WATER | ENERGY | LIFE CITY OF RIVERSIDE PUBLIC UTILITIES	**CITY OF RIVERSIDE** **PUBLIC UTILITIES DEPARTMENT** **NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION-WESTERN ELECTRICITY COORDINATING COUNCIL INTERNAL COMPLIANCE PROGRAM**

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1. INTRODUCTION

1.1 Purpose

The purpose of Riverside Public Utilities' ("RPU") Internal Compliance Program ("ICP") is to ensure that RPU sustains a strong atmosphere of compliance with respect to the reliability standards that have been promulgated by the North American Electric Reliability Corporation ("NERC") and the Western Electricity Coordinating Council ("WECC") and subsequently approved and allowed to become effective by the Federal Energy Regulatory Commission ("FERC"). RPU has made a commitment to invest the necessary resources to implement and maintain a robust and effective ICP as documented below.

The ICP documents general policies, procedures, and guidelines related to RPU's compliance with the reliability standards. It delineates overall compliance responsibilities, describes various internal compliance monitoring and enforcement measures, and provides for training to ensure that compliance responsibilities are thoroughly understood by RPU personnel involved with compliance matters.

1.2 Background

NERC was founded in 1968 by representatives of the electric utility industry for the purpose of developing and promoting voluntary compliance with rules and protocols for the reliable operation of the bulk power electric transmission systems of North America. The bulk power system generally includes facilities operated at 100 kV or higher and is defined as "facilities and control systems necessary for operating an interconnected electric energy transmission network…and electric energy from generation facilities needed to maintain transmission reliability." FPA § 215(a)(1). Following the passage of the U.S. Energy Policy Act of 2005, which called for the creation of an international "electricity reliability organization" to develop and enforce reliability standards (*see* FPA § 215(b) and (c)), NERC was subsequently certified by FERC as the electric reliability organization. NERC's voluntary set of reliability standards were then approved by FERC and became mandatory under federal law as of June 18, 2007. Users, owners, and operators of the bulk power system are listed in a compliance registry maintained by NERC according to the different utility functions they perform and are responsible for knowing the content of and complying with the reliability standards. FPA § 215(b)(1). NERC continues to develop new reliability standards and revise existing reliability standards.

WECC is responsible for coordinating and promoting electric system reliability for the Western Interconnection, which includes the City of Riverside, and has been delegated authority for overseeing compliance with the reliability standards by users, owners, and operators of the bulk power system within the Western Interconnection.

NERC and WECC have adopted Compliance Monitoring and Enforcement Program Implementation Plans that are used to monitor, assess, and enforce compliance with FERC-approved NERC reliability standards and WECC regional reliability standards. Each registered entity must comply with all reliability standards that are applicable to functions for which they are registered.

Subject to FERC oversight, NERC and WECC are authorized to enforce the reliability standards with monetary and non-monetary penalties and sanctions. Monetary penalties include fines ranging from $1,000 to $1 million per violation per day, depending on factors such as the level of risk to the bulk power system created by the violation. Under Section 215(e)(6) of the Federal Power Act, penalties for violating the reliability standards must be reasonably related "to the seriousness of the violation" and must take into consideration efforts by the "user, owner, or operator to remedy the violation in a timely manner." FERC may also independently investigate and enforce compliance with the reliability standards.

2. SCOPE

RPU is registered with WECC and NERC as a Distribution Provider and Resource Planner .[1] It is the policy of RPU to comply and document compliance with all reliability standards that apply to these functional categories.

3. ORGANIZATION AND STRUCTURE

RPU staff with responsibilities supporting the ICP include (i) the Public Utilities General Manager, (ii) the Deputy General Manager, (iii) the Utilities Assistant General Manager-Energy Delivery, (iv) the Utilities Assistant General Manager-Resources, (v) the Utilities Regulatory Compliance Manager, and (vi) Responsible Managers and Subject Matter Experts as assigned (refer to Attachment A-Organization Chart). Staff shall perform their assigned duties consistent with the exercise of due diligence, and shall promote an organizational culture that encourages a commitment to compliance with the law.

Pursuant to the Riverside City Charter sections 407, 601, and 1200, the Public Utilities General Manager, with the approval of the City Manager, has the authority to assign particular employees to particular duties or job functions within the organization, and to fill any job vacancies on an interim basis pending permanent appointments.

RPU shall use reasonable efforts not to assign responsibility for activities under the ICP to individuals known to have deliberately engaged in reliability standards violations or conduct inconsistent with compliance with the reliability standards.

3.1 Administrative Responsibilities

3.1.1 Public Utilities General Manager

a. The Public Utilities General Manager has overall responsibility for RPU's ICP and shall actively support and be involved in RPU's NERC and WECC reliability standard compliance efforts.

b. Substantive modifications to the ICP which are necessary to comply with additional or revised FERC, NERC, and/or WECC regulations shall be approved by the Public Utilities General Manager, in consultation with the Deputy General Manager, the Utilities Regulatory Compliance Manager and the City Attorney's Office. Other substantive modifications shall be approved by the Board of Public Utilities and the City Council.

3.1.2 Deputy General Manager

As delegated by the Public Utilities General Manager, the Deputy General Manager has the following responsibilities and authorities:

[1] **Distribution Provider ("DP"):** Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.

Resource Planner ("RP"): The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.

a. The Deputy General Manager shall report RPU's compliance activities on a periodic basis to the Public Utilities General Manager, the Board of Public Utilities and the City Council, if recommended by the Board of Public Utilities.

b. The Deputy General Manager, in consultation with the City Attorney's Office, shall notify the Public Utilities General Manager of an actual or potential violation of applicable reliability standards. Any decisions regarding litigation or potential litigation shall be made by the City Council.

c. The Deputy General Manager, in consultation with the City Attorney's Office, shall notify the Public Utilities General Manager if a final penalty or sanction (i.e., financial liability or other obligations inuring to RPU that reflects either the outcome of settlement negotiations involving RPU and WECC, NERC, or FERC or the result of investigation and/or dispute resolution processes administered by WECC, NERC, or FERC) is assessed.

3.1.3 Utilities Assistant General Manager-Energy Delivery and Utilities Assistant General Manager-Resources

As delegated by the Public Utilities General Manager, responsibilities and authorities of the Utilities Assistant General Manager-Energy Delivery and the Utilities Assistant General Manager-Resources include:

a. Understanding the scope of the reliability standards applicable to their division.

b. Allocating sufficient staff and resources to ensure compliance with applicable reliability standards.

c. Identifying and assigning Responsible Managers for their divisions. Responsible Managers must be City of Riverside Management II employees.

d. Review and approval of internal compliance policies and documentation.

e. Attending internal compliance team meetings at the request of the Utilities Regulatory Compliance Manager.

f. Directing staff to cooperate with compliance activities described in the ICP, including but not limited to, meeting attendance, training, reporting, communication, and managing compliance documentation. Staff shall perform duties in a manner that complies with applicable reliability standards.

g. Certifying final responses for approval by the Deputy General Manager or the Public Utilities General Manager, including but not limited to, compliance certification statements to NERC/WECC (e.g. Annual Self-certification, Periodic Data Submittals, Exception Reporting, Spot Checks, Self-Reported Violations, and any other data submittals of a similar nature).

