Consideration of Comments

Disturbance and Sabotage Reporting (Project 2009-01)

The Disturbance and Sabotage Reporting Drafting Team thanks all commenters who submitted comments on the second formal posting for Project 2009-01—Disturbance and Sabotage Reporting. The standard was posted for a 45-day public comment period from October 28, 2011 through December 12, 2011 and included an initial ballot during the last 10 days of the comment period. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 76 sets of comments, including comments from approximately 171 different people from approximately 140 companies representing nine of the ten Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Project2009-01_Disturbance_Sabotage_Reporting.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration

EOP-004-2 was posted for a 45-day formal comment period and initial ballot from October 28-December 12, 2011. The DSR SDT received comments from stakeholders to improve the readability and clarity of the requirements of the standard. The revisions that were made to the standard are summarized in the following paragraphs.

Purpose Statement

The DSR SDT revised the purpose statement to remove ambiguous language "with the potential to impact reliability". The Purpose statement now reads:

> "To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities."

[1] The appeals process is in the Standard Processes Manual
http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_Rev%201_20110825.pdf

Operating Plan

Based on stakeholder comments, Requirement R1 was revised for clarity. Part 1.1 was revised to replace the word “identifying” with “recognizing” and Part 1.2 was eliminated. This also aligns the language of the standard with FERC Order 693, Paragraph 471.

> “(2) specify baseline requirements regarding what issues should be addressed in the **procedures for recognizing** {emphasis added} sabotage events and making personnel aware of such events;”

Requirement R1, Part 1.3 (now Part 1.2) was revised by eliminating the phrase “as appropriate” and adding language indicating that the Responsible Entity is to define its process for reporting and with whom to report events. Part 1.2 now reads:

> “1.2 A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity’s Reliability Coordinator; law enforcement governmental or provincial agencies.”

The SDT envisions that most entities will only need to slightly modify their existing CIP-001 Sabotage Reporting procedures to comply with the Operating Plan requirement in this proposed standard. As many of the features of both sabotage reporting procedures and the Operating Plan are substantially similar, the SDT feels that some information in the sabotage reporting procedures may need to updated and verified.

Operating Plan Review and Communications Testing

Requirement R1, Part 1.4 was removed and Requirement 1, Part, 1.5 was separated out as new Requirement 4. Requirement R4 was revised and is now R3. FERC Order 693, Paragraph 466 includes provisions for periodic review and update of the Operating Plan:

> “466. The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures.”

Requirement R3 requires an annual test of the communication portion of Requirement R1 while Requirement R4 requires an annual review of the Operating Plan.:

> "R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2."

> "R4. Each Responsible Entity shall conduct an annual review of the event reporting Operating Plan in Requirement R1."

The DSR SDT envisions that the annual test will include verification that communication information contained in the Operating Plan is correct. As an example, the annual update of the Operating Plan could include calling "others as defined in the Responsibility Entity's Operating Plan" (see Part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated. Note that there is no requirement to test the reporting of events to the Electric Reliability Organization and the Responsible Entity's Reliability Coordinator.

Operating Plan Implementation

Most stakeholders indicated that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to:

> "R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1."

Reporting Timelines

The DSR SDT received many comments regarding the various entries of Attachment 1. Many commenters questioned the reliability benefit of reporting events to the ERO within 1 hour. Most of the events with a one hour reporting requirement were revised to 24 hours based on stakeholder comments; those types of events are currently required to be reported within 24 hours in the existing mandatory and enforceable standards. The only remaining type of event that is to be reported within one hour is "A reportable Cyber Security Incident" as it is required by CIP-008 and FERC Order 706, Paragraph 673:

> "direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"

The table was reformatted to separate one hour reporting and 24 hour reporting. The last column of the table was also deleted and the information contained in the table was transferred to the sentence above each table. These sentences are:

> "One Hour Reporting: Submit Attachment 2 or DOE-OE-417 report to the parties identified pursuant to Requirement R1, Part 1.2 within one hour of recognition of the event."

> "Twenty-four Hour Reporting: Submit Attachment 2 or DOE-OE-417 report to the parties identified pursuant to Requirement R1, Part 1.2 within twenty-four hour of recognition of the event."

Note that the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred.

<u>Cyber-Related Events</u>

The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1. Stakeholders pointed out these events are adequately addressed through the CIP-008 and "Damage or Destruction of a Facility "reporting thresholds. CIP-008 addresses Cyber Security Incidents which are defined as:

> "Any malicious act or suspicious event that:
>
> - Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or,
> - Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset."

A Critical Asset is defined as:

> "Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System."

Since there is an existing event category for damage or destruction of Facilities, having a separate event for "Damage or Destruction of a Critical Asset" is unnecessary.

Damage or Destruction

The event for “Destruction of BES equipment” has been revised to “Damage or destruction of a Facility”. The threshold for reporting information was expanded for clarity:

> “Damage or destruction of a Facility that: affects an IROL
> OR
> Results in the need for actions to avoid an Adverse Reliability Impact
> OR
> Results from intentional human action.”

Facility Definition

The DSR SDT used the defined term “Facility” to add clarity for this event as well as other events in Attachment 1. A Facility is defined as:

> “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”

The DSR SDT did not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.

Physical Threats

Several stakeholders expressed concerns relating to the “Forced Intrusion” event. Their concerns related to ambiguous language in the footnote. The SDR SDT discussed this event as well as the event “Risk to BES equipment”. These two event types had overlap in the perceived reporting requirements. The DSR SDT removed “Forced Intrusion” as a category and the “Risk to BES equipment” event was revised to “Any physical threat that could impact the operability of a Facility”.

Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported.

The footnote regarding this event type was expanded to provide additional guidance in:

> "Examples include a train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center). Also, report any suspicious device or activity at a Facility. Do not report copper theft unless it impacts the operability of a Facility."

Use of DOE OE-417

The DSR SDT received many comments requesting consistency with DOE OE-417 thresholds and timelines. These items, as well as, the Events Analysis Working Group's (EAWG) requirements were considered in creating Attachment 1, but differences remain for the following reasons:

- EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'
- OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America
- NERC has no control over the criteria in OE-417, which can change at any time
- Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary

In an effort to minimize administrative burden, US entities may use the OE-417 form rather than Attachment 2 to report under EOP-004. The SDT was informed by the DOE of its new online process coming later this year. In this process, entities may be able to record email addresses associated with their Operating Plan so that when the report is submitted to DOE, it will automatically be forwarded to the posted email addresses, thereby eliminating some administrative burden to forward the report to multiple organizations and agencies.

Miscellaneous

Other minor edits were made to Attachment 1. Several words were capitalized but not defined terms. The DSR SDT did not intend for these terms to be capitalized (defined terms) and these words were reverted to lower case. The event type "Loss of monitoring or all voice communication capability" was divided into two separate events as "Loss of monitoring capability" and "Loss of all voice communication capability".

Attachment 2 was updated to reflect the revisions to Attachment 1. The reference to “actual or potential events” was removed. Also, the event type of “other” and “fuel supply emergency” was removed as well.

It was noted that ‘Transmission Facilities’ is not a defined term in the NERC Glossary. Transmission and Facilities are separately defined terms. The combination of these two definitions are what the DSR SDT has based the applicability of “Transmission Facilities” in Attachment 1.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Gerald Beckerle	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Cook	TVA		5, 6, 1, 3
2.	Jake Miller	Dynegy	SERC	5
3.	Joel Wise	TVA	SERC	1, 3, 5, 6
4.	Tim Hattaway	PowerSouth	SERC	1, 5
5.	Robert Thomasson	BREC	SERC	1
6.	Shaun Anders	CWLP	SERC	1, 3
7.	Jim Case	Entergy	SERC	1, 3, 6
8.	Tim Lyons	OMU	SERC	3, 5
9.	Len Sandberg	Dominion Virginia Power	SERC	1, 3, 5, 6
10.	Brad Young	LGE-KU	SERC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

11.	Larry Akens	TVA	SERC	1, 3, 5, 6
12.	Mike Hirst	Cogentrix	SERC	5
13.	Wayne Van Liere	LGE-KU	SERC	3
14.	Scott Brame	NCEMC	SERC	1, 3, 4, 5
15.	Steve Corbin	SERC Reliability Corp.	SERC	10
16.	John Johnson	SERC Reliability Corp.	SERC	10
17.	John Troha	SERC Reliability Corp.	SERC	10

2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliaiblity Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Ben Wu	Orange and Rockland Utilities	NPCC	1
7.	Peter Yost	Consolidated Edison co. of New York, Inc.	NPCC	3
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Chantel Haswell	FPL Group, Inc.	NPCC	5
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy Macdonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
15.	Robert Pellegrini	The United Illuminating Company	NPCC	1
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
18.	Saurabh Saksena	National Grid	NPCC	1
19.	Michael Schiavone	National Grid	NPCC	1
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	Tina Teng	Independent Electricity System Operator	NPCC	2
22.	Donald Weaver	New Brunswick System Operator	NPCC	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
3.	Group	Steve Alexanderson	Pacific Northwest Small Public Power Utility Comment Group			X	X					X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Russell A. Noble	Cowlitz County PUD No. 1	WECC	3, 4, 5
2.	Ronald Sporseen	Blachly-Lane Electric Cooperative	WECC	3
3.	Ronald Sporseen	Central Electric Cooperative	WECC	3
4.	Ronald Sporseen	Consumers Power	WECC	1, 3
5.	Ronald Sporseen	Clearwater Power Company	WECC	3
6.	Ronald Sporseen	Douglas Electric Cooperative	WECC	3
7.	Ronald Sporseen	Fall River Rural Electric Cooperative	WECC	3
8.	Ronald Sporseen	Northern Lights	WECC	3
9.	Ronald Sporseen	Lane Electric Cooperative	WECC	3
10.	Ronald Sporseen	Lincoln Electric Cooperative	WECC	3
11.	Ronald Sporseen	Raft River Rural Electric Cooperative	WECC	3
12.	Ronald Sporseen	Lost River Electric Cooperative	WECC	3
13.	Ronald Sporseen	Salmon River Electric Cooperative	WECC	3
14.	Ronald Sporseen	Umatilla Electric Cooperative	WECC	3
15.	Ronald Sporseen	Coos-Curry Electric Cooperative	WECC	3
16.	Ronald Sporseen	West Oregon Electric Cooperative	WECC	3
17.	Ronald Sporseen	Pacific Northwest Generating Cooperative	WECC	3, 4, 8
18.	Ronald Sporseen	Power Resources Cooperative	WECC	5

				1	2	3	4	5	6	7	8	9	10
4.	Group	Emily Pennel	Southwest Power Pool Regional Entity										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Clem Cassmeyer	Western Farmer's Electric Cooperative	SPP	1, 3, 5
3.	Michelle Corley	Cleco Power	SPP	1, 3, 5
4.	Kevin Emery	Carthage Water and Electric Plant	SPP	NA
5.	Jonathan Hayes	Southwest Power Pool	SPP	2
6.	Philip Huff	Arkansas Electric Cooperative Corporation	SPP	3, 4, 5, 6
7.	Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

				1	2	3	4	5	6	7	8	9	10
5.	Group	Patricia Robertson	BC Hydro	X	X	X		X					

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Patricia Robertson	BC Hydro	WECC	1
2.	Rama Vinnakota	BC Hydro	WECC	2
3.	Pat Harrington	BC Hydro	WECC	3
4.	Clement Ma	BC Hydro	WECC	5
5.	Daniel O'Hearn	BC Hydro	WECC	6

6.	Group	Mary Jo Cooper	ZGlobal on behalf of City of Ukiah, Alameda Municipal Power, Salmen River Electric, City of Lodi			X							X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Elizabeth Kirkley	City of Lodi	WECC	3
2.	Colin Murphey	City of Ukiah	WECC	3
3.	Douglas Draeger	Alameda Municipal Power	WECC	3
4.	Ken Dizes	Salmen River Electric Coop	WECC	3

7.	Group	WILL SMITH	MRO NSRF										

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM WEBB	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	NSP (XCEL)	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	1, 3, 5, 6
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

16. MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17. RICHARD BURT	MPC	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Steve Rueckert	Western Electricity Coordinating Council										X

No Additional members listed.

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	Jesus Sammy Alcaraz	Imperial Irrigation District	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Tino Zaragoza	IID	WECC	1
2. Jesus Sammy Alcaraz	IID	WECC	3
3. Diana Torres	IID	WECC	4
4. Marcela Caballero	IID	WECC	5
5. Cathy Bretz	IID	WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Jean Nitz	ACES Power Marketing Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Chris Bradley	Big Rivers Electric Corporation	SERC	1
2. Erin Woods	East Kentucky Power Cooperative	SERC	1, 3, 5
3. Susan Sosbe	Wabash Valley Power Association	RFC	3
4. Scott Brame	North Carolina Electric Membership Corporation	RFC	5, 1, 3, 4
5. Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1
6. Lindsay Shepard	Western Farmers Electric Cooperative	SPP	1, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2. Greg Woessner	KissimmeeUtility Authority	FRCC	3
3. Jim Howard	Lakeland Electric	FRCC	3
4. Lynne Mila	City of Clewiston	FRCC	3
5. Joe Stonecipher	Beaches Energy Services	FRCC	1
6. Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7. Randy Hahn	Ocala Utility Services	FRCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection

Additional Member	Additional Organization	Region	Segment Selection
1. S. T. Abrams	Santee Cooper	SERC	1
2. Wayne Ahl	Santee Cooper	SERC	1
3. Rene Free	Santee Cooper	SERC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	Joe Tarantino	Sacramento Municipal Utility District (SMUD)	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Kevin Smith	BANC	WECC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. Group	Robert Rhodes	SPP Standards Review Group		X								

Additional Member	Additional Organization	Region	Segment Selection
1. John Allen	City Utilities of Springfield	SPP	1, 4
2. Clem Cassmeyer	Western Farmer's Electric Cooperative	SPP	1, 3, 5
3. Michelle Corley	Cleco Power	SPP	1, 3, 5
4. Kevin Emery	Carthage Water and Electric Plant	SPP	NA
5. Jonathan Hayes	Southwest Power Pool	SPP	2
6. Philip Huff	Arkansas Electric Cooperative Corporation	SPP	3, 4, 5, 6
7. Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15. Group	Connie Lowe	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Louis Slade		RFC	3, 6
2. Michael Crowley		SERC	1, 3
3. Mike Garton		NPCC	5, 6
4. Michael Gildea		MRO	5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16. Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
2. Larry Raczkowski	FE	RFC	1, 3, 4, 5, 6
3. Jim Eckels	FE	RFC	1
4. John Reed	FE	RFC	1
5. Ken Dresner	FE	RFC	5
6. Bill Duge	FE	RFC	5
7. Kevin Querry	FE	RFC	5

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
17.	Group	Annette M. Bannon	PPL Electric Utilities and PPL Supply Organizations`	X				X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities	RFC	1
2.	Annette Bannon	PPL Generation	RFC	5
3.	Annette Bannon	PPL Generation	WECC	5
4.	Mark Heimbach	PPL EnergyPlus	MRO	6
5.	Mark Heimbach	PPL EnergyPlus	NPCC	6
6.	Mark Heimbach	PPL EnergyPlus	RFC	6
7.	Mark Heimbach	PPL EnergyPlus	SERC	6
8.	Mark Heimbach	PPL EnergyPlus	SPP	6
9.	Mark Heimbach	PPL EnergyPlus	WECC	6

18.	Group	Tom McElhinney	Electric Compliance	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	John Babik		FRCC	5
3.	Garry Baker			3

19.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Scott Harris	KCP&L	SPP	1, 3, 5, 6
2.	Monica Strain	KCP&L	SPP	1, 3, 5, 6
3.	Brett Holland	KCP&L	SPP	1, 3, 5, 6
4.	Jennifer Flandermeyer	KCP&L	SPP	1, 3, 5, 6

20.	Individual	Stewart Rake	Luminant Power					X					
21.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
22.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
23.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
24.	Individual	Silvia Parada Mitchell	Compliance & Responsbility Office	X		X		X	X				
25.	Individual	Antonio Grayson	Southern Comnpany	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
26.	Individual	John Brockhan	CenterPoint Energy	X									
27.	Individual	Brenton Lopez	Salt River Project	X		X		X	X				
28.	Individual	Bo Jones	Westar Energy	X		X		X	X				
29.	Individual	Michael Johnson	APX Power Markets (NCR-11034)						X				
30.	Individual	David Proebstel	Clallam County PUD No.1			X							
31.	Individual	Michael Moltane	ITC	X									
32.	Individual	Tracy Richardson	Springfield Utility Board			X							
33.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
34.	Individual	Kevin Conway	Intellibind								X		
35.	Individual	Chris Higgins / Jim Burns / Ted Snodgrass / Jeff Millennor / Russell Funk	Bonneville Power Administration	X		X		X	X				
36.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
37.	Individual	David Burke	Orange and Rockland Utilities, Inc.	X		X							
38.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
39.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
40.	Individual	Rodney Luck	Los Angeles Department of Water and Power	X		X		X	X				
41.	Individual	Daniel Duff	Liberty Electric Power					X					
42.	Individual	Lisa Rosintoski	Colorado Springs Utilities	X		X		X	X				
43.	Individual	Michael Falvo	Independent Electricity System Operator		X								
44.	Individual	John Bee on Behalf of Exelon	Exelon	X		X		X					
45.	Individual	John D. Martinsen	Public Utility District No. 1 of Snohomish County										
46.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
47.	Individual	Kathleen Goodman	ISO New England		X								

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
48.	Individual	Curtis Crews	Texas Reliability Entity										X
49.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
50.	Individual	Anthony Jablonski	ReliabilityFirst										X
51.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
52.	Individual	Dennis Sismaet	Seattle City Light	X		X	X	X	X				
53.	Individual	John Seelke	PSEG	X		X		X	X				
54.	Individual	Barry Lawson	NRECA										
55.	Individual	Terry Harbour	MidAmerican Energy	X		X		X					
56.	Individual	Thad Ness	American Electric Power	X		X		X	X				
57.	Individual	Guy Andrews	Georgia System Operations Corporation	X		X	X	X	X				
58.	Individual	Ed Davis	Entergy Services										
59.	Individual	Margaret McNaul	Thompson Coburn LLP on behalf of Miss. Delta Energy Agency										
60.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
61.	Individual	Kirit Shah	Ameren	X		X		X	X				
62.	Individual	Linda Jacobson-Quinn	FEUS			X							
63.	Individual	Tom Foreman	Lower Colorado River Authority	X		X		X	X				
64.	Individual	Richard Salgo	NV Energy										
65.	Individual	Nathan Mitchell	American Public Power Association			X							
66.	Individual	Angela Summer	Southwestern Power Administration	X									
67.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X					
68.	Individual	Tim Soles	Occidental Power Services, Inc. (OPSI)			X			X				
69.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
70.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
71.	Individual	James Sauceda	Energy Northwest - Columbia					X					
72.	Individual	Scott Berry	Indiana Municipal Power Agency				X						

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
73.	Individual	Maggy Powell	Constellation Energy on behalf of Baltimore Gas & Electric, Constellation Power Generation, Constellation Energy Commodities Group, Constellation Control and Dispatch, Constellation NewEnergy and Constellation Energy Nuclear Group.	X		X		X	X				
74.	Individual	Michael Brytowski	Great River Energy	X		X		X	X				
75.	Individual	Christine Hasha	Electric Reliability Council of Texas, Inc.		X								
76.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									

1. The DSR SDT has revised EOP-004-2 to remove the training requirement R4 based on stakeholder comments from the second formal posting. Do you agree this revision? If not, please explain in the comment area below.

Summary Consideration: As a result of the industry comments, the SDT has further modified the standard as follows:

- Requirement R1, Part 1.3 (now Part 1.2) was revised to add clarifying language by eliminating the phrase "as appropriate" and indicating that the Responsible Entity is to define its process for reporting and with whom events are communicated.

- Combined relevant parts of Requirement R1, Parts 1.4, 1.5 and Requirement R4 into Requirement 1, Part 1.3.

- Deleted the requirement for drills or exercises

- Clarified that only Registered Entities conduct annual tests of the communication process outlined in Requirement 1, Part 1.2

- Changed the review of the Operating Plan to 'annually'

The DSR SDT envisions the testing under Requirement R1, Part 1.3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsibility Entity's Operating Plan" (see Part 1.2) to verify their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.

Despite some industry opposition, both the periodic review of the Operating Plan and the testing requirements were maintained to meet the intent of FERC Order 693, Paragraph 466:

"The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures."

Organization	Yes or No	Question 1 Comment
Beaches Energy Services, City of	Negative	First, I wish to thank the SDT for their hard work and making significant progress in significant improvements in the standard. I commend the

Organization	Yes or No	Question 1 Comment
Green Cove Springs		direction that the SDT is taking. There are; however, a few unresolved issues that cause me to not support the standard at this time. 1. An issue of possible differences in interpretation between entities and compliance monitoring and enforcement is the phrase in 1.3 that states "the following as appropriate". Who has the authority to deem what is appropriate? The requirements should be clear that the Responsible Entity is the decision maker of who is appropriate, otherwise there is opportunity for conflict between entities and compliance. *Requirement R1,* Part *1.3 (now Part 1.2) was revised to add clarifying language by eliminating the phrase "as appropriate" and indicating that the Responsible Entity is to define its process for reporting and with whom to communicate events to as stated in the entity's Operating Plan.* In addition, 1.4 is onerous and burdensome regarding the need to revise the plan within 90 days of "any" change, especially considering the ambiguity of "other circumstances". "Other circumstances" is open to interpretation and a potential source of conflict. *Requirement R1, Part 1.4 was removed from the standard.*
Response: Thank you for your comment. Please see response above.		
New Brunswick Power Transmission Corporation	Negative	It is NBPT's opinion that because this is a standard associated with reporting events after an occurrence, it is overly burdensome to require drills and exercises for verification purposes as described in R4. *Requirement R4 related to an annual test of the communication portion of Requirement R1 by a drill or exercise. This has been revised to:* *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications*

Organization	Yes or No	Question 1 Comment
		process in Part 1.2.
Response: Thank you for your comment. Please see response above.		
United Illuminating Co.	Negative	R4 is not clear what is expected. There is a difference between testing a process that consists of identify an event then select commuication contacts versus needing to test contacts for each event in Attachment 1 and drill each event and document each event drill. *Requirement R4 related to an annual test of the communication portion of Requirement R1 by a drill or exercise and this has been removed. This has been revised to:* *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* *The DSR SDT envisions that the testing under Requirement r3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.* In R2 the phrase "as specified" should be replaced or completed, as specified by what. *The DSR SDT has deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to read: "Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004*

Organization	Yes or No	Question 1 Comment
		Attachment1."
Response: Thank you for your comment. Please see response above.		
City of Farmington	Negative	R4 requires verification through a drill or exercise the communication process created as part of R1.3. Clarification of what a drill or exercise should be considered. In order to show compliance to R4 would the entity have to send a pseudo event report to Internal Personnel, the Regional Entity, NERC ES-ISAC, Law Enforcement, and Governmental or provincial agencies listed in R1.3 to verify the communications plan? It would not be a burden on the entity so much, however, I'm not sure the external parties want to be the recipient of approximately 2000 psuedo event reports annually. *Requirement R4 related to an annual test of the communication portion of Requirement R1 by a drill or exercise and this has been removed. This has been revised to:* *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* *The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.*
Response: Thank you for your comment. Please see response above.		
Hydro One Networks, Inc.	Negative	Referring to Requirement R4, the communication process can be verified without having to go through a drill or exercise. Any specific testing or

Organization	Yes or No	Question 1 Comment
		verification of the process is the responsibility of the Responsible Entity. *Requirement R4 related to an annual test of the communication portion of Requirement R1 by a drill or exercise and this has been removed This has been revised to:* *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* *The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.* *Despite some industry opposition, both periodic review of the Operating Plan and the test requirements were maintained to meet the intent of FERC Order 693, paragraph 466: "The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures."*
Response: Thank you for your comment. Please see response above.		
Ameren Services	Negative	The current language in the parenthesis of R4 suggests that the training requirement was actually not removed, in that "a drill or exercise" constitutes training. As documented in the last sentence of the Summary of Key Concepts section, "The proposed standard deals exclusively with after-the-fact reporting." We feel that training, even if it is called drills or exercises is not necessary for an after-the-fact report. *Requirement R4 related to an annual test of the communication portion of*

Organization	Yes or No	Question 1 Comment
		Requirement R1 by a drill or exercise and this has been removed. This has been revised to: *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* *The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.* *Despite some industry opposition, both periodic review of the Operating Plan and the test requirements were maintained to meet the intent of FERC Order 693, paragraph 466: "The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures."*
Response: Thank you for your comment. Please see response above.		
Liberty Electric Power LLC	Negative	Voting no due to training not being an option to fill the "drill" requirement. The reason for R4 seems to be to assure personnel will respond to an event in accordance with the entity procedure. Entities meet their obligations for other regulatory requirements with training, and should be permitted to do so for R4. *Requirement R4 related to an annual test of the communication portion of Requirement R1 by a drill or exercise and this has been removed. This has been revised to:* *R3. Each Responsible Entity shall conduct an annual test, not including*

Organization	Yes or No	Question 1 Comment
		notification to the Electric Reliability Organization, of the communications process in Part 1.2. *The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated. This language does not preclude the verification of contact information taking place during a training event.*
Response: Thank you for your comment. Please see response above.		
ACES Power Marketing, Hoosier Energy Rural Electric Cooperative, Inc., Sunflower Electric Power Corporation, Great River Energy	Negative	We appreciate the efforts of the SDT in considering the comments of stakeholders from prior comment periods. We believe this draft is greatly improved over the previous version and we agree with the elimination of the term "sabotage" which is a difficult term to define. The determination of an act of sabotage should be left to the proper law enforcement authorities. However, we also realize that the proper authorities would be hard pressed to make these determinations without reporting from industry when there are threats to BES equipment or facilities. We understand and agree there should be verification of the information required for such reporting (contact information, process flow charts, etc). But we still believe improvements can be made to the draft standard. The use of the words "or through a drill or exercise" in Requirement R4 still implies that training is required if no actual event has occurred. When you conduct a fire "drill" you are training your employees on evacuation routes and who they need to report to. Not only are you verifying your process but you are training your employees as well. It is imperative that the information in the Event

Organization	Yes or No	Question 1 Comment
		Reporting process is correct but we don't agree that performing a drill on the process is necessary. We recommend modifying the requirement to focus on verifying the information needed for appropriate communications on an event. And we agree this should take place at least annually. *Requirement R4 related to an annual test of the communication portion of Requirement R1 by a drill or exercise and this has been removed. This has been revised to:* *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* *The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.* *This language does not preclude the verification of contact information taking place during a training event.*
Response: Thank you for your comment. Please see response above.		
Florida Municipal Power Agency	No	First, we wish to thank the SDT for their hard work and making significant progress in significant improvements in the standard. We commend the direction that the SDT is taking. There are; however, a few unresolved issues that cause us to not support the standard at this time. An issue of possible differences in interpretation between entities and compliance monitoring and enforcement is the phrase in 1.3 that states "the following as appropriate". Who has the authority to deem what is appropriate? The

Organization	Yes or No	Question 1 Comment
		requirements should be clear that the Responsible Entity is the decision maker of who is appropriate, otherwise there is opportunity for conflict between entities and compliance. *Requirement R1, Part 1.3 (now Part 1.2) was revised to add clarifying language by eliminating the phrase "as appropriate" and indicating that the Responsible Entity is to define its process for reporting and with whom to communicate events to as stated in the entity's Operating Plan. Part 1.2 now reads: "A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies."* In addition, 1.4 is onerous and burdensome regarding the need to revise the plan within 90 days of "any" change, especially considering the ambiguity of "other circumstances". "Other circumstances" is open to interpretation and a potential source of conflict. *Requirement R1, Part 1.4 was removed from the standard.*
Response: Thank you for your comment. Please see response above.		
Illinois Municipal Electric Agency	No	IMEA agrees with the removal of the training requirement, but also believes verification is not a necessary requirement for this standard; therefore, R4 is not necessary and should be removed. *Requirement R4 related to an annual test of the communication portion of Requirement 1. This has been revised to:* *R3. Each Responsible Entity shall conduct an annual test, not including*

Organization	Yes or No	Question 1 Comment
		notification to the Electric Reliability Organization, of the communications process in Part 1.2. *The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.*
Response: Thank you for your comment. Please see response above.		
Indiana Municipal Power Agency	No	IMPA does not believe that R4 is necessary. In addition, if a drill or exercise is used to verify the communication process, some of the parties listed in R1.3 may not want to participate in the drill or exercise every 15 months, such as law enforcement and governmental agencies. IMPA would propose a contacting these agencies every 15 months to verify their contact information only and updating their information in the plan as needed, without performing a drill or exercise. *This has been revised to:* *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* *The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see Part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.* *The testing requirement is included in the Standard to meet the intent of*

Organization	Yes or No	Question 1 Comment
		FERC Order 693, paragraph 466: "The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures."
Response: Thank you for your comment. Please see response above.		
ISO New England	No	Please see further comments; we do not believe R4 is a necessary requirement in the standard and suggest it be deleted. *Requirement R4 related to an annual test of the communication portion of Requirement 1. This has been revised to:* *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* *The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see Part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.* *The testing requirement is included in the Standard to meet the intent of FERC Order 693, paragraph 466: "The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures."*

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. Please see response above.		
Northeast Power Coordinating Council	No	Requirement R4 is unnecessary. Whether or not the process, plan, procedure, etc. is "verified" is of no consequence. EOP standards are intended to have entities prepare for likely events (restoration/evacuation), and to provide tools for similar unforeseen events (ice storms, tornadoes, earthquakes, etc.). They should not force a script when results are what matters. *Requirement R4 related to an annual test of the communication portion of Requirement 1. This has been revised to:* *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* *The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see Part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.* *The testing requirement is included in the Standard to meet the intent of FERC Order 693, paragraph 466: "The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures."*
Response: Thank you for your comment. Please see response above.		

Organization	Yes or No	Question 1 Comment
Southern Company	No	Southern agrees with removing the training requirement of R4 from the previous version of the standard. However, Southern suggests that drills and exercises are also training and R4 in this revised standard should be removed in its entirety *The "drill or exercise" language has been deleted. Requirement R4 related to an annual test of the communication portion of Requirement 1. This has been revised to:* *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* *The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see Part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.* *The testing requirement is included in the Standard to meet the intent of FERC Order 693, paragraph 466: "The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures."*
Response: Thank you for your comment. Please see response above.		
Ameren	No	The current language in the parenthesis of R4 suggests that the training requirement was actually not removed, in that "a drill or exercise" constitutes training. As documented in the last sentence of the Summary of

Organization	Yes or No	Question 1 Comment
		Key Concepts section, "The proposed standard deals exclusively with after-the-fact reporting." We feel that training, even if it is called drills or exercises is not necessary for an after-the-fact report. *The "drill or exercise" language has been deleted. Requirement R4 related to an annual test of the communication portion of Requirement 1. This has been revised to:* *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* *The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.* *The testing requirement is included in the Standard to meet the intent of FERC Order 693, paragraph 466: "The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures."*
Response: Thank you for your comment. Please see response above.		
Liberty Electric Power	No	Training should be left in the standard as an option, along with an actual event, drill or exercise, to demonstrate that operating personnel have knowledge of the procedure. *The "drill or exercise" language has been deleted. Requirement R4 related*

Organization	Yes or No	Question 1 Comment
		to an annual test of the communication portion of Requirement 1. This has been revised to: *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* *The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.* *This language does not preclude the verification of contact information taking place during a training event.*
Response: Thank you for your comment. Please see response above.		
SERC OC Standards Review Group	No	We agree with removing the training requirement of R4; however we believe that drills and exercises are also training and R4 should be removed in its entirety because drills and exercises on an after the fact process do not enhance reliability. *The "drill or exercise" language has been removed. Requirement R4 related to an annual test of the communication portion of Requirement 1 This has been revised to:* *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* *The DSR SDT envisions that the testing under Requirement R3 will include*

Organization	Yes or No	Question 1 Comment
		verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated. *The testing requirement is included in the Standard to meet the intent of FERC Order 693, paragraph 466: "The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures."*
Response: Thank you for your comment. Please see response above.		
ACES Power Marketing Standards Collaborators/Great River Energy	No	We understand and agree there should be verification of the information required for such reporting (contact information, process flow charts, etc). But we still believe improvements can be made to the draft standard, in particular to requirement R4. The use of the words "or through a drill or exercise" still implies that training is required if no actual event has occurred. When you conduct a fire "drill" you are training your employees on evacuation routes and who they need to report to. Not only are you verifying your process but you are training your employees as well. It is imperative that the information in the Event Reporting process is correct but we don't agree that performing a drill on the process is necessary. We recommend modifying the requirement to focus on verifying the information needed for appropriate communications on an event. And we agree this should take place at least annually. *Requirement R4 related to an annual test of the communication portion of Requirement R1 by a drill or exercise and this has been removed. This has*

Organization	Yes or No	Question 1 Comment
		been revised to: *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* *The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.* *This language does not preclude the verification of contact information taking place during a training event.*
Response: Thank you for your comment. Please see response above.		
Ingleside Cogeneration LP	Yes	: Yes. Ingleside Cogeneration LP agrees that training on an incident reporting operations plan should be at the option of the entity. However, we recommend that a statement be included in the "Guideline and Technical Basis" section that encourages drills and exercises be coincident with those conducted for Emergency Operations. Since front-line operators must send out the initial alert that a reportable condition exists, such exercises may help determine how to manage their reporting obligations during the early stages of the troubleshooting process. This is especially true where a notification must be made within an hour of discovery - a very short time period. *The "drill or exercise" language has been removed. Requirement R4 related to an annual test of the communication portion of Requirement 1. This has*

Organization	Yes or No	Question 1 Comment
		been revised to: *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* *The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.* *This language does not preclude the verification of contact information taking place during a training event.*
Response: Thank you for your comment. Please see response above.		
American Public Power Association	Yes	APPA agrees that removal of the training requirement was an appropriate revision to limit the burden on small registered entities. However, APPA requests clarification from the SDT on the current draft of R4. If no event occurs during the calendar year, a drill or exercise of the Operating Plan communication process is required. APPA believes that if this drill or exercise is required, then it should be a table top verification of the internal communication process such as verification of phone numbers and stepping through a Registered Entity specific scenario. This should not be a full drill with requirements to contact outside entities such as law enforcement, NERC, the RC or other entities playing out a drill scenario. This full drill would be a major burden for small entities. *The "drill or exercise" language has been removed. Requirement R4 related to an annual test of the communication portion of Requirement 1. This has*

Organization	Yes or No	Question 1 Comment
		been revised to: *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* *The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.*
Response: Thank you for your comment. Please see response above.		
FirstEnergy	Yes	FirstEnergy supports this removal and thanks the drafting team.
Response: Thank you for your comment. Please see response above.		
Compliance & Responsbility Office	Yes	See comments in response to Question 4.
Response: Thank you for your comment. See response to Question 4.		
NV Energy	Yes	Thank you for responding to the stakeholder comments on this issue.
Response: Thank you for your comment.		
Constellation Energy on behalf of Baltimore Gas & Electric, Constellation Power Generation, Constellation Energy Commodities	Yes	Yes, we support removal of the training requirement.

Organization	Yes or No	Question 1 Comment
Group, Constellation Control and Dispatch, Constellation NewEnergy and Constellation Energy Nuclear Group.		
Response: Thank you for your comment.		
Pacific Northwest Small Public Power Utility Comment Group	Yes	
Southwest Power Pool Regional Entity	Yes	
BC Hydro	Yes	
ZGlobal on behalf of City of Ukiah, Alameda Municipal Power, Salmen River Electric, City of Lodi	Yes	
MRO NSRF	Yes	
Western Electricity Coordinating Council	Yes	
Imperial Irrigation District	Yes	
Santee Cooper	Yes	
Sacramento Municipal Utility District (SMUD)	Yes	

Organization	Yes or No	Question 1 Comment
SPP Standards Review Group	Yes	
Dominion	Yes	
PPL Electric Utilities and PPL Supply Organizations`	Yes	
Electric Compliance	Yes	
Kansas City Power & Light	Yes	
Luminant Power	Yes	
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
CenterPoint Energy	Yes	
Salt River Project	Yes	
Westar Energy	Yes	
APX Power Markets (NCR-11034)	Yes	
Clallam County PUD No.1	Yes	
ITC	Yes	
Springfield Utility Board	Yes	

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Yes	
Intellibind	Yes	
Bonneville Power Administration	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
Orange and Rockland Utilities, Inc.	Yes	
Xcel Energy	Yes	
Duke Energy	Yes	
Colorado Springs Utilities	Yes	
Independent Electricity System Operator	Yes	
Exelon	Yes	
Public Utility District No. 1 of Snohomish County	Yes	
South Carolina Electric and Gas	Yes	
American Transmission Company, LLC	Yes	
Nebraska Public Power District	Yes	

Organization	Yes or No	Question 1 Comment
Seattle City Light	Yes	
PSEG	Yes	
MidAmerican Energy	Yes	
American Electric Power	Yes	
Georgia System Operations Corporation	Yes	
FEUS	Yes	
Lower Colorado River Authority	Yes	
Southwestern Power Administration	Yes	
Occidental Power Services, Inc. (OPSI)	Yes	
Northeast Utilities	Yes	
City of Austin dba Austin Energy	Yes	
Energy Northwest - Columbia	Yes	
Electric Reliability Council of Texas, Inc.	Yes	
Oncor Electric Delivery Company LLC	Yes	

Organization	Yes or No	Question 1 Comment
Progress Energy		
Los Angeles Department of Water and Power		
Texas Reliability Entity		
ReliabilityFirst		
NRECA		
Entergy Services		
Thompson Coburn LLP on behalf of Miss. Delta Energy Agency		

2. The DSR SDT includes two requirement regarding implementation of the Operating Plan specified in Requirement R1. The previous version of the standard had a requirement to implement the Operating plan as well as a requirement to report events. The two requirements R2 and R3 were written to delineate implementation of the Parts of R1. Do you agree with these revisions? If not, please explain in the comment area below.

R2. Each Responsible Entity shall implement the parts of its Operating Plan that meet Requirement R1, Parts 1.1 and 1.2 for an actual event and Parts 1.4 and 1.5 as specified.

R3. Each Responsible Entity shall report events in accordance with its Operating Plan developed to address the events listed in Attachment 1.

Summary Consideration: Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to:

"R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1."

Organization	Yes or No	Question 2 Comment
Ameren Services	Negative	(2) The new wording while well intentioned, effectively does not add clarity and leads to confusion. From our perspective, R1, which requires and Operating Plan, which is defined by the NERC glossary as: "A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan." *The DSR SDT thanks you for your comment. The SDT has made changes to the*

Organization	Yes or No	Question 2 Comment
		requirements highlighted in your comments. *FERC Order 693, Paragraph 466 includes provisions for periodic review and update of the Operating Plan: "466. The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures."* (3) Is not a proper location for an after-the-fact reporting standard? In fact it could be argued that after-the-fact reports in and of themselves do not affect the reliability of the bulk electric system. *The DSR SDT does not agree with this comment. Reporting of an event will give the Electric Reliability Organization and your Reliability Coordinator the situational awareness of what has occurred on your part of the BES. Plus as described in your Operating Plan, you would have communicated the event as you saw fit. By broadcasting that an event has occurred you will increase the awareness of your company (as described in your Operating Plan) and increase the awareness of the Electric Reliability Organization and your Reliability Coordinator.* (4) But considering the proposed standard as written with the Operating Plan in requirement R1, and implementation of the Operating Plan in requirement R2 (except the actual reporting which is in R3) and then R3 which requires implementing the reporting section R1.3, it is not clear how these requirements can be kept separate in either implementation nor by the CEA. *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2). The test and review requirement is*

Organization	Yes or No	Question 2 Comment
		included in the Standard to meet the intent of FERC Order 693, paragraph 466: "The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures." (5) The second sentence in the second paragraph of "Rationale for R1" states:"The main issue is to make sure an entity can a) identify when an event has occurred and b) be able to gather enough information to complete the report." This is crucial for a Standard like this that is intended to mandate actions for events that are frequently totally unexpected and beyond normal planning criteria. This language needs to be added to Attachment 1 by the DSR SDT as explained in the rest of our comments. *The DSR SDT has updated the Rationale for Part 1.2 (previous Part 1.3) to read as: "Part 1.2 could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information." Whereas Part 1.2 now states:* *"1.2 A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies."*
Response: Thank you for your comment. Please see response above.		
Old Dominion Electric Coop.	Negative	I disagree with two things in the presently drafted standard. First, I do not feel a separate requirement to implement the plan is necessary (R2), *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of*

Organization	Yes or No	Question 2 Comment
		Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to read: *"R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1."* and I do not think that verification of the communications process should require a minimum of a drill or exercise. This is verified now under th current standard CIP-001 through verifice contact with the appropriate authorities and this should be enough to verify that the communications for the plan is in place. *The "drill or exercise" language has been removed. Requirement R4 related to an annual test of the communication portion of Requirement 1. This has been revised to:* *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2. The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.*
Response: Thank you for your comment. Please see response above.		
ACES Power Marketing, Hoosier Energy Rural Electric Cooperative, Inc., Sunflower Electric Power Corporation,	Negative	Requirement R2 requires Responsible Entities to implement the various sub-requirements in R1. We believe it is unnecessary to state that an entity must implement their Operating Plan in a separate requirement. Having a separate requirement seems redundant. If the processes in the Operating Plan are not

Organization	Yes or No	Question 2 Comment
Great River Energy/ ACES Power Marketing Standards Collaborators/ Great River Energy		implemented, the entity is non-compliant with the standard. *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to read:* *"R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1."* There doesn't need to be an extra requirement saying entities need to implement their Operating Plan. *The test and review requirement is included in the Standard to meet the intent of FERC Order 693, paragraph 466: "The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures."*
Response: Thank you for your comment. Please see response above.		
Hydro One Networks, Inc.	Negative	Requirement R2 seems to not be necessary. Who would have a plan and not implement it? This may also introduce double jeopardy issues should some entity not have a plan as required in R1. They would be unable to implement something they did not have so automatically non-compliant with R1 and R2. o Requirements R2 and R3 seem to be redundant. Isn't implementing the Operating Plan the same as reporting events in accordance with its Operating Plan? *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of*

Organization	Yes or No	Question 2 Comment
		Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to read: *"R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1."* The standard mentions collecting information for Attachment 2, but the standard does not state what to do with Attachment 2. Is it merely a record for demonstrating compliance with R3? *The DSR SDT has updated Requirement R2 to read: "Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in Attachment 1."* *The DSR SDT has also added the following statement to Attachment 1 for 1 hour reporting time frame and 24 hour reporting time frame, respectfully:* *"One Hour Reporting: Submit Attachment 2 or DOE-OE-417 report to the parties identified pursuant to Requirement R1, Part 1.2 within one hour of recognition of the event"* *And* *"Twenty-four Hour Reporting: Submit Attachment 2 or DOE-OE-417 report to the parties identified pursuant to Requirement R1, Part 1.2 within twenty-four hour of recognition of the event."*
Response: Thank you for your comment. Please see response above.		

