List of Subjects in 7 CFR Part 989

Grapes, Marketing agreements, Raisins, Reporting and recordkeeping requirements.

For the reasons set forth in the preamble, 7 CFR part 989 is amended as follows:

PART 989—RAISINS PRODUCED FROM GRAPES GROWN IN CALIFORNIA

■ 1. The authority citation for 7 CFR part 989 continues to read as follows:

Authority: 7 U.S.C. 601–674.

■ 2. Section 989.347 is revised to read as follows:

§ 989.347 Assessment rate.

On and after August 1, 2015, an assessment rate of $17.00 per ton is established for assessable raisins produced from grapes grown in California.

Dated: November 20, 2015.

Rex A. Barnes,

Associate Administrator, Agricultural Marketing Service.

[FR Doc. 2015–30013 Filed 11–24–15; 8:45 am]

BILLING CODE P

DEPARTMENT OF AGRICULTURE

Rural Housing Service

Rural Business-Cooperative Service

Rural Utilities Service

Farm Service Agency

7 CFR Part 1956

RIN 0570–AA88

Rural Development Loan Servicing; Correction

AGENCY: Rural Housing Service, Rural Business-Cooperative Service, Rural Utilities Service, and Farm Service Agency USDA.

ACTION: Direct final rule; correction.

SUMMARY: This document contains corrections to the published rule in the **Federal Register** of March 13, 2015, entitled ''Rural Development Loan Servicing.''

DATES: Effective November 25, 2015.

FOR FURTHER INFORMATION CONTACT: Melvin Padgett, Rural Development, Business Programs, U.S. Department of Agriculture, 1400 Independence Avenue SW., STOP 3226, Washington, DC 20250–3225; telephone (202) 720–1495; email *melvin.padgett@wdc.usda./gov.*

SUPPLEMENTARY INFORMATION: In the rule that is the subject of this correction, the Agency revised 7 CFR 1956.101 as intended, but the Agency inadvertently did not make the correct conforming change in 7 CFR 1956.147. To correct this oversight, the Agency is ''reserving'' 7 CFR 1956.147 in its entirety. This correction has no substantive effect on how debts are settled under this part.

Need for Correction

As published, the text that remains in 7 CFR 1956.147 after the March 13, 2015, rule may be misleading and cause confusion as a result of the changes made to 7 CFR 1956.101 in the March 13, 2015, rule.

List of Subjects in 7 CFR Part 1956

Loan programs—agriculture, Loan programs—housing and community development.

Accordingly, 7 CFR 1956.147 is corrected by making the following correcting amendment:

PART 1956—DEBT SETTLEMENT

■ 1. The authority citation for part 1956 continues to read as follows:

Authority: 5 U.S.C. 301; and 7 U.S.C. 1989.

§ 1956.147 [Removed and Reserved]

■ 2. Remove and reserve § 1956.147.

Dated: November 12, 2015.

Lisa Mensah,

Under Secretary, Rural Development.

Dated: November 17, 2015.

Michael Scuse,

Under Secretary, Farm and Foreign Agricultural Services.

[FR Doc. 2015–29781 Filed 11–24–15; 8:45 am]

BILLING CODE 3410–XY–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket Nos. RM15–7–000, RM15–12–000, and RM15–13–000 Order No. 818]

Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of ''Remedial Action Scheme'' and Related Reliability Standards

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

ACTION: Final rule.

SUMMARY: The Commission approves Reliability Standards and definitions of terms submitted in three related petitions by the North American Electric Reliability Corporation (NERC), the Commission-approved Electric Reliability Organization. The Commission approves Reliability Standards EOP–011–1 (Emergency Operations) and PRC–010–1 (Undervoltage Load Shedding). The proposed Reliability Standards consolidate, streamline and clarify the existing requirements of certain currently-effective Emergency Preparedness and Operations (EOP) and Protection and Control (PRC) standards. The Commission also approves NERC's revised definition of the term Remedial Action Scheme as set forth in the NERC Glossary of Terms Used in Reliability Standards, and modifications of specified Reliability Standards to incorporate the revised definition. Further, the Commission approves the implementation plans, and the retirement of certain currently-effective Reliability Standards.

DATES: This rule will become effective January 25, 2016.

FOR FURTHER INFORMATION CONTACT:

Juan Villar (Technical Information), Office of Electric Reliability, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (772) 678–6496, *Juan.Villar@ferc.gov.*

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Mark Bennett (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 502–8524, *Mark.Bennett@ferc.gov.*

SUPPLEMENTARY INFORMATION:

Order No. 818

Final Rule

(Issued November 19, 2015)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission approves Reliability Standards and definitions of terms submitted in three related petitions by the North American Electric Reliability Corporation (NERC), the Commission-approved Electric Reliability Organization (ERO). In particular, the Commission approves Reliability Standards EOP–011–1 (Emergency

[1] 16 U.S.C. 824o.

Operations) and PRC–010–1 (Undervoltage Load Shedding). The Commission finds that the Reliability Standards consolidate, streamline, and clarify the existing requirements of several currently-effective Emergency Preparedness and Operations (EOP) and Protection and Control (PRC) standards, and address certain Commission directives set forth in Order No. 693.[2]

2. Further, the Commission approves NERC's revised definition of the term Remedial Action Scheme as set forth in the NERC Glossary of Terms Used in Reliability Standards (NERC Glossary), and modifications of specified Reliability Standards to incorporate the revised definition. Also, the Commission approves the associated implementation plans and assigned violation risk factors and violation severity levels for Reliability Standard EOP–011–1 and Reliability Standard PRC–010–1, as well as the retirement of certain currently-effective Reliability Standards.

I. Background

3. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO subject to Commission oversight or by the Commission independently. In 2006, the Commission certified NERC as the ERO pursuant to FPA section 215.[3]

4. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including initial versions of EOP–001, EOP–002, and EOP–003.[4] In addition, the Commission directed NERC to develop certain modifications to the EOP standards. In Order No. 693, the Commission also approved several Undervoltage Load Shedding (UVLS)-related Reliability Standards, including PRC–010–0, PRC–021–1 and PRC–022–1.[5] Further, the Commission directed NERC to modify Reliability Standard PRC–010–0 to develop an ''integrated and coordinated'' approach to all protection systems.[6] In Order No. 693, the Commission approved the NERC Glossary, including NERC's currently-effective Special Protection System and Remedial Action Scheme definitions.

II. NERC Petitions

5. NERC submitted three related petitions that we address together in this Final Rule.[7]

A. NERC EOP Petition—Reliability Standard EOP–011–1 (Docket No. RM15–7–000)

6. On December 29, 2014, NERC filed a petition seeking Commission approval of Reliability Standard EOP–011–1, a revised definition of ''Energy Emergency'' and the associated violation risk factors and violation severity levels, effective date and implementation plan. NERC stated that the purpose of Reliability Standard EOP–011–1 is ''to address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Operating Plans to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator area.'' [8] NERC explained that Reliability Standard EOP–011–1 consolidates the requirements of three existing standards: EOP–001–2.1b, EOP–002–3.1 and EOP–003–2 ''into a single Reliability Standard that clarifies the critical requirements for Emergency Operations while ensuring strong communication and coordination across the functional entities.'' [9] NERC also asserted that Reliability Standard EOP–011–1 satisfies seven Commission directives set forth in Order No. 693.[10]

7. NERC noted that Reliability Standard EOP–011–1, Requirements R2 and R6 incorporate Attachment 1, which describes three Energy Emergency levels used by the reliability coordinator and the process for communicating the condition of a balancing authority experiencing an Energy Emergency.[11]

8. Reliability Standard EOP–011–1 includes six requirements, and is applicable to balancing authorities, reliability coordinators and transmission operators. Requirement R1 requires transmission operators to develop, maintain and implement reliability coordinator-reviewed operating plans to mitigate operating emergencies in its ''transmission operating area.'' [12] Requirement R1 provides that, ''as applicable,'' operating plans must: (1) Describe the roles and responsibilities for activating the operating plan; and (2) include processes to prepare for and mitigate emergencies, such as Reliability Coordinator notification, transmission system reconfiguration, and redispatch of generation. NERC explained that Requirement R1 uses the phrase ''as applicable'' to provide ''flexibility to account for regional differences and pre-existing methods for mitigating emergencies.'' [13] NERC added that an entity's decision to omit an element as not ''applicable'' must include an explanation in its plan. NERC further explained that the requirement for transmission operators to maintain operating plans includes the expectation that the plans are current and up-to-date.[14]

9. Requirement R2 requires balancing authorities to develop, maintain and implement reliability coordinator-reviewed operating plans to mitigate capacity and energy emergencies in its ''balancing authority area.'' Similar to the operating plans developed by transmission operators pursuant to the first requirement, the elements of the operating plans developed by balancing authorities allow for flexibility, provided an explanation is provided for omitted elements.[15]

10. Requirement R3 requires reliability coordinators to review the operating plans submitted by transmission operators and balancing authorities and is designed to ensure that there is appropriate coordination of reliability risks identified in the operating plans. In reviewing operating plans, reliability coordinators shall consider compatibility, coordination

[2] *Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. and Regs. ¶ 31,242, *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[3] *North American Electric Reliability Corp.,* 116 FERC ¶ 61,062, *order on reh'g & compliance,* 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc.* v. *FERC,* 564 F.3d 1342 (D.C. Cir. 2009).

