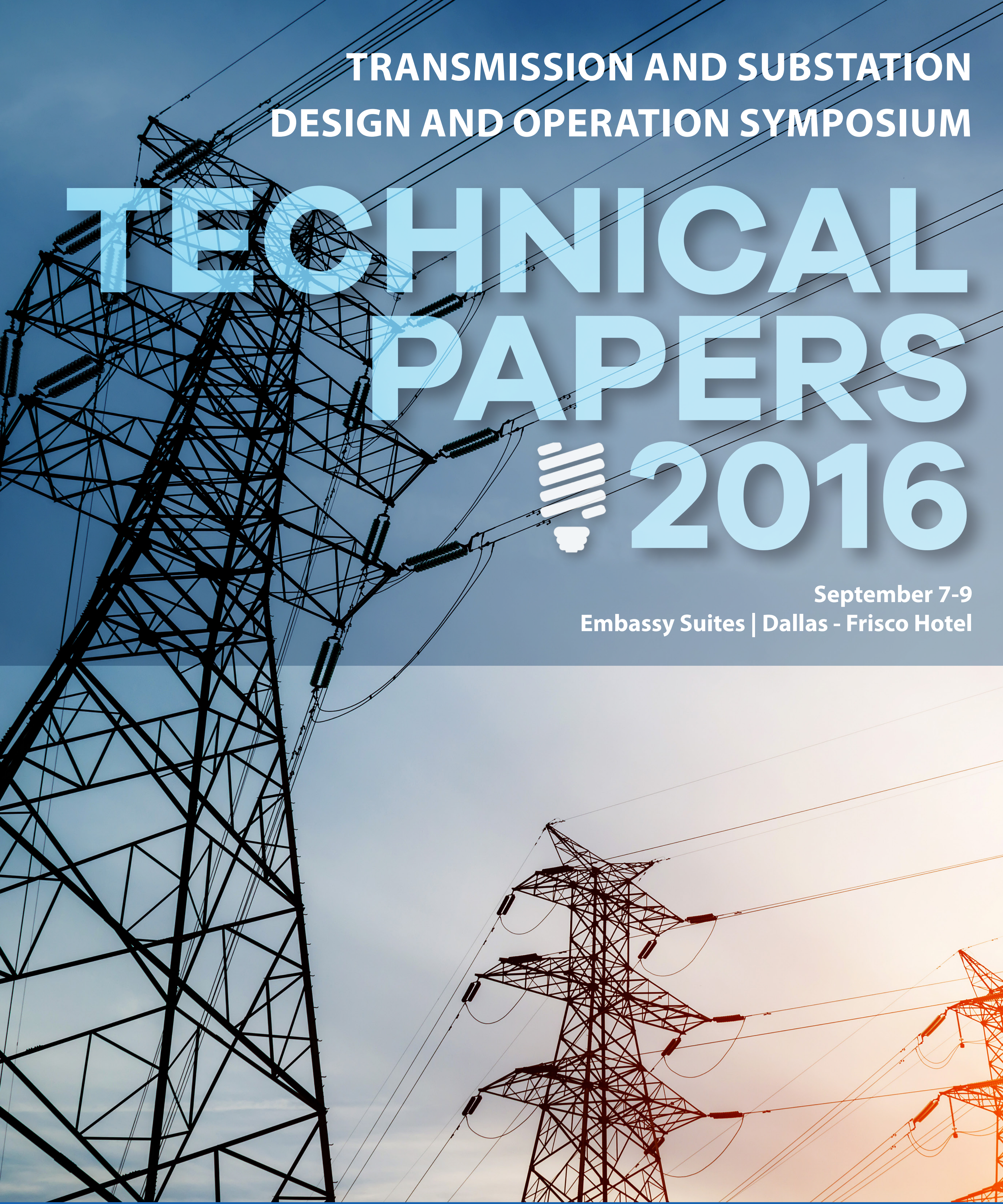

TRANSMISSION AND SUBSTATION DESIGN AND OPERATION SYMPOSIUM

TECHNICAL PAPERS 2016

September 7-9
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DIVISION FOR ENTERPRISE DEVELOPMENT
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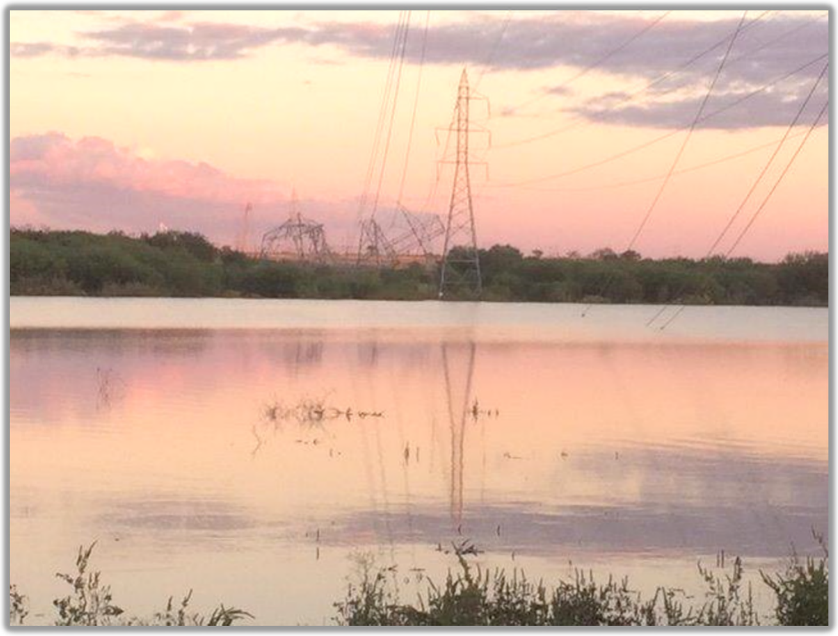
TRANSMISSION LINE RAPID RESPONSE MANAGEMENT FOLLOWING AN EXTREME WEATHER EVENT

Adrian Sepulveda, P.E., Project Engineer, Lower Colorado River Authority
Oliver Chiang, P.E., Senior Engineer, Lower Colorado River Authority
James Denman, Telecom Technician Lead, Lower Colorado River Authority



49th Annual Transmission & Substation Design & Operation Symposium

The University of Texas at Arlington

Division for Enterprise Development

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Introduction

In October of 2015, a tornado knocked out four LCRA transmission lines (One double circuit 138kV and one double circuit 345kV transmission lines) in Central Texas, which included a 48 count fiber carrying critical LCRA communications on the double circuit 138kV lines. The double circuit 138kV and 345kV transmission lines are located in the same corridor and were damaged in a 2.45-mile long section. The purpose of this paper is to discuss how LCRA staff, construction crews, and vendors rapidly responded to this extreme weather event and the lessons learned along the way. Construction and engineering design decisions and challenges will be discussed in detail. The paper will provide insight on contingency response plans being developed based on this event and how the damaged transmission lines were restored and re-energized in less than two months.

The Storm Event

On the morning of October 30, 2015, a tornado knocked out four LCRA transmission lines in and around Zorn, Texas ***(see Figure 1)***. Wind gusts were recorded to have reached over 100mph, which equates to an F1 category tornado. Per the National Electrical Safety Code (NESC), structures in this part of the country are to be designed for a 3-sec 90mph wind gust extreme wind event. The damaged LCRA transmission lines are in the same corridor and consist of a double circuit 138kV line and a double circuit 345kV line. The double circuit 138kV line also had optical ground wire (OPGW) with a 48 count fiber carrying critical traffic for LCRA and public safety.

The event happened around 7 am CST and word got back to the LCRA engineering staff around 9:30 am. There was also a fallen distribution line located in a span where adjacent towers on the 138kV double circuit line collapsed. Crews could not get out on site until that distribution line was cleared. Finding out who owned it in a timely manner proved to be a chore since there were multiple operators in the area including San Marcos Utilities, Blue Bonnet Electric Cooperative (BBEC), and Guadalupe Valley Electric Cooperative (GVEC). LCRA personnel finally found out it was a BBEC line and it was not until 3 pm that we received the all clear to safely access the right of way (ROW) and assess the damage.

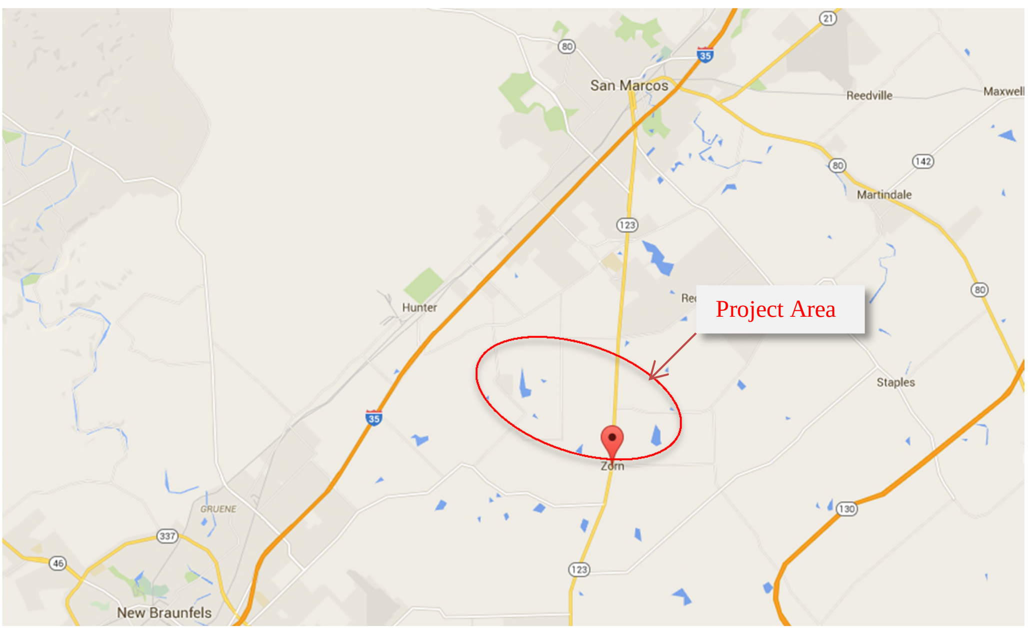

Figure 1: Zorn to Hays Energy General Project Map Overview

Assessing the Damage

Once our contractor, IRBY Construction, and LCRA personnel were able to access the ROW, it was verified that the damage was extensive and repair on the affected structures was not an option. The lines and structures needed to be rebuilt. LCRA operations were in communication with ERCOT letting them know our estimated time of repair as more information was received from the field. Based on our transmission system layout, the 138kV lines were more critical to get back in service before the 345kV lines. LCRA's internal timeline to get the lines back in service was before the end of the year (2 months).

In the beginning of the event, management, construction crews, and engineering primarily focused on restoring power. However there was another component that was critical to LCRA. The OPGW on the double circuit 138kV line is a communications backbone that supports a mixture of SONET (Synchronous Optical Network) and MPLS (Multi-Protocol Label Switch) networks. The tornado damage had compromised the communications supplied by the fiber and needed to be restored immediately. We could not wait the estimated two month delay because the data communications being transported over this section of OPGW line contained SCADA (Supervisory Control and Data Acquisition) for a great portion of the network ***(see Figure 2)***.

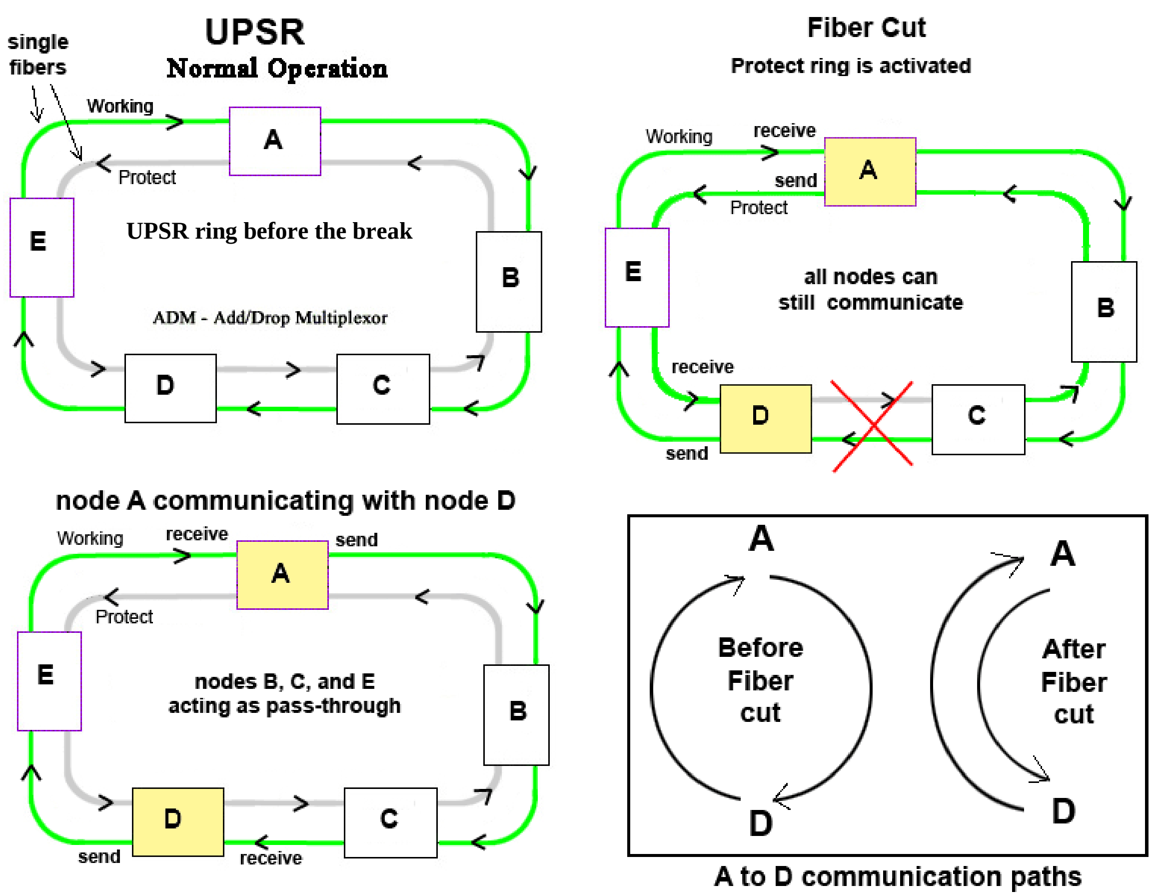

Figure 2: SONET Topology Diagram

The damaged fiber caused our network to be in single contingency, meaning if another failure were to occur, LCRA operations would not be able to view or control more than forty substations. Another component was our external customers that depend on this fiber and network to be in service. We transport two-way radio communications for several Central Texas Sheriff and police departments' 911 dispatch. If another failure were to occur along the protect path, public safety could be at risk. This single contingency scenario is due to the SONET technology and our communications network design. Our MPLS network design kept traffic flowing and there was no impact to our external customers or our transmission SCADA telemetry. Our MPLS network is semi mesh like the examples below ***(see Figure 3)***. There are multiple ways around failure in the physical topology.

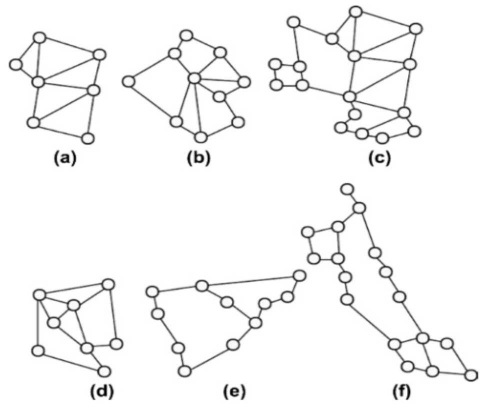

Figure 3: Typical Mesh Network Examples

A 138kV transmission line upgrade project from Zorn to Seguin was 2-3 weeks into construction in the area when this event occurred. We were able to contract this same crew to restore the downed lines on a time and expense (T&E) basis with a price not to exceed. Once BBEC communicated to us that their fallen distribution line was de-energized and the ROW was safe to access, construction crews were able to start clearing the ROW within the next two days. ROW cleanup took about a week to complete starting November 2nd and ending around November 8th.

On the double circuit 138kV line, two structures had damaged arms and six structures had completely failed and collapsed. On the double circuit 345kV line four lattice tower structures had collapsed. The section of damaged line was about 2.45 miles long between Zorn to Hays Energy Substations for both the 138kV and 345kV double circuit lines.

Decisions

OPGW – The Need for Communication

As information was being disseminated from the field, decisions had to be made quickly. We decided that once the ROW was clear and safe to access, the OPGW had to be put back in service before the new structures could be erected and the conductors strung. We had a few options to analyze. Initially, stringing up ADSS (All-Dielectric Self-Supporting) fiber optic wire looked like the fastest and easiest to source since it was readily available and easy to prepare and splice. However, we had 2.45 miles that would have to be strung in the middle of the ROW where the emergency restoration would be in progress. It would have taken approximately forty poles to support the ADSS and we would have had to schedule dig tests. This approach would have taken some time and have made it difficult to meet the schedule that LCRA had implemented. The other option was to run ADSS on the ground, however, ADSS is not as durable as other fiber optic cable options, therefore this was not an option.

Even though it was more expensive, harder to source, and more difficult to prepare and splice, we decided that running AC-34/52/646 OPGW on the ground would be the best method since it would be the quickest and most reliable way to get the fiber back in service. We were fortunate that a reel of AC-34/52/646 (72-fiber count) OPGW from our inventory, originally reserved for the Zorn to Seguin project, was made available to us. This temporary solution of running OPGW on the ground still had its challenges. The ROW was saturated and it required special equipment (such as bulldozers) to pull the fiber wire. There were also a couple road crossings where we set wood poles to get the OPGW across.

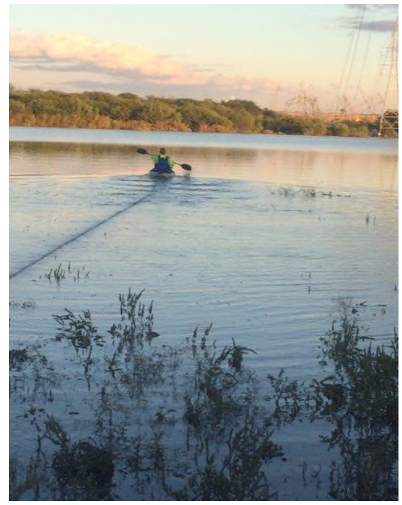

Figure 4: Pulling OPGW Across Lake

The most interesting challenge was the 70-acre lake that was in the middle of the ROW. This required crews to use a kayak to pull the fiber wire across the lake ***(see Figure 4)*** and remain submerged in the lake crossing through the duration of the restoration. It was our first "submarine" fiber wire, and maybe the first for Central Texas. The OPGW path was staked so that construction crews knew the location of it at all times. This was to prevent the fibers from being run over during cleanup and construction. Despite these precautions, it did not prevent the OPGW from getting run over by a vehicle. Thankfully there was no apparent damage to the fibers and the communication signals. Despite these minor setbacks, we were able to restore communications by November 2nd; only having an outage of 3 days.

Double Circuit 138kV Design Considerations

The damaged section on the 138kV double circuit line consisted of AC-34/52/646 48-fiber count, 795 ACSR "Drake" conductor on the south side, and 1433.6 ACSS/TW "Merrimack" conductor on the north side. Tangent single peak double circuit lattice structures ranged from 45'-80' (bottom of conductor heights). The dead end structure outside of Zorn substation was a 50' single peak double circuit 75° lattice structure. The dead end structure outside of Hays Energy was an in-line 80' steel pole structure with davit arms.

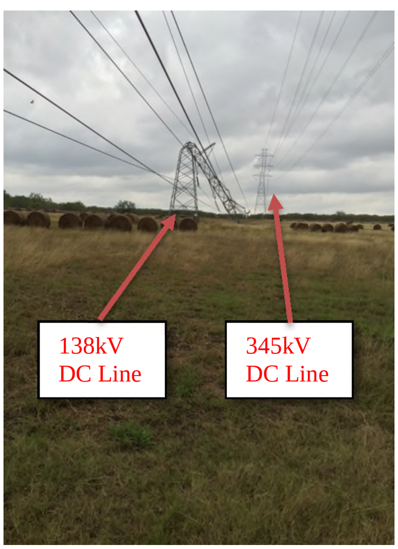

Figure 5: 138kV Double Circuit (DC) Line Damage at STR# 6

Construction crews assessing the damage from the field determined that there were eight damaged tangent lattice towers in a row on the 138kV double circuit line (out of 13 tangent structures in the section). Damage on these structures was extensive and deemed non-repairable ***(see Figure 5)***. In an effort to take advantage of the structure replacements, we coordinated with our systems planning department to see the future necessity to increase the ampacity on the line. We made the decision to design for double circuit Merrimack conductor with two AC-34/52/646 72-fiber count optical ground wires.

The decision to design both 138kV circuits in the damaged section for Merrimack instead of Drake had a couple of advantages and disadvantages. Merrimack can operate at a much higher maximum operating temperature (MOT) with greater current carrying capacity at reduced sags without loss of strength because the aluminum strands have been fully annealed. The steel core is the main structural supporting member in this conductor's composition with a small portion of the strength coming from the aluminum strands.

Merrimack's sag response is primarily determined by the steel core, which translates to reduced sags with increasing temperature when compared to Drake conductor. However, because Merrimack is stronger, it is usually pulled to a higher maximum design tension. It also has a larger diameter and weighs more per linear foot. This means that any new and existing structures would need to account for these increases in tension, weight, and wind and ice loading.

Our proposed design still allowed us to utilize the existing in-line steel pole dead end structure right outside of Hays Energy Substation. However, the existing double circuit 75° lattice tower dead end outside of the Zorn Substation would be over-stressed and need to be replaced. Because of the decision to replace the south 138kV circuit from Drake to Merrimack and add an additional OPGW (the previous configuration only allowed for one OPGW since it was single peak lattice structures), we made the decision to replace all thirteen tangent lattice towers in the damaged section.

We were able to utilize the structure designs from the Zorn to Seguin project. We initially thought about using double circuit steel monopole structures because they would be lighter and easier to handle down the right-of way opposed to hauling and handling concrete poles that would weigh as much as 66,000 lbs. Erection would be slightly easier as larger, heavier equipment would not be necessary. Since the Zorn to Seguin project was well underway, we had some of that project's material at our disposal. With that in mind, we designed for steel pole replacements utilizing the steel poles that were already fabricated for the Zorn to Seguin project. However, in coordinating with the pole fabricator, steel pole lead times to replace the structures (approximately 18+ weeks) were going to jeopardize the Zorn to Seguin project's completion date.

We then had to look into the Zorn to Seguin project's concrete pole inventory to make a design work for the restoration based on the available structure heights and configurations. In coordinating with our pole fabricator, Valmont-Newmark, we did not have to use that project's inventory because they were able to fabricate the concrete structures in a little over a week. They could expedite the order because they already had designs on file, concrete molds for the structure types readily available, and recently approved fabrication drawings. We were in close communication with Valmont the day of the storm event and were able to order fourteen concrete pole structures that evening.

Thirteen double circuit tangent lattice structures were replaced in the damaged 138kV line section with fourteen double circuit davit arm concrete pole structures. Pole heights ranged from 115' to 130'. Due to the available structure heights, we had to reduce span lengths from the previous design and layout the structures in strategic locations taking into account conductor blowout and electrical clearances. Four of the fourteen concrete poles were delivered Monday November 9, 2015 from Valmont's Bellville, TX plant. The rest of the concrete poles were delivered throughout that week, with the last poles delivered Friday November 13, 2015.

The single circuit deadends that we used to replace the double circuit deadend lattice tower outside Zorn Substation were from our spare inventory from past projects. One weathered and one galvanized pole with their anchor cages were located in our Zorn laydown yard. These spare deadend structures had ring vangs at all conductor and static attachment points ***(see Figures 6 & 7)***. The ring vang can be fabricated in a couple of ways: 1) As two half circle pieces of plate steel with complete joint penetration welds at the joints and fillet welds from the plate to the pole on both sides the entire pole circumference, or 2) as a continuous circular piece of plate steel with a hole cut out in the center and slid down the pole to fit at the desired elevation. The ring vang in *option 2* is still fillet welded on both sides all the way around the circumference of the pole. This ring vang design benefited from the versatility of line angle pull-offs the structure could be installed.

Figure 6: Spare Deadend Pole with Ring Vangs

Figure 7: Installed 138kV Spare Deadend Poles

Because of all of these considerations, we were able to issue construction drawings on the double circuit 138kV line within a week of the event (on November 6, 2015) and a preliminary hardware material list was ordered that weekend (October 31, 2015). It should be noted that due to the expedited request, concrete pole structure costs were marked up. This was a justified expenditure due to the urgency.

Double Circuit 345kV Design Considerations

On the double circuit 345kV line, only four of the eleven double circuit lattice towers were damaged or failed in the storm ***(see Figure 8)***. The decision was made early on after the amount of damage was confirmed that we only needed to replace the downed tangent towers. We chose to go back with new lattice towers instead of engineered steel poles since 1) we had an in-house design from LCRA's CREZ projects, 2) we had most of the CREZ tower assemblies in our surplus stock (cages, arms, upper pedestals, etc.), and 3) the lead times to get engineered poles were not realistic to get the transmission lines back in service in adequate time. We only had to order the tower adaptions, which the vendor (Trinity-Formet) was able to fabricate and deliver in a week from their Monterrey, Mexico plant.

Figure 8: 345kV Double Circuit Line Damage at STR# 8-9

The double circuit lines had bundled 795 ACSR/SD "Condor" and 715 ACSR "Redwing" conductors. We decided that we would go back with bundled 795 ACSR "Drake" on both circuits since it is a standard in our system. We had most of the hardware and conductor in stock and could get the outstanding material quickly.

We analyzed the existing towers for the addition of OPGW to replace the 3/8" EHS shield wire but the structures were not capable to handle the extra loads that would be applied to the towers. Therefore, the decision was made to put the OPGW back onto the double circuit 138kV line section that was going to be rebuilt.

Construction and Construction Means and Methods

During construction clean-up, the existing conductors on both double circuit lines were snubbed (anchored using buried log guying assemblies, grips, and come-alongs) to the ground so that crews could safely remove the downed structures ***(see Figures 9 & 10)***. Once it was determined that the 138kV double circuit line would be re-built, this was an unnecessary step and contributed to our lessons learned.

Figure 9: 345kV Snubbed Conductor

Figure 10: 345kV Snubbed Conductors

Conductors and static wires still needed to be snubbed for the 345kV double circuit line since a number of tangent towers did not require removal in that section.

In order to achieve our goals of getting the 138kV lines back in service before December 8, 2015 and the 345kV lines back in service before the end of the year, construction crews worked 7 days a week. The only day they took off was on Thanksgiving.

To help with material lead times, we were able to use some material from the Zorn to Seguin project. The material used was the following: (1) Merrimack reel, (1) OPGW reel, and all tangent concrete structure davit arms. This did not delay the construction schedule for the Zorn to Seguin project and was completed on time.

Once the concrete structures for the 138kV lines arrived on site, it was necessary to mat the ROW because the ground was still saturated from the ongoing rain. A matting company was contracted to provide, install, and remove the mats. These particular mats were an interlocking system made of fiberglass material supported on an oak frame ***(see Figures 11 & 12)***. The mats were required so that the 200 ton crane could handle and erect the concrete structures (***see Figure 13)***.

Figure 11: Stacks of Fiberglass Matting = 2 Miles

Figure 12: Installed Matting Down the ROW

Figure 13: 138kV Concrete Pole Erection

To expedite the stringing of the new conductor on both double circuit 138kV and 345kV transmission lines, a helicopter was used to pull the lead lines ***(see Figure 14)***. This construction practice allowed the conductor and shield wire lead lines to be pulled in for the 138kV double circuit transmission lines in two days and likewise for the 345kV lines. While a more expensive construction practice, the cost was justified as it easily saved the construction crew days' worth of work from having to manually put the lead lines into the dollies.

Figure 14: Helicopter Pulling Conductor Lead Line on 138kV Circuit

The additional time that was afforded to get the 345kV lines back in service allowed us to acquire the hardware. Since all the hardware had to be corona free, the lead times were a little longer than the 138kV material. Thankfully we had a couple extra weeks, and our vendors were able to expedite the fabrication of the material. The hardware arrived as the crews were taking the conductor out of the dollies.

Construction Timeline

- 11/2-11/8 – Clear ROW including steel structures, conductors, and foundation removal (138kV and 345kV lines)
- 11/9-11/16 – Pour foundations (345kV), lace steel (345kV), set two poles (138kV) per day, pour dead end foundation in Zorn Substation (138kV)
- 11/17-11/24 – Set 345kV structures, run lead lines with helicopter and pull conductor and two OPGW wires on 138kV lines
- 11/27-11/29 – Work over Thanksgiving holidays. Crews took Thanksgiving Day (11/26) off.
- 11/30-12/7 – Pull 345kV conductor, energize 138kV lines
- 12/8-12/15 – Clip 345kV lines, start clean up/repairs
- 12/16-12/23 – Finish clean-up of ROW

Lessons Learned

Throughout this event there were many opportunities to learn how to improve our procedures. The following are a few key lessons learned:

- Broken Lines of Communication
    - As with any major incident, the first thing that needs to be established is a chain of command and a central point of communication, i.e. an incident manager. There should be a team that reports to this manager and part of that team needs to be at ground zero to keep communications flowing from the field back to the office. Priorities should be in sync across the team from management to engineering and then to the field. Broken lines of communications caused unnecessary days of work and risk.

    - It was apparent that shortly after the weather event word of the importance of the fiber did not make it to the field crews. Two to three days after the event, construction crews were trying to stabilize the system with dozers and other means in order to salvage the rest of the double circuit 138kV structures in the damaged section from Zorn to Hays Energy. At this point in time, construction crews did not know engineering had planned on tearing down the whole section of line. This was an important lesson learned in keeping that open flow of communication between departments. It would have been less strain on construction crews to safely let the structures in the section fall and would have saved time.

- Re-assessment of Inventory
    - Having a storage of spare parts on hand such as eight miles of OPGW and its individual components contributed to the fast restoration times. Strategic partnerships with other utilities can help offset the cost of storing and sourcing such material.

    - LCRA practices have typically been to save any structures that end up not getting utilized on a capital project for one reason or another. They are tracked and managed in our department so we are aware of our spare structure inventory. We are currently in the process of re-assessing our current inventory for similar emergency situations.

- Construction Tools
    - Getting conductor grips can be a problem. We had to stock up on Condor grips for the DC 345kV transmission line. We recognize the need to have grips for all the conductor types in our system, whether we have them or our contractor.

- Technology
    - Having cameras that tag and geo-references photos. Getting pictures from field crews via text and knowing their location to ID the structures. When we started getting pictures from the field, we did not know which structures were damaged or had fallen.

- Established relationships with contractors and vendors
    - Having long term agreements (LTA's) with our vendors and contractors set us up to expedite all aspects of the restoration.

Even though there was some communication breakdown, the restoration overall went smoothly. Through the collaborative efforts of all personnel involved in the restoration (LCRA personnel, our vendors, and our contractor), we were able to get our lines back in service in less than two months, beating our internal timeline.

BURNS McDONNELL

Integrated Factory Acceptance Testing for Substations

TRANSMISSION AND SUBSTATION DESIGN AND OPERATION SYMPOSIUM (TSDOS)

Integrated Factory Acceptance Testing for Substations

Jerome Farquharson, Director/Global Practice Manager
Alan Farmer, Senior Technical Project Manager
Kevin Madis, Senior Reliability Compliance Specialist

Compliance and Critical Infrastructure Protection
Burns & McDonnell Engineering

Agenda

- Introductions
- Technology/Drivers
- Industry Challenges
- Implementing Security - Defense in Depth (DinD)
- What is an Integrated Factory Acceptance Test (IFAT)
- Closing the IFAT

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Introductions

- **Alan Farmer**, GICSP, PMP – Technical Project Manager, Burns & McDonnell Engineering
- **Kevin Madis**, CISSP, CISA – Senior Reliability Compliance Specialist, Burns & McDonnell Engineering

Presenters

- **Alan Farmer,** Technical Project Manager, Burns & McDonnell Engineering
- Mr. Farmer is an experienced Power Generation consultant responsible for bringing many Critical Asset power plants/control centers/wind farms/substations to NERC CIP compliance on many control systems. Mr. Farmer was a technical SME for numerous audits, spot checks and mitigation plans. He continues to Interface with clients to implement both cyber and physical security.

Presenters

- **Kevin Madis,** Senior Reliability Compliance Specialist, Burns & McDonnell Engineering
- Mr. Madis is a highly skilled and dedicated professional with over sixteen years of experience in large, fast paced organizations. He has wide-ranging experience in the design and implementation of IT projects, business and IT risk analysis. Mr. Madis possesses extensive experience with NERC CIP, network design, and integrating vendor products to support compliance.

Think About It…

- Implementing security on Protection and Control systems at substations is becoming more and more critical for the reliability of the electric sector.
- What does this mean to the substation and the transmission operators?
- How do we take the IT best practice of layered defense and apply it to a Protection and Control system environment?
- What is the impact of installing security on a Protection and Control system?
- How does it affect the substation, the vendor, and the integrator?

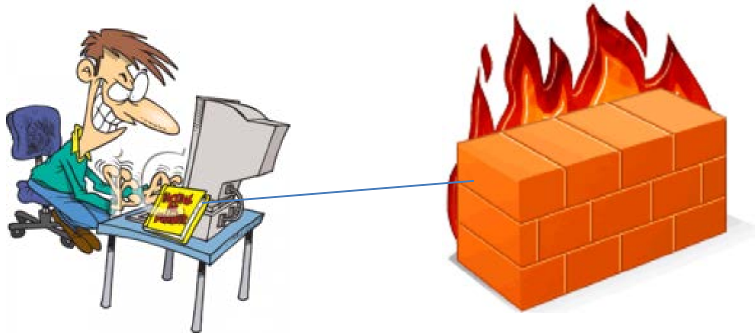
Lets Begin!

Agenda

- Introductions
- Technology/Drivers
- Industry Challenges
- Implementing Security - Defense in Depth (DinD)
- What is an Integrated Factory Acceptance Test (IFAT)
- Closing the IFAT

Technology Drivers

- Increasing number of digital access points in energy delivery communications networks
- Continuing need for remote access
- Increasing adoption of authentication and encryption technologies
- Increasing sophisticated detection and alarming mechanisms
- Virtualization



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Industry Challenges

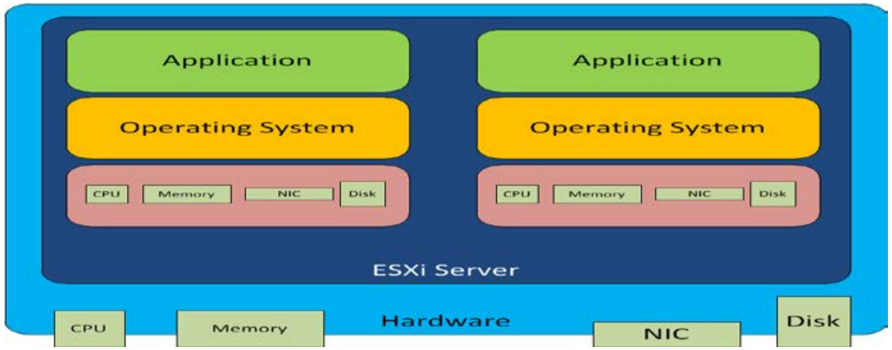
- Different Protection and Control Vendors
- Lack of Qualified Resources
- Protection and Control Systems were designed for functionality and performance, not security.
- Electrical Maintenance has to conduct end-to-end testing with interconnected entities for firmware upgrades.
- Lack of accurate inventory and as-built drawings to go forward with smart design and process improvement.

Industry Challenges

- Can you integrate these solutions into a single solution?
- Vendors don’t usually integrate their systems with one another
- Some power providers are discussing the idea of managing their security from a single management layer
- This type of integrated solution calls for better network designing and extensive testing prior to deployment

Why Integrate Security?

- Protection and Control systems often use IT systems and networking technologies
- The addition of IT technologies pose threats to the ICS system (NIST SP 800-82)
- Protection and Control systems may have implemented IT based solutions, but they have not kept up with IT technology



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Defense in Depth

- North American Energy Reliability Corporation (NERC) is mandating technical controls and safeguards for critical sites through it's Critical Infrastructure Protection (CIP) standards.
  - Electronic Security Perimeter(s) (CIP-005)
  - Systems Security Managements (CIP-007)
  - Incident Reporting and Response Planning(CIP-008)
  - Recovery Plans for BES Cyber Systems (CIP-009)
  - Configuration Change Management and Vulnerability Assessments (CIP-010)

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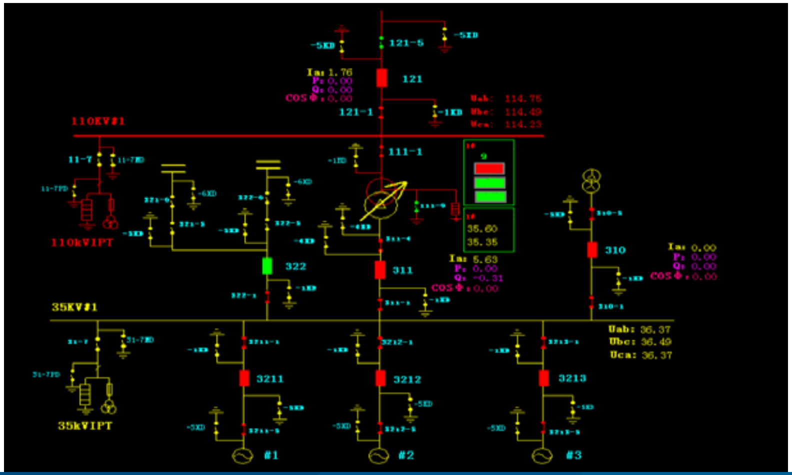
What is a FAT?

- Factory Acceptance Test (FAT) is a testing activity that historically has been used to bring together the ICS Vendor, Engineering and Protection and Control
- Conducting a FAT provides important advantages and benefits including:
  - time savings
  - cost savings



What is an IFAT?

- The IFAT takes the FAT one step farther. The systems are brought together to ensure they operate and communicate together
- Verification and Testing of security controls
- Use a simulator for each link to external systems
- Lastly, need to include Electronic Access Point (EAP) device(s) to ensure that communications outside function properly

What We Look At…

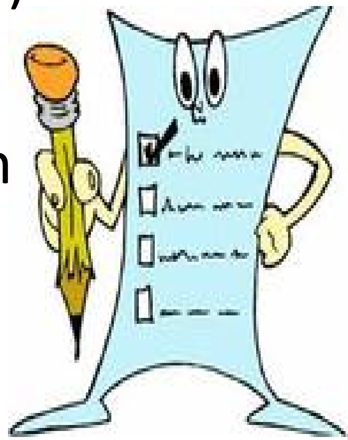
- System Familiarization - Bill of Materials
- System Layout Drawings
- Domain Controller Configuration, including RADIUS
- Secure Communications (SSH)
- Data Link Testing
- Remote Access
- Integration of Security Solution
- Third Party Applications (i.e. Switch Management, Password Complexity, Centralized Backup Solutions)

IFAT

- TEST, TEST, and TEST AGAIN!!!
- The answer for integrating anything into the ICS has always been a Factory Acceptance Test (FAT)
  - Implementing security is no exception
- Security Factory Acceptance Test (IFAT)
  - Vendors, customer and integrator come together prior to installation
  - These issues would normally have to be dealt with during the outage
  - This process saves the site considerable time during the outage
  - They can then concentrate on other upgrades

IFAT Test Plans

- IFAT test plan should include in detail:
  - Description of the scope and approach of the test
  - References to related documents (such as specifications, user guides, etc.)
  - Types of tests to be carried out
  - Features and combinations of features to be tested
  - Features not to be tested (and the reasons why)
  - Test environment
  - System equipment including model and version numbers



IFAT Test Plans (*Continued*)

- IFAT test plan should include in detail:
  - Test setup requirements
  - Test pass and fail criteria
  - Test suspension and resumption criteria
  - Any test equipment and tools
  - Staffing training and skill requirements, and responsibilities
  - Schedule for test performance and all test-related tasks, including post-test reports
  - Any risks requiring contingency planning
  - A list and description of test deliverables
  - The names and titles of all persons who must approve the test plan

IFAT Test Procedures

- Once the overall test plan is approved, the individual test procedures can be developed.
    - Completing the up-front work of test planning
    - A common error is to grab a features list or specifications document
    - This approach inevitably becomes a stop-and-go activity

Questions to Ask

- What vendors will be integrated into this plan?
- Are they willing to work with the other vendors in a neutral environment?
- To what extent will they cooperate?
- Who will integrate this solution?
- Who will write the test plans and oversee the IFAT?
- What facilities are needed to accommodate the vendors?
- What on-site security will be required by each vendor?
- How can we maintain secure data transactions?
- How can NDAs be handled between vendors?

Conducting the IFAT

- Have the operators attend the IFAT - If the operators do not understand what they're working with, they won't be able to secure it properly
- Don't overly complicate - If you add too much security to a system, people will find a workaround to get the job done.

Conducting the IFAT

- Ports and Services
- Anti-Virus
- Patch Management
- Account Management
- Password Management
- Backup and Recovery

Conducting the IFAT

Centralized Account Management Options → Ports & Services → Password Protection → Network Intrusion Detection & Firewall → Security Information Event Management (SIEM)

Conducting the IFAT

- Network port configurations
- Eliminate default passwords
- Use Secure Communication, when available
- Least privilege
- Use RADIUS
- Limit who can access remotely
- System Incident & Event Monitoring System
- Introduction of 3rd party

Test Results

- Best Case – Everything passes and is shipped as tested
- Worst Case - Major issues that do not perform as required and cannot be resolved
- If the test cases are not well-written, test procedures or test results could be interpreted differently by the vendor and customer


Test Results

Typically:

- Both vendor and customer agree that an issue does not meet its expected test results
- Both vendor and customer agree that some performance issue does not meet its specified requirements.
- A third solution is that the customer conditionally accept the system

Agenda

- Introductions
- Technology/Drivers
- Industry Challenges
- Implementing Security - Defense in Depth (DinD)
- What is an Integrated Factory Acceptance Test (IFAT)
- Closing the IFAT

Closing the IFAT

System Release

- Variance List
- Action Items

System is Compliant upon commissioning

- Systems have been fully tested prior to and after implementation meeting many of the NERC CIP requirements: CIP-005, CIP-007, CIP-009

Sample Schedule

Security FAT Schedule

Dates: 07/29/2013 - 08/02/2013

NOTE: Ending Time of Security FAT may be earlier depending on completion status.

Time	Monday	Tuesday	Wednesday	Thursday	Friday
8:00		**Begin Day 2: Morning Meeting**	**Begin Day 3: Morning Meeting**	**Begin Day 4: Morning Meeting**	**Begin Day 5: Morning Meeting**
8:30 9:00	**Early Slot Available for Setup if DCS vendor can accommodate**	nCircle Configuration. Baseline Scan if ready	Finalize nCircle Configuration. Baseline Scan if ready	nCircle Baseline Scan	FCT-001 - NTP Synchronization FCT-002 - Firewall/Router Configuration Specification FCT-003 - Encrypt Passwords in Configuration FCT-004 - Email Alerts FCT-005 - Windows Interactive Logon Banner Test FCT- 006 - Networking Device Logon Banner Test FCT- 007 - SNMP Community Strings FCT-008 - Unnecessary Software on Windows Systems FCT-009 - CoreTrace Whitelisting Application
9:30 10:00 10:30 11:00 11:30	Begin Day 1: Introduction (Kickoff) Safety Training Preliminary Security Coverage Review 'Initial System Baselines Gathered (BMcD Collection Script and Commands) **nCircle Setup**	TPR-001 - Deny Access By Default Test TPR-002 - Verification of Ports and Services TPR-003 - Verification of No External Interactive Access TPR-004 - Logging on Access Attempts TPR-005 - Overly Broad Rule Test TPR-006 - Appropriate Use Banner TPR-007 - SNMP Community String Test TPR-008 - RADIUS Test TPR-009 - Access Point Backup Test	AV-001 - AV Deployment Configuration AV-002 – Console Anti-Virus Check AV-003 – Anti-Virus Deployment to Applicable Systems SP-001 - Patch Deployment Configuration SP-002 – Console Patch Check SP-003 - Patch Deployment to Applicable Systems SP-004 – Other Device Patch Check	SBR-001 - Demonstration of Backup SBR-002 - Demonstration of HMI Restore SBR-003 - CatTools Network Device Backup SBR-004 - CatTools Network Device Restore SBR-005 – Controller Restore NC-009 - Bandwidth Monitoring NC - 010 - NAS Tesint NC-011 - OHI Driver Testing NC-012 - Domain Controller Failover	
12:00 **12:30**	**LUNCH**	**LUNCH**	**LUNCH**	**LUNCH**	**LUNCH**
1:00 1:30 2:00 2:30 3:00 3:30 4:00 4:30 5:00	Preliminary Security Coverage Review 'Initial System Baselines Gathered (BMcD Collection Script and Commands) nCircle Setup SC-001 – Security Server Communication SC-002 – Cyber Asset Communication with SAN SC-003 – Remote Access to HMI(s) SC-004 – KVM Testing SC-007 - nCircle Communication with Scan Agents SC-008 - Use of Secure Protocols for Network Device Configurations SC-010 - Wireless Testing	DP-001 - Dial-Up Elimination PS-001 - Windows Ports Verification PS-002 - Networking Device Ports Verification PS-003 – Other Device Port Verification PS-004 - Windows Services Verification PS-005 - Networking Device Services Verification PS-006 – Other Device Services Verification	AM-001 – System/Service Account Verification AM-002 - Default Windows Accounts AM-003 - Default Networking Device Accounts AM-004 - Default Device Accounts AM-005 - Operator Account Settings AM-006 - Shared Accounts AM-007 - Accounts Associated with Automated Functions AM-008 - Kiwi Tools Account AM-009 - Windows Password Settings (Local and Domain) AM-010 - Device Password Settings AM-011 - Cisco Account Configuration AM-012 - Local and Domain Account Lockout Settings AM-013 - Disable Local Accounts AM-014 - Windows Remote Access Users	SM-001 - SIEM Configuration SM-002 - Windows Log Collection/Retention SM-003 - Networking Device Log Retention SM-004 - Device Log Collection/Retention SM-005 - SIEM Reporting SM-006 - SIEM Configuration to Reduce Overhead SM-007 - Link State Monitoring (SIEM Notification) SM-008 - Windows Audit Policy Settings For Domain Controllers, Members and Local Systems SM-009 - Handoff Syslog SM-010 - Device Logging Settings	Final Wrap Up of - Tests Final Baselines Gathered (BMcD Collection Script and Commands) **Security FAT End Meeting**
5:30	**End Day 1: Debrief Meeting**	**End Day 2: Debrief Meeting**	**End Day 3: Debrief Meeting**	**End Day 4: Debrief Meeting**	
6:00 >6:30	**Elective Time: Used to Perform Test or Conduct Work Outside of Normal Schedule**				

Variance Report

Appendix C - Variation Report **Variation #:** ____

Vendor: ____
Originator: ____ **Date:** 6/29/2014 19:21
Approver: ____

Systems: ____

Test Description: ____

Importance: ☐ HIGH ☐ MEDIUM ☒ LOW
Description of issue: **Status:** ☐ FAIL ☐ PASS W/ISSUE

Resolution: Resolved

IMPACT OF CHANGE:
Mark all areas affected: ☐ Other Security FAT Tests/Equipment ☐ Site Installation ☐ Scope

Description:

STATUS: ☐ Resolved During Security FAT ☒ Remains Open

RECEIVED BY
Signature: ____ Date: ____

Who Benefits

- The Vendor
- The Customer
- The Integrator

Questions

An Introduction and Review of Practical Synchrophasor Applications for Substation Equipment Analysis

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An Introduction and Review of Practical Synchrophasor Applications for Substation Equipment Analysis

Abstract:

Synchrophasor data and its applications are moving out of the realm of research and wide area transmission grid visibility and into mainstream utility operations for substation equipment performance analysis. This article introduces synchronized phasor measurements as a concept and then presents a literature review of utility applications such as identifying loose connections, failing equipment, and a straightforward method for determining substation phasing. As utilities continue to add equipment that supports sending and archiving phasor measurement unit (PMU) data, the leveraging of this data can potentially save time, money, and prevent unplanned equipment outages.

1. Introduction

This section is intended to introduce the topic of synchrophasors to a wide audience that may not have experience dealing with this area of electrical system parameters. First, the concept of a phasors is explored, and then expanded to the topic of synchrophasors. The requirements for a synchrophasor "system" are described, synchrophasor data are described, and a grid transient event using synchrophasor data is presented.

Phasors

An alternating current (AC) signal is typically thought of as a sinusoidal function. An ideal three-phase system will have three of these sinusoidal AC signals that are separated by 120 degrees. A phasor is another way of looking at AC signals – instead of a "wave", it is shown as a vector with a magnitude and direction (angle). Figure 1.1 contains two plots – the plot on the left is a time-domain plot of three sinusoidal waveforms, and the plot on the right is a phasor domain plot for the same three waveforms.

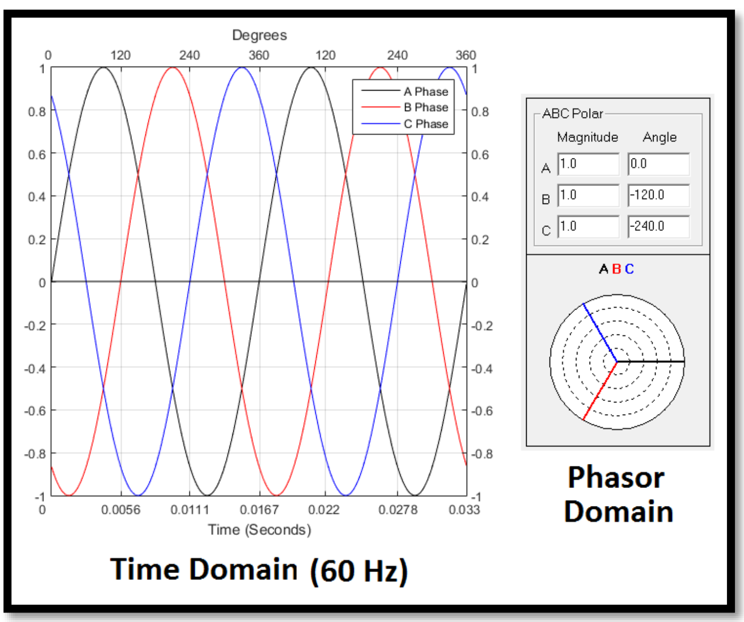


Figure 1.1: Time & Phasor Domain for 3-Phase Signals

When put in motion in the phasor domain, the phasors will 'rotate' counterclockwise around the center. In the Phasor Domain image from Figure 1.1, if one can imagine the counterclockwise rotation, the A-phase zero crossing is at 0 degrees; B-phase follows A-phase's zero crossing 120 degrees later; C-phase follows the A-phase zero crossing 240 degrees later.

When considering power system information, it is typical to examine the phase angle difference between two locations for the same phase (for example, a location in West Texas and a location in South Texas). Figure 1.2 shows an example of two A-phase signals that are separated by 30 degrees.

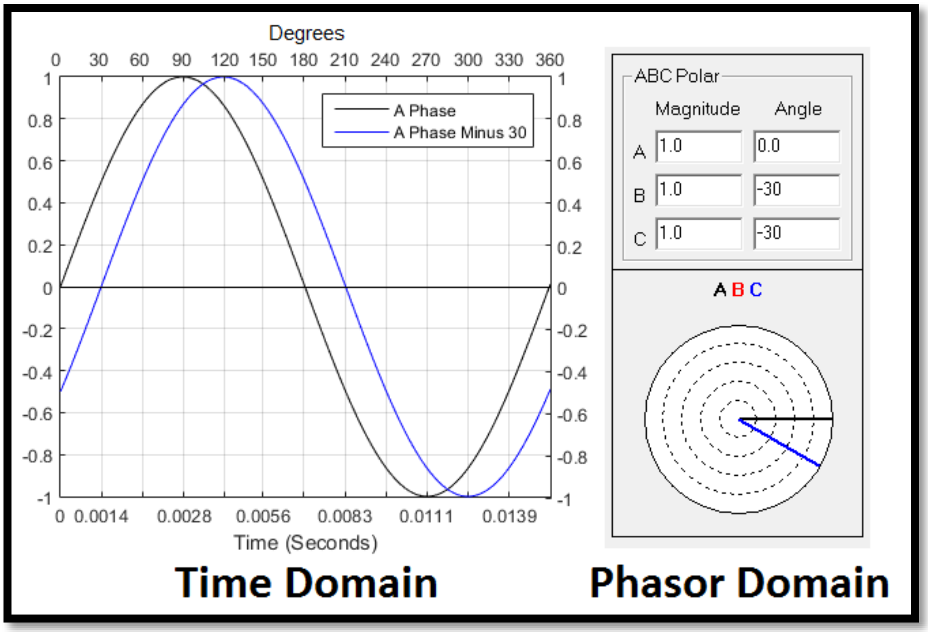


Figure 1.2: 30 Degree Difference in A-Phase Signals

Once again, as the phasors rotate counterclockwise around the center point, the black line crosses zero first, and the blue line crosses 30 degrees later. The significance of this will be highlighted later.

<u>Synchrophasors</u>

The term "synchrophasor measurement" is a blending of the phrase "time-synchronized phasor measurement". A "synchrophasor measurement" always includes an exact timestamp, and for parameters like voltage and current, are always presented in a way that magnitude and direction are included. The values may be in polar magnitude & angle form, or rectangular x & y form, but either way, a magnitude and direction may be determined. Other parameters, such as frequency and 'rate of change of frequency' are commonly included with synchrophasor measurements. ([1] and [2]).

Synchrophasors are of interest to electric utilities because of the depth of information that may be ascertained from the measurements. The measurements are timestamp-specific, and they are usually performed at a much higher rate than other types of telemetry – i.e., SCADA may gather one measurement every two seconds, but it's very common for synchrophasor systems to gather measurements 30 times per second. Because all of these measurements are timestamp-specific to a common clock, the measurements represent a snapshot of the electric system at a very specific moment in time.

There are three systems to consider for synchrophasor measurements: the measurement system, the communications network, and the data storage system. The minimum hardware required to generate synchrophasor measurements are a time source such as a Global Positioning System (GPS) satellite clock or network-distributed time clock that supports a high-accuracy time output; potential transformers and/or current transformers; and a phasor measurement unit (PMU) device. A PMU may be a dedicated device or it may be a dual-purpose device such as a fault recorder or protective relay. The communications network will dictate whether live-data streaming is possible to another location, or if local storage will be used. In some systems, phasor data concentrators (PDC's) are used locally (in substations) to time-align, store, consolidate, or pre-process data before it is forwarded on to another location. To take full advantage of synchrophasor measurements, a data storage system with ample storage space is necessary for the large amounts of data that may be generated by a synchrophasor system. The incoming data is again time-aligned with its precise timestamp as it is collected and stored.

A simple synchrophasor network system is shown in Figure 1.3. This is representative of the research system in use at Baylor University.

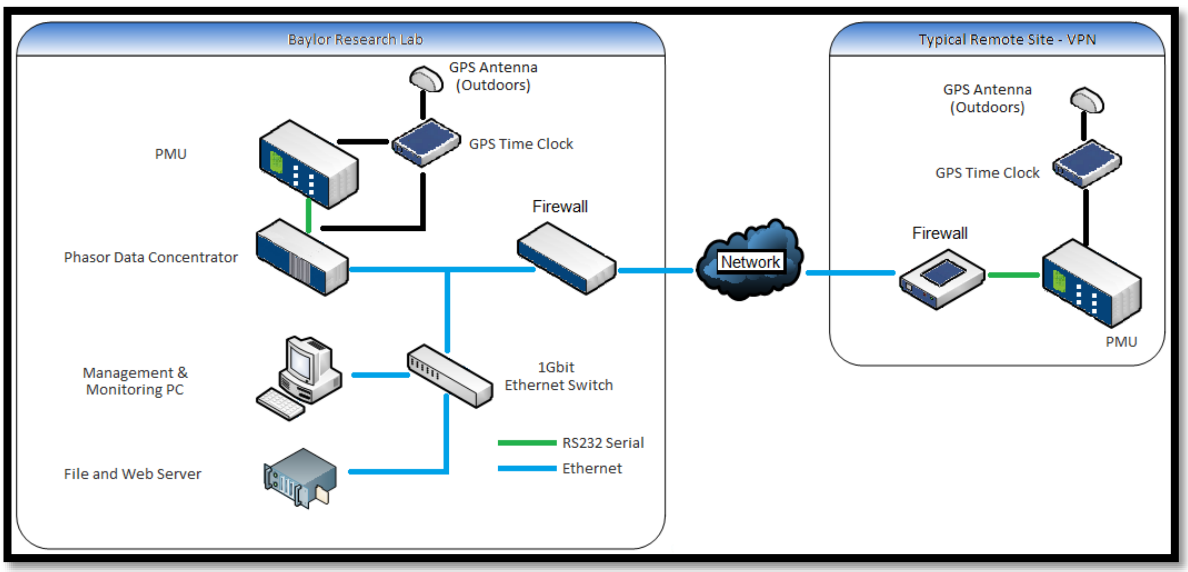


Figure 1.3: Simplified Synchrophasor Network

Synchrophasor Data

The most common data collection rate for synchrophasor data is 30 measurements per second – 108,000 measurements per hour. An example of 5 measurements – spanning 133 msec – is shown in Table 1.1. Note that the data are presented with a voltage magnitude and phase angle.

Table 1.1: Example Synchrophasor Measurements

Timestamp	BAYLOR_ECE:V1YPM_Magnitude	BAYLOR_ECE:V1YPM_Angle	BAYLOR_ECE:Frequency
5:00:00.000	81703.5234	69.1494	60.0013
5:00:00.033	81726.5313	69.1592	60.0012
5:00:00.066	81740.6953	69.1685	60.0012
5:00:00.100	81732.4063	69.1818	60.0011
5:00:00.133	81734.5781	69.1968	60.0011

While the continuous high acquisition rate does generate a significant amount of data, the data may be automatically searched for patterns or triggers with only events of interest flagged and analyzed. The high collection rate allows for very high resolution when observing power system transients.

Grid Transient Event

One example for the usefulness for synchrophasors is to view how the grid responds to transients. Figure 1.4 shows a transient in the ERCOT system that occurred on January 27, 2016.

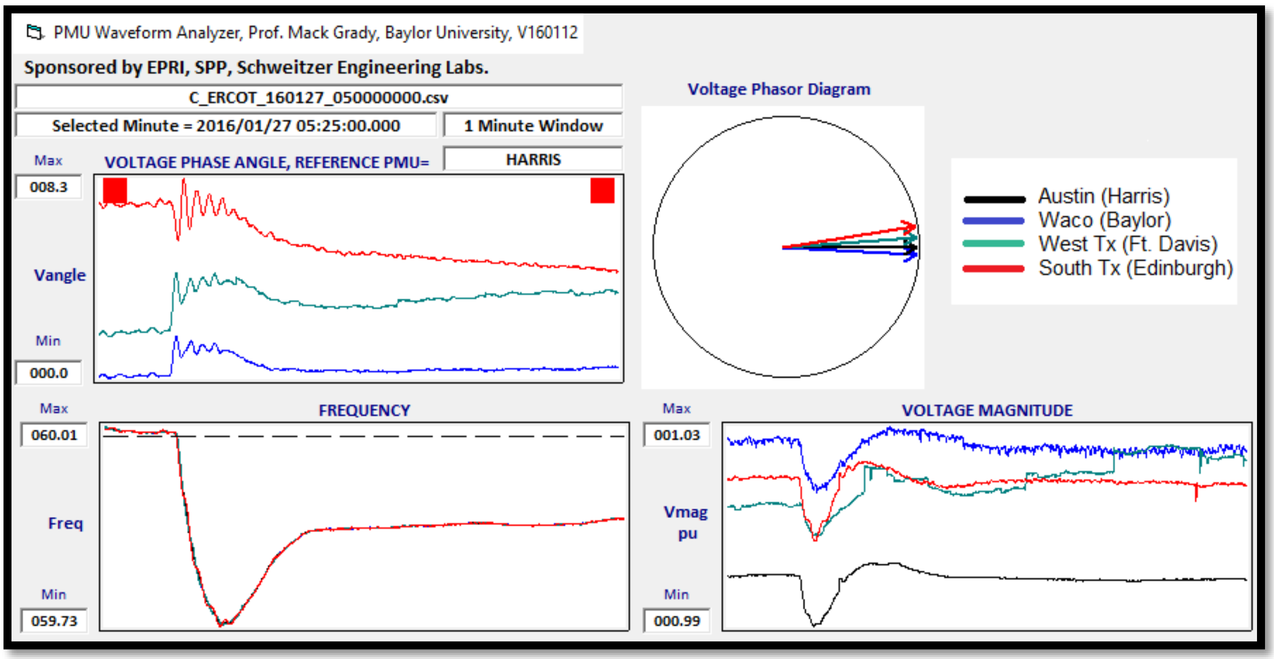


Figure 1.4: ERCOT Grid Transient

These PMU's are located in south Texas (Edinburgh), west Texas (near Fort Davis), Austin, and Waco. The Austin PMU is being used as the "reference", so all phase angles within Figure 1.4 are expressed as a differential with Austin. Power flow is reflected by the angular difference – electric power flows from higher angular values towards lower angular values. In this event, the angular difference between Austin and south Texas drops considerably (the red trace), while the phase angle between west Texas and Austin rises. This signifies that less power is flowing south-to-north after the event than before the event. Because of the significant drop in frequency (from ~60 Hz to ~59.74 Hz), and because of the change in direction of the power flow, we can conclude that this was a large unit trip in south Texas (later, we found out that it was a trip at the South Texas Nuclear Generating Station).

One of the key points to emphasize in a synchrophasor system is that there must always be one reading or site chosen as the 'reference' that all of the other sites will be compared against. In the case of the Baylor synchrophasor network, Austin is chosen as the reference because its measurements are three phase and from PT's at a 69kV substation in downtown Austin. The other sources of PMU data are from wall outlet measurements – which have been found to be highly effective and an accurate source of voltage magnitude, phase angle, and frequency information, but are subject to distribution feeder noise and transients [3]. In Table 1.1 the angle shown for the Baylor PMU is in its 'raw measurement' form. The 'raw measurement' of angles for two PMU's may be compared to determine the angle between the two locations, and it is from this difference that power system information may be determined.

This example reflects a traditional use for synchrophasor data – a wide area view of the grid, with phase angles reflecting power flows, a view of the damping in system oscillations, and overall response to grid transients. Synchrophasor data are also being used for state estimator verification and for generator model validation. However, now that utilities are collecting this data and examining it more thoroughly, they have begun to use the data not just for power system event analysis, but for monitoring and analysis of individual pieces of substation equipment. The same data that have proven useful to grid engineers is now being analyzed for equipment performance.

2. Using Synchrophasor Data for Equipment Diagnosis and Monitoring

Author's note: This section features information presented by the North American Synchrophasor Initiative's (NASPI's) Alison Silverstein in the NASPI technical report "Diagnosing Equipment Health and Mis-operations with PMU Data" from May 1, 2015. The full document is available on the NASPI web site at https://www.naspi.org/documents [4]. The authors wish to acknowledge and thank Ms. Silverstein and all of those involved in the preparation of that document, and thank them for the use of their information in this article.

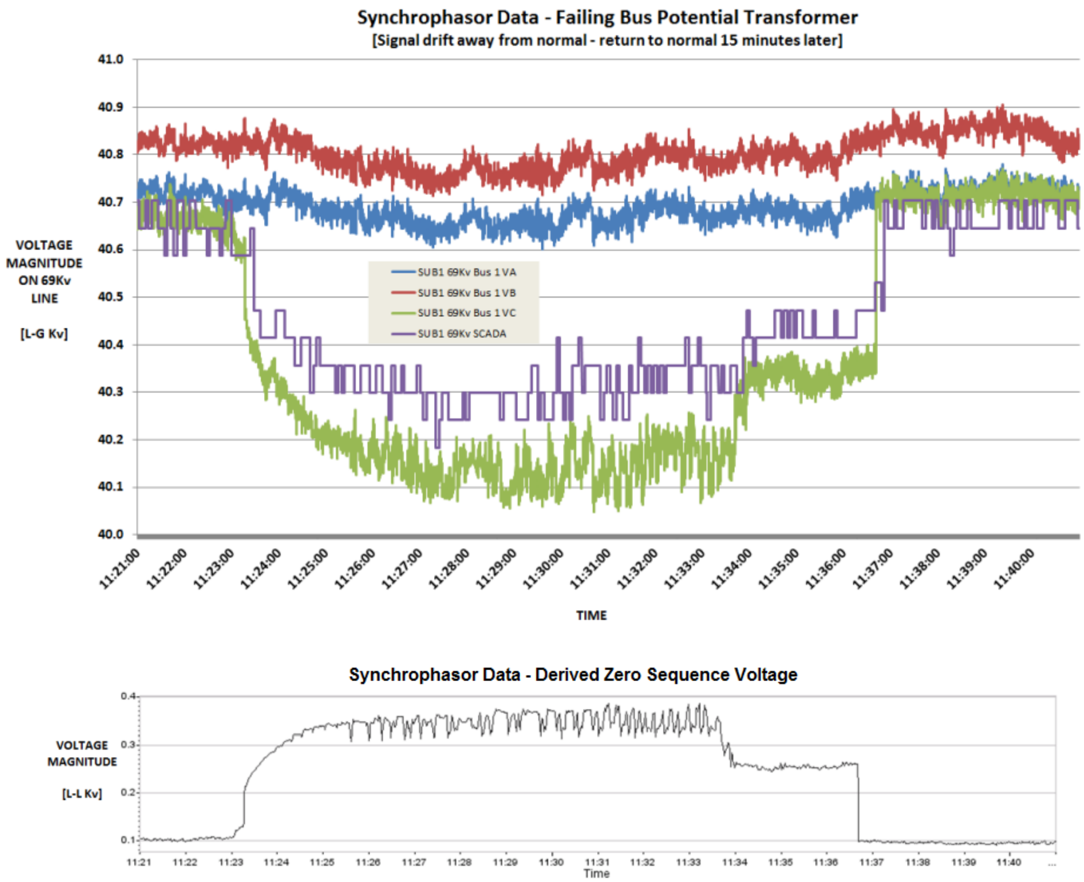
One of the advantages of using synchrophasor measurements to monitor and diagnose equipment health and status is the data rate at which measurements are transmitted and stored. The commonly-used data transmittal and acquisition rate of 30 samples per second tremendously magnifies activity that would only appear as a slight 'blip' in a traditional SCADA system measurement. This makes it easier to programmatically or visually locate suspicious equipment activity.

Failing Potential Transformer – Jim Kleitsch, American Transmission Company (Wisconsin)

American Transmission Company (ATC) was reviewing fault operations when they noticed a strange pattern in PMU data from one of their potential transformers (PT). The C-phase voltage at one of their 69kV stations was momentarily deviating away from the other two phases, and then suddenly returning to a 'normal' alignment. The deviation was not large enough to trigger a SCADA alarm, but was significant enough to be instantly recognizable on a graph of the measurements.

ATC was using both secondary windings on this PT, and upon further investigation, found that both secondary windings were experiencing the same erroneous measurements. Maintenance personnel concluded that the problem was with the primary winding side of the PT, and that the PT should be replaced before failure of the primary winding and possible unplanned outage could occur, up to or including a potentially catastrophic event that may cause additional substation damage. A maintenance outage was scheduled, a mobile substation was installed, and the PT was replaced with no customers being impacted.

The upper graph in Figure 2.1 shows a comparison of the three phases of synchrophasor data, along with the SCADA data acquired from the C-phase measurements. ATC has also provided a plot of the zero-sequence voltage for the three phases. Ideally, the zero-sequence voltage (phasor sum of the three voltages) should be near zero; in this case, the zero sequence voltage increased significantly as the C-phase PT deviated from the two 'correct' voltage measurements.



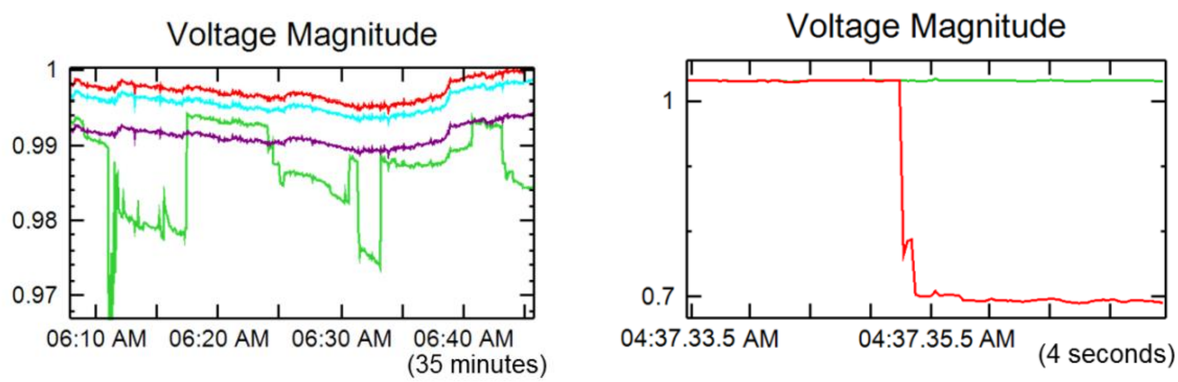
(Source: ATC, from Kleitsch)

Figure 2.1: Failing Potential Transformer

<u>Loose Connections & Blown Fuses – Austin White & Steven Chisholm, Oklahoma Gas & Electric</u>

OG&E personnel detected some suspicious measurements from one of their Coupling Capacitor Voltage Transformers (CCVT). The green voltage trace in the left-side plot of Figure 2.2 is fluctuating, but without enough deviation-from-normal to trigger SCADA alarms. Upon investigation, a technician found that fuse connections were loose in the CCVT safety switch. OG&E has found several loose connections by monitoring for similar patterns.

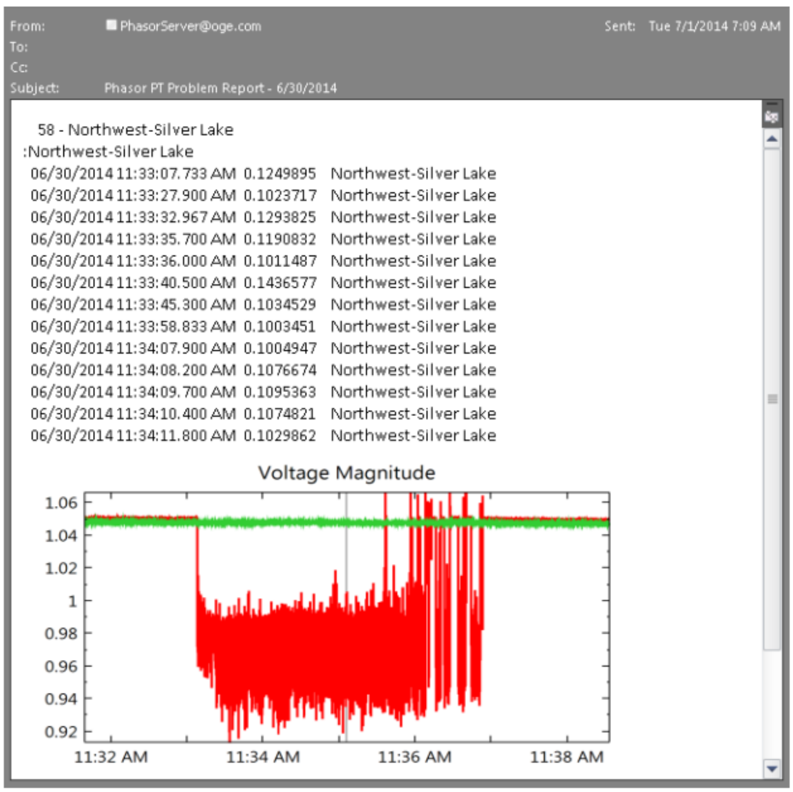
The red voltage trace on the right side of Figure 2.2 shows a 30 sample-per-second plot of a blown fuse on one phase. The voltage drops by one-third in magnitude because this PMU is sending back positive sequence voltage. This type of voltage deviation would have been detectable by SCADA, but SCADA would not have had the stored waveform reading like the PMU data contains.



(Source: OG&E, from White & Chisholm)

Figure 2.2: OG&E Loose Connection (Left) & Blown Fuse (Right)

OG&E has done considerable customization of their phasor measurement data acquisition system. One of the tools that they have created is a "PT Problem Report Tool", which creates a dV/dT measurement on all voltage magnitude measurements in order to detect fluctuations in PMU voltage data. A daily report is created for any voltage fluctuations that exceed OG&E's threshold settings. Figure 2.x shows an example email output from their phasor PT reporting system.


From: PhasorServer@oge.com
Sent: Tue 7/1/2014 7:09 AM
To:
Cc:
Subject: Phasor PT Problem Report - 6/30/2014

58 - Northwest-Silver Lake
:Northwest-Silver Lake

06/30/2014	11:33:07.733 AM	0.1249895	Northwest-Silver Lake
06/30/2014	11:33:27.900 AM	0.1023717	Northwest-Silver Lake
06/30/2014	11:33:32.967 AM	0.1293825	Northwest-Silver Lake
06/30/2014	11:33:35.700 AM	0.1190832	Northwest-Silver Lake
06/30/2014	11:33:36.000 AM	0.1011487	Northwest-Silver Lake
06/30/2014	11:33:40.500 AM	0.1436577	Northwest-Silver Lake
06/30/2014	11:33:45.300 AM	0.1034529	Northwest-Silver Lake
06/30/2014	11:33:58.833 AM	0.1003451	Northwest-Silver Lake
06/30/2014	11:34:07.900 AM	0.1004947	Northwest-Silver Lake
06/30/2014	11:34:08.200 AM	0.1076674	Northwest-Silver Lake
06/30/2014	11:34:09.700 AM	0.1095363	Northwest-Silver Lake
06/30/2014	11:34:10.400 AM	0.1074821	Northwest-Silver Lake
06/30/2014	11:34:11.800 AM	0.1029862	Northwest-Silver Lake

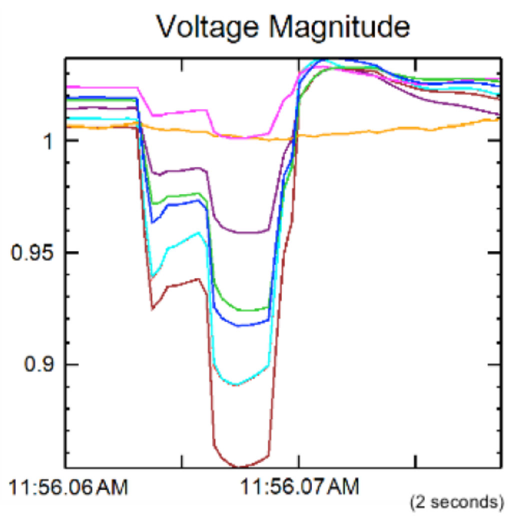
(Source: OG&E, from White)

Figure 2.3: OG&E Phasor PT Problem Report

Operations Patterns that Link Voltage Sags with Disabled Power Line Carrier System, Austin White, Oklahoma Gas & Electric

OG&E had a 138kV line in the Oklahoma City area that was prone to carrier system over-tripping. The Directional Comparison Blocking (DCB) scheme was sometimes failing to send the block tripping signal, so when the relays detected a fault and did not receive the block trip signal, the relays would operate quickly (communications-based relaying, 'operate quickly unless a signal is received') for a fault on an adjacent line. To temporarily alleviate the problem of over-tripping, OG&E decided to occasionally disable communications-based tripping on the line and rely on time-based protective relaying.

Once the carrier system was disabled, there were reports of voltage sags in the entire transmission system during faults on this line. By analyzing the synchrophasor data, it was determined that the lack of high-speed communications-based relaying was introducing a long-duration fault in to the system and causing the voltage to sag throughout the system. Figure 2.4 shows voltage magnitude sags from around the OG&E system during one of these events. The fault, instead of clearing in 5-6 cycles for communications-based tripping, persisted for ~36 cycles because of the step-distance relaying time settings. Because of concerns for customer equipment ride-through, it was determined that it was better to have the possibility for an over-trip with a faulty carrier system than to have long duration voltage sags.

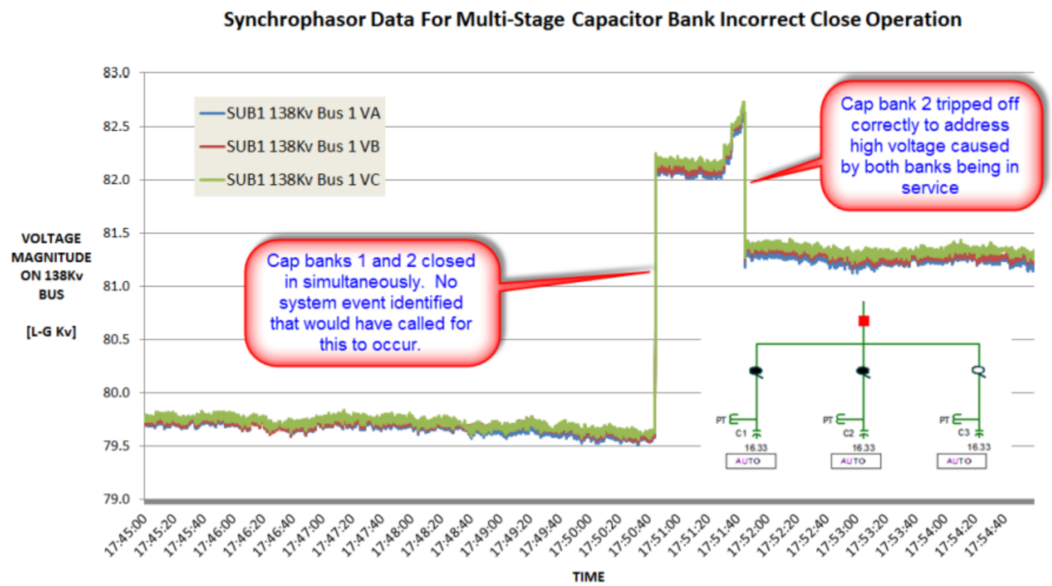


(Source: OG&E, from White)

Figure 2.4: Voltage Sag during Fault for non-Carrier / Time-Only Relaying

Capacitor Bank Switching – Jim Kleitsch, American Transmission Company (Wisconsin)

ATC has three 16 MVAR capacitor banks at one of its 138kV substations, and these banks are configured to switch in sequence. In the incident shown in Figure 2.5, banks 1 and 2 closed simultaneously. It was suspected that a voltage dip may have caused this unintended operation, but neither relays nor SCADA captured any event logs during this period that may have explained this activity. ATC's synchrophasor system effectively captured the voltage magnitudes and allowed ATC engineers to conclude that the event was due to a switching error instead of any sort of response to a system event.

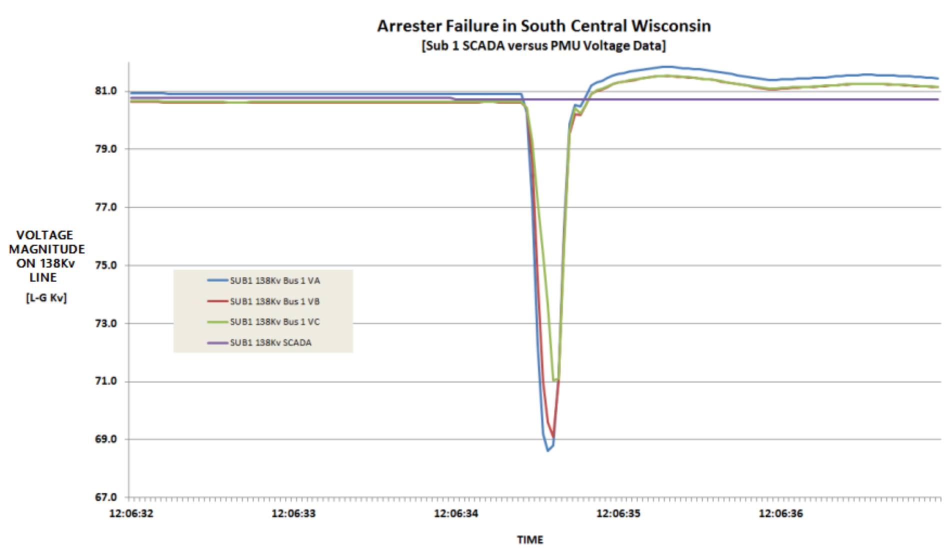


(Source: ATC)

Figure 2.5: ATC Multi-Stage Cap Bank Incorrect Operation

<u>Lightning Arrester Failure – Jim Kleitsch, American Transmission Company (Wisconsin)</u>

ATC system operators received a number of phone calls regarding a voltage dip, but no SCADA alarms had been generated. The control room operators requested that ATC engineers examine PMU data, and within a few minutes the engineers were able to provide the duration and magnitude of the voltage transient from varying locations around the system. Figure 2.6 shows the voltage dip as seen by SCADA (the purple line) and as seen by the PMU's (red, blue, and green lines).



(Source: ATC)

Figure 2.6: Voltage Dip from Failing Lighting Arrester

3. Determining Phasing via Low Side of a Distribution Transformer

This example will describe in detail how instantaneous time-synchronized phasor measurements were used to determine the phasing for a new substation. For those who may not have access to continuous synchrophasor data as described in the previous examples, using the built-in ability of some protective relays to make this simultaneous power system measurement is one way that synchrophasor measurements may be used with no data collection infrastructure required. While there is much value in the high-speed continuous data logging of a synchrophasor network, even those utilities without such a network may obtain benefits from synchrophasor technology.

In 2015, Brazos Electric had constructed a new delivery substation as a tapped station on another utility's transmission line. Phasing at the station was specified in the initial job requirements, but there were doubts that the incoming transmission line phasing was correct once the station approached completion.

Brazos engineering was asked if it might be possible to use synchrophasors to determine if the incoming phasing was correct. A protective relay with synchrophasor capability, a GPS clock, and potential transformers had been installed on the distribution bus side of the delta-wye transformer. There were no PT's on the primary (transmission) side of the transformer. Because of the phase angle shift due to delta-wye transformer characteristics, the phase angle shift relative to a nearby 69kV transmission station would need to be determined.

Delta-Wye Transformer Phasing

The system voltage phase rotation is normally A-B-C with a counterclockwise rotation. This was shown previously in Figure 1.1. For Brazos' delivery transformers, there are two standard ways to connect the transformer – A-B-C connected to the H1-H2-H3 bushings, or C-B-A connected to the H1-H2-H3 bushings. When an A-B-C phase rotation electrical system is connected A-B-C to a delta-wye transformer, the secondary voltages lag the primary voltages by 30 degrees. Conversely, when an A-B-C phase rotation is connected C-B-A to a delta-wye transformer, the secondary voltages lead the primary voltages by 30 degrees.

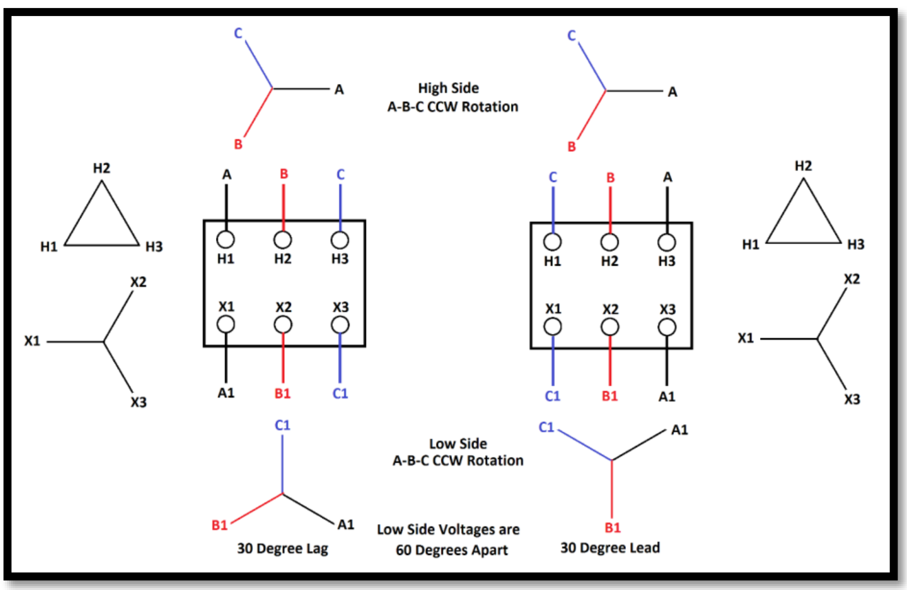


Figure 3.1: Delta-Wye Transformer Lag/Lead, courtesy Stan Ginsburg, BEPC

The station that Brazos engineering was asked to investigate was designed as a C-B-A connection. Since the distribution system is designed so that feeders from an adjacent substation may connect to the feeders at this station, phasing is critical to prevent connecting different phases together and faulting both feeders.

Reference Phase Angle

A reference transmission station was necessary for comparison purposes. Since Brazos does not have phasor data from any stations on a streaming basis, it was necessary to communicate with two transmission sites with synchrophasor capable protective relays via two dial-up modems at the same time. Both relays were given the command to run a synchrophasor metering measurement at the same specified time, and when that time threshold was reached, both relays displayed the instantaneous voltages and phase angles for all three phases based on simultaneous GPS-synchronized measurements. Note that traditional ‘streaming’ PMU measurements were not necessary at all – yet this is still taking advantage of the principle of simultaneous phase angle referencing with the synchrophasor measurement.

Two simultaneous transmission relay readings are shown below. Even though they are separated by miles of transmission line and are at different voltages (69kV and 138kV), the phase angle difference between the two stations is less than four degrees. Since they are “in phase with each other”, this confirms that the reference station chosen (in this case, the 69kV station near the distribution station) is adequate for establishing the phasing of the distribution station.

```
=>met pm 14:06:00
Synchronized Phasor Measurement Data Will be Displayed at 14:06:00.000

SEL 421                    Date: 03/03/2015  Time: 14:06:00.000

Time Quality   Maximum time synchronization error:    0.000 (ms)  TSOK = 1

               VY Phase Voltages         VY Pos. Sequence Voltage
            VA       VB       VC              V1
MAG (kV)       40.484    40.508    40.558           40.517
ANG (DEG)       62.717   -57.218  -177.315           62.723

FREQ (Hz) 59.979        Frequency Tracking = Y                 TRM
```

Figure 3.2: Synchrophasor Measurement for Reference, 69kV Station

```
=>met pm 14:06:00
Synchronized Phasor Measurement Data Will be Displayed at 14:06:00.000

SEL 421                    Date: 03/03/2015  Time: 14:06:00.000

Time Quality   Maximum time synchronization error:    0.000 (ms)  TSOK = 1

               Phase Voltages          Pos. Sequence Voltage
            VA       VB       VC              V1
MAG (kV)       80.895    81.059    80.407           80.786
ANG (DEG)       66.162   -53.762  -174.359           66.015

FREQ (Hz) 59.980                                   GVW
```

Figure 3.3: Synchrophasor Measurement for Reference, 138kV Station

Running the simultaneous "meter phasor measurements" commands on the 69kV reference transmission station and the protective relay on the distribution bus / low side of the delta-wye transformer:

```
=>met pm 16:01:30
Synchronized Phasor Measurement Data Will be Displayed at 16:01:30.000

SEL 421                    Date: 03/04/2015  Time: 16:01:30.000

             VY Phase Voltages        VY Pos. Sequence Voltage
          VA        VB        VC             V1
MAG (kV)      40.808    40.846    40.912          40.855
ANG (DEG)     -24.594  -144.455   95.377          -24.561         TRM
```

Figure 3.4: 69kV Reference Synchrophasor Measurement

```
=>met pm 16:01:30

Synchronized Phasor Measurement Data Will be Displayed at 16:01:30.000

XMFR                     Date: 03/04/05    Time: 16:01:30.000

             Phase Voltages         Synch Voltage    Pos.-Seq. Voltage
          VA        VB        VC         VS               V1
MAG (kV)      7.751     7.771     7.757       0.001          0.014
ANG (DEG)     -56.183   63.821  -176.013     12.773         159.647      WND
```

Figure 3.6: 13.2kV Transformer Low-side Synchrophasor Measurement, Incorrect Phasing

Comparing the three phase angles, two issues are immediately apparent:

1. The C-B-A connection does not have the secondary A-phase leading the primary A-phase by 30 degrees (in this case, A-phase secondary lags A-phase primary by just under 32 degrees).
2. B and C phases are not in phase with the rest of the system. The B-phase and C-phase measurements show that the two phases are rolled.

Graphically, this may can be shown as phasors (Figure 3.6 - Black = A Phase; Red = B Phase; Blue = C Phase) and it is easy to see the phasing mismatch. The two B-phase measurements are separated by over 150 degrees, and the two C-phase measurements are separated by almost 90 degrees.