Organization	Yes or No	Question 2 Comment
Beaches Energy Services, City of Green Cove Springs	Negative	Requirements R2 and R3 are to implement the Operating Plan. Hence, R3 should be a bullet under R2 and not a separate requirement. In addition, for R2, the phrase "actual event" is ambiguous and should mean: "actual event that meets the criteria of Attachment 1" I suggest the following wording to R2 (which will result in eliminating R3) "Each Responsible Entity shall implement its Operating Plan: o For actual events meeting the threshold criteria of Attachment 1, in accordance with Requirement R1 parts 1.1, 1.2 and 1.3 *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to read:* *"R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1."* o For review and updating of the Operating Plan, in accordance with Requirement R1 parts 1.4 and 1.5" Note that I believe that if the SDT decides to not combine R2 and R3, then we disagree with the distinction between the two requirements. *Requirements R2 and R3 have been combined. Requirement 1, Part 1.4 was removed.* The division of implementing R1 through R2 and R3 as presented is "implementing" vs. "reporting". We believe that the correct division should rather be "implementation" of the plan (which includes reporting) vs. revisions to the plan. *The DSR SDT has updated Requirement R2 to read as: "R2. Each Responsible Entity shall implement the Operating Plan that meets Requirement R1 for events listed in Attachment 1."* *FERC Order 693 section 617 states "…the Commission directs the ERO to develop a*

Organization	Yes or No	Question 2 Comment
		modification to EOP-004-1 through the reliability Standards development process that includes any Requirement necessary for users, owners, and operators of the Bulk-Power System to provide data…". In order for entities to provide data they are required to implement their Operating Plan.
Response: Thank you for your comment. Please see response above.		
Ameren	No	(1) The new wording while well intentioned, effectively does not add clarity and leads to confusion. From our perspective, R1, which requires and Operating Plan, which is defined by the NERC glossary as: "A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan." *The DSR SDT has maintained Requirement 1 with the wording of "Operating Plan" which gives entities the flexibility of containing an Operating Process or Operating Procedure, as stated as "An Operating Plan may contain Operating Procedures and Operating Processes. Please note the use of "may contain" in the NERC approved definition.* *Requirement 1 now reads as"* *Each Responsible Entity shall have an Operating Plan that includes:* *1.1. A process for recognizing each of the events listed in EOP-004 Attachment 1.* *1.2. A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the*

Organization	Yes or No	Question 2 Comment
		Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies. (2) Is not a proper location for an after-the-fact reporting standard? In fact it could be argued that after-the-fact reports in and of themselves do not affect the reliability of the bulk electric system. *The DSR SDT does not agree with this comment. Reporting of an event will give the Electric Reliability Organization and your Reliability Coordinator the situational awareness of what has occurred on your part of the BES. Plus as described in your Operating Plan, you would have communicated the event as you saw fit. By broadcasting that an event has occurred you will increase the awareness of your company (as described in your Operating Plan) and increase the awareness of the Electric Reliability Organization and your Reliability Coordinator.* (3) But considering the proposed standard as written with the Operating Plan in requirement R1, and implementation of the Operating Plan in requirement R2 (except the actual reporting which is in R3) and then R3 which requires implementing the reporting section R1.3, it is not clear how these requirements can be kept separate in either implementation nor by the CEA. *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2).* *The test and review requirement is included in the Standard to meet the intent of FERC Order 693, paragraph 466: "The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting*

Organization	Yes or No	Question 2 Comment
		procedures." (4) The second sentence in the second paragraph of "Rationale for R1" states: "The main issue is to make sure an entity can a) identify when an event has occurred and b) be able to gather enough information to complete the report." This is crucial for a Standard like this that is intended to mandate actions for events that are frequently totally unexpected and beyond normal planning criteria. This language needs to be added to Attachment 1 by the DSR SDT as explained in the rest of our comments *The DSR SDT has updated the Rationale for Part 1.2 (previous Part 1.3) to read as: "Part 1.2 could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information." Whereas Part 1.2 now states:* *"1.2 A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies."*
Response: Thank you for your comment. Please see response above.		
American Electric Power	No	AEP prefers to avoid requirements that are purely administrative in nature. Requirements should be clear in their actions of supporting of the BES. For example, we would prefer requirements which state what is to be expected, and allowing the entities to develop their programs, processes, and procedures accordingly. It has been our understanding that industry, and perhaps NERC as well, seeks to reduce the amount to administrative (i.e. document-based) requirements. We are confident

Organization	Yes or No	Question 2 Comment
		that the appropriate documentation and administrative elements would occur as a natural course of implementing and adhering to action-based requirements. In light of this perspective, we believe that that R1 and R2 is not necessary, and that R3 would be sufficient by itself. Our comments above notwithstanding, AEP strongly encourages the SDT to consider that R2 and R3, if kept, be merged into a single requirement as a violation of R2 would also be a violation of R3. Two violations would then occur for what is essentially only a single incident. Rather than having both R2 and R3, might R3 be sufficient on its own? R2 is simply a means to an end of achieving R3. *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2).* . *The test and review requirement is included in the Standard to meet the intent of FERC Order 693, paragraph 466: "The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures."* If there is a need to explicitly reference implementation, that could be addressed as part of R1. For example, R1 could state "Each Responsible Entity shall implement an Operating Plan that includes..."R1 seems disjointed, as subparts 1.4 and 1.5 (updating and reviewing the Operating Plan) do not align well with subparts 1.1 through 1.3 which are process related. If 1.4 and 1.5 are indeed needed, we recommend that they be a part of their own requirement(s). Furthermore, the action of these requirements should be changed from emphasizing provision(s) of a process to demonstrating the underlying activity.

Organization	Yes or No	Question 2 Comment
		The DSR SDT has maintained Requirement 1 with the wording of "Operating Plan" which gives entities the flexibility of containing an Operating Process or Operating Procedure, as stated as "An Operating Plan may contain Operating Procedures and Operating Processes. Please note the use of "may contain" in the NERC approved definition. *Requirement 1 now reads as "Each Responsible Entity shall have an Operating Plan that includes:* *1.1. A process for recognizing each of the events listed in EOP-004 Attachment 1.* *1.2. A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies.* 1.4 AEP is concerned by the vagueness of requiring provision(s) for updating the Operating Plan for "changes", as such changes could occur frequently and unpredictably. *Part 1.4 was removed from the standard.* *It is the sole responsibility of the Applicable Entity to determine when an annual review of the Operating Plan is required. The Operating Plan has the minimum requirement for an annual review. You may review your Operating Plan as often as you see appropriate.*
Response: Thank you for your comment. Please see response above.		
Occidental Power Services,	No	Attachment 1 and R3 require event reports to be sent to the ERO and the entity's RC and to others "as appropriate." Although this gives the entity some discretion, it

Organization	Yes or No	Question 2 Comment
Inc. (OPSI)		might also create some "Monday morning quarterbacking" situations. This is especially true for the one hour reporting situations as personnel that would be responding to these events are the same ones needed to report the event. OPSI suggests that the SDT reconsider and clarify reporting obligations with the objective of sending initial reports to the minimum number of entities on a need-to-know basis. *Requirement R1, Part 1.3 (now Part 1.2) was revised to add clarifying language by eliminating the phrase "as appropriate" and indicating that the Responsible Entity is to define its process for reporting and with whom to communicate events to as stated in the entity's Operating Plan.* *The DSR SDT also received many comments regarding the various events of Attachment 1. Many commenters questioned the reliability benefit of reporting events to the ERO and their Reliability Coordinator within 1 hour. Most of the events with a one hour reporting requirement were revised to 24 hours based on stakeholder comments as well as those types of events are currently required to be reported within 24 hours in the existing mandatory and enforceable standards. The only remaining type of event that is to be reported within one hour is "A reportable Cyber Security Incident" as it required by CIP-008.* *FERC Order 706, paragraph 673 states: "…each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but, in any event within one hour of the event…"*
Response: Thank you for your comment. Please see response above.		
Ingleside Cogeneration LP	No	Attachment 1 and requirement R3 are written in a manner which would seem to indicate that internal personnel and law enforcement personnel would have to be copied on the submitted form - either Attachment 2 or OE-417. We believe the intent is to submit such forms to the appropriate recipients only (e.g.; the ERO and

Organization	Yes or No	Question 2 Comment
		the DOE). The requirement should be re-written to clarify that this is the case. *The DSR SDT thanks you for your comment. Requirement 1 has been updated and now reads as"* *Each Responsible Entity shall have an Operating Plan that includes:* *1.1. A process for recognizing each of the events listed in EOP-004 Attachment 1.* *1.2. A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies.* *The Applicable Entity's Operating Plan is to contain the process for reporting events listed in Attachment 1 to the Electric Reliability Organization, the Responsible Entity's Reliability Coordinator and for communicating to others as defined in the Responsible Entity's Operating Plan. All events in Attachment 1 are required to be reported to the Electric Reliability Organization and the Responsible Entity's Reliability Coordinator. The Operating Plan may include: internal company personnel, your Regional Entity, law enforcement, and governmental or provisional agencies, as you identify within your Operating Plan. This gives you the flexibility to tailor your Operating Plan to fit your company's needs and wants.*
Response: Thank you for your comment. Please see response above.		
Florida Municipal Power Agency	No	Both requirements are to implement the Operating Plan. Hence, R3 should be a bullet under R2 and not a separate requirement. In addition, for R2, the phrase "actual event" is ambiguous and should mean: "actual event that meets the criteria of Attachment 1"We suggest the following wording to R2 (which will result in eliminating R3)"Each Responsible Entity shall implement its Operating Plan: o For actual events meeting the threshold criteria of Attachment 1 in accordance with

Organization	Yes or No	Question 2 Comment
		Requirement R1 parts 1.1, 1.2 and 1.3 *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to read:* *"R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1."* o For review and updating of the Operating Plan in accordance with Requirement R1 parts 1.4 and 1.5"Note that we believe that if the SDT decides to not combine R2 and R3, then we disagree with the distinction between the two requirements. *The test and review requirement is included in the Standard to meet the intent of FERC Order 693, paragraph 466: "The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures."* The division of implementing R1 through R2 and R3 as presented is "implementing" vs. "reporting". We believe that the correct division should rather be "implementation" of the plan (which includes reporting) vs. revisions to the plan. *The DSR SDT has updated Requirement R2 to read as: "R2. Each Responsible Entity shall implement the Operating Plan that meets Requirement R1 for events listed in Attachment 1."* *FERC Order 693 section 617 states "…the Commission directs the ERO to develop a modification to EOP-001-1 through the reliability Standards development process that includes any Requirement necessary for users, owners, and operators of the*

Organization	Yes or No	Question 2 Comment
		Bulk-Power System to provide data…". In order for entities to provide data they are required to implement their Operating Plan.
Response: Thank you for your comment. Please see response above.		
Indiana Municipal Power Agency	No	Both requirements seem to be implementing the Operating Plan which means R3 should be a bullet under R2 and not a separate requirement. IMPA supports making R2 and R3 one requirement and eliminating the current R3 requirement. *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to read:* *"R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1."* In addition, R2 needs to be clarified when addressing an actual event. IMPA recommends saying "an actual event that meets the criteria of Attachment 1." *The DSR SDT has implemented your suggestion.* *Requirement R2now reads as: "Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1.".*
Response: Thank you for your comment. Please see response above.		

Organization	Yes or No	Question 2 Comment
CenterPoint Energy	No	CenterPoint Energy believes the current R2 is unnecessary and duplicative. Upon reporting events as required by R3, entities will be implementing the relevant parts of their Operating Plan that address R1.1 and R1.2. This duplication is clear when reading M2 and M3. Acceptable evidence is an event report. R2 should be modified to remove this duplicative requirement. *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to read:* *“R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1.”*
Response: Thank you for your comment. Please see response above.		
Orange and Rockland Utilities, Inc./Consolidated Edison Co. Of NY, Inc.	No	Comments: o R1.3 should be revised as follows: A process for communicating events listed in Attachment 1 to the Electric Reliability Organization, the Responsible Entity’s Reliability Coordinator and the following as determined by the responsible entity: ["appropriate: - deleted] [otherwise it is not clear who determines what communication level is appropriate] o R1.4 should be revised as follows: Provision(s) for updating the Operating Plan following ["within 90 calendar days of any" - deleted] change in assets or personnel (if the Operating Plan specifies personnel or assets) , ["other circumstances" - deleted] that may no longer align with the Operating Plan; or incorporating lessons learned pursuant to Requirement R3. o R1.5 should be deleted. Responsible Entities can determine the frequency of Operating Plan updates. Requirement 1.4 requires updating the Operating Plan within 90 calendar days for changes in “assets, personnel.... or incorporating lessons

Organization	Yes or No	Question 2 Comment
		learned”. *Requirement 1 has been updated and now reads as”* *Each Responsible Entity shall have an Operating Plan that includes:* *1.1. A process for recognizing each of the events listed in EOP-004 Attachment 1.* *1.2. A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity’s Reliability Coordinator; law enforcement governmental or provincial agencies.* This requirement eliminates the need for Requirement 1.5 requiring a review of the Operating Plan on an annual basis. *The test and review requirement is included in the Standard to meet the intent of FERC Order 693, paragraph 466: “The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures.”*
Response: Thank you for your comment. Please see response above.		
ISO New England	No	In accordance with the results-based standards concept, all that is required, for the “what” is that company X reported on event Y in accordance with the reporting requirements in attachment Z of the draft standard. Therefore, we proposed the only requirement that is necessary is R3, which should be re-written to read..."Each

Organization	Yes or No	Question 2 Comment
		Responsible Entity shall report to address the events listed in Attachment 1." *Requirement 1 and 2 is the basis of the "what" you have described in your comment. Whereas Attachment 1 contains a minimum list of events that apply to Requirement 1, this is why Requirement R2 was rewritten as: "R2. Each Responsible Entity shall implement the Operating Plan that meets Requirement R1 for events listed in Attachment 1."* *The DSR SDT was directed to incorporate certain items such as; FERC Order 693, paragraph 466: "The Commission affirms the NOPR directive and directs the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures."*
Response: Thank you for your comment. Please see response above.		
SERC OC Standards Review Group	No	It is confusing why R3 is not considered part of R2, which deals with implementation of the Operating Plan and it appears that R3 could be interpreted as double jeopardy. We suggest deleting R3. *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to read:* *"R2. Each Responsible Entity shall implement the Operating Plan that meets Requirement R1 for events listed in Attachment 1."*
Response: Thank you for your comment. Please see response above.		

Organization	Yes or No	Question 2 Comment
Oncor Electric Delivery Company LLC	No	NERC's Event Analysis Program tends to parallel many of the reporting requirements as outlined in EOP-004 Version 2. Oncor recommends that NERC considers ways of streamlining the reporting process by either incorporating the Event Analysis obligations into EOP-004-2 or reducing the scope of the Event Analysis program as currently designed to consist only of "exception" reporting. *The Event Analysis Program may use a reported event as a basis to analyze an event. The reporting required in EOP-004-2 provides the input to the Events Analysis Process. The processes of the Event Analysis Program fall outside the scope of this project, but the DSR SDT has collaborated with them of events contained in Attachment 1.*
Response: Thank you for your comment. Please see response above.		
NV Energy	No	On my read of the Standard, R2 and R3 appear to be duplicative, and I can't really distinguish the difference between the two. The action required appears to be the same for both requirements. Even the Measures for these two sound similar. It is not clear to me what it means to "implement" other than to have evidence of the existence and understanding of roles and responsibilities under the "Operating Plan." I suggest elimination of R2 and inclusion of a line item in Measure 1 calling for evidence of the existence of an "Operating Plan" including all the required elements in R1. *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to read:* *"R2 Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1."*

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. Please see response above.		
Northeast Power Coordinating Council	No	R1.3 should be revised as follows: A process for communicating events listed in Attachment 1 to the Electric Reliability Organization, the Responsible Entity's Reliability Coordinator and the following as determined by the responsible entity:...Without this change it is not clear who determines what communication level is appropriate. *Requirement 1, Part 1.3 (now Part 1.2) was updated per comments received.* *1.2 A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies.* R1.4 should be revised as follows: Provision(s) for updating the Operating Plan following any change in assets or personnel (if the Operating Plan specifies personnel or assets), that may no longer align with the Operating Plan; or incorporating lessons learned pursuant to Requirement R3. R1.5 should be deleted. Responsible Entities can determine the frequency of Operating Plan updates. Requirement 1.4 requires updating the Operating Plan within 90 calendar days for changes in "assets, personnel.... or incorporating lessons learned", (or our preceding proposed revision). *Requirement 1, part 1.4 has been deleted and Requirement R2 has been updated to read as: "R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1."* This requirement eliminates the need for Requirement 1.5 requiring a review of the Operating Plan on an annual basis.

Organization	Yes or No	Question 2 Comment
		The only true requirement that is results-based, not administrative and is actually required to support the Purpose of the Standard is R3. *The DSR SDT revised the purpose statement to remove ambiguous language "with the potential to impact reliability". The Purpose statement now reads:* *"To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities."*
Response: Thank you for your comment. Please see response above.		
Illinois Municipal Electric Agency	No	R2 is not necessary, and should be removed. Subrequirement R1.4 is also not necessary and should be removed. *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2based on stakeholder comments and revised R3 (now R2) to read:* *"R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1."*
Response: Thank you for your comment. Please see response above.		
Kansas City Power & Light	No	Requirement R1.1 is confusing regarding the "process for identifying events listed in Attachment 1". Considering Attachment 1, the Events Table, already identifies the events required for reporting, please clearly describe in the requirement what the "process" referred to in requirement R1.1 represents. *The DSR SDT has reviewed FERC Order 693 and paragraph 471 states: "...(2) specify*

Organization	Yes or No	Question 2 Comment
		baseline requirement regarding what issues should be addressed in the procedures for recognizing sabotage events and making personnel aware of such events…" *The DSR SDT has written Requirement 1, Part 1.1 to read as: "A process for recognizing each of the events listed in EOP-004 Attachment 1". An Applicable Entity may rely on SCADA alarms as a process for recognizing an event or being made aware of an event through a scheduled Facility check. The DSR SDT has not been overly prescriptive on part 1.1 but has allowed each Applicable Entity to determine their own process for recognizing events listed in Attachment 1.*
Response: Thank you for your comment. Please see response above.		
Luminant Power	No	Requirements R1, R2, and R4 are burdensome administrative requirements and are contradictory to the NERC stated Standards Development goals of reducing administrative requirements by moving to performance requirements. *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to read:* *"R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1."* *Requirement R1, Part 1.3 (now Part 1.2) was revised to indicate that the Responsible Entity is to define its process for reporting and with whom to report events. Part 1.2 now reads:* *"1.2 A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004*

Organization	Yes or No	Question 2 Comment
		Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies." There is only one Requirement needed in this standard: "The Responsible Entity shall report events in accordance with Attachment 1." Attachment 1 should describe how events should be reported by what Entity to which party within a defined timeframe. If this requirement is met, all the other proposed requirements have no benefit to the reliability of the Bulk Electric System. Per the NERC Standard Development guidelines, only items that provide a reliability benefit should be included in a standard. *The DSR SDT has updated Attachment 1 to a minimum threshold for Applicable Entities to report contained events. Requirement R2 has been updated to reflect that Applicable Entities shall implement their Operating Plan per Requirement 1 for events listed in Attachment 1. Requirement R2 reads as: "R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1."*
Response: Thank you for your comment. Please see response above.		
Xcel Energy	No	Suggest modifying R3 to indicate this is related to R 1.3.Each Responsible Entity shall report events to entities specified in R1.3 and as identified as appropriate in its Operating Plan. *Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3*

Organization	Yes or No	Question 2 Comment
		(now R2) *R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1."*
Response: Thank you for your comment. Please see response above.		
Colorado Springs Utilities	No	The act of implementing the plan needs to include reporting events per R1, sub-requirement 1.3. R2 should simply state something like, "Each Responsible Entity shall implement the Operating Plan that meets the requirements of R1, as applicable, for an actual event or as specified." Suggest eliminating R3 which, seems to create double jeopardy effect. *Requirement R2 was updated to reflect comments received to read as: "R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment 1." R3 was deleted.*
Response: Thank you for your comment. Please see response above.		
Intellibind	No	The language proposed is not clear and will continue to add confusion to entities who are trying to meet these requirements. It is not clear that the drafting team can put itself in the position of how the auditors will interpret and implement compliance against thithe R2 requirement. Requirements should be written to stand alone, not reference other requirements (or parts of the requirments. If the R1 parts 1.1, 1.2, 1.4 and 1.5 are so significant for this requirement, then they should be rewritten in R2. *Most stakeholders believed that Requirements R2 and R3 were redundant and having*

Organization	Yes or No	Question 2 Comment
		both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to read: *"R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment 1."*
Response: Thank you for your comment. Please see response above.		
Southern Company	No	These requirements as drafted in this revised standard potentially create a situation where an entity could be deemed non-compliant for both R2 and R3. For example, if a Responsible Entity included a reporting obligation in its Operating Plan, and failed to report an event, the Responsible Entity could be deemed non-compliant for R2 for not "implementing" its plan and for R3 for not reporting the event to the appropriate entities. A potential solution to address this would be to add Requirement 1, Part 1.3 to Requirement 2 and remove Requirement 3 in its entirety. *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to read:* *"R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment 1."* We also request clarification on Measure M3. Which records should have "dated and time-stamped transmittal records to show that the event was reported"? Some of the communication is handled via face-to-face conversation or through telephone

Organization	Yes or No	Question 2 Comment
		conversation. *Measurement 3 has been deleted since Requirement 3 has been deleted. The new Measurement 2 allows for "…or other documentation". This may be in any form that the Applicable Entity wishes to maintain that they met Requirement 2. The Electric Reliability Organization does allow "Attestations" along with voice recordings as proof of compliance.*
Response: Thank you for your comment. Please see response above.		
Independent Electricity System Operator	No	We agree with the revision to R2 and R3, but assess that a requirement to enforce implementation of Part 1.3 in Requirement R1 is missing. Part 1.3 in Requirement R1 stipulates that:1.3. A process for communicating events listed in Attachment 1 to the Electric Reliability Organization, the Responsible Entity's Reliability Coordinator and the following as appropriate: o Internal company personnel o The Responsible Entity's Regional Entity o Law enforcement o Governmental or provincial agenciesThe implementation of Part 1.3 is not enforced by R2 or R3 or any other Requirements in the standard. Suggest to add another requirement or expand Requirement R4 (and M4) to require the implementation of this Part in addition to verifying the process. *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to read:* *"R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment 1."* *Requirement 1 has been updated and now reads as"*

Organization	Yes or No	Question 2 Comment
		Each Responsible Entity shall have an Operating Plan that includes: *1.1 A process for recognizing each of the events listed in EOP-004 Attachment 1.* *1.2 A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies.*
Response: Thank you for your comment. Please see response above.		
Independent Electricity System Operator	Affirmative	The IESO believes that a requirement to enforce implementation of Part 1.3 in Requirement R1 is missing. Part 1.3 in Requirement R1 stipulates that: 1.3. A process for communicating events listed in Attachment 1 to the Electric Reliability Organization, the Responsible Entity's Reliability Coordinator and the following as appropriate: o Internal company personnel o The Responsible Entity's Regional Entity o Law enforcement o Governmental or provincial agencies The implementation of Part 1.3 is not enforced by R2 or R3 or any other Requirements in the standard. The IESO suggests that another requirement be added or Requirement R4 (and M4) be expanded to require the implementation of this Part in addition to verifying the process. *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to read:* *"R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the*

Organization	Yes or No	Question 2 Comment
		timeframe specified in EOP-004 Attachment 1." *Requirement 1 has been updated and now reads as"* *Each Responsible Entity shall have an Operating Plan that includes:* *1.1 A process for recognizing each of the events listed in EOP-004 Attachment 1.* *1.2 A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies.*
Response: Thank you for your comment. Please see response above.		
Bonneville Power Administration	Yes	BPA believes the measures for R2 are unclear since they are similar to R3's reporting measures.
Response: Thank you for your comment. The SDT has revised the standard to have a single implementation requirement with a single associated measure.		
Compliance & Responsbility Office	Yes	See comments in response to Question 4.
Response: Thank you for your comment. See response to Question 4.		
Constellation Energy on behalf of Baltimore Gas & Electric, Constellation Power Generation, Constellation Energy Commodities Group,	Yes	While we support the delineation of the different activities associated with implementation and reporting, further clarification would be helpful. R1. 1.3: As currently written, it is somewhat confusing, in particular the use of the qualifier "as appropriate". *The DSR SDT has updated Requirement 1, Part 1.2 to read as: "A process for*

Organization	Yes or No	Question 2 Comment
Constellation Control and Dispatch, Constellation NewEnergy and Constellation Energy Nuclear Group.		*communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies."* In addition, the use of the word "communicating" to capture both reporting to reliability authorities and notifying others may leave the requirement open to question. Below is a proposed revision: 1.3 A process for reporting events listed in Attachment 1 to the Electric Reliability Organization, the Responsible Entity's Reliability Coordinator and for communicating to others as defined in the Responsible Entity's Operating Plan, such as: o Internal company personnel o The Responsible Entity's Regional Entity o Law Enforcement o Government or provincial agenciesR1, 1.4: the last phrase of the requirements seems to be leftover from an earlier version. The requirement should end after the word "Plan".R1, 1.5: "Process" should not be capitalized. While we understand the intent of the draft language and appreciate the effort to streamline the requirements, we propose an adjusted delineation below that we feel tracks more cleanly to the structure of a compliance program. Proposed revised language:R2. Each Responsible Entity shall implement its Operating Plan to meet Requirement R1, parts 1.1 and 1.2 for an actual event(s).M2. Responsible Entities shall provide evidence that it implemented it Operating Plan to meet Requirement R1, Parts 1.1 and 1.2 for an actual event. *The DSR SDT has updated Requirement 1, Part 1.2 to read as: "A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator;*

Organization	Yes or No	Question 2 Comment
		law enforcement governmental or provincial agencies." *The Applicable Entity's Operating Plan is to contain the process for reporting events listed in Attachment 1 to the Electric Reliability Organization, the Responsible Entity's Reliability Coordinator and for communicating to others as defined in the Responsible Entity's Operating Plan. All events in Attachment 1 are required to be reported to the Electric Reliability Organization and the Responsible Entity's Reliability Coordinator. The Operating Plan may include: internal company personnel, your Regional Entity, law enforcement, and governmental or provisional agencies, as you identify within your Operating Plan. This gives you the flexibility to tailor your Operating Plan to fit your company's needs and wants.* *DSR SDT has revised R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment 1.* *DSR SDT has revised M2. "Each Responsible Entity will have, for each event experienced, a dated copy of the completed EOP-004 Attachment 2 form or DOE form OE-417 report submitted for that event; and dated and time-stamped transmittal records to show that the event was reported supplemented by operator logs or other operating documentation. Other forms of evidence may include, but are not limited to, dated and time stamped voice recordings and operating logs or other operating documentation for situations where filing a written report was not possible.* Evidence may include, but is not limited to, an submitted event report form (Attachment 2) or a submitted OE-417 report, operator logs, or voice recording.R3. Each Responsible Entity shall implement its Operating Plan to meet Requirement R1, parts 1.4 and 1.5.M3. Responsible Entities shall provide evidence that it implemented it Operating Plan to meet Requirement R1, Parts 1.4 and 1.5. Evidence may include, but is not limited to, dated documentation of review and update of the Operating Plan.

Organization	Yes or No	Question 2 Comment
		R4. Each Responsible Entity shall verify (through implementation for an actual event, or through a drill, exercise or table top exercise) the communication process in its Operating Plan, created pursuant to Requirement 1, Part 1.3, at least annually (once per calendar year), with no more than 15 calendar months between verification. M4. The Responsible Entity shall provide evidence that it verified the communication process in its Operating Plan for events created pursuant to Requirement R1, Part 1.3. Either implementation of the communication process as documented in its Operating Plan for an actual event or documented evidence of a drill, exercise, or table top exercise may be used as evidence to meet this requirement. The time period between verification shall be no more than 15 months. Evidence may include, but is not limited to, operator logs, voice recordings, or dated documentation of a verification. *Requirement 4 (now R3) was revised as:* *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]* *M3. Each Responsible Entity will have dated and time-stamped records to show that the annual test of Part 1.2 was conducted. Such evidence may include, but are not limited to, dated and time stamped voice recordings and operating logs or other communication documentation. The annual test requirement is considered to be met if the responsible entity implements the communications process in Part 1.2 for an actual event. (R3)*
Response: Thank you for your comment. Please see response above.		
Exelon	Yes	Why is the reference to R1.3 missing from EOP-004-2 Requirement R2?

Organization	Yes or No	Question 2 Comment
		R1.3 was associated with implementation in R3 which was removed from the standard. DSR SDT has revised R2 to read as: "Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment 1."
Response: Thank you for your comment. Please see response above.		
Pacific Northwest Small Public Power Utility Comment Group	Yes	
Southwest Power Pool Regional Entity	Yes	
BC Hydro	Yes	
ZGlobal on behalf of City of Ukiah, Alameda Municipal Power, Salmen River Electric, City of Lodi	Yes	
MRO NSRF	Yes	
Western Electricity Coordinating Council	Yes	
Imperial Irrigation District	Yes	
Santee Cooper	Yes	

Organization	Yes or No	Question 2 Comment
Sacramento Municipal Utility District (SMUD)	Yes	
SPP Standards Review Group	Yes	
Dominion	Yes	
FirstEnergy	Yes	
PPL Electric Utilities and PPL Supply Organizations`	Yes	
Electric Compliance	Yes	
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
Westar Energy	Yes	
APX Power Markets (NCR-11034)	Yes	
Clallam County PUD No.1	Yes	
ITC	Yes	
Springfield Utility Board	Yes	

Organization	Yes or No	Question 2 Comment
Manitoba Hydro	Yes	
Duke Energy	Yes	
Liberty Electric Power	Yes	
Public Utility District No. 1 of Snohomish County	Yes	
South Carolina Electric and Gas	Yes	
American Transmission Company, LLC	Yes	
Nebraska Public Power District	Yes	
Seattle City Light	Yes	
PSEG	Yes	
MidAmerican Energy	Yes	
Georgia System Operations Corporation	Yes	
FEUS	Yes	
Lower Colorado River Authority	Yes	

Organization	Yes or No	Question 2 Comment
American Public Power Association	Yes	
Northeast Utilities	Yes	
City of Austin dba Austin Energy	Yes	
Energy Northwest - Columbia	Yes	
Electric Reliability Council of Texas, Inc.	Yes	
		R2 and R3 appear redundant.
Progress Energy		
Los Angeles Department of Water and Power		
Texas Reliability Entity		
ReliabilityFirst		
NRECA		
Entergy Services		
Thompson Coburn LLP on behalf of Miss. Delta Energy Agency		

Organization	Yes or No	Question 2 Comment
Southwestern Power Administration		

3. **The DSR SDT revised reporting times for many events listed in Attachment 1 from one hour to 24 hours. Do you agree with these revisions? If not, please explain in the comment area below.**

Summary Consideration: The DSR SDT appreciates the industry comments on the difficulty associated with reporting events that impact reliability. However, the SDT desires to point out that it is not the objective of this standard to provide an analysis of the event; but to provide the known facts of the events at the reporting threshold of onehour or 24hours depending upon the type of event. The SDT worked with the DOE and the NERC EAWG to develop reporting timelines consistent between the parties in an effort to promote consistency and uniformity.

The SDT has not established any requirement for a final or follow up report. The obligation is to report the facts known at the time. Once the report has been provided to the parties identified in the Operating Plan, no further action is required. All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:

> **"…direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"**

For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report, and is consistent with current in-force standard EOP-004-1.

Organization	Yes or No	Question 3 Comment
Ameren Services	Negative	(6)By our count there are still six of the nineteen events listed with a one hour reporting requirement and the rest are all within 24 hour after the occurrence (or recognition of the event). This in our opinion, is reporting in real-time, which is against one of the key concepts listed in the background section:"The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in Attachment 1. Real-time reporting is achieved through the RCIS and is covered in other standards (e.g. the TOP family of

Organization	Yes or No	Question 3 Comment
		standards). The proposed standard deals exclusively with after-the-fact reporting." *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"…direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1.* (7)We believe the earliest preliminary report required in this standard should at the close of the next business day. Operating Entities, such as the RC, BA, TOP, GOP, DP, and LSE should not be burdened with unnecessary after-the-fact reporting while they are addressing real-time operating conditions. Entities should have the ability to allow their support staff to perform this function during the next business day as needed. We acknowledge it would not be an undue burden to cc: NERC on other required governmental reports with shorter reporting timeframes, but NERC should not expand on this practice. *No preliminary report is required within the revised standard. Also, timelines have been revised (Please see response to item (6) above).* (8)We agree with the extension in reporting times for events that now have 24 hours of reporting time. As a GO there are still too many potential events that still require a 1 hour reporting time that is impractical, unrealistic and could lead to inappropriate escalation of normal failures. For example, the sudden loss of several control room display screens for a BES generator at 2 AM in the morning, with only 1 hour to report something, might be mistakenly interpreted as a cyber-attack. The reality is

Organization	Yes or No	Question 3 Comment
		most likely something far more mundane such as the unexpected failure of an instrument transformer, critical circuit board, etc. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"…direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1.* (9) The "EOP-004 Attachment 1: Events Table" is quite lengthy and written in a manner that can be quite subjective in interpretation when determining if an event is reportable. We believe this table should be clear and unambiguous for consistent and repeatable application by both reliability entities and a CEA. The table should be divided into sections such as: 9a) Events that affect the BES that are either clearly sabotage or suspected sabotage after review by an entity's security department and local/state/federal law enforcement.(b) Events that pose a risk to the BES and that clearly reach a defined threshold, such as load loss, generation loss, public appeal, EEAs, etc. that entities are required to report by the end of the next business day.(c) Other events that may prove valuable for lessons learned, but are less definitive than required reporting events. These events should be reported voluntarily and not be subject to a CEA for non-reporting.(d)Events identified through other means outside of entity reporting, but due to their nature, could benefit the industry by an event report with lessons learned. Requests to report and perform analysis on these type of events should be vetted through a ERO/Functional Entity process to ensure resources provided to this effort have an effective reliability benefit.

Organization	Yes or No	Question 3 Comment
		The DSR SDT has modified Attachment 1 to bring more clarity. The more subjective events were rewritten as follows: • *The 'Damage or Destruction' event category has been revised to say 'to a Facility', (a defined term) and thresholds have be modified to provide clarity. The footnote was deleted* • *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. Also, the footnote only contains examples.* *These two remaining event categories that aren't related to power system phenomena are essential as they effectively translate the intent of CIP-001 into EOP-004.* (10)Any event reporting shall not in any manner replace or inhibit an Entity's responsibility to coordinate with other Reliability Entities (such as the RC, TOP, BA, GOP as appropriate) as required by other Standards, and good utility practice to operate the electric system in a safe and reliable manner. *The DSR SDT agrees and believes the revised reporting timelines support that concept.* (11) The 1 hour reporting maximum time limit for all GO events in Attachment 1 should be lengthened to something reasonable - at least 24 hours. Operators in our energy centers are well-trained and if they have good reason to suspect an event

Organization	Yes or No	Question 3 Comment
		that might have serious impact on the BES will contact the TOP quickly. However, constantly reporting events that turn out to have no serious BES impact and were only reported for fear of a violation or self-report will quickly result in a cry wolf syndrome and a great waste of resources and risk to the GO and the BES. The risk to the GO will be potential fines, and the risk to the BES will be ignoring events that truly have an impact of the BES. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"…direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1.* (12)The 2nd and 3rd Events on Attachment 1 should be reworded so they do not use terms that may have been deleted from the NERC Glossary by the time FERC approves this Standard. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* (13) The terms "destruction" and "damage" are key to identifying reportable events. Neither has been defined in the Standard. The term destruction is usually defined as 100% unusable. However, the term damage can be anywhere from 1% to 99%

Organization	Yes or No	Question 3 Comment
		unusable and take anywhere from 5 minutes to 5 months to repair. How will we know what the SDT intended, or an auditor will expect, without additional information? *The 'Damage or Destruction' event category has been revised to say ' …to a Facility', (a defined term) and thresholds have be modified to provide clarity.* *The DSR SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as:* *"A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)"* *The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.* (14)We also do not understand why "destruction of BES equipment" (first item Attachment 1, first page) must be reported < 1 hour, but "system separation (islanding) > 100 MW" (Attachment 1, page 3) does not need to be reported for 24 hours. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"…direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the*

Organization	Yes or No	Question 3 Comment
		incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. (15)The first 2 Events in Attachment 1 list criteria Threshold for Reporting as "...operational error, equipment failure, external cause, or intentional or unintentional human action." The term "intentional or unintentional human action" appears to cover "operational error" so these terms appear redundant and create risk of misreporting. Can this be clarified? *The second event has been deleted and the language has been clarified in the 'Threshold for Reporting' column in the 'Damage or Destruction' event category. The updated Threshold for Reporting now reads as:* *"Damage or destruction of a Facility that:* • *Affects an IROL (per FAC-014)* *OR* • *Results in the need for actions to avoid an Adverse Reliability Impact* *OR* • *Results from intentional human action."* (16)The footnote of the first page of Attachment 1 includes the explanation "...ii) Significantly affects the reliability margin of the system..." However, the GO is prevented from seeing the system and has no idea what BES equipment can affect the reliability margin of the system. Can this be clarified by the SDT? *The footnote has been deleted and relevant information moved to the 'Threshold for Reporting column in the 'Damage or Destruction' event category.* (17) The use of the term "BES equipment" is problematic for a GO. NERC Team 2010-

Organization	Yes or No	Question 3 Comment
		17 (BES Definition) has told the industry its next work phase will include identify *The term "BES equipment" is no longer used. The 'Damage or Destruction' event category has been revised to say 'to a Facility', (a defined term) and thresholds have be modified to provide clarity.* *The DSR SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as:* *"A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)"* *The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.*
Response: Thank you for your comment. Please see response above.		
Beaches Energy Services, City of Green Cove Springs	Negative	3. Att. 1, going from 1 to 24 hrs: The times don't seem aggressive enough for some of the Events related to generation capacity shortages, e.g., we would think public appeal, system wide voltage reduction and manual firm load shedding ought to be within an hour. These are indicators that the BES is "on the edge" and to help BES reliability, communication of this status is important to Interconnection-wide reliability. *This standard concerns after-the-fact reporting. It is assumed that Responsible Entities will make appropriate real-time notifications as per other applicable standards, operating agreements, and good utility practice. This standard does not preclude a Responsible Entity from reporting more quickly than required by Attachment 1.*

Organization	Yes or No	Question 3 Comment
		4. The Rules of Procedure language for data retention (first paragraph of the Evidence Retention section) should not be included in the standard, but instead referred to within the standard (e.g., “Refer to Rules of Procedure, Appendix 4C: Compliance Monitoring and Enforcement Program, Section 3.1.4.2 for more retention requirements”) so that changes to the RoP do not necessitate changes to the standard. *The DSR SDT believes that although the evidence retention language is the same as the current RoP, it is not specifically linked, so changes to the RoP will not necessitate changes to the standard.* In R4, it might be worth clarifying that, in this case, implementation of the plan for an event that does not meet the criteria of Attachment 1 and going beyond the requirements R2 and R3 could be used as evidence. Consider adding a phrase as such to M4, or a descriptive footnote that in this case, “actual event” may not be limited to those in Attachment 1. *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to read:* *“R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1. ”* Comments to Attachment 1 table: On “Damage or destruction of Critical Asset” and “... Critical Cyber Asset”, Version 5 of the CIP standards is moving away from the

Organization	Yes or No	Question 3 Comment
		binary critical/non-critical paradigm to a high/medium/low risk paradigm. Suggest adding description that if version 5 is approved by FERC, that "critical" would be replaced with "high or medium risk", or include changing this standard to the scope of the CIP SDT, or consider posting multiple versions of this standard depending on the outcome of CIP v5 in a similar fashion to how FAC-003 was posted as part of the GO/TO effort of Project 2010-07. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* On "forced intrusion", the phrase "at BES facility" is open to interpretation as "BES Facility" (e.g., controversy surrounding CAN-0016) which would exclude control centers and other critical/high/medium cyber system Physical Security Perimeters (PSPs). We suggest changing this to "BES Facility or the PSP or Defined Physical Boundary of critical/high/medium cyber assets". This change would cause a change to the applicability of this reportable event to coincide with CIP standard applicability. On "Risk to BES equipment", that phrase is open to too wide a range of interpretation; we suggest adding the word "imminent" in front of it, i.e., "Imminent risk to BES equipment". For instance, heavy thermal loading puts equipment at risk, but not imminent risk. Also, "non-environmental" used as the threshold criteria is ambiguous. For instance, the example in the footnote, if the BES equipment is near railroad tracks, then trains getting derailed can be interpreted as part of that BES equipment's "environment", defined in Webster's as "the circumstances, objects, or conditions by which one is surrounded". It seems that the SDT really means "non-weather related", or "Not risks due to Acts of Nature". *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen*

Organization	Yes or No	Question 3 Comment
		because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. Also, the footnote only contains examples. On “public appeal”, in the threshold, the descriptor “each” should be deleted, e.g., if a single event causes an entity to be short of capacity, do you really want that entity reporting each time they issue an appeal via different types of media, e.g., radio, TV, etc., or for a repeat appeal every several minutes for the same event? *To clarify your point, the threshold has been changed to ‘Public appeal or load reduction event’.* Should LSE be an applicable entity to “loss of firm load”? As proposed, the DP is but the LSE is not. In an RTO market, will a DP know what is firm and what is non-firm load? Suggest eliminating DP from the applicability of “system separation”. The system separation we care about is separation of one part of the BES from another which would not involve a DP. *The DSR SDT believes the current applicability is correct and the threshold provides sufficient discrimination to drive the proper Applicable Entities to report.* On “Unplanned Control Center Evacuation”, CIP v5 might add GOP to the applicability, another reason to add revision of EOP-004-2 to the scope of the CIP v5 drafting team, or in other ways coordinate this SDT with that SDT. Consider posting a couple of versions of the standard depending on the outcome of CIP v5 in a similar fashion to the multiple versions of FAC-003 posted with the GO/TO effort of Project 2010-07. *The DSR SDT believes the current applicability is correct. The ‘Damage or Destruction’ events specifically relating to Critical Assets and Critical Cyber Assets were removed*

Organization	Yes or No	Question 3 Comment
		from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds. Note that EOP-008-0 is only Applicable to Balancing Authorities, Transmission Operators and Reliability Coordinators, this is the basis for the "Entity with reporting Responsibilities" and reads as" "Each RC, BA, TOP that experiences the event".
Response: Thank you for your comment. Please see response above.		
Arkansas Electric Cooperative Corporation	Negative	AECC appreciates the efforts of the SDT to address our comments from the previous posting and feels the Standards have shown great improvement in the current posting. Our negative vote stems from concerns around the 1 hour reporting requirements for events having no size thresholds and ambiguity for external entity reporting in R1.3. Please refer to the comments submitted by the SPP Standards Review Group. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"…direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. For the revised event category 'A physical threat that could impact the operability of a Facility' the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred.*
Response: Thank you for your comment. Please see response above.		