[4] Order No. 693, FERC Stats. and Regs. ¶ 31,242.

[5] *Id.* PP 1509, 1560, and 1565. The Commission neither approved nor rejected proposed Reliability Standard PRC–020–1, explaining that the standard only applied to Regional Reliability Organizations. *Id.* P 1555.

[6] *Id.* P 1509.

[7] Reliability Standards EOP–011–1 and PRC–010–1 are not attached to this Final Rule, nor are the additional Reliability Standards that NERC proposes to modify to incorporate the term Remedial Action Scheme. The Reliability Standards are available on the Commission's eLibrary document retrieval system in the identified dockets and on the NERC Web site, *www.nerc.com.*

[8] NERC EOP Petition at 2.

[9] *Id.* at 3.

[10] *Id.* at 12–18.

[11] Attachment 1 describes three alert levels: Energy Emergency Alert Level 1 (all available generation resources in use, concern about sustaining required contingency reserves); Energy Emergency Alert Level 2 (load management procedures in effect, energy deficient balancing authority implements its emergency Operating Plan but maintains minimum contingency reserve requirements); and Energy Emergency Alert Level 3 (firm load interruption is imminent or in process, energy deficient balancing authority unable to maintain minimum contingency reserve requirements).

[12] Operating Plan is defined in 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 . . .''

[13] NERC EOP Petition at 9.

[14] *Id.* at 8–9.

[15] *Id.*

and inter-dependency with other entity operating plans and notify transmission providers and balancing authorities if revisions to their operating plans are necessary.[16]

11. Requirement R4 requires transmission operators and balancing authorities to resolve any issues identified by the reliability coordinator and resubmit their revised operating plans within a time period specified by the reliability coordinator. Requirement R5 requires reliability coordinators to notify balancing authorities and transmission operators in its area, and neighboring reliability coordinators, within 30 minutes of receiving an emergency notification. Requirement R6 requires a reliability coordinator with a balancing authority experiencing a potential or actual Energy Emergency to declare an Energy Emergency alert in accordance with Attachment 1.

12. Proposed Reliability Standard EOP–011–1 also includes the following revised definition of Energy Emergency:

> Energy Emergency—A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load obligations.

NERC explained that the revised definition is intended to clarify that an Energy Emergency is not limited to a load-serving entity and, based on a review of the impact on the body of NERC Reliability Standards, ''does not change the reliability intent of other requirements of Definitions.'' [17]

13. NERC proposed an effective date for Reliability Standard EOP–011–1 that is the first day of the first calendar quarter that is 12 months after the date of Commission approval, and a retirement date for currently-effective Reliability Standards EOP–001–2.1b, EOP–002–3.1 and EOP–003–2 of midnight of the day immediately prior to the effective date of Reliability Standard EOP–011–1.

B. NERC PRC Petition—Proposed Reliability Standard PRC–010–1 (Docket No. RM15–12–000)

14. On February 6, 2015, NERC filed a petition seeking approval of Reliability Standard PRC–010–1 (Undervoltage Load Shedding), a revised definition of Undervoltage Load Shedding Program (UVLS Program) for inclusion in the NERC Glossary, and the associated violation risk factors, violation severity levels, effective date and implementation plan. NERC also proposed the retirement of four PRC Reliability Standards.[18] NERC stated that the purpose of Reliability Standard PRC–010–1 is to ''establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs'' as directed by the Commission in Order No. 693.[19]

15. NERC explained that Reliability Standard PRC–010–1 is a single, comprehensive standard that addresses the same reliability principles outlined in the four currently-effective UVLS-related Reliability Standards.[20] Reliability Standard PRC–010–1 replaces the applicability to and involvement of ''Regional Reliability Organization'' in Reliability Standards PRC–020–1 and PRC–021–1 and improves upon and consolidates the four currently-effective UVLS-Related Standards into one comprehensive standard. NERC explained that Reliability Standard PRC–010–1 ''reflects consideration of the 2003 Blackout Report recommendations,'' [21] particularly, Recommendation 21 for NERC to ''make more effective and wider use of system protection measures'' [22] and Recommendation 21C for NERC to ''determine the goals and principles needed to establish an integrated approach to relay protection for generators and transmission lines, as well as of UFLS and UVLS programs.'' [23]

16. Reliability Standard PRC–010–1 incorporates a new definition of UVLS Program, which reads:

> Undervoltage Load Shedding Program (UVLS Program): An automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.

NERC explained that ''to ensure that the applicability of the proposed Reliability Standard covers undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: Voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System. By focusing on the enumerated risks, the definition is meant to exclude locally-applied relays that are not designed to mitigate wide-area voltage collapse.'' [24] NERC stated that the UVLS Program definition ''clearly identifies and separates centrally controlled undervoltage-based load shedding, which is now addressed by the proposed definition of Remedial Action Scheme.'' [25]

17. Reliability Standard PRC–010–1 applies to planning coordinators and transmission planners because ''either may be responsible for designing and coordinating the UVLS Program . . . [and] also applies to Distribution Providers and Transmission Owners responsible for the ownership, operation and control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.'' [26] NERC explained that the planning coordinator or transmission planner that establishes a UVLS Program is responsible for identifying the UVLS equipment and the necessary distribution provider and transmission owner (referred to as ''UVLS entities'' in the Applicability section) that performs the required actions.

18. NERC stated that Reliability Standard PRC–010–1 ''applies only after an entity has determined the need for a UVLS Program as a result of its own planning studies.'' [27] NERC explained that the eight requirements in Reliability Standard PRC–010–1 meet four primary objectives: (1) The Reliability Standard requires applicable entities to evaluate a UVLS Program's effectiveness prior to implementation, including coordination with other protection systems and generator voltage ride-through capabilities; (2) applicable entities must comply with UVLS program specifications and implementation schedule; (3) applicable entities must perform periodic assessment and performance analysis; and (4) applicable entities must maintain and share UVLS Program data.[28]

19. Requirement R1 requires each planning coordinator or transmission planner to evaluate the viability and effectiveness of its UVLS program before implementation to confirm its effectiveness in resolving the undervoltage conditions for which it

[16] *Id.* at 10–11.

[17] *Id.* at 18.

[18] Reliability Standards PRC–010–0 (Assessment of the Design and Effectiveness of UVLS Program); PRC–020–1 (Under-Voltage Load Shedding Program Database); PRC–021–1 (Under-Voltage Load Shedding Program Data); and PRC–022–1 (Under-Voltage Load Shedding Program Performance).

[19] NERC PRC Petition at 14 (citing Order No. 693, FERC Stats & Regs ¶ 31,242 at P 1509).

[20] *Id.*

[21] *Id.* at 2 (citing the U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* April, 2004 (2003 Blackout Report)).

[22] *Id.* at 4 (citing 2003 Blackout Report at 3, 158).

[23] *Id.* at 6.

[24] *Id.* at 16.

[25] *Id.* at 15. NERC's petition for approval of the proposed definition of Remedial Action Scheme (Docket No. RM15–13–000) is discussed below.

[26] *Id.*

[27] *Id.* at 14.

