prescribing regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This proposed regulation is within the scope of that authority as it proposes to remove Class D and E airspace at Panama City-Bay County Airport, Panama City, FL.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (Air).

The Proposed Amendment

Accordingly, pursuant to the authority delegated to me, the Federal Aviation Administration proposes to amend 14 CFR Part 71 as follows:

PART 71 —DESIGNATION OF CLASS A, B, C, D, AND E AIRSPACE AREAS; AIR TRAFFIC SERVICE ROUTES; AND REPORTING POINTS

1. The authority citation for Part 71 continues to read as follows:

Authority: 49 U.S.C. 106(g); 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 71.1 [Amended]

2. The incorporation by reference in 14 CFR 71.1 of Federal Aviation Administration Order 7400.9T, Airspace Designations and Reporting Points, signed August 27, 2009, and effective September 15, 2009, is amended as follows:

Paragraph 5000 Class D Airspace.

* * * * *

ASO FL D Panama City, FL [Removed]

* * * * *

Paragraph 6004 Class E Airspace Designated as an Extension to a Class D Surface Area.

* * * * *

ASO FL E4 Panama City, FL [Removed]

* * * * *

Paragraph 6005 Class E Airspace Areas Extending Upward from 700 feet or More Above the Surface of the Earth.

* * * * *

ASO FL E5 Panama City, FL [Removed]

Issued in College Park, Georgia, on March 17, 2010.

Michael Vermuth,

Acting Manager, Operations Support Group, Eastern Service Center, Air Traffic Organization.

[FR Doc. 2010–6665 Filed 3–24–10; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM10–6–000]

Interpretation of Transmission Planning Reliability Standard

March 18, 2010.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: Requirement R1.3.10 of the Commission-approved transmission planning Reliability Standard TPL–002–0 provides that planning authorities and transmission planners must consider in their planning studies the effects of the operation of their protection systems, including backup and redundant protection systems. The North American Electric Reliability Corporation (NERC), the Commission-certified electric reliability organization, requests approval of an interpretation of Reliability Standard TPL–002–0. In this order, the Commission proposes to reject NERC's proposed interpretation of Requirement R1.3.10 of Reliability Standard TPL–002–0 and, instead, proposes an alternative interpretation of the provision.

DATES: Comments are due May 10, 2010.

ADDRESSES: You may submit comments, identified by docket number by any of the following methods:

- *Agency Web Site: http://ferc.gov.* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- *Mail/Hand Delivery:* Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

Notice of Proposed Rulemaking

1. On November 17, 2009, the North American Electric Reliability Corporation (NERC) submitted a petition (NERC Petition) requesting approval of NERC's interpretation of Requirement R1.3.10 of Commission-approved transmission planning Reliability Standard TPL–002–0 (System Performance Following Loss of a Single Bulk Electric System Element). NERC developed the interpretation in response to a request for interpretation submitted to NERC by PacifiCorp on January 12, 2009. The Commission proposes to reject the NERC proposed interpretation of Requirement R1.3.10 of Reliability Standard TPL–002–0 and, instead, proposes an alternative interpretation of the provision.

I. Background

2. Section 215 of the Federal Power Act (FPA) requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval.[1] Specifically, the Commission may approve, by rule or order, a proposed Reliability Standard or modification to a Reliability Standard if it determines that the Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[2] Once approved, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[3]

3. Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[4] and subsequently certified NERC.[5] On April 4, 2006, NERC submitted to the Commission a petition seeking approval of 107 proposed Reliability Standards. On March 16, 2007, the Commission issued a Final Rule, Order No. 693,[6] approving 83 of the 107 Reliability Standards, including transmission planning Reliability Standards TPL–

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

[2] *Id.* 824o(d)(2).

[3] *Id.* 824o(e)(3).

[4] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards,* Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g,* Order No. 672–A, FERC Stats. & Regs. ¶ 31,212 (2006).

[5] *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 (DC Cir. 2009).

