Southwest Power Pool Regional Entity

Southwest Power Pool

REGIONAL ENTITY TRUSTEES MEETING

July 29, 2013

Marriott City Center

Denver, Colorado

A G E N D A

8:00 a.m. – 12:00 p.m.

1. Call to Order/Introductions .... Emily Pennel
2. Antitrust Guidelines .... Emily Pennel
3. Approval of Meeting Minutes – June 18, 2013 .... John Meyer
4. CIP Transition V3-V5 *(via phone/webex)* .... Kevin Perry
5. Discuss Recall of Regional UFLS Standard .... Ron Ciesiel
6. Long Term Reliability Assessment .... Debbie Currie

   Action Requested: SPP RE Trustees accept LTRA
7. Facility Ratings Alert Update .... Debbie Currie
8. Staff Reports

   8a. General Manager's Report .... Ron Ciesiel
   8b. Enforcement Report .... Jimmy Cline
   8c. Compliance Report .... Ron Ciesiel
9. NERC Operating Committee Report *(via phone/webex)* .... Jim Useldinger
10. NERC Committee Representative Written Reports - Comments or Questions

    10a. Planning Committee .... Noman Williams
    10b. Compliance and Certification Committee .... Jennifer Flandermeyer
    10c. Critical Infrastructure Protection Committee .... Robert McClanahan
    10d. System Protection and Control .... Lynn Schroeder
    10e. Interchange Subcommittee .... Jeremy West
11. Staff Written Reports - Comments or Questions

    11a. Staff Goals and Metrics .... Ron Ciesiel
    11b. Year-to-Date Financial Statement .... Ron Ciesiel
    11c. Outreach Activity .... Emily Pennel
    11d. Summary of Recent System Events .... Debbie Currie
12. New Action Items .... Emily Pennel

13. Future Meetings .... John Meyer

October 28 - Little Rock

SPP Regional Entity Antitrust Guidelines

It is SPP RE's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or which might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

Southwest Power Pool Regional Entity

Southwest Power Pool

REGIONAL ENTITY TRUSTEES MEETING

JUNE 18, 2013

SPP CORPORATE CENTER, LITTLE ROCK, ARKANSAS

- A G E N D A –

8:00 a.m. – 12:00 p.m.

Meeting Materials

1. **Call to Order, Introductions** ....John Meyer
2. **Antitrust Guidelines**..Emily Pennel
3. **Approval of Meeting Minutes – Jan. 28, 2013** ....John Meyer

The meeting was called to order at 8:00 a.m. The Trustees approved the April meeting minutes with no discussion.

4. **SPP RE 2014 Business Plan and Budget** .... Ron Ciesiel

The draft 2014 budget is $11.8 million; the largest budget item is Compliance Enforcement/ Organization Registration, followed by Reliability Assessments/Performance Analysis. The Training/Education budget item is for SPP RE's outreach to Registered Entities; it does not include internal staff training or the RTO's training program. Chairman Meyer noted the importance of education and outreach. As we move toward a greater focus on Event Analysis, we have shifted some budget dollars to the Performance Analysis budget.

We are projecting a small decrease in full time equivalents, as we've seen a decrease in violations (down 30% from 2011) and as the UFLS regional standard project concluded. Most other REs currently have a flat or decreasing personnel budget.

Our SPP, Inc. indirect expenses have increased. SPP, Inc. provides services such as IT, Accounting, Human Resources, and building space to SPP RE. For these services, SPP, Inc. bills us with a per/hour overhead rate. When SPP completed the new facility, the overhead rate increased, resulting in an annual increase of $400,000 to SPP RE. This overhead charge is one of the largest items in the budget, along with salaries. The overhead formula was approved by FERC.

Assessments will be up 8%. There is a two-year lag on budget adjustments to assessments and a one-year lag on penalty collection; these lags causes SPP RE's budget to increase/decrease from year-to-year. Some regions are considering a rate conciliation effort to balance these annual swings.

We have allocated an increased amount for a hearing, should one occur. We are undergoing a hearing currently, and expenditures are running higher than expected. Consulting costs are down. Staff has a goal to reduce consulting expenses as staff matures, though we will continue to use contractors to assist with audits. Travel is also down. Direct expenses are down $152,000 and indirect expenses are up $460,000, for a total increase of $309,000.

We are reaching a fully deployed organization for 2013-2015, presuming violations stay at the current level and pending the new CIP standards.

The SPP RE Trustees unanimously approved the SPP RE 2014 Business Plan & Budget, subject to adjustment for violation penalty payments received prior to July 1, 2013, plus any other non-substantive changes required for filing with NERC.

All RE budgets will be submitted to the NERC Board of Trustees for approval August 15.

5. **Regional Standards Development Process Manual** ....Emily Pennel

The Trustees heard a presentation from the Standards Process Manual Task Force (SPMTF) on the group's revisions to the Regional Standards Development Process Manual (Manual). The Trustees reviewed the draft revisions, ballot results, and affirmative advisory votes from the MOPC, Board of Directors, and Members Committee.

The Trustees unanimously approved the revised Manual for submittal for NERC for approval.

The Trustees consider the Manual's language - "within the SPP RTO or RE region" - to include any entity within any of the SPP, Inc. footprints or any entity that has any active business interests within any of these footprints. The Trustees understand that SPP RE staff will make the decision as to whether Registered Ballot Body participants meet the Manual's segment criteria.

6a. **General Manager's Report** .... Ron Ciesiel

SPP RE and the other REs have implemented a pilot program for the new standardized Audit Lifecycle Template; most related changes are internal. A standardized auditor handbook is under development and is expected to be rolled out in September.

FERC postponed implementation of the Bulk Electric System (BES) definition for a year, until July 2014. Registration issues, Rules Of Procedure changes, and other related issues are also being pushed out to next July. FERC asked for further examination of sub-100 kV facilities' impact on the BES. In SPP, we already have sub-100 kV systems in our planning models and are aware of BES impacts. SPP RE hasn't registered any sub-100 kV facilities.

6b. **Enforcement Report** .... Joe Gertsch

Ninety incoming violations have been issued YTD in 2013. We are still seeing more CIP than 693 violations. So far in 2013 we have sent 11 settlements, 16 dismissals, and 26 Find, Fix, Tracks (FFTs) to NERC. The active caseload is 205 violations, with a caseload index of 9.7 months. Enforcement is setting interim goals to ensure violations are being processed timely.

There are currently 70 open High Impact violations; we work with the impacted entities to mitigate these expeditiously due to their higher impact on BES reliability. Chairman Meyer noted the importance of mitigating these High Impact violations to maintain reliability. Mr. Ciesiel noted we would prefer that entities recognize and fix issues rather than being forced to fix them through the Compliance Monitoring and Enforcement Program (CMEP). A violation's duration now has a higher impact on penalty determination than in the past. Cooperation credits are also considered during penalty determination.

Chairman Meyer asked Mr. Gertsch to begin noting in his monthly Enforcement report how many High Impact violations are CIP or 693.

We have reduced consultants' assistance with mitigation plans and are processing them in-house. We cannot submit a violation to NERC unless the entity has a mitigation plan that has been accepted by SPP RE. It is important for entities to focus on mitigation, though it was noted that an entity that believes it is not at fault may not want to complete a mitigation plan. Mr. Gertsch said that a mitigation plan is not an admission of guilt. Chairman Meyer noted that industry should explore how we can revise the CMEP to encourage expedited mitigation.

6c. **Compliance Report** .... Ron Ciesiel

We are still in a state of flux regarding the transition to CIP Version 5; we will hopefully have a clearer path at the July Trustee meeting.

Once the BES definition exclusion process opens in 2014, we expect a rush of applications. We will first process requests that would change an entity's registration.

Regarding the Reliability Assurance Initiative: we have implemented the "Paragraph 81" requirement retirements from active oversight. Reliability Standards Auditor Worksheets are being revamped to incorporate the retirements of Compliance Application Notes. NERC made an FFT filing, including suggestions to improve that process. A work team is holding focus groups to determine how we could improve the Self Report process.

The semi-annual Facility Ratings Alert reports are due from entities July 31, 2013. Mitigation of discovered issues is due one year from discovery or December 31, 2014, whichever is sooner.

We added a four-quarter rolling average to our monthly Misoperations chart. Regional operations success rates have continued to improve. Incorrect settings/logic/design errors and communications failures continue to be the highest cause of misoperations. Our region has a higher rate of communications failures than other regions. We have passed the misoperations raw data to the System Protection and Control Working Group to see if they can help determine the cause of these errors. A NERC North American Misoperations Analysis report is pending. These causes need to be studied systematically rather than just on a company-by-company basis.

6d. **Summary of Recent System Events** .... Alan Wahlstrom

The number of regional system events is dropping, which is a good qualitative indicator of improvements brought about by the CMEP. We have had eight regional events YTD but only two were categorized as Category 1 events. Six events were coded as "category 0" related to vandalism or weather. The first category 1 event was the evacuation of a control center due to fire. We developed and posted a Lesson Learned on this event. The second category 1 event was a lightning strike that caused catastrophic insulator failure on a 345 KV line, resulting in ~1,400 MW of generation loss by two entities in adjacent regions. NERC and the regions are reviewing this event.

Starting this year, we are working with NERC and the impacted entities to apply cause codes to each event. We are already seeing some trends, which is the first step in correcting the root cause, such as identifying a piece of equipment that has been involved in several events.

An Event Analysis Subcommittee developed a Winter Weather Readiness Reliability Guide that focuses on maintaining individual unit reliability and preventing future cold weather events. Another Event Analysis Subcommittee, the Trend Working Group, examined 11 cold weather events to determine common issues. Chairman Meyer noted the importance of this focus on cold weather reliability.

7a. **Staff goals and metrics update** .... Ron Ciesiel

Staff is on track with our 2013 goals and metrics except caseload maintenance, which is behind.

7b. **YTD Financial Statement** .... Ron Ciesiel

We are under-running on personnel expenses due to several open positions. We are also under-running on travel and contractors/consultants. Once the positions are filled, the indirect expenses from the overhead charge will increase.

7c. **SPP RE Outreach Activity** ....Emily Pennel

We have had 583 "plays" on our video series YTD. We taped four sessions at the CIP workshop that will be posted soon. There were 172 stakeholders who participated in the CIP workshop. We are hosting a webinar June 27 on EOP-003 and PRC-006 Standards Effective October 1, 2013.

7d. **Past Action Items** ....Emily Pennel

The three action items from the April meeting were completed.

8. **New Action Items** ....Emily Pennel

We did not create any new action items.

9. **Future Meetings** ....John Meyer

July 29, 2013 - Denver
October 28, 2013 - Little Rock

The meeting was adjourned at 12:16 p.m.

Respectfully submitted,

Emily Pennel
SPP RE Trustees Secretary

SPP Southwest Power Pool

Southwest Power Pool

SPP REGIONAL Entity Trustees **MEETING**

June 18, 2013

ATTENDANCE LIST

Name	System
Darrell Piatt	FERC
Stacy Duckett	SPP
Sheila Scott	SPP RE
Emily Pennel	SPP RE
Steven Keller	SPP RE
Joe Gertsch	SPP RE
Kevin B. Perry	SPP RE
Alan Wahlstrom	SPP RE
Dave Christiano	RE Trustee
John Meyer	RE Trustee
Gerry Burrows	RE Trustees
Ron Ciesiel	SPP RE
Jimmy Cline	SPP RE
David Douglass	KCPL
Don ~~[illegible]~~ Schmit	NPPD
John Allen	Springfield
Ingrid Rayo	BMcD
Chris Parr	Board Public Utilities for Unified Gov't KC
Chris Haley	SPP
Bryan Kauffman	AEP

Mark Robinson	SPP
Noumvi Ghomsi	Public Service Commission MO
Kim Van Brimer	SPP

CIP Version 5 Transition

SPP RE Trustees Meeting

July 29, 2013

Kevin B. Perry
kperry.re@spp.org · 501.614.3251

SPP Southwest Power Pool Regional Entity

Agenda

- Background
- Version 5 Transition Guidance Overview
- Approach Options

- Additional Information Included With Presentation

Background

- CIP Version 5 is pending
  - FERC issued a Notice of Proposed Rulemaking on April 18, 2013.
  - Concerns with:
    - Asset categorization approach
    - Identify, assess, and correct language
    - Low impact BES Cyber System controls
    - 15-minute impact qualification
    - Maintenance laptops
    - Implementation plan schedule

Background

- CIP Version 5 Approval
  - Unknown when FERC will approve CIP Version 5.
  - Commissioner LaFleur comments suggest FERC wants to approve Version 5 before Version 4 becomes effective.
  - If Version 5 is approved before the Version 4 effective date, Version 4 will be rescinded and entities will remain on Version 3 until Version 5 becomes effective.
- Registered Entities are looking for timely transition guidance.
  - Provisions need to be made to allow transition.

Version 5 Transition Guidance Overview

- Latest proposed guidance document provided by NERC on July 17, 2013.
  - Effective upon issuance until Version 5 enforcement date.
  - Will supersede V4 guidance released April 11, 2013.
  - Draft guidance has undergone significant changes since initial proposal.
  - Currently offers three approaches.
  - Currently includes a provision for removal of Critical Assets no longer deemed Critical based on selected approach.

Version 5 Transition Guidance Overview

- Proposed Transition Guidance includes plan for transition implementation study.
  - Six to eight voluntary participants.
  - Collect and evaluate CIP Version 5 implementation experiences. Issue report end of 1Q 2014 addressing:
    - Effective methods, approaches, and policies for technical controls implementation
    - Effective tools, policies, and training for employee skills alignment
    - Hurdles encountered and their outcomes
    - Implementation difficulties with requirements and concepts

Transition Period Approach Options

- Three approaches to choose from.
  - Status Quo: Continue to maintain a valid CIP Version 3 Risk Based Assessment Methodology.
    - Risk based evaluation criteria required
    - Risk basis must continue to be demonstrated
  - Alternative 1: Adopt the CIP Version 4 Bright-Line Criteria in its entirety.
    - Replaces Risk Based Assessment Methodology – entity will not have to maintain methodology document or risk-based justification of evaluation criteria
    - Previously published V4 transition caveats apply

Transition Period Approach Options

- Three approaches to choose from (continued).
  - Alternative 2: Utilize the CIP Version 5 Bright-Line Criteria impact ratings to identify Critical Assets.
    - Replaces Risk Based Assessment Methodology – entity will not have to maintain methodology document or risk-based justification of evaluation criteria
    - High and Medium impact assets will be identified as Critical Assets
    - Cyber Assets essential to the operation of the Critical Asset will be identified as Critical Cyber Assets and be subject to CIP-003-3 through CIP-009-3
- Must assert approach used.

ADDITIONAL INFORMATION

Caveats

- Caveats for adopting Alternative 1:
  - Must adopt the Version 4 Bright-Line Criteria in its entirety, with the exception of criterion 1.4 Blackstart Resources and criterion 1.5 Cranking Paths.
    - Generation and transmission substations solely meeting Criteria 1.4 or 1.5 will not be identified as Critical Assets
  - Control Centers that control Blackstart Resources (Criterion 1.15) and/or Cranking Paths (Criterion 1.16) are Critical Assets even though the assets they control no longer are.
    - Consistent with CIP Version 5 Bright-Line Criteria treatment of these assets

Caveats

- After providing 90-days' notice to applicable third-party (RC, TP, PC, and/or PA) and receiving no objection, Registered Entities can remove Critical Assets that do not meet the applicable Bright-Line Criteria.
  - Blackstart Resources (V4 Criterion 1.4; V5 Low Impact).
  - Cranking Path substations (V4 Criterion 1.5; V5 Low Impact).
  - Other Critical Assets not meeting any of the remaining applicable Bright-Line Criteria.

Version 5 Transition Timeline Summary

- Version 5 RSAW development completed 3Q 2013.
- Transition study begins October 2013.
- Transition study completed end of 1Q 2014.
- Transition study report issued end of 1Q 2014.
- Final transition guidance issued 2Q 2014.
- Self-correcting language FERC compliance filing 2Q 2014.
- Version 5 enforcement date to be determined.

Recommendations

- If Alternative 1 is adopted, carefully read and understand the CIP Version 4 Rationale and Implementation Reference Document:

  http://www.nerc.com/docs/standards/sar/Project_2008-06_CIP-002-4_Guidance_clean_20101220.pdf

- Example – Criterion 1.15 discussion:
  - A control center or generation control center that provides critical operating functions and tasks as identified in CIP–002 must be protected per the requirements of the Cyber Security Standard. The monitoring and operating control function includes controls performed automatically, remotely, manually, or by voice instruction.

Recommendations

- Consult the SPP Engineering Department before removing any generation facility from the Critical Asset list to verify the facility is not critical under Version 4 Criterion 1.3 or Version 5 Criteria 2.3 or 2.6.
  - SPP, as the Planning Authority and/or Transmission Planner can designate Critical Asset generation.
- Consult the SPP IROL Relief Guides for identifying Critical Assets under Version 4 Criteria 1.8 and 1.9 or Version 5 Criterion 2.8.
  - The IROL Relief Guides serve as the official notice of critical Transmission Facilities identified as Critical Assets by the SPP Reliability Coordinator.

Recommendations

- Upon adopting Alternative 1 or 2, replace the Version 3 Risk Based Assessment Methodology with a document asserting adoption of the applicable Bright-Line Criteria.
  - Have the assertion document signed and dated by the CIP Senior Manager in the same manner as the required approval of the Version 3 Risk Based Assessment Methodology.
  - Include the assertion document in the annual review and approval required by CIP-002-3, Requirement R4.

Southwest Power Pool, Inc.

SYSTEM PROTECTION & CONTROL WORKING GROUP (SPCWG)

REGIONAL COMPLIANCE WORKING GROUP (RCWG)

Recommendation to the Markets and Operations Policy Committee (MOPC)

Withdrawal of PRC-006-SPP-1

Organizational Roster

The following members represent the System Protection and Control Working Group:

Rick Gurley (Chairman), AEP
Lynn Schroeder, Westar
Shawn Jacobs, OG&E
Heidt Melson, SPS
Louis Guidry, CLECO
Ken Zellefrow, CUS
Matthew Thykkuttathil, Sunflower
Brent Carr, AECC
Bud Averill, GRDA
Tom Miller, ITC Holdings
Steve Wadas, NPPD

The following members represent the Regional Compliance Working Group:

Jennifer Flandermeyer (Chairman), KCP&L
John Allen (Vice-Chairman), CUS
Louis Guidry, CLECO
Bryan Kauffman, SPS
Robert McClanahan, AECC
Caleb Muckala, WFEC
Thad Ness, AEP
John Rhea, OG&E
Lindsay Shepard, Sunflower
Tony Eddleman, NPPD
Greg Froehling, Rayburn Country
Bo Jones, Westar
Chris Lang, GSEC
Fred Meyer, EDE
Mike Murray, INDN
Doug Peterchuck, OPPD
Eric Ruskamp, LES

Background

Considering that PRC-024-1 has been approved by NERC (May 2013) and has been filed with FERC, the SPP Under-Frequency Load Shedding Standard Drafting Team (UFLS SDT) has reconsidered the benefit of the SPP Regional Standard (PRC-006-SPP-1).