[28] *Id.* at 17.

was designed, and that it is integrated through coordination with generator ride-through capabilities and other protection and control systems. Also, the planning coordinator or transmission planner must provide the UVLS Program specifications and implementation schedule to the applicable UVLS entities. Requirement R2 requires UVLS entities to meet the UVLS Program's specifications and implementation schedule provided by the planning coordinator or transmission planner or address any necessary corrective actions in accordance with Requirement R5.

20. Requirement R3 requires each planning coordinator or transmission planner to perform periodic comprehensive assessments at least every 60 calendar months to ensure continued effectiveness of the UVLS program, including whether the program resolves identified undervoltage issues and that it is integrated and coordinated with generator voltage ride-through capabilities and other specified protection and control systems. Requirement R4 requires each planning coordinator or transmission planner to commence a timely assessment of a voltage excursion subject to the UVLS Program, within 12 calendar months of the event, to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event. Requirement R5 requires a corrective action plan for any program deficiencies identified during an assessment performed under either Requirement R3 or R4, and provide an implementation schedule to UVLS entities within three calendar months of its completion.

21. Pursuant to Requirement R6, a planning coordinator must update the data necessary to model its UVLS Program for use in event analyses and program assessments at least each calendar year. Requirement R7 requires each UVLS entity to provide data to its planning coordinator, according to the planning coordinator's format and schedule, to support maintenance of the UVLS Program database. Requirement R8 requires a planning coordinator to provide its UVLS Program database to other planning coordinators and transmission planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request.

22. NERC proposed an effective date for Reliability Standard PRC–010–1 and the definition of UVLS Program of the first day of the first calendar quarter that is 12 months after the date that the standard and definition are approved by the Commission. NERC proposed to retire PRC–010–0, PRC–020–1, PRC–021–1, and PRC–022–1 at midnight of the day immediately prior to the effective date of PRC–010–1.[29] Further, NERC explained that Reliability Standard PRC–010–1 addresses reliability obligations that are set forth in Requirements R2, R4 and R7 of currently-effective Reliability Standard EOP–003–2.[30] Since NERC has proposed to retire EOP–003–2 in the petition seeking approval of Reliability Standard EOP–011–1 (Docket No. RM15–7–00, discussed above), concurrent Commission action on the two petitions will prevent a possible reliability gap.

C. NERC RAS Petition—Revisions to the Definition of ''Remedial Action Scheme'' (Docket No. RM15–13–000)

23. On February 3, 2015, NERC filed a petition seeking approval of a revised definition of Remedial Action Scheme in the NERC Glossary, as well as modified Reliability Standards that incorporate the new Remedial Action Scheme definition and eliminate use of the term Special Protection System, and the associated implementation plan.[31] NERC stated that the defined terms Special Protection System and Remedial Action Scheme are currently used interchangeably throughout the NERC Regions and in various Reliability Standards. NERC explained that ''[a]lthough these defined terms share a common definition in the NERC Glossary of Terms today, their use and application have been inconsistent as a result of a lack of granularity in the definition and varied regional uses of the terms. The proposed revisions add clarity and granularity that will allow for proper identification of Remedial Action Schemes and a more consistent application of related Reliability Standards.''[32]

24. NERC explained that the revised Remedial Action Scheme definition consists of a ''core'' definition, including a list of objectives and a separate list of exclusions for certain schemes or systems not intended to be covered by the revised definition.[33] NERC stated that a broad definition is needed because of ''all the possible scenarios an entity may develop'' for its Remedial Action Scheme and a ''very specific, narrow definition may unintentionally exclude schemes that should be covered.''[34] Accordingly, NERC proposed the following revised ''core'' definition of Remedial Action Scheme:

A scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). (sic) RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The definition then lists fourteen exclusions, describing specific schemes and systems that do not constitute a Remedial Action Scheme, because each is either a protection function, a control function, a combination of both, or used for system configuration.[35]

25. In the implementation plan, NERC proposed an effective date for the revised Reliability Standards and the revised definition of Remedial Action Scheme on the first day of the first calendar quarter that is 12 months after Commission approval.[36] NERC also proposed that, for entities with existing schemes that become newly classified as ''Remedial Action Schemes'' resulting from the application of the revised definition, the entities will have additional time of up to 24 months from the effective date to be fully compliant with all applicable Reliability Standards.[37] Further, NERC asked the Commission to take final action concurrently with the NERC petition on proposed Reliability Standard PRC–010–1 (Docket No. RM15–12–000) because ''[t]he proposed definitions of UVLS Program and Remedial Action Scheme in each project have been coordinated to cover centrally controlled UVLS as a Remedial Action Scheme. Final action by the Commission is needed

[29] *Id.* Ex. B (Implementation Plan).

[30] *Id.* at 23.

[31] NERC RAS Petition at 1–2. NERC requested approval of the following Reliability Standards to incorporate the proposed definition of Remedial Action Scheme and eliminate use of the term Special Protection System: EOP–004–3, PRC–005–3(ii), PRC–023–4, FAC–010–3, TPL–001–0.1(i), FAC–011–3, TPL–002–0(i)b, MOD–030–3, TPL–003–0(i)b, MOD–029–2a, PRC–015–1, TPL–004–0(i)a, PRC–004–WECC–2, PRC–016–1, PRC–001–1.1(i), PRC–005–2(ii), PRC–017–1. NERC did not propose any changes to the Violation Risk Factors or Violation Severity Levels for the modified standards.

[32] *Id.* at 4–5.

[33] *Id.* at 16. NERC noted that ''for each exclusion, the scheme or system could still classify as a Remedial Action Scheme if employed in a broader scheme that meets the definition of Remedial Action Scheme.''

[34] *Id.* at 17.

[35] *Id.* at 18.

[36] NERC RAS Petition, Ex. C (Implementation Plan) at 4.

[37] *Id.*

contemporaneously on both petitions to facilitate implementation and avoid a gap in coverage of centrally controlled UVLS.'' [38]

III. Notice of Proposed Rulemaking

26. On June 18, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to approve the Reliability Standards and NERC Glossary definitions set forth in NERC's three petitions pertaining to EOP–011–1, PRC–010–1 and a revised definition of Remedial Action Scheme as just, reasonable, not unduly discriminatory or preferential and in the public interest. [39] The Commission also proposed to approve the related violation risk factors, violation severity levels and implementation plans.

27. The Commission proposed to approve the retirement of Reliability Standards EOP–001–2.1b, EOP–002–3.1, EOP–003–2, PRC–010–0, PRC–020–1 and PRC–021–1. However, the Commission expressed concerns about whether it was appropriate to retire PRC–022–1 before a replacement Reliability Standard is approved and implemented to address the potential misoperation of UVLS equipment. Accordingly, the Commission proposed to deny NERC's request to retire Reliability Standard PRC–022–1 concurrent with the effective date of PRC–010–1.

28. In the NOPR, the Commission stated that Reliability Standards EOP–011–1 and PRC–010–1 provide greater clarity and that the consolidation of currently-effective EOP and PRC standards provides additional efficiencies for responsible entities. The Commission also agreed with NERC that the new definition of Remedial Action Scheme will improve reliability by eliminating ambiguity and encouraging the consistent identification of Remedial Action Schemes and a more consistent application of related Reliability Standards.

29. While the Commission proposed to approve Reliability Standard PRC–010–1, the Commission raised questions and sought clarification regarding an example of a ''BES subsystem'' that NERC provided in the ''Guidelines for UVLS Program Definition.'' The Commission indicated that, depending on the response from NERC and others, a directive for further modification may be appropriate.[40]

30. In response to the NOPR, the Commission received comments from: NERC, Edison Electric Institute (EEI), Peak Reliability, Transmission Access Policy Study Group (TAPS), International Transmission Company (ITC), Louisville Gas and Electric Company and Kentucky Utilities Company (LG&E/KU) and Idaho Power Company (Idaho Power).