Organization	Yes or No	Question 3 Comment
PowerSouth Energy Cooperative	Negative	Attachment 1 needs to be eliminated. It is confusing to operators and doesn't enhance the reliability of the BES. *Attachment 1 is the basis for EOP-004-2; it contains the events and thresholds for reporting. OE-417, as well as, the EAWG's requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004. Note you may have to report the same event more quickly to the DOE than is required by EOP-004, but this cannot be helped due to bullet point 2 above.*
Response: Thank you for your comment. Please see response above.		
Clark Public Utilities	Negative	Attachment 1 provides confusion not clarification. Just use the OE-417 reporting form for any and all events identified in that form for any one-hour or six-hour reporting. Utilities are required by law to provide the DOE notification and the SDT has just confused the situation by attempting (as it appears) to rename the one-hour reporting events. In some instances, Attachment 1 contradicts the DOE reporting. Public appeals for load reduction are required within 24 hours (according to the Events Table) but OE-417 requires such pubic appeals to be reported within one

Organization	Yes or No	Question 3 Comment
		hour. Clark recommends the Events Table show first the one hour reporting of OE-417, then the six hour reporting of OE-417, and finally any additional reporting that is desired but not reportable to DOE. This will help in not confusing seemingly related events. The table should indicate which form is to be used and should mandate Form OE-417 for all DOE reportable events and the Attachment 2: Event Reporting Form for all reportable events not subject to the DOE reporting requirements. *Attachment 1 is the basis for EOP-004-2; it contains the events and thresholds for reporting. OE-417, as well as, the EAWG's requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004. Note you may have to report the same event more quickly to the DOE than is required by EOP-004, but this cannot be helped due to bullet point 2 above.* Clark questions whether the event labeled Forced Intrusion really needs to be reported in one hour. It can take several hours to determine if a forced entry actually occurred. Clark is also unsure if reporting forced intrusions at these facilities (if no other disturbance occurs) will provide any information useful in preventing system disturbances but believes this event should be changed to a 24 hour notification.

Organization	Yes or No	Question 3 Comment
		'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. The event labeled Detection of a reportable Cyber Security Incident should have the Entity with Reporting Responsibility changed to the following: "Applicable Entities under CIP-008." The Threshold for Reporting on this event is based on the criteria in CIP-008. If an entity is not an applicable entity under CIP-008, it should not have a reporting requirement based on CIP-008 that appears in EOP-004. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.*
Response: Thank you for your comment. Please see response above.		
City of Farmington	Negative	Attachment 1: BES equipment is too vague - consider changing to BES facility and including that reduces the reliability of the BES in the footnote. Is the footnote an and or an or? *The 'Damage or Destruction' event category has been revised to say 'to a Facility', (a defined term) and thresholds have be modified to provide clarity.* *The DSR SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as:*

Organization	Yes or No	Question 3 Comment
		"A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)" *The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.* Attachment 1: Version 5 of CIP Requirements the use of the terms Critical Asset and Critical Cyber Asset. The drafting team should consider revising the table to be flexible so it will not require modification when new versions of CIP become effective. Clarify if Damage or Destruction is physical damage (aka - cyber incidents would be part of CIP-008 covered separately in Attachment 1.) *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* Attachment 1: Unplanned Control Center evacuation - remove "potential" from the reporting responsibility Attachment 1: *The 'potential' language has been removed. The threshold for Reporting now reads as: "Each RC, BA, TOP that experiences the event".* SOL Tv - is not defined. *The SOL Violation (WECC only) event has been revised to remove Tv and replace it with "30 minutes" to be consistent with TOP-007-WECC requirements. The event has*

Organization	Yes or No	Question 3 Comment
		also been revised to indicate an SOL associated with a Major WECC transfer path. Attachment 2 - 3: change to, "Did the event originate in your system?" The requirement only requires reporting for Events - not potential events. This implies if there is potential for an event to occur, the entity should report (potential of a public appeal or potential to shed firm load) *The 'actual or potential' language has been removed.* Attachment 2 4: "Damage or Destruction to BES equipment" should be "Destruction of BES Equipment" like it is in Attachment 1 and "forced intrusion risk to BES equipment" remove "risk" *The 'Damage or Destruction' event category has been revised to say '…to a Facility', (a defined term) and thresholds have be modified to provide clarity. Also, the reporting timeline is now 24 hours.* *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred.* The OE-417 requires several of the events listed in Attachment 1 be reported within 1 hour. FEUS recommends the drafting team review the events and the OE-417 form and align the reporting window requirements. For example, public appeals, load shedding, and system separation have a 1 hour requirement in OE-417. *OE-417, as well as, the EAWG's requirements were considered in creating Attachment*

Organization	Yes or No	Question 3 Comment
		1, but there remain differences for the following reasons: • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004. Note you may have to report the same event more quickly to the DOE than is required by EOP-004, but this cannot be helped due to bullet point 2 above.*
Response: Thank you for your comment. Please see response above.		
Wisconsin Public Service Corp.	Negative	EOP-004 Attachment 1 states: That any Damage or destruction of a Critical Cyber Asset per CIP-002 Applicable Entities under CIP-002 Through intentional or unintentional human action. Requires reporting in 1 hour of recognition of event. This is too low of a threshold for reporting. Unintentional damage could be caused by an individual spilling coffee on a laptop. Hardly the item for a report. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.*
Response: Thank you for your comment. Please see response above.		

Organization	Yes or No	Question 3 Comment
ACES Power Marketing, Hoosier Energy Rural Electric Cooperative, Inc., Sunflower Electric Power Corporation, Great River Energy	Negative	For many of the events listed in Attachment 1, there would be duplicate reporting the way it is written right now. For example, in the case of a fire in a substation (Destruction of BES equipment), the RC, BA, TO, TOP and perhaps the GO and GOP could all experience the event and each would have to report on it. This seems quite excessive and redundant. We recommend eliminating this duplicate reporting. *The DSR SDT has tried to minimize duplicative reporting, but recognizes there may be events that trigger more than one report. The current applicability ensures an event that could affect just one of the entities with reporting responsibility isn't missed.*
Response: Thank you for your comment. Please see response above.		
Consumers Energy	Negative	Forced intrusion needs to be specifically defined. A 1-hour report requirement is not necessary but for critical events that would have wide-ranging impact. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"...direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event..."* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. For the revised event category 'A physical threat that could impact the operability of a Facility' the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred.*

Organization	Yes or No	Question 3 Comment
		Requirements 2 and 3 should be combined into a single requirement. *The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to:* *"R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment 1."*
Response: Thank you for your comment. Please see response above.		
MidAmerican Energy Co.	Negative	MidAmerican Energy believes Attachment 1 expands the scope of what must be reported beyond what is required by FERC directives and beyond what is needed to improve security of the BES. Based on our understanding of Attachment 1, the category of "damage or destruction of a critical cyber asset" will likely result in hundreds or thousands of small equipment failures being reported to NERC and DOE, with no improvement to security. For example, hard drive failures, server failures, PLC failures and relay failures could all meet the criteria of "damage or destruction of a critical cyber asset." which would be required reporting in 1 hour. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"…direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. For the revised event category 'A physical threat*

Organization	Yes or No	Question 3 Comment
		that could impact the operability of a Facility' the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred. EOP-004-2 needs to clearly state that initial reports can be made by a phone call, email or another method, in accordance with paragraph 674 of FERC Order 706. MidAmerican recommends replacing Attachment 1 and Attachment 2 with the categories and timeframes that are listed in OE-417. This eliminates confusion between government requirements in OE-417 and NERC standards. *Attachment 1 provides the flexibility to make a verbal report. The header of Attachment 1 states:* *"NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the table below. In such cases, the affected Responsible Entity shall notify parties per R1 and provide as much information as is available at the time of the notification. Reports to the ERO should be submitted to one of the following: e-mail: esisac@nerc.com, Facsimile: 609-452-9550, Voice: 609-452-1422."* *Attachment 2 provides the flexibility to make a verbal report. The header of Attachment 2 states:* *"This form is to be used to report events. The Electric Reliability Organization and the Responsible Entity's Reliability Coordinator will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Reports to the ERO should be submitted via one of the following: e-mail: esisac@nerc.com, Facsimile: 609-452-9550, voice: 609-452-1422."* *OE-417, as well as, the EAWG's requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs;*

Organization	Yes or No	Question 3 Comment
		accommodation of other reporting obligations was considered as an opportunity not a 'must-have' • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004. Note you may have to report the same event more quickly to the DOE than is required by EOP-004, but this cannot be helped due to bullet point 2 above.*
Response: Thank you for your comment. Please see response above.		
MidAmerican Energy Co.	Negative	MidAmerican Energy believes Attachment 1 expands the scope of what must be reported beyond what is required by FERC directives and beyond what is needed to improve security of the BES. EOP-004-2 needs to clearly state that initial reports can be made by a phone call, email or another method, in accordance with paragraph 674 of FERC Order 706. MidAmerican recommends replacing Attachment 1 and Attachment 2 with the categories and timeframes that are listed in OE-417. This eliminates confusion between government requirements in OE-417 and NERC standards. *Attachment 1 provides the flexibility to make a verbal report. The header of Attachment 1 states:* *"NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the table below. In such cases, the affected Responsible*

Organization	Yes or No	Question 3 Comment
		Entity shall notify parties per R1 and provide as much information as is available at the time of the notification. Reports to the ERO should be submitted to one of the following: e-mail: esisac@nerc.com, Facsimile: 609-452-9550, Voice: 609-452-1422." *Attachment 2 provides the flexibility to make a verbal report. The header of Attachment 2 states:* *"This form is to be used to report events. The Electric Reliability Organization and the Responsible Entity's Reliability Coordinator will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Reports to the ERO should be submitted via one of the following: e-mail: esisac@nerc.com, Facsimile: 609-452-9550, voice: 609-452-1422."* *OE-417, as well as, the EAWG's requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004. Note you may have to report the same event more quickly to the DOE than is required by EOP-004, but this cannot be helped due to bullet point 2 above.*

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. Please see response above.		
Seattle City Light	Negative	Overarching Concern related to EOP-004-2 draft: The contemporaneous drafting efforts related to both the proposed Bulk Electric System ("BES") definition changes, as well as the CIP standards Version 5, could significantly impact the EOP-004-2 reporting requirements. Caution needs to be exercised when referencing these definitions, as the definitions of a BES element could change significantly and Critical Assets may no longer exist. As it relates to the proposed reporting criteria, it is debatable as to whether or not the destruction of, for example, one relay would be a reportable incident under this definition going forward given the current drafting team efforts. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* Related to "Reportable Events" of Attachment 1: 1. A reportable event is stated as, "Risk to the BES", the threshold for reporting is, "From a non-environmental physical threat". This appears to be a catch-all event, and basically every other event in Attachment 1 should be reported because it is a risk to the BES. Due to the subjectivity of this event, suggest removing it from the list. *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as*

Organization	Yes or No	Question 3 Comment
		a threat, not when it may have first occurred. 2. A reportable event is stated as, "Damage or destruction of Critical Asset per CIP-002". The term"Damage" would have to be defined in order for an entity to determine a threshold for what qualifies as "Damage" to a CA. One could argue that normal"Damage" can occur on a CA that is not necessary to report. There should also be caution here in adding CIP interpretation within this standard. Reporting Thresholds 1. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* The SDT made attempts to limit nuisance reporting related to copper thefts and so on which is supported. However a number of the thresholds identified in EOP-004-2 Attachment 1 are very low and could congest the reporting process with nuisance reporting and reviewing. An example is the "BES Emergency requiring manual firm load shedding of greater than or equal to 100 MW or the Loss of Firm load for = 15 Minutes that is greater than or equal to 200 MW (300 MW if the manual demand is greater than 3000 MW). In many cases these low thresholds represent reporting of minor wind events or other seasonal system issues on Local Network used to provide distribution service. *These thresholds reflect those used in the current in-force EOP-004-1, and haven't congested the reporting process to date.* Firm Demand 1. The use of Firm Demand in the context of the draft Standards could be used to describe commercial arrangements with a customer rather than a

Organization	Yes or No	Question 3 Comment
		reliability issue. Clarification of Firm Demand would be helpful *The DSR SDT did not use the words 'Firm Demand' anywhere in the proposed standard.*
Response: Thank you for your comment. Please see response above.		
Constellation Energy; Constellation Energy Commodities Group; Constellation Power Source Generation, Inc.	Negative	Please see the comments offered in the concurrent comment form. While Constellation is voting negative on this ballot, we recognize the progress made by the drafting team and find the proposal very close to acceptable. It should be noted that our negative vote is due to remaining concerns with the Attachment 1: Event Table categories language. In the comment form Constellation proposes revisions to both the requirement language and to the Event Table language; however, the Event Table language is the greater hurdle *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"…direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. For the revised event category 'A physical threat that could impact the operability of a Facility' the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred.*

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. Please see response above.		
Salt River Project	Negative	Related to “Reportable Events” of Attachment 1: 1. A reportable event is stated as, “Risk to the BES”, the threshold for reporting is, “From a non-environmental physical threat”. This as appears to be a catch-all event, and basically every other event should be reported because it is a risk to the BES. Due to the subjectivity of this event, suggest removing it from the list. *‘Forced intrusion’ and ‘Risk to BES Equipment’ have been combined under a new event type called ‘A physical threat that could impact the operability of a Facility’. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred.* 2. A reportable event is stated as, “Damage or destruction of Critical Asset per CIP-002”. The term “Damage” would have to be defined in order for an entity to determine a threshold for what qualifies as “Damage” to a CA. One could argue that normal “Damage” can occur on a CA that is not necessary to report. There should also be caution here in adding CIP interpretation within this standard. *The ‘Damage or Destruction’ events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and ‘Damage or Destruction of a Facility’ reporting thresholds.*
Response: Thank you for your comment. Please see response above.		
Southern California Edison Co.	Negative	SCE and WECC are in agreement on one key point (removing the requirement to

Organization	Yes or No	Question 3 Comment
		determine if an act was "sabotage"), however, I continue to believe SCE will find the one-hour reporting requirement difficult to manage. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"…direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. For the revised event category 'A physical threat that could impact the operability of a Facility' the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred.*
Response: Thank you for your comment. Please see response above.		
City of Redding	Negative	The following comments are directed toward Attachment 1: We commend the SDT for properly addressing the sabotage issue. However, additional confusion is caused by introducing term "damage". As "damage" is not a defined term it would be beneficial for the drafting team to provide clarification for what is meant by "damage". *The 'Damage or Destruction' event category has been revised to say '…to a Facility', (a defined term) and thresholds have be modified to provide clarity. Also, the reporting timeline is now 24 hours.*

Organization	Yes or No	Question 3 Comment
		The threshold for reporting "Each public Appeal for load reduction" should clearly state the triggering is for the BES Emergency as routine "public appeal" for conservation could be considered a threshold for the report triggering.. *The DSR SDT believes the current language of the event category 'BES Emergency…' clearly excludes routine conservation requests. The Threshold for Reporting has been updated to read as: "Public appeal for load reduction event".* Regarding the SOL violations in Attachment 1 the SOL violations should only be those that affect the WECC Paths. *The SOL Violation (WECC only) event has been revised to remove Tv and replace it with "30 minutes" to be consistent with TOP-007-WECC requirements. The event is now "SOL for Major WECC Transfer Paths (WECC only)". .*
Response: Thank you for your comment. Please see response above.		
Avista Corp.	Negative	The VSLs associated with not reporting in an hour for some of the events (Destruction of BES Equipment) is too severe. Operators need to be able to deal with events and not worry about reporting until the system is secure. Back office personnel are only available 40-50 hours per week, so the reporting burden falls on the Operator. *The DSR SDT believes the VSL is appropriate for the only remaining 1 hour event.*
Response: Thank you for your comment. Please see response above.		
Avista Corp.	Negative	There is definitely a need to communicate and report out system events to NERC, RCs, and adjacent utilities. However, this new standard has gone too far with regards to reporting of certain events within a 1 hour timeframe and the associated VSLs for going beyond the hour time period. Operators need to be able to deal with the system events and not worry about reporting out for the "Destruction of BES

Organization	Yes or No	Question 3 Comment
		equipment" (first row in Attachment 1 -Reportable Events). Operators only have 40-50 hours out of 168 hours in a week where supporting personnel are also on shift, so this reporting burden will usually fall on the Operators not back office support. Again this is another example of the documentation requirements of a standard being more important than actually operating the system. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"…direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. For the revised event category 'A physical threat that could impact the operability of a Facility' the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred.* The "Destruction of BES equipment" event is too ambiguous and will lead to interpretations by auditors to determine violations. The ambiguity will also lead to the reporting of all BES equipment outages to avoid potential violations of the standard. It usually takes more than an hour to determine the cause and extent of an outage. *The 'Damage or Destruction' event category has been revised to say '…to a Facility', (a defined term) and thresholds have be modified to provide clarity. Also, the reporting timeline is now 24 hours.*

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. Please see response above.		
National Association of Regulatory Utility Commissioners	Negative	Therequirement that any event with the potential to impact reliability be reported is overly broad and requires more focus. *'Forced intrusion' and 'Risk to BES Equipment' (which this footnote referenced) have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred.*
Response: Thank you for your comment. Please see response above.		
Alameda Municipal Power, Salmon River Electric Cooperative	Negative	We feel that the drafting team has done an excellent job of providing clarify and reasonable reporting requirements to the right functional entity. We support the modifications but would like to have two additional minor modification in order to provide additional clarification to the Attachment I Event Table. We suggest the following clarifications: For the Event: BES Emergency resulting in automatic firm load shedding Modify the Entity with Reporting Responsibility to: Each DP or TOP that experiences the automatic load shedding within their respective distribution serving or Transmission Operating area. *The DSR SDT believes the current language is sufficient and cannot envision how a BA, TOP, or DP could 'experience the automatic load shedding' if it didn't take place in its balancing, transmission operating, or distribution serving area.*

Organization	Yes or No	Question 3 Comment
		For the Event: Loss of Firm load for = 15 Minutes Modify the Entity with Reporting Responsibility to: Each BA, TOP, DP that experiences the loss of firm load within their respective balancing, Transmission operating, or distribution serving area. With these modifications or similar modifications we fully support the proposed Standard. *The DSR SDT believes the current language is sufficient and cannot envision how a BA, TOP, or DP could 'experience the loss of firm load' if it didn't take place in its balancing, transmission operating, or distribution serving area.*
Response: Thank you for your comment. Please see response above.		
Orange and Rockland Utilities, Inc.	No	o Generally speaking the SDT should work with the NERC team drafting the Events Analysis Process (EAP) to ensure that the reporting events align and use the same descriptive language. o EOP-004 should use the exact same events as OE-417. These could be considered a baseline set of reportable events. If the SDT believes that there is justification to add additional reporting events beyond those identified in OE-417, then the event table could be expanded. o If the list of reportable events is expanded beyond the OE-417 event list, the supplemental events should be the same in both EOP-004-2 and in the EAP Categories 1 through 5. *OE-417, as well as, the EAWG's requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may*

Organization	Yes or No	Question 3 Comment
		trigger further information requests from EAWG as necessary *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004.* o It is not clear what the difference is between a footnote and “Threshold for Reporting”. All information should be included in the body of the table, there should be no footnotes. *All footnotes are deleted and appropriate content moved to ‘Thresholds for Reporting’ with the exception of the footnote relating to the new event category ‘A physical threat that could impact the operability of a Facility’. This remaining footnote provides examples only.* o Event: “Risk to BES equipment” should be deleted. This is too vague and subjective. Will result in many “prove the negative” situations.’ *‘Forced intrusion’ and ‘Risk to BES Equipment’ have been combined under a new event type called ‘A physical threat that could impact the operability of a Facility’. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred.* o Event: “Destruction of BES equipment” is again too vague. The footnote refers to equipment being “damaged or destroyed”. There is a major difference between

Organization	Yes or No	Question 3 Comment
		destruction and damage. *The 'Damage or Destruction' event category has been revised to say 'to a Facility', (a defined term) and thresholds have be modified to provide clarity.* o Event: "Damage or Destruction of a Critical Asset or Critical Cyber Asset" should be deleted. Disclosure policies regarding sensitive information could limit an entity's ability to report. Unintentional damage to a CCA does not warrant a report. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* o Event: "BES Emergency requiring public appeal for load reduction" should be modified to note that this does not apply to routine requests for customer conservation during high load periods *The DSR SDT believes the current language of the event category 'BES Emergency…' clearly excludes routine conservation requests.*
Response: Thank you for your comment. Please see response above.		
Ameren	No	(1)By our count there are still six of the nineteen events listed with a one hour reporting requirement and the rest are all within 24 hour after the occurrence (or recognition of the event). This in our opinion, is reporting in real-time, which is against one of the key concepts listed in the background section:"The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in Attachment 1. Real-time reporting is achieved through the RCIS and is covered in other standards (e.g. the TOP family of

Organization	Yes or No	Question 3 Comment
		standards). The proposed standard deals exclusively with after-the-fact reporting." *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. For the revised event category 'A physical threat that could impact the operability of a Facility' the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred.* (2)We believe the earliest preliminary report required in this standard should at the close of the next business day. Operating Entities, such as the RC, BA, TOP, GOP, DP, and LSE should not be burdened with unnecessary after-the-fact reporting while they are addressing real-time operating conditions. Entities should have the ability to allow their support staff to perform this function during the next business day as needed. We acknowledge it would not be an undue burden to cc: NERC on other required governmental reports with shorter reporting timeframes, but NERC should not expand on this practice. *No preliminary report is required within the revised standard.* (3)We agree with the extension in reporting times for events that now have 24 hours of reporting time. As a GO there are still too many potential events that still require

Organization	Yes or No	Question 3 Comment
		a 1 hour reporting time that is impractical, unrealistic and could lead to inappropriate escalation of normal failures. For example, the sudden loss of several control room display screens for a BES generator at 2 AM in the morning, with only 1 hour to report something, might be mistakenly interpreted as a cyber-attack. The reality is most likely something far more mundane such as the unexpected failure of an instrument transformer, critical circuit board, etc. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. For the revised event category 'A physical threat that could impact the operability of a Facility' the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred.*
Response: Thank you for your comment. Please see response above.		
Duke Energy	No	All events in Attachment 1 should have reporting times of no less than 24 hours. As stated on page 6 of the current draft of the standard: "The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in Attachment 1. Real-time reporting is achieved through the RCIS and is covered in other standards (e.g. the TOP family of standards). The proposed standard deals exclusively with after-the-fact reporting."We maintain

Organization	Yes or No	Question 3 Comment
		that a report which is required to be made within one hour after an event is, in fact, a real time report. In the first hour or even several hours after an event the operator may appropriately still be totally committed to restoring service or returning to a stable bulk power system state, and should not stop that recovery activity in order to make this "after-the-fact" report. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. For the revised event category 'A physical threat that could impact the operability of a Facility' the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred.*
Response: Thank you for your comment. Please see response above.		
American Public Power Association	No	APPA echoes the comments made by Central Lincoln: We do not believe the SDT has adequately addressed the FERC Order to "Consider whether separate, less burdensome requirements for smaller entities may be appropriate." The one and 24 hour reporting requirements continue to be burdensome to the smaller entities that do not maintain 24/7 dispatch centers. The one hour reporting requirement means that an untimely "recognition" starts the clock and reporting will become a higher

Organization	Yes or No	Question 3 Comment
		priority than restoration. The note regarding adverse conditions does not help unless we were to consider the very lack of 24/7 dispatch to be such a condition. APPA recommends the SDT evaluate a less burdensome requirement for smaller entities with reporting requirements in Attachment 1. This exception needs to address the fact that not all entities have 24 hour 7 day a week operating personnel. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. For the revised event category 'A physical threat that could impact the operability of a Facility' the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred.* *The DSR SDT believes that reliability is best served by imposing reporting criteria based on impact to the BES rather than an arbitrary entity size threshold. With these latest revisions, all the proposed event categories provide thresholds that will capture the appropriate entities and provide a manageable timeframe.* However, APPA cautions the SDT that changes to this standard may expose entities to reporting violations on DOE-OE-417 which imposes civil and criminal penalties on reporting events to the Department of Energy. APPA recommends that the SDT reach out to DOE for clarification of reporting requirements for DOE-OE-417 for small entities, asking DOE to change their reporting requirement to match EOP-004-2. If

Organization	Yes or No	Question 3 Comment
		DOE cannot change their reporting requirement the SDT should provide an explanation in the guidance section of Reliability Standard EOP-004-2 that addresses these competing FERC/DOE directives. *OE-417, as well as, the EAWG's requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004. Note you may have to report the same event more quickly to the DOE than is required by EOP-004, but this cannot be helped due to bullet point 2 above.*
Response: Thank you for your comment. Please see response above.		
BC Hydro	No	As an event would be verbally reported to the RC, all the one hour requirements to submit a written report should be moved from one hour to 24 hours. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact*

Organization	Yes or No	Question 3 Comment
		appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…" *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. For the revised event category 'A physical threat that could impact the operability of a Facility' the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred.*
Response: Thank you for your comment. Please see response above.		
Bonneville Power Administration	No	BPA believes that the first three elements in Attachment 1 are too generic and should be with only the intentional human criterion. The suspicious device needs to be determined as a threat (and not left behind tools) before requiring a report. *The 'Damage or Destruction' event category has been revised to say 'to a Facility', (a defined term) and thresholds have be modified to provide clarity. These thresholds include intentional human action as well as impact-based for those cases when cause isn't known. The determination of a threat as you suggest is now part of the revised event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred.*

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. Please see response above.		
CenterPoint Energy	No	CenterPoint Energy agrees with the revision that allows more time for reporting some events; however, some 1 hour requirements remain. The Company does not agree with this timeframe for any event. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. For the revised event category 'A physical threat that could impact the operability of a Facility' the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred.*
Response: Thank you for your comment Please see response above.		
Consolidated Edison Co. of NY, Inc.	No	Comments: We have a number of comments on Attachment 1 and will make them here: o Generally speaking the SDT should work with the NERC team drafting the Events Analysis Process (EAP) to ensure that the reporting events align and use the same descriptive language. o EOP-004 should use the exact same events as OE-417. These could be considered a baseline set of reportable events. If the SDT believes that there is justification to add additional reporting events beyond those identified in OE-417, then the event table could be expanded. o If the list of reportable events

Organization	Yes or No	Question 3 Comment
		is expanded beyond the OE-417 event list, the supplemental events should be the same in both EOP-004-2 and in the EAP Categories 1 through 5. *OE-417, as well as, the EAWG's requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004.* o It is not clear what the difference is between a footnote and "Threshold for Reporting". All information should be included in the body of the table, there should be no footnotes. *All footnotes are deleted and appropriate content moved to 'Thresholds for Reporting' with the exception of the footnote relating to the new event category 'Any physical threat that could impact the operability of a Facility'. This remaining footnote provides examples only.* o Event: "Risk to BES equipment" should be deleted. This is too vague and subjective. Will result in many "prove the negative" situations.'

Organization	Yes or No	Question 3 Comment
		'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. o Event: "Destruction of BES equipment" is again too vague. The footnote refers to equipment being "damaged or destroyed". There is a major difference between destruction and damage. *The 'Damage or Destruction' event category has been revised to say 'to a Facility', (a defined term) and thresholds have be modified to provide clarity.* o Event: "Damage or Destruction of a Critical Asset or Critical Cyber Asset" should be deleted. Disclosure policies regarding sensitive information could limit an entity's ability to report. Unintentional damage to a CCA does not warrant a report. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* o Event: "BES Emergency requiring public appeal for load reduction" should be modified to note that this does not apply to routine requests for customer conservation during high load periods.

Organization	Yes or No	Question 3 Comment
		The DSR SDT believes the current language 'BES Emergency...' clearly excludes routine conservation requests.
Response: Thank you for your comment. Please see response above.		
Electric Reliability Council of Texas, Inc.	No	Destruction of BES equipment: 1. Request that the term "destruction" be clarified. *The 'Damage or Destruction' event category has been revised to say 'to a Facility', (a defined term) and thresholds have be modified to provide clarity.* Damage or destruction of Critical Asset per CIP-002: 1. Request that the terms "damage" and "destruction" be clarified. 2. Is the expectation that an entity report each individual device or system equipment failure or each mistake made by someone administering a system? *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* 3. Request that "initial indication of the event" be changed to "confirmation of the event". Event monitoring and management systems may receive many events that are determined to be harmless and put the entity at no risk. This can only be determined after analysis of the associated events is performed. *The 'initial indication of the event' is no longer part of the threshold for 'Damage or Destruction of a Facility'* Risk to BES equipment: Request that the terms "risk" be clarified. *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'.*

Organization	Yes or No	Question 3 Comment
		Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred.
Response: Thank you for your comment. Please see response above.		
Exelon	No	Due to the size of the service territories in ComEd and PECO it’s difficult to get to some of the stations within in an hour to analyze an event which causes concern with the 1 hour criteria. It is conceivable that the evaluation of an event could take longer then one hour to determine if it is reportable. Exelon cannot support this version of the standard until the 1 hour reporting criteria is clarified so that the reporting requirements are reasonable and obtainable. Exelon has concerns about the existing 1 hour reporting requirements and feels that additional guidance and verbiage is required for clarification. We would like a better understanding when the 1 hour clock starts please consider using the following clarifying statement, in the statements that read, “recognition of events” please consider replacing the word “recognition” with the word “confirmation” as in a “confirmed event” *All one hour reporting timelines have been changed to 24 hours with the exception of a ‘Reportable Cyber Security Incident’. This is maintained due to FERC Order 706, Paragraph 673:* *“direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…”* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force*

Organization	Yes or No	Question 3 Comment
		standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. For the revised event category 'A physical threat that could impact the operability of a Facility' the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred.
Response: Thank you for your comment. Please see response above.		
Energy Northwest - Columbia	No	Energy Northwest - Columbia (ENWC) has concerns about the existing 1 hour reporting requirements and feels that additional guidance and verbiage is required for clarification. ENWC would like the word "recognition" in the statement that reads, "recognition of events," be replaced by "confirmation" as in "confirmed event."Also, we would like clarification as to when the 1 hour clock starts. Please consider changing recognition in "within 1 hour of recognition of event" and incorporating in "confirmation." *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions.*
Response: Thank you for your comment. Please see response above.		

Organization	Yes or No	Question 3 Comment
Indiana Municipal Power Agency	No	IMPA believes that some of the times may not be aggressive enought that are related to generation capacity shortages. *This standard concerns after-the-fact reporting. It is assumed that Responsible Entities will make appropriate real-time notifications as per other applicable standards, operating agreements, and good utility practice. This standard does not preclude a Responsible Entity from reporting more quickly than required by Attachment 1.* In addition, IMPA believes clarity needs to be added when saying within 1 hour of recognition of event. For example, A fence cutting may not be discovered for days at a remote substation and then a determination has to be made if it was "forced intrusion" - Does that one hour apply once the determination is made that is was "forced intrusion" or from the time the discovery was made? Some of the 1 hour time limits can be expanded to allow for more time, such as forced intrusion, destruction of BES equipment, Risk to BES equipment, etc. *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'Any physical threat that could impact the operability of a Facility'. Timelines start at the moment the Responsible Entity determines the event represents a threat, not when it first occurred.*
Response: Thank you for your comment. Please see response above.		
Luminant Power	No	Luminant agrees with the changes the SDT made, however, the timeline should be modified to put higher priority activities before reporting requirements. The SDT should consider allowing entities the ability to put the safety of personnel, safety of the equipment, and possibly the stabilization of BES equipment efforts prior to initiating the one hour reporting timeline. Reporting requirements should not be prioritized above these important activities. The requirement to report one hour after the recognition of such an event may not be sufficient in all instances. Entities

Organization	Yes or No	Question 3 Comment
		should not have a potential violation as a result of putting these priority issues first and not meeting the one hour reporting timeline. *All one hour reporting timelines have been changed to 24 hours with the exception of a ‘Reportable Cyber Security Incident’. This is maintained due to FERC Order 706, Paragraph 673:* *“direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…”* *Actions taken to maintain the reliability of the BES in real-time always take precedence over reporting. The revised thresholds should ensure there is no perverse driver to act differently.*
Response: Thank you for your comment. Please see response above.		
MidAmerican Energy	No	MidAmerican Energy agrees with the direction of consolidating CIP-001, EOP-004 and portions of CIP-008. However, we have concerns with some of the events included in Attachment 1 and reporting timelines. EOP-004-2 needs to clearly state that initial reports can be made by a phone call, email or another method, in accordance with paragraph 674 of FERC Order 706. *All one hour reporting timelines have been changed to 24 hours with the exception of a ‘Reportable Cyber Security Incident’. This is maintained due to FERC Order 706, Paragraph 673:* *“direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…”* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions.*

Organization	Yes or No	Question 3 Comment
		MidAmerican Energy believes draft Attachment 1 expands the scope of what must be reported beyond what is required by FERC directives and beyond what is needed to improve security of the BES. Based on our understanding of Attachment 1, the category of "damage or destruction of a critical cyber asset" will result in hundreds or thousands of small equipment failures being reported to NERC and DOE, with no improvement to security. For example, hard drive failures, server failures, PLC failures and relay failures could all meet the criteria of "damage or destruction of a critical cyber asset." *The DSR SDT agrees and the 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* We recommend replacing Attachment 1 and Attachment 2 with the categories and timeframes that are listed in OE-417. This eliminates confusion between government requirements in OE-417 and NERC standards. *OE-417, as well as, the EAWG's requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may*

Organization	Yes or No	Question 3 Comment
		trigger further information requests from EAWG as necessary *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004.* Reporting timelines and reporting formFERC Order 706, paragraph 676, directed NERC to require a responsible entity to "at a minimum, notify the ESISAC and appropriate government authorities of a cyber security incident as soon as possible, but, in any event, within one hour of the event, even if it is a preliminary report." In paragraph 674, FERC stated that the Commission agrees that, in the "aftermath of a cyber attack, restoring the system is the utmost priority." They clarified: "the responsible entity does not need to initially send a full report of the incident...To report to appropriate government authorities and industry participants within one hour, it would be sufficient to simply communicate a preliminary report, including the time and nature of the incident and whatever useful preliminary information is available at the time. This could be accomplished by a phone call or another method." While FERC did not order completion of a full report within one hour in Order 706, the draft EOP-004 Attachment 1 appears to require submittal of formal reports within one hour for six of the categories, unless there have been "certain adverse conditions" (in which case, as much information as is available must be submitted at the time of notification). *It is assumed that Responsible Entities will make appropriate real-time notifications as per other applicable standards, operating agreements, and good utility practice. As stated above, all one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673. For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions, which would certainly include the aftermath of a cyber attack that had*

Organization	Yes or No	Question 3 Comment
		major impact on the BES. The Violation Severity Levels are extreme for late submittal of a report. For example, it would be a severe violation to submit a report more than three hours following an event for an event requiring reporting in one hour. *The DSR SDT believes the VSL is appropriate now that it only applies to the remaining 1 hour reportable event, which is the Reportable Cyber Event under CIP-008.* MidAmerican Energy suggests incorporating the language from FERC Order 706, paragraph 674, into the EOP-004 reporting requirement to allow preliminary reporting within one hour to be done through a phone call or another method to allow the responsible entity to focus on recovery and/or restoration, if needed.MidAmerican Energy agrees with the use of DOE OE-417 for submittal of the full report of incidents under EOP-004 and CIP-008. We would note there are two parts to this form -- Schedule 1-Alert Notice, and Schedule 2-Narrative Description. Since OE-417 already requires submittal of a final report that includes Schedule 2 within 48 hours of the event, MidAmerican Energy believes it is not necessary to include a timeline for completion of the final report within the EOP-004 standard. We would note that Schedule 2 has an estimated public reporting burden time of two hours so it is not realistic to expect Schedule 2 to be completed within one hour. Events included in Attachment 1:MidAmerican Energy believes draft Attachment 1 expands the scope of what must be reported beyond what is required by FERC directives and beyond what is needed to improve security of the BES. The categories listed in Attachment 1 with one-hour reporting timelines cause the greatest concern. None of these categories are listed in OE-417, and all but the last row would not be considered a Cyber Security Incident under CIP-008, unless there was malicious or suspicious intent. *All one hour reporting timelines have been changed to 24 hours with the exception of*

Organization	Yes or No	Question 3 Comment
		a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673: *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions.*
Response: Thank you for your comment. Please see response above.		
SERC OC Standards Review Group	No	No event should have a reporting time less than at the close of the next business day. Any reporting of an event that requires a less reporting time should only be to entities that can help mitigate an event such as an RC or other Reliability Entity. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions.*
Response: Thank you for your comment. Please see response above.		

