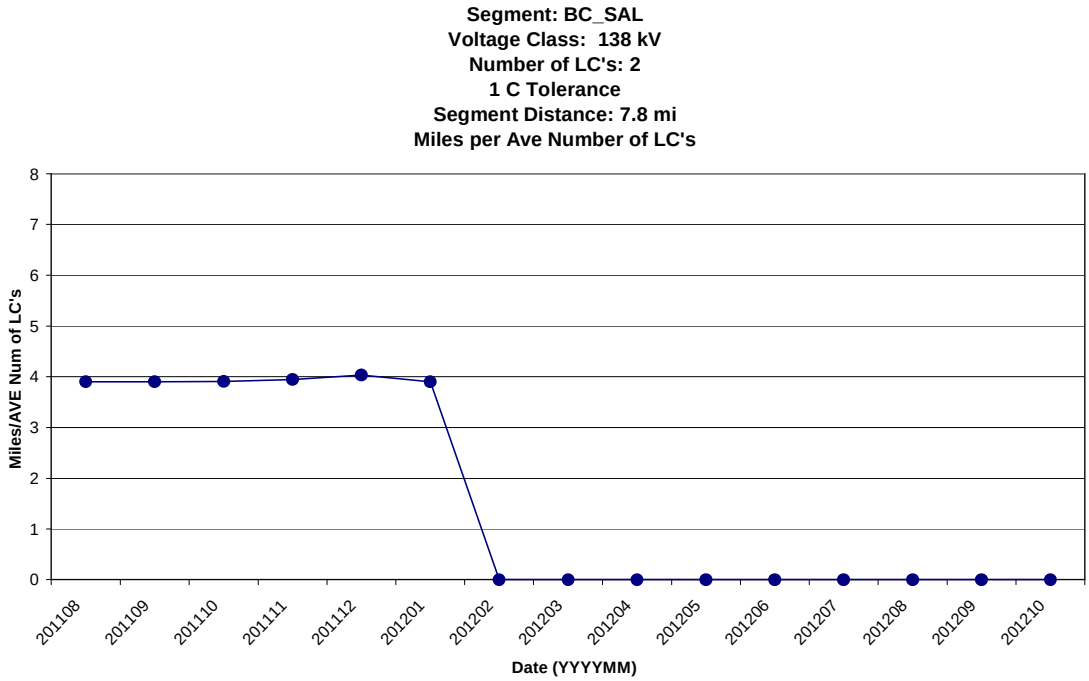


Figure 28b: Monthly trend of miles per average number of LC's at Bell County-Salado for 1 ^{o}C accuracy.

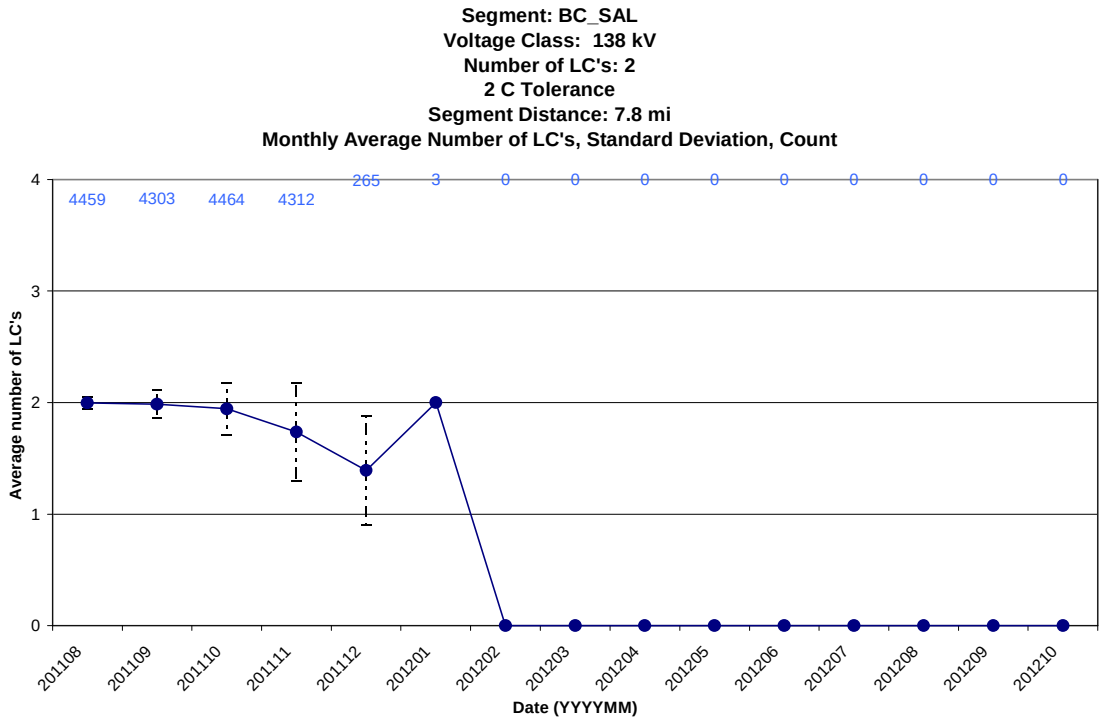


Figure 29a: Monthly Trend of number of LC's at Bell County-Salado for 2 ^{o}C accuracy.

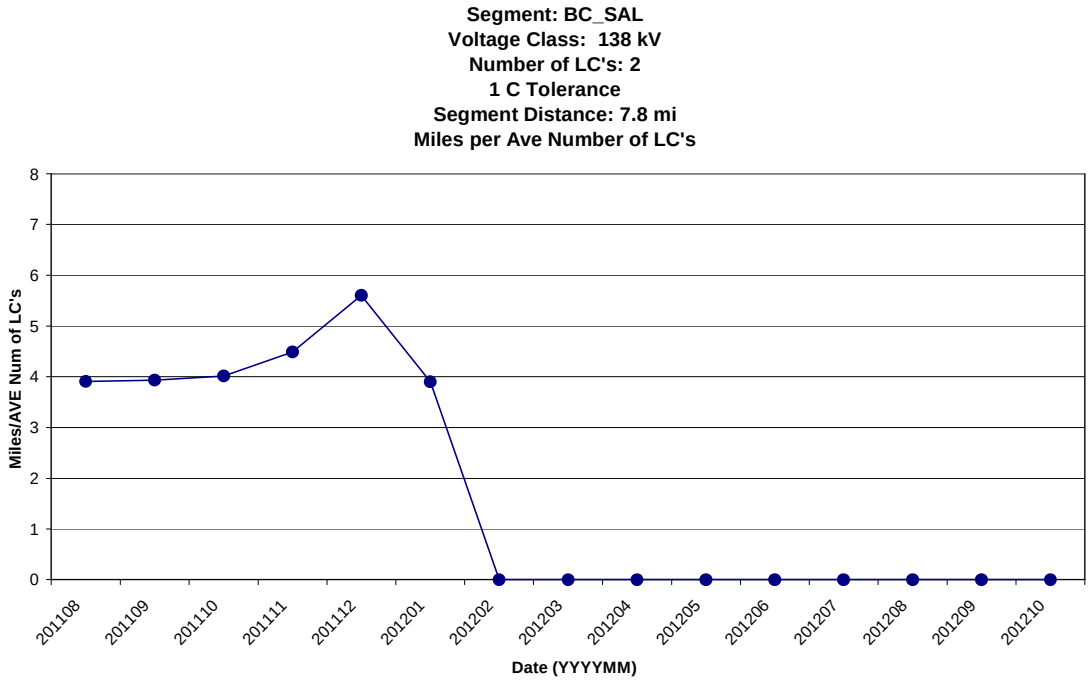


Figure 29b: Monthly trend of miles per average number of LC's at Bell County-Salado for 2 ^{o}C accuracy.

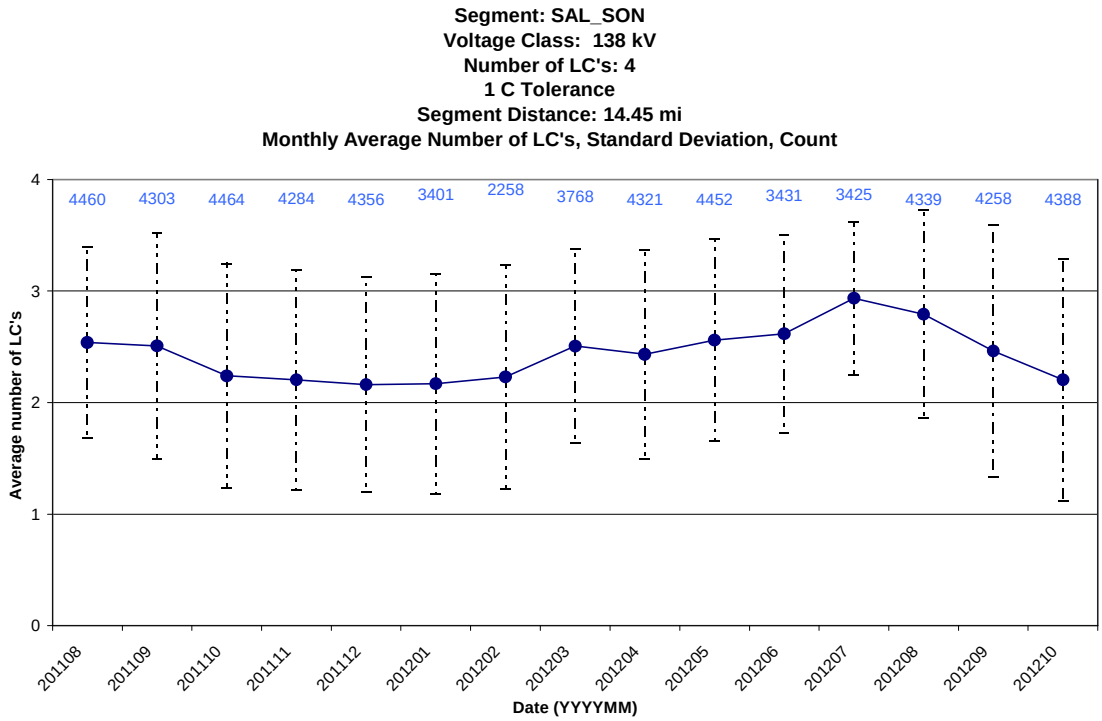


Figure 30a: Monthly Trend of number of LC's at Salado-Sonterra for 1 ^{o}C accuracy.

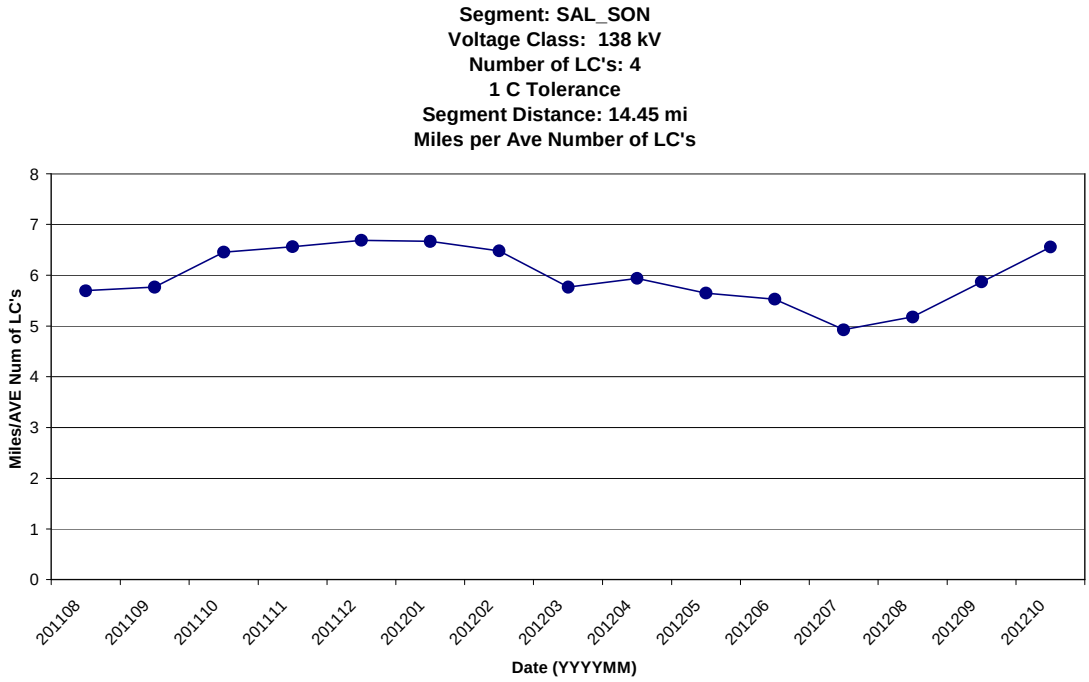


Figure 30b: Monthly trend of miles per average number of LC's at Salado-Sonterra for 1 ^{o}C accuracy.

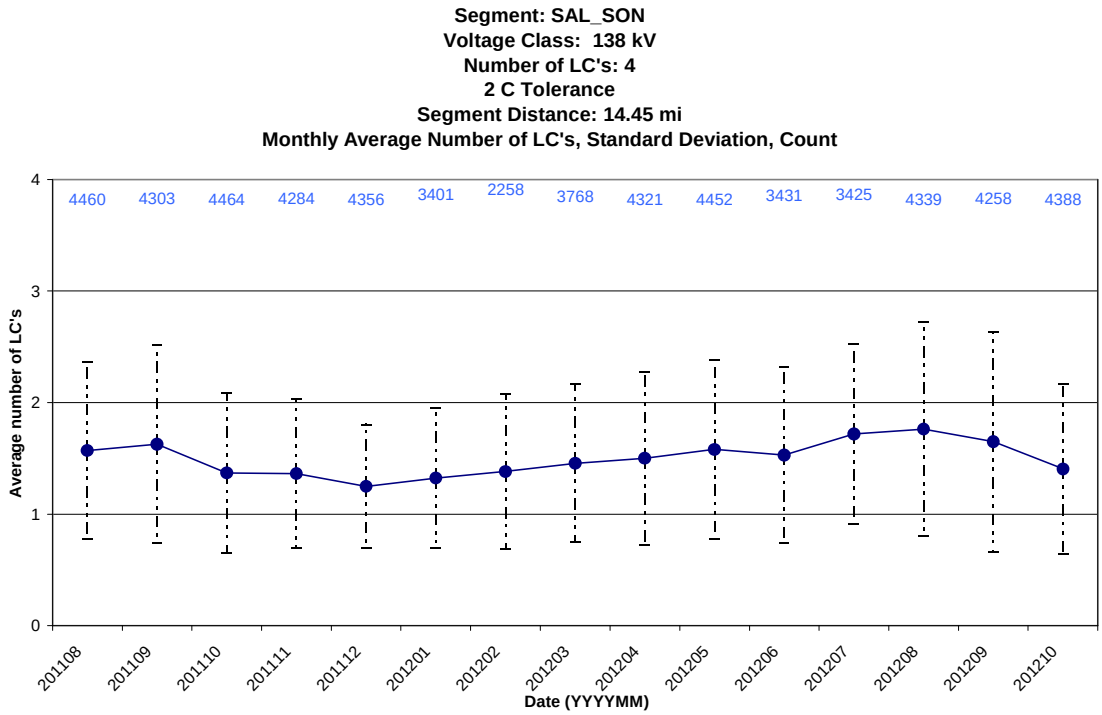


Figure 31a: Monthly Trend of number of LC's at Salado-Sonterra for 2 ^{o}C accuracy.

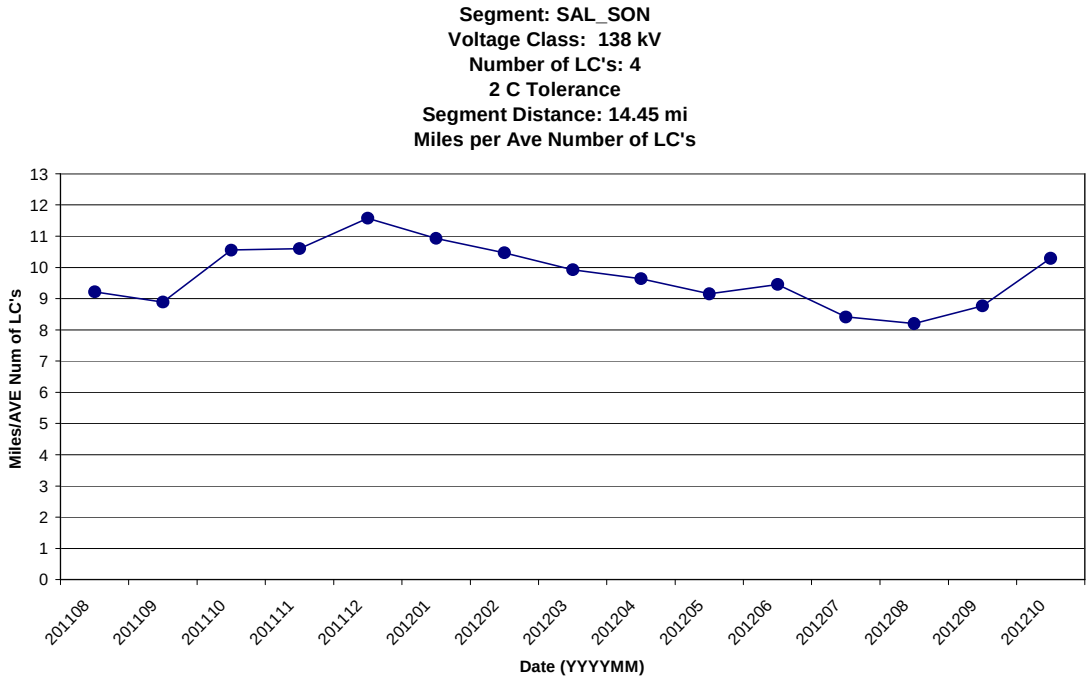


Figure 31b: Monthly trend of miles per average number of LC's at Salado-Sonterra for 2 ^{o}C accuracy.

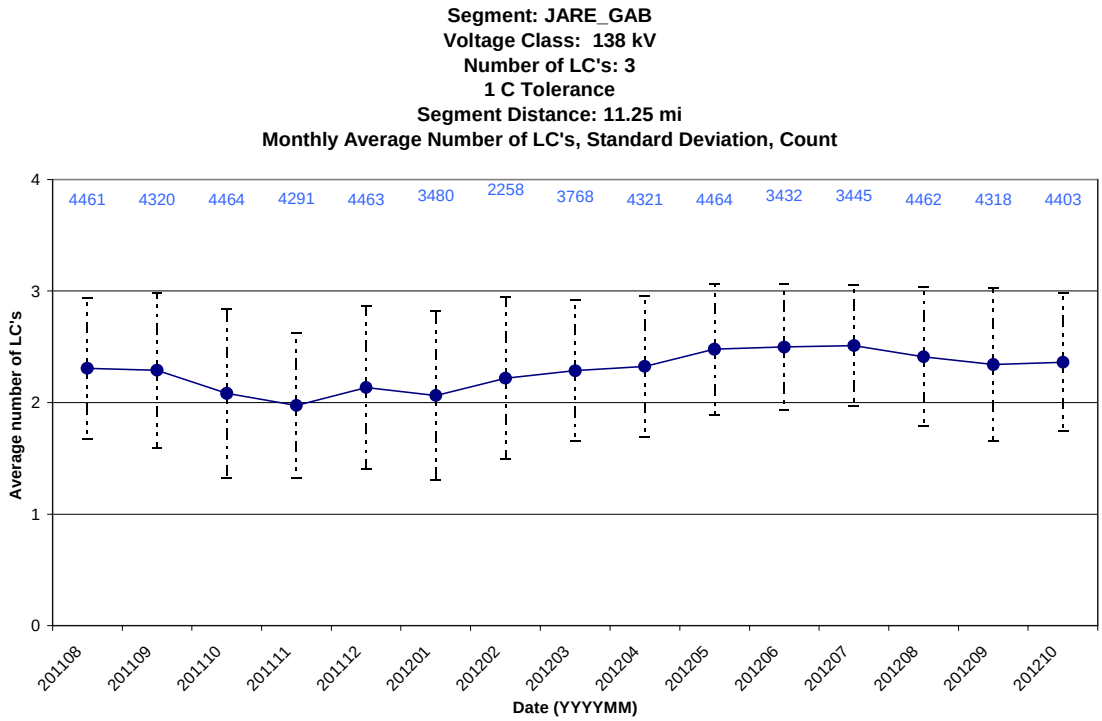


Figure 32a: Monthly Trend of number of LC's at Jarrell East-Gabriel for 1 ^{o}C accuracy.

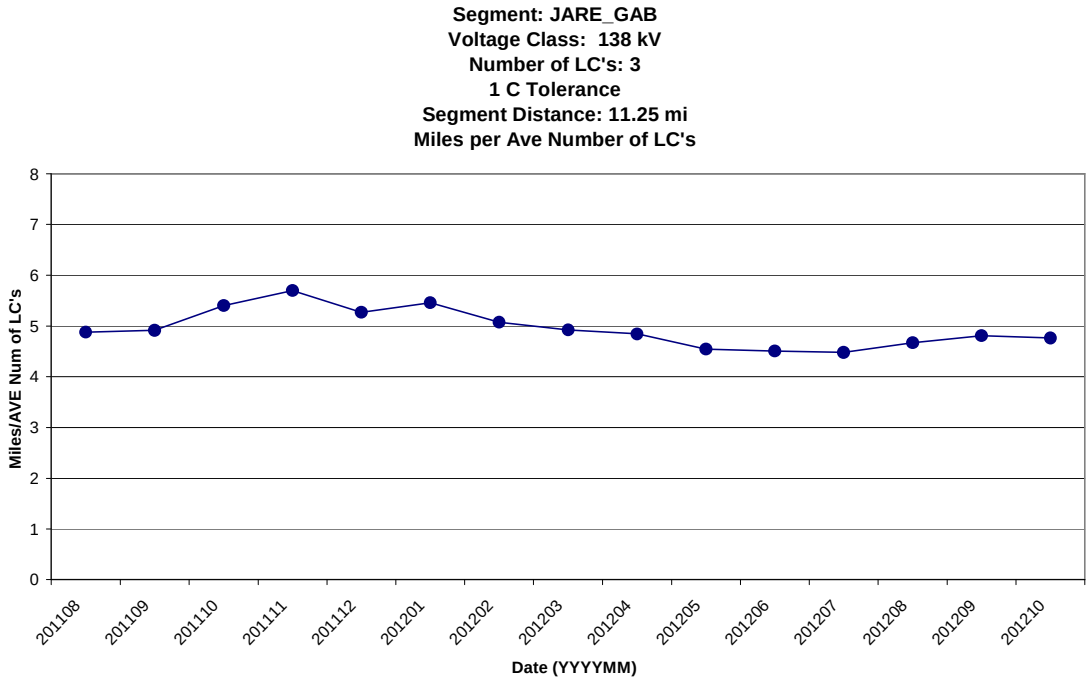


Figure 32b: Monthly trend of miles per average number of LC's at Jarrell East-Gabriel for 1 ^{o}C accuracy.

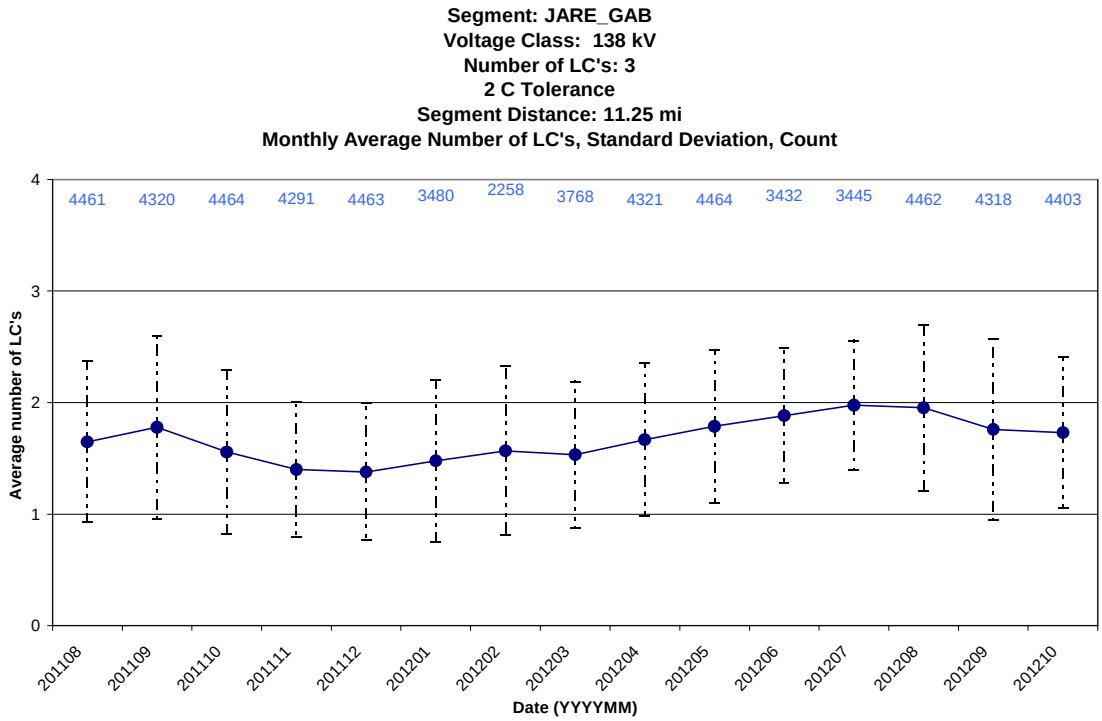


Figure 33a: Monthly Trend of number of LC's at Jarrell East-Gabriel for 2 ^{o}C accuracy.

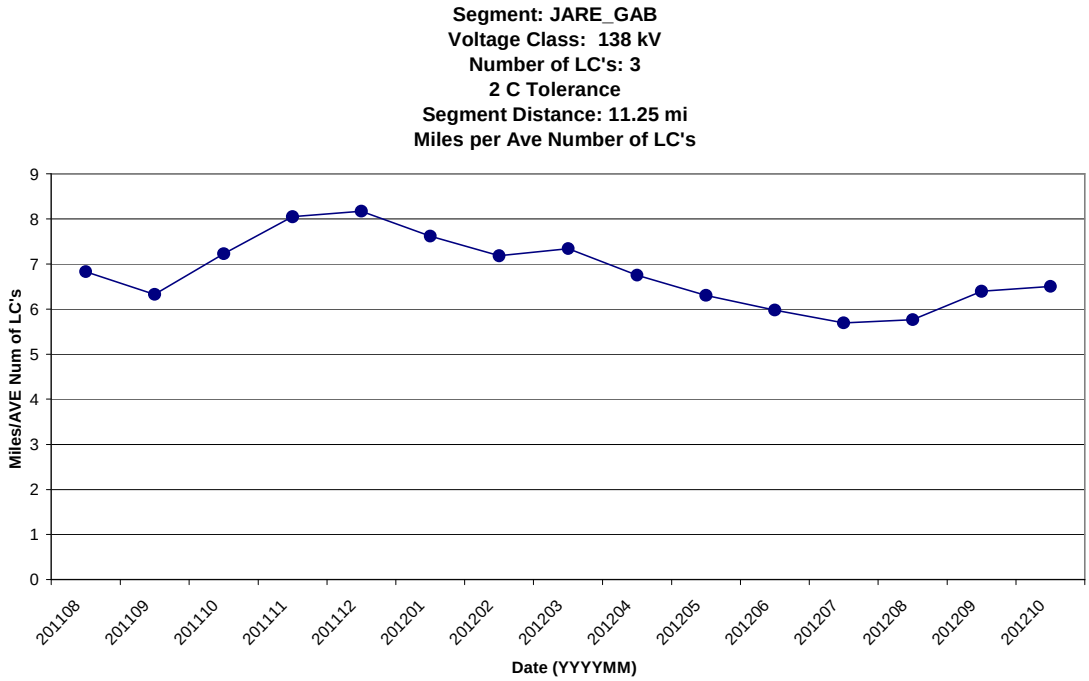


Figure 33b: Monthly trend of miles per average number of LC's at Jarrell East-Gabriel for 2 ^{o}C accuracy.

1.6 Benefits

The study makes the case that a 1 ^{o}C and 2 ^{o}C temperature accuracy for conductor temperature measurements by tension-monitoring equipment is acceptable based on two factors: conductor temperature accuracy and minimizing a rating error. Overall, the statistics on the number of loadcells needed show that previous guidelines of approximately four loadcells per 20 miles were correct. More specifically, in segments greater than nine miles long with three or more deployed loadcells, one loadcell per five miles was required to provide a 2 ^{o}C or less error. In segments that were less than nine miles, a minimum of two loadcells were required to provide a 2 ^{o}C or less error. In all cases, the statistics show that the segments were over-instrumented or correctly instrumented to be within 1 ^{o}C or 2 ^{o}C average conductor temperature accuracy.

Of the 14 monitored segments, 10 had well-distributed percentages of time that a loadcell was the limiting element in meeting temperature accuracy. Thus the majority of segments could not be monitored using a critical span for temperature accuracy. The four exceptions were on short segments with only two loadcells. Having more duplication of tension-measuring equipment seems to reduce the risk of bias.

Seasonal and system drift was limited and difficult to discern from the data. However, the average number of loadcells within a year typically didn't vary more than ±10-15% from month to month. Results indicate that future applications of loadcells may consider seasonal and monthly variation as a secondary influence on the minimum number of loadcells needed for deployment.

1.7 References

[1] Stephan 2012, "Guide for application of Direct Real-time monitoring systems." CIGRÉ Technical Brochure N° 498. Working Group Committee B2.36.

1.8 Footnotes

[1] Rating methods based on tension-monitoring technology address all of the elements affecting Dynamic Line Ratings. The spatial variability of wind, solar energy and ambient temperature are addressed, as are the variances in transmission line materials, construction, maintenance and aging. Plus the technology accounts for variables such as conductor core temperatures exceeding surface temperatures and heating introduced by magnetic losses when conductors are operated at high currents.

Figure 1 depicts a transmission line section supported by suspension insulators and terminated by deadend insulators. A wind blows on some of the spans, while other spans exist in a dead calm.

In the spans cooled by wind, the conductor will contract and the mechanical tension in the conductor will tend to increase to a level greater than the tension in adjacent spans. Since the suspension insulators between spans are free to move, they will swing inward toward the span having the higher tension until the tensions on both sides of the suspension insulators are equal.

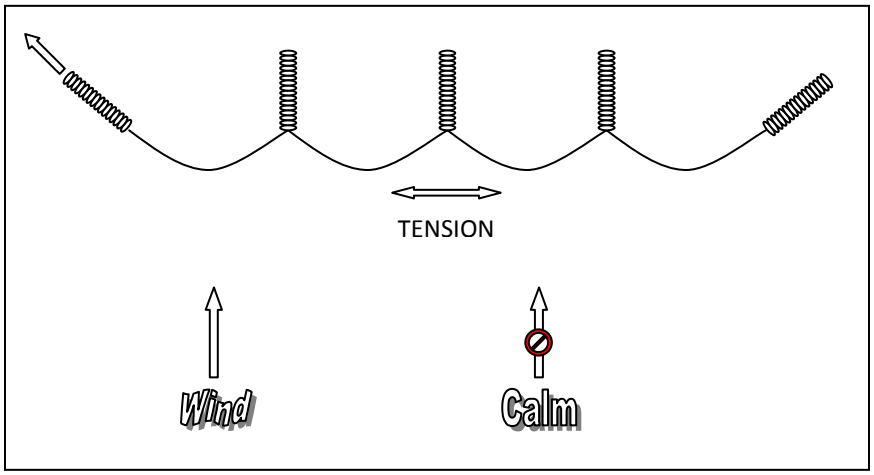


Figure 1 – Tension Equalization

In the spans not cooled by wind, the conductor will expand and the mechanical tension will tend to drop to a level less than the tension in adjacent spans. The suspension insulators will swing away from the span until all tensions are equalized.

The tension adjustments will continue until all tensions are equalized. The spatial variability of wind, ambient temperature and solar radiation will then have been resolved into a single variable (tension) that is a function of the average temperature of the conductor between deadends.

APPENDIX F. DAY-AHEAD FORECASTING

1. Day-Ahead Forecasting

1.1 Preface

The transmission capacity released by DLR (Dynamic Line Rating) is as variable as the weather over time. The key question is how much additional released capacity will be available for the next day's operations and the next year's operations. The answer has major implications for asset utilization, economy of power delivery and system reliability.

1.2 Scope

DLR data from the eight transmission lines will be examined to identify patterns in ratings that can be used to forecast dynamic transmission capacity. Based on those patterns, a methodology will be defined that provides a practical and easily implemented forecast of future capacity. It was anticipated that the data will justify a methodology that raises the static limits presently employed in transmission system planning. However, that is not a foregone conclusion and other techniques remain open to exploration.

There is always some uncertainty in any forecasting technique. The degree of uncertainty that is acceptable and the impact of that uncertainty on planning and operations will be assessed.

Also to be assessed is whether a given methodology is universally applicable or if it needs to be tuned for a given set of conditions such as voltage class, size of conductor, length of line and surrounding terrain.

The following data presentations will be required to identify and formulate an initial methodology. The data is identical to that produced under the tasks associated with defining the capacity released over current ambient-only temperature dynamic approach.

- Plot of the difference between the Dynamic Line Rating and the Ambient Adjusted Rating on a monthly basis as a probability distribution as a percent of time.
- Plot of the DLR and the AAR on a monthly basis as a daily distribution.
- Plot of the DLR, conductor temperature and ambient temperature as a time-of-day plot.

Additional data presentation formats may be required based on questions or conclusions drawn from an examination of the initial data set.

A report summarizing findings and making recommendations on future practices or studies will be written.

1.3 Task execution

Each month the data from the subject lines in the project was processed to produce the types of graphs shown below. For comparison purposes, two 345 kV transmission lines (Tradinghouse-Lake Creek West and Tradinghouse-Lake Creek East) are shown side by side for the summer month of August and the

winter month of December 2012. The processed data shown below is typical of all the data processed for all of the eight lines during the course of the study.

The monthly probability distribution graphs in Figure 1 show the percentage of time that a given level of Dynamic Line Rating was available during each month. The Dynamic Line Ratings of both lines exceeded the Static Ratings by at least 95% of the time during both the summer and winter months. Note that although the lines are parallel and separated by only two to three miles, they show different probability distributions.

The monthly distribution probability graphs in Figure 2 show the percentage of time that the Dynamic Line Rating exceeded the Ambient-Adjusted Rating (AAR) throughout each month. Again the same two parallel transmission lines are shown for the months of August and December. Note that trends are similar between the two lines during the same time of year. However, the trends are not similar when comparing the same line at different times of the year.

