Southwest Power Pool
SYSTEM PROTECTION AND CONTROL WORKING GROUP and SPP UFLS
Standard Drafting Team Meeting
MINUTES
May 13, 2010
9:00 a.m. – 11:00 a.m.
Net conference

Item 1 – Administrative:

Shawn Jacobs, Chairman, called the System Protection and Control Working Group (SPCWG) meeting to order at 9:00 a.m. The agenda was approved (Attachment 1 – Agenda).

Following members were available for this meeting:

Shawn Jacobs	: OG&E
Heidt Melson	: SPS
Lynn Schroeder	: WERE
Doug Jackson	: AEP
Tim Hinken	: KCPL
Louis Guidry	: CELE
Ken Zellefrow	: SPRM
Ron McIvor	: OPPD
Steve Wadas	: NPPD
Bud Averill	: AEP
Mak Nagle	: SPP Staff

Other meeting attendees were:

Jason Speer	: SPP Staff
Kevin Goolsby	: SPP Staff
John Allen	: SPRM
John Anderson	: WERE
Brent Carr	: AECC
Fred Meyer	: EMDE
Darrell Piatt	: FERC

Item 2: Aurora Alert

NERC has issued a new Aurora advisory, which is an expansion to the initial NERC advisory from 2007. Comments about this new alert were due to NERC by May 14th and several members had already written their comments. The SPP compliance group had agreed to consolidate all of the comments and create a single comment document for the SPP SPCWG.

Item 3: NPPD Redundancy

Steve Wadas brought up a system redundancy question to the group. NPPD was going to build a new 345kV line and use dual line carrier schemes. The power line carrier would travel on separate phases, using separate PLC equipment, coax, tuners, and wavetraps. NPPD wanted to verify that this would meet SPP Criteria 7.2.3 involving system redundancy in SPP. The SPCWG confirmed that the NPPD scheme would meet the SPP redundancy criteria.

Item 4: SPP UFLS Standard

The Standard Drafting Team reviewed the response to comments from the 3rd draft of the UFLS standard as well as the NERC RRSWG comments on the draft. The SDT decided that there would need to be a 4th draft instead of sending the 3rd draft for ballot.

NERC RRSWG made several comments on the SPP UFLS standard. SPP staff will try to coordinate the next SDT meeting with a NERC representative, to better understand NERC's comments.

The SDT went through the consideration of comments from the 3rd draft and assigned each of the questions and comments to the following people. (Attachment 2 – 3rd Draft Response to Comments)

Question 1 – Louis Guidry, Bud Averill
Question 2 – Louis Guidry, Bud Averill
Question 4 – Lynn Schroeder, Ken Zellefrow, Doug Jackson
Question 5 – Lynn Schroeder, Ken Zellefrow, Doug Jackson
Additional Comments - Lynn Schroeder, Ken Zellefrow, Doug Jackson
NERC RRSWG Comments – Shawn Jacobs, Heidt Melson

Item 5: Closing Administrative Duties

The next meeting has been scheduled for June 16 (1pm-5pm) and June 17 (8am-12pm) in Dallas.

The net conference was adjourned at 10:45 a.m.

Respectfully submitted,

Mak Nagle, Secretary

SOUTHWEST POWER POOL
SYSTEM PROTECTION AND CONTROL WORKING GROUP and SPP REGIONAL STANDARD DEVELOPMENT MEETING
May 13, 2010 (9:00 a.m. till 11:00 a.m.)
Net Conference

- AGENDA -

Item 1 – Administrative
- Call to order
- Proxies
- Approve agenda

Item 2 – Aurora Alert

Item 3 – NPPD Redundancy (Steve)

Item 4 – SPP UFLS Standard (All)
- Responses to comments received for 3rd Draft
- NERC RRSWG Comments
- 4th Draft

Item 5 – Closing Administrative Duties
- Next meeting place & date
- Upcoming meeting topics
- Adjourn meeting

1. **Section 3.2 has been added for entities that have a total forecasted Native Load less than 100 MW. Do you agree with this approach? If not, what would you recommend?**

Responses
Yes - 4
No - 1

Organization	Question 1:	Question 1 Comments:
AEP	Yes	
BPU	No	See comments at the end – I generally agree, but would also like the ability to request a waiver.
Calpine		
GSEC		We support this section if SPP can clarify that Section 3.2 does not apply to a Distribution Provider (DP) with less than 100 MW that has aggregated their load with other DPs. We believe that is the intent of R3.2, but Question 1 implies differently.
OMPA	Yes	Each entity should participate in the overall UFLS program. A generic 30% load relief level without specific frequency targets is admirable; however, such entities should shed load at each setpoint in R3.1; otherwise, the tendency could be to shed load only at 58.7 Hz.
NPPD	Yes	This will not affect our company since our load is much greater than 100MW. I see this as a benefit to both small and large load serving companies. This will require all UFLS PDP's and UFLS PTO's to shed their share of load. The companies with loads less than 100MW can load shed their 30% of their forecasted peak Native Load in one step verses 3 stages if they don't have the number of circuits to shed. The large companies will benefit by having the smaller companies shed their percentage.
SPRM	Yes	