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

001–0 through TPL–004–0. In addition, pursuant to section 215(d)(5) of the FPA,[7] the Commission directed NERC to develop modifications to 56 of the 83 approved Reliability Standards, including TPL–002–0.[8]

4. NERC's Rules of Procedure provide that a person that is "directly and materially affected" by Bulk-Power System reliability may request an interpretation of a Reliability Standard.[9] In response, the ERO will assemble a team with relevant expertise to address the requested interpretation and also form a ballot pool. NERC's Rules of Procedure provide that, within 45 days, the team will draft an interpretation of the reliability standard and submit it to the ballot pool. If approved by the ballot pool and subsequently by the NERC Board of Trustees (Board), the interpretation is appended to the Reliability Standard and filed with the applicable regulatory authorities for approval.

II. Transmission Planning Reliability Standards

5. Each of the transmission planning Reliability Standards, TPL–001–0 through TPL–004–0, requires the planning authorities and transmission planners (planner) to provide a "valid assessment" that would "ensure that reliable systems are developed that meet specified performance requirements" both in the near-term (years one through five) and in the longer-term (years six through ten, or as needed). For each of these Reliability Standards, entities must adequately assess a range of operating conditions on their systems and plan to meet certain performance criteria that the Reliability Standards specify for each of four classes of contingencies.[10] The principles that planners must apply to the design of the assessment and of the supporting studies are set forth in the Requirements of the specific Reliability Standard.

6. Table I, which is incorporated into each TPL Reliability Standards, sets forth the different types of contingencies that planners must study pursuant to the specific Reliability Standard, and the performance criteria the system must meet when experiencing those contingencies to reliably meet all projected customer demand.

7. Reliability Standard TPL–002–0 requires planners to assess system performance subject to Category B contingencies ("event resulting in the loss of a single element") outlined in Table I. As provided in Table I, Category B contingencies include:

(1) A single-line-to-ground (SLG) or three-phase (3Ø) fault with "normal clearing" that removes from service either a generator, transmission circuit or transformer;[11]

(2) Loss of an element without a fault; or

(3) Outage of a single pole (direct current) line with normal clearing.

8. Requirement R1 of Reliability Standard TPL–002–0 states:

> R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B. To be valid, the Planning Authority and Transmission Planner assessments shall: * * *

9. Requirement R1 proceeds with sub-Requirements R1.1 through R1.5, which provide the criteria that must be met to qualify the assessment directed by Requirement R1 as valid. In particular, Requirement R1.3 mandates that the assessment shall

> [b]e supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B. The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

Further, Requirement R1.3.10 requires the planner to

> [i]nclude the effects of existing and planned protection systems, including any backup or redundant systems.

10. In sum, Requirement R1 provides the parameters of a valid assessment of system performance when experiencing a single contingency; Requirement R1.3 defines the criteria for the "base cases" that must be included in the studies to support the assessment.[12] Requirement R1.3.10 provides as a base case criteria that the studies must include the effects of existing and planned protection systems, *including any backup or redundant systems.*

11. Requirement R1.3.10 requires that planners study how a utility's protection system,[13] which isolates faults within a defined geographic area, would operate under circumstances "including backup or redundant systems." A utility designs its protection system with "primary" protection,[14] and may also employ "redundant" protection that operates for a primary protection system component that fails. Utilities also use "backup" protection that functions to isolate a fault when the primary protection system does not operate. Depending on the specific design, backup may remove more elements, or take longer to isolate the fault than the primary protection system.[15]

III. NERC Proposed Interpretation

12. In the NERC Petition, NERC explains that it received a request from PacifiCorp for an interpretation of Reliability Standard TPL–002–0, Requirement R1.3.10, addressing three specific questions. Below, we restate the PacifiCorp questions and NERC interpretations:

Question 1: Does TPL–002–0 R1.3.10 require that all elements that are expected to be removed from service through normal operation of the protection systems be removed in simulations?

Response 1: TPL–002–0 requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL–002–0, R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.