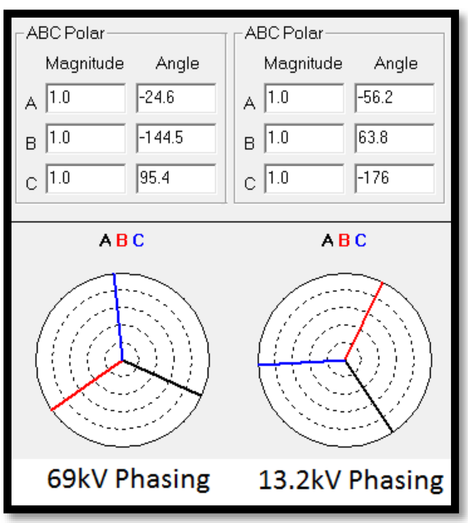


Figure 3.7: Delta-Wye Transformer Measurement with Rolled Phases

Based on these measurements, Brazos engineering recommended that phases B and C be rolled at a convenient transmission structure. This work was done, and after the work, new phasor measurements were compared.

The new phasor measurements were:

69kV Station:			
	Phase Voltages		
	VA	VB	VC
ANG (DEG)	-158.773	81.236	-38.860

Figure 3.7: 69kV Reference Synchrophasor Measurement

13.2kV Station:			
	Phase Voltages		
	VA	VB	VC
ANG (DEG)	-129.498	110.462	-9.537

Figure 3.8: 13.2 kV Transformer Low-side Synchrophasor Measurement, Correct Phasing

Displayed graphically, it is evident that the distribution voltages lead the transmission voltages by 30 degrees on each phase (counterclockwise rotation), establishing that the phasing for the new substation is now correct (Figure 3.9). Something to think about - the successful phasing of this substation was accomplished without high speed streaming data, storage systems, or even leaving the office.

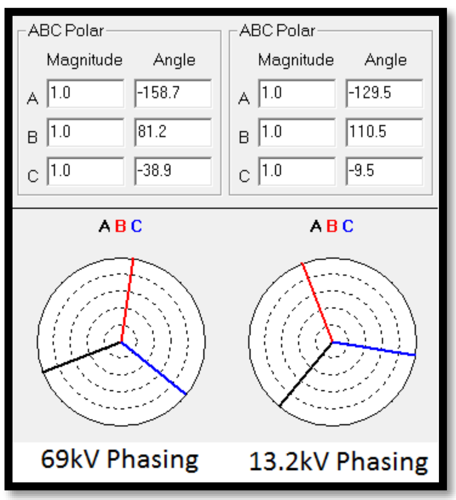


Figure 3.9: Delta-Wye Transformer, C-B-A Connection, Correct Phasing

4. Conclusion

As more utilities implement synchrophasor-compatible equipment in the substation, the information provided by these measurements is becoming very important to many departments within the electric utility. Continuous synchrophasor measurements bridge the gap between the sub-cycle measurements of a brief and limited protective relay event log and the periodic (if logged) SCADA data.

High-rate signal capture can provide insight in to failing or mis-operating equipment that may normally be missed by other observation methods. Loose connections, intermittent potential transformers, switching transients, and lightning arrester failures represent but a few of the events that become much more visible when viewed through the lens of high speed data acquisition. Identifying small problems before they can become much larger issues can save the utility time, money, preventing unplanned outages and improving system reliability. Stored synchrophasor data can be filtered and analyzed for patterns.

Likewise, the ability to take instantaneous measurements at a precise moment in time offers many possibilities for analysis. Determining the phasing at points in the transmission or distribution network is as simple as executing a few commands and comparing measurements.

Looking towards the future, it is possible that there will be phasor data concentrators in every substation, acting as data storage devices for voltage, current, frequency, and other measurements (dF/dt, $2^{nd}/4^{th}/5^{th}$ harmonic information from transformers, etc). This wealth of data will prove invaluable to any of the many personnel who perform analytics on the power system. As communications technologies improve, and computer storage space becomes less and less expensive, an investment in continuously streaming synchrophasor technology is something that offers a strong benefit to the electric utility.

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500 KV COMPACT STRUCTURE DESIGN APPROACH

Transmission & Substation
Design & Operation Symposium
September, 2016

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1 ABSTRACT

Entergy Corporation is a major utility with headquarters in New Orleans, LA and operations in 4 southern states and the city of New Orleans. Entergy's five operating companies have 15,000 miles of transmission lines, 40 generating plants powered by a diverse fuel mix with 30,000 megawatts of power capacity serving 2.8 million customers. The company has annual revenues of $11.5 billion dollars and 13,000 dedicated employees.

The Entergy service territory, particularly in south Louisiana, has been experiencing significant growth, mainly from industrial development. Planners at Entergy have determined that additional 500 kV transmission capacity is needed to service the area. The current Entergy standard structure at 500 kV is a horizontal configuration on lattice towers or tubular H-frames requiring a 225 foot right of way. Due to the short lead times associated with some of the industrial development projects and the difficulty in acquiring the standard right of way on a timely basis to facilitate the development projects, the Entergy Line design team identified a need to explore ways to compact the design. The planners have suggested that the line design team explore ways of fitting a new 500 kV line with an ampacity rating of 3000 amps in an existing 230 kV corridor which is 125 feet wide. This would eliminate the need for the lengthy right of way acquisition process.

Entergy contracted POWER Engineers, Inc. to support the development of a 500 kV, single circuit, compact design to supplement their current 500 kV structure families. The design approach included evaluating the challenges specific to Entergy's system, defining constraints and parameters important to those challenges, and preparing a cost-benefit analysis of the available options.

The design team of Entergy and POWER assigned priorities to common performance metrics and the design parameters that impact those metrics to highlight the important aspects of the structure design. The team then performed a parametric study of phase geometry, structure configuration and conductor configuration for the predetermined key performance metrics to quantify the importance of the parameters involved. The team studied the highest impact parameters in detail to understand the limits of compaction and related challenges.

Numerous structure configurations were developed based on the design efforts. The configurations included single and two pole structure types of varying phase arrangements. Clearance and insulation requirements were varied, ranging from Entergy's standard configurations to the limits determined through detailed analysis of those requirements. As phase spacing was decreased, the conductor configurations were adjusted to achieve audible noise requirements. The advantages and disadvantages of the various structure configurations were compared. This comparison included consideration for reliability performance, galloping, aesthetics, design flexibility, constructability, maintenance and costs.

The analysis led to the conclusion that one structure configuration did not necessarily satisfy the requirements of all of the possible situations and criteria that engineers may face on future projects. To best address the anticipated challenges, primary and secondary configurations were selected. These configurations will be used individually or in combinations to address a wide variety of likely design situations.

2 INITIAL STEPS

Entergy has seen an increase in industrial development and load growth in parts of their service territory. The Entergy planning department determined that the additional load requirement would be best served with 500 kV transmission service. Most of these projects require an expedited in-service date to serve the projected customer requirements. New Rights of Way are difficult and time consuming to obtain. The Entergy Transmission Line Department working in conjunction with the planners identified a need to develop a family of 500 kV structures that could fit in narrower ROW. It was determined that a viable solution would be to upgrade existing 230 kV lines to 500 kV by rebuilding in the existing ROW, thus eliminating the need to acquire new or additional ROW. The Entergy standard at 500 kV is a horizontal configuration using V-string insulators on lattice towers or tubular H-frames requiring a 225 foot ROW. The standard 230 kV ROW width is 125 feet.

Entergy decided this development effort would best be led by an outside consultant working with the Entergy team, who had the resources and experience that could investigate the various electrical and mechanical constraints such as audible noise and EMF fields at the edge of the ROW, insulation coordination, and optimal conductor selection to achieve the ampacity and impedance requirements. Structure configurations and framings that took into account live line working, structure erection, foundation costs, and optimal compaction would also need to be investigated. The Entergy team prepared a Request for Proposal identifying the required studies and deliverables and sent it to several of the major consulting firms that had the requisite experience. Bids were reviewed by the Entergy team and POWER Engineers, Inc. was selected to lead the effort.

The first step in the process was to develop a comprehensive "Design Criteria" specification defining the parameters that the new family of structures had to meet. Through several collaborative teleconferences between the Entergy team and POWER Engineers, a specification was developed. The specification included a number of specific Environmental, Electrical, Structural, Mechanical, and Line Layout criteria that the new design would be required to meet. The specification also defined the electrical studies that would be required and specified development of PLS-CADD™ structure modeling and Load Criteria files. The design criteria was used as a baseline for initial design efforts; although opportunities for revision of the criteria were explored if deemed important to the objective of a compact structure design.

3 DESIGN APPROACH

The term "compact design" has a variety of meanings and is often used in response to a specific set of situations requiring a structure design which is more compact than the current approach. To determine the requirements and parameters that impact this specific effort, the team qualitatively assigned priorities to common performance metrics and the design parameters that impact those metrics. This work was facilitated by a key consideration matrix similar to that shown in Table 1. An importance factor from 1 to 5 was assigned by each of the team members. Then a "consensus" number was agreed on and used in the evaluation matrix. The holistic review of parameters and relationships to performance measures allowed the team to qualitatively assign priority to performance measures while understanding which parameters would impact the performance. This matrix also allows a quick understanding of what other performance measures may be impacted by adjustment of a given parameter.

TABLE 1: KEY CONSIDERATION MATRIX																								
CATEGORY	CONDUCTOR CONFIGURATION						SW CONFIG			INSULATOR CONFIG				STRUCTURE CONFIGURATION					OTHER CONSIDERATIONS					
PARAMETER	TYPE	DIAMETER	ALUMINUM AREA	BUNDLE QUANTITY	BUNDLE SPACING	TENSION LIMITS	QUANTITY	SHIELDING ANGLE	TYPE/SIZE	INSULATOR TYPE	ARRANGEMENT	STRIKE DISTANCE	CREEPAGE	PHASE ARRANGE	PHASE SPACING	WORKING SPACE	MECH. LOADING	FOUNDATION TYPE	DESIGN SPAN	ROW WIDTH	GROUND CLR	VEGETATION MGMT	GROUNDING	OVERVOLTAGES
PERF. MEASURES	PARAMETER PERFORMANCE RELATIONSHIPS (X=PARAMETER IMPACTS MEASURE)																							
Capital Costs	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Operational Costs			X	X			X		X	X	X	X	X			X						X		
Resistive Losses			X	X																				
Corona Losses		X		X	X									X	X	X								
Induced Losses				X			X		X					X	X	X								
Audible Noise		X		X	X									X	X	X				X	X			X
Radio Interference		X		X	X									X	X	X				X	X			X
Electric Field				X	X									X	X	X					X			X
Magnetic Field														X	X	X					X			X
Conductor Ampacity			X	X																				
Surge Impedance		X		X	X						X	X	X	X	X	X								X
Lightning Performance							X	X				X		X	X	X							X	
Contamination Performance													X											
TOV Flashover Performance												X												X
Conductor Blowout	X					X					X	X		X	X	X			X	X				
Structure Height	X					X	X	X						X	X	X	X		X		X			
Aesthetics						X	X	X		X	X	X		X	X	X	X		X		X	X		X
Land Use						X	X	X						X	X	X	X	X	X		X	X		
Probability of Mechanical Failure		X															X	X						
Galloping Performance	X					X	X	X			X	X		X	X	X								
Vibration Performance	X					X													X					
Live-Line Maintenance										X														X

Following the qualitative assignment of importance to key performance measures, the team studied the related parameters as defined by the key consideration matrix. A parametric study was performed based on some assumed limits of application to highlight which of the related parameters had the greatest impact. This also supported an early understanding of ideal configurations for future consideration and eliminated some less than ideal configurations.

Based on the results of the parametric study, the important parameters were studied in more detail to determine their actual limits of application. The detailed study results allowed the development of configurations with varying levels of compactness. The numerous configurations were developed considering parameters ranging from Entergy’s standard approaches to the limits determined through the detailed analysis of those requirements. The advantages and disadvantages of the various configurations were then compared to support selection of the preferred configuration(s).

The final design step included the detailed design of the structures and creation of PLS-Pole™ models for implementation within Entergy's set of standards for use on future projects.

4 PARAMETERS AND COMPACTION LIMITS

The results of the qualitative analysis of the key consideration matrix highlighted some minimum, pass/fail type requirements for the desired performance. The parametric study determined which priority parameters should be studied in detail to determine limits of compaction. The following subsections of this paper describe the parametric study, detailed study of parameters and definition of constraints in more detail.

4.1 Parametric Study

The parametric study considered varying phase configurations, structure dimensions and conductor configurations. The study produced results for the predetermined key performance measures:

- Achievable span length as limited by conductor blowout and correlated ROW clearance requirements including vegetation buffers.
- Audible noise at the ROW edge.
- Electric field at the ROW edge.
- Magnetic field at the ROW edge.

4.1.1 Phase Configurations and Structure Dimensions

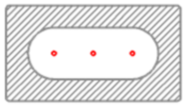
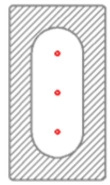
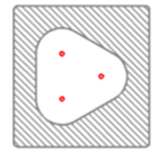
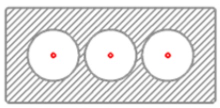
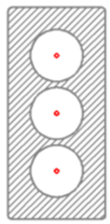
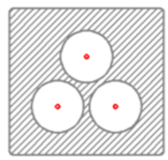
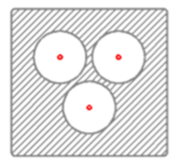
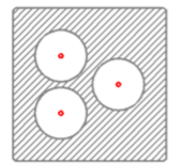
Based on a historical review of structure configurations, five generic phase configuration categories were defined:

- Horizontal
- Vertical
- Delta
- Inverted Delta
- Rotated Delta

For each configuration, there are a variety of options including whether the phases are separated by supporting structural elements or whether the insulation system is I-String or V-String. Furthermore, structure dimensions are determined by required spacing between phases and between each phase and structural elements. These spacing requirements will vary per the following:

- Required clearances based on switching transient overvoltage studies
- Insulation requirements resulting from insulation coordination studies
- Insulation arrangements including selection of V-string vs. I-string
- Line layout including span lengths and resulting impacts on galloping performance

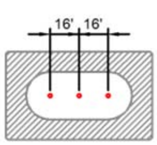
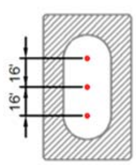
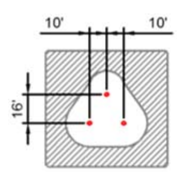
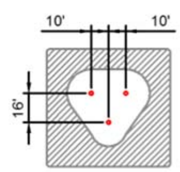
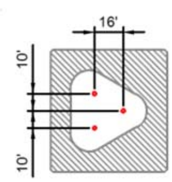
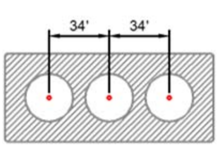
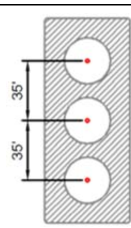
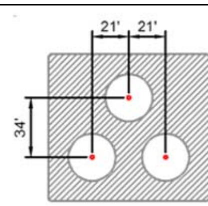
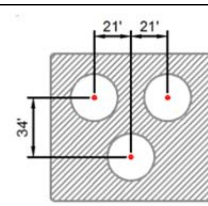
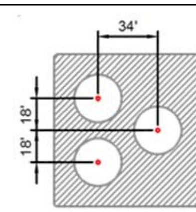
The possible arrangements considered are described in Table 2.

TABLE 2: PHASE CONFIGURATIONS					
	HORIZONTAL	VERTICAL	DELTA	INVERTED DELTA	ROTATED DELTA
PHASES NOT SEPARATED BY STRUCTURAL ELEMENTS					
PHASES SEPARATED BY STRUCTURAL ELEMENTS					

Notes:

1. The gray hatching describes regions reserved for structural supporting elements.
2. The red circle describes the phase bundle locations for the configuration.

The detailed studies required to define these parameters are not possible without a selected configuration. Therefore, the parametric study considered varying structure dimensions to support understanding of the impact of phase configuration and structure dimensions on the studied performance measures. The range of structure dimensions considered was intended to describe the possible arrangements. Five structure dimensional cases were considered for each phase configuration. The structure dimensional cases were assigned numeric descriptions, 1 being the most compact configuration considered and 5 being the least compact configuration considered. The structure dimensional ranges are described in the following table. Subsequent analysis indicated if the phasing configuration and structure dimension combinations were technically feasible or even necessary to achieve the project objectives.

TABLE 3: STRUCTURE DIMENSIONAL CASES					
	HORIZONTAL	VERTICAL	DELTA	INVERTED DELTA	ROTATED DELTA
CASE 1 MOST COMPACT					
CASE 5 LEAST COMPACT					

4.1.2 Conductor Configurations

Entergy's standard conductor configuration for 500 kV lines is 3 bundle, 954 kcmil, 45/7 "Rail" ACSR with an 18" bundle spacing, which supports a planning requirement of 3000 amps. To support a high level understanding of the conductor configuration impact on the key performance measures, the conductor diameter, bundle quantity and bundle spacing were varied while providing the 3000 amp requirement. As the conductor diameter increases, the audible noise from corona decreases. Also, as the conductor bundle spacing increases, the audible noise from corona increases. These relationships were used to guide the conductor configuration combinations selected. The conductor configurations considered included the following variations:

TABLE 4: CONDUCTOR CONFIGURATIONS										
BUNDLE QTY	CASE A		CASE B		CASE C		CASE D		CASE E	
	COND. DIA (IN)	BUND. SPAC. (IN)	COND. DIA (IN)	BUND. SPAC. (IN)	COND. DIA (IN)	BUND. SPAC. (IN)	COND. DIA (IN)	BUND. SPAC. (IN)	COND. DIA (IN)	BUND. SPAC. (IN)
3	0.8	22	1.0	20	1.165	18	1.4	16	1.6	14
4	0.8	22	1.0	20	1.165	18	1.4	16	1.6	14

4.1.3 Parametric Study Results

The parametric study included the following:

- Five phase configurations (Horizontal, Delta, Inverted Delta, Rotated Delta, Vertical)
- Five structure dimensional cases (1=Most Compact through 5=Least Compact)
- Two bundle quantities (3 or 4)
- Five conductor configurations (A through E as previously noted)

These noted parameter options result in 250 specific configurations studied.

The following graph describes the achievable span length as limited by the project blowout criteria for each phase configuration and structure dimension case. This analysis was only performed on a single conductor configuration, as conductor size and number of subconductors will have only a small influence on this performance measure. Conductors that have a different weight to diameter ratio will have slightly different rates of blowout.

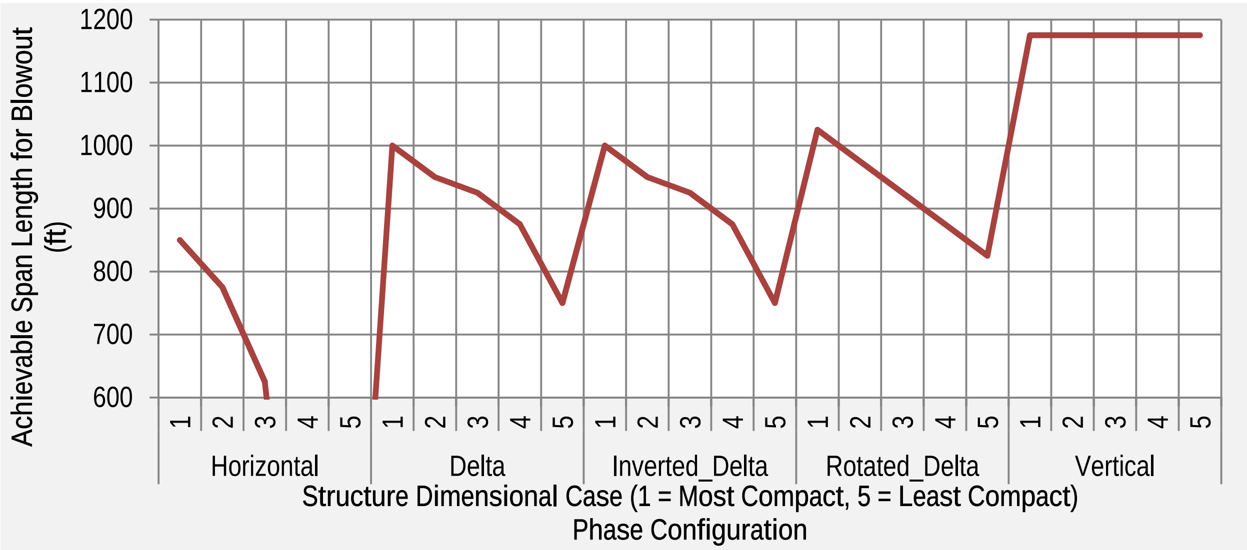


Figure 1: Achievable Span Lengths

The achievable span lengths vary from very small to approximately 1,200 ft for the studied configurations. For some dimensional cases, the Horizontal phase configuration couldn't achieve realistic span lengths. The Vertical phase configuration achieved the maximum achievable span length. The Delta, Inverted Delta and Rotated Delta configurations achieved very similar span lengths.

The following graph describes the achieved audible noise values at the edge of the ROW for each phase configuration, structure dimensional case and conductor configuration.

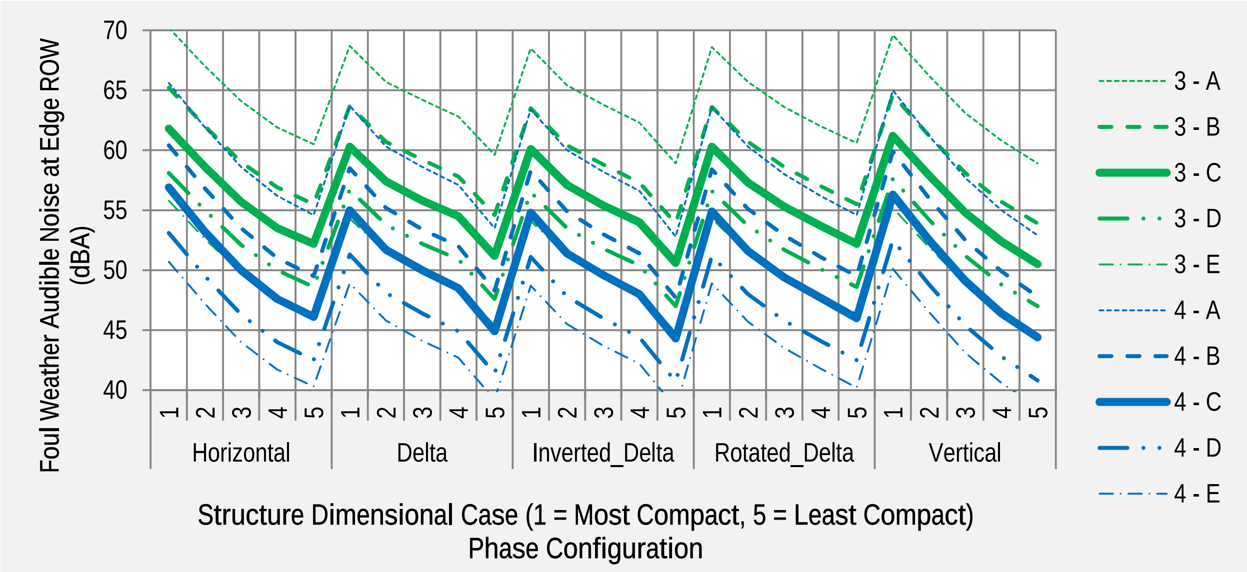


Figure 2: Audible Noise

As the structure dimensions decrease (more compact) the audible noise increases. Increasing the number of subconductors in a phase bundle from 3 to 4 reduced the audible noise value by approximately 5 dBA. Increasing the subconductor diameter reduced the audible noise value. Decreasing the bundle spacing also reduced the audible noise value, by a smaller amount.

Of the key performance measures studied, the audible noise and achievable span as limited by conductor blowout constituted the greatest challenges to the project. Other studied parameters that did not approach the selected limits are omitted from this paper. The approximate analysis contained within this study indicated that some of the studied structure and conductor configurations can achieve desired audible noise performance, while others may require some adjustment to comply. The achievable span length can be considered a cost indicator, with the larger achievable span lengths indicating the expected lower overall cost when applying the selected structure and conductor configurations to a line.

The Horizontal phase configuration results in the highest audible noise values and the smallest achievable span lengths, therefore the worst performer of the phase configurations considered. The three Delta type phase configurations all have very similar results. The Vertical phase configuration achieves the largest achievable span lengths with slightly higher audible noise values when compared to the Delta type configurations.

4.2 Detailed Study of Parameters and Compaction Limits

Based on the parametric study results, the following analyses were performed on some of the most feasible configurations:

- Transient Overvoltage Analysis
- Insulation Coordination Analysis
- Live-Line Working Distance Analysis
- Conductor Configuration Selection

The first three items listed involved the study of items that impact clearance requirements. These studies resulted in clearance requirements that define limits to compaction. The conductor configuration selection is described in more detail in the following subsection.

4.2.1 Compaction Limits

Minimum clearance requirements and insulation lengths determine limits to compaction. A reduction in required clearance or reduction in required insulation length can result in a more compact structure design.

Transient overvoltage values were determined considering parameters common to Entergy's system combined with the results of the parametric study. The transient overvoltage values were applied to the calculation of minimum approach distances and NESC minimum clearance requirements applying alternate clearance calculations. The efforts highlighted some opportunity to reduce clearance below those typically applied within Entergy's system.

The insulation coordination analysis considered lightning performance, switching surge performance and contamination. The analysis determined required insulation requirements to achieve the desired performance. The efforts highlighted some opportunity to reduce the required insulation values below those typically applied within Entergy's system.

The detailed study to define compaction limits generally supports reduction in values historically applied in Entergy's system. Reduction in such limits facilitates the development of a relatively compact structure. Although, there are some noted disadvantages to reduction in clearances including some expected reduction in performance, difficulties in live working and changes to standard insulation assemblies. The compaction limits were studied in detail to determine how compact the structure design could be; the need and efficiency of applying such limits was determined in subsequent design steps.

4.2.2 Conductor Configuration Selection

The conductor configuration study resulted in two possible conductor configurations. Selecting a single conductor configuration would have prematurely forced a required phase configuration, or structure configuration, to meet audible noise performance requirements prior to proper analysis of an optimal phase or structure configuration. The study was therefore focused on two primary configurations. The first conductor configuration was selected to meet the audible noise performance requirements when applied on the largest structure dimensional cases studied in the parametric study. A second conductor configuration was selected to meet the audible noise performance requirements when applied on the more compact structure dimensional cases.

Candidate conductor configurations were selected based on the aforementioned audible noise performance requirements which forces minimum conductor diameter and bundle quantities combined with the project ampacity requirements of 3,000 amps. Seven independent comparisons related to procurement costs and parameters which affect structure weights and line costs were performed on each of the candidate conductor configurations. The comparisons provided some level of understanding of the most cost effective conductor configuration, but it is difficult to determine the best possible choice based on independent review of options. To support a global comparison, the candidate configurations were assigned scores considering each parameter studied by the formula:

$$Score = \sum \frac{F_i \left(\frac{i_{candidate}}{i_{baseline}}\right)}{\sum F_i} ; Where\ i = parameters\ and\ F = importance\ factor$$

The total score for the baseline configuration is equal to one. The score of the other candidate configurations will vary from this baseline score by the ratio of their achieved values for each parameter considered to the value achieved by the baseline with some consideration for parameter importance by the assigned importance factors. The lowest achieved score is considered the best conductor configuration. Three bundle, 954 kcmil, 45/7 "Rail" ACSR was selected as the baseline configuration. The following figure describes the scores achieved by each candidate configuration. The value of the importance factors for each parameter is highlighted by the height of that parameter in the figure. The lowest scoring conductor configurations correlate to the best options.

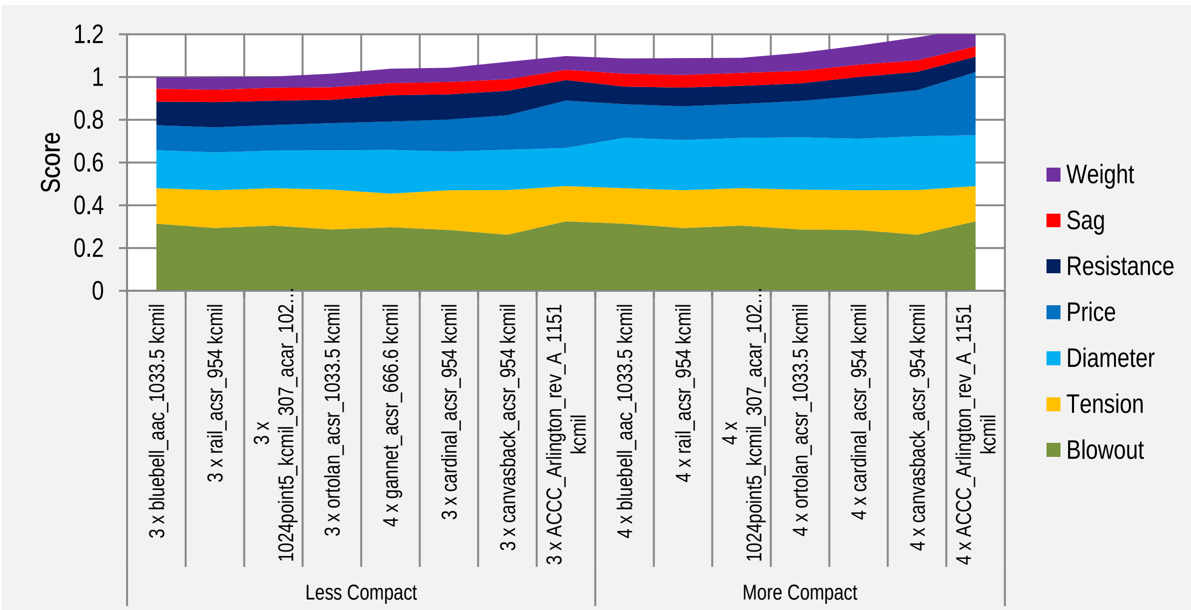


Figure 3: Candidate Conductor Overall Score Composition Comparison

The top scoring conductor configurations for the less compact design were the 3 bundle, 954 kcmil, 45/7 "Rail" ACSR and the 3 bundle 1,033 kcmil, "Bluebell" AAC. The top scoring conductor configurations for the more compact design involved the same two conductors in a 4 bundle configuration. In addition to these studied parameters, the "Rail" ACSR conductor has the additional advantage of being Entergy's current standard conductor. Use of an existing standard facilitates the use of existing conductor and related hardware with benefits in storage of replacement items and emergency restoration. For these reasons, the 954 kcmil, 45/7 "Rail" ACSR conductor in a three bundle configuration was selected for future study of less compact structure configurations and a four bundle configuration of the same conductor was selected for future study of more compact structure configurations.

5 STRUCTURE CONFIGURATIONS

Possible structure configurations were compared to facilitate the selection of a preferred configuration. The approach to the comparisons included the development of candidate structure configurations based on previously studied constraints, followed by the selection of a short-list of structure configurations for in depth comparison. The selection of a short-list of structure configurations was supported by a design team review of candidate options considering industry experience and performance measures that were important to the project objectives. Short-list structure configurations were modeled within PLS-Pole™ to develop approximate cost estimates to support comparison of each configuration.

Structure configurations are constrained by Entergy standard criteria and design practices. The aforementioned detailed analysis of parameters defined some possible reduction in constraints. A reduction in a constraint can take several forms. For example, the need to accommodate live-line work can be eliminated from consideration for some structure configurations. Another example includes the reduction of required clearances or insulation strength by application of a studied transient overvoltage (TOV). Reduced constraints are expected to have compaction and possible cost advantages. The disadvantage of reducing constraints comes in the form of deviation from standard approaches or reduction in performance. The advantages and disadvantages of constraint reduction were studied for the short-list of structure configurations.

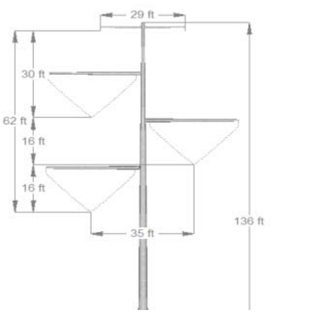
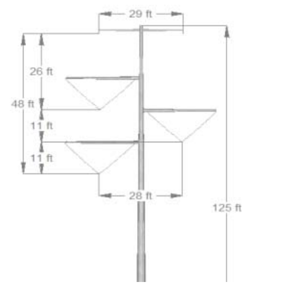
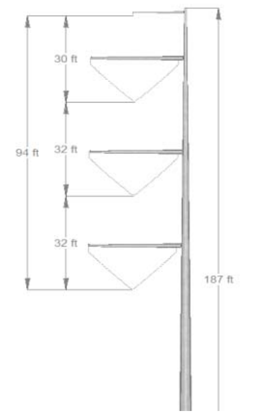
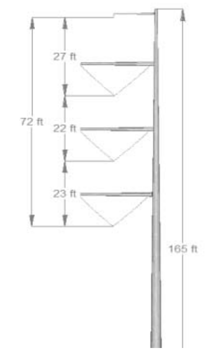
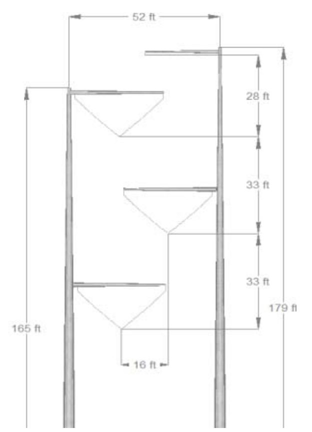
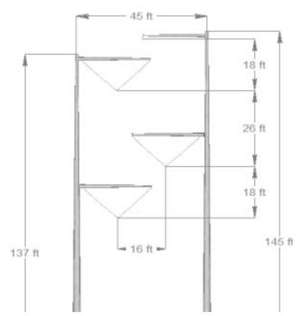
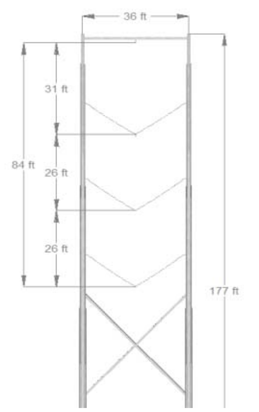
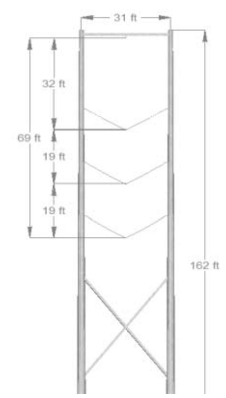
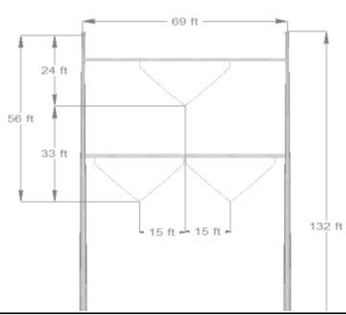
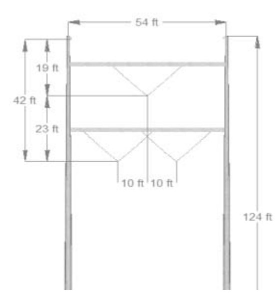
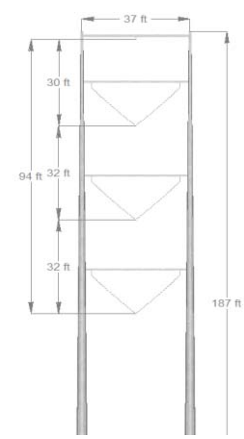
Short-list configuration selection was guided by the following considerations:

- The parametric study indicated that the vertical phase configuration options would provide the best opportunity for relatively longer design spans as limited by conductor blowout and ROW width given their narrow phase spacing in the horizontal plane. This opportunity for longer spans is expected to achieve lower overall costs. For this reason, preference was given to vertical configurations.
- Two pole structures are expected to have lower overall foundation costs given that there will be two foundations in lieu of a single large foundation. Therefore, a general preference was given to two pole structure configurations.
- For the sake of comparison and validation of the noted preferences, some configurations which do not consider the general preferences are included for further study.

The short-list structure configurations were developed within PLS-CADD™ and PLS-Pole™ to support an in depth comparison. The results of this comparison were provided in a Structure Configuration Scorecard. The Scorecard considered numerous components in the following categories for each structure configuration:

- Configuration Parameters and Analysis Results
- Qualitative Comparison
- Estimated Cost Comparison

The following table describes the short-list configurations studied.

TABLE 5: STRUCTURE CONFIGURATIONS			
			
Rotated Delta, One-Pole, Standard Spacing	Rotated Delta, One-Pole, Compact Spacing	Vertical, One-Pole, Standard Spacing	Vertical, One-Pole, Compact Spacing
			
Rotated Delta, Two-Pole, Standard Spacing	Rotated Delta, Two-Pole, Compact Spacing	Vertical, Two-Pole, Standard Spacing	Vertical, Two-Pole, Compact Spacing
			
Delta, Two-Pole, Standard Spacing	Delta, Two-Pole, Compact Spacing	Vertical, Two-Pole W/Arms, Standard Spacing	

The following table summarizes the key scorecard results.

TABLE 6: STRUCTURE CONFIGURATION SCORECARD												
COMPONENT	UNIT	STRUCTURE CONFIGURATIONS										
		Rotated Delta, One Pole Compact Spacing	Vertical, One Pole Standard Spacing	Vertical, Two Pole Braced Standard Spacing	Rotated Delta, One Pole Standard Spacing	Vertical, One Pole Compact Spacing	Rotated Delta, Two Pole Compact Spacing	Vertical, Two Pole Braced Compact Spacing	Vertical, Two Pole w/Arms Standard Spacing	Delta, Two Pole Standard Spacing	Rotated Delta, Two Pole Standard Spacing	Delta, Two Pole Compact Spacing
CONFIGURATION PARAMETERS AND ANALYSIS RESULTS												
Achievable Span Length	Ft	875	1150	1150	825	1150	1000	1150	1150	875	1000	1000
Estimated Structure Weight	Lb/str	16870	34074	33533	20082	30569	32050	34320	46216	27981	41217	28822
Estimated Structure Height	Ft	125	187	177	136	165	157	162	187	132	178	124
Number of Subconductors	Qty	3	3	3	3	4	3	4	3	3	3	4
Number of Shield Wires	Qty	2	1	1	2	1	1	1	1	2	1	2
Number of Foundations	Qty/str	1	1	2	1	1	2	2	2	2	2	2
Standard Insulator Assy	Pass/Fail	Fail	Pass	Pass	Pass	Fail	Fail	Fail	Pass	Pass	Pass	Fail
Standard Insulators	Pass/Fail	Fail	Pass	Pass	Pass	Fail	Fail	Fail	Pass	Pass	Pass	Fail
Live-Line Maint.	Pass/Fail	Fail	Pass	Pass	Pass	Fail	Fail	Fail	Pass	Pass	Pass	Fail
Surge Impedance Loading	MVA	1100	1000	1075	1025	1175	1050	1250	1000	1050	950	1175
QUALITATIVE COMPARISON												
Lightning Flashover Performance	1 = Best 5 = Worst	3	4	3	1	5	4	5	4	1	4	3
Switching Surge Performance		5	1	1	1	5	5	5	1	1	1	5
Galloping Performance		2	3	4	1	4	3	5	3	1	2	2
Aesthetics		3	4	2	4	3	4	1	3	3	5	2
Design Flexibility		3	5	5	3	5	1	5	5	3	1	3
Structure Family Considerations		3	5	5	3	5	4	5	5	3	4	3
Structure Constructability		1	4	5	1	3	2	4	5	3	4	3
Foundation Constructability		2	5	3	3	5	2	3	4	3	3	3
Wire Constructability		1	1	5	1	1	2	5	5	3	2	3
Line Restoration		1	1	5	1	1	2	5	5	3	2	3
Line Maintenance		1	1	5	1	1	2	5	5	3	2	3
ESTIMATED COST COMPARISON PER MILE												
Cost Comparison	% of Baseline	100%	104%	106%	108%	115%	121%	122%	126%	126%	131%	134%

The configuration parameters and analysis results category described the constraints used to develop each structure configuration and the results of the PLS-CADD™ and PLS-Pole™ Modeling. The maximum allowable span length as limited by conductor blowout and ROW edge clearances was determined within PLS-CADD™ for each structure configuration and used as the design span for that configuration. This approach of applying the maximum allowable span as the design span reflects the notion that the optimal design span for each configuration is the maximum span allowed by this criterion. However, it is noted that the cost savings correlated to maximizing span lengths is not always realized given the number of constraints that can disallow long spans in a given corridor such as vegetation, line angles, and pinch points in the ROW. Structure heights were selected to support the required ground clearances in the design span assuming flat terrain. The structural steel members were optimized within PLS-Pole™ for the design span and required structure height. The resulting PLS-Pole™ models were used to estimate steel weights and ground line reactions.

In addition to the noted quantitative comparison, a qualitative comparison described the relative performance of each configuration in performance measures which are not easily quantified. The last comparison item included a cost comparison between each of the options on a per mile cost basis.

6 CONCLUSION

The estimated cost comparisons were only intended to consider costs that vary with each structure configuration and did not consider overheads, access constraints, ROW, mobilization or demobilization costs. The estimated costs were only expected to be relatively accurate for the sake of comparison. The costs were based on information provided by Entergy and POWER's experience.

The estimated cost comparison results indicated costs varying by approximately 30% between the structure configurations considered. The vertical configurations provided the largest allowable span length; but achieving these longer spans required taller and heavier structures at each structure location. In most cases, the compact versions were more expensive solutions than the standard configurations; this was a result of the compact options requiring 4 subconductors per bundle in lieu of the 3 subconductors per bundle applied to the standard configurations. The least expensive configuration was the rotated delta, single pole structure with compact spacing. This configuration is a relatively compact version of the rotated delta, single pole structure; but not so compact that it requires the four subconductors per bundle to achieve the desired audible noise performance.

The four lowest cost solutions varied in cost by less than 10% and included the following configurations:

- Rotated Delta, One-Pole, Compact Spacing
- Vertical, One-Pole, Standard Spacing
- Vertical, Two-Pole, Standard Spacing
- Rotated Delta, One-Pole, Standard Spacing

The differences in estimated costs are well within the expected accuracy of the economic analysis. Therefore, the choice of a preferred structure configuration was not based purely on economics. In addition to the consideration of costs, the selection of the preferred structure configuration considered the application of Entergy standard conductor configuration and insulator assemblies. The selection also considered constructability and maintenance. Some of these components have related costs which were not reflected in the cost comparison. Additionally, these qualitative advantages can be significant to implementation and feasibility of any configuration.

The analysis led to the conclusion that one structure configuration will not necessarily meet all of the situations and criteria that the designers/engineers may face on upcoming 500 kV projects. In other words, "one size does not fit all". To best address the challenges anticipated, the recommended best approach was to select a primary structure configuration in combination with a secondary or complementary configuration that can be used individually or in combinations to address a wide variety of likely design situations.

Based on this analysis, the selected primary structure configuration was the rotated delta, one-pole with standard spacing, which can be seen in Figure 4A. This structure configuration included the following important advantages:

- Top third in lowest relative cost
- Applies Entergy standard 3-bundle conductor configuration
- Applies Entergy standard insulator assembly
- Top tier in terms of constructability, line restoration and maintenance

Additionally, the selected complementary configuration was the vertical, two-pole with standard spacing, Figure 4B. These two structure configurations can be used individually or in combinations to address specific design challenges, including very poor soil conditions, narrower (pinch points) ROW, longer or shorter span requirements, structure height considerations, differing load zones, constructability issues, etc. all while meeting the criteria established.

Figure 4A: Recommended Primary Configuration Rotated Delta, One-Pole, Standard Spacing

Figure 4B: Recommended Secondary Configuration Vertical, Two-Pole, Standard Spacing

The final design steps included the completion of tasks that facilitate the use of the structures within Entergy's system. This included the finalization and development of structure drawings, PLS-Pole^{TM} models and cost estimates. Additionally, a compact structure application design guide was developed to aid designers with the application of the structures in projects.

Performance and Pitfalls of Lattice Steel and Monopole Tower Material Source Inspections

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***Abstract* - In the current competitive environment that all utilities need to operate under, it is imperative that all phases of a structure's fabrication be closely monitored to ensure that a high quality product is delivered to the utility. Review of the material test reports and charpy testing of the steel profiles are required to ensure that a quality steel product is provided to the structure fabricator. This will ensure the long term material life of the structure. The structure fabrication and galvanizing processes need to be monitored to ensure that all piece parts are fabricated in accordance with the design drawings, specifications and galvanized properly. The bundling and shipping process needs to be monitored to ensure that the piece parts are bundled correctly in accordance with the design drawings and delivered to the jobsite.**

Transmission structures are the backbone of America's electrical transmission system. Deterioration of these structures could result in costly repairs, structural failure, loss of power, and loss of revenue. Fabrication issues could limit the life of these structures if deficiencies and non-conforming conditions introduce corrosion and localized cracking prematurely into the structural components. It is imperative that an effective inspection plan is put in place during manufacturing to ensure that quality products are delivered to the utility.

This paper will explore the structure fabrication pitfalls which were found during Southern California Edison's (SCE) Tehachapi Renewable Transmission Project (TRTP). It will discuss the inspection process and measures that were put into place to remedy these pitfalls and ensure that a high quality product was delivered to SCE. It will provide recommendations on the key items which should be monitored closely during the structure fabrication process.

I. MATERIAL SOURCE INSPECTION

Material Source Inspection is the process of inspecting materials for quality, quantity and adherence to client specifications. The ultimate goal of any source inspection program is to identify errors in quality or quantity early on at the fabricator's location as opposed to discovering an error after receipt at the project site which could result in construction delays and added costs.

The benefits of a source inspection program are as follows:

- Insure all parties clearly understand the “order requirements” before start of fabrication.
- Verify the fabricator's intentions to meet the order requirements before the start of fabrication
- Verify that the fabricator's quality control, inspection and test capabilities match the need for the project.
- Resolve discrepancies and deviations from the material specifications during fabrication and before shipment
- Provide independent determination of product conformity/nonconformity.
- Provide independent observations of all welding activities for conformance to AWS D1.1 Structural Welding Code.
- Insure that the customer receives a quality product meeting all expectations
- Minimize project risks and maximize profitability (cost savings)
- Provide suggestions for improvements in the fabricator’s program, and business performance
- Improve overall quality of fabricator’s finished products and materials

The process of performing source inspections mirrors the production life cycle of a product – starting with design, through fabrication and ending with shipment. The performance of inspections along the entire life of the project ensures that all production steps are examined and issues resolved during fabrication such that ultimately there are “no surprises” in the end. There are three basic steps which must be taken to ensure an effective source inspection program. These steps are:

1. Develop and create a source inspection plan that includes procedures, checklists, forms, and training programs.
2. Screen and qualify Project Inspectors to perform the detailed inspections. The selection of the Inspectors should be based on technical skills and proximity to the fabricators.
3. Effective program management and technical support utilizing online tools for real-time access to schedules, status, results, and reports.

II. TRTP PROJECT BACKGROUND

Southern California Edison’s Tehachapi Renewable Transmission Project, Segments 4-11 is a series of new and upgraded transmission facilities from 69 kV to 500 kV spanning a project area of approximately 173 square miles with a cost of approximately $2.7 billion (Figure 1). The project is designed to deliver electricity from renewable wind energy generators in Kern County south through Los Angeles County and east to the existing Mira Loma Substation in Ontario, San Bernardino County. The project integrates levels of renewable energy generated in the Tehachapi Wind Resource Area in excess of 700 megawatts (MW) and up to approximately 4,500 MW.

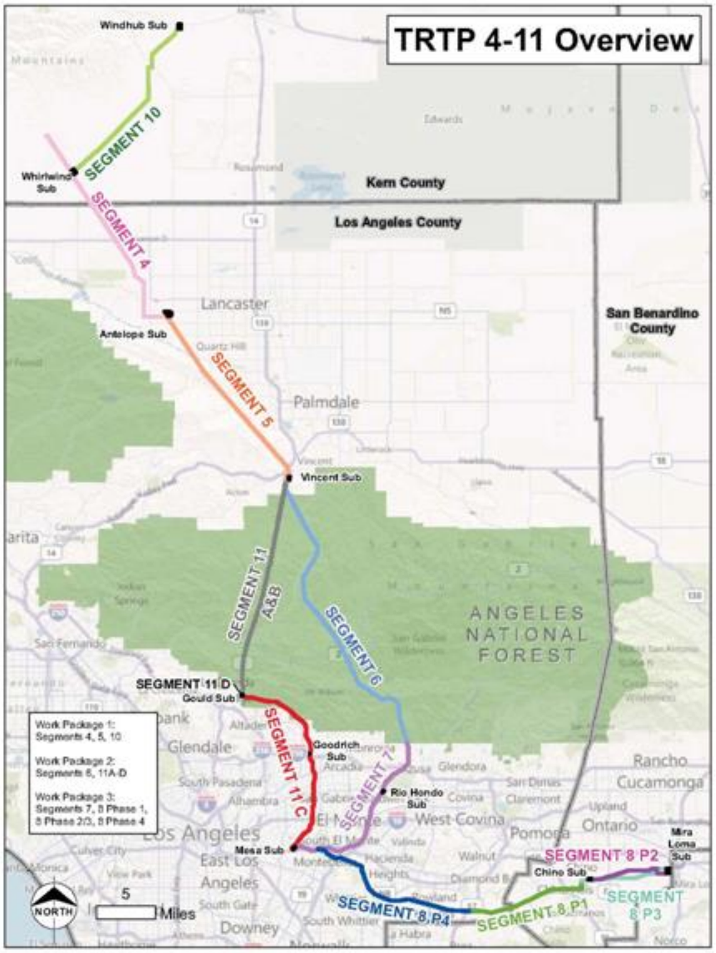

Figure 1 – TRTP Segments 4-11 Project Map

The following are quantities of transmission structures which were procured for the project:

- 662 Lattice Steel Towers - (398 - 500kV single circuit towers, 187 - 500kV double circuit towers, 8 - 220kV single circuit towers and 69 - 220kV double circuit towers) – 58.8 million pounds of steel
- 96 Tubular Steel Poles – 9 million pounds of steel

Fabricator	Location	Material Provided
SAE Towers	Monterrey, Mexico	Lattice Steel Tower
Formet	Monterrey Mexico	Lattice Steel Tower
Comemsa	Queretaro, Mexico	Lattice Steel Tower
Sisttemex	Queretaro, Mexico	Lattice Steel Tower
Valmont	US Locations (8) , China & Mexico	Tubular Steel Poles

As one of the largest transmission line projects in the country and with strict in-service dates, it was imperative that all materials received were produced in accordance with SCE specifications. Early in the project it became evident that some of the fabricators' internal QA/QC programs were not as robust as SCE's. As a result, SCE contracted with Bureau Veritas (BV) to embed inspectors at the fabricators' facilities to provide constant monitoring during the fabrication process. Many issues were discovered by the inspectors at the various fabricator locations. These issues needed to be resolved as quickly as possible to ensure that quality materials were delivered on time.

In the subsequent sections of this paper, the pitfalls and issues which were identified in the fabrication of the lattice steel towers and the tubular steel poles will be discussed. From these issues, process and performance improvement recommendations will be made. These recommendations can serve as a basis for future source inspection programs on future projects.

III. LATTICE TOWER FABRICATION PITFALLS

Four fabricators were used to supply lattice steel towers for the TRTP project. All of the fabricators were located in Mexico. During the course of performing inspections at the lattice tower fabricators' facilities, BV inspectors identified many pitfalls and issues in the fabrication of the lattice towers. While seemingly minor, many of these issues needed to be resolved quickly to ensure that any potential delays were minimized in the fabrication and delivery of the lattice towers. The pitfalls which were identified are as follows:

- Drawings
    - Different revisions of the same tower drawings were used by the fabricators and the utility.
    - Utility approval of proposed fabricator modifications to the towers took much longer than expected.

- Raw Materials
    - Late delivery of materials caused delays in production.
    - Materials that did not meet the grade, chemical, physical and strength requirements needed to be replaced.
    - Repair of long lead materials (large angle profiles) damaged during production caused production delays and additional cost.

- Fabrication
    - Heavy shop load caused production delays.
    - Ensure that the shop has significant equipment and space to process the work, (material storage, lay down space for prototypes, stacking and bundling of completed parts).
    - Ensure the shop has sufficient experienced staff to handle workflow. Inexperienced personnel may lead to rejection of parts by the inspectors requiring re-manufacturing.
    - Proper machinery is needed to process the material, (machine size, bending, capacity, etc.).

- Use of sub-suppliers and their respective workloads may cause delays if their workloads are heavy.
- Quality of sub-supplier material and parts needs to be in accordance to the project specifications.
- Contract and labor disputes with shop personnel can affect on-time delivery.
- The fabricator/sub-supplier’s QC staff must be sufficient in number and trained to know the requirements of each order.
- Maintenance of equipment used for fabrication is a critical factor. Machine break downs may cause delays in delivery. Dulled tooling causes additional fabrication time and rejection of parts not meeting dimensional requirements.
- Monitoring of set up and welding processes is necessary to ensure requirements are met.
- Segregation of rejected pieces is necessary to ensure they are not shipped to the client.
- Camber of long piece parts needs to be checked prior to galvanizing.
- Proper lighting is needed to ensure inspection quality.

- Galvanizing
  - Proper ventilation is needed to ensure worker safety.
  - Tank arrangement needs to be reviewed to ensure a smooth flow of the galvanizing process and eliminate the potential for contamination of the tanks.
  - Process control sheets need to be used to ensure that correct tank chemistries, dip times, and temperatures are being used to optimize the process and ensure that the proper galvanized thickness is achieved.
  - Constant monitoring of tank cleanliness is needed to ensure acceptability of finished parts.
  - Experienced personnel must be utilized that understand the process and the final results required.
  - Experienced quality personnel are needed to inspect the galvanized product and bring any anomalies to the facility for correction.
  - Camber of long piece parts needs to be checked after galvanizing.
  - Sufficient space is needed to layout/move parts for inspection.
  - Proper lighting is needed in order to find discrepancies.

- Dulling
  - For TRTP there were three colors of gray approved by the architect for this project, light, medium and dark. This was achieved through chemical dipping.
  - Ensure the dulling process is achievable for each color variation.
  - Ensure chemicals are available and can be delivered in time to the fabricator.
  - The fabricator has to be experienced in the dulling process to achieve each color level consistently.
  - Visual monitoring of the color along with an acceptability range is necessary to meet dulling requirements. A reflectometer along with visual comparators were used to gauge the color variations and compared to the accepted range to ensure compliance.
  - Proper lighting is required.

- Prototype Inspection
  - Protoype inspection of a newly designed tower is critical to ensure proper fit and confirm drawings are correct.
  - Due to the terrain where towers were installed helicopters were used to fly in towers by section. Proper fit is critical for all helicopter assembled towers due to the expense of installation.

- Bundling
  - A bundling plan is necessary to ensure that proper geometry, dunnage, wiring, and crating is established.
  - Proper space is needed in order to bundle and store all materials prior to shipment.
  - Bundles must be wired sufficiently to ensure no pieces are lost during shipment.
  - Tagging must be correct and readable. Tags and markers must not fade due to environmental exposure during storage at material yard.
  - Labels must be affixed properly to ensure they are not lost during shipment.
  - Spacers must be used to promote air flow and decrease the probability of white rust formation.
  - Spaces in crates must be checked to prevent pest invasion.
  - Forklifts must be protected to decrease handing damage during moving and loading of bundles for shipment.
  - Packing list and shipping documents must be complete in order to ensure that the proper material is shipped and received.
  - For international fabricators, Customs delays must be accounted for to prevent delays in delivery.

IV. LATTICE TOWER FABRICATION PERFORMANCE IMPROVEMENT

At the conclusion of the lattice tower fabrication, the project team at SCE and BV reviewed the list of pitfalls and developed recommendations which would result in process and performance improvements. These recommendations should be considered on future projects and should be included on source inspection plans. If the utility works with the fabricator to incorporate these recommendations, the fabrication and inspection process should be improved. These process improvements are as follows.

1) **Structure Drawings** – The latest revisions of all lattice tower structure drawings developed by the utility should be used. Drawing verification needs to be performed to ensure that the fabricator, the inspectors and the utility are all using the same drawing revisions. The review and approval of any drawing between the utility and fabricator needs to be done in a timely manner. Delays in drawing approvals may impact the fabricator's production schedule which may delay the delivery of the materials.

2) **Steel** – The fabricator should provide the utility with the source of the steel to be used and the material properties of the steel. To minimize any potential embrittlement issues, the material should be charpy tested to ensure material ductility. For materials whose thickness

is greater than 0.5", holes need to be drilled and cuts need to be saw cut. To minimize any galvanizing issues and to ensure a long term dull gray finish, the silicon and phosphorous content of the steel should be between the following ranges: silicon + phosphorus content <0.03% or between 0.15% and 0.22%. If the materials need to be dulled, the material surfaces should be treated with zinc phosphates. The materials should not be exposed to any hydrochloric acid prior to service. The use of hydrochloric acid for dulling could lead to the formation of iron oxides on the surface of the members giving the members a reddish appearance.

3) **Sub-Suppliers** – The fabricator has the option of utilizing sub-suppliers to assist in the fabrication of the materials. The sub-suppliers need to be qualified by the utility and they need to follow the identical quality control standards being followed by the fabricator. Inspections should be performed at the sub-supplier's facilities.

Figure 2 - An inspector checks bolt hole diameters.

4) **Bolt Holes** – Bolt holes should be checked to ensure that they are drilled or punched to the correct size and in the proper locations within the acceptable tolerance levels. Go/no-go gauges should be used to check the hole diameters (Figure 2). The holes should be checked to verify that they are cylindrical and perpendicular to the surface of the material. If the holes are consistently smaller than the allowable tolerance levels, the drill bits or punch dies should be checked for wear and replaced.

5) **Welding** – Any welding which needs to be performed should be done by a certified welder. All welds need to be UT tested and checked to verify quality.

6) **Prototype Model** – If the fabricator is fabricating a particular structure design for the first time; the assembly of a prototype model needs to be performed (Figure 3). The prototype assembly will find and resolve issues and conflicts not found in the design drawings. Prototype assembly can be performed in either black steel condition or in a galvanized condition. All bolts should be used in the assembly. The prototype model can be assembled in the horizontal position. Representatives from the fabricator, the utility and the

Figure 3 - Prototype assembly.

inspector shall review the prototype model and note all issues and corrections which need to be made. A fit-up report shall be created by the fabricator and formally submitted to the utility for review and resolution. Once the prototyping has been completed and approved, the piece marks can be input into CNC machines. No further prototyping of that particular tower design need be performed.

7) **Bundling** – Inspection during the bundling process is critically important as all pieces need to be in the correct bundles to minimize any problems in the field during the structure erection process. The inspectors need to verify with the fabricator's representative that the correct pieces are in the proper bundles. Spacers need to be placed between members to minimize the possibility of white rust formation. The bundle needs to be strapped together in a manner to ensure that the bundle will stay together during transit to the project site. Proper tags and id labeling need to be affixed to the bundles. Any tags and labeling need to be durable to remain in place and legible during shipping and storage at the material yards.

8) **Preparation for Shipment** - Care should be exercised during the handling and shipment of the bundles to minimize damage to the bundles and pieces within the bundle. Bundles shall be secured to ensure that the vibrations during transit will not cause bundles to contact each other (Figure 4). Dunnage should be used where necessary to help secure and separate bundles during transit.

9) **Shipping** – Shipping of the completed materials from international fabricators can be challenging due to governmental regulations of materials entering the US. Prior to the shipment of material, the fabricator should provide the utility with the procedures for shipping the material as well as the process to meet US Customs requirements. In some instances the maximum loads of trucks within a foreign country may be different from that of the US. Should the fabricator choose to maximize the truck loads within the foreign country, the materials will need to be handled and redistributed prior to entering the US. Inspections at these redistribution locations may be required to ensure that the materials are not damaged and all required documents are in order to cross the border.

Figure 4 - Bundles ready for shipment.

V. TUBULAR STEEL POLE FABRICATION PITFALLS

One fabricator was selected to supply tubular steel poles for the TRTP project. The supplier was located in the USA, however, fabrication of the poles and cross arms occurred in the USA, Mexico and China. Similar to what was done at the lattice tower fabricators' facilities, BV inspectors identified many pitfalls and issues in the fabrication of the tubular steel poles. Many of the same pitfalls which were experienced with the lattice tower fabrication were also experienced in the fabrication of the tubular steel poles. While seemingly minor, many of these issues needed to be resolved quickly to ensure that any potential delays were minimized in the fabrication and delivery of the lattice towers. The pitfalls which were identified are as follows:

- Drawings
  - The length of time needed for drawing submittal, review and approval are key to maintaining the delivery schedule.
  - Correctness of drawings. If a drawing is incorrect, parts which are fabricated to that drawing and will need to be repaired or replaced at some point in the fabrication process and may contribute to delays in delivery.
  - Locations of steps, tie offs need to be reviewed to ensure they do not conflict with the longitudinal weld of the poles.

- Raw Materials
  - Delivery of materials. Late delivery causes delays in production.
  - Materials that do not meet the grade, chemical, physical and strength requirements needed to be replaced thus causing delays.
  - Repair of long lead materials resulted in production delays and additional cost.

- Fabrication
  - Heavy shop load may cause production delays.
  - Ensure that the shop has significant equipment and space to process the work, (raw material storage, lay down space, and storage of completed parts).
  - Ensure the shop has sufficient experienced staff to handle workflow. Inexperienced personnel may lead to rejection of parts and remanufacturing.
  - Proper machinery is needed to process the material, (machine size, bending, capacity, etc.).
  - Contract and labor disputes with shop personnel can affect on time delivery.
  - The fabricator's QC staff must be sufficient in number and trained to know the requirements of each order.
  - Maintenance of equipment used for fabrication is a critical factor. Machine break downs may cause delays in delivery. Dulled tooling causes additional fabrication time and rejection of parts not meeting dimensional requirements.
  - Sufficient space is needed to lay out the pole sections and inspect prior to proceeding to the next process.
  - Monitoring of set up and welding processes is necessary to ensure requirements are met.
  - Proper lighting is needed.

- Galvanizing
  - Proper ventilation is needed to ensure safety.

- Process control sheets need to be used to ensure that the correct chemistries, dip times, and temperatures are being used to optimize the process and ensure the proper galvanizing thickness is reached.
- Constant monitoring of tank cleanliness is needed to ensure acceptability of finished parts.
- Experienced personnel must be utilized that understand the process and the final results required.
- Experienced quality personnel are needed to inspect the galvanized product and bring any anomalies to the facility for correction.
- Sufficient space is needed to layout/move pole sections for inspection.
- Sufficient labor/machines are needed to move pole sections for 100% visual inspection to be performed.
- Proper lighting is needed in order to find discrepancies.

- Dulling
  - Ensure the dulling process is achievable for each color variation.
  - Ensure chemicals are available and can be delivered in time to the fabricator.
  - The fabricator has to be experienced in the dulling process to achieve each color level.
  - Visual monitoring of the color along with an acceptability range is necessary to meet dulling requirements. A reflectometer along with visual comparators were used to gauge the color variations and compared to the accepted range to ensure compliance.
  - Proper lighting is required to inspect dull surfaces.

- Shipment
  - Proper space is needed to store all materials prior to shipment.
  - Pole ID tags must be correct and readable.
  - Shipping labels must be affixed properly to ensure they are not lost during shipment.
  - Forklifts must be protected to decrease handing damage during moving and loading of pole sections for shipment.
  - Packing list and shipping documents must be complete in order to ensure that the proper material is shipped and received.

VI. TUBULAR STEEL POLE FABRICATION PERFORMANCE IMPROVEMENT

Similar to what was done for the lattice towers, at the conclusion of the tubular steel pole fabrication, the project team at SCE and BV reviewed the list of pitfalls and developed recommendations which would result in process and performance improvements. These recommendations should be considered on future projects and should be included on source inspection plans. If the utility works with the fabricator to incorporate these recommendations, the fabrication and inspection process should be improved which will result in a quality product. These process improvements are as follows.

1) **Materials** - All materials shall meet the ASTM standards in accordance with the utility's specifications. For coil materials (Figure 5), mechanical testing needs to be performed after de-coiling and leveling as per ASTM A6. It is recommended that all materials be tested in an independent lab to verify the accuracy of Material Test Report (MTR) from the material suppliers.

Figure 5 – Steel coils.

2) **Base/Flange Plates** - All thick materials such as base plates or flanges plates should be thoroughly inspected for any surface defects (visual) as well as any laminar defects (by ultrasonic methods). Thick plates need to be cleaned of mill scale and other potential contaminants by grinding or blast cleaning prior to being welded to the pole shaft.

3) **QA/QC Manual -** It is important to review the fabricator's QA/QC manual. This manual details the fabricator's QA/QC process and procedures. The inspectors should use this as a guide as they perform the material source inspections.

4) **Weld Procedures Specifications (WPS), Procedure Qualification Record (PQR) and Welder Performance Qualification Records (WPQR's)** - All weld procedures must be qualified in accordance with the requirements of AWS D1.1 and need to be on hand and available for use by the welders and inspectors. Procedure Qualification Records (PQR's), if required should be made available for review, when requested. All welders also need to be certified in accordance with the requirements of AWS D1.1. Critical Pre-heating and interpass temperatures should be determined per the requirements of AWS D1.1 and properly communicated to all welders.

5) **Dimensional Check** – Dimensional checks should be performed to verify that the fabricated sections are in accordance with the customer approved fabrication drawings.

6) **UT Inspection** - All welds should be UT tested to ensure full penetration (Figure 6).

7) **Fittings** - All critical connections, including random slip joints, should be test fit at the fabricator's facility to ensure proper fit up in accordance to established tolerance limits.

Figure 6 – UT testing of base plate weld.

8) **Galvanizing Venting and Drainage Holes** - The cut out holes for galvanizing venting and drainage shall be in accordance with the recommended American Galvanizers Associations (AGA) guidelines.

9) **Process Travelers** - Fabricators should maintain a record of process at each work station through a proven process tracking traveler system. This report should be available to customers in case back tracking is required.

10) **Post Inspections** – For poles which have a galvanized finish, the galvanized coating should be thoroughly inspected per ASTM A123 (Figure 7). All welds for base plate and flange plate should also be tested with UT for Post Galvanizing Toe Cracks.

Figure 7 – Galvanized coating thickness check.

11) **Warranty** - Customers should request that the fabricators provide a warranty certification or a certificate of compliance for finished products.

VII. CONCLUSION

On a fast tracked project, there is no allowance for defective materials which will require remediation or re-fabrication. A robust and well managed source inspection program is necessary to ensure that the materials produced are of high quality. The source inspection approach provides an added confidence level that the material received is in accordance with a utility's specifications, and most important of all, it fits. Through source inspection, material deficiencies are identified early, prior to shipment, and resolved at the fabricators' facilities. The proactive approach of inspecting at the source and curbing any problems at the fabricator's facility before the material ever reaches the jobsite pays dividends in the end. Remediating any material problems in the field or sending material back to the fabricator for rework can disrupt schedule and may have cost implications.

The recommendations on performance improvements provided in this paper can serve as a basis in the development of a robust source inspection program for lattice steel towers and tubular steel poles.

Bridging the Gap Between the Aging Workforce and Today's Most Advanced Technology

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Abstract

It's no secret; there's an aging workforce in today's electric utility industry. A huge loss of critical skills and knowledge base exists when these men and women leave the workforce. The younger less experienced workers continue to fill the void. What happens when these experienced workers retire and continue their careers in a different role as a construction oversight inspector? The younger and less experienced workers will need someone to lean on and trust. The oversight inspectors number one goal is to keep the crews safe while mitigating the costly effects of incidents that can occur when the grid is constructed incorrectly.

While on the jobsite, the oversight inspector must be vigilant at all times and provide the crews the knowledge to ensure safe and quality construction. As utilities continue to put a strong emphasis on safety, they expect detailed daily incident and progress reports on the contracted crew. To satisfy the utilities objectives, upper management and some of the inspectors felt tablets would be a way for the oversight inspector to provide these reports expeditiously and dramatically decrease the time inspectors spent away from crews. The inspector would now be able to keep a close eye on the crew and proactively identify potential hazards that could lead to serious injury.

Now, imagine setting a tablet or a smartphone in front of senior oversight inspectors who still carried around a flip phone and getting responses ranging from anxiety to outright fear. This article will show how PCA bridged the gap to help our inspectors get over the fear of operating a tablet and realize the benefits that stem from it. It will provide an overview of what PCA oversight field inspectors use the tablets for, how we initiated the roll-out of the tablets, bumps in the road, and the benefits that PCA and the utilities PCA works for see in the tablets.

Bridging the Gap Between the Aging Workforce and Today's Most Advanced Technology

The Baby Boomer Workforce

Imagine setting a tablet or smartphone in front of senior oversight inspectors, and getting responses ranging from anxiety to outright fear. In the utility industry, it is no secret we have an aging workforce. With most of the Power Consulting Associates, LLC (PCA) field staff being born between 1946 and 1964, they are categorized as Baby Boomers (Staff, 2010). In 2014, there were 78 million Baby Boomers in the U.S., and they made up 68% of the existing workforce. By 2029, over 20% of the population will be over 65 (Colby & Ortman, 2014). With estimates that 11% plan to never stop working, that leaves a large number of Baby Boomers looking for work and continuing to participate in the workforce (Services). See Figure 1.

As client demands increase the need for process efficiency and staff efficacy, technology has inevitably become an industry standard. Utility workers must now be prepared to use this technology as an everyday tool, adding additional challenges to a Baby Boomer workforce. This article will show how PCA bridged the gap to help our inspectors get over the fear of operating a tablet and realize the benefits that stem from it. It will provide an overview of how we implemented a field employee tablet roll-out company wide and give insight into how the team approached challenges and client benefits. This paper will discuss the challenges we faced in bringing these extremely knowledgeable individuals into the technology world and how we keep this prized workforce that all of us so desperately need working.

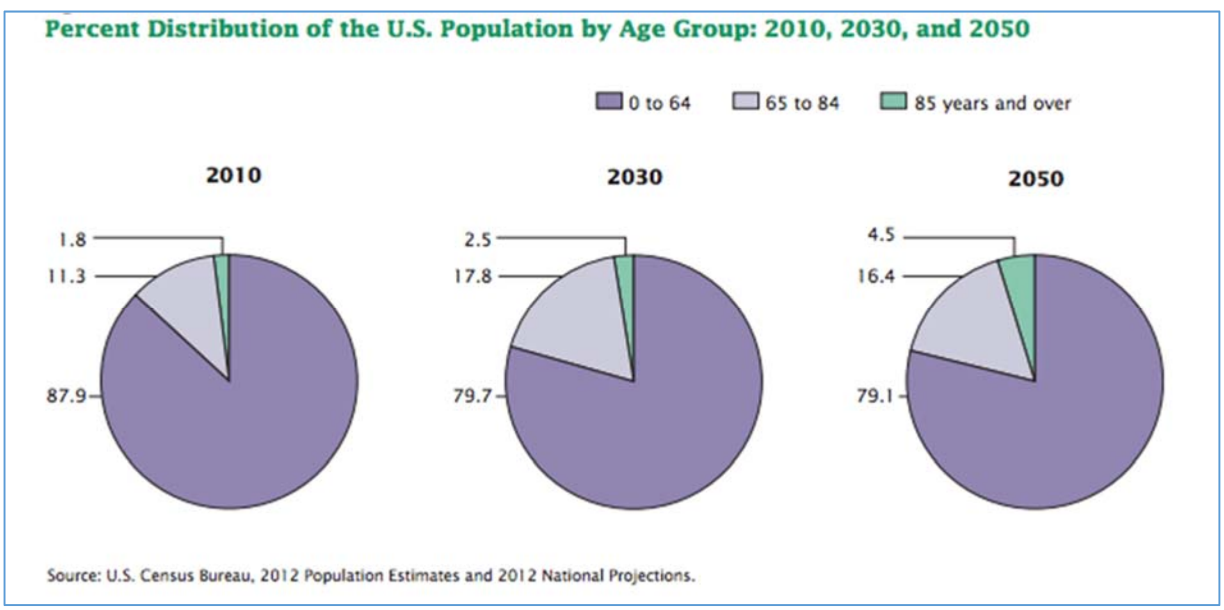

Figure 1: Baby Boomer Population is Aging (Colby & Ortman, 2014)

The Aging Utility Workforce

According to Russel Ray, Chief Editor for Power Engineering News magazine, every sector of the energy industry is expected to lose a large share of its work force as millions of experienced professionals, Baby Boomers born between 1946 and 1964, become eligible for retirement over the next few years. (Ray, 2014)

Ray estimates, the power sector will need more than 100,000 new skilled workers by 2018 to replace those retiring workers. The utility industry is facing a shortage of qualified workers not only for field personnel but also for management, engineering and other inside utility personnel due to increased competition for college graduates. (Ray, 2014) So attracting new talent has become a tough undertaking for the field and the office in the industry.

On the Nuclear side, the Nuclear Energy Institute estimates that more than one-third of their workforce will be eligible for retirement by 2018, which means the industry must hire 20,000 new workers over the next four years to replace them. (Ray, 2014)

So the industry in general is going to need to plan to compete with other industries for the new generation of skilled workers. The replacement plan will need to include training and a plan for knowledge sharing.

According to the Department of Labor, as much as 50 percent of the nation's utility workforce will retire in the next five to 10 years (Ray, 2014). In a PricewaterhouseCoopers (PwC) report estimates put the range of eligible personnel that could retire right now between 20 and 33 percent and between 39 and 63 percent in the next five years. (See Figure 2)

Figure 2: Utility Retirement Trends (PwC)

Therefore, as employees leave, utilities are experiencing a sense of urgency to train new personnel and retain existing employees. There is good news as some utilities are forming partnerships with universities and other organizations that are designed to tap the nation’s pool of talented younger workers. The bad news is electric utilities are losing workers at an increasing rate, according to a report from PricewaterhouseCoopers.

The voluntary turnover rate at electric utilities rose from 3.9 percent in 2010 to 4.9 percent in 2012. For high performers and tenured employees, the turnover rate increased from 2.7 percent in 2010 to 3.7 percent in 2012. The 2013 report also found that the turnover of utility employees during their first year was significantly higher, rising from 2.3 percent in 2011 to 5.5 percent in 2012. “This has created a turning point for utilities precisely because they have had so many decades of stability,” the PwC report found. (PwC, 2013)

As the economy improves, PwC expects that first-year turnover at utilities will continue to increase, and so will the cost. If 10 percent of new employees leave and given the cost to hire ranges from $2,300 to $3,600 each, this will be significant cost – not to mention productivity losses according to the PwC report. Due to the growing number of retirement-eligible employees, increasing turnover costs and the inability to bring in a younger workforce of utility personnel, the resulting loss of productivity in the power sector will be a challenge. The PwC report states; “More than ever before, work processes and procedures should be documented and continuously improved.” (PwC, 2013)

Some utilities are encouraging older employees to delay retirement or to come back as contractors to stop the flow of experienced personnel out the door. Some will retire and come back as a contractor due to wanting a change, more freedom, or maybe they are just tired of the bureaucracy and the technology expectations placed upon them. There has to be enough incentive to offset the risk to themselves. This does not necessarily solve the overall problem to attract the younger workforce to the utility industry. Utilities will still need to compete with other industries for talent.

Bridging the Knowledge Gap

At PCA, we are bridging the gap for the utilities by seeking out these retirees and welcoming them back as employees to give them the freedom of retirement along with the purpose of continuing to work and use their skills. We offer the benefits they are accustomed to having along with support and recognition they have worked so hard to attain. The old adage, “Take care of your employees, and they will take care of your clients!” is so important with the Boomer population. But we also have to bring them into the technology age due to existing requirements and documentation that our client utilities demand.

So how do we go from a flip-phone and no email to sending documents, filling out forms, daily/weekly reports, and emailing field observations by iPad? Partially by trial and error, coaxing and coaching them along, and by brute force at times.

At PCA, we hire a number of retirees from the utility to oversee construction and perform onsite inspection. Many of these are Baby Boomers and the technology they possess is a broad spectrum. Levels of technology knowledge vary with the aging workforce. Some have been in line construction their whole career with only a flip-phone and no email. Many of the aging workforce were moved into management positions near the end of their careers and trained on computer technology including email, electronic forms, internet connections, and various communication devices. Other Baby Boomers stayed in the technical field performing the day to day business of building new infrastructure, repairing the old, and keeping the lights on. Many of the latter personnel did not have or need electronic media to perform their day to day functions. Paper worked fine as it does so today, but transferring the documentation to other company levels for the distribution of information is the challenge with paper. The following tips were found to be useful:

1) With training of an individual, too much technology at one time can challenge any of us. How many dread the software updates that change the day to day use of the programs? Don't we all say, "It was working fine; why did they have to make it better?" Of course in this day and age, the software always needs updating to fix bugs and security threats, or to maximize efficiency and for more innovation.

2) The majority of our field personnel are retired utility professionals that have worked their way from a ground-man grunt through apprenticeship, journeyman lineman, lead, foreman, supervisor, and into management. They have worked in one of the most dangerous professions there is, in all kinds of weather conditions, just to keep each of us with basic electricity flowing in our homes. Most are very technical and tend to be visual learners. While they may present a "Cowboy" and fearless mentality at times, they understand the force of electricity and respect its power and danger. They tend to like policies and procedures to make sure everyone they work with goes home safely at night but cannot stand bureaucratic issues that get in their way.

Training Methodology

As a note I am not endorsing one specific product over another but just reporting on the items that we tried and what we eventually found worked the best for our workforce. In the beginning we received mailed timesheets and reports. We had to move these boomers from a flip-phone to an iPad or Android device. The first thing we had to make them understand is that they could not break an iPhone or an iPad. We let them keep their flip-phone and introduced an iPad and/or an iPhone for them to access an email account. PCA did try some cheaper Android type devices, but found the screen size, the updating process of the software and the user friendliness was not at the same level as the iPad. PCA put the basic icons on these devices to minimize the fear of which icons to use to get started.

1) iPad Introduction – Basic Icons
   a) Email
   b) Contacts
   c) Text
   d) Camera
   e) Weather
   f) PDF type forms, for timesheets and reports

2) Apps & Locking Down
   a) We went so far as to take some apps off, so this would not overwhelm them. They did not need a GPS as most of them knew where every line and substation was in the system they retired from. Directions from them usually included. "Turn left at the Church and go a few miles and turn right at the big oak tree, then drive to the line or substation on the left." They did not need Google Maps at first. For some, we would give them a separate GPS to keep the phone and directions separate. I use that myself sometimes, since I might be on a hands free device phone call and need to see directions.
   b) It was important to lock the devices so apps could not be added or deleted inadvertently. We did later enact some Push functions to push out updates.

3) PCA office personnel first taught them how to read and respond to a text and read an email. We did not focus at first on responding to an email just after receiving it. The next step was replying to text and or email. When it comes to the older generation, bigger screens tend to work better due to keyboards and eyesight. The iPad worked best for PCA's aging workforce. Screen and keyboard size along with iPad's user friendly functions helped the field personnel adapt much quicker.

4) Documentation was the next step in the process. Next we trained them how to take a picture of a handwritten report or timesheet and email it was the next step, whether of construction progress, field problems or photos. The field personnel had paper forms such as a timesheet, daily/weekly report and/or field observation to use, so we had to get them into a digital format. Again, not trying to force learning and overwhelm them, the field personnel could hand write these forms and then just take a picture of it and

send it. This created a bit more office support at first but was just the first step of documentation with the eventual goal of them filling out the forms and emailing it. Handwritten reports are now only for emergencies.

5) Excel forms and programs can be a challenge if you are just doing basic computer skills, so PCA took steps to have a basic form such as a PDF fillable form that cannot be changed. As each person developed their skills, we slowly introduced the ability of just filling out a locked form in either Excel or Word. PDF forms also still worked well. Locking certain fields proves to be a big help, a lot of times they were deleting parts of the report by accident. Locked versions of Excel also eliminate the use of spell check on Excel, so several macros were created to run every time the inspector saved his report. Also other files types and apps get experimented with to solve this issue, since the majority of our client's documents are in Excel forms. Today they digitally enter all documentation on Dropbox/email, so every one of the 60 field employees submit everything digitally.

Training Tips: Applying Adult Learning Theory

The age ranges of the boomers are 51-69. Generation X are the 35-50 year olds while the newest and upcoming workforce are the Millennials that range in age from 18 to 34. So the PCA field personnel are overseeing work being done by the Generation X'ers and the upcoming Millennials, both with different learning requirements and lifestyles. When training older students in particular baby boomers, the following tips should be considered. (see Figure 3)

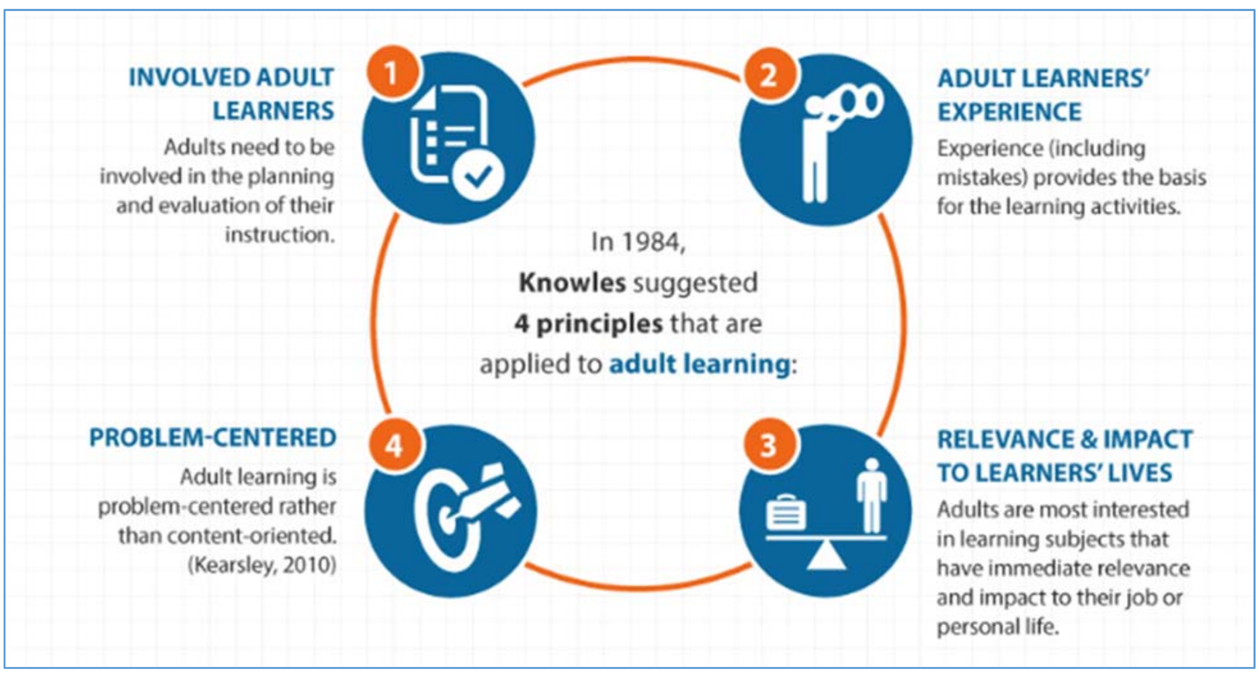

Figure 3: Four Principles of Adult Learning (Pappas, 2014)

1) Tips for teaching adult learners:
   a) Teach with sensitivity and respect.
   b) Gentle, patient and creative guidance is needed.
   c) Treat them like the adults they are.
   d) They are generally more sophisticated and experienced.
   e) Benefit from realistic examples of skills they can use in “real life”. (Doherty, 2012)

2) Older adults learn more effectively when the information is related to things they already know. Adult learners feel empowered when they discover they have a great deal to teach younger classmates, and the dynamic is mutually beneficial. You must incorporate intergenerational discussions on issues but, you must be aware they may be rusty, therefore be generous when it comes to formatting issues and focus on the content. Adult learners tend to be self-conscious or apologetic in the classroom. Some may exhibit shame because they feel they are decades behind their classmates. A key to successfully training these individuals is to break the insecurity and remind them how much they bring to the academic table, having lived and experienced so much in life. The life experience that a baby boomer has is a powerful enhancement to learning. (Doherty, 2012)

3) Consider and acknowledge the technology Gap-Students in their 50’s, 60’s and 70’s are not nearly as tech savvy or tech dependent. Assess each student’s level of proficiency and work with it. Don’t force the learning. PCA has had to adapt to the individual and not the other way around. So consider the following:
   a) Watch your language-you’ll lose a student in the first 5 minutes if you use computer terms. Our technology trainers must avoid tech talk unless absolutely necessary and they have to break it down into small bits and relate it to other life experiences. Learn their technology jargon, once you know what they are saying to describe what they are trying to accomplish the easier it is to help them. This was one of the biggest issues since you assist them with everything remotely. You have to rely on their descriptions of the iPad and figure out what they are trying to do and where they are going wrong. (examples: Mash = touching the screen, put it in the box = Uploading a form onto Dropbox, outer space = where everything that they can’t find on the computer goes, It’s in the air = sent an email, take a hammer to it = fix the iPad.)
   b) Find out what interests them and go from there. Make a connection using the computer and the internet. It was easier to relate to them by breaking everything down into the simplest method, use colors and shapes and screen location instead of telling them to go to a particular app. Often we used very basic explanations of certain apps and programs to help them understand what they are trying to accomplish and not just expect them to do it without understanding. For example, explaining why it’s important to name files correctly and the reasons for different types of files. Most of the field employees now know the difference between an excel document, a word document and a PDF and the capabilities of each.
   c) Slow and steady is the best course of action. They are not in a rush therefore you shouldn’t be either. Make the assumption that you are going too fast. Take your cues not from your agenda but by the look in their eyes. We have all seen the

furrowed brow and glazed look when you have lost someone. That is your cue that you need to back up and figure out where you lost your student and start again from there.

d) Nothing frustrates people more than not being able to drive! Play the wingman and let the student drive from the get go. Think basic, basic, basic and assume they don't know a thing about the technology but they can learn anything. Of course never assume they cannot learn. They did not get where they are in life and in the utility business by lack of skills.
e) Break things down with step by step instructions. Practice until the steps become habitual. Be patient, reassuring and sing their praises when they get it right.
f) Take a break- there's a limit to how much anyone can absorb. Remember the old adage, "The Mind Can Only Comprehend What the Butt Can Endure!" No matter how far you've gotten, stop after 45 minutes and use a 15-minute break to chat and relax.
g) Use a Rule of 3 Times
    i) First - do something hands on
    ii) Second time they do it, have them take notes
    iii) The third time they do it, have them follow their notes to be sure the notes are clear without you guiding them.
h) Practice does make us perfect. Inspire your students to practice 15 minutes a day what you've taught them. Actively practice what they are learning. Don't just dump it in a PowerPoint and expect them to follow along. Most of these folks are hands-on learners. Think Visual-Auditory-Kinesthetic. We encouraged them to play with the iPads and practice taking pictures to get more familiar with it. Facetime has been a valuable learning tool as well to watch them go through the steps to fill out a report as they say what they are doing. This helps catch small things they are doing that is causing them problems or steps they might have forgot. They get lost very easily and its helpful to see what they are seeing to accurately know what they have done.
i) Be efficient with lessons and activities since adults are balancing jobs, children, grandchildren, and tons of responsibilities. Don't waste their time. Be brief, captivating, challenging and high quality.
j) Make it fun. Everyone learns better when you engage and entertain to some degree. Be creative in the learning.
k) Most individuals including Boomers learn better by breaking it up into smaller more manageable pieces. (Pappas, 2014)

4) All of us learn more when we teach, so have the break-out sessions between two individuals. Make one boomer show another boomer how to do something. These guys have done this for years in their lineman profession when they have had to train the younger guys. Each and every one of them has been a teacher. They will surprise you. (Pappas, 2014)

5) Peer to peer training engagement is a valuable tool. When working with a similar aged person, they can train each other through teaching and not feel embarrassed by lack of knowledge. (Pappas, 2014)

6) Lastly, adults don't have anyone forcing them to learn. This may be why they feel they can't learn new things. To keep everyone on track, focus on the importance of the goal. Let them know the importance of what each is doing and reiterate the knowledge they have and what they bring to the table. (Pappas, 2014)

Navigating the Challenges

Rule #1: "You Can't Break It," was an important aspect for training. Trust me, any ex-lineman can break anything, but what I mean by this is that you cannot press the wrong buttons and cause the iPad to catch on fire. Touch screen technology was so foreign to them; the biggest struggle was getting them to understand that they are not physically pressing a button. The iPad responds to heat and touch so they had to be gentle with it, which made them think they were going to break it. Like all of us, we can break an iPhone or iPad by dropping it, leaving it on the back of the truck, driving over it on the right-of-way, or throwing it up against a concrete pole after becoming frustrated with the device. I think all of these have happened but most importantly, how do we prevent the last one? Training! When employees were frustrated in the beginning they were encouraged to call for help. Getting frustrated and spending too much time on something was not an effective use of time. Inspectors were encouraged to ask for help from their grandkids or their own children. When in doubt turn it off, walk away for a little bit then turn it back on. Resetting the device solves more than half of any issues that they are having.