3.1.4 Utilities Regulatory Compliance Manager

The Utilities Regulatory Compliance Manager shall have day-to-day operational responsibility for the ICP. The Utilities Regulatory Compliance Manager may report directly to the Public Utilities General Manager or to the Deputy General Manager. The Utilities Regulatory Compliance Manager shall not report to an individual who oversees daily operations in the Energy Delivery or Power Resources Divisions.

For the purposes of the ICP, the Utilities Regulatory Compliance Manager shall have adequate resources and appropriate authority as delegated herein to provide independent oversight for all activities related to the implementation of the ICP. The Utilities Regulatory Compliance Manager shall be independent of those responsible for compliance with the reliability standards. The Utilities Regulatory Compliance Manager shall also have independent direct access to the governing authority or an appropriate subgroup of the governing authority which may include, but not be limited to, the Public Utilities General Manager, the City Manager, the Public Utilities Board and the City Council in the event that an actual or potential violation of applicable reliability standards warrants such access.

As delegated by the Public Utilities General Manager, responsibilities and authorities of the Utilities Regulatory Compliance Manager include:

a. Ensuring the effective development and implementation of RPU's ICP.

b. Overseeing the implementation of RPU's NERC Reliability Standard Compliance Policies ("RSCPs"). An example of an RSCP is provided in Attachment B.

c. Oversight and responsibility for all communication and correspondence related to the ICP, WECC and NERC.

d. Conducting reviews and assessment to verify the effectiveness of the ICP.

e. Communicate updates and changes to the (i) the Subject Matter Experts, (ii) Responsible Managers, and (iii) executive management and City Attorney's Office as necessary.

f. Initiating internal compliance team meetings to discuss current issues, lessons learned best practices and other routine matters regarding the reliability standards. These meetings shall be held on a regular, but at least quarterly, basis.

g. Attending applicable training sessions and workshops to remain current in compliance practices and requirements.

h. Internal reporting of any non-compliance or potential non-compliance with the applicable reliability standards.

i. Preparing responses and compiling evidence in response to NERC/WECC requests for information (or the delegation thereof) and preparing RPU's responses to self-certifications, spot-check letters, and similar compliance monitoring and enforcement activities by NERC/WECC, in consultation with the City Attorney's Office.

4. PROCEDURES

4.1 Reliability Standard Compliance Policies

RPU has developed an approved RSCP for each applicable reliability standard. The RSCPs describe procedures that RPU will follow to ensure compliance with the reliability standards. Complete and current RSCPs and the ICP are maintained, updated, and distributed by the Utilities Regulatory

Compliance Manager. Electronic copies are located on the Utilities Regulatory Compliance Manager's internal hard drive and are posted on RPU's intranet Share Point portal available to RPU personnel.

The Responsible Manager shall ensure that the substantive compliance actions described in the RSCPs are carried out in accordance with the procedures described therein and shall review the RSCPs that they are responsible for implementing on an annual basis. Following this review, Responsible Managers shall make recommendations for retention or modification of the RSCPs to the Utilities Regulatory Compliance Manager. The final modified RSCPs shall be reviewed and approved by either the Utilities Assistant General Manager-Energy Delivery or Utilities Assistant General Manager-Resources and the Deputy General Manager. The Utilities Regulatory Compliance Manager shall maintain the RSCP Revision History Log (refer to Attachment C).

4.2 Compliance Program

On an annual basis, or more frequently due to FERC, NERC or WECC actions, the ICP shall be reviewed and improved where practicable. The Regulatory Compliance Manager will initiate a request for review and the SMEs and Responsible Managers shall confirm the compliance documents are up-to-date. As part of this review, RPU shall assess the risk of violations and take appropriate steps to design, implement, or modify the ICP. The risk assessment shall be based upon impact and probability. The Violation Risk Factor shall be considered for each applicable requirement. Trends shall be identified for priority placement.

The final modified ICP shall be reviewed by the City Attorney's Office and shall be approved by the Public Utilities General Manager. Such review is evidenced by various methods including, but not limited to, the Revision History, minutes of the internal meetings, internal audits, internal reports and copies of correspondence or request for action, to the extent not subject to applicable legal privileges.

Further, substantive modifications to the ICP, other than those that are necessary to comply with additional or revised FERC, NERC, and/or WECC requirements, shall also be approved by the Public Utilities Board and the City Council.

4.3 Immediate Review

Immediate reviews (outside of the annual cycle) of the RSCPs and/or the ICP may be conducted by the Responsible Manager or the Utilities Regulatory Compliance Manager in consultation with appropriate RPU and/or City staff. Circumstances that could trigger an immediate review of an RSCP or the ICP include, but are not limited to, the following: (i) FERC approval of revisions to an existing reliability standard; (ii) approval, by FERC, of a new interpretation of an existing reliability standard; (iii) issuance, by WECC, of a Notice of Alleged Violation; (iv) submittal, by RPU, of an Exception Report; (v) self-reporting, by RPU, of an actual or potential violation; or (vi) when the findings of an internal audit warrant such.

If an event occurs that results in the need to immediately review a RSCP or the ICP, the Utilities Regulatory Compliance Manager, with the assistance of appropriate RPU staff and, if necessary, the City Attorney's Office, shall prepare a report describing the details of the event and making recommendations, which may include, for example, modification to the RSCP with appropriate documentation, additional training, or changes in reporting, testing or procedures. If the review was triggered by an actual or potential violation of applicable reliability standards, the report shall include the elements described below under the heading "Actual or Potential Reliability Standards Violations."

5. TRAINING

5.1 Requirements

Training for RPU personnel directly responsible for compliance with the reliability standards is to be conducted within each Utility division responsible for carrying out the applicable RSCP.

At the direction of the Utilities Regulatory Compliance Manager, the Responsible Managers reporting to the Public Utilities Assistant General Manager-Energy Delivery and the Public Utilities Assistant General Manager-Resources shall (i) establish regular training schedules, (ii) develop and provide (or arrange for) training, and (iii) verify that all RPU personnel have received appropriate training to ensure that the reliability standards and the respective responsibilities of RPU personnel related to reliability standards are clearly understood.