One of the major benefits of the SPP Regional Standard was to involve the Generator Owners in the UFLS plan. PRC-024-1 requires the Generator Owners to coordinate their trip settings with SPP and it requires them to follow the underfrequency and overfrequency graphs that are attached to the Standard or provide evidence of equipment limitations. The SPP UFLS SDT has always understood the importance of including the Generator Owners in the UFLS plan, considering that the UFLS program is designed to activate when there is a generation-load mismatch. The enforcement of PRC-024-1 will require the Generator Owners to participate in the UFLS program and to not negatively impact a UFLS event by tripping offline during a frequency excursion.

The current draft of the SPP Regional Standard was approved by the SPP stakeholders in October, 2011. Since then, the drafts of PRC-024-1 have changed throughout the stakeholder process. Because of this, there is a difference between the generator trip zones that are required in the SPP Regional Standard versus PRC-024-1. If the SPP Regional Standard is not withdrawn, a modification will need to be made so that the generator trip zone in PRC-006-SPP-1 does not conflict with the NERC Standard.

All of the requirements that are included in the SPP Regional Standard have been included in the UFLS plan that will be adopted by SPP as the Planning Coordinator, which will be enforced by NERC through Regional Entities (SPP, MRO and SERC) through NERC PRC-006-1. Therefore, withdrawal of the SPP Regional Standard will not affect the reliability to the SPP system.

Working Group Reviews

The System Protection and Control Working Group met and discussed the removal of PRC-006-SPP-1. The SPCWG approved the withdrawal unanimously.

The Regional Compliance Working Group has also reviewed the NERC standards, SPP Regional Standard and UFLS Plan recommending that the regional standard will not be necessary to achieve the desired outcome. The diligence and work from the SPCWG will not be lost and is representative in the compliance response to the NERC standard effective 10-1-13. The RCWG voted by majority to withdraw the request for approval of the regional standard from FERC.

Recommendation

Recommend that the MOPC provide an advisory vote that PRC-006-SPP-1 be withdrawn from FERC consideration as a Regional Standard due to the fact that NERC PRC-024-1 has been approved by NERC and is waiting on FERC approval.

Approved:

SPCWG	6/12/13
	Approved unanimously
RCWG	6/25/13
	Majority approval

Action Requested: Provide advisory vote.

SPP UFLS Regional Standard

SPP RE Trustees Meeting

Denver, CO

July 29, 2013

Ron Ciesiel
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SPP Southwest Power Pool

Background

- Oct. 2011
  - SPP stakeholders approved SPP Regional Standard (PRC-006-SPP-1)
- July 2012
  - SPP RE Trustees approved SPP Regional Standard
- November 2012
  - NERC Board of Trustees adopted SPP Regional Standard
- SPP Regional Standard is pending approval by Federal Energy Regulatory Commission (FERC)

Why SPP Regional Standard was needed

- SPP Under Frequency Load Shedding Standard Drafting Team (UFLS SDT) identified the need to require Generator Owners to participate in the SPP UFLS program
- PRC-006-1
  - Does not require Generator Owners to supply data to Planning Coordinator (PC)
  - Effective October 2013
- PRC-024-1
  - Requires Generator Owners to supply data to PC
  - Was not expected for several years

Why SPP Regional Standard is no longer needed

- PRC-024-1
  - Has been approved by NERC and is waiting on FERC approval
  - Will require Generator Owners to supply generator trip settings
- All requirements in SPP Regional Standard are included in SPP UFLS Plan
  - SPP system reliability will not be affected

UFLS SDT Recommendation

- UFLS SDT recommended MOPC provide an advisory vote that PRC-006-SPP-1 be withdrawn from FERC consideration since NERC PRC-024-1 has been approved by NERC and is waiting on FERC approval
- At their July meeting, MOPC gave a favorable advisory vote for recalling PRC-006-SPP-1
- Board of Directors will provide advisory vote at July 30 meeting

2013 Long-Term Reliability Assessment

July 29,2013

Debbie Currie
dcurrie.re@spp.org · 501.688.8228

Southwest Power Pool

Assessment Staff

- David Kelley, Manager of Interregional Coordination (RTO)
- Chris Haley, Engineer Associate III (RTO)
- Debbie Currie, Lead Engineer (SPP RE)

Long Term Reliability Assessment

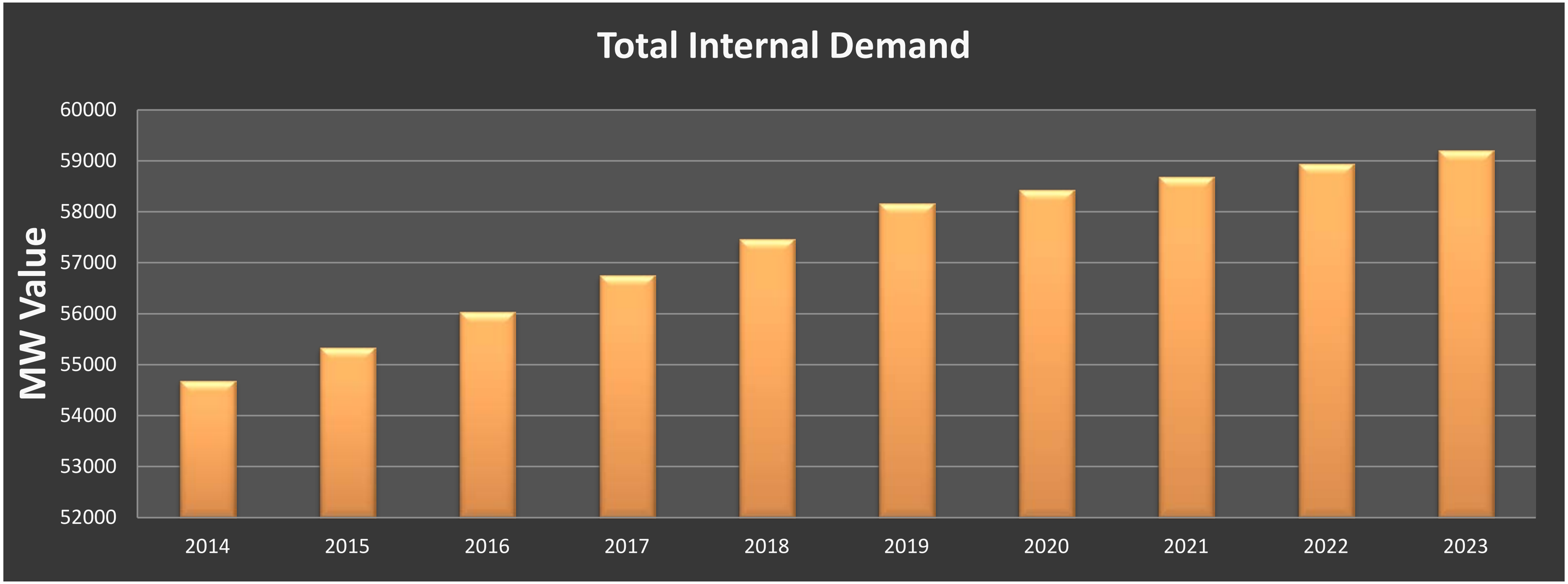
- Widely-read continent-wide publication
- Projected 10-year long-term outlook (2014-2023)
- Primary objectives:
  - Qualitative outlook of region's reliability
  - Make recommendations for mitigations/actions as needed
- Provides high-level overview for SPP RE + Nebraska assessment area
  - Demand growth
  - Capacity adequacy
  - Operational reliability

Assessment Process

- Created with data/information submitted by SPP Reporting Entities
  - Methodology changed to MDWG model data with 2012/2013 Winter Assessment
- SPP staff validates and cross-checks data to verify consistency
- SPP staff, Transmission Working Group and Operations Reliability Working Group review/validate data and develop assessment
- Assessment undergoes peer review process at NERC prior to finalization

Coincident Peak Demand

- ~54,700 MW projected 2014 Total Internal Demand
- ~59,200 MW projected 2023 Total Internal Demand
- Modest load growth projected over next ten years



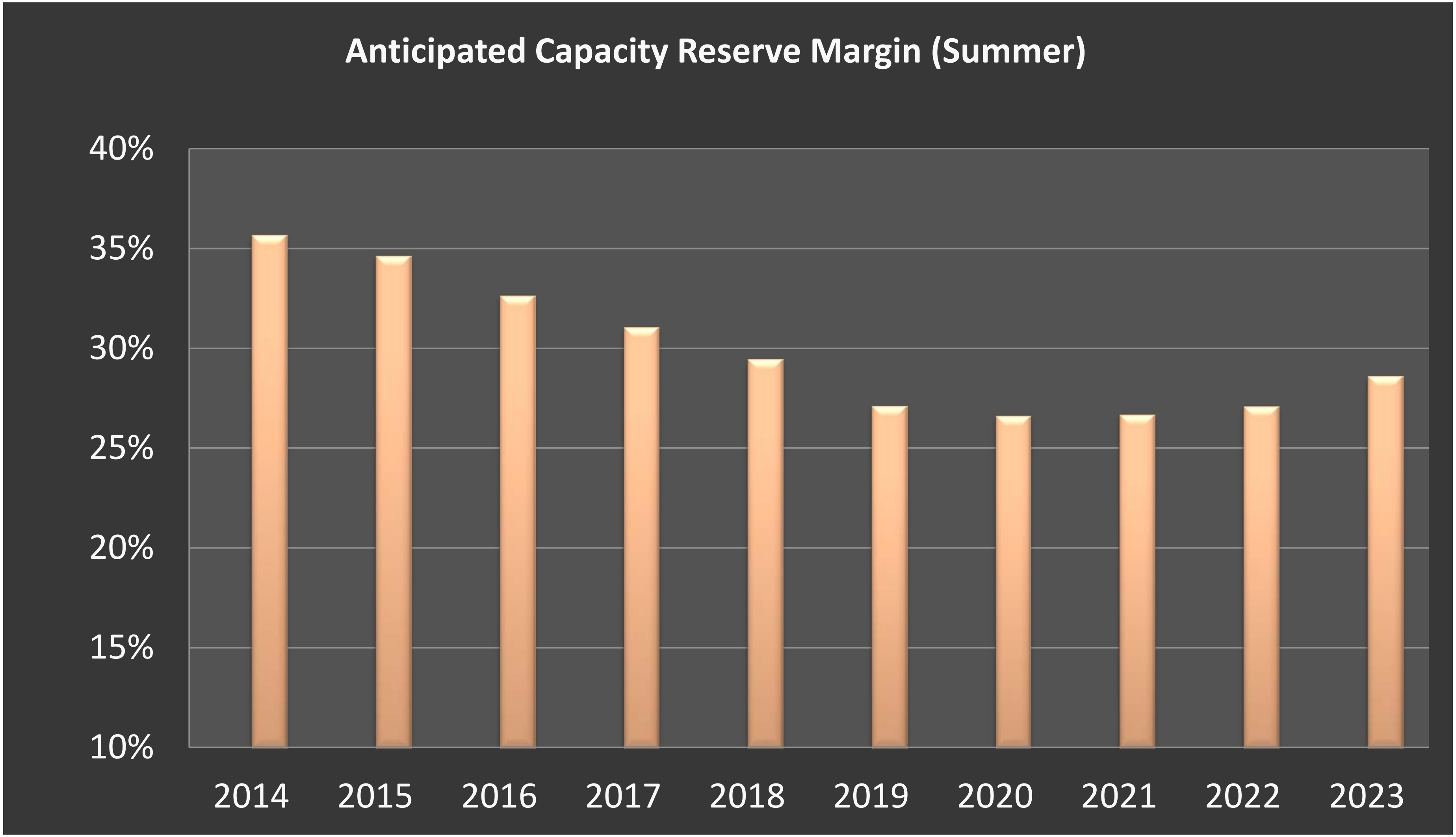
Demand Response 2014-2023

- Demand Response (DR) consists of Interruptible, Non-Controllable, and Direct Control Load Management
- 647 MW projected supply-side DR for 2014
- 624 MW projected load-modifying DR for 2014
- 952 MW projected supply-side DR for 2023
- 590 MW projected load-modifying DR for 2023

Available and Future Planned Capacity

- ~88,000 MWs Total Internal Capacity in 2014
- ~91,000 MWs Total Internal Capacity in 2023
  - Includes Existing Certain, Future Planned, Total Supply-Side Demand Response, Imports/Exports and Outages
  - Reserve margin based on expected Existing and Future Capacity Additions
- ~19,000 MWs generation (mostly wind) in Generation Interconnection queue over the next ten years

Anticipated Capacity Reserve Margin 2014-2023



Environmental Regulations

- SPP continues its new bi-annual study process
  - Four-year look ahead for reliability issues
  - Weekly snapshots through the four years
  - Scheduled outages taken into account

Reliability Assessment

- Reliability issues not expected
- Reserve margins are adequate
  - SPP members required to maintain 12% capacity margin, which translates to a 13.6% reserve margin
  - Forecasted anticipated reserve margin is ~35% in 2014, decreasing to ~28% in 2023

Transmission

- ~2,500 miles 100+ kV expected over 10-year assessment period
- Particular emphasis on western part of grid due to influx of renewable generation

Standing and Emerging Issues

- Load growth due to oil and gas drilling
  - Substantial load growth concentrated in KS, OK, TX and NM
  - Short construction time makes planning difficult
  - SPP is enhancing planning processes
- Aging Infrastructure
  - EHV transmission system is aging
  - System constructed without consideration of regional or national needs
  - Opportunity exists to manage a coordinated infrastructure replacement going forward
  - SPP in unique position to play a key role

Standing and Emerging Issues, Continued

- HVDC line proposals under consideration
  - Tres Amigas Project – planned to connect SPP, WECC, and ERCOT
    - Interconnection agreement between Tres Amigas, and SPS approved by FERC on 4/9/13
    - Phase I (750 MW) expected in service in summer 2016
  - Two Clean Line Energy projects could each add 700 miles of HVDC in different areas of SPP

Summary

- Generation fleet is diverse in terms of location, fuel type, and capability
- SPP reporting area shows modest load growth, sufficient resources, and adequate reserve margins for 2014-2023 assessment period
- Long-term challenges include oil & gas drilling and integration of variable generation

[I-1a] Southwest Power Pool (SPP) is a NERC Regional Entity (RE) that covers 370,000 square miles and encompasses all or part of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas. The SPP RE reporting footprint includes the Midwest Reliability Organization Regional (MRO) Entity members that are part of the SPP Planning Coordinator, which consists of the Nebraska entities.[1] SPP's footprint consists of 20 BA Areas including 48,368 miles of transmission lines, 915 generating plants, and 6,408 substations at 100 kV and above.

[1-1b] The SPP Reliability Coordinator (RC) is coordinating with Entergy, CLECO, Lafayette Utilities System, Louisiana Energy and Power Authority, and MISO for the transition of those entities to the MISO Reliability Coordination footprint and eventually into the MISO BA Area and the MISO Market. This transition will begin in June 2013 and continue thru December 2013. This transition into the MISO Market and BA is expected to result in significant changes in flows as compared to what has historically been observed and managed using existing congestion management processes. SPP and MISO are evaluating ways to mitigate reliability concerns from these operational changes by improving how flows are accounted and reviewing congestion management techniques for potential enhancements. These additional coordination activities are expected to continue to ensure the continued reliable operation of the interconnected transmission system.

Demand, Resources, and Planning Reserve Margins

[RM-1] The SPP RE Assessment Area's target Reserve Margin is 13.6 percent and has not changed since last year's Long Term Reliability Assessment.[2] The SPP RE is projected to have adequate Planning Reserve Margins throughout the assessment period well above the SPP Reserve Margin requirement. Due to the modest annual demand growth projected over the

[1] In 2010 NERC created a Reliability Assessment Procedure that re-aligned the reporting areas for the Regional Entities. Beginning in 2011 SPP RE assumed the reporting responsibilities of the Nebraska entities (NPPD, OPPD, and LES) that are part of the SPP Planning Coordinator. The re-alignment of footprints increased the demand forecast for the SPP RE footprint.

[2] SPP's target Reserve Margin of 13.6 percent also serves as NERC's Reference Reserve Margin.

next 10 years, the existing and planned generation in the SPP RE footprint will provide sufficient planning reserve margins each year of the assessment period.

[RM-2] Not applicable.

[RM-3] SPP has not identified any potential issues or circumstances that could result in substantial changes from these projections.

[D-1, D-2, D-3] SPP RE is showing a decrease in Total Internal Demand from 2012 to 2013. This forecast decrease in Total Internal Demand is primarily due to a methodology change in SPP RE forecasting. Beginning with the 2012/2013 winter assessment, SPP RE reported a coincident peak demand forecast based on modeling data submitted by individual entities. Previously, SPP RE reported a non-coincident Total Internal Demand forecast based on aggregated member data. SPP RE will continue to use this methodology for future demand forecasts.

The SPP RE assessment area is experiencing an increase in oil and gas drilling that is causing substantial load growth in certain areas. This load growth, from the energy sector, is primarily occurring in northern Oklahoma, southwestern Kansas, Texas, and New Mexico based on input in the High Priority Incremental Load Study that began in April 2013. Long term weather models for the SPP RE footprint show normal historical weather patterns.[3]

[DSM-1] Even though SPP RE is showing a continued annual growth in Energy Efficiency/Conservation and Demand Response programs through 2023, the overall impact to load is relatively small.

[DSM-2, DSM-3] Demand response programs in the SPP RE footprint are voluntary and are primarily targeted for summer peak load reduction use. SPP RE members primarily include their own Demand Response/Energy Efficiency programs as reductions in their load forecasts.

[3] Weather models used by SPP Members vary.

[O-3] The utilization of Demand Response resources is not vital to meeting the energy and capacity obligations of the SPP region.

[DSM-4] Three voluntary customer demand response programs have been implemented in the SPP footprint since 2009. Westar Energy launched a program in 2009 for residential and small to mid-size commercial customers. The program has more than 32,000 customers enrolled and has load reduction capacity of 27 MWs. Westar anticipates enrollment of 90,000 participants with a potential load reduction capability of 90 MW by the end of 2015. Oklahoma Gas & Electric's program began in 2010 and with 40,000 residential-customer smart meters installed, it provides up to 84 MWs of Demand response during peak hours. The newest program, Kansas City Board of Public Utilities' residential customer thermostat program will provide a demand reduction of approximately 3 MWs with 3,500 subscribers expected by the end of 2013.

[G-1] Not applicable.

[G-2] SPP RE does not expect to have any reliability issues because of the modest amount of projected retirements of approximately 400MW. With the new generation projected to come into service during the assessment period there are no operational or planning concerns at this time. There have been no project cancellations, and while some derates were reported from the previous year's assessment, they were not material.