IV. Discussion

31. Pursuant to FPA section 215(d)(2), we approve Reliability Standards EOP–011–1 and PRC–010–1, the revised definition of Remedial Action Scheme and NERC Glossary definitions, and associated violation risk factors and violation severity levels and implementation plans as just, reasonable, not unduly discriminatory or preferential and in the public interest. The Commission believes that the modified Reliability Standards provide greater clarity, and the consolidated EOP and PRC standards will provide additional efficiencies for responsible entities. We also determine that Reliability Standard EOP–011–1 adequately addresses seven Order No. 693 directives, and that Reliability Standard PRC–010–1 establishes an integrated and coordinated approach to the design, evaluation and reliable operation of UVLS Programs, and therefore satisfies the Commission directive issued in Order No. 693.[41] Further, we approve the retirement of certain Reliability Standards as identified by NERC.[42]

32. We discuss below the following issues raised in the NOPR and comments: (1) The deregistration of load-serving entities and Reliability Standard EOP–011–1; (2) the scheduling and scope of reliability coordinator reviews of Operating Plans under Reliability Standard EOP–011–1; (3) the retirement of Reliability Standard PRC–022–1; (4) the term ''BES subsystem'' and related diagram in NERC's PRC Petition; and (5) other issues raised by commenters.

A. Reliability Standard EOP–011–1

1. The Deregistration of Load-Serving Entities

NOPR

33. In the NOPR, while proposing to approve Reliability Standard EOP–011–1 and a new Energy Emergency definition, the Commission stated that the removal of load-serving entities from the Reliability Standard raises questions about who would perform the roles traditionally performed by load-serving entities.[43] The NOPR explained that the Commission's decision concerning NERC's compliance filing in Docket No. RR15–4–000 related to NERC's Risk-Based Registration initiative would guide the Commission's action on this question in this proceeding.

Comments

34. NERC, EEI, TAPS, ITC and Idaho Power support the Commission's proposed approval of Reliability Standard EOP–011–1. Further, NERC, EEI and TAPS state that excluding load-serving entities from the Reliability Standard will not create a reliability gap. NERC states that currently-effective Reliability Standard EOP–002–3.1 Requirement R9 is the only requirement in the three Reliability Standards being replaced by Reliability Standard EOP–011–1 that applies to load-serving entities. NERC explains that the North American Energy Standards Board (NAESB) has modified the process for E-tag specifications, removing the load-serving entities' role in making changes to the priority of transmission service requests. Therefore, the ''Standard Drafting Team did not incorporate Requirement R9 into Reliability Standard EOP–011–1, because Requirement R9 has become obsolete due to technological changes.'' [44]

35. Additionally, NERC explains that, due to the Real-time nature of energy emergencies, balancing authorities and distribution providers will handle responsibilities related to Reliability Standard EOP–002–3.1 that have been performed by load-serving entities. Referring to the Mapping Document and Application Guidelines for Reliability Standard EOP–011–1, NERC states that ''LSEs have no Real-time reliability

[38] NERC RAS Petition at 3–4.

[39] *Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of ''Remedial Action Scheme'' and Related Reliability Standards,* Notice of Proposed Rulemaking, 80 FR 36,293 (June 24, 2015), 151 FERC ¶ 61,230 (2015) (NOPR).

[40] NOPR, 151 FERC ¶ 61,230 at P 27.

[41] Order No. 693, FERC Stats & Regs. ¶ 31,242 at P 1509.

[42] As noted above, the Commission in Order No. 693 did not approve or remand proposed Reliability Standard PRC–020–1 but, rather, took no action on the Reliability Standard pending the receipt of additional information. Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1555. Our approval of NERC's request renders PRC–020–1 ''retired,'' *i.e.,* withdrawn, and no longer pending before the Commission.

[43] NOPR, 151 FERC ¶ 61,230 at P 24, n.36. Currently effective EOP–002–3.1 applies, *inter alia,* to load-serving entities. Reliability Standard EOP–011–1 replaces EOP–002–3.1, and applies to balancing authorities, reliability coordinators and transmission operators, but not load-serving entities.

[44] NERC Comments at 4.

functionality with respect to EEAs [Energy Emergency Alerts].'' [45]

36. TAPS and EEI agree with NERC's analysis of the roles and responsibilities of load-serving entities and that excluding them will not create any reliability gaps. TAPS states that ''there is no reliability benefit to retaining EOP–002–3.1's Requirement R9, and thus no reliability risk from eliminating the LSE obligation to comply with it.'' [46] EEI asserts that ''NERC is correct that 'tasks currently assigned to the LSE function under NERC Reliability Standards would continue to be performed by other functions subject to currently applicable LSE Reliability Standard Requirements or by market participants (including LSEs) pursuant to existing tariffs, market rules, market protocols and other market agreements.' '' [47] Regarding Operating Plans that transmission operators and balancing authorities are to develop under Reliability Standard EOP–011–1 Requirements R1 and R2, EEI states that ''it is clear that the responsible entities required to perform the activities attributed to the LSE function necessary to aid in arresting an Energy Emergency must be identified to ensure necessary mitigation can be accomplished in order to ensure reliable operation of the BES.'' [48]

37. LG&E/KU seeks clarification on two questions pertaining to the exclusion of load-serving entities from Reliability Standard EOP–011–1 ''to ensure that even if NERC's EOP proposal is accepted, [balancing authorities] will have a meaningful way of addressing any operational gaps with Energy Emergencies and LSEs.'' [49] First, LG&E/KU seeks clarification that an Energy Emergency can be isolated to a load-serving entity's inability to meet its own load obligations, as indicated in NERC's revised definition of Energy Emergency. Second, LG&E/KU seeks clarification that Operating Plans developed by balancing authorities may describe the role for load-serving entities in responding to an Energy Emergency, and may include such Operating Plans in applicable tariffs.

Commission Determination

38. Consistent with our determination in the ''risk-based registration'' proceeding, we find that the elimination of load-serving entities from Reliability Standard EOP–011–1 will not prevent the Reliability Standard from achieving its stated purposes or otherwise create reliability gaps.[50] We find that Reliability Standard EOP–011–1 enhances reliability by requiring that actions necessary to mitigate capacity and energy emergencies are focused in single operating plans, and ensures communication and coordination among relevant entities during emergency operations. We are persuaded by NERC's explanation that excluding load-serving entities will not adversely impact reliability due to technological changes concerning NAESB tagging specifications, and that load-serving entities ''have no Real-time reliability functionality with respect to EEAs [Energy Emergency Alerts].'' [51] Further, as both NERC and EEI have stated, ''tasks currently assigned to the LSE function under NERC Reliability Standards would continue to be performed by other functions subject to currently applicable LSE Reliability Standard Requirements or by market participants (including LSEs) pursuant to tariffs, market rules, market protocols and other market agreements.'' [52]

39. We disagree with LG&E/KU's suggestion that the reference to load-serving entities in NERC's revised definition of Energy Emergency indicates the possibility of an ''operational gap.'' NERC revises the definition of ''Energy Emergency,'' approved in this Final Rule, as ''[a] condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load obligations.'' [53] Based on a plain reading of this definition, we agree with LG&E/KU that a load-serving entity's inability to meet its own load obligations could result in an Energy Emergency. Moreover, consistent with our findings in the RBR Compliance Order, we agree with LG&E/KU that operating plans developed by balancing authorities—including operating plans contained in applicable tariffs—may describe the role for load-serving entities in responding to an Energy Emergency.[54] EEI's observation regarding Reliability Standard EOP–011–1 Requirements R1 and R2 for transmission operators and balancing authorities to develop Operating Plans to mitigate Energy Emergencies reinforces this determination: ''[a]lthough these requirements do not specifically identify the 'who' or 'what' actions to be taken, it is clear that the responsible entities required to perform the activities attributed to the LSE function necessary to aid in arresting an energy emergency must be identified to ensure necessary mitigation can be accomplished in order to ensure reliable operation of the BES.'' [55] Accordingly, we conclude that elimination of the load-serving entity function from Reliability Standard EOP–011–1 does not result in an operational gap and, rather, provides a reasonable means of addressing Energy Emergencies.

2. The Scheduling and Scope of Reliability Coordinator Reviews of Operating Plans

40. Reliability Standard EOP–011–1, Requirement R3 obligates a reliability coordinator to review the Operating Plan(s) to mitigate operating emergencies submitted by a transmission operator or a balancing authority. Pursuant to Requirement R3.1, a reliability coordinator must, within 30 days of receipt, (i) review each Operating Plan for compatibility and inter-dependency with other transmission operator or balancing authority Operating Plans, (ii) review each Operating Plan for coordination to avoid risk to ''Wide Area'' reliability, and (iii) notify each transmission operator and balancing authority of the results of the review.