The Responsible Manager shall keep written records of this training, including attendance, and shall provide documentation, including copies of any materials distributed at the training, to the Utilities Regulatory Compliance Manager. Overview and awareness training regarding the ICP and the reliability standards is mandatory for all appropriate RPU personnel and will be conducted annually. The Utilities Regulatory Compliance Manager shall be responsible for developing and providing (or arranging for) the overview and awareness training and verifying that appropriate RPU personnel attend the training.

Consultants and contractors shall receive training appropriate to their duties and responsibilities. RPU employees, consultants, and contractors not involved in activities related to the reliability standards will not be required to attend training.

5.2 External Industry Participation

The Utilities Regulatory Compliance Manager shall participate in WECC, NERC and other outreach activities to share compliance program activities with other entities, adjacent utilities, and/or local organizations. RPU personnel responsible for reliability standard requirements shall be encouraged to attend WECC-related conferences and user meetings.

5.3 Incentives for Compliance

RPU currently offers a number of award programs which recognizes employees who display consistent job performance leading to reliable utility services and exceptional customer service. These programs may be used to encourage employee compliance with the reliability standards and accountability for compliance.

6. COMPLIANCE MONITORING

6.1 Self-Assessment

The Utilities Regulatory Compliance Manager shall establish a self-assessment schedule and procedure for the Utilities Regulatory Compliance Manager or the Responsible Managers to employ in order to verify that RPU personnel are fully complying with the reliability standards and are generating documentation germane to their substantive compliance responsibilities and that existing RSCPs and related policies, procedures, and/or guidelines are effective means of ensuring ongoing compliance. Self-assessment procedures may include, but are not limited to, requests for required reports, review of retained documents, reliability risk, and independent verification of testing and results.

6.2 Internal Auditing

Internal auditing shall be conducted on an annual cycle and may be performed by or through the staff of a neighboring utility, a joint powers authority such as the Southern California Public Power Authority, or outside consultants with expertise in reliability standards compliance, in addition to RPU or City personnel not routinely involved in substantive compliance matters. The Utilities Regulatory Compliance Manager shall also consider and/or request the assistance of the Internal Auditors for the City of Riverside. Such a request may include: (i) instruction and guidance to RPU personnel, consultants, or other individuals regarding principles and standards for internal auditing; (ii) provision of written guidelines to be followed throughout the audit, including methods for, and timing of, communications, standards for written reports, and acceptable conduct; and, (iii) provision of assistance and advice, upon request, throughout the compliance audit process.

7. ACTUAL OR POTENTIAL RELIABILITY STANDARDS VIOLATIONS

7.1 Self-Reporting

In the event that possible or potential violations of reliability standards are reported anonymously[2] or discovered by City staff, such possible or potential violations shall immediately be brought to the attention of the Utilities Regulatory Compliance Manager, who shall immediately inform the City Attorney's Office.

The Utilities Regulatory Compliance Manager, in consultation with the Deputy General Manager, the Public Utilities Assistant General Manager-Energy Delivery and/or the Public Utilities Assistant General Manager-Resources, and the City Attorney's Office, shall immediately review the reliability standard(s) that may have been violated to determine if a violation has occurred or is occurring. If so, the Utilities Regulatory Compliance Manager shall submit to WECC a self-report (via the process established by WECC for the submittal of self-reports). If it is clear that a violation has occurred or is continuing to occur, RPU shall take reasonable steps to correct the problem; a mitigation plan shall be prepared and submitted along with the self-report or shortly thereafter.

In all instances, City staff involved in self-reporting the violation shall cooperate with WECC with respect to any inquiries, investigations, or other processes occurring as a result of the self-report.

City staff should report potential or actual violations to their immediate supervisor or seek guidance from the Utilities Regulatory Compliance Manager and may do so without fear of retaliation.

7.2 Reports

If notified of an actual or potential violation of applicable reliability standards whether through internal compliance monitoring processes (such as review of RSCPs and related documentation or internal audits, for example) or via a communication from WECC or NERC (such as a notice of violation, a notice of investigation, or similar type of communication), the Utilities Regulatory Compliance Manager shall investigate the circumstances surrounding the alleged violation (or supervise the investigation thereof) and prepare a report for any valid actual or potential violation. The report of the alleged violation shall be provided to the Deputy General Manager. The report shall include the following:

[2] An anonymous report can be made by contacting the City of Riverside Waste and Abuse Hotline at (951) 826-2232 or complete an online complaint form, or by sending hard copy correspondence to the Utilities Regulatory Compliance Manager. Items reported through the hotline will be addressed by the City's Internal Audit Department and the Public Utilities General Manager.

a. The details of the actual or potential violation and actions taken or to be taken to remedy the violation (if there appears to be a reasonable basis for concluding that a violation is occurring), including modification to the RSCPs, additional training, or changes in reporting, testing or procedures.

b. A discussion of whether the alleged violation was caused by City staff and, if so, whether the conduct, action, or omission to act that resulted in an alleged violation should lead to disciplinary action. This section of the report shall be treated as confidential and shall be handled in accordance with the City of Riverside Personnel Policy and Procedures and in consultation with the City of Riverside Human Resources Department.

c. Recommendations regarding a general course of action beyond immediate remedial actions which may consist of engaging in settlement negotiations with WECC, NERC, and/or FERC related to the alleged violation, disputing the alleged violation or proposed penalty, implementing a plan to mitigate the violation (if one has not been implemented already), or taking other actions, consistent with applicable procedural rules and processes administered by WECC, NERC, and FERC. Self-reporting, development of mitigation plans, making exception reports, and/or responding to other requests for information related to the alleged violation shall not be delayed pending the reports to the Public Utilities Board and City Council.

7.3 Notifications

In the event of an actual or potential violation of applicable reliability standards, the Utilities Regulatory Compliance Manager shall have prepared and presented the report as described above. The Public Utilities General Manager shall inform the Public Utilities Board and/or City Council of the actual or potential violation. Per Riverside City Charter, any decisions regarding litigation or potential litigation shall be made by the City Council.

For notification purposes, WECC requires a "CEO (or equivalent) Contact" role be identified and added to the WECC web portal. This role shall be assigned to the Deputy General Manager.

7.3.1. Penalty Determinations

If a final penalty or sanction (*i.e.*, financial liability or other obligations inuring to RPU that reflects either the outcome of settlement negotiations involving RPU and WECC, NERC, or FERC or the result of investigation and/or dispute resolution processes administered by WECC, NERC, or FERC) is assessed, the Public Utilities General Manager, in consultation with the City Attorney's Office shall notify the Public Utilities Board and the City Council.

8. SUMMARY

To ensure RPU sustains a strong atmosphere of compliance with respect to the reliability standards, RPU has develop this Internal Compliance Policy to document general policies, procedures, and guidelines related to RPU's compliance with reliability standards.

Questions regarding the ICP should be sent to the Utilities Regulatory Compliance Manager.

