UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	))	**Docket Nos.**	**___________** **RM12-6-___** **RM12-7-___**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF REVISIONS TO THE DEFINITION OF "BULK ELECTRIC SYSTEM" AND REQUEST FOR EXPEDITED ACTION

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595 – facsimile

Charles A. Berardesco
Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
Stacey Tyrewala
Senior Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
stacey.tyrewala@nerc.net

Counsel for the North American Electric Reliability Corporation

December 13, 2013

TABLE OF CONTENTS

TABLE OF CONTENTS

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	))	**Docket Nos. ___________ RM12-6-___ RM12-7-___**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF REVISIONS TO THE DEFINITION OF "BULK ELECTRIC SYSTEM" AND REQUEST FOR EXPEDITED ACTION

Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits proposed revisions completed in Phase 2 of Project 2010-17 to the definition of the term "Bulk Electric System" ("BES Definition") in the *NERC Glossary of Terms Used in Reliability Standards* for Commission approval. NERC requests that the Commission approve the proposed BES Definition (**Exhibit A**) and find that the proposed BES Definition is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4] NERC also requests approval of the associated implementation plan (**Exhibit B**), and expedited Commission action to the extent necessary for the Commission to issue an order on the proposed BES Definition by no later than March 31, 2014.

---

1 16 U.S.C. § 824o (2006).

2 18 C.F.R. § 39.5 (2013).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

4 Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards*, *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf ("NERC Glossary").

As required by Section 39.5(a)[5] of the Commission's regulations, this petition presents the technical basis and purpose of the proposed revisions to the BES Definition and a summary of the development proceedings (**Exhibit E)**. NERC is requesting privileged treatment of portions of **Exhibit D**. The proposed BES Definition was approved by the NERC Board of Trustees on November 21, 2013.

I. EXECUTIVE SUMMARY

NERC's proposed BES Definition is an integral part of the NERC Reliability Standards and is included in the *NERC Glossary of Terms Used in Reliability Standards*. The development of the BES Definition occurred in two phases. Phase 1 culminated in the language that is the subject of Order Nos. 773 and 773-A ("Phase 1 BES Definition"). Phase 2, the subject of this petition, addresses the Commission's directives in Order Nos. 773 and 773-A, and responds to industry concerns raised during development of Phase 1. The proposed revisions to the BES Definition build upon Phase 1 and include significant improvements to the Inclusions and Exclusions, without modifying the core definition. In particular, the addition of Note 2 to Exclusion E1 (Radial Systems), which functionally allows for a configuration with a loop of 50 kV or less to qualify for Exclusion E1, is a well-designed solution that is technically supported by the analysis provided in **Exhibit D** and satisfies the Commission's directives in Order Nos. 773 and 773-A.

The proposed revisions to the BES Definition are expected to result in minimal changes to the Elements included in the BES, although some changes are expected as Regional Entities transition to a consistent approach in application of the BES Definition. The proposed revisions to the BES Definition add clarity and granularity that will allow for greater transparency and

---

[5] 18 C.F.R. § 39.5(a) (2013).

consistency in the identification of Elements and facilities that make up the Bulk Electric System ("BES") and is responsive to the technical and policy concerns discussed in Order Nos. 773 and 773-A. Provided below is a detailed explanation of the elements of the BES Definition and the proposed Phase 2 revisions.

A. Overview of the Elements of the BES Definition

The proposed BES Definition consists of a "core" definition and a list of configurations of facilities that will be included or excluded from the "core" definition, *i.e.*, Inclusions and Exclusions. The Inclusions address five specific facilities configurations to provide clarity that the facilities described in these configurations are included in the BES. Similarly, the Exclusions address four specific facilities configurations that are *not* included in the BES.

The Inclusions and Exclusions address typical system facilities and configurations such as generation and radial systems, provide additional granularity that improves consistency, and provide a practical means to determine the status of common system configurations.

The core definition, with the more granular proposed Inclusions and Exclusions, should produce consistency in identifying BES Elements across the reliability regions.[6] The case-by-case exception process, to add elements to, and remove elements from, the BES adds transparency and uniformity to the process of determining what constitutes the Bulk Electric System.[7]

---

6 Consistent with Order No. 672, the proposed BES Definition achieves the specific reliability goal of ensuring that the Definition of BES eliminates regional variations, providing a consistent identification of BES Facilities across the nation's reliability regions. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards,* Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 321, *order on reh'g,* Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006). The proposed BES Definition also achieves its reliability goals effectively and efficiently in accordance with Order No. 672. *Id.* at P 328.

7 Upon Commission approval of the proposed BES Definition, NERC will file with the Commission amendments to the NERC Rules of Procedure to include the new BES Definition.

B. Summary of Proposed Revisions to the BES Definition

No changes are proposed to the core BES Definition, Inclusion I3 (Blackstart Resources) or Exclusion E2 (Behind the Meter Generation). Minor clarifying changes are proposed to:

- Inclusion I1 (Transformers);
- Inclusion I2 (Generating Resources); and
- Inclusion I5 (Static or Dynamic Reactive Power Devices).

Substantive revisions are proposed to Inclusion I4 (Dispersed Power Producing Resources) and Exclusions E1 (Radial Systems), E3 (Local Networks) and E4 (Reactive Power Devices), as described below.

- Inclusion I4 (Dispersed Power Producing Resources):
    - Collector systems, from the point where the generation aggregates to 75 MVA to a common point of connection at a voltage of 100 kV or above, are proposed to be included in the BES.

- Exclusion E1 (Radial Systems):
    - A threshold of 50 kV is proposed as the operating voltage below which loops between radial systems will not preclude the application of Exclusion E1;[8]
    - In accordance with Order Nos. 773 and 773-A, Exclusion E1 is proposed to be modified so that it does not apply to tie-lines, *i.e.*, generator interconnection facilities, for BES generators.

- Exclusion E3 (Local Networks):
    - In accordance with Order Nos. 773 and 773-A, the 100 kV minimum operating voltage for Exclusion E3 is proposed for removal;
    - In accordance with Order Nos. 773 and 773-A, Exclusion E3 is proposed to be modified so that it does not apply to tie-lines, *i.e.*, generator interconnection facilities, for BES generators;
    - A revision is proposed to Exclusion E3 to include any part of a permanent Flowgate.

- Exclusion E4 (Reactive Power Devices):
    - A revision is proposed to Exclusion E4 to remove ownership implications consistent with the component-based nature of the BES Definition.

---

[8] This ensures that Elements at or above 100 kV in a looped configuration are not excluded from the BES by application of Exclusion E1. *See* Order No. 773-A at P 44.

Together, these proposed revisions improve upon the Phase 1 Definition of BES approved by the Commission in Order Nos. 773 and 773-A and provide a technically grounded and legally supportable foundation for identifying Elements and facilities that make up the BES. The proposed BES Definition is designed to ensure that all facilities necessary for operating an interconnected electric energy transmission network are included in the BES. The proposed BES Definition is consistent, repeatable, and verifiable and will provide clarity that will assist NERC and affected entities in implementing Reliability Standards.

C. Implementation and Request for Expedited Action

The Phase 1 version of the BES Definition approved by the Commission in Order Nos. 773 and 773-A is scheduled to go into effect on July 1, 2014. The implementation plan for the proposed Phase 2 BES Definition states that the Definition "shall become effective on the first day of the second calendar quarter after the date that the definition is approved by an applicable governmental authority…"[9] In order to ensure a smooth transition and avoid potential regulatory uncertainty, NERC requests expedited Commission action to the extent necessary for the Commission to issue an order on the proposed Phase 2 BES Definition by no later than March 31, 2014.

If approved by the Commission, the proposed Phase 2 BES Definition will supersede, in its entirety, the Phase 1 version. NERC is requesting expedited Commission action in order to allow the proposed Phase 2 BES Definition revisions to go into effect on July 1, 2014, the effective date of the Phase 1 BES Definition. Expedited action is consistent with the

[9] *See* **Exhibit B**.

Commission's acknowledgement of the need to process revisions to the BES Definition well in advance of the July 1, 2014 effective date.[10]

II. REQUEST FOR PRIVILEGED TREATMENT

Pursuant to 18 C.F.R. § 388.112 (2013), NERC is requesting that portions of **Exhibit D**, a white paper on the BES Radial Exclusion (E1) low voltage loop threshold, be treated as privileged and confidential. Information in **Exhibit D** includes confidential information as defined by the Commission's regulations at 18 C.F.R. Part 388 and orders, as well as NERC Rules of Procedure. This includes non-public information related to Registered Entity sensitive business information and confidential information regarding critical energy infrastructure. In accordance with the Commission's Rules of Practice and Procedure, 18 C.F.R. § 388.112, a non-public version of the information redacted from the public filing is being provided under separate cover. Because information in **Exhibit D** is deemed confidential by NERC, Regional Entities and Registered Entities, NERC requests that the confidential, non-public information be provided special treatment in accordance with the above regulation.

III. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[11]

---

[10] *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order Granting Extension of Time, 143 FERC ¶ 61,231 at P 16 (2013)("the Commission expects NERC to file the changes to comply with the Order Nos. 773 and 773-A directives in sufficient time to allow the Commission to process NERC's proposal in response to the directives well in advance of the July 1, 2014 effective date.").

[11] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2013), to allow the inclusion of more than two persons on the service list in this proceeding.

Charles A. Berardesco*
Senior Vice President and General Counsel
Holly A. Hawkins*
Assistant General Counsel
Stacey Tyrewala*
Senior Counsel
North American Electric Reliability
Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
stacey.tyrewala@nerc.net

Mark G. Lauby*
Vice President and Director of Standards
Laura Hussey*
Director of Standards Development
North American Electric Reliability
Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595 – facsimile
mark.lauby@nerc.net
laura.hussey@nerc.net

IV. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[12] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[13] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[14] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[15] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

---

12 16 U.S.C. § 824o (2006).
13 *Id.* § 824(b)(1).
14 *Id.* § 824o(d)(5).
15 18 C.F.R. § 39.5(a) (2012).

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[16] and Section 39.5(c)[17] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Process

The proposed BES Definition was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[18] NERC develops Definitions in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[19] In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies the criteria for approving Reliability Standards.[20] The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a Definition before the

---

[16] 16 U.S.C. § 824o(d)(2).

[17] 18 C.F.R. § 39.5(c)(1).

[18] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.").

[19] The NERC Rules of Procedure are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[20] 116 FERC ¶ 61,062 at P 250 (2006).

Definition is submitted to the Commission for approval. The proposed BES Definition was developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Definitions. **Exhibit E** includes a summary of the development history and record of development of the Definition, and details the processes followed to develop the Definition.

C. Procedural Background

1. <u>Order No. 693</u>

On March 16, 2007, in Order No. 693, pursuant to section 215(d) of the FPA, the Commission approved 83 of 107 proposed Reliability Standards, six of eight proposed regional differences, and the NERC Glossary, which includes NERC's BES Definition.[21]

2. <u>Order Nos. 743 and 743-A</u>

On November 18, 2010, the Commission revisited the BES Definition in Order No. 743, which directed NERC, through NERC's Reliability Standards Development Process, to revise its BES Definition to ensure that it encompasses all facilities necessary for operating an interconnected transmission network.[22] The Commission also directed NERC to address the Commission's technical and policy concerns. Among the Commission's concerns were: (i) inconsistencies in the application of the definition; (ii) a lack of oversight, and (iii) exclusion of facilities from the BES required for the operation of the interconnected transmission network. In Order No. 743, the Commission concluded that the best way to address these concerns was to eliminate the Regional Entity discretion to define the BES without NERC or Commission review, maintain a bright-line threshold that includes all facilities operated at or above 100 kV

---

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

[22] Order No. 743, 133 FERC ¶ 61,150 at P 16.

except defined radial facilities, and adopt an exemption process and criteria for removing from the BES those facilities that are not necessary for operating the interconnected transmission network. In Order No. 743, the Commission allowed NERC to "propose a different solution that is as effective as, or superior to, the Commission's proposed approach in addressing the Commission's technical and other concerns so as to ensure that all necessary facilities are included within the scope of the definition."[23] The Commission directed NERC to file the revised BES Definition and its process to exempt facilities from inclusion in the BES within one year of the effective date of the final rule.[24] In Order No. 743-A, the Commission reaffirmed its determinations in Order No. 743.

On January 25, 2012, NERC submitted two petitions pursuant to the directives in Order No. 743: (1) NERC's proposed revision to the BES Definition which includes provisions to include and exclude facilities from the "core" definition; and (2) revisions to NERC's Rules of Procedure to add a procedure creating an exception process to classify or de-classify an element as part of the BES. In Docket No. RM12-6-000, NERC filed a petition requesting Commission approval of a revised BES Definition in the NERC Glossary. The definition consists of a "core" definition and a list of facilities and configurations that will be included in, or excluded from, the "core" definition. NERC proposed the following "core" BES Definition:

> Unless modified by the [inclusion and exclusion] lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

The Commission issued the BES Notice of Proposed Rulemaking ("NOPR") on June 22, 2012, and required that comments be filed within 60 days after publication in the *Federal Register*, or

---

23 *Id.*

24 *Id. at* P 113.

September 4, 2012.[25] While seeking comment on various provisions of NERC's petitions, the NOPR proposed to approve NERC's modification to the currently-effective BES Definition and changes to the Rules of Procedure to add the exception process. The NOPR also requested comment on the appropriate role for NERC and the Commission in the identification of BES facilities and elements. NERC submitted comments on September 4, 2012, and reply comments on September 19, 2012.[26]

3. Order Nos. 773 and 773-A

On December 20, 2012, in Order No. 773, the Commission issued a Final Rule approving modifications to the currently-effective definition of BES developed by NERC. In Order No. 773-A, the Commission issued an order on rehearing and clarification. In the Orders, the Commission has directed NERC to: (1) modify the exclusions for radial systems (Exclusion E1) and local networks (Exclusion E3) so that they do not apply to tie-lines, *i.e.* generator interconnection facilities, for BES generators; and (2) modify the local network exclusion to remove the 100 kV minimum operating voltage to allow systems that include one or more looped configurations connected below 100 kV to be eligible for the local network exclusion.[27] The proposed revisions to the BES Definition address the Commission's concerns, as explained below.

On May 23, 2013, NERC filed a Motion for an Extension of Time, from July 1, 2013 to July 1, 2014, of the effective date of the BES Definition. NERC explained that, without an extension of time, there would be a period of time during which the existing BES Definition

---

25 *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, 139 FERC ¶ 61,247 (June 22, 2012) ("NOPR").

26 NERC's initial comments are available here: http://www.nerc.com/files/FINAL_Comments_BES_NOPR_complete.pdf and NERC's reply comments are available here: http://www.nerc.com/files/FINAL_BES_NOPR_Reply%20comments_clean.pdf.

27 Order No. 773 at PP 155, 164.

without the Commission-directed modifications would be in effect. On June 13, 2013, the Commission granted NERC's request for an extension of time.[28]

V. JUSTIFICATION FOR APPROVAL

As discussed herein, the proposed BES Definition is just, reasonable, not unduly discriminatory or preferential, and is in the public interest. Provided below is an explanation of the components of the BES Definition and the proposed revisions.

A. Discussion of Proposed Revisions to the Definition of "Bulk Electric System"

No changes are proposed to the core BES Definition, Inclusion I3 (Blackstart Resources) or Exclusion E2 (Behind the Meter Generation). Minor clarifying changes are proposed to Inclusions I1 (Transformers), I2 (Generating Resources), and I5 (Static or Dynamic Reactive Power Devices). Substantive revisions are proposed to Inclusion I4 (Dispersed Power Producing Resources) and Exclusions E1 (Radial Systems), E3 (Local Networks), and E4 (Reactive Power Devices).

1. "Core" Definition

> **Bulk Electric System (BES)**: Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

No revisions are proposed to the core Definition or the accompanying "note"[29] which applies to the entire Definition and recognizes that Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process. The core Definition is used to establish the bright-line of 100 kV, the overall demarcation point between Bulk Electric System and Non-Bulk Electric System Elements.

[28] *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order Granting Extension of Time, 143 FERC ¶ 61,231 (2013).

[29] Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

2. Inclusions

Inclusions identify specific facility configurations to provide clarity that the facilities described are included in the Bulk Electric System (unless the facilities are excluded based on one of the specific Exclusions in the BES Definition) and reduce the potential for the exercise of discretion and subjectivity.

a. Inclusion I1 (Transformers)

> **Inclusion I1 (Transformers)**: Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.

A minor clarifying change is proposed to Inclusion I1—the phrase "under Exclusion E1 or E3" is proposed to be changed to "by application of Exclusion E1 or E3." Inclusion I1 provides clarification regarding exactly which transformers are part of the Bulk Electric System. This clarification is necessary because transformers have windings operating at different voltages and multiple windings in some circumstances. Inclusion I1 includes in the Bulk Electric System those transformers operating at 100 kV or higher on the primary winding and at least one secondary winding, so as to be in concert with the core definition. The 100 kV threshold for secondary windings provides a clear demarcation between facilities used to transfer power as opposed to those that serve Load because transformers with two terminals >100 kV transfer power between portions of the BES. In Order No. 773, the Commission stated that Inclusion I1 is "a reasonable approach to identifying transformers that are appropriately included as part of the bulk electric system."[30]

[30] Order No. 773 at P 80.

b. Inclusion I2 (Generating Resources)

> **Inclusion I2 (Generating Resources):** Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
> a) Gross individual nameplate rating greater than 20 MVA. Or,
> b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.

Inclusion I2 has been revised for clarity but is substantively unchanged. The language of Inclusion I2 has been separated into sub-parts (a) and (b) in order to clarify the relationship between these sub-parts—this is an "or" statement. Inclusion I2 mirrors the text of the NERC *Statement of Compliance Registry Criteria* (Appendix 5B of the NERC Rules of Procedure) for generating units, and Inclusion I2 was approved by the Commission in Order No. 773.[31] The Commission "agree[d] with NERC and other commenters that multiple step-up transformers that are solely used to deliver the generation to the bulk electric system at 100 kV or above qualify the generator and the step-up transformers pursuant to inclusion I2."[32]

c. Inclusion I3 (Blackstart Resources)

> **Inclusion I3 (Blackstart Resources):** Blackstart Resources identified in the Transmission Operator's restoration plan.

No revisions are proposed to Inclusion I3. Blackstart Resources are vital to the reliable operation of the Bulk Electric System.[33] Consequently, Blackstart Resources are included in the BES regardless of their size (MVA) or the voltage at which they are connected. The term "restoration plan" in inclusion I3 refers to the restoration plans in the EOP Reliability

---

[31] Order No. 773 at P 91.

[32] *Id.*

[33] The term "Blackstart Resource" is defined in the NERC Glossary as "A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan."

Standards.[34] In Order No. 773, the Commission noted that "NERC's inclusion of blackstart resources in the definition is an improvement to the definition."[35]

d. Inclusion I4 (Dispersed Power Producing Resources)

Dispersed power producing resources are small-scale generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include, but are not limited to, solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells.

> **Inclusion I4 (Dispersed Power Producing Resources)**: Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
> a) The individual resources, and
> b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

Inclusion I4 has been revised to clarify the facilities designated as BES by application of this Inclusion and to include the collector system at the point of aggregation, *i.e.*, "[t]he system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above."

i. Inclusion of Collector Systems in the BES

In the BES NOPR, the Commission requested comments on this issue—whether Inclusion I4 "includes as part of the bulk electric system the individual elements (from each energy-producing resource at the site through the collector system to the common point at a voltage of 100 kV or above) used to aggregate the capacity and any step-up transformers used to

---

[34] *See* Order No. 773 at P 102 ("We also agree with NERC's statement that the 'restoration plan' in inclusion I3 refers to the restoration plans in the EOP Reliability Standards.").

[35] Order No. 773 at P 102.

connect the system to a common point at a voltage of 100 kV or above." NERC, in its comments on the BES NOPR, stated that "[e]nergy delivery elements in collector systems and interconnection facilities were specifically not included in Inclusion I4, which deals exclusively with generation resources. This was intended to avoid categorically including as part of the BES assets that may include local distribution facilities."

While the Commission did not direct NERC to categorically include collector systems pursuant to Inclusion I4, the Commission stated that it "disagrees that collector systems described in inclusion I4 that solely deliver aggregated generation to the bulk electric system contain local distribution facilities because power is delivered from the collector system to the bulk electric system."[36] Upon reflection of the Commission's statement in Order No. 773 and input from Commission technical staff during standard development, the drafting team reconsidered its earlier position and revised Inclusion I4 to include collector systems from the point where the generation aggregates to 75 MVA to a common point of connection at a voltage of 100 kV or above.

There are significant differences in collector system configurations; therefore, the standard drafting team did not establish a continent-wide bright-line determination for such Elements in their entirety. Rather, the standard drafting team identified the portions of the collector system which consistently provide a reliability benefit to the interconnected transmission network and are easily identified within collector systems. The result identifies the point of aggregation of 75 MVA and above and the interconnecting facilities to the interconnected transmission network. The aggregation threshold is consistent with the aggregation of capacity in Inclusion I2 and recognizes that the loss of those facilities would

---

[36] Order No. 773 at P 114.

represent a loss of 75 MVA capacity to the Bulk Electric System and thus a potential reliability impact on the operation of the BES.

As the Commission has noted, a bright-line threshold eliminates ambiguity.[37] While the Commission has stated that "[i]n general…it is appropriate to have the bulk electric system contiguous, without facilities or elements 'stranded' or 'cut-off' from the remainder of the bulk electric system…",[38] the standard drafting team determined that the inclusion of the collector system in Inclusion I4 is appropriate and consistent with the overall tenet of the BES Definition, which is to identify Elements that provide a reliability benefit to the interconnected transmission network. On a "bright-line" basis, the standard drafting team only included those portions of the collector system that are strictly utilized for delivering the aggregated capacity of the dispersed power resources to the interconnected transmission system. The intervening equipment is being treated in a similar fashion to Cranking Paths. Furthermore, where collector systems support the reliable operation of the surrounding interconnected transmission system and do not have a distribution function, those excluded facilities may be candidates for inclusion through the BES Exception Process.

ii. Inclusion of Variable Generation Resources

Consistent with the Commission's recognition that the purpose of Inclusion I4 is to include variable generation,[39] all forms of generation resources, including variable generation

---

37 Order No. 743 at P 141.

38 Order No. 773 at P 165.

39 Order No. 773 at P 115 ("We disagree . . . that inclusion I4 should be interpreted to not include the dispersed power producing resources within a wind plant in the [BES]. We agree with NERC's statement that the purpose of this inclusion is to include such variable generation (e.g., wind and solar resources). NERC noted that, while such generation could be considered subsumed in inclusion I2 (because the gross aggregate nameplate rating of the power producing resources must be greater than 75 MVA), NERC considered it appropriate for clarity to add this separately-stated inclusion to expressly cover dispersed power producing resources using a system designed primarily for aggregating capacity. In addition, although dispersed power producing resources (wind, solar, etc.) are typically variable suppliers of electrical generation to the interconnected transmission network, there are geographical areas that depend on these types of generation resources for the reliable operation of the interconnected

resources, continue to be included in the proposed revisions to the BES Definition. This is not a proposed change. Owners and operators of variable generation resources meeting the Registry Criteria have always been subject to registration and compliance with Reliability Standards. As the Commission noted in Order No. 773, "owners and operators of these resources that meet the 75 MVA gross aggregate nameplate rating threshold are, in some cases, already registered and have compliance responsibilities as generator owners and generator operators."[40]

Given the increasing penetration of wind, solar, and other non-traditional forms of generation, the standard drafting team believes that continuing the inclusion of individual variable generation units within the scope of a bright-line BES Definition is appropriate to ensure that, where necessary to support reliability, these units may be subject to Reliability Standards.

e. Inclusion I5 (Static or Dynamic Reactive Power Devices)

> **Inclusion I5 (Static or Dynamic Reactive Power Devices)**: Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Inclusion I5 has been revised to clarify that Exclusion E4 (Reactive Power Devices) would exclude Elements identified for inclusion in Inclusion I5. As the Commission noted in Order No. 773, Exclusions E1 and E3 would not override Inclusion I5 because Exclusions E1 and E3 exclude transmission elements only and not resources.[41] Exclusion E4, which is specific to resources (*i.e.*, Reactive Power devices), would override Inclusion I5. This clarification is an improvement to the BES Definition as it makes the relationship between specific and related

---

transmission network. The Commission believes that owners and operators of these resources that meet the 75 MVA gross aggregate nameplate rating threshold are, in some cases, already registered and have compliance responsibilities as generator owners and generator operators.").

[40] *Id.*

[41] Order No. 773 at P 123 ("The Commission does not agree with G&T Cooperatives that Exclusions E1 and E3 override inclusion I5 and exclude the reactive power devices. Exclusions E1 and E3 exclude transmission elements only and not resources.").

Inclusions and Exclusions transparent, which will facilitate consistent application of the BES Definition by industry.

The Commission approved Inclusion I5 in Order No. 773 and stated that "the inclusion adds clarity to the application of the bulk electric system definition by providing specific criteria for reactive power devices."[42] Similarly, the proposed revision to Inclusion I5 provides additional clarity.

3. Exclusions

Exclusions identify facility configurations that should not be included in the Bulk Electric System. The four Exclusions are for: (1) radial systems; (2) behind-the-meter generating units; (3) local networks; and (4) retail customer Reactive Power devices. As explained in Section VI below, Exclusions do not automatically supersede Inclusions. For example, if an Element qualifies under Inclusion I3 (Blackstart Resources), the Element would not be eligible for exclusion by application of any potential Exclusion (in this case, likely Exclusion E1 or Exclusion E3) because Blackstart Resources are included in the BES regardless of configuration or location.

a. Exclusion E1 (Radial Systems)

Exclusion E1 (Radial Systems): A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

a) Only serves Load. Or,
b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,
c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

[42] Order No. 773 at P 123.

Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

There are two substantive proposed revisions to Exclusion E1: (1) the addition of Note 2; and (2) the addition of Inclusions I2 and I4 in parts (b) and (c). As explained below, these proposed revisions satisfy the Commission's directives in Order Nos. 773 and 773-A. The technical analysis provided in **Exhibit D** supports the proposed addition of Note 2 and will allow the Commission to make an informed decision.

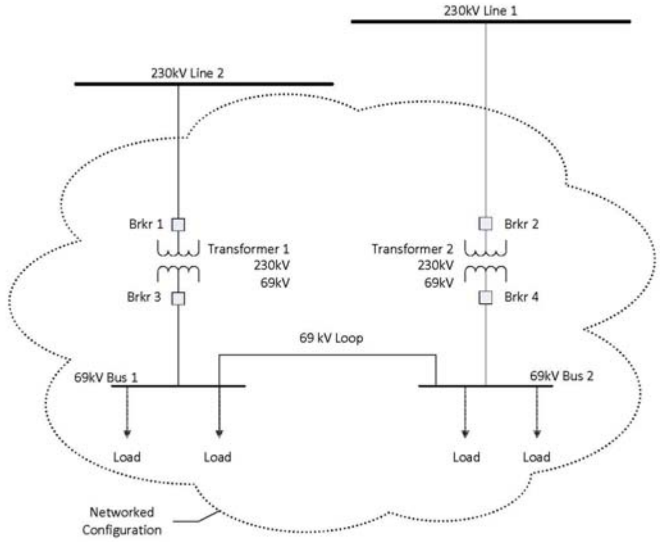
Exclusion E1 (Radial Systems) provides for the exclusion of radial systems that meet the specific criteria identified in the exclusion language. By definition, radial systems only consist of "transmission Elements." Therefore, Exclusion E1 does not allow for the exclusion of Real Power and Reactive Power resources captured by Inclusions I2 through I5, nor generator step-up transformers or portions of collector systems captured by Inclusions I2 and I4.

i. Networked Configuration with a sub-100 kV Loop

In Order No. 773, the Commission held that radial systems with elements operating at 100 kV or higher in a configuration that emanate from two or more points of connection cannot be deemed "radial" if the configuration remains contiguous through elements that are operated below 100 kV.[43] The Commission held that such a configuration is a networked configuration and does not qualify for Exclusion E1. The Commission included a depiction of this configuration, reproduced below, in Order No. 773 as Figure 3.

[43] Order No. 773 at P 155.

FERC Order No. 773 Figure 3
Networked Configuration w/69 kV Loop



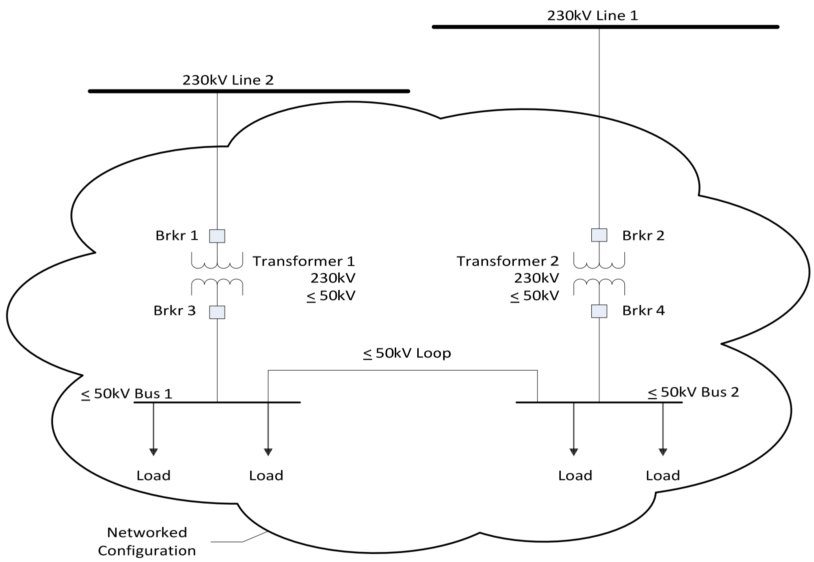
The Commission disagreed with commenters that this decision is contrary to the language of Exclusion E1 and directed NERC to ensure that Elements at or above 100 kV in a looped configuration are not excluded from the BES under Exclusion E1.[44] Similarly, the Commission directed NERC to remove the 100 kV floor in Exclusion E3 (Local Networks).[45] Removing the 100 kV minimum operating voltage in Exclusion E3 allows networked configurations below 100 kV, that may not otherwise be eligible for Exclusion E1, to be eligible for Exclusion E3.

In consideration of the Commission's directives, Exclusion E1 has been revised to include Note 2. Note 2 to Exclusion E1 states that the "presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion." Under the Phase 1 BES Definition, the presence of a loop meant that a configuration would be ineligible for consideration under Exclusion E1 and instead would

44 Order No. 773-A at P 36.
45 Order No. 773-A at P 125.

have to be considered under Exclusion E3. Note 2 functionally allows for a configuration with a loop of 50 kV or less to qualify for Exclusion E1– this is illustrated below in Figure A.

NERC Figure A Networked Configuration w/ a 50 kV (or less) Loop



This improvement to the BES Definition is responsive to the Commission's concerns in Order Nos. 773 and 773-A. The Commission stated in Order No. 773-A that "[i]t strikes us as unreasonable to characterize lines as radial by ignoring connecting facilities below 100 kV."[46] Instead, Note 2 recognizes the physical realities of the interconnected transmission system. For example, it would be an illogical result for two otherwise radial systems connected by a 2 kV loop to be deemed a local network simply by virtue of the presence of this 2 kV loop. With this understanding, the standard drafting team set out to determine at which voltage level the presence of a loop could create an impact on the BES. The standard drafting team conducted technical analysis including modeling the physics of loop flows through sub-100 kV systems, in order to determine an appropriate threshold.

46 *Id.*

In Order Nos. 773 and 773-A, the Commission indicated that additional factors beyond impedance must be considered to demonstrate that looped or networked connections operating below 100 kV need not be considered in the application of Exclusion E1.[47] The standard drafting team conducted a two-step process to establish a technical justification for the establishment of a voltage threshold below which sub-100 kV loops do not preclude the application of Exclusion E1.

- **Step 1**: A review was performed to determine the minimum voltage levels that are monitored by Balancing Authorities, Reliability Coordinators, and Transmission Operators for Interfaces, Paths, and Monitored Elements. This minimum voltage level reflects a value that industry experts consider necessary to monitor and facilitate the operation of the Bulk Electric System. This step provided a technically sound approach to screen for a minimum voltage limit that served as a starting point for the technical analysis performed in Step 2 of this study.

- **Step 2**: Technical studies modeling the physics of loop flows through sub-100 kV systems were performed to establish which voltage level, while less than 100 kV, should be considered in the evaluation of Exclusion E1.

Under Step 1, each Region was requested to provide the key groupings of elements they monitor to ensure reliable operation of the interconnected transmission system. This list, contained in **Exhibit D** Appendix 1, was reviewed to identify the lowest voltage element in the major element groupings monitored by operating entities in the eight Regions. Identification of this lowest voltage level served as a starting point to begin a closer examination into the voltage level where the presence of a contiguous loop should not preclude the evaluation of radial systems when applying Exclusion E1 of the BES definition.

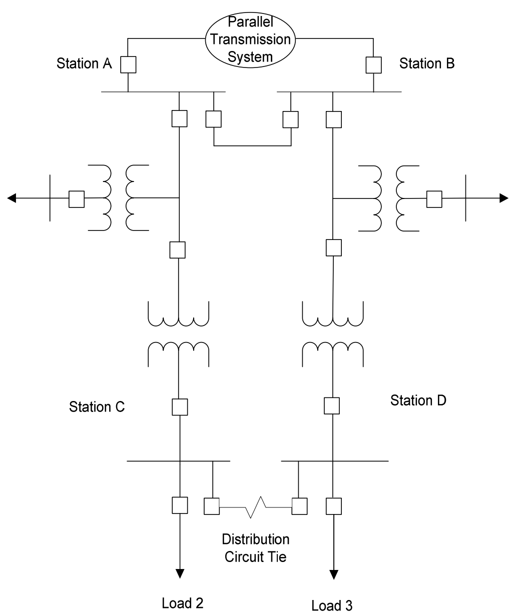
The threshold of 30 kV was established in Step 1 as a reasonable starting point to initiate the technical sensitivity analysis performed in Step 2 of this study. The purpose of this step was

[47] Order No. 773 at P 155, n.139 ("the Commission believes that excluding these configurations solely on the level of impedance does not consider other factors, including voltage, the system configuration, type of conductors, length of conductors, and proximity of the networked system in the interconnected transmission network.").

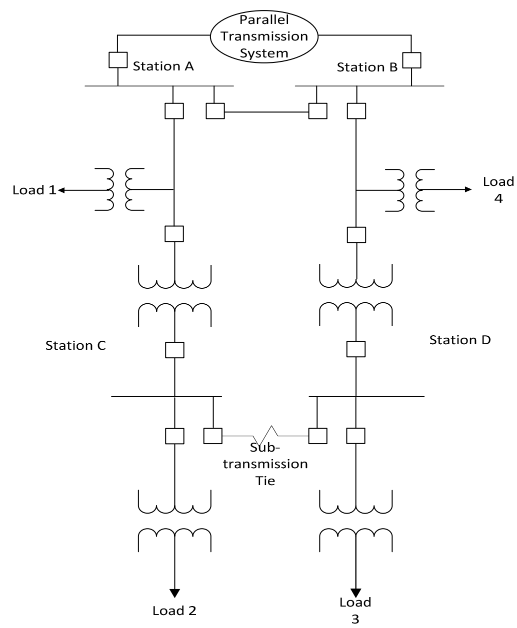
to determine if there is a technical justification to support a voltage threshold for the purpose of determining whether facilities greater than 100 kV can be considered to be radial when applying the BES Definition Exclusion E1. If the resulting voltage threshold was deemed appropriate through technical study efforts, then contiguous loop connections operated at voltages below this value would not preclude the application of Exclusion E1. Conversely, contiguous loops connecting radial lines at voltages above this kV value would negate the ability for an entity to use Exclusion E1 for the subject facilities.

This study focused on two typical configurations: a distribution loop and a sub-transmission loop. Examples of these configurations are depicted below in Figures B and C.

NERC FIGURE B: Example of a Radial System with Low Voltage Distribution Loop



NERC FIGURE C: Example of a Radial System with Sub-Transmission Loop



The study evaluated a range of voltages for the loop and the parallel transmission system with the goal of determining the voltage level below which single Contingencies on the transmission system would not result in power flow from a low voltage distribution or sub-transmission loop to the BES. The study included sensitivity analysis varying the loads and impedances. Variations in loop and transmission system impedances account for a range of physical parameters such as conductor length, conductor type, system configuration, and proximity of the loop to the transmission system. This study provided the low voltage floor that can be used as a consideration for BES Exclusion E1.

The proposed revisions are an equally effective and efficient solution to addressing the Commission's concerns in Order Nos. 773 and 773-A. The analysis described herein establishes that a 50 kV threshold for sub-100 kV loops, such as those depicted above in Figures B and C, does not preclude the application of Exclusion E1. This approach should ease the administrative burden on entities in order to prove that they qualify for an Exclusion and is an improvement to the BES Definition.

ii. Generator Interconnection Facilities

The proposed addition of Inclusions I2 (Generating Resources) and I4 (Dispersed Power Producing Resources) in parts (b) and (c) of Exclusion E1 satisfy the Commission's directive to modify Exclusions E1 and E3 to ensure that generator interconnection facilities at or above 100 kV connected to BES generators identified in Inclusion I2 are not excluded from the BES.[48]

In Order No. 773, the Commission stated that, if the generator is necessary for the operation of the interconnected transmission network, it is appropriate to have the generator interconnection facility operating at or above 100 kV that delivers the generation to the BES included as well.[49] Consistent with this directive and with this logic, parts (b) and (c) of Exclusion E1 have been modified to incorporate references to Inclusions I2 and I4. This

[48] Order No. 773-A at P 50 ("We grant rehearing to the extent that, rather than direct NERC to implement exclusions E1 and E3 as described above, we direct NERC to modify the exclusions pursuant to FPA section 215(d)(5) to ensure that generator interconnection facilities at or above 100 kV connected to bulk electric system generators identified in inclusion I2 are not excluded from the bulk electric system.").

[49] Order No. 773 at PP 164-65.

proposed revision ensures that generator interconnection facilities at or above 100 kV connected to BES generators identified in Inclusions I2 and I4 are not excluded from the BES.

b. Exclusion E2 (Behind the Meter Generation)

> **Exclusion E2 (Behind the Meter Generation)**: A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

No revisions are proposed to Exclusion E2. Exclusion E2 excludes from the BES a generating unit or units on the customer's side of the retail meter that serves all or part of the retail Load, so long as the following two conditions are met: (i) the net capacity provided by the generating unit(s) to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit(s) or the retail Load by a Balancing Authority, or pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority. Under these circumstances, the generating unit(s) are not necessary for the reliable operation of the interconnected transmission system, and therefore do not need to be included in the BES, because they serve a single retail Load, provide a limited amount of capacity to the BES, and are fully backed up by other resources. The Commission approved Exclusion E2 in Order No. 773 and noted that it "provides additional clarity to the definition of bulk electric system."[50]

[50] Order No. 773 at P 183.

c. Exclusion E3 (Local Networks)

Exclusion E3 (Local Networks): Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);
b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and
c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

Exclusion E3 has been substantively revised in accordance with the Commission's directives in Order Nos. 773 and 773-A; the 100 kV minimum operating voltage for Exclusion E3 has been removed. In addition, several clarifying changes are proposed for approval. Exclusion E3 (Local Networks) provides for the exclusion of local networks that meet the specific criteria identified in the exclusion language. By definition, local networks only consist of "transmission Elements." Therefore, Exclusion E3 does not allow for the exclusion of Real Power and Reactive Power resources captured by Inclusions I2 through I5, nor generator step-up transformers or portions of collector systems captured by Inclusions I2 and I4.

i. Removal of the 100 kV Floor

In Order Nos. 773 and 773-A, the Commission directed NERC to modify Exclusion E3 to remove the 100 kV minimum operating voltage in the local network definition.[51] In Order No. 773-A, the Commission agreed that "removing the phrase 'or above 100 kV but' from the definition of local networks in the first sentence of exclusion E3 is an appropriate way to meet

[51] Order No. 773 at P 199 ("we direct NERC to modify exclusion E3 to remove the 100 kV minimum operating voltage in the local network definition."); Order No. 773-A at P 34.

the Commission's directive to remove the 100 kV minimum operating voltage in the local network definition."[52] Consistent with the Commission's direction, the phrase "or above 100 kV but" has been removed from Exclusion E3 in the proposed BES Definition.

i. Generator Interconnection Facilities

The proposed addition of Inclusions I2 (Generating Resources) and I4 (Dispersed Power Producing Resources) in part (a) of Exclusion E3 satisfy the Commission's directive to modify Exclusions E1 and E3 to ensure that generator interconnection facilities at or above 100 kV connected to BES generators identified in Inclusion I2 are not excluded from the BES.[53]

In Order No. 773, the Commission stated that, if the generator is necessary for the operation of the interconnected transmission network, it is appropriate to have the generator interconnection facility operating at or above 100 kV that delivers the generation to the BES included as well.[54] Consistent with this directive and with this logic, part (a) of Exclusion E3 have been modified to incorporate references to Inclusions I2 and I4. This proposed revision ensures that generator interconnection facilities at or above 100 kV connected to BES generators identified in Inclusions I2 and I4 are not excluded from the BES.

ii. Flowgate

A change is proposed to part (c) of Exclusion E3 to include any part of a permanent Flowgate. The standard drafting team believes that the reliable operation of the interconnected transmission system requires operator situational awareness of any and all parts of permanent Flowgates in order to adequately provide for reliable operation.[55] Hence, the presence of any

---

[52] Order No. 773-A at P 40.
[53] Order No. 773-A at P 50.
[54] Order No. 773 at PP 164-65.
[55] *See* Consideration of Comments: Project 2017-17: August 2, 2013 at p. 17.

part of a Flowgate should preclude the application of Exclusion E3 and is an improvement to the BES Definition.

iii. Clarifying Changes

In the revised BES Definition, the term "retail customer Load" has been simplified to "retail customers" in order to provide clarity. A clarifying change is also proposed to part (b) to make clear that the term "Power" refers to "Real Power," rather than Reactive Power.[56] "Real Power" is defined in the NERC Glossary as "[t]he portion of electricity that supplies energy to the load." These revisions clarify the plain words of the proposed BES Definition.

d. Exclusion E4 (Reactive Power Devices)

> **Exclusion E4 (Reactive Power Devices)**: Reactive Power devices installed for the sole benefit of a retail customer(s).

Exclusion E4 has been revised to remove ownership implications as the BES Definition is a component-based definition and does not take into account the ownership of the actual equipment. Exclusion E4 is the technical equivalent of Exclusion E2 for reactive power devices. The Commission accepted Exclusion E4 in Order No. 773.[57]

The proposed revision to Exclusion E4 is responsive to concerns raised by industry representatives, which have noted that Exclusion E4 should not be confined to such devices that are owned and operated by a retail customer solely for its own use because there are instances in which capacitor banks have been installed for the benefit of a steel-making facility but, for various reasons, that equipment is owned, operated and maintained by its local utility. In Order

---

56 The term "Reactive Power" is defined in the NERC Glossary as "The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar)."

57 Order No. 773 at P 237.

No. 773, rather than directing such a change, the Commission noted that this issue could be explored by NERC in the development of Phase 2 of the BES Definition.[58] The proposed revision to Exclusion E4 improves the clarity of this Exclusion and is consistent with the purpose of the BES Definition.

VI. APPLICATION OF THE DEFINITION OF BULK ELECTRIC SYSTEM

The proposed BES Definition is generally applied in three steps, as discussed below. Going forward, NERC will work with industry regarding the application of the BES Definition to the configuration of Elements.

STEP 1: CORE DEFINITION: The core definition is used to establish the bright-line of 100 kV, the overall demarcation point between BES and Non-BES Elements. The core BES Definition identifies the Real Power and Reactive Power resources connected at 100 kV or higher, as included in the BES. To fully appreciate the scope of the core definition, an understanding of the term "Element" is needed. "Element" is defined in the NERC Glossary as: "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."

STEP 2: INCLUSIONS: This step involves applying the specific Inclusions, provides additional clarification for the purposes of identifying specific Elements that are included in the BES. The Inclusions address Transmission Elements and Real Power and Reactive Power resources with specific criteria to provide for a consistent determination of whether an Element is classified as BES or non-BES. There are five Inclusions in the Definition. The facilities described in Inclusions I1, I2, I4 and I5 are each operated (if transformers – Inclusion I1) or

58 Order No. 773 at P 237.

connected (if generating resources, dispersed power producing resources or Reactive Power resources – Inclusions I2, I4 and I5) at or above the 100 kV threshold. Inclusion I3 encompasses Blackstart Resources identified in a Transmission Operator's restoration plan, which are necessary for the reliable operation of the interconnection transmission system and should be included in the BES regardless of their size (MVA) or the voltage at which they are connected.

STEP 3: EXCLUSIONS: This step evaluates specific situations for potential exclusion from the BES. The exclusion language is written to specifically identify Elements or groups of Elements for exclusion from the BES. Step three (3) should be applied in the following sequence:

- Exclusion E2 (Behind the Meter Generation) provides for the specific exclusion of certain Real Power resources that reside behind-the-retail meter (on the customer's side) and supersedes the more general Inclusion I2 (Generating Resources). Behind-the-meter generation that meets these specific criteria do not affect reliability of the BES because the net capacity supplied to the BES is less than 75 MVA and the specific criteria impose obligations to support reliability when the resources are unavailable.

- Exclusion E4 (Reactive Power Devices) provides for the specific exclusion of Reactive Power devices installed for the sole benefit of a retail customer(s) and supersedes the more general Inclusion I5 (Static or Dynamic Reactive Power Devices). Reactive Power devices installed for the sole benefit of a retail customer are, by definition, not required for operation of the interconnected transmission system.

- Exclusion E3 (Local Networks) provides for the exclusion of local networks that meet the specific criteria identified in the exclusion language. Exclusion E3 does not allow for the exclusion of Real Power and Reactive Power resources captured by Inclusions I2 through I5. In instances where a transformer (under Inclusion I1) is an Element of a local network (under Exclusion E3), the transformer would be excluded pursuant to Exclusion E3. Exclusion E3 may not be used to exclude transmission Elements (captured by the core definition and Inclusion I1) when Real Power resources are present that are captured by Inclusion I2, I3, or I4. This assures that interconnection facilities for BES generators are not excluded.

- Exclusion E1 (Radial Systems) provides for the exclusion of 'transmission Elements' from radial systems that meet the specific criteria identified in the exclusion language. Exclusion E1 does not allow for the exclusion of Real Power

> and Reactive Power resources captured by Inclusions I2 through I5. In instances where a transformer (under Inclusion I1) is an Element of a radial system (under Exclusion E1), the transformer would be excluded pursuant to Exclusion E1. Exclusion E1 may not be used to exclude transmission Elements (captured by the core definition and Inclusion I1) when Real Power resources are present that are captured by Inclusion I2, I3, or I4. This assures that interconnection facilities for BES generators are not excluded.

Merely applying the core Definition, and the Inclusions or Exclusions is not necessarily the end of the inquiry regarding whether an Element is part of the BES as entities may seek a case-specific exception.

NERC will continue to work with industry regarding the application of the BES Definition. As explained herein, the proposed BES Definition is a significant improvement that is technically supported and satisfies the Commission's directives in Order Nos. 773 and 773-A. The proposed BES Definition is consistent, repeatable, and verifiable and will provide clarity that will assist NERC and affected entities in implementing Reliability Standards.

VII. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission:

- approve the proposed BES Definition and associated elements included in **Exhibit A,** effective as proposed herein;
- approve the implementation plan included in **Exhibit B**; and
- issue an order on the proposed BES Definition by no later than March 31, 2014.

Respectfully submitted,

/s/ Stacey Tyrewala

Charles A. Berardesco
Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
Stacey Tyrewala
Senior Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099 – facsimile
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
stacey.tyrewala@nerc.net

Counsel for the North American Electric Reliability Corporation

Date: December 13, 2013

Exhibit A

Proposed Definition

Bulk Electric System (BES): Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.
- **I2** – Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
  a) Gross individual nameplate rating greater than 20 MVA. Or,
  b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.
- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.
- **I4** - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
  a) The individual resources, and
  b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.
- **I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:
  a) Only serves Load. Or,
  b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,
  c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

  Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

  Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

- **E2 -** A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

- **E3 -** Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

    a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);
    b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and
    c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

- **E4 –** Reactive Power devices installed for the sole benefit of a retail customer(s).

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Effective Dates

This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the definition shall become effective on the first day of the second calendar quarter after Board of Trustees adoption or as otherwise made effective pursuant to the laws of applicable governmental authorities.

Version History

Phase	Date	Action	Change Tracking
1	1/25/12	Respond to FERC Order No. 743 to clarify the definition of the Bulk Electric System	
2	11/21/13	Adopted by NERC Board of Trustees	Phase 2 clarifications to the original revisions. Respond to directives in FERC Orders 773 and 773-A.

Exhibit B

Implementation Plan

Implementation Plan for Project 2010-17: Definition of BES (Phase 2)

Prerequisite Approvals
None.

Effective Dates
This definition shall become effective on the first day of the second calendar quarter after the date that the definition is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter after the date the definition is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Compliance obligations for the Phase 2 definition would begin:

- Twenty-four months after the applicable effective date of the definition (for newly identified Elements), or
- If a longer timeframe is needed for an entity to be fully compliant with all standards applicable to an Element or group of Elements that are newly identified as BES when the Phase 2 definition is applied, the appropriate timeframe may be determined on a case-by-case basis by mutual agreement between the Regional Entity and the Element owner/operator, and subject to review by the ERO.

This implementation plan is consistent with the timeframe provided in Phase 1.

Exhibit C

Redlined Comparison of Proposed Definition

Project 2010-17 Definition of Bulk Electric System (Phase 2)

Effective Dates

This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the definition ~~will go into effect~~ shall become effective on the first day of the second calendar quarter after Board of Trustees adoption~~. Compliance obligations for Elements included by~~ or as otherwise made effective pursuant to the ~~definition shall begin 24 months after the~~ laws of applicable ~~effective date of the definition.~~ governmental authorities.

Version History

Version	Date	Action	Change Tracking
1	~~TBD~~January 25, 2012	Respond to FERC Order No. 743 to clarify the definition of the Bulk Electric System	N/A
2	TBD	Phase 2 clarifications to the original revisions Respond to directives in FERC Orders 773 and 773-A	Y

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms ~~used in the proposed standard~~. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below ~~become approved when~~will be balloted in the ~~proposed standard is approved.~~same manner as a Reliability Standard. When the ~~standard~~approved definition becomes effective, ~~these~~the defined ~~terms~~term will be ~~removed from the individual standard and~~ added to the Glossary.

Bulk Electric System (BES): Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded ~~under~~by application of Exclusion E1 or E3.
- **I2** ~~-~~ Generating resource(s) ~~with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA~~ including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above~~.~~ with:
    - a) Gross individual nameplate rating greater than 20 MVA. Or,
    - b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.
- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.
- **I4** - Dispersed power producing resources ~~with~~that aggregate to a total capacity greater than 75 MVA (gross ~~aggregate~~ nameplate rating~~) utilizing~~), and that are connected through a system designed primarily for ~~aggregating~~delivering such capacity~~, connected at~~ to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
    - a) The individual resources, and
    - ~~)~~b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

- **I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1~~.~~ unless excluded by application of Exclusion E4.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:
  a) Only serves Load. Or,
  b) Only includes generation resources, not identified in ~~Inclusion~~Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,
  c) Where the radial system serves Load and includes generation resources, not identified in ~~Inclusion~~Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

  Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.
  Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

- **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.
- **E3** - Local networks (LN): A group of contiguous transmission Elements operated at ~~or above 100 kV but~~ less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail ~~customer Load~~customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:
  a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in ~~Inclusion~~Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating~~) ;~~);
  b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

c) Not part of a Flowgate or transfer path: The LN does not contain ~~a monitored Facility~~any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

- **E4** – Reactive Power devices ~~owned and operated by~~ installed for the sole benefit of a retail customer ~~solely for its own use.~~(s).

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Exhibit D

White Paper on Bulk Electric System Radial Exclusion (E1) Low Voltage Loop Threshold- Public Version

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

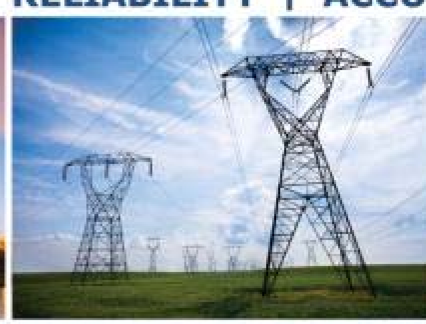
PUBLIC VERSION

White Paper on Bulk Electric System Radial Exclusion (E1) Low Voltage Loop Threshold

September 2013

RELIABILITY | ACCOUNTABILITY






Project 2010-17: Definition of Bulk Electric System

Table of Contents

Bulk Electric System Radial Exclusion (E1)
Low Voltage Loop Threshold

Background

The definition of "Bulk Electric System" (BES) in the NERC Glossary consists of a core definition and a list of facilities configurations that will be included or excluded from the core definition. The core definition is used to establish the bright line of 100 kV, the overall demarcation point between BES and non-BES elements. Exclusion E1 applies to radial systems. In Order No. 773 and 773-A, the Federal Energy Regulatory Commission's (Commission or FERC) expressed concerns that facilities operating below 100 kV may be required to support the reliable operation of the interconnected transmission system. The Commission also indicated that additional factors beyond impedance must be considered to demonstrate that looped or networked connections operating below 100 kV need not be considered in the application of Exclusion E1.[1]

This document responds to the Commission's concerns and provides a technical justification for the establishment of a voltage threshold below which sub-100 kV equipment need not be considered in the evaluation of Exclusion E1.

> *NOTE: This justification does not address whether sub- 100 kV systems should be evaluated as Bulk Electrical System (BES) Facilities. Sub- 100 kV systems are already excluded from the BES under the core definition. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process." Sub-100 kV facilities will only be included as BES Facilities if justified under the NERC Rules of Procedure (ROP) Appendix 5C Exception Process.*

---

[1] *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 at P155, n.139 (2012); *order on reh'g*, Order No. 773-A, 143 FERC ¶ 61,053 (2013).

Executive Summary

The Project 2010-17 Standard Drafting Team conducted a two-step process to establish a technical justification for the establishment of a voltage threshold below which sub-100 kV loops do not affect the application of Exclusion E1. The justification for establishing a lower voltage threshold for application of Exclusion E1 consisted of a two-step technical approach:

- Step 1: A review was performed to determine the minimum voltage levels that are monitored by Balancing Authorities, Reliability Coordinators, and Transmission Operators for Interfaces, Paths, and Monitored Elements. This minimum voltage level reflects a value that industry experts consider necessary to monitor and facilitate the operation of the Bulk Electric System (BES). This step provided a technically sound approach to screen for a minimum voltage limit that served as a starting point for the technical analysis performed in Step 2 of this study.

- Step 2: Technical studies modeling the physics of loop flows through sub-100 kV systems were performed to establish which voltage level, while less than 100 kV, should be considered in the evaluation of Exclusion E1.

The analysis establishes that a 50 kV threshold for sub-100 kV loops does not affect the application of Exclusion E1. This approach will ease the administrative burden on entities as it negates the necessity for an entity to prove that they qualify for Exclusion E1 if the sub-100 kV loop in question is less than or equal to 50 kV. This analysis provides an equally effective and efficient alternative to address the Commission's directives expressed in Order No. 773 and 773-A.

It should be noted that, although this study resulted in a technically justified 50 kV threshold based on proven analytic methods, there are other preventative loop flow methods that entities can apply on sub-100 kV loop systems to address physical equipment concerns. These methods include:

- Interlocked control schemes;
- Reverse power schemes;
- Transformer, feeder and bus tie protection; and
- Custom protection and control schemes.

These methods are discussed in detail in Appendix 4. The presence of such equipment does not alter the criteria developed in this white paper, nor does it influence the conclusions reached. Additionally, the presence of this equipment does not remove or lessen an entity's obligations associated with the bright-line application of the Bulk Electric System (BES) definition.

Radial Systems Exclusion (E1)

The proposed definition (first posting) of radial systems in the Phase 2 BES Definition (Exclusion E1) was: *A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:*

- a) *Only serves Load. Or,*
- b) *Only includes generation resources, not identified in Inclusions I2 and I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,*
- c) *Where the radial system serves Load and includes generation resources, not identified in Inclusions I2 and I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).*

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

Note 2 - The presence of a contiguous loop, operated at a voltage level of 30 kV or less[2], between configurations being considered as radial systems, does not affect this exclusion.

STEP 1 – Establishment of Minimum Monitored Regional Voltage Levels

All operating entities have guidelines to identify the elements they believe need to be monitored to facilitate the reliable operation of the interconnected transmission system. Pursuant to these guidelines, operating entities in each of the eight Regions in North America have identified and monitor key groupings of the transmission elements that limit the amount of power that can be reliably transferred across their systems. The groupings of these elements have different names: for instance, Paths in the Western Interconnection; Interfaces or Flowgates in the Eastern Interconnection; or Monitored Elements in the Electric Reliability Council of Texas (ERCOT). Nevertheless, they all constitute element groupings that operating entities (Reliability Coordinators, Balancing Authorities, and Transmission Operators) monitor because they understand that they are necessary to ensure the reliable operation of the interconnected transmission system under diverse operating conditions.

To provide information in determining a voltage level where the presence of a contiguous loop between system configurations may not affect the determination of radial systems under Exclusion E1 of the BES definition, voltage levels that are monitored on major Interfaces, Flowgates, Paths, and ERCOT Monitored Elements were examined. This examination focused on elements owned and operated by entities in North America. The objective was to identify the lowest monitored voltage level on these key element groupings. The lowest monitored line voltage on the major element groupings provides an indication of the lower limit which operating entities have historically believed necessary to ensure the

[2] The first posting of this Phase 2 definition used a threshold of 30 kV; however as a result of the study work described in this paper, the Standard Drafting Team has revised the threshold to 50 kV for subsequent industry consideration.

reliable operation of the interconnected transmission system. The results of this analysis provided a starting point for the technical analysis which was performed in Step 2 of this study.

Step 1 Approach

Each Region was requested to provide the key groupings of elements they monitor to ensure reliable operation of the interconnected transmission system. This list, contained in Appendix 1, was reviewed to identify the lowest voltage element in the major element groupings monitored by operating entities in the eight Regions. Identification of this lowest voltage level served as a starting point to begin a closer examination into the voltage level where the presence of a contiguous loop should not affect the evaluation of radial systems under Exclusion E1 of the BES definition.

Step 1 Results

An examination of the line listings of the North American operating entities revealed that the majority of operating entities do not monitor elements below 69 kV as shown in Table 1. However, in some instances elements with line voltages of 34.5 kV were included in monitored element groupings. In no instance was a transmission line element below 34.5 kV included in the monitored element groupings.

Region	Key Monitored Element Grouping	Lowest Line Element Voltage
FRCC	Southern Interface	115
MRO	NDEX	69
NPCC	Total East PJM (Rockland Electric) – Hudson Valley (Zone G)[1]	34.5
RFC	MWEX	69
SERC	VACAR IDC[2]	100
SPP RE	SPSNORTH_STH	115
TRE	Valley Import GTL	138
WECC	Path 52 Silver Peak – Control 55 kV	55

Notes:

1. Two interfaces in NPCC/NYISO have lines with 34.5 kV elements.
2. The TVA area in SERC was not included in the tables attached to this report; however, a review of the Flowgates in TVA revealed monitored elements no lower than 115 kV. There were a number of Flowgates with 115 kV monitored elements in SERC, the monitored grouping listed is representative.

Table 1: Lowest Line Element Voltage Monitored by Region

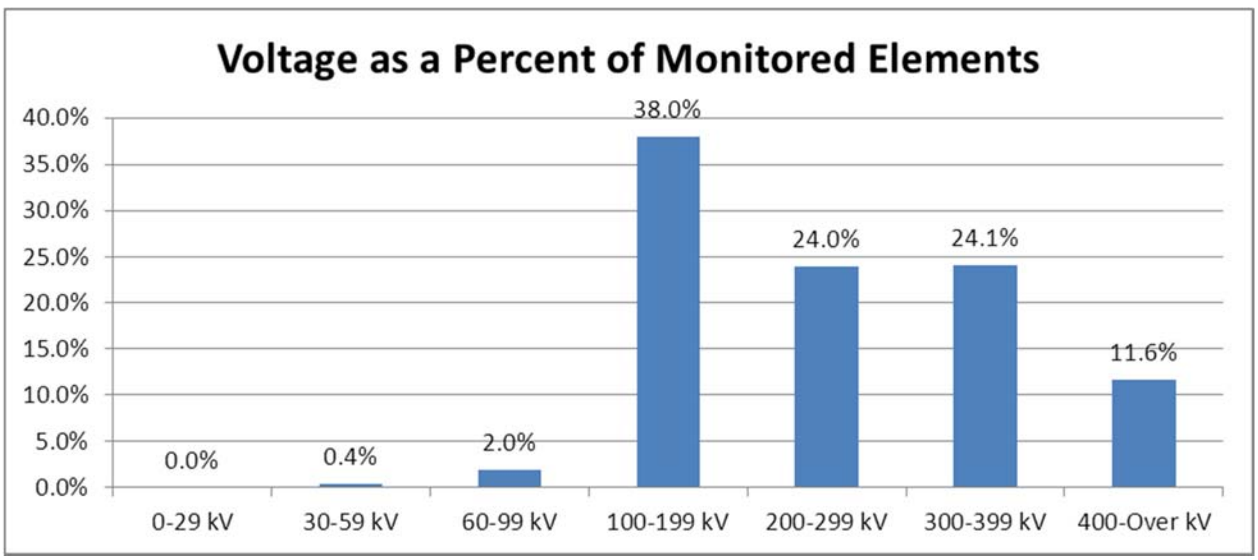
In a few rare occasions there were transformer elements with low-side windings lower than 30 kV included in the key monitored element groupings as shown in Table 2.

Region	Interface	Element	Voltage (kV)
NPCC/NYISO	WEST CENTRAL: Genesee (Zone B) – Central (Zone C)	(Farmtn 34.5/115kV&12/115 kV) #4 34.5/115 & 12/115	12/115
NPCC/ISO-NE	New England - Southwest Connecticut	SOTHNGTN 5X - Southington 115 kV /13.8 kV Transformer (4C-5X)	115/13.8
		SOTHNGTN 6X - Southington 115 kV /13.8 kV Transformer (4C-6X)	115/13.8
		SOTHNGTN 11X - Southington 115 kV /27.6 kV Transformer (4C-11X)	115/27.6

Table 2: Lowest Line Transformer Element Voltages Monitored by Region

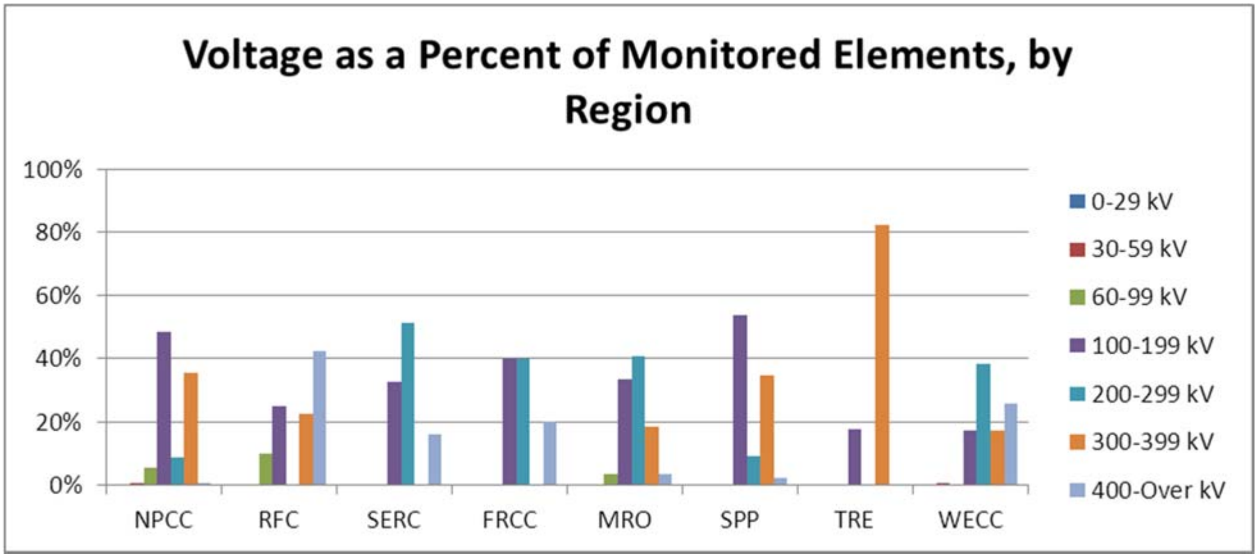
Upon closer investigation, for New England's Southwest Connecticut interface, it was determined that the inclusion of these elements was the result of longstanding, historical interface definitions and not for the purpose of addressing BES reliability concerns. Transformers serving lower voltage networks continue to be included based on familiarity with the existing interface rather than a specific technical concern. These transformers could be removed from the interface definition with no impact on monitoring the reliability of the interconnected transmission system. For the New York West Central interface, the low voltage element was included because the interface definition included boundary transmission lines between Transmission Owner control areas; hence, it was included for completeness to measure the power flow from one Transmission Owner control area to the other Transmission Owner control area.

Further examination of the information provided by the eight NERC regions revealed that half of the Regions only monitor transmission line elements with voltages above the 100 kV level. The other four Regions, NPCC, RFC, MRO, and WECC, monitor transmission line elements below 100 kV as part of key element groupings. However, in each of these cases, the number of below 100 kV transmission line elements comprised less than 2.5% of the total monitored key element groupings. Figures 1 and 2 below depict the results of Step 1 of this study.



Notes:
1. Data/Chart includes Transmission Lines only.
2. Data/Chart is a summary of individual elements (interfaces not included)

Figure 1: Voltage as Percent of Monitored Elements



Notes:
1. Data/Chart includes Transmission Lines only.
2. Data/Chart is a summary of individual elements (interfaces not included)

Figure 2: Voltage as Percent of Monitored Elements per Region

Step 1 Conclusion

The results of Step 1 of this study regarding regional monitoring levels resulted in a determination that 30 kV was a reasonable voltage level to initiate the sensitivity analysis conducted in Step 2 of this study. This value is below any of the regional monitoring levels. As noted herein, an examination of the line listings of the North American operating entities revealed that the majority of operating entities do not monitor elements below 69 kV as shown in Table 1. However, in some instances elements with line voltages of 34.5 kV were included in monitored element groupings. In no instance was a transmission line element below 34.5 kV included in the monitored element groupings.

STEP 2 - Load Flows and Technical Considerations

The threshold of 30 kV was established in Step 1 as a reasonable starting point to initiate the technical sensitivity analysis performed in Step 2 of this study. The purpose of this step was to determine if there is a technical justification to support a voltage threshold for the purpose of determining whether facilities greater than 100 kV can be considered to be radial under the BES Definition Exclusion E1. If the resulting voltage threshold was deemed appropriate through technical study efforts, then contiguous loop connections operated at voltages below this value would not preclude the application of Exclusion E1. Conversely, contiguous loops connecting radial lines at voltages above this kV value would negate the ability for an entity to use Exclusion E1 for the subject facilities.

This study focused on two typical configurations: a distribution loop and a sub-transmission loop. The study evaluated a range of voltages for the loop and the parallel transmission system with the goal of determining the voltage level below which single contingencies on the transmission system would not result in power flow from a low voltage distribution or sub-transmission loop to the BES. The study included sensitivity analysis varying the loads and impedances. Variations in loop and transmission system impedances account for a range of physical parameters such as conductor length, conductor type, system configuration, and proximity of the loop to the transmission system. This study provided the low voltage floor that can be used as a consideration for BES exclusion E1.

Analytical Approach – Distribution Circuit Loop Example

The Project 2010-17 Standard Drafting Team sought to examine the interaction and relative magnitude of flows on the 100 kV and above Facilities of the electric system and those of any underlying low voltage distribution loops. While not the determining factor leading to this study's recommendation, line outage distribution factors (LODF) were a useful tool in understanding the relationship between underlying systems and the BES elements. It illustrated the relative scale of interaction between the BES and the lower voltage systems and its review was a consideration when this study was performed. As an example, the Standard Drafting Team considered a system similar to the one depicted in Figure 3 below. In this simplified depiction of a portion of an electric system, two radial 115 kV lines emanate from 115 kV substations A and B to serve distribution loads via 115 kV distribution transformers at stations C and D. Stations C and D are "looped" together via either a distribution bus tie (zero impedance) or a feeder tie (modeled with typical distribution feeder impedances).

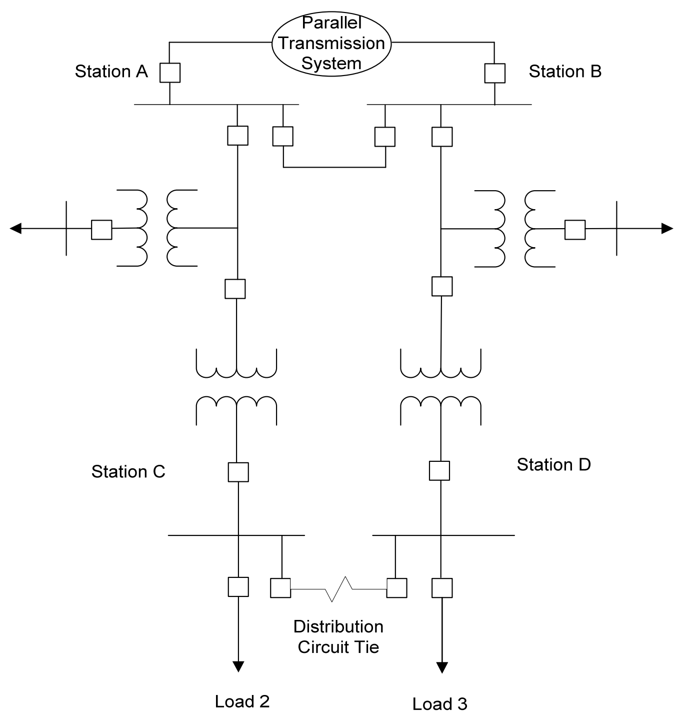


Figure 3: Example Radial Systems with Low Voltage Distribution Loop

With the example system, the Standard Drafting Team conducted power flow simulations to assess the performance of the power system under single contingency outages of the line between stations A and B. The analyses determined the LODF which represent the portion of the high voltage transmission flow that would flow across the low voltage distribution circuit or bus ties under a single contingency outage of the line between stations A and B. To the extent that the LODF values were negligible, this indicated a minor or insignificant contribution of the distribution loops to the operation of the high voltage system. But, more importantly, the analyses determined whether any instances of power flow reversal, i.e.,

resultant flow delivered into the BES, would occur during contingent operating scenarios. Instances of flow reversal into the BES would indicate that the underlying distribution looped system is exhibiting behavior similar to a sub-transmission or transmission system, which would call into question the applicability of radial exclusion E1.

The study work in this approach examined the sensitivity of parallel circuit flow on the distribution elements to the size of the distribution transformers, the operating voltage of distribution delivery buses at stations C and D and the strength of the transmission network serving stations A and B as manifested in the variation of the transmission network transfer impedances used in the model.
In order to simply, yet accurately, represent this low voltage loop scenario between two radial circuits, a Power System Simulator for Engineering (PSSE) model was created. Elements represented in this model included the following:

- Radial 115 kV lines from station A to station C and station B to station D;
- Interconnecting transmission line from station A to station B;
- Distribution transformers tapped off the 115 kV lines between stations A and C and between stations B and D and at stations C and D;
- Feeder tie impedance to represent a feeder tie (or zero impedance bus tie) between distribution buses at stations C and D;
- Transfer impedance equivalent between stations A and B, representing the strength of the interconnected transmission network[3].

Within this model, parameters were modified to simulate differences in the length and impedance of the transmission lines, the amount of distribution load, the strength of the transmission network supplying stations A and B, the size of the distribution transformers and the character of the bus or feeder ties at distribution Stations C and D.

Distribution Model Simulation

Table 3 below illustrates the domain of the various parameters that were simulated in this distribution circuit loop scenario. A parametric analysis was performed using all combinations of variables shown in each column of the upper portion of Table 3. Sensitivity analysis was performed as indicated in the lower portion of the table.

[3] The relative strength of the surrounding transmission system network is a function of the quantity of parallel transmission paths and the impedance of those paths between the two source substations. A high number of parallel paths with low impedance translates to a low transfer impedance, which allows power to more readily flow between the stations. Conversely, a low number of parallel paths having higher impedance is represented by a relatively large transfer impedance.

Trans KV	Trans Length	Dist KV	Dist Length	XFMR MVA	Dist Load % rating	Z Transfer
115	10 miles	12.5	0 (bus tie)	10	40	Weak
		23	2 miles	20	80	
		34.5	5 miles	40		
Sensitivity Analysis:		46				Strong Medium

Notes:

1. The "medium" value for transfer impedances was derived from an actual example system in the northeastern US. This was deemed to be representative of a network with typical, or medium, transmission strength. Variations of a stronger (more tightly coupled) and a weaker transmission network were selected for the "strong" and "weak" cases, respectively. Impedance values of X=0.54%, X=1.95%, and X=4.07% were applied for the strong, medium and weak cases, respectively.

Table 3: Model Parameters Varied

The model was used to examine a series of cases simulating a power transfer on the 115 kV line[4] from station A to station B of slightly more than 100 MW. Loads and impedances were simulated at the location shown in Figure 5 of Appendix 2. Two load levels were used in each scenario: 40% of the rating of the distribution transformer and 80% of the rating. Distribution transformer ratings were varied in three steps: 10 MVA, 20 MVA, and 40 MVA. Finally, the strength of the interconnected transmission network was varied in three steps representing a strong, medium, and weak transmission network. The choices of transfer impedance were based on typical networks in use across North America. A specific model from the New England area of the United States yielded an actual transfer impedance of 0.319 + j1.954%. This represents the 'medium' strength transmission system used in the analyses. The other values used in the study are minimum ('strong') and maximum ('weak') ends of the typical range of transfer impedances for 115 kV systems interconnected to the Bulk Electric System of North America. Distribution feeder connections were simulated in three different ways, first with zero impedance between the distribution buses at stations C and D, second with a 2-mile feeder connection with typical overhead conductor, and third with a 5-mile connection.

Distribution Model Results

23 kV Distribution System

The results show LODFs ranging from a low of 0.2% to a high of 6.7%. In all of the cases, the direction of power flow to the radial lines at stations A and B was *toward* stations C and D. In other words, there were no instances of flow reversal from the distribution system back to the 115 kV transmission system. The lowest LODF was found in the case with the smallest distribution transformers (10 MVA), the 5-mile distribution circuit tie, and the strong transmission transfer impedance. The case with the highest LODF

[4] The threshold voltage of 115 kV provides conservative results. At a higher voltage, such as 230 kV, the reflection of distribution impedance to the transmission system is significantly larger, and hence, the amount of distribution power flow will be much smaller.

was that which used the largest distribution transformers (40 MVA) with the lightest load and the use of a zero-impedance bus tie between the two distribution stations.

12.5 kV Distribution System

As compared to the simulations using the 23 kV distribution system, the 12.5 kV system model yielded far lower LODF values. This result is reasonable, as the reflection of impedances on a 12.5 kV distribution system will be nearly four times as large as those for a 23 kV distribution system, and the transformer sizes in use at the 12.5 kV class are generally smaller, i.e., higher impedance. As with the cases simulated for the 23 kV system, the 12.5 kV system exhibited a power flow direction in the radial line terminals at stations A and B in the direction of the distribution stations C and D; no flow reversal was seen in any of the contingency cases.

Given the lower voltage of the distribution system, the cases studied at this low voltage level were limited to the scenario with the high transfer impedance value ('weak' transmission case). This is a conservative assumption as all cases with lower transfer impedance will yield far lower LODF values. With that, the range of LODF values was found to be 1.0% to 6.7%. When compared with the 23 kV system results in the weak transmission case, the range of LODF values was 1.8% to 6.7%. Higher LODF values were found in the cases with the largest transformer size, which is to be expected.

Table 4 below provides a sample of the results of the various simulations that were conducted. The full collection of results is provided in Appendix 3.

Case	D, KV	Z_{xfer}	Z_{Dist}	XFMR MVA	Load, MW	LODF
623a5	23	strong	5 mi	10	4	0.2%
623a5pk	23	strong	5 mi	10	8	0.3%
633b0pk	23	strong	0	20	16	0.4%
723c0	23	medium	0	40	16	3.4%
723c5pk	23	medium	5 mi	40	32	1.6%
823b0	23	weak	0	20	8	3.8%
823c0	23	weak	0	40	16	6.7%
812a5	12.5	weak	5 mi	10	4	1.0%
812b0	12.5	weak	0	20	8	3.8%
812b5pk	12.5	weak	5 mi	20	16	1.3%
812c0	12.5	weak	0	40	16	6.7%
834a5pk	34.5	weak	5 mi	10	8	1.7%
834b5pk	34.5	weak	5 mi	20	16	3.0%
834d0	34.5	weak	0	40	16	8.9%
834d0pk	34.5	weak	0	40	32	8.7%
846e0	46	weak	0	50	16	10.3%
846e2	46	weak	2 mi	50	20	9.0%
846e5	46	weak	5 mi	50	20	7.4%

Table 4: Select Sample of Study Results for Distribution Scenario

34.5 kV and 46 kV Distribution Systems

As with the analysis done for the 12.5 kV system, a conservative transfer impedance value, that of the 'weak' transmission network, was used in selecting the transfer impedance to be used in the simulations at 34.5 kV and 46 kV. With this conservative parameter, the simulation results show distribution factors (LODF) ranging from a low of 1.7% to a high of 10.3%. In all of the cases, the direction of power flow to the radial lines remained *from* stations A and B *toward* stations C and D. In other words, there were no instances of flow reversal from the distribution system back to the 115 kV transmission system.

Analytical Approach – Sub-transmission Example

In addition to the distribution circuit loop example described above, the study examined the performance of systems typically described as ’sub-transmission.’ The study sought to examine the interaction and relative magnitude of flows on the 100 kV and above Facilities of the interconnected transmission system and those of the underlying parallel sub-transmission facilities. The study considered a system similar to the one depicted in Figure 4 below. In this simplified depiction of a portion of a transmission and sub-transmission system, a 40-mile transmission line connecting two sources with transfer impedance between the two sources representing the parallel transmission network. Each source also supplies a 10-mile transmission line with a load tap at the mid-point of the line, each serving a load of 16 MW. At the end of each of these lines is a step-down transformer to the sub-transmission voltage, where an additional load is served. The two sub-transmission stations are connected by a 25-mile sub-transmission tie line. Loads and impedances were simulated at the location shown in Figure 6 of Appendix 2.

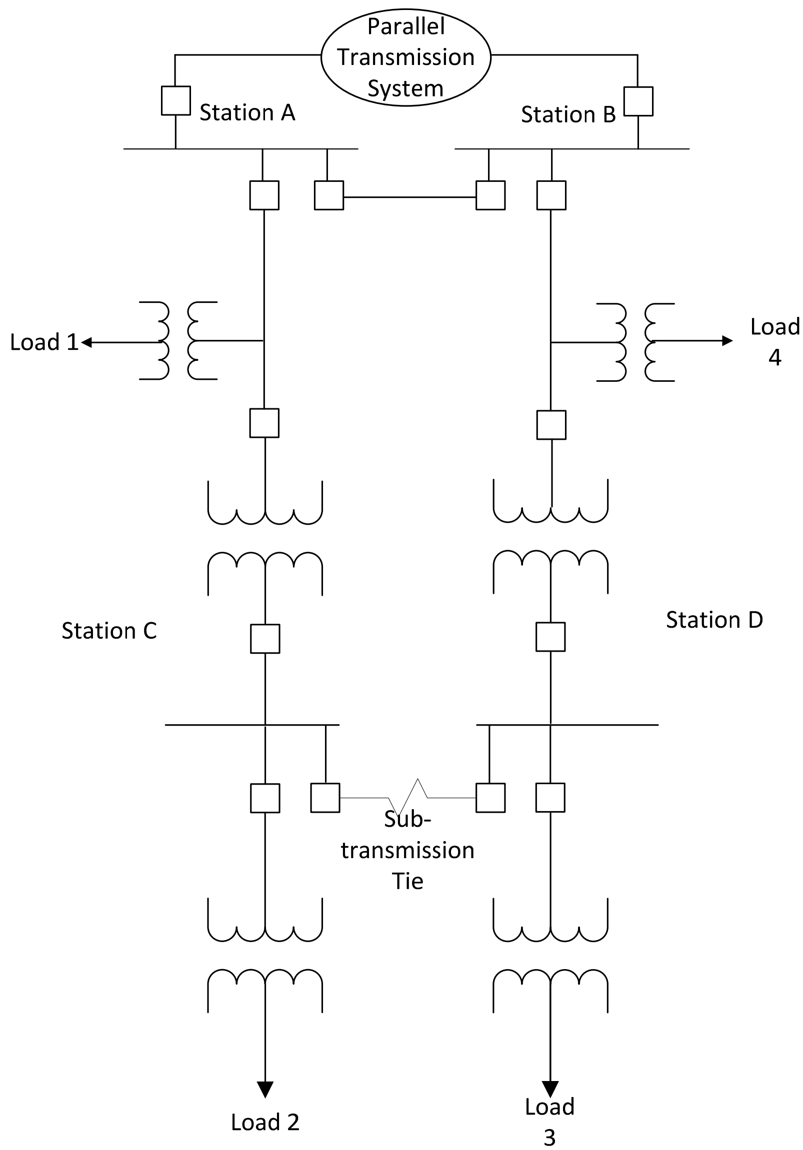


Figure 4: Example Radial Systems with Sub-transmission Loop

Given this example sub-transmission system, a PSSE model was created to simulate the power flow characteristics of the system during a contingency outage of the transmission line between stations A and B. Within this model, parameters were modified to simulate differences in the amount of load being served, transformer size and the amount of pre-contingent power flow on the transmission line. All simulations were performed with a transfer impedance representative of a 'weak' transmission network, which was confirmed as conservative in the distribution system analysis.

Sub-transmission Model Simulation

Simulations were performed for each sub-transmission voltage (34.5 kV, 46 kV, 55 kV, and 69 kV) using a transmission voltage of 115 kV. This analysis identified the potential for power flowing back to the transmission system only for sub-transmission voltages of 55 kV and 69 kV. Sensitivity analysis was performed using higher transmission voltages to confirm that cases modeling a 115 kV transmission

system yield the most conservative results. Therefore, it was not necessary to perform sensitivity analysis for sub-transmission voltages of 34.5 kV and 46 kV for transmission voltages higher than 115 kV. Table 5 below illustrates the domain of the various parameters that were simulated in this sub-transmission circuit loop scenario. A parametric analysis was performed using combinations of variables shown in each column of Table 5.

Trans KV	Trans Length	Sub-T KV	Sub-T Length	XFMR MVA	Dist Load % rating	Trans MW Preload
115	40 miles	34.5	25 miles	40	40	115
		46		50		
		55		60		
		69				
Sensitivity Analyses:						
138	40 miles	55	25 miles	50	40	115
161		69		60		135
230						150
						220

Table 5: Model Parameters and Sensitivities

Sub-transmission Model Results

115 kV Transmission System with 34.5-69 kV Sub-transmission

The results for cases depicting a 115 kV transmission system voltage and ranges of 34.5 kV to 69 kV sub-transmission voltages show line outage distribution factors (LODF) in the range of 9% to slightly higher than 20%. Several cases show a reversal of power flow in the post-contingent system such that power flow is delivered from the sub-transmission system *into the 115 kV BES*. The worst case is found in the 69 kV sub-transmission voltage class. This result is as expected, given that the impedance of the 69 kV sub-transmission system is less than the impedances of lower voltage systems. In no instance was a reversal of power flow observed in sub-transmission systems rated below 50 kV.

138 kV and 161 kV Transmission Systems with 55-69 kV Sub-transmission

The results for cases of 138 kV and 161 kV transmission system voltages supplying sub-transmission voltages of 55 kV and 69 kV show LODFs ranging from 9% to 16%. These cases also result in reversal of power flows in the post-contingent system such that power flow is delivered from the sub-transmission system into the 115 kV BES.

230 kV Transmission System with 55-69 kV Sub-transmission

By simulating a higher BES source voltage of 230 kV paired with sub-transmission voltages of 55 kV and 69 kV, the transformation ratio is sufficiently large to result in a significant increase to the reflected sub-transmission system impedance. Therefore, in these cases, LODFs range from 5% to 7%, and these cases also show no reversal of power flow toward the BES in the post-contingent system. Table 6 below

provides a sample of the results of the various simulations that were conducted. All results are provided in Appendix 3.

Case	T, KV	S-T, KV	Trans Pre-load, MW	XFMR MVA	Load, MW	LODF	Flow Rev to BES?
834d25	115	34.5	115	40	20	9.4%	
846e25	115	46	114	50	20	13.3%	
855e25	115	55	112	50	20	15.7%	Yes
869f25	115	69	110	60	24	20.3%	Yes
855e25-138	138	55	114	50	20	11.7%	
855e25-138'	138	55	134	60	20	11.9%	Yes
869f25-138	138	69	112	60	24	15.6%	Yes
869f25-138'	138	69	132	60	24	15.8%	Yes
855e25-161	161	55	114	50	20	9.1%	
855e25-161'	161	55	155	60	20	9.2%	
869f25-161	161	69	113	60	24	12.5%	
869f25-161'	161	69	153	60	24	12.6%	Yes
855e25-230	230	55	116	50	20	4.9%	
855e25-230'	230	55	219	60	20	5.0%	
869f25-230	230	69	116	60	24	7.0%	
869f25-230'	230	69	218	60	24	7.0%	

Table 6: Select Sample of Study Results for Sub-transmission Scenario

Step 2 Conclusion

After conducting extensive simulations (included in Appendix 3), the results of Step 2 of this analysis indicates that 50 kV is the appropriate low voltage loop threshold below which sub-100 kV loops should not affect the application of Exclusion E1 of the BES Definition. Simulations of power flows for the cases modeled in this study show there is no power flow reversal into the BES when circuit loop operating voltages are below 50 kV. This study also finds, for loop voltages above 50 kV, certain cases result in power flow toward the BES. Therefore, the study concludes that low voltage circuit loops operated below 50 kV should not affect the application of Exclusion E1.

As described throughout the preceding section, the scenarios and configurations utilized in this analysis represent the majority of cases that will be encountered in the industry. The models used in this analysis establish reasonable bounds and use conservative parameters in the scenarios. However, there may be actual cases that deviate from these modeled scenarios, and therefore, results could be somewhat different than the ranges of results from this analysis. Such deviations are expected to be rare and can be processed through the companion BES Exception Process.

Study Conclusion

The Project 2010-17 Standard Drafting Team conducted a two-step study process to yield a technical justification for the establishment of a voltage threshold below which sub-100 kV loops should not affect the application of Exclusion E1.

All operating entities have guidelines to identify the elements they believe need to be monitored to facilitate the reliable operation of the interconnected transmission system. Pursuant to these guidelines, operating entities in each of the eight Regions in North America have identified and monitor key groupings of the transmission elements that limit the amount of power that can be reliably transferred across their systems. The objective of Step 1 was to identify the lowest monitored voltage level on these key element groupings. The lowest monitored line voltage on the major element groupings provides an indication of the lower limit which operating entities have historically believed necessary to ensure the reliable operation of the interconnected transmission system.

As a result of studying such regional monitoring levels, Step 1 concluded that 30 kV was a reasonable voltage level to initiate the sensitivity analysis conducted in Step 2. This is a conservative value as it is below any of the regional monitoring levels.

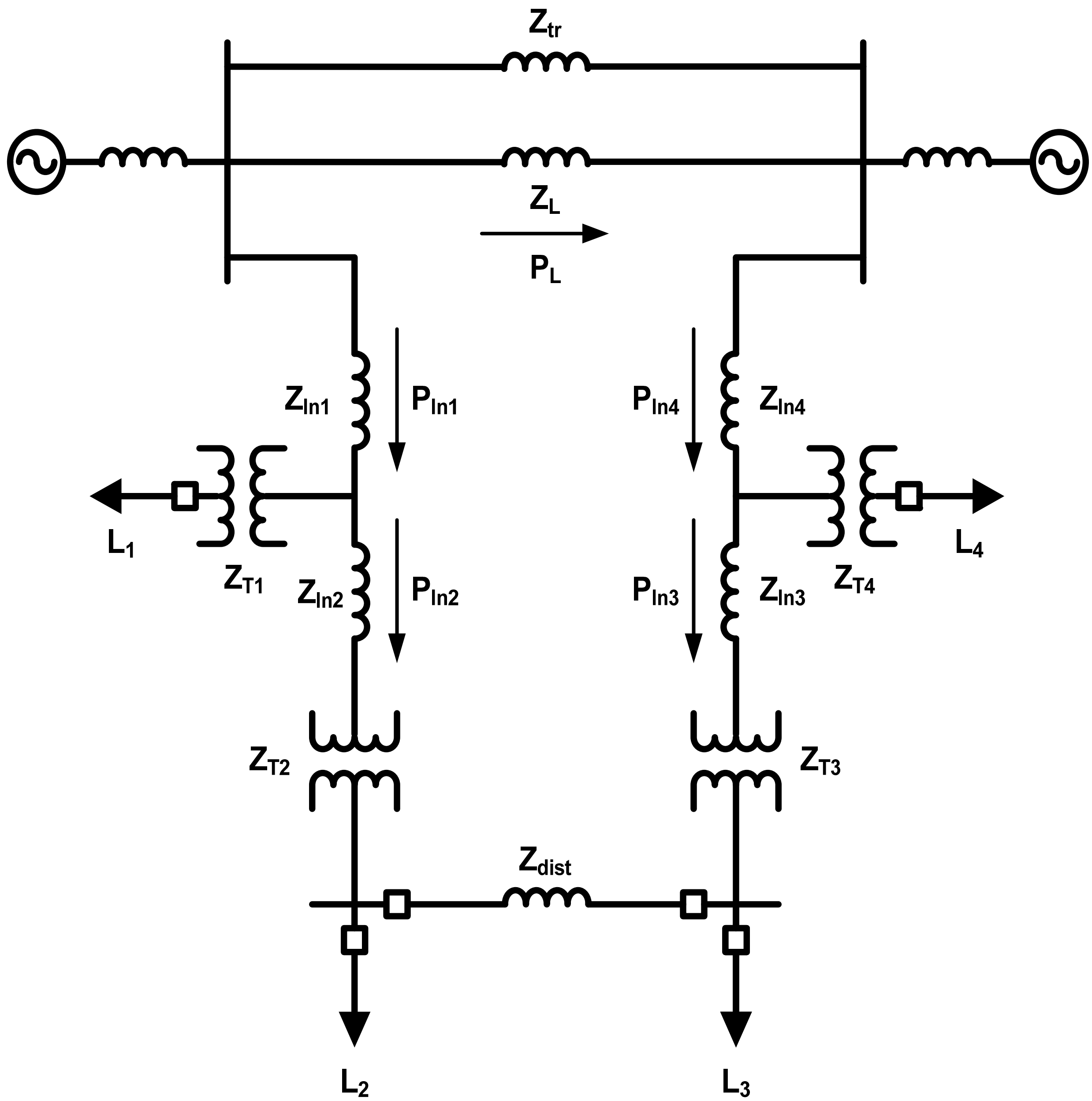
Using the conservative value established by Step 1, the Standard Drafting Team conducted extensive simulations of power flows which demonstrated that there is no power flow reversal into the BES when circuit loop operating voltages are below 50 kV. Therefore, the study concludes that low voltage circuit loops operated below 50 kV should not affect the application of Exclusion E1. This analysis provides an equally effective and efficient alternative to address the Commission's directives expressed in Order No. 773 and 773-A.

The scenarios and configurations utilized in this analysis represent the majority of cases that will be encountered in the industry. The models used in this analysis establish reasonable bounds and use conservative parameters in the scenarios. However, there may be actual cases that deviate from these modeled scenarios, and therefore, results could be somewhat different than the ranges of results from this analysis. Such deviations are expected to be rare and can be processed through the companion BES Exception Process.

Appendix 1: Regional Elements

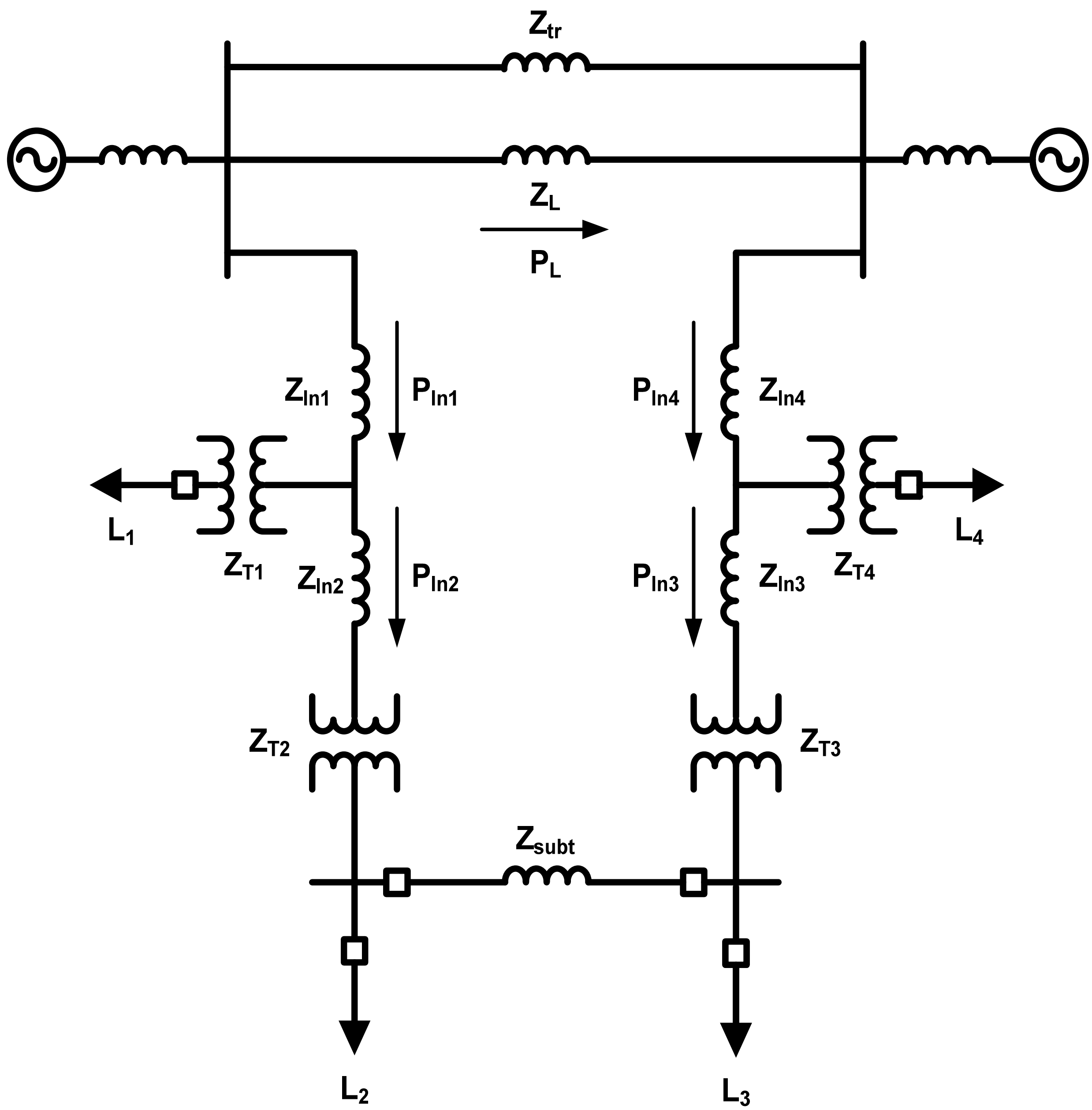
PRIVILEGED AND CONFIDENTIAL INFORMATION HAS BEEN REDACTED FROM THIS PUBLIC VERSION

Appendix 2: One-Line Diagrams



Note: Refer to the notes in Appendix 3 for a description of the symbols in this diagram.

Figure 5: Example Radial Systems with Low Voltage Distribution Tie



Notes: Refer to the notes in Appendix 3 for a description of the symbols in this diagram.
Step-down transformers from sub-transmission voltage to distribution voltage were not explicitly modeled in the simulations.

Figure 6: Example Radial Systems with Sub-transmission Tie

Appendix 3: Simulation Results

										------------ HV Line "L" in-service ------------				-- HV Line "L" out-of-service --				
Case	**Z_L (mi.)**	**Z_{tr} (mi.)**	**$Z_{ln1\text{-}4}$ (total mi.)**	**Z_{dist} (mi.)**	**Z_{T1}, $Z_{T\text{-}4}$ (Z/MVA)**	**Z_{T2}, Z_{T3} (Z/MVA)**	**L_1, L_4 (MW)**	**L_2, L_3 (MW)**	**P_L (MVA)**	**P_{ln1} (MVA)**	**P_{ln2} (MVA)**	**P_{ln3} (MVA)**	**P_{ln4} (MVA)**	**$P_{ln1'}$ (MVA)**	**$P_{ln2'}$ (MVA)**	**$P_{ln3'}$ (MVA)**	**$P_{ln4'}$ (MVA)**	**LODF**
	23 kV Base Cases																	
623a0	10	Strong	15	0	10%/10	10%/10	4.0	4.0	110.7	10.9	6.9	1.1	5.1	11.2	7.2	0.8	4.8	0.003
623a2	10	Strong	15	2	10%/10	10%/10	4.0	4.0	110.7	10.7	6.7	1.4	5.4	10.9	6.9	1.1	5.1	0.002
623a5	10	Strong	15	5	10%/10	10%/10	4.0	4.0	110.7	10.3	6.3	1.7	5.7	10.5	6.5	1.5	5.5	0.002
623a0pk	10	Strong	15	0	10%/10	10%/10	8.0	8.0	111.4	19.0	10.9	5.1	13.1	19.3	11.2	4.8	12.8	0.003
623a2pk	10	Strong	15	2	10%/10	10%/10	8.0	8.0	111.4	18.7	10.7	5.4	13.4	18.9	10.9	5.1	13.1	0.002
623a5pk	10	Strong	15	5	10%/10	10%/10	8.0	8.0	111.5	18.3	10.3	5.7	13.7	18.6	10.5	5.5	13.5	0.003
623b0	10	Strong	15	0	10%/20	10%/20	8.0	8.0	111.1	21.7	13.7	2.3	10.3	22.3	14.2	1.8	9.8	0.005
623b2	10	Strong	15	2	10%/20	10%/20	8.0	8.0	111.2	20.7	12.7	3.3	11.3	21.2	13.2	2.9	10.9	0.004
623b5	10	Strong	15	5	10%/20	10%/20	8.0	8.0	111.3	19.7	11.7	4.3	12.3	20.1	12.1	4.0	12.0	0.004
623b0pk	10	Strong	15	0	10%/20	10%/20	16.0	16.0	112.6	37.8	21.7	10.3	26.3	38.3	22.3	9.7	25.8	0.004
623b2pk	10	Strong	15	2	10%/20	10%/20	16.0	16.0	112.7	36.7	20.7	11.3	27.3	37.2	21.2	10.9	26.9	0.004
623b5pk	10	Strong	15	5	10%/20	10%/20	16.0	16.0	112.8	35.7	19.7	12.3	28.4	36.1	20.1	12.0	28.0	0.004

Case	Z_L (mi.)	Z_{tr} (mi.)	Z_{ln1-4} (total mi.)	Z_{dist} (mi.)	Z_{T1}, Z_{T-4} (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	----------- HV Line "L" in-service ----------- P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	-- HV Line "L" out-of-service -- $P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	LODF
623c0	10	Strong	15	0	10%/40	10%/40	16.0	16.0	112.2	42.7	26.6	5.4	21.4	43.7	27.7	4.3	20.3	0.009
623c2	10	Strong	15	2	10%/40	10%/40	16.0	16.0	112.5	39.6	23.6	8.4	24.4	40.4	24.4	7.7	23.7	0.007
623c5	10	Strong	15	5	10%/40	10%/40	16.0	16.0	112.7	37.3	21.3	10.8	26.8	37.8	21.8	10.3	26.3	0.004
623c0pk	10	Strong	15	0	10%/40	10%/40	32.0	32.0	115.1	74.9	42.8	21.2	53.3	76.0	43.9	20.2	52.2	0.010
623c2pk	10	Strong	15	2	10%/40	10%/40	32.0	32.0	115.4	71.8	39.7	24.3	56.4	72.6	40.5	23.6	55.6	0.007
623c5pk	10	Strong	15	5	10%/40	10%/40	32.0	32.0	115.6	69.4	37.4	26.7	58.8	70.0	37.9	26.2	58.3	0.005
723a0	10	Medium	15	0	10%/10	10%/10	4.0	4.0	108.3	10.9	6.9	1.1	5.1	11.9	7.9	0.1	4.1	0.009
723a2	10	Medium	15	2	10%/10	10%/10	4.0	4.0	108.3	10.6	6.6	1.4	5.4	11.5	7.5	0.5	4.5	0.008
723a5	10	Medium	15	5	10%/10	10%/10	4.0	4.0	108.4	10.3	6.3	1.8	5.8	11.1	7.1	1.0	5.0	0.007
723a0pk	10	Medium	15	0	10%/10	10%/10	8.0	8.0	110.4	18.9	10.9	5.1	13.1	20.0	12.0	4.0	12.1	0.010
723a2pk	10	Medium	15	2	10%/10	10%/10	8.0	8.0	110.5	18.6	10.6	5.4	13.4	19.6	11.6	4.4	12.5	0.009
723a5pk	10	Medium	15	5	10%/10	10%/10	8.0	8.0	110.6	18.3	10.3	5.7	13.7	19.1	11.1	4.9	12.9	0.007
723b0	10	Medium	15	0	10%/20	10%/20	8.0	8.0	109.7	21.6	13.6	2.4	10.4	23.6	15.6	0.4	8.4	0.018
723b2	10	Medium	15	2	10%/20	10%/20	8.0	8.0	110.0	20.6	12.6	3.4	11.4	22.3	14.3	1.7	9.8	0.015
723b5	10	Medium	15	5	10%/20	10%/20	8.0	8.0	110.2	19.7	11.7	4.4	12.4	21.0	13.0	3.1	11.1	0.012
723b0pk	10	Medium	15	0	10%/20	10%/20	16.0	16.0	114.0	37.8	21.8	10.2	26.3	39.9	23.8	8.2	24.2	0.018
723b2pk	10	Medium	15	2	10%/20	10%/20	16.0	16.0	114.3	36.8	20.8	11.3	27.3	38.5	22.5	9.6	25.6	0.015
723b5pk	10	Medium	15	5	10%/20	10%/20	16.0	16.0	114.5	35.8	19.8	12.3	28.3	37.2	21.1	10.9	27.0	0.012

Case	Z_L (mi.)	Z_{tr} (mi.)	Z_{ln1-4} (total mi.)	Z_{dist} (mi.)	Z_{T1}, Z_{T-4} (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	------------ HV Line "L" in-service ------------ P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	-- HV Line "L" out-of-service -- $P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	LODF
723c0	10	Medium	15	0	10%/40	10%/40	16.0	16.0	112.6	42.7	26.7	5.3	21.3	46.5	31.4	1.6	17.6	0.034
723c2	10	Medium	15	2	10%/40	10%/40	16.0	16.0	113.5	39.7	23.7	8.4	24.4	42.4	26.4	5.7	21.7	0.024
723c5	10	Medium	15	5	10%/40	10%/40	16.0	16.0	114.1	37.4	21.4	10.7	26.7	39.3	23.3	8.8	24.8	0.017
723c0pk	10	Medium	15	0	10%/40	10%/40	32.0	32.0	121.2	75.5	43.4	20.7	52.7	79.5	47.4	16.7	48.7	0.033
723c2pk	10	Medium	15	2	10%/40	10%/40	32.0	32.0	122.0	72.2	40.1	23.9	55.9	75.2	43.1	21.1	53.1	0.025
723c5pk	10	Medium	15	5	10%/40	10%/40	32.0	32.0	122.7	69.8	37.7	26.4	58.5	71.8	39.7	24.4	56.5	0.016
823a0	10	Weak	15	0	10%/10	10%/10	4.0	4.0	106.1	10.8	6.8	1.2	5.2	12.9	8.9	-0.9	3.1	0.020
823a2	10	Weak	15	2	10%/10	10%/10	4.0	4.0	106.2	10.5	6.5	1.5	5.5	12.4	8.4	-0.4	3.6	0.018
823a5	10	Weak	15	5	10%/10	10%/10	4.0	4.0	106.4	10.2	62.0	1.8	5.8	11.9	7.9	0.2	4.2	0.016
823a0pk	10	Weak	15	0	10%/10	10%/10	8.0	8.0	109.6	18.9	10.9	5.1	13.1	21.1	13.0	3.0	11.0	0.020
823a2pk	10	Weak	15	2	10%/10	10%/10	8.0	8.0	109.7	18.6	10.6	5.4	13.4	20.6	12.6	3.5	11.5	0.018
823a5pk	10	Weak	15	5	10%/10	10%/10	8.0	8.0	109.8	18.3	10.3	5.7	13.8	20.0	12.0	4.0	12.1	0.015
823b0	10	Weak	15	0	10%/20	10%/20	8.0	8.0	108.4	21.5	13.5	2.5	10.5	25.6	17.6	-1.6	6.4	0.038
823b2	10	Weak	15	2	10%/20	10%/20	8.0	8.0	108.8	20.6	12.6	3.4	11.4	24.0	16.0	0.1	8.1	0.031
823b5	10	Weak	15	5	10%/20	10%/20	8.0	8.0	109.2	19.6	11.6	4.4	12.4	22.3	14.3	1.8	9.8	0.025
823b0pk	10	Weak	15	0	10%/20	10%/20	16.0	16.0	115.3	37.9	21.9	10.2	26.2	42.2	26.1	5.9	21.9	0.037
823b2pk	10	Weak	15	2	10%/20	10%/20	16.0	16.0	115.7	36.9	20.8	11.2	27.2	40.4	24.4	7.7	23.7	0.030
823b5pk	10	Weak	15	5	10%/20	10%/20	16.0	16.0	116.2	35.9	19.8	12.2	28.2	38.7	22.7	9.4	25.5	0.024

										------------ HV Line "L" in-service ------------				-- HV Line "L" out-of-service --				
Case	Z_L (mi.)	Z_{tr} (mi.)	Z_{ln1-4} (total mi.)	Z_{dist} (mi.)	Z_{T1}, Z_{T-4} (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	$P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	LODF
823c0	10	Weak	15	0	10%/40	10%/40	16.0	16.0	113.1	42.7	26.7	5.3	21.3	50.3	34.3	-2.3	13.7	0.067
823c2	10	Weak	15	2	10%/40	10%/40	16.0	16.0	114.4	39.7	23.7	8.3	24.3	45.4	29.3	2.8	18.8	0.050
823c5	10	Weak	15	5	10%/40	10%/40	16.0	16.0	115.5	37.4	21.4	10.6	26.7	41.4	25.4	6.8	22.8	0.035
823c0pk	10	Weak	15	0	10%/40	10%/40	32.0	32.0	126.7	76.0	43.9	20.2	52.2	84.4	52.3	11.8	43.8	0.066
823c2pk	10	Weak	15	2	10%/40	10%/40	32.0	32.0	128.2	72.7	40.6	23.5	55.6	78.9	48.6	17.4	49.5	0.048
823c5pk	10	Weak	15	5	10%/40	10%/40	32.0	32.0	129.3	70.1	38.0	26.1	58.2	74.5	42.4	21.8	53.9	0.034
Sensitivity to Length of Lines 1-4																		
723a0_30	10	Medium	30	0	10%/10	10%/10	4.0	4.0	108.3	10.8	6.8	1.2	5.2	11.8	7.8	0.2	4.2	0.009
723a2_30	10	Medium	30	2	10%/10	10%/10	4.0	4.0	108.4	10.5	6.5	1.5	5.5	11.4	7.4	0.6	4.6	0.008
723a5_30	10	Medium	30	5	10%/10	10%/10	4.0	4.0	108.5	10.2	6.2	1.8	5.8	11.0	7.0	1.0	5.0	0.007
Selected 34.5 kV cases																		
834a0	10	Weak	15	0	10%/10	10%/10	4.0	4.0	106.1	10.8	6.8	1.2	5.2	12.9	8.9	-0.9	3.1	0.020
834a2	10	Weak	15	2	10%/10	10%/10	4.0	4.0	106.1	10.7	6.7	1.3	5.3	12.7	8.7	-0.7	3.3	0.019
834a5	10	Weak	15	5	10%/10	10%/10	4.0	4.0	106.2	10.5	6.5	1.5	5.5	12.4	8.4	-0.4	3.6	0.018
834a0pk	10	Weak	15	0	10%/10	10%/10	8.0	8.0	109.6	18.9	10.9	5.1	13.1	21.1	13.0	3.0	11.0	0.020
834a2pk	10	Weak	15	2	10%/10	10%/10	8.0	8.0	109.6	18.8	10.8	5.2	13.3	20.8	12.8	3.2	11.2	0.018
834a5pk	10	Weak	15	5	10%/10	10%/10	8.0	8.0	109.7	18.6	10.6	5.4	13.4	20.5	12.5	3.5	11.5	0.017
834b0	10	Weak	15	0	10%/20	10%/20	8.0	8.0	108.4	21.5	13.5	2.5	10.5	25.6	17.6	-1.6	6.4	0.038

Case	Z_L (mi.)	Z_{tr} (mi.)	Z_{ln1-4} (total mi.)	Z_{dist} (mi.)	Z_{T1}, Z_{T-4} (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	----------- HV Line "L" in-service ----------- P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	-- HV Line "L" out-of-service -- $P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	LODF
834b2	10	Weak	15	2	10%/20	10%/20	8.0	8.0	108.6	21.1	13.1	2.9	10.9	24.8	16.8	-0.7	7.3	0.034
834b5	10	Weak	15	5	10%/20	10%/20	8.0	8.0	108.9	20.5	12.5	3.5	11.5	23.8	15.8	0.3	8.3	0.030
834b0pk	10	Weak	15	0	10%/20	10%/20	16.0	16.0	115.3	37.9	21.9	10.2	26.2	42.2	26.1	5.9	21.9	0.037
834b2pk	10	Weak	15	2	10%/20	10%/20	16.0	16.0	115.5	37.4	21.4	10.7	26.7	41.3	25.3	6.8	22.8	0.034
834b5pk	10	Weak	15	5	10%/20	10%/20	16.0	16.0	115.8	36.8	20.7	11.3	27.3	40.3	24.2	7.8	23.9	0.030
834c0	10	Weak	15	0	10%/40	10%/40	16.0	16.0	113.1	42.7	26.7	5.3	21.3	50.3	34.3	-2.3	13.7	0.067
834c2	10	Weak	15	2	10%/40	10%/40	16.0	16.0	113.8	41.2	25.2	6.9	22.9	47.8	31.7	0.4	16.4	0.058
834c5	10	Weak	15	5	10%/40	10%/40	16.0	16.0	114.6	39.5	23.5	8.5	24.6	45.0	29.0	3.2	19.2	0.048
834c0pk	10	Weak	15	0	10%/40	10%/40	32.0	32.0	126.7	76.0	43.9	20.2	52.2	84.4	52.3	11.8	43.8	0.066
834c2pk	10	Weak	15	2	10%/40	10%/40	32.0	32.0	127.5	74.2	42.1	21.9	54.0	81.5	49.4	14.7	46.8	0.057
834c5pk	10	Weak	15	5	10%/40	10%/40	32.0	32.0	128.3	72.4	40.3	23.8	55.8	78.5	46.4	17.9	49.9	0.048
834d0	10	Weak	15	0	7%/40	7%/40	16.0	16.0	111.6	46.3	30.3	1.7	17.7	56.2	40.1	-8.1	7.9	0.089
834d2	10	Weak	15	2	7%/40	7%/40	16.0	16.0	112.8	43.6	27.6	4.4	20.4	51.8	35.8	-3.6	12.4	0.073
834d5	10	Weak	15	5	7%/40	7%/40	16.0	16.0	113.9	41.1	25.1	7.0	23.0	47.6	31.6	0.6	16.6	0.057
834d0pk	10	Weak	15	0	7%/40	7%/40	32.0	32.0	124.9	80.0	47.9	16.2	48.2	90.9	58.8	5.3	37.3	0.087
834d2pk	10	Weak	15	2	7%/40	7%/40	32.0	32.0	126.3	77.0	44.9	19.2	51.2	86.1	54.0	10.2	42.2	0.072
834d5pk	10	Weak	15	5	7%/40	7%/40	32.0	32.0	127.5	74.2	42.1	22.0	54.1	81.4	49.3	15.0	47.0	0.056

										----------- HV Line "L" in-service -----------				-- HV Line "L" out-of-service --				
Case	Z_L (mi.)	Z_{tr} (mi.)	Z_{ln1-4} (total mi.)	Z_{dist} (mi.)	Z_{T1}, Z_{T-4} (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	$P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	LODF
Selected 12.47 kV cases																		
812a0	10	Weak	15	0	10%/10	10%/10	4.0	4.0	106.1	10.8	6.8	1.2	5.2	12.9	8.9	-0.9	3.1	0.020
812a2	10	Weak	15	2	10%/10	10%/10	4.0	4.0	106.4	10.1	6.1	1.9	5.9	11.6	7.6	0.4	4.4	0.014
812a5	10	Weak	15	5	10%/10	10%/10	4.0	4.0	106.7	9.4	5.4	2.6	6.6	10.5	6.5	1.5	5.5	0.010
812a0pk	10	Weak	15	0	10%/10	10%/10	8.0	8.0	109.6	18.9	10.9	5.1	13.1	21.1	13.0	3.0	11.0	0.020
812a2pk	10	Weak	15	2	10%/10	10%/10	8.0	8.0	109.9	18.1	10.1	5.9	13.9	19.7	11.7	4.3	12.4	0.015
812a5pk	10	Weak	15	5	10%/10	10%/10	8.0	8.0	110.2	17.5	9.5	6.5	14.5	18.6	10.6	5.5	13.5	0.010
812b0	10	Weak	15	0	10%/20	10%/20	8.0	8.0	108.4	21.5	13.5	2.5	10.5	25.6	17.6	-1.6	6.4	0.038
812b2	10	Weak	15	2	10%/20	10%/20	8.0	8.0	109.4	19.2	11.2	4.8	12.8	21.7	13.6	2.5	10.5	0.023
812b5	10	Weak	15	5	10%/20	10%/20	8.0	8.0	110.0	17.9	9.9	6.1	14.1	19.4	11.4	4.7	12.7	0.014
812b0pk	10	Weak	15	0	10%/20	10%/20	16.0	16.0	115.3	37.9	21.9	10.2	26.2	42.2	26.1	5.9	21.9	0.037
812b2pk	10	Weak	15	2	10%/20	10%/20	16.0	16.0	116.4	35.4	19.4	12.6	28.6	38.0	22.0	10.2	26.2	0.022
812b5pk	10	Weak	15	5	10%/20	10%/20	16.0	16.0	117.0	34.1	18.0	14.0	30.0	35.6	19.6	12.6	28.6	0.013
812c0	10	Weak	15	0	10%/40	10%/40	16.0	16.0	113.1	42.7	26.7	5.3	21.3	50.3	34.3	-2.3	13.7	0.067
812c2	10	Weak	15	2	10%/40	10%/40	16.0	16.0	115.9	36.6	20.6	11.5	27.5	40.0	24.0	8.3	24.3	0.029
812c5	10	Weak	15	5	10%/40	10%/40	16.0	16.0	116.8	34.4	18.4	13.7	29.7	36.2	20.2	12.0	28.0	0.015
812c0pk	10	Weak	15	0	10%/40	10%/40	32.0	32.0	126.7	76.0	43.9	20.2	52.2	84.4	52.3	11.8	43.8	0.066
812c2pk	10	Weak	15	2	10%/40	10%/40	32.0	32.0	129.7	69.2	37.1	27.1	59.1	73.0	40.9	23.5	55.5	0.029

										----------- HV Line "L" in-service -----------				-- HV Line "L" out-of-service --				
Case	**Z_L (mi.)**	**Z_{tr} (mi.)**	**Z_{ln1-4} (total mi.)**	**Z_{dist} (mi.)**	**Z_{T1}, Z_{T-4} (Z/MVA)**	**Z_{T2}, Z_{T3} (Z/MVA)**	**L_1, L_4 (MW)**	**L_2, L_3 (MW)**	**P_L (MVA)**	**P_{ln1} (MVA)**	**P_{ln2} (MVA)**	**P_{ln3} (MVA)**	**P_{ln4} (MVA)**	**$P_{ln1'}$ (MVA)**	**$P_{ln2'}$ (MVA)**	**$P_{ln3'}$ (MVA)**	**$P_{ln4'}$ (MVA)**	**LODF**
812c5pk	10	Weak	15	5	10%/40	10%/40	32.0	32.0	130.8	66.7	34.7	29.4	61.5	68.8	36.7	27.6	59.6	0.016
Selected 46 kV cases																		
846e0	10	Weak	15	0	10%/40	7%/50	16.0	20.0	112.1	53.1	37.1	2.9	18.9	64.7	48.7	-8.6	7.4	0.103
846e2	10	Weak	15	2	10%/40	7%/50	16.0	20.0	113.2	50.7	34.7	5.3	21.3	60.9	44.8	-4.7	11.3	0.090
846e5	10	Weak	15	5	10%/40	7%/50	16.0	20.0	114.3	48.2	32.1	7.9	24.0	56.7	40.7	-0.4	15.6	0.074
Sub-transmission cases																		
115-69 kV																		
669f25	40	Strong	20	25	10%/40	7%/60	16.0	24.0	114.0	76.0	59.8	-10.8	5.2	79.6	63.4	-14.2	1.8	0.032
769f25	40	Medium	20	25	10%/40	7%/60	16.0	24.0	111.7	75.3	59.1	-10.1	5.9	87.3	71.0	-21.2	-5.2	0.107
869f25	40	Weak	20	25	10%/40	7%/60	16.0	24.0	109.8	74.7	58.5	-9.6	6.4	97.0	80.6	-30.0	-14.0	0.203
115-55 kV																		
655e25	40	Strong	20	25	10%/40	7%/50	16.0	20.0	114.5	62.1	46.0	-5.0	11.0	64.8	48.7	-7.5	8.5	0.024
755e25	40	Medium	20	25	10%/40	7%/50	16.0	20.0	113.3	61.8	45.7	-4.8	11.2	70.9	54.8	-13.0	3.0	0.080
855e25	40	Weak	20	25	10%/40	7%/50	16.0	20.0	112.1	61.5	45.4	-4.5	11.5	79.1	62.9	-20.2	-4.2	0.157
855f25																		
115-46 kV																		
646e25	40	Strong	20	25	10%/40	7%/50	16.0	20.0	115.0	57.3	41.2	-0.2	15.8	59.5	43.4	-2.1	13.9	0.019
746e25	40	Medium	20	25	10%/40	7%/50	16.0	20.0	114.6	57.2	41.2	-0.1	15.9	64.9	48.8	-6.8	9.2	0.067
846e25	40	Weak	20	25	10%/40	7%/50	16.0	20.0	114.2	57.2	41.1	0.0	16.0	72.4	56.2	-13.1	2.9	0.133
115-34.5 kV																		
634d25	40	Strong	20	25	10%/40	7%/40	16.0	16.0	115.3	46.2	30.2	2.6	18.7	47.7	31.7	1.4	17.4	0.013

										------------ HV Line "L" in-service ------------				-- HV Line "L" out-of-service --				
Case	Z_L (mi.)	Z_{tr} (mi.)	Z_{ln1-4} (total mi.)	Z_{dist} (mi.)	Z_{T1}, Z_{T-4} (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	$P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	LODF
734d25	40	Medium	20	25	10%/40	7%/40	16.0	16.0	115.4	46.3	30.2	2.6	18.6	51.5	35.5	-1.9	14.1	0.045
834d25	40	Weak	20	25	10%/40	7%/40	16.0	16.0	115.5	46.3	30.2	2.6	18.6	57.1	41.0	-6.4	9.6	0.094
138-69 kV																		
869f25-138	40	Weak	20	25	10%/40	7%/60	16.0	24.0	112.0	66.5	50.4	-1.8	14.2	84.0	67.9	-18.3	-2.3	0.156
869f25-138'	40	Weak	20	25	10%/40	7%/60	16.0	24.0	131.9	71.1	55.0	-6.3	9.8	92.0	75.8	-25.6	-9.6	0.158
138-55 kV																		
855e25-138	40	Weak	20	25	10%/40	7%/50	16.0	20.0	113.5	55.1	39.0	1.5	17.5	68.4	52.3	-10.8	5.2	0.117
855e25-138'	40	Weak	20	25	10%/40	7%/60	16.0	20.0	134.0	58.5	42.4	-1.7	14.3	74.4	58.3	-16.2	-0.2	0.119
161-69 kV																		
869f25-161	40	Weak	20	25	10%/40	7%/60	16.0	24.0	113.2	60.7	44.7	3.7	19.7	74.8	58.8	-9.8	6.2	0.125
869f25-161'	40	Weak	20	25	10%/40	7%/60	16.0	24.0	153.0	68.0	52.0	-3.3	12.7	87.3	71.2	-21.4	-5.4	0.126
161-55 kV																		
855e25-161	40	Weak	20	25	10%/40	7%/50	16.0	20.0	114.1	50.7	34.7	5.6	21.6	61.1	45.1	-4.2	11.8	0.091
855e25-161'	40	Weak	20	25	10%/40	7%/60	16.0	20.0	154.8	56.0	40.0	0.6	16.6	70.3	54.3	-12.6	3.4	0.092
230-69 kV																		
869f25-230	40	Weak	20	25	10%/40	7%/60	16.0	24.0	116.3	51.3	35.3	12.8	28.8	59.4	43.3	5.0	21.0	0.070
869f25-230'	40	Weak	20	25	10%/40	7%/60	16.0	24.0	217.7	61.2	45.2	3.2	19.2	76.5	60.4	-11.4	4.7	0.070
230-55 kV																		
855e25-230	40	Weak	20	25	10%/40	7%/50	16.0	20.0	116.1	43.8	27.8	12.3	28.3	49.5	33.5	6.7	22.8	0.049
855e25-230'	40	Weak	20	25	10%/40	7%/50	16.0	20.0	218.7	50.8	34.8	5.6	21.6	61.7	45.7	-4.7	11.3	0.050

Notes:

The following notes provide information to understand the meaning of each column heading and underlying assumptions used in the analysis. See also the one-line diagrams in Figures 5 and 6 of Appendix 2 for additional information.

