Southwest Power Pool

TRANSMISSION WORKING GROUP MEETING

July 2, 2014

Net Conference

• Summary of Action Items •

1. No action was taken

Southwest Power Pool

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TRANSMISSION WORKING GROUP MEETING

July 2, 2014

Net Conference

• M I N U T E S •

Agenda Item 1 – Administrative Items

TWG Vice-Chair Travis Hyde called the meeting to order at 8:32 a.m. The following members were in attendance (Attachment 1a, 1b – Attendance, Proxies) or represented by proxy:

Mo Awad, Westar Energy, Inc.
Scott Benson, Lincoln Electric System
Dustin Betz, Nebraska Public Power District, proxy for Randy Lindstrom
John Boshears, City Utilities of Springfield
John Fulton, Southwestern Public Service Co.
Joe Fultz, Grand River Dam Authority
Travis Hyde, Oklahoma Gas & Electric
Matt McGee, American Electric Power
Nathan McNeil, Midwest Energy, Inc.
Nate Morris, Empire District Electric
Michael Mueller, Arkansas Electric Cooperative Corporation
Alan Myers, ITC Great Plains
John Payne, Kansas Electric Power Cooperative, Inc.
Jon Shipman, Omaha Public Power District, proxy for Dan Lenihan
Jason Shook, GDS Associates representing ETEC
Tim Smith, Western Farmers Electric Cooperative
Harold Wyble, Kansas City Power & Light

Kirk Hall, SPP staff, informed the group that there was a quorum.

Agenda Item 2 – Mandated Reliability Benefit Metric

Juliano Freitas and Josh Ross, SPP staff, reviewed the methodologies (Attachment 2a, 2b – Mandated Reliability Benefit Metric, Vote Results) for the calculation of Mandated Reliability Benefits for projects in the 2015 ITP10. They highlighted the pros and cons of each methodology, as well discussed hybrid calculations requested by the ESWG. During their presentation, they highlighted the SPP staff recommendation as well as the ESWG approved methodology. Juliano and Josh requested an approval from the TWG to take to the July MOPC meeting.

The group discussed the reasoning behind the hybrid calculation methodologies recommended by staff and approved by the ESWG. Juliano and Alan Myers, ESWG Chair, noted that the methodologies all have shortcomings. The staff recommendation and the approved ESWG methodology were meant to be a compromise since no methodology was perfect as a standalone.

Scott Benson made a motion to approve System Reconfiguration as the methodology for calculating Mandated Reliability Benefits for all kV levels. John Boshears seconded the motion.

During discussion on the motion, staff clarified for members that this metric was not the only metric being calculated for reliability projects.

The motion failed with 7 votes for, 8 votes against, and 2 abstentions.

After the meeting Nate Morris from Empire District Electric gave his reasoning for his abstention:

> "Empire agrees with the motion as stated using System Reconfiguration in determining reliability benefit(s). Empire feels that System Reconfiguration does better allocate the benefits of specific projects to the zones which will actually realize said specific benefits. However, Empire abstained from voting simply from the fact that there was not adequate notice of this item being an action item. Empire does not agree with how the vote was requested by SPP and did not participate due to this rushed approach. Given multiple recent examples, Empire feels that the membership has not been allotted the proper amount of time to vet processes brought before the group. Again, Empire does in fact support using a single benefit metric, specifically System Reconfiguration, but does not support the method in which the action item was requested by SPP."

After the meeting Alan Myers from ITC Great Plains provided the reasoning for his 'No' vote:

> "I believe that all of the stand-alone methodologies examined to date for allocating the benefits of mandated reliability projects each have distinct strengths and weaknesses. Because of this I believe that clear consensus within the stakeholder community for a single methodology does not exist. For these reasons, the hybrid approach that was recommended by ESWG is a superior alternative to the strict use of the system reconfiguration methodology. As such, I voted in opposition to recommending adoption of the system reconfiguration method alone."

After the meeting Mo Awad from Westar Energy provided an explanation for his abstention from the vote:

> "While the material was posted in a timely manner, this agenda item was not listed as an "action item". At the meeting, we were informed that this is an "action item" and a vote is needed."

Nathan McNeil from Midwest Energy provided his reasoning for his 'No' vote after the meeting:

> "Midwest voted no to the 100% system reconfiguration approach due to high allocation of EHV projects to local zones when those projects are primarily intended to support regional flows and provide a path for generation access and outlet away from those local zones for generation that may not be owned by or needed by the local area. Also, since the calculations are based on one-hour snapshot power flow models, the results may not be a good representation of how the system responds throughout the entire year. This is particularly true for western Kansas if the hours chosen are peak load, lower wind cases that do not capture the full impact of flow across the system in this area. I would have supported the hybrid approach recommended by SPP staff."

Agenda Item 3 – CRR-012 Wind Accreditation

Mitch Williams, GWG Chair, reviewed the Criteria Revision Request (Attachment 3 – CRR-012) for Criteria 12.2. Scott Benson questioned the why the accreditation for solar was staying the same. Mitch noted that there is not a significant amount of experience with solar generation and only 50 MW of solar generation in the SPP footprint. The intention was to leave the value for solar unchanged and review it at a later date when more data could be collected and analyzed. The group agreed with this approach and recommended no changes to the Criteria Revision Request.

The meeting was adjourned at 10:03 am

Respectfully Submitted,

Jody Holland
Secretary

Southwest Power Pool, Inc.

TWG NET CONFERENCE

July 2nd, 2014

Net Conference – Little Rock, Arkansas

• A G E N D A •

8:30 a.m. – 10:00 p.m.