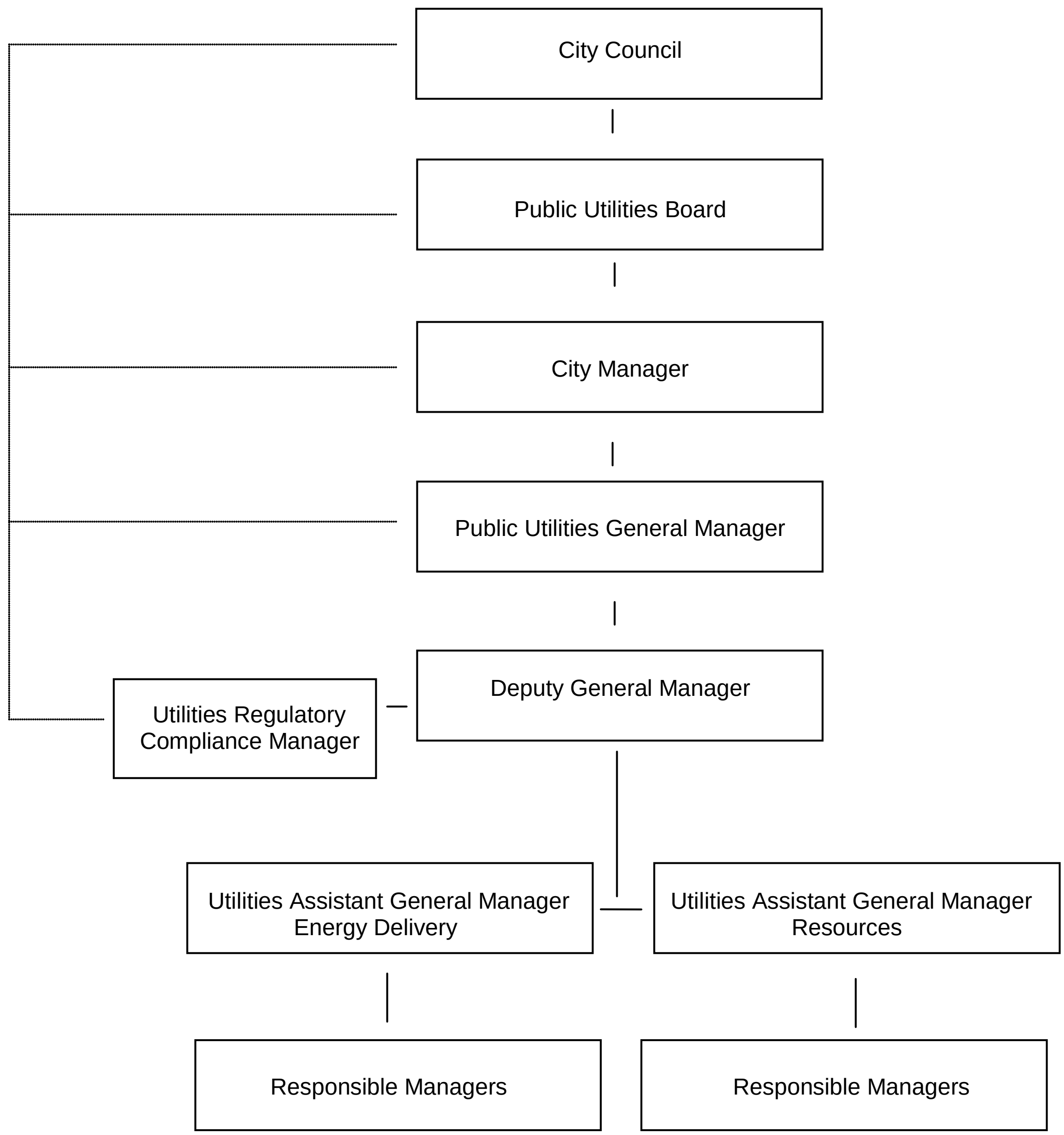
VERSION HISTORY

VERSION	DATE	CHANGE TRACKING
1	9/9/2008	Adopted by City Council
2	4/26/2011	Amended to meet FERC Policy Statement on Penalty Guidelines revised on 3/18/10
3	12/31/2013	Amended to (i) meet WECC Internal Compliance Program Assessment guidelines, (ii) add Utilities Chief Operations Officer, and (iii) improve format
4	XX/XX/2017	Amended to (i) replace Utilities Chief Operations Officer with Deputy General Manager, (ii) to remove the Purchase/Selling Entity and Load Serving Entity registration as these functions were deactivated by FERC in 2015, (iii) update Section 4.2 and, (iv) amend contact information for anonymous reporting.

ATTACHMENT A

RIVERSIDE PUBLIC UTILITIES
INTERNAL COMPLIANCE PROGRAM

Organization Chart



The Utilities Regulatory Compliance Manager shall also have independent direct access to the governing authority or an appropriate subgroup of the governing authority which may include, but not be limited to, the Utilities General Manager, the City Manager, the Public Utilities Board and the City Council in the event that an actual or potential violation of applicable reliability standards warrants such access.

RPU RELIABILITY STANDARD COMPLIANCE POLICY
NERC Reliability Standard
EOP-004-2 Event Reporting

Background: Riverside Public Utilities ("RPU") is registered with the Western Electricity Coordinating Council ("WECC") and the North American Electric Reliability Corporation ("NERC") as a **Distribution Provider and Resource Planner.** It is the policy of RPU to comply with reliability standards promulgated by the WECC and the NERC, as subsequently approved and allowed to become effective by the Federal Energy Regulatory Commission ("FERC"). Any conflict between this RPU Compliance Policy and the applicable NERC and/or WECC reliability standard(s) shall be resolved in favor of the NERC/WECC reliability standard(s).

References: NERC Reliability Standard EOP-004-2 - *Event Reporting*

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

Applicability: The referenced NERC Reliability Standard is specifically applicable to RPU as a Distribution Provider.

Riverside Public Utilities Policy: RPU, as a registered Distribution Provider, is subject to Requirements 1, 2 and 3 of NERC Reliability Standard EOP-004-2.

Requirement 1 provides that "[e]ach Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-2 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*"

Requirement 2 provides that "[e]ach Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]"*

Requirement 3 provides that "[e]ach Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]"*

RPU operates at 69kV and neither its load nor its generating facilities are connected to the Bulk Electric System. RPU does operate and maintain an Under Frequency Load Shedding system agreed upon in the Master Metered Sub-System Agreement by RPU and the California Independent System Operator (CAISO) and in accordance with the WECC Off Nominal Frequency Study.

