UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Interpretation of Transmission Planning	)	Docket No. RM10-6-000
Reliability Standard	)	

COMMENTS OF THE EDISON ELECTRIC INSTITUTE, THE AMERICAN PUBLIC POWER ASSOCIATION, THE CANADIAN ELECTRICITY ASSOCIATION, THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION, THE TRANSMISSION ACCESS POLICY STUDY GROUP, AND THE ELECTRIC POWER SUPPLY ASSOCIATION

The Edison Electric Institute ("EEI"), the American Public Power Association ("APPA"), the Canadian Electricity Association ("CEA"), the National Rural Electric Cooperative Association ("NRECA"), the Transmission Access Policy Study Group ("TAPS"), and the Electric Power Supply Association ("EPSA") (collectively referred to as the "Trade Associations") submit these comments regarding the Notice of Proposed Rulemaking ("NOPR") issued by the Federal Energy Regulatory Commission ("FERC" or "Commission") in the above-captioned proceeding.[1] The NOPR proposes to reject the North American Electric Reliability Corporation ("NERC") interpretation of Reliability Standard TPL-002-0 Requirement R1.3.10 and make mandatory and enforceable an alternative interpretation developed by the Commission.

EEI is the association of the nation's shareholder-owned electric utilities, international affiliates, and industry associates world-wide. APPA is the national service organization representing the interests of not-for-profit, publicly owned electric utilities throughout the United States. CEA is the national forum and voice of the evolving electricity business in Canada. At the heart of CEA is a core of corporate utility member companies. In addition, major electrical manufacturers and corporate consulting companies and several hundred other company and

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1 *Interpretation of Transmission Planning Reliability Standard*, Notice of Proposed Rulemaking, 75 Fed. Reg. 14,386 (Mar. 25, 2010), 130 FERC ¶ 61,208 (2010) ("NOPR").

individual members are grouped within CEA's broad structure. NRECA is the not-for-profit national service organization representing approximately 930 not-for-profit, member-owned rural electric cooperatives. The great majority of these cooperatives are distribution cooperatives that provide retail electric service to over 42 million customer-owners in 47 states. In addition, NRECA members include approximately 66 generation and transmission cooperatives that supply wholesale power to their distribution cooperative owner-members. TAPS is an informal association of transmission-dependent utilities in more than 30 states, promoting open and non-discriminatory transmission access. EPSA is the national trade association representing competitive power suppliers, including generators and marketers. These suppliers, who account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities serving power markets. EPSA seeks to bring the benefits of competition to all power customers.

The Trade Associations' members are users, owners, and operators of the bulk-power system and are subject to the Reliability Standards established by NERC, acting as the Commission-certified Electric Reliability Organization ("ERO"), including Reliability Standard TPL-002-0—System Performance Following Loss of a Single BES Element. In addition, the Trade Associations' members have actively participated in the development of the Reliability Standard interpretation at issue through the NERC Reliability Standards Development Procedure.[2]

I. EXECUTIVE SUMMARY

The Trade Associations support the interpretation of TPL-002-0 Requirement R1.3.10 proposed by NERC and approved by 99% of the NERC stakeholders as well as the NERC Board

[2] The Reliability Standards Development Procedure approved by the Commission is contained in Section 300 and Appendix 3A of the NERC Rules of Procedure. The interpretation was developed through NERC Project 2009-14, and the NERC website, www.nerc.com, contains the full record of that development.

of Trustees. The proposed NERC interpretation correctly addresses the technical issues presented by the Standard, harmonizing what, on the surface, may be vague Requirements in a manner that reflects the historical practice and engineering expertise of the industry while protecting the reliability of the bulk-power system.

In contrast, the Trade Associations do not support the Commission's proposed interpretation. The NOPR uses conflicting terminology to justify a position that is technically deficient. As a result, the NOPR fails to recognize that the unplanned non-operation of the primary protection system is not studied under TPL-002-0 but rather under the Table I Category C conditions described in the Transmission Planning Reliability Standards. As is apparent in NERC's proposed interpretation, only planned primary protection system outages are addressed under TPL-002-0 (by way of Requirement R1.3.12) thereby requiring that, for such outages, the transmission planners consider the effects of "backup or redundant systems" under Requirement R1.3.10.

The NOPR's proposed approach would have significant, negative effects on reliability and on the users, owners, and operators of the bulk-power system. Under the Commission's proposed interpretation, each primary protection system will need to be paired with an equivalent, independent protection system so that the Category B planning conditions will be met. Because this level of redundancy has not been implemented for most sub-345 kV transmission facilities, System Operating Limits may need to be decreased until the appropriate protection systems can be installed for these facilities. Significant construction would be required, necessitating significant transmission maintenance outages. As a result, available transmission capacity would be affected. Further, the installation of the redundancy required by the NOPR will be expensive—approximately $24 billion nation-wide—and will not significantly increase bulk-power system reliability even though many of these costs will ultimately be borne by ratepayers.[3] The Commission's decision to forgo the required Regulatory Flexibility Act analysis in which it might have otherwise analyzed these costs raises questions regarding whether these costs issues have been adequately considered by the Commission in formulating this NOPR.

FERC's proposed approach should be rejected because the NOPR would adopt a technically flawed approach that imposes significant costs on the industry with little benefit. However, there are statutory concerns as well. The Commission has exceeded its statutory authority in proposing to substantively modify the compliance obligations imposed by a Reliability Standard without using the ERO process required by section 215 of the Federal Power Act.[4] Section 215 establishes the process through which Reliability Standards, including the interpretations that become part of Reliability Standards, must be developed and approved. The statute reserves to the ERO the right to draft and propose Reliability Standards. The Commission is limited to approving, rejecting, or requesting general changes to a proposed Reliability Standard. The Commission cannot, itself, create or modify the obligations imposed by a Standard. Nevertheless, the Commission has proposed to do so in this NOPR. While the language of the Standard will not change under the Commission's "interpretation," the compliance obligations of Registered Entities will—substantially so. As a result, the Commission is proposing to do what the statute forbids it from doing directly; the Commission is modifying a Standard on its own.

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[3] As explained in greater detail in the attached affidavit, this estimate is based on the total expected US demand in 2018 of 898,749 MW together with the total number of transmission lines below 345 kV and the number of transmission transformers, distribution transformers, and buses that would be affected by the needed redundancy. In addition, this estimate takes into consideration the retrofits of generating stations and substations where the retrofit would be more difficult due to the existing layout.

[4] 16 U.S.C. 824o (2006) ("FPA § 215").

II. THE COMMISSION SHOULD RESPECT THE STATUTORY ROLES OF THE ERO AND ITS STAKEHOLDERS

Under section 215 of the Federal Power Act, the Commission and the ERO perform essential—but distinct—statutory roles in Reliability Standard development. The ERO performs the legislative function of drafting Reliability Standards and defining their scope; as the D.C. Circuit has characterized it, the ERO is "charged with establishing" Reliability Standards.[5] The Commission is limited to rejecting or approving a Reliability Standard while giving "due weight" to the ERO's technical expertise, directing the development of a Reliability Standard to address a specific matter, and enforcing compliance with Reliability Standards. As Chairman Wellinghoff's recent Congressional testimony explains, "the Commission does not have the authority to modify or author a standard and must depend upon the ERO to do so."[6]

This separation of authority, as the Commission has noted, is essential to the due process encapsulated within section 215,[7] which assigns the "responsibility for developing a proposed Reliability Standard to the ERO."[8] Under FERC precedent, determining the "text or substance" of a Reliability Standard is uniquely reserved to the ERO,[9] and interpretations of Reliability Standards are part of the substance of Reliability Standards. Indeed, they are developed and proposed by the ERO and approved by the Commission in the same way as Reliability Standards and become part of the Reliability Standards once approved.[10]

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5 *Alcoa, Inc. v. FERC*, 564 F.3d 1342 at 1344 (D.C. Cir. 2009).

6 Chairman Jon Wellinghoff, Federal Energy Regulatory Commission, Testimony before the Energy and Environment Subcommittee of the Committee on Energy and Commerce, United States House of Representatives at 5 (Mar. 23, 2010).

7 *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 71 Fed. Reg. 8,662 (Feb. 17, 2006), FERC Stats. & Regs. ¶ 31,204 at P 264-268 (2006), *order on reh'g*, Order No. 672-A, 71 Fed. Reg. 19,814 (Apr. 18, 2006), FERC Stats. & Regs. ¶ 31,212 (2006) (characterizing the section 215 Reliability Standards development process as a due process protection).

8 Order No. 672 at P 416.

9 Order No. 672 at P 34.

10 *See Electric Reliability Organization Interpretations of Specific Requirements of Frequency Response and Bias and Voltage and Reactive Control Reliability Standards,* Order No. 724, 127 FERC ¶ 61,158 at P 4

The NOPR in this proceeding attempts to bypass the limitations that section 215 places on the Commission's legislative authority regarding Reliability Standards—limitations the Commission has recognized in past orders. As the Commission explained in Order No. 693, anytime the ERO proposes a Reliability Standard the Commission has only four permitted courses of action: "(1) [a]pprove; (2) approve as mandatory and enforceable; and direct modification pursuant to section 215(d)(5) [of the Federal Power Act]; (3) request additional information; or (4) remand."[11] Even when the Commission disagrees with a proposed Reliability Standard, it has recognized that the FPA does not grant FERC the authority to direct that the ERO make certain changes and then require that any revised Reliability Standard developed by the ERO reflect only that specific directive.[12] As the Commission has noted, "*[t]he Commission's directives are not intended to usurp or supplant the Reliability Standard development procedure*."[13]

To the extent the Commission wishes to shape a Reliability Standard, it must do so within the parameters imposed by section 215; the Commission "cannot change the Reliability Standard and must send the Reliability Standard to the ERO for modification."[14] Nevertheless, in this NOPR, the Commission is proposing to substantively modify the compliance obligations imposed by Reliability Standard TPL-002-0 without the benefit of the section 215 stakeholder process, and by doing so fails to give "due weight" to the ERO's technical expertise as directed

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(describing the process for developing and approving interpretations in the context of approving an interpretation of BAL-003-0); BAL-003-0.1b (containing the approved interpretation as part of the Standard).

11 *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 Fed. Reg. 16,416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 at P 184 (2007), *order on reh'g*, Order No. 693-A, 72 Fed. Reg. 40,717 (July 25, 2007), 120 FERC ¶ 61,053 (2007) ; *see also* Order No. 672 at P 390 ("We will either accept or remand a proposed Reliability Standard.").

12 Order No. 693 at P 186 ("[W]here the Final Rule identifies a concern and offers a specific approach to address the concern, we will consider an equivalent alternative approach provided that the ERO demonstrates that the alternative will address the Commission's underlying concern or goal as efficiently and effectively as the Commission's proposal."); *see* Order No. 672-A at P 34.

13 Order No. 693 at P 187 (emphasis added).

14 Order No. 672 at P 424; *see* Order No. 672-A at P 34.

by section 215.

A. The Commission Lacks the Authority to Interpret Reliability Standards under the Federal Power Act

Unlike its authority to interpret its own regulations, FERC lacks the authority to make legislative interpretations of Reliability Standards. As the Supreme Court has explained, an agency's authority to interpret its own regulations stems from its legislative authority to issue regulations: "the power authoritatively to interpret its own regulations is a component of the agency's delegated lawmaking powers."[15] However, under the regime established by section 215, it is the ERO, not FERC, that has the legislative authority to draft Reliability Standards, the "regulations" that establish the reliability obligations of users, owners, and operators of the bulk-power system. The Commission cannot draft Reliability Standards in the same manner that it can draft regulations or issue orders under section 205 of the Federal Power Act or even draft and interpret regulations to implement section 215. The legislative authority of the Commission under section 215 is fundamentally more limited than its authority under other sections of the Act. As a result, FERC lacks the authority to interpret Reliability Standards in the same manner in which it interprets its own regulations.

In the same way that an agency's authority to interpret its own regulations is implicit in its authority to issue those regulations, FERC's authority to approve interpretations of Reliability Standards (interpretations are not a concept addressed by section 215) is presumably implicit in FERC's authority to approve Reliability Standards themselves.[16] However, this authority is

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15 *Martin v. OSHRC*, 499 U.S. 144, 151 (1991).