Z_L

The table provides the length of line "L" in miles to provide a high-level, qualitative understanding of the line impedance. The line impedance (Z_L) is the length of the line in miles times the per mile impedance. Assumptions used in determining the per mile impedance are as follows:

Voltage (kV)	Conductor	Phase Spacing	GMD	Impedance (Ω/mile)	Impedance (p.u./mile)
230	954 ACSR	20' H-frame	25.20'	0.100 + j0.786	0.000189 + J 0.00149
161	954 ACSR	16' H-frame	20.16'	0.100 + j0.759	0.000384 + j 0.00293
138	795 ACSR	13' H-frame	16.38'	0.117 + j0.738	0.000615 + j 0.00388
115	795 ACSR	11' H-frame	13.86'	0.117 + j0.718	0.000886 + j 0.00543

Z_{tr}

The transfer impedance (Z_{tr}) represents the impedance of the system in parallel with the subsystem under study. Analysis was performed for three levels of parallel transfer impedance which have been characterized as strong, medium, and weak. The strong system has relatively low impedance and thus will pick up more power flow when line "L" is tripped. The weak system has relatively high impedance and thus will pick up less power flow when line "L" is tripped. The medium system has a mid-range impedance value. The actual values of the transfer impedance vary between the distribution cases and the sub-transmission cases.

	Z_{tr} in distribution cases (p.u.)	Z_{tr} in sub-transmission cases (p.u.)
Strong	0.00089 + j 0.00543	0.00354 + j 0.0217
Medium	0.00319 + j 0.0195	0.0128 + j 0.0782
Weak	0.00664 + j 0.0407	0.0266 + j 0.163

Z_{ln1-4}

The table provides the total length of lines "ln1" through "ln4." In all simulations these four lines have equal length. The total length in miles provides a high-level, qualitative understanding of the line impedance. The line impedances are the length of each line in miles times the per mile impedance. Assumptions used in determining the per mile impedance are the same as provided above for line "L."

Z_{dist}

The table provides the length of the line in miles to provide a high-level, qualitative understanding of the line impedance. The impedance of the distribution system or sub-transmission system (Z_{dist}) is the length

of the distribution tie or sub-transmission line in miles times the per mile impedance. A value of zero miles is used when the distribution tie is a solid bus tie. Assumptions used in determining the per mile impedance are as follows:

Voltage (kV)	Conductor	Phase Spacing	GMD	Impedance (Ω/mile)	Impedance (p.u./mile)
69	636 ACSR	6’ Horizontal	7.56’	0.145 + j0.657	0.00305 + j 0.0138
55	556 ACSR	6’ Horizontal	7.56’	0.168 + j0.677	0.00555 + j 0.0224
46	477 ACSR	6’ Triangular	6.00’	0.193 + j0.647	0.00913 + j 0.0306
34.5	477 ACSR	4’ Triangular	4.00’	0.193 + j0.598	0.0162 + j 0.0503
23	477 ACSR	4’ Triangular	4.00’	0.193 + j0.598	0.0365 + j 0.113
12.47	336 ACSR	2’ Horizontal	2.52’	0.274 + j0.563	0.176 + j 0.362

Z_{T1-4}

The transformer impedance is reported as percent impedance on the transformer MVA base. Each transformer has three ratings: OA (oil and air), FA (forced air – i.e., fans), and FOA (forced oil and air – i.e., pumps and fans). The transformer MVA base rating is the OA rating. The FA rating is 133% of the OA rating and the FOA rating is 167% of the OA rating (e.g., a 20 MVA transformer has a 20 MVA OA rating, 26.7 MVA FA rating, and 33.3 MVA FOA rating, typically identified as a nameplate of 20/26.7/33.3 MVA).

The transformer impedance and rating for each voltage level are based on typical values. Distribution transformer impedance is generally higher to limit current on the distribution equipment. Secondary current typically is not a concern on sub-transmission transformers, so impedance is typically lower to limit reactive power losses and voltage drop.

L_1, L_2, L_3, L_4

The transformer load is based on the transformer OA rating. Transformers are loaded at 80 percent of the transformer base MVA in the simulations modeling a peak system load condition. The substations modeled have two transformers, with each transformer able to supply the total station load. Thus, if one transformer is forced out-of-service, the load on the remaining transformer will be 160 percent of its base rating, which is approximately equal to its FOA rating.

Transformers are loaded at 40 percent of the transformer base MVA in the simulations modeling a light system load condition.

HV Line "L" in-service: P_L, P_{ln1}, , P_{ln2}, P_{ln3}, P_{ln4}

The loading on each line, with all lines in service, is listed in MVA. The loading on line “L” is the power that is redistributed between the parallel transmission system and the distribution or sub-transmission system when line “L” is taken out of service.

HV Line "L" out-of-service: P_{ln1}, , P_{ln2}, P_{ln3}, P_{ln4}

The loading on each line, with line “L” out-of-service, is listed in MVA.

LODF

The Line Outage Distribution Factor (LODF) is the fraction of the load on line “L” that is picked up on the distribution or sub-transmission system. This information is included for illustrative purposes to understand the analysis, but was not used in identifying the voltage threshold for Exclusion E1.

Appendix 4: Summary of Loop Flow Issue Through Systems <50 kV

In the course of developing 'real-world' scenarios for the analysis of potential sub-100 kV loop flows, the Standard Drafting Team found that the industry has employed various measures to minimize the subject loop flows. Some of these methods that were found to be applied by entities on sub-100 kV loop systems are described below. However, it is important to note that the presence of the equipment in the following examples does not remove or lessen an entity's obligations associated with the bright-line application of the Bulk Electric System (BES) definition.

Sustained power flow through substation power transformers and low voltage loops is generally undesirable and, in some instances injurious. For this reason, power system engineers typically address this issue in their design, operating, and planning criteria and apply methods to prevent this condition from occurring. The high impedance of transformers and low voltage elements inherently prevent excessive flow, but in many instances this flow can exceed ratings of equipment. For these reasons entities develop control schemes, add relaying, and provide operational and planning guidelines to prevent this loop flow. Figure 7 depicts two systems that could provide a possible loop flow across the low voltage system and back up to the high voltage system. The loop flow in these diagrams is increased when the breaker on the high voltage side (breaker B) is opened.

The diagrams presented below depict a generic power system. The higher voltage and lower voltage circuit breakers and bus arrangements will, in practice, vary (i.e., straight bus, half-breaker, ring bus, breaker-and-a-half, etc.), but the concepts remain the same.

Specifically, Figure 7, shown below, depicts segments of an electrical power system. They consist of a greater than 100 kV system and a sub-100 kV system. Figure 7 depicts the power flow through the electrical system under the condition that all circuit breakers are closed (normal condition). In the event that circuit breaker B opens (i.e., manually, supervisory control, or protective device operation) and (1) and either of the sub-100 kV line circuit breakers (A or C) or (2) either of the low-side transformer circuit breakers (D or F) or (3) the low-side bus tie circuit breaker (E) does not open, a condition could occur where some amount of flow will occur through the sub-100 kV system to the greater than 100 kV system. This flow is severely limited by the high impedance of the two transformers in series and the sub-100 kV system impedance. This condition, however, may be deemed undesirable from an equipment standpoint and precautions may be taken to prevent it. Subsequent sections of this appendix show some of the physical schemes that entities can employ in this regard.

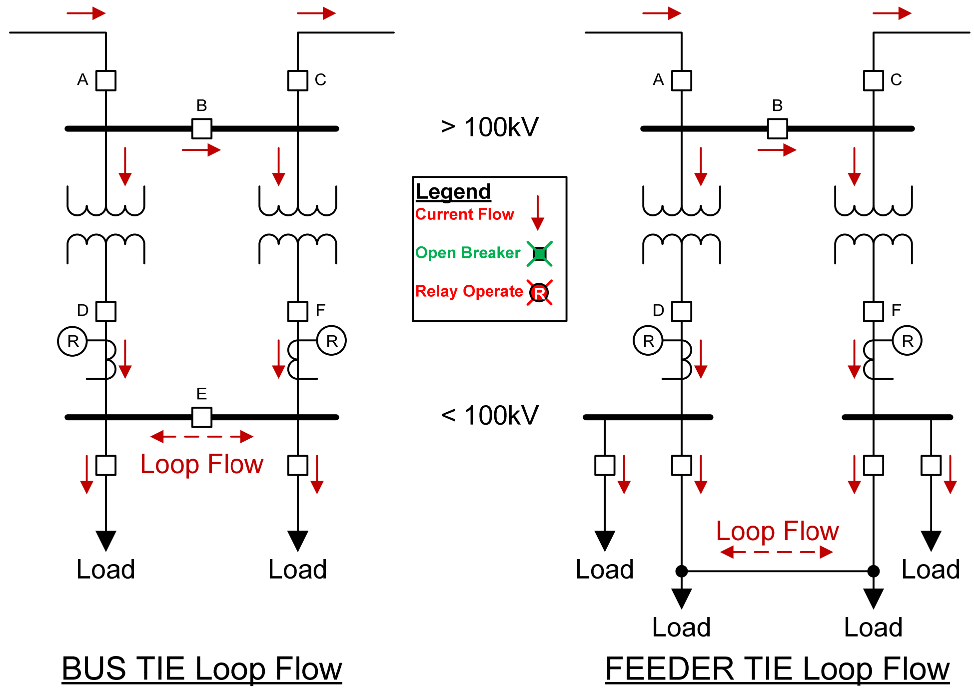


Figure 7. Summary of Loop Flow

Interlocked Control Schemes

Interlocking control schemes can be used to prevent low voltage loop flow. One method to preclude sustained power flow from the lower voltage to the higher voltage portion of the system is to include control system interlocks which will cross-trip certain circuit breaker(s) when other specified circuit breakers are opened. This condition is generally rare since bus designs and protective relay system operations generally do not result in this condition occurring. Operational guidelines usually instruct personnel to avoid the use of the interlocking schemes during normal or planned switching. However, unplanned actions can cause breakers to open and result in the desirable operation of the interlocking schemes. This method, therefore, is considered to be conservative but, never-the-less, it is applied in some instances.

Figure 8 below shows how an interlock scheme would function to prevent low voltage loop flow. When the high side breaker (breaker B) is opened, the low side breaker (breaker E) is also opened. This action prevents low side loop flow. The interlocking scheme could be applied in various combinations and the figure below is a simplified illustration of such a scheme.

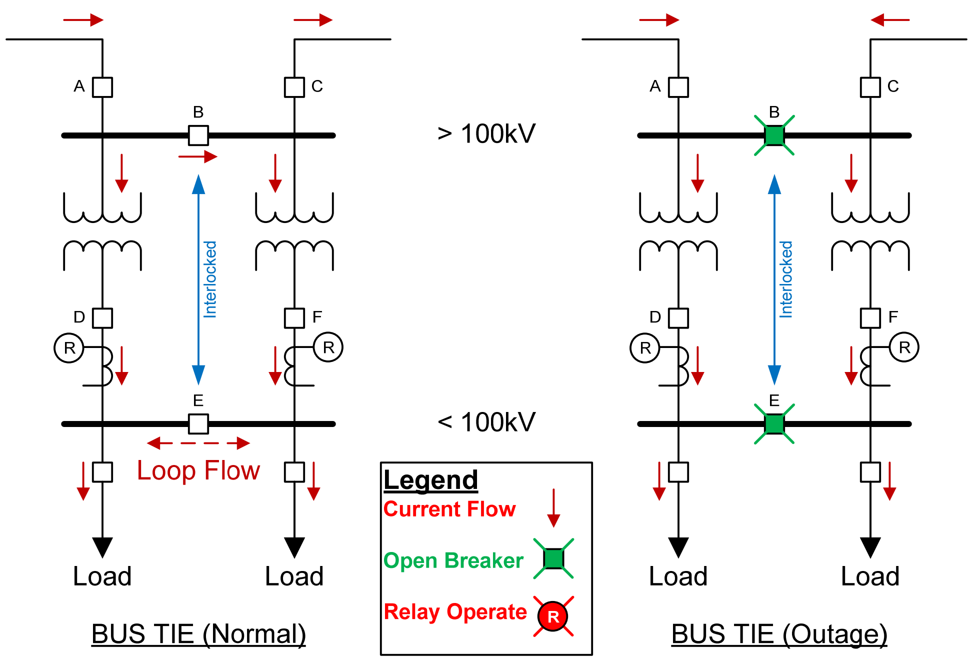


Figure 8. Interlocking Schemes

Reverse Power Schemes

Protection schemes can also be deployed to prevent sustained loop flows through the sub-100 kV system. Reverse power applications are one example of a protection scheme that prevents sustained undesirable low voltage loop flow. In some instances, protective devices will preclude sustained loop flows due to their settings and in other instances protective schemes are specifically applied to preclude this undesirable operating condition.

Figure 9 below shows how a reverse power scheme would function to prevent sub-100 kV loop flow. When the high side breaker (breaker B) is opened, current may flow from the high voltage side (breaker A) through the low voltage bus and back to the high voltage side (breaker C). A relay on breaker F is applied to sense the reverse flow (relay shown in yellow in the diagram) and will operate if this flow continues (relay shown in red in the diagram). When the reverse power relay operates it will trip breaker F. This action prevents reverse power flow through the transformer and low voltage loop flow. The reverse power scheme is set to sense a minimum amount of power flowing in a reverse direction and is usually set much less than the transformer rating. The figure below is a simplified illustration of a reverse power scheme.

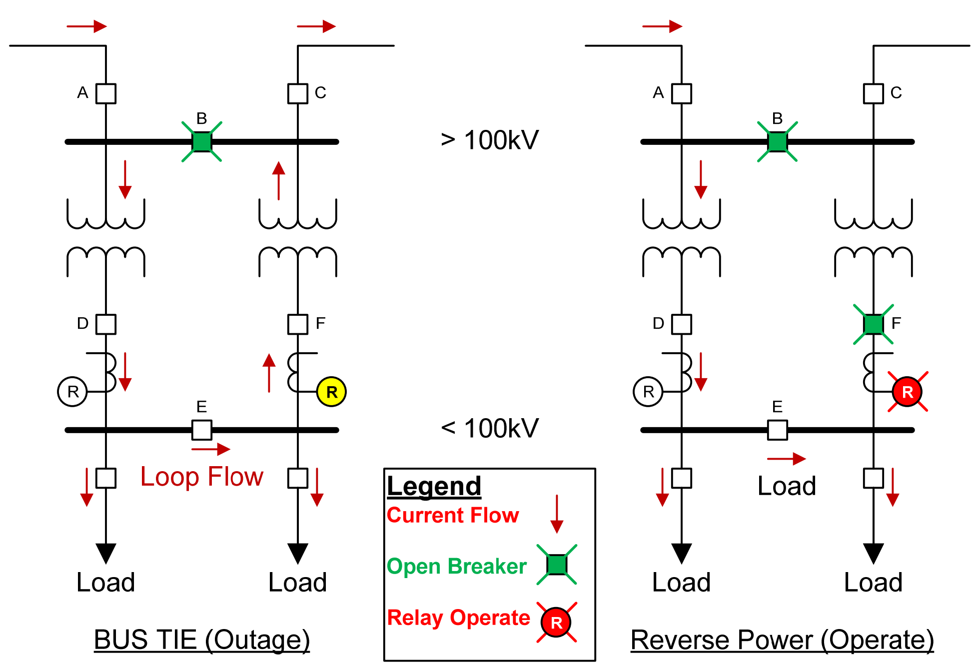


Figure 9. Reverse Power Schemes

Transformer Overcurrent Limitations

Transformer overcurrent protection schemes can also be deployed to prevent sustained loop flows through the sub-100 kV system. Figure 10 below shows how a transformer overcurrent scheme would function to prevent sub-100 kV loop flow. When the high side breaker (breaker B) is opened, current may flow from the high voltage side (breaker A) through the low voltage bus and back to the high

voltage side (breaker C). The relay on the transformer and breaker D is applied to protect the transformer from excessive overloads and faults on the low voltage system. If a fault occurs or the transformer is over-loaded then the relay on breaker D will sense this excessive flow (relay shown in yellow in the diagram) and will operate if this flow continues (relay shown in red in the diagram). When the transformer overcurrent relay operates it will trip breaker D. This action unloads the transformer in question and prevents low voltage loop flow. The transformer overcurrent relay is typically set to allow the transformer to be loaded to the emergency rating of the transformer plus a small safety margin. The figure below is a simplified illustration of a transformer overcurrent scheme.

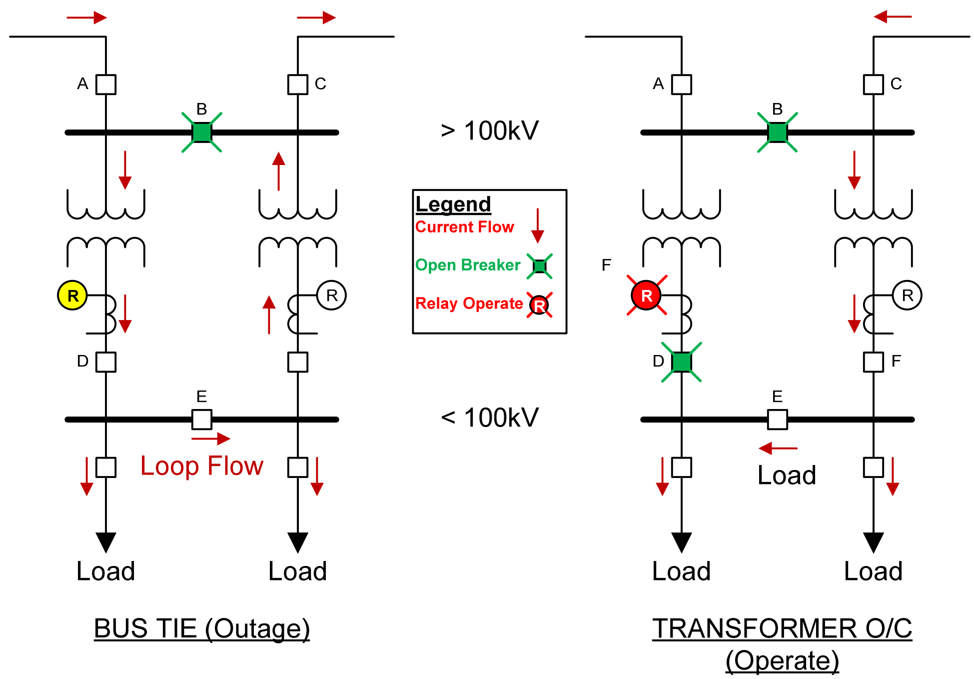


Figure 10. Transformer Overcurrent Limitations

Feeder Overcurrent Limitations

Feeder overcurrent protection schemes can also be deployed to prevent sustained loop flows through the sub-100 kV system. Figure 11 below shows how a feeder overcurrent scheme would function to prevent sub-100 kV loop flow. When the high side breaker (breaker B) is opened, current may flow from the high voltage side (breaker A) through the low voltage feeder, through a feeder tie, and back to the high voltage side (breaker C). The relay on the feeder and breaker G is applied to protect the feeder from excessive overloads and faults on the low voltage feeder. If a fault occurs or the feeder is over loaded, the relay on breaker G will sense this excessive flow (relay shown in yellow in the diagram) and will operate if this flow continues (relay shown in red in the diagram). When the feeder overcurrent relay operates it will trip breaker G. This action opens the feeder breaker and prevents low voltage loop flow. The feeder overcurrent relay is typically set to allow the feeder to be loaded to the emergency rating of the feeder rating plus a small safety margin. The figure below is a simplified illustration of a feeder overcurrent power scheme.

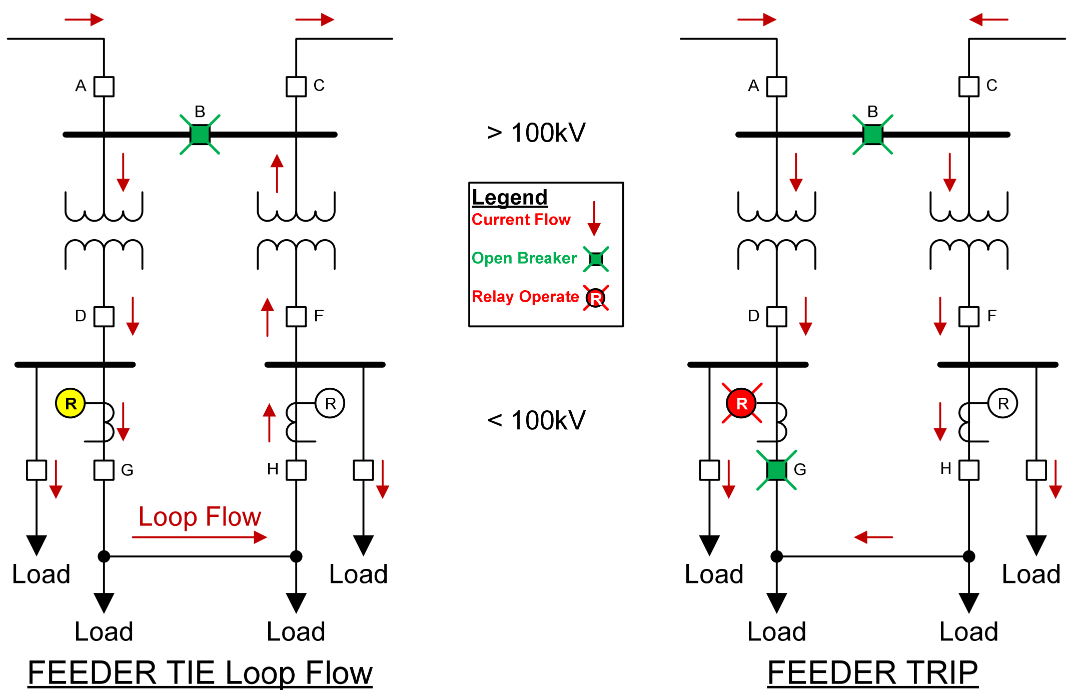


Figure 11. Feeder Overcurrent Limitations

Bus Tie Overcurrent Limitations

Bus tie overcurrent protection schemes can also be deployed to prevent sustained loop flows through the sub-100 kV system. Figure 12 below shows how a bus tie overcurrent scheme would function to prevent sub-100 kV loop flow. When the high side breaker (breaker B) is opened, current may flow from the high voltage side (breaker A) through the low voltage bus and back to the high voltage side (breaker C). The relay on the bus tie and breaker E is applied to protect the bus from excessive overloads and faults on the low voltage bus(ses). If a fault occurs or the bus is over loaded, then the overcurrent relay on breaker E will sense this excessive flow (relay shown in yellow in the diagram) and will operate if this flow continues (relay shown in red in the diagram). When the bus tie overcurrent relay operates, it will trip breaker E. This action opens the bus tie breaker and prevents sustained low voltage loop flow. The bus tie overcurrent relay is typically set to allow the bus to be loaded to the emergency rating plus a small safety margin. The figure below is a simplified illustration of a bus tie overcurrent power scheme.

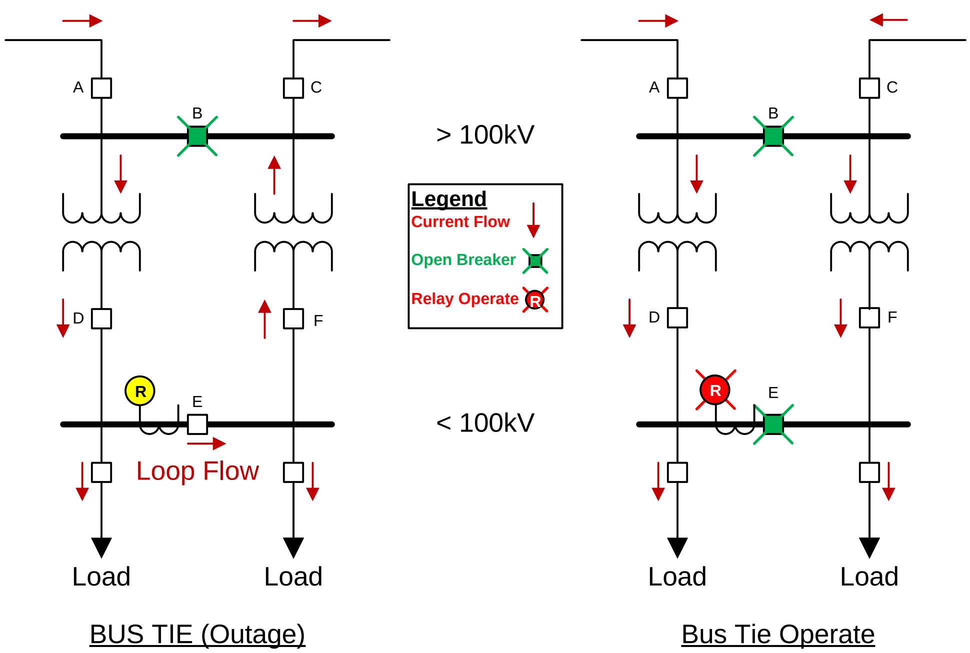


Figure 12. Bus Tie Overcurrent Limitations

Custom Protection and Control Schemes

Custom protection and control schemes may also be deployed to prevent loop flows through the sub-100 kV system. Figure 13 below shows how such schemes would function to prevent sub-100 kV loop flow. When the greater than 100 kV line 1 breakers (breakers D and G) open, current may flow from the high voltage side (breaker E) through the low voltage bus and back to the high voltage side (breaker H). The custom scheme implemented at the substation will trip or run back generation to prevent over loads and sustained loop flows on the low voltage system.

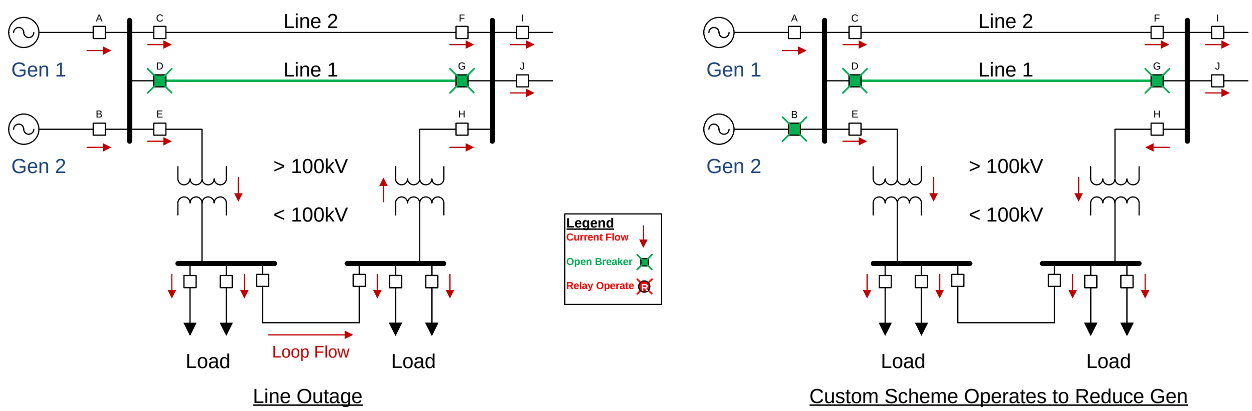


Figure 13. Custom Scheme Operations

Appendix 4 Summary

The issues and methods described in Appendix 4 are reflective of why, in most instances, conditions of sustained loop flows through sub-100 kV systems are alleviated. When the low voltage is much less than 100 kV, the design considerations shown above become even more pertinent and preventative methods are employed; BES reliability is not the main concern, protecting the equipment from physical damage is the primary concern. In the vast majority of cases, robust planning and operating criteria and procedures will alleviate any concerns regarding sustained loop flows.

Exhibit E

Summary of Development History and Record of Development of Proposed Definition

Exhibit E - Summary of the Standard Development Proceedings and Record of Development of Proposed Definition of Bulk Electric System

The development record for the proposed revisions to the Definition of Bulk Electric System is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in **Exhibit F**.

II. Standard Development History

A. Standard Authorization Request Development

The Standard Authorization Request ("SAR") for Phase 2 of Project 2010-17 Definition of the Bulk Electric System ("BES") was submitted on December 2, 2011 as a request for a revision to an existing Standard. The initial draft of the Phase 2 SAR was posted from January 4, 2012, to February 3, 2012, for a 30-day public comment period. Stakeholders were asked to provide feedback on the scope of the proposed Phase 2 project as well as specific suggestions for existing sources of data or technical input to support revisions. A supplemental SAR for Phase 2 was submitted on January 16, 2013, and the final SAR for Phase 2 was revised on March 12, 2012 and finalized on July 10, 2012.

B. The First Posting – Formal Comment Period and Initial Ballot

The first draft of the Phase 2 Definition of BES was posted for a 45-day comment period from May 29, 2013, to July 12, 2013, with an initial ballot held from July 3, 2013 to July 12,

---

1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d)(2) (2006).

2013. Several documents were posted for guidance with the first draft, including the Unofficial Comment Form; NERC Planning Committee Report on Analysis of Thresholds; the Drafting Team Initial Rationale for Radial Exclusion Voltage Threshold; and the Phase 2 SAR and supplemental SAR. The initial ballot received an 85.53% quorum, and an approval of 49.73%. There were 93 sets of responses on the first draft, with comments from more than 225 different people from approximately 138 companies representing all 10 of the industry segments. In response to comments, the standard drafting team made several changes to the draft definition including:

- Removed "dispersed power producing resources" from Inclusion I2 and modified several other inclusions/exclusions;
- Replaced and modified Inclusion I4, which covered dispersed power producing resources;
- Modified Note 2 of Exclusion E1: Radial Systems, to increase the voltage level from 30 kV to 50 kV
- Modified the language in the "Implementation Plan and effective date language";
- Made minor typographical modifications to Inclusion I2(a), Exclusion E3(b), and Exclusion E4

C. The Second Posting – Formal Comment Period and Additional Ballot

The second draft of the Definition for Phase 2 was posted for a formal 30-day comment period from August 6, 2013 to September 4, 2013, with an additional ballot held from August 26, 2013 to September 4, 2013.[2] The additional ballot achieved a 78.68% quorum, and an approval of 66.11%. The standard drafting team received 65 sets of comments from 153 different people from approximately 117 different companies representing all 10 industry segments. Several changes were made to the draft of the Phase 2 Definition of BES including:

[2] On August 2, 2013, the NERC Standards Committee authorized a waiver of the NERC Standard Processes Manual to permit the comment period that began on August 6, 2013 as well as any subsequent comment period prior to a final ballot of Phase 2 of the Definition of Bulk Electric System. The waiver allows the comment periods to be shortened from 45 days to 30, with a ballot during the last ten days of the comment period.

- Modified the language of Inclusion I4 to clearly reflect the SDT's intent to include individual dispersed power producing units (such as wind and solar units) that aggregate to greater than 75 MVA , along with the collector system that connects these units, from the point they aggregate to greater than 75 MVA to the point of connection at 100 kV or higher;
- Modified the language in the Implementation Plan to reflect the differences in regulatory regimes in various jurisdictions;
- Corrected minor typographical errors in the white paper on the 50 kV threshold.

D. Third Posting - Formal Comment Period and Additional Ballot

The third draft of the standard was posted with the Implementation Plan, and a number of supporting documents including the Unofficial Comment Form, White Paper to Support sub-100 kV Threshold, the Phase 2 SAR, and the meeting minutes for the August 2, 2013, Standards Committee meeting. The NERC Standards Committee authorized a waiver of the NERC Standard Process Manual to shorten the next and any subsequent comment periods for Phase 2 of Project 2010-17, prior to the final ballot from 45 days to 30 days, with a ballot conducted during the last 10 days of the comment period.

The 30-day comment period ran from September 27, 2013 to October 28, 2013, and included an additional ballot from October 18, 2013 to October 29, 2013. The additional ballot achieved a 75.83% quorum, and an approval of 72. 55%. The standard drafting team received 40 sets of comments from approximately 98 different people from approximately 66 different companies representing all 10 industry segments. The standard drafting team did not receive any technically supported arguments to support making any changes to the posted definition or the Implementation Plan.

E. Fourth Posting – Final Ballot

The fourth draft of the standard was posted with the Implementation Plan, and a number of supporting documents including the White Paper to Support sub-100 kV Threshold and the

Phase 2 SAR. The final ballot for Phase 2 was open from November 8, 2013 to November 18, 2013. The final ballot achieved a quorum of 81.68%, and an approval of 74.34%.

Project 2010-17 Proposed Definition of Bulk Electric System

Related Files

Status:

The proposed Definition of Bulk Electric System was adopted by the NERC Board of Trustees on November 21, 2013, and will be filed with the appropriate regulatory agency.

Background:

On December 20, 2012 the Federal Energy Regulatory Commission (the Commission) issued Order No. 773, approving the definition of Bulk Electric System filed as a result of Phase 1 of the Definition of Bulk Electric System project. In Order No. 773, as clarified in Order 773-A, the Commission directed NERC to: (1) modify the exclusions for radial systems (Exclusion E1) and local networks (Exclusion E3) so that they do not apply to tie-lines, i.e. generator interconnection facilities, for BES generators; and (2) modify the local network exclusion to remove the 100 kV minimum operating voltage to allow systems that include one or more looped configurations connected below 100 kV to be eligible for the local network exclusion.

In Order No. 773-A, the Commission noted that facilities below 100 kV can be a significant factor in a major blackout. The Commission cited the joint NERC and Commission staff report on the September 8, 2011, Arizona-Southern California blackout in support of its decision to include all facilities that have a material impact on the reliability of the Bulk-Power System. The Commission's analysis of the impact of the revisions to the definition of BES to address Order No. 773 directives reflects the intention that the revised definition would not dramatically impact the footprint of the BES.

On May 23, 2013, NERC filed a motion with FERC, requesting that the effective date of Order 773 be extended by one year, from July 1, 2013 to July 1, 2014. On June 6, 2013, FERC granted this request. In its order, FERC stated that "NERC should submit a filing that includes proposed modifications to comply with the directives pertaining to exclusions E1 and E3 as soon as possible prior to December 31, 2013. Any delay in the submission of a filing that addresses the responsive modifications could impede the Commission's ability to act on the directives prior to July 1, 2014."

Purpose/Industry Need:

On November 18, 2010 FERC issued Order 743 and directed NERC to revise the definition of Bulk Electric System so that the definition encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. Phase I of Project 2010-17 Definition of Bulk Electric System concluded on November 21, 2011 with stakeholder approval of a revised definition of Bulk Electric System and application form titled 'Detailed Information to Support an Exception Request' referenced in the Rules of Procedure Exception Process. The revised definition, modifications to the Rules of Procedure to provide a process for determining exceptions to the definition, and an application form to support that process, will all be presented to the NERC Board of Trustees for adoption and then filed with regulatory authorities for approval.

Phase 2 of the project was initiated to develop appropriate technical justification to support refinements to the definition that were suggested by stakeholders during Phase I, and to refine the definition as technically justified. In addition, during Phase 2 the drafting team will address FERC's directives from Orders 773 and 773-A.

Draft	Action	Dates	Results	Consideration of Comments
Draft 4 Clean (43)| Redline to Last Posting (44) | Redline to Last Approved (45) Implementation Plan Clean (46) Supporting Documents: White Paper to Support sub-100 kV Threshold (47) SAR (48)	Final Ballot Info (49) Vote>>	11/08/13 - 11/18/13 (closed)	Summary (50) Ballot Results (51)	
Draft 3 Clean (28)| Redline to Last Posting (29) Implementation Plan Clean (30) | Redline to Last Posting (31) Supporting Documents: Unofficial Comment Form (Word) (32)	Additional Ballot Updated Info (36) Info (37) Vote>>	10/18/13 - 10/29/13 Extended an additional day to achieve quorum. (closed)	Summary (39) Ballot Results (40)	Consideration of Comments (42)
	Formal Comment Period Info (38) Submit Comments>>	09/27/13 - 10/29/13 (closed)	Comments Received (41)	

White Paper to Support sub-100 kV Threshold (33) SAR (34) Standards Committee Authorization to Waive the Standard Process (35)				
Draft 2 Clean (15) Redline to Last Posting (16) Implementation Plan Clean (17) Redline to Last Posting (18) Supporting Documents White Paper to Support sub-100 kV Threshold (19) SAR (20) Unofficial Comment Form (21) Notice of Request to Waive the Standard Process (22)	Formal Comment Period Updated Info(23) Submit Comments>>	08/06/13 - 09/04/13 (closed)	Comments Received (24)	Consideration of Comments>>(27)
	Additional Ballot Vote>>	08/26/13 - 09/04/13 (closed)	Summary>>(25) Ballot Results>>(26)	

Draft 1 - Phase 2 Definition Clean (1)| Redline to Last Approved (2) Implementation Plan (3) Supporting Documents Unofficial Comment Form (Word Version)(4) NERC Planning Committee Report on Analysis of Thresholds (5) Drafting Team Initial Rationale for Radial Exclusion Voltage Threshold (6) Phase 2 SAR (7) Phase 2 Supplemental SAR (8) -------------------	Comment Period Info>>(9) Submit Comments>> --------------- Join Ballot Pool>> -------------- Initial Ballot Updated Info (10) Vote>>	05/29/13 - 07/12/13 (closed) --------------------- -- 05/29/13 - 06/27/13 (closed) --------------------- --- 07/03/13 - 07/12/13 (closed)	Comments Received>>(11) Summary>>(12) Ballot Results>>(13)	Consideration of Comments>>(14)
Phase 1: Bulk Electric System Definition Reference Document (April 2013)	For Information On June 13, 2013, FERC issued an order extending the effective date of the definition of Bulk Electric System developed in Phase 1. As a result, this			

	reference document is outdated. Revisions to the document will be developed at a later date to conform to the definition being developed in Phase 2			
Phase 2 SAR Supplemental SAR	For Information			
Draft 1 Guidance Document Supporting Materials: Unofficial Comment Form (Word) Definition of Bulk Electric System (Filed with FERC 01/23/12)	Informal Comment Period Info>> Submit Comments>>	10/4/2012 - 11/5/2012 (closed)	Comments Received>>	Consideration of Comments>>
Phase 2	Posted for Information	7/10/2012		

FINAL SAR Clean | Redline				
Phase 2 Draft 1 SAR Supporting Materials: Definition of Bulk Electric System (last approved) Unofficial Comment Form (Word)	Comment Period Info>> Submit Comments>>	1/4/2012 - 2/3/2012 (closed)	Comments Received>>	
Draft 3 Definition of Bulk Electric System Clean | Redline to Last Posting Implementation Plan for Definition Clean | Redline to Last Posting Detailed Information to Support BES Exceptions Request Clean | Redline to Last Posting	Recirculation Ballots Info>> Vote>>	11/10/2011 - 11/21/2011 (closed)	Summary>> BES Definition Full Record>> BES Exceptions Full Record>>	
Draft 2 Definition of Bulk Electric System	Initial Ballot of Definition of BES Updated Info>>	9/30/2011 - 10/10/2011 (closed)	Summary>> Full Record>>	Consideration of Comments>>

Clean | Redline to Last Posting Implementation Plan for Definition Clean | Redline to Last Posting Supporting Materials Comment Form (Word) Draft Supplemental SAR 090111 Letter to A. Mosher from Chairman Anderson 082411 Letter to Chairman Anderson from from A. Mosher Technical Justification for Local Network Exclusion	Info>> Vote>>			
	Join Ballot Pool>>	8/26/2011 - 9/26/2011 (closed)		
	Comment Period Updated Info>> Info>> Submit Comments>>	8/26/2011 - 10/10/2011 (closed)	BES Definition Comments Received>>	Consideration of Comments>>
Draft 2 Detailed Information to Support BES Exceptions Request Supporting Materials	Initial Ballot of Detailed Information to Support BES Exceptions Request Info>> Vote>>	9/30/2011 - 10/10/2011 (closed)	Summary>> Full Record>>	Consideration of Comments>>

Comment Form (Word)	Join Ballot Pool>>	8/26/2011 - 9/26/2011 (closed)		
	Comment Period Info>> Submit Comments>>	8/26/2011 - 10/10/2011 (closed)	BES Exceptions Comments Received>>	Consideration of Comments>>
Draft 1 Technical Principles for Demonstrating BES Exceptions Comment Form (Word)	Comment Period Submit Comments>> Info>>	5/11/2011 - 6/10/2011 (closed)	Comments Received>>	Technical Principles Consideration of Comments>>
SAR Version 2 Clean | Redline to last posting Definition of Bulk Electric System Clean | Redline to last posting Implementation Plan for Definition Clean Comment Form (Word)	Bulk Electric System Definition Revision Status Info>>			Definition of Bulk Electric System Consideration of Comments>>
	Comment Period Info>> Submit Comments>>	4/28/2011 - 5/27/2011 (closed)	Comments Received>>	

Draft SAR Version 1 Definition of Bulk Electric System Clean | Redline to last approval Supporting Materials: Concept Paper Unofficial BES SAR & Definition Comment Form (Word) Official BES Definition Exception Process Comment Form (Word)	Comment Period Info>> Submit Comments>>	12/17/2010 – 1/21/2011 (closed)	BES Definition Exception Process Comments Received Comments Received >>	BES SAR & Definition Consideration of Comments>> BES Definition Exception Process Consideration of Comments Q1>> Q2>> Q3>>

Project 2010-17 Definition of Bulk Electric System (Phase 2)

Standard Development Roadmap

This section is maintained by the drafting team during the development of the definition and will be removed when the definition becomes effective.

Development Steps Completed:

1. SAR posted for comment 1/4/12 – 2/3/12
2. SC authorized SAR for development 4/12/12

Proposed Action Plan and Description of Current Draft:

This draft is the first comment posting and initial ballot for the Phase 2 revised definition of the Bulk Electric System (BES).

Future Development Plan:

Anticipated Actions	Anticipated Delivery
1. Recirculation ballot	3Q13
2. BOT adoption	4Q13

Project 2010-17 Definition of Bulk Electric System (Phase 2)

Effective Dates

This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the definition will go into effect on the first day of the second calendar quarter after Board of Trustees adoption.

Version History

Version	Date	Action	Change Tracking
1	January 25, 2012	Respond to FERC Order No. 743 to clarify the definition of the Bulk Electric System	N/A
2	TBD	Phase 2 clarifications to the original revisions Respond to directives in FERC Orders 773 and 773-A	Y

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below will be balloted in the same manner as a Reliability Standard. When the approved definition becomes effective, the defined term will be added to the Glossary.

Bulk Electric System (BES): Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.
- **I2** – Generating resource(s) and dispersed power producing resources, including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
  a) Gross individual nameplate rating greater than 20 MVA, OR,
  b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.

> **Rationale for revising I2 to consolidate I2 and I4**: Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells.

- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.
- **I4** - Omitted.
- **I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:
  a) Only serves Load. Or,
  b) Only includes generation resources, not identified in Inclusions I2 or I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2 or I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.
Note 2 – The presence of a contiguous loop, operated at a voltage level of 30 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

Rationale: The drafting team has proposed a threshold of 30 kV or less for loops between radial systems when considering the application of Exclusion E1. The SDT used a three step approach to determine the voltage level. As a first step, regional voltage levels that are monitored on major interfaces, paths, and monitored elements to ensure the reliable operation of the interconnected transmission system were examined to determine the lowest monitored voltage level. Next, power system analyses determined the maximum amount of power that can be transferred through the low voltage systems, when looped, under a worst case scenario at various voltage levels. Finally, examination of design considerations that the industry deploys to prevent loop flow through low voltage systems at the various voltage levels confirms that protection is implemented to prevent such flows through low voltage looped systems. A formal white paper is being prepared to support this approach.

- **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.
- **E3** - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

  a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2 or I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

  b) Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

- **E4** – Reactive Power devices installed for the sole benefit of a retail customer.

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Explanation of changes:

- **I1 –** Made a non-material semantic change to provide greater clarity as suggested by industry comments.
- **I2 –** (1) Split the inclusion into an 'a' and 'b' as suggested by industry to clarify that this is an 'or' statement. This is not shown in redline as it is strictly a structure change and redlining this would mask the changes made for dispersed power producing resources. (2) Added the dispersed power producing resources phrase to provide clarity as to the inclusion of such resources herein and to continue to provide the granularity for these resources noted in FERC Orders 773 and 773-A. (3) Added a brief rationale for the revision to I2. The text box will be removed from the final filed version of the definition. The text box language will be placed in the appropriate section(s) of the Reference Document when that document is revised for Phase 2.
- **I4 –** Omitted this as a separate inclusion as it is no longer needed with the inclusion of dispersed power producing resources in Inclusion I2. Since Inclusion I2 includes what is being referred to as generator interconnection facilities, a separate inclusion to handle collector systems is not needed. The numbering of the inclusions has been retained so as not to invalidate software tools developed for the Phase 1 definition.
- **I5 –** Made a semantic addition to provide clarity as suggested by industry comments.
- **E1 –** Added Note 2 on looped configurations, which provides a floor below which an entity does not have to consider the loop in its determination of a radial system. Preliminary justification for the value is shown in separate supporting documents for this posting, and a brief description of the rationale is included in a text box within E1. A formal white paper will be developed justifying this approach. The language in the text box will be deleted from the final filed definition and will be included in the appropriate sections of the Reference Document.
  - **E1 b) and c) –** Changed to address directives in Orders 773 and 773-A for generator interconnection facilities. The "…with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating)" language remains in the definition even with the addition of Inclusion I2 as it refers to the aggregate of multiple sites along the radial.
- **E3 –** (1) Addressed directive in Orders 773 and 773-A by deleting the 'or above 100 kV but' phrasing. (2) Semantic change replacing 'retail customer Load' with 'retail customers' to provide clarity as suggested by industry comments.
  - **E3a) -** Changed to address directives in Orders 773 and 773-A for the generator interconnection facilities.
  - **E3c) -** Made a semantic change to provide clarity as suggested by industry comments.
- **E4 –** Deleted ownership implications as the BES definition is a component-based definition and does not take into account the ownership or operation of the actual equipment.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the definition and will be removed when the definition becomes effective.

Development Steps Completed:

1. SAR posted for comment 1/4/12 – 2/3/12
2. SC authorized SAR for development 4/12/12

Proposed Action Plan and Description of Current Draft:

This draft is the first comment posting and initial ballot for the Phase 2 revised definition of the Bulk Electric System (BES).

Future Development Plan:

Anticipated Actions	Anticipated Delivery
1. Recirculation ballot	3Q13
2. BOT adoption	4Q13

Project 2010-17 Definition of Bulk Electric System (Phase 2)

Effective Dates

This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the definition will go into effect on the first day of the second calendar quarter after Board of Trustees adoption.

Version History

Version	Date	Action	Change Tracking
1	January 25, 2012	Respond to FERC Order No. 743 to clarify the definition of the Bulk Electric System	N/A
2	TBD	Phase 2 clarifications to the original revisions Respond to directives in FERC Orders 773 and 773-A	Y

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below will be balloted in the same manner as a Reliability Standard. When the approved definition becomes effective, the defined term will be added to the Glossary.

Bulk Electric System (BES): Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded ~~under~~by application of Exclusion E1 or E3.
- **I2** – Generating resource(s) and dispersed power producing resources, including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
  a) Gross individual nameplate rating greater than 20 MVA, OR,
  b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.

> **Rationale for revising I2 to consolidate I2 and I4:** Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells.

- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.
- **I4** - ~~Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above~~ Omitted.
- **I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:
  a) Only serves Load. Or,

b) Only includes generation resources, not identified in Inclusions I2 or I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2 or I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

Note 2 – The presence of a contiguous loop, operated at a voltage level of 30 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

Rationale: A threshold of 30 kV or less has been proposed for loops between radial systems when considering the application of Exclusion E1. The SDT used a three step approach to determine the voltage level. As a first step, regional voltage levels that are monitored on major interfaces, paths, and monitored elements to ensure the reliable operation of the interconnected transmission system were examined to determine the lowest monitored voltage level. Next, power system analyses determined the maximum amount of power that can be transferred through the low voltage systems, when looped, under a worst case scenario at various voltage levels. Finally, examination of design considerations that the industry deploys to prevent loop flow through low voltage systems at the various voltage levels confirms that protection is implemented to prevent such flows through low voltage looped systems.

- **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.
- **E3** - Local networks (LN): A group of contiguous transmission Elements operated at ~~or above 100 kV but~~ less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers ~~Load~~ and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2 or I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

b) Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

c) Not part of a Flowgate or transfer path: The LN does not contain a~~ny monitored Facility of a~~part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

- **E4** – Reactive Power devices ~~owned and operated by~~installed for the sole benefit of ~~the~~a retail customer~~solely for its own use~~.

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Explanation of changes:

- **I1 –** Made a non-material semantic change to provide greater clarity as suggested by industry comments.
- **I2 –** (1) Split the inclusion into an 'a' and 'b' as suggested by industry to clarify that this is an 'or' statement. This is not shown in redline as it is strictly a structure change and redlining this would mask the changes made for dispersed power producing resources. (2) Added the dispersed power producing resources phrase to provide clarity as to the inclusion of such resources herein and to continue to provide the granularity for these resources noted in FERC Orders 773 and 773-A. (3) Added a brief rationale for the revision to I2. The text box will be removed from the final filed version of the definition. The text box language will be placed in the appropriate section(s) of the Reference Document when that document is revised for Phase 2.
- **I4 –** Omitted this as a separate inclusion as it is no longer needed with the inclusion of dispersed power producing resources in Inclusion I2. Since Inclusion I2 includes what is being referred to as generator interconnection facilities, a separate inclusion to handle collector systems is not needed. The numbering of the inclusions has been retained so as not to invalidate software tools developed for the Phase 1 definition.
- **I5 –** Made a semantic addition to provide clarity as suggested by industry comments.
- **E1 –** Added Note 2 on looped configurations, which provides a floor below which an entity does not have to consider the loop in its determination of a radial system. Preliminary justification for the value is shown in separate supporting documents for this posting, and a brief description of the rationale is included in a text box within E1. A formal white paper will be developed justifying this approach. The language in the text box will be deleted from the final filed definition and will be included in the appropriate sections of the Reference Document.
  - **E1 b) and c) –** Changed to address directives in Orders 773 and 773-A for generator interconnection facilities. The "…with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating)" language remains in the definition even with the addition of Inclusion I2 as it refers to the aggregate of multiple sites along the radial.
- **E3 –** (1) Addressed directive in Orders 773 and 773-A by deleting the 'or above 100 kV but' phrasing. (2) Semantic change replacing 'retail customer Load' with 'retail customers' to provide clarity as suggested by industry comments.
  - **E3a) -** Changed to address directives in Orders 773 and 773-A for the generator
- **E4 -** Deleted ownership implications as the BES definition is a component-based definition and does not take into account the ownership or operation of the actual equipment.

Implementation Plan for Project 2010-17: Definition of BES (Phase 2)

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this project can be implemented.

Effective Dates

This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required the definition shall go into effect on the first day of the second calendar quarter after Board of Trustees adoption.

Compliance obligations for the Phase 2 definition would begin:

- Twenty-four months after the applicable effective date of the definition (for newly identified Elements), or
- If a longer timeframe is needed for an entity to be fully compliant with all standards applicable to an Element or group of Elements that are newly identified as BES when the Phase 2 definition is applied, the appropriate timeframe may be determined on a case-by-case basis by mutual agreement between the Regional Entity and the Element owner/operator, and subject to review by the ERO.

This implementation plan is consistent with the timeframe provided in Phase 1.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2010-17 Definition of Bulk Electric System
Phase 2 | First Draft

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the first draft of the Definition of the Bulk Electric System (Project 2010-17 – Phase 2). The electronic comment form must be completed by **8 p.m. ET, July 12, 2013**.

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information

The SDT has been working on addressing the issues presented in the Standard Authorization Requests for Project 2010-17 Definition of the BES – Phase 2. The output of this work is shown in the first posting of the Phase 2 roadmap document.

In Phase 1, industry asked several questions regarding the technical justification of the threshold values shown in the definition. Due to the FERC mandated scheduled for work on Phase 1, analysis of the various thresholds was delayed until Phase 2. At the direction of the NERC Board of Trustees, the NERC Planning Committee was tasked with analysis of threshold values as part of Phase 2 of the project. The NERC Planning Committee responded in its report entitled "Review of Bulk Electric System Definition Thresholds" dated March 2013, which has been posted on the Project 2010-17 webpage as part of the background material for this posting. The NERC Planning Committee report recommended that the following thresholds be maintained:

- 100 kV bright-line
- 20/75 MVA generation
- No minimum value for reactive devices

The report did suggest possible changes to the local network exclusion regarding power flow and voltage levels. However, the SDT believes that such changes are contrary to the philosophy of local networks, would necessitate additional analysis workload, and would turn the evaluation from an operating timeframe to a planning environment. Therefore, the SDT is maintaining the status quo for the local network exclusion in Phase 2 with regard to threshold values and power flow issues.

FERC issued Order No. 773-A on April 18, 2013. In that order, FERC affirmed Order 773 and directed NERC to eliminate the 100 kV minimum in the local network exclusion, and to also make certain that generation interconnection facilities that are used to interconnect BES generation with BES transmission elements are determined to be BES elements.

The SDT has posed two questions in this posting addressing how it responded to those directives.

Question 1 below deals with the removal of the 100 kV minimum from the local network exclusion:

> "**E3** - Local networks (LN): A group of contiguous transmission Elements operated at ~~or above 100 kV but~~ less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers ~~Load~~ and not to accommodate bulk power transfer across the interconnected system."

Question 2 below deals with the proposed solution for generation interconnection facilities in the local network and radial system exclusions:

> "**E3a** - Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2 or I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);" and
> "**E1b** - Only includes generation resources, not identified in Inclusions I2 or I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating)." And
> "**E1c** - Where the radial system serves Load and includes generation resources, not identified in Inclusions I2 or I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating)."

The SDT is proposing an equal and effective alternative to the issue of sub-100 kV loop analysis with respect to Exclusion E1. A threshold of 30 kV or less has been proposed for loops between radial systems when considering the application of Exclusion E1. The SDT used a three-step approach to determine the voltage level. As a first step, regional voltage levels that are monitored on major interfaces, paths, and monitored elements to ensure the reliable operation of the interconnected transmission system were examined to determine the lowest monitored voltage level. Next, power system analyses determined the maximum amount of power that can be transferred through the low voltage systems, when looped, under a worst case scenario at various voltage levels. Finally, examination of design considerations that the industry deploys to prevent loop flow through low voltage systems at the various voltage levels confirms that protection is implemented to prevent such flows through low voltage looped systems. Question 3 addresses this proposal.

Note 2 – The presence of a contiguous loop, operated at a voltage level of 30 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

Question 4 deals with clarification on the topic of dispersed power resources as requested by industry in Phase 1. Based on Orders 773 and 773-A, the SDT has revised Inclusions I2 and I4 to address concerns raised by the Commission and to establish consistency in the treatment of BES generation resources:

"**I2** - Generating resource(s) and dispersed power producing resources, including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:"

Dispersed power producing resources are small-scale power generation technologies utilizing a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells.

and,

I4 - ~~Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.~~ Omitted.

Question 5 deals with all of the language clarifications made in response to industry comments which are listed here:

- **I1 –** Semantic change from 'under Exclusion E1 or E3' to 'by application of Exclusion E1 or E3' to provide greater clarity as suggested by industry comments.
- **I2 –** Splitting the inclusion into an 'a' and 'b' as suggested by industry to provide clarity.
- **I5 –** Semantic addition to provide clarity as suggested by industry comments.
- **E3 –**Semantic change replacing 'retail customer Load' with 'retail customers' to provide clarity as suggested by industry comments.
- **E3c) -** Semantic change replacing 'a monitored Facility of' with 'any part of a' to provide clarity as suggested by industry comments.
- **E4 -** Semantic change to provide clarity as suggested by industry.

Question 6 is a generic question added to this list to accommodate any other industry concerns with the proposed Phase 2 definition.

Questions

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

The SDT has asked one specific question for each specific aspect of the definition.

1. The SDT has deleted the phrase "… or above 100 kV but…" from the local network exclusion language (E3) in response to a FERC directive. Do you agree that the SDT has correctly addressed this directive? If you do not agree that this change addresses the directive, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes
   ☐ No
   Comments:

2. As identified in the FERC directive, the SDT has revised the local network (Exclusion E3) and radial system (Exclusion E1) exclusions so that they do not allow for the utilization of these exclusions for generation interconnection facilities that are used to interconnect BES generation identified in the generation inclusion (Inclusion I2) with BES transmission elements. Do you agree that the SDT has correctly addressed this directive? If you do not agree that this change addresses the directive, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes
   ☐ No
   Comments:

3. The SDT has proposed an equally effective and efficient alternative to the Commission's sub-100 kV loop concerns for radial systems by the addition of Note 2 in Exclusion E1. Do you agree with this approach? If you do not support this approach or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions and rationale in your comments.

   ☐ Yes
   ☐ No
   Comments:

4. The SDT has revised the generation resources and dispersed power resources inclusions (Inclusions I2 and I4) in response to industry comments and Commission concerns. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes
   ☐ No
   Comments:

5. The SDT has made a number of clarifying changes to language in response to industry comments as follows: (a) I1: Change 'under' to 'by application of'; (b) I2: Split out the inclusion to clearly show that it is an 'or' condition; (c) I5: Add 'unless excluded by application of Exclusion E4'; (d) E3: Change '… retail customer Load…' to 'retail customers'; (f) E3c: Change '… a monitored Facility of a …' to '… any part of a…'; (g) E4: Add the phrase 'installed for the sole benefit of'. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions (using the letter of the change) in your comments.

   ☐ Yes
   ☐ No
   Comments:

6. Are there any other concerns with this definition that haven't been covered in previous questions and comments?

   ☐ Yes
   ☐ No
   Comments:

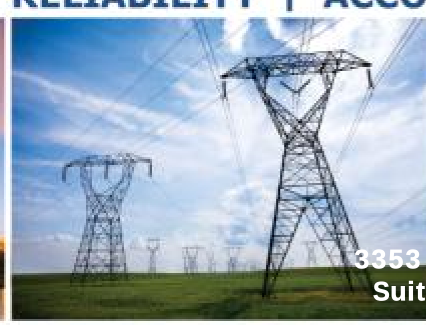
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Review of Bulk Electric System Definition Thresholds

March 2013

RELIABILITY | ACCOUNTABILITY






3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Preface and NERC Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces reliability standards; assesses reliability annually via a 10-year assessment and winter and summer seasonal assessments; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	ReliabilityFirst Corporation
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into several assessment areas within the eight Regional Entity boundaries, as shown in the map and corresponding table above. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in British Columbia, Ontario, New Brunswick, and Nova Scotia. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory and enforceable in that jurisdiction.

Table of Contents

Executive Summary

In March 2012, the Definition of BES Standard Drafting Team (DBES SDT) asked the Planning Committee (PC) to review some of the thresholds in the Bulk Electric System (BES) definition that the DBES SDT identified within the Phase I BES work and to supply technical justifications for the following thresholds:

1. 100 kV bright-line transmission threshold (in the core definition)
2. Generation threshold MVA values associated with single-unit and multiple-unit facilities (in Inclusions I2 and I4)
3. Reactive power threshold (MVA level) (in Inclusion I5)
4. Power flow allowed out of Local Networks (LN) (in Exclusion E3)

After analysis and review, the PC offers the following recommendations to the DBES SDT for consideration:

5. Maintain the 100 kV bright line (core definition).
6. Maintain Inclusions I2 and I4 as currently defined.
7. Maintain Inclusion I5 as currently defined.
8. Use Technical Alternative C, which proposes clarifying changes to the existing Exclusion E3 item (b) as given below in bold:
    a. **Real** power flows only in the LN **from every point of connection to the BES for the system as planned with all-lines in service and also for first contingency conditions as per TPL-001-2, Steady State & Stability Performance Planning Events P0, P1, and P2**, and the LN does not transfer energy originating outside the LN for delivery through the LN **to the BES**
9. Establish a size limit in the LN definition to prevent the exclusion of large networks that may have a significant impact on reliable BES operation. This recommendation is explained in detail in the following section as well as in Appendix 3.

The NERC PC discussed and approved the recommendations in this report and its transmittal to the DBES SDT at its December 2012 meeting. Following the meeting, the PC Executive Committee made further changes based on the discussion by the PC, and the final report was approved by the PC by an email ballot.

1. Introduction

In FERC Order No. 693, the Commission explained that section 215(a) of the Federal Power Act (FPA) broadly defines the bulk power system as:

> *Facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) [and] electric energy from generating facilities needed to maintain transmission system reliability.*

The Commission also initially approved NERC's definition of Bulk Electric System, which is an integral part of the NERC Reliability Standards and is included in the NERC Glossary of Terms Used in Reliability Standards[2], as the following:

> *As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.*

In response to the Commission's directive in Order No. 743 that NERC develop a revised definition of Bulk Electric System using NERC's Reliability Standards development process, NERC began work in 2011 to eliminate the Regional and subjectivity contained within the definition. In early 2012, the NERC Board of Trustees approved a revised BES definition and subsequently filed it with FERC under docket RM12-6 and RM12-7. This concluded the Phase I work associated with developing a revised definition.

In its filing, NERC proposed the following core definition of Bulk Electric System:

> *Unless modified by the [inclusion and exclusion] lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.*

As stated in the NERC filing, the revised definition of Bulk Electric System:

- removes the basis for regional discretion in the current Bulk Electric System definition;
- establishes a bright-line threshold so that the Bulk Electric System is facilities that operate at 100 kV or higher, if they are Transmission Elements, or connected at 100 kV or higher, if they are real power or reactive power resources; and
- contains specific Inclusions (I1-I5) and Exclusions (E1-E4).

During the initial revision of the definition of the Bulk Electric System in Phase I of Project 2010-17, industry stakeholders expressed concerns related to the lack of technical justification associated with the existing thresholds in the definition. Due to time constraints in the Phase I schedule, Phase II of the project was initiated to address the lack of technical justification. As part of this initiative, the DBES SDT asked the PC for assistance in developing technical justification for the thresholds in the revised definition.

1.1 Problem Statement

Properly identified BES Elements are important to the reliability of the interconnected bulk power system. The ability to properly identify BES Elements is dependent on a BES definition that is based on factors directly associated with reliability. The revised BES definition approved by the NERC Board of Trustees and filed with FERC contains historical thresholds from the current BES definition found in the NERC Glossary of Terms and the NERC Statement of Compliance Registry Criteria.[3] These historical thresholds are not currently supported by documented technical justifications.

[2] http://www.nerc.com/files/Glossary_of_Terms.pdf

[3] On December 20, 2012, FERC issued a Final Rule on *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*: http://www.ferc.gov/whats-new/comm-meet/2012/122012/E-5.pdf

The DBES SDT requested support from the NERC PC (see Appendix 1A and 1B for request authorization) and Operating Committee (OC) to develop technical justifications to assist the SDT in considering revisions to the following thresholds that are part of the current NERC Board of Trustees-approved definition of the BES:

1. 100 kV bright-line transmission threshold (in the core definition)
2. Generation threshold MVA values associated with single-unit and multiple-unit facilities (in Inclusions I2 and I4)
3. Reactive power threshold (MVA level) (in Inclusion I5)
4. Power flow allowed out of Local Networks (LN) (in Exclusion E3)

1.2 Planning Committee Assignments

To complete this request in a timely manner, the PC assigned the development of technical justifications for the thresholds listed above to designated subcommittees of the PC as outlined below:

Technical Justification	Assigned To:
100 kV bright-line transmission threshold	Planning Committee Executive Committee
Generation threshold	Reliability Assessment Subcommittee
Reactive power threshold	System Analysis and Modeling Subcommittee
Power flow allowed out of local networks	System Analysis and Modeling Subcommittee

1.3 Considerations for Technical Justification

The PC, in conjunction with its technical subcommittees, noted that using power flow or dynamic studies may not lead to definitive results and are highly dependent on varying assumptions used in the models, such as generation dispatch, load level, system conditions, etc. Also, other aspects of reliability, such as resource adequacy, reserve margins, voltage support, etc. need to be considered along with performing power flow and dynamic analyses. Therefore, the PC recommended that these studies not be performed at this time in determining technical justification for the above thresholds.

2. Technical Justification for the 100 kV Bright Line

NERC's filing to FERC under docket RM12-6-000 proposed to establish a bright-line transmission threshold so that the "bulk electric system" would include facilities operated at 100 kV or higher if they are Transmission Elements, or connected at 100 kV or higher if they are real-power or reactive-power resources. The DBES SDT asked the PC to provide technical justification for the 100 kV threshold included in the core BES definition or propose a better alternative, if justified (see Appendix 1).

2.1 Alternatives to the 100 kV Bright Line

Several alternatives to the 100 kV bright-line transmission threshold were considered. The alternatives outlined below were selected for further research and consideration.

2.1.1 Technical Alternative A – Surge Impedance Loading (SIL)

Description: Incorporate transmission lines that have a Surge Impedance Loading (SIL) above a specific criteria value (for example, 100 MVA) and for all substations connected to a line that meets this criteria.

Technical Discussion: A key component to the reliability of the power system is the ability to continue to provide service to load not only from nearby generating sources, but also from external sources. This has been the basis for justifying the addition of a number of Extra High Voltage (EHV) transmission facilities throughout North America. To assess the ability of a transmission line to carry load, or the amount of load a transmission line can effectively carry, engineers calculate its Surge Impedance Loading.

SIL is a loading level at which the transmission line attains self-sufficiency in reactive power (i.e., no net reactive power into or out of the line), and is a convenient "yardstick" for measuring relative loadability (or ability of the line to carry load) of long transmission lines operating at different nominal voltages.

For example, considering the SIL alternative, on a per-unit basis, for uncompensated overhead transmission lines, three 500 kV circuits, six 345 kV circuits, or thirty-four 161 kV[4] circuits would be required to achieve the same loadability of a single 765 kV line. Specifically, a 765 kV line can reliably transmit 2,200–2,400 MW (i.e., 1.0 SIL) for distances up to 300 miles, whereas the similarly situated 500 kV and 345 kV lines with bundled conductors can only deliver about 900 MW and 400 MW, respectively, over the same distance.

For short distances, these previous relationships can produce slightly different results, which reflects the thermal capacity of transmission line. The thermal capacity of a transmission line is determined by the number or size of line conductors and terminal equipment ratings. However, SILs for typical compensated overhead lines are two to three times those of uncompensated overhead lines. For underground lines where air is not the insulating dielectric, SILs are three to twelve times that of uncompensated overhead lines, with multipliers increasing as line voltages decrease.

The relative loadability of the same overhead 765 kV, 500 kV, and 345 kV lines also can be viewed in terms of transmission "reachover," for which a certain amount of power can be transmitted. In the first example, 1,500 MW sent over a 765 kV line would represent a loading of approximately 0.62 SIL, which, according to the loadability characteristic of the transmission line, could be transported reliably over a distance of up to 550 miles.

By contrast, a 345 kV line carrying the same 1,500 MW would operate at 3.8 SIL—this power would be transportable up to approximately 50 miles (assuming adequate thermal capacity). This distance would increase to about 110 miles for a double-circuit 345 kV line.

The generalized line loadability characteristic incorporates the assumptions of a well-developed system at each terminal of the line and operating criteria designed to promote system reliability.[5]

[4] Thirty four 161 kV added to original calculations
[5] Source is American Electric Power System Facts (no endorsement; used posted transmission information)

SIL is a long-accepted indicator of system loadability and capability and is at least one indicator of the reliability of a transmission line. System studies would need to be performed to support a given bright line threshold, such as the 100 MVA mark, with delayed clearing fault simulations occurring while at the same time monitoring for cascading events, extreme frequency excursions, and uncontrolled separation (among other events).

However, calculations from a sample power flow model's branch data indicate that additional stress and stability studies would need to be performed for all interconnections. Follow-up correlation analysis would be necessary to determine whether correlation to SIL exceeds correlation to a voltage level, and to identify the appropriate bright-line SIL threshold for the BES.

A transmission line's SIL is easy to calculate, but the values obtained correspond to a voltage level, which does not provide a better, technically justified alternative to using the 100 kV voltage level. (SIL is proportionate to the square of voltage). SIL would simply be a surrogate to using a bright-line voltage criteria. In addition, transmission lines would still carry portions of power transfers, even though they may be below a certain SIL value, as the SIL value is only an indication of reactive power equilibrium for that line. Virtually all transmission lines above 200 kV would be captured by this criterion for the SIL level. Transmission lines below 200 kV would most likely be included in the BES if the line has series compensation or is built underground, which increases the SIL for those types of lines.

Given that SIL would only be a surrogate for the voltage level of a transmission line, the PC recommends not selecting this method for determining the bright-line threshold in the BES definition.

2.1.2 Technical Alternative B – Short Circuit Values

Description: Incorporate facilities with a short circuit value greater than a specified threshold (e.g., 5,000 MVA).

Technical Discussion: Technical Alternative B to the 100 kV bright-line transmission threshold in the BES definition would be to perform a calculation that reflects the strength of the network at any given location or node (such as a substation bus) using the Short Circuit MVA method. Using this approach, facilities with many sources (either transmission lines or generation sources) would fall under the definition of the BES, given the level of short circuit MVA.

The classical approach and the method defined by ANSI/IEEE are two such industry-accepted methods for calculating short circuits. Both methods assume that the fault impedance is zero (bolted short circuit) and the pre-fault voltage is constant during the evolution of the fault. In actuality, the fault has its own impedance, and the voltage drop, due to the short-circuit current, lowers the driving voltage.[6]

The classical approach is used to calculate the system Thévenin equivalent impedance behind the fault and then to calculate the Short Circuit MVA at the point of the fault. The ANSI/IEEE method for short circuit MVA calculation, which is described in IEEE Std. C37.010-1979[7] and its revision in 1999, is used for high-voltage (above 1000 V) equipment.

In order to include all higher voltage facilities that may be carrying power over longer distances, a bright-line voltage level would also need to be included when using this method. This value could be based on operating and design specifications of the interconnection.

Technical Alternative B is easy to calculate and is completed regularly by industry stakeholders. Calculated Short-Circuit MVA values are normally calculated at substation buses and display the projected fault current at each bus.

However, to use Technical Alternative B as a bright-line criterion in the BES definition, there must also be additional criteria developed to address the inclusion of the associated transmission lines, including transformers connected to those substations (which may include sub-100 kV facilities). Additionally, an MVA threshold value itself would be arbitrary and, therefore, short circuit calculated values would vary, depending on study models, which generators are online, etc. Using this method to identify BES facilities would result in frequent changes and thus be not practical to implement. The PC does

[6] http://ecmweb.com/content/short-circuit-calculation-methods

[7] http://standards.ieee.org/

not recommend the use of the Short-Circuit MVA method as a replacement for the bright-line transmission threshold identified in the current BES definition.

2.1.3 Technical Alternative C – Substation MVA Rating

Technical Discussion: Include substations with two or more lines connected to a substation with a total rated MVA greater than a specified threshold (e.g., 800 MVA or greater) and any transmission lines with MVA ratings greater than a specified value (e.g., 400 MVA or greater). The total substation MVA value would be the sum of all of the MVA values (or ratings) of the transmission lines connected to a substation and may include sub-100 kV facilities within the substation.

Technical Discussion: Technical Alternative C uses the total connected MVA rating of all lines into substations, regardless of voltage level. The computed MVA would *not* include transformation within the substation, nor would it include generation or load connected to the substation. This method would only include circuits connected to a substation in the determination of the connected MVA value. The connected MVA method would use networked transmission lines, as used in the current BES definition, and would also include lines that connect to the substation via the transmission system. At the same time, it would exclude the following types of transmission lines: radial transmission lines, transmission lines to lower voltage facilities with no transmission sources, loads, and lines connected directly to generation sources. This alternative does not consider the power flow on the lines, but rather their MVA ratings.

Transmission line MVA calculations would then be based on the most restrictive continuous rating of the transmission facility. Continuous ratings would be used since the BES is planned to serve peak load without relying on short-term overload capability. No stability ratings would be used.

Possible advantages of using the total substation-connected MVA alternative over the 100 kV voltage threshold are that the MVA-based determination captures substations with multiple circuits connected to it. (Individual lines are not as important, given the criteria to operate the system at N-1 levels).

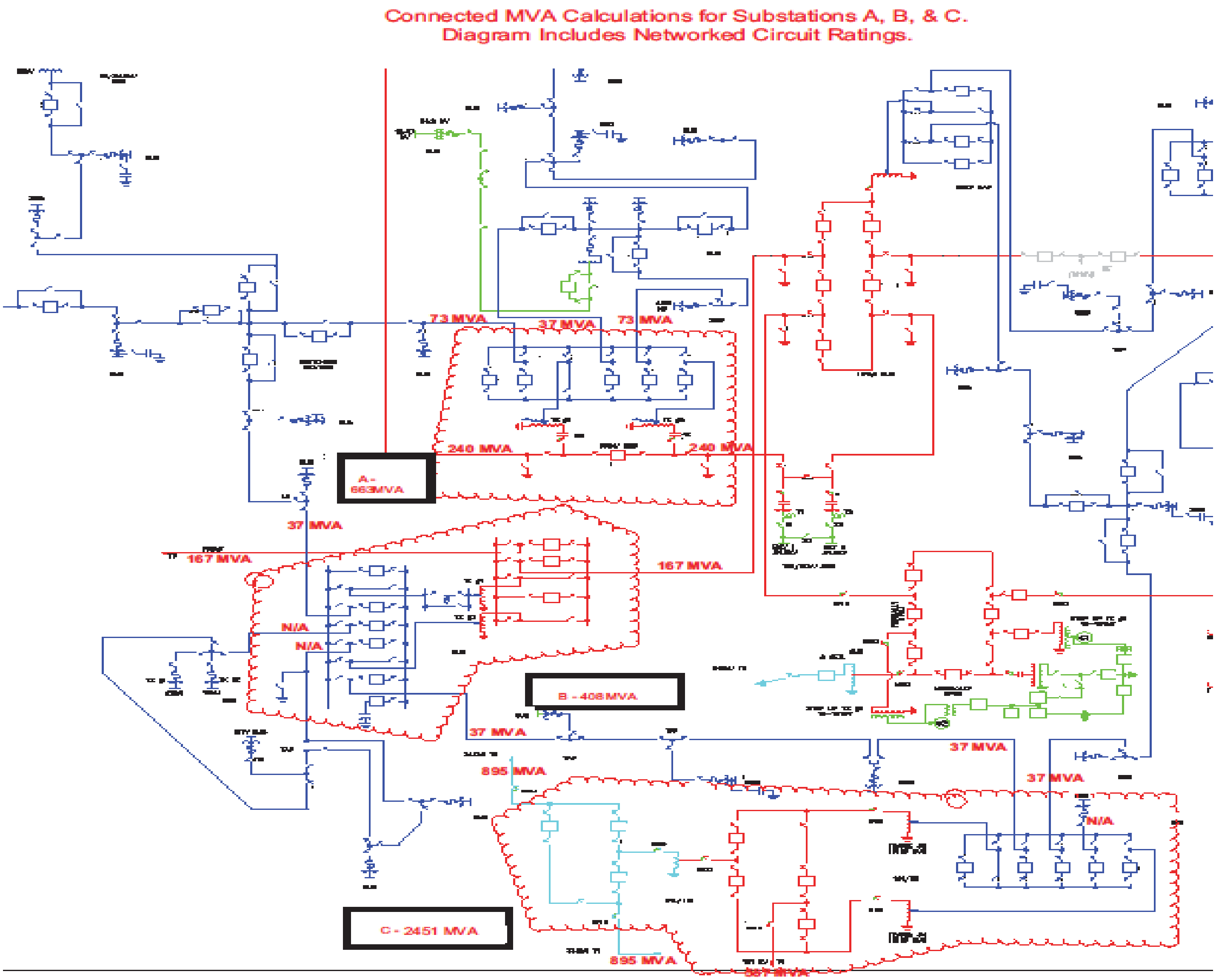
This method also determines the capacity of lower voltage facilities (such as transmission lines operated at voltages less than 100 kV) that are normally closed circuits in lower voltage networks and that contribute reliability benefits to the bulk power system. The connected MVA method may alleviate concerns that facilities operating at voltages less than 100 kV are not considered BES facilities unless they are determined to contribute to the reliability of the local network or interconnection. The connected MVA method also is more efficient to administer, as it reduces the number of inclusions and exclusions necessary to separate BES facilities that contribute to the reliability of network from those that do not (also referred to as non-BES facilities).

However, the disadvantages of applying the connected MVA method may include challenges to address all possible scenarios (e.g., whether generation facilities with multiple fuel types should be included or excluded). The connected MVA method would require revision to the BES if transmission lines or equipment were uprated.

The connected MVA method could create inconsistent classification of Elements that serve similar purposes (e.g., a transmission line between two major substations would be included; however, if two intervening step-down stations were constructed, the section between the two step-down stations may be excluded even though its function as a transmission path is not changed).

Figure 1 below shows example one-line diagrams of three substations and the summation of MVA of lines interconnecting the substations back to the interconnected system. The MVA interconnection of substations A and B is less than 800 MVA and would not be included in the BES. However, substation C, with an interconnection MVA of 2,451 MVA, would be included.

Figure 1: Connected MVA Calculations for Substations A, B, and C



Because MVA values are essentially arbitrary and reconfiguration could exclude assets with BPS functionality, the PC does not recommend the use of the connected MVA of substation method as a replacement for the bright-line transmission threshold identified in the current BES definition.

2.1.4 Technical Alternative D – Transfer Distribution Factors

Description: Use transfer distribution factors, such as Power Transfer Distribution Factors (PTDFs)[8] and Outage Transfer Distribution Factors (ODTFs),[9] to determine a bright-line threshold for inclusion of lines and transformers in the BES. Calculated values above a specified percentage (e.g., 3%) would determine which facilities would be considered BES.

[8] Linear methods use PTDF to express the percentage of a power transfer or transaction that flows on a transmission path. PTDF is defined as the coefficient of the linear relationship between the amount of a transaction and the flow on a line or transformer, and the

Technical Discussion: Technical Alternative D would use transfer distribution factors as a bright-line threshold for inclusion of lines and transformers in the BES. Calculated values above a specified percentage (e.g., 1%, 3%, or 5%) would determine which facilities are classified as BES facilities and which facilities are not. The selection of this method to identify bulk system assets has several disadvantages. First, it would require detailed power flow analyses be performed to make the determination, and that method would need to be reviewed periodically (possibly biennially) to account for system changes that would affect the OTDF and PTDF values. Also, it would require a review if lines or equipment were uprated. OTDF values are dynamic and may result in frequent changes to which facilities are classified as BES.

The PC does not recommend the use of transfer distribution factors as a replacement for the bright-line transmission threshold identified in the current BES definition.

2.1.5 Technical Alternative E – Angular Difference

Description: Determine facilities within the BES by calculating the angular differences between substation buses. The values used in this alternative would be determined by power flow analyses or real-time synchrophasor data gathered from operating phasor measurement units (PMUs).

Technical Discussion: Technical Alternative E suggests using angular differences between substation buses to determine BES and non-BES facilities. This method could use data from power flow analyses or real-time synchrophasor data gathered from phasor measurement units (PMU).[10]

The voltage phasor angle difference between two ends of a transmission line becomes large when the power flow on the line is large or the line impedance is large. Similar relationships are expected to apply to the angle difference between two buses in different areas of a power system.

A large angular difference indicates, in a general sense, a stressed power system with large power flow or increased impedance between the areas. Simulations of the grid before the August 2003 Northeast Blackout showed increasing angle differences between Cleveland and western Michigan, which suggests that large angle differences could be a precursor to a system blackout.

A recent simulation study[11] of potential phasor measurements on the 39-bus New England test system shows that, of several phasor measurements, angle differences were the best in discriminating alert limits and emergency conditions.

The increasing deployment of wide-area measurement of phasor angles spurs interest in finding ways to use phasor angles to determine system stress. Picking one bus in each of two areas and monitoring the phasor angle difference has an inherent problem in that, although the angle difference is generally expected to increase with system stress, many factors contribute to angle difference, including which two buses are chosen and the local power flows within each area. It is then harder to give a specific meaning to the angular difference and specify threshold values that indicate when the angular difference becomes dangerously large.

Angle differences are inherently dynamic and change with generation, load, and transmission conditions instantaneously. The PC could not determine how this method could be used to identify BES facilities. The PC does not recommend the use of angular difference as a replacement for the bright-line transmission threshold identified in the current BES definition.

---

incremental percentage of a power transfer flowing through a facility or set of facilities for a particular transfer when there are no contingencies.

[9] OTDF is the percentage of a power transfer that flows through a monitored facility for a particular transfer when the contingent facility is taken out of service.

[10] I. Dobson, M. Parashar, C. Carter, Combining Phasor Measurements to Monitor Cutset Angles, 43rd Hawaii International Conference on System Sciences, January 2010, Kauai, Hawaii. 2010 IEEE.

[11] V. Venkatasubramanian, Y. X. Yue, G. Liu, M. Sherwood, Q. Zhang, Wide-area monitoring and control algorithms for large power systems using synchrophasors, IEEE Power Systems Conference and Exposition, Seattle WA, March 2009.

2.2 Conclusions and Recommendation

Over the years, the industry has widely used the 100 kV threshold that appears in the current BES definition to delineate between transmission and subtransmission facilities in some areas of North America. However, the technical justification for using that voltage level as a bright-line threshold has been missing from the BES definition.

Significant portions of power flow transfers from generation to load centers are carried by facilities operated at 100 kV and above. The 100–299 kV systems support the EHV (i.e., greater than 300 kV) systems during times of normal and emergency operations and contingencies. A significant portion of the total generation in North America is connected at voltages between 100 kV and 299 kV. Each interconnection and its associated entities perform technical analyses (including power flow and dynamics) of their systems along with joint regional and interregional analyses. Most technical analyses model 100 kV and above facilities, and sub-100 kV facilities in certain cases. Contingent and monitored facilities are at the 100 kV and above level in these analyses. See Appendix 2 for detailed statistics and values for each interconnection.

While the PC recommends keeping the 100 kV voltage threshold in the revised NERC definition of the BES, it also recognizes and has considered the inclusion of sub-100 kV facilities in the BES because of the findings and recommendations from the report on the Arizona – Southern California Outages of September 8, 2011. The proposed NERC Rules of Procedure exception process may be used to include pertinent sub-100 kV facilities on a case-by-case basis.

Sub-100 kV facilities, as shown from the interconnection discussions in Appendix 2, may be necessary for the operation of the BES but will need to be considered in the future on a case-by-case basis for inclusion in the BES. Registered Entities and Regional Entities will need to address how to make these determinations going forward.

Many and varied interconnection studies indicate that 100 kV is the proper threshold needed for BES reliability. Additionally, none of the alternatives considered in the PC’s analysis provides a convincing technical justification for change from the bright-line threshold.

The PC recommends maintaining the 100 kV bright line (core definition) without enhancement or changes.

3. Technical Justification for Generator Thresholds

In the Phase 1 Bulk Electric System definition filing, Inclusion I2 of the BES definition provides the following statement:

> "Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above."

The filing also states that this inclusion mirrors the text of the NERC Registry Criteria (Appendix 5B of the NERC Rules of Procedure) for generating resources. The Phase 1 filing notes that a "basic tenet that was followed in developing the [revised definition] was to avoid changes to Registrations . . . if such changes are not technically required for the [revised definition] to be complete."

While Inclusion I2 specifies "generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above," the NERC Registry Criteria specifies a "direct connection" to the bulk power system.

Also in the Phase 1 Bulk Electric System filing, Inclusion I4 of the BES definition provides the following statement:

> "Inclusion I4 identifies as part of the bulk electric system dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above."

NERC stated in its Phase 1 filing that the goals of Inclusion I4 were to accommodate the effects of variable generation on the Bulk Electric System. It further states that even though Inclusion I4 could be considered subsumed in Inclusion I2 (generating resources), NERC believes it is appropriate "to expressly cover dispersed power producing resources utilizing a system designed primarily for aggregating capacity" as a separate inclusion criteria.

3.1. Capacity Breakdown

For its reliability assessments, NERC collects two different types of capacity data to classify generators on the bulk power system: 1) nameplate/installed capacity, and 2) seasonal rated capacity.

The nameplate (or installed) capacity of a generation resource is defined as the maximum output (usually in MW) the resource can achieve under specific conditions designated by the manufacturer. Nameplate capacity usually does not include resource uprates (i.e., upgrades made to the generator to increase output) or derates and capacity reductions for station or auxiliary services and loads.

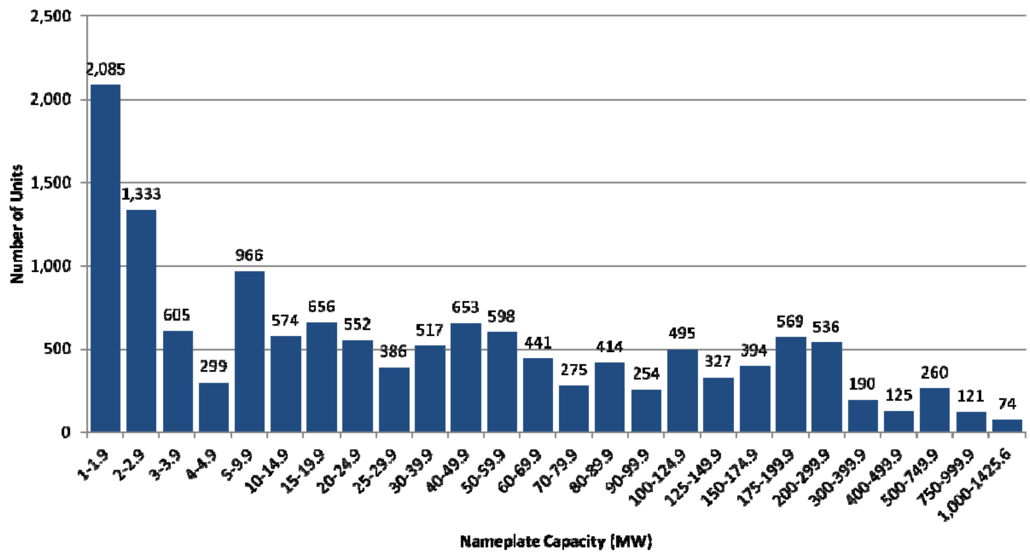
The net capacity (for both summer and winter seasons) is the maximum output (MW) a generator can supply to system load at the time of summer or winter peak demand. The net capacity includes resource uprates (upgrades) and/or derates and capacity reductions for station/auxiliary services. However, net capacity values can be impacted by market conditions, environmental regulations, and other factors.

Based on data from the 2010 Long-Term Reliability Assessment, there are approximately 13,699 generating resources in the United States that can be broken down into different classes based on the capacity (MW) of the resource.

- Less than 10 MW: 5,288 resources (39%)
- Between 10 MW and 99.9 MW: 5,320 resources (39%)
- Between 100 MW and 499.9 MW: 2,636 resources (19%)
- Greater than 500 MW: 455 resources (3%)

Figure 2 shows an aggregation of nameplate capacity of generating resources (MW) by the number of units.

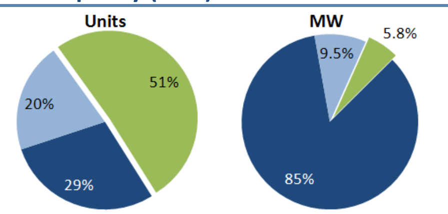
Figure 2: Number of Generating Units by Nameplate Capacity (MW)[12]



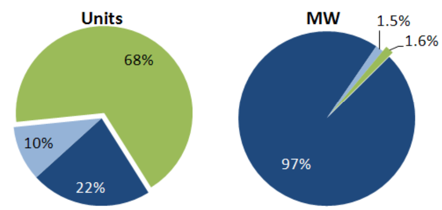
Further analysis was developed to identify the amount capacity and number of units currently in the BES (in the U.S. only) based on the EIA-860 form. In addition to the current threshold level, a two other thresholds were developed as a reference to understand what the associated impacts would. These included setting a threshold for plants and units that were above 20 MW and another for 75 MW. The analysis is included below:

Figure 3a: Number of Generating Units by Nameplate Capacity (MW)[13]

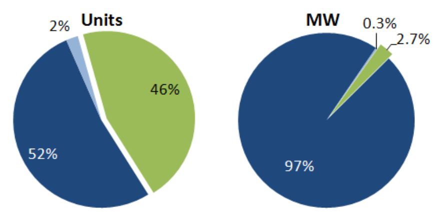
	Category	BES	Color	Units	MW
75/75 Units	Units ≥ 75	BES UNITS		3,942	945,330.1
	Units < 75 that are part of Plants ≥ 75	BES PLANTS		2,767	105,470.8
	Units < 75 that are part of Plants < 75	NOT BES		6,984	65,289.1
	TOTAL			13,693	1,116,090.0
	Total % Excluded from BES			**51.0%**	**5.8%**



	Category	BES	Color	Units	MW
20/20 Units	Units ≥ 20	BES UNITS		7,170	1,082,161.0
	Units <20 that are part of Plants ≥ 20	BES PLANTS		4,472	16,350.7
	Units < 20 that are part of Plants < 20	NOT BES		2,051	17,578.3
	TOTAL			13,693	1,116,090.0
	Total % Excluded from BES			**15.0%**	**1.6%**



	Category	BES	Color	Units	MW
75/20 Units	Units ≥ 20	BES UNITS		7,170	1,082,161.0
	Units < 20 that are part of Plants ≥ 75	BES PLANTS		302	3,252.9
	Units < 20 that are part of Plants < 75	NOT BES		6,221	30,676.1
	TOTAL			13,693	1,116,090.0
	Total % Excluded from BES			**45.4%**	**2.7%**



[12] Data source is 2010 Long-Term Reliability Assessment
[13] Data source is 2010 Long-Term Reliability Assessment

The analysis shown in Figure 2a used the following assumptions:

- EIA-860 Data (2011 Existing Unit Level Information)
  - Covers the 48 U.S. States
  - Nameplate Rating
  - Excludes Inoperable Units (i.e., mothballed)
  - Excludes units less than 1 MW (≈1,600 MW, 2,800 Units)
  - Excludes units "not connected to the transmission grid" (≈5,000 MW)

3.2 Alternatives to the 20/75 MVA Threshold

The PC explored multiple alternatives regarding the generator thresholds contained in the proposed Bulk Electric System definition and selected the following five alternatives for further analysis and consideration:

3.2.1 Technical Alternative A

Description: All generation resources directly connected to the bulk power transmission system, regardless of capacity value (MW), generator size (MVA), or voltage at the point of interconnection, to be considered part of the BES. This alternative would not include photovoltaic resources or wind turbines connected directly to distribution systems.

Technical Discussion: Setting a small capacity value of generator resources for modeling with well-defined points of interconnection at BES voltage levels would not require significant changes in the way generation is recognized in simulation models. The difficulties associated with representing small generation resources at defined points of interconnection are those of developing and maintaining reliable datasets of resource performance in an operational environment.

Future system studies will most likely be concerned about the cumulative behavior of new "classes" of generation, where a class is made up of a large number of very small generating resources (which could include different types of resources from rooftop solar systems). These generating resources will most likely have the following characteristics:

- no readily identifiable point of interconnection with the BES;
- capacity that will be combined with demand from nearby loads; and
- generating resources making up the class will be so small, their locations and ownership so diverse, and their technical details so varied, that explicit representation within system models in the traditional equipment-based sense will be impossible.

There may be areas where the aggregate output and the operating performance of small generating resources are essential to maintaining BES reliability.

In 1997, WECC began recognizing motor behavior as it found that a large amount of its load was electric motors. Recent technical reference paper on the FIDVR phenomenon[14] is developing modeling of new classes of load whose cumulative behavior is of great importance to the grid. The approach recognizes that it is necessary to represent the basic physical characteristics of device class but that it is impractical to get this representation by modeling individual facilities.

It would be a natural extension of composite load modeling to recognize that a class, or classes, of distributed small generating resources can have a cumulative impact on the reliability of the BES. The PC does not consider setting a small (e.g., 1 MW) generator threshold to be practical from engineering and administrative perspectives. Therefore, the PC does not recommend this alternative.

[14] http://www.nerc.com/docs/pc/tis/FIDV_R_Tech_Ref_V1-1_PC_Approved.pdf

3.2.2 Technical Alternative B

Description: Technical Alternative B would require the development of either a uniform generator performance criterion or the development of a uniform method to assess a generator's potential impact on the reliability of the BES and determine whether a generator should be considered part of the BES or excluded from the BES.

Technical Discussion: The draft whitepaper "Generation Exclusion Below 75 MVA in BES Definition – Position Paper" developed by the BES Standard Drafting Team was considered in this assessment. Various case studies identified in the paper only considered steady-state conditions, in effect testing the deliverability of the resources dispatched in place of the generation being removed. It would be expected to find minimal issues using this method. And, if this method or a similar method is applied to select large generating resources, the results are expected to be similar.

Several experts in the field of dynamic simulation studies, including John Undrill, PhD,[15] were consulted on potential methods to determine a generation threshold based on a study of dynamic simulations. These methods would require the development of specific criteria based on engineering judgment that could vary between interconnections. Based on the confluence of feedback from technical experts, no clear technical rationale was identified to establish a minimum generator threshold criterion. Therefore, the PC does not recommend this alternative.

3.2.3 Technical Alternative C

Description: Technical Alternative C would change the proposed Inclusion I2 to include all generating resource(s) whose nameplate ratings are greater than 20 MVA. This would include generating resources where the generator terminals through the high-side of the step-up transformer(s) are connected at a voltage of 100 kV or above.

Technical Discussion: The PC considered enhancing Inclusion I2 of the proposed BES definition by eliminating the distinction between individual and aggregate generating facilities and selecting a single bright-line registration criterion, such as 20 MVA. This would modify the proposed Inclusion I2 as shown below and remove Inclusion I4:

> *"Inclusion I2 consisting of generating resources(s) with individual or aggregate nameplate rating greater than 20 MVA including the generator terminals connected through the high side of the step-up transformer(s) at a voltage of 100 kV or above."*

From a policy perspective, a single criterion of 20 MVA is greater than the data requirements currently imposed by the U.S. Energy Information Administration Form EIA-860,[16] which collects generator-level specific information about existing and planned generators at electric power plants with 1 MW or greater of combined nameplate capacity. In addition, a 20 MW generator threshold value is supported by FERC in Order 2006[17] and by NERC GADS.[18]

The PC has concluded that there is no technical rationale for having a generator threshold value for a single resource and a different threshold value for a group of resources at a plant or facility. The potential impact to the BES for the loss of a single generating resource or a plant or facility at the same generation level would be similar. Therefore, the same generation threshold should apply to a single generating resource as to a plant or facility. However, there is also no technical rationale that has been identified at this time in order to establish a single generator threshold value, whether that value represents a single unit or a total plant. Therefore, this alternative is not recommended.

3.2.4 Technical Alternative D

Description: Technical Alternative D would seek to define BES generation resources based on physical or contractual characteristics.

---

[15] John Undrill, PhD is an IEEE Fellow, a member of the National Academy of Engineering: http://www.nae.edu/42087.aspx and is a Research Professor at the Arizona State University School of Electrical, Computer, and Energy Engineering: http://engineering.asu.edu/ecee/eceeresearchfaculty

[16] Form EIA-860 detailed data request: http://www.eia.gov/electricity/data/eia860/index.html

[17] Standardization of Small Generator Interconnection Agreements and Procedures Docket No. RM 02-12-000 paragraph 75: http://www.ferc.gov/eventcalendar/files/20050512110357-order2006.pdf

[18] NERC GADS' minimum reporting threshold is greater than or equal to 20 MW starting in January of 2013.

Technical Discussion: The PC considered Technical Alternative D in an effort to define BES generation resources based on their physical or contractual characteristics. These characteristics include:

- Generation resource connection voltage to the BES;
- Capacity obligations of the generation resource;
- Nameplate capacity of the generation resource (using U.S. Energy Information Administration (EIA) reporting threshold of greater than 1 MW);
- The inertia constant of the generation resource; and
- Using Adequate Level of Reliability metrics to determine generation resource contributions to reliability.

The PC determined that establishing a generator threshold criterion based on characteristics that may change over time or characteristics that may be considered vague would not be practical and would lack technical merit. Therefore, the PC does not recommend this alternative.

3.3 Recommendation for Generator Thresholds

The PC recommends maintaining the currently proposed Inclusion I2 that consists of generating resources with gross individual nameplate rating greater than 20 MVA or gross plant or facility aggregate nameplate rating greater than 75 MVA, including the generator terminals through the high side of the step-up transformer(s) connected at a voltage of 100 kV or above.

The PC also recommends maintaining the currently proposed Inclusion I4, which identifies as part of the Bulk Electric System dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating), utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.

The PC has not found a superior technical justification to support a different threshold.

In making these recommendations, the PC recognizes that the technical impact on reliability of a given amount of generation at a single point in the bulk power system is the same whether the generation comes from a single unit or is the combined output of a total plant. The PC also realizes that it would be impossible to determine a single megawatt threshold that would apply universally. For example, based on the functions a generator provides, reactive capability and voltage stability support, and on the characteristics of other generation located within the same region, a 20 MW unit in Florida may not be necessary for the reliability of the bulk electric system, whereas a 20 MW unit in Quebec may. Therefore, the PC recommends that in addition to maintaining the current 20/75 MVA thresholds, the results of applying this portion of the BES definition should be closely monitored to evaluate the number of inclusions and exclusions, as well as technical exception requests, and use the results of this evaluation to consider future adjustments to these thresholds.

The PC supports having different MW thresholds for the size of single units and for the combined output of plants. Further, given the unit sizes and numbers of units shown in Figure 2a above, the PC believes that the 20 MVA threshold for single units is still appropriate, as it encompasses over 97 percent of the capacity in the U.S. Based on EIA-860 data (2011 existing unit level information for the U.S.), the current 20/75 MVA thresholds will initially exclude approximately 31,000 MW of capacity from the bright-line definition, which represents 2.7 percent of the total capacity. Raising the unit threshold to 75 MVA would exclude an additional 35,000 MW of capacity, bringing the total capacity excluded from the bright-line definition to 65,000 MW, which represents 5.8 percent of the total capacity in the U.S. Similar results can be assumed if Canadian resources are included in the analysis.

Generators in the 20 to 75 MVA range significantly contribute to the voltage and reactive support of the system; this is also true for sub-20 MVA units. The PC also recognizes that there may be situations in which representing units and plants below the 20/75 MVA thresholds in modeling studies is critical to the accuracy of those studies. Many such units are small combustion turbines or low-head hydro units. The small hydro units tend to be older, 0.85 power factor machines, giving them strong reactive support capabilities. Excluding such units from powerflow and dynamics studies can result in changing flow patterns, potential overloads, and understating transfer capabilities. For instance, the many small hydro units in Maine contribute significant voltage support and stability contributions in the calculations of transfer capability from New Brunswick into New England; removing them from the calculations reduces that transfer capability.

Finally, it would be impossible to determine a single MVA threshold that would apply universally under all conditions and in all situations. The threshold above which generators are necessary for reliable operation of the interconnected system would vary for different reliability concerns; e.g., voltage regulation versus rotor angle stability versus frequency response. In addition, for any given reliability concern, the threshold would vary depending on the characteristics of the system to which the generators are connected.

Therefore, the PC recommends that in maintaining the current 20/75 MVA thresholds, if owners of units above 20 MVA believe that they do not have a material impact on the reliability of the bulk power system, the NERC Rules of Procedure provide a mechanism to request an exception. The results of applying this portion of the BES definition should be closely monitored to evaluate the number of inclusions and exclusions, as well as technical exception requests, that occur and use the results of this evaluation to consider future adjustments to these thresholds.

4. Technical Justification for Reactive Device Threshold

4.1 Background

Inclusion I5 specifically includes reactive devices in the definition of Bulk Electric System, Phase 1 as follows:

> **I5** – Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1.

Inclusion I5 does not possess a threshold in terms of reactive resource sizing. As a result, all reactive resources connected at 100 kV or higher are automatically included in the BES definition regardless of their nameplate rating if they are not excluded in E4. This results in devices such as STATCOMs, SVCs, and reactive devices connected to the tertiary windings of BES transformers being included.

Neither the core definition nor Inclusion I5 provides a threshold for reactive device exemption; however, Exclusion E4 provides an exemption for reactive devices installed specifically for customer reactive support.

> **E4** – Reactive Power devices owned and operated by the retail customer solely for its own use.

The System Analysis and Modeling Subcommittee (SAMS) was tasked with determining an appropriate reactive threshold for excluding some reactive devices from the BES.

Consideration of reactive support and its control are fundamental to the operation of the BES; however, many reactive resources are located on sub-100 kV systems (e.g., the low side of power transformers in subtransmission or distribution substations), where they can more effectively supply the reactive demands of the load, and where they are often less expensive to install and maintain. Reactive resources compensate for the reactive demands of loads by correcting their power factor. Load power factor correction offsets or eliminates the reactive demand of these loads on the BES so that the BES is only required to provide real power to the load. While sub-100 kV reactive resources may not necessarily be integral to BES operation, they still decrease reactive demands on the BES, which benefits the reliability of the BES by reducing losses, supporting voltage, and freeing up capacity on the transmission system.

Furthermore, some reactive resources are connected at varying voltage levels (including sub-100 kV). Their primary function is to provide reactive support and voltage control. These reactive resources have a direct impact on the reliable operation of the BES, and it is important to consider them as integral components of the BES.

4.2 Alternatives to the Zero-Mvar Threshold under Consideration

The PC explored multiple alternatives regarding the reactive device thresholds contained in the proposed Bulk Electric System definition and selected two alternatives for further analysis and consideration.

4.2.1 Technical Alternative A

Description: This alternative would provide a threshold for excluding reactive devices sized below a value based on the generator inclusion threshold (Inclusion I1). Since generators below 20/75 MVA are excluded, a similar or related threshold could be to exclude reactive devices with Mvar capabilities equal to those of a 20 MVA generator.

Technical Discussion: The PC considered a threshold for reactive resources for exemption from the BES based on the typical reactive output of a 20 MVA machine (i.e., using generator bright-line criteria in Phase 1 of BES project).

Currently, 20 and 75 MVA thresholds exist for the inclusion of generation resources depending upon individual unit or aggregate plant nameplate capacities, respectively. A similar approach could be taken for reactive resources; by examining the reactive capability of a 20 MVA generator, say 0.8 per unit nameplate at maximum capacity, a value of 12 Mvar could be selected. Alternatively, if the range of typical reactive output is considered, say at 0.85 power factor, a value of 10.5 Mvar could be selected.

However, without a clear technical justification for the generator threshold, and considering potential inconsistencies between the two thresholds given that generators and reactive devices have different primary objectives, extending the generator threshold to reactive resources does not have a sound technical basis. Reactive resources are not installed for the same reason that generation is installed (i.e., providing real power to support loads), and they are typically only installed as required for voltage support of reliable power system operation. Therefore, the PC does not recommend this alternative.

4.2.2 Technical Alternative B

Description: This alternative examines the deployed reactive resources as modeled in interconnection power flow modeling cases to determine whether there is a bright line to be drawn between load-compensating resources and BES-supporting resources.

Technical Discussion: In examining transmission system power flow models, reactive devices installed with the sole intent of supporting local load power factor are typically netted into the load as non-BES Elements. Other devices are modeled explicitly so that the effect of their statuses can be taken into account when performing system studies. By reviewing the system modeling cases and evaluating the size of devices present in the model, a lower limit might be determined for the reactive devices that directly support reliable BES operation.

When corresponding with generator thresholds, simply selecting a class of reactive devices based on their distribution throughout the transmission system does not provide a sound technical justification for the selection of a threshold. However, the Eastern Interconnection Reliability Assessment Group modeling case demonstrated that if a reactive threshold of 10.5 Mvar were selected (corresponding to the previously mentioned generator threshold of 20 MVA at 0.85 power factor) roughly 5% of the reactive devices less than 10.5 Mvar would be directly connected at 100 kV and above (exclusive of generators). This 5% represents a small but significant number of reactive devices—significant because they provide critical voltage support to the reliability of the bulk power system.

It is difficult to discern whether a small reactive device is required for reliability or for other purposes. Therefore, applying the BES exception process to exclude a subset of this relatively small class of Elements on a case-by-case basis is preferable to providing a blanket exclusion for all reactive devices of this class. Further, it is consistent with a bright-line approach.

Also, the interconnection modeling cases may not show the detail of all reactive resources on the transmission system. This is attributed to equivalencing and reactive supply/load netting within the model. As a result, the cases may be unreliable sources of data for obtaining the actual number and sizes of reactive devices physically installed on the interconnected transmission system. It can be argued that even load-netted reactive devices could have a significant impact on BES reliability if placed in or out of service inappropriately.

Therefore, the PC does not recommend this alternative.

4.3 Conclusion and Recommendation

Reactive resources do not serve the same primary purpose as generating resources and are typically installed at BES voltages as needed to support reliable BES operation. Inclusion I5, in its current state, provides an inherent bright-line distinction between devices installed to support the BES and devices installed at lower voltages to supply the reactive component of the load (e.g., load power factor correction). Inclusion I5 includes any reactive resource directly connected at 100 kV or above, regardless of its design, configuration of its connecting facility, or planned operation.

The PC agrees that devices included by Inclusion I5 are installed to support the BES and therefore should be included. A threshold of zero Mvar for exemption is recommended since reactive devices of all sizes can be installed for the purpose of meeting the NERC TPL standards, and a zero-Mvar threshold ensures that all reactive resources connected at BES voltages (including those located in radial systems and local networks) are included.

Reactive resources connected at 100 kV or higher can be excluded on a case-by-case basis through the BES exception process in the Rules of Procedure. This is consistent with other components of the bright-line BES definition (e.g., generation and blackstart units) in that the potential exists for standalone BES Elements. Furthermore, Exclusion E4 provides for exemption of end-use customer-owned devices, which should capture most—if not all—of the reactive resources installed at BES voltages for the purposes of power-factor correction (i.e., not explicitly installed to support reliable BES operation).

Proposing a non-zero Mvar threshold for exemption or including reactive resources below 100 kV would add unnecessary complexity to the current bright-line inclusion. The current wording of Inclusion I5, taken in tandem with Exclusion E4, provides clear guidance on what is considered integral to BES reliability.

Therefore, the PC recommends maintaining the current threshold stated in Inclusion I5.

5. Technical Justification for Power Flow Out of Local Networks

5.1 Background

Exclusion E3 provides an exemption for "local networks" in the definition of Bulk Electric System, Phase 1 as follows:

> **E3** – Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LNs emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:
>
> - Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);
> - Power flows only into the LN, and the LN does not transfer energy originating outside the LN for delivery through the LN; and
> - Not part of a flowgate or transfer path: The LN does not contain a monitored facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored facility in the ERCOT or Québec Interconnections, and is not a monitored facility included in an Interconnection Reliability Operating Limit (IROL).

The intent of defining an LN is to provide an exemption for components of transmission systems that were installed to improve the level of service to retail customer Load. An LN's design and operation is intended to be such that, at the points of connection to the BES, the LN's effect on the BES is similar to that of a radial system (i.e., as in Exclusion E1), particularly with regard to the fact that in aggregate, real power flow always flows from the BES into the LN. Any re-distribution of parallel flows into the LN from the BES will be negligible compared to the load being served by the LN. Furthermore, since the primary purpose of an LN is to improve the level of service to retail customer Load, and not to support the reliable operation of the interconnected BES, the separation of an LN from the BES shall not diminish the reliability of the BES.

In other words, an LN can effectively be treated in the same way as a radial system but with multiple feeds that enhance local reliability or meet customer requirements, and as such, the characteristics of an LN should match those of a radial system as closely as possible.

The wording of Exclusion E3 raises two issues related to the phrase "power only flows into the LN":

1) The wording "power only flows into the LN" can be strictly interpreted as meaning that *no* power will flow out of *any* connection point of the LN, at *any* time. While power may not flow out of an LN during normal conditions (e.g., LNs are not permitted to wheel power), the potential exists for parallel flows following a contingency event (i.e., single, double, etc.).
2) The following questions also arise: Should there be a distinction between real and reactive power flow? Does the limitation that "power only flows into the LN" also imply that reactive power is absorbed by the LN at all points of interconnection and at all times?

With regard to these issues, the PC was tasked with providing a threshold for permissible flow out of an LN, along with appropriate time duration for outward flows and the associated system conditions. Specifically, the problem statement is:

> "It is anticipated that the technical justification will consist of interconnection-wide studies that target the surrounding BES Elements at the connection points of the subject LN. The studies would utilize the criteria currently established within the definitions of Adequate Level of Reliability[19] and Adverse Reliability Impact[20] to determine the appropriate

[19] From the NERC Glossary of Terms, *Adverse Reliability Impact*: "The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection."

values for the thresholds associated with the potential power flow out of the LN. The final analysis should indicate the amount of acceptable parallel flow through an LN where a loss of the LN or portions of the LN would not result in a reduction of the reliability of the surrounding interconnected Transmission network."

In addition to the issues described above pertaining to the allowable flow through an LN, the PC concluded that the BES definition would greatly benefit from a bright-line distinction for the maximum allowable size (i.e., a maximum MW load limit) of an LN, and in such a way that a system cannot be subdivided into multiple adjoining LNs. In other words, the definition should not allow multiple LNs to be directly tied to one another, nor should it allow for LNs to be embedded or nested within one another. If large amounts of load are not properly taken into account across an interconnection due to exclusion as LNs, then significant impacts to BES reliability—such as frequency stability issues and system operating limit violations—could result due to separation of an LN from the BES.