Question 2: Is a Category B disturbance limited to faults with [N]ormal [C]learing where the protection system operates as designed

[7] 16 U.S.C. 824o(d)(5).

[8] Order No. 693, FERC Stats & Regs. ¶ 31,242 at P 1797.

[9] NERC Rules of Procedure, Appendix 3A, Reliability Standards Development Procedure, Version 6.1, at 26–27 (2007).

[10] TPL–001–0 through TPL–004–0 each includes the same Table I, titled "Transmission System Standards—Normal and Emergency Conditions," which identifies the classes of contingencies as Category A through Category D. TPL–002–0 addresses Category B contingencies.

[11] *See, Section IV. C.* for the definition of normal clearing.

[12] Requirement R1.3 uses the term "categories" to define the criteria that must be included in the base cases.

[13] A protection system consists of protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry for the protection of bulk electric system elements. It detects faults and initiates operation of circuit breakers, thereby isolating the faulted element(s) from the remainder of the interconnected transmission system.

[14] A primary protection scheme is the first line of defense designed to remove the minimum number of elements in the shortest time.

[15] A backup protection system isolates the fault or disturbance by removing additional elements some period of time after the non-redundant primary protection system would do so, operating because that primary protection system did not function properly. Remote backup protection refers to protection systems that operate breakers distant from the site of the contingency and therefore result in the isolation of a larger portion of the bulk electric system.

in the time expected with proper functioning of the protection system(s) or do Category B disturbances extend to protection system misoperations and failures?

Response 2: This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL–003–0—System Performance following Loss of Two or More Bulk Electric System Elements (Category C) and TPL–004–0—System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System (BES) Elements (Category D).

Question 3: Does TPL–002–0, R1.3.10 require that planning for Category B [C]ontingencies assume a [C]ontingency that results in something other than a [N]ormal [C]learing event even though the TPL–002–0 Table I—Category B matrix uses the phrase "SLG or 3-Phase Fault, with Normal Clearing?"

Response 3: TPL–002–0, R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.[16]

13. In support of its request for approval, NERC contends that the proposed interpretation directly supports the reliability purpose of TPL–002–0 because it clarifies what is required for the "System simulations" cited in the main requirement without expanding the reach of the standard.[17] NERC maintains that the proposed interpretation clearly identifies what needs to be done—that all elements expected to be removed from service through normal operation of the protection system must be removed in simulations and that only normal clearing is required in the simulations. NERC states that the proposed interpretation clearly distinguishes that misoperations and failures of the protection system are not part of Reliability Standard TPL–002–0, but are addressed in other standards. NERC states that the interpretation will result in ensuring that an adequate level of reliability for the Bulk-Power System will be achieved and maintained by providing clarity and certainty in support of the objective.

14. In approving the proposed interpretation, the NERC Board stated that it applied a standard of strict construction that does not expand the reach of the Reliability Standard or correct a perceived gap or deficiency in the standard.[18] The NERC Board recommended that any gaps or deficiencies in a Reliability Standard that are evident through the interpretation process be addressed promptly by the standards drafting team. NERC states that it will examine any gaps or deficiencies in Reliability Standard TPL–002–0 in its consideration of the next version of this standard through the Reliability Standards Development Procedure.[19]

IV. Discussion

15. We propose to reject NERC's proposed interpretation of Reliability Standard TPL–002–0, Requirement R1.3.10. NERC proposes to interpret that simulations to assess the impact of single contingency operation "do[ ] not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation" to be in compliance with Requirement R1.3.10 of Reliability Standard TPL–002–0. NERC's proposed interpretation miscategorizes non-operation of non-redundant primary protection systems as protection system failure which is addressed in TPL–003–0 and TPL–004–0. However, pursuant to TPL–002–0, planners are required to study the effects of existing and planned protection systems, including backup and redundant systems. Accordingly, by categorizing the non-operation of non-redundant primary protection systems as a protection system failure, NERC's proposed interpretation misses studying the effects of backup and redundant protection systems pursuant to Requirement R1.3.10 of TPL–002–0. Rather, for the reasons discussed below, we believe that the Requirement R1.3.10 of TPL–002–0 requires that planners study, in their system assessments, the non-operation of primary protection systems in order to ascertain whether and how reliance on the as-designed backup or redundant protection systems affects reliability. Accordingly, we propose an interpretation of Requirement R1.3.10 of Reliability Standard TPL–002–0 consistent with our understanding.