16 For this reason the Commission frequently uses the same standard to review proposed interpretations that it uses to review proposed Reliability Standards. *See Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards*, Order No. 713, 124 FERC ¶ 61,071 at P 40 (2008) ("The Commission concludes that the interpretation is just, reasonable, not unduly discriminatory or preferential, and in the public interest. Therefore, the Commission approves the ERO's interpretation of Requirements R1 and R2 of VAR-002-1."). In fact, in Order No. 713 FERC expressed concern that NERC's Rules of Procedure

limited simply to the *approval* of interpretations and does not logically encompass the drafting of interpretations. Indeed, a new interpretation always becomes part of the Standard itself and Registered Entities are expected to comply with such interpretations.[17] Instead, in the same way that an agency's authority to interpret its regulations is inherent in its authority to draft those regulations, the ERO's authority to develop and propose interpretations of Reliability Standards is inherent in the ERO's unique authority to develop and propose Reliability Standards for FERC approval.

The NOPR in this proceeding seeks to blur this distinction between the statutory roles of FERC and the ERO, as evidenced by the Commission's proposal to interpret a Reliability Standard in a very formal way[18] and thereby assume a legislative role assigned only to the ERO by the Federal Power Act. In previous orders addressing proposed Reliability Standards, the Commission has respected this role and remanded interpretations with which it disagrees. For example, in Order No. 724, the Commission approved the ERO's proposed interpretation of BAL-003-0, but remanded the proposed interpretation of VAR-001-1.[19]

Despite the uncertainty regarding the source of the Commission's interpretive authority over Reliability Standards, the Commission has not proffered an explanation of the authority pursuant to which it proposes to interpret this Reliability Standard in the stated manner. Unlike

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were silent with regard to NERC Board of Trustees approval of interpretations of Reliability Standards. FERC thus directed that the process for developing an interpretation of a Reliability Standard follow the same process as the development of a Reliability Standard. *Id.* at P 5 n.8.

17 *See*, *e.g.*, TOP-002-2a (containing the FERC-approved interpretation of Requirement R11 at Appendix 1).

18 *See* NOPR at P 1 ("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.").

19 *Electric Reliability Organization Interpretations of Specific Requirements of Frequency Response and Bias and Voltage and Reactive Control Reliability Standards*, Order No. 724, 127 FERC ¶ 61,158 at P 47 (2009).

other reliability orders, which cite to specific statutory authority for the proposed actions,[20] the NOPR identifies no specific source of its authority.

The interpretation of a Reliability Standard is a legislative function that is not granted to FERC under section 215 of the Federal Power Act. Nowhere in section 215 is the Commission granted the authority to interpret, modify, or develop Reliability Standards. As a result, if the Commission does issue a final rule adopting the FERC-proposed interpretation, the Commission would be acting beyond its statutory authority.

B. <u>The Commission Is Proposing to Modify TPL-002 Without the Use of the Process Mandated by Section 215 of the Federal Power Act</u>

Although the Commission claims that it is only proposing to "interpret" TPL-002-0, the result of the FERC-proposed interpretation will be a fundamental modification to the Reliability Standard—a modification that would be made without the benefit and due process of the section 215 stakeholder development process.[21] Rather than direct the ERO to "address[] a specific matter"[22] to accommodate the Commission's concerns, FERC has proposed to substantively change the Reliability Standard's meaning without actually changing the language.

The development and drafting of Reliability Standards is an authority reserved to the ERO. The ERO files the Reliability Standards that it proposes for approval with the Commission.[23] The Commission may approve the Reliability Standard[24] or remand the proposed Standard to the ERO for further consideration.[25] The Commission may also direct the ERO to

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20 *See, e.g.*, *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 Fed. Reg. 16,416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 at P 170 (2007), Order No. 693-A, 72 Fed. Reg. 40,717 (July 25, 2007), 120 FERC ¶ 61,053 (2007).

21 This process must assure "fair stakeholder representation" and "balanced decisionmaking." FPA § (c)(2)(A).

22 FPA § 215(d)(5).

23 FPA § 215(d)(1).

24 FPA § 215(d)(2).

25 FPA § 215(d)(4).

submit a proposed Reliability Standard addressing a "specific matter."[26] The Commission may not, however, draft a Reliability Standard. Indeed, the statutory definition of the term "reliability standard" demonstrates that the Commission's role is limited to approval of the Standard.[27]

In the event that FERC believes that a Reliability Standard needs clarification or modification, its options are limited because the Commission cannot draft a Reliability Standard. Instead, when it does not wish to approve a Reliability Standard, it may only remand the Reliability Standard or remand with directions to develop a Reliability Standard that addresses a specific matter.[28] Rather than remanding TPL-002-0 when it was proposed, the Commission chose to approve it.[29] Now the Commission is proposing a binding interpretation of the Reliability Standard that substantially changes the purpose and scope of the Reliability Standard without using the section 215 process.

The Commission cannot change Reliability Standards in this manner through its own "interpretation." An interpretation should be "reasonable and . . . consistent with and add[] clarity to" the interpreted Standard but should not create any new obligations under the Standard.[30] In contrast, this "interpretation" represents an expansion of the obligations imposed by the Reliability Standard. Indeed, if this proposed interpretation did not represent a significant substantive change in the meaning of the Reliability Standard, the Commission would not have gone to great lengths to explain that it would only be effective prospectively.[31] This expansion of obligations under the Standard is a change to the legal requirements imposed by the

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[26] FPA § 215(d)(5).

[27] FPA § 215(a)(3) ("The term 'reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system.").

[28] Order No. 693 at P 184.

[29] *See* Order No. 693 at P 1784.

[30] *See North American Electric Reliability Corp.*, 129 FERC ¶ 61,191 at P 16-17 (2009) (approving an interpretation of TOP-002-2). The interpretation must "represent[] the language in the Reliability Standard as it is currently worded." *North American Electric Reliability Corp.*, 130 FERC ¶ 61,184 at P 13 (2010) (approving an interpretation of CIP-007-2).

[31] NOPR at P 27.

Reliability Standard itself and as such must go through the section 215 process.

Moreover, the proposal to interpret TPL-002-0 in this manner not only violates the procedural obligations of the Commission under section 215, it also undermines the purposes of the framework embodied in that section. The balanced, stakeholder-driven standards development procedure provides essential benefits for the development and implementation of mandatory Reliability Standards to protect bulk-power system reliability. First, this procedure builds consensus among the users, owners, and operators of the bulk-power system that are ultimately responsible for complying with the Standards. Second, it takes advantage of the accumulated expertise of the industry and the ERO.[32] Third, it provides for a thorough vetting process to ensure that the technical issues and concerns raised by a proposed Standard are addressed before the Standard is made mandatory and enforceable.

The framework embodied in section 215 also allows for effective participation by all North American stakeholders in the development of Reliability Standards. Because Standards are first developed through the stakeholder process and then submitted to the relevant governmental authorities for approval, such a process is respectful of jurisdictional sovereignty by allowing for the approval of the resulting Standards in all relevant jurisdictions. This model also recognizes jurisdictional sovereignty through the existence of the remand provision in the Federal Power Act, which is also incorporated into the processes for Reliability Standards approval in a number of Canadian provinces, and which is incorporated into the existing NERC Reliability Standards Development Procedure. This component assures that no governmental authority has the ability to unilaterally modify Standards that would apply to the whole interconnected bulk electric system and that any variances are accommodated through the collective process. At the same

[32] Stephen M. Spina, Michael C. Griffen, and William F. Hederman Jr., *NERC's Reliability Standards: The Good, the Bad, and the Fill-in-the-Blanks*, PUBLIC UTILITIES FORTNIGHTLY at 43 (Aug. 2006) (describing the long history of NERC in working for bulk electric system reliability).

time, it gives public authorities the confidence that the system has a government backstop, providing governmental authorities on both sides of the border with the confidence that Standards developed through that process reflect their concerns. In fact, in its initial orders approving NERC and the original mandatory Reliability Standards, the Commission recognized the importance of a standard-setting process that allows NERC to consider the concerns of U.S., Canadian, and Mexican entities. Such recognition was consistent with the intent of the NERC Standards development process under section 215, which was designed to allow NERC to operate effectively on an international basis.[33]

The Commission's NOPR threatens to undermine this international consensus-driven approach. A Reliability Standard developed through FERC mandate could result in unintended consequences, including undermining the confidence of the industry in NERC's American National Standards Institute-certified Standards development process. Cooperative action is more effective in preserving reliability than imposed obligations. Second, as reflected in the technical discussion below, the interpretation has not benefited from the expertise of the system engineers, operators, and planners responsible for running and planning the bulk-power system in a manner that provides reliable power to customers. As a result, implementation of the proposed interpretation is likely to be operationally problematic or even harmful. Finally, because the NOPR proposal has not undergone a strenuous vetting process, the Commission has not benefited from the industry's understanding of the consequences, such as the exorbitant costs, that will flow from the interpretation.

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33 See *Motion to Intervene, Request for Clarification, and, in the Alternative, Request for Rehearing of the Edison Electric Institute, the American Public Power Association, the National Rural Electric Cooperative Association, the Canadian Electricity Association, the Large Public Power Council, the Transmission Access Policy Study Group, and the Electricity Consumers Resource Council* in Docket No. RR09-6-001 (April 19, 2010) ("Joint Association Rehearing Request") for a thorough discussion of the legislative intent of Congress with respect to the creation of a non-governmental international standard-setting organization. That discussion is incorporated by reference in these Comments.

FERC's NOPR also threatens to undermine NERC's ability to operate effectively as an international standard-setting organization. NERC is structured to ensure that no governmental authority has the ability to modify a proposed Reliability Standard or an interpretation to that Standard, and NERC is in the best position to balance differing needs and concerns in the U.S. and Canada. To the extent the Commission now proposes a modification to an interpretation of a Reliability Standard, the Commission prevents NERC from performing its balancing function among the governmental authorities and developing an interpretation that addresses the concerns of all relevant governmental authorities.

Congress instituted the ERO-balanced interest process for developing Reliability Standards for important policy reasons. The Commission's imposition of a greatly expanded Reliability Standard through a purported "interpretation" not only contravenes the legal obligations imposed by the Federal Power Act but also undermines the policy goals that Congress was trying to achieve.

C. <u>The Commission Has Not Given "Due Weight" to the Technical Expertise of the ERO</u>

Reflecting the authority of the ERO to develop Reliability Standards and propose them to the Commission for approval, section 215(d)(2) of the Federal Power Act requires the Commission to give "due weight to the technical expertise of the Electric Reliability Organization with respect to the content of a proposed standard."[34] The Commission's own regulations reiterate this requirement.[35] Although the Commission has emphasized that this does not confer a rebuttable presumption that an ERO-proposed Reliability Standard satisfies the section 215 standard for approval, it nonetheless requires the Commission to give serious

[34] FPA § 215(d)(2).
[35] 18 C.F.R. § 39.5(c)(1).

consideration to the technical expertise of the ERO.[36] Indeed, the statutory language indicates that this "due weight" is indeed a form of deference to the ERO, at least on technical issues. Under section 215(d)(2), the Commission obligation to give "due weight" to the ERO's technical expertise is contrasted with the Commission's responsibility *not* to "defer" to the ERO on issues related to competition. By implication, the "due weight" given to the ERO's technical expertise is deference. In the NOPR, no deference has been given.

The interpretation proposed by the ERO goes directly to the "content of a proposed standard." Nevertheless, the Commission did not in any meaningful sense give "due weight" to the technical expertise of the ERO, even though the Commission is required to do so under the Federal Power Act and the FERC regulations. Notably, nowhere in the NOPR does the Commission explain why it will not afford the ERO's technical expertise "due weight" regarding the proposed interpretation or even discuss its obligation to give "due weight" to the ERO's technical expertise.[37] Instead, the Commission simply concludes that the ERO's proposal "mischaracterizes non-operation of non-redundant primary protection systems as protection system failure" and as a result "misses studying the effects of backup and redundant protection systems pursuant to Requirement R1.3.10."[38]

This conclusion that the ERO interpretation fails to account for the effects of backup and redundant protection systems is incorrect. The ERO's proposed interpretation provides that

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36 Order No. 672 at P 344-345.