[G-3] SPP RE relies on members to provide the information needed to model all load and generation, including any changes to generation ratings and long term outage plans. SPP RE does not designate units for seasonal availability. SPP RE does not have specific criterion to address Behind-the-Meter generation, although individual entities may net the generation from their load.

[G-4] The expected on-peak capacity values for variable generation are determined by historical performance guidelines.[4] The net capability for wind is determined on a monthly basis, and there are eight steps that outline the process for establishing net capability. Wind facilities that have been in commercial operation for 3 years or less must include the most recently available data. If MW values are not available, estimates based on wind data correlated with reference towers outside a 50 mile radius of the facility's location must be approved by the SPP RTO Generation Working Group (GWG).

The net capability for solar resources is also determined on a monthly basis via the same 8-step process applicable to wind resources. Solar data that is correlated beyond 200 miles of the reference measuring device must also be approved by SPP RTO GWG.

Facilities that have been in commercial operation for 4 years or more must include a minimum of 4 years or up to 10 years of the most recent commercial operation data available, whichever is greater. Metered hourly net power output (MWH) data may be used. After three years of commercial operations, if the Load Serving Member does not perform or provide the net capability calculations to SPP as described above, then the net capability for the resource will be 0 MW. Net capability calculations are to be updated at least once every three years.

[G-5] SPP RTO evaluates operational procedures on an ongoing basis to determine if any improvements can be made for efficiency and reliability. Because of the level of wind resources in the footprint, SPP RTO is investigating the addition of wind into its automatic security constrained dispatch calculations. This would allow SPP RTO to better manage local congestion issues where wind is the primary impacting resource. It is anticipated that SPP RTO would then be able to manage system reliability by quicker and more effective control actions.

[CT-1] On-Peak Capacity Transactions do not have a significant impact on operational reliability due to the volume of internal generation capacity available within the SPP RE assessment area.

[4] SPP Criteria, Section 12.0

[CT-2]SPP RE members reported 3,184MW of Firm Imports, 25MW of Expected Imports, 2,252MW of Firm Exports and 49MW of Expected Exports in 2014. During the assessment period, 2014 has the highest reported number of imports and exports. All of these capacity transactions have firm transmission service contracts with terms between 3 to10 years.

[CT-3] N/A

[CT-4]SPP RE members, along with some members of the SERC Region, jointly participate in a Reserve Sharing Group. Group members receive contingency reserve assistance from each other; the group does not require support from generation resources outside the SPP RE Region.[5] The SPP RE's Operating Reliability Working Group sets the Reserve Sharing Group's Minimum Daily Contingency Reserve Requirement. The Reserve Sharing Group maintains a minimum first Contingency Reserve equal to the generating capacity of the largest unit scheduled to be on line plus one-half of the capacity of the next largest generating unit scheduled to be on-line. SPP sets aside Transmission Reserve Margin (TRM) to allow for loss of the most impacting generation on each flowgate. This ensures that reserve assistance amongst members is viable.

Transmission and System Enhancements

[T-1] SPP RE has identified several transmission reliability upgrades. The following list, which is broken out by state (may cross state lines), shows a description, location, and in-service date year for these identified upgrades.

Arkansas

- 18 miles of 345 kV transmission line from Flint Creek to Shipe Road in northwest Arkansas in 2014
- 55 miles of 345 kV transmission line from Shipe Road to Osage Creek (passing near East Rogers) in northwest Arkansas in 2015

[5] While the RSG does have generation-owning members outside the SPP footprint, that generation is not expected to provide support into SPP except for intra-hour contingency events.

Kansas

- 114 miles 345 kV double circuit transmission line from Spearville to Clark Co to Thistle in southwest Kansas in 2014
- 58 miles of 345 kV transmission line from Elm Creek to Summit in north central Kansas in 2016
- 78 miles double circuit 345 kV transmission line from Thistle to Wichita in south Kansas in 2014

Oklahoma

- 76 miles of 345 kV transmission line from Northwest Texarkana to Valliant in southeast Oklahoma in 2015
- 100 miles of 345 kV transmission line from Seminole to Muskogee in central Oklahoma in 2013
- 5 miles of 345 kV transmission line from Arcadia to Redbud in central Oklahoma in 2019
- 126 miles of 345 kV transmission line from Woodward District EHV to Tatonga to Mathewson to Cimarron in northwestern Oklahoma in 2021
- 122 miles of double circuit 345 kV transmission line from Hitchland to Woodward District EHV in northwest Oklahoma in 2014
- 93 miles of 345 kV transmission line from Elk City to Gracemont in western Oklahoma in 2018
- 107 miles of double circuit 345 kV transmission line from Thistle to Woodward District EHV in northwest Oklahoma and southwest Kansas in 2014

Missouri

- 30 miles of 345 kV transmission line from Iatan to Nashua in northwest Missouri in 2015
- 181 miles of 345 kV transmission line from Sibley to Mullin's Creek to Nebraska City in northwest Missouri and southeast Nebraska in 2017

Nebraska

- 222 miles of 345 kV transmission line from Gentleman to Cherry County to Holt County in northwestern Nebraska in 2018

- 40 miles of 345 kV transmission line from Neligh to Hoskins in north central Nebraska in 2016

Texas

- 305 miles of 345 kV transmission line from Woodward District EHV in west Oklahoma to Tuco in Texas panhandle in 2014

[T-2] The most congested flowgates and areas in the SPP region are identified on a monthly basis. Some of these congested flowgates are considered longer-term transmission constraints. SPP has identified several long-term constraints in two areas and proposed transmission solutions that may help alleviate these constraints.

- In the Texas panhandle, the interface monitoring Southwest Public Service North-South lines and flowgate monitoring Osage – Canyon East 115 kV for the loss of the Deaf Smith – Bushland 230 kV is expected to be relieved with the installation of the new 305-mile Tuco - Woodward 345 kV line in spring 2014. The flowgate monitoring Osage – Canyon East 115 kV for the loss of the Deaf Smith – Bushland 230 kV is also expected to be relieved with the installation of the new Castro County – Newhart 115 kV line in spring 2015. Another constraint in the Texas panhandle is the flowgate monitoring the Grapevine 230/115 kV transformer for the loss of Elk City – Sweetwater 230 kV line, which is expected to be alleviated by installation of 38-mile Bowers – Howard 115 kV line in late 2014.

- A top long-term constraint in the Kansas City area is the flowgate monitoring Pentagon – Mund 115 kV for the loss of 87th Street – Craig 345 kV line, which is expected to be alleviated by installation of a new 31-mile Iatan – Nashua 345 kV line in June 2015.

[T-3] For the purpose of improving reliability, there are several significant transmission projects involving upgrades to existing transmission lines:

- In north-central Oklahoma, 41 miles of 69 kV line will be converted to 138 kV from Cottonwood to Crescent and from Cashion to Dover. In western Oklahoma, 44 miles of 69 kV from Anadarko to Franklin will be converted to 138 kV. In southwestern Oklahoma, the 33-mile Lindsay Flood Tap to Cornville 69 kV line will be converted to 138 kV. In central Oklahoma, 32 miles of 69 kV line will be converted to 138 kV in the Cushing area.
- In Kansas, there will be a 48-mile rebuild of a 115 kV line from St John to Medicine Lodge and 32 miles of 138 kV line from Medicine Lodge to Harper in south-central Kansas in the first five years of the assessment period. Additionally, in the last five years of the assessment period, the Kansas entities plan to rebuild the 34-mile Harper to Clearwater 138 kV line in this same area. Kansas entities also plan to rebuild 41 miles of 115 kV from Chapman–Abilene Energy Center to North Street in north-central Kansas.
- In the Texas panhandle, the 45-mile 69 kV Potter to Channing line will be converted to 115 kV during the first five years of the assessment. During the last five years of the assessment period, this line and an additional 35-mile line to Dallam is planned for conversion to 230 kV. In east Texas, 44 miles of 69 kV will be converted to 138 kV from Martinsville to Tempson.

[T-4] The following projects are considered interregional interconnection-related projects:

- Stegall Project: Add a 345/115 kV transformer at Basin Electric's Stegall substation and build a 22-mile 115 kV line from Stegall to Scotts Bluff. This project will address low voltage at Victory Hill in southwest Nebraska for the loss of the Stegall 345/230 kV transformer. This project is expected to be in-service in 2015.
- Messick Project: New 500/230 kV transformer and substation at Messick. The transformer will tie together Entergy and Cleco's systems. The project addresses the overloads of the SWEPCO International Paper – Wallace 138 kV and International Paper

– Mansfield 138 kV lines for the loss of the Dolet Hills – Shreveport 345 kV. This project is expected to be in-service in 2015.

- Shipe Road – East Roger – Kings River: This project is a new multi-line 345 kV in northwest Arkansas connecting to the underlying 161 kV system. The Kings River 161 kV termination to the existing system involves interconnecting to Entergy's system. This project is needed to address overloads on the 161 kV system in the northwest Arkansas area for the loss of the Flint Creek – Brookline 345 kV. This project is expected to be in-service in 2016.
- Gentleman – Cherry County – Holt: This project is a 345 kV multi-line project through a large portion of central Nebraska. The Cherry County – Holt 345 kV line segment is proposed to interconnect with a WAPA 345 kV line. The construction of this project is driven by reliability needs, economic needs, and the need to meet renewable policies both in Nebraska and other areas in the SPP footprint. This project is expected to be in-service in 2018.

[T-5] SPP has identified several reliability projects that have been delayed but are expected to be in-service during the assessment period. Mitigation plans and operator actions have been put into place to alleviate any reliability concerns.

[SE-1] Not applicable.

[SE-2] SPP does not currently have a UVLS program.

[SE-3] The Centennial Wind Farm Special Protection Scheme (SPS) was approved in September, 2012 to eliminate the need to curtail the existing wind farms in Northwest Oklahoma under the N-1 condition for the loss of either the Woodward District EHV or the loss of Tatonga to Northwest 345kV line. This SPS is scheduled to be removed once the expansion to the Woodward District EHV substation is completed in 2014. The plans are in place to expand the Woodward District EHV substation to breaker and a half, install a second 345/138kV bus tie transformer and construct new 345kV lines out of this substation to facilitate the operations of all of the wind farms presently connected to the system. This includes new 345kV lines to Hitchland, Tuco, and Thistle.

The Ensign Wind Farm Special Protection Scheme (SPS) was approved in September, 2011. It was designed to detect an overload on the MKEC Station – Cudahay 115kV line, which would then trip generation from the Ensign Wind Farm and alleviate the overload. This SPS is scheduled to be removed in 2014. Future construction of a second North Judson Large – Spearville line should eliminate the single contingency exposure to overloading the MKEC Station – Cudahay line and make it possible to retire the SPS.

[SE-4] SPP RTO expects to implement its Day 2 market for its RTO footprint on March 1, 2014. This market, otherwise known as the Integrated Marketplace, will centralize unit commitment across 16 Balancing Authority (BA) Areas and consolidate operations into a single BA, known as the SPP RTO Consolidated Balancing Authority. SPP RTO will provide a five-minute security-constrained economic dispatch in order to provide real-time balancing activities while also providing centralized commitment of resources through the end of the operating horizon. It is expected that this structure will better allow SPP RTO to manage the variability of load and resources and provide additional flexibility in dealing with short-term reliability issues.

SPP RTO is also investigating centralizing the data gathering from several Phasor Measurement Units (PMU) systems within the footprint in order to enhance reliability analysis and situational awareness.

[SE-5] At this time, SPP RTO is in the early stages of investigating appropriate smart grid programs.

Long-Term Reliability Issues

[RI-1] SPP RE has adequate resources. The drought currently being experienced and forecast to continue into the assessment period covers the western portion of the SPP RE assessment area. This area is generally less impacted by drought as most of the SPP RE resources that heavily depend on water are located in the eastern half of the footprint, which is not expected to experience significant drought conditions. The increase in installed variable generation composed almost entirely of wind generation, in the SPP RE assessment area will continue to cause operational challenges. These challenges arise because local area transmission congestion can occur as transmission projects are interconnected and before planned transmission upgrades are fully complete. In addition, SPP studies, which focus on reliability, are based on deterministic criteria and do not necessarily capture wind generation outlet constraints given limited power flow models and current assumptions about reduced wind output during most assessments. Beginning in 2014, a portion of the SPP footprint will consolidate into a single BA. This consolidation will provide balancing benefits for the widespread installed wind generation. Impending unit retirements are not expected to impact reliability outside of the local area. The SPP RE assessment area is capacity sufficient and is expected to continue to be sufficient even considering resource retirements.

[RI-2] SPP's Operational Planning group performs bi-annual system planning studies in order to capture potential reliability impacts of retirements and retrofits. Analysis results that reveal reliability concerns are then passed to the SPP RTO long-term planning group. This study process consists of the creation of weekly snapshots, through the next 4 years, that take into account load forecasts, known transmission, and known generation outages. Local issues found are reported to the SPP Transmission Operators involved. Since SPP RE is capacity sufficient, the impacts of long-term maintenance outages are expected to be more economic in nature. Based on the results of studies done to this point, it is expected that there will be sufficient time to perform any necessary generator retrofits.

Again, these retrofits are expected to impact the economics of generation supply more than the ability to reliably serve load across the region. Local issues may require uneconomic generation to be designated “must run” during long-term outages, but reliability is expected to be maintained.

[RI-3] Due to oil and natural gas drilling, parts of Texas, Oklahoma, Kansas and New Mexico SPP are experiencing substantial load growth on the transmission system. These loads are difficult to plan for from a transmission perspective because drilling facilities can be quickly established causing an unplanned for increase in demand. This leaves very little time to complete transmission projects to serve the pump loads when needed. Economic, regulatory, and geological issues can affect where, when, and how long new wells will be installed and operated. SPP and Transmission Owners rely on communication with entities adding load to the transmission system to accurately predict where and to what extent this load growth will occur in the future. SPP is enhancing applicable planning processes in order to plan transmission projects to support these loads.

Most of the Extra-High Voltage (EHV) transmission system across North American and the SPP region was constructed in the thirty year period between 1950 and 1980 with little or no consideration to broader regional, interregional or national needs. Because of SPP’s geographic location in the Eastern Interconnection and ties with the Western Interconnection and ERCOT, SPP is uniquely situated to play a key role in the strategic processes necessary to identify critical corridors via rightsizing key lines during rebuilds, reconfiguring grid topology as well as the potential conversion of select lines from AC to DC operation to manage congestion and improve overall grid efficiency across North America. Assessment and evaluation of this issue has just begun, therefore the LTRA reference case has not considered the potential impacts of aging infrastructure replacement and corridor planning in the SPP region.

As noted in last year’s long-term reliability assessment, several HVDC lines are being planned to traverse the SPP region. On April 9, 2013, FERC approved an interconnection agreement between Tres Amigas, LLC and Southwestern Public Service Co. (SPS) with SPP as a signatory for Phase I of the Tres Amigas project is expected to consist of a 750-MW, two-node intertie between the Western and Eastern Interconnections. Construction will include the expansion of SPS's Eddy County substation and a 73 mile, 345 kV line. The project is planned to be operational in the summer of 2016.[1]

A Clean Line Energy project, the Plain & Eastern line, is a 3,500 MW capacity, 700 mile long HVDC facility that is planned to begin in western Oklahoma and end in western Tennessee.[2] A second Clean Line Energy project, the Grain Belt Express Line[3] will consist of an approximately 700 mile HVDC transmission line that will begin in western Kansas and extend eastward through Missouri and beyond. Both of the Clean Line Energy projects remain in the planning stages.

As these projects move closer to construction and commercial operation, SPP may be faced with a large number of transmission requests. SPP may not be able to approve all of the requests until additional transmission facilities are built. However, SPP's current processes should prevent any reliability impacts to the BES. The LTRA reference case has not considered the commercial realization of these projects.

[C-1] Throughout the 10-year Assessment Period, SPP is expected to have adequate reserve margins. SPP's planning processes have identified a number of transmission projects needed for reliability purposes and it is expected that those projects will be completed as scheduled or mitigation plans will be developed. The most significant transmission challenge facing portions of the SPP footprint are related to an increase in oil & gas drilling. New oil and gas drilling facilities can be built so quickly that the resulting load increase is not sufficiently captured in SPP's planning processes and models. SPP also continues to have an influx of variable generation resources which causes operational challenges. However, SPP is enhancing the planning processes to better capture the impacts of the oil & gas projects and variable

[1] http://tresamigasllc.com/index.php
[2] http://www.plainsandeasterncleanline.com/site/home
[3] http://www.grainbeltexpresscleanline.com/site/home

generation. Given the SPP region's generation capacity, transmission infrastructure and enhancements being made to processes and models, SPP is expected to be able to meet any challenges that arise over the next 10 years including environmental regulations.

July 2013 Facility Rating Alert Update

Debbie Currie
Lead Engineer
July 29, 2013

SPP Southwest Power Pool

Background

- Facilities Ratings Alert issued by NERC in 4Q 2010
- Entities were asked to assess the physical attributes of their transmission lines and compare the ‘as-built’ to the ‘design’ ratings
- Facilities were ranked into three categories: High, Medium, and Low
- Entities began assessments and remediation efforts in 2011
- Assessments are staged over 3 years [2011 to 2013]

North America Status as of January 2013

- High Priority Facilities:
- All 76,125 high priority miles (100%) have been assessed
- All 3,519 circuits (100%) have been assessed
- 7,966 discrepancies across 940 circuits were identified
- 718 of 940 circuits containing discrepancies have been remediated
- 18 Transmission Facility Owners did not provide a projected completion date for their not-yet-remediated high priority facilities

SPP Status as of July 15, 2013 (High Priority)

- Nine entities completed High Priority Line assessments
- Over 99% of High Priority Discrepancies have been remediated
  - ~ 5,200 high priority miles assessed
  - ~ 400 discrepancies identified
  - 3 discrepancies not yet remediated

North American Status as of January 2013

- Medium Priority Facilities:
- 87,560 of 101,473 miles (86.3%) were assessed
- 5,308 of 6,284 circuits (84.5%) were assessed
- 14,993 discrepancies across 2,017 circuits were identified
- 15 Transmission Facility Owners requested and were granted extensions for completing their medium priority facility remediation

SPP Status as of July 15, 2013 (Medium Priority)

- Twelve Entities in SPP Region reported assessment results on Medium Priority Lines
  - ~ 6,100 miles assessed using Lidar, Aerial Patrol and/or Field Inspections
  - ~ 1,900 discrepancies found
  - ~13% remediated
  - One extension request for remediation granted
  - Majority of reporting entities working on medium priority discrepancy remediation

SPP Status as of July 15, 2013 (Low Priority)*

- Seventeen Entities in SPP Region reported assessment results on Low Priority Lines
  - ~ 6,700 miles inspected using Lidar, Aerial Patrol and/or Field Inspections
  - ~ 300 discrepancies found; ~38% remediated
- Large number of reporting entities did not provide an update for low priority facilities or did not complete assessment of low priority facilities following inspection
- Low Priority Assessments scheduled to be completed by December 31, 2013; discrepancies to be remediated within one year of discovery

*Preliminary Totals

Ron Ciesiel
SPP RE General Manager
Rciesiel.re@spp.org

Southwest Power Pool Regional Entity
201 Worthen Drive
Little Rock, AR 72233
P 501-614-3265

TO: SPP Regional Entity Trustees

FROM: Ron Ciesiel, SPP RE General Manager

DATE : July 29, 2013

SUBJECT: SPP RE General Manager Report

Emerging Issues

NERC Reliability Assurance Initiative [RAI]

NERC has posted a series of whitepapers on revamping a number of their processes to become more efficient and effective in carrying out its duties. The topics include a revamped Standards Development Process, Compliance Oversight Process, and Enforcement Process.
A recent ***Internal Controls Working Guide*** has been added to the suite of published document.See:
http://www.nerc.com/pa/comp/Reliability%20Assurance%20Initiative/RAI%20Internal%20Controls%20Working%20Guide%20Document.pdf

The RE Executives met in a strategic retreat to discuss this initiative and lay out an ERO strategy of rolling this initiative out to the underlying SPP Registered Entities/Members.