Organization	Yes or No	Question 3 Comment
Southwestern Power Administration	No	One hour is not enough time to make these assessments for all of the six items in attachment 1. All timing requirements should be made the same in order to simplify the reporting process. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions.*
Response: Thank you for your comment. Please see response above.		
ITC	No	See comments to Question #4
Response: Thank you for your comment. See response to Question 4.		
Southern Company	No	Southern request clarification on one of the entries in Attachment 1. The concern is with the last row on page 21 of Draft 3. What is the basis for "Voltage deviations"? The Threshold is Â±10% sustained for â‰¥ 15 minutes. Is the voltage deviation based on the Voltage Schedule for that particular timeframe, or is it something else (pre-contingency voltage level, nominal voltage, etc.)? *A sustained voltage deviation of ± 10% on the BES is significant deviation and is indicative of a shortfall of reactive resources either pre- or post-contingency. The DSR SDT is indifferent to which of nominal, pre-contingency, or scheduled voltage, is used*

Organization	Yes or No	Question 3 Comment
		as the baseline, but for simplicity and to promote a common understanding suggest using nominal voltage. In addition, the second row of Attachment 1 lists "Damage or destruction of a Critical Cyber Asset per CIP-002" as a reportable event. The threshold includes "...intentional or unintentional human action" and gives us 1 hour to report. The term "damage" may be overly broad and, without definition, is not limited in any way. If a person mistypes a command and accidentally deletes a file, or renames something, or in any way changes anything on the CCA in error, then this could be considered "damage" and becomes a reportable event. The SDT should consider more thoroughly defining what is meant by "damage". Should it incorporate the idea that the essential functions that the CCA is performing must be adversely impacted? *The DSR SDT agrees and the 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* Lastly, no event should have a reporting time shorter than at the close of the next business day. Any reporting of an event that requires a shorter reporting time should only be to entities that can help mitigate an event such as an RC or other Reliability Entity. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber*

Organization	Yes or No	Question 3 Comment
		security incident as soon as possible, but in any event, within one hour of the event…" *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions.*
Response: Thank you for your comment. Please see response above.		
FEUS	No	The OE-417 requires several of the events listed in Attachment 1 be reported within 1 hour. FEUS recommends the drafting team review the events and the OE-417 form and align the reporting window requirements. For example, public appeals, load shedding, and system seperation have a 1 hour requirement in OE-417. *OE-417 thresholds and reporting timelines were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America. Non-US Responsible Entities cannot be obligated to report in shorter timelines simply to make the two forms line up. The current in-force EOP-004 requires 24 hour reporting on the items you have identified and so does the latest version of EOP-004-2* • *NERC has no control over the criteria in OE-417, which can change at any time* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004.*

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. Please see response above.		
SPP Standards Review Group	No	The purpose of the reporting requirement should be clear either in the text of the requirements or through an explanation that is embodied in the language of the approved set of standards. This would be consistent with a "Results-based" architecture. What is lacking in the proposed language of this standard is recognition that registered entities differ in size and relevance of their impact on the Bulk Electric System. Also, events that are reportable differ in their impact on the registered entity. A "one-size fits all" approach to this standard may cause smaller entities with low impact on the grid to take extraordinary measures to meet the reporting/timing requirements and yet be too "loose" for larger more sophisticated and impacting entities to meet the same requirements. Therefore, we believe language of the standard must clearly state the intent that entities must provide reports in a manner consistent with their capabilities from a size/reliability impact perspective and from a communications availability perspective. Timing requirements should allow for differences and consider these variables.Also, we would suggest including language to specifically exclude situations where communications facilities may not be available for reporting. For example, in situations where communications facilities have been lost, initial reports would be due within 6 hours of the restoration of those communication facilities. *The DSR SDT has reviewed Attachment 1 and made revisions to Event types, used the NERC approved term 'Facility', and revised some of the language under 'Entity with Reporting Responsibility' to ensure that these reportable events correctly represent the relative impact to the BES. Also, all one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"*

Organization	Yes or No	Question 3 Comment
		For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. We would also suggest that Attachment 1 be broken into two distinct parts such that those events which must be reported within 1 hour standout from those events that have to be reported within 24 hours. *The DSR SDT agrees and has implemented your suggestion.*
Response: Thank you for your comment. Please see response above.		
Kansas City Power & Light	No	The reportable events listed in Attachment 1 can be categorized as events that have had a reliability impact and those events that could have a reliability impact. The listed events that could have a reliability impact should have a 24 hour reporting requirement and the events that have had a reliability impact are appropriate at a 1 hour reporting. The following events with a 1 hour report requirement are recommended to change to 24 hour: Forced Intrusion and Risk to BES Equipment. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event..."* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions.*

Organization	Yes or No	Question 3 Comment
		In addition, the Attachment 1 Events Table is incomplete as many of the listed events are incomplete regarding reporting time requirements and event descriptions. *Attachment 1 has been revised to more clearly indicate reporting timelines and some of the event descriptions were changed to add clarity.* Also recommend removing (ii) from note 5 with event "Destruction of BES equipment" as this part of the note is already described in the event description and insinuates reporting of equipment losses that do not have a reliability impact. *This footnote has been deleted* The events, "Damage or destruction of Critical Asset per CIP-002" and "Damage or destruction of a Critical Cyber Asset per CIP-002", does not have sufficient clarity regarding what that represents. A note similar in nature to Note 5 for BES equipment is recommended. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.*
Response: Thank you for your comment. Please see response above.		
Los Angeles Department of Water and Power	No	The reporting time of within 1 hour of recognition for a "Forced Intrusion" (last event category on page 20 of Draft 3, dated October 25, 2011) when considered with the associated footnote "Report if you cannot reasonably determine likely motivation" is overly burdensome and unrealistic. What is "reasonably determine likely motivation" is too general and requires further clarity. For example, LADWP has numerous facilities with extensive perimeter fencing. There is a significant

Organization	Yes or No	Question 3 Comment
		difference between a forced intrusion like a hole or cut in a property line fence of a facility versus a forced intrusion at a control house. Often cuts in fences, after further investigation, are determined to be cases of minor vandalism. An investigation of this nature will take much more than the allotted hour. The NERC Design Team needs to develop difference levels for the term "Force Intrusion" that fit the magnitude of the event and provide for adequate time to determine if the event was only a case of minor vandalism or petty thief. The requirement, as currently written, would unnecessarily burden an entity in reporting events that after given more time to investigate would more than likely not have been a reportable event. *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred.*
Response: Thank you for your comment. Please see response above.		
Northeast Power Coordinating Council	No	The SDT should work with the NERC team drafting the Events Analysis Process (EAP) to ensure that the reporting events align and use the same descriptive language.EOP-004 should use the exact same events as OE-417. These could be considered a baseline set of reportable events. If the SDT believes that there is justification to add additional reporting events beyond those identified in OE-417, then the event table could be expanded. If the list of reportable events is expanded beyond the OE-417 event list, the supplemental events should be the same in both EOP-004-2 and

Organization	Yes or No	Question 3 Comment
		in the EAP Categories 1 through 5. *OE-417 thresholds and reporting timelines were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America. Non-US Responsible Entities cannot be obligated to report in shorter timelines simply to make the two forms line up. The current in-force EOP-004 requires 24 hour reporting on the items you have identified and so does the latest version of EOP-004-2* • *NERC has no control over the criteria in OE-417, which can change at any time* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004.* It is not clear what the difference is between a footnote and "Threshold for Reporting". All information should be included in the body of the table, there should be no footnotes. *All footnotes are deleted and appropriate content moved to 'Thresholds for Reporting' with the exception of the footnote relating to the new event category 'A physical threat that could impact the operability of a Facility'. This remaining footnote provides examples only.* Event: Risk to BES equipment should be deleted. This is too vague and subjective. This will result in many "prove the negative" situations. *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new*

Organization	Yes or No	Question 3 Comment
		event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. Event: Damage or Destruction of a Critical Asset or Critical Cyber Asset should be deleted. Disclosure policies regarding sensitive information could limit an entity's ability to report. Unintentional damage to a CCA does not warrant a report. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* Event: BES Emergency requiring public appeal for load reduction should be modified to note that this does not apply to routine requests for customer conservation during high load periods. *The DSR SDT believes the current language of the event category 'BES Emergency...' clearly excludes routine conservation requests.*
Response: Thank you for your comment. Please see response above.		
Florida Municipal Power Agency	No	The times don't seem aggressive enough for some of the Events related to generation capacity shortages, e.g., we would think public appeal, system wide voltage reduction and manual firm load shedding ought to be within an hour. These are indicators that the BES is "on the edge" and to help BES reliability,

Organization	Yes or No	Question 3 Comment
		communication of this status is important to Interconnection-wide reliability. *This standard concerns after-the-fact reporting. It is assumed that Responsible Entities will make appropriate real-time notifications as per other applicable standards, operating agreements, and good utility practice. This standard does not preclude a Responsible Entity from reporting more quickly than required by Attachment 1.*
Response: Thank you for your comment. Please see response above.		
NorthWestern Energy	Affirmative	In Attachment 1 NorthWestern Eneergy does not agree with the Transmission loss event, the threshold for reporting is "Unintentional loss of Three or more Transmission Facilities (excluding successful automatic reclosing)." There are lots of instances where this can happen and not have any major impacts to the BES. This reporting requirement is stemming from the Event Analysis Reporting Requirements and in many instances does not constitute an emergency. *You are correct. This event is used as a trigger to the Events Analysis Process.* Also, in Attachment 1 it is not clear when the DOE OE-417 form MUST be submitted. It give an option to use this form or another form but does not state when it must be used - confusing. *For the purposes of EOP-004, Responsible Entities may use either Attachment 2 or OE-417. Submission of OE-417 to the DOE is mandatory for US entities and outside the scope of NERC. Giving you the option to submit OE-417 to NERC and your RC to satisfy EOP-004 is permitted as a matter of convenience so you don't have to submit two different forms for the same event.*
Response: Thank you for your comment. Please see response above.		
Rutherford EMC	Affirmative	The SDT should consider adding a clause in the standard exempting small DP/LSEs

Organization	Yes or No	Question 3 Comment
		from the standard if the DP/LSE annually reviews and approves that it owns no facilities or equipment creating an event as decribed in Attachment 1. *The DSR SDT believes that reliability is best served by imposing reporting criteria based on impact to the BES rather than an arbitrary entity size threshold. With these latest revisions, all the proposed event categories provide thresholds that will capture the appropriate entities and provide a manageable timeframe.*
Response: Thank you for your comment. Please see response above.		
Fort Pierce Utilities Authority	Affirmative	The triggering event “Detection of a reportable Cyber Security Incident” listed in Attachment 1 assigns essentially all utilities reporting responsibility. This is not in line its reporting threshold, which is an event meeting the criteria in CIP-008. Shouldn’t the responsibility fall on only those responsible for compliance with CIP-008, version 3 or 4, as determined by CIP-002? The SDT should also give additional consideration to necessary provisions to make it align with the proposed CIP-008-5. *The ‘Entity with Reporting Responsibility’ has been changed to reflect your comment to ‘Each Responsible Entity applicable under CIP-008 that experiences the Cyber Security Incident.*
Response: Thank you for your comment. Please see response above.		
Nebraska Public Power District	Yes	Although 24 hours is a vast improvement, one business day would make more sense for after the fact reporting. *All one hour reporting timelines have been changed to 24 hours with the exception of a ‘Reportable Cyber Security Incident’. This is maintained due to FERC Order 706, Paragraph 673:* *“direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber*

Organization	Yes or No	Question 3 Comment
		security incident as soon as possible, but in any event, within one hour of the event…" *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions.*
Response: Thank you for your comment. Please see response above.		
FirstEnergy	Yes	Although we agree with the timeframes for reporting, we have other concerns as listed in our response to Question 4.
Response: Thank you for your comment. Please see response to question 4.		
Intellibind	Yes	Does this reporting conflict with reporting for DOE, and Regions? If so, what reporting requirements will the entity be held accountable to? Managing multiple reporting requirements for the multiple agencies is very problematic for entities and this standard should resolve those reporting requirments, as well as reduce the reporting down to one form and one submission. Reporting to ESISAC should take care of all reporting by the company. NERC should route all reports to the DOE, and regions through this mechanism. *OE-417 thresholds and reporting timelines were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America. Non-US Responsible Entities cannot be obligated to report in shorter timelines simply to make the two forms line up. NERC has no control over the criteria in OE-417, which can change at any time*

Organization	Yes or No	Question 3 Comment
		In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004. NERC cannot take on the statutory obligation of US entities to report to the DOE.
Response: Thank you for your comment. Please see response above.		
Dominion	Yes	Dominion appreciates the changes that have been made to increase the 1 hr reporting time to 24 hours.
Response: Thank you for your comment.		
APX Power Markets (NCR-11034)	Yes	In my opinion the remaining items with 1 hour reporting requirements will in most cases require the input of in-complete information, since you maybe aware of the outage/disturbance, but not aware of any reason for it. If that is acceptable just to get the intitial report that there was an outage/disturbance then we are OK. I believe it would help to have that clarifed in the EOP, or maybe a CAN can be created for that. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions.*

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. Please see response above.		
Compliance & Responsbility Office	Yes	See comments in response to Question 4.
Response: Thank you for your comment. See response to Question 4.		
Lower Colorado River Authority	Yes	The proposed reporting form for EOP-004-2 is less extensive than the Brief Report required by the Event Analysis process, but there is some duplication of efforts. EOP-004 has an “optional” Written Description section for the event, while the Brief Report requires more detailed information such as a sequence of events, contributing causes, restoration times, etc. Please clarify whether Registered Entities will still be required to submit both forms. Please also ensure there will not be duplication of efforts between the two reports. Although this is fairly minor, the clarification should be addressed. *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary.*
Response: Thank you for your comment. Please see response above.		
City of Austin dba Austin Energy	Yes	The proposed reporting form for EOP-004-2 is less extensive than the Brief Report required by the Event Analysis process, but there is some duplication of efforts. EOP-004 has an “optional” Written Description section for the event, while the Brief Report requires more detailed information such as a sequence of events, contributing causes, restoration times, etc. Please clarify whether Registered Entities will still be required to submit both forms. Please also ensure there will not be duplication of efforts between the two reports. Although this is fairly minor, the clarification should be addressed. *Reports made under EOP-004 provide a minimum set of information, which may*

Organization	Yes or No	Question 3 Comment
		trigger further information requests from EAWG as necessary.
Response: Thank you for your comment. Please see response above.		
Public Utility District No. 1 of Snohomish County	Yes	The proposed reporting form for EOP-004-2 is less extensive than the Brief Report required by the Event Analysis process, but there is some duplication of efforts. The EOP-004 has an "optional" Written Description section for the event, while the Brief Report requires more detailed information such as a sequence of events, contributing causes, restoration times, etc. Please clarify if both forms will still be required to be submitted. We also need to ensure that there won't be a duplication of efforts between the two reports. This is fairly minor, but the clarification need should be addressed. *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary.*
Response: Thank you for your comment. Please see response above.		
Seattle City Light	Yes	The proposed reporting form for EOP-004-2 is less extensive than the Brief Report required by the Event Analysis process, but there is some duplication of efforts. The EOP-004 has an "optional" Written Description section for the event, while the Brief Report requires more detailed information such as a sequence of events, contributing causes, restoration times, etc. Please clarify if both forms will still be required to be submitted. We also need to ensure that there won't be a duplication of efforts between the two reports. This is fairly minor, but the clarification need should be addressed. *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary.*
Response: Thank you for your comment. Please see response above.		

Organization	Yes or No	Question 3 Comment
Salt River Project	Yes	The proposed reporting form for EOP-004-2 is less extensive than the Brief Report required by the NERC Event Analysis process, but there is some duplication of efforts. EOP-004 has an "optional" Written Description section for the event, while the Brief Report requires more detailed information such as a sequence of events, contributing causes, restoration times, etc. Please clarify whether Registered Entities will still be required to submit both forms. Please also ensure there will not be duplication of efforts between the two reports. Although this is fairly minor, the clarification should be addressed. *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary.*
Response: Thank you for your comment. Please see response above.		
Constellation Energy on behalf of Baltimore Gas & Electric, Constellation Power Generation, Constellation Energy Commodities Group, Constellation Control and Dispatch, Constellation NewEnergy and Constellation Energy Nuclear Group.	Yes	We agree with the change to the reporting times in Attachment 1. While this is an improvement, other concerns with the language in the events table language remain. Please see additional details below:General items: o All submission instructions (column 4 in Events Table) should qualify the recognition of the event as "of recognition of event as a reportable event." *Column 4 has been deleted. The table headings now state that Responsible Entities must submit the report within X hours of recognition of event.* o Is the ES-ISAC the appropriate contact for the ERO given that these two entities are separate even though they are currently managed by NERC? *Yes. This is the current reporting contact and this is the advice that the DSR SDT team received from NERC.* In addition, are the phone numbers in the Attachment 1 NOTE accurate? Is it possible they will change in a different cycle than the standard?

Organization	Yes or No	Question 3 Comment
		Yes. The standard will require updating should the phone number change. Specific Event Language: o Destruction of BES Equipment, footnote: Footnote 1, item iii confuses the clarification added in items i. and ii. Footnote 1 should be modified to state BES equipment that (i) an entity knows will affect an IROL or has been notified the loss affects an IROL; (ii) significantly affects the reserve margin of a Balancing Authority or Reserve Sharing Group. Item iii should be dropped. *The 'Damage or Destruction' event category has been revised to say "to a Facility', (a defined term) and thresholds have be modified to provide clarity. Footnotes for this event have been deleted.* o Damage or destruction of Critical Asset per CIP-002: Within the currently developing revisions to CIP-002 (version 5), Critical Asset will be retired as a glossary term. As well as addressing the durability of this event category, additional delineation is needed regarding which asset disruptions are to be reported. A CA as currently defined incorporates assets in a broad perspective, for instance a generating plant may be a Critical Asset. As currently written in Attachment 1, reporting may be required for unintended events, such as a boiler leak that takes a plant offline for a minor repair. Event #1 - Destruction of BES Equipment - captures incidents at the relevant equipment regardless of whether they are a Critical Asset or not. We recommend dropping this event. However, if reference to CIP-002 assets remains, it will be important to capture reporting of the events relevant to reliability and not just more events. o Damage or destruction of a Critical Cyber Asset per CIP-002: Because CCAs are defined at the component level, including this trigger is appropriate; however, as with CAs, the CCA term is scheduled to be retired under CIP-002 version 5. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately*

Organization	Yes or No	Question 3 Comment
		addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds. o Forced Intrusion: The footnote confuses the goal of including this event category. In addition, "forced" doesn't need to define the incident. Constellation proposes the following to better define the event:Intrusion that affects or attempts to affect the reliable operation of the BES (1)(1) Examples of "affecting reliable operation of the BES are": (i) device operations, (ii) protective equipment degradation, (iii) communications systems degradation including telemetered values and device status. o Risk to BES equipment: This category is too vague to be effective and the footnote further complicates the expectations around this event. The catch all concept of reporting potential risks to BES equipment is problematic. It's not clear what the reliability goal of this category is. Risk is not an event, it is an analysis. How are entities to comply with this "event", never mind within an hour? It appears that the information contemplated within this scenario would be better captured within the greater efforts underway by NERC to assess risks to the BES. This event should be removed from the Attachment 1 list in EOP-004. *'Forced intrusion' and 'Risk to BES Equipment' (which this footnote referenced) have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred.* o BES Emergency requiring system-wide voltage reduction: the Entity with Reporting Responsibility should be limited to RC and TOP.

Organization	Yes or No	Question 3 Comment
		Entity with Reporting Responsibility states 'Initiating entity is responsible for reporting', which the DSR SDT feels is adequate direction in conjunction with the event: BES Emergency requiring system-wide voltage reduction. o Voltage deviations on BES Facilities: The Threshold for Reporting language needs more detail to explain +/- 10% of what? Proposed revision: Â± 10% outside the voltage schedule band sustained for â‰¥ 15 continuous minutes o IROL Violation (all Interconnections) or SOL Violation (WECC only): Should "Interconnections" be capitalized? o Transmission loss: The reporting threshold should provide more specifics around what constitutes Transmission Facilities. One minor item, under the Threshold for Reporting, "Three" does not need to be capitalized. *Both Transmission and Facilities are defined terms and the DSR SDT feels this gives sufficient direction.*
Response: Thank you for your comment. Please see response above.		
Pacific Northwest Small Public Power Utility Comment Group	Yes	While we agree with the revisions as far as they went, we do not believe the SDT has adequately addressed the FERC Order to "Consider whether separate, less burdensome requirements for smaller entities may be appropriate." The one and 24 hour reporting requirements continue to be burdensome to the smaller entities that do not maintain 24/7 dispatch centers. The one hour reporting requirement means that an untimely "recognition" starts the clock and reporting will become a higher priority than restoration. The note regarding adverse conditions does not help unless we were to consider the very lack of 24/7 dispatch to be such a condition. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber*

Organization	Yes or No	Question 3 Comment
		security incident as soon as possible, but in any event, within one hour of the event…" *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. For the revised event category 'A physical threat that could impact the operability of a Facility' the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred.* *The DSR SDT believes that reliability is best served by imposing reporting criteria based on impact to the BES rather than an arbitrary entity size threshold. With these latest revisions, all the proposed event categories provide thresholds that will capture the appropriate entities and provide a manageable timeframe.*
Response: Thank you for your comment. Please see response above.		
Clallam County PUD No.1	Yes	While we agree with the revisions as far as they went, we do not believe the SDT has adequately addressed the FERC Order to "Consider whether separate, less burdensome requirements for smaller entities may be appropriate." The one and 24 hour reporting requirements continue to be burdensome to the smaller entities that do not maintain 24/7 dispatch centers. The one hour reporting requirement means that an untimely "recognition" starts the clock and reporting will become a higher priority than restoration. The note regarding adverse conditions does not help unless we were to consider the very lack of 24/7 dispatch to be such a condition. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber*

Organization	Yes or No	Question 3 Comment
		security incident as soon as possible, but in any event, within one hour of the event…" *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. For the revised event category 'A physical threat that could impact the operability of a Facility' the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred.* *The DSR SDT believes that reliability is best served by imposing reporting criteria based on impact to the BES rather than an arbitrary entity size threshold. With these latest revisions, all the proposed event categories provide thresholds that will capture the appropriate entities and provide a manageable timeframe.*
Response: Thank you for your comment. Please see response above.		
Illinois Municipal Electric Agency	Yes	With the understanding this is within 24 hrs., and good professional judgment determines the amount of time to report the event to appropriate parties.
Response: Thank you for your comment.		
Ingleside Cogeneration LP	Yes	Yes. Any reporting that is mandated during the first hour of an event must be subject to close scrutiny. Many of the same resources that are needed to troubleshoot and stabilize the local system will be engaged in the reporting - which will impair reliability if not carefully applied. We believe that the ERO should reassess the need for any immediate reporting requirements on a regular basis to confirm that it provides some value to the restoration process. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706,*

Organization	Yes or No	Question 3 Comment
		Paragraph 673: *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1. Also, Attachment 1 provides the flexibility to make a verbal report under adverse conditions. For the revised event category 'A physical threat that could impact the operability of a Facility' the reporting timeline of 24 hours starts when the situation has been determined as a threat, not when it may have first occurred.*
Response: Thank you for your comment. Please see response above.		
Southwest Power Pool Regional Entity	Yes	
ZGlobal on behalf of City of Ukiah, Alameda Municipal Power, Salmen River Electric, City of Lodi	Yes	
MRO NSRF	Yes	
Western Electricity Coordinating Council	Yes	
Imperial Irrigation District	Yes	

Organization	Yes or No	Question 3 Comment
ACES Power Marketing Standards Collaborators	Yes	
Santee Cooper	Yes	
Sacramento Municipal Utility District (SMUD)	Yes	
Electric Compliance	Yes	
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Springfield Utility Board	Yes	
Manitoba Hydro	Yes	
Xcel Energy	Yes	
Liberty Electric Power	Yes	
Colorado Springs Utilities	Yes	
Independent Electricity System Operator	Yes	
South Carolina Electric and	Yes	

Organization	Yes or No	Question 3 Comment
Gas		
ISO New England	Yes	
American Transmission Company, LLC	Yes	
PSEG	Yes	
American Electric Power	Yes	
Georgia System Operations Corporation	Yes	
NV Energy	Yes	
Occidental Power Services, Inc. (OPSI)	Yes	
Northeast Utilities	Yes	
Great River Energy	Yes	
Oncor Electric Delivery Company LLC	Yes	
PPL Electric Utilities and PPL Supply Organizations`		
Progress Energy		

Organization	Yes or No	Question 3 Comment
Texas Reliability Entity		
ReliabilityFirst		
NRECA		
Entergy Services		
Thompson Coburn LLP on behalf of Miss. Delta Energy Agency		

4. **Do you have any other comment, not expressed in questions above, for the DSR SDT?**

Summary Consideration: The issues addressed in this question resulted in the DSR SDT reviewing and updating each requirement, Attachment 1 and Attachment 2. The DSR SDT has removed ambiguous language such as “risk” and “potential” based on comments received. All of the time frames in Attachment 1 have been moved to 24 hours upon recognition with the exception to reporting of CIP-008 events that remains one hour per FERC Order 706. Attachment 2 has been rewritten to mirror Attachment 1 events for entities who wish to use Attachment 2 in lieu of the DOE Form OE 417. VSLs have been reviewed to match the updated requirements.

Organization	Yes or No	Question 4 Comment
Cleco Corporation, Cleco Power, Cleco Power LLC	Abstain	Cleco does not use the VSL or VRF.
Response: Thank you for your comment		
Oklahoma Gas and Electric Co.	Abstain	Please see comments on SPP ballot
Response: Thank you for your comment. See response to those comments.		
Alberta Electric System Operator	Abstain	The Alberta Electric System Operator will need to modify parts of this standard to fit the provincial model when it develops the Alberta Reliability Standard.
Response: Thank you for your comment.		
Gainesville Regional Utilities	Affirmative	Looking forward to the added clarity.
Response: Thank you for your comment.		

Organization	Yes or No	Question 4 Comment
Manitoba Hydro	Affirmative	Manitoba Hydro is voting affirmative but would like to point out the following issues: -Attachment 1: The term 'Transmission Facilities' used in Attachment 1 is capitalized, but it is not a defined term in the NERC glossary. The drafting team should clarify what is meant by 'Transmission Facilities' and remove the capitalization. – *The DSR SDT has reviewed the NERC Glossary of Terms and notes that Transmission and Facilities are both defined. The combination of these two definitions are what the DSR SDT has based the applicability of "Transmission Facilities" in Attachment 1.* Attachment 2: The inclusion of 'fuel supply emergency' in Attachment 2 creates confusion as it infers that reporting a 'fuel supply emergency' may be required by the standard even though it is not listed as a reportable event in Attachment 1. On a similar note, it is not clear what the drafting team is hoping to capture by including a checkbox for 'other' in Attachment 2. *The DSR SDT has removed both "fuel supply emergency" and "other" from Attachment 2.*
Response: Thank you for your comment. Please see response above.		
Oncor Electric Delivery	Affirmative	NERC's Event Analysis Program tends to parallel many of the reporting requirements as outlined in EOP-004 Version 2. Oncor recommends that NERC consider ways of streamlining the reporting process by either incorporating the Event Analysis obligations into EOP-004-2 or reducing the scope of the Event Analysis program as currently designed to consist only of "exception" reporting. *The reporting of events as required in EOP-004 is the input to the Events Analysis Program. Events are reported to the ERO and the EAP will follow up as per the EAP processes and procedures.*

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. Please see response above.		
City Utilities of Springfield, Missouri	Affirmative	SPRM supports the comments from SPP.
Response: Thank you for your comment. Please see response to comments from SPP.		
Kootenai Electric Cooperative	Affirmative	The changes are an improvement over the existing standards.
Response: Thank you for your comment.		
Empire District Electric Co.	Affirmative	We agree with the comments provided by SPP
Response: Thank you for your comment. Please see response to SPP comments.		
Lakeland Electric	Negative	1. Further clarity is needed. For example the standard stipulates in R1.3 ". .as appropriate." Who deems what is appropriate? Also in R1.4 ". .other circumstances" is open to interpretation. *Requirement R1, Part 1.3 (now Part 1.2) was revised to add clarifying language by eliminating the phrase "as appropriate" and indicating that the Responsible Entity is to define its process for reporting and with whom to communicate events to as stated in the entity's Operating Plan.* *Requirement R1, Part 1.4 was removed from the standard* 2. Remove paragraph 1 of the data retention section as it parrots the Rules of Procedure, Appendix 4C: Compliance Monitoring and Enforcement Program, Section 3.1.4.2. Possibly place a pointer to the CMEP in the data retention section. *The item in question is standard boilerplate language that is being placed in all NERC standards.*

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. Please see response above.		
CPS Energy	Negative	oR1.4: CPS Energy believes that "updating the Operating Plan within 90 calendar days of any change..." is a very burdensome compliance documentation requirement. *Requirement R1, Part 1.4 was removed from the standard.* oAttachment 1: Events Table: In DOE OE-417 local electrical systems with less than 300MW are excluded from reporting certain events since they are not significant to the BES. CPS Energy believes that the benefit of reporting certain events on systems below this value would outweigh the compliance burden placed on these small systems. *Upon review of the DOE OE 417, it states "Local Utilities in Alaska, Hawaii, Puerto Rico, the U.S. Virgin Islands, and the U.S. Territories - If the local electrical system is less than 300 MW, then only file if criteria 1, 2, 3 or 4 are met". Please be advised this exception applies to entities outside the continental USA.*
Response: Thank you for your comment. Please see response above.		
Lakeland Electric	Negative	An issue of possible differences in interpretation between entities and compliance monitoring and enforcement is the phrase in 1.3 that states "the following as appropriate". Who has the authority to deem what is appropriate? *Requirement R1, Part 1.3 (now Part 1.2) was revised to add clarifying language by eliminating the phrase "as appropriate" and indicating that the Responsible Entity is to define its process for reporting and with whom to communicate events to as stated in the entity's Operating Plan*

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. Please see response above.		
Dynegy Inc.; Southern Illinois Power Coop.; Louisville Gas and Electric Co.	Negative	Comments submitted as part of the SERC OC; I agree with the comments of the SERC OC Standards Review group that have been provided to NERC.; We are a signatory to the SERC OC RRG comments filed last week.
Response: Thank you for your comment. Please see response to the SERC OC RRG comments.		
Hydro One Networks, Inc.	Negative	First and foremost we are not supportive of continuance of standards that are not "results based". Standards written to gather data, make reports etc. should not be written. There should be other processes for reporting in place that will not be subject to ERO oversight and further compliance burdens. *The DSR SDT has been following the guidance set by NERC to write a "results based" standard. As with any process there may be many different ways to achieve the same outcome. The NERC Quality Process has not indicated any request to update this Standard, concerning the Results Based Standard format.* o We are disappointed that the standard does not appear to reduce reporting requirements nor does it promote more efficient reporting. We encourage the SDT to take a results based approach and coordinate and reduce reporting through efficiencies between the various agencies and NERC. *The DSR SDT is staying within scope of the approved SAR and will be forwarding your concern of efficiencies between various agencies and NERC* o The Purpose statement is very broad, and "...by requiring the reporting of events with the potential to impact reliability and their causes..." on the Bulk Electric System it can be said that every event occurring on the Bulk Electric System would have to be reported. There is already an event analysis process in place. Could this reporting

Organization	Yes or No	Question 4 Comment
		be effectively performed in that effort? *The DSR SDT revised the purpose statement to remove ambiguous language "with the potential to impact reliability". The Purpose statement now reads:* *"To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities."* o The standard prescribes different sets of criteria, and forms. *Attachment 1 is the basis for EOP-004-2; it contains the events and thresholds for reporting. OE-417, as well as, the EAWG's requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004. Note you may have to report the same event more quickly to the DOE than is required by EOP-004, but this cannot be helped due to bullet point 2 above.* o There should be one recipient of event information. That recipient should be a

Organization	Yes or No	Question 4 Comment
		"clearinghouse" to ensure the proper dissemination of information. *The DSR SDT is proposing revisions to the NERC Rules of Procedure that address your comment:* *812. NERC Reporting Clearinghouse* *NERC will establish a system to collect report forms as established for this section or standard, from any Registered Entities, pertaining to data requirements identified in Section 800 of this Procedure. Upon receipt of the submitted report, the system shall then forward the report to the appropriate NERC departments, applicable regional entities, other designated registered entities, and to appropriate governmental, law enforcement, regulatory agencies as necessary. This can include state, federal, and provincial organizations.* o Why is this standard applicable to the ERO? *The ERO is applicable to CIP-008 and therefore is applicable to this proposed Standard.*
Response: Thank you for your comment. Please see response above.		
FirstEnergy Corp., FirstEnergy Energy Delivery, FirstEnergy Solutions, Ohio Edison Company	Negative	FirstEnergy appreciates the hard work of the drafting team and believes it has made great improvements to the standards. However, we must vote negative at this time until a few issues are clarified per our comments submitted through the formal comment period.
Response: Thank you for your comment. Please see response to your other comments.		
Lakeland Electric	Negative	In general; here has not been sufficient prudency review for the standard, especially R1, to justify a performance based standard around a Frequency Response Measure *Based on your short comment, Requirement 1 has been modified as requested by stakeholders. The DSR SDT cannot answer the issue of Frequency Response Measures*

Organization	Yes or No	Question 4 Comment
		since it is not within the scope of the SAR.
Response: Thank you for your comment. Please see response above.		
Northeast Power Coordinating Council	Negative	NPCC believes that further revision of the standard is necessary so is not able to support the VSLs at this time. Comments to the standard will be made in the formal comment period.
Response: Thank you for your comment. Please see responses to your other comments.		
Central Lincoln PUD; Blachly-Lane Electric Co-op; Central Electric Cooperative, Inc. (Redmond, Oregon); Clearwater Power Co.; Consumers Power Inc.; Coos-Curry Electric Cooperative, Inc; Fall River Rural Electric Cooperative; Lane Electric Cooperative, Inc.; Northern Lights Inc.; Pacific Northwest Generating Cooperative; Raft River Rural Electric Cooperative; Umatilla Electric Cooperative; West Oregon Electric Cooperative, Inc.; Cowlitz County PUD	Negative	Please see comments submitted by the Pacific Northwest Small Public Power Utility Comment Group.
Response: Thank you for your comment. Please see responses to comments of the Pacific Northwest Small Public Power Utility		

Organization	Yes or No	Question 4 Comment
Comment Group.		
Rochester Gas and Electric Corp.	Negative	RG&E supports comments to be submitted to NPCC.
New Brunswick System Operator	Negative	See comments submitted by the NPCC Reliability Standards Committee and the IRC Standards Review Committee.
Florida Municipal Power Pool	Negative	See FMPA's comments
Response: Thank you for your comment. See responses to those comments.		
Commonwealth of Massachusetts Department of Public Utilities	Negative	Standards written to gather data, make reports etc. should not be written. There should be other processes for reporting in place that will not be subject to ERO oversight and further compliance burdens. *FERC Order 693 section 617 states "…the Commission directs the ERO to develop a modification to EOP-004-1 through the reliability Standards development process that includes any Requirement necessary for users, owners, and operators of the Bulk-Power System to provide data…". In order for entities to provide data they are required to implement their Operating Plan. EOP-004-2 will satisfy this FERC directive.*
Response: Thank you for your comment. Please see response above.		
Hydro One Networks, Inc.	Negative	Suggested key concepts for the SDT consideration in this standard: ? Develop a single form to report disturbances and events that threaten the reliability of the bulk electric system ? Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements ? Establish clear criteria for reporting ? *The DSR SDT has only provided one form within this proposed Standard, please see*

Organization	Yes or No	Question 4 Comment
		Attachment 2. Based on stakeholder feedback, the DSR SDT has allowed stakeholders to use the DOE Form OE 417. Please note that not every Stakeholder in NERC wishes to use the DOE Form OE 417. Establish consistent reporting timelines ? *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"...direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event..."* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1.* Provide clarity around who will receive the information and how it will be used ? Explore other opportunities beside a standard to effectively achieve the same outcome. Standards should be strictly results based, whose purpose is to achieve an adequate level of reliability on the BES. *The DSR SDT has clearly stated who will receive the information: Part 1.3 (now Part 1.2) was revised to add clarifying language by eliminating the phrase "as appropriate" and indicating that the Responsible Entity is to define its process for reporting and with whom to report events. Part 1.2 now reads:* *"1.2 A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations*

Organization	Yes or No	Question 4 Comment
		needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies." *The information received will be mainly used for situational awareness and other processes.*
Response: Thank you for your comment. Please see response above.		
Orlando Utilities Commission	Negative	The contemporaneous drafting efforts related to both the proposed Bulk Electric System ("BES") definition changes, as well as the CIP standards Version 5, could significantly impact the EOP-004-2 reporting requirements. Caution needs to be exercised when referencing these definitions, as the definitions of a BES element could change significantly and Critical Assets may no longer exist. As it relates to the proposed reporting criteria, it is debatable as to whether or not the destruction of, for example, one relay would be a reportable incident under this definition going forward given the current drafting team efforts. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.*
Response: Thank you for your comment. Please see response above.		
James A Maenner	Negative	The information in section "5 Background" should be moved from the standard to a supporting document. *The DSR SDT will refer to guidance within the Standards Development process on the proper place to maintain Background information.*

Organization	Yes or No	Question 4 Comment
		The reporting exemption language for weather in the Note on Attachment 1 - Events Table should be included in R3, not just a note. *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2based on stakeholder comments and revised R3 (now R2) to:* *"R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment 1."* The "Guideline and Technical Basis", last 3 pages, should be moved from the standard to a supporting document. *The Guideline and Technical Basis section is a part of the Results-Based Standard format and the information contained in it is in the correct place.*
Response: Thank you for your comment. Please see response above.		
Kansas City Power & Light Co.	Negative	The proposed Standard is in need of additional work to complete the Attachment 1, complete the VSL's, and clarify language and content within the proposed standard. *The DSR SDT has reviewed and revamped all Requirements and both Attachments based on stakeholders feedback. This will provide clarity for entities to follow.*
Response: Thank you for your comment. Please see response above.		

Organization	Yes or No	Question 4 Comment
SERC Reliability Corporation	Negative	The purpose of the standard "To improve industry awareness and the reliability of the Bulk Electric System by requiring the reporting of events with the potential to impact reliability and their causes, if known, by the Responsible Entities" has not been achieved as written. There is the potential for the information and data contemplated by this standard to be useful in achieving the stated purpose through follow-on activities of the industry, the regions, and NERC. However, as drafted, Attachment 1 will inform the ERO of the existence of only a portion of the "events with the potential to impact reliability and their causes, if known". *The DSR SDT revised the purpose statement to remove ambiguous language "with the potential to impact reliability". The Purpose statement now reads:* *"To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities."* Events listed in Appendix E to the ERO Event Analysis Process document should be incorporated into the standard instead of hardwiring inconsistency by requiring a different set of events. Alternatively, the SDT should explore deleting Attachment 1 and instead referencing the ERO Event Analysis process (which as a learning organization will have systematic changes to the reporting thresholds over time). At first this may seem contrary to the SDT objective of eliminating fill-in-the-blank aspects of the existing standard but the SDT should explore the Commission's willingness to accept a reference document for reporting thresholds. Additionally, it is unclear how NERC's role as the ES-ISAC is supported through the requirements of this reliability standard. It appears to undermine the ability of NERC (ES-ISAC) to be made timely aware of threats to the critical infrastructure--at odds with it's purpose. Thus, this draft does not achieve the elimination of redundant reporting envisioned in the SAR, nor does it achieve the objective of supporting NERC in the analysis of disturbances or blackouts. *The DSR SDT is following NERC's ANSI approved process for standards development.*

Organization	Yes or No	Question 4 Comment
		The ERO Events Analysis process does not have the frame work as required by the ANSI development process. Within this proposed Standard, when an Attachment 1 event is recognized, the ERO (which is the ES-ISAC) will be one of the first to be notified, as will the entities Reliability Coordinator. This will enhance situational awareness as per the entity's Operation Plan and this Standard. *FERC Order 693 section 617 states "…the Commission directs the ERO to develop a modification to EOP-004-1 through the reliability Standards development process that includes any Requirement necessary for users, owners, and operators of the Bulk-Power System to provide data…". In order for entities to provide data they are required to implement their Operating Plan. EOP-004-2 will satisfy this FERC directive.*
Response: Thank you for your comment. Please see response above.		
Tucson Electric Power Co.	Negative	The tie between an Operating Plan and reportable disturbance events is not clear. Being the exception, I feel that a reportable disturbance methodology should be part of an Emergency Operating Plan. *EOP-004-2 provides Applicable Entities with the minimum report requirements for events contained in Attachment 1. NERC has defined Operating Plan in part as: "A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes." An entity may include a reportable disturbance methodology within their Operating Plan since this Standard does not preclude it.*
Response: Thank you for your comment. Please see response above.		
United Illuminating Co.	Negative	The VSL table is mistyped. R2 lists 1.1 and 1.5. R4 VRF should be lower.