37 While the technical expertise of the industry is brought to bear in the ERO Reliability Standards development process through the drafting team itself and the comments provided by industry experts to the drafting team, the Commission's notice and comment procedures for the NOPR do not provide an equivalent opportunity for the technical expertise of the industry to shape and strengthen the Standard. In the NERC procedures there is considerable back and forth between the drafting team and the industry experts on a proposed Standard to ensure that, by the time it is presented to the NERC Board of Trustees for approval, any technical issues have been addressed. In contrast, the Commission's notice and comment procedures do not provide the same opportunity for the technical discussions between stakeholders and the drafting team that are essential to developing well-vetted and technically superior Reliability Standards.

38 NOPR at P 15.

under TPL-002-0 transmission planners must plan their systems to satisfy Category B contingency conditions, presuming normal clearing of the primary protection system and considering the effects of backup and redundant protection systems to the extent they have effects under those circumstances. This gives full effect to all of the language in the Reliability Standard in a manner consistent with the long-standing transmission planning practices of the industry, a highly-technical area of power system engineering in which the industry stakeholders who developed the proposed interpretation through the NERC Reliability Standards Development Procedure have substantial experience. Indeed, NERC has undertaken a significant initiative to address reliability issues related to protection system redundancy, which is at the heart of the NOPR.[39]

It is because of the technical complexity of engineering issues such as this that the Federal Power Act requires FERC to give "due weight" to the technical expertise of the ERO. The Commission should not dismiss such expertise without explanation as to why NERC is incorrect or why the Commission has otherwise chosen to disregard NERC's technical expertise.

III. THE COMMISSION HAS CONTRADICTED ITS POLICY ON INTERPRETATIONS OF RELIABILITY STANDARDS

Approving an interpretation that changes the meaning of the Standard and the obligations that it imposes contradicts the Commission's precedent on reviewing proposed interpretations. As the Commission has explained in approving previous interpretations, it will approve a proposed interpretation under section 215 if the interpretation is "reasonable and . . . consistent with and adds clarity to" the interpreted Standard but does not create any new obligations under

39 NERC System Protection and Control Subcommittee, Protection System Reliability: Redundancy of Protection System Elements (Jan. 2009), *available at*: http://www.nerc.com/docs/pc/spctf/Redundancy_Tech_Ref_1-14-09.pdf ("Protection System Reliability").

the Standard.[40]

The interpretation at issue here expands the reach of the Reliability Standards by changing the planning requirement from single contingency with normal protection system clearing to single contingency accompanied by the unplanned non-operation of the primary protection system—essentially requiring N-2 planning as part of TPL-002-0.[41] This is not only inconsistent with the language of the Reliability Standard, but also adds a new obligation for transmission planners subject to this Standard. As indicated by the voting on the proposed ERO interpretation, transmission planners have applied this Standard as assuming proper operation of applicable primary protection systems. However, under the Commission's proposal, these transmission planners would need to plan their systems to meet Category B requirements assuming not only a single contingency but also the failure of the primary protection system for that contingency to operate. In effect, this FERC interpretation creates a new obligation under TPL-002-0.

Commission precedent on the interpretation of Reliability Standards also indicates that an interpretation should remove apparent conflict between Requirements in a Reliability Standard, not create a conflict.[42] The interpretation proposed by the Commission does the opposite, creating a conflict where none existed before. TPL-002-0 Requirement R1.3.10 requires that the "base case" of the planning study account for the effects of backup or redundant protection systems, while the Category B contingencies that must be addressed by the planning studies

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40 *See North American Electric Reliability Corp.*, 129 FERC ¶ 61,191 at P 16-17 (2009) (approving an interpretation of TOP-002-2). The interpretation must "represent[] the language in the Reliability Standard as it is currently worded." *North American Electric Reliability Corp.*, 130 FERC ¶ 61,184 at P 13 (2010) (approving an interpretation of CIP-007-2).

41 Wiedman Affidavit ¶ 16, 20-21.

42 *See Electric Reliability Organization Interpretations of Specific Requirements of Frequency Response and Bias and Voltage and Reactive Control Reliability Standards*, 127 FERC ¶ 61,158 at P 14 (2009) (explaining that the interpretation of BAL-003-0 was approved in part because it clarified why Requirement R2 and R5 did not conflict).

under TPL-002-0 include only single contingencies with "normal clearing." Normal clearing is then defined as "when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems."[43]

The proposed ERO interpretation harmonizes this language, which could be considered unclear on the surface, indicating that the planning study presumes the correct operation of the protection systems as normal clearing in response to a contingency and that where the backup or redundant protection systems affect the study under those circumstances, such as when the primary protection system has been disabled due to maintenance, the effects of the backup or redundant protection systems should be considered in the planning study. This interpretation gives effect to each part of the Reliability Standard, including the various Sub-Requirements, in a manner that is consistent with the language at issue.

In contrast, the Commission's interpretation of normal clearing creates a conflict within the Reliability Standard where none existed before. The Commission asserts that the non-operation of a protection system is not a protection system failure and is therefore not a contingency. Instead, the Commission's interpretation proposes to interpret non-operation of a protection system as part of the base case of the planning study that is applied *before* the Category B contingency is applied.[44] This creates a conflict in the language of the Standard that did not exist before because to account for the Commission's understanding of what is necessary to address the effects of backup or redundant protection systems, the Commission concludes that "normal clearing" does not apply to the primary non-redundant protection system, even though the definition of normal clearing in the Standard specifies that it is when the protection system

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43 TPL-002-0, Table I note (e).

44 NOPR at P 26 ("[T]he backup protection system becomes the analytical starting point for the examined normal operating conditions, *i.e.*, the base case . . . The operating characteristics (*i.e.*, time and elements removed) of the primary protection system are simply no longer part of the analysis.").

"operates as designed . . with proper functioning." The Commission's proposed interpretation tried to harmonize this by claiming that "non-operation" of a protection system is not the same as a protection system failure, but in doing so ignores the definition, long applied in the industry and incorporated in the *NERC Glossary*, that the misoperation of a protection system component (the opposite of normal clearing under TPL-002-0 Table I note (e)) includes a failure to operate "within the specified time when a fault or abnormal condition occurs within a zone of protection."[45]

As a result, the Commission's proposed interpretation creates a conflict between the language contained in separate parts of the same Reliability Standard: normal clearing, which is required for protection systems under Category B conditions and which the Standard defines as clearing in the expected time frame for proper functioning, is interpreted to include the failure of the primary protection scheme to function. This only introduces confusion and contradiction into the Reliability Standard and violates the Commission's own precedent for Reliability Standard interpretations.

IV. THE COMMISSION'S PROPOSED INTERPRETATION IS INCONSISTENT WITH THE LANGUAGE, INTENT, AND HISTORY OF THE RELIABILITY STANDARD

The Commission's proposed interpretation rests on two faulty premises that are inconsistent with the language of TPL-002-0. First, the Commission asserts that the failure of a transmission protection system to operate is not a contingency under the transmission planning Reliability Standards.[46] Second, the Commission asserts that the only way to model the effects of backup or redundant protection systems and thereby give effect to the full language of TPL-002-2 Requirement R1.3.10 is to perform the required assessments presuming the failure of the

45 *Glossary of Terms Used in Reliability Standards*, North American Electric Reliability Corporation at 11 (Apr. 20, 2009) (defining Misoperation), *available at*: http://www.nerc.com/docs/standards/rs/Glossary_2009April20.pdf.

46 NOPR at P 16.

primary protection system to operate as intended. Both assumptions are inaccurate and are only justified by ignoring or misinterpreting other language within the Standard.

Moreover, the terminology used by the Commission in the NOPR is confusing and does not reflect the transmission engineering and planning terminology used by the industry. As a result, the technical explanation offered in the NOPR to justify the conclusion appears at odds with the understanding of the engineers who plan the system, including the protection systems, and are responsible for operating the system reliably on a daily basis. For that reason, the affidavit of Mr. Thomas Wiedman ("Wiedman Affidavit") attached to these comments contains a discussion of the industry terminology used in the transmission planning and protection system context and the confusion that the NOPR terminology creates when planning engineers assess what this NOPR will mean for the industry.[47] Nevertheless, whatever the reasoning behind the proposal, the Commission's conclusion is apparent. Therefore, the Wiedman Affidavit explains the concerns that flow from that conclusion.

A. **The Failure of the Primary Protection System Is an Unplanned Event**

As explained in the Wiedman Affidavit, the Commission's proposed interpretation is incorrect from an engineering perspective because it "incorrectly defines normal clearing as including the non-operation of a non-redundant protection system and thus exceeds the testing requirement defined in TPL-002-0, which assumes that the loss of a single element of the bulk-power system is cleared by a fully functioning protection system."[48]

Protection systems are designed to clear faults on the transmission system.[49] When they operate correctly, as designed, they have engaged in normal clearing as that term is defined in

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[47] Wiedman Affidavit ¶ 7-15.

[48] Wiedman Affidavit ¶ 6.

[49] NOPR at P 11 n.13 ("A protection system . . . detects faults and initiates operation of circuit breakers, thereby isolating the faulted element(s) from the remainder of the interconnected transmission system.").

TPL-002-0 and other transmission planning standards.[50] When they fail to operate correctly, the fault clearing is delayed and the transmission system is at risk because the fault may not be isolated from the rest of the transmission system. Because of the serious reliability implications when a protection system fails to operate as designed—what the Commission describes as the "non-operation" of a protection system—it is considered an unplanned event. This fits within the Commission's previous discussion of a single contingency, which describes it as "a failure of a single element" such as a "transmission line, a transformer, a generator or a single pole of a DC line."[51]

Because protection system non-operation for any reason other than a planned outage is an unplanned event it is not studied under TPL-002-0 because the contingency conditions from Category B of Table I in TPL-002-0 presume "normal clearing" by protection systems, which presumes correct operation of operational primary protection systems. As defined in note (e) to Table I, 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 systems." NERC's technical paper on protection system redundancy reiterates the assumptions that are part of normal clearing: "Normal clearing time is a Protection System mode of operation that does not take into consideration Protection System failure, and assumes that the Protection System is fully functional and will operate as designed and intended."[52]

Improper fault clearing, referred to as "delayed clearing" under the transmission planning Reliability Standards, is the unplanned event that occurs when a protection system fails to operate. In the same technical paper as the one noted above, NERC describes delayed clearing

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50 As explained in the Wiedman Affidavit ¶ 14, "NERC's definitions of Normal Clearing and Delayed Clearing are consensus definitions within the industry. Note that Normal Clearing expects proper functioning of protection systems."

51 Order No. 693 at P 1716 and n.439.

52 *See* Protection System Reliability at 14.

as "a result of a Protection System failure to trip the breaker directly and/or initiate breaker failure logic."[53] Unplanned protection system outages are unplanned events that are not addressed under TPL-002-0's assumption of normal clearing, but instead are addressed by those Reliability Standards that cover unplanned delayed clearing.[54]

B. <u>As Unplanned Events, Protection System Failures Are Studied Under Other Transmission Planning Standards</u>

TPL-002-0 only deals with protection systems with normal clearing—the proper operation of a protection system—as well as planned outages of protection systems. Other transmission planning standards address protection system failures, *i.e.* unplanned outages of protection systems.

Although the NOPR is inconsistent on what is intended by "non-operation" of a protection system,[55] there are only three possibilities: protection system failure, inadvertent disabling of protection, and intentional disabling of protection for maintenance. Only the last of these types of non-operation is addressed under TPL-002. Primary protection system failure or unplanned non-operation is an event addressed in TPL-003-0 and TPL-004-0, which deal with Category C and Category D contingencies, respectively, and therefore address unplanned events including delayed clearing.[56] Inadvertent disabling of a protection system is the equivalent to the failure of a protection system in that the transmission operator is unaware that the system has been disabled. This is also covered by TPL-003-0 and TPL-004-0.

On the other hand, intentional disabling of a protection system, such as for maintenance,

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[53] *Id.* at 15.

[54] The Wiedman Affidavit ¶ 9-21, contains a detailed description of delayed and normal clearing and the relationship of these concepts to the TPL-002-0 Reliability Standard.