Prior to the adoption of the Phase 1 BES definition, there were significant regional differences in both the definition of BES and its application that permitted exclusions for portions of a load-serving transmission network. The Phase 1 definition's Exclusion E3 for LNs is intended to standardize this exclusion for systems that are often referred to as "load pockets" along with the Transmission Elements that connect them (assuming that the Transmission Elements are all operated at voltages of at least 100 kV but less than 300 kV, and assuming the underlying generation inclusions and exclusions are met). However, the interaction between an LN and the BES needs to be carefully considered. Providing exclusion for LNs regardless of size could lead to the exclusion of very large networks, which could affect BES reliability. The loss of large networks could have far-reaching, interconnection-wide system impacts.Selecting a bright line for load that can be served by an LN will limit the unintended consequences of such exclusions, and, if needed, the exception process in the Rules of Procedure provides a path for exemption of larger LNs.

5.2 Alternatives to the Zero Power Flow Limitation under Consideration

The PC explored multiple alternatives regarding power flow out of LNs contained in the proposed Bulk Electric System definition and selected three alternatives for further analysis and consideration.

5.2.1 Technical Alternative A

Description: This alternative would propose an acceptable amount of outward power flow for LNs that would be consistent with generation limits set forth elsewhere in the BES definition.

Technical Discussion: The PC considered generation limits set forth elsewhere in the BES Phase 1 definition to define an acceptable amount of outward power flow for LNs. For example, applying a limit on outward flow from an LN corresponding with the 75 MVA embedded generation maximum would provide consistency with the radial system Exclusion E1.

With radial systems, the outward flow of power will always occur at a single connection point on the BES. However, with an LN, outward flow of generation may occur at any terminal on the LN. Without knowing or considering the internal conditions within the LN, outward flows may lead to unpredictable impacts to the overlying BES. Furthermore, without a clear technical justification for the generator threshold, extending this threshold to LNs does not have a sound basis.

Therefore, the PC does not recommend this alternative.

---

[20] Currently under development for inclusion in the Glossary of Terms, *Adequate Level of Reliability*: "The intent of the set of NERC Reliability Standards is to deliver an Adequate Level of Reliability defined by the following bulk power system characteristics:

- The system is controlled to stay within acceptable limits during normal conditions.
- The system performs acceptably after credible contingencies.
- The system limits the impact and scope of instability and cascading outages when they occur.
- The system's facilities are protected from unacceptable damage by operating them within facility ratings.
- The system's integrity can be restored promptly if it is lost.
- 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."

5.2.2 Technical Alternative B

Description: This alternative considers the use of outage transfer distribution factors (OTDFs) to define a threshold for an acceptable amount of through-flow on LNs.

Technical Discussion: OTDFs represent the percentage of a power transfer that flows through the monitored facility for a particular transfer when the facility is switched out of service after a contingency. In relation to an LN, the monitored facilities would include the terminals of the LN, and the contingent facilities would include BES Elements in parallel with the local network. The Flowgate Methodology described in MOD-030-2 sets a 5% threshold for OTDF, in conjunction with other criteria for including a monitored facility as a flowgate. In a similar fashion, an OTDF of 5% or less could be selected as a reasonable threshold for defining the permissible flow through an LN upon the occurrence of a BES contingency, and subsequently for determining a reasonable amount of flow out of an LN.

While computation of OTDFs and related factors are commonplace calculations and well-understood, such factors do not necessarily form a bright line for exclusion from the BES; the permitted flow computed in the OTDF will depend on the contingent Element and will be heavily dependent upon system conditions. Appropriate system conditions and contingencies would need to be specified. This would complicate the definition and completion of supporting analysis and potentially lead to inconsistencies in the application of this approach.

Therefore, the PC does not recommend this alternative.

5.2.3 Technical Alternative C

Description: This alternative would use the existing definition, along with clarifications, to identify the circumstances under which power is expected only to flow into an LN.

Technical Discussion: This alternative relies on the existing Exclusion E3 and, while preserving the concept of an LN, proposes clarification without confusing the bright-line distinction between an LN and the BES. The recommended changes to Exclusion E3 item (b) are given below in bold:

- **Real** power flows only in the LN **from every point of connection to the BES for the system as planned with all-lines in service and also for first contingency conditions as per TPL-001-2, Steady State & Stability Performance Planning Events P0, P1, and P2**, and the LN does not transfer energy originating outside the LN for delivery through the LN **to the BES.**

The PC considered specifying that both real and reactive power must flow into the LN. The "**real** power" clarification is recommended to align with the recommendation on Inclusion I5 for an appropriate reactive device threshold; if all reactive devices connected directly at 100 kV and above are included in the BES definition, then their impact to reliability will be accounted for independently of Exclusion E3. In this case, an LN may deliver some reactive power to the BES in the same way that, under some conditions, a load-serving distribution network delivers reactive power to the BES.

The PC recommends adding the words "**from every point of connection to the BES**" for clarity. If real power flows out of the network at any interconnection point under normal conditions or single-contingency conditions, then at least some portion of the LN is being used to transfer power to the overlying BES network. The portions of a proposed LN that allow parallel flow must be removed from the LN, and the remaining portions of the proposed LN should be further studied to ensure that they do not participate in such flows.

Limiting the study of a proposed LN "**for the system as planned**" (i.e., over the planning horizon) is recommended. This allows some flexibility for outward flow under abnormal or unplanned conditions.

The "**single contingency**" wording is also recommended for clarity. The intent would be to study single contingencies on the BES outside of the LN, as well as contingencies within the LN, and to monitor the LN for any outward flow under these conditions. The PC understands that the system is *planned* for multiple contingencies; however, the expectation of real-time performance for multiple contingencies under myriad unplanned system operating conditions is much more difficult to define. The study of multiple contingencies requires closer examination of credible contingencies. To avoid creating a very complex LN definition, the PC selected "single contingency," because existing NERC Reliability Standards call for the system to be *operated* to single-contingency conditions. Including a single-contingency requirement would imply that the definition of LN would hold under NERC-mandated operating conditions. The threshold is zero power out of the LN—what is being clarified are the conditions under which that threshold applies.

The single-contingency load flow test should not be burdensome to administer. First, contingency analysis is required to be performed annually as part of the TPL requirements. The purpose of basing the determination on the planning horizon is to preserve the bright line so that the facilities can be characterized as they are planned to be operated. Clarifying the definition in such a manner avoids the need to constantly reclassify Elements in response to the myriad of operating conditions that may occur on the system.

5.3 Conclusion and Recommendation

The PC recommends using Technical Alternative C, which proposes changes that clarify the existing Exclusion E3. The recommended changes to Exclusion E3 item (b) are given below in bold:

> **Real** power flows only in the LN **from every point of connection to the BES for the system as planned with all-lines in service and also for first contingency conditions as per TPL-001-2, Steady State & Stability Performance Planning Events P0, P1, and P2**, and the LN does not transfer energy originating outside the LN for delivery through the LN **to the BES.**

The PC further suggests that a size limit be established in the LN definition to prevent the exclusion of large networks that may have a significant impact on reliable BES operation. This recommendation is explained in detail in the following section, as well as in Appendix 3.

5.4 Further Considerations for Limits on the Size of Local Networks

In determining the connected MVA bright-line value for the size of LNs, NERC Reliability Standard EOP-004[21] Disturbance Reporting could be used as a starting value for inclusion or exclusion. Attachment 1 of EOP-004 indicates the magnitude of firm demand loss during disturbances that are of concern and require reporting to NERC. Attachment 1's relevant text is as follows:

> Equipment failures/system operational actions that result in the loss of firm system demands for more than 15 minutes, as described below:
>
> - Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.
> - All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50% of the total customers being supplied immediately prior to the incident, whichever is less.

A review of interconnection facilities serving approximately 300 MW of load determined that the system consisted of 800–900 MVA of interconnection capability to maintain the reliability of the interconnected system. This capability over the load value is usually installed for N-1 planning criteria, and support of this assumption is justified in a review of average circuit loadings on the system.

As an example, an entity with a peak load of approximately 4,500 MW calculated an average circuit loading on their system to be approximately 23.6%. Using this average circuit-loading approach determined that an additional 1,271 MVA of interconnecting MVA capacity would be required to serve 300 MW of load. Using 800 MVA for substations with interconnecting capability is a conservative estimate.

As another example, transmission lines with 400 MVA of transfer capability would calculate to the approximate values:

- 2,000 amps at 115 kV
- 1,674 amps at 138 kV

[21] NERC Reliability Standard EOP-004: http://www.nerc.com/files/EOP-004-1.pdf

- 1,434 amps at 161 kV
- 1,004 amps at 230 kV
- 670 amps at 345 kV

The selection of 400 MVA for a single-circuit bright-line test is that most system configurations do not rely on a single circuit to serve 300 MW of load, but rather use multiple, lower rated facilities. Therefore, a rating above 300 MVA would be appropriate for a single transmission line.

The PC suggests the addition of a gross load limit in the form of another qualifier under Exclusion E3:

- The gross load served by the LN is less than 300 MW.

The addition of this limit on local networks will ensure that the systems that support metropolitan areas will not be excluded by default. As with other bright lines established in the BES definition (e.g., 100 kV core definition and 20/75 MVA generator thresholds), this specific number was selected to clearly categorize networks and Elements to prevent significant adverse impacts to the BES in a way that can be applied consistently across power systems, Regions, and interconnections. The PC identified the 300 MW limit based on a preponderance of evidence presented by a cross section of regional representation that is supported by the following data points:

- U.S. Department of Energy Electric Disturbance Events form OE-417[22] and NERC Standard EOP-004 provide a bright-line criteria of 300 MW for reporting load loss.
- The typical upper limit of a radial system reported by SAMS members was approximately 100 MW. The upper limit on the maximum consequential load loss reported by SAMS members was less than 300 MW.
- Examination of 100–300 kV line ratings across the interconnections shows that the majority are rated less than 300 MW (see Table 2 and Appendix 3). Flows on transmission lines are typically a fraction of the line rating (i.e., this is an upper bound), and the system is required to tolerate the flow shifts created by a single contingency (i.e., a line outage); therefore, an LN should not have the potential to induce a greater shift in flow.

Table 2: Summary Statistics for Branches in 2010 Power Flow Models

	Mean (MW)	Median (MW)	Standard Deviation. (MW)	Maximum (MW)	Minimum(MW)	Percent of lines rated < 300 MW (%)
ERAG	266.6	216.0	181.6	1800.0	7.0	73.9
WECC	233.9	159.0	202.5	3031.1	12.0	76.1
ERCOT	289.1	228.0	144.6	1220.0	12.0	62.4

Even for zero outward power flow as allowed in the LN definition, this 300 MW load limit could entail a change in flow of up to 300 MW on the terminals of the overlying BES (i.e., a 300 MW swing between two terminals of the LN). A very simple illustration based on an actual network is provided in Appendix 3. The BES and higher voltage networks and are depicted in red, and a lower voltage network to be considered as an LN is depicted in blue.

[22] The Electric Emergency Incident and Disturbance Report (Form OE-417) collects information on electric incidents and emergencies. The Department of Energy uses the information to fulfill its overall national security and other energy emergency management responsibilities, as well as for analytical purposes. http://www.oe.netl.doe.gov/oe417.aspx

6. Recommendations

After analysis and review, the PC offers the following recommendations to the DBES SDT:

- Maintain the 100 kV bright line (core definition).
- Maintain Inclusions I2 and I4 as currently defined.
- Maintain Inclusion I5 as currently defined.
- Use Technical Alternative C, which proposes clarifying changes to the existing Exclusion E3 item (b) as given below in bold:
  - **Real** power flows only in the LN **from every point of connection to the BES for the system as planned with all-lines in service and also for first contingency conditions as per TPL-001-2, Steady State & Stability Performance Planning Events P0, P1, and P2**, and the LN does not transfer energy originating outside the LN for delivery through the LN **to the BES.**
- Establish a size limit in the LN definition to prevent the exclusion of large networks that may have a significant impact on reliable BES operation. This recommendation is explained in detail in the following section, as well as in Appendix 3.

Appendix 1A: Request from the BES SDT to the PC

From:	Heidrich, Peter
To:	"Mark Lauby"; Jeff Mitchell; "jcastle@nyiso.com"; Crisp, Ben; "bowet@pjm.com"
Cc:	"Ed Dobrowolski"; "Lawson, Barry R."
Subject:	FW: Project 2010-17 DBES Phase 2 Problem Statements - Revised
Date:	Monday, February 27, 2012 1:13:43 PM
Attachments:	bes_phase2_problem_statement_20120223_r1_clean.pdf

Dear Sir:

Additionally, the DBES SDT would like an opportunity to review the 'technical assistance project outline' for accuracy and completeness prior to presentation at the Joint OC/PC/CIPS Meeting.

Therefore, when you complete your review of the 'problem statements' and draft the outline document, please forward a draft copy of the outline to me. The SDT is prepared to conduct a timely review of the outline as not to interfere with the scheduling of the presentation to the Joint OC/PC/CIPC.

Thank you,

Peter A. Heidrich
Manager of Reliability Standards
Florida Reliability Coordinating Council
1408 N. Westshore Blvd., Suite 1002
Tampa, FL 33607-4512
813-207-7994 - office
813-787-7620 - cell
813-289-5646 - fax

FRCC
Florida Reliability Coordinating Council, Inc.

From: Heidrich, Peter
Sent: Monday, February 27, 2012 12:04 PM
To: 'Mark Lauby'; 'jeff.mitchell@rfirst.org'; 'jcastle@nyiso.com'; Crisp, Ben; 'bowet@pjm.com'
Cc: 'Ed Dobrowolski'; Lawson, Barry R.
Subject: Project 2010-17 DBES Phase 2 Problem Statements - Revised

Dear Sir:

The Project 2010-17 DBES SDT meet the week of February 20th and discussed the initial 'problem statements' provided for consideration by the leadership of the Technical Committees. Following discussion and review of the comments submitted during the initial posting of the phase 2 SAR, revisions were made to the 'problem statements'. Attached you will find the revised the 'problem statements' which include additional language speaking to potential sources of technical information (provided by industry) that the Technical Committees may consider for possible analysis.

The SDT is in no way promoting a particular type of analysis or study to be conducted. The potential sources of technical information are being forwarded to the Technical Committees to support the characteristics of 'openness' and 'transparency' advocated through the Standard Development Process.

If you are in need of any additional information or clarification surrounding the issues identified in the attached document, please do not hesitate to ask.

Thank you,

Peter A. Heidrich
Manager of Reliability Standards
Florida Reliability Coordinating Council
1408 N. Westshore Blvd., Suite 1002
Tampa, FL 33607-4512
813-207-7994 - office
813-787-7620 - cell
813-289-5646 - fax

FRCC
Florida Reliability Coordinating Council, Inc.

Appendix 1B: Authorization and Problem Statement from the BES Definition SDT (NERC Standards Project 2010-17, Phase II)

A1.1 Background:

The ERO has the obligation to identify the Elements necessary for the reliable operation of the interconnected Transmission network to ensure that the ERO, the Regional Entities, and the industry have the ability to properly identify the applicable entities and Elements subject to the NERC Reliability Standards. The NERC Board of Trustees-approved definition of the Bulk Electric System (BES) establishes detailed criteria that allows for the identification of BES Elements in a consistent manner on a continent-wide basis.

During the initial revision of the definition of the BES in Phase I of Project 2010-17, industry stakeholders expressed concerns related to the lack of technical justification associated with the existing parameters in the definition.

A1.2 Problem Statement: Transmission Facilities and Real and Reactive Resources:

The reliability of the interconnected transmission network is impacted by properly identified BES Elements. The ability to properly identify BES Elements is dependent on a BES definition that is based on factors directly associated with reliability. The NERC Board of Trustees-approved definition of the BES utilizes historical parameters from the current NERC Glossary of Terms definition of BES and the NERC Statement of Compliance Registry Criteria, neither of which is supported by technical justification.

The DBES SDT is seeking support from the NERC Technical Committees (Operating and Planning) for the development of technical justification to assist the SDT in developing potential revisions to the following parameters currently embedded in the NERC Board of Trustee approved definition of the BES:

- 100 kV bright line (core definition)
- Generation thresholds (Inclusions I2 and I4)
- MVA values associated with single-unit and multiple-unit facilities
- Reactive power sizing (MVA level) parameters (Inclusion I5)

It is anticipated that the technical justification will consider the criteria currently established within the definitions of Adequate Level of Reliability and Adverse Reliability Impact, to determine the appropriate values for the thresholds associated with the identification of Transmission Facilities and Real and Reactive Resources as BES Elements.
The SDT received the following suggestions of studies that could be utilized for these issues:

<u>100 kV Bright Line</u>

- Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion to determine 100 kV or 200 kV threshold, at pp. 11-18 (May 15, 2009)[23]
- Concept of considering Surge Impedance Loading (SIL) alongside the corresponding normal thermal ratings, whichever is less, for typical compensated/uncompensated and overhead/underground transmission lines at various kV levels. A single MVA bright line could then act to screen which subsystem Elements fall in or out of the BES definition.[24,25]

[23] http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspxID=21&Source=/Standards/Development
[24] IEEE Transactions on Power Apparatus and Systems, Vol.PAS-98, No.2 March/April 1979 pp 606-617, "Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines," as well as its referenced articles.
[25] AECI related white paper prepared for the BES Definition SDT, as well as AECI's referenced Eastern Interconnection PSEE 2011 Winter Peak Branch-data, with per-unit SIL calculations, for further analysis, available from AECI upon request.

- NPCC study presented in the NPCC/NERC 9/21/09 filing in FERC Docket No. RC09-3-000

Generation Thresholds and Reactive Power sizing

- ISO-NE and NYISO planning and operating study process to demonstrate loss of largest source without Adverse Reliability Impact to the Bulk Electric System.
- Snohomish County PUD White Paper entitled "A Performance-Based Exemption Process to Exclude Local Distribution Facilities from the Bulk Electric System" (April 2011) discusses a methodology for distinguishing BES from non-BES Elements based on their performance in the electric system.
- Project 2007-09 for proposed standard MOD-026 developed generation modeling thresholds.[26]
- Draft white paper for possible exclusion of generators from BES as submitted to the DBESSDT.

A1.3 Local Networks:

Local networks (LN) (Exclusion E3) provide local electrical distribution service and are not planned, designed, or operated to benefit or support the balance of the interconnected transmission network. Their purpose is to provide local distribution service, not to provide transfer capacity for the interconnected transmission network. Their design and operation is such that at the point of connection with the interconnected transmission network, their effect on that network is similar to that of a radial facility, particularly in that flow always moves from the BES into the LN. As governed by the fundamentals of parallel electric circuits, any distribution of parallel flows into the LN from the BES is negligible, and, more importantly, is overcome by the Load served by the LN, thereby ensuring that the net actual power flow direction will always be into the LN at all interface points. An LN is not intended to enhance the operability of the interconnected transmission network; therefore, its separation from the BES will not diminish the reliability of the interconnected transmission network.

The NERC Board of Trustees-approved definition of the BES identifies the characteristics, based on the bright-line concept, which establishes specific criteria that must be met to allow an LN to be excluded from the BES. One such characteristic identifies the threshold associated with power flows and states:

> *Power flows only into the LN, and the LN does not transfer energy originating outside the LN for delivery through the LN.*

This requirement assumes that the condition (power flows only into the LN) will have to be met at each connection point of the LN. The SDT is seeking support from the NERC Technical Committees (Operating and Planning) for the development of technical justification to potentially revise the power flow provision (including duration and system conditions) identified in Exclusion E3 of the NERC Board of Trustees-approved definition of the BES.

It is anticipated that the technical justification will consist of interconnection-wide studies that target the surrounding BES Elements at the connection points of the subject LN. The studies would utilize the criteria currently established within the definitions of Adequate Level of Reliability and Adverse Reliability Impact to determine the appropriate values for the thresholds associated with the potential power flow out of the LN. The final analysis should indicate the amount of acceptable parallel flow through an LN where a loss of the LN or portions of the LN would not result in a reduction of the reliability of the surrounding interconnected transmission network.

[26] http://www.nerc.com/files/Project_2007-09_Generator_Verfication_PRC-024_and%20MOD-026.pdf

Appendix 1C: BES SDT Response to PC Report (Draft 2012 BES definition report)

From: Heidrich, Peter [mailto:pheidrich@frcc.com]
Sent: Friday, January 25, 2013 4:48 PM
To: Dave Nevius; jeff.mitchell@rfirst.org; Crisp, Ben; John Moura
Cc: Ordax, Vince; dbessdt@nerc.com
Subject: BES SDT Response to PC Report (2012 BES Definition Report)

Gentlemen,

Following the receipt of the preliminary report titled *2012 BES Definition Report* drafted by the NERC Planning Committee (PC) in response to the Project 2010-17 Definition of Bulk Electric System Standard Drafting Team's (BES SDT) request for a technical evaluation of the thresholds contained in the Phase 1 BES definition, a sub-team was established under the BES SDT to investigate potential alternative conclusions, based on the draft PC report and recommendations in regards to the generator thresholds (20 & 75 MVA) currently embedded in the BES definition.

The conclusions of the sub-team are documented in the attached report titled: *Generation Threshold Sub-Team Report, January 2013*. Prior to the final approval of the PC report, the BES SDT is requesting that the PC, and specifically the Reliability Assessment Subcommittee (RAS), evaluate the conclusions drawn by the sub-team for potential reconsideration of the recommendations associated with this issue. To facilitate an open and transparent discussion, the BES SDT is extending an invitation to the RAS to participate on a conference call to discuss these issues during their February meeting.

Pending a resolution, the BES SDT requests deferring the PC approval of the *2012 BES Definition Report* until the regularly scheduled March meeting of the full committee. This will allow any potential revisions drafted by the RAS to be incorporated into the final report and then fully vetted by the entire PC for delivery to the BES SDT in mid-March. The BES SDT acknowledges that this will result in a delay of delivery of the final report and the BES SDT accepts that delay.

Thank you,

Peter A. Heidrich
Chair, Bulk Electric System Definition SDT

Manager of Reliability Standards
Florida Reliability Coordinating Council
1408 N. Westshore Blvd., Suite 1002
Tampa, FL 33607-4512
813-207-7994 - office
813-787-7620 - cell
813-289-5646 - fax

Note: The report, *Generation Threshold Sub-Team Report, January 2013*, is not publically posted at this time.

Appendix 2: Interconnection Study Guidelines

A2.1 Eastern Interconnection Study

In the Eastern Interconnection (EI), ERAG annually develops power flow models of the bulk transmission system and performs inter-regional transmission assessment studies on some of those models. The power flow models incorporate varying specificity in the different transmission voltage levels, but most (if not all) of the facilities at 100 kV and above are included.

Since its inception, ERAG has traditionally studied the transmission systems in MRO, RFC, SERC, and SPP at 100 kV and above, because those facilities are inherently necessary to operate the Bulk Electric System. The 100–200 kV facilities are necessary to the operation of the Bulk Electric System, because they are the substantial underlying portions (i.e., voltages under 230, 345, 500, and 765 kV) of the rest of the BES, they carry significant portions of bulk power transfers, and they provide a backup transfer path when higher voltage facilities (i.e., 230, 345, 500, and 765 kV) are out of service.

Without including the 100–200 kV facilities in the BES, the higher voltage (i.e. 230, 345, 500, and 765 kV) facilities would not be able to solely, reliably carry the needed power to load without experiencing overloads, low voltages, SOLs, and possibly IROLs, as seen in previous ERAG studies and reports.

A2.1.1 Generation

The 100–200 kV level of transmission facilities is important for the interconnection of generation. Nearly a third of the total generation in the Eastern Interconnection is connected to the 100–200 kV level.

Table A2-1: Total Generation in Eastern Interconnection[27]

Total Generation in EI	884,519 MW	% of Total
Above 200 kV	565,929	64.0%
100–200 kV	249,833	28.2%
69 kV	25,472	2.9%
Below 69 kV	43,285	4.9%

A2.1.2 Load

The 100–200 kV level of transmission facilities is critical for generation to be delivered to load. Nearly a quarter of the load in the Eastern Interconnection is connected to the 100–200 kV level.

Table A2-2: Total Load in Eastern Interconnection[28]

Total Load in EI	645,556 MW	% of Total
Above 200 kV	53,302	32.8%
100–200 kV	147,076	22.8%
69 kV	111,909	17.3%
Below 69 kV	174,855	27.1%

[27] Data is from the ERAG 2012 Summer Peak case within the MMWG 2011 Series of power flow models.

[28] Data is from the 2012 Summer Peak case within the MMWG 2011 Series of power flow models. Generating plant auxiliary loads are included, if modeled.

A2.1.3 Transmission Line Mileage

The BES definition should include most of the transmission that is important to deliver generation to load. A majority of the total BES transmission line mileage is made up of 100–200 kV facilities. The total transmission miles that falls in the 100–200 kV range is 67% of the total miles. Mileage data for the tables below was taken from the 2011 NERC Long-Term Reliability Assessment data submittals.

Table A2-3: Transmission Circuit Line Mileage in Eastern Interconnection

Area	100-120 kV	121-150 kV	151-199 kV	Total	Area	100-199 kV %
FRCC	2,251	2,277	0	4,528	FRCC	38%
MISO	7,606	19,071	5,778	32,456	MISO	66%
MRO	5,428	3,670	264	9,362	MRO	44%
NPCC[29]	19,439	3,527	138	23,104	NPCC	52%
PJM	4,911	23,120	395	28,426	PJM	54%
SERC	35,427	4,095	17,263	56,785	SERC	67%
SPP	9,082	8,729	4,801	22,612	SPP	69%

Table A2-4: Transmission Circuit Line Mileage in Eastern Interconnection

Area	200-299 kV	300-399 kV	400-599 kV	600 kV+	Total
FRCC	6,095	0	1,350	0	7,445
MISO	3,022	13,117	340	0	16,479
MRO	9,801	2,041	257	0	12,099
NPCC[30]	11,759	8,145	1,600	160	21,664
PJM	9,148	9,417	3,816	2,206	24,587
SERC	18,383	1,577	7,473	0	27,433
SPP	3,572	6,559	114	0	10,245

A2.1.4 Transmission Assessment Study Results

Data for the tables below was taken from the ERAG summer seasonal studies listed in Tables A2-5 and A2-6. Many of the limited facilities for the studied transfers are on the 100–200 kV level, which indicates that the 100–200 kV facilities are inherent to the reliable operation of the BES.

Table A2-5: Limiting Elements in 2007 Study

	Limiting Element					Contingency	
2007 Study	Total	100-199 kV	Percentage	200+ kV	Percentage	100-199 kV	200+ kV
MRSwS	18	17	94.4	1	5.6	4	13
SeR	8	4	50.0	4	50.0	4	6
RN	7	2	28.6	5	71.4	0	0
RFC	76	44	57.9	32	42.1	28	47

[29] Quebec Interconnection (QI) is excluded. The total of NPCC when adding QI is the following: 100–120 kV: 23,731; 121–150 kV: 3,527; 151–199 kV: 1,460; Total: 28,718; 100–199 kV %: 45%

[30] Quebec Interconnection (QI) is excluded. The total of NPCC when adding QI is the following: 200–299 kV: 13,733; 300–399 kV: 11,494; 400–599 kV: 2,357; 600 kV+: 7,257; Total: 34,842

Table A2-6: Limiting Elements in 2011 Study							
	Limiting Element					Contingency	
2011 Study	Total	100–199 kV	Percentage	200+ kV	Percentage	100–199 kV	200+ kV
MRSwS	19	14	73.7	5	26.3	9	13
SeR	6	3	50.0	5	50.0	4	3
RN	2	1	50.0	1	50.0	0	2
RFC	16	6	37.5	10	62.5	6	8

A2.2 Québec Interconnection

The Bulk Power System (BPS) in the Quebec Interconnection includes substations that have a 735 kV voltage level with their connected lines and transformers. These facilities do not directly serve end-use customers. They constitute the transmission system and provide interfaces for moving large amounts of power from remote northern generation to load centers in southern Québec (approximately 600 miles away). BPS assets have been identified through impact-based studies, using the NPCC A-10 methodology. The Régie de l'énergie of Québec provides the regulatory oversight within the Province of Québec, which includes the definition of the BPS and BES.

A2.3 Electric Reliability Council of Texas (ERCOT)

In ERCOT Interconnection, the Steady State Working Group (SSWG) annually develops power flow models of the transmission system, and ERCOT staff, various ERCOT work groups, and market participants perform transmission assessment studies on these models. The power flow models incorporate almost all utility transmission facilities operated at 60 kV and above.

ERCOT is the smallest of the three interconnections in the United States[31] and operates wholly within Texas. As the independent organization (IO) under the Public Utility Regulatory Act (PURA), ERCOT is charged with nondiscriminatory coordination of market transactions, system-wide transmission planning, network reliability, and ensuring the reliability and adequacy of the regional electric network in accordance with ERCOT and NERC reliability criteria. ERCOT's relatively small size and unique market structure allows it to model almost all utility transmission facilities operated at 60 kV and above.

A2.3.1 Generation

The 100–200 kV level of transmission facilities is important for ERCOT since 44% of all generation is connected at 138 kV. Almost 99% of all the generation in ERCOT is connected at voltages above 100 kV.

Table A2-7: Total Generation in ERCOT[32]		
Total Generation in ERCOT	74,948 MW	% of Total
345 kV	41,053 MW	54.8%
138 kV	33,042 MW	44.1%
69 kV	853 MW	1.1%

A2.2.2 Load

The 100–200 kV level of transmission facilities is critical for the deliverability of generation to load. The amount of load in ERCOT connected at 138kV is 86%.

Table A2-8: Total Load in ERCOT[33]		
Total Load in ERCOT	73,387 MW	% of Total
345 kV	987 MW	1.3%
138 kV	63,097 MW	86.0%

[31] Considering Installed Capacity, the Québec Interconnection in Canada is smaller than ERCOT.

[32] Data is the level of dispatched generation from the SSWG 2012 Summer Peak case within the SSWG 2011 Series of power flow models.

[33] Data is from the 2012 Summer Peak case within the SSWG 2011 Series of power flow models.

69 kV	9,304 MW	12.7%

A2.3.3 Transmission Line Mileage

The total transmission line miles in ERCOT that falls in the 100–200 kV range is 58%, and over three quarters of the line miles operate at voltages above 100 kV. Over 22% of the physical transmission line miles in ERCOT operate at 69 kV.

However, ERCOT's 69 KV transmission lines are predominantly in rural areas and serve small electric loads and wind plants that are dispersed over a large geographic region. As shown in the tables above, the 69 kV system in ERCOT serves approximately 1% of the electric load and 13% of the generation in ERCOT. The loss of the small, lightly loaded 69 kV lines spread over a large geographic region in ERCOT do not pose a threat to the Bulk Electric System.

Table A2-9: Total Transmission Line Miles in ERCOT

Total Line Miles in ERCOT	Miles	% of Total
345 kV	9,498	18.8%
230 kV	13	0.1%
138 kV	29,349	58.3%
69 kV	11,460	22.8%

A2.3.5 Transmission Assessment Study Results

ERCOT Staff supervises and exercises comprehensive independent authority of the overall planning of transmission projects in the ERCOT Interconnection (transmission system) as outlined in PURA and Public Utility Commission of Texas (PUCT) Substantive Rules. ERCOT's authority with respect to local transmission projects is limited to supervising and coordinating the planning activities of Transmission and Distribution Service Providers. In performing its evaluation of different transmission projects, ERCOT takes into consideration the need for and cost-effectiveness of proposed transmission projects in meeting the ERCOT and NERC planning criteria. Therefore, ERCOT studies regularly identify constraints at 69 kV even though the facilities are not needed for the reliable operation of the BES.

A2.4 Western Interconnection

All facilities that have an impact on the BES should be included in the definition of the BES. The BES definition should be easy to understand and administer. BES classification should not be a moving target. For reliability, a more inclusive definition of the BES is desirable, rather than potentially omitting a facility that in a time of need may be necessary to support the BES.

For the purposes of this paper, WECC base cases have been utilized. The individual Transmission Planner's data submittals determined the level of detail in WECC base cases. The WECC Data Preparation Manual states that Transmission Planners should represent their systems in sufficient detail such that the impact of any disturbances, whether internal or external to their own systems, can be adequately evaluated. The level of detail represented by the Transmission Planners should be the same as that used by individual Transmission Planners in conducting their internal bulk transmission system studies or facility ratings studies.

WECC respects Transmission Planners' judgment and strongly considers it in the development of WECC base cases. Through an analysis of WECC base cases it can be seen that Transmission Planners in WECC model a majority of the load and generation connected to 100 kV and above. The inclusion of data in base cases indicates that this is the level of detail needed to model the BES for power flow and stability studies.

A2.4.1 Generation

In WECC, over 80% of the generation modeled in base cases is primarily connected through generator step-up transformers with high-side voltages of 100 kV and above. The table below shows that the largest portion of the generation modeled in WECC (40%) connects between 200 and 300 kV. Total generation in WECC maintains the currently filed 100 kV bright-line threshold without adjustment.

Table A2-10: Total Generation in WECC[34]		
Total Generation in WECC	**245,737 MVA**	**% of Total**
300 kV and Greater	61,274 MVA	24.93
200 to 300 kV	98,717 MVA	40.17
100 to 200 kV	42,553 MVA	17.32
50 to 100 kV	17,501 MVA	7.13
Less than 50 kV	25,692 MVA	10.45

A2.4.2 Load

The WECC base cases model load at various voltages. The table below shows that the vast majority of load is modeled below 200 kV, with a large portion modeled between 50 and 100 kV.

Table A2-11: Total Load in WECC[35]		
Total Load in WECC	**172,750 MW**	**% of Total**
300 kV and Greater	15 MW	0.01
200 to 300 kV	16,257 MW	9.41
100 to 200 kV	63,963 MW	37.03
50 to 100 kV	58,749 MW	34.00
Less than 50 kV	33,766 MW	19.55

A2.4.3 Transmission Line Mileage

The definition of the BES should include the transmission that is critical for delivering generation to load. Of the transmission line miles collected, over 40% of the total in WECC falls in the 100–200 kV range.

Table A2-111: Transmission Line Miles by Voltage Class[36]				
Line Voltage kV	**100- 199**	**200-299**	**300-399**	**400-599**
WECC (miles)	50,306	42,336	11,637	20,262

A2.4.4 Transmission Assessment Study Results

In WECC, path limits are primarily established through the WECC Rating Review Process. Path limits are set based upon transient and post-transient stability limits, as well as thermal limits. A review of paths that went through this process indicates that, although most paths are limited by 345 kV and 500 kV Elements, instances exist where the transfer capability limits are determined by facilities between 100 kV and 200 kV.

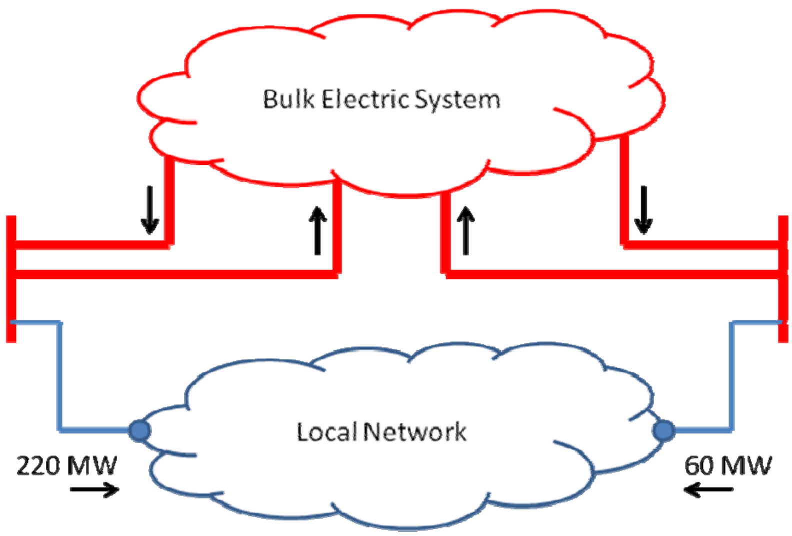
[34] Note: Data is the generation available in the WECC 2012 Heavy Summer operating case within the WECC 2011 series of power flow models.
[35] Data is the load forecasted in the WECC 2012 Heavy Summer operating case within the WECC 2011 series of power flow models.
[36] Data is from the 2011 Long Term Reliability Data Collection. No data collected for transmission facilities below 100 kV

Appendix 3: Operational Considerations to Support Load Limit on Local Networks

The SAMS proposes to set a 300 MW maximum limit for the amount of load that may be served by a proposed local network (LN). This limit is proposed to ensure that LNs do not affect the reliable operation of the BES.

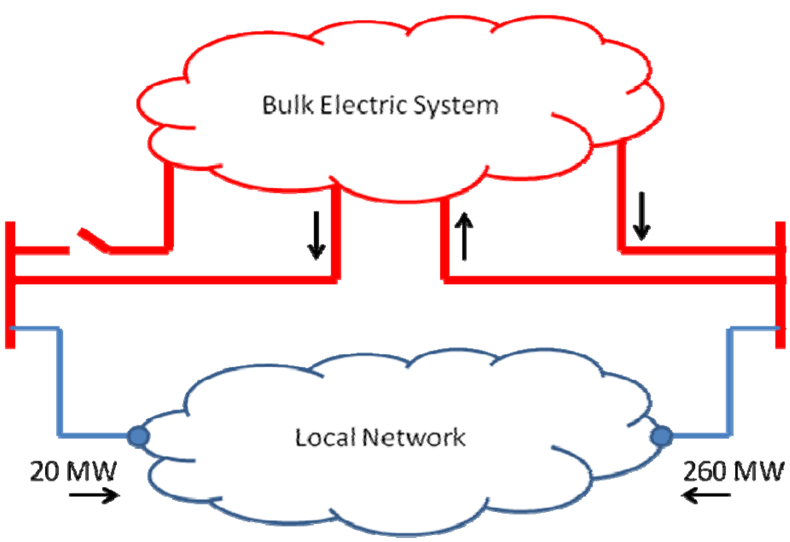
As represented in the figure below, under normal operating conditions, a two-terminal LN receives 220 MW on its western terminal and 60 MW on its eastern terminal (Figure A3-1).

Figure A3-1: Bulk Electric System Flow through Local Network



For a single BES contingency, the flow into the LN shifts from west to east by 200 MW, so that the LN now receives 20 MW on its western terminal and 260 MW on its eastern terminal (Figure A3-2).

Figure A3-2: Bulk Electric System Flow through Local Network

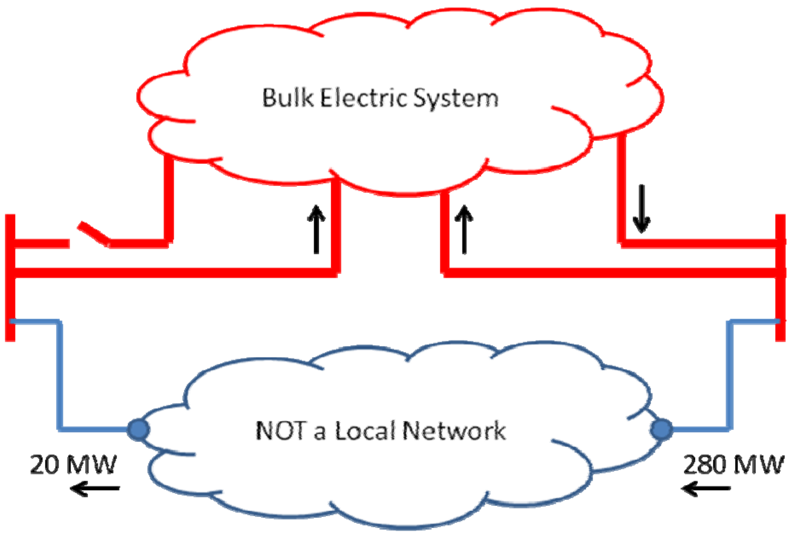


The 200 MW shift would be reflected in the BES and would be picked up by one of the BES transmission lines on the eastern side of the system; this change could represent a substantial increase in load for the affected line.

If a gross load limit were not placed on the size of the LN, then such a shift could be much larger, and the resulting impact to the BES could be significant. In a similar vein, consideration also may need to be given to limiting the size of a radial system (identified in Exclusion E1) since the total loss of load in the radial system could have a similarly significant impact to the BES depending on its location in the system.

Now consider the same system, but because of conditions within what was previously considered an LN (for example, non-BES generation dispatch and shifting load), the power now flows through the lower voltage system (Figure A3-3).

Figure A3-3: Bulk Electric System Flow through Local Network



In this case, the lower voltage system is not an LN since it is supporting flow through to the BES.

The 300 MW bright line is further supported by the following operational considerations:

1. Primary frequency response initially will be provided by the responding generating units in an interconnection. The industry-approved draft of the BAL-003-1 standard proposes that at least 1,700 MW of support will be provided within the smallest interconnection by primary frequency response controls.[37] This provides 5.7 times the resource margin needed to stabilize an interconnection for a 300 MW loss or gain in LN load. The interconnections recover from losses of generation in this MW range on a regular basis.

2. The requirements of the existing BAL-002-1 Disturbance Control Standard. Requirement R3 of the standard states, "[a]s a minimum, the Balancing Authority or Reserve Sharing Group (RSG) shall carry at least enough Contingency Reserve to cover the most severe single contingency." Requirement R4.2 states that recovery shall occur within 15 minutes of the start of a Reportable Disturbance.[38] Since the most severe single contingency in a Balancing Authority or RSG is typically a nuclear generating unit, the requirements of BAL-002-1 would provide from 2.5 to 3 times the resource margin needed to support a 300 MW LN.[39,40] This is supported by the fact that 89% of Balancing Authorities are part of an RSG. All RSGs were identified as carrying a minimum Contingency Reserve of 750 MW, which provides the resource margin stated above. Seven of the eight remaining Balancing Authorities that have

[37] NERC Website (2012, October 30). BAL-003-1 Attachment A. Retrieved from http://www.nerc.com/docs/standards/sar/Attachment_A_Frequency_Response_Standard_Supporting_Document_Clean_rev1.pdf

[38] A Reportable Disturbance is an event that causes an ACE change greater than or equal to 80% of the most severe single contingency of a Balancing Authority or RSG.

[39] The available resource margin was based on the average net electrical output of a nuclear generating unit, which was calculated to be 980 MW from the reactor data posted on the U.S. Nuclear Regulatory Commission Website (9/14/2012). List of Power Reactor Units. Retrieved from http://www.nrc.gov/reactors/operating/list-power-reactor-units.html.

[40] Resource margin was calculated by dividing the contingency reserve used to meet the most severe single contingency (980 MW-net) by the proposed LN limit of 300 MW. This margin differs from a planning reserve margin.

load and do not participate in an RSG carry over 300 MW of Contingency Reserves and would also be supported by surrounding entities as required by TOP-004-2, Requirement R6. The surrounding entities' AGC systems would also help balance real and reactive power needs. The eighth entity has 100 MW of load and a contingency reserve of at least 220 MW; no real and reactive power balancing issues are anticipated for this entity.

3. The ability of a Balancing Authority or Reserve Sharing Group to adjust real power resources to account for a 300 MW loss or gain in load. The 2012 estimated peak demands of Balancing Authorities average between 6,000 MW and 10,000 MW.[41,42] Therefore, a 300 MW LN represents approximately 3% to 5% of the average estimated peak demand of a Balancing Authority. Since the generating resources that supply the demand are able to adjust power output by ±2% per minute on AGC, a 300 MW loss or gain in LN load could be mitigated within the 15-minute recovery period allowed for a disturbance.[43,44]

Given the balancing capabilities identified in points 1 and 2 above and the fact that LNs are not intended for bulk power transfer, their disconnection from the BES should not affect reliability when limited to 300 MW.

Since LNs are not intended for bulk power transfer, their disconnection from the BES should not affect reliability when limited to 300 MW, given the balancing capabilities identified in points 1 and 2 above.

NOTE: The TPL transmission system planning standards require that projected customer demands and projected Firm (non-recallable reserved) Transmission Services are supplied at all demand levels (as applicable). The proposed standard TPL-001-2 further clarifies that system peak and off-peak load be modeled in the Near-Term Transmission Planning Horizon. Therefore, firm loads cannot be excluded from the planning process even if they are located within an LN.

[41] Based on whether the estimated peak demands (MW) of the largest ISOs/RTOs are included.

[42] Estimated peak demand (MW) data obtained from NERC Website (2012). 2012 CPS2 Blounds. Retrieved from http://www.nerc.com/docs/oc/rs/2012%20CPS2%20Bounds%20Report%20Final(Update20120821).pdf

[43] Kirby, Brendan & Hirst, Eric (1996, December 16). Generator response to intrahour load fluctuations. IEEE Transactions on Power Systems, 13(4), 1373-1378. Retrieved from http://www.consultkirby.com/files/PE627.pdf

[44] The paper referenced in footnote 7 states that hydro units can respond at 50% to 100% of their output per minute, combustion turbines at 10% to 20% of their output per minute, and coal powered units at 1% to 3% of their output per minute. The above information regarding thermal and hydro generating units is also supported by the following book: Kundur, P. (1994). Control of Active Power and Reactive Power, *Power system stability and control* (p. 618). New York, NY: McGraw-Hill, Inc.
An entity with 9,000 MW of generation is considered in this paper (the entity is within the average demand range of the Balancing Authorities considered herein).

BES Radial Exclusion
Low Voltage Level Criteria

Jonathan Sykes

Pacific Gas and Electric Co.

BES Definition SDT

SLC May 23, 2013

Problem Statement

To satisfy FERC Order 773-A, additional factors beyond impedance must be considered to demonstrate that looped or networked connections operating below 100 kV should not be considered in the evaluation of Exclusion E1.

FERC Order 773/773a

FERC Order 773-A

Page 20, Paragraph 28...In the Final Rule, the Commission held that radial systems with elements operating at 100 kV or higher in a configuration that emanate from two or more points of connection cannot be deemed "radial" if the configuration remains contiguous through elements that are operated below 100 kV.

FERC Order 773

Page 95, Footnote 139…this footnote provides some parameters for the SDT to consider as a technical justification to include some low voltage loops (typical of distribution feeders) under the E1 exclusion:

- Voltage
- Impedance
- Proximity
- Length of Conductor
- Interconnected Transmission System

Procedure

3 Step Process

- Review the regional voltage levels that are monitored on major interfaces, paths, and monitored elements in the operation of the various interconnections
- Study the physics of the loop flows through the low voltage loops (typical for distribution feeders) and determine various situations from worst case to practical situations
- Review design considerations that the industry uses to prevent loop flow through low voltage loops

1 - Regional Criteria

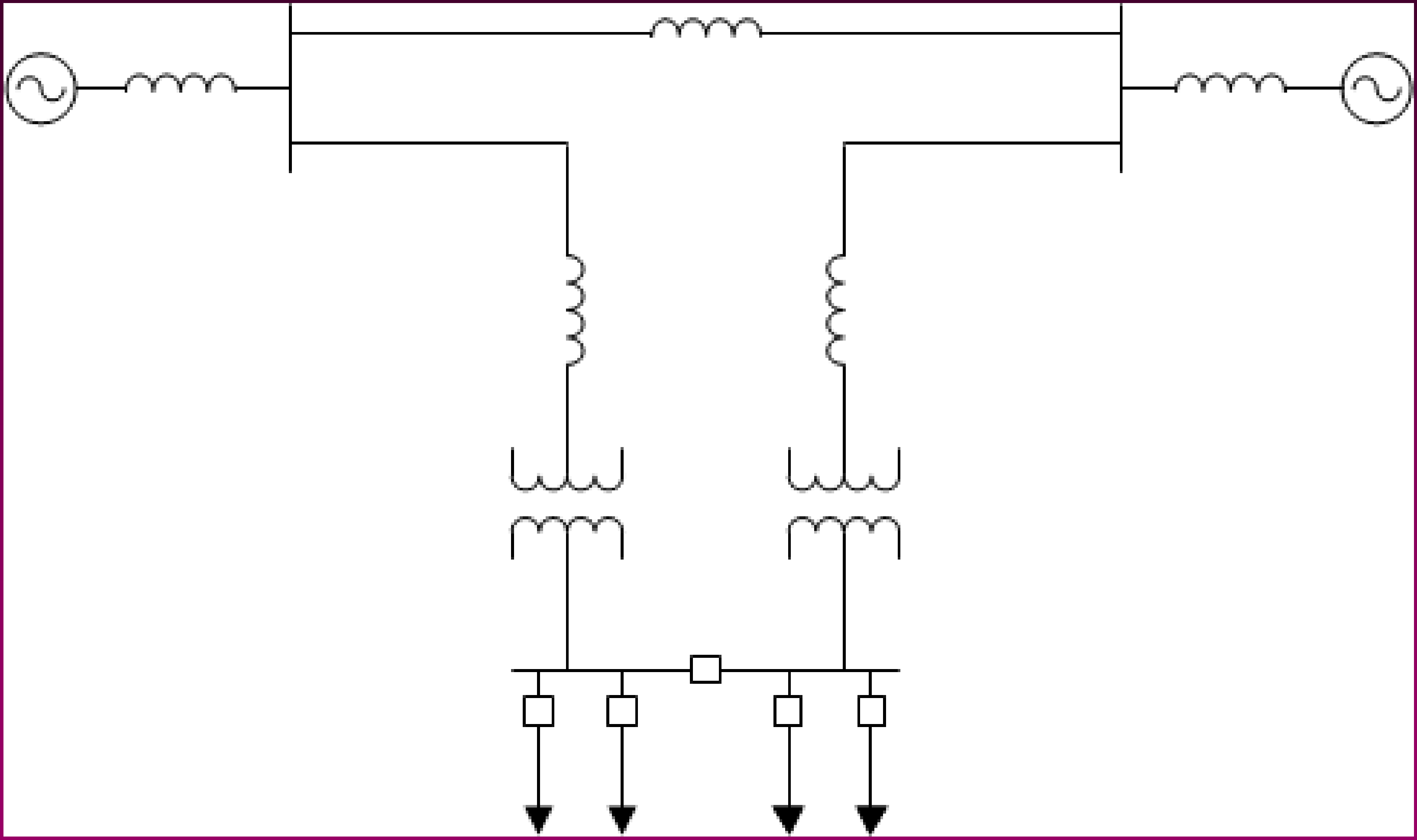
- WECC Minimum Voltage Levels
  - Paths, SOLs, modeling
- Eastern Interconnection Voltage Levels
  - Defined Interfaces, SOLs, IROLs, modeling
- ERCOT
  - Monitored Elements, SOLs, IROLs, modeling
- Sub-transmission Voltage Levels

2 – Loop Flow

- Study the physics of low voltage loop flow
- Worst case scenarios
- Loop flow across low side bus
- Loop flow across low side lines
- % of high side flow transferred to low side for N-1
- Low voltage loop flow based on typical conductor ratings.

2 – Loop Flow

- Parametric study



3 – Design Considerations

- Owners and operators design to prevent low voltage loop flow
- Protection and control schemes
- Interlocking schemes/reverse power
- Supply continuity considerations

Voltage Considerations

- 55 kV
- 44 kV
- 34.5 kV
- 22 kV
- 12 kV
- 4 kV

Chose 30 kV as a bright-line

based on initial discussions by sub-team; more discussion and analysis is needed.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

E-mail completed form to:
SARCOMM@nerc.net

Standards Authorization Request

Form

Title of Proposed Standard definition	NERC Glossary of Terms - Phase 2: Revision of the Bulk Electric System
Request Date	December 2, 2011

SAR Requester Information	SAR Type (Check all that apply)	
Name: Project 2010-17 Definition of Bulk Electric System (BES) SDT	☐	New Standard
Primary Contact: Peter Heidrich (Manager of Reliability Standards, FRCC) , Project 2010-17 Definition of Bulk Electric System (BES) SDT Chair	X	Revision to existing Standard
Telephone: (813) 207-7994 Fax: (813) 289-5646	☐	Withdrawal of existing Standard
E-mail: pheidrich@frcc.com	☐	Urgent Action

SAR Information
Industry Need (What is the industry problem this request is trying to solve?)
This project supports the ERO's obligation to identify the Elements necessary for the reliable operation of the interconnected transmission network to ensure that the ERO, the Regional Entities, and the industry have the ability to properly identify the applicable entities and Elements subject to the NERC Reliability Standards.
Purpose or Goal (How does this request propose to address the problem described above?)
Research possible revisions to the definition of BES (Phase 2) to address the issues identified through Project 2010-17 Definition of Bulk Electric System (BES) (Phase 1). The definition encompasses all Elements necessary for the reliable operation of the interconnected transmission network. The definition development may include other improvements to the definition as deemed appropriate by

SAR Information
the drafting team, with the consensus of stakeholders, consistent with establishing a high quality and technically sound definition of the Bulk Electric System (BES).
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?)
Revise the BES definition to identify the appropriate electrical components necessary for the reliable operation of the interconnected transmission network.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
Collect and analyze information needed to support revisions to the definition of Bulk Electric System (BES) developed in Phase 1 of this project to provide a technically justifiable definition that identifies the appropriate electrical components necessary for the reliable operation of the interconnected transmission network. The definition development may include other improvements to the definition as deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing a high quality and technically sound definition of the BES.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Collect and analyze information needed to support revisions to the definition of BES developed in Phase 1 of this project to provide a technically justifiable definition that identifies the appropriate electrical components necessary for the reliable operation of the interconnected transmission network. The definition development will include an analysis of the following issues which were identified during the development of Phase 1 of Project 2010-17 Definition of the BES. Clarification of these issues will appropriately define which Elements are necessary for the reliable operation of the interconnected transmission network. • Develop a technical justification to set the appropriate threshold for Real and Reactive Resources necessary for the reliable operation of the Bulk Electric System (BES) • The NERC Board of Trustees approved BES Phase 1 definition does not encompass a contiguous BES - Determine if there is a need to change this position • Determine if there is a technical justification to revise the current 100 kV bright-line voltage level • Determine if there is a technical justification to support allowing power flow out of the local

SAR Information
network under certain conditions and if so, what the maximum allowable flow and duration should be Provide improved clarity to the following: • The relationship between the BES definition and the ERO Statement of Compliance Registry Criteria established in FERC Order 693 • The use of the term "non-retail generation" • The language for Inclusion I4 on dispersed power resources • The appropriate 'points of demarcation' between Transmission, Generation, and Distribution Phase 2 of the definition development may include other improvements to the definition as deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing a high quality and technically justifiable definition of the BES. Based on the potential revisions to the definition of the BES and an analysis of the application of, and the results from, the exception process, the drafting team will review and if necessary propose revisions to the 'Technical Principles' associated with the Rules of Procedure Exception Process to ensure consistency in the application of the definition and the exception process.

Reliability Functions

The Standard will Apply to the Following Functions (Check box for each one that applies.)		
This section is not applicable as the SAR is for a definition which is about Elements, Applicability of entities is covered in Section 4 of each Reliability Standard.		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.

The Standard will Apply to the Following Functions (Check box for each one that applies.)		
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.

The Standard will Apply to the Following Functions (Check box for each one that applies.)		
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles (Check box for all that apply.)	
X	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
X	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
X	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
X	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
X	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Applicable Reliability Principles (Check box for all that apply.)
Does the proposed Standard comply with all of the following Market Interface Principles? (Select 'yes' or 'no' from the drop-down box.)
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Standards Authorization Request Form

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	NERC Glossary of Terms - Phase 2: Revision of the Bulk Electric System definition (This is a supplement to the original SAR for this project which was approved by the Standards Committee on April 12, 2012.)		
Date Submitted:	January 16, 2013		
SAR Requester Information			
Name:	Peter Heidrich		
Organization:	FRCC and Chair of the Definition of Bulk Electric System Standards Drafting Team		
Telephone:	1.813.207.7994	E-mail:	pheidrich@frcc.com
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
X Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Address the directives in FERC Order 773 issued December 20, 2012.
Purpose or Goal (How does this request propose to address the problem described above?):
Address the directives in FERC Order 773 issued December 20, 2012.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
Address the directives in FERC Order 773 issued December 20, 2012.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
Address the directives in FERC Order 773 issued December 20, 2012.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Address the directives in FERC Order 773 issued December 20, 2012.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
This section is not applicable as the SAR is for a definition which is about Elements. Applicability of entities is covered in Section 4 of each Reliability Standard.	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service	Administers the transmission tariff and provides transmission services

Reliability Functions		
	Provider	under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
X	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
X	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
X	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
X	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.

Reliability and Market Interface Principles	
X	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Y
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Y
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Y
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Y

Related Standards	
Standard No.	Explanation
N/A	N/A

Related SARs	
SAR ID	Explanation
Project 2010-17: NERC Glossary of Terms - Phase 2: Revision of the Bulk Electric System definition	This is the original SAR for the BES definition project – Phase 2. This SAR is a supplement to the original SAR.

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A

Regional Variances	
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

Standards Announcement

Project 2010-17 Definition of the Bulk Electric System Phase 2 | Draft 1

Formal Comment Period: May 29, 2013 – July 12, 2013
Ballot Pool Forming Now: May 29, 2013 – June 27, 2013

Upcoming – Initial Ballot: July 3-12, 2013

Now Available

A formal comment period for Phase 2 of the Definition of the Bulk Electric System (DBES) is open through **8 p.m. Eastern on Friday, July 12, 2013.** A ballot pool is being formed and the ballot pool window is open through **8 a.m. Eastern on Thursday, June 27, 2013** (*please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly*).

Special note concerning Phase 1 DBES implementation and relationship to Phase 2: Although NERC is prepared to implement the Phase 1 definition on July 1, 2013 as planned, on May 23, 2013 NERC filed a Motion For an Extension Of Time, asking FERC to grant an extension of the effective date of the Phase 1 definition of Bulk Electric System, from July 1, 2013 to July 1, 2014, in order to alleviate regulatory uncertainty. If the extension is granted, the implementation plan for Phase 1 would also be extended based on the extension of the effective date. FERC approved the Phase 1 definition of BES in Order No. 773, but also directed changes. These changes, along with work previously assigned to the drafting team for Phase 2, are being implemented through the standards development process during Phase 2 of this project.

Background information for this project can be found on the project page.

Instructions for Joining Ballot Pool(s)

Registered Ballot Body members must join the ballot pool to be eligible to vote in the balloting of the DBES - Phase 2. Registered Ballot Body members may join the ballot pool at the following page: Join Ballot Pool

During the pre-ballot window, members of the ballot pool may communicate with one another by using the “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.)

The ballot pool list server for this ballot pool is: bp-2013 Project 2010-17@nerc.com

The ballot pool is open **through 8 a.m. Eastern on Thursday, June 27, 2013**.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Friday, July 12, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An initial ballot will be conducted July 3, 2013 through 8 p.m. ET Friday, July 12, 2013.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2010-17 Definition of Bulk Electric System Phase 2 | Draft 1

Ballot now open through 8 p.m. Eastern July 12, 2013

Now Available

A ballot for Phase 2 of the Definition of Bulk Electric System (DBES) is open through **8 p.m. Eastern on Friday, July 12, 2013**.

Special note concerning Phase 1 DBES implementation and relationship to Phase 2: Although NERC was prepared to implement the Phase 1 definition on July 1, 2013 as planned, on May 23, 2013 NERC filed a Motion For an Extension Of Time, asking FERC to grant an extension of the effective date of the Phase 1 definition of Bulk Electric System, from July 1, 2013 to July 1, 2014, in order to alleviate regulatory uncertainty. On June 13, 2013, FERC issued an order granting the requested extension. In the order, FERC provided the following information:

> *…the Commission expects NERC to file the changes to comply with the Order Nos. 773 and 773-A directives in sufficient time to allow the Commission to process NERC's proposal in response to the directives well in advance of the July 1, 2014 effective date. Therefore, NERC should submit a filing that includes proposed modifications to comply with the directives pertaining to exclusions E1 and E3 as soon as possible prior to December 31, 2013. Any delay in the submission of a filing that addresses the responsive modifications could impede the Commission's ability to act on the directives prior to July 1, 2014. The Commission does not anticipate granting any further extensions of the effective date beyond July 1, 2014.*

Background information for this project can be found on the project page.

Instructions

Members of the ballot pool associated with this project may log in and submit their vote for the definition by clicking here.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the definition. If the comments do not show the need for significant revisions, the definition will proceed to a final ballot.

Standards Development Process

The [Standard Processes Manual] contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Individual or group. (94 Responses)
Name (64 Responses)
Organization (64 Responses)
Group Name (30 Responses)
Lead Contact (30 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (24 Responses)
Comments (94 Responses)
Question 1 (55 Responses)
Question 1 Comments (70 Responses)
Question 2 (54 Responses)
Question 2 Comments (70 Responses)
Question 3 (58 Responses)
Question 3 Comments (70 Responses)
Question 4 (54 Responses)
Question 4 Comments (70 Responses)
Question 5 (50 Responses)
Question 5 Comments (70 Responses)
Question 6 (61 Responses)
Question 6 Comments (70 Responses)

Group
Florida Municipal Power Agency
Frank Gaffney
Agree
We support TAPS comments
Individual
ddd
ddd
Agree
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Yes
No
AECI suggests the SDT consider the following change for I2: REPLACE: “Generating resource(s)

and dispersed power producing resources," WITH: "Generating resource(s) and dispersed power producing resources connected at 100 kV and above," RATIONALE: Clarity of intent. Inclusion I2's order and new separation of wording, appears to make "the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above" stand autonomous. Because "step-up transformer" is not defined in the NERC Glossary, AECI is deeply concerned that the current wording can become twisted to instruct industry to first locate their Plants greater than 75 MVA and Units greater than 20 MVA, next locate all the transformers connecting them to the core BES at a voltage of 100 kV or above, and finally include all the wires "between," which is most all of the sub-transmission systems and including sub-sub-transmission following FERC's most recent logic. The core BES definition's "Unless modified by the lists shown below", will further support this reading and go against what the BES Phase II SDT has been assuring industry, that primarily elements 100 kV and above are part of the BES. AECI expresses this further concern for SDT consideration: With E3 now excluding I2, it appears to be in technical conflict with E2, where E3 for a potential LN but with any interior unit greater than 20 MW yet continuously consuming All interior generation and more (per E3b), cannot be excluded and yet E2 can. Why?
Yes
AECI appreciates the SDT's establishing a kV floor and yet feels that a 70kV floor could accommodate FERC's concerns, with minor additions to establish some threshold for obvious sub-network transfer-limitations between sub-network transformer terminals.
No
The SDT needs to clarify "generator terminals" due to this current definition's potential inclusion all the way down to individual PV cell's solder-pads and battery's terminals. (These technically are the first electrical access-points for where conversion takes place from other energies to electrical energy.) From a BES Reliability aspect, the worst-case contingency is total loss of the resource at its greatest aggregated entry point to the BES. Therefore AECI recommends that the SDT revert to their earlier wording. Technically, loss increments below that worst-case level, and especially for weather-sensitive solar and wind, seem no different to System Operators than derations on any large coal-fired Units. On the other hand, if the SDT's intent is to draft Standards in a manner to disincent renewable energy producers from aggregating their resources to the grid in excess of 75 MVA, then perhaps the SDT is providing the proper forcing-function here. If so, they should show equal concern for any other type of new generating units that are sized in excess of the same 75 MVA threshold.
Yes
Yes
AECI recommends for E3c: REPLACE: "Flowgate", WITH: "reliability type Flowgate", RATIONALE: The Eastern Interconnection's Book of Flowgates contains both "(Informational)" and "(Reliability)" types of Flowgates. Line-item example excerpts: "/ Type: PTDF (Informational)" -versus- "/ Type: PTDF (Reliability)". AECI believes only elements from the reliability type FGs could be of concern here.

Group
Northeast Power Coordinating Council
Guy Zito
No
The Directive was addressed by the revision, but generally Exclusion E3 does not recognize that regardless of how power gets to the load, it impacts the Bulk Electric System. The term bulk power is used in the opening sentence of E3. A definition of bulk power would lend credence and justification to E3, and the elimination of "or above 100 kV but". The new Note 2 associated with Exclusion E1 and the changes to E3 have added ambiguity that did not exist before. The base definition does not address sub 100kV contiguous loops. The existing Inclusions do not include sub 100kV contiguous loops either. Note 2 clarifies that as long as the contiguous loop is below 30kV E1 still applies. E3 explains how any sub 300kV contiguous loop could be excluded as a local area network, but there is nothing in the definition that clearly states that contiguous loops operated below 100kV are considered part of the BES unless excluded by E3. The 100kv threshold has been removed from the first sentence of E3, but it is inconsistent that the 100kV reference remains in the second part of the E3 exclusion. It is unclear what value the second sentence of the E3 exclusion provides, and its removal should be considered. Under the premise that the very first paragraph of the BES Definition already establishes the bottom voltage threshold of 100kv, we agree with removing the mention of the 100kV bottom threshold in exclusion E3. The version of exclusion E3 criterion (c) filed with FERC January 25, 2012 (RM12-6-000) requires a "Local Network" not to contain a monitored facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored facility in the ERCOT or Quebec Interconnections, and is not a monitored facility included in an Interconnection Reliability Operating Limit (IROL). The definition became more vague by changing exclusion E3 criterion (c) from "a monitored Facility of a permanent Flowgate…" to "any part of a permanent Flowgate…" and could allow for too broad a reading. The original language from Phase 1 of the BES definition regarding exclusion E3 criterion (c) provided more clarity and guidance on how to apply this exclusion. It is recommended that the original language from Phase 1 of the BES definition be reinstated. Facilities should be included in the BES only if the elements of the Facility are transferring power (flow) through a Flowgate, transfer path, or IROL. The Phase 1 BES definition was approved by NERC after positive industry acceptance providing that Phase 2 would reconsider some of the thresholds proposed in Phase 1. The important 75MVA generation threshold limit was included. The FERC requested changes now limit the possibilities for exclusion: 1) limitation on the possibility of radial exclusion because of looping below 100 kV; 2) refusal of radial or local exclusions when there is at least one generator above 20 MVA. Those limitations for exclusion go in the opposite direction to what industry expected. NERC must realize that the definition will be applied to entities not under FERC jurisdiction. It is important that NERC consult Canadian jurisdictions about the BES definition.
No

I2 does not include “non-retail” generation which is inconsistent with E1 and E3. E1b, c, and E3a contain redundant statements regarding the 75MVA generator threshold. These statements should be corrected for clarity and consistency. For Simple E1 Radial System Exclusions--The Drafting Team application of this FERC directive is clear for simple E1 Radial System Exclusions. Any tie-line connected radially to the BES and operated at 100kV or above connecting I2 or I3 generation (aggregating to more than 75MVA) is part of the BES. However, beyond this simple configuration the application of the tie-line directive is less clear. For the More Complex E1 Radial System Exclusions--More complex applications of the tie-line directive under the proposed BES Definition are less clear. Consider that Inclusion I2 states the tie-line includes “… the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above...” It could be argued that this was intended to apply to a short line or bus connection between the generator and the generator step-up unit. But in reality it could be a long connection. Regardless, a fault can occur on any length of line or bus. Application of the tie-line directive is less clear when there are multiple feeders and transformations between the generating resource and the BES which include sub-100kV operating voltages. For example, a GT with a 13.8kV output feeds local distribution. This local distribution is also served by a 69-to-13.8kV step-down transformer that is fed by a 69kV sub-transmission feeder supplied by a 138-to-69kV transformer connected to the BES by a 138kV feeder serving multiple step-down transformers to load. This Radial System has only one connection to the BES at 138kV. What facilities are covered by the tie-line directive, either the entire path from “… the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above” or only the portion of the 138kV feeder from the high-side terminals of the 138-to-69kV step-down transformer to the BES? For the E3 Local Network Exclusion--Applying the tie-line directive within a Local Network could be problematic. The proposed wording introduces issues similar to those involving Cranking Paths from Black Start units. Local Networks by the definition “emanate from multiple points of connection at 100 kV or higher.” Defining a single tie-line through the Local Network presents problems. Is the tie-line the shortest path geographically or electrically? Does the tie-line directive suggest single or multiple paths to the BES? The CIP drafting team recognized this problem and defined the path, eliminating Regional or Entity discretion and avoiding substantial ambiguity and confusion. Following the CIP Drafting Team example, suggest adding the following wording: Note 3: The BES tie-line is defined as the portion of the single shortest contiguous path operated at 100kV or above from the I2 or I3 resource to the BES. The Radial System or Local Network excluded must be defined so that it does not include a BES tie-line. Portions of the tie-line path operated below 100kV are not part of the BES. Application of this note does not extend to tie-line facilities operated below the 100kV core definition.
No
Exclusion E1 provides a floor (30 kV threshold) for which an entity does not have to consider the loop in its determination of a radial system. Due to the international nature of the ERO, consideration must be given to what the various Provinces consider to be “distribution level”, and any proposed revision should recognize this dissimilarity. In addition, in the United States various state representatives have cited jurisdictional issues associated with lowering the

threshold to 30 kV. This also impacts the 100 kV bright-line threshold definition. The 30kV threshold as currently written is too restrictive. In a similar way as 100 kV is the delineator between the medium and high system voltage classes in the American National Standards Institute (ANSI) standard on voltage ratings (C84.1), the voltage threshold in note 2 of exclusion E1 should be based on well defined standard system voltage classes to better correlate to operational and system design considerations and practices. The Exception Procedure could be used to include lower (than 100 kV; bright line) voltage systems in the BES envelope when interactions between these systems and the BES are deemed critical to reliable operations in their local or regional area. The demarcation point between transmission and distribution may be different in non-FERC jurisdictions, such as the Canadian Provinces. For example, in Ontario, legislation establishes 50kV as the technical boundary line between transmission and distribution. In establishing voltage thresholds, NERC needs to consider non-U.S. legislated demarcation points, and the standard development process must make allowances for such regulatory and/or jurisdictional differences. The establishment of the voltage floor for the E1 exclusion as currently written is inconsistent with the language and structure of the legislative framework in Ontario. The Exception Process is not appropriate to determine the jurisdictional issue of whether facilities are part of the Bulk Electric System. Note 2 should be modified to read as follows: Note 2 – The presence of a contiguous loop, operated at a voltage level below the applicable cut-off between configurations being considered as radial systems, does not affect this exclusion. The applicable cutoff is 30kV or less, unless deemed otherwise by regulatory authority. A technical justification is not required where a Provincial jurisdictional finding is applicable.
No
It should be considered that dispersed generators that are represented to the marketplace or modeled in study cases as 20MVA or higher should be included in the definition just as a single traditional generating unit of 20 MVA is included. By removing I4, the aggregating portion of the inclusion has been muddied. Suggest adding I2-c to include dispersed resources that are aggregated and modeled at 20MVA or higher. This would add clarity and consistency to the definition. The impact of the proposed response to Commission directives (and the directives themselves) in effect bring wind generation collector systems and any other aggregation system for other resource technologies into the definition of Bulk Electric System. Recommend that there be an exclusion for wind generation collector systems which are radial in nature and do not serve any retail load provided adequate protection for the BES via protective systems installed at the point of interconnection. Bringing many thousands of 1-2 MW generators directly into the reliability regime of the ERO is not necessary, or justified. In plants with an aggregate rating greater than 75 MVA, the individual generators should be treated in the same manner as if they were each a stand-alone facility. If the individual generator is at or below 20 MVA in a stand-alone facility it would not be included in the BES and the owner of such a facility would not even have to register as a generator owner. That same size generator in an aggregated facility should be treated the same and it should be excluded from the BES. The portion of the facility at which the 75MVA or greater aggregation occurs should be where the BES boundary should be occurring. To demonstrate the concept, an illustration marked as Figure 1 has been submitted to Monica Benson (NERC). From FERC

Order 733A beginning at paragraph 50, “we direct NERC to modify the exclusions pursuant to FPA section 215(d)(5) to ensure that generator interconnection facilities at or above 100 kV connected to bulk electric system generators identified in inclusion I2 are not excluded from the bulk electric system”. To that end, I2 should be revised to read: I2 - Generating resource(s) and dispersed power producing resources, including their power delivering assets operated at a voltage of 100 kV or above with:
No
For Exclusion E4 Reactive Devices - The drafting team agreed that use, and not ownership, should dictate the disposition of reactive devices. Reactive devices used to support retail customer loads, and not used in day-to-day operations for BES voltage control for either steady state or contingency operations, may be excluded from the BES regardless of ownership. Devices need not be owned by “a retail customer” as a prerequisite for exclusion. Reactive devices owned by others, such as a Transmission Owner, and installed solely for the benefit of retail customer load should also qualify for exclusion. The proposed wording still carries remnants of the previous retail customer concept. It refers to a singular customer. Yet, reactive devices may be installed to benefit a group of retail customers collectively referred to as retail load. Suggest revising E4 to either read: E4--Reactive Power devices installed for the sole benefit of retail customers. or E4--Reactive Power devices installed for the sole benefit of retail load.
Yes
The specifics of system configurations and applications in the Inclusions and Exclusions should be reviewed to be made less complex. If they are not simplified they can be expected to generate a large number of requests for exclusion consuming resources in regional processing and at the ERO. As an alternative, an updated, conforming Guidance Document clarifying the intent and containing explicit explanations and one-line diagram examples should be provided. The version previously posted does not conform to the Phase 2 changes proposed. Phase 2 of the BES definition process was supposed to address the 100kV threshold, the generator thresholds and the reactive resource thresholds for inclusion or exclusion. No formal studies have shown that these numbers are the correct numbers for this definition. The studies provided under Phase 2 had no more technical justification than those discussions by the Standard Drafting Team in Phase 1. Being able to have that technical justification provides the support necessary to maintain a reliable transmission system and provides a basis for analysis of reliability by industry participants. Based on FERC orders 773 and 773-A and NERC’s response to those orders, the value of Note 1 under E1 has been diminished and suggest it be removed. It must be considered that industry has typically considered the terms ‘network’ and ‘contiguous’ to exclude elements or facilities that contain a normally open device (switch, breaker, disconnect, etc.) between them. 1) NERC must consider that any new or changes to standards as a result of FERC directives that apply to load reliability and load supply continuity are limited to the FERC jurisdiction only. For example, in Canada, local load reliability requirements are under the authority of local regulators such as the OEB in Ontario. 2) The Implementation Plan does not conflict with the Ontario regulatory practice with respect to the effective date of the standard. It is suggested that this conflict be removed by

appending to the effective date wording, after “applicable regulatory approval” in the Effective Dates Section of the Implementation Plan, the following: “, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.” The same changes should be made to the first sentence in the Effective Date Section on page 2 of the Definition document. The main concern about the Phase 2 definition is that it reduces more than the Phase 1 definition by the possibility of exclusions, and that no proper technical analysis had been given to justify or reduce the proposed threshold. FERC's request should not force obligations on non-United States jurisdictions. NERC must consult with and treat both United States and non-United States jurisdictions equally.
Individual
Tracy Richardson
Spirngfield Utility Board
Agree
American Public Power Association.
Group
Arizona Public Service Company
Janet Smith, Regulatory Compliance Supervisor
Yes
Yes
Yes
Yes
Yes
Yes
I5 is still problematic. It only excludes reactive resources which are excluded by E4. We suggest following: “unless excluded by exclusion of E1 to E4”. For example there is no justification to include reactive resources connected to a radial system as part of BES which are there to serve the radial system. Since the radial system is not part of BES, why include the reactive resources connected to radial system as part of BES.
Group
Northeast Utilities
Tim Reyher
No

While it is recognized that electrical systems operated below 100KV can be configured such that they should require BES treatment (i.e. the 92 KV networked system involved in the 2011 Southern California – Arizona outage), a 30KV threshold is too low to significantly impact the reliable operation of the higher voltage transmission system. We propose increasing this threshold to a voltage in the 40-50KV range. The new Note 2 associated with Exclusion E1 and the changes to E3 have added ambiguity that did not exist before. The base definition does not address sub-100kV contiguous loops. The existing Inclusions do not include sub 100kV contiguous loops either. Note 2 clarifies that as long as the contiguous loop is below 30kV E1 still applies. E3 explains how any sub 30kV contiguous loop could be excluded as a local area network, but there is nothing in the definition to clearly state that contiguous loops operated below 100kV are considered part of the BES unless excluded by E3. An additional Inclusion should be added that specifically includes “all contiguous loop operated below 100kV that is not solely used for the distribute power to load unless excluded by application of Exclusion E1 or E3.” The proposed change to the E1 exclusion definition to add Note 2 will require an examination of NU sub-transmission system connections (69KV in CT and 34KV in NH) and their connections to the >100KV transmission systems. Elements >100KV originally categorized as E1 or E3 may become BES inclusions if there is underlying sub-transmission path. A cursory review determine no elements categorized as E1 in CT would be changed; however, 16 of the 30 E1 elements in NH could become BES due to 34KV paths.

While it is recognized that electrical systems operated below 100KV can be configured such that they should require BES treatment (i.e. the 92 KV networked system involved in the 2011 Southern California – Arizona outage), a 30KV threshold is too low to significantly impact the reliable operation of the higher voltage transmission system. We propose increasing this threshold to a voltage in the 40-50KV range. The new Note 2 associated with Exclusion E1 and the changes to E3 have added ambiguity that did not exist before. The base definition does not address sub-100kV contiguous loops. The existing Inclusions do not include sub 100kV contiguous loops either. Note 2 clarifies that as long as the contiguous loop is below 30kV E1 still applies. E3 explains how any sub 30kV contiguous loop could be excluded as a local area network, but there is nothing in the definition to clearly state that contiguous loops operated below 100kV are considered part of the BES unless excluded by E3. An additional Inclusion should be added that specifically includes “all contiguous loop operated below 100kV that is not solely used for the distribute power to load unless excluded by application of Exclusion E1 or E3.” The proposed change to the E1 exclusion definition to add Note 2 will require an examination of NU sub-transmission system connections (69KV in CT and 34KV in NH) and their connections to the >100KV transmission systems. Elements >100KV originally categorized as E1 or E3 may become BES inclusions if there is underlying sub-transmission path. A cursory review determine no elements categorized as E1 in CT would be changed; however, 16 of the 30 E1 elements in NH could become BES due to 34KV paths.

Yes

While it is recognized that electrical systems operated below 100KV can be configured such that they should require BES treatment (i.e. the 92 KV networked system involved in the 2011 Southern California – Arizona outage), a 30KV threshold is too low to significantly impact the reliable operation of the higher voltage transmission system. We propose increasing this threshold to a voltage in the 40-50KV range. The new Note 2 associated with Exclusion E1 and the changes to E3 have added ambiguity that did not exist before. The base definition does not address sub-100kV contiguous loops. The existing Inclusions do not include sub 100kV contiguous loops either. Note 2 clarifies that as long as the contiguous loop is below 30kV E1 still applies. E3 explains how any sub 30kV contiguous loop could be excluded as a local area network, but there is nothing in the definition to clearly state that contiguous loops operated below 100kV are considered part of the BES unless excluded by E3. An additional Inclusion should be added that specifically includes “all contiguous loop operated below 100kV that is not solely used for the distribute power to load unless excluded by application of Exclusion E1 or E3.” The proposed change to the E1 exclusion definition to add Note 2 will require an examination of NU sub-transmission system connections (69KV in CT and 34KV in NH) and their connections to the >100KV transmission systems. Elements >100KV originally categorized as E1 or E3 may become BES inclusions if there is underlying sub-transmission path. A cursory review determine no elements categorized as E1 in CT would be changed; however, 16 of the 30 E1 elements in NH could become BES due to 34KV paths.
Individual
Dennis Schmidt
City of Anaheim
No
This Question No. 2 has clearer language than the Exclusions E1 and E3 themselves when it qualifies the interconnected generation as “BES generation.” As discussed below, Exclusions E1 and E3 should be modified to make clear that non-BES generation (i.e., any non-Inclusion I2/I3 generation that is connected to non-BES facilities, including distribution facilities operated below 100 kV) does not disqualify a registered entity from either Exclusion E1 or Exclusion E3. Exclusions E1 and E3 should clearly state that the 75 MVA limitation on generation resources contained in Exclusions E1(c) for radial systems and E3(a) for local networks applies to generation resources that are actually connected to the potentially excluded radial system or local network. The 75 MVA limitation should not apply to non-BES generation that may be connected to a sub-100 kV distribution system beyond the radial system or local network. Anaheim believes that the Drafting Team may intend for the existing (i.e., Phase 1) definition to be applied in this manner. For example, both the radial system and local network definitions refer to “contiguous transmission Elements,” which do not include “distribution Elements.” A 75 MVA (or greater) generator connected to a 69 kV local distribution Element is not contiguous to the BES, nor is it connected to a transmission Element; therefore, such distribution system generation should not preclude the radial system or local network from being excluded from the BES. Anaheim’s proposed revisions to

Exclusions E1 and E3 to address this issue are provided below. To the extent that the Drafting Team already intends for the existing (i.e., Phase 1) BES definition to be interpreted and applied as described in these comments and that no further changes to the Exclusions are warranted, then Anaheim requests that the Drafting Team confirm this in future guidance documents or that the Drafting Team so specify in response to these comments. Exclusion E1: E1 – Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: a) Only serves Load. b) Only includes generation resources, not identified in Inclusion I2 or I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). c) Where the radial system both serves Load and includes generation resources, the generation resources (i) are not identified in Inclusions I2 or I3 and (ii) have an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating) directly connected to the radial system. [Anaheim proposes no changes to the remainder of Exclusion E1; for brevity, the remainder of this exclusion has not been restated.] Exclusion E3: E3 – Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LNs emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customs and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following: a) Limits on connected generation: The LN does not include generation resources identified in Inclusions I2 or I3 and does not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating) directly connected to the LN at a voltage of 100 kV or above; [Anaheim proposes no changes to the remainder of Exclusion E3; for brevity, the remainder of this exclusion has not been restated.]
Yes
For clarity, a minor grammatical change should be incorporated into Inclusion I2. Specifically, a comma should be placed after the word “transformer(s)” and before the phrase “connected at a voltage of 100 kV or above.” Thus, Inclusion I2, as revised, should state: Inclusion I2 – Generating resource(s) and dispersed power producing resources, including the generator terminals through the high side of the step-up transformer(s), connected at a voltage of 100 kV or above with: a) Gross individual nameplate rating greater than 20 MVA, or b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.
Group
Dominion
Louis Slade
Yes
However, please see our comments to remaining questions. .
Yes

No
Dominion believes that there should be some way to insure that the requirement does not require exclusion be validated solely by use of powerflow. We therefore suggest the following revision to E1 (a) Only serves Load. A normally open switching device between radial systems may operate in a ‘make before break’ fashion to allow for reliable system reconfiguration to maintain continuity of service and not require a powerflow model. We endorse the MRO comment - "The NSRF believes the 30kV threshold is too low and the SDT justification is inadequate. The BES operates at various kV classes. As power density and distance grow, lower voltage classes are rendered ineffective at transporting bulk electric system power. Therefore, certain voltage classes below 100 kV are clearly limited in their ability to transport bulk electric power and should be ruled as distribution facilities under the 2005 FPA." We endorse the MRO Comment - "MRO members have expertise in performing interconnected system modeling & operational analysis which indicates that all three attributes comprising the technical justification used by the SDT are always satisfied with the 60kV threshold. The recommended 60kV threshold recognizes that 69kV is the lowest voltage at which loops between radial systems have the potential to support adequate amount of power transfer under certain worst case scenarios and thus may impact the >100kV system performance/reliability. In other words, system modeling & operational analysis experience indicates that 69kV is the lowest voltage at which loops between radial systems present any possibility that any one of the three attributes in the SDT’s technical justification may not be satisfied. "
Yes
Yes
Yes
Based on FERC orders 773 and 773-A and NERC’s response to those orders, Dominion no longer sees the value of Note 1 under E1 and suggests it be removed. Further Dominion believes the industry has typically considered the terms ‘network’ and ‘contiguous’ to exclude elements or facilities that contain a normally open device (switch, breaker, disconnect, etc) between them. Although Dominion initially thought it understood the meaning of the BES definition, our attendance at seminars in June and the attempted application of the BES definition to the Dominion system has led to some confusion. Please provide additional clarity on the Local Network exclusion E3b. The BES definition is vague and ambiguous as to whether flow out of the network requires study under N-0, N-1, N-2, etc. conditions. The SDT has stated that one does not have to perform loadflow studies to determine a local network. It has also stated in the guidance document that two years of historical flow data may be used to make the determination. Both of these imply the BES is to be evaluated under an N-0 situation. On the other hand the SDT has stated “This definition, as approved, clearly specifies no outward flow from the local network under any conditions and for any duration.” {comments on guidance document October 4, 2012 through November 5, 2012}. This implies

that some type of contingency analysis must be performed. Consider as an example, Figure E3-3 of the April 2013 Guidance document. With all lines in service as depicted, the 138 kV system is undoubtedly a local network. However, if the definition truly means “under any condition” then one could select an a set of <300 kV and 138 kV contingencies that would force power through the 138 kV and then back onto the BES since there is no alternate path. This would negate the assertion that this is non-BES and excludable. We doubt if that is the SDT intent and believe the definition as written is silent on the contingency issue. Clearly there needs to be a practical limit to how many contingencies one would need to take or clarificiation whether contingencies should be taken at all. Evaluation at all load levels, all credible dispatches with a variety of contingencies is tremendously burdensome. Our preference would be to evaluate with all lines in service (N-0) since this would insure maximum buy-in from stakeholders. E3b should read : E3b) “Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN under normal (non-contingency) conditions…” The Guidance document, as revised for phase II, is important to understand the BES definition. It introduces concepts not explicitly mentioned in the BES definition (“The SDT’s intent was that hourly integrated power flow values over the course of the most recent two-year period would be sufficient to make such a demonstration.”) However, the guidance document does not have legal standing since it is not FERC approved. We think it should go through the interpretation process for stakeholder review and be integrated into the BES definition with FERC approval.
Group
Cogeneration Association of California
Donald Brookhyser
Yes
There are several issues regarding industrial facilities that should be addressed in Phase 2. Including the facilities of any individual industrial customer in the BES and making them subject to NERC standards and enforcement unreasonably expands a program designed to regulate utilities. This shifts the responsibility for utility functions to individual, non-jurisdictional entities, including industrial customers, and customer generators. It is ironic that these entities built generation for increased reliability of service to their installations – not to serve the grid - and in many cases to substitute for the less-than-reliable utility grid service. The comments to FERC on the NOPR and in the requests for rehearing raised several issues with regard to industrial facilities that FERC deferred to Phase 2. These comments include those advocating exemption of industrial facilities with power flowing through and out to the grid, such as those asserted by Dow and Valero. The issues associated with industrial

customers employing self-generation to serve on-site load should appropriately be included in this Phase 2 effort. To address these issues, CAC, EPUC and CLECA propose four development initiatives within Phase 2: • First, there should be an additional exclusion from the bright-line test: •If the element is not owned or operated by a public utility regulated by a state authority as a common carrier, or by FERC as a public utility, there is a presumption that the element is not part of the Bulk Electric System (BES); • For any element that is not a public utility, and that is asserted to be material to the reliability of the BES, the burden is on the regional entity or the interconnected public utility to demonstrate that the non-public utility customer facilities are an essential and material part of the BES. • This shift in burden is important because of the difficulty for an individual industrial customer/self-generator to obtain the necessary data to model its impact on grid reliability. Confidential modeling of power flows or information of other customers' usage is not going to be provided by the utilities to customer generators as market participants. • Second, there should be a functional test specified for determining "material impact" to grid reliability, to facilitate the exclusion of elements. FERC in Order 743 and subsequent orders finds that a functional test of "no material impact" may not be sufficient to identify elements that are "necessary to operate the system." In footnote 35 of the April 18 rehearing order, FERC indicates that NERC has the option to develop such a test. A test of "no material impact and unnecessary to operate the system" should be developed, particularly to allow the exclusion of industrial facilities never intended to support grid reliability. • Third, NERC should further analyze the issue of power flowing out of a local network. Industrial facilities have often constructed two interconnections to the grid. This has typically been done to ensure reliability of service to the end-use industrial facility, but in doing so, it may also inadvertently provide a path for flows of small amounts of power through the interconnection points back to the grid. The purpose of the dual interconnection is reliability and not to provide transfers of energy across the bus. The transmission operator is not likely to depend on the interconnection point as a means to provide grid service to other customers or to model that service in its transmission planning studies. NERC's technical studies should provide FERC with some criteria for exempting industrial facilities with single-sourced dual feeds that are not intended to support the grid as a transfer path for power and are not modeled as such by the Transmission Planner or Balancing Authority. • Fourth, NERC, under the E-1 exclusions for radial lines, should not unilaterally dismiss the exclusion for radial lines if the industrial customer has more than one line servicing its facility. Most large manufacturing facilities are served by multiple feeds to maximize service reliability. This is done because the load is more reliable than the lines serving the facility. A refinery, chemical plant or other 24/7 facility cannot afford to operate without redundant power lines. Dual feeds, typically from the same utility substation, are constructed to provide benefits to both the utility and the large industrial customer. With that configuration the utility can maintain its revenue stream while performing routine maintenance without shutting-in a facility. In the case of a refinery, if it were forced to shut down during routine line maintenance, it can take up to several days to safely shut down and even longer to start up. By having redundant lines, often on the same poles, a facility can save millions of dollars in shut down costs and other related expenses. It would be commercially negligent in many cases for large customers not to have the redundancy. Utilities can provide increased reliability and perform repairs more

safely with the redundant lines. In no way does the fact that two lines providing service to a single large industrial facility, typically from the same utility source, change the characteristic of that service as being anything more than a radial line feed.
Individual
Steve Alexanderson
Central Lincoln
Yes
Central Lincoln agrees the SDT has addressed the directive, but continues to believe the conditions on outflow and through flow are excessively restrictive. Please see further comments in the response to Question 6.
Yes
Yes
Central Lincoln supports the approach, but questions the threshold. Central Lincoln protests that the SDT plans to make its white paper on the technical analysis to justify the 30 kV threshold available after the comment/ballot period is over. While a 5 kV shift would not affect Central Lincoln, we are aware of entities that would be in favor of a 35 kV threshold instead. Please give us the information needed to evaluate the SDT's choice of 30 kV.
Yes
Yes
Yes
1)Central Lincoln remains concerned regarding the limits imposed by b) on local networks. We note that by order 773A, FERC considers this limit to be absolute with no allowance for minimal reverse flows for even brief periods under multiple contingencies. While denying rehearing on this issue, FERC specifically invited Phase 2 to adjust this outcome in paragraph 79 of the order. We also note that the BES Definition Reference would allow very brief flows out of a local network as long as the integrated hourly flow was still into the local network. FERC, however, did not rule on the Reference document, only the definition itself. Even if FERC did allow the language of the Reference document, the first multiple contingency event that results in out flow or through flow for the better part of an hour would cause an excluded network to become immediately included, and subject to standards without any implementation period (assuming 24 months had passed from the effective date of the definition). The Planning Committee provided several options to SDT on this matter. We understand the SDT’s reluctance to impose system studies on what is intended to be a simply determined bright line criterion, but the present exclusion is not very useful. Central Lincoln would support using a fixed two year (or longer) window rather than the most recent two year sliding window suggested in the reference document. However it is determined, it should

be included within the approved definition so that the reference document disclaimer does not apply. 2)Non-retail generation still lacks a definition to be approved by NERC and FERC, even though this this item was specifically included in the approved SAR. We note that the term is defined in the Reference Document where the disclaimer stating it is not an official position of NERC ensures this definition has little value. While the Reference Document states “Non-retail generation is any generation that is not behind a retail customer’s meter,” we continue to hear it defined without the “not.” It is very important that entities and regions have a common understanding of the term, and ask the team to include its definition within the BES definition.
Individual
Doug Hohlbaugh
FirstEnergy
Yes
Yes
Yes
FirstEnergy supports the proposed 30kV threshold for Exclusion E1 based on the explanation provided in the June 26, 2013 industry webinar and information presented by the drafting team in the supplemental material/presentation titled “BES Radial Exclusion Low Voltage Level Criteria”.
Yes
Yes
No
Individual
PHAN, Si Truc
Hydro-Quebec TransEnergie
No
The phase 1 BES definition was approved by NERC after a positive acceptation by industry, providing that phase 2 would reconsider some of the thresholds proposed in phase 1. Among the thresholds, the limit of 75 MVA was an important one. Now, FERC request important changes that limit the possibility of exclusion : 1) limitation on the possibility of radial exclusion because of looping below 100 kV; 2) refusal of radial or local exclusions when there are at least one generator above 20 MVA. Those limitations for exclusion go in the opposite

direction to what industry expected. In that sense, HQT (Hydro-Québec-TransÉnergie) doesn't approved those changes. Moreover, it is not acceptable that those restrictions requested by FERC be imposed to all non-FERC jurisdiction. It is important that NERC consult also the Canadian jurisdictions about the BES definition.
No
Same comment as for question 1
No
HQT do not agree that sub-100 kV looping should refrain radial exclusion, since it doesn't carry impact on reliability of the BES, but only on non-BES. Though high voltage below 100 kV should not constitute a looping, it is much more necessary that medium voltage should not constitute a looping. According to ANSI and IEEE, medium voltage is 35 kV.
No
Same comment as for question 1
Yes
Yes
The main concern about phase 2 definition is that it reduces more than phase 1 definition the possibility of exclusions, and that no proper technical analysis had been given to justify or reduce the proposed threshold. FERC's request should not force obligations on non-US jurisdiction, but non-US jurisdiction should be consulted equally by NERC.
Individual
Grit Schmieder-Copeland
Pattern Gulf Wind LLC
No
While generators should not be seperated into different categories, and I agree with the general concept to combine power/generation resources into one inclusion, I disagree with the lanugage that for dispersed power resources the entire generation facility up to the generator terminal becomes part part of the BES. The critical load for dispersed power resources (considering the actual Net Capacity Factors) is apparently reached at an output of 75 MVA. Including equipment such as collector circuits and individual generators that carry well below the critical load of 20 MVA as applicable to conventional generators does seem unreasonable and undue and will have very little to do with protecting reliability and the BPS, but will increase maintenance and operating cost to unjustifieable levels. Only at the point where the such generation is aggregated and a critical load can be reached would dispersed power generators meet any criticality to the BPS, but the loss of individual small generators or collection circuits would not have significant impact on the BPS including causing any

cascading outages. Equipment included in compliance with NERC standards(as handeled in practise for the past 5+ years) should be limited to the point where generation is aggregated including the GSU and (if owned/operated by GO/GOP) generator tie-lines.
No
Individual
Thomas Breene
Wisconsin Public Service / Upper Peninsula Power
Yes
Yes
No
WPS believes the 30kV threshold is too low especially when 34.5kV is widely used for distribution. Additionally, there are numerous instances where 46 kV is appropriately classified as distribution through application of FERC's 7-factor test and we suggest a 50 kV threshold is more appropriate than a 30 kV threshold. The BES operates at various kV classes. As power density and distance grow, lower voltage classes are rendered ineffective at transporting bulk electric system power. Therefore, certain voltage classes below 100 kV are clearly limited in their ability to transport bulk electric power and should be ruled as distribution facilities under the 2005 FPA.
No
WPS recommends that both I2 and I4 be retained, yet reworded such as this: "I2 – Generating resource(s) and dispersed power producing resource(s), with gross individual nameplate rating greater than 20 MVA, including the generator terminals through the high-side of the generator step-up transformer(s) connected at a voltage of 100 kV or above." "I4 – For generating and dispersed power producing facilities with gross plant/facility aggregate nameplate rating greater than 75 MVA, the bus where the aggregate generation is greater than 75 MVA and continuing thru the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above. (Note: this does not include the individual generating resources themselves, or the collector feeder system(s).)" The intent is to focus compliance activity at the point where power is aggregated to the point (usually a bus) where it becomes significant to the BES not at small (1 to 2 Mw) generators or distribution level Mw collector systems. The reliability issue for small generating units whether they are diesels, wind turbines, solar units, or nuclear modules is not the risk of loss of small independent individual units. The common mode risk of loss of significant amounts of generation is at the point of aggregation.
Yes

Yes
With E3 and E1 the SDT has created an “opt-out” process instead of an “opt-in” process. Only a small portion of networked facilities less than 100kV has a material impact on the BES. A better approach would be to utilize the BES process for exceptions and include those that have material impact to the BES. Needlessly processing these sub 100kV systems through the burdensome exclusion process is not an effective use of resources.
Individual
Brian J. Murphy
NextEra Energy
No
Inclusion I2 has been modified to incorporate I4 and I4 was eliminated. This is a good step, but the wording needs to be revised to recognize the insignificance of the individual wind turbine generators to the bulk electric system. Here is the proposed re-write: “I2 – Generating resource(s) and dispersed power producing resources with: a) Gross individual nameplate rating greater than 20 MVA, including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above; or, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA, beginning at a bus where the aggregate generation is greater than 75MVA and continuing thru the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above” 100kV bright line: The use of the 100kV bright line is recommended to be continued in the base definition, the inclusions and exclusions. Specific analysis should be performed to demonstrate the need for change on an individual basis.
Individual
Bob Thomas
Illinois Municipal Electric Agency
Agree
Transmission Access Policy Study Group
Individual
Jack Stamper
Clark Public Utilities
Agree
Snohomish County PUD
Individual

John Seelke
Public Service Enterprise Group
Yes
Yes
Yes
No
The “Phase 1: Bulk Electric System Definition Reference Document dated April 2103 addresses I4 on pp. 15-20. These examples to not include the following in the BES: (a) the below 100 kV collector system; (b) step-up transformers with primary and secondary sides below 100 kV, and (c) the main GSU that connects at 100 kV to the system. This discrepancy between traditional generation and dispersed generation needs to be explained so that there is no discrimination between them with respect to the BES definition.
Yes
Yes
The issue of requiring facilities that connect BES generation to the grid to be included in the BES was settled by FERC in Order 773. We believe that consistency is needed on the issue of contiguity; furthermore, this was a Phase 2 issue that SDT is supposed to address per its SAR – see page 2 of the SAR which states a portion of the scopes as follows: “The NERC Board of Trustees approved BES Phase 1 definition does not encompass a contiguous BES - Determine if there is a need to change this position.” For example, the connection of reactive devices to the grid in the Guidance document (pp. 21-22) are in “black” that “indicates Elements that are not evaluated for the specific inclusion depicted in the individual diagrams being shown.” The SDT should complete the activities in its SAR in Phase 2 or explain why it has not.
Individual
John Bee
Exelon and its Affiliates
No
Exelon does not support the changes made to items I2 and I4 in the proposed BES Definition. By combining items I2 and I4, the BES DT has effectively pulled in dispersed power producing resource collector system elements which are <100kV and which do not normally carry

>75MVA in aggregate flow. In doing so, the BES DT has inappropriately strayed from the work plan for Phase 2 as defined in the Phase 2 original and supplemental SARs. In the original Phase 2 SAR, the BES DT was tasked with providing technical justification for the following items; 1. Develop a technical justification to set the appropriate threshold for Real and Reactive Resources necessary for the reliable operation of the Bulk Electric System (BES) 2. The NERC Board of Trustees approved BES Phase 1 definition does not encompass a contiguous BES - Determine if there is a need to change this position 3. Determine if there is a technical justification to revise the current 100 kV bright-line voltage level. 4. Determine if there is a technical justification to support allowing power flow out of the local network under certain conditions and if so, what the maximum allowable flow and duration should be Additionally, the Phase 2 original SAR tasked the BES DT with improving the clarity of the following items; 1. The relationship between the BES definition and the ERO Statement of Compliance Registry Criteria established in FERC Order 693 2. The use of the term “non-retail generation” 3. The language for Inclusion I4 on dispersed power resources 4. The appropriate ‘points of demarcation’ between Transmission, Generation, and Distribution Finally, the supplemental Phase 2 SAR required the BES DT to: 1. Address the directives in FERC Order 773 issued December 20, 2012 The proposed changes to I2 and I4 inappropriately exceed the work plan as outlined in the SARs because they do not improve clarity for I4 and they are not in response to a directive from FERC Order 773. In Phase 1, the BES DT intended to exclude the collector system elements for dispersed power producing resources and stated so multiple times in responses to stakeholder comments, webinars and in the original draft of the Guidance document. By changing positions on whether collector systems should be included in the BES, the BES DT has not improved clarity but has instead materially changed the BES Definition itself. In addition, in Order No. 773, FERC specifically declined to “direct NERC to categorically include collector systems pursuant to inclusion I4”. (Order No. 773, P114). Therefore this change is not in response to a FERC directive. Furthermore, under the current registration criteria for inclusion in the NERC Registry, Generation Owners and Generation Operators for individual generation resources >20MVA connected at 100KV or higher or aggregate resources > 75MVA (Aggregate) connected at 100KV or higher are required to register and are thus subject to the NERC Reliability Standards. Individual elements of dispersed power producing resources do not reach these thresholds until the point of where all of the elements are summed together. The individual dispersed power producing resource elements before this “summed” point have little or no impact to the BES as they are generally isolated from the BES behind protection system elements such as relays and circuit breakers. Exelon feels that only those elements in a collector system that carry more than 75 MVA of aggregate flow should be included in the BES. Thus, Exelon opposes the changes to I2 and I4 in the current Phase 2 draft BES definition and has submitted a NEGATIVE vote on the proposed BES definition.
Individual
Bret Galbraith

Seminole Electric
Yes
Exclusion E1 allows for the exclusion of radials that contain particular amounts of load and generation resources; however, there is no mention of radials that contain reactive devices. Therefore, if a radial falls under Exclusion E1(c) for generation and load, but also has a reactive device, it is unclear whether this Exclusion can be utilized. From past discussions, it appears that E1(c) covers reactive devices; however, Seminole asks that the SDT revise/clarify this Exclusion to specifically include reactive devices.
Individual
Jim Cyrulewski
JDRJC Associates LLC
Agree
MISO
Individual
Nazra Gladu
Manitoba Hydro
Yes
Yes
Yes
Yes
Yes
No
(1) Although Manitoba Hydro is in general support of the changes, we would like to include the following clarifying comment: Implementation Plan, Effective Dates - replace the words “go into effect” with “become effective”. Moreover, append the wording, after “applicable regulatory approval”: “, or as otherwise made effective pursuant to the laws applicable to

such ERO governmental authorities." Prior to the wording "In those jurisdiction….". The same changes should be made to the first sentence in the Effective Date Section of the proposed Definition document.
Individual
Kenn Backholm
Public Utility District No.1 of Snohomish County
Yes
The Public Utility District No.1 of Snohomish County agrees the SDT has addressed the directive, but continues to believe the conditions on outflow and through flow are excessively restrictive. Please see further comments in the response to Question 6.
Yes
The Public Utility District No.1 of Snohomish County suggests increasing the 30kV threshold to "35kV or less" as 34.5kV is a common distribution voltage used in rural communities and should not be classified as BES. From Wikipedia "Rural electrification systems, in contrast to urban systems, tend to use higher distribution voltages because of the longer distances covered by distribution lines (see Rural Electrification Administration). 7.2, 12.47, 25, and 34.5 kV distribution is common in the United States…"
Yes
The Public Utility District No.1 of Snohomish County supports the SDT's approach and recommends increasing the voltage from "30 kV or less" to "35 kV or less" noted in Question 1.
No
The Public Utility District No.1 of Snohomish County supports the omitted I4 and does not support the revisions to the generation resources and dispersed power resources inclusions. The change will classify systems as BES that interconnects a generation unit with a peak generation capability of less than 2 MVA and typical capacity factor of 25-30 percent. It is difficult to understand how these types of systems could be considered bulk. A greater than 75 MVA plant would typically have many miles of a 34.5 kV collector system connecting 480/690 volt to 34.5 kV generator step up transformers. Failure or mis-operations of these collector system components would equate to the loss of a MW or two, 30 percent of the time. The Public Utility District No.1 of Snohomish County does not believe enforcing NERC Reliability Standards on these, or similar systems supports reliability. In fact it could stifle green distributed generation developments.
Yes
The Public Utility District No.1 of Snohomish County supports the SDT's approach.
Yes
The Public Utility District No.1 of Snohomish County remains concerned regarding the limits imposed on local networks. We note that by order 773A, FERC considers this limit to be absolute with no allowance for minimal reverse flows for even brief periods under multiple

contingencies. While denying rehearing on this issue, FERC specifically invited Phase 2 to adjust this outcome in paragraph 79 of the order. We also note that the BES Definition Reference would allow very brief flows out of a local network as long as the integrated hourly flow was still into the local network. FERC, however, did not rule on the Reference document, only the definition itself. Even if FERC did allow the language of the Reference document, the first multiple contingency event that results in out flow or through flow for the better part of an hour would cause an excluded network to become immediately included, and subject to standards without any implementation period (assuming 24 months had passed from the effective date of the definition). The Planning Committee provided several options to SDT on this matter. We understand the SDT's reluctance to impose system studies on what is intended to be a simply determined bright line criterion, but the present exclusion is not very useful. The Public Utility District No.1 of Snohomish County supports including the option of perform one element out ("N-1") contingency at peak conditions or a fixed two year (or longer) window could be used rather than the most recent two year sliding window suggested in the reference document. These options would provide more certainty and better support the reliability of the BES. However it is determined, it should be included within the approved definition so that the reference document disclaimer does not apply. Non-retail generation still lacks a definition to be approved by NERC and FERC, even though this item was specifically included in the approved SAR. We note that the term is defined in the Reference Document where the disclaimer stating it is not an official position of NERC makes this definition of little value. While the Reference Document states "Non-retail generation is any generation that is not behind a retail customer's meter," we continue to hear it defined without the "not." It is very important that entities and regions have a common understanding of the term, and ask the team to include its definition within the BES definition.
Individual
Joe Tarantino
Sacramento Municipal Utility District
Yes
SMUD agrees the SDT has addressed the Commission's Directive. However, removal of 100kv threshold from the first part of E3 but the 100kV reference remains in the second part of the E3 exclusion which is inconsistent. It is unclear what value the second sentence of the E3 exclusion provides and should be removed from the E3 exclusion.
No
I2 is inconsistent with E1& E3 by not including "non-retail" generation. E1-b & c and E3-a contain redundant statements regarding the 75MVA generator threshold. These statements should be corrected for clarity and consistency.
Yes
SMUD supports the SDT's approach but believes it to be prudent for the DT to increase the voltage threshold to avoid unnecessary inclusions of rural electrical systems.

No
SMUD supports the omitted Inclusion-I4 but does not fully agree with the revisions for Inclusion-I2. SMUD is concerned regarding Inclusion-I2 that now includes a common BES determination for components of hydro/thermal AND wind/solar resources. Since Inclusion-I2 establishes a 100 kV or above threshold for generators, this draft's current language would exclude many of the 'dispersed resources'. If it is determined that the 'dispersed resource' are subject to BES through 'multiple step-up transformer', the current draft language would inappropriately expand the BES Definition to potentially include all generators regardless of voltage level when subcategories I2a & I2b are met. Instead, to eliminate this potential expansion SMUD urges the BES SDT to create an Inclusion that defines an element(s) as BES where a single component(s) has the potential to removes 75 MVA of resources and remove the 'dispersed power producing resources' from Inclusion-I2. The 75 MVA threshold would eliminate the administrative and cost burden associated with testing and documentation for 'small-scale' machines that are connected to sub-100 kV, are less than 3 MW, and, individually have little or no impact to reliability of the BES. Subjecting the 'collector system' that typically consist of several miles of radial 34.5 kV, its system components and its dispersed generation resources to the BES and subsequent application of NERC Reliability Standards would not provide a proportionate impact to reliability.
Yes
Yes
SMUD remains concerned regarding the limits imposed on local networks. We note that by order 773A, FERC considers this limit to be absolute with no allowance for minimal reverse flows for even brief periods under multiple contingencies. While denying rehearing on this issue, FERC specifically invited Phase 2 to adjust this outcome in paragraph 79 of the order. We also note that the BES Definition Reference would allow very brief flows out of a local network as long as the integrated hourly flow was still into the local network. FERC, however, did not rule on the Reference document, only the definition itself. Even if FERC did allow the language of the Reference document, the first multiple contingency event that results in out flow or through flow for the better part of an hour would cause an excluded network to become immediately included, and subject to standards without any implementation period (assuming 24 months had passed from the effective date of the definition). The Planning Committee provided several options to SDT on this matter. We understand the SDT's reluctance to impose system studies on what is intended to be a simply determined bright line criterion, but the present exclusion is not very useful. SMUD supports including the option of perform one element out ("N-1") contingency at peak conditions or a fixed two year (or longer) window could be used rather than the most recent two year sliding window suggested in the reference document. These options would provide more certainty and better support the reliability of the BES. However it is determined, it should be included within the approved definition so that the reference document disclaimer does not apply. Non-retail generation still lacks a definition to be approved by NERC and FERC, even though this this item was specifically included in the approved SAR. We note that the term is defined in the

Reference Document where the disclaimer stating it is not an official position of NERC makes this definition of little value. While the Reference Document states “Non-retail generation is any generation that is NOT behind a retail customer’s meter,” we continue to hear it defined without the “not.” It is very important that entities and regions have a common understanding of the term, and ask the team to include its definition within the BES definition.
Individual
Kayleigh Wilkerson
Lincoln Electric System
Agree
MRO NSRF
Group
MRO NERC Standards Review Forum (NSRF)
Russel Mountjoy
Yes
Yes
The NSRF would like clarification on Blackstart resources that are connected at < 100kV. A Blackstart resource would be included in the BES per I3; however the path that is less than 100kV would not be included in the BES
No
The NSRF believes the 30kV threshold is too low and the SDT justification is inadequate. The BES operates at various kV classes. As power density and distance grow, lower voltage classes are rendered ineffective at transporting bulk electric system power. Therefore, certain voltage classes below 100 kV are clearly limited in their ability to transport bulk electric power and should be ruled as distribution facilities under the 2005 FPA. MRO members have expertise in performing interconnected system modeling & operational analysis which indicates that all three attributes comprising the technical justification used by the SDT are always satisfied with the 60kV threshold. The recommended 60kV threshold recognizes that 69kV is the lowest voltage at which loops between radial systems have the potential to support adequate amount of power transfer under certain worst case scenarios and thus may impact the >100kV system performance/reliability. In other words, system modeling & operational analysis experience indicates that 69kV is the lowest voltage at which loops between radial systems present any possibility that any one of the three attributes in the SDT’s technical justification may not be satisfied. Or another consideration would be the Transmission Distribution Factor (TDF) or percent participation. For example, entities could consider 24 – 69 kV facilities with a 0.2 to 0.3% TDF and 50% or greater normalized transfer factor or 50% or more participation.
No

The NSRF recommends that both I2 and I4 be retained, yet reworded such as this: “I2 – Generating resource(s) and dispersed power producing resource(s), with gross individual nameplate rating greater than 20 MVA, including the generator terminals through the high-side of the generator step-up transformer(s) connected at a voltage of 100 kV or above.” “I4 – For generating and dispersed power producing facilities with gross plant/facility aggregate nameplate rating greater than 75 MVA, the bus where the aggregate generation is greater than 75 MVA and continuing thru the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above. (Note: this does not include the individual generating resources themselves, or the collector feeder system(s).)” The intent is to focus compliance activity at the point where power is aggregated to the point (usually a bus) where it becomes significant to the BES not at small (1 to 2 Mw) generators or distribution level Mw collector systems. However, if I2 moves forward as drafted, we feel it is imperative to launch an effort similar to the GOTO/Project 2010-07, to modify and add clarity to standards as they would apply to a dispersed power resource. This is important, as many of the current GO/GOP standards would be difficult and impractical to apply to a dispersed power resource. In addition, we recommend that interim compliance application guidance be developed to help owners and operators of dispersed power resources understand how to apply current standards, while also providing guidance to the auditors. The inclusion of small individual generators will drive significant industry burden to comply without producing any additional system reliability benefits. The inclusion of 1 – 2 MW units as separate NERC BES elements will drive unintended consequences for NERC standards and perhaps the wind industry as a whole as companies are suddenly subjected to large populations of elements for standards such as PRC-004, PRC-005, FAC-008-3, TOP-002 R14, and VAR-002 (there may be others). The reliability issue for small generating units whether they are diesels, wind turbines, solar units, or nuclear modules is not the risk loss of small independent individual units, it is the common mode risk loss of significant amounts of generation at the point of aggregation of >75MVA.
Yes
Yes
With E1 (and E3) the SDT has created and “opt-out” process instead of an “opt-in” process. Only a small portion of networked facilities less than 100kV has a material impact on the BES. A better approach would be to utilize the BES process for exceptions and include those that have material impact to the BES. Needlessly processing these sub 100kV systems through the burdensome exclusion process is not effective use of resources. Please clarify that E1 and E3 are to be applied for normal (intact) system conditions. Rewording suggestions are: E1 - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher “under normal conditions…” E3 - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV “under normal conditions” that distribute power to Load rather than transfer bulk power across the interconnected system.
Individual
Daniela Hammons

CenterPoint Energy
No
CenterPoint Energy recommends the voltage level of “30 kV or less” in Note 2 be changed to “35 kV or less”. Based on this change, Note 2 would be: “The presence of a contiguous loop, operated at a voltage level of 35 kV or less, between configurations being considered as radial systems, does not affect this exclusion.” We suggest the voltage level should be established based on whether the contiguous loop is operated at common distribution voltages (e.g., 12.47 and 34.5 kV). The vast majority of distribution feeders are, of course, operated radially. Distribution feeders that are operated as a contiguous loop, or “networked”, are equipped with “network protectors” that initiate tripping of interrupting devices. A network protector automatically disconnects its associated power transformer from the secondary network when the power starts flowing in the reverse direction; that is, the interrupting device opens if the secondary grid back-feeds through the transformer to supply power to the primary grid. Therefore, there cannot be any loop flows between radial systems, as network protectors prevent such flows.
Group
Tennessee Valley Authority
Dennis Chastain
Yes
Yes
No
We agree with the approach, but not the voltage level chosen. Including loops greater than 30 kV will be unreasonably burdensome. We believe the threshold should be 70 kV. Any loops greater than 70 kV, that could affect the BES, should be added through the exception process.
Yes
Yes
Individual

RoLynda Shumpert
South Carolina Electric and Gas
Yes
Yes
Yes
We agree in general but if a technical justification can be developed, we recommend a threshold of 70 kV.
No
We agree in general but the SDT should review solar, fuel cell, and other DC technologies to clarify the term "generator terminals" in regards to the PRC standards. Additionally, clarification should be made that limits the inclusion to the greatest contingency loss, i.e. the step up transformer to the grid.
No
Change the wording in E-4 from "installed" to "operated". Change the wording in E-3c from "part" to "element". Change "permanent Flowgate" to "permanent Reliability type Flowgate". The Eastern Interconnection Book of Flowgates differentiates between "informational" and "Reliability" type Flowgates.
Group
SERC EC Planning Standards Subcommittee
Jim Kelley
Yes
Yes
Yes
If technical justification can be developed, a threshold of 70kV is recommended.
No
We agree in general but the SDT should review solar, fuel cell and other DC technologies to clarify the term "generator terminals" in regards to the PRC standards. Additionally, clarification should be made that limits inclusion to the greatest contingency loss which is the step-up transformer to the grid.
No
E4 change the word "installed" to "operated". E3c change "part" to "element" and add "Reliability type" to the statement: permanent Reliability type Flowgate. The rationale is that

the Eastern Interconnection Book of Flow gates contains some entries flagged "informational" and this would differentiate between the flow gates (reliability versus informational). The comments expressed herein represent a consensus of the views of the above named members of the SERC Planning Standards Subcommittee (PSS) only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
No
Group
National Grid
Michael Jones
No
The version of exclusion E3 criterion (c) filed with FERC January 25, 2012 (RM12-6-000) requires a “local network” not to contain a monitored facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored facility in the ERCOT or Quebec Interconnections, and is not a monitored facility included in an Interconnection Reliability Operating Limit (IROL). By changing exclusion E3 criterion (c) from “a monitored Facility of a permanent Flowgate…” to “any part of a permanent Flowgate…” the definition became vaguer and could allow for too broad of a reading. The original language from Phase 1 of the BES definition regarding exclusion E3 criterion (c) provided more clarity and guidance on how to apply this exclusion. It is recommended that the original language from Phase 1 of the BES definition be re-instated. Facilities should be included only if the elements of the Facility are transferring power (flow) through a flowgate, transfer path, or IROL.
No
In a similar way as 100 kV is the delineator between the medium and high system voltage classes in the American National Standards Institute (ANSI) standard on voltage ratings (C84.1), the voltage threshold in note 2 of exclusion E1 should be based on a well defined standard system voltage classes to better correlate to operational and system design considerations and practices. This could e.g., be done by aligning the voltage threshold with the insulator classes as defined in ANSI standard on insulators (C29.13) or the maximum rated voltage in Institute of Electrical and Electronics Engineers (IEEE) standards for medium voltage switchgear (C37.20.2 and C37.20.4). Based on ANSI C29.13, the threshold in note 2 of exclusion E1 could be set to 46 kV. The Exception Procedure could be used to include lower (than 100 kV; bright line) voltage systems in the BES envelope when interactions between these systems and the BES are deemed critical to reliable operations in their local or regional area.