The first step in this initiative is the implementation of the standardized audit lifecycle template developed through a 3rd party assessment of the RE audit practices and processes. All of the REs have agreed to implement this standardized audit process as soon as practical. Initial feedback from current audits are expected to be reviewed at the September 2013 ERO Auditor Workshop.

Other activities include pilot programs on entity risk assessments and internal controls are underway in various regions.

BES Definition and Exemption Process

The FERC has granted a one-year extension for the implementation of the approved BES Definition to allow more development of the Phase 2 standard development and to allow for more debate concerning some of the FERC issues surrounding sub-100kV networks.

All aspects of implementation of the Definition are being deferred including all inclusions and exclusions.

SPP RE along with the other 7 REs and NERC are completing the development of the uniform software program and should be ready to begin user training in the 4th quarter of 2013.

2014 Preliminary Budget Development

A team from the SPP RE with support from SPP RTO staff developed the final draft of the 2014 SPP RE Budget. The SPP RE Trustees approved the 2014 Business Plan and Budget at its June 18, 2013 meeting.
See http://www.spp.org/section.asp?group=1856&pageID=27

Public Speaking Engagements

I presented an RE update at the SPP MOPC meeting in July 2013.

I participated, along with the other RE Executives, in a panel discussion at the EEI Executive Conference in June 2013.

Administrative and Organizational Issues

Organizational

The following employees have an employment anniversary around this time of year and I would like to recognize the following employees for their years of service:

Jeff Rooker	31 years
Emily Pennel	7 years
Alan Wahlstrom	7 years
Joe Gertsch	5 years
Tasha Ward	4 years
Steven Keller	2 years

Staffing

The following personnel were added to the RE staff since the last RE Trustees Meeting:

None

The following personnel left the RE staff since the last report:

None

Currently, the SPP RE has 4 open positions, including the Director of Compliance position, Manager of Accounting, one compliance technical position[not actively seeking a replacement at this time], and a Law Clerk [not actively seeking a replacement at this time].

Interviews are underway for the Director and Manager positions which are expected to be filled in August 2013.

Administrative

The SPP RE Trustees have been invited to meet with the NERC Board of Trustees in November 2013 in Atlanta, Georgia in advance of the NERC Board meetings.

Respectfully submitted:

Ronald W. Ciesiel
SPP RE General Manager
July 29, 2013

Enforcement Update

July 29, 2013

Jimmy Cline
Compliance Enforcement Attorney
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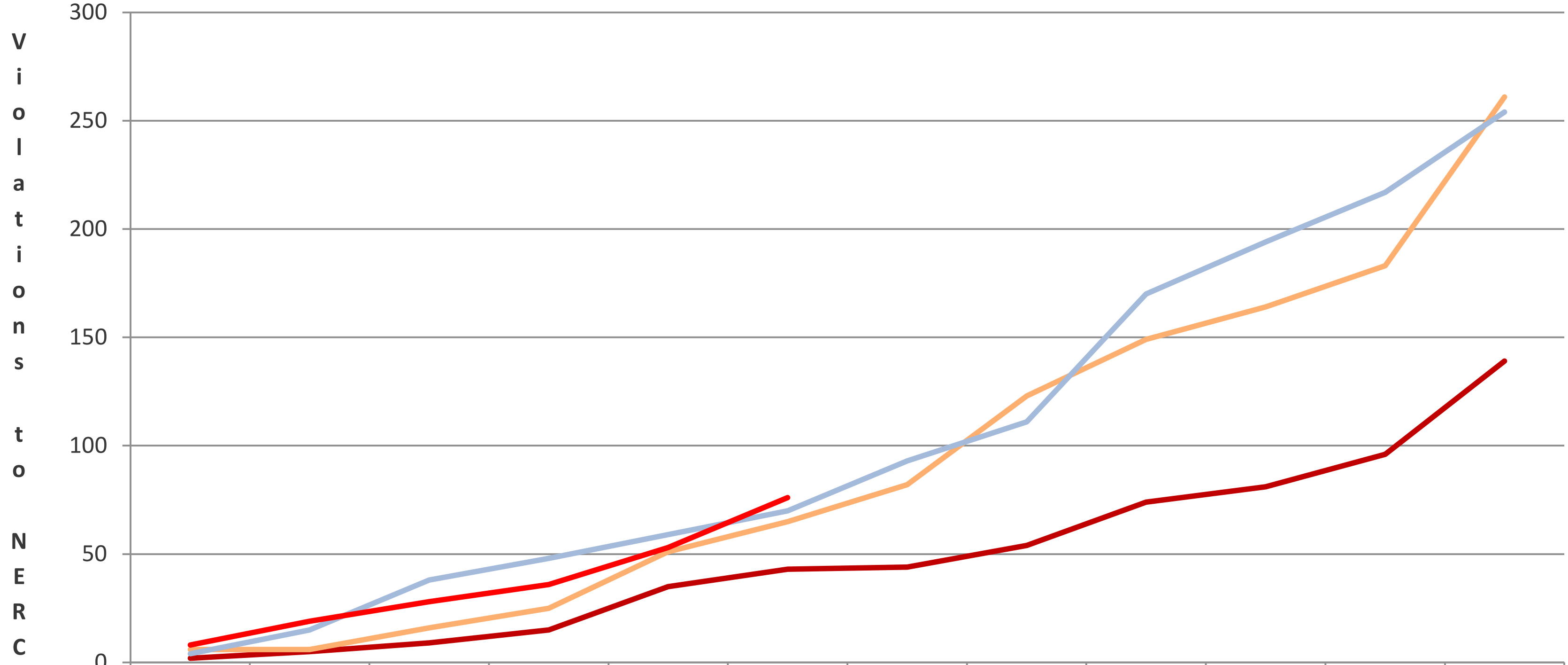
501-688-1759

Southwest Power Pool Regional Entity

SPP RE Enforcement Activities June 30, 2013	2007	2008	2009	2010	2011	2012	First Quarter	April	May	June	Total 2013
NPV											
Issued	6	56	132	254	239	173	56	13	21	12	102
NAVAPS											
NAVAPS Issued	6	45	10	7	0	2	0	0	0	0	0
NOCV											
NOCV Sent to Entity/NERC	0	8	25	15	4	1	0	0	0	0	0
NOCV BOTCC Approved	0	7	11	29	4	1	0	0	0	0	0
Settlements											
To NERC for Approval	0	0	0	89	118	131	5	0	6	5	16
BOTCC Approved	0	0	0	50	81	152	23	12	5	0	40
Administrative Citations											
To NERC for Approval	0	0	0	16	22	N/A	N/A	N/A	N/A	N/A	N/A
BOTCC Approved	0	0	0	0	38	N/A	N/A	N/A	N/A	N/A	N/A
Find, Fix, Track											
To NERC for Approval	-	-	-	-	43	78	14	8	4	14	40
BOTCC Approval	-	-	-	-	36	74	16	6	10	3	35
Dismissals											
To NERC/SPP RE SRT for Approval	0	0	1	16	75	43	9	0	7	4	20
NERC/SPP RE SRT Approved		0	1	16	75	43	8	1	6	5	20
Notice of Penalty/FFTR											
Approved by FERC	0	5	13	57	180	184	76	14	0	11	101
Violations Awaiting BOTCC Approval										28	
Active Violations - Caseload										194	
Caseload Index (months)*										9.2	

* Based on 2012 process rate of 21.1 violations/month.

Enforcement Monthly Violation Processing



	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
2010	2	5	9	15	35	43	44	54	74	81	96	139
2011	6	6	16	25	51	65	82	123	149	164	183	261
2012	4	15	38	48	59	70	93	111	170	194	217	254
2013	8	19	28	36	53	76						

Running Total Violations

Enforcement Caseload – June 30, 2013

- 194 - Open Violations
  - 22 - Joint Settlement w/ Other Regions
  - 1 - NAVAPS
  - 45 - Settlement
  - 124 - Settlement Not Requested (NAVAPS/NOCV)
  - 40 - Administrative Hold
- 60 - 693 Violations
- 134 - CIP Violations
- 64 - High Impact Violations
- Discovery Method
  - 73 - Audit
  - 84 - Self Report
  - 17 - Self Certification
  - 4 - Spot Check
  - 22 - Investigation

Violation Aging

VIOLATION AGING TABLE as of May 31, 2013	< 50 days	50-100 days	101-200 days	201-300 days	>300 days
Violations (No Navaps/ Settlement)	20	22	27	10	16
NAVAPS Issued/ No NOCV or Settlement	0	0	0	1	0
In Settlement but Settlement Agreement not Approved	10	1	1	18	5

VIOLATION AGING TABLE as of June 30, 2013	< 50 days	50-100 days	101-200 days	201-300 days	>300 days
Violations (No Navaps/ Settlement)	13	18	38	3	14
NAVAPS Issued/ No NOCV or Settlement	0	0	0	0	1
In Settlement but Settlement Agreement not Approved	10	6	12	20	7

Violations Older than 300 Days

	2008	2009	2010	2011	2012
Violations (No NAVAPS/Settlement)	0	0	0	3	11
NAVAPS Issued / No Settlement	0	0	1	0	0
In Settlement /Settlement Agreement not Approved	0	0	1	3	3

High Impact Violation* Summary

- 64 – Open High Impact Violations
  - 1 - NAVAPS / Hearing
  - 19 - Settlement
  - 3 - Multi Region
  - 15 - Administrative Hold
  - 26 - Disposition Undetermined
- Open High Impact Violations Mitigation Status
  - 14 - Mitigation Plan Complete
  - 23 - Mitigation Plan Accepted
  - 5 - Submitted
  - 0 - Mitigation Plan Work In Progress
  - 22 - Mitigation Plan Initiated (No Action)

•As noted in our 2013 Metrics , High Impact violations are violations with a High Violation Risk Factor (VRF) and the following Medium and Low VRF violations as identified by Compliance staff: COM-002-2 R2, CIP-002-3 R2, CIP-002-3 R3, CIP-005-3a R2, CIP-005-3a R3, CIP-007-3 R2, CIP-007-3 R3, CIP-007-3 R6, and PRC-005 R2. Link to NERC VRF Table http://www.nerc.com/pa/Stand/Pages/default.aspx

SPP RE 2013 Violation Dismissals

- Consolidation with another violation 11
- NERC V3 – V5 Guidance (approach 2) 2
- Self Report of wrong standard and/or requirement . 4
- Provided exculpatory evidence 1
- Interpreted the standard incorrectly 1

Total 20

June Mitigation Plan Summary

- Mitigation Plan Status (June / Year)

Submitted	28 / 100
Accepted	37 / 90
Certified Complete	53 / 99
Completion Verified	27 / 70

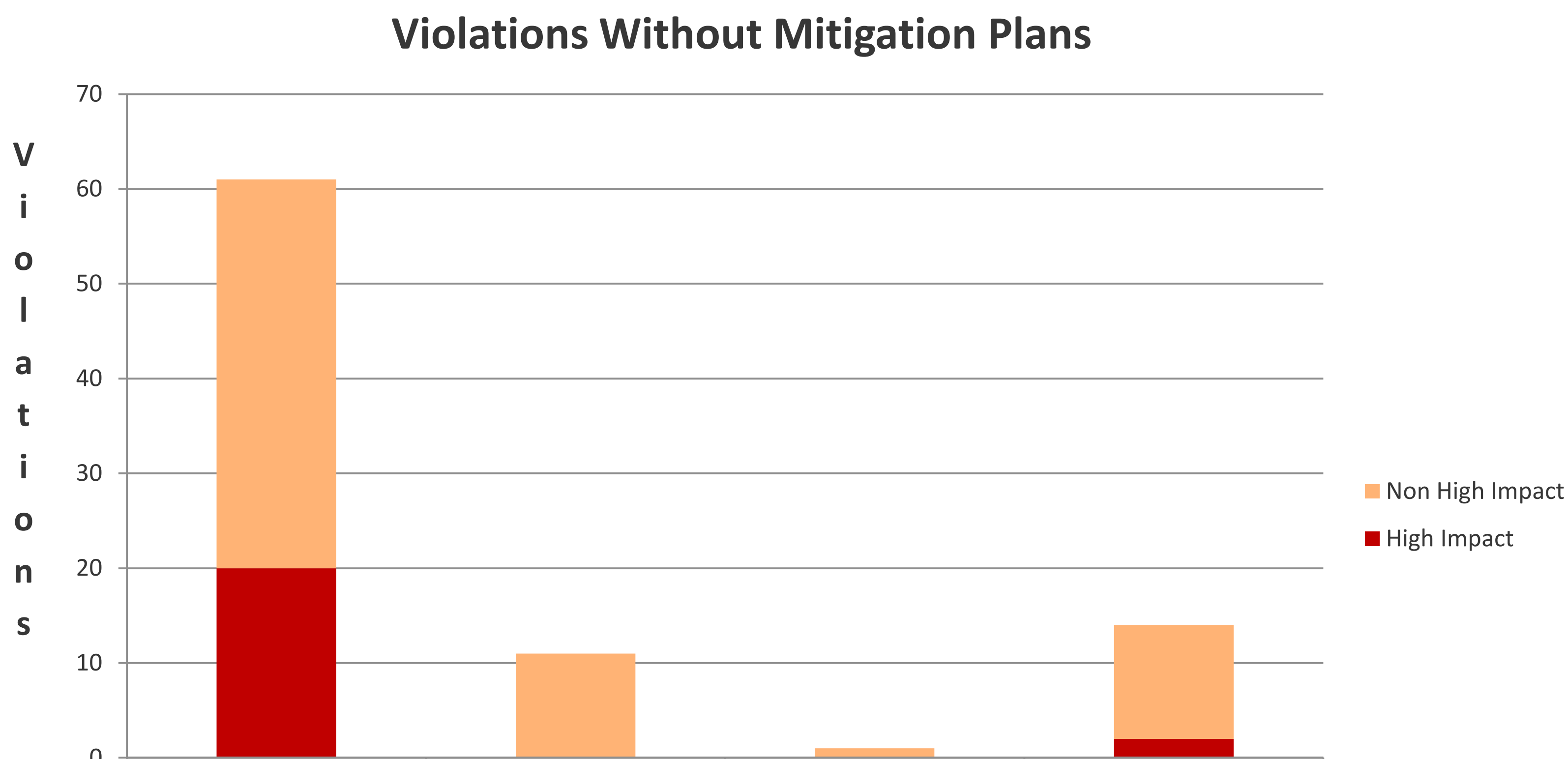
- Violations with no Mitigation Plans

Work in Progress	11
Initiated	61
Rejected	0
Awaiting Approval	1

Violations Without Mitigation Plans Detail

	61 Initiated	11 Work In Progress	1 Submitted /Not Accepted	14 On Hold
693	22	2	0	13
CIP	39	9	1	1

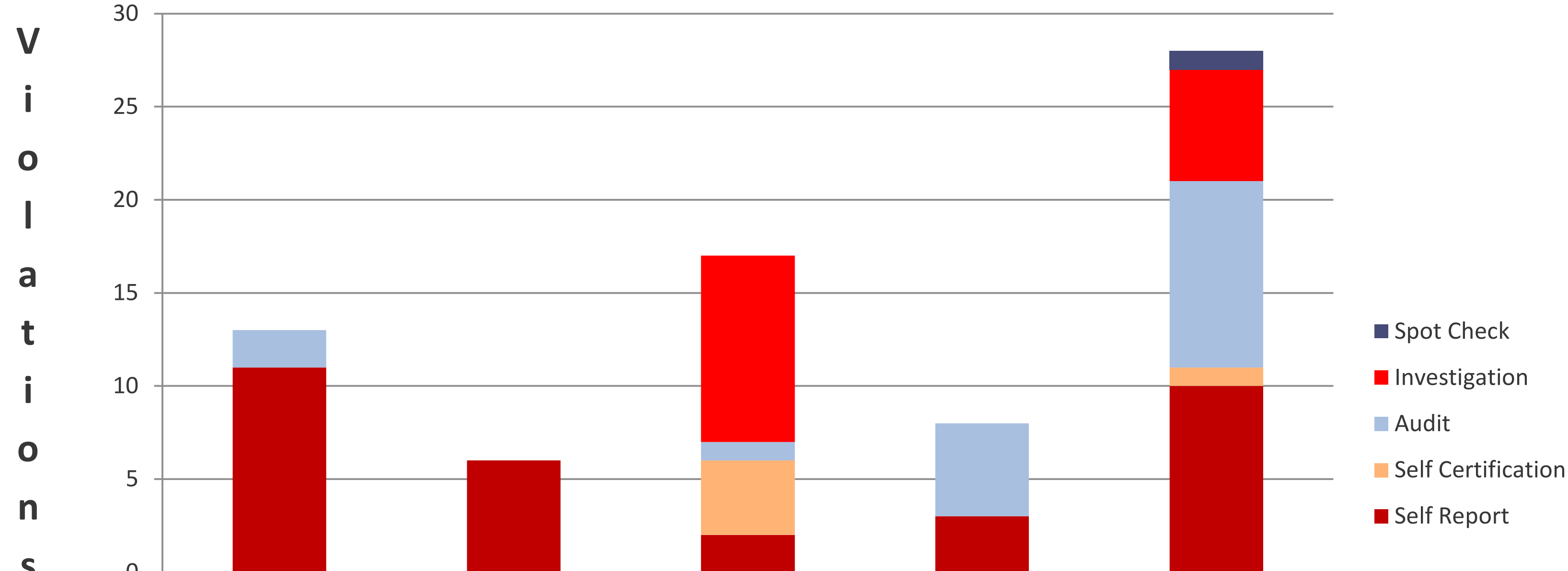
Violations Without Mitigation Plans Detail



	61 Initiated	11 Work In Progress	1 Submitted /Not Accepted	14 On Hold
Non High Impact	41	11	1	12
High Impact	20	0	0	2

Violations Without Mitigation Plans Detail

Violations Without Mitigation Plans Submitted Aging Table



	13 1 to 50 Days	6 51 to 100 Days	17 101 to 200 Days	8 201 to 300 Days	28 > 300 Days
Spot Check	0	0	0	0	1
Investigation	0	0	10	0	6
Audit	2	0	1	5	10
Self Certification	0	0	4	0	1
Self Report	11	6	2	3	10

SPP Southwest Power Pool Regional Entity

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SPP RE TRUSTEES MEETING
DENVER, COLORADO
COMPLIANCE GROUP REPORT

Ron Ciesiel

SPP RE General Manager

July 29, 2013

Southwest Power Pool Regional Entity

TOPICS OF TODAY'S DISCUSSION

- Bulk Electric System Definition
- Reliability Assurance Initiative
- Misoperation Report 1Q 2013
- Vegetation Contacts 2Q 2013
- Most Violated Standards as of June 30, 2013
- Outreach Activities

BULK ELECTRIC SYSTEM [BES] DEFINITION

- NERC applied for and received a one year extension for application of Definition from 7/1/13 to 7/1/14 [See FERC Order 773]
    - Delay impacts all aspects of the Definition, including ‘inclusions’ and ‘exclusions’
- A Standards Drafting Team is working on Phase 2 of the Definition intended to clear up open issues from Phase 1 and address issues raised in FERC Order
    - Recent Ballot results were only 49% approval
    - Expect to have to review sub-100 kV networks down to as low as 30 kV

BES Definition [cont.]