2. **Can your generator frequency trip points meet Attachment 1 and 2 requirements or be modified to meet these requirements without endangering the generation equipment? If not, what are your limits?**

<u>Responses</u>
Yes - 1
No - 3

Organization	Question 2:	Question 2 Comments:
AEP	No	As noted in previous comments on this standard AEP and other generator owners have some units that can not comply with the frequency operating requirements as written. These units have limitations prohibiting them from operating down to the low frequency trip points stated in the proposed standard. • Three steam turbines cannot meet the requirement as currently proposed. The minimum operating frequency of these units is: at 59.4Hz for 180 seconds and at 58.4Hz for 30 seconds. • Four combustion turbines cannot meet the requirement as currently proposed. The minimum operating frequency of these units is: at 58.5 Hz for 2 seconds and at 57.0 Hz at 0.1 seconds.
BPU	Yes	I am making an assumption that we could match this. Three of our four gas turbines do not have 81U underfrequency relaying at present.
Calpine		
GSEC		
OMPA		N/A - OMPA's generators are not directly connected to the BES; rather, they are connected at 69kV or lower voltage.
NPPD	No	Our company has one peaker plant, two coal plants, three gas turbine plants, and one nuclear plant that does not meet Attachment 1 or 2. The one peaker plant settings can be changed to meet requirement R8. The two coal plants will be forced into some form of modification. The only way to avoid a system modification at the plant would be to remove R8 from the standard. If R8 doesn't get removed the plant is looking at the costs for various modification options. Other than our issue with R8, we have no other concerns. The Standard is detailed enough that we can easily comply with it, which is an improvement over other standards. The three gas turbine plant settings can be changed to meet requirement R8. This is only possible since we have a microprocessor relay with multiple set points which can be set to meet R8 and meet turbine manufacture

		requirements. Here is the comments from our nuclear plant. The nuclear plant has potential consequences to the long term operation of the main generator below the existing setting of 58.5 HZ which is within the recommendation of IEEE STD C37.106. The turbine will be able to support the low frequency setting, but there will be long term degradation on the generator for running continuous outside recommended range of 98% to 102% of rated frequency. We will not be able to meet the new guideline for the over frequency trip, since our overspeed protection is set at 103% (1854 RPM equivalent to 61.8 HZ) and the new guideline recommendation is to set the protection above 62.2 HZ equivalent to 1866 RPM. Keep in mind that we don't have high frequency relay for trip protection, but we have overspeed protection. The overspeed protection is driven by the new turbine vendor guideline to prevent operation above 1854 RPM. We have a maximum of two hour of operating above the limit (accumulative) for the life of the LP and we already used about an hour of that time. Due to the new DEH modification we no longer need to overspeed the turbine above 1800 RPM for testing purpose and that is good, since we only have one hour left for operating above 103% (saved for potential future plant overspeed events). Does SPP have requirements on overspeed protection by non devices that are not relays? The current SPP criteria is stated as 58.5 Hz which match C37.106, what happens if we have manufacturer restrictions that will not allow us to meet attachment 1 or 2. We would like SPP to remove the portion of R8 that requires additional Load shedding shall be equal to or greater than the maximum amount of generation that can be tripped, instituted at the same frequency and time delays as the generator if the generator set points are not above attachment 1 or below attachment 2. The planning coordinator should first study if the generator will trip off line prior to making them shed load. We did not see any requirements in the NERC standard that the generator trips had to be outside the curves and that additional load shedding was required if they don't. This additional load shedding might be more aggressive load shedding then required. Can the PC modify the three stages of load shedding in the BA so the generator doesn't have to run outside manufacture requirments or trip additional load. Here is some limits on one of our machines: Mechanical resonance, under/over speed conditions and generic performance characteristics of steam turbines are listed below. These values vary between manufacturers and it should be noted that the durations are cumulative over the life of the turbine, not a single event. • Under/over speed condition of 1% will not damage turbine indefinitely (59.4/60.6Hz) • Under/over speed condition of 2% for 90 min could damage turbine (58.8/61.2Hz) • Under/over speed condition of 3% for 10 to 15 min could damage turbine (58.2/61.8Hz) • Under/over speed condition of 4% for 1 min could damage turbine (57.6/62.4Hz)
SPRM	No	City Utilities has some gas fired peaking turbines that don't meet the curves. We have not determined at this point whether the relay settings can be adjusted without potential equipment damage. The settings of interest are at 58.0 Hz with 1.07 second delay (on Attachment 1 curve), 61.2 Hz with 20 second time delay (> 30 seconds required per Attachment 2 curve) and 61.8 Hz with 1.0 second time delay (on Attachment 2 curve).