[55] The Commission explains at P 15 that the term does not cover protection system failure, but also states at P 20 and n.23 that the term does not cover intentional/planned outages because that would be covered under Requirement R1.3.12.

[56] Wiedman Affidavit ¶ 21. Under Table I, Note (e) of these Reliability Standards, delayed clearing of a fault is described as "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."

would be a known operating condition by the transmission operator, and is expressly covered under TPL-002-0 Requirement R1.3.12, which states that the transmission planner should "[i]nclude the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed."[57]

Furthermore, the Commission's proposed interpretation not only introduces an internal inconsistency into the TPL-002-0 Reliability Standard, it also appears to contradict the Commission's understanding of the Transmission Planning Reliability Standards as reflected in Order No. 733, which recognizes that TPL-002-0 does not address unplanned protection system outages. In that order, the Commission explained that in the TPL Reliability Standards, Category B, the conditions for TPL-002-0, covers most applications of primary relays, while it is Category C, the conditions for TPL-003-0, that covers "backup and remote circuit breaker failure relay applications."[58] The NOPR's conclusion that the base case for TPL-002 should require the assessment of the non-operation of the primary protection system appears to contradict the Commission's understanding in Order No. 733, which reflects, however unintentionally, the proposed NERC interpretation of TPL-002.

C. The ERO's Proposed Interpretation Does Include the Effects of Backup or Redundant Protection Systems

TPL-002-0 Requirement R1.3.10 requires planning studies for Category B contingency conditions to consider "the effects of existing and planned protection systems, including any backup or redundant systems." While the NOPR asserts that the Commission's proposed interpretation, requiring the consideration of the "non-operation" of a non-redundant primary protection system under TPL-002-0 is necessary to ensure that the "backup or redundant

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57 *See* Wiedman Affidavit ¶ 17.

58 *Transmission Relay Loadability Reliability Standard*, Order No. 733, 130 FERC ¶ 61,221 at P 85 (2010).

systems" phrase "is not rendered a nullity,"[59] this conclusion rests on a faulty premise. The Commission presumes that if a planning study treats protection systems as operating as intended the planning study will not address backup or redundant protection systems. As a result, the Commission interprets the Standard as requiring a simulation of the "non-operation" of the primary protection system.[60]

This presumption is incorrect. Backup or redundant protection systems may operate under the explicit conditions specific in TPL-002-0 that form the basis of the ERO's proposed interpretation without presupposing the non-operation of the primary protection system. As a result, the ERO interpretation gives effect to all of the language of the Reliability Standard without relying on the "non-operation" concept that is not supported by the text of the Standard.

As noted above, the Requirement R1.3.10 must be read in harmony with the other Sub-Requirements that establish the TPL-002-0 base case. Under TPL-002-0 Requirement R1.3.12, transmission planners must consider the planned outage "of any bulk electric equipment (including protection systems or their components)" at the appropriate demand levels. The planning assessments that include the removal of protection systems due to planned outages will, by necessity, involve an assessment of the effects of "backup or redundant" protection systems. As the language in both R1.3.10 and R1.3.12 is given effect under these circumstances, which match NERC's proposed interpretation, it is inaccurate to assert that the interpretation of the industry renders the language in R1.3.10 a "nullity."

As this indicates, the assumption that the effects of backup systems can *only* be studied when the simulation presumes unplanned non-operation of the primary protection system is incorrect. As a result of the Commission's presumption that this is nevertheless true, the

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59 NOPR at P 21.
60 NOPR at P 15.

Commission has created an additional, unwritten, requirement to study protection system failures combined with contingencies such as transmission line outages. A better result comes from acknowledging that backup protection systems may operate even if there is no unplanned failure of the primary protection system, and that studying the system in this way satisfies TPL-002-0 Requirement R1.3.10. Situations where a protection system fails or is non-operational, combined with one or more other contingencies, are covered under TPL-003-0 and TPL-004-0, which address multiple contingency planning.

D. <u>The Commission's Interpretation Would Increase the Contingency Severity for TPL-003-0 and TPL-004-0</u>

The same language at issue in TPL-002-0 Requirement R1.3.10 appears in Reliability Standards TPL-003-0 Requirement R1.3.10 and TPL-004-0 Requirement R1.3.7. As a result, any interpretation of this language in TPL-002-0 would also apply to the other two Standards. This would result in a significant increase in the contingency severity that must be considered under those Standards as well as a significant increase in the severity of the contingency that must be considered under TPL-002-0.

For example, under the existing interpretation of TPL-003-0, a transmission planner's planning assessment must show that in the event of two contingencies, such as the loss of a transmission circuit and the loss of a transformer, the system must be stable and remain within applicable thermal and voltage limits and any loss of demand or curtailed firm transfers must be planned and controlled. However, after applying the Commission's interpretation, these same requirements must still be met after presuming that all relevant primary protection systems suffer an unplanned failure.

The Commission's analysis of this NOPR must take into consideration the implications it will have for compliance with these other Reliability Standards and what it will mean for planning transmission systems and investing in the required upgrades. Incorporating the Commission's interpretation into these other planning standards will result in costs above and beyond the substantial costs for compliance with the Commission's interpretation of TPL-002-0 described in the attached Wiedman Affidavit and in Section V(C), below.

E. The History of the Implementation of This Reliability Standard Contradicts the Commission's Interpretation

The TPL-002-0 Reliability Standard language at issue is identical to the earlier voluntary Reliability Standard IA.M.2, which stated that the system simulation/testing for system performance following the loss of a single bulk system element should "[i]nclude the effects of existing and planned protection systems, including any backup or redundant systems." Utilities have been implementing that Reliability Standard since it was developed under the voluntary regime, and have been implementing it in a manner consistent with the ERO's proposed interpretation. As the voluntary Reliability Standard was developed by the industry based on its own existing practices to formalize what they considered appropriate planning practices for transmission planning entities, the performance by the industry under this voluntary Standard should demonstrate the interpretation that was intended by the entities that developed the Reliability Standard and should be followed when interpreting this Reliability Standard because the language of the Reliability Standard has not changed.[61]

That the Commission proposal is inconsistent with the implementation of the identical voluntary Reliability Standard over the years suggests that it is not an accurate interpretation of the Standard.

[61] The Wiedman Affidavit ¶ 22-26 describes the history of the industry's planning for single contingencies and how the proposed NERC interpretation of TPL-002-0 matches the industry approach.

V. THE COMMISSION'S PROPOSED INTERPRETATION WILL HAVE UNINTENDED CONSEQUENCES

A. The Commission's Interpretation May Undermine Reliability

1. The Construction Work Required to Comply With the New Standard Will Undermine Reliability

If the Commission carries through with its proposed interpretation, transmission companies will be required to complete substantial protection system construction projects throughout their transmission systems. In order to satisfy the requirements of TPL-002-0 under a single contingency condition as interpreted by the Commission, transmission owners will need to ensure that all of their transmission protection systems have redundant backup protection systems that provide at least the same fault-clearing capability as the primary protection system. As explained in the Wiedman Affidavit, for each existing primary protection system, there will need to be an equivalent independent protection system: "[e]ach system would have its own input sources (current transformers and voltage transformer secondaries), DC circuitry, DC source, Primary Protection System and Local Backup Protection System."[62] While most 345 kV and above transmission facilities will satisfy this requirement, the vast majority of sub-345 kV facilities will not.[63]

Because the installation of new protection systems typically requires the extended removal from service of associated bulk-power system transmission facilities, transmission companies across the United States will be requesting substantial and widespread line outages.[64] As a result of these outages and the outages that are scheduled to address other maintenance and construction needs, transmission capacity will be severely restricted, with potentially severe reliability consequences, especially on constrained systems. Given the widespread nature of the

62 Wiedman Affidavit ¶ 27.
63 *Id.*
64 Wiedman Affidavit ¶ 30.

redundancy installations necessary and the shortage of necessary expertise and materials, these outages will be spread over as many as 10 to 20 years.[65] While these outages will be coordinated with the relevant entities, and presumably will occur on a rolling basis, the vast number of requested outages could result in a significant and prolonged decrease in transmission capacity and reliability within the United States, particularly in constrained areas or during peak usage periods.

The history of the implementation of this Reliability Standard according to the ERO's interpretation indicates that the current approach has not undermined reliability. Carrying through with the interpretation proposed in the NOPR will, for a significant length of time, substantially decrease bulk-power system reliability in the United States.

2. The Commission's Interpretation Will Create a Less Secure System

The Commission's proposed interpretation is not technically sound as it does not consider an important fundamental in protection system design and the possible adverse reliability impact the suggested interpretation could have on the bulk-power system due to the focus on reliability over security in protection system design. The intent of the NOPR appears to be to require the installation of redundant systems where "non-operation of non-redundant primary protection systems" would lead to reliability problems under Category B conditions. Virtually all protection systems are designed to strike a balance between protection system reliability and security. Protection system reliability is defined by the ability of a protection system to properly operate for any disturbance it is designed to address. Protection system security is defined by the protection system's ability to restrain, or avoid operation, for any disturbance which it is not designed to address. Designing a protection system erring excessively on the side of reliability (as suggested by the Commission's proposed interpretation) will create a protection system that

[65] *Id.*

is much less secure. On the other hand, designing a system that errs excessively on the side of security will create a protection system that is much less reliable. Thus, protection system designers consider the specific needs of the particular bulk electric system facilities for which protection systems are needed and then balance the reliability and security needs for the area.[66] As the Commission's suggested interpretation overwhelmingly focuses on protection system reliability to the detriment of security, it will likely lead to unintended consequences that could actually reduce overall system reliability.

B. The Commission's Proposed Interpretation Will Have Serious Implications for Power Markets Because It Will Decrease Applicable System Operating Limits

Planning performed according to this interpretation will likely lead to decreases in System Operating Limits ("SOLs"), which will have significant market impacts because it will decrease the amount of available transmission capacity. A Final Rule implementing this interpretation would, therefore, be contrary to the Commission's criteria for approving Reliability Standards, among which is the requirement that a proposed Standard "not unreasonably restrict transmission capability on the Bulk-Power System beyond any restriction necessary for reliability."[67] Past experience under this Reliability Standard as understood by the industry and the ERO has shown that the ERO's interpretation preserves reliability; the Commission's proposed interpretation goes beyond the restrictions needed to preserve reliability and instead could serve to decrease available transmission capability.

Reliability Standard FAC-011-2 contains the requirements for establishing SOLs and requires that those SOLs be established by using the same conditions addressed by TPL-002-0.

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66 This issue of dependability or reliability vs. security is addressed in detail in EEI's request for rehearing of Order No. 733 in Docket No. RM08-13-001 at 20-22 (Apr. 19, 2010). That pleading is incorporated herein by reference.

67 Order No. 672 at P 332.

Sub-Requirement R2.2 of FAC-011-2 is substantively identical to Table I Category B in TPL-002-0. As a result, any interpretation of TPL-002-0 will, necessarily, create a similar interpretation of FAC-011-0. As explained above, the Commission's proposed interpretation of TPL-002-0 requires a presumption that any non-redundant primary protection scheme not operate. FAC-011-2 will require a similar assumption. However, under that assumption, the only way to satisfy the operating conditions in FAC-011-2 (which are identical to the System Limits of Impacts in TPL-002-0 Table I)[68] will be to operate using a lower SOL.

Because lower SOLs will decrease the amount of transmission capacity available on the relevant systems, the implementation of this approach throughout the United States will result in a widespread decrease in transmission capacity. Any widespread decrease in transmission capacity will have serious repercussions for the wholesale power markets and likely result in greatly increased use of generation redispatching. This will drive up costs and severely limit the flexibility of existing power markets. Ultimately, this will drive up the cost of power to end-users. Given that markets have been successfully and reliably operating under the existing industry interpretation of TPL-002-0, the Commission's proposed interpretation will provide little increase in reliability in exchange for these serious, negative market effects.