Group
seattle city light
paul haase
Agree
Snohomish Public Utility District
Individual
Roger Dufresne
Hydro-Québec Production
Agree
Hydro-Québec TransÉnergie Division
Individual
David Burke
Orange and Rockland Utilities Inc.
Yes
No
We generally agree with the Guidance Document that was provided by NERC Drafting Team. The document showed that if there are any I2 Elements within a local network, the specific I2 Elements are deemed to be BES Elements, but the rest of the local network would still be qualified as Exclusion E3.
No
We generally agree with the Drafting Team to introduce a threshold to Exclusion E1 but believe the Step 1 in the Low Voltage Level Criteria is arbitrary. ORU (RECO) is the owner of the lowest threshold facility at 34kV facilities. The ORU (RECO) facilities at 34kV and 69kV facilities do not have an impact on the BES. Our opinion is that the 30 kV threshold is too low, therefore, we are requesting that the Drafting Team consider a higher voltage level as a new threshold. If a monitored element/facility at a lower voltage (sub-100 kV) level (including monitored Flowgates) does not pose any impact to BES system, such element/facility should not be considered as a criteria in E1 or E3.
Yes
Individual
Don Jones
Texas Reliability Entity

No
(1) The current draft appears to disallow E1 and E3 exclusions based on the presence of retail generation (such as generation within industrial facilities) within a radial system or local network. This is because the language of I2 does not distinguish between retail generation and non-retail generation. We do not think the current language reflects the intention of the drafting team. (2) Consider the following situation: an industrial facility is connected to the BES at one point with 100 MVA of retail generation connected at 138 kV that never provides more than 25 MVA to the grid. That generation is identified in I2, but it is excluded by E2, so it is not BES generation. However, the radial transmission facilities do not qualify as a "radial system" because of the presence of "generation resources [] identified in Inclusions I2 or I3." (3) This can be corrected by (a) referring to E2 in I2 (perhaps add to I2: "unless excluded by application of Exclusion E2") ; or (b) referring to "BES generation" in E1 and E3 rather than merely referring to "I2."
No
We cannot support this proposal without an adequate technical justification provided prior to the ballot. The posted materials indicate that the 30 kV threshold was "based on initial discussions by sub-team; more discussion and analysis needed." Those materials only provide a rough outline of the analysis that could be done; they do not indicate that any such analysis was actually done, and they do not provide a technical justification. Also, there is no explanation of how the current proposal is "equally effective and efficient" as applied to the Commission's stated concerns.
No
(1) We have no objection to combining conventional and dispersed generating facilities into one BES inclusion, but we do object to the characterization (in the blue box) of wind farms as "small-scale power generation technologies." In the ERCOT region there is now over 10,000 MW of installed wind capacity. Wind generation sometimes has served up to 25% of the entire ERCOT load, and wind provided over 9% of energy produced in ERCOT in 2012. Large-scale wind resources (facilities over 75 MVA) must be included within the BES and subject to appropriate reliability standards. (2) We would like to see clarification that dispersed power producing resources are generally viewed in the aggregate rather than as separate BES elements. The performance of each individual wind turbine and element of the collector system is not a large concern, but we are concerned about the reliability impact of 75+ MVA of generation connected to the transmission system. We encourage the team to consider viewing a BES wind farm as an aggregated generating facility, including the turbines, the collector system, and the step-up transformer. Such an aggregated generating resource should have an associated GO and GOP, and be subject to appropriate reliability standards.
Yes
We would like to see a revised Reference Document (and any white papers) posted prior to the ballot so we can fully understand how NERC intends to implement the revised definition before voting. There were some surprises in the Reference Document after Phase 1 was approved by NERC. A revised Reference Document should be part of the ballot package so

that all Ballot Pool members can understand exactly what they are voting for (and so the NERC Board can understand what it is approving).
Individual
Marie Knox
MISO
Agree
ISO/RTO Council - Standards Review Committee
Individual
Saul Rojas
New York Power Authority
No
Removal of 100kv threshold from the first part of E3 but the 100kV reference remains in the second part of the E3 exclusion which is inconsistent. It is unclear what value the second sentence of the E3 exclusion provides and should be removed from the E3 exclusion.
No
I2 is inconsistent with E1& E3 by not including “non-retail” generation. E1b&c and E3a contain redundant statements regarding the 75MVA generator threshold. These statements should be corrected for clarity and consistency.
No
The 30kV threshold is too restrictive and the sub-100kV loop threshold should be determined by the method the SDT utilized by regional transmission system makeup. This exclusion and restrictive loop threshold could lead to additional exception requests.
No
It should be considered that dispersed generators that are represented to the marketplace or modeled in study cases as 20MVA or higher should be included in the definition just as a single traditional generating unit of 20 MVA is included. By removing I4, the aggregating portion of the inclusion seems to be less clear. One suggestion would be to add I2-c to include dispersed resources that are aggregated and modeled at 20MVA or higher are included. This would add clarity and consistency to the definition.
Yes
No comments.
Yes
Phase 2 of the BES definition process was supposed to address the 100kV threshold, the generator thresholds and the reactive resource thresholds for inclusion or exclusion. No formal studies have shown that these numbers are the correct numbers for this definition. The studies provided under phase 2 had no more technical justification than those discussions by the SDT under phase 1. Being able to have that technical justification provides the support necessary to maintain a reliable transmission system and provides a basis for analysis of reliability by industry participants.

Group
SPP Standards Review Group
Robert Rhodes
Yes
Please see our comment in Question 6 regarding removal of the 100 kV limit?
Yes
Please see our comment in Question 6 regarding removal of the 100 kV limit?
No
It is difficult to agree with the approach when the details of the evaluation and analyses that were performed have not been made available for review by the industry. Once these details are known and have been reviewed by the industry, a more informed decision on what voltage level should be incorporated into the exclusion can be made. As it stands, we are very uncomfortable with the 30 kV limit and feel it is too low. Is the contiguous loop referenced in Note 2 normally closed or normally open? Whichever, it needs to be clarified in the note.
Yes
Yes
Yes
E3 has been changed in response to a FERC directive to remove the lower bound for LNs of 100 kV. While the removal does directly address the directive from FERC, the removal of the 100 kV lower limit may bring other questions, issues and uncertainty into consideration. In E1, the SDT developed an alternative response to a directive which appears to be a very good work-around. Although we don’t have specific language to offer, could the SDT develop a similar alternative for E3 without totally eliminating the existing 100 kV limit? Regarding the 30 kV limit in Note 2 of E1, does incorporating this value in the Note imply or could it be interpreted that these particular 30-100 kV looping facilities would become part of the BES? Although they aren’t specifically addressed in any of the Inclusions, perhaps it would be appropriate to specifically state that they would not be included. If an entity had two 115 kV radial lines and adds a looping 34.5 kV line between them that is operated normally closed, are these facilities considered radial lines subject to E1 or Local Networks subject to E3?
Individual
Joylyn Faust
Consumers Energy Company

Consumers Energy provides comments on the following issue raised by the Phase 2 BES definition: (1) the changes proposed to Inclusions I2 and I4. Dispersed Power Producing Resources Should Not Be Treated the Same as Other Generation Because They Do Not Have the Same Impact on the BES. The Phase 2 BES definition proposes to entirely eliminate Inclusion I4 and revise Inclusion I2 to, among other changes, include dispersed power producing resources. Consumers Energy does not agree with this change because different generating resources have different impacts on the BES, and thus are entitled to different treatment. This change is primarily premised on the theory that NERC should treat all power generation sources equally. While this theory sounds appealing upon first blush, it ignores the reality that different generation sources are in fact not equal because they differently impact the BES. In the case of dispersed power producing resources, the potential impact on the BES of these resources is not the same as a larger power producing resource (e.g. a 500 MW coal unit). The unexpected addition or loss of a larger generating unit can majorly impact the reliability of the BES. The addition or loss of a single unit (e.g., a 1.4 MW wind turbine), or even several smaller units, has little, if any, material impact on the BES. Because of differing impacts on the BES, dispersed power producing resources are entitled to different treatment. In addition, merely adding the phrase “and dispersed power producing resources” to I2 significantly expands the scope of assets drawn into the BES. Under the Phase 1 definition, only the generating units themselves were included in the BES (see, e.g., Figure I4-1 of NERC’s “Phase 1: Bulk Electric System Definition Reference Document” dated April 2013). The Phase 1 definition did not include all of the equipment between the generator terminal through the high-side of the step-up transformer. This exclusion of certain equipment was for good reason – dispersed power producing resources do not individually have significant impact on the BES, and only collectively have an impact. Under the proposed Phase 2 definition, the entire dispersed power producing facility (e.g., an entire wind farm) will be included in the BES. While we appreciate that such an expansion was likely the Drafting Team’s intent, this expansion makes little sense. Dispersed power producing resources simply do not – until aggregated – have sufficient impact on the BES to warrant such an expansion of the scope of the BES. A better approach would be to limit the scope of the BES to only include equipment from the point where the aggregated generation achieves 75 MVA – i.e., from the substation bus where the collector circuits aggregate to exceed 75 MVA. As such, Consumers Energy proposes that NERC retain Inclusion I4, but change its wording to something like this: “Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system design primarily for aggregating capacity, from the connection point at a voltage of 100 kV or above down through the connecting transformer to a single common point of aggregation.” This approach reasonably limits the BES definition as applied to dispersed power producing units in a fashion proportional to their impact on the BES.
Yes
Consumers Energy provides comments on the following issue raised by the Phase 2 BES definition: 2) a recommended change to Inclusion I3. Inclusion I3 Should Exclude Blackstart

Resources Connected to the BES Only On A Very Limited Basis The Phase 2 BES definition (and the Phase 1 BES definition) in Inclusion I3 provides that all Blackstart Resources identified in the Transmission Operator's restoration plan are part of the BES. NERC should modify Inclusion I3 to exclude Blackstart Resources that are only connected to the BES on a very limited basis. NERC should impose requirements on an asset proportional to the asset's impact on the BES. As such, assets that have little-to-no impact on the BES should be subject to only minimal requirements. In the case of Blackstart Resources, some such resources have extremely little impact on the BES during a typical day. For example, some gas peaker units are only connected to the BES for less than 24 hours in a year because they are used only during extreme weather conditions or when the system is actually "black." Given their low impact on the BES, NERC should regulate these units in a way proportional to their limited use. Therefore, Consumers Energy proposes that NERC modify Inclusion I3 to cover "Blackstart Resources identified in the Transmission Operator's restoration plan, unless such a resource is connected to the Bulk Electric System for less than 24 hours per year." This modification would provide the regulation in proportion to these units' impact on the BES. CONCLUSION: WHEREFORE, Consumers Energy Company urges NERC and the Standard Drafting Team for Project 2010-17 to reflect on these comments in developing the proposed Phase 2 BES definition.
Individual
Michelle D'Antuono
Occidental Energy Ventures Corp.
No
Occidental Energy Ventures Corp. (on behalf of all Occidental NERC Registered Entities) ("OEVC") believes that the literal application of FERC's directive creates vulnerabilities that must be addressed. First, E3 as proposed will require that no energy may flow out of the Local Network for any reason. This would include Reactive Power which is essential to supporting local system voltage. It is not inconceivable that entities will take steps to eliminate Reactive Power export in order to avoid the costs of reliability compliance. Similarly, there is no relief in exclusion E3 for the unintended outflow of energy under multiple contingency conditions. Already in Orders 773 and 773-A, FERC has taken a stance that there are no acceptable scenarios where an excluded Local Network may do so. We believe this is unreasonable, adds excessive costs, and does little to reduce Bulk Electric System risk. FERC's very conservative "no-exceptions" view will prevail by default if the drafting team does not provide the alternative language in the guideline document – and shown below for reference: "Real power flows only in the LN from every point of connection to the BES for the system as planned with all-lines in service and also for first contingency conditions as per TPL-001-2, Steady State & Stability Performance Planning Events P0, P1, and P2, and the LN does not transfer energy originating outside the LN for delivery through the LN to the BES."
No
Although OEVC believes the language changes for E1 and E3 adequately addresses the FERC directive, some entities have expressed a need for clarity when considering E1 and E3 for

cogeneration that would normally be excluded by application of E2. As OEVC understands the position of these entities, the logic of applying I2, then E2, and finally E1 or E3 according to the hierarchy could include, then exclude, and then re-include an industrial generator that would otherwise qualify for Exclusion E2. OEVC understands from the Webinar that this is not the intent of the SDT and that clarification will be made so that no one can misinterpret the SDT's intent. Also, the language in E3 might be interpreted to mean that ANY BES generation within an LN would disqualify the entity from claiming the E3 exclusion. It would seem that only the pathway from the BES generator to the BES should be included in the BES to satisfy the FERC directive and that the remainder of the LN might still qualify. (Perhaps this will be clarified in the Guidance Document). Finally, it still seems unnecessary to limit non-retail generation within the LN to 75 MVA when FERC has now stated that power cannot flow out of the LN under any conditions.
No
OEVC agrees in general with the approach taken by the SDT to derive the 30 kV limit. At some point, a practical limitation of the ability to evaluate the performance of the low-voltage system dictates that a threshold be set. Taken to the absurd logical extreme, without Note 2, the radial exclusion could be applied only after every 115 volt household connection was evaluated. However, without a view into the study results, we have no way to assess whether the 30 kV limit makes the most sense. We fully respect the project team's judgment, but it seems like this limit could easily be set at 70 kV without any noticeable reliability impact.
Yes
No
Group
Cooper Compliance Corp
Mary Jo Cooper
Yes
No
We agree that the Exclusion E3 is correct providing Including I2 is modified. We recommend that I2 is further clarified to include a more specific definition of a Generator Interconnection Facility (Transmission Interface) and provide clarification that the generation counted against the "aggregate capacity of non-retail less than or equal to 75 MVA (gross nameplate rating)" that disqualifies the radial exclusion in E1 or the local area network exclusion E3. Regarding the Transmission Interface, FERC recommendations contained in Docket No. RM12-16-000 define the Standards applicable to the Transmission Interface. These Standards are FAC-001-1, FAC-003-3, PRC_004-2.1a, and PRC-005-1.1b. We have identified a potential gap in which a generator is connected to a portion of a 115 kV line owned by a distribution provider prior to

connecting to what otherwise would be considered the BES. Absent the generator, the line would only be used to serve load and would be excluded under E3. We recommend clarification that does not require the distribution provider to register as a Transmission Owner and Operator based on the small section of line used as part of the Transmission Interface. Instead, we recommend that the distribution line also qualifies as a generator interconnection facility and is part of the transmission interface to the generator only. The following are our recommended changes to Inclusion I2. Generating resource(s) and dispersed power producing resources connected at voltage of 100kV or above, including the Generator Interconnection Facilities with: a) Gross individual nameplate rating greater than 20 MVA, OR, b) Gross plan/facility aggregate nameplate rating greater than 75 MVA. The Generator Interconnection Facilities include the generator terminals through the point of interconnection to the transmission elements that would otherwise be considered transmission elements included within the definition of Bulk Electric System. Regarding the clarification on what is counted towards the 75 MVA that disqualifies the radial or local area network exclusions, we believe it is the drafting teams intent that the count of generation is only to include generation that has been defined within the Inclusions or through the exception process. However, we feel the actual definition could be enhanced to provide this clarification. In separate comments made by the City of Anaheim they propose the following modifications to the definition, which we agree better defines this definition. Exclusion E1: E1 – Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and satisfies one of the following additional criteria: a) The radial system only serves Load. b) If the radial system includes only generation resources, the generation resources (i) must not satisfy the criteria set forth in either Inclusion I2 or Inclusion I3 and (ii) must not have an aggregate capacity of greater than 75 MVA (gross nameplate rating) directly connected to the radial system at a voltage of 100 kV or above. c) If the radial system both serves Load and includes generation resources, the generation resources (i) must not satisfy the criteria set forth in either Inclusion I2 or Inclusion I3 and (ii) must not have an aggregate capacity of greater than 75 MVA (gross nameplate rating) of non-retail generation directly connected to the radial system at a voltage of 100 kV or above. Exclusion E3: E3 – Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LNs emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customs and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following: a) Limits on connected generation: The LN does not include generation resources identified in Inclusions I2 or I3 and does not have an aggregate capacity of more than 75 MVA (gross nameplate rating) of non-retail generation directly connected to the LN at a voltage of 100 kV or above. b) Power flows into the LN; it rarely, if ever, flows out. The LN does not transfer energy originating outside of the LN for delivery through the LN.
Yes
No

See comment to question No. 2.
Yes
Yes
We recommend that the drafting team address what qualifies as a generator Interconnection Facility (Transmission Interface) for those radial lines that connect generation while addressing FERCs concern that generation has to be continuous. We do not believe that distribution facilities that serve load and that also have generation connected to it at 100 kV or above should automatically qualify as Transmission. We recommend that those facilities are Transmission Interface facilities and instead should be treated in the same manner as a Generator Interconnection Facility. We ask that the drafting team include within the definition of Bulk Electric System, the sub BES system otherwise known as the Transmission Interface. We propose the following definition of Transmission Interface: A Transmission Interface are the transmission line continuous from the generation identified in Inclusion I2 and I3 and the static or dynamic devices identified in I5 that absent the generation, static, or dynamic devices would be excluded under E1.
Group
City of Tacoma
Chang Choi
Yes
Yes
Yes
Comments: Many utilities utilize 35 kV distribution radial networks from a 2 or 3 transformer bank source. TPWR supports raising the 30 kV threshold to 35 kV.
No
TPWR supports the omitted I4 and does not support the revisions to the generation resources and dispersed power resources inclusions. The change will classify systems as BES that interconnects a generation unit with a peak generation capability of less than 2 MVA and typical capacity factor of 25-35 percent. It is difficult to understand how these small generation systems could be considered BES.
Yes
Yes
TPWR remains concerned regarding the limits imposed by b) on local networks. We note that by order 773A, FERC considers this limit to be absolute with no allowance for minimal reverse flows for even brief periods under multiple contingencies. While denying rehearing on this issue, FERC specifically invited Phase 2 to adjust this outcome in paragraph 79 of the order.

We also note that the BES Definition Reference would allow very brief flows out of a local network as long as the integrated hourly flow was still into the local network. There is no phase in period for a facility that loses its BES exclusion. For example, should a local network experience multiple contingencies that causes an unusual power flow disqualifying its exclusion, then 24 months should be allowed to resume BES applicability.
Group
PacifiCorp
Ryan Millard
Yes
No
Although PacifiCorp believes that the SDT has addressed the FERC directive, the directive in general allows for equivalent viable alternatives. PacifiCorp believes that FERC's directive is overreaching and fails to consider the already minimal upper limit of 75 MVA (gross nameplate rating) established in Exclusion E1. A generating resource's registration status or BES status should not have a bearing as to whether it must have a contiguous path to the BES. The previous limited upper limit of 75 MVA established a point at which the registered generator(s) would not interfere with the reliable operation of the interconnected system in the event of a loss of the < 75 MVA generator(s) or of the < 75 MVA generator's(s') ability to respond to the loss of critical generation elsewhere in the system. In the relatively few situations in which the registered generating resource is critical to the operation of the interconnected system, the associated transmission could be included within the scope of the BES through the approved exception process.
Yes
While the proposal is currently limited to a voltage level of 30 kV or less, PacifiCorp suggests an expansion of the language to include minimum voltage levels based on the characteristics of each interconnection (e.g., 30 kV for the Eastern Interconnection and 40 kV for the Western Interconnection).
No
PacifiCorp does not agree with the proposed changes to Inclusions I2 and I4 because such changes would include generating resources within the BES regardless of a resource's individual MVA rating and all of the equipment from each generator terminal to the > 100 kV transmission interconnection if the facility aggregate rating exceeds 75 MVA. A similar outcome was included in the Phase I definition in the previous version of Inclusion I4 that addressed dispersed power producing resources specifically and, as a result, one of the SDT's tasks in the Phase 2 SAR was to address the treatment of dispersed power producing resources. A dispersed power generating facility necessarily consists of individual units of a limited size to take advantage of the distributed nature of the resource (e.g., wind or solar) upon which the facility relies for its fuel source. One benefit of such facilities' unit size and geographical distribution is that they are not as susceptible to a substantial loss of generating

capability as a single unit of 20 MVA or greater (the registration threshold for a single generating unit). If the arrayed generators were each 2 MVA then the probability of losing 20 MVA at the generator level would be .00000001%. If the units were 5 MVA each the probability of losing all four units at the generator level would be .01%. The probability of losing a single 20 MVA unit would be 10%. These variations illustrate that there will be different values depending upon the arrayed generator's size. Given the reliability advantage this diversity affords it does not seem reasonable to treat this type of facility in the same way as a single unit facility of 20 MVA or greater. As recognized by the SDT and FERC in Order No. 773, a dispersed generating facility of 75 MVA or greater (NERC Registry Criterion Section III.c.2) can have an impact on the BES. To recognize this impact and to also account for the dispersed nature and reliability advantage as described above, PacifiCorp requests that the SDT strongly consider the following two potential alternative revisions to the proposed Inclusion I2: PacifiCorp's preferred option would be: "I2 – Generating resource(s) and dispersed power producing resources, with: a) Gross individual nameplate rating greater than 20 MVA, including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above, OR, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA, beginning at a bus where the aggregate generation is greater than 75 MVA and continuing through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above." The following diagram demonstrates the 75 MVA aggregation impacted by PacifiCorp's preferred option: (diagram provided to Wendy Muller at NERC). This preferred option would also include traditional sources of generation comprised of several small generators. NERC's registration criteria would still include this type of a facility as a registered GO or GOP. PacifiCorp's second option is: "I2 – Generating resource(s) and dispersed power producing resources, including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: a) Gross individual nameplate rating greater than 20 MVA, OR, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA. For facilities with an aggregate rating of 75MVA or more that consist of individual units rated at 4 MVA or less, the portion of the facility that is included in the BES as generation shall start at the point at which the 75MVA or greater aggregation occurs and continue out to the interconnection with the transmission system rated at 100 kV or more." Under this proposed change, a dispersed generating facility of 75 MVA or more consisting of individual generators of 4 MVA or less would be included in the BES definition as generation resources in a similar manner as other types of generation resources, but the unique nature of the small, distributed generating units that comprise them and their inherent reliability advantages would also be appropriately recognized in the definition. NERC's registration criteria would still include this type of a facility as a registered GO or GOP.
No
PacifiCorp does not agree with certain of the SDT's clarifying changes enumerated above, for the following reasons: • Item (b): rationale provided in response to question 4 above; and • Item (d): Reactive Power devices are often installed on substation busses less than 100 kV for the sole benefit of the retail customers of the utility. If a substation or substation bus is excluded from the BES through either Exclusion 1 or Exclusion 3 and is installed for the sole

benefit of the retail customers, then that device should also be excluded from the BES. PacifiCorp offers the following suggested wording for Exclusion E4 for the SDT’s consideration: Reactive Power devices installed for the sole benefit of retail customers.
No
Individual
Herb Schrayshuen
Self
No
The earlier version of exclusion E3 criterion requires a Local Network not to contain a monitored facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored facility in the ERCOT or Quebec Interconnections, and is not a monitored facility included in an IROL. The definition now is more vague. The original language was better. Facilities should be included in the BES only if the elements of the Facility are transferring significant amounts of power which would impact the reliability of the BES.
Yes
No
The 30 kV limit may be too low. 50kV or high limits may be technically justified. An analysis to support the choice of any limit is needed.
No
Proposal for I2 as follows: I2 - Generating resource(s) and dispersed power producing resources, including their power delivering assets operated at a voltage of 100 kV or above with:
No
It is never possible to determine whether a reactive device is for the "sole benefit" of retail customers. The presence of a reactive device may benefit the retail customer from a rates perspective or a local voltage perspective, but the presence of the reactive device, no matter where it is located, even at the distribution level, also provides system wide BES/BPS benefits.
Yes
NERC is an international body. The BES SDT in any next version of the Phase 2 definition should take full account of Canadian regulatory frameworks. NERC must consider all jurisdictions. The existing legislated definitions of "distribution" in the Provinces must be allowed for in any definition of BES even if it is though a "local jurisdiction" exception footnote.
Group
Pepco Holdings Inc & Affiliates
David Thorne

Yes
Yes
Yes
While we agree this approach addresses the Commissions sub-100 kV loop concerns for radial systems, the choice of a 30 kV threshold seems somewhat arbitrary. The intent is to allow small “distribution system” loops between connection points and still satisfy the E1 exclusion for radial transmission systems. IEEE 100 “The Authoritative Dictionary of IEEE Standard Terms” defines a Distribution Line as “Electric power lines which distribute power from a main source substation to consumers, usually at a voltage of 34.5 kV or less.” Based on this industry standard definition, we believe a 40kV threshold would be more appropriate, so as to allow all looped distribution circuits, including those operating at 34.5kV, to satisfy Exclusion E1 for radial systems. Additionally, the rationale box included as part of Note 2 states: “…..As a first step, regional voltage levels that are monitored on major interfaces, paths and monitored elements to ensure the reliable operation of the interconnected system…” Just because elements are monitored, does not necessarily mean that those elements are specifically critical to the reliable operation of the system. In many cases it is strictly a function of providing adequate data for the modeling of the system. It would be unlikely that an underlying distribution loop would have any significant impact on the transmission system. It may be possible that the underlying loop system may itself have flow problems, but that is not the same as that loop creating a problem on the transmission system.
Yes
Yes
Yes
There were many suggestions and comments on the first draft of the BES Reference Document. As the SDT continues to revise the document, it is hoped that the SDT consider including additional figures to provide for clarification. It is recognized that there are probably many individual, unique configurations and that every one of them cannot or should not be included. However, consideration should be given to general clarifications that will aid the entire industry in understanding the details of the definitions application.
Individual
Donald Weaver
New Brunswick System Operator
Agree
NPCC Reliability Standards Committee
Individual

Randi Nyholm
Minnesota Power
Agree
MRO NERC Standards Review Forum (NSRF)
Individual
Daniel Duff
Liberty Electric Power LLC
Agree
Essential Power
Group
Southwest Power Pool Regional Entity
Emily Pennel
Yes
Yes
Yes
Yes
Yes
No
Group
DTE Electric
Kent Kujala
Yes
Yes
No
30kV is too low, 60kV would be more realistic. The lower the voltage chose the great the burden on industry in excluding these elements with no corresponding benefit to reliability.
Yes

Yes
No
Individual
Thomas Foltz
American Electric Power
Yes
Yes
No
While AEP does not necessarily disagree with the 30KV threshold, we are however confused by the concept of a contiguous loop being part of a radial feed, as we find “radial” and “loop” as mutually exclusive terms. This phrase is ambiguous and needs further clarification before a voltage threshold can be discussed.
No
AEP does not believe that the generator terminals of individual dispersed power producing resources should by default be included in the BES definition. We suggest revising I2 to include dispersed power producing resources from the point of connection where the resource’s aggregate nameplate rating is greater than 20 MVA through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above. As currently drafted, individual wind turbines would be included as part of this definition. AEP offers the following additional reasons why individual wind turbines specifically should not be in scope: *Given their small size and interment availability of the prime mover, they do not individually constitute a risk to the reliability of the BES. * The ability of the GO to perform maintenance and testing activities required by PRC-005-2 is limited due to the physical design of the system and may also be limited due to warranty agreements with the OEM. * A wind farm may experience hundreds of breaker operations a day and have not automated ability to determine whether the operation was caused by a Protection System operation. Under this scenario, the resources needed to show compliance with the proposed PRC-004-3 may be unduly burdensome to the GO.
Yes
Yes
Under E3, did the team intend to also eliminate the 100kv threshold from the phrase “LN’s emanate from multiple points of connection at 100 kV or higher to improve the level of service…”?

Individual
Mike Hirst
Cogentrix Energy Power Management, LLC
Agree
North American Generator Forum: Standards Review Team
Individual
Kenneth A Goldsmith
Alliant Energy
Agree
MRO NSRF
Individual
Jason Snodgrass
Georgia Transmission Corporation
Yes
Yes
Yes
Because of the addition of “dispersed power producing resources” to I2…GTC believes it’s more appropriate to replace the term “generator” with “resource” in the following phrase: ..."including the generator terminals through the high-side..."
Yes
Yes
GTC recommends the additional clarifier to E4: Reactive Power devices installed for the sole benefit of a retail or wholesale customer.
Group
Iberdrola USA
Joe Turano
Yes
Yes
Yes

Yes
Yes
It seems counter-intuitive that a 600 MVAR dynamic range SVC directly connected to the 345 kV system would have the 345 kV bus and the 18 kV bus-connected capacitive & reactive equipment be BES, yet the 345/18 kV transformer would not be BES. The NERC “BES Definition Reference Document” is an important aid in interpreting different circumstances of applicability of the BES Definition. It should be kept up to date as the definition changes, with specific examples of applications of those changes. Specific comments on the “Reference Document” are: • For BES Exclusion E2 (behind-the-meter customer-owned generation), the NERC SDT recommends using 1 year of integrated hourly revenue metering to test for flow into the BES of less than 75 MVA. However, for BES Exclusion E3 (local networks), the NERC SDT recommends using 2 years of integrated hourly metering to test for flow into the BES at all points of connection of the candidate local network to the BES. • Several figures seem to have possible exclusions that are not mentioned, in portions of those figures. Specifically: o Figures E1-4a, E1-5, and E1-6 have the same 15 MVA, then 10 MVA generator on the middle left of the diagram that could have its generator lead to the tap point qualify for a radial exclusion; but the tapped lead is shown as BES. The vertical blue line from the ≥100 kV bus would still be BES. o Figures E1-7a, E1-8a, E1-9, and E1-10 have either radial loads or industrial customers with retail generation on the middle left and right of the diagram that could have their tapped supply lines qualify for a radial exclusion; but the tapped lines are shown as BES. The vertical blue line from the ≥100 kV bus would still be BES. o Figure S1-9b only considers the 69 kV network as a candidate for a local network exclusion. This is not a valid consideration, because whether or not the red arrows point up or down, the 69 kV system is not BES by nature of the core definition. Moreover, there are not enough points measured to determine flow polarity of the parallel parts of the 138 kV system. It would be necessary to either/also measure 2 other points on the 138 kV network for that network to be a candidate for the local network exclusion. No conclusions or recommendations can be drawn from this example as shown. Figures S1-10, S1-11, and S1-12 show the entire 138 kV loop on the left of the diagram as a local network exclusion (shown as green) – as noted above this is not consistent with FERC Order 773 and 773-A, nor Figures S1-9a and S1-9b.
Group
IRC Standards Review Committee
Greg Campoli
No
We are unable to find the technical justification for removal of the 100kV threshold. We are unable to support this until the technical basis is presented.
Yes

No
The SDT describes the steps taken that led to proposing the 30 KV limit in Note 2 for which an entity does not have to consider a loop between two otherwise radial systems. However, the steps presented are not in our view technical justification for the proposed threshold. Before we can support this proposal, we would appreciate the SDT provide technical justification as to why 30kV is the appropriate level but not any other voltage levels, e.g. why not 50kV or 69kV?
Yes
Yes
No
Individual
Diane J. Barney
New York State Department of Public Service
No
While the goal of having some cut off level below which the facilities can clearly be eliminated from consideration is theoretically reasonable, history has demonstrated the designation can be abused and used for alternative purposes. There is no technical basis for the 30 kV cut off. NERC has an obligation to provide technical advice to FERC, so that any number provided to FERC is interpreted as technical advice. NERC should not include any numbers in any definition or standard for which it cannot provide a technical basis. Surveys do not provide a technical basis. Discussions have indicated that because facilities less than 100 kV triggered a major event in the southwest, a lower level voltage needs to be identified. Note that if either the current NERC BES definition or a functional analysis had been applied to the system at issue, either definition approach should have identified the involved facilities as bulk elements. A lower threshold would therefore be superfluous, and would be over-inclusive to an even greater degree than the current definition.
Yes
NERC has an obligation to provide technical advice to FERC, so that any number provided to FERC by NERC is interpreted as technical advice. A major purpose of the BES Phase II effort was to establish a technical basis for the 100 kV brightline and the 20/75 MVA generation levels. While NERC has provided a report purportedly providing a technical basis for these threshold levels, the report fails to do so. NERC should not include any numbers in any

definition or standard for which it cannot provide a technical basis. Surveys do not provide a technical basis. Particularly troublesome is the presentation of alternatives to the 100 kV brightline. The report authors looked at 5 alternatives to establishing a technical basis for determining the bulk system. The report failed to evaluate the methodology historically applied to the NPCC system. If a major NERC region was able to successfully apply their methodology, why was it not evaluated and why would it be impossible to expect other regions to perform a similar analysis as the base for determining the BES?
Individual
Michael Falvo
Independent Electricity System Operator
Yes
Under the premise that the very first paragraph of the BES Definition already establishes the bottom voltage threshold of 100kV, we agree with removing the mention of the 100kV bottom threshold in exclusion E3.
Yes
In general we agree with these changes and propose the following alternative language for more clarity: 'Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above, and dispersed power producing resources connected at a common point at a voltage of 100 kV or above with;'
No
The IESO does not agree with this approach as we identify two major concerns related to Note 2 in Exclusion E1. First, by adding a new voltage threshold of 30 kV, a new category of "wires" operated at voltages between 30 kV and 100 kV which may become part of BES is effectively created. On the one hand, this would be inconsistent with the BES definition introductory paragraph (Bulk Electric System (BES): Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy). On the other hand, this could result in a huge effort/cost in part of all facility owners as it appears that the intent is to include this new category of "wires" in the BES elements and potentially rely on the BES Exception process to exclude them one by one. Second, the demarcation point between transmission and distribution may be different in non FERC jurisdictions, such as Canadian provinces. For example, in Ontario, legislation establishes 50kV as the technical boundary line between transmission and distribution. In establishing voltage thresholds, NERC needs to consider non-US legislated demarcation points, and the standard development process must make allowances for such regulatory and/or jurisdictional differences. The establishment of the voltage floor for the E1 exclusion is inconsistent with the language and structure of the legislative framework in Ontario. Furthermore, we believe that the exception process is not appropriate to determine the jurisdictional issue of whether facilities are part of the bulk power system. Therefore, the IESO proposal is to remove Note 2 altogether from Exclusion E1 and rely on the BES Exception

process to determine facilities operated below 100 kV that must be included in the BES. In the alternative that Note 2 in Exclusion E1 is retained, we request that it be modified to read as follows: “Note 2 – The presence of a contiguous loop, operated at a voltage of 30 kV or less, between configuration being considered as radial systems, does not affect this exclusion for US registered entities. For a non-US Registered Entity, the voltage level should be implemented in a manner consistent with the demarcation points within their respective regulatory framework.
Yes
In general we agree with these changes and propose the following alternative language for more clarity: ‘Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above, and dispersed power producing resources connected at a common point at a voltage of 100 kV or above with;’
Yes
Yes
1) NERC must ensure that any new or changes to standards as a result of FERC directives that apply to load reliability and load supply continuity are limited to the FERC jurisdiction only. In Canada, local load reliability requirements are under the authority of local regulators such as the Ontario Energy Board in Ontario. 2) Implementation Plan may result in a conflict with Ontario regulatory practice with respect to the effective date of the standard. It is suggested that this conflict be removed by appending the effective date wording, after “applicable regulatory approval” in the Effective Dates Section of the Implementation Plan, to the following effect: “, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.” prior to the wording “In those jurisdiction….”. The same changes should be made to the first sentence in the Effective Date Section of the proposed Definition document. 3) In our opinion, SDT has correctly crafted the language in E1 and E3 in the approved definition. To address some of the FERC concerns, it may be simpler and clean to introduce a new inclusion “I” for sub 100kV system(s) that are used for bulk power transfer (not a sink) across the BES from one area to the other.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
No
The change in the question was evidently intended to cover the 34.5 kV interconnection systems of wind farms, but it also pulls into the BES the 230 kV feeders supplying aux power for fossil plants (compare Figs. E1-7 and E1-7a in the FERC order 773/773a-amended Guidance Document). The HV-to-MV transformers for aux loads may be included as well (no per Fig. E1-7a, yes per SDT inputs in the 6/26/13 webinar if the transformers are of the 2 or 3-winding type). It makes sense to include in-line components (i.e. the GSU-to- connection point conductors), but there does not appear to be any justification for adding auxiliary

transformers and their HV feeders to the BES. These are in-house systems that have no significance for the grid in general. The change to E3 should have been limited to wind farms.
No
See comments above.
Yes
Yes
Yes
Yes
The language of the proposed BES definition is rather convoluted and is therefore difficult to apply correctly without the Guidance Document. The FERC order 773/773a-amended Guidance Document is not complete or final for the Phase-2 BES definition. Its exclusion E1 statement is that of phase-1, not Phase-2, for example, and a disclaimer on p.1 states that "…this reference document is outdated. Revisions to the document will be developed at a later date to conform to the definition being developed in Phase 2." It appears that the Phase-2 BES definition is being rushed through the approval process, and it would be preferable to take the time to compile a complete and
Individual
Michael Lowman
Duke Energy
Yes
Yes
Yes
Yes
No
Duke Energy believes the SDT should consider changing the language of E4 to "Reactive Power devices installed for the benefit of a retail customer(s)."
Yes
Duke Energy believes that ambiguity exists between the industry and FERC within the language of E1 regarding "single point of connection". See paragraph 138 and 142 of Order 773. The language "single point of connection" in E1 should be revised for clarity. If E1 is edited, the change may impact the terminology used ("multiple points of connection") in E3.

Individual
Jim Thate
Delta-Montrose Electric Association
Yes
The proposed BES definitions need more clarification, and the utilities should be granted more time for comments and responses.
Individual
Barbara Kedrowski
Wisconsin Electric
No
Wisconsin Electric agrees with the NAGF comments in response to Question 1.
No
Wisconsin Electric supports the comments filed by the NAGF in response to this question with the following edits: “The equipment being included in the BES definition should only be that equipment that actually carries greater than 75 MVA – the collector systems, main transformers, and high-voltage interconnections, not the individual wind turbines. Implementing standards at the individual wind turbine level (<2 MW in many cases) does not improve reliability and only creates additional workload for both the registered entities and the Regions. A 2 MW wind generator will neither have an impact due to the loss of generation nor cause cascading outages due to a failure to trip a 600 volt machine.
Yes
1. Wisconsin Electric is concerned that the drafting team has not considered the potential impacts of the proposed definition on other standards or their requirements. For this reason the definition should be rejected until such time as adequate consideration has been given to such inter-dependencies and potential impacts on various standards which assume a BES definition for their related requirements. 2. Wisconsin Electric participated in the June 26th webinar and during the webinar it was stated that the PRC and CIP standards have unique and unrelated BES bright line criteria. The final definition of BES must apply to all standards in a clear and unambiguous manner. Under the CIP Version 5 standards, clarification is needed to

determine whether wind turbine controls become “Low Impact BES Cyber Systems” under the bright line criteria. 3. Wisconsin Electric agrees with the NAGF comments to Question #6 Part 1. 4. Clarification should be provided that the BES definition pertains only to normal operating conditions.
Individual
Melissa Kurtz
US Army Corps of Engineers
Agree
MRO NSRF
Individual
Daryl Hanson
Otter Tail Power Company
Agree
MIDWEST RELIABILITY ORGANIZATION NERC Standards Review Forum (NSRF)
Individual
David Jendras
Ameren
Yes
Yes
No
(1) We believe that the threshold of 30 kV is too low and needs to be raised to at least 70 kV because subtransmission facilities are not intended to transfer power long distances and do not respond to regional or interregional transfers. We believe that using a least common denominator approach for voltage levels does not align with the intended use of the low voltage networks in providing energy to firm loads throughout the Midwest. (2) At our subtransmission facilities directional overcurrent relays are installed on all of the stepdown transformers from the BES to limit the backfeed from the subtransmission system to the transmission system. We request the SDT to consider a distribution factor or powerflow cutoff in its discussions. We are not proposing significant contingency analyses be performed per the TPL standards in order to qualify for the exclusion. However, the proposed threshold of 30 kV without considering the network response, or magnitude of back-feed, or application of directional overcurrent relays on non-BES transformers appears to us to be too simplistic and arbitrary for this exclusion definition. (3) If multiple generating units connected at a common point to the BES but less than 75 MW are determined to be non-BES, it would seem that the low voltage networks and their supplies having a similar impact would also be determined to be non-BES.
Yes

We request that the SDT renumber the Inclusions to yield I1 through I4 (i.e. move the I5 language to I4), as we believe this will be clearer than having a blank or unused I4.
Yes
Yes
The determination of BES facilities should be straight-forward and easy for both entities and auditors to review and understand. We agree that, implementation of some bright-line criteria to determine BES facilities are in the best interest of reliability. We encourage the SDT to streamline the 78 page BES guidance document because we feel the process of determining BES facilities is still not straight-forward.
Group
Southern California Edison
Marcus Lotto
No
SCE agrees with the deletion of the phrase “… or above 100 kV but…” from the Local network (LN) exclusion language (E3). However, SCE believes that even with this change the E3 exclusion will be of little benefit in clarifying the issue FERC identified in Order 773-A. As revised, the exclusion will still bring into the scope of the BES definition facilities that have no impact, and were never envisioned to be a part of the BES. Moving forward, SCE recommends that the SDT consider revising the definition to remove the generation threshold from E3 a, especially if it intends to keep the current E3 b “Power flows only into the LN” language the same. With E3 b in-place, as currently written, it doesn’t matter how much generation is located in a LN if the load is sufficiently large that there is no flow out of the LN to negatively impact the BES. Another approach would be to revise E3 b by deleting the language “Power flows only into the LN” language. FERC does not seem to be adverse to minimal power flowing out of a LN: In Order 773A FERC declined to direct NERC to allow minimal flows up to a 100MVA limit to transfer out of an LN, but indicated that the Phase 2 project was a more appropriate forum to pursue this matter further. The best option would be to combine the two approaches outlined above. This would truly characterize LNs and clearly eliminate from the exclusion those looped facilities which operate in parallel with the BES.
No
By revising E1 in this manner, the SDT eliminates the issue of identifying dispersed power producing resources, but in-turn creates a more restrictive definition as it relates to the “wires and lines” component of the definition. The SDT definition is too heavily reliant on static Generator MVA thresholds, which should not be the major determining factor for bringing LNs, and now Radial lines, into the BES definition. The original FERC directive in Order Nos. 743 and743-A asked that the functional test be used in the determination as a first step for BES determination, and should be incorporated in the procedures for inclusion of the LNs into the BES. SCE’s position is that facilities operated in-parallel with BES should be considered part of the BES regardless of voltage level. For the “wires and lines” side of the BES definition,

the “impact on the Bulk Power System, should be a determining factor for identifying these LNs or Radial systems as BES, not the total amount of interconnected generation.
No
The alternative identified as “Note 2” in the proposed Phase 2 BES Definition gives preferential treatment to contiguous looped facilities, which should be defined as LNs. The rationale used to justify this particular exclusion should be modified and included in the BES Guidance Document so that it can be applied to both the E1 and E3. With some minor revisions, the E1 loop exclusion rationale could similarly be applied to LNs which connect to multiple points, such as within substations with double breaker and breaker-and-a-half configurations. Another alternative would be to identify LNs interconnected to the BES with breaker-and-a-half configurations as radial systems, and be eligible for the E1 exclusion. In addition, the 30kV looped facilities threshold identified for exempting looped radial facilities is too low. This threshold has the potential to include facilities owned and operated by transmission dependent utilities/ “Distribution Providers” into the scope of the BES definition.
Yes
SCE requests that NERC properly define “non-retail generation.” SCE’s understanding of the term “non-retail generation” is to describe those generation facilities whose purpose is to exclusively sell power into wholesale markets. This understanding would define Co-Generation facilities as “non-retail,” and therefore not counted in the 75 MVA aggregate threshold amount. In addition, the 75 MVA aggregate thresholds defined by the gross nameplate MVA rating of the generators would count generating facilities where the generators individually and/or in aggregate meet the 75 MVA threshold but exports less than 75 MVA to the grid. The clarification of “non-retail” generation is important since summing-up generators producing this power is a major factor for determining what “wires and lines” meet/ don’t meet the E1 and E2 Exclusions.
Individual
Kathleen Goodman
ISO New England Inc.
Yes
Yes
No
The 30 kV limit in Note 2 for which an entity does not have to consider a loop between two otherwise radial systems should be raised to 50 kV. There are numerous 34.5 kV and 46 kV circuits used in distribution that would require review with the 30 kV limit. The review required for those 34.5 or 46 kV circuits is not warranted.

Yes
Yes
No
Group
ACES Standards Collaborators
Jason Marshall
Yes
While we believe the concerns expressed by the FERC directive could have been handled through the bulk electric system (BES) exception process, we agree that the proposed changes do address the FERC directive. Most transmission above 100-kV that terminates into sub-transmission below 100 kV should be treated as radial since its impacts on the BES, in most cases, is negligible. Since the vast majority of networked facilities below 100 kV will not ultimately be part of the BES, it would make more sense to use the BES exception process to include those that do impact the BES rather than subject all instances to the more complicated E3 exclusion.
Yes
The modifications appear to address the directive. It removes the possibility that the BES will not be contiguous from a generator connected at 100 kV or higher and the rest of the BES that is 100 kV or higher. Furthermore, it does not appear to draw in sub-transmission facilities that are connected below 100 kV to generator facilities that are included by inclusions I2 and I3. For example, a Blackstart Resource connected on a 69 kV line may be part of the BES but the 69 kV facilities connecting the unit to the BES would not be. Assuming this is correct; we agree the changes address the directive appropriately.
No
While we agree with the approach and thank the drafting team for their creativity in coming up with the approach, we think it needs more refinement. There is a high level description in the supporting documents of how this approach was arrived at. However, there is a dearth of details. We think more details are necessary to agree to the appropriate voltage level cutoff. For instance, 34.5 kV is a common distribution voltage that can be networked. It is hard to fathom any networked 34.5 kV system could have a material impact on the BES because of its relative high impedance. Thus, at a minimum, we suggest raising the cutoff to 35 kV to address these situations. We also suggest supplying the detail data/reports that were used to arrive at the 30 kV cutoff.
No
(1) While we are not opposed to combining I2 and I4, we think I4 provides additional clarity and granularity. I4 collectively with the Phase 1: BES Definition Reference Document is very

clear that the collector system is not included in the BES. Exclusion of the collector system is not clear from I2 particularly without a modified reference document. If the combination of I2 and I4 persists, we recommend that the reference document should clearly state that the collector system is not included similarly to the current version. (2) We do not understand why the question states that the changes address Commission concerns. The Commission was very clear in approving I4. Paragraph 58 of Order 773-A states the “Commission … confirms its finding that including I4 provides useful granularity in the bulk electric system definition.” By combining I4 into I2, this granularity is removed.
Yes
(1) In general, these are clarifying changes and we are supportive of them. However, one change is not a clarifying change but is in fact a substantive change. Changing “a monitored Facility of a permanent Flowgate…” to “any part of a permanent Flowgate…” is not a clarifying change but is in fact a substantive change. Consider that a Flowgate contains a monitored facility and often a contingent Facility. The contingent Facility will now be included whereas it was not previously included. In the end, these contingent Facilities probably will already be included by the bright line 100 kV threshold as they are usually a larger facility than the monitored facility. However, this should not be represented as a clarifying change. (2) “OR” should be “or”.
Yes
Given that Facilities below 100 kV could be included in the definition of the BES by the BES exception process, the drafting team should consider removing “of 100 kV or higher” from E1. Any radial facility regardless of voltage class should be excluded. By removing the clause, we think it will offer further support to exclude radial facilities below 100 kV that a requester may attempt to add via the BES exception process. We understand the exclusion is intended to apply to the bright line definition of 100 kV which offers further reason to remove the clause. Because it can only ever apply to 100 kV or higher facilities, it is superfluous.
Individual
Randy MacDonald
NB Power Transmission
Agree
NPCC Reliability Standards Committee
Group
North American Generator Forum Standards Review Team
Patrick Brown
No
The change in question was evidently intended to cover the 34.5 kV interconnection systems of wind farms, but it also pulls into the BES the 230 kV feeders supplying aux power for fossil plants (compare Figs. E1-7 and E1-7a in the FERC order 773/773a-amended Guidance Document). The HV-to-MV transformers for aux loads may be included as well (no per Fig. E1-7a, yes per SDT inputs in the 6/26/13 webinar if the transformers are of the 2 or 3-winding

type). It makes sense to include in-line components (i.e. the GSU-to- connection point conductors), but there does not appear to be any justification for adding auxiliary transformers and their HV feeders to the BES. These are in-house systems that have no significance for the grid in general. The change to E3 should have been limited to wind farms.
No
See comments for Question 1
Yes
No
The equipment being included in compliance with NERC Standards should only be that equipment carrying >75 MVA - the collector systems, GSU and Gen Tie, not the individual turbines. Implementing standards at the individual wind turbine level (< 2MW in many cases) does not improve reliability and only created additional workload for both the registered entities and the regions. A 2 MW wind generator will neither have an impact due to the loss of the generation nor start cascading outages due to a failure to trip a 600 volt machine. As a point of reference, many large generating stations have station service loads of that magnitude.
Yes
Yes
The language of the proposed BES definition is rather convoluted and is therefore difficult to apply correctly without the Guidance Document. The FERC order 773/773a-amended Guidance Document is not complete or final for the phase-2 BES definition, however. Its exclusion E1 statement is that of phase-1, not phase-2, for example, and a disclaimer on p.1 states that "…this reference document is outdated. Revisions to the document will be developed at a later date to conform to the definition being developed in Phase 2." It appears that the phase-2 BES definition is being rushed through the approval process, and it would be preferable to take the time to compile a complete and consistent body of documentation before putting the matter up for a vote.
Individual
Michael Moltane
ITC
Yes
Via the information disseminated by the SDT, it appears to us that the drafting team intended

the additions to E1 to essentially say that loops between radial systems at voltages over 30 kV are BES and cannot be excluded through the application of E3b. This is an attempt at establishing as much of a bright line as possible and is embodied in Note 2 under E1. We are having trouble seeing this in the proposed standard language. Regardless, to meet this intent the language in E1 needs to be cleaned up and E3b removed. Alternatively, another Inclusion could be added to cover the above 30 kV networked facilities to meet this intent. Further, we don't agree with establishing a 30 kV bright line for parallel systems, as we envision this being fought in the courts as an encroachment into distribution, and will get bogged down. Rather, something that can be reasonably expected to be adopted now should be proposed so that we can get clarity/alignment with the phase 1 effort and then come back for a phase 3 effort to determine the best process for dealing the sub-100 kV networks. The reference to 30 kV should be removed altogether and the PC recommendations for E3b should be adopted (The PC recommendation follows): (Begin PC quote) ""Real power flows only in the LN from every point of connection to the BES for the system as planned with all lines in service and also for first contingency conditions as per TPL-001-2, Steady State & Stability Performance Planning Events P0, P1, and P2, and the LN does not transfer energy originating outside the LN for delivery through the LN to the BES."""""""" (end of PC quote) Note that the first contingency conditions referred to above must include contingencies of elements within the proposed Local Network in addition to contingencies on the proposed BES. This should be explicitly stated in the standard so there's no confusion. Finally, TPL-001 indicates that it is the Planning Coordinator and the Transmission Planner responsibilities to perform the studies. For the purposes of application of the proposed exclusion E3b we recommend that one functional entity be responsible for this determination (probably the Planning Coordinator).
Individual
Spencer Tacke
Modesto Irrigation District
No
There is no technical basis or study to support the change.
No
Yes
No
1. WECC studies have shown that there are thousands of MWs of wind and PV generating plants currently on-line, and thousands of MWs under development, in the WECC system, of 20 MW and less capacity. Ignoring the impacts of these units on the BES would be a mistake, as recent studies by the WECC MVWG (Modeling and Validation Work Group) have shown. 2. The revisions have made the definition of the BES so complicated, that the definition is no

longer in a form that can be applied in a straight forward and reasonable manner. Also, there are no technical justifications provided for some of the exclusion criteria (e.g, 75 MVA and 300 kV values).
Individual
Don Streebel
Idaho Power Company
Yes
We agree that making the changes that are the subject of Q1 meets the Commission's directive to "modify the local network exclusion to remove the 100 kV minimum operating voltage to allow systems that include one or more looped configurations connected below 100 kV to be eligible for the local network exclusion".
Yes
We agree that making the changes that are the subject of Q2 meets the Commission's directive to "implement exclusion E1 (radial systems) and exclusion E3 (local networks) so that they do not apply to generator interconnection facilities for bulk electric system generators identified in inclusion I2".
Yes
Idaho Power System Protection group: Yes, we agree with the approach in general, but are concerned with a 30kV cutoff. In our system, connections are made in our distribution load service at 35kV. If we are interpreting the language correctly, an evaluation would be required for all of our 35kV load service for any connections in that subsystem, which represents a significant additional burden. Idaho Power System Planning group: We are in favor of adding note 2 to Exclusion E1 of the BES definition. However, we would suggest rewording note 2 as follows, while matching the simplicity of note 1 of Exclusion E1: "A tie operated at a voltage of 30 kV or less between radial systems does not affect this exclusion." We believe it is not the intent to place the threshold of 30 kV or less on the contiguous loop that is created by adding the tie between the two radial systems, but rather the intent is to place the threshold of 30 kV or less on the tie itself between the two radial systems.
Yes
What is lost in deleting I4 per se and rolling up "dispersed power producing resources" into I2 is the distinctive characteristic of dispersed power producing resources of "utilizing a system designed primarily for aggregating capacity, connected at a common point ". Without making this distinction, the "dispersed power producing resources" are just another generating resource. Therefore, there is no need to add "dispersed power producing resources" to I2 if I4 is deleted per se as suggested. At the same time, if the distinctive characteristic of dispersed power producing resources of "utilizing a system designed primarily for aggregating capacity, connected at a common point " was also rolled up to I2, then why delete I4 at all? IF the recommendation to delete I4 and modify I2 as presented in the Project 2010-17 draft 1 is the decision of the Project Team, we would recommend further adding "utilizing a system designed primarily for aggregating capacity, connected at a common point" to clarify

"dispersed power producing resources". In conclusion, we would not be in favor of making the changes that are the subject of Q4.
Yes
We would be in favor of making the changes that are the subject of Q5.
Yes
Another issue that came up, relative to Q4, is that even with the clarification of the "dispersed power producing resources", the question remains as to how to treat new and existing, large and small generator sources connected to feeders that connect to the same BES bus. Do we need to keep a running total of the installed aggregated capacity and then, once the 75MVA aggregate threshold is reached, change the BES classification of all these previously non-BES units? It would be hard to argue that these are NOT “utilizing a system designed for aggregating capacity”.
Individual
Edward O'Brien
Modesto Irrigation District
Agree
sacramento Municipal Utility District Balancing Area of Northern California
Individual
Tommy Drea
Dairyland Power Cooperative (DPC)
Agree
DPC supports comments submitted by the MRO NSRF.
Individual
Rich Salgo
NV Energy
Yes
Yes
Yes
While the details of the threshold voltage are still being ironed out, the concept of this note acheives the objective of properly allowing for E1 exclusions in the presence of distribution circuit loops or ties.
Yes
Yes, this was an efficient change to consolidate the two inclusions and in the long run, will eliminate confusion and possible inconsistency.
Yes

No
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
However, ATC believes this would not include the significant network facilities below 100kV. This would have to be addressed through a revision to the Inclusions.
Yes
However, ATC would like clarification on Blackstart resource paths that are operated at < 100kV. A Blackstart resource would be included in the BES per I3; however the path that is less than 100kV would not be included in the BES.
No
ATC believes the 30kV threshold is too low and should be increased to at least 50kV.
Yes
ATC has no comments.
Yes
No comments.
Yes
Please clarify that E3b is to be applied for normal (intact) and emergency system conditions. Rewording suggestion is as follows: E3b) Power flows only into the LN under normal and emergency conditions and the LN does not transfer energy originating outside the LN for delivery through the LN; Also ATC believes the SDT should include a note to define normal and emergency conditions.
Individual
Tony Kroskey
Brazos Electric Power Cooperative
Agree
ACES Power Marketing
Group
Colorado Springs Utilities
Kaleb Brimhall
Yes
Yes

No
1.Can the standards drafting team clarify the reliability issue that they are trying to mitigate with this language? What are we trying to prevent? 2.Why was the 30 kV threshold chosen as opposed to any other voltage, what is the technical justification? a.Instead of a kV threshold can we use a capacity rating, for example – use the 75 MVA rating used for collection point asset inclusion? I know that there has been some discussion on this already, but we are not convinced that 30kV is a sound threshold. 3.If we do decide to stay with a kV rating, then we need to ensure that the “nominal voltage” is used as opposed to an “operating voltage.” This is important to prevent a one-time operating voltage from drawings something in. 4.The “notes” should be incorporated into the definition itself, not left as notes to create confusion or additional need for clarification down the road.
Yes
1.Define “dispersed power producing resources."
Yes
Yes
1.We appreciate the clarifying language change of E3c. Monitoring status should not necessarily include or exclude a Facility from the BES. We want to make sure that we do not discourage or hamper monitoring of facilities by incorrectly involving Facilities that are “monitored” but do not have an effect on the BES into this definition or other NERC standards.
Group
Hydro One Networks Inc.
David Kiguel
No
Although the proposed change addresses the FERC directive, we do not agree with deleting 100 kV. Under the premise that the very first paragraph of the BES Definition already establishes the bottom voltage threshold of 100 kV, its deletion may introduce ambiguity and confusion. By definition and as per FERC Order 773 “the Commission stated that the core definition also establishes a 100 kV criterion as a bright-line threshold” unless lower voltage elements are included by the exception process and that distribution systems should not be BES. Hence, we believe that, as the SDT correctly stated “above 100kV” in the currently approved definition and E3 are consistent with the intent of BES definition. Finally, it is worth noting that NERC is an international reliability standards setting organization and the BES definition was also approved and/or accepted by the applicable governmental authorities in other jurisdictions. Finally it is worth pointing that, in Order 773, the Commission further stated that “the 100 kV threshold is a reasonable “first step or proxy” for determining which facilities should be included in the bulk electric system. Indeed, it is reasonable to anticipate that this threshold will remove from the bulk electric system the vast majority of facilities that are used in local distribution, which tend to be operated at lower, sub-100 kV voltages”

Yes
We agree that transmission element(s) and/or generation should not be excluded by definition. However, it is important to clarify that such configurations can be excluded through the exception process if and when they are not necessary for the operation of BES or interconnected BES.
No
Exclusion E1 provides a floor (30 kV threshold) which an entity does not have to consider the loop in its determination of a radial system. Data provided to the drafting team shows that there are no transmission elements below 50 kV in Ontario (and Canada) and very few in the 30-59 kV range (1%) in the US. A sub-set of this 1% can be included as BES through the exception process if deemed necessary for the operation of interconnected BES. The demarcation point between transmission and distribution may be different in non FERC jurisdictions, such as the Canadian provinces. Accordingly, we suggest that the 30 kV threshold be adjusted to 50 kV for Ontario (and Canada), since legislation establishes 50 kV as the technical boundary line between transmission and distribution. It would also alleviate any “unintended consequences” in future standards development. For example, in Ontario, legislation establishes 50 kV as the technical boundary line between transmission and distribution. In establishing voltage thresholds, NERC needs to consider non-US legislated demarcation points, and the standard development process must make allowances for such regulatory and/or jurisdictional differences. The establishment of the voltage floor for the E1 exclusion is inconsistent with the language and structure of the legislative framework in Ontario. Furthermore, we believe that the exception process is not appropriate to resolve the jurisdictional issue of whether facilities are part of the BES or not. As such, Note 2 should be modified to read as follows: “Note 2 – The presence of a contiguous loop, operated at a voltage of 30 kV or less, between configurations being considered as radial systems, does not affect this exclusion for US registered entities. For a non-US Registered Entity, the voltage level should be implemented in a manner that is consistent with the demarcation points within their respective regulatory framework.
No
The combination of I2 with I4 is not as a result of FERC’s directive and/or clearly stated in the scope of the Phase 2 SAR. In Order 773, Commission states: a) “Other than the directive to modify exclusion E3 as discussed below, the Commission declines to direct NERC to further modify the definition or the specified inclusions and exclusions” (Paragraph 52) b) the Commission will not direct NERC to categorically include collector systems pursuant to inclusion I4. (Paragraph 114) We believe that I2 and I4 wordings as approved by the stakeholders, NERC BoT, FERC and applicable governmental authorities in Canada should be retained. As such, we do not support this change to the definition because NERC should also consider unintended consequences that could result out of this change. In our opinion, I4 is meant for renewable energy resources (in particular Wind). These resources are inherently different from both the planning and the real time operations perspectives. This change will essentially designate every element of a wind farm above 75 MVA to its interconnection as a BES facility including the collector systems which may not be necessary. For example, this will

essentially mean that collector systems shall be required to comply with TPL standards performance assessment and design.
Yes
Yes
We suggest NERC must ensure that: 1) any new or changes to standards as a result of FERC directives that apply to load supply reliability and/or continuity be limited to the FERC jurisdiction only. In Canada, local load reliability requirements are under the authority of local regulators such as the Ontario Energy Board in the Province of Ontario. 2) An Implementation Plan does not conflict with Ontario regulatory practice with respect to the effective date of the standards. It is suggested that this conflict be removed by appending to the effective date wording, after “applicable regulatory approval” in the Effective Dates Section of the Implementation Plan, to the following effect: “, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.” Prior to the wording “In those jurisdiction….”. The same changes should be made to the first sentence in the Effective Date Section of the proposed Definition document. 3) In our opinion, SDT has correctly crafted the language in E1 and E3 in the approved definition. However it seems that the BES exception process has not been adequately communicated for “inclusion of facilities” that are not captured by the definition but may be necessary for the BES operation. To address such FERC concerns, NERC should take steps (e.g. directing Regions) to provide assurance to FERC that the exception process will be administered in an effective way by NERC, Regions and the Reliability Coordinators along with Facility Owners to include sub 100 kV system(s) that are a) used for bulk power transfer (not a sink) across the BES from one area to the other or b) are necessary for the operation of interconnected BES in a reliable manner or c) can have an adverse impact on the interconnect BES.
Group
Transmission Access Policy Study Group
William Gallagher
Yes
Yes
TAPS supports the SDT’s general approach and language in Note 2 to Exclusion E1. In light of FERC’s interpretation of “radial,” it is vital that a minimum threshold be added to Exclusion E1; without such a threshold, many TAPS members would have to perform a more burdensome E3 analysis, and likely go through the much more resource-intensive exceptions process, for Elements that are clearly not necessary for the reliable operation of the grid. We therefore strongly support the SDT’s proposal of a minimum threshold. TAPS does, however, suggest that the threshold be 40 kV rather than 30 kV, because we believe that >100 kV radials connected by a loop between 30 kV and 40 kV are highly unlikely to be necessary for

the reliable operation of the interconnected grid, and so 40 kV would be a more efficient threshold than 30 kV; the rare case that should be part of the BES should be included through the Exceptions process. We understand that the SDT has been assembling technical support for a 30 kV proposal, and accordingly provide the following evidence in support of using 40 kV instead. We propose 40 kV as being between the commonly-used voltages of 34.5 kV and 46 kV. Neither threshold (30 kV or 40 kV) will capture "all and only" those Elements that should be part of the BES, because neither threshold is (or can be) sufficiently granular; instead, the goal should be for E1 (and the rest of the core definition) to get as close as possible to the appropriate end-state, in order to minimize the need for case-by-case Exceptions of either the inclusion or exclusion variety. We understand that a primary reason behind the SDT's use of 30 kV is the belief that in some portions of the continent, voltages as low as 34.5 kV are monitored by entities that have the responsibility to monitor to ensure the reliable operation of the interconnected transmission system. We do not know which entities the SDT is referring to (presumably it does not include all entities, since DPs monitor all voltages), but we note that RFC and MISO, whose overlapping footprints are a very significant area, monitor down to 40 kV. This suggests that the people with responsibility and on-the-ground experience in those regions believe that 40 kV is the threshold below which impacts can safely be assumed to be minimal. Second, while the SDT has stated that it reads Order 773 as finding that impedance alone is insufficient to demonstrate that looped or networked connections operating below 100 kV should not be considered in the evaluation of Exclusion E1, it is surely an important factor. The consideration of impedance supports a 40 kV threshold. The impedance of a circuit is inversely proportional to the square of the voltage. The amount of parallel flow is inversely proportional to the impedance of a circuit. Thus, other things being equal, a 69 kV line carries 25% of the flow of a 138 kV line, and a 34.5 kV line carries 6.25% of the flow of a 138 kV line. Taking into consideration other factors such as transformer impedances (which are usually much greater than the impedances of the lines themselves) and the size and spacing of conductors, TAPS members believe that the large majority of 30-40 kV loops connecting >100 kV radials will carry less than 5% of the flow of a 138 kV line. For purposes of Transmission Loading Relief in NERC and NAESB standards (IRO-006 and WEQ-008, respectively), FERC has accepted a 5% transfer distribution factor as being insignificant. It is therefore reasonable to allow >100 kV radials connected by a 34.5 kV loop to qualify for Exclusion E1: any loop flow is more likely than not to be insignificant, and it is a waste of resources to require all such systems to assess their eligibility for Exclusion E3 or go through the exceptions process. Instead, if there are isolated cases of such configurations that should be included in the BES, they can be added through the inclusion Exceptions process. Most TAPS members' experience is that 34.5 kV lines tend to be used for local distribution, while 69 kV (and sometimes 46 kV) is used for subtransmission. The goal, ultimately, is to have the all of the necessary Elements, and no unnecessary Elements, in the BES. We believe that using a 40 kV threshold will achieve that goal with fewer NERC, Regional Entity, and registered entity resources than the 30 kV threshold proposed by the SDT.
An unintended consequence of the merging of I2 and I4 could be that dispersed behind-the-meter retail customer generation, which itself is not BES under Exclusion E2, results in the distribution system on which it is located being a BES collector system under I2. TAPS offers

three options to resolve this unintended consequence. The first option is to bring more of the former I4 language into I2, e.g., “utilizing a system designed primarily for aggregating capacity” to the inclusion, so that I2 would read: Generating resource(s), and dispersed power producing resources utilizing a system designed primarily for aggregating capacity, including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: a) Gross individual nameplate rating greater than 20 MVA, OR, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA. The second option is to include the term “non-retail” after dispersed and before power producing. And the third option is to clarify the use of the term “plant/facility” in b) such that it is clear that it does not refer to all the retail back-up generators or net-metering power producing resources connected to one distribution system connected to one connection to > 100 kV. TAPS also notes that many reliability standards are not a good fit for small individual generating units at dispersed, intermittent power resources such as wind farms; for example, given the frequency with which wind turbines trip on and offline (as they are designed to do), tracking each operation at each turbine to determine whether any misoperations have occurred would extremely onerous and yield minimal reliability benefit. We acknowledge that this concern is outside the scope of this project, but believe that the SDT should be aware of the issue as it revises the BES definition.
Yes
Yes
TAPS applauds the SDT’s work to address FERC’s directives on a very accelerated timeline, as well as the SDT’s hard work on this project over the last six years.
Individual
David Gordon
Massachusetts Municipal Wholesale Electric Company
Agree
American Public Power Association
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela Hunter
No
Southern agrees with NERC’s proposed removal of the phrase from the first sentence of Exclusion E3 (Local Network Exclusion). However, the second sentence in Exclusion E3 also appears to reference points of connection at 100kV or higher. Because the first sentence is now modified to include transmission Elements operated below 100kV, the second sentence should also be modified to remove the phrase “at 100kV or higher”. Therefore, the second sentence should read: “LN’s emanate from multiple points of connection to improve the level

of service to retail customers and not to accommodate bulk power transfer across the interconnected system.”
No
Southern recognizes and appreciates that the changes described in Question 2 respond simply and concisely to FERC’s directive in Order 773 to implement exclusions E1(b) and (c) and E3(a) so that the exclusions do not apply to tie-lines for generators identified in Inclusion I2. It appears both from the revisions to Inclusion I2 and from FERC’s discussion in the orders that FERC is intending to cover tie-lines to small-scale power generation technologies such as wind, solar, geothermal, energy storage, etc. However, from reviewing the revised language and the Bulk Electric System Guidance Document, it appears that one unintended consequence of this directive (and NERC’s implementation of this directive) may be to pull into the BES, for example, 230 kV or other high voltage feeders supplying auxiliary power to conventional generation resources (i.e., not dispersed power producing resources). While it may be appropriate to include certain components connecting the generation step-up units to the connection point, Southern has not seen any technical justification for adding auxiliary transformers and their high voltage feeders to the BES, which may have little to no significance to the reliable operation of the interconnected BES. Southern suggests that the SDT consider pursuing technical justification in Phase 2 or a later Phase for adding a note or some more nuanced language in Exclusions E1 or E3 that would more accurately reflect the distinctions described above by excluding from the BES these auxiliary elements while still addressing the intent of FERC’s directive regarding dispersed power producing resources.
Yes
Southern generally agrees with the SDT’s approach in adding Note 2 to Exclusion E1 to address FERC’s concerns regarding sub-100kV loops for radial systems. Respecting and appreciating that the SDT may have intended to mirror not only the concept, but also the language and format of Note 1 immediately above, Southern believes the language “does not affect the exclusion”, by itself, can be confusing to entities trying to make applicability and compliance determinations. To more directly and clearly articulate the concept of “not affecting the exclusion” as meaning that the described configuration qualifies for the exclusion and thus is excluded from the BES, Southern suggests the following revised Note 2 in quotes below. To the extent similar language can also be added to Note 1, Southern believes that it would also benefit from the added clarity. “Note 2 – The presence of a contiguous loop, operated at a voltage level of 30 kV or less, between configurations otherwise being considered as radial systems, does not affect this exclusion from applying, and thus such configurations should be eligible for Exclusion E1 and thus not included in the BES.”
No
The equipment being included in compliance with NERC Standards should only be that equipment carrying >75 MVA - the collector systems, GSU and Gen Tie, not the individual turbines. Implementing standards at the individual wind turbine level (< 2MW in many cases) does not improve reliability and only created additional workload for both the registered entities and the regions.

Yes
Yes
The 2010-17 project webpage indicates that the Planning Committee’s March 2013 report addresses the technical justification of threshold values, and that it will be updated by the drafting team after the definition has been revised in Phase 2. In its comments submitted in Project 2010-17 on February 2, 2012 (“Initial Comment Form”), Southern responded to two questions posed by the SDT that asked about the propriety of pursuing technical justification, but did not appear to be directly related to the threshold values. Southern includes those responses here for the SDT’s convenience. First, in Question 3 of the Initial Comment Form, the SDT asked whether it should pursue justification that supports the assumption that there is a reliability benefit of a contiguous BES. In Order 773, FERC stated that “it is generally appropriate to have the BES contiguous.” (P 167). To the extent that “contiguous” may be considered synonymous with “interconnected”, Southern agrees that pursuing technical justification to support such an assumption may be appropriate. Second, in Question 5 of the Initial Comment Form, the SDT asked whether it should pursue technical justification to support including an automatic interrupting device in Exclusions E1 and E3. It is not entirely clear whether this was addressed by FERC in either Order 773 or Order 773-A. As Southern stated in its February 12, 2012 comments, the scope of the term “automatic interrupting device” is unclear and could benefit from some clarification by NERC. To the extent that the term “automatic interrupting device” would constitute gas-operated breakers, as opposed to relays, Southern would agree that such devices, to the extent they are associated with Radial Systems qualifying under Exclusion E1 and Local Networks qualifying under Exclusion E3, should also be excluded from the BES under those exceptions.
Individual
Scott Berry
Indiana Municipal Power Agency
Agree
Indiana Municipal Power Agency (IMPA) supports the comments submitted by the Transmission Access Policy Study Group (TAPS). On question 3 on the Project 2010-17 comment sheet, IMPA agrees with the comments submitted by TAPS on this question and firmly believes the threshold voltage should be 40kV for all of the reasons given in the answer by TAPS. This is the main reason why IMPA voted negative on the ballot.
Individual
Brett Holland
Kansas City Power & Light
Agree
North American Generator Forum
Individual
Barry Lawson

National Rural Electric Cooperative Association
No
On page 2, last paragraph, of the Unofficial Comment Form the language regarding sub-100 kV loop analysis seems to indicate that the 30 kV level has already been determined and selected through technical analysis. It is NRECA's understanding that such technical analysis was not conducted prior to posting the phase 2 BES definition, and that such analysis is being conducted now by a sub-group of the drafting team. NRECA requests that the drafting team not focus on trying to specifically justify the 30kV bright-line, but instead, it should develop a methodology/test to determine the highest reasonable voltage level that we should be using for application of Exclusion E1. Such methodology/test should take into consideration the issues FERC identified in Order Nos. 773 and 773-A regarding their concerns with sub-100 kV looping facilities under Exclusion E1 and other comments from stakeholders that provide technical support or justification for certain voltage levels for use in Exclusion E1.
Individual
Michael Goggin
American Wind Energy Association
Yes
Yes
Yes
No
AWEA is seriously concerned that taking the body of NERC reliability standards that now apply to Bulk Electric System (BES) components and indiscriminately applying them to dispersed power producing resources under the proposed Inclusions I2 and I4 will impose a major burden and potentially result in significant confusion about the applicability of standards, with little to no benefit for electric system reliability. These inclusions as currently drafted could potentially even harm electric reliability by misallocating attention and resources away from concerns that are far more likely to negatively affect BES reliability. AWEA strongly urges that the BES definition be revised to only apply to the Point-of-Interconnection with the bulk electric system, as that is the only place within the wind project where more than 75 MVA of generating is aggregated and thus could reasonable affect BES reliability. In the alternative,

we ask that NERC revise Inclusion I2 as follows: I2 – Generating resource(s) [DELETE: and dispersed power producing resources,] including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: a) Gross individual nameplate rating greater than 20 MVA, OR, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA. [ADD: The application of individual NERC BES-relevant standards to dispersed generation resources is to be specified in the applicability section of individual standards.] The intent of this revision is to ensure that before BES-relevant standards are applied to dispersed generators, each standard is evaluated to determine whether it is reasonable to apply that standard to dispersed generators and whether applying that specific standard to dispersed generators will significantly improve electric reliability. Many NERC standards that apply to the BES were crafted before the significant growth of dispersed generation and without dispersed generators in mind. Combined with the fact that many dispersed generators are variable renewable resources that have limited capacity value and are asynchronously connected to the power system, many NERC standards are likely to have limited applicability or benefit if applied to dispersed generators. To our knowledge, a compelling rationale has not been provided for why applying all NERC BES- relevant standards to dispersed generators would significantly improve BES reliability. A blanket application of NERC standards to dispersed generators by including them in the definition of BES would be unduly burdensome, confusing, and provide little to no reliability benefit. As of the end of 2012, per AWEA's Annual Market Report, there were approximately 45,100 utility-scale wind turbines operating in the U.S., many of which are aggregated in wind projects that exceed 75 MVA in aggregate and are connected at a common point of voltage of 100 kV or above. Including each of these wind turbines and their collector systems in the BES definition would impose a large and undue burden on wind project owners and operators by potentially forcing them to comply with a number of NERC compliance processes and reliability standards that were crafted with large central-station generators in mind and cannot reasonably be applied to each of the dispersed generators within a wind project. We do not believe that the body of NERC requirements are adequately adapted to the technical differences of small, aggregated generation units. For example, the administrative burden and cost of complying with the GO/GOP standards at the individual generating unit level would be very substantial. For standards such as PRC-005, R1, and R2, applying these standards to dispersed generators would call for regular relay and protection system testing at numerous places within the wind plant, potentially including the internal circuitry of each individual wind turbine. One wind plant owner has indicated that, for one of its plants, applying the BES definition to the individual dispersed generators would increase the number of elements subject to the PRC-005 maintenance and testing requirements by more than a factor of 100. As another example, TOP-002 R14 and TOP-003 R1 require status reporting of unplanned and planned generator outages, respectively. We do not believe that the Balancing Authority (BA) or Transmission Operator (TO) would benefit from being notified about the operational status of any single dispersed generator at the typical wind turbine size of 2 MW or less. For the VAR series of standards, small size voltage control and waveform stabilization circuitry could require operational status monitoring and outage notification to the TO for this equipment. There are many other examples of potential confusion or unnecessary work and cost that can arise from the inclusion of small, individual dispersed generation assets, and their aggregation circuitry and equipment, in the BES definition. Most importantly, no one has demonstrated that there would be any material reliability benefit from applying all BES component standards to individual dispersed generators. The nameplate capacity of an individual wind turbine generator rarely exceeds 3 MW, and the average output of such a turbine is typically under 1 MW. Moreover, the capacity value contribution that grid operators typically assume for wind projects for meeting peak electricity demand is typically less than 20% of the nameplate capacity of the wind project. In the typical electrical layout of a wind plant, around a dozen wind turbines are aggregated onto an electrical string of the collector array (which operates at voltages well below 100kV), so even losing a single electrical string or even multiple electrical strings will typically only result in the loss of a few dozen MW of generation at most. Such minimal impacts fall well below the 75 MVA threshold that Inclusion 4 seeks to establish for determining what should be included in the definition of the BES, as well as any reasonable threshold for determining which electrical components are likely to cause a reliability problem on the BES. In contrast, the electrical equipment at the Point-of-Interconnection (POI) with the BES (and not the individual generators and their collector system), is a far more appropriate point for delineating between the BES and non-BES electrical components and implementing a blanket application of NERC standards for BES components, as the POI for a wind project comprised of more than 75 MVA of generation and operating at more than 100 kV is the only part of the wind project that could reasonably affect BES reliability. One of the only credible arguments for requiring that all BES reliability standards apply to individual wind turbines is if one believed that wind turbines could be potentially susceptible to a common mode failure that would cause a large number of the generators within a wind plant to trip offline within a matter of seconds. Fortunately, all wind turbines installed in the U.S. in recent years and going forward are already compliant with the demanding voltage and frequency ride-through requirements of FERC Order 661A, which are far more stringent than the ride-through requirements placed on other types of generation. In the event of a system disturbance that causes a voltage or frequency deviation that would affect all generators nearly simultaneously, a wind plant would be more likely to remain online than almost all conventional generators, and the wind plant would likely only trip offline if the power system had collapsed to the point that nearly all other generation had already tripped offline. As a result, there is no compelling reliability reason for including individual wind generators and their electrical collector systems in the BES definition. Applying all BES-relevant standards to individual dispersed generators not only fails to improve electric reliability, but it could even potentially harm electric reliability by misallocating attention and resources away from concerns that are far more likely to negatively affect BES reliability. Scarce resources exist for maintaining power system reliability, and devoting resources and attention to an issue that is unlikely to affect BES reliability can actually harm reliability by distracting attention from components that are more likely to cause a reliability problem. Moreover, taking the whole body of standards that were drafted with large central-station generators in mind and indiscriminately applying them to dispersed generators with very different characteristics is likely to cause significant confusion, further distracting from efforts that are important for maintaining and improving bulk power

system reliability. As a result, the BES definition should be revised as indicated above, to ensure that before BES-relevant standards are applied to dispersed generators, each standard is evaluated to determine whether it is reasonable to apply that standard to dispersed generators and whether applying that specific standard to dispersed generators will significantly improve electric reliability.
Yes
No
Individual
Luis Zaragoza
Tri-State Generation and Transmission, Inc.
Yes
Yes
Yes
Yes
Yes
Yes
Notwithstanding the NERC “Review of Bulk Electrical System Definition Thresholds” published in March, 2013, Tri-State continues to believe that there is no reliability benefit to the BES by having no minimum threshold for reactive devices on radial or non-radial systems. Two items in particular give cause for concern about the recommended resolution in the review. First, the review states that, since there is no clear technical justification for the threshold on generator size, any basis for setting a threshold for reactive devices comparable to the BES definition for generators does not have a technical basis. That is in itself a circular, non-technical response, and not a technical reason for not having a threshold for the reactive devices. The other argument that only 5% of the reactive devices would be excluded by using a threshold also has no technical merit. Secondly, the review did not even attempt to analyze what step voltage change a reactive device might have when it is in service. There are multitudes of reasons why a reactive device might be placed at a location and its unavailability may have a very small impact on the reliability of a system. Certainly it could have much less impact on system, especially a radial system, than loss of a 20 MW generator or a 75 MW aggregate plant would have. In addition, Tri-State believes that reactive devices installed on radial systems are equivalent to reactive devices installed for the sole benefit of

retail customers (E4) and exclusion E1 should be added to the end of I5, i. e. "… excluded by application of E1 or E4." Tri-State also disagrees with the findings in the same review regarding exclusions of Local Networks. Once again, the alleged lack of a technical basis for BES generator size is used as rationale for not allowing any flow out of a Local Network in Technical Alternative A. There is no technical merit to that argument. The argument for disregarding Technical Alternative B also seems to have no technical basis. Tri-State continues to believe that Local Networks could be excluded based on a minimum percentage of time that real/reactive power may flow out of the network. An unintended consequence of not allowing this to occur may be that entities will begin operating these systems radially to avoid falling under the definition of the BES.
Group
US Bureau of Reclamation
Erika Doot
Yes
Yes
Yes
Yes
Reclamation agrees with the addition of the term "dispersed power resources" in I2. However, Reclamation believes that certain aspects of Inclusion I2 are quite problematic. We have included comments on outstanding issues in I2 related to generation step up transformers (GSUs) in response to Question 6.
Yes
Yes
First, Reclamation suggests that the term "normally open" in E1 Note 1 is vague and should include some type of threshold for what is "normally open" (e.g. 80% of annual operating hours). The Bureau interprets "normally open" to mean under normal conditions rather than under emergency or maintenance conditions. Reclamation believes clarification of the term is necessary to make compliance obligations clear and avoid a variety of regional and entity interpretations about which switches qualify as "normally open." Second, Reclamation believes that certain aspects of Inclusion I2 are quite problematic. Inclusion I2 implies that a generation step-up transformer (GSU) is considered part of the generator in the BES designation by stating that "[g]enerating resource(s) … including the generator terminals through the high-side of the step up-transformer(s) connected at a voltage of 100 kV or above…" are considered BES. However, this does not address situations where there is more than one transformer before the transmission voltage. For example, a qualifying generator

may pass through multiple series transformers, of which only the last has terminals at 100kv or above. The first transformer in the series would be considered the generator step up-transformer but not the other transformers in the series. Such series of transformers could also involve sections of line which then raises the question of how they are classified. A generator greater than 20 MW Generator could be stepped up to some under 100 kV voltage, run some distance to a BES substation and then be transformed at that station to 100 kV or greater voltage. It seems that this would be not deemed a Generation Resource under I2 and would avoid needing to meet any requirements. Finally, in some instances, the Transmission Owner may own, operate, and maintain GSUs. To address this lack of clarity, Reclamation suggests that the drafting team revise the BES definition to better address GSUs in a separate inclusion. In addition, if GSUs with only one terminal over 100kv are considered BES, Reclamation questions why other transformers must have a "primary terminal and at least one secondary terminal operated at 100kv or higher" to be considered BES resources. Third, Reclamation suggests that NERC clarify the relationship between the new BES definition and roles described in the functional model. The Functional Model does not address roles and responsibilities related to transformers. In some instances, a Transmission Owner may own GSUs and it is unclear whether the Generator Owner or Transmission Owner would have compliance responsibility for the GSUs. Finally, Reclamation suggests that NERC define the term "generation resources" to clarify which generator components are considered part of "generation resources."
Individual
Alice Ireland
Xcel Energy
Yes
Yes
No
Xcel Energy asserts that the 30kV threshold proposed in Note 2 for Exclusion E1 is too low, and instead proposes a 60kV threshold. Our extensive experience and expertise in performing interconnected system modeling & operational analysis in three diverse Regions (MRO, SPP, WECC) indicates that all three attributes comprising the technical justification used by the SDT are always satisfied with the 60kV threshold. The recommended 60kV threshold recognizes that 69kV is the lowest voltage at which loops between radial systems have the potential to support adequate amount of power transfer under certain worst case scenarios and thus may impact the >100kV system performance/reliability. In other words, Xcel Energy’s system modeling & operational analysis experience indicates that 69kV is the lowest voltage at which loops between radial systems present any possibility that any one of the three attributes in the SDT’s technical justification may not be satisfied.
No

We do not agree that dispersed power resources should be treated the same at traditional generators, as they are quite different in design and operation from traditional generators and individually do not have the same impact on reliability. For the 2 main reasons detailed below, we recommend that both I2 and I4 be retained, yet reworded such as this: “I2 – Generating resource(s) and dispersed power producing resources, with gross individual nameplate rating greater than 20 MVA, including the generator terminals through the high-side of the generator step-up transformer(s) connected at a voltage of 100 kV or above.” “I4 – For generating and dispersed power producing facilities with gross plant/facility aggregate nameplate rating greater than 75 MVA, the bus where the aggregate generation is greater than 75 MVA and continuing thru the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above. (Note: this does not include the individual generating resources themselves, or the collector feeder system(s).)” 1) We are very concerned that the application of NERC reliability standards to dispersed power producing resources under the proposed BES Phase II definition will impose a major burden. The inclusions as currently drafted could even harm electric reliability by misallocating resources away from reliability areas that are far more likely to negatively affect BES reliability. As of the end of 2011, there were approximately 38,000 utility-scale wind turbines operating in the U.S., many of which are aggregated in wind projects that exceed 75 MVA in aggregate and are connected at a common point of voltage of 100 kV or above. Including each of these wind turbines and their collector systems in the BES definition would impose a large and undue burden on wind project owners and operators, result in significant confusion about the applicability of standards, and contribute no significant benefit to reliability. For example, the application of PRC-005, R1, and R2 at the individual dispersed generator unit level would require regular relay and protection system testing at numerous places within the wind plant, potentially including the internal circuitry of each individual wind turbine. Specifically, the applicability section 4.2.5.3 of PRC-005-2 implies that only the Protection System for the aggregating step up transformer is included in scope, and that the Protection System for the individual dispersed generators and aggregating systems are not. The current BES I2 includes both the dispersed generators and the aggregating system for wind farms greater than 75 MVA, applying PRC-005-2 requirements at 4.2.5.1 and 4.2.5.2 for generator trip relays, and generator step-up transformers, respectively. We do not think that application of these test requirements at the sub- 3MVA turbine level are the intent nor the reasonable scope of a national reliability standard. We have similar concerns with other standards including PRC-019-1, PRC-024-1, PRC-025-1, and PRC-027-1 and how application of these requirements would conflict or confuse implementation of this Phase II definition as applied to distributed generators and the associated aggregating systems. As another example, TOP-002 R14 requires status reporting of unplanned generator outages. We do not believe that the BA or TOP would benefit from the operational notification status of any single dispersed generator at the typical wind turbine size of 3 MVA or less. 2) A possible argument for requiring that all GO/GOP reliability standards apply to individual wind turbines is if wind turbines were susceptible to a common mode failure that would cause a large number of the generators within a wind plant to trip offline within a matter of seconds. Fortunately, all wind turbines installed in the U.S. in recent years and going forward comply with the demanding voltage

and frequency ride-through requirements of FERC Order 661A, which are far more stringent than the ride-through requirements placed on other types of generation. In the event of a system disturbance that causes a voltage or frequency deviation that would affect all generators nearly simultaneously, a wind plant would be more likely to remain online than almost all conventional generators, and the wind plant would likely only trip offline if the power system had collapsed to the point that nearly all other generation had already tripped offline. As a result, there is no compelling reliability reason for including individual wind generators and their electrical collector systems in the BES definition.
Yes
Yes
As explained under question 4, we feel that dispersed power resources should not be treated the same as traditional generating resources. However, if I2 moves forward as drafted, we feel it is imperative to launch an effort similar to the GOTO/Project 2010-07, to modify and add clarity to standards as they would apply to a dispersed power resource. This is important, as many of the current GO/GOP standards would be difficult and impractical to apply to a dispersed power resource. In addition, we recommend that interim compliance application guidance be developed to help owners and operators of dispersed power resources understand how to apply current standards, while also providing guidance to the auditors.
Individual
Nathan Mitchell
American Public Power Association
Yes
Yes
No
APPA appreciates the SDT efforts to set a non-zero threshold for exclusion E1 as proposed in Note 2. However, the 30kV voltage threshold selected is too low and should be revised to exclude the 34.5 kV voltage class. APPA believes including 34.5kV facilities will create a significant compliance burden on registered entities, especially small entities. To set a threshold this low will cast the compliance net onto radial facilities that perform distribution functions that are not currently subject to NERC reliability standards because these facilities are excluded as radials serving load. APPA believes that selecting the 30 kV threshold will place an obligation on small entities to prove that power flows will not transfer through their distribution systems for worst case scenarios. Without this change, APPA remains concerned that addressing the 34.5 kV voltage class may overload the Rules of Procedure (ROP) Exception Process. APPA recommends a higher threshold be studied and proposes 40 kV as an alternative. In nearly all circumstances, the distribution factors on 34.5 kV circuits that operate in normally closed configurations parallel to 115 kV and higher BES paths differ by 20-

to 1 or more, due to the combined impact of relative line voltage impedances, transformer impedances, and longer line lengths on the lower voltage path(s) that loop through our load centers and then connect back to the BES. Further, 34.5 kV circuits rarely affect SOLs or rated paths. These circuits rarely form part of the interface between balancing areas. Exceptions to the general rule that could have a significant impact on the BES should be addressed through the Exception Process. APPA's comments to the Commission on BES Phase I Definition NOPR September 4, 2012: Should the Commission in its final rule direct "other registered entities" to conduct a study of all of their sub-100 kV facilities and state their potential impact to the Regional Entity for evaluation for inclusion in the BES, then this directive would be excessively burdensome to the industry, especially small registered entities. The Commission's proposal would in effect require small registered entities (primarily Generator Owners and Distribution Providers) to hire consultants to perform studies to assess the potential impact of large numbers of non-BES facilities on the BES transmission network. APPA requests that in the final rule the Commission give NERC and the Regional Entities the flexibility to develop, with industry input, a reasonable approach for the evaluation of sub-100 kV facilities that does not create an excessive burden on the industry, especially small entities. Adoption of the 40 kV threshold would largely alleviate this potential burden.
Yes
Yes
No
Individual
Terry Harbour
MidAmerican Energy
Yes
Yes
MidAmerican would like clarification on Blackstart resources that are connected at < 100kV. A Blackstart resource would be included in the BES per I3; however the path that is less than 100kV would not be included in the BES
No
MidAmerican believes the 30kV threshold is too low. MidAmerican believes that the SDT should consider an “opt in” strategy for sub-100kV or Sub-60kV facilities rather than the current proposed change which assumes facilities down to 34.5 kV are in NERC scope unless entities “opt out” through the exemption process. Rather than include them in the BES definition and require standard modifications to exclude them when it is not appropriate, it is more efficient to modify those standards where their inclusion is determined to be

appropriate. This has already been done in some recently modified standards (e.g. the generator verification standards now filed for regulatory approval, the modifications made to standards for the generator interconnections).
No
In plants with an aggregate rating greater than 75 MVA, the individual generators should be treated in the same manner as they would be in a stand-alone facility. If the individual generator is at or below 20 MVA in a stand-alone facility it would not be included in the BES and the owner of such a facility would not even have to register as a generator owner. That same size generator in an aggregated facility should be treated the same and it should be excluded from the BES. The portion of the facility at which the 75MVA or greater aggregation occurs should be where the BES boundary occurs. Inclusion I2 has been modified to incorporate I4 and I4 was eliminated. This is a good step, but the wording needs to be revised to recognize the relative insignificance of the small generators to the bulk electric system. There may be cases in some requirements of some standards where it is appropriate to include generators below 20 MVA in those requirements. Rather than include them in the BES definition and require standard modifications to exclude them when it is not appropriate, it is more efficient to modify those standards where their inclusion is determined to be appropriate. This has already been done in some recently modified standards (e.g. the generator verification standards now filed for regulatory approval, the modifications made to standards for the generator interconnections). Here is the proposed markup: “I2 – Generating resource(s) and dispersed power producing resources with: a) Gross individual nameplate rating greater than 20 MVA, including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above, OR, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA, beginning at a bus where the aggregate generation is greater than 75MVA and continuing thru the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above”
Yes
Yes
With E1 (and E3) the SDT has created and “opt-out” process instead of an “opt-in” process. Only a small portion of networked facilities less than 100kV have a material impact on the BES. A better approach would be to utilize the BES process for exceptions and include those that have material impact to the BES. Needlessly processing these sub 100kV systems through the burdensome exclusion process is not an effective use of resources.
Individual
Carter B. Edge
SERC Reliability Corporation
No Comment
No Comment
No Comment

The inclusion language uses the words "generator terminals". "Generator terminals" are not a good demarcation point for defining a bright-line for the collector system that represents faciltites that are necessary for reliable operationThese words will not be clear with some power producing resources (wind, solar, low-head hydro, etc.). The SDT should review solar, fuel cell and other DC technologies to clarify the term “generator terminals” as it relates these types of generating resources. An alternative may be to define a proxy for generating resource "generator terminals" (may be made up of multiple individual resources) by the connection point below the step-up transformer where aggregate capacity exceeds the individual unit registration threshold of 20MVA.
No Comment
No

Standards Announcement

Project 2010-17 Definition of the Bulk Electric System Phase 2 | Draft 1

Initial Ballot Results

Now Available

An initial ballot for Phase 2 of the Definition of Bulk Electric System (DBES) concluded at **8 p.m. Eastern on Friday, July 12, 2013**.

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the initial ballot.

Approval
Quorum: 85.53%
Approval: 49.73%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the definition. The definition will then proceed to an additional ballot.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2010-17 Definition of BES - Phase 2
Ballot Period:	7/3/2013 - 7/12/2013
Ballot Type:	Initial
Total # Votes:	337
Total Ballot Pool:	394
Quorum:	**85.53 % The Quorum has been reached**
Weighted Segment Vote:	49.73 %
Ballot Results:	**The standard will proceed to an additional ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	105	1	41	0.5	41	0.5	11	12
2 - Segment 2.	8	0.5	1	0.1	4	0.4	2	1
3 - Segment 3.	90	1	32	0.478	35	0.522	9	14
4 - Segment 4.	36	1	14	0.519	13	0.481	3	6
5 - Segment 5.	88	1	31	0.47	35	0.53	7	15
6 - Segment 6.	51	1	19	0.514	18	0.486	6	8
7 - Segment 7.	2	0.2	2	0.2	0	0	0	0
8 - Segment 8.	2	0.1	0	0	1	0.1	0	1
9 - Segment 9.	4	0.4	1	0.1	3	0.3	0	0
10 - Segment 10.	8	0.8	6	0.6	2	0.2	0	0
Totals	**394**	**7**	**147**	**3.481**	**152**	**3.519**	**38**	**57**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Eric Scott	Negative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	ATCO Electric	Glen Sutton	Abstain	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Negative	

1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Big Rivers Electric Corp.	Chris Bradley	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	
1	Central Iowa Power Cooperative	Kevin J Lyons	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dominion Virginia Power	Michael S Crowley	Negative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	Amber Anderson	Affirmative	
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	
1	JDRJC Associates	Jim D Cyrulewski	Negative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Negative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin	Affirmative	
1	Lincoln Electric System	Doug Bantam	Negative	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Abstain	
1	Memphis Light, Gas and Water Division	Allan Long		
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnesota Power, Inc.	Randi K. Nyholm	Negative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney	Affirmative	
1	North Carolina Electric Membership Corp.	Robert Thompson		
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	
1	Northeast Utilities	David Boguslawski	Negative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel		

1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson	Negative	
1	PacifiCorp	Ryan Millard	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson	Negative	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tennessee Valley Authority	Howell D Scott	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine		
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	
2	Midwest ISO, Inc.	Marie Knox	Negative	
2	New Brunswick System Operator	Alden Briggs	Negative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Robert S Moore	Negative	
3	Alameda Municipal Power	Douglas Draeger	Negative	
3	Ameren Services	Mark Peters	Negative	
3	Arkansas Electric Cooperative Corporation	Philip Huff	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Electric	James L Layton	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl		
3	Central Electric Power Cooperative	Adam M Weber	Negative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Negative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Palo Alto	Eric R Scott	Affirmative	
3	City of Redding	Bill Hughes	Abstain	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	City of Ukiah	Colin Murphey	Negative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Negative	

3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	
3	East Kentucky Power Coop.	Patrick Woods	Affirmative	
3	El Paso Electric Company	Tracy Van Slyke	Abstain	
3	Entergy	Joel T Plessinger	Affirmative	
3	Fayetteville Public Works Commission	Allen R Wallace		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Negative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Kootenai Electric Cooperative	Dave Kahly		
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Negative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Abstain	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Jeff Franklin	Negative	
3	Modesto Irrigation District	Jack W Savage	Negative	
3	Muscatine Power & Water	John S Bos	Negative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera		
3	North Carolina Electric Membership Corp.	Doug White	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Negative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salmon River Electric Cooperative	Ken Dizes	Negative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	Southern California Edison Company	David B Coher		
3	Tacoma Public Utilities	Travis Metcalfe		
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	Alabama Municipal Electric Authority	Raymond Phillips	Affirmative	

4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	
4	Arkansas Electric Cooperative Corporation	Ronnie Frizzell	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Buckeye Power, Inc.	Manmohan K Sachdeva	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Abstain	
4	City Utilities of Springfield, Missouri	John Allen		
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	
4	Consumers Energy Company	Tracy Goble	Negative	
4	Cowlitz County PUD	Rick Syring		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Negative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Negative	
4	Integrys Energy Group, Inc.	Christopher Plante	Negative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	National Rural Electric Cooperative Association	Barry R. Lawson	Abstain	
4	North Carolina Eastern Municipal Power Agency	Cecil Rhodes	Affirmative	
4	North Carolina Electric Membership Corp.	John Lemire	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Negative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Negative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Scott Takinen	Negative	
5	Arkansas Electric Cooperative Corporation	Brent R Carr	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Buckeye Power, Inc.	Paul M Jackson	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Abstain	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Michael Shultz	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Cowlitz County PUD	Bob Essex		
5	CPS Energy	Robert Stevens	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Negative	
5	Detroit Edison Company	Alexander Eizans	Negative	
5	Detroit Renewable Power	Marcus Ellis	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Negative	

5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	El Paso Electric Company	Gustavo Estrada	Abstain	
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Mark F Draper	Negative	
5	First Wind	John Robertson	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	Hydro-Québec Production	Roger Dufresne	Negative	
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Negative	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Negative	
5	MEAG Power	Steven Grego	Abstain	
5	MidAmerican Energy Co.	Neil D Hammer	Negative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Leo Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	
5	Ontario Power Generation Inc.	David Ramkalawan		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Bonnie Marino-Blair	Negative	
5	Pattern Gulf Wind LLC	Grit Schmieder-Copeland	Negative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	PSEG Fossil LLC	Tim Kucey	Negative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Negative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Negative	
6	AEP Marketing	Edward P. Cox	Negative	
6	APS	Randy A. Young	Negative	
6	Arkansas Electric Cooperative Corporation	Keith Sugg	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	

6	City of Redding	Marvin Briggs	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Negative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	
6	Duke Energy	Greg Cecil		
6	El Paso Electric Company	Luis Rodriguez	Abstain	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson		
6	Lincoln Electric System	Eric Ruskamp	Negative	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall	Negative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Affirmative	
6	North Carolina Municipal Power Agency #1	Matthew Schull	Abstain	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Negative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Ty Bettis		
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Negative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Negative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway	Negative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	
7	Alcoa, Inc.	Thomas Gianneschi	Affirmative	
7	EnerVision, Inc.	Thomas W Siegrist	Affirmative	
8		Edward C Stein		
8		Debra R Warner	Negative	
9	Central Lincoln PUD	Bruce Lovelin	Negative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	
9	New York State Department of Public Service	Thomas G. Dvorsky	Negative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Negative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	

404.446.2560 voice : 404.446.2595 fax
Atlanta Office: 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Consideration of Comments

Project 2010-17 Definition of Bulk Electric System

The Project 2010-17 Drafting Team thanks all commenters who submitted comments on Draft 1, Phase 2 of the Bulk Electric System definition. The definition was posted for a 45-day formal comment period from May 29, 2013 through July 12, 2013. Stakeholders were asked to provide feedback on the definition and associated documents through a special electronic comment form. There were 93 sets of responses, including comments from approximately 225 different people from approximately 138 companies representing all 10 segments of the Industry Segments as shown in the table on the following pages.

The SDT has made the following changes to the proposed definition due to industry comments;

- I2 – Generating resource(s) ~~and dispersed power producing resources,~~ including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
- I2 a) - Gross individual nameplate rating greater than 20 MVA~~,~~. O~~R~~r,
- I4 - ~~Omitted. d~~Dispersed power producing resources consisting of:
- Individual resources ~~with~~that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and
- b) The ~~utilizing a~~ system designed primarily for ~~aggregating~~delivering capacity from the point where those resources aggregate to greater than 75 MVA ~~, connected at~~to a common point of connection at a voltage of 100 kV or above.
- Note 2: The presence of a contiguous loop, operated at a voltage level of ~~30~~50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.
- Exclusion E 3(b): Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN;
- E4 - Reactive Power devices installed for the sole benefit of a retail customer(s).
- Implementation Plan and effective date language - This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required the definition shall ~~go into effect~~ become effective on the first day of the second calendar quarter after Board of Trustees adoption or as otherwise made effective pursuant to the laws of applicable governmental authorities.

Minority concerns:

- Several commenters wanted the SDT to revise the applicability of current standards due to their feeling that changes were required due to the new BES definition. The DBES SDT conducted a review of applicability of Reliability Standards. The review consisted of the Reliability Standards that are applicable to the Transmission Owners (TO), Generator Owners (GO), Transmission Operators (TOP), and Generator Operators (GOP). The review was based on the premise that the applicability of Reliability Standards is limited to BES Elements unless otherwise stated in the 'Applicability' section of the standard or identified in the individual requirements. The review was conducted to: (1) Assess the impact of the revised BES definition on the current applicability of the subject Reliability Standards, and, (2) Identify areas where the applicability could be improved from a clarity perspective and (3) Assess the proper application of BPS vs. BES. The results of this analysis were forwarded to the NERC Standards Committee for consideration: (1) The BES SDT found no issues that were identified as an immediate concern based on the revised definition of the BES, therefore the BES SDT did not develop any supporting draft SARs or potential redline changes; (2) The BES SDT identified several areas where the clarity of the applicability could be improved. These issues were documented and provided to the NERC SC with the expectation is that these issues would be added to the 'Standards Issues Database' for consideration by future SDTs. Additionally, the results of the BPS vs. BES assessment were provided to the NERC SC, again with the expectation is that these issues would be added to the 'Standards Issues Database' for consideration by future SDTs.

- Several commenters attempted to re-open items that were decided and approved in Phase 1 and for which no changes are being made in Phase 2. The SDT notes that those issues raised were previously decided by the Commission in its related Orders, and were not a topic for reconsideration in Phase 2.
- Several commenters raised concerns about the SDT treatment of the thresholds that reside within the BES definition. The results of the NERC Planning Committee's (PC) evaluation of the various thresholds contained in the BES definition were presented to the SDT for consideration in developing revisions to the definition in Phase 2. The PC determined that all thresholds should remain at the status-quo. The SDT, based on the recommendations from the PC, has opted to retain the original thresholds in the definition.

The SDT wishes to emphasize to commenters that the looping facilities that operate at voltages below 100 kV are NOT included in the BES. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process."

All comments submitted may be reviewed in their original format on the project page.

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

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

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

10 — Regional Reliability Organizations, Regional Entities

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

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

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	David Dockery	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

2. KAMO Electric Cooperative		SERC	1, 3
3. M & A Electric Power Cooperative		SERC	1, 3
4. Northeast Missouri Electric Power Cooperative		SERC	1, 3
5. N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6. Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Donald Weaver	New Brunswick System Operator	NPCC	2
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Wayne Sipperly	New York Power Authority	NPCC	5
9.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
10.	Christina Koncz	PSEG Power LLC	NPCC	5
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
20.	Ben Wu	Orange and rockland Utilities	NPCC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Louis Slade	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Crowley	Electric Transmission	SERC	1, 3
2.	Craig Crider	Electric Transmission	SERC	1, 3
3.	David Roop	Electric Transmission	SERC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
4.	John Loftis	Electric Transmission	SERC	1, 3
5.	George Wood	Electric Transmission	SERC	1, 3
6.	Nick Goerger	Electric Transmission	SERC	1, 3
7.	Carl Eng	Electric Transmission	SERC	1, 3
8.	William Bigdely	Electric Transmission	SERC	1, 3
9.	Jeff Bailey	Nuclear	NPCC	5
10.	Chip Humphrey	F&H	RFC	5
11.	Sean Iseminger	F&H	SERC	5
12.	Louis Slade	NERC Compliance Policy	SERC	1, 3, 5, 6
13.	Connie Lowe	NERC Compliance Policy	RFC	5, 6
14.	Mike Garton	NERC Compliance Policy	NPCC	5, 6
15.	Randi Heise	NERC Compliance Policy	MRO	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Russel Mountjoy	MRO NERC Standards Review Forum (NSRF)	X	X	X	X	X	X				X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Co	MRO	1
3.	Dan Inman	Minnkota Power Coop	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Coop	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	Western Area Power Administration	MRO	1, 6
7.	Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Lee Kittleson	Otter Tail Power	MRO	1, 3, 5
10.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
11.	Marie Knox	Midcontinent Independent System Operator	MRO	2
12.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
13.	Scott Bos	Muscatine Power & Water	MRO	1, 3, 5, 6
14.	Scott Nickels	Rochester Public Utilities	MRO	4
15.	Terry Harbour	MidAmerican Energy Co.	MRO	1, 3, 5, 6
16.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
17.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	David Thompson		SERC	5
4.	Marjorie Parsons		SERC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Jim Kelley	SERC EC Planning Standards Subcommittee	X				X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	Edin Habibovic	Entergy Services	SERC	1
3.	James Manning	NC Electric Membership Corporation	SERC	1
4.	Philip Kleckley	SC Electric & Gas Company	SERC	1
5.	Shih-Min Hsu	Southern Company	SERC	1
6.	Darrin Church	Tennessee Valley Authority	SERC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Michael Jones	National Grid	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brian Shanahan	National Grid (Niagara Mohawk)	NPCC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	paul haase	seattle city light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	pawel krupa	seattle city light	WECC	1
2.	dana wheelock	seattle city light	WECC	3
3.	hao li	seattle city light	WECC	4
4.	mike haynes	seattle city light	WECC	5
5.	dennis sismaet	seattle city light	WECC	6

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mo Awad	Westar Energy	SPP	1, 3, 5, 6
2.	Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 3, 5
3.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
4.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
5.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
6.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6

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

7.	Stephen McGie	City of Coffeyville	SPP	NA
8.	Jason Shook	Representing East Texas Electric Cooperative	SPP	NA
9.	Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4
10.	Don Taylor	Westar Energy	SPP	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Mary Jo Cooper	Cooper Compliance Corp	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Colin Murphy	CIty of Ukiah	WECC	3
2.	Elizabeth Kirkley	City of Lodi	WECC	3
3.	Douglas Drager	City of Alameda	WECC	3
4.	Ken Dize	Salmon River Electric Co-opt	WECC	3
5.	Blaine Ladd	California Pacific Company	WECC	1, 3
6.	Michael Knott	Granite State Electric	NPCC	3
7.	Angela Kimmey	Pasadena Water and Power	WECC	1, 3
8.	Xavier Baldwin	Burbank Water and Power	WECC	3, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Chang Choi	City of Tacoma	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Travis Metcalfe	Tacoma Public Utilities	WECC	3
2.	Keith Morisette	Tacoma Public Utilities	WECC	4
3.	Chris Mattson	Tacoma Power	WECC	5
4.	Michael Hill	Tacoma Public Utilities	WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	David Thorne	Pepco Holdings Inc & Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Delmarva Power & Light Co	RFC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. Group	Kent Kujala	DTE Electric			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dan Herring		RFC	3, 4, 5
2.	Al Eizans		RFC	3, 4, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15. Group	Joe Turano	Iberdrola USA	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	Iberdrola USA	NPCC	1
2.	Ray Kinney	NYSEG	NPCC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Greg Campoli	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terry Bilke	MISO	MRO	2
2.	Al DiCaprio	PJM	RFC	2
3.	Kathleen Goodman	ISO-NE	NPCC	2
4.	Matt Morais	ERCOT	ERCOT	2
5.	Ali Miremadi	CAISO	WECC	2
6.	Ben Li	IESO	NPCC	2
7.	Charles Yeung	SPP	SPP	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Annette Bannon	PPL Generation, LLC on behalf of Supply NERC Registered Affiliates	RFC	5
3.			WECC	5
4.	Ellizabeth Davis	PPL EnergyPlus, LLC	MRO	6
5.			NPCC	6
6.			SERC	6
7.			SPP	6
8.			RFC	6
9.			WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
2.	Mohan Sachdeva	Buckeye Power, Inc.	RFC	3, 4
3.	Kevin Lyons	Central Iowa Power Cooperative	MRO	
4.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
5.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
6.	Laurel Heacock	Oglethorpe Power Corporation	SERC	
7.	Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Group	Patrick Brown	North American Generator Forum Standards Review Team					X					

NERC

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Allen Schriver	NextEra Energy		5
2.	Steve Berger	PPL Susquehanna, LLC		5
3.	Joe Crispino	PSEG Fossil, LLC		5
4.	Pamela Dautel	IPR-GDF Suez Generation NA		5
5.	Dan Duff	Liberty Electric Power		5
6.	Mikhail Falkovich	PSEG		5
7.	Don Lock	PPL Generation, LLC		5
8.	Joe O'Brien	NIPSCO		5
9.	Dana Showalter	E.ON		5
10.	William Shultz	Southern Company		5
11.	Mark Young	Tenaska, Inc		5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Group	David Kiguel	Hydro One Networks Inc.	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Curtis	Hydro One Networks Inc.	NPCC	1, 3
2.	Oded Hubert	Hydro One Networks Inc.	NPCC	1
3.	Bing Young	Hydro One Networks Inc.	NPCC	1, 3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21.	Individual	Janet Smith, Regulatory Compliance Supervisor	Arizona Public Service Company	X		X		X	X				
22.	Individual	Tim Reyher	Northeast Utilities	X									
23.	Individual	Donald Brookhyser	Cogeneration Association of California										
24.	Individual	Ryan Millard	PacifiCorp	X		X		X	X				
25.	Individual	Emily Pennel	Southwest Power Pool Regional Entity										X
26.	Individual	Marcus Lotto	Southern California Edison	X									
27.	Individual	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				
28.	Individual	William Gallagher	Transmission Access Policy Study Group	X		X	X	X	X				
29.	Individual	Pamela Hunter	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company;	X		X		X	X				

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
			Southern Company Generation; Southern Company Generation and Energy Marketing										
30.	Individual	Erika Doot	US Bureau of Reclamation	X			X						
31.	Individual	Tracy Richardson	Spirngfield Utility Board			X							
32.	Individual	Dennis Schmidt	City of Anaheim			X							
33.	Individual	Steve Alexanderson	Central Lincoln			X	X						
34.	Individual	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				
35.	Individual	PHAN, Si Truc	Hydro-Quebec TransEnergie	X									
36.	Individual	Grit Schmieder-Copeland	Pattern Gulf Wind LLC					X					
37.	Individual	Thomas Breene	Wisconsin Public Service / Upper Peninsula Power			X	X	X	X				
38.	Individual	Brian J. Murphy	NextEra Energy	X		X		X	X				
39.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
40.	Individual	Jack Stamper	Clark Public Utilities	X									
41.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
42.	Individual	John Bee	Exelon and its Affiliates	X		X		X					
43.	Individual	Bret Galbraith	Seminole Electric			X	X	X	X				
44.	Individual	Jim Cyrulewski	JDRJC Associates LLC	X									
45.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
46.	Individual	Kenn Backholm	Public Utility District No.1 of Snohomish County	X		X	X	X	X			X	
47.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
48.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
49.	Individual	Daniela Hammons	CenterPoint Energy	X									
50.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
51.	Individual	Roger Dufresne	Hydro-QuÃ©bec Production					X					
52.	Individual	David Burke	Orange and Rockland Utilities Inc.	X		X							

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
53.	Individual	Don Jones	Texas Reliability Entity										X
54.	Individual	Marie Knox	MISO		X								
55.	Individual	Saul Rojas	New York Power Authority	X		X		X	X				
56.	Individual	Joylyn Faust	Consumers Energy Company			X	X	X					
57.	Individual	Michelle D'Antuono	Occidental Energy Ventures Corp.			X		X		X			
58.	Individual	Herb Schrayshuen	Self								X		
59.	Individual	Donald Weaver	New Brunswick System Operator		X								
60.	Individual	Randi Nyholm	Minnesota Power	X									
61.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
62.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
63.	Individual	Mike Hirst	Cogentrix Energy Power Management, LLC					X					
64.	Individual	Kenneth A Goldsmith	Alliant Energy				X						
65.	Individual	Jason Snodgrass	Georgia Transmission Corporation	X									
66.	Individual	Diane J. Barney	New York State Department of Public Service									X	
67.	Individual	Michael Falvo	Independent Electricity System Operator		X								
68.	Individual	Michael Lowman	Duke Energy	X		X		X	X				
69.	Individual	Jim Thate	Delta-Montrose Electric Association				X						
70.	Individual	Barbara Kedrowski	Wisconsin Electric			X	X	X					
71.	Individual	Melissa Kurtz	US Army Corps of Engineers					X					
72.	Individual	Daryl Hanson	Otter Tail Power Company	X									
73.	Individual	David Jendras	Ameren	X		X		X	X				
74.	Individual	Kathleen Goodman	ISO New England Inc.		X								
75.	Individual	Randy MacDonald	NB Power Transmission	X									
76.	Individual	Michael Moltane	ITC	X									
77.	Individual	Spencer Tacke	Modesto Irrigation District			X	X		X				
78.	Individual	Don Streebel	Idaho Power Company	X									

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
79.	Individual	Edward O'Brien	Modesto Irrigation District			X	X		X				
80.	Individual	Tommy Drea	Dairyland Power Cooperative (DPC)	X		X		X					
81.	Individual	Rich Salgo	NV Energy	X		X		X					
82.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
83.	Individual	Tony Kroskey	Brazos Electric Power Cooperative	X									
84.	Individual	David Gordon	Massachusetts Municipal Wholesale Electric Company					X					
85.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
86.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
87.	Individual	Barry Lawson	National Rural Electric Cooperative Association				X						
88.	Individual	Michael Goggin	American Wind Energy Association								X		
89.	Individual	Luis Zaragoza	Tri-State Generation and Transmission, Inc.	X		X		X					
90.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
91.	Individual	Nathan Mitchell	American Public Power Association			X	X						
92.	Individual	Terry Harbour	MidAmerican Energy	X		X		X	X				
93.	Individual	Carter B. Edge	SERC Reliability Corporation										X

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The SDT will consider your comments as if they were filed separately when reviewing and responding to the comments from the entities indicated.