RPU complies with Requirement 1, pursuant to RPU Standard Practice 230.001 – Reporting Events to Regulatory Agencies (RPU's Operating Practice). According to Standard Practice 230.001, events are analyzed and the Department of Energy (DOE) and NERC-required reports are completed and provided to the DOE, NERC, WECC, the WECC Reliability Coordinator (Peak Reliability), the CAISO and Southern California Edison.

RPU will comply with Requirement 2, when it has a reportable event pursuant to RPU's Standard Practice 230.001.

RPU will comply with Requirement 3 by verifying contact information every calendar year while reviewing RPU's Standard Practice 230.001.

Noncompliance: Actual or anticipated failure to adhere to this RPU policy, or the underlying WECC or NERC policy, shall be immediately reported in accordance with the City of Riverside Public Utilities NERC-WECC Internal Compliance Program.

Record Retention: All written and electronic records related to compliance with this policy shall be retained for the greater of the period required by the (i) City of Riverside Record Retention Policy, (ii) Western Electricity Coordinating Council, or (iii) North American Electric Reliability Corporation.

Attachment: NERC Reliability Standard EOP-004-2

This RPU NERC Reliability Standard Compliance Policy supersedes RPU's prior policy for compliance with NERC Reliability Standard EOP-004-2 dated 7/1/2015.

Required Signatures:

Pat Hohl
Assistant General Manager-Energy Delivery

Kevin Milligan
Deputy General Manager

7/31/2016
Date

VERSION HISTORY

VERSION	DATE	CHANGE TRACKING
1	6/17/2007	Effective Date
2	10/3/2008	More Descriptive
3	03/02/2009	Replaced California-Mexico Reliability Coordinator with WECC Reliability Coordinator Added Version History
4	9/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
5	1/1/2014	Revised to comply with NERC Reliability Standard EOP-004-2
6	7/31/2014	Periodic review and updates
7	7/1/2015	Periodic review. Removed PSE reference. Revised paragraph on Noncompliance.
8	7/31/2016	Periodic review. Removed LSE reference.

A. Introduction

1. **Title:** Event Reporting

2. **Number:** EOP-004-2

3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.

4. **Applicability:**

   4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as "Responsible Entity."

   4.1.1. Reliability Coordinator

   4.1.2. Balancing Authority

   4.1.3. Transmission Owner

   4.1.4. Transmission Operator

   4.1.5. Generator Owner

   4.1.6. Generator Operator

   4.1.7. Distribution Provider

5. **Effective Dates:**

   The first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. **Background:**

   NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:

   1. CIP-001 could be merged with EOP-004 to eliminate redundancies.
   2. Acts of sabotage have to be reported to the DOE as part of EOP-004.
   3. Specific references to the DOE form need to be eliminated.
   4. EOP-004 had some 'fill-in-the-blank' components to eliminate.

The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.

The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the “road map” that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.

B. Requirements and Measures

R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-2 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-2 Attachment 1 and in accordance with the entity responsible for reporting.

R2. Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. Each Responsible Entity will have as evidence of reporting an event, copy of the completed EOP-004-2 Attachment 2 form or a DOE-OE-417 form; and evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). (R2)

R3. Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2 Evidence Retention

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirements R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirements R2, R3 and Measure M2, M3.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4 Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	Operations Planning	Lower	The Responsible Entity had an Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R2	Operations Assessment	Medium	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after meeting an event threshold for reporting. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours. OR The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Planning	Medium	The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month. OR The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.	The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months. OR The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.	The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months. OR The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.	The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more. OR The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.

D. Variances

None.

E. Interpretations

None.

F. References

Guideline and Technical Basis (attached)

EOP-004 - Attachment 1: Reportable Events

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 standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780.

Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in actions to avoid a BES Emergency.
Damage or destruction of a Facility	BA, TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action.
Physical threats to a Facility	BA, TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at a Facility. Do not report theft unless it degrades normal operation of a Facility.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Physical threats to a BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at a BES control center.
BES Emergency requiring public appeal for load reduction	Initiating entity is responsible for reporting	Public appeal for load reduction event.
BES Emergency requiring system-wide voltage reduction	Initiating entity is responsible for reporting	System wide voltage reduction of 3% or more.
BES Emergency requiring manual firm load shedding	Initiating entity is responsible for reporting	Manual firm load shedding ≥ 100 MW.
BES Emergency resulting in automatic firm load shedding	DP, TOP	Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or SPS/RAS).
Voltage deviation on a Facility	TOP	Observed within its area a voltage deviation of ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)	RC	Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).
Loss of firm load	BA, TOP, DP	Loss of firm load for ≥ 15 Minutes: ≥ 300 MW for entities with previous year's demand ≥ 3,000 OR ≥ 200 MW for all other entities
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA, GOP	Total generation loss, within one minute, of : ≥ 2,000 MW for entities in the Eastern or Western Interconnection OR ≥ 1,000 MW for entities in the ERCOT or Quebec Interconnection
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).
Unplanned BES control center evacuation	RC, BA, TOP	Unplanned evacuation from BES control center facility for 30 continuous minutes or more.
Complete loss of voice communication capability	RC, BA, TOP	Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.
Complete loss of monitoring capability	RC, BA, TOP	Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.

EOP-004 - Attachment 2: Event Reporting Form

<table>
<tr><th colspan="3">EOP-004 Attachment 2: Event Reporting Form
Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780.</th></tr>
<tr><th colspan="2">Task</th><th>Comments</th></tr>
<tr><td>1.</td><td>Entity filing the report include:
Company name:
Name of contact person:
Email address of contact person:
Telephone Number:
Submitted by (name):</td><td></td></tr>
<tr><td>2.</td><td>Date and Time of recognized event.
Date: (mm/dd/yyyy)
Time: (hh:mm)
Time/Zone:</td><td></td></tr>
<tr><td>3.</td><td>Did the event originate in your system?</td><td>Yes ☐ No☐ Unknown ☐</td></tr>
<tr><td rowspan="2">4.</td><td colspan="2">Event Identification and Description:</td></tr>
<tr><td>(Check applicable box)
☐ Damage or destruction of a Facility
☐ Physical Threat to a Facility
☐ Physical Threat to a control center
☐ BES Emergency:
☐ public appeal for load reduction
☐ system-wide voltage reduction
☐ manual firm load shedding
☐ automatic firm load shedding
☐ Voltage deviation on a Facility
☐ IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)
☐ Loss of firm load
☐ System separation
☐ Generation loss
☐ Complete loss of off-site power to a nuclear generating plant (grid supply)
☐ Transmission loss
☐ unplanned control center evacuation
☐ Complete loss of voice communication capability
☐ Complete loss of monitoring capability</td><td>Written description (optional):</td></tr>
</table>

Guideline and Technical Basis

Distribution Provider Applicability Discussion

The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the "Threshold for Reporting" for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more that 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.