C. The Commission's Proposed Interpretation Will Require Significant Expenditures Without a Significant Increase in Reliability

FERC's proposed interpretation would result in significant costs for Registered Entities because of the significant capital expenditures to install and implement redundant and back-up protection systems. First, significant engineering work will be needed to introduce the necessary redundancy. Given that each transmission owner will need to significantly expand its

68 FAC-011-2 Requirement R2.2 states that "[f]ollowing the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur." (footnote omitted)

engineering resources to address this need, it is unlikely that enough such resources exist to provide the expertise to make such changes in accordance with Good Utility Practice.[69]

In addition, Registered Entities, after discovering that their sub-345 kV transmission systems are not capable of satisfying the newly-interpreted Category B contingency requirements under TPL-002-0 Table I, will need to purchase and install redundant protection systems to ensure that the "non-operation" of the primary protection system does not affect the ability of the transmission system to reliably respond to a single contingency under Category B.[70] This will be an exceedingly expensive proposition. The Wiedman Affidavit contains a detailed estimate of the expenditures necessary, which are expected to total approximately $24.06 billion for the US transmission system.[71] This estimate is based on the total expected US demand in 2018 of 898,749 MW together with the total number of transmission lines below 345 kV (expecting that each line will have at least two main terminals of relays) and the number of transmission transformers, distribution transformers, and buses that would be affected by the needed redundancy. In addition, this estimate takes into consideration the retrofits of generating stations and substations where the retrofit would be more difficult due to the layout of the substations. Notably, this does not include the ongoing operating and maintenance expenses related to the additional protection systems or the costs related to generation redispatch as described in these comments.

As the Commission has indicated in the past, there should be a relationship between the costs incurred in the course of complying with a Reliability Standard and the reliability benefit to

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[69] Wiedman Affidavit ¶ 30 and 33.

[70] As explained in the Wiedman Affidavit ¶ 29, lines operating at 345 kV and above typically have two high-speed relay protection schemes because the stability effect of faults on these lines create a need for a very short critical clearing time. At lower voltage levels, the clearing times can be two to three times higher than the clearing times for 345 kV and above lines.

[71] Wiedman Affidavit ¶ 31-32.

the bulk-power system resulting from that investment. In approving NERC as the ERO, the Commission explained that any Reliability Standard developed by the ERO "should achieve its reliability goal effectively and efficiently."[72] As indicated in the Wiedman Affidavit, there would very little increase in reliability or efficiency result from the costs that will be incurred by the industry because of the Commission's proposed interpretation.[73] As a result, the expenditures do not seem justified.

D. The Commission's Proposed Interpretation Will Result In Significant Costs to Ratepayers

The Commission should also consider the effect on ratepayers from this proposed interpretation. As explained above and in the Wiedman Affidavit, Registered Entities will incur significant costs as the result of the Commission's proposed interpretation, due in part to increased planning assessment costs, but mainly as a result of the substantial capital investments in additional redundant protection systems. In many instances, these costs will ultimately be born by ratepayers, as will any costs resulting from the decreasing amounts of available transmission capacity.

The Commission itself has stated that it "will allow recovery of all costs prudently incurred to comply with the Reliability Standards"[74] pursuant to section 1241 of EPAct 2005.[75] In addition, many states typically allow utilities to pass through such costs to their ratepayers. As a result, the substantial planning and protection systems investment expenses resulting from the Commission's proposed interpretation would likely be passed through to ratepayers. Given that one of the central parts of the Commission's regulatory regime under the Federal Power Act

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72 *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 at P 240 (2006), *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) ("ERO Certification Order").

73 Wiedman Affidavit ¶ 34-35.

74 Order No. 672 at P 259.

75 Pub. L. No. 109-58, 119 Stat. 594, Section 1241, 16 U.S.C. § 824s (2006).

is the protection of ratepayers, the proposal discussed in the NOPR should not be undertaken without serious consideration of the increased costs that will be faced by ratepayers, particularly in light of the minimal reliability benefits that will be achieved.

VI. THE COMMISSION HAS NOT FULFILLED ITS OBLIGATIONS UNDER THE REGULATORY FLEXIBILITY ACT

In the NOPR, the Commission failed to include its initial regulatory flexibility analysis as required by section 603 of the Regulatory Flexibility Act ("RFA")[76] when it published the TPL-002-0 reliability interpretation NOPR in the *Federal Register*[77]even though the compliance costs imposed on small entities may be severe. For example, approximately 333 public power systems are currently shown on the NERC Compliance Registry.[78] Only 44 public power systems have total annual electric outputs of 4,000,000 MW hours or more (the standard for determining a "small electric utility") based on the most recent data available from the Energy Information Administration; the remaining 289 are small utilities and are among the small entities that are the focus of the protections accorded by the RFA.

One of these small electric utilities estimated the cost to protect their system to the level proposed by the NOPR. The utility owns 30 terminals and estimated that it would cost $100,000 per terminal to retrofit the terminals for a total cost of $3 Million. If this is considered the typical cost for a small electric utility, then the total burden imposed on such small entities will be approximately $867 million. It is not prudent to require small electric utilities to make this type of investment for a minimal, if any, benefit to BES reliability. A proper RFA analysis would address these issues.

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76 5 U.S.C. § 603 (2006).

77 *Interpretation of Transmission Planning Reliability Standard*, 130 FERC ¶ 61,208 (2010), 75 Fed. Reg. 14,386 (Mar. 25, 2010).

78 NERC Compliance Registry Matrix, *available at*: http://www.nerc.com/files/NERC_Compliance_Registry_Matrix_Sorted_by_Entity20100429.pdf.

Under RFA § 603 the Commission is required to prepare and make available for comment an initial regulatory flexibility analysis describing the impact that any proposed rule will have on small entities.[79] Further, the statute requires the Commission to publish either the initial regulatory flexibility analysis or a summary of the analysis in the Federal Register at the time the applicable notice of proposed rulemaking is published.[80] Despite this requirement, which the Commission has successfully fulfilled in the past when assessing proposed interpretations of Reliability Standards,[81] the Commission did not publish an initial regulatory flexibility analysis or a summary of the analysis when proposing its interpretation of TPL-002-0 Requirement R1.3.10.

As an alternative to a full RFA analysis, the Commission is permitted to certify that an initial regulatory flexibility analysis is unnecessary if it concludes that the proposed rule will not have a "significant economic impact on a substantial number of small entities."[82] However, the Commission is also required to provide this certification at the time the Commission publishes the notice of proposed rulemaking in the *Federal Register*. Again, no such certification, or indeed any mention of the RFA was provided when the NOPR was published in the *Federal Register* on March 25, 2010.[83] In similar past proposed rulemakings on Reliability Standards and Reliability Standard interpretations the Commission has addressed its RFA obligations, often certifying that proposed Reliability Standards and interpretations would have no significant

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79 5 U.S.C. § 603.

80 *Id.*

81 *See, e.g.*, *Electric Reliability Organization Interpretations of Specific Requirements of Frequency Response and Bias and Voltage and Reactive Control Reliability Standards*, Notice of Proposed Rulemaking, 125 FERC ¶ 61,204 at P 41-43, 73 Fed. Reg. 71,971 (Nov. 26, 2008).

82 5 U.S.C. § 605(b) (2006).

83 75 Fed. Reg. 14,386 (Mar. 25, 2010).

economic impact on a substantial number of small entities in the electric industry.[84] In this proceeding, however, this obligation was overlooked.

Therefore, since the Commission has neither published an initial regulatory flexibility analysis, nor certified that such an analysis is unnecessary when proposing the interpretation of TPL-002-0, the Commission should republish its NOPR. In the revised notice, the Commission should address its obligations under the RFA by either performing a regulatory flexibility analysis or certifying that such an analysis is unnecessary. This will afford interested entities an opportunity to comment on the Commission's analysis or certification as required by the RFA and will also extend the comment period on the full NOPR. Given the more than $24 billion in costs that this proposal will impose on the electric industry, a significant part of which may fall on small entities, this analysis is critical to the rulemaking in this docket.

VII. THE IMPLEMENTATION PROPOSED BY THE COMMISSION FOR ITS INTERPRETATION IS IMPRACTICAL

The Commission has proposed to make its interpretation effective only on a prospective basis:

> 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.[85]

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[84] *Revision to Electric Reliability Organization Definition of the Bulk Electric System*, 130 FERC ¶ 61,204 at P 35-36 (2010), 75 Fed. Reg. ¶ 14,097 at 14,102-03 (Mar. 24, 2010); *Version One Regional Reliability Standard for Resource and Demand Balancing*, 130 FERC ¶ 61,202 at P 50 (2010); 75 Fed. Reg. ¶ 14,103 at 14,111 (Mar. 24, 2010); *Time Error Correction Reliability Standard*, 130 FERC ¶ 61,201 at P 40-45 (2010), 75 Fed. Reg. ¶ 15,371 at 15,375 (Mar. 29, 2010); *Transmission Relay Loadability Reliability Standard*, 127 FERC ¶ 61,175 at P 116-18 (2009), 74 Fed. Reg. ¶ 25,461 at 25,477 (May 28, 2009); *Revised Mandatory Reliability Standards for Interchange Scheduling and Coordination*, 127 FERC ¶ 61,246 at P 28-30 (2009), 74 Fed. Reg. ¶ 30,027 at 30,030 (Jun. 24, 2009); *Mandatory Reliability Standards for the Calculation of Available Transfer Capability*, 126 FERC ¶ at P 149-50 (2009), 74 Fed. Reg. ¶ 12,747 at 12,768-69 (Mar. 25, 2009); *Electric Reliability Organization Interpretations of Specific Requirements of Frequency Response and Bias and Voltage and Reactive Control Reliability Standards*, 125 FERC ¶ 61,204 at P 41-43 (2008), 73 Fed. Reg. ¶ 71,971 at 71,976 (Nov. 26, 2010) (proposing approval of the NERC interpretation of BAL-003-0).

[85] NOPR at P 27.

Under the proposed interpretation, many Registered Entities will be out of compliance when the interpretation becomes effective because of the significant lead time involved in performing the studies and instituting the transmission plan changes needed to become compliant under the new interpretation. Furthermore, as explained in the Wiedman Affidavit, it may take up to 20 years to install the protection system redundancy necessitated by the Commission's interpretation given the limitations of available manufacturing capacity, engineering resources, and transmission line outage windows.[86]

As a result, Registered Entities will be faced with immediate substantial penalties for noncompliance with TPL-002-0 R1.3.10. Given that penalties for Reliability Standards apply on a per-violation per-day basis, a failure to have performed the necessary TPL-002-0 planning assessment by the effective date of the interpretation could quickly add up to a significant monetary penalty. For instance, TPL-002-0 R1.3.10 has been assigned a Medium Violation Risk Factor[87] and failures to comply with this sub-requirement are assigned either a High or Severe Violation Severity Level. Therefore, the per-day monetary sanction that may result from non-compliance,[88] without the application of mitigating or aggravating factors in accordance with the NERC Sanction Guidelines, is $6,000 to $335,000 per day.[89] A 30-day period of non-compliance could result in a sanction of more than $10 million. A three month period of non-compliance could lead to a penalty of more than $30 million. As the Commission's proposed interpretation marks a significant expansion of this Reliability Standard compared to the industry approach both before and after compliance became mandatory and enforceable,[90] any shift to this

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86 Wiedman Affidavit ¶ 30 and 33.

87 *See North American Electric Reliability Corporation*, 119 FERC ¶ 61,145 at Appendix B (2007).

88 16 U.S.C. § 825o-1(b) (2006) (promulgating a "civil penalty of not more than $1,000,000 for each day that such violation continues").

89 NERC Sanction Guidelines, Appendix A: Base Penalty Amount Table.

90 The Commission tacitly acknowledges this by describing how the interpretation will be effective on a going-forward basis only. NOPR at 27.

new interpretation without a significant lead time would be fundamentally unfair to those entities subject to this Reliability Standard.

Therefore, in the event that FERC does approve the proposed FERC-drafted interpretation, the Commission should develop an implementation plan that provides Registered Entities with a reasonable period of time to come into compliance.

VIII. THE PROPOSED INTERPRETATION WILL UNDERMINE THE INTERNATIONAL STANDARD-SETTING PROCESS AND COULD RESULT IN DIFFERING INTERPRETATIONS OF STANDARDS ON THE NORTH AMERICAN BULK-POWER SYSTEM

Through its proposed interpretation of TPL-002-0, FERC is proposing an interpretation that has not been vetted through the NERC Reliability Standards Development Procedure. It has not been considered by any of the Canadian representatives to the NERC Standards development process, and has not been offered for consideration to any of the relevant Canadian governmental authorities.