The daily distribution probability graphs in Figure 3 show the levels of Dynamic Line Ratings available during each hour of the day during the month. Data for the Minimum Rating, Median Rating, 85th Percentile, 90th, 95th and 99th Percentiles are shown. Example: At noon during the month of August 2012, the Dynamic Line Rating for the Tradinghouse – Lake Creek West line was greater than 1917 amperes 90% of the time compared to the Static Rating of 1794 amperes. Again, note that the variation of the data across the four panes for the two lines and the two months of data is different for each line and in each month

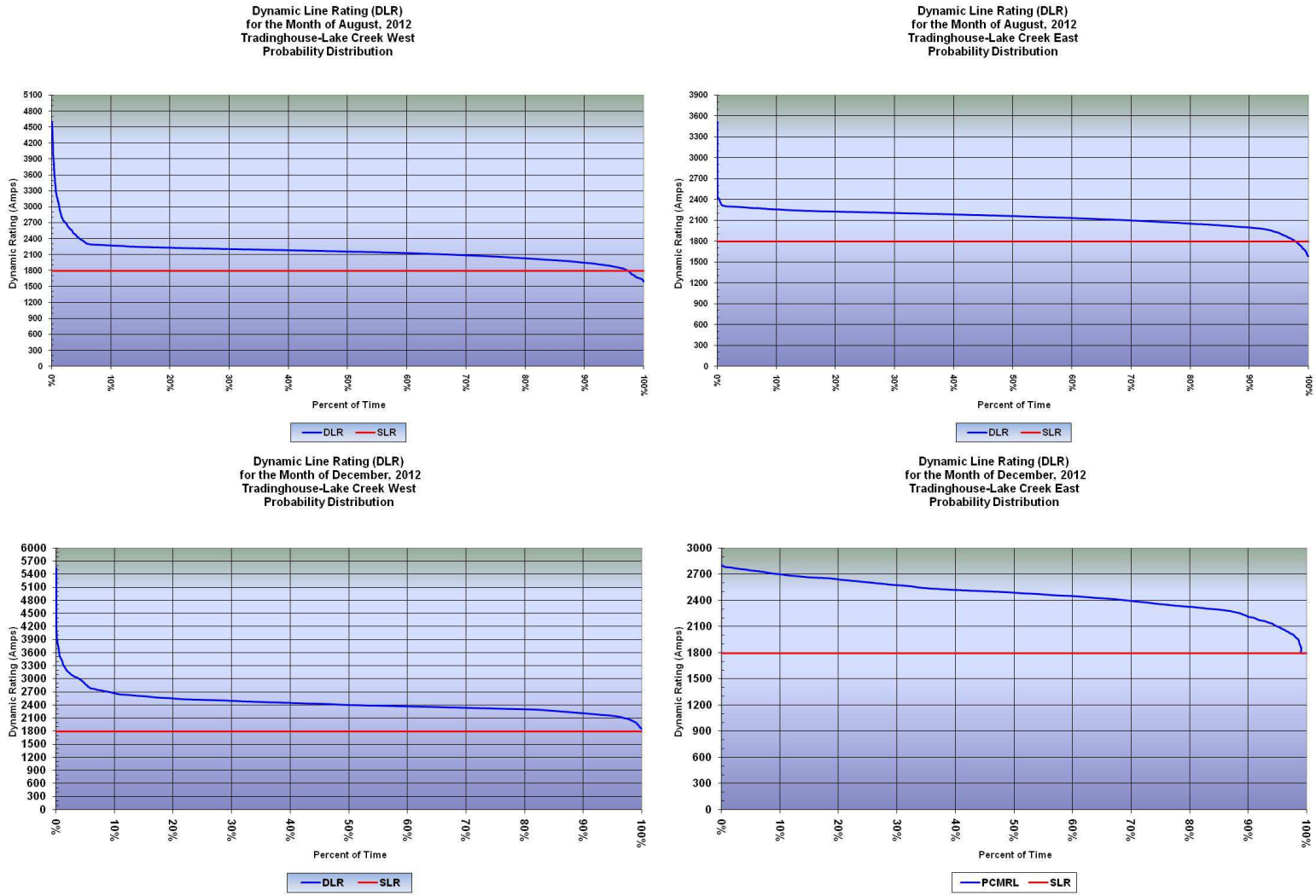


Figure 1 – Dynamic Line Rating Monthly Probability Distribution Graphs - 2 Transmission Lines - August & December 2012

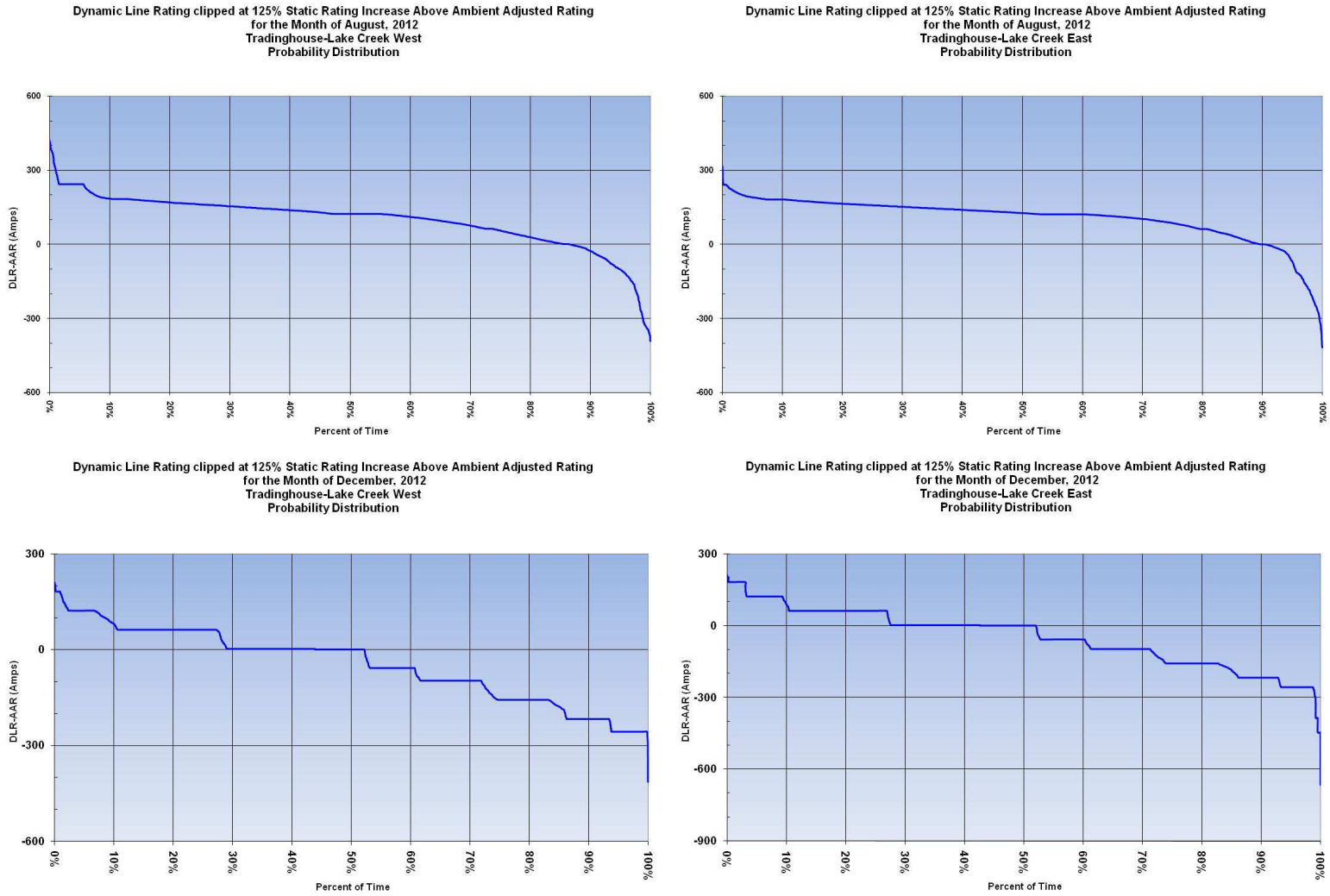


Figure 2 – Dynamic Line Rating Increase Above Ambient-Adjusted Rating - 2 Transmission Lines - August & December 2012

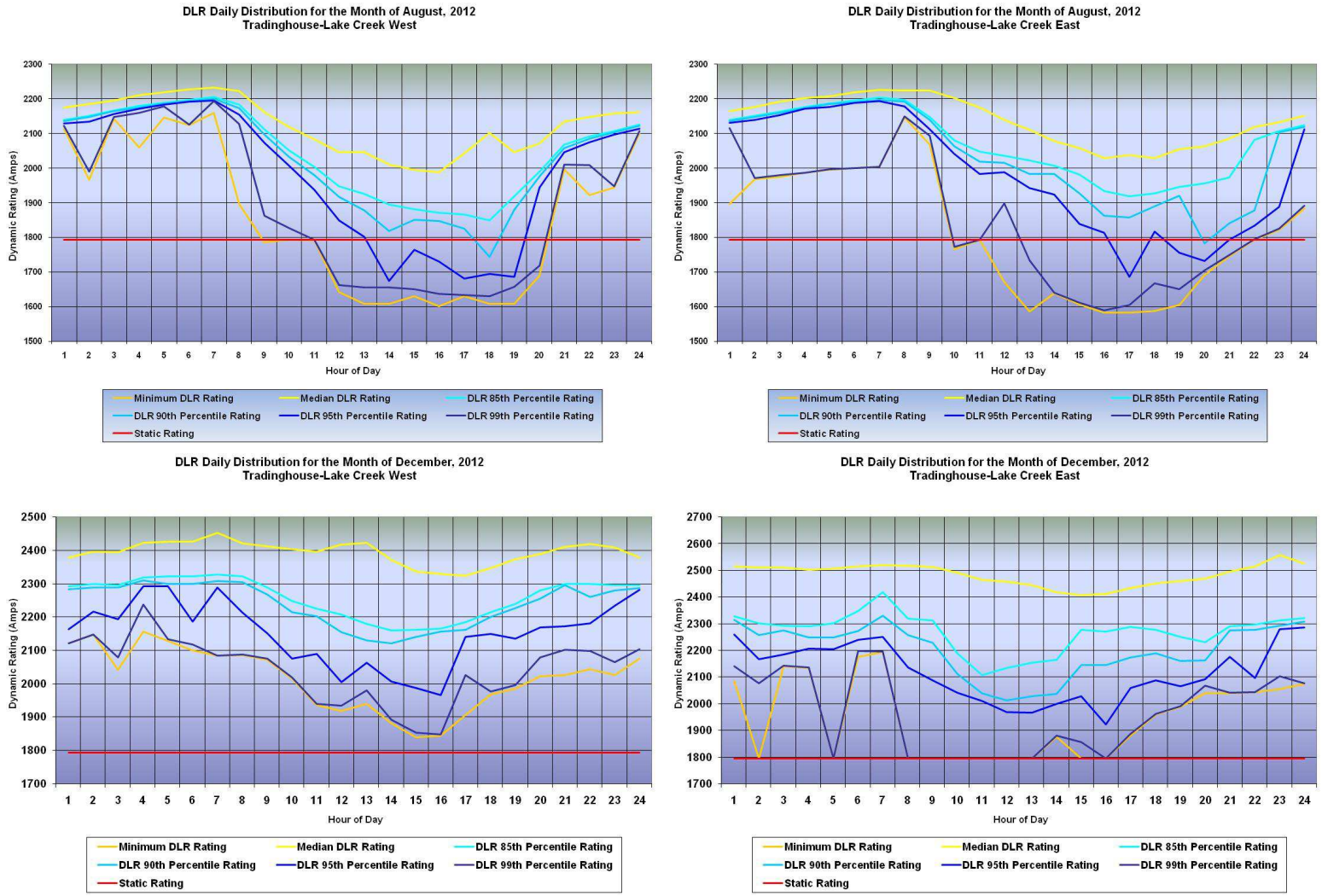


Figure 3 - Dynamic Line Rating Daily Probability Distribution Graphs - 2 Transmission Lines - August & December 2012

2. Results

As noted in the Task Execution section, the amount of transmission capacity released by DLR is as variable as the weather over time and distance. A common denominator could not be identified that would establish a single predictor of capacity across an entire geographical region, voltage class or other criteria. The conclusion is consistent with expectations, given the spatial and temporal nature of weather coupled with the differing topologies of each transmission line.

However, the data did lend itself to development of a practical methodology that provides both planning and operations functions with a usable prediction of future capacity for each individual transmission line. That methodology results in the ability to safely raise the static rating limits on a transmission line while ensuring that the conductor always remains within its specified maximum operating temperature and thus its sag limits.

Figure 4 shows the 90th percentile of Dynamic Line Ratings (DLR) for each month during 2012 on the Tradinghouse – Lake Creek East 345 kV transmission line. For any given month, the available capacity on the transmission line was greater than the 90th percentile line on the graph. Note that for October, 90% of Dynamic Line Ratings were at least 1955 amps (the published static limit was 1794 amps).

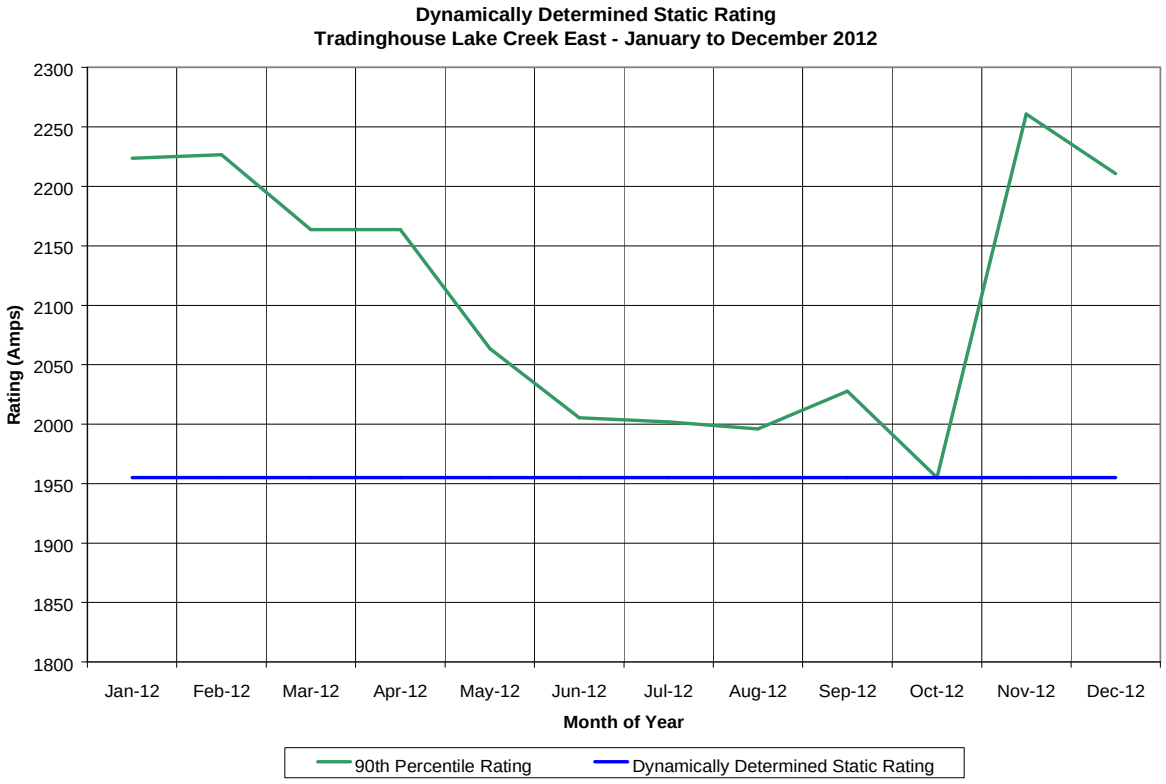


Figure 4 -90th Percentile of Dynamic Line Ratings for Each Month During 2012 Tradinghouse – Lake Creek East 345 kV

Figure 5 depicts the available capacity of the Tradinghouse – Lake Creek 345 kV transmission line during October 2012. The present static rating for the line is 1794 amps. This line is capable of exceeding its static rating more than 97% of the time, with more than 9% additional capacity being available at least 90% of the time.

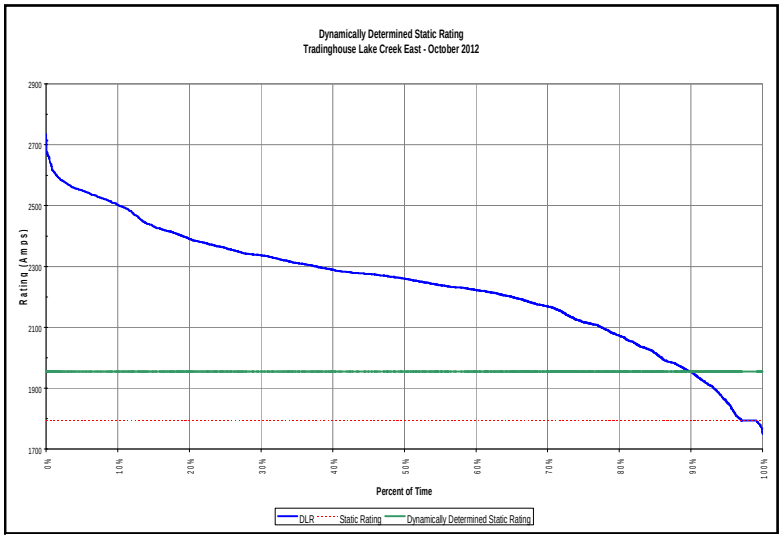


Figure 5 – Available Capacity October 2012

What would be the impact of raising the static rating from 1794 amps to 1955 amps (90th percentile)? The available transfer capability would go up, congestion would be relieved, and there would be more room with which to ensure system reliability. Operating practices would remain unchanged since they would still be based on a fixed static rating. It would be business as usual with less congestion and more reliability.

But what would be the impact of the added risk? Most transmission lines are operated to survive a first-contingency event. The risk of a first-contingency event occurring is 0.001 to 0.005. The risk that the 1955 amp rating will not be available is 0.10. The risk of both events occurring at the same time is 0.005 x 0.10 = 0.0005. 99.95% of the time the system operates (including first-contingency events) without operator intervention. What about the other 0.05% of the time? If a DLR system is in place, the operator will receive a warning when the projected post-contingency load is approaching the Dynamic Line Rating.

Figure 6 graphically portrays a DLR system function known as a dynamic alarm. The static rating has been increased to a higher level as described above. The load can be actual load or, more typically, the projected post-contingency load output by the EMS security analysis. The DLR system will trend both the load and the Dynamic Line Rating. When the two trends are projected to converge in 15 minutes, an alarm is triggered to alert the operator. The operator may then respond as he deems appropriate. Responses might include:

- Redispatching the system to accommodate any possible contingency event.
- Taking no action but having a remedial action plan at hand should a contingency event actually occur. Dynamic Line Ratings coupled with dynamic alarms make it possible to garner all the economic and operational benefits of a higher and more realistic static rating with complete safety.

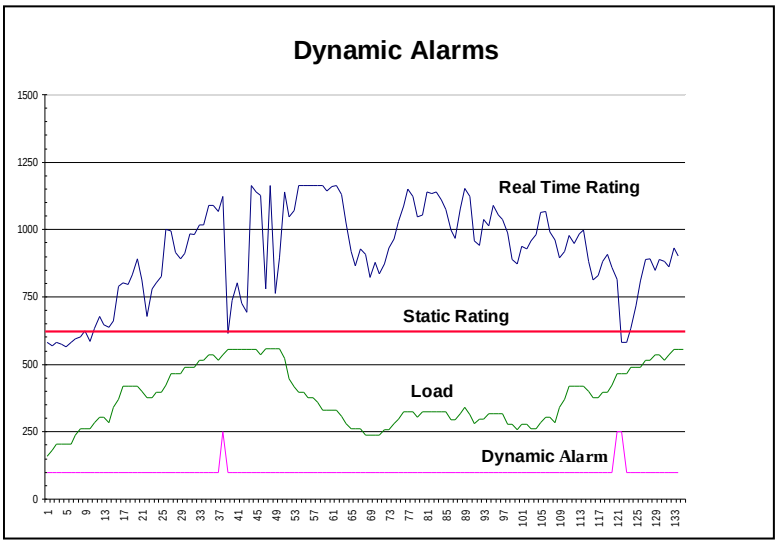


Figure 6 – Dynamic Alarms

3. Conclusion – Day-Ahead Forecasting

Project results and the methodology developed and applied to present those results are practical and effective initial steps in developing a forecast criteria and methodology.

Data from the project shows that DLR varies in both time and space along a transmission line; it also varies between lines, even if the lines are in close proximity. A common denominator could not be identified that would establish a single predictor of capacity across an entire geographical region, voltage class or other criteria. The conclusion is consistent with expectations, given the spatial and temporal nature of weather coupled with the differing topologies of each transmission line.

However, the data did lend itself to development of a practical methodology that provides both planning and operations functions with a usable prediction of future capacity for each individual transmission line. That methodology results in the ability to safely raise the static rating limits on a transmission line while ensuring that the conductor always remains within its specified maximum operating temperature and thus its sag limits.

The developed methodology permits grid operators in the control room to comfortably, even transparently, utilize a new higher static rating with no or very minimal change to present day-of and day-ahead practices.

Since the higher ratings can readily be accommodated in the control room with the developed methodology, planning functions can also safely utilize the higher static ratings in their assessments and plans for grid capacity upgrades.

Most load growth is gradual and can be foreseen a year or more in advance. Those are ideal conditions under which to capitalize on DLRs rapid (90-day) deployment and extremely low capital utilization. As the need for additional capacity becomes visible on the horizon, DLR systems can be deployed on the target lines (usually 9-12 months in advance). That provides sufficient time to gain a clear picture of exactly where the new higher static rating should be set. Plans for physical upgrades to the lines can then be scheduled in keeping with the company's least regrets capital strategy.

The methodology developed by this project can be utilized immediately by both System Operations and System Planning on individual transmission lines. In order to develop a capacity forecasting tool on which multiple line behavior can be patterned and decisions made based on wide geographical areas, voltage classes or other global criteria, a greater length of time and cross-section of lines is required to formulate a statistical model of the data. In particular, a statistical database needs to be developed to capture and classify seasonal and local variations in ratings, which are influenced by the local geography, line attributes and mesoscale and microscale meteorological conditions.

The success of this project in the development of a capacity forecasting method for individual lines suggests that pursuing a forecasting method for multiple lines at once may be warranted.

3.1 Conclusion – DLR as a Planning Tool

DLR will be a successful tool to enable transmission planners to mitigate congestion, increase system reliability and redeploy capital to its most efficient uses through a least regrets strategy. We see five potential applications for DLR as a planning tool.

a. **Least regrets capital strategy:** DLR can be utilized in the planning process to enable a least regrets capital strategy, which minimizes any potential stranded investment.[16,2] The SGDP Project demonstrated that DLR is a valuable tool to be applied during project identification and solution development. DLR can be an effective screening tool that can be used in identifying and analyzing the value of proposed transmission investments and help avoid potential capital-intensive stranded assets. DLR can be a filtering gate allowing utilities to redirect scarce capital to higher-value projects for the long term. DLR as a screening tool can enable planners to tackle the highest-value project first, enabling them to better deal with the demands FERC policies place on planners.

   Specifically, DLR offers very competitive solutions for projects in the planning queue that require a few percent up to 10 to 15% or higher increased capacity. The actual released capacity depends on

[16] Duke University,"Calculating Regret Scores," presented to SEARUC, June 9, 2013.

[2] The Brattle Group, "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," July 2013.

the topology of each transmission corridor. Typically, there are many projects of this type in the queue every year. Since all lines must be able to support one to multiple N-1 contingency events, there are frequently cases where the base loading of a line plus the N-1 contingency load exceed the line rating capacity by a few percent. These cases may stay at this level for several years during the long-term planning process, or loading may grow enough to necessitate a well-justified extensive capital expenditure. Generally these lines do not make the need/cost/benefit test to become funded during the short-term budget cycle. Projects that do have load growth in the area may ultimately clear the threshold and become funded. Other projects may drop off the queue when some other grid topology changes and the load is addressed by some other solution or system change. When projects do not move on to funding, the marginal overloads are dealt with in real time by the operating system that manages the grid to maintain no violations for N-1 contingencies. This leads to non-economic dispatch and line congestion costs. Instead, DLR maintains economic dispatch and can act as a gate in the 0% to 15% capacity need range, allowing for more cost-effective long-term planning of transmission assets.

b. **More realistic and reliable transmission corridor rating:** Each transmission corridor is subject to weather parameters, especially wind direction and speed. These parameters are the determinants of transmission capacity for a given wire size. Typically, the topology of the transmission corridor remains the same over an extensive period. DLR can be used to collect historical and statistically significant data to characterize the meteorological patterns within each corridor. Analytics can then be applied that will help create a “rating signature” for each monitored corridor, rather than using static ratings based on assumed weather conditions. This ratings signature can then be used for more representative ratings for all monitored transmission corridors. This will help improve asset utilization and increase reliability.

c. **DLR for Operations Planning:** As transmission owners come under increased regulatory pressure on allowed ROE and face daily challenges to realize that allowed ROE, DLR can be used as a financial mitigation tool. Specifically, DLR enables the transmission owner to realize additional revenue, which is available with DLR-wide deployment. DLR lets the transmission owner take full advantage of the actual transmission capacity in real time, which is more than the static capacity used to plan for operations without DLR. Further, DLR protects the transmission asset from overheating and ensures that transmission operations always comply with NERC and NEC phase to ground clearance requirements.

   The SGDP Project demonstrated that the actual transfer capacity of the grid is more than the currently used capacity based on static assumptions or based on AAR for the vast majority of the time. The project also demonstrated the value of DLR as a clearance reliability tool.

d. **DLR as a Bridge to Planned Transmission Build-up:** The demand for capacity often presents itself faster than time and capital can address it. DLR can provide a bridge that immediately addresses the need while keeping system reliability intact. Planning and construction can proceed at a pace that precludes cost overruns. Capital can be scheduled to take advantage of lower costs in the marketplace, especially if the demand for capacity is steadily ramping up. Capital can also be

redirected to more urgent or desirable projects. And, of course, DLR provides the least regrets option when the supposed demand fails to materialize.

e. **Addressing the next limiting element:** When DLR is deployed on a line, the true capacity of that line becomes known. The monetary value of each added unit of capacity is also then known. If that true capacity is capped by the next limiting element, it becomes a simple matter to calculate the economic benefit of upgrading the next limiting element.

APPENDIX G. PERSISTENCE OF DYNAMIC RATINGS

Persistence of Dynamic Ratings

1. Executive Summary

Persistence is defined as the range of future real-time ratings as a function of current rating, time and probability. The objective of Persistence Based Ratings (PBR) is to predict the probability of available capacity above the static ratings and to reduce the load curtailment probability to less than 1%. Note that future ratings have the ability to increase or decrease from their current value. However, the greatest concern is for the ratings going lower than their current value.

As a research and development exercise, the challenges and outcomes of the SGDP Project were uncertain. In the project plan, it was assumed that the line currents would be relatively high and that occasional load curtailments would be necessary because of contingency limits. Those curtailments would have provided a real world laboratory that allowed development of real-time PBR algorithms for operational purposes.

Unfortunately, the loads of all circuits were quite low. This resulted in only four circuits with load levels sufficient for statistical evaluation of the potential benefits of PBR, and even in these circuits only for only a few months of the data collection period. Nonetheless, based on these statistics alone, the study demonstrates that a fully automated application of PBR would allow operation of the lines at 105-125% of static ratings, at less than 1% risk of load curtailment.

The operational trial of persistence slated for this study was not able to be completed. The low line loads that were prevalent throughout this project precluded a meaningful trial and validation of the preliminary results reported here.

2. Background

For effective operational use of dynamic ratings, the system's operators need to have information about the persistence of the observed ratings, i.e., knowledge of the possible change of ratings during the next 15 to 60 minutes. Studies, especially a recent one in California[17], have shown that rating conditions can have substantial short-term persistence. The California investigation showed that for the selected relatively short time periods and during summer conditions, persistence information offered a feasible approach for more effective utilization of transmission capabilities. The short extent of the study did not verify the application for other climates or for weather conditions throughout the year, nor did it study the most effective use of such information.

[17] Attachment D for Multi-Area Real-Time Transmission Line Rating Study, CIEE Award C-05032, WA 121, Under CEC/CIEE Prime Contract 500-99-013.

2.1 Scope

This study originally consisted of three phases. The outcome was unknown, and different layers of challenges, which required changes in the task, were uncovered as the project proceeded. The second and third phases were dependent on having sufficient load levels a significant amount of time to capture a data set large enough to develop algorithms and software. Because the load levels on the project's lines were much lower than anticipated, the original scope of the second and third phases could not be implemented. The scope was modified to substitute an analytical study demonstrating one practical application based on the limited amount of historical data that came out of Phase 1. This demonstration application may be useful for future studies and operations.

Phase 1. Validation of concept and estimate of benefits

Data from the five separate line corridors is collected and evaluated statistically, to identify the persistence and its dependence on localities, seasons and other external variables (line length, conductor's thermal time constant, etc.) This data is used to estimate the potential benefits and risks. It will also provide the data for bench-testing algorithms and software to be developed in Phase 2.

Task Changes to Phase 1

Because load levels over a 12-month period for the eight project lines were low, there was not sufficient data to identify persistence trends based on seasons, localities and other external variables. Instead, benefits and risks were assessed based on a few months of data at four segments where load levels were sufficient.

Phase 2. Development of algorithms and software

Based on data from Phase 1, algorithms and software that automatically calculate in real time the risk level for different rating levels were to be developed and bench-tested against collected historical data.

Task Changes to Phase 2

Load levels in the majority of the months over a 12-month period for the eight lines through most corridors were below those required to support persistence. Those low load levels were projected to continue into Phase 3 where they would preclude successful operational trials. Therefore, Phase 2's slated development of algorithms and automated software for use in Phase 3 was canceled. Instead, a historical analysis of available data was conducted. One of two persistence methods was chosen and applied to the available data to look at potential benefits and risks.

Phase 3. Operational Trials and Final Report

Operational trials are conducted with the developed software. Oncor will establish a small team of at least one person from System Operations and one from System Planning. This team will evaluate the persistence data collected during six months and compare it to operational records. The purpose is to identify operating actions, especially contingencies, which could have been managed differently based on persistence information. The economic consequences of such alternative actions are estimated and summarized. A final report is produced.

Task Changes to Phase 3

As noted under Phase 2's task changes, the loads required to support persistence were generally not available on the eight lines scheduled for operational trials. Blindly proceeding with the trials made no sense. This final report provides analytical results on a few segments each with a few months of sufficient data. The report includes potential benefits, risks and an application of one persistence method based on historical statistical analysis.

2.2 Task Execution

Data Processing

Data processing included steps to identify segments with sufficient loading and to remove suspect data caused by system errors.

Sufficient Load for Persistence Calculations

Two conditions are required for the calculation of persistence ratings: (1) a sufficient conductor temperature rise (delta T) above the no-load temperature[18] to enable calculating a dynamic rating based on the effective wind along a section of line using empirically calibrated state change equations and IEEE algorithms, and (2) the presence of a sufficient delta T for at least three consecutive 10-minute sample intervals. To ensure that both conditions were met, a 350 amp-per-conductor load threshold was chosen with which to filter the data set.

As discussed in the scope of this report, load levels in most of the line corridors were below the 350 amp thresholds. In addition, other system errors required removing data from the analysis. These system errors included periods of maintenance and known issues uncovered from careful evaluation of system data. The process of load and system error filtering is discussed in the next section.

Filtering Data

Load filtering

Four segments were identified that had sufficient loads. A segment was determined to have sufficient loads if 10% or more of the load data during a month was at or above 350 A. The segments with sufficient load data were Lake Creek-Temple (345 kV), Tradinghouse-Lake Creek East (345 kV), Temple Pecan Creek-Temple (345 kV) and Bell County-Salado (138 kV).

In choosing segments that met sufficient load levels, the individual loadcells in the segment needed to have simultaneous sufficient load levels. This was usually not an issue since a segment usually shares similar loads. However, Temple Pecan Creek-Temple had only one of three possible months where loadcells had sufficient loads simultaneously.

[18] The no-load temperature of each line segment in this project was measured by a device called a Net Radiation Sensor (NRS), which determines the temperature of the conductor if the conductor were carrying zero current.

Three of the segments represent complete 345 kV lines while the other represents a segment along a 138 kV line. Further filtering based on system health and shadowing of the Net Radiation Sensor reduced (as discussed below) the 138 kV segment from six months to three months.

Table 1 shows the list of segments and the number of months that each segment met the load threshold and was without system errors.

Table 1: Shows segment, associated line name and the number of months that each segment met the threshold level of 350 A per conductor for at least 10% of the time and had no simultaneous system errors.

Segment	Line Number	kV	# of loadcells	Months where load was sufficient
Lake Creek-Temple	300A	345	6	2 (Dec 2011, Jan 2012)
Temple Pecan Creek-Temple	315A	345	2	1 (Aug 2011)
Tradinghouse-Lake Creek East	290A	345	3	2 (Oct 2011, Nov 2011)
Bell County-Salado	1710C	138	2	3 (Sep – Nov 2011)

Shadow Filtering

To remove error due to shadow effects on Net Radiation Sensors (NRS) a procedure was developed to filter out periods of shadowing. This second level of filtering was performed after load filtering and selecting candidate segments as discussed in the previous section.

The process involved calculating the actual and ideal daily Net Radiation Gain curves for each loadcell for each month and looking for periods of time of reduced measured Net Radiation values.

Net Radiation Gain (NRG) is the difference between the measured ambient temperature and net radiation temperature at each loadcell. An NRG value for each 10-minute interval was averaged over a month and compared to the calculated NRG curve using IEEE steady-state thermal calculations. If the

difference between actual and ideal NRG was more than 1.75 °C, the period of time was flagged as a significant shadowing event and was removed from the data set.

Figure 1 shows the assumptions used in RateKit in calculating ideal NRG for a particular month. RateKit was run in batch mode to calculate daily hourly NRG on a day in the middle of each month of the study. Assumptions included: ambient temperature of 20 °C, wind speed of 3 ft/s wind normal to the conductor, 0.65 emissivity and absorptivity. Conductor orientation was adjusted based on the line orientation near each loadcell.