Multiple Reports for a Single Organization

For entities that have multiple registrations, the DSR SDT intends that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

Summary of Key Concepts

The DSR SDT identified the following principles to assist them in developing the 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
- Establish consistent reporting timelines
- Provide clarity around who will receive the information and how it will be used

During the development of concepts, the DSR SDT considered the FERC directive to "further define sabotage". There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to reporting events. The term “sabotage” is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.

The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.

The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.

Data Gathering

The requirements of EOP-004-1 require that entities “promptly analyze Bulk Electric System disturbances on its system or facilities” (Requirement R2). The requirements of EOP-004-2 specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-2 may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.

Law Enforcement Reporting

The reliability objective of EOP-004-2 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. 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. 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. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry

- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

Present expectations of the industry under CIP-001-1a:

It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have lead to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.

Coordination of Local and State Law Enforcement Agencies with the FBI

The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.

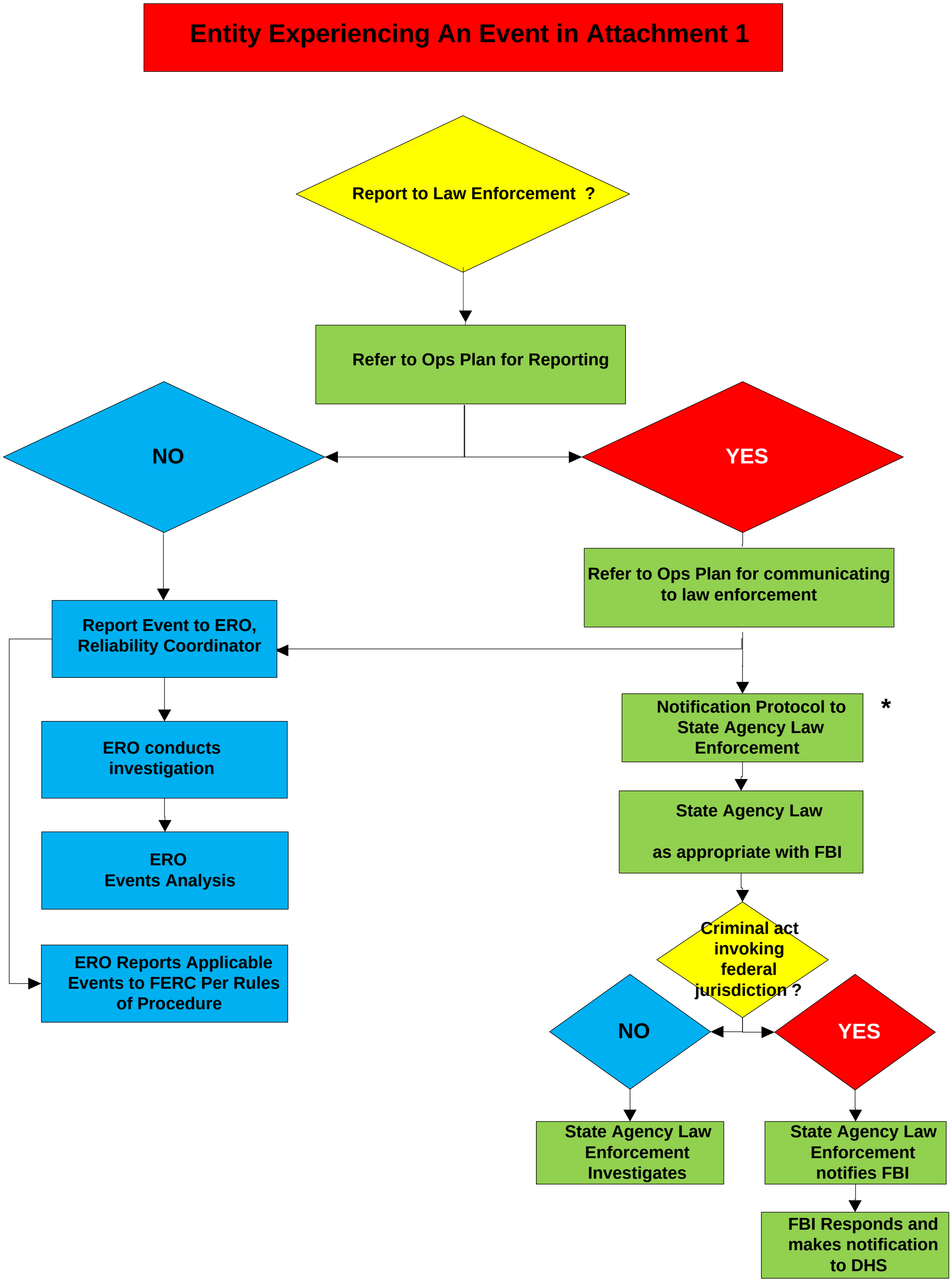
Coordination of Local and Provincial Law Enforcement Agencies with the RCMP

A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).

A Reporting Process Solution – EOP-004

A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.

Example of Reporting Process including Law Enforcement



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts

Introduction

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

- CIP-001 — Sabotage Reporting
- EOP-004 — Disturbance Reporting

The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.

Summary of Concepts and Assumptions:

The Standard:

- Requires reporting of “events” that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

Discussion of Disturbance Reporting

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.

3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).

Discussion of Event Reporting

There are situations worthy of reporting because they have the potential to impact reliability.

Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.

Examples of such events include:

- Bolts removed from transmission line structures
- 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)
- Destruction of Bulk Electric System equipment

What about sabotage?

One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *". . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event."*

Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.

Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.

Potential Uses of Reportable Information

Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

Collection of Reportable Information or "One stop shopping"

The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.

The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.

Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on

how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective.
The communication protocol(s) 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. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.

Rationale for R2:
Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-2 Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.

Rationale for R3:
Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.

Rationale for EOP-004 Attachment 1:
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.