Moving away from the flip-phone was a necessity. As each person became more comfortable with the iPad, the older flip-phones were almost out of date anyway and some had passed their usable life. When that occurred we replaced the flip-phone with an iPhone. Since they were comfortable with the iPad, the iPhone was not a challenge. At first we thought of trying to get them to use just one device to save money and limit multiple devices. That idea did not work. A phone is a difficult device to try and perform multiple functions on for most people, especially when it came to filling out forms on small screens with miniature keyboards. Therefore, multiple devices became our standard platform. Some employees were more technology savvy and wanted a laptop and not an iPad, some wanted both and depending on their needs we supplied them with each.

Choosing the right platform was a challenge. Again, I'm not endorsing one product over the other but some challenges we faced was there was not a standard supplied Android device such as Apple provides with the iPad.

We originally purchased our Android tablets from Verizon. The issue with the method of procurement was dependent on current stock or in several cases the tablet we were using previously was being discontinued by Verizon. Each successive Android tablet had their own unique apps pre-loaded and the application button layout would look different on each model. This constantly required an update in the procedure and instruction to our inspectors. Also each successive tablet had a different version of the Android operating system, so our office support staff were having to deal with different versions of different Android devices on different platforms. Android updates at times were difficult as some had to be done by our IT staff in person. The older Android tablets already deployed to our inspectors underwent little to no updates because of delays by the cellular provider. Android updates are dependent on the manufacturer and cellular provider working in conjunction to release the latest edition. Trying to talk a novice through an update process over the phone can be frustrating to both the office and field personnel. This made peer-to-peer training difficult as inspectors could not ask fellow employees for assistance in the field if they carry two different tablet manufacturers. Also the app icons could change depending on the software update. This confused and frustrated the inspector who were used to seeing the previous icon and then trying to search for the new icon.

There is a consistency with the iPad which helps in the comfort level for our inspectors. We tried to take the frustration out of it. The simplicity of layout (button location and apps) and similarity to the popular iPhone was a boon for our initial instruction and peer-to-peer training. The one thing we like about Apple, when they change an IOS update, it is pushed out to all of their devices and does not usually require a field person to go through a challenging update process. Every iPad received the same update as Apple controlled the delivery and implementation so there was consistency as well as security. This level of security allowed the IT staff the ability to better manage how the inspector uses or accesses the iPad on an everyday basis. In the end, just keeping it simple was the best course of action.

Summary

It’s no secret; there is an aging workforce in today’s electric utility industry. A huge loss of critical skills and knowledge base exists when these men and women leave the workforce. The younger less experienced workers continue to fill the void. What happens when these experienced workers retire and continue their careers in a different role as a construction oversight inspector? The younger and less experienced workers will need someone to lean on and trust. The oversight inspector’s number one goal is to keep the crews safe while mitigating the costly effects of incidents that can occur when the grid is constructed incorrectly.

While on the jobsite, the oversight inspector must be vigilant at all times and provide the crews the knowledge to ensure safe and quality construction. As utilities continue to put a strong emphasis on safety, they expect detailed daily incident and progress reports on the contracted crew. To satisfy the utilities objectives, upper management and some of the inspectors felt tablets would be a way for the oversight inspector to provide these reports expeditiously and dramatically decrease the time inspectors spent away from crews. The inspector would now be able to keep a close eye on the crew and proactively identify potential hazards that could lead to serious injury.

This article shows how PCA bridged the gap to help our senior oversight inspector, who still carried around the flip phone, get over the fear of operating a tablet and realize the benefits that stem from it. This overview provides the techniques and the plan PCA used to roll-out tablets, the bumps in the road, teaching strategies and the benefits that PCA achieved.

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Challenges of Performing Electrical Tests in EHV Substations

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I. Abstract

With ever growing demand for power, it is not uncommon for transmission utilities to build and operate substations at High Voltage (HV) and Extra High Voltage (EHV) levels. Maintenance and testing of assets in EHV stations is critical for proper electric power grid operation and reliability. Performing electrical measurements accurately and reliably in such environments is always a challenge because of the presence of unwanted electrostatic noise and interference. Testing Bushing Current Transformers (BCT) on a transformer or circuit breaker can be especially problematic because of induced voltage on bushing terminals from their proximity to overhead energized lines. In these high noise environments, tests recommended in IEEE standard C57.13.1 such as ratio, polarity, excitation and DC insulation resistance may suffer from inconsistent and unreliable measurements.

This paper addresses how to perform IEEE recommended tests on BCTs safely and accurately in EHV stations. It discusses how different sources of undesired electrical signals can affect the measurement circuit. Techniques such as smart grounding principle are shown that can suppress electrostatic interference and makes the test setup immune to external factors. Paper concludes with a case study of testing multiple BCTs on a 765/500/13.8 kV, 750 MVA auto transformer with tertiary in an energized EHV substation in inclement weather condition, where the BCTs were tested with high accuracy and precision despite extreme interference conditions.

II. Introduction

Current Transformers (CT), DC power supplies, circuit breakers and relays are some of the key components of the protection and control systems. The reliable operation of a protection system depends to a large extent on the performance of these devices. Any mis-operation of these components may leave the power system in a vulnerable state with the possibility for irreparable damages. Periodic testing of these assets will ensure a protection circuit that would operate when it is called upon.

CTs not only provide a means to reflect the status of the primary circuit but also provide isolation between the high voltage primary and secondary measurement and control devices. BCTs on transformers and circuit breakers are electrically tested as per IEEE recommendations to verify their performance and ensure that they meet manufacturer's specifications. Testing BCTs can become a challenge when they are under overhead energized lines such that measurements suffer by induced voltage on bushing terminals. This problem gets more pronounced when testing is performed in EHV stations. This paper attempts to address the issue by first understanding the root cause of the problem, recommending the solution, performing the test as per the recommendations and finally evaluating the results.

III. IEEE Recommended Tests for Relaying Type CTs

Due to the importance that CTs play in power system protection, the IEEE Power Engineering Society recommends certain field test measures for relaying type CTs. These tests are designed to verify proper operation, connection, and condition of the CTs. IEEE Standard C57.13.1, "*IEEE Guide for Field Testing of Relaying Current Transformers"*, Reference [1] outlines the intention for the designated tests as well as the test procedures. Following are a list of the recommended tests and measurements.

1. *Ratio Test:*

   This test verifies the ratio and connection of the CT, as well as any taps that are available. This can be accomplished with the equipment both in and out of service. The out-of-service voltage method require injecting a voltage into the secondary (V_1) and measuring the primary voltage (V_2), which will be directly related to the CT turns ratio(N_1/N_2).

   $$\frac{N_1}{N_2} = \frac{V_1}{V_2} \tag{1}$$

   The in-service current method requires placing ammeters on both the secondary and primary leads and recording the current values. These values will also be directly related to the CT turns ratio.

2. *Polarity Test:*

   This test verifies that the current flow in the secondary matches the designed flow respective to the primary current. This is especially important for CTs being used in differential or comparative relaying. This can be accomplished in a number of ways including: temporarily applying a DC voltage to either the primary or secondary and verifying analog meter deflection, applying an AC voltage to the secondary and using an oscilloscope to compare with the primary voltage, paralleling a reference CT with the secondary of the test CT and verifying current magnitudes, and measurement of phase angle. Another method commonly used by field test instruments is comparison of the phase angle between secondary voltage V_s and primary voltage V_P where phase angle close to zero would indicate correct polarity and close to 180^o would represent incorrect polarity.

3. *Insulation Resistance Test:*

   This test verifies that the CT insulation is satisfactory between both winding to winding and winding to ground. This is usually performed with an insulation resistance tester. Three tests are usually performed to check the integrity of the insulation system:

   a. Primary to ground
   b. Secondary to ground
   c. Primary to secondary

4. *Resistance Measurement:*

   This test verifies the DC resistance of the CT secondary winding as well as the connections within and on the equipment. This can be measured using a traditional low resistance ohmmeter or calculated using a DC volt-amp circuit.

5. *Excitation Test:*

   This test verifies the saturation characteristics of the CT and its taps, thereby confirming accuracy ratings, connections, and absence of internal short circuits. This is performed by applying a varying ac voltage to the secondary winding and recording the associated current. The supplied voltage is increased until the CT has fully saturated. Knee point can be calculated using the ANSI 45 criteria which finds the unique point crossing the excitation curve with a 45° tangent. The plot of this measurement is compared to previous data and any deviation should be investigated.

6. *Admittance Test:*

   This test verifies the nearly constant internal and external burden of the CT as it is installed. This is performed by injecting an acoustic signal into the CT and detecting the circuit admittance. This measurement will be compared to previous system results and any deviation will indicate an abnormal condition.

7. *Burden Test:*

   Part of the rating classification of a CT is its ability to supply a known current into a known burden and meet a stated accuracy. Burden test verifies that the CT can maintain a designated accuracy for a known burden and supplied current. A rated secondary current is applied to the burden connected to the CT secondary and voltage is measured across it to calculate the impedance and phase angle of the burden. In field, it is very important to verify that the burden of the circuit does not exceed the conditions in which the CT will maintain it specified accuracy and performance. Any significant drop in current will show that the CT's designed burden has been exceeded.

Other specialized tests that may be used include:

i. *CT in a closed delta*

   If there are no secondary terminals brought out these CTs must be tested for ratio and polarity before being assembled.

ii. *Inter-Core Coupling Test*

   Inter-core coupling occurs when an unintended conducting loop is established between isolated CTs. This is especially possible on closely mounted secondary cores with a common primary lead, such as BCTs. This coupling can produce current imbalances which will affect differential or comparative relaying schemes. This test is performed by applying a varying voltage on the secondary winding and measuring full winding voltages on adjacent CT cores one at a time while keeping remaining CT secondaries shorted.

IV. Field Challenges of Testing BCTs in EHV Environments

EHV environments can compound the difficulty of testing BCTs. This is a result of a variety of factors, but the most influential is the high level of induced voltage. Today U.S. electric utilities operate complex transmission systems at voltages up to 765 kV. These EHV power lines interact with external objects to create capacitive, inductive, and conductive coupling. Equipment under or near an energized line will become charged by capacitive coupling resulting in an induced voltage that can reach several kilovolts. This voltage can be calculated using the equation (2) listed in reference [3]:

$$V_{object} = V_{line}\left(\frac{Capacitace_{line-object}}{Capacitace_{line-object}+Capacitace_{object-earth}}\right) \quad (2)$$

When testing a BCT, the bushing terminals can be left open, effectively insulating the tested equipment from ground. When this occurs, the open-circuit voltage that is induced can be calculated using the equation (3) listed in reference [3]:

$$V_{open} = 0.25 * V_{LL} * h_o\sqrt{\frac{h_1^2}{d_{1o}^4}+\frac{h_2^2}{d_{2o}^4}+\frac{h_3^2}{d_{3o}^4}-\frac{h_1h_2}{(d_{1o}^2)(d_{2o}^2)}-\frac{h_2h_3}{(d_{2o}^2)(d_{3o}^2)}-\frac{h_3h_1}{(d_{3o}^2)(d_{1o}^2)}} \quad (3)$$

Where,

V_{LL}= line voltage between phases (kV)
h_o = height of the object above ground (m)
h_j = mean height of phase conductor j (j = 1, 2, 3) (m)
d_{jo} = distance between phase conductor j and object (m)

This induced voltage makes testing BCTs extremely difficult, especially for verification of ratio and polarity in an automated test set. The addition of stray voltage on any floating bushing terminals will drastically change the voltage on the primary winding, making it impossible to accurately measure voltages on the primary. This has been verified by field measurements that result in ratio errors in excess of 15-20%. This will preclude the use of any test equipment that requires ungrounded terminals or does not take measures to guard against the induced voltage. While excitation, insulation, and inter-core coupling tests can be completed with an automated test set, ratio and polarity testing must be performed by other means or with an automated instrument that is capable of measuring with one terminal grounded that guards out the induced voltage effects. With advancements in instrumentation and measurement techniques, some of the new test instruments have means to automatically ground the bushing terminal under test internally which allows high level of noise immunity and suppress the induced voltage effects.

V. Interference and Noise:

The IEEE recommended field tests on relaying class CTs are mostly performed by the secondary voltage injection method because of the ease of connections and instrument portability. Measurements for tests such as excitation, winding resistance, inter core coupling and burden are primarily taken on the secondary side of the CT. Since the secondary circuit is electrically isolated from the primary side, interference and noise from surroundings negligibly affect these tests, and even under high interference conditions the results are within an acceptable range.

Insulation resistance tests between the CT primary to ground and primary to secondary can be affected by induced voltage on high side bushing terminals. Some instruments even warn the users of presence of any live potential due to the coupling effect and induced voltage on the bushings.

As shown in Figure 1, the ratio and polarity tests are the two tests where the test instrument's primary side leads are connected to the bushings of the BCT under test. Since the voltage induced in the CT primary when using secondary test voltage method would be only a few volts, it is challenging to measure it accurately under the influence of external electrostatic interference and in the presence of a resulting, much higher noise floor. Even a small level of interference can easily throw the ratio error off by a great amount leaving the results unacceptable and unreliable. Since the level of interference and external conditions can vary greatly from one high voltage substation to another, it becomes a big challenge to measure the ratio and polarity accurately, reliably and with repeatability.

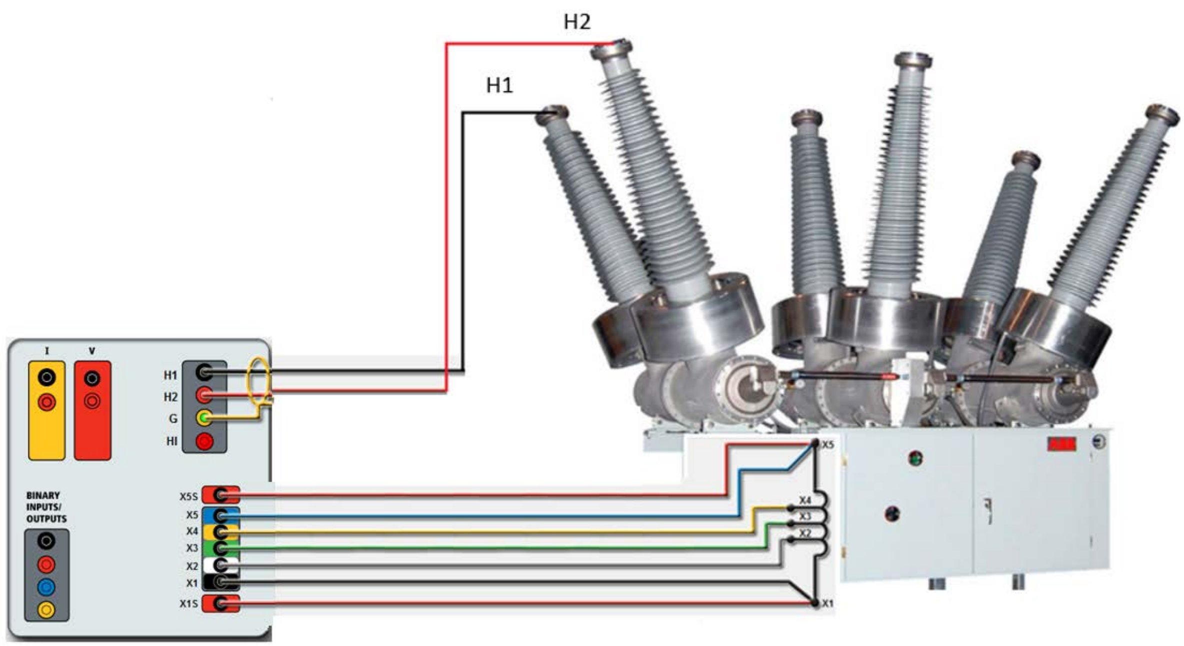

Figure 1: Connections to primary and secondary side of the CT for ratio and polarity test

Another factor that may affect the ratio and polarity results is the impedance of the measuring circuit. As shown in Figure 2, when testing BCTs mounted on a transformer bushing the voltage drop across the transformer winding can introduce an error in the measurement. The voltage V_2 measured by the test instrument can be different than the actual induced voltage V_2' across the CT primary. Any difference between V_2' and V_2 would contribute to the ratio and phase angle error. Ratio and phase angle error of CTs are discussed in detail in reference [2].

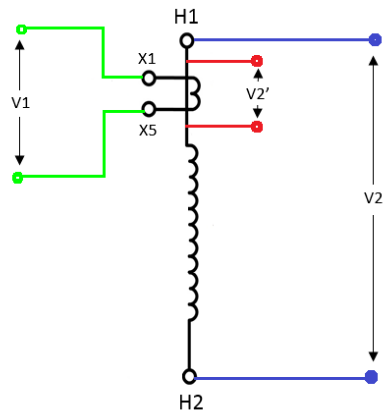

Figure 2: Measuring circuit diagram for the ratio and polarity test

VI. Interference Suppression Methods:

Methods to minimize ratio errors due to interference and transformer circuit impedance are better explained by looking at the transformer exact equivalent circuit. As per Figure 3, a transformer can be represented as an ideal transformer with a turns ratio of N_1 to N_2 by adding the following components.

Primary winding resistance R_P and primary leakage reactance X_P

Secondary winding resistance R_S and secondary leakage reactance X_S

Core loss component R_C and magnetizing reactance X_m

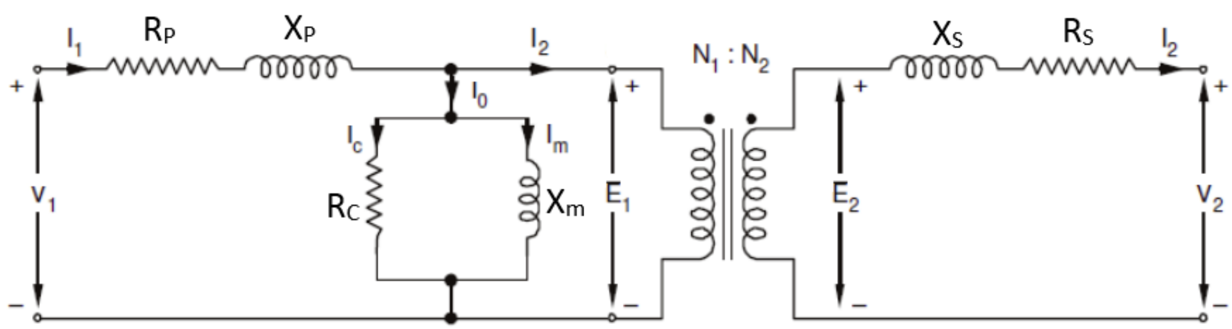

Figure 3: Transformer exact equivalent circuit

Secondary winding impedance when referred to primary side can be represented by an equivalent circuit as shown in Figure 4

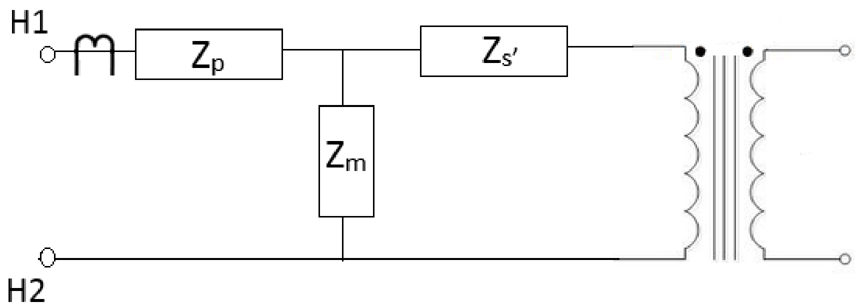

Figure 4: Transformer equivalent circuit as referred to primary

Where,

$$Z_P = R_P + j * X_P$$

$$Z_m = R_C \,||\, X_m$$

$$Zs' = \left(\frac{N_1}{N_2}\right)^2 * (Rs + j * Xs)$$

For any transformer, magnetizing impedance Z_m is much larger than primary winding impedance Z_P and secondary winding impedance Z_s'.

$$Z_m \gg Z_P \text{ or } Z_s \qquad (4)$$

To reduce the error in the measurement, it is important to reduce the impedance or inductance of the circuit. Under an open circuit condition, the impedance seen by the measuring circuit (as viewed from H1-H2 terminals) is primarily magnetizing impedance as shown in Figure 5. Under an induced voltage condition on the bushing terminals, this can lead to an undesired voltage drop in the measuring circuit and can lead to a ratio error outside the tolerances.

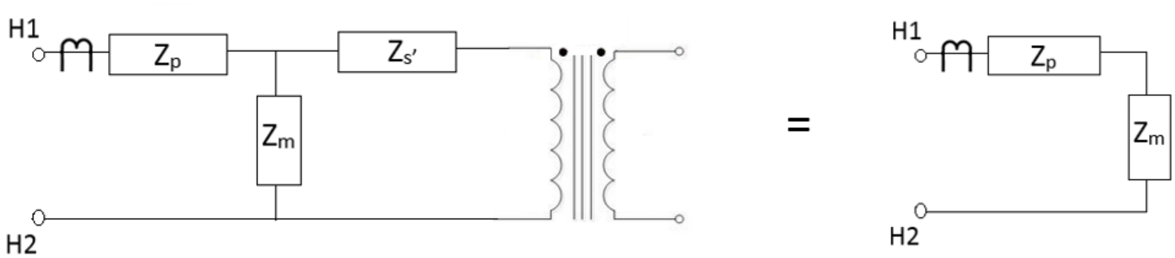

Figure 5: Transformer circuit impedance under open circuit condition

In order to reduce the impedance of the circuit, it is recommended to short the corresponding secondary winding of the transformer as shown in the diagram below.

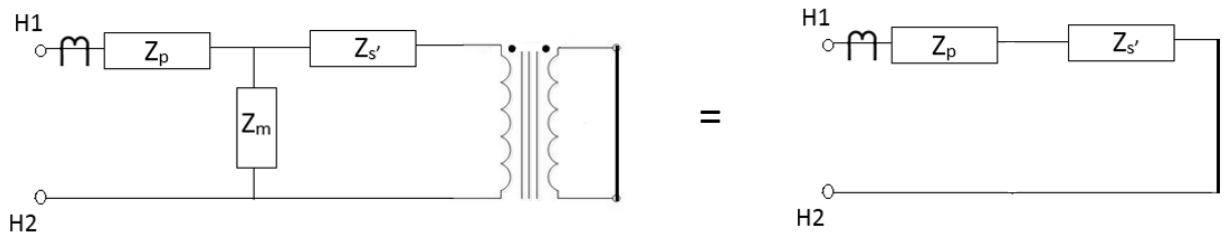

Figure 6: Transformer circuit impedance under short circuit condition

With the secondary winding short circuited, the impedance seen by the measuring circuit is reduced to the primary and secondary winding impedance. The voltage drop across winding impedance is much lower and this helps in reducing the ratio and phase angle error.

When working under high voltage energized lines, the induced voltage on the bushing terminals and high inductance of the transformer winding together can create a problem. Any induced voltage would cause leakage or stray current through the circuit and with high impedance it would create a higher voltage drop, thereby affecting the measurements. Therefore, in addition to shorting the secondary winding it is recommended to ground the bushing terminal corresponding to the BCT under test to guard against any induced voltage due to coupling effect. Technicians operating the test instrument should be careful in implementing smart grounding principle and avoid any possibility of ground loops which can create a circulating path and influence the current flow in the measurement circuit. It is important to note that only one terminal should be grounded on high voltage bushing terminals to suppress the interference from overhead energized lines. It is also recommended to connect the unused bushing terminals to the return path H2 lead. This serves two purposes; it reduces the effect of any induced stray voltage on the floating terminals and depending upon the winding configuration, it would further reduce the overall impedance of the measurement circuit.

The following diagrams depict the recommended connections for testing BCTs on different transformer configurations:

1) Testing H1 BCTs of a transformer with delta winding configuration is shown in Figures 7 and 8. Connection configurations for all the delta winding bushings are given in Table 1.

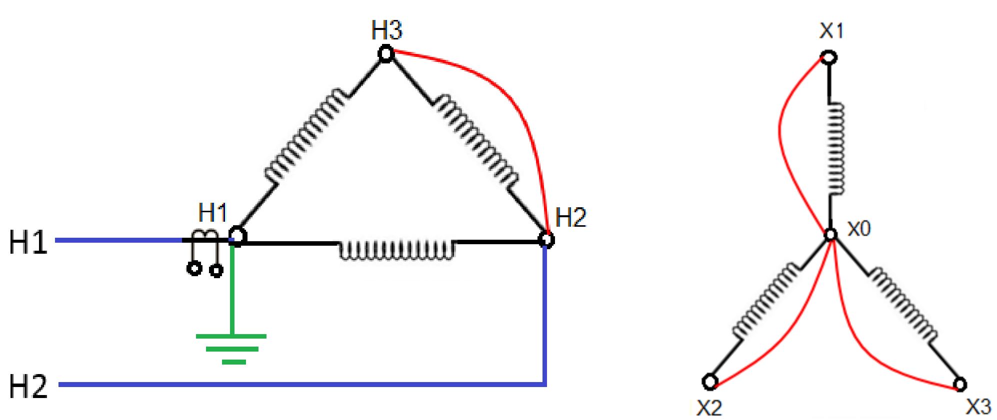

Figure 7: Connection diagram for testing primary side BCTs for a delta-wye configuration

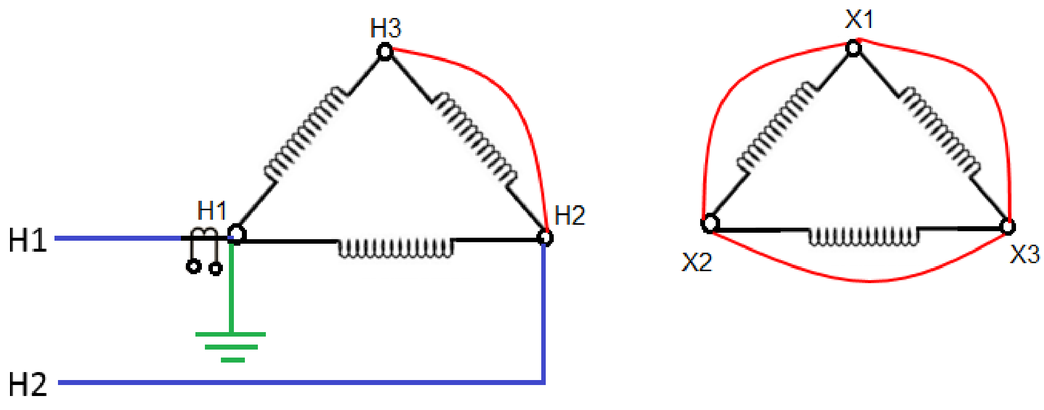

Figure 8: Connection diagram for testing primary side BCTs for a delta-delta configuration

BCT under Test	H1 lead	H2 lead	Ground	Jumpers H side	Jumpers X side
H1	H1	H2	H1	H2, H3	X1,X2,X3 and X0 (if available)
H2	H2	H3	H2	H3, H1	X1,X2,X3 and X0 (if available)
H3	H3	H1	H3	H1, H2	X1,X2,X3 and X0 (if available)

Table 1: Connections for each BCT for a delta configuration winding

2) Testing H1 BCTs of a transformer with wye winding configuration is shown in Figures 9 and 10. Connection configurations for all the wye winding bushings are given in Table 2.

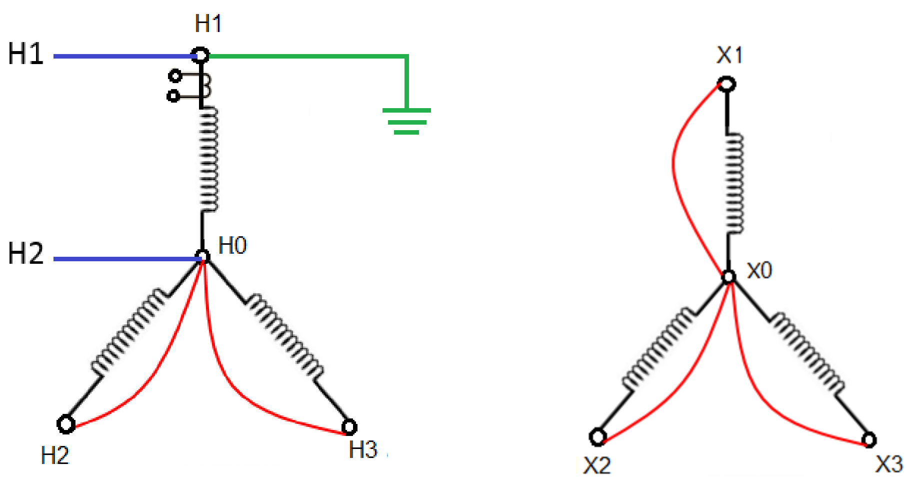

Figure 9: Connection diagram for testing primary side BCTs for a wye-wye configuration

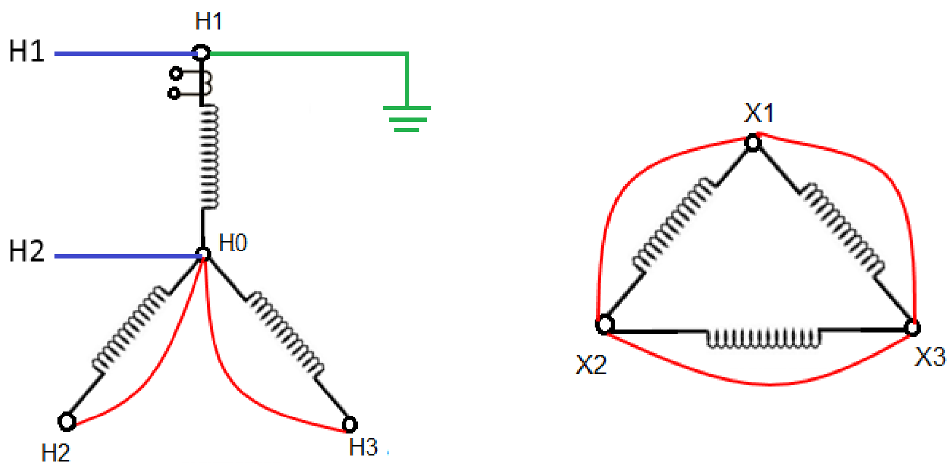

Figure 10: Connection diagram for testing primary side BCTs for a wye-delta configuration

BCT under Test	H1 lead	H2 lead	Ground	Jumpers H side	Jumpers X side
H1	H1	H0	H1	H2, H3, H0	X1,X2,X3 and X0 (if available)
H2	H2	H0	H2	H3, H1, H0	X1,X2,X3 and X0 (if available)
H3	H3	H0	H3	H1, H2, H0	X1,X2,X3 and X0 (if available)
H0	H0	H1	H0	H1, H2, H3	X1,X2,X3 and X0 (if available)

Table 2: Connections for each BCT for a wye configuration winding

3) Testing H1 BCTs of a single phase auto transformer with tertiary winding is shown in Figure 11. Connection configurations for all the bushings of an auto transformer with tertiary are given in Table 3.

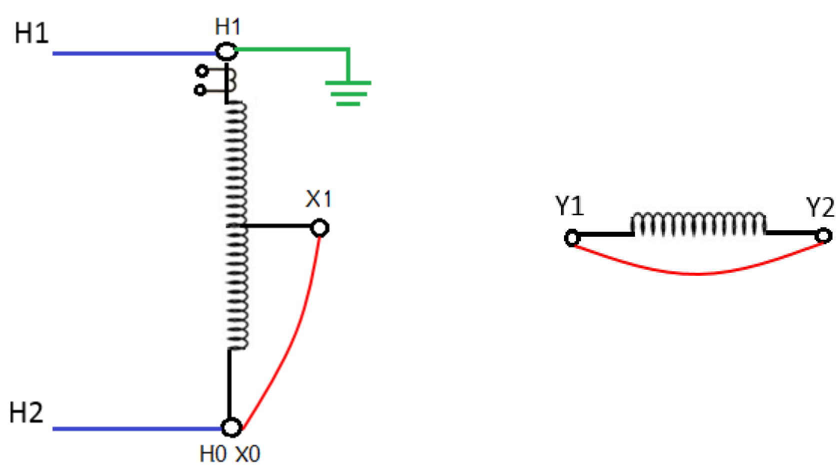

Figure 11: Connection diagram for testing high side BCTs on an auto transformer with tertiary

BCT under Test	H1 lead	H2 lead	Ground	Jumpers Primary side	Jumpers Tertiary side
H1	H1	H0	H1	X1, H0	Y1 and Y2
X1	X1	H0	X1	H1, H0	Y1 and Y2
X0	X0	H1	H0	H1, X1	Y1 and Y2
Y1	Y1	Y2	Y1	H1, X1, H0	N/A
Y2	Y2	Y1	Y2	H1, X1, H0	N/A

Table 3: Connections for each BCT of a single phase auto transformer with tertiary

VII. Case Study

Electrical testing in proximity of overhead energized lines and inductance associated with large windings of power transformers were proving to be problematic for one of the largest utilities in the USA. The company was finding it impossible to test BCTs on transformers in their 765 kV substations. The results obtained were inconsistent and unreliable because of large amounts of error in the measurements. This utility which owns North America's largest transmission network and operates numerous 500 kV and 765 kV stations, was looking to develop a complete and effective solution to this challenging problem.

A crucial part of the commissioning process for power transformers in EHV substations is the testing of BCTs. A 765/500/13.8 kV, 750 MVA single phase auto transformer with seventeen BCTs was tested in an energized EHV substation during inclement weather conditions as shown in Figure 12.

Figure 12: Picture showing the testing under energized lines and rainy condition

As shown in Table 4, a total of seventeen BCTs mounted on different bushings of a single phase auto transformer with tertiary were tested for all the IEEE recommended tests.

BCT	1	2	3	4	5	6
H1	3000:5 C800	3000:5 C800	1000:5 0.15S B1.8	3000:5 C800	3000:5 C800	1698: 5 C200
X1	3000:5 C800	3000:5 C800	3000:5 C800	3000:5 C800		
X0	3000: 5 C800	920: 5 C200				
Y1	30000: 5 C800	5000: 5 C800	4963: 5 C200			
Y2	30000: 5 C800	5000: 5 C800				

Table 4: BCT with different classes and ratios mounted on different bushings

With cloudy and rainy weather conditions along with the nearby energized lines, the outside field conditions were not very conducive to get precise and accurate measurements where even a small measurement error (in the mV range) of high side voltage could have easily thrown the ratio readings off. Insulation resistance was first performed as per the recommended connections in IEEE Standard C57.13.1. When performing the primary to ground insulation resistance test, the test instrument detected a presence of live voltage on bushing terminals and gave a “live voltage present” warning message. The presence of induced voltage and size of the transformer gave indications that test results might get influenced and would pose a challenging situation.

Figure 13: Picture showing the location of each bushing on single phase auto transformer with tertiary

As shown in Figure 13, connections to the bushings were made by bringing a wire from top of the bushing for easy access. The test was first carried out by connecting the leads in a traditional way. The H1 lead was connected to the H1 bushing and the H2 lead to the H0/X0 bushing. All tests such as excitation and winding resistance were performed on the BCT without any difficulty. While performing the ratio and polarity tests, readings would not stabilize on high side terminals and manually recording the results gave a ratio error of 20-23 %. After performing a variety of connections that involved different bushings and trying different BCTs it was evident that traditional connections would not work in this situation.

To ensure that repeatable and accurate measurements are obtained, three actions were taken:

- Reduce the effect of electrical noise and electrostatic interference from overhead energized lines by grounding the bushing of the BCT under test. This also required that the test instrument used should be capable of measuring very low voltage levels through a one terminal grounded circuit.
- Short the secondary and tertiary winding (separately) to reduce the circuit impedance
- Short all the floating unused terminals and connect to the return path (H2 lead).

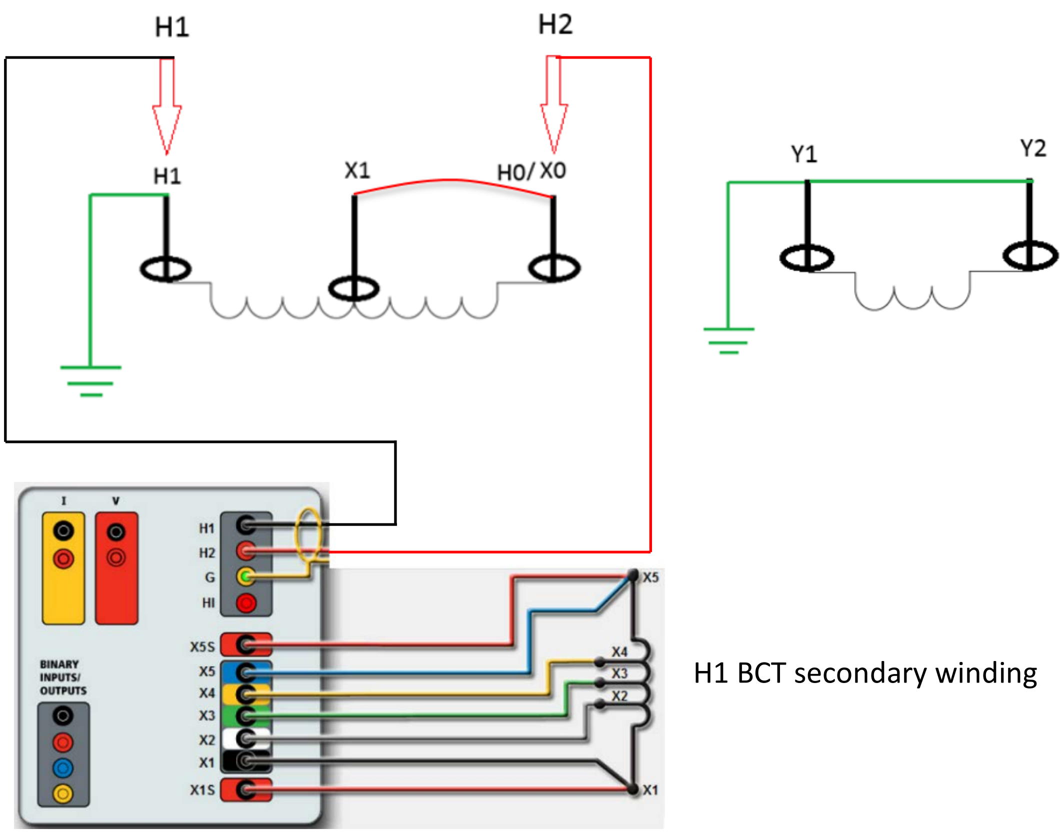

Figure 14: Connection diagram for testing BCTs on single phase auto transformer with tertiary

Using the connections shown in Figure 14, testing was repeated and consistent results were obtained for all the tests. The following results were collected on a C800 3000:5 multi tap CT mounted on the H1 bushing as shown in Figure 15.

Tap		X1-X2	X1-X3	X1-X4	X1-X5	X2-X3	X2-X4	X2-X5	X3-X4	X3-X5	X4-X5
RATIO	Nameplate	1000:5	2200:5	2500:5	3000:5	1200:5	1500:5	2000:5	300:5	800:5	500:5
	Measured	1000.32:5	2200.83:5	2500.68:5	3000.26:5	1200.51:5	1500.37:5	1999.95:5	299.855:5	799.435:5	499.58:5
	% Error	0.032	0.038	0.027	0.009	0.043	0.024	0.003	0.048	0.071	0.084
	Test V (V)	99.530	218.98	248.81	298.52	119.45	149.28	198.99	29.835	79.543	49.708
	Test I (A)	0.1644	0.0747	0.0658	0.0548	0.1370	0.1096	0.0822	0.5485	0.2057	0.3292
	Prim V (V)	0.4975	0.4975	0.4975	0.4975	0.4975	0.4975	0.4975	0.4975	0.4975	0.4975
Phase Dev.		0°29'	0°29'	0°29'	0°29'	0°29'	0°29'	0°29'	0°29'	0°29'	0°29'
Polarity		Correct	Correct	Correct	Correct	Correct	Correct	Correct	Correct	Correct	Correct
Knee	Volt.(V)	196.05	431.26	489.45	587.71	235.22	293.38	391.63	58.422	156.44	98.259
	Cur.(A)	0.2604	0.1186	0.1042	0.0867	0.2179	0.1737	0.1300	0.8603	0.3223	0.5170

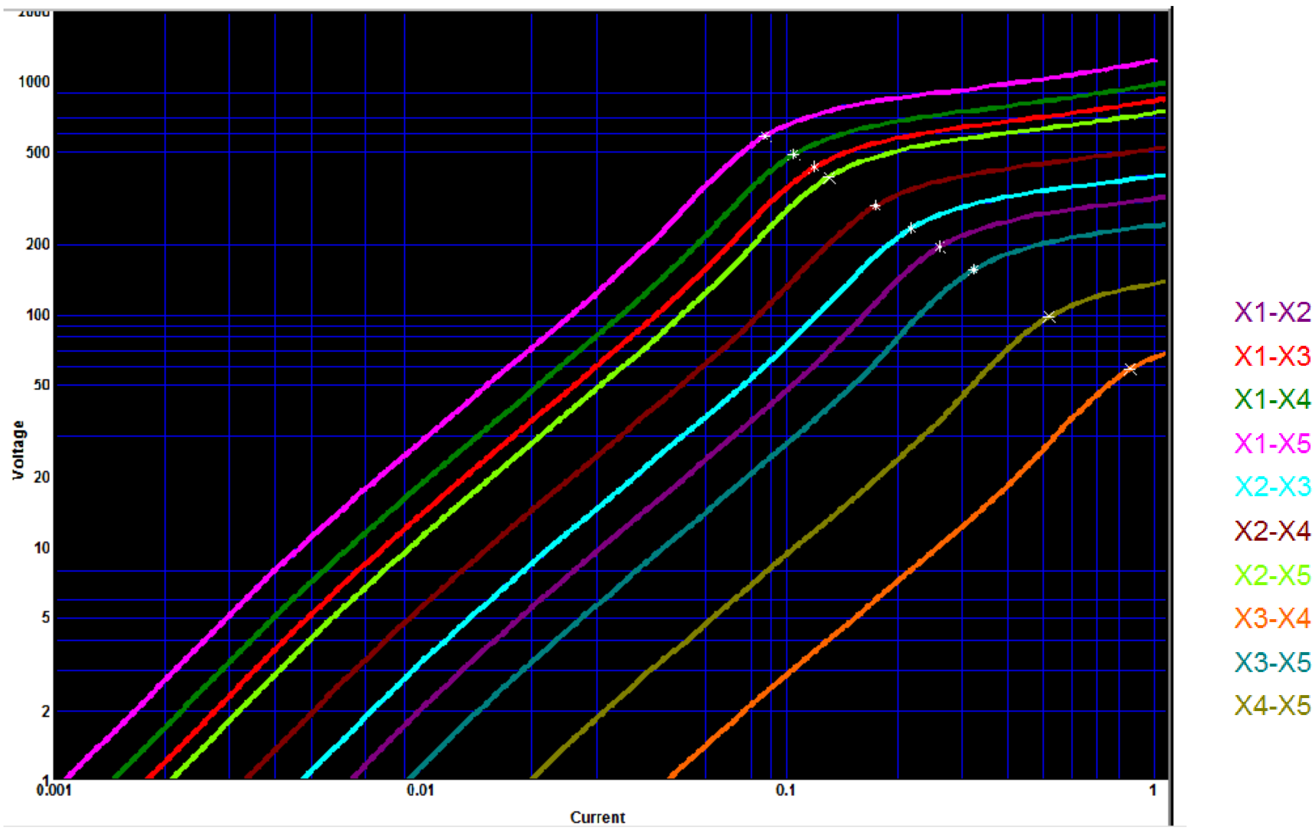

Figure 15: Ratio and Saturation results of H1 BCT

Based upon the connections successfully applied for the first BCT, the other BCTs were tested using the same procedure and highly accurate results were obtained on all of the CTs. It is noted that since the bushing terminal was grounded to eliminate the interference present, it was not possible to run insulation resistance tests with this setup. Insulation resistance tests were run separately at the completion of all the tests. The results obtained on C800 5000:5 BCT mounted on tertiary winding Y1 bushing are shown in Figure 16.

	Tap	X1-X2	X1-X3	X1-X4	X1-X5	X2-X3	X2-X4	X2-X5	X3-X4	X3-X5	X4-X5
RATIO	Nameplate	1500:5	2000:5	4000:5	5000:5	500:5	2500:5	3500:5	2000:5	3000:5	1000:5
	Measured	1495.39:5	1995.21:5	3995.07:5	4995.44:5	499.822:5	2499.69:5	3500.06:5	1999.86:5	3000.24:5	1000.37:5
	% Error	0.308	0.240	0.123	0.091	0.036	0.013	0.002	0.007	0.008	0.037
	Test V (V)	89.405	119.28	238.85	298.66	29.883	149.45	209.25	119.56	179.37	59.809
	Test I (A)	0.0796	0.0597	0.0298	0.0238	0.2383	0.0476	0.0340	0.0596	0.0397	0.1191
	Prim V (V)	0.2989	0.2989	0.2989	0.2989	0.2989	0.2989	0.2989	0.2989	0.2989	0.2989
Phase Dev.		359°58'	359°58'	359°58'	359°58'	359°58'	359°58'	359°58'	359°58'	359°58'	359°58'
Polarity		Correct	Correct	Correct	Correct	Correct	Correct	Correct	Correct	Correct	Correct
Knee	Volt.(V)	123.45	164.86	329.93	412.22	41.430	206.47	288.78	165.07	247.40	82.414
	Cur.(A)	0.1016	0.0762	0.0381	0.0304	0.3053	0.0609	0.0434	0.0761	0.0506	0.1510
Resist. (Ohms)		0.448	0.587	1.187	1.549	0.139	0.739	1.101	0.600	0.962	0.362

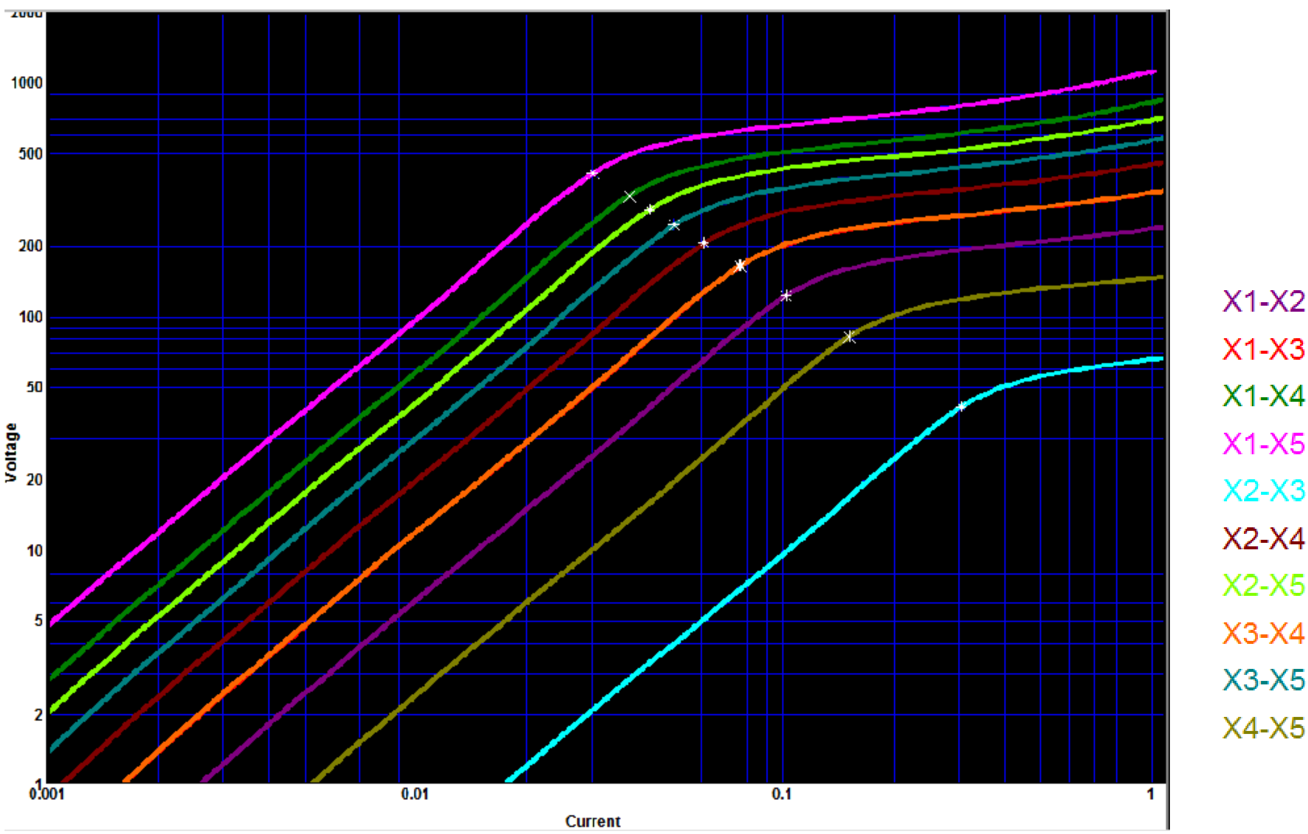

Figure 16: Ratio and Saturation results of Y1 BCT

Three other transformers in 500 kV and 765 kV substations with multiple BCTs were tested with the same concept and all the CTs ratio and polarity measurements were obtained with high accuracy and repeatability. Overall more than fifty CTs were tested with the same procedure. This proved the theory and concept used for testing BCTs in EHV substations as described in the paper.

The utility was able to identify the correct technique to counteract the challenges faced in the EHV stations to obtain consistent and reliable measurement on the BCTs. A standard procedure was developed for each of the different types of winding configurations to help the field technicians make correct connections and measure accurately. It is noted that when working with lower inductance transformer windings where there is little or no interference, some of the recommended steps above could be skipped and reliable measurements can still be obtained.

VIII. Conclusion

As was seen in the test cases with the major utility, effective grounding and isolation techniques can be used to safely obtain highly accurate measurements on BCTs even in less than ideal environments. This paper outlined these measurement techniques for various winding configurations to reduce the noise and interference seen especially in EHV substations. This interference was reduced to levels that provided near perfect accuracy. These methods improved the measurement values of secondary injection tests by minimizing winding impedance and eliminating the effects of electrostatic voltage buildup on bushing terminals. This allows for precise testing of BCTs as outlined by IEEE, thus verifying the integrity and operability of the protective systems serving the electric grid.

IX. References

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[3] Abdel-Salam, Mazen, Hussein Anis, Ahdab El-Morshedy, and Roshdy Radwan, "*High-Voltage Engineering: Theory and Practice*", 2nd ed. New York: M. Dekker, 2000.

X. Authors

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Advanced Diagnostic Testing for Power Transformers

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Advanced Diagnostic Testing for Power Transformers

Conventional field testing techniques for power transformers have been used for more than 80 years. Over time, new technologies and techniques have been developed, but in our industry, they are often adopted slowly over a long period of time. This paper will be a general introduction to the advanced diagnostic testing tools that have become recognized electrical techniques within the past 20 years, or so. The theory and analysis of these relatively new diagnostic tests will be discussed in order to gain an understanding of when they are most appropriately used in a transformer that warrants further investigation, and how to interpret the results to identify fault modes within a power transformer.

We will be discussing four Advanced Transformer Diagnostic tests. First, diagnostics are tests we perform on a power asset to determine its health and the likelihood that this asset can continue to operate safely and efficiently. While these tests are labeled "advanced", it does not necessarily mean that they are complicated; or any more difficult to comprehend, apply, execute, or interpret than the standard diagnostic tests widely embraced by the industry. They have emerged as the industry has identified these needs, and developed new techniques. They are merely an extension of the knowledge and testing techniques that have been used previously.

1 Variable Frequency Power Factor Test

The power factor test is a diagnostic tool used to assess the status of a transformer's insulation system, looking to identify deteriorating or contaminated insulation.

The test is simple to perform and simple in concept to interpret. Once we have a benchmark power factor result, we look for a change from that benchmark. A change can indicate aging of the insulation system, moisture contamination, or the presence of some other contaminant within the insulation system.

Because the power factor test is so simple, there are several shortcoming with its use.
It is well known that a power factor test represents the average condition of the total insulation system under test. In a large transformer's insulation system, there may be a small area of severe contamination, or damage, but it is possible that the power factor result may not change sufficiently to alert us to the severity of the developing condition, because the average of the total system is still within the acceptable range. Likewise, when a power factor result increases, it is impossible to know from this measurement, whether this is due to a uniform change in the condition of the insulation system, or if there is a localized area of severe deterioration which is influencing the result.

A further shortcoming is that when an insulation system has been determined to be contaminated (by an elevated power factor result), no one knows the cause- the type, location, or source of this contamination. Is it moisture, aging, some other type contaminant, oil conductivity, or some combination of these?

And then finally, the standard power factor measurement has what we call a 'blind spot'. You can perform a standard power factor measurement at 60 Hz, get an acceptable reading, while the insulation system is becoming contaminated with moisture. The problem is that the moisture hasn't reached the level at which the power factor test can discern it. So an acceptable pf measurement result can truly mean that the insulation system is in acceptable condition, but it is also conceivable that we are missing the start of a deteriorating condition. Figure 3 illustrates an example of this blind spot.

In some cases, wet insulation may be indicated by an increase in the measured power factor. However, by the time the test results are effected, the insulation is usually quite wet. The industry needs a method to measure the moisture accurately during routine testing to identify the developing problem early on. That task can be accomplished with the variable frequency power factor test.

Variable Frequency Power Factor Test

In order to fill some of the voids left by the standard power measurement, we advocate performing advanced power factor measurements, in which you determine the power factor at eight discrete frequencies between 15 and 400 Hz. This is known as the variable frequency power factor test.

Figure 1 shows what we would expect to see for the CH, CHL and CL test results when the tested insulation system is in acceptable condition. When a transformer becomes contaminated with moisture, the general shape of the variable frequency power factor test plots change such that at low frequencies, the power factor is notably higher. See Figure 2.

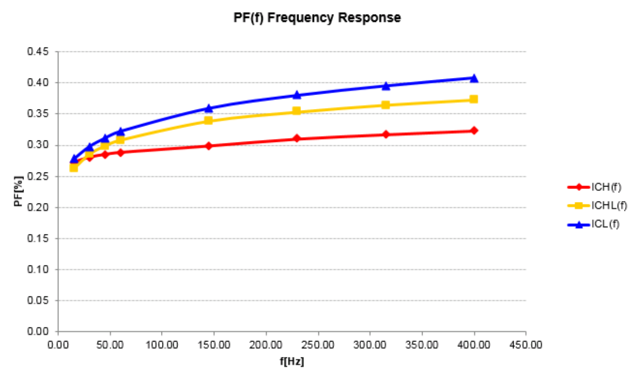

Figure 1 Variable Frequency Power Factor Test

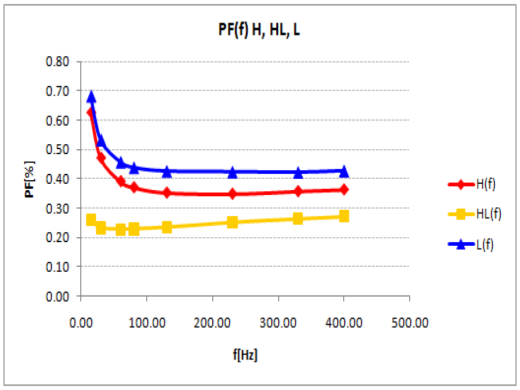

Figure 2. PF results with Excess Moisture

Figure 3 is an excellent example of the blind spot of the standard power factor measurement. A colleague collected this data when testing 2 transformers, both of which yielded routine 60 Hz CHL power factor results of 0.4%. Most people would stop at that point and conclude that the dielectric systems of the transformers are both in very good condition. However, in this case, that would be wrong.

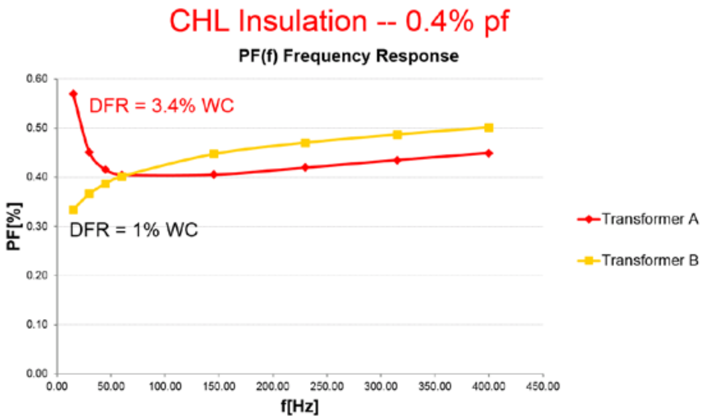

Figure 3. Illustration of the ‘Blind Spot’.

After performing the advanced power factor measurements, it turns out that the transformers are very different. The transformer B curve follows the expected results for a transformer with healthy and dry insulation. However, Transformer A results indicate an insulation system contaminated with moisture. The pf test result curves just happen to intersect each other at the line frequency. Because Transformer A has a power factor result of 0.4% at 60 Hz, it provides a false sense of security that its insulation is healthy. However, the significant moisture contamination will be influencing the performance of the transformer, even though it has not yet effected the measured standard power factor test.

In summary, advanced power factor measurements will eliminate the “blind spot”, allowing one to see early signs that contamination is present. Those findings suggest that additional testing should be done to confirm the moisture content of the solid insulation, or to discern that other contamination is the cause of the elevated VFPF. Today, we can do that by utilizing a Dielectric Frequency Response (DFR) test.

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2 DFR (Dielectric Frequency Response) measurement,

DFR (Dielectric Frequency Response) is another variable frequency power factor measurement, which sweeps an even wider frequency band, discriminates the loss agent, and can give an actual percent moisture content.

Moisture Effects: Why should we care about the moisture content of a transformer?
An elevated moisture content has three very dangerous effects in transformers that are often overlooked:
A. An elevated water (moisture) content will decrease the dielectric strength of both the paper and the oil in a transformer. The plots in Figure 4 demonstrates how the breakdown voltage in mineral oil (yellow), and other insulating liquids, decreases with increasing moisture saturation.

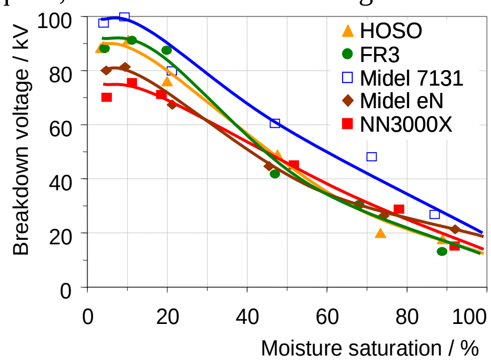

Figure 4 Moisture effect on dielectric strength

B Moisture in paper insulation is one of the prime catalysts that increases aging and deterioration of the cellulose material due to elevated temperature. As such it has a direct impact on the transformer aging rate and the life expectancy of the solid insulation system.

Refer to the chart in Figure 5 of moisture verses life expectancy, it illustrates that ***in this study***, a transformer at 70 degrees C with a 1% moisture content, will have a life expectancy of 100 years. However if the transformer becomes wet (with a 4% moisture content in the paper) that transformer’s life expectancy will be significantly reduced to 10 years.
NOTE:

1. In this study, the insulation used was standard Kraft paper, with a maximum rated operating temperature of 95°C, (the IEC standard). This is not the thermally upgraded insulation required for use by C57.12.00, which has a rated temperature of 110°C.
2. In C5712.00 the minimum life expectancy of the insulation system is required to be 180,000 hours (20.55 yrs.). This applies to transformers that are maintained dry and oxygen free, while operated at a hottest spot temperature of 110°C continuously.

Despite the obvious differences cited above, this graph does demonstrate the point that increasing the moisture content in the insulation system will lead to a shorter expected life of the insulation materials.

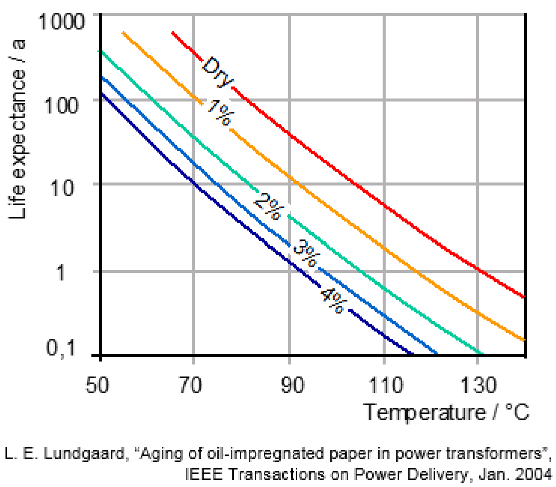

Figure 5 Moisture effect on aging

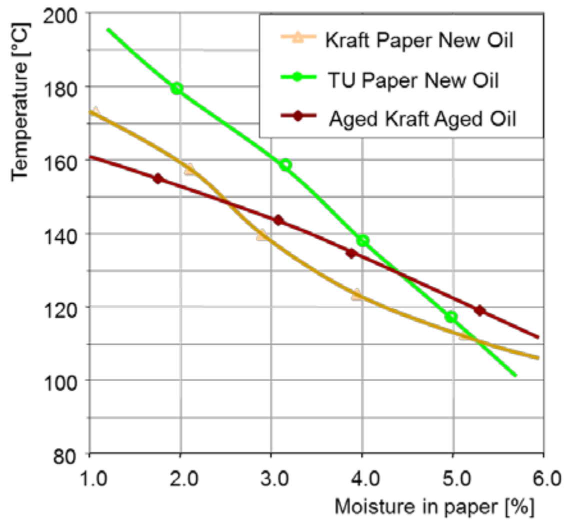

Figure 6 Bubble Formation conditions .

C The third effect is the increased danger of bubble formation in an operating transformer. Bubbling occurs when water inside the cellulose insulation cannot migrate out of the insulation normally, but vaporizes during rapid heating of the windings. Bubbles displace the insulating liquid, which decreases its dielectric strength, and can promote inception of partial discharge. The PD can persist, or may evolve into shorted turns or windings, and then a failure of the transformer.

The graph in Figure 6 illustrates that as the moisture content of the paper increases, the bubbling inception temperature decreases. Therefore for thermally upgraded kraft paper (TU), with a 4% moisture content and new oil, the inception voltage for bubbling to occur is roughly 138 degrees C.

Note the IEEE Loading Guide allows the transformer to be operated at 140 to 180°C hot spot temperature during a short term overload. The common caution is to suggest a 140°C limit, since bubbling could occur when operating an aged transformer at these temperatures, even with a low moisture content.

In reality, bubbles will only form if the local temperature and the local moisture content exceed the values documented from experiments. Many engineers have incorrectly interpreted warnings about bubbling, and will use the calculated hottest spot temperature (or the winding temperature gauge) with the average moisture content to evaluate the risk for bubbling. This provides an unrealistically low estimate of the safe loading capability, and therefore, an extremely conservative approach to the issue.

Where does the moisture come from, and where does it reside?

New transformers will have some residual moisture. If the factory drying process is good, then the water content is normally 0.3 –0.5% moisture in paper. While in-service, leaks can develop at any of the gasketed joints, radiators, or in some bushing seals allowing moisture to enter. Thirdly, as a part of the aging and deterioration of the cellulose insulation, carbon dioxide, carbon monoxide, and moisture are released as byproducts of the chemical reaction. This moisture becomes available to act as a catalyst to continue the aging process.

Figure 7 demonstrates the complex nature of moisture analysis, and the process of moisture migration.

In an operating transformer, the hotter winding and insulation temperatures occur at the top of the unit. As the insulation temperature increases, some moisture will move from the insulation into the oil. With decreasing temperature, the water will move back to the cellulose material. The cooler insulation at the bottom of the tank will hold relatively more moisture. The arrows between water in cellulose and water in oil point out this moisture exchange between cellulose and oil. Since the time constant for moisture to reach equilibrium is measured in weeks, we find that there cannot be a thermal, or moisture, equilibrium in an operating transformer.

At any time, most of the water is in the cellulose insulation. In the example of Figure 7, we see that *if* it were to reach equilibrium at a temperature of 40°C, with a moisture in oil value of 16 ppm, there would be 0.3 gallons of water in the oil, and 55.5 gallons in the cellulose.

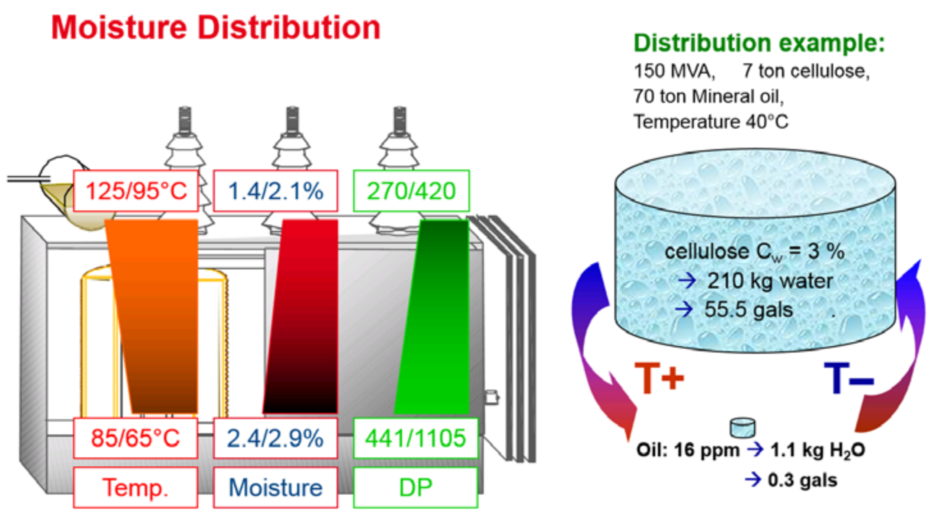

Figure 7 Moisture dynamics

Moisture in the Insulation Indirect Methods
Moisture in Oil to Moisture in Paper Estimation Method
Methods of estimating the moisture content of the paper and pressboard have been used for many years. One of the earliest was the rule of thumb that the percent moisture in paper was the same as the percent power factor. This was disproven long ago, and the relationship with pf tests was discussed previously.

Other efforts to estimate the moisture content of the paper and pressboard have been based on the use of equilibrium charts, where the moisture content of the paper is derived from the moisture content of the oil. For accurate results, it is critical that the transformer is at equilibrium. However as we have seen, thermodynamic equilibrium will not occur in an operating transformer, so all of these estimates have significant error.

The process involves getting an oil sample, analyzing it using ASTM D1533, the Karl Fisher Titration method. Then the result of the tested moisture in oil is used with an equilibrium curve to estimate the moisture content in the paper. And although it is simple, it leads to inaccurate conclusions. More recent advances have led to the use of sensors installed in the oil to measure the percent saturation of moisture in oil directly. It eliminated oil samples, but the next step is still to use the same equilibrium curve methods to estimate the moisture content in paper.

Although I stated that the ASTM titration method is routinely performed, round robin studies have compared results from one laboratory to others, and shown that it is still subject to inaccuracies. The resulting predicted moisture content in paper can have a very wide range. For example a range from 2.5-5.0% was reported in one study where I have a presentation slide, but no documentation of the source.

Aging of paper and oil produces byproducts that increase the ability of the oil to hold moisture, and effects the moisture migration process. Therefore, for aged oils, a different equilibrium curve must be found and used. For example, a sample with 15ppm water in oil, will give moisture in paper results between 1.7% and 4.5% depending on the oil-paper-condition and which equilibrium curve is used.

Issues with equilibrium moisture estimation methods
The use of Equilibrium Curves to correlate moisture in oil to moisture content in paper has widespread use because it is easy to perform. However, there are many issues that prevent an accurate assessment:

- Need to wait for *Near* equilibrium which would take days to weeks
- There is uncertainty in the estimates, and interpreting the curves.
- If the oil sample is contaminated during sampling, transportation, or processing errors will result.
- Standard Equilibrium curves are not accurate for aged oil.
- This method has a tendency to over-estimate the moisture content.

Results from an EPRI study are reported below in Figure 8. We see that when all of the errors involved in the assumptions, and estimates necessary to use an equilibrium method are summed, the estimated moisture content of the paper has an expected accuracy of +/- 200%!

Magnitude of Errors for Assumptions Made

Equilibrium:	± 20%
Uniform oil distribution:	± 15%
Oil solubility:	± 100%
Uniform WCP distribution:	± 20%
Temperature increase or decrease:	± 20%
Equal temperature & moisture time constants:	± 15%
All insulation has same sorption characteristics:	± 15%
Sum of all Errors:	**>** ± 200%*

*Does not take into account sampling and actual KF measurement

Source: [B. Ward: Moisture Estimation in Transformer Insulation, Panel Session IEEE Transformers Committee, 2004]

Figure 8 Estimate of the accuracy in equilibrium methods

Any process that utilizes one or more equilibrium charts to estimate the moisture content in paper is fraught with estimations, errors, and inaccuracies. The industry needs a method to measure the moisture accurately during routine testing to catch the problem early on. To do that, we now recommend the Dielectric Frequency Response Test.

Moisture in the insulation Direct Methods
Dielectric Frequency Response Testing

Performed in accordance with *IEEE PC57.161™/D1.1 - Draft Trial-Use Guide for Dielectric Frequency Response Test*

1.1 Scope

This guide is applicable to the methods of Dielectric Frequency Response (DFR) of liquid immersed transformers. The guide includes recommendations for instrumentation, procedures for performing the tests and techniques for analyzing the data. This guide can be used in both field and factory applications.

1.2 Purpose

The purpose of this guide is to provide the user with information that will assist in performing Dielectric Frequency Response measurements and interpreting the results from these measurements.

Power Factor- Frequency Dependency: Frequency Domain Spectroscopy (FDS)

This method measures the power factor over a very wide range of frequencies typically from 1 kHz down to 0.1 mHz. In doing so, the results reflect the different influences of insulation geometry, oil conductivity, and moisture within specific frequency ranges. The analysis of the pf vs. frequency plot identifies these effects, and leads to conclusions about the contamination of the insulating liquid, and the moisture content of the solid insulation materials.

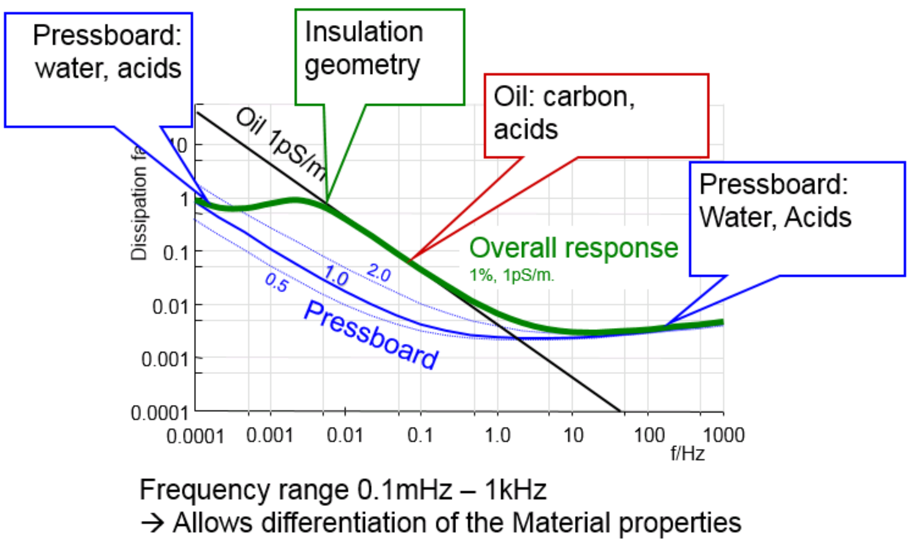

Figure 9 Superposition of PF Curves

In the plot of Figure 9, we see the blue curve which represents the conductive and polarization losses that dominate the pf response of the pressboard insulation, and the black line response of the oil conductive losses. The overall response (green line) represents the superposition of the effects of the pressboard that is dominant in both the extreme upper and lower frequencies, and the oil conductivity. It also includes the "hump" where the geometry of the insulation components used in the high – low gap of the winding structure limits the oil response in lower frequencies. The high frequency part, dominated by pressboard, is not sufficient for our objective, since this range is not very sensitive to moisture. The low frequency branch (left from point of inflexion, approximately 0.3 mHz) most clearly reflects the moisture content.

The Moisture determination is based on a comparison of the dielectric properties of the tested transformer to modelled dielectric properties. The models are based on laboratory measurements on pressboard samples and the conductivity of oil. Both are combined by the XY-model taking into account the geometry of the insulation system and the insulation temperature. A curve fitting algorithm compares the measured dielectric properties to the various modelled dielectric properties. The best fitting curve match provides the assessment criteria of the moisture content and oil conductivity of the tested transformer.

The assessment of the dielectric response curve is based on the differentiation produced by the main influences. These are temperature (which must be input by the user), oil conductivity, the insulation geometry and the water content in the solid insulation. Furthermore, it is necessary to compensate for aging byproducts as they behave similar to water. This is done automatically by the software.

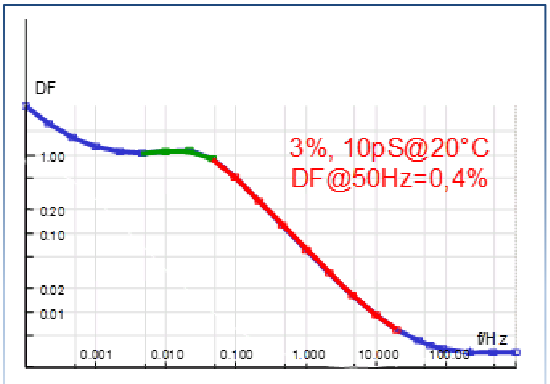

Figure 10 "Perfect" example of DFR curve

The curve produced from the test results will look similar for all multilayer oil-paper-insulations. However, it shifts to the right at high moisture content or temperature (higher frequencies); and appears farther to the left (lower frequencies) at cold temperatures or dry insulations. See Figures 10 and 11
As a result, the required measurement time to define the shape of the response curve depends on the condition of the specific transformer.

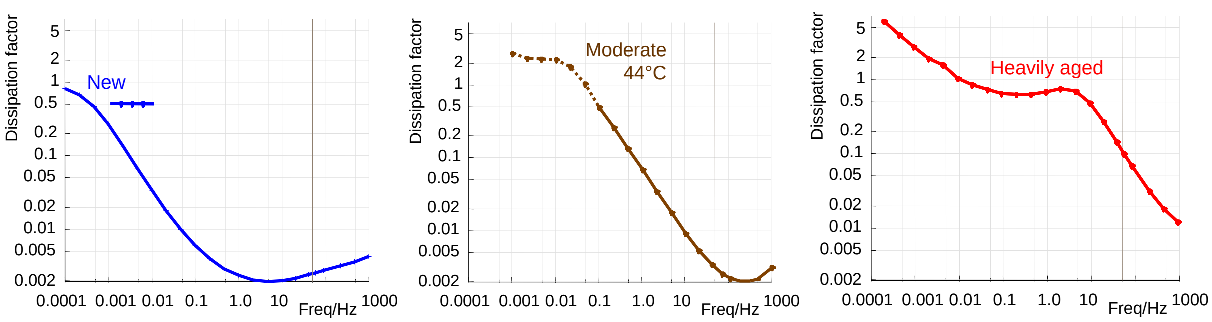

Figure 11

The fitting algorithm works automatically and emphasizes the low frequency values. Since water influences the results, especially in the low frequencies left of the hump, the fitting should be good particularly in this range.
Note that the moisture content reported is an average of the solid insulation structures measured, including paper and pressboard, built into the HV-LV winding insulation (CHL).

Summary:
The moisture Assessment is based on Differentiation of the responses as the transformer materials exert their influences on the shape of the DFR pf curve.
Main influences:

- Temperature (correct temperature necessary for correct assessment!)
- Oil conductivity
- Geometry of the insulation
- Water content in the solid insulation

- Compensation of aging products, if ignored, moisture will be overestimated for aged insulation

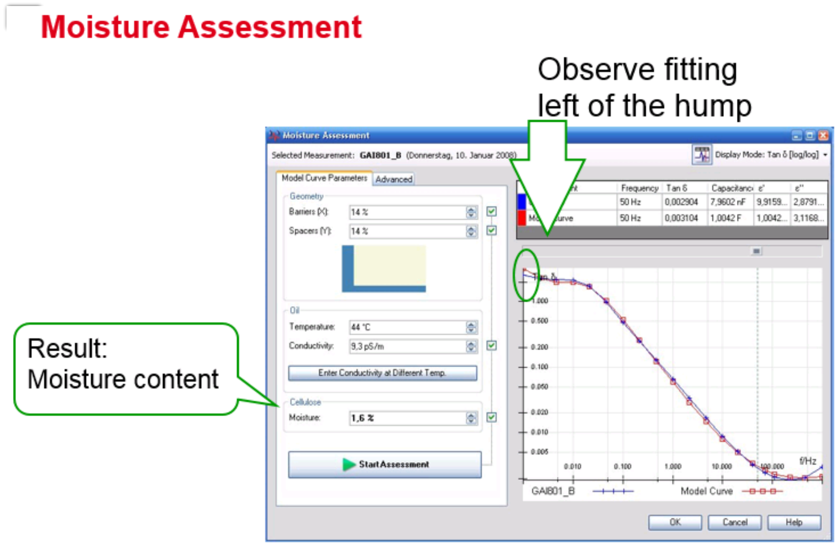

Figure 12 Moisture Assessment Report

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3 Sweep Frequency Response Analysis Testing

SFRA testing is one of the most sensitive methods for the detection of radial and axial deformation of windings, or physical movement of the core.

SFRA Testing is done in accordance with:
C57.149-2012 - IEEE Guide for the Application and Interpretation of Frequency Response Analysis for Oil-Immersed Transformers

> 1.1 Scope
> This guide is applicable to the measurement of Frequency Response Analysis (FRA) of an oil-immersed power transformer. The guide will include the requirements and specifications for instrumentation, procedures for performing the tests, techniques for analyzing the data, and recommendations for long-term storage of the data and results. This guide can be used in both field and factory applications.

Why perform SFRA?
Extreme mechanical forces on the core and coil assembly can be caused by impacts during shipping and handling, and by short circuit fault currents. This test can identify mechanical changes or deformation in the windings, core, and lead structures.

When viewed from its terminals, a transformer is a highly complex RLC network. Mechanical deformations, caused by high short circuit currents or shipping damage, change the behavior of the network and therefore the frequency response. The SFRA test is a sensitive method to detect mechanical deformations in the transformer, as reflected by changes in the RLC network. Those mechanical deformations are rarely detectable with conventional electrical measurements such as winding resistance or leakage reactance. The SFRA analysis is typically based on comparison to prior tests. Which means a reference measurement is necessary to evaluate any observed anomalies. Without it, comparisons will need to be made to "duplicate" units, or from one phase to another.

SFRA measurements are usually performed at two locations.
Manufacturer's factory
A baseline (fingerprint) measurement is recommended before the power transformer is shipped to the customer. Often 2 baseline test are performed, one in the fully assembled condition during factory testing, and then a second one when the unit has been prepared for shipping.
On-Site In the field
The test is recommended again, after transportation, to detect shipping damage. Depending on the baseline tests results that are available, the test may be done before acceptance- in the shipping configuration, and again at the end of the commissioning process. In each case, the results would be compared to the baseline that was produced in that same assembly configuration. During service, many operators will perform the tests after through faults, or another indication of fault alarms (DGA alarm, protection relay tripping). It is recommended after detecting abnormalities during conventional electrical tests, and also after major maintenance activities to the LTC, bushings, or windings.

Sweep Frequency Response Analysis involves testing over a wide frequency range. Different failures affect the frequency response in different sections of the frequency range. When reviewing a plot of the results, the main transformer components will produce frequency responses in different sections of the frequency band. They can be identified as shown in Figure 13 below.

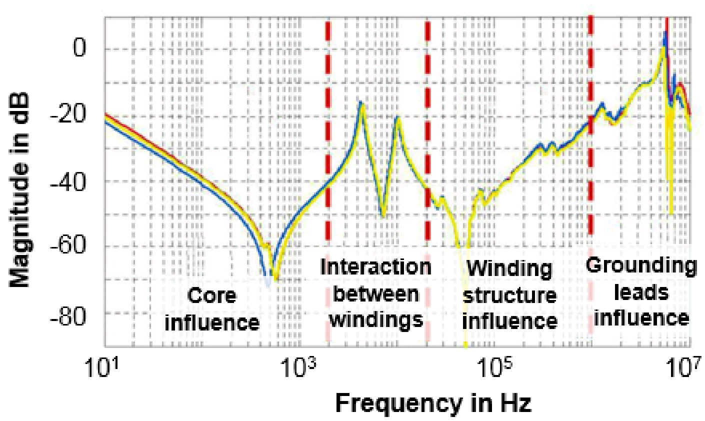

Figure 13

The defects or damage categories which cause deviations in the Sweep frequency response of a power transformer and which can be detected reliably are:

- Axial and radial winding deformation
- Displacements between high- and low-voltage windings
- Partial winding collapse
- Shorted or open turns
- Faulty grounding of the core or shields
- Core movement
- Broken clamping structures
- Deteriorated internal lead connections

SFRA versus traditional methods
The graph in Figure 14 below shows a typical frequency response plot. Many electrical problems in the low frequency range of an SFRA may be detected as well with the more conventional measurement methods. When evaluating mechanical problems, the traditional tests like capacitance, short circuit

impedance, and winding resistance show limited responses to movement. So the accuracy and reliability of those tests cannot complete with the SFRA results. Abnormal results from the conventional tests should prompt the tester to perform the SFRA test for better analysis.

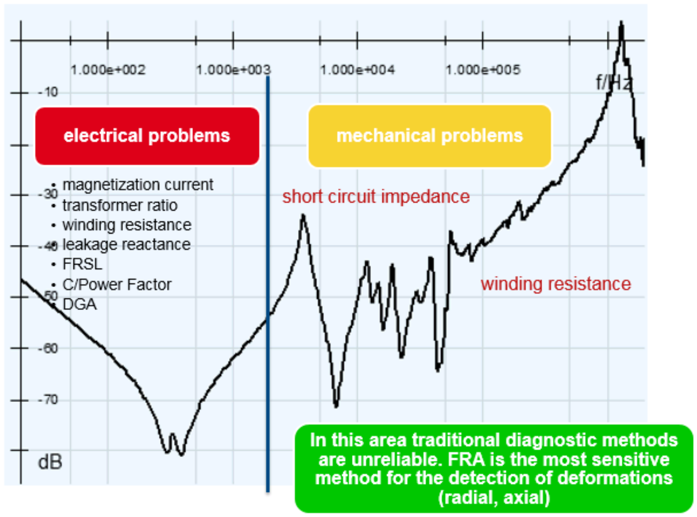

Figure 14 Comparison of Test Techniques, and their relationship to one another.

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4 Partial Discharge Measurement and Location

Partial Discharges are recognized as "localized partial breakdowns" of the insulation system. Partial discharges often occur before insulation fails from electrical stresses. The energy that is discharged can erode the insulation systems to the point that ultimately it will lead to an arcing flashover through the insulation system. Since deterioration of the insulation system is the most common reason for transformer failures, targeted testing is a prudent choice.

The electromagnetic emissions of PDs can be measured, and the energy released can be 'heard' by acoustic detectors placed on the tank wall. When multiple sensors are used, the signals can be analyzed to triangulate to the source of the partial discharges.

It is widely accepted that PD measurements are a very valuable tool for quality assurance, and investigations. Critical defects can be detected, and in some cases the type of defect can be recognized. Finally, one can factor the results with a precise fault location, into a transformer risk assessment, to develop a maintenance strategy.

When to test: The most common event that leads one to decide to do PD location testing would be a DGA result indicating significant PD activity. PD sensors, or other tests, may also provide results that would trigger a PD test recommendation.

Testing is done in accordance with:
C57.127-2007 - IEEE Guide for the Detection and Location of Acoustic Emissions From Partial Discharges in Oil-Immersed Power Transformers and Reactors

1.1 Scope

This guide is applicable to the detection and location of acoustic emissions from partial discharges and other sources in oil immersed power transformers and reactors. Both electrical sources (partial discharge) and

mechanical sources (such as loose clamping, bolts, or insulation parts) generate these emissions. There are descriptions of acoustic instrumentation, test procedures, and interpretation of results. When this guide is used with oil-immersed reactors, it must be understood that interpretation of signals may be different because of the construction of the reactor.
Accuracy of location depends on the type of fault, configuration of tank, type of instrumentation, and experience.

Background PD signal propagation path

Detection of the PD source requires placing acoustic sensors at various locations around the tank of an energized transformer. The PD signals generated by the fault are then recorded and analyzed. When travelling from the PD source to the reception sensor, there are several different paths that an acoustic PD signal may take:

> Via the direct oil path from the source to the tank wall and sensor. Most successful source locations result from finding this direct propagation path.
> By structure borne paths, here the sound wave hits the tank wall and travels through the steel wall to the sensor. Due to the high sound velocities in steel this wave often arrives at the sensor earlier than the wave that goes directly through the oil to the sensor.
> By bouncing waves, that are reflected off of the tank wall or other internal components.

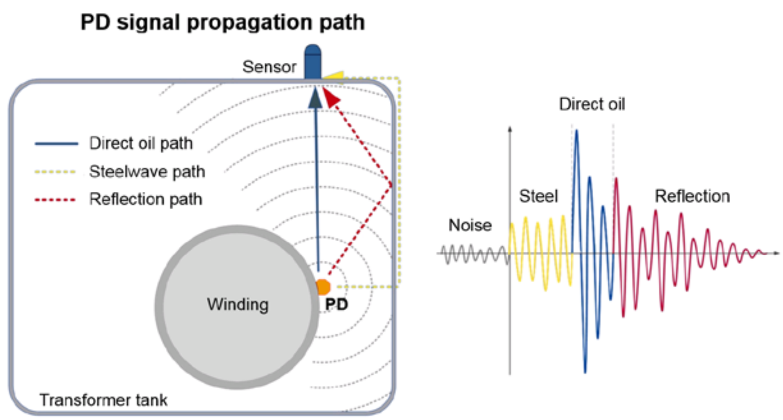

Figure 15 Propagation paths and signal components

Notes:
The software must be able to analyze the PD signal and distinguish between the propagation modes to compare the signals from the multiple sensors.
Relocating the sensor can help to improve the signal quality, shortening the propagation path, and may remove the structure borne path waves.
The propagation speed in oil is dependent on the oil temperature and the frequency of the sound signal.

When using one acoustic sensor and an electrical trigger, the possible position of the PD is located on a sphere around the sensor, with the distance (determined by the time of travel) as its radius. With multiple sensors there are spheres for every sensor, and the common intersection point (if it exists) of these spheres gives the location of the PD source. As shown in Figure 16, the intersection lines (in blue) of the absolute time spheres are visualized in the PDL software. These spheres are placed around the black, yellow and blue sensors.

When using only acoustic sensors, no absolute starting time is known, so only a trajectory surface between the two sensors can be found, indicating the time difference between both sensors. With more sensors there are more trajectory surfaces. If the intersection of these trajectory surfaces have a point in common, it will be at the PD source origin.

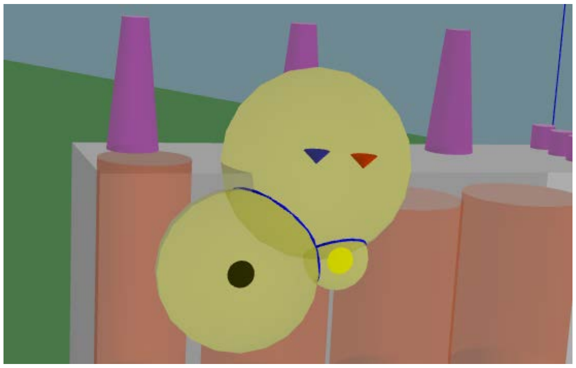

Figure 16 PD Source Location

Recent improvements in the technology of PD detection and location, have largely come from the improved computing technology, and improved signal processing capabilities, along with extensive testing experience.

Methods to improve the signal quality

Noise Processing: Averaging

Since the PD events usually are very repeatable, and occur regularly at a particular point on the voltage sine wave, this knowledge can be used to isolate the signal from the nearly random background noise.