1. Reliability Benefit Metric Update (Action Item) .... Staff (1 hr.)

2. CRR-012 Wind Accreditation .... Mitch Williams (30 min.)

All sessions in Central Daylight Time (Chicago, GMT-05:00)
Session detail for 'TWG Net Conference':

Participant	Name	Email	Date
1	david treichler	david.treichler@oncor.com	7/2/2014
2	Steve Hardebeck	hardebsm@oge.com	7/2/2014
3	noumvi ghomsi	noumvi.ghomsi@psc.mo.gov	7/2/2014
4	Travis Hyde	hydetd@oge.com	7/2/2014
5	Kevin Foflygen	kevin.foflygen@cityutilities.n	7/2/2014
6	Chenal WebEx	awhite@spp.org	7/2/2014
7	Harold Wyble (KCPL)	harold.wyble@kcpl.com	7/2/2014
8	Scott Jordan	sjordan@spp.org	7/2/2014
9	Jonathan Hayes	jhayes@spp.org	7/2/2014
10	Scott Benson (LES)	sbenson@les.com	7/2/2014
11	Jerry Bradshaw	jerry.bradshaw@cityutilities.r	7/2/2014
12	J. Fultz	jfultz@grda.com	7/2/2014
13	Dustin Betz (NPPD)	ddbetz@nppd.com	7/2/2014
14	Kyle Watson	kwatso2@entergy.com	7/2/2014
15	Dona Parks (GRDA)	dparks@grda.com	7/2/2014
16	Jon Shipman (OPPD)	jeshipman@oppd.com	7/2/2014
17	John Payne (KEPCo)	jpayne@kepco.org	7/2/2014
18	John Boshears (SPRM)	john.boshears@cityutilities.n	7/2/2014
19	John Fulton	john.fulton@xcelenergy.com	7/2/2014
20	Alan Myers	amyers@itcgeatplains.com	7/2/2014
21	Jason Shook (GDS/ETEC)	jason.shook@gdsassociates.c	7/2/2014
22	Nate Morris (EDE)	nmorris@empiredistrict.com	7/2/2014
23	Tim Smith (WFEC)	t_smith@wfec.com	7/2/2014
24	Nathan McNeil	nmcneil@mwenergy.com	7/2/2014
25	Matt McGee	mcmcgee@aep.com	7/2/2014
26	Bob Burner	g.burner@duke-energy.com	7/2/2014
27	Don Le	don.le@nee.com	7/2/2014
28	Mo Awad	mo.awad@westarenergy.com	7/2/2014
29	Michael Wegner (ITC)	mwegner@itctransco.com	7/2/2014
30	Stuart Houston	shouston@empiredistrict.con	7/2/2014
31	Gimod Olapurayil (ITC)	golapurayil@itctransco.com	7/2/2014
32	Michael Mueller	michael.mueller@aecc.com	7/2/2014
33	Kirk Hall	khall@spp.org	7/2/2014
34	Jeff Knottek	jeff.knottek@cityutilities.net	7/2/2014
35	Dee Edmondson	dedmondson@spp.org	7/2/2014
36	Al Tamimi	atamimi@sunflower.net	7/2/2014
37	Jeremy Severson (BEPC)	jseverson@bepc.com	7/2/2014
38	Randy Collier (CUS)	randy.collier@cityutilities.net	7/2/2014
39	Joe Lang	jlang@les.com	7/2/2014
40	jim useldinger	jim.useldinger@kcpl.com	7/2/2014
41	Chris Jamieson	cjamieson@spp.org	7/2/2014
42	Mitchell L Williams WFEC	m_williams@wfec.com	7/2/2014
43	Sandeep Baidwan	sbaidwan@lspower.com	7/2/2014

Kirk Hall

From: LENIHAN, DANIEL J <djlenihan@oppd.com>
Sent: Monday, June 30, 2014 4:37 PM
To: Kirk Hall
Cc: Jody Holland; 'Williams, Noman (nlwilliams@sunflower.net)'; Shipman, Jon; Verzal, Josh
Subject: TWG 07/02/14 - OPPD proxy

Kirk,

I will not be able to participate in the TWG meeting on 7/2. Jon Shipman from OPPD will call into the meeting for me and will be my proxy.

Thanks,

Dan Lenihan, P.E.
Manager, Transmission & Distribution Planning
Omaha Public Power District
Energy Control Center, ECC-5
4325 Jones Plaza, Omaha, Nebraska 68105-1066
Voice: (402) 552-5126
Fax: (402) 552-5679
Email: djlenihan@oppd.com

From: bounce-42264-27831@spplist.spp.org [mailto:bounce-42264-27831@spplist.spp.org] **On Behalf Of** Kitty McArthur
Sent: Wednesday, June 25, 2014 4:48 PM
To: Transmission Working Group
Cc: Kirk Hall; Jody Holland; Williams, Noman
Subject: TWG 07/02/14

Members and Representatives,

Meeting materials have been posted:

TWG 07/02/14 Agenda & Bkg. Materials

TWG 07/02/14 registration

Have a great day!
Kitty

Kitty McArthur
Southwest Power Pool
501-614-3230
kmcarthur@spp.org

SPP Southwest Power Pool

Kirk Hall

From: Lindstrom, Randy R. <rrlinds@nppd.com>
Sent: Thursday, June 19, 2014 11:48 AM
To: Kirk Hall
Cc: Betz, Dustin
Subject: FW: Possible TWG Meeting Times

Importance: High

Kirk – I will not be available for the next TWG Conference Call. I give my voting proxy to Dustin Betz for that Conference Call.

Randy R. Lindstrom
Transmission Planning Supervisor
Transmission Compliance & Planning
Nebraska Public Power District Operations
Office: 402-563-5240

From: Alex Watkins [mailto:awatkins@spp.org]
Sent: Thursday, June 19, 2014 8:27 AM
To: Lindstrom, Randy R.
Subject: Possible TWG Meeting Times
Importance: High

TWG Members,

As mentioned today during the call the TWG will need an additional meeting to approve Mandated Reliability Benefits Metric Methodology. Please use the following link to fill out your availabilities.

http://doodle.com/cqp2mp9834rkwwd9

Thanks!