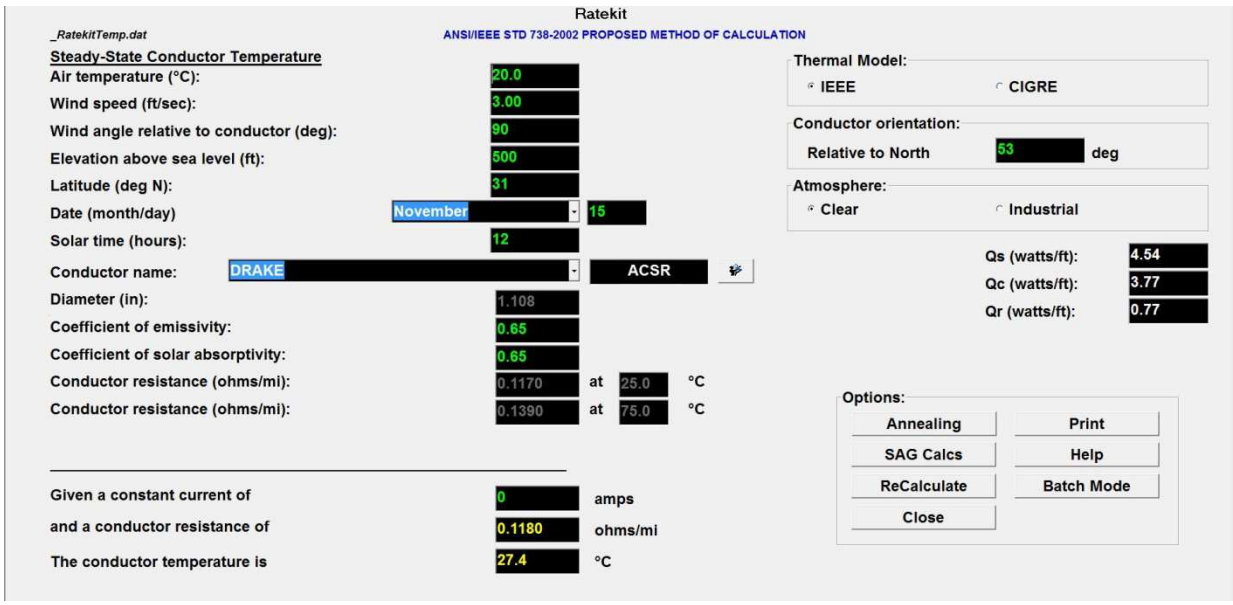


Figure 1: IEEE Steady-state conductor calculation assumptions to calculate ideal NRG.

Figure 2 shows a daily plot for a loadcell in September 2011 comparing the measured NRG (yellow curve) and calculated NRG (pink curve). The third curve (with red points) shows flagged times during the day that shadowing occurred.

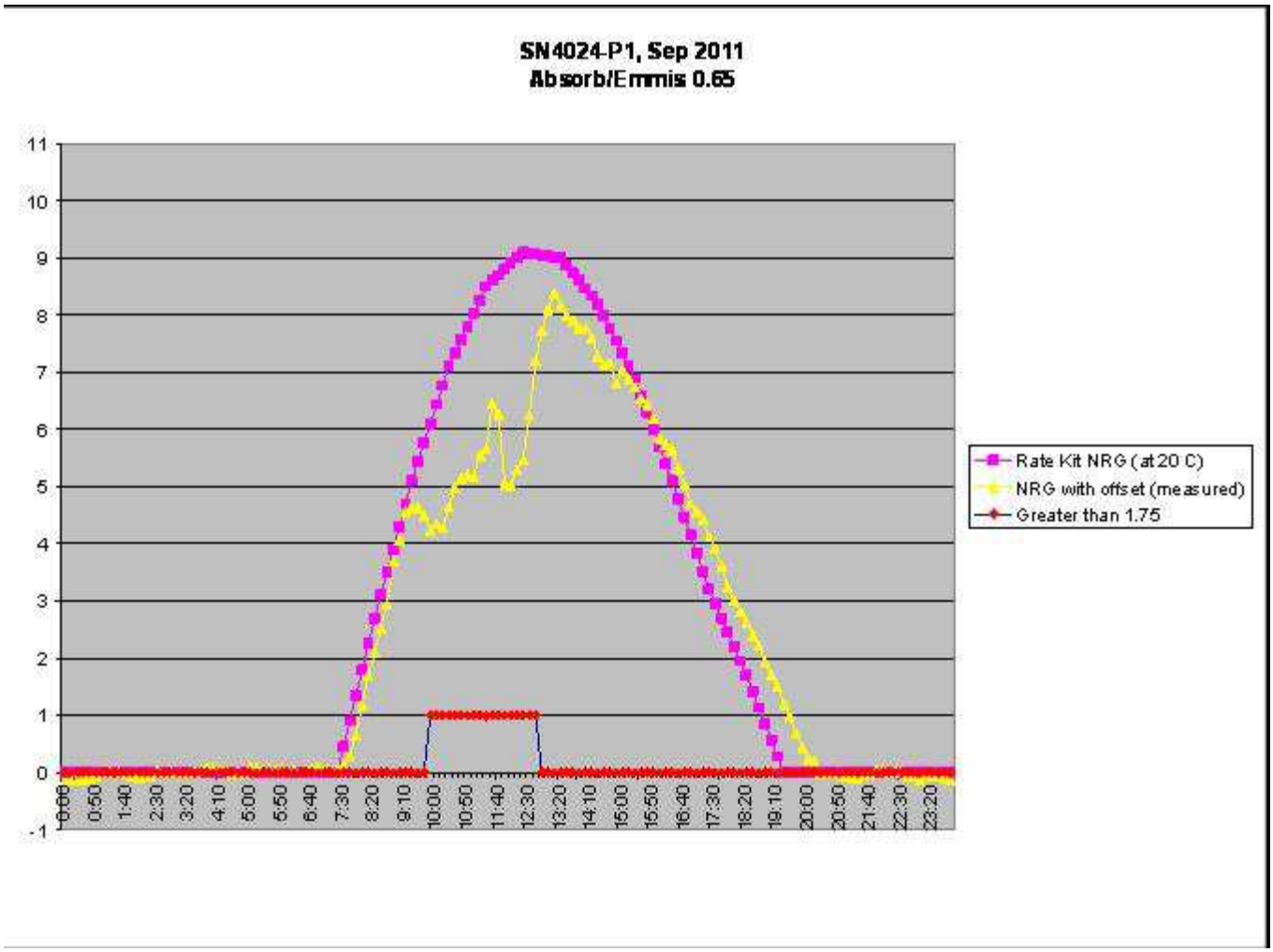


Figure 2: Example of how measured NRG (yellow curve) and calculated NRG (pink curve) compared for CAT serial number 4024 Port 1 (on the Bell County-Salado segment) during September 2011. The red curve shows flagged data occurring approximately between 10:00 and 13:00. This procedure was done for each month at each loadcell on each segment that met load thresholds.

In April 2012 adjustments were made to Net Radiation Sensors to reduce shadowing effects. However, all time periods with sufficient load data were prior to this date.

System Health Filtering

The final set of filtering occurred by reviewing system health reports for outages or other problems that may have affected the raw data.

Monthly system health reports were created by running a program that tabulated statistical data on the raw data. These reports were then checked for anomalous data, and a monthly health report was written to summarize outages.

The most notable outage on candidate lines with sufficient load was on the Bell County-Salado line. Because of anomalously high tension values, one of the loadcells was disabled in February 2012 and

data from December 2011 to February 2012 was considered anomalous. Table 2 summarizes outages that affected segments used in the study.

Table 2: Months and line sections affected by various outages

Months	Segment	Line Name	Line Number	kV	Issues and Comments
December 2011	Lake Creek-Temple	Lake Creek-Temple	300A	345	No data was available from the CAT-1 units reporting from Lake Creek Substation from 12/14/11 @ 21:20 through 12/16/11 @ 12:10. It is assumed that there was a RTU/SCADA outage during that time. During that time, no data was available for 3 of the 6 loadcells, but ICW continued to generate ratings based on the remaining three loadcells. Data not available from Structures 2/4, 8/4 and 15/5.
January 2012	Lake Creek-Temple	Lake Creek-Temple	300A	345	Line outage from 01/23/11 @ 6:06 through 01/25/11 14:48. ICW substituted a static rating for that time frame, as designed.
December 2011 - present	Bell County-Salado	Bell County-Gabriel	1710C	138	The tension value on CAT-1 unit SN 4024 Port 1 (Structure 13/2) has remained at an anomalous value. It may be that there is either a problem with the loadcell or moisture ingress. This was investigated during TVG's April 2012 site visit. **The loadcell has failed due to some undetermined reason. A new loadcell has been shipped and needs to be installed once a line clearance can be arranged.** The loadcell has been be disabled from rating generation since 2/20/12 until the issue can be investigated and resolved. The problem was seen as early as December 2011 and this data has been removed from analysis.

2.3 Analysis

Principle and Application of Persistence Method

Static ratings assume that the most unfavorable solar, wind and ambient temperature conditions all happen concurrently. Real-time rating systems determine the transmission line's capacity under the present actual solar, wind and ambient conditions. Real-time ratings generally exceed static ratings 99% of the time since actual weather conditions rarely approach the worst case weather conditions on which static ratings are based. Real-time ratings can be used to increase the available transfer capacity of lines safely as long as the operators are willing to act within a short time period if contingencies occur. The objective of the Persistence Method is to provide useful information about the probability of future, 15 to 60 minute line capacities. One important application is when real-time weather conditions are actually unfavorable and the real-time capacity of the transmission line is low and thus critical.

The Persistence Principle

The Persistence Principle is based on the following facts:

a. The median real-time rating is typically 135-145% of the static rating, based on CIGRÉ TB 299. The ratings close to static ratings have very low probability of occurrence.
b. Lowest observed real-time ratings occur invariably during the time periods when effective wind speeds are low, generally less than 2 fps. Such wind speeds seldom persist for more than 20 minutes during daytime conditions.[19]
c. The likelihood that a low real-time rating is followed by other low ratings for 30-40 minutes is very low. On the other hand, at low wind speeds the time constant of the conductor is higher. For example, a Drake ACSR requires 30+ minutes to reach 90-95% of its final temperature rise. Thus a low real-time rating does not imply a high likelihood that a conductor will reach its limiting temperature in the near future.[20]
d. Ratings can remain low for prolonged periods only if wind speeds remain depressed for an extended period. This generally happens only when ambient temperatures are moderate and solar radiation is low – typically when weather fronts become stagnant. These conditions are rare but not impossible, as shown by the conditions prior to the 2003 blackout.[21] These are seldom relevant if ratings are based on CIGRÉ 299 guidelines.
e. Typically, the 30-minute average persistence rating is 5-15% higher than the real-time rating. Thus, judicious application of persistence ratings can significantly reduce operator interventions.

Persistence Application Methods

There are two possible methods in applying persistence to operational applications.

a. Continuous analysis of ratings in which the statistical distribution of persistence ratings would be calculated continuously, and the persistence limit would be set based on a selected confidence level (e.g. 2-sigma) based on the statistical distribution of the most recent one to two hours observations. This would require prolonged periods of moderate currents (over 350 A in the case of Drake) and is not feasible for present operating conditions of the studied lines.
b. Analyze ratings from historical data sets where conductor currents are greater than 350 A per conductor. This allows selection of statistical persistence boundaries as functions of the present real-time rating. For example, if the statistics show that the 2-sigma level of the persistence rating is 75 A higher than the present real-time rating at 1000 A, the operators could set the load curtailment levels at 1075 A when the real-time rating is 1000 A.

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[19] T. Seppa, E. Cromer, W. Whitlatch: Summer Thermal Capabilities of Transmission Lines in Northern California Based on a Comprehensive Study of Wind Conditions, IEEE Trans. Power Delivery, Vol. 8, No. 3, pp.1551-1561, 1992.

[20] For Drake ACSR, the end temperature after 40 minutes of transient change is 90% if wind speed is 1 fps, 95% if wind speed is 2 fps and 97% if wind speed is 3 fps.

[21] Tapani O. Seppa; Fried Wire?, Public Utilities Fortnightly, pp. 39-42 (December 2003)

As already discussed, Method (b) was chosen due to lack of high load data on many of the segments.

Calculating Persistence Values

For Method (b), the procedure for calculating persistence used the following steps:

1. Filter out loadcell data for each 10-minute measurement using load, shadowing and system health filters as discussed above.
2. Ensure that the next 30 minutes beyond the current time stamp do not have filter flags due to load levels, shadowing or system health reasons. If there are no flags, then this provided a full 30 minutes of data to calculate persistence ratings.
3. Find the minimum present and persistence ratings for each loadcell to represent the present and persistence segment rating.
4. Calculate persistence ratings as the average of the next 30 minutes of ratings at the segment level. This provided the historical persistence data set.

An example of the results of Method (b) calculation can be seen in Figure 3. The present line rating is shown on the horizontal axis, and the associated persistence rating based on the average rating on the next 30 minutes is located on the vertical axis. The data point shows the persistence rating referenced to the present rating. If the rating goes up in the next 30 minutes, the data point will be plotted above the equivalency line. If the average rating decreases over the next 30 minutes, the data point is below the equivalency line.

The variation in the scatter plot is indicative of the fact that ratings statistically have ample opportunity to decrease and increase on average in the next 30 minutes. The dispersion and tendency in one direction or another is different for different lines as the data shows in Figures 3 to 6.

Of particular note is that there is a tendency for persistence ratings to go up when the present rating is low. For example, in Figure 3 this is apparent for present ratings below 1050 A. The majority of persistence ratings are above the equivalency line at present ratings below 1050 A.

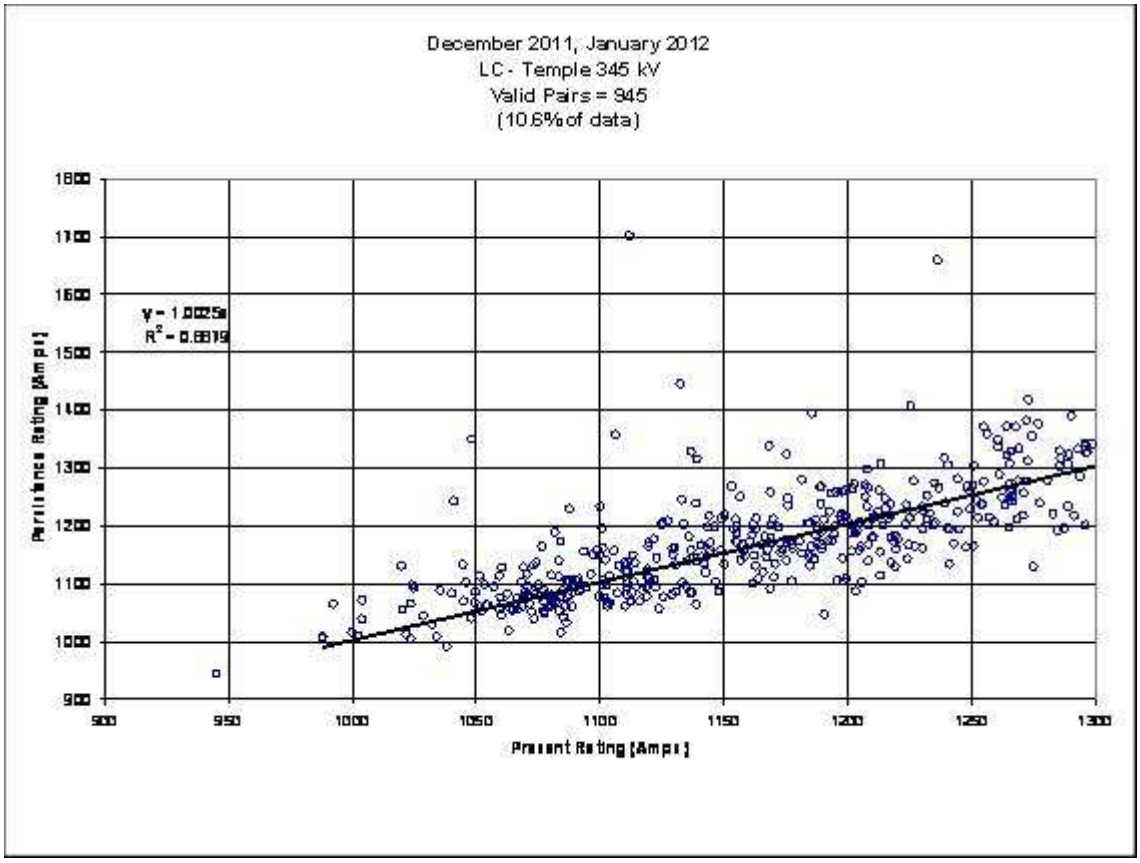

Figure 3: Scatter plot of present rating to persistence rating for Lake Creek-Temple (345 kV) in December 2011 and January 2012.

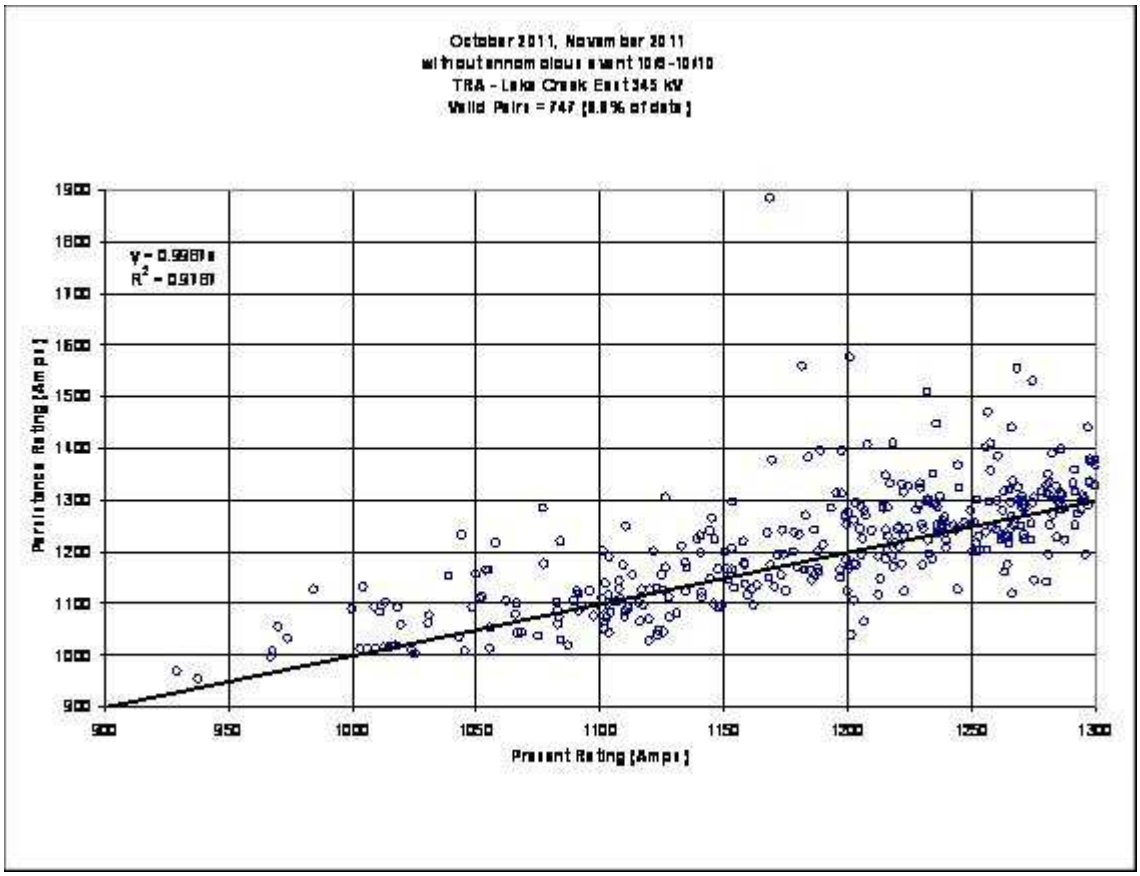

Figure 4: Scatter plot of present rating to persistence rating for Tradinghouse-Lake Creek East (345 kV) for October and November 2011. Days from October 9-10, 2011, were removed because of a meteorological stagnation that would have skewed the rating data.

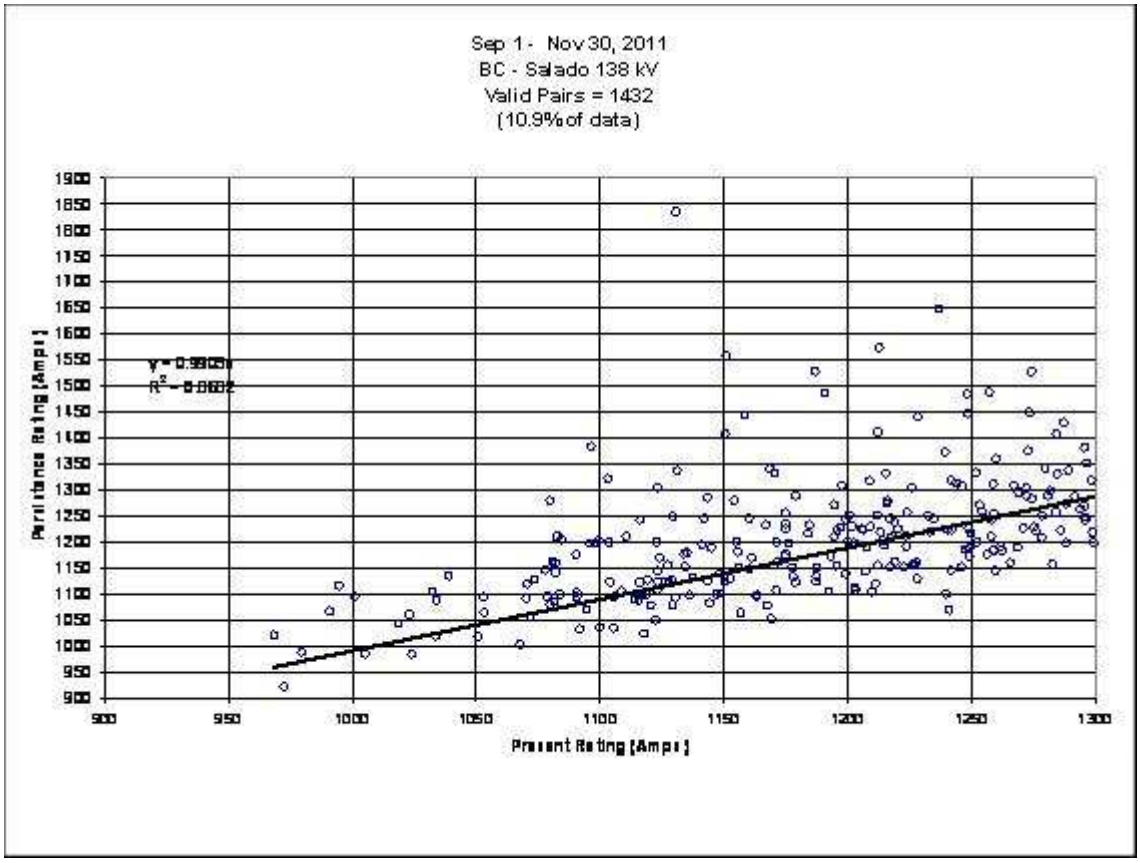

Figure 5: Scatter plot of present rating to persistence rating for Bell County-Salado (138 kV) from September through November 2011.

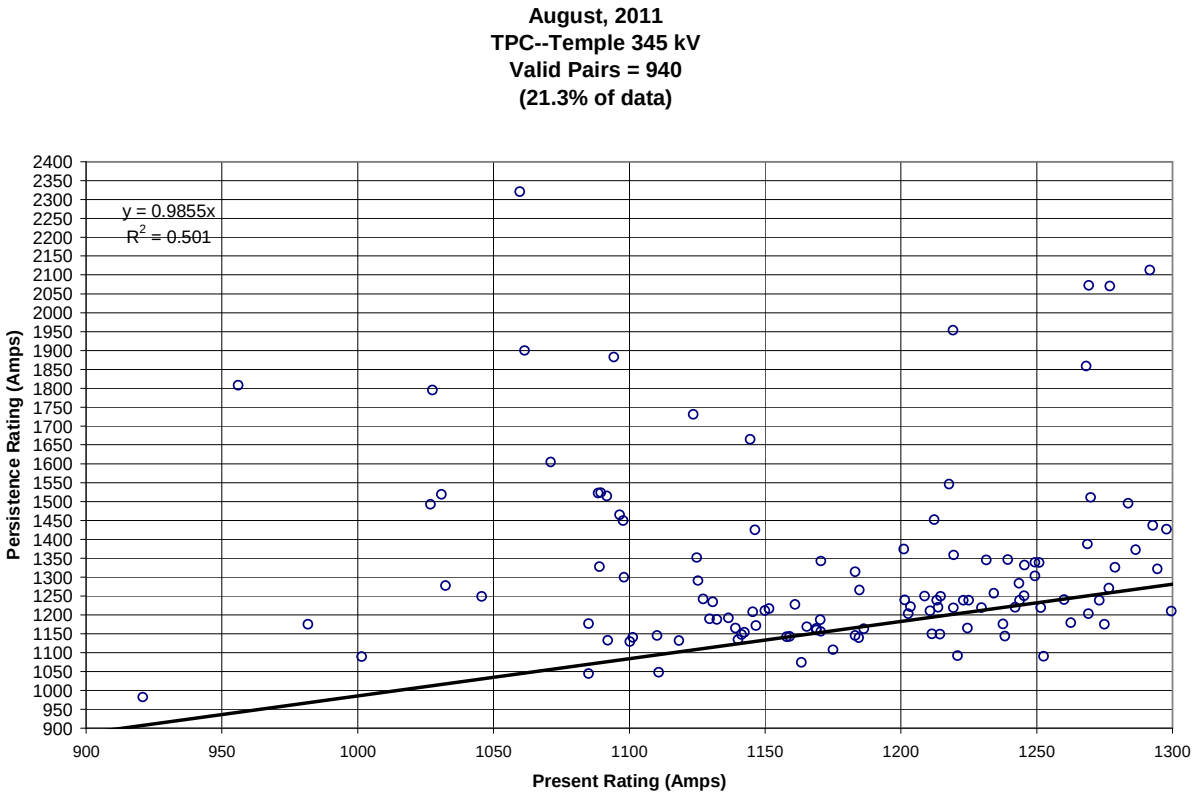

Figure 6: Scatter plot of present rating to persistence rating for Temple Pecan Creek-Temple (345 kV) for August 2011.

Figures 7-10 show cumulative probability functions of real-time ratings, PBR and "persistence step" ratings for the four circuits studied. The curves are based on 100 A bins and provide insight into the benefits and risk of using persistence Method (b) discussed above. 100 A bins were used (instead of 50 or 25 A) because of the limited amount of data points due to load levels.

A persistence step can be used by an operator as a simple and conservative way to gain capacity. Because the study only had a limited number of months on a few segments, a continuous calculation of persistence based on a 2-sigma variance was not available. Instead, the persistence step method is a logical way to gain benefit. It provides less benefit than the continuous persistence method, but it provides less risk.

To apply a persistence step, the persistence data in each bin has a flat buffer applied to it to reduce the uncertainty of the persistence rating in the next 30 minutes. For example, in Figure 7 the real-time rating risk level for 1050 A is about 11.9 %. Using persistence data alone would provide 1150 A for the next 30 minutes at the same risk level. However, using the persistence step method, the increase is about 40% of the gain of persistence alone or about 1090 A for the next 30 minutes. With this gain, the risk level according to the persistence curve alone is approximately 7%. Similar trends are seen for the other circuits in Figures 8-9, in which the persistence step curve provides increased gains of 40-60% and risk level is reduced by 40% or more.

The persistence steps used for all segments were 50 A for present ratings that fall into the 900-1000 A bin, 25 A for present ratings in the 1000-1100 A bin, 12.5 A for present ratings in 1100-1200 A bin, and 6.25 A for present ratings in the 1200-1300 A bin. With more months of data, persistence steps could be refined for each segment.

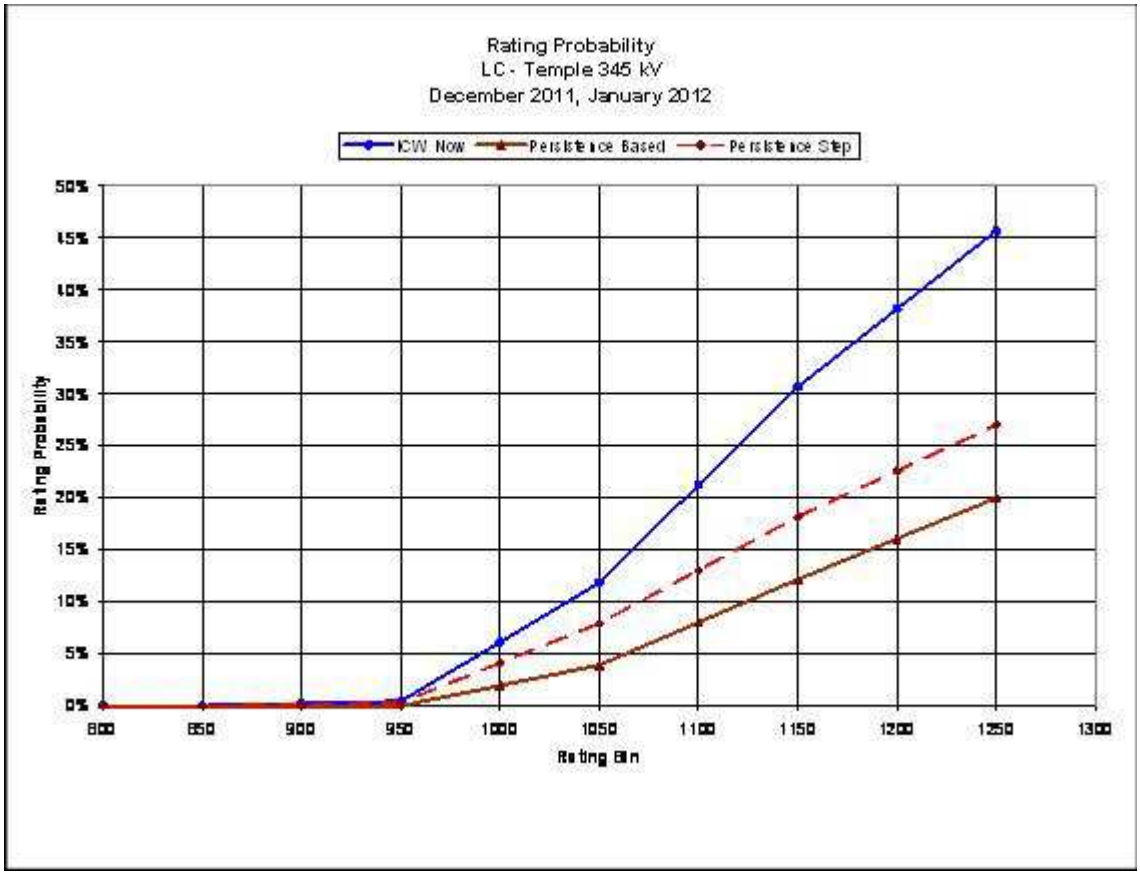

Figure 7: Cumulative probability functions for real-time rating, persistence and persistence step using 100 A bins for Lake Creek-Temple (345 kV) for December 2011 and January 2012.

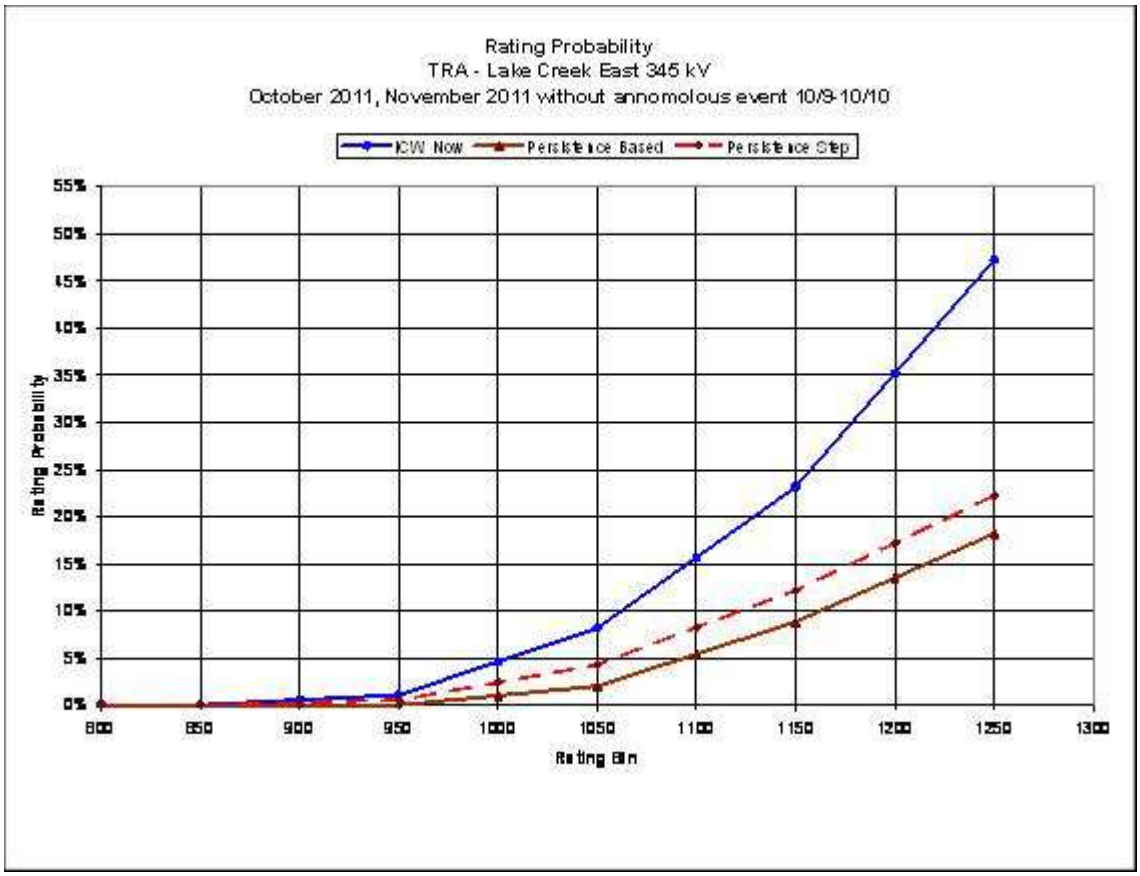

Figure 8: Cumulative probability functions for real-time rating, persistence and persistence step using 100 A bins for Tradinghouse-Lake Creek East (345 kV) for October and November 2011.