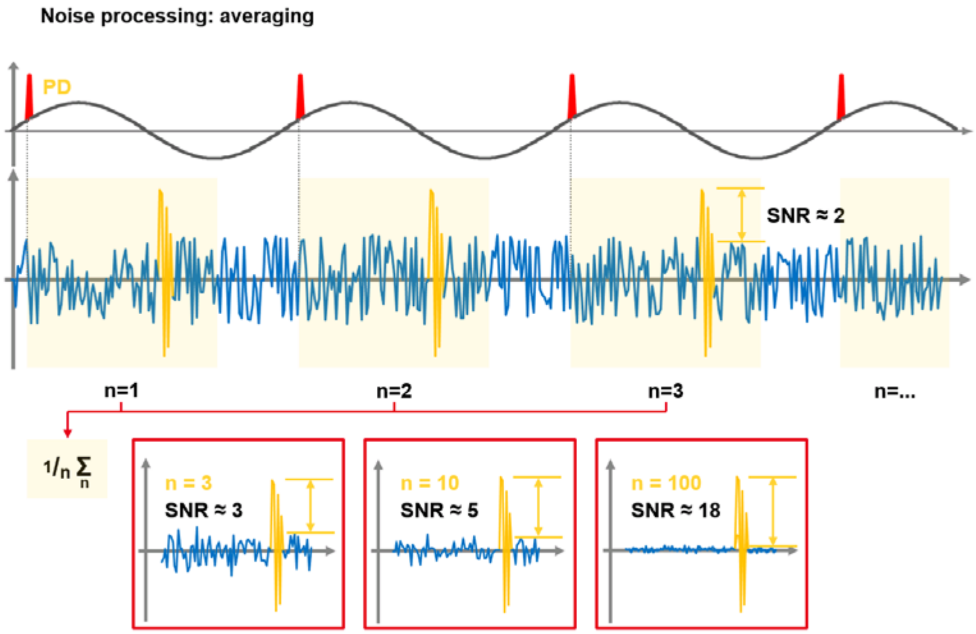

Figure 17 Signal processing - Averaging

Averaging the recorded signal over many repeating occurrences will tend to decrease the random noise level, and increase the signal-to-noise ratio (SNR) by a factor of $\sqrt{n}$, (where n is the number of recorded signals/impulses). So with a stable PD triggering source, it is possible to increase the quality of the signal and to statistically reduce the observed noise. See Figure 17.

Noise Processing: Filtering
By strategically choosing an appropriate high frequency pass filter, external noises such as pumps, fans, rain, core vibration, component vibrations, etc. can be reduced.

Finally, the improvements in testing equipment and techniques includes using fiber optic cables for electrical isolation of the measurement unit, improving the safety of PD measurements on high voltage circuits; increasing personnel safety for the user; and to provide significant noise reduction.

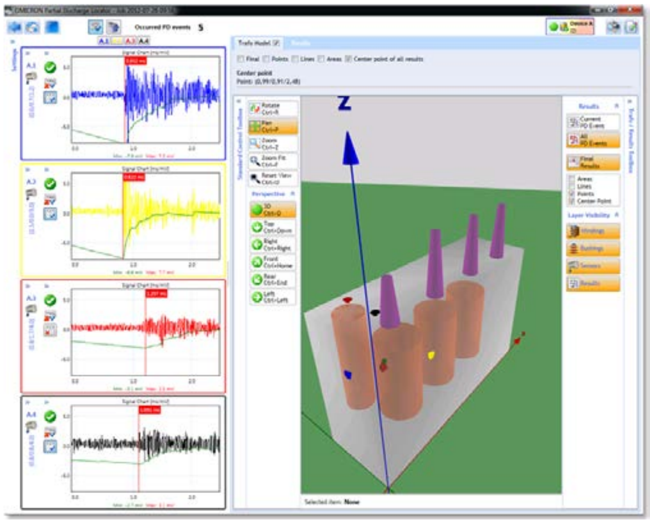

Figure 18 PD Location Report

The software will provide the analysis and a report showing the recorded signals, and multiple images of the suspected PD fault location. Figure 18

This concludes the introduction of four, relatively new, advanced diagnostic tests for power transformers.
Advanced Power Factor - Variable Frequency (15 Hz to 400 Hz)
DFR (Dielectric Frequency Response)
SFRA (Sweep Frequency Response Analysis)
Partial Discharge Location

References:
IEEE and ASTM standards are noted when discussed.
All figures, unless noted otherwise, come from OMICRON instructional power point presentations.

A Case Study of Pipeline Induced AC Mitigation on a Complex Right-of-Way

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ABSTRACT

Co-location of a new transmission line with an existing pipeline Right-of-Way particularly, in urban areas, can have many benefits including lower costs and quicker acquisition of easements. Indeed, in many instances the Public Utility Commission or other governmental agencies may suggest or direct co-location with other utilities. However closely aligning HVAC transmission lines with O&G pipelines will result in inducing Voltages and currents into the pipeline(s). These induced Voltages and currents may have very undesirable consequences for the pipeline(s) including: unsafe touch and step potentials, damage to the pipeline's protective coatings, damage to the pipeline steel including the possibility of pipeline puncture and product loss, and accelerated corrosion of the pipeline steel. There are many techniques available to mitigate these effects, but mitigation costs may be very costly, adding complexity and probable construction delays to the project. It is far better to assess these costs and complexities during the route selection process rather than to be committed to a preferred route only to discover that IAC mitigation will be complex, costly and will result in delaying completion of the project.

This paper presents a case history from a recent pipeline induced AC mitigation project in southern California. The presentation fully illustrates the complexity, time delays and costs associated with mitigation of induced AC effects on four closely spaced large diameter natural gas pipelines from a newly constructed 220 kV wind farm transmission line after the preferred route had been selected and Right-of-Way had been purchased.

INTRODUCTION

More and more pressure is being placed upon transmission line designers and support staff to site new transmission lines on rights-of-way that are co-located with underground utilities. Some of the considerations that affect route selection include: cost of right-of-way (ROW), particularly in urban areas; land utilization issues; aesthetics and other issues associated with NIMBY; directives by BLM and other governmental entities; rulings by public utility commissions; and other difficulties associated with ROW acquisition. The net result is that it has become common practice to site new transmission lines on common corridors with other utilities. Most frequently the other utilities are underground pipelines. With many fast track projects little, if any, thought is given to AC induction effects on nearby or paralleling underground utilities until route selection has been finalized and circuit engineering is well underway. This is extremely shortsighted and can be very costly to the electric utility in the form of excessively complex, extensive, and costly AC mitigation measures. When collocating a new circuit with existing underground utilities, the power company becomes liable for the full costs on the studies, design, and installation of any pipeline mitigation that may be required. These difficulties and related costs can most easily be minimized during the route selection process. But, project management must be proactive in engaging the services of an experienced consultant during the early stages of the project. This paper presents a case history where excessive engineering and construction costs and startup delays resulted from lack of forward thinking during route selection in the early stages of the project.

PIPELINE AC INDUCTION

At this day and time AC induction into underground pipelines is a well understood phenomenon by experienced practitioners in the industry and has been well documented in the industry. [a, b, c, d, e, f, g, h, I, j, k, l] Unfortunately the phenomenon is not well known by most T&D engineers responsible for siting new circuits. AC induction may be an issue on any metallic pipeline on the collocated ROW. This includes municipal water lines although municipal operators are generally less sophisticated and demanding than are the oil and gas (O&G) utility operators. AC induced corrosion of O&G pipelines has become a topic of serious discussion within the industry and is looked at closely whenever a new transmission line (TL) is proposed close to their ROW.

Mitigating against the probability of AC Corrosion on underground O&G pipelines is now far more of an issue than it was a decade ago. Mitigation to overcome the probability of AC induced corrosion is generally more extensive, and therefore costlier, than just mitigating for personnel safety or against direct pipeline damage alone. But, that is the world that we now live in. If the power company is not proactive with investigating the issue, the pipeline company(s) will. In that case, they will be far less concerned with the cost of the required mitigation scheme than the power company who will be responsible for reimbursement of all costs. In some instances, a pipeline operator might escalate the projected costs in an attempt to convince the power company to change the route segment. Therefore, it is generally in the power companies' best interest to proactively select a consultant to investigate the ROW segments in question during the early stages of route selection.

A CASE STUDY ON A COMPLEX RIGHT-OF-WAY

NextEra Energy began construction of a large wind farm project in eastern Kern County, California over a decade ago. Southern California Edison (SCE) proposed a 220 kV, 1,414 megawatt circuit to transport the energy to the grid and to allow for future load growth. Initial load, with the wind farm only, would be 240 megawatts. Therefore, the initial load would be only seventeen percent of circuit design. Part of the route along Segment 3B, was designed to cross and closely parallel four large diameter natural gas pipelines. Two of the lines were owned and operated by Pacific Gas and Electric Company (PG&E). The other two lines were owned and operated by El Paso Natural Gas Company, later becoming Kinder-Morgan Company (KM). Figure 1 shows the layout of the ROW. Total length of the close parallelism was 4.43 miles.

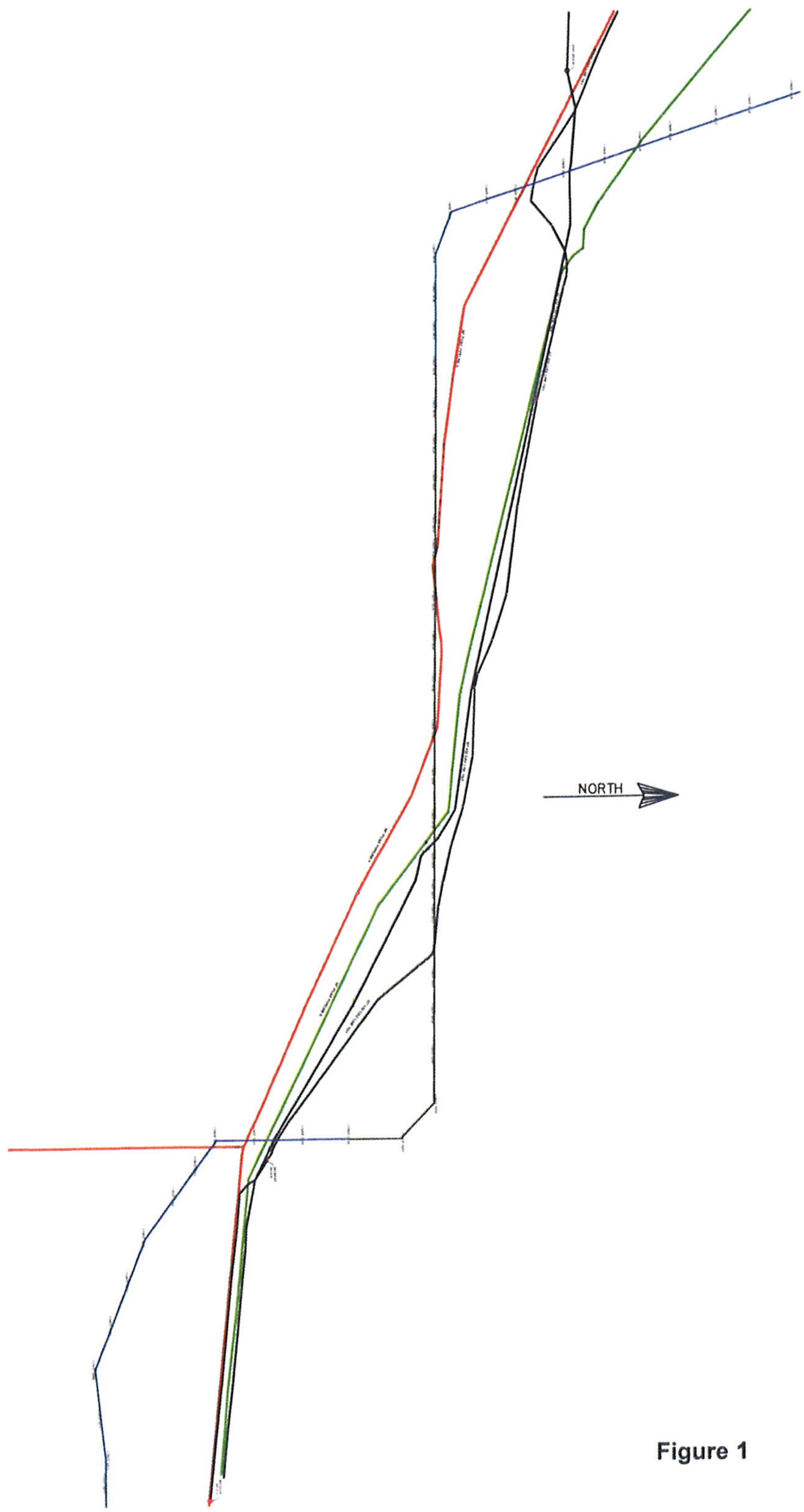

Figure 1

By the time that our firm was engaged to perform an induced AC mitigation study, the transmission line (TL) route had been finalized and the individual towers had already been staked with no chance for any relocation.

EXCESSIVE COST OF MITIGATION

Acquisition cost for independent ROW across essentially arid pasture land for less than 4.5 miles of alternate circuit route in an arid, undeveloped region of southern California is unknown but certainly would be only a small fraction of the expenditures outlined below. Provided that the circuit had been relocated with an adequate separation distance of two hundred to four hundred feet from the existing pipelines, no induced AC mitigation would have been required. However, since the ROW alignment was fixed, we were obligated to mitigate against all of the following effects:

- Personnel protection against unsafe step and touch potentials under "steady state" conditions [(m)]
- Damage to the pipeline wall and/or protective coatings under fault conditions
- Personnel protection against unsafe step and touch potentials under fault conditions [(m)]
- Corrosion damage to the pipe wall from induced Voltage under "steady state" conditions

For the short section of concern within the bounds of the Segment 3B alignment the following mitigation features were required to fully mitigate all of the concerns stated above:

- 48 shallow and deep ground rods ranging in depth from 75 feet to 887 feet. These rods were drilled into solid granite beneath a shallow overburden.
- 3,631 lineal feet of zinc ribbon installed as a horizontal mitigation wire close to the pipe. Backhoe excavation was required due to the rocky overburden.
- Gradient control mats were required for personnel safety at ten aboveground valve sites.
- Sixty cathodic decoupling devices were required between the pipelined and the installed grounding features.
- Sixteen specialized test stations were required to monitor AC discharge densities.
- A fifty-foot segment of 34-inch diameter pipeline, where a power line tower had been installed too close, had to be backfilled and provided with drainage culverts to assure safe touch potentials on the pipeline.

Due to the very close and complex interactions between the proposed TL and the existing pipelines, minimal separation distances between some of the TL structures and the pipelines, and multiple crossings; very extensive computer modeling was required to find acceptable and constructible solutions to the various exposures. Our engineering services on this project extended over about a six-year interval involving initial studies, electronic modeling of the ROW with and without mitigation features, design of all required mitigation in two phases, multiple sets of For-Construction plan and specifications, construction support, and acceptance testing. Total cost for all of our provided services was $931, 661. or $210,307. per mile of parallelism.

Total billing for construction of the required Phase Two only mitigation features was $4,029,000. or $909,481. per mile of parallelism. Added to this are the additional costs for in-house engineering, additional surveying and field investigations, constructability reviews, environmental impacts, administrative burden, etc. for both the TL designer and for SCE, and the complete costs of the Phase One mitigation program. None of these additional costs have been estimated for the case history under discussion here.

Initial computer modeling effort clearly showed the magnitude of the problem and the project management team was so advised. Project management's (PM) response was that it was no longer possible to relocate any of the towers and that we must mitigate against the IAC effects to the pipeline operator's satisfaction. Open and very cooperative dialog was maintained between all parties during the succeeding efforts. This was absolutely essential to successful conclusion of the project. The pipeline company's demands were firm but reasonable and studies proceeded post haste. Mid way through the project we recommended constructing the mitigation features in two phases in order to keep the project on track to meet the initial delivery requirements from the wind farm project. Due to personnel safety issues, it would not even be possible to back feed the circuit until at least some of the mitigation features were installed.

Phase One design was sufficient to assure safe operation of the pipelines with a maximum load of only 240 megawatts. Once all of these mitigation features had been constructed it was possible to back feed and subsequently transmit the wind farm load. Taking this two phase approach resulted in only delaying the initial back feed by a few weeks. Designing the Phase Two mitigation requirements was much more demanding and time consuming. Multiple conference calls with all project team members, involving more than twenty individuals, were required to discuss the various mitigation options available to us. Principal concerns during these discussions were constructability, cost, time to construct, and impact on the existing structures. A very large number of mitigation schemes were explored during the design effort. A considerable amount of additional field work was required by ELK, a subcontractor to ELK, and the TL designer. All of this design effort took well over a year to complete. No additional load could be added to the circuit until after all of the Phase Two mitigation features had been constructed and commissioned.

CONCLUSION

It is far more cost effective and will create far less schedule impacts during design and construction to investigate AC induction impacts during the route selection process rather than waiting until after a preferred route selection has been finalized. When making a preferred route presentation to the utility commission, the high cost for induced AC mitigation on particular segments can argue strongly in favor of the power company's preference for different segments.

Studies conducted during the route selection phase may be more general and less detailed, not requiring a For-Construction package. The only requirement is to identify the mitigation features that would be required for the proposed alignment and structure type(s) and to estimate construction costs. Many times minor adjustments in alignment, structure type(s) and/or conductor phasing can make significant differences in the overall complexity and costs for mitigation. One may anticipate preliminary study costs in the range of $2,000. To $15,000. per mile of parallelism, depending on length and complexity. For the case of a single pipeline and a single circuit, a long parallelism, and minimal changes in geometry. Cost would be at the low end. For the case of parallelisms that are short, in remote locations, or complex with multiple pipelines and multiple circuits; cost per mile will be considerably higher than is the case for similar rights-of-way.

Once final route selection has been made and TL design is in progress, the consultant that performed the preliminary assessment can be retained to finalize the mitigation design and to provide a complete For-Construction Package. Many times it may be advantageous for the consultant to provide construction support and/or acceptance testing of the final installation.

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AMERICAN ELECTRIC POWER

Breakthrough Overhead Line Design (BOLD)

Transmission Line Design Considerations

Eric A. Miller, P.E. and Elizabeth Decima

9/7/2016

BOLD™ (Breakthrough Overhead Line Design) is a high-capacity, high-efficiency transmission line design which optimizes structure geometry through the use of curved steel arms and compact conductor phase spacing. The unique geometry and electrical characteristics of a BOLD transmission line can be designed and constructed in a manner similar to typical transmission line projects; however, there are several considerations that line engineers need to consider with BOLD projects. The inaugural BOLD line constructed in Ft Wayne, Indiana was designed by American Electric Power using a process similar to developing a new structure or tower series. The BOLD structures developed are fully compatible for use in PLS-CADD™ and PLS POLE™. One key transmission line design requirement for long lines, which are limited by voltage or stability considerations, is that 95% of the line needs to retain the compact phase spacing to maintain the electrical benefits of the BOLD technology. The compactness of the conductor requires additional consideration for the line engineer with regards to galloping criteria, rolling clearances, and structural geometry. The unique electrical characteristics of BOLD also provide a line engineer with a solution to install EHV transmission lines in a narrower right-of-way corridor.

Introduction

AEP has been a pioneer in the development of extra high voltage (EHV) transmission technology by developing and constructing the first 345 kV and 765 kV lines in the United States in the 1950s and 1960s, respectively. AEP continues to lead this trend in transmission line innovation with the latest BOLD initiative.

The BOLD, or Breakthrough Overhead Line Design, initiative set out to design a cutting edge generation of transmission lines which would achieve greater capacity and efficiency by increasing the utilization of right-of-way (ROW) corridors. This more effective use of the ROW would reduce visual and environmental impacts. BOLD offers both electrical and geometric benefits.

The BOLD technology leverages physics to maximize electrical performance. The phase separation is reduced into a compact "delta" configuration (Figure 1) and the conductor diameter, number of sub-conductors, and bundle spacing are optimized. Figure 1 shows the BOLD insulator assembly for one 345kV circuit for a 3 conductor bundle.

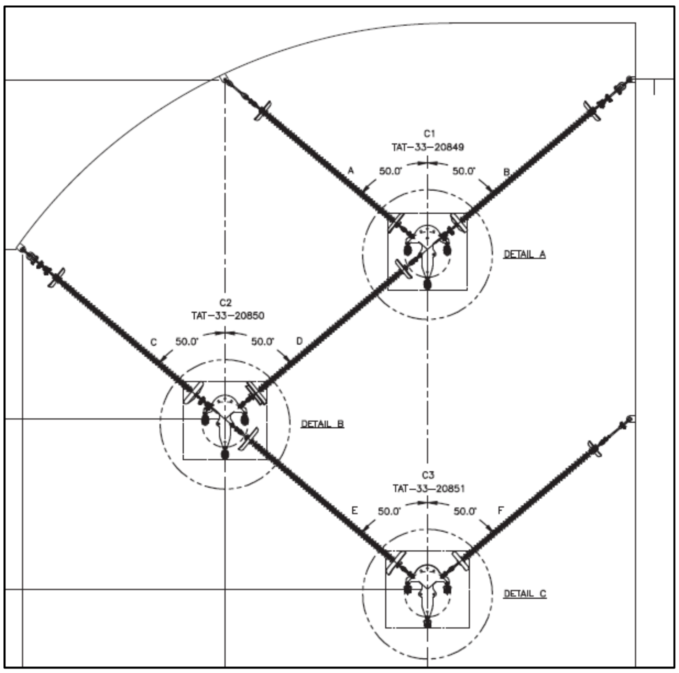


Figure 1

The electrical benefit of the compact configuration is a line with reduced inductance and increased capacitance which results in higher surge impedance loading (SIL). SIL is a measure of the relative loadability among alternative line designs. By bundling with multiple subconductors per phase, the SIL capacity increases and electric stress decreases to achieve desired corona and audible noise performance. A 345kV double circuit BOLD 3-bundled conductor design offers a 43% improved surge impedance loading over a traditional double circuit 2-bundled conductor design of the same voltage class [1].

When BOLD was developed, a goal of the project team was to address more than just optimizing the electrical properties. The team also considered aesthetics and structural optimization to support the delta configured phase conductors in a visually appealing way, which is desired by the general public and would facilitate public acceptance during siting. The compact delta conductor configuration is attached to a curved arm which also offers geometric benefits by minimizing the structure height. This feature of

BOLD is most beneficial to transmission line engineers. The end result of BOLD is a highly efficient line operating on shorter structures with less visual impact to the general public (Figure 2). BOLD has been developed for 345kV tubular and lattice designs and current efforts are underway to fully develop 230kV and 138kV designs.

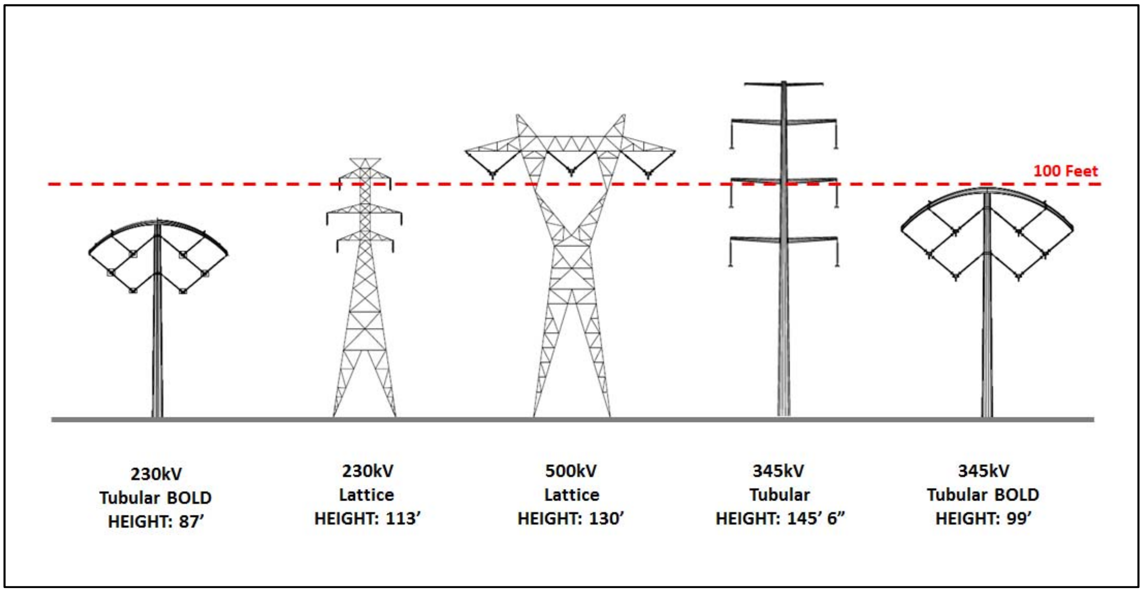


Figure 2

BOLD- Transmission Line Design Considerations

The responsibility to successfully implement the BOLD technology in real world transmission line projects ultimately falls on the transmission line engineer. Once a project has been identified as a candidate for BOLD, the transmission line process will be similar to a traditional line design project. As with any new structure family or technology, there are some key considerations the line engineer needs to keep in mind as the project is advanced from concept to construction.

This paper will provide a high level overview of the inaugural BOLD project process and then discuss key topics for a line engineer such as PLS-CADD™ modeling, compact spacing requirements, galloping and rolling clearances, ROW width, and geometric considerations.

Inaugural BOLD Project- Structure Development

The challenge of turning the BOLD technology into reality began with the identification of a candidate project in Fort Wayne, IN. Several planning solutions were analyzed before deciding that the optimal solution was to rebuild the 22 mile double circuit, 6-wired, 138kV existing tower line with double circuit BOLD construction operating one circuit at 138kV and the other circuit at 345kV. It was decided that the project would be a structure for structure replacement to minimize impacts to property owners. Average span length for the existing towers was 900’ with a maximum span length of 1219’ in a flat terrain environment. Figure 3 shows the optimized BOLD 345kV tubular structure overlaid on the existing 138kV tower. The 345kV circuit uses a 3 bundle 954 kCM ACSR conductor and the 138kV circuit uses a 2 bundle 954 kCM ACSR conductor.

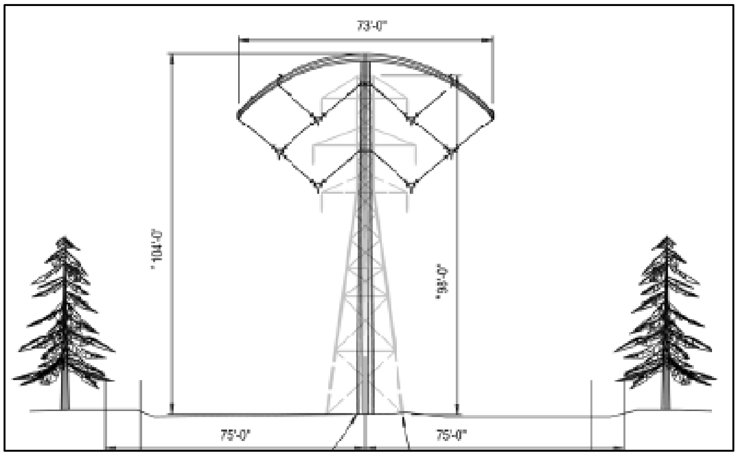


Figure 3

BOLD structure development started with a conceptual design based on the optimized phase spacing in the compact delta configuration. The optimized design was an iterative process to balance the electrical benefits, and the associated impacts on audible noise, corona, and EMF, with the geometric constraints of insulating lengths, arm length, and real world conductor motion from wind and ice.

Once the geometry was conceptually developed, the next step was electrical and structural modeling of the conductor and structure to refine a prototype structure to be used for full scale structural testing, hardware testing, and electrical testing.

Full scale structural testing was conducted at the Valmont-Newmark structural testing facility in Valley, Nebraska. Figure 4 shows the structural test set-up. The full scale testing confirmed the structure strength was consistent with the calculated values and confirmed that some of the unique aspects of the BOLD construction, such as the curved arm bending process (Figure 5) and interconnected insulator assemblies, could be accurately modeled and had no impact on structural performance. The structural testing was conducted using the actual insulator assemblies.


Figure 4


Figure 5

Hubbell Power Systems conducted single phase testing on the prototype insulators and hardware to conclude they met AEP's design criteria. Three phase electrical testing was also conducted at the EPRI Power Delivery Laboratory in Lenox, MA for power frequency, corona effects, audible noise, lightning surges, and switching surges.

Completion of the prototype testing series allowed the project development team to move into the next design phase of the structure development which was to produce an optimized BOLD structure family in PLS-CADD™. It was determined that the line would require a range of tangent and dead end structures, as well as a running angle structure. The lightest and most frequently used tangent structure was designed for wind spans up to 900’ and 0-2° line angles (Figure 6). Two heavier tangent structures were designed for longer wind spans and line angles up to 6°. The running corner structure was developed for wind spans up to 1,000’ and 5-15° line angles (Figure 7). One dead end structure was designed for line angles of 0-30° and a heavier dead structure was designed for 30-60° line angles (Figure 8).

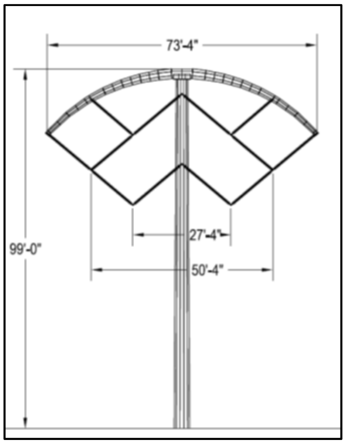


Figure 6

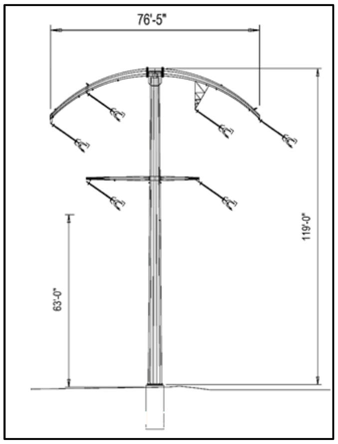


Figure 7

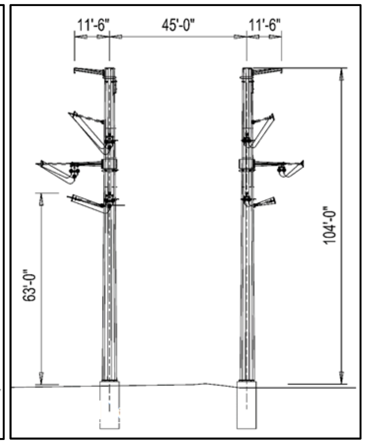


Figure 8

PLS-CADD Modeling

The BOLD PLS-CADD models are developed using standard functions within the program and are a collaborative effort between the line engineer and pole manufacturer. Structure performance drawings, which provide load case, geometry, and attachment details, are provided by the line engineer to the pole manufacturer. The pole manufacturer then develops the pole shaft model and provides the dimensions of the curved BOLD arm. At this time, the pole manufacturer cannot provide PLS pole models of the curved arm but can provide the arm dimensions. The line engineer can then use the arm dimensions provided by the manufacturer to create the arm, similar in PLS-CADD to a typical davit arm, using a series of short tangent segments and tapering the arm diameter (Figure 9). The process is similar to ordering a typical davit arm structure but designing the davit arms as a separate component not provided by the pole manufacturer.

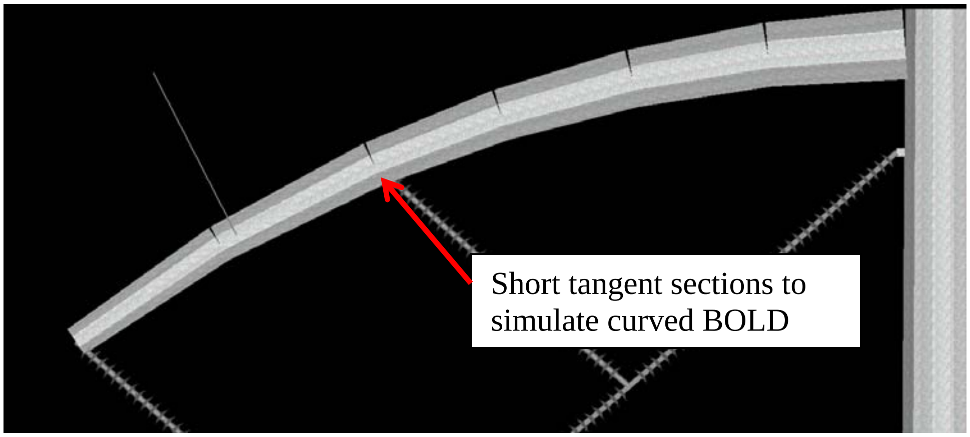
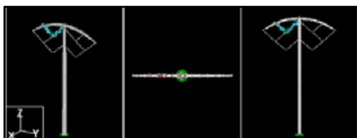


Figure 9

Connections, such as the insulator vangs and the "knuckle", or the top section of the pole shaft where the arms attach, are structurally designed and checked by the pole manufacturer. The line engineer designs the insulators using the 2 part insulator function in PLS-CADD. Limits should be set within the model to check that insulators do not go into compression under wind cases as dictated by the project design criteria, similar to typical V-string insulators. The insulator attachment points will be vangs on the structure or the vertex of an adjacent V-sting insulator, depending on which insulator is being modeled. Figure 10 shows a typical BOLD 2 part insulator connectivity table from PLS-CADD.



Model Check Report

No errors or relevant warnings detected.

	2-Parts Label	Side A Str. Attach	Side B Str. Attach	Tip Label	Property Set	Down Right	Cond. 1 Min Load Angle (deg)	Cond. 1 Max Load Angle (deg)	Cond. 2 Min Load Angle (deg)	Cond. 2 Max Load Angle (deg)	Cond. 3 Min Load Angle (deg)	Cond. 3 Max Load Angle (deg)	Cond. 4 Min Load Angle (deg)	Cond. 4 Max Load Angle (deg)
1	C1	Arm1:b3	V1	C1	230kv-1-R2SCA(3Dove)	Down/Right	-45	45	-45	45	-45	45	-45	45
2	C2	Arm1:b5	C1	C2	230kv-2-R2SCA(3Dove)	Down/Right	-45	45	-45	45	-45	45	-45	45
3	C3	C2	V2	C3	230kv-3-R2SCA(3Dove)	Down/Right	-45	45	-45	45	-45	45	-45	45
4	C4	Arm2:b3	V3	C4	230kv-1-R2SCA(3Dove)	Down/Right	-45	45	-45	45	-45	45	-45	45
5	C5	Arm2:b5	C4	C5	230kv-2-R2SCA(3Dove)	Down/Right	-45	45	-45	45	-45	45	-45	45
6	C6	C5	V4	C6	230kv-3-R2SCA(3Dove)	Down/Right	-45	45	-45	45	-45	45	-45	45
7														

Figure 10

It should be noted that due to the interconnected property of the BOLD insulators, some of the insulator strings will be subjected to loads that are doubled in magnitude. As shown in Figure 11, two insulator strings, with the load magnitude labeled $2{*}T_L$ and $2{*}T_R$, will support the load from the conductor attached to the vang and the load from an interconnected insulator attached to the same vang.

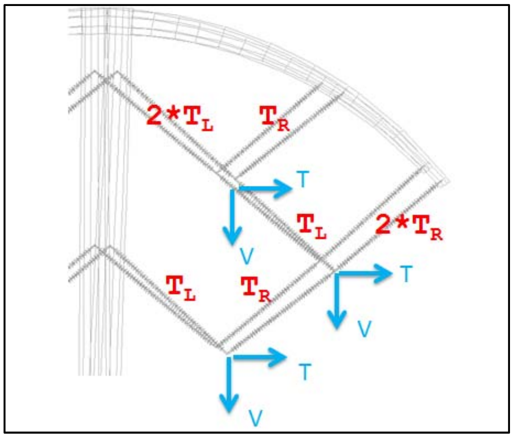


Figure 11

95% Phase Compaction Requirement

One key requirement for all line engineers working on a long transmission line BOLD project, which are limited by voltage or stability considerations, is to maintain the compact phase spacing for 95% of the overall line length. Lines in excess of fifty miles are a suggested approximation for characterizing a transmission line as "long", and therefore being subjected to the 95% phase compaction requirement. Increasing phase to phase clearances is a possible design option which may be considered for long spans, at dead end structures due to increased dead end spacing needs, or when rolling to a horizontal configuration. However, electrical modeling of long transmission lines has shown that the compact phase spacing is required for 90-95% of the line length to maintain the electrical benefits discussed previously. Setting the requirement at 95% will conservatively ensure the line will operate as intended. Deviation from this requirement would require additional electrical modeling to ensure intended performance of the line is achieved. Short lines, or lines which are thermally limited, and not limited by voltage or stability considerations, are not subject to the 95% phase compaction requirement. For these lines, the compact phase spacing should be maintained for structure height minimization and aesthetic reasons but the electrical performance will not be affected by increasing the phase spacing in more than 5% of the line.

Galloping Criteria

For areas where galloping is either historically known to occur or is expected, the line engineer will need to consider the potential for galloping in the design. Special consideration is required for BOLD projects due to the compact phase spacing of the conductors. Several galloping analysis methods are used in the transmission industry and the results of these different methods can vary dramatically. Studies have shown that installing in-span interphase insulators, or I^3 insulators, can reduce the galloping magnitude by half [2]. Figure 12 shows a picture of a typical midspan insulator. Depending on the project span lengths and galloping specifications, the line engineer has several options to mitigate galloping concerns. These mitigation options can be applied to lessen other forms of conductor motion also:

- Decrease span lengths (possible added benefit of using a more narrow corridor as discussed in ROW considerations)
- If only a few of the longer spans have excessive galloping ellipses, the phase spacing can be increased on those spans only, keeping in mind the 95% compact spacing requirement
- Install I^3 insulators at the time of initial construction
- Install conductor with compact spacing and monitor performance over time; install I^3 insulators at a later date if deemed necessary
- Use anti-galloping conductor

Figure 12

Rolling Clearances

Rolling from a compact vertical BOLD configuration to a horizontal configuration, such as a station bay, can also require some consideration from the line engineer. Depending on the span lengths and geometry, the line engineer has several options to meet the design criteria minimum phase to phase rolling clearances:

- Increase phase spacing at a dead end structure outside the station, keeping in mind the 95% compact spacing requirement
- Install an intermediate suspension structure between a BOLD dead end and the station bay, keeping in mind the 95% compact spacing requirement (see Figure 13)
- Vary the tensions in each phase for the entrance span into the station (i.e.- install the top phase with higher tension than the middle phase and the bottom phase with lower tension than the middle phase)
- Install I^3 insulators on the rolling spans at the time of initial construction

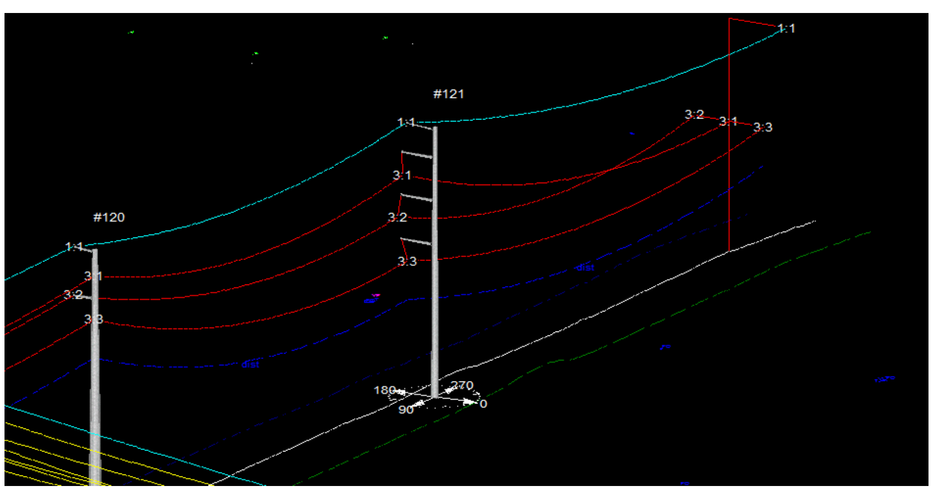


Figure 13

Right-of-Way (ROW) Requirements

One additional benefit to a BOLD line is the flexibility it provides a line engineer to install EHV lines using a narrower ROW width due to lower audible noise and magnetic fields. This can be a particularly useful solution for ROW constrained areas, such as urban settings, or if the engineer intends to limit the galloping ellipses.

As shown in Figure 14, audible noise and magnetic fields of a 345kV BOLD line with 3 subconductors at the edge of 105' ROW compares favorably to traditional 345kV designs at the edge of 150' ROW. The audible noise from BOLD is more than 1-2 dBA lower than that of conventional design at the edge of 105' ROW and less than that of traditional designs measured at the edge of the 150' ROW. The magnetic field from BOLD is 50% of that produced from traditional designs at equal electrical loading at the edge of each ROW. The magnetic field from BOLD at the edge of the 105' ROW is less than that of traditional designs at the edge of the 150' ROW. If the electric load of BOLD is doubled, the resulting magnetic field at the edge of either the 105' or 150' ROW will equal the magnetic field of traditional designs with the base loading.

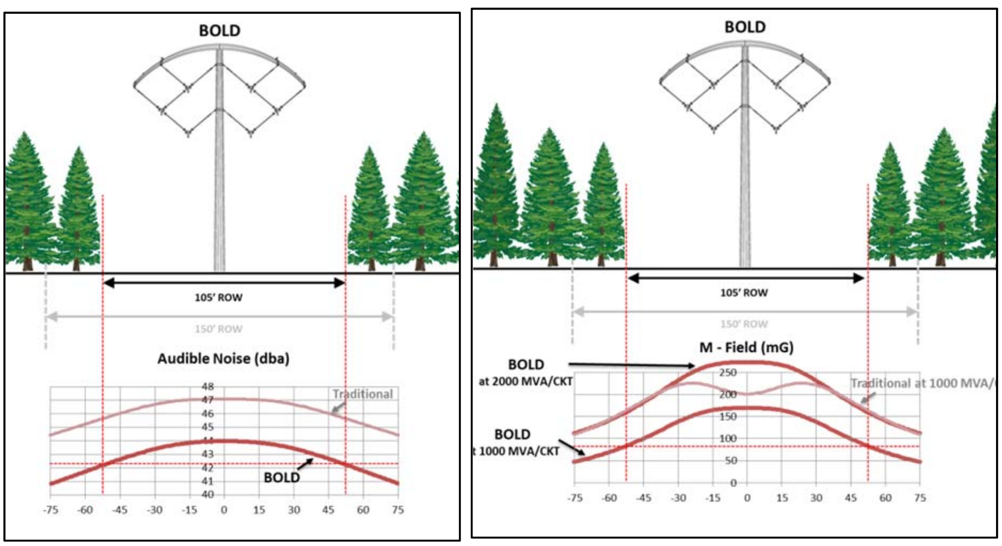


Figure 14

For a greenfield project without a constrained ROW, the line engineer will typically determine structure locations to optimally minimize the number of structures and project costs. For these projects, ROW width will be determined by conductor blowout. Conductor blowout for BOLD structures is similar to the blowout of a typical suspension I-string insulated conductor even though the BOLD arm is longer and the middle phase is further from the pole shaft than traditional designs. For typical transmission span lengths, the I-string insulator swing on a traditional 345kV structure will horizontally position the conductor in a vertical plane close to the location of the outermost BOLD phase when both are loaded under 6#/ft wind cases, as shown in Figure 15. In Figure 15, the pink lines represent the BOLD conductor blown out position at midspan and the blue lines represent the traditional conductor in a similar condition for 1,000' span lengths. Figure 16 shows ROW widths required for a 345kV double circuit structure optimized line (150' ROW with optimized structure spacing), a 345kV double circuit ROW optimized line (105' minimum ROW with shorter spans to limit blowout), and a 345kV single circuit line ROW optimized line (50' minimum ROW with shorter spans to limit blowout).

Some structures which have design features to address galloping concerns may have middle phase davit arms which are longer than the top and bottom phase arms to reduce or eliminate the galloping ellipse overlap. Structures with this design feature would have greater ROW width requirements due to the increased blowout width. The traditional design selected for the blowout comparison in Figure 15 does not have this design feature.

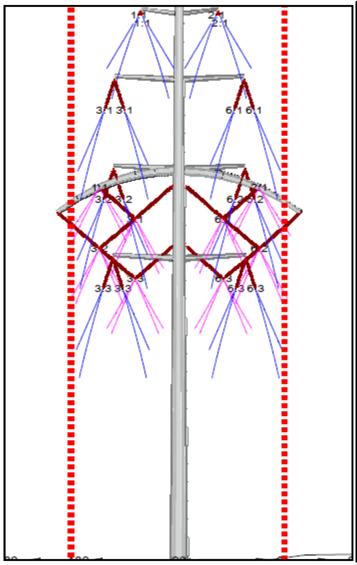


Figure 15

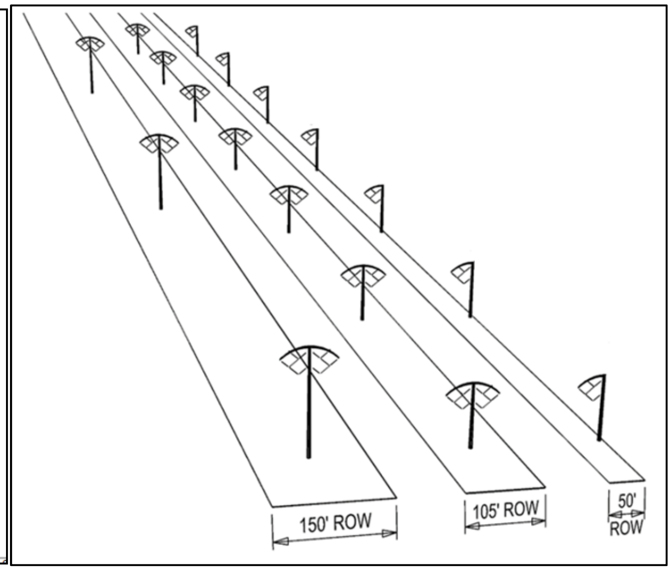


Figure 16

Arm Geometry

BOLD arms are typically longer than traditional steel pole davit arms due to the optimized insulator geometry. Some traditional tubular structures designed for galloping may have a longer middle davit arm, comparable to the length of the BOLD arm, but most traditional designs will utilize davit arms considerably shorter than the BOLD arm. For a 345kV BOLD structure, the tip to tip distance of the arms is 73'-4" compared to 43'-0" for the traditional tubular structure with davit arms shown in Figure 17. The line engineer needs to account for this additional length and may need to adjust typical offsets when placing BOLD structures adjacent to public road ROW or railroads to avoid overhanging these facilities.

Corridor construction, or constructing parallel lines in a common ROW easement, is another situation where the line engineer may need to evaluate typical offset distances between adjacent lines. Depending on the geometry of the lines, the longer BOLD arms may present phase to ground clearances which are less than traditional lines in corridor construction. In most cases, placing BOLD structures near the adjacent line structures, and not at midspan where maximum conductor blowout occurs, will alleviate inadequate phase to ground clearances.

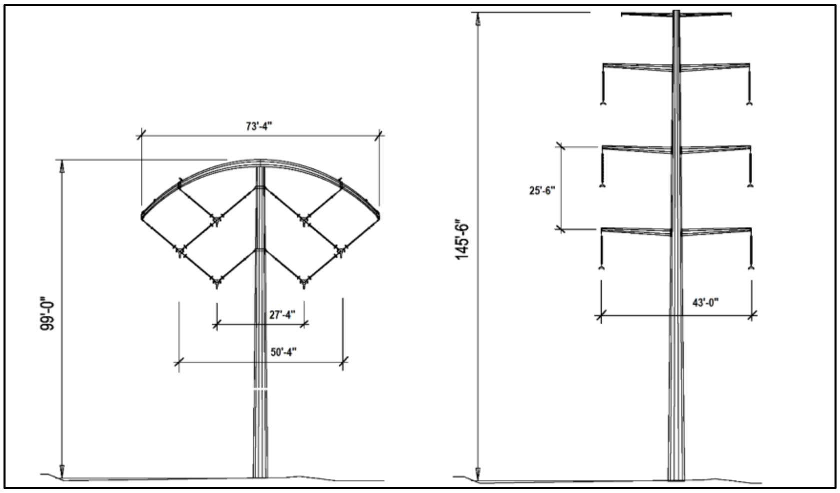


Figure 17

BOLD Dead End Structure Geometry

BOLD dead end structures are similar to traditional dead end structures and consist of two independent poles with one circuit terminated on each pole. Ideally the compact delta phase spacing will be maintained at the dead end structures. For light line angles, this can be achieved by terminating the top and bottom phase on the pole shaft, similar to traditional tubular structures, and installing a davit arm to terminate the middle phase on (see Figure 18).

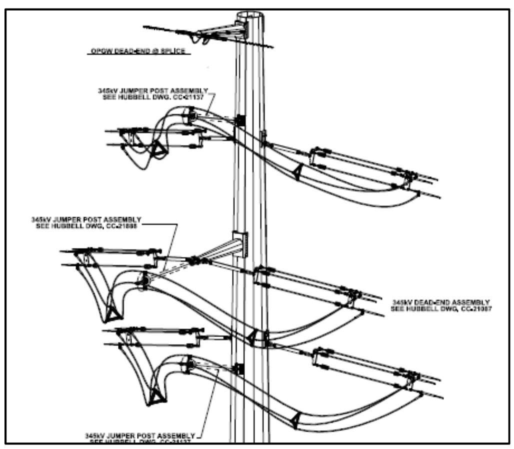


Figure 18

The compact phase spacing presents a unique geometry for the line engineer to consider, particularly for heavy line angles. One clearance to check for medium to heavy line angles is the phase to ground clearance between the middle phase, which terminates on a davit arm, and the steel pole as shown in Figure 19. As the line angle increases, the middle phase davit arm will need to be lengthened to maintain the compact delta phase spacing of the adjacent tangent structures. Installing a second davit arm, with both arms perpendicular to the middle phase conductor, is a solution if the arm length becomes excessive for heavy line angles.

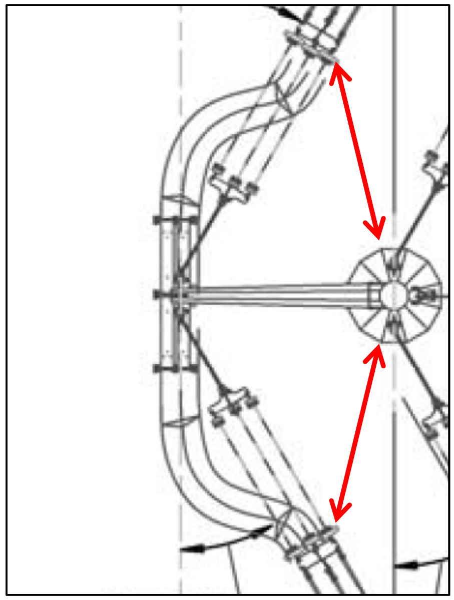


Figure 19

Some projects may require one face of the poles to be “clean” of wires for maintenance access purposes. For these projects, it would be necessary to install all jumper loops on the same side of the pole as the middle phase davit arm. The compact phase spacing with heavy line angles can create challenges for construction crews to make up jumper loops that maintain adequate clearance between the top phase jumper loop and the middle phase corona rings on the energized end of the insulator (Figure 20). A recommended best practice is to create 3D models of the jumper loops and insulator assemblies to discover where design modifications may be needed prior to finalizing the insulator assembly designs. The line engineer has several options for increasing clearances at the dead end insulators:

- Space the phases out and use a typical dead end vertical configuration with all 3 phases and shield wire terminated on the pole shaft, keeping in mind the 95% compact spacing requirement. Jumper loops would be installed on the inside angle of the pole, similar to traditional construction.
- Maintain the BOLD delta configuration but increase the vertical distance between the top and bottom phases as required per the 3D model clearance check, keeping in mind the 95% compact spacing requirement. Depending on the line angle, 2 post insulators may be needed to “walk” the jumper loop around the larger exterior angle.
- If maintaining a clean pole face for maintenance is not a requirement, then installing the top and bottom jumpers around the inside angle of the pole, and installing the middle phase jumper around or under the davit arm, will provide adequate room for all 3 phase jumpers

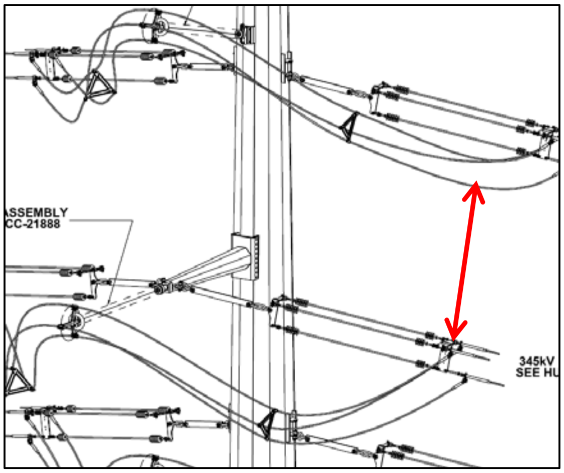


Figure 20

Conclusion

BOLD offers transmission utilities with an alternative solution to address many of the challenges that are faced in the current environment including increased public opposition, difficulty obtaining new ROW easements, and cost sensitivity. The transmission line engineer plays an integral role in promoting the BOLD solution [1] and successfully integrating this technology. As discussed in this paper, BOLD technology can be seamlessly integrated with little modification to traditional transmission line design procedures and tools utilized by most utilities today. It has been successfully implemented on two 345kV projects in Indiana and has been conceptually developed for numerous other applications.


Figure 21

References

1. R. Gutman and M.Z. Fulk, "AEP's BOLD Response to New Industry Challenges," Transmission & Distribution World, November 2015.
2. D.G. Havard. "Conductor Galloping" IEEE ESMOL and TP&C Meeting. Las Vegas, Nevada. January 2008

A Beginners Guide to Weld Inspection of Steel Utility Structures

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Abstract

The Utility Transmission and Distribution industry has countless suppliers of weldments of all shapes and sizes, from extremely high quality to some that are, let's say, less than perfect. Without a background in welding or weld inspection, the customer may have no idea from which end of the spectrum their manufacturer is supplying them. This paper will discuss the importance of inspection on finished utility structures, what the customer should expect, and how they can help to ensure that they get what they paid for.

A Beginners Guide to Weld Inspection of Steel Utility Structures

- Introduction

The steel utility structure industry supplies structures, parts and weldments of all shapes, sizes, and uses, as a result, a countless number of manufacturers, representatives and suppliers exist. At times, following the flowchart of the supply chain can be a daunting task and insuring high quality of the final utility structures can be challenging. As parts of the supply chain puzzle regularly change, the potential for problems associated with weldments becomes a critical issue. The inspection of these welded products is an important step to insuring the longevity of the utility infrastructure. All products, both galvanized or weathering steel, must be thoroughly inspected prior to installation to help to confirm no visible deficiencies are present.

- Inspections Before Weldments have been Completed.

Before diving into inspections performed on parts that have been completed, we need to address the necessity for plant level checks to confirm conformance to the many details that go into the fabrication of a utility structures.

Prior to the striking of the first arc of the welder, numerous variables need to be confirmed to assure not only the highest quality product but equally important, that the right product is being built. Pre-production plant audits, when performed properly can eliminate issues that could potentially delay projects and cause headaches in the field. A typical plant audit may include a review of the customer and manufacture specifications to verify agreement. It would further include a review of quality manual, fabrication work instructions, welding procedures and welder qualification documentation to name a few. A pre-production plant audit gives the customer the confidence that the manufacturer is appropriately equipped to finish the job and meet the customer's expectations.

Vendor surveillance is another key piece of the puzzle in an effort to stop problems before they proliferate. The journalist Glenn Greenwald wrote, "Surveillance breeds conformity."[1] regarding America's surveillance state and that conformity is what utilities need from their suppliers and manufacturers… Conformity to codes, specifications and procedures. In an ideal world where quality is the highest priority, vendor surveillance would be unimportant. But unfortunately we do not, in fact, live in an ideal world. In many cases, quality becomes a "roadblock" to production and profitability. Items with high importance like material traceability, weld procedure parameters, weld joint fit-up, and pre and post-weld heat treatments can be next to impossible to check after the manufacturing of a part is complete. A properly trained inspector understands the importance of checking the fabrication requirements including: base metals, welding consumables, welding technique, material preparation and fit-up, workmanship and repairs. These variables and many more can have drastic effects to the lifespan and serviceability of your structures.

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[1] Glenn Grennwald: "How America's Surveillance State Breeds Conformity and Fear", July 4th 2012.

Visual weld inspection should be performed by or under the supervision of a Certified Weld Inspector (CWI) per the American Welding Society's *Structural Welding Code – Steel AWS D1.1/D1.1M:2015*. AWS D1.1 should be used as a minimum mandatory welding requirement. Table 6.1 in D1.1, Visual Inspection Acceptance Criteria, details discontinuity categories and inspection criteria for both statically loaded non-tubular connections and cyclically loaded (fatigue sensitive) non-tubular connections. The table addresses the following discontinuity categories: cracks, weld/base metal fusion, craters, weld profiles, time of inspection, undersized welds, undercut, and porosity.

Almost all weld defects can be attributed to out of welding process parameters, poor welder technique and /or a welder that was not qualified, per the code, to perform the welding operation being performed.[2]

Preheat Being Performed.

The control of heat input or lack thereof can have can have wide scale consequence including lack of fatigue strength in the weldment and embrittlement of the weld and heat affected zone.

[2] "Planning Advisory Notice – Welding Discontinuities and Defects" , Brian Reese, May/June 2016, Tower Times.

Out of tolerance fit-up.

Visual inspection of the fit-up of an assembly is crucial due to the fact that it can NOT be seen once the members are welded. In the photo above, the thru-vang to shaft tolerance was exceeded which could have caused a weakened joint if not caught prior to weld-out. This non-conformance would have been extremely difficult to catch after the fact.

Vendor surveillance in conjunction with a comprehensive audit will consistently result in better quality products conforming to the customer specifications, a higher probability of meeting the project schedule, and lowered costs associated with delays and reworks. All this is achieved prior to structures being delivered to the site.

- Importance of Visual Inspection

A comprehensive weld inspection must be performed on all finished structures to ensure that all weldments are acceptable to the applicable codes, standards, and specifications for weld discontinuities.

Typical weld discontinuities include: Cracks, porosity, inclusions, undercut, underfill, weld spatter, arc strikes, poor weld profiles, and incomplete joint penetration to name a few.

One of the most critical weld discontinuities are cracks. American Weld Society's AWS A3.0/A3.0M, 2010, *Standard Terms and Definitions*, defines a crack is defined as a fracture-type discontinuity characterized by a sharp and high ratio of length and width to opening displacement. Cracks can occur in the weld, the heat affected zone or in the base metal when stresses are greater than the material strength. Per AWS D1.1, no cracks are acceptable. – "any crack shall be unacceptable, regardless of size or location." Cracks are extremely problematic and will lower the lifespan of the structure along with reducing a weldments resistance to fatigue stressors.

Cracks can also be caused as a result of other discontinuities. Porosity, inclusions, undercut and underfill are all discontinuities that can cause stress risers to occur which can initiate crack propagation and therefore need to be repaired if found in excess to the code.

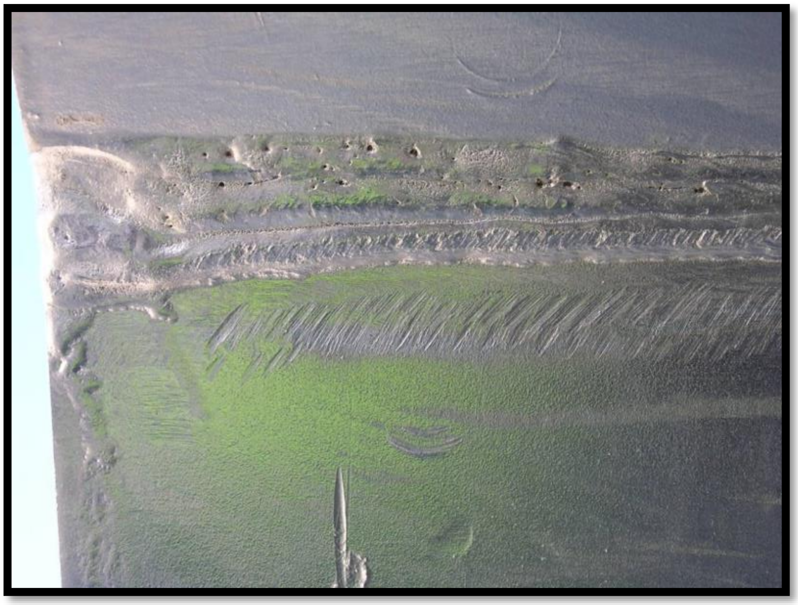

Illustration of porosity.

Arc strikes are the result of welder carelessness and are caused by the accidental initiation of an arc away from the weld joint, causing a localized area of melted metal that rapidly cools due to the lower temperature of the surrounding metal.

Illustration of an arc strike.

Poor weld profiles and incomplete penetration along with incomplete fusion are all discontinuities that can be found through a comprehensive weld inspection and should be repaired.

Undersized welds, defined as any weld not meeting the size requirements of the project specifications and codes, can have a detrimental effect on the structure integrity of the utility structure as well. These welds may have little or no defects other than being undersized per the weld detail or customer specifications and may not give the weldment the structural capacity it was designed to have.

Inspector checking weld size.

- Nondestructive Testing Methods to Aid Visual Inspection

Often, nondestructive testing (NDT) methods can be used in conjunction with a comprehensive visual inspection to support findings or in some cases provide a more in-depth view into a weldment. Both magnetic particle testing and liquid penetrant methods can be used to aid the inspector in detecting surface baring discontinuities such as, cracks and porosity. While ultrasonic, phased array, and x-ray methods can be used for the detection of sub-surface discontinuities such as inclusions and lack of penetration.

Magnetic Particle being used to confirm the existence of a crack.

Proper qualification and certification of personnel for all methods of NDT is critically important to insuring that each testing method is performed accurately and reliably. At a minimum, all technicians performing nondestructive testing should be certified to a company's written practice that follows the guidelines of the American Society for Nondestructive Testing's (ASNT) Recommended Practice SNT-TC-1A for the Personnel Qualification and Certification in Nondestructive Testing. If used by a qualified technician with a comprehensive procedure, NDT can in conjunction with visual inspection eliminate an extremely high percentage of weld discontinuities from a structure.

- Summary

The comprehensive inspection of structural steel utility products is an important step to insuring high quality products are delivered to the customer without the potential for added costs due to delays or even worse, potential catastrophic failures. An inspector's qualifications, including training program should be extensive in the methods he or she employs in conjunction with the visual inspection.

If a thorough inspection program, including vendor surveillance and possibly facility quality audits are employed, the customer will greatly increase the chances of a successful utility project.

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Mr. Ehler is a 1998 graduate of Baylor University in Waco, Texas with dual degrees in Environmental Science and Psychology. After spending several years in the heavy construction and utility industries, Mr. Ehler was one of the founding employees of ReliaPOLE Inspection Services Company, a Houston based inspection firm focused on the global pole and lattice tower industries. In 2015, Mr. Ehler and ReliaPOLE branched out to form Texas NDT Academy. As TXNDT's Senior Instructor and General Manager, Mr. Ehler is committed to providing his students with the ideal curriculum consisting of both the theories and science behind each course offered, but also their use in real world applications and best practices.

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Real Time Operational Considerations for Phase Shifting Transformer

Prepared for

TRANSMISSION AND SUBSTATION DESIGN AND OPERATION SYMPOSIUM

UNIVERSITY OF TEXAS ARLINGTON

July 17, 2016

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1.0 ABSTRACT

With increased renewable generation integration and the resulting congestion issues within the electric grid, the implementation of a Phase Shifting Transformer (PST) may provide economical solutions to alleviate near-term reliability concerns. While the PST may be feasible for most system conditions, there may be conditions during which system operators will have to limit the contribution of the PST to power flow. Oklahoma Gas and Electric (OG&E) studied the implementation of a PST to address specific congestions issues by evaluating various combinations of generation, transmission and load scenarios as well as PST design parameters. This evaluation revealed boundaries that inform both the specification and operation of the PST in real time. The Power System Simulator for Engineering (PSS/E) software and the Electromagnetic Transient Program (EMTP) software were employed to simulate multiple system conditions and develop operational plans for real time operation of the PST.

2.0 INTRODUCTION

2.1 Background

A Phase Shifting transformer is a transformer that can control or modify the difference in phase angles between its primary windings (source) and secondary windings (load). This allows for control of the power flow, specifically the direction of the power flow on lines local to the PST. Therefore, a PST can be a useful tool for alleviating congestion and an alternative to more traditional transmission improvement projects such as line upgrades and new construction.

Phase-shifting transformers are available in many different designs, including symmetric and asymmetric voltage magnitude, single or dual core, and various connection types. A symmetrical voltage magnitude PST was chosen for this project and was modeled in PSS/E for use in this analysis. The number of cores and connection type are heavily influenced by the required specifications and were left to the choice of the vendors during the bid process.

2.2 Problem Description

The area west/north-west of the 345kV OG&E Tatonga substation (Woodward Area) has approximately 2044 MW of wind generation capacity presently in operation and a firm expectation of growth to 3287 MW of wind generation capacity by 2018. Additionally, other less firm generation interconnection projects currently in the queue could increase that number to almost 4500 MW.

OG&E transmission planning staff proposed the assessment of the addition of a phase shifting transformer as an economical alternative to additional 345kV or 138kV transmission circuits required to alleviate congestion caused by the current and forecasted generation. The specific purpose of the PST is to reduce the thermal loading on the Woodward District to Windfarm Switching Station 138kV line in high wind conditions while maintaining local system steady state and stability reliability under N-0 and N-1 contingency scenarios. (Carlos Grande-Moran, 2012)

This technical paper supports the parameters specified in the PST bid document, and determines the usable phase shift angles for operation of the PST for a selection of modeled scenarios.

3.0 PARAMETER VALIDATION

To support the equipment bid specification, analysis was on four key parameters: phase shift angle range, angle step size, impedance, and capacity. The sensitivity analyses utilized Power System Simulation for Engineering (PSS/E 33.0) software from Siemens Power Technologies International.

3.1 Methodology and Assumptions

To assess the sensitivity of the local area power-flow to the four parameters listed above, four Southwest Power Pool (SPP) Integrated Transmission Planning Near Term (ITPNT) models were selected to simulate seasonal and generation dispatch variations in the 2017 and 2020 study years. Table 3-1 provides additional detail on the study models. Further, the PST was modeled with an initial available phase angle range of -25 degrees to 25 degrees (PSS/E convention) and the cases were solved for the entire angle range at 1 degree increments. Five local bus voltages were monitored as well as the MVA flow across the PST, and the power-flow on the Woodward to Windfarm 138 kV transmission line for N-0 and N-1[1] system conditions.

Table 3-1: Base Study Models

Generation Subsystem	2017 Summer Peak Scenario 0		2020 Light Load Scenario 0		2020 Light Load Scenario 5		2020 Summer Peak Scenario 0	
	PGEN	PMAX	PGEN	PMAX	PGEN	PMAX	PGEN	PMAX
Non Woodward Local Gen (OGE, WFEC)	7573.1	11547.6	2919.3	11494.6	3906.1	11494.6	7968.3	11494.6
Woodward Area Wind	81.0	2218.5	352.0	2218.5	1282.6	2218.5	84.0	2218.5
KCPL	5106.4	6857.7	940.0	6650.6	1078.5	6650.6	4933.8	6650.6

3.2 Angle Range

The PST phase shift angle and the power-flow on the Woodward to Windfarm 138 kV transmission line for N-0 and N-1[1] were graphed to determine the relationship between the two variables and determine the desired range for the PST specification. Figure 3-1 and Figure 3-2 detail the power-flow results on the

[1] Only the most severe N-1 contingency was tested for the parameter validation (515407 [TATONGA7 345.00] – 515497 [MATHWSN7 345.00]

Woodward to Windfarm 138 kV transmission line through the full range of phase shift angles for the 2017 Summer Scenario 0 models.

Figure 3-1: Woodward to Windfarm 138 kV Line Power-flow: 2017 Summer Scenario 0 (N-0)

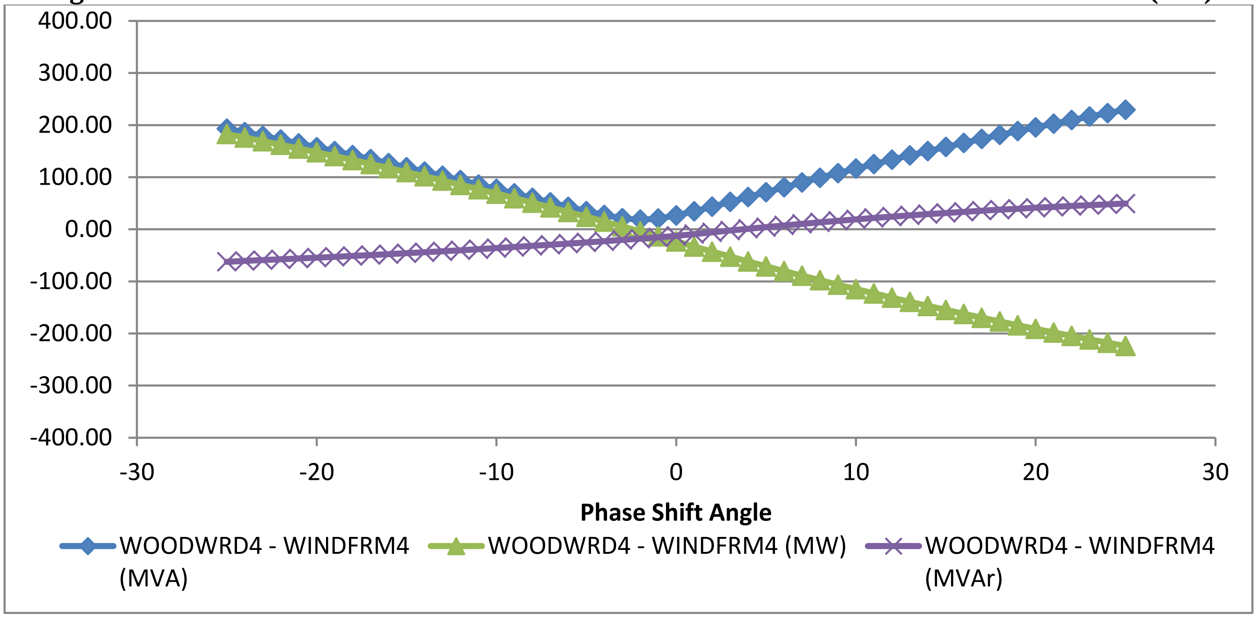
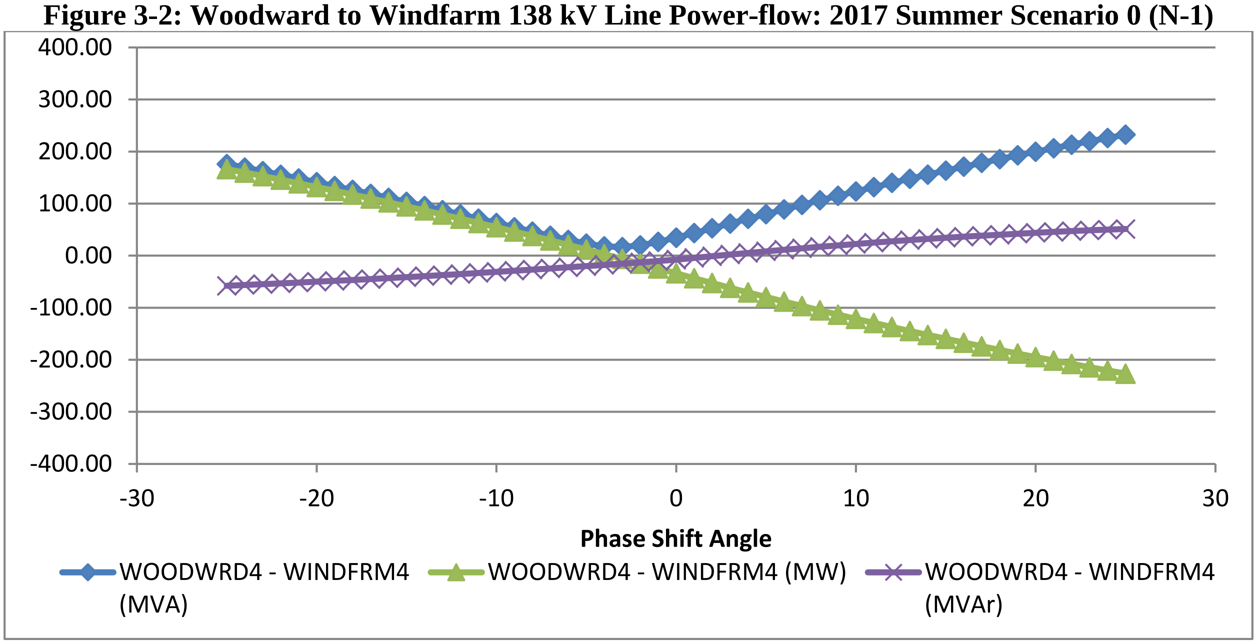


Figure 3-2: Woodward to Windfarm 138 kV Line Power-flow: 2017 Summer Scenario 0 (N-1)



The graphs shown in Figure 3-1, and Figure 3-2 show an inverse relationship between typical Woodward to Windfarm power-flow (from Woodward to Windfarm) and phase shift angles. Therefore, positive (PSS/E convention) phase shift angles are most useful in reducing power-flow on the line.

3.3 Angle Step Size

The incremental change in local bus voltages and power-flow on Woodward to Windfarm was monitored for the angle range of -25 to 25 degrees, N-0 and N-1 scenarios and for the five PST impedance models (further discussed in Section 3.4) to assess the sensitivity of those power-flow variables to PST angle step size. Table 3-2 summarizes the maximum incremental change in bus voltages and Windfarm line loading for a step size of 1 degree.

Table 3-2: Voltage & Power-flow vs Step Size

Step Size Sensitivity Results Summary		
Case	Max Voltage Change (%)	Max Change WfarmLine (MVA)
2017 Summer Scenario 0	0.219%	9.348
2017 Summer Scenario 0 (N-1)	0.224%	9.150
2020 Summer Scenario 0	0.220%	9.911
2020 Summer Scenario 0 (N-1)	0.213%	9.807
2020 Light Scenario 0	0.195%	10.911
2020 Light Scenario 0 (N-1)	0.170%	10.690
2020 Light Scenario 5	0.179%	9.926
2020 Light Scenario 5 (N-1)	0.234%	9.983

Operationally, OG&E desired to maintain granular control of the local power-flow. Based on the results presented in Table 3-2, the incremental change in Woodward line loading is a greater angle step size constraint (>10 MVA or 7% of Rate A) than the incremental change in the local bus voltage (<0.3%).

3.4 Impedance

The PST was modeled in PSS/E as a two winding transformer with zero impedance at zero degrees phase shift, and a linear approximation of the incremental impedance change between zero degrees phase shift and the maximum phase shift. A review of the initial vendor documentation showed a mean of 8% impedance at 25 degrees phase shift. Therefore, the analysis described in Sections 3.1, 3.2, and 3.3 was repeated for PST models of 6%, 7%, 8%, 9% and 10% impedance at maximum phase shift to determine the sensitivity to one percent change in impedance. Table 3-3 summarizes the maximum change in local bus voltage and Woodward line loading for the five PST impedance scenarios.

Table 3-3: PST Impedance Sensitivity Summary

Max Voltage Step Change from 4% change in TX Impedance	**0.0005 pu**
Max WindFarm Line Loading Step Change from 4% change in TX Impedance	**0.33 MW**

The maximum impedance of the PST did not have a significant impact on the other parameters specified. Therefore, the initial PST specification defined a maximum impedance of 8%.

3.5 Capacity

The PST was specified at a maximum capacity of 286 MVA (ONAF at 65C rise) to match connected equipment and line ratings.

4.0 STEADY STATE & STABILITY ANALYSIS

The purpose of the steady state analysis was to define PST angle ranges that limit or eliminate N-0 and N-1 thermal and voltage violations at varying local wind generation output scenarios. These results can be used by OG&E internally to inform daily operation of the PST.

4.1 Methodology and Assumptions

A study was constructed to test nine dispatch scenarios (0 to 4000 MW of local wind generation in 500 MW increments) on each of the four base study models (defined in Table 3-1) for all PST phase shift angles (1 degree increments). Steady state analysis was completed on all scenarios for N-0 and N-1 contingencies within the study area and the results were filtered to report only scenario violations on facilities that the PST had sufficient control of the voltage or loading. Sufficient control was defined as: the maximum loading or voltage change (from -10 to 25 degrees phase shift) on a scenario (base case + contingency) is greater than the maximum violation (thermal or voltage). Meaning, the effect of the PST in its full angle range is able to remedy a violation

Stability analysis was performed on twenty (20) normal clearing three-phase faults and twenty-one (21) stuck breaker delayed clearing single-line-to-ground faults in the area local to the PST. The following parameters were monitored and reviewed for acceptable responses:

- Generator parameters:
  - ANGLE: Machine relative rotor angle
  - SPD: Machine rotor speed
  - ETRM: Machine terminal voltage
  - POWR: Machine electrical power
  - VARS: Machine reactive power
- System parameters:
  - VOLT: Voltage at key system buses
  - FLOW: P and Q flow for key lines

- FREQ: Frequency at key system bus

4.2 Results

The steady state analysis resulted in defined usable angle ranges for 32 of the 36 base case / dispatch level combinations. Usable phase shift angles could not be identified for any of the four 4000 MW dispatch scenarios or the 3500 MW dispatch scenarios for the 2020 Light Load cases. In these scenarios, thermal rating and/or voltage violations existed for all available phase shift angles. This may be an indication of the ultimate local Woodward area wind generation capacity without substantial topological modifications. Figure 4-1 through Figure 4-4 present the detailed angle ranges for each base case / generation dispatch level combination.

Figure 4-1: Usable Angle Ranges - 2017 Summer Peak Scenario 0

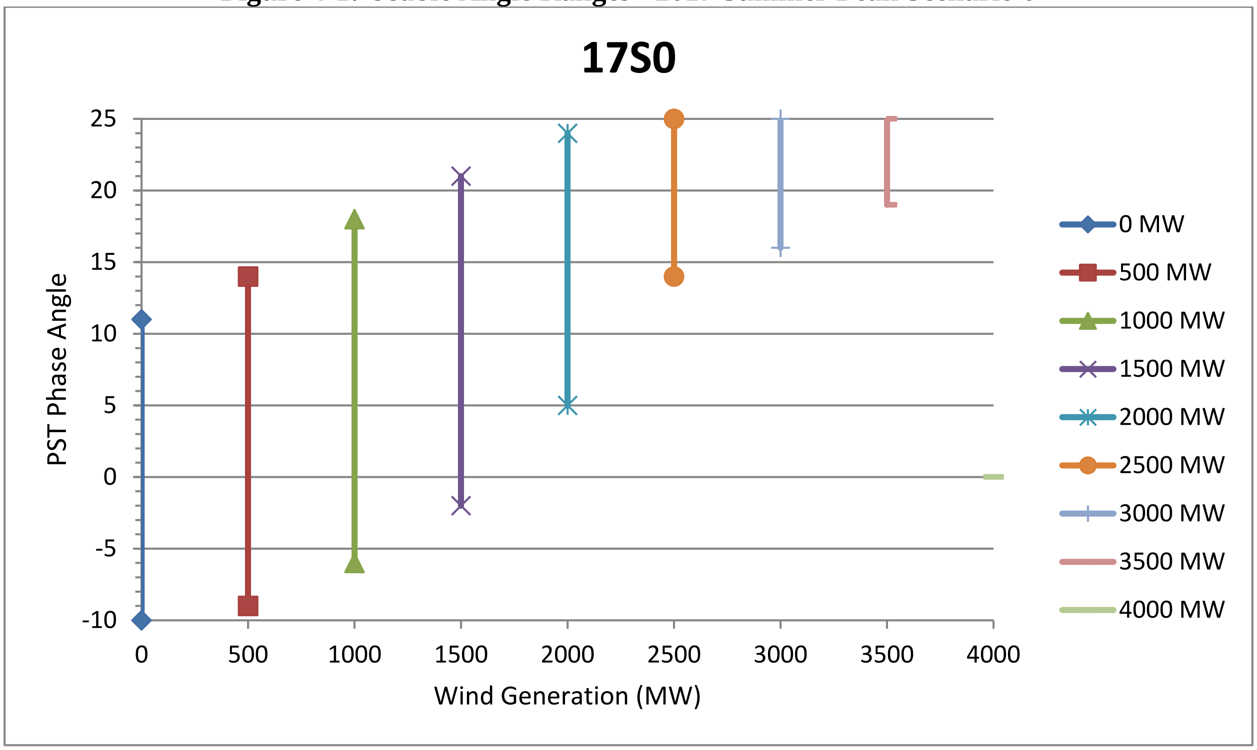


Figure 4-2: Usable Angle Ranges – 2020 Light Load Scenario 0

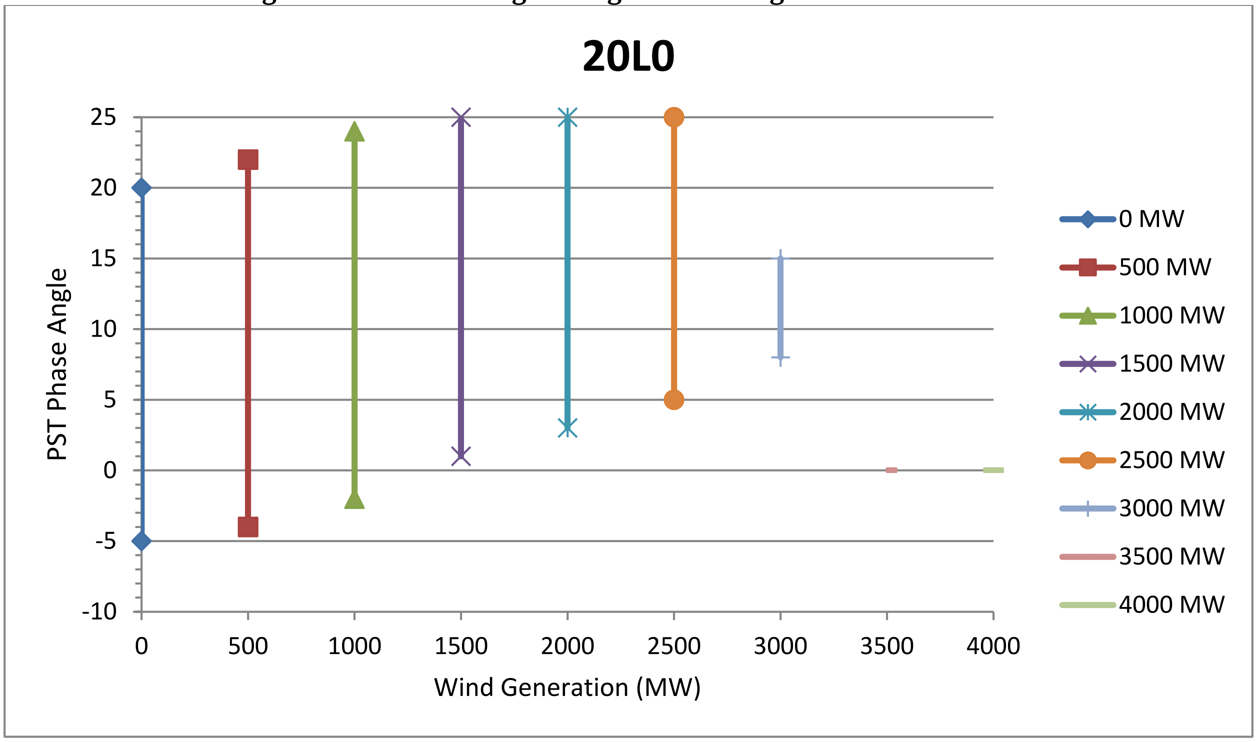


Figure 4-3: Usable Angle Ranges – 2020 Light Load Scenario 5

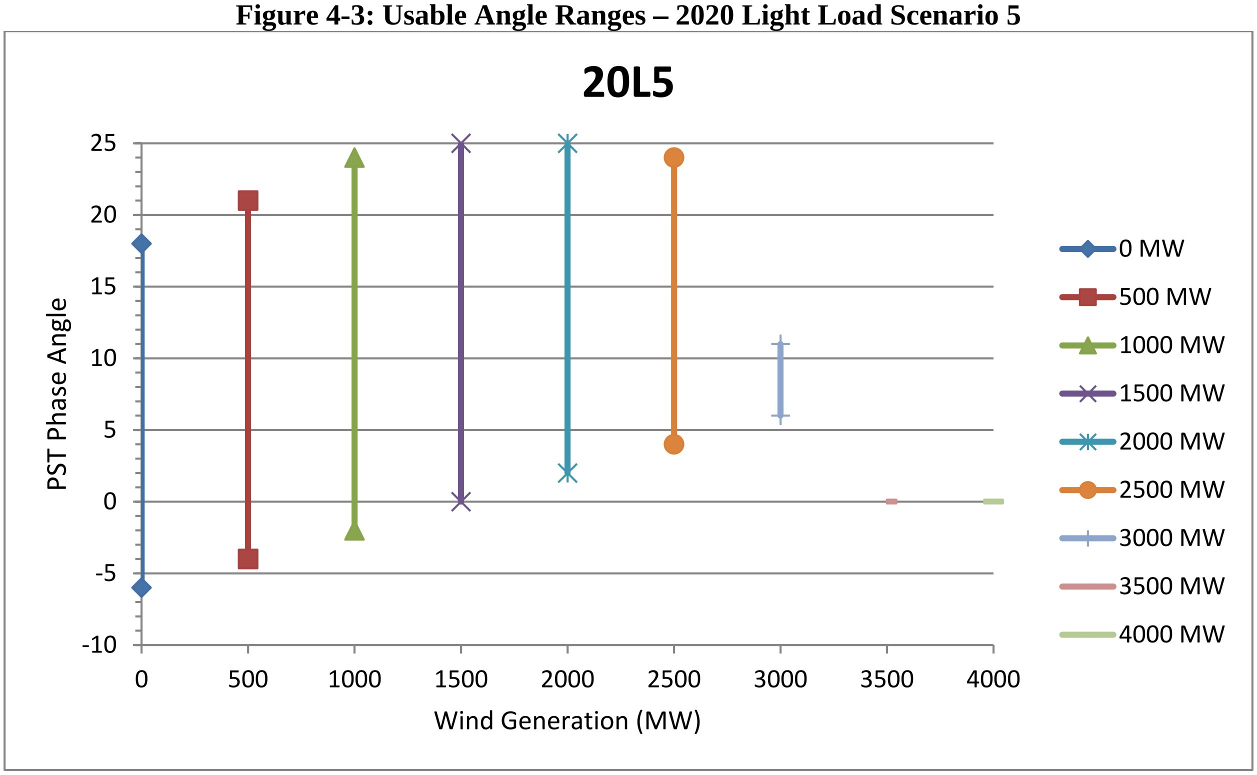
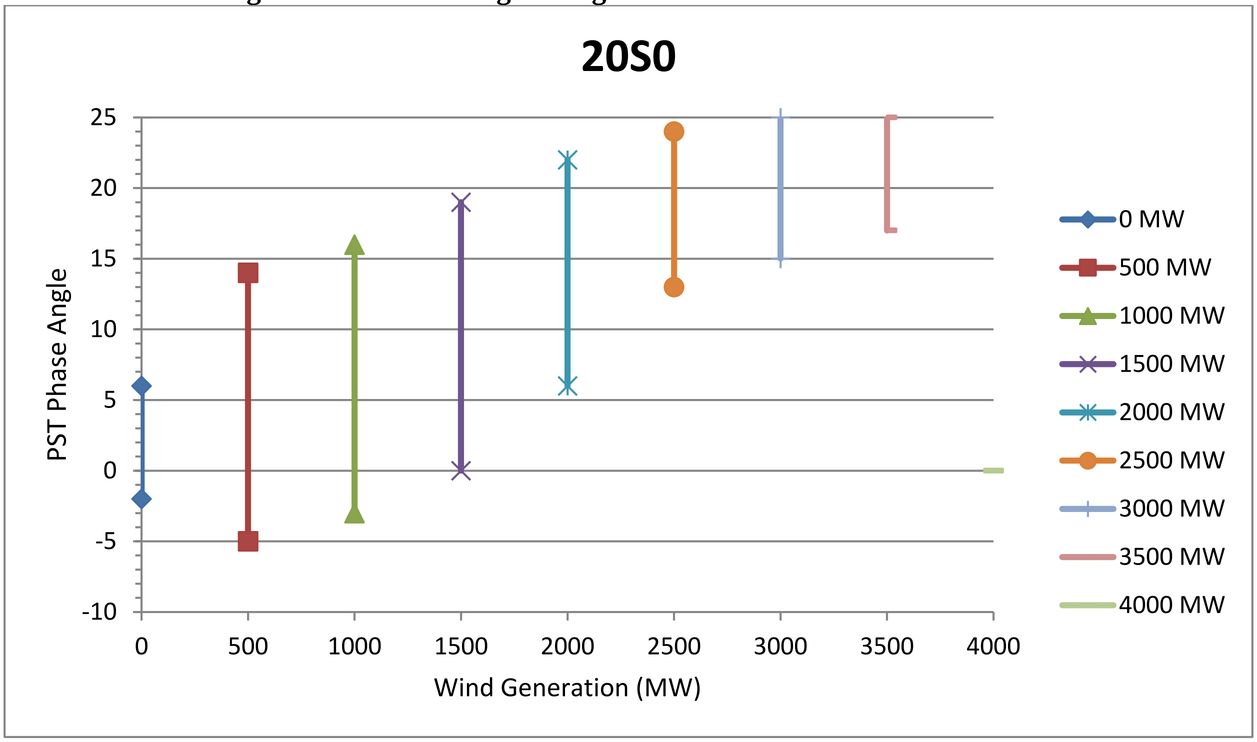


Figure 4-4: Usable Angle Ranges - 2020 Summer Peak Scenario 0



5.0 DIURNAL WIND PATTERNS

The figures presented in Section 4.0 were utilized in conjunction with historical local diurnal wind patterns to illustrate typical seasonal operation of the PST.