Alex Watkins
Engineer I, Steady State Planning
awatkins@spp.org
501.688.8216

SPP Southwest Power Pool

Metrics Review & Recommendations

TWG

July 2, 2014

Southwest Power Pool

Helping our members work together to keep the lights on... today and in the future

Agenda

- **Introduction**
- **Assessment of benefit metrics and alternative allocation methodologies**
    A. Benefits of Mandated Reliability Projects

Overview

- **ESWG has been tasked with reviewing the calculation and allocation of benefit metrics for:**
  - 2015 ITP10
  - RCAR II
- **MOPC directed ESWG to provide recommendations by July 2014**
- **Brattle is engaged for an independent assessment of alternative methodologies on "tentative metrics"**
- **Today – will continue discussions on pros/cons of alternatives and show preliminary findings on the impact of RCAR I results**

	Benefit Metrics	Calculated in RCAR I?	Considered for 2015 ITP10 and RCAR II?	Included in This Assessment?
	Adjusted Production Cost (APC)	✓	Yes	
	Emission Rates and Values	✓	Yes	
	Ancillary Service Needs and Production Costs	✓	Yes	
	Avoided or Delayed Reliability Projects	✓	Yes	
	Capacity Cost Savings due to Reduced On-Peak Transmission Losses	✓	Yes	
A.	**Benefits of Mandated Reliability Projects**	✓	**Yes**	**Allocation method**
B.	**Benefits from Meeting Public Policy Goals**	✓	**Yes**	**Overall approach**
C.	**Mitigation of Transmission Outage Costs**	✓	**Yes**	**Allocation method**
D.	**Increased Wheeling Through and Out Revenues**		**Yes**	**How to include**
E.	**Marginal Energy Losses Benefits**		**Yes**	**How to include**
	Reducing the Cost of Extreme Events		No	
	Capital Savings due to Reduction of Members' Minimum Required Margin		No	
	Reduced Loss of Load Probability		No	

A. ASSUMED BENEFIT OF MANDATED RELIABILITY PROJECTS

Reliability Benefit Allocation Methodologies

- **Highway/Byway (current methodology)**
  - Allocates assumed benefits of mandated reliability projects in the same manner costs are allocated
- **Distribution Factor (DFAX)**
  - Measures relative usage of Reliability Upgrades by the load of each transmission zone assuming no transmission outages and that each zone is served by all generation in SPP (excluding renewable generation)
- **Line Outage Distribution Factor (LODF)**
  - Measures incremental usage of reliability upgrades under first contingency conditions (i.e., when existing facilities are on outage)
- **System Reconfiguration (SR)**
  - Measures relief on usage of existing facilities after reliability upgrades are added (assuming all else equal to case with upgrades)

Notes:
These allocation methodologies do not impact the total reliability benefit of projects.
They only impact the allocation of benefit to zones.

Reliability Metric Status – 6/24 Recap

- A motion to utilize the modified hybrid approach that assigns the following allocation methodology for the Assumed Benefit of Mandated Reliability Projects metric was approved by the ESWG.
  - Allocation breakdown:
    - >300 kV: 1/3 SR, 2/3 LRS
    - 100-300 kV: 2/3 SR, 1/3 LRS
    - <100 kV: 100% SR
  - 8 members voted for the motion.
  - 4 members voted against the motion.

Analysis Update

Allocation of RCAR I Mandated Reliability Benefits for All Projects Analyzed*

Zone	H/B		DFAX		LODF		SR		
	Prelim.	Updated	Prelim. DC	Updated DC	Prelim. DC	Updated DC	Prelim. DC	Updated DC	Updated AC
AEP	22.9%	22.4%	20.0%	20.5%	22.6%	19.0%	19.2%	17.4%	16.9%
CUS	0.8%	0.8%	0.6%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%
EDE	1.2%	1.3%	1.0%	1.0%	0.3%	0.3%	0.5%	0.4%	0.5%
GMO	2.1%	2.1%	0.9%	1.0%	0.2%	0.3%	0.3%	0.4%	0.5%
GRDA	1.4%	1.5%	1.5%	1.7%	0.4%	0.4%	0.4%	0.5%	0.4%
KCPL	3.9%	3.9%	2.1%	2.2%	1.8%	2.1%	1.4%	1.8%	2.7%
LES	1.2%	1.2%	0.8%	0.8%	0.2%	0.2%	0.3%	0.4%	0.3%
MIDW	1.5%	1.6%	1.4%	1.4%	1.6%	1.9%	1.7%	1.8%	1.5%
MKEC	1.6%	1.6%	1.9%	1.8%	0.1%	0.2%	0.0%	0.0%	0.0%
NPPD	4.7%	4.8%	4.3%	4.4%	7.2%	7.6%	6.8%	7.0%	6.0%
OGE	9.5%	9.6%	12.0%	13.2%	11.4%	11.2%	16.1%	15.0%	15.8%
OPPD	2.5%	2.6%	2.4%	2.5%	0.1%	0.1%	0.2%	0.3%	0.5%
SEPC	1.4%	1.4%	1.3%	1.2%	3.6%	4.7%	4.0%	5.0%	5.6%
SPS	19.6%	19.8%	30.6%	28.0%	26.2%	24.9%	23.8%	22.7%	21.3%
WFEC	6.0%	6.1%	3.3%	3.5%	5.3%	5.2%	4.4%	3.7%	2.2%
WR	19.6%	19.4%	16.0%	16.3%	18.9%	21.8%	20.9%	23.4%	25.7%
TOTAL	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Results updated to reflect:

- Revisions to project data
- AC power flow analysis for system reconfiguration

Changes mostly affected the allocation of high-voltage upgrades

* These results are based on preliminary analysis including approximately 80% of the RCAR I upgrades.