Organization	Yes or No	Question 4 Comment
		Requirement R4 (now R3) calls for conducting an annual test of the communications process in Requirement 1, Part 1.2. It is not strictly administrative in nature and therefore does not meet the VRF guideline for a Lower VRF. .
Response: Thank you for your comment. Please see response above.		
PSEG Energy Resources & Trade LLC, PSEG Fossil LLC, Public Service Electric and Gas Co.	Negative	There are several items that need clarification. See PSEG's separately provided comments.
Response: Thank you for your comment. Please see response to your other comments.		
Kansas City Power & Light Co.	Negative	There is no VSL for R4. *The VSL for Requirement R4 was inadvertently redlined in the redline version of the standard, but it was present in the clean version.*
Response: Thank you for your comment. Please see response above.		
Ameren Services	Negative	We believe that these [VRFs and VSLs] will change as we expect some changes in the draft standard.
Response: Thank you for your comment.		
New York State Department of Public Service	Negative	While the proposed standard consolidates many reporting requirements, the requirement that any event with the "potential to impact reliability" be reported is overly broad and will prove to be burdensome and distracting to system operations. *The DSR SDT revised the purpose statement to remove ambiguous language "with the potential to impact reliability". The Purpose statement now reads:*

Organization	Yes or No	Question 4 Comment
		"To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities."
Response: Thank you for your comment. Please see response above.		
Springfield Utility Board		o The Draft 3 Version History still lists the term "Impact Event" instead of "Event". *This has been corrected.* o Draft 3 of EOP-004-2 - Event Reporting does not provide a definition for the term "Event" nor does the NERC Glossary of Terms Used in Reliability Standards. SUB recommends that "Event" be listed and defined in "Definitions and Terms Used in the Standard" as well as the NERC Glossary, providing a framework and giving guidance to entities for how to determine what should be considered an "Event" (ex: sabotage, unusual occurrence, metal theft, etc.). *The DSR SDT has reviewed this issue and has changed "Event" to "event". Attachment 1 contains each reportable 'event".*
Response: Thank you for your comment. Please see response above.		
Northeast Utilities		- Incorporate NERC Event Analysis Reporting into this standard. Make the requirements more specific to functional registrations as opposed to having requirements applicable to "Responsible Entities".- The description of a Transmission Loss Event in A *Attachment 1 is the basis for EOP-004-2; it contains the events and thresholds for reporting. OE-417, as well as, the EAWG's requirements were considered in creating Attachment 1. The DSR SDT has reviewed and reworded "Entities with Reporting Responsibilities" to require the minimum amount of entities who will be required to report each event.*
Response: Thank you for your comment. Please see response above.		

Organization	Yes or No	Question 4 Comment
Progress Energy		(1) Attachment 1 lists “Destruction of BES Equipment” as a reportable event but then lists “equipment failure” as one of several thresholds for reporting, with a one hour time limit for reporting. It is simply not common sense to think of the simple failure of a single piece of equipment as “destruction of BES equipment”. Does the standard really expect that every BES equipment failure must be reported within one hour, regardless of cause or impact to BES reliability? What is the purpose of such extensive reporting? *The DSR SDT has modified Attachment 1 to bring more clarity. The more subjective events were rewritten as follows:* • *The ‘Damage or Destruction’ event category has been revised to say ‘to a Facility’, (a defined term) and thresholds have be modified to provide clarity. The footnote was deleted* (2) The same comment as (1) above is applicable to the “Damage or destruction of Critical Asset” because one threshold is simple “equipment failure” as well. *The ‘Damage or Destruction’ events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and ‘Damage or Destruction of a Facility’ reporting thresholds.* (3) Footnote 2 (page 20) says copper theft is not reportable “unless it effects the reliability of the BES”, but footnote 1 on the same page says copper theft is reportable if “it degrades the ability of equipment to operate properly”. In this instance, the proposed standard provides two different criteria for reporting one of the most common events on the same page. *The DSR SDT has removed all footnotes with the exception of the updated event within Attachment 1 that states: “A physical threat that could impact the operability of a Facility”. This event has the following footnote, which states: “Examples include a*

Organization	Yes or No	Question 4 Comment
		train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center). Also report any suspicious device or activity at a Facility. Do not report copper theft unless it impacts the operability of a Facility." (4) Forced Intrusion must be reported if "you cannot determine the likely motivation", and not based on a conclusion that the intent was to commit sabotage or intentional damage. This would require reporting many theft related instances of cut fences and forced doors (including aborted theft attempts where nothing is stolen) which would consume a great deal of time and resources and accomplish nothing. This criteria is exactly the opposite of the existing philosophy of only reporting events if there is an indication of an intent to commit sabotage or cause damage. *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. Also, the footnote only contains examples.* (5) "Risk to BES equipment...from a non-environmental physical threat" is reportable, but this is an example of a vague, open ended reporting requirement that will either

Organization	Yes or No	Question 4 Comment
		generate a high volume of unproductive reports or will expose reporting entities to audit risk for not reporting potential threats that could have been reported. The standard helpfully lists train derailments and suspicious devices as examples of reportable events. *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. Also, the footnote only contains examples.* The existing CAN for CIP-001 (CAN-0016) is already asking for a list of events that were analyzed so the auditors can determine if a violation was committed due to failure to report. I can envision the CAN for this new standard requiring a list of all "non-environmental physical threats" that were analyzed during the audit period to determine if applicable events were reported. This could generate a great deal of work simply to provide audit documentation even if no events actually occur that are reportable. It would also be easy for an audit team to second guess a decision that was made by an entity not to report an event (what is risk?...how much risk was present due to the event?...). Also, the reporting for this vague criteria must be done within one hour. Any event with a one hour reporting requirement should be crystal clear and unambiguous. *The DSR SDT has reworded and updated Attachment 1 per comments received and believes that the language used obviates the need for CAN-016. CAN-0016 has been*

Organization	Yes or No	Question 4 Comment
		remanded. (6) Transmission Loss...of three or more Transmission Facilities" is reportable. "Facility" is a defined term in the NERC Glossary, but "Transmission Facility" is not a defined term, which will lead to confusion when this criteria is applied. This requirement raises many confusing questions. What if three or more elements are lost due to two separate or loosely related events - is this reportable or not? What processes will need to be put in place to count elements that are lost for each event and determine if reporting is required? Why must events be reported that fit an arbitrary numerical criteria without regard to any material impact on BES reliability? *The DSR SDT used the defined term "Facility" to add clarity for several events listed in Attachment 1. A Facility is defined as:* *"A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)"* *The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.* *Both Transmission and Facilities are defined terms and the DSR SDT feels this gives sufficient direction.*
Response: Thank you for your comment. Please see response above.		
MRO NSRF		: The MRO NSRF wishes to thank the SDT for incorporating changes that the industry had with reporting time periods and aligning this with the Events Analysis Working Group and Department of Energy's OE 417 reporting form.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment.		
FirstEnergy		1. Attachment 1 - Regarding the 1st event listed in the table, "Destruction of BES Equipment" and its accompanying Footnote 1, we believe that this event should be broken into two separate events that incorporate the specifics in the footnote as follows: a. "Destruction of BES equipment that associated with an IROL per FAC-014-2." Regarding the 1st event we have proposed - We have proposed this be made specific to IROL as stated in Footnote 1 part i. Also, we believe that only the RC and TOP would have the ability to quickly determine and report within 1 hour if the destruction is associated with an IROL. The other entities listed would not necessarily know if the event affects and IROL. Therefore, we also propose that the Entities with Reporting Responsibilities (column 2) be revised to only include the RC and TOP. *The DSR SDT agrees with your comment and made the following changes:* *'Threshold for Reporting' column in the 'Damage or Destruction' event category. The updated Threshold for Reporting now reads as:* *"Damage or destruction of a Facility that:* • *Affects an IROL (per FAC-014)* *OR* • *Results in the need for actions to avoid an Adverse Reliability Impact* *OR* • *Results from intentional human action."* b. "Destruction of BES equipment that removes the equipment from service." Regarding the 3rd event we have proposed - We have proposed this be made specific to destruction of BES equipment that removes the equipment from service as stated in Footnote 1 part iii. Also, the other part of footnote 1 part iii which states "Damaged or destroyed due to intentional or unintentional human action" is not

Organization	Yes or No	Question 4 Comment
		required since it is covered in the threshold for reporting. Also the term "Damaged" in this part iii is not appropriate since these events are limited to equipment that has been destroyed. We also propose that the Entities with Reporting Responsibilities (column 2) for this event would remain the same as it states now since any of those entities may observe out of service BES equipment.Regarding part ii of footnote 1, we do not believe that this event needs to be separated. Regarding the phrase "significantly affects the reliability margin of the system be clarified so that it is not left up to the entity to interpret a "significant" affect. Lastly, since we have incorporated parts i and iii into the two separate events and removed part ii as proposed above, the only statement that needs to be left in the Footnote 1 is: "Do not report copper theft from BES equipment unless it degrades the ability of equipment to operate correctly (e.g., removal of grounding straps rendering protective relaying inoperative)." *The DSR SDT has removed all footnotes with the exception of the updated event within Attachment 1 that states: "Any physical threat that could impact the operability of a Facility". This event has the following footnote, which states: "Examples include a train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center). Also report any suspicious device or activity at a Facility. Do not report copper theft unless it impacts the operability of a Facility."* 2. Attachment 1 - We ask that the team add an "Event #" column to the table so that each of the events listed can be referred to by #, such as Event 1, Event 2, etc. *The DSR SDT believes that the minimum reporting attributes are contained in Attachment 1.* 3. Attachment 1 - Event titled "Damage or destruction of a Critical Cyber Asset per

Organization	Yes or No	Question 4 Comment
		CIP-002", the proposed threshold for reporting seems incomplete. We suggest the threshold for this event match the threshold for the Critical Asset event which states: "Initial indication the event was due to operational error, equipment failure, external cause, or intentional or unintentional human action."4. Attachment 1 - Events titled "Damage or destruction of a Critical Assets per CIP-002" and "Damage or destruction of a Critical Cyber Asset per CIP-002" seem ambiguous due to the term "damage". We suggest removal of "damage" or clarity as to what is considered a damaged asset.5. VSL Table - Instead of listing every entity, it may be more efficient to simply say "The Responsible Entity" in the VSL for each requirement.6. Guideline and Technical Basis section - This section does not provide guidance on each of the requirements of the standard. We suggest the team consider adding guidance for the requirements. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.*
Response: Thank you for your comment. Please see response above.		
Southwest Power Pool Regional Entity		1. EOP-004-2 R1.4 states entities must update their Operating Plans within 90 calendar days of incorporating lessons learned pursuant to R3. However, neither R3 nor Attachment 1 include a timeline for incorporating lessons learned. It is unclear when the "clock starts" on incorporating improvements or lessons learned. Within 90 days of what? 90 days of the event? 90 days from when management approved the lesson learned? Auditors need to know the trigger for the 90-day clock. *Requirement R1, Part 1.4 was removed from the standard.* 2. The Event Analysis classification includes Category 1C "failure or misoperation of

Organization	Yes or No	Question 4 Comment
		the BPS SPS/RAS". This category is not included in EOP-004-2's Attachment 1. This event, "failure or misoperation of the BPS SPS/RAS", needs to either be added to Attachment 1 or removed from the Event Analysis classification. It is important that EOP-004-2 Attachment 1 and the Event Analysis categories match up.Thank you for your work on this standard. *Attachment 1 is the basis for EOP-004-2; it contains the events and thresholds for reporting. OE-417, as well as, the EAWG's requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004. Note you may have to report the same event more quickly to the DOE than is required by EOP-004, but this cannot be helped due to bullet point 2 above.*
Response: Thank you for your comment. Please see response above.		
Independent Electricity System Operator		1. Measures M1, M2 and M3: Suggest to achieve consistent wording among them by saying the leading part to "Each Responsible Entity shall provide...." *The DSR SDT is following the guidance within the Standards Development process on*

Organization	Yes or No	Question 4 Comment
		the wording pertaining to items outside the realm of a requirement. 2. In our comments on the previous version, we suggested the SDT to review the need to include IA, TSP and LSE for some of the reporting requirements in Attachment 1. The SDT's responded that it had to follow the requirements of the standards as they currently apply. Since these entities are applicable to the underlying standards identified in Attachment 1, they will be subject to reporting. We accept this rationale. However, the revised Attachment 1 appears to be still somewhat discriminative on who needs to report an event. For example, the event of "Detection of a reportable Cyber Security Incident" (6th row in the table) requires reporting by a list of responsible entities based on the underlying requirements in CIP-008, but the list does not include the IA, TSP and LSE. We again suggest the SDT to review the need for listing the specific entities versus leaving it general by saying: "Applicable Entities under CIP-008" for this particular item, and review and establish a consistent approach throughout Attachment 1. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008.* 3. VSLs: a. Suggest to not list all the specific entities, but replace them with "Each Responsible Entity" to simplify the write-up which will allow readers to get to the violation condition much more quickly. b. For R1, it is not clear whether the conditions listed under the four columns are "OR" or "AND". We believe it means "OR", but this needs to be clarified in the VSL table.4. The proposed implementation plan conflicts with Ontario regulatory practice respecting the effective date of the standard. It is suggested that this conflict be removed by appending to the implementation plan wording, after "applicable regulatory approval" in the Effective Dates Section on P. 2 of the draft standard and P. 1 of the draft implementation plan, to the following effect: ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities." *The DSR SDT is following the guidance within the Standards Development process on*

Organization	Yes or No	Question 4 Comment
		the wording pertaining to items outside the realm of a requirement.
Response: Thank you for your comment. Please see response above.		
NRECA		1. Please ensure that the work of the SDT is done in close coordination with Events Analysis Process (EAP) work being undertaken by the PC/OC and BOT, and with any NERC ROP additions or modifications. NRECA is concerned that the EAP work being done by these groups is not closely coordinated even though their respective work products are closely linked -- especially since the EAP references information in EOP-004. *Attachment 1 is the basis for EOP-004-2; it contains the events and thresholds for reporting. OE-417, as well as, the EAWG's requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004. Note you may have to report the same event more quickly to the DOE than is required by EOP-004, but this cannot be helped due to bullet point 2 above.*

Organization	Yes or No	Question 4 Comment
		2. The SDT needs to be consistent in its use of "BES" and "BPS" - boths acronyms are used throughout the SDT documents. NRECA strongly prefers the use of "BES" since that is what NERC standards are written for. *The DSR SDT has used BES within EOP-004-2. All references to BPS have been removed.* 3. Under "Purpose" section of standard, 3rd line, add "BES" between "impact" and "reliability." Without making this change the "Purpose" section could be misconstrued to refer to reliability beyond the BES. *The DSR SDT revised the purpose statement to remove ambiguous language "with the potential to impact reliability". The Purpose statement now reads:* ***"To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities."*** 4. In the Background section there is reference to the Events Analysis Program. Is that the same thing as the Events Analysis Process? Is it something different? Is it referring to a specific department at NERC? Please clarify in order to reduce confusion. Also in the Background section there is reference to the Events Analysis Program personnel. Who is this referring to -- NERC staff in a specific department? Please clarify. *The DSR SDT was explaining that the DSR SDT and has been coordinating with the "Events Analysis Working Group.* 5. In M1 please be specific regarding what "dated" means. *This is a common term used with many NERC Standards and simply means that your evidence is dated and time stamped.* 6. In M3 please make it clear that if there wasn't an event, this measure is not applicable

Organization	Yes or No	Question 4 Comment
		The DSR SDT has not implied that Applicable Entities need to prove that something did not happen. 7. In R4 it is not clear what "verify" means. Please clarify. *R4 (now R3) was revised to remove "verify"* *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* 8. In Attachment 1 there are references to Critical Asset and Critical Cyber Asset. These terms will likely be eliminated from the NERC Glossary of Terms when CIP V5 moves forward and is ultimately approved by FERC. This could create future problems with EOP-004 if CIP V5 is made effective as currently drafted. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008.* 9. In Attachment 1 the one hour timeframe for submitting data for the first 7 items listed is very tight. Other than being required by the EOE)E-417 form, NRECA requests that the SDT provide further support for this timeframe. If there are not distinct reasons why 1 hour is the right timeframe for this, then other timeframes should be explored with DOE. *The DSR SDT also received many comments regarding the various events of Attachment 1. Many commenters questioned the reliability benefit of reporting events to the ERO and their Reliability Coordinator within 1 hour. Most of the events with a one hour reporting requirement were revised to 24 hours based on stakeholder comments as well as those types of events are currently required to be reported within 24 hours in the existing mandatory and enforceable standards. The only remaining type of event that is to be reported within one hour is "A reportable Cyber*

Organization	Yes or No	Question 4 Comment
		Security Incident" as it required by CIP-008. *FERC Order 706, paragraph 673 states: "…each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but, in any event within one hour of the event…"* *Note that members of NRECA may be required to submit the DOE Form OE 417, and this agency's reporting requirements are not within scope of the project.* 10. While including Footnote 1 is appreciated, NRECA is concerned that this footnote will create confusion in the compliance and audit areas and request the SDT to provide more definitive guidance to help explain what these "Events" refer to. NRECA has the same comment on Footnote 2 and 3. Specifically in Footnote 3, how do you clearly determine and audit from a factual standpoint something that "could have damaged" or "has the potential to damage the equiment?" *The DSR SDT has removed all footnotes with the exception of the updated event within Attachment 1 that states: "A physical threat that could impact the operability of a Facility". This event has the following footnote, which states: "Examples include a train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center). Also report any suspicious device or activity at a Facility. Do not report copper theft unless it impacts the operability of a Facility."* 11. In the Guideline and Technical Basis section, in the 1st bullet, how do you determine, demonstrate and audit for something that "may impact" BES reliability? *This statement has been removed per comments received.* 12. On p. 28, first line, this sentence seems to state that NERC, law enforcement and other entities - not the responsible entity - will be doing event analysis. My understanding of the current and future Event Analysis Process is that the

Organization	Yes or No	Question 4 Comment
		responsible entity does the event analysis. Please confirm and clarify. *EOP-004-2 requires Applicable Entities to "report " and "communicate" as stated in Requirement 1, Part 1.2: "A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies."* *The Event Analysis Program may use a reported event as a basis to analyze an event. The processes of the Event Analysis Program fall outside the scope of this project, but the DSR SDT has collaborated with them of events contained in Attachment 1.* *The Standard does not require the Applicable Entity to analyze a reported event.*
Response: Thank you for your comment. Please see response above.		
Exelon		1. Please replace the text "Operating Plan" with procedure(s). Many companies have procedure(s) for the reporting and recognition of sabotage events. These procedures extend beyond operating groups and provide guidance to the entire company. *Thank you for your comment. The DSR SDT intends on keeping "Operating Plan" within EOP-004-2 since NERC has it defined as:* *"A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan". As stated, the Operating Plan may contain Operating procedures or Operating Processes. This will give Applicable Entities the greatest flexibility in achieving compliance with this Standard.*

Organization	Yes or No	Question 4 Comment
		2. The Loss of Off-site power event criteria is much improved from the last draft of EOP 004-2; however, some clarification is needed to more accurately align with NERC Standard NUC-001 in both nomenclature and intent. Specifically, as Exelon has previously commented, there are many different configurations supplying offsite power to a nuclear power plant and it is essential that all configurations be accounted for. As identified in the applicability section of NUC-001 the applicable transmission entities may include one or more of the following (TO, TOP, TP, TSP, BA, RC, PC, DP, LSE, and other non-nuclear GO/GOPs). Based on the response to previous comments submitted for Draft 2, Exelon understands that the DSR SDT evaluated the use of the word “source” but dismissed the use in favor of “supply” with the justification “[that] ‘supply’ encompasses all sources”. Exelon again suggests that the word “source” is used as the event criteria in EOP-004-2 as this nomenclature is commonly used in the licensing basis of a nuclear power plant. By revising the threshold criteria to “one or more” Exelon believes the concern the DSR SDT noted is addressed and ensures all sources are addressed. In addition, by revising the threshold for reporting to a loss of “one or more” will ensure that all potential events (regardless of configuration of off-site power supplies) will be reported by any applicable transmission entity specifically identified in the nuclear plant site specific NPIRs.As previously suggested, Exelon again proposes that the loss of an off-site power source be revised to an “unplanned” loss to account for planned maintenance that is coordinated in advance in accordance with the site specific NPIRs and associated Agreements. This will also eliminate unnecessary reporting for planned maintenance.Although the loss of one off-site power source may not result in a nuclear generating unit trip, Exelon agrees that an unplanned loss of an off-site power source regardless of impact should be reported within the 24 hour time limit as proposed. Suggest that the Loss of Offsite power to a nuclear generating plant event be revised as follows:Event: Unplanned loss of any off-site power source to a Nuclear Power PlantEntity with Reporting Responsibility: The applicable Transmission Entity that owns and/or operates the off-site power source to a

Organization	Yes or No	Question 4 Comment
		Nuclear Power Plant as defined in the applicable Nuclear Plant Interface Requirements (NPIRs) and associated Agreements.Threshold for Reporting: Unplanned loss of one or more off-site power sources to a Nuclear Power Plant per the applicable NPIRs. *Based on comments received, this event has been updated within Attachment 1 to read as:* *"Complete loss of off-site power to a nuclear generating plant (grid supply)".* 3. Attachment 1 Generation loss event criteria Generation lossThe â‰¥ 2000 MW/â‰¥ 1000 MW generation loss criteria do not provide a time threshold or location criteria. If the 2000 MW/1000 MW is intended to be from a combination of units in a single location, what is the time threshold for the combined unit loss? For example, if a large two unit facility in the Eastern Interconnection with an aggregate full power output of 2200 MW (1100 MW per unit) trips one unit (1100 MW) [T=0 loss of 1100 MW] and is ramping back the other unit from 100% power and 2 hours later the other unit trips at 50% power [550 MW at time of trip]. The total loss is 2200 MW; however, the loss was sustained over a 2 hour period. Would this scenario require reporting in accordance with Attachment 1? What if it happened in 15 minutes? 1 hour? 24 hours? Exelon suggests the criteria revised to include a time threshold for the total loss at a single location to provide this additional guidance to the GOP (e.g., within 15 minutes to align with other similar threshold conditions). Threshold for Reporting ï€ â‰¥ 2,000 MW unplanned total loss at a single location within 15 minutes for entities in the Eastern or Western Interconnection â‰¥ 1000 MW unplanned total loss at a single location within 15 minutes for entities in the ERCOT or Quebec Interconnection *The DSR SDT has not modified this event since it is being maintained as it is presently enforceable within EOP-004-1.* 4. Exelon appreciates that the DSR SDT has added the NRC to the list of Stakeholders in the Reporting Process, but does not agree with the SDT response to FirstEnergy's

Organization	Yes or No	Question 4 Comment
		comment to Question 17 [page 206] that stated “NRC requirements or comments fall outside the scope of this project.” Quite the contrary, this project should be communicated and coordinated with the NRC to eliminate confusion and duplicative reporting requirements. There are unique and specific reporting criteria and coordination that is currently in place with the NRC, the FBI and the JTTF for all nuclear power plants. If an event is in progress at a nuclear facility, consideration should be given to coordinating such reporting as to not duplicate effort, introduce conflicting reporting thresholds, or add unnecessary burden on the part of a nuclear GO/GOP who’s primary focus is to protect the health and safety of the public during a potential radiological sabotage event (as defined by the NRC) in conjunction with potential impact to the reliability of the BES. *The DSR SDT has established a minimum amount of reporting for events listed in Attachment 1. The NRC does not fall under the jurisdiction of NERC and so therefore it is not within scope of this project.* 5. Attachment 1 Detection of a reportable Cyber Security Incident event criteria.The threshold for reporting is “that meets the criteria in CIP-008”. If an entity is exempt from CIP-008, does that mean that this reportable event is therefore also not applicable in accordance with EOP-004-2 Attachment 1? *If an entity is exempt from CIP-008, then they do not have to report this type of event. Entities can report any situation at anytime to whomever they wish. If an entity is responsible for items that fall under a Cyber Security Incident, then they would report per this standard.*
Response: Thank you for your comment. Please see response above.		
Duke Energy		1. Reporting under EOP-004-2 should be more closely aligned with Events Analysis Reporting. *Attachment 1 is the basis for EOP-004-2; it contains the events and thresholds for reporting. OE-417, as well as, the EAWG’s requirements were considered in creating*

Organization	Yes or No	Question 4 Comment
		Attachment 1, but there remain differences for the following reasons: • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004. Note you may have to report the same event more quickly to the DOE than is required by EOP-004, but this cannot be helped due to bullet point 2 above.* 2. Attachment 1 - Under the column titled "Entity with Reporting Responsibility", several Events list multiple entities, using the phrase "Each RC, BA, TO, TOP, GO, GOP, DP that experiences..." or a similar phrase requiring that multiple entities report the same event. We believe these entries should be changed so that multiple reports aren't required for the same event. *The DSR SDT agrees that there may be some dual reporting for the same event. The minimum Applicable Entities have been review and updated where updates could be made. The DSR SDT believes that a dual report will provide a clearer picture of the breadth and depth of an event the Electric Reliability Organization and the Applicable Entities Reliability Coordinator.* 3. Attachment 1 - The phrase "BES equipment" is used several times in the Events Table and footnotes to the table. "Equipment" is not a defined term and lacks clarity. "Element" and "Facility" are defined terms. Replace "BES equipment" with

Organization	Yes or No	Question 4 Comment
		"BES Element" or "BES Facility". *The DST SDT has removed the term "equipment" from Attachment 1 per comments received.* 4. Attachment 1 - The Event "Risk to BES equipment" is unclear, since some amount of risk is always present. Reword as follows: "Event that creates additional risk to a BES Element or Facility." *The DSR SDT has removed this event from Attachment 1. Several stakeholders expressed concerns relating to the "Forced Intrusion" event. Their concerns related to ambiguous language in the footnote. The SDR SDT discussed this event as well as the event "Risk to BES equipment". These two event types had overlap in the perceived reporting requirements. The DSR SDT removed "Forced Intrusion" as a category and the "Risk to BES equipment" event was revised to "A physical threat that could impact the operability of a Facility".* 5. Attachment 1 - The Threshold for Reporting Voltage deviations on BES Facilities is identified as "+ 10% sustained for > 15 continuous minutes." Need to clarify + 10% of what voltage? We think it should be nominal voltage. *A sustained voltage deviation of ± 10% on the BES is significant deviation and is indicative of a shortfall of reactive resources either pre- or post-contingency. The DSR SDT is indifferent to which of nominal, pre-contingency, or scheduled voltage, is used as the baseline, but for simplicity and to promote a common understanding suggest using nominal voltage.* 6. Attachment 1 - Footnote 1 contains the phrase "has the potential to". This phrase should be struck because it creates an impossibly broad compliance responsibility. Similarly, Footnote 3 contains the same phrase, as well as the word "could" several times, which should be changed so that entities can reasonably comply.

Organization	Yes or No	Question 4 Comment
		The DSR SDT has removed all footnotes with the exception of the updated event within Attachment 1 that states: "A physical threat that could impact the operability of a Facility". This event has the following footnote, which states: "Examples include a train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center). Also report any suspicious device or activity at a Facility. Do not report copper theft unless it impacts the operability of a Facility." 7. Attachment 1 - The "Unplanned Control Center evacuation" Event has the word "potential" in the column under "Entity with Reporting Responsibility". The word "potential" should be struck.8. Attachment 2 - Includes "fuel supply emergency", which is not listed on Attachment 1. *The DSR SDT has removed the word "potential" from this event. It now reads as: "Each RC, BA, TOP that experiences the event"*
Response: Thank you for your comment. Please see response above.		
Energy Northwest - Columbia		1. The Loss of Off-site power event criteria is much improved from the last draft of EOP 004-2; however, some clarification is needed to more accurately align with NERC Standard NUC-001 in both nomenclature and intent. Specifically, there are many different configurations supplying offsite power to a nuclear power plant and it is essential that all configurations be accounted for. As identified in the applicability section of NUC-001 the applicable transmission entities may include one or more of the following (TO, TOP, TP, TSP, BA, RC, PC, DP, LSE, and other non-nuclear GO/GOPs). Based on the response to previous comments submitted for Draft 2, Energy Northwest understands that the DSR SDT evaluated the use of the word "source" but dismissed the use in favor of "supply" with the justification "[that] 'supply' encompasses all sources". Energy Northwest suggests that the word

Organization	Yes or No	Question 4 Comment
		“source” is used as the event criteria in EOP-004-2 as this nomenclature is commonly used in the licensing basis of a nuclear power plant. By revising the threshold criteria to “one or more” Energy Northwest believes the concern the DSR SDT noted is addressed and ensures all sources are addressed. In addition, by revising the threshold for reporting to a loss of “one or more” will ensure that all potential events (regardless of configuration of off-site power supplies) will be reported by any applicable transmission entity specifically identified in the nuclear plant site specific NPIRs.Energy Northwest proposes that the loss of an off-site power source be revised to an “unplanned” loss to account for planned maintenance that is coordinated in advance in accordance with the site specific NPIRs and associated Agreements. This will also eliminate unnecessary reporting for planned maintenance.Although the loss of one off-site power source may not result in a nuclear generating unit trip, Energy Northwest agrees that an unplanned loss of an off-site power source regardless of impact should be reported within the 24 hour time limit as proposed. Suggest that the Loss of Offsite power to a nuclear generating plant event be revised as follows:Event: Unplanned loss of any off-site power source to a Nuclear Power PlantEntity with Reporting Responsibility: The applicable Transmission Entity that owns and/or operates the off-site power source to a Nuclear Power Plant as defined in the applicable Nuclear Plant Interface Requirements (NPIRs) and associated Agreements.Threshold for Reporting: Unplanned loss of one or more off-site power sources to a Nuclear Power Plant per the applicable NPIRs. *Based on comments received, this event has been updated within Attachment 1 to read as:* *“Complete loss of off-site power to a nuclear generating plant (grid supply)”.* 2. Please consider changing "Operating Plan" with "Procedure(s)". Procedures extend beyond operating groups and provide guidance to the entire company.

Organization	Yes or No	Question 4 Comment
		The DSR SDT intends on keeping "Operating Plan" within EOP-004-2 since NERC has it defined as: *"A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan". As stated, the Operating Plan may contain Operating procedures or Operating Processes. This will give Applicable Entities the greatest flexibility in achieving compliance with this Standard.*
Response: Thank you for your comment. Please see response above.		
Colorado Springs Utilities		Agree with concept to combine CIP-001 into EOP-004. Agree with elimination of "sabotage" concept. Appreciate the attempt to combine reporting requirements, but it seems that in practice will still have separate reporting to DOE and NERC/Regional Entities. EOP-004-2 A.5. "Summary of Key Concepts" refers to Att. 1 Part A and Att. 1 Part B. I believe these have now been combined. EOP-004-2 A.5. "Summary of Key Concepts" refers to development of an electronic reporting form and inclusion of regional reporting requirements. It is unfortunate no progress was made on this front.
Response: Thank you for your comment. The DSR SDT is providing a proposed revision to the NERC Rules of Procedure to address the electronic reporting concept. These proposed revisions will be posted with the standard.		
American Transmission Company, LLC		ATC appreciates the work of the SDT in incorporating changes that the industry had with reporting time periods and aligning this with the Events Analysis Working Group and Department of Energy's OE 417 reporting form.
Response: Thank you for your comment.		

Organization	Yes or No	Question 4 Comment
Manitoba Hydro		Attachment 1 - The term 'Transmission Facilities' used in Attachment 1 is capitalized, but it is not a defined term in the NERC glossary. The drafting team should clarify this issue. *Both Transmission and Facilities are defined terms and the DSR SDT feels this gives sufficient direction.* Attachment 2 - The inclusion of 'Fuel supply emergency' in Attachment 2 creates confusion as it infers that reporting a 'fuel supply emergency' may be required by the standard even though 'fuel supply emergency' is not listed in Attachment 1. On a similar note, it is not clear what the drafting team is hoping to capture by including a checkbox for 'other' in Attachment 2. *The DSR SDT has removed both "fuel supply emergency" and "other" from Attachment 2.*
Response: Thank you for your comment. Please see response above.		
NV Energy		Attachment 1 includes an item "Detection of a reportable cyber security incident." The reporting requirement is a report via Attachment 2 or the OE417 report form submittal. However, under CIP-008, to which this requirement is linked, the reporting is accomplished via NERC's secure CIPIS reporting tool. This appears to be a conflict in that the entity is directed to file reporting under CIP-008 that differs from this subject standard. *CIP-008-4, Requirement 1, Part 1.3 states that an entity must have:* *1.3 Process for reporting Cyber Security Incidents to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC). The Responsible Entity must ensure that all reportable Cyber Security Incidents are reported to the ES-ISAC either directly or through an intermediary.*

Organization	Yes or No	Question 4 Comment
		EOP-004-2 also allows for submittal of the report to the ESISAC. Attachment 1 also includes a provision for reporting the "loss of firm load greater than or equal to 15 minutes in an amount of 200MW (or 300MW for peaks greater than 3000MW). This appears to be a rather low threshold, particularly in comparison with the companion loss of generation reporting threshold elsewhere in the attachment. The volume of reports triggered by this low threshold will likely lead to an inordinate number of filed reports, sapping NERC staff time and deflecting resources from more severe events that require attention. I suggest either an increase in the threshold, or the addition of the qualifier "caused by interruption/loss of BES facilities" in this reporting item. This qualifier would therefore exclude distribution-only outages that are not indicative of a BES reliability issue. *The DSR SDT has not modified this event since it is being maintained as it is presently enforceable within EOP-004-1.*
Response: Thank you for your comment. Please see response above.		
BC Hydro		Attachment 1: Reportable Events: BC Hydro recommends further defining “BES equipment” for the events Destruction of BES equipment and Risk to BES equipment. Attachment 1: Reportable Events: BC Hydro recommends defining the Forced intrusion event as the wording is very broad and open to each entities interpretation. What would be a forced intrusion ie entry or only if equipment damage occurs? *The DSR SDT has modified Attachment 1 to bring more clarity. The more subjective events were rewritten as follows:* • *The ‘Damage or Destruction’ event category has been revised to say ‘ to a Facility’, (a defined term) and thresholds have be modified to provide clarity.*

Organization	Yes or No	Question 4 Comment
		The footnote was deleted • *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. Also, the footnote only contains examples.* *These two remaining event categories that aren't related to power system phenomena are essential as they effectively translate the intent of CIP-001 into EOP-004.*
Response: Thank you for your comment. Please see response above.		
ISO New England		Attachment 1should be revisited. "Equipment Damage" is overly vague and will also potentially result in reporting on equipment failures which may simply be related to the age and/or vintage of equipment. *The DSR SDT has revised this event based on comments received. The new event is "Damage or destruction of a Facility" which has a threshold of "Damage or destruction of a Facility that:* *Affects an IROL (per FAC-014)* *OR* *Results in the need for actions to avoid an Adverse Reliability Impact* *OR*

Organization	Yes or No	Question 4 Comment
		Results from intentional human action."
Response: Thank you for your comment. Please see response above.		
Constellation Energy on behalf of Baltimore Gas & Electric, Constellation Power Generation, Constellation Energy Commodities Group, Constellation Control and Dispatch, Constellation NewEnergy and Constellation Energy Nuclear Group.		Background Section: The background section in this revision of EOP-004 reads more like guidance than a background of the development of the event reporting standard. Because of the background remains as part of the standard, the language raises questions as to role it plays relative to the standard language. For instance, the Law Enforcement Reporting section states:"Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES." It's not clear how "potential to impact to a wider area of the BES" is defined and where it fits into the standard. As well, and perhaps more problematic, is the Reporting Hierarchy for Reportable Events flow chart. While the flow chart concept is quite useful as a guidance tool, the flow chart currently in the Background raises questions. For instance, the Procedure to Report to Law Enforcement sequence does not map to language in the requirements. Further, Entities would not know about the interaction between law enforcement agencies. *The DSR SDT included the flow chart as an example of how an entity might report and communicate an event. For clarity, we have added the phrase "Example of Reporting Process Including Law Enforcement" to the top of the page.* Please see additional recommended revisions to the requirement language and to the Events Table in the Q2 and Q3 responses. *The DSR SDT has removed the wording of "potential" based on comments received.* Attachment 2: Event Reporting Form: The review of the form is one of the many aspects to compare with the developments within the Events Analysis Process (EAP) developments. We support the effort to create one form for submissions. The

Organization	Yes or No	Question 4 Comment
		recent draft EAP posted as part of Planning Committee and Operating Committee agendas includes a form requiring a few bits of additional relevant information when compared to the EOP-004 form. This may be a valuable approach to avoid follow up inquiries that may result if the form is too limited. We suggest that consideration be given to the proposed EAP form. One specific note on the Proposed EOP-004 Attachment 2: The "Potential event" box in item 3 should be eliminated to track with the removal of the "Risk to the BES" category. *The DSR SDT has updated Attachment 2 to remove potential event and "Risk to the BES" category based on comments received.*
Response: Thank you for your comment. Please see response above.		
Bonneville Power Administration		BPA believes that Attachment 1 has too many added reportable items because unintentional, equipment failure & operational errors are included in the first three items. A. Change to only "intentional human action". Otherwise, the first item "destruction of BES equipment" is too burdensome, along with its short time reporting time: i. - If a single transformer fails that shouldn't require a report. ii.- Emergency actions have to be taken for any failure of equipment, e.g. a loss of line reduces a path SOL and requires curtailments to reduce risk to the system. *The DSR SDT has modified Attachment 1 to bring more clarity. The more subjective events were rewritten as follows:* • *The 'Damage or Destruction' event category has been revised to say 'to a Facility', (a defined term) and thresholds have be modified to provide clarity. The footnote was deleted* B. The item for "risk to BES" is not necessary until the suspicious object has been identified as a threat. If what turns out to be air impact wrench left next to BES

Organization	Yes or No	Question 4 Comment
		equipment, that should not be a reportable incident as this current table implies. *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. Also, the footnote only contains examples.* *These two remaining event categories that aren't related to power system phenomena are essential as they effectively translate the intent of CIP-001 into EOP-004.* C. The nuclear "LOOP" should be only reported if total loss of offsite source (i.e. 2 of 2 or 3 of 3) when supplying the plants load. If lightning or insulator fails causing one of the line sources to trip that's not a system disturbance especially if it is just used as a backup. It should only be a NRC process if they want to monitor that. *The DSR SDT has updated this event per your comment, it now reads as: "Complete loss of off-site power to a nuclear generating plant (grid supply)"* The VRF/VSL: BPA believes that the VRF for R2 & R4 should be "Lower". *The DSR SDT has reviewed and updated the two new requirements and believe the VRF's follow the NERC Standard development process.*
Response: Thank you for your comment. Please see response above.		
CenterPoint Energy		CenterPoint Energy appreciates the SDT's consideration of comments and removal of the term, Impact Event. However, the Company still suggests removing the phrase "with the potential to impact" from the purpose as it is vast and vague. An

Organization	Yes or No	Question 4 Comment
		alternative purpose would be "To improve industry awareness and the reliability of the Bulk Electric System by requiring the reporting of events that impact reliability and their causes if known". The focus should remain on those events that truly impact the reliability of the BES. *The DSR SDT revised the purpose statement to remove ambiguous language "with the potential to impact reliability". The Purpose statement now reads:* ***"To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities."*** CenterPoint Energy remains very concerned about the types of events that the SDT has retained in Attachment 1 as indicated in the following comments: Destruction of BES Equipment - The loss of BES equipment should not be reportable unless the reliability of the BES is impacted. *The DSR SDT has modified Attachment 1 to bring more clarity. The more subjective events were rewritten as follows:* • *The 'Damage or Destruction' event category has been revised to say 'to a Facility', (a defined term) and thresholds have be modified to provide clarity. The footnote was deleted* Footnote 5, iii should be modified to tie the removal of a piece of equipment from service back to reliability of the BES. Risk to BES equipment: This Event is too vague to be meaningful and should be deleted. The Event should be modified to "Detection of an imminent physical threat to BES equipment". *The SDR SDT discussed this event as well as the event "Risk to BES equipment". These two event types had overlap in the perceived reporting requirements. The DSR SDT removed "Forced Intrusion" as a category and the "Risk to BES equipment" event was revised to "A physical threat that could impact the operability of a Facility".*

Organization	Yes or No	Question 4 Comment
		Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. *The footnote regarding this event type was expanded to provide additional guidance in:* *"Examples include a train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center). Also report any suspicious device or activity at a Facility. Do not report copper theft unless it impacts the operability of a Facility."* Any reporting time frame of 1 hour is unreasonable; Entities will still be responding to the Event and gathering information. A 24 hour reporting time frame would be more reasonable and would still provide timely information. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"…direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1.*