Figure **5-1** and Figure 5-2 show typical wind generation output patterns for a Summer and Fall day respectively and with corresponding allowable PST phase shift angles based on the analysis in Section 4.0. While the allowable phase shift range varied significantly with generation levels, for each of these examples, the operators could react to changing system conditions with minimal operation of the PST (1 – 3 angle changes).

Figure 5-1: Summer Day w/ Average Wind Variability

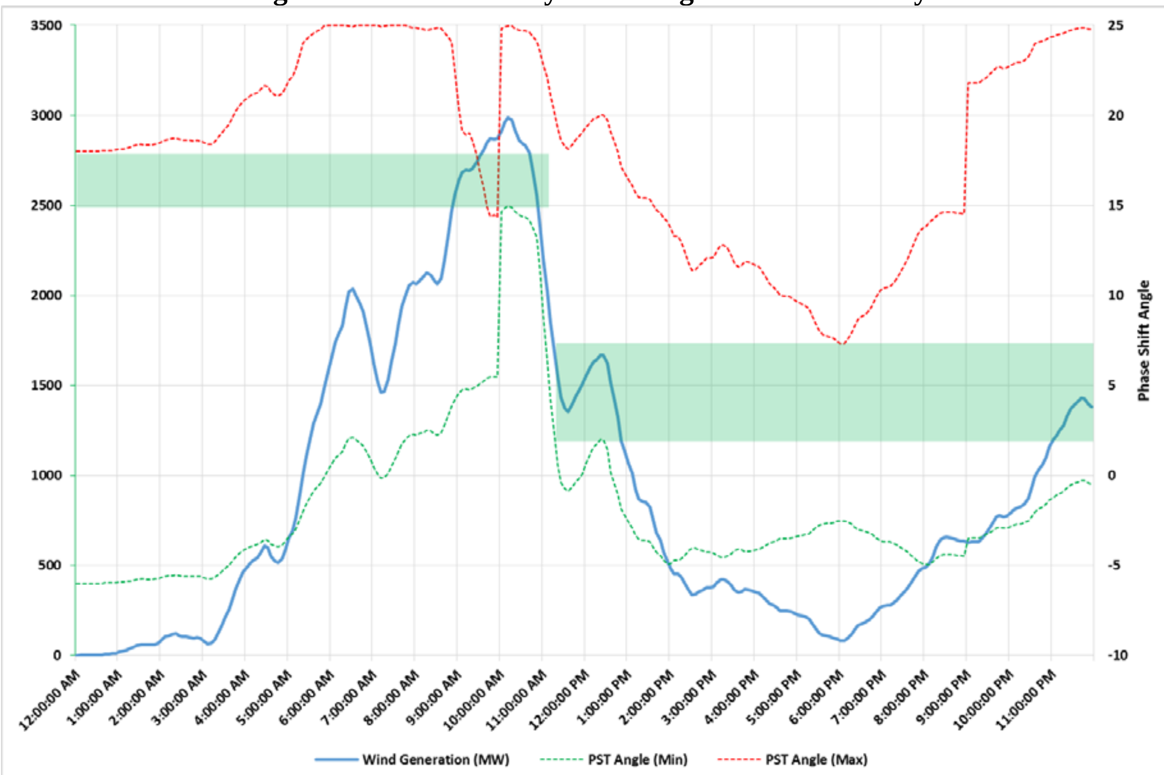
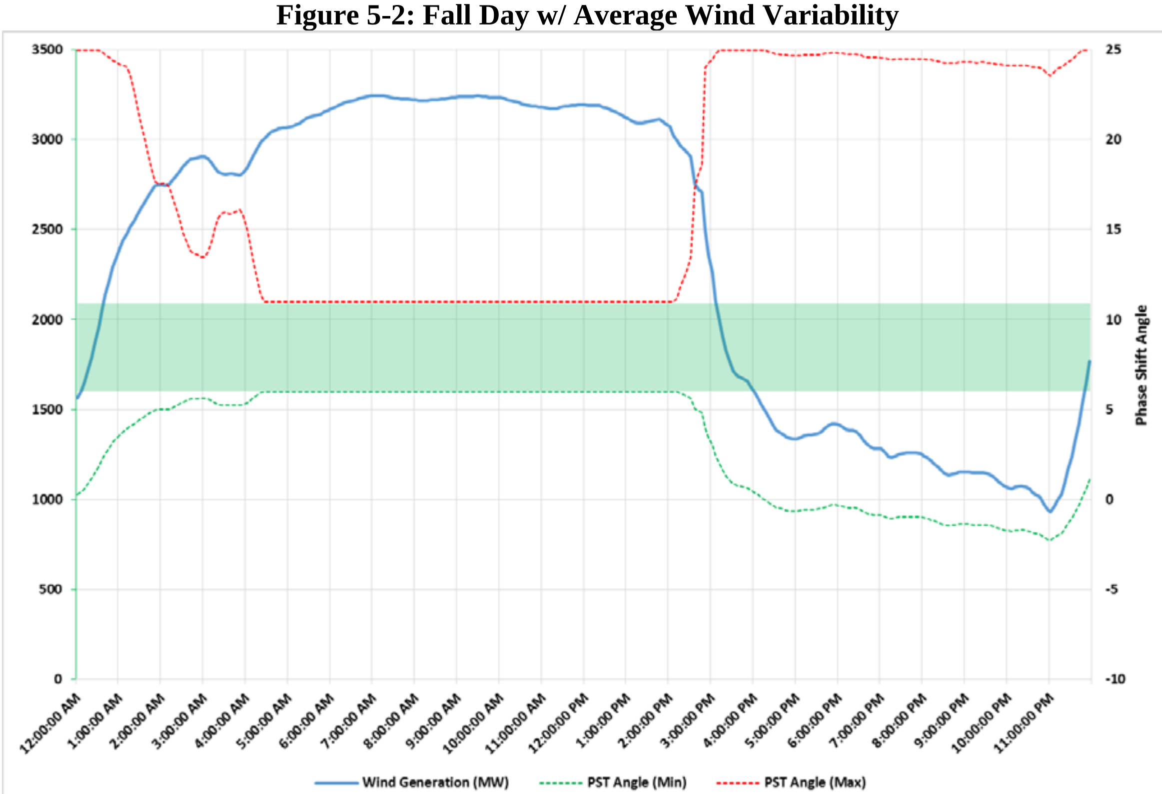


Figure 5-2: Fall Day w/ Average Wind Variability



6.0 FINANCIAL ANALYSIS

A single-core PST was capable of meeting the required specifications found during this assessment. The total cost of the proposed single-core PST project was less than the cost of upgrading existing facilities or of any new construction that could alleviate existing flowgates in the Woodward Area. The single-core PST could be installed into the existing substation and required no additional land or right-of-way acquisition, and these factors along with the reduced construction scope allowed for an earlier completion date than the other projects evaluated. The earlier completion date was preferred by project stakeholders due to the congestion reduction in the intermediate time frame which provided additional value to the PST project. Finally, the performance of the PST project was greater than that of projects of similar cost and was on par with the performance of far more expansive projects. The combination of these and other operational factors led to the selection of the phase shifting transformer project by the stakeholders.

7.0 CONCLUSIONS

This study determined applicability of a phase shifting transformer to reduce congestion in the Woodward Area as a replacement or deterrent for more expensive transmission line upgrades for local Woodward Wind generation levels up to 3500 MW for various system conditions. Further, the analysis was able to provide reasonable operational expectations for the PST under typical generation patterns and provide guidelines based on generation level and season for the system operators.

ACKNOWLEDGEMENTS

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[1] "Phase-shifting Transformer Modeling in PSS®E" Carlos Grande-Moran, PhD, Siemens (March 2012)https://ewh.ieee.org/soc/pes/newyork/NewSite/PDFs/Protection%20Related/Phase_Shifting_Transformer_Modeling.pdf

Saving Time & Money:

A Case Study of a Texas Utility's Experience Utilizing a **Customized Factory-Built Substation** Approach for its Standard Outdoor Open-Air Distribution Substation

Prepared For

TRANSMISSION AND SUBSTATION DESIGN AND OPERATION SYMPOSIUM

Prepared By

Joseph W. Baker, P.E., P.Eng.
DIS-TRAN Packaged Substations

DIS-TRAN PACKAGED SUBSTATIONS

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1.0 ABSTRACT

This paper will demonstrate the process one Texas-based investor-owned utility, Texas-New Mexico Power Co. (TNMP), utilized to convert its standard outdoor, open-air distribution substation from an on-site constructed facility to a factory-built product, customized to its unique requirements. The paper will address the project objectives established by the utility at the outset in order to clearly define success. The paper will describe, in detail, the collaborative approach used by the utility and the substation manufacturer, DIS-TRAN Packaged Substations (DTPS), from concept phase through the detailed design phase of the project. This collaborative approach ensured all key stakeholders' concerns were addressed not only in the design, but also in the final on-site assembly of the substation modules. This paper will highlight and explain how the substation manufacturer's design team utilized 3D modeling tools during the interactive design process to pre-diagnose and resolve numerous "last mile" constraints, such as shipping restrictions and site rigging availability. The case study will conclude with an itemized listing detailed cost assessment, the impact this factory-built substations approach had on the substation's completion schedule, lessons learned, and overall successful project outcome.

2.0 INTRODUCTION

As Texas-New Mexico Power strives to accommodate its growing customers' needs, the company reviews its current substations, evaluates plans to increase the voltage of its substations, and strategically lays the ground work to expand its electrical grid. Though voltage up-grades are necessary and must happen in a timely manner, quality and safety is still TNMP's utmost concern [1].

2.1 Texas-New Mexico Power (TNMP) Background | Service Area

Figure 2-1: TNMP Service Area Map*

*Map provided by TNMP on July 5, 2016

Founded in 1935, TNMP is an electricity transmission and distribution service provider, providing electric service to customers on behalf of competitive retail providers within the Electrical Reliability Council of Texas (ERCOT) power system. The company uses more than 9,000 miles of transmission and distribution lines to provide electricity to more than 243,000 homes and businesses in more than 70 communities from small rural farming areas to the suburbs of Houston and Dallas-Fort Worth. TNMP is also a power provider for critical international petroleum customers along the Texas Gulf Coast. While its formal name is Texas-New Mexico Power Co., it serves users solely in the state of Texas. TNMP is a subsidiary of Public Service Company of New Mexico (PNM). While PNM is headquartered in Albuquerque, New Mexico, TNMP's main office is in Lewisville, Texas. TNMP employees more than 375 people in more than 20 communities throughout Texas [2]. It takes great pride in not only delivering reliable power and quality service to its customers with accurate meter readings and prompt response to power outages, but also giving back to its valued employs and community. TNMP employees and retirees can request a contribution of as much as $500 a year on behalf of a Texas nonprofit organization with which he or she volunteers. In addition, in 2015, TNMP awarded $30,000 in grants to Texas nonprofits, municipalities, and school districts. TNMP success, in return, benefits the community it serves [3].

2.2 TNMP's Need for Growth

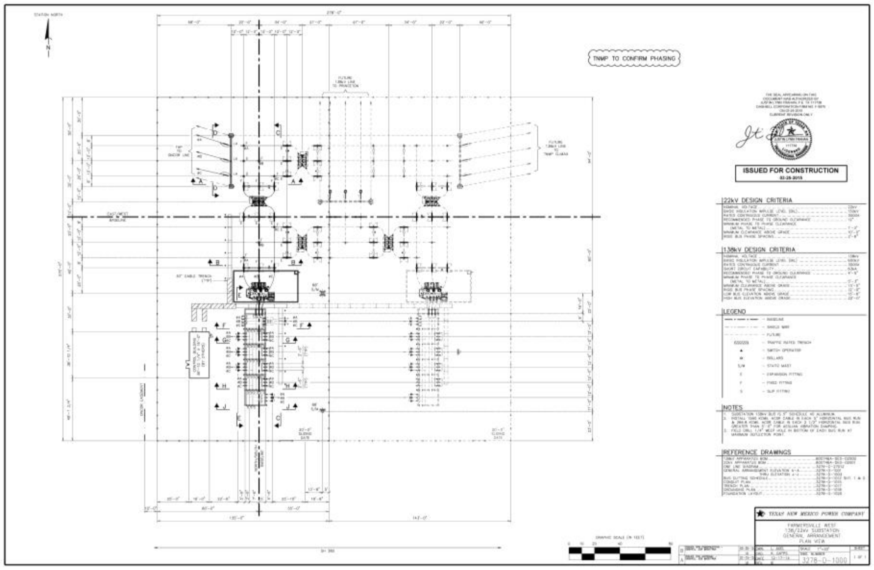
Due to significant retail customer growth, TNMP is in the process of converting a large part of its system in west Texas from 69kV to 138kV. TNMP's standard substation consists of a six breaker ring bus which accommodates a transmission bypass and four other connections. Those connections vary between capacitor banks, transmission connections, and distribution bays.

Originally, TNMP planned to rebuild its existing Flat Top Substation. However, after review, the company decided a large footprint substation would better address its oil and gas customers' needs in the Permian Basin. Chris Gerety, Director of Engineering and Land Services for TNMP, says the big voltage conversion needs to happen. "Once we saw how much activity was out there we decided it was better to overbuild and have our standard substation and distribution bay verses trying to retrofit a brownfield site with some sort of custom design," he explains [1].

2.3 Project Needs

TNMP's project called for a 25kV distribution bay consisting of six bays and five 25kV distribution circuit breakers. With quality and safety as its utmost concern, TNMP is insistent its substations are uniform. "We put a lot of time and effort into designing the substation from a reliability stand point. We are very redundant and very robust. So we want to continue that effort and maintain our design," says Gerety [1]. A standard substation improves safety by ensuring TNMP's workforce is familiar with its facilities and equipment. Gerety continues, "From a safety perspective, that was really one of the biggest driving forces to have a similar design. This way our field folks have a clear understanding of how the site operates, making their job that much easier and safer." [1]

Figure 2-2: Page 1 of TNMP's Original Quote Drawings



3.0 THE NEED FOR AN ALTERNATIVE APPROACH

"When a company says to you, 'By the way, we've looked at your box and we think we can actually build it in the factory and ship it to you already assembled, you get excited.'"

– Chris Gerety, Director of Engineering & Land Services, Texas-New Mexico Power

3.1 Project Location Hurdles

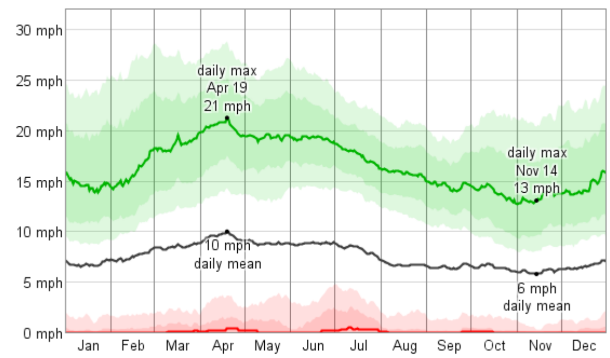
The location of TNMP's new, large footprint substation is remote and located more than 20 miles south of the small town of Pecos, Texas. "It's out in the middle of nowhere," describes Joe Sandifer, safety inspector for TechServ. Sandifer worked on-site for TNMP's project [4]. Managing remote resources, as in this case, is extremely difficult. "You don't just have a Lowe's down the road where you can pick up construction materials. You don't have any local large electric supply houses that keep large inventory of things. You have to

Figure 3-1: Project Location On Map

drive three to four hours away round trip to find the things you need if you are short supplies," explains Gerety. [1]

In west Texas there are weather constraints as well. Wind is the biggest hurdle. In Pacos, the average daily maximum wind speed is 21mph [5]. The dryness in the area mixed with high winds leads to dust storms. Having worked in the industry for more than 20 years building substations across the country, Duke Taylor, DIS-TRAN Packaged Substations' Factory-Built Substation Manager, is familiar with the project's location. He also specifically worked on TNMP's project. "Where this project was erected, the problem was dust. They had bad dust storms going on," says Taylor [6].

Table 3-1: Wind Speed Chart



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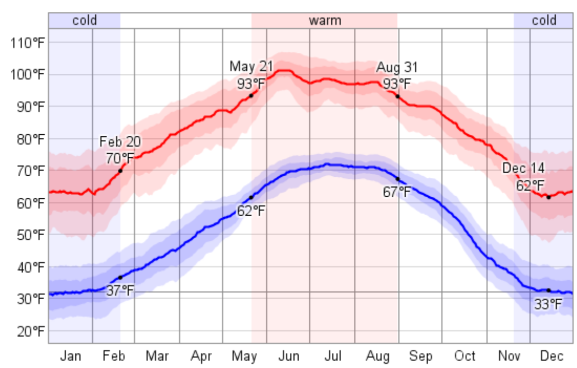
Gerety says temperatures are also a problem [1]. The warm season lasts from May 21 to August 31 with an average daily high temperature above 93 degrees. The cold season lasts from November 20 to February 20 with the average daily high temperature below 70 degrees [5]. This narrows the time frame of comfortable building conditions. "Ultimately because there are adverse weather conditions, if [crews] are having to do construction techniques that can't be performed in those difficult weather conditions you don't have any choice but to just have everyone stand down and be sitting," says Gerety [1].

Table 3-2: Temperature Chart



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3.2 Construction Quality & Safety Management

With TNMP's traditional substation construction methods, a crew would build the high side of a substation and then move on to the low side. Gerety says he prefers to manage one crew at time and avoids having multiple crews on site. This inevitably leads to a "waiting period". However, with a factory-built substation, "The distribution side just showed up built and it basically just went into service," explains Gerety [1]. The indoor construction environment with a factory-built substation reduces the risks of accidents and related worker reliabilities. By relocating much of the work to the controlled safety conditions of a factory environment, much of the serious safety risks inherent in an electrified substation are mitigated [7]. TNMP's distribution bay design leaves little room for contractors to be elevated and assemble bus in the field. Crews would need to work off of ladders. Standard machinery would not fit in the interior sections of the structure. Working out of a factory, and on a concrete slab, DIS-TRAN Packaged Substations was able to use scaffolding in the tight construction areas of the bays, making assembly both faster and safer [6].

Photo 3-1: Project Assembly Inside Factory Utilizing Scaffolding

TNMP highly values both safety and quality. Previously, TNMP built its distribution bays through its traditional supply chain methods. The electric company has its own corporate strategic supplier that supplies individual building materials; is the various lots of materials are then drop shipped to the site. The supplies are collected until all of the pieces arrive. Then, erection of the project can begin [1]. Building off site however, ensures controlled construction quality management. Rather than being delivered to a remote location without much protection from adverse weather conditions, materials are delivered to the plant location and are safely secured and stored in a manufacturer's warehouse. This prevents damage or deterioration from moisture and other elements [7]. Those elements can also affect the quality of aluminum welding. West Texas' dry air, windy conditions, and dust can potentially interfere with a project's quality control goals [8].

Photo 3-2: Project Being Shipped

Structurally, factory-built substations must be designed and built to withstand the rigors of transportation. Travis Eaglin is a design engineer technician for DIS-TRAN Packaged Substations. Eaglin contributed to the design of TNMP's project. "We had to design the structure so that it could basically survive a seismic event, says Eaglin. "We are talking about [a substation] running down the road, hitting pot holes and curbs, going more than 60 miles per hour," he continues [9]. Modular buildings that are built to withstand the same conditions are typically stronger than conventional construction [7].

3.3 Cost & Time Savings

TNMP's traditional delivery processes are extremely tedious. "[Our crews in] the field tear apart all the pallets and packages, and say, 'Oh we have everything, except these 100 things.' And then we go back and forth with the field saying, 'We've reordered. Do you have it?'" says Gerety. This process can take weeks and eats into construction time. Gerety further explains, "For us, we are always being pushed at a corporate level to get dollars spent and be back in-service as quickly as possible." [1] DIS-TRAN Packaged Substations assured TNMP its distribution bay would show up on site, built, and ready to go in-service.

While the design stage of a factory-built substation may not take less time than a standard substation, the time savings for the customer is in the field [8]. By being constructed in a controlled environment, there are more tools and options to perform the work more precisely, at lower cost, and faster. A contractor will have less to assemble in the field. Also, expensive field equipment may not be necessary. Eaglin typically references a popular children's toy when describing factory-built substations, "They're ready to go. You basically bolt everything into place like Legos you put together." [9] Leaving the erection phase of a substation project quick. This means less hours "on-the-clock" for contractors and less field and travel expenses. "You add up the fact that you have to pay [contractors] per diem every day, you have to pay for a hotel, all kinds of different things you have to pay for if someone is in the field instead of working in a factory," says Gerety [1].

With electric companies utilizing factory-built substations and paying contractors less per project, there could be the assumption contracting companies would be against this new method and use of technology. However, Sandifer argues he prefers erecting factory-built substations. "It does not mean a smaller paycheck. It just means we can finish one project and move on to the next," he says [4]. Factory-built substations allow electric companies and their contractor partners to complete more projects year-to-year and provide better service to their customers.

4.0 DESIGN INTEGRATIONS

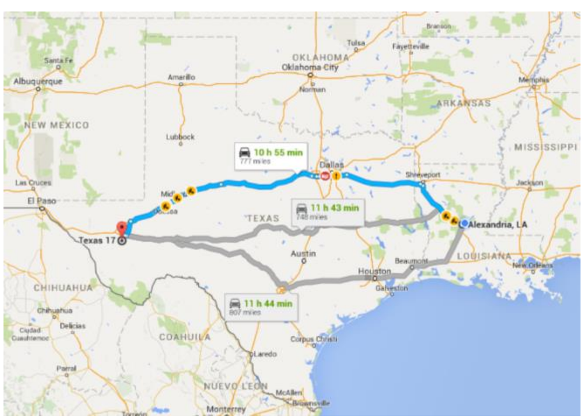
"We had to stick to TNMP's main design. Minor details around them are what we tweaked in order to accommodate shipping constraints."

- David Perry, Project Manager, DIS-TRAN Packaged Substations

4.1 The Communication Process

DIS-TRAN Packaged Substations goal was clear: turn an electric company's standard distribution bay structure into a factory-built substation without changing its design. TNMP wanted its new substation to have the same number of breakers, switches, and bays as its standard substation. However, there was a process in reaching this understanding. David Perry was DIS-TRAN Packaged Substations' project manager assigned to the project. It is his responsibility to understand the customer's needs, interpret the information they provide, and then communicate those project requirements to DTPS' engineers. In return, he relays the engineers' concepts and drawings back to the customer. "The hardest part wasn't so much between us and the customer. The customer trusted us. We knew what they wanted," says Perry. The big challenge in the communication process was juggling the *many* different individuals involved in the project. TNMP had its own project managers as well as its own engineers. Perry also needed to be the point-of-contact between TNMP's subcontractors, and the trucking company used to deliver the substation. Constantly maintaining open communication throughout the entire project is crucial. "A FBS [factory-built substation] requires you to be more involved than you have to be during a typical substation," says Perry. Traditionally, project managers need only to talk to the customer, and project coordinators and engineers within their own company. Factory-built substations require additional details throughout the design development. Shipping requirements and restrictions, for example, play a large component in the design process [10].

Figure 4-1: Shipping Route

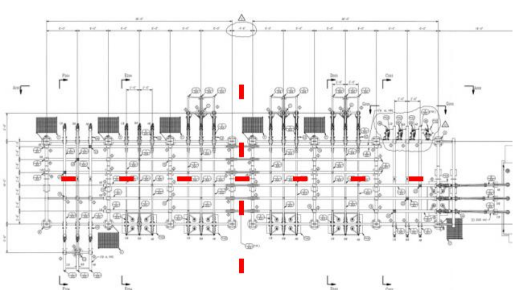


Perry stayed in constant communication with the trucking company selected to ship the completed substation. This communication was crucial in ensuring a substation this large would be able to ship safely, and legally, to TNMP's desired location in west Texas. Perry recalls phone conversations occurring almost every other day. Each new engineering and design drawing needed to be sent over to the transporter for review. The trucking company would then let Perry know, based on the design, if the substation would fit on the truck safely and what type of permits would be required. "As you ship something this big across different states, everything changes," explains Perry [10]. The state of Louisiana has a shipping height limit of 13'6" [11]. The state required the trucking company to obtain special permits in order to ship the distribution bay. However, once the shipment entered the state of Texas, special permits were not required [10].

4.2 Balancing Customer Needs & Shipping Requirements

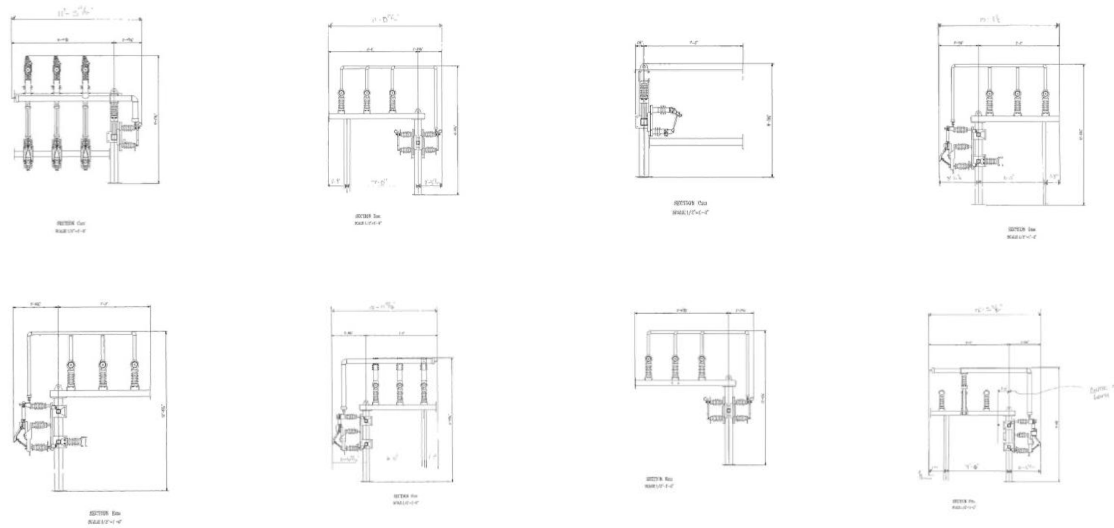
Though the state of Louisiana does not restrict the length of oversize shipments, it does require various degrees of pilot and escort cars depending on the width and length of the cargo. On four lane roads, anything 12'-14' wide requires a front escort car. Over 90' in length requires one rear escort car. Over 125' requires a state police escort [11]. The varying requirements can change the overall cost of shipping significantly. Frank Camus, Vice President of Engineering and Design for DIS-TRAN Packaged Substations, played an integral role in establishing the design intention for TNMP's distribution bay by guiding the team to begin with the end in mind. Camus explains, "Since nearly anything is possible from a design perspective, it is really important for us to determine what the customer places the most value on since there are trade-offs involved. In order to strike the optimum solution for the customer, we must balance the impact on transportation cost of shipping larger modules with the field cost impact of shipping smaller modules" [8]. DTPS presented several design and shipping possibilities to TNMP in effort to optimize the cost-benefit of a factory-built substation. In the end, TNMP opted for a divided substation that would be shipped in four segments.

Figure 4-2: Split Quadrant Design Concept



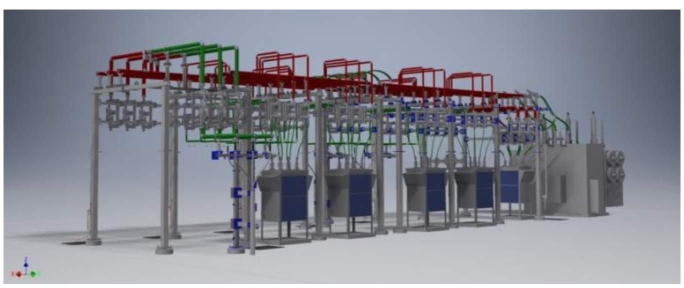
"There was probably five or six of us sitting around in a room, figuring out how we are going to segment [the substation]," recalls Eric Veuleman, DIS-TRAN Packaged Substations' Engineering Manager. DTPS needed to maintain TNMP's dimensional footprint. There was not any flexibility on the layout design. Scaling the structure down was not an option. "All of [TNMP's] overall heights were set, their bay widths, their spacing," explains Veuleman [12]. Taking into consideration shipping requirements and cost, DIS-TRAN Packaged Substations' engineering and design team decided to essentially halve TNMP's distribution structure. This was in effort to keep shipments 40' or less [13]. The standard width of TNMP's distribution bay is also wider than state law allows. Therefore, the design also needed to be quartered, separating the substation into four parts (four modules) [9]. Figure 4-3 shows drawings sent to the trucking company.

Figure 4-3: Substation Pre-Assembled Components



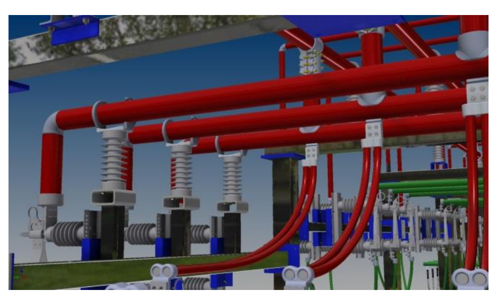
4.3 Dimensions of Accuracy to Design

Figure 4-4: 3D Drawing of TNMP's Factory-Built Distribution Bay



It took the DIS-TRAN Packaged Substations' engineering and design team about two weeks to modify TNMP's standard design and convert it into a functional, shippable, factory-built substation. Though the design phase of the project did not necessarily take any less time than when creating a traditional substation, the 3D modeling aspect of the project ensured the substation's components and measurements would be exact. The split substation's connections would be able to line up. In return, this would speed along construction and virtually eliminate assembly problems in the field [12].

Figure 4-5: 3D Drawing of Project's Pre-Fabricated Bus (PFB)



3D modeling opens up new avenues of efficient substation construction. 3D substation models start with the same information used in 2D drawings, then add volumetric and connective data by joining the faces, edges and points of flat surfaces together. The result is a complete representation of a three-dimensional object or structure that is an order of magnitude more accurate and actionable than 2D drawings.

The design process becomes increasingly reliable because it is less prone to human error while offering an improved ability for users to perform integrity checks. The technology incorporates the ability to analyze the impact of environmental and physical forces acting upon the structure. Though this distribution bay would not be erected in a seismic area, DTPS' engineering and design team accounted for the substation withstanding a seismic event. The team calculated loads to simulate a high seismic event and modeled the seismic conditions in its finite element structural analysis software package, STAAD.PRO. The seismic loadings applied simultaneously with a 70 MPH wind load were intended to simulate the transit loads the structure was expected to be subjected to. These loading conditions could not simply be applied to the structure in its final as-installed condition but rather the structure had to be modeled in each as-shipped module condition. This ensured DTPS its factory-built distribution bay would be strong enough to survive the rigors of traveling down the highway.

5.0 CONSTRUCTION & ASSEMBLY

"If the design team could do it, we could build it."
– Duke Taylor, Factory-Built Substation Manager, DIS-TRAN Packaged Substations

5.1 Factory-Built Logistics

With the design complete, and the substations' steel and parts already ordered and delivered, Duke Taylor and the rest of his team at DIS-TRAN Packaged Substations' Project Support Service Center were ready to start building TNMP's factory-built distribution bay. Traditional substations of this size are typically assembled one piece at a time in the field on top of previously constructed foundations. However, because this substation would first be erected in a factory on a concrete floor, the DTPS team needed to develop a solution on how to build a substation without a foundation. A steel rail system was created to temporarily mount the substation on the factory floor and hold base plates and columns in place during construction. The entire system is adjustable. It functions much like a bed frame that can expand or contract depending on the size of mattress. "Without it, we wouldn't have been able to build it," says Taylor [6].

Because the substation would initially be built without a concrete foundation and was designed to be shipped in partial assemblies, support steel needed to be put in place to hold the structure safely and securely during shipping. As shown in Photo 5-1, the steel supports were in place throughout the factory-built construction phase. The design team fabricated step-by-step erection drawings showing the contractors how and when in the erection process to remove each steel support [8].

Photo 5-1: Steel Rail System and Supports

Taylor and his team were able to factory build TNMP's distribution bay in ten days. Though Taylor says the project could have been completed in half that time if it were not for a problem with the switches provided to DIS-TRAN Packaged Substations by a switch manufacturer [6]. The switch mountings did not match the vendor-provided drawings. Once mounted, each switch was a few inches short. To avoid any more time delays, Taylor drilled new holes, raising the switches to match up with the bus [14]. The end result was an aligned substation ready to be shipped to its site location.

5.2 Delivery & Installation

Photo 5-2: Substation Delivery and Unloading

TNMP's factory-built substation was delivered to its site just one day later. Taylor along with Joe Sandifer, the contractor for the project, were on-site as the four trucks pulled up carrying quadrants of the distribution bay. "I had never seen anything like that before. We always have had to do everything on the job site. But it was perfect," recalls Sandifer [4]. It took about three and a half hours to unload each quadrant from the trucks. Installation would occur in a few weeks. Due to site issues, TNMP was unable to begin its foundation work during the factory construction phase of the project. When the factory-built substation arrived on-site, the foundation work was still not complete.

Photo 5-3: Substation Assembly

DIS-TRAN Packaged Substation waited for a call from TechServ, TNMP's contractor, to be notified when assembly would begin. The plan was for a DTPS' team member to be on-site during substation construction. This was TNMP's first factory-built substation and DTPS wanted to be present in case any assembly questions arose. However, when TechServ called, it was not to give DTPS an assembly date. "I was kind of amazed. We got a phone call saying, 'We put it together.

It went together fine,'" says Taylor [6]. Sandifer says assembly was simple. His team was able to erect the distribution bay in just one day. "When we put the quadrants together, every bolt hole matched up. We had no problems at all," recalls Sandifer [4]. Taylor credits the substations' precision and overall project's success to DTPS' use of 3D modeling [6].

6.0 LESSONS LEARNED

"That's the learning experience. Things we didn't account for but should have."

- Frank Camus, Vice President of Engineering & Design, DIS-TRAN Packaged Substations

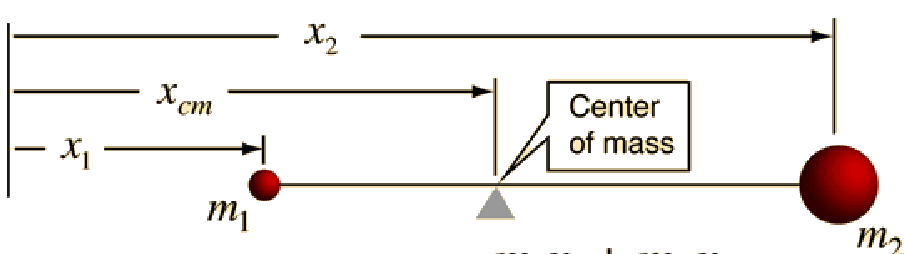
6.1 Pre-Planning an "Exit Strategy"

A tremendous amount of thought went into the design and construction process of creating this factory-built substation. However, when it came time to move the assembled quadrants of the distribution bay out of the factory, DIS-TRAN Packaged Substations ran into a couple problems.

Photo 6-1: Elevating the Substations' Quadrants for Shipping

First, DTPS' engineers factored the center of gravity for the substation in its entirety. That calculation became irrelevant though as soon as the substation was split into quadrants. A new center of gravity needed to be formulated and the structures steel lifting-eyes had to be relocated [14]. Not accounting for the "new" center of gravity once the substation was split, set DIS-TRAN Packaged Substations back a day. Rather than taking only one day to load the shipping trucks, it took two [6].

Figure 6-1: Center of Gravity Formula



For two masses: $x_{cm} = \dfrac{m_1 x_1 + m_2 x_2}{m_1 + m_2}$

Secondly, DTPS' engineers and designers did not account for its factory doors' clearance. "We thought we had door measurements. Obviously we didn't. Or, someone didn't verify those measurements," Eaglin says with a laugh [9]. The factory doors obstructed the substations' columns. DTPS workers had to maneuver the substation to clear the doors and the tight turn outside of the factory doors by unloading and reloading the substation while pivoting the trucks and then repeating the process [6]. "This one pushed the limits. If it was two inches taller it wouldn't have made it. We would have had to take the door down to the Project Support Services facility," says Perry [10].

6.2 Shipping: The Lower, The Better

When working with the trucking company, Perry specifically asked for four low boy trucks. This would ensure better clearance and in effort to comply with state highway height regulations, all four trucks would take the same route to the site location. However, the trucking company was unable to supply DIS-TRAN Packaged Substations with the fourth low boy, and instead, provided a step deck [14]. En route to the site, a quadrant of the substation being carried by the step deck hit a tree and a section of transfer bus was damaged. Because of DIS-TRAN Packaged Substations use of 3D modeling, the pre-fabricated bus was able to be recreated, shipped and delivered in little time. However the need for low boy trucks when transporting factory-built substations was made apparent. "If we had the four low boys we wouldn't have had a problem," says Perry. The struggle came when working with the trucking company. As a project manager, Perry wanted to trust the company he hired to do its job. He says in the future, he will be able to speak from experience, and stress all shipping trucks be the same height and ride low to the ground [10].

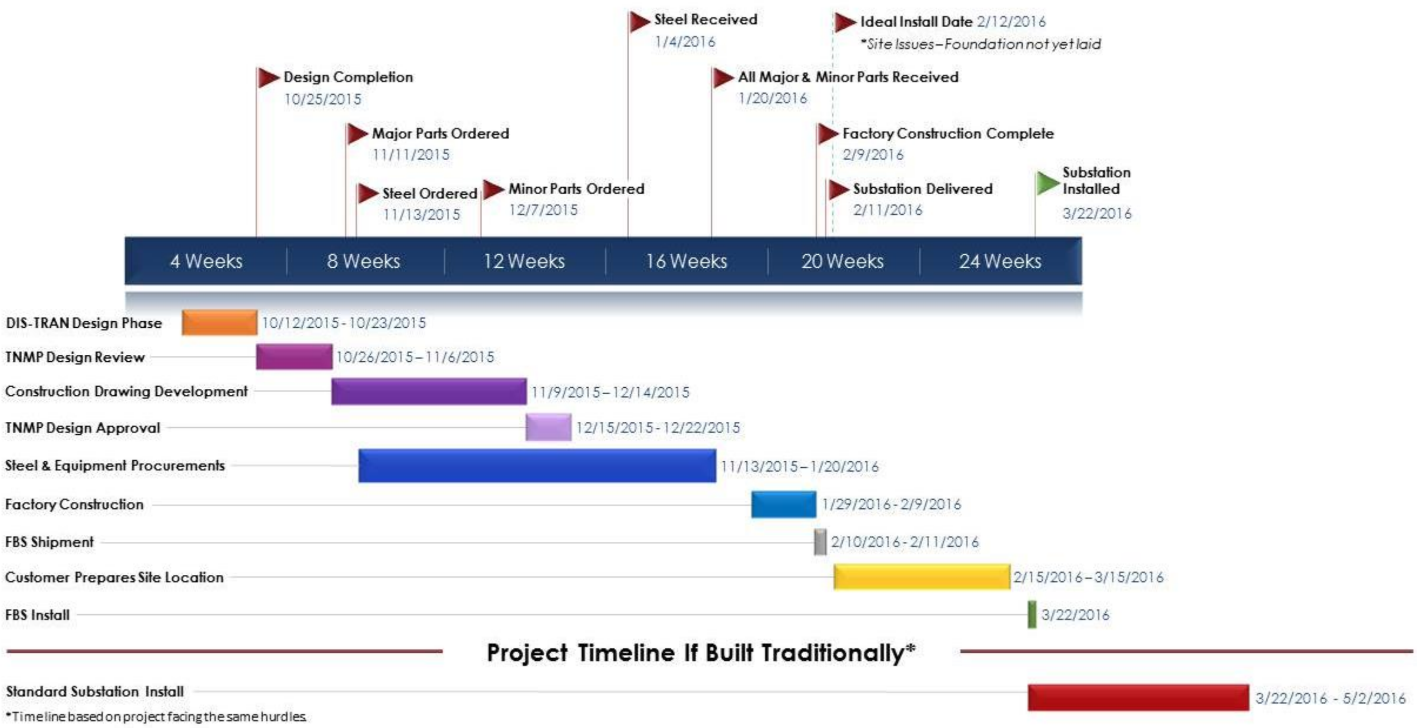
7.0 ANALYSIS

> "We had a really positive experience and the project was very favorable on our side."
> - *Chris Gerety, Director of Engineering & Land Services, Texas-New Mexico Power*

7.1 Schedule

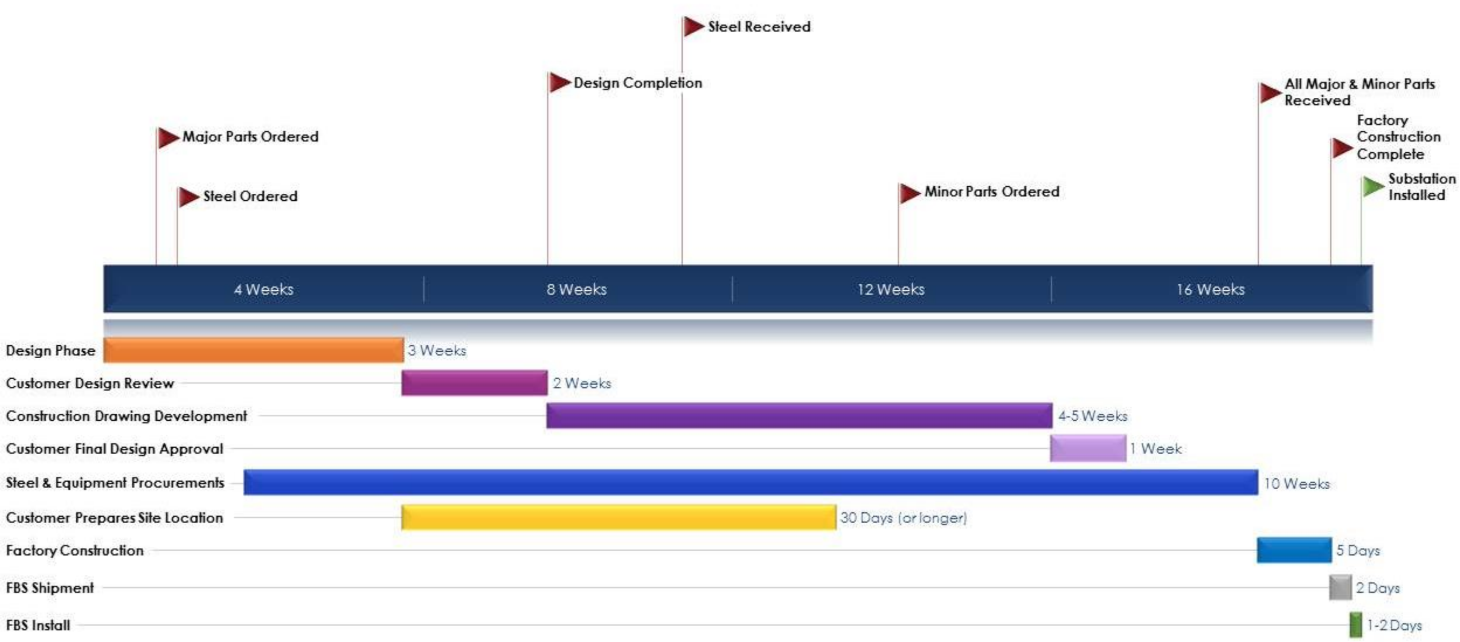
TNMP's factory-built substation was erected in just one field day's work. Sandifer says, based on his experience, a substation that size erected solely in the field would typically take weeks to construct. "You have to put it all together and then you need a welder there to do all the welding on the bus. Plus you have to put on the insulators and the switches," explains Sandifer [4]. Figure 7-1 shows TNMP's factory-built substation's timeline and gives a comparison of the project if traditionally built.

Figure 7-1: Project Timeline Comparison



Ideally, the benefit of having a factory-built substation is maximized when using parallel construction. Meaning, while substation is being assembled in the factory, the normal three week process of digging, pouring, and curing the substation's foundation is taking place [10]. This would allow for the factory-built substation to be erected the following day, or even the day-of, shipment.

Figure 7-2: Ideal FBS Timeline



7.2 Cost

DIS-TRAN Packaged Substations' total contract amount was slightly greater than $250,000. This total included factory labor and construction. The average weekly cost of a six person field construction crew with per diem and hotel is $18,000 [4]. Gerety says having TNMP's distribution bay factory-built possibly shaved two to three months off their total construction time [1]. Based on Gerety's assessment, the elimination of material shortages, eradication of alignment issues, and the removal of weather delays, DTPS conservatively estimates TNMP saw a construction labor savings of $60,000 to $80,000.

The time-savings of factory-built substations also allow for the project to get online more quickly. The sooner a substation gets online, the sooner revenue can be generated.

8.0 CONCLUSION

Both DIS-TRAN Packaged Substations and TNMP are pleased with the projects' outcome. Its factory-built substation significantly reduced on-site construction time and expense. The factory setting not only helped control costs and schedules by eliminating environmental disruptions, but also offered more tools and options to perform work more precisely and safely. Applying the factory-built approach to this project allowed TNMP to put in service its standard-design distribution structure, utilizing all its standard equipment much more quickly and at an overall lower cost than it would have if utilizing traditional field construction practices.

Photos 8-1: Connected Substations' Quadrants

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How Disruptions in DC Power and Communications Circuits Can Affect Protection

Karl Zimmerman and David Costello, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—Modern microprocessor-based relays are designed to provide robust and reliable protection even with disruptions in the dc supply, dc control circuits, or interconnected communications system. Noisy battery voltage supplies, interruptions in the dc supply, and communications interference are just a few of the challenges that relays encounter.**

This paper provides field cases that investigate protection system performance when systems are subjected to unexpected switching or interruptions in dc or communications links. The discussion emphasizes the importance of environmental and design type testing, proper dc control circuit design and application, reliable and safe operating and maintenance practices with respect to dc control circuits and power supplies, and considerations for reliable communications design, installation, and testing. Some practical recommendations are made with regard to engineering design and operations interface with equipment to improve protection reliability and reduce the possibility of undesired operations.

I. The Role of DC and Communications in Protection Systems

Fig. 1 shows a one-line diagram of a typical two-terminal line protection system using distance relays in a communications-assisted pilot scheme.

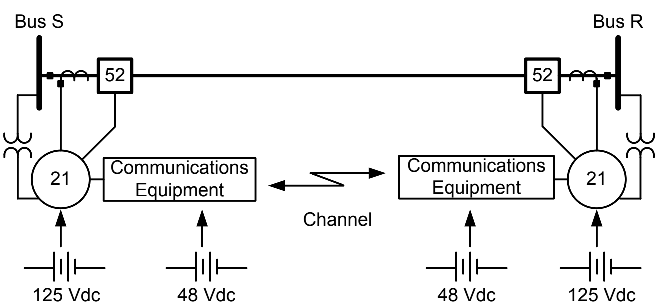

Fig. 1. Two-Terminal Digital Line Pilot Protection Scheme.

To successfully clear all faults on the line within a prescribed time (e.g., less than 5 cycles), all of the elements in Fig. 1—breaker, relay, dc supplies, communications, current transformers (CTs), voltage transformers (VTs), and wiring—need to perform correctly. It is not unusual for lines to have redundant and backup protection schemes, often using different operating principles, with multiple channels and/or dc supplies.

Human factors (such as design, settings, procedures, and testing) are not shown in Fig. 1 but must also perform correctly. Additionally, security is as important a consideration as dependability. All of the elements and human factors must perform correctly to ensure that the protection scheme correctly restrains for out-of-section faults or when no fault is present.

II. The Effect of DC and Communications Disruptions on Overall Reliability

Protection systems must be robust even with transients, harsh environmental conditions, and disruptions in dc supply, dc circuits, or interconnected communications. These disruptions include loss of dc power due to failure or human action, noise on the battery voltage, dc grounds, interruptions in dc supply, and subsequent restart or reboot sequences. In the case of communications, these disruptions include channel noise, channel delays, interruptions due to equipment problems or human action, unexpected channel switching, and restart or resynchronization sequences.

Fault tree analysis has been beneficial in analyzing protection system reliability, comparing designs, and quantifying the effects of independent factors. For example, the rate of total observed undesired operations in numerical relays is 0.0333 percent per year (a failure rate of $333 \cdot 10^{-6}$). By comparison, the rate of undesired operations in line current differential (87L) schemes where disturbance detection is enabled is even lower at 0.009 percent per year (a failure rate of $90 \cdot 10^{-6}$). However, undesired operations caused by relay application and settings errors (human factors) are 0.1 percent per year (a failure rate of $1{,}000 \cdot 10^{-6}$) [1].

Unavailability, which is the failure rate multiplied by the mean time to repair, is another measure used to compare reliability. The unavailability of dc power systems is low at $30 \cdot 10^{-6}$, compared with $137 \cdot 10^{-6}$ for protective relays and $1{,}000 \cdot 10^{-6}$ for human factors. These data assume a faster mean time to repair a dc power system problem (one day) compared to relays and human factors (five days). Communications component unavailability indices are similar to those of protective relays [2].

The North American Electric Reliability Corporation (NERC) *State of Reliability 2014* report found that from the second quarter of 2011 to the third quarter of 2013, 5 percent of misoperations involved the dc system as the cause, compared with 15 percent for communications failures, 21 percent for relay failures, and 37 percent for human factors [3].

From these data, we can see that dc and communications failures are a small but significant factor in reliability.

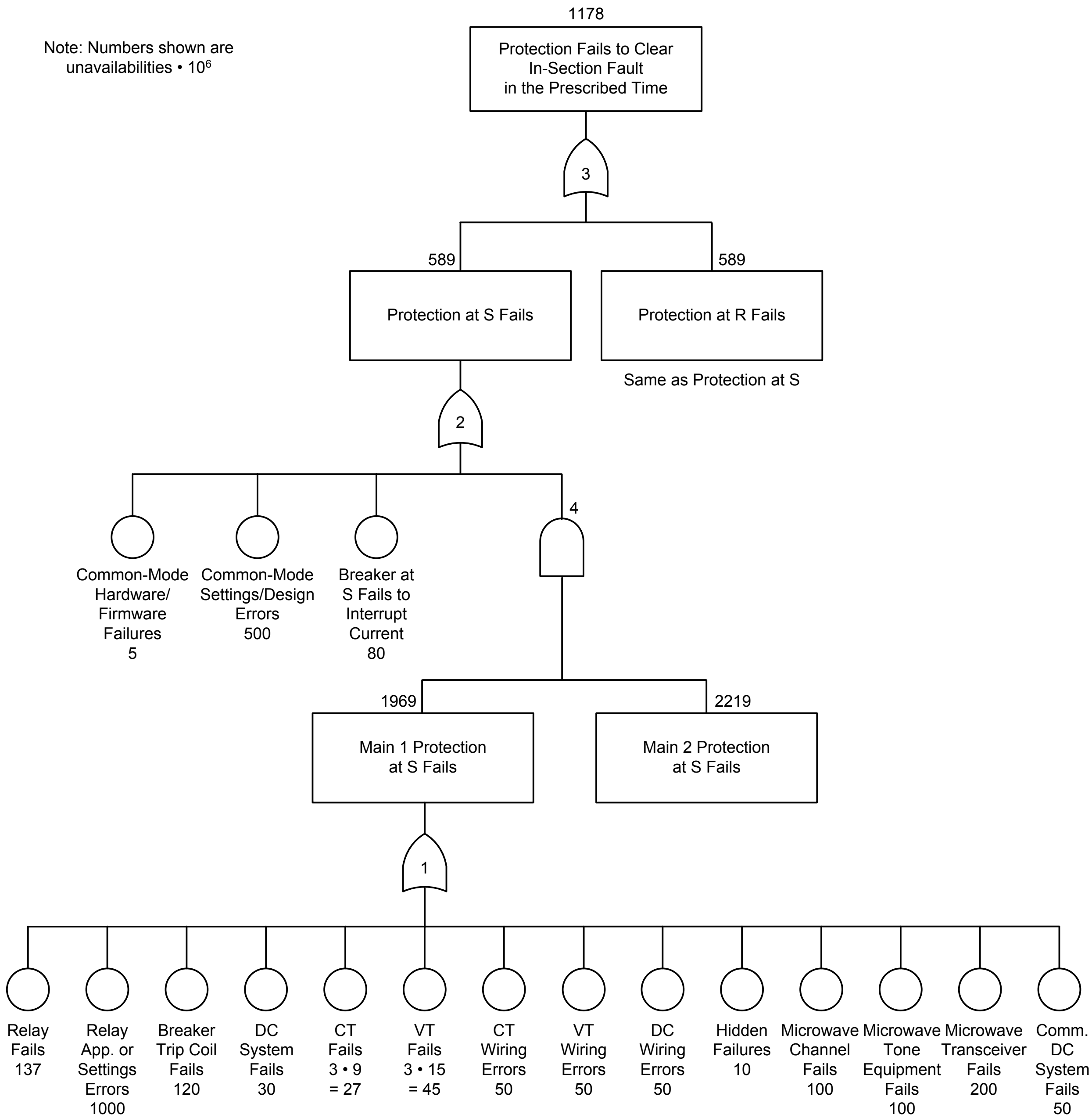

Fig. 2. Dependability Fault Tree for Dual-Redundant Permissive Overreaching Transfer Trip (POTT) Scheme [2].

Fault trees allow us to see how the failure rate of one device impacts the entire system (see Fig. 2). Fault trees also allow us to evaluate how hidden failures, common-mode failures, improved commissioning tests, and peer reviews impact reliability.

However, fault trees do not easily identify how a failure or activity in one subsystem affects another subsystem. Inspired by Christopher Hart, acting chairman of the National Transportation Safety Board, we wanted to investigate the interaction of components, subsystems, and human factors on the reliability of the entire protection system. At the 2014 Modern Solutions Power Systems Conference, Mr. Hart spoke of the aviation industry as a complex system of coupled and interdependent subsystems that must work together successfully so that the overall system works. In aviation, a change in one subsystem likely has an effect throughout other subsystems (see Fig. 3) [4].

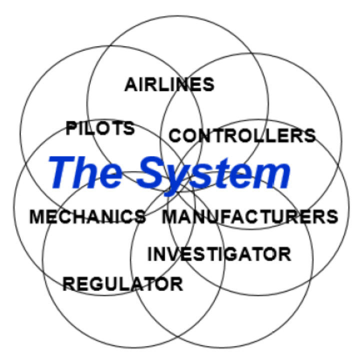

Fig. 3. Aviation Safety Involves Complex Interactions Between Subsystems.

The protection system, and the entire power system, is very similar to the aviation industry. Fault trees and high-level apparent cause codes do not necessarily make these subsystem interdependencies apparent.

For example, in December 2007, while performing maintenance testing, a technician bumped a panel and a microprocessor-based, high-impedance bus differential relay closed its trip output contact (87-Z OUT1 in Fig. 4), tripping the bus differential lockout relay (86B in Fig. 4). Fortunately, due to testing that was being performed that day, the lockout relay output contacts were isolated by open test switches that kept it from tripping any of the 230 kV circuit breakers.

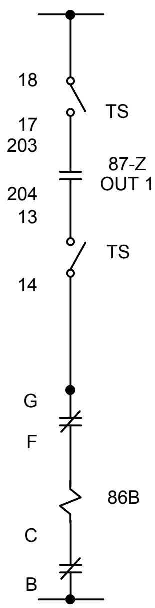

Fig. 4. DC Control Circuit Showing Bus Differential Trip Output.

The bus differential relay contact closure was easily repeated by bumping the relay chassis. The simple apparent cause could have been classified as human error, product defect (failure to meet industry shock, bump, and vibration standards), or relay hardware failure. However, subsequent analysis by the relay manufacturer showed momentary low resistance across the normally open contact when the chassis was bumped. Additionally, visual inspection noted evidence of overheating in the contact area (the outside of the plastic case was slightly dimpled). The contact part was x-rayed while it was still mounted on the main printed circuit board. The adjacent, presumed-healthy contact was x-rayed for comparison. The x-ray images are shown in Fig. 5, with the adjacent, healthy Form-C contact on the left and the damaged Form-C contact on the right. In each contact, there is a stationary normally open contact surface (top), a moving contact surface (center), and a stationary normally closed contact surface (bottom). Note the difference in contact surfaces and spacing. The relay manufacturer estimated that the output contact was likely not defective but rather had been damaged due to interrupting current in excess of the contact's interruption rating.

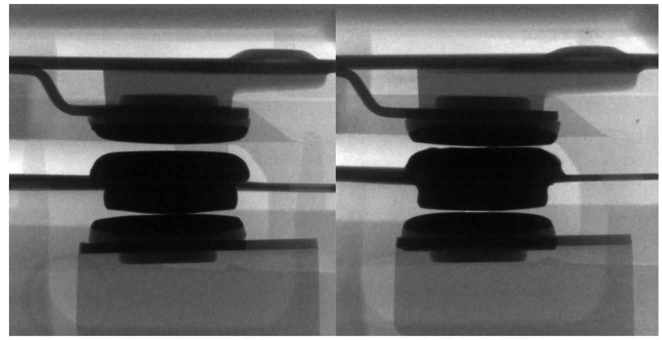

Fig. 5. X-Ray Images of the Healthy, Adjacent Contact (Left) and Damaged Contact (Right).

The output contact manufacturer further inspected the output contact part. The output relay cover was removed and the inside of the part was observed and photographed (see Fig. 6). The plastic components were melted, the spring of the contact point was discolored and deformed by heat, and the contact surfaces were deformed, rough, and discolored. The root cause of the contact damage was confirmed: at some point prior to the misoperation, the interrupting current was in excess of the contact's interruption rating.

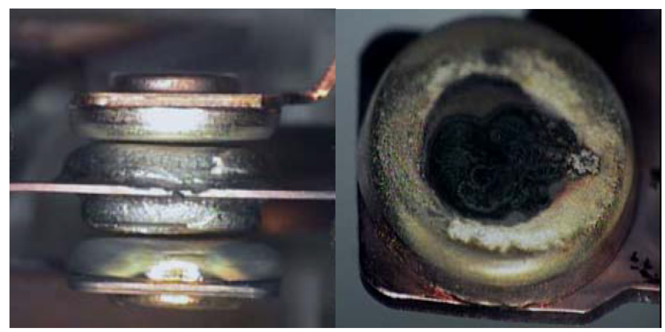

Fig. 6. Pictures From Contact Manufacturer Confirming Heat Damage From Exceeding Current Interruption Rating.

It is important at this point to persist in analysis and examine testing mandates, procedures, and work steps to find root cause. In this case, commissioning testing, represented as one human factor subsystem in the fault tree (relay application), performed to improve reliability was flawed in such a way that the protective relay hardware was damaged and induced a failure in that subsystem. In addition, maintenance testing, mandated by NERC and intended to improve reliability, was flawed in such a way that the relay was damaged and could have potentially caused a misoperation.

In this example, the failure mode was a relay contact closing when the relay chassis was bumped. According to NERC data, 60 percent of root-cause analyses stop at determining the mode [5]. True root-cause analysis requires us to dig deeper to understand the failure mechanism or process that led to the failure. Then, we can educate others and ensure that improvements prevent the problem from reoccurring. In NERC contributing and root-cause vernacular, this incident would be due to a *defective relay* (A2B6C01) caused by an *incorrect test procedure* (A5B2C07) caused by a *failure to ensure a quality test procedure* (A4B2C06). An important theme in the case studies that follow is how an action or failure in one subsystem affects other subsystems and overall reliability.

III. Traditional DC Problems

The dc control circuits used in protection systems have always been complex. Problems that need to be mitigated include circuit transients, sneak or unintended paths, stored capacitance, let-through and leakage currents, and more [6]. For example, electromechanical auxiliary relays were once commonly used for local annunciation, targeting, or contact multiplication. Some of these relays were high speed and quite sensitive. Care was taken to ensure that let-through currents from connected output contacts did not inadvertently cause these auxiliary relays to pick up.

Especially when used with transformer sudden pressure relays with poor dielectric withstand capability, extra security measures were taken to prevent auxiliary relays from operating in case a voltage surge caused a flashover in the normally open contacts of the pressure relay. In Fig. 7, the normally closed contact from the sudden pressure relay (63) shunts the auxiliary relay operating coil (94) so that if the normally open contact flashes during a voltage transient, the auxiliary relay will not operate [7].

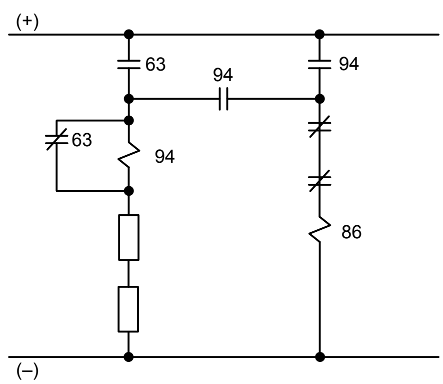

Fig. 7. Typical Security Precaution for Dielectric Strength Failure of a Sudden Pressure Relay Contact.

Precautions must be taken to avoid these same dc circuit anomalies as we transition to new technology platforms and design standards. As auxiliary relays are replaced by microprocessor-based relays, pick-up time delays are required on relay inputs that are used to directly monitor these same sudden pressure relay normally open contacts to maintain security [8].

IV. Traditional Communications Problems

Communications that are used for protection systems perform well but are not perfect. One well-known communications component problem involves the application of power line carrier for transmission line protection schemes. In directional comparison blocking (DCB) schemes, high-frequency transients can produce an undesired momentary block signal during an internal fault. Fig. 8 shows one such incident. Engineers must adjust frequency bandwidths, add contact recognition delay, or tolerate the possibility of a slight delay in tripping for internal faults.

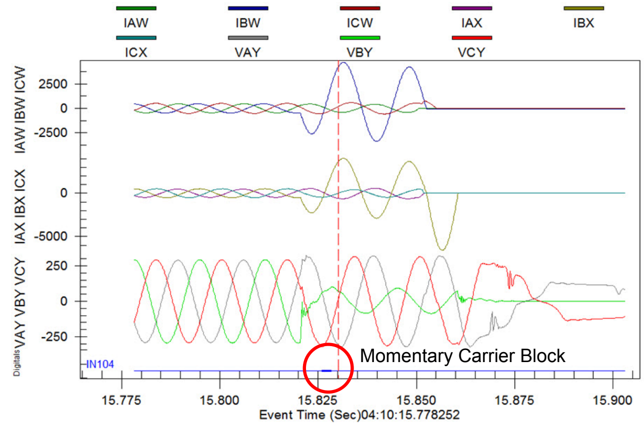

Fig. 8. Momentary Carrier Block Input Produced by Fault-Induced Transient.

Conversely, if an external fault occurs, the momentary dropout of the carrier blocking signal, referred to as a "carrier hole," can produce an undesired trip, as shown in Fig. 9. These dropouts are often attributed to a flashover of the carrier tuner spark gap and can be avoided by improved maintenance of the carrier equipment or can be dealt with by adding a dropout delay on the received block input.

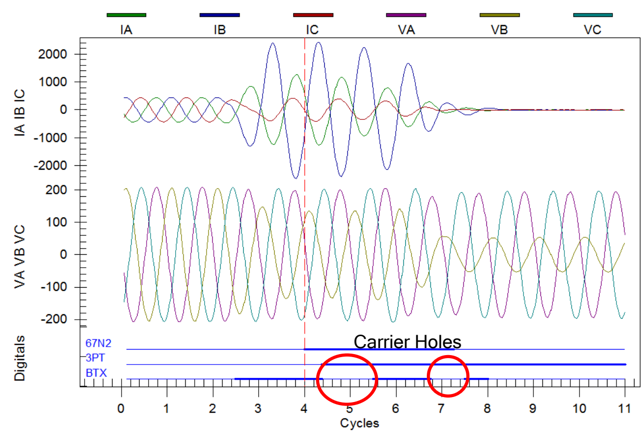

Fig. 9. Carrier Holes in a DCB Scheme.

Protection system communications options today include many media in addition to power line carrier, such as microwave, spread-spectrum radio, direct fiber, multiplexed fiber networks, Ethernet networks, and more. Each medium has its own set of potential problems, such as channel noise, fault-induced transients, channel delays, dropouts, asymmetry, security, buffers and retry, interruptions due to equipment problems or human action, unexpected channel switching, and restart or resynchronization sequences. The trends in our industry include communicating more, exploring new and creative applications for communications, and replacing intrastation copper wiring with microprocessor-based devices and communications networks. As more and more communications and programmable logic are used, it is critical to analyze, design, and test for potential communications problems.

V. Traditional Procedure Problems

The sequence in which work tasks are performed is important. A familiar example will highlight this concept. A primary microprocessor-based line relay had been taken out of service for routine maintenance testing. Trip and breaker failure initiate output contacts, as well as voltage and current circuit inputs, had been isolated by opening test switches. After successful secondary-injection testing, the relay tripped the circuit breaker during the process of putting the protection system back into service [9].

Event data showed only one current (A-phase) at the time of trip. This indicated that the technician had reinstalled the trip circuit first by closing the trip output test switch. Next, a single current was reinstalled by closing its test switch. Because there was load flowing through the in-service breaker and CTs, the relay, at this step in the sequence of events, measured A-phase current and calculated 3I0 current and no voltages. It issued a trip.

This was a valuable lesson for this utility in the early adoption phase of these relays and led to a specific procedure and sequence that is used when returning a relay to service. The sequence of steps used to restore the system to service is the reverse of that used to remove the system from service and is as follows.

1. Place all three voltage circuits back into service (i.e., close the voltage test switches).
2. Place all three current circuits back into service.
3. Use meter commands or event data to verify the proper phase rotation, magnitude, and polarity of the analog measurements.
4. Reinstall the dc control inputs.
5. Use target commands or event data to verify the statuses of control inputs.
6. Reset relay targets and verify that trip and breaker failure outputs are reset.
7. Place the trip and breaker failure output circuits back into service.

Similarly, when disrupting communications circuits or dc power, we must thoughtfully consider what parts of the protection system should be isolated and the careful order of steps to take in the process of returning the system to service. Analysis, design, and testing should be devoted to this, considering our increased dependence on interdevice communications and programmable logic.

The following section highlights some interesting system events where disruptions in dc and/or communications directly affected protection.

VI. Protection System Events Caused by DC or Communications System Disruptions

A. Case Study 1: Breaker Flashover Trip After Relay Restart

Fig. 10 shows the simplified one-line diagram of a 161 kV substation for an event in which a breaker failure flashover logic scheme operated after a relay restart (i.e., dc power supply to the relay was cycled off and on), causing a substation bus lockout.

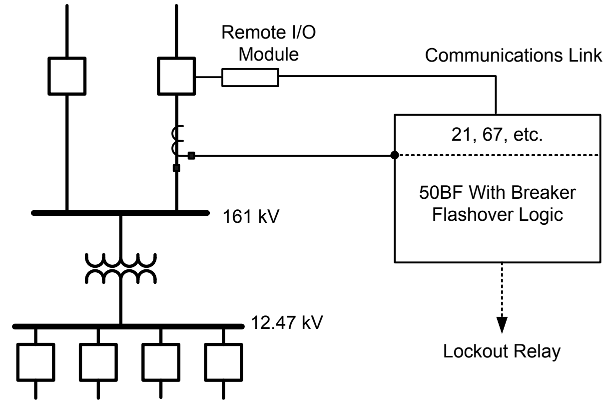

Fig. 10. Case Study 1 System One-Line Diagram Uses Remote I/O Module for Breaker Interface.

In this system, the breaker status auxiliary contacts (52a and 52b) and other monitored breaker elements are connected to a remote I/O module. The I/O module converts hard-wired inputs and outputs to a single fiber link from the module at the breaker to the relay located in a remote control house (see Fig. 11).

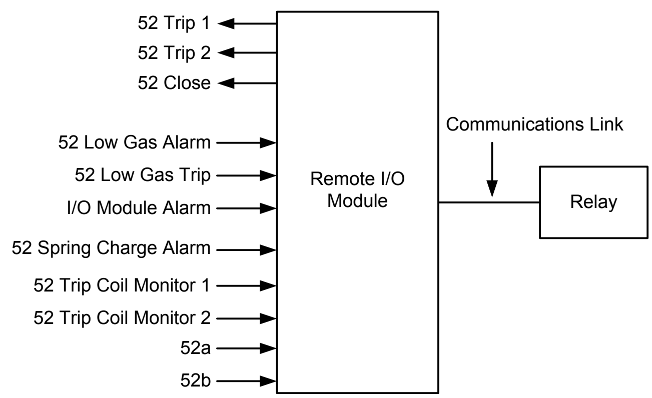

Fig. 11. Monitored Points From the 161 kV Circuit Breaker Using a Remote I/O Module and Fiber Interface to the Relay.

The user applied the I/O module to eliminate extra wiring and inherent noise and hazards associated with long (i.e., several hundred feet) runs of copper wire. Also, the fiber connection was continuously monitored.

The monitored communications link can be set to default to a safe state, as specified by the engineer. In this case, if communications were lost (e.g., fiber was disconnected or damaged or there was an I/O module failure), the breaker status would default to its last known state before the communications interruption.

The breaker failure flashover logic is shown in Fig. 12. It detects conditions where current (50FO) flows through an open breaker (NOT 52a). When a breaker trips or closes, the logic is blocked with a 6-cycle dropout delay. The user can define a time delay for breaker failure to be declared. In this case, it was 9 cycles.

The event data in Fig. 13 show the status of the relay elements immediately after the power cycle. Current is already present, but the breaker status (52AC1) is a logical 0 (not asserted). Thus, the breaker failure flashover element (FOBF1) asserts and produces the breaker failure output

(BFTRIP1), which subsequently operates the substation lockout relay.

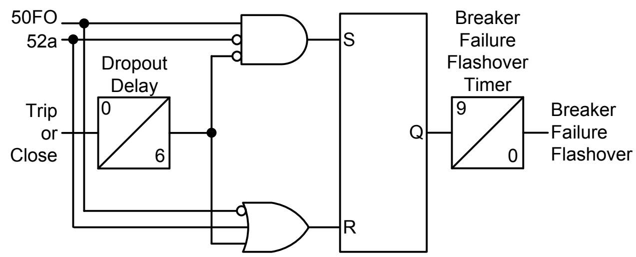

Fig. 12. Breaker Failure Flashover Logic.

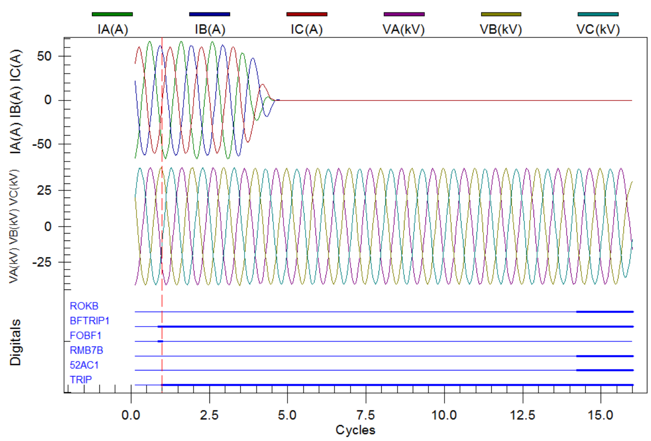

Fig. 13. Breaker Failure Flashover Logic Asserts Due to Current Measured While Breaker Is Sensed Open.

The undesired trip occurred because the breaker failure flashover logic began processing before the communications link between the I/O module and the relay was reestablished. We can see the communications link status between the relay and the I/O module (ROKB) asserted about 14 cycles later.

The event report does not show much about what happened before the trip during the relay restart process. However, from an internal sequential event record, we were able to assemble the timeline, as shown in Fig. 14.

The relay restart sets the latch (Q) and starts the 9-cycle breaker failure flashover timer. At 9 cycles, FOBF1 asserted. By the time the communications link was established (at 22 cycles), the trip had already occurred.

Important lessons were learned in this case study. Relays and I/O modules might reboot, operators may cycle power to relays when looking for dc grounds or performing other troubleshooting, relays may employ diagnostic self-test restarts, and so on. There is no default state for most logic during a relay restart. In a relay restart, all of the logic resets and begins processing from an initial de-energized state, as is the case when a relay is powered up and commissioned for the first time. In this case, designers considered a loss of communications but did not consider how a loss of dc supply or relay power cycle would affect the communications status and the logic processing order during a start-up sequence.

In the breaker failure flashover logic, the breaker status is used directly in a trip decision. We should supervise the breaker failure flashover logic with the monitored communications bit (i.e., FOBF1 AND ROKB) to prevent the flashover logic from being active until communication is established. To further avoid such undesired operations, commissioning tests should include power cycles to test for secure power-up sequences in logic processing.

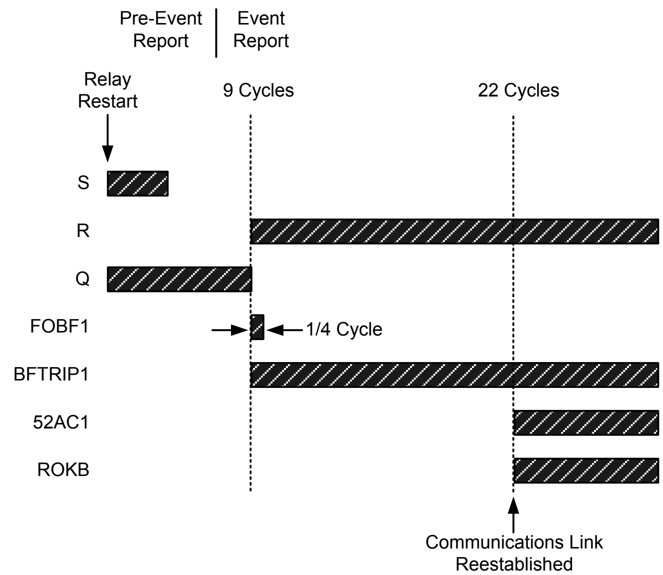

Fig. 14. Event Timeline Shows Relay Restart and Arming of Flashover Logic Before Breaker Status Is Recognized.

B. Case Study 2: Protective Relay Applied as a Lockout Relay Operates Due to a Power Cycle

In Case Study 2, a microprocessor-based transformer differential relay was applied as a lockout relay, as shown in Fig. 15. When dc power to the relay was switched off and on, the lockout logic output asserted, causing a substation trip and loss of supply to several customers.

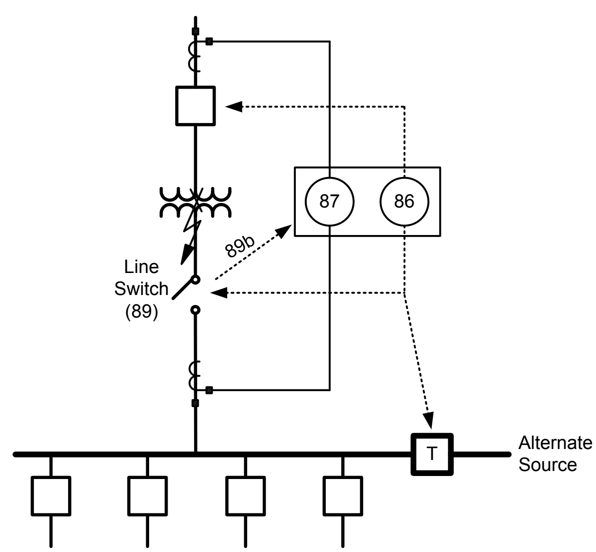

Fig. 15. One-Line Diagram of Relay Applied as a Transformer Differential Relay and Lockout Relay Together.

Discrete lockout and auxiliary relays are widely used in protection systems. Why not use a discrete lockout relay here instead of building these functions inside the microprocessor-based relay? The decision to do this was driven by several factors. One factor was reduced cost—fewer relays and less panel space and wiring. In addition, periodic maintenance testing was reduced by having fewer devices and by extending the maintenance intervals due to the inherent self-monitoring capability of the microprocessor-based relay versus the electromechanical lockout relay. Additionally, some system events have also led engineers away from using discrete auxiliary and lockout relays. One infamous event that is often cited for this change in design was initiated by a failed auxiliary relay at Westwing substation [10].

The internal relay lockout logic for Case Study 2 is shown in Fig. 16.

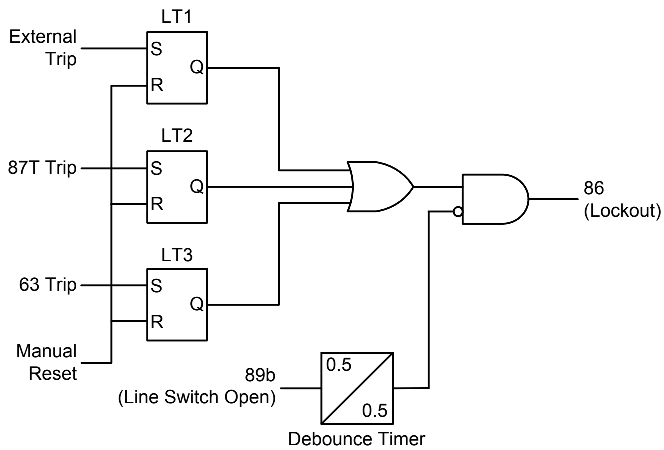

Fig. 16. Internal Lockout Logic.

The "latch" functions (LT1, LT2, and LT3) are all retained in nonvolatile memory. That is, even if the relay loses control power, it retains the status of the latch functions. In this case, an actual internal transformer fault occurred. The transformer protection (87T) and internal lockout function (86LO) operated to clear the fault. Dispatchers were able to switch load to an alternate source. All operations were correct up to this point.

The timeline in Fig. 17 shows the sequence.

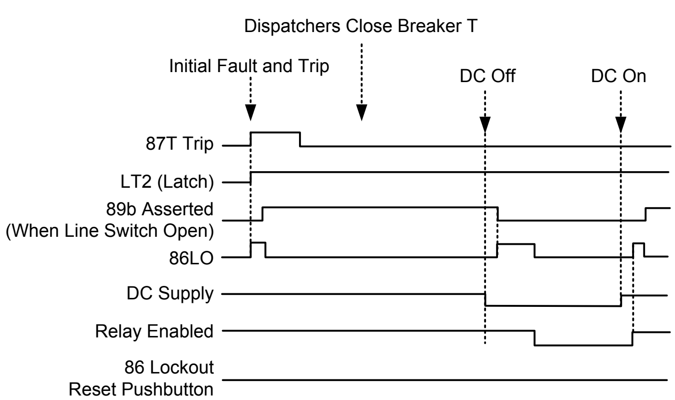

Fig. 17. Event Timeline Shows 86LO Trips for DC Off and On.

When the maintenance crew arrived at the station, the correct procedure was to reset the lockout using a pushbutton on the relay. Instead, as stated earlier, the dc supply was switched off and on. The 86LO function asserted incorrectly when dc was switched off and asserted incorrectly again when dc was switched on.

On power down, the relay stayed enabled for several cycles after the point at which logical inputs deasserted. Thus, the 89b input was sensed as deasserted (line switch closed) before the relay was disabled, producing the 86 lockout.

On power up, the relay enabled before the 89b input was sensed, thus producing the 86 lockout again.

The first and most obvious lesson learned in this case study is that, as technology changes, engineers and operators must strictly adhere to updated operating procedures for resetting lockout functions. Well-understood interfaces, such as physical lockout relays, are being mimicked or replaced, and it is important to document and train field personnel.

Another lesson learned is to test the impact of cycling dc power off and on. Protection systems should be robust, relays and I/O modules might reboot, and operators may cycle power to relays when looking for dc grounds or performing other troubleshooting. In this case, designers did not consider how a loss of dc supply or relay power cycle would affect the programmable logic processing order during a power-down or power-up sequence.

The user has since added logic so that the lockout function is supervised by a healthy relay (Relay Enabled). In addition, the line switch status is now supervised by a dropout delay that is longer than the relay power-down enable time (see Fig. 18).

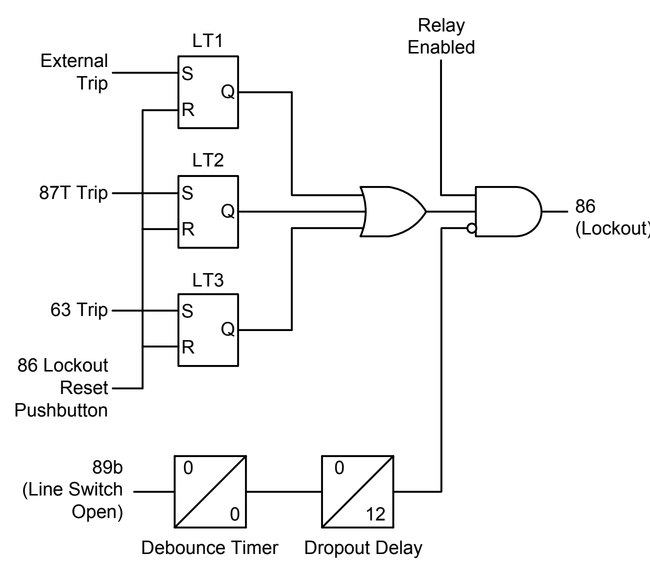

Fig. 18. Modified Lockout Function Logic.

C. Case Study 3: Direct Transfer Trip Due to a Noisy Channel

Fig. 19 shows the protection one-line diagram for a 138 kV system with two-ended transmission. The line is protected by distance and directional elements in a permissive overreaching transfer trip (POTT) scheme, along with a direct transfer trip (DTT) scheme if either end trips.

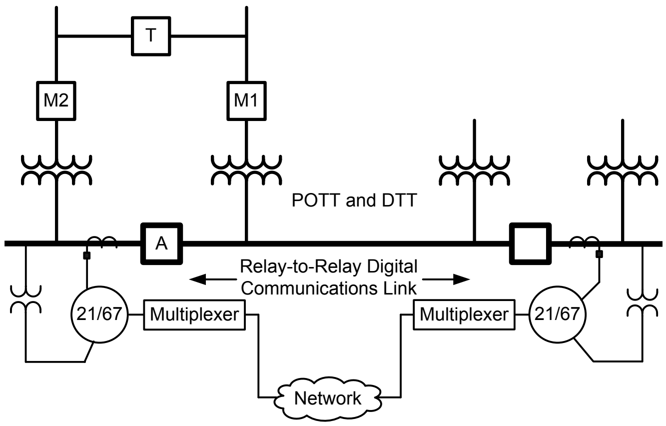

Fig. 19. One-Line Diagram of a 138 kV Transmission Line.

In this case, the communications channel is a multiplexed digital network. The channel was abnormally noisy, with about 10 channel dropouts per minute and an overall channel unavailability around 0.5 percent. One of the noise bursts and associated channel dropouts resulted in a momentary assertion of the DTT input (see Fig. 20). Note that the protection system also experienced an unrelated breaker failure.

Significant efforts are made to secure protective relays that use channels; these efforts include data integrity checks, debounce delays, disturbance detectors, watchdog counters, and more. In this case, even with a 50 percent bit error rate, the probability of a bad message getting through the relay data integrity checks was one in 49 million [11]. Although the probability was low, it was not zero, and if enough bad messages were sent, it was still possible for one to get through the integrity check, as in this case.

In this example, we see how monitoring a noisy channel may provide a leading indicator for detecting problems. Also, regardless of media and integrity checks, it is prudent to add security on schemes that use direct transfer tripping. In this case, requiring two consecutive messages (an 8-millisecond delay) instead of one (a 4-millisecond delay) improved security by an additional 10^4 factor.

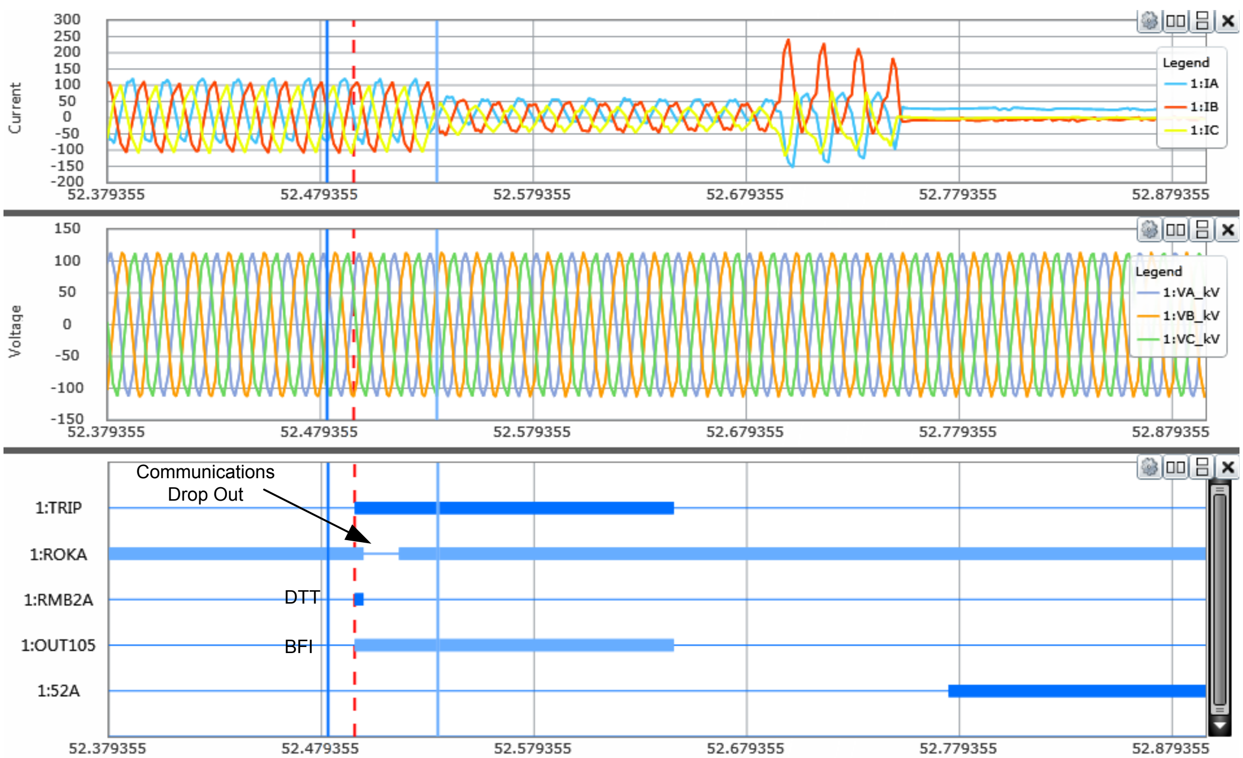

Fig. 20. Channel Noise Results in a Momentary DTT Assertion.

D. *Case Study 4: Communications Channel Problem on 87L*

Another two-terminal transmission line was protected by an 87L scheme. In the event data shown in Fig. 21, the system experienced a degradation of one of the optical fiber transmitters used in the 87L scheme. This failing component injected continuous noise into the channel and its connected equipment.

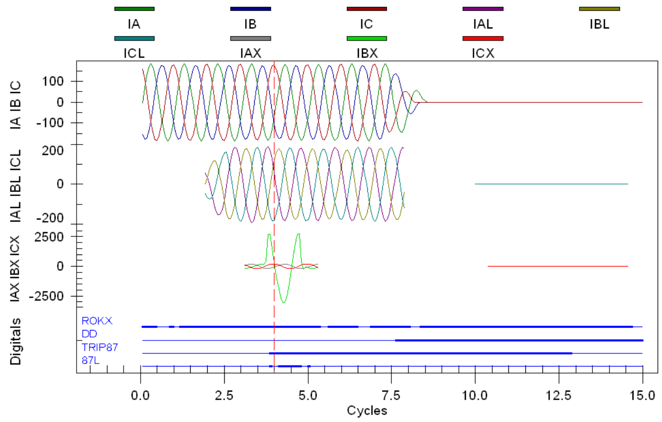

Fig. 21. 87L Produced Undesired Trip Due to Communications Failure With Disturbance Detection Not Enabled.

In Fig. 21, we can observe the channel status (ROKX) chattering—it should be solidly asserted. Eventually, bad data, in this case erroneous remote terminal current (IBX), made it through data integrity checks and caused an undesired 87L operation. Disturbance detection was not enabled.

Important lessons were learned in this case study. Channel performance must be monitored, and alarms, reports, and other notifications of noise and channel dropouts must be acted on with urgency. In modern 87L relays, regardless of data integrity checks, disturbance detection should be applied to supervise tripping. If disturbance detection had been enabled in this case, the 87L element would have been secure and the undesired operation would have been avoided.

E. *Case Study 5: Relay Trips During Power Cycle While Performing Commissioning*

An older microprocessor-based relay was being commissioned. During testing, the dc control power was cycled and the relay tripped by directional ground overcurrent. The problem was repeatable.

The relay power supply produces two low-voltage rails from its nominal input voltage for use by various hardware components. A 5 V rail, in this case, was used by the analog-to-digital (A2D) converter, and a 3.3 V rail was used by the microcontroller (µP) and digital signal processor (DSP). Protective circuits reset components when their respective supply voltages drop below acceptable operating limits.