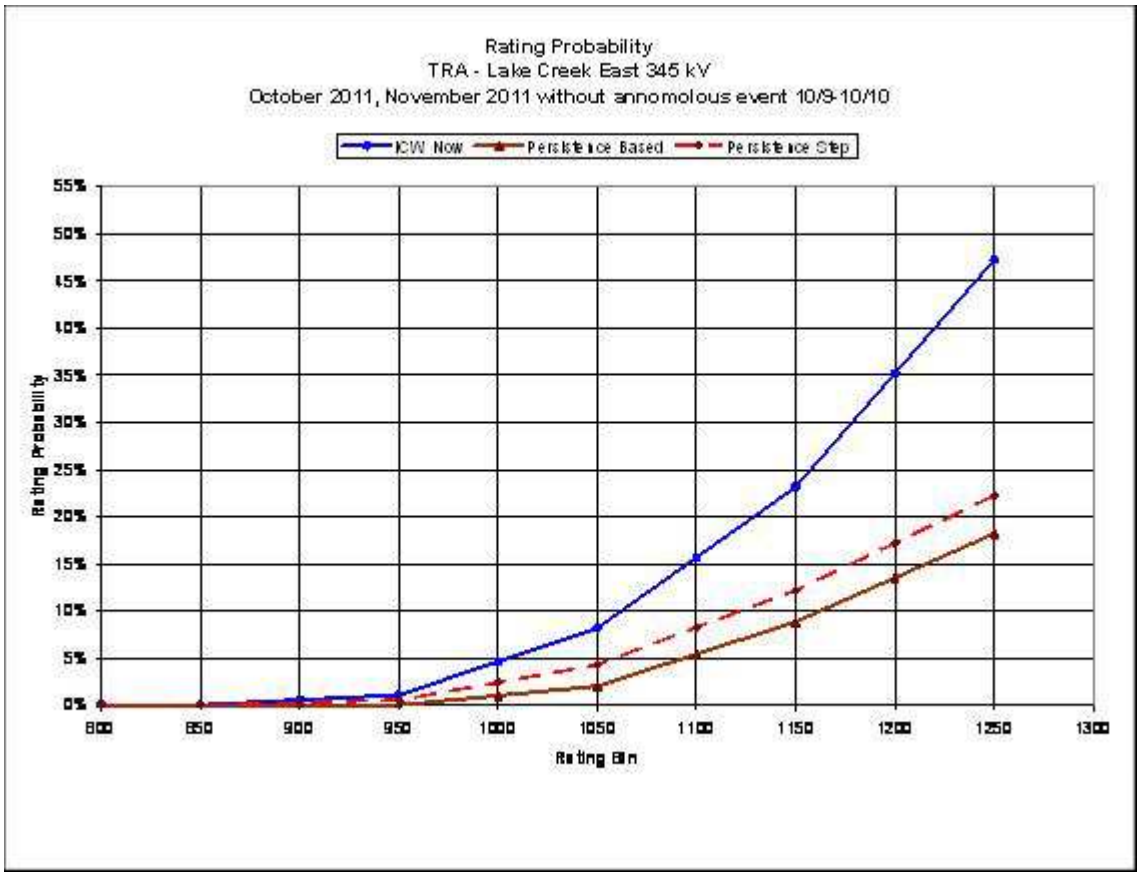

Figure 9: Cumulative probability functions for real-time rating, persistence and persistence step using 100 A bins for Bell County-Salado (138 kV) for September, October, and November 2011.

An example where using the persistence steps does not seem to provide much reduction of risk over using pure persistence data is in the Temple Pecan Creek-Temple segment where its one month of data had the highest percentage of time that loads met the threshold of any segment during the study. As can be seen in Figure 10, the persistence step provides 85-95% of the increase with only a small reduction in risk. More data on this segment during other months would be needed to verify the strongly increasing future ratings below the 1100 A per conductor level.

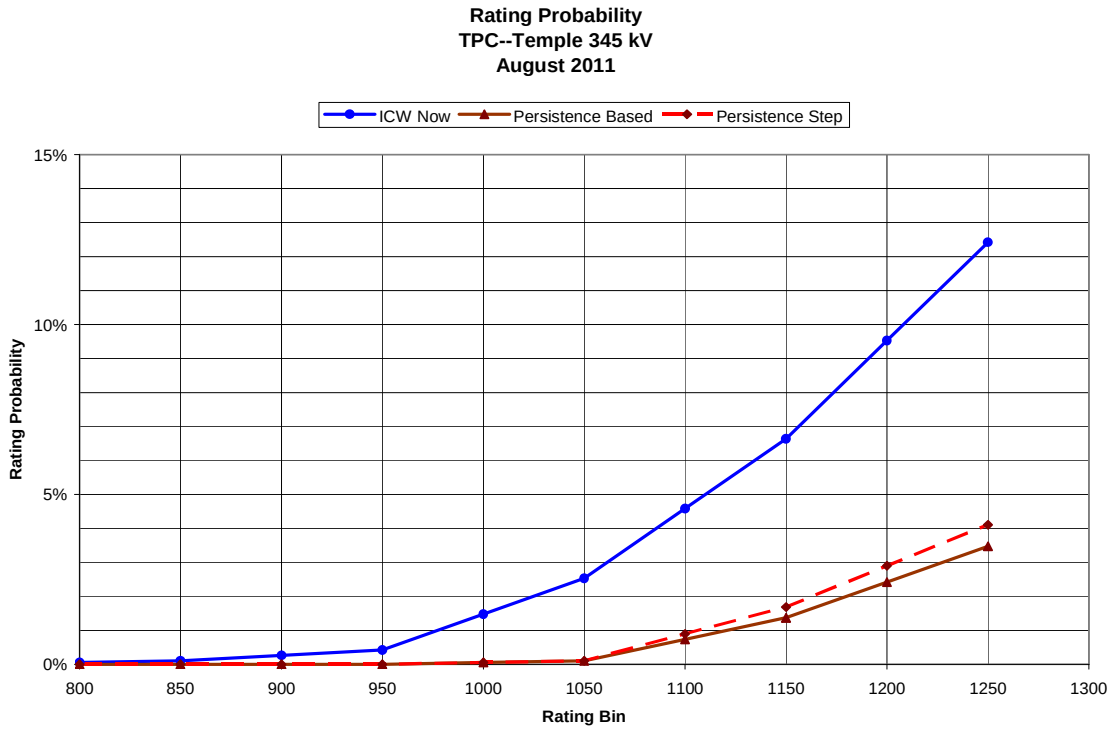

Figure 10: Cumulative probability functions for real-time rating, persistence and persistence step using 100 A bins for Temple Pecan Creek-Temple (345 kV) for August 2011.

3. Results and Benefits

The filtered data of three 345 kV segments was available for one to two months. Lake Creek-Temple and Tradinghouse-Lake Creek East both had two months of available filtered data, while Temple Pecan Creek-Temple had only one month of available filtered data. One 138 kV segment (Bell County-Salado) had three months of available filtered data. Figures 3-6 show scatter plots of the four different segments comparing the present rating on the x-axis to the persistence rating on the y-axis.

In each case, real-time ratings indicate that static rating assumptions met the IEEE-CIGRÉ recommendations in TB 299, representing a rate of occurrence less than 1% of the time. This can be verified from the scatter plots by counting the number of points below static level on the x-axis (897 A per subconductor for the 345 kV segments and 990 A for the 138 kV segment).

The scatter plots also show that, for the same time periods, persistence values have 1% risk levels at about 1010 A per subconductor for two 345 kV segments, 1130 A per subconductor on Temple Pecan Creek-Temple (also a 345 kV segment) and 1040 A on the 138 kV segment, which can be seen by the number of points below these levels on the y-axis. Thus, based on these statistics alone, a fully automated application of PBR would allow operation of the lines at 105-125% of static ratings, at less than 1% risk of load curtailment.

4. Conclusion

In each case, real-time ratings indicate that static rating assumptions met the IEEE-CIGRÉ recommendations in TB 299, representing a rate of occurrence less than 1% of the time. Persistence values have 1% risk levels at about 1010 A per subconductor for two 345 kV segments, 1130 A per subconductor on Temple Pecan Creek-Temple (also a 345 kV segment) and 1040 A on the 138 kV segment. Based on these statistics alone, a fully automated application of PBR would allow operation of the lines at 105-125% of static ratings, at less than 1% risk of load curtailment. Because the study only had a limited number of months on a few segments for persistence calculation purposes during the 12 months of monitoring, a continuous calculation of persistence based on a 2-sigma variance was not available. Instead, a persistence step method was developed that could allow slightly more restricted benefits, typically 103 to 113% of the benefit gain in line capabilities over static ratings, while reducing the risks. While the reduction of risk is likely much less than 1% of the time, it was difficult to quantify given the small database, which was limited in capturing seasonal and location diversity.

A capacity forecasting engine (CFE) has been developed that essentially replaces and enhances the concept of persistence. The CFE methodology had not been adequately conceived at the time the scope for this Smart Grid Demonstration Project was prepared. CFE has the ability to predict capacity with an equal or better accuracy than the persistence methodology. More importantly, it can predict capacity not only for the 15- to 60-minute persistence window but also for the next 24 to 48 hours for day-of and day-ahead operations and markets. To further optimize transmission capacity and benefits to the consumer, a natural next step would be to apply the CFE principles to a more representative capacity state of the grid for day-of and day-ahead operations and markets.

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APPENDIX H. ECONOMIC TRADE SPACE ANALYSIS

ECONOMIC TRADE SPACE ANALYSIS

for the

DYNAMIC LINE RATING PROJECT

Document No. 10-16404-DLR-ETSA

Version 1.1

April 30, 2013

SwRI® Project No. 10.16404

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REVISION NOTICE

Version Identifier	Date of Issue	Summary of Changes
1.0	March 15, 2013	Initial issue.
1.1	April 30, 2013	Final issue.

This document contains information that is as complete as possible. Where final numerical values or specification references are not available, best estimates are given and noted To Be Reviewed (**TBR**). Items not yet defined are noted To Be Determined (**TBD**). The following table summarizes the TBD/TBR items in this revision of the document, and supplements the revision notice above.

Section	Description

1. BACKGROUND

This section provides background information on the line rating techniques currently in use within the grid, Dynamic Line Rating (DLR) technology, and the nature of congestion that DLR attempts to reduce. The study area of the economic and environmental study, which is different from the actual monitored lines, is defined and rationalized.

1.1 Project Overview

The project focused on the deployment of DLR technology on several transmission line corridors within the Energy Reliability Council of Texas (ERCOT) electrical grid and how that technology can help to relieve congestion within the grid better than the existing methods of line rating. The project included installation of DLR equipment, validation of the technology by comparison to other existing methods, economic impacts of increased line capacity, and environmental impacts through shifts in generation patterns enabled through real-time ratings.

The study focused on the economic and environmental impacts. The data utilized was sourced through a combination of data collected from the deployment study, market data publicly available through ERCOT, and data specifically generated by ERCOT to assist in analyzing DLR impacts.

1.2 Current Line Rating Methods

Line rating in the high-voltage transmission grid involves utilizing the temperature of the conductor on the line to predict the amount of sag the line is experiencing and whether that sag causes the line to be in danger of violating ground clearance rules. The temperature of the conductor is a factor of three major variables: temperature of the air surrounding the conductor (ambient temperature), the amount of power flowing through the line (amperage), and the cooling effect of wind on the conductor. Utilizing formulas developed years ago, catenary curves can be developed to determine the amount of sag that may occur in a particular line segment. The spatial context of the length and location of the transmission lines has traditionally made real-time monitoring of the conductor temperature and/or clearance of the line to the ground technically infeasible.

1.2.1Static Rating

The use of static rating of lines is a standard practice across the transmission grid industry. In this method, historical averages of “high” ambient temperature, a prescribed wind velocity (typically 2 feet per second) and sunlight exposure are used along with current flow to determine a conductor temperature and, hence, a line-sag potential. The static rating and its associated conductor sag are used to lay out a transmission line design to maintain a minimum ground clearance. This method, however, is not conducive for out-of-norm temperature conditions. To account for this, the Static Line Rating method is very conservative, resulting in lines being underutilized the majority of the time to account for the buffer that is built in to ensure line safety during out-of-norm temperature events.

1.2.2 Ambient Adjusted Rating

Ambient Adjusted Ratings (AAR) are similar to the static rating method with the exception that actual ambient air temperatures, as reported by the National Weather service or from temperature sensors on sample towers within determined weather zones, are utilized as the ambient temperature input to the rating model. This method provides for a real-time temperature reading, which then adjusts the sag calculations for a line rating more in line with ambient weather conditions. It should be noted that the wind continues to not be factored in the AAR; instead, the same 2-feet-per-second wind velocity is used.

1.2.3 Dynamic Line Rating Technology

Dynamic Line Rating improves on the static and ambient-adjusted ratings by taking into account the most significant cooling factor on line conductors: wind. Studies [1] [2] [3] [4] have shown that wind has a significant cooling effect on line conductors, even during high-temperature weather events. This is due to the convective cooling process. The DLR technology measures the impact of wind on the conductor through its tension-based model for determining line sag. Rather than monitoring wind directly at different points on the line span, DLR measures tension on the line across multiple spans of the ruling span line section and then computes factors that incorporate the cooling effect of wind on the conductor with the ambient temperature and influence of solar radiation. These measurements are more accurate in determining the actual conductor temperature and thus the ampacity that can be sent through the line. The studies referenced show that there is a typical 10% additional capacity that can be leveraged and, at times, upwards of 50-60% unutilized capacity that can be used to decrease line congestion within the transmission system.

1.3 Congestion in the Grid

Congestion is a major cause of cost increases in the delivery of power across a transmission grid. Whenever a line rating shows a potential for a sag violation, ampacity in the line is throttled back to prevent the sag violation. Reduction in ampacity means less power is transmitted through the line, resulting in an increase in other lines or a reduction in power available throughout the transmission system. This results in line congestion, where transmission grid State Estimator models predict impacts to power availability that require system operators to take definitive actions to redispatch power sources to handle the required load, often at higher energy prices.

Much of the predicted line congestion is due to N-1 contingencies, where the line is loaded below capacity (sometimes as much as 75%) but will become overloaded if an N-1 contingency becomes reality. N-1 contingencies result in much of the congestion mitigation actions taken by the system operator using static or AAR; if dynamic readings were available, the additional 5 to 15% that is more likely available could potentially relieve the congestion without operator input.

One of the goals of DLR is to reduce congestion by enabling higher throughputs on the existing lines from the lower-cost power generators, thus reducing the overall cost of energy to the end users.

1.3.1Economic Impacts of Congestion

Congestion creates an economic distress to end users on the power transmission system. Congestion causes the use of higher-cost generation resources to be utilized. During real-time operations, a computer model of the system is run to simulate the grid operations to optimize the delivered cost of power at every node in the grid. The program referred to in general as a State Estimator uses real-time telemetry of load demand, load flow on transmission elements, and available generation resources to optimize operations to provide reliable service at best-economic terms. The ERCOT system calls this process Security-Constrained Economic Dispatch (SCED). SCED is run at a minimum of every five minutes, and the solution of the SCED run is the dispatch orders to each generation plant to meet the load demand.

During the SCED process, certain transmission elements (lines and transformers) may become overloaded if the least-cost generation was dispatched. When the SCED analysis sees this, it takes incremental steps to redispatch the generation such that the most economic solution can be found to maintain reliability, i.e., ensure transmission elements will not overload under N-1 contingencies and that the combined generation and transmission delivery costs are minimized at each node.

At certain times depending on generation availability, system conditions and energy demand, the SCED solution requires direct intervention to maintain the reliable service and more costly generation is dispatched. The effective nodal price points may go up, and the increased nodal prices represent congestion rent or costs.

The project goal is to determine whether incremental capacity made available through DLR can mitigate these congestion costs.

Prior to real-time operations, a Day-Ahead Market (DAM) analysis is performed for each hour of the day. Generation providers offer their bids for the next day's generation identifying their willingness to participate in the market with a bid of units of power at specific rates. On the demand side, market participants identify their expected hourly load demands by location and quantity. The DAM analysis is optimized to build a generation schedule that focuses on reliability first and then economics, to meet the demand forecast. When reliability criteria and capacity on transmission elements are challenged by the analysis solution, the DAM analysis develops dispatch plans to try to minimize the overall cost of power to the Nodal Market. The analysis relieves that congestion with typically less economical generators. At the end of the DAM analysis, the generation providers have a good idea of what their role will be in supplying the next-day's energy, and the price to put that power into the grid is set.

Because congestion relief generation services can be considerably more expensive, ERCOT has implemented a congestion cost cap to mitigate the impact of congestion on the Load-Serving Entities (LSE). Congestion rent is the charges to LSE market participants for the energy they use minus the payments to the generators for the energy they provide. This difference can range from $0.0 per MWh up to the system-wide cap of $3,500 per MWh. Utilizing DLR technology may help reduce congestion by providing additional throughput within the lines based on a more dynamic analysis of the conductor condition in a real-time monitoring environment. Ultimately, DLR may provide historical data that can

show with high reliability/availability an increase in capacity that can be utilized in the DAM bidding process.

1.3.2 Environmental Impacts of Congestion

While not the rule within every grid, typical inefficient and more costly generation resources are provided by generation that produces greater impact on the environment. Many of these generation plants are older plants that do not implement cleaner technologies or may be plants from smaller providers that have not upgraded to cleaner technologies. As such, there is a potential for greater environmental impacts with increased congestion. While we do not expect to see significant harmful environmental impacts within the Texas grid (due to the abundant use of natural gas, clean coal and wind generation), the impact still has been studied and extrapolated to identify potential positive environmental impacts due to decreased congestion. We especially looked at congestion where wind energy is prevented from entering the grid, resulting in increased use of fossil fuel technologies, whether from primary generation or ancillary services.

1.4 Study Area

The original study area identified for DLR and economic impact was along the Interstate 35 corridor between Waco and Gabriel, Texas. At the time the proposal was submitted, this was identified as a congestion point within the Oncor transmission network worthy of study. Not long after award of the project, during the installation process, changes to two of the power generation plants, specifically the shutdown of the Lake Creek and Tradinghouse generation, eliminated the congestion these lines were experiencing. While the DLR equipment remained installed on these lines, they were no longer providing data for an economic study that needed to factor congestion costs.

Utilizing congestion reports from ERCOT and factoring in needs to address environmental issues, it was decided to base this economic study on another area of the grid that is experiencing significant and costly congestion issues that may be relieved with DLR technology.

Our study area encompassed lines in several areas of the transmission grid where we have noticed significant and costly congestion costs. This included lines in West Texas where wind generation enters the grid and load growth has occurred due to an increase in oil-related activities; one line in the Dallas Metroplex that is a significant energy hub; and two lines in East Texas where power transfers between transmission providers (from Oncor to CenterPoint Energy).

The most significant area selected for study was Odessa-Midland. It provided several attractive reasons for study:

1. The area has shown significant congestion over the past few years.
2. Power consumption has increased due to resurgence in oil drilling using new techniques that enable drilling in old, previously tapped-out wells.
3. Significant wind generation enters the transmission grid in this area.

4. The major west-east transmission lines for connecting wind energy to the more populous areas of Texas begin in the Odessa-Midland area.

The DLR technology as installed, while not residing in the area selected for the economic study, still supports the economic analysis by providing data on real transmission capability versus transmission capability per the static or ambient adjusted methods. By taking conservative, yet meaningful averages from the DLR study for capacity gained through DLR, we are able to extrapolate the effect DLR technology would have if applied within the economic study area.

2. SCOPE OF THE ECONOMIC TRADE SPACE ANALYSIS

DLR means different things to different market entities and has an impact not only on the economics of energy generation and transmission, but on the environmental aspects of said generation, especially as it relates to wind generation in Texas. This study looked at the economics as it is perceived by the different entities in energy generation, transmission and delivery within the market. It also looked at the potential for environmental benefits based on changes to the generation patterns resulting from increased capacity. Finally, the analysis looked at wind generation and how it may be impacted through DLR technology.

2.1 Economic Study

The purpose of this study is to determine the economic benefits that may be derived through DLR technology to provide a real-time power flow capability analysis of transmission lines in the areas of installation. To the extent possible, we attempt to extrapolate these results throughout the transmission market and the impact that DLR would have on reducing congestion and congestion costs. Our study takes into account multiple perspectives of the energy market, from those that place power onto the market, those that pay for consumption of power, and the operator of the energy market. In our study ERCOT is the Independent System Operator (ISO).

2.1.1 Department of Energy Perspective

DLR technology provides benefits in line with DOE goals to reduce congestion and reduce costs to the ratepayer by increasing throughput of transmission lines and providing greater utilization of the transmission lines' capacity by providing a real-time perspective on actual capacity based on conductor temperature rather than an overly conservative capacity model based on either a quasi-deterministic approach for static ratings or an ambient temperature adjusted model taking into account the general ambient temperature for the line's location.

2.1.2 Transmission Provider Perspective

From the electric power industry perspective, the benefits of DLR technology are realized through the cost benefits derived through the buying and selling of power in the ISO energy market, the delivery of that power through the wires of the transmission and distribution companies, and ultimately the cost to the ratepayer.

While congestion resides on different elements of the transmission system, i.e., lines and transformers, there is no direct incentive to the transmission provider to reduce congestion costs and, therefore, less of an incentive for DLR application. In the current market design, the delivery of power is not by commodity unit, i.e., MWh delivered per hour on a given asset. Rather, most transmission providers are regulated and receive their compensation on an overall capacity basis, as an ability to deliver power reliably. Incrementally changing the hourly delivery through a dynamic rating does not generate increased revenues and a correlated means to calculate a typical return of investment.

2.1.3 Market Operator Perspective

The market operator's perspective revolves primarily on the reliability of the grid, the economic efficiency of the electric grid, and the satisfaction of consumer requests for power.

The primary cause of congestion is not in the actual violation of line transmission criteria (N-1 events) but in the potential for violations based on projected line capacity requirements under N-1 contingencies. The economic dispatch of generation and system estimator toolset incorporates a set of scenarios based on the bids and offers on the market to attempt to most economically and reliably meet load requirements, project congestion and relieve that congestion through the market process. For brevity of reference, this toolset is known as SCED (Security-Constrained Economic Dispatch) in the ERCOT system.

The primary benefit of DLR for the market operator is in the resolution of projected congestion in the real-time market through the improved utilization of traditionally underutilized transmission lines due to the conservative line rating models. The more that congestion is resolved in SCED through the effect of real-time DLR data streaming into the SCED system, the less probability or need that congestion will have to be resolved during the operation day through direct operator intervention. This results in fewer hands-on decisions that have to be evaluated and made by the operations staff, as well as less administrative capability that has to be maintained to manage the congestion cost billing and collection.

Additionally, the market operator gains benefit by having increased system awareness through real-time DLR data on which to base control decisions. While SCED may work with a conservative rating capacity increase, the system operators may be able to see increased capacity based on their real-time actual system condition DLR feeds. Therefore, they may be able to relieve SCED constraints without dispatch instructions, resulting in not only a reduced cost to the market but also reduced risk that is always introduced during "human in the loop" processes where a system operator makes a dispatch change.

2.1.4 Retail Perspective

Ultimately, energy prices are felt by consumers through the price per kWh they pay through their retail provider. Increased congestion costs require market participants to increase their costs to the consumer in order to maintain their profitability. Benefits to the retail provider include:

- Less risk for congestion: By increasing throughput of existing lines, there is less risk for congestion, which is ultimately paid by the retail provider.

- Less congestion cost: Reducing congestion provides direct impact to the retail provider by reducing congestion costs.
- Reduced Congestion Revenue Rights (CRR) buying: To hedge against congestion, market participants buy these rights, a type of insurance that protects the CRR owner against what can be significant congestion costs. Lessening the need for CRRs reduces the overall operating costs of retail providers and effectively the ratepayer.
- Fewer insolvency risks: Significant congestion costs can place a retail provider in dire financial trouble during days of significant congestion. Increased purchases of CRRs can reduce that risk but at additional costs to the retail provider and ultimately the end consumer.

DLR technology, by increasing line throughput and utilizing underutilized line capacity, should help reduce congestion costs and thus be directly reflected back to the ratepayer in the form of cheaper energy.

2.2 Environmental Study

The scope of this study, combined with the dynamic nature of the energy market, prevents a comprehensive generator-by-generator study of the environmental reductions that may be possible through DLR technology. Our study in this area primarily focuses on the gross emission reductions noticed through the use of DLR to increase capacity of the selected lines.

2.3 Wind Energy Integration

The proposed impact to environmental output from electrical generation we have chosen to study is in the area of wind generation. Specifically, we have chosen to focus on the amount of fossil fuel generation we could reduce by putting as much wind generation onto the grid as possible. With Texas now being the largest wind producer in the nation (and plans are to make Texas the largest solar producer also), it becomes obvious that the more renewable generation is placed onto the grid, the fewer contaminants go into the air from energy generation. Congestion at the bottlenecks to transmission of Texas wind energy from west to east Texas prevents wind from entering the grid, resulting in increased use of contaminant-generating electrical generation. DLR technology should provide relief to those congestion bottlenecks, allow more wind-generated energy to enter the grid, and reduce the needs for fossil fuel generation.

2.4 Shift Factors for Security-Constrained Economic Dispatch

Shift Factors identify generation resources that would have an impact on the congestion if they were ramped up or activated in response to an SCED action and generation resources that were ramped down or deactivated as a part of that response. ERCOT produces a report that lists these Shift Factors for every N-1 event and line component, which can be correlated to constraint events to identify how generation was moved in response to an SCED action.

To determine potential environmental impacts due to congestion and the alleviation of those impacts through DLR, we analyzed the Shift Factors for the days of study to determine how DLR would have

resulted in a change of generation resources from more than one level to a different level of polluting generation values based on dispatched operating signals.

3. METHODOLOGY OF THE STUDY

This section discusses the methodology used in conducting the economic and environmental study of DLR and provides the results of the study.

3.1 Analysis of Captured Data from the DLR Systems

The core of the economic analysis study revolves around the impact of DLR technology to change the capacity ratings of transmission lines. The capture and analysis of data from the DLR systems has been conducted in a parallel study for this project. Those results were then analyzed by the economic analysis team to identify consistently reported capacity increases that have been identified greater than 95% of the time. This provided the economic study with a conservative increase impact that could then be used to study the economic impact on a set of congested lines.

3.2 Identification of Lines with Significant Congestion

Congestion within the ERCOT transmission grid is not a continual, identifiable problem. Congestion moves around the grid during different times of the day and different days of the year. While some lines show congestion more than others, the congestion may appear for a few days or during a particular time period and then disappear again. Many reasons can be behind this, from changes in the transmission patterns to relieve the congestion, changes in grid topology as new lines are added or existing lines upgraded, maintenance outages and forced outages, to generator bidding behavior changes for economic reasons.

The study team conducted significant analysis of the congestion reports over the course of a year in an attempt to identify a particular area or trend. These congestion reports came from ERCOT and are a part of both its publicly published data and utility-restricted data. From these reports, we decided to focus on an area that held significant impact to the introduction of wind generation onto the grid.

3.3 Relief of Congestion Between Planning and Installation

One of the difficulties that led to the economics study being based on a congestion area that was not monitored by the project's DLR technology was the relief of congestion that occurred on the DLR study area between the planning of this project and installation of DLR technology. During the planning for the DLR project, an area of consistent congestion along the Interstate 35 corridor between Waco and Gabriel was identified. As DLR installation was about to occur, changes to the generation plants within that corridor significantly reduced the congestion in that area. The direct results of the data collected in the study area validated the practicality of DLR application and quantified the increase in capacity available from real-time DLR. However, the lower load levels in the project transmission corridor did not develop any congestion events during the project period.

This is an example of the difficulty of pinpointing where ongoing congestion will occur. Many factors out of the control of the transmission provider cause the congestion to occur and modify with time. Regardless, the information gained during the project provided ample insight into how DLR affects the available line capacity and how that can be applied to meet capacity needs and mitigate congestion.

3.4 Analysis of Transmission and Distribution Lines to Identify Congested Area

An analysis of congestion reports from ERCOT was conducted to attempt to identify lines of significant and/or regular congestion. The dynamic variability of congestion prevented the identification of transmission lines that are regularly congested. Our philosophy was to identify lines that cause significant cost when they are congested and have a higher occurrence level in minutes of congestion. While the lines may only be congested a few hours a year, significant cost is experienced within the market through this congestion. Six lines were studied for DLR economic benefits. These lines represent a mix of geographical distribution within the grid, as well as in voltage levels. The six lines selected:

1. Morgan Creek – China Grove 138 kV (Odessa area)
2. Odessa – Odessa North 138 kV (Odessa area)
3. Odessa North – North Cowden 69 kV (Odessa area)
4. Carrollton Northwest – Lakepointe 138 kV (Dallas Metroplex)
5. Jewett Rattlesnake Road (345 kV) (East Texas ownership transfer point)
6. Jewett – Big Brown (345 kV) (East Texas ownership transfer point)

Out of these lines, the Odessa area lines provided an opportunity to show an economic impact of DLR technology on transmission for a given area.

3.4.1 Validity of Lines Chosen for the Economic Study

Our choice of lines to study for economic purposes was driven by a need to focus on an area where economic impact of DLR technology could be shown with either positive or negative impacts. The focus on the Odessa-Midland region provided several benefits favorable for the DLR economic study, including:

- Location: The lines being studied are at the end of the grid and represent a major infusion point of energy flowing west to east.
- Renewables: The lines are located in one of the most significant wind generation areas of the state and are where much of that energy enters the grid to be transmitted to the more populous central and eastern portions of the state.
- Loading: New oil and gas drilling technologies are allowing for renewed drilling on previously tapped-out wells. This has led to an increase in electric demand in the study region, contributing to the congestion of the lines.

3.5 Simulation of Day-Ahead Market with DLR Ratings

It is important to note that DLR, as a real-time telemetry system, is fed into ERCOT's real-time SCED analysis for operations every five minutes. Unfortunately, SCED cannot be rerun to assess whether an alternative rating, e.g., the DLR rating, could have provided a different congestion result. The best alternative was to seek ERCOT's assistance to rerun several DAM results with DLRs to see how the economic model would change with different ratings available for operation.

Our approach to producing data for the economic study involved analyzing the impact to the DAM results if DLR were implemented in a section of lines. We have been working with ERCOT to produce new DAM model results utilizing the results of the DLR monitoring study to evaluate the impact on congestion if additional line capacity were to be provided within the congested lines.

For our study, we analyzed DAM models where the ambient temperature ratings from the original DAM analysis rating were replaced by a percentage factor of either 5% or 10% above the base rating used, which simulates historical DLR capacity increases in the greater than 95th percentile as identified in the DLR monitoring study.

3.5.1 Identification of Days to Rerun

Given the transient nature of congestion within the transmission system, we were unable to identify a statistically significant set of days suitable for rerunning DAM models. Our approach was to select one day per month over the course of the year to have the data provided for study. We selected the first Tuesday of each month, with the exception of July where the 16th showed significant congestion for the study lines. This gave us 12 days of reports to study. In addition, we reran the overall peak congestion day from 2011 to assess the potential peak impact.

3.5.2 ERCOT Assistance in New DAM Simulations

Our team worked closely with ERCOT in the identification and selection of the new DAM reports to be generated. Several test reports were generated and provided to us in order for us to determine what the best parameters might be for running a full year study.

It should be noted that the running of the DAM model and the production of the report is an intensive operation by ERCOT and we needed to limit the amount of runs that were made. ERCOT provided this data to the study team and worked with us to ensure the DAM reports were providing us with the best information related to the economic study.

DAM models were run at three capacity levels: base case, 105% capacity and 110% capacity. This provided the study team with 36 DAM reports on which to conduct analysis.

3.5.3 Justification of Capacity Levels

Our choice in using the 105% and 110% capacity levels for increased line ratings was selected based on our findings from the DLR monitoring study conducted by the team. This study gathered data from the

six actually monitored lines over the period of one year. As shown in Figure 1, DLR resulted in an average of >8% increased capacity for the 138 kV lines in the study. Figure 2 shows an average increase of >5% in the 345 kV lines for the study period.

3.5.4Analysis of DAM Data

Analysis shows that with a conservative projection of 5%, increased capacity from DLR congestion costs can be significantly reduced within the DAM model. The data furthermore shows that a 10% increase in capacity does not readily mean a further reduction in congestion costs.

In our initial congestion relief DAM runs, we extended the increase in capacity to 120% and 125% of the base rating used in the DAM run. When we looked at the results, we found that the 105% and 110% increase practically eliminated all of the direct congestion on a line segment when it had been there in the base case. This is consistent with the overall DAM and SCED operating environment. As each State Estimator analysis is performed, the system tries to balance itself, redispatching incremental generation values to make sure all elements of the grid remain within N-1 compliance. Therefore, congestion events are almost always within several percent of capacity of resolution. The 5% and 10% increments provided sufficient incremental capacity to reduce congestion.