- Reminder of Priorities
  - SPP RE Priorities
    - Requests that would change registration
      - Single element entities
    - Newly identified facilities because of definition implementation
      - Do not expect many, if any, in SPP RE
      - Likely items may be < 100 kV facilities that need review
        - » 2-year compliance phase-in
    - Requests from other entities for exceptions for pieces of system without changes to registration

BES Definition [cont.]

- Recommended interim activities for Registered Entities
  - Registered Entities should be compiling a list of self-nominated ‘exclusions’ [facilities that meet one of the listed exclusions]
    - SPP RE will review and accept/reject facilities on the list as meeting exclusion criteria
      - REs and NERC will have uniform data submittal requirements
      - Expected completion of software development on ~ 9-1-13
        - Template rollout in 4Q 2013

Reliability Assurance Initiative [RAI]

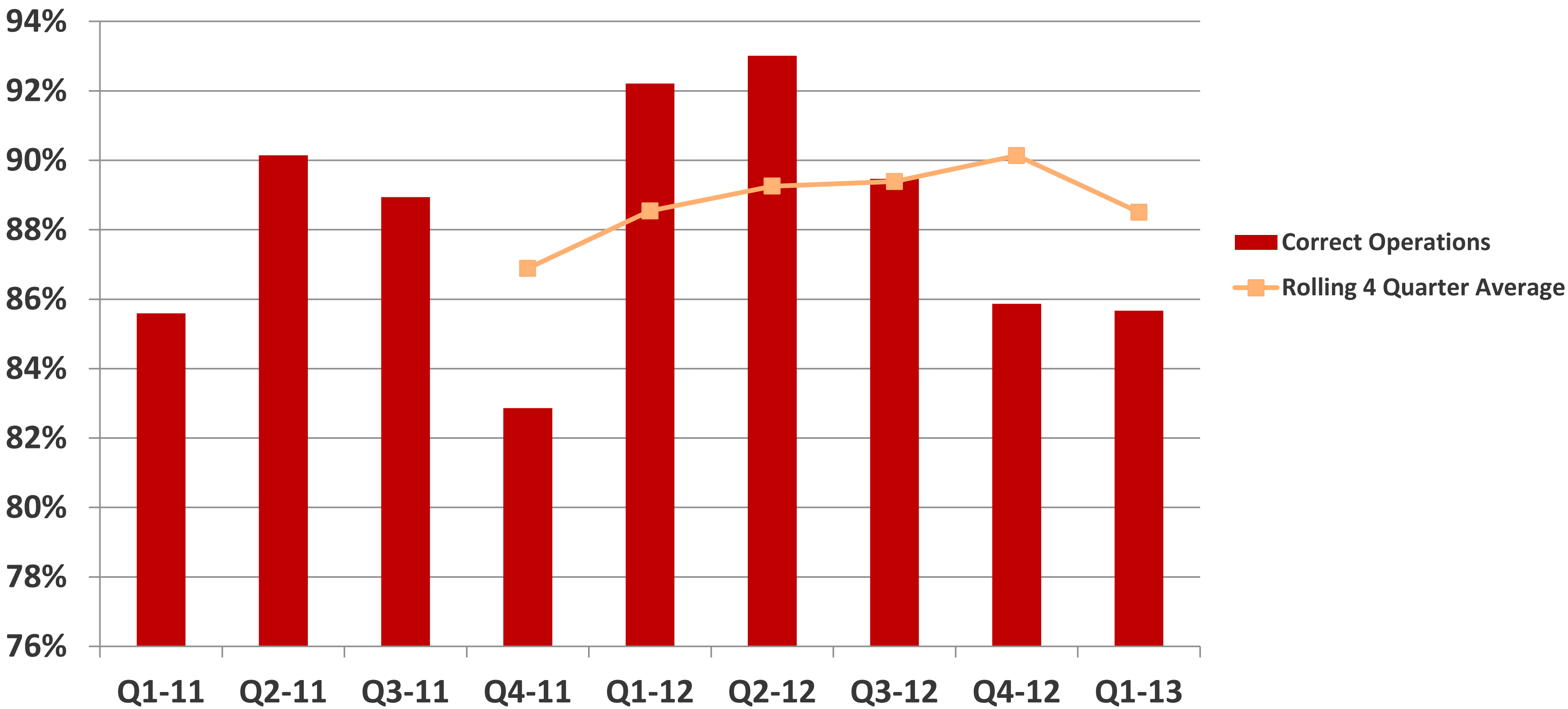
- Standards Process Revamping
  - Streamlined process steps
  - Results-based requirements
  - Cost/Benefit Review
  - 5-year sunset review for every standard
    - Blue Ribbon panel standards review to be discussed and set for approval at August NERC Board Meetings [see slides 16/17 for more info]
- Compliance initiative
  - Monitoring based on ‘risk’ assessments performed by RE
    - Paragraph 81 requirement retirements have been operationally implemented while waiting for FERC approval
  - Entities internal programs may dictate disposition technique
  - More stakeholder involvement in development of Reliability Standards Auditor Worksheets [RSAWS]

Reliability Assurance Initiative [RAI]

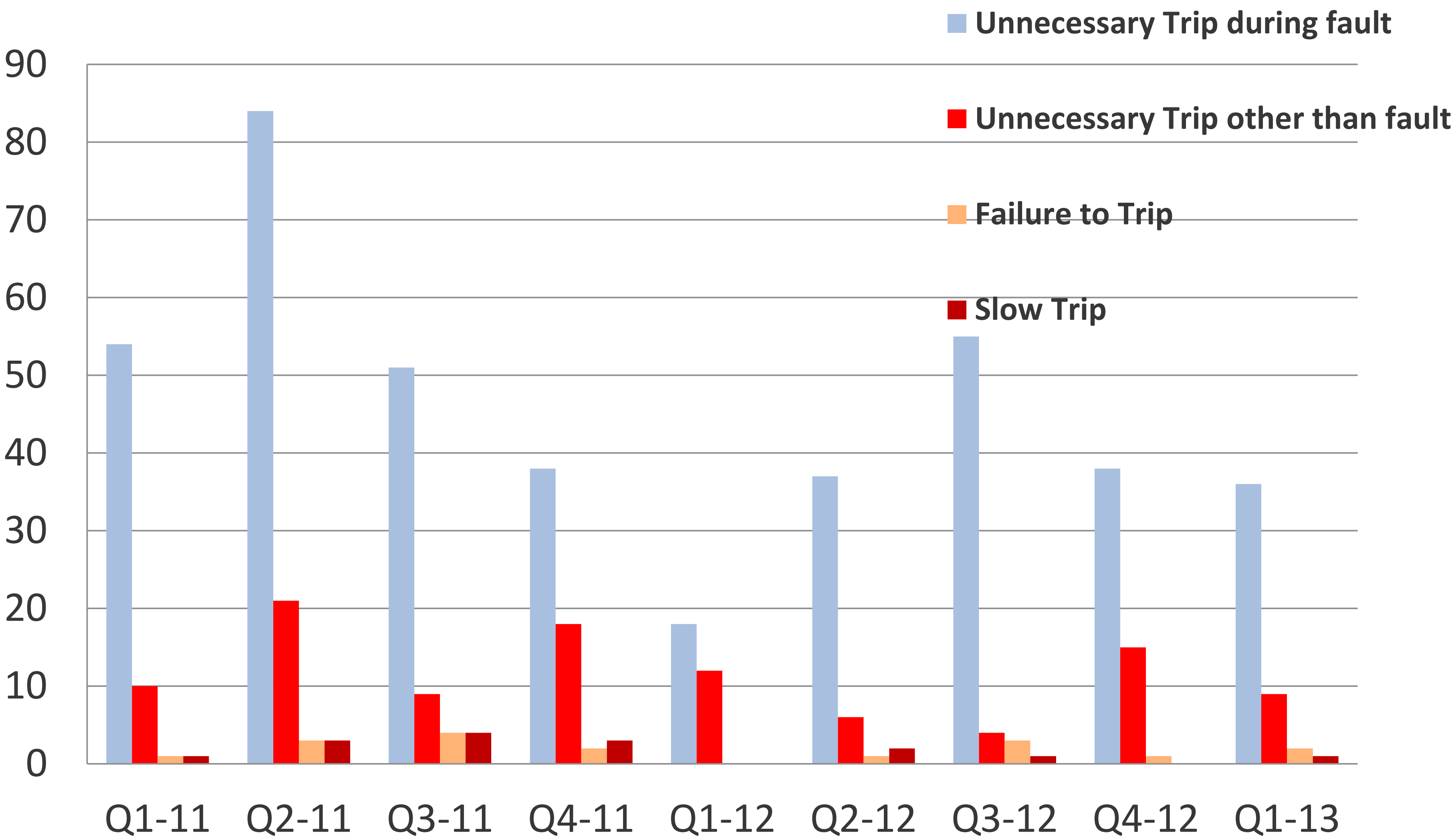
- Data Requirements
  - Emphasis should be on more recent data
    - Internal reviews & ongoing sampling may relieve need to keep all historical data
- Enforcement
  - Separate minor and major issues using different techniques
    - Find, Fix & Track initiative now in place
      - » Push decision making closer to beginning of oversight process
      - » Revisions to process underway based on FERC 6-20-13 order
  - Self-Reporting processes/requirements under review
- Events will continue to get attention
  - Reminder EOP-004 -2 becomes effective 1-1-14
  - Event assessment with Lessons Learned completed and shared
  - Entity self-assessment is important
  - Implementation of 'Recommendations' from major events will be viewed in a favorable light

SPP RE Misoperation Report as of 1Q 2013

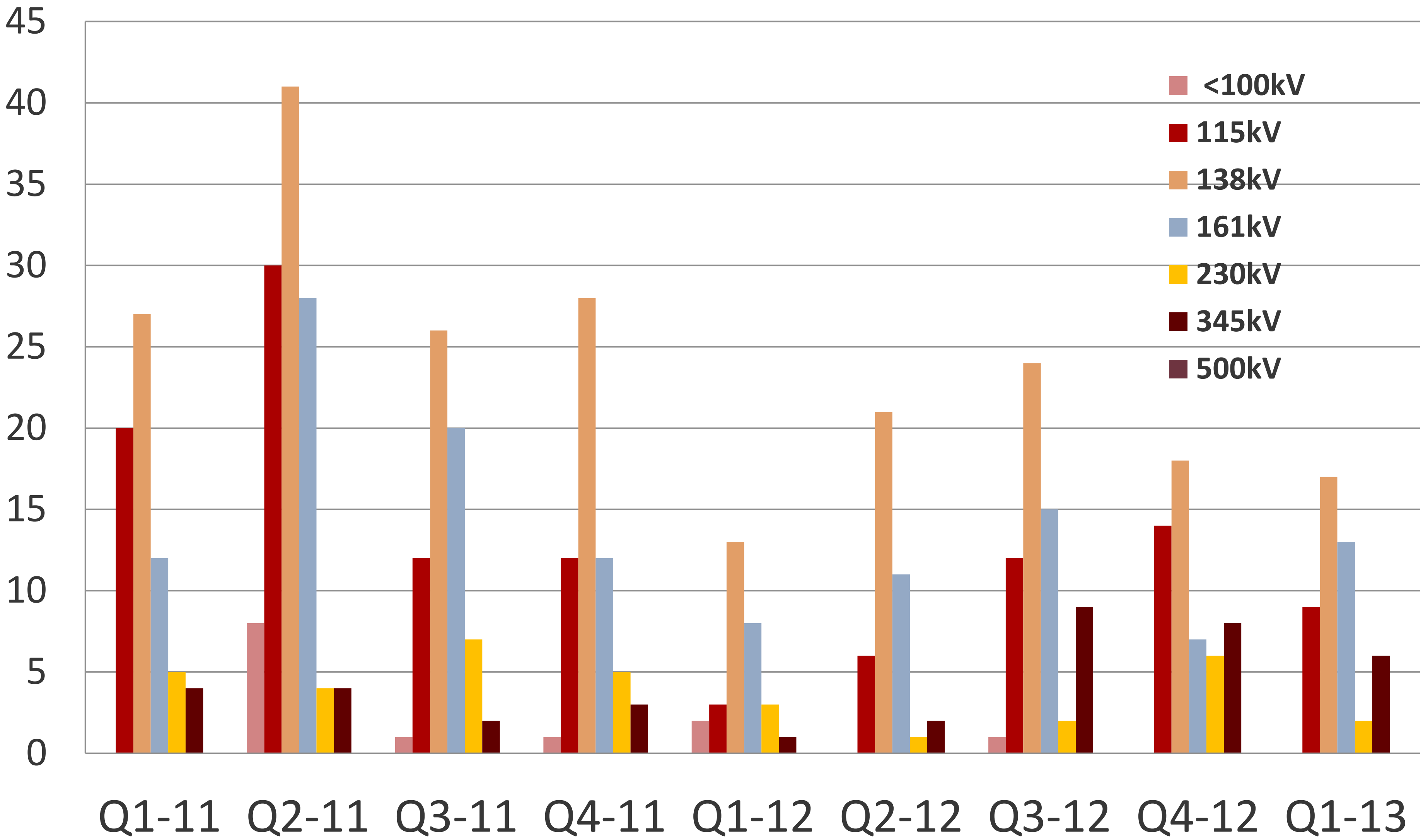
Relay Operational Performance – Success Rate



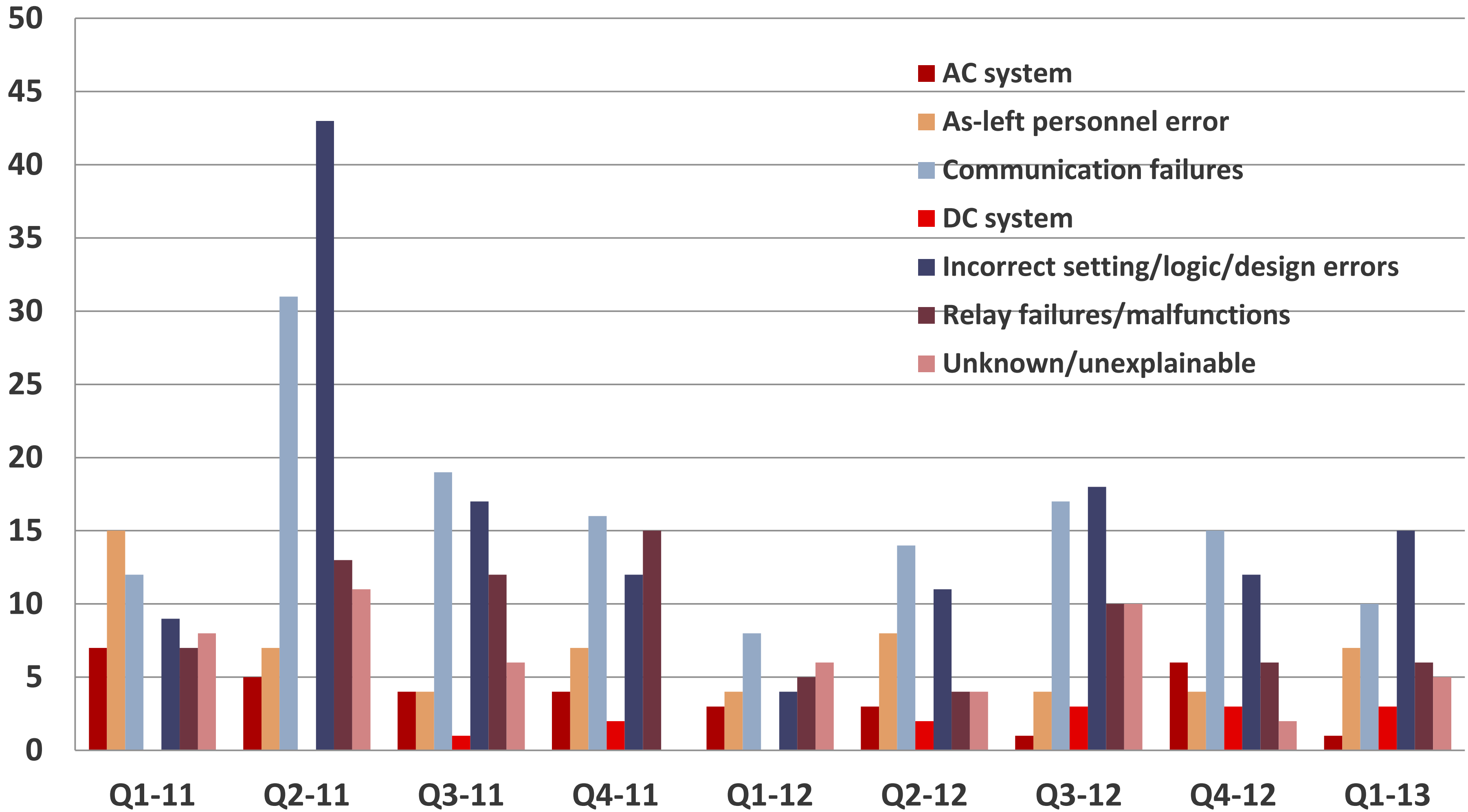
Misoperation Category



Misoperation by Voltage



Causes of Misoperations - 1Q11 to 1Q13



2Q 2013 DATA IS DUE AUGUST 31, 2013

Vegetation Contacts 2Q 2013

- Transmission Owners in the SPP RE footprint had ***no reportable contacts*** in the ***2Q 2013*** timeframe
  - Restarts trend of no contacts after a Category 3 Reportable contact in 1Q 2013
    - Ended 9 quarters of no reportable contacts