Comments

41. Peak Reliability asserts that the ''inflexible'' 30 day period for reliability coordinator reviews of operating plans in Reliability Standard EOP–011–1 Requirement R3.1 is not reasonable. According to Peak Reliability, because transmission operators have an ''open ended'' opportunity to submit operating plans under the provision, reliability coordinators cannot schedule in advance the needed resources to perform a proper review in the 30-day window. Peak Reliability notes that, in its experience, many entities update their plans at the end of the year, creating a large spike in review work at that time. Peak Reliability, therefore, recommends revising Requirement R3.1 to include language requiring ''a mutually agreed predetermined schedule'' to ensure that the reliability coordinator can efficiently allocate its

[45] *Id.* at 5–6.

[46] TAPS Comments at 4.

[47] EEI Comments at 5–6, quoting NERC's compliance filing in RR15–4–000 at 1.

[48] *Id.* at 6.

[49] LG&E/KU Comments at 2.

[50] *See North American Electric Reliability Corp.*, 153 FERC ¶ 61,024, at P 20 (2015) (RBR Compliance Order) (approving the proposed elimination of the load-serving entity function).

[51] NERC Comments at 5, quoting the EOP–011–1 Mapping Document and Application Guidelines.

[52] EEI Comments at 5–6.

[53] NERC EOP Petition, Ex. B (Implementation Plan) at 1.

[54] RBR Compliance Order, 153 FERC ¶ 61,024 at 21.

[55] EEI Comments at 6.

resources and provide a thorough review of submitted operating plans.[56]

42. Peak Reliability also seeks clarification regarding the scope of reliability coordinator review of operating plans, and whether a reliability coordinator must review each required element of an operating plan specified in Requirement R2 for ''compatibility and interdependency'' with other balancing authority and transmission operator operating plans, or ''evaluate these elements on a higher level.'' [57] Peak Reliability asserts that the ''appropriate level of review'' by reliability coordinators is ''for coordination to avoid risk to Wide Area reliability.'' Based on this assertion, Peak Reliability recommends that Reliability Standard EOP–011–1 require balancing authorities and transmission operators to identify and coordinate possible operating plan discrepancies before submission for reliability coordinator review, as currently required under Reliability Standard EOP–001–2.1b Requirement R6.[58]

Commission Determination

43. We are not persuaded by Peak Reliability's comments that the 30 day review period in Requirement R3.1 is unduly onerous. No reliability coordinator other than Peak Reliability expressed concern about the 30 day review period for operating plans in Requirement R3.1. NERC explains that transmission operators and balancing authorities must update their operating plans on an ''ongoing and as-needed basis.'' [59] The need for registered entities to update operating plans to address evolving bulk electric system conditions should prevent reliability coordinators from being overwhelmed or unduly burdened by operating plan submissions. However, if Peak Reliability experiences an ''end of the year spike in workload,'' [60] as a reliability coordinator, Peak Reliability can adjust its resource allocation to accommodate such known ''spikes'' in activity. Accordingly, we conclude the 30 day review period in Requirement R3.1 is reasonable and reject Peak Reliability's recommendation for language requiring a ''mutually agreed predetermined schedule.''

44. Additionally, we believe that Peak Reliability's concern regarding the extent of reliability coordinator Operating Plan review for ''compatibility and interdependency'' under Reliability Standard EOP–011–1 Requirement 3.1.1 is misplaced. Based on the record before us, particularly the Standard Drafting Team's decision to require reliability coordinators to review rather than approve operating plans, and the ongoing nature of emergency planning, we conclude that Requirement R3.1.1 contemplates high level assessments focused on the coordination of operating plans between and among transmission operators and balancing authorities.[61] Moreover, while Peak Reliability may request that NERC (*e.g.,* through a standard authorization request or ''SAR'') include a provision in EOP–011–1 to require coordination among transmission operators and balancing authorities prior to submitting an operating plan for reliability coordinator review, we are not persuaded to direct NERC to develop such a provision.

B. Reliability Standard PRC–010–1

1. Retirement of Reliability Standard PRC–022–1

NOPR

45. In the NOPR, while proposing to approve Reliability Standard PRC–010–1 and the retirement of PRC–010–0, PRC–020–1 and PRC–021–1, the Commission was not persuaded that Reliability Standard PRC–010–1, Requirement R4 is an adequate replacement for currently-effective PRC–022–1, which contains requirements specifically addressing misoperations. Rather, the Commission proposed that Reliability Standard PRC–022–1 would remain in effect until an acceptable replacement Reliability Standard is in place to address the potential misoperation of UVLS equipment.

Comments

46. NERC states that, on June 9, 2015, it filed proposed Reliability Standards PRC–010–2 and PRC–004–5 as part of its UVLS Phase II Petition (Project 2008–02.2), which includes requirements and applicability criteria related to UVLS misoperations.[62] NERC explains that its filing requests that the Commission approve Reliability Standards PRC–004–5 and PRC–010–2 concurrently with the Commission's action on Reliability Standard PRC–010–1 ''to ensure an integrated and coordinated approach to UVLS Programs and fill the gap in Reliability Standard coverage that might be perceived through retirement of PRC–022–1.'' [63] EEI agrees, stating that NERC's filing of proposed Reliability Standards PRC–004–5 and PRC–010–2 address the Commission's concerns expressed in the NOPR.[64]

Commission Determination

47. We agree with NERC and EEI that the Delegated Letter Order approval of Reliability Standards PRC–004–5 and PRC–010–2 in Docket No. RD15–5–000 concurrent with this Final Rule precludes the need to retain currently-effective Reliability Standard PRC–022–1.[65] Accordingly, we find that Reliability Standard PRC–022–1 can be retired without creating a gap in coverage with regard to UVLS protective relay misoperations and equipment performance evaluations.

2. The Term ''BES Subsystem'' and Related Diagram

NOPR

48. In the NOPR, the Commission sought clarification of the meaning of NERC's use of the term ''BES subsystem'' in a diagram illustrating a UVLS system that would not be included in the definition of UVLS Program if the consequences of the contingency do not impact the bulk electric system, and whether it would be considered a Remedial Action Scheme.[66]

Comments

49. NERC comments that the term ''BES subsystem'' and accompanying diagram are ''intended to demonstrate that whether PRC–010–1 applies to a UVLS system depends on whether the UVLS system is used to mitigate undervoltage conditions impacting areas of the BES, leading to voltage instability, voltage collapse or Cascading.'' [67] NERC also states that ''the term 'BES subsystem' is a shorthand reference to an area of the BES that a Registered Entity is responsible for, consistent with its obligations under mandatory Reliability Standards. This reference does not revise the Commission-

[56] Peak Reliability Comments at 6–7.

[57] *Id.* at 7.

[58] *Id.* at 7–8.

[59] *See* NERC EOP Petition at 9.

[60] *See* Peak Reliability Comments at 5–6.

[61] *See* NERC EOP Petition, Exhibit G (Summary of Development History and Complete Record of Development) at 1166 (the Standard Drafting Team indicates that the provision is intended to require the reliability coordinator review of deficiencies, inconsistencies or conflicts between operating plans that would cause further system degradation during emergency conditions).

[62] Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standards PRC–004–5 and PRC–010–2, (Docket No. RD15–5–000).

[63] NERC Comments at 8.

[64] EEI Comments at 7.

[65] *See* Delegated Letter Order issued November 19, 2915.

[66] *See* NOPR, 151 FERC ¶ 61,230 at P 27 (including diagram).