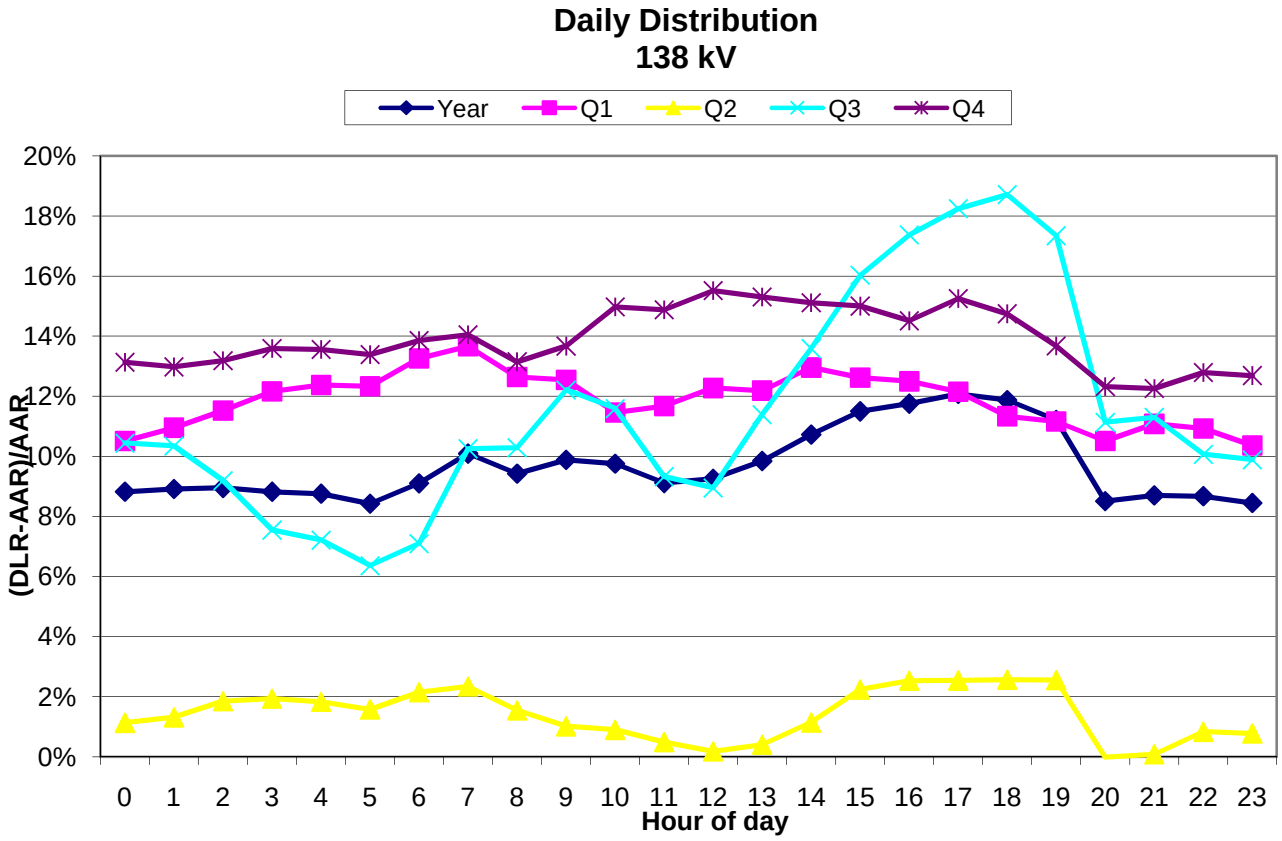

Figure 1. Yearly Distribution Plot of DLR Increased Capacity 138 kV

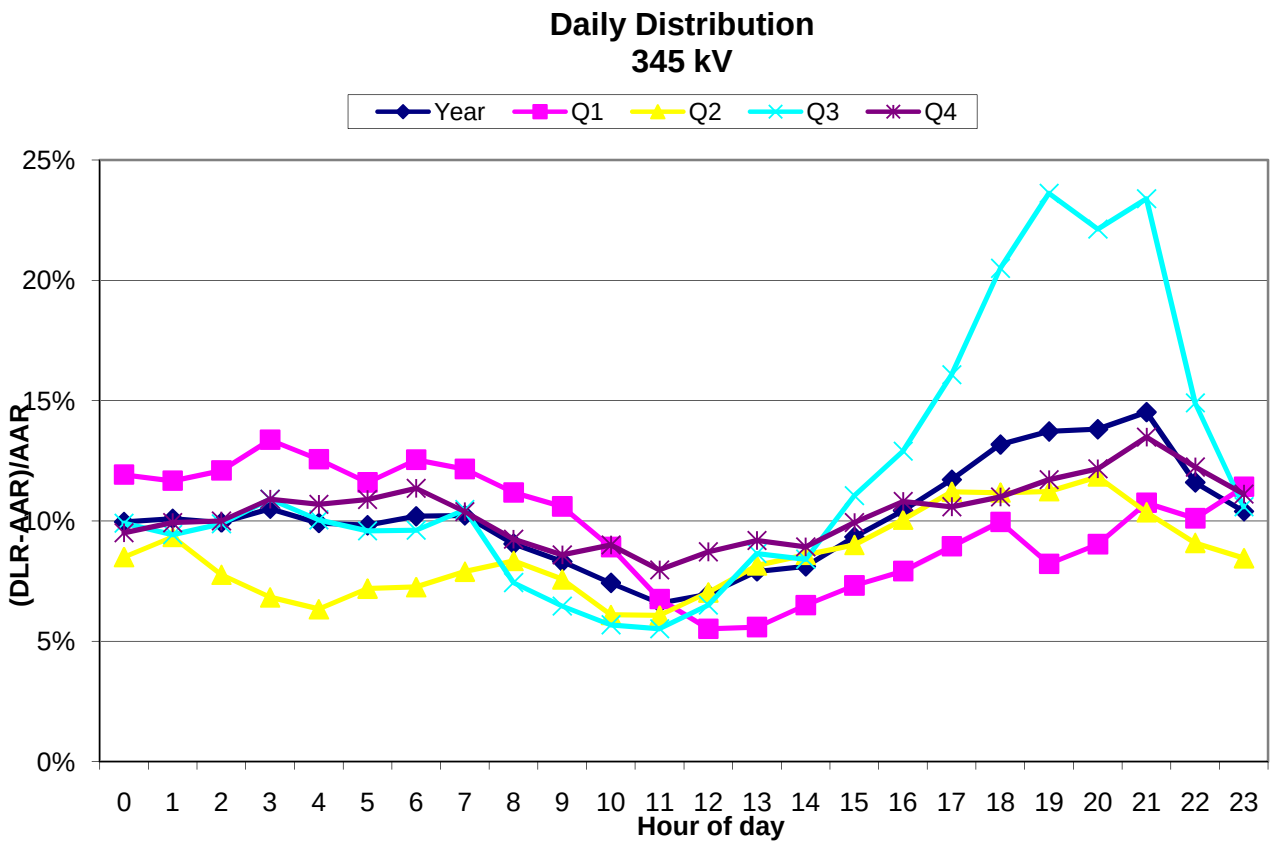

Figure 2. Yearly Distribution Plot of DLR Increased Capacity 345 kV

Figure 3Figure shows the average congestion impact across the day, summarized for the study year. In this plot we can see the congestion impact is reduced in a DAM model run with 105% capacity for the six economic study lines. Notice that the 110% capacity model actually results in higher congestion costs than the 105%, although it is still significantly less than the base (no DLR) model.

The average savings (represented as a percent savings from the base model) over the year can be seen in Figure 4 along with the significant increase in congestion cost savings achieved during the most heavily loaded parts of the day.

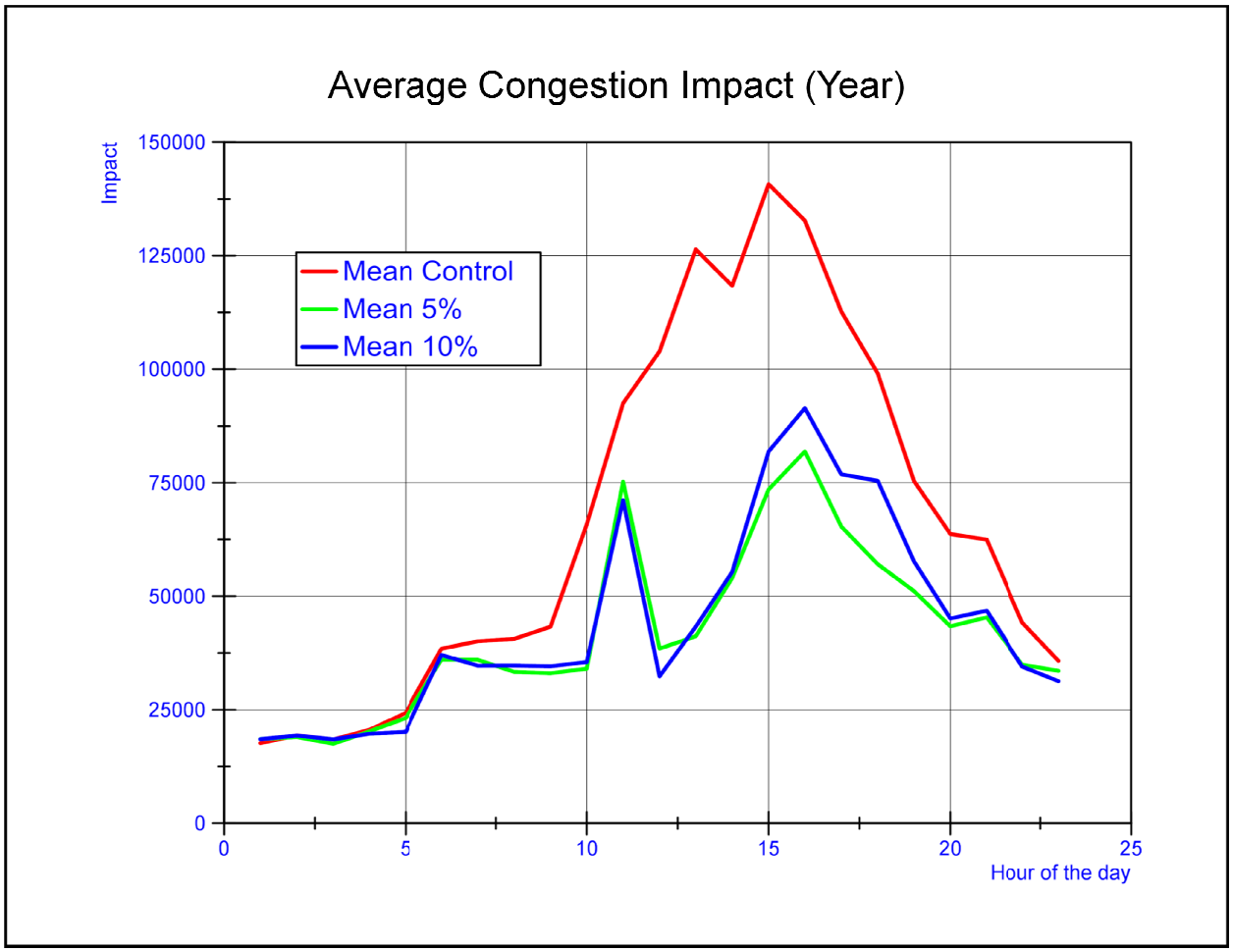

Figure 3. Average DAM Congestion Impact (Year)

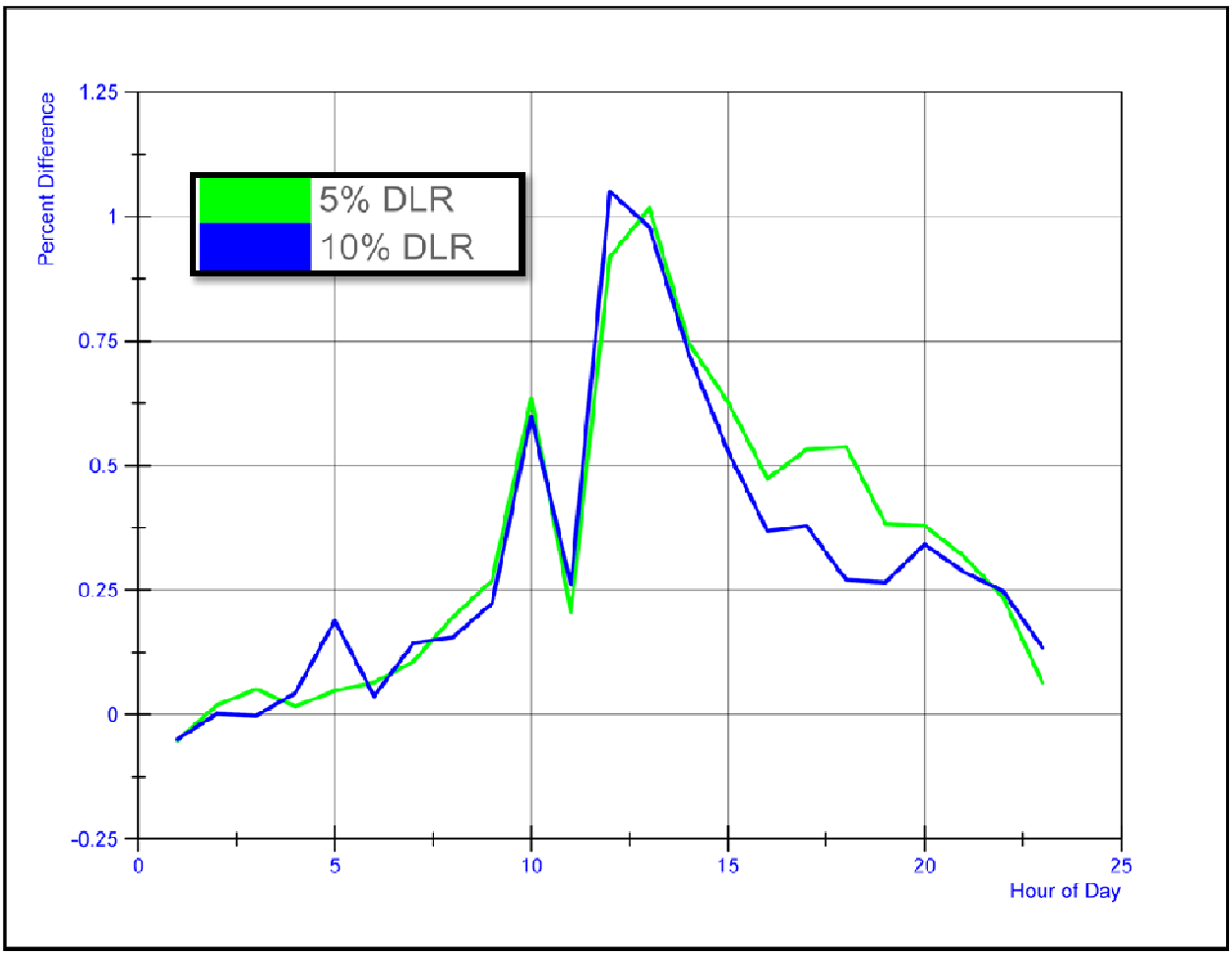

Figure 4. Percent DAM Congestion Savings Over Static/AAR

The monthly congestion impact, as a percentage of congestion savings over the base model, is shown in Figure 5. It is important to note that each month only contains data for one day of the month and so is subject to skewing based on weather or other generation/transmission events that can occur. In general, the results show a consistent savings that can be achieved, with a greater impact in the critical high-load summer months.

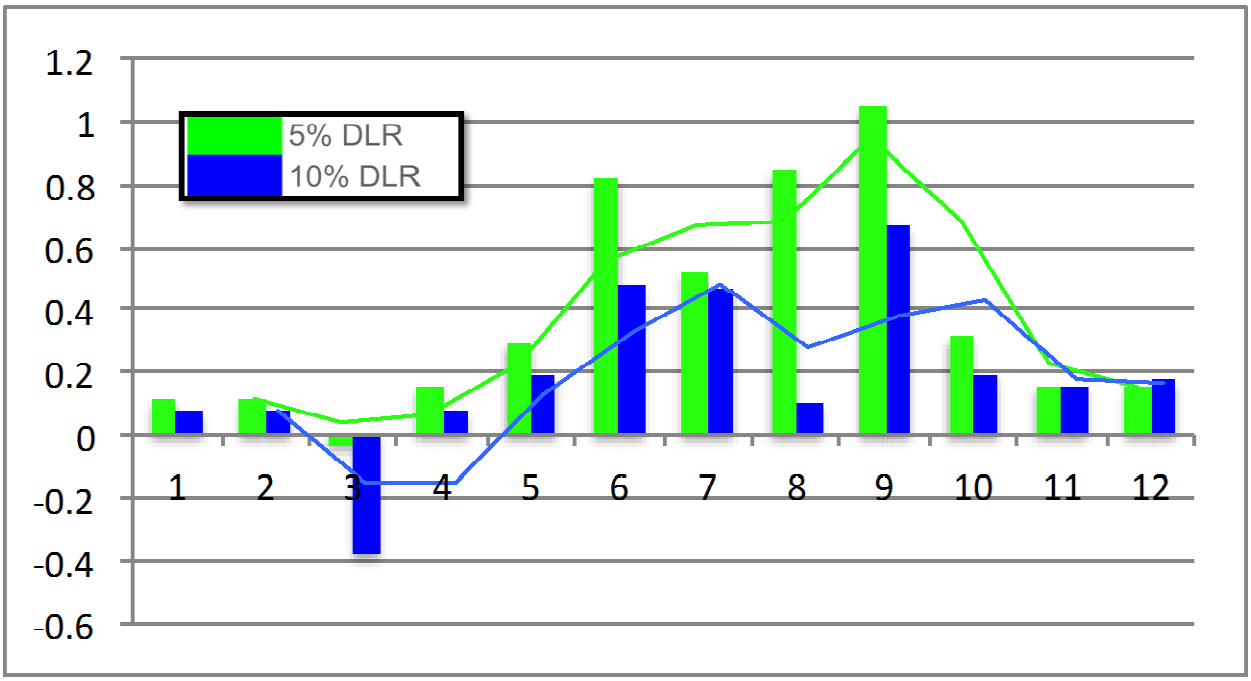

Figure 5. Monthly Congestion Impact

The next two plots show the cost impact for one day in January (Figure 6) and July (Figure 7). The plots show an hourly impact as well as a cumulative summary for the day.

Note that in January (Figure 6), the 105% and 110% capacity lines track almost perfectly; thus, there was no quantitative difference between the two on this day's congestion relief.

In the July plot (Figure 7), we see that 110% capacity resulted in more congestion cost savings than 105% capacity.

Predictive DLR within the DAM shows that significant savings are achieved, especially during the peak hours of the day, with congestion cost savings at times over 100% of the base-case congestion costs. This shows that DLR can be effective in reducing congestion during peak demand periods and thus reducing costs across the market.

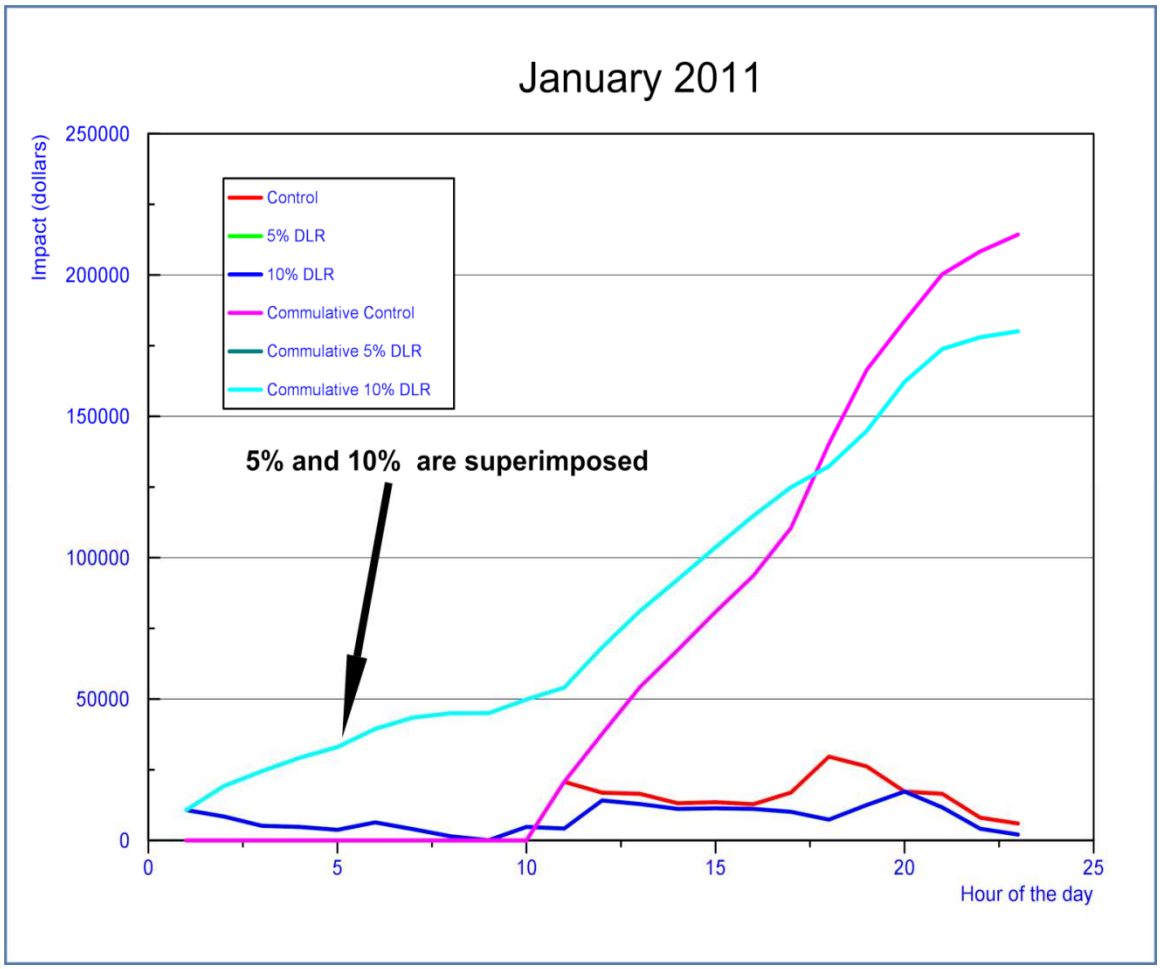

Figure 6. January Cost Impact Hourly and Cumulative

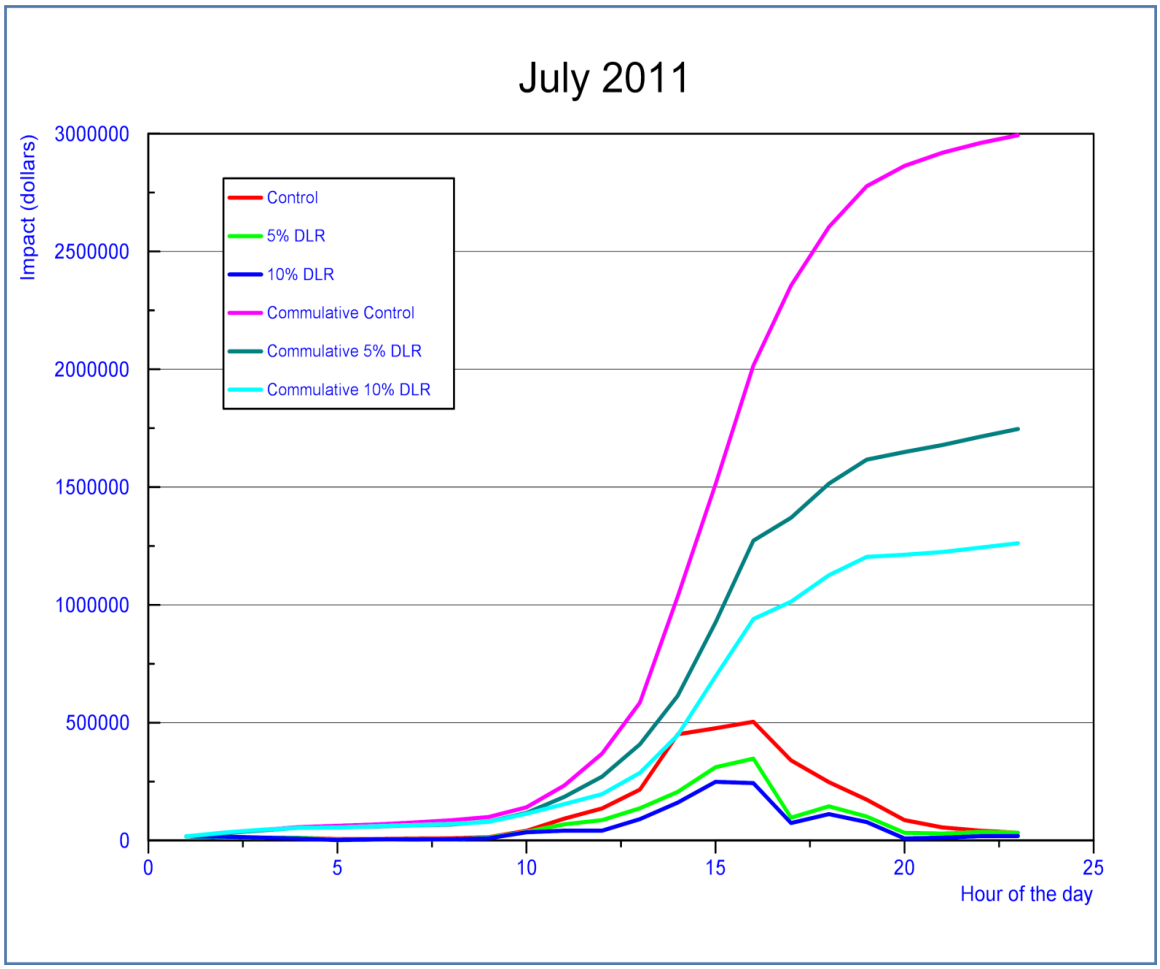

Figure 7. July Cost Impact Hourly and Cumulative

3.6 Correlation of DAM to SCED

Congestion in the grid costs significantly more when it is identified in the daily modeling of the system through the SCED. SCED runs every five minutes during the operational day, providing a prediction of the potential constraints in the system and alerting the system operators to problems that may need human intervention through generation shifting.

Having developed an understanding of how DLR can affect congestion costs through DAM modeling, we then focused on how the daily operations model (SCED) could potentially be impacted and what the potential cost impact could be through congestion mitigation.

For this correlation, we looked at the direct impact on the six lines selected for this study and at the impact on the peripheral lines that radiate from connection points along those six lines. Discussion on this approach is in Section 4.

Using a congestion reduction model of 75% for direct lines with DLR and 54% for peripheral lines (as averaged over 12 months), we see a congestion rent impact within the DAM as shown in Figure 8.

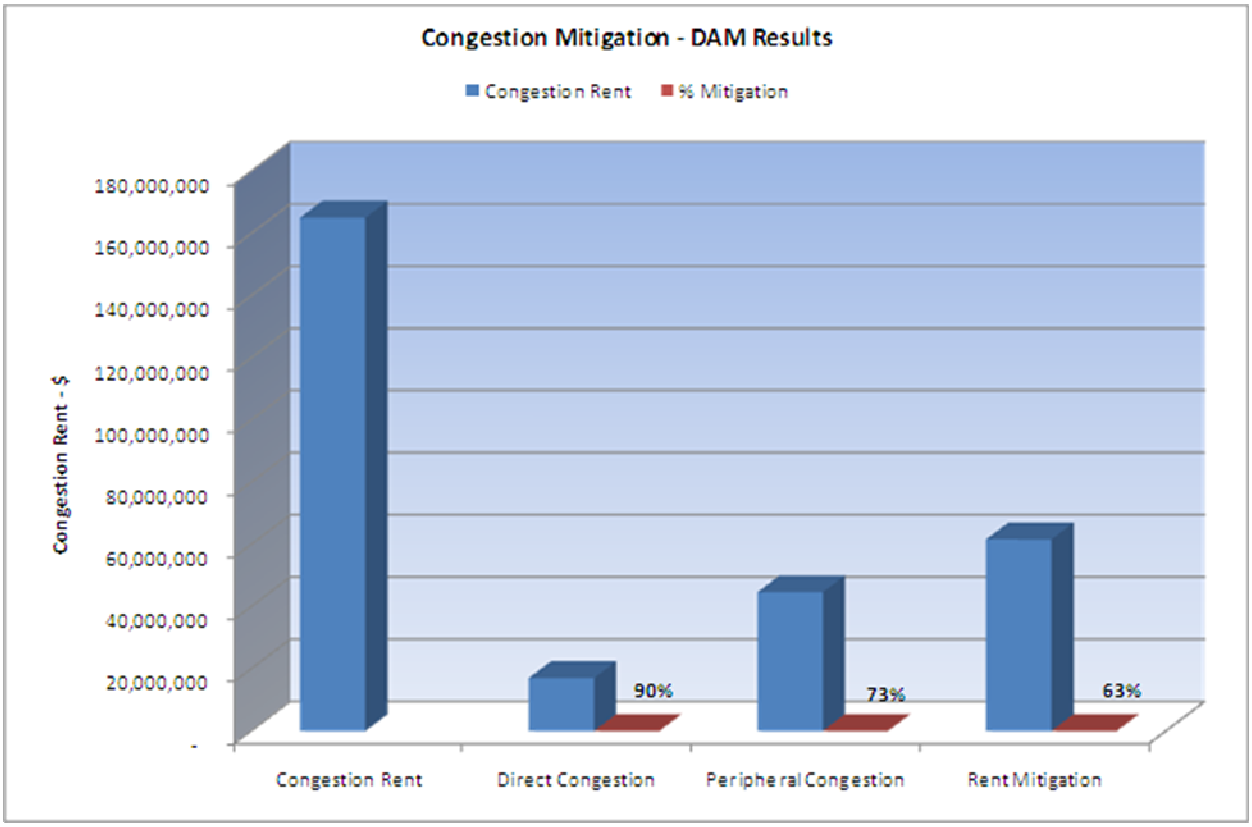

Figure 8. Congestion Impact within DAM on Direct and Peripheral Lines

Extrapolating these results into the SCED congestion, we see the impact to congestion rent as shown in Figure 9.

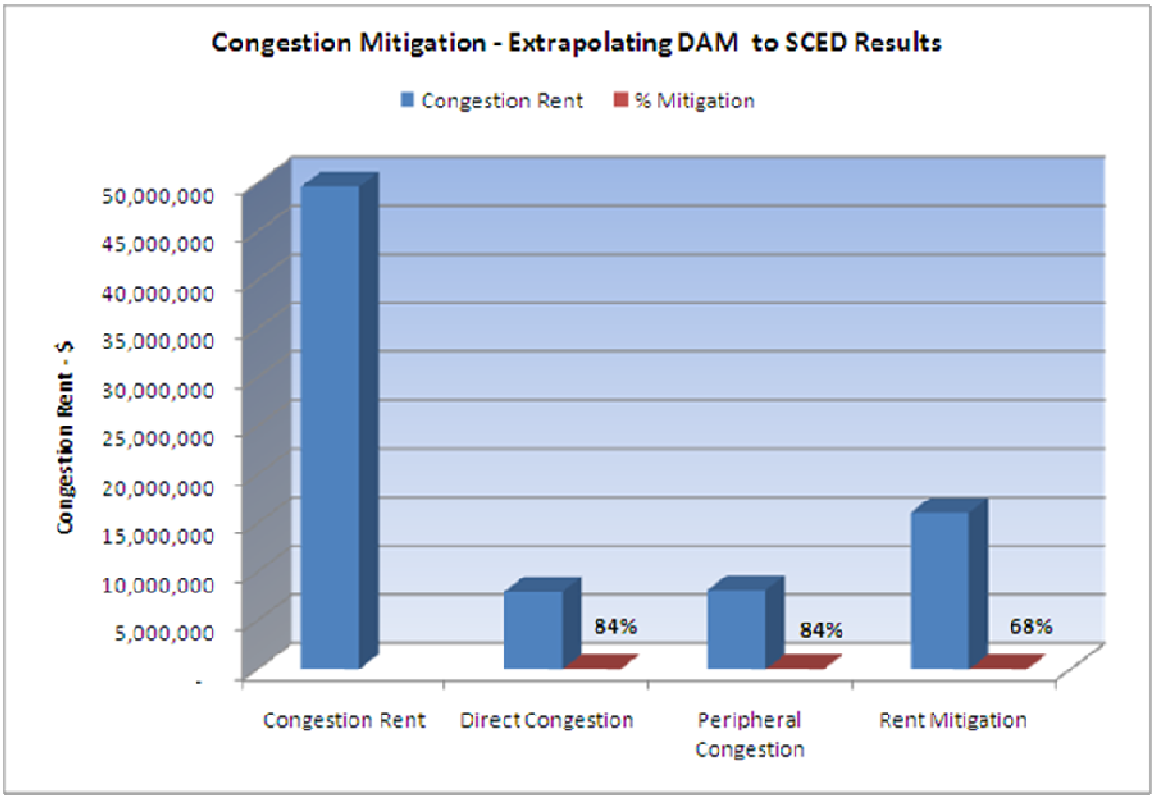

Figure 9. Congestion Impact within SCED on Direct and Peripheral Lines

Analyzing these two views shows that for a given year on a set of target lines, DLR has the potential to reduce congestion costs by an average of 65% (63% rent mitigation in DAM, 68% in SCED).

Based on these results, we now make an assumption that DLR can have an impact of reducing congestion rent by 65% on the annual congestion. Making a further assumption that DLR would not be deployed on all lines but on a percentage of them that show regular congestion, we are able to show a congestion mitigation impact within the SCED. For example, if one-sixth of the lines were directly monitored with DLR within the Oncor transmission system (30 of 180 lines), the congestion impact savings for the past two years (2011 and 2012) would be:

0.16 * $345,109,414 (two-year congestion cost) * 65% = $35,891,380

This results in a savings of approximately 10% over the two-year period.

Extrapolating across all of ERCOT, where 2012 SCED congestion costs were $618,908,587 and assuming that only one-twentieth of the lines were monitored, we believe that congestion impact savings would be:

0.05 * $618,908,587 * 65% = $20,114,529

As can be seen in these results, DLR can result in a cost savings potential, in this case, of approximately 3% ERCOT-wide.

To help validate our above assumptions and analysis, we looked at the DAM (base case, +5% DLR, +10% DLR) and SCED data from November 1, 2011. DAM congestion for that day is shown in Figure 10.

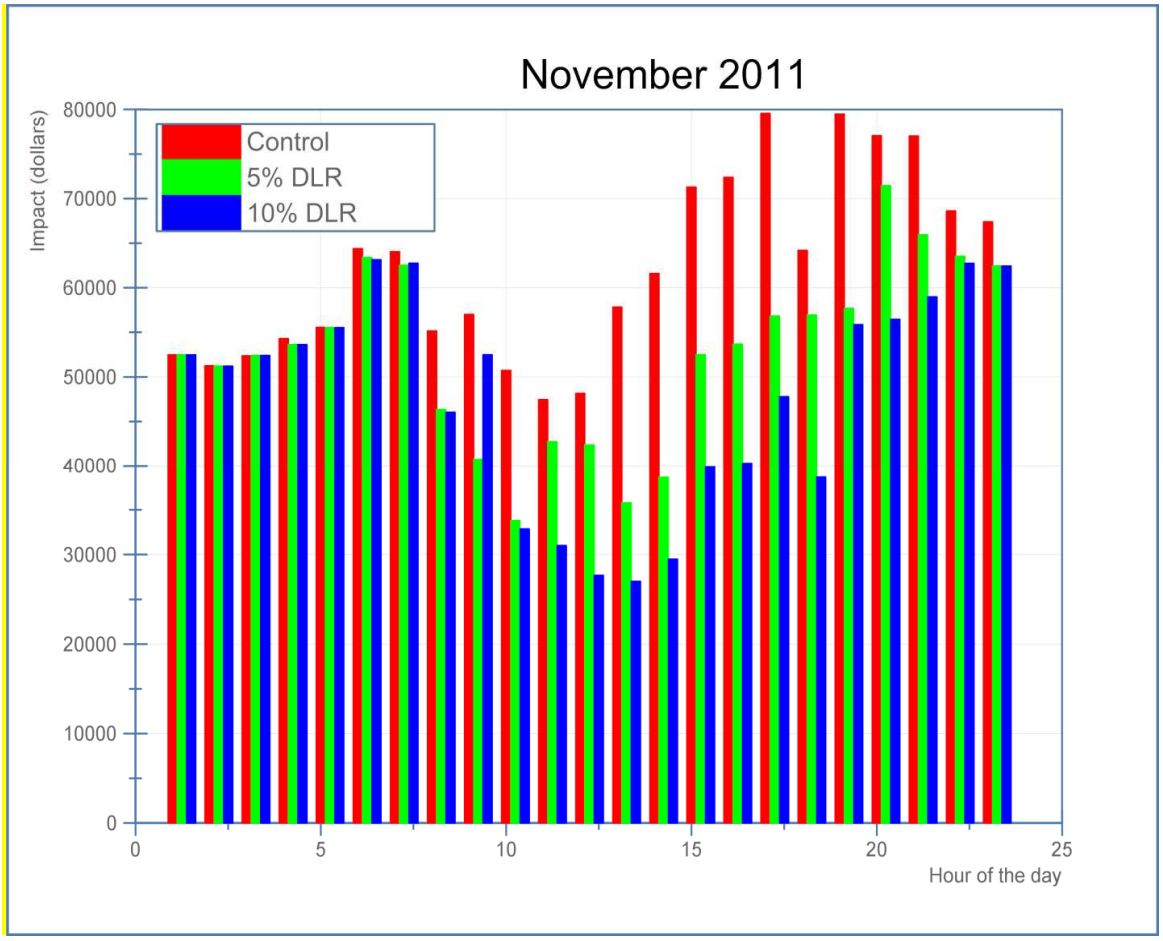

Figure 10. DAM Hourly Congestion Costs per Hour, November 1, 2011

SCED congestion for that day is shown in Figure 11.