Recall from a previous case study that, due to ride-through capacitance, the power supply stays active for several cycles after input power is removed. Fig. 22 provides a graphical representation of how the power supply rails decay at a certain ramp rate, rather than an instantaneous step change, after power is turned off at time T1.

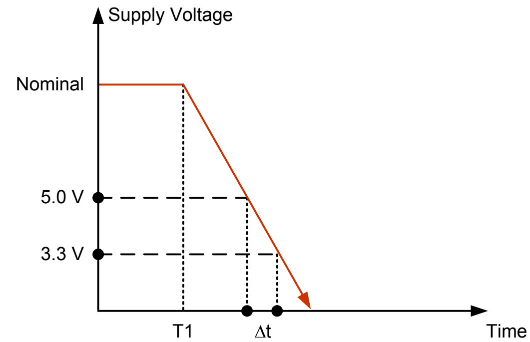

Fig. 22. DC Supply Voltage Ramp Down to 0 V After a Power Cycle at Time T1.

The root cause for this case study was a hardware design that allowed the µP and the DSP to remain enabled for several milliseconds after A2D disabled. As A2D disabled, it sent erroneous data to the µP and the DSP, which appeared as a false 3I0 current pulse, which caused the trip.

Fortunately, this design issue was found during commissioning tests instead of much later when pulling relay dc power (with trips enabled) to find a dc ground.

Important lessons were learned in this case study. Cycling control power, while replicating as accurately as possible in service conditions, is invaluable and as important as industry standard environmental tests. In this case, the criticality of the power-down sequence of components common to one piece of hardware was revealed.

Consider that the North American Northeast Blackout of 2003 was aggravated by a lack of up-to-date information from the supervisory control and data acquisition (SCADA) system. A remote terminal unit (RTU) was disabled after both redundant power supplies failed due to not meeting industry dielectric strength specifications. Independent testing (simple high-potential isolation testing) had not detected this product weakness. Self-test monitoring did not alert the operators that the RTU was dead. Fail-safe design practices, such as reporting full-scale or zero values for all data fields during loss of communications or for watchdog timer failures, were not in place. Redundant power supplies, installed to improve the availability of the system, did not overcome these larger handicaps [2] [12]. These problems are not “hidden failures” just because we do not test or check for them.

As the industry moves toward more complicated and interdependent Ethernet IEC 61850-9-2 systems, power cycling tests become even more critical. Such systems may employ a data acquisition and merging unit built by one manufacturer, a subscribing protective relay built by a second manufacturer, and an Ethernet network built by a third manufacturer. What if the data acquisition shuts down at 5 V and outputs erroneous data to the rest of the components that remain active for a few cycles more?

VII. Conclusion

Protection systems and the power industry have much in common with the aviation industry. Both are complex systems of coupled and interdependent subsystems that must work together successfully so that the overall system works. We must continue to understand root cause and that changes in one subsystem have an effect throughout other subsystems.

DC control circuits and communications channels have always had complexity and problems to overcome. Our work instructions and procedures have always had to be carefully considered. However, as we transition to new technology platforms and design standards, special precautions must be taken to avoid the types of pitfalls discussed in this paper.

When disrupting dc control circuits or communications channels, we must thoughtfully consider what parts of the protection system should be isolated from trip circuits. Isolate trip circuits before indiscriminately cycling power in relay panels when, for example, troubleshooting dc grounds.

Analysis, design, and testing should be devoted to understanding what happens when power is cycled on systems and subsystems, especially considering our increased dependence on interdevice communications and programmable logic. Critical communicated logic inputs should be supervised with device and communications link statuses. Logic should be forced to a secure state during communications interruptions. Status dropout delays should be included as a necessity for security margin. DTT signals should be supervised with debounce delays. Received analog values should be supervised with disturbance detectors.

Include the ability to isolate trip circuits and devices, whether by physical test links or virtual links for communicated signals. Especially when implementing new technology platforms, strive to make the operator interface familiar and ensure that operating procedures are clear, documented, and proven.

Test, test, test; avoid undesired operations by including power cycle and logic processing sequence checks in design and commissioning tests.

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IX. Biographies

Karl Zimmerman is a regional technical manager with Schweitzer Engineering Laboratories, Inc. in Fairview Heights, Illinois. His work includes providing application and product support and technical training for protective relay users. He is a senior member of IEEE, a member of the IEEE Power and Energy Society Power System Relaying Committee, and vice chairman of the Line Protection subcommittee. Karl received his B.S.E.E. degree at the University of Illinois at Urbana-Champaign and has over 20 years of experience in the area of system protection. He has authored over 35 papers and application guides on protective relaying and was honored to receive the 2008 Walter A. Elmore Best Paper Award from the Georgia Institute of Technology Protective Relaying Conference.

David Costello graduated from Texas A&M University in 1991 with a B.S. in electrical engineering. He worked as a system protection engineer at Central Power and Light and Central and Southwest Services in Texas and Oklahoma and served on the System Protection Task Force for ERCOT. In 1996, David joined Schweitzer Engineering Laboratories, Inc. as a field application engineer and later served as a regional service manager and senior application engineer. He presently holds the title of technical support director and works in Fair Oaks Ranch, Texas. David has authored more than 30 technical papers and 25 application guides. He was honored to receive the 2008 Walter A. Elmore Best Paper Award from the Georgia Institute of Technology Protective Relaying Conference and the 2013 Outstanding Engineer Award from the Central Texas section of the IEEE Power and Energy Society. He is a senior member of IEEE, a registered professional engineer in Texas, and a member of the planning committees for the Conference for Protective Relay Engineers at Texas A&M University.

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Conference for Protective Relay Engineers.

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Everyday Aesthetics versus Special Situations

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Introduction

The design process for power delivery structures includes many important factors. Our industry is fortunate to have a number of design standards and engineering practice manuals published that establish the design parameters and key criteria that must be considered. For example, ASCE 48 – American Society of Civil Engineers Standard for the Design of Steel Transmission Pole Structures lists the following <u>loading</u> considerations:

1. *Conductor and shield wire properties,*
2. *Minimum legislated loads,*
3. *Historic climate conditions,*
4. *Structure orientation,*
5. *Construction and maintenance operations,*
6. *Line security provisions, and*
7. *Unique loading situations*

The standard also requires <u>geometric configuration</u> considerations:

> *that are based on electrical, economic, and safety requirements specified by the Owner*

The next revision of the standard has added *aesthetics* to this list of configuration considerations. The committee also discussed the idea of creating an appendix on the subject of aesthetics as a non-binding, but helpful reference in our publication. Ultimately, a separate task committee has been formed by the ASCE SEI Technical Activities Division to write and publish a Committee Report on Transmission Structure Aesthetics applicable to all materials and structure types.

So what does this mean? Is it now necessary to make every structure a landmark? How is this requirement supposed to be met when it is so subjective and beauty is in the eye of the beholder? What is this going to cost and who is going to pay for it? Can aesthetic structures be properly maintained and reliable? Rest assured, our current designs considerations are all still in place. Aesthetic consideration simply means that, as we design structures responsibly, we include thoughtful treatment of their visual characteristics.

This is relevant to routine situations you deal with every day and it certainly applies in special situations where a unique structure might be the best thing for the project and the public.

The Dilemma

The functional and safety requirements of our structure designs are so uniquely different from roads, bridges and pipelines that, in many ways, we operate in an 'insulated' world. Physical and electrical design considerations dictate, to large degree, the resulting appearance of our structure designs. Historically, we were able to focus on function and leave it at that, easily deflecting any arguments to change our traditional approach. However, growing pressure to pay attention to aesthetics for public acceptance and regulatory approval is a tension point in our industry. Broad and often inaccurate assumptions about what it means to be aesthetic, coupled with our industry's cultural aversion to change, create a dilemma that stalls out sensible progress. The situation cries out for clarity.

Reality

As designers of critical infrastructure components, ‘architectural’ influence is typically low on our list of priorities, if on our radar at all. Ironically, power lines are among the most visually consumed structures by the public. Their prolific presence is unavoidable as they pin and span through our cities, around our neighborhoods and across our countryside. They have become a dominant part of the built environment and often dominate the landscape. They seem to be everywhere, looming as conspicuous sentinels in every direction. Yes, our designs must perform with electrical reliability and structural integrity for many decades… all the more reason to carefully consider another lasting design attribute… aesthetic quality.

The engineering community that has been trained to design these complex structures and power line systems typically does not have architectural or aesthetic training to bring to the job or add to the equation. Again, the size, shape and scale of transmission structures are predominately controlled by significant electrical and safety parameters that are not going away. Installation and operational economics are also determining factors in structure configurations. So it has been generally assumed that nothing different can be done in the area of power delivery structure aesthetics. Really, is this the reality we are stuck with… Is this the full extent of our visual options… poles or towers? … galvanized or weathering?... single leg or H-frame?... guyed or self-supporting?

The Challenge

The professional engineering principles that hold the public health, safety and welfare paramount, also speak to aesthetic quality in engineering design. The American Society of Civil Engineers (ASCE) policy statement 117 says:

> *An engineering design can enhance or detract from the environment by virtue of the quality of its visual characteristics…Visual quality and aesthetics must be considered throughout the life-cycle*

of the project. Aesthetic quality can be achieved in ways that maintain or enhance functional quality.

So again, does this mean that every power delivery structure needs to somehow be a unique and beautiful landmark structure? Is there room to improve the normal, everyday structure that would help it avoid being unnecessarily awkward? Should aesthetics be more than public participation boards showing poles versus towers, galvanized versus weathering or H-Frames versus guyed structures? The ASCE policy seems to suggest, as a matter of awareness and design intent, that aesthetic quality can and should be achieved.

Perspective

Visual quality is something we consume all the time, whether we realize it or not. We live and move, and even design in a world that reacts to visual queues, or is that cues? ← see?! Even when we are asked to come up with a business presentation, we try to compose a visual design that communicates our message most effectively. PowerPoint provides as much help and as many built-in options as it can, but you ultimately have to make a decision about your layout and style and deliver that presentation to your audience.

Architecturally, buildings and bridges and parks are carefully planned with both function and aesthetics in mind. Elements of art and principles of design are skillfully combined to create intentional visual relationships. The purpose can be whatever the designer is trying to achieve within the project itself, or in relation to the project's contextual environment. Regardless, the point of aesthetic consideration is to anticipate and influence human reaction to a design. We expect and praise this practice in the built environment, why should power lines get a pass?

Opportunity

Translating the practice of aesthetic consideration into non-traditional applications, like power delivery structures, is uncomfortable for some of us. However, there is good news. First, including aesthetic consideration in the design process does not mean that every structure has to be a monument or signature work of art. It does not mean that structurally integrity is going to be compromised. It does not mean that the cost is going to be astronomical. It does not mean that we have to sacrifice performance and safety of our critical life-line infrastructure. Actually, appropriate attention and reasonable inclusion of aesthetic specifications should lead to better public acceptance and faster project completion cycles. Beyond that, I contend that bar can be raised on what I call ‘everyday aesthetics’ and basic skills related to architectural appreciation. Developing an eye for visual attributes such as scale, proportion, balance, rhythm and emphasis can naturally lead to incremental visual improvements for little to no additional cost. Likewise, recognizing environmental context and perspective could lead to implementing a single special structure or a customized line segment at a strategic location that helps gain project approval and results in an earlier energization date.

The main message here is to be tasteful in your design decisions that relate to visual impact. Take time to adopt the perspective of the observing public. Take advantage of training opportunities that increase your aesthetic awareness and knowledge of architectural concepts, especially as they can be applied to our structures. Purely structural solutions can be generated and defended, but I contend that they are not truly professional in the spirit of the ASCE aesthetic policy and our profession’s responsibility to the public welfare unless the engineer steps back from his design before calling it done and assesses its resulting aesthetic quality.

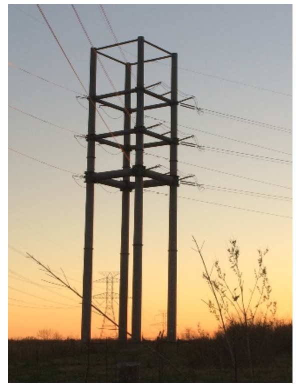
As a standard design consideration, the design engineer should identify opportunities to enhance visual quality without sacrificing structural or functional integrity. This effort might be the very first step on a project, or it could be a final design review. It may be dramatic and attention grabbing, or it may be as simple as electively adjusting the shape or dimension of a plate purely for aesthetic reasons, doing nothing to enhance or compromise the capacity of the member or connection. It might mean that the stress ratio is not as optimum as it could be or that the drafter or CNC programmer must follow a few more angles or arcs. Surprisingly, subtle details can have dramatic visual impact when viewed as a whole and from the vantage point of the public.

It is certainly possible, and actually far too commonplace, to issue a construction package that meets the functional design requirements, but falls short from the perspective of aesthetic quality. Is this due to carelessness, ignorance or neglect? Granted, our structures have a job to do that the general public does not have an appreciation for. Therefore, our structures look awkward already, but we should seek to avoid making them “unnecessarily awkward”. What can we control to lessen the negative visual impact? The whole message on this point is to design for visually neutral characteristics. In other words, try to look normal. Simply by eliminating the low hanging fruit, the world will be a better place!

My Story

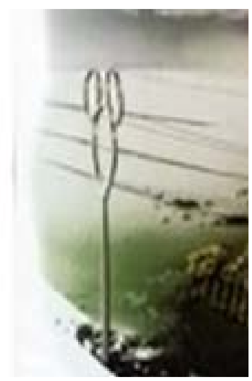
As I entered this industry out of college, I had an Architectural Engineering degree and a strong appreciation for aesthetic principles. The structural engineering foundation I brought matched well with the requirements of my new job as a transmission engineer, but the architecture part of my education seemed like it would not apply. In fact, I choose to leave that job after a few years to work for a consulting engineer designing high-rise buildings. Our firm even specialized in visual presentation and I was able to complement my degree with on the job training. Years later I returned to the utility business and defaulted to a compartmentalized perspective on aesthetics because the appearance of our structures were so functionally driven that the most we could do was to offer a couple structure type and finish options. That's when I specified and purchased a 4 leg portal H-frame I now call 'Gargantua':





Even with the high load requirements and other difficult design constraints, I was not satisfied that I did everything I could to influence the visual impact. A few more years later, I left the utility again to design tubular poles for a manufacturing company. I was fortunate to open an inquiry for a 'mouse-head' structure to be installed at Disney World in Florida. I immediately recognized the opportunity to come up with a solution that would become a landmark structure in our industry. The 'Mickey Pole' became a reality and is probably to most recognizable transmission pole in the world.





Since that time, I was blessed to lead multiple production operations and product development teams involving different material types and manufacturing processes. This afforded me opportunities to explore different material and shape combinations and finishes to satisfy aesthetic goals.

The take away from my story is that even for someone with an architectural background, it has been a progressive process to discover that aesthetic consideration is an important factor in the design process of power delivery infrastructure.

Conclusion

It requires thoughtfulness and skill to apply aesthetic principles in our design process, whether the goal is to blend or to highlight a structure or even a viewable line segment. Including aesthetics in your structure design considerations guides your decisions to 1) eliminate the unnecessarily awkward, 2) include thoughtful and subtle details or 3) recognize when to highlight a special situation.

Our industry is starting to respond. An ASCE task committee had been formed to develop a report on the Aesthetic Design of Transmission Line Structures to provide guidance to the profession in this area. An independent group called the North American Transmission Structure Aesthetic Competition (NATSAC) has recently announced the first in a series of competitions to raise the awareness of aesthetics in the design process.

Awareness and education in the area of aesthetics for power delivery structures will have a cumulative effect over time. We can move needle one structure or line project at a time by including aesthetic consideration as part of our standard design process.

Aesthetic levers to think about:

Taper	too much, too little	tepee vs silo
Diameter	too fat, too skinny	toothpick vs smokestack
Proportion	too big, too little	top heavy vs twig
Spacing	too far, too close	clustered vs stray
Color	too bright, too dark	beacon vs eclipse
Ratio	too similar, too different	oddball vs hypnotic
Complexity	too cluttered, too boring	train wreck vs monotony
Texture	too busy, too flat	fake vs floating
Rhythm	too hyper, too plain	garage sale vs fence line

Common but avoidable visual impact issues:

Camber and lean = instability, danger, weakness – scrawny

Disproportionate arms = mismatched, disturbing, confusion – T Rex

Finish faux pas = splotchy, flakey, streaky, rusty, inconsistency – skin condition

Odd configuration arrangement = confusing, chaotic, unnatural – awkward teenager

Random Spans and jumpers = haphazard, purposeless, crowded – Spaghetti bowl

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Short Circuit Load Effect to Substation Structural Design in Accordance with Changes in IEEE 605 1998 and 2008

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Division for Enterprise Development

Short Circuit Load Effect to Substation Structural Design in Accordance with Changes in IEEE 605 1998 and 2008

Arvid Podsim, Ligang Lei

Abstract:

Saber Power was presented a 138 kV substation upgrade. The original substation was built in the Texas coastal area in 2006. The substation capacity is planned to be upgraded from 3000A to 4000A. The new structural design must follow the latest standards and codes, including IEEE 605 – 2008, ASCE 113, AISC, and ASCE 7. IEEE 605 is the IEEE guide for bus design in air insulated substations. The structural member forces, stresses and deflections are calculated via structural analysis software RISA-3D. As the code IEEE 605 updated from 1998 version to 2008 version, if the short circuit duration time is 66.7ms (4 cycles at 60Hz), the short circuit force increases by 2 times; and if the short circuit duration time is 250ms (15 cycles at 60Hz), the short circuit force increases by 3 times. The main reason is the change of formula for the decrement factor (D_f), which is the factor to account for the momentary peak factor effect. As a result, the original insulators' cantilever strength might not meet the latest standards requirement. The parameters related to the short circuit forces are analyzed by sensitivity analysis, including the short circuit duration time (t_f), conductor center-to-center spacing (D), and system reactance resistance ratio (X/R). Three potential solutions are presented, and suggestions are provided in the conclusions.

1. Introduction

The air insulated substation is located in the coastal area in southeast Texas. According to Federal Emergency Management Agency (FEMA), the site is classified as Zone VE, and the Basic Flood Elevation of 13ft [3]. The ground elevation is about 15ft above sea level, and thus the flood load can be ignored, although the site might be subject to flooding. The base wind speed for 3-sec peak gust is 132 mile per hour at 50-yr mean recurrence interval [1]. The earthquake load is negligible in the utility substation design. The latest standards and codes, including IEEE 605 – 2008, AISC, ASCE 7, and ASCE 113, are used to calculate the wind load under extreme condition, ice load, short circuit load, and load combinations for the conductors (rigid bus).

The structural model for the substation was set up using RISA-3D software. It included the structural details of the wave trap, high switch stand, low switch stand, single bus support, low bus, high bus, A-frame bus, and the insulators, without dead end or static mast. Due to the unsymmetrical geometry, the whole substation was modeled, and the isometric view of the RISA-3D model is shown below in Figure 1.

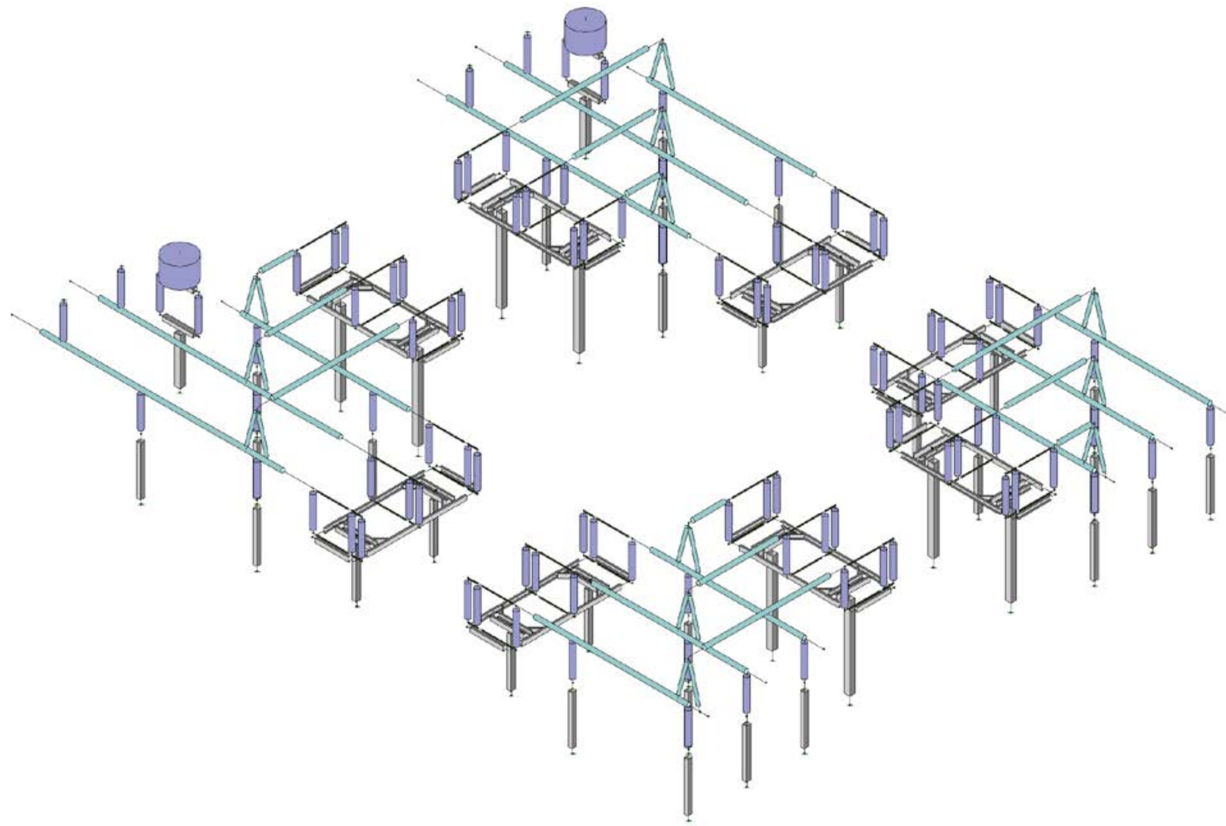


Figure 1: Isometric view of the RISA model

The structural analysis was modeled to check the stresses and deflections of all steel members, the weld strengths and deflections of all rigid buses, and the torsion strength and cantilever strength of all insulators. The reaction forces obtained can be used for the geotechnical foundation design.

The wind load under extreme condition does not change significantly by the ASCE 7 code upgrade [1, 2], as the basic wind speed and wind load factors are changing simultaneously, and thus the calculation details can be ignored. The short circuit load changes significantly, due to the change in calculating the decrement factor (D_f), when the IEEE 605 code was updated from 1998 version to 2008 version.

2. Rigid Bus Design

Typically there are two types of metallic aluminum alloys generally used for rigid (tubular) bus, 6061-T6 and 6063-T6. The 6061-T6 has higher allowable stress with lower conductivity, and 6063-T6 has lower allowable stress with higher conductivity, the 6" schedule 40 6063-T6 was selected as the rigid bus conductors to upgrade the substation to 4000A [4].

There are three types of external forces applied to the rigid buses: the weight of the conductor with damping wires, wind load under extreme conditions, and short circuit load. The conductor weight is calculated directly from the pipe geometry, and the wind load is defined by IEEE Std. C2 [5] or ASCE 7 [1]. The short circuit load is discussed in section 3. The load combinations for Load Resistance Factored Design (LRFD) methods are defined by ASCE 113 [6].

3. Short Circuit Load on the Rigid Bus

When an electrical fault occurs, the current flowing through the bus may be 10 times greater than the load current. The high current will induce significant higher magnetic fields around the rigid bus tubes, which in turn cause higher internal forces between the conductors. This paper references three different formulas to calculate the short circuit load, demonstrated below:

Case A: IEEE 605-1998 Method

The short circuit load for the rigid bus can be calculated by the equation below [9] (for English unit):

$$F_{sc} = K_f * 2C * \Gamma * \frac{I_{SC}^2}{D} * {D_f}^2 \qquad \text{(Eq. 1)}$$

Where:

F_{SC} = effective short circuit forces (lb/ft)

K_f = mounting structure flexibility factor, a function of mounting structure class (A, B, C, D) and bus height. The value can be read from Figure 2.

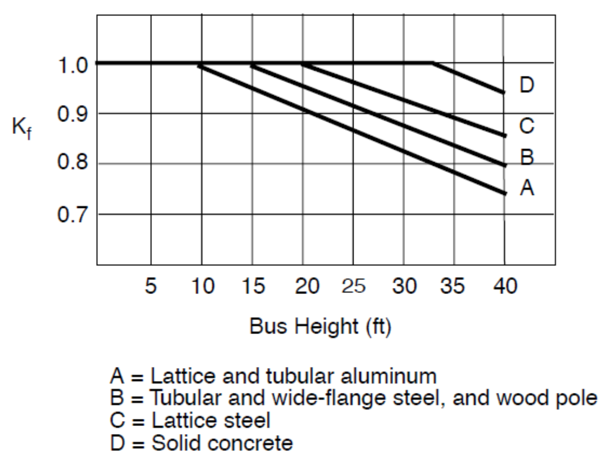


Figure 2: K_f for Various Type of Single-Phase Mounting Structures [9]

$C = 5.4 \times 10^{-7}$

Γ = constant based on type of fault (phase to phase, or three phase) and conductor configuration

I_{sc} = RMS (root mean square) symmetrical short circuit current, amperes

D = conductor spacing center-to-center, inches

D_f = decrement factor, due to the asymmetrical wave in the first half-cycle of the fault, which is calculated as:

$$D_f = \sqrt{1 + \frac{T_a}{t_f}(1 - e^{-\frac{2t_f}{T_a}})} \qquad \text{(Eq. 2)}$$

Where:

t_f = fault duration time, seconds

$$T_a = \frac{X}{R}\frac{1}{2\pi f} \qquad \text{(Eq. 3)}$$

Where:

X/R = system reactance resistance ratio

f = 60 Hz, typical AC frequency in the USA

X/R value is defined by the source impedance, and t_f is controlled by protective relay and circuit breaker operating time, so D_f is not a variable for civil engineers. Thus the short circuit load is mainly determined by short circuit current (I_{SC}) and conductor spacing (D).

Case B: IEEE 605-2008 Method

The revised short circuit load equation [4] in the new code is very similar, and the coefficients are changed correspondingly, as shown below for English unit:

$$F_{sc} = K_f * {D_f}^2 * 3.6 * \Gamma * \frac{I_{sc}^2}{10^7 D} \qquad \text{(Eq. 4)}$$

Where:

D = conductor spacing center-to-center, ft

D_f = decrement factor, calculated as:

$$D_f = \frac{1 + e^{-\frac{1}{2fT_a}}}{2} \qquad \text{(Eq. 5)}$$

Where:

Ta is calculated in (Eq. 3), the same as Case A.

The IEEE 605-2008 only changes the unit for phase spacing (D) and the decrement factor (D_f). Additionally, the new equation does not require the parameter fault duration (t_f). All other parameter definitions are the same as IEEE 605-1998.

Case C: RUS 2001 Method

The Design Guide for Rural Substations [7] does not consider the fault type (phase to phase fault, or three phase fault) or the conductor configuration (in plane arrangement or triangular arrangement), and the maximum short circuit force for evenly spaced buses is calculated as below (for US units):

$$F_{sc} = (37.4 \times 10^{-7})K_{sc}\frac{i^2}{D} \qquad \text{(Eq. 6)}$$

Where:

F_{SC} = short circuit forces (lb/ft)

K_{SC} = short circuit force reduction factor (0.5 to 1.0)

i = RMS value of three-phase symmetrical short circuit current, amperes

D = centerline-to-centerline spacing of bus conductor, inches

4. Structural Analysis Results

The load components and combinations for rigid bus are calculated following IEEE 605-2008 and ASCE 113, and the structural strength and deflections are analyzed by RISA-3D. The unity check (UC, commonly used by civil engineers) for the steel members, which includes wave traps, high switch stands, low switch stands and single bus supports, follows AISC [8]. The stress for the rigid bus is checked against the allowable weld strength for aluminum 6063-T6, which by code [4] is half of the material yield strength, i.e., 12.5 ksi. The member deflection is checked against the member type, deflection direction and structure class (A, B or C), following Chapter 4 of ASCE 113 [6]. All above requirements are met for the steel members in the updated substation design, including the short circuit load increases. Therefore, the structural design and analysis details can be ignored.

In the original substation design, based on 3000A, the NEMA type TR 288 porcelain insulators were used for the air disconnect switches, and NEMA type TR 289 (high strength) insulators were used for the single bus supports and wave traps. To upgrade the substation bus rating to 4000 A, the existing support structures and foundations can be used, no change in conductor center-to-center space (9ft) will be required and the support locations (maximum span 20ft) would not change. Because both insulators TR-288 and TR-289 have the same bolt pattern for connections, the original TR-288 insulators can be easily adapted to TR-289 if deemed necessary. The increase in bus ampacity to 4000 A will require all the TR 288 insulators be replaced with TR 289 insulators to comply with IEEE 605-2008.

The bending moment (cantilever strength) and torsion strength for each insulator were checked against the manufacture rated cantilever strength and torsion strength. The strength resistance factor is 0.50 for ultimate strength or Load Resistant Factored Design (LRFD) or 0.40

for working strength or Allowable Stress Design (ASD). The insulators for the switches will meet the IEEE 605-2008 requirements, however, the TR 289 insulators for some of the single bus and dead end supports do not meet the cantilever strength requirement. The wind load is similar as the original design (about 10% increase due to the bus diameter changes), however, the short circuit load increases significantly.

All short circuit load parameters are identical in both the original and upgraded substation design. The short circuit current (I_{SC}) and X/R ratio were specified by the utility, and conductor center-to-center spacing (D), boundary conditions (K_f and Γ) of the rigid bus remain the same as the original design. However, the short circuit load does change significantly due to the code IEEE 605 upgrade from 1998 to 2008, leading to greater bending moment for the porcelain insulators. Therefore, a sensitivity analysis is performed using IEEE std. 605 and RUS-2001, and the key parameters will be identified for the future projects.

5. <u>Sensitivity Analysis for Short Circuit Load</u>

As stated in section 3, the IEEE 605-2008 method for calculating short circuit load changed from the previous 1988 version, and different structural analysis methods (ASD or LRFD) are used between IEEE 605 and RUS 1742E-300 (RUS 2001). For this analysis, the bus elevation and the fault types are less critical for the calculations, it is assumed the constant $\Gamma=1.0$ (phase to phase short circuit) and mounting structure flexibility factor $K_f=1.0$ (type B mounting structure with bus height of 15ft). The maximum available short current at the source was determined to be 40,000 A.

The sensitivity analysis should cover all other related parameters, including fault current duration (t_f), conductor center-to-center spacing (D), and X/R ratio. Based on the authors' previous work experience, the following ranges of values are specified for the above parameters:

- fault current duration (t_f): 4 cycles, 10 cycles, and 15 cycles at 60 Hz;
- conductor spacing (D) for 138 kV substation: 7 ft, 9 ft, 12 ft;
- System reactance resistance (X/R) ratio: 1, 2, 5, 8, 10, 12, 15, 18, 20, 30, 50.

The ASD method is used in RUS 2001 (1742E-300) instead of LRFD method, without considering the load combination factors, so it is assumed as a simplified method to calculate the short circuit load, and the difference between ASD method and LRFD method should be generally less than 20%. The short circuit load calculated from three different methods are compared in Table 1, 2, 3 and Figure 3, 4, 5 respectively for different fault current duration times (t_f).

Table 1: Short Circuit Load Comparison for 4 cycles (t_f =66.7ms)

Spacing (ft)	Input		IEEE 605-1998 Version*		IEEE 605-2008 Version		RUS 2001
	X/R	Ta (s)	D_f	F_{sc}(lb/ft)	D_f	F_{sc}(lb/ft)	F_{sc}(lb/ft)
7	1	0.0027	1.02	21.39	0.52	22.39	47.73
	2	0.0053	1.04	22.21	0.60	30.01	47.73
	5	0.0133	1.09	24.66	0.77	48.38	47.73
	8	0.0212	1.15	27.11	0.84	57.73	47.73
	10	0.0265	1.18	28.70	0.87	61.60	47.73
	12	0.0318	1.21	30.24	0.88	64.42	47.73
	15	0.0398	1.26	32.42	0.91	67.47	47.73
	18	0.0477	1.29	34.40	0.92	69.64	47.73
	20	0.0531	1.32	35.62	0.93	70.76	47.73
	30	0.0796	1.40	40.53	0.95	74.31	47.73
	50	0.1326	1.50	46.52	0.97	77.35	47.73
9	1	0.0027	1.02	16.64	0.52	17.41	37.12
	2	0.0053	1.04	17.27	0.60	23.34	37.12
	5	0.0133	1.09	19.18	0.77	37.63	37.12
	8	0.0212	1.15	21.08	0.84	44.90	37.12
	10	0.0265	1.18	22.32	0.87	47.91	37.12
	12	0.0318	1.21	23.52	0.88	50.11	37.12
	15	0.0398	1.26	25.21	0.91	52.48	37.12
	18	0.0477	1.29	26.76	0.92	54.16	37.12
	20	0.0531	1.32	27.70	0.93	55.03	37.12
	30	0.0796	1.40	31.52	0.95	57.80	37.12
	50	0.1326	1.50	36.18	0.97	60.16	37.12
12	1	0.0027	1.02	12.48	0.52	13.06	27.84
	2	0.0053	1.04	12.95	0.60	17.51	27.84
	5	0.0133	1.09	14.39	0.77	28.22	27.84
	8	0.0212	1.15	15.81	0.84	33.68	27.84
	10	0.0265	1.18	16.74	0.87	35.93	27.84
	12	0.0318	1.21	17.64	0.88	37.58	27.84
	15	0.0398	1.26	18.91	0.91	39.36	27.84
	18	0.0477	1.29	20.07	0.92	40.62	27.84
	20	0.0531	1.32	20.78	0.93	41.28	27.84
	30	0.0796	1.40	23.64	0.95	43.35	27.84
	50	0.1326	1.50	27.14	0.97	45.12	27.84

*Note: The short circuit duration time is the parameter used only in IEEE 605-1998.

Most substation relay systems can detect fault condition by 4 cycles, i.e., t_f =66.7ms. The short circuit loads from IEEE 2008 version is about twice the values from IEEE 1998 version. For example, if X/R=8 and D=9ft, the short circuit load is about 45 lb/ft in IEEE 605-2008, compared to 21 lb/ft from the previous version. The RUS 2001 method is independent of the X/R value.

Table 2: Short Circuit Load Comparison for 10 cycles (t_f =166.7ms)

Spacing (ft)	Input		IEEE 605-1998 Version*		IEEE 605-2008 Version		RUS 2001
	X/R	Ta (s)	D_f	F_{sc}(lb/ft)	D_f	F_{sc}(lb/ft)	F_{sc}(lb/ft)
7	1	0.0027	1.01	20.90	0.52	22.39	47.73
	2	0.0053	1.02	21.23	0.60	30.01	47.73
	5	0.0133	1.04	22.21	0.77	48.38	47.73
	8	0.0212	1.06	23.19	0.84	57.73	47.73
	10	0.0265	1.08	23.85	0.87	61.60	47.73
	12	0.0318	1.09	24.50	0.88	64.42	47.73
	15	0.0398	1.11	25.48	0.91	67.47	47.73
	18	0.0477	1.13	26.46	0.92	69.64	47.73
	20	0.0531	1.15	27.11	0.93	70.76	47.73
	30	0.0796	1.21	30.24	0.95	74.31	47.73
	50	0.1326	1.32	35.62	0.97	77.35	47.73
9	1	0.0027	1.01	16.25	0.52	17.41	37.12
	2	0.0053	1.02	16.51	0.60	23.34	37.12
	5	0.0133	1.04	17.27	0.77	37.63	37.12
	8	0.0212	1.06	18.04	0.84	44.90	37.12
	10	0.0265	1.08	18.55	0.87	47.91	37.12
	12	0.0318	1.09	19.06	0.88	50.11	37.12
	15	0.0398	1.11	19.82	0.91	52.48	37.12
	18	0.0477	1.13	20.58	0.92	54.16	37.12
	20	0.0531	1.15	21.08	0.93	55.03	37.12
	30	0.0796	1.21	23.52	0.95	57.80	37.12
	50	0.1326	1.32	27.70	0.97	60.16	37.12
12	1	0.0027	1.01	12.19	0.52	13.06	27.84
	2	0.0053	1.02	12.38	0.60	17.51	27.84
	5	0.0133	1.04	12.95	0.77	28.22	27.84
	8	0.0212	1.06	13.53	0.84	33.68	27.84
	10	0.0265	1.08	13.91	0.87	35.93	27.84
	12	0.0318	1.09	14.29	0.88	37.58	27.84
	15	0.0398	1.11	14.86	0.91	39.36	27.84
	18	0.0477	1.13	15.43	0.92	40.62	27.84
	20	0.0531	1.15	15.81	0.93	41.28	27.84
	30	0.0796	1.21	17.64	0.95	43.35	27.84
	50	0.1326	1.32	20.78	0.97	45.12	27.84

*Note: The short circuit duration time is the parameter used only in IEEE 605-1998.

The short circuit load from IEEE 605-2008 is much greater than the values from IEEE 605-1998, especially if the X/R ratio is higher. For example, for the short circuit duration time of 10 cycles, assuming a conductor spacing of 12ft, and X/R ratio of 15, the effective short circuit load is 19.8

lb/ft from 1998 version, and it is 50.1 lb/ft from 2008 version, which is approximately 2.5 times greater.

Table 3: Short Circuit Load Comparison for 15 cycles (t_f =250ms)

Spacing (ft)	Input		IEEE 605-1998 Version*		IEEE 605-2008 Version		RUS 2001
	X/R	Ta (s)	D_f	F_{sc}(lb/ft)	D_f	F_{sc}(lb/ft)	F_{sc}(lb/ft)
7	1	0.0027	1.01	20.79	0.52	22.39	47.73
	2	0.0053	1.01	21.01	0.60	30.01	47.73
	5	0.0133	1.03	21.66	0.77	48.38	47.73
	8	0.0212	1.04	22.32	0.84	57.73	47.73
	10	0.0265	1.05	22.75	0.87	61.60	47.73
	12	0.0318	1.06	23.19	0.88	64.42	47.73
	15	0.0398	1.08	23.85	0.91	67.47	47.73
	18	0.0477	1.09	24.50	0.92	69.64	47.73
	20	0.0531	1.10	24.94	0.93	70.76	47.73
	30	0.0796	1.15	27.11	0.95	74.31	47.73
	50	0.1326	1.23	31.23	0.97	77.35	47.73
9	1	0.0027	1.01	16.17	0.52	17.41	37.12
	2	0.0053	1.01	16.34	0.60	23.34	37.12
	5	0.0133	1.03	16.85	0.77	37.63	37.12
	8	0.0212	1.04	17.36	0.84	44.90	37.12
	10	0.0265	1.05	17.70	0.87	47.91	37.12
	12	0.0318	1.06	18.04	0.88	50.11	37.12
	15	0.0398	1.08	18.55	0.91	52.48	37.12
	18	0.0477	1.09	19.06	0.92	54.16	37.12
	20	0.0531	1.10	19.40	0.93	55.03	37.12
	30	0.0796	1.15	21.08	0.95	57.80	37.12
	50	0.1326	1.23	24.29	0.97	60.16	37.12
12	1	0.0027	1.01	12.13	0.52	13.06	27.84
	2	0.0053	1.01	12.25	0.60	17.51	27.84
	5	0.0133	1.03	12.64	0.77	28.22	27.84
	8	0.0212	1.04	13.02	0.84	33.68	27.84
	10	0.0265	1.05	13.27	0.87	35.93	27.84
	12	0.0318	1.06	13.53	0.88	37.58	27.84
	15	0.0398	1.08	13.91	0.91	39.36	27.84
	18	0.0477	1.09	14.29	0.92	40.62	27.84
	20	0.0531	1.10	14.55	0.93	41.28	27.84
	30	0.0796	1.15	15.81	0.95	43.35	27.84
	50	0.1326	1.23	18.22	0.97	45.12	27.84

*Note: The short circuit duration time is the parameter used only in IEEE 605-1998.

The short circuit load reduces in the IEEE 605-1998 version as the short circuit duration time (t_f) increases. As t_f is not a parameter in the IEEE 605-2008 version, it does not have any effect for the short circuit load calculation. For example, if the conductor space is 9ft, and X/R ratio is 10, the effective short circuit load is 18.55 lb/ft for the 10 cycles (166.7ms) using the 1998 version, and it is 17.70 lb/ft for the 15 cycles (250ms) using the 1998 version, but it is 47.91 lb/ft in both cases by the 2008 version.

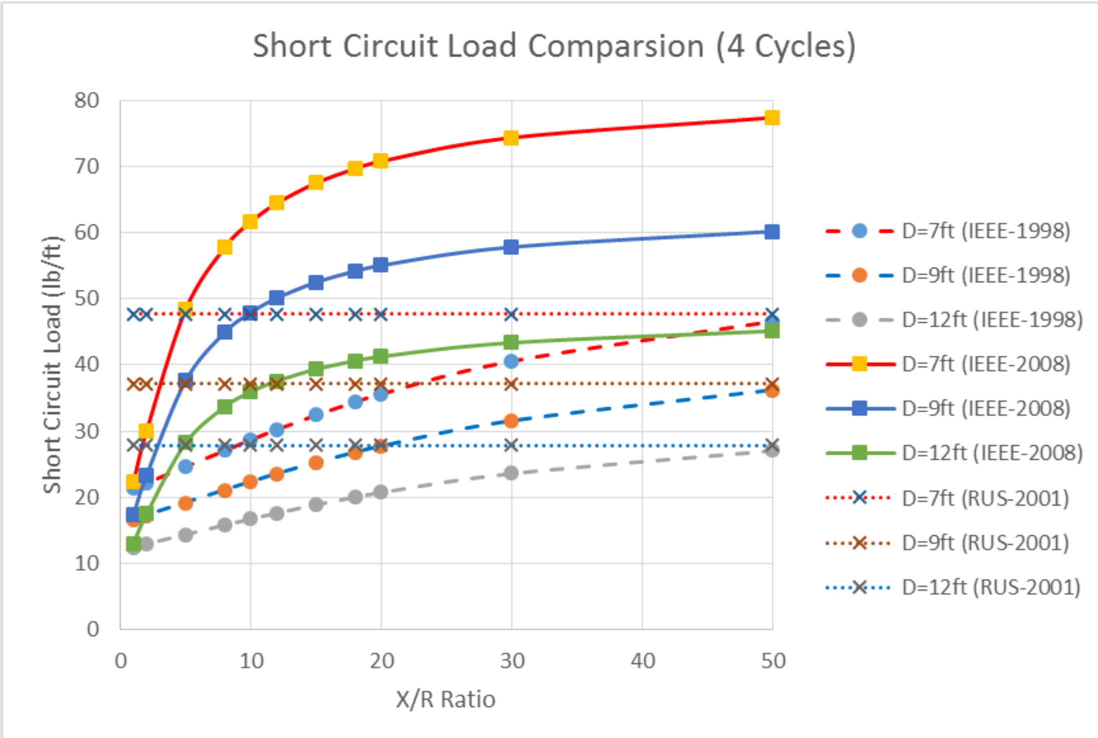


Figure 3: Short Circuit Load Comparison for 4 cycles (t_f =66.7ms)

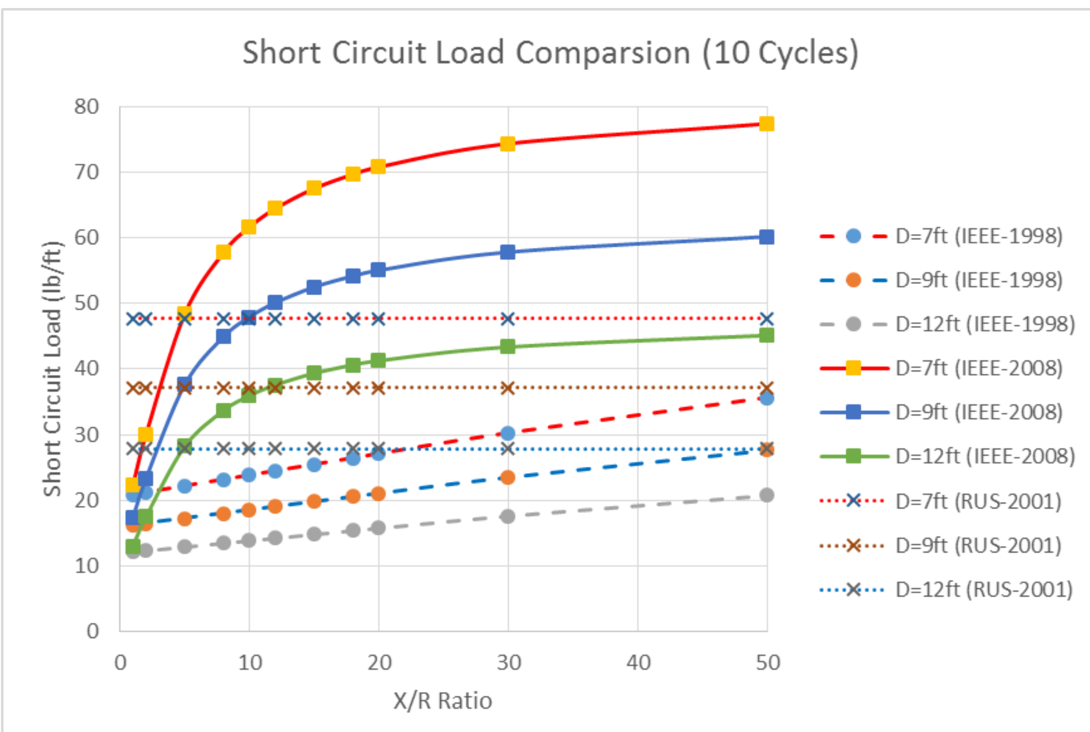


Figure 4: Short Circuit Load Comparison for 10 cycles (t_f =166.7ms)

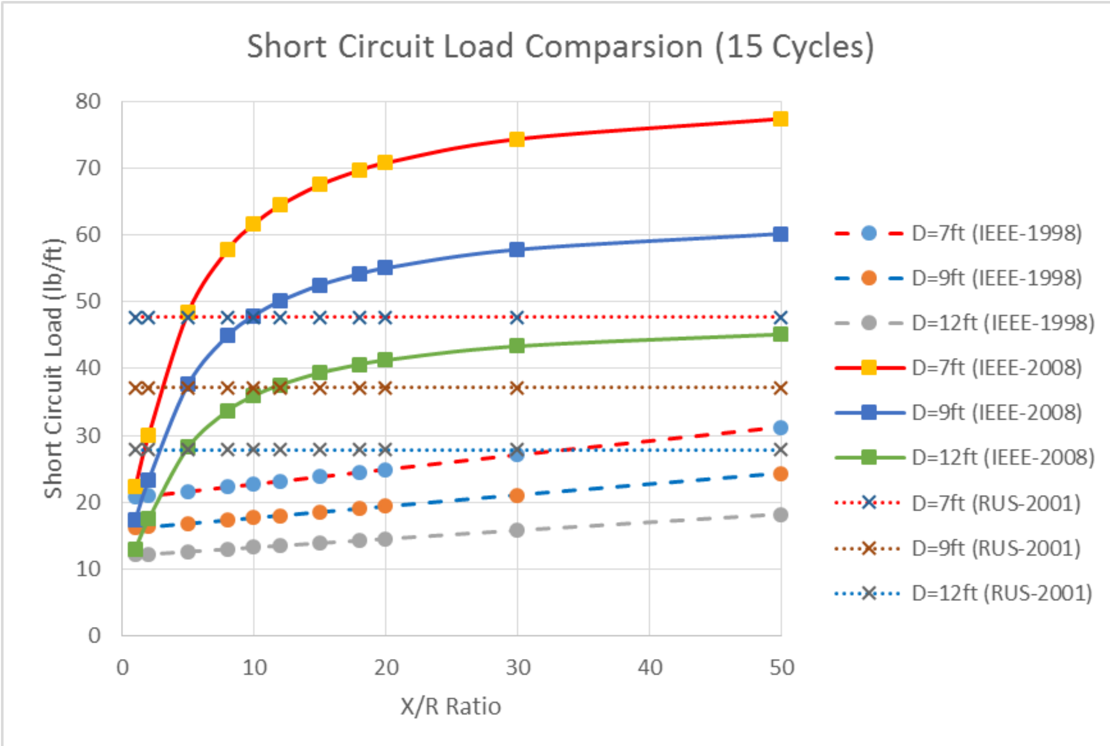


Figure 5: Short Circuit Load Comparison for 15 cycles (t_f =250ms)

6. Discussion for Short Circuit Load

Besides the short circuit current (I_{sc}), the conductor center-to-center spacing (D) is the most critical parameter for the short circuit load. All the formulas illustrate the short circuit load is proportional to square of I_{sc} over spacing D (i.e., I_{sc}^2/D). As shown in table1, 2 and 3, the load can be reduced to 75% if the space increases from 9 ft to 12ft. In fact some utility companies specify the minimum conductor spacing is 10ft or even 12ft for 138 kV substations.

The system X/R ratio will affect the short circuit load, as X/R ration increases, the short circuit load increases. X/R ratio is typically identified by electrical short circuit analysis. Therefore, there is not much liberty for structure engineers, although it is a controlling factor in structural design.

To meet the insulator strength requirements, there are three choices in general: 1) increase the conductor center-to-center space (D); 2) upgrade the insulator manufacture rated strength (standard strength insulator, high strength insulator, and extra high strength insulator); 3) use additional insulators to support the rigid bus. If the site space is limited, or the conductor center-to-center space is restricted, the structural engineer can use the insulators with higher rated strength, for example, extra high strength insulators. Finally, structural modification can be implemented so that the bus span is reduced, or two insulators to support the rigid bus at the same location, which would result in longer time and higher cost.

7. Conclusion

Most formulas in the standards and codes only consider the static short circuit load, without the dynamic impact for the structural analysis, and the calculation result is relatively conservative [8]. Due to IEEE 605 upgrade from 1998 version to 2008 version, although the short circuit current (I_{sc}) is defined the same as the original design, the structural analysis is conducted, and the insulators cantilever strengths do not meet the requirements. As a result, three potential solutions are presented to improve the insulator structural safety. From the sensitivity analysis, it concludes there are very few variables for civil design. In the future projects, the conductor center-to-center space would be increased to 12ft instead of 9ft for 138 kV substations around the coastal areas.

There are many physical and electrical parameters defined by other professionals in the substation structural design, thus, civil geometry design is very limited. Civil and structural engineers need input from the utility, customer specifications, standards and codes.

References:

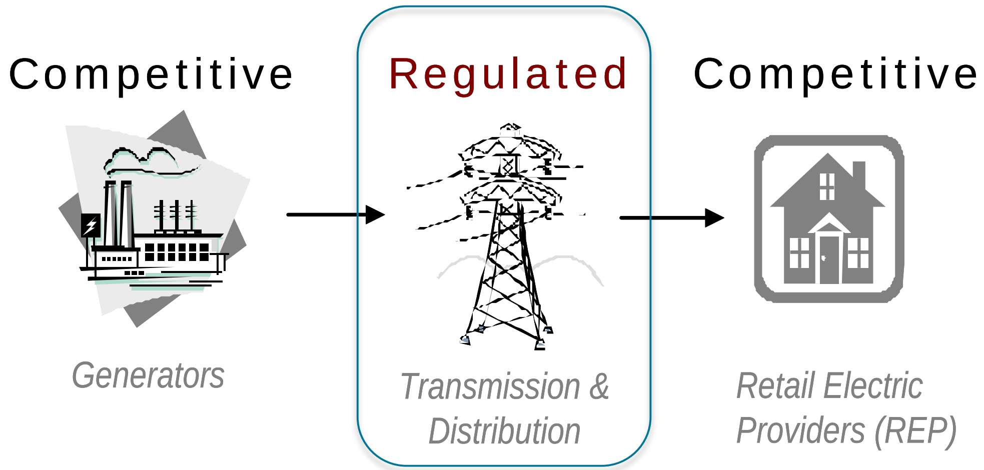
[1] ASCE 7-05, Minimum Design Loads for Buildings and Other Structures
[2] ASCE 7-10, Minimum Design Loads for Buildings and Other Structures
[3] FEMA P-550, Recommended Residential Construction for Coastal Areas
[4] IEEE Std. 605-2008, IEEE Guide for Bus Design in Air Insulated Substations
[5] IEEE Std. C2-2012, National Electrical Safety Code
[6] ASCE 113-2008, Substation Structural Design Guide
[7] RUS Bulletin 1742E-300, Design Guide for Rural Substations
[8] Electric Power Research Institute (EPRI), Reevaluation of IEEE Standard 605's Calculation of Short Circuit Force on Rigid Busbar Structures
[9] IEEE Std. 605-1998, IEEE Guide for Bus Design in Air Insulated Substations

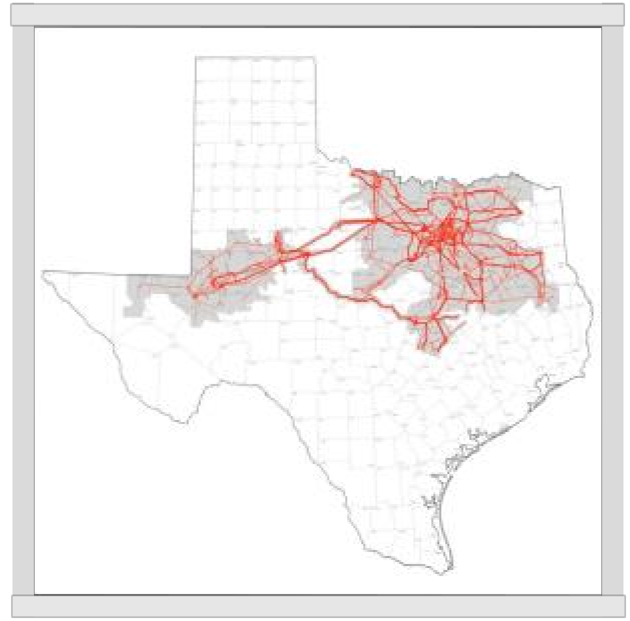
Energy Storage as another Smart Grid Strategy

Michael Quinn – VP & CTO

September 8th, 2016

Oncor – Who We Are





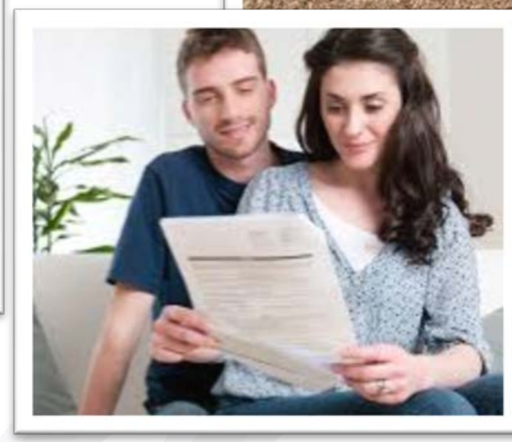
- **Largest TDU in Texas and 6th largest in U.S.**
- **121,000 miles of lines serving 3.2 million customers and an estimated 10 million people**
- **Significant annual capital expenditures, with investments including smart grid, advanced meters, automated distribution, etc.**

Reliable delivery through the application of technology

ONCOR

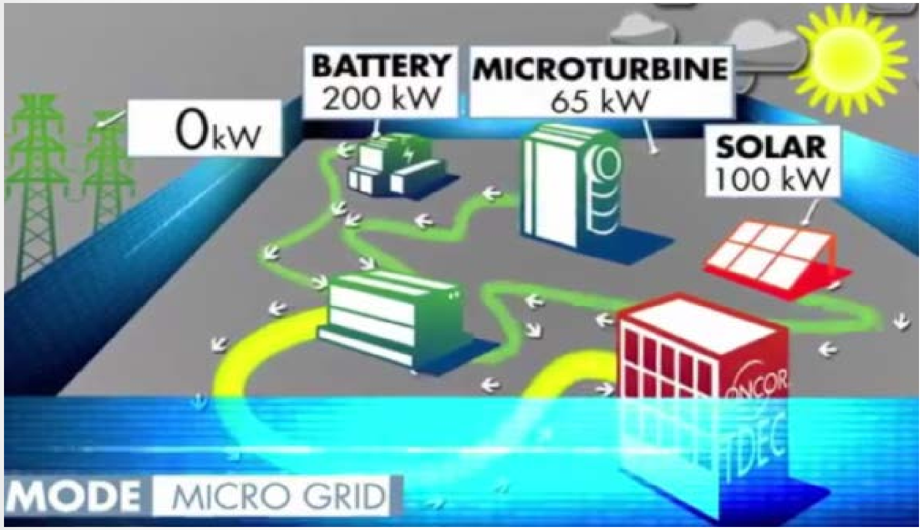
What factors are driving our industry to change?

- **Federal regulations:**
  - FERC 1000
  - Clean Air rules
- **Changing generation and demand:**
  - More wind and solar
  - Energy storage
  - Demand response
- **Customer expectations:**
  - Information
  - Service
- **Security:**
  - Physical
  - Cyber



ONCOR

FOUR ENERGY STORAGE-RELATED INITIATIVES OVER LAST 24 MONTHS



- Neighborhood Storage Reliability Initiative
- Brattle Study on Distributed Storage
- Technology Demonstration & Education Center
- Feeder Storage RFA & RFP

NEIGHBORHOOD STORAGE RELIABILITY INITIATIVE

Purpose

- Evaluate effectiveness of deploying small-scale battery storage to bridge short duration outages and improve local power quality

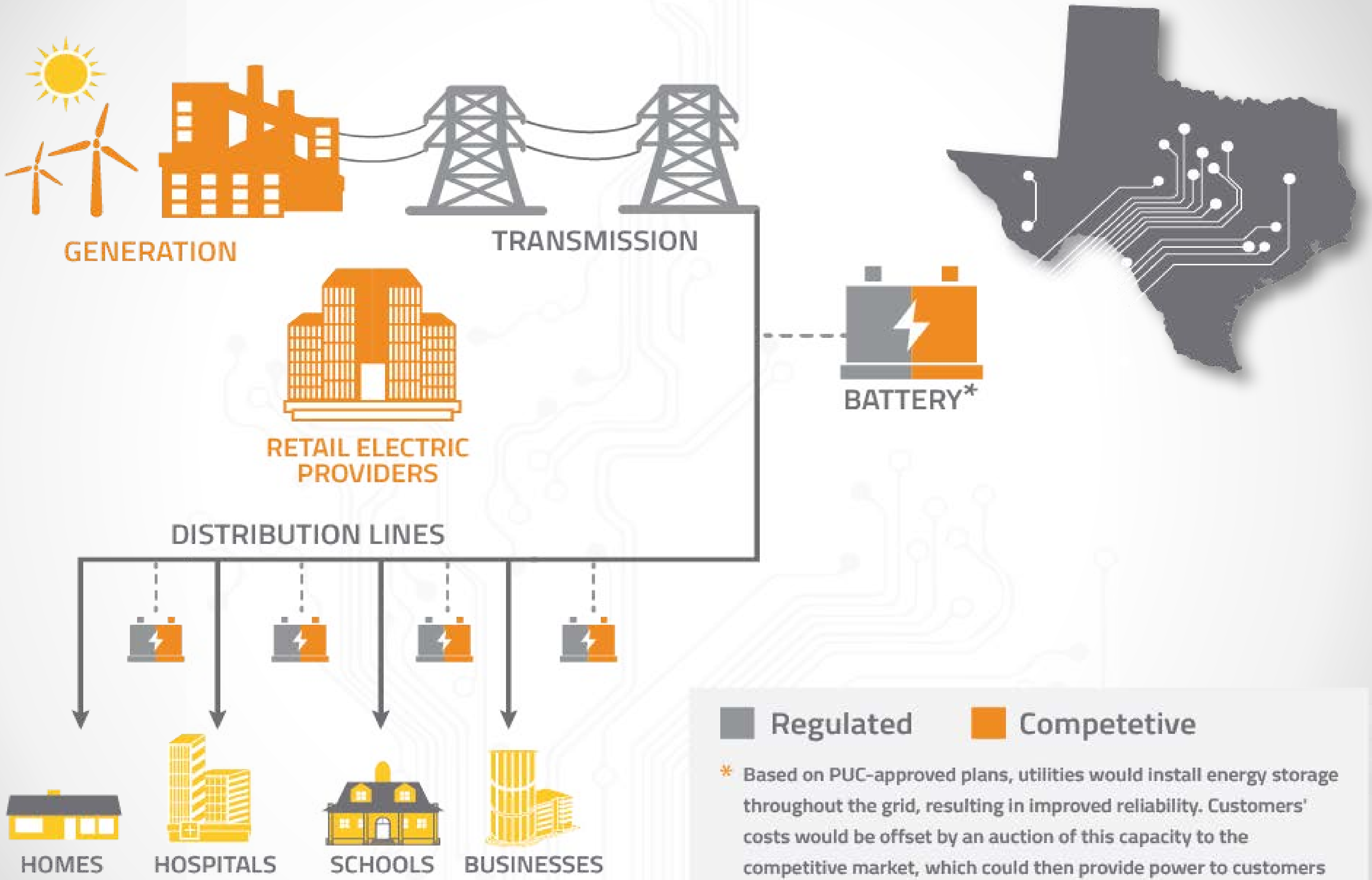
Details

- Six 25 kW lithium ion batteries
- Installation, testing and monitoring

Capacity

- These batteries are capable of bridging outages up to a few hours of duration

ONCOR



* Based on PUC-approved plans, utilities would install energy storage throughout the grid, resulting in improved reliability. Customers' costs would be offset by an auction of this capacity to the competitive market, which could then provide power to customers when they need it the most.

What questions were we seeking to answer by building a microgrid?

- **What DER will be part of the future grid and does it matter where they are located?**

- **Will DER have an impact on reliability or is the main driver to be an economic generation alternative?**

- **How do we educate our customers, regulators and legislators to their potential?**

- **Which customers are good candidates for integrated DER solutions fashioned as a microgrid?**

https://www.youtube.com/watch?v=hSOTfAOoGBs

Microgrid Elements

Key Microgrid Attributes

- Grouping of interconnected loads and distributed energy resources
- Can operate in island mode or grid-connected if desired
- Transition to island mode is completely autonomous

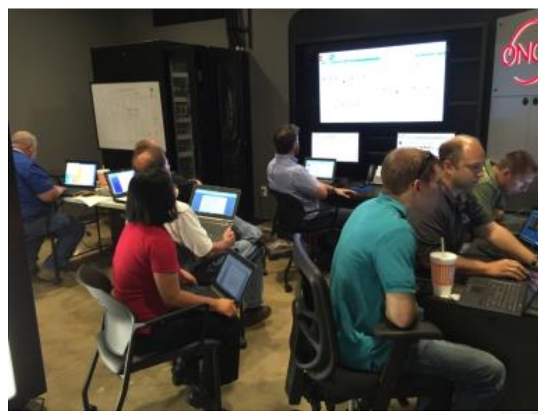
Immersion Room

Solar Arrays

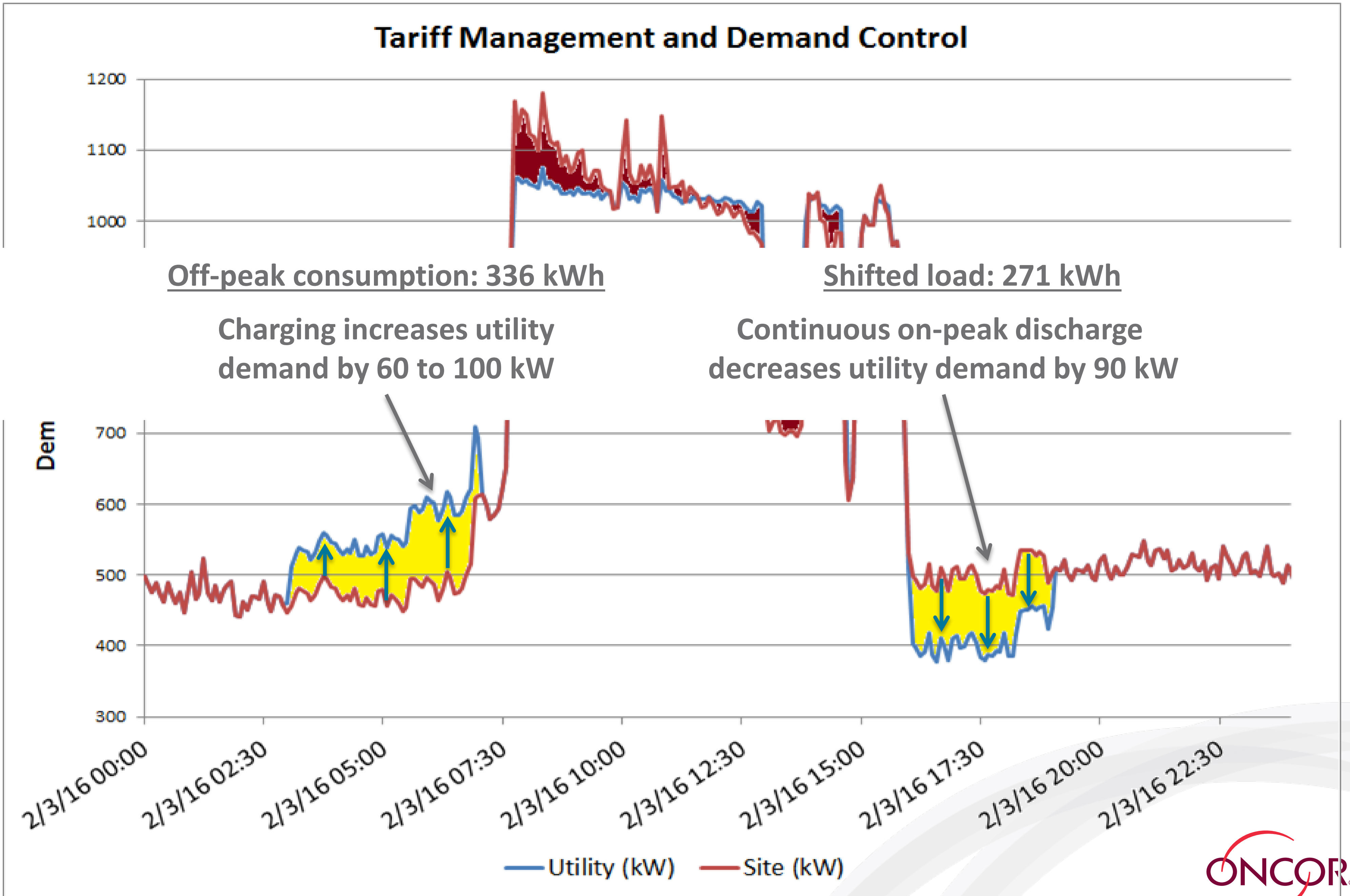
Microturbine

Energy Storage

Legacy Equipment



Sophisticated Control Center



Tariff Management and Demand Control
1200
1100
1000
Off-peak consumption: 336 kWh
Shifted load: 271 kWh
Charging increases utility demand by 60 to 100 kW
Continuous on-peak discharge decreases utility demand by 90 kW
Dem
700
600
500
400
300
2/3/16 00:00
2/3/16 02:30
2/3/16 05:00
2/3/16 07:30
2/3/16 10:00
2/3/16 12:30
2/3/16 15:00
2/3/16 17:30
2/3/16 20:00
2/3/16 22:30
Utility (kW)
Site (kW)
ONCOR

Feeder Reliability Energy Storage Improvement Program

- Request for Analysis.
- Development of criteria.
- Analysis of feeders against criteria.
- Selection of candidate feeders.
- Selection of bidders.
- Development of RFP.
  - Ownership model
  - Services model and variants
- Analysis of alternatives.
- Regulatory review.
- Selection of preferred solution.
- Evaluation of alternative business models against costs bid.


Questions?

TRANSMISSION AND SUBSTATION DESIGN AND OPERATION SYMPOSIUM

UNIVERSITY OF TEXAS ARLINGTON

A Dynamic Transformer Condition Assessment Methodology

Luiz Cheim, Pierre Lorin, Pravin Khanna

SUMMARY

Electrical utility operators face a growing number of challenges every day for the reliable operation of the transmission grid. These challenges range from managing aging infrastructure to meeting compliance requirements as the transmission operators focus more and more on achieving performance and safety targets. In North America as well as in Europe, the average age of operating power transformers is around 40 years and although age alone cannot be considered a significant risk factor, it certainly plays an important role in the failure mechanisms and statistics when other associated parameters are also taken into account. These factors could be the age of the whole installation, including protection devices and gauges, availability of spare parts, expert knowledge and information about a given outdated design, lack of historical operational data and test results, cumulative effects of external stresses such as lightning and overloads, among others. Combined, all these aspects certainly increase the risk of failure, particularly in those regions where demand growth and power quality play a leading role, as additional constraints to an already aged infrastructure.

Aging, however, is not the only constraint. The increasingly complex nature of the interconnectivity in the multi-area networks, together with the already significant lack of power transformers' expert knowledge, originated from non-replacements of retirees or even from a professional migration of the engineering workforce into other fields of work, has been continuously changing the face of the electricity market.

The industry is responding to those challenges in a number of ways. In the power transformer sector one can detect multiple activities such as the introduction of online smart sensors (gas in oil, moisture, bushing condition, etc.), design optimization, ease of integration of transformer operational data, use of new on-site diagnostic techniques such as Dielectric Frequency Response (DFR) Test, Sweep Frequency Response Analysis (SFRA), Partial Discharge Tests, just to mention a few.

Many utilities worldwide are moving towards the creation of new data centers as part of their "smart grid" initiatives. All this, however, creates important new requirements related to the need for sophisticated applications capable of handling massive amounts of data originated from new as well as aged assets in order to support the few available experts able to analyze such a large amount of data. Also models are needed to turn raw data into actionable information that can be used by decision makers at several positions in the organization such as asset managers, maintenance managers and operations managers.

The paper describes the authors' effort to develop and implement a novel Software application, given the above scenario and the following capabilities:

a) long term experience with the design, manufacturing, testing and commissioning of power transformers
b) know-how of a large number of legacy transformer designs
c) global databases and expertise on transformer condition assessment (service)
d) experience with a globally employed tool for the operational risk assessment of power transformers
e) experience with the application and development of online sensors

The novelty introduced by the newly developed tool is to make use of the same condition assessment algorithms that have been successfully applied offline, for many years now, transforming them into a powerful online tool which can operate at the utility/industry's headquarters or wherever a central data repository is located (thus, fleet wide), with the addition of smart tools for the continuous interpretation of online sensors whatever their brand (i.e. gas, moisture, bushings, etc.) and sophisticated statistical tools for trend analysis, detection of outliers, determination of statistical "norms", comparative analysis, etc.

The tool is a smart grid application which incorporates "expert knowledge" and risk assessment capabilities, processing infrequent data such as maintenance and operation inputs, available history data/past events as well as data from off-line tests (transformers electrical tests, oil quality parameters), simultaneously to on-line data from monitoring sensors. The assessed risk level for each transformer can then be displayed either on a fleet level through dashboards customized for each different user or at a

transformer/ sensor level, thanks to an intuitive interface providing drill-down capabilities

Having 24/7 access to updated information related to the condition of each transformer will help to better plan actions needed to increase the availability of the fleet, while reducing total cost of ownership.

1. INTRODUCTION

One of the most challenging technical difficulties facing power transformers experts worldwide is the determination of the actual operational *risk of failure* of a given unit or of a whole fleet of transformers. Utilities and users alike typically take the approach of calculating the so called *experience failure rate,* which is basically calculated dividing the total number of failed transformers, along a given period of time, by the product between the total number of transformers and the time span. The result is normally given in per cent per year, providing the user with a good indication with respect to the number of units which should be expected to fail in that given time frame, say typically of a year. Such approach, however, fails to provide any indication whatsoever as for the actual operating condition of the fleet, of the individual unit as well as the relative situation (ranking) of all units.

In order to overcome that, several approaches have been proposed so as to establish a methodology to determine the individual health (Health Index) of a given transformer and the relative position of each unit from a given fleet. See for example Reference [1]. Although acknowledged as a strong step in the right direction, the authors believe that such approach may fail to provide accurate information about the actual operating condition of individual transformers for a number of reasons, as summarized below:

a) This approach does not usually take into account failure modes (thermal, dielectric, etc.);

b) Unrelated operational parameters are frequently combined in some sort of aggregation function which places everything in the same basket (gas, paint, corrosion, temperature…);

c) The determination of weights and scores is purely subjective, not necessarily based on sound statistical analysis or even demonstrated by experience;

d) Fine tuning weights and scores poses a real challenge due to the above (a-c)

e) Most so called *aggregation approaches* can hardly withstand a robust sensitivity analysis

The authors are familiar with and have been using an alternative approach called Mature Transformer Management Program - MTMP for ten years now, in which the difficulties above were resolved through a number of steps which shall be detailed below. Such approach has been successfully demonstrated and applied to over 7,000 transformers worldwide.

MTMP is a fundamentally off-line tool which requires the active and direct involvement of transformers' experts in order to collect the right kind of operational and historical data, as a snap shot, and then use the best of their knowledge, experience and analytical procedures to determine transformer operational risk.

Following the new requirements and trends under the smart grid initiatives, the authors took the burden of converting the MTMP into an automated, dynamically applied tool which allows the continuous online risk assessment, through the newly developed Dynamic Transformer Management Program – DTMP, as described below.

2. MTMP-MATURE TRANSFORMER MANAGEMENT PROGRAM

MTMP is a four-step power transformer management program, consisting of:

a) Transformer Fleet Screening

b) Transformer Design and Condition Assessment

c) Life Assessment/Profiling

d) Implementation of Engineering Solutions/Recommendations

The fleet screening or the risk assessment process is the first or precursor step in the transformer life management process. This process is used to sort through the readily available operational and historical information about each transformer in the fleet. It is through this first step that an actual operational risk of failure is calculated to individual transformers**.**

Figure 1 (a) below shows a schematic diagram containing the main steps into the calculation of risk. As seen, MTMP selects a large number of parameters pertaining to several key aspects of transformer design, manufacturing, maintenance and operation, including accessories, location of install, etc. The large list of available data is then separated accordingly for the calculation of five kinds of risk:

a) Short-circuit
b) Dielectric
c) Thermal
d) Accessories (LTC, cooling, etc.)
e) Miscellaneous (environmental, etc.)

A proprietary assessment function is used to put together individual risks as above. All transformers which are submitted to the analysis are plotted in the so called criticality map shown in Figure 1 (b), where the horizontal axis indicate the risk of failure and the vertical axis shows the importance of each unit (typically provided by the user).

A simple inspection of Figure 1(b) provides the user with valuable information as for the optimized use of resources, paving the way for a complete paradigm change from time-base to condition based maintenance. Needless to say that tight O&M budgets should be primarily employed to minimize operational risks of the units in the red zone, then yellow and finally green, since these are the units of lowest risk – although all units may require some sort of maintenance!

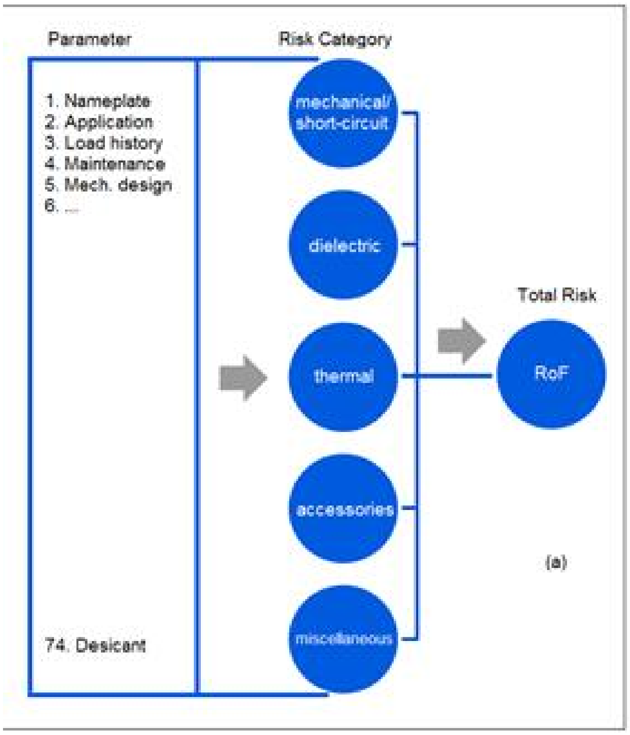


Figure 1 (a) – MTMP approach to calculate (a) individual risk categories and total risk of failure

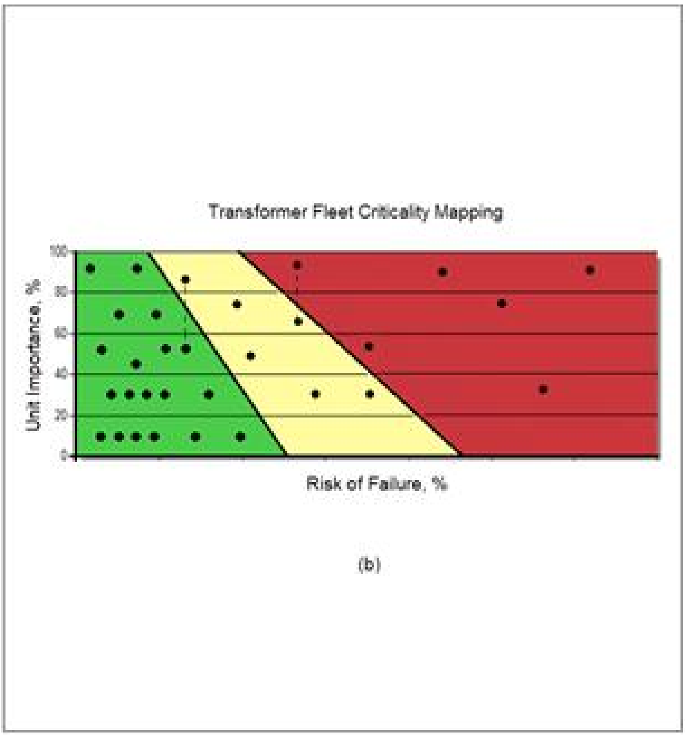


Figure 1 (b) – MTMP approach to calculate (b) mapping all units in the criticality map – risk vs. importance.

A simple inspection of Figure 1(b) provides the user with valuable information as for the optimized use of resources, paving the way for a

complete paradigm change from time-base to condition based maintenance. Needless to say that tight O&M budgets should be primarily employed to minimize operational risks of the units in the red zone, then yellow and finally green, since these are the units of lowest risk – although all units may require some sort of maintenance!

Although this is a robust and proven approach, already applied to thousands of transformers worldwide, strictly speaking it is still a snap shot of the actual operating condition of the units, valid for the data that was available at the time of the assessment. Now, if new data is available from the time of assessment to the reporting or during any time interval which has not been incorporated into the analysis, for example, future months or years after the assessment above has been delivered to the user, then any significant change in data which may affect operational risk will go undetected. This is the major contribution of the new tool which will be discussed below through the so called Dynamic Transformer Management Program - DTMP.

3. DYNAMIC TRANSFORMER MANAGEMENT PROGRAM (DTMP)

3.1 Fundamental Requirements

The implementation of the Dynamic Transformer Management Program requires a number of steps as summarized below and illustrated in Figure 2:

a) Conversion of the MTMP snap-shot tool into an online, continuous tool

b) Creation of new algorithms to handle online data, from multiple types of sensors (e.g. gas in oil, moisture, bushing, etc.) as well as offline data

c) Implementation of trend analysis algorithms, applicable to multiple types of variables

d) Application of statistical tools to determine for example "norms" and outliers

e) Incorporation of maintenance data/historical information into the analytical tools

f) Development of an expert system for the correlation of variables, identification of defects and making recommendations

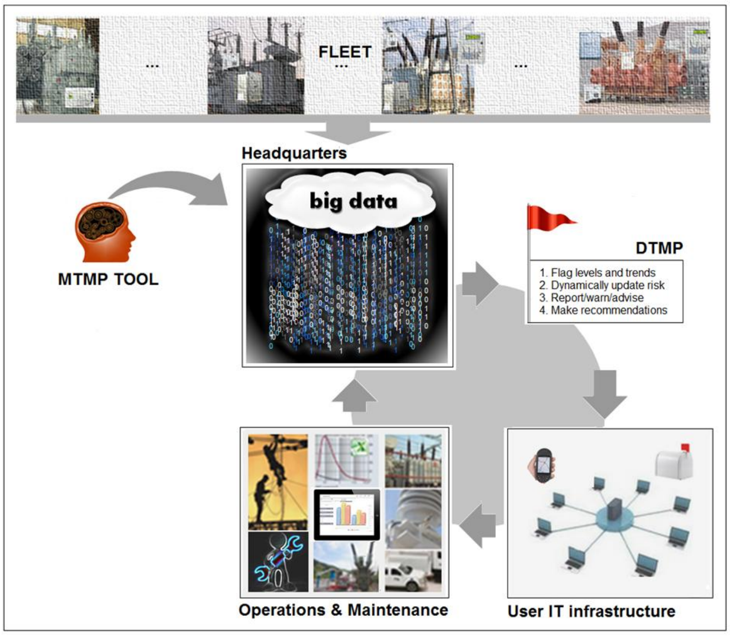
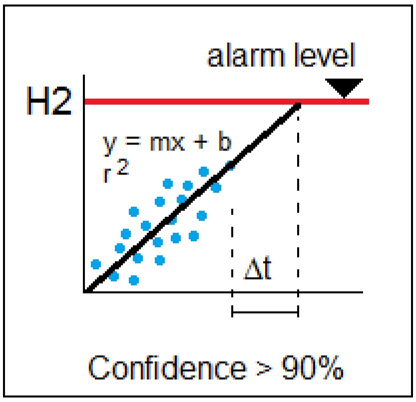


Figure 2 – DTMP concept illustrated

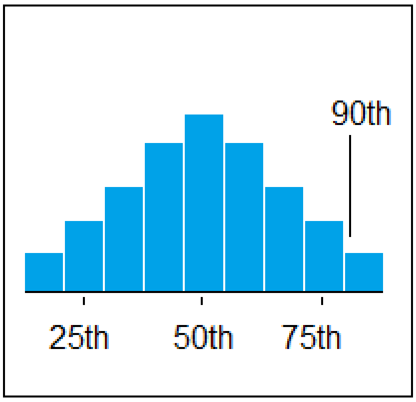
3.2. Power Transformers Performance Models

As indicated before the MTMP tool was implemented some ten years ago with the sole purpose of supporting human experts in order to assess the operational risk of the transformer fleet. The new requirements, as per the illustration in Figure 2, is that the tool must continuously interact with the data streaming from multiple transformers and also new type of data, such as data from online sensors which were not available when the tool was developed. Besides, different transformers may be dressed with different sensors and also different types of parameters (e.g. transformer "x" has a gas in oil sensor of type S1 while transformer "y", of the same fleet, has a bushing sensor and gas in oil sensor type S2). Thus, besides the required implementation of the MTMP algorithms into the tool, it was also necessary to create a large number of new routines to cope with the above, providing in addition statistical routines capable of dynamically detecting trends, level alarms, outliers, statistical comparison between an individual unit and a family of similar units, etc. These are illustrated in Figure 3 below.



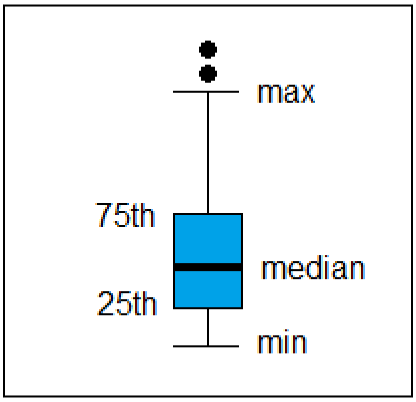
(a)

Figure 3 – DTMP performance models (a) trend



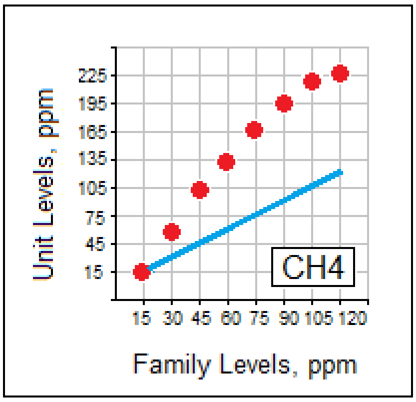
(b)

Figure 3 – DTMP performance models (b) percentiles and norms



(c)

Figure 3 – DTMP performance models (c) outliers



(d)

Figure 3 – DTMP performance models

(d) Comparative statistics QQ plot

3.3. IT Platform Requirements/Example Cases

The performance of such a tool relies on the capability to bring together expertise from three main areas namely transformer expertise, condition assessment (off-line diagnosis and on-line monitoring) and last but not least IT. Developing the solution presented in this paper required massive efforts to select an adapted IT platform and to develop it in order to be able to:

A) Access many different types of data stored in different databases and analytical systems;

B) Execute the models described in the first part of the paper;

C) Reliably store the treated information over a long period of time;

D) Comply with constraints from different users IT environment and cyber-security rules

E) Display results in many different customized dashboards to provide specific information needed by each different stake-holder (asset manager, maintenance engineer, and technician) to support their decision making processes;

F) Provide fast drill-down capabilities to be able to quickly move from the fleet (bird’s eye view) down to a single transformer or even to a specific monitoring sensor;

G) Allow human experts to make comparative analysis of the behaviour of a given unit to a family of similar units, also allowing the user to select the family criteria and the parameter to be compared (e.g. Hydrogen historical levels);

H) Show dynamic variations in risk (fleet wide and individually), warning when necessary;

I) Be scalable to handle large number of assets and flexible to integrate changes in the fleet (old assets to be retired and replaced by new ones)

J) Be upgradable over the coming years considering forthcoming IT environments (Hardware and Software)

Figures 4 below show real cases in which the application automatically calculated the operational risk (fleet wide), indicating most features enumerated above. The application can also show the asset details, containing operational risk breakdown for the unit, location of the unit in the fleet risk criticality map, sensor information, historical data, alarm messages, charts and so forth.

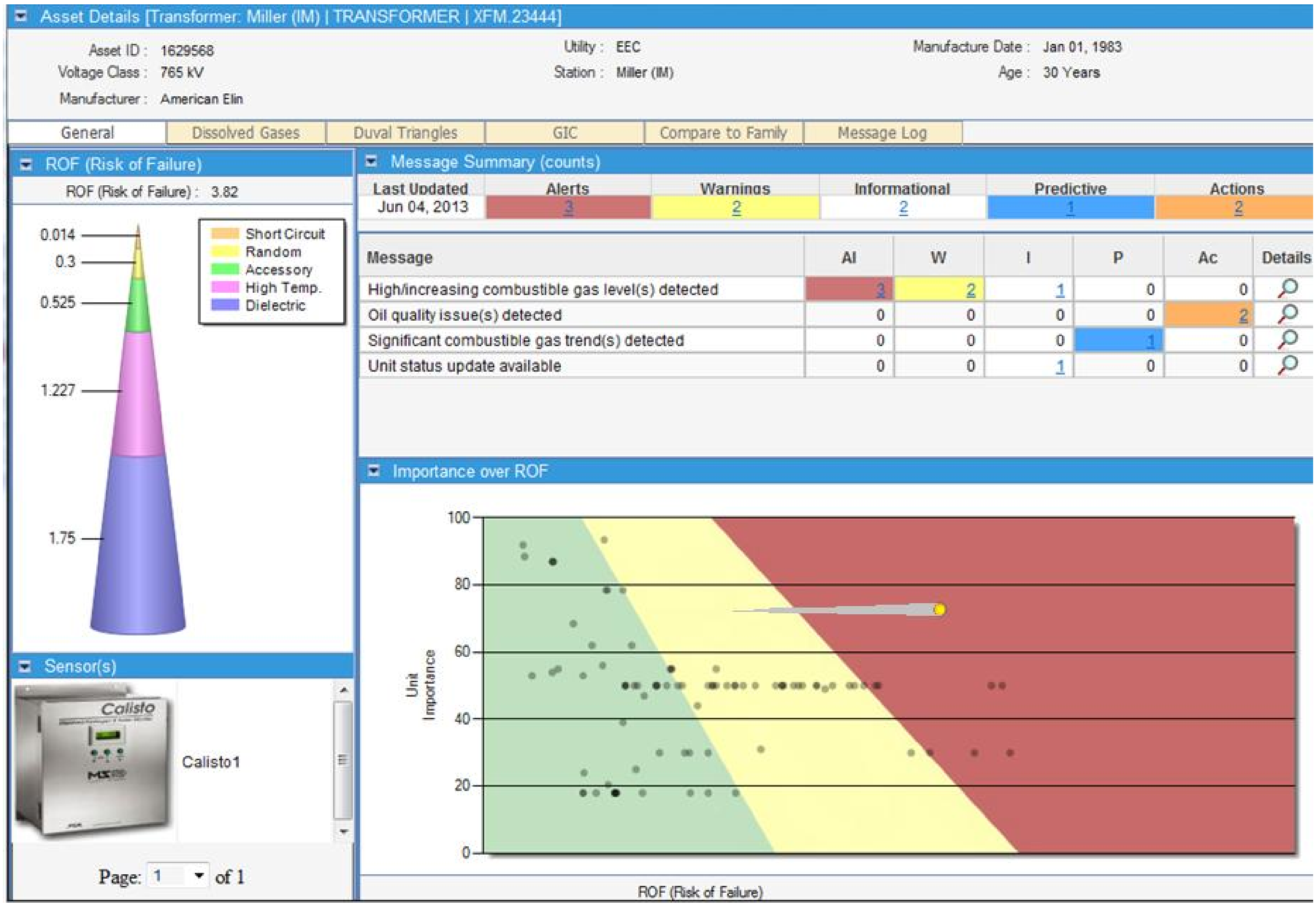


Figure 4 – Individual asset detail as compared to the whole fleet – this single screen contains details of sensor data, online and offline information, alarm messages and general notifications, tracking of the operation risk (see grey wake behind yellow dot in the chart), Duval Triangle capability, trend analysis, and so forth. The cone on the left hand side shows the breakdown of the operational risk for that particular unit using the MTMP criteria mentioned above. In this particular example the critical aspect is the dielectric, followed by High Temperature of the windings.