Organization	Yes or No	Question 4 Comment
		System Separation: The 100 MW threshold is too low for a reliability impact. A more appropriate threshold is 500 MW. *The DSR SDT has reviewed your request and have determined the event as written “Each separation resulting in an island of generation and load ≥ 100 MW” does impact the reliability of the BES.* Loss of Monitoring or all voice communication capability: The two elements of this Event should be separated for clarity as follows: “Loss of monitoring of Real-Time conditions” and “Loss of all voice communication capability.” *The DSR SDT has broken this event down into two distinct events: “Loss of all voice communication capability” and “Complete or partial loss of monitoring capability”, per comments received.*
Response: Thank you for your comment. Please see response above.		
Orange and Rockland Utilities, Inc./Consolidated Edison Co. of NY, Inc.		Comments: o Requirement 4 does not specifically state details necessary for an entity to achieve compliance. Requirement 4 should provide more guidance as to what is required in a drill. Audit / enforcement of any requirement language that is too broad will potentially lead to Regional interpretation, inconsistency, and additional CANs. o R4 should be revised to delete the 15 month requirement. CAN-0010 recognizes that entities may determine the definition of annual. *Requirement R4 has been revised as you suggested.* o The Purpose of the Standard should be revised because some of the events being reported on have no impact on the BES. Revise Purpose as follows: To improve industry awareness and the reliability of the Bulk Electric System by requiring the reporting of [add] "major system events.” [delete - “with the potential to impact

Organization	Yes or No	Question 4 Comment
		reliability and their causes, if known, by the Responsible Entities.”] *The DSR SDT revised the purpose statement to remove ambiguous language “with the potential to impact reliability”. The Purpose statement now reads:* ***“To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.”***
Response: Thank you for your comment. Please see response above.		
Entergy Services		Entergy agrees with and supports comments submitted by the SERC OC Standards Review group.
Response: Thank you for your comment.		
ITC		Footnote 1 and the corresponding Threshold For Reporting associated with the first Event in Attachment 1 are not consistent and thus confusing. Qualifying the term BES equipment through a footnote is inappropriate as it leads to this confusion. For instance, does iii under Footnote 1 apply only to BES equipment that meet i and ii or is it applicable to all BES equipment? *The SDR SDT discussed this event as well as the event “Risk to BES equipment”. These two event types had overlap in the perceived reporting requirements. The DSR SDT removed “Forced Intrusion” as a category and the “Risk to BES equipment” event was revised to “A physical threat that could impact the operability of a Facility”.* *Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported.*

Organization	Yes or No	Question 4 Comment
		The footnote regarding this event type was expanded to provide additional guidance in: *"Examples include a train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center). Also report any suspicious device or activity at a Facility. Do not report copper theft unless it impacts the operability of a Facility."* The inclusion of equipment failure, operational error and unintentional human action within the threshold of reporting for "destruction" required in the first 3 Events listed in Attachment 1 is also not appropriate. It is clear through operational history that the intent of the equipment applied to the system, the operating practices and personnel training developed/delivered to operate the BES is to result in reliable operation of the BES which has been accomplished exceedingly well given past history. This is vastly different than for intentional actions and should be excluded from the first 3 events listed in Attachment. To the extent these issues are present in another event type they will be captured accordingly. *The DSR SDT has modified Attachment 1 to bring more clarity. The more subjective events were rewritten as follows:* • *The 'Damage or Destruction' event category has been revised to say 'to a Facility', (a defined term) and thresholds have be modified to provide clarity. The footnote was deleted* • *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its*

Organization	Yes or No	Question 4 Comment
		Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. Also, the footnote only contains examples. *These two remaining event categories that aren't related to power system phenomena are essential as they effectively translate the intent of CIP-001 into EOP-004.* Footnote 1 should be removed and the Threshold for Reporting associated with the first three events in Attachment 1 should be updated only to include intentional human action. This will also result in including all BES equipment that was intentionally damaged in the reporting requirement and not just the small subset qualified by the existing footnote 1. This provides a much better data sample for law enforcement to make assessments from than the smaller subset qualified by what we believe the intent of footnote 1 is. *The SDR SDT discussed this event as well as the event "Risk to BES equipment". These two event types had overlap in the perceived reporting requirements. The DSR SDT removed "Forced Intrusion" as a category and the "Risk to BES equipment" event was revised to "A physical threat that could impact the operability of a Facility".* *Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported.* *The footnote regarding this event type was expanded to provide additional guidance in:*

Organization	Yes or No	Question 4 Comment
		"Examples include a train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center). Also report any suspicious device or activity at a Facility. Do not report copper theft unless it impacts the operability of a Facility."
Response: Thank you for your comment. Please see response above.		
APX Power Markets (NCR-11034)		For Attachment 1 and the events titled "Unplanned Control Center evacuation" and "Loss of monitoring or all voice communication capabiliy".RC, BA, and TOP are the only listed entity types listed for reporting responsibility. We are a GOP that offers a SCADA service in several regions and those type of events could result in a loss of situational awareness for the regions we provide services. I believe the requirement for reporting should not be limited to Entity Type, but on their impact for situational awareness to the BES based on the amount of generation they control (specific to our case), or other criteria that would be critical to the BES (i.e. voltage, frequency). *Note that EOP-008-0 is only applicable to Balancing Authorities, Transmission Operators and Reliability Coordinators, this is the basis for the "Entity with reporting Responsibilities" and reads as" "Each RC, BA, TOP that experiences the event".*
Response: Thank you for your comment. Please see response above.		
ACES Power Marketing Standards Collaborators/ Great River Energy		For many of the events listed in Attachment 1, there would be duplicate reporting the way it is written right now. For example, in the case of a fire in a substation (Destruction of BES equipment), the RC, BA, TO, TOP and perhaps the GO and GOP could all experience the event and each would have to report on it. This seems quite excessive and redundant. We recommend eliminating this duplicate reporting. *The DSR SDT has tried to minimize duplicative reporting, but recognizes there may be*

Organization	Yes or No	Question 4 Comment
		events that trigger more than one report. The current applicability ensures an event that could affect just one of the entities with reporting responsibility isn't missed.
Response: Thank you for your comment. Please see response above.		
Intellibind		I do not see that the rewrite of this standard is meeting the goal of clear reliability standards, and in fact the documents are looking more like legal documents. Though the original EOP-004 and CIP-001 was problematic at times, this rewrite, and the need to have such extensive guidance, attachments, and references for EOP-004-2 will create an even more difficult standard to properly meet to ensure compliance during an audit. Though CIP-001 and EOP-004 were related, combining them in a single standard is not resolving the issues, and is in fact complicating the tasks.Requirements in this standard should deal with only one specific issue, not deal with multiple tasks. I am not sure how an auditor will consistently audit against R2, and how a violation will be categorized when an entity implements all portions of their Operating Plan, however fails to fully address all the requirements in R1, thereby not fully implementing R2, in strict interpretation. *The DSR SDT does not agree that the proposed EOP-004-2 "will create an even more difficult standard to properly meet to ensure compliance during an audit". The DSR SDT main concern is the reporting of events per Attachment 1 is in-line with the Purpose of this Standard that states: "To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities." The NERC Reliability Standards are designed to support the reliability of the BES.* *Requirement R2has been updated to read as: ""R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment1." Based on comments received.* The drafting team should not set up a situation where an entity is in double jeopardy for missing an element of a requirement.I also suggest that EOP-004-2 be given a

Organization	Yes or No	Question 4 Comment
		new EOP designation rather than calling it a revision. This way implementation can be better controlled, since most companies have written specific CIP-001 and EOP-004 document that will not simple transfer over to the new version. This standard is a drastic departure from the oringial versions. I appreciate the level of work that is going into EOP-004-2, it appears that significant time and effort has been going into the supporting documentation. It is my opinion that if this much material has to be created to state what the standard really requires, then the standard is flawed. When there are 21 pages of explanation for five requirements, especially when we have previously had 16 pages that originally covered 2 separate reliability standards, we need to reevaluate what we are really doing. *The DSR SDT has revised EOP-004 and CIP-001 using the results based standard development process. This process calls for the drafting team to develop documentation regarding its thoughts during the development process. This allows for a more robust standard which contains background material for an entity to have sufficient guidance to show compliance with the standard.*
Response: Thank you for your comment. Please see response above.		
Imperial Irrigation District		IID strongly believes the reporting flowchart should not be part of a standard. The suggestion is to replace it with a more clear, right to the point requirement. *The DSR SDT has discussed this issue and believes it would be too prescriptive to have a flow chart as a requirement. If desired, an entity can have a flow chart as part of the Operating Plan as stated in Requirement 1.*
Response: Thank you for your comment. Please see response above.		
Illinois Municipal Electric Agency		IMEA appreciates this opportunity to comment. IMEA appreciates the SDT's efforts to simplify reporting requirements by combining CIP-001 with EOP-004. [IMEA encourages NERC to continue working towards a one-stop-shop to simplify reporting on ES-ISAC.] IMEA supports, and encourages SDT consideration of, comments

Organization	Yes or No	Question 4 Comment
		submitted by APPA and Florida Municipal Power Agency.
Response: Thank you for your comment. Please see the responses to the other comments that you mention.		
Westar Energy		In Requirement 1.3, the statement “and the following as appropriate” is vague and subject to interpretation. Who determines what is appropriate? We feel it would be better if the SDT would specify for each event, which party should be notified. *Requirement R1, Part 1.3 (now Part 1.2) was revised to add clarifying language by eliminating the phrase “as appropriate” and indicating that the Responsible Entity is to define its process for reporting and with whom to report events. Part 1.2 now reads:* *“1.2 A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity’s Reliability Coordinator; law enforcement governmental or provincial agencies.”*
Response: Thank you for your comment. Please see response above.		
South Carolina Electric and Gas		In terms of receiving reports, is it the drafting teams expectation that separate reports be developed by both the RC and the TOP, GO, BA, etc. for an event that occurs on a company's system that is within the RC's footprint? One by the RC and one by the TOP, GO, BA, etc. In terms of meeting reporting thresholds, is it the drafting teams expectation that the RC aggregate events within its RC Area to determine whether a reporting threshold has been met within its area for the quantitative thresholds? *The DSR SDT has tried to minimize duplicative reporting, but recognizes there may be events that trigger more than one report. The current applicability ensures an event*

Organization	Yes or No	Question 4 Comment
		that could affect just one of the entities with reporting responsibility isn't missed. *It is possible for the Applicable Entities within the Reliability Coordinator's area to be part of a JRO/CFR but this is outside the scope of this Project.*
Response: Thank you for your comment. Please see response above.		
Occidental Power Services, Inc. (OPSI)		Load Serving Entities that do not own or operate BES assets should not be included in the Applicability. In current posting, the SDT states that it includes LSEs based on CIP-002; however, if the LSE does not have any BES assets, CIP-002 should also not be applicable, because the LSE could not have any Critical Assets or Critical Cyber Assets. It is understood that the SDT is trying to comply with FERC Order 693, Section 460 and 461; however, Section 461 also states "Further, when addressing such applicability issues, the ERO should consider whether separate, less burdensome requirements for smaller entities may be appropriate to address these concerns." A qualifier in the Applicability of EOP-004-2 that would include only LSEs that own or operate BES assets would seem appropriate. The proposed CIP-002 Version V has such a qualifier in that it applies to a "Load-Serving Entity that owns Facilities that are part of any of the following systems or programs designed, installed, and operated for the protection or restoration of the BES: o A UFLS program required by a NERC or Regional Reliability Standard o A UVLS program required by a NERC or Regional Reliability Standard"The SDT should consider the same wording in the Applicability section of EOP-004-2 on order to be consistent with what will become the standing version of CIP-002 (Version 5). *The DSR SDT has "considered" section 460 and 461 of FERC Order 693 and has tried to minimize duplicative reporting, but recognizes there may be events that trigger more than one report. The current applicability ensures an event that could affect just one of the entities with reporting responsibility isn't missed.* *The DSR SDT wishes to draw your attention to section 459 of FERC Order 693 which states: " … an adversary may target a small user, owner or operator because it may*

Organization	Yes or No	Question 4 Comment
		have similar equipment or protections as a larger facility, that is, the adversary may use an attack against a smaller facility as a training 'exercise'".
Response: Thank you for your comment. Please see response above.		
American Electric Power		M4: Recommend removing the text "for events" so that it instead reads "The Responsible Entity shall provide evidence that it verified the communication process in its Operating Plan created pursuant to Requirement R1, Part 1.3."R4: It is not clear to what extent the verification needs to be applied if the process used is complex and includes a variety of paths and/or tasks. The draft team may wish to consider changing the wording to simply state "each Responsible Entity shall test each of the communication paths in the operating plan". We also recommend dropping "once per calendar year" as it is inconstant with the measure itself which allows for 15 months. *The DSR SDT has revised R4 (now R3 and the associated measure M3:* *M3. Each Responsible Entity will have dated and time-stamped records to show that the annual test of Part 1.2 was conducted. Such evidence may include, but are not limited to, dated and time stamped voice recordings and operating logs or other communication documentation. The annual test requirement is considered to be met if the responsible entity implements the communications process in Part 1.2 for an actual event. (R3)*
Response: Thank you for your comment. Please see response above.		
Indiana Municipal Power Agency		Many of the items listed in Attachment 1 are onerous and burdensome when it comes to making judgments or determinations. What one may consider "Risk to BES equipment" another person may not make the same determination. Clarity needs to

Organization	Yes or No	Question 4 Comment
		be added to make the events easier to determine and that will result in less issues when it comes to compliance audits. IMPA does not understand the usage of the terms Critical Asset and Critical Cyber Asset as they will be retired with CIP version 5.IMPA believes the data retention requirements are way too complicated and need to be simplified. It seems like it would be less complicated if one data retention period applied to all data associated with this standard. *The DSR has revised many of the events listed in Attachment 1 to provide clarity. We have also removed the references to Critical Asset and Critical Cyber Asset.* On "public appeal", in the threshold, the descriptor "each" should be deleted, e.g., if a single event causes an entity to be short of capacity, do you really want that entity reporting each time they issue an appeal via different types of media, e.g., radio, TV, etc., or for a repeat appeal every several minutes for the same event? *The DSR SDT has updated the Public Appeal event to read as: "Public appeal for load reduction event" based on comments received.*
Response: Thank you for your comment. Please see response above.		
MidAmerican Energy		MidAmerican proposes eliminating the phrase "with no more than 15 months between reviews" from R1.5. While we agree this is best practice, it creates the need to track two conditions for the review, eliminates flexibility for the responsible entity and does not improve security to the Bulk Electric System. There has not been a directive from FERC to specify the definition of annual within the standard itself. In conjunction with this comment, the Violation Severity Levels for R4 should be revised to remove the references to months. *The DSR SDT has removed this phrase from the requirement (now R3).*

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. Please see response above.		
Oncor Electric Delivery Company LLC		NERC's Event Analysis Program tends to parallel many of the reporting requirements as outlined in EOP-004 Version 2. Oncor recommends that NERC considers ways of streamlining the reporting process by either incorporating the Event Analysis obligations into EOP-004-2 or reducing the scope of the Event Analysis program as currently designed to consist only of "exception" reporting. *The DSR SDT has reviewed the Event Analysis Programs criteria. The DSR SDT has determined that Attachment 1 covers the minimum reporting requirements.*
Response: Thank you for your comment. Please see response above.		
Compliance & Responsbility Office		NextEra Energy, Inc. (NextEra) appreciates the DSR SDT revising proposed EOP-004-2, based on the previous comments of NextEra and the stakeholders. NextEra, however, believes that EOP-004-2 needs additional refinement prior to approval. R1.3In R1.3, NextEra is concerned that the term “internal company personnel” is unclear and may be misinterpreted. For example, NextEra does not believe this term should include all company or corporate personnel, or even all personnel in the Responsible Entity’s company or business unit. Instead, the definition of personnel should be limited to those who could be directly impacted by the event or are working on the event. Thus, NextEra suggests that the language in R1.3 be revised to read: “Internal Responsible Entity personnel whose tasks require them to take specific actions to mitigate, stop the spread and/or normalize the event, or personnel who are directly impacted by the event.” NextEra is concerned that R1.3, as written, will be interpreted differently from company to company, region to region, auditor to auditor, and, therefore, may result in considerable confusion during actual events as well as during the audits/stop checks of EOP-004-2 compliance.

Organization	Yes or No	Question 4 Comment
		The DSR SDT has written Requirement R1, Part 1.2 in a way to allow the entity to determine who should receive the communication within your company as stated in your Operating Plan. Also, in R1.3, NextEra is concerned that many of the events listed in Attachment A already must be reported to NERC under its trial (soon to be final) Event Analysis Reporting requirements (Event Analysis). NextEra believes duplicative and different reporting requirements in EOP-004-2 and the Event Analysis rules will cause confusion and inefficiencies during an actual event, which will likely be counterproductive to promoting reliability of the bulk power system. Thus, NextEra believes that any event already covered by NERC's Event Analysis should be deleted from Attachment 1. Events already covered include, for example, loss of monitoring or all voice, loss of firm load and loss of generation. If this approach is not acceptable, NextEra proposes, in the alternative, that the reporting requirements between EOP-004-2 and Event Analysis be identical. For instance, in EOP-004-2, there is a requirement to report any loss of firm load lasting for more than 15 minutes, while the Event Analysis only requires reporting the of loss of firm load above 300 megawatts and lasting more than 15 minutes. Similarly, EOP-004-2 requires the reporting of any unplanned control center evacuation, while the Event Analysis only requires reporting after the evacuation of the control center that lasted 30 minutes or more. Thus, NextEra requests that either EOP-004-2 not address events that are already set forth in NERC's Event Analysis, or, in the alternative, for those duplicative events to be reconciled and made identical, so the thresholds set forth in the Event Analysis are also used in EOP-004-2. *The DSR SDT has worked with the EAWG to develop Attachment 1. At one point they matched. The event for loss of load matches and we revised the "unplanned control center evacuation" event to be for 30 minutes or more.* In addition, NextEra believes that a reconciliation between the language "of recognition" in Attachment 1 and "process to identify" in R1.1 is necessary. NextEra prefers that the language in Attachment 1 be revised to read " . . . of the

Organization	Yes or No	Question 4 Comment
		identification of the event under the Responsible Entity's R1.1 process." For instance, the first event under the "Submit Attachment 2 . . . ." column should read: "The parties identified pursuant to R1.3 within 1 hour of the identification of an event under the Responsible Entity's R1.1 process." This change will help eliminate confusion, and will also likely address (and possibly make moot) many of the footnotes and qualifications in Attachment 1, because a Responsible Entity's process will likely require that possible events are properly vetted with subject matter experts and law enforcement, as appropriate, prior to identifying them as "events". Thus, only after any such vetting and a formal identification of an event would the one hour or twenty-four hour reporting clock start to run. R1.4, R1.5, R3 and R4NextEra is concerned with the wording and purpose of R1.4, R1.5, R3 and R4. *The language was revised in Requirement 1, Part 1.1 to "recognize" based on other comments received.* For example, R1.4 requires an update to the Operating Plan for ". . . any change in assets, personnel, other circumstances . . . ." This language is much too broad to understand what is required or its purpose. Further, R1.4 states that the Operating Plan shall be updated for lessons learned pursuant to R3, but R3 does not address lessons learned. Although there may be lessons learned during a post event assessment, there is no requirement to conduct such an assessment. Stepping back, it appears that the proposed EOP-004-2 has a mix of updates, reviews and verifications, and the implication that there will be lessons learned. Given that EOP-004-2 is a reporting Standard, and not an operational Standard, NextEra is not inclined to agree that it needs the same testing and updating requirements like EOP-005 (restoration) or EOP-008 (control centers). Thus, it is NextEra's preference that R1.4, R1.5 and R4 be deleted, and replaced with a new R1.4 as follows:R1.4 A process for ensuring that the Responsibly Entity reviews, and updates, as appropriate its Operating Plan at least annually (once each calendar year) with no more than 15 months between reviews.If the DSR SDT does not agree with this approach, NextEra, in the alternative, proposes a second approach that consolidates R1.4, R1.5 and R4 in a new R1.4 as follows:R1.4 A process for ensuring that the Responsibly Entity tests

Organization	Yes or No	Question 4 Comment
		and reviews its Operating Plan at least annually (once each calendar year) with no more than 15 months between a test and review. Based on the test and review, the Operating Plan shall be updated, as appropriate, within 90 calendar days. If an actual event occurs, the Responsible Entity shall conduct a post event assessment to identify any lessons learned within 90 calendar days of the event. If the Responsible Entity identifies any lessons learned in post event assessment, the lessons learned shall be incorporated in the Operating Plan within 90 calendar days of the date of the final post event assessment. NextEra purposely did not add language regarding "any change in assets, personnel etc," because that language is not sufficiently clear or understandable for purposes of a mandatory requirement. Although it may be argued that it is a best practice to update an Operating Plan for certain changes, unless the DST SDT can articulate specific, concrete and understandable issues that require an updated Operating Plan prior to an annual review, NextEra recommends that the concept be dropped. *Requirement 1, Part 1.4 was merged with Part 1.5 as well as R4. The resulting requirement is now Requirement 3:* *"Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]* Nuclear Specific ConcernsEOP-004-2 identifies the Nuclear Regulatory Commission (NRC) as a stakeholder in the Reporting Process, but does not address the status of reporting to the NRC in the Event Reporting flow diagram on page 9. Is the NRC considered Law Enforcement as is presented in the diagram? Since nuclear stations are under a federal license, some of the events that would trigger local/state law enforcement at non-nuclear facilities would be under federal jurisdiction at a nuclear site. *The process flowchart is an example of how an entity might operate. If an event requires notification of the NRC, this would be an example of notification of a regulatory authority. It is anticipated that the reporting entity would also notify law*

Organization	Yes or No	Question 4 Comment
		enforcement if appropriate. There are some events listed in Attachment 1 that seem redundant or out of place. For example, a forced intrusion is a one hour report to NERC. However, if there is an ongoing forced intrusion at a nuclear power plant, there are many actions taking place, with the NRC Operations Center as the primary contact which will mobilize the local law enforcement agency, etc. *The DSR SDT removed "Forced Intrusion" as a category and the "Risk to BES equipment" event was revised to "Any physical threat that could impact the operability of a Facility".* It is unclear that reporting to NERC in one hour promotes reliability or the resolution of an emergency in progress. *All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:* *"…direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1.* Also, is there an ability to have the NRC in an emergency notify NERC? The same concerns related to cyber security events.Procedures versus PlanNextEra also suggests replacing "Operating Plan" with "procedures". Given that EOP-004-2 is a reporting Standard and not an operational Standard, it is typical for procedures that address this standard to reside in other departments, such as Information Management and Security. In other words, the procedures needed to address the requirements of EOP-004-2 are likely broader than the NERC-defined Operating Plan.

Organization	Yes or No	Question 4 Comment
		Within your Operating Plan you are required to "report" events to the ERO and your RC and communicate this information (to others) as you define it within your company's Operating Plan. This will allow you to customize any events as you see fit. Clean-Up ItemsIn Attachment 1, Control Centers should be capitalized in all columns so as not to be confused with control rooms. *Since "control center" is not a defined term, it has been revised to lower case.* Also, the final product should clearly state that the process flow chart that is set forth before the Standard is for illustrative purposes, so there is no implication that a Registered Entity must implement multiple procedures versus one comprehensive procedure to address different reporting requirements. *The introduction of the flow chart is clearly marked "Example of Reporting Process including Law Enforcement".*
Response: Thank you for your comment. Please see response above.		
PacifiCorp		No comment.
Arizona Public Service Company		No comments
PPL Electric Utilities and PPL Supply Organizations`		Our comments center around the footnotes and events 'Destruction of BES equipment' and 'Loss of Off-site power to a nuclear generating plant'. We request the SDT consider adding a statement to the standard that acknowledges that not all registered entities have visibility to the information in the footnotes. E.G. Destruction of BES equipment. A GO/GOP does not necessarily know if loss of specific BES equipment would affect any IROL and therefore would not be able to consider this criteria in its reporting decision. Loss of BES equipment would be reported to the BA/RC and the BA/RC would know of an IROL impact and the BA/RC

Organization	Yes or No	Question 4 Comment
		is the appropriate entity to report. We request the SDT consider the information in the footnotes for inclusion in the table directly. Consider Event 'Destruction of BES equipment'. Is footnote 1 a scoping statement? Is it part of the threshold? Is it the impact? Is it defining Destruction? If the BES equipment was destroyed by weather and does not affect an IROL, then is no report is needed? Alternatively, do you still apply the threshold and say it was external cause and therefore report? *Several event categories were removed or combined to improve Attachment 1. The footnotes that you mention were removed and included in the threshold for reporting column. If an entity does not experience an event, then they should not report on it. As you suggest, most GO /GOPs do not see the transmission system. It is anticipated that they will report for events on their Facilities.* We suggest including a flowchart on how to use Attachment 1 with an example. The flowchart would explain the order in which to consider the event and the threshold, and footnotes if they remain. Regarding Attachment 1 Footnote 1 'do not report copper theft...unless it degrades the ability of equipment to operate correctly.', is this defining destruction as not operating correctly ? or is the entirety of footnote 1 a definition of destruction? Regarding Attachment 1 Footnote 1, iii, we request this be changed for consistency with the Event and suggest removing damage from the footnote. i.e. The event is 'destruction' whereas the footnote says 'damaged or destroyed'. The standard does not provide guidance on damage vs destruction which could lead to differing reporting conclusions. Is the reporting line out of service, beyond repair, or is it timeframe based? Regarding Attachment 1 Footnote 2 ' to steal copper... unless it affects the reliability of the BES', is affecting the reliability of the BES a consideration in all the events? PPL believes this is the case and request this statement be made. This could be included in the flowchart as a decision point. Regarding Event 'Loss of Off-site power to a nuclear generating plant', the threshold for reporting does not designate if the off-site loss is planned and/or unplanned - or if the reporting threshold includes the loss of one source of off-site power or is the reporting limited to when all off-site sources are unavailable. PPL recommends the event be ‘Total unplanned loss of offsite power to a nuclear generating plant (grid

Organization	Yes or No	Question 4 Comment
		supply)'Thank you for considering our comments. *The SDR SDT discussed "Forced Intrusion" as well as the event "Risk to BES equipment". These two event types had overlap in the perceived reporting requirements. The DSR SDT removed "Forced Intrusion" as a category and the "Risk to BES equipment" event was revised to "A physical threat that could impact the operability of a Facility".* *Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported.* *The footnote regarding this event type was expanded to provide additional guidance in:* *"Examples include a train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center). Also report any suspicious device or activity at a Facility. Do not report copper theft unless it impacts the operability of a Facility."* *The DSR SDT has updated the Requirements based on comments received along with updating Attachment 1 and 2. Please review the updated standard for all your concerns.*
Response: Thank you for your comment. Please see response above.		
City of Austin dba Austin		Overarching Concern related to EOP-004-2 draft:The contemporaneous drafting efforts related to both the proposed Bulk Electric System ("BES") definition changes

Organization	Yes or No	Question 4 Comment
Energy		and CIP Standards Version 5 could significantly impact the EOP-004-2 reporting requirements. Caution needs to be exercised when referencing these definitions, as the definition of a BES element could change significantly and the concepts of “Critical Assets” and “Critical Cyber Assets” no longer exist in Version 5 of the CIP Standards. *The ‘Damage or Destruction’ events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and ‘Damage or Destruction of a Facility’ reporting thresholds.* Additionally, it is debatable whether the destruction of, for example, one relay would be a reportable incident given the proposed language. Related to “Reportable Events” of Attachment 1:1. The “Purpose” section of the Standard indicates it is designed to require the reporting of events “with the potential to impact reliability” of the BES. Footnote 1 and the “Threshold for Reporting” associated with the Event described as “Destruction of BES equipment” expand the reporting scope beyond that intent. For example, a fan on a generation unit can be destroyed because a plant employee drops a screwdriver into it. We believe such an event should not be reportable under EOP-004-2. Yet, as written, a Responsible Entity could interpret that event as reportable (because it would be “unintentional human action” that destroyed a piece of equipment associated with the BES). If the goal of the SDT was to include such events, we think the draft Standard goes too far in requiring reporting. If the SDT did not intend to include such events, the draft Standard should be revised to make that fact clear. *‘Forced intrusion’ and ‘Risk to BES Equipment’ have been combined under a new event type called ‘A physical threat that could impact the operability of a Facility’. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT*

Organization	Yes or No	Question 4 Comment
		believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. 2. Item iii) in Footnote 1 seems redundant with the Threshold for Reporting.3. The word “Significantly” in item ii) of footnote 1 introduces an element of subjectivity. What is “significant” to one person may not be significant to someone else.4. The word “unintentional” in Item iii) of footnote 1 may introduce nuisance reporting. The SDT should consider: (1) changing the Event description to “Damage or destruction of BES equipment” (2) removing the footnote and (3) replacing the existing “Threshold for Reporting” with the following language:”Initial indication the event: (i) was due to intentional human action, (ii) affects an IROL or (iii) in the opinion of the Responsible Entity, jeopardizes the reliability margin of the system (e.g., results in the need for emergency actions)” *The SDR SDT revised this event to “Damage or destruction of a Facility” and removed the footnote. The threshold for reporting now reads:* *Damage or destruction of a Facility that:* *Affects an IROL (per FAC-014)* *OR* *Results in the need for actions to avoid an Adverse Reliability Impact* *OR* *Results from intentional human action.* 5. One reportable event is “Risk to the BES” and the threshold for reporting is, “From a non-environmental physical threat.” This appears to be intended as a catch-all reportable event. Due to the subjectivity of this event description, we suggest removing it from the list. *The ‘Damage or Destruction’ events specifically relating to Critical Assets and Critical*

Organization	Yes or No	Question 4 Comment
		Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds. 6. One reportable event is "Damage or destruction of Critical Asset per CIP-002." The SDT should define the term "Damage" in order for an entity to determine a threshold for what qualifies as "Damage" to a CA. Normal "damage" can occur on a CA that should not be reportable (e.g. the screwdriver example, above). *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* 7. For the event called "BES Emergency requiring public appeal for load reduction," the SDT should make it clear who should report such an event. For example, in the ERCOT Region, there is a requirement that ERCOT issue public appeals for load reduction (See ERCOT Protocols Section 6.5.9.4). As the draft of EOP-004-2 is currently written, every Registered Entity in the ERCOT Region would have to file a report when ERCOT issues such an appeal. Such a requirement is overly burdensome and does not enhance the reliability of the BES. The Standard should require that the Reliability Coordinator file a report when it issues a public appeal to reduce load. *The DSR SDT has tried to minimize duplicative reporting, but recognizes there may be events that trigger more than one report. The current applicability ensures an event that could affect just one of the entities with reporting responsibility isn't missed.* Reporting Thresholds1. See Paragraph 1 in the "Related to 'Reportable Events' of Attachment 1" section, above. 2. We believe damage or destruction of Critical

Organization	Yes or No	Question 4 Comment
		Assets or CCAs resulting from operational error, equipment failure or unintentional human action should not be reportable under this Standard. We recommend changing the thresholds for “Damage or destruction of Critical Asset...” and “Damage or destruction of a [CCA]” to “Initial Indication the event was due to external cause or intentional human action.” 3. We support the SDT’s attempted to limit nuisance reporting related to copper thefts. However, a number of the thresholds identified in EOP-004-2 Attachment 1 are very low and could clog the reporting process with nuisance reporting and reviewing. An example is the “BES Emergency requiring manual firm load shedding” of â‰¥ 100 MW or “Loss of Firm load for â‰¥ 15 Minutes” that is â‰¥ 200 MW (300 MW if the manual demand is greater than 3000 MW). In many cases, those low thresholds would require reporting minor wind events or other seasonal system issues on a local network used to provide distribution service. Firm Load1. The use of the term “Firm load” in the context of the draft Standard seems inappropriate. “Firm load” is not defined in the NERC Glossary (although “Firm Demand” is defined). If the SDT intended to use “Firm Demand,” they should revise the draft Standard to use that language. If the SDT wishes to use the term “Firm load” they should define it. [For example, we understand that some load agrees to be dropped in an emergency. In fact, in the ERCOT Region, we have a paid service referred to as “Emergency Interruptible Load Service” (EILS). If the SDT intends that “Firm load” means load other than load which has agreed to be dropped, it should make that fact clear.] *The thresholds and events listed in Attachment 1 are currently required under DOE OE-417 and NERC reporting requirements.* Comments to Attachment 21. The checkbox for “fuel supply emergency” should be deleted because it is not listed as an Event on Attachment 1. *The DSR SDT has removed both “fuel supply emergency” and “other” from Attachment 2.*

Organization	Yes or No	Question 4 Comment
		2. There should be separation between “forced intrusion” and “Risk to BES equipment.” They are separate Events on Attachment 1. *Several stakeholders expressed concerns relating to the “Forced Intrusion” event. Their concerns related to ambiguous language in the footnote. The SDR SDT discussed this event as well as the event “Risk to BES equipment”. These two event types had overlap in the perceived reporting requirements. The DSR SDT removed “Forced Intrusion” as a category and the “Risk to BES equipment” event was revised to “A physical threat that could impact the operability of a Facility”.* *Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported.* Comments to Guideline and Technical BasisThe last paragraph appears to state NERC will accept an OE-417 form as long as it contains all of the information required by the NERC form and goes on to state the DOE form “may be included or attached to the NERC report.” If the intent is for NERC to accept the OE-417 in lieu of the NERC report, this paragraph should be clarified. *The DSR SDT received many comments requesting consistency with DOE OE-417 thresholds and timelines. These items as well as the Events Analysis Working Group’s (EAWG) requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry’s needs; accommodation of other reporting obligations was considered as an opportunity not a ‘must-have’* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across*

Organization	Yes or No	Question 4 Comment
		North America • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use the OE-417 form rather than Attachment 2 to report under EOP-004. The SDT was informed by the DOE of its new online process coming later this year. In this process, entities may be able to record email addresses associated with their Operating Plan so that when the report is submitted to DOE, it will automatically be forwarded to the posted email addresses, thereby eliminating some administrative burden to forward the report to multiple organizations and agencies.*
Response: Thank you for your comment. Please see response above.		
Salt River Project/ Lower Colorado River Authority		Overarching Concern related to EOP-004-2 draft:The contemporaneous drafting efforts related to both the proposed Bulk Electric System ("BES") definition changes and CIP Standards Version 5, could significantly impact the EOP-004-2 reporting requirements. Caution needs to be exercised when referencing these definitions, as the definition of a BES element could change significantly and the concepts of “Critical Assets” and “Critical Cyber Assets” no longer exist in Version 5 of the CIP Standards. *The ‘Damage or Destruction’ events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and ‘Damage or Destruction of a Facility’ reporting thresholds.* Additionally, it is debatable whether the destruction of, for example, one relay would

Organization	Yes or No	Question 4 Comment
		be a reportable incident given the proposed language. Related to "Reportable Events" of Attachment 1:1. The "Purpose" section of the Standard indicates it is designed to require the reporting of events "with the potential to impact reliability" of the BES. Footnote 1 and the "Threshold for Reporting" associated with the Event described as "Destruction of BES equipment" expand the reporting scope beyond that intent. For example, a fan on a generation unit can be destroyed because a plant employee drops a screwdriver into it. We believe such an event should not be reportable under EOP-004-2. Yet, as written, a Responsible Entity could interpret that event as reportable (because it would be "unintentional human action" that destroyed a piece of equipment associated with the BES). If the goal of the SDT was to include such events, we think the draft Standard goes too far in requiring reporting. If the SDT did not intend to include such events, the draft Standard should be revised to make that fact clear. *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred.* 2. Item iii) in Footnote 1 seems redundant with the Threshold for Reporting.3. The word "Significantly" in item ii) of footnote 1 introduces an element of subjectivity. What is "significant" to one person may not be significant to someone else.4. The word "unintentional" in Item iii) of footnote 1 may introduce nuisance reporting. The SDT should consider: (1) changing the Event description to "Damage or destruction of BES equipment" (2) removing the footnote and (3) replacing the

Organization	Yes or No	Question 4 Comment
		existing "Threshold for Reporting" with the following language:"Initial indication the event: (i) was due to intentional human action, (ii) affects an IROL or (iii) in the opinion of the Responsible Entity, jeopardizes the reliability margin of the system (e.g., results in the need for emergency actions)" *The SDR SDT discussed this event as well as the event "Risk to BES equipment". These two event types had overlap in the perceived reporting requirements. The DSR SDT removed "Forced Intrusion" as a category and the "Risk to BES equipment" event was revised to "A physical threat that could impact the operability of a Facility".* *Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported.* *The footnote regarding this event type was expanded to provide additional guidance in:* *"Examples include a train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center). Also report any suspicious device or activity at a Facility. Do not report copper theft unless it impacts the operability of a Facility."* 5. One reportable event is, "Risk to the BES" and the threshold for reporting is, "From a non-environmental physical threat." This appears to be intended as a catch-all reportable event. Due to the subjectivity of this event description, we suggest removing it from the list. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical*

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Organization	Yes or No	Question 4 Comment
		"Firm load" is not defined in the NERC Glossary (although "Firm Demand" is defined). If the SDT intended to use "Firm Demand," they should revised the draft Standard. If the SDT wishes to use the term "Firm load" they should define it. [For example, we understand that some load agrees to be dropped in an emergency. In fact, in the ERCOT Region, we have a paid service referred to as "Emergency Interruptible Load Service" (EILS). If the SDT intends that "Firm load" means load other than load which has agreed to be dropped, it should make that fact clear.] *The thresholds and event types in Attachment 1 are from current DOE OE-417 and NERC reporting requirements.* Comments to Attachment 21. The checkbox for "fuel supply emergency" should be deleted because it is not listed as an Event on Attachment 1. *The DSR SDT has removed both "fuel supply emergency" and "other" from Attachment 2.* 2. There should be separation between "forced intrusion" and "Risk to BES equipment." They are separate Events on Attachment 1. *Several stakeholders expressed concerns relating to the "Forced Intrusion" event. Their concerns related to ambiguous language in the footnote. The SDR SDT discussed this event as well as the event "Risk to BES equipment". These two event types had overlap in the perceived reporting requirements. The DSR SDT removed "Forced Intrusion" as a category and the "Risk to BES equipment" event was revised to "A physical threat that could impact the operability of a Facility".* *Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events*

Organization	Yes or No	Question 4 Comment
		meaningful to industry awareness are reported. Comments to Guideline and Technical BasisThe last paragraph appears to state NERC will accept an OE-417 form as long as it contains all of the information required by the NERC form and goes on to state the DOE form "may be included or attached to the NERC report." If the intent is for NERC to accept the OE-417 in lieu of the NERC report, this paragraph should be clarified. *The DSR SDT received many comments requesting consistency with DOE OE-417 thresholds and timelines. These items as well as the Events Analysis Working Group's (EAWG) requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use the OE-417 form rather than Attachment 2 to report under EOP-004. The SDT was informed by the DOE of its new online process coming later this year. In this process, entities may be able to record email addresses associated with their Operating Plan so that when the report is submitted to DOE, it will automatically be forwarded to the posted email addresses, thereby eliminating some administrative burden to forward the report to multiple organizations and agencies.*

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. Please see response above.		
Public Utility District No. 1 of Snohomish County/Seattle City Light		Overarching Concern related to EOP-004-2 draft:The contemporaneous drafting efforts related to both the proposed Bulk Electric System ("BES") definition changes, as well as the CIP standards Version 5, could significantly impact the EOP-004-2 reporting requirements. Caution needs to be exercised when referencing these definitions, as the definitions of a BES element could change significantly and Critical Assets may no longer exist. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* As it relates to the proposed reporting criteria, it is debatable as to whether or not the destruction of, for example, one relay would be a reportable incident under this definition going forward given the current drafting team efforts. Related to "Reportable Events" of Attachment 1:1. A reportable event is stated as, "Risk to the BES", the threshold for reporting is, "From a non-environmental physical threat". This appears to be a catch-all event, and basically every other event in Attachment 1 should be reported because it is a risk to the BES. Due to the subjectivity of this event, suggest removing it from the list. *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that*

Organization	Yes or No	Question 4 Comment
		events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. 2. A reportable event is stated as, “Damage or destruction of Critical Asset per CIP-002”. The term “Damage” would have to be defined in order for an entity to determine a threshold for what qualifies as “Damage” to a CA. One could argue that normal “Damage” can occur on a CA that is not necessary to report. There should also be caution here in adding CIP interpretation within this standard. *The ‘Damage or Destruction’ events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and ‘Damage or Destruction of a Facility’ reporting thresholds.* Reporting Thresholds1. The SDT made attempts to limit nuisance reporting related to copper thefts and so on which is supported. However a number of the thresholds identified in EOP-004-2 Attachment 1 are very low and could congest the reporting process with nuisance reporting and reviewing. An example is the “BES Emergency requiring manual firm load shedding of greater than or equal to 100 MW or the Loss of Firm load for â‰¥ 15 Minutes that is greater than or equal to 200 MW (300 MW if the manual demand is greater than 3000 MW). In many cases these low thresholds represent reporting of minor wind events or other seasonal system issues on Local Network used to provide distribution service. Firm Demand1. The use of Firm Demand in the context of the draft Standards could be used to describe commercial arrangements with a customer rather than a reliability issue. Clarification of Firm Demand would be helpful *The DSR SDT has updated the requirements based on comments received along with updating Attachment 1 and 2. Please review the updated standard for all your*