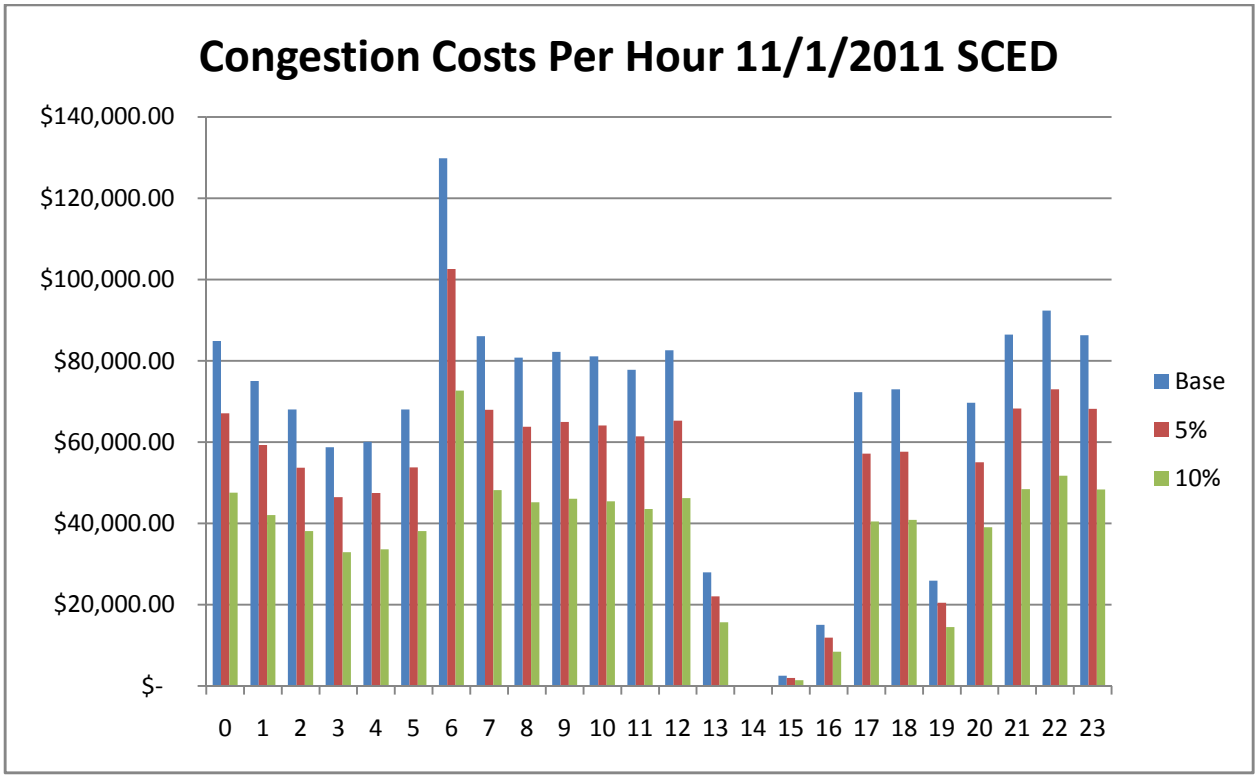

Figure 11. SCED Congestion Costs per Hour, November 1, 2011

Utilizing the DAM data reruns analysis as presented in Section 3.5 and doing the above calculations on the SCED data for that day, we see congestion cost reductions as shown in Figure 12.

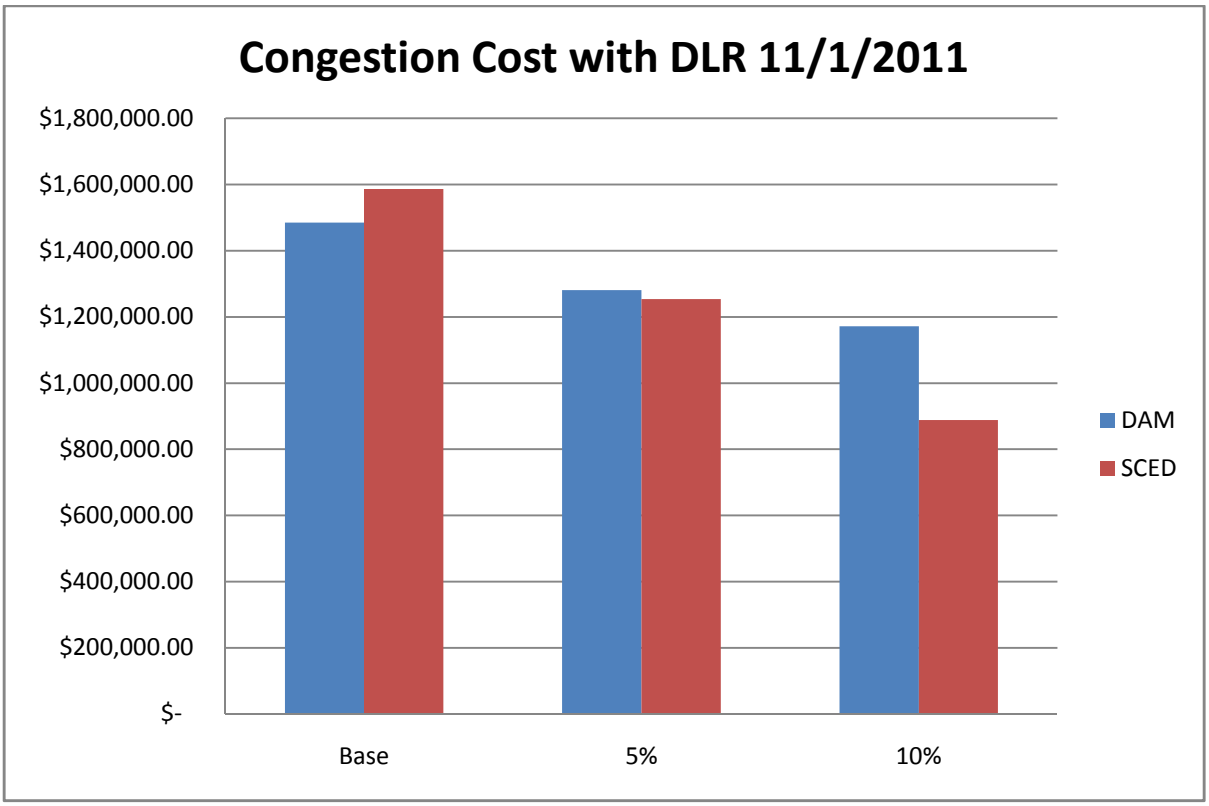

Figure 12. DAM and SCED Congestion Relief Cost Impact for November 1, 2011

The percentage congestion relief cost impact is shown in Figure 13. It is important to note that for this particular day, there is a much greater impact to SCED congestion costs than to DAM. Also, it can be seen that 10% DLR has a significant impact on SCED congestion, eliminating 44% of the congestion costs for November 1.

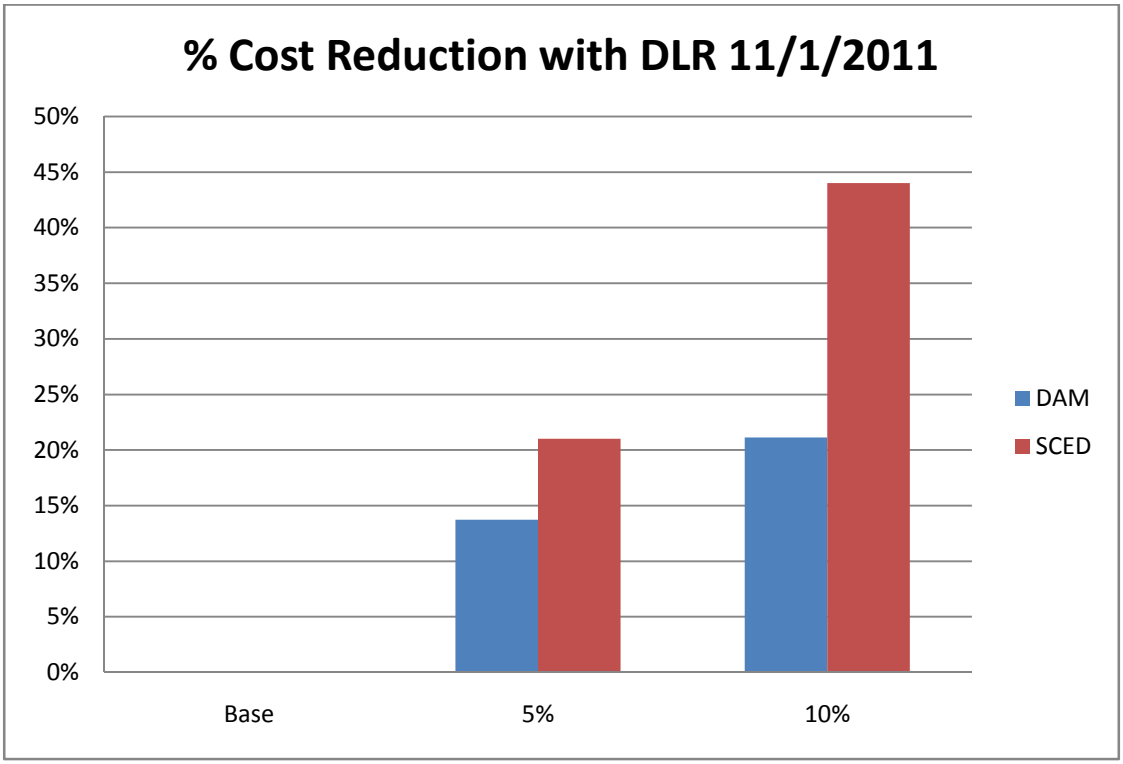

Figure 13. Percent Cost Reduction DAM/SCED November 1, 2011

While this analysis for November 1, 2011, shows different cost reductions between DAM and SCED than our annual analysis previously discussed, it does support that DLR has a positive impact to congestion rent mitigation and shows that the impact is greater to SCED, where overall congestion costs are higher. Additionally, it shows that 10% DLR has significant impact to SCED analysis, whereas it had a much smaller impact over 5% in the DAM.

3.7 Environmental Analysis Based on Shift Factors in SCED

Shift Factors define a set of recommended actions for increasing and/or decreasing generation on each side of a constrained element in the system that will change the congestion constraint proportionately to the Shift Factor. A file is produced for every SCED run where all of the active constraints are identified along with a set of Shift Factors that can be applied to relieve the constraint. Each Shift Factor is associated with a single generator unit. Any given constraint in any given SCED run may have 50 or more Shift Factors that can be applied to relieve the constraint.

The Shift Factors for a given constraint range from negative to positive, where a negative constraint represents a positive impact on the congestion constraint, i.e., a reduction in congestion, while a positive Shift Factor represents a negative impact on the congestion constraint. These Shift Factors are used by the system operators to increase generation on one side of a constrained element while decreasing generation on another unit, thus balancing out the system around the constrained element and relieving the congestion. The more negative a Shift Factor, the greater impact an incremental change in that unit's generation will have on congestion relief. Conversely, the more positive the Shift Factor, the greater the incremental generation has on increasing congestion.

The typical method for implementing the Shift Factors is to work inwards from both directions using the most negative and most positive Shift Factors first and moving towards the middle of the list until congestion is relieved.

While the Shift Factor files provide a change in generation through a negative or positive Shift Factor, the files do not provide information on incremental change in magnitude of the power output of the generator or what the power output result would be when the Shift Factor is implemented. Because of this, we were not able to determine our results in terms of megawatts of power changed and effectively direct environmental change. Our approach then was to determine unit-less change, or the delta in emissions output, between base and DLR cases.

Our approach to analyzing the environmental impact of DLR technology involves analysis of the Shift Factors as they relate to a change in generation pattern due to system constraints. We did this by identifying the differences in SCED-identified constraints between the base and normal case and in a system where DLR was in effect for the six lines identified for the economic analysis.

ERCOT provided Shift Factor files for our 12 study days used for the economic analysis. For each day, it produced a base case file, a DLR file where capacity was increased 5% on our six lines, and a DLR file where capacity was increased 10%. This resulted in the creation of 36 files, three per month. Each file contains from ~100k to ~300k individual Shift Factors for the day. Approximately 5.4M Shift Factors were analyzed for the scope of this study.

3.7.1Nature of Primary Generation in the ERCOT System

The nature of primary electricity generation in Texas has changed several times over the past 50 years. Starting in the early 1950s, natural gas plants were the primary additions to the generation fleet. This trend changed to coal in the mid- to late 1970s due to a perceived shortage in natural gas deposits. Nuclear plants sprang up in the late 1980s and early 1990s. With the discovery of new natural gas deposits and the emergence of fracking technology, natural gas has again become the predominant electricity producer in Texas, although in the past decade wind has made significant impact on the electricity market.

According to the Texas Comptroller of Public Accounts office, natural gas generation in 2006 accounted for 49% of all Texas electricity generation, followed by coal at 36.5%, nuclear at 10.3%, with renewables, other gases, petroleum, and hydro making up the remaining 4.2%. The picture, however, is changing.

In 2006, Texas had 2,739 MW of installed wind production [7]. By 2010, that number increased to over more than 10,000 MW of installed capacity [8]. In addition, another 6,500 MW have been announced for construction and turn-on over the next five years.

In looking at new generation plants completed since 1995, natural gas leads by accounting for around 75% of all energy generation. Wind is the second largest new generation contributor, accounting for an additional 20%, with coal, nuclear, solar and biomass making up the other 5% in new generation capability.

3.7.2 Use of DOE eGRID Database for Environmental Outputs

Emissions data was taken from the Department of Energy eGrid 2010 Version 1-1, which provides the emissions output of generation plants from 2007. A mapping file was created to match Texas generation plant names with the eGrid-identified plant names. Two files from ERCOT, a generator units file and a generator sites file, were used to provide the mapping from a generator key name in the Shift Factor files to the plant name within eGrid.

For this study, which focused on the difference in emissions output when DLR is applied to a part of the transmission system, only plant-level emissions data was used. This means that where the Shift Factor files identified a particular generator within a plant, that generator was mapped to the plant rather than to the generator unit. The rationale behind this decision was because an analysis of the Shift Factor files showed that when a Shift Factor was applied for a given constraint, there was typically a Shift Factor identified for each generator within a plant, and it was usually the same Shift Factor. For example, if a generation plant has five boilers, the Shift Factor file usually contained a Shift Factor entry for each boiler at that plant for the same constraint for the same hour.

For each plant, we utilized the following eGrid data fields for emissions output:

- Plant annual NOx total output emission rate (lb/MWh)
- Plant annual SO2 total output emission rate (lb/MWh)
- Plant annual CO2 total output emission rate (lb/MWh)
- Plant annual CH4 total output emission rate (lb/GWh)
- Plant annual N2O total output emission rate (lb/GWh)

To properly weigh the emissions outputs for each Shift Factor, we multiplied the Shift Factor by the lb/xWh rate to produce a weighted emissions rate. Our analysis shows the resultant difference in emissions output from base versus DLR in unit-less form.

3.7.3 Analysis Methodology

Since the Shift Factor files do not provide a picture of what actually happened, only what could happen, our approach had to be one of what-ifs. While DLR was implemented on only six lines within the system, our analysis encompasses the entire ERCOT grid, looking at total system emissions change. Our first step was to determine what differences would be the subject of focus between the base and DLR files.

Identification of Constraint Differences

Since our study area encompassed the implementation of DLR on only six lines in the system, many of the constraints and their identified Shift Factors remained the same across the files. To reduce the data set, we conducted a union across the three files (base, +5% DLR, +10% DLR) to identify where the constraint cases differed. Our study then focused on those changes. Changes were identified by whether the number of times a given constraint appeared in any one file was greater than in another file, was less than in another file, or the constraint appeared in any one file and not in one of the others. Table 1 provides an example.

Table 1. Example Constraint Difference from August Data Set

10% DLR	Count	5% DLR	Count	Base	Count	B-5	B-10	5-10
CUELCA_THOMAS1_1	4791	CUELCA_THOMAS1_1	4791	CUELCA_THOMAS1_1	4791	0	0	0
				DOW_RISN_1	960	960	960	0
DRSY_SANA_T1_1	1040	DRSY_SANA_T1_1	1040	DRSY_SANA_T1_1	1040	0	0	0
FALFUR_69A1	126	FALFUR_69A1	126	FALFUR_69A1	126	0	0	0
FDR_OZN_1	5280	FDR_OZN_1	5280	FDR_OZN_1	5280	0	0	0
GBY_AT2	1608	GBY_AT2	1608	GBY_AT2	1608	0	0	0
GBY_AT2L	1608	GBY_AT2L	1608	GBY_AT2L	1608	0	0	0
GIL_PHM_1	10184	GIL_PHM_1	10184	GIL_PHM_1	10184	0	0	0
		HAMILT_PICACH1_1	4	HAMILT_PICACH1_1	4	0	4	4
HIC_LOCU_1	6384	HIC_LOCU_1	6384	HIC_LOCU_1	6384	0	0	0
HILLCTRY_MR4H	6375	HILLCTRY_MR4H	6375	HILLCTRY_MR4H	6375	0	0	0
HILLCTRY_MR4L	6375	HILLCTRY_MR4L	6375	HILLCTRY_MR4L	6375	0	0	0

In this example taken from the August data, a count of the number of times a constraint occurs in each file is compared to determine where changes to the generation pattern could occur when DLR is implemented. In this case, the DOW_RISN_1 and HAMILT_PICACH1_1 constraint cases differed. In the case of DOW_RISN_1, constraints identified in the base case did not appear in the DLR cases, while in the HAMILT_PICACH1_1 constraint case, the constraint did not appear in the 10% DLR case.

To verify this methodology of identifying change, spot checks were done on some of the zero-change cases. In 100% of those spot checks, it was verified that there was no change in the Shift Factors across the three files.

Analysis of Selected Constraint Cases ('All' Method)

As stated previously, the Shift Factor files are a set of recommended or potential shifts in generation that could be executed to relieve a given constraint in a given interval. No data was available to determine which, if any, of these Shift Factors were actually implemented or the scope of those shifts for a given constraint. Since this information was not available, our first approach was to look at the Shift Factor changes, *en masse*, to determine what the potential change in emissions could be. This

approach makes the hypothesis that if all Shift Factors were executed as specified in each file, a change in generation emissions output could be equally compared between the base and the DLR cases.

Initial analysis of the reduced data sets showed that there was little to no change between the +5% DLR and +10% DLR files, so we decided to focus on the differences between the base and +5% DLR cases.

To determine the emissions output for a set of Shift Factors from a given file, summation method of emissions output as described in the equation below was used.

$$Emissions = P_{case} = \sum_1^c E_{Type} * SF_{case}$$

Where:

SF = Shift Factor

Case = base or +5% DLR

E = emission

Type = emission data type (NOx, SO2, CO2, CH4 or N2O)

C = number of constraint rows to be analyzed for a given constraint

Once the emissions were computed for the base and DLR cases, the following equation was used to calculate the differences:

$$Change\ with\ 5\%\ DLR = \Delta_{DLR} = \frac{P_{DLR} - P_{Base}}{Abs(P_{Base})}$$

Where:

DLR = Shift Factor file with DLR

Base = Shift Factor file without DLR

This resulted in a set of data elements, by emissions type, showing the percent difference in emissions output in the +5% DLR Shift Factor recommendations versus in the base case.

The data in Figure 14 shows that for seven of the 12 months of the year DLR resulted in a positive net reduction of emissions output throughout the grid. This was especially true during the winter months (January-April). During the core summer months (June-August), there was minimal emissions impact, while during the fall (October-December) there was a net increase in emissions with DLR.

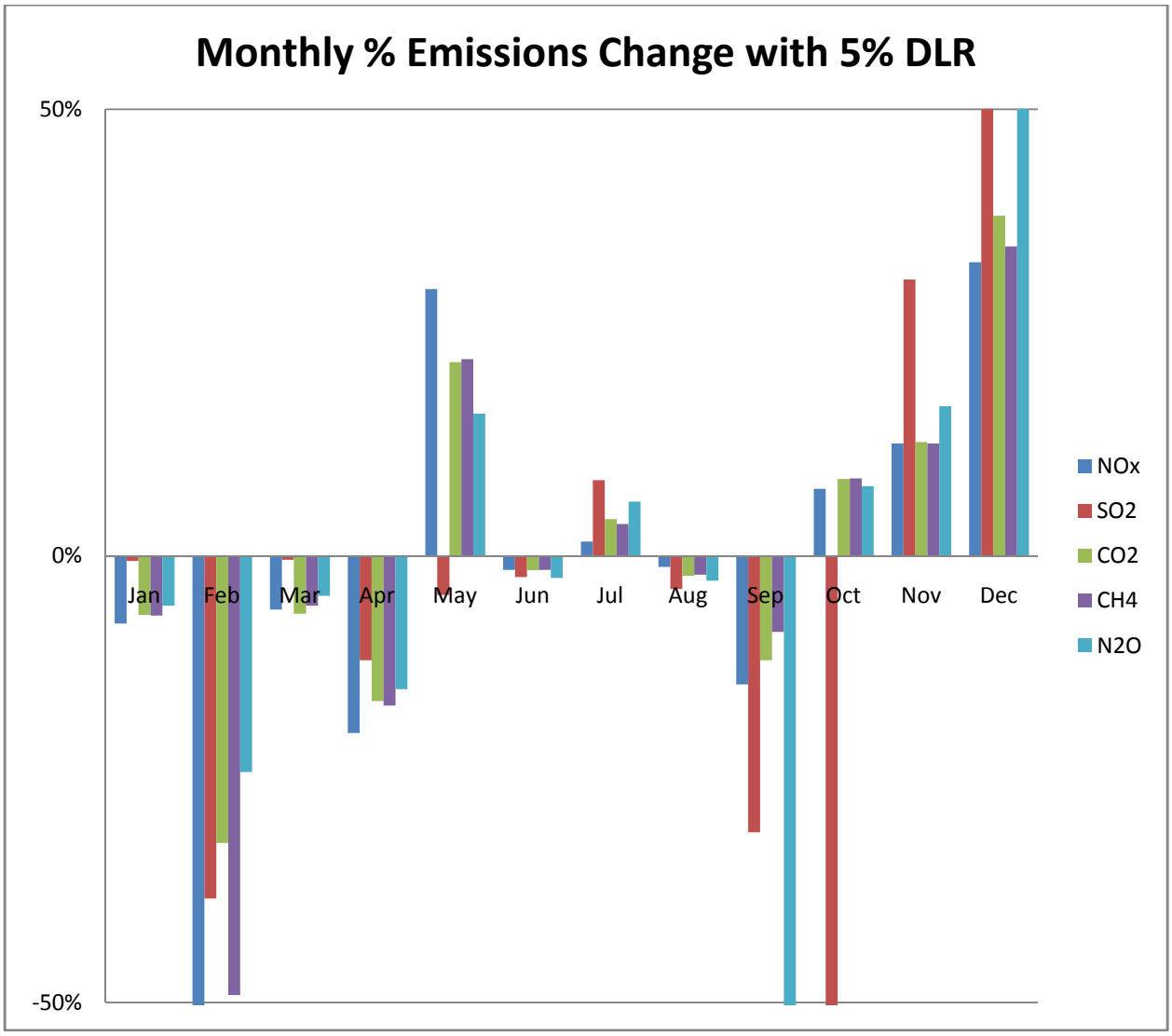

Figure 14. Net Emissions Difference using +5% DLR on Six Lines within the ERCOT Grid

*Note: y-axis scale reduced to +/- 50% to enhance view-ability of the data.

While the data shows a net positive impact with DLR, it is not definitive and warrants further study. Since the data only represents one day each month, it is subject to skewing due to unknown anomalous events that could happen in a day, such as a significant weather event or a major generation plant problem. For example, the October data was taken from only a few data points since there were only two differing constraints in the October Shift Factor files, resulting in only 11 data points that could be analyzed. While the SO2 emissions difference for October looks significant, in reality it had minimum impact on the system-total SO2 emissions for the day.

The following graphs show more detail of the net effect of DLR on a particular emission throughout the year. Note that the y-axis scales are the reduction in pollutant from the base model in pounds per MW

or pounds per GW (as identified in Section 3.7.2), but the total values are unit-less since the actual affected MW/GW were unreported in the data. Thus, these charts show relative change only.

Figure 15 shows the cumulative change in emissions rates throughout the year. We can see there is a general reduction in emissions output during the winter months, relatively little change during the summer, and a steep increase in emissions during the fall. The remaining emissions graphs reflect similar trends (see Figures 16 - 18).

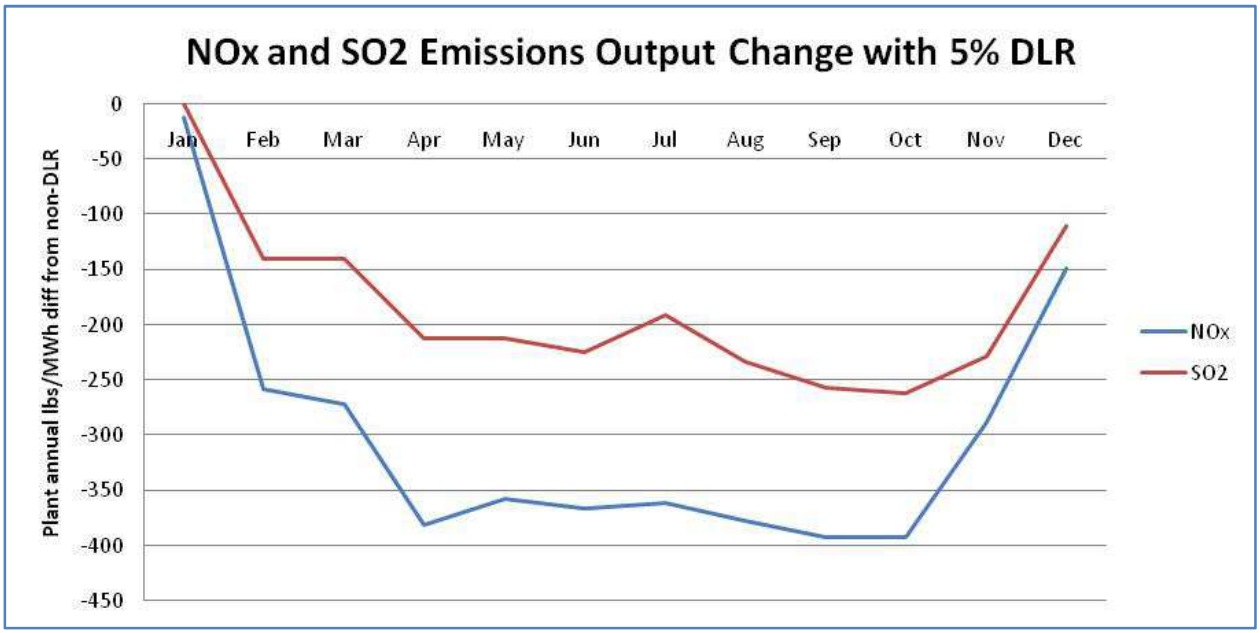

Figure 15. NOx and SO2 Emissions Output

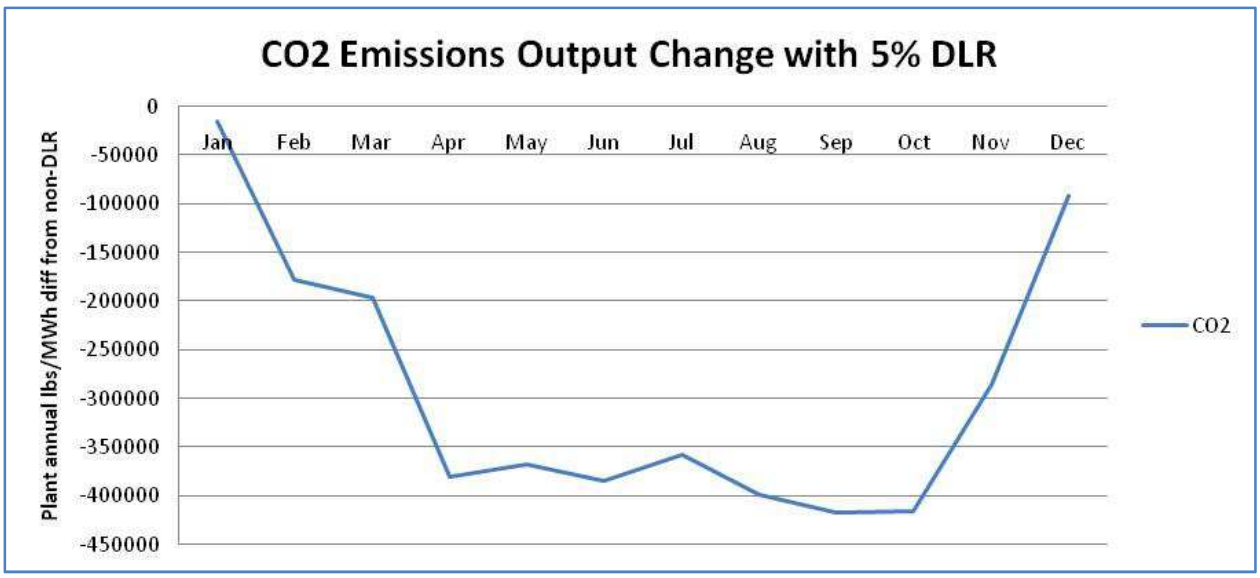

Figure 16. CO2 Emissions Output

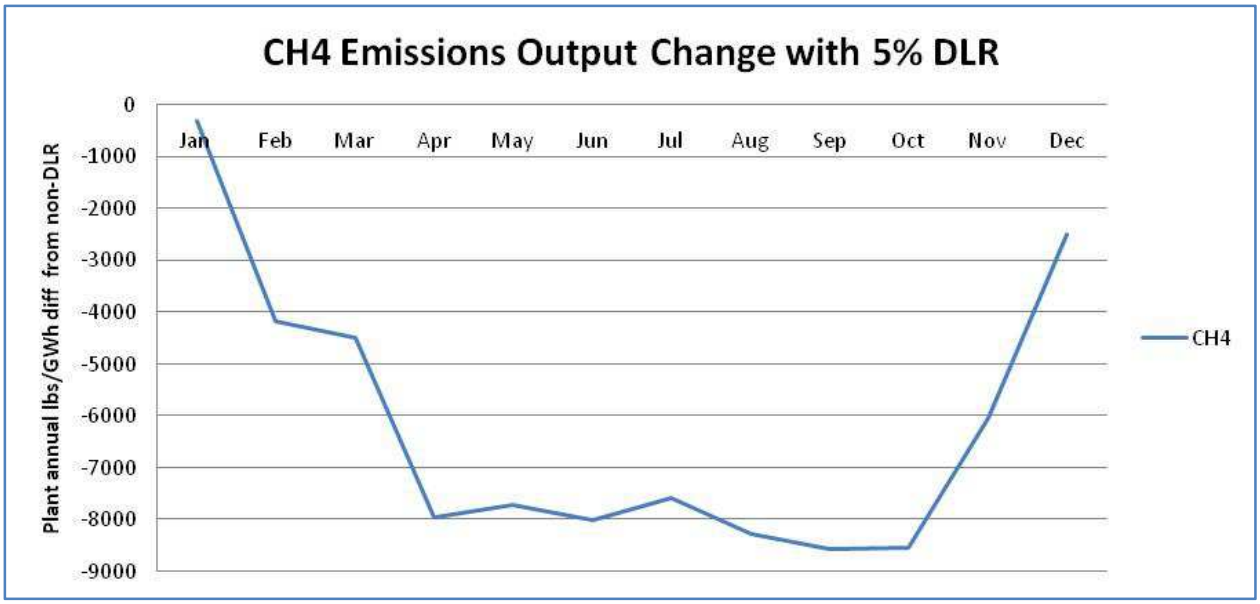

Figure 17. CH4 Emissions Output

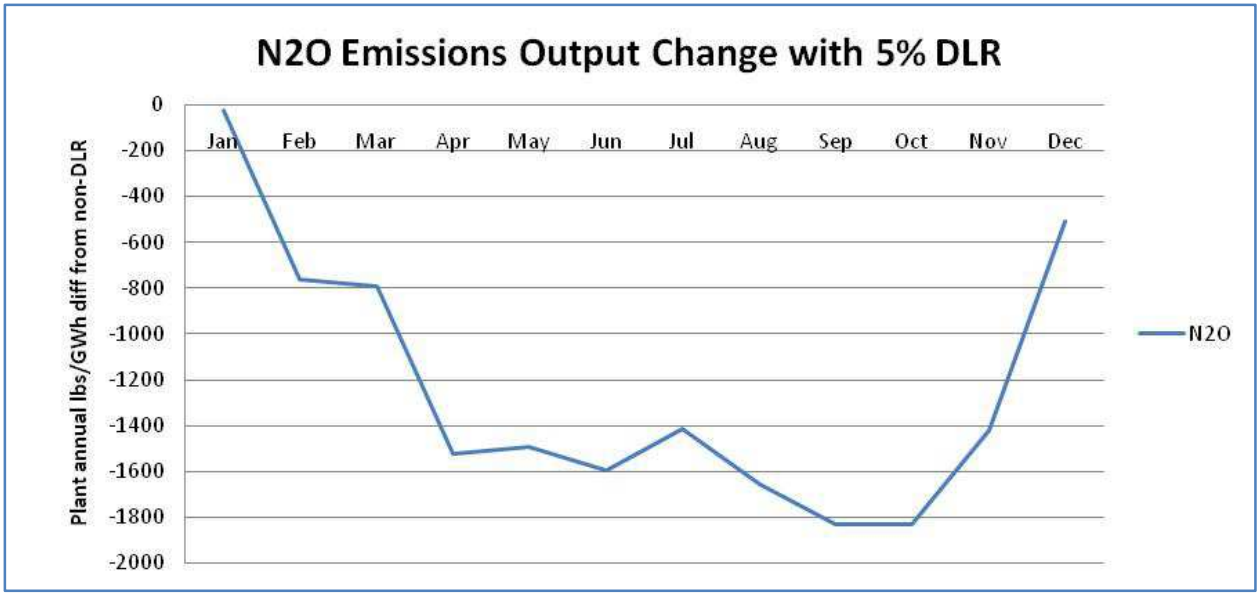

Figure 18. N2O Emissions Output

The results of this study methodology show that there is an impact to emissions outputs when lines are monitored in real time using DLR. The net effect for the year is a 10-25% reduction in emissions output with DLR over the normal AAR method predominant with the ERCOT transmission network.