On the other hand, NERC's proposed interpretation has been considered by industry stakeholders in the U.S. and Canada, and was overwhelmingly approved by all entities. In the voting on the proposed interpretation at NERC, the weighted average of the stakeholders voting for approval of the ERO's interpretation was 98.85%.[91] Furthermore, of the Canadian entities that voted on the interpretation, 100% voted in favor of NERC's interpretation.[92] The Canadian industry overwhelmingly supported the proposed NERC interpretation and, importantly, advocated for no alternative approach.

NERC's proposed interpretation of Reliability Standard TPL-002-0 was provided to the relevant Canadian governmental authorities on December 8, 2009. The interpretation is

91 Final Ballot Results, Project 2009-14: Interpretation of TPL-002-0a Requirement R1.3.10 for PacifiCorp, *available at*: http://www.nerc.com/docs/standards/sar/Stds_Announce_Final_Results_RFI_Project2009-14_2009Aug7.pdf.

92 *Id.*

currently in effect in certain of those provinces,[93] and should go into effect in the remaining provinces in the near future. Since the Commission is not proposing to remand NERC's proposed interpretation of TPL-002-0, there is no process for reconsideration of the interpretation. Thus, if the Commission adopts its proposed interpretation in the Final Order, there will necessarily be differing interpretations of TPL-002-0 in the U.S. and Canada.

In Order No. 693, the Commission recognized the importance of the Reliability Standard development process "tak[ing] into consideration the international nature of Reliability Standards."[94] The following passage from Order No. 693 demonstrates the Commission's understanding of the importance of the NERC standard-setting process from an international perspective:

> Consistent with section 215 of the FPA and our regulations, any modification to a Reliability Standard, including a modification that addresses a Commission directive, must be developed and fully vetted through NERC's Reliability Standard development process. The Commission's directives are not intended to usurp or supplant the Reliability Standard development procedure. Further, this allows the ERO to take into consideration the international nature of Reliability Standards and incorporate any modifications requested by our counterparts in Canada and Mexico.[95]

Section 215 of the Federal Power Act gives the Commission only two choices when presented with a proposed Standard or interpretation to a Standard: either approve it or remand it to the ERO with or without recommendations. From an international perspective, such limited choices allow NERC to effectively function as an international standard-setting body. Thus, if the Commission disagrees with NERC's proposed interpretation, it must remand that interpretation, not modify the interpretation. A remand will allow NERC to reconsider the

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93 For example, in Ontario, a Standard goes into effect once approved by the NERC Board of Trustees.

94 Order No. 693 at P 187. *Cf.* Order No. 672 at P 331 ("A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard.").

95 Order No. 693 at P 187.

interpretation from the perspective of all the relevant governmental authorities and develop a revised interpretation applicable to the entire North American transmission grid.[96]

Should the Commission adopt its proposed interpretation to TPL-002-0, as explained above, the likely result would be the very result FERC sought to avoid in certifying NERC as the ERO, namely "conflicting Reliability Standards across international borders but within the same interconnected Bulk-Power System."[97] This will create serious difficulties for the three Regional Entities with dual US and Canadian responsibilities (Northeast Power Coordinating Council, Midwest Reliability Organization, and Western Electricity Coordinating Council) who will need to oversee two very different interpretations of these standards, even for entities within the same Interconnection. Differing interpretations of a Reliability Standard could also undermine the reliability and security of the North American bulk-power system. The Commission has stated that "international coordination is important to the Reliable Operation of the Bulk-Power System,"[98] but this proposed interpretation disregards such international coordination.

Further, the Commission's approval of its proposed interpretation could cause Canadian governmental authorities to reconsider their commitment to the entire NERC Reliability Standards Development Procedure. As further explained in the Joint Association Rehearing Request, Canadian governmental authorities entered into Memoranda of Understanding ("MOU") with NERC based on the understanding that Canadian entities would have a role to play in the standard-setting process. This understanding was based on the provisions in section 215, as well as the NERC Rules of Procedure reflecting the role of Canadian entities in the

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96 The importance of the remand function is reflected in the "Principles for an Electric Reliability Organization that Can Function on an International Basis," which FERC relied upon in Order No. 672 in addressing multiple issues with regard to the criteria for approving an ERO. In terms of the remand of a Standard, the Bilateral Principles provide that "the ERO should notify all relevant regulatory authorities, and should work to ensure that all concerns of such regulatory authorities are addressed prior to the resubmission of the standard to FERC and authorities in Canada."

97 ERO Certification Order at P 286 (2006).

98 Order No. 672 at P 400.

standard-setting process. Such a process includes the development of interpretations to Reliability Standards. Actions by the Commission that limit the role of Canadian entities in the standard-setting process could cause Canadian governmental authorities to reconsider the MOUs signed by such entities.

IX. CONCLUSION

Wherefore, the Trade Associations respectfully request that the Commission consider these comments in its consideration of the proposed interpretation of TPL-002-0 Requirement R1.3.10 and accept NERC's proposed interpretation.

Respectfully submitted,

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May 10, 2010

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Interpretation of Transmission Planning	)	Docket No. RM10-6-000
Reliability Standard	)	
	)	

AFFIDAVIT OF
THOMAS E. WIEDMAN, P.E.

1. My name is Thomas E. Wiedman. I am president of Wiedman Power System Consulting, Ltd., Corp. (WPSCL). WPSCL is a consulting engineering firm specializing in power system protection, planning, and operations.

2. I hold a Bachelor of Science degree in Electrical Engineering from the University of Illinois Chicago (1970), a Master of Business Administration degree from Loyola University Chicago (1974), and a Master of Science degree in Electrical Engineering from the Illinois Institute of Technology (1994).

3. I am a professional engineer licensed in the State of Illinois. My career spans 40 years. I accepted a position as electrical engineer with Commonwealth Edison Company of Chicago, Illinois (ComEd) in 1970. I retired from ComEd/Exelon in 2004. At the time of my retirement I had been Director of Transmission Planning for four years. Prior to that position, I had been Manager of Bulk System Security Operations for three years and Manager of System Protection and Control for five years. Prior to my management positions, I served in technical engineering positions of increasing responsibility involving the planning, designing, and testing of protection systems for generating stations, transmission systems, and distribution systems. From 1983 – 1994 I served as Protection Planning Section Engineer within the System Planning Department. In that

position, I was responsible for the development of protection planning criteria, applications, and settings of protective relays for the ComEd generation and transmission systems. The protection planning section was a part of System Planning and my responsibilities included the development of protection for all transmission planning projects and system protection upgrades. Thus, I was responsible for ensuring that the transmission protection system was correctly designed in order to provide reliable operation of the ComEd transmission system encompassing 69 kV, 138 kV, 345 kV, and 765 kV facilities under both normal and fault conditions. I was one of the principle investigators of the August 14, 2003 Blackout and specialized in analyzing the individual events from an operational and protection perspective. I have been a member of the North American Electric Reliability Corporation (NERC) System Protection and Control Task Force (now a subcommittee) since its inception. This subcommittee brings together twenty-five relay engineers from across North America to discuss and present opinions and recommendations on relay matters from an interconnection-wide perspective. I have created and continue to teach two graduate level courses on system protection at the Illinois Institute of Technology. These two courses are a consolidation of the principles and applications of protective relaying that have as their foundation the eight protective relaying courses I developed and taught to graduate-level electrical engineers at ComEd/Exelon as a part of their after-hours education program. I have been a contributing member of the Institute of Electrical and Electronics Engineers (IEEE) Power System Relaying Committee (PSRC) since 1983. I have chaired working groups and have been a contributing member for engineering standards on transmission line protection, substation protection, generator protection, system protection, and distribution resource protection. I am a past PSRC Standards Subcommittee Chair and received the IEEE PSRC Award for Outstanding Leadership and Career Service in 1998.

4. The purpose of my affidavit is to offer a technical opinion on the Federal Energy Regulatory Commission's (FERC or Commission) March 18, 2010 Notice of Proposed Rulemaking (NOPR) in Docket No. RM10-6-000, entitled "Interpretation of Transmission Planning Reliability Standard."[1] In this affidavit, I provide an opinion on the interpretation proposed by the Commission in the NOPR. My opinion is focused on the concepts of Protection System protection as they relate to NERC Reliability Standard TPL-002-0—System Performance Following Loss of a Single Bulk Electric System element and specifically to Requirement R1.3.10, which states "Include the effects of existing and planned Protection Systems, including any backup or redundant systems."

Description of Notice of Proposed Rulemaking

5. The Commission proposes a requirement that transmission planners study, in their TPL-002-0 assessments, the non-operation of Primary Protection Systems in order to ascertain whether and how reliance on the as-designed backup or redundant protections systems affects reliability. Further, the Commission proposes that the non-operation of a Primary Protection System is not of itself a contingency but rather a part of the base case model. The Commission asserts that normal clearing of a contingency depends on the Protection System that operates to clear the contingency, and that therefore only by modeling the non-operation of the 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, the Commission proposes to interpret

[1] *Interpretation of Transmission Planning Reliability Standard*, Notice of Proposed Rulemaking, 75 Fed. Reg. 14,386 (Mar. 25, 2010), 130 FERC ¶ 61,208 (2010) ("NOPR").

modeling of the non-operation of Primary Protection Systems in TPL-002-0 base cases as the compliance obligation imposed by Requirement R1.3.10 of Reliability Standard TPL-002-0 rather than addressing the non-operation of a component of a Protection System as explicitly stated in Standards TPL-003-0 and TPL-004-0. I believe it is the Commission's opinion that the non-operation of Primary Protection Systems is to be considered normal clearing and a base case assumption whether this non-operation is the result of planned maintenance or the result of a Primary Protection System component failure. The Commission considers the operation of redundant Primary Protection or backup relay systems, with their additional time delay and potential to remove additional elements, as normal clearing under TPL-002-0.

The Commission's Proposed Interpretation Is Incorrect

6. This interpretation of TPL-002-0 proposed by the Commission is incorrect. The interpretation approved by the NERC Board of Trustees and submitted to the Commission on November 17, 2009, is a correct interpretation of Requirement R1.3.10 of Reliability Standard TPL-002-0. The Commission's proposed interpretation incorrectly defines normal clearing as including the non-operation of a non-redundant Protection System and thus exceeds the testing requirement defined in TPL-002-0, which assumes that the loss of a single element of the bulk power system is cleared by a properly functioning Protection System.

7. To understand the errors contained in the proposed interpretation, it is important to establish a common understanding of the terms used by protection engineers and transmission planners, and compare them to the terms used by the Commission. The terms protective relaying engineers use are published in the IEEE standards and

publications and within the documents published by NERC's System Protection and Control Subcommittee (SPCS). These terms have been developed by protective relay engineers over many years to describe the basis for protective relay system designs that I have developed throughout my 40 years as a relay protection engineer and manager. This affidavit compares these terms with the terms used in the NOPR and, in doing so, establishes that the NOPR's proposed interpretation exceeds the level of reliability required by Reliability Standard TPL-002-0.

IEEE and SPCS Terminology

> A power system Element is any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.[2]
>
> A Contingency is the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.[3]
>
> 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.[4]
>
> Protection System Redundancy - A fundamental concept of redundancy is that Protection Systems need to be designed such that electric system faults will be cleared, even if a component of the Protection System fails. Redundancy is a system design that duplicates components and/or systems to provide alternatives in case one component and/or system fails. "Redundancy," in the context of the NERC Technical Paper entitled "Protection System Reliability: Redundancy of Protection System Elements," further specifies that the fault clearing will meet the system performance requirements of the NERC Reliability Standards. Redundancy means that two or more functionally equivalent Protection Systems are used to protect each electric system element.[5]

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2 NERC Glossary of Terms (Apr. 20, 2010) (defining Element), *available at*: http://www.nerc.com/docs/standards/rs/Glossary_of_Terms_2010April20.pdf.

3 *Id.* (defining Contingency).

4 *Id.* (defining Protection System).