Organization	Yes or No	Question 4 Comment
		concerns.
Response: Thank you for your comment. Please see response above.		
Pacific Northwest Small Public Power Utility Comment Group		Project 2008-06 proposes to withdraw the terms "Critical Asset" and "Critical Cyber Asset" from the NERC Glossary. In order to avoid a reliability gap when this occurs, we propose including High and Medium Impact BES Cyber Systems and Assets. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* The revised wording to add, "as appropriate" to R1.3 is a concern. We understand the SDT's intent to not require all the bulleted parties to be notified for every event type. But will a good faith effort on the part of the registered entity to deem appropriateness be subject to second guessing and possible sanctions by the Compliance Enforcement Authority if they disagree? We note that CIP-001 required an interpretation to address this issue, but cannot assume that interpretation will carry over. We suggest spelling out exactly who shall deem appropriateness. *The phrase "as appropriate" was removed and Requirement 1, Part 1.2 was revised to:* *A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies.* R4 continues to be an onerous requirement for smaller entities. Verification was not

Organization	Yes or No	Question 4 Comment
		part of the SAR and we are not convinced it is needed for reliability. We are unsure how a DP with no generation, no BES assets, no Critical Cyber Assets, and less than 100 MW of load; would meet R4. Shall they drill for impossible events? We ask that R4 be removed. At a minimum it should exclude entities that cannot experience the events of Attachment 1.Entities that cannot experience the events of Attachment 1should likewise be exempt from R1.2, 1.3, R2, and R3. *Requirement R4 (now R3) was revised to :* *Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2.* *Requirement R1, Part 1.1 specifies that an entity must have a process for recognizing "applicable events". An entity is only required to have the Operating Plan as it relates to events applicable to that entity. The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see Part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated. This language does not preclude the verification of contact information taking place during a training event. The DSR SDT has updated the Requirements based on comments received along with updating Attachment 1 and 2. Please review the updated Standard for all your concerns.*
Response: Thank you for your comment. Please see response above.		
Clallam County PUD No.1		Project 2008-06 proposes to withdraw the terms "Critical Asset" and "Critical Cyber Asset" from the NERC Glossary. In order to avoid a reliability gap when this occurs,

Organization	Yes or No	Question 4 Comment
		we propose including High and Medium Impact BES Cyber Systems and Assets. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* The revised wording to add, "as appropriate" to R1.3 is a concern. We understand the SDT's intent to not require all the bulleted parties to be notified for every event type. But will a good faith effort on the part of the registered entity to deem appropriateness be subject to second guessing and possible sanctions by the Compliance Enforcement Authority if they disagree? We note that CIP-001 required an interpretation to address this issue, but cannot assume that interpretation will carry over. We suggest spelling out exactly who shall deem appropriateness. Part 1.3 (now Part 1.2 was revised to: 1.2 A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies. R4 continues to be an onerous requirement for smaller entities. Verification was not part of the SAR and we are not convinced it is needed for reliability. We are unsure how a DP with no generation, no BES assets, no Critical Cyber Assets, and less than 100 MW of load; would meet R4. Shall they drill for impossible events? We ask that R4 be removed. At a minimum it should exclude entities that cannot experience the events of Attachment 1. Entities that cannot experience the events of Attachment 1should likewise be exempt from R1.2, 1.3, R2, and R3. *Part 1.1 has been revised to include "applicable events listed in EOP-004, Attachment*

Organization	Yes or No	Question 4 Comment
		1." If an entity cannot experience an event, then it would not be an applicable event. *Requirement R4 (now R3) has been revised to:* *R3. Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]* *The DSR SDT envisions that the testing under R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see Part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated. This language does not preclude the verification of contact information taking place during a training event.*
Response: Thank you for your comment. Please see response above.		
FEUS		R4 requires verification through a drill or exercise the communication process created as part of R1.3. Clarification of what a drill or exercise should be considered. In order to show compliance to R4 would the entity have to send a pseudo event report to Internal Personnel, the Regional Entity, NERC ES-ISAC, Law Enforcement, and Governmental or provincial agencies listed in R1.3 to verify the communications plan? It would not be a burden on the entity so much, however, I'm not sure the external parties want to be the recipient of approximately 2000 psuedo event reports annually. *Requirement R4 (now R3) related to an annual test of the communication portion of Requirement R1 by a drill or exercise and this has been removed. Requirement R1, R3 now reads: "Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2."The DSR SDT envisions that the testing under Requirement 3 will include*

Organization	Yes or No	Question 4 Comment
		verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see Part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated. This language does not preclude the verification of contact information taking place during a training event. Attachment 1: BES equipment is too vague - consider changing to BES facility and including that reduces the reliability of the BES in the footnote. Is the footnote an and or an or?Attachment 1: Version 5 of CIP Requirements remove the terms Critical Asset and Critical Cyber Asset. The drafting team should consider revising the table to include BES Cyber Systems. Clarify if Damage or Destruction is physical damage (aka - cyber incidents would be part of CIP-008.) *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* Attachment 1: Unplanned Control Center evacuation - remove "potential" from the reporting responsibility *The DSR SDT has removed both "fuel supply emergency" and "other" from Attachment 2.* Attachment 2 - 3: change to, "Did the event originate in your system?" The requirement only requires reporting for Events - not potential events. *The DSR SDT has streamlined Attachment 2, per comments received.*

Organization	Yes or No	Question 4 Comment
		Attachment 2 4: "Damage or Destruction to BES equipment" should be "Destruction of BES Equipment" like it is in Attachment 1 and "forced intrusion risk to BES equipment" remove "risk" *The DSR SDT has streamlined Attachment 2 to reflect the events of Attachment 1, per comments received.*
Response: Thank you for your comment. Please see response above.		
ReliabilityFirst		ReliabilityFirst thanks the SDT for their effort on this project. ReliabilityFirst has a number of concerns/questions related to the draft EOP-004-2 standard which include the following:1. General Comment - The SDT should consider any possible impacts that could arise related to the applicability of Generator Owners that may or may not own transmission facilities. This will help alleviate any potential or unforeseen impacts on these Generator Owners *The DSR SDT cannot apply items such as GO/TO issues when NERC and the Regions are not in agreement to what the issue and solution is.* 2. General Comment - Though the rationale boxes contain useful editorial information for each requirement, they should rather contain the technical rationale or answer the question "why is this needed" for each requirement. The rationale boxes currently seem to contain suggestions on how to meet the requirements. ReliabilityFirst suggests possibly moving some of the statements in the "Guideline and Technical Basis" into the rationale boxes, as some of the rationale seems to be contained in that section. *The DSR SDT will continue to update rationale boxes per comments received.* 3. General comment - The end of Measure M4 is incorrectly pointing to R3. This should refer to R4. *Measurement 4 has been corrected.* 4. General Comment - ReliabilityFirst recommends the "Reporting Hierarchy for

Organization	Yes or No	Question 4 Comment
		Reportable Events" flowchart should be removed from the "Background" section and put into an appendix. ReliabilityFirst believes the flowchart is not really background information, but an outline of the proposed process found in the new standard. *The DSR SDT provided a flow chart for stakeholders to use if desired. EOP-004-2 sets a minimum level of reporting per the events described in Attachment 1. The DSR SDT has received negative feedback in past drafts, the DSR SDT was too prescriptive.* 5. Applicability Comment - ReliabilityFirst questions the newly added applicability for both the Regional Entity (RE) and ERO. Standards, as outlined in many, if not all, the FERC Orders, should have applicability to users, owners and operators of the BES and not to the compliance monitoring entities (e.g. RE and ERO). Any requirements regarding event reporting for the RE and ERO should be dealt with in the NERC Rules of Procedure and/or Regional Delegation Agreements. It is also unclear who would enforce compliance on the ERO if the ERO remains an applicable entity. *The ERO is an Applicable Entity under the current version of CIP-008 and therefore they are held to EOP-004-2. Note, this proposed Standard has been through two Quality Reviews and there has been no rejection from NERC .* 6. Requirement Comment - ReliabilityFirst believes the process for communicating events in Requirement R1, Part 1.3 should be all inclusive and therefore include the bullet points. Bullet points are considered to be "OR" statements and thus ReliabilityFirst believes they should be characterized as sub-parts. Listed below is an example:1.3. A process for communicating events listed in Attachment 1 to the following:1.3.1 Electric Reliability Organization, 1.3.2 Responsible Entity's Reliability Coordinator 1.3.3 Internal company personnel 1.3.4 The Responsible Entity's Regional Entity 1.3.5 Law enforcement 1.3.6 Governmental or provincial agencies *Requirement R4 related to an annual test of the communication portion of Requirement R1 by a drill or exercise and this has been removed. Requirement R3 now reads: "Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in*

Organization	Yes or No	Question 4 Comment
		Part 1.2. ". The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see Part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated. 7. Requirement Comment - ReliabilityFirst questions why Requirement R1, Part 1.1 and Part 1.2 are not required to be verified when performing a drill or exercise in Requirement R4? ReliabilityFirst believes that performing a drill or exercise utilizing the process for identifying events (Part 1.1) and the process for gathering information (Part 1.2) are needed along with the verification of the process for communicating events as listed in Part 1.3. *Requirement R4 related to an annual test of the communication portion of Requirement R1 by a drill or exercise and this has been removed. Requirement R3 now reads: "Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2. ". The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see Part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.* 8. Compliance Section Comment - Section 1.1 states "If the Responsible Entity works for the Regional Entity..." and ReliabilityFirst questions the intent of this language. ReliabilityFirst is unaware of any Responsible Entities who work for a Regional Entity. Also, if the Regional Entity and ERO remain as applicable entities, in Section 1.1 of

Organization	Yes or No	Question 4 Comment
		the standard, it is unclear who will act as the Compliance Enforcement Authority (CEA). *The DSR SDT has followed the guidance in the Standards Development process to assure that "template" information is correct. The language included is directly from NERC guideline documents* 9. Compliance Section Comment - ReliabilityFirst recommends removing the second, third and fourth paragraphs from Section 1.2 since ReliabilityFirst believes entities should retain evidence for the entire time period since their last audit. *The DSR SDT has followed the guidance in the Standards Development process to assure that "template" information is correct. The language included is directly from NERC guideline documents* 10. Compliance Section Comment - ReliabilityFirst recommends modifying the fifth paragraph from Section 1.2 as follows: "If a Registered Entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or until a data hold release is issued by the CEA." ReliabilityFirst believes, as currently stated, the CEA would be required to retain information for an indefinite period of time. *The DSR SDT has followed the guidance in the Standards Development process to assure that "template" information is correct. The language included is directly from NERC guideline documents.* 11. Compliance Section Comment - ReliabilityFirst recommends removing the sixth paragraph from Section 1.2 since the requirement for the CEA to keep the last audit records and all requested and submitted subsequent audit records is already covered in the NERC ROP. *The DSR SDT has followed the guidance in the Standards Development process to assure that "template" information is correct. The language included is directly from*

Organization	Yes or No	Question 4 Comment
		NERC guideline documents 12. Attachment 1 Comment - It is unclear what the term/acronym "Tv" is referring to. It may be beneficial to include a footnote clarifying what the term "Tv" stands for. *Tv is based on FAC-010 and the DSR SDT believes that this is clear to affected stakeholders.* 13. VSL General Comment - although ReliabilityFirst believes that the applicability is not appropriate, as the REs and ERO are not users, owners, or operators of the Bulk Electric System, the Regional Entity and ERO are missing from all four sets of VSLs, if the applicability as currently written stays as is. If the Regional Entity and ERO are subject to compliance for all four requirements, they need to be included in the VSLs as well. Furthermore, for consistency with other standards, each VSL should begin with the phrase "The Responsible Entity..." *The DSR SDT will follow the guidance in the Standards Development process to assure that "template" information is correct.* 14. VSL 4 Comment - The second "OR" statement under the "Lower" VSL should be removed. By not verifying the communication process in its Operating Plan within the calendar year, the responsible entity completely missed the intent of the requirement and is already covered under the "Severe" VSL category. *The DSR SDT will follow the guidance in the Standards Development process to assure that "template" information is correct.*
Response: Thank you for your comment. Please see response above.		
Northeast Power Coordinating		Requirement 4 does not specifically state the details necessary for an entity to

Organization	Yes or No	Question 4 Comment
Council		achieve compliance. Requirement 4 should provide more guidance as to what is required in a drill. Audit/enforcement of any requirement language that is too broad will potentially lead to Regional interpretation, inconsistency, and additional CANs.R4 should be revised to delete the 15 month requirement. CAN-0010 recognizes that entities may determine the definition of annual.The standard is too specific, and drills down into entity practices, when the results are all that should be looked for.The standard is requiring multiple reports. *Requirement R4 related to an annual test of the communication portion of Requirement R1 by a drill or exercise and this has been removed. Requirement R3 now reads: "Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2. ". The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see Part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.* The Purpose of the Standard is very broad and should be revised because some of the events being reported on have no impact on the BES. Revise Purpose wording as follows: To improve industry awareness and the reliability of the Bulk Electric System "by requiring the reporting of major system events with the potential to impact reliability and their causes..." on the Bulk Electric System it can be said that every event occurring on the Bulk Electric System would have to be reported. *The DSR SDT revised the purpose statement to remove ambiguous language "with the potential to impact reliability". The Purpose statement now reads:* *"To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities."*

Organization	Yes or No	Question 4 Comment
		Referring to Requirement R4, the testing of the communication process is the responsibility of the Responsible Entity. There is an event analysis process already in place.The standard prescribes different sets of criteria, and forms.There should be one recipient of event information. That recipient should be a "clearinghouse" to ensure the proper dissemination of information. *EOP-004 is a standard that requires reporting of events to the ERO. The events analysis program receives these reports and determines whether further analysis is appropriate.* Why is this standard applicable to the ERO? *NERC as the ERO is currently a Responsible Entity under CIP-008, and therefore the proposed EOP-004-2 has the ERO as a Responsible Entity.* Requirement R2 is not necessary. It states the obvious.Requirements R2 and R3 are redundant.The standard mentions collecting information for Attachment 2, but nowhere does it state what to do with Attachment 2. *Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2 based on stakeholder comments and revised R3 (now R2) to:* *"Requirement R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment 1."*

Organization	Yes or No	Question 4 Comment
		None of the key concepts identified on page 5 of the standard are clearly stated or described in the requirements: o Develop a single form to report disturbances and events that threaten the reliability of the bulk electric system. *OE-417, as well as, the EAWG's requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004. Note you may have to report the same event more quickly to the DOE than is required by EOP-004, but this cannot be helped due to bullet point 2 above.* o Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements. o Establish clear criteria for reporting. o Establish consistent reporting timelines. *The DSR SDT does allow entities to use the DOE Form OE 417 in lieu of Attachment 2 to report an event. Attachment 1 has been updated to provide consistent criteria for reporting as well as reporting timelines. All one hour reporting timelines have been changed to 24 hours with the exception of a 'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673:*

Organization	Yes or No	Question 4 Comment
		"…direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…" *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1.* o Provide clarity for who will receive the information and how it will be used. The standard's requirements should be reviewed with an eye for deleting those that are redundant, or do not address the Purpose or intent of the standard. *Requirement R1 has been updated and now reads as"* *Each Responsible Entity shall have an Operating Plan that includes:* *1.1. A process for recognizing each of the events listed in EOP-004 Attachment 1.* *1.2. A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies.* *The Applicable Entity's Operating Plan is to contain the process for reporting events listed in Attachment 1 to the Electric Reliability Organization, the Responsible Entity's Reliability Coordinator and for communicating to others as defined in the Responsible Entity's Operating Plan. All events in Attachment 1 are required to be reported to the Electric Reliability Organization and the Responsible Entity's Reliability Coordinator. The Operating Plan may include: internal company personnel, your Regional Entity, law enforcement, and governmental or provisional agencies, as you identify within your Operating Plan. This gives you the flexibility to tailor your Operating Plan to fit your*

Organization	Yes or No	Question 4 Comment
		company's needs and wants.
Response: Thank you for your comment. Please see response above.		
American Public Power Association		Requirement R1:1.3. A process for communicating events listed in Attachment 1 to the Electric Reliability Organization, the Responsible Entity's Reliability Coordinator and the following as appropriate: o Internal company personnel o The Responsible Entity's Regional Entity o Law enforcement o Governmental or provincial agencies APPA believes that including the list of other entities needing to be included in a process for communicating events under 1.3 may open this requirement up for interpretation. APPA requests that the SDT remove from the requirement the listing of; "Internal company personnel, The Responsible Entity's Regional Entity, Law enforcement & Governmental or provincial agencies" and include these references in a guidance document. The registered entities need to communicate with the ERO and the RC if applicable for compliance with this standard and to maintain the reliability of the BES. Communication with other entities such as internal company personnel, law enforcement and the Regional Entity are expected, but do not impact the reliability of the BES. This will simplify the reporting structure and will not be burdensome to registered entities when documenting compliance. If this is not an acceptable solution, APPA suggests revising 1.3 to remove the wording "the following as appropriate" and add "other entities as determined by the Responsible Entity. Examples of other entities may include, but are not limited to:" Then it is clear that the list is examples and should not be enforced by the auditor. *Requirement R1 has been updated and now reads as* *"Each Responsible Entity shall have an Operating Plan that includes:* *1.1. A process for recognizing each of the events listed in EOP-004 Attachment 1.* *1.2. A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004*

Organization	Yes or No	Question 4 Comment
		Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies. *The Applicable Entity's Operating Plan is to contain the process for reporting events listed in Attachment 1 to the Electric Reliability Organization, the Responsible Entity's Reliability Coordinator and for communicating to others as defined in the Responsible Entity's Operating Plan. All events in Attachment 1 are required to be reported to the Electric Reliability Organization and the Responsible Entity's Reliability Coordinator. The Operating Plan may include: internal company personnel, your Regional Entity, law enforcement, and governmental or provisional agencies, as you identify within your Operating Plan. This gives you the flexibility to tailor your Operating Plan to fit your company's needs and wants.* 1.4. Provision(s) for updating the Operating Plan within 90 calendar days of any change in assets, personnel, other circumstances that may no longer align with the Operating Plan; or incorporating lessons learned pursuant to Requirement R3. APPA understands that the SDT is following the FERC order requiring a 90 day limit on updates to any changes to the plan. However, APPA believes that "updating the Operating Plan within 90 calendar days of any change..." is a very burdensome compliance documentation requirement. APPA reminds the SDT that including DPs in this combined standard has increased the number of small Responsible Entities that will be required to document compliance. APPA requests that the SDT combine requirement 1.4 and 1.5 so the Operating Plan will be reviewed and updated with any changes on a yearly basis. If this is not an acceptable solution, APPA suggests that the "Lower VSL" exclude a violation to 1.4. The thought being, a violation of 1.4 by itself is a documentation error and should not be levied a penalty. *Requirement 1, Part 1.4 has been removed from the standard.* Attachment 1: Events TableAPPA believes that the intent of the SDT was to mirror the DOE OE-417 criteria in reporting requirements. With the inclusion of DP in the

Organization	Yes or No	Question 4 Comment
		Applicability, however, APPA believes the SDT created an unintended excessive reporting requirement for DPs during insignificant events. *Attachment 1 is the basis for EOP-004-2; it contains the events and thresholds for reporting. OE-417, as well as, the EAWG's requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004. Note you may have to report the same event more quickly to the DOE than is required by EOP-004, but this cannot be helped due to bullet point 2 above.* APPA recommends that a qualifier be added to the events table. In DOE OE-417 local electrical systems with less than 300MW are excluded from reporting certain events since they are not significant to the BES. APPA believes that the benefit of reporting certain events on systems below this value would not outweigh the compliance burden placed on these small systems. Therefore, APPA requests that the standard drafting team add the following qualifier to the Events Table of Attachment 1: "For systems with greater than 300MW peak load." This statement should be placed in the Threshold for Reporting column for the following Events: BES Emergency requiring appeal for load reduction, BES

Organization	Yes or No	Question 4 Comment
		Emergency requiring system-wide voltage reduction, BES Emergency requiring manual firm load shedding, BES Emergency resulting in automatic firm load shedding. This will match the DOE OE-417 reporting criteria and relieve the burden on small entities. *Upon review of the DOE OE 417, it states "Local Utilities in Alaska, Hawaii, Puerto Rico, the U.S. Virgin Islands, and the U.S. Territories - If the local electrical system is less than 300 MW, then only file if criteria 1, 2, 3 or 4 are met". Please be advised this exception applies to entities outside the continental USA.* *The DSR SDT has tried to minimize duplicative reporting, but recognizes there may be events that trigger more than one report. The current applicability ensures an event that could affect just one of the entities with reporting responsibility isn't missed.* Definition of "Risk to BES equipment":The SDT attempted to give examples of the Event category "Risk to BES equipment" in a footnote. This footnote gives the Responsible Entity and the Auditor a lot of room for interpretation. APPA suggests that the SDT either define this term or give a triggering mechanism that the industry would understand. One suggestion would be "Risk to BES equipment: An event that forces a Facility Owner to initiate an unplanned, non-standard or conservative operating procedure." Then list; "Examples include train derailment adjacent to BES Facilities that either could have damaged the equipment directly or has the potential to damage the equipment..." This will allow the entity to have an operating procedure linked to the event. If this suggestion is taken by the SDT then the Reporting column of Attachment 1 needs to be changed to: "The parties identified pursuant to R1.3 within 1 hour of initiating conservative operating procedures." *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and*

Organization	Yes or No	Question 4 Comment
		determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. Also, the footnote only contains examples.
Response: Thank you for your comment. Please see response above.		
Western Electricity Coordinating Council		Results-based standards should include, within each requirement, the purpose or reason for the requirement. The requirements of this standard, while we support the requirements, do not include the goal or proupose of meeting each stated requirement. The Measures all include language stating “the responsible entity shall provide...”. During a quality review of a WECC Regional Reliability Standard we were told that the “shall provide” language is essentially another requirement to provide something. If it is truly necessary to provide this it should be in the requirements. It was suggested to us that we drop the “shall provide” language and just start each Measure with the “Evidence may include but is not limited to...”. *The DSR SDT changed each instance of “shall” to “will” within the measures. We will defer to NERC Quality Review comments for any additional revisions.*
Response: Thank you for your comment. Please see response above.		
Sacramento Municipal Utility District (SMUD)		SMUD and BANC agree with the revised language in EOP-004-1 requirements, but we have identified the following issues in A-1:We commend the SDT for properly addressing the sabotage issue. However, additional confusion is caused by introducing term "damage". As "damage" is not a defined term it would be beneficial for the drafting team to provide clarification for what is meant by "damage".

Organization	Yes or No	Question 4 Comment
		The DSR SDT has modified Attachment 1 to bring more clarity. The more subjective events were rewritten as follows: • *The 'Damage or Destruction' event category has been revised to say ' to a Facility', (a defined term) and thresholds have be modified to provide clarity. The footnote was deleted* • *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. Also, the footnote only contains examples.* *These two remaining event categories that aren't related to power system phenomena are essential as they effectively translate the intent of CIP-001 into EOP-004.* *As discussed in prior comment forms, the DSR SDT has elected not to define "sabotage". As defined in an Entity's operating Plan, the requirement is to report and communicate an event as listed in Attachment 1. EOP-004-2 does not require analysis of any event listed in Attachment 1.* The threshold for reporting "Each public Appeal for load reduction" should clearly state the triggering is for the BES Emergency as routine "public appeal" for conservation could be considered a threshold for the report triggering. *To clarify your point, the threshold has been changed to 'Public appeal or load reduction event'.*

Organization	Yes or No	Question 4 Comment
		Regarding the SOL Violations in Attachment 1 the SOL Violations should only be those that affect the WECC paths. *The DSR SDT has included the following language for WECC's SOL violation in Attachment 1:* *"IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)"* The SDT made attempts to limit nuisance reporting related to copper thefts and so on which is supported. However a number of the thresholds identified in EOP-004-2 Attachment 1 are very low and could congest the reporting process with nuisance reporting and reviewing. *The DSR SDT made reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary.*
Response: Thank you for your comment. Please see response above.		
Southern Comnpany		Southern has the following comments:(1) In Requirement R1.4, we request the SDT to clarify what is meant by the term "assets"? *The DSR SDT has deleted Requirement R1, Part 1.4, thus "assets" is not contained in EOP-004-2 based on comments received.* 2) If requirement 4 is not deleted, should we have to test every possible event described in our Operating Plan or each event listed in Attachment 1 to verify communications? *The DSR SDT has deleted Requirement R4 based on comments received.* (3) In the last paragraph of the "Summary of Key Concepts" section on page 6 of

Organization	Yes or No	Question 4 Comment
		Draft 3, there is a statement that "Real-time reporting is achieved through the RCIS..." The only reporting required on RCIS by the Standards is for EEAs and TLRs. Please review and modify this language as needed. *The DSR SDT believes "The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in Attachment 1. Real-time reporting is achieved through the RCIS and is covered in other standards (e.g. the TOP family of standards). The proposed standard deals exclusively with after-the-fact reporting" is correct.* (4) Evidence Retention (page 12 of Draft 3): The 3 calendar year reference has no bearing on a Standard that may be audited on a cycle greater than 3 years. *The DSR SDT has updated the Evidence Retention section with standard language provided by NERC staff.* (5) In the NOTE for Attachment 1 (page 20 of Draft 3), what is meant by "periodic verbal updates" and to whom should the updates be made? *The DSR SDT has updated the note in question to remove the language of "periodic verbal updates", it now reads as:* *"NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the table below. In such cases, the affected Responsible Entity shall notify parties per R1 and provide as much information as is available at the time of the notification. Reports to the ERO should be submitted to one of the following: e-mail: esisac@nerc.com, Facsimile: 609-452-9550, Voice: 609-452-1422."* (6) There are Prerequisite Approvals listed in the Implementation Plan. Is it appropriate to ask industry to vote on this Standard Revision that has a prerequisite approval of changes in the Rules of Procedure that have not been approved? *The proposed revisions to the Rules of Procedure should have been posted with the*

Organization	Yes or No	Question 4 Comment
		standard. This posting will occur with the successive ballot of EOP-004-2. (7) We believe the reporting of the events in Attachment 1 has no reliability benefit to the Bulk Electric System. We suggest that Attachment 1 should be removed. *The DSR SDT disagrees with this comment. Attachment 1 is the minimum set of events that will be required to report and communicate per your Operating Plan will be aware of system conditions.*
Response: Thank you for your comment. Please see response above.		
Texas Reliability Entity		Substantive comments:1.ERO and Regional Entities should not be included in the Applicability of this standard. Just because they may be subject to some CIP requirements does not mean they also have to be included here. The ERO and Regional Entities do not operate equipment or systems that are integral to the operation of the BES. Also, none of the VSLs apply to the ERO or to Regional Entities. *The DSR SDT is following guidance that NERC has provided to the DSR SDT. The ERO and the RE are applicable entities under CIP-008. Reporting of Cyber Security Incidents is the responsibility of the ERO and the RE.* 2.The first entry in the Events Table should say “Damage or destruction of BES equipment.” Equipment may be rendered inoperable without being “destroyed,” and entities should not have to determine within one hour whether damage is sufficient to cause the equipment to be considered “destroyed.” Footnote 1 refers to equipment that is “damaged or destroyed.” *The ‘Damage or Destruction’ event category has been revised to say ‘to a Facility’, (a defined term) and thresholds have be modified to provide clarity.* *The DSR SDT used the defined term “Facility” to add clarity for several events listed in*

Organization	Yes or No	Question 4 Comment
		Attachment 1. A Facility is defined as: *"A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)"* *The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.* 3.In the Events Table, consider whether the item for "Voltage deviations on BES facilities" should also be applicable to GOPs, because a loss of voltage control at a generator (e.g. failure of an automatic voltage regulator and power system stabilizer) could have a similar impact on the BES as other reportable items. *The DSR SDT disagrees with this comment. Attachment 1 is the minimum set of events that will be required to report and communicate per your Operating Plan will be aware of system conditions.* 4.In the Events Table, under Transmission Loss, does this item require that at least three Facilities owned by one entity must be lost to trigger the reporting requirement, or is the reporting requirement also to be triggered by loss of three Facilities during one event or occurrence that are owned by two or three different entities? *The DSR SDT has stated in Attachment 1 that "Each TOP that experiences the transmission loss". This would mean per individual TOP.* 5.In the Events Table, under Transmission Loss, it is unclear how Facilities are to be counted to determine when "three or more" Facilities are lost. In the NERC Glossary, Facility is ambiguously defined as "a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)." In many cases, a "set of electrical equipment" can be selected and counted in different ways, which makes this item ambiguous.

Organization	Yes or No	Question 4 Comment
		Both Transmission and Facilities are defined terms and the DSR SDT feels this gives sufficient direction. 6.In the Events Table, under Transmission Loss, it appears that a substation bus failure would only count as a loss of one Facility, even though it might interrupt flow between several transmission lines. We believe this type of event should be reported under this standard, and appropriate revisions should be made to this entry. *The DSR SDT used the defined term "Facility" to add clarity for this event as well as other events in Attachment 1. A Facility is defined as:* *"A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)"* *The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.* 7.In the Events Table, under Transmission Loss, consider including generators that are lost as a result of transmission loss events when counting Facilities. For example, if a transmission line and a transformer fail, resulting in a generator going off-line, that should count as a loss of "three or more" facilities and be reportable under this standard. *Attachment 1 is the minimum set of events that will be required to report and communicate per your Operating Plan will be aware of system conditions.* 8.In the Events Table, under "Unplanned Control Center evacuation" and "Loss of monitoring or all voice communication capability," GOPs should be included. GOPs also operate control centers that would be subject to these kinds of occurrences. *Attachment 1 is the minimum set of events that will be required to report and*

Organization	Yes or No	Question 4 Comment
		communicate per your Operating Plan will be aware of system conditions. 9.In the Events Table, under "Loss of monitoring or all voice communication capability," we suggest adding that if there is a failure at one control center, that event is not reportable if there is a successful failover to a backup system or control center. *The DSR SDT has split this event into two separate events based on comments received, it now reads as: "Loss of all voice communication capability" and "Complete or partial loss of monitoring capability".* 10."Fuel supply emergency" is included in the Event Reporting Form, but not in Attachment 1, so there is no reporting threshold or deadline provided for this type of event. *Attachment 2 was updated to reflect the revisions to Attachment 1. The reference to "actual or potential events" was removed. Also, the event type of "other" and "fuel supply emergency" was removed as well.* Clean-up items:1.In R1.5, capitalize "Responsible Entity" and lower-case "process". *The DSR SDT has deleted Requirement 1, part 1.5.* 2.In footnote 1, add "or" before "iii)" to clarify that this event type applies to equipment that satisfies any one of these three conditions. *All footnotes are deleted and appropriate content moved to 'Thresholds for Reporting' with the exception of the footnote relating to the new event category 'A physical threat that could impact the operability of a Facility'. This remaining footnote provides examples only.* 3.In the Event Reporting Form, "forced intrusion" and "Risk to BES equipment" are run together and should be separated. *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new*

Organization	Yes or No	Question 4 Comment
		event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. VSLs:1.We support the substance of the VSLs, but the repeated long list of entities makes the VSLs extremely difficult to read and decipher. The repeated list of entities should be replaced by "Responsible Entities." 2.If the ERO and Regional Entities are to be subject to requirements in this standard (which we oppose), they need to be added to the VSLs. *The DSR SDT has revised the VSLs to eliminate the list of entities and lead with "Responsible Entity".*
Response: Thank you for your comment. Please see response above.		
		Suggest removing 1.4 since 1.5 ensures a annual review. . The implementation of the plan should also include the necessary reporting. *Requirement R1, Part 1.4 has been removed.*
Response: Thank you for your comment. Please see response above.		
Electric Compliance		The concepts of "Critical Assets" and "Critical Cyber Assets" no longer exist in Version 5 of the CIP Standards and so this may cause confusion. Recommend modifying to be in accordance with Version 5. Additionally, it is debatable whether the

Organization	Yes or No	Question 4 Comment
		destruction of, for example, one relay would be a reportable incident given the proposed language. We recommend modifying the language to insure nuisance reporting is minimized. One reportable event is, "Risk to the BES" and the threshold for reporting is, "From a non-environmental physical threat." This appears to be a catch-all reportable event. Due to the subjectivity of this event description, we suggest removing it from the list. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as stakeholders pointed out that these events were adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility "reporting thresholds. CIP-008 addresses Cyber Security Incidents which are defined as:* *"Any malicious act or suspicious event that:* *• Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or,* *• Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset."* *A Critical Asset is defined as:* *"Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System."* *Since there is an existing event category for damage or destruction of Facilities, having a separate event for "Damage or Destruction of a Critical Asset" is unnecessary.* Footnote 1 and the "Threshold for Reporting" associated with the Event described as "Destruction of BES equipment" expand the reporting scope. For example, a fan on a

Organization	Yes or No	Question 4 Comment
		transformer can be destroyed because a technician drops a screwdriver into it. We believe such an event should not be reportable under EOP-004-2. Yet, as written, a Responsible Entity could interpret that event as reportable (because it would be “unintentional human action” that destroyed a piece of equipment associated with the BES). If the goal of the SDT was to include such events, we think the draft Standard goes too far in requiring reporting. If the SDT did not intend to include such events, the draft Standard should be revised to make that fact clear. Proposed Footnote: BES equipment that become damaged or destroyed due to intentional or unintentional human action which removes the BES equipment from service that i) Affects an IROL; ii) Significantly affects the reliability margin of the system (e.g., has the potential to result in the need for emergency actions); iii). Do not report copper theft from BES equipment unless it degrades the ability of equipment to operate correctly (e.g., removal of grounding straps rendering protective relaying inoperative). *All footnotes are deleted and appropriate content moved to ‘Thresholds for Reporting’ with the exception of the footnote relating to the new event category ‘A physical threat that could impact the operability of a Facility’. This remaining footnote provides examples only.* The word “Significantly” in item ii) of footnote 1 and “as appropriate” in section 1.3 introduces elements of subjectivity. What is “significant” or “appropriate” to one person may not be to someone else. *All footnotes are deleted and appropriate content moved to ‘Thresholds for Reporting’ with the exception of the footnote relating to the new event category ‘A physical threat that could impact the operability of a Facility’. This remaining footnote provides examples only.* In section 1.4, we believe that revising the plan within 90 days of “any” change should be changed to 180 days or else classes of events should be made so that only

Organization	Yes or No	Question 4 Comment
		substantial changes are required to made within the 90 day timeframe. *Requirement R1, Part 1.4 was removed from the standard.*
Response: Thank you for your comment. Please see response above.		
Georgia System Operations Corporation		The ERO and the Regional Entity should not be listed as Responsible Entities. The ERO and the Regional Entity should not have to meet the requirements of this standard, especially reporting to itself. *The ERO and the RE are applicable under the CIP-008 standard and are therefore applicable under EOP-004.* Attachment 1 (all page numbers are from the clean draft):Page 20, destruction of BES equipment: part iii) of the footnote adds damage as an event but the heading is for destruction. Is it just for destruction? Or is it for damage or destruction? *The DSR SDT has modified Attachment 1 to bring more clarity. The 'Destruction' event category has been revised to include damage or destruction of a Facility', (a defined term) and thresholds have be modified to provide clarity. The footnote was deleted* Page 21, Risk to BES equipment: Footnote 3 gives an example where there is flammable or toxic cargo. These are environmental threats. However, the threshold for reporting is for non-environmental threats. Which is it? *For this event, environmental threats are considered to be severe weather, earthquakes, etc. rather than an external threat.* Page 21, BES emergency requiring public appeal for load reduction: A small deficient

Organization	Yes or No	Question 4 Comment
		entity within a BA may not initiate public appeals. The BA is typically the entity which initiates public appeals when the entire BA is deficient. The initiating entity should be the responsible entity not the deficient entity. *The DSR SDT revised this event to indicate the "initiating" entity is responsible for reporting.* Page 21, BES emergency requiring manual firm load shedding: If a RC directs a DP to shed load and the DP initiates manually shedding its load as directed, is the RC the initiating entity? Or is it the DP? *The DSR SDT believes the wording of "initiating entity" provides enough clarity for each applicable entity to understand. In this case, the RC made the call to shed load and therefore should report.* Page 22, system separation (islanding): a DP does not have a view of the system to see that the system separated or how much generation and load are in the island. Remove DP. *The DSR SDT disagrees with your comment. DP's may be the first to recognize that they are islanded or separated from the system.* Attachment 2 (all page numbers are from the clean draft):Page 25: fuel supply emergencies will no longer be reportable under the current draft. *The DSR SDT has removed both "fuel supply emergency" and "other" from Attachment 2 based on comments received.* Miscellaneous typos and quality issues (all page numbers are from the clean draft):Page 5, the last paragraph: There are two cases where Parts A or B are referred to. Attachment 1 no longer has two parts (A & B).Page 27, Discussion of Event Reporting: the second paragraph has a typo at the beginning of the sentence.