Research should be conducted to further quantify this emissions impact. If it were possible to know exactly what the pre- and post-redispatch notices were, we could quantify the actual unit loading change and calculate the environmental impact in actual tonnage.

Factors such as expanding the number of DLR lines could show even greater reduction. Placement of DLR was not factored into this study but could be to show impact such as increased wind, solar or hydro generation (all of which have zero emissions). Furthermore, analysis could be conducted to study why emissions output showed significant increase in May, November and December. We hypothesize this may be related to planned plant maintenance in preparation for a peak season: May in preparation for the heavy summer season and November-December in preparation for the winter heating season.

Additionally, as pointed out previously, our study data only represents one day per month and is subject to event skewing (which was not determinable through the data). Correlation between the types of primary generation and shifted generation could identify how DLR might benefit the environment by allowing more environmentally efficient generators to put more power onto the grid. Finally, a study that could match up Shift Factor recommendations with actual actions taken by the system operators could provide a much more definitive answer to emissions impact.

Analysis of Selected Constraints (Hourly Top Five Method)

Our previous analysis looked at the system Shift Factors as a whole, doing a comparison of all the Shift Factors for a given constraint. Thus, the Shift Factors file is a set of recommendations for all possible constraints as identified in the specific SCED run. The reality is that not all constraints actually happen;

and, when they do happen, the system operators will only shift generation as needed to relieve the constraint. We were unable to gain knowledge on the exact methodology for exercising Shift Factors; however, in discussions with ERCOT officials and through our own team knowledge, we were able to develop an additional hypothesis for analysis. This hypothesis is that when a given constraint occurs, the system operators will adjust generation by executing the most negative and most positive Shift Factors, working their way toward the middle until congestion is relieved.

To conduct this analysis, we selected the top five distinct negative and positive Shift Factors for a given constraint within the same event. Our analysis was done to reflect a shift of generation at up to five units at both extremes of the Shift Factor priority list. In general, when a shift is defined, a Shift Factor is assigned to each generator at a generation plant, thus our choice in top five resulted in from five to 25 individual rows of shift per negative and positive Shift Factor. The net result was approximately 50 total shifts, negative and positive, per constraint. This is in contrast to the "All" method (Section 19.7.3), where from a few hundred to a few thousand shifts per constraint were analyzed. We then analyzed the resulting data set using the same equations as in the "All" method.

Because of the difficulty in extracting data using this method, only one month, January, was fully analyzed (Figure 19). A few of the constraints from August were also analyzed. This method shows a greater impact on emissions output when DLR is implemented.

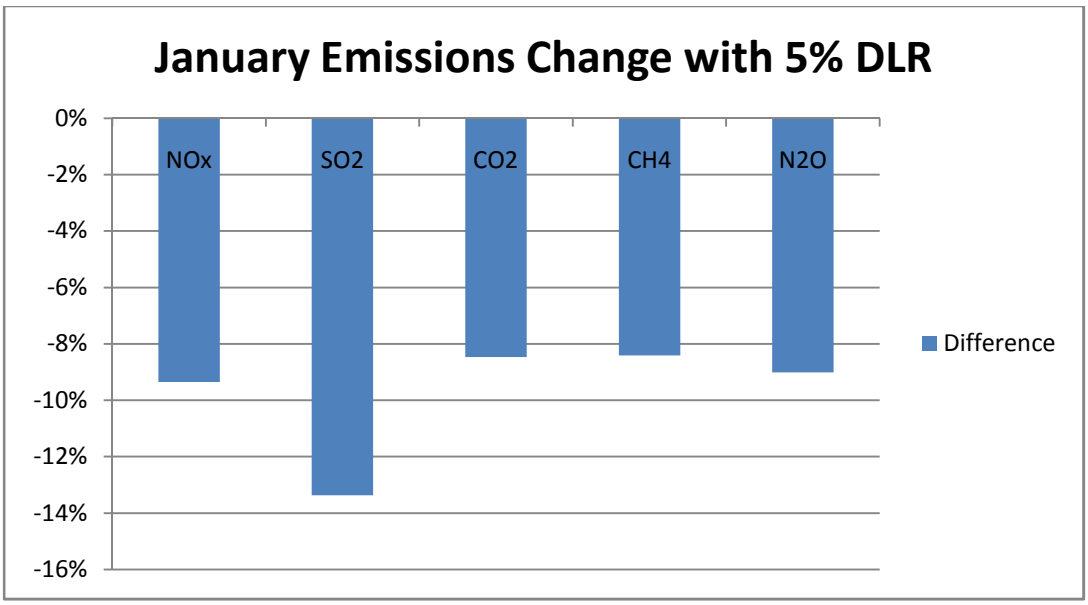

Figure 19. January Emissions Difference using the Top Five Method

4. ECONOMICS OF DLR TECHNOLOGY

This section discusses the impact of DLR technology on the economics of the energy market. It discusses the impact of the lines directly monitored (lines where DLR has been installed), peripheral lines that radiate out from the monitored lines, and the grid as a whole.

4.1 Direct Impact on Monitored Lines

As a part of this study to further understand the impact of DLR to the relief of congestion, analysis was conducted to study the economic impact to the lines directly monitored by DLR; that is, the lines upon which the DLR equipment is installed. As stated before, the lines used for the economic study were not actually monitored; however, using the data from the capacity-released study that resulted from monitoring the actual test lines, we were able to simulate the effect of DLR on the six lines we chose for the economic study.

This study used the same DAM runs with adjusted DLRs as before but focused only on the six target lines. In order to further understand the impact of DLR on congestion, the congestion rent was distributed into three summations: base case constraints, transformer constraints and line constraints. Base cases are defined as operations scenarios where large blocks of power transfer are modeled as compared to individual N-1 constrained element analyses; for example, a West-North zonal transfer of a block of wind generation being there in one instant and not there in the next on the grid. This type of constraint has actually happened as a weather front passed west to east and no wind pockets were embedded in the front or quickly followed the front when wind generation had been high and then nonexistent.

Transformer cases are constraints related to a transformer capacity being insufficient to meet load at the other voltage (such as from a 138 kV to a 69 kV line). Line cases are constraints related to line capacity.

Figure 20 shows the impact of DLR on the six directly targeted lines. Congestion rent decreases significantly when 5% DLR is added into the DAM for the six lines and is completely eliminated at plus 10% DLR.

4.2 Direct Impact on Peripheral Lines

This part of the study looked at the lines that radiate out from the actual monitored lines to look at the scope of the economic impact. The vision of DLR is not to monitor each and every line within a transmission system; rather, it is to monitor critical lines where congestion is prevalent as an alternative to near-term capital improvements or system upgrades.

For purposes of this study, a peripheral line is a transmission line that is adjacent to a directly monitored line, either feeding into the line or being fed from one of the monitored lines through a connection point, such as a transmission substation.

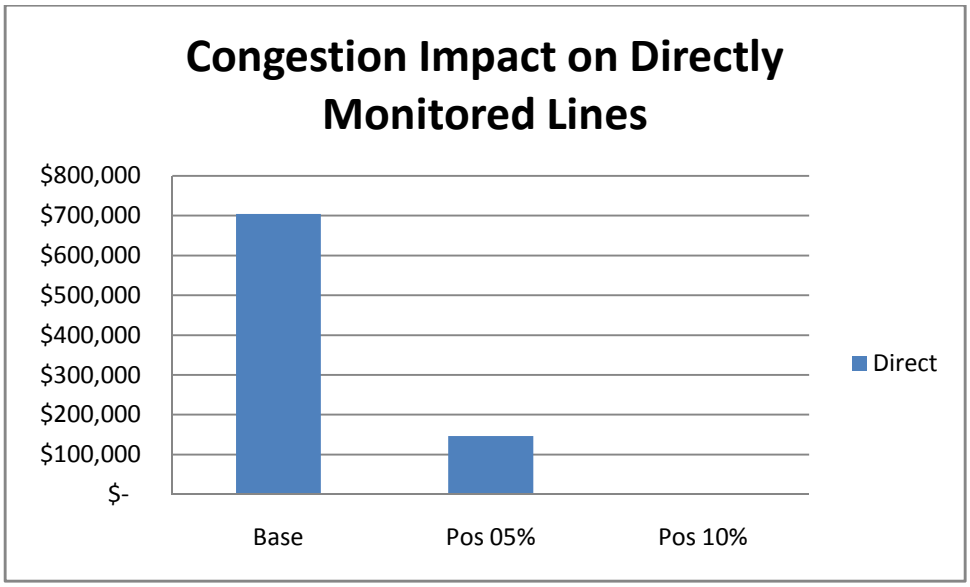

Figure 20. Oncor Line and Transformer Congestion Data

Our results show a significant reduction in peripheral line congestion around DLR-monitored lines. As can be seen in Table 2, peripheral line congestion was reduced by 42% when directly monitored line capacity was increased to 105% and by 44% with 110% capacity. We can see that the cost impact begins to decrease as you move away from the directly monitored lines but that the impact is still significant. We also notice that while 10% DLR has significant impact over 5% DLR on the directly monitored lines, it has negligible impact on peripheral lines, here showing only a 2% increased benefit. This is a trend that continues as we look at the system-wide impact.

Table 2. Congestion Comparison between Direct and Peripheral Lines

	Direct	Peripheral	Grand Total
Control	$ 704,535	$ 1,096,893	$ 1,801,428
Pos 05%	$ 146,668	$ 632,967	$ 779,635
Pos 10%		$ 609,873	$ 609,873

Percent Reduction in Congestion

% Reduction	Direct	Peripheral	Grand Total
Control			
Pos 05%	79%	42%	57%
Pos 10%	100%	44%	66%

4.3 Extrapolated Impact on Utility Transmission System

As discussed in Section 3.5.4, the direct monitoring of only a few lines with DLR can result in a significant economic benefit across the entire energy market. The benefit of +5% DLR on chronically congested lines ripples through the system, resulting in less congestion cost not only at the monitored lines but in other areas as well. Our thoughts on this relate to the maturity and efficiency of the SCED program to mitigate congestion through the decisions on bids and offers. By providing improved line capacity based on real world conditions (especially factoring in wind cooling effects), better line capacity data is provided to the SCED, which is then able to resolve more of the congestion than when static or ambient ratings were used.

5. Market Impact on ISO System

An analysis of the DAM models with increased throughput of +5% and +10% shows a significant impact on the energy market. During the hours and days studied in the DAM analysis, congestion cost savings within the DAM on those lines were better than 20%, with peak savings exceeding 100%, i.e., congestion was fully mitigated on the target line. It is clear from the study data that with an ability to increase line capacity within the SCED based on monitored readings, there is a clear economic impact that can be realized by the market when congestion costs are reduced.

Another important note is that a general increase in line capacity does not always guarantee a reduction in congestion savings. Time of day, season, events within the transmission system, etc., all have an effect on congestion that cannot be guaranteed to be relieved through increased line capacity. However, the trend, and the annual summary, shows that DLR does have a congestion cost impact potential across the energy market and is especially significant during the peak load periods of the day and the peak demand months of the year.

6. Capital Deferment of New Transmission Investments

One of the primary goals for using DLR technology is to defer the need for capital improvements or system upgrades to relieve congestion. SLRs and AARs do not provide a true picture of the line capacity, resulting in congestion being identified on lines where they may in fact have the additional capacity available. When a line is proven to be chronically congested, it is typically scheduled for some sort of capital improvement to permanently relieve the congestion. We believe through our study that not all lines identified for capital improvement actually need it. DLR technology can be used to accurately measure line capacity in real time, potentially relieving congestion through an increased line rating.

7. ENVIRONMENTAL IMPACTS OF DLR

This section focuses on the impact of DLR as it relates to wind generation, a significantly growing energy resource within the ERCOT grid.

7.1 Integration of Wind Energy

As a part of this study, we wanted to look at whether DLR made any impact on wind generation entering the grid. Since wind is a zero-emission resource, the more that can enter the grid the less overall generation emissions will be. In Texas, the majority of wind generation is in sparsely populated West Texas, and the energy generated must traverse half the width of the state to reach the more densely populated areas. While the lines we chose for the economic study were selected with wind in mind, our primary focus was on congestion no matter the source.

For the 12 days of data provided to us for the year, we extracted the Shift Factors that were directed strictly at wind generation, identified in the eGrid database as having a primary fuel type of WND and resulting zeros in the emissions columns. To resolve the fact that a large amount of wind generation had been added in Texas since the last update to eGrid (2007), our custom mapping file matched new wind generation plants to an existing wind plant in eGrid since the emissions values would remain the same (i.e., zero).

The net result of our analysis shows that there was an increase in generator shift toward wind generators when DLR was applied to our target lines.

The net increase in wind was 3% for the year (encompassing data for one day of each month). The average difference in wind generation is shown in Figure 21, which is a running cumulative shift in wind generation pattern when 5% DLR is applied. Note that only three of our six study lines are in the wind zone, which makes this potential increase significant.

The method used to calculate this impact was to summarize all of the negative Shift Factor decisions (which are commands to increase generation), summarize all of the positive Shift Factors (commands to decrease generation), and then compute the difference to determine a net negative or positive shift. This was done for the base case (no DLR) and the 5% DLR case, and then the percent difference between these two cases was computed.

While this data is not definitive due to the limited amount of data, it is significant in the fact that SCED appears to be utilizing the increased line capacity to recommend generation shifts to more wind production. A more thorough study, one that analyzes distinct lines involved in wind generation input to the grid and contains more days of data, could be conducted to provide a more definitive answer. As the data exists now, we do see a potential increase in wind generation; as a result, we would expect a reduction in emissions from generation that could be achieved through DLR technology.

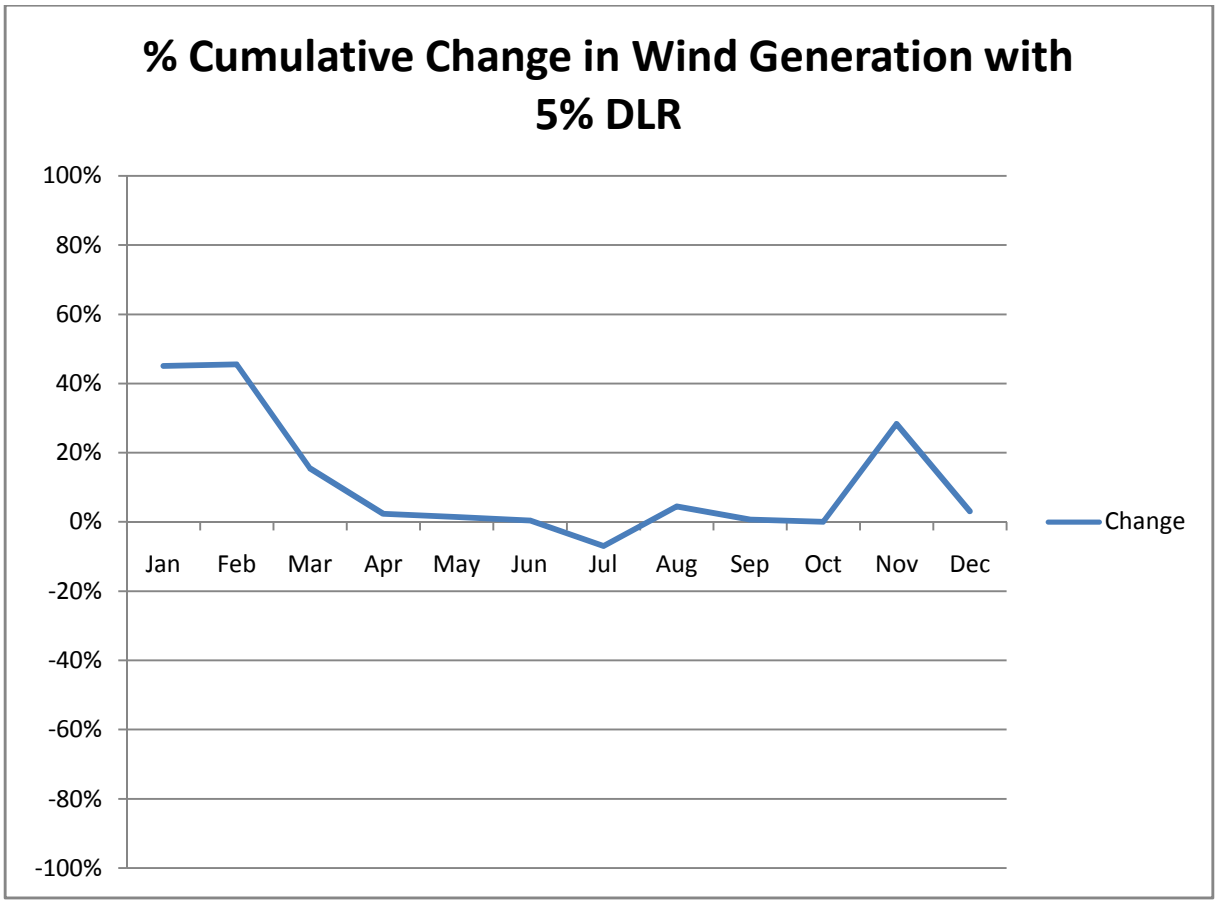

Figure 21. Running Average Shift to Wind Generation with DLR

Note the lack of a systemic change in the period from April through October in Figure 21. This is indicative of the lack of wind available for generation in these months. The units are not on the Shift Factor list because the wind is not there for generation, especially during peak periods of the day.

7.2 Changes in Generation Patterns to Relieve Congestion

Our study shows that the addition of DLR produces a change in the generation pattern within the grid. This change in generation results in a positive impact to congestion cost, as well as a reduction in emissions output. Additionally, our results show a potential increase in wind generation within the ERCOT system.

8. CONCLUSIONS AND RECOMMENDATIONS FOR FUTURE STUDIES

Presented here are our summary conclusions as well as recommendations for further study.

8.1 Economics of DLR on the Energy Market

Our study shows that DLR technology can have an impact on the price of energy within the transmission grid; in particular, the reduction of congestion costs associated directly with line constraints and indirectly on transformer constraints. The study results show that congestion mitigation can be obtained with as little as a 5-10% increase in capacity over the currently used line ratings using DLR.

8.2 Emissions Impacts of DLR

The results of the study show a positive impact on emissions outputs from generation plants across the system grid when DLR is able to increase capacity. This impact is shown through a change in generation shift patterns in response to N-1 and other contingency cases. The quantification of this impact in tonnage was not possible here and should be the subject of a more in-depth study focused on emissions outputs. The missing factor was the actual incremental generation-dispatch changes in response to congestion constraints on the grid (data of which was not publicly available).

Our hypothesis in this study was that DLR would enable a reduction in shift patterns, allowing more generation to occur as scheduled in the SCED where more efficient generators could be selected (efficient being defined as generators offering energy at levels where their plants run most efficiently) and would reduce the shifting of generation to less environmentally efficient generation. While efficiency levels of individual generators were not a focus of this study, the data seems to support validity to our hypothesis; a more detailed study could potentially provide definitive proof. Additionally, we have shown with DLR that there is an increase in the SCED to provide shifts that increase wind generation, a zero-emission resource, when it is available.

8.3 Recommendations for Further Study

Much of this study time was focused on identifying the data needed to conduct these analyses, discovering how to get that data (whether through access to the public files or through reruns of analysis by ERCOT), and how to process the data into meaningful results. With the knowledge we have developed through this study and with the data results of the capacity-released study, we are now in a better position to conduct more in-depth studies of DLR technology and its impact to the economics and emissions of energy generation within a system grid. We believe there are further studies that would be of value to the DOE and to the energy community at large and we outline those below.

8.3.1DLR Impact to Daily Operations

As shown in our analysis, DLR has the potential for a significant impact on daily operations congestion costs as identified through the SCED. DLR not only has a greater cost reduction impact, but 10% DLR

makes a much more significant contribution to cost reduction in daily operations than it does in the DAM. Since DLR is a real-time monitoring system, realizing its significance to reducing SCED congestion costs was our most important economic goal. We have been able to show that, in Oncor's case, the potential savings for DLR would have had an impact of an 11% reduction on congestion costs if it were installed on one-sixth of Oncor's lines. Extrapolated across the entire ERCOT grid and assuming a smaller DLR penetration rate of one-twentieth of the lines (5%), we show that there would still be a 3% overall reduction in daily congestion costs. We believe that if those 5% of lines were specifically selected due to chronic or extremely high congestion costs, a greater reduction in congestion costs could be attained without increasing the size of the DLR deployment.

8.3.2 Emissions Impact

Our study of emissions impact encompassed a limited time period of data, one day per month for a year. To produce a more definitive study, this data set should be increased to analyze Shift Factor decisions from a denser set of data for each month. With this information, the study could also look into more detail on the particular types of generation plants and into patterns of generation shift. The missing link is the incremental dispatch orders with each SCED run. This data is not available but required to quantify the megawatt shifts in generation that can then be expanded to calculate the tonnage shift in emissions. Again this is a large data set and so would need to be processed daily in order to accumulate data encompassing more days of each month. Since these files required ISO reruns to incorporate DLRs, coordination with the ISO would be necessary to get not only the base-case files but data that included DLRs.

8.3.3 Wind Integration

Wind was not a focus of our study; however, we were able to take a cursory look at the impact to wind generation. This study could be significantly enhanced by specifically selecting lines along the wind generation path and studying the impact of DLR in increasing wind generation reaching the end loads. By analyzing the Shift Factor files specifically for wind, this study could not only determine the impact to wind generation but could identify potential DLR deployment schemes that could be utilized to increase usable wind generation.

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APPENDIX A

Acronyms

LIST OF ACRONYMS

AAR	Ambient-Adjusted Ratings
CRR	Congestion Revenue Rights
DAM	Day-Ahead Market
DLR	Dynamic Line Rating
DOE	Department of Energy
ERCOT	Electric Reliability Council of Texas
ISO	Independent System Operator
LSE	Load-Serving Entities
SCED	Security-Constrained Economic Dispatch
SwRI	Southwest Research Institute
TBD	To Be Determined
TBR	To Be Reviewed

APPENDIX I. LESSONS LEARNED

INSTALLATION AND COMMISSIONING OF DYNAMIC LINE RATING TECHNOLOGY WITHIN THE ONCOR TRANSMISSION GRID

for the

LESSONS LEARNED – DYNAMIC LINE RATING PROJECT

Document No. 10-16404-DLR-LL

Version 2.1

April 30, 2013

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REVISION NOTICE

Version Identifier	Date of Issue	Summary of Changes
1.0	January 31, 2012	Initial Draft
1.0.1	March 16, 2012	Draft version with additional lessons learned
2.0	March 15, 2013	Additional lessons learned added to document and formatted document for final delivery
2.1	April 30, 2013	Final Issue.

This document contains information that is as complete as possible. Where final numerical values or specification references are not available, best estimates are given and noted TBR (To Be Reviewed). Items which are not yet defined are noted TBD (To Be Determined). The following table summarizes the TBD/TBR items in this revision of the document and supplements the revision notice above.

Section	Description

1. PROJECT PLANNING

Project planning involves those activities to prepare a Dynamic Line Rating (DLR) installation on a set of transmission lines. This includes determining which lines to monitor, what equipment is needed, when to schedule the installation (including planning for proper installation clearances), and scheduling crews and equipment to complete the installation within the clearance timeline.

1.2 Determination of Lines to Monitor

The first step in planning for a DLR installation is to determine which lines to monitor. Initial selection involves determining a transfer path where possible and significant commercial constraint is observed. Since the goal of DLR technology is to reduce constraints by allowing the transmission operator to operate the lines at higher than normal current loads, it is recommended that initial installations be placed in transmission paths with high historical constraint problems.

Monitoring of actual line loading and congestion, as well as predicting line loading using a power flow program, were determined to be the best methods to identify lines as candidates for DLR equipment. This process is the same used for planning upgrades to the transmission system. The process is well established, validated and is continually modified to address changing transmission conditions. The process has faults, however, in that a number of assumptions about future load growth and generation changes had to be made. These projections have considerable uncertainty associated, particularly where generation assumptions are made.

Note that the variability of actual congestion load events can make it difficult to determine the best lines to monitor. Analysis of congestion versus load growth congestion is dependent on many variables and is sporadic, being dependent of factors such as time of year, generation outages, line outages or other factors. Additionally, the impact to downstream lines is difficult to model given the variability of electron flow through an open grid. Integrating as many variables as practical, as well as careful analysis of planned lines to monitor by experienced transmission operations engineers, can help ensure selection of the best lines to monitor for the best economic results from DLR technology.

Take into consideration any planned maintenance outages for the lines identified. Lines that will be out of service for extended periods may not be suitable candidates for near-term data collection using DLR technology.

1.3 Determining Placement of CAT-1 Devices

Nexans/TVG prescribes a standard process for placement of the CAT-1 DLR technology. CAT-1 remote units should be placed along the transmission line in spatial intervals, where one CAT-1 unit with two loadcells is placed per 10 miles of transmission line. For example, on a 40-mile transmission line, a CAT-1 unit should be placed at mile 8, 16, 24 and 32. Actual unit placement is determined by identifying any deadend structures along the line. If deadend structures are not available in line with the standard

spatial arrangement, then structures at the spatial intervals should be converted into floating or standard deadends. Tip: Using deadends eases installation and reduces cost.

1.4 Understanding Tension-Sag Relationships on As-Built

In order to receive accurate sag measurements from the DLR system precise values of span length are needed for each span being monitored. Imprecise measurements can lead to significant sag measurement error. For example, an error of 18 feet in span length equates to a one-foot error in sag for a 138 kV line with an estimated span length of 640 feet under 3500 lb/force tension. An error of 13 feet in span length equates to one-foot error in sag for a 345 kV line with an estimated span length of 1,555 feet under 5500 lb/force tension.

1.5 Determining Placement of the CATMaster Units

The CAT-1 DLR system communicates and sends its data with the use of 900 MHz spread-spectrum radio technology. In order to communicate effectively, it requires direct line of sight from the CAT-1 devices (located on the transmission line structures) and the CATMaster (normally located in a substation, switching station or microwave station). The CATMaster is a rack-mountable device that contains the receiving radio as well as a Remote Terminal Unit (RTU) to facilitate placement of the CAT-1 data onto the Supervisory Control and Data Acquisition (SCADA) network. In order to determine whether a chosen CAT-1 DLR-implemented structure has clear line of sight to each CATMaster, a software analysis is performed using off-the-shelf radio path/loss software. The latitude/longitude coordinates of each CAT-1 structure and CATMaster location are entered into the radio path/loss software.

The first step of the process here was to determine all potential SCADA access sites along the transmission line corridors that were owned by the utility. Any SCADA access sites that have clear line of sight to a CAT-1 device were found to be potential CATMaster sites.

The next step was to determine the radio coverage each potential SCADA access site has in the region of the transmission line corridor, which is usually limited to about a 15-mile circumference. Then, using the software, each CAT-1 radio path was shown in a ground elevation profile plot to determine if there were any obstructions to any potential SCADA access site within 15 miles of the CAT-1 unit. The ideal path from the CAT-1 device to the ideal CATMaster was chosen. Note that, for this project, many of the CAT-1 units had more than one CATMaster site that they could potentially communicate to. If there was no clear path from a CAT-1 unit to a CATMaster, a CAT-1 Repeater was utilized. The CAT-1 repeater simply uses two radios and two antennae to receive and transmit the data from a CAT-1 unit to a CATMaster. The CAT-1 Repeater locations were chosen along the transmission lines at advantageous high spots in elevation.

In order to back up the findings that were determined by software analysis, the radio paths were tested on-site using a radio test kit. This third step was performed on all radio paths except for those on the Bosque-Elm Mott 138 kV line. The radio test kit uses equivalent radio types. One radio (and antenna) was placed near the CAT-1 unit at the correct bearing, and another radio and antenna was placed at the proposed CATMaster site, also at the correct bearing. The radios were then energized and a radio signal

strength test performed to ensure that the radio path chosen was clear from obstruction. Performing this on-site test ensures that there are no obstructions that might not show up in a topographical software package (trees, buildings, etc.).

The importance of aligning the on-site radio paths cannot be understated. During the installation of the DLR demonstration project equipment, the installation of the CAT-1 devices on the Bosque-Elm Mott 138 kV line was performed after the software-based radio path analysis was performed but before the on-site radio path verification tests. The software-based analysis indicated that the lines of sight were clear, but the Bosque-Elm Mott line had a very rare feature; the structures along the line were straight with negligible line angles or changes in structure elevation. This caused the radio paths from two out of the three installed CAT-1 devices to be blocked by the very structures themselves. To get this system going, an additional repeater was executed. After this, all three of the CAT-1 units were fully operational with acceptable radio signal strengths. The on-site radio tests would have caught this issue, and the additional CAT-1 repeater requirement could have been known prior to installation. Any future DLR installations should not be performed without adequate radio path testing.

Tip: Conduct a radio path analysis to determine optimal equipment placement.

While performing the radio path software analysis and on-site testing does add cost to the project, the cost is small in relation to potential troubleshooting, crew dispatching and equipment installation/reinstallation that may be required to ensure a clear communication path between the CAT-1 devices and the CATMaster.

Careful CATMaster placement limits the total number of CATMasters required to receive the CAT-1 data from the transmission line structures and therefore optimizes the cost of materials and installation. In addition, careful planning ensures that the CAT-1 data will be successfully received by the CATMasters. This careful planning eliminates any rework or system problems during the installation phase.

1.6 Determining Placement of Repeater Equipment

The CAT-1 DLR system sends data with the use of 900 MHz spread-spectrum radio technology. This requires direct line of sight from the CAT-1 devices to the CATMaster. The CATMaster is a rack-mountable device that contains the receiving radio, as well as an RTU to facilitate placement of the CAT-1 data on to the SCADA network. The CATMasters are installed at strategic substations or switching stations along the transmission line corridor.

CAT-1 repeaters were utilized to stretch the radio path to the nearest CATMaster installation. Utilizing the radio path/loss test, it was determined where the radio path was not optimal due to topological differences and ground obstructions. Repeaters reduce the overall equipment costs, as they cost much less than the CATMaster units and have less stringent requirements for housing and installation.

2. INSTALLATION PLANNING

Proper planning for installation of DLR equipment will make the process smoother and faster. Included here are several areas of planning that should be addressed.

2.2 Clearance Planning

Tip: Understand clearance scheduling procedures prior to planning installation.

It is usually harder to get required installation clearances on lines that have high historical constraints. Therefore, early planning is required to install DLR technology on high-congestion lines since clearances may not be grantable on critical lines until the cooler months of the year.

Clearances need to be planned to include an outage period after installation to allow for no-load calibration. On the lines tested, clearances were only planned for the length of time required for construction (i.e., installation of the equipment). In several instances, clearances were lifted on the lines before calibration could occur, resulting in additional clearances having to be planned after installation.

2.3 Structure Access

Tip: Conduct physical location scouting.

An important aspect of installation planning was the scouting of structures that were identified for installation. This was not always accomplished during the initial project planning stages and, as a result, some identified structures were discovered to be inaccessible or hard to reach. This necessitated some last-minute changes to more accessible structures. Furthermore, this caused last-minute updates to occur in documentation and configuration, which could have been avoided if field scouting had been conducted prior to final selection of the installation structures.

In one instance, the landowner refused access to his property for installation to a selected structure. This forced a last-minute structure change for a 345 kV installation. It is recommended that landowner access be secured during the planning stage and that a mitigation strategy be developed to deal with landowners refusing to grant property access.

2.4 Structure Configuration

Physical scouting of the structures selected for placement should also consider sunlight patterns to determine where shading of the Net Radiation Sensor might occur during sunlight hours. Notes should be taken and provided to the installation planning group so that a proper location to mount the sensor can be identified in the drawing for that structure to ensure the sensor is not shaded during the day.

2.5 Utility-Vendor Coordination

Tip: Ensure the vendor reviews the installation plan.

With the vendor being the expert on its DLR technology and the utility being the expert on its transmission line grid, it is important for the two to coordinate during the installation planning process. The vendor should provide the utility with the installation parameters required for the system. The utility should then develop engineering drawings that show any structure modifications necessary for installation, as well as the bill of materials required to complete the installation during a single scheduled clearance.

3. EQUIPMENT PLANNING

Nexans/TVG provided Oncor Engineering the specifics on how and where the equipment was to be mounted on the structures. Oncor Engineering generated a set of installation drawings for each affected structure for the DLR project. This provided the construction crews a document to work from as well as a materials list of all equipment and hardware required to perform the job. Table 1 is an example bill of material from the engineering drawing for a 345 kV steel pole deadend installation.

Table 1. Example Bill of Materials

Bill of Material			
Item No.	**Description**	**Quan.**	**TSN#**
1	CONNECTOR, DEADEND, 2 PIECE, 795 KCMIL	4	309158
2	JUMPER TERMINAL, 15 DEG, 1590 KCMIL	8	305374
3	ANCHOR SHACKLE, 60K	4	310926
4	CHAIN LINK, 150K	2	486318
5	LOADCELL	2	NA
6	CAT-1 MAIN UNIT W RADIO	1	NO TSN
7	CAT-PAC POWER SUPPLY	1	NO TSN
8	CHANNEL, HALF SLOT, 1-5/8’ X 1-5/8’	1	NO TSN
9	BOLT, HEX HEAD, ½’ X 2-1/4’	12	311169
10	WASHER, ROUND, ½”	24	302437
11	WASHER, LOCK, ½”	12	302428
12	NET RADIATION SENSOR (NRS), W BRACKET	1	NO TSN
13	ANTENNA MOUNTING BRACKET, W ANTENNA	1	NO TSN
14	BANDING STRAP (USE AS REQUIRED)	NA	489768
15	BANDING CLAMPS (USE AS REQUIRED)	NA	489769
16	TIE, CABLE (USE AS REQUIRED)	NA	479419
17	CLAMP, THREE BOLT	2	304165
18	WIRE, GUY, 3/8”	NA	303581

Engineering drawings were developed for each type of structure selected for installation. A bill of materials identifying all equipment necessary for the installation was included within each drawing, providing the installation crews one document detailing both the materials needed and the details on where to install the equipment on the structure.