Organization	Supporting Comments of "Entity Name"
Brazos Electric Power Cooperative	ACES Power Marketing
Massachusetts Municipal Wholesale Electric Company Springfield Utility Board	American Public Power Association
Liberty Electric Power LLC	Essential Power
Hydro-Quebec Production	Hydro-Quebec TransEnergie Division
Indiana Municipal Power Agency	Transmission Access Policy Study Group (TAPS). On question 3 on the Project 2010-17 comment sheet, IMPA agrees with the comments submitted by TAPS on this question and firmly believes the threshold voltage should be 40kV for all of the reasons given in the answer by TAPS. This is the main reason why IMPA voted negative on the ballot.
Illinois Municipal Electric Agency Florida Municipal Power Agency	Transmission Access Policy Study Group
MISO	ISO/RTO Council - Standards Review Committee

Organization	Supporting Comments of “Entity Name”
JDRJC Associates LLC	
Minnesota Power Dairyland Power Cooperative (DPC) Otter Tail Power Company Lincoln Electric System Alliant Energy US Army Corps of Engineers	MRO NERC Standards Review Forum (NSRF)
Kansas City Power & Light Cogentrix Energy Power Management LLC	North American Generator Forum
New Brunswick System Operator NB Power Transmission	NPCC Reliability Standards Committee
Modesto Irrigation District	Sacramento Municipal Utility District Balancing Area of Northern California
Clark Public Utilities Seattle City Light	Snohomish County PUD

1. **The SDT has deleted the phrase "… or above 100 kV but…" from the local network exclusion language (E3) in response to a FERC directive. Do you agree that the SDT has correctly addressed this directive? If you do not agree that this change addresses the directive, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: A number of comments expressed opposition to the change directed by the Commission for the deletion of "…or above 100 kV but…" from the Exclusion E3 language. The opposition was typically due to the perception that the deletion would make it likely that facilities operated lower than 100 kV would be swept into the BES. This change does not result in the inclusion of sub-100 kV elements in the BES. Sub-100 kV elements, if otherwise excluded from the BES, will not be brought into the BES by application of this revised language. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36 which states: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process."

Comments were received suggesting that certain amounts of out-flow should be allowed to exist within the confines of the E3 exclusion. The language to which these comments refer, the provision requiring that there be no out-flow from the candidate local network, was industry, Board, and Commission-approved in Phase 1 and is not part of the Phase 2 scope of work; hence the SDT proposes no change to the definition in this regard.

Several commenters suggested that the reference to the 100 kV threshold should be removed from the second sentence of Exclusion E3 in addition to its removal in the first sentence. The SDT has determined that it is necessary to retain the 100 kV threshold in the second sentence in order to properly confine the bounds of the E3 exclusion.

Commenters raised concerns with the change made by the SDT to the Exclusion E3(c) criterion wherein "a monitored Facility of a permanent Flowgate" was changed to "any part of a permanent Flowgate". The SDT believes that the reliable operation of the interconnected transmission system requires operator situational awareness of any and all parts of permanent flowgates in order to adequately provide for reliable operation. Hence, the presence of any part of a flowgate should preclude the application of the E3 Exclusion. Accordingly, the SDT is making no changes to this revised language of Exclusion E3(c).

A comment was received that sought clarification about whether the power flow provision of Exclusion E3 (b) refers to real power only, or whether it includes reactive power. The language of Exclusion E3 (b) regarding power flow direction has been intended to be specific to real power, not reactive power. Pursuant to this comment, the SDT has revised the Exclusion E3 (b) language, adding the word "Real" preceding "Power". Exclusion E3 (b) now reads as follows:

Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN;

Finally, comments were received questioning the threshold of 30 kV proposed in the new Note 2 for Exclusion E1. To address this issue, the SDT has embarked upon technical analyses to examine the justification for the threshold, and has determined that 50 kV is the technically justifiable voltage threshold. [Also see consideration of these comments in response to Question 3.]

Organization	Yes or No	Question 1 Comment
Hydro One Networks Inc.	No	Although the proposed change addresses the FERC directive, we do not agree with deleting 100 kV. Under the premise that the very first paragraph of the BES Definition already establishes the bottom voltage threshold of 100 kV, its deletion may introduce ambiguity and confusion. By definition and as per FERC Order 773 "the Commission stated that the core definition also establishes a 100 kV criterion as a bright-line threshold" unless lower voltage elements are included by the exception process and that distribution systems should not be BES. Hence, we believe that, as the SDT correctly stated "above 100kV" in the currently approved definition and E3 are consistent with the intent of BES definition. Finally, it is worth noting that NERC is an international reliability standards setting organization and the BES definition was also approved and/or accepted by the applicable governmental authorities in other jurisdictions. Finally it is worth pointing that, in Order 773, the Commission further stated that "the 100 kV threshold is a reasonable "first step or proxy" for determining which facilities should be included in the bulk electric system. Indeed, it is reasonable to anticipate that this threshold will remove from the bulk electric system the vast majority of facilities that are used in local distribution, which tend to be operated at lower, sub-100 kV voltages"

Response: This change does not result in the inclusion of sub-100 kV elements in the BES. Sub-100 kV elements, if otherwise excluded from the BES, will not be brought into the BES by application of this revised language. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36 which states: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems

Organization	Yes or No	Question 1 Comment
and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process."		
Occidental Energy Ventures Corp.	No	Occidental Energy Ventures Corp. (on behalf of all Occidental NERC Registered Entities) ("OEVC") believes that the literal application of FERC's directive creates vulnerabilities that must be addressed. First, E3 as proposed will require that no energy may flow out of the Local Network for any reason. This would include Reactive Power which is essential to supporting local system voltage. It is not inconceivable that entities will take steps to eliminate Reactive Power export in order to avoid the costs of reliability compliance. Similarly, there is no relief in exclusion E3 for the unintended outflow of energy under multiple contingency conditions. Already in Orders 773 and 773-A, FERC has taken a stance that there are no acceptable scenarios where an excluded Local Network may do so. We believe this is unreasonable, adds excessive costs, and does little to reduce Bulk Electric System risk. FERC's very conservative "no-exceptions" view will prevail by default if the drafting team does not provide the alternative language in the guideline document - and shown below for reference:"Real power flows only in the LN from every point of connection to the BES for the system as planned with all lines in service and also for first contingency conditions as per TPL-001-2, Steady State & Stability Performance Planning Events P0, P1, and P2, and the LN does not transfer energy originating outside the LN for delivery through the LN to the BES."
Response: The language to which these comments refer, the provision requiring that there be no out-flow from the candidate local network, was industry, Board, and Commission approved in Phase 1 and is not at issue in this Phase 2 posting; hence the SDT proposes no change to the definition in this regard. The language of Exclusion E3 (b) regarding power flow direction has been intended to be specific to real power, not reactive power. Pursuant to this comment, the SDT has revised the Exclusion E3 (b) language, adding the word "Real" preceding "Power". Exclusion E3 (b) now reads as follows: E3 (b): Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through		

Organization	Yes or No	Question 1 Comment
the LN;		
New York Power Authority	No	Removal of 100kv threshold from the first part of E3 but the 100kV reference remains in the second part of the E3 exclusion which is inconsistent. It is unclear what value the second sentence of the E3 exclusion provides and should be removed from the E3 exclusion.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	Southern agrees with NERC's proposed removal of the phrase from the first sentence of Exclusion E3 (Local Network Exclusion). However, the second sentence in Exclusion E3 also appears to reference points of connection at 100kV or higher. Because the first sentence is now modified to include transmission Elements operated below 100kV, the second sentence should also be modified to remove the phrase "at 100kV or higher". Therefore, the second sentence should read: "LN's emanate from multiple points of connection to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system."
Response: The SDT has determined that it is necessary to retain the 100 kV threshold in the second sentence in order to properly confine the bounds of the E3 exclusion. No change made.		
Southern California Edison	No	SCE agrees with the deletion of the phrase "... or above 100 kV but..." from the Local network (LN) exclusion language (E3). However, SCE believes that even with this change the E3 exclusion will be of little benefit in clarifying the issue FERC identified in Order 773-A. As revised, the exclusion will still bring into the scope of the BES definition facilities that have no impact, and were never envisioned to be a part of the BES. Moving forward, SCE recommends that the SDT consider revising the definition to remove the generation threshold from E3 a, especially if it intends to keep the current E3 b "Power flows only into the LN" language the same. With E3 b in-place, as currently written, it doesn't matter how much generation is located in a LN if the load is sufficiently large that there is no flow out of the LN to negatively impact the BES. Another approach would be to revise E3 b by deleting the language

Organization	Yes or No	Question 1 Comment
		"Power flows only into the LN" language. FERC does not seem to be adverse to minimal power flowing out of a LN: In Order 773A FERC declined to direct NERC to allow minimal flows up to a 100MVA limit to transfer out of an LN, but indicated that the Phase 2 project was a more appropriate forum to pursue this matter further. The best option would be to combine the two approaches outlined above. This would truly characterize LNs and clearly eliminate from the exclusion those looped facilities which operate in parallel with the BES.
Response: While the SDT agrees that the generation size and the threshold for flow out of the candidates for local network exclusion are somewhat related, the industry, Board, and the Commission accepted and approved these limitations for the E3 exclusion in Phase 1. In Phase 2, the SDT, as directed, sought the counsel of subject matter experts of the NERC Planning Committee on these threshold issues, and the result of this inquiry was that the SDT adopted the status quo, leaving Exclusion E3 unchanged. Accordingly, the SDT concludes that there is no justification for changing either the out-flow provision or the threshold for connected generation in local networks.		
North American Generator Forum Standards Review Team	No	The change in question was evidently intended to cover the 34.5 kV interconnection systems of wind farms, but it also pulls into the BES the 230 kV feeders supplying aux power for fossil plants (compare Figs. E1-7 and E1-7a in the FERC order 773/773a-amended Guidance Document). The HV-to-MV transformers for aux loads may be included as well (no per Fig. E1-7a, yes per SDT inputs in the 6/26/13 webinar if the transformers are of the 2 or 3-winding type). It makes sense to include in-line components (i.e. the GSU-to- connection point conductors), but there does not appear to be any justification for adding auxiliary transformers and their HV feeders to the BES. These are in-house systems that have no significance for the grid in general. The change to E3 should have been limited to wind farms.
PPL NERC Registered Affiliates	No	The change in the question was evidently intended to cover the 34.5 kV interconnection systems of wind farms, but it also pulls into the BES the 230 kV feeders supplying aux power for fossil plants (compare Figs. E1-7 and E1-7a in the FERC order 773/773a-amended Guidance Document). The HV-to-MV transformers for aux loads may be included as well (no per Fig. E1-7a, yes per SDT inputs in the

Organization	Yes or No	Question 1 Comment
		6/26/13 webinar if the transformers are of the 2 or 3-winding type). It makes sense to include in-line components (i.e. the GSU-to- connection point conductors), but there does not appear to be any justification for adding auxiliary transformers and their HV feeders to the BES. These are in-house systems that have no significance for the grid in general. The change to E3 should have been limited to wind farms.
Wisconsin Electric	No	Wisconsin Electric agrees with the NAGF comments in response to Question 1.
Response: The change addressed in this question was not related to the delivery systems of wind farms. Rather, it was in response to the Commission's directive in Order 773, specifically in Paragraph 199 where the Commission states "Therefore, we direct NERC to modify exclusion E3 to remove the 100 kV minimum operating voltage in the local network definition." The SDT proposes no change to the language of Exclusion E3.		
Northeast Power Coordinating Council	No	The Directive was addressed by the revision, but generally Exclusion E3 does not recognize that regardless of how power gets to the load, it impacts the Bulk Electric System. The term bulk power is used in the opening sentence of E3. A definition of bulk power would lend credence and justification to E3, and the elimination of "or above 100 kV but". The new Note 2 associated with Exclusion E1 and the changes to E3 have added ambiguity that did not exist before. The base definition does not address sub 100kV contiguous loops. The existing Inclusions do not include sub 100kV contiguous loops either. Note 2 clarifies that as long as the contiguous loop is below 30kV E1 still applies. E3 explains how any sub 300kV contiguous loop could be excluded as a local area network, but there is nothing in the definition that clearly states that contiguous loops operated below 100kV are considered part of the BES unless excluded by E3. The 100kv threshold has been removed from the first sentence of E3, but it is inconsistent that the 100kV reference remains in the second part of the E3 exclusion. It is unclear what value the second sentence of the E3 exclusion provides, and its removal should be considered. Under the premise that the very first paragraph of the BES Definition already establishes the bottom voltage threshold of 100kv, we agree with removing the mention of the 100kV bottom

Organization	Yes or No	Question 1 Comment
		threshold in exclusion E3. The version of exclusion E3 criterion (c) filed with FERC January 25, 2012 (RM12-6-000) requires a "Local Network" not to contain a monitored facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored facility in the ERCOT or Quebec Interconnections, and is not a monitored facility included in an Interconnection Reliability Operating Limit (IROL). The definition became more vague by changing exclusion E3 criterion (c) from "a monitored Facility of a permanent Flowgate..." to "any part of a permanent Flowgate..." and could allow for too broad a reading. The original language from Phase 1 of the BES definition regarding exclusion E3 criterion (c) provided more clarity and guidance on how to apply this exclusion. It is recommended that the original language from Phase 1 of the BES definition be reinstated. Facilities should be included in the BES only if the elements of the Facility are transferring power (flow) through a Flowgate, transfer path, or IROL. The Phase 1 BES definition was approved by NERC after positive industry acceptance providing that Phase 2 would reconsider some of the thresholds proposed in Phase 1. The important 75MVA generation threshold limit was included. The FERC requested changes now limit the possibilities for exclusion: 1) limitation on the possibility of radial exclusion because of looping below 100 kV; 2) refusal of radial or local exclusions when there is at least one generator above 20 MVA. Those limitations for exclusion go in the opposite direction to what industry expected. NERC must realize that the definition will be applied to entities not under FERC jurisdiction. It is important that NERC consult Canadian jurisdictions about the BES definition.

Response: With respect to providing a definition of "bulk power" as used in the opening sentence of Exclusion E3, this term is used generically, and is only meant to provide a conceptual sense of the purpose and character of the facilities suitable for exclusion. This terminology has not changed from the industry, Board, and Commission approved Phase 1 definition. The SDT has determined that a definition of this term is not necessary to improve the clarity of Exclusion E3.

Organization	Yes or No	Question 1 Comment
The SDT has determined that it is necessary to retain the 100 kV threshold in the second sentence in order to properly confine the bounds of the E3 exclusion. The SDT believes that the reliable operation of the interconnected transmission system requires operator situational awareness of any and all parts of permanent flowgates in order to adequately provide for reliable operation. Hence, the presence of any part of a flowgate should preclude the application of the E3 Exclusion. Accordingly, the SDT is making no changes to this revised language of Exclusion E3(c). The SDT understands that the changes ordered by the Commission place limitations on the exclusion beyond what was expected by the industry; however, the SDT is bound by the directives of that Order and therefore recommends no change. A Canadian entity and several observers have participated in the development of the BES Definition in both Phases. The SDT believes it has given due consideration to the Canadian perspectives.		
Self	No	The earlier version of exclusion E3 criterion requires a Local Network not to contain a monitored facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored facility in the ERCOT or Quebec Interconnections, and is not a monitored facility included in an IROL. The definition now is more vague. The original language was better. Facilities should be included in the BES only if the elements of the Facility are transferring significant amounts of power which would impact the reliability of the BES.
National Grid	No	The version of exclusion E3 criterion (c) filed with FERC January 25, 2012 (RM12-6-000) requires a "local network" not to contain a monitored facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored facility in the ERCOT or Quebec Interconnections, and is not a monitored facility included in an Interconnection Reliability Operating Limit (IROL). By changing exclusion E3 criterion (c) from "a monitored Facility of a permanent Flowgate..." to "any part of a permanent Flowgate..." the definition became vaguer and could allow for too broad of a reading. The original language from Phase 1 of the BES definition regarding exclusion E3 criterion (c) provided more clarity and guidance on how to apply this

Organization	Yes or No	Question 1 Comment
		exclusion. It is recommended that the original language from Phase 1 of the BES definition be re-instated. Facilities should be included only if the elements of the Facility are transferring power (flow) through a flowgate, transfer path, or IROL.
Response: The SDT believes that the reliable operation of the interconnected transmission system requires operator situational awareness of any and all parts of permanent flowgates in order to adequately provide for reliable operation. Hence, the presence of any part of a flowgate should preclude the application of the E3 Exclusion. Accordingly, the SDT is making no changes to this revised language of Exclusion E3(c).		
Hydro-Quebec TransEnergie	No	The phase 1 BES definition was approved by NERC after a positive acceptation by industry, providing that phase 2 would reconsider some of the thresholds proposed in phase 1. Among the thresholds, the limit of 75 MVA was an important one. Now, FERC request important changes that limit the possibility of exclusion : 1) limitation on the possibility of radial exclusion because of looping below 100 kV; 2) refusal of radial or local exclusions when there are at least one generator above 20 MVA. Those limitations for exclusion go in the opposite direction to what industry expected. In that sense, HQT doesn't approved those changes. Moreover, it is not acceptable that those restrictions requested by FERC be imposed to all non-FERC jurisdiction. It is important that NERC consult also the Canadian jurisdictions about the BES definition.
Response: The SDT understands that the changes ordered by the Commission place limitations on the exclusion beyond what was expected by the industry; however, the SDT is bound by the directives of that Order and therefore recommends no change.		
Modesto Irrigation District	No	There is no technical basis or study to support the change.
IRC Standards Review Committee	No	We are unable to find the technical justification for removal of the 100kV threshold. We are unable to support this until the technical basis is presented.
Response: The SDT is making this change pursuant to the Commission's directives in Order 773, and therefore, a technical		

Organization	Yes or No	Question 1 Comment
justification is not applicable.		
Northeast Utilities	No	While it is recognized that electrical systems operated below 100KV can be configured such that they should require BES treatment (i.e. the 92 KV networked system involved in the 2011 Southern California - Arizona outage), a 30KV threshold is too low to significantly impact the reliable operation of the higher voltage transmission system. We propose increasing this threshold to a voltage in the 40-50KV range. The new Note 2 associated with Exclusion E1 and the changes to E3 have added ambiguity that did not exist before. The base definition does not address sub-100kV contiguous loops. The existing Inclusions do not include sub 100kV contiguous loops either. Note 2 clarifies that as long as the contiguous loop is below 30kV E1 still applies. E3 explains how any sub 30kV contiguous loop could be excluded as a local area network, but there is nothing in the definition to clearly state that contiguous loops operated below 100kV are considered part of the BES unless excluded by E3. An additional Inclusion should be added that specifically includes "all contiguous loop operated below 100kV that is not solely used for the distribute power to load unless excluded by application of Exclusion E1 or E3." The proposed change to the E1 exclusion definition to add Note 2 will require an examination of NU sub-transmission system connections (69KV in CT and 34KV in NH) and their connections to the >100KV transmission systems. Elements >100KV originally categorized as E1 or E3 may become BES inclusions if there is underlying sub-transmission path. A cursory review determine no elements categorized as E1 in CT would be changed; however, 16 of the 30 E1 elements in NH could become BES due to 34KV paths.
Response: The 30 kV value in the first posting of Phase 2 was initially chosen based on a high-level evaluation and was inserted in the definition to introduce the concepts to the industry and seek supported technical opinions from the industry. As the technical justification has now been completed, a final value of 50 kV has been selected for inclusion in this current posting. The white paper detailing the technical justification for this position has been posted as a supporting document.		

Organization	Yes or No	Question 1 Comment
This change does not result in the inclusion of sub-100 kV elements in the BES. Sub-100 kV elements, if otherwise excluded from the BES, will not be brought into the BES by application of this revised language. Order 773, paragraph 155 states: “Thus, the Commission, while disagreeing with NERC’s interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process.” This was reaffirmed by the Commission in Order 773A, paragraph 36 which states: “Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process.” The proposed threshold value of 30 kV, which has now been modified to 50 kV, for looped facilities, is a qualifier for how the 100 kV and above facilities will be evaluated for potential exclusion. For example, whether the criteria of Exclusion E1 (radial system) would be used for evaluation or if the looped facilities exceed the threshold value thus requiring evaluation under the criteria of Exclusion E3 (local network).		
Central Lincoln	Yes	Central Lincoln agrees the SDT has addressed the directive, but continues to believe the conditions on outflow and through flow are excessively restrictive. Please see further comments in the response to Question 6.
Sacramento Municipal Utility District	Yes	SMUD agrees the SDT has addressed the Commission’s Directive. However, removal of 100kv threshold from the first part of E3 but the 100kV reference remains in the second part of the E3 exclusion which is inconsistent. It is unclear what value the second sentence of the E3 exclusion provides and should be removed from the E3 exclusion.
Public Utility District No.1 of Snohomish County	Yes	The Public Utility District No.1 of Snohomish County agrees the SDT has addressed the directive, but continues to believe the conditions on outflow and through flow are excessively restrictive. Please see further comments in the response to Question 6.
SPP Standards Review Group	Yes	Please see our comment in Question 6 regarding removal of the 100 kV limit?
Response: Thank you for your support and please see responses to comments for Q6.		

Organization	Yes or No	Question 1 Comment
American Transmission Company	Yes	However, ATC believes this would not include the significant network facilities below 100kV. This would have to be addressed through a revision to the Inclusions.
Response: The elimination of the phrase "…or above 100 kV but…" does not cause the inclusion of any facilities below 100 kV. In the event that there are significant network facilities operating below 100 kV, these can be examined for inclusion through the Exception Process under the Rules of Procedure. No change made.		
Dominion	Yes	However, please see our comments to remaining questions. .
Response: Thank you for your support and please see responses to remaining questions.		
Independent Electricity System Operator	Yes	Under the premise that the very first paragraph of the BES Definition already establishes the bottom voltage threshold of 100kV, we agree with removing the mention of the 100kV bottom threshold in exclusion E3.
Idaho Power Company	Yes	We agree that making the changes that are the subject of Q1 meets the Commission's directive to "modify the local network exclusion to remove the 100 kV minimum operating voltage to allow systems that include one or more looped configurations connected below 100 kV to be eligible for the local network exclusion".
ACES Standards Collaborators	Yes	While we believe the concerns expressed by the FERC directive could have been handled through the bulk electric system (BES) exception process, we agree that the proposed changes do address the FERC directive. Most transmission above 100-kV that terminates into sub-transmission below 100 kV should be treated as radial since its impacts on the BES, in most cases, is negligible. Since the vast majority of networked facilities below 100 kV will not ultimately be part of the BES, it would make more sense to use the BES exception process to include those that do impact the BES rather than subject all instances to the more complicated E3 exclusion.
Associated Electric Cooperative,	Yes	

Organization	Yes or No	Question 1 Comment
Inc. - JRO00088		
MRO NERC Standards Review Forum (NSRF)	Yes	
Tennessee Valley Authority	Yes	
SERC EC Planning Standards Subcommittee	Yes	
Cooper Compliance Corp	Yes	
City of Tacoma	Yes	
Pepco Holdings Inc & Affiliates	Yes	
DTE Electric	Yes	
Iberdrola USA	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Southwest Power Pool Regional Entity	Yes	
Colorado Springs Utilities	Yes	
Transmission Access Policy Study Group	Yes	

Organization	Yes or No	Question 1 Comment
US Bureau of Reclamation	Yes	
FirstEnergy	Yes	
Wisconsin Public Service / Upper Peninsula Power	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
South Carolina Electric and Gas	Yes	
Orange and Rockland Utilities Inc.	Yes	
American Electric Power	Yes	
Duke Energy	Yes	
Ameren	Yes	
ISO New England Inc.	Yes	
NV Energy	Yes	
American Wind Energy Association	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Xcel Energy	Yes	

Organization	Yes or No	Question 1 Comment
American Public Power Association	Yes	
MidAmerican Energy	Yes	
Response: Thank you for your support.		

2. **As identified in the FERC directive, the SDT has revised the local network (Exclusion E3) and radial system (Exclusion E1) exclusions so that they do not allow for the utilization of these exclusions for generation interconnection facilities that are used to interconnect BES generation identified in the generation inclusion (Inclusion I2) with BES transmission elements. Do you agree that the SDT has correctly addressed this directive? If you do not agree that this change addresses the directive, or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: Commenters identified that the language of Inclusion I2 does not distinguish between retail generation and non-retail generation. As such, it was challenged that the current proposal for Exclusions E1 and E3 do not take into consideration Exclusion E2 generation that would not be classified as BES generation. The Commission's final rule identified the requested changes should be applied to "bulk electric system generators" and additional clarity was requested. The SDT determined that a change was not necessary. The SDT would like to highlight that Exclusion E2 generation units could not apply to Exclusion E1b because Exclusion E1b applies to generating resource connections only and Exclusion E2 generation serves Load to the retail customer. Additionally, Exclusion E1c specifically highlights and excludes Exclusion E2 generation with the words "…with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating)." Exclusion E3 uses similar wording to exclude Exclusion E2 generation.

Some commenters expressed the opinion that there was a redundancy introduced in Exclusions E1b, c, and E3a with the retention of the greater than 75MVA threshold. The SDT disagrees because the 75 MVA threshold is required to accommodate situations such as the existence of multiple 10 MVA nameplate units within the radial system or local network which could add up to greater than 75 MVA.

Commenters sought to clarify the 75 MVA limits to connected generation in Exclusion E3 with respect to other non-BES generation that may be connected to a sub-100 kV distribution system. Additionally, commenters identified concerns with respect to the fact that the presence of <u>any</u> BES generation will disqualify the E3 exclusion. The SDT wants to make this point clear: the language means that any BES generation within a local network would disqualify the entity from claiming the E3 exclusion; and any non-BES generation (with the exception of any non-BES generation identified in Exclusion E2) which totals an aggregate greater than 75 MVA would also disqualify the entity from claiming the E3 exclusion.

The language for the generator interconnection facilities portion of Inclusion I2 is still not clear to some commenters. Commenters identified the language is not concerning in a simple interconnection but the confusion/risk comes when there are multiple feeders and transformations between the generating resource and the BES with respect to the literal interpretation involving the term "step-up transformer(s)" in an arrangement that is also used to serve local Load. The SDT has determined that the best place to clarify industry concerns on this matter is within the Reference Document. The SDT has specifically inserted an example of a multiple transformation interconnection facility in the Reference Document that clarifies that if there is a transformer with a high-side connection below 100 kV within the interconnection that is also used to deliver power to serve Load below 100 kV, then the generation resource and interconnection facilities (i.e., transformer) is excluded from the BES. The SDT would also like to refer to the Commission's agreement with this distinction within Order 773, paragraph 92.

Organization	Yes or No	Question 2 Comment
Texas Reliability Entity	No	(1) The current draft appears to disallow E1 and E3 exclusions based on the presence of retail generation (such as generation within industrial facilities) within a radial system or local network. This is because the language of I2 does not distinguish between retail generation and non-retail generation. We do not think the current language reflects the intention of the drafting team. (2) Consider the following situation: an industrial facility is connected to the BES at one point with 100 MVA of retail generation connected at 138 kV that never provides more than 25 MVA to the grid. That generation is identified in I2, but it is excluded by E2, so it is not BES generation. However, the radial transmission facilities do not qualify as a "radial system" because of the presence of "generation resources [] identified in Inclusions I2 or I3." (3) This can be corrected by (a) referring to E2 in I2 (perhaps add to I2: "unless excluded by application of Exclusion E2") ; or (b) referring to "BES generation" in E1 and E3 rather than merely referring to "I2."
Response: The SDT would like to highlight that Exclusion E2 generation units could not apply to Exclusion E1b because Exclusion E1b applies to generating resource connections only and Exclusion E2 generation serves Load to the retail customer. Additionally, Exclusion E1c specifically highlights and excludes Exclusion E2 generation with the words "…with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating)." Exclusion E3 uses similar wording to exclude Exclusion E2 generation. No change made.		
Associated Electric Cooperative, Inc. - JRO00088	No	AECI suggests the SDT consider the following change for I2: REPLACE: "Generating resource(s) and dispersed power producing resources," WITH: "Generating resource(s) and dispersed power producing resources connected at 100 kV and

Organization	Yes or No	Question 2 Comment
		above," RATIONALE: Clarity of intent. Inclusion I2's order and new separation of wording, appears to make "the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above" stand autonomous. Because "step-up transformer" is not defined in the NERC Glossary, AECI is deeply concerned that the current wording can become twisted to instruct industry to first locate their Plants greater than 75 MVA and Units greater than 20 MVA, next locate all the transformers connecting them to the core BES at a voltage of 100 kV or above, and finally include all the wires "between," which is most all of the sub-transmission systems and including sub-sub-transmission following FERC's most recent logic. The core BES definition's "Unless modified by the lists shown below", will further support this reading and go against what the BES Phase II SDT has been assuring industry, that primarily elements 100 kV and above are part of the BES. AECI expresses this further concern for SDT consideration: With E3 now excluding I2, it appears to be in technical conflict with E2, where E3 for a potential LN but with any interior unit greater than 20 MW yet continuously consuming All interior generation and more (per E3b), cannot be excluded and yet E2 can. Why?
Response: The SDT has determined that the best place to clarify industry concerns on this matter is within the Reference Document. The SDT has specifically inserted an example of a multiple transformation interconnection facility in the Reference Document that clarifies that if there is a transformer with a high-side connection below 100 kV within the interconnection that is also used to deliver power to serve Load below 100 kV, then the generation resource and interconnection facilities (i.e., transformer) is excluded from the BES. The SDT would also like to refer to the Commission's agreement with this distinction within Order 773, paragraph 92. No change made. This is because the Commission Order referred to BES generation and Exclusion E2 generation serves Load to the retail customer and is not BES generation. No change made.		
Occidental Energy Ventures Corp.	No	Although OEVC believes the language changes for E1 and E3 adequately addresses the FERC directive, some entities have expressed a need for clarity when considering E1 and E3 for cogeneration that would normally be excluded by application of E2. As OEVC understands the position of these entities, the logic of applying I2, then E2,

Organization	Yes or No	Question 2 Comment
		and finally E1 or E3 according to the hierarchy could include, then exclude, and then re-include an industrial generator that would otherwise qualify for Exclusion E2. OEVC understands from the Webinar that this is not the intent of the SDT and that clarification will be made so that no one can misinterpret the SDT's intent. Also, the language in E3 might be interpreted to mean that ANY BES generation within an LN would disqualify the entity from claiming the E3 exclusion. It would seem that only the pathway from the BES generator to the BES should be included in the BES to satisfy the FERC directive and that the remainder of the LN might still qualify. (Perhaps this will be clarified in the Guidance Document). Finally, it still seems unnecessary to limit non-retail generation within the LN to 75 MVA when FERC has now stated that power cannot flow out of the LN under any conditions.
Response: Application of the definition can, at times, be a multiple step operation. However, if an entity applies the definition in the hierarchical fashion as described in detail in the Reference Document, it will greatly diminish the steps involved and any possible confusion. No change made. The SDT wants to make this clear: the language means that any BES generation within a local network would disqualify the entity from claiming the E3 exclusion; and any non-BES generation (with the exception of any non-BES generation identified in Exclusion E2) which totals an aggregate greater than 75 MVA would also disqualify the entity from claiming the E3 exclusion. The SDT disagrees as the 75 MVA threshold is required to accommodate situations such as the existence of multiple 10 MVA nameplate units within the radial system or local network which could add up to a total greater than 75 MVA. No change made.		
PacifiCorp	No	Although PacifiCorp believes that the SDT has addressed the FERC directive, the directive in general allows for equivalent viable alternatives. PacifiCorp believes that FERC's directive is overreaching and fails to consider the already minimal upper limit of 75 MVA (gross nameplate rating) established in Exclusion E1. A generating resource's registration status or BES status should not have a bearing as to whether it must have a contiguous path to the BES. The previous limited upper limit of 75 MVA established a point at which the registered generator(s) would not interfere

Organization	Yes or No	Question 2 Comment
		with the reliable operation of the interconnected system in the event of a loss of the < 75 MVA generator(s) or of the < 75 MVA generator's(s') ability to respond to the loss of critical generation elsewhere in the system. In the relatively few situations in which the registered generating resource is critical to the operation of the interconnected system, the associated transmission could be included within the scope of the BES through the approved exception process.
Response: The SDT is responding to the mandated Commission directive. If an entity feels that the Commission overreached, that matter needs to be discussed between the entity and the Commission and is outside the scope of the SDT. No change made.		
Southern California Edison	No	By revising E1 in this manner, the SDT eliminates the issue of identifying dispersed power producing resources, but in-turn creates a more restrictive definition as it relates to the "wires and lines" component of the definition. The SDT definition is too heavily reliant on static Generator MVA thresholds, which should not be the major determining factor for bringing LNs, and now Radial lines, into the BES definition. The original FERC directive in Order Nos. 743 and743-A asked that the functional test be used in the determination as a first step for BES determination, and should be incorporated in the procedures for inclusion of the LNs into the BES. SCE's position is that facilities operated in-parallel with BES should be considered part of the BES regardless of voltage level. For the "wires and lines" side of the BES definition, the "impact on the Bulk Power System, should be a determining factor for identifying these LNs or Radial systems as BES, not the total amount of interconnected generation.
Response: With this change, the SDT is implementing the Commission's directives in Order 773A to modify Exclusions E1 and E3 so that they do not apply to generator interconnection facilities for BES generators identified in inclusion I2. Any sub-100kV facilities that an entity feels are BES facilities that are not captured by the definition can be submitted as such through the exception process. No change made.		
Northeast Power Coordinating Council	No	I2 does not include "non-retail" generation which is inconsistent with E1 and E3. E1b, c, and E3a contain redundant statements regarding the 75MVA generator

Organization	Yes or No	Question 2 Comment
		threshold. These statements should be corrected for clarity and consistency. For Simple E1 Radial System Exclusions--The Drafting Team application of this FERC directive is clear for simple E1 Radial System Exclusions. Any tie-line connected radially to the BES and operated at 100kV or above connecting I2 or I3 generation (aggregating to more than 75MVA) is part of the BES. However, beyond this simple configuration the application of the tie-line directive is less clear. For the More Complex E1 Radial System Exclusions--More complex applications of the tie-line directive under the proposed BES Definition are less clear. Consider that Inclusion I2 states the tie-line includes "... the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above..." It could be argued that this was intended to apply to a short line or bus connection between the generator and the generator step-up unit. But in reality it could be a long connection. Regardless, a fault can occur on any length of line or bus. Application of the tie-line directive is less clear when there are multiple feeders and transformations between the generating resource and the BES which include sub-100kV operating voltages. For example, a GT with a 13.8kV output feeds local distribution. This local distribution is also served by a 69-to-13.8kV step-down transformer that is fed by a 69kV sub-transmission feeder supplied by a 138-to-69kV transformer connected to the BES by a 138kV feeder serving multiple step-down transformers to load. This Radial System has only one connection to the BES at 138kV. What facilities are covered by the tie-line directive, either the entire path from "... the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above" or only the portion of the 138kV feeder from the high-side terminals of the 138-to-69kV step-down transformer to the BES? For the E3 Local Network Exclusion--Applying the tie-line directive within a Local Network could be problematic. The proposed wording introduces issues similar to those involving Cranking Paths from Black Start units. Local Networks by the definition "emanate from multiple points of connection at 100 kV or higher." Defining a single tie-line through the Local Network presents problems. Is the tie-line the shortest path geographically or electrically? Does the tie-line directive suggest

Organization	Yes or No	Question 2 Comment
		single or multiple paths to the BES? The CIP drafting team recognized this problem and defined the path, eliminating Regional or Entity discretion and avoiding substantial ambiguity and confusion. Following the CIP Drafting Team example, suggest adding the following wording: Note 3: The BES tie-line is defined as the portion of the single shortest contiguous path operated at 100kV or above from the I2 or I3 resource to the BES. The Radial System or Local Network excluded must be defined so that it does not include a BES tie-line. Portions of the tie-line path operated below 100kV are not part of the BES. Application of this note does not extend to tie-line facilities operated below the 100kV core definition.
Response: The Commission's final rule identified the requested changes should be applied to "bulk electric system generators" and additional clarity was requested. The SDT determined that a change was not necessary. The SDT would like to highlight that Exclusion E2 generation units could not apply to Exclusion E1b because Exclusion E1b applies to generating resource connections only and Exclusion E2 generation serves Load to the retail customer. Additionally, Exclusion E1c specifically highlights and excludes Exclusion E2 generation with the words "…with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating)." Likewise, Exclusion E3 uses similar wording to exclude Exclusion E2 generation. No change made. The SDT disagrees as the 75 MVA threshold is required to accommodate situations such as the existence of multiple 10 MVA nameplate units within the radial system or local network which could add up to greater than 75 MVA. No change made. The SDT has determined that the best place to clarify industry concerns on this matter is within the Reference Document. The SDT has specifically inserted an example of a multiple transformation interconnection facility in the Reference Document that clarifies that if there is a transformer with a high-side connection below 100 kV within the interconnection that is also used to deliver power to serve Load below 100 kV, then the generation resource and interconnection facilities (i.e., transformer) is excluded from the BES. The SDT would also like to refer to the Commission's agreement with this distinction within Order 773, paragraph 92. No change made.		
New York Power Authority	No	I2 is inconsistent with E1& E3 by not including "non-retail" generation. E1b&c and E3a contain redundant statements regarding the 75MVA generator threshold. These statements should be corrected for clarity and consistency.

Organization	Yes or No	Question 2 Comment
Sacramento Municipal Utility District	No	I2 is inconsistent with E1& E3 by not including “non-retail” generation. E1-b & c and E3-acontain redundant statements regarding the 75MVA generator threshold. These statementsshould be corrected for clarity and consistency.
Response: The Commission’s final rule identified the requested changes should be applied to “bulk electric system generators” and additional clarity was requested. The SDT determined that a change was not necessary. The SDT would like to highlight that Exclusion E2 generation units could not apply to Exclusion E1b because Exclusion E1b applies to generating resource connections only and Exclusion E2 generation serves Load to the retail customer. Additionally, Exclusion E1c specifically highlights and excludes Exclusion E2 generation with the words “…with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).” Likewise, Exclusion E3 uses similar wording to exclude Exclusion E2 generation. No change made. The SDT disagrees as the 75 MVA threshold is required to accommodate situations such as the existence of multiple 10 MVA nameplate units within the radial system or local network which could add up to greater than 75 MVA. No change made.		
Hydro-Quebec TransEnergie	No	Same comment as for question 1
PPL NERC Registered Affiliates	No	See comments above.
North American Generator Forum Standards Review Team	No	See comments for Question 1
Response: Please see response to Q1.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	Southern recognizes and appreciates that the changes described in Question 2 respond simply and concisely to FERC’s directive in Order 773 to implement exclusions E1(b) and (c) and E3(a) so that the exclusions do not apply to tie-lines for generators identified in Inclusion I2. It appears both from the revisions to Inclusion I2 and from FERC’s discussion in the orders that FERC is intending to cover tie-lines to small-scale power generation technologies such as wind, solar, geothermal, energy storage, etc. However, from reviewing the revised language and the Bulk Electric System Guidance Document, it appears that one unintended consequence of

Organization	Yes or No	Question 2 Comment
		this directive (and NERC's implementation of this directive) may be to pull into the BES, for example, 230 kV or other high voltage feeders supplying auxiliary power to conventional generation resources (i.e., not dispersed power producing resources). While it may be appropriate to include certain components connecting the generation step-up units to the connection point, Southern has not seen any technical justification for adding auxiliary transformers and their high voltage feeders to the BES, which may have little to no significance to the reliable operation of the interconnected BES. Southern suggests that the SDT consider pursuing technical justification in Phase 2 or a later Phase for adding a note or some more nuanced language in Exclusions E1 or E3 that would more accurately reflect the distinctions described above by excluding from the BES these auxiliary elements while still addressing the intent of FERC's directive regarding dispersed power producing resources.
Response: The SDT does not agree that the Commission's Order is intended to cover only small scale power generation facilities. And, lacking a specific example or configuration, the SDT does not understand why the commenter feels that this change has an unintended consequence of pulling in auxiliary power resources. No change made.		
City of Anaheim	No	This Question No. 2 has clearer language than the Exclusions E1 and E3 themselves when it qualifies the interconnected generation as "BES generation." As discussed below, Exclusions E1 and E3 should be modified to make clear that non-BES generation (i.e., any non-Inclusion I2/I3 generation that is connected to non-BES facilities, including distribution facilities operated below 100 kV) does not disqualify a registered entity from either Exclusion E1 or Exclusion E3. Exclusions E1 and E3 should clearly state that the 75 MVA limitation on generation resources contained in Exclusions E1(c) for radial systems and E3(a) for local networks applies to generation resources that are actually connected to the potentially excluded radial system or local network. The 75 MVA limitation should not apply to non-BES generation that may be connected to a sub-100 kV distribution system beyond the radial system or local network. Anaheim believes that the Drafting Team may intend for the existing (i.e., Phase 1) definition to be applied in this manner. For example, both the radial

Organization	Yes or No	Question 2 Comment
		system and local network definitions refer to "contiguous transmission Elements," which do not include "distribution Elements." A 75 MVA (or greater) generator connected to a 69 kV local distribution Element is not contiguous to the BES, nor is it connected to a transmission Element; therefore, such distribution system generation should not preclude the radial system or local network from being excluded from the BES. Anaheim's proposed revisions to Exclusions E1 and E3 to address this issue are provided below. To the extent that the Drafting Team already intends for the existing (i.e., Phase 1) BES definition to be interpreted and applied as described in these comments and that no further changes to the Exclusions are warranted, then Anaheim requests that the Drafting Team confirm this in future guidance documents or that the Drafting Team so specify in response to these comments. Exclusion E1:E1 - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: a) Only serves Load.b) Only includes generation resources, not identified in Inclusion I2 or I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating).c) Where the radial system both serves Load and includes generation resources, the generation resources (i) are not identified in Inclusions I2 or I3 and (ii) have an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating) directly connected to the radial system. [Anaheim proposes no changes to the remainder of Exclusion E1; for brevity, the remainder of this exclusion has not been restated.]Exclusion E3:E3 - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LNs emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customs and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:a) Limits on connected generation: The LN does not include generation resources identified in Inclusions I2 or I3 and does not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating) directly connected to the LN at a voltage of 100 kV or above;[Anaheim proposes no changes to the remainder of

Organization	Yes or No	Question 2 Comment
		Exclusion E3; for brevity, the remainder of this exclusion has not been restated.]
Response: The intent of the SDT is that non-BES generation (with the exception of any non-BES generation identified in Exclusion E2) which totals an aggregate greater than 75 MVA would also disqualify the entity from claiming the E3 exclusion. Future revisions of the Reference Document will include new diagrams for any changes introduced as a result of Phase 2 decisions. No change made.		
Cooper Compliance Corp	No	We agree that the Exclusion E3 is correct providing Including I2 is modified. We recommend that I2 is further clarified to include a more specific definition of a Generator Interconnection Facility (Transmission Interface) and provide clarification that the generation counted against the "aggregate capacity of non-retail less than or equal to 75 MVA (gross nameplate rating)" that disqualifies the radial exclusion in E1 or the local area network exclusion E3. Regarding the Transmission Interface, FERC recommendations contained in Docket No. RM12-16-000 define the Standards applicable to the Transmission Interface. These Standards are FAC-001-1, FAC-003-3, PRC_004-2.1a, and PRC-005-1.1b. We have identified a potential gap in which a generator is connected to a portion of a 115 kV line owned by a distribution provider prior to connecting to what otherwise would be considered the BES. Absent the generator, the line would only be used to serve load and would be excluded under E3. We recommend clarification that does not require the distribution provider to register as a Transmission Owner and Operator based on the small section of line used as part of the Transmission Interface. Instead, we recommend that the distribution line also qualifies as a generator interconnection facility and is part of the transmission interface to the generator only. The following are our recommended changes to Inclusion I2.Generating resource(s) and dispersed power producing resources connected at voltage of 100kV or above, including the Generator Interconnection Facilities with:a) Gross individual nameplate rating greater than 20 MVA, OR, b) Gross plan/facility aggregate nameplate rating greater than 75 MVA.The Generator Interconnection Facilities include the generator terminals through the point of interconnection to the

Organization	Yes or No	Question 2 Comment
		transmission elements that would otherwise be considered transmission elements included within the definition of Bulk Electric System. Regarding the clarification on what is counted towards the 75 MVA that disqualifies the radial or local area network exclusions, we believe it is the drafting teams intent that the count of generation is only to include generation that has been defined within the Inclusions or through the exception process. However, we feel the actual definition could be enhanced to provide this clarification. In separate comments made by the City of Anaheim they propose the following modifications to the definition, which we agree better defines this definition. Exclusion E1: E1 - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and satisfies one of the following additional criteria: a) The radial system only serves Load.b) If the radial system includes only generation resources, the generation resources (i) must not satisfy the criteria set forth in either Inclusion I2 or Inclusion I3 and (ii) must not have an aggregate capacity of greater than 75 MVA (gross nameplate rating) directly connected to the radial system at a voltage of 100 kV or above.c) If the radial system both serves Load and includes generation resources, the generation resources (i) must not satisfy the criteria set forth in either Inclusion I2 or Inclusion I3 and (ii) must not have an aggregate capacity of greater than 75 MVA (gross nameplate rating) of non-retail generation directly connected to the radial system at a voltage of 100 kV or above. Exclusion E3: E3 - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LNs emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customs and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following: a) Limits on connected generation: The LN does not include generation resources identified in Inclusions I2 or I3 and does not have an aggregate capacity of more than 75 MVA (gross nameplate rating) of non-retail generation directly connected to the LN at a voltage of 100 kV or above.b) Power flows

Organization	Yes or No	Question 2 Comment
		into the LN; it rarely, if ever, flows out. The LN does not transfer energy originating outside of the LN for delivery through the LN.
Response: The Commission's final rule identified the requested changes should be applied to "bulk electric system generators". The SDT would like to highlight that Exclusion E2 generation units could not apply to Exclusion E3 because Exclusion E2 generation serves Load to the retail customer. No change made. Additionally, Exclusion E1c specifically highlights and excludes Exclusion E2 generation with the words "…with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating)." Likewise, Exclusion E3 uses similar wording to exclude Exclusion E2 generation. Registration issues and applicability issues of other standards are beyond the scope of the SDT. However, the BES SDT conducted a review of applicability of Reliability Standards. The review consisted of the Reliability Standards that are applicable to the Transmission Owners (TO), Generator Owners (GO), Transmission Operators (TOP) and the Generator Operators (GOP). The review was based on the premise that the applicability of Reliability Standards is limited to BES Elements unless otherwise stated in the 'Applicability' section of the standard or identified in the individual requirements. The review was conducted to: 1. Assess the impact of the revised BES definition on the current applicability of the subject Reliability Standards, and; 2. Identify areas where the applicability could be improved from a clarity perspective and assessed the proper application of BPS vs. BES. The results of this analysis were forwarded to the NERC Standards Committee for consideration: 1. The BES SDT found no issues that were identified as an immediate concern based on the revised definition of the BES, therefore the BES SDT did not develop any supporting draft SARs or potential redline changes. 2. The BES SDT identified several areas where the clarity of the applicability could be improved. These issues were documented and provided to the NERC SC with the expectation is that these issues would be added to the 'Standards Issues Database' for consideration by future SDTs. Additionally, the results of the BPS vs. BES assessment were provided to the NERC SC, again with the expectation is that these issues would be added to the 'Standards Issues Database' for consideration by future SDTs.		
Orange and Rockland Utilities Inc.	No	We generally agree with the Guidance Document that was provided by NERC Drafting Team. The document showed that if there are any I2 Elements within a local network, the specific I2 Elements are deemed to be BES Elements, but the rest of the local network would still be qualified as Exclusion E3.
Modesto Irrigation District	No	

Organization	Yes or No	Question 2 Comment
Response: In response to Commission directives, any Inclusion I2 Elements would prevent an entity from applying the E3 Exclusion.		
American Transmission Company	Yes	However, ATC would like clarification on Blackstart resource paths that are operated at < 100kV. A Blackstart resource would be included in the BES per I3; however the path that is less than 100kV would not be included in the BES.
MidAmerican Energy	Yes	MidAmerican would like clarification on Blackstart resources that are connected at < 100kV. A Blackstart resource would be included in the BES per I3; however the path that is less than 100kV would not be included in the BES
MRO NERC Standards Review Forum (NSRF)	Yes	The NSRF would like clarification on Blackstart resources that are connected at < 100kV. A Blackstart resource would be included in the BES per I3; however the path that is less than 100kV would not be included in the BES
Response: Your statement is correct.		
Independent Electricity System Operator	Yes	In general we agree with these changes and propose the following alternative language for more clarity: 'Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above, and dispersed power producing resources connected at a common point at a voltage of 100 kV or above with;'
Response: The SDT has separated Inclusions I2 and I4 for the clarity the industry is seeking.		
SPP Standards Review Group	Yes	Please see our comment in Question 6 regarding removal of the 100 kV limit?
Response: Thank you for your support and please see the response to Q6.		
ACES Standards Collaborators	Yes	The modifications appear to address the directive. It removes the possibility that the BES will not be contiguous from a generator connected at 100 kV or higher and the rest of the BES that is 100 kV or higher. Furthermore, it does not appear to draw in

Organization	Yes or No	Question 2 Comment
		sub-transmission facilities that are connected below 100 kV to generator facilities that are included by inclusions I2 and I3. For example, a Blackstart Resource connected on a 69 kV line may be part of the BES but the 69 kV facilities connecting the unit to the BES would not be. Assuming this is correct; we agree the changes address the directive appropriately.
Response: Thank you for your support.		
Public Utility District No.1 of Snohomish County	Yes	The Public Utility District No.1 of Snohomish County suggests increasing the 30kV threshold to "35kV or less" as 34.5kV is a common distribution voltage used in rural communities and should not be classified as BES. From Wikipedia "Rural electrification systems, in contrast to urban systems, tend to use higher distribution voltages because of the longer distances covered by distribution lines (see Rural Electrification Administration). 7.2, 12.47, 25, and 34.5 kV distribution is common in the United States..."
Response: The SDT has provided a white paper as supporting documentation for this posting that provides a detailed technical analyses justifying a- 50 kV threshold. [Also see consideration of these comments in response to Question 3.]		
Idaho Power Company	Yes	We agree that making the changes that are the subject of Q2 meets the Commission's directive to "implement exclusion E1 (radial systems) and exclusion E3 (local networks) so that they do not apply to generator interconnection facilities for bulk electric system generators identified in inclusion I2".
Hydro One Networks Inc.	Yes	We agree that transmission element(s) and/or generation should not be excluded by definition. However, it is important to clarify that such configurations can be excluded through the exception process if and when they are not necessary for the operation of BES or interconnected BES.
Dominion	Yes	

Organization	Yes or No	Question 2 Comment
Tennessee Valley Authority	Yes	
SERC EC Planning Standards Subcommittee	Yes	
City of Tacoma	Yes	
Pepco Holdings Inc & Affiliates	Yes	
DTE Electric	Yes	
Iberdrola USA	Yes	
IRC Standards Review Committee	Yes	
Arizona Public Service Company	Yes	
Southwest Power Pool Regional Entity	Yes	
Colorado Springs Utilities	Yes	
US Bureau of Reclamation	Yes	
Central Lincoln	Yes	
FirstEnergy	Yes	
Wisconsin Public Service / Upper Peninsula Power	Yes	
Public Service Enterprise Group	Yes	

Organization	Yes or No	Question 2 Comment
Manitoba Hydro	Yes	
South Carolina Electric and Gas	Yes	
Self	Yes	
American Electric Power	Yes	
Georgia Transmission Corporation	Yes	
Duke Energy	Yes	
Ameren	Yes	
ISO New England Inc.	Yes	
NV Energy	Yes	
American Wind Energy Association	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Xcel Energy	Yes	
American Public Power Association	Yes	
Response: Thank you for your support.		

3. The SDT has proposed an equally effective and efficient alternative to the Commission's sub-100 kV loop concerns for radial systems by the addition of Note 2 in Exclusion E1. Do you agree with this approach? If you do not support this approach or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions and rationale in your comments.

Summary Consideration: A number of comments indicated that the 30 kV voltage shown in the initial posting was too low or did not have a technical justification. The 30 kV value was initially chosen based on a high-level evaluation and was inserted in the definition to introduce the concept and seek feedback and technical opinions from the industry. Comments and suggestions were received questioning the threshold of 30 kV proposed in Note 2 for Exclusion E1. To address this issue, the SDT has created a white paper that is posted as a supporting document for the second posting of this project which provides an overview of the regional criteria and contingency load flow analysis. The SDT has determined that 50 kV is a technically justifiable voltage threshold and has changed the value in Note 2 to 50 kV. This value represents a nominal voltage level (50 kV) that is between operating voltage levels (46 kV and 55 kV) to ~~i~~nsure that a clear bright-line is established.

Comments were received that indicated systems less than 100 kV would be included in the BES. The looping facilities that operate at voltages below 100 kV are NOT included in the BES. Order No. 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order No. 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process."

Some comments concerned the wording or the use of Note 2. The SDT has considered these comments and has decided to leave the format of Notes 1 and 2 as shown in the posting. Note 2 indicates that no loops below 50kV need to be considered when evaluating radials. It should be noted that normally open switches at any voltage will not disqualify the use of Exclusion E1.

Note 2: The presence of a contiguous loop, operated at a voltage level of ~~30~~50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

Organization	Yes or No	Question 3 Comment
Ameren	No	(1) We believe that the threshold of 30 kV is too low and needs to be raised to at least 70 kV because subtransmission facilities are not intended to transfer power

Organization	Yes or No	Question 3 Comment
		long distances and do not respond to regional or interregional transfers. We believe that using a least common denominator approach for voltage levels does not align with the intended use of the low voltage networks in providing energy to firm loads throughout the Midwest. (2) At our subtransmission facilities directional overcurrent relays are installed on all of the stepdown transformers from the BES to limit the backfeed from the subtransmission system to the transmission system. We request the SDT to consider a distribution factor or powerflow cutoff in its discussions. We are not proposing significant contingency analyses be performed per the TPL standards in order to qualify for the exclusion. However, the proposed threshold of 30 kV without considering the network response, or magnitude of back-feed, or application of directional overcurrent relays on non-BES transformers appears to us to be too simplistic and arbitrary for this exclusion definition. (3) If multiple generating units connected at a common point to the BES but less than 75 MW are determined to be non-BES, it would seem that the low voltage networks and their supplies having a similar impact would also be determined to be non-BES.

Response: (1) and (2) - The 30 kV value was initially chosen based on a high-level evaluation and was inserted in the definition to introduce the concept to the industry and seek feedback and technical opinions from the industry. Comments and suggestions were received questioning the threshold of 30 kV proposed in Note 2 for Exclusion E1. To address this issue, the SDT has created a white paper that is posted as a supporting document for the second posting of this project which provides a review of regional criteria and contingency load flow analysis and has determined that 50 kV is the technically justifiable voltage threshold and has changed the value in Note 2 to 50 kV. This value represents a nominal voltage level (50 kV) that is between operating voltage levels (46 kV and 55 kV) to insure that a clear bright-line is established.

> Note 2: The presence of a contiguous loop, operated at a voltage level of ~~30~~50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

(3) The looping facilities that operate at voltages below 100 kV are NOT included in the BES. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in

Organization	Yes or No	Question 3 Comment
the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process."		
Colorado Springs Utilities	No	1.Can the standards drafting team clarify the reliability issue that they are trying to mitigate with this language? What are we trying to prevent? 2.Why was the 30 kV threshold chosen as opposed to any other voltage, what is the technical justification? a.Instead of a kV threshold can we use a capacity rating, for example - use the 75 MVA rating used for collection point asset inclusion? I know that there has been some discussion on this already, but we are not convinced that 30kV is a sound threshold. 3.If we do decide to stay with a kV rating, then we need to ensure that the "nominal voltage" is used as opposed to an "operating voltage." This is important to prevent a one-time operating voltage from drawings something in. 4.The "notes" should be incorporated into the definition itself, not left as notes to create confusion or additional need for clarification down the road.
Response: The SDT is addressing FERC directives in Orders 773 and 773A and industry comments concerning the BES Definition Phase 1 postings. The 30 kV value was initially chosen based on a high-level evaluation and was inserted in the definition to introduce the concept to the industry and seek feedback and technical opinions from the industry. Comments and suggestions were received questioning the threshold of 30 kV proposed in Note 2 for Exclusion E1. To address this issue, the SDT has created a white paper that is posted as a supporting document for the second posting of this project which provides a review of regional criteria and contingency load flow analysis and has determined that 50 kV is the technically justifiable voltage threshold and has changed the value in Note 2 to 50 kV. This value represents a nominal voltage level (50 kV) that is between operating voltage levels (46 kV and 55 kV) to insure that a clear bright-line is established. Note 2: The presence of a contiguous loop, operated at a voltage level of ~~30~~50 kV or less, between configurations being		

Organization	Yes or No	Question 3 Comment
considered as radial systems, does not affect this exclusion. The threshold value chosen represents a nominal voltage level (50 kV) that is between operating voltage levels (46 kV and 55 kV) to insure that a clear bright-line is established. The SDT has considered the comments concerning the text and format of Note 2 and has decided to leave the format of Note 2 as shown in the posting.		
DTE Electric	No	30kV is too low, 60kV would be more realistic. The lower the voltage chose the great the burden on industry in excluding these elements with no corresponding benefit to reliability.
Northeast Power Coordinating Council	No	Exclusion E1 provides a floor (30 kV threshold) for which an entity does not have to consider the loop in its determination of a radial system. Due to the international nature of the ERO, consideration must be given to what the various Provinces consider to be “distribution level”, and any proposed revision should recognize this dissimilarity. In addition, in the United States various state representatives have cited jurisdictional issues associated with lowering the threshold to 30 kV. This also impacts the 100 kV bright line threshold definition. The 30kV threshold as currently written is too restrictive. In a similar way as 100 kV is the delineator between the medium and high system voltage classes in the American National Standards Institute (ANSI) standard on voltage ratings (C84.1), the voltage threshold in note 2 of exclusion E1 should be based on well defined standard system voltage classes to better correlate to operational and system design considerations and practices. The Exception Procedure could be used to include lower (than 100 kV; bright line) voltage systems in the BES envelope when interactions between these systems and the BES are deemed critical to reliable operations in their local or regional area. The demarcation point between transmission and distribution may be different in non-FERC jurisdictions, such as the Canadian Provinces. For example, in Ontario, legislation establishes 50kV as the technical boundary line between transmission and distribution. In establishing voltage thresholds, NERC needs to consider non-

Organization	Yes or No	Question 3 Comment
		U.S. legislated demarcation points, and the standard development process must make allowances for such regulatory and/or jurisdictional differences. The establishment of the voltage floor for the E1 exclusion as currently written is inconsistent with the language and structure of the legislative framework in Ontario. The Exception Process is not appropriate to determine the jurisdictional issue of whether facilities are part of the Bulk Electric System. Note 2 should be modified to read as follows: Note 2 - The presence of a contiguous loop, operated at a voltage level below the applicable cut-off between configurations being considered as radial systems, does not affect this exclusion. The applicable cutoff is 30kV or less, unless deemed otherwise by regulatory authority. A technical justification is not required where a Provincial jurisdictional finding is applicable.
Hydro One Networks Inc.	No	Exclusion E1 provides a floor (30 kV threshold) which an entity does not have to consider the loop in its determination of a radial system. Data provided to the drafting team shows that there are no transmission elements below 50 kV in Ontario (and Canada) and very few in the 30-59 kV range (1%) in the US. A sub-set of this 1% can be included as BES through the exception process if deemed necessary for the operation of interconnected BES. The demarcation point between transmission and distribution may be different in non FERC jurisdictions, such as the Canadian provinces. Accordingly, we suggest that the 30 kV threshold be adjusted to 50 kV for Ontario (and Canada), since legislation establishes 50 kV as the technical boundary line between transmission and distribution. It would also alleviate any “unintended consequences” in future standards development. For example, in Ontario, legislation establishes 50 kV as the technical boundary line between transmission and distribution. In establishing voltage thresholds, NERC needs to consider non-US legislated demarcation points, and the standard development process must make allowances for such regulatory and/or jurisdictional differences. The establishment of the voltage floor for the E1 exclusion is inconsistent with the language and structure of the legislative framework in Ontario. Furthermore, we believe that the exception process is not appropriate to resolve the jurisdictional issue of whether facilities are part of the

Organization	Yes or No	Question 3 Comment
		BES or not. As such, Note 2 should be modified to read as follows: "Note 2 - The presence of a contiguous loop, operated at a voltage of 30 kV or less, between configurations being considered as radial systems, does not affect this exclusion for US registered entities. For a non-US Registered Entity, the voltage level should be implemented in a manner that is consistent with the demarcation points within their respective regulatory framework.
MidAmerican Energy	No	MidAmerican believes the 30kV threshold is too low. MidAmerican believes that the SDT should consider an "opt in" strategy for sub-100kV or Sub-60kV facilities rather than the current proposed change which assumes facilities down to 34.5 kV are in NERC scope unless entities "opt out" through the exemption process. Rather than include them in the BES definition and require standard modifications to exclude them when it is not appropriate, it is more efficient to modify those standards where their inclusion is determined to be appropriate. This has already been done in some recently modified standards (e.g. the generator verification standards now filed for regulatory approval, the modifications made to standards for the generator interconnections).
MRO NERC Standards Review Forum (NSRF)	No	The NSRF believes the 30kV threshold is too low and the SDT justification is inadequate. The BES operates at various kV classes. As power density and distance grow, lower voltage classes are rendered ineffective at transporting bulk electric system power. Therefore, certain voltage classes below 100 kV are clearly limited in their ability to transport bulk electric power and should be ruled as distribution facilities under the 2005 FPA.MRO members have expertise in performing interconnected system modeling & operational analysis which indicates that all three attributes comprising the technical justification used by the SDT are always satisfied with the 60kV threshold. The recommended 60kV threshold recognizes that 69kV is the lowest voltage at which loops between radial systems have the potential to support adequate amount of power transfer under certain worst case scenarios and thus may impact the >100kV system performance/reliability. In other words, system modeling & operational analysis experience indicates that 69kV is the

Organization	Yes or No	Question 3 Comment
		lowest voltage at which loops between radial systems present any possibility that any one of the three attributes in the SDT's technical justification may not be satisfied. Or another consideration would be the Transmission Distribution Factor (TDF) or percent participation. For example, entities could consider 24 - 69 kV facilities with a 0.2 to 0.3% TDF and 50% or greater normalized transfer factor or 50% or more participation.

Response: The 30 kV value was initially chosen based on a high-level evaluation and was inserted in the definition to introduce the concept to the industry and seek feedback and technical opinions from the industry. Comments and suggestions were received questioning the threshold of 30 kV proposed in Note 2 for Exclusion E1. To address this issue, the SDT has created a white paper that is posted as a supporting document for the second posting of this project which provides a review of regional criteria and contingency load flow analysis and has determined that 50 kV is the technically justifiable voltage threshold and has changed the value in Note 2 to 50 kV. This value represents a nominal voltage level (50 kV) that is between operating voltage levels (46 kV and 55 kV) to insure that a clear bright-line is established.

> Note 2: The presence of a contiguous loop, operated at a voltage level of ~~30~~50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

The looping facilities that operate at voltages below 100 kV are NOT included in the BES. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process."

Organization	Yes or No	Question 3 Comment
American Public Power Association	No	APPA appreciates the SDT efforts to set a non-zero threshold for exclusion E1 as proposed in Note 2. However, the 30kV voltage threshold selected is too low and should be revised to exclude the 34.5 kV voltage class. APPA believes including 34.5kV facilities will create a significant compliance burden on registered entities, especially small entities. To set a threshold this low will cast the compliance net onto radial facilities that perform distribution functions that are not currently subject to NERC reliability standards because these facilities are excluded as radials serving load. APPA believes that selecting the 30 kV threshold will place an

Organization	Yes or No	Question 3 Comment
		obligation on small entities to prove that power flows will not transfer through their distribution systems for worst case scenarios. Without this change, APPA remains concerned that addressing the 34.5 kV voltage class may overload the Rules of Procedure (ROP) Exception Process. APPA recommends a higher threshold be studied and proposes 40 kV as an alternative. In nearly all circumstances, the distribution factors on 34.5 kV circuits that operate in normally closed configurations parallel to 115 kV and higher BES paths differ by 20-to 1 or more, due to the combined impact of relative line voltage impedances, transformer impedances, and longer line lengths on the lower voltage path(s) that loop through our load centers and then connect back to the BES. Further, 34.5 kV circuits rarely affect SOLs or rated paths. These circuits rarely form part of the interface between balancing areas. Exceptions to the general rule that could have a significant impact on the BES should be addressed through the Exception Process. APPA's comments to the Commission on BES Phase I Definition NOPR September 4, 2012: Should the Commission in its final rule direct "other registered entities" to conduct a study of all of their sub-100 kV facilities and state their potential impact to the Regional Entity for evaluation for inclusion in the BES, then this directive would be excessively burdensome to the industry, especially small registered entities. The Commission's proposal would in effect require small registered entities (primarily Generator Owners and Distribution Providers) to hire consultants to perform studies to assess the potential impact of large numbers of non-BES facilities on the BES transmission network. APPA requests that in the final rule the Commission give NERC and the Regional Entities the flexibility to develop, with industry input, a reasonable approach for the evaluation of sub-100 kV facilities that does not create an excessive burden on the industry, especially small entities. Adoption of the 40 kV threshold would largely alleviate this potential burden.
American Transmission Company	No	ATC believes the 30kV threshold is too low and should be increased to at least 50kV.
CenterPoint Energy	No	CenterPoint Energy recommends the voltage level of “30 kV or less” in Note 2 be changed to “35 kV or less”. Based on this change, Note 2 would be: “The presence

Organization	Yes or No	Question 3 Comment
		of a contiguous loop, operated at a voltage level of 35 kV or less, between configurations being considered as radial systems, does not affect this exclusion." We suggest the voltage level should be established based on whether the contiguous loop is operated at common distribution voltages (e.g., 12.47 and 34.5 kV). The vast majority of distribution feeders are, of course, operated radially. Distribution feeders that are operated as a contiguous loop, or "networked", are equipped with "network protectors" that initiate tripping of interrupting devices. A network protector automatically disconnects its associated power transformer from the secondary network when the power starts flowing in the reverse direction; that is, the interrupting device opens if the secondary grid back-feeds through the transformer to supply power to the primary grid. Therefore, there cannot be any loop flows between radial systems, as network protectors prevent such flows.
Hydro-Quebec TransEnergie	No	HQT do not agree that sub-100 kV looping should refrain radial exclusion, since it doesn't carry impact on reliability of the BES, but only on non-BES. Though high voltage below 100 kV should not constitute a looping, it is much more necessary that medium voltage should not constitute a looping. According to ANSI and IEEE, medium voltage is 35 kV.
National Grid	No	In a similar way as 100 kV is the delineator between the medium and high system voltage classes in the American National Standards Institute (ANSI) standard on voltage ratings (C84.1), the voltage threshold in note 2 of exclusion E1 should be based on a well defined standard system voltage classes to better correlate to operational and system design considerations and practices. This could e.g., be done by aligning the voltage threshold with the insulator classes as defined in ANSI standard on insulators (C29.13) or the maximum rated voltage in Institute of Electrical and Electronics Engineers (IEEE) standards for medium voltage switchgear (C37.20.2 and C37.20.4). Based on ANSI C29.13, the threshold in note 2 of exclusion E1 could be set to 46 kV. The Exception Procedure could be used to include lower (than 100 kV; bright line) voltage systems in the BES envelope when interactions between these systems and the BES are deemed critical to reliable operations in

Organization	Yes or No	Question 3 Comment
		their local or regional area.
Occidental Energy Ventures Corp.	No	OEVC agrees in general with the approach taken by the SDT to derive the 30 kV limit. At some point, a practical limitation of the ability to evaluate the performance of the low-voltage system dictates that a threshold be set. Taken to the absurd logical extreme, without Note 2, the radial exclusion could be applied only after every 115 volt household connection was evaluated. However, without a view into the study results, we have no way to assess whether the 30 kV limit makes the most sense. We fully respect the project team's judgment, but it seems like this limit could easily be set at 70 kV without any noticeable reliability impact.
National Rural Electric Cooperative Association	No	On page 2, last paragraph, of the Unofficial Comment Form the language regarding sub-100 kV loop analysis seems to indicate that the 30 kV level has already been determined and selected through technical analysis. It is NRECA's understanding that such technical analysis was not conducted prior to posting the phase 2 BES definition, and that such analysis is being conducted now by a sub-group of the drafting team. NRECA requests that the drafting team not focus on trying to specifically justify the 30kV bright-line, but instead, it should develop a methodology/test to determine the highest reasonable voltage level that we should be using for application of Exclusion E1. Such methodology/test should take into consideration the issues FERC identified in Order Nos. 773 and 773-A regarding their concerns with sub-100 kV looping facilities under Exclusion E1 and other comments from stakeholders that provide technical support or justification for certain voltage levels for use in Exclusion E1.
ISO New England Inc.	No	The 30 kV limit in Note 2 for which an entity does not have to consider a loop between two otherwise radial systems should be raised to 50 kV. There are numerous 34.5 kV and 46 kV circuits used in distribution that would require review with the 30 kV limit. The review required for those 34.5 or 46 kV circuits is not warranted.

Organization	Yes or No	Question 3 Comment
New York Power Authority	No	The 30kV threshold is too restrictive and the sub-100kV loop threshold should be determined by the method the SDT utilized by regional transmission system makeup. This exclusion and restrictive loop threshold could lead to additional exception requests.
Self	No	The 30 kV limit may be too low. 50kV or high limits may be technically justified. An analysis to support the choice of any limit is needed.
IRC Standards Review Committee	No	The SDT describes the steps taken that led to proposing the 30 KV limit in Note 2 for which an entity does not have to consider a loop between two otherwise radial systems. However, the steps presented are not in our view technical justification for the proposed threshold. Before we can support this proposal, we would appreciate the SDT provide technical justification as to why 30kV is the appropriate level but not any other voltage levels, e.g. why not 50kV or 69kV?
Tennessee Valley Authority	No	We agree with the approach, but not the voltage level chosen. Including loops greater than 30 kV will be unreasonably burdensome. We believe the threshold should be 70 kV. Any loops greater than 70 kV, that could affect the BES, should be added through the exception process.
Texas Reliability Entity	No	We cannot support this proposal without an adequate technical justification provided prior to the ballot. The posted materials indicate that the 30 kV threshold was “based on initial discussions by sub-team; more discussion and analysis needed.” Those materials only provide a rough outline of the analysis that could be done; they do not indicate that any such analysis was actually done, and they do not provide a technical justification. Also, there is no explanation of how the current proposal is “equally effective and efficient” as applied to the Commission’s stated concerns.
Orange and Rockland Utilities Inc.	No	We generally agree with the Drafting Team to introduce a threshold to Exclusion E1 but believe the Step 1 in the Low Voltage Level Criteria is arbitrary. ORU (RECO) is

Organization	Yes or No	Question 3 Comment
		the owner of the lowest threshold facility at 34kV facilities. The ORU (RECO) facilities at 34kV and 69kV facilities do not have an impact on the BES. Our opinion is that the 30 kV threshold is too low, therefore, we are requesting that the Drafting Team consider a higher voltage level as a new threshold. If a monitored element/facility at a lower voltage (sub-100 kV) level (including monitored Flowgates) does not pose any impact to BES system, such element/facility should not be considered as a criteria in E1 or E3.
New York State Department of Public Service	No	While the goal of having some cut off level below which the facilities can clearly be eliminated from consideration is theoretically reasonable, history has demonstrated the designation can be abused and used for alternative purposes. There is no technical basis for the 30 kV cut off. NERC has an obligation to provide technical advice to FERC, so that any number provided to FERC is interpreted as technical advice. NERC should not include any numbers in any definition or standard for which it cannot provide a technical basis. Surveys do not provide a technical basis. Discussions have indicated that because facilities less than 100 kV triggered a major event in the southwest, a lower level voltage needs to be identified. Note that if either the current NERC BES definition or a functional analysis had been applied to the system at issue, either definition approach should have identified the involved facilities as bulk elements. A lower threshold would therefore be superfluous, and would be over-inclusive to an even greater degree than the current definition.
ACES Standards Collaborators	No	While we agree with the approach and thank the drafting team for their creativity in coming up with the approach, we think it needs more refinement. There is a high level description in the supporting documents of how this approach was arrived at. However, there is a dearth of details. We think more details are necessary to agree to the appropriate voltage level cutoff. For instance, 34.5 kV is a common distribution voltage that can be networked. It is hard to fathom any networked 34.5 kV system could have a material impact on the BES because of its relative high impedance. Thus, at a minimum, we suggest raising the cutoff to 35 kV to address these situations. We also suggest supplying the detail data/reports that were used

Organization	Yes or No	Question 3 Comment
		to arrive at the 30 kV cutoff.
Wisconsin Public Service / Upper Peninsula Power	No	WPS believes the 30kV threshold is too low especially when 34.5kV is widely used for distribution. Additionally, there are numerous instances where 46 kV is appropriately classified as distribution through application of FERC's 7-factor test and we suggest a 50 kV threshold is more appropriate than a 30 kV threshold. The BES operates at various kV classes. As power density and distance grow, lower voltage classes are rendered ineffective at transporting bulk electric system power. Therefore, certain voltage classes below 100 kV are clearly limited in their ability to transport bulk electric power and should be ruled as distribution facilities under the 2005 FPA.
Xcel Energy	No	Xcel Energy asserts that the 30kV threshold proposed in Note 2 for Exclusion E1 is too low, and instead proposes a 60kV threshold. Our extensive experience and expertise in performing interconnected system modeling & operational analysis in three diverse Regions (MRO, SPP, WECC) indicates that all three attributes comprising the technical justification used by the SDT are always satisfied with the 60kV threshold. The recommended 60kV threshold recognizes that 69kV is the lowest voltage at which loops between radial systems have the potential to support adequate amount of power transfer under certain worst case scenarios and thus may impact the >100kV system performance/reliability. In other words, Xcel Energy's system modeling & operational analysis experience indicates that 69kV is the lowest voltage at which loops between radial systems present any possibility that any one of the three attributes in the SDT's technical justification may not be satisfied.

Response: The 30 kV value was initially chosen based on a high-level evaluation and was inserted in the definition to introduce the concept to the industry and seek feedback and technical opinions from the industry. Comments and suggestions were received questioning the threshold of 30 kV proposed in Note 2 for Exclusion E1. To address this issue, the SDT has created a white paper that is posted as a supporting document for the second posting of this project which provides a review of regional criteria and contingency load flow analysis and has determined that 50 kV is the technically justifiable voltage threshold and has changed the

Organization	Yes or No	Question 3 Comment
value in Note 2 to 50 kV. This value represents a nominal voltage level (50 kV) that is between operating voltage levels (46 kV and 55 kV) to ~~e~~insure that a clear bright-line is established. Note 2: The presence of a contiguous loop, operated at a voltage level of ~~30~~50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.		
Dominion	No	Dominion believes that there should be some way to insure that the requirement does not require exclusion be validated solely by use of powerflow. We therefore suggest the following revision to E1 (a) Only serves Load. A normally open switching device between radial systems may operate in a 'make before break' fashion to allow for reliable system reconfiguration to maintain continuity of service and not require a powerflow model. We endorse the MRO comment - "The NSRF believes the 30kV threshold is too low and the SDT justification is inadequate. The BES operates at various kV classes. As power density and distance grow, lower voltage classes are rendered ineffective at transporting bulk electric system power. Therefore, certain voltage classes below 100 kV are clearly limited in their ability to transport bulk electric power and should be ruled as distribution facilities under the 2005 FPA." We endorse the MRO Comment - "MRO members have expertise in performing interconnected system modeling & operational analysis which indicates that all three attributes comprising the technical justification used by the SDT are always satisfied with the 60kV threshold. The recommended 60kV threshold recognizes that 69kV is the lowest voltage at which loops between radial systems have the potential to support adequate amount of power transfer under certain worst case scenarios and thus may impact the >100kV system performance/reliability. In other words, system modeling & operational analysis experience indicates that 69kV is the lowest voltage at which loops between radial systems present any possibility that any one of the three attributes in the SDT's technical justification may not be satisfied. "
SPP Standards Review Group	No	It is difficult to agree with the approach when the details of the evaluation and analyses that were performed have not been made available for review by the

Organization	Yes or No	Question 3 Comment
		industry. Once these details are known and have been reviewed by the industry, a more informed decision on what voltage level should be incorporated into the exclusion can be made. As it stands, we are very uncomfortable with the 30 kV limit and feel it is too low. Is the contiguous loop referenced in Note 2 normally closed or normally open? Whichever, it needs to be clarified in the note.
Response: The 30 kV value was initially chosen based on a high-level evaluation and was inserted in the definition to introduce the concept to the industry and seek feedback and technical opinions from the industry. Comments and suggestions were received questioning the threshold of 30 kV proposed in Note 2 for Exclusion E1. To address this issue, the SDT has created a white paper that is posted as a supporting document for the second posting of this project which provides a review of regional criteria and contingency load flow analysis and has determined that 50 kV is the technically justifiable voltage threshold and has changed the value in Note 2 to 50 kV. This value represents a nominal voltage level (50 kV) that is between operating voltage levels (46 kV and 55 kV) to e~~i~~nsure that a clear bright-line is established. Note 2: The presence of a contiguous loop, operated at a voltage level of ~~30~~50 kV or less, between configurations being considered as radial systems, does not affect this exclusion. The operation of the normally open switches will not impact Exclusion E1.		
Southern California Edison	No	The alternative identified as "Note 2" in the proposed Phase 2 BES Definition gives preferential treatment to contiguous looped facilities, which should be defined as LNs. The rationale used to justify this particular exclusion should be modified and included in the BES Guidance Document so that it can be applied to both the E1 and E3. With some minor revisions, the E1 loop exclusion rationale could similarly be applied to LNs which connect to multiple points, such as within substations with double breaker and breaker-and-a-half configurations. Another alternative would be to identify LNs interconnected to the BES with breaker-and-a-half configurations as radial systems, and be eligible for the E1 exclusion. In addition, the 30kV looped facilities threshold identified for exempting looped radial facilities is too low. This threshold has the potential to include facilities owned and operated by transmission dependent utilities/ "Distribution Providers"

Organization	Yes or No	Question 3 Comment
		into the scope of the BES definition.
Response: The 30 kV value was initially chosen based on a high-level evaluation and was inserted in the definition to introduce the concept to the industry and seek feedback and technical opinions from the industry. Comments and suggestions were received questioning the threshold of 30 kV proposed in Note 2 for Exclusion E1. To address this issue, the SDT has created a white paper that is posted as a supporting document for the second posting of this project which provides a review of regional criteria and contingency load flow analysis and has determined that 50 kV is the technically justifiable voltage threshold and has changed the value in Note 2 to 50 kV. This value represents a nominal voltage level (50 kV) that is between operating voltage levels (46 kV and 55 kV) to insure that a clear bright-line is established. Note 2: The presence of a contiguous loop, operated at a voltage level of ~~30~~50 kV or less, between configurations being considered as radial systems, does not affect this exclusion. Note 2 indicates that no ties below 50kV need to be considered when evaluating radials. The Local Network, Exclusion E3, contains different requirements that an entity has to meet to utilize this exclusion. The looping facilities that operate at voltages below 100 kV are NOT included in the BES. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process."		
Independent Electricity System Operator	No	The IESO does not agree with this approach as we identify two major concerns related to Note 2 in Exclusion E1.First, by adding a new voltage threshold of 30 kV, a new category of "wires" operated at voltages between 30 kV and 100 kV which may become part of BES is effectively created. On the one hand, this would be inconsistent with the BES definition introductory paragraph (Bulk Electric System (BES): Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy). On the other hand, this could result in a huge effort/cost in part of all facility owners as it appears that the intent is to include this new category of "wires" in the BES elements and potentially rely on the BES Exception process to exclude

Organization	Yes or No	Question 3 Comment
		them one by one. Second, the demarcation point between transmission and distribution may be different in non FERC jurisdictions, such as Canadian provinces. For example, in Ontario, legislation establishes 50kV as the technical boundary line between transmission and distribution. In establishing voltage thresholds, NERC needs to consider non-US legislated demarcation points, and the standard development process must make allowances for such regulatory and/or jurisdictional differences. The establishment of the voltage floor for the E1 exclusion is inconsistent with the language and structure of the legislative framework in Ontario. Furthermore, we believe that the exception process is not appropriate to determine the jurisdictional issue of whether facilities are part of the bulk power system. Therefore, the IESO proposal is to remove Note 2 altogether from Exclusion E1 and rely on the BES Exception process to determine facilities operated below 100 kV that must be included in the BES. In the alternative that Note 2 in Exclusion E1 is retained, we request that it be modified to read as follows: “Note 2 - The presence of a contiguous loop, operated at a voltage of 30 kV or less, between configuration being considered as radial systems, does not affect this exclusion for US registered entities. For a non-US Registered Entity, the voltage level should be implemented in a manner consistent with the demarcation points within their respective regulatory framework.
Northeast Utilities	While it is recognized that electrical systems operated below 100KV can be configured such that they should require BES treatment (i.e. the 92 KV networked system involved in the 2011 Southern California - Arizona outage), a 30KV threshold is too low to significantly impact the reliable operation of the higher voltage transmission system. We propose increasing this threshold to a voltage in the 40-50KV range. The new Note 2 associated with Exclusion E1 and the changes to E3 have added ambiguity that did not exist before. The base definition does not address sub-100kV contiguous loops. The existing Inclusions do not include sub 100kV contiguous loops either. Note 2 clarifies that as long	

Organization	Yes or No	Question 3 Comment
	as the contiguous loop is below 30kV E1 still applies. E3 explains how any sub 30kV contiguous loop could be excluded as a local area network, but there is nothing in the definition to clearly state that contiguous loops operated below 100kV are considered part of the BES unless excluded by E3. An additional Inclusion should be added that specifically includes "all contiguous loop operated below 100kV that is not solely used for the distribute power to load unless excluded by application of Exclusion E1 or E3."The proposed change to the E1 exclusion definition to add Note 2 will require an examination of NU sub-transmission system connections (69KV in CT and 34KV in NH) and their connections to the >100KV transmission systems. Elements >100KV originally categorized as E1 or E3 may become BES inclusions if there is underlying sub-transmission path. A cursory review determine no elements categorized as E1 in CT would be changed; however, 16 of the 30 E1 elements in NH could become BES due to 34KV paths.	

Response: The looping facilities that operate at voltages below 100 kV are NOT included in the BES. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process."

The 30 kV value was initially chosen based on a high-level evaluation and was inserted in the definition to introduce the concept to the industry and seek feedback and technical opinions from the industry. Comments and suggestions were received questioning the threshold of 30 kV proposed in Note 2 for Exclusion E1. To address this issue, the SDT has created a white paper that is posted as a supporting document for the second posting of this project which provides a review of regional criteria and contingency load flow analysis and has determined that 50 kV is the technically justifiable voltage threshold and has changed the value in Note 2 to 50 kV. This value represents a nominal voltage level (50 kV) that is between operating voltage levels (46 kV and 55 kV) to e~~i~~nsure that a clear bright-line is established.

> Note 2: The presence of a contiguous loop, operated at a voltage level of ~~30~~50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

The threshold value chosen represents a nominal voltage level (50 kV) that is between operating voltage levels (46 kV and 55 kV) to insure that a clear bright-line is established.

Organization	Yes or No	Question 3 Comment
American Electric Power	No	While AEP does not necessarily disagree with the 30KV threshold, we are however confused by the concept of a contiguous loop being part of a radial feed, as we find “radial” and “loop” as mutually exclusive terms. This phrase is ambiguous and needs further clarification before a voltage threshold can be discussed.
Response: Note 2 indicates that no ties below 50 kV need to be considered when evaluating radials. It should be noted that normally open switches at any voltage will not disqualify the use of Exclusion E1. The looping facilities that operate at voltages below 100 kV are NOT included in the BES. Order 773, paragraph 155 states: “Thus, the Commission, while disagreeing with NERC’s interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process.” This was reaffirmed by the Commission in Order 773A, paragraph 36: “Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process.”		
Associated Electric Cooperative, Inc. - JRO00088	Yes	AECI appreciates the SDT's establishing a kV floor and yet feels that a 70kV floor could accommodate FERC's concerns, with minor additions to establish some threshold for obvious sub-network transfer-limitations between sub-network transformer terminals.
Central Lincoln	Yes	Central Lincoln supports the approach, but questions the threshold. Central Lincoln protests that the SDT plans to make its white paper on the technical analysis to justify the 30 kV threshold available after the comment/ballot period is over. While a 5 kV shift would not affect Central Lincoln, we are aware of entities that would be in favor of a 35 kV threshold instead. Please give us the information needed to evaluate the SDT's choice of 30 kV.
City of Tacoma	Yes	Comments: Many utilities utilize 35 kV distribution radial networks from a 2 or 3 transformer bank source. TPWR supports raising the 30 kV threshold to 35 kV.
Idaho Power Company	Yes	Idaho Power System Protection group: Yes, we agree with the approach in general, but are concerned with a 30kV cutoff. In our system, connections are made in our distribution load service at 35kV. If we are interpreting the language correctly, an

Organization	Yes or No	Question 3 Comment
		evaluation would be required for all of our 35kV load service for any connections in that subsystem, which represents a significant additional burden. Idaho Power System Planning group: We are in favor of adding note 2 to Exclusion E1 of the BES definition. However, we would suggest rewording note 2 as follows, while matching the simplicity of note 1 of Exclusion E1: "A tie operated at a voltage of 30 kV or less between radial systems does not affect this exclusion." We believe it is not the intent to place the threshold of 30 kV or less on the contiguous loop that is created by adding the tie between the two radial systems, but rather the intent is to place the threshold of 30 kV or less on the tie itself between the two radial systems.
SERC EC Planning Standards Subcommittee	Yes	If technical justification can be developed, a threshold of 70kV is recommended.
Sacramento Municipal Utility District	Yes	SMUD supports the SDT's approach but believes it to be prudent for the DT to increase the voltage threshold to avoid unnecessary inclusions of rural electrical systems.
Transmission Access Policy Study Group	Yes	TAPS supports the SDT's general approach and language in Note 2 to Exclusion E1. In light of FERC's interpretation of "radial," it is vital that a minimum threshold be added to Exclusion E1; without such a threshold, many TAPS members would have to perform a more burdensome E3 analysis, and likely go through the much more resource-intensive exceptions process, for Elements that are clearly not necessary for the reliable operation of the grid. We therefore strongly support the SDT's proposal of a minimum threshold. TAPS does, however, suggest that the threshold be 40 kV rather than 30 kV, because we believe that >100 kV radials connected by a loop between 30 kV and 40 kV are highly unlikely to be necessary for the reliable operation of the interconnected grid, and so 40 kV would be a more efficient threshold than 30 kV; the rare case that should be part of the BES should be included through the Exceptions process. We understand that the SDT has been assembling technical support for a 30 kV proposal, and accordingly provide the following evidence in support of using 40 kV instead. We propose 40 kV as being

Organization	Yes or No	Question 3 Comment
		between the commonly-used voltages of 34.5 kV and 46 kV. Neither threshold (30 kV or 40 kV) will capture “all and only” those Elements that should be part of the BES, because neither threshold is (or can be) sufficiently granular; instead, the goal should be for E1 (and the rest of the core definition) to get as close as possible to the appropriate end-state, in order to minimize the need for case-by-case Exceptions of either the inclusion or exclusion variety. We understand that a primary reason behind the SDT’s use of 30 kV is the belief that in some portions of the continent, voltages as low as 34.5 kV are monitored by entities that have the responsibility to monitor to ensure the reliable operation of the interconnected transmission system. We do not know which entities the SDT is referring to (presumably it does not include all entities, since DPs monitor all voltages), but we note that RFC and MISO, whose overlapping footprints are a very significant area, monitor down to 40 kV. This suggests that the people with responsibility and on-the-ground experience in those regions believe that 40 kV is the threshold below which impacts can safely be assumed to be minimal. Second, while the SDT has stated that it reads Order 773 as finding that impedance alone is insufficient to demonstrate that looped or networked connections operating below 100 kV should not be considered in the evaluation of Exclusion E1, it is surely an important factor. The consideration of impedance supports a 40 kV threshold. The impedance of a circuit is inversely proportional to the square of the voltage. The amount of parallel flow is inversely proportional to the impedance of a circuit. Thus, other things being equal, a 69 kV line carries 25% of the flow of a 138 kV line, and a 34.5 kV line carries 6.25% of the flow of a 138 kV line. Taking into consideration other factors such as transformer impedances (which are usually much greater than the impedances of the lines themselves) and the size and spacing of conductors, TAPS members believe that the large majority of 30-40 kV loops connecting >100 kV radials will carry less than 5% of the flow of a 138 kV line. For purposes of Transmission Loading Relief in NERC and NAESB standards (IRO-006 and WEQ-008, respectively), FERC has accepted a 5% transfer distribution factor as being insignificant. It is therefore reasonable to allow >100 kV radials connected by a 34.5

Organization	Yes or No	Question 3 Comment
		kV loop to qualify for Exclusion E1: any loop flow is more likely than not to be insignificant, and it is a waste of resources to require all such systems to assess their eligibility for Exclusion E3 or go through the exceptions process. Instead, if there are isolated cases of such configurations that should be included in the BES, they can be added through the inclusion Exceptions process. Most TAPS members' experience is that 34.5 kV lines tend to be used for local distribution, while 69 kV (and sometimes 46 kV) is used for subtransmission. The goal, ultimately, is to have the all of the necessary Elements, and no unnecessary Elements, in the BES. We believe that using a 40 kV threshold will achieve that goal with fewer NERC, Regional Entity, and registered entity resources than the 30 kV threshold proposed by the SDT.
Public Utility District No.1 of Snohomish County	Yes	The Public Utility District No.1 of Snohomish County supports the SDT's approach and recommends increasing the voltage from "30 kV or less" to "35 kV or less" noted in Question 1.
South Carolina Electric and Gas	Yes	We agree in general but if a technical justification can be developed, we recommend a threshold of 70 kV.
NV Energy	Yes	While the details of the threshold voltage are still being ironed out, the concept of this note acheives the objective of properly allowing for E1 exclusions in the presence of distribution circuit loops or ties.
PacifiCorp	Yes	While the proposal is currently limited to a voltage level of 30 kV or less, PacifiCorp suggests an expansion of the language to include minimum voltage levels based on the characteristics of each interconnection (e.g., 30 kV for the Eastern Interconnection and 40 kV for the Western Interconnection).
Pepco Holdings Inc & Affiliates	Yes	While we agree this approach addresses the Commissions sub-100 kV loop concerns for radial systems, the choice of a 30 kV threshold seems somewhat arbitrary. The intent is to allow small "distribution system" loops between connection points and still satisfy the E1 exclusion for radial transmission systems. IEEE 100 "The

Organization	Yes or No	Question 3 Comment
		Authoritative Dictionary of IEEE Standard Terms" defines a Distribution Line as "Electric power lines which distribute power from a main source substation to consumers, usually at a voltage of 34.5 kV or less." Based on this industry standard definition, we believe a 40kV threshold would be more appropriate, so as to allow all looped distribution circuits, including those operating at 34.5kV, to satisfy Exclusion E1 for radial systems. Additionally, the rationale box included as part of Note 2 states: ".....As a first step, regional voltage levels that are monitored on major interfaces, paths and monitored elements to ensure the reliable operation of the interconnected system..." Just because elements are monitored, does not necessarily mean that those elements are specifically critical to the reliable operation of the system. In many cases it is strictly a function of providing adequate data for the modeling of the system. It would be unlikely that an underlying distribution loop would have any significant impact on the transmission system. It may be possible that the underlying loop system may itself have flow problems, but that is not the same as that loop creating a problem on the transmission system.
Response: The 30 kV value was initially chosen based on a high-level evaluation and was inserted in the definition to introduce the concept to the industry and seek feedback and technical opinions from the industry. Comments and suggestions were received questioning the threshold of 30 kV proposed in Note 2 for Exclusion E1. To address this issue, the SDT has created a white paper that is posted as a supporting document for the second posting of this project which provides a review of regional criteria and contingency load flow analysis and has determined that 50 kV is the technically justifiable voltage threshold and has changed the value in Note 2 to 50 kV. This value represents a nominal voltage level (50 kV) that is between operating voltage levels (46 kV and 55 kV) to insure that a clear bright-line is established. Note 2: The presence of a contiguous loop, operated at a voltage level of ~~30~~50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power	Yes	Southern generally agrees with the SDT's approach in adding Note 2 to Exclusion E1 to address FERC's concerns regarding sub-100kV loops for radial systems. Respecting and appreciating that the SDT may have intended to mirror not only the

Organization	Yes or No	Question 3 Comment
Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		concept, but also the language and format of Note 1 immediately above, Southern believes the language "does not affect the exclusion", by itself, can be confusing to entities trying to make applicability and compliance determinations. To more directly and clearly articulate the concept of "not affecting the exclusion" as meaning that the described configuration qualifies for the exclusion and thus is excluded from the BES, Southern suggests the following revised Note 2 in quotes below. To the extent similar language can also be added to Note 1, Southern believes that it would also benefit from the added clarity. "Note 2 - The presence of a contiguous loop, operated at a voltage level of 30 kV or less, between configurations otherwise being considered as radial systems, does not affect this exclusion from applying, and thus such configurations should be eligible for Exclusion E1 and thus not included in the BES."
Response: Note 2 indicates that no ties below 50kV need to be considered when evaluating radials. It should be noted that normally open switches at any voltage will not disqualify the use of Exclusion E1. The looping facilities that operate at voltages below 100 kV are NOT included in the BES. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process."		
FirstEnergy	Yes	FirstEnergy supports the proposed 30kV threshold for Exclusion E1 based on the explanation provided in the June 26, 2013 industry webinar and information presented by the drafting team in the supplemental material/presentation titled "BES Radial Exclusion Low Voltage Level Criteria".
Cooper Compliance Corp	Yes	
Iberdrola USA	Yes	
PPL NERC Registered Affiliates	Yes	

Organization	Yes or No	Question 3 Comment
North American Generator Forum Standards Review Team	Yes	
Arizona Public Service Company	Yes	
Southwest Power Pool Regional Entity	Yes	
US Bureau of Reclamation	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
Georgia Transmission Corporation	Yes	
Duke Energy	Yes	
Modesto Irrigation District	Yes	
American Wind Energy Association	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Response: Thank you for your support.		

4. **The SDT has revised the generation resources and dispersed power resources inclusions (Inclusions I2 and I4) in response to industry comments and Commission concerns. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The SDT has considered the comments of the industry and determined that the point of aggregation at which dispersed generation could have a reliability impact on the BES is at 75 MVA and therefore the SDT has broken apart Inclusions I2 and I4 to provide the consistency, clarity, and granularity that these inclusions require. The SDT believes that these changes adequately address the ambiguity caused by the use of the term "generator terminals" within the definition.

Many commenters feel that existing standards do not adequately address the different generator types, fuel sources, and intermittency. It is recommended that standard applicability be addressed through a new SAR prepared by industry.

I2 – Generating resource(s) ~~and dispersed power producing resources,~~ including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:

I4 - ~~Omitted.~~ ~~d~~Dispersed power producing resources consisting of:

a) Individual resources ~~with~~that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and

b) The ~~utilizing a~~ system designed primarily for ~~aggregating~~delivering capacity from the point where those resources aggregate to greater than 75 MVA ~~, connected at~~to a common point of connection at a voltage of 100 kV or above.

Organization	Yes or No	Question 4 Comment
Texas Reliability Entity	No	(1) We have no objection to combining conventional and dispersed generating facilities into one BES inclusion, but we do object to the characterization (in the blue box) of wind farms as "small-scale power generation technologies." In the ERCOT region there is now over 10,000 MW of installed wind capacity. Wind generation sometimes has served up to 25% of the entire ERCOT load, and wind provided over 9% of energy produced in ERCOT in 2012. Large-scale wind resources (facilities over 75 MVA) must be included within the BES and subject to appropriate reliability standards. (2) We would like to see clarification that dispersed power producing resources are

Organization	Yes or No	Question 4 Comment
		generally viewed in the aggregate rather than as separate BES elements. The performance of each individual wind turbine and element of the collector system is not a large concern, but we are concerned about the reliability impact of 75+ MVA of generation connected to the transmission system. We encourage the team to consider viewing a BES wind farm as an aggregated generating facility, including the turbines, the collector system, and the step-up transformer. Such an aggregated generating resource should have an associated GO and GOP, and be subject to appropriate reliability standards.
Response: The SDT respectively disagrees with your comment that wind farms are not small scale power generation technologies. Individual turbines have been categorized as small scale due to their nameplate rating, not their aggregate capacity. In response to your comment and many others regarding the need to view dispersed generation in aggregate, the SDT has broken apart Inclusions I2 and I4 to provide the clarity and granularity that these inclusions require. **I2** – Generating resource(s) ~~and dispersed power producing resources,~~ including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: **I4** - ~~Omitted. d~~Dispersed power producing resources consisting of: a) Individual resources ~~with~~that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and b) The ~~utilizing a~~ system designed primarily for ~~aggregating~~delivering capacity from the point where those resources aggregate to greater than 75 MVA ~~, connected at~~to a common point of connection at a voltage of 100 kV or above.		
ACES Standards Collaborators	No	(1) While we are not opposed to combining I2 and I4, we think I4 provides additional clarity and granularity. I4 collectively with the Phase 1: BES Definition Reference Document is very clear that the collector system is not included in the BES. Exclusion of the collector system is not clear from I2 particularly without a modified reference document. If the combination of I2 and I4 persists, we recommend that the reference document should clearly state that the collector system is not included similarly to the current version. (2) We do not understand why the question states that the changes address

Organization	Yes or No	Question 4 Comment
		Commission concerns. The Commission was very clear in approving I4. Paragraph 58 of Order 773-A states the "Commission ... confirms its finding that including I4 provides useful granularity in the bulk electric system definition." By combining I4 into I2, this granularity is removed.
American Electric Power	No	AEP does not believe that the generator terminals of individual dispersed power producing resources should by default be included in the BES definition. We suggest revising I2 to include dispersed power producing resources from the point of connection where the resource's aggregate nameplate rating is greater than 20 MVA through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above. As currently drafted, individual wind turbines would be included as part of this definition. AEP offers the following additional reasons why individual wind turbines specifically should not be in scope:*Given their small size and interment availability of the prime mover, they do not individually constitute a risk to the reliability of the BES.* The ability of the GO to perform maintenance and testing activities required by PRC-005-2 is limited due to the physical design of the system and may also be limited due to warranty agreements with the OEM.* A wind farm may experience hundreds of breaker operations a day and have not automated ability to determine whether the operation was caused by a Protection System operation. Under this scenario, the resources needed to show compliance with the proposed PRC-004-3 may be unduly burdensome to the GO.
Exelon and its Affiliates	No	Exelon does not support the changes made to items I2 and I4 in the proposed BES Definition. By combining items I2 and I4, the BES DT has effectively pulled in dispersed power producing resource collector system elements which are <100kV and which do not normally carry >75MVA in aggregate flow. In doing so, the BES DT has inappropriately strayed from the work plan for Phase 2 as defined in the Phase 2 original and supplemental SARs. In the original Phase 2 SAR, the BES DT was tasked with providing technical justification for the following items; 1. Develop a technical justification to set the appropriate threshold for Real and Reactive Resources necessary for the reliable operation of the Bulk Electric System (BES) 2. The NERC

Organization	Yes or No	Question 4 Comment
		Board of Trustees approved BES Phase 1 definition does not encompass a contiguous BES - Determine if there is a need to change this position 3. Determine if there is a technical justification to revise the current 100 kV bright-line voltage level. 4. Determine if there is a technical justification to support allowing power flow out of the local network under certain conditions and if so, what the maximum allowable flow and duration should be. Additionally, the Phase 2 original SAR tasked the BES DT with improving the clarity of the following items;1. The relationship between the BES definition and the ERO Statement of Compliance Registry Criteria established in FERC Order 693 2. The use of the term "non-retail generation" 3. The language for Inclusion I4 on dispersed power resources 4. The appropriate 'points of demarcation' between Transmission, Generation, and Distribution. Finally, the supplemental Phase 2 SAR required the BES DT to:1. Address the directives in FERC Order 773 issued December 20, 2012 The proposed changes to I2 and I4 inappropriately exceed the work plan as outlined in the SARs because they do not improve clarity for I4 and they are not in response to a directive from FERC Order 773. In Phase 1, the BES DT intended to exclude the collector system elements for dispersed power producing resources and stated so multiple times in responses to stakeholder comments, webinars and in the original draft of the Guidance document. By changing positions on whether collector systems should be included in the BES, the BES DT has not improved clarity but has instead materially changed the BES Definition itself. In addition, in Order No. 773, FERC specifically declined to "direct NERC to categorically include collector systems pursuant to inclusion I4". (Order No. 773, P114). Therefore this change is not in response to a FERC directive. Furthermore, under the current registration criteria for inclusion in the NERC Registry, Generation Owners and Generation Operators for individual generation resources >20MVA connected at 100KV or higher or aggregate resources > 75MVA (Aggregate) connected at 100KV or higher are required to register and are thus subject to the NERC Reliability Standards. Individual elements of dispersed power producing resources do not reach these thresholds until the point of where all of the elements are summed together. The individual dispersed power producing resource elements before this "summed" point have little or no impact to the BES as they are

Organization	Yes or No	Question 4 Comment
		generally isolated from the BES behind protection system elements such as relays and circuit breakers. Exelon feels that only those elements in a collector system that carry more than 75 MVA of aggregate flow should be included in the BES. Thus, Exelon opposes the changes to I2 and I4 in the current Phase 2 draft BES definition and has submitted a NEGATIVE vote on the proposed BES definition.
MidAmerican Energy	No	In plants with an aggregate rating greater than 75 MVA, the individual generators should be treated in the same manner as they would be in a stand-alone facility. If the individual generator is at or below 20 MVA in a stand-alone facility it would not be included in the BES and the owner of such a facility would not even have to register as a generator owner. That same size generator in an aggregated facility should be treated the same and it should be excluded from the BES. The portion of the facility at which the 75MVA or greater aggregation occurs should be where the BES boundary occurs. Inclusion I2 has been modified to incorporate I4 and I4 was eliminated. This is a good step, but the wording needs to be revised to recognize the relative insignificance of the small generators to the bulk electric system. There may be cases in some requirements of some standards where it is appropriate to include generators below 20 MVA in those requirements. Rather than include them in the BES definition and require standard modifications to exclude them when it is not appropriate, it is more efficient to modify those standards where their inclusion is determined to be appropriate. This has already been done in some recently modified standards (e.g. the generator verification standards now filed for regulatory approval, the modifications made to standards for the generator interconnections).Here is the proposed markup:"I2 - Generating resource(s) and dispersed power producing resources with: a) Gross individual nameplate rating greater than 20 MVA, including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above, OR, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA, beginning at a bus where the aggregate generation is greater than 75MVA and continuing thru the

Organization	Yes or No	Question 4 Comment
		high-side of the step-up transformer(s) connected at a voltage of 100 kV or above”
NextEra Energy	No	Inclusion I2 has been modified to incorporate I4 and I4 was eliminated. This is a good step, but the wording needs to be revised to recognize the insignificance of the individual wind turbine generators to the bulk electric system. Here is the proposed re-write:”I2 - Generating resource(s) and dispersed power producing resources with: a) Gross individual nameplate rating greater than 20 MVA, including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above; or, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA, beginning at a bus where the aggregate generation is greater than 75MVA and continuing thru the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above” 100kV bright line: The use of the 100kV bright line is recommended to be continued in the base definition, the inclusions and exclusions. Specific analysis should be performed to demonstrate the need for change on an individual basis.
Response: The SDT agrees with your comments and has revisited Inclusions I2 and I4. The inclusions have been broken apart to provide the clarity and granularity that the industry has requested. **I2** – Generating resource(s) ~~and dispersed power producing resources,~~ including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: **I4** - ~~Omitted. d~~Dispersed power producing resources consisting of: a) Individual resources ~~with~~that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and b) The ~~utilizing a~~ system designed primarily for ~~aggregating~~delivering capacity from the point where those resources aggregate to greater than 75 MVA ~~, connected at~~to a common point of connection at a voltage of 100 kV or above.		
American Wind Energy Association	No	AWEA is seriously concerned that taking the body of NERC reliability standards that now apply to Bulk Electric System (BES) components and indiscriminately applying them to dispersed power producing resources under the proposed Inclusions I2 and I4 will impose a major burden and potentially result in significant confusion about the applicability of standards, with little to no benefit for electric system reliability.

Organization	Yes or No	Question 4 Comment
		These inclusions as currently drafted could potentially even harm electric reliability by misallocating attention and resources away from concerns that are far more likely to negatively affect BES reliability. AWEA strongly urges that the BES definition be revised to only apply to the Point-of-Interconnection with the bulk electric system, as that is the only place within the wind project where more than 75 MVA of generating is aggregated and thus could reasonable affect BES reliability. In the alternative, we ask that NERC revise Inclusion I2 as follows:I2 - Generating resource(s) [DELETE: and dispersed power producing resources,] including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: a) Gross individual nameplate rating greater than 20 MVA, OR, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA. [ADD: The application of individual NERC BES-relevant standards to dispersed generation resources is to be specified in the applicability section of individual standards.]The intent of this revision is to ensure that before BES-relevant standards are applied to dispersed generators, each standard is evaluated to determine whether it is reasonable to apply that standard to dispersed generators and whether applying that specific standard to dispersed generators will significantly improve electric reliability. Many NERC standards that apply to the BES were crafted before the significant growth of dispersed generation and without dispersed generators in mind. Combined with the fact that many dispersed generators are variable renewable resources that have limited capacity value and are asynchronously connected to the power system, many NERC standards are likely to have limited applicability or benefit if applied to dispersed generators. To our knowledge, a compelling rationale has not been provided for why applying all NERC BES- relevant standards to dispersed generators would significantly improve BES reliability. A blanket application of NERC standards to dispersed generators by including them in the definition of BES would be unduly burdensome, confusing, and provide little to no reliability benefit. As of the end of 2012, per AWEA's Annual Market Report, there were approximately 45,100 utility-scale wind turbines operating in the U.S., many of which are aggregated in wind projects that exceed 75 MVA in aggregate

Organization	Yes or No	Question 4 Comment
		and are connected at a common point of voltage of 100 kV or above. Including each of these wind turbines and their collector systems in the BES definition would impose a large and undue burden on wind project owners and operators by potentially forcing them to comply with a number of NERC compliance processes and reliability standards that were crafted with large central-station generators in mind and cannot reasonably be applied to each of the dispersed generators within a wind project. We do not believe that the body of NERC requirements are adequately adapted to the technical differences of small, aggregated generation units. For example, the administrative burden and cost of complying with the GO/GOP standards at the individual generating unit level would be very substantial. For standards such as PRC-005, R1, and R2, applying these standards to dispersed generators would call for regular relay and protection system testing at numerous places within the wind plant, potentially including the internal circuitry of each individual wind turbine. One wind plant owner has indicated that, for one of its plants, applying the BES definition to the individual dispersed generators would increase the number of elements subject to the PRC-005 maintenance and testing requirements by more than a factor of 100. As another example, TOP-002 R14 and TOP-003 R1 require status reporting of unplanned and planned generator outages, respectively. We do not believe that the Balancing Authority (BA) or Transmission Operator (TO) would benefit from being notified about the operational status of any single dispersed generator at the typical wind turbine size of 2 MW or less. For the VAR series of standards, small size voltage control and waveform stabilization circuitry could require operational status monitoring and outage notification to the TO for this equipment. There are many other examples of potential confusion or unnecessary work and cost that can arise from the inclusion of small, individual dispersed generation assets, and their aggregation circuitry and equipment, in the BES definition. Most importantly, no one has demonstrated that there would be any material reliability benefit from applying all BES component standards to individual dispersed generators. The nameplate capacity of an individual wind turbine generator rarely exceeds 3 MW, and the average output of such a turbine is typically under 1 MW. Moreover, the capacity value contribution that grid operators typically

Organization	Yes or No	Question 4 Comment
		assume for wind projects for meeting peak electricity demand is typically less than 20% of the nameplate capacity of the wind project. In the typical electrical layout of a wind plant, around a dozen wind turbines are aggregated onto an electrical string of the collector array (which operates at voltages well below 100kV), so even losing a single electrical string or even multiple electrical strings will typically only result in the loss of a few dozen MW of generation at most. Such minimal impacts fall well below the 75 MVA threshold that Inclusion 4 seeks to establish for determining what should be included in the definition of the BES, as well as any reasonable threshold for determining which electrical components are likely to cause a reliability problem on the BES. In contrast, the electrical equipment at the Point-of-Interconnection (POI) with the BES (and not the individual generators and their collector system), is a far more appropriate point for delineating between the BES and non-BES electrical components and implementing a blanket application of NERC standards for BES components, as the POI for a wind project comprised of more than 75 MVA of generation and operating at more than 100 kV is the only part of the wind project that could reasonably affect BES reliability. One of the only credible arguments for requiring that all BES reliability standards apply to individual wind turbines is if one believed that wind turbines could be potentially susceptible to a common mode failure that would cause a large number of the generators within a wind plant to trip offline within a matter of seconds. Fortunately, all wind turbines installed in the U.S. in recent years and going forward are already compliant with the demanding voltage and frequency ride-through requirements of FERC Order 661A, which are far more stringent than the ride-through requirements placed on other types of generation. In the event of a system disturbance that causes a voltage or frequency deviation that would affect all generators nearly simultaneously, a wind plant would be more likely to remain online than almost all conventional generators, and the wind plant would likely only trip offline if the power system had collapsed to the point that nearly all other generation had already tripped offline. As a result, there is no compelling reliability reason for including individual wind generators and their electrical collector systems in the BES definition. Applying all BES-relevant standards to individual dispersed generators not only fails to improve electric reliability, but it

Organization	Yes or No	Question 4 Comment
		could even potentially harm electric reliability by misallocating attention and resources away from concerns that are far more likely to negatively affect BES reliability. Scarce resources exist for maintaining power system reliability, and devoting resources and attention to an issue that is unlikely to affect BES reliability can actually harm reliability by distracting attention from components that are more likely to cause a reliability problem. Moreover, taking the whole body of standards that were drafted with large central-station generators in mind and indiscriminately applying them to dispersed generators with very different characteristics is likely to cause significant confusion, further distracting from efforts that are important for maintaining and improving bulk power system reliability. As a result, the BES definition should be revised as indicated above, to ensure that before BES-relevant standards are applied to dispersed generators, each standard is evaluated to determine whether it is reasonable to apply that standard to dispersed generators and whether applying that specific standard to dispersed generators will significantly improve electric reliability.
Response: The SDT has revisited Inclusions I2 and I4. The inclusions have been broken apart to provide the clarity and granularity that the industry has requested. **I2** – Generating resource(s) ~~and dispersed power producing resources,~~ including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: **I4** - ~~Omitted. d~~Dispersed power producing resources consisting of: a) Individual resources ~~with~~that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and b) The ~~utilizing a~~ system designed primarily for ~~aggregating~~delivering capacity from the point where those resources aggregate to greater than 75 MVA ~~, connected at~~to a common point of connection at a voltage of 100 kV or above. With regard to the applicability of NERC standards to dispersed generating resources, or wind turbines specifically, it is recommended that a SAR be generated by the industry to address the applicability of standards to specific types of generation.		
Northeast Power Coordinating	No	It should be considered that dispersed generators that are represented to the

Organization	Yes or No	Question 4 Comment
Council		marketplace or modeled in study cases as 20MVA or higher should be included in the definition just as a single traditional generating unit of 20 MVA is included. By removing I4, the aggregating portion of the inclusion has been muddied. Suggest adding I2-c to include dispersed resources that are aggregated and modeled at 20MVA or higher. This would add clarity and consistency to the definition. The impact of the proposed response to Commission directives (and the directives themselves) in effect bring wind generation collector systems and any other aggregation system for other resource technologies into the definition of Bulk Electric System. Recommend that there be an exclusion for wind generation collector systems which are radial in nature and do not serve any retail load provided adequate protection for the BES via protective systems installed at the point of interconnection. Bringing many thousands of 1-2 MW generators directly into the reliability regime of the ERO is not necessary, or justified. In plants with an aggregate rating greater than 75 MVA, the individual generators should be treated in the same manner as if they were each a stand-alone facility. If the individual generator is at or below 20 MVA in a stand-alone facility it would not be included in the BES and the owner of such a facility would not even have to register as a generator owner. That same size generator in an aggregated facility should be treated the same and it should be excluded from the BES. The portion of the facility at which the 75MVA or greater aggregation occurs should be where the BES boundary should be occurring. To demonstrate the concept, an illustration marked as Figure 1 has been submitted to Monica Benson (NERC). From FERC Order 733A beginning at paragraph 50, "we direct NERC to modify the exclusions pursuant to FPA section 215(d)(5) to ensure that generator interconnection facilities at or above 100 kV connected to bulk electric system generators identified in inclusion I2 are not excluded from the bulk electric system". To that end, I2 should be revised to read: I2 - Generating resource(s) and dispersed power producing resources, including their power delivering assets operated at a voltage of 100 kV or above with:
New York Power Authority	No	It should be considered that dispersed generators that are represented to the

Organization	Yes or No	Question 4 Comment
		marketplace or modeled in study cases as 20MVA or higher should be included in the definition just as a single traditional generating unit of 20 MVA is included. By removing I4, the aggregating portion of the inclusion seems to be less clear. One suggestion would be to add I2-c to include dispersed resources that are aggregated and modeled at 20MVA or higher are included. This would add clarity and consistency to the definition.
PacifiCorp	No	PacifiCorp does not agree with the proposed changes to Inclusions I2 and I4 because such changes would include generating resources within the BES regardless of a resource's individual MVA rating and all of the equipment from each generator terminal to the > 100 kV transmission interconnection if the facility aggregate rating exceeds 75 MVA. A similar outcome was included in the Phase I definition in the previous version of Inclusion I4 that addressed dispersed power producing resources specifically and, as a result, one of the SDT's tasks in the Phase 2 SAR was to address the treatment of dispersed power producing resources. A dispersed power generating facility necessarily consists of individual units of a limited size to take advantage of the distributed nature of the resource (e.g., wind or solar) upon which the facility relies for its fuel source. One benefit of such facilities' unit size and geographical distribution is that they are not as susceptible to a substantial loss of generating capability as a single unit of 20 MVA or greater (the registration threshold for a single generating unit). If the arrayed generators were each 2 MVA then the probability of losing 20 MVA at the generator level would be .00000001%. If the units were 5 MVA each the probability of losing all four units at the generator level would be .01%. The probability of losing a single 20 MVA unit would be 10%. These variations illustrate that there will be different values depending upon the arrayed generator's size. Given the reliability advantage this diversity affords it does not seem reasonable to treat this type of facility in the same way as a single unit facility of 20 MVA or greater. As recognized by the SDT and FERC in Order No. 773, a dispersed generating facility of 75 MVA or greater (NERC Registry Criterion Section III.c.2) can have an impact on the BES. To recognize this impact and to also account for the dispersed nature and reliability advantage as described above, PacifiCorp

Organization	Yes or No	Question 4 Comment
		requests that the SDT strongly consider the following two potential alternative revisions to the proposed Inclusion I2:PacifiCorp's preferred option would be:"I2 - Generating resource(s) and dispersed power producing resources, with: a) Gross individual nameplate rating greater than 20 MVA, including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above, OR, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA, beginning at a bus where the aggregate generation is greater than 75 MVA and continuing through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above."The following diagram demonstrates the 75 MVA aggregation impacted by PacifiCorp's preferred option: (diagram provided to Wendy Muller at NERC).This preferred option would also include traditional sources of generation comprised of several small generators. NERC's registration criteria would still include this type of a facility as a registered GO or GOP. PacifiCorp's second option is:"I2 - Generating resource(s) and dispersed power producing resources, including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: a) Gross individual nameplate rating greater than 20 MVA, OR, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA. For facilities with an aggregate rating of 75MVA or more that consist of individual units rated at 4 MVA or less, the portion of the facility that is included in the BES as generation shall start at the point at which the 75MVA or greater aggregation occurs and continue out to the interconnection with the transmission system rated at 100 kV or more."Under this proposed change, a dispersed generating facility of 75 MVA or more consisting of individual generators of 4 MVA or less would be included in the BES definition as generation resources in a similar manner as other types of generation resources, but the unique nature of the small, distributed generating units that comprise them and their inherent reliability advantages would also be appropriately recognized in the definition. NERC's registration criteria would still include this type of a facility as a registered GO or GOP. **Please see diagram at the end of the report (P. 126)**

Organization	Yes or No	Question 4 Comment
Self	No	Proposal for I2 as follows:I2 - Generating resource(s) and dispersed power producing resources, including their power delivering assets operated at a voltage of 100 kV or above with:
Hydro One Networks Inc.	No	The combination of I2 with I4 is not as a result of FERC's directive and/or clearly stated in the scope of the Phase 2 SAR. In Order 773, Commission states: a) "Other than the directive to modify exclusion E3 as discussed below, the Commission declines to direct NERC to further modify the definition or the specified inclusions and exclusions" (Paragraph 52)b) the Commission will not direct NERC to categorically include collector systems pursuant to inclusion I4. (Paragraph 114)We believe that I2 and I4 wordings as approved by the stakeholders, NERC BoT, FERC and applicable governmental authorities in Canada should be retained. As such, we do not support this change to the definition because NERC should also consider unintended consequences that could result out of this change. In our opinion, I4 is meant for renewable energy resources (in particular Wind). These resources are inherently different from both the planning and the real time operations perspectives. This change will essentially designate every element of a wind farm above 75 MVA to its interconnection as a BES facility including the collector systems which may not be necessary. For example, this will essentially mean that collector systems shall be required to comply with TPL standards performance assessment and design.
North American Generator Forum Standards Review Team	No	The equipment being included in compliance with NERC Standards should only be that equipment carrying >75 MVA - the collector systems, GSU and Gen Tie, not the individual turbines. Implementing standards at the individual wind turbine level (< 2MW in many cases) does not improve reliability and only created additional workload for both the registered entities and the regions. A 2 MW wind generator will neither have an impact due to the loss of the generation nor start cascading outages due to a failure to trip a 600 volt machine. As a point of reference, many large generating stations have station service loads of that magnitude.