Most Violated Standards

Based on rolling 12 months through 6/30/13 [Represents ~ 80% of total violations]

SPP RE Rank	NERC 12 Month Rank*	Standard	Description	Number Violations	Risk Factor
1	1	CIP-007	Systems Security Management (HI)	37	Med./Lower
2	2	CIP-005	Electronic Security Perimeters (HI)	30	Med./Lower
3	3	CIP-006	Physical Security-Critical Assets	26	Med./Lower
4	4	PRC-005	Protection System Maintenance (HI)	9	High
5	6	CIP-004	Personnel & Training	9	Lower
6	7	CIP-003	Security Management Controls	9	Lower/Med.
7	5	CIP-002	Critical Cyber Asset Identification (HI)	7	Medium
8	8	VAR-002	Network Voltage Schedules	5	Med./Lower
9	**	TOP-004	Transmission Operations (HI)	4	High/Med.
10	**	PRC-008	UFLS Relay Maintenance	4	Medium

* As of 12-31-12

** Not in NERC Rolling 12 month Top Ten.

(HI) Standards in RED include requirements designated as High Impact Violations

Outreach

- Fall Workshop, Oct. 8-9, in Little Rock and via webinar
  Agenda includes:
  - *NERC Guidance on CIP Version Transition*
  - *Entity Perspectives on Internal Controls*
  - *NERC's Committee Structure/RAI Update*
  - *Company-Wide Compliance Forums*
  - *12 break-out sessions*
- Four new videos posted to video training webpage
  - CIP-005 R3
  - Firewalls: 13 Ways to Break Through
  - NetAPT Demo
  - CIP-007 R3 and R4
- Webinars
  - 8/27/13, Standards Development Status Report presented by NERC
  - 9/19/13, Winter Reliability Assessment
  - 9/20/13, Determining and Communicating TOP System Operating Limits

Questions/Comments

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Independent Experts’ Key Findings

Published report 7/13 (not yet approved by NERC Board of Trustees)

1. Recommended retiring 147 requirements and consolidating remaining requirements for overall 43% reduction
2. Of the 257 retained requirements, 81 are in “Steady-State” (no work needed) and 176 need enhancement
3. Identified gaps:
   a. Outage coordination
   b. Governor frequency response
   c. Situational awareness models
   d. Clear three-part communications
4. While newer standards are improved, the majority are not at Steady-State

Independent Experts' Recommendations

1. Retire 147 requirements and focus initial improvement efforts on 16 high-risk standards
2. Continue developing risk-based approaches to identify high priority reliability issues
3. Realign standards from the current 14 families into 10 families grouped by reliability functions
4. Address identified gaps
5. At an appropriate time in CIP standards' development, use a team of experts to evaluate the CIP requirements

SPP Regional Trustee Update July, 2013

NERC Operating Committee Meeting

June 2013

Jim Useldinger

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Revised MISO Reliability Plan

- MISO and Joint Parties (AECI, LG&E, PowerSouth, Southern, SPP, TVA) executed the "Operations Reliability Coordination Agreement"
  - Defines terms of Operations Transition Period
    - Initial Limits, phased approach, timing, less than 5% impacts
  - Sets the stage for development of an "Operation Coordination Process" for use beyond transition period
- The Joint Parties supported and recommended the approval of the MISO Reliability Plan
- OC approved the MISO Reliability Plan on June 20

Balancing Authority Reliability-based Control (BARC) SDT

- DT developed a Standard for continent-wide reserve policy – vote failed
- DT developed Reliability Guideline on Reserve Policy
  - Helps address FERC Order 693 Directive regarding the establishment of a continent-wide reserve policy
- OC approved posting Guideline for 45-day comment period

SW Outage (Arizona-California) Follow-up Items

- ORS survey of reliability coordination
  - Practices the RCs utilize, in conjunction with their TOPs, to monitor SOLs/IROLs in the absence of RTCA capability at a TOP
  - How reliability entities are informed of the practices, procedures, and tool status used for monitoring SOL/IROLs at each entity within their RC area and neighboring entities
  - How should the OC and industry consider the Real-time Tools Best Practices TF report
- ORS assigned task to develop a Guideline addressing the utilization of Operational Tools

Event Analysis Subcommittee Activities

- OC approved Event Analysis Process doc update
  - Removed references to compliance
  - Remains a voluntary process
- EAS discovered two equipment vendor issues, related to relays and SF-6 breakers, through review of event reports
  - Lead to lessons learned and possible alerts or advisories to industry\
- EMSTF provided summary of recent EMS outage statistics
  - (1) Software failure, (2) change management, (3) testing
- Hosting an EMS Monitoring and Situational Awareness Conference at conclusion of Sept OC meeting

Support Personnel Training

- EAS responded to a Request for Research to NERC Project – Support Personnel Training
  - Researched event data: 44 possible Human Error – 10 events Human Error and inadequate training – 6 of these EMS/SCADA loss
  - Report concluded that it is not necessary to require EMS support personnel, transmission and generation field personnel, engineering support personnel to receive level of training or certification required of a BA, TOP, RC
  - OC approved report
- PER Informal Development Project – PER-005
  - Intended to focus on closing out FERC Order 693 and 742 Directives
  - Ad hoc team developing PER-005 changes
  - OC developed comments for ad hoc team intended to push back on need to require Operator equivalent training for personnel other than System Operators

Coordinated Interchange Standard Development

- DT reactivated to continue work on project
- OC provided comments to DT work
  - Requirements already exist for the TOP and RC to perform a reliability analysis, to include the impact of interchange on SOL/IROLs
  - Mechanisms such as generation redispatch and transmission reconfiguration (including cancellation of outages) in addition to interchange modifications that can be used to address potential impacts

Work Force Development

- Discussion focused on accounts of 2 companies utilizing military veterans to fill electric industry positions
- Veterans bring skill sets that translate well, including: leadership, commitment, discipline, crisis management, teamwork
- Recruitment specialists/organizations that specifically set up to help veterans find career in the energy industry
  - Center for Energy Workforce Development (www.cewd.org)
  - Troops to Energy Jobs (www.troopstoenergyjobs.com)
  - IncSys (www.incsys.com)

OC Officer Election

- Jim Castle, NYISO, as Chair
- Jim Case, Entergy Services, as Vice-Chair

NERC Planning Committee
June 11- 12, 2013
SPP RET July 2013 Update Report

1. The PC approved updated version of the PC strategic plan. The strategic plan calls for the PC to continue providing input to the standards develop process by providing technical expertise, research and feedback.
    - The PC has incorporated the RISC recommendations in to the plan. Reduction of misoperations is a significant area of focus. The PC will work with the RISC to conduct a gap analysis review of the work being conducted in support of misoperation analysis at the next RISC meeting.

2. The NERC Geomagnetic Disturbance (GMD) task force provided an update on the work of the task force and the associated with FERC Order No. 779.
    - Order No. 779 compels NERC to develop a standard requiring responsible entities (likely Generator and Transmission Owners) to develop operating procedures.
    - Order No. 779 requires a new standard be filed by January 2014 for FERC approval.
    - The Order also compels NERC to develop a standard for assessing risks of GMDs to transformers and other equipment (i.e. identify those most at risk through study) and for the development of mitigation plans. Ultimately, the standard will likely require a new type of study be performed similar to how entities perform separate studies for power flow, dynamic analysis and short circuit studies.
    - The work the task force has already completed provides a basis for responding to the order and includes developing operating procedure templates, review of system operator training for best practices, and developing reference storm models. The task force is also working on developing a guide for calculating geomagnetic induced currents, equipment models, and mitigation measures.

3. The 2013 State of Reliability report included a list of actionable steps that generator and transmission owners can take to reduce the number of misoperations caused by incorrect relay setting/logic/design errors, relay failure/malfunction, or communication failure.
    - The System Protection and Control Subcommittee (SPCS) has been tasked working with industry to implement these action steps. The SPCS is also working to enhance the misoperation data reporting template based on suggestions from the task force that developed the recommendations.

4. The PC approved the formation of the AC Substation Equipment Task Force (ACSETF). The purpose of the task force is to analyze AC equipment failure data, to research root causes, and identify key factors that may exacerbate the impact of equipment failure to the BES.
    - The root cause analysis will include evaluating equipment configuration and bus design. Key findings and recommendations will be used to identify potential mitigating actions to reduce reliability risk.

5. The PC approved the Probabilistic Assessment Report. The purpose of the report is to provide reliability to supplement the Long-Term Reliability Assessment.
    - This is first full report that has been approved. It includes indices such as Expected Unserved Energy (EUE), Loss of Load Hours (LOLH) and Planning Reserve Margin.

6. A representative from Public Service Electric and Gas (PSEG) presented a SAR they plan to submit to the Standards Committee. The SAR calls for the creation of a Demand Response Provider function in the NERC Function Model. The SAR will implemented over a four year time period and calls for the creation of a Demand Response Provider definition in the NERC glossary.
    - The goal is to register Demand Response Providers that are not already registered in another function. Part of the stated purpose is to improve DADS data collection efforts. In response to previous work by the NERC Functional Model Working Group (FMWG) declaring that there is no need to create a demand response function, the PC has drafted a letter asking the FMWG to review their findings and conclusions that demand response does not provide primary support for reliability.

7. NERC staff presented updates on the five-year review efforts for the MOD standards. The efforts are divided into three separate projects – MOD A, MOD B, and MOD C.
    - MOD A proposes to combine the ATC/AFC/TTC/CBM/TRM standards into a single standard and to remove those requirements that are business practices move them to NAESB.
    - MOD B will combine MOD-010 through MOD-015 into a single standard dealing with data collection for steady-state, dynamics, and short-circuit models. A separate standard will be created for model validation.

- MOD C will combine MOD-016 through MOD-019 and MOD-021 into a single standard.

The standard development effort is on a fast track with the goal of having the final versions approved by the BOT before the end of 2013.

8. NERC will initiate a research project to determine which aspects/characteristics of turbine and boiler controls need be modeled to correctly predict the behavior of the generator during a disturbance. There have been a number of events in which the electrical generator has ridden through the transient event without the actuation of protective relays only to trip moments later due to turbine and boiler control actuation. This is suspected to be the cause of a number of unit trips during the September 2011 San Diego area outage. A third party will conduct the research but NERC is looking for volunteers to assist with providing input to and reviewing the research. Are there any SPP entities who wish to participate?

9. The System Analysis and Modeling Subcommittee (SAMS) reviewed both versions of the FAC-001 standards at the request of the Standards Committee in preparation for the upcoming Project 2010-02 Connecting New Facilities to the Grid.
    - SAMS determined that there is a technical justification and support for a new standard and is preparing a report to support this position.
        i. SAMS has also determined that the standards clarification is needed for inspection/maintenance requirements which should be removed as they are usually contained in interconnection agreements,
        ii. Requirement for the Planning Coordinator to notify the RC of all new facilities to be added.
        iii. SAMS is indicated that applicability of the standard to the Transmission Operator will be considered during standard development

10. The Planning Committee elected David Weaver (Exelon) as the new Vice-Chair.

NERC Compliance and Certification Committee (CCC)
Report to Southwest Power Pool Regional Entity Trustees
Submitted by Jennifer Flandermeyer, SPP RRO Representative
Senior Manager, Operations Compliance, Kansas City Power & Light
June 18, 2013

NERC CCC Meeting

1. The NERC CCC held its quarterly meeting in Kansas City, MO on June 18-19, 2013. The materials for this meeting can be found:
    - Agenda: _ http://www.nerc.com/comm/CCC/Agenda%20Highlights%20and%20Minutes%202013/June%202013%20CCC%20Agenda%20Package%20Final.pdf
    - Minutes and Presentations: Not yet posted.

2. Committee Administrative items were completed – approval of meeting minutes, action item reviews, quorum establishment, open positions by sector, and roster updates.

3. Report was provided on the NERC Board meetings and RISC meetings from Ms. Patti Metro, Vice-Chair CCC and Mr. Clay Smith respectively.

4. ERO Monitoring Subcommittee (EROMS)
    a. The CCC wants to conduct the perception survey utilizing TalentQuest going forward and took an action item to engage TalentQuest with the appropriate funding by NERC. There was substantial discussion with the CCC on participation of the industry on the perception survey and how to encourage further feedback. In addition, discussion focused on use of TalentQuest
    b. Mr. Hughes presented how NERC will respond to the 2011 and 2012 recommendations and the plan to develop mitigation plans as needed and to report out to EROMS with the details and provide the CCC a report our by exception only, Exhibit D.
    c. Mr. Hughes provided a status of 2012 Self-Certifications (ORC and CMEP will not be conducted in for 2012 since these areas were included in the to the 3rd party audit completed in February 2013 in lieu of these completing self-certifications for these programs NERC will provide updates on audit mitigation activities at CCC meetings).

5. Standards Interface Subcommittee (SIS)
    a. The SIS discussed the single Portal Proposal and continues to monitor.
    b. The SIS discussed the standards Cost Analysis Project and continues to monitor.

6. Procedures Subcommittee (PROCS)
    a. Mr. Matt Goldberg discussed the Rules of Procedure (ROP) possible revisions and Ms. Rebecca Michael assisted.
    b. Mr. Matt Goldberg discussed the CCC Policies and Procedures Review.
    c. Action item for Mr. Goldberg to present a draft work scope document at the next CCC F2F meeting on the consolidation of the PROCS and SIS.

7. Organization and Certification Subcommittee (ORCS)
    a. Ms. Jennifer Flandermeyer discussed the completion of the Southwest Outage Report action item.
    b. Ms. Jennifer Flandermeyer discussed the RISC request on Planning Authority / Planning Coordinator issue.
    c. Ms. Jennifer Flandermeyer discussed the Update on CCC Work plan Items assigned to ORCS.
    d. Status of the Multi-Region Registered Entity (MRRE) process provided by Jack Wiseman.
    e. Action item for NERC to provide the ORCS with MRRE pilot document for review and comment.

8. CCC Ongoing Projects *
    a. Team 1 – Mr. Bob Hoopes presented the RAI Benefits and Impacts Matrix that will be submitted to NERC at the end of July for consideration.
    b. Team 2 - Mr. Bob Hoopes presented the RAI Question and Answer Document. Mr. Earl Shockley commended the CCC on the excellent product and reminded everyone it was posted on the NERC website for the industry. It is a living document so there will be changes as we move through the RAI process.
    c. Team 3 – Mr. Jim Stanton presented the RSAW RAI project status.
        - Good discussions surrounding how to improve RSAWS and have more compliance input upfront to ensure there is a direct tie between the language in the standard and the guidance provided in the RSAW. This is the strong feedback from RAI to the Standards process – critical to the success of RAI.
        - Action item was taken for NERC to provide an email account where the industry could provide comments for improvements.
    d. Team 4 - Mr. Terry Bilke presented the Data Retention (Identify Reasonable Record Retention) status. This project is due until the end of year timeframe. A survey will be submitted for industry consideration to assist with broad spectrum of approaches to consider.
    e. Team 5 – Ms. Martyn Turner presented the status on Internal Control Guidance (coordination w/RBRCWG). It is projected to be posted on the NERC website at the beginning of July or in coordination with the next RAI workshop.

9. NERC Staff Update
    a. Mr. Earl Shockley presented an update on the Reliability Assurance Initiative (RAI).
    b. Mr. Earl Shockley gave an update on the RAI Governance, RAI Projects, RAI Workshop, and the CCC Support of the RAI Activities.
    c. Action item for NERC to provide the CCC more details regarding milestones so as to add better clarity of deliverables.
    d. Mr. Terry Bilke presented the KRSSC Letter from Earl Shockley and asked for a CCC member to volunteer to oversee the NERC KRSSC project on CIP-001.
    e. Ms. Mechelle Ferguson Thomas presented an update on the recently completed independent audit of NERC (this was a closed session for CCC members only).

10. Future scheduled CCC meetings are as follows:

    – September 18 – 19, 2013, Denver, CO
    – December 4 – 5, 2013, Atlanta, GA

NERC Critical Infrastructure Protection Committee (CIPC)
Report to Southwest Power Pool Regional Entity Trustees
Submitted by Robert McClanahan, Chair, SPP Critical Infrastructure Protection WG
July 17, 2013

NERC CIPC Meeting

- The NERC CIPC held its quarterly meeting in Atlanta, GA on June 11-12, 2013. The materials for this meeting can be found at:
    - Agenda:
        - http://www.nerc.com/comm/CIPC/Agendas%20Highlights%20and%20Minutes%202013/CIPC%20Agenda%20June%2011-12,%202013.pdf
    - Presentations:
        - http://www.nerc.com/comm/CIPC/Agendas%20Highlights%20and%20Minutes%202013/CIPC%20Presentations.zip
    - Draft Minutes:
        - http://www.nerc.com/comm/CIPC/Agendas%20Highlights%20and%20Minutes%202013/CIPC%20Draft%20Minutes%20Complete%20Package.pdf
- A cyber security training workshop was conducted for CIPC Members and Alternates prior to the CIPC meeting.
- Matt Blizard, NERC Director of Critical Infrastructure Protection, gave an overview of current activities in the Critical Infrastructure Department and within the industry. He reported that the Electric Sector Coordinating Council (ESCC) will be undergoing some changes in the near future. A group of industry CEOs, currently operating under the National Infrastructure Assurance Council (NIAC), will transition into the ESCC.
- Michael Peterson, PG&E Corporate Security, provided an overview of an incident at the Metcalf Substation in the Silicon Valley in April 2013. The substation was damaged by a physical attack. Details of the event are not available due to an ongoing criminal investigation.
- Bill Lawrence of NERC Staff provided an overview of the upcoming GridEx II exercise on November 13-14, and encouraged entities to participate.
    - NOTE: The SPP CIPWG is planning to develop a regional plan to allow SPP Member Companies to participate in both the National and a Regional exercise simultaneously.
- The CIPC subcommittees and task forces provided updates on their progress.
- Tobias Whitney of NERC Staff provided an update on the CIP V3 to V4 to V5 transition. To be quite honest, there is still a great deal of confusion as to how the transition from version to version will be handled by NERC and audited by the Regions. Asset owners will need clarity from NERC and the Regions on what is expected during the transition.
- Scott Mix of NERC discussed the Sufficiency Review Program (SRP). Mr. Mix reminded the CIPC that the SRP is not a compliance program and that the only opportunity for potential violations is if an

immediate threat to BES reliability exists. The program began as a risk-based assessment method (RBAM) review; but now acts like a mock audit. The program is full for 2013 and is looking for 25 entities to participate in 2014.