4. CONCLUSIONS

The paper presents the challenges faced by the authors and some of the solutions used to define reliable models to assess the condition of a transformer fleet as well as individual units. It shows some of the possible limits of health index aggregation methods commonly used and misleading conclusions one can draw depending on the statics tools used to analyse the data.

We strongly recommend here to have a structured approach when evaluating risk of failures where different properties of the transformer (mechanical, electrical, thermal, accessories and miscellaneous) need to be considered separately. The tool is based on a two steps approach where human experts are involved to assess the condition of the most important transformers and define a fingerprint that will then be stored in the automated tool and updated over time with new off-line (e.g. annual DGA or Power Factor if available, visual inspection, electrical and/or special tests) and on-line data (sensors, SCADA, etc.).

Statistical methods are then applied to data coming from on-line monitoring systems in order to properly calculate trends and identify outliers. These assessment methods allow emulating the analysis procedure utilized during off-line condition assessment studies or troubleshooting made by human experts.

As a result massive flow of data can be automatically turned into actionable information to support asset managers, maintenance and operation personnel in their daily decisions, aiming to secure a high availability of the asset at a minimum cost. If a strong experience is needed to develop reliable assessment model one should not forget that the IT component of such a solution is also of prime importance since users need to be able to visualize easily both high level Key Performance Indicators (KPI) on a fleet level and detailed information at a specific transformer to decide which action is finally needed to mitigate risks, prioritize maintenance or allow to overload a unit for a given period.

This article focus on the application to transformers but the same IT platform also hosts algorithms to cover other types of High Voltage equipment in a T&D Substation, a power plant or in an industrial plant.

The strength of the proposed methodology is that even though it is a new approach that will evolve over time, based on on-going field deployment, the heart of the assessment tool is based on more than ten years of human-applied expertise, from experts in several regions of the world, assessing thousands of transformers from many different types and origins, with a large variety of designs and operating conditions

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Authors: M. Perkins, B. Beaster, A. Fazlagic, L. Honeycutt, M. Goff, JP Sardin

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WHITE PAPER / **ELECTRONIC AND PHYSICAL SECURITY IMPROVEMENTS FOR CIP-014**

EVALUATING PROCESS IMPROVEMENTS FOR SUBSTATION SECURITY

BY Robert J. Hope

Securing the consistent operation and delivery of electricity is key to the protection of our everyday life. As threats to substation security evolve over time, utilities need to readjust the implementation process of CIP-014 requirements in order to accommodate the unique substation environment.

Over the last two years, there has been a large shift in the focus and approach to designing the electrical grid to maintain its resiliency and address security. The electrical grid has always been designed with strength in its redundancy. If an electrical transmission line or electrical substation experiences an unplanned outage, the grid will isolate the affected infrastructure and re-route power to the end user as best it can.

The majority of these types of events are caused by acts of nature or the simple failure of equipment and material due to age and stress. Most of these situations are relatively short in duration, but sometimes it takes days. Aging infrastructure and catastrophic acts of nature have always been the greatest threat to the grid.

With the rapidly changing landscape of technology in the United States today, electricity is no longer an item of convenience. Our everyday life and the country's economy depend on the consistent operation and delivery of electricity. Without electricity, our day-to-day lives would be significantly affected and, in some cases, could lead to civil unrest.

In the past, threats to the grid have always been a security consideration, but primarily focused on acts of vandalism and theft. However, the conversation regarding the types of threats to the electrical power system has changed since the attack on PG&E's Metcalf Substation on April 16, 2013. A coordinated and well-planned assault on Metcalf successfully took multiple power transformers offline in a matter of minutes.

This event went relatively unnoticed until an article published by the *Wall Street Journal* in February 2014 detailed the events of the attack. The resulting media attention on the Metcalf event prompted the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC) and the industry as a whole to take a serious look at the security of the electrical grid. FERC, NERC and the electrical utility industry have responded with proper consideration and attention to the grid's physical security by creating CIP-014.

Most utilities that are subject to the compliance requirements of CIP-014 are well underway in the process. Assessments to determine affected sites, as well as threat and risk assessments, have been completed. Through those activities, security plans and implementation schedules were developed and are in the process of being implemented.

The implementation process can lead to difficulties, as many utilities learned that this operating environment is quite different from what they were accustomed to in the past. Not only are there different assessment needs and methodologies, but the recommendations developed in these assessments have introduced means and methods not traditional to the substation environment, requiring a different thought process. These realities, if not managed and properly planned for, can cause difficulty in mitigation option implementation, program longevity and strategy effectiveness.

MITIGATION SELECTION

The CIP-014 process clearly illustrated that the days of walking a site with a clipboard and security checklist may have passed. The operational and political impact from an event can be far-reaching. The threat environment today is very different from the threat environment of 10 or 20 years ago. Threats both domestic and from abroad have become more diverse, and their means and methods of attack have expanded.

Assessment methodologies on CIP-014-regulated sites included threat vectors such as direct fired weapons (e.g., rifles and rocket propelled grenades (RPGs)), as well as improvised explosive devices and vehicle-borne improvised explosive devices. These are methods that were not really considered a mere 10 years ago. While there is no definitive information as to the who and why for the attack on the Metcalf Substation, one thing was clear: there are vulnerabilities inherent to the substation industry that need to be addressed at these high-impact sites to maintain confidence and resiliency in the U.S. grid.

Unfortunately, success in a security program is much like success in a safety program. Success is defined by a non-event. In the safety realm, it is easy to identify existing hazards, mitigation methods and success at the end of the day when no one was hurt and no near misses occurred. Security doesn't have that luxury. The bad guys are not necessarily seen prior to attack initiation. Regardless of this fact, the goal of corporate security is a non-event, i.e., nothing happened today.

Because of these facts, mitigation initiatives need to take into account the operational tempo of the organization, the maturity of the current security to support future plans, and the ability to manage and maintain the security program. Mitigation of vulnerabilities in a diverse threat operating environment can range from complex strategies of sensors and cameras to more basic strategies of walls and barriers, and most commonly in the substation industry, a hybrid of the two.

The R4 Threat and Risk Assessment of CIP-014 is crafted in a manner that enables system operators to implement mitigation options that are congruent with the active threat environment. Regardless of the threat environment, the direction most elected by utilities is to expand their operational control and observation outside of their perimeter eliminate lines of sight to those critical assets that could most affect the station and/or have the longest lead time to restore to service, and eliminate low-impact access to the sites as a whole.

EXPANDING CONTROL AND OBSERVATION

One of the keys of a successful security program is situational awareness. This is most often accomplished by substation operators through increasing their operational control and observation activities outside of their existing perimeters. The goal of this increased awareness is to detect a potential adversary as early as possible, so a response can be initiated that either interdicts the threat prior to the event or responds quickly to minimize the negative effect to the substation, buying security margin. Most often this is accomplished through the use of advanced analytics on both high-resolution infrared illuminated and thermal fixed and pan-tilt-zoom cameras; detection tools such as ground-based radar; and/or other ground- or fence-based sensors (vibration detection). By providing earlier detection supported by assessment tools, such as cameras, the security operations center can make a determination as to friend or foe and initiate the appropriate response.

These technologies are highly technical, require certified integrators to install, program and commission, and need consideration and input from various work groups prior to identifying device locations. Locations can be driven by site constraints, terrain and coverage capabilities of each device utilized. The selected integrator assists with assigning device locations, as well as with the integration of multiple systems for a unified alarm, video surveillance and access control system.

The most common location for these devices is around the site perimeter. This provides the cameras the most unobstructed view outside the perimeter in which to detect if analytics are utilized and/or assess alarms that are received. These locations, while advantageous from a security perspective, can cause issues with nearby facilities in regard to privacy concerns and getting the appropriate power and data to the device, which may require trenching on the site. Additionally, perimeter-based devices may be in close proximity to incoming lines, which can significantly affect the functionality and life cycle of the device. The effects of these incoming lines can vary based on the type and manufacturer. Therefore, it is best to understand the limitations of proposed devices during device layout and location activities.

It is also important to understand that high-resolution cameras can use a significant amount of data and bandwidth. To support this requirement, a full understanding of the communication availabilities or limitations of the site needs to be known. Where shortfalls are identified, alternatives exist, such as microwave, cellular or the potential option of fiber expansion. Other options include considering on-site video storage, which can be recalled as needed, as well as lowering frame rates and resolution to accommodate communication limitations while still meeting the needs of the security organization. Many utilities have separated the security network from the operational network. This minimizes, or even eliminates, the throttling of bandwidth that can take place during high data traffic periods, which may affect device performance and reduce the number of people who can access the data.

At locations where utilities have identified specific threats and/or site constraints that limit mitigation options, some utilities are looking to implement shot detection. This type of technology can certainly play a role within a security strategy. By detecting a shot, not the negative effects of the impact, operators have the ability to take assets offline in an attempt to minimize asset damage. Once again, these systems are very technical and need specialized assistance in layout, implementation and maintenance.

Lastly, it is important that the security group and the security operations center are capable of monitoring and responding to the alarms. As the numbers of these types of systems and devices increase, the computing capabilities of the workstations in the security operations center will increase to support alarm response The response provided by the security personnel must be supported by clear, maintained procedures. This ensures both the accuracy and continuity of response to alarms at critical sites.

ELIMINATE LINES OF SIGHT AND LOW-IMPACT SITE ACCESS

It was overheard once that substation fencing was 10 percent of the cost and 5 percent of the thought. This was congruent with the time, as our threat model was based on theft, vandalism and trespass. Traditionally, an electrical substation is encompassed by a seven- or eight-foot-tall chain-link fence with a two-inch mesh. Assets within the station can easily be identified and accessed, and there are clear lines of sight for an adversary exterior to the perimeter.

While the threats of theft, vandalism and trespass are still present, the consideration of a more complex adversary needs to be considered, and physical protection starts at the perimeter. Low-impact access is defined as access that can be gained through the use of basic tools, such as snips, or can easily be scaled or climbed. To address this vulnerability, many utilities have elected to proceed with a hardened perimeter that is either a hardened fence or wall-based.

There has been significant debate regarding traditional wall construction with ballistic-rated material when erecting a new perimeter or just around critical assets. The answer really lies in the organization's security strategy and current threat environment. When we examine the events of the Metcalf Substation, we identify that an adversary was moving and shooting, engaging known targets of interest, and adjusting shots where possible based on audible and visual feedback, i.e., the sights and sounds of a leaking or arcing transformer or asset. Should those attributes be eliminated, the act of putting rounds consistently on target to disable an asset becomes much more difficult.

For example, if only a screening wall (non-ballistic) is erected around an asset, it is safe to assume a bullet can pass through the wall and still impact the asset. However, the adversary will not be able to determine if they are even hitting the target reliably or in a critical area, thereby taking away or greatly reducing the audible and visual stimuli. In other terms, we are devaluing the target from the method of engaging an asset with a firearm. While circumstances or site constraints exist that can dictate ballistic-rated material as the best solution, many utilities continue to evaluate alternatives that help manage cost and still provide a high level of protection.

When it is determined that a hardened perimeter is a security tactic to be implemented, the first step is to determine the look, feel and operation of the perimeter system. There is a wide variety of hardening material that can be installed. Some utilities may decide a solid perimeter with 100 percent opacity, and potentially a ballistic rating, is the correct approach. This can be a viable option, as it can either completely or significantly eliminate sight lines to critical assets based on terrain and greatly reduce low-impact site access. However, these types of perimeters can be costly to implement.

Another owner may determine a steel mesh with cut- and climb-resistant properties is the best approach. This type can have the same attributes of reducing lines of sight and low-impact access, but without the ballistic-rated or resistant component. Others may elect to raise the existing fence, use a tighter mesh and place ballistic barriers around those critical assets. There is no right or wrong approach; it just needs to be congruent with the security plan and address the vulnerabilities identified in the R4 assessment.

The final decision should not be made in a vacuum by a single group at a utility. Each owner and operator should engage its engineering, security, permitting, communications, construction, and operations and maintenance departments to arrive at the best solution as they all will have specific concerns. The engineering teams will identify potential conflicts, obstructions, civil features and site access modifications. At the same time, security professionals should also review the site access, potential station vulnerabilities and ideal monitoring locations for security integrators. The permitting team should inform the engineering and security groups of ordinances and restrictions for the locality that could create delays in the construction process.

Once the site review is completed with the project team, the engineering teams will collect all notes and generate the overall security execution plan for the station. This execution plan will detail enhancements to the perimeter, potential perimeter installation conflicts, clearance violations, considerations from the security team and security integrators, modifications required to existing assets and concerns from the permitting specialists. This detailed plan will be the basis for the project moving forward and should be routed for approval to all parties upon completion. Before the execution plan is finalized, additional site surveys may need to be conducted to mitigate identified problems that may cause delays in construction or affect the overall effectiveness of the implemented program.

When the execution plan is finalized, detailed design and permitting will begin. The substation engineering group will modify the station as needed for the installation of the perimeter fence, and the transmission line team will begin the line mitigation process. The permitting teams should promptly convey any findings from local ordinances or requirements to all affected parties. Some cases may need a full site plan review, wetlands and environmental impact studies, or even special use permits that can take significant time to process. Knowing these considerations allows for a more accurate phasing schedule for the project. It is important to understand ahead of time and convey to the affected parties, such as the construction teams, to address the full scope of work, potential required outages and limitations on construction practices dictated by the site and permitting requirements.

Finally, when construction begins, the physical presence of the substation will generate questions from the community, such as what they need to know and whether there are any dangers to consider. A consistent message and communication protocol, such as who on-site to contact for inquiries, needs to be established for all crews working at the station to help maintain message continuity to the public.

CONCLUSION

Protecting our nation's critical assets is a priority today as our threat environment becomes more diverse. This includes the transmission and distribution sector of our infrastructure. Though the steady and consistent delivery of electrical power in the United States is often taken for granted by many, the absence of this resource for an extended period of time could be detrimental to civil order and confidence in the industry. While the events at the Metcalf Substation illustrated vulnerabilities, these vulnerabilities can be mitigated.

There is no panacea to address the issues of substation security. Each utility needs to determine a solution that is right for them to address their threat environment and is conducive to the sites. Threats can adapt and change means and methods faster than most industries can change a security posture. Success comes from taking positive steps to improve a security posture in order to devalue the target to the adversary. While many of these initiatives are new to many entities, through proper advance planning and the establishment of an executable security plan, the improvements can be undertaken successfully.

These improvements are highly visible and require the right team to be successfully planned and implemented. Comprehensive solutions such as these require a team of engineers, security personnel, permitting specialists, communications groups and construction crews to properly execute the project.

Burns & McDonnell has completed many successful substation security projects with a variety of requirements and methods. We have a diverse workforce and can provide all of the resources needed to complete a substation security project from conception to completion. Our teams are composed of security consultants, engineers, permitting specialists, and public involvement and government affairs personnel who deliver a comprehensive package to meet all project needs in one place.

BIOGRAPHIES

ROBERT J. HOPE is section manager for the Security Services Department at Burns & McDonnell. He is responsible for providing leadership and experienced counsel in all areas of security and Threat and Risk Assessments for public and private sector organizations. Robert and his team have taken an active role in many substation hardening efforts across the country specific to CIP-014 and have developed a methodology specific to the regulation and industry. Robert is a sought-after speaker for topics such as NERC CIP, CIP-014, CFATS, force protection and physical security. His team develops all-encompassing security strategies for clients, inclusive of threat and risk identification and evaluation, consequence assessment, electronic security design and implementation support, development of policies, and procedures customized and tailored toward the business and regulatory needs of clients. Robert is a veteran of the U.S. Marine Corps.

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Architecture and Methods for Substation SCADA Cybersecurity: Best Practices

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I. Introduction

There are over 3000 electricity providers in the United States, encompassing investor and publicly owned utilities as well as electric cooperatives. There has been ongoing trends to increasingly automate and provide remote control and monitoring of electric energy delivery systems. The deployment of computer network technologies has increased the efficiency and reliability of electric power infrastructure. However, the increased use of digital communications has also increased the vulnerability to malicious cyber attacks [1]. In 2004 the National Research Councils (National Academies) formed a committee of specialists to address these vulnerabilities and propose possible solutions with an objective to prioritize the R&D needs for developing countermeasures. The committee addressed many potential concerns in the electric power delivery system and classified them based upon different criteria and presented recommendations to minimize the gap between the academic research directions and the needs of the electric utility industry.

The complexity and diversity of the electric power delivery system in the U.S. has opened many ports for attackers and intruders [1]. This complexity and diversity is attributed to the fact that power delivery system is a network of substations, transmission and distribution lines, sub-networks of controlling, sensing and monitoring units, and human operator involvement for running the system [1]. Accordingly, any incident such as the occurrence of a fault or disturbance in this complex network cannot be deferred and should be resolved within an order of milliseconds, otherwise there is risk of large-scale outages similar to the occurrences in India and the U.S. in 2003 [2].

There are three main vulnerabilities in supervisory control and data acquisition (SCADA) systems commonly identified—physical vulnerability, cyber vulnerability and personal vulnerability [1]. In terms of cyber threats, SCADA systems are the most critical elements in the electric power grid in the U.S. Unauthorized access to a SCADA system could enable/disable unexpected equipment (such as disable the protection system or a circuit breaker) which could cause large scale disruptions of electric power delivery.

This paper provides an overview of power system SCADA technologies in transmission substations (Section 2) and summarizes the best practices for implementing a cyber security program. After introducing SCADA system operations in Section 2, a description of the security challenges for SCADA systems is presented in Section 3. In Section 4, NECRC Critical Infrastructure Protection standards CIP-002 through CIP-009 are summarized. An overview of industry best practices is presented in Section 5.

II. Power System SCADA

A. SCADA's Historical Background and Definition

A supervisory control and data acquisition (SCADA) system is the network that provides a capability of real time-remote monitoring the state of an electric power and as well as the ability to remote control its operation. The first attempts to control and monitor systems remotely began as early as the 1890s when more patents started to be issued [3]. These efforts were translated into real applications in the early of 1900s when different remote control and monitoring techniques were developed [3]. The first SCADA platform, which was developed by John B. Harlow in 1921, had two main functions: detecting the system status remotely and then updating the control center automatically. In the1980s, the development of remote terminal units (RTU) by using microprocessor-based electronics and intelligent electronic devices (IEDs) increased the flexibility of the SCADA system in terms of functionality and capability [3]. The time line of developing the automation and SCADA systems is illustrated in Fig. 1.

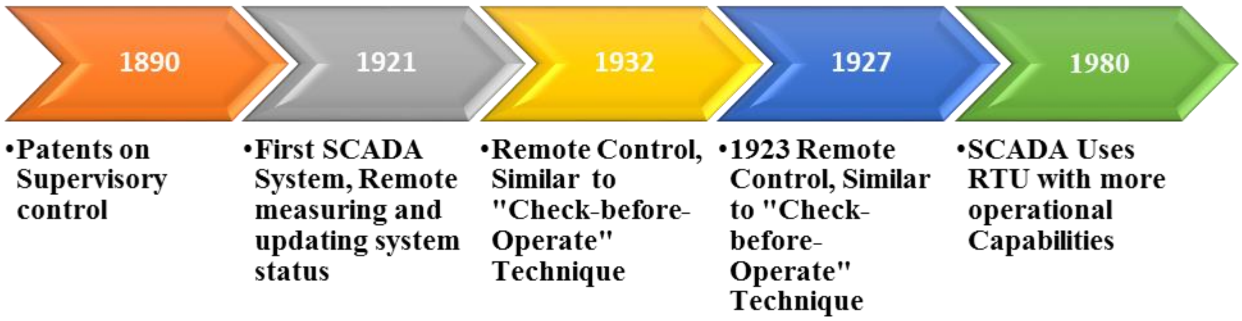

Figure 1: Timeline of SCADA development

B. SCADA Components

In most electric power systems, the implementation of a SCADA network consists of three main subsystems that are required for data acquisition, monitoring and controlling the power system as described in Table1. The components are further illustrated in Fig. 2 as an example of the flow of a measured voltage between the master station and the field instruments [3] .

A. SCADA and Substation Automation

At the substation level of an electric power system, substation automation (SA) is one of the primary applications for SCADA technology. IDEs are the backbone of the various automation levels performed in a substation [3]. These levels are listed in Table 2.

Table 1: SCADA Components

Master Station/Control Center	A group of computers and Human Machine Interfaces (HMIs) used to monitor the state of the system and send command signals to control or adjust certain parameters in the power system.
Communication Network	Communication network connects the master station with the field instrument for sending the control signals and receiving the measurements through different communication channels. SCADA uses different communication protocol such as: 1- Traditional protocol Modbus, IEC 60870 2- Modern protocols, IEC 61850 and DNP3
Field Instruments	Field instruments are described as the hands/eyes/ears of the SCADA system [3]. Field instruments are divided into three parts: 1- Sensors (e.g., temperature), transducers, CT, PT. 2- Actuator (circuit breaker, load tap changer) 3- Controller such as RTU, IED, protective relay.

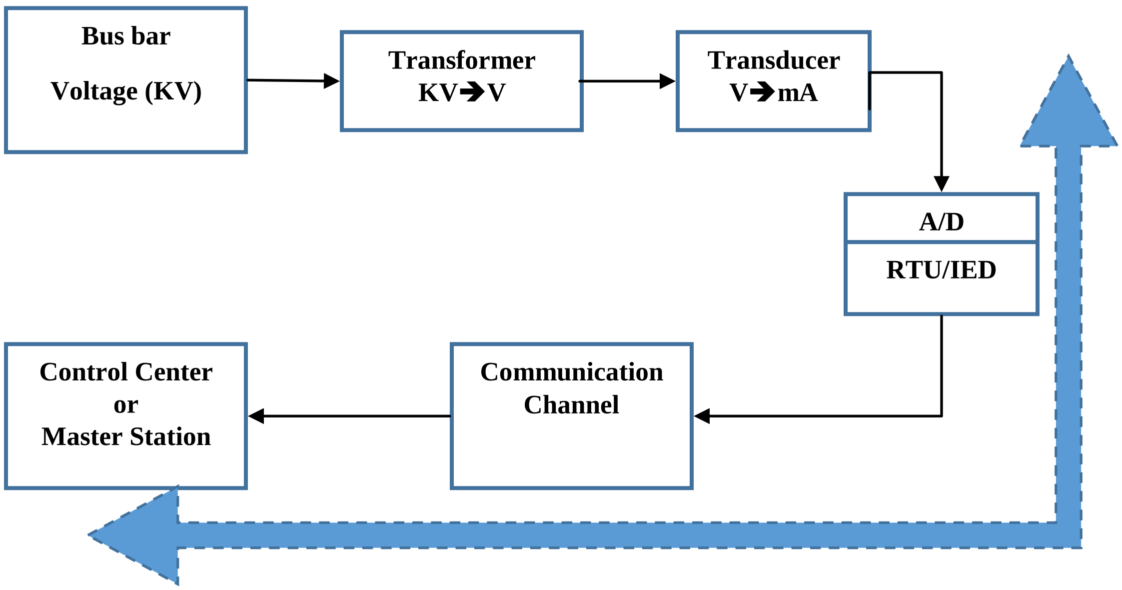

Figure 2: Flow path of measured signals or operation data between the control center and the field devices.

Table 2: Automation levels

1st Level	IEDs communication with the field instruments
2nd Level	IEDs communication with each other or IEDs integration
3rd Level	Full automation control of substation

In modern SA, IEDs are the key components in which two different types of data are analyzed and sent/received by SCADA to take actions by the master station or control center. The transferred data between the control center and the field devices are divided into two types—operational and nonoperational data [3].

1- Operational data is the instantaneous measured data by the field instruments such as current, voltage, watts, VARs, fault location, switch gear status, etc. The operational data is called SCADA data because it is used for monitoring and control the power system.
2- Nonoperational data is historical data or events used for off-line analysis for future planning decisions or setting configuration parameters for equipment. For example, fault events and power quality data are used for future analysis for risk reduction or decision making regarding upgrades, expansions or compliance reporting. Another example would be revising the settings of protective relays.

The operational and non-operational data are transferred between the master station (for control purposes) or the data warehouse (for analysis purposes) and the filed devices through different protocols. Fig. 3 shows the communication technique for transferring the data [3].

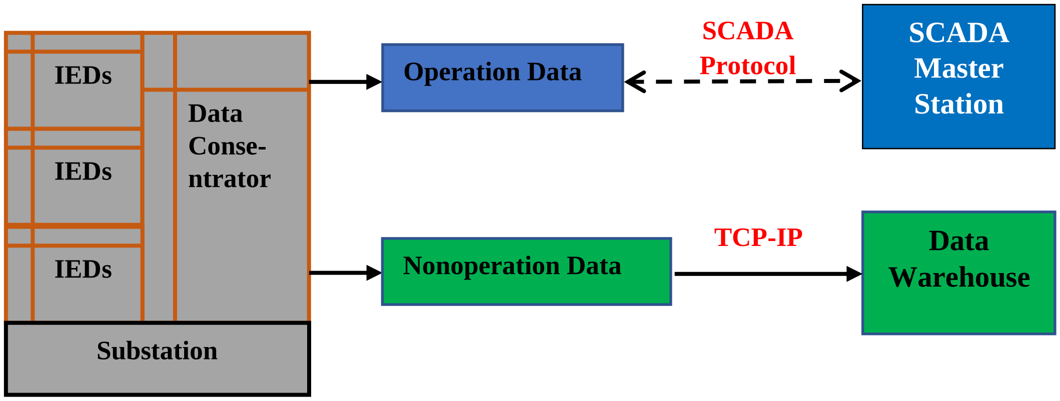

Figure 3: Schematic layout illustrates the communication protocols used between the Substation and the Control Center and between the Substation and Data Warehouse for transferring the operation and nonoperation data respectively.

B. SCADA Communication

The main component of a SCADA system is the communication channels. Communication in a SCADA system provides for exchanging data throughout the network for real-time monitoring and control. The communication channels have two main functions [3]:

1- To provide the control center (master) a real-time access to the field instruments
2- To convey the command signals from the control center to the field instruments

The communication speed of the SCADA system is extremely crucial because it is needed for real-time decisions. The required communication speed by the control center for monitoring and controlling is illustrated in Table 3 [3].

Table 3: Communication speed for automation functions.

Function	Required Time	Currently
- Open/close signal for circuit breakers, isolators and switches. - Report position or status.	1-2 seconds	2 seconds using high communication speed and IDEs
- Sense and send analog measurements for voltage, current, power.	10-60 seconds	10 seconds using high communication speed and IDEs
- Other measurements which are used for analysis such as waveform data and metering.	Longer period	Longer period

C. SCADA Communication Protocols

The main advantage of having a communication protocol is to establish communication between devices from different vendors [3]. In North America, there are three communication protocols used in the SCADA system as follows:

1- ICCP (IEC 670-6) protocol is used for communication between control centers.
2- DNP3 is used for communication between control center field instruments (master to slave communication).
3- IEEE 61850 or DNP3 is used for communication between field instruments.

DNP3 is most commonly used with future trends toward adopting IEC 61850 protocols. These are summarized in Table 4.

Table 4: Modern SCADA Protocol

IEC 61850 [3]	**Distributed Network Protocol (DNP3)** [3]
IEC 61850 can be used for communication between field instruments; it was developed specifically for full substation automation. The main feature of IEC 61850 over other protocols is that it supports IEDs interoperability, which means that IEDs from different vendors can communicate with each other. Two communication topologies are supported by IEC 61850— peer-to-peer and master-slave communication.	**DNP3** is used in communication between master-slave and between field devices. It uses four layers: physical layer, data link layer, pseudo transport layer and application layer. Cyclic redundancy check (SRC) is utilized for error detection.

III. SCADA Security Challenges

Although there are many benefits of SCADA implementation in an electric power system, SCADA systems may introduce vulnerabilities to cyber-attacks. There has been considerable efforts in developing methods, processes and tools for increasing network security in business and enterprise computer systems. In addition, advances in those aspects of network security that are unique to industrial process control have also seen ongoing advancements [7]. However, increasing priority to cybersecurity is justified based on the cyber attack that occurred in Ukraine on December 23, 2015 [15].

In the next subsections, general cyber security concepts such as terminology definitions related to the vulnerability (attack and control), security goals and security tools are summarized.

A. General Cyber Security Concepts

1- Threat Types

In the field of cybersecurity threats are classified into four types, any of which can cause a potential loss or damage to the SCADA system [5], [6]:

1. **Interception:**

    Interception occurs when an unauthorized party obtains access to a system such that messages and data can be read. The intruder or the interceptor can be a person or virus. This form of threat attacks the integrity of the system's data.

2. **Interruption:**

    This type of threat can be described when any of a system's components or functions become unavailable. An example of this threat is Denial of Service (DoS) attack that overwhlems the capacity of a network to respond to netwrok services.

3. **Modification:**

    Changing of system configurations or readjusting the system`s set-points is referred to as modification. This implies not only a threat to message traffic but also to stored data in computer memory and firmware.

4. **Fabrication:**

    Fabrication refers to creating false data message content rather than altering some of the system parameters or values. Fabrication often involves injecting counterfeit data into the network.

5. Security Goals

Confidentiality, integrity, and availability are the three main security goals in establishing a secure netwrok. Confidentiality implies that non-disclosed data should be inaccessible by unauthorized persons[7]. Integrity means that unauthorized parties should not be able to modify data. Availability provides for data being available when it is requested by authorized people [7].

1. Security Tools

Security methods are typically described in terms of (i) authentication (ii) authorization and (iii) auditing. Two major types of security tools are firewalls and intrusion detection/prevention systems.

Firewalls:

A firewall is a hardware device and software code used to filter the traffic from outside network to the inside network [6]. Generally, a firewall is implemented as a router with additional rules that only allows packets to and from a list of identified addresses while also checking ath connection state [3]. The firewall may performs various different functions. For example, a firewall inspects (accepts or rejects) the packets based on predefined rules related to the conditions of the packets which are determined by the firewall designer. It can also prevents access from outside the network to inside or allow only certain users to get access remotely [6].

Intrusion Detection System (IDS) and Intrusion Protection System (IPS):

"Prevention is best combined with detection and response" [8]**:** A firewall can be compromised due to different reasons such as mistakes or errors which could allow access by malicious actors into the SCADA system [6]. In this case, the second, or complement, level of defense tool is ISD/IPS [6]. IPS monitors the SCADA system to detect any abnormal activity while IPS takes a certain action (response) after an anomaly is detected [6].

IV. NERC Critical Infrastructure Protection Standards (CIP-002-3 through CIP-009-3) and a Proposed Architecture

In the section, CIP-002-3 through CIP-009-3 are summarized and an architecture based on [9] is provided in order to meet CIP-5 requirements.

A. CIP-002-3 through CIP-009-3—Summary

CIP-3 standards are established in order to identify and protect the critical and vulnerable cyber assets (for reliability purposes) in the bulk electric system [2]. In CIP-3, eight (8) standards are explained in details in NEREC website [2], and they are summarized in Table 5.

Table 5: Summery of CIP-002-3 through CIP-009-3

CIP-00X-3	Summery
CIP-002-3	To use risk-based assessment to identify and document the Critical Cyber Assets which subsequently support reliable operations.
CIP-003-3	To have security management control (commitment policy) to secure Critical Cyber Assets
CIP-004-3	To require people who are authorized for access to Critical Cyber Assets to have a required level of personal risk assessment, training and security awareness.
CIP-005-3	Electronic Security Perimeter
CIP-006-3	To insure physical security of the Critical Cyber Assets
CIP-007-3	System Security Management
CIP-008-3	Incident Reporting and Response Planning
CIP-009-3	To insure recovery plans for Critical Cyber Assets

B. Proposed SCADA Architecture for Secure Data Transfer

The cyber security community has changed the focus from preventive measures (such as firewalls) to more defense techniques such as intrusion detection and incident cleanup and response [9]. However, the number and severity of successful attacks is increasing [9]. As a result, U.S. department of Energy conducted research to develop new SCADA Architecture for secure data transfer. The architecture is described for setting up the SCADA network in terms of four levels as illustrated in Fig. 4.

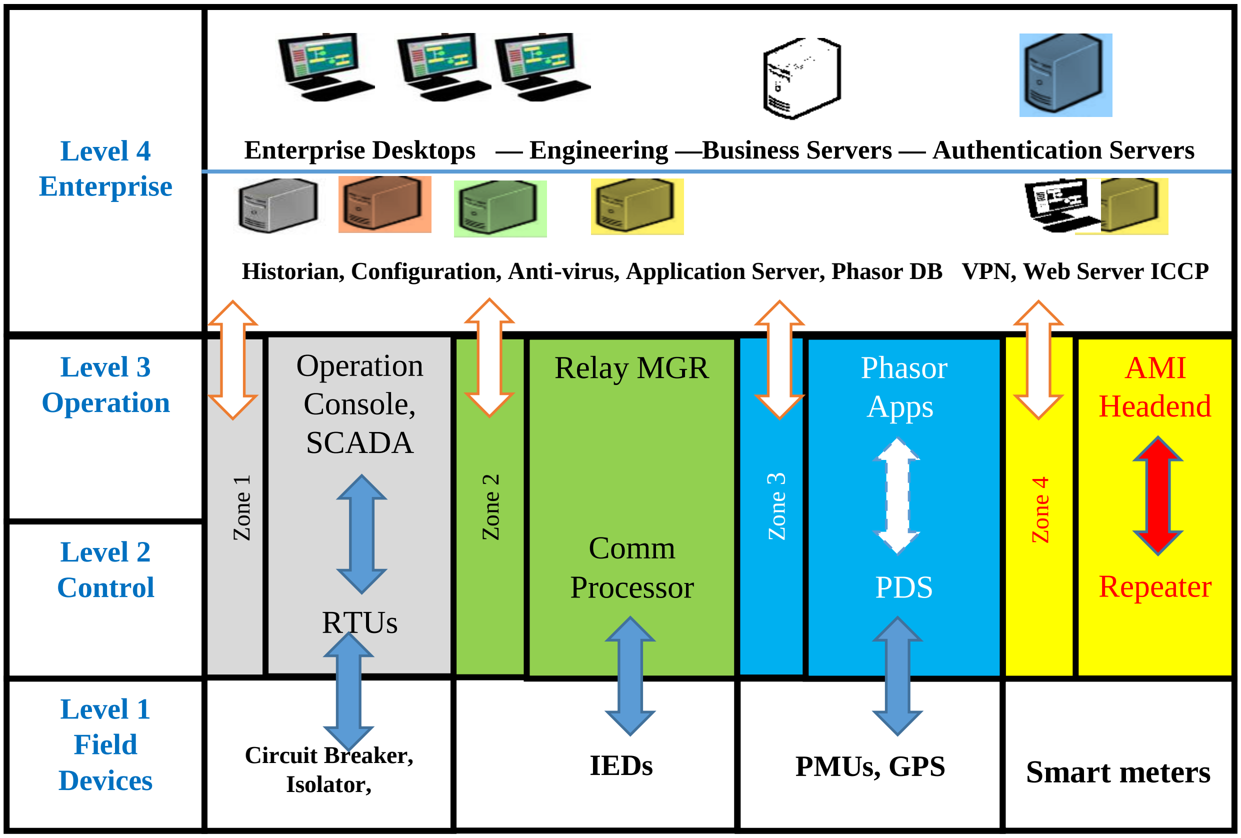

Figure 4: Proposed Architecture [8]. PDC: Phasor data consolidator and PMU: Phasor Measurement Unit.

The principle difference between the traditional and the updated architecture is that it includes vertical isolation zones. This provides separation between SCADA, protective relays, metering/AMI and other substation functions interfaced through Intelligent Electronic Devices (IED) across all 4 levels as shown in Fig. 4. The zones are Zone 1: SCADA Security Zone; Zone 2: Protection Relays Security Zone; Zone 3: Phasor security zone and Zone 4: AMI Security Zone.

The architecture also considers the following six specific use cases as detailed in [9]:

Use Case 1: Enterprise Network to Operations Network.
Use Case 2: Operations Network to External Control Center Network (Phasor Data).
Use Case 3: Operations Network to External Control Center Network – ICCP Data.
Use Case 4: Operations Network to NERC, Regulatory Data.
Use Case 5: Operations Network to Vendor Network, Support & Maintenance
Use Case 6: Operations Network to Advanced Metering Infrastructure

This architecture provides vertical isolation across all the four levels as shown in Fig. 5. This isolation supports the revised version of NERC Critical Infrastructure Protection (CIP) standards CIP-5 [2]. One of the most significant changes from NERC CIP-3 to NERC CIP-5 relates to using BES Cyber Systems Impact levels instead of critical assets or cyber assets. NERC CIP-5 requires responsible entities to identify BES cyber systems in terms of their impact on the bulk electric system in three levels: high, medium or low impact rate [2], [10]. For example, "the High Impact category covers Control Centers is used to meet the functional obligations of a Reliability Coordinator, a Balancing Authority (for generation equal to or greater than 3000 MW in a single Interconnection" [2], [10]. There are 13 criteria which determine the impact ratings [2], [10].

Two other issues have been changed in CIP-3 and added in CIP-5. The first one is removal of "zero defect" requirement to allow responsible entities to identify and resolve issues. The second one is implementation of two new CIP Standards [2], [10]:

1. CIP-010 on Configuration Change Management and Vulnerability Assessments
2. CIP-011 on Information Protection

V. Overview of Best Practices

There has been increased attention given to cybersecurity for industrial control processes. The U.S. Department of Energy has provided guidelines and resources related to securing SCADA networks [11]. A first step in establishing a security program would be to identify critical and non-critical assets and determine what levels of user access is needed for reliable operation. Next would be to identify threats and to establish how each of these could be monitored and tested. This leads to implementing detection techniques and the associated event logging and notification processes of personnel and organizations. Procedures for responding to an incident should be formulated and documented. This includes preparing written documentation and training methods. A security program should also include defined administrative responsibilities and processes for managing software and hardware updates. Best practices have also been recommended for computer networks [11]-[14] as well as for aspects directly related to the electric utility industry [12]. The following are guidelines outlined in [11].

1. Identify all connections to SCADA networks: Conduct a thorough risk analysis to assess the risk and necessity of each connection to the SCADA network. This may include internal local area and wide area networks, business networks, wireless network devices including satellite uplinks, modem or dial-up connections, and connections to business partners, vendors or regulatory agencies.
2. Disconnect unnecessary connections to the SCADA network: Isolate the SCADA network from other network connections to the greatest extend possible. Incorporate "demilitarized zones" (DMZs) and data warehousing to facilitate secure transfer of data from the SCADA network to business networks.
3. Evaluate and strengthen the security of any remaining connections to the SCADA network: it is essential to implement firewalls, intrusion detection systems (IDSs), and other appropriate security measures at each point of entry.
4. Harden SCADA networks by removing or disabling unnecessary services: Remove or disable unused services and network daemons to reduce the risk of direct attack.
5. Do not rely on proprietary protocols to protect the system: Security of a SCADA system should not be based on the secrecy of vendor proprietary protocols.
6. Implement the security features provided by device and system vendors: Analyze each SCADA device to determine whether security features are present. Set all security features to provide the maximum level of security.

7. Establish strong controls over any medium that is used as a backdoor into the SCADA network: strong authentication must be implemented to ensure secure communications. Modems, wireless, and wired networks used for communications and maintenance represent a significant vulnerability to the SCADA network and remote sites. To minimize the risk attack, disable inbound access and replace with a callback system.
8. Implement internal and external intrusion detection systems and establish continuous incident monitoring: establish an intrusion detection strategy that includes alerting network administrators of malicious network activity originating from internal or external sources.
9. Perform technical audits of SCADA devices and networks, and any other connected networks, to identify security concerns: There are commercial and open-source security tools available that allow system administrators to conduct audits of systems/networks to identify active services, patch level, and common vulnerabilities.
10. Conduct physical security surveys and assess all remote sites connected to the SCADA network to evaluate security: Conduct a physical security survey and inventory access points at each facility that has a connection to the SCADA system.
11. Establish SCADA "Red Teams" to identify and evaluate possible attack scenarios: Feed information resulting from the "Red Team" evaluation into risk management processes to assess the information and establish appropriate protection strategies.
12. Clearly define cyber security roles, responsibilities, and authorities for managers, system administrators and users.
13. Document network architecture and identify systems that serve critical functions or contain sensitive information that require additional levels of protection.
14. Establish a rigorous, ongoing risk management process.
15. Establish a network protection strategy based on the principle of defense-in-depth.
16. Clearly identify cyber security requirements and Establish effective configuration management processes.
17. Conduct routine self-assessments and establish system backups and disaster recovery plans.
18. Establish policies and conduct training to minimize the likelihood that organizational personnel will inadvertently disclose sensitive information regarding SCADA system design, operations, or security controls.

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Using ACCR to Save Tall Towers, Tall Sail Boats, and Great Blue Herons

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ABSTRACT

The purpose of this paper is to discuss how the Lower Colorado River Authority (LCRA) utilized an ACCR conductor from 3M to upgrade a transmission line, spanning Lake-Travis, without requiring structure replacements. The ACCR conductor was used over the three span lake crossing section with spans of 2293’, 3161’, and 1538’. Lake Travis is a flood control reservoir on the Colorado River just a short distance West of Austin. The reservoir is a popular destination for recreational use. Design constraints included federally protected birds, accommodations for tall sail boats, high flood waters, and more.

This section contains both the longest span in our system (3161’), and the forth longest span in our system (2293’). The main span crossing Lake Travis is supported by two 233’ tall lattice towers. Coincidentally, Lake Travis and this line are located just minutes down the road from the global headquarters for 3M’s Energy Business Group.

INTRODUCTION

LCRA Planners wanted to double the capacity of one of its oldest transmission lines. The line, Marshall Ford to Lago Vista, is a 6.5 mile 138 kV line. It was originally built in 1938 as TL-1 from Buchanan Dam to Marshall Ford Dam. The original conductor was a 203.2 ACSR Brahma. This line contains the longest span in our system, 3161’ span crossing Lake Travis. The adjacent span on one side is the fourth longest span in our system, a 2293’ span that crosses a canyon.

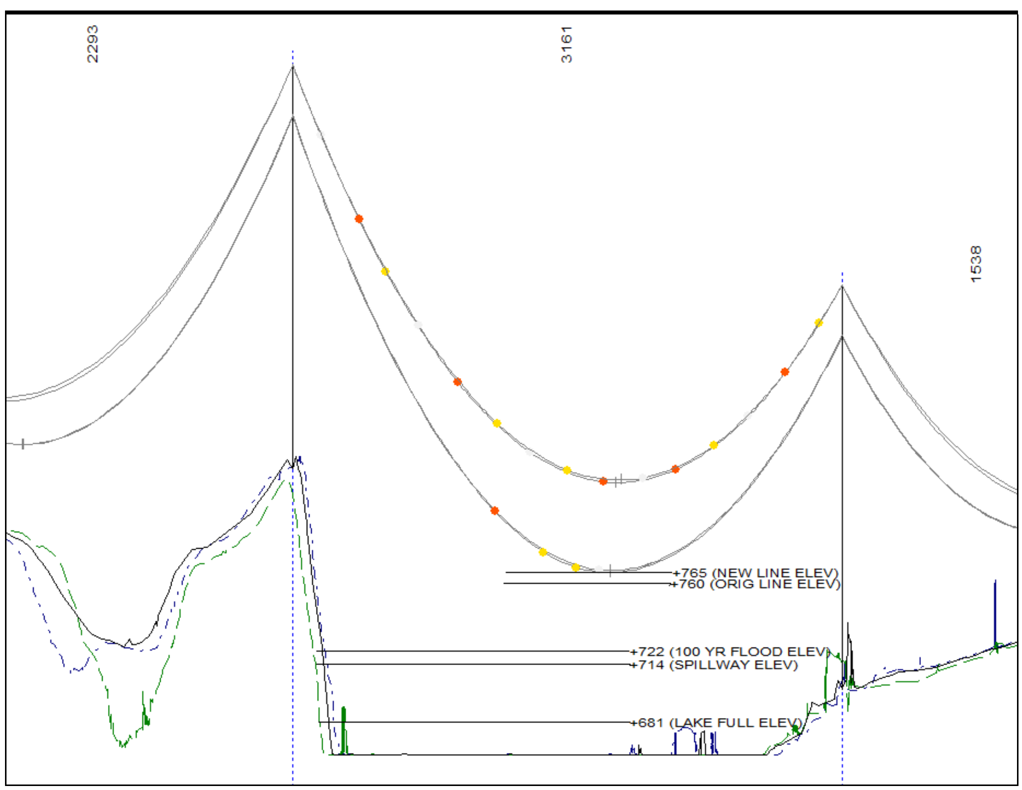

Figure 1 – Profile view of Transmission Like Crossing Lake Travis

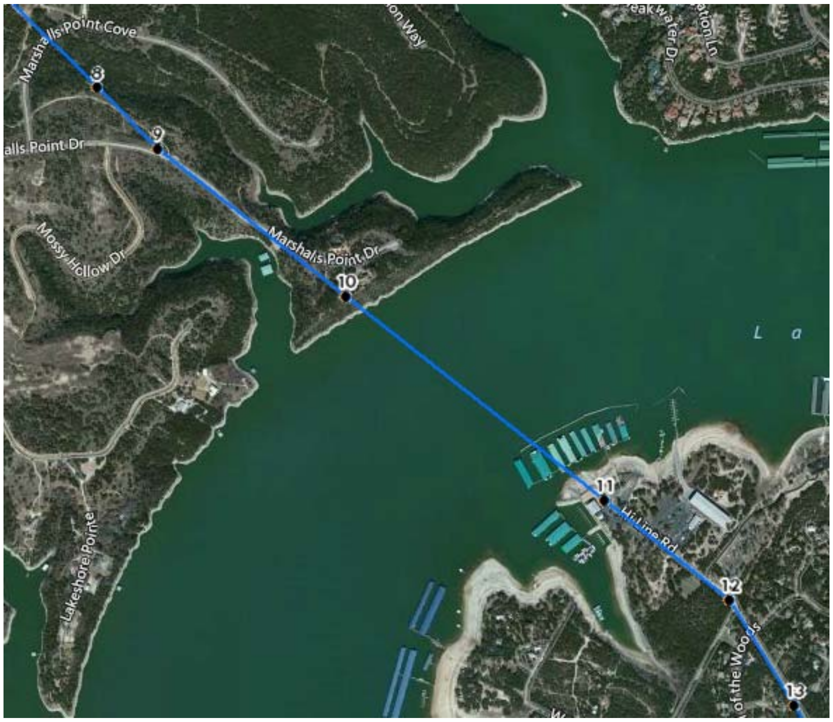

Figure 2 - Plan View of Lake Crossing

Lake Travis is formed by Mansfield Dam (formerly Marshall Ford Dam) which is owned and operated by LCRA. The dam was built from 1937 to 1942, and it was constructed to serve dual purposes, to create a water supply reservoir and to help control flood waters. As such, the water level in the lake is highly variable. The record high is +710.44’ MSL and the record low is +614.18’ MSL, a nearly 100’ range. Even though these are the extreme values, the lake level still sees significant fluctuation. Figure 3 shows the lake level over the past three years.

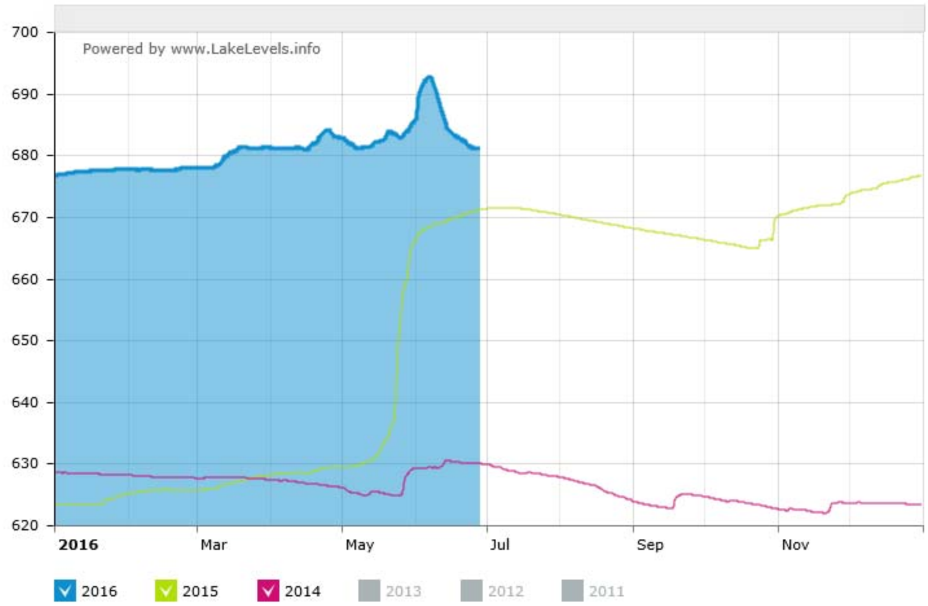

Figure 3 - Historic Lake Levels (Lake Travis)

The lake is also a popular spot for recreation and boating due to its proximity to Austin and the surrounding communities. The lake crossing goes over a marina, where many sailboats dock. The tallest sailboat on the lake has a height of 58' from water level to top of the mast. This far exceeds the NESC clearance requirement of 44.6' above the "design high-water level" or the "normal flood level"

Figure 4 - Line Crossing Over Marina

The line was upgraded in 1987 to a 795 ACSR Condor, and the two structures at the lake crossing were raised from 150' to 232' to comply with the "new NESC sailboat clearance requirements". The towers now had to be lit to comply with FAA regulations. There were a lot of complaints about the tower lighting from lake area residents, one of whom stated the inside of his house was "like being in a disco now". It was a big issue at the time, and one that lasted several years. LCRA tried several different types of lights, with shielding and without, but ultimately the towers had to be lit, and LCRA ended up paying court settlements to cover damages to landowner's property.

B2 Austin American-Statesman Saturday, December 9, 1989

Lake-area residents renew opposition to aircraft light towers

By David Matustik
American-Statesman Staff

Two aircraft warning lights that tower above Hudson Bend on Lake Travis are once again the focus of complaints from residents who say the Lower Colorado River Authority has reneged on promises to shield the lights from their view.

The lights, which flash white during the day and red at night, destroy the tranquility of lakeside living and reduce property values, residents and property owners say.

The lights, opposed by some landowners since they were installed in spring 1987, were shielded until October when LCRA officials pulled off the louvers because of air safety concerns, potential liability and their revised interpretation of Federal Aviation Administration guidelines.

Residents have been negotiating with LCRA for more than 2½ years and several months ago presented petitions to LCRA with 200 signatures of people opposing the lights.

Opposition organizers now say they are frustrated that the lights again are fully exposed and predict lawsuits will follow if LCRA doesn't act soon on the visual pollution problem.

"They are like a rogue elephant that runs over everything," said Robert Brandes, a landowner, who has already settled a lawsuit against LCRA for damages to his land when the lights were installed.

The court settlement, in which LCRA agreed to pay $100,000 and guarantee certain water rights to Brandes and his partners, also stated the lights would remain shielded, Brandes said, adding that he's ready to go back to court.

"You can't camp out there without the red light. You can't see the stars," Brandes said. "They have destroyed the ambience. It's like being in a disco now."

Staff graphics

LCRA officials acknowledge they could have handled the tower lighting issue better, but say safety and liability concerns take precedence over aesthetics.

"It's clear we have not handled the communication part of this project, nor have we in the minds of some of the neighbors honored what they consider is an agreement," LCRA Deputy General Manager Mark Rose said. "I understand why the neighborhood groups are upset."

But, he said, "our basic concern is whether the solution in place is legal and practical for the long-term."

"It's a constant annoyance," said Richard Crank of Volente who daily steps onto his deck and sees the lights across the lake. Crank, too, said he is considering a lawsuit.

Staff photo by Taylor Johnson

Volente resident Richard Crank says the flashing aircraft warning lights atop the LCRA high-line power poles, background, are 'a constant annoyance.' The lights were installed in spring 1987.

"From the very beginning, it's been a snafu," Crank said.

LCRA officials "go home and don't have to look at it," said Anita Goodson, who lives next door to Crank. "We have to look at it."

Unlighted transmission towers supported electric lines across the lake for decades, but were replaced in early 1987 as part of a system upgrade, said Walter Reid, LCRA's executive director of electric operations.

Once the towers were higher than 200 feet, LCRA officials decided FAA guidelines required some type of warning lights.

The strobe lights were so intense that it was like living in a bar as the flashing lights bounced off homeowners' walls, Goodson said.

LCRA changed the intensity and configuration of the lights. Still the property owners were upset.

Finally, LCRA installed shields, or louvers, in June 1988. After several adjustments, property owners were somewhat satisfied.

But two months ago, LCRA removed the shields after reconsideration of FAA guidelines and a flyover by LCRA personnel who decided the shields did not amply warn pilots.

Property owners say LCRA has alternatives to the current lighting scheme that include removing all the lights and either lowering the towers or taking the lines under the lake at an estimated cost of $3 million.

LCRA officials say those alternatives, which would require FAA and Texas Public Utility Commission approval, could prove expensive and unjustifiable to electric ratepayers.

Property owners, however, counter that LCRA has made much more costly decisions, citing the abandonment of a Fayette County lignite mine after more than $226 million was spent.

Figure 5 - Newspaper Clipping (Austin American Statesman, Dec. 9th, 1989)

Due to the height of these towers, and their immediacy to the lake, they are also popular amongst birds, and nests can be frequently found at different spots on the towers. These towers had a history of registering line faults that were attributed to birds coming between the wires and the tower.

BACKGROUND

In 2014 Power Engineers was enlisted to do the engineering design to upgrade the line. The line upgrade consisted of reconductoring with bundled (2) 795 ACSR Drake required. This meant performing a tear-down and rebuild with new structures for the majority of the line. For the lake crossing towers, in addition to a history of issues with land owners, FAA requirements, providing clearance for tall sailboats, and the high costs of replacing such tall, heavily loaded towers, we also needed to consider constructability issues. On the east side of the lake, development had filled in around the tower, leaving very little room to locate a new structure, and even less room to assemble and erect the new structure. On the west side of the lake, the structure is located on top of a bluff with difficult access to the top, especially for large, heavy structures. Given all of these challenges and the history of issues, we wanted to look into options to salvage these two towers. The towers are galvanized steel structures that are less than 30 years old, and they are in good condition. From an analysis in PLS-TOWER, we found that the design had some excess capacity, so this appeared to be a possible solution. We also wanted to do what we could to address the bird electrocution issues as part of this project.

CONDUCTOR STUDY

Due to the cost and difficulties associated with installing new lake crossing structures, it was preferable to salvage the two tall lattice towers. However, structural analysis indicated the towers were not capable of supporting the specified conductor so an analysis of various conductor types was performed. A 1233.6 Yukon ACSS/TW-HS285 appeared to provide the required ampacity while minimizing the modifications required to the towers and also meeting NESC clearance requirements.

Further investigation indicated however that the NESC minimum clearances were not sufficient for this crossing. The water level in the reservoir is highly variable, and the reference elevation referred to in the NESC as the '*design high-water level*' is ambiguous. The maximum clearance for sailboats per the NESC is 42.6' above the '*design high-water level*'. The LCRA determined that a number of boats that either docked or frequently launched onto Lake Travis were taller than this, with the largest one, a Hunter 450 Passage, having a 58' height above the water. This indicated that we would need at least 65' of clearance above any lake level that would be suitable for sailboats. This represents a significant increase over the NESC minimum and more clearance than the existing conductor.

Therefore, LCRA and POWER Engineers investigated a large number of high temperature-low sag (HTLS) conductors that met the electrical loading requirements (~1866 amps) within allowable Maximum Operating Temperatures (MOTs). The investigation had two inter-related goals: minimize the tower modifications and maximize the clearance over the lake.

The electrical and mechanical requirements narrowed the search to two additional candidates: an ACCC Bittern, and a Hudson ACCR-TW_1158-T13. Figure 6 below shows the sag vs. electrical load for each of the wire candidates. Another key factor was the sag under ice loading. The sag under a ½", ¾", and 1" ice load is included in Figure 6 (the sag under the respective ice load was converted to an equivalent operating temperature). All of the conductors exhibited maximum sags under ice loading that exceeded those sags resulting from the MOT. While it is improbable that there would be boat traffic during an icing event, the prominence and history of this crossing drove the decision to err on the conservative side.

As a sidebar, ACCC's ULS (Ultra Low Sag) conductor was not commercially available at the time of this study. For comparison's sake, it was added into the graph in Figure 6.

After internal discussions and deliberations, the consensus was that the Hudson ACCR-TW_1158-T13 was the best option. It provided the needed amperage, the required sag, and minimized the additional load on the tower. LCRA had not previously used an ACCR conductor, but this was the perfect opportunity to try out this "new" type of conductor. ACCR has a significant track record of successful uses by other utilities, and as such it appeared to be a low risk solution.

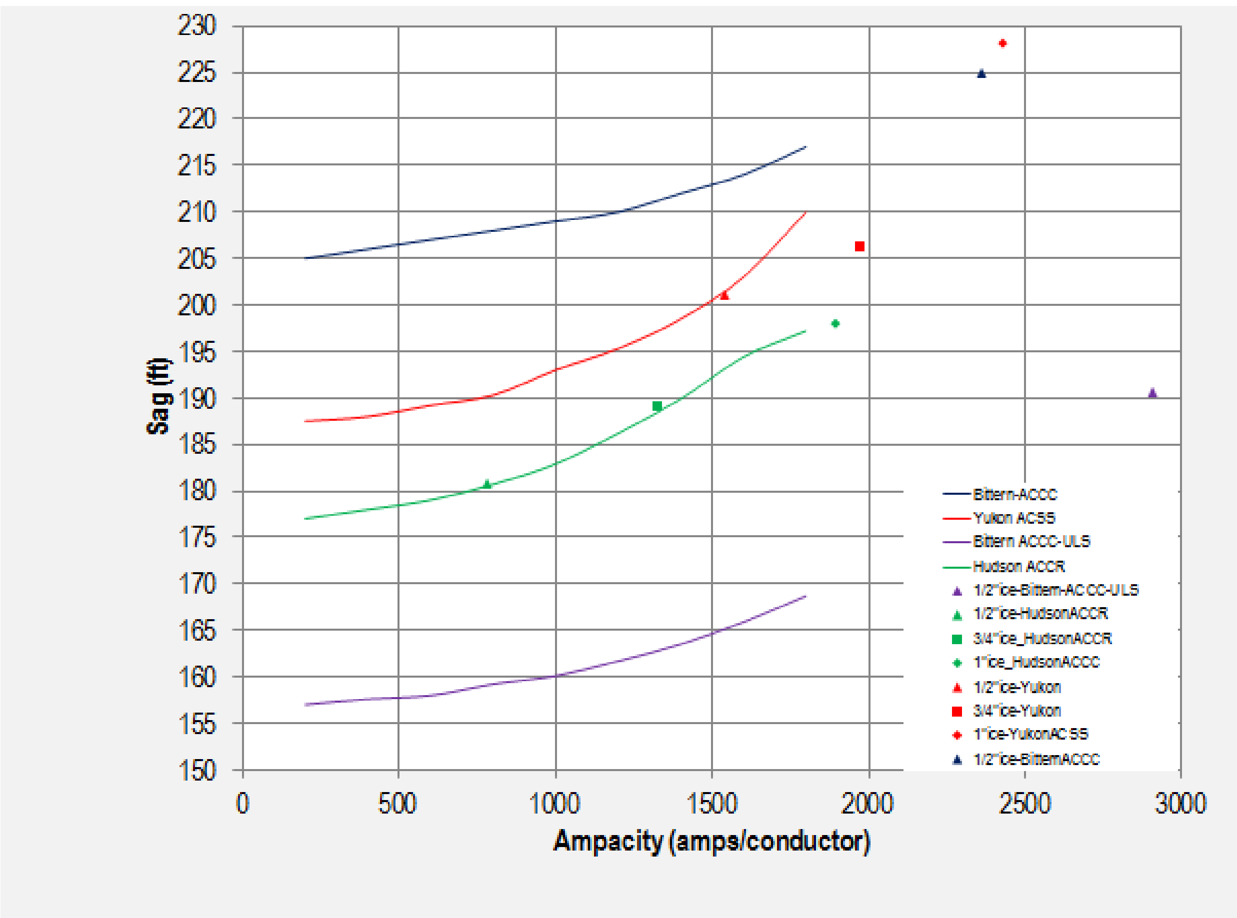

Figure 6: Electrical Load vs. Sag

TOWER MODIFICATIONS

The lattice towers were originally designed for a 795 ACSR Condor conductor. As noted, our analysis indicated that the main tower members were utilized to about 85% capacity under maximum design loading. The table below illustrates the physical characteristics for each conductor in the study

Conductor	Diameter (inch)	Unit Weight	R.B.S. (lbs)	Tension @ 60°F, Creep (lbs)	Controling Case
795 Condor ASCR	1.093	1.024	28,200	6,160	50% RBS at NESC HVY, Initial
Yukon ACSS	1.245	1.584	41,900	10,475	25% RBS at 60° Creep
Bittern ACCC	1.345	1.563	45,000	11,250	25% RBS at 60° Creep
Hudson ACCR	1.199	1.263	40,300	7,265	50% RBS at NESC HVY, Initial

Figure 7: Physical Properties of Wire Candidates

The Bittern ACCC overloaded the hanger arms on the outboard arms. The difficulty in holding the conductor to change out these members was a factor to ponder in conductor selection. Conversely, both the Yukon and the Hudson candidates did not overload the tower arms. All three scenarios required changing select bolts for A325 bolts and replacing the horizontal member of the tension only strut system at a couple panel points.

The only other modification to the towers was modifying the bridge such that the middle phase could be supported by a V-string rather than an I-string suspension insulator as described below.

BIRD DETERRENT

The LCRA has had issues with great blue herons and other birds being electrocuted by this line at the location of these two towers. Great blue heron deaths must be reported to US Fish and Wildlife, along with a plan for corrective action. In 2012, LCRA had tried to address the issue by adding insulators to close the window around the middle phase as shown in Figure 8 and 9. However, there were still faults occurring on the middle phase that were attributed to birds.


Figure 8 - Original insulator configuration

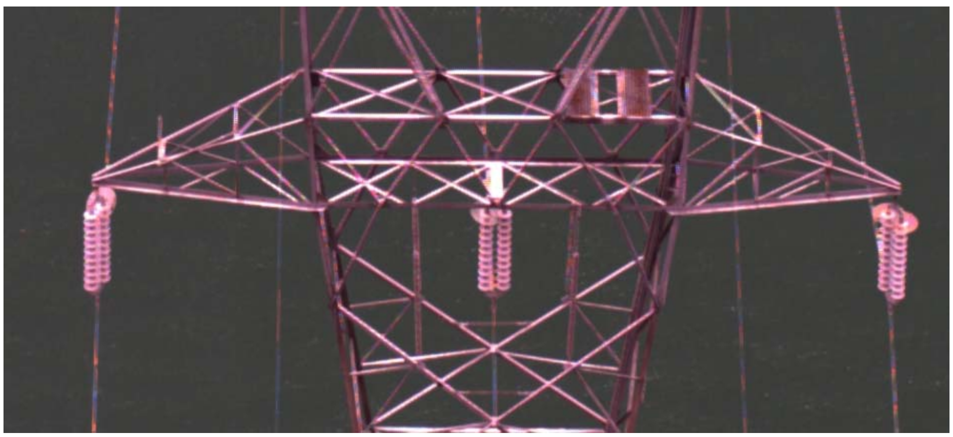
Figure 9 - Second insulator configuration (added vertical and horizontal insulators in the window)

In order to determine how to address the problem, we first needed to understand exactly what was happening. We started our investigation by placing game cameras on the tower, in order to see where birds were landing, and where they were coming between the lines and the tower. We were able to confirm that birds were still flying through the window where the middle phase passed through the tower.

Figure 10 - Game Camera Showing Bird Passing Through the Window

Figure 11 - Game Camera Showing Tail End of Flashover

To further block the window to prevent birds from flying between the middle phase and the tower, the middle phase was changed from an I-string to a V-string. This required additional tower modifications to support the V-string. It was also noted during construction, that the horizontal insulators that had previously been installed to block the window, had significant pecking of the sheds. It appeared that these insulators were likely attracting birds and serving as perches. They were removed during construction. Since these two changes have been made, no additional bird deaths have been recorded.

Figure 12 - Current Insulator Configuration (v-string for middle phase and removed bottom horizontal insulators)

CONSTRUCTION

Since only a handful of minor tower modifications were required, these modifications were made using helicopters to deliver material, personnel, and tools directly to the tops of the towers on both sides of the lake.

3M worked with Engineering up front on the span data (everyday tensions, span length, vertical projection, etc), damping requirements, and marker ball placement. In addition to the conductor, 3M provided all the compression dead-ends and suspension shoes.

There was some concern in connecting a high temp ACCR/TW to the non-high temp conductor, the bundled Drake ACSR used on the rest of the line. These issues were mitigated by using the ACSR for the jumpers, so that sufficient heat loss could be attained before the ACSR compressed dead-end connectors. Any excess heat would only affect the jumpers and jumper terminals. See Figure 13 for the transition between the two conductors.

During construction there were some minor issues with hardware fit up. This was largely due to the mix of new materials coming from 3M, for which detailed hardware dimensions were not available during design, and the use of existing materials on the towers. Small hardware changes were be able to made using in-stock hardware from LCRA and Techline to keep the project on tract with only minor delays. For future uses of this conductor, we would recommend doing assembly fit up tests prior to construction.

Figure 13 – Double-tongued compression dead end to bundled Drake ACSR jumpers

As with all ‘exotic’ conductor suppliers, 3M was very involved in training the contractor in material handling and proper installation. Representatives provided the contractor and LCRA inspectors with a training course prior to initiating the work.

Similar to many conductors with cutting edge core material, honoring a larger bend radius is one of the key elements for proper installation. Roller array blocks were used at dead ends. Due to the large vertical departure angle on the tall tangent towers, a spreader beam with two blocks was used. This also made installing the thermolign double suspension grips much easier as the support points were placed outside of the area where the hardware installation was to occur.

Figure 14 – Roller array block from in-line dead-end to snub location

Figure 15 – Spreader beam used on tall tangent towers

To grip the conductor, a Distribution Grip (DG grip) was required in order to limit any possible local bending. 3M also recommended the use of a bull-wheel tensioner, and the thermolign suspension supports. Other than these differences, installing the ACCR was very much like the installation of any other ACSR conductor.


Figure 16 – Distribution Grip (DG grip) used to grab ACCR conductor

Figure 17 –Thermolign Double Suspension Insulator Assembly

SUMMARY

By installing the ACCR conductor, we were able to double the line's electrical capacity and increase clearance over the water by about five feet.

Cost estimates for both replacing both towers and using an HTLS conductor and completed, and the cost for the 3M conductor was less than half of the cost of replacing the two towers. This option was preferable to replacing the towers, as development has filled-in all around the base of one of the towers, leaving very little room to locate, much less assemble and erect, a new structure. Also, both towers are already lit in order to meet FAA requirements, new structures would have been roughly 30' taller than the existing structures, which could have caused potential FAA issues.

In the end, we were able to upgrade the line, save the towers, provide adequate clearance for tall sailboats, significantly reduce bird electrocutions, and save a substantial amount of money.

AMERICAN ELECTRIC POWER

Breakthrough Overhead Line Design (BOLD)

System and Performance Considerations

Nicolas Koehler, P.E. and Sriharsha Hari
Additional acknowledgement to Richard Gutman
Presented by: Sriharsha Hari, Senior Engineer
9/7/2016

BOLDTM (Breakthrough Overhead Line Design) is a new transmission line developed by American Electric Power, providing a high-capacity, high-efficiency solution in a low-profile, compact configuration. BOLD's compact phase arrangement, combined with an optimized bundle configuration, provide electrical characteristics that drive superior performance and can provide significant advantages over traditional designs. This paper reviews the system and performance benefits of BOLD compared with those of a typical 345 kV double-circuit line design. Experiences related to integrating BOLD into transmission planning studies and case studies of specific projects are also discussed.

Introduction

Electric utilities today are engaged in many transmission projects to enhance reliability, integrate new sources of power generation, and modernize the nation's electric grid. Continued load growth, combined with renewable generation built in remote geographic areas and ongoing retirements of coal-fired stations serving largely native load, calls for efficient transmission capable of carrying bulk power over long distances. Concurrently, public opposition to new line construction, particularly where highest operating voltage and capacity are involved, necessitates new thinking with regard to power transmission design that will minimize the land use, environmental impact and system costs. In spite of this need for a modern and efficient extra-high-voltage transmission system, regulators and communities often resist such new infrastructure construction, citing concerns about higher utility costs, falling property values, landscape distractions, loss of property for easements, and the effects of electromagnetic fields (EMF).

A new and innovative double-circuit 345 kV line design developed at AEP, trademarked Breakthrough Overhead Line Design (BOLD™), offers more intrinsic power-carrying capability than three circuits of the same voltage class using conventional designs. BOLD, available in this and other voltage classes, presents a portfolio of performance and aesthetic benefits that can be tailored to specific requirements of a broad variety of new and rebuild transmission projects. By packing more energy in a compact, efficient, and appealing design than traditional structures, BOLD can help utilities overcome restraints with a long-term and cost-effective solution for service reliability and customer satisfaction.

Improved electrical characteristics and performance are the primary benefits realized by BOLD, but are not the only advantages of the technology. BOLD was originally designed with long, heavily loaded transmission lines in mind. The low-impedance, high-capacity characteristics allow BOLD to carry heavier loads across long distances without the need for series compensation. Additionally, the compact nature of the design also allows BOLD to be installed in populated urban areas with less impact to residents while also offering similar electrical benefits for short length lines. Phase compaction allows BOLD towers to fit into less right-of-way than would typically be needed to accommodate high voltage lines. The aesthetic appeal of the design also lessens the visual impact that landowners are typically concerned with.

The Loadability Challenge

The power flow of an alternating-current transmission line is affected by the thermal, voltage-drop and steady-state stability limitations. Thermal rating, which is an outcome of the conductor or terminal equipment selection process, is usually most limiting for lines shorter than 50 miles. For longer lines, voltage-drop or stability considerations are the key limiting factors, both of which are affected by length-dependent line impedance.[1]

Although the most effective way to reduce line impedance and improve loadability is to raise the transmission voltage class, this method is faced with public opposition, particularly at the highest available transmission voltage. This is why utilities tend to choose lower-voltage options supported with series compensation to reduce transmission path impedance and attain required power-transfer objectives.

Series compensation traditionally has been utilized in the system as a short-term remedy to stretch system capability until a longer-term solution is implemented or as a substitute for higher-voltage transmission. However, operational issues such as sub-synchronous resonance (SSR) and sub-synchronous control interactions (SSCI), which pose a risk to electric machinery and can lead to system instabilities, are quite common to series compensation applications. Other concerns include system protection complexities, maintenance or spare equipment requirements, limited life expectancy, electrical losses and future grid expansion issues including tapping the compensated line.

The BOLD Solution[2]

BOLD features a streamlined, low-profile structure with phase-conductor bundles arranged into compact delta configurations. The structure of BOLD comprises of an arched cross-arm supporting both circuits set atop a tubular-steel pole, which imparts a more favorable aesthetic appearance. Single-circuit or double-circuit lines can be supported by BOLD. Single-circuit construction can be expanded in the future to incorporate double circuit. Initial BOLD projects feature the 345 kV design, but the design series now includes 230 kV and is being expanded into additional voltage classes.

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[1] R.D. Dunlop, R. Gutman, P.P. Marchenko, "Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-98, No. 2, March/April 1979.

[2] R. Gutman and M.Z. Fulk, "AEP's BOLD Response to New Industry Challenges," Transmission & Distribution World, November 2015.

Figure 1: BOLD installation near Fort Wayne, Indiana

The average 100-foot, 345 kV BOLD structure is about one-third shorter than a traditional double-circuit design. Each phase may contain multiple conductor bundles 18 inches to 32 inches in diameter. The separation distances among the three phases are as low as 14 feet and are maintained using two interphase insulators per circuit. Standard insulators attach each of these bundles to the cross-arm and tubular structure bodies. The cross-arm itself supports two shield wires positioned to provide zero-degree shield angle to protect the outmost phases from being exposed to direct lightning strikes.

BOLD's patented configuration packs roughly 50 percent more capacity into the a right-of-way (ROW). Additionally, BOLD markedly improves line surge impedance loading (SIL), lowers series impedance and reduces ground-level EMF effects. SIL is a convenient yardstick for measuring relative loadability among line design solutions. BOLD typically uses three conductors per phase at 345 kV, which offers significant gains in line loadability and energy efficiency for long-distance and local applications.

While BOLD structures can be used in a typical 150-foot ROW for traditional 345 kV lines, BOLD's low-height, visually appealing profile can fit within a 105-foot ROW, a potential reduction of nearly one-third of typical ROW width. These visual benefits are expected to improve public acceptance of new transmission projects.

BOLD vs. Traditional Design

BOLD offers significant improvements in the three factors that most influence loadability and efficiency, which are the key drivers for transmission lines to carry power over long distances: SIL (43 percent increase), impedance (30 percent reduction) and energy loss reduction (33 percent lower resistive loss). Additionally, BOLD lines include a 51 percent reduction in ground-level magnetic field, which is very favorable considering the attention EMF typically receives in line-siting regulatory proceedings.

BOLD features large, multi-conductor phase bundles arranged in a compact-delta configuration suspended from a single cross-arm. Large phase bundles placed in close proximity to each other reduce line reactance (X) and increase line charging (B), resulting in lower surge impedance ($\sqrt{X/B}$) and larger surge impedance loading (reciprocal of surge impedance, in per unit). By using multi-conductor phase bundles, high transmission efficiency and ampacity is ensured and the ground-level magnetic field exposure from the line is reduced by utilizing the compact-delta configuration.

Significant gains are attained in thermal capacity and line efficiency, resulting in lower operating temperatures by incorporating three-conductor phase bundles. Overall system performance is improved by unloading higher-impedance/lower-capacity lines. Alternative phase bundle designs are possible, typically using between two to four conductors per phase.

BOLD technology also greatly reduces the need to install, maintain, or replace series compensation equipment (including SSR or SSCI mitigation), a substantial financial benefit considering the long life expectancy of a transmission line.

Insulation Coordination Studies

Transmission line insulation coordination is the process of determining the appropriate line insulators, tower clearances, hardware, tower grounding, and terminal equipment in relation to the operating and transient voltages that can appear on a power system. Specifically, lightning insulation coordination assesses the overvoltage stresses from shielding failures or lightning strikes to the tower or shield wire system relative to a transmission line's insulation strength. Such a study is essential in determining if the strike distances (tower clearances) are appropriate enough to keep any flashoverrate (flashes per 100 km per year) to a minimum desired value. Similarly, studies are conducted to assess the risk of switching surge flashovers.

Figure 2: Electrical testing set up

Comparative lightning and switching overvoltage studies were carried out using PSCAD™ electromagnetic transient simulation software for the BOLD and traditional 345 kV designs. Similar studies examined the BOLD and traditional 230 kV designs. The goal of these studies was to ensure reliable performance of BOLD's highly-compact configuration and to provide a basis for the development of line insulators, hardware and terminal equipment. The main conclusions of these studies are summarized below.

Lightning Overvoltage:

1. The BOLD tower is lower in height than a traditional tower. This results in a lower number of lightning flashes to a BOLD line per year.
2. BOLD's compact configuration has shown a significant improvement of the lightning backflashover rate, whether a strike hits the shield wire at the tower or mid-span.
3. While the conventional line's shielding failure flashover rate is low, BOLD virtually eliminates shielding failure flashovers in flat terrain.
4. Overall, it can be concluded that the estimated lightning performance of BOLD is as good as – or better than – that of conventional line designs. This statement should be tempered with the fact

that these studies utilized the generic lightning impulse strength characteristics from the EPRI Red Book.[3]

Switching Overvoltage:

1. Simulations of BOLD 345 kV and 230 kV lines without shunt reactors resulted in high phase-to-ground and phase-to-phase flashover probabilities. Adding a shunt reactor at the receiving end of the line reduced the flashover probabilities essentially to zero.
2. Using pre-insertion resistors in 345 kV circuit breakers of BOLD is an effective way of controlling the phase-to-ground and phase-to-phase switching overvoltages. For BOLD 230 kV, line-end surge arresters can be used to reduce the risk of switching surge flashovers.
3. System strength at the switching location has a marginal impact on the switching overvoltage level. The impact on the estimated switching surge flashover rate is negligible.

Prototype Development and Testing

BOLD development began with exhaustive analysis and design efforts, followed by extensive laboratory testing. AEP teamed with Hubbell Power Systems and Valmont Industries on some aspects of the development to ensure the new line design met established performance requirements and would have the requisite structures, insulators, and hardware ready for practical installation.

Hubbell Power Systems tests conducted at the Wadsworth, OH, facility confirmed the modeled insulator hardware corona performance and found it met AEP's design criteria. Valmont Industries fabricated the tubular-steel structure. BendTech and American Pipe Bending, which are Valmont subcontractors, provided cross-arm bending services using an induction heating process. Mechanical tests of the structure were conducted at Valmont's facility in Nebraska.

The Electric Power Research Institute's Power Delivery Laboratory in Lenox, MA, tested a full-scale single-circuit prototype of BOLD for power frequency, corona effects, audible noise, lightning and switching surges, and phase-to-phase insulation.

Project Application – Fort Wayne, Indiana

In 2010, PJM (a Regional Transmission Organization covering 13 states plus the District of Columbia, of which AEP is a member) identified widespread low-voltage conditions and multiple 138 kV line overloads in the Fort Wayne, Indiana area as part of its annual Regional Transmission Expansion

[3] "Transmission Line Reference Book, 345 kV and Above," Second Edition, Electric Power Research Institute, Palo Alto, CA, 1982.

Planning (RTEP) analysis process. The planning criteria violations stem from several contributing factors. The Fort Wayne area relies on several 345/138 kV transformers to serve the local load; there is a very limited amount of local generation in the area to serve load. Area fossil unit retirements combined with new generation primarily comprised of wind reduced the availability of reactive power in the area, exacerbating the low voltage conditions. This base generation change in the area, combined with heavy power flows into Michigan, all were factors in the PJM identified reliability violations.

The solution was two-fold. A new 765 kV source was introduced to Sorenson substation on the southwest side of Fort Wayne. The expanded station acts as a source of reactive power into the area, helping relieve some of the voltage concerns. However, the addition of increased flows from the 765 kV system required a complementary solution to mitigate overloaded lines in and around Fort Wayne. There were several options available to accomplish this, all with multiple pros and cons associated with each.

First, the overloaded 138 kV lines could be rebuilt or reconductored at 138 kV. This avoids any complications introduced with converting or building to higher voltages and reduces right-of-way costs associated with new construction or larger right-of-way requirements for higher voltages. However, the cost to rebuild the nine 138 kV lines was prohibitive. Outage constraints would not allow for each line to be taken out of service as it was rebuilt, and the age and condition of the existing towers on the identified lines left the ability for reconductoring each line questionable at best. Furthermore, rebuilding and leaving the 138 kV system in place would require additional reactive compensation to meet system needs on the lower voltage network.

Second, a new, greenfield 345 kV double circuit line could be constructed from Sorenson station to Robison Park station, which would complete a 345 kV loop around the greater Fort Wayne area. Greenfield construction eliminates the need for long-duration outages when replacing existing lines. This option also allows for full utilization of double circuit 345 kV capability with no need to convert existing stations to 345 kV. Unfortunately, this greenfield option would require additional cost for new right-of-way for the line. The line route would be forced outside the suburban areas around Fort Wayne, resulting in 40+ miles of new construction. Since the construction would be on all new right-of-way, significant landowner impacts would be introduced by constructing a line where no line had been previously.

Third, the existing 138 kV corridor that already exists between Sorenson and Robison Park could be rebuilt as a 345 kV double circuit line. While this option has the advantage of eliminating the need for new right-of-way, thereby reducing overall cost, there is still a need for existing right-of-way expansion due to the size and requirements of traditional 345 kV construction. This option would also require the conversion of several existing 138 kV station to 345 kV operation in order to fully utilize the capacity and capability of a double circuit 345 kV line.

The three options presented above each have unique challenges associated with the benefits they provide. A fourth option was developed utilizing BOLD construction to rebuild the existing 138 kV line as a double circuit line, with one side operated at 345 kV and the other side at 138 kV. This allows for the full capacity utilization of a typical 345 kV double circuit corridor while not requiring the station conversions along the existing 138 kV path. Due to the compact nature of BOLD, it was anticipated that the higher voltage line could be more easily installed within the existing right-of-way than a conventional 345 kV double circuit line. Landowner impact would be lessened with BOLD from both right-of-way acquisition and visual impact standpoints. The reduced line impedance plus increased line charging provided by BOLD would eliminate the need for additional voltage support in the area, especially on the 138 kV system. However, since BOLD was still a new technology, there would be a small price premium for the line itself that would need to be considered versus other options.

For the Fort Wayne line, ROW and landowner impact were particularly important factors in developing solutions to the PJM identified issues. The existing Sorenson to Robison Park 138 kV corridor passes through some heavily developed and well established areas. AEP held several open houses in the area to discuss the project with residents and businesses that may be affected by the project development.

Figure 3: Portions of the existing Sorenson – Robison Park 138 kV line.

Ultimately, the BOLD option was chosen for several reasons. The high capacity, low impedance nature of BOLD enabled the use of a single line to help alleviate the PJM identified violations. BOLD achieves nearly five times the capacity in the same corridor that already existed, and the self-compensating nature of the BOLD design helps boost system voltages without the need for additional voltage support. As mentioned previously, ROW considerations played a heavy part in the final project selection. Land development and encroachments limited the ability to expand the existing Sorenson to Robison Park corridor and left little choice in creating new line routes. Feedback gathered from public open houses indicated that most in the affected communities had a positive impression of the BOLD tower design and profile.

Figure 4: 765 and 345 kV line routes for the Sorenson – Robison Park project.

Other factors went into the decision to rebuild the existing Sorenson – Robison Park 138 kV line as well, though they did not directly relate to mitigating the reliability violations. By utilizing a three-conductor bundle on the BOLD line, losses will be reduced by approximately 33% compared with a standard two-conductor bundle. The existing Sorenson – Robison Park line was constructed in the 1940s. A separate rehabilitation project for the line would be needed in the near future regardless of the project option selected to solve the voltage and thermal violations in the area. Combining the line rehabilitation needs with the ability to install a 345 kV line to solve the PJM identified issues while also maintaining the 138 kV circuit was the best option for the Fort Wayne area.

Project Application – Western Indiana

Two portions of other AEP lines were identified by PJM as overloaded in other RTEP studies, including the Meadow Lake – Reynolds 345 kV line and the Meadow Lake – Dequine 345 kV lines. These two line sections are part of a long 345 kV double circuit corridor that runs from Reynolds station in western Indiana to Sullivan station in southwestern Indiana, approximately 120 miles in length.

Reynolds station is owned by NIPSCO and is the site of a future 765/345 kV project approved by Midwest ISO (MISO, an RTO covering much of the central United States) and PJM that will connect NIPSCO's Reynolds station to Duke's Greentown 765 kV station. Sullivan is an AEP-owned 765/345 kV station serving as one of two outlets for AEP's Rockport Plant, a major generating station in southern Indiana. Additionally, two large wind farms are connected to the AEP system in this area. Meadow Lake currently has a capacity of 600 MW (nameplate) with an additional 200 MW in the PJM queue. Fowler Ridge wind farm, 750 MW (nameplate), is connected at Dequine 345 kV station.

PJM has already approved a rebuild of the 7-mile section of line between Meadow Lake and Reynolds 345 kV stations as a baseline project in 2013. In 2014, with the implementation of FERC Order 1000 competitive requirements in PJM, a reconductoring project for Dequine to Meadow Lake was chosen. AEP is currently working with PJM to convert the reconductoring to a rebuild project offering significant incremental benefits associated with a complete rebuild.

AEP plans to utilize BOLD technology in the proposed rebuilds on the Meadow Lake – Reynolds and Meadow Lake – Dequine 345 kV lines. The nature of the interconnected system at Reynolds and Sullivan essentially creates a 765 kV connection across the 345 kV double circuit corridor, which is limited due to the age and configuration of the existing line. An original project, of which the Reynolds – Greentown 765 kV line is a part, was proposed to connect Reynolds station to Sullivan station at 765 kV along with a third line connecting west out of Reynolds. Presently, only the initial portion between Reynolds and Greentown has been approved. The Reynolds – Greentown 765 kV line along with the wind generation at Meadow Lake and Dequine are contributing to the PJM-identified issues on the 345 kV system. These factors led AEP to work towards rebuilding the entire 120 mile corridor with double circuit 345 kV BOLD technology.

AEP performed power transfer analysis for several variations of construction along the Reynolds to Sullivan 345 kV corridor. The results are seen in Figure 5:

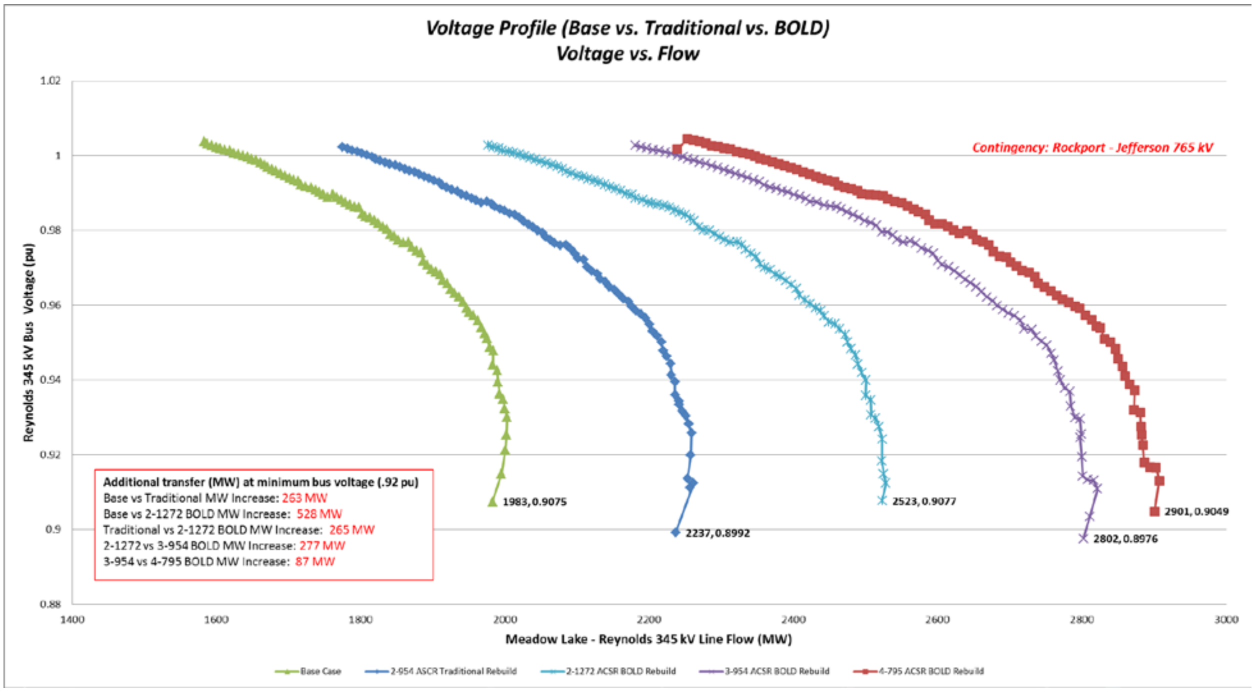

Figure 5: Transfer analysis results on Meadow Lake – Reynolds 345 kV line.

Power transfer analyses relate voltage performance at a certain bus compared to the power flow across a given line under heavy transfer scenarios. In the figure above, AEP compares the voltage performance at Reynolds 345 kV bus (y-axis) versus the MW flow on the Meadow Lake – Reynolds 345 kV portion of the Reynolds – Sullivan 345 kV corridor (x-axis). By reconductoring or rebuilding the line with 2-bundled 954 ACSR conductor as a conventional design, the transfer limit at a voltage violation point (0.92 pu voltage at the Reynolds 345 kV bus) is increased by 263 MW. If the line were rebuilt utilizing a BOLD 2-bundled 1272 ACSR conductor configuration, the transfer limit is increased by 528 MW over the existing line capability. Using a 3-bundled 954 ACSR BOLD configuration increases the transfer limit by an additional 277 MW over the 2-bundled 1272 ACSR BOLD option. A 4-bundled 795 ACSR BOLD design increases the transfer limit another 77 MW.