Organization	Yes or No	Question 4 Comment
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	The equipment being included in compliance with NERC Standards should only be that equipment carrying >75 MVA - the collector systems, GSU and Gen Tie, not the individual turbines. Implementing standards at the individual wind turbine level (< 2MW in many cases) does not improve reliability and only created additional workload for both the registered entities and the regions.
Public Utility District No.1 of Snohomish County	No	The Public Utility District No.1 of Snohomish County supports the omitted I4 and does not support the revisions to the generation resources and dispersed power resources inclusions. The change will classify systems as BES that interconnects a generation unit with a peak generation capability of less than 2 MVA and typical capacity factor of 25-30 percent. It is difficult to understand how these types of systems could be considered bulk. A greater than 75 MVA plant would typically have many miles of a 34.5 kV collector system connecting 480/690 volt to 34.5 kV generator step up transformers. Failure or mis-operations of these collector system components would equate to the loss of a MW or two, 30 percent of the time. The Public Utility District No.1 of Snohomish County does not believe enforcing NERC Reliability Standards on these, or similar systems supports reliability. In fact it could stifle green distributed generation developments.
City of Tacoma	No	TPWR supports the omitted I4 and does not support the revisions to the generation resources and dispersed power resources inclusions. The change will classify systems as BES that interconnects a generation unit with a peak generation capability of less than 2 MVA and typical capacity factor of 25-35 percent. It is difficult to understand how these small generation systems could be considered BES.
Pattern Gulf Wind LLC	No	While generators should not be seperated into different categories, and I agree with the general concept to combine power/generation resources into one inclusion, I disagree with the lanugage that for dispersed power resources the entire generation

Organization	Yes or No	Question 4 Comment
		facility up to the generator terminal becomes part part of the BES. The critical load for dispersed power resources (considering the actual Net Capacity Factors) is apparently reached at an output of 75 MVA. Including equipment such as collector circuits and individual generators that carry well below the critical load of 20 MVA as applicable to conventional generators does seem unreasonable and undue and will have very little to do with protecting reliability and the BPS, but will increase maintenance and operating cost to unjustifieable levels. Only at the point where the such generation is aggregated and a critical load can be reached would dispersed power generators meet any criticality to the BPS, but the loss of individual small generators or collection circuits would not have significant impact on the BPS including causing any cascading outages. Equipment included in compliance with NERC standards(as handeled in practise for the past 5+ years) should be limited to the point where generation is aggregated including the GSU and (if owned/operated by GO/GOP) generator tie-lines.
Wisconsin Electric	No	Wisconsin Electric supports the comments filed by the NAGF in response to this question with the following edits: "The equipment being included in the BES definition should only be that equipment that actually carries greater than 75 MVA - the collector systems, main transformers, and high-voltage interconnections, not the individual wind turbines. Implementing standards at the individual wind turbine level (<2 MW in many cases) does not improve reliability and only creates additional workload for both the registered entities and the Regions. A 2 MW wind generator will neither have an impact due to the loss of generation nor cause cascading outages due to a failure to trip a 600 volt machine.
Wisconsin Public Service / Upper Peninsula Power	No	WPS recommends that both I2 and I4 be retained, yet reworded such as this:"I2 - Generating resource(s) and dispersed power producing resource(s), with gross individual nameplate rating greater than 20 MVA, including the generator terminals through the high-side of the generator step-up transformer(s) connected at a voltage of 100 kV or above.""I4 - For generating and dispersed power producing facilities with gross plant/facility aggregate nameplate rating greater than 75 MVA,

Organization	Yes or No	Question 4 Comment
		the bus where the aggregate generation is greater than 75 MVA and continuing thru the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above. (Note: this does not include the individual generating resources themselves, or the collector feeder system(s).)"The intent is to focus compliance activity at the point where power is aggregated to the point (usually a bus) where it becomes significant to the BES not at small (1 to 2 Mw) generators or distribution level Mw collector systems. The reliability issue for small generating units whether they are diesels, wind turbines, solar units, or nuclear modules is not the risk of loss of small independent individual units. The common mode risk of loss of significant amounts of generation is at the point of aggregation.
Transmission Access Policy Study Group		An unintended consequence of the merging of I2 and I4 could be that dispersed behind-the-meter retail customer generation, which itself is not BES under Exclusion E2, results in the distribution system on which it is located being a BES collector system under I2. TAPS offers three options to resolve this unintended consequence. The first option is to bring more of the former I4 language into I2, e.g., "utilizing a system designed primarily for aggregating capacity" to the inclusion, so that I2 would read: Generating resource(s), and dispersed power producing resources utilizing a system designed primarily for aggregating capacity, including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:a) Gross individual nameplate rating greater than 20 MVA, OR, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA. The second option is to include the term "non-retail" after dispersed and before power producing. And the third option is to clarify the use of the term "plant/facility" in b) such that it is clear that it does not refer to all the retail back-up generators or net-metering power producing resources connected to one distribution system connected to one connection to > 100 kV.

Organization	Yes or No	Question 4 Comment
		TAPS also notes that many reliability standards are not a good fit for small individual generating units at dispersed, intermittent power resources such as wind farms; for example, given the frequency with which wind turbines trip on and offline (as they are designed to do), tracking each operation at each turbine to determine whether any misoperations have occurred would extremely onerous and yield minimal reliability benefit. We acknowledge that this concern is outside the scope of this project, but believe that the SDT should be aware of the issue as it revises the BES definition.
Response: The SDT has considered the comments of the industry and determined that the point of aggregation at which dispersed generation could have a reliability impact on the BES is at 75 MVA. The SDT has revisited Inclusions I2 and I4. The inclusions have been broken apart to provide the clarity and granularity that the industry has requested. **I2** – Generating resource(s) ~~and dispersed power producing resources,~~ including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: **I4** - ~~Omitted. d~~Dispersed power producing resources consisting of: a) Individual resources ~~with~~that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and b) The ~~utilizing a~~ system designed primarily for ~~aggregating~~delivering capacity from the point where those resources aggregate to greater than 75 MVA ~~, connected at~~to a common point of connection at a voltage of 100 kV or above.		
Hydro-Quebec TransEnergie	No	Same comment as for question 1
Response: Please see response to Q1.		
Cooper Compliance Corp	No	See comment to question No. 2.
Response: Please see response to Q2.		
Sacramento Municipal Utility District	No	SMUD supports the omitted Inclusion-I4 but does not fully agree with the revisions for Inclusion-I2. SMUD is concerned regarding Inclusion-I2 that now includes a

Organization	Yes or No	Question 4 Comment
		common BES determination for components of hydro/thermal AND wind/solar resources. Since Inclusion-I2 establishes a 100 kV or above threshold for generators, this draft's current language would exclude many of the 'dispersed resources'. If it is determined that the 'dispersed resource' are subject to BES through 'multiple step-up transformer', the current draft language would inappropriately expand the BES Definition to potentially include all generators regardless of voltage level when subcategories I2a & I2b are met. Instead, to eliminate this potential expansion SMUD urges the BES SDT to create an Inclusion that defines an element(s) as BES where a single component(s) has the potential to removes 75 MVA of resources and remove the 'dispersed power producing resources' from Inclusion-I2. The 75 MVA threshold would eliminate the administrative and cost burden associated with testing and documentation for 'small-scale' machines that are connected to sub-100 kV, are less than 3 MW, and, individually have little or no impact to reliability of the BES. Subjecting the 'collector system' that typically consist of several miles of radial 34.5 kV, its system components and its dispersed generation resources to the BES and subsequent application of NERC Reliability Standards would not provide a proportionate impact to reliability.
Public Service Enterprise Group	No	The "Phase 1: Bulk Electric System Definition Reference Document dated April 2103 addresses I4 on pp. 15-20. These examples to not include the following in the BES: (a) the below 100 kV collector system; (b) step-up transformers with primary and secondary sides below 100 kV, and (c) the main GSU that connects at 100 kV to the system. This discrepancy between traditional generation and dispersed generation needs to be explained so that there is no discrimination between them with respect to the BES definition.

Response: The SDT has revisited Inclusions I2 and I4. The inclusions have been broken apart to provide the clarity and granularity that the industry has requested.

I2 – Generating resource(s) ~~and dispersed power producing resources,~~ including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:

Organization	Yes or No	Question 4 Comment
I4 - ~~Omitted. d~~Dispersed power producing resources consisting of: a) Individual resources ~~with~~that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and b) The ~~utilizing a~~ system designed primarily for ~~aggregating~~delivering capacity from the point where those resources aggregate to greater than 75 MVA ~~, connected at~~to a common point of connection at a voltage of 100 kV or above. Clarifications for components that will be included under this inclusion can be found in the Reference Document under preparation by the SDT.		
MRO NERC Standards Review Forum (NSRF)	No	The NSRF recommends that both I2 and I4 be retained, yet reworded such as this:"I2 - Generating resource(s) and dispersed power producing resource(s), with gross individual nameplate rating greater than 20 MVA, including the generator terminals through the high-side of the generator step-up transformer(s) connected at a voltage of 100 kV or above."”I4 - For generating and dispersed power producing facilities with gross plant/facility aggregate nameplate rating greater than 75 MVA, the bus where the aggregate generation is greater than 75 MVA and continuing thru the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above. (Note: this does not include the individual generating resources themselves, or the collector feeder system(s).)"The intent is to focus compliance activity at the point where power is aggregated to the point (usually a bus) where it becomes significant to the BES not at small (1 to 2 Mw) generators or distribution level Mw collector systems. However, if I2 moves forward as drafted, we feel it is imperative to launch an effort similar to the GOTO/Project 2010-07, to modify and add clarity to standards as they would apply to a dispersed power resource. This is important, as many of the current GO/GOP standards would be difficult and impractical to apply to a dispersed power resource. In addition, we recommend that interim compliance application guidance be developed to help owners and operators of dispersed power resources understand how to apply current standards, while also providing guidance to the auditors. The inclusion of small individual generators will drive significant industry burden to comply without producing any additional system reliability benefits. The inclusion of

Organization	Yes or No	Question 4 Comment
		1 - 2 MW units as separate NERC BES elements will drive unintended consequences for NERC standards and perhaps the wind industry as a whole as companies are suddenly subjected to large populations of elements for standards such as PRC-004, PRC-005, FAC-008-3, TOP-002 R14, and VAR-002 (there may be others).The reliability issue for small generating units whether they are diesels, wind turbines, solar units, or nuclear modules is not the risk loss of small independent individual units, it is the common mode risk loss of significant amounts of generation at the point of aggregation of >75MVA.
Xcel Energy	No	We do not agree that dispersed power resources should be treated the same at traditional generators, as they are quite different in design and operation from traditional generators and individually do not have the same impact on reliability. For the 2 main reasons detailed below, we recommend that both I2 and I4 be retained, yet reworded such as this:"I2 - Generating resource(s) and dispersed power producing resources, with gross individual nameplate rating greater than 20 MVA, including the generator terminals through the high-side of the generator step-up transformer(s) connected at a voltage of 100 kV or above.""I4 - For generating and dispersed power producing facilities with gross plant/facility aggregate nameplate rating greater than 75 MVA, the bus where the aggregate generation is greater than 75 MVA and continuing thru the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above. (Note: this does not include the individual generating resources themselves, or the collector feeder system(s).)" 1) We are very concerned that the application of NERC reliability standards to dispersed power producing resources under the proposed BES Phase II definition will impose a major burden. The inclusions as currently drafted could even harm electric reliability by misallocating resources away from reliability areas that are far more likely to negatively affect BES reliability. As of the end of 2011, there were approximately 38,000 utility-scale wind turbines operating in the U.S., many of which are aggregated in wind projects that exceed 75 MVA in aggregate and are connected at a common point of voltage of 100 kV or above. Including each of

Organization	Yes or No	Question 4 Comment
		these wind turbines and their collector systems in the BES definition would impose a large and undue burden on wind project owners and operators, result in significant confusion about the applicability of standards, and contribute no significant benefit to reliability. For example, the application of PRC-005, R1, and R2 at the individual dispersed generator unit level would require regular relay and protection system testing at numerous places within the wind plant, potentially including the internal circuitry of each individual wind turbine. Specifically, the applicability section 4.2.5.3 of PRC-005-2 implies that only the Protection System for the aggregating step up transformer is included in scope, and that the Protection System for the individual dispersed generators and aggregating systems are not. The current BES I2 includes both the dispersed generators and the aggregating system for wind farms greater than 75 MVA, applying PRC-005-2 requirements at 4.2.5.1 and 4.2.5.2 for generator trip relays, and generator step-up transformers, respectively. We do not think that application of these test requirements at the sub- 3MVA turbine level are the intent nor the reasonable scope of a national reliability standard. We have similar concerns with other standards including PRC-019-1, PRC-024-1, PRC-025-1, and PRC-027-1 and how application of these requirements would conflict or confuse implementation of this Phase II definition as applied to distributed generators and the associated aggregating systems. As another example, TOP-002 R14 requires status reporting of unplanned generator outages. We do not believe that the BA or TOP would benefit from the operational notification status of any single dispersed generator at the typical wind turbine size of 3 MVA or less. 2) A possible argument for requiring that all GO/GOP reliability standards apply to individual wind turbines is if wind turbines were susceptible to a common mode failure that would cause a large number of the generators within a wind plant to trip offline within a matter of seconds. Fortunately, all wind turbines installed in the U.S. in recent years and going forward comply with the demanding voltage and frequency ride-through requirements of FERC Order 661A, which are far more stringent than the ride-through requirements placed on other types of generation. In the event of a system disturbance that causes a voltage or frequency deviation

Organization	Yes or No	Question 4 Comment
		that would affect all generators nearly simultaneously, a wind plant would be more likely to remain online than almost all conventional generators, and the wind plant would likely only trip offline if the power system had collapsed to the point that nearly all other generation had already tripped offline. As a result, there is no compelling reliability reason for including individual wind generators and their electrical collector systems in the BES definition.
Consumers Energy Company	Consumers Energy provides comments on the following issue raised by the Phase 2 BES definition: (1) the changes proposed to Inclusions I2 and I4.Dispersed Power Producing Resources Should Not Be Treated the Same as Other Generation Because They Do Not Have the Same Impact on the BES. The Phase 2 BES definition proposes to entirely eliminate Inclusion I4 and revise Inclusion I2 to, among other changes, include dispersed power producing resources. Consumers Energy does not agree with this change because different generating resources have different impacts on the BES, and thus are entitled to different treatment. This change is primarily premised on the theory that NERC should treat all power generation sources equally. While this theory sounds appealing upon first blush, it ignores the reality that different generation sources are in fact not equal because they differently impact the BES. In the case of dispersed power producing resources, the potential impact on the BES of these resources is not the same as a larger power producing resource (e.g. a 500 MW coal unit). The unexpected addition or loss of a larger generating unit can majorly impact the reliability of the BES. The addition or loss of a single unit (e.g., a 1.4 MW wind turbine), or even several smaller units, has little, if any, material impact on the BES. Because of differing impacts on the BES, dispersed power producing resources are entitled to different treatment. In addition, merely adding the phrase "and dispersed power producing resources" to I2 significantly expands the scope of assets drawn into the BES. Under the Phase 1 definition, only the generating units themselves were included in the BES (see, e.g., Figure I4-1 of NERC's "Phase 1: Bulk Electric System Definition Reference Document" dated April 2013). The Phase 1 definition did not include all of the equipment between the generator terminal through the high-side of the step-up transformer. This exclusion of certain equipment was for good reason - dispersed power producing resources do not individually have significant impact on the BES, and only collectively have an impact. Under the proposed Phase 2 definition, the entire dispersed power producing facility (e.g., an entire wind farm) will be included in the BES. While we appreciate that such an	

Organization	Yes or No	Question 4 Comment
		expansion was likely the Drafting Team's intent, this expansion makes little sense. Dispersed power producing resources simply do not - until aggregated - have sufficient impact on the BES to warrant such an expansion of the scope of the BES.A better approach would be to limit the scope of the BES to only include equipment from the point where the aggregated generation achieves 75 MVA - i.e., from the substation bus where the collector circuits aggregate to exceed 75 MVA. As such, Consumers Energy proposes that NERC retain Inclusion I4, but change its wording to something like this: "Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system design primarily for aggregating capacity, from the connection point at a voltage of 100 kV or above down through the connecting transformer to a single common point of aggregation." This approach reasonably limits the BES definition as applied to dispersed power producing units in a fashion proportional to their impact on the BES.

Response: The SDT revisited Inclusions I2 and I4. The inclusions have been broken apart to provide the clarity and granularity that the industry has requested.

I2 – Generating resource(s) ~~and dispersed power producing resources,~~ including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:

I4 - ~~Omitted. d~~Dispersed power producing resources consisting of:

a) Individual resources ~~with~~that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and

b) The ~~utilizing a~~ system designed primarily for ~~aggregating~~delivering capacity from the point where those resources aggregate to greater than 75 MVA ~~, connected at~~to a common point of connection at a voltage of 100 kV or above.

Standard applicability to small scale dispersed generation should be addressed through a new SAR proposed by industry.

Organization	Yes or No	Question 4 Comment
Associated Electric Cooperative, Inc. - JRO00088	No	The SDT needs to clarify "generator terminals" due to this current definition's potential inclusion all the way down to individual PV cell's solder-pads and battery's terminals. (These technically are the first electrical access-points for where conversion takes place from other energies to electrical energy.) From a BES Reliability aspect, the worst-case contingency is total loss of the resource at its

Organization	Yes or No	Question 4 Comment
		greatest aggregated entry point to the BES. Therefore AECI recommends that the SDT revert to their earlier wording. Technically, loss increments below that worst-case level, and especially for weather-sensitive solar and wind, seem no different to System Operators than derations on any large coal-fired Units. On the other hand, if the SDT's intent is to draft Standards in a manner to disincent renewable energy producers from aggregating their resources to the grid in excess of 75 MVA, then perhaps the SDT is providing the proper forcing-function here. If so, they should show equal concern for any other type of new generating units that are sized in excess of the same 75 MVA threshold.
SERC EC Planning Standards Subcommittee	No	We agree in general but the SDT should review solar, fuel cell and other DC technologies to clarify the term "generator terminals" in regards to the PRC standards. Additionally, clarification should be made that limits inclusion to the greatest contingency loss which is the step-up transformer to the grid.
South Carolina Electric and Gas	No	We agree in general but the SDT should review solar, fuel cell, and other DC technologies to clarify the term "generator terminals" in regards to the PRC standards. Additionally, clarification should be made that limits the inclusion to the greatest contingency loss, i.e. the step up transformer to the grid.
SERC Reliability Corporation	The inclusion language uses the words "generator terminals". "Generator terminals" are not a good demarcation point for defining a bright-line for the collector system that represents faciltites that are necessary for reliable operation. These words will not be clear with some power producing resources (wind, solar, low-head hydro, etc.). The SDT should review solar, fuel cell and other DC technologies to clarify the term “generator terminals” as it relates these types of generating resources. An alternative may be to define a proxy for generating resource "generator terminals" (may be made up of multiple individual resources) by the connection point below the step-up transformer where aggregate capacity exceeds the individual unit registration threshold	

Organization	Yes or No	Question 4 Comment
	of 20MVA	

Response: The SDT has revisited Inclusions I2 and I4. The inclusions have been broken apart to provide the clarity and granularity that the industry has requested.

I2 – Generating resource(s) ~~and dispersed power producing resources,~~ including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:

I4 - ~~Omitted. d~~Dispersed power producing resources consisting of:

a) Individual resources ~~with~~that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and

b) The ~~utilizing a~~ system designed primarily for ~~aggregating~~delivering capacity from the point where those resources aggregate to greater than 75 MVA ~~, connected at~~to a common point of connection at a voltage of 100 kV or above.

With these changes, the ambiguity caused by the term "generator terminals" has been removed.

Organization	Yes or No	Question 4 Comment
Modesto Irrigation District	No	

Response: Without a specific comment, the SDT is unable to respond.

Organization	Yes or No	Question 4 Comment
Colorado Springs Utilities	Yes	1. Define "dispersed power producing resources."

Response: The SDT feels that the note included in the definition and within the reference document adequately explain the intent of "dispersed power producing resource and therefore a definition is not required.

Organization	Yes or No	Question 4 Comment
Georgia Transmission Corporation	Yes	Because of the addition of "dispersed power producing resources" to I2...GTC believes it's more appropriate to replace the term "generator" with "resource" in the following phrase: ..."including the generator terminals through the high-side..."
Independent Electricity System Operator	Yes	In general we agree with these changes and propose the following alternative language for more clarity:' Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above, and dispersed power producing resources connected at a common point

Organization	Yes or No	Question 4 Comment
		at a voltage of 100 kV or above with;’
Idaho Power Company	Yes	What is lost in deleting I4 per se and rolling up "dispersed power producing resources" into I2 is the distinctive characteristic of dispersed power producing resources of "utilizing a system designed primarily for aggregating capacity, connected at a common point ". Without making this distinction, the "dispersed power producing resources" are just another generating resource. Therefore, there is no need to add "dispersed power producing resources" to I2 if I4 is deleted per se as suggested. At the same time, if the distinctive characteristic of dispersed power producing resources of "utilizing a system designed primarily for aggregating capacity, connected at a common point " was also rolled up to I2, then why delete I4 at all? IF the recommendation to delete I4 and modify I2 as presented in the Project 2010-17 draft 1 is the decision of the Project Team, we would recommend further adding "utilizing a system designed primarily for aggregating capacity, connected at a common point" to clarify "dispersed power producing resources". In conclusion, we would not be in favor of making the changes that are the subject of Q4.
Response: The SDT has revisited Inclusions I2 and I4. The inclusions have been broken apart to provide the clarity and granularity that the industry has requested. **I2** – Generating resource(s) ~~and dispersed power producing resources,~~ including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: **I4** - ~~Omitted. d~~Dispersed power producing resources consisting of: a) Individual resources ~~with~~that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and b) The ~~utilizing a~~ system designed primarily for ~~aggregating~~delivering capacity from the point where those resources aggregate to greater than 75 MVA ~~, connected at~~to a common point of connection at a voltage of 100 kV or above.		
US Bureau of Reclamation	Yes	Reclamation agrees with the addition of the term "dispersed power resources" in I2. However, Reclamation believes that certain aspects of Inclusion I2 are quite problematic. We have included comments on outstanding issues in I2 related to

Organization	Yes or No	Question 4 Comment
		generation step up transformers (GSUs) in response to Question 6.
Response: Please see response to Q6.		
Ameren	Yes	We request that the SDT renumber the Inclusions to yield I1 through I4 (i.e. move the I5 language to I4), as we believe this will be clearer than having a blank or unused I4.
Response: The SDT has reinstated the I4 inclusions and therefore renumbering is not required.		
American Transmission Company	Yes	ATC has no comments.
NV Energy	Yes	Yes, this was an efficient change to consolidate the two inclusions and in the long run, will eliminate confusion and possible inconsistency.
Dominion	Yes	
Tennessee Valley Authority	Yes	
SPP Standards Review Group	Yes	
Pepco Holdings Inc & Affiliates	Yes	
DTE Electric	Yes	
IRC Standards Review Committee	Yes	
PPL NERC Registered Affiliates	Yes	
Arizona Public Service Company	Yes	
Southwest Power Pool Regional	Yes	

Organization	Yes or No	Question 4 Comment
Entity		
Central Lincoln	Yes	
FirstEnergy	Yes	
Manitoba Hydro	Yes	
Orange and Rockland Utilities Inc.	Yes	
Duke Energy	Yes	
ISO New England Inc.	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
American Public Power Association	Yes	
Response: Thank you for your support.		

5. **The SDT has made a number of clarifying changes to language in response to industry comments as follows: (a) I1: Change 'under' to 'by application of'; (b) I2: Split out the inclusion to clearly show that it is an 'or' condition; (c) I5: Add 'unless excluded by application of Exclusion E4'; (d) E3: Change '… retail customer Load…' to 'retail customers'; (f) E3c: Change '… a monitored Facility of a …' to '… any part of a…'; (g) E4: Add the phrase 'installed for the sole benefit of'. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions (using the letter of the change) in your comments.**

Summary Consideration: Several commenters attempted to re-open items that were decided and approved in Phase 1 and for which no changes are being made in Phase 2. The SDT notes that those issues raised were previously decided by the Commission in its related Orders, and were not a topic for reconsideration in Phase 2.

The SDT made the following changes due to industry comments:

I2 a) - Gross individual nameplate rating greater than 20 MVA~~,~~. O~~R~~r,

E4 - Reactive Power devices installed for the sole benefit of a retail customer(s).

Organization	Yes or No	Question 5 Comment
South Carolina Electric and Gas	No	Change the wording in E-4 from "installed" to "operated". Change the wording in E-3c from "part" to "element". Change "permanent Flowgate" to "permanent Reliability type Flowgate". The Eastern Interconnection Book of Flowgates differentiates between "informational" and "Reliability" type Flowgates.
SERC EC Planning Standards Subcommittee	No	E4 change the word "installed" to "operated". E3c change "part" to "element" and add "Reliability type" to the statement: permanent Reliability type Flowgate. The rationale is that the Eastern Interconnection Book of Flow gates contains some entries flagged "informational" and this would differentiate between the flow gates (reliability versus informational).The comments expressed herein represent a consensus of the views of the above named members of the SERC Planning Standards Subcommittee (PSS)

Organization	Yes or No	Question 5 Comment
		only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Response: Regarding Exclusion E4 - the SDT agreed that "installed" is the proper term as it best describes the intent of the use of reactive devices, however, as a result of consideration of other Exclusion E4 comments, the SDT has modified Exclusion E4 to read: **E4** - Reactive Power devices installed for the sole benefit of a retail customer(s). Regarding Item (g) - the SDT notes that the issue raised regarding "permanent Flowgate" was previously decided by the Commission in its related Orders, and was not a topic for reconsideration in Phase 2. The SDT reconfirms that the description "… any part of …" properly characterizes the intent for Exclusion Ec3. Reliable operation of the system requires operator situational awareness of all permanent Flowgates in order to balance the physical network constraints against any commercial considerations that may occur in the network. This need for situational awareness requires knowledge of "any part of" a permanent Flowgate.		
Duke Energy	No	Duke Energy believes the SDT should consider changing the language of E4 to "Reactive Power devices installed for the benefit of a retail customer(s)."
Northeast Power Coordinating Council	No	For Exclusion E4 Reactive Devices - The drafting team agreed that use, and not ownership, should dictate the disposition of reactive devices. Reactive devices used to support retail customer loads, and not used in day-to-day operations for BES voltage control for either steady state or contingency operations, may be excluded from the BES regardless of ownership. Devices need not be owned by "a retail customer" as a prerequisite for exclusion. Reactive devices owned by others, such as a Transmission Owner, and installed solely for the benefit of retail customer load should also qualify for exclusion. The proposed wording still carries remnants of the previous retail customer concept. It refers to a singular customer. Yet, reactive devices may be installed to benefit a group of retail customers collectively referred to as retail load. Suggest revising E4 to either read:E4--Reactive Power devices installed for the sole benefit of retail customers. orE4--Reactive Power devices installed for the sole benefit of retail load.
PacifiCorp	No	PacifiCorp does not agree with certain of the SDT's clarifying changes enumerated

Organization	Yes or No	Question 5 Comment
		above, for the following reasons: o Item (b): rationale provided in response to question 4 above; and o Item (d): Reactive Power devices are often installed on substation busses less than 100 kV for the sole benefit of the retail customers of the utility. If a substation or substation bus is excluded from the BES through either Exclusion 1 or Exclusion 3 and is installed for the sole benefit of the retail customers, then that device should also be excluded from the BES. PacifiCorp offers the following suggested wording for Exclusion E4 for the SDT’s consideration: Reactive Power devices installed for the sole benefit of retail customers.
Response: The SDT agreed to modify Exclusion E4 to read: **E4** - Reactive Power devices installed for the sole benefit of a retail customer(s).		
Self	No	It is never possible to determine whether a reactive device is for the "sole benefit" of retail customers. The presence of a reactive device may benefit the retail customer from a rates perspective or a local voltage perspective, but the presence of the reactive device, no matter where it is located, even at the distribution level, also provides system wide BES/BPS benefits.
Response: The SDT notes that the issue raised was previously decided by the Commission in its related Orders, and was not a topic for reconsideration in Phase 2. No change made.		
ACES Standards Collaborators	Yes	(1) In general, these are clarifying changes and we are supportive of them. However, one change is not a clarifying change but is in fact a substantive change. Changing “a monitored Facility of a permanent Flowgate...” to “any part of a permanent Flowgate...” is not a clarifying change but is in fact a substantive change. Consider that a Flowgate contains a monitored facility and often a contingent Facility. The contingent Facility will now be included whereas it was not previously included. In the end, these contingent Facilities probably will already be included by the bright line 100 kV threshold as they are usually a larger facility than the

Organization	Yes or No	Question 5 Comment
		monitored facility. However, this should not be represented as a clarifying change. (2) “OR” should be “or”.

Response: Regarding Item (g) -the SDT reconfirms that the description “… any part of …” properly characterizes the intent for Ec3. Reliable operation of the system requires operator situational awareness of all permanent Flowgate types in order to balance the physical network constraints against any commercial considerations that may occur in the network. This need for situational awareness requires knowledge of “any part of” a permanent Flowgate. No change made.

Regarding Item (d) – the SDT capitalized “OR” in the posting to highlight the change. Inclusion I2a has been changed to read:

I2 a) - Gross individual nameplate rating greater than 20 MVA~~,~~. O~~R~~r,

Organization	Yes or No	Question 5 Comment
New York Power Authority	Yes	No comments.
American Transmission Company	Yes	No comments.
Public Utility District No.1 of Snohomish County	Yes	The Public Utility District No.1 of Snohomish County supports the SDT's approach.
Idaho Power Company	Yes	We would be in favor of making the changes that are the subject of Q5.
Associated Electric Cooperative, Inc. - JRO00088	Yes	
Dominion	Yes	
MRO NERC Standards Review Forum (NSRF)	Yes	
Tennessee Valley Authority	Yes	
SPP Standards Review Group	Yes	

Organization	Yes or No	Question 5 Comment
Cooper Compliance Corp	Yes	
City of Tacoma	Yes	
Pepco Holdings Inc & Affiliates	Yes	
DTE Electric	Yes	
Iberdrola USA	Yes	
IRC Standards Review Committee	Yes	
PPL NERC Registered Affiliates	Yes	
North American Generator Forum Standards Review Team	Yes	
Hydro One Networks Inc.	Yes	
Arizona Public Service Company	Yes	
Southwest Power Pool Regional Entity	Yes	
Colorado Springs Utilities	Yes	
Transmission Access Policy Study Group	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power	Yes	

Organization	Yes or No	Question 5 Comment
Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
US Bureau of Reclamation	Yes	
Central Lincoln	Yes	
FirstEnergy	Yes	
Hydro-Quebec TransEnergie	Yes	
Wisconsin Public Service / Upper Peninsula Power	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
Sacramento Municipal Utility District	Yes	
Occidental Energy Ventures Corp.	Yes	
American Electric Power	Yes	
Georgia Transmission Corporation	Yes	
Independent Electricity System	Yes	

Organization	Yes or No	Question 5 Comment
Operator		
Ameren	Yes	
ISO New England Inc.	Yes	
NV Energy	Yes	
American Wind Energy Association	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Xcel Energy	Yes	
American Public Power Association	Yes	
MidAmerican Energy	Yes	
Response: Thank you for your support.		

6. Are there any other concerns with this definition that haven't been covered in previous questions and comments?

Summary Consideration: Several commenters raised issues concerning the implementation plan with respect to jurisdictional boundaries. After conferring with NERC Legal, the SDT has revised the jurisdictional language.

Several commenters raised concerns about the SDT treatment of the thresholds that reside within the BES definition. The results of the NERC Planning Committee's (PC) evaluation of the various thresholds contained in the BES definition were presented to the SDT for consideration in developing revisions to the definition in Phase 2. The PC determined that all thresholds should remain at the status-quo. The SDT, based on the recommendations from the PC, has opted to retain the original thresholds in the definition.

The looping facilities that operate at voltages below 100 kV are NOT included in the BES. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process."

Several commenters expressed concerns related to the power flow associated with local networks and the methodology recommended to determine the amount of actual power flow. Exclusion E3b defines an absolute value associated with power flow from a local network to maintain the bright-line concepts of the definition. The SDT has determined that the best method to quantify the amount of power flow associated with a local network is to evaluate the hourly integrated flows over the most recent 2 year period. Although this allows for some amount of flow from the local network this is considered to be inconsequential when considering the impact of minimal flows over very short periods of time.

Numerous commenters provided comments on the contents of the BES Definition Reference Document. The SDT appreciates the comments concerning the BES Definition Reference Document; however this comment period concerns the Phase 2 revision of the BES definition. As the SDT gains more certainty in final outcome of the definition development, the BES Definition Reference Document will be updated and posted for industry comment.

Organization	Yes or No	Question 6 Comment
Manitoba Hydro	No	(1) Although Manitoba Hydro is in general support of the changes, we would like to include the following clarifying comment: Implementation Plan, Effective Dates - replace the words "go into effect" with "become effective". Moreover, append the

Organization	Yes or No	Question 6 Comment
		wording, after “applicable regulatory approval”:”, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.” Prior to the wording “In those jurisdiction....”. The same changes should be made to the first sentence in the Effective Date Section of the proposed Definition document.
Response: After conferring with NERC Legal, the SDT has revised the jurisdictional language. This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required the definition shall go ~~into effect~~become effective on the first day of the second calendar quarter after Board of Trustees adoption or as otherwise made effective pursuant to the laws of applicable governmental authorities.		
Cogeneration Association of California	Yes	There are several issues regarding industrial facilities that should be addressed in Phase 2. Including the facilities of any individual industrial customer in the BES and making them subject to NERC standards and enforcement unreasonably expands a program designed to regulate utilities. This shifts the responsibility for utility functions to individual, non-jurisdictional entities, including industrial customers, and customer generators. It is ironic that these entities built generation for increased reliability of service to their installations - not to serve the grid - and in many cases to substitute for the less-than-reliable utility grid service. The comments to FERC on the NOPR and in the requests for rehearing raised several issues with regard to industrial facilities that FERC deferred to Phase 2. These comments include those advocating exemption of industrial facilities with power flowing through and out to the grid, such as those asserted by Dow and Valero. The issues associated with industrial customers employing self-generation to serve on-site load should appropriately be included in this Phase 2 effort. To address these issues, CAC, EPUC and CLECA propose four development initiatives within Phase 2: o First, there should be an additional exclusion from the bright-line test: oIf the element is not owned or operated by a public utility regulated by a state authority as a common carrier, or by FERC as a public utility, there is a presumption that the element is not part of the Bulk Electric System (BES);

Organization	Yes or No	Question 6 Comment
		o For any element that is not a public utility, and that is asserted to be material to the reliability of the BES, the burden is on the regional entity or the interconnected public utility to demonstrate that the non-public utility customer facilities are an essential and material part of the BES. o This shift in burden is important because of the difficulty for an individual industrial customer/self-generator to obtain the necessary data to model its impact on grid reliability. Confidential modeling of power flows or information of other customers' usage is not going to be provided by the utilities to customer generators as market participants. o Second, there should be a functional test specified for determining "material impact" to grid reliability, to facilitate the exclusion of elements. FERC in Order 743 and subsequent orders finds that a functional test of "no material impact" may not be sufficient to identify elements that are "necessary to operate the system." In footnote 35 of the April 18 rehearing order, FERC indicates that NERC has the option to develop such a test. A test of "no material impact and unnecessary to operate the system" should be developed, particularly to allow the exclusion of industrial facilities never intended to support grid reliability. o Third, NERC should further analyze the issue of power flowing out of a local network. Industrial facilities have often constructed two interconnections to the grid. This has typically been done to ensure reliability of service to the end-use industrial facility, but in doing so, it may also inadvertently provide a path for flows of small amounts of power through the interconnection points back to the grid. The purpose of the dual interconnection is reliability and not to provide transfers of energy across the bus. The transmission operator is not likely to depend on the interconnection point as a means to provide grid service to other customers or to model that service in its transmission planning studies. NERC's technical studies should provide FERC with some criteria for exempting industrial facilities with single-sourced dual feeds that are not intended to support the grid as a transfer path for power and are not modeled as such by the Transmission Planner or Balancing

Organization	Yes or No	Question 6 Comment
		Authority. o Fourth, NERC, under the E-1 exclusions for radial lines, should not unilaterally dismiss the exclusion for radial lines if the industrial customer has more than one line servicing its facility. Most large manufacturing facilities are served by multiple feeds to maximize service reliability. This is done because the load is more reliable than the lines serving the facility. A refinery, chemical plant or other 24/7 facility cannot afford to operate without redundant power lines. Dual feeds, typically from the same utility substation, are constructed to provide benefits to both the utility and the large industrial customer. With that configuration the utility can maintain its revenue stream while performing routine maintenance without shutting-in a facility. In the case of a refinery, if it were forced to shut down during routine line maintenance, it can take up to several days to safely shut down and even longer to start up. By having redundant lines, often on the same poles, a facility can save millions of dollars in shut down costs and other related expenses. It would be commercially negligent in many cases for large customers not to have the redundancy. Utilities can provide increased reliability and perform repairs more safely with the redundant lines. In no way does the fact that two lines providing service to a single large industrial facility, typically from the same utility source, change the characteristic of that service as being anything more than a radial line feed.

Response: The BES definition is a bright-line 'component' based definition that does not take into account ownership or operational responsibilities of subject facilities and when appropriately applied produces consistent results on a continent-wide basis. In the event that the BES definition designates an Element as BES that an entity believes is not necessary for the reliable operation of the interconnected Transmission network, the ERO Rules of Procedure exception process may be utilized on a case-by-case basis to either include or exclude an Element. The SDT recognizes that there is a certain level of burden on the entity when utilizing the exception process, however, a 'blanket' exclusion based on facility ownership is contradictory to the fundamental tenets that are the basis for the BES definition. No change made.

During Phase 1 of the project the SDT developed a document which provides guidance to an entity on the development of technical justification which can support an exceptions request. This document is titled: Detailed Information to Support an Exception Request

Organization	Yes or No	Question 6 Comment
and is currently available on the BES definition project page. During the development of this document the SDT explored the possibility of a single functional test that would result in identifying facilities that have no material impact on, and are unnecessary to operate, the interconnected Transmission network. The SDT determined that no single parameter was by itself solely indicative of that facility's material impact on or whether it is necessity to operate the interconnected Transmission network. Therefore, the SDT determined that a single functional test was not a feasible solution for defining the BES nor were the results of a single functional test adequate justification for granting exclusion through the exceptions process. No change made. Industrial customers with multiple feeds from the interconnected Transmission network to their facilities (providing there is a looped facility connecting these feeds) are subject to the criteria established by Exclusion E3 when analyzing for potential exclusion from the BES. In the event that the BES definition designates an Element as BES that an entity believes is not necessary for the reliable operation of the interconnected Transmission network, the ERO Rules of Procedure exception process may be utilized on a case-by-case basis to either include or exclude an Element. No change made.		
Independent Electricity System Operator	Yes	1) NERC must ensure that any new or changes to standards as a result of FERC directives that apply to load reliability and load supply continuity are limited to the FERC jurisdiction only. In Canada, local load reliability requirements are under the authority of local regulators such as the Ontario Energy Board in Ontario. 2) Implementation Plan may result in a conflict with Ontario regulatory practice with respect to the effective date of the standard. It is suggested that this conflict be removed by appending the effective date wording, after "applicable regulatory approval" in the Effective Dates Section of the Implementation Plan, to the following effect:", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities." prior to the wording "In those jurisdiction....".The same changes should be made to the first sentence in the Effective Date Section of the proposed Definition document. 3) In our opinion, SDT has correctly crafted the language in E1 and E3 in the approved definition. To address some of the FERC concerns, it may be simpler and clean to introduce a new inclusion "I" for sub 100kV system(s) that are used for bulk power transfer (not a sink) across the BES from one area to the other.
Response: 1). Jurisdictional concerns between regulatory authorities are beyond the scope of this project and are not the		

Organization	Yes or No	Question 6 Comment
responsibility of the SDT to resolve. The proper channels exist to address these concerns; however they reside outside of the Standard Development Process. 2). After conferring with NERC Legal, the SDT has revised the jurisdictional language. This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required the definition shall go ~~into effect~~become effective on the first day of the second calendar quarter after Board of Trustees adoption or as otherwise made effective pursuant to the laws of applicable governmental authorities. 3). The analysis of sub-100 kV loops associated with the evaluation of Elements under the E1 and E3 exclusions is used as a 'qualifier' for the potential exclusion of the Elements that operate at or above 100 kV. The failure to not meet the 'bright-line' criteria established by Exclusions E1 and E3 does not result in the inclusion of the sub-100 kV loops in the BES. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process." Therefore, an Inclusion for sub 100kV system(s) that are used for bulk power transfer (not a sink) across the BES from one area to the other would not be appropriate.		
Central Lincoln	Yes	1) Central Lincoln remains concerned regarding the limits imposed by b) on local networks. We note that by order 773A, FERC considers this limit to be absolute with no allowance for minimal reverse flows for even brief periods under multiple contingencies. While denying rehearing on this issue, FERC specifically invited Phase 2 to adjust this outcome in paragraph 79 of the order. We also note that the BES Definition Reference would allow very brief flows out of a local network as long as the integrated hourly flow was still into the local network. FERC, however, did not rule on the Reference document, only the definition itself. Even if FERC did allow the language of the Reference document, the first multiple contingency event that results in out flow or through flow for the better part of an hour would cause an excluded network to become immediately included, and subject to standards without any implementation period (assuming 24 months had passed from the

Organization	Yes or No	Question 6 Comment
		effective date of the definition). The Planning Committee provided several options to SDT on this matter. We understand the SDT's reluctance to impose system studies on what is intended to be a simply determined bright line criterion, but the present exclusion is not very useful. Central Lincoln would support using a fixed two year (or longer) window rather than the most recent two year sliding window suggested in the reference document. However it is determined, it should be included within the approved definition so that the reference document disclaimer does not apply. 2) Non-retail generation still lacks a definition to be approved by NERC and FERC, even though this this item was specifically included in the approved SAR. We note that the term is defined in the Reference Document where the disclaimer stating it is not an official position of NERC ensures this definition has little value. While the Reference Document states "Non-retail generation is any generation that is not behind a retail customer's meter," we continue to hear it defined without the "not." It is very important that entities and regions have a common understanding of the term, and ask the team to include its definition within the BES definition.

Response: 1. Although Exclusion E3b defines an absolute value associated with power flow from a local network to maintain the bright-line concepts of the definition. The SDT has determined that the best method to quantify the amount of power flow associated with a local network is to evaluate the hourly integrated flows over the most recent 2 year period. Although this allows for some amount of flow from the local network this is considered to be inconsequential when considering the impact of minimal flows over very short periods of time. The 2 year period is recommended as a sliding time frame to account for system changes that periodically occur on any electrical system. For instances that result in a change of BES classification of a subject local network, the entity should contact it's Regional Entity for the Regional practices that address the situation in question. The disclaimer in the BES Definition Reference Document is under the purview of NERC Legal and is not under the control of the SDT.

2. The Phase 2 SAR identified the following in regards to clarification associated with non-retail generation.

Provide improved clarity to the following: The use of the term "non-retail generation"

The SDT provided the following clarification concerning non-retail and retail generation in the BES Definition Reference Document. Non-retail generation is any generation that is not behind a retail customer's meter. Retail generation is behind the meter generation with all or some of the generation serving the on-site Load.

Organization	Yes or No	Question 6 Comment
Wisconsin Electric	Yes	1. Wisconsin Electric is concerned that the drafting team has not considered the potential impacts of the proposed definition on other standards or their requirements. For this reason the definition should be rejected until such time as adequate consideration has been given to such inter-dependencies and potential impacts on various standards which assume a BES definition for their related requirements. 2. Wisconsin Electric participated in the June 26th webinar and during the webinar it was stated that the PRC and CIP standards have unique and unrelated BES bright line criteria. The final definition of BES must apply to all standards in a clear and unambiguous manner. Under the CIP Version 5 standards, clarification is needed to determine whether wind turbine controls become "Low Impact BES Cyber Systems" under the bright line criteria. 3. Wisconsin Electric agrees with the NAGF comments to Question #6 Part 1.4. Clarification should be provided that the BES definition pertains only to normal operating conditions.

Response: 1). The DBES SDT conducted a review of applicability of Reliability Standards. The review consisted of the Reliability Standards that are applicable to the Transmission Owners (TO), Generator Owners (GO), Transmission Operators (TOP), and Generator Operators (GOP). The review was based on the premise that the applicability of Reliability Standards is limited to BES Elements unless otherwise stated in the 'Applicability' section of the standard or identified in the individual requirements. The review was conducted to: (1) Assess the impact of the revised BES definition on the current applicability of the subject Reliability Standards, and, (2) Identify areas where the applicability could be improved from a clarity perspective and (3) Assess the proper application of BPS vs. BES. The results of this analysis were forwarded to the NERC Standards Committee for consideration: (1) The BES SDT found no issues that were identified as an immediate concern based on the revised definition of the BES, therefore the BES SDT did not develop any supporting draft SARs or potential redline changes; (2) The BES SDT identified several areas where the clarity of the applicability could be improved. These issues were documented and provided to the NERC SC with the expectation is that these issues would be added to the 'Standards Issues Database' for consideration by future SDTs. Additionally, the results of the BPS vs. BES assessment were provided to the NERC SC, again with the expectation is that these issues would be added to the 'Standards Issues Database' for consideration by future SDTs.
2). The applicability of Reliability Standards is limited to BES Elements unless otherwise stated in the 'Applicability' section of the

Organization	Yes or No	Question 6 Comment
standard or identified in the individual requirements. The applicability of the CIP Standards is beyond the scope of the DBES SDT's responsibilities. 3). See response to the comments provided by the North American Generator Forum.		
Colorado Springs Utilities	Yes	1. We appreciate the clarifying language change of E3c. Monitoring status should not necessarily include or exclude a Facility from the BES. We want to make sure that we do not discourage or hamper monitoring of facilities by incorrectly involving Facilities that are "monitored" but do not have an effect on the BES into this definition or other NERC standards.
Response: Thank you for your support.		
Associated Electric Cooperative, Inc. - JRO00088	Yes	AECI recommends for E3c: REPLACE: "Flowgate", WITH: "reliability type Flowgate", RATIONALE: The Eastern Interconnection's Book of Flowgates contains both "(Informational)" and "(Reliability)" types of Flowgates. Line-item example excerpts: "/ Type: PTDF (Informational)" -versus- "/ Type: PTDF (Reliability)". AECI believes only elements from the reliability type FGs could be of concern here.
Response: The SDT believes that the reliable operation of the interconnected transmission system requires operator situational awareness of any and all parts of permanent flowgates in order to adequately provide for reliable operation. Hence, the presence of any part of a flowgate should preclude the application of the E3 Exclusion. Accordingly, the SDT is making no changes to this revised language of Exclusion E3(c).		
Idaho Power Company	Yes	Another issue that came up, relative to Q4, is that even with the clarification of the "dispersed power producing resources", the question remains as to how to treat new and existing, large and small generator sources connected to feeders that connect to the same BES bus. Do we need to keep a running total of the installed aggregated capacity and then, once the 75MVA aggregate threshold is reached, change the BES classification of all these previously non-BES units? It would be hard to argue that these are NOT "utilizing a system designed for aggregating capacity".
Response: Entities are required to evaluate their respective systems to identify scenarios where the scope of what is considered to		

Organization	Yes or No	Question 6 Comment
be BES has been changed, for example, situations such as new construction, reconfiguration, decommissioning of facilities, etc. If system topology changes dictate that the scope of the BES has changed and newly identified Elements are now considered to be BES, the entity has the responsibility to inform the Regional Entity of this change (See ERO Rules of Procedure, Section 500 – Organization Registration and Certification, Paragraph 501, Part 1.3.5). The BES Reference Document provides specific examples that address this concern (See Figures I2-5 and I2-6). In these examples the use of multiple transformers and interconnecting bus work is described for various scenarios. Figure I2-5 describes a generation resource that utilizes multiple step-up transformers and interconnecting bus work that is installed for the sole purpose of stepping up the voltage output of the generator to a voltage of 100 kV or above. Based on this scenario the generation resource is considered to be a BES Element. Figure I2-6 describes a generation resource that utilizes multiple step-up transformers and interconnecting bus work that serves two purposes: first, the interconnecting bus work serves Load at a voltage level <100 kV, and second provides a connection of the generation resource to a voltage level ≥ 100 kV. Based on this scenario the generation resource is not considered to be a BES Element.		
Xcel Energy	Yes	As explained under question 4, we feel that dispersed power resources should not be treated the same as traditional generating resources. However, if I2 moves forward as drafted, we feel it is imperative to launch an effort similar to the GOTO/Project 2010-07, to modify and add clarity to standards as they would apply to a dispersed power resource. This is important, as many of the current GO/GOP standards would be difficult and impractical to apply to a dispersed power resource. In addition, we recommend that interim compliance application guidance be developed to help owners and operators of dispersed power resources understand how to apply current standards, while also providing guidance to the auditors.
Response: The SDT recommends to the commenter to complete and submit a Standard Authorization Request (SAR) identifying the concerns raised here and the proposal to initiate a project to address the concerns. Guidance on any interim compliance applications is beyond the scope of this project and the responsibilities of the SDT.		
Dominion	Yes	Based on FERC orders 773 and 773-A and NERC's response to those orders, Dominion no longer sees the value of Note 1 under E1 and suggests it be removed. Further Dominion believes the industry has typically considered the terms 'network'

Organization	Yes or No	Question 6 Comment
		and 'contiguous' to exclude elements or facilities that contain a normally open device (switch, breaker, disconnect, etc) between them. Although Dominion initially thought it understood the meaning of the BES definition, our attendance at seminars in June and the attempted application of the BES definition to the Dominion system has led to some confusion. Please provide additional clarity on the Local Network exclusion E3b. The BES definition is vague and ambiguous as to whether flow out of the network requires study under N-0, N-1, N-2, etc. conditions. The SDT has stated that one does not have to perform loadflow studies to determine a local network. It has also stated in the guidance document that two years of historical flow data may be used to make the determination. Both of these imply the BES is to be evaluated under an N-0 situation. On the other hand the SDT has stated "This definition, as approved, clearly specifies no outward flow from the local network under any conditions and for any duration." {comments on guidance document October 4, 2012 through November 5, 2012}. This implies that some type of contingency analysis must be performed. Consider as an example, Figure E3-3 of the April 2013 Guidance document. With all lines in service as depicted, the 138 kV system is undoubtedly a local network. However, if the definition truly means "under any condition" then one could select an a set of <300 kV and 138 kV contingencies that would force power through the 138 kV and then back onto the BES since there is no alternate path. This would negate the assertion that this is non-BES and excludable. We doubt if that is the SDT intent and believe the definition as written is silent on the contingency issue. Clearly there needs to be a practical limit to how many contingencies one would need to take or clarificiation whether contingencies should be taken at all. Evaluation at all load levels, all credible dispatches with a variety of contingencies is tremendously burdensome. Our preference would be to evaluate with all lines in service (N-0) since this would insure maximum buy-in from stakeholders. E3b should read :E3b) "Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN under normal (non-contingency) conditions..."

Organization	Yes or No	Question 6 Comment
		The Guidance document, as revised for phase II, is important to understand the BES definition. It introduces concepts not explicitly mentioned in the BES definition ("The SDT's intent was that hourly integrated power flow values over the course of the most recent two-year period would be sufficient to make such a demonstration.") However, the guidance document does not have legal standing since it is not FERC approved. We think it should go through the interpretation process for stakeholder review and be integrated into the BES definition with FERC approval.
Response: The SDT feels that Note 1 under Exclusion E1 provides necessary clarity to the exclusion and has determined that the note will be retained. The BES definition is a component-based definition that applies for all operating scenarios (normal operating conditions and contingency conditions). To establish a bright-line aspect to the Exclusion E3 criteria, the SDT developed Exclusion E3b which addresses the power flow at the local network interfaces. This 'operational' criterion was necessary to show that the local network would have minimal impact to the surrounding interconnected Transmission network under the potential scenarios the local network has experienced during the most recent two-year period. An entity who determines that all or a portion of its Facilities meet the local network exclusion should be able to demonstrate, by inspection of actual system data, that flow of power is always into the local network at each point of interface with the BES at all times. The SDT's intent was that hourly integrated power flow values over the course of the most recent two-year period would be sufficient to make such a demonstration and that further study analysis of the local network should be reserved for the BES Exceptions Process. No change made. The BES Reference Document provides a descriptive explanation of the application of the BES definition that supports the understanding and interpretation of a definition. The SDT has developed BES Definition Reference document in accordance with the Standard Process Manual Section 11.0: Process for Approving Supporting Documents. The SDT will be updating the document to reflect that revisions made to the BES definition during Phase 2 of the project. If the commenter wishes to pursue a formal interpretation of the BES definition, the Standard Process Manual provides the procedural steps that are necessary (see Section 7.0: Process for Developing an Interpretation).		
Consumers Energy Company	Yes	Consumers Energy provides comments on the following issue raised by the Phase 2 BES definition: 2) a recommended change to Inclusion I3.Inclusion I3 Should Exclude Blackstart Resources Connected to the BES Only On A Very Limited Basis The Phase 2

Organization	Yes or No	Question 6 Comment
		BES definition (and the Phase 1 BES definition) in Inclusion I3 provides that all Blackstart Resources identified in the Transmission Operator's restoration plan are part of the BES. NERC should modify Inclusion I3 to exclude Blackstart Resources that are only connected to the BES on a very limited basis. NERC should impose requirements on an asset proportional to the asset's impact on the BES. As such, assets that have little-to-no impact on the BES should be subject to only minimal requirements. In the case of Blackstart Resources, some such resources have extremely little impact on the BES during a typical day. For example, some gas peaker units are only connected to the BES for less than 24 hours in a year because they are used only during extreme weather conditions or when the system is actually "black." Given their low impact on the BES, NERC should regulate these units in a way proportional to their limited use. Therefore, Consumers Energy proposes that NERC modify Inclusion I3 to cover "Blackstart Resources identified in the Transmission Operator's restoration plan, unless such a resource is connected to the Bulk Electric System for less than 24 hours per year." This modification would provide the regulation in proportion to these units' impact on the BES.CONCLUSION: WHEREFORE, Consumers Energy Company urges NERC and the Standard Drafting Team for Project 2010-17 to reflect on these comments in developing the proposed Phase 2 BES definition.
Response: Blackstart Resources are defined in the NERC Glossary of Terms Used in Reliability Standards and identified in the NERC Statement of Compliance Registry Criteria as a criterion for functional registration. These resources were the basis for the development of Inclusion I3. The proposed revision would establish criterion that detracts from the bright-line aspect of the definition. The SDT feels that under the situations described by the commenter, the best place to address the commenter's concerns is through the potential revision to the 'Applicability' of the appropriate Reliability Standards.		
Duke Energy	Yes	Duke Energy believes that ambiguity exists between the industry and FERC within the language of E1 regarding "single point of connection". See paragraph 138 and 142 of Order 773. The language "single point of connection" in E1 should be revised for clarity. If E1 is edited, the change may impact the terminology used ("multiple

Organization	Yes or No	Question 6 Comment
		points of connection") in E3.
Response: Based on the development record of the Phase 1 definition and the 'Commission Determination' from Order 773 (paragraph 142), the SDT feels that the language in Exclusion E1 regarding 'single point of connection' is sufficiently clear to ensure consistent application of the BES definition on a continent-wide basis. Additionally the BES Reference Document provides further explanation of what constitutes a 'single point of connection'. Section III.1, BES Exclusion E1, Part 'Single point of connection' states: "For example, the start of the radial system may be a hard tap of the Transmission line, or could be the tap point within a ring or breaker and a half bus configuration. No change made.		
SPP Standards Review Group	Yes	E3 has been changed in response to a FERC directive to remove the lower bound for LNs of 100 kV. While the removal does directly address the directive from FERC, the removal of the 100 kV lower limit may bring other questions, issues and uncertainty into consideration. In E1, the SDT developed an alternative response to a directive which appears to be a very good work-around. Although we don't have specific language to offer, could the SDT develop a similar alternative for E3 without totally eliminating the existing 100 kV limit? Regarding the 30 kV limit in Note 2 of E1, does incorporating this value in the Note imply or could it be interpreted that these particular 30-100 kV looping facilities would become part of the BES? Although they aren't specifically addressed in any of the Inclusions, perhaps it would be appropriate to specifically state that they would not be included. If an entity had two 115 kV radial lines and adds a looping 34.5 kV line between them that is operated normally closed, are these facilities considered radial lines subject to E1 or Local Networks subject to E3?
Response: Although Note 2 is directly linked to Exclusion E1 in the definition, the threshold value is a direct reflection of what constitutes a local network. The presence of sub-100 kV loops below the threshold value, for example, a $\leq$30 kV loop, does not affect the ability to apply the criteria of Exclusion E1 to the subject facilities. However for loops that operate at a voltage of >30 kV, the subject facilities are required to be evaluated based on the criteria of Exclusion E3 (local networks). Therefore, no clarification is necessary in regards to the language in Exclusion E3.		

Organization	Yes or No	Question 6 Comment
The looping facilities that operate at voltages below 100 kV are NOT included in the BES. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process." Based on the proposed threshold value of 30 kV for looped facilities, in the example provided, the configuration would not be subject to the criteria of Exclusion E1 (radial system) and would require evaluation under the criteria of Exclusion E3 (local network).		
Seminole Electric	Yes	Exclusion E1 allows for the exclusion of radials that contain particular amounts of load and generation resources; however, there is no mention of radials that contain reactive devices. Therefore, if a radial falls under Exclusion E1(c) for generation and load, but also has a reactive device, it is unclear whether this Exclusion can be utilized. From past discussions, it appears that E1(c) covers reactive devices; however, Seminole asks that the SDT revise/clarify this Exclusion to specifically include reactive devices.
Response: Exclusion E1 establishes criterion that is based on the presence of Load and generation. Reactive devices are not a determinative factor when assessing a potential radial system for exclusion from the BES. Exclusion E1 does not address reactive devices. Reactive devices are subject to the criteria established by Inclusion I5 and Exclusion E4. No change to Exclusion E1 was made.		
US Bureau of Reclamation	Yes	First, Reclamation suggests that the term "normally open" in E1 Note 1 is vague and should include some type of threshold for what is "normally open" (e.g. 80% of annual operating hours). The Bureau interprets "normally open" to mean under normal conditions rather than under emergency or maintenance conditions. Reclamation believes clarification of the term is necessary to make compliance obligations clear and avoid a variety of regional and entity interpretations about which switches qualify as "normally open." Second, Reclamation believes that certain aspects of Inclusion I2 are quite problematic. Inclusion I2 implies that a generation step-up transformer (GSU) is

Organization	Yes or No	Question 6 Comment
		considered part of the generator in the BES designation by stating that "[g]enerating resource(s) ... including the generator terminals through the high-side of the step up-transformer(s) connected at a voltage of 100 kV or above..." are considered BES. However, this does not address situations where there is more than one transformer before the transmission voltage. For example, a qualifying generator may pass through multiple series transformers, of which only the last has terminals at 100kv or above. The first transformer in the series would be considered the generator step up-transformer but not the other transformers in the series. Such series of transformers could also involve sections of line which then raises the question of how they are classified. A generator greater than 20 MW Generator could be stepped up to some under 100 kV voltage, run some distance to a BES substation and then be transformed at that station to 100 kV or greater voltage. It seems that this would be not deemed a Generation Resource under I2 and would avoid needing to meet any requirements. Finally, in some instances, the Transmission Owner may own, operate, and maintain GSUs. To address this lack of clarity, Reclamation suggests that the drafting team revise the BES definition to better address GSUs in a separate inclusion. In addition, if GSUs with only one terminal over 100kv are considered BES, Reclamation questions why other transformers must have a "primary terminal and at least one secondary terminal operated at 100kv or higher" to be considered BES resources. Third, Reclamation suggests that NERC clarify the relationship between the new BES definition and roles described in the functional model. The Functional Model does not address roles and responsibilities related to transformers. In some instances, a Transmission Owner may own GSUs and it is unclear whether the Generator Owner or Transmission Owner would have compliance responsibility for the GSUs. Finally, Reclamation suggests that NERC define the term "generation resources" to clarify which generator components are considered part of "generation resources."

Organization	Yes or No	Question 6 Comment
Response: Note 1 under Exclusion E1 states: "A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion." Based on the development record of Phase 1 of the project, the industry has not identified any concerns with the clarity of the classification of 'normally open'. This is a standardized term used in the operating realm of the industry and does not need further clarification beyond identification of the device as being a 'normally open' on a print or operating one-line diagram. The step-up transformer(s) associated with generation resources are considered part of the generation resource and included in the BES by application of Inclusion I2. The BES Reference Document provides specific examples that address this generation resource concern (See Figures I2-5 and I2-6). In these examples the use of multiple transformers and interconnecting bus work is described for various scenarios. Figure I2-5 describes a generation resource that utilizes multiple step-up transformers and interconnecting bus work that is installed for the sole purpose of stepping up the voltage output of the generator to a voltage of 100 kV or above. Based on this scenario the generation resource is considered to be a BES Element. Figure I2-6 describes a generation resource that utilizes multiple step-up transformers and interconnecting bus work that serves two purposes: first, the interconnecting bus work serves off-site Load at a voltage level <100 kV, and second provides a connection of the generation resource to a voltage level ≥ 100 kV. Based on this scenario the generation resource is not considered to be a BES Element. Transformers identified in Inclusion I1 serve a Transmission function. Step-up transformers associated with generation resources are utilized for the purpose of connecting generation to voltages ≥100 kV. Both classifications of transformers serve a purpose associated with either Transmission reliability or generation resource reliability. No change made. The BES definition is a component-based definition that does not take into account the 'ownership' of a facility. Ownership establishes registration and registration establishes the applicability of Reliability Standards. No change made. Defining the term 'generating resource' is beyond the scope the Project 2010-17. Based on the development record of Phase 1 of the project, the industry has not identified any concerns with the clarity of the term 'generating resource'. The SDT feels that the term is well known in the industry and further clarification is not necessary. No change made.		
City of Anaheim	Yes	For clarity, a minor grammatical change should be incorporated into Inclusion I2. Specifically, a comma should be placed after the word "transformer(s)" and before the phrase "connected at a voltage of 100 kV or above." Thus, Inclusion I2, as revised, should state: Inclusion I2 - Generating resource(s) and dispersed power producing resources, including the generator terminals through the high side of the step-up transformer(s), connected at a voltage of 100 kV or above with: a) Gross

Organization	Yes or No	Question 6 Comment
		individual nameplate rating greater than 20 MVA, orb) Gross plant/facility aggregate nameplate rating greater than 75 MVA.
Response: The proposed revision would change the intent of Inclusion I2. The language "…connected at a voltage of 100 kV or above …" refers to the transformer connection voltage not to the generator connection voltage. No change made.		
ACES Standards Collaborators	Yes	Given that Facilities below 100 kV could be included in the definition of the BES by the BES exception process, the drafting team should consider removing "of 100 kV or higher" from E1. Any radial facility regardless of voltage class should be excluded. By removing the clause, we think it will offer further support to exclude radial facilities below 100 kV that a requester may attempt to add via the BES exception process. We understand the exclusion is intended to apply to the bright line definition of 100 kV which offers further reason to remove the clause. Because it can only ever apply to 100 kV or higher facilities, it is superfluous.
Response: The language "of 100 kV or higher" currently contained Exclusion E1 has been retained from the Phase 1 definition that has been approved by the Commission. Removal of the language does not improve clarity or address issues associated with implementation, therefore the language will be retained in the Phase 2 definition.		
Georgia Transmission Corporation	Yes	GTC recommends the additional clarifier to E4: Reactive Power devices installed for the sole benefit of a retail or wholesale customer.
Response: This proposed revision would potentially exclude every Reactive Power device. The Reactive Power devices that are intended to be excluded by application of Exclusion E4 have specific functionalities/purposes associated with their installations. For example: Power quality applications designed to meet customer strict criteria for voltage tolerances. No change made.		
Arizona Public Service Company	Yes	I5 is still problematic. It only excludes reactive resources which are excluded by E4. We suggest following: "unless excluded by exclusion of E1 to E4". For example there is no justification to include reactive resources connected to a radial system as part of BES which are there to serve the radial system. Since the radial system is not part of BES, why include the reactive resources connected to radial system as part of BES.

Organization	Yes or No	Question 6 Comment
Response: The results of the NERC Planning Committee's (PC) evaluation of the reactive resource threshold contained in the BES definition were presented to the SDT for consideration in developing revisions to the definition in Phase 2. The PC determined that all reactive resources regardless of size are material to the reliability of the BES. The SDT is basing the inclusion of reactive resources on the PC analysis. No change made.		
Iberdrola USA	Yes	It seems counter-intuitive that a 600 MVAR dynamic range SVC directly connected to the 345 kV system would have the 345 kV bus and the 18 kV bus-connected capacitive & reactive equipment be BES, yet the 345/18 kV transformer would not be BES. The NERC "BES Definition Reference Document" is an important aid in interpreting different circumstances of applicability of the BES Definition. It should be kept up to date as the definition changes, with specific examples of applications of those changes. Specific comments on the "Reference Document" are: o For BES Exclusion E2 (behind-the-meter customer-owned generation), the NERC SDT recommends using 1 year of integrated hourly revenue metering to test for flow into the BES of less than 75 MVA. However, for BES Exclusion E3 (local networks), the NERC SDT recommends using 2 years of integrated hourly metering to test for flow into the BES at all points of connection of the candidate local network to the BES. o Several figures seem to have possible exclusions that are not mentioned, in portions of those figures. Specifically: o Figures E1-4a, E1-5, and E1-6 have the same 15 MVA, then 10 MVA generator on the middle left of the diagram that could have its generator lead to the tap point qualify for a radial exclusion; but the tapped lead is shown as BES. The vertical blue line from the 100 kV bus would still be BES. o Figures E1-7a, E1-8a, E1-9, and E1-10 have either radial loads or industrial customers with retail generation on the middle left and right of the diagram that could have their tapped supply lines qualify for a radial exclusion; but the tapped lines are shown as BES. The vertical blue line from the 100 kV bus would still be BES. o Figure S1-9b only considers the 69 kV network as a candidate for a local network exclusion. This is not a valid consideration, because whether or not the red arrows

Organization	Yes or No	Question 6 Comment
		point up or down, the 69 kV system is not BES by nature of the core definition. Moreover, there are not enough points measured to determine flow polarity of the parallel parts of the 138 kV system. It would be necessary to either/also measure 2 other points on the 138 kV network for that network to be a candidate for the local network exclusion. No conclusions or recommendations can be drawn from this example as shown. Figures S1-10, S1-11, and S1-12 show the entire 138 kV loop on the left of the diagram as a local network exclusion (shown as green) - as noted above this is not consistent with FERC Order 773 and 773-A, nor Figures S1-9a and S1-9b.
Response: The SDT determined that the BES is not required to be contiguous in nature. The SDT has addressed the concerns raised by the Commission in Orders 773 & 773A on the topic of contiguity. The SDT appreciates the comments concerning the BES Definition Reference Document; however this comment period concerns the Phase 2 revision of the BES definition. As the SDT gains more certainty in final outcome of the definition development the BES Definition Reference Document will be updated and posted for industry comment.		
New York State Department of Public Service	Yes	NERC has an obligation to provide technical advice to FERC, so that any number provided to FERC by NERC is interpreted as technical advice. A major purpose of the BES Phase II effort was to establish a technical basis for the 100 kV brightline and the 20/75 MVA generation levels. While NERC has provided a report purportedly providing a technical basis for these threshold levels, the report fails to do so. NERC should not include any numbers in any definition or standard for which it cannot provide a technical basis. Surveys do not provide a technical basis. Particularly troublesome is the presentation of alternatives to the 100 kV brightline. The report authors looked at 5 alternatives to establishing a technical basis for determining the bulk system. The report failed to evaluate the methodology historically applied to the NPCC system. If a major NERC region was able to successfully apply their methodology, why was it not evaluated and why would it be impossible to expect other regions to perform a similar analysis as the base for determining the BES?

Organization	Yes or No	Question 6 Comment
Response: The results of the NERC Planning Committee's (PC) evaluation of the various thresholds contained in the BES definition were presented to the SDT for consideration in developing revisions to the definition in Phase 2. The PC determined that all thresholds should remain at the status-quo. The SDT, based on the recommendations from the PC, has opted to retain the original thresholds in the definition.		
Self	Yes	NERC is an international body. The BES SDT in any next version of the Phase 2 definition should take full account of Canadian regulatory frameworks. NERC must consider all jurisdictions. The existing legislated definitions of "distribution" in the Provinces must be allowed for in any definition of BES even if it is though a "local jurisdiction" exception footnote.
Response: Jurisdictional concerns between regulatory authorities are beyond the scope of this project and are not the responsibility of the SDT to resolve. The proper channels exist to address these concerns; however they reside outside of the Standard Development Process.		
Tri-State Generation and Transmission, Inc.	Yes	Notwithstanding the NERC "Review of Bulk Electrical System Definition Thresholds" published in March, 2013, Tri-State continues to believe that there is no reliability benefit to the BES by having no minimum threshold for reactive devices on radial or non-radial systems. Two items in particular give cause for concern about the recommended resolution in the review. First, the review states that, since there is no clear technical justification for the threshold on generator size, any basis for setting a threshold for reactive devices comparable to the BES definition for generators does not have a technical basis. That is in itself a circular, non-technical response, and not a technical reason for not having a threshold for the reactive devices. The other argument that only 5% of the reactive devices would be excluded by using a threshold also has no technical merit. Secondly, the review did not even attempt to analyze what step voltage change a reactive device might have when it is in service. There are multitudes of reasons why a reactive device might be placed at a location and its unavailability may have a very small impact on the reliability of a system. Certainly it could have much less impact on system, especially a radial system, than

Organization	Yes or No	Question 6 Comment
		loss of a 20 MW generator or a 75 MW aggregate plant would have. In addition, Tri-State believes that reactive devices installed on radial systems are equivalent to reactive devices installed for the sole benefit of retail customers (E4) and exclusion E1 should be added to the end of I5, i. e. "... excluded by application of E1 or E4." Tri-State also disagrees with the findings in the same review regarding exclusions of Local Networks. Once again, the alleged lack of a technical basis for BES generator size is used as rationale for not allowing any flow out of a Local Network in Technical Alternative A. There is no technical merit to that argument. The argument for disregarding Technical Alternative B also seems to have no technical basis. Tri-State continues to believe that Local Networks could be excluded based on a minimum percentage of time that real/reactive power may flow out of the network. An unintended consequence of not allowing this to occur may be that entities will begin operating these systems radially to avoid falling under the definition of the BES.
Response: Phase 2 of the project included an evaluation of the thresholds contained in the BES definition. This task was assigned to the NERC Planning Committee (PC). The results of the NERC PC's evaluation were presented to the SDT for consideration in developing revisions to the definition in Phase 2. The content and conclusions drawn by the NERC PC are beyond the control of the SDT. Exclusion E1 establishes criterion that is based on the presence of Load and generation. Reactive devices are not a determinative factor when assessing a potential radial system for exclusion from the BES. Exclusion E1 does not address reactive devices. Reactive devices are subject to the criteria established by Inclusion I5 and Exclusion E4. No change to Exclusion E1 was made.		
New York Power Authority	Yes	Phase 2 of the BES definition process was supposed to address the 100kV threshold, the generator thresholds and the reactive resource thresholds for inclusion or exclusion. No formal studies have shown that these numbers are the correct numbers for this definition. The studies provided under phase 2 had no more technical justification than those discussions by the SDT under phase 1. Being able

Organization	Yes or No	Question 6 Comment
		to have that technical justification provides the support necessary to maintain a reliable transmission system and provides a basis for analysis of reliability by industry participants.
Response: Phase 2 of the project included an evaluation of the thresholds contained in the BES definition. This task was assigned to the NERC Planning Committee (PC). The results of the NERC PC's evaluation were presented to the SDT for consideration in developing revisions to the definition in Phase 2. The content and conclusions drawn by the NERC PC are beyond the control of the SDT.		
American Transmission Company	Yes	Please clarify that E3b is to be applied for normal (intact) and emergency system conditions. Rewording suggestion is as follows: E3b) Power flows only into the LN under normal and emergency conditions and the LN does not transfer energy originating outside the LN for delivery through the LN; Also ATC believes the SDT should include a note to define normal and emergency conditions.
Response: The BES definition is stateless (i.e., normal, emergency, or restorative). No change made. Defining terms such as normal and emergency conditions is beyond the scope of the approved SAR for this project. No change made.		
Southern California Edison	Yes	SCE requests that NERC properly define "non-retail generation." SCE's understanding of the term "non-retail generation" is to describe those generation facilities whose purpose is to exclusively sell power into wholesale markets. This understanding would define Co-Generation facilities as "non-retail," and therefore not counted in the 75 MVA aggregate threshold amount. In addition, the 75 MVA aggregate thresholds defined by the gross nameplate MVA rating of the generators would count generating facilities where the generators individually and/or in aggregate meet the 75 MVA threshold but exports less than 75 MVA to the grid. The clarification of "non-retail" generation is important since summing-up generators producing this power is a major factor for determining what "wires and lines" meet/ don't meet the E1 and E2 Exclusions.

Organization	Yes or No	Question 6 Comment
Response: The SDT provided the following clarification concerning non-retail and retail generation in the BES Definition Reference Document. Non-retail generation is any generation that is not behind a retail customer's meter. Retail generation is behind the meter generation with all or some of the generation serving the on-site Load. Based on the description provided for 'co-generation' facilities, it appears that based on the statement concerning 'exports to the grid'; co-generation facilities are considered to be 'retail' generation and therefore are not included in the aggregate totals for evaluation of radial systems (Exclusion E1) or local networks (Exclusion E3). No change made.		
Sacramento Municipal Utility District	Yes	SMUD remains concerned regarding the limits imposed on local networks. We note that by order 773A, FERC considers this limit to be absolute with no allowance for minimal reverse flows for even brief periods under multiple contingencies. While denying rehearing on this issue, FERC specifically invited Phase 2 to adjust this outcome in paragraph 79 of the order. We also note that the BES Definition Reference would allow very brief flows out of a local network as long as the integrated hourly flow was still into the local network. FERC, however, did not rule on the Reference document, only the definition itself. Even if FERC did allow the language of the Reference document, the first multiple contingency event that results in out flow or through flow for the better part of an hour would cause an excluded network to become immediately included, and subject to standards without any implementation period (assuming 24 months had passed from the effective date of the definition). The Planning Committee provided several options to SDT on this matter. We understand the SDT's reluctance to impose system studies on what is intended to be a simply determined bright line criterion, but the present exclusion is not very useful. SMUD supports including the option of perform one element out ("N-1") contingency at peak conditions or a fixed two year (or longer) window could be used rather than the most recent two year sliding window suggested in the reference document. These options would provide more certainty and better support the reliability of the BES. However it is determined, it should be included within the approved definition so that the reference document disclaimer does not apply. Non-retail generation still lacks a definition to be approved by NERC and FERC, even

Organization	Yes or No	Question 6 Comment
		though this this item was specifically included in the approved SAR. We note that the term is defined in the Reference Document where the disclaimer stating it is not an official position of NERC makes this definition of little value. While the Reference Document states "Non-retail generation is any generation that is NOT behind a retail customer's meter," we continue to hear it defined without the "not." It is very important that entities and regions have a common understanding of the term, and ask the team to include its definition within the BES definition.
Public Utility District No.1 of Snohomish County	Yes	The Public Utility District No.1 of Snohomish County remains concerned regarding the limits imposed on local networks. We note that by order 773A, FERC considers this limit to be absolute with no allowance for minimal reverse flows for even brief periods under multiple contingencies. While denying rehearing on this issue, FERC specifically invited Phase 2 to adjust this outcome in paragraph 79 of the order. We also note that the BES Definition Reference would allow very brief flows out of a local network as long as the integrated hourly flow was still into the local network. FERC, however, did not rule on the Reference document, only the definition itself. Even if FERC did allow the language of the Reference document, the first multiple contingency event that results in out flow or through flow for the better part of an hour would cause an excluded network to become immediately included, and subject to standards without any implementation period (assuming 24 months had passed from the effective date of the definition). The Planning Committee provided several options to SDT on this matter. We understand the SDT's reluctance to impose system studies on what is intended to be a simply determined bright line criterion, but the present exclusion is not very useful. The Public Utility District No.1 of Snohomish County supports including the option of perform one element out ("N-1") contingency at peak conditions or a fixed two year (or longer) window could be used rather than the most recent two year sliding window suggested in the reference document. These options would provide more certainty and better support the reliability of the BES. However it is determined, it should be included within the approved definition so that the reference document disclaimer does not

Organization	Yes or No	Question 6 Comment
		apply. Non-retail generation still lacks a definition to be approved by NERC and FERC, even though this item was specifically included in the approved SAR. We note that the term is defined in the Reference Document where the disclaimer stating it is not an official position of NERC makes this definition of little value. While the Reference Document states “Nonâ€retail generation is any generation that is not behind a retail customer’s meter,” we continue to hear it defined without the “not.” It is very important that entities and regions have a common understanding of the term, and ask the team to include its definition within the BES definition.
Response: Exclusion E3b defines an absolute value associated with power flow from a local network to maintain the bright-line concepts of the definition. The SDT has determined that the best method to quantify the amount of power flow associated with a local network is to evaluate the hourly integrated flows over the most recent 2 year period. Although this allows for some amount of flow from the local network this is considered to be inconsequential when considering the impact of minimal flows over very short periods of time. The 2 year period is recommended as a sliding time frame to account for system changes that periodically occur on any electrical system. For instances that result in a change of BES classification of a subject local network, the entity should contact it’s Regional Entity for the Regional practices that address the situation in question. The disclaimer in the BES Definition Reference Document is under the purview of NERC Legal and is not under the control of the SDT. No change made. The Phase 2 SAR identified the following in regards to clarification associated with non-retail generation. Provide improved clarity to the following: The use of the term “non-retail generation” The SDT provided the following clarification concerning non-retail and retail generation in the BES Definition Reference Document. Non-retail generation is any generation that is not behind a retail customer’s meter. Retail generation is behind the meter generation with all or some of the generation serving the on-site Load. No change made.		
Transmission Access Policy Study Group	Yes	TAPS applauds the SDT’s work to address FERC’s directives on a very accelerated timeline, as well as the SDT’s hard work on this project over the last six years.
Response: Thank you for your support.		

Organization	Yes or No	Question 6 Comment
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	The 2010-17 project webpage indicates that the Planning Committee's March 2013 report addresses the technical justification of threshold values, and that it will be updated by the drafting team after the definition has been revised in Phase 2. In its comments submitted in Project 2010-17 on February 2, 2012 ("Initial Comment Form"), Southern responded to two questions posed by the SDT that asked about the propriety of pursuing technical justification, but did not appear to be directly related to the threshold values. Southern includes those responses here for the SDT's convenience. First, in Question 3 of the Initial Comment Form, the SDT asked whether it should pursue justification that supports the assumption that there is a reliability benefit of a contiguous BES. In Order 773, FERC stated that "it is generally appropriate to have the BES contiguous." (P 167). To the extent that "contiguous" may be considered synonymous with "interconnected", Southern agrees that pursuing technical justification to support such an assumption may be appropriate. Second, in Question 5 of the Initial Comment Form, the SDT asked whether it should pursue technical justification to support including an automatic interrupting device in Exclusions E1 and E3. It is not entirely clear whether this was addressed by FERC in either Order 773 or Order 773-A. As Southern stated in its February 12, 2012 comments, the scope of the term "automatic interrupting device" is unclear and could benefit from some clarification by NERC. To the extent that the term "automatic interrupting device" would constitute gas-operated breakers, as opposed to relays, Southern would agree that such devices, to the extent they are associated with Radial Systems qualifying under Exclusion E1 and Local Networks qualifying under Exclusion E3, should also be excluded from the BES under those exceptions.

Response: The Project page for 2010-17 indicates that the 'technical reference document' will be updated by the SDT after the definition has been revised in Phase 2. This reference is to the BES Definition Reference Document and is not related to the NERC Planning Committee report.

The Phase 2 SAR states the following in regards to the continuity of the BES:

> "The NERC Board of Trustees approved BES Phase 1 definition does not encompass a contiguous BES - Determine if

Organization	Yes or No	Question 6 Comment
there is a need to change this position." In Orders 773 and 773A the Commission provided directives that speak directly to the issue of continuity of the BES. The SDT has addressed the Commission's concerns in regards to embedded BES generation that resides in a radial system or local network. As stated in the comment the Commission feels that it is generally appropriate to have a contiguous BES. Based on the Commission's documented directives the SDT has revised the BES definition accordingly. The Phase 2 SAR posting yielded comments that eliminated automatic interrupting devices (AID) from the scope of the SAR.		
Ameren	Yes	The determination of BES facilities should be straight-forward and easy for both entities and auditors to review and understand. We agree that, implementation of some bright-line criteria to determine BES facilities are in the best interest of reliability. We encourage the SDT to streamline the 78 page BES guidance document because we feel the process of determining BES facilities is still not straight-forward.
Response: The purpose of the BES Definition Reference Document is to assist the industry with the application of the revised definition. The document is intended to provide clarification and explanations for the application of the revised definition in a consistent, continent-wide basis for the majority of BES Elements. The recommended application of the definition is contained in the 'hierarchical application' (Section IV) and provides a step-by-step process for the determination of BES and non-BES Elements. Sections II & III provide examples of the application of the various Inclusions and Exclusions contained in the definition. Although it appears that the number of examples is excessive, the diversity of components comprising the interconnected Transmission network dictates the need to be as detailed as possible to cover the vast majority of situations. With that being said the examples that are provided should not be considered as all inclusive and when industry requests additional clarification that can be provided through additional diagrams the SDT will make every effort to accommodate the request.		
Public Service Enterprise Group	Yes	The issue of requiring facilities that connect BES generation to the grid to be included in the BES was settled by FERC in Order 773. We believe that consistency is needed on the issue of contiguity; furthermore, this was a Phase 2 issue that SDT is supposed to address per its SAR - see page 2 of the SAR which states a portion of the scopes as follows: "The NERC Board of Trustees approved BES Phase 1 definition does not encompass a contiguous BES - Determine if there is a need to change this position." For example, the connection of reactive devices to the grid in the Guidance

Organization	Yes or No	Question 6 Comment
		document (pp. 21-22) are in "black" that "indicates Elements that are not evaluated for the specific inclusion depicted in the individual diagrams being shown." The SDT should complete the activities in its SAR in Phase 2 or explain why it has not.
Response: The Phase 2 SAR states the following in regards to the continuity of the BES: "The NERC Board of Trustees approved BES Phase 1 definition does not encompass a contiguous BES - Determine if there is a need to change this position." In Orders 773 and 773A the Commission provided directives that speak directly to the issue of continuity of the BES. The SDT has addressed the Commission's concerns in regards to embedded BES generation that resides in a radial system or local network. As stated in the comment the Commission feels that it is generally appropriate to have a contiguous BES. Based on the Commission's documented directives the SDT has revised the BES definition accordingly.		
North American Generator Forum Standards Review Team	Yes	The language of the proposed BES definition is rather convoluted and is therefore difficult to apply correctly without the Guidance Document. The FERC order 773/773a-amended Guidance Document is not complete or final for the phase-2 BES definition, however. Its exclusion E1 statement is that of phase-1, not phase-2, for example, and a disclaimer on p.1 states that "...this reference document is outdated. Revisions to the document will be developed at a later date to conform to the definition being developed in Phase 2." It appears that the phase-2 BES definition is being rushed through the approval process, and it would be preferable to take the time to compile a complete and consistent body of documentation before putting the matter up for a vote.
PPL NERC Registered Affiliates	Yes	The language of the proposed BES definition is rather convoluted and is therefore difficult to apply correctly without the Guidance Document. The FERC order 773/773a-amended Guidance Document is not complete or final for the Phase-2 BES definition. Its exclusion E1 statement is that of phase-1, not Phase-2, for example, and a disclaimer on p.1 states that "...this reference document is outdated. Revisions to the document will be developed at a later date to conform to the definition being developed in Phase 2." It appears that the Phase-2 BES definition is

Organization	Yes or No	Question 6 Comment
		being rushed through the approval process, and it would be preferable to take the time to compile a complete and
Response: The SDT appreciates the comments concerning the BES Definition Reference Document; however this comment period concerns the Phase 2 revision of the BES definition. As the SDT gains more certainty in final outcome of the definition development the BES Definition Reference Document will be updated and posted for industry comment. Phase 2 of the project is being conducted in accordance with the Standards Process Manual and the project schedule has been developed to support the implementation of the Phase 2 definition on July 1, 2014.		
Hydro-Quebec TransEnergie	Yes	The main concern about phase 2 definition is that it reduces more than phase 1 definition the possibility of exclusions, and that no proper technical analysis had been given to justify or reduce the proposed threshold. FERC's request should not force obligations on non-US jurisdiction, but non-US jurisdiction should be consulted equally by NERC.
Response: It is not clear from the comments what specific concerns should be considered for potential revision. The SDT recognizes that in being responsive to the Commission directives the scope of the BES has incrementally increased, however the ERO is obligated to address the Commission's concerns and the SDT has determined that the revisions in the proposed definition adequately address these concerns. Jurisdictional concerns between regulatory authorities are beyond the scope of this project and are not the responsibility of the SDT to resolve. The proper channels exist to address these concerns; however they reside outside of the Standard Development Process.		
Delta-Montrose Electric Association	Yes	The proposed BES definitions need more clarification, and the utilities should be granted more time for comments and responses.
Response: Phase 2 of the project is being conducted in accordance with the Standards Process Manual and the project schedule has been developed to support the implementation of the Phase 2 definition on July 1, 2014.		
Northeast Power Coordinating Council	Yes	The specifics of system configurations and applications in the Inclusions and Exclusions should be reviewed to be made less complex. If they are not simplified they can be expected to generate a large number of requests for exclusion

Organization	Yes or No	Question 6 Comment
		consuming resources in regional processing and at the ERO. As an alternative, an updated, conforming Guidance Document clarifying the intent and containing explicit explanations and one-line diagram examples should be provided. The version previously posted does not conform to the Phase 2 changes proposed. Phase 2 of the BES definition process was supposed to address the 100kV threshold, the generator thresholds and the reactive resource thresholds for inclusion or exclusion. No formal studies have shown that these numbers are the correct numbers for this definition. The studies provided under Phase 2 had no more technical justification than those discussions by the Standard Drafting Team in Phase 1. Being able to have that technical justification provides the support necessary to maintain a reliable transmission system and provides a basis for analysis of reliability by industry participants. Based on FERC orders 773 and 773-A and NERC's response to those orders, the value of Note 1 under E1 has been diminished and suggest it be removed. It must be considered that industry has typically considered the terms 'network' and 'contiguous' to exclude elements or facilities that contain a normally open device (switch, breaker, disconnect, etc.) between them. 1) NERC must consider that any new or changes to standards as a result of FERC directives that apply to load reliability and load supply continuity are limited to the FERC jurisdiction only. For example, in Canada, local load reliability requirements are under the authority of local regulators such as the OEB in Ontario. 2) The Implementation Plan does not conflict with the Ontario regulatory practice with respect to the effective date of the standard. It is suggested that this conflict be removed by appending to the effective date wording, after "applicable regulatory approval" in the Effective Dates Section of the Implementation Plan, the following:", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities." The same changes should be made to the first sentence in the Effective Date Section on page 2 of the Definition document.

Organization	Yes or No	Question 6 Comment
		The main concern about the Phase 2 definition is that it reduces more than the Phase 1 definition by the possibility of exclusions, and that no proper technical analysis had been given to justify or reduce the proposed threshold. FERC's request should not force obligations on non-United States jurisdictions. NERC must consult with and treat both United States and non-United States jurisdictions equally.

Response: The purpose of the BES Definition Reference Document is to assist the industry with the application of the revised definition. The document is intended to provide clarification and explanations for the application of the revised definition in a consistent, continent-wide basis for the majority of BES Elements. The recommended application of the definition is contained in the 'hierarchical application' (Section IV) and provides a step –by-step process for the determination of BES and non-BES Elements. Sections II & III provide examples of the application of the various Inclusions and Exclusions contained in the definition. Although it appears that the number of examples is excessive, the diversity of components comprising the interconnected Transmission network dictates the need to be as detailed as possible to cover the vast majority of situations. With that being said the examples that are provided should not be considered as all inclusive and when industry requests additional clarification that can be provided through additional diagrams the SDT will make every effort to accommodate the request.

Phase 2 of the project included an evaluation of the thresholds contained in the BES definition. This task was assigned to the NERC Planning Committee (PC). The results of the NERC PC's evaluation were presented to the SDT for consideration in developing revisions to the definition in Phase 2. The content and conclusions drawn by the NERC PC are beyond the control of the SDT.

The SDT feels that Note 1 under Exclusion E1 provides necessary clarity to the exclusion and has determined that the note will be retained.

After conferring with NERC Legal, the SDT has revised the jurisdictional language.

> This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required the definition shall go ~~into effect~~become effective on the first day of the second calendar quarter after Board of Trustees adoption or as otherwise made effective pursuant to the laws of applicable governmental authorities.

The SDT recognizes that in being responsive to the Commission directives the scope of the BES has incrementally increased, however the ERO is obligated to address the Commission's concerns and the SDT has determined that the revisions in the proposed definition adequately address these concerns.

Organization	Yes or No	Question 6 Comment
Pepco Holdings Inc & Affiliates	Yes	There were many suggestions and comments on the first draft of the BES Reference Document. As the SDT continues to revise the document, it is hoped that the SDT consider including additional figures to provide for clarification. It is recognized that there are probably many individual, unique configurations and that every one of them cannot or should not be included. However, consideration should be given to general clarifications that will aid the entire industry in understanding the details of the definitions application.
Response: Thank you for your comments.		
City of Tacoma	Yes	TPWR remains concerned regarding the limits imposed by b) on local networks. We note that by order 773A, FERC considers this limit to be absolute with no allowance for minimal reverse flows for even brief periods under multiple contingencies. While denying rehearing on this issue, FERC specifically invited Phase 2 to adjust this outcome in paragraph 79 of the order. We also note that the BES Definition Reference would allow very brief flows out of a local network as long as the integrated hourly flow was still into the local network. There is no phase in period for a facility that loses its BES exclusion. For example, should a local network experience multiple contingencies that causes an unusual power flow disqualifying its exclusion, then 24 months should be allowed to resume BES applicability.
Response: Although Exclusion E3b defines an absolute value associated with power flow from a local network to maintain the bright-line concepts of the definition. The SDT has determined that the best method to quantify the amount of power flow associated with a local network is to evaluate the hourly integrated flows over the most recent 2 year period. Although this allows for some amount of flow from the local network this is considered to be inconsequential when considering the impact of minimal flows over very short periods of time. For instances that result in a change of BES classification of a subject local network, the entity should contact it's Regional Entity for the Regional practices that address the situation in question.		
American Electric Power	Yes	Under E3, did the team intend to also eliminate the 100kv threshold from the phrase

Organization	Yes or No	Question 6 Comment
		“LN’s emanate from multiple points of connection at 100 kV or higher to improve the level of service...”?
Response: No, the SDT retained the phrase to maintain the clarity associated with the identification of the multiple points of connection.		
ITC	Yes	Via the information disseminated by the SDT, it appears to us that the drafting team intended the additions to E1 to essentially say that loops between radial systems at voltages over 30 kV are BES and cannot be excluded through the application of E3b. This is an attempt at establishing as much of a bright line as possible and is embodied in Note 2 under E1. We are having trouble seeing this in the proposed standard language. Regardless, to meet this intent the language in E1 needs to be cleaned up and E3b removed. Alternatively, another Inclusion could be added to cover the above 30 kV networked facilities to meet this intent. Further, we don’t agree with establishing a 30 kV bright line for parallel systems, as we envision this being fought in the courts as an encroachment into distribution, and will get bogged down. Rather, something that can be reasonably expected to be adopted now should be proposed so that we can get clarity/alignment with the phase 1 effort and then come back for a phase 3 effort to determine the best process for dealing the sub-100 kV networks. The reference to 30 kV should be removed altogether and the PC recommendations for E3b should be adopted (The PC recommendation follows):(Begin PC quote) ""Real power flows only in the LN from every point of connection to the BES for the system as planned with all lines in service and also for first contingency conditions as per TPL-001-2, Steady State & Stability Performance Planning Events P0, P1, and P2, and the LN does not transfer energy originating outside the LN for delivery through the LN to the BES."""""""" (end of PC quote)Note that the first contingency conditions referred to above must include contingencies of elements within the proposed Local Network in addition to contingencies on the proposed BES. This should be explicitly stated in the standard so there’s no confusion.

Organization	Yes or No	Question 6 Comment
		Finally, TPL-001 indicates that it is the Planning Coordinator and the Transmission Planner responsibilities to perform the studies. For the purposes of application of the proposed exclusion E3b we recommend that one functional entity be responsible for this determination (probably the Planning Coordinator).
Response: The looping facilities that operate at voltages below 100 kV are NOT included in the BES. Order 773, paragraph 155 states: “Thus, the Commission, while disagreeing with NERC’s interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process.” This was reaffirmed by the Commission in Order 773A, paragraph 36: “Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process.” The proposed threshold value of 30 kV for looped facilities, is a qualifier for how the 100 kV and above facilities will be evaluated for potential exclusion, e.g., whether the criteria of Exclusion E1 (radial system) would be used for evaluation or if the looped facilities exceed the threshold value thus requiring evaluation under the criteria of Exclusion E3 (local network). The BES definition is a bright-line component based definition. Due to the diverse nature of the interconnected Transmission network, Introducing study requirements into the bright-line will result in inconsistent results when applied on a continent-wide basis. The SDT believes that evaluation of facilities by performing studies is best suited for the Exception Process and not the application of the definition. No change made.		
Cooper Compliance Corp	Yes	We recommend that the drafting team address what qualifies as a generator Interconnection Facility (Transmission Interface) for those radial lines that connect generation while addressing FERCs concern that generation has to be continuous. We do not believe that distribution facilities that serve load and that also have generation connected to it at 100 kV or above should automatically qualify as Transmission. We recommend that those facilities are Transmission Interface facilities and instead should be treated in the same manner as a Generator Interconnection Facility. We ask that the drafting team include within the definition of Bulk Electric System, the sub BES system otherwise known as the Transmission Interface. We propose the following definition of Transmission Interface: A Transmission Interface are the transmission line continuous from the generation identified in Inclusion I2 and I3 and the static or dynamic devices identified in I5 that

Organization	Yes or No	Question 6 Comment
		absent the generation, static, or dynamic devices would be excluded under E1.
Response: Defining the term 'Transmission interface' is beyond the scope the Project 2010-17. The SDT recommends that the commenter complete and submit a Standard Authorization Request (SAR) identifying the concerns raised here and the proposal to initiate a project to address the concerns.		
Hydro One Networks Inc.	Yes	We suggest NERC must ensure that:1) any new or changes to standards as a result of FERC directives that apply to load supply reliability and/or continuity be limited to the FERC jurisdiction only. In Canada, local load reliability requirements are under the authority of local regulators such as the Ontario Energy Board in the Province of Ontario. 2) An Implementation Plan does not conflict with Ontario regulatory practice with respect to the effective date of the standards. It is suggested that this conflict be removed by appending to the effective date wording, after "applicable regulatory approval" in the Effective Dates Section of the Implementation Plan, to the following effect:", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities." Prior to the wording "In those jurisdiction....".The same changes should be made to the first sentence in the Effective Date Section of the proposed Definition document. 3) In our opinion, SDT has correctly crafted the language in E1 and E3 in the approved definition. However it seems that the BES exception process has not been adequately communicated for "inclusion of facilities" that are not captured by the definition but may be necessary for the BES operation. To address such FERC concerns, NERC should take steps (e.g. directing Regions) to provide assurance to FERC that the exception process will be administered in an effective way by NERC, Regions and the Reliability Coordinators along with Facility Owners to include sub 100 kV system(s) that are a) used for bulk power transfer (not a sink) across the BES from one area to the other or b) are necessary for the operation of interconnected BES in a reliable manner or c) can have an adverse impact on the interconnect BES.

Organization	Yes or No	Question 6 Comment
Response: 1. Jurisdictional concerns between regulatory authorities are beyond the scope of this project and are not the responsibility of the SDT to resolve. The proper channels exist to address these concerns; however they reside outside of the Standard Development Process. 2. After conferring with NERC Legal, the SDT has revised the jurisdictional language. This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required the definition shall go ~~into effect~~become effective on the first day of the second calendar quarter after Board of Trustees adoption or as otherwise made effective pursuant to the laws of applicable governmental authorities. 3. Any assurances made to FERC concerning the BES Exception Process contained in the NERC Rules of Procedure are beyond the responsibilities of the SDT.		
Texas Reliability Entity	Yes	We would like to see a revised Reference Document (and any white papers) posted prior to the ballot so we can fully understand how NERC intends to implement the revised definition before voting. There were some surprises in the Reference Document after Phase 1 was approved by NERC. A revised Reference Document should be part of the ballot package so that all Ballot Pool members can understand exactly what they are voting for (and so the NERC Board can understand what it is approving).
Response: The SDT appreciates the comments concerning the BES Definition Reference Document; however this comment period concerns the Phase 2 revision of the BES definition. As the SDT gains more certainty in final outcome of the definition development the BES Definition Reference Document will be updated and posted for industry comment.		
Northeast Utilities	Yes	While it is recognized that electrical systems operated below 100KV can be configured such that they should require BES treatment (i.e. the 92 KV networked system involved in the 2011 Southern California - Arizona outage), a 30KV threshold is too low to significantly impact the reliable operation of the higher voltage transmission system. We propose increasing this threshold to a voltage in the 40-50KV range.

Organization	Yes or No	Question 6 Comment
		The new Note 2 associated with Exclusion E1 and the changes to E3 have added ambiguity that did not exist before. The base definition does not address sub-100kV contiguous loops. The existing Inclusions do not include sub 100kV contiguous loops either. Note 2 clarifies that as long as the contiguous loop is below 30kV E1 still applies. E3 explains how any sub 30kV contiguous loop could be excluded as a local area network, but there is nothing in the definition to clearly state that contiguous loops operated below 100kV are considered part of the BES unless excluded by E3. An additional Inclusion should be added that specifically includes "all contiguous loop operated below 100kV that is not solely used for the distribute power to load unless excluded by application of Exclusion E1 or E3." The proposed change to the E1 exclusion definition to add Note 2 will require an examination of NU sub-transmission system connections (69KV in CT and 34KV in NH) and their connections to the >100KV transmission systems. Elements >100KV originally categorized as E1 or E3 may become BES inclusions if there is underlying sub-transmission path. A cursory review determine no elements categorized as E1 in CT would be changed; however, 16 of the 30 E1 elements in NH could become BES due to 34KV paths.

Response: The 30 kV value was initially chosen based on a high-level evaluation and was inserted in the definition to introduce the concept to the industry and seek feedback and technical opinions from the industry. Comments and suggestions were received questioning the threshold of 30 kV proposed in Note 2 for Exclusion E1. To address this issue, the SDT has created a white paper that is posted as a supporting document for the second posting of this project which provides a review of regional criteria and contingency load flow analysis and has determined that 50 kV is the technically justifiable voltage threshold and has changed the value in Note 2 to 50 kV. This value represents a nominal voltage level (50 kV) that is between operating voltage levels (46 kV and 55 kV) to e~~i~~nsure that a clear bright-line is established.

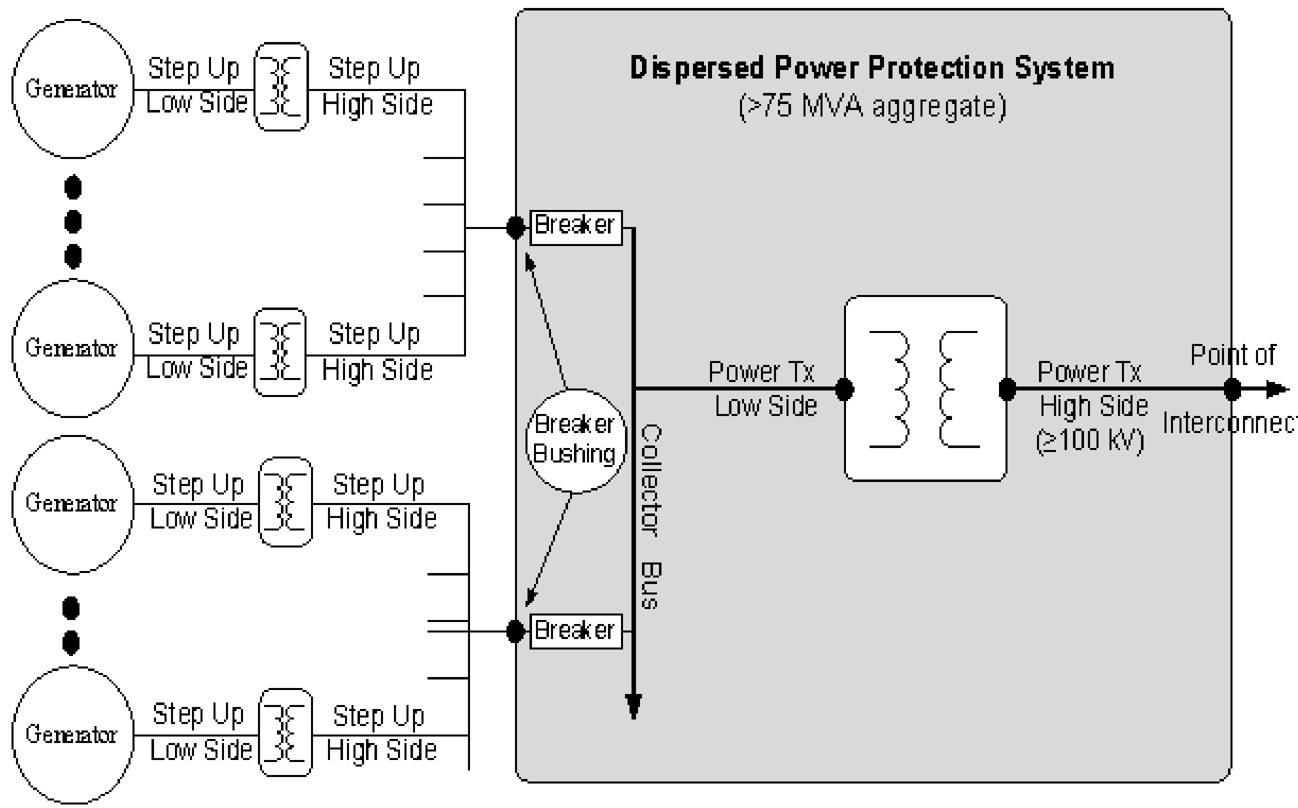
The looping facilities that operate at voltages below 100 kV are NOT included in the BES. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not

Organization	Yes or No	Question 6 Comment
be included in the bulk electric system, unless determined otherwise in the exception process.” The proposed threshold value of 30 kV for looped facilities, is a qualifier for how the 100 kV and above facilities will be evaluated for potential exclusion. For example, whether the criteria of Exclusion E1 (radial system) would be used for evaluation or if the looped facilities exceed the threshold value thus requiring evaluation under the criteria of Exclusion E3 (local network).		
MRO NERC Standards Review Forum (NSRF)	Yes	With E1 (and E3) the SDT has created and “opt-out” process instead of an “opt-in” process. Only a small portion of networked facilities less than 100kV has a material impact on the BES. A better approach would be to utilize the BES process for exceptions and include those that have material impact to the BES. Needlessly processing these sub 100kV systems through the burdensome exclusion process is not effective use of resources. Please clarify that E1 and E3 are to be applied for normal (intact) system conditions. Rewording suggestions are: E1 - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher “under normal conditions...” E3 - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV “under normal conditions” that distribute power to Load rather than transfer bulk power across the interconnected system.
MidAmerican Energy	Yes	With E1 (and E3) the SDT has created and “opt-out” process instead of an “opt-in” process. Only a small portion of networked facilities less than 100kV have a material impact on the BES. A better approach would be to utilize the BES process for exceptions and include those that have material impact to the BES. Needlessly processing these sub 100kV systems through the burdensome exclusion process is not an effective use of resources.
Wisconsin Public Service / Upper Peninsula Power	Yes	With E3 and E1 the SDT has created an “opt-out” process instead of an “opt-in” process. Only a small portion of networked facilities less than 100kV has a material impact on the BES. A better approach would be to utilize the BES process for exceptions and include those that have material impact to the BES. Needlessly processing these sub 100kV systems through the burdensome exclusion process is

Organization	Yes or No	Question 6 Comment
		not an effective use of resources.
Response: The looping facilities that operate at voltages below 100 kV are NOT included in the BES. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process." The proposed threshold value of 30 kV for looped facilities, is a qualifier for how the 100 kV and above facilities will be evaluated for potential exclusion. For example, whether the criteria of Exclusion E1 (radial system) would be used for evaluation or if the looped facilities exceed the threshold value thus requiring evaluation under the criteria of Exclusion E3 (local network).		
Modesto Irrigation District		1. WECC studies have shown that there are thousands of MWs of wind and PV generating plants currently on-line, and thousands of MWs under development, in the WECC system, of 20 MW and less capacity. Ignoring the impacts of these units on the BES would be a mistake, as recent studies by the WECC MVWG (Modeling and Validation Work Group) have shown. 2. The revisions have made the definition of the BES so complicated, that the definition is no longer in a form that can be applied in a straight forward and reasonable manner. Also, there are no technical justifications provided for some of the exclusion criteria (e.g, 75 MVA and 300 kV values).
Response: 1. The SDT feels that the revisions made to the definition provide the needed clarity to properly address the generating resource and dispersed power producing resource concerns identified above. 2. The SDT feels that the proposed revisions have improved clarity of the Phase 1 definition while addressing the directives provided by the Commission in Orders 773 & 773A. Phase 2 of the project included an evaluation of the thresholds contained in the BES definition. This task was assigned to the NERC Planning Committee (PC). The results of the NERC PC's evaluation were presented to the SDT for consideration in developing revisions to the definition in Phase 2. The content and conclusions drawn by the NERC PC are beyond the control of the SDT.		

END OF REPORT

**Diagram from PacifiCorp regarding Q4:



Standard Development Roadmap

This section is maintained by the drafting team during the development of the definition and will be removed when the definition becomes effective.

Development Steps Completed:

1. SAR posted for comment 1/4/12 – 2/3/12
2. SC authorized SAR for development 4/12/12
3. First posting and initial ballot completed 7/12/13

Proposed Action Plan and Description of Current Draft:

This draft is the second comment posting and successive ballot for the Phase 2 revised definition of the Bulk Electric System (BES).

Future Development Plan:

Anticipated Actions	Anticipated Delivery
1. Recirculation ballot	3Q13
2. BOT adoption	4Q13

Project 2010-17 Definition of Bulk Electric System (Phase 2)

Effective Dates

This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the definition shall become effective on the first day of the second calendar quarter after Board of Trustees adoption or as otherwise made effective pursuant to the laws of applicable governmental authorities.

Version History

Version	Date	Action	Change Tracking
1	January 25, 2012	Respond to FERC Order No. 743 to clarify the definition of the Bulk Electric System	N/A
2	TBD	Phase 2 clarifications to the original revisions Respond to directives in FERC Orders 773 and 773-A	Y

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below will be balloted in the same manner as a Reliability Standard. When the approved definition becomes effective, the defined term will be added to the Glossary.

Bulk Electric System (BES): Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.
- **I2** – Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
  a) Gross individual nameplate rating greater than 20 MVA. Or,
  b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.
- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.
- **I4** - Dispersed power producing resources consisting of:
  a) Individual resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and
  b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells. (to be removed from final draft – will be moved to the Reference Document)

- **I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:
  a) Only serves Load. Or,

b) Only includes generation resources, not identified in Inclusions I2, I3, or I4 with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.
Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

Rationale: The drafting team has proposed a threshold of 50 kV or less for loops between radial systems when considering the application of Exclusion E1. The SDT used a two step approach to determine the voltage level. As a first step, regional voltage levels that are monitored on major interfaces, paths, and monitored elements to ensure the reliable operation of the interconnected transmission system were examined to determine the lowest monitored voltage level. Next, power system analyses determined the maximum amount of power that can be transferred through the low voltage systems, when looped, under a worst case scenario at various voltage levels. A formal white paper has been prepared to support this approach and is included with this posting.

- **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.
- **E3** - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

  a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

  b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

- **E4 –** Reactive Power devices installed for the sole benefit of a retail customer(s).

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the definition and will be removed when the definition becomes effective.

Development Steps Completed:

1. SAR posted for comment 1/4/12 – 2/3/12
2. SC authorized SAR for development 4/12/12
3. First posting and initial ballot completed 7/12/13

Proposed Action Plan and Description of Current Draft:

This draft is the ~~first~~second comment posting and ~~initial~~successive ballot for the Phase 2 revised definition of the Bulk Electric System (BES).

Future Development Plan:

Anticipated Actions	Anticipated Delivery
1. Recirculation ballot	3Q13
2. BOT adoption	4Q13

Project 2010-17 Definition of Bulk Electric System (Phase 2)

Effective Dates

This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the definition ~~will go into effect~~ shall become effective on the first day of the second calendar quarter after Board of Trustees adoption or as otherwise made effective pursuant to the laws of applicable governmental authorities.

Version History

Version	Date	Action	Change Tracking
1	January 25, 2012	Respond to FERC Order No. 743 to clarify the definition of the Bulk Electric System	N/A
2	TBD	Phase 2 clarifications to the original revisions Respond to directives in FERC Orders 773 and 773-A	Y

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below will be balloted in the same manner as a Reliability Standard. When the approved definition becomes effective, the defined term will be added to the Glossary.

Bulk Electric System (BES): Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.
- **I2** – Generating resource(s) ~~and dispersed power producing resources,~~ including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
  a) Gross individual nameplate rating greater than 20 MVA~~,~~. O~~R~~r,
  b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.

~~**Rationale for revising I2 to consolidate I2 and I4**: Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells.~~

- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.
- **I4** - ~~Omitted. d~~Dispersed power producing resources consisting of:
  a) Individual resources ~~with~~that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and
  b) The ~~utilizing a~~ system designed primarily for ~~aggregating~~delivering capacity from the point where those resources aggregate to greater than 75 MVA ~~, connected at~~to a common point of connection at a voltage of 100 kV or above.

Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells. (to be removed from final draft – will be moved to the Reference Document)

- **I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:
    a) Only serves Load. Or,
    b) Only includes generation resources, not identified in Inclusions I2, ~~or~~ I3, or I4 with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,
    c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, ~~or~~ I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

    Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.
    Note 2 – The presence of a contiguous loop, operated at a voltage level of ~~30~~50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

    Rationale: The drafting team has proposed a threshold of ~~3~~50 kV or less for loops between radial systems when considering the application of Exclusion E1. The SDT used a ~~three~~two step approach to determine the voltage level. As a first step, regional voltage levels that are monitored on major interfaces, paths, and monitored elements to ensure the reliable operation of the interconnected transmission system were examined to determine the lowest monitored voltage level. Next, power system analyses determined the maximum amount of power that can be transferred through the low voltage systems, when looped, under a worst case scenario at various voltage levels. ~~Finally, examination of design considerations that the industry deploys to prevent loop flow through low voltage systems at the various voltage levels confirms that protection is implemented to prevent such flows through low voltage looped systems.~~ A formal white paper ~~is being~~has been prepared to support this approach and is included with this posting.

- **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing

Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

- **E3** - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:
  a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, ~~or~~ I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);
  b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and
  c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).
- **E4** – Reactive Power devices installed for the sole benefit of a retail customer(s).

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

~~**Explanation of changes:**~~ Not needed this posting – will explain changes in one place, the background section of the comment form.

- ~~**I1** – Made a non-material semantic change to provide greater clarity as suggested by industry comments.~~
- ~~**I2** – (1) Split the inclusion into an 'a' and 'b' as suggested by industry to clarify that this is an 'or' statement. This is not shown in redline as it is strictly a structure change and redlining this would mask the changes made for dispersed power producing resources. (2) Added the dispersed power producing resources phrase to provide clarity as to the inclusion of such resources herein and to continue to provide the granularity for these resources noted in FERC Orders 773 and 773-A. (3) Added a brief rationale for the revision to I2. The text box will be removed from the final filed version of the definition. The text box language will be placed in the appropriate section(s) of the Reference Document when that document is revised for Phase 2.~~
- ~~**I4** – Omitted this as a separate inclusion as it is no longer needed with the inclusion of dispersed power producing resources in Inclusion I2. Since Inclusion I2 includes what is being referred to as generator interconnection facilities, a separate inclusion to handle collector systems is not needed. The numbering of the inclusions has been retained so as not to invalidate software tools developed for the Phase 1 definition.~~
- ~~**I5** – Made a semantic addition to provide clarity as suggested by industry comments.~~
- ~~**E1** – Added Note 2 on looped configurations, which provides a floor below which an entity does not have to consider the loop in its determination of a radial system. Preliminary justification for the value is shown in separate supporting documents for this posting, and a brief description of the rationale is included in a text box within E1. A formal white paper will be developed justifying this approach. The language in the text box will be deleted from the final filed definition and will be included in the appropriate sections of the Reference Document.~~
  - ~~**E1 b) and c)** – Changed to address directives in Orders 773 and 773-A for generator interconnection facilities. The "…with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating)" language remains in the definition even with the addition of Inclusion I2 as it refers to the aggregate of multiple sites along the radial.~~
- ~~**E3** – (1) Addressed directive in Orders 773 and 773-A by deleting the 'or above 100 kV but' phrasing. (2) Semantic change replacing 'retail customer Load' with 'retail customers' to provide clarity as suggested by industry comments.~~

Implementation Plan for Project 2010-17: Definition of BES (Phase 2)

Prerequisite Approvals
There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this project can be implemented.