Brattle Assessment

Highway/Byway Methodology

- **Basic assumptions for allocating reliability benefits:**
  - Reliability upgrades ≥ 300 kV provide regional reliability benefits allocated to all zones based on load ratio share (LRS)
  - Reliability upgrades at 100-300 kV provide mostly (2/3) local and some (1/3) regional benefits (based on LRS)
  - Reliability upgrades < 100kV provide local benefits allocated to only the individual zones projects are located in
- **Attractive because it is intuitive, simple to calculate, transparent, and reasonable long-term proxy**
- **However:**
  - Incorporates neither actual usage, nor the need for specific upgrade, nor specific reliability benefit of individual projects
  - Does not necessarily capture potentially higher local reliability benefits of highway projects or the potentially higher regional reliability benefits of byway projects

DFAX Methodology

Attempts to calculate incremental flows on reliability upgrades to serve load in each zone

- Uses incremental power flows from all generation in the SPP footprint (excluding renewables, scaled based on their nameplate capacity) to each load zone
- Positive and negative DFAX are first weighted based on share of annual hours with positive and negative flows from PROMOD simulations
- Then normalized to size of each load zone using load ratio shares

Intends to measure the usage of upgrades under normal (N-0) system conditions but:

- Does not consider the reliability needs that triggered these upgrades in the first place (zones using upgrades may not be the ones that initially needed them)
- Many moving parts in implementing the DFAX approach (e.g., generation assumptions) can significantly impact the allocation of estimated benefits
- Incremental flows from <u>all</u> SPP generation to individual load zones (and excluding renewable generation) does not reflect actual usage of upgrade (next slide)

DFAX Methodology (cont'd)

All-generation-to-load zone approach does not accurately capture system use

- Disadvantages zones far from main SPP resources; makes it appear the zone is importing most of its generation from distant resources, thereby relying much more on regional facilities

Excluding renewables from generation-to-load power flow analysis does not capture some of the reliability need

- Analysis to identify reliability needs include at least some renewable generation (e.g., in power flow cases for both for system peak and shoulder period)

Results sensitive to sequence of calculations

- SPP applies Promod shares to DFAX, then normalizes for size of load zone; PJM first normalizes DFAX then applies Promod shares

Applying power flow usage to all hours of the year based on positive and negative flows does not focus on reliability (but same for LODF and SR)

- Reliability need or benefit is not driven by 8,760 hours of both positive and negative flows (as simulated in Promod)
- Hourly usage reflects neither the need for nor the benefit of the upgrade

LODF Methodology

Measures incremental flows shifted onto a reliability upgrade during (first contingency) outages of existing transmission facilities. However:

- Does not reflect need for the reliability upgrades
- Only measures additional "usage" of upgrade during N-1 outages of the existing transmission facilities (i.e., does not consider usage during N-0 conditions)
- Applying usage during N-1 conditions to 8,760 hours of the year is unrealistic and not related to reliability need
- Tends to result in disproportionate allocation of benefits to nearby zones, particularly for high voltage upgrades driven by regional flows
- <u>Substantial</u> effort to calculate (requires power flow evaluation of outage of every existing transmission element), particularly for AC power flow

System Reconfiguration Methodology

Measures incremental flows shifted onto existing system during outage of the reliability upgrade

- Proxy for how much the upgrade reduces flows on the existing system
- Captures benefits of lower-voltage upgrades on immediately neighboring systems
- Computationally much simpler than LODF

However:

- Subject to same limitations as LODF
- Does not reflect need for high-voltage reliability upgrades driven by broad changes in regional power flows (i.e., beyond the load serving needs of the local zone)
- Would disproportionately allocate reliability benefits of high-voltage upgrades to nearby zones
  - High voltage upgrades attract a lot of flows from the nearby existing system even if that system did not need to be upgraded for the purpose of serving zonal load
  - Would burden local zones with integration of new generation that is exported to rest of SPP footprint

Load Ratio Shares

H/B allocates a major portion of reliability benefits based on load ratio share. Even though this does not provide a "technical gauge" on usage, need, or beneficiaries, there are some good reasons to use LRS:

- Load ratio shares (mostly 12-CP or 4-CP, occasionally 1-CP) are routinely used by utilities to allocate company-wide costs to different subsidiaries and different customer classes
- Transmission-related disturbances can be wide-spread; if reliability events result in load shedding, that will often be distributed on a load ratio share
- Most reliability projects ultimately are built to serve load or interconnect generation needed to serve load; larger utilities will require more of that, so load ratio share will be a good long-term proxy
- Even if public policy requirements indirectly trigger reliability upgrades, larger utilities will likely cause more of that
- Part of the transmission system is necessary to support reserve sharing. Zones with higher peak loads will likely get a greater share of reserve sharing benefits
- NERC reliability-related penalties are allocated based on LRS

SPP Recommendations

Use hybrid approach to reflect the different characteristics of higher and lower voltage reliability upgrades

- Load ratio shares (LRS) to allocate reliability benefits of high-voltage transmission upgrades (>300kV)
  - Recognizes broad regional reliability needs, system usage, and broad impact and reliability benefits of highest-voltage (highway) portion of the grid
- System reconfiguration (SR) results to allocate reliability benefits of low-voltage transmission upgrades (<100kV)
  - Recognizes relief to local system provided by low-voltage upgrades without artificially limiting it to single local zones
- Use average of LRS and SR to allocate reliability benefits of medium-voltage upgrades (100-300kV)
  - Recognizes mix of local and regional needs and benefits associated with these facilities