Tip: Include compass orientation on the engineering drawings.

In several instances, equipment placement was not identified by compass direction, leaving the installation choices to the installation crew. A directly affected piece of equipment was the Net Radiation Sensor, which needed to be put where it would gather full sunlight all day. In some instances, the sensors were not installed on the correct side of the structure, resulting in partial shading during portions of the day. This causes the NRS to record lower than actual solar radiation readings.

Accurate planning and agreement on the spatial arrangement of the CAT-1 devices prior to development of engineering drawings provides the best situation for the generation of accurate DLRs, reduces engineering rework and helps ensure all materials are identified to the crews prior to installation, especially when installation is in a difficult-to-access area.

3.1 DLR Repeater Equipment

Performing the radio path/loss analysis described during the project planning process allows for repeater installation and equipment needs to be identified prior to development of the engineering drawings; thus, the appropriate equipment needs can be identified in the bill of materials provided to the installation crew.

3.2 Radio Signal Interference

The CATs use the same unlicensed frequency range as radios used for Automated Meter Systems (AMS) data collection and controls. Additionally, this radio frequency range is used in the West Texas oil fields for communications between oil wells and collector sites. Our current solution is to alter the antenna layout to improve separation between the DLR system and AMS. We believe this will become an increasing problem as utilities expand their automated deployments for AMS and Distributed Automation (DA), so diligent testing will be required to ensure that antenna placement is able to overcome interference in an increasing utilized radio frequency range.

4. INSTALLATION SCHEDULING

Installation scheduling went according to plan for scheduling line maintenance where an outage is required, with a few exceptions unique to DLR.

For the DLR installation it was necessary to include the vendor in the schedule, allowing vendor personnel to perform as on-site engineering resources. Vendor personnel provided additional training and guidance on details of the installations, specifically where problems or questions arose.

Tip: Don't take landowner access permissions for granted.

The landowner of Structure 22/4 (Lake Creek - Temple 345 kV, Tradinghouse-Temple Pecan Creek 345 kV) would not allow the installation crew on his property, forcing the crew to make a last-minute structure change to 23/5. A method to avoid this issue must be established.

There were a few cases where the installation foreman did some scouting of the structures that were to be visited in the near future and found that some structures were inaccessible or hard to reach. This caused a few structure changes. In future DLR installation, it is recommended that this scouting be performed during the planning phase and not during installation. Last-minute updates in documentation and configuration could have been avoided if the structure access had been confirmed prior.

5. CREW SCHEDULING AND TRAINING

While dependent on the size of the installation being conducted, it is recommended that a minimum number of crews be utilized to conduct the entire installation. This allows for more efficient training to be conducted and for the crew to become more experienced, and thus more efficient, for each installation. Because only one team was utilized during the Department of Energy (DOE) DLR project, the team became more efficient over time and was able to complete some installations ahead of schedule, allowing line clearances to be released sooner and lines to be re-energized early.

Engineering drawings provided by the utility based on installation details and specifics provided by the vendor were found to be of great assistance to the installation crews. These drawings included a bill of materials required for each installation structure.

It is recommended that engineering drawings developed by the utility be provided to the vendor for review in order to ensure that installation details for the DLR technology are correct. A joint review session of installation drawings would allow them to be validated for accuracy and completeness prior to delivery to the installation crews.

6. INSTALLATION OF DLR CAT-1 EQUIPMENT

The set of DLR equipment for a standard pole/line installation is shown in Figure 1.

6.1 Installing Loadcells onto the Line

All loadcells (shown in Figure 2, installed in Figure 3) were installed in accordance with the "Dynamic Line Rating Additions" engineering drawings that were developed during the planning phases of the project. The drawings and bill of materials for each structure, as well as crew training prior to installation, allowed installation to proceed quickly.

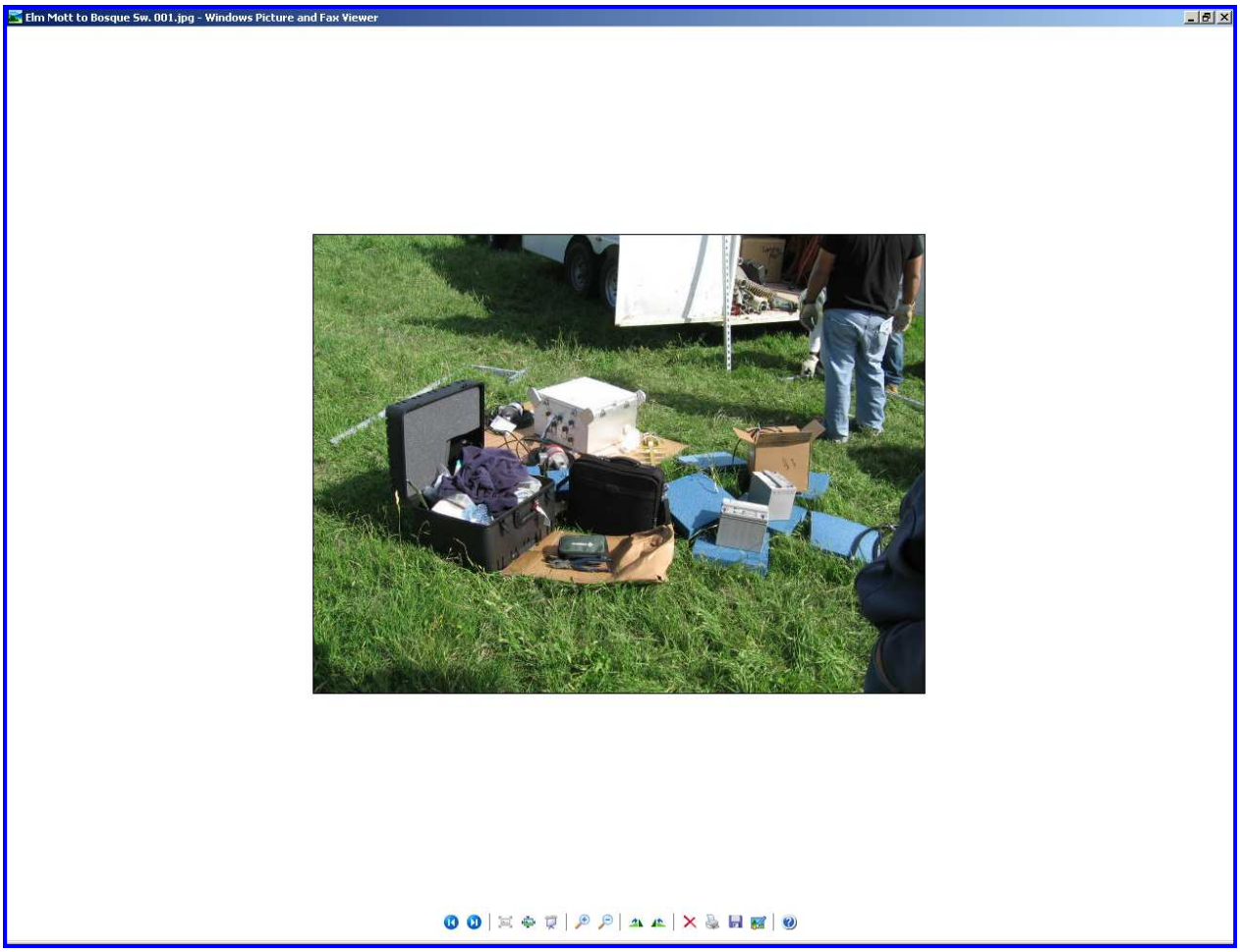

Figure 1. DLR Equipment Prior to Installation

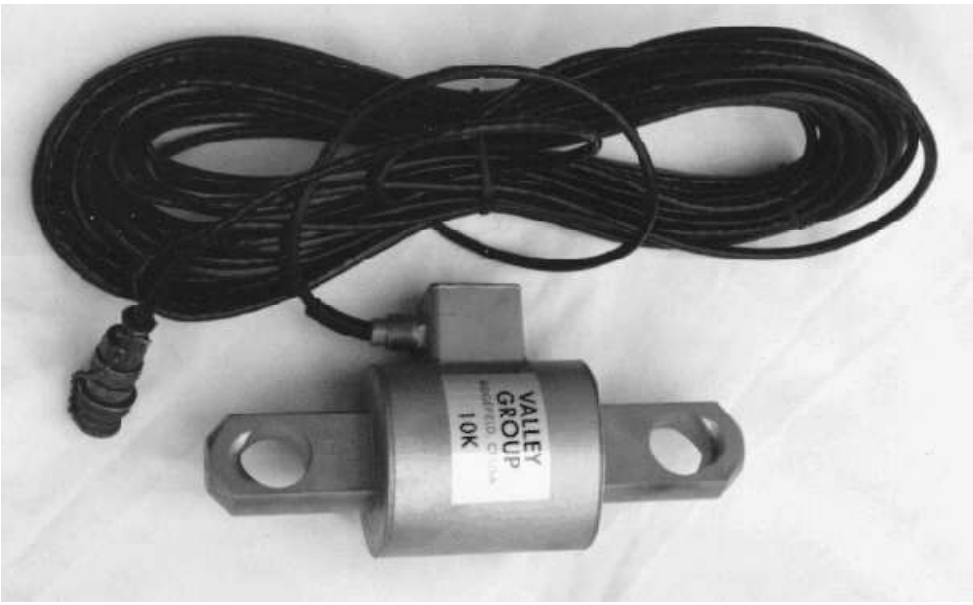

Figure 2. CAT-1 Loadcell

Damage to the equipment can occur if care is not taken during installation. Two of the 45 loadcells had their outer cable jackets damaged, resulting in progressive moisture ingress that led to erroneous tension readings. It is recommended that an equipment safety and care brief be conducted on site prior to actual installation to remind crews of proper installation techniques and the need to not damage equipment during installation.

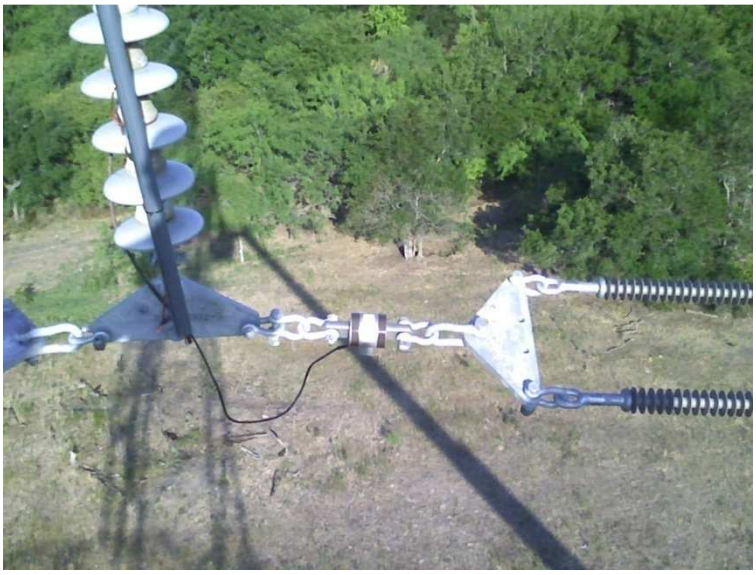

Figure 3. Installed Loadcell on a 345 kV Line

With the initial installation plan for the 345 kV loadcells in a floating deadend arrangement (15 loadcells out of 45 required for the project), the loadcell cable was wrapped around the vertical insulator string. The loadcell cable was progressively damaged due to electrostatic discharge (static tracking) burning away the outer cable insulation. Due to the high charges developed in the vertical insulator string, specifically the metal cap-pin areas, and the fact that the inner shield of the loadcell cables is the closest path to ground, the repeated static discharge would progressively damage the cable and cause errors in the tension readings generated by the loadcell.

The 15 affected loadcells were replaced, and a new mounting arrangement was designed. The new mounting arrangement uses a #2 bare copper wire wrapped around the ball shank at the top of each cap of the insulator string. This wire is then grounded to eliminate the buildup of a capacitive charge. In addition, the loadcell is fed through a two-inch PVC conduit, which keeps the loadcell cable a few inches away from the vertical insulator string and provides additional protection. This new design must be used for all subsequent 345 kV DLR implementations using a floating deadend arrangement.

6.2 Antenna Installation and Orientation

All of the required hardware and design drawings were prepared prior to antenna installation. The exact antenna orientation and bearing was known in advance. This planning allowed all of the structure antennae to be installed quickly and accurately.

It is recommended that these installation instructions be followed for mounting and orienting the antennae:

19. The antenna cable is prepared on the ground by removing the packing materials and then installing a ground strap kit about six feet from one end of the cable. The end of the cable with the grounding strap is connected to the antenna.
20. An antenna mounting bracket is secured close to the top of each structure. In the case of a wood H-frame or steel pole structure, the bracket is mounted so that the antenna is three feet away from the overhead ground wire. The mounting bracket is secured to the structure with either steel banding (steel structures) or with bolts through the structure (lattice tower and wood).
21. The antenna is mounted to the antenna mounting bracket using the supplied U-bolt hardware.
22. The antenna is oriented in accordance with Nexans/TVG instructions provided during the CAT-1 placement and radio path testing that occurred in the planning phase. This ensures the proper bearing is set on the antenna to provide maximum signal strength to the “receiving” master antenna. Then the U-bolts securing the antenna are tightened.
23. The antenna cable is screwed onto the mating connector on the antenna and sealed using a cold-shrink hardware kit.
24. The antenna grounding strap is either secured to the pole ground (wood) or to the structure (steel).
25. The antenna cable is fed down the structure to the assigned CAT-1 enclosure location and affixed to the structure using the appropriate banding strap and banding clamp arrangement (wood or steel structures) or downlead clamps (lattice structures).

6.3 Net Radiation Sensor Installation

In the planning phase, all of the required hardware and design drawings were prepared and available prior to installation. The exact Net Radiation Sensor (NRS) orientation was known in advance. This planning allowed the NRS assembly to be installed quickly and accurately. In addition, having all of the preliminary assembly performed on the ground significantly reduced installation and “bucket” time. NRSs must be installed in locations that will result in exposure to full sunlight throughout the entire day. Improper placement can result in shading of the sensor by the structure, the lines or a nearby structure. Because compass readings were not on the engineering drawings, the construction contractor installed them where he saw fit, which was not always the optimal placing. It is recommended that these specific installation instructions be followed for mounting and installing the NRS:

26. On the ground, the NRS bracket is assembled with the supplied hardware.
27. On the ground, the NRSs are mounted to the NRS bracket with the correct supplied hardware.
28. The complete NRS assembly is mounted in accordance with the “Dynamic Line Rating Additions” drawings generated during the planning phase so that the NRSs are parallel with the overhead conductor. The NRS bracket is mounted on the southernmost leg of any structure to minimize shadowing from the structure or other object in the path of the sun. The mounting elevation of the NRS is performed “by eye” so that the NRSs are at the same elevation as the “belly” of the sag of the conductor. The NRS assembly is secured to the structure with either steel banding (steel structures) or with bolts through the structure (wood).
29. The NRS assembly is grounded to the structure using #6 jacketed and stranded copper wire.

30. The NRS cables are fed down the structure to the assigned CAT-1 enclosure location and affixed to the structure using the appropriate banding strap and banding clamp arrangement (wood or steel structures) or downlead clamps (lattice structures).

6.4 CAT-1 Main Unit Installation

In the planning phase, all of the required hardware (Figure 4) and design drawings were prepared and available prior to installation. The exact CAT-1 placement was known in advance. This planning allowed the CAT-1 enclosures to be installed quickly and accurately. In addition, having all of the preliminary assembly performed on the ground significantly reduced installation and bucket time.

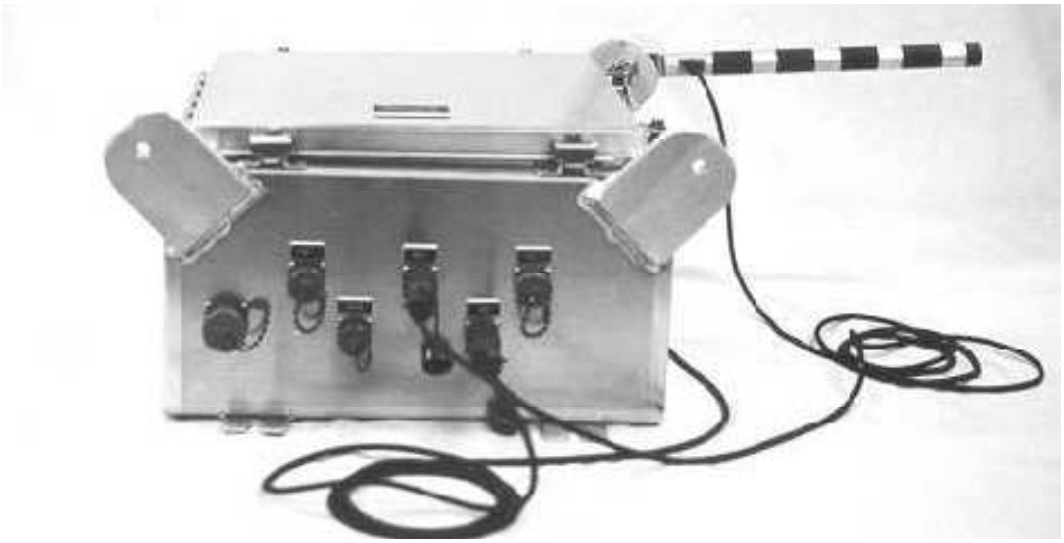

Figure 4. CAT-1 Main Unit Enclosure

It is important to ensure that all sensor and antenna cables are at or near the planned CAT-1 enclosure location on the structure. Also note that batteries and solar panels are not installed during this CAT-1 main unit installation phase.

A drawing of the port configuration is shown in Figure 5 where connections to the antenna, ambient sensor, NRS and the CAT-PAC are located.

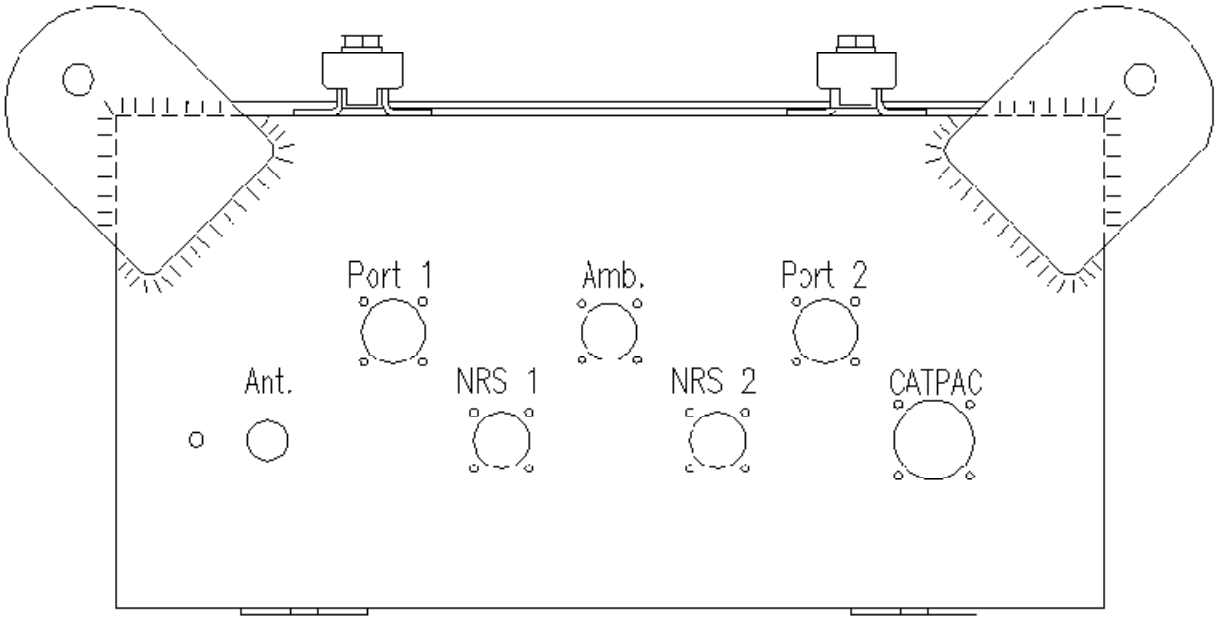

Figure 5. CAT-1 Main Unit Port Configuration

It is recommended that these specific installation instructions be followed for installation of the CAT-1 main unit:

31. On the ground, the CAT and CAT-PAC enclosures are removed from the packaging and placed face-first on the ground, protected by a cardboard box.
32. Galvanized steel, half-channel uni-strut brackets are cut to five-foot lengths (quantity two) and one-foot lengths (quantity two).
33. The CAT and CAT-PAC enclosures are mounted to the brackets using galvanized bolt hardware per the "Dynamic Line Rating Additions" drawings generated during the planning phase of the project.
34. The complete assembly is flipped over so that the front of the enclosures is facing up. The ambient sensor is mounted to the top left tab of the CAT-1 enclosure. The ambient sensor cable connector is connected to the CAT-1 enclosure via the mating connector marked AMB.
35. Appropriate holes are drilled through the structure to allow the completed CAT-1 assembly from Step 4 to be bolted to the structure, so that the doors of the enclosures are facing south (allows for optimum solar panel exposure and therefore optimum charging of the batteries). The CAT-1 and CAT-PAC assemblies are grounded to the structure using #6 jacketed and stranded copper wire.
36. The cables coming from the loadcells, NRSs and antenna are dressed by wrapping them in a loop and securing them with cable ties behind the enclosures, making sure that there is sufficient length at the end of the cables to make the connections to the CAT-1 enclosures.

6.5 Securing Cables

While securing cables is noted in the proceeding sections on installation, it should also be noted that where more than one system cable is required to be secured, the same banding clamp or downlead clamp was used to secure the cables with the same clamp. This is considered appropriate procedure for installation.

6.6 Proper Terminating of all Cables to the CAT-1 Main Unit

Ensure that either the cables are all color-coded prior to installation or that connectors are designed to only mate with the correct socket on the enclosure.

It is recommended that these specific cable terminating procedures be followed:

37. As described in the installation process for the CAT-1 main unit, all of the cables are secured to the structure and available for termination at the CAT-1 enclosure.
38. The antenna cable connector is screwed into the mating connector on the bottom of the CAT-1 enclosure labeled "COMM."
39. The remainder of the cables are color-coded for easy installation:
    a. The Port 1 (black) loadcell cable connector is assembled into the mating connector at the bottom of the CAT-1 enclosure labeled "PORT 1."
    b. If required for the specific CAT-1 unit, the Port 2 (red) loadcell cable connector is assembled into the mating connector at the bottom of the CAT-1 enclosure labeled "PORT 2."
    c. The Port 1 (blue) NRS cable connector is assembled into the mating connector at the bottom of the CAT-1 enclosure labeled "NRS 1."
    d. If required for the specific CAT-1 unit, the Port 2 (green) NRS cable connector is assembled into the mating connector at the bottom of the CAT-1 enclosure labeled "NRS 2."

6.7 Solar Panel Installation

Performing all preliminary assembly on the ground significantly reduces installation and bucket time.

Solar panels are mounted to the CAT-PAC enclosure. Do not mount the panels to the tower.

It is recommended that these specific instructions be followed to mount the solar panels to the CAT-PAC enclosure:

40. The solar panels and solar panel brackets (two each) are assembled on the ground using the supplied mounting hardware. In addition, the solar panel alignment angle is set to the latitude of the area (31 degrees north latitude in this case) to provide maximum solar exposure.
41. The solar panels are mounted to the two bottom tabs of the CAT-PAC enclosure using the supplied mounting hardware.
42. One of the solar panel cable connectors is assembled into the mating connector at the bottom of the CAT-PAC enclosure labeled "SOLAR 1."
43. The remaining solar panel cable connector is assembled into the mating connector at the bottom of the CAT-PAC enclosure labeled "SOLAR 2."
44. Any cable slack is looped together and secured with cable ties.

6.8 Battery Installation

It is recommended that the batteries be installed within the CAT-PAC enclosure using these specific instructions:

45. Two batteries are installed in the CAT-PAC enclosure, taking care to verify correct polarity when they are connected to the CAT-PAC circuitry.
46. Using a digital multimeter, voltage is checked at the supplied test points inside the CAT-PAC enclosure and verified to be at correct polarity and voltage (>11.5 VDC).
47. Connect one end of the power umbilical cable to the CAT-PAC (port labeled "POWER OUT"), and the other end of the cable to the CAT-1 enclosure (port labeled "POWER IN").
48. The CAT-1 enclosure door is opened, and the digital multimeter is moved to the test points on the control board inside the CAT-1 enclosure. The switch inside the CAT-PAC is moved to the "RUN" position. The voltage is checked to ensure proper voltage and verified to be at correct polarity and voltage (>11.5 VDC).
49. The CAT-PAC enclosure is closed and sealed with the wing catch hardware.

6.9 Testing the CAT-1 Unit for Proper Installation

Follow these instructions to ensure proper installation of the CAT-1 unit and proper communications with the CATMaster RTU:

50. The "MODE SELECTOR" switch is moved to the "LOCAL" position.
51. An RS-232 cable connection is made to the "Radio Diagnostics" port on the side of the radio. Using a personal computer (PC) connected to the other end of the cable, a software package supplied by MDS (the radio manufacturer) is used to perform diagnostics on the radio (inside the CAT-1 enclosure). The RSSI is verified to be -84 dBm or better, which finally verifies that the radio path is acceptable and that all of the connections and alignments have been made properly.
52. The RS-232 diagnostic cable is then moved to the LOCAL PORT connector on the control board inside the CAT-1 enclosure. A terminal program (such as Hyperterminal) is used to communicate with the CAT-1 control board. Additional diagnostics are performed to ensure that all of the CAT-1 sensors (loadcells, temperature sensors) are operational and calibrated.
53. The "MAIN POWER" switch on the control board inside the CAT-1 enclosure is moved to the "OFF" position.
54. The "MODE SELECTOR" switch is moved to the "AUTO" position.
55. The "MAIN POWER" switch on the control board inside the CAT-1 enclosure is moved to the "ON" position.
56. After a few seconds, a string of characters will begin to scroll across the computer screen. The appropriate string of characters indicates that the CAT-1 unit established communications with the CATMaster RTU and data has been received.
57. Remove the RS-232 connection to the main board.
58. Close the CAT-1 enclosure and seal with the wing catch hardware.

7. CALIBRATION OF LOADCELLS

The accurate assignment of conductor temperature to a given sag and tension characteristic is the most critical aspect of the calibration of the loadcells. Small errors in conductor temperature for a sag measurement will extrapolate to large errors in conductor behavior modeling at the extreme temperatures of interest for design and operation. For whatever method is used to measure conductor temperature for calibration of the DLR equipment, such as LiDAR, it is important that the equipment be accurately calibrated so that a correct temperature is assigned to the conductor during DLR calibration.

7.1 Obtaining No-Load Conductor Temperatures

59. The first step in the process is to generate the effective ruling span that each loadcell monitors. A proprietary program called "SPRING" is used to enter a large number of spans reaching away from a particular loadcell. The program then calculates the ruling span used for the temperature-sag-tension relationship of the conductor.
60. Next, plot the tension and temperature data collected for each loadcell and its corresponding NRS. All of the data is plotted, and the no-load and low-load data is specifically highlighted in this step.
61. Appropriate no-load and/or low-load points are chosen. A commercially available sag-tension program (such as Sag10 from Southwire) is used to model the as-built sag-tension-temperature relationship of the conductor. Another proprietary program is used to generate the calibration coefficients, whose curve is plotted in the same graph as Step 2.
62. A number of tools (some proprietary, some available online) are used to simulate the actual conductor temperatures that would have been calculated for a certain data set for a loadcell.
63. A myriad of tests are performed on the resultant simulated output data to verify that the conductor temperatures that would be generated with the calibration curve coefficients are indeed accurate.
64. If any discrepancies are identified in Step 5, the process is repeated based on the nature of the discrepancy.

The process ensures a time-tried and proven methodology to arrive at accurate conductor temperatures.

It was identified that the load values provided to the IntelliCAT for Windows (ICW) system for many of the segments of the 138 kV lines were inaccurate. For the 138 kV lines that are being monitored (Bosque-Elm Mott, Waco Atco-Temple Elm Creek and Bell County-Gabriel) the load value is telemetered at one end of the line. For subsequent segments of the line, the load value is calculated. Although the system still generates accurate conductor temperatures, the dynamic rating is inaccurate. This needs to be taken into account for any new lines being monitored that have load taps.

For the process to work best and most accurately, it does require data taken during an outage or low-load conditions. Ensure that construction clearances include additional time for no-load calibration of the equipment.

7.2 SCADA Configuration

During the study, it was realized that there was an analog-to-digital quantizing error present in the DLR systems. A measurement accuracy error within the SCADA configuration file caused the foot/lb force of the line quantize to a 60-foot/lb force variation, plus or minus 30-foot/lb force. This led to a greater standard deviation in the measurements. This was diagnosed as a problem with the SCADA system configuration. It was recommended that the affected CAT-1 SCADA configurations be modified to reduce the quantizing levels to the intended 16-foot/lb force. Procedures and training should include conveying the desired quantizing level to the appropriate value during the SCADA configuration.

8. INTEGRATION TO ENERGY MANAGEMENT SYSTEM

DLR systems have to be integrated to the utility Energy Management System (EMS) in order for the new Dynamic Line Ratings to be effective in enabling capacity release. This section discusses some of the lessons learned with integration to an EMS.

8.1 IntelliCAT Windows Software Hardware Requirements

Nexans/TVG has specific hardware requirements for the ICW server. ICW is designed to run as a service on a server running Windows NT, 2000 or XP PC, Pentium 3 or better, minimum 1 Gb RAM, minimum 300 Gb available hard drive space. In addition, the PC must be connected to the EMS Inter-Control Center Protocol (ICCP) network. When a large number of transmission lines are to be monitored, it is recommended that the ICW server have at least 4096 MB of RAM with a processor speed of at least 2.4 GHz.

The ICW installation occurred in two parts. The first part occurred when the CAT-1 DLR equipment was installed on the Bosque-Elm Mott 138 kV line in April 2011. At that time, the earlier "application" version in ICW was removed from service and the latest "service" version was installed, as well as updates to the configuration files to customize the basic software functionality to the specific lines that are being monitored. At this juncture, two lines with five CAT-1 units were implemented. The lines being monitored were the Bosque-Elm Mott 138 kV line and the Collin-Frisco line installed in 2006.

The second part of the installation occurred after the remaining 138 kV line and all of the 345 kV lines were instrumented between September 29 and November 2, 2011. On November 4, 2011, ICW and its components were updated to incorporate the additional lines to be monitored. After that work was completed, nine transmission lines involving 28 CAT-1 units were incorporated.

Shortly after the new lines were incorporated into ICW, it was learned that the ICW software would occasionally stop working and then restart. On November 17, 2011, changes were made to the configuration file that allowed ICW to take additional time to restart, which allowed the ICW software to run continuously to date.

The root cause of the ICW performance issue was identified to be the server on which the ICW software and its components were running. Oncor had continued to use the original server that was installed circa 2006. The server was identified to meet the minimum requirements (Xeon 3.20 GHz and 1024 MB

of RAM). But with the number of lines being monitored and the number of calculations and processes that needed to be performed, the server's CPU was frequently running at 100% of capacity and subsequently caused failures.

In January 2011, the server was replaced (Xeon 3.33 GHz processor and 4096 MB of RAM). Again, the ICW software has continued to work flawlessly to date.

Subsequent testing at Nexans/TVG facilities has proven that with a server with a 2.4 GHz processor and 2048 MB of RAM, at least double the number of lines and CATs could be easily processed by ICW. Therefore, at least 18 lines with 56 CAT-1 units could be processed.

8.2 IntelliCAT Windows Software Installation

The ICW software has four main components – the ICW software, the ICW controller, EasyOPC-DA and SISCO AXS4-ICCP. All of the components are installed via compact disk. After each component is installed, some configuration changes are made to enable them all to run as a service, and some application-specific configuration changes are made to allow the software components to interoperate.

Additionally, there are two configuration files that are created and installed. The first is the configuration file called ICW.ini. This file assigns the appropriate parameters for each CAT-1 unit, each transmission line and each segment of a transmission line. In addition, it assigns the ICCP point parameters for all of the CAT-1 inputs to ICW, as well as the output points generated by ICW to the EMS (e.g. DLR values, conductor temperatures, alarm status values).

The second configuration file is called Calibration.ini. This file contains the algorithm calibration coefficients for each of the loadcells installed on the transmission lines.

Last, the SISCO AXS4-ICCP software is configured to provide ICCP connectivity between the ICW server and the EMS.

The software and method used allow for easy additions of transmission lines by installation of a new configuration file. This minimizes downtime between configuration changes to less than a minute and is easily performed by EMS/TGM personnel with minimum effort. In addition, adjustment to the calibration of the system is just as simple and non-intrusive as the configuration adjustments.

Flags were created to signal suspicious CAT-1 ratings to EMS/TGM personnel. All output flags from the ICW software are mapped out via ICCP, but the implementation of a method to signal suspicious CAT-1 ratings was developed by EMS/TGM personnel.

8.3 Integration of IntelliCAT to the EMS

Alarm codes as defined by the vendor were implemented within the utility EMS using a different naming convention. This created confusion when the utility discussed alarm events with the vendor. When implementing alarm codes within the EMS, work with the vendor(s) to define an EMS-DLR alarm code map to allow for quicker discussion and resolution of alarm codes.

If possible, establish Alarm Alerts that designate when there is an issue with the DLR rating and when the issue has been cleared and DLR ratings are reinstated into the system.

9. FURTHER NOTES

Items contained in this section are lessons learned that did not fit into the previous categories but are important to know for future installations.

9.1 Use of Multiple Vendors for Real-time Data Acquisition

As a part of our study, we implemented several line rating technology systems in order to provide correlation to the DLR technology as well as to verify accuracy of the line ratings, particularly in the determination of the line sag. One issue that came up both between technologies and within devices of the same technology is time synchronization. When multiple devices are on the same line, it is vitally important that the reports given from each device are using a common time stamp so that the readings can be correlated and related to each other. We noticed that a misalignment of more than a minute between device clocks can cause a dramatic reduction in measurement correlation. Whenever installing any measurement device to the system, it is imperative that a communications link be developed that lets the device get the same time stamp from the transmission service provider as the RTU system.

APPENDIX A

List of Acronyms

LIST OF ACRONYMS

DLR	Dynamic Line Rating
DOE	Department of Energy
EMS	Energy Management System
ICCP	Inter-Control Center Protocol
ICW	IntelliCAT for Windows
NRS	Net Radiation Sensor
PC	Personal Computer
RAM	Random Access Memory
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SwRI	Southwest Research Institute
TBD	To Be Determined
TBR	To Be Reviewed

END OF REPORT