- Melanie Seader of EEI provided an overview of what is occurring on Capitol Hill.
  - Legislative Update
    - There seems to be a desire to allow the recent Executive Order run its course before taking up legislation. A discussion draft of new bill codifying the Executive Order has been circulated. The bill would make changes to DHS authority.
  - Markey / Waxman Report
    - Congressmen Waxman and Markey are well-known in the critical infrastructure protection space. They recently released a report on the responses that they received to a voluntary survey that they sent to industry participants. The report makes is seem as though the Congressmen started with their desired conclusion and worked backwards to support that conclusion. The report noted several major “findings”:
      - The industry is the target of constant cyber attack
      - The industry only conforms to mandatory standards, not voluntary ones
      - The industry has taken no steps to mitigate the risk from geomagnetic disturbances (GMD)
    - Their ultimate conclusion is that more regulation of the industry is necessary.
- GridSecCon 2013 will be held on October 15-17, 2013 in Jacksonville, FL. Days 1-2 will be a workshop on current security-focused issues. The third day will be a full-day of training on cyber and physical security topics.
- CIPC Meeting Schedule for 2013:
  - September 17-18 in Denver, CO
  - December 10-11 in Atlanta, GA

System Protection and Control Subcommittee

June 25, 26, 27 2013

FERC Order No. 758 – Sudden Pressure Relays *[Present report at September 2013 PC meeting]*

There was discussion on the reliability impact for sudden pressure relays vs. other devices (such as temperature monitors and over speed trip) and their reliability risk. The language in the order discusses "devices that detect faults or abnormal system conditions that will affect reliable operation". The SPCS is creating a list to differentiate between (1) devices that clear faults or mitigate abnormal system conditions to support reliable operation of the bulk power system *ex. Sudden pressure relay* (2) devices that take action of abnormal equipment conditions for the purposes other than supporting reliable operation of the bulk power and (3) devices that monitor the health of the individual equipment and are advisory in nature *ex. oil temperature monitor*. In this proposed approach item 1) would be included, item 2) and 3) would be excluded in PRC-005. We also discussed the testing schedule, noting that sudden pressure relays could require an outage.

Protection System Misoperation Reporting *[Report on misoperation template changes at the September 2013 PC meeting]*

<u>1600 Data Request to collect Misoperation Data Project 2010-05.1</u>

This will be a request for misoperation data since the PRC-004-3 standard does not include the template. The data request will be written by NERC staff and reviewed by ERO RAPA, SPCS, and Project 1020-05.1SDT after which it will be presented to the PC. This should be in place before the PRC-004-3 so there is no gap. June of 2014 will most likely be the earliest date the new PRC-004-3 could be approved by FERC plus timeframe to implement. Today's standard requires meeting the regional requirement for reporting, the new standard (PRC004-3) will use the data request as a vehicle for reporting. This data request will not be "one time" such as with the NERC 754, rather it will be an ongoing periodic requirement. If more or less fields are needed in the misoperation template this will be easier to change than a standard. This will allow uniformity across the region. Regions could ask for additional data per agreement with members or through a separate 1600 approved data request.

<u>ERO-RAPA SPS White Paper Next Step</u>

ERO-RAPA is looking at the next step for the SPS white paper and what could be done to move forward until the standards are revised to meet the whitepaper intent. On a volunteer basis the regions could begin categorizing the SPSs and determining if they are PS or PL type schemes. There may be one procedure for all regions to move forward before standards are revised. The RAPA group has also prepared a new template for SPS reporting and has sent to the SPCS for consideration. Collecting data on all correct operations of an SPS could be burdensome on some regions. For SPSs that are continuously operating the quantity of data could be burdensome. Better understanding of what this data will be used for and what the SPS definition becomes is needed before a finalized template should be approved.

Misoperation Reporting Enhancement – Changes to Template

PC approved SPCS template changes per PSMTF proposal including those concerning the sub causes/additional causes for more granularities. Added a relay load ability related sub cause in the template as a possible addition. Template changes to be done by SPCS.

SPCS reviewed PSMTF recommendations for inclusion in revision of the template. Recommend to break incorrect relay settings/logic/design into three separate multiple first level causes. Also plan to add more details for filling out the description of events. There was significant discussion if the communication causes should be broken down further. Due to the nature of the data and the fact that depending upon the scheme communication failures may not be entirely captured this will be left as one cause. If an operation/misoperation occurs repeatedly within a 24 hour period this should possibly be considered one operation/misoperation in the template. Decided to leave this as it is today and not expand the 24 hour period.

Training Modules and Misoperation Trends

NERC is preparing training modules for each primary cause in way for risk control to assist entities. There may also be workshops. SPP misoperation rate for 2012Q4 was 13.9%, second highest behind RFC at 16.8%.

Protection System Commissioning

The SPCS reviewed the Lesson Learned for relay commissioning in response to a misoperation due to incorrect CT ratios that was undetected during commissioning. Minor changes were made to finalize this document.

BES Definition

An update on definition of BES drafting team work was given with potential impacts on applicability of PRC standards. The drafting team reviewed all standards that could be impacted. The boundaries will change for what is a BES, but the application in standards will not change. For example PRC023 will apply for any new lines with a two year implementation. For 69kV to become part of the BES, someone would need to recommend it go through the exception process then if it does become part of the BES the TP would then address per PRC023 appendix B. E3 in the new draft definition allows you to exclude certain elements (such as certain 115kV) - note that 69kV is not part of the BES that E3 is referencing. For all circuits from 30kV to 100kV the base proposed definition does not include but will need to look at the inclusion (I's) to determine if it will be part of the BES.

Protection System Response to Power Swings *[Submit report for approval in July 2013]*

The Power Swing paper was presented to PC in June, and is out for additional comments and review. Initial feedback was that report seems to indicate that a standard may not be necessary. Relays tripping on stable swings were not a culprit on past events; therefore a limited standard (or no standard) may be appropriate. Additionally PRC023 has already helped address tripping on stable swings. SPCS plans to modify the paper slightly to further support that this issue is adequately addressed without a standard. In FERC order 733 a key part of their concern may have been an inaccurate conclusion that past events involved tripping on stable swings as a root cause. Upon research of this topic the SPCS is now stating that based on historical events and to maintain the proper balance of dependability/security a standard in not appropriate and could result in adverse reliability of the BES. The paper details the research and also provides a recommendation if it is decided to proceed with a standard. PRC023 phase III originally was to create a power swing standard, this may be modified upon review of the final SPCS paper on this topic.

DME standard

The DME standard development was revitalized in early 2013. There will be a companion document for placement of equipment. Two workshops are coming up at which a draft standard will be presented to receive industry input. This will be followed by posting of the draft around August of 2013. The data request that is active today will be used to verify information in a technical study regarding placement of DME and to help address the possibility of clusters of equipment. Methods for placement and numbers (per NERC) are conservative but may require additional equipment to be installed. The standard will not dwell on equipment, rather the data that is needed. The existing draft requires SOE and FR at 20% of buses where the maximum available 3phase short circuit MVA is 1500MVA or greater. It also requires that DDR be installed at least one per 3000MW of historical peak load in the PC area, at generating plants 1000MVA or greater gross rating, at major transfer paths, and at ROL interconnections. NERC Webinar slides are available detailing locations needed and quantities to monitor for SOE, FR and DDR in the draft.

Power Plant and Transmission System Protection Coordination

IEEE PSRC reviewed and made several suggested modifications to the document. Based on this feedback a redlined document could now be developed by a subgroup reporting recommended changes back to SPCS.

IEEE Report on Response of Transmission Line Relays to off Normal Frequencies *[Present report at December 2013 PC meeting]*

Report is complete at request of SPCS due to relays tripping during off nominal frequency in the NE blackout. The group discussed options of how to best reach the industry with this information. There will be no recommendations, only a notification to the industry that the information is available. Plans at this time are to possibly set up a webinar in conjunction with IEEE.

Pacific Southwest Recommendations *[Present report at September 2013 PC meeting]*

SPCS reviewed the final draft response to Planning Committee on WECC Recommendation NERC6 – Sub-100-kV Relays. The group believes that attachment B of PRC-023 already addresses this for sub100kV elements that are part of the BES per the exception process. Finalization of this paper will be done at a later meeting.

Order No. 754 Data Request

SPCS reviewed requests for clarification since the previous SPCS meeting of which there have been two minor questions. 1) CT column ground faults for free standing CTs – we are not collecting data on this. 2) Relative to base case selection, would a 2016 base case meet the intent – the request references a 2013 case, but using this 2016 case would be fine as long as the model did not contain projects that likely would not happen. Official Q/A is on the website.

The Web data portal for entering data is under development and should be done in August. Webinars should be available for industry training in August. This will aid the analysis of the data.

Discussed live tank breaker (all CTs on one side) and a fault between the breaker and the first CT. Breaker failure would need to clear this type of fault, and if the breaker failure relay fails then remote clearing would be necessary. Does this meet the redundancy requirement? The industry is looking at this as it does meet the redundancy requirement. A formal response will be drafted.

Event Analysis

Lesson learned on solid state contact applications – hybrid contacts. If an input is wired to a high Z device this can incorrectly show a close due to stray voltages. To correct this loading is needed in the circuit. SPSs have misoperated due to this. SEL is developing an application guide to address this issue also.

345kV SF6 puffer type breaker failures, not extinguishing arc when called to open. There is a manufacture (HVB) that has issued maintenance advisory – NERC will be putting out a recommendation to industry and attach the HVB maintenance advisory asking how many each entity has and if they have performed the maintenance. The weight and size of the nozzle causes it to break off. There has been 7-8 of these types of failures.

Review of PRC Standards Under Development

a. PRC-001-2 and PRC-027-1, System Protection Coordination

b. PRC-004-3, Protection System Misoperations

c. PRC-005-3, Protection System Maintenance and Testing

d. PRC-024-1, Generator Frequency and Voltage Protective Relay Settings

e. PRC-025-2, Generator Relay Loadability

Future Meetings

a. October 22-24, 2013, possible location Atlanta

Pending Items

a. SW Outage Recommendation 21: Acceleration Control Function (support to SAMS)

b. Review data from Order No. 754 data request

c. Review regional misoperation data (PSMTF recommendation)

NERC Interchange Subcommittee
SPP RE Trustees Update
July 2013
Submitted by: Jeremy West, Entergy

Executive Summary:

The NERC Interchange Subcommittee has been dormant since 2012, but NERC is resuming the Coordinate Interchange Standards Drafting Team this year. The main points which the drafting team plans to address are:

- FERC Paragraph 81 compliance in the INT standards
- Coverage of issued FERC directives that impact the INT standards
- Revisiting the changes made in the original drafting team efforts and finalizing necessary standards changes to address industry concerns
- New INT standards for Dynamic Transfers and electronic and backup Interchange capabilities

An overview of key modifications made by the CISDT can be found in this Industry Webinar.

The future efforts of the CISDT are:

- Pending NERC Quality Review of the finalized INT standards
- Submission of the finalized INT standards to the NERC Standards Committee for approval to be posted and to hold an initial ballot
- Tentative meeting September 4-5, 2013; location TBD

Details:

The Coordinate Interchange Standards Drafting Team (CISDT) posted drafts of INT-004-3, INT-006-4, INT-009-2, INT-010-2, and INT-011-1 for a 30-day public comment period from November 10, 2009 through December 11, 2009. Following the posting, the drafting team reviewed comments and drafted additional changes before Project 2008-12 was put on hold by ERO in 2010. The CISDT reconvened in early 2013 to address needed changes to the NERC INT Standards and related documents.

The CISDT had a conference call on May 23, 2013. The following agenda items were covered during that meeting:

1. *Review / Finalize INT-011 (formerly INT-012) for Quality Review and Posting*
   a. NERC staff discussed the best way to account for intra-Balancing Authority transfers, as directed by FERC. The team decided to modify the definition of Request for Interchange, Arranged Interchange, and Confirmed Interchange to include “intra-Balancing Authority

transactions". They also decided to keep Requirement R1 the same with only minor changes to the accounting for intra-Balancing Authority transfers.

b. The SDT agreed that the number for this standard could be changed from INT-012 to INT-011 now that the formerly proposed INT-011 is being eliminated.

2. *Addressing Directive 866*

a. FERC Directive 866 directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that: (1) makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation.

b. The SDT is proposing to modify the definitions of Operational Planning Analysis and Real-time Assessment to incorporate Interchanges and intra-Balancing Authority transfers in order to address Directive 866.

3. *Review/Revise INT Standards for Posting*

The SDT reviewed and revised the rationale and background sections for INT-004-3, INT-006-4, INT-009-2, and INT-010-2. They also edited the requirements to eliminate overlapping.

4. *June 4 Conference Call*

The meeting notes from the June 4th conference call are currently in the process of being updated and posted to the project web page. That call was used to finalize the INT standards prior to submission within the NERC process. The finalized INT Standards and associated documents are in Quality Review at NERC and will be sent to be reviewed by the NERC Standards Committee (SC) within the next few weeks. The SC will determine if the INT Standards can be posted for a 45 day comment and initial ballot period. All posted documents should appear at this link, Project 2008-12 Coordinate Interchange Standards Related Files DL. Documents found here will give more detailed information on the latest modifications.

5. *Future Meetings*

The CISDT plans to meet September 4-5, 2013 with the location to be determined.

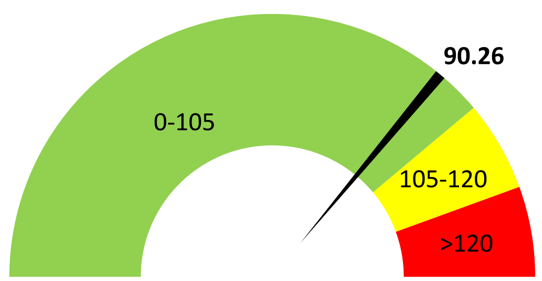
SPP RE Metrics Reporting As of February 28, 2013

W/in Target	Outside Target but w/in Alloted Range	Outside Alloted Range

1. High Impact

Accept MP or issue NAVAPS at avg. of <= 105 days

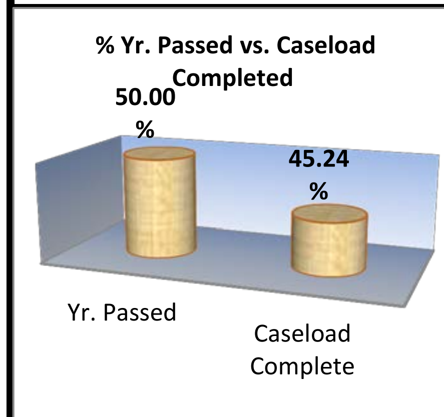
Current Avg. Days = **90.26**

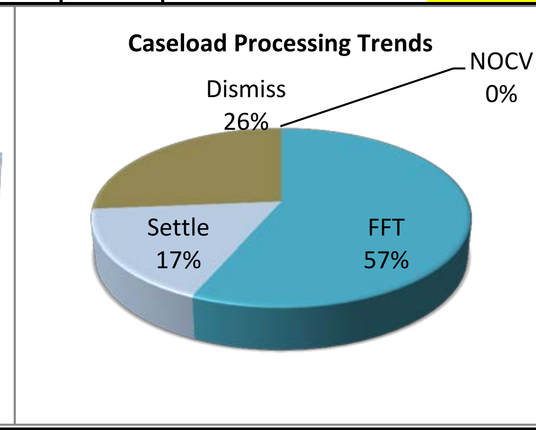


2. Maintain Caseload

Maintain a one year caseload

FFT	Settle	Dismiss	NOCV	Total:	Yr. Passed	50.00%
43	13	20	0	76	Caseload Complete	45.24%



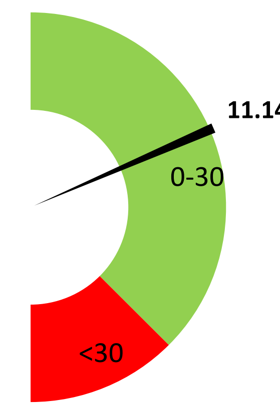


3. Mit. Accept/Reject

Accept/Reject Mit Plans w/in 30 days

Current Avg. Days = **11.14**

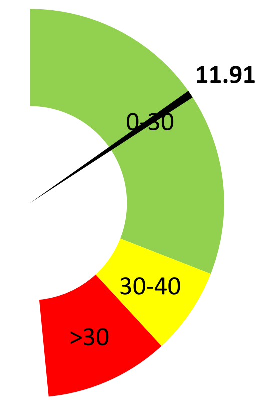
Metric Eligibility = 100.00%



4. Mit. Plan Completion

Complete Mitigation reviews <= 30 days

Current Avg. Days = **11.91**

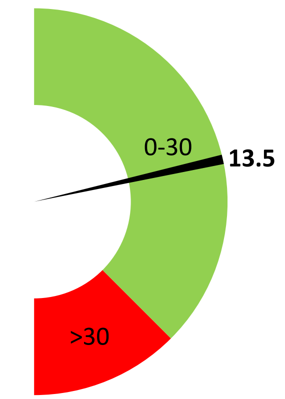


5. Milestones

Review Milestones w/in 30 days of qrtr. ending

Current Avg. Days **13.5**

Metric Eligibility 100.00%

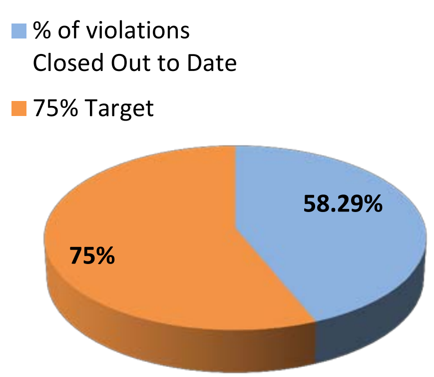


6. Documentation Close Out

Close Out 75% of all Closed Violations.