[67] NERC Comments at 6–7.

approved definition of 'Bulk Electric System' or create a new term.'' [68]

50. NERC explains that the diagram ''is not intended to necessarily illustrate a centrally controlled UVLS (considered a [Remedial Action Scheme]), but to illustrate how Registered Entities should evaluate whether the term UVLS Program and proposed Reliability Standard PRC–010–1 applies to a UVLS system.'' [69] NERC points out that, if a UVLS system in the ''BES subsystem'' is used to mitigate undervoltage conditions impacting the BES (leading to voltage instability, voltage collapse, or Cascading), the system would fall under the new definition of UVLS Program (or RAS if centrally controlled) and thus in the scope of Reliability Standard PRC–010–1.[70]

51. EEI states that the example of ''BES subsystem'' in the ''Guidelines for UVLS Program Definition'' does not represent a centrally controlled UVLS and therefore would not be considered a Remedial Action Scheme. EEI explains that the term UVLS Program ''is for a scheme that consists of distributed relays and controls, not for a scheme that is centrally controlled. The key point is that for a UVLS system to fall under the definition of Undervoltage Load Shedding Program, it must be used to protect the BES against voltage instability, voltage collapse, or Cascading.'' [71] EEI also notes that the term ''BES subsystem'' is not intended to be a new NERC term, but rather ''was used in the example to illustrate a possible localized undervoltage contingency on a very small portion of the BES but not a contingency that impacts a larger area of the BES that could result in voltage instability, voltage collapse, or Cascading.'' [72]

Commission Determination

52. Based on the explanations provided above, we determine that a directive for further modification of the example of ''BES subsystem'' and related diagram in NERC's ''Guidelines for UVLS Program Definition'' to ensure consistency with the Commission-approved definition of ''bulk electric system'' proposed in the NOPR is not necessary. Rather, we are persuaded that EEI's concern with the diagram is addressed by NERC's explanation that, depending on the role of a particular UVLS system, the diagram could illustrate an example of a UVLS Program or a centrally-controlled Remedial Action Scheme.[73]

C. Other Issues Raised By Commenters

1. Reliability Standard PRC–010–1—Applicability

53. Peak Reliability asserts that Reliability Standard PRC–010–1 ''does not adequately address the operation of UVLS Programs, as it does not apply to the NERC functional entities that operate the Bulk Electric System,'' particularly, reliability coordinators, transmission operators, and balancing authorities.[74] Peak Reliability contends that UVLS Programs should be included in operational planning and real-time assessments, and that all entities responsible for operating the bulk electric system must be given access to UVLS Program databases.[75] Further, Peak Reliability requests that the Commission direct NERC to explain why Reliability Standard PRC–010–1 and Reliability Standard IRO–009–1 apply to different functional entities (since the purpose of both is to prevent instability, uncontrolled separation or cascading outages), and recommends that the treatment of UVLS in operations planning and real-time assessments be addressed.[76]

54. We are not persuaded by Peak Reliability's assertion that Reliability Standard PRC–010–1 should apply to reliability coordinators, transmission operators, and balancing authorities. Rather, as NERC explains ''[t]he applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the UVLS Program. Reliability Standard PRC–010–1 also applies to Distribution Providers and Transmission Owners responsible for the ownership, operation and control of UVLS equipment as required by the UVLS Program established by the Transmission Planner and Planning Coordinator.'' [77] As NERC's rationale above indicates, the applicability section of the Reliability Standard identities the functional entities responsible for the design, operation and control of UVLS Programs and related equipment.

55. While Peak Reliability seeks to expand applicability to functional entities so that UVLS Program databases would be shared with reliability coordinators, transmission operators, and balancing authorities, we believe that this need to expand applicability is unfounded. Reliability Standard PRC–010–1, Requirement R8, provides that other functional entities with a reliability need can request UVLS data, and that such requests must be answered in 30 days.

56. Nor are we persuaded by Peak Reliability's argument that UVLS programs should be considered in operations planning and real-time operations. We understand that Peak Reliability refers to the consideration of UVLS programs in the derivation of Interconnection Reliability Operating Limits (IROLs) for Category B contingencies as defined in the currently-effective transmission planning standard TPL–002–0b (commonly known as N–1 contingencies under normal system operation).[78] With this understanding, we disagree with Peak Reliability on the relevance of using UVLS in the derivation of IROLs for N–1 contingencies. The 2003 Canada-United States Blackout Report stated that ''[s]afety nets should not be relied upon to establish transfer limits.'' [79] This statement is consistent with the performance criteria established in TPL–002–0b and TPL–001–4, which generally prohibit the loss of non-consequential load for certain N–1 contingencies.[80] We conclude that UVLS programs under PRC–010–1 are examples of such ''safety nets'' and should not be tools used by bulk electric system operators to calculate operating limits for N–1 contingencies. Likewise, with this understanding, there is no imperative to make PRC–010–1 applicable to reliability coordinators, transmission operators, and balancing authorities.

57. Peak Reliability comments that Reliability Standard PRC–010–1 ''creates some confusion of the applicability of UVLS Programs due to the similarities, and apparent overlap, in the definitions of UVLS Programs and IROLs.'' [81] We disagree. Peak Reliability's comparison of UVLS Programs with establishing and operating within IROLs is misplaced because UVLS Programs and IROLs represent separate and distinct approaches to system security. UVLS Programs act as safety nets for contingencies more severe than N–1 contingencies, such as the simultaneous

[68] *Id.* at 7.

[69] *Id.*

[70] *Id.*

[71] EEI Comments at 8.

[72] *Id.*

[73] *Id.*

[74] Peak Reliability Comments at 9.

[75] *Id.* at 9–10.

[76] *Id.* at 11–12.

[77] NERC EOP Petition at 15, and id. Ex. D (Order No. 672 Criteria) at 2–3.

[78] The Commission-approved Version 4 standard, TPL–001–4, will replace TPL–002–0b on January 1, 2016. *See Transmission Planning Reliability Standards,* Order No. 786, 145 FERC ¶ 61,051 (2013).

[79] 2003 Blackout Report at 109.

[80] *See* TPL–002–0b, Table 1, footnote b and TPL–001–4, Table 1, Footnote 12.

[81] Peak Reliability Comments at 11.

loss of two single circuits or a double-circuit line which are both Category C contingencies permitting loss of non-consequential firm load.[82] In contrast, the NERC Glossary defines IROLs as ''[a] System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Bulk Electric System.'' This corresponds with the TPL–004–1 provisions requiring that the system must remain stable when experiencing an N–1 contingency (such as Category B or P1 contingencies).[83] In sum, we disagree with Peak Reliability's premise regarding similarities, and overlaps, in the definition of UVLS programs and IROLs.

2. Reliability Standard PRC–010–1—Appropriate Level of Detail in UVLS Program Assessment

58. Reliability Standard PRC–010–1, Requirements R3, R4, and R5 obligate planning coordinators and transmission planners to perform an assessment of their UVLS program in various circumstances. Idaho Power contends that Reliability Standard PRC–010–1, Requirements R3, R4, and R5, do not ''specifically state what must be included in the assessment, as was included in PRC–022–1 R1.1–4'' and, therefore, do not sufficiently explain what applicable entities must include in UVLS Program assessments.[84]

59. We disagree with Idaho Power. Reliability Standard PRC–022–1 requires applicable entities to ''analyze and document all UVLS operations and misoperations,'' and specifically mentions set points and tripping times and a summary of the findings. In contrast, Reliability Standard PRC–010–1 Requirement R3, requires planning coordinators and transmission planners to perform comprehensive assessments of their UVLS Programs at least once every 5 years. Each assessment ''shall include, but is not limited to, studies and analyses that evaluate whether . . . the UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed [and] the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems.'' Requirement R4 requires applicable entities to assess whether UVLS programs resolve undervoltage issues associated with voltage excursions triggering UVLS programs. Pursuant to Requirement R5, planning coordinators and transmission planners must develop a corrective action plan to address UVLS program deficiencies identified during assessments performed under Requirements R3 and R4. We conclude that the comprehensive nature of the assessments required under Reliability Standard PRC–010–1 is sufficient, and precludes the need to include the specific items listed in PRC–022–1, Requirement R1.

3. Definition of Special Protection System

60. ITC supports the approval of the revised definition of Remedial Action Scheme. ITC points out that NERC proposes to move to a single definition, Remedial Action Scheme, to eliminate the use of two terms, *i.e.,* Special Protection System.[85] Thus, ITC requests that the Commission direct NERC to remove the definition of Special Protection System from the NERC Glossary to eliminate any potential for confusion.

61. We deny ITC's request that the Commission direct NERC to remove the definition of ''Special Protection System'' from the NERC Glossary. In its RAS Petition, NERC states that it ''will continue to modify the NERC Reliability Standards until all of them reference only the defined term Remedial Action Scheme. At that time, the definition of Special Protection System will be retired.''[86] We are satisfied with NERC's approach of retiring the term ''Special Protection System'' once the Reliability Standards are fully updated to reference the revised definition of Remedial Action Scheme.