Preliminary Results

Updated

Allocation of RCAR I Mandated Reliability Benefits by Project Type

	All Projects				ITP10				Other			
SPP-wide Benefits												
Total	$2.50 billion				$0.73 billion				$1.77 billion			
Analyzed*	$1.93 billion				$0.65 billion				$1.28 billion			
Zone	**H/B**	**DFAX**	**LODF**	**SR**	**H/B**	**DFAX**	**LODF**	**SR**	**H/B**	**DFAX**	**LODF**	**SR**
AEP	22.4%	20.5%	19.0%	16.9%	22.2%	20.5%	15.4%	7.1%	22.4%	20.4%	20.8%	21.8%
CUS	0.8%	0.6%	0.0%	0.0%	1.4%	0.9%	0.0%	0.1%	0.5%	0.4%	0.0%	0.0%
EDE	1.3%	1.0%	0.3%	0.5%	2.3%	1.5%	0.0%	0.1%	0.7%	0.8%	0.4%	0.7%
GMO	2.1%	1.0%	0.3%	0.5%	3.8%	1.2%	0.0%	0.1%	1.3%	0.9%	0.4%	0.7%
GRDA	1.5%	1.7%	0.4%	0.4%	1.8%	2.1%	0.2%	0.3%	1.3%	1.4%	0.5%	0.5%
KCPL	3.9%	2.2%	2.1%	2.7%	7.2%	2.2%	1.1%	1.2%	2.3%	2.2%	2.6%	3.4%
LES	1.2%	0.8%	0.2%	0.3%	1.8%	0.9%	0.2%	0.5%	0.9%	0.7%	0.3%	0.2%
MIDW	1.6%	1.4%	1.9%	1.5%	0.8%	0.2%	1.6%	1.4%	2.0%	2.1%	2.1%	1.6%
MKEC	1.6%	1.8%	0.2%	0.0%	2.1%	0.4%	0.4%	0.0%	1.4%	2.6%	0.1%	0.0%
NPPD	4.8%	4.4%	7.6%	6.0%	6.1%	5.3%	14.8%	10.4%	4.1%	3.9%	4.0%	3.7%
OGE	9.6%	13.2%	11.2%	15.8%	13.2%	20.0%	10.7%	21.4%	7.8%	9.8%	11.5%	13.0%
OPPD	2.6%	2.5%	0.1%	0.5%	4.7%	4.1%	0.0%	1.0%	1.5%	1.6%	0.1%	0.3%
SEPC	1.4%	1.2%	4.7%	5.6%	1.0%	0.5%	6.2%	6.6%	1.6%	1.6%	3.9%	5.0%
SPS	19.8%	28.0%	24.9%	21.3%	18.2%	32.0%	26.3%	20.9%	20.7%	26.0%	24.2%	21.6%
WFEC	6.1%	3.5%	5.2%	2.2%	3.0%	4.2%	6.7%	2.6%	7.7%	3.2%	4.4%	2.0%
WR	19.4%	16.3%	21.8%	25.7%	10.4%	4.0%	16.4%	26.4%	24.0%	22.5%	24.6%	25.3%
TOTAL	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

	Proctor Comprise		
	$0.65 B	$1.28 B	$1.93 B
	ITP10	**Other**	**TOTAL**
Zone	DFAX	SR	
AEP	20.5%	21.8%	21.4%
CUS	0.9%	0.0%	0.3%
EDE	1.5%	0.7%	1.0%
GMO	1.2%	0.7%	0.8%
GRDA	2.1%	0.5%	1.0%
KCPL	2.2%	3.4%	3.0%
LES	0.9%	0.2%	0.5%
MIDW	0.2%	1.6%	1.1%
MKEC	0.4%	0.0%	0.1%
NPPD	5.3%	3.7%	4.3%
OGE	20.0%	13.0%	15.4%
OPPD	4.1%	0.3%	1.6%
SEPC	0.5%	5.0%	3.5%
SPS	32.0%	21.6%	25.1%
WFEC	4.2%	2.0%	2.7%
WR	4.0%	25.3%	18.2%
TOTAL	**100.0%**	**100.0%**	**100.0%**

Notes:
These results are based on preliminary analysis including approximately 80% of the upgrades.
The allocation factors under DFAX are very sensitive to specific assumptions and implementation of the approach.

Preliminary Results (cont'd)