Effective Dates
This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required the definition shall go become effective on the first day of the second calendar quarter after Board of Trustees adoption or as otherwise made effective pursuant to the laws of applicable governmental authorities.

Compliance obligations for the Phase 2 definition would begin:

- Twenty-four months after the applicable effective date of the definition (for newly identified Elements), or
- If a longer timeframe is needed for an entity to be fully compliant with all standards applicable to an Element or group of Elements that are newly identified as BES when the Phase 2 definition is applied, the appropriate timeframe may be determined on a case-by-case basis by mutual agreement between the Regional Entity and the Element owner/operator, and subject to review by the ERO.

This implementation plan is consistent with the timeframe provided in Phase 1.

Implementation Plan for Project 2010-17: Definition of BES (Phase 2)

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this project can be implemented.

Effective Dates

This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required the definition shall go ~~into effect~~become effective on the first day of the second calendar quarter after Board of Trustees adoption or as otherwise made effective pursuant to the laws of applicable governmental authorities.

Compliance obligations for the Phase 2 definition would begin:

- Twenty-four months after the applicable effective date of the definition (for newly identified Elements), or
- If a longer timeframe is needed for an entity to be fully compliant with all standards applicable to an Element or group of Elements that are newly identified as BES when the Phase 2 definition is applied, the appropriate timeframe may be determined on a case-by-case basis by mutual agreement between the Regional Entity and the Element owner/operator, and subject to review by the ERO.

This implementation plan is consistent with the timeframe provided in Phase 1.

Bulk Electric System Radial Exclusion (E1)
Low Voltage Loop Threshold

Executive Summary

The Project 2010-17 Standard Drafting Team (SDT) conducted a two-step study process to yield a technical justification for the establishment of a voltage threshold below which sub-100 kV loops do not affect the application of Exclusion E1. This analysis provides an equally effective and efficient alternative to address the Federal Energy Regulatory Commission's (Commission or FERC) directives expressed in Order No. 773 and 773-A. The analysis establishes that a 50 kV threshold for sub-100 kV loops does not affect the application of Exclusion E1. Furthermore, this approach will ease the administrative burden on entities to prove that they qualify for an exclusion.

Introduction

In Order No. 773 and 773A, the Commission expressed concerns that facilities operating below 100 kV may be required to support the reliable operation of the interconnected transmission system. The Commission also indicated that additional factors beyond impedance must be considered to demonstrate that looped or networked connections operating below 100 kV need not be considered in the application of Exclusion E1.[1] This document responds to the Commission's concerns and provides a technical justification for the establishment of a voltage threshold below which sub-100 kV equipment need not be considered in the evaluation of Exclusion E1.

*NOTE: This justification does not address whether sub- 100 kV systems should be evaluated as Bulk Electrical System (BES) Facilities. Sub- 100 kV systems are already excluded from the BES under the core definition. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process." Sub- 100 kV facilities will only be included as BES Facilities if justified under the NERC Rules of Procedure (ROP) Appendix 5C Exception Process.*Study Methodology

The justification for establishing a lower voltage threshold for application of Exclusion E1 consisted of a two-step technical approach:

Step 1: A review was performed to determine the minimum voltage levels that are monitored by Balancing Authorities, Reliability Coordinators, and Transmission Operators for Interfaces, Paths, and Monitored Elements. This minimum voltage level reflects a value that industry experts consider necessary to monitor and facilitate the operation of the Bulk Electric System (BES). This step provided a technically sound approach to screen for a minimum voltage limit that served as a starting point for the technical analysis performed in Step 2 of this study.

Step 2: Technical studies modeling the physics of loop flows through sub-100 kV systems were performed to establish which voltage level, while less than 100 kV, should be considered in the evaluation of Exclusion E1.

[1] *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 at P155, n.139 (2012); *order on reh'g*, Order No. 773-A, 143 FERC ¶ 61,053 (2013).

Radial Systems Exclusion (E1)

The proposed definition (first posting) of radial systems in the Phase 2 BES Definition (Exclusion E1) was:

A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

a) *Only serves Load. Or,*
b) *Only includes generation resources, not identified in Inclusions I2 and I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,*
c) *Where the radial system serves Load and includes generation resources, not identified in Inclusions I2 and I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).*

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

Note 2 - The presence of a contiguous loop, operated at a voltage level of 30 kV or less[2]*, between configurations being considered as radial systems, does not affect this exclusion.*

[2] The first posting of this Phase 2 definition used a threshold of 30 kV; however as a result of the study work described in this paper, the SDT has revised the threshold to 50 kV for subsequent industry consideration.

STEP 1 – Establishment of Minimum Monitored Regional Voltage Levels

All operating entities have guidelines to identify the elements they believe need to be monitored to facilitate the reliable operation of the interconnected transmission system. Pursuant to these guidelines, operating entities in each of the eight Regions in North America have identified and monitor key groupings of the transmission elements that limit the amount of power that can be reliably transferred across their systems. The groupings of these elements have different names: for instance, Paths in the Western Interconnection; Interfaces or Flowgates in the Eastern Interconnection; or Monitored Elements in the Electric Reliability Council of Texas (ERCOT). Nevertheless, they all constitute element groupings that operating entities (Reliability Coordinators, Balancing Authorities, and Transmission Operators) monitor because they understand that they are necessary to ensure the reliable operation of the interconnected transmission system under diverse operating conditions.

To provide information in determining a voltage level where the presence of a contiguous loop between system configurations may not affect the determination of radial systems under Exclusion E1 of the BES definition, voltage levels that are monitored on major Interfaces, Flowgates, Paths, and ERCOT Monitored Elements were examined. This examination focused on elements owned and operated by entities in the contiguous United States. The objective was to identify the lowest monitored voltage level on these key element groupings. The lowest monitored line voltage on the major element groupings provides an indication of the lower limit which operating entities have historically believed necessary to ensure the reliable operation of the interconnected transmission system. The results of this analysis provided a starting point for the technical analysis which was performed in Step 2 of this study.

Step 1 Approach

Each Region was requested to provide the key groupings of elements they monitor to ensure reliable operation of the interconnected transmission system. This list, contained in Appendix 1, was reviewed to identify the lowest voltage element in the major element groupings monitored by operating entities in the eight Regions. Identification of this lowest voltage level served as a starting point to begin a closer examination into the voltage level where the presence of a contiguous loop should not affect the evaluation of radial systems under Exclusion E1 of the BES definition.

Step 1 Results

An examination of the line listings of the U.S. operating entities revealed that the majority of operating entities do not monitor elements below 69 kV as shown in Table 1. However, in some instances elements with line voltages of 34.5 kV were included in monitored element groupings. In no instance was a transmission line element below 34.5 kV included in the monitored element groupings.

Region	Key Monitored Element Grouping	Lowest Line Element Voltage
FRCC	Southern Interface	115
MRO	NDEX	69
NPCC	Total East PJM (Rockland Electric) – Hudson Valley (Zone G)[1]	34.5
RFC	MWEX	69
SERC	VACAR IDC[2]	115
SPP RE	SPSNORTH_STH	115
TRE	Valley Import GTL	138
WECC	Path 52 Silver Peak – Control 55 kV	55

Notes:

1. Two interfaces in NPCC/NYISO have lines with 34.5 kV elements.
2. The TVA area in SERC was not included in the tables attached to this report; however, a review of the Flowgates in TVA revealed monitored elements no lower than 115 kV.

Table 1: Lowest Line Element Voltage Monitored by Region

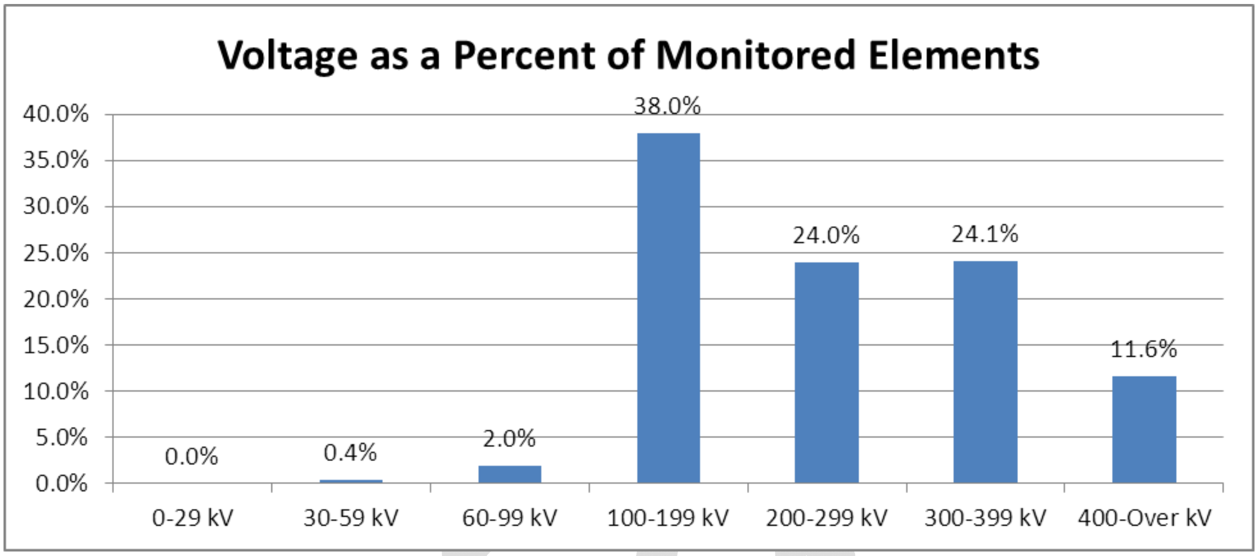
In a few rare occasions there were transformer elements with low-side windings lower than 30 kV included in the key monitored element groupings as shown in Table 2.

Region	Interface	Element	Voltage (kV)
NPCC/NYISO	WEST CENTRAL: Genesee (Zone B) – Central (Zone C)	(Farmtn 34.5/115kV&12/115 kV) #4 34.5/115 & 12/115	12/115
NPCC/ISO-NE	New England - Southwest Connecticut	SOTHNGTN 5X - Southington 115 kV /13.8 kV Transformer (4C-5X)	115/13.8
		SOTHNGTN 6X - Southington 115 kV /13.8 kV Transformer (4C-6X)	115/13.8
		SOTHNGTN 11X - Southington 115 kV /27.6 kV Transformer (4C-11X)	115/27.6

Table 2: Lowest Line Transformer Element Voltages Monitored by Region

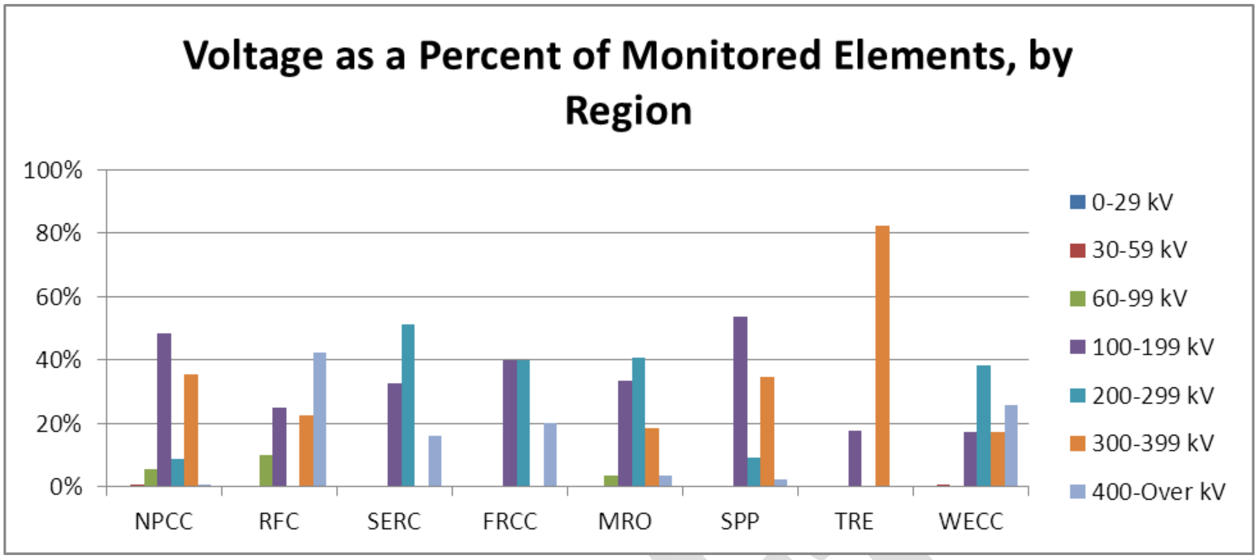
Upon closer investigation, for New England's Southwest Connecticut interface, it was determined that the inclusion of these elements was the result of longstanding, historical interface definitions and not for the purpose of addressing BES reliability concerns. Transformers serving lower voltage networks continue to be included based on familiarity with the existing interface rather than a specific technical concern. These transformers could be removed from the interface definition with no impact on the reliability of the interconnected transmission system. For the New York West Central interface, the low voltage element was included because the interface definition included boundary transmission lines between Transmission Owner control areas; hence, it was included for completeness to measure the power flow from one Transmission Owner control area to the other Transmission Owner control area.

Further examination of the information provided by the eight NERC regions revealed that half of the Regions only monitor transmission line elements with voltages above the 100 kV level. The other four Regions, NPCC, RFC, MRO, and WECC, monitor transmission line elements below 100 kV as part of key element groupings. However, in each of these cases, the number of below 100 kV transmission line elements comprised less than 2.5% of the total monitored key element groupings. Figures 1 and 2 below depict the results of Step 1 of this study.



Notes:
1. Data/Chart includes Transmission Lines only.
2. Data/Chart is a summary of individual elements (interfaces not included)

Figure 1: Voltage as Percent of Monitored Elements



Notes:
1. Data/Chart includes Transmission Lines only.
2. Data/Chart is a summary of individual elements (interfaces not included)

Figure 2: Voltage as Percent of Monitored Elements per Region

Step 1 Conclusion

The results of this Step 1 study regarding regional monitoring levels resulted in a determination that 30 kV was a reasonable voltage level to initiate the sensitivity analysis conducted in Step 2 of this study. This value is below any of the regional monitoring levels.

STEP 2 - Load Flows and Technical Considerations

The threshold of 30 kV was established in Step 1 as a reasonable starting point to initiate the technical sensitivity analysis in Step 2 of this study. The purpose of this step was to determine if there is a technical justification to support a voltage threshold for the purpose of determining whether facilities can be considered to be radial under the BES Definition Exclusion E1. If the resulting voltage threshold was deemed appropriate through technical study efforts, then contiguous loop connections operated at voltages below this value would not preclude the use of Exclusion E1. Conversely, contiguous loops connecting radial lines at voltages above this kV value would negate the ability for an entity to use Exclusion E1 for the subject facilities.

This study focused on two typical configurations: a distribution loop and a sub-transmission loop. The goal was to use these configurations and adjust the various loads, voltages, flows, and impedances to determine the level at which single contingencies on the transmission system would cause flows on the low voltage system. These studies provided the low voltage floor that can be used as a consideration for BES exclusion E1.

NOTE: This justification does not address whether sub- 100 kV systems should be evaluated as Bulk Electrical System (BES) Facilities. Sub- 100 kV systems are already excluded from the BES under the core definition. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process." Sub- 100 kV facilities will only be included as BES Facilities if justified under the NERC Rules of Procedure (ROP) Appendix 5C Exception Process.

Analytical Approach – Distribution Circuit Loop Example

The Project 2010-17 SDT sought to examine the interaction and relative magnitude of flows on the 100 kV and above Facilities of the electric system and those of any underlying low voltage distribution loops. While not the determining factor leading to this study's recommendation, line outage distribution factors (LODF) were a useful tool in understanding the relationship between underlying systems and the BES elements. It illustrated the relative scale of interaction between the BES and the lower voltage systems and its review was a consideration when the study analysis was performed. As an example, the SDT considered a system similar to the one depicted in Figure 3 below. In this simplified depiction of a portion of an electric system, two radial 115 kV lines emanate from 115 kV substations A and B to serve distribution loads via 115 kV/distribution transformers at stations C and D. Stations C and D are "looped" together via either a distribution bus tie (zero impedance) or a feeder tie (modeled with typical distribution feeder impedances).

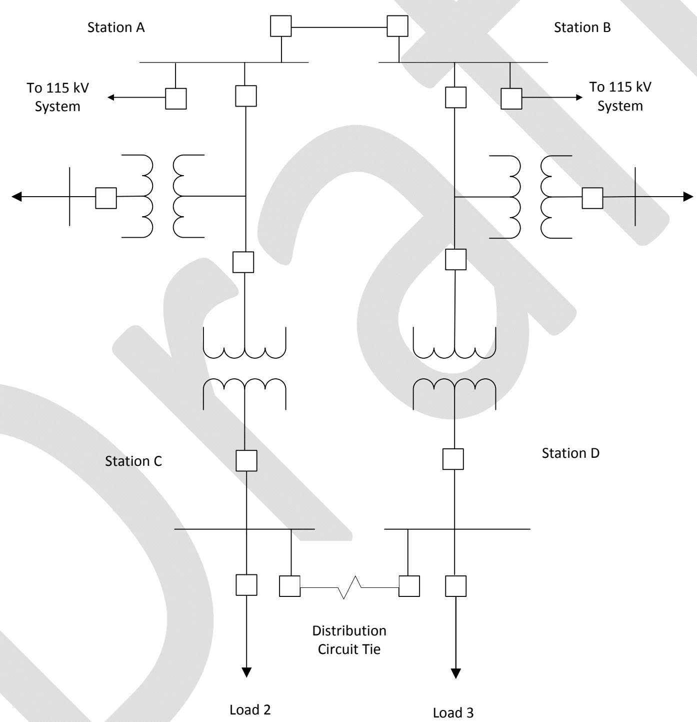


Figure 3: Example Radial Systems with Low Voltage Distribution Loop

With the example system, the SDT conducted power flow simulations to assess the performance of the power system under single contingency outages of the line between stations A and B. The analyses determined the LODF which represent the portion of the high voltage transmission flow that would distribute across the low voltage distribution circuit or bus ties under a single contingency outage of the line between stations A and B. To the extent that the LODF values were negligible, this indicated a minor or insignificant contribution of the distribution loops to the operation of the high voltage system. But, more importantly, the analyses determined whether any instances of power flow reversal, i.e., resultant flow delivered into the BES, would occur during contingent operating scenarios. Instances of flow reversal into the BES would indicate that the underlying distribution looped system is exhibiting behavior similar to a sub-transmission or transmission system, which would call into question the applicability of radial exclusion E1.

The study work in this approach examined the sensitivity of parallel circuit flow on the distribution elements to the size of the distribution transformers, the operating voltage of distribution delivery buses at stations C and D and the strength of the transmission network serving stations A and B as manifested in the variation of the transmission network transfer impedance used in the model.

In order to simply, yet accurately, represent this low voltage loop scenario between two radial circuits, a Power System Simulator for Engineering (PSSE) model was created. Elements represented in this model included the following:

- Radial 115 kV lines from station A to station C and station B to station D;
- Interconnecting transmission line from station A to station B;
- Distribution transformers between 115 kV and the distribution buses at stations C and D;
- Feeder tie impedance to represent a feeder tie (or zero impedance bus tie) between distribution buses at stations C and D;
- Network equivalent source impedances at source stations A and B;
- Transfer impedance equivalent between stations A and B, representing the strength of the interconnected transmission network.

Within this model, parameters were modified to simulate differences in the length and impedance of the transmission lines, amount of distribution load, strength of the transmission network supplying stations A and B, size of the distribution transformers, and the character of the bus or feeder tie at distribution Stations C and D.

Distribution Model Simulation

Table 3 below illustrates the domain of the various parameters that were simulated in this distribution circuit loop scenario. A parametric analysis was performed using all combinations of variables shown in each column of Table 3.

Trans KV	Trans Length	Dist KV	Dist Length	XFMR MVA	Dist Load % rating	Z Transfer
115	10 miles	12.5	0 (bus tie)	10	40	Strong
	30 miles	23	2 miles	20	80	Medium
		34.5	5 miles	40		Weak
		46				

Notes:

1. The "medium" value for transfer impedances was derived from an actual example system in the northeastern US. This was deemed to be representative of a network with typical, or medium, transmission strength. Variations of a stronger (more tightly coupled) and a weaker transmission network were selected for the "strong" and "weak" cases, respectively. Impedance values of X=0.54%, X=1.95%, and X=4.07% were applied for the strong, medium and weak cases, respectively.

Table 3: Model Parameters Varied

The model was exercised in a series of cases simulating a power transfer on the 115 kV line[3] from station A to station B of slightly more than 100 MW. Loads and impedances were simulated at the location shown in Figure 5 of Appendix 2. Two load levels were used in each scenario: 40% of the rating of the distribution transformer and 80% of the rating. Distribution transformer ratings were varied in three steps: 10 MVA, 20 MVA, and 40 MVA. Finally, the strength of the interconnected transmission network was varied in three steps representing a strong, medium, and weak transmission network. The choices of transfer impedance were based on typical networks in use across North America. A specific model from the New England area of the United States yielded an actual transfer impedance of 0.319 + j1.954%. This represents the 'medium' strength transmission system used in the analyses. The other values used in the study are minimum ('strong') and maximum ('weak') ends of the typical range of transfer impedances for 115 kV systems interconnected to the Bulk Electric System of North America. Distribution feeder connections were simulated in three different ways, first with zero impedance between the distribution buses at stations C and D, second with a 2-mile feeder connection with typical overhead conductor, and third with a 5-mile connection.

Distribution Model Results

23 kV Distribution System

The results show LODFs ranging from a low of 0.2% to a high of 6.7%. In all of the cases, the direction of power flow to the radial lines was *toward* stations C and D. In other words, there were no instances of flow reversal from the distribution system back to the 115 kV transmission system.

The lowest LODF was found in the case with the smallest distribution transformers (10 MVA), the 5-mile distribution circuit tie, and the strong transmission transfer impedance. The case with the highest LODF

[3] The threshold voltage of 115 kV provides conservative results. At a higher voltage, such as 230 kV, the reflection of distribution impedance to the transmission system is significantly larger, and hence, the amount of distribution power flow will be much smaller.

was that which used the largest distribution transformers (40 MVA) with the lightest load and the use of a zero-impedance bus tie between the two distribution stations.

12.5 kV Distribution System

As compared to the simulations using the 23 kV distribution system, the 12.5 kV system model yielded far lower LODF values. This result is reasonable, as the reflection of impedances on a 12.5 kV distribution system will be nearly four times as large as those for a 23 kV distribution system, and the transformer sizes in use at the 12.5 kV class are generally smaller, i.e., higher impedance. As with the cases simulated for the 23 kV system, the 12.5 kV system exhibited a power flow direction in the radial line terminals at stations A and B in the direction of the distribution stations C and D; no flow reversal was seen in any of the contingency cases.

Given the lower voltage of the distribution system, the cases studied at this low voltage level were limited to the scenario with the high transfer impedance value ('weak' transmission case). This is a conservative assumption as all cases with lower transfer impedance will yield far lower LODF values. With that, the range of LODF values was found to be 1.0% to 6.7%. When compared with the 23 kV system results in the weak transmission case, the range of LODF values was 1.8% to 6.7%. Higher LODF values were found in the cases with the largest transformer size, which is to be expected.

Table 4 below provides a sample of the results of the various simulations that were conducted. The full collection of results is provided in Appendix 3.

Case	D, KV	Z_{xfer}	Z_{Dist}	XFMR MVA	Load, MW	LODF
623a5	23	strong	5 mi	10	4	0.2%
623a5pk	23	strong	5 mi	10	8	0.3%
633b0pk	23	strong	0	20	16	0.4%
723c0	23	medium	0	40	16	3.4%
723c5pk	23	medium	5 mi	40	32	1.6%
823b0	23	weak	0	20	8	3.8%
823c0	23	weak	0	40	16	6.7%
812a5	12.5	weak	5 mi	10	4	1.0%
812b0	12.5	weak	0	20	8	3.8%
812b5pk	12.5	weak	5 mi	20	16	1.3%
812c0	12.5	weak	0	40	16	6.7%
834a5pk	34.5	weak	5 mi	10	8	1.7%
834b5pk	34.5	weak	5 mi	20	16	3.0%
834d0	34.5	weak	0	40	16	8.9%
834d0pk	34.5	weak	0	40	32	8.7%
846e0	46	weak	0	50	16	10.3%
846e2	46	weak	2 mi	50	20	9.0%
846e5	46	weak	5 mi	50	20	7.4%

Table 4: Select Sample of Study Results for Distribution Scenario

34.5 kV and 46 kV Distribution Systems

As with the analysis done for the 12.5 kV system, a conservative transfer impedance value, that of the 'weak' transmission network, was used in selecting the transfer impedance to be used in the simulations at 34.5 kV and 46 kV. With this conservative parameter, the simulation results show distribution factors (LODF) ranging from a low of 1.7% to a high of 10.3%. In all of the cases, the direction of power flow to the radial lines remained *from* stations A and B *toward* stations C and D. In other words, there were no instances of flow reversal from the distribution system back to the 115 kV transmission system.

Analytical Approach – Sub-transmission Example

In addition to the distribution circuit loop example described above, the study examined the performance of systems typically described as 'sub-transmission'. The study sought to examine the interaction and relative magnitude of flows on the 100 kV and above Facilities of the interconnected transmission system and those of the underlying parallel sub-transmission facilities. The study considered a system similar to the one depicted in Figure 4 below. In this simplified depiction of a portion of a transmission and sub-transmission system, a 40-mile transmission line connecting two sources with transfer impedance between the two sources representing the parallel transmission network. Each source also supplies a 10-mile transmission line with a load tap at the mid-point of the line, each serving a load of 16 MW. At the end of each of these lines is a step-down transformer to the sub-transmission voltage, where an additional load is served. The two sub-transmission stations are connected by a 25-mile sub-transmission tie line. Loads and impedances were simulated at the location shown in Figure 6 of Appendix 2.

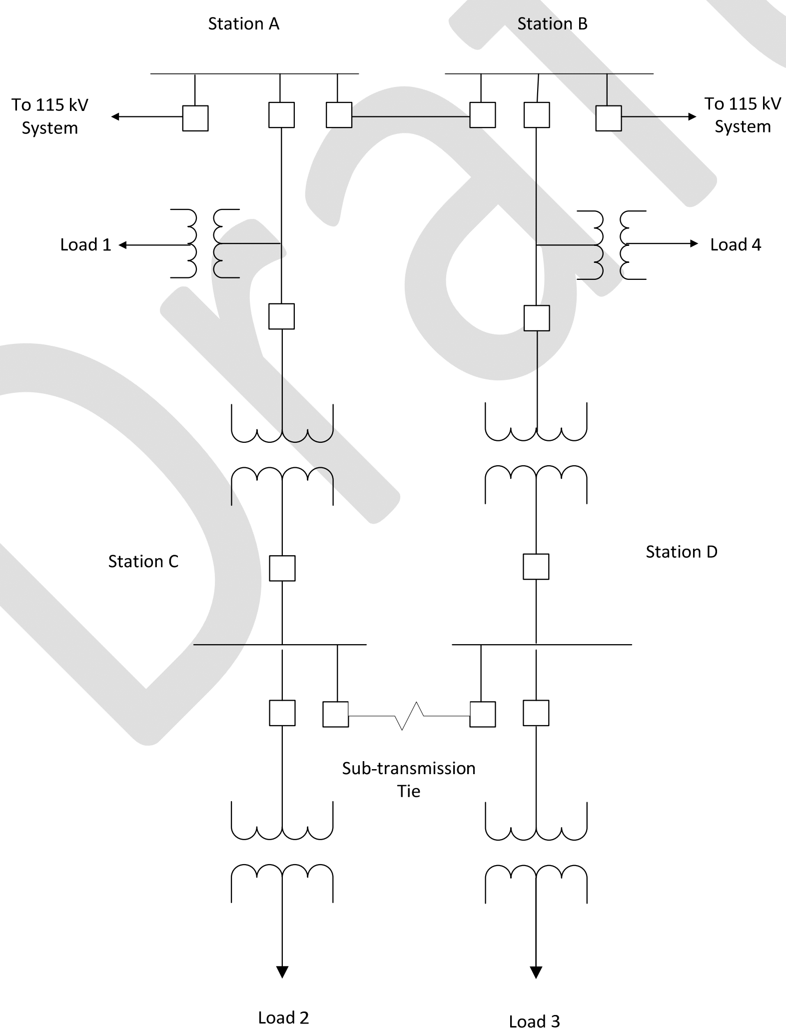


Figure 4: Example Radial Systems with Sub-transmission Loop

Given this example sub-transmission system, a PSSE model was created to simulate the power flow characteristics of the system during a contingency outage of the transmission line between stations A and B. Within this model, parameters were modified to simulate differences in the amount of load being served, transformer size and the amount of pre-contingent power flow on the transmission line. All simulations were performed with a transfer impedance representative of a 'weak' transmission network.

Sub-transmission Model Simulation

Simulations were performed for each sub-transmission voltage (34.5 kV, 46 kV, 55 kV, and 69 kV) using a transmission voltage of 115 kV. This analysis identified the potential for power flowing back to the transmission system only for sub-transmission voltages of 55 kV and 69 kV. Sensitivity analysis was performed using higher transmission voltages to confirm that cases with 115 kV transmission are the most conservative. Therefore, it was not necessary to perform sensitivity analysis for sub-transmission voltages of 34.5 kV and 46 kV for transmission voltages higher than 115 kV.

Table 5 below illustrates the domain of the various parameters that were simulated in this sub-transmission circuit loop scenario. A parametric analysis was performed using combinations of variables shown in each column of Table 5.

Trans KV	Trans Length	Sub-T KV	Sub-T Length	XFMR MVA	Dist Load % rating	Trans MW Preload
115	40 miles	34.5	25 miles	40	40	115
		46		50		
		55		60		
		69				
Sensitivity Analyses:						
138	40 miles	55	25 miles	50	40	115
161		69		60		135
230						150
						220

Table 5: Model Parameters and Sensitivities

Sub-transmission Model Results

115 kV Transmission System with 34.5-69 kV Sub-transmission

The results for cases depicting a 115 kV transmission system voltage and ranges of 34.5 kV to 69 kV sub-transmission voltages show line outage distribution factors (LODF) in the range of 9% to slightly higher than 20%. Several cases show a reversal of power flow in the post-contingent system such that power flow is delivered from the sub-transmission system *into the 115 kV BES*. The worst case is found in the 69 kV sub-transmission voltage class. This result is as expected, given that the impedance of the 69 kV sub-transmission system is less than the impedances of lower voltage systems.

138 kV and 161 kV Transmission Systems with 55-69 kV Sub-transmission

The results for cases of 138 kV and 161 kV transmission system voltages supplying sub-transmission voltages of 55 kV and 69 kV show LODFs ranging from 9% to 16% These cases also result in reversal of power flows in the post-contingent system such that power flow is delivered from the sub-transmission system into the 115 kV BES.

230 kV Transmission System with 55-69 kV Sub-transmission

By simulating a higher BES source voltage of 230 kV paired with sub-transmission voltages of 55 kV and 69 kV, the transformation ratio is sufficiently large to result in a significant increase to the reflected sub-transmission system impedance. Therefore, in these cases, LODFs range from 5% to 7%, and these cases also show no reversal of power flow toward the BES in the post-contingent system.

Table 6 below provides a sample of the results of the various simulations that were conducted. All results are provided in Appendix 3.

Case	T, KV	S-T, KV	Trans Pre-load, MW	XFMR MVA	Load, MW	LODF	Flow Rev to BES?
834d25	115	34.5	115	40	20	9.4%	
846e25	115	46	114	50	20	13.3%	
855e25	115	55	112	50	20	15.7%	Yes
869f25	115	69	110	60	24	20.3%	Yes
855e25-138	138	55	114	50	20	11.7%	
855e25-138’	138	55	134	60	20	11.9%	Yes
869f25-138	138	69	112	60	24	15.6%	Yes
869f25-138’	138	69	132	60	24	15.8%	Yes
855e25-161	161	55	114	50	20	9.1%	
855e25-161’	161	55	155	60	20	9.2%	
869f25-161	161	69	113	60	24	12.5%	
869f25-161’	161	69	153	60	24	12.6%	Yes
855e25-230	230	55	116	50	20	4.9%	
855e25-230’	230	55	219	60	20	5.0%	
869f25-230	230	69	116	60	24	7.0%	
869f25-230’	230	69	218	60	24	7.0%	

Table 6: Select Sample of Study Results for Sub-transmission Scenario

Step 2 Conclusion

Step 2 of this analysis concludes that 50 kV is the appropriate low voltage loop threshold below which sub-100 kV loops should not affect the application of Exclusion E1. Simulations of power flows for the cases modeled in this study show there is no power flow reversal into the BES when circuit loop operating voltages are below 50 kV. This study also finds, for loop voltages above 50 kV, certain cases result in power flow toward the BES. Therefore, the study concludes that low voltage circuit loops operated below 50 kV should not affect the application of Exclusion E1.

Study Conclusion

The Project 2010-17 SDT conducted a two-step study process to yield a technical justification for the establishment of a voltage threshold below which sub-100 kV loops should not affect the application of Exclusion E1. This analysis provides an equally effective and efficient alternative to address the Commission's directives expressed in Order No. 773 and 773-A. It establishes that a 50 kV threshold for sub-100 kV loops does not affect the application of Exclusion E1.

Appendix 1

The information contained in Appendix 1 could be confidential and sensitive to entities and regional organizations and is removed from this draft report.

Appendix 2

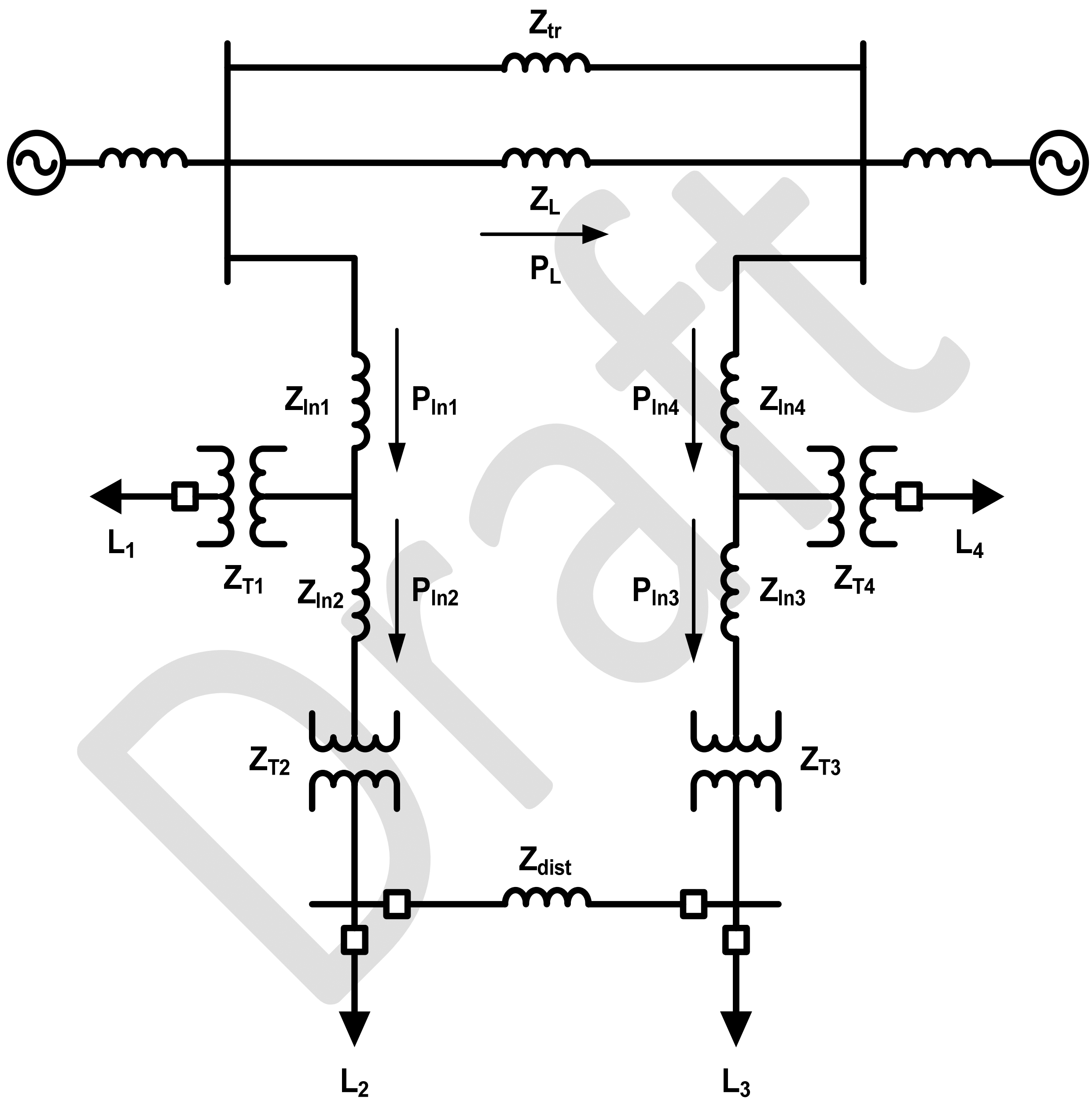


Figure 5: Example Radial Systems with Low Voltage Distribution Tie

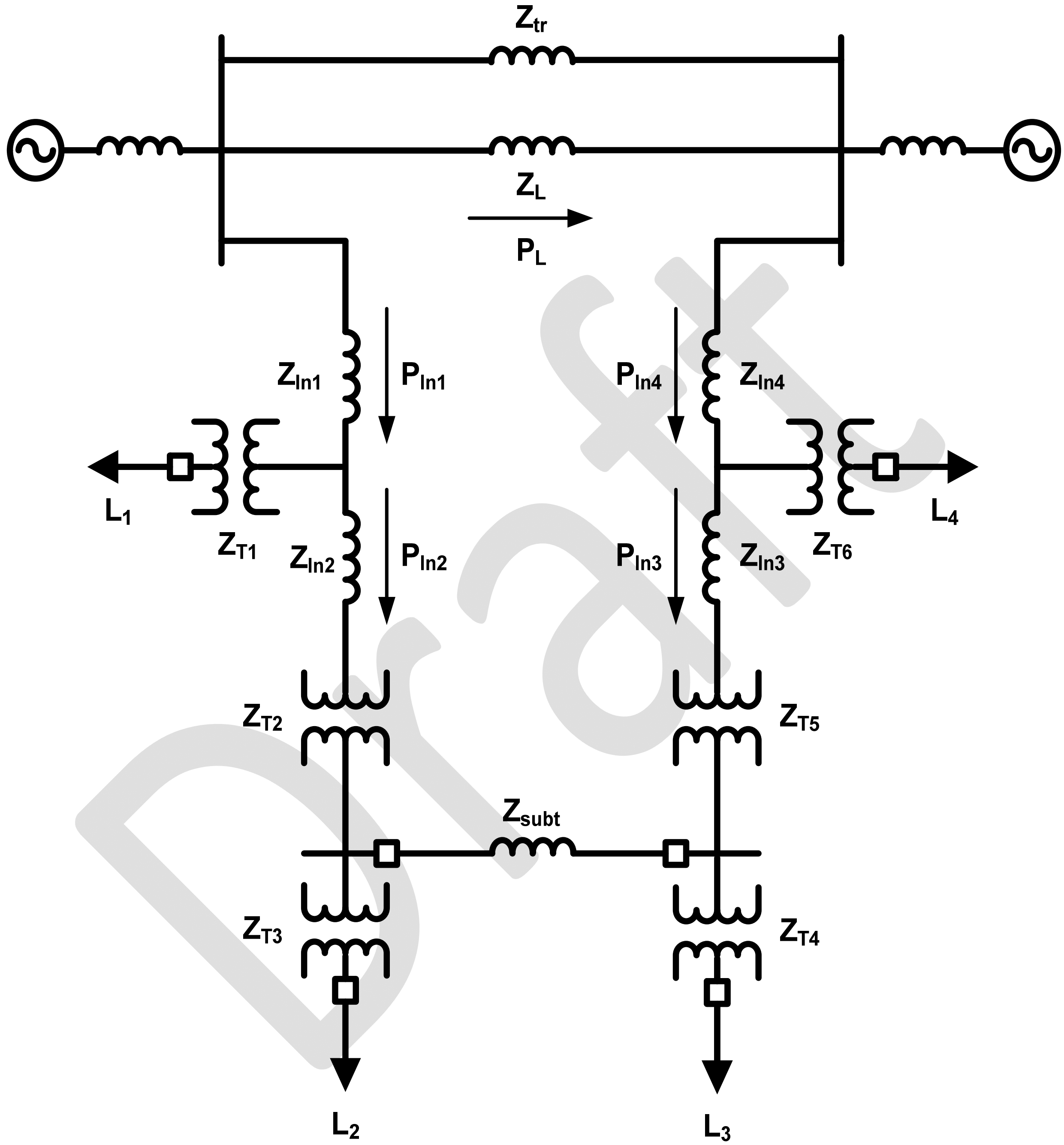


Figure 6: Example Radial Systems with Sub-transmission Tie

Appendix 3

Case	Z_L	Z_{tr}	Z_{ln1-4} (total)	Z_{dist}	Z_{T1-4} (Z/MVA)	L_1, L_4	L_2, L_3	X------- HV Line "L" in-of-service -------X					X- HV Line "L" out-of-service -X				df
								P_L	P_{ln1}	P_{ln2}	P_{ln3}	P_{ln4}	$P_{ln1'}$	$P_{ln2'}$	$P_{ln3'}$	$P_{ln4'}$	
23 kV Base Cases																	
623a0	10 mi	$0.10xZ_L$	15 mi	0	10%/10	4.0	4.0	110.7	10.9	6.9	1.1	5.1	11.2	7.2	0.8	4.8	0.003
623a2	10 mi	$0.10xZ_L$	15 mi	2 mi	10%/10	4.0	4.0	110.7	10.7	6.7	1.4	5.4	10.9	6.9	1.1	5.1	0.002
623a5	10 mi	$0.10xZ_L$	15 mi	5 mi	10%/10	4.0	4.0	110.7	10.3	6.3	1.7	5.7	10.5	6.5	1.5	5.5	0.002
623a0pk	10 mi	$0.10xZ_L$	15 mi	0	10%/10	8.0	8.0	111.4	19.0	10.9	5.1	13.1	19.3	11.2	4.8	12.8	0.003
623a2pk	10 mi	$0.10xZ_L$	15 mi	2 mi	10%/10	8.0	8.0	111.4	18.7	10.7	5.4	13.4	18.9	10.9	5.1	13.1	0.002
623a5pk	10 mi	$0.10xZ_L$	15 mi	5 mi	10%/10	8.0	8.0	111.5	18.3	10.3	5.7	13.7	18.6	10.5	5.5	13.5	0.003
623b0	10 mi	$0.10xZ_L$	15 mi	0	10%/20	8.0	8.0	111.1	21.7	13.7	2.3	10.3	22.3	14.2	1.8	9.8	0.005
623b2	10 mi	$0.10xZ_L$	15 mi	2 mi	10%/20	8.0	8.0	111.2	20.7	12.7	3.3	11.3	21.2	13.2	2.9	10.9	0.004
623b5	10 mi	$0.10xZ_L$	15 mi	5 mi	10%/20	8.0	8.0	111.3	19.7	11.7	4.3	12.3	20.1	12.1	4.0	12.0	0.004
623b0pk	10 mi	$0.10xZ_L$	15 mi	0	10%/20	16.0	16.0	112.6	37.8	21.7	10.3	26.3	38.3	22.3	9.7	25.8	0.004
623b2pk	10 mi	$0.10xZ_L$	15 mi	2 mi	10%/20	16.0	16.0	112.7	36.7	20.7	11.3	27.3	37.2	21.2	10.9	26.9	0.004
623b5pk	10 mi	$0.10xZ_L$	15 mi	5 mi	10%/20	16.0	16.0	112.8	35.7	19.7	12.3	28.4	36.1	20.1	12.0	28.0	0.004
623c0	10 mi	$0.10xZ_L$	15 mi	0	10%/40	16.0	16.0	112.2	42.7	26.6	5.4	21.4	43.7	27.7	4.3	20.3	0.009
623c2	10 mi	$0.10xZ_L$	15 mi	2 mi	10%/40	16.0	16.0	112.5	39.6	23.6	8.4	24.4	40.4	24.4	7.7	23.7	0.007

623c5	10 mi	$0.10xZ_L$	15 mi	5 mi	10%/40	16.0	16.0	112.7	37.3	21.3	10.8	26.8	37.8	21.8	10.3	26.3	0.004
623c0pk	10 mi	$0.10xZ_L$	15 mi	0	10%/40	32.0	32.0	115.1	74.9	42.8	21.2	53.3	76.0	43.9	20.2	52.2	0.010
623c2pk	10 mi	$0.10xZ_L$	15 mi	2 mi	10%/40	32.0	32.0	115.4	71.8	39.7	24.3	56.4	72.6	40.5	23.6	55.6	0.007
623c5pk	10 mi	$0.10xZ_L$	15 mi	5 mi	10%/40	32.0	32.0	115.6	69.4	37.4	26.7	58.8	70.0	37.9	26.2	58.3	0.005
723a0	10 mi	$0.36xZ_L$	15 mi	0	10%/10	4.0	4.0	108.3	10.9	6.9	1.1	5.1	11.9	7.9	0.1	4.1	0.009
723a2	10 mi	$0.36xZ_L$	15 mi	2 mi	10%/10	4.0	4.0	108.3	10.6	6.6	1.4	5.4	11.5	7.5	0.5	4.5	0.008
723a5	10 mi	$0.36xZ_L$	15 mi	5 mi	10%/10	4.0	4.0	108.4	10.3	6.3	1.8	5.8	11.1	7.1	1.0	5.0	0.007
723a0pk	10 mi	$0.36xZ_L$	15 mi	0	10%/10	8.0	8.0	110.4	18.9	10.9	5.1	13.1	20.0	12.0	4.0	12.1	0.010
723a2pk	10 mi	$0.36xZ_L$	15 mi	2 mi	10%/10	8.0	8.0	110.5	18.6	10.6	5.4	13.4	19.6	11.6	4.4	12.5	0.009
723a5pk	10 mi	$0.36xZ_L$	15 mi	5 mi	10%/10	8.0	8.0	110.6	18.3	10.3	5.7	13.7	19.1	11.1	4.9	12.9	0.007
723b0	10 mi	$0.36xZ_L$	15 mi	0	10%/20	8.0	8.0	109.7	21.6	13.6	2.4	10.4	23.6	15.6	0.4	8.4	0.018
723b2	10 mi	$0.36xZ_L$	15 mi	2 mi	10%/20	8.0	8.0	110.0	20.6	12.6	3.4	11.4	22.3	14.3	1.7	9.8	0.015
723b5	10 mi	$0.36xZ_L$	15 mi	5 mi	10%/20	8.0	8.0	110.2	19.7	11.7	4.4	12.4	21.0	13.0	3.1	11.1	0.012
723b0pk	10 mi	$0.36xZ_L$	15 mi	0	10%/20	16.0	16.0	114.0	37.8	21.8	10.2	26.3	39.9	23.8	8.2	24.2	0.018
723b2pk	10 mi	$0.36xZ_L$	15 mi	2 mi	10%/20	16.0	16.0	114.3	36.8	20.8	11.3	27.3	38.5	22.5	9.6	25.6	0.015
723b5pk	10 mi	$0.36xZ_L$	15 mi	5 mi	10%/20	16.0	16.0	114.5	35.8	19.8	12.3	28.3	37.2	21.1	10.9	27.0	0.012
723c0	10 mi	$0.36xZ_L$	15 mi	0	10%/40	16.0	16.0	112.6	42.7	26.7	5.3	21.3	46.5	31.4	1.6	17.6	0.034
723c2	10 mi	$0.36xZ_L$	15 mi	2 mi	10%/40	16.0	16.0	113.5	39.7	23.7	8.4	24.4	42.4	26.4	5.7	21.7	0.024
723c5	10 mi	$0.36xZ_L$	15 mi	5 mi	10%/40	16.0	16.0	114.1	37.4	21.4	10.7	26.7	39.3	23.3	8.8	24.8	0.017

723c0pk	10 mi	0.36xZ_L	15 mi	0	10%/40	32.0	32.0	121.2	75.5	43.4	20.7	52.7	79.5	47.4	16.7	48.7	0.033
723c2pk	10 mi	0.36xZ_L	15 mi	2 mi	10%/40	32.0	32.0	122.0	72.2	40.1	23.9	55.9	75.2	43.1	21.1	53.1	0.025
723c5pk	10 mi	0.36xZ_L	15 mi	5 mi	10%/40	32.0	32.0	122.7	69.8	37.7	26.4	58.5	71.8	39.7	24.4	56.5	0.016
823a0	10 mi	0.75xZ_L	15 mi	0	10%/10	4.0	4.0	106.1	10.8	6.8	1.2	5.2	12.9	8.9	-0.9	3.1	0.020
823a2	10 mi	0.75xZ_L	15 mi	2 mi	10%/10	4.0	4.0	106.2	10.5	6.5	1.5	5.5	12.4	8.4	-0.4	3.6	0.018
823a5	10 mi	0.75xZ_L	15 mi	5 mi	10%/10	4.0	4.0	106.4	10.2	62.0	1.8	5.8	11.9	7.9	0.2	4.2	0.016
823a0pk	10 mi	0.75xZ_L	15 mi	0	10%/10	8.0	8.0	109.6	18.9	10.9	5.1	13.1	21.1	13.0	3.0	11.0	0.020
823a2pk	10 mi	0.75xZ_L	15 mi	2 mi	10%/10	8.0	8.0	109.7	18.6	10.6	5.4	13.4	20.6	12.6	3.5	11.5	0.018
823a5pk	10 mi	0.75xZ_L	15 mi	5 mi	10%/10	8.0	8.0	109.8	18.3	10.3	5.7	13.8	20.0	12.0	4.0	12.1	0.015
823b0	10 mi	0.75xZ_L	15 mi	0	10%/20	8.0	8.0	108.4	21.5	13.5	2.5	10.5	25.6	17.6	-1.6	6.4	0.038
823b2	10 mi	0.75xZ_L	15 mi	2 mi	10%/20	8.0	8.0	108.8	20.6	12.6	3.4	11.4	24.0	16.0	0.1	8.1	0.031
823b5	10 mi	0.75xZ_L	15 mi	5 mi	10%/20	8.0	8.0	109.2	19.6	11.6	4.4	12.4	22.3	14.3	1.8	9.8	0.025
823b0pk	10 mi	0.75xZ_L	15 mi	0	10%/20	16.0	16.0	115.3	37.9	21.9	10.2	26.2	42.2	26.1	5.9	21.9	0.037
823b2pk	10 mi	0.75xZ_L	15 mi	2 mi	10%/20	16.0	16.0	115.7	36.9	20.8	11.2	27.2	40.4	24.4	7.7	23.7	0.030
823b5pk	10 mi	0.75xZ_L	15 mi	5 mi	10%/20	16.0	16.0	116.2	35.9	19.8	12.2	28.2	38.7	22.7	9.4	25.5	0.024
823c0	10 mi	0.75xZ_L	15 mi	0	10%/40	16.0	16.0	113.1	42.7	26.7	5.3	21.3	50.3	34.3	-2.3	13.7	0.067
823c2	10 mi	0.75xZ_L	15 mi	2 mi	10%/40	16.0	16.0	114.4	39.7	23.7	8.3	24.3	45.4	29.3	2.8	18.8	0.050
823c5	10 mi	0.75xZ_L	15 mi	5 mi	10%/40	16.0	16.0	115.5	37.4	21.4	10.6	26.7	41.4	25.4	6.8	22.8	0.035
823c0pk	10 mi	0.75xZ_L	15 mi	0	10%/40	32.0	32.0	126.7	76.0	43.9	20.2	52.2	84.4	52.3	11.8	43.8	0.066
823c2pk	10 mi	0.75xZ_L	15 mi	2 mi	10%/40	32.0	32.0	128.2	72.7	40.6	23.5	55.6	78.9	48.6	17.4	49.5	0.048
823c5pk	10 mi	0.75xZ_L	15 mi	5 mi	10%/40	32.0	32.0	129.3	70.1	38.0	26.1	58.2	74.5	42.4	21.8	53.9	0.034

Sensitivity to Length of Lines 1-4

723a0_30	10 mi	0.36xZ_L	30 mi	0	10%/10	4.0	4.0	108.3	10.8	6.8	1.2	5.2	11.8	7.8	0.2	4.2	0.009
723a2_30	10 mi	0.36xZ_L	30 mi	2 mi	10%/10	4.0	4.0	108.4	10.5	6.5	1.5	5.5	11.4	7.4	0.6	4.6	0.008
723a5_30	10 mi	0.36xZ_L	30 mi	5 mi	10%/10	4.0	4.0	108.5	10.2	6.2	1.8	5.8	11.0	7.0	1.0	5.0	0.007

Selected 34.5 kV cases

834a0	10 mi	0.75xZ_L	15 mi	0	10%/10	4.0	4.0	106.1	10.8	6.8	1.2	5.2	12.9	8.9	-0.9	3.1	0.020
834a2	10 mi	0.75xZ_L	15 mi	2 mi	10%/10	4.0	4.0	106.1	10.7	6.7	1.3	5.3	12.7	8.7	-0.7	3.3	0.019
834a5	10 mi	0.75xZ_L	15 mi	5 mi	10%/10	4.0	4.0	106.2	10.5	6.5	1.5	5.5	12.4	8.4	-0.4	3.6	0.018
834a0pk	10 mi	0.75xZ_L	15 mi	0	10%/10	8.0	8.0	109.6	18.9	10.9	5.1	13.1	21.1	13.0	3.0	11.0	0.020
834a2pk	10 mi	0.75xZ_L	15 mi	2 mi	10%/10	8.0	8.0	109.6	18.8	10.8	5.2	13.3	20.8	12.8	3.2	11.2	0.018
834a5pk	10 mi	0.75xZ_L	15 mi	5 mi	10%/10	8.0	8.0	109.7	18.6	10.6	5.4	13.4	20.5	12.5	3.5	11.5	0.017
834b0	10 mi	0.75xZ_L	15 mi	0	10%/20	8.0	8.0	108.4	21.5	13.5	2.5	10.5	25.6	17.6	-1.6	6.4	0.038
834b2	10 mi	0.75xZ_L	15 mi	2 mi	10%/20	8.0	8.0	108.6	21.1	13.1	2.9	10.9	24.8	16.8	-0.7	7.3	0.034
834b5	10 mi	0.75xZ_L	15 mi	5 mi	10%/20	8.0	8.0	108.9	20.5	12.5	3.5	11.5	23.8	15.8	0.3	8.3	0.030
834b0pk	10 mi	0.75xZ_L	15 mi	0	10%/20	16.0	16.0	115.3	37.9	21.9	10.2	26.2	42.2	26.1	5.9	21.9	0.037
834b2pk	10 mi	0.75xZ_L	15 mi	2 mi	10%/20	16.0	16.0	115.5	37.4	21.4	10.7	26.7	41.3	25.3	6.8	22.8	0.034
834b5pk	10 mi	0.75xZ_L	15 mi	5 mi	10%/20	16.0	16.0	115.8	36.8	20.7	11.3	27.3	40.3	24.2	7.8	23.9	0.030
834c0	10 mi	0.75xZ_L	15 mi	0	10%/40	16.0	16.0	113.1	42.7	26.7	5.3	21.3	50.3	34.3	-2.3	13.7	0.067
834c2	10 mi	0.75xZ_L	15 mi	2 mi	10%/40	16.0	16.0	113.8	41.2	25.2	6.9	22.9	47.8	31.7	0.4	16.4	0.058
834c5	10 mi	0.75xZ_L	15 mi	5 mi	10%/40	16.0	16.0	114.6	39.5	23.5	8.5	24.6	45.0	29.0	3.2	19.2	0.048

834c0pk	10 mi	0.75xZ_L	15 mi	0	10%/40	32.0	32.0	126.7	76.0	43.9	20.2	52.2	84.4	52.3	11.8	43.8	0.066
834c2pk	10 mi	0.75xZ_L	15 mi	2 mi	10%/40	32.0	32.0	127.5	74.2	42.1	21.9	54.0	81.5	49.4	14.7	46.8	0.057
834c5pk	10 mi	0.75xZ_L	15 mi	5 mi	10%/40	32.0	32.0	128.3	72.4	40.3	23.8	55.8	78.5	46.4	17.9	49.9	0.048
834d0	10 mi	0.75xZ_L	15 mi	0	7%/40	16.0	16.0	111.6	46.3	30.3	1.7	17.7	56.2	40.1	-8.1	7.9	0.089
834d2	10 mi	0.75xZ_L	15 mi	2 mi	7%/40	16.0	16.0	112.8	43.6	27.6	4.4	20.4	51.8	35.8	-3.6	12.4	0.073
834d5	10 mi	0.75xZ_L	15 mi	5 mi	7%/40	16.0	16.0	113.9	41.1	25.1	7.0	23.0	47.6	31.6	0.6	16.6	0.057
834d0pk	10 mi	0.75xZ_L	15 mi	0	7%/40	32.0	32.0	124.9	80.0	47.9	16.2	48.2	90.9	58.8	5.3	37.3	0.087
834d2pk	10 mi	0.75xZ_L	15 mi	2 mi	7%/40	32.0	32.0	126.3	77.0	44.9	19.2	51.2	86.1	54.0	10.2	42.2	0.072
834d5pk	10 mi	0.75xZ_L	15 mi	5 mi	7%/40	32.0	32.0	127.5	74.2	42.1	22.0	54.1	81.4	49.3	15.0	47.0	0.056

Selected 12.47 kV cases

812a0	10 mi	0.75xZ_L	15 mi	0	10%/10	4.0	4.0	106.1	10.8	6.8	1.2	5.2	12.9	8.9	-0.9	3.1	0.020
812a2	10 mi	0.75xZ_L	15 mi	2 mi	10%/10	4.0	4.0	106.4	10.1	6.1	1.9	5.9	11.6	7.6	0.4	4.4	0.014
812a5	10 mi	0.75xZ_L	15 mi	5 mi	10%/10	4.0	4.0	106.7	9.4	5.4	2.6	6.6	10.5	6.5	1.5	5.5	0.010
812a0pk	10 mi	0.75xZ_L	15 mi	0	10%/10	8.0	8.0	109.6	18.9	10.9	5.1	13.1	21.1	13.0	3.0	11.0	0.020
812a2pk	10 mi	0.75xZ_L	15 mi	2 mi	10%/10	8.0	8.0	109.9	18.1	10.1	5.9	13.9	19.7	11.7	4.3	12.4	0.015
812a5pk	10 mi	0.75xZ_L	15 mi	5 mi	10%/10	8.0	8.0	110.2	17.5	9.5	6.5	14.5	18.6	10.6	5.5	13.5	0.010
812b0	10 mi	0.75xZ_L	15 mi	0	10%/20	8.0	8.0	108.4	21.5	13.5	2.5	10.5	25.6	17.6	-1.6	6.4	0.038
812b2	10 mi	0.75xZ_L	15 mi	2 mi	10%/20	8.0	8.0	109.4	19.2	11.2	4.8	12.8	21.7	13.6	2.5	10.5	0.023
812b5	10 mi	0.75xZ_L	15 mi	5 mi	10%/20	8.0	8.0	110.0	17.9	9.9	6.1	14.1	19.4	11.4	4.7	12.7	0.014
812b0pk	10 mi	0.75xZ_L	15 mi	0	10%/20	16.0	16.0	115.3	37.9	21.9	10.2	26.2	42.2	26.1	5.9	21.9	0.037

812b2pk	10 mi	$0.75xZ_L$	15 mi	2 mi	10%/20	16.0	16.0	116.4	35.4	19.4	12.6	28.6	38.0	22.0	10.2	26.2	0.022
812b5pk	10 mi	$0.75xZ_L$	15 mi	5 mi	10%/20	16.0	16.0	117.0	34.1	18.0	14.0	30.0	35.6	19.6	12.6	28.6	0.013
812c0	10 mi	$0.75xZ_L$	15 mi	0	10%/40	16.0	16.0	113.1	42.7	26.7	5.3	21.3	50.3	34.3	-2.3	13.7	0.067
812c2	10 mi	$0.75xZ_L$	15 mi	2 mi	10%/40	16.0	16.0	115.9	36.6	20.6	11.5	27.5	40.0	24.0	8.3	24.3	0.029
812c5	10 mi	$0.75xZ_L$	15 mi	5 mi	10%/40	16.0	16.0	116.8	34.4	18.4	13.7	29.7	36.2	20.2	12.0	28.0	0.015
812c0pk	10 mi	$0.75xZ_L$	15 mi	0	10%/40	32.0	32.0	126.7	76.0	43.9	20.2	52.2	84.4	52.3	11.8	43.8	0.066
812c2pk	10 mi	$0.75xZ_L$	15 mi	2 mi	10%/40	32.0	32.0	129.7	69.2	37.1	27.1	59.1	73.0	40.9	23.5	55.5	0.029
812c5pk	10 mi	$0.75xZ_L$	15 mi	5 mi	10%/40	32.0	32.0	130.8	66.7	34.7	29.4	61.5	68.8	36.7	27.6	59.6	0.016

Selected 46 kV cases

846e0	10 mi	$0.75xZ_L$	15 mi	0	7%/50	16.0	20.0	112.1	53.1	37.1	2.9	18.9	64.7	48.7	-8.6	7.4	0.103
846e2	10 mi	$0.75xZ_L$	15 mi	2 mi	7%/50	16.0	20.0	113.2	50.7	34.7	5.3	21.3	60.9	44.8	-4.7	11.3	0.090
846e5	10 mi	$0.75xZ_L$	15 mi	5 mi	7%/50	16.0	20.0	114.3	48.2	32.1	7.9	24.0	56.7	40.7	-0.4	15.6	0.074

Subtransmission cases

115-69 kV

669f25	40 mi	$0.10xZ_L$	20 mi	25 mi	7%/60	16.0	24.0	114.0	76.0	59.8	-10.8	5.2	79.6	63.4	-14.2	1.8	0.032
769f25	40 mi	$0.36xZ_L$	20 mi	25 mi	7%/60	16.0	24.0	111.7	75.3	59.1	-10.1	5.9	87.3	71.0	-21.2	-5.2	0.107
869f25	40 mi	$0.75xZ_L$	20 mi	25 mi	7%/60	16.0	24.0	109.8	74.7	58.5	-9.6	6.4	97.0	80.6	-30.0	-14.0	0.203

115-55 kV

655e25	40 mi	$0.10xZ_L$	20 mi	25 mi	7%/50	16.0	20.0	114.5	62.1	46.0	-5.0	11.0	64.8	48.7	-7.5	8.5	0.024
755e25	40 mi	$0.36xZ_L$	20 mi	25 mi	7%/50	16.0	20.0	113.3	61.8	45.7	-4.8	11.2	70.9	54.8	-13.0	3.0	0.080
855e25	40 mi	$0.75xZ_L$	20 mi	25 mi	7%/50	16.0	20.0	112.1	61.5	45.4	-4.5	11.5	79.1	62.9	-20.2	-4.2	0.157
855f25																	

115-46 kV

646e25	40 mi	0.10xZ_L	20 mi	25 mi	7%/50	16.0	20.0	115.0	57.3	41.2	-0.2	15.8	59.5	43.4	-2.1	13.9	0.019
746e25	40 mi	0.36xZ_L	20 mi	25 mi	7%/50	16.0	20.0	114.6	57.2	41.2	-0.1	15.9	64.9	48.8	-6.8	9.2	0.067
846e25	40 mi	0.75xZ_L	20 mi	25 mi	7%/50	16.0	20.0	114.2	57.2	41.1	0.0	16.0	72.4	56.2	-13.1	2.9	0.133

115-34.5 kV

634d25	40 mi	0.10xZ_L	20 mi	25 mi	7%/40	16.0	16.0	115.3	46.2	30.2	2.6	18.7	47.7	31.7	1.4	17.4	0.013
734d25	40 mi	0.36xZ_L	20 mi	25 mi	7%/40	16.0	16.0	115.4	46.3	30.2	2.6	18.6	51.5	35.5	-1.9	14.1	0.045
834d25	40 mi	0.75xZ_L	20 mi	25 mi	7%/40	16.0	16.0	115.5	46.3	30.2	2.6	18.6	57.1	41.0	-6.4	9.6	0.094

138-69 kV

869f25-138	40 mi	0.75xZ_L	20 mi	25 mi	7%/60	16.0	24.0	112.0	66.5	50.4	-1.8	14.2	84.0	67.9	-18.3	-2.3	0.156
869f25-138'	40 mi	0.75xZ_L	20 mi	25 mi	7%/60	16.0	24.0	131.9	71.1	55.0	-6.3	9.8	92.0	75.8	-25.6	-9.6	0.158

138-55 kV

855e25-138	40 mi	0.75xZ_L	20 mi	25 mi	7%/50	16.0	20.0	113.5	55.1	39.0	1.5	17.5	68.4	52.3	-10.8	5.2	0.117
855e25-138'	40 mi	0.75xZ_L	20 mi	25 mi	7%/60	16.0	20.0	134.0	58.5	42.4	-1.7	14.3	74.4	58.3	-16.2	-0.2	0.119

161-69 kV

869f25-161	40 mi	0.75xZ_L	20 mi	25 mi	7%/60	16.0	24.0	113.2	60.7	44.7	3.7	19.7	74.8	58.8	-9.8	6.2	0.125
869f25-161'	40 mi	0.75xZ_L	20 mi	25 mi	7%/60	16.0	24.0	153.0	68.0	52.0	-3.3	12.7	87.3	71.2	-21.4	-5.4	0.126

161-55 kV

855e25-161	40 mi	0.75xZ_L	20 mi	25 mi	7%/50	16.0	20.0	114.1	50.7	34.7	5.6	21.6	61.1	45.1	-4.2	11.8	0.091
855e25-161'	40 mi	0.75xZ_L	20 mi	25 mi	7%/60	16.0	20.0	154.8	56.0	40.0	0.6	16.6	70.3	54.3	-12.6	3.4	0.092

230-69 kV

869f25-230	40 mi	0.75xZ_L	20 mi	25 mi	7%/60	16.0	24.0	116.3	51.3	35.3	12.8	28.8	59.4	43.3	5.0	21.0	0.070
869f25-230'	40 mi	0.75xZ_L	20 mi	25 mi	7%/60	16.0	24.0	217.7	61.2	45.2	3.2	19.2	76.5	60.4	-11.4	4.7	0.070

230-55 kV

855e25-230	40 mi	$0.75xZ_L$	20 mi	25 mi	7%/50	16.0	20.0	116.1	43.8	27.8	12.3	28.3	49.5	33.5	6.7	22.8	0.049
855e25-230'	40 mi	$0.75xZ_L$	20 mi	25 mi	7%/60	16.0	20.0	218.7	50.8	34.8	5.6	21.6	61.7	45.7	-4.7	11.3	0.050

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

E-mail completed form to:
SARCOMM@nerc.net

Standards Authorization Request

Form

Title of Proposed Standard definition	NERC Glossary of Terms - Phase 2: Revision of the Bulk Electric System
Request Date	December 2, 2011

SAR Requester Information	SAR Type (Check all that apply)	
Name: Project 2010-17 Definition of Bulk Electric System (BES) SDT	☐	New Standard
Primary Contact: Peter Heidrich (Manager of Reliability Standards, FRCC) , Project 2010-17 Definition of Bulk Electric System (BES) SDT Chair	X	Revision to existing Standard
Telephone: (813) 207-7994 Fax: (813) 289-5646	☐	Withdrawal of existing Standard
E-mail: pheidrich@frcc.com	☐	Urgent Action

SAR Information
Industry Need (What is the industry problem this request is trying to solve?)
This project supports the ERO's obligation to identify the Elements necessary for the reliable operation of the interconnected transmission network to ensure that the ERO, the Regional Entities, and the industry have the ability to properly identify the applicable entities and Elements subject to the NERC Reliability Standards.
Purpose or Goal (How does this request propose to address the problem described above?)
Research possible revisions to the definition of BES (Phase 2) to address the issues identified through Project 2010-17 Definition of Bulk Electric System (BES) (Phase 1). The definition encompasses all Elements necessary for the reliable operation of the interconnected transmission network. The definition development may include other improvements to the definition as deemed appropriate by

SAR Information
the drafting team, with the consensus of stakeholders, consistent with establishing a high quality and technically sound definition of the Bulk Electric System (BES).
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?)
Revise the BES definition to identify the appropriate electrical components necessary for the reliable operation of the interconnected transmission network.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
Collect and analyze information needed to support revisions to the definition of Bulk Electric System (BES) developed in Phase 1 of this project to provide a technically justifiable definition that identifies the appropriate electrical components necessary for the reliable operation of the interconnected transmission network. The definition development may include other improvements to the definition as deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing a high quality and technically sound definition of the BES.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Collect and analyze information needed to support revisions to the definition of BES developed in Phase 1 of this project to provide a technically justifiable definition that identifies the appropriate electrical components necessary for the reliable operation of the interconnected transmission network. The definition development will include an analysis of the following issues which were identified during the development of Phase 1 of Project 2010-17 Definition of the BES. Clarification of these issues will appropriately define which Elements are necessary for the reliable operation of the interconnected transmission network. • Develop a technical justification to set the appropriate threshold for Real and Reactive Resources necessary for the reliable operation of the Bulk Electric System (BES) • The NERC Board of Trustees approved BES Phase 1 definition does not encompass a contiguous BES - Determine if there is a need to change this position • Determine if there is a technical justification to revise the current 100 kV bright-line voltage level • Determine if there is a technical justification to support allowing power flow out of the local

SAR Information
network under certain conditions and if so, what the maximum allowable flow and duration should be Provide improved clarity to the following: • The relationship between the BES definition and the ERO Statement of Compliance Registry Criteria established in FERC Order 693 • The use of the term "non-retail generation" • The language for Inclusion I4 on dispersed power resources • The appropriate 'points of demarcation' between Transmission, Generation, and Distribution Phase 2 of the definition development may include other improvements to the definition as deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing a high quality and technically justifiable definition of the BES. Based on the potential revisions to the definition of the BES and an analysis of the application of, and the results from, the exception process, the drafting team will review and if necessary propose revisions to the 'Technical Principles' associated with the Rules of Procedure Exception Process to ensure consistency in the application of the definition and the exception process.

Reliability Functions

The Standard will Apply to the Following Functions (Check box for each one that applies.)		
This section is not applicable as the SAR is for a definition which is about Elements, Applicability of entities is covered in Section 4 of each Reliability Standard.		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.

The Standard will Apply to the Following Functions (Check box for each one that applies.)		
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.

The Standard will Apply to the Following Functions (Check box for each one that applies.)		
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles (Check box for all that apply.)	
X	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
X	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
X	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
X	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
X	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Applicable Reliability Principles (Check box for all that apply.)
Does the proposed Standard comply with all of the following Market Interface Principles? (Select 'yes' or 'no' from the drop-down box.)
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Unofficial Comment Form

Project 2010-17 Definition of Bulk Electric System – Phase 2

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by September 4, 2013.

If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Project Page

Background Information - Project 2010-17 – Definition of the BES (Phase 2)

The SDT has been working on addressing the issues and directives for Project 2010-17 Definition of the BES – Phase 2. The latest output of this work is shown below and in the second posting of the Phase 2 roadmap document. In this second posting, the SDT is responding to industry comments raised in the first posting and initial ballot period. The SDT has made several changes to the definition:

- **Inclusion I2**: Dispersed power producing resources have been taken out of Inclusion I2 and returned to its own separate inclusion (I4). This was done due to confusion on how to address the generator terminal issue for dispersed power producing resources.
- **Inclusion I4**: The SDT has moved dispersed power producing resources back to its own separate inclusion as explained above. In addition, the SDT made a change to accommodate industry concerns on the inclusion of 'collector systems' to address the true reliability concern for loss of 75 MVA aggregated generation.
- **Exclusion E1**:
  - Exclusion E1b - With the re-institution of Inclusion I4, that inclusion needed to be added to the list in E1.
  - Note 2 has been changed from 30 kV to 50 kV per the recommendation in the supporting white paper on sub-100 kV looping analysis which is posted for industry consumption.

Note - The SDT wishes to clarify and emphasize that the looping facilities that operate at voltages below 100 kV are NOT included in the BES. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process." The sub-100 kV looping facilities are only determinative of whether the above 100 kV elements are evaluated for potential exclusion under the criteria set forth in Exclusions E1 or E3. If the less than 100 kV looping facilities include a Normally Open (N.O.) device, then Note 2 does not apply – Note 1 is applicable in that instance.

- **Exclusion E3**:
  - Exclusion E3a - With the re-institution of Inclusion I4, that inclusion needed to be added to the list in E3a.
  - Exclusion E3b - 'Real' has been added to clarify the SDT's intent

- **Exclusion E4**: Pluralized the customer term.

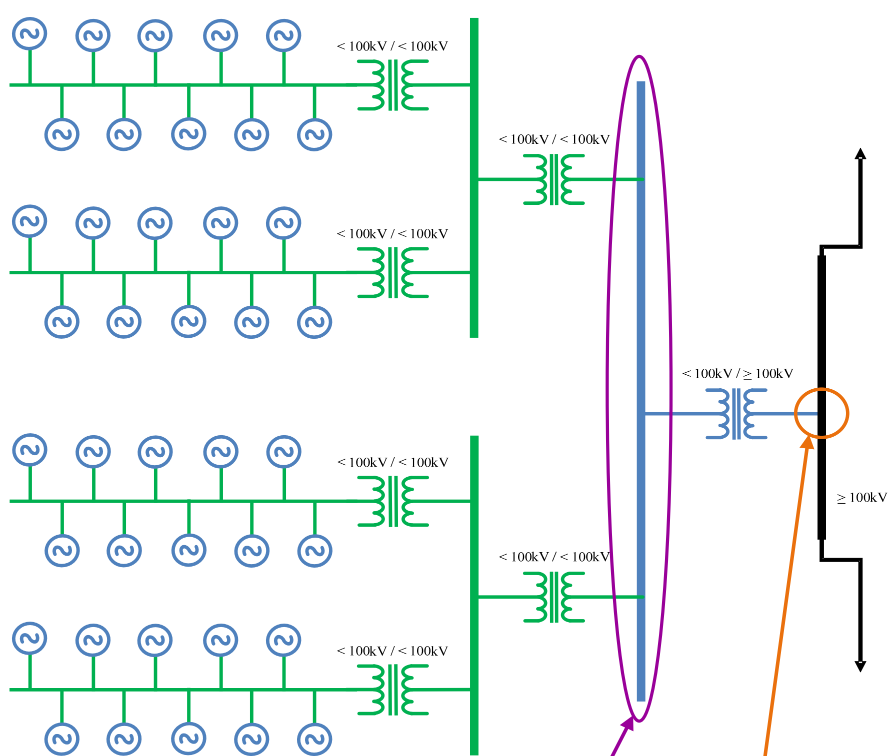
<u>Question 1</u> deals with the changes made to Inclusions I2 and I4. A diagram is provided here for reference on how one particular configuration would be interpreted by the SDT under these revisions. As part of the review of these changes, the SDT wishes to remind the industry that the approved Phase 1 definition included the individual dispersed power producing resources in situations where they aggregated to 75 MVA prior to connecting to the BES. Nothing introduced in Phase 2 has changed this approved condition.

I2 – Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:

I4 - Dispersed power producing resources consisting of:

a) Individual resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and
b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

Typical dispersed generation site and substation design with a gross aggregate nameplate rating of 80 MVA (Individual Generator Unit Rating: 2 MVA). By application of Inclusion I4 the dispersed power producing resources and the Elements from the point of aggregation at 75 MVA to the common point connection are BES Elements.
Green identifies non-BES portions of the Collector System.
Blue identifies the dispersed power producing resources and BES Elements .



The point of aggregation is where the individual generator name plate ratings of the dispersed generation total > 75 MVA (actual 80 MVA) and a single point failure would result in loss of all generation contained on the dispersed generation site.

The common point of connection is where the individual transmission Element(s) of the collector system is connected to the 100 kV or higher Transmission system. (Note: This point is typically specified in the respective Transmission Owner and Generator Operator Interconnection Agreements.)

Question 2 deals with the change from 30 kV to 50 kV in Exclusion E1, Note 2.

Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

The SDT has proposed an equal and effective alternative to the issue of sub-100 kV loop analysis with respect to Exclusion E1. The SDT has proposed a threshold of 50 kV or less for loops between radial systems when considering the application of Exclusion E1. The SDT used a two step approach to determine the voltage level. As a first step, regional voltage levels that are monitored on major interfaces, paths, and monitored elements to ensure the reliable operation of the interconnected transmission system were examined to determine the lowest monitored voltage level. Next, power system analyses determined the maximum amount of power that can be transferred through the low voltage systems, when looped, under a worst case scenario at various voltage levels. A formal white paper has been prepared to support this approach and is included with this posting.

Note - The SDT wishes to clarify and emphasize that the looping facilities that operate at voltages below 100 kV are NOT included in the BES. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process." The sub-100 kV looping facilities are only determinative of whether the above 100 kV elements are evaluated for potential exclusion under the criteria set forth in Exclusions E1 or E3.
Question 3 deals with the clarification to Exclusion E3b on Real Power.

E3b - Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

Question 4 is a generic question added to accommodate any other industry concerns with the proposed Phase 2 definition.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

The SDT has asked one specific question for each specific aspect of the definition.

1. The SDT has separated Inclusion I2 and I4 to provide the clarity requested by the industry in the first posting comments. In addition, again in response to industry comments, the SDT has added language to Inclusion I4b to identify the equipment from an aggregation point of greater than 75 MVA to the connection to the BES. Do you agree with these changes? If not, please provide technical rationale for your disagreement along with suggested language changes.

Yes:

No:

Comments:

2. The SDT has proposed an equally effective and efficient alternative to the Commission's sub-100 kV loop concerns for radial systems by the addition of Note 2 in Exclusion E1 with a threshold value of 50 kV, and posted a technical rationale to support this threshold. Do you agree with this threshold? If you do not support this threshold, please provide specific suggestions and technical rationale in your comments.

   Yes:

   No:

   Comments:

3. The SDT has added the term 'Real' to Exclusion E3b to clarify its intent. Do you agree with this change? If you do not support this change, please provide specific suggestions and technical rationale in your comments.

   Yes:

   No:

   Comments:

4. Are there any other concerns with this definition that haven't been covered in previous questions and comments?

   Yes:

   No:

   Comments:

Notice of Request to Waive the Standard Process

Project 2010-17 Definition of Bulk Electric System

As required by Section 16 of the NERC Standard Processes Manual (SPM), this is official notice to stakeholders that the leadership of the Definition of Bulk Electric System Standards Drafting Team and NERC Standards Staff (Requesters) are requesting that the Standards Committee consider a waiver of the Standard Processes Manual. The Requesters ask to shorten the next formal comment and ballot period, and any subsequent comment formal comment and ballot periods prior to final ballot, from 45 days to 30 days in order to meet a regulatory deadline. Pursuant to Section 16 of the SPM, the Standards Committee may reduce the duration of formal comment periods for good cause shown and to meet a regulatory deadline.

The Standards Committee will meet via teleconference to consider this waiver request no earlier than Thursday, August 1, 2013 (to comply with the five business day notice required by Section 16 of the SPM). The Standards Committee's teleconference will be noticed through an announcement and posted on the NERC website. Additional details about the waiver request are included below, and should a waiver be granted by the Standards Committee, it will be posted on the project page.

Justification for Current Waiver Request

NERC is required to file with FERC no later than December 31, 2013 a revised definition of Bulk Electric System that addresses FERC directives from Orders No. 773 and 773-A.[1] The basis cited in the order for this deadline is the Standard Drafting Team's approved project schedule, which planned for additional comment periods being 30 days duration with the ballot occurring during the last 10 days.

An initial ballot of the revised definition ended on July 12, 2013 and achieved approximately 50% approval. Given the time necessary to address significant volumes of stakeholder comments, the Team's ability to adequately consider comments and develop revisions to reach stakeholder consensus through possibly multiple successive ballots will be significantly limited if the schedule is not revised to accommodate 30-day postings. Thus, without the requested waiver, there is a high degree of risk that NERC will not meet the regulatory deadline.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

[1] *Order Granting Extension of Time*, 143 FERC ¶ 61,231 at P. 16

For more information or assistance, please contact Laura Hussey,
Director of Standards Development, at laura.hussey@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2010-17 Definition of the Bulk Electric System Phase 2

An Additional Ballot is open through September 4, 2013

Now Available

An additional ballot for Phase 2 of the Definition of the Bulk Electric System (DBES) is open through **8 p.m. Eastern on Wednesday, September 4, 2013.**

Background information for this project can be found on the project page.

Instructions

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

As a reminder, this ballot is being conducted under the revised Standard Processes Manual, which requires all negative votes to have an associated comment submitted (or an indication of support of another entity's comments). Please see NERC's announcement regarding the balloting software updates and the guidance document, which explains how to cast your ballot and note if you've made a comment in the online comment form or support another entity's comment.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the definition. If the comments do not show the need for significant revisions, the definition will proceed to a final ballot.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

Individual or group. (65 Responses)
Name (45 Responses)
Organization (45 Responses)
Group Name (20 Responses)
Lead Contact (20 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (5 Responses)
Comments (65 Responses)
Question 1 (57 Responses)
Question 1 Comments (60 Responses)
Question 2 (48 Responses)
Question 2 Comments (60 Responses)
Question 3 (47 Responses)
Question 3 Comments (60 Responses)
Question 4 (49 Responses)
Question 4 Comments (60 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
Yes
Yes
Suggest the following rewording of the Effective Dates section of the Implementation Plan to add clarity regarding approvals: In those jurisdictions where no regulatory approval is required the definition shall become effective on the first day of the second calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws of applicable governmental authorities. In those jurisdictions where no regulatory approval is required the definition shall (go should be deleted) become effective on the first day of the second calendar quarter after Board of Trustees adoption. NPCC participating members suggest that when addressing the requirements pertaining to load reliability and continuity in a standard, they must include that for a non-U.S. Registered Entity it should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-U.S. jurisdiction.
Individual

Thomas Breene
Wisconsin Public Service Corporation
No
We agree with including the Generating stations with dispersed generation from the point of aggregation to 75 MVA as I4-b does. We agree with the statement made on the BES Phase II webinar of August 21 that this is the point where the dispersed power plant is significant to the reliability of the BES. We disagree with including the individual resources themselves since, as indicated on the webinar, they are not significant to the reliability of the BES . Including dispersed power producing resources less than 25MVA ignores differences in engineering design and operating philosophies. For our company each 2MVA wind turbine is designed to sync on and off the grid several times a day. For this reason, the engineering design incorporates a large contactor to handle these operations. This contactor is controlled by the turbine PLC which contains the main protective relay functions (i.e. frequency, over/under voltage, imbalance…etc) traditionally contained in discrete protective relays. A generator breaker is designed in series with the contactor, which includes a self contained overcurrent element that serves as a backup function, but is different in traditional design in that each Protection Component is contained in the breaker device. Due to the PLC control/protection integration, equipment differences, and operating philosophies implementation of NERC Reliability Standards such as PRC-004, PRC-005 and FAC-008 would be impractical and onerous lending little to no reliability improvement. We suggest eliminating I4a completely since, as indicated on the webinar I4b encompasses the portion of the dispersed power generating plant that is significant to the reliability of the BES
Yes
We agree with the 50kv limit since the SDT has posted a reasonable technical rationale.
Yes
No
Individual
Joseph DePoorter
Madison Gas and Electric Company
No
MG&E is voting against the BES Phase II definition due to the fact that it contains Inclusion (I)4a; Individual resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating). MG&E recommends that I4a be removed and I4b be maintained as the point of aggregation is what is modeled and makes the most sense. Recommend I4 to read as: “Dispersed power producing resources consisting of the system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above”. Please see the following

reasons for our negative vote: 1. An individual 1.5 mW wind turbine does not impact the BES when it reduces its output (remember just because a turbine is rated at 1.5mW doesn't mean it automatically reaches that output when the wind blows) or trips offline. Entities have been making comments that the place where power is aggregated (usually the bus) should be included and not individual wind turbines, solar collectors, manure digesters, etc (as shown in the comment form). The amount of compliance time for PRC-004 would never be completed. Wind turbines have up to 250 plus reasons why they can trip. Usually due to the change in wind direction. If the wind changes direction and the turbine head cannot keep up within a certain degree of angle, the unit will trip. Coming back on line when the angle requirements are met. So, Entity's will need to apply the R2 of PRC-004-2a, for every wind turbine trip. We do not have the resources to review these trips and that 1.5 wind turbine does not impact the BES. We will agree that the point of interconnection (of greater than 75 MVA) is important and should be contained in the BES definition as written in I4B. PRC-004-2a is only one Standard, notwithstanding; BAL-001-TRE-01, FAC-001, FAC-003, FAC-008-3, MOD-024, MOD-025, MOD-026, MOD-027, PRC-005, PRC-006-SPP-01, PRC-019, PRC-024, PRC-025, and TOP-003. A 75 MVA wind farm is not equal to a 75 MVA combustion turbine. Yes, energy flow is modeled the same (at full name plate output) but these two extremely different facilities are quite different. The wind facility is not dispatchable (only reduction in Mw output can take place when there is an output) and wind facilities usually are set at a constant power factor and do not adjust for frequency deviations. 2. The SDT has recommended that a SAR be submitted in order to refine the Standards that would be applicable to individual power producing resources contained under I4 of the phase II definition. This response is not acceptable. The SDT should not passively answer an entity's question by stating that a different process "may" fix the issue at hand. Recommend I4a be deleted and I4b be maintained as I4a. During the 8/21/2013 webinar the presenter emphasized the critical nature of the aggregate generation of dispersed power producing resources to the reliability of the interconnected transmission system. I4 subpart (a) is inconsistent with the stated critical nature of the aggregate generation. The presenter also indicated that standards that apply to GO/GOP associated standards should be addressed via a SAR to correct reliability standards that impose a burden on the industry without providing a significant benefit to reliability. The appropriate manner to address this discrepancy is not to submit a SAR to modify the standards that would inappropriately invoke requirements on individual generators due to their inclusion in the BES definition, but to eliminate I4 subpart (a) and modify standards in the future to address any reliability issues that may need the imposition of requirements for individual dispersed power producing resources. Please Note that FAC-001 and FAC-002 have established processes for generators (of all shapes and sizes) to interconnect to the BES. 3. I4a should be deleted in its entirety. The SDT is forcing every dispersed power Facility over 75 MVA to be in the definition, where the SDT should be keeping individual resources out and allow other Standards and SDTs to determine if that should be included within each individual Standard. The BES definition should be written to give broad details and each individual Standard should be where details are maintained. This is already the case for the following Standards; MOD-025-1, R1 and VAR-001-2, R3 are two examples where the Standard dictates what is applicable and what is not. 4. We do not

believe that since FERC has approved Phase I that the SDT is bound by that approval as being unchangeable. The Commission has only approved a part of the process and nowhere is it stated that once Phase I is approved that it cannot be changed. This is proof with the other changes that the SDT has made in Phase II compared to Phase I. 5. NERC or the SDT have not provided the industry with event analysis or lessons learned information that an individual dispersed power producing resource (not whole facilities) within a Facility has led to instability of the BES. 6. The inclusion of I4a does not alien itself with the current NERC and Regional RAI process. NERC's CEO and President has said that everything cannot be a priority. The amount of records management will only benefit a company who sells their services in managing individual power producing resources (i.e. paper work). The Registered entity and their Region will not see the benefit of tracking several thousand wind turbines and solar panels, for what? The "what" is unknown because the SDT is taking words of the "Statement of Compliance Registry Criteria" and applying it to our standards development process. Currently Entities do not register per Facility, but this definition does force entities to register per Facility. The SDT is mixing apples and oranges. 7. The BES SDT has stated that the collector system is not included within the definition. But, FAC-008-3, is written to support the reliability of the BES and Requirement 2 states that each Generator Owner shall have a documented methodology between the generator (R1) to the point of interconnection. This means that the collector system is part of the BES definition. Please clarify how one standard pulls in the collector system and the proposed definition keeps it out? The removal of I4a will solve this issue. If individual resources need to be in based on system instability issues, then this can be addressed at a later date, once it is proven that individual resources need to be considered part of the BES and the individual resources cause BES instability..
Yes
Yes
Yes
The inclusion of I4a does not support the reliabile operation of the BES. As stated before, we agree that the point of interconnection should be included, not the individual intermitent resources.
Group
Oklahoma Municipal Power Authority
Ashley Stringer
Agree
Transmission Access Policy Study (TAPS) Group
Group
Southwest Power Pool Regional Entity
Emily Pennel
No

Separation of I2, no issue No: 75MVA threshold may be higher than what FERC will support. Comments: Paragraph 167 of Order 773 implies that FERC sees the aggregation point for tie lines at 20MVA. However, there was some flexibility provided in the rehearing comments on this point. Paragraph 113 of Order 773 states that multiple step-up transformers (in particular 34.5/115kV) are expected to be included by FERC.
Yes
The technical justification document supports this conclusion.
Yes
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes
This change returns it to the original language in Phase I. Either way it still has the same intent.
No
Note two was added in draft 1 to Phase II. This change to Note 2 changes it from 30KV to 50KV, due to analysis they performed. 50KV threshold is less restrictive than 30KV. FERC forced Note 2 – this note requires determining loops between radial lines, and including radials with >50 KV loops
Yes
This is in regard to local networks and this change is less restrictive.
Yes
Inclusion I5 is about reactive sources. However it only excludes E4. There is no reason why all exclusions E1 to E4 should not apply to reactive sources. The current definition will include reactive sources in radial system as part of BES. There is no technical reason for excluding radial system and yet including reactive sources in radial system as part of BES
Individual
David Thorne
Pepco Holdings Inc
Yes
Yes
Yes

No
Individual
Scott Bos
Muscatine Power and Water
No
MP&W appreciates the changes SDT made to I4. However, we think that the wording of I4a still does not adequately communication that desired treatment of small dispersed power producing resources as an aggregate, rather than on an individual basis, when the aggregate capacity is 75 MVA or more. To address this issue, we suggest the following wording change to I4a, “Aggregation point of dispersed resources when they aggregate to a total capacity of greater than 75 MVA (gross nameplate rating, and” An individual 1.5 MW wind turbine does not impact the BES when it reduces its output (remember just because a turbine is rated at 1.5 MW doesn't mean it automatically reaches that output when the wind blows) or trips offline. Entities have been making comments that the place where power is aggregated (usually the bus) should be included and not individual the wind turbines, solar collectors, manure digesters, etc. The amount of compliance time for PRC-004 would never be enough. Wind turbines have up to 250 plus reasons why they can trip. Usually due to the change in wind direction. If the wind changes direction and the turbine head can not keep up within a certain degree of angle, the unit will trip. Coming back on line when the angle requirement is met. So, Entity's will need to apply the R2 of PRC-004-2a, for every wind turbine trip. Not all Entities have the resources to review these trips and that 1.5 MW wind turbine does not impact the BES. MP&W beleives that the point of interconnection (of greater than 75 MVA) is important and should be contained in the BES definition as written in I4B. PRC-004-2a is only one Standard, notwithstanding; BAL-001-TRE-01, FAC-001, FAC-003, MOD-024, MOD-025, MOD-026, MOD-027, PRC-005, PRC-006-SPP-01, PRC-019, PRC-024, PRC-025, and TOP-003.
Yes
Yes
Yes
The SDT has recommended that a SAR be submitted in order to refine the Standards that would be applicable to individual power producing resources contained under I4 of the phase II definition. This response is not acceptable. The SDT should not passively answer an entity's question by stating that a different process "may" fix the issue at hand. MP&W recommends I4a be deleted and I4b be maintained as I4a. I4a should be deleted in its entirety. The SDT is forcing every dispersed power Facility over 75 MVA to be in the definition, where the SDT should be keeping individual resources out and allow other Standards and SDTs to determine if that should be included within each individual Standard. The BES definition should be written to give broad details and each individual Standard should be where the details are

maintained. This is already the case for the following Standards; MOD-025-1, R1 and VAR-001-2, R3 are two examples where the Standard dictates what is applicable and what is not. MP&W does not believe that since FERC has approved Phase I that the SDT is bound by that approval as being unchangeable. The Commission has only approved a part of the process and no where is it stated that once Phase I is approved that it can not be changed. This is proof with the other changes that the SDT has made in Phase II compared to Phase I. NERC or the SDT have not provided the industry with event analysis or lessons learned information that an individual dispersed power producing resource within a Facility has led to instability or cascading events on the BES. The inclusion of I4a does not align itself with the current NERC and Regional RAI process. NERC's CEO and President has even said that everything cannot be a priority. The amount of records management will only benefit a consultant who sells their services in managing individual power producing resources (i.e. paper work). The Registered Entity and their Region will not see the benefit of tracking several thousand wind turbines and solar panels, for what? The "what" is unknown because the SDT is taking words of the "Statement of Compliance Registry Criteria" and applying it to our standards development process. Currently Entities do not register per Facility, but this definition does force entities to register per Facility. The SDT is mixing apples and oranges.
Individual
John Seelke
Public Service Enterprise Group
No
The proposed elimination of the “collector system” as part of the BES makes the BES non-contiguous. In Order 773, the Commission (P 113 and P 114) stated that radial collector systems used solely to aggregate generation SHOULD be part of the BES since multiple transformers connections did not exempt I2 generators. However, FERC did not direct NERC to include the collector system in the BES. However, it did require that radial lines that connect I2 generators (call “tie lines” in Order 773) should be part of the BES (P 164-P 167) for reasons of contiguity. This BES definition proposed in Phase 2 creates an unlevel competitive environment between I4 generators and I2 generators. Moreover, in its SAR for Phase 2, the question of BES contiguity was supposed to be addressed. The team’s response on this issue allows dispersed power generators to be non-contiguous from the point where ac power is produced to where it is injected into the grid. The connections of I2 BES generators are, however, ARE included in the BES. In the diagram shown in the comment form, if the dispersed generators were forty 2 MVA diesel generators connected as shown, would their collector system be excluded from the BES also? What is there were eight 10 MVA gas turbines connected via a collector system? How about six 16 MVA gas turbines? As a member of the RBB, we direct that the team include collector systems that are solely used to aggregate generation in the BES definition.
Yes
Yes

No
Individual
Scott Berry
Indiana Municipal Power Agency
No
For question 1, Indiana Municipal Power Agency agrees with the comments submitted by Frank Gaffney, Floriday Municipal Power Agency.
Yes
IMPA appreciates the work that the SDT has done to come up with an alternative to the Commission's sub-100kV loop concerns for radial systems. IMPA supports the SDT's white paper and the proposed 50kV threshold value.
Yes
No
Individual
Barbara Kedrowski
Wisconsin Electric Power Company
No
Wisconsin Electric appreciates the work the Standard Drafting Team (SDT) has accomplished, but is concerned that the team has not corrected a fatal flaw in the definition of the Bulk Electric System. During the 8/21 webinar, the SDT said that they don't have the power to change an existing approved definition with regard to the inclusion of individual distributed generation resources, yet that's what they in fact do every time they draft a standard revision. FERC accepted the Phase 1 definition, but we believe the SDT had the opportunity to correct the flawed definition. The SDT team did not address industry's comments that individual wind turbines (and other dispersed generating units) should not be included in the definition. The SDT stated that industry has the option to address whether dispersed generation should be applicable to a standard by revising the applicability of those standards. This method of correcting for the wrong elements' inclusion in the definition will take time and resources from the industry. During this time period, the industry would still need to assume responsibility for compliance to each affected standard because it would be unknown when/if the revisions would be accepted and approved. For instance, compliance to Reliability Standard PRC-005 requires the industry to include thousands of individual wind turbines (and small solar panels) in the maintenance and testing of relays and associated equipment. Resources required to complete this testing are specialized and significant, with

little to no measureable benefit to the BES (and an indirect detriment by taking those resources away from other tasks that are beneficial). In regards to CIP Version 5 requirements, if each wind turbine is part of the BES, then each wind turbine's monitoring and control systems will be "BES Cyber Systems". Again, resources will be required for compliance with no benefit to reliability. Individual dispersed generation units (generally less than 2 MW) do not impact the reliability of the Bulk Electric System. The SDT points out that it is not including collector circuits of dispersed generators because collector circuits do not have a true reliability impact, but the SDT fails to recognize that the individual dispersed generators have even less of an impact. The issue of concern is a single point of failure affecting 75 MWs of generation, not the failure of an individual wind turbine. By excluding the collector systems, but including the individual generators, the SDT team is not following FERC's Order 773 (issued 12/20/2012) Paragraph 165, in which the Commission stated that it is appropriate to have the bulk electric system contiguous, without facilities or elements "stranded" or "cut-off" from the remainder of the bulk electric system. The individual dispersed generating units are stranded from the remainder of the bulk electric system in the current draft of the definition. The SDT stated during the 8/21 webinar, that industry can use the exception process to exclude wind turbines, or other dispersed generators. This viewpoint has a fundamental problem. It mandates that individual generators be included in a faulty definition that pulls in insignificant elements into the BES and then requires industry to exclude them (essentially an entire asset type). That requires hundreds of dispersed generator owners to rely on the regulator to be reasonable and allow us to exclude all of our individual dispersed generators. The proposed Phase 2 definition poses a huge compliance and regulatory burden that doesn't add to the reliability of the BES.
Individual
John Bee
Exelon and its' affiliates
Yes
Yes
Yes
Yes
Suggest adding the following to E4: or for the sole purpose of regulating internal generating station auxiliary buses. So that it reads: E4 – Reactive Power devices installed for the sole benefit of a retail customer(s) or for the sole purpose of regulating internal generating station auxiliary buses.

Individual
Bob Thomas
Illinois Municipal Electric Agency
Agree
Transmission Access Policy Study Group (TAPS) and SERC OC Review Group
Group
Salt River Project
Bob Steiger
Yes
Yes
Yes
No
Individual
Gary Kruempel, Terry Harbour, Tom Mielnik
MidAmerican Energy Company
No
The SDT has made significant progress by separating dispersed power producing resources from traditional generating resources. By including I4 subpart (b) the SDT has identified the critical element(s) that impact reliability. However, by failing to address the issue of reliability standards as they apply to individual dispersed power resources, the SDT has perpetuated a gross error implemented in phase one of the BES, by including each individual dispersed resource as BES. During the 8/21/2013 webinar the presenter emphasized the critical nature of the aggregate generation of dispersed power producing resources to the reliability of the interconnected transmission system. I4 subpart (a) is inconsistent with the stated critical nature of the aggregate generation. The presenter also indicated that standards that apply to GO/GOP associated standards should be addressed via a SAR to correct reliability standards that impose a burden on the industry without providing a significant benefit to reliability. The appropriate manner to address this discrepancy is not to submit a SAR to modify the standards that would inappropriately invoke requirements on individual generators due to their inclusion in the BES definition, but to eliminate I4 subpart (a) and modify standards in the future to address any reliability issues that may be required of individual dispersed power producing resource. The following language is recommended for I4: Dispersed Power Producing Resources: Where dispersed power producing resources aggregate to greater than 75 MVA the to a common point of connection at a voltage of 100 kV or above. Note:

Individual dispersed power producing resources are not BES, but does not exempt registration as a GO or GOP. Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells. Justification: A dispersed power generating facility necessarily consists of individual units of a limited size to take advantage of the distributed nature of the resource (e.g., wind or solar) upon which the facility relies for its fuel source. One benefit of such facilities' unit size and geographical distribution is that they are not as susceptible to a substantial loss of generating capability as a single unit of 20 MVA or greater (the registration threshold for a single generating unit). If the arrayed generators were each 2 MVA then the probability of losing 20 MVA at the generator level would be .00000001%. If the units were 5 MVA each the probability of losing all four units at the generator level would be .01%. The probability of losing a single 20 MVA unit would be 10%. These variations illustrate that there will be different values depending upon the arrayed generator's size. Given the reliability advantage this diversity affords it does not seem reasonable to treat this type of facility in the same way as a single unit facility of 20 MVA or greater. As recognized by the SDT and FERC in Order No. 773, a dispersed generating facility of 75 MVA or greater (NERC Registry Criterion Section III.c.2) can have an impact on the BES. To recognize this impact and to also account for the dispersed nature and reliability advantage as described above, it is requested that the individual power producing resources be excluded from the BES. A technical example of the impact of the loss of an individual wind turbine to the BES is available to the SDT upon request.
Yes
Yes
No
Individual
Shaun Moran, Lynn Schmidt, Joe O'Brien, Ed Mackowicz,
NIPSCO
No
We requested some clarification regarding a wind farm within NIPSCO from members of the SDT, and promptly received feedback. The main concern is that we are not sure of the intent of inclusion I4 because it is attempting to include a bus within an intermediate voltage. In our case it is 69 kV that may or may not be included since there are 2 transformations within the path to the 138KV; 1 up to 69 kV and 2 parallel transformers up to the 138 kV. In addition the entire 69 kV path is not "designed primarily for delivering" this wind power to the 138 kV system; the 69 kV system includes many lines serving various demand. Some on the SDT felt

that the single step-up transformer is the same as 2 transformers in parallel, while others did not. Following this discussion we failed to receive a uniform clarification. Some opinions were that the 69 kV system would be included in the BES while others believed it would not; we have similar differing interpretations within NIPSCO. Further clarification needs to be made on whether or not multiple transformations are or are not included.
Yes
We'd rather see it at 70 kV, however we appreciate the analysis that was performed justifying the 50 kV.
Yes
good
Yes
Another major concern is whether our 138 kV industrial customers with multiple feeds are part of the BES. One of the criteria is whether power ever flows through the customer's system. This could be very difficult to prove with evidence. Perhaps during the last year's peak load or maximum transfer across the host TOP's system, the flow could be integrated over an hour; if there is system flow across the customer's system during the integrated hour, then the customer's system should be considered part of the BES and the customer should have multiple years to comply with becoming part of the BES. If the customer becomes part of the BES would this mean that they would have to become a TO/TOP? Would it require that they have NERC certified operators? We see these as emerging concerns. Additionally, it appears that several small wind generators may become part of the BES which would bring PRC-004 misoperations into play for them. It is our understanding that such generators trip off line based on wind and wind direction. Keeping track of these operations and the associated analysis may become quite an undertaking. Other standards such as PRC-005 may also become a concern.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
Yes
We suggest that NERC and the SDT consider revising Note 2 to read as follows: Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion. Non-US Registered Entities can adopt the same voltage level or should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency.
Yes
No

Individual
David Jendras
Ameren
Yes
No
In our opinion, the SDT has improved the E1 exclusion criteria by increasing the 30 kV threshold to 50 kV. However, we still believe that the threshold is too low and request that it be raised to at least 70 kV. As the definition now stands, we will have to perform what we feel is unnecessary analysis to prove that most of our local subtransmission networks should also be excluded.
Yes
We agree with the addition of the word “Real”, but we have other concerns with E3b and we have identified in the comments to question 4 below.
Yes
1. We request the SDT to provide clarification for E3b testing conditions, specifically for all facilities in service or for single transmission contingency conditions. We believe that the criteria needs to be very clear so it is not confusing for entities when determining inclusion of local network facilities as BES facilities. 2. Also, we do not believe that 1 MW of back-feed from local network facilities to transmission facilities for a few hours out of the year constitutes classification of the local network facilities as BES facilities. We request that the SDT consider for inclusion that the magnitude of the injections from the local network should be in line with other injections into the transmission system such as: (a) Generators with a nameplate greater than 20 MVA, or (b) Aggregate resources greater than 75 MVA. 3. In our opinion, the standard puts additional burden on local network owners including local subtransmission network owners to prove that their facilities should be excluded from consideration as BES facilities. (a) We believe that, testing for BES inclusion could be included in the annual TPL contingency analysis, but it may not be possible to complete this type of analysis before the end of the year unless the criteria is clearly defined and limited in scope, otherwise numerous models reflecting varying system conditions would need to be considered. (b) We ask the SDT to recall that it was suggested in the last webinar that SCADA data could be used to prove that there was no back-feed from the local network to the transmission system. (c) We realize that the accuracy of SCADA data at low flow levels can be suspect at low load flows but if considered with the type of relaying, that is if the relaying limits power flow back into the BES transmission system, this could be used as a means of quick determination for inclusion. We appreciate the work of the SDT effort to provide a reasonable and balanced approach to the determination of BES facilities, and doing all of this within a very short period of time. Again we ask the SDT for consideration with respect of the 50kV threshold being raised to 70kV, and that with respect to injections into the transmission

network from the various generation and local network sources that they be considered as a comparable basis in the determination of BES facilities.
Individual
Chifong Thomas
BrightSource Energy, Inc.
No
No. We agree with the separation of I2 and I4 and this does provide clarity by creating a distinction between more traditional generation and distributed generation resources. We disagree with I4 to be applied only when both (A) and (B) are true. We recognize that each single small generator or even a group of these small generators cannot impact the BES and therefore, we would support the including only of the individual generating resources (A) (i.e., greater than 75 MVA) in the definition. The inclusion of the aggregate point (B) below 100 kV will improve reliability by focusing on the area that can cause the loss of 75MVA of distributed generation resources. We recognize that there will be complication in determining the aggregate point and to the implementation of standards associated with this portion of the collector system. For example, the various standards that are associated with the BES definition will also need to apply to this portion of the collector system and associated low voltage equipment.
Yes
Yes
Individual
Amber Anderson
East Kentucky Power Cooperative
No
In the consideration of comments, the drafting team indicated that a SAR might be submitted to appropriately adjust GO and GOP standards requirements for dispersed generating facilities. We agree that is the approach to undertake. In order to support this approach, I4 should be deleted to avoid the situation where inappropriate provisions could become effective and compliance become difficult or impossible for entities until work is completed through the SAR to adjust those requirements. In the filing with FERC this procedure could be explained so that FERC can be assured that their approval of inclusion of dispersed generating facilities in the Phase I order will be appropriately implemented.

Group
Dominion
Louis Slade
Yes
Yes
Yes
No
Individual
Thomas Foltz
American Electric Power
No
AEP does not agree with the premise that BES elements (measured for compliance) should be as granular as the individual dispersed power resource. We do not see the reliability benefit of tracking all of the compliance elements for individual wind turbines when the focus should be placed on the aggregate of the facilities. Does the RC want to be notified of an outage of each individual wind turbine in real-time, or a loss of significant portion of the wind farm? If we are not careful, we will have entities at these resources and others monitoring them (BAs, TOPs, RCs) focusing on minor issues that will distract from more relevant reliability needs. We believe it would be beneficial and provide more clarity if the verbiage “aggregate to a total capacity greater than 75 MVA (gross nameplate rating) at a common point of connection to a voltage of 100 kV or above” were moved to the beginning of the I4 paragraph rather than as a sub-bullet. For example, “Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA….”. We appreciated the development of the diagram to explain the scenario. We encourage the team to continue to provide these illustrations to clarify the intent and the application.
No
The thought process of the note #2 is confusing the process. One could take this to mean that a 69 kV system would be included by exclusion. AEP does not believe this to be the case, but the wording of this note does not lead to an obvious conclusion. We suggest that the SDT make another attempt to provide a simpler and clearer approach. AEP also suggests that E1 have transmission removed from between the words contiguous and Elements. We recommend that it instead say “Radial systems: A group of contiguous Elements that emanates from a single point of connection of 100 kV or higher and:”
Yes

Yes
To reiterate, AEP does not agree with the premise that BES elements (measured for compliance) should be as granular as the individual dispersed power resource. We do not see the reliability benefit of tracking all of the compliance elements for individual wind turbines when the focus should be placed on the aggregate of the facilities. Does the RC want to be notified of an outage of each individual wind turbine in real-time, or a loss of significant portion of the wind farm? If we are not careful, we will have entities at these resources and others monitoring them (BAs, TOPs, RCs) focusing on minor issues that will distract from more relevant reliability needs. We appreciated the development of the diagram to explain the scenario. We encourage the team to continue to provide these illustrations to clarify the intent and the application. When the guidance documents were produced last year, we had a better understanding of how the pieces of the definition fit together (and where there were significant gaps). We encourage the SDT to develop the scenarios and the diagrams first for industry review then the definition should be crafted to meet those. We understand the pressure to meet the FERC deadlines, but continuing to tweak this foundation little by little had proved to be a difficult task and an overhaul of the approach might yield better results. If this requires modifying the SAR to provide the SDT with the flexibility to address broader concerns, AEP endorses this approach.
Individual
William Waudby
Consumers Energy Company
No
The proposed wording of I4(b) is acceptable in that includes “…from the point where resources aggregate to greater than 75 MVA…”. Consumers Energy objects to I4(a) which includes all “individual resources that aggregate to a total ampacity greater than 75 MVA”. This could be interpreted to include each of the small generators, each 690V to 34.5kV transformer and the collector systems on a wind farm. I4(a) should be removed from the BES definition leaving only I4(b) as an inclusion. Consumers Energy recommends a negative ballot until the wind farm generators, transformers and collector systems are excluded.
Yes
Yes
No
Individual
Kenneth A Goldsmith
Alliant Energy

No
Alliant Energy agrees with the changes to I2 and I4b, however, firmly believe I4a must be deleted. There is no way an individual dispersed generator in the range of <1 MW to 5 MW will have any reliability impact on the reliability of the BES. In addition, in the MRO footprint alone there would be ~7500 generators added to the list of BES equipment, which would be extremely costly to manage from both the Registered Entity and Regional Entity's perspective.
Yes
Yes
Yes
Alliant Energy reiterates that Inclusion I4a must be removed from the definition of the BES. It makes no technical sense, and creates an extremely burdensome compliance workload and risk.
Individual
Nazra Gladu
Manitoba Hydro
Yes
Yes
Yes
Yes
(1) General Comment - replace “ Board of Trustees ” with “ Board of Trustees’ ” throughout the applicable documents/standards for consistency with other standards.
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
Yes
Yes
Yes

Yes
HQT's position remains the same concerning the BES Definition, as limitations on exclusion are increased in phase 2 as imposed by FERC without proper hearing of non-US jurisdictions. One other comment on the Implementation plan refers to the second sentence of Effectives dates. The second sentence should be arranged differently as it refers both to "no regulatory approval required" and "applicable governmental authorities". The last part of the sentence should be moved with the first sentence to add clarity.
Individual
Kayleigh Wilkerson
Lincoln Electric System
No
Although appreciative of the drafting team’s efforts, LES is concerned with the proposed inclusion of the individual dispersed power producing resources as part of the Bulk Electric System versus the point at which the resources aggregate to a capacity greater than 75MVA. As currently proposed, the burden would be on the registered entities to either seek multiple exclusions through the BES Exception Process or else race to add numerous BES Elements to existing programs, processes and maintenance schedules to ensure compliance with Reliability Standards such as PRC-005-1.1b, PRC-004-2a, FAC-001, etc. To prevent broad sweeping changes to existing compliance requirements without sufficient technical justification, LES recommends Inclusion I4a be removed altogether and I4b be retained. In the event a reliability-related need is identified in the future pertaining to the individual resources, LES suggests that revisions be made to those standards deemed applicable.
Individual
Don Schmit
Nebraska Public Power District
Yes
Still have concern with including individual wind turbines as it relates to total generation.
No
The white paper for the low voltage loop threshold is a logical review of the issues. We would like to see some clarification for certain configurations. For example, two 115kV/69kV parallel transformers at the same substation serving only load at 69kV and no looped 69kV lines: 1) with 115kV and 69kV bus tie breakers, 2) with no 115kV bus tie breaker but does have a 69kV tie breaker, 3) with no 115kV bus tie breaker and no 69kV tie breaker, and 4) with 115kV bus tie breaker and no 69kV tie breaker. All breakers are normally closed but if no breakers exist then transformers are connected directly by bus operating in parallel for all

cases. Does this make the interrupting device on the high side of each transformer BES elements? Does this make the transformer a BES element or suggest an analysis for an exception must be made to remove them from the BES? Our concern is how a PRC-005 audit/enforcement group will interpret these configurations if it is not clearly stated in an example or considered in the white paper. How would the SDT interpret a configuration where a 115kV “radial” line feeds a substation with a 56MVA 115/69kV transformer. The 69kV side of the transformer is connected to a networked 69kV system owned by another entity. The 69kV system does connect back to the transmission system in multiple points in the other entities system. There is some 69kV generation greater than 20MVA or 75MVA aggregate but the substation and line in question is not used for black start. Note the 115kV/69kV transformer would never allow greater than 75MVA to pass through it back to the 115kV line since the transformer is too small. Is the substation with the 115/69kV transformer a BES substation? Is the 115kV line to the 115kV/69kV substation BES? Please clarify. It seems transformer size should have some impact but the reference document does not reference this.
Yes
Yes
It is imperative to have the BES reference document be updated to reflect the latest changes and drafting team position on various items with the definition since the definition is not self-explanatory due to the significant BES system variations. Perhaps some additional examples with low voltage looped systems would be beneficial similar to the scenarios noted in question 2 above. We also have concerns with the disclaimer in the reference document on page 1 and noted below. We would hope this document would be endorsed by NERC to help address the complexity of the definition and to aid in transparency. “Disclaimer-This document is not an official position of NERC and will not be binding on enforcement decisions of the NERC Compliance Program. This reference document reflects the professional opinion of the DBES SDT, given in good faith for illustrative purposes only.”
Group
seattle city light
paul haase
Agree
Sacramento Municipal Utility District (SMUD)
Individual
Larry Watt
Lakeland Electric
Agree
Lakeland Electric supports the Florida Municipal Power Agency comments.
Individual
Bret Galbraith
Seminole Electric Cooperative, Inc.