5 NERC System Protection and Control Task Force, Protection System Reliability: Redundancy of Protection System Elements (Nov. 2008).

Primary Protection is that segment of the Protection System that is designed to operate before other devices respond to a disturbance due to its sensitivity and speed.[6] For example, a 138 kV line Protection System may include a high speed Primary Protection System which includes relays and their associated communication systems. Together, this Primary Protection System can determine that a fault is internal within the line and initiate line tripping within 0.016 – 0.032 seconds.

Backup Protection is a form of protection that operates independently of specified components in the Primary Protective system. It may duplicate the Primary Protection or may be intended to operate only if the Primary Protection fails or is temporarily out of service.[7] There are three types of Backup Protection applied in the power system: Local Backup, Remote Backup, and circuit Breaker Failure (Backup).

Local Backup Protection is a form of Backup Protection in which the backup protective relays are at the same station as the primary protective relays.[8] Local Backup is a segment of the power system element's Protection System that is intended to operate independently of the Primary Protection. Local Backup Protection may operate as fast or faster than Primary Protection depending on where the fault is located within the protected element. If a 138 kV line faulted, tripping would be initiated in 0.016 – 0.7 seconds by Local Backup Protection if its Primary Protection is non-operable. Local Backup clears the line fault by tripping the same circuit breakers as the Primary Protection. It is comprised of three zones of distance relays to detect multi-phase faults and two relays that detect faults involving ground.

Remote Backup is a form of Backup Protection in which the protection is at a station or stations other than that which has the Primary Protection.[9] For example, a faulted 138 kV line whose Primary Protection and Local Backup Protection has failed or become non-operable must rely on Remote Backup to clear the line fault.

Breaker Failure is the failure of a circuit breaker to operate or to interrupt a fault. The failure of a circuit breaker to interrupt fault current following the attempt to energize its trip coil by a protective relay is described as breaker failure. The reasons for such failures include:

- Inadequate or damaged interrupter,

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6 IEEE Standard 100, The Authoritative Dictionary of IEEE Standards Terms, Seventh Edition (defining Primary Protection).

7 *Id.* (defining Backup Protection).

6 *Id.* (defining Local Backup).

9 *Id.* (defining Remote Backup).

- Mechanically damaged mechanism, and
- Lack of electrical continuity of the trip circuit.

> A Breaker Failure (Backup) relay recognizes the condition of current continuing to flow in the circuit breaker after a reasonable period of time has elapsed since a relay made an attempt to energize the trip coil of the circuit breaker. On recognizing such a condition, the Breaker Failure relay initiates the clearing of all the circuit that can feed current to the fault via the failed breaker. [10] For example, a faulted 138 kV line could initiate tripping of its circuit breaker in 0.016 seconds and also initiate its associated initiate breaker failure timer set at 0.10 seconds. Surrounding circuit breakers would trip to isolate the fault in another 0.05 seconds.

Examples of Backup or Redundant Protection Systems

8. The following two examples demonstrate how the effects of a backup or redundant Protection System are included in planning assessments without presuming the "non-operation of the primary protection system."

The first example is a line with Primary Protection employing a Directional Comparison Carrier Blocking scheme where a directional distance relay looks out over more than 100% of the line but has a blocking signal that prohibits tripping if the fault is beyond 100% of the line. Local Backup line protection includes a zone distance relay and an instantaneous ground overcurrent relay that look out over only a portion of the total line distance.

A transmission planner performing a study for a line fault close to the local station would simulate it as follows. The Local Backup line protection scheme initiates tripping of the local breaker first. The primary line protection scheme initiates tripping, followed by a trip of the remote line breaker when allowed by the primary directional comparison carrier blocking scheme. Although the design of the Primary Protection scheme provides fast fault isolation for faults at any location on the line, the scheme requires a delay to

[10] *Id.* (defining Breaker Failure Backup).

compensate for the time required to transmit and receive the blocking signal communication and accommodate logic processing time. The Local Backup Protection requires no scheme delay for the modeled close-in fault, resulting in faster local fault isolation. Consistent with TPL-002-0 Requirement R1.3.10, this example study includes the effects of Normal Clearing of a single element by both the primary and the as-designed Local Backup line Protection Systems.

A second example demonstrating how the effects of a backup or redundant Protection System is included in TPL-002 is as follows. Whenever there is a need to study a planned outage of a protection scheme in the Planning Horizon, simulations will be made for the next fault contingency according to TPL-002-0. These simulations will clear the fault with the clearing times associated with the remaining in-service protection schemes, which may also remove additional facilities while clearing the faulted element. This would be the clearing times associated with a redundant scheme if there is one. If there is no redundant scheme, it would be the clearing times associated with the backup scheme. Both steady state and stability simulations would be used to study the conditions. Therefore, Requirement R1.3.10 has meaning for TPL-002-0 without invoking the "non-operation of non-redundant primary protection systems" as a base case condition.

Commission Terminology

9. In the NOPR, the Commission defines Primary Protection as follows:

> A Primary Protection scheme is the first line of defense designed to remove the minimum number of elements in the shortest time.[11]

The Commission's definition of Primary Protection scheme as the first line of defense is consistent with the way industry relay protection engineers define Primary Protection.

[11] NOPR n.14.

The Protection System for a given power system element such as a transmission line includes a Primary Protection System and a Local Backup Protection system.

10. The Commission defines Backup Protection as:

> 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.[12]

11. The Commission defines Remote Backup Protection as:

> 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.[13]

The Commission and protective relaying engineers share the same understanding of the term Remote Backup.

12. The Commission does not define Local Backup Protection in the NOPR. Instead the Commission describes "as-designed" backup capability in the context of comparing and contrasting Normal Clearing versus Delayed Clearing:

- "Normal clearing with longer clearing times" can occur with a non-operable Primary Protection System when this non-operation disables both primary and Breaker Failure initiation protection.
- "Breaker Failure initiation protection" is a Backup Protection System that initiates Breaker Failure just the same as the Primary Protection System.

13. "Breaker Failure initiation protection" is one quality of Local Backup Protection as both Primary and Local Backup Protection Systems together form the Local Backup

12 *Id.* n.15

13 *Id.*

Protection System for a power system element. These subsystems trip their associated circuit breaker(s) and initiate Breaker Failure protection.

14. Normal and Delayed clearing are terms defined in the NERC Glossary of Terms:

> Normal Clearing: A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.[14]
>
> Delayed Clearing: Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.[15]

NERC's definitions of Normal Clearing and Delayed Clearing are consensus definitions within the industry. Note that Normal Clearing expects proper functioning of Protection Systems. Delayed Clearing expects correct operation of Backup Protection Systems.

15. The Commission describes "as-designed" back-up protection as:

> 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.[16]
>
> 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.[17]

"As-designed backup," as used by the Commission, in this case is synonymous with Local Backup.

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[14] NERC Glossary of Terms

[15] *Id.*

[16] NOPR at P 23.

[17] NOPR at P 23 n.24.

Contrast Between NOPR and Industry Understanding of Normal Clearing

16. The NERC term Normal Clearing requires the Protection System, both Primary Protection and Local Backup Protection, to be properly functioning. The industry has accepted this definition as the design basis for the protection requirements included in TPL-002-0. In contrast, the Commission's proposed interpretation is to state that Normal Clearing can occur when Primary Protection is non-operational. Thus, the base case assumption the Commission is proposing is that the Primary Protection Systems are non-operating (non-functioning) and that tripping for line, transformer, and generator faults depends on Local Backup or other "as-designed" Backup Protection. This understanding is not accurate. It is an industry accepted understanding that a failure of the Primary Protection System is not a planned activity and therefore should not be a base case assumption, but rather a condition to be tested. There is a big difference between "failures" and "planned outages" and that difference is essentially our ability to plan for the event. Testing for Protection System component failures is currently a part of the TPL-003-0 portion of the Transmission Planning Standards.

17. Planned maintenance activities are included in TPL-002-0 assessments in Requirement R1.3.12, which directs Transmission Planners and Planning Authorities to "[i]nclude the planned (including maintenance) outage of any bulk electric equipment (including Protection Systems or their components) at those demand levels for which planned (including maintenance) outages are performed." If Primary Protection Systems are planned out of service while the power system elements are in service (a strategy out of the norm for the industry) NERC Planning Standard TPL-002-2 Requirement R1.3.12 and the NERC Transmission Operations standards, notably TOP-002-2—Normal

Operations Planning Requirements R2, R6, and R11; TOP-003-0—Planned Outage Coordination Requirement R1; and TOP-004-2—Transmission Operations Requirements R2, R4, and R6 require system studies. These studies would have as a part of their base cases the assumption that the Primary Protection System is out of service. The operation standard requirements are to identify system operational limits and to protect against instability and uncontrolled separations resulting from multiple contingencies.[18] Thus system reliability would not increase with the addition of Redundancy as planned maintenance requires assessment today so that power system elements remain within operational limits. The non-operability of Primary Protection Systems is included in TPL-002-0 Requirement R1.3.12, TPL-003-0 Requirement R1.3.12, and TPL-004-0 Requirement R1.3.9 only in regards to the planned maintenance of the Protection System.

18. In P 24, the NOPR develops a concept of Normal Clearing (with longer clearing times) and distinguishes it from Delayed Clearing. Normal Clearing (with longer clearing times) is where a Protection System component could be common to both Primary and Backup Protection and, should it fail, it would render the entire Protection System non-operational. If so, then it is not just the time to operate but also which circuit breakers are tripped by Remote Backup. Thus transmission planning studies would assess the system response to a fault that is cleared in a longer time caused by a change in the base case assumptions by using Local Backup tripping times versus the Primary Protection tripping times. If Local Backup contains a relay element common to the Primary Protection then the planning studies would need to include the simulated tripping of other circuit breakers

[18] TOP-002-2, TOP-003-0, and TOP-004-2

via Remote Backup. The Commission considers this concept to be Normal Clearing rather than Delayed Clearing.

19. If Local Backup does contain a relay element common to the Primary Protection of the element, then it is not a complete Local Backup and the design needs to be changed; this is an error in design requiring revision and not a TPL-002-0 issue. For example, it is industry practice to have three zones of impedance relays on a 138 kV transmission line rather than two zones. Zone 3 can be used for both Primary and Local Backup Protection. Should it fail, the Primary Protection would fail, but the Zone 2 relay would be unaffected by this failure and the line would successfully trip.

20. The Commission concludes that because the non-operation of Primary Protection should be in the base case and the times to operate of the "as-designed" Backup Protection become the Normal Clearing scenario and not a contingency time to operate. In P 26, the Commission interprets the Standard to test the contingency with the Backup Protection as the analytical starting point for examined normal operating conditions, *i.e.*, the base case, even though this Backup Protection adds additional time and may even remove additional elements from service as a result. This is a severe test beyond TPL-002-0 planning requirements due to the Commission alteration of the definition of Normal Clearing and is unnecessary if the element's Local Backup is designed to function in the event that Primary Protection is non-functioning. A test of this sort is defined in TPL-003-0.

21. TPL-003-0—System Performance Following Loss of Two or More Bulk Electric System Elements (Category C) provides for the testing of the power system in the event of a single line to ground fault with Delayed Clearing. The conditions tested in this case are the faulted line and the relay failure or non-operation. The Delayed Clearing can be

caused by a single relay failure within a Protective System (for example the Primary Protection System) or a stuck circuit breaker. TPL-004-0—System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D) requires assessment of a three phase fault with Delayed Clearing (stuck breaker or protections system failure). I believe these Standards to be the appropriate Standards evaluating whether events resulting in the loss of two elements allow the affected system to meet the Characteristics of a System with an Adequate Level of Reliability[19] for a power system in the United States.

<u>Industry Practice in Transmission Planning Under TPL-002-0</u>

22. The industry does not currently follow the NOPR's interpretation of single contingency transmission planning and, in fact, follows the interpretation approved by the NERC Board and submitted to the Commission on November 17, 2009. Based on my over 40 years of experience as a system protection engineer, I do not believe that the NOPR's proposed interpretation is reasonable. It is the industry's practice and intent to have Local Backup Protection be designed to detect all of its element's faults in the event that the Primary Protection System is non-operable. The industry does not consider the non-operation of Primary Protection to be Normal Clearing. Planned maintenance of a Protection System is a part of a base case assumption as stated in the TPL-002-0 Standard. Remote Backup Protection is to operate to clear faults in the event that both Primary and Local Backup Protection fail. This is Delayed Clearing.