Updated

Allocation of RCAR I Mandated Reliability Benefits by Voltage Level

	All Projects				< 100 kV				100–300 kV				> 300 kV			
SPP-wide Benefits																
Total	$2.50 billion				$0.36 billion				$1.41 billion				$0.72 billion			
Analyzed*	$1.93 billion				$0.24 billion				$1.09 billion				$0.60 billion			
Zone	**H/B**	**DFAX**	**LODF**	**SR**	**H/B**	**DFAX**	**LODF**	**SR**	**H/B**	**DFAX**	**LODF**	**SR**	**H/B**	**DFAX**	**LODF**	**SR**
AEP	22.4%	20.5%	19.0%	16.9%	44.8%	36.8%	46.0%	44.6%	17.4%	16.5%	14.2%	15.7%	22.4%	21.1%	16.8%	7.9%
CUS	0.8%	0.6%	0.0%	0.0%	0.0%	0.4%	0.0%	0.0%	0.5%	0.4%	0.0%	0.0%	1.6%	0.9%	0.0%	0.1%
EDE	1.3%	1.0%	0.3%	0.5%	0.0%	0.8%	2.2%	3.5%	0.8%	0.8%	0.0%	0.1%	2.5%	1.6%	0.0%	0.2%
GMO	2.1%	1.0%	0.3%	0.5%	0.0%	0.9%	0.1%	0.1%	1.4%	0.9%	0.3%	0.6%	4.2%	1.1%	0.3%	0.4%
GRDA	1.5%	1.7%	0.4%	0.4%	3.7%	3.8%	1.8%	1.3%	0.7%	0.9%	0.2%	0.3%	2.0%	2.2%	0.3%	0.3%
KCPL	3.9%	2.2%	2.1%	2.7%	0.0%	2.2%	0.6%	1.9%	2.6%	1.7%	2.1%	3.0%	7.9%	2.9%	2.5%	2.3%
LES	1.2%	0.8%	0.2%	0.3%	0.0%	0.4%	0.0%	0.0%	1.1%	0.8%	0.3%	0.3%	2.0%	0.9%	0.2%	0.6%
MIDW	1.6%	1.4%	1.9%	1.5%	0.0%	0.3%	0.0%	0.0%	2.3%	2.4%	2.5%	1.9%	0.8%	0.2%	1.7%	1.4%
MKEC	1.6%	1.8%	0.2%	0.0%	0.0%	0.5%	0.0%	0.0%	2.1%	2.9%	0.1%	0.0%	1.4%	0.3%	0.4%	0.0%
NPPD	4.8%	4.4%	7.6%	6.0%	0.0%	1.7%	0.3%	0.0%	4.8%	4.4%	4.7%	4.4%	6.7%	5.4%	15.9%	11.2%
OGE	9.6%	13.2%	11.2%	15.8%	2.9%	12.9%	15.5%	21.8%	8.4%	8.6%	9.1%	9.5%	14.5%	21.8%	13.3%	24.9%
OPPD	2.6%	2.5%	0.1%	0.5%	0.1%	1.5%	0.1%	0.1%	1.7%	1.8%	0.1%	0.3%	5.1%	4.1%	0.0%	1.1%
SEPC	1.4%	1.2%	4.7%	5.6%	0.0%	0.5%	0.4%	0.9%	1.9%	1.8%	4.8%	5.9%	1.1%	0.5%	6.3%	6.8%
SPS	19.8%	28.0%	24.9%	21.3%	3.4%	10.6%	4.5%	3.1%	27.2%	31.3%	33.5%	30.6%	13.1%	29.0%	17.5%	11.8%
WFEC	6.1%	3.5%	5.2%	2.2%	22.7%	6.7%	12.4%	4.8%	4.0%	2.2%	2.8%	1.4%	3.3%	4.6%	6.5%	2.6%
WR	19.4%	16.3%	21.8%	25.7%	22.4%	19.8%	16.2%	17.7%	23.2%	22.5%	25.1%	25.9%	11.5%	3.5%	18.2%	28.4%
TOTAL	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Notes:
These results are based on preliminary analysis including approximately 80% of the upgrades.
The allocation factors under DFAX are very sensitive to specific assumptions and implementation of the approach.

Preliminary Results (cont'd)

Updated

Allocation of RCAR I Mandated Reliability Benefits Under Recommended Hybrid Approach

	All Projects	< 100 kV	100–300 kV			> 300 kV		
SPP-wide Benefits								
Total	$2.50 billion	$0.36 billion	$1.41 billion			$0.72 billion		
Analyzed*	$1.93 billion	$0.24 billion	$1.09 billion			$0.60 billion		
		100%	50.0%	50.0%		0.0%	100.0%	
Zone	**Recommended Hybrid Approch**	SR	SR	LRS	Weighted Average	SR	LRS	Weighted Average
AEP	**23.3%**	44.6%	15.7%	22.4%	19.0%	7.9%	22.4%	22.4%
CUS	**1.0%**	0.0%	0.0%	1.6%	0.8%	0.1%	1.6%	1.6%
EDE	**2.0%**	3.5%	0.1%	2.5%	1.3%	0.2%	2.5%	2.5%
GMO	**2.7%**	0.1%	0.6%	4.2%	2.4%	0.4%	4.2%	4.2%
GRDA	**1.4%**	1.3%	0.3%	2.0%	1.2%	0.3%	2.0%	2.0%
KCPL	**5.8%**	1.9%	3.0%	7.9%	5.4%	2.3%	7.9%	7.9%
LES	**1.3%**	0.0%	0.3%	2.0%	1.2%	0.6%	2.0%	2.0%
MIDW	**1.0%**	0.0%	1.9%	0.8%	1.4%	1.4%	0.8%	0.8%
MKEC	**0.8%**	0.0%	0.0%	1.4%	0.7%	0.0%	1.4%	1.4%
NPPD	**5.2%**	0.0%	4.4%	6.7%	5.5%	11.2%	6.7%	6.7%
OGE	**14.0%**	21.8%	9.5%	14.5%	12.0%	24.9%	14.5%	14.5%
OPPD	**3.1%**	0.1%	0.3%	5.1%	2.7%	1.1%	5.1%	5.1%
SEPC	**2.4%**	0.9%	5.9%	1.1%	3.5%	6.8%	1.1%	1.1%
SPS	**16.8%**	3.1%	30.6%	13.1%	21.9%	11.8%	13.1%	13.1%
WFEC	**2.9%**	4.8%	1.4%	3.3%	2.3%	2.6%	3.3%	3.3%
WR	**16.3%**	17.7%	25.9%	11.5%	18.7%	28.4%	11.5%	11.5%
TOTAL	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Note: These results are based on preliminary analysis including approximately 80% of the upgrades.