V. Information Collection Statement

62. The collection of information contained in this Final Rule is subject to review by the Office of Management and Budget (OMB) regulations under section 3507(d) of the Paperwork Reduction Act of 1995 (PRA).[87] OMB's regulations require approval of certain informational collection requirements imposed by agency rules.[88] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

63. The Commission is submitting these reporting and recordkeeping requirements to OMB for its review and approval under section 3507(d) of the PRA. The NOPR solicited comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the provided burden estimate, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques. No comments were received.

A. Proposed Reliability Standard EOP–011–1

64. *Public Reporting Burden:* As of March 2015, there are 105 balancing authorities, 11 reliability coordinators and 329 transmission operators registered with NERC. These registered entities will have to comply with 6–8 new requirements in the new proposed Reliability Standard EOP–011–1. As proposed, each registered balancing authority will have to comply with Requirements R2, R4, and, under certain circumstances, R5. Each reliability coordinator will have to comply with Requirements R1 and its subparts, R2 and its subparts, R3 and its subparts, R5 and R6. Each transmission operator will have to comply with Requirements R1 and its subparts and R4.

65. Reliability Standard EOP–011–1 replaces a combined total of 40 requirements or subparts that are found in Reliability Standards EOP–001–2.1b, EOP–003.1 and EOP–003–2. These three Reliability Standards are to be retired, concurrent with the effective date of Reliability Standard EOP–011–1. Accordingly, the requirements in Reliability Standard EOP–011–1 do not create any new burdens for applicable balancing authorities or transmission operators because the requirements in Reliability Standard EOP–011–1 are already burdens or tasks imposed on this set of registered entities by Reliability Standards EOP–001–2.1b, EOP–003.1 and EOP–003–2 under FERC–725A (1902–0244).

66. Reliability Standard EOP–011–1 requires reliability coordinators to perform the additional tasks of reviewing, correcting, and coordinating their balancing authorities' and transmission operators' operating procedures for emergency conditions. The Commission estimates that this will add approximately 1,500 man-hours per

[82] The TPL Standards require that the system remain stable and that cascading and uncontrolled islanding shall not occur for any Category B or C contingency (*i.e.,* currently-effective TPL Standards, N–1 and N–2 contingencies) or for any Category P1 through P7 contingency (*i.e.,* TPL–001–4, N–1 and N–2 contingencies.) *See* Table 1 of any of the TPL Standards.

[83] *See* TPL Standards, Table 1.

[84] Idaho Power Comments at 2.

[85] ITC Comment at 3.

[86] NERC RAS Petition at 5.

[87] 44 U.S.C. 3507(d).

[88] 5 CFR 1320.11.

year for each reliability coordinator as described in detail in the following table:

RM15–7–000 (MANDATORY RELIABILITY STANDARDS: RELIABILITY STANDARD EOP–011–1)

	Number of applicable registered entities (1)	Annual number of responses per respondent (2)	Total number of responses (1) * (2) = (3)	Average burden (hours) and cost per response (4)	Total annual burden hours and total annual cost (3) * (4) = (5)	Cost per respondent ($) (5) ÷ (1)
RC tasks necessary for EOP–011–1 compliance	11	1	21	1,500 [89] $92,387	16,500 $1,016,257	$92,387

B. Proposed Reliability Standard PRC–010–1

Public Reporting Burden: As of April 2015, there are 467 registered distribution providers and 50 transmission providers that are not overlapping in their registration with the distribution provider registration. We estimate that five percent of all distribution providers (23) and transmission providers (3) have under voltage load shedding programs that fall under the Reliability Standard. The Reliability Standard is applicable to planning coordinators and transmission planners, distribution providers, and transmission owners. However, only distribution providers and transmission owners would be responsible for the incremental compliance burden under Reliability Standard PRC–010–1, Requirement R2, as described in detail in the following table:

RM15–12–000 (MANDATORY RELIABILITY STANDARDS: RELIABILITY STANDARD PRC–010–1) [90]

	Number of applicable registered entities (1)	Annual number of responses per respondent (2)	Total number of responses (1) * (2) = (3)	Average burden (hours) and cost per response (4)	Total annual burden hours and total annual cost (3) * (4) = (5)	Cost per respondent ($) (5) ÷ (1)
DP—Requirement 2	23	1	23	[91] 36 $1,960.32	828 $45,087.36	1,960
TP—Requirement 2	3	1	3	[92] 36 $1,960.32	108 $5,880.96	1,960
DP—R2 Data Retention	23	1	23	12 [93] $367.92	276 $8,462.16	368
TP—R2 Data Retention	3	1	3	12 $367.92	36 $1,103.76	368
Total	....	....	....	....	$60,534.24	....

C. Remedial Action Scheme Revisions

67. *Public Reporting Burden:* The Commission approved the definition of Special Protection System (Remedial Action Scheme) in Order No. 693. We approve a revision to the previously approved definition. The revisions to the Remedial Action Scheme definition and related Reliability Standards are not expected to result in changes to the scope of systems covered by the Reliability Standards and other Reliability Standards that include the term Remedial Action Scheme. Therefore, the Commission does not expect the revisions to affect applicable entities' current reporting burden.

FERC–725G4, Mandatory Reliability Standards: Reliability Standard PRC–010–1 (Undervoltage Load Shedding).

FERC–725S, Mandatory Reliability Standards: Reliability Standard EOP–011–1 (Emergency Operations).

Action: Proposed Collection of Information.

OMB Control No: OMB Control No. 1902–0270 (FERC–725S); OMB Control No. 1902–XXXX (FERC–725G4).

Respondents: Business or other for-profit and not-for-profit institutions.

Frequency of Responses: One time and on-going.

Necessity of the Information: The revision to NERC's definition of the term bulk electric system implements the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk-Power System. Specifically, the Reliability Standards consolidate, streamline and clarify the existing requirements of certain currently-effective Emergency Preparedness and Operations and

[89] The 1,500 hour figure is broken into 1300 hours at the engineer wage rate and 200 hours at the clerk wage rate. These estimates assume that the engineer's wage rate will be $66.35 and the clerk's wage rate will be $30.66. These figures are taken from the Bureau of Labor Statistics at *http://www.bls.gov/oes/current/naics2_22.htm;* Occupation Code: 17–2071 (engineer) and 43–4071 (clerk).

[90] DP = distribution provider and TP = transmission provider.

[91] The 36 hour figure is broken into 24 hours at the engineer wage rate and 12 hours at the clerk wage rate. These estimates assume that the engineer's wage rate will be $66.35 and the clerk's wage rate will be $30.66. These figures are taken from the Bureau of Labor Statistics at *http://www.bls.gov/oes/current/naics2_22.htm;* Occupation Code: 17–2071 (engineer) and 43–4071 (clerk).

[92] *Id.*

[93] Clerk's wage rate is used for managing data retention.

Protection and Control Reliability Standards.

68. *Internal review:* The Commission has reviewed the requirements pertaining to Reliability Standards PRC–010–1 and EOP–011–1 and made a determination that the requirements of these Reliability Standards are necessary to implement section 215 of the FPA. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

69. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, Office of the Executive Director, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, email: *DataClearance@ferc.gov,* phone: (202) 502–8663, fax: (202) 273–0873].

70. Comments concerning the information collections in this Final Rule and the associated burden estimates, should be sent to the Commission in this docket and may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by email to OMB at the following email address: *oira_submission@omb.eop.gov.* Please reference the docket number of this Final Rule (Docket Nos. RM15–13–000, RM15–12–000, and RM15–7–000) in your submission.

VI. Regulatory Flexibility Act Certification

71. The Regulatory Flexibility Act of 1980 (RFA) [94] generally requires a description and analysis of Proposed Rules that will have significant economic impact on a substantial number of small entities.

72. Reliability Standard EOP–011–1 is expected to impose an additional burden on 11 entities (reliability coordinators). The remaining 434 entities (balancing authorities and transmission operators and a combination thereof) will maintain the existing levels of burden. Comparison of the applicable entities with FERC's small business data indicates that approximately 7 of the 11 entities are small entities, or 63.63 percent of the respondents affected by this Reliability Standard.[95]

73. On average, each small entity affected may have a one-time cost of $92,387 representing a one-time review of the program for each entity, consisting of 1,500 man-hours at $66.35/hour (for engineer wages) and $30.66/hour (for record clerks), as explained above in the information collection statement.