This analysis indicates that utilizing a 3-bundled 954 ACSR BOLD design allows the 345 kV double circuit corridor to act as a proxy for a 765 kV line between Reynolds and Sullivan stations. When comparing the case with no additional transfers modelled, a 3-bundled 954 ACSR BOLD designed line carries nearly 600 MW more across the Meadow Lake – Reynolds 345 kV corridor.

In contrast to the Fort Wayne area, the western portion of Indiana is very rural. Most of the land along the Reynolds – Sullivan corridor consists of farmland, where ROW restrictions are less of a concern. AEP plans to use BOLD lattice tower design instead of the monopole design in this project. The BOLD lattice tower offers the same electrical and compact advantages as the monopole design, but does so at less cost.

The existing tower design is lattice, so BOLD will replace lattice for lattice at a reduced overall tower height.

Conclusion

BOLD offers many advantages over conventional line construction. Reduced impedance combined with increased surge impedance loading results in more efficient power flows across long distances. The phase compaction and reduced height also allows BOLD to be constructed through constrained areas where traditional construction may have a large impact. AEP, partly in association with Hubbell Power Systems and Valmont Industries, has developed and executed myriad test scenarios to ensure that BOLD offers all the advantages inherent in a compact solution without compromising safety or reliability. Two installations are already moving forward in Indiana, with one nearing completion, along with others under development.

AMERICAN ELECTRIC POWER

The Advantage of SFRA Testing as Part of the Commissioning Testing on High Voltage Transformers

SFRA as a Diagnostic Tool

Steven A. Plehinger

AEP (Texas)

3/29/2016

Abstract

We depend on a wide assortment of commissioning tests to evaluate the condition of our High Voltage transformers before placing them into service. Not a lot has changed over the last 20 years. Why is that? For the most part the tests that were performed in the past have been adequate in determining the condition of the units in question. The majority of the tests that are performed on high voltage equipment evaluate either the dielectric strength or the conductivity of the circuit applied. Now we have a way to look at the geometric integrity of that circuit and acquire a repeatable baseline that can be used as a diagnostic tool. Because of that we were able to find a problem with a 130 MVA Auto Transformer that passed all of the routine commissioning tests but did not pass the SFRA test. What we would like to illustrate is: what we found, how we diagnosed the acquired results, how the results determined there was a problem and what was needed to make the necessary repairs to the transformer.

BACKGROUND

The unit in question was a new 138/70.5/13.9kV 130 MVA Auto Transformer. Normally we will have crews perform their commissioning tests after the “24 hour set time” however; they were working out of town. So the decision was made to go ahead and perform SFRA testing first. Figure 1-1

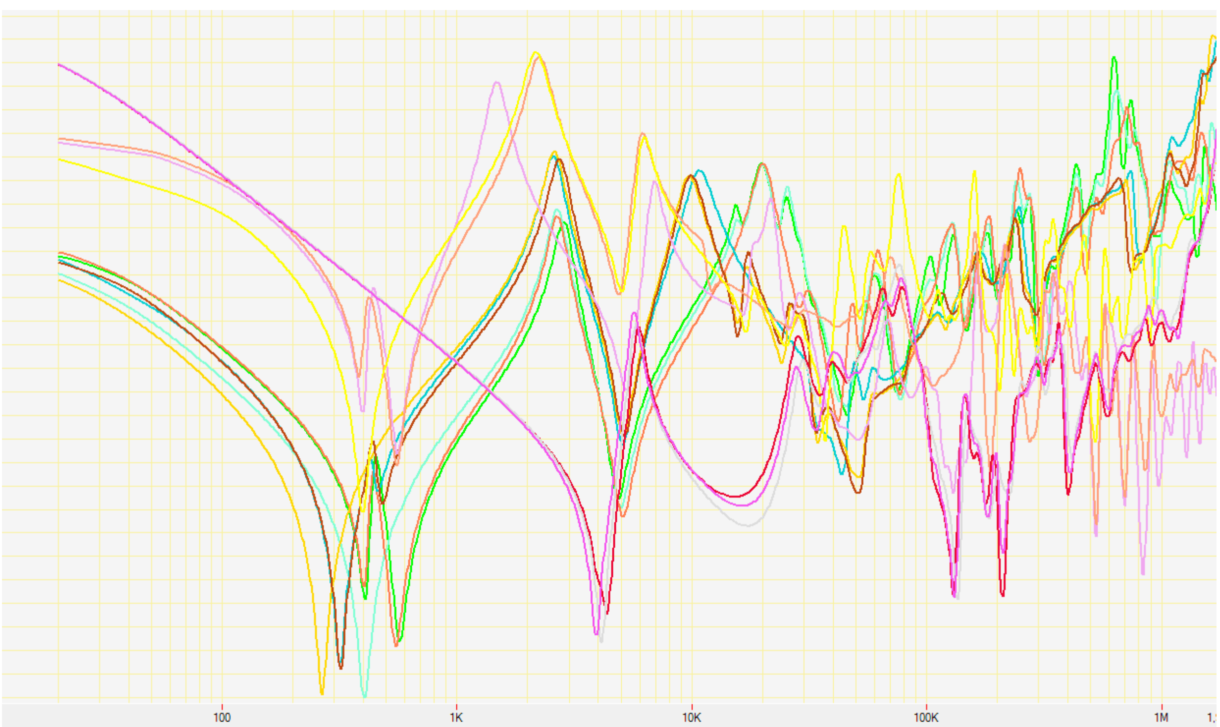

Figure 1-1

We set the “NLTC” on tap one and the “TCUL” on extreme raise and started our tests. What was found was our Open Circuit tests resembled the Factory Tests; (Figure1-2/1-3) except for the “Tertiary Open Circuit Tests” ;(Figure 1-4)

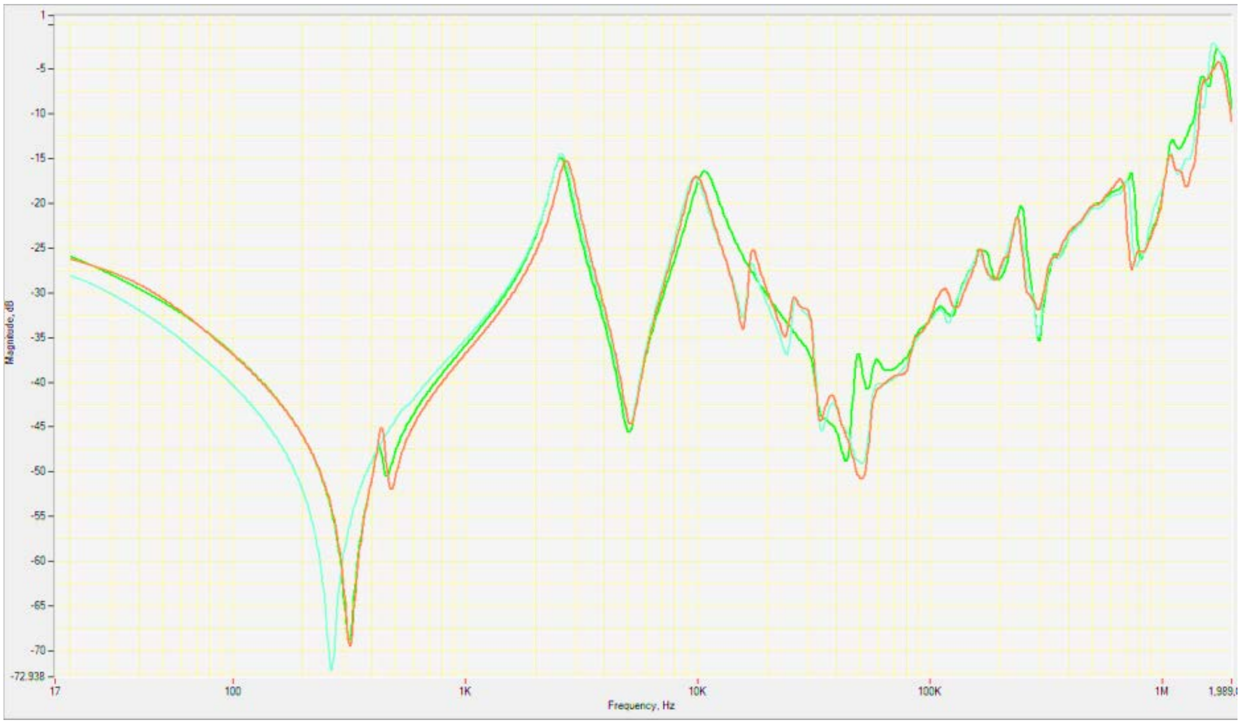

Figure 1-2 (Our test)

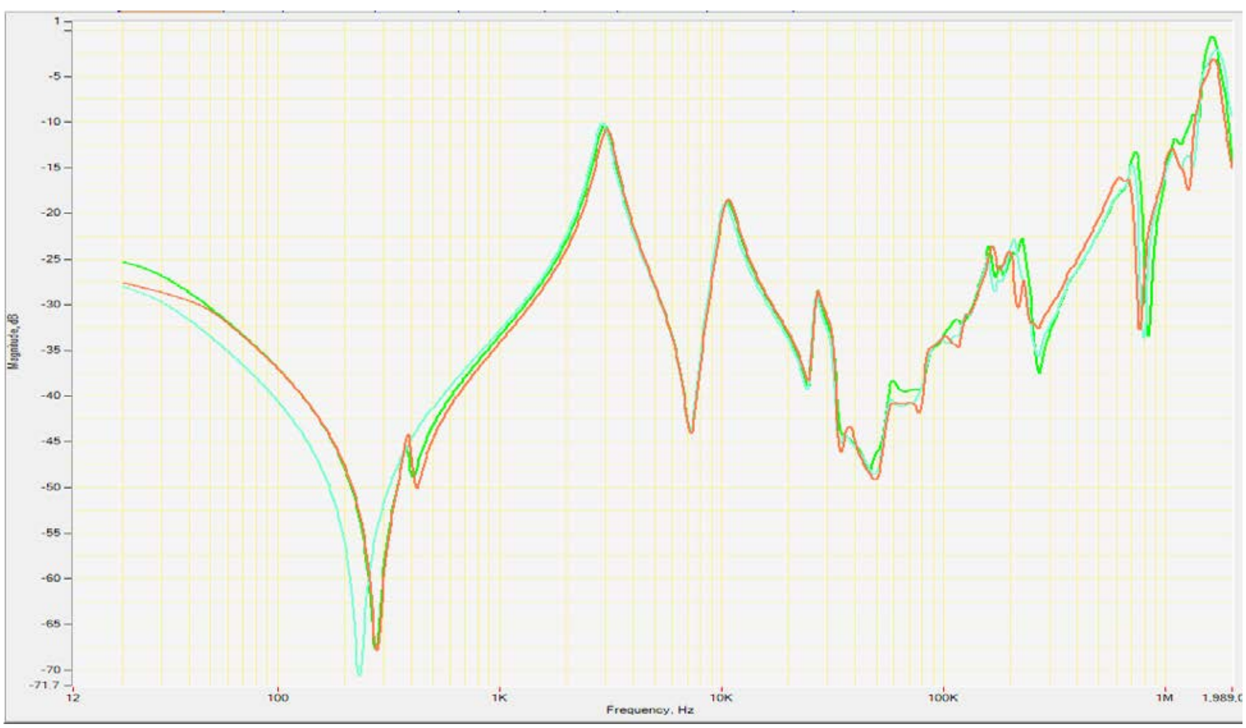

Figure 1-3 (Factory Test)

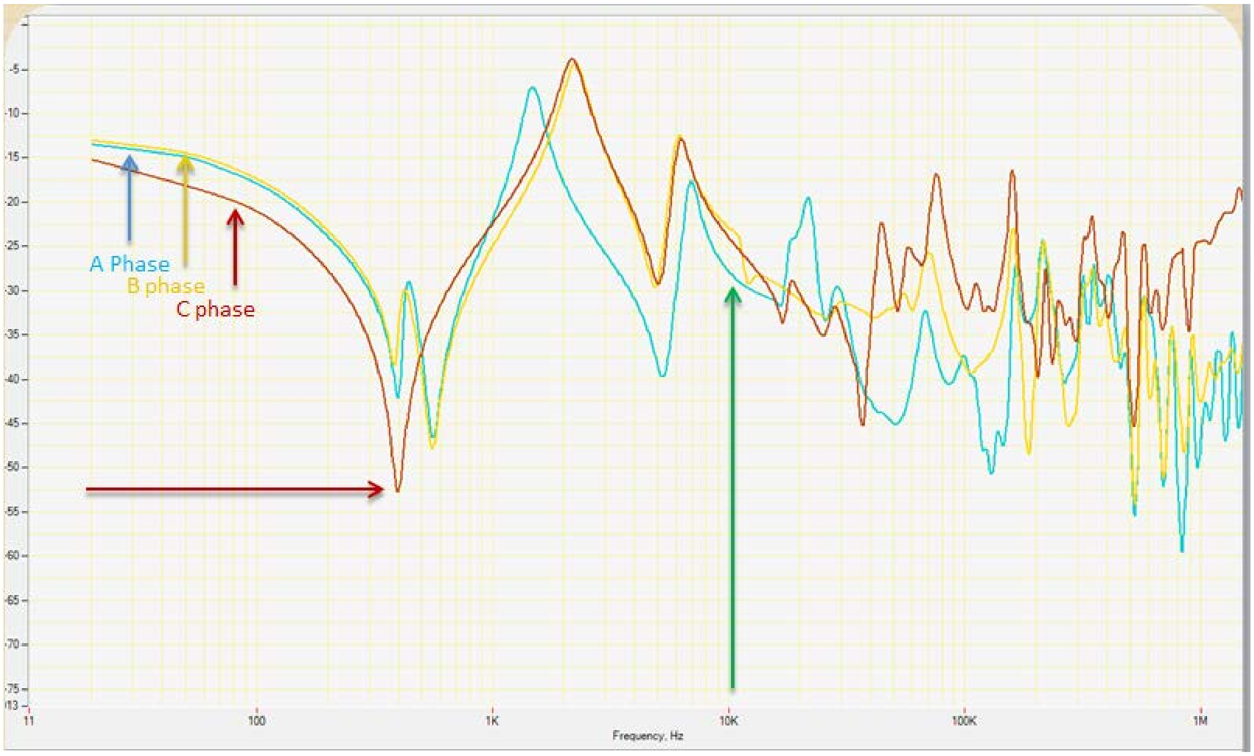

Figure 1-4 (Tertiary Open Circuit Test)

It is typical for the center phase to have slightly increased impedance (more negative dB) at low frequencies. One of the obvious problems with this trace is C-Phase has the lowest dB. Now all three phases should "come back together" as frequencies rise toward 10K Hz and they clearly do not.

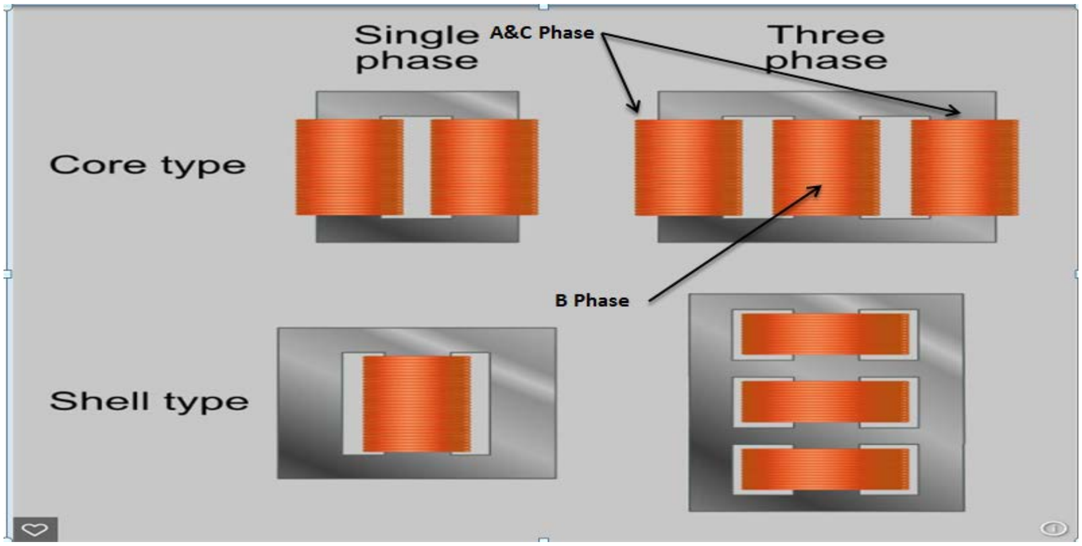

Figure 1-5 (Core and Winding Configuration)

Typically in a three phase, core-form winding configuration A-and C-phases have equivalent reluctances. B-phase will have a comparatively lower reluctance. The responses for all three phases should be similar at low frequencies; “When shorted.”

Our Open Circuit Tests were similar to the factory, but when we shorted the tertiary, C Phase was comparable to an open circuit trace; Figure (1-6).

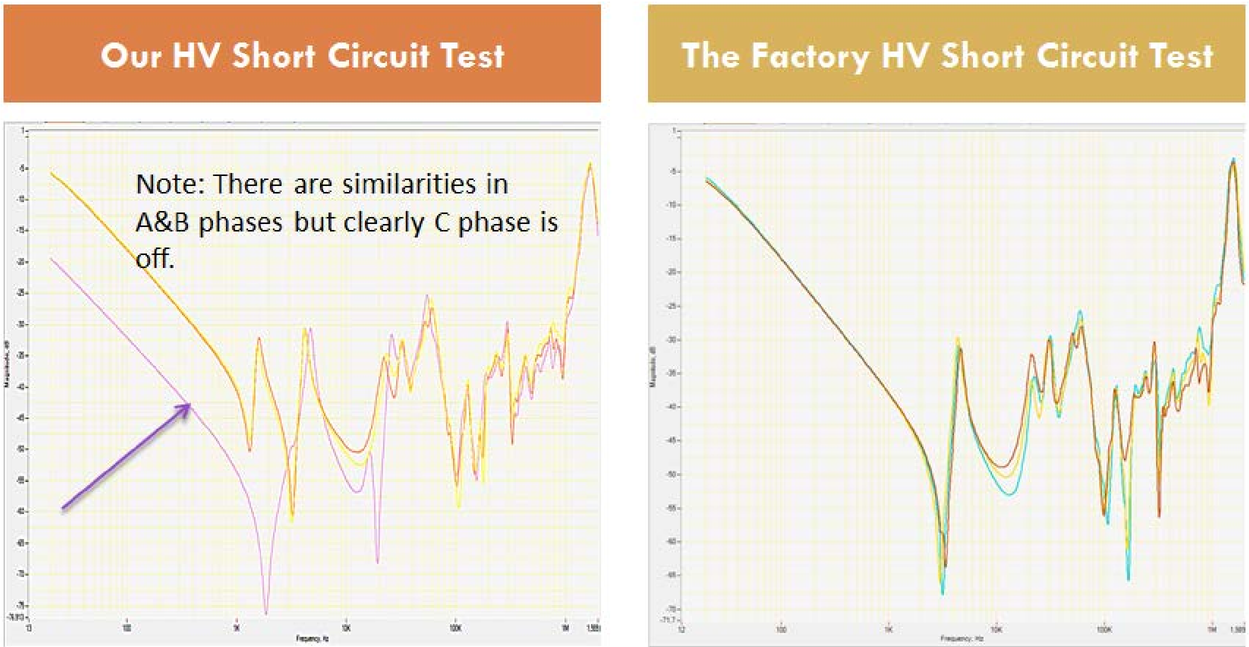

Figure 1-6 (High to Neutral with Tertiary Shorted)

It made no difference whether we were testing the high or low voltage winding the abnormality continually occurred on C Phase. We know that a change from 5 Hz to 2 kilohertz and changes of ±3 dB (or more) can indicate a variety of problems like; an open circuit, shorted turns, and residual magnetism. A DC core ground test was the last test that was executed on this unit before we performed the vacuum and hot oil fill. We were wondering if residual magnetism had compromised the integrity of the test. We had the crews come out and de-mag the transformer and perform all of their commissioning tests. All of the commissioning tests passed. We came back and repeated the SFRA tests and got the same results as before. We knew that the open circuit tests were comparable to the factory tests at least to the 10K Hz range. The shorted tests were suspicious; the abnormality always occurred on C Phase. We established it had to do with what influence the shorts had with the test. We know when you add shorts; the effect of the core is removed. That pointed to the tertiary because the traces acted more like an “Open Circuit Test,” even though we had the shorts in place. We established we weren't getting a good reference to the shorted tertiary winding on C Phase. It seemed evident it was either a high resistance connection inside the transformer or the leads might be touching one another.

WHAT WAS DONE

The decision was made to remove the oil from the transformer and perform an internal inspection on the unit. We found that the "Inter Winding" connection on the tertiary "C Phase" bushing was bolted up on the weld which was not allowing the pad to lay flat, and that caused a high resistance connection on that phase; Figure (2-1).

Figure 2-1 (Tertiary "Inter Winding" Connection)

We re-terminated all of the connections on the tertiary bushings. We then found that some of the wrapping on the leads that were going to the tertiary bushings had come unwrapped; Figure 2-2.

Figure 2-2 (Paper Insulation coming unwrapped)

We redid the wrapping on the leads. We also found some of the blocking had worked its way loose; Figure 2-3.

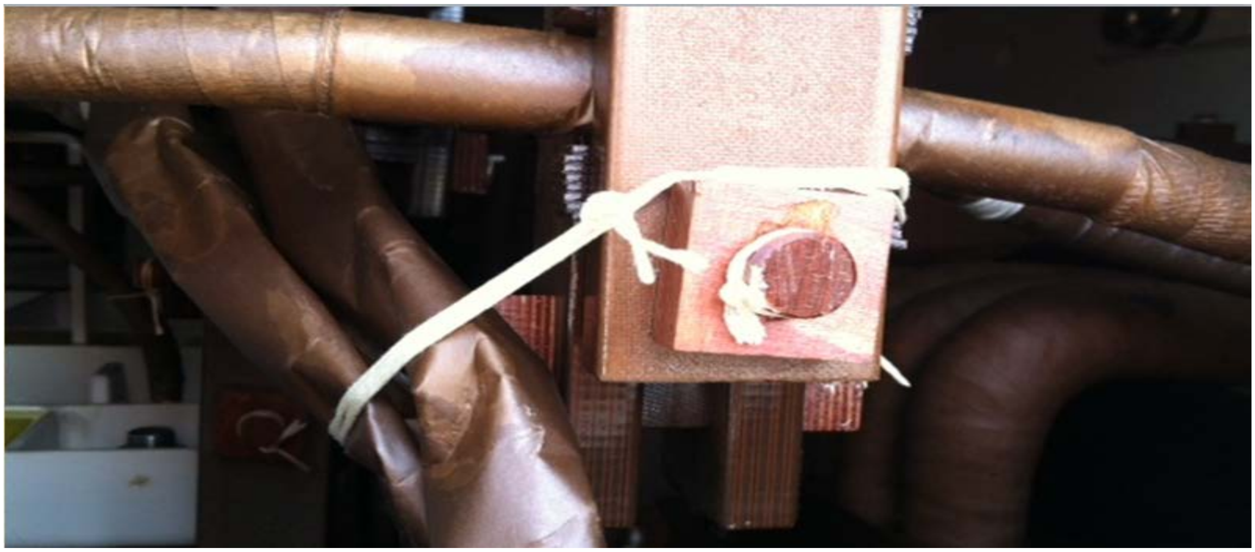

Figure 2-3 (Misaligned blocking)

Misaligned blocking was repositioned to acquire proper spacing between the leads.

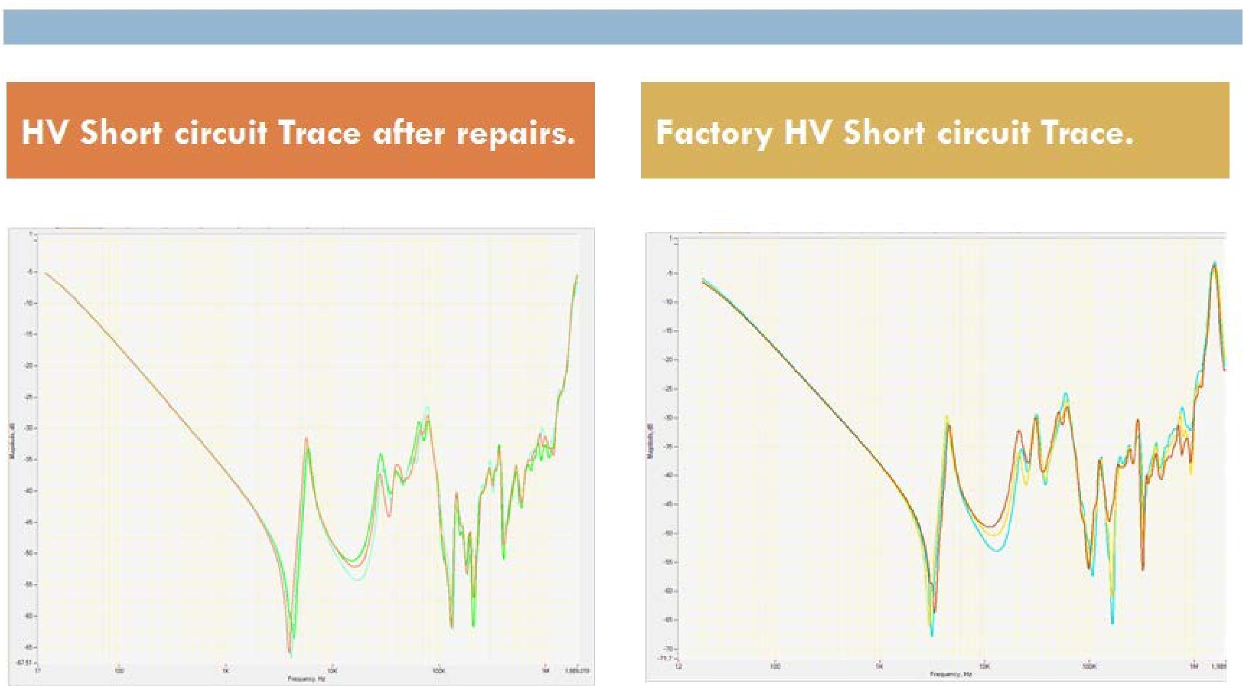

Figure 2-4 (After repairs Comparison)

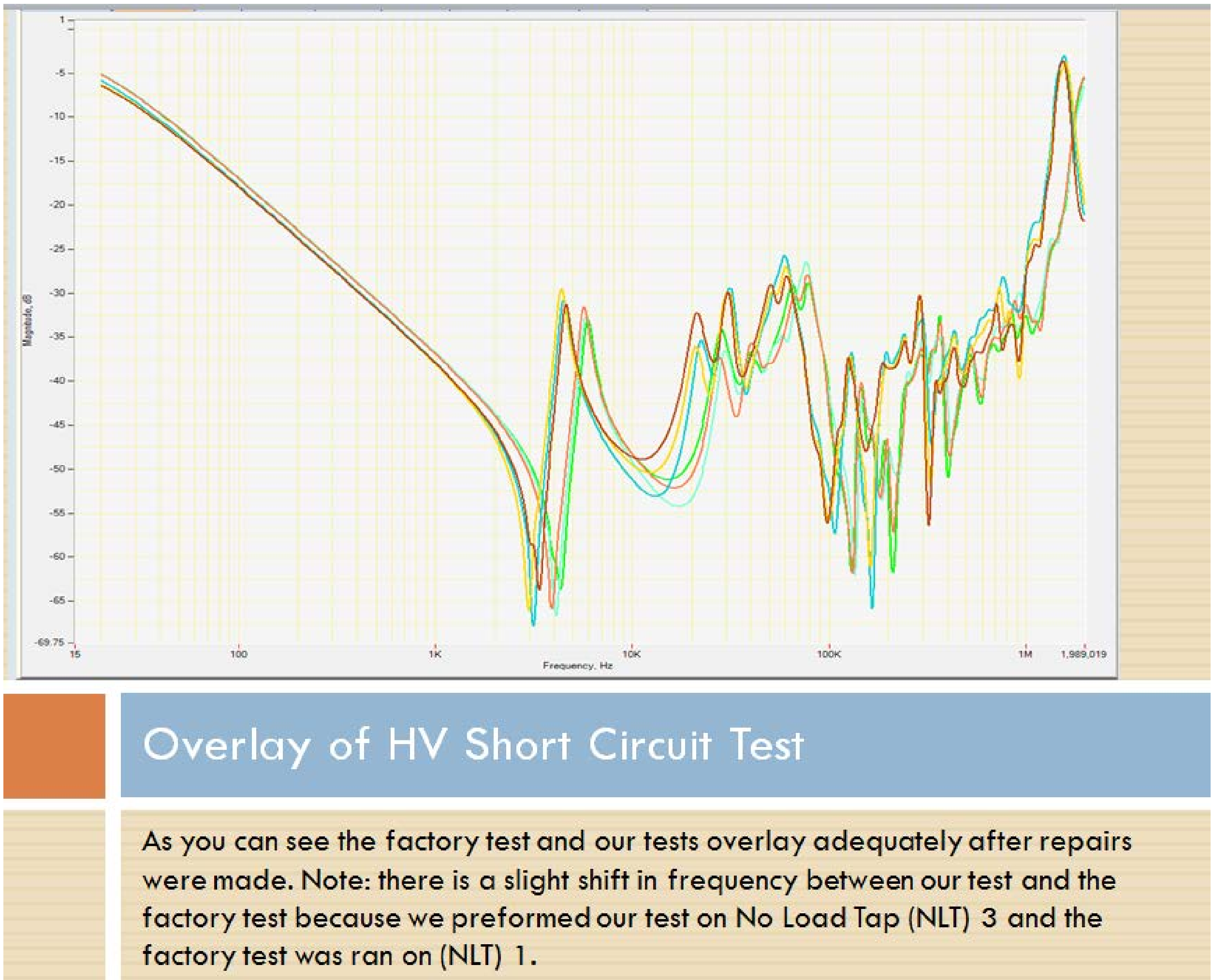

Figure 2-5 (After repairs Overlay)

Performed SFRA and all of the tests were comparable to the factory tests. The tertiary winding on this transformer is going to be used for station use. The loading consequently could have caused a hot spot inside the transformer, that would probably cause the unit to start gassing and that could have led to failure of this transformer. Finding this problem was beneficial to the life of the transformer and the reliability of the station.

Technical Considerations for Undergrounding of EHV Lines

49th Annual Transmission and Substation Design and Operation Symposium

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Abstract - The installation of extra high voltage (EHV) overhead transmission lines face opposition from environmental groups, local jurisdictions and community groups due to impacts such as aesthetics, magnetic field exposure, and occupation of land. Utilities, transmission developers and power generating companies increasingly require conducting environmental impact studies which include alternatives to evaluate undergrounding lines or sections of lines especially as their corridors traverse rural and residential areas, enter congested areas in urban cities to access substations, are adjacent to sensitive receptors such as schools, urban redevelopment areas, or are in close proximity to areas of scenic beauty or historical or cultural sites. Consideration of undergrounding options is also being included in environmental studies as part of the regulatory process to obtain approval for the project. EHV underground cables require careful considerations with respect to overall system selection, design, ampacity, loading, reactive compensation, transition stations, switching, installation requirements, repair, maintenance and cost. This paper provides an analysis of available cable system technologies for EHV applications and addresses other technical requirements for conversion of EHV lines to EHV underground cables.

1 Introduction

Overhead transmission lines (OHL) have been the preferred system installation by utilities and other entities for the transmission of electrical power due to their ability to transfer power over long distances, cross different geographies, adapt to different terrains, their flexibility and generally lower cost as compared to underground transmission lines (UGL). As a result, OHL form the backbone of bulk power grids and as of 2009, there were 452,699 circuit-miles of OHL installed in North America. [1]. In contrast, underground transmission lines (UGL) have been used where OHL were unfeasible such as urbanized areas due to the lack of right-of-way (ROW) associated with the prohibitive cost of land for ROW acquisition and crossing of large bodies of water. As a result, there are approximately 4,500 miles of UGL representing less than 1 percent of the total number of lines. [2]

An increasing number of transmission lines are planned to meet projected energy supply and demand and to improve reliability of the power grids. The Edison Electric Institute projects transmission investments of $19 billion and $19.8 billion in 2016 and 2017, respectively. [3].

The construction of new OHL faces increasing opposition by communities traversed by the lines, environmental groups and residents living in close proximity of the lines based on aesthetic impacts, potential health related impacts, ROW land requirements, and loss of property values. In addition, environmental impact reports for addition of new lines now include the evaluation of underground alternatives to facilitate the regulatory and approval process. This is evidenced by high profile 500-kV projects for which planning studies evaluated the feasibility of undergrounding options as shown in Table 1-1.

Project	Study Year	Section Evaluated	Location	Decision
SunZia Transmission Line Project [4]	2013	35	Near White Sands Missile Base	Pending
Heartland Project [5]	2010	6 and 12	Edmonton, Canada	Pending
Trails Project [6] [7]	2010	6	Everglades, Florida	Constructed OHL
I5 Project [8]	2001	80	Washington State	Pending
Tehachapi Renewable Transmission Project [9] [10] [11]	2012	3.7	Chino Hills, California	Forced underground

Table 1-1. OH Projects Evaluated for Feasibility of Undergrounding

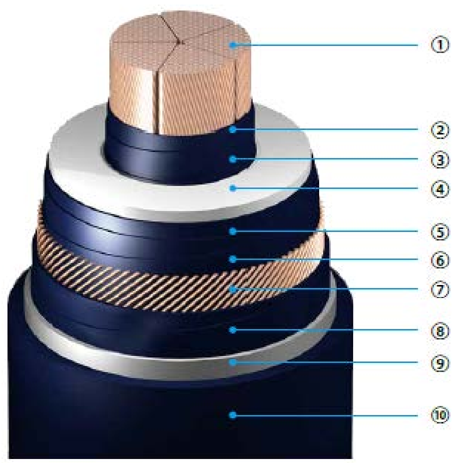
2 EHV Cable Systems and Components

2.1 General Components of an UGL Systems

This section presents the types of EHV underground transmission systems available. Currently, there exist four distinct underground transmission cable systems with worldwide acceptance and usage which are as follows: 1) Extruded Dielectric Cable Systems – Cross-Linked Polyethylene Insulated; 2) Self-Contained Fluid-Filled Cables (SCFF); 3) High-Pressure Fluid-Filled Pipe-Type Cables (HPPT); 4) Gas Insulated Lines (GIL). All four systems consist of the following main components: Cables, joints or splices and cable terminations. Self-contained cables and pipe-type cables for applications above 230-kV require oil-filling plus ancillary equipment such as oil feeding tanks, pumping plants and alarm systems are needed for oil-filled systems. Also required are bonding and grounding equipment and cathodic protections systems for pipe cables. High temperature superconducting (HTS) cables may be a future option but the current state of art does not permit installations at EHV levels.

2.2 Cross-Linked Polyethylene Insulated Cables

Cross-Linked Polyethylene (XLPE) insulated cables are currently the most used cables in the US and worldwide and have surpassed installations of oil-filled cables [12]. They have been used extensively including installations from 230-kV to 500-kV in North America [11], Japan [13] and Russia [14]. Figure 2-1 shows the components of an EHV XLPE insulated cable.



1. Copper or Aluminum Conductor
2. Semi-Conductive Tape
3. Inner Semi-Conductive Extruded Shield
4. Insulation (Extruded XLPE)
5. Outer Extruded Semi-Conductive Shield
6. Semi-Conductive Bedding and Water Blocking Tapes
7. Wire Metallic Shield
8. Semi-Conductive Bedding and Water Blocking Tapes
9. Metallic Sheath (Corrugated Copper, Corrugated Aluminum, Smooth Aluminum, Copper Laminate, Aluminum Laminate, Lead, or Corrugated Stainless Steel)
10. Protective Jacket (PE, PVC)

Figure 2-11. Construction of XLPE Insulated Cable

This cable type was initially developed in the 1960s but with continuous advances in polymer science, the development of extra and super-clean materials, and improvements in manufacturing process and quality control have made this cable technology suitable for installation at 500kV. The widespread use stems primarily from the elimination of oil which eliminates complexities in design, installation, and maintenance, reduction in repair time and reduction in adverse environmental impacts since the cables are oil free. The main advantages of XLPE cables respective to SCFF or HPPT cables are: less insulation losses; higher current capacity; less capacitance and less charging current; no ancillary equipment such as oil tanks, pressure systems, alarms and communication systems are needed; no filling oils to create fire risks; no environmental threat due to spills and leaks; reduced maintenance, and reduced repair time.

2.3 Self-Contained Oil-Filled Cables

Single-conductor fluid-filled cables have been used since the 1920s and have found applications worldwide. SCFF cables have been developed and tested to voltages up to 1,100-kV [15]. A relative short installation at 525-V AC was at the Grand Coulee Dam. The EHV SCFF cable consists of a hollow copper or aluminum conductor which is filled with low viscosity dielectric oil with internal oil pressures ranging from 15 psi to 200 psi depending on the cable construction and application. The cable insulation consists of either Kraft paper or triple laminate paper-polypropylene-paper (PPLP) tapes. Pressure in the cable is maintained by pressure tanks for low and medium pressure cables or by pumping plants for high pressure cables.

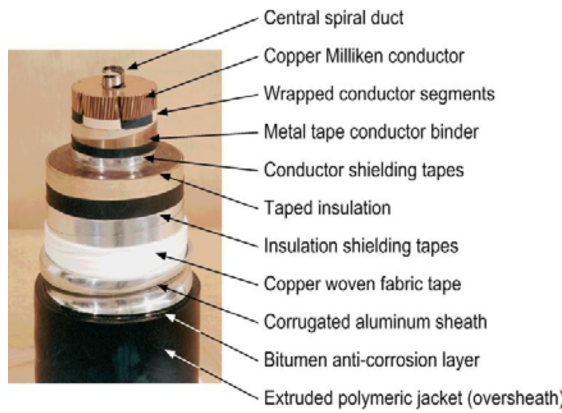


Figure 2-2. Construction of SCFF Cable

2.4 Pipe-Type Cables

High-Pressure Pipe-Type (HPPT) cables were developed in the 1930s in both gas filling and oil-filling. For application at 230kV and above they require oil-filling. Pipe cables have been successfully tested to 500kV at the EPRI Waltz-Mills testing facility in Pennsylvania and to 765kV by EPRI and the US Department of Energy. At present there are no installations worldwide above 345kV [2]. The construction of a pipe-type cable is shown in Figure 2-2. PPLP insulation, as compared to conventional Kraft paper, has higher dielectric strength which reduces the thickness needed at a certain voltage level; it has lower losses which results in higher ampacity and permits installing larger conductors for the same pipe size for increased capacity. Installation, maintenance, and repair are complex and require specialized equipment and trained and skilled personnel.

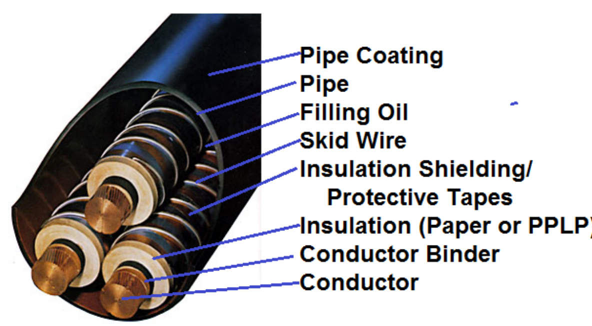


Figure 2-3. Construction of HPPT Cable

2.5 Gas Insulated Lines [16] [17] [18] [19]

The Gas-Insulated Line (GIL), also referred to as the SF6 insulated electronegative cable system, is a transmission system designed for high capacity power transfer. The GIL is a very versatile transmission system that can be installed in shallow box tunnels, deep tunnels, above ground and underground. The GIL underground transmission system is available to 550-kV and 4,000 amperes [13]. The basic design of the GIL is shown in Figure 2-4. GIL exhibit low capacitance and low charging currents allowing lengths up to 60 miles without reactive compensation. Also, they generate low magnetic field profiles. The main disadvantages of GIL installations are their relative inability to easily follow

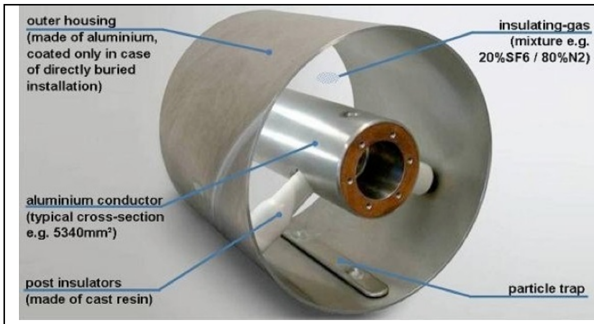


Figure 2-4. Construction of GIL

route changes in plan and profile, the possibility of introducing contaminants into the pipe during installation and welding and potential SF6 gas leakage.

2.6 Cable Designs

Cable designs are based on North American and International standards such as AEIC CS2, AEIC CS7, AEIC CS 9[20] and IEC 62067[21]. These standards also specify factory tests, type tests and long term qualification testing. EHV cables, however, operate at high internal stress levels as shown in the Table 2-1 for XLPE cables. Paper insulated cables operated at even higher stresses.

The cable design must take into consideration not only the level of insulation thickness, but also for the case of XLPE cables, radial metallic moisture barriers to prevent water ingress which could lead to water treeing. The metallic shielding also requires careful consideration for transport of anticipated fault current levels.

Rated Voltage (kV)	**Conductor Sizes** (Kcmil)	**Nominal Internal AC Stress Limit** (kV/mm)	**Nominal External AC Stress Limit** (kV/mm)	**Generic Nominal Insulation Thickness** (mm)	**Reference**
230	1000-5000	11	5	23	AEIC CS9[20]
345	1000-5000	14	6	26	AEIC CS9[20]
500	1000-5000	15-16	7	31	-

Table 2-1. Stress Levels for XLPE Cables

2.7 Splices

Cable joints or splices are needed to join individual cable lengths or spans after installation. Cables are shipped on individual reels with practical lengths up to 2500 feet. Longer reels present logistical challenges in shipping, transportation, and site installation. For XLPE cables, premolded joint shown in Figure 2-6 and prefabricated joint designs are available to voltages of 500-kV. For SCFF both normal and oil stop joints, Figure 2-5, are available up to 500-kV. For pipe-type cables, normal, semi-stop and stop joints are available to 345-kV. Manholes must be properly sized to accommodate joint length for assembly and final positioning plus length of any offsets since EHV joints can be up to 7-10 feet in length depending on the system type. Standards such as IEEE 404 [22] are applicable to joints design and testing requirements.

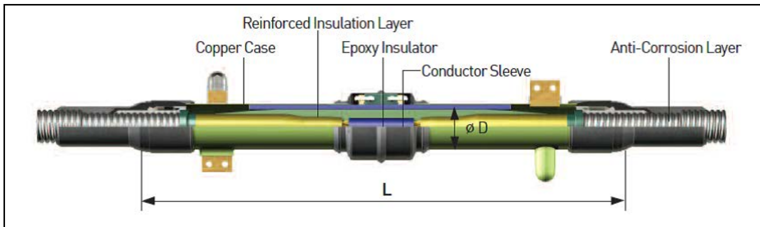


Figure 2-5. Construction of SCFF Cable Stop Joint

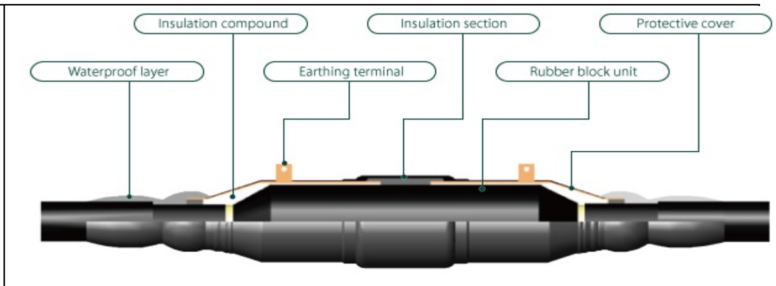


Figure 2-6. Construction of XLPE Cable Premolded Joint

2.8 Terminations

Cable terminations are needed to transition cables from underground to an overhead system. Their function is to terminate the electric field in the cables and provide environmental protection via the external bushing which could be porcelain or a polymer composite consisting of a fiberglass tube bonded to EPDM rubber as shown in Figure 2-7. Standards such as IEEE 48 [23] are applicable to termination designs and testing requirements. Table 2-2 shows the dimensions and weight of terminations rated from

275 to 550-kV for XLPE cables. Due to their height and weight, terminations at 230-kV and above require seismic testing by shake table per IEEE 693, Annex N.

Max. Voltage	BIL	Max. Height	Max. Weight
kV	kV	Inch	Lb
275	1050	138	1980
362	1175	169	3740
420	1425	169	4400
550	1550	197	5500

Table 2-2. Dimensions and Weight of EHV XLPE Cable Terminations

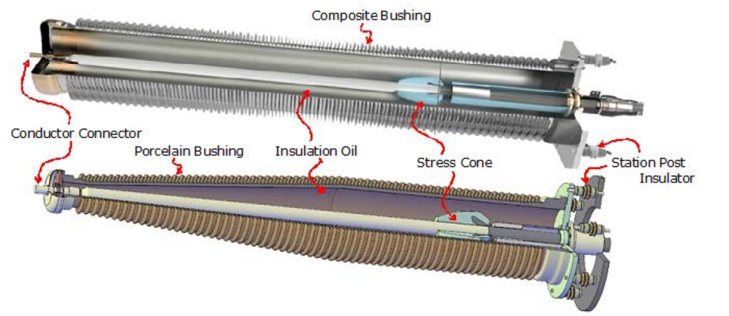


Figure 2-7. Construction of EHV XLPE Cable Termination

3 Construction Methods and Installation Practices

3.1 Conduit and Manhole Systems

Worldwide, the most common installation technique for insulated cables is by direct burial or installation in a tunnel. Although direct burial is lower in cost, in North America the preferred installation method especially in urban areas is the duct and manhole system installed by open cut trenching. Duct and manhole systems have several advantages including easier coordination with cable system installation, high protection for the cables due to concrete encasements of conduits, and in the event of a fault, cables can be removed from conduits without need for excavations. The process starts by excavating the trench, PVC, FRE or HDPE conduits are installed in the trench using plastic spacers to achieve the design configuration, concrete of 1,500 to 3,000 psi compressive strength is then poured over the conduit assembly, Figure 3-1, and the trench portion above the concrete is then backfilled with clean excavated material or a thermal backfill consisting of weak mix of thermal sand, cement, and water.

Figure 3-1. Conduit Installation

Direct Buried Systems

Direct buried systems, although not common in North America, have been used with success in Europe, the Middle East, and other parts of the world. It has a lower installation cost than the duct and manhole systems and it is more flexible since trenches can be opened to match the cable reel lengths.
It also produces high ampacity for the same cable size as since it is thermally more efficient in eliminating the thermal resistance of the conduit and the thermal resistance of the air space within the conduit. Plus cables can be spaced closer together thus minimizing trench size requirements. The main disadvantage is that the entire system has to be abandoned when the cables have reached their useful service life. For the installation process, after excavations, a layer of well graded sand or low thermal resistivity material or

Figure 3-2. Direct Buried 275-kV Joints

fluidized thermal backfill is placed at the bottom of the trench, the cables are then pulled in the trench on rollers and spaced to required dimensions, a low compressive strength and low thermal resistivity material consisting of fluidized thermal backfill or cement bound sand is placed over the cables, concrete caps are installed over the cables' envelope, and the trench is finally backfilled with the excavated soil.

3.2 Tunnels [24]

There are two types of tunnel installations consisting of deep tunnels and shallow tunnels. Deep tunnel installations have been used in metropolitan areas such Tokyo, London and Berlin in lieu of open cut trenching to avoid severe traffic impacts on congested roadways. Deep tunnels are usually installed 200 to 400 feet below grade by the use of tunnel boring machines or TBM and are usually 10 feet in diameter. Shallow or box type tunnels are installed by open cut trenching and consist of precast concrete sections having rectangular cross sections. Shallow tunnels are lower in cost than deep tunnels and allow heat to dissipate from the tunnel through the soil to ambient but forced air cooling is still required. Figure 3-3 shows the box tunnel for a 400-kV XLPE cable installation.

Figure 3-3. Shallow Box Tunnel for 400-kV Installation

3.3 Transitions

There are two methods to terminate or transition cables: poles and compounds. Poles are normally used up to 230kV and require less area and are used for hybrid lines which contain cable sections. At 345-kV and above terminal compounds or transition stations are required due to the size and weight of cable terminations which would make installation on poles impractical. Terminal stations require more land and fencing but can accommodate multiple circuits and additional equipment such as breakers and shunt reactors. Pipe type cables, at least at one end, require a terminal compound for installation of oil pumping plant and associated oil tank. Figure 3-4 shows a transition station for 4-500-kV XLPE cable circuits.

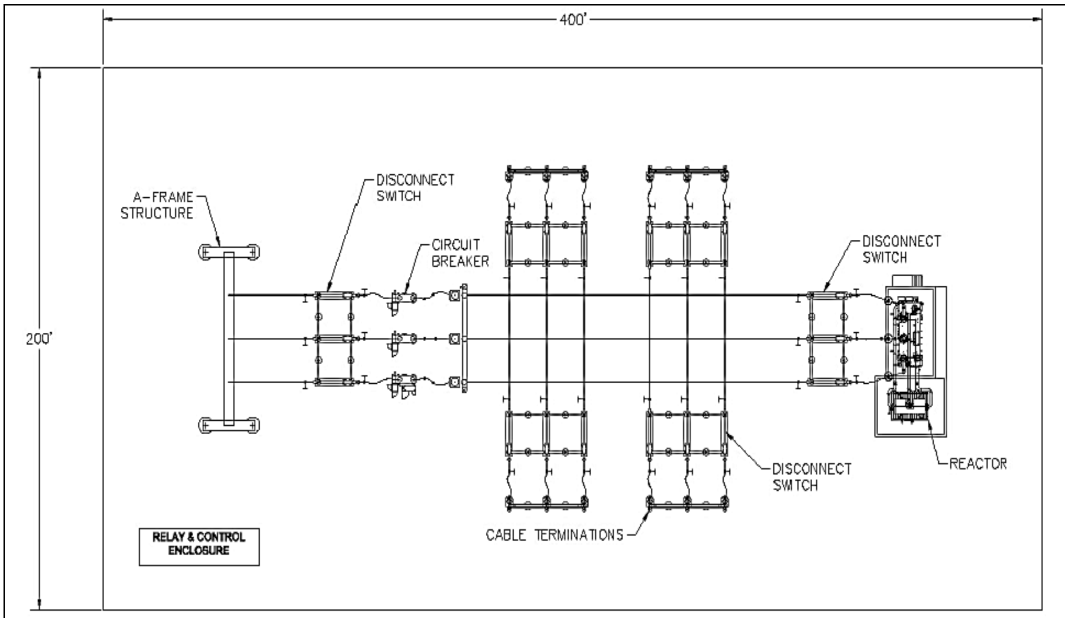


Figure 3-4. Layout of Transition Station for 4-500-kV OHL to UGL

4 Planning and System Considerations

4.1 Routing

As indicated previously, cable systems are in most cases constructed in heavily urbanized areas through public established corridors such as thoroughfares. Cables are not well suited along routes with large elevation changes such as mountainous areas. Available space for installation may still be constrained by other underground utilities. For installation in non public ROW trenches, temporary easements and permanent easements of 20 to 80 feet would be needed depending on the number of circuits. Constructing in urban areas poses impacts such as noise, road closures, impact to residents in terms of access and impact to businesses for access and parking. Figure 4-1 shows width requirements for one trench which can have multiple circuits.

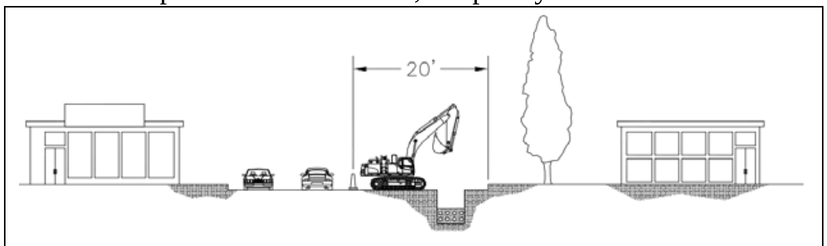


Figure 4-1. ROW Requirement for Single Trench Installation

4.2 Critical Circuit Length of UGL [25]

For overhead lines, air acts as the insulating medium. Cables, however, require dielectrics such as Kraft paper, PPLP, and extruded plastics such as XLPE. As a result, cables exhibit much higher capacitance and charging current than overhead lines. The charging current can be substantial and will cause heating thus limiting the circuit length based on the following:

$$P_L = \sqrt{S_G^2 - (w\, C\, L\, V^2\, 10^{-3})^2}$$

where

P_L = active power at load receptor (MW);
C = capacitance per unit length (μF/km);
V = line (phase to phase) voltage (kV);
S_G = apparent power at injecting point (MVA)
$w = 2\pi f$, f = system frequency
L = length of cable (km)

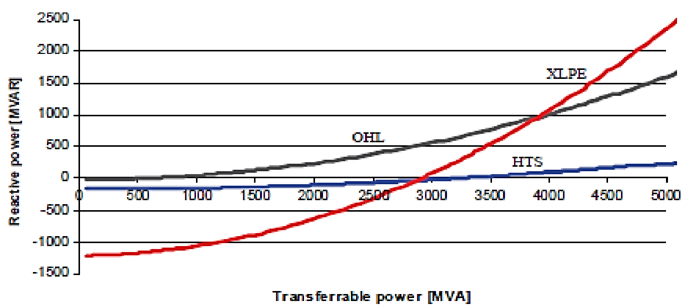


Figure 4-2. Transferable Power for 380-kV OHL XLPE UGL & HTS

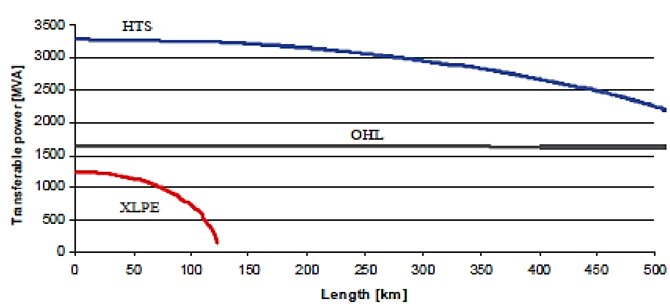


Figure 4-3. Critical For 380-kV OHL, XLPE UGL & HTS

Figure 4-2 shows the transfer capacity while Figure 4-3 shows the critical line length for a 380-kV OHL, 380-kV XLPE UGL and HTS system [26]. To increase the maximum XLPE cable circuit length, VAR compensation would be needed when the real power transfer is reduced to 80% of the thermal capacity of the UGL. For the 380-kV XLPE cable system this length would be approximately 70 Km or 43 miles as shown in the Figure 4-3.

4.3 Electrical Characteristics Comparison of OHL and UGL and Reactive Compensation

OHL have characteristic impedance of about 300 Ω while for UGL, it is in the order of 50 Ω due to differences in both inductance and capacitance. The capacitance of UGL is at least 15-20 times higher than OHL while the inductance ranges between 0.25-1 times that of OHL as shown in Table 4-1 for 230-kV circuits [27]. Consequently, the capacitive reactive power of a cable system becomes a critical factor particularly for the highest voltages. The high capacitance of cables can impact steady state voltages through the power system plus the flow of charging current can cause high system voltages due to the voltage rise over external impedances which under light loading system conditions may exceed 110% of the nominal rating and possibly exceed the rating of other system components. Charging currents will reduce the real power that can be transmitted through a UGL due to energy losses and limit circuit length. Thus, shunt reactors must be added to compensate for 50 to 60% of the MVAR produced by the circuit capacitance.

PARAMETERS	UNIT	50 MILE CIRCUIT			
		OHL	UGL		
			HPPT	XLPE	GIL
Shunt Capacitance	µF	0.8	21.5	13.0	4.4
Series Inductance	mH	100	35	50	18
Series Reactance	Ω	38	13	19	7
Charging Current	A	38	1076	648	222
Dielectric Loss	kW	-	1070	25	-
Reactive Charging	MVA	15	429	258	88
Capacitive Energy	kJ	13	379	228	78
Surge Impedance	Ω	365	40	62	63
Surge Impedance Loading	MW	145	1311	851	836

Table 4-1. Characteristics of 230-kV OHL and UGL

4.4 Power Transfer and Load Rating Capability

OHL have higher continuous rating than UGL for the same conductor size but their thermally limited in overload capability which is in minutes. Cables, however, are thermally limited in continuous capacity but have overload capability of several hours which is due to their very long time constants which could be in the 30-300 [28] hours resulting from the high heat capacity of the cable components and surrounding earth Therefore, in hybrid configurations where cables are in series with an OHL, and due to the fact that the system is normally operated 50 to 70 percent loading of continuous rating the cables could be overloaded for hours at the emergency rating of the OHL which allows for enough time for corrective action to be taken during abnormal system conditions [29]. Figure 4-4 shows two UGL with a larger conductor (Cable No. 1) and smaller conductor (Cable No.2) which would meet the required ampacity of the OHL.

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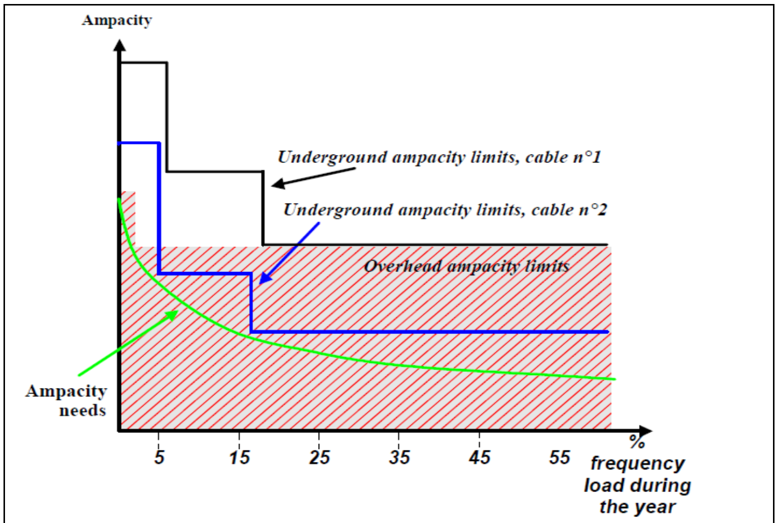

Figure 4-4. Overload Capacity of OHL and UGL

4.5 Overvoltages and Insulation Coordination

Overvoltages and insulation coordination are critical considerations for EHV hybrid lines which contain both OHL and UGL sections. The overvoltages are generated by injection of charges into line conductors or by rapid variations of the electromagnetic field in the proximity of the EHV system. Typical sources of overvoltages are lightning strikes on overhead conductor or equipment, lightning strikes on the ground wires or towers which are followed by flashovers onto line conductors, switching surges and temporary overvoltages. For hybrid systems, the cable section is protected by placing zinc oxide arresters at one or both ends of the cable section depending on length and level of protection. The zinc-oxide arresters are resistive components with non-linear voltage-current characteristics. During an overvoltage condition, as the voltage builds across the arrester, its characteristics transition from a resistive to a conductive state to dissipate the surge energy [30].

5 Design Considerations

5.1 Ampacity and Thermal Resistivity

The electrical ampacity rating of an overhead transmission line is dependent upon the physical and metallurgical characteristics of the installed conductor and the vertical clearances between the conductor and ground and/or other objects. The conductor temperature rise above ambient temperature is a thermodynamic heat balance function between heat input and heat dissipation: 1) Electrical conductor resistance heating with current (Joule's effect) and solar heating and heat dissipation: 2) Wind or airflow cooling by convection and surface radiation cooling. For underground conductors, the maximum operating rating is based on the critical temperature of the dielectric material or insulation which is 90°C continuous and105°C emergency for XLPE and oil impregnated paper. The limitation comes not from the conductor but from the degradation of the insulation which leads to thermal aging and loss of life when the critical temperature is exceeded.

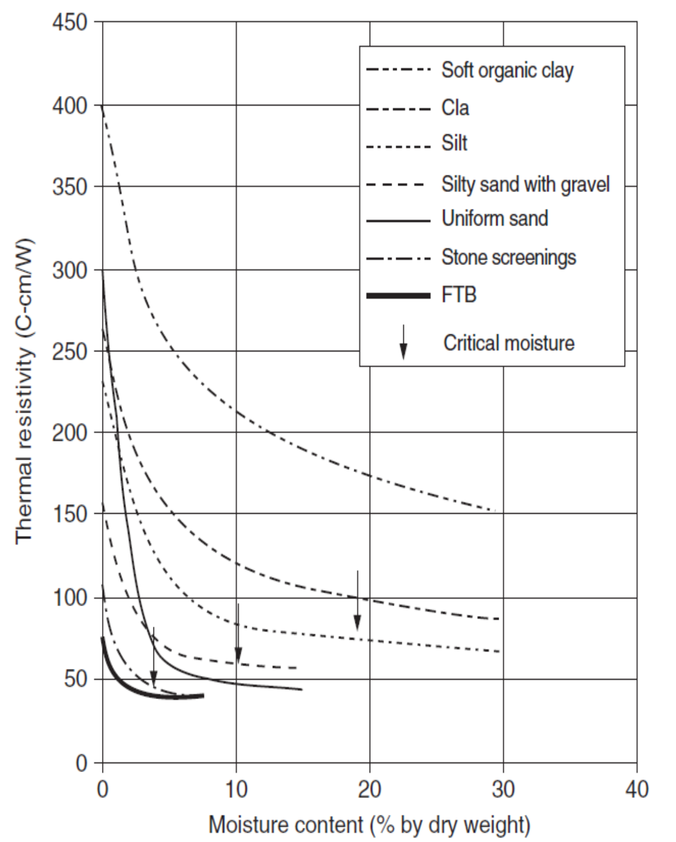

Figure 5-1. Thermal Resistivity vs Moisture Content for Soils

The ampacity modeling takes into account the demand resistive losses in the conductor and cable metallic shielding, the energy loss in the insulation, the thermal property of backfill materials, the thermal characteristics the surrounding earth, depth of burial and ambient earth temperature [31]. The heat generated by losses in the cable must flow to ambient earth through backfills and native soils and their thermal properties, Figure 5-1, can have a significant impact on ampacity [32].

5.2 Thermo-Mechanical Design [33]

Thermo-mechanical design is critical to assure overall reliability and will require analysis of the cables expansion with loading, downhill movement of the cables on slopes, the methods of controlling the cable expansion and thrust forces, and the restraining or fastening of the cables to prevent downhill movement. The cable will expand and contract with the daily load cycle and the expansion, m, can be calculated as shown in Eq.5-1 below a critical temperature, t_c, as given in Eq. 5-2. For installation in duct and manholes systems, cable can be installed in rigid, semi-flexible and flexible configurations. For rigid installations, the expansion will occur in the duct line and the conduit inner diameter should be at least 1.5 times the inside diameter of the cable [34]. For semi-rigid and flexible systems the cables are trained in offsets which must be designed to absorb the cable expansion without exceeding the maximum strain for the metallic covering on the cable and the minimum allowable cable bending radius.

$$m = \frac{(EA \propto t - 2K)^2}{2EA\mu W}\ mm \quad Eq.5-1 \qquad for\ t \leq t_c \qquad t_c = \frac{Wl + 2K}{EA\alpha}\ °C \quad Eq.5-2$$

where

t_c = critical temperature, °C, Eq. 5-2	t = daily change in conductor temperature, °C
m = daily cable expansion, mm	E = Young's modulus of elasticity, Kgf/mm^2
α = coefficient of expansion, /°C	t = daily conductor temperature change, 20°C
μ = coefficient of friction	W = weight of cable, Kg/m

For semi-rigid systems where the joint is fixed in place, the strain on metallic coverings can be calculated from Eq. 5-3.[35]:

$$e = \frac{8rLFm}{(L^2 + F^2)^2} \qquad Eq.5-3$$

where

e = strain, %	r = radius over cable metallic covering, mm
L = length of cable offset, mm	F = width of cable offset, mm

Limiting values of strain are 0.1% for lead, 0.15% for copper copolymer laminates, 0.15% for aluminum copolymer laminates, and 0.275% for corrugated aluminum [28] [30]

5.3 Electromagnetic Fields (EMF) from OHL and UGL

OHL generate both an electric field whereas UGL only generate magnetic field due to the shielding effect of metallic coverings and this field is generally "lower" then OHL, Figure 5-2, due to closer spacing of the cable phases. These two factors are used to drive requests for undergrounding because of major public concern with perceived health related effects such as childhood leukemia and cancer resulting from epidemiological studies. The values shown in Figure 5-2 are not directly applicable to other situations, since magnetic fields are a function of phase arrangement and spacing, number of circuits, currents in conductors and the screens or groundwires. [12]

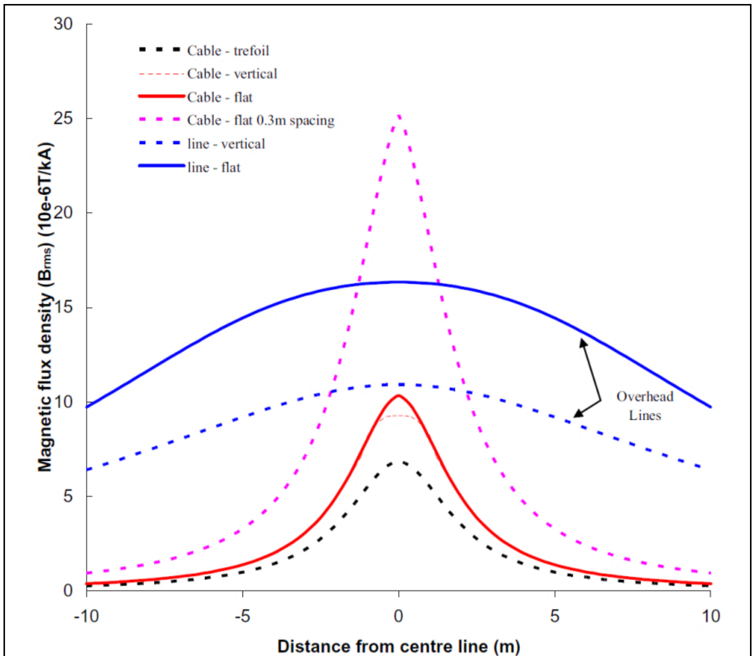

Figure 5-2. Magnetic Field from OHL and UGL

6 Control of Induced Sheath Voltages

Alternating currents flowing into the cable conductors induce voltages in the metallic covering of the cables themselves also adjacent cables. The induced voltages cause large currents in the several hundreds amperes to flow or circulate in the metallic coverings of the cables if solidly grounded since the flow is limited only by the impedance of the metallic covering. The sheath induced currents cause losses which will produce heating and reduce overall conductor ampacity. Special bonding methods [36] are necessary to limit the circulating currents and to control induced sheath voltage and these are single point bonding, cross bonding, and star impedance bonding. The universally used method is crossbonding which is shown in Figure 6-1. For efficiency of the scheme, the cables should be transposed at every splice location to balance the induced sheath voltages and the cable lengths between splice locations should be of equal length else resultant currents will flow.

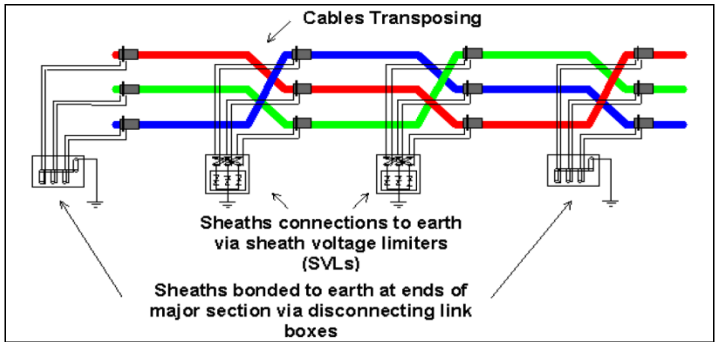

Figure 6-1. Cross Bonding of UGL with Transposition

7 Reliability and Availability

7.1 Reliability

Overhead and underground lines are inherently reliable. The two transmission systems, though, are different with respect to reliability and availability. OHL suffer from outages due to environmental factors such wind, ice accumulation, rain and fog, and seismic activity and potential sabotage with most faults being of transient nature such as insulator flashovers which are self-correcting. UGL are susceptible to "dig-ins", seismic activity, insulation breakdowns and corrosion which typically lead to forced outages. Table 7-1 provides failure rates for XLPE and SCOF cable systems from 60 to 500 kV from CIGRE TB 379 [37] and for HPPT cables from Public Service Commission of Wisconsin (PSCW) [41]. Data from PSCW has been changed to follow the CIGRE format.

Component		**XLPE CABLES (AC) (CIGRE TB 379) [37]**			**SCOF CABLES (AC) (CIGRE TB 379) [37]**			**HPPT (PSWC) [41]**
C. Failure Rate - All Failures		*60-219kV*	*220-500kV*	*ALL*	*60-219kV*	*220-500kV*	*ALL*	*ALL*
Cable	*Failure rate [fail./yr 100cct.mile]*	*0.137*	*0.214*	*0.142*	*0.175*	*0.399*	*0.240*	0.120
Joint	*Failure rate [fail./yr 100 comp.]*	*0.007*	*0.048*	*0.008*	*0.004*	*0.014*	*0.006*	0.041
Termination	*Failure rate [fail./yr 100 comp.]*	*0.011*	*0.05*	*0.013*	*0.014*	*0.028*	*0.019*	0.279

Table 7-1. Failure Rate for UGL for XLPE, SCOF and HPPT Cables

Failure rates for overhead lines as reported by the indicated references are shown Table 7-2.

Rated Voltage	**Line Miles Years (mile.yr)**	**Forced Outage Failure Rate (per 100 mile.yr)**	**Reference**
200 – 299	80,962	0.9102	Transpower [38]
300 – 399	24,125	0.1699	Transpower [38]
500 – 599V	11,903	0.8821	Transpower [38]
110-219	Not Specified	5.0	CIGRE TB 110 [39]
230-362	Not Specified	3.2	CIGRE TB 110[39]
367-764	Not Specified	1.9	CIGRE TB 110[39]

Table 7-2. Failure Rate for OHL as Reported by Indicated Reference

7.2 Availability

Circuit outages will depend on of the type of fault, involved equipment, and collateral damage. Repair times will depend on availability of spare parts, availability of trained and skilled personnel, which may need to be provided by the original cable supplier, and the availability of special tools and equipment to make the repair. Table 7-3 provides repair times as reported by the indicated references.

Cable System Type	Repair Time (days)	Reference
SCOF	29	CIGRE TB 379 [37]
XLPE	20	CIGRE TB 379 [37]
HPPT	60-270	JLARC [40], WISCONSIN [41]

Table 7-3 Repair Time for Underground Lines as Reported in CIGRE TB 379

The average yearly maintenance days per CIGRE TB110 are as shown in the Table 7-4,

		110-219 kV	220-362 kV	363-764 kV	
OHL	days	30	21	10	CIGRE TB 110[39]
UGL	days	18	27	23	CIGRE TB 110[39]

Table 7-4. Yearly Average Maintenance for OHL and UGL

8 Costs

Although cost is not a technical consideration, it is often a major consideration in the decision to underground overhead lines. The cost comparison of OH line and UG cables is not straightforward since each installation is dependent on several factors including voltage, required current rating, number of lines to meet the current rating, circuit configuration, redundancy to meet N-1 reliability criteria, geographic location, right of way requirements and land topography. Specific projects would need to be evaluated individually based on the aforementioned criteria. However, the JLARC in its report [41] found that at the median ratio of underground to overhead costs for “generic” estimates (not identified in relation to a particular kV level) was about 7.0 to 1.0 for North American-based sources and if European sources were included the ration was 10.0 to 1.0, possibly because more projects had been done in Europe. The report found that there is a general relationship between the UG to OH cost ratios based on voltage level and based on this relationship the average cost ratios are about as follows:

- 230kV - 6.1 to 1.0
- 345kV - 8.5 to 1.0
- 400kV - 9.7 to 1.0

However, there are cases where UG lines will cost less than OH lines such as in highly urbanized areas where the cost of acquired ROW would be economically prohibitive.

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Codes, Standards, Specification & Promises –

Why Details Matter in Steel Pole & Tower Fabrication!

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ABSTRACT

Very serious consequences can and do occur when attention to even the seemingly innocuous of details of Codes, Standards, Specifications & Promises (either unintentionally or intentionally) are not strictly complied with, or kept. Codes, Standards, and Specifications are written the way they are for a reason – to incorporate "consensus best practices" and/or to remedy practices that have been demonstrated to have created a structural performance problem, or worse, a structural failure. When we consider that a structural failure of a pole or tower can most often be traced back to a failure to comply with a Code, Standard, Specification or a Promises (all become human errors) we then realize how important those details can be. Whether the error was an error of knowledge/training (such as effects of a "taped edge" at the top of a below grade barrier coating); an error of performance (perhaps an incorrectly input loading condition during design, or failure to properly review a Material test report before production); or the worst of all errors, an error of intent (cutting corners – i.e. a welder's intentional failure to properly follow a developed welding procedure or the Welding Code's minimum requirements for "pre-heat" before welding on a heavy base plates); they are still human errors. We write Codes, Standards, Specifications, Guidelines, etc. in order to discuss these errors as an Industry or Company and to write instructions both to educate everyone on the problem, but also to eliminate them so that others can learn from prior errors. Simple broken schedule promises can be just as costly, if not costlier than a serious field problem if they become "surprises" to the purchaser. This presentation will briefly discuss a number of observed consequences (including structural failures) resulting from the most common deviations found to the Codes, Standards, Specifications, and Promises made. These are accumulated from investigations of structural failures, or while providing technical assistance in properly resolving errors occurring in the field during assembly and erection, and/or discovered during 3rd party inspection services monitoring daily fabrication of a Client's order in a fabricator's shop. The goal of the presentation will be to elevate awareness of the potential seriousness and risks when adherence to seemingly minute details of design and fabrication become trivialized, or promises/commitments made are broken.

Introduction

Very serious consequences can and do occur when attention to even the seemingly innocuous of details of Codes, Standards, Specifications & Promises (either unintentionally or intentionally) are not strictly complied with, or kept. Codes, Standards, and Specifications are written the way they are for a reason – to incorporate "consensus best practices" and/or to remedy practices that have been demonstrated to have created a structural performance problem, or worse, a structural failure.

For the most part, attention to details during both design and manufacturing is relatively invisible, until the events in the below images occur:



We rely on Codes, Standards, Specifications, and Promises, to make sure our lines stay structurally reliable!

As a reminder, **Codes** are a collection of <u>laws</u> or <u>regulations</u> pertaining to a specific activity or subject. Examples are:

- the National Electric Safety Code,
- The American Welding Society - Structural Welding Code.

Standards are a collection of industry consensus "best practice requirements" pertaining to a specific activity or subject. Examples are:

- ASCE Standards:
  (ASCE 48-11 Steel Pole Standard, ASCE 10-97 Tower Standard)
- AISC Standards
  (AISC 360-10 Standard Practices for Design & Fabrication)
- ASTM Standards
  (ASTM A6 ASTM A572, ASTM A123, etc.
  All material & galvanizing standards)
- IEEE Standards

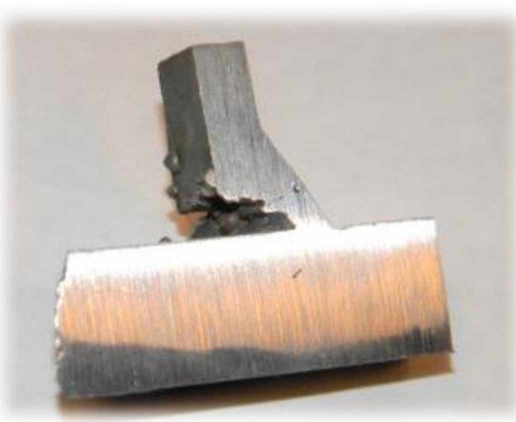
Specifications are specific instructions of workmanship, materials, etc., required to be followed to achieve a required level of performance in our pole and tower products. Each Utility generally issues a company specific specification or set of contract requirements with a purchase, and, these specifications generally reaffirm the Codes and Standards required to be followed in the fabrication of the product.

Promises are a declaration or assurance that a supplier will do a particular thing or that a particular thing will happen if they are awarded an order for their product. Examples are:

- Promise of capability
- Promise of qualification
- Promise of quality
- Promise of schedule

The "Hostage Effect"

When materials purchased don't meet the required Codes, Standards, Specifications and Promises, but project schedules or other pressures constrain actionable options on non-conforming product we have found that most Purchasers feel held hostage to the situation – hence we have termed for this and call it "The Hostage Effect". A couple of years' warranty will be long forgotten when those non-conformances potentially begin to manifest into significant performance or reliability issues.



How many times have you heard this?

"But This is the way we have always done it"[1]

When we consider that a structural failure of a pole or tower can most often be traced back to a simple failure to comply with a Code, Standard, Specification or a Promise, all failures become human errors. Only then do we realize how important those details can be. Whether the error was:

- ***an error of knowledge/training***
  (such as effects of a "taped edge" at the top of a below grade barrier coating);
- ***an error of performance***
  (perhaps an incorrectly input loading condition during design, or failure to properly review a Material test report before production);
- ***or the worst of all errors, an error of intent***
  (cutting corners – i.e. a welder's intentional failure to properly follow a developed welding procedure or the Welding Code's minimum requirements for "pre-heat" before welding on a heavy base plates);

they are still human errors. We write Codes, Standards, Specifications, Guidelines, etc. in order to discuss these errors as an Industry or Company and to write instructions both to educate everyone on the problem, but also to eliminate them so that others can learn from prior errors.

Simple broken schedule promises can be just as costly, if not costlier than a serious field problem if they become "surprises" to the purchaser.

So, if details matter so much, how can we spot suppliers of poles and towers who are paying attention to those details? What are the observable characteristics we should be looking for?

1. ***Is there a formal Project Contract/Agreement between the Owner and the Supplier:***
   What is the form of the agreement?
   What are the Codes, Standards, and Specifications the Supplier has been instructed to follow?
   Have any exceptions been taken to the codes, standards, and specifications, and were they specifically accepted by the owner????

2. ***The Owner's Specification:***
   Does the Supplier have a thorough understanding of the owner's specifications?
   Does the Supplier have a thorough understanding of other project requirements?
   Does the Owner fully understand any exceptions taken to their Specification?

3. ***What is Supplier's Quality Program:***
   What does it cover?

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[1] From a Paper: *"Powerline Tower Arm Failure Analysis", Authored by Dr. Wayne Reitz, Ph.D., PE*

Does it work? / Is it being followed?

4. ***The Supplier's Team on the Shop Floor:***
   Who are they?
   Do they appear knowledgeable?
   Are they cooperative when asked questions?

5. ***The Fabrication Drawings:***
   How are the drawings controlled?
   Do the drawings appear complete?
   How are changes to the drawings handled?

6. ***Fabrication Work Instructions:***
   Are proper WI's prepared for the various tasks in the shop?
   Are those WI's really available to all shop employees?
   Are employees trained in the WI's?

7. ***Cutting, Burning, & Welding:***
   Are the requirements of AISC, and AWS being followed?

8. ***Equipment:***
   Does the Supplier have the equipment they needs to properly do the job?

9. ***Safety & Housekeeping:***
   Does the Supplier have an adequate Safety Program in place?

10. ***Inspection & Test Equipment:***
    What testing is being done?
    Is the equipment for the testing properly certified and calibrated?
    Are those personnel doing the testing properly certified?

11. ***Material Control:***
    How is incoming material received and inspected for conformity to the specifications or other requirements?
    How is material issued and controlled throughout the shop?
    Is there traceability?

12. ***Suppliers' QA/QC Activities:***
    How are project specific requirements incorporated into the supplier's fabrication process?
    Is there a process/program in place to ensure subcontractor quality adherence to the required Codes, Standards, Specs.

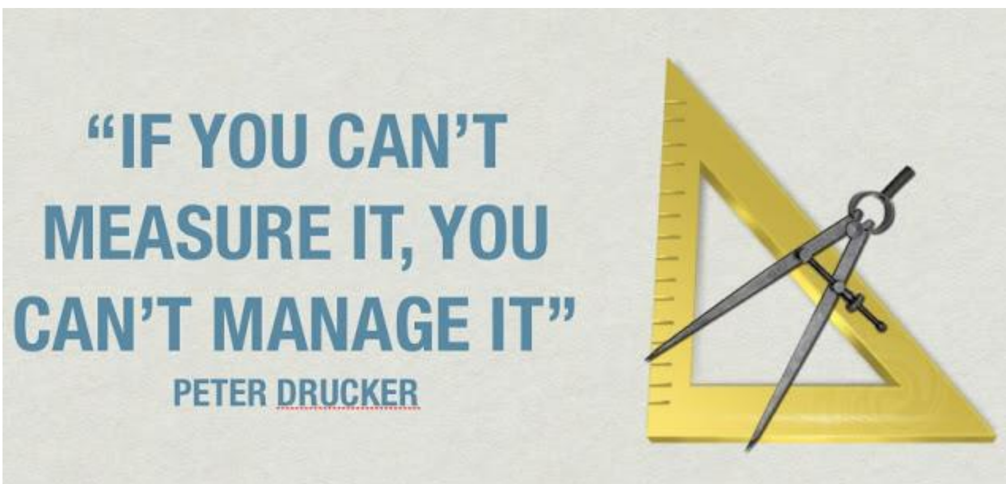
13. ***Galvanizing Requirements:***
    What does the supplier require of the Galvanizer?

How is post galvanizing UT for “toe cracks” accomplished?
How are any special galvanizing requirements communicated?
Are conformance to specification “certifications” requested?

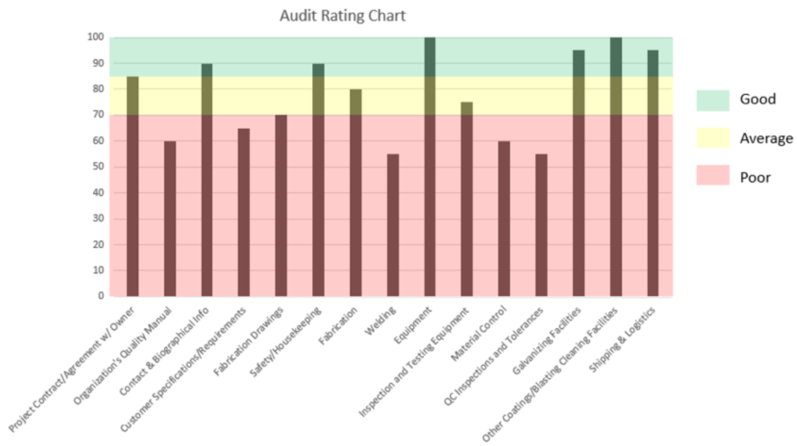
14. ***Other Finishing (Blasting/Coatings):***
    Are work instructions/procedures in place?
    Are coating materials (paints, etc.) being properly stored?
    How are Customer specific requirements communicated?
    Is verification inspection being done?

15. ***Shipping and Logistics Requirements:***
    How are any special shipping requirements communicated?
    Does it appear there are suitable “loading plans” for the safe and efficient loading/unloading of trucks?

Actionable Data



It is very extremely helpful to be able to quantify conformance to quality. Each of the 15 categories can be reduced to a “scorecard”.



From the individual category ratings, each can be "weighted" and an overall composite scorecard can be developed.

Audit Scorecard of Facility:

Date of Audit:

Section:	Item:	Rating:	Weight:	Score:	Notes (refer to summary letter and detailed notes):
1	Project Contract/Agreement w/ Owner	90	5%	4.5	
2	Organization's Quality Manual	85	2%	1.7	
3	Contact & Biographical Info	90	1%	0.9	
4	Customer Specifications/Requirements	65	5%	3.25	
5	Fabrication Drawings	70	8%	5.6	
6	Safety/Housekeeping	90	2%	1.8	
7	Fabrication	80	15%	12	
8	Welding	75	15%	11.25	
9	Equipment	100	3%	3	
10	Inspection and Testing Equipment	75	5%	3.75	
11	Material Control	60	10%	6	
12	QC Inspections and Tolerances	55	15%	8.25	
13	Galvanizing Facilities	95	5%	4.75	
14	Other Coatings/Blasting Cleaning Facilities	100	5%	5	
15	Shipping & Logistics	95	4%	3.8	
			100.00%	75.55	

Why is this important? From these scorecards, analytical trends can be determined over time. Is your supplier getting better, or worse at complying with the Codes, Standards of our industry, and the Specifications you have provided them? And, are they meeting the Promises they have made to you as a Purchaser?

What about: "We only buy from a 'trusted' manufacturer"?

Absolutely, you always should! You don't NOT have a home inspection done just because you trust the builder? It is a scientific fact that people perform better when they are being observed doing what it is that they do!

The "Hawthorne Effect" (also referred to as the **observer effect**) – Google it!

Figure 1: Hawthorne Works, CA. 1925

The most prevalent Non-Conformances our firm typically finds when "observing" in a pole or tower fabrication facility:

1. MTR's not being reviewed properly for conformance
2. Quality "Escapes" – Green Tagged product with conformance issues
3. Joint gaps too large during fit up of weld joints
4. Improper preheat being used during welding of heavy plates
5. Improperly qualified WPS's
6. Welding out of position
7. Welding out of WPS parameters
8. No repair procedures for fixing non-conforming product
9. Lack of traceability
10. Poor knowledge/training of NDT Techs
11. Lack of understanding of "Special Customer Requirements"

And all of the above is with us watching! What happens when no one is???

Conclusion:

There is potential seriousness and risks when adherence to seemingly minute details of design and fabrication become trivialized, or promises/commitments made are broken. Codes, Standards, and Specifications are written the way they are for a reason – to incorporate "consensus best practices" and/or to remedy practices that have been demonstrated to have created a structural performance problem, or worse, a structural failure. The consequences of not doing so can be catastrophic structural failures.

ABOUT THE AUTHORS:

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Advanced Aerial Inspection Resources
Texas Non-Destructive Testing Academy

Mr. Oliphant began his professional career in 1974 as a Civil Engineering Officer in the United States Air Force. He has since accumulated approximately 40 years of professional experience and expertise related to the structural design, manufacturing, and inspection of wood poles, tubular steel poles, prestressed concrete poles, fiberglass composite poles, as well as lattice steel towers.

In 2010, Mr. Oliphant received the Gene Wilhoite Award presented by the Structural Engineering Institute for his significant lifetime contributions to the advancement of the "Art and Science of Transmission Line Engineering". He is also an inventor/co-inventor on seven patents related to design and manufacturing of electrical transmission pole structures.

Mr. Oliphant is a Charter Member of the Structural Engineering Institute of the American Society of Civil Engineers and a Fellow of both organizations. He is a 1974 graduate of Texas A&M University with an undergraduate degree in Civil Engineering, and a 1987 graduate of the University of Houston with a graduate degree in Business Administration. He is Registered Professional Engineer in the state of Texas as well as an American Welding Society, Certified Weld Inspector.

Zachary J Oliphant

Principal, President
ReliaPOLE Inspection Services Company, Inc.
Advanced Aerial Inspection Resources
Texas Non-Destructive Testing Academy

Upon graduation from Baylor University in 2002, Mr. Oliphant, was a founding member of ReliaPOLE Solutions, Inc. Mr. Oliphant has had an integral role and involvement in various aspects of the Utility Structures business and upon acquisition by Trinity Industries took a leadership role over the distribution and lighting segment of the business. In 2012, Mr. Oliphant moved into a Director of Sales role and had national sales responsibility for the entire business unit. In 2013, Mr. Oliphant was promoted to Vice President of Sales for the Trinity Poles business unit. He was heavily involved in the pre and post-acquisition integration of the $600M purchase of Meyer Steel Structures business unit from ABB. In May, 2015 Mr. Oliphant left Trinity Industries to take over as President of ReliaPOLE Inspection Services Company, Advanced Aerial Inspection Resources, and Texas Non-Destructive Testing Academy.

Insulation Coordination Analysis for Substation Surge Arrester Applications

Hardik Parikh

Not Available for Publication

3-D Scanning & Design for Substations

Mark Tablante
Cary Gallaway

Not Available for Publication

The Development and Implementation of a Vibration Mitigation Solution for Tubular Guyed-V Structures

Mark H Fairbairn
Richard Slocum

Not Available for Publication

Thermal Mechanical Testing on Single Stage ACSR Fittings

Daniel Stanton
Eyass Khansa

Not Available for Publication

Safety Maintenance Requirements for Circuit Breakers

James White

Not Available for Publication

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