16. In support of our proposed interpretation, we explain that planning assessments are developed through base case simulations. We then distinguish a contingency from the base case, and conclude that the non-operation of a non-redundant primary protection system is not a contingency. Finally, we explain that normal clearing of a contingency depends on the protection system that operates to clear the contingency, and that only by modeling the non-operation of non-redundant primary protection systems in the base case would the planner include the effects of existing and planned protection systems, including backup or redundant systems. For these reasons, our proposed interpretation would require modeling of the non-operation of primary protection systems to be in compliance with Requirement R1.3.10 of Reliability Standard TPL–002–000, and not by the requirements to be in compliance with Reliability Standards TPL–003–0 and TPL–004–0.

A. Assessment Through Base Case Simulations

17. Reliability Standard TPL–002–0 requires that planning authorities and planners demonstrate, through a valid assessment, that their portion of the interconnected transmission system will supply the projected customer demands and projected firm transmission service over a variety of conditions. A planner performs the assessment of its portion of the interconnected transmission system through computer modeling and simulations, in which the planner first creates base cases that reflect an array of system operating conditions. Using these base cases as a starting point, the planner then assesses the performance of the system and tests the base cases by subjecting them through computer modeling and simulations to various Category B Contingencies outlined in Table I.

18. Performance of the system as modeled, assuming all of the Contingencies taken one at a time and at any location in the bulk electric system, must meet the performance criteria specified in Table I for Category B Contingencies. The performance criteria in Table I specifies that, in the event of a Category B Contingency, the system (1) remains stable and both thermal and voltage limits remain within applicable ratings;[20] (2)

[16] NERC Petition at 10. In support for its request for an interpretation, PacifiCorp states that "[i]f TPL–002–0, R1.3.10 requires that planning for Category B Contingencies must assume failure or misoperation of all existing and planned protection systems, protection system failures previously identified as Category C [ ] Contingencies or Category D [ ] Contingencies would now become Category B Contingencies * * *" *Id.* at Appendix A at 1–2.

[17] NERC Petition at 11.

[18] *Id.* at 5.

[19] NERC states that this standard is included in Project 2006–02—Assess Transmission Future Needs and Develop Transmission Plans that is expected to be completed in the first half of 2010.

[20] TPL–002–0, Table I defines "applicable ratings" in its footnote "a". If other than normal ratings are applied, the planner must show that the bulk electric system can withstand the next contingency

continues to serve all firm demand and firm transfers;[21] and (3) does not have any cascading outages. If the studies or system simulation tests show that, for Category B Contingencies, any of the system base cases do not meet these performance criteria, pursuant to Requirement R2 of Reliability Standard TPL–002–0, the planner must determine and document a modification.

B. Distinguishing a Contingency From the Base Case

19. As previously discussed, Table I of Reliability Standard TPL–002–0 sets forth the Category B Contingencies that a planner must assess pursuant to Reliability Standard TPL–002–0. Table I defines contingencies in terms of their "initiating event(s)" and the elements the initiating event takes out of service. The determination of what elements would be taken out of service as a result of a Category B Contingency should not be confused with the number of elements ultimately taken out of service by the system's response to the initiating event.[22] For example, a contingency may involve a fault at a transformer at a generating unit. In response to the fault, operation of the primary protection system at the unit transformer, as designed, removes both the unit transformer and the associated generator from service. This scenario qualifies as a single contingency because there is only one initiating event involving one element—the transformer—even though the end state of the system includes the loss of two system elements—a unit transformer and a generator.