3. **Do you agree with revisions made to the Measures in support of the revisions to the Requirements? If not, what would you recommend?**

<u>Responses</u>
Yes - 5
No - 0

Organization	Question 3:	Question 3 Comments:
AEP	Yes	AEP does not see any conflict in the Measures with respect to the Requirements. However, the Measures are very general and don't add much value.
BPU	Yes	
Calpine		
GSEC		We need clarification. Will all DPs, regardless of size, be required to have individual engineering assessments and mitigation plans per R2? If not, will DPs just participate with the Planning Coordinator (PC) and the PC will perform the engineering assessment and mitigation plan and then the PC would provide such results to the DP for compliance documentation for R2/M2?
OMPA	Yes	Need to clarify M2. Is the Planning Coordinator (SPP) responsible for initiating the Engineering Assessment? has the Assessment been defined?
NPPD	Yes	
SPRM	Yes	

4. Do you agree with the Violation Severity Levels that were added to this draft? If not, what would you recommend?

Responses
Yes - 5
No - 1

Organization	Question 4:	Question 4 Comments:
AEP	No	Overall, the VSL appear to be on par with the requirements. But, AEP has some comments regarding some of the draft requirements. Therefore, it would premature to address all of the Violation Severity Levels. We are reserving our comments until those requirements are addressed in a future draft.
BPU	Yes	
Calpine		
GSEC	Yes	
OMPA	Yes	Regarding R3.1 and R3.2 - What does it mean to "demonstrate"?
NPPD	Yes	
SPRM	Yes	

5. Do you agree that this standard is ready for Ballot? If not, provide specific suggestions that would make it acceptable to you.

Responses
Yes - 1
No - 6

Organization	Question 5:	Question 5 Comments:
AEP	No	As we stated in the last draft, AEP questions if the maximum step sizes are too large, and, in considering the allowed intentional time delay of up to 30 cycles, could result in excess shedding of load and unnecessarily high frequency. First, the step sizes need to be limited in size in order that a small load-generation imbalance just sufficient to trigger a step will not cause excessive load loss and high frequency. Secondly, the total delay time should not be so long as to result in the tripping of another step before the previous step has dumped its load and had a chance to arrest the declining frequency. Assuming a typical rate of frequency decline of .05 Hz/sec for every one percent imbalance, with ten percent steps and a .3 Hz increment between steps, our calculations show that total time delay should be limited to approximately 27 cycles. We understand that SPP is coordinating a UFLS study with Powertech to determine the validity of the three UFLS step ranges and to verify the intentional relay time delay of 30 cycles does not result in excess shedding of load. We recommend waiting until the study is finalized. With respect to Requirement 8 of this draft we have the following comments to offer. The requirement to "arrange for load shedding to be installed" still does not make sense to AEP and comments to that effect were also made by other entities. Units that are unable to comply with the standard are in many cases units that see very little operation and would likely be offline during a frequency excursion. "Arranging for load shedding to be installed" would in effect cause an excessive amount of load to be dropped since the units being compensated for would likely not even be in service. Units operate throughout the load range. How would anyone know how much compensating load has to be arranged for if this standard is approved as written? Would a generator have to "arrange for load shedding" based on full unit capability or some lesser amount? Again this would likely result in excessive load shedding.
BPU	No	BPU fully intends to abide by standards. SDT has revised R1 and created new R3.2, but BPU's forecast peak