23. The industry does test for the non-operation of a non-redundant Protection System in the base case. In conjunction with Requirement R1.3.12, transmission planners would assess

[19] "Definition of "Adequate Level of Reliability," approved by the NERC Board of Trustees in February 2008.

the operation of the system with the non-redundant Protection System out of service due to maintenance, as described further below. However, because taking the non-redundant Protection System out of service would be a planned action, any such assessment would also look at any additional planned actions, such as taking the now unprotected element out of service, prior to conducting the assessment under TPL-002-0.

Use of Planning Standards by Transmission Planners

24. NERC planning standards have been developed over time, originating with the planning criteria of individual transmission owners and regions. The current TPL Standards are assessments that planners have agreed upon as ways to manage power system risks. Currently, there are four standards, TPL-001-0 through TPL-004-0. Although there are individual Requirements listed in the Standards, the overriding intent is the assessment and management of system risk as a whole. The intent of the TPL Standards is to consider them together and they are intended to focus on credible events. TPL-001-0 assessments address the system condition – System Normal. TPL-002-0 addresses single element outage contingencies. TPL-003-0 addresses multiple contingencies, and TPL-004-0 addresses those contingencies that can lead to a system cascade. These contingencies are to be considered credible. The difficult part of the process is to define what contingencies are credible. Credible contingencies are events that are plausible and likely to occur, and that likelihood can vary in different parts of the same Interconnection, and at different times. TPL-004-0 addresses less-likely multiple contingencies or Extreme Contingencies.

25. Table 1, Transmission System Standards – Normal and Emergency Conditions, is included in all four of the TPL Standards as a summary of assessment criteria. It is a

good road map. Category A, TPL-001-0, requires that the system remain stable, within normal thermal and voltage limits, and that there be no loss of load and no cascading outages. All facilities (power system Elements) are in service in Category A. In category B, TPL-002-0, single elements are removed from service one at a time in a simulation model. The planning requirement is that for a loss of an Element without a fault, or a loss of an Element with a fault that is cleared normally, the system will remain stable, be within emergency thermal and voltage ratings, only planned and controlled interruption of load is allowed, and there will be no cascading. In Category C, TPL-003-0, credible multiple contingencies are evaluated. For example, the transmission system must remain stable for a bus section fault that is cleared Normally. Another example is that in the event of a single line to ground fault on a generator, transmission line, transformer, or bus section the system is to remain stable and within applicable ratings in the event of a stuck breaker or a Protection System failure. Load shedding in a controlled fashion is acceptable for Category C. In Category C, TPL-003-0, the terms Normal Clearing and Delayed Clearing are defined with respect to the functioning of the installed Protection Systems.   Category D events, TPL-004-0, are unlikely but their consequences are severe. For example, a three-phase fault with Delayed Clearing can depress voltage, causing generators to trip, which in turn further depresses voltage over a wide area, possibly leading to a system cascade. Planners study these scenarios to evaluate the sensitivity of the interconnected system and to develop mitigation plans to lessen the impacts of these occurrences.

Existing Approach to Single Contingency Transmission Planning

26. The industry plans for single contingencies by developing a base case that includes the elements of the power system that are expected to be in service at the seasonal time of the year the planner intends to study. Often the season is the summer and summer loads are modeled at time of peak demand. Generators are modeled as dispatched economically and reliably to supply the loads. Summer base cases are prepared for years one through five in the future and in the longer-term (years six through ten, or as needed). System thermal and voltage constraints are added to the case. In addition, some base cases are designed at off-peak demand or at times of winter peaks. The off-peak and winter demand cases could include element outages if the planner knows of planned maintenance or construction. Once the base case is developed, elements of the power system are automatically removed from service one at a time using power flow calculations. The effects of the removal from service are then assessed to determine if the system remains within limits. Transient stability studies are performed as a part of the assessment if needed. The assessment process includes TPL-002-0 requirements and requirements set forth in the planner's planning criteria for their segment of the interconnected system. Currently, a single component failure of a Protection System is not evaluated within TPL-002-0. Such an evaluation is required in TPL-003-0 coincident with a single line to ground fault.

Effect of the Commission Interpretation on the Electric Industry

27. The Commission's proposed interpretation would require transmission owners to ensure that their Protection Systems have Redundant Protection Systems as an alternative to including all non-operable Primary Protection Systems included in their base cases.

Essentially, the Protection System would have two independent Protection Systems. Each system would have its own input sources (current transformers and voltage transformer secondaries), DC circuitry, DC source, Primary Protection System, and Local Backup Protection System. For the portion of the power system that the planner is responsible for, a retrofit of this magnitude, especially at the 230 kV, 161 kV, 138 kV and 115 kV voltage levels would be considerable. The planner would be compelled to evaluate the cost alternatives between modeling the system as the Commission proposes versus adding the Redundancy.

Effect on Planning Assessments

28. The Commission's interpretation would cause many study cases to be built—one case for every line, transformer, and generator under study as each non-operating Protection System must be considered one at a time. As an example, for a transmission owner that has 300 lines, 100 transformers, and 50 generators, 450 cases would have to be built. Contingencies would then be considered one at a time in each case. Evaluations of the results of the contingencies would be completed. Then the system reinforcements, able to withstand the multiple element outages, would be simulated as a part of a backup strategy. Each reinforcement alternative would be cost-estimated and compared to the Redundancy strategy. The base case development can be automated to an extent, but the man-hours necessary to perform such evaluations would be beyond present resource capacities. Planners may have to default to adding Redundancy since they may not have the resources to do these alternative analyses.

Effects on Various Voltage Levels of Transmission Facilities from the Commission's Proposal

29. Power system elements at 345 kV and above likely have Redundant Protection Systems, because the stability effect of faults on these lines create a need for a very short critical clearing time, although there are likely some exceptions to this. The loss of one of these lines can cause stability problems if the Protection System trips the line with a time delay. For example, if a 345 kV line emanates from a generating station and the line suffers a three phase fault, transient stability studies are performed to calculate the time it may take to trip while keeping the remaining system stable. This time is called "critical clearing time." Critical clearing times on 345 kV and above transmission lines can be 0.1 to 0.2 seconds. This is because the generators are large in output but "light" in inertia relatively speaking. The best way to make sure the line trips in 0.05 seconds is to have two high speed relay protection schemes.

Some transmission lines at the 230 kV and 161 kV voltage level would have a level of Protection Systems Redundancy if stability performance requirements had established their need. It is unlikely that autotransformers with secondary voltages at 230 kV and below, including 138 kV and 115 kV system elements, would have Redundant Protection Systems. It is unlikely that generators connecting to the 230 kV systems and below have Redundant Protection Systems. At lower voltage levels, the clearing times can be two to three times higher than the clearing times for 345 kV and above lines because the machines are "heavy" with respect to inertia given their electrical output. There are typically more lines per machine, and, in addition, autotransformers connect the lower voltages to higher voltages. Taken together, this can result in the critical clearing times being double or triple that of the 345 kV and above.

It is likely that many substations are shared by transmission and distribution facilities. Transmission and distribution elements could share the same circuit breakers, especially at substations with ring bus and breaker-and-half configurations. All of these system elements would have Local Backup Protection. The addition of Redundancy at these voltage levels would result from the Commission's proposed interpretation.

Hidden Costs of the Commission's Proposal

30. The cost of adding Redundancy will also include the costs of outages. Outage windows are scarce. The Redundancy projects would be competing with capacity projects for engineering and operating resources. The costs of all projects would increase as these scarce resources are taxed beyond their capacities. The net result besides cost is that some projects would not be completed before the high demand times of the year. Outages would creep into seasonal peaking times or equipment would not get installed. The net result would be a decrease in system reliability. Necessarily, the Redundancy projects would have to be implemented over a long time frame, possibly 10 to 20 years, due simply to the scarcity of resources.

Cost to the Industry from the Commission's Proposal

31. The cost of such retrofitted Protection Systems will vary among transmission and generation owners. Retrofits are always the most costly of installations, especially at generating stations and at substations where the retrofits were not a part of the substation's ultimate planned layout. Four transmission owners volunteered estimates for the purposes of this affidavit.

Large transmission owner A responded that 500 transmission line terminals in 100 substations at 230 kV and below could add Redundancy at about $120,000 per terminal.

This transmission system supplies about 20,000 MW of demand. There would be extenuating circumstances at some substations due to their physical layouts. It may be necessary to add relay input sources such as voltage transformers and current transformers to attain Redundancy. These input sources could need additional cabling into the control building. The control building may not be large enough to include a doubling of Protection Systems. The costs of these additional requirements could increase project cost by 30% or more.

Large transmission owner B responded that the cost estimate for 55 substations is $71 million. This estimate includes the requirements for expansion of substation buildings, redundant bus and autotransformer protection, redundant batteries, 55 lines and circuit breaker replacements.

Medium sized transmission owner C has estimated its costs to be $200,000 per terminal for 300 line terminals.

Large transmission owner D estimated non-communication relay system additions at $80,000 per terminal, $100,000 per terminal with transmitters/receivers, and $200,000 per terminal for two Protection Systems, transmitters/receivers, and power line carrier equipment.

32. Using data from the NERC 2009 Long Term Reliability Assessment, the total US demand in 2018 is projected to be 898,749 MW. Together with the transmission owner estimates and power flow element data I estimate the cost of adding Redundancy as described in paragraph 27 at voltage levels below 345 kV to be approximately $24 billion. This is an estimate and does not consider circuit breaker replacements. The following table shows the calculations and assumptions used.

Element Category	Estimated # of Elements	Estimated Cost per Element Category	Total Estimated Cost
lines 345kV and above	2,500	$ -	
lines 200 - 230kV	4,000	$ 1,600,000,000.00	
lines 100kV - 200kV	27,000	$ 10,800,000,000.00	
transmission transformers	9,000	$ 1,800,000,000.00	
effected distribution transforme	1,000	$ 200,000,000.00	
buses	9,000	$ 1,800,000,000.00	
Element Estimated Cost			$ 16,200,000,000.00
substation adder (30%)	4,000		$ 4,860,000,000.00
generating station elements	3,000	$ 3,000,000,000.00	$ 3,000,000,000.00
Estimated Cost of Redundancy			$ 24,060,000,000.00

Each transmission line estimated as having at least two main terminals of relays
# of buses estimated = # of transformers
# of 100kV - 200kV lines reported in Docket No. RM08-13-000 Order No. 733_PRC-023-1

Implementation Timing Concerns

33. Necessarily, the Redundancy projects would have to be implemented over a long time frame, possibly 10 to 20 years, because of the scarcity of resources, especially engineer manpower and manufacturing capabilities.

Questionable Benefits to Bulk Electric System Reliability

34. NERC in its letter of May 5, 2008 to the FERC,[20] defined Adequate Level of Reliability with a list of characteristics:

> 1. The System is controlled to stay within acceptable limits during normal conditions.
> 2. The System performs acceptably after credible Contingencies.
> 3. The System limits the impact and scope of instability and cascading outages when they occur.
> 4. The System's Facilities are protected from unacceptable damage by operating them within Facility Ratings.
> 5. The System's integrity can be restored promptly if it is lost.
> 6. The System has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.[21]

[20] Letter David N. Cook, NERC Vice-President and General Council, to FERC, Re: Definition of "Adequate Level of Reliability" (May 5, 2008).

[21] Capitalized terms are taken from the NERC Glossary of Terms Used in Reliability Standards.

35. I believe a Protection System that includes a Local Backup Protection System that can detect its Element's faults achieves the Adequate Level of Reliability as defined by NERC in the face of a Primary Protection System component failure. The focus for planners and protection engineers should be to assure this is true rather than to add another layer of protection.

FURTHER AFFIANT SAYETH NOT

Thomas Wiedman

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President
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Subscribed and sworn to before me, this 10th day of May, 2010.

Josh Esser

Notary Public

JOSH ESSER
NOTARY PUBLIC
STATE OF WISCONSIN