20. It is also important to distinguish an element taken out of service by a contingency or the operation of a protection system from an element or protection system component that the base case assumes is not in operation. Transmission elements that are not in service and generators that are not dispatched or that are assumed to be "out of service" in the base case are not considered to be contingencies. For example, if the base case assumes that three generators and one line will be out of service for load conditions or maintenance, the base case system without those facilities in service is the normal operating condition. Requirement R1.3.10 requires the system planner to study the effects of the non-operation of the non-redundant primary protection system in the base case simulations, not the effects of protection systems that are out of service.[23]

21. The Commission proposes to interpret that the non-operation of a non-redundant primary protection system is not a contingency and Requirement R1.3.10 requires that the planner model, as a condition in the base case, the non-operation of the primary protection system, accounting for operation of the redundant protection system or, alternatively, the fact that the protection system is not redundant, as appropriate. Only by modeling and simulating system conditions with base cases representing element outages and clearing times associated with non-operation of the primary protection system will a planner comply with Requirement R1.3.10 of Reliability Standard TPL–002–0, that is, to study the "effects of * * * any backup or redundant [protection] systems" on Category B contingencies. The Commission intends its proposed interpretation to ensure that the phrase is not rendered a nullity.

C. Normal Versus Delayed Clearing of the Contingency

22. Requirement R1.3.10 also requires that a planner's studies and simulations model the Category B Contingencies *with normal clearing.* Footnote "e" of Table I defines "normal" and "delayed" clearing as follows:

> Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection system. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

23. The assumptions in a base case as to which protection system will operate to clear the contingency against which the base case is tested determines the amount of time associated with "operate[] as designed." Thus, the base case assumptions determine which method of clearing constitutes normal clearing. If the base case being tested assumes the primary protection system operates, normal clearing of the contingency will be the clearing that is consistent with the as-designed operation of the primary protection system. If the base case assumes the primary protection system will not operate, normal clearing will be that clearing that is consistent with the redundant protection, if provided, or as-designed backup protection for that primary protection system.[24] In a study or simulation test, how the protection systems operate will determine which circuit breakers will open and the times it takes for specific breakers to open. The changes in system topology due to the opening of circuit breakers (which takes elements out of service), the operating times in which those circuit breakers open, and the total time required to clear the fault from the system all affect how the bulk electric system performs.

24. Delayed clearing of the contingency results only when the protection system in service in the base case (whether primary or back-up) does not operate as-designed due to a failure, such as a relay failing to operate (one form of relay misoperation), stuck breaker or other disabling condition. The concepts of normal and delayed clearing apply in the same manner to non-redundant primary protection systems. An example of normal clearing with longer clearing times is if the non-operation of a primary protection system disables both the primary protection and its breaker-failure-initiate protection. The backup protection that the system base case must test would be the next level of backup that would operate in the event of the contingency. The next level of backup protection may, for example, be the protection systems located at the adjacent substations, and will typically take longer to operate the necessary breakers by removing more elements to clear the fault than the operation of the primary or breaker-failure-initiate protection systems.[25] These longer clearing times do not constitute or create a situation of delayed clearing, however, because the longer clearing times are the as-designed operating

through system adjustments that do not result in the loss of firm load or firm transfers. System adjustments for Category B Contingencies do not include tripping of capacity resources.

[21] *See* Order No. 693, FERC Stats & Regs. ¶ 31,242 at P 1791–1795.

[22] In Order No. 693, the Commission explained, "a single contingency consists of a failure of a single element that faithfully duplicates what will happen in the actual system. * * *. Thus, if the system is designed such that failure of a single element removes from service multiple elements in order to isolate the faulted element, then that is what should be simulated to assess system performance." Order No. 693, FERC Stats & Regs. ¶ 31,242 at P 1716.

[23] TPL–002–0, R.1.3.12 provides for the inclusion of a planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components).