		native load is 140 MW (well above 100 MW). While it appears we should be able to meet this standard, BPU is greatly concerned that there could be a future scenario wherein BPU could not meet the specified level without tripping all or a portion of the refinery or the local Manville insulation plant, BPU finds inherent safety concerns in willfully tripping either of these. BPU would like to see a revision to request a waiver for cases of security or safety.
Calpine	No	Regarding R8 and R8.1: Calpine wishes to thank the Standard drafting team for their work on this issue. We agree that there is a need for a coordinated underfrequency load shedding program and agree that early generator tripping can have a detrimental effect on system reliability. We also agree that, if a existing generator cannot comply with the underfrequency performance requirements, shedding load in an amount equal to the lost generation is an effective solution. However, requiring owners of existing generation to arrange for load shedding places an undue burden on entities that have met all existing requirements for interconnection. Existing generation should be exempt from the requirement to arrange for load shedding by other entities. Non-utility Generator Operators do not have load to shed, and allowing an exemption for entities installing generators in the future that can arrange to shed load provides an unfair competitive advantage to such entities and reduces the future reliability of the Bulk Electric System by allowing otherwise avoidable load shedding. All new generation commissioned after the effective date of this Standard should be required to meet the frequency performance requirements of this Standard. We recommend the following change to R8 and M8 (Changes and deletions below in capital letters) R8. Each Generator Owner with individual generating units greater than 20 MVA (gross nameplate rating) or generating plant/Facilities greater than 75 MVA (gross nameplate rating) directly connected to the BES shall verify by review of relay settings, generator control system settings, and generator operating guides that their generating unit(s) will not trip above the Generator underfrequency curve in Attachment 1 and will not trip below the Generator overfrequency curve in Attachment 2. Should this not be practical due to the operating characteristics of certain EXISTING units, the (DELETE Generator Owner) ASSOCIATED TRANSMISSION OWNER OR DISTRIBUTION PROVIDER shall arrange for Load shedding to be installed in addition to that required Load shedding as listed in R3. [VRF: Medium][Time Horizon: Long-term Planning] 8.1. This additional Load shedding shall be equal to or greater than the maximum amount of generation that can be tripped, instituted at the same frequency and time delays as the generator would be expected to trip and shall be within the same island. M8. EACH GENERATOR OWNER IDENTIFIED IN R8 SHALL HAVE EVIDENCE THAT IT COMPLIES WITH THE REQUIREMENTS OF R8. WHERE EXISTING GENERATORS CANNOT MEET THE UNDERFREQUENCY REQUIREMENTS OF THE STANDARD (DELETE For each existing generator that cannot meet the

		underfrequency requirements of this Standard,) ASSOCIATED TRANSMISSION OWNER OR DISTRIBUTION PROVIDER (DELETE Each Generator Owner of generation shall have evidence that it complies with the R8 or) SHALL HAVE EVIDENCE THAT IT has made arrangements for additional Load shedding (DELETE, if appropriate,) as required in R8.
GSEC	No	We need further clarification on the Section 4.2 (Applicability). The reference to “any provider” is not clear. “Provider” is not a defined term. Is this a continuing attempt to impose requirements on entities that don’t qualify as DPs under the Statement of Registry Criteria? If so, we continue to think it is inappropriate for SPP to try to impose requirements on entities that NERC has determined to not affect the BES. If that’s not what the reference to “any provider” means, then we simply don’t understand what it does mean, and it should be clarified or deleted.
OMPA	Yes	
NPPD	No	R8 needs to address those units that can not meet attachment 1 or 2 based on manufacturer requirements and warranty issues with out requiring additional load shedding. Loading shedding studies in the area of these plants should be studied to see if faster trip times on stage 1, 2, and 3 or if different frequency set trip points other than 59.3, 59.0 or 58.7 can be used to arrest the frequencies prior to reaching the generator trip points. This would allow the PC to meet attachment 1 and 2 in the NERC standard draft.
SPRM	No	Believe the Attachment 1 and 2 curves are overly restrictive and that previous UFLS studies indicate this. It appears that the lowest frequency in previous studies is approximately 58.4 Hz for about 1 second and highest frequency is about 60.2 Hz for about 1 second. Yet the proposed curves (1) Go as low as 58.0 Hz and require “ride-through” at 58.4 Hz for approximately 9 seconds and ; (2) Require “ride-through” capability well above apparent likely overfrequencies that the units will be exposed to. Recommend that these curves be adjusted to be less restrictive (less broad) as indicated by past studies. Perhaps the study currently being performed should be used to modify these curves.

Additional Comments:

Organization	Additional Comments:
AEP	It appears that the SDT has addressed a number of our comments from the last draft. We commend the hard work of the SDT. However, AEP feels there are a few more outstanding concerns before this can proceed.
BPU	BPU historically is covered by Westar's UFLS. BPU is aware that waivers have been requested in the past as part of SPP UFLS program. Although the wider permitted % of load that can be tripped is helpful, BPU would still like to see a provision enabling a utility to request a waiver. BPU does not plan to trip safety/security related loads nor either of the two cities it serves. This means BPU is working with a significantly reduced portfolio of available to trip as we embark on a UFLS program.
Calpine	
GSEC	
OMPA	
NPPD	
SPRM	