Preliminary Results (cont'd)

Updated

Allocation of RCAR I Mandated Reliability Benefits Under Modified Hybrid Approach

	All Projects	< 100 kV	100–300 kV			> 300 kV		
SPP-wide Benefits								
Total	$2.50 billion	$0.36 billion	$1.41 billion			$0.72 billion		
Analyzed*	$1.93 billion	$0.24 billion	$1.09 billion			$0.60 billion		
		100%	66.7%	33.3%		33.3%	66.7%	
Zone	**Modified Hybrid Approch**	SR	SR	LRS	Weighted Average	SR	LRS	Weighted Average
AEP	**21.1%**	44.6%	15.7%	22.4%	17.9%	7.9%	22.4%	17.6%
CUS	**0.6%**	0.0%	0.0%	1.6%	0.5%	0.1%	1.6%	1.1%
EDE	**1.5%**	3.5%	0.1%	2.5%	0.9%	0.2%	2.5%	1.7%
GMO	**1.9%**	0.1%	0.6%	4.2%	1.8%	0.4%	4.2%	2.9%
GRDA	**1.1%**	1.3%	0.3%	2.0%	0.9%	0.3%	2.0%	1.4%
KCPL	**4.7%**	1.9%	3.0%	7.9%	4.6%	2.3%	7.9%	6.0%
LES	**1.0%**	0.0%	0.3%	2.0%	0.9%	0.6%	2.0%	1.5%
MIDW	**1.2%**	0.0%	1.9%	0.8%	1.5%	1.4%	0.8%	1.0%
MKEC	**0.6%**	0.0%	0.0%	1.4%	0.5%	0.0%	1.4%	0.9%
NPPD	**5.5%**	0.0%	4.4%	6.7%	5.2%	11.2%	6.7%	8.2%
OGE	**14.6%**	21.8%	9.5%	14.5%	11.2%	24.9%	14.5%	17.9%
OPPD	**2.2%**	0.1%	0.3%	5.1%	1.9%	1.1%	5.1%	3.8%
SEPC	**3.5%**	0.9%	5.9%	1.1%	4.3%	6.8%	1.1%	3.0%
SPS	**18.3%**	3.1%	30.6%	13.1%	24.8%	11.8%	13.1%	12.6%
WFEC	**2.7%**	4.8%	1.4%	3.3%	2.0%	2.6%	3.3%	3.0%
WR	**19.4%**	17.7%	25.9%	11.5%	21.1%	28.4%	11.5%	17.1%
TOTAL	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Note: These results are based on preliminary analysis including approximately 80% of the upgrades.

First Name	**Last Name**			
Travis	Hyde	N		
John	Payne	N		
Nathan	McNeil	N		
Alan	Myers	N		
Mohammad	Awad	Abstain		
Nate	Morris	Abstain		
John	Fulton	N		
Matthew	McGee	Y		
Joe	Fultz	N		
Jason	Shook	Y		
Harold	Wyble	Y		
Dustin	Betz	Y		
Jon	Shipman	Y		
Scott	Benson	Y		
John	Boshears	Y		
Tim	Smith	N		
Michael	Mueller	N		

Criteria Revision Request

CRR No.	012	**CRR Title**	Revise Renewable Resource Capacity Accreditation
Criteria Section(s) Requiring Revision		**Section No.: 12.1.5.3.g** **Title: Rating Adjustments**	
Date		6/13/2014	
Impact Analysis Required		☐ Yes – If yes, estimated cost: TBD ☒ No	
Requested Resolution		☒ **Normal** ☐ **Expedited** ☐ **Urgent Action** Provide explanation if Expedited and/or Urgent Action is selected:	
Type of Revision		☐ **Correction/Clean-Up** ☐ **Clarification** ☒ **Policy Change**	
Revision Description		Change SPP capacity accreditation methodology for wind resources from the existing methodology of using the top 10 % of load hours with 85% confidence to top 3 % of load hours with *60%* confidence factor. Verbiage change to the introduction of the renewable accreditation methodology 12.1.5.3.g based on feedback during MOPC Meeting: g. The recommended methodology to evaluate the net capability established for wind or solar facilities shall be determined on a monthly basis, as stated below. If a member's desire to use a more restrictive methodology to evaluate the net capability of wind or solar they may do so, however net capability determined by the alternative methodology employed cannot credit the wind or solar with a capability greater than determined with the methodology stated below:	
Reason for Revision		The change will adjust SPP's policy to be more consistent with other RTO's and will better account for solar generation.	
Tariff Implications or Changes		☐ Yes – Section No.: *(Include a summary of impact and/or specific changes)* ☒ No	

Protocol Implications or Changes	☐ Yes - Section No.: *(Include a summary of impact and/or specific changes)* ☒ No
ORWG Review	**See Comment below** Date of Vote: 6/19/2014 Vote: Passed to approve CRR 12 as stated. Opposed: 5 Abstained: 0 ORWG Members agreed to use the top 3% load hours but still had reservations about the Confidence Factor of 60% as reflected in the vote of 6-5. The confidence factor that was stated other than the 60% was 75% which equates to 4.5% of nameplate that is comparable to the percent nameplate seen during the peak hours for the last 2 years. The average at peak for the last 4 years is 12% nameplate. *I am waiting for the ORWG to send out something a bit more formal. There was a lot of good discussion about the confidence factor.*
TWG Review	Date of Vote: 3/12/2014 Vote: Passed From the TWG Minutes: Travis Hyde motioned to approve the recommendation. Harold Wyble seconded the motion. The motion passed with two abstentions from John Boshears and Nathan McNeil. Opposed: 0 Abstained: 2
CAWG Review	**See Comment below** Date of Vote: Vote: Opposed: Abstained: The CAWG did not act upon the CRR 12 during the meeting on 6/20/2014. The Working Group did re-affirm the following points: 1) SPP should evaluate the current SPP capacity margin to ensure that it is adequate to meet the needs for a reliable system. 2) SPP should inform RSC and CAWG, on an ongoing basis, if the increase in accredited wind capacity, as a result of the criteria change, is partly or wholly responsible for causing any changes in the need for transmission upgrades in the SPP footprint. 3) RSC and CAWG should be presented with the GWG annual report regarding the performance of wind and solar facilities. The report should include a yearly comparison of wind and solar output during peak periods. This would allow the criteria to be reevaluated, if necessary, based on information on actual wind and solar output at peak periods.
MWG Review	Date of Vote: Vote: Opposed: Abstained:

MOPC Review	The MOPC had a very meaningful discussion on this topic after the GWG presentation by Mitch Williams, the GWG Chair. During the discussion there were concerns about the proposed Criteria changes were too stringent and others that it was not enough and was long overdue to be changed based on the original requirements. The comments below from the ORWG and TWG are representative of the concerns voiced again at the MOPC. A motion was made to accept the Criteria Change and was passed by the MOPC. Date of Vote: April 16, 2014 Vote: ______ Opposed: ________ Abstained: ________
Board Review	Date of Vote: Vote: Opposed: Abstained:

Sponsor	
Name	Generation Working Group (Scott Jordan, Sec.)
E-mail Address	sjordan@spp.org
Company	SPP
Phone Number	501-614-3985
Date	

Comment	
Name	ORWG
E-mail Address	jsmith@spp.org (Jason Smith, Sec. ORWG)
Company	SPP
Phone Number	501-614-3293
Date	4/7/2014

ORWG has concerns about the potential impact on reliability this change makes by awarding additional capacity to resources that have no control on their ability to produce when needed. This can result in an interpretation that sufficient capacity is present when it is not. SPP needs to continue to look at how the capacity near peak hours reflects the actual output experienced at those peak hours. ORWG also believes that we need to look at the overall capacity accreditation philosophy to include the impacts of other fuels such as natural gas during peak periods.

Comment	
Name	CAWG (by Scott Jordan paraphrasing meeting discussions with CAWG)
E-mail Address	sjordan@spp.org
Company	SPP
Phone Number	501-614-3985
Date	4/2/2014

Mitch Williams and Scott Jordan met with the CAWG to discuss the GWG approved SPP Criteria Change for Section 12.1.5.3.g proposed verbiage changes. The CAWG as a whole had concerns and voiced them during the call. The CAWG did not formalize the concerns. The main concerns were the fact that a fw of the stakeholders were concerned in the increase in the accreditation number using the new Criteria, the average percent increase from the top 10% load hours and a confidence factor of 85% to 3% load hours and a confidence factor of 60%, the base increase for the first 3 years from 3% to 5%, the sample of 17 wind farms may not be large enough, should a comparison of all the wind farms using the old and new requirements, and should an ELCC Study be performed.

Proposed Criteria Language Revision

12.1.5.3 Rating Adjustments

a. The rated net capability of a unit may be above or below the actual tested net generation as a result of adjustments for Rating Conditions, with the exception of units with winter season ratings greater than their summer rating. For these units, the winter season rated net capability shall be no greater than the actual tested net generation. No rating adjustment for ambient conditions shall be made.

b. Seasonal net capability shall not be reduced to provide regulating margin or spinning reserve. It shall reflect operation at the power factor level at which the generating equipment is normally expected to be operated over the daily peak load period.

c. Extended capability of a unit or plant obtained through bypassing of feed-water heaters, by utilizing other than normal steam conditions, by abnormal operation of auxiliaries in steam plants, or by abnormal operation of combustion turbines or diesel units may be included in the seasonal net capability if the following conditions are met; a) the extended capability based on such conditions shall be available for a period of not less than four continuous hours when needed and meets the other restrictions, and b) appropriate procedures have been established so that this capability shall be available promptly when requested by the system operator.

d. The seasonal net capability established for nuclear units shall be determined taking into consideration the fuel management program and any restrictions imposed by governmental agencies.

e. The seasonal net capability established for hydroelectric plants, including pumped storage projects, shall be determined taking into consideration the reservoir storage program and any restrictions imposed by governmental agencies and shall be based on median hydro conditions.

f. The seasonal net capability established for run-of-the-river hydroelectric plants shall be determined using historical hydrological data on a monthly basis.

g. The recommended methodology to evaluate the net capability established for wind or solar facilities shall be determined on a monthly basis, as stated below~~follows~~.~~:~~ If a member's desire to use a more restrictive methodology to evaluate the net capability of wind or solar they may do so, however net capability determined by the alternative methodology employed cannot credit the wind or solar with a capability greater than determined with the methodology stated below:

i. Assemble all available hourly net power output (MWH) data measured at the system interconnection point.

ii. Select the hourly net power output values occurring during the top ~~10~~3% of load hours for the SPP Load Serving ~~Member~~ Entity for each month of each year for the evaluation period.

iii. Select the hourly net power output value that can be expected from the facility ~~85~~60% of the time or greater. For example, for a 5 year period with the ~~360~~ 110 hourly net power output values ranked from highest to lowest, the capacity of the facility will be the MW value in the ~~306th~~ 65th data point.

iv. A seasonal or annual net capability may be determined by selecting the appropriate monthly MW values corresponding to the Load Serving ~~Member's~~ Entity's peak load month of the season of interest (e.g., ~~72~~ 22 hours for a typical 30 day month and ~~360~~ 110 hours for a 5 year period).

v. Facilities in commercial operation 3 years or less:

a. The data must include the most recent 3 years.

b. Values may be calculated from wind or solar data, if measured MW values are not yet available. Wind data correlated with a reference tower beyond fifty miles is subject to Generation Working Group approval. Solar data correlated with a reference measuring device beyond two hundred miles is subject to Generation Working Group approval. For calculated values, at least one year must be based on site specific data.

c. If the Load Serving ~~Member~~ Entity chooses not to perform the net capability calculations as described above during the first 3 years of commercial operation, the Load Serving ~~Member~~ Entity may submit ~~3~~5% for wind facilities and 10% for solar facilities of the site facility's nameplate rating.

vi. Facilities in commercial operation 4 years and greater:

a. The data must include all available data up to the most recent 10 years of commercial operation.

b. Only metered hourly net power output (MWH) data may be used.

c. After three years of commercial operations, if the Load Serving ~~Member~~ Entity 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.

vii. The net capability calculation shall be updated at least once every three years.