[24] For example, for a fault near one end of a line protected by distance relaying without communications, normal clearing from the end close to the fault will be zone 1 or times associated with primary clearing while the remote end will be zone 2 or times associated with back-up clearing. Both of these times are normal clearing as they are in accordance with design criteria.

[25] In the circumstance of this example, the Commission refers to the system that initiates breaker failure protection as the backup protection system that is coordinated to operate when the non-redundant primary protection system does not operate within a specified period of time.

times of the backup protection system being utilized.

25. With this understanding, the Commission proposes to interpret Requirement R1.3.10 as requiring a planner to study the effects of the as-designed backup protection system, and a planner must consider whether this clearing is consistent with the as-designed normal clearing of the protection system being studied. It follows that where a study's base case is designed to test the effects of backup protection systems, the base case assumption that the backup protection system operates in the time normally expected is not equivalent to delayed clearing due to a primary protection system component failure.

26. Rather, the backup protection system becomes the analytical starting point for the examined normal operating conditions, *i.e.,* the base case, and any additional time and elements removed from service resulting from operation of that backup protection beyond those the primary protection system would require is intentional and as designed. The operating characteristics (*i.e.,* time and elements removed) of the primary protection system are simply no longer part of the analysis. Delayed clearing in the case of simulating the effects of backup protection systems only results when there is a failure of a protection system component in the protection systems being simulated.

27. Finally, we propose that the interpretation of R1.3.10 discussed herein will apply prospectively from the effective date of any Final Rule and no entity will be subject to financial penalties for having operated in a manner inconsistent with this proposed interpretation prior to the effective date of any Final Rule.

D. Related Discussion in Order No. 693

28. The Commission did not specifically discuss a protection system failure or misoperation in Order No. 693. However, the Commission discussed the issue of a single point of protection system failure and how it factors into planning studies under the System Protection Coordination (PRC) Reliability Standards. The Commission stated:

> With respect to MISO's comment that virtually all protection systems have backups and therefore the Commission's proposals are not necessary, unless the backup protection has the same design goals and capabilities as the primary protection, a relay failure in the primary protection may still threaten system reliability. Further, we note that while the [Protection and Control] Reliability Standards do not specifically require protection systems consisting of redundant and independent protection groups for each critical element in the Bulk-Power System, such requirements are included as one potential solution in the TPL Reliability Standards.[26]

29. Therefore, the Commission has recognized the effect that non-operation of primary protection systems may have on reliability in the context of observing that redundant or backup protection systems may minimize the reliability risks that non-operation of primary protection systems poses. Consistent with the concern the Commission discussed regarding the PRC Reliability Standards, Requirement R1.3.10 of Reliability Standard TPL–002–0 provides that the effect of non-operation of primary protection systems be studied for a valid assessment of system reliability.

V. Comment Procedures

30. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due May 10, 2010. Comments must refer to Docket No. RM10–6–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

31. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's Web site at *http://www.ferc.gov*. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

32. Commenters that are not able to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426.

33. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

[26] Order No. 693, FERC Stats & Regs. ¶ 31,242 at P 1436, n.380 (if delayed clearing results in reliability criteria violations, one solution can be the use of redundant relay systems, citing TPL–002–0 Table I, footnote e).

VI. Document Availability

34. 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 FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington DC 20426.

35. From FERC'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.

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

By direction of the Commission.

Kimberly D. Bose,

Secretary.

[FR Doc. 2010–6565 Filed 3–24–10; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

24 CFR Part 1000

[Docket No. FR–5275–C–07]

Native American Housing Assistance and Self-Determination Reauthorization Act of 2008: Negotiated Rulemaking Committee Meeting; Correction

AGENCY: Office of the Assistant Secretary for Public and Indian Housing, HUD.

ACTION: Notice of Negotiated Rulemaking Committee Meeting; correction.

SUMMARY: HUD published a document in the **Federal Register** on March 19, 2010, announcing a meeting of the Native American Housing Assistance & Self-Determination Negotiated Rulemaking Committee. The document contained an incorrect telephone number for the location where the meeting is to take place. The location,