Organization	Yes or No	Question 4 Comment
		The DSR SDT has corrected these typos.
Response: Thank you for your comment. Please see response above.		
Thompson Coburn LLP on behalf of Miss. Delta Energy Agency		The first three incident categories designated on Attachment 1 as reportable events should be modified. As the Standard is current drafted, each incident category (i.e., destruction of BES equipment, damage or destruction of Critical Assets, and damage or destruction of Critical Cyber Assets) requires reporting if the event was due to unintentional human action. For example, under the reporting criteria as drafted, inadvertently dropping and damaging a piece of computer equipment designated as a Critical Cyber Asset while moving or installing it would appear to require an event report within an hour of the incident. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as stakeholders pointed out that these events were adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility "reporting thresholds. CIP-008 addresses Cyber Security Incidents which are defined as:* *"Any malicious act or suspicious event that:* *• Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or,* *• Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset."* *A Critical Asset is defined as:* *"Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System."*

Organization	Yes or No	Question 4 Comment
		Since there is an existing event category for damage or destruction of Facilities, having a separate event for "Damage or Destruction of a Critical Asset" is unnecessary. MDEA requests that the Drafting Team consider modifying footnote 1 and each of the first three event categories to reflect that reportable events include only those that (i) affect an IROL; (ii) significantly affect the reliability margin of the system; or (iii) involve equipment damage or destruction due to intentional human action that results in the removal of the BES equipment, Critical Assets, and/or Critical Cyber Assets, as applicable, from service. *All footnotes are deleted and appropriate content moved to 'Thresholds for Reporting' with the exception of the footnote relating to the new event category 'A physical threat that could impact the operability of a Facility'. This remaining footnote provides examples only.* Footnote 2 (which now pertains only to the fourth incident category - forced intrusions) should also apply to the first three event categories. Specifically, responsible entities should report intentional damage or destruction of BES equipment, damage or destruction of Critical Assets, and damage or destruction of Critical Cyber Assets if either the damage/destruction was clearly intentional or if motivation for the damage or destruction cannot reasonably be determined and the damage or destruction affects the reliability of the BES. *All footnotes are deleted and appropriate content moved to 'Thresholds for Reporting' with the exception of the footnote relating to the new event category 'A physical threat that could impact the operability of a Facility'. This remaining footnote provides examples only.* Attachment 1 is also unclear to the extent that the incident category involving reports for the detection of reportable Cyber Security Incidents includes a reference to CIP-008 as the reporting threshold. While entities in various functional categories

Organization	Yes or No	Question 4 Comment
		(i.e., RCs, BAs, TOPs/TOs, GOPs/GOs, and DPs) are listed as being responsible for the reporting of such events, some entities in these functional categories may not currently be subject to CIP-008. If it is the Drafting Team's intent to limit event reports for Cyber Security Incidents to include only registered entities subject to CIP-008, that clarification should be incorporated into the listing of entities with reporting responsibility for this incident category in Attachment 1. *The "Entity with reporting responsibility" for the event "A reportable Cyber Security Incident" has been revised to "Each Responsible Entity applicable under CIP-008-4 or its successor that experiences the Cyber Security Incident".*
Response: Thank you for your comment. Please see response above.		
Luminant Power		The following comments all apply to Attachment 1: o As a general comment, SDT should specifically list the entities the reportable event applies to in the table for clarity. Do not use general language referencing another standard or statements such as "Deficient entity is responsible for reporting", "Initiating entity is responsible for reporting", or other similar statements used currently in the table. This leaves this open and subject to interpretation. *The DSR SDT disagrees with your comment. This language provides the most flexibility for applicable entities and maintains a minimum level of who is required to report or communicate events based an entity's Operating Plan, as described in Requirement 1.* Also, there are a number of events that do not apply to all entities. o Destruction of BES equipment should be Intentional Damage or Destruction of BES equipment. Unintentional actions occur and should not be a requirement for reporting under disturbance reporting. *The event for "Destruction of BES equipment" has been revised to "Damage or destruction of a Facility". The threshold for reporting information was expanded for*

Organization	Yes or No	Question 4 Comment
		clarity: *"Damage or destruction of a Facility that: affects an IROL* *OR* *Results in the need for actions to avoid an Adverse Reliability Impact* *OR* *Results from intentional human action."* o Actions or situations affecting equipment or generation unit availability due to human error, equipment failure, unintentional human action, external cause, etc. are reported in real time to the BA and other entities as required by other NERC Standards. Disturbance reporting should avoid the type of events that, for instance, would cause the total or partial loss of a generating unit under normal operational circumstances. There are a number of issues with the table in this regard. *The DSR SDT has removed such language based on comments received.* o For clarity, consider changing the table to identify for each event type "who" should be notified. This appears to be missing from the table overall. *The DSR SDT has updated Requirement R1, Part 1.2 to read as: ""1.2 A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies."* o Reportable Events, the meaning for the Event labeled "Destruction of BES equipment" is not clear. Footnote 1 adds the language "iii) Damaged or destroyed due to intentional or unintentional human action which removes the BES equipment

Organization	Yes or No	Question 4 Comment
		from service." This language can be interpreted to mean that any damage to any BES equipment caused by human action, regardless of intention, must be reported within 1 hour of recognition of the event. This requirement will be overly burdensome. If this is not the intent of the definition of "Destruction of BES equipment", the footnote should be re-worded. As such, it is subjective and left open to interpretation. It should focus only on intentional actions to damage or interrupt BES functionality. It should not be worded as such that every item that trips a unit or every item that is damaged on a unit requires a report. That is where the language right now is not clear. There are and will continue to be unintentional human error that results in taking equipment out of service. This standard was meant to replace sabotage reporting. *All footnotes are deleted and appropriate content moved to 'Thresholds for Reporting' with the exception of the footnote relating to the new event category 'A physical threat that could impact the operability of a Facility'. This remaining footnote provides examples only.* o Damage or destruction of Critical Asset per CIP-002 and Damage or destruction of a Critical Cyber Asset per CIP-002 should be removed from the table as Intentional Damage or Destruction of BES equipment would cover this as well. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as stakeholders pointed out that these events were adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility "reporting thresholds. CIP-008 addresses Cyber Security Incidents which are defined as:* *"Any malicious act or suspicious event that:* *• Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or,* *• Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber*

Organization	Yes or No	Question 4 Comment
		Asset." *A Critical Asset is defined as:* *"Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System."* *Since there is an existing event category for damage or destruction of Facilities, having a separate event for "Damage or Destruction of a Critical Asset" is unnecessary.* o Risk to BES equipment should be removed from the table as it is very subjective and broad. At a minimum, the 1 hour reporting timeline should begin after recognition and assessment of the incident. As an example, a fire close to BES equipment may not truly be a threat to the equipment and will not be known until an assessment can be made to determine the risk. *The DSR SDT has removed this event based on comments received.* o Detection of a Reportable Cyber Security incident should be removed from the table as this is covered by CIP-008 requirements. Having this in two separate standards is double jeopardy and confusing to entities. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as stakeholders pointed out that these events were adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility "reporting thresholds. CIP-008 addresses Cyber Security Incidents which are defined as:* *"Any malicious act or suspicious event that:*

Organization	Yes or No	Question 4 Comment
		• Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, *• Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset."* *A Critical Asset is defined as:* *"Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System."* *Since there is an existing event category for damage or destruction of Facilities, having a separate event for "Damage or Destruction of a Critical Asset" is unnecessary.* o Generation Loss event reporting should only apply to the BA. These authorities have the ability and right to contact generation resources to supply necessary information needed for reporting. This would also eliminate redundant reporting by multiple entities for the same event. *The DSR SDT has tried to minimize duplicative reporting, but recognizes there may be events that trigger more than one report. The current applicability ensures an event that could affect just one of the entities with reporting responsibility isn't missed.* o Suggest that Generation Loss MW loss would match up with the 1500 MW level identified in CIP Version 4 or Version 5 for consistency between future CIP standards and this disturbance reporting standard. This would then cover CIP and significant MW losses that should be reported. *The DSR SDT disagrees as this threshold is based on the current EOP-004-1.* o The Generation Loss MW loss amount needs to have a time boundary. Luminant

Organization	Yes or No	Question 4 Comment
		would suggest a loss of 1500 MW within 15 minutes. *The DSR SDT disagrees as this threshold is based on the current EOP-004-1.* o Unplanned Control Center evacuation should not apply to entities that have backup Control Centers where normal operations can continue without impact to the BES. *The DSR SDT disagrees with your comment. By reporting and communicating per an entity's Operating Plan, you will provide situational awareness to entities per your Operating Plan.* o Loss of monitoring or all voice communication capability should be separated. Also the 24 hour reporting requirement may not be feasible if communications is down for longer than 24 hours. *The DSR SDT has split this event into two separate events based on comments received, it now reads as: "Loss of all voice communication capability" and "Complete or partial loss of monitoring capability".* Luminant would suggest removal of the communication reporting event as there are a number of things that could cause this to occur for longer than the reporting requirement allows, thus putting entities at jeopardy of a potential violation that is out of their control. How does an entity report if all systems and communications are down for more than 24 hours? What about in instances of a partial or total blackout? These events could last much longer than 24 hours. All computer communication would likely also be down thus rendering electronic reporting unavailable. *EOP-004-2 only requires an entity to report and communicate per their Operating Plan within the time frames set in Attachment 1.*
Response: Thank you for your comment. Please see response above.		

Organization	Yes or No	Question 4 Comment
Kansas City Power & Light		The implementation plan indicates that much of CIP-008 is retained. The reporting requirements in CIP-008 and the required reportable events outlined in Attachment 1 are an overlap with CIP-008-3 R1.1 which says “Procedures to characterize and classify events as reportable Cyber Security Incidents” and CIP-008-3 R1.3 which requires processes to address reporting to the ES-ISAC. There is also a NERC document titled, Security Guideline for the Electricity Sector: Threat and Incident Reporting, which is a guideline to “assist entities to identify and classify incidents for reporting to the ES-ISAC”. The SDT should consider the content of the Security Guideline for the Electricity Sector: Threat and Incident Reporting when considering the reporting requirements proposed EOP-004. The efforts to incorporate CIP-008 into EOP-004 are insufficient and will result in serious confusion between proposed EOP-004 and CIP-008 and reporting expectations. Considering the complexity CIP incident reporting and the interests of ES-ISAC, it may be beneficial to leave CIP-008 out of the proposed EOP-004 and limit EOP-004 to the reporting interests of NERC. *Attachment 2 (or the DOE Form OE 417) is the reporting form to be used for reporting a “Cyber Security Incident”.* The flowchart states, “Notification Protocol to State Agency Law Enforcement”. Please correct this to, “Notification to State, Provincial, or Local Law Enforcement”, to be consistent with the language in the background section part, “A Reporting Process Solution - EOP-004”. *The DSR SDT has updated the “Example of reporting _Process including Law Enforcement”, and please note that this is only an “example”.* Measure 4 is not clear enough regarding the extent to which drills should be performed. Does the measure mean that all events in the events list need to be drilled or is drilling a subset of the events list sufficient? Please clearly indicate the extent of drilling that is required or clearly indicate in the requirement the extent of the drills to be performed is the responsibility of the Responsible Entity to identify in their “processes”.

Organization	Yes or No	Question 4 Comment
		Requirement R4 (now R3) has been revised and the measure now reads: *Each Responsible Entity will have dated and time-stamped records to show that the annual test of Part 1.2 was conducted. Such evidence may include, but are not limited to, dated and time stamped voice recordings and operating logs or other communication documentation. (R3)* Evidence Retention - it is not clear what the phrase "prior 3 calendar years" represents in the third paragraph of this section regarding data retention for requirements and measures for R2, R3, R4 and M2, M3, M4 respectively. Please clarify what this means. Is that different than the meaning of "since the last audit for 3 calendar years" for R1 and M1? *This has been revised for clarity and to be consistent with NERC Guidance documents. The new evidence retention reads:* *Each Responsible Entity shall retain the current, in force document plus the 'date change page' from each version issued since the last audit or the current and previous version for Requirements R1, R4 and Measures M1, M4.* *Each Responsible Entity shall retain evidence from prior 3 calendar years for Requirements R2, R3 and Measures M2, M3.* VSL for R2 under Severe regarding R1.1 may require revision considering the comment regarding R1.1 in item 2 previously stated. In addition, the VRF for R2 is MEDIUM. R2 is administrative regarding the implementation of the requirements specified in R1. Documentation and maintenance should be considered LOWER. There is no VSL for R4 and a VSL for R4 needs to be proposed. *The DSR SDT reviewed and updated both VSL's for the new requirements.*
Response: Thank you for your comment. Please see response above.		

Organization	Yes or No	Question 4 Comment
SPP Standards Review Group		The inclusion of optional entities to which to report events in R1.3 introduces ambiguity into the standard that we feel needs to be eliminated. We propose the following replacement language for R1.3:A process for communicating events listed in Attachment 1 to the Electric Reliability Organization, the Responsible Entity's Reliability Coordinator and the Responsible Entity's Regional Entity.We would also propose to incorporate the law enforcement and governmental or provincial agencies mentioned in R1.3 in Attachment 1 by adding them to the existing language for each of the event cells. For example, the first cell in that column would read:The parties identified pursuant to R1.3 and applicable law enforcement and governmental or provincial agencies within 1 hour of recognition of event.Similarly, the phrase '...and applicable law enforcement and governmental or provincial agencies...' should be inserted in all the remaining cells in the 4th column. *Requirement R1, Part 1.3 (now Part 1.2) was revised to add clarifying language by eliminating the phrase "as appropriate" and indicating that the Responsible Entity is to define its process for reporting and with whom to report events. Requirement R1,Part 1.2 now reads:* *"1.2 A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies."*
Response: Thank you for your comment. Please see response above.		
Santee Cooper		The on-going development of the definition of the BES could have significant impacts on reporting requirements associated with this standard.The event titled "Risk to the

Organization	Yes or No	Question 4 Comment
		BES" appears to be a catch-all event and more guidance needs to be provided on this category. *Several stakeholders expressed concerns relating to the "Forced Intrusion" event. Their concerns related to ambiguous language in the footnote. The SDR SDT discussed this event as well as the event "Risk to BES equipment". These two event types had overlap in the perceived reporting requirements. The DSR SDT removed "Forced Intrusion" as a category and the "Risk to BES equipment" event was revised to "A physical threat that could impact the operability of a Facility".* *Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported.* The event titled "Damage or Destruction of a Critical Asset or Critical Cyber Asset per CIP-002" is ambiguous and further guidance is recommended. Ambiguity in a standard leaves it open to interpretation for all involved. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as stakeholders pointed out that these events were adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility "reporting thresholds. CIP-008 addresses Cyber Security Incidents which are defined as:* *"Any malicious act or suspicious event that:* *• Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or,*

Organization	Yes or No	Question 4 Comment
		• Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.” *A Critical Asset is defined as:* *“Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.”* *Since there is an existing event category for damage or destruction of Facilities, having a separate event for “Damage or Destruction of a Critical Asset” is unnecessary.*
Response: Thank you for your comment. Please see response above.		
Florida Municipal Power Agency		The Rules of Procedure language for data retention (first paragraph of the Evidence Retention section) should not be included in the standard, but instead referred to within the standard (e.g., “Refer to Rules of Procedure, Appendix 4C: Compliance Monitoring and Enforcement Program, Section 3.1.4.2 for more retention requirements”) so that changes to the RoP do not necessitate changes to the standard. *The language incorporated in this section of the standard is boilerplate language provided by NERC staff for inclusion in each standard.* In R4, it might be worth clarifying that, in this case, implementation of the plan for an event that does not meet the criteria of Attachment 1 and going beyond the requirements R2 and R3 could be used as evidence. Consider adding a phrase as such to M4, or a descriptive footnote that in this case, “actual event” may not be limited to those in Attachment 1.

Organization	Yes or No	Question 4 Comment
		Most stakeholders believed that Requirements R2 and R3 were redundant and having both in the standard was not necessary. Requirement R2 called for implementation of Parts 1.1, 1.2, 1.4 and 1.5. Requirement R3 called for reporting events in accordance with the Operating Plan. The DSR SDT deleted Requirement R2based on stakeholder comments and revised R3 (now R2) to: *"Requirement R2. Each Responsible Entity shall implement its event reporting Operating Plan for applicable events listed in EOP-004 Attachment 1, and in accordance with the timeframe specified in EOP-004 Attachment 1."* Comments to Attachment 1 table:On "Damage or destruction of Critical Asset" and "... Critical Cyber Asset", Version 5 of the CIP standards is moving away from the binary critical/non-critical paradigm to a high/medium/low risk paradigm. Suggest adding description that if version 5 is approved by FERC, that "critical" would be replaced with "high or medium risk", or include changing this standard to the scope of the CIP SDT, or consider posting multiple versions of this standard depending on the outcome of CIP v5 in a similar fashion to how FAC-003 was posted as part of the GO/TO effort of Project 2010-07. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as stakeholders pointed out that these events were adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility "reporting thresholds. CIP-008 addresses Cyber Security Incidents which are defined as:* *"Any malicious act or suspicious event that:* *• Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or,* *• Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber*

Organization	Yes or No	Question 4 Comment
		Asset." *A Critical Asset is defined as:* *"Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System."* *Since there is an existing event category for damage or destruction of Facilities, having a separate event for "Damage or Destruction of a Critical Asset" is unnecessary.* On "forced intrusion", the phrase "at BES facility" is open to interpretation as "BES Facility" (e.g., controversy surrounding CAN-0016) which would exclude control centers and other critical/high/medium cyber system Physical Security Perimeters (PSPs). We suggest changing this to "BES Facility or the PSP or Defined Physical Boundary of critical/high/medium cyber assets". This change would cause a change to the applicability of this reportable event to coincide with CIP standard applicability. *The DSR SDT has modified Attachment 1 to bring more clarity. The more subjective events were rewritten as follows:* • *The 'Damage or Destruction' event category has been revised to say ' to a Facility', (a defined term) and thresholds have be modified to provide clarity. The footnote was deleted* • *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its*

Organization	Yes or No	Question 4 Comment
		Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. Also, the footnote only contains examples. *These two remaining event categories that aren't related to power system phenomena are essential as they effectively translate the intent of CIP-001 into EOP-004.* On "Risk to BES equipment", that phrase is open to too wide a range of interpretation; we suggest adding the word "imminent" in front of it, i.e., "Imminent risk to BES equipment". For instance, heavy thermal loading puts equipment at risk, but not imminent risk. Also, "non-environmental" used as the threshold criteria is ambiguous. For instance, the example in the footnote, if the BES equipment is near railroad tracks, then trains getting derailed can be interpreted as part of that BES equipment's "environment", defined in Webster's as "the circumstances, objects, or conditions by which one is surrounded". It seems that the SDT really means "non-weather related", or "Not risks due to Acts of Nature". *The DSR SDT has modified Attachment 1 to bring more clarity. The more subjective events were rewritten as follows:* • *The 'Damage or Destruction' event category has been revised to say ' to a Facility', (a defined term) and thresholds have be modified to provide clarity. The footnote was deleted* • *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its*

Organization	Yes or No	Question 4 Comment
		Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. Also, the footnote only contains examples. *These two remaining event categories that aren't related to power system phenomena are essential as they effectively translate the intent of CIP-001 into EOP-004.* On "public appeal", in the threshold, the descriptor "each" should be deleted, e.g., if a single event causes an entity to be short of capacity, do you really want that entity reporting each time they issue an appeal via different types of media, e.g., radio, TV, etc., or for a repeat appeal every several minutes for the same event? *The DSR SDT has updated the event concerning "public appeals" based on comments received and now reads as: "Public appeal for load reduction event".* Should LSE be an applicable entity to "loss of firm load"? As proposed, the DP is but the LSE is not. In an RTO market, will a DP know what is firm and what is non-firm load? Suggest eliminating DP from the applicability of "system separation". The system separation we care about is separation of one part of the BES from another which would not involve a DP. *The DSR SDT believes the "Entity with Reporting Responsibility" maintains the minimum number and type of entities that will be required to report such an event.* On "Unplanned Control Center Evacuation", CIP v5 might add GOP to the applicability, another reason to add revision of EOP-004-2 to the scope of the CIP v5 drafting team, or in other ways coordinate this SDT with that SDT. Consider posting a couple of versions of the standard depending on the outcome of CIP v5 in a similar fashion to the multiple versions of FAC-003 posted with the Go/TO effort of Project 2010-07.

Organization	Yes or No	Question 4 Comment
		The DSR SDT can only provide information on approved standards, not yet to be defined standards.
Response: Thank you for your comment. Please see response above.		
Dominion		There is still inconsistency in Attachment 1 vs. the DOE OE-417 form; in future changes, Dominion suggests align/rename events similar to that of the 'criteria for filing' events listed in the DOE OE-417, by working in coordination with the DOE. *Thank you for your comment. Attachment 1 is the basis for EOP-004-2; it contains the events and thresholds for reporting. OE-417, as well as, the EAWG's requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an opportunity not a 'must-have'* • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004. Note you may have to report the same event more quickly to the DOE than is required by EOP-004, but this cannot be helped due to bullet point 2 above.* *Please note that not all entities in North America are required to submit the DOE Form OE 417.* Minor comment; in the Background section, the drafting team refers to bulk power

Organization	Yes or No	Question 4 Comment
		system (redline page 5; 1st paragraph and page 7; 2nd paragraph) rather than bulk electric system. *This has been revised to Bulk Electric System.* The note in Attachment 1 states in part that “the affected Responsible Entity shall notify parties per R1 and ...” Dominion believes the correct reference to be R3. In addition, capitalized terms “Event” and “Event Report” are used in this note. Dominion believes the terms should be non-capitalized as they are not NERC defined terms. *The DSR SDT has updated this note based on comments received and now reads as: “NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written event report within the timing in the table below. In such cases, the affected Responsible Entity shall notify parties per R1 and provide as much information as is available at the time of the notification. Reports to the ERO should be submitted to one of the following: e-mail: esisac@nerc.com, Facsimile: 609-452-9550, Voice: 609-452-1422.”* Attachment 1 - “Detection of a reportable Cyber Security Incident - That meets the criteria in CIP-008”. This essentially equates the criteria to be defined by the entity in its procedures as required by CIP-008 R1.1., additional clarification should be added in Attachment 1 to make this clear. *The DSR SDT believes that this event language provides enough clarity by providing the minimum events to be reported.* The last sentence in Attachment 2 instructions should clarify that the email, facsimile and voice communication methods are for ERO notification only. *The DSR SDT agrees and has revised the sentence to include “to the ERO”.* Dominion continues to believe that the drill or exercise specified in R4 is

Organization	Yes or No	Question 4 Comment
		unnecessary. Dominion suggests deleting this activity in the requirement. *Requirement R4 related to an annual test of the communication portion of Requirement R1 by a drill or exercise and this has been removed. Requirement R3 now reads: "Each Responsible Entity shall conduct an annual test, not including notification to the Electric Reliability Organization, of the communications process in Part 1.2. ".* *The DSR SDT envisions that the testing under Requirement R3 will include verification of contact information contained in the Operating Plan is correct. As an example, the annual review of the Operating Plan could include calling "others as defined in the Responsible Entity's Operating Plan" (see Part 1.2) to verify that their contact information is up to date. If any discrepancies are noted, the Operating Plan would be updated.*
Response: Thank you for your comment. Please see response above.		
Ingleside Cogeneration LP		We are encouraged that the 2009-01 project team has eliminated duplicate reporting requirements from multiple organizations and governmental agencies. Ingleside Cogeneration LP believes that there are further improvements that can be made in this area - as the remaining overlap seem to be a result of legalities and preferences, not technical issues. We would like to see an ongoing commitment by NERC for a single process that will consolidate and automate data entry, submission, and distribution. *Attachment 1 is the basis for EOP-004-2; it contains the events and thresholds for reporting. OE-417, as well as, the EAWG's requirements were considered in creating Attachment 1, but there remain differences for the following reasons:* • *EOP-004 requirements were designed to meet NERC and the industry's needs; accommodation of other reporting obligations was considered as an*

Organization	Yes or No	Question 4 Comment
		opportunity not a 'must-have' • *OE-417 only applies to US entities, whereas EOP-004 requirements apply across North America* • *NERC has no control over the criteria in OE-417, which can change at any time* • *Reports made under EOP-004 provide a minimum set of information, which may trigger further information requests from EAWG as necessary* *In an effort to minimize administrative burden, US entities may use OE-417 rather than Attachment 2 to report under EOP-004. Note you may have to report the same event more quickly to the DOE than is required by EOP-004, but this cannot be helped due to bullet point 2 above.* *Please note that not all entities in North America are required to submit the DOE Form OE 417.*
Response: Thank you for your comment. Please see response above.		
SERC OC Standards Review Group		We believe that reporting of the events in Attachment 1 has no reliability benefit to the bulk electric system. In addition, Attachment 1, in its current form, is likely to be impossible to implement consistently across North America. A requirement, to be considered a reliability requirement, must be implementable. We suggest that Attachment 1 should be removed. *The DSR SDT disagrees with this comment. Attachment 1 is the minimum set of events that will be required to report and communicate per your Operating Plan will be aware of system conditions.* We have a question about what looks like a gap in this standard: Assuming one of thedrivers for the standard is to protect against a coordinated physical or cyber attack on the grid, what happens if the attack occurs in 3-4 geographically diverse areas? State or provisional law enforcement officials are not accountable under the standard, so we have no way of knowing if they report the attack to the FBI or the

Organization	Yes or No	Question 4 Comment
		RCMP. Even if one or two of them did, might not the FBI, in different parts of the country, interpret it as vandalism, subject to local jurisdiction?It seems that NERC is the focal point that would have all the reports and, ideally, some knowledge how the pieces fit together. It looks like NERC's role is to solely pass information on "applicable" events to the FERC. Unless the FERC has a 24x7 role not shown in the standard, should not NERC have some type of assessment responsibility to makes inquiries at the FBI/RCMP on whether they are aware of the potential issue and are working on it?"The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers." *Requirement R1, Part 1.2 was updated and now reads as: "A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies."* *By reporting to the ERO all events, this will allow the ERO to coordinate with other agencies as they see fit.*
Response: Thank you for your comment. Please see response above.		
ZGlobal on behalf of City of Ukiah, Alameda Municipal Power, Salmen River Electric, City of Lodi		We feel that the drafting team has done an excellent job of providing clarification and reasonable reporting requirements to the right functional entity. However we feel additional clarification should be made in the Attachment I Event Table. We suggest the following modifications:For the Event: BES Emergency resulting in automatic firm load sheddingModify the Entity with Reporting Responsibility to: Each DP or TOP that experiences the automatic load shedding within their respective distribution serving or Transmission Operating area. *The DSR SDT believes the "Entity with Reporting Responsibility" contains the minimum*

Organization	Yes or No	Question 4 Comment
		entities that will be required to report and reads as: "Each DP or TOP that experiences the automatic load shedding" For the Event: Loss of Firm load for â‰¥ 15 MinutesModify the Entity with Reporting Responsibility to: Each BA, TOP, DP that experiences the loss of firm load within their respective balancing, Transmission operating, or distribution serving area. *The DSR SDT believes the "Entity with Reporting Responsibility" contains the minimum entities that will be required to report and reads as: "Each BA, TOP, DP that experiences the loss of firm load"*
Response: Thank you for your comment. Please see response above.		
PSEG		We have several comments:1. The "Law Enforcement Reporting" section on p. 6 is unclearly written. The first three sentences are excerpted here: "The reliability objective of EOP-004-2 is to prevent outages which could lead to Cascading by effectively reporting events. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement."The outages described prior to the last sentence are "vandalism and terrorism." The next sentence states "Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES." If the SDT intended to only have events reported to law enforcement that could to Cascading, it should state so clearly and succinctly. But other language implies otherwise. *The DSR SDT has updated the "Example of reporting _Process including Law Enforcement", and please note that this is only an "example".* a. The footnote 1 on Attachment 1 (p. 20) states: "Do not report copper theft from BES equipment unless it degrades the ability of equipment to operate correctly (e.g.,

Organization	Yes or No	Question 4 Comment
		removal of grounding straps rendering protective relaying inoperative).” Rendering a relay inoperative may or may not lead to Cascading. *The DSR SDT has removed all footnotes with the exception of the updated event within Attachment 1 that states: “A physical threat that could impact the operability of a Facility”. This event has the following footnote, which states: “Examples include a train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center). Also report any suspicious device or activity at a Facility. Do not report copper theft unless it impacts the operability of a Facility.”* b. With regard to “forced intrusion,” footnote 2 on Attachment 1 states: “Report if you cannot reasonably determine likely motivation (i.e., intrusion to steal copper or spray graffiti is not reportable unless it effects (sic) the reliability of the BES.” The criterion, or criteria, for reporting an event to law enforcement needs to be unambiguous. The SDT needs to revise this “Law Enforcement Section” so that is achieved. The “law enforcement reporting” criterion, or criteria, should also be added to the flow chart on p. 9. We suggest the following as a starting point for the team to discuss: there should be two criteria for reporting an event to law enforcement: (1) BES equipment appears to have been deliberately damaged, destroyed, or stolen, whether by physical or cyber means, or (2) someone has gained, or attempted to gain, unauthorized access by forced or unauthorized entry (e.g., via a stolen employee keycard badge) into BES facilities, including by physical or cyber means. *The DSR SDT has modified Attachment 1 to bring more clarity. The more subjective events were rewritten as follows:* *The ‘Damage or Destruction’ event category has been revised to say ‘ to a Facility’, (a defined term) and thresholds have be modified to provide clarity. The footnote was*

Organization	Yes or No	Question 4 Comment
		deleted *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. Also, the footnote only contains examples.* *These two remaining event categories that aren't related to power system phenomena are essential as they effectively translate the intent of CIP-001 into EOP-004.* 2. The use of the terms "communicating events" in R1.3, and the use of the term "communication process" are confusing because in other places such as R3 the term "reporting" is used. If the SDT intends "communicating" to mean "reporting" as that later term is used in R3, it should use the same "reporting" term in lieu of "communicating" or "communication" elsewhere. Inconsistent terminology causes confusion. PSEG prefers the word "reporting" because it is better understood. *Requirement R1, Part 1.3 (now Part 1.2) was revised to add clarifying language by eliminating the phrase "as appropriate" and indicating that the Responsible Entity is to define its process for reporting and with whom to report events. Requirement R1, Part 1.2 now reads:* *"1.2 A process for communicating each of the applicable events listed in EOP-004 Attachment 1 in accordance with the timeframes specified in EOP-004 Attachment 1 to the Electric Reliability Organization and other organizations needed for the event type; i.e. the Regional Entity; company personnel; the Responsible Entity's Reliability Coordinator; law enforcement governmental or provincial agencies."*

Organization	Yes or No	Question 4 Comment
		The SDT envisions that most entities will only need to slightly modify their existing CIP-001 Sabotage Reporting procedures in order to comply with the Operating Plan requirement in this proposed standard. As many of the features of both are substantially similar, the SDT feels that some information may need to updated and verified. 3. Attachment 1 needs to more clearly define what is meant by “recognition of an event.”a. When equipment or a facility is involved, it would better state within “X” time (e.g., 1 hour) of “of confirmation of an event by the entity that either owns or operates the Element or Facility.” *Based on stakeholder comments, Requirement R1 was revised for clarity. Requirement R1, Part 1.1 was revised to replace the word “identifying” with “recognizing” and Part 1.2 was eliminated. This also aligns the language of the standard with FERC Order 693, Paragraph 471.* *“(2) specify baseline requirements regarding what issues should be addressed in the procedures for recognizing {emphasis added} sabotage events and making personnel aware of such events;”* b. Other reports should have a different specification of the starting time of the reporting deadline clock. For example, in the requirement for reporting a “BES Emergency requiring public appeal for load reduction,” it is unclear what event is required to be reported - the “BES Emergency requiring public appeal” or “public appeal for load reduction.” If the later is intended, then the event should be reported within “24 hours after a public appeal for load reduction is first issued.” These statements need to be reviewed and customized for each event by the SDT so they are unambiguous. *All one hour reporting timelines have been changed to 24 hours with the exception of a*

Organization	Yes or No	Question 4 Comment
		'Reportable Cyber Security Incident'. This is maintained due to FERC Order 706, Paragraph 673: *"…direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *For the remaining events, 24 hours should provide sufficient time to manage the incident in real-time before having to report and is consistent with current in-force standard EOP-004-1.* In summary, the starting time for the reporting clock to start running should be made clear for each event. This will require that the SDT review each event and customize the starting time appropriately. The phrase "recognition of an event" should not be used because it is too vague. *Based on stakeholder comments, Requirement R1 was revised for clarity. Part 1.1 was revised to replace the word "identifying" with "recognizing" and Part 1.2 was eliminated. This also aligns the language of the standard with FERC Order 693, Paragraph 471.* *"(2) specify baseline requirements regarding what issues should be addressed in the procedures for recognizing {emphasis added} sabotage events and making personnel aware of such events;"* 4. When EOP-004-2 refers to other standards, it frequently omits the version of the standard. Example: see the second and third row of Attachment 1 that refers to "CIP-002." Include the version on all standards referenced. *References to CIP-002 have been removed from the standard. The intent of referencing those standards is to prevent rewriting the standard within EOP-004-2. The threshold for reporting CIP-008 events is written as "That meets the criteria in CIP-008-4 or its successor."*

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. Please see response above.		
Ameren		Yes. We have the other comments as follow:(1) The "EOP-004 Attachment 1: Events Table" is quite lengthy and written in a manner that can be quite subjective in interpretation when determining if an event is reportable. We believe this table should be clear and unambiguous for consistent and repeatable application by both reliability entities and a CEA. *The DSR SDT has reviewed and further revised Attachment 1 based on comments received. We believe that it is both concise and easily interpreted.* The table should be divided into sections such as: 9a) Events that affect the BES that are either clearly sabotage or suspected sabotage after review by an entity's security department and local/state/federal law enforcement.(b) Events that pose a risk to the BES and that clearly reach a defined threshold, such as load loss, generation loss, public appeal, EEAs, etc. that entities are required to report by the end of the next business day.(c) Other events that may prove valuable for lessons learned, but are less definitive than required reporting events. These events should be reported voluntarily and not be subject to a CEA for non-reporting. *The DSR SDT received many comments regarding the various entries of Attachment 1. Many commenters questioned the reliability benefit of reporting events to the ERO within 1 hour. Most of the events with a one hour reporting requirement were revised to 24 hours based on stakeholder comments as well as those types of events are currently required to be reported within 24 hours in the existing mandatory and enforceable standards. The only remaining type of event that is to be reported within one hour is "A reportable Cyber Security Incident" as it required by CIP-008 and FERC Order 706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a*

Organization	Yes or No	Question 4 Comment
		cyber security incident as soon as possible, but in any event, within one hour of the event…" *The table was reformatted to separate one hour reporting and 24 hour reporting. The last column of the table was also deleted and the information contained in it was transferred to the sentence above each table. These sentences are:* *"One Hour Reporting: Submit Attachment 2 or DOE-OE-417 report to the parties identified pursuant to Requirement R1, Part 1.2 within one hour of recognition of the event."* *"Twenty-four Hour Reporting: Submit Attachment 2 or DOE-OE-417 report to the parties identified pursuant to Requirement R1, Part 1.2 within twenty-four hour of recognition of the event."* (d)Events identified through other means outside of entity reporting, but due to their nature, could benefit the industry by an event report with lessons learned. Requests to report and perform analysis on these type of events should be vetted through a ERO/Functional Entity process to ensure resources provided to this effort have an effective reliability benefit. *The DSR SDT has deleted the "lessons learned" language. Requirement R4 now only requires an annual review of the Operating Plan - the '90 days' and ' other circumstances' elements have been removed.* (2)Any event reporting shall not in any manner replace or inhibit an Entity's responsibility to coordinate with other Reliability Entities (such as the RC, TOP, BA, GOP as appropriate) as required by other Standards, and good utility practice to operate the electric system in a safe and reliable manner. *The DSR SDT concurs with your comment.*

Organization	Yes or No	Question 4 Comment
		(3) The 1 hour reporting maximum time limit for all GO events in Attachment 1 should be lengthened to something reasonable - at least 24 hours. Operators in our energy centers are well-trained and if they have good reason to suspect an event that might have serious impact on the BES will contact the TOP quickly. However, constantly reporting events that turn out to have no serious BES impact and were only reported for fear of a violation or self-report will quickly result in a cry wolf syndrome and a great waste of resources and risk to the GO and the BES. The risk to the GO will be potential fines, and the risk to the BES will be ignoring events that truly have an impact of the BES. *The DSR SDT received many comments regarding the various entries of Attachment 1. Many commenters questioned the reliability benefit of reporting events to the ERO within 1 hour. Most of the events with a one hour reporting requirement were revised to 24 hours based on stakeholder comments as well as those types of events are currently required to be reported within 24 hours in the existing mandatory and enforceable standards. The only remaining type of event that is to be reported within one hour is "A reportable Cyber Security Incident" as it required by CIP-008 and FERC Order 706, Paragraph 673:* *"direct the ERO to modify CIP-008 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but in any event, within one hour of the event…"* *The table was reformatted to separate one hour reporting and 24 hour reporting. The last column of the table was also deleted and the information contained in it was transferred to the sentence above each table. These sentences are:* *"One Hour Reporting: Submit Attachment 2 or DOE-OE-417 report to the parties identified pursuant to Requirement R1, Part 1.2 within one hour of recognition of the*

Organization	Yes or No	Question 4 Comment
		event." *"Twenty-four Hour Reporting: Submit Attachment 2 or DOE-OE-417 report to the parties identified pursuant to Requirement R1, Part 1.2 within twenty-four hour of recognition of the event."* (4)The 2nd and 3rd Events on Attachment 1 should be reworded so they do not use terms that may have been deleted from the NERC Glossary by the time FERC approves this Standard. *The 'Damage or Destruction' events specifically relating to Critical Assets and Critical Cyber Assets were removed from Attachment 1, as these events are adequately addressed through the CIP-008 and 'Damage or Destruction of a Facility' reporting thresholds.* (5) The terms "destruction" and "damage" are key to identifying reportable events. Neither has been defined in the Standard. The term destruction is usually defined as 100% unusable. However, the term damage can be anywhere from 1% to 99% unusable and take anywhere from 5 minutes to 5 months to repair. How will we know what the SDT intended, or an auditor will expect, without additional information? *The DSR SDT has modified Attachment 1 to bring more clarity. The more subjective events were rewritten as follows:* *The 'Damage or Destruction' event category has been revised to say ' to a Facility', (a defined term) and thresholds have be modified to provide clarity. The footnote was deleted* *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new*

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		event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. Also, the footnote only contains examples. *These two remaining event categories that aren't related to power system phenomena are essential as they effectively translate the intent of CIP-001 into EOP-004.* (6)We also do not understand why "destruction of BES equipment" (first item Attachment 1, first page) must be reported < 1 hour, but "system separation (islanding) > 100 MW" (Attachment 1, page 3) does not need to be reported for 24 hours. *The DSR SDT has modified Attachment 1 to bring more clarity. The more subjective events were rewritten as follows:* *The 'Damage or Destruction' event category has been revised to say 'to a Facility', (a defined term) and thresholds have be modified to provide clarity. The footnote was deleted* *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting*

Organization	Yes or No	Question 4 Comment
		timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it may have first occurred. Also, the footnote only contains examples. *These two remaining event categories that aren't related to power system phenomena are essential as they effectively translate the intent of CIP-001 into EOP-004.* (7)The first 2 Events in Attachment 1 list criteria Threshold for Reporting as "...operational error, equipment failure, external cause, or intentional or unintentional human action." The term "intentional or unintentional human action" appears to cover "operational error" so these terms appear redundant and create risk of misreporting. Can this be clarified? *The DSR SDT has updated this language based on comments received and now reads as: " Damage or destruction of a Facility that:* *Affects an IROL (per FAC-014)* *OR* *Results in the need for actions to avoid an Adverse Reliability Impact* *OR* *Results from intentional human action."* (8)The footnote of the first page of Attachment 1 includes the explanation "...ii) Significantly affects the reliability margin of the system..." However, the GO is prevented from seeing the system and has no idea what BES equipment can affect the reliability margin of the system. Can this be clarified by the SDT? *The DSR SDT has removed all footnotes with the exception of the updated event within Attachment 1 that states: "A physical threat that could impact the operability of a Facility". This event has the following footnote, which states: "Examples include a*

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		train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center). Also report any suspicious device or activity at a Facility. Do not report copper theft unless it impacts the operability of a Facility." (9) The use of the term "BES equipment" is problematic for a GO. NERC Team 2010-17 (BES Definition) has told the industry its next work phase will include identifying the interface between the generator and the transmission system. The 2010-17 current effort at defining the BES still fails to clearly define whether or not generator tie-lines are part of the BES. In addition, NERC Team 2010-07 may also be assigned the task of defining the generator/transmission interface and possibly whether or not these are BES facilities. Can the SDT clarify the use of this term? For example, does it include the entire generator lead-line from the GSU high-side to the point of interconnection? Does it include any station service transformer supplied from the interconnected BES? *The DSR SDT has modified Attachment 1 to bring more clarity. The more subjective events were rewritten as follows:* • *The 'Damage or Destruction' event category has been revised to say ' to a Facility', (a defined term) and thresholds have be modified to provide clarity. The footnote was deleted* • *'Forced intrusion' and 'Risk to BES Equipment' have been combined under a new event type called 'A physical threat that could impact the operability of a Facility'. Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported. Note that the reporting timeline (now revised to 24 hours) starts when the situation has been determined as a threat, not when it*

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		may have first occurred. Also, the footnote only contains examples. *These two remaining event categories that aren't related to power system phenomena are essential as they effectively translate the intent of CIP-001 into EOP-004.*
Response: Thank you for your comment. Please see response above.		
Performance Analysis Subcommittee		There continues to be some confusion regarding whether the loss of firm load was consistent with the planned operation of the system or was an unintended consequence. As such it might be helpful if instead of a single check box for loss of firm load there were two check boxes 1) loss of firm load – consequential and 2) loss of firm load non-consequential. *Thank you for your comment. The DSR SDT believes that Attachment 2 contains the minimum amount of information under this standard. Any entity reporting an event can add as much information as they see fit.*
Response: Thank you for your comment. Please see response above.		
Southwestern Power Administration's		"Attachment 1 contains elements that do not need to be included, and redundant elements such as: Forced intrusion at BES Facility - A facility break-in does not necessarily mean that the facility has been impacted or has undergone damage or destruction. *The DSR SDT discussed this event as well as the event "Risk to BES equipment". These two event types had overlap in the perceived reporting requirements. The DSR SDT removed "Forced Intrusion" as a category and the "Risk to BES equipment" event was*

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		revised to "Any physical threat that could impact the operability of a Facility". *Using judgment is unavoidable for this type of event. This language was chosen because the Responsible Entity is the best position to exercise this judgment and determine whether or not an event poses a threat to its Facilities. The DSR SDT believes this revised event type will minimize administrative burden and ensure that events meaningful to industry awareness are reported.* *The footnote regarding this event type was expanded to provide additional guidance in:* *"Examples include a train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center). Also report any suspicious device or activity at a Facility. Do not report copper theft unless it impacts the operability of a Facility."* Detection of a reportable Cyber Security Incident per CIP-008 - If entities are addressing this requirement in CIP-008, why do so again in EOP-004 (Attachment 2-EOP-004, Reporting Requirement number 5)? *The reporting aspects of CIP-008 have been removed from CIP-008 and are included in EOP-004. Please see the Implementation Plan with regards to the retirement of CIP-008, R1.3* Transmission Loss: Each TOP that experiences transmission loss of three or more facilities - This element should be removed or rewritten so that it only applies when the loss includes a contingent element of an IROL facility." *The DSR SDT disagrees with limiting this type of event to only "a contingent element*

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		of an IROL facility." It is important for situational awareness and trending analysis to have these types of events reported.
Response: Thank you for your comment. Please see response above.		
The Performance Analysis Subcommittee		There continues to be some confusion regarding whether the loss of firm load was consistent with the planned operation of the system or was an unintended consequence. As such it might be helpful if instead of a single check box for loss of firm load there were two check boxes 1) loss of firm load – consequential and 2) loss of firm load non-consequential. *The DSR SDT believes that this information should be obtained in follow up through the Events Analysis Program. The reporting entity may have concerns or difficulties in determining if load is consequential or non-consequential in its initial analysis for the report. Further investigation outside of the reporting time of 24 hours may be needed to make this determination.*
Response: Thank you for your comment. Please see response above.		
Xcel Energy		
Los Angeles Department of Water and Power		
Liberty Electric Power		
Nebraska Public Power District		
Southwestern Power Administration		

Organization	Yes or No	Question 4 Comment
Electric Reliability Council of Texas, Inc.		

END OF REPORT