% of year passed based on 75% target 37.50%

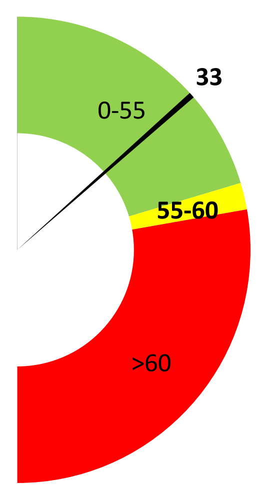
% of closed violations closed out **58.29%**



7. Publish Off-Site Audit

Publish Off-site w/in 55 days

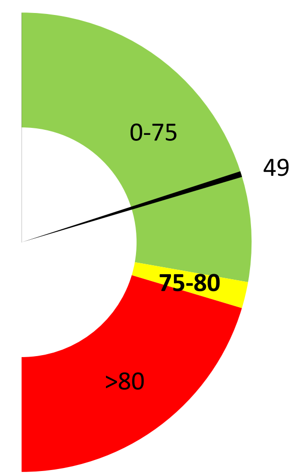
Current Avg. Days = **33**



8. Publish On-Site Audit

Publish On-site w/in 75 days

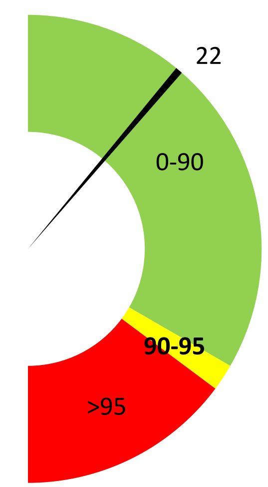
Current Avg. Days = **49**



9. Publish Spot Checks

Publish Spot Checks w/in 90 days

Current Avg. Days = **22**

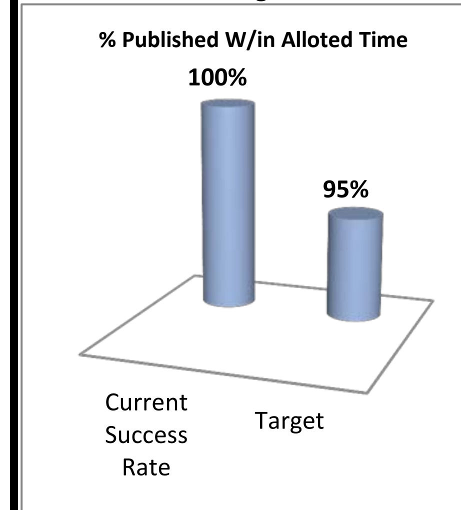


10. Publish: Excep., PDS, Self-cert

Publish reports w/in alloted timeframe 95% of time or greater

Current Success Rate **100%**

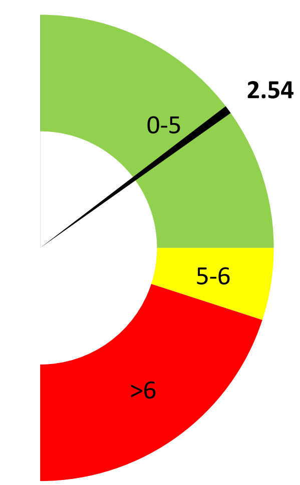
Target 95%



11. Process Incoming Viol.

Notify NERC of new violations w/in 5 business days

Current Avg. Days = **2.54**



12. Reduce Cash Costs

10 % reduction below estimated audit costs

X < -5%	-10% < X < -5%	x <= -10%

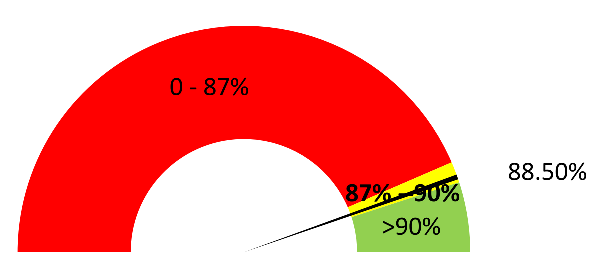
Current Percentage of Estimated Costs based on All Reported Costs:

-23.06%

13. Maintain/Increase Misop Success

90 % success rate or greater over rolling 4 quarter avg.

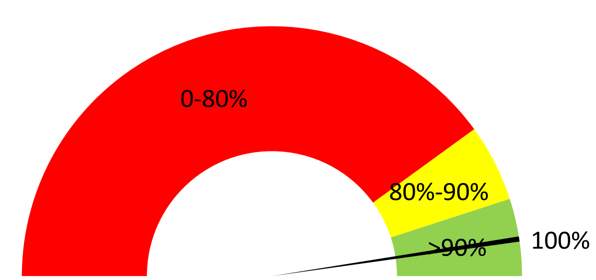
Current Success Rate: **88.50%**



14. Cause Code Success Rate

Achieve 90% success rate in Cause Coding Events

Current Success Rate: **100.00%**



15.Issue Reliability Assmnt.

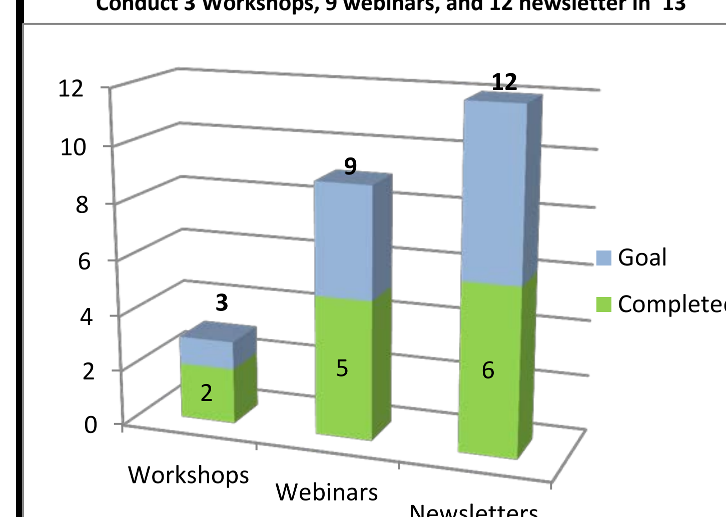
Issue 100% of assesments on time

On Time? **"Y" or "N"**

Y	**Summer**
Y	**LTRA**
No Data	**Winter**

16. Outreach

Conduct 3 Workshops, 9 webinars, and 12 newsletter in '13



SOUTHWEST POWER POOL REGIONAL ENTITY

STATEMENT OF ACTIVITIES

2013 JUNE YTD DRAFT (UNAUDITED)

(In Whole Dollars)	2013 JUNE YTD ACTUAL	2013 JUNE YTD BUDGET	VARIANCE	2013 FULL YEAR PROJECTION	2013 FULL YEAR BUDGET	VARIANCE
Funding						
ERO Funding	4,265,027	4,265,027	-	8,530,054	8,530,054	-
Penalty Sanctions	497,510	497,510	-	995,020	995,020	-
Total SPP RE Funding	**4,762,537**	4,762,537	**-**	**9,525,074**	**9,525,074**	**-**
Testing Fees	-	-	-	-	-	-
Workshops	-	-	-	-	-	-
Interest	1,462	-	1,462	-	-	-
Miscellaneous	-	-	-	-	-	-
Total Funding (A)	**4,763,999**	**4,762,537**	**1,462**	**9,525,074**	**9,525,074**	**-**
Expenses						
Personnel Expenses						
Salaries	1,664,975	2,036,311	(371,335)	3,610,016	4,072,621	(462,605)
Payroll Taxes	137,608	155,778	(18,170)	288,919	311,555	(22,636)
Benefits	148,715	156,082	(7,367)	302,987	312,164	(9,177)
Retirement Costs	76,972	81,453	(4,481)	157,323	162,905	(5,582)
Total Personnel Expenses	**2,028,270**	**2,429,623**	**(401,352)**	**4,359,245**	**4,859,245**	**(500,000)**
Meeting Expenses						
Meetings	22,569	43,250	(20,681)	74,901	86,500	(11,599)
Travel	174,529	243,000	(68,471)	460,599	499,000	(38,401)
Conference Calls	-	-	-	-	-	-
Total Meeting Expenses	**197,098**	**286,250**	**(89,152)**	**535,500**	**585,500**	**(50,000)**
Operating Expenses						
Contracts & Consultants	218,599	350,200	(131,601)	1,163,768	1,383,150	(219,382)
Office Rent	-	-	-	-	-	-
Office Costs	-	1,250	(1,250)	416	2,500	(2,084)
Administrative Costs	7,170	-	7,170	11,953	-	11,953
Professional Services	89,326	173,600	(84,274)	175,612	316,100	(140,488)
Computer Purchase & Maint.	-	-	-	-	-	-
Depreciation	-	-	-	-	-	-
Miscellaneous/ Contingency	-	-	-	-	-	-
Total Operating Expenses	**315,096**	**525,050**	**(209,955)**	**1,351,750**	**1,701,750**	**(350,000)**
Total Direct Expenses	**2,540,463**	**3,240,923**	**(700,459)**	**6,246,495**	**7,146,495**	**(900,000)**
SPP Inc. Indirect Expenses	2,167,741	2,184,162	(16,420)	4,568,323	4,368,323	200,000
SPP RE Indirect Expenses						
Total Indirect Costs	**2,167,741**	**2,184,162**	**(16,420)**	**4,568,323**	**4,368,323**	**200,000**
Total Expenses (B)	**4,708,204**	**5,425,084**	**(716,880)**	**10,814,818**	**11,514,818**	**(700,000)**
Net Change in Assets (A-B)	**55,795**	**(662,547)**	**718,342**	**(1,289,744)**	**(1,989,744)**	**700,000**
Fixed Assets						
Depreciation	-	-	-	-	-	-
Computer & Software CapEx	-	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-	-
Equipment CapEx	-	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-	-
Increase/(Decrease) in Fixed Assets (C)	**-**	**-**	**-**	**-**	**-**	**-**
Total Budget (Expenses plus Incr (Dec) in Fixed Assets (B+C))	**4,708,204**	**5,425,084**	**(716,880)**	**11,081,999**	**11,514,818**	**(432,819)**
Change in Working Capital (Total Funding less Total Budget) (A-B-C)	**55,795**	**(662,547)**	**718,342**	**(1,556,925)**	**(1,989,744)**	**432,819**
FTEs*	**29.3**	**34.5**	**(5)**			
Beginning WC - 01/01/2013	3,198,329	1,358,075	1,840,254	2,706,445	1,358,075	1,348,370
Change to WC - 2013 YTD	55,795	(662,547)	718,342	(1,556,925)	(1,989,744)	432,819
Working Capital as of 6/30/13	**3,254,124**	**695,528**	**2,558,596**	**1,149,520**	**(631,669)**	**1,781,189**

*Headcount (RE direct staff count as of 12/31/2012 and shared staff YTD billed hours/1880).

Southwest Power Pool Regional Entity

2013 Outreach Report

July 18

June Newsletter:

- FERC Extends BES Implementation to July 1, 2014
- Reminder: June Webinars

Videos:

- Four new videos posted:
  - **CIP-005 R3**
  - **Firewalls: 13 Ways to Break Through**
  - **NetAPT Demo**
  - **CIP-007 R3 and R4**

- 679 plays YTD

Workshops:

- Created and published **agenda** for Oct. 8-9 Fall Workshop

Webinars

- 78 registrants for June 27 webinar on *EOP-003 and PRC-006 Effective 10/1/13*
- Scheduled Aug. 27 webinar on Standards Development Status Report Presented By NERC
- Scheduled Sept. 19 webinar on 2013 Winter Reliability Assessment,
- Scheduled Sept. 20 webinar on Determining and Communicating TOP System Operating Limits

June 10

May Newsletter:

- From Ron's Desk (*BES definition, State of Reliability Report, ERO Strategic Plan, Staff Metrics*)
- June 27 webinar on EOP-003 and PRC-006, Effective 10/1/13
- Trouble Finding Standards info on NERC's New Website?
- 2013 Summer Assessment: Sufficient Reserves For SPP Region
- July 15 Deadline for Facility Ratings Alert, Low Priority Lines
- Consider Joining Spare Equipment Database
- New Standard Versions Effective July 1, 2013
- CIP Tip: Free NERCFilt Module
- FERC Issues NOPRs on Transmission Planning Standards and Interpretation of Disturbance Control Performance
- May 9 NERC Board Approvals
- New on NERC.com and NERC Events

Videos:

- 583 “plays” YTD for all videos
- Filmed four videos at CIP Workshop; currently being edited

Workshops:

- 172 stakeholders attended CIP workshop in-person or via webex

May 20

April Newsletter:

- From Ron’s Desk: CIP Transition, RAI, BES Processing, and Paragraph 81 Retirements
- CIP Workshop Hotel Cut-off 4/29/13 - Event Available via Webinar
- June 27 webinar on EOP-003 and PRC-006, Effective 10/1/13
- May 9 webinar on Long Term Reliability Assessment
- Understanding NERC’s CIP Transition Guidance
- New Regional Lesson Learned on Control Center Evacuation
- Important Reminders re: Data Submittal and Deadlines
- TOP Blackstart Plans due to RC May 1
- April webCDMS Tip – Using IE 10
- FERC Issues NOPR on Generator Requirements at the Transmission Interface

Videos:

- 539 “plays” YTD for all videos

Webinars:

- 90 registrants for May 9 webinar on Long-Term Reliability Assessment
- Held several work sessions for June 27 webinar on EOP-003 and PRC-006 Effective 10/1/13

Website:

- Updated all RE webpages with new NERC.com links

Workshops:

- Finalized logistics and presentations for CIP Workshop

April 22

March Newsletter:

- Equipment in New Protection System Definition Must be Included in Maintenance/Testing Program by 4/1/13
- Need More Info on EFT Server? Join April 18 Webinar
- May 9 Webinar on Long Term Reliability Assessment
- CIP V4 Compliance Guidance
- Are you Accurately Completing your Self-Certification?
- Missed the Spring Workshop? Get presentations, handouts, FAQs, & videos
- Mar. webCDMS Tip – Purchasing Additional webCDMS Digital Certificates
- Slides Posted: 2013 Summer Assessment and Misoperations webCDMS Module
- Reminder re: Q1 Reporting Deadlines

- FERC Approves FAC-003-2 - Transmission Vegetation Management
- Reliability Assurance Initiative – All Concept White Papers Now Posted
- CANs to be Phased Out
- NERC Events and New on NERC.com

Videos:

- Posted two new videos posted to video training webpage:
  - Event Analysis – An Entity's Perspective
  - Compliance Education at My Organization panel

- 463 "plays" YTD for all videos

Webinars:

- 100 registrants for March 22 webinar on Misoperations Reporting in webCDMS – FAQ also provided to registrants
- 47 registrants for April 18 webinar on How to Use the EFT Server
- Scheduled June 27 webinar on EOP-003 and PRC-006 Effective 10/1/13

Website:

- Added links to all training videos from Outreach page
- Added webpage for CIP Workshop

Workshops:

- 120 stakeholders registered to-date for May 21-21 CIP workshop
- Holding conference calls and practice sessions for presentations; finalizing logistics

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March 18

February Newsletter:

- March Workshop Available via Webinar
- Clarification re: Mitigation Plan Proposed and Actual Completion Dates
- Check out our May 21-22 CIP Workshop Agenda
- Quick CIP Tip: CIP-006-3 R1
- Feb. webCDMS Tip – Submit Self-Report for New Self-Cert Non-compliance Responses
- March-May Webinars
- Staff News: Welcome Back to Greg Sorenson
- The White House on Cyber Security
- Four New EMS/SCADA Lessons Learned
- NERC Trustees Approve Multiple Standards
- NERC Pilots Cost Effective Analysis Process

Webinars:

- 64 registrants for March 15 Stakeholder Input on Summer Assessment Webinar

Website:

- Major updates to Standards Process Manual Task Force webpage

Workshops:

- 162 stakeholders attended March 5-6 workshop in-person or via webinar; feedback very positive, particularly regarding small group discussions

February 15

January Newsletter:

- 2012 By the Numbers
- Clarification re: CIP V4 and V5 Implementation
- Have you Registered for March Workshop? Hotel Cut-off 2/18
- Registration Open for May 21-22 CIP Workshop
- Webinars on Misops Reporting, Assessments, EFT Server
- 100 Ways Your Organizations Are Making Training "Stick"
- Three New Training Videos Posted
- Quick CIP Tip: CIP-007 R.5.1.2
- January webCDMS Tip – Revoking/Reassigning webCDMS Digital Certificates
- Reminder – Comments due 2/9 on Revised SPP RE Standards Process Manual
- Staff News: Welcome Mike Hughes & Congrats to Shon Austin

Webinars:

- Scheduled March 15 Stakeholder Input on Summer Assessment Webinar
- Scheduled May 9 Stakeholder Input on LTRA webinar

Workshops:

- Completed preparations for March 5-6 workshop
- Published agenda for May 21-11 CIP workshop and confirmed all guest speakers
- Scheduled conference calls and practice sessions for CIP Workshop
- Held conference calls and practice sessions for March workshop

January 18

Videos:

- Posted three new videos:
  - Human Performance: Entity Perspectives & Experiences
  - Human Performance: Impact on Reliability
  - Training Employees on Compliance

Webinar:

- Scheduled How to Use EFT Server & Evidence Protection webinar, April 18, 10:00-10:45 CST

Workshops:

- Developed draft agenda for May 21-11 CIP workshop and confirmed eight guest speakers; will publish agenda in February

- Scheduled conference calls and practice sessions for March 5-6 workshop

2013 Event Report

Debbie Currie
Lead Engineer

July 29, 2013

Southwest Power Pool

SPP Regional Events (Jan. 1– June 30, 2013)

- 9 events, 2 Category 1 Events analyzed via NERC's Event Analysis process
  - Category 1f event involved evacuation of a primary control center due to smoke from a nearby fire
  - Category 1a event initiated by a lightning strike and failed insulator that led to the loss of ~1400 MWs of generation by two entities located in two regions
  - 7 events were "Category 0" events that will be used by NERC for trending purposes
    - Weather
    - Vandalism

Evacuation of Control Room Due to Fire

- Fire occurred in powerhouse adjacent to primary control center
  - Decommissioned water tank being dismantled
  - Welding spark ignited flammable material in tank
  - Smoke penetrated the control center
- Hot work procedures not followed
- Event has been cause coded and a Lesson Learned posted on SPP.org

Generation Loss Initiated by Lightning Strike

- Lightning strike caused catastrophic insulator failure on a 345 KV line
- Protective relaying correctly initiated isolation of the fault
- One substation breaker did not fully open
- Protective relaying scheme initiated further breaker action at two substations
- Resulted in ~1400 MW generation loss by two entities located in adjacent regions
- Event has been successfully cause coded

Activity Related to Large NERC-wide Events

- February 2011 Winter Weather Event
  - Winter Weather Readiness Reliability Guide published by NERC Operating Committee March 5, 2013
  - Previous Cold Weather Events - Trend Report
    - Study of winter weather events from 1983 to 2011
- September 2011 SW Blackout Event
  - FERC designation of sub-100 kV facilities as part of new BES definition
  - Effective date of the new BES definition delayed to July 1, 2014

Winter Weather Readiness Reliability Guide

- Focus on maintaining individual unit reliability and preventing future cold weather related events
- Compilation of industry practices
  - Safety
  - Management Roles and Expectations
  - Processes and Procedures
  - Evaluation of Potential Problem Areas
  - Testing
  - Training
  - Communications

Previous Cold Weather Events – Trend Report

- Event Analysis Subcommittee Trend Working Group examined 11 cold weather events
  - 3 events comparable in size and scope to February 2011 event
    - December 24-27, 1983 – FRCC Cold Weather Event
    - December 21-24, 1989 – TRE and FRCC Cold Weather Event
    - Week of January 16, 1994 – RFC Cold Weather Event
  - Firm load was lost
  - The event impacted more than one utility
  - Generation loss caused capacity issues and immediate action was required by system operators
  - Common Issues
    - Constraints on natural gas supply to generators
    - Generating unit trips, de-rates or failures to start due to equipment freezing

Links

- SPP RE Event Analysis Webpage
- NERC Event Analysis Process Documents
- SPP RE Lessons Learned
- NERC Lessons Learned
- Winter Weather Readiness Reliability Guide
- February 2011 Winter Weather Event Report
- September 2011 Southwest Blackout Event Report
- BES Definition – FERC Orders 773 and 773-A