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	

ATTACHMENT C

VERSION HISTORY **1/1/2017**

	RPU RELIABILITY STANDARD COMPLIANCE POLICY	VERSION	DATE	CHANGE TRACKING
1 N	CIP-002-1	0	6/17/2007	
	CIP-002-1	1	10/3/2008	KEMA Risk based methodology assessment report
	CIP-002-1	2	10/1/2009	Revised RSCP and Updated RPU Critical Cyber Asset Identification Report
	CIP-002-2	3	4/1/2010	Update NERC Standard Number and minor revisions
	CIP-002-3	4	10/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
	CIP-002-3	5	10/1/2011	Annual Review pursuant to R2, R3, R4
	CIP-002-3	6	10/1/2012	Annual Review pursuant to R2, R3, R4
	CIP-002-3	7	10/1/2013	Annual Review pursuant to R2, R3, R4. Updated names of Sr. Manager and General
	CIP-002-3	8	10/1/2014	Annual Review pursuant to R2, R3, R4
	CIP-002-3	9	7/1/2015	Removed PSE reference. Revised paragraph on Noncompliance
	CIP-002-3	10	10/1/2015	Annual Review pursuant to R2, R3, R4
	CIP-002-5.1 -011-2	11	7/1/2016	CIP-002-5.1 effective date. RSCPs for CIP-002-3 -009-3 have been retired
2	COM-001-2	1	10/1/2015	Effective date
	COM-001-2.1	2	3/1/2016	FERC errata on 11/13/2015. Removed reference to LSE.
3	COM-002-4	1	7/1/2016	Effective date
4	EOP-004-1	1	6/17/2007	
	EOP-004-1	2	10/3/2008	More descriptive
	EOP-004-1	3	3/2/2009	Replaced California-Mexico Reliability Coordinator with WECC Reliability Coordinator
	EOP-004-1	4	9/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
	EOP-004-2	5	1/1/2014	Revised to comply with NERC Reliability Standard EOP-004-2
	EOP-004-2	6	7/31/2014	Periodic review and updates
	EOP-004-2	7	7/1/2015	Periodic review. Removed PSE reference. Revised paragraph on Noncompliance.
	EOP-004-2	8	7/31/2016	Periodic review. Removed LSE reference.
5 N	EOP-005-2	1	7/1/2013	Effective Date
	EOP-005-2	2	7/31/2014	Periodic review and updates
	EOP-005-2	3	7/1/2015	Periodic review. Removed PSE reference.
	EOP-005-2	4	7/31/2016	Periodic review. Removed LSE reference.
6	FAC-002-0	1	6/17/2007	
	FAC-002-0	2	9/16/2008	More descriptive
	FAC-002-0	3	9/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
	FAC-002-1	4	10/1/2011	Update NERC Standard Number
	FAC-002-1	5	10/31/2013	Updated reference to Transmission System Planning Criteria
	FAC-002-1	6	1/21/2014	Requirement 2 retirement approved by FERC
	FAC-002-1	7	7/31/2014	Periodic review and updates
	FAC-002-1	8	7/1/2015	Periodic review. Removed PSE reference. Revised paragraph on Noncompliance.
	FAC-002-2	9	1/1/2016	NERC revised standard effective date
	FAC-002-2	10	7/31/2016	Periodic review. Removed LSE reference.
7	IRO-010-1a	1	10/1/2011	Effective Date
	IRO-010-1a	2	10/19/2012	Updated information flow processes
	IRO-010-1a	3	1/10/2014	Added Peak Reliability as Reliability Coordinator. Removed non-essential fourth paragraph under section heading Riverside Public Utilities Policy.
	IRO-010-1a	4	7/31/2014	Periodic review and updates
	IRO-010-1a	5	7/1/2015	Periodic review. Removed PSE reference. Revised paragraph on Noncompliance.
	IRO-010-2	6	1/1/2017	Applicable to DP. Removed LSE reference.
8 N	MOD-004-1	1	4/1/2011	Implementation
	MOD-004-1	2	6/1/2011	Removed references to CAISO Operating Procedure S-322
	MOD-004-1	3	3/30/2012	Removed reference to L.1.6 of Appendix L
	MOD-004-1	4	10/19/2012	Revised applicability based on CAISO Tariff
	MOD-004-1	5	6/15/2013	Removed reference to L.1.7 due to CAISO Tariff revision
	MOD-004-1	6	7/31/2014	Periodic review and updates
	MOD-004-1	7	7/1/2015	Periodic review. Removed PSE reference. Revised paragraph on Noncompliance.
	MOD-004-1	8	7/31/2016	Periodic review. Removed LSE reference. Only R4 applicable to RP.
9 N	MOD-020-0	1	6/17/2007	

VERSION HISTORY **1/1/2017**

	RPU RELIABILITY STANDARD COMPLIANCE POLICY	VERSION	DATE	CHANGE TRACKING
	MOD-020-0	2	8/5/2008	Inapplicable RSCP
	MOD-020-0	3	9/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
	MOD-020-0	4	10/1/2012	New AGM
	MOD-020-0	5	7/31/2014	Periodic review and updates
	MOD-020-0	6	7/1/2015	Periodic review. Removed PSE reference.
	MOD-020-0	7	7/31/2016	Periodic review. Removed LSE reference. Revised compliance language.
10	MOD-031-1	1	7/1/2016	Effective date
	MOD-031-1	2	7/31/2016	Periodic review. Revised compliance language for R4.
	MOD-031-2	1	10/1/2016	MOD-031-2 effective date
11	MOD-032-1	1	7/1/2016	Effective date
12 N	NUC-001-2	1	11/15/2010	Inapplicable RSCP
	NUC-001-2.1	2	7/31/2014	Periodic review and updates
	NUC-001-2.1	3	7/1/2015	Periodic review. Removed PSE reference.
	NUC-001-3	4	1/1/2016	Updated NERC Reliability Standard NUC-001-3 effective date 1/1/2016
	NUC-001-3	5	7/31/2016	Periodic review. Removed LSE reference.
13 N	PRC-004-1	0	6/17/2007	
	PRC-004-1	1	4/17/2008	Inapplicable RSCP
	PRC-004-1	2	7/13/2009	Changed "Council" to "Corporation"
	PRC-004-1	3	9/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
	PRC-004-2a	4	4/1/2012	Updated NERC RS PRC-004-2a
	PRC-004-2.1a	5	11/25/2013	Update NERC RS PRC-004-2.1a
	PRC-004-2.1a	6	7/31/2014	Periodic review and updates
	PRC-004-2.1(i)a	7	7/1/2015	Updated NERC RS PRC-004-2.1(i)a effective 5/29/2015. Periodic review. Removed PSE reference.
	PRC-004-4(i)	8	7/1/2016	Updated NERC RS PRC-004-4(i). Removed LSE reference.
14	PRC-005-1	0	6/17/2007	
	PRC-005-1	1	4/17/2008	Inapplicable RSCP
	PRC-005-1	2	7/13/2009	Changed "Council" to "Corporation"
	PRC-005-1	3	9/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
	PRC-005-1a	4	12/9/2011	Update NERC Standard Number effective 9/26/2011. No material changes
	PRC-005-1b	5	5/11/2012	Update NERC Standard Number PRC-005-1b effective 3/14/2012. No material changes
	PRC-005-1.1b	6	11/25/2013	Update NERC Standard Number PRC-005-1.1b
	PRC-005-1.1b	7	7/31/2014	Periodic review and updates
	PRC-005-1.1b	7.1	7/31/2016	Periodic review. Removed PSE and LSE reference.
	PRC-005-2	8	4/1/2015	PRC-005-2 is effective and applicable to RPU as a Distribution Provider.
	PRC-005-2(i)	9	7/1/2015	Update NERC Reliability Standard Number PRC-005-2(i) effective 5/29/2015. Periodic review. Removed PSE reference. Revised paragraph on Noncompliance.
	PRC-005-2(i)	9.1	7/31/2016	Periodic review. Removed PSE and LSE reference.
	PRC-005-6	10	1/1/2016	Update NERC Reliability Standard Number PRC-005-6 effective 1/1/2016
	PRC-005-6	10.1	7/31/2016	Periodic review. Removed PSE and LSE reference. Updated Versio History to include review/revisions to PRC-005-1.1b, PRC-005-2(I).
15	PRC-006-1	1	10/1/2013	Effective Date
	PRC-006-1	2	3/31/2014	Revised compliance process for R9. Removed reference dates on WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan and Southern Island Load Tripping Plan.
	PRC-006-1	3	7/31/2014	Periodic review and updates
	PRC-006-1	4	12/15/2014	Update to reference SP SUB-002
	PRC-006-1	5	7/1/2015	Periodic review. Removed PSE reference. Revised paragraph on Noncompliance.
	PRC-006-2	6	10/1/2015	NERC revised reliability standard effective date
	PRC-006-2	7	7/31/2016	Periodic review. Removed LSE reference.
16	PRC-008-0	1	6/17/2007	
	PRC-008-0	2	11/12/2008	More descriptive
	PRC-008-0	3	9/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
	PRC-008-0	4	2/1/2013	Replaced reference to Standard Practice ST-001 with Standard Practice SUB-001