74. Reliability Standard PRC–010–1 is expected to impose an additional burden on 26 entities (distribution providers and transmission providers or a combination thereof). Comparison of the applicable entities with FERC's small business data indicates that approximately 8 of the 26 entities are small entities, or 30.77 percent of the respondents affected by this Reliability Standard.

75. On average, each small entity affected may have a cost of $1,960, representing a one-time review of the program for each entity, consisting of 36 man-hours at $66.35/hour (for engineer wages) and $30.66/hour (for record clerks), as explained above in the information collection statement. Regarding the revisions to the Remedial Action Scheme definition and the related Reliability Standards including the revised definition, as discussed above, the Commission estimates that proposals will have no cost impact on applicable entities, including any small entities.

76. The Commission estimates that Reliability Standards EOP–011–1 and PRC–010–1 in this Final Rule impose an additional burden on a total of 37 entities. FERC's small business data indicates that 15 of the 37 respondents are small entities, or 40.54 percent of the respondents affected by these proposed Reliability Standards. On average, each small entity affected may have a cost of $92,387 and $1,960 (EOP–011–1 and PRC–010–1 respectively), representing a one-time review of the program for each entity. We do not consider these costs to be a significant economic impact on small entities. Accordingly, the Commission certifies that Reliability Standards EOP–011–1 and PRC–010–1 will not have a significant economic impact on a substantial number of small entities.

VII. Environmental Analysis

77. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[96] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[97] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

VIII. Document Availability

78. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington, DC 20426.

79. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

80. User assistance is available for eLibrary and the Commission's Web site during normal business hours from the Commission's Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

IX. Effective Date and Congressional Notification

81. This Final Rule is effective January 25, 2016. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement

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[94] 5 U.S.C. 601–12.

[95] The Small Business Administration sets the threshold for what constitutes a small business. Public utilities may fall under one of several different categories, each with a size threshold based on the company's number of employees, including affiliates, the parent company, and subsidiaries. For the analysis in this NOPR, we are using a 500 employee threshold for each affected entity. Each entity is classified as Electric Bulk Power Transmission and Control (NAICS code 221121).

[96] *Regulations Implementing the National Environmental Policy Act of 1969,* Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

[97] 18 CFR 380.4(a)(2)(ii).

Fairness Act of 1996.[98] The Commission will submit the final rule to both houses of Congress and to the General Accountability Office.

By the Commission.

Issued: November 19, 2015.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2015–29971 Filed 11–24–15; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF THE TREASURY

Alcohol and Tobacco Tax and Trade Bureau

27 CFR Part 9

[Docket No. TTB–2015–0006; T.D. TTB–131; Ref: Notice No. 150]

RIN 1513–AC18

Establishment of the Eagle Foothills Viticultural Area

AGENCY: Alcohol and Tobacco Tax and Trade Bureau, Treasury.

ACTION: Final rule; Treasury decision.

SUMMARY: The Alcohol and Tobacco Tax and Trade Bureau (TTB) establishes the approximately 49,815-acre ''Eagle Foothills'' viticultural area in Gem and Ada Counties in Idaho. The viticultural area lies entirely within the established Snake River Valley viticultural area. TTB designates viticultural areas to allow vintners to better describe the origin of their wines and to allow consumers to better identify wines they may purchase.

DATES: This final rule is effective December 28, 2015.

FOR FURTHER INFORMATION CONTACT: Dominique Christianson, Regulations and Rulings Division, Alcohol and Tobacco Tax and Trade Bureau, 1310 G Street NW., Box 12, Washington, DC 20005; phone 202–453–1039, ext. 278.

SUPPLEMENTARY INFORMATION:

Background on Viticultural Areas

TTB Authority

Section 105(e) of the Federal Alcohol Administration Act (FAA Act), 27 U.S.C. 205(e), authorizes the Secretary of the Treasury to prescribe regulations for the labeling of wine, distilled spirits, and malt beverages. The FAA Act provides that these regulations should, among other things, prohibit consumer deception and the use of misleading statements on labels and ensure that labels provide the consumer with adequate information as to the identity and quality of the product. The Alcohol and Tobacco Tax and Trade Bureau (TTB) administers the FAA Act pursuant to section 1111(d) of the Homeland Security Act of 2002, codified at 6 U.S.C. 531(d). The Secretary has delegated various authorities through Treasury Department Order 120–01, dated December 10, 2013, to the TTB Administrator to perform the functions and duties in the administration and enforcement of this law.

Part 4 of the TTB regulations (27 CFR part 4) authorizes TTB to establish definitive viticultural areas and regulate the use of their names as appellations of origin on wine labels and in wine advertisements. Part 9 of the TTB regulations (27 CFR part 9) sets forth standards for the preparation and submission of petitions for the establishment or modification of American viticultural areas (AVAs) and lists the approved AVAs.

Definition

Section 4.25(e)(1)(i) of the TTB regulations (27 CFR 4.25(e)(1)(i)) defines a viticultural area for American wine as a delimited grape-growing region having distinguishing features, as described in part 9 of the regulations, and a name and a delineated boundary, as established in part 9 of the regulations. These designations allow vintners and consumers to attribute a given quality, reputation, or other characteristic of a wine made from grapes grown in an area to the wine's geographic origin. The establishment of AVAs allows vintners to describe more accurately the origin of their wines to consumers and helps consumers to identify wines they may purchase. Establishment of an AVA is neither an approval nor an endorsement by TTB of the wine produced in that area.

Requirements

Section 4.25(e)(2) of the TTB regulations (27 CFR 4.25(e)(2)) outlines the procedure for proposing an AVA and provides that any interested party may petition TTB to establish a grape-growing region as an AVA. Section 9.12 of the TTB regulations (27 CFR 9.12) prescribes standards for petitions for the establishment or modification of AVAs. Petitions to establish an AVA must include the following:

- Evidence that the area within the proposed AVA boundary is nationally or locally known by the AVA name specified in the petition;
- An explanation of the basis for defining the boundary of the proposed AVA;
- A narrative description of the features of the proposed AVA affecting viticulture, such as climate, geology, soils, physical features, and elevation, that make the proposed AVA distinctive and distinguish it from adjacent areas outside the proposed AVA boundary;
- The appropriate United States Geological Survey (USGS) map(s) showing the location of the proposed AVA, with the boundary of the proposed AVA clearly drawn thereon; and
- A detailed narrative description of the proposed AVA boundary based on USGS map markings.

Eagle Foothills Petition

TTB received a petition from Martha Cunningham, owner of the 3 Horse Ranch Vineyards, on behalf of the local grape growers and vintners, proposing the establishment of the ''Eagle Foothills'' AVA in Gem and Ada Counties, Idaho. The proposed AVA is immediately north of the city of Eagle and is approximately 10 miles northwest of the city of Boise. The Eagle Foothills AVA is located entirely within the established Snake River Valley AVA (27 CFR 9.208) and does not overlap with any other existing or proposed AVA. The original proposed name for the AVA was ''Willow Creek Idaho.'' However, TTB determined that the petition did not sufficiently demonstrate that the region is known by that name. Therefore, the petitioner submitted a request to change the proposed AVA name to ''Eagle Foothills.''

The proposed Eagle Foothills AVA contains approximately 49,815 acres, with 9 commercially-producing vineyards covering a total of 67 acres distributed throughout the proposed AVA. The petition states that an additional 4 acres will soon be added to an existing vineyard and that an additional 7 commercial vineyards covering approximately 472 acres are planned within the next few years.

According to the petition, the distinguishing features of the proposed Eagle Foothills AVA are its topography, climate, and soils. The proposed AVA is located within the Unwooded Alkaline Foothills ecoregion of Idaho. This ecoregion is defined as an arid, sparsely populated region of rolling foothills, benches, and alluvial fans underlain by alkaline lake bed deposits. A network of seasonal creeks flowing southwesterly through the proposed AVA have created deep gulches and a rugged terrain that has a variety of slope aspects favorable to the vineyard owners. The elevation within the proposed AVA ranges from 2,490 feet to approximately 3,400 feet, with an average elevation of 2,900 feet.

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[98] *See* 5 U.S.C. 804(2).