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	PRC-008-0	5	7/31/2014	Periodic review and updates
	PRC-008-0	6	7/1/2015	Periodic review. Removed PSE reference. Revised paragraph on Noncompliance.
	PRC-008-0	7	7/31/2016	Periodic review. Removed LSE reference.
17 N	PRC-010-0	0	6/17/2007	
	PRC-010-0	1	4/17/2008	Inapplicable RSCP
	PRC-010-0	2	9/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
	PRC-010-0	3	1/21/2014	Requirement 2 retirement approved by FERC
	PRC-010-0	4	7/31/2014	Periodic review and updates
	PRC-010-0	5	7/1/2015	Periodic review. Removed PSE reference.
	PRC-010-0	6	7/31/2016	Periodic review. Removed LSE reference.
18 N	PRC-011-0	0	6/17/2007	
	PRC-011-0	1	4/17/2008	Inapplicable RSCP
	PRC-011-0	2	9/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
	PRC-011-0	3	7/31/2014	Periodic review and updates
	PRC-011-0	4	7/1/2015	Periodic review. Removed PSE reference.
	PRC-011-0	5	7/31/2016	Periodic review. Removed LSE reference.
19 N	PRC-015-0	0	6/17/2007	
	PRC-015-0	1	4/17/2008	Inapplicable RSCP
	PRC-015-0	2	9/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
	PRC-015-0	3	7/31/2014	Periodic review and updates
	PRC-015-0	4	7/1/2015	Periodic review. Removed PSE reference.
	PRC-015-0	5	7/31/2016	Periodic review. Removed LSE reference.
20 N	PRC-016-0	0	6/17/2007	
	PRC-016-0	1	4/17/2008	Inapplicable RSCP
	PRC-016-0.1	2	5/13/2009	Update NERC Standard Number
	PRC-016-0.1	3	9/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
	PRC-016-0.1	4	7/31/2014	Periodic review and updates
	PRC-016-0.1	5	7/1/2015	Periodic review. Removed PSE reference.
	PRC-016-0.1	6	7/31/2016	Periodic review. Removed LSE reference.
21 N	PRC-017-0	0	6/17/2007	
	PRC-017-0	1	4/17/2008	Inapplicable RSCP
	PRC-017-0	2	7/13/2009	Changed "Council" to "Corporation"
	PRC-017-0	3	9/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
	PRC-017-0	4	7/31/2014	Periodic review and updates
	PRC-017-0	5	7/1/2015	Periodic review. Removed PSE reference.
	PRC-017-0	6	7/31/2016	Periodic review. Removed LSE reference.
22 N	PRC-021-1	0	6/17/2007	
	PRC-021-1	1	4/17/2008	Inapplicable RSCP
	PRC-021-1	2	9/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
	PRC-021-1	3	7/31/2014	Periodic review and updates
	PRC-021-1	4	7/1/2015	Periodic review. Removed PSE reference.
	PRC-021-1	5	7/31/2016	Periodic review. Removed LSE reference.
23 N	PRC-022-1	0	6/17/2007	
	PRC-022-1	1	4/17/2008	Inapplicable RSCP
	PRC-022-1	2	9/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
	PRC-022-1	3	1/21/2014	Requirement 2 retirement approved by FERC
	PRC-022-1	4	7/31/2014	Periodic review and updates
	PRC-022-1	5	7/1/2015	Periodic review. Removed PSE reference.
	PRC-022-1	6	7/31/2016	Periodic review. Removed LSE reference.
24 N	PRC-023-1	1	7/1/2010	Inapplicable RSCP
	PRC-023-1	2	9/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
	PRC-023-2	3	7/1/2012	Updated Reliability Standard -2. Aligned description of why RPU has concluded that the Standard is inapplicable
	PRC-023-2	4	7/31/2014	Periodic review and updates

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	PRC-023-3	5	10/1/2014	PRC-023-3 effective date
	PRC-023-3	6	7/1/2015	Periodic review. Removed PSE reference.
	PRC-023-3	7	7/31/2016	Periodic review. Removed LSE reference.
25 N	PRC-025-1	1	10/1/2014	Effective date
	PRC-025-1	2	7/1/2015	Periodic review. Removed PSE reference.
	PRC-025-1	3	7/31/2016	Periodic review. Removed LSE reference.
26	TOP-001-1	1	6/17/2007	
	TOP-001-1	2	7/31/2008	More descriptive
	TOP-001-1	3	1/29/2009	Replaced California-Mexico Reliability Coordinator with WECC Reliability Coordinator
	TOP-001-1	4	7/13/2009	Removed reference to the Metered Subsystem Agreement. Simplified wording in
	TOP-001-1	5	9/1/2010	NERC Deactivated RPU as GO/GOP as of 6/17/2007
	TOP-001-1a	6	11/17/2011	Removed reference of SCE. Update NERC Standard Number
	TOP-001-1a	7	1/10/2014	Added Peak Reliability as Reliability Coordinator
	TOP-001-1a	8	7/31/2014	Periodic review and updates
	TOP-001-1a	9	7/1/2015	Periodic review. Removed PSE reference. Revised paragraph on Noncompliance.
	TOP-001-1a	10	7/31/2016	Periodic review. Removed LSE reference.
27	TOP-003-3	1	1/1/2017	Effective date