Yes
(1) The definition utilizes the term “non-retail generation.” This term does not appear to be clarified within the definition. However, the drafting team has attempted to clarify the term in the guidance document. Unfortunately, the guidance document is not final, meaning that it can be revised before being finalized. Please define retail and non-retail generation as separate definitions for inclusion into the Glossary contingent upon each other or make the BES definition approval contingent on the guidance document being approved. See Exclusion E1(c). (2) The terms “plant and facility” are not defined and are ambiguous. Please provide quantitative and/or qualitative factors that an entity can utilize in determining what is a plant/facility. See Inclusion I2. (3) The following note will be placed in the Reference document: “Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system.” Please strike the following language from the paragraph “or an enhancement of,” as it is more of a persuasive statement than an objective statement. (4) In Exclusion E1(c), please clarify that reactive devices, such as capacitor banks, can be included in this section also. Reactive devices are differentiated from real power devices in Inclusion I2 and so we request clarification that reactive devices can be included in Exclusion E1(c). (5) Inclusion I2 includes generation above 20 MVA/75MVA connected at 100 kV or higher. However, the base definition includes all generation units connected at 100 kV or higher. Units below 20 MVA/75MVA are never actually excluded. The net effect is to include all generation under the base definition regardless of size. To avoid future interpretation issues and ensure consistency with the intent communicated in the Phase 1 guidance document (page 13, Figure I2-6), Inclusion I2 needs to be written as an exclusion of units less than 20 MVA/75 MVA. If this not the intent of I2, then the definition needs to be modified to clarify the intent. (6) Exclusion E2 currently states “: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services…”. This statement could easily be covered under the section currently labeled I2 and suggested above to be rewritten as an exclusion. We would like to suggest potential language to simplify the definition, eliminate inclusion I2 to ensure that units under 20 MVA/75 MVA are actually excluded from the definition, and incorporate these ideas into exclusion E2 so that Exclusion E2 would be: E2 – Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: a) Gross individual nameplate rating less than 20 MVA. Or, b) Gross plant/facility aggregate nameplate rating less than 75 MVA. Or, c) One or more generating units on the customer’s side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the

retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority. (7) It would be extremely valuable for the team as part of any guidance document to develop and review a decision tree supporting the definition and include this decision tree in the next revision of the guidance document.
Individual
Wayne Sipperly
New York Power Authority
LPPC
No
Inclusion 4b does not support a contiguous BES due to the exclusion of a portion of the path from the generator terminals to the resource aggregation point. Inclusion 4b is not consistent with the elements included under Inclusion I2 which applies to all generating resources.
Yes
Yes
Yes
Support the development of a SAR that will create a project to review all of the GO and GOP standards for effective applicability to dispersed power resources so that generator owners and operators are only subject to the Standards requirements that have reliability impacts and those standard requirements that are applicable to the generator type.
Group
Transmission Access Policy Study Group
William Gallagher
Yes
Although we support the SDT’s willingness to address the lack of clarity caused by the previous posting’s merging of I4 with I2, we are concerned that the wording of the new version of I4 does not capture the SDT’s intent, and could lead to absurd results if read literally. As we understand it, the SDT’s intent is to include only dispersed power producing resources that both (a) aggregate to more than 75 MVA, and (b) are connected through a system designed primarily for delivering capacity at a common point of connection of 100 kV or above. We believe that the SDT also intends that only the individual resources and the point from which they aggregate to 75 MVA should be included in the BES; in other words, the portion of the collector system that carries <75 MVA is not BES by virtue of I4. In order to express that intent clearly, we suggest the following revised text: I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such

capacity from the point at which those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. The BES portion of such resources includes: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. We believe that this text is consistent with the intent reflected in the diagram provided by the SDT in the comment form, and is more clear and accurate than the text of I4 as posted.
Yes
TAPS appreciates the SDT's work on the sub-100 kV loop issue. For the reasons set out in the SDT's white paper, and in TAPS' comments on the 30 kV threshold that was proposed in the first posting of Phase 2 of the BES definition project, TAPS strongly supports the proposed 50 kV threshold.
Yes
We suggest that the SDT clarify, either in the definition itself or in the reference document, that a momentary flow-through caused by an abnormal/contingency condition does not make a system ineligible for Exclusion E3. TAPS members are willing to work with the SDT on defining appropriate limits for such minimal, momentary flow-throughs.
Group
Southern Company
Wayne Johnson
Yes
The separation of dispersed generation where a collector system aggregates the total generation prior to connecting to the BES is clear in I4.
Yes
It is clear that looping facilities operating at voltages < 100 kV are NOT included in the BES and that contiguous loops operated at voltage < 50 kV in configurations being considered as radial systems does not affect this exclusion (i.e., they are also NOT included in the BES).
Yes
Yes
A) Inclusion I2a should be deleted and I2b should be used to define the threshold for all generating facilities. It is inconsistent to include a 21 MVA single generator (using I2a) and not include 74.5 MVA aggregated conglomeration of individual generators (using I2b). Since 75 MVA is used as the threshold in multiple places in this definition, a single generator at 75 connected at > 100kV should be the individual unit size threshold. B) Please specify what size of Reactive Power resources is included by I5. Order 773 acknowledged that Inclusion I5 is the technical equivalent of Inclusion I2 (generating resources) for reactive power devices. Since generating resources in Inclusion I2 are limited to those connected at 100kV or above with individual and aggregate ratings of 20MVA and 75 MVA, respectively, it could be

consistent -- if technically justified -- to include a threshold of >75MVAR for reactive power resources. Some technical justification should be pursued to determine whether 75 MVAR or a different size threshold would be appropriate to include in Inclusion I5 for Reactive Power resources. C) Southern Transmission believes that Exclusion E3 should include a limit on the size of a Local Network (LN). This position is consistent with the proposal from the NERC System Analysis and Modeling Subcommittee (SAMS). Without placing a size limitation on such a network, a single contingency could result in significant flows across the BES to serve the LN from a different location. The SAMS provided technical justification for a 300 MW load limit and Southern would be supportive of such a limit. Southern also agrees with the SAMS that the flow should be into the LN under single contingency conditions. (See NERC's Review of Bulk Electric System Definition Thresholds, March 2013, Section 5.3) D) Southern believes that the second part of Exclusion E3 should be deleted for three reasons: First, Exclusion E3a refers to "non-retail generation". Southern believes that whether a unit is "retail" or "non-retail" should be irrelevant when determining inclusion in the BES. Regardless of how a generator is classified, if it is large enough to impact flows on the system, then it should be included in the BES. Second, the phrase "and do not have" in the second phrase of Exclusion E3a is ambiguous and redundant and could lead to confusion and misapplication. Specifically, it is ambiguous as to whether the last phrase regarding aggregate non-retail capacity: (a) refers back to the generation resources identified in Inclusion I2, I3, or I4 (thus defining a smaller subset of generation resources from I2, I3, and I4 that are carved out from the definition of LN, but other Inclusion I2-I4 generation resources can be part of the local network); or (b) simply refers back to "generation resources" (therefore, local networks exclude BOTH Inclusion I2-I4 generation resources AND, separately, generation resources with aggregate non-retail generation >75MVA). Third, Inclusions I2 and I4 already both use the 75 MVA limit. It seems redundant to state that a Local Network under Exclusion E3a does not include generation resources with aggregate capacities greater than 75 MVA when Exclusion E3a already states that local networks do not include generation resources identified in Inclusion I2 and I4 (which, in turn, include generation resources with aggregate capacities above 75 MVA). To clarify and to eliminate confusing and unnecessary redundancy, Southern suggests striking all language after "Inclusion I4." Exclusion E3a should therefore read: "a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4."
Individual
Mahmood Safi
Omaha Public Power District
No
Omaha Public Power District (OPPD) agrees and appreciates the SDT's efforts to provide clarity by separating dispersed power producing resources from Inclusion I2 and returned to its own separate Inclusion I4. However, OPPD is still concerned with the Inclusion I4a that includes the individual generator as part of BES. Where, the Inclusion I4b clearly and correctly recognizes the aggregate point to be identified as a BES facility. We agree that the

aggregation point (or bus) should be part of the BES, if the total aggregated generation is at 75 MVA or higher, as stated in the Inclusion I4b. OPPD believes that the individual unit by itself can't impact the reliability of BES. On the other hand, the compliance responsibilities that go along with are burdensome with no benefit to the reliability of the BES. Therefore, OPPD suggests consider removing Inclusion I4a from the BES Definition Inclusions. We strongly believe that I4b is completely addressing the dispersed power producing resources inclusion into BES. Additionally, OPPD supports comments provided by Madison Gas & Electric (MG&E).
Yes
Yes
No
Individual
Don Streebel
Idaho Power Company
Yes
Yes
Yes
Yes
1. In the wording for E3b (Local Networks), the phrase "and the LN does not transfer energy originating outside the LN for delivery through the LN" does not seem to add any value or specificity to the LN Exclusion. In fact, the phrase seems misleading and serves to add confusion since some amount of energy flowing in a parallel BES path outside the LN will always flow through the LN, even if it's just a trickle and does not impact the sign of the measured power flow at the LN points of connection. Suggested reword for E3b is "Real power flows only into the LN at each LN connection point." 2. We agree that your clarifying single-line diagram for Inclusion I4 (40 - 2 MVA generators aggregated up through the point of aggregation to the common point of connection) for dispersed power producing resources properly designates the point of aggregation of the dispersed power producing resources as a BES element. We also agree with the basis for this designation which states for the point of aggregation "where the individual generator nameplate ratings of the dispersed generation total > 75 MVA (actual 80 MVA) and a single point failure would result in loss of all generation contained on the dispersed generation site". However, following the same logic in basis, we do not agree with the BES designation for each individual 2 MVA generator in your

clarifying single-line diagram. We think it makes sense that the reliability of the power system should be considered for the loss of the 80 MVA and we agree that a potential single point of failure exists at the point of aggregation that could result in the loss of all generation. However, we do not think that the loss of one 2 MVA generator would have any significant negative impact on the reliability of the power system. If the loss of greater than 20 MVA via a single point failure scenario is deemed significant to the reliability of the power system (Inclusion I2, a), then that same logic suggests that each of the two buses that aggregates 40 MVA of generation should be designated as BES. If, on the other hand, due to the dispersed nature of the generation in the clarifying single-line diagram, the loss of greater than 75 MVA via a single point failure scenario is deemed significant to the reliability of the power system (Inclusion I2, b), then that same logic suggests that the point of aggregation that aggregates 80 MVA of generation should be designated as BES. No place in the BES core definition nor in any of the inclusions (or exclusions) is there a concern for the loss of 2 MVA of generation as having a negative reliability impact on the power system. Therefore, we would not designate each individual 2 MVA generator as BES as you have in your clarifying single-line diagram and would suggest the following wording for Inclusion I2 for your consideration: I2 - Generating resource(s) with: a) gross individual nameplate rating greater than 20 MVA, including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above or, b) the point of aggregation of gross plant/facility with aggregate nameplate rating greater than 75 MVA, including the system designed primarily for delivering the aggregated capacity from the point where the resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. I4 - DELETED
Individual
Diane Barney
NARUC
Yes
NARUC shares the concern raised by New York about the Phase II Report’s failure to meet its purported goal of providing a technical justification for 100kV bright line rule and generation thresholds. NY raised specific concerns about a survey not being appropriate technical support for specific numbers and the drafting team did not specifically address this, or other concerns raised about the technical justification, in its response. NARUC is also concerned that the methodology utilized historically by the NPCC was not considered as one of five alternatives. So in response to whether or not there are other concerns with this definition that have not been covered in previous questions and comments, NARUC notes that it shares these concerns that have been raised, as well as the lack of a response from the drafting team thus far and requests a thorough response.
Individual

Thomas Dvorsky
New York State Department of Public Service
Yes
NERC has an obligation to provide technical advice to FERC, so that any number provided to FERC by NERC is interpreted as technical advice. A major purpose of the BES Phase II effort was to establish a technical basis for the 100 kV brightline and the 20/75 MVA generation levels. While NERC has provided a report purportedly providing a technical basis for these threshold levels, the report fails to do so. NERC should not include any numbers in any definition or standard for which it cannot provide a technical basis. Surveys do not provide a technical basis. Particularly troublesome is the presentation of alternatives to the 100 kV brightline. The report authors looked at 5 alternatives to establishing a technical basis for determining the bulk system. The report failed to evaluate the methodology historically applied to the NPCC system. If a major NERC region was able to successfully apply their methodology, why was it not evaluated and why would it be impossible to expect other regions to perform a similar analysis as the base for determining the BES? This comment is being resubmitted as the response provided in the previous comment period does not address the issues raised.
Group
NAGF Standards Review Team
Patrick Brown
No
1. Replace the current ballot’s draft I4 language: “I4 - Dispersed power producing resources consisting of: a) Individual resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.” With the proposed comment I4 language: “I4 - Dispersed power producing resource projects, or portion(s) thereof, designed primarily for supplying wholesale power (e.g., a wind farm, or solar farm) that aggregate to a total capacity greater than 75 MVA (gross nameplate rating) at a common point of connection to a voltage of 100 kV or above consisting of: a) The individual resources, and b) The delivery system designed primarily for delivering capacity from i) the point where those resources aggregate to the total connected capacity; to ii) a common point of connection at a voltage of 100 kV or above.” Rationale: • “projects … designed primarily for wholesale” – nothing in this posted version distinguishes between generation for retail (behind the meter) and generation for wholesale. As such rooftop PVs, generator assistance programs, or other similar small power-producing incentives, might be otherwise interpreted as included under

I4. • "(e.g., a wind farm, or solar farm)" – Because the SDT's I4 text-box will be dropped from the final version, we believe this inclusion is necessary to retain an illustration of the intent. • I4.a - While imposing BES Standards of governance toward management of individual small units is counter-productive and administratively burdensome, we do agree that differentiating applicability to various Standards should be specified through those Standards. To that end, we are dedicated to drafting and vigorously promoting a SAR to appropriately address dispersed power producing resource applicability within individual NERC Standards. In keeping with that commitment it is suggested that I4a be deleted from the BES definition. This would avoid temporarily imposing inappropriate requirements that would later have to be eliminated by modification of individual standard requirements. A better approach would be to add requirements where needed for individual small units. • I4.b – We believe our proposed wording: o Appropriately addresses impact to BES reliability. Rather than offering some illusion for reliability at a lesser impact level, this proposal recognizes that reliability rests in TPs, BAs, RCs, and TOPs responsibly addressing the single greatest contingency arising from, and the behavior of, dispersed power producing resources in the aggregate. Enforcing governance for management to any lesser level is not productive and has no true value to BES reliability. o Better aligns with FERC's Determination within Order 770 paragraph 114. o Aligns with FERC's Determination for I2 within Order 773 paragraph 91. o Aligns with FERC's Determination for I2 within Order 773 paragraph 92.
Yes
1. The language of the proposed BES definition is rather convoluted and is therefore difficult to apply correctly without the Reference Document. The FERC order 773/773a-amended Reference Document is not complete or final for the phase-2 BES definition, however. Its exclusion E1 statement is that of phase-1, not phase-2, for example, and a disclaimer on p.1 states "…this reference document is outdated. Revisions to the document will be developed at a later date to conform to the definition being developed in Phase 2." It appears that the phase-2 BES definition is being rushed through the approval process, and it would be preferable to take the time to compile a complete and consistent body of documentation before putting the matter up for a vote. This is especially important for correctly classifying very small, standby, non-Blackstart Resource gensets feeding the aux buses of generation plants for emergency purposes. Such emergencies include blackouts and max-generation situations, and in the latter case displacing some of the aux load can temporarily boost the net amount of power delivered by the plant. 2. Figure I2-5 of the Reference Document suggests that such standby generators are part of the BES, if the plant totals more than 75 MVA, because they "contribute to the gross aggregate rating of the site." Fig. I2-5 depicts all units exporting to the grid, however, and we are considering here only standby gensets feeding aux buses that remain net importers of power. Exclusion E3 may apply, however. Fig. S1-9b of the Reference Document shows a system composed of several generating plants and users, but the conclusions reached by the SDT should be unchanged if one drew a box around the diagram and labeled it a single generating plant. Specifically, the SDT decided that Exclusion 3 is invoked by the circumstance that the bus fed by the 5 MVA generator at lower

left is exclusively an importer of power, and this ruling should apply as well for standby gensets that feed aux buses within generation plants. Making such a classification would require that a Local Network (LN) can exist within a generation plant, as opposed be being found exclusively in the systems of TOs and DPs. Such an interpretation may be permitted by the circumstance that the definition of an LN uses the word "transmission" with a lower-case "t", as opposed the TO and DP-oriented term "Transmission" in the NERC Glossary, but the LN definition also references serving "retail customer load." This definition should be changed, or (better) the BES definition should explicitly state that gensets < 20 MVA feeding power-importing aux buses of generation plants are excluded from the BES. The term "nameplate rating" should be replaced by the NERC-defined term "Facility Rating" to harmonize the BES definition with NERC's standards. 3. Inclusion I2a should be deleted and I2b should be used to define the threshold for all generating facilities. It is inconsistent to include a 21 MVA single generator (using I2a) and not include 74.5 MVA aggregated conglomeration of individual generators (using I2b). Since 75MVA is used as the threshold in multiple places in this definition, a single generator unit (Facility Rating) at 75 MVA connected at > 100kV should be the individual unit size threshold. 4. Please specify what size of reactive power resources is included by I5 (> 75MVAR?).
Individual
Patrick Farrell
Southern California Edison Company
Yes
SCE believes that the revision to I4, the inclusion for dispersed power producing resources, is a move in the right direction, but we think that additional clarity could be provided by changing "common point of connection" to "common point of interconnection".
Yes
Clearly identifying "Real" Power makes sense and helps clarify the intent.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
No
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; and PPL Generation, LLC, PPL Montana, LLC, and PPL Susquehanna, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. The SDT should consider the comments of the North American Generator Forum in this respect.

Yes
a. The language of the proposed BES definition is somewhat vague and is therefore difficult to apply correctly without the Reference Document. The FERC order 773/773a-amended Reference Document is not complete or final for the phase-2 BES definition, however. Its exclusion E1 statement is that of phase-1, not phase-2, for example, and a disclaimer on p.1 states that "…this reference document is outdated. Revisions to the document will be developed at a later date to conform to the definition being developed in Phase 2." It appears that the phase-2 BES definition is being rushed through the approval process, and it would be preferable to take the time to compile a complete and consistent body of documentation before putting the matter up for a vote. This is especially important for correctly classifying very small, standby, non-Blackstart Resource gensets feeding the aux buses of generation plants for emergency purposes. Such emergencies include blackouts and max-generation situations, and in the latter case displacing some of the aux load can temporarily boost the net amount of power delivered by the plant. Figure I2-5 of the Reference Document suggests that such standby generators are part of the BES, if the plant totals more than 75 MVA, because they "contribute to the gross aggregate rating of the site." Fig. I2-5 depicts all units exporting to the grid, however, and we are considering here only standby gensets feeding aux buses that remain net importers of power. Exclusion E3 may apply, however. Fig. S1-9b of the Reference Document shows a system composed of several generating plants and users, but the conclusions reached by the SDT should be unchanged if one drew a box around the diagram and labeled it a single generating plant. Specifically, the SDT decided that Exclusion 3 is invoked by the circumstance that the bus fed by the 5 MVA generator at lower left is exclusively an importer of power, and this ruling should apply as well for standby gensets that feed aux buses within generation plants. Making such a classification would require that a Local Network (LN) can exist within a generation plant, as opposed be being found exclusively in the systems of TOs and DPs. Such an interpretation may be permitted by the circumstance that the definition of an LN uses the word "transmission" with a lower-case "t", as opposed the TO and DP-oriented term "Transmission" in the NERC Glossary, but the LN definition also references serving "retail customer load." This definition should be changed, or (better) the BES definition should explicitly state that gensets < 20 MVA feeding power-importing aux buses of generation plants are excluded from the BES. b. The term "nameplate rating" should be replaced by the NERC-defined term "Facility Rating" to harmonize the BES definition with NERC's standards. c. Inclusion I2a should be deleted and I2b should be used to define the threshold for all generating facilities. It is inconsistent to include a 21 MVA single generator (using I2a) and not include 74.5 MVA aggregated conglomeration of individual generators (using I2b). Since 75MVA is used as the threshold in multiple places in this definition, a single unit (facility rating) at 75 MVA connected at > 100kV should be the individual unit size threshold. d. Please specify what size of reactive power resources is included by I5 (> 75MVAR?).
Group

SERC Planning Standards Subcommittee
Jim Kelley
Yes
Yes
In our opinion, the SDT has improved the E1 exclusion criteria by increasing the 30 kV threshold to 50 kV. We wish to thank the SDT for its diligence in justifying an increase to 50 kV. However, we still believe that the threshold is too low and would like to see it raised to at least to 70 kV.
Yes
Yes
E3b: The testing conditions for E3b should be clearly stated, namely for all facilities in service or for single transmission contingency conditions. We believe that the criteria need to be anchored so as not to manufacture a justification for inclusion of local network facilities as BES facilities Add word “normally” between “not” and “transfer” to E3b: Real Power flows only into the LN and the LN does not normally transfer energy originating outside the LN for delivery through the LN; and We do not believe that 1 MW of back-feed from local network facilities to transmission facilities for a few hours of the year constitutes classification of the local network facilities as BES facilities. We believe that the magnitude of the injections from the local network should be reviewed in line with other injections into the transmission system such as a) generators with a nameplate greater than 20 MVA, or b) aggregate resources greater than 75 MVA. In our opinion, the standard puts additional burden on local network owners including local subtransmission network owners to prove that their facilities should be excluded from consideration as BES facilities. In theory, this testing could be included in the annual TPL contingency analysis, but it may not be possible to complete this type of analysis before the end of the year for numerous models reflecting varying system conditions. It was suggested in the last webinar that SCADA data could be used to prove that there was no back-feed from the local network to the transmission system, but the accuracy of some SCADA data at low flow levels can be suspect and the SCADA data does not identify the exact system conditions that were experienced when the SCADA measurements were recorded, including outages to local subtransmission facilities. We appreciate the work of the SDT to try and provide a reasonable and balanced approach to the determination of BES facilities, and within a very short period of time. We ask that the injections into the transmission network from the various generation and local network sources be considered on a comparable basis in the determination of BES facilities. The comments expressed herein represent a consensus of the views of the above named members of the SERC PSS and the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Individual

Scott Langston
City of Tallahassee
Yes
Yes
Yes
No
Individual
Oliver Burke
Entergy Services, Inc.
Agree
SERC OC Review Group comments
Individual
Terry Volkmann
Volkmann Consulting, Inc
No
There is no technical justification to include disperse generation into the BES definition. The impact of the aggregation is studied and addressed in the FAC-001 and FAC-002 processes. Once the effects of dispatchability and frequency / voltage control in aggregation are addressed and mitigated in these processes, the inclusion of each individual generator into the BES definition provides no further value to the industry and reliability.
Yes
Yes
No
Group
SPP Standards Review Group
Robert Rhodes
Yes
While we don’t have an issue with separating I4 from I2 as in the previous draft, we do have

concern with the wording of the inclusion, especially the phrase ‘primarily designed’. While the diagram provided in the comment form clearly shows the distinction, it is difficult to pull it from the wording of I4. Additionally, we are confused by what was explained during the NERC industry webinar and what is shown in the above figure. The figure and the words in I4 indicate the point of aggregation is included in the BES. The discussion during the webinar did not include it in the BES.
Yes
Yes
This change has been made to clarify the drafting team’s intent. We would be interested in knowing what that intent is.
Yes
In the Implementation Plan, delete ‘go’ at the beginning of the 3rd line of the 1st paragraph. Whitepaper On Page 9, Line 9 of the 1st paragraph, delete the ‘/’. On Page 9, Line 3 of the 2nd paragraph, replace ‘represent’ with ‘represents’. On Page 9, Line 4 of the 2nd paragraph, replace ‘distribute’ with ‘flow’.
Group
Florida Municipal Power Agency
Frank Gaffney
No
FMPA thanks the SDT for its efforts. Although FMPA agrees with separating I4 from I2, we believe the SDT made a grammatical / logical error in the new I4. Inclusion I4 as posted reads: I4 - Dispersed power producing resources consisting of: a) Individual resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. The logical structure of I4 a) and I4 b) read literally does not reflect the intent of the SDT. The SDT seems to want to both: i) Identify the intersection of bullet a) and bullet b) [e.g., only a) vehicles with b) more than 2 axels need to be weighed at a truck stop, e.g., the subset of a) vehicles and b) with more than two axels] ii) While at the same time describe what is part of the BES [e.g., a pie is made of a) filling and b) crust, e.g., the addition of a) and b)]. The use of “and” at the end of bullet a) read literally would be interpreted as adding a) and b), i.e., a pie being made of filling and crust, and does not limit the scope to the intersection of bullets a) and b). That is, the BES pie is made of individual resources that aggregate to > 75 MVA with no criteria over which that aggregation is performed (is it service territory, geography, within a fence, etc.) and b) the portion of a collector system that carries > 75 MVA in aggregation. The word “and” cannot perform both functions of adding a)+b) while at the same time identifying the intersecting subset of set a) and set b), which is what the SDT seems to be attempting to do. What the team must have meant was: I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross

nameplate rating), and that are connected through a system designed primarily for delivering such capacity from the point at which those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. The BES portion of such resources includes: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. This intent is reflected in the diagram provided by the SDT in the comment form. This grammatical / logic error almost caused FMPA to vote Negative. The version of I4 posted read literally, an auditor does not know on what basis the 75 MVA of generation would be integrated, e.g., over the service territory of the entity? The auditor also is uninformed of whether this includes behind the meter generation or not. FMPA implores the SDT to correct this grammatical / logical error. If this error is not corrected, we will likely be changing our vote, and making recommendations to vote Negative on recirculation / final ballot.
Yes
Yes
Individual
Ryan Walter
Tri-State Generation and Transmission Association, Inc.
No
The NERC draft shows a schematic for resources that aggregate at a single bus location. Tri-State Generation and Transmission Association, Inc. (Tri-State) has included a drawing (Sent via email to Wendy Muller (NERC Standards Development Administrator)) that shows four examples of distributed generation that could have been developed as phases of a single developer or as multiple developers. The drawings show Tri-State's interpretation of which elements (highlighted in yellow) would be included based on the draft BES definition Inclusion I4. As written, it would include any line element from the point where the aggregated generation exceeds 75 MVA through the transformer that steps the voltage up to 100 kV or greater and include every dispersed generator attached to the line, even if it is a solitary unit. Please provide comments as to our interpretation. Inclusion I4a should be deleted. It does not appear to follow the intent of the FERC Order 773. In Order 773, paragraph 106 "NERC states that the inclusion is meant to address the dispersed power producing resources themselves, not the individual elements of the collector systems operated below 100 kV." Tri-State agrees with the EEI comment within this paragraph, "that inclusion I4 applies to generating resources meeting the threshold in the aggregate, not the individual generating units". There is no apparent requirement within the Commission Determination where FERC is requiring this inclusion. Tri-State does not find the inclusion of individual generating resources as low as 2MVA beneficial to the BES. A loss of a 2MVA

generating resource on low voltages does not pose the same risk as the loss of an aggregated loss of 75MVA. If inclusion I4a is not deleted, a minimum MVA level for the individual resource to be included in the BES should be added, just as I2 has. Tri-State recommends the Standard Drafting Team replace the current ballot's draft I4 language with: "The system designed primarily for delivering capacity of dispersed power resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above."
Yes
Yes
No
Group
BANC & SMUD
Joe Tarantino
No
Although we believe the Drafting Team has provided vast improvement to the Draft #2 of the Phase 2-I4 BES Definition SMUD is posting a Negative position for Draft #2 for the following reasons. Salient Issues: • In accordance with Paragraph 115 of the Commission's Order 773, exclude the collector system from the BES definition. o Wind/Solar BES delineation should be limited the GSU where the total plant capacity is connected at a common point to 100kV or greater. o During Phase-1, it was suggested that a 75 MVA threshold be established where the loss of a single element would render the entire 75 MVA of resources unavailable. This was in lieu of including the individual small-scaled machines as BES to avoid subjecting those machines to administrative burden for little or no impact on the BES as compared to the compliance obligation. • Redundant to TPL & TOP standards where loss of the resource(s) for a single element is addressed in system studies that include evaluation for adequate level of resources, system impacts and Single Largest Contingencies. • Must include the phrase "(e.g., wind or solar)" after "Dispersed power producing resource projects" to fully clarify the applicability of Inclusion I4. • Support a Standard Authorization Request or other mechanism to reduce administrative burden for compliance to specific standards (e.g., PRC-004 (Misoperations) & PRC-005 (Maintenance & Testing). The following is suggested wording for I4 that are associated with the points above: "I4 - Dispersed power producing resource projects, or portion(s) thereof, designed primarily for supplying wholesale power (e.g., a wind farm, or solar farm) that aggregate to a total capacity greater than 75 MVA (gross nameplate rating) at a common point of connection to a voltage of 100 kV or above consisting of: a) The individual resources, and b) The delivery system designed primarily for delivering capacity from i) the point where those resources aggregate to the total connected capacity; to ii) a common point of connection at a voltage of 100 kV or above." Rationale: 1. "projects …

designed primarily for wholesale…": Nothing in this posted version distinguishes between generation for retail (behind the meter) and generation for wholesale. As such, rooftop PVs, generator assistance programs, or other similar small power-producing incentives, might be otherwise interpreted as included under I4. 2. "(e.g., a wind farm, or solar farm)": Because the SDT's I4 text-box will be dropped from the final version, we believe this inclusion is necessary to retain an illustration of the intent. 3. I4.a: While applying BES NERC Reliability Standards to the management of individual small units is counter-productive and administratively burdensome, we do agree that differentiating applicability of various Standards should be specified within those Standards. 4. I4.b: We believe the proposed wording: a. Appropriately addresses impact to BES reliability. Rather than offering some illusion for reliability at a lesser impact level, this proposal recognizes that reliability rests in TPs, BAs, RCs, and TOPs responsibly addressing the single greatest contingency arising from, and the behavior of, dispersed power producing resources in the aggregate. Enforcing governance for management to any lesser level is not productive and has no true value to BES reliability. b. Better aligns with FERC's Determination within Order 770 paragraph 114. c. Aligns with FERC's Determination for I2 within Order 773 paragraph 91. d. Aligns with FERC's Determination for I2 within Order 773 paragraph 92.
Yes
Yes
During Phase-1, it was suggested that a 75 MVA threshold be established where the loss of a single element would render the entire 75 MVA of resources unavailable. This was in lieu of including the individual small-scaled machines as BES to avoid subjecting those machines to administrative burden for little or no impact on the BES as compared to the compliance obligation. (Please refer to response to Q2 for additional details.)
Group
PacifiCorp
Kelly Cumiskey
No
The SDT has made significant progress by separating dispersed power producing resources from traditional generating resources in Inclusion I2. By including I4 subpart (b), the SDT has identified the critical element(s) that impact reliability. However, by failing to sufficiently address the real issue of the impact of the mandatory reliability standards on individual dispersed power resources, the SDT has perpetuated a gross error identified during phase one of the BES definition project, by including each "individual" dispersed power producing resource as potentially within the scope of the BES. During NERC's August 21, 2013 webinar on this project, the presenter emphasized the critical nature of the aggregate generation of dispersed power producing resources for the reliability of the interconnected transmission system. To that end, Inclusion I4 subpart (a) is inconsistent with NERC's express statements

concerning the critical nature of the generation in the aggregate. The presenter also indicated that those reliability standards that apply to the GO/GOP functions should be addressed via a SAR in order to modify those standards that impose an unreasonable burden on sectors within the industry without providing a commensurate benefit to reliability. PacifiCorp believes that the appropriate manner to address this discrepancy is in fact not to submit a SAR to modify the standards, but rather to first eliminate Inclusion I4 subpart (a) – and thus remove the collective set of individual resources from within the BES – and then modify those standards in the future to address any lingering reliability gaps that may apply to dispersed power producing resources on an individual basis. PacifiCorp recommends the following language for I4: Dispersed Power Producing Resources: For dispersed power producing resources that aggregate to a total capacity greater than 75 MVA, the system designed primarily for delivering capacity from the point where such resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. Note: While individual dispersed power producing resources are not considered part of the BES, that does not exempt registration as a GO or GOP for those entities that solely own and/or operate such resources where the aggregate is greater than 75 MVA. Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells. PacifiCorp's justification for this revised language is as follows: a dispersed power producing resource necessarily consists of individual units of a limited size to take advantage of the distributed nature of the resource (e.g., wind or solar) upon which the facility relies for its fuel source. One benefit of such facilities' unit size and geographical distribution is that the facility is not as susceptible to a substantial loss of generating capability as a single unit of 20 MVA or greater (the registration threshold for a single generating unit). If the arrayed generators were each 2 MVA then the probability of losing 20 MVA at the generator level would be .00000001%. If the units were 5 MVA each the probability of losing all four units at the generator level would be .01%. The probability of losing a single 20 MVA unit would be 10%. These variations illustrate that there will be different values depending upon the arrayed generator's size. Given the reliability advantage this diversity affords it does not seem reasonable to treat this type of facility in the same way as a single unit facility of 20 MVA or greater. As recognized by the SDT, a dispersed generating facility of 75 MVA or greater (NERC Registry Criterion Section III.c.2) can have an impact on the BES. To recognize this impact and to also account for the dispersed nature and reliability advantage as described above, PacifiCorp requests that the SDT exclude individual dispersed power producing resources from the BES through a revised Inclusion I4 substantially similar to the proposal above. A technical example of the impact of the loss of an individual wind turbine to the BES is available from PacifiCorp to the SDT upon request.
Yes
Yes

No
Individual
Alice Ireland
Xcel Energy
No
To be clear, Xcel Energy is strongly supportive of the change made to Exclusion E1, to raise the exclusion threshold for radial and local networks from 30 kV to 50 kV. However, we are voting negative due the unnecessary inclusion of dispersed power individual resources in Inclusion I4(a). We understand that the individual dispersed generators ended up being included in the Phase I BES definition, but based on the development history, it is clear that the industry did not believe they should be included and thought they WERE NOT included. It wasn’t until the guidance document was finalized that it was apparent where the drafting team landed on the subject. Phase II of this project provides the best opportunity to refine and improve the BES definition such that industry compliance efforts are focused on activities that will truly have an impact on reliability. Please see our detail comments and justifications below: While we strongly support the separation of I2 and I4 and the 75 MVA threshold for aggregating facilities in Inclusion I4 (b), Xcel Energy continues to disagree with the inclusion of small individual dispersed generators per Inclusion I4 (a). We provided alternative language for I4 in the last comment period. That recommendation still stands. Including individual dispersed generators in the BES definition will cause a huge diversion in work activities as entities are forced to simultaneously seek relief via the Exception Process to exclude reliability insignificant individual dispersed generators from their programs while at the same time attempting to modify their existing compliance programs to accommodate individual dispersed generators in the event that the exception applications are not approved. NERC and the Regions will be faced with a huge backlog of exception requests for small distributed generators while Generator Owners with dispersed generating assets will struggle to implement reliability standards that were never drafted with the intent of being applicable to anything but large scale generating stations. In the August 21, 2013 webinar, the BES definition drafting team indicated that its justification for the 75 MVA aggregating threshold in I4 (b) was that 75 MVA is the level that the drafting team believes that single failures resulting in the loss of generation could have an appreciable impact on the grid. It seems inconsistent that a 2 MVA individual dispersed generator is deemed significant to reliability but the equipment that is utilized to connect individual dispersed generators totaling to <75 MVA is deemed not significant to reliability. Furthermore, with no requirement that the BES be contiguous, how can individual 2 MVA wind turbine generator at a >75 MVA wind farm have a greater effect on BES reliability than an identical individual 2 MVA wind turbine at a <75 MVA wind farm? With no technical rationale or difference in effects on BES reliability, how can identical 2 MVA units legally be treated so differently? In the Consideration of Comments document for the first draft of Phase II BES definition, the Drafting Team acknowledged that there are both existing and pending reliability standards

which likely will need to be reviewed and revised to clarify or correct the applicability of the standard requirements to small scale generation and recommended that the industry create a SAR to call for this action. Relative to the approval and implementation time frames being discussed for the new BES definition, we do not believe any such action could be taken in a timely enough fashion to resolve industry uncertainty and avoid major regulatory burden with no commensurate improvement in grid reliability. Examples: • PRC-005-2 Protection System testing – the based relay test requirements were developed with large generators in mind, and differ significantly from requirements in DOE Order 661A, of 2005 that requires wind plants to meet Low Voltage Ride-Through (LVRT) and Power Factor Design Criteria. These standards significantly change the protection scheme applied to individual turbines, and is not addressed here. Wind turbine protection systems are often integral to the wind farm control system and the PRC-005-2 requirements were developed for protection equipment typically applied on large scale generation not wind farm control systems. • TOP-002 Normal Operations Planning – Under R14 of this standard, an unplanned outage for any individual wind turbine would require a status notification report from the GO to the TO/TOP. This level of reporting, at typically less than 3 MVA, is much less that any practical reliability threshold, and would simply result in a documentation effort with no value. Similar concerns exist for FAC-008-3, PRC-001-1, PRC-004-2a, PRC-019-1, PRC-024-1, and PRC-025-1, and other standards where it is quite evident that small scale dispersed generators were not considered during the standard's development. Unless Inclusion I4 (a) is eliminated, we do not believe implementation of the new BES definition should go forward until all reliability standards have been reviewed and revised as necessary to clarify the applicability to individual dispersed generating assets. What reliability benefit is there to a "bright line" BES definition if there is not a corresponding clarity in the applicability of reliability standards to the elements deemed to be included in the BES?
Yes
Xcel Energy strongly supports this modification.
Yes
No
Group
Bonneville Power Administration
Jamison Dye
Yes
Yes
Yes

No
Individual
Russel Mountjoy
MRO
No
MRO recommends the removal of I4 a) and 14b Industry requested the point of aggregation to be added in place of the individual generators themselves, not as well. The inclusion of this statement, I4 b, tends to lead industry to believe the individual generators will still remain under the new definition of the BES in addition to the aggregation point. The addition of individual resources which are not material to the BES creates undue burden on the registered entities and regional entities through the process of identifying these assets in order to have to apply for an exception due to these assets not being material to the BES. Proposed re-write of I4: Aggregate point where dispersed power producing resources aggregate at a common bus to a total capacity greater than 75 MVA (gross name plate rating) linking to a common point of connection at a voltage of 100kV or above.
Yes
Yes
No
Group
Duke Energy
Colby Bellville
Yes
Duke Energy agrees with the changes made by the SDT.
Yes
Duke Energy agrees with the modifications made by the SDT.
Yes
No
Individual
David Kiguel (by Ayesha Sabouba)
Hydro One

Yes
We reluctantly support the separation of I2 and I4 because we believe that their wordings in the BES definition as approved by the industry, NERC BOT, FERC and applicable governmental authorities in Canada should have been retained. In our opinion, I4 is meant for renewable energy resources (in particular Wind). These resources are inherently different when considered for planning and for real time operations. This change will essentially designate every element of a wind farm above 75MVA to its interconnection at 100kV as a BES element including the medium voltage collector systems (less than 50kV) adding burden which may not be necessary. Further, it is not clear what and how standards will apply to collector systems designated as BES.
Yes
We agree that 50kV is more reasonable and are voting positively to the change made by SDT. This change was essentially initiated to address a FERC directive in its Order 773. However it should be noted that the demarcation point between transmission and distribution may be different in non FERC jurisdictions, such as Canadian provinces. In establishing voltage thresholds, NERC needs to consider non-US legislated demarcation points, and the standard development process must make allowances for such regulatory and/or jurisdictional differences and frameworks consistent with NUC 001 and TPL footnote b. We suggest that NERC and the SDT consider revising Note 2 to read as follows: Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion. Non-US Registered Entities can adopt the same voltage level or should implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency.
Yes
Yes
In Canada, local load reliability requirements are under the provincial authority of local regulators such as the Ontario Energy Board in Ontario. We understand that NERC needs to follow FERC Orders and directives. In our opinion NERC must ensure that any provisions within the BES definition and/or NERC standards that are to address load reliability and load supply continuity issues and NOT interconnected BES reliability should be limited to the FERC jurisdiction only. Accordingly we suggest that when addressing such requirements in a standard it must include that for a non-US Registered Entity it should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction. Good examples to address these issues are through the Standards process as was done for NUC 001 and TPL001 Footnote b.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
No

ATC appreciates the changes the SDT made to I4, however, believe the wording of I4a still does not adequately communicate the desired treatment of small dispersed power producing resources as an aggregate, rather than an individual basis, when the aggregate capacity is 75 MVA or more. To address this issue, we suggest the following wording change to I4a, “Aggregate of dispersed resources when they aggregate to a total capacity of greater than 75 MVA (gross nameplate rating, and”
Yes
Yes
Yes
ATC has the following additional comment for consideration by the SDT: • Exclusion 3b does not currently define the limited set of conditions entities are to consider when determining if real power flows only into the local network (LN). Without this clarification, entities will have no certainty regarding the exclusion determination made, which can have a material impact on the entity under all of the NERC standards. ATC recommends the following revision to E3b: E3b) Real Power flows only into the LN under intact system and most severe single contingency conditions and the LN does not transfer energy originating outside the LN for delivery through the LN; and’ This revision is warranted for the reason noted above. In addition, the language is consistent with how the system is operated under the NERC TOP standards and the proposed addition matches NERC’s own statements to the FERC as recorded in paragraph 71 of FERC Order 773-A. As noted in the same paragraph, FERC agreed with NERC’s reasoning. Therefore, this clarification should be recorded in the BES definition.
Individual
John Robertson
First WInd
No
First Wind supports the separation of I2 and I4 and the 75 MVA threshold for aggregating facilities in Inclusion I4 (b), and the exclusion of collector system components that aggregate less than 75 MVA of generation, First Wind disagrees with the inclusion of small individual dispersed generators per Inclusion I4 (a). This problem can be resolved by either removing I4 (a) in its entirety or revising it to clarify that the only BES-relevant standards that apply to individual dispersed generators are those that affirmatively state that they apply to dispersed generators. While individual generators were included in the Phase I BES definition, Phase II of this project provides an opportunity to refine and improve the BES definition such that industry compliance efforts are focused on activities that will truly have a beneficial impact on reliability. Including individual dispersed generators in the BES definition will cause a major diversion away from efforts that improve BES reliability, as entities are forced to simultaneously seek relief via the Exception Process to exclude individual dispersed generators that are insignificant from a reliability standpoint from their programs while at

the same time attempting to modify their existing compliance programs to accommodate individual dispersed generators in the event that the exception applications are not approved. Regions will be faced with a huge backlog of exception requests for small distributed generators while Generator Owners with dispersed generating assets struggle to implement reliability standards that were never drafted with the intent of being applicable to anything but large scale generating stations. As a result, proceeding with the BES definition as currently drafted would actually impair, rather than improve, bulk electric system reliability. First Wind supports the exclusion of collector system components that aggregate less than 75 MVA, it seems inconsistent that a 1-2 MVA individual dispersed generator is deemed significant to reliability but the equipment that is utilized to connect multiple dispersed generators totaling up to 75 MVA is deemed not significant to reliability. The logic that led to the exclusion of collector system equipment that aggregates less than 75 MVA, as well as the logic expressed on the webinar that 75 MVA is the threshold at which the loss of generation could have an impact on BES reliability, argues for also excluding individual dispersed generators. Furthermore, what is the logic of including individual 1-2 MVA wind turbine generator at a >75 MVA wind farm while excluding an individual wind turbine at a <75 MVA wind farm? With no technical rationale or difference in effects on BES reliability, how can identical 2 MVA units be treated so differently? The only compelling reason for applying BES standards to individual dispersed generators would be if there were a real risk of a common mode failure affecting a large share of the dispersed generators in a >75 MVA wind plant. However, per FERC Order 661A, wind turbine generators already comply with voltage and frequency ride-through standards that are far more stringent than those apply to other types of generators. As a result, if a common mode failure caused by a grid disturbance were to affect the wind turbines in a >75 MVA wind plant, the impact on the wind plant would be irrelevant for grid reliability because the voltage and/or frequency deviation would have already caused most if not all of the conventional generators in the grid operating area to trip offline. No compelling rationale has been offered for why including individual dispersed wind turbine generators in the BES definition will improve grid reliability.
Yes
Yes
No
Individual
Anthony Jablonski
ReliabilityFirst
Yes
Even though ReliabilityFirst votes in the Affirmative, ReliabilityFirst is aware of some concerns among Registered Entities for the potential issue of individual wind units (i.e. single

generators) being required to register based on the language of the revised definitions (specifically I4). Though ReliabilityFirst staff agrees with I4 and does not believe this is an issue, ReliabilityFirst recommends NERC and the Regional Entities come up with a common understanding on how Entities are registered based on their ownership of wind units which are designated as BES through the new definition.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
No
FOR: Inclusion I4 REPLACE: Complete wording of I4 WITH: “I4 - Dispersed power producing resource projects , or portion(s) thereof, designed primarily for supplying wholesale power (e.g., a wind farm, or solar farm) that aggregate to a total capacity greater than 75 MVA (gross nameplate rating) at a common point of connection to a voltage of 100 kV or above consisting of: a) The individual resources, and b) The delivery system designed primarily for delivering capacity from i) the point where those resources aggregate to the total connected capacity; to ii) a common point of connection at a voltage of 100 kV or above.” RATIONALE: (1)• “projects … designed primarily for wholesale” – nothing in this posted version distinguishes between generation for retail (behind the meter) and generation for wholesale. As such roof-top PVs, generator assistance programs, or other similar small power-producing incentives, might be otherwise interpreted as included under I4. (2)• “(e.g., a wind farm, or solar farm)” – Because the SDT’s I4 text-box will be dropped from the final version, we believe this inclusion is necessary to retain an illustration of the intent. (3)• I4.a - While imposing BES Standards of governance toward management of individual small units is counter-productive and administratively burdensome, we do agree that differentiating applicability to various Standards should be specified through those Standards. To that end, we are dedicated to drafting and vigorously promoting a SAR to appropriately address dispersed power producing resource applicability within individual NERC Standards. (4)• I4.b – We believe our proposed wording: o Appropriately addresses impact to BES reliability. Rather than offering some illusion for reliability at a lesser impact level, this proposal recognizes that reliability rests in TPs, BAs, RCs, and TOPs responsibly addressing the single greatest contingency arising from, and the behavior of, dispersed power producing resources in the aggregate. Enforcing governance for management to any lesser level is not productive and has no true value to BES reliability. o Better aligns with FERC’s Determination within Order 770 paragraph 114. o Aligns with FERC’s Determination for I2 within Order 773 paragraph 91. o Aligns with FERC’s Determination for I2 within Order 773 paragraph 92. ALTERNATE APPROACH: In the consideration of comments, the drafting team indicated that a SAR might be submitted to appropriately adjust GO and GOP standards requirements for dispersed generating facilities. We agree that is the approach to undertake. In order to

support this approach, I4 should be deleted to avoid the situation where inappropriate provisions could become effective and compliance become difficult or impossible for entities until work is completed through the SAR to adjust those requirements. In the filing with FERC this procedure could be explained so that FERC can be assured that their approval of inclusion of dispersed generating facilities in the phase I order will be appropriately implemented. AECI also supports NAGF's recommendation for the SDT with regard to I2 changes.
Yes
AECI appreciates the SDT's willingness to tackle this issue and provide a higher kV level than 0, as well as its technical justification.
Yes
Yes
AECI supports the NAGF's draft comment for concern, duplicated immediately below: "The language of the proposed BES definition is rather convoluted and is therefore difficult to apply correctly without the Reference Document. The FERC order 773/773a-amended Reference Document is not complete or final for the phase-2 BES definition, however. Its exclusion E1 statement is that of phase-1, not phase-2, for example, and a disclaimer on p.1 states that "…this reference document is outdated. Revisions to the document will be developed at a later date to conform to the definition being developed in Phase 2." It appears that the phase-2 BES definition is being rushed through the approval process, and it would be preferable to take the time to compile a complete and consistent body of documentation before putting the matter up for a vote. This is especially important for correctly classifying very small, standby, non-Blackstart Resource gensets feeding the aux buses of generation plants for emergency purposes. Such emergencies include blackouts and max-generation situations, and in the latter case displacing some of the aux load can temporarily boost the net amount of power delivered by the plant. Figure I2-5 of the Reference Document suggests that such standby generators are part of the BES, if the plant totals more than 75 MVA, because they, "contribute to the gross aggregate rating of the site." Fig. I2-5 depicts all units exporting to the grid, however, and we are considering here only standby gensets feeding aux buses that remain net importers of power. Exclusion E3 may apply, however. Fig. S1-9b of the Reference Document shows a system composed of several generating plants and users, but the conclusions reached by the SDT should be unchanged if one drew a box around the diagram and labeled it a single generating plant. Specifically, the SDT decided that Exclusion 3 is invoked by the circumstance that the bus fed by the 5 MVA generator at lower left is exclusively an importer of power, and this ruling should apply as well for standby gensets that feed aux buses within generation plants. Making such a classification would require that a Local Network (LN) can exist within a generation plant, as opposed be being found exclusively in the systems of TOs and DPs. Such an interpretation may be permitted by the circumstance that the definition of an LN uses the word "transmission" with a lower-case "t", as opposed the TO and DP-oriented term "Transmission" in the NERC Glossary, but the LN definition also references serving "retail

customer load." This definition should be changed, or (better) the BES definition should explicitly state that gensets < 20 MVA feeding power-importing aux buses of generation plants are excluded from the BES. Additionally, the MVA size of reactive power generator that is included by I5 should be specificed. "
Group
ACES Standards Collaborators
Ben Engelby
Yes
(1) We thank the drafting team for separating dispersed power producing resources to a separate inclusion category. This avoids some of the confusion in the prior posting. (2) We have a question regarding the diagram provided in the comment form. Why is each generating unit considered a part of the BES? Wouldn't the point of aggregation be the first BES element? If a single dispersed power producing resource fails, there is no impact on the BES. We request the drafting team consider this aspect.
Yes
We thank the drafting team for increasing the minimum threshold to 50 kV for sub-100 kV looped radial systems.
Yes
Yes
We understand that NERC has developed a process for handling exception requests. We are concerned this process could be similar to the TFE exception process. We recommend that the exception process should be included with future BES definition postings with the opportunity to comment on the process.
Individual
Michael Goggin
American Wind Energy Association
No
While we strongly support the separation of I2 and I4 and the 75 MVA threshold for aggregating facilities in Inclusion I4 (b), and the exclusion of collector system components that aggregate less than 75 MVA of generation, we still strongly disagree with the inclusion of small individual dispersed generators per Inclusion I4 (a). This problem can be resolved by either removing I4 (a) in its entirety or revising it to clarify that the only BES-relevant standards that apply to individual dispersed generators are those that affirmatively state that they apply to dispersed generators. While individual generators were included in the Phase I BES definition, that is not a compelling reason why they should also be included in Phase II. Phase II of this project provides an opportunity to refine and improve the BES definition such that industry compliance efforts are focused on activities that will truly have a beneficial

impact on reliability. Including individual dispersed generators in the BES definition will cause a major diversion away from efforts that improve BES reliability, as entities are forced to simultaneously seek relief via the Exception Process to exclude individual dispersed generators that are insignificant from a reliability standpoint from their programs while at the same time attempting to modify their existing compliance programs to accommodate individual dispersed generators in the event that the exception applications are not approved. With more than 45,000 wind turbines installed in the U.S. and the vast majority of them in wind plants larger than 75 MVA, NERC will be faced with a huge backlog of exception requests for small distributed generators while Generator Owners with dispersed generating assets struggle to implement reliability standards that were never drafted with the intent of being applicable to anything but large scale generating stations. As a result, proceeding with the BES definition as currently drafted would actually impair, rather than improve, bulk electric system reliability. In the Consideration of Comments document for the first draft of Phase II BES definition, the Drafting Team acknowledged that there are both existing and pending reliability standards which likely will need to be reviewed and revised to clarify or correct the applicability of the standard requirements to small-scale generation and recommended that the industry create a SAR to call for this action. Relative to the approval and implementation time frames being discussed for the new BES definition, we do not believe any such action could be taken in a timely enough fashion to resolve industry uncertainty and avoid a major regulatory burden that would distract from efforts that actually improve grid reliability. Examples of standards that were not drafted with small dispersed generators in mind include: • PRC-005-2 Protection System testing – the relay test requirements were developed with large generators in mind, and differ significantly from requirements in FERC Order 661A, of 2005 that require wind plants to meet Low Voltage Ride-Through (LVRT) and Power Factor Design Criteria. These standards significantly change the protection scheme applied to individual turbines, and there is no clarity about how they should be applied. Wind turbine protection systems are often integral to the wind farm control system and the PRC-005-2 requirements were developed for protection equipment typically applied to large-scale generation, not wind farm control systems. • TOP-002 Normal Operations Planning – Under R14 of this standard, an unplanned outage for any individual wind turbine would require a status notification report from the GO to the TO/TOP. While such a report can be important for large central station generation, it would provide no value for a small individual wind turbine generator. This level of reporting, at typically less than 3 MVA, is much lower that any practical reliability threshold, and would simply result in a documentation effort with no value. Similar concerns exist for FAC-008-3, PRC-001-1, PRC-004-2a, PRC-019-1, PRC-024-1, and PRC-025-1, and other standards in which small-scale dispersed generators were not considered during the standards' development. Unless Inclusion I4 (a) is eliminated, or significantly revised to clarify that the only BES-relevant standards that apply to dispersed generators are those that affirmatively state that they apply to dispersed generators, we do not believe implementation of the new BES definition should go forward until all reliability standards have been reviewed and revised as necessary to clarify the applicability to individual dispersed generating assets. What reliability benefit is there to a "bright line" BES definition if there is not a corresponding clarity in the applicability

of reliability standards to the elements deemed to be included in the BES? On the August 21, 2013 webinar, the BES definition drafting team indicated that its justification for the 75 MVA aggregating threshold in I4 (b) was that 75 MVA is the level that the drafting team believes that single failures resulting in the loss of generation could have an appreciable impact on the grid. While we support the exclusion of collector system components that aggregate less than 75 MVA, it seems inconsistent that a 2 MVA individual dispersed generator is deemed significant to reliability but the equipment that is utilized to connect multiple dispersed generators totaling up to 75 MVA is deemed not significant to reliability. The logic that led to the exclusion of collector system equipment that aggregates less than 75 MVA, as well as the logic expressed on the webinar that 75 MVA is the threshold at which the loss of generation could have an impact on BES reliability, argues for also excluding individual dispersed generators. Furthermore, what is the logic of including individual 2 MVA wind turbine generator at a >75 MVA wind farm while excluding individual 2 MVA wind turbine at a <75 MVA wind farm? With no technical rationale or difference in effects on BES reliability, how can identical 2 MVA units be treated so differently? The only compelling reason for applying BES standards to individual dispersed generators would be if there were a real risk of an abrupt common mode failure affecting a large share of the dispersed generators in a >75 MVA wind plant. However, per FERC Order 661A, wind turbine generators already comply with voltage and frequency ride-through standards that are far more stringent than those that apply to other types of generators. As a result, if a common mode failure caused by a grid disturbance were to affect the wind turbines in a >75 MVA wind plant, the impact on the wind plant would be irrelevant for grid reliability because the voltage and/or frequency deviation would have already caused most if not all of the conventional generators in the grid operating area to trip offline. While weather-driven changes in wind speed can significantly change the aggregate output of a wind plant, those changes in output occur too gradually to pose a risk to bulk power system reliability, and regardless such changes in output would not be regulated or mitigated by BES-relevant standards. No compelling rationale has been offered for why including individual dispersed wind turbine generators in the BES definition will improve grid reliability.
Individual
Dan Inman
Minnkota Power Cooperative
No
During the 8/21/2013 webinar the presenter emphasized the critical nature of the aggregate generation of dispersed power producing resources to the reliability of the interconnected transmission system. I4 subpart (a) is inconsistent with the stated critical nature of the aggregate generation. The presenter also indicated that standards that apply to GO/GOP associated standards should be addressed via a SAR to correct reliability standards that

impose a burden on the industry without providing a significant benefit to reliability. The appropriate manner to address this discrepancy is not to submit a SAR to modify the standards that would inappropriately invoke requirements on individual generators due to their inclusion in the BES definition, but to eliminate I4 subpart (a) and modify standards in the future to address any reliability issues that may need the imposition of requirements for individual dispersed power producing resources. The following language is suggested for a revised I4: I4 - Dispersed power producing resources consisting of the system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. Proceeding in this manner will avoid temporary inappropriate standards requirements being applied to individual dispersed power resources and still address the individual resources in standards where needed to support reliability.
Yes
Yes
No
Individual
Richard Vine
California Independent System Operator
No
It is clear that the SDT has taken significant action to distinguish between dispersed power producing resources and traditional generating resources through modification of inclusion I4. However, the California ISO is concerned that the new verbiage under I4 a), as well as the color-coded diagram included on the comment form to provide clarification of BES elements, actually results in ambiguity as to whether each individual power producing resource must be treated as a BES Element. In particular, use of the phrase “Individual resources that aggregate…” under I4 a), along with use of the word “and” between I4 a) and I4 b), leaves open to interpretation whether each individual power producing resource (e.g., each wind turbine within a wind farm that aggregates to greater than 75 MVA) must be treated as a BES element or whether only the aggregated whole is a BES element. Though it may be that the SDT meant to capture that the combination of all aggregated resources and the delivery system together comprise a BES element, it could be construed that each individual resource under a) is a BES element and the system for delivering capacity referred to under b) is a BES element. This is further confused by the drawing included on the comment form which uses a blue color to identify each individual power producing resource and uses the same blue color to identify the system for delivering capacity. The legend in the comment box above this drawing states “Green identifies non-BES portions of the Collector System. Blue identifies the dispersed power producing resources and BES Elements.” The ISO is concerned that this

ambiguity may create uncertainty regarding whether particular Reliability Standard requirements apply only to the aggregated resource as a whole or to the individual power producing resources that comprise the aggregated resource, which is a matter that is better addressed on a Standard-specific basis. In light of this ambiguity, the ISO is abstaining and recommends that the SDT clarify its definition so that the focus is on aggregated resource rather than the individual components.
Individual
Spencer Tacke
Modesto Irrigation District
No
No
Yes
I voted NO for the following reasons: 1. WECC studies have shown that there are thousands of MWs of wind and PV generating plants currently on-line, and thousands of MWs under development, in the WECC system, of 20 MW and less capacity units. Ignoring the impacts of these units on the BES would be a mistake, as recent studies by the WECC MVWG (Modeling and Validation Work Group) have shown (i.e., June 2013 Meeting). 2. The revisions have made the definition of the BES so complicated, that the definition is no longer in a form that can be applied in a straight forward and reasonable manner. Also, there are no technical justifications provided for some of the exclusion criteria (e.g, 75 MVA). 3. The best way to define the BES is by using the engineering methodology developed by the WECC BES Definition Task Force, and published in May 2010. That study work showed that for the location in question to have a material impact to the interconnected bulk electric power system, there must be an equivalent short circuit MVA exceeding 6000 at that location. Thank you.
Individual
Kenn Backholm
Public Utility District No.1 of Snohomish County
No
Snohomish supports the Project 2010-17 – Definition of the BES (Phase 2) Standard Drafting Team in its efforts to clarify the BES definition. Although Snohomish supports the current definition and will be voting affirmative, we are concerned with the compliance burden to

small dispersed generators that typically are less than 2 MW and have capacity factors in the 25 to 35% range, and may be inclined to change our position if the following issues are not resolved. Snohomish believes these concerns can be addressed within the Reliability Standards applicable to GO/GOPs or with the suggested changes below". 1.Replace the current ballot's draft I4 language: "I4 - Dispersed power producing resources consisting of: a) Individual resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above." With the proposed comment I4 language: "I4 - Dispersed power producing resource projects , or portion(s) thereof, designed primarily for supplying wholesale power (e.g., a wind farm, or solar farm) that aggregate to a total capacity greater than 75 MVA (gross nameplate rating) at a common point of connection to a voltage of 100 kV or above consisting of: a) The individual resources, and b) The delivery system designed primarily for delivering capacity from i) the point where those resources aggregate with a total connected capacity greater than 75MVA; to ii) a common point of connection at a voltage of 100 kV or above." Rationale: "projects … designed primarily for wholesale" – nothing in the currently posted version of Inclusion I4 distinguishes between generation for retail (behind the meter) and generation for wholesale. As such roof-top PVs, generator assistance programs, or other similar small power-producing incentives, might be otherwise interpreted as included under I4. There is a real possibility that, with net metering laws, tax incentives, and related public policies strongly favoring the development of, for example, small, individually-owned solar PV systems, those small systems could easily exceed the 75 MVA thresholds in the aggregate. Considered individually, these small systems have no discernible impact on the reliable operation of the BES. With sufficient market penetration, these systems might conceivably have some impact on the BES, but mediating that impact should be the responsibility of TPs, BAs, TOPs, and other system operators. The regulatory burden imposed on small owners of individual distributed generation systems that would result from classifying such small generators as part of the BES would be significant, and a strong disincentive running contrary to current public policy favoring such systems. Yet, because such small systems have no impact on the reliable operation of the BES, extending regulation in this way would have no benefit for BES reliability. • "(e.g., a wind farm, or solar farm)" – Because the SDT's I4 text-box will be dropped from the final version, we believe this language is necessary to clearly express the intent of the BES to cover utility-scale wind farms, solar farms, and similar installations that consist of many relatively small units that are aggregated for wholesale while excluding small, individually-owned systems, such as rooftop solar PV arrays, that are not aggregated for the wholesale market but are owned by and benefit individual retail customers • I4.a - Imposing BES related Reliability Standards on individual small units is counter-productive and administratively burdensome. To the extent that applying individual Reliability Standards to such small, non-aggregated units is demonstrably necessary to protect BES reliability, application should be governed by the language of individual Standards rather than by classifying such small systems as BES. To that end, we are dedicated to drafting and vigorously promoting a SAR to appropriately address the applicability of individual NERC Standards to dispersed power-producing resources. • I4.b

– We believe our proposed wording: oAppropriately addresses impact to BES reliability. The proposed language recognizes that reliability rests depends on TPs, BAs, RCs, and TOPs responsibly addressing the single greatest contingency arising from, and the behavior of, dispersed power producing resources in the aggregate. Enforcing reliability standards on the owners of small, dispersed, and non-aggregated resources is not productive and has no true value to BES reliability. Better aligns with FERC's Determination in Order 773 paragraph 114. , where FERC determined that it will not direct NERC to include collector systems within wind farms and similar generation systems in the BES through Inclusion I4. oAligns with FERC's Determination for I2 in Order 773 paragraph 91 and 92, that multiple step-up transformers that connect generators to the BES at above 100-kV should be included in the BES, while connections at lower voltages that operate as part of a local distribution system should not be classified as part of the BES.
Yes
Yes
No

**Figure submitted by Tri-State G&T referenced in Q1 comments:*

http://www.nerc.com/pa/Stand/Documents/BES_I4_Clarification_for_Included_Elements_09042013.pdf

Standards Announcement

Project 2010-17 Definition of Bulk Electric System Phase 2

Additional Ballot Results

Now Available

An additional ballot for Phase 2 of the **Definition of Bulk Electric System (DBES)** concluded at **8 p.m. Eastern on Wednesday, September 4, 2013.**

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the additional ballot.

Approval
Quorum: 78.68% Approval: 66.11%

Background information for this project can be found on the project page.

Next Steps
The drafting team will consider all comments received during the formal comment period.

Standards Development Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2010-17 Definition of BES - Phase 2
Ballot Period:	8/26/2013 - 9/4/2013
Ballot Type:	Additional Ballot
Total # Votes:	310
Total Ballot Pool:	394
Quorum:	**78.68 % The Quorum has been reached**
Weighted Segment Vote:	66.11 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	47	0.627	28	0.373	0	10	20
2 - Segment 2	8	0.2	2	0.2	0	0	0	4	2
3 - Segment 3	90	1	36	0.563	28	0.438	0	6	20
4 - Segment 4	36	1	18	0.643	10	0.357	0	1	7
5 - Segment 5	88	1	33	0.611	21	0.389	0	7	27
6 - Segment 6	51	1	26	0.619	16	0.381	0	3	6
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	2	0.1	1	0.1	0	0	0	0	1
9 - Segment 9	4	0.4	2	0.2	2	0.2	0	0	0
10 - Segment 10	8	0.8	7	0.7	1	0.1	0	0	0
Totals	**394**	**6.6**	**173**	**4.363**	**106**	**2.238**	**0**	**31**	**84**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	COMMENT RECEIVED
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	COMMENT RECEIVED
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED

1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	ATCO Electric	Glen Sutton	Abstain	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Negative	COMMENT RECEIVED
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Big Rivers Electric Corp.	Chris Bradley		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	Amber Anderson	Negative	COMMENT RECEIVED
1	El Paso Electric Company	Dennis Malone	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	COMMENT RECEIVED
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin	Affirmative	
1	Lincoln Electric System	Doug Bantam	Negative	COMMENT RECEIVED
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(AECI)
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Abstain	
1	Memphis Light, Gas and Water Division	Allan Long		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnesota Power, Inc.	Randi K. Nyholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (MG&E)
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	COMMENT RECEIVED
1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS - (Scott Bos)
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPPD)
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	North Carolina Electric Membership Corp.	Robert Thompson	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO)
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted under the title of 'PPL NERC Registered Affiliates')
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	COMMENT RECEIVED
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		

1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase (Seattle City Light))
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Abstain	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Abstain	
2	New Brunswick System Operator	Alden Briggs		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Alameda Municipal Power	Douglas Draeger		
3	Ameren Services	Mark Peters	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
3	Arkansas Electric Cooperative Corporation	Philip Huff		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	

3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Farmington	Linda R Jacobson		
3	City of Palo Alto	Eric R Scott	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	City of Ukiah	Colin Murphey		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Negative	SUPPORTS THIRD PARTY COMMENTS - (William Waudby)
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	East Kentucky Power Coop.	Patrick Woods	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger	Affirmative	
3	Fayetteville Public Works Commission	Allen R Wallace		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Kootenai Electric Cooperative	Dave Kahly		
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Abstain	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	COMMENT RECEIVED
3	Mississippi Power	Jeff Franklin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)

3	Modesto Irrigation District	Jack W Savage	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
3	Muscatine Power & Water	John S Bos	Negative	COMMENT RECEIVED
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPPD comments provided by Don Schmit.)
3	New York Power Authority	David R Rivera	Affirmative	
3	North Carolina Electric Membership Corp.	Doug White	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Schmidt, O'brien, Moran, Mackowicz)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward		
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Rutherford EMC	Thomas M Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	COMMENT RECEIVED
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill		
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase (Seattle City Light))
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	Southern California Edison Company	David B Coher		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	COMMENT RECEIVED
				SUPPORTS THIRD PARTY

3	Wisconsin Public Service Corp.	Gregory J Le Grave	Negative	COMMENTS - (See Tom Breene's comments - WPSC)
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy Comments)
4	Alabama Municipal Electric Authority	Raymond Phillips		
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	COMMENT RECEIVED
4	Arkansas Electric Cooperative Corporation	Ronnie Frizzell		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Buckeye Power, Inc.	Manmohan K Sachdeva		
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (William Waudby)
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Breene for Wisconsin Public Service Corp)
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	COMMENT RECEIVED
4	Modesto Irrigation District	Spencer Tacke	Negative	COMMENT RECEIVED
4	National Rural Electric Cooperative Association	Barry R. Lawson	Abstain	
4	North Carolina Eastern Municipal Power Agency	Cecil Rhodes	Affirmative	
4	North Carolina Electric Membership Corp.	John Lemire	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	COMMENT RECEIVED
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase (Seattle City Light))
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative, Inc (SEC))
4	Tacoma Public Utilities	Keith Morisette	Affirmative	

4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (We Energies)
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Previous comments submitted by AZPS)
5	Arkansas Electric Cooperative Corporation	Brent R Carr		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Buckeye Power, Inc.	Paul M Jackson		
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Michael Shultz	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (William Waudby)
5	Cowlitz County PUD	Bob Essex		
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Abstain	
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	El Paso Electric Company	Gustavo Estrada	Affirmative	
5	Essential Power, LLC	Patrick Brown	Negative	COMMENT RECEIVED
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	

5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Generator Forum Standards Reveiw Team)
5	Lincoln Electric System	Dennis Florom	Negative	COMMENT RECEIVED
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Abstain	
5	MidAmerican Energy Co.	Neil D Hammer		
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (Scott Bos)
5	Nebraska Public Power District	Don Schmit	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi		
5	Ontario Power Generation Inc.	David Ramkalawan		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Bonnie Marino-Blair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kelly Cumiskey, PacifiCorp)
5	Pattern Gulf Wind LLC	Grit Schmieder-Copeland	Negative	SUPPORTS THIRD PARTY COMMENTS - (North American Generator Form SRT)
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF Standard's Review Team)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Negative	COMMENT RECEIVED
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase, Seattle City Light)
				SUPPORTS THIRD PARTY COMMENTS -

5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	(Seminole Electric Cooperative Inc.)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	COMMENT RECEIVED
5	Wisconsin Public Service Corp.	Scott E Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Breene Wisconsin Public Service Corp.)
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz (AEP))
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Arkansas Electric Cooperative Corporation	Keith Sugg		
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	El Paso Electric Company	Luis Rodriguez	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Sacramento Municipal Utility District)
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Affirmative	
6	North Carolina Municipal Power Agency #1	Matthew Schull	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	

6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Abstain	
6	PacifiCorp	Kelly Cumiskey	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Ty Bettis		
6	Power Generation Services, Inc.	Stephen C Knapp	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Negative	COMMENT RECEIVED
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	COMMENT RECEIVED
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Breene – Wisconsin Public Service Corporation)
6	Xcel Energy, Inc.	David F Lemmons	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland, Xcel Energy)
7	Alcoa, Inc.	Thomas Gianneschi		
7	EnerVision, Inc.	Thomas W Siegrist	Affirmative	
8		Edward C Stein		
8		Debra R Warner	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	COMMENT RECEIVED
9	New York State Department of Public Service	Thomas G. Dvorsky	Negative	COMMENT RECEIVED
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Negative	COMMENT RECEIVED
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	

10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project 2010-17 Definition of Bulk Electric System

The Project 2010-17 Drafting Team thanks all commenters who submitted comments on Draft 2, Phase 2 of the Bulk Electric System definition. The definition was posted for a 30-day formal comment period from August 6, 2013 through September 4, 2013. Stakeholders were asked to provide feedback on the definition and associated documents through a special electronic comment form. There were 65 sets of responses, including comments from approximately 153 different people from approximately 117 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the project page.

Summary Consideration:

Inclusion I4. Based on industry comments, the SDT modified the language of Inclusion I4 to clearly reflect the SDT's intent to include individual dispersed power producing units (such as wind and solar units) that aggregate to greater than 75 MVA , along with the collector system that connects these units, from the point they aggregate to greater than 75 MVA to the point of connection at 100kV or higher. While the SDT recognizes that some stakeholders do not agree with the inclusion of individual dispersed power producing units, FERC Orders 773 and 773-A approved the inclusion of these individual units. No stakeholder has provided a technical rationale to support removal of the individual units from the definition. The SDT believes that stakeholder concerns about inclusion of individual units may be addressed by specifying the Facilities to which an individual standard applies within the Applicability section of that standard.

The revised language for inclusion I4 now reads:

> **I4** - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
>
> a) The individual resources, and
> b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

Implementation Plan. The SDT received comments by Canadian entities reflecting the fact that there are varying approaches for making NERC standards effective in North American jurisdictions. NERC Legal has worked with the Canadian Electricity Association to develop effective date language that provides for the full range of approaches for making standards effective. This language does not change the time frame for implementation from the previous posting; it is simply intended to reflect the differences in regulatory regimes in various jurisdictions. In response to comments and based on the input from NERC legal, the language in the Implementation Plan was clarified as follows.

> This definition shall become effective on the first day of the second calendar quarter after the date that the definition is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter after the date the definition is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

White Paper on 50kV threshold: The SDT corrected minor typographical errors in the white paper on the 50 kV threshold.

Minority issues:

1. Several Canadian entities commented that the 50 kV threshold for loop analysis should not be applied to Canadian entities due to provincial regulations and because it is action taken to respond to a FERC directive. The SDT disagrees. Although the project to revise the definition of Bulk Electric System was undertaken in response to a FERC Order, the SDT believes the threshold in question provides an appropriate bright-line that supports continent-wide reliability of the BES based on physical principles, as demonstrated in the technical analysis in the white paper supporting the selection of the 50 kV threshold. Therefore, the SDT sees no reason for a reference to non-US Registered Entities.

2. Some comments suggested deleting Inclusion I4a concerning the inclusion of individual dispersed power producing resources. The proposed definition continues to include, through inclusion I4, individual dispersed power producing resources if those resources aggregate to a total value greater than 75 MVA. This inclusion treats dispersed power producing resources in a manner that is comparable to other non-dispersed power producing resources and is an approach that was accepted and emphasized by the Commission in Orders No. 773 & 773-A. The SDT has explored various options associated with dispersed power producing resources; however, none of the options explored provided an equal and effective approach to address the Commission's reliability concerns with these facilities. The SDT continues to believe that the best resolution to the industry's concerns is through clarification of the applicability of individual Reliability Standards and not a revision to the BES definition. Given these facts, the SDT is retaining Inclusion I4a but has revised the language of inclusion I4, based on industry comments, to provide greater clarity of the SDT's intent.

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

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Ben Wu	Orange and Rockland Utilities	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
8.	Michael Jones	National Grid	NPCC	1
9.	Mark Kenny	Northeast Utilities	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1

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

11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
15.	Donald Weaver	New Brunswick System Operator	NPCC	2
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	Brian Robinson	Utility Services	NPCC	8
22.	Brian Shanahan	National Grid	NPCC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Group	Louis Slade	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Connie Lowe	NERC Compliance Policy	RFC	5, 6
2.	Miek Garton	NERC Compliance Policy	NPCC	5, 6
3.	Randi Heise	NERC Compliance Policy	MRO	3
4.	Michael Crowley	Electric Transmission Compliance	SERC	1, 3
5.	William Bigdely	Electric Transmission Planning	SERC	1, 3
6.	Craig Crider	Electric Transmission Planning	SERC	1, 3
7.	Jeff Bailey	Nuclear		5
8.	Chip Humphrey	Power Generation		5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	paul haase	seattle city light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	pawel krupa	seattle city light	WECC	1
2.	dana wheelock	seattle city light	WECC	3
3.	hao li	seattle city light	WECC	4
4.	maike haynes	seattle city light	WECC	5
5.	dennis sismaet	seattle city light	WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Patrick Brown	NAGF Standards Review Team					X					

Additional Member	Additional Organization	Region	Segment Selection

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

1.	Allen Schriver	NextEra Energy Resources	5
2.	Steve Berger	PPL Susquehanna, LLC	5
3.	Terry Crawley	Southern Company Generation	5
4.	Pamela Dautel	IPR-GDF Suez Generation NA	5
5.	Dan Duff	Liberty Electric Power	5
6.	Katie Legates	American Electric Power	5
7.	Don Lock	PPL Generation, LLC	5
8.	Chris Schaeffer	Duke Energy	5
9.	Dana Showalter	E.ON Climate & Renewables	5
10.	William Shultz	Southern Company	5
11.	Mark Young	Tenaska, Inc	5

5.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	1	2	3	4	5	6	7	8	9	10
				X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Annette Bannon	PPL Susquehanna, LLC	RFC	5
3.		PPL Montana, LLC	WECC	5
4.		PPL Generation, LLC	RFC	5
5.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
6.			NPCC	6
7.			RFC	6
8.			SERC	6
9.			SPP	6
10.			WECC	6

6.	Group	Jim Kelley	SERC Planning Standards Subcommittee	1	2	3	4	5	6	7	8	9	10
				X				X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Philip Kleckey	SCE&G	SERC	1, 3, 5, 6
2.	John Sullivan	Ameren	SERC	1, 3
3.	William Berry	OMU	SERC	3
4.	Bob Thomas	IMEA	SERC	4

7.	Group	Robert Rhodes	SPP Standards Review Group	1	2	3	4	5	6	7	8	9	10
					X								

	Additional Member	Additional Organization	Region	Segment Selection

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

	Member	Organization	Region	Segment Selection
1.	John Boshears	City Utilities of Springfield	SPP	1, 4
2.	Allan George	Sunflower Electric Power Corporation	SPP	1
3.	Jonathan Hayes	Southwest Power Pool	SPP	2
4.	Tara Lightner	Sunflower Electric Power Corporation	SPP	1
5.	Jerry McVey	Sunflower Electric Power Corporation	SPP	1
6.	James Nail	City of Independence, MO	SPP	3
7.	Kevin Nincehelser	Westar Energy	SPP	1, 3, 5, 6
8.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
10.	Sean Simpson	Board of Public Utilities, City of McPherson	SPP	NA
11.	Don Taylor	Westar Energy	SPP	1, 3, 5, 6
12.	Mark Wurm	Board of Public Utilities, City of McPherson	SPP	NA

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

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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Joe Tarantino	BANC & SMUD	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kevin Smith	Balancing Authority Northern California	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Lorissa Jones	Transmission Reliability Program	WECC	1
2.	John Anasis	Technical Operations	WECC	1
3.	Berhanu Tesema	Transmission Planning	WECC	1
4.	Chuck Matthews	Transmission Planning	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Colby Bellville	Duke Energy	X		X		X	X				

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Greg Cecil		RFC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	David Dockery	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
2.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
3.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
4.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
5.	Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4
6.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
7.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Individual	Ashley Stringer	Oklahoma Municipal Power Authority				X						
15.	Individual	Emily Pennel	Southwest Power Pool Regional Entity										X
16.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
17.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
18.	Individual	William Gallagher	Transmission Access Policy Study Group	X		X	X	X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
19.	Individual	Wayne Johnson	Southern Company	X		X		X	X				
20.	Individual	Kelly Cumiskey	PacifiCorp	X		X		X	X				
21.	Individual	Thomas Breene	Wisconsin Public Service Corporation			X	X	X	X				
22.	Individual	Joseph DePoorter	Madison Gas and Electric Company			X	X	X	X				
23.	Individual	David Thorne	Pepco Holdings Inc	X		X							
24.	Individual	Scott Bos	Muscatine Power and Water	X		X		X	X				
25.	Individual	John Seelke	Public Service Enterprise Group	X	X			X	X				
26.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
27.	Individual	Barbara Kedrowski	Wisconsin Electric Power Company			X	X	X					
28.	Individual	John Bee	Exelon and its' affiliates	X		X		X					
29.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
30.	Individual	Gary Kruempel, Terry Harbour, Tom Mielnik	MidAmerican Energy Company	X		X							
31.	Individual	Shaun Moran, Lynn Schmidt, Joe O'Brien, Ed Mackowicz,	NIPSCO	X		X		X	X				
32.	Individual	Michael Falvo	Independent Electricity System Operator		X								
33.	Individual	David Jendras	Ameren	X		X		X	X				
34.	Individual	Chifong Thomas	BrightSource Energy, Inc.					X					
35.	Individual	Amber Anderson	East Kentucky Power Cooperative	X		X		X					
36.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
37.	Individual	William Waudby	Consumers Energy Company			X	X	X					
38.	Individual	Kenneth A Goldsmith	Alliant Energy				X						
39.	Individual	Nazra Gladu	Manitoba Hydro	X		X	X	X					
40.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
41.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
42.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
43.	Individual	Larry Watt	Lakeland Electric	X									
44.	Individual	Bret Galbraith	Seminole Electric Cooperative, Inc.			X	X	X	X				
45.	Individual	Wayne Sipperly	New York Power Authority	X		X		X	X				
46.	Individual	Mahmood Safi	Omaha Public Power District	X		X		X	X				
47.	Individual	Don Streebel	Idaho Power Company	X									
48.	Individual	Diane Barney	NARUC									X	
49.	Individual	Thomas Dvorsky	New York State Department of Public Service									X	
50.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
51.	Individual	Scott Langston	City of Tallahassee	X									
52.	Individual	Oliver Burke	Entergy Services, Inc.	X									
53.	Individual	Terry Volkmann	Volkmann Consulting, Inc								X		
54.	Individual	Ryan Walter	Tri-State Generation and Transmission Association, Inc.	X		X		X					
55.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
56.	Individual	Russel Mountjoy	MRO										X
57.	Individual	David Kiguel (by Ayesha Sabouba)	Hydro One	X									
58.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
59.	Individual	John Robertson	First WInd	X				X					
60.	Individual	Anthony Jablonski	ReliabilityFirst										X
61.	Individual	Michael Goggin	American Wind Energy Association								X		
62.	Individual	Dan Inman	Minnkota Power Cooperative	X									
63.	Individual	Richard Vine	California Independent System Operator		X								
64.	Individual	Spencer Tacke	Modesto Irrigation District			X	X		X				
65.	Individual	Kenn Backholm	Public Utility District No.1 of Snohomish County	X		X	X	X	X			X	

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The SDT thanks you for following the guidelines and will consider your comments as supporting the positions of the entities shown here.

Organization	Supporting Comments of “Entity Name”
Lakeland Electric	Lakeland Electric supports the Florida Municipal Power Agency comments.
New York Power Authority	LPPC
seattle city light	Sacramento Municipal Utility District (SMUD)
Entergy Services, Inc.	SERC OC Review Group comments
Oklahoma Municipal Power Authority	Transmission Access Policy Study (TAPS) Group
Illinois Municipal Electric Agency	Transmission Access Policy Study Group (TAPS) and SERC OC Review Group

1. **The SDT has separated Inclusion I2 and I4 to provide the clarity requested by the industry in the first posting comments. In addition, again in response to industry comments, the SDT has added language to Inclusion I4b to identify the equipment from an aggregation point of greater than 75 MVA to the connection to the BES. Do you agree with these changes? If not, please provide technical rationale for your disagreement along with suggested language changes.**

Summary Consideration: The proposed definition continues to include individual dispersed power producing resources, through Inclusion I4, if those resources aggregate to a total value greater than 75 MVA. Inclusion I4 treats dispersed power producing resources in a manner that is comparable to other non-dispersed power producing resources and is an approach that was accepted and emphasized by the Commission in Orders No. 773 & 773-A. The SDT has explored various options associated with dispersed power producing resources; however, none of the options explored provided an equal and effective approach to address the Commission's reliability concerns with these facilities. The SDT continues to believe that the best resolution to the industry's concerns about inclusion of individual dispersed power-producing units is through clarification of the applicability of individual Reliability Standards and not a revision to the BES definition. Given these facts, the SDT is retaining Inclusion I4a but has revised the language of inclusion I4, based on industry comments, to provide greater clarity of the SDT's intent. The revised language is as follows:

> **I4** - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
>
> a) The individual resources, and
> b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

Organization	Yes or No	Question 1 Comment
NAGF Standards Review Team	No	1. Replace the current ballot's draft I4 language:"I4 - Dispersed power producing resources consisting of: a) Individual resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or

Organization	Yes or No	Question 1 Comment
		above."With the proposed comment I4 language:"I4 - Dispersed power producing resource projects, or portion(s) thereof, designed primarily for supplying wholesale power (e.g., a wind farm, or solar farm) that aggregate to a total capacity greater than 75 MVA (gross nameplate rating) at a common point of connection to a voltage of 100 kV or above consisting of: a) The individual resources, and b) The delivery system designed primarily for delivering capacity from i) the point where those resources aggregate to the total connected capacity; to ii) a common point of connection at a voltage of 100 kV or above." Rationale: o "projects ... designed primarily for wholesale" - nothing in this posted version distinguishes between generation for retail (behind the meter) and generation for wholesale. As such rooftop PVs, generator assistance programs, or other similar small power-producing incentives, might be otherwise interpreted as included under I4. o "(e.g., a wind farm, or solar farm)" - Because the SDT's I4 text-box will be dropped from the final version, we believe this inclusion is necessary to retain an illustration of the intent. o I4.a - While imposing BES Standards of governance toward management of individual small units is counter-productive and administratively burdensome, we do agree that differentiating applicability to various Standards should be specified through those Standards. To that end, we are dedicated to drafting and vigorously promoting a SAR to appropriately address dispersed power producing resource applicability within individual NERC Standards. In keeping with that commitment it is suggested that I4a be deleted from the BES definition. This would avoid temporarily imposing inappropriate requirements that would later have to be eliminated by modification of individual standard requirements. A better approach would be to add requirements where needed for individual small

Organization	Yes or No	Question 1 Comment
		units. o I4.b - We believe our proposed wording: o Appropriately addresses impact to BES reliability. Rather than offering some illusion for reliability at a lesser impact level, this proposal recognizes that reliability rests in TPs, BAs, RCs, and TOPs responsibly addressing the single greatest contingency arising from, and the behavior of, dispersed power producing resources in the aggregate. Enforcing governance for management to any lesser level is not productive and has no true value to BES reliability. o Better aligns with FERC's Determination within Order 770 paragraph 114. o Aligns with FERC's Determination for I2 within Order 773 paragraph 91. o Aligns with FERC's Determination for I2 within Order 773 paragraph 92.
Associated Electric Cooperative, Inc. - JRO00088	No	FOR: Inclusion I4REPLACE: Complete wording of I4WITH: "I4 - Dispersed power producing resource projects , or portion(s) thereof, designed primarily for supplying wholesale power (e.g., a wind farm, or solar farm) that aggregate to a total capacity greater than 75 MVA (gross nameplate rating) at a common point of connection to a voltage of 100 kV or above consisting of:a) The individual resources, and b) The delivery system designed primarily for delivering capacity from i) the point where those resources aggregate to the total connected capacity; to ii) a common point of connection at a voltage of 100 kV or above."RATIONALE: (1) o "projects ... designed primarily for wholesale" - nothing in this posted version distinguishes between generation for retail (behind the meter) and generation for wholesale. As such roof-top PVs, generator assistance programs, or other similar small power-producing incentives, might be otherwise

Organization	Yes or No	Question 1 Comment
		interpreted as included under I4. (2) o "(e.g., a wind farm, or solar farm)" - Because the SDT's I4 text-box will be dropped from the final version, we believe this inclusion is necessary to retain an illustration of the intent. (3) o I4.a - While imposing BES Standards of governance toward management of individual small units is counter-productive and administratively burdensome, we do agree that differentiating applicability to various Standards should be specified through those Standards. To that end, we are dedicated to drafting and vigorously promoting a SAR to appropriately address dispersed power producing resource applicability within individual NERC Standards. (4) o I4.b - We believe our proposed wording:o Appropriately addresses impact to BES reliability. Rather than offering some illusion for reliability at a lesser impact level, this proposal recognizes that reliability rests in TPs, BAs, RCs, and TOPs responsibly addressing the single greatest contingency arising from, and the behavior of, dispersed power producing resources in the aggregate. Enforcing governance for management to any lesser level is not productive and has no true value to BES reliability.o Better aligns with FERC's Determination within Order 770 paragraph 114.o Aligns with FERC's Determination for I2 within Order 773 paragraph 91.o Aligns with FERC's Determination for I2 within Order 773 paragraph 92. ALTERNATE APPROACH:In the consideration of comments, the drafting team indicated that a SAR might be submitted to appropriately adjust GO and GOP standards requirements for dispersed generating facilities. We agree that is the approach to undertake. In order to support this approach, I4 should be deleted to avoid the situation where inappropriate provisions could become effective and compliance become difficult or impossible for entities until work is completed through the SAR to adjust those requirements. In the filing with FERC this procedure could be explained so that FERC can be assured that their approval of inclusion of dispersed generating facilities in the phase I order will be appropriately implemented. AECI also supports NAGF's recommendation for the

Organization	Yes or No	Question 1 Comment
		SDT with regard to I2 changes.
Response: The SDT does not believe introducing the term 'wholesale' into the definition provides any additional clarity. No change made. The proposed Inclusion I4 treats dispersed power producing resources comparably to the non-dispersed power producing resources in Inclusion I2 and is consistent with the established values shown in the Statement of Compliance Registry Criteria. The threshold values shown have been accepted by the Commission and endorsed by the Planning Committee. No change made.		
American Electric Power	No	AEP does not agree with the premise that BES elements (measured for compliance) should be as granular as the individual dispersed power resource. We do not see the reliability benefit of tracking all of the compliance elements for individual wind turbines when the focus should be placed on the aggregate of the facilities. Does the RC want to be notified of an outage of each individual wind turbine in real-time, or a loss of significant portion of the wind farm? If we are not careful, we will have entities at these resources and others monitoring them (BAs, TOPs, RCs) focusing on minor issues that will distract from more relevant reliability needs. We believe it would be beneficial and provide more clarity if the verbiage "aggregate to a total capacity greater than 75 MVA (gross nameplate rating) at a common point of connection to a voltage of 100 kV or above" were moved to the beginning of the I4 paragraph rather than as a sub-bullet. For example, "Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA....".We appreciated the development of the diagram to explain the scenario. We encourage the team to continue to provide these illustrations to clarify the intent and the application.
Alliant Energy	No	Alliant Energy agrees with the changes to I2 and I4b, however, firmly believe I4a must be deleted. There is no way an individual dispersed generator in the range

Organization	Yes or No	Question 1 Comment
		of <1 MW to 5 MW will have any reliability impact on the reliability of the BES. In addition, in the MRO footprint alone there would be ~7500 generators added to the list of BES equipment, which would be extremely costly to manage from both the Registered Entity and Regional Entity's perspective.
Lincoln Electric System	No	Although appreciative of the drafting team's efforts, LES is concerned with the proposed inclusion of the individual dispersed power producing resources as part of the Bulk Electric System versus the point at which the resources aggregate to a capacity greater than 75MVA. As currently proposed, the burden would be on the registered entities to either seek multiple exclusions through the BES Exception Process or else race to add numerous BES Elements to existing programs, processes and maintenance schedules to ensure compliance with Reliability Standards such as PRC-005-1.1b, PRC-004-2a, FAC-001, etc. To prevent broad sweeping changes to existing compliance requirements without sufficient technical justification, LES recommends Inclusion I4a be removed altogether and I4b be retained. In the event a reliability-related need is identified in the future pertaining to the individual resources, LES suggests that revisions be made to those standards deemed applicable.
American Transmission Company, LLC	No	ATC appreciates the changes the SDT made to I4, however, believe the wording of I4a still does not adequately communicate the desired treatment of small dispersed power producing resources as an aggregate, rather than an individual basis, when the aggregate capacity is 75 MVA or more. To address this issue, we suggest the following wording change to I4a, "Aggregate of dispersed resources when they aggregate to a total capacity of greater than 75 MVA (gross nameplate rating, and"

Organization	Yes or No	Question 1 Comment
Minnkota Power Cooperative	No	During the 8/21/2013 webinar the presenter emphasized the critical nature of the aggregate generation of dispersed power producing resources to the reliability of the interconnected transmission system. I4 subpart (a) is inconsistent with the stated critical nature of the aggregate generation. The presenter also indicated that standards that apply to GO/GOP associated standards should be addressed via a SAR to correct reliability standards that impose a burden on the industry without providing a significant benefit to reliability. The appropriate manner to address this discrepancy is not to submit a SAR to modify the standards that would inappropriately invoke requirements on individual generators due to their inclusion in the BES definition, but to eliminate I4 subpart (a) and modify standards in the future to address any reliability issues that may need the imposition of requirements for individual dispersed power producing resources. The following language is suggested for a revised I4:I4 - Dispersed power producing resources consisting of the system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. Proceeding in this manner will avoid temporary inappropriate standards requirements being applied to individual dispersed power resources and still address the individual resources in standards where needed to support reliability.
First WInd	No	First Wind supports the separation of I2 and I4 and the 75 MVA threshold for aggregating facilities in Inclusion I4 (b), and the exclusion of collector system components that aggregate less than 75 MVA of generation, First Wind disagrees with the inclusion of small individual dispersed generators per Inclusion I4 (a). This problem can be resolved by either removing I4 (a) in its entirety or revising it to clarify that the only BES-relevant standards that apply to individual dispersed

Organization	Yes or No	Question 1 Comment
		generators are those that affirmatively state that they apply to dispersed generators. While individual generators were included in the Phase I BES definition, Phase II of this project provides an opportunity to refine and improve the BES definition such that industry compliance efforts are focused on activities that will truly have a beneficial impact on reliability. Including individual dispersed generators in the BES definition will cause a major diversion away from efforts that improve BES reliability, as entities are forced to simultaneously seek relief via the Exception Process to exclude individual dispersed generators that are insignificant from a reliability standpoint from their programs while at the same time attempting to modify their existing compliance programs to accommodate individual dispersed generators in the event that the exception applications are not approved. Regions will be faced with a huge backlog of exception requests for small distributed generators while Generator Owners with dispersed generating assets struggle to implement reliability standards that were never drafted with the intent of being applicable to anything but large scale generating stations. As a result, proceeding with the BES definition as currently drafted would actually impair, rather than improve, bulk electric system reliability. First Wind supports the exclusion of collector system components that aggregate less than 75 MVA, it seems inconsistent that a 1-2 MVA individual dispersed generator is deemed significant to reliability but the equipment that is utilized to connect multiple dispersed generators totaling up to 75 MVA is deemed not significant to reliability. The logic that led to the exclusion of collector system equipment that aggregates less than 75 MVA, as well as the logic expressed on the webinar that 75 MVA is the threshold at which the loss of generation could have an impact on BES reliability, argues for also excluding individual dispersed generators. Furthermore, what is the logic of including individual 1-2 MVA wind turbine generator at a >75 MVA wind farm while excluding an individual wind turbine at a <75 MVA wind farm? With no technical rationale or difference in effects on BES reliability, how can identical 2 MVA units be treated so differently? The only compelling reason

Organization	Yes or No	Question 1 Comment
		for applying BES standards to individual dispersed generators would be if there were a real risk of a common mode failure affecting a large share of the dispersed generators in a >75 MVA wind plant. However, per FERC Order 661A, wind turbine generators already comply with voltage and frequency ride-through standards that are far more stringent than those apply to other types of generators. As a result, if a common mode failure caused by a grid disturbance were to affect the wind turbines in a >75 MVA wind plant, the impact on the wind plant would be irrelevant for grid reliability because the voltage and/or frequency deviation would have already caused most if not all of the conventional generators in the grid operating area to trip offline. No compelling rationale has been offered for why including individual dispersed wind turbine generators in the BES definition will improve grid reliability.
Florida Municipal Power Agency	No	FMPA thanks the SDT for its efforts. Although FMPA agrees with separating I4 from I2, we believe the SDT made a grammatical / logical error in the new I4. Inclusion I4 as posted reads: I4 - Dispersed power producing resources consisting of:a) Individual resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. The logical structure of I4 a) and I4 b) read literally does not reflect the intent of the SDT. The SDT seems to want to both: i) Identify the intersection of bullet a) and bullet b) [e.g., only a) vehicles with b) more than 2 axels need to be weighed at a truck stop, e.g., the subset of a) vehicles and b) with more than two axels]ii) While at the same time describe what is part of the BES [e.g., a pie is made of a) filling and b) crust, e.g., the addition of a) and b)]. The use of “and” at the end of bullet a) read literally would be interpreted as adding a) and b), i.e., a pie being made of filling and crust, and does not limit the scope to the intersection of bullets a) and

Organization	Yes or No	Question 1 Comment
		b). That is, the BES pie is made of individual resources that aggregate to > 75 MVA with no criteria over which that aggregation is performed (is it service territory, geography, within a fence, etc.) and b) the portion of a collector system that carries > 75 MVA in aggregation. The word “and” cannot perform both functions of adding a)+b) while at the same time identifying the intersecting subset of set a) and set b), which is what the SDT seems to be attempting to do. What the team must have meant was:I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity from the point at which those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. The BES portion of such resources includes: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. This intent is reflected in the diagram provided by the SDT in the comment form. This grammatical / logic error almost caused FMPA to vote Negative. The version of I4 posted read literally, an auditor does not know on what basis the 75 MVA of generation would be integrated, e.g., over the service territory of the entity? The auditor also is uninformed of whether this includes behind the meter generation or not. FMPA implores the SDT to correct this grammatical / logical error. If this error is not corrected, we will likely be changing our vote, and making recommendations to vote Negative on recirculation / final ballot.
Indiana Municipal Power Agency	No	For question 1, Indiana Municipal Power Agency agrees with the comments submitted by Frank Gaffney, Floriday Municipal Power Agency.

Organization	Yes or No	Question 1 Comment
California Independent System Operator	No	It is clear that the SDT has taken significant action to distinguish between dispersed power producing resources and traditional generating resources through modification of inclusion I4. However, the California ISO is concerned that the new verbiage under I4 a), as well as the color-coded diagram included on the comment form to provide clarification of BES elements, actually results in ambiguity as to whether each individual power producing resource must be treated as a BES Element. In particular, use of the phrase “Individual resources that aggregate...” under I4 a), along with use of the word “and” between I4 a) and I4 b), leaves open to interpretation whether each individual power producing resource (e.g., each wind turbine within a wind farm that aggregates to greater than 75 MVA) must be treated as a BES element or whether only the aggregated whole is a BES element. Though it may be that the SDT meant to capture that the combination of all aggregated resources and the delivery system together comprise a BES element, it could be construed that each individual resource under a) is a BES element and the system for delivering capacity referred to under b) is a BES element. This is further confused by the drawing included on the comment form which uses a blue color to identify each individual power producing resource and uses the same blue color to identify the system for delivering capacity. The legend in the comment box above this drawing states “Green identifies non-BES portions of the Collector System. Blue identifies the dispersed power producing resources and BES Elements.” The ISO is concerned that this ambiguity may create uncertainty regarding whether particular Reliability Standard requirements apply only to the aggregated resource as a whole or to the individual power producing resources that comprise the aggregated resource, which is a matter that is better addressed on a Standard-specific basis. In light of this ambiguity, the ISO is abstaining and recommends that the SDT clarify its definition so that the focus is on aggregated resource rather than the individual components.

Organization	Yes or No	Question 1 Comment
Madison Gas and Electric Company	No	MG&E is voting against the BES Phase II definition due to the fact that it contains Inclusion (I) 4a; Individual resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating). MG&E recommends that I4a be removed and I4b be maintained as the point of aggregation is what is modeled and makes the most sense. Recommend I4 to read as: "Dispersed power producing resources consisting of the system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above". Please see the following reasons for our negative vote: 1. An individual 1.5 mW wind turbine does not impact the BES when it reduces its output (remember just because a turbine is rated at 1.5mW doesn't mean it automatically reaches that output when the wind blows) or trips offline. Entities have been making comments that the place where power is aggregated (usually the bus) should be included and not individual wind turbines, solar collectors, manure digesters, etc (as shown in the comment form). The amount of compliance time for PRC-004 would never be completed. Wind turbines have up to 250 plus reasons why they can trip. Usually due to the change in wind direction. If the wind changes direction and the turbine head cannot keep up within a certain degree of angle, the unit will trip. Coming back on line when the angle requirements are met. So, Entity's will need to apply the R2 of PRC-004-2a, for every wind turbine trip. We do not have the resources to review these trips and that 1.5 wind turbine does not impact the BES. We will agree that the point of interconnection (of greater than 75 MVA) is important and should be contained in the BES definition as written in I4B. PRC-004-2a is only one Standard, notwithstanding; BAL-001-TRE-01, FAC-001, FAC-003, FAC-008-3, MOD-024, MOD-025, MOD-026, MOD-027, PRC-005, PRC-006-SPP-01, PRC-019, PRC-024, PRC-025, and TOP-003. A 75 MVA wind farm is not equal to a 75 MVA combustion turbine. Yes, energy flow is modeled the same (at full name plate output) but these two extremely different facilities are quite different. The wind facility is not

Organization	Yes or No	Question 1 Comment
		dispatchable (only reduction in Mw output can take place when there is an output) and wind facilities usually are set at a constant power factor and do not adjust for frequency deviations.2. The SDT has recommended that a SAR be submitted in order to refine the Standards that would be applicable to individual power producing resources contained under I4 of the phase II definition. This response is not acceptable. The SDT should not passively answer an entity's question by stating that a different process "may" fix the issue at hand. Recommend I4a be deleted and I4b be maintained as I4a. During the 8/21/2013 webinar the presenter emphasized the critical nature of the aggregate generation of dispersed power producing resources to the reliability of the interconnected transmission system. I4 subpart (a) is inconsistent with the stated critical nature of the aggregate generation. The presenter also indicated that standards that apply to GO/GOP associated standards should be addressed via a SAR to correct reliability standards that impose a burden on the industry without providing a significant benefit to reliability. The appropriate manner to address this discrepancy is not to submit a SAR to modify the standards that would inappropriately invoke requirements on individual generators due to their inclusion in the BES definition, but to eliminate I4 subpart (a) and modify standards in the future to address any reliability issues that may need the imposition of requirements for individual dispersed power producing resources. Please Note that FAC-001 and FAC-002 have established processes for generators (of all shapes and sizes) to interconnect to the BES.3. I4a should be deleted in its entirety. The SDT is forcing every dispersed power Facility over 75 MVA to be in the definition, where the SDT should be keeping individual resources out and allow other Standards and SDTs to determine if that should be included within each individual Standard. The BES definition should be written to give broad details and each individual Standard should be where details are maintained. This is already the case for the following Standards; MOD-025-1, R1 and VAR-001-2, R3 are two examples where the Standard dictates what is applicable and what is not.

Organization	Yes or No	Question 1 Comment
		4. We do not believe that since FERC has approved Phase I that the SDT is bound by that approval as being unchangeable. The Commission has only approved a part of the process and nowhere is it stated that once Phase I is approved that it cannot be changed. This is proof with the other changes that the SDT has made in Phase II compared to Phase I. 5. NERC or the SDT have not provided the industry with event analysis or lessons learned information that an individual dispersed power producing resource (not whole facilities) within a Facility has led to instability of the BES. 6. The inclusion of I4a does not alien itself with the current NERC and Regional RAI process. NERC's CEO and President has said that everything cannot be a priority. The amount of records management will only benefit a company who sells their services in managing individual power producing resources (i.e. paper work). The Registered entity and their Region will not see the benefit of tracking several thousand wind turbines and solar panels, for what? The "what" is unknown because the SDT is taking words of the "Statement of Compliance Registry Criteria" and applying it to our standards development process. Currently Entities do not register per Facility, but this definition does force entities to register per Facility. The SDT is mixing apples and oranges.7. The BES SDT has stated that the collector system is not included within the definition. But, FAC-008-3, is written to support the reliability of the BES and Requirement 2 states that each Generator Owner shall have a documented methodology between the generator (R1) to the point of interconnection. This means that the collector system is part of the BES definition. Please clarify how one standard pulls in the collector system and the proposed definition keeps it out? The removal of I4a will solve this issue. If individual resources need to be in based on system instability issues, then this can be addressed at a later date, once it is proven that individual resources need to be considered part of the BES and the individual resources cause BES instability.

Organization	Yes or No	Question 1 Comment
Muscatine Power and Water	No	MP&W appreciates the changes SDT made to I4. However, we think that the wording of I4a still does not adequately communication that desired treatment of small dispersed power producing resources as an aggregate, rather than on an individual basis, when the aggregate capacity is 75 MVA or more. To address this issue, we suggest the following wording change to I4a, "Aggregation point of dispersed resources when they aggregate to a total capacity of greater than 75 MVA (gross nameplate rating, and"An individual 1.5 MW wind turbine does not impact the BES when it reduces its output (remember just because a turbine is rated at 1.5 MW doesn't mean it automatically reaches that output when the wind blows) or trips offline. Entities have been making comments that the place where power is aggregated (usually the bus) should be included and not individual the wind turbines, solar collectors, manure digesters, etc. The amount of compliance time for PRC-004 would never be enough. Wind turbines have up to 250 plus reasons why they can trip. Usually due to the change in wind direction. If the wind changes direction and the turbine head can not keep up within a certain degree of angle, the unit will trip. Coming back on line when the angle requirement is met. So, Entity's will need to apply the R2 of PRC-004-2a, for every wind turbine trip. Not all Entities have the resources to review these trips and that 1.5 MW wind turbine does not impact the BES. MP&W beleives that the point of interconnection (of greater than 75 MVA) is important and should be contained in the BES definition as written in I4B. PRC-004-2a is only one Standard, notwithstanding; BAL-001-TRE-01, FAC-001, FAC-003, MOD-024, MOD-025, MOD-026, MOD-027, PRC-005, PRC-006-SPP-01, PRC-019, PRC-024, PRC-025, and TOP-003.
MRO	No	MRO recommends the removal of I4 a) and 14b Industry requested the point of aggregation to be added in place of the individual generators themselves, not as

Organization	Yes or No	Question 1 Comment
		well. The inclusion of this statement, I4 b, tends to lead industry to believe the individual generators will still remain under the new definition of the BES in addition to the aggregation point. The addition of individual resources which are not material to the BES creates undue burden on the registered entities and regional entities through the process of identifying these assets in order to have to apply for an exception due to these assets not being material to the BES. Proposed re-write of I4: Aggregate point where dispersed power producing resources aggregate at a common bus to a total capacity greater than 75 MVA (gross name plate rating) linking to a common point of connection at a voltage of 100kV or above.
BrightSource Energy, Inc.	No	No. We agree with the separation of I2 and I4 and this does provide clarity by creating a distinction between more traditional generation and distributed generation resources. We disagree with I4 to be applied only when both (A) and (B) are true. We recognize that each single small generator or even a group of these small generators cannot impact the BES and therefore, we would support the including only of the individual generating resources (A) (i.e., greater than 75 MVA) in the definition. The inclusion of the aggregate point (B) below 100 kV will improve reliability by focusing on the area that can cause the loss of 75MVA of distributed generation resources. We recognize that there will be complication in determining the aggregate point and to the implementation of standards associated with this portion of the collector system. For example, the various standards that are associated with the BES definition will also need to apply to this portion of the collector system and associated low voltage equipment.
Omaha Public Power District	No	Omaha Public Power District (OPPD) agrees and appreciates the SDT's efforts to provide clarity by separating dispersed power producing resources from Inclusion

Organization	Yes or No	Question 1 Comment
		I2 and returned to its own separate Inclusion I4. However, OPPD is still concerned with the Inclusion I4a that includes the individual generator as part of BES. Where, the Inclusion I4b clearly and correctly recognizes the aggregate point to be identified as a BES facility. We agree that the aggregation point (or bus) should be part of the BES, if the total aggregated generation is at 75 MVA or higher, as stated in the Inclusion I4b. OPPD believes that the individual unit by itself can't impact the reliability of BES. On the other hand, the compliance responsibilities that go along with are burdensome with no benefit to the reliability of the BES. Therefore, OPPD suggests consider removing Inclusion I4a from the BES Definition Inclusions. We strongly believe that I4b is completely addressing the dispersed power producing resources inclusion into BES. Additionally, OPPD supports comments provided by Madison Gas & Electric (MG&E).
Public Utility District No.1 of Snohomish County	No	Snohomish supports the Project 2010-17 - Definition of the BES (Phase 2) Standard Drafting Team in its efforts to clarify the BES definition. Although Snohomish supports the current definition and will be voting affirmative, we are concerned with the compliance burden to small dispersed generators that typically are less than 2 MW and have capacity factors in the 25 to 35% range, and may be inclined to change our position if the following issues are not resolved. Snohomish believes these concerns can be addressed within the Reliability Standards applicable to GO/GOPs or with the suggested changes below".1.Replace the current ballot's draft I4 language:"I4 - Dispersed power producing resources consisting of:a) Individual resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above."With the proposed comment I4 language:"I4 - Dispersed power producing resource projects , or portion(s) thereof, designed primarily for

Organization	Yes or No	Question 1 Comment
		supplying wholesale power (e.g., a wind farm, or solar farm) that aggregate to a total capacity greater than 75 MVA (gross nameplate rating) at a common point of connection to a voltage of 100 kV or above consisting of:a) The individual resources, andb) The delivery system designed primarily for delivering capacity from i) the point where those resources aggregate with a total connected capacity greater than 75MVA; to ii) a common point of connection at a voltage of 100 kV or above."Rationale:"projects ... designed primarily for wholesale" - nothing in the currently posted version of Inclusion I4 distinguishes between generation for retail (behind the meter) and generation for wholesale. As such roof-top PVs, generator assistance programs, or other similar small power-producing incentives, might be otherwise interpreted as included under I4. There is a real possibility that, with net metering laws, tax incentives, and related public policies strongly favoring the development of, for example, small, individually-owned solar PV systems, those small systems could easily exceed the 75 MVA thresholds in the aggregate. Considered individually, these small systems have no discernible impact on the reliable operation of the BES. With sufficient market penetration, these systems might conceivably have some impact on the BES, but mediating that impact should be the responsibility of TPs, BAs, TOPs, and other system operators. The regulatory burden imposed on small owners of individual distributed generation systems that would result from classifying such small generators as part of the BES would be significant, and a strong disincentive running contrary to current public policy favoring such systems. Yet, because such small systems have no impact on the reliable operation of the BES, extending regulation in this way would have no benefit for BES reliability. o "(e.g., a wind farm, or solar farm)" - Because the SDT's I4 text-box will be dropped from the final version, we believe this language is necessary to clearly express the intent of the BES to cover utility-scale wind farms, solar farms, and similar installations that consist of many relatively small units that are aggregated for wholesale while excluding small, individually-owned systems, such as rooftop solar PV arrays, that are not aggregated for the

Organization	Yes or No	Question 1 Comment
		wholesale market but are owned by and benefit individual retail customers o I4.a - Imposing BES related Reliability Standards on individual small units is counter-productive and administratively burdensome. To the extent that applying individual Reliability Standards to such small, non-aggregated units is demonstrably necessary to protect BES reliability, application should be governed by the language of individual Standards rather than by classifying such small systems as BES. To that end, we are dedicated to drafting and vigorously promoting a SAR to appropriately address the applicability of individual NERC Standards to dispersed power-producing resources. o I4.b - We believe our proposed wording: oAppropriately addresses impact to BES reliability. The proposed language recognizes that reliability rests depends on TPs, BAs, RCs, and TOPs responsibly addressing the single greatest contingency arising from, and the behavior of, dispersed power producing resources in the aggregate. Enforcing reliability standards on the owners of small, dispersed, and non-aggregated resources is not productive and has no true value to BES reliability. Better aligns with FERC's Determination in Order 773 paragraph 114. , where FERC determined that it will not direct NERC to include collector systems within wind farms and similar generation systems in the BES through Inclusion I4. oAligns with FERC's Determination for I2 in Order 773 paragraph 91 and 92, that multiple step-up transformers that connect generators to the BES at above 100-kV should be included in the BES, while connections at lower voltages that operate as part of a local distribution system should not be classified as part of the BES.
Tri-State Generation and Transmission Association, Inc.	No	The NERC draft shows a schematic for resources that aggregate at a single bus location. Tri-State Generation and Transmission Association, Inc. (Tri-State) has included a drawing (Sent via email to Wendy Muller (NERC Standards Development Administrator-**see link at the end of the report*)) that shows four examples of distributed generation that could have been developed as phases of a

Organization	Yes or No	Question 1 Comment
		single developer or as multiple developers. The drawings show Tri-State's interpretation of which elements (highlighted in yellow) would be included based on the draft BES definition Inclusion I4. As written, it would include any line element from the point where the aggregated generation exceeds 75 MVA through the transformer that steps the voltage up to 100 kV or greater and include every dispersed generator attached to the line, even if it is a solitary unit. Please provide comments as to our interpretation. Inclusion I4a should be deleted. It does not appear to follow the intent of the FERC Order 773. In Order 773, paragraph 106 "NERC states that the inclusion is meant to address the dispersed power producing resources themselves, not the individual elements of the collector systems operated below 100 kV." Tri-State agrees with the EEI comment within this paragraph, "that inclusion I4 applies to generating resources meeting the threshold in the aggregate, not the individual generating units". There is no apparent requirement within the Commission Determination where FERC is requiring this inclusion. Tri-State does not find the inclusion of individual generating resources as low as 2MVA beneficial to the BES. A loss of a 2MVA generating resource on low voltages does not pose the same risk as the loss of an aggregated loss of 75MVA. If inclusion I4a is not deleted, a minimum MVA level for the individual resource to be included in the BES should be added, just as I2 has. Tri-State recommends the Standard Drafting Team replace the current ballot's draft I4 language with:"The system designed primarily for delivering capacity of dispersed power resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above."
Consumers Energy Company	No	The proposed wording of I4(b) is acceptable in that includes "...from the point where resources aggregate to greater than 75 MVA...". Consumers Energy objects to I4 (a) which includes all "individual resources that aggregate to a total ampacity

Organization	Yes or No	Question 1 Comment
		greater than 75 MVA". This could be interpreted to include each of the small generators, each 690V to 34.5kV transformer and the collector systems on a wind farm. I4(a) should be removed from the BES definition leaving only I4(b) as an inclusion. Consumers Energy recommends a negative ballot until the wind farm generators, transformers and collector systems are excluded.
PacifiCorp	No	The SDT has made significant progress by separating dispersed power producing resources from traditional generating resources in Inclusion I2. By including I4 subpart (b), the SDT has identified the critical element(s) that impact reliability. However, by failing to sufficiently address the real issue of the impact of the mandatory reliability standards on individual dispersed power resources, the SDT has perpetuated a gross error identified during phase one of the BES definition project, by including each "individual" dispersed power producing resource as potentially within the scope of the BES. During NERC's August 21, 2013 webinar on this project, the presenter emphasized the critical nature of the aggregate generation of dispersed power producing resources for the reliability of the interconnected transmission system. To that end, Inclusion I4 subpart (a) is inconsistent with NERC's express statements concerning the critical nature of the generation in the aggregate. The presenter also indicated that those reliability standards that apply to the GO/GOP functions should be addressed via a SAR in order to modify those standards that impose an unreasonable burden on sectors within the industry without providing a commensurate benefit to reliability. PacifiCorp believes that the appropriate manner to address this discrepancy is in fact not to submit a SAR to modify the standards, but rather to first eliminate Inclusion I4 subpart (a) - and thus remove the collective set of individual resources from within the BES - and then modify those standards in the future to address any lingering reliability gaps that may apply to dispersed power producing resources on an individual basis.PacifiCorp recommends the following language

Organization	Yes or No	Question 1 Comment
		for I4:Dispersed Power Producing Resources: For dispersed power producing resources that aggregate to a total capacity greater than 75 MVA, the system designed primarily for delivering capacity from the point where such resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. Note: While individual dispersed power producing resources are not considered part of the BES, that does not exempt registration as a GO or GOP for those entities that solely own and/or operate such resources where the aggregate is greater than 75 MVA. Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells. PacifiCorp's justification for this revised language is as follows: a dispersed power producing resource necessarily consists of individual units of a limited size to take advantage of the distributed nature of the resource (e.g., wind or solar) upon which the facility relies for its fuel source. One benefit of such facilities' unit size and geographical distribution is that the facility is not as susceptible to a substantial loss of generating capability as a single unit of 20 MVA or greater (the registration threshold for a single generating unit). If the arrayed generators were each 2 MVA then the probability of losing 20 MVA at the generator level would be .00000001%. If the units were 5 MVA each the probability of losing all four units at the generator level would be .01%. The probability of losing a single 20 MVA unit would be 10%. These variations illustrate that there will be different values depending upon the arrayed generator's size. Given the reliability advantage this diversity affords it does not seem reasonable to treat this type of facility in the same way as a single unit facility of 20 MVA or greater. As recognized by the SDT, a dispersed generating facility of 75 MVA or greater (NERC Registry Criterion Section III.c.2) can have an impact on the BES. To recognize this impact and to also account for the dispersed nature and reliability advantage as described above,

Organization	Yes or No	Question 1 Comment
		PacifiCorp requests that the SDT exclude individual dispersed power producing resources from the BES through a revised Inclusion I4 substantially similar to the proposal above.A technical example of the impact of the loss of an individual wind turbine to the BES is available from PacifiCorp to the SDT upon request.
MidAmerican Energy Company	No	The SDT has made significant progress by separating dispersed power producing resources from traditional generating resources. By including I4 subpart (b) the SDT has identified the critical element(s) that impact reliability. However, by failing to address the issue of reliability standards as they apply to individual dispersed power resources, the SDT has perpetuated a gross error implemented in phase one of the BES, by including each individual dispersed resource as BES. During the 8/21/2013 webinar the presenter emphasized the critical nature of the aggregate generation of dispersed power producing resources to the reliability of the interconnected transmission system. I4 subpart (a) is inconsistent with the stated critical nature of the aggregate generation. The presenter also indicated that standards that apply to GO/GOP associated standards should be addressed via a SAR to correct reliability standards that impose a burden on the industry without providing a significant benefit to reliability. The appropriate manner to address this discrepancy is not to submit a SAR to modify the standards that would inappropriately invoke requirements on individual generators due to their inclusion in the BES definition, but to eliminate I4 subpart (a) and modify standards in the future to address any reliability issues that may be required of individual dispersed power producing resource.The following language is recommended for I4:Dispersed Power Producing Resources: Where dispersed power producing resources aggregate to greater than 75 MVA the to a common point of connection at a voltage of 100 kV or above. Note: Individual dispersed power producing resources are not BES, but does not exempt registration as a GO or GOP. Dispersed power producing resources are small-scale power generation

Organization	Yes or No	Question 1 Comment
		technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells. Justification: A dispersed power generating facility necessarily consists of individual units of a limited size to take advantage of the distributed nature of the resource (e.g., wind or solar) upon which the facility relies for its fuel source. One benefit of such facilities' unit size and geographical distribution is that they are not as susceptible to a substantial loss of generating capability as a single unit of 20 MVA or greater (the registration threshold for a single generating unit). If the arrayed generators were each 2 MVA then the probability of losing 20 MVA at the generator level would be .00000001%. If the units were 5 MVA each the probability of losing all four units at the generator level would be .01%. The probability of losing a single 20 MVA unit would be 10%. These variations illustrate that there will be different values depending upon the arrayed generator's size. Given the reliability advantage this diversity affords it does not seem reasonable to treat this type of facility in the same way as a single unit facility of 20 MVA or greater. As recognized by the SDT and FERC in Order No. 773, a dispersed generating facility of 75 MVA or greater (NERC Registry Criterion Section III.c.2) can have an impact on the BES. To recognize this impact and to also account for the dispersed nature and reliability advantage as described above, it is requested that the individual power producing resources be excluded from the BES.A technical example of the impact of the loss of an individual wind turbine to the BES is available to the SDT upon request.
Volkmann Consulting, Inc	No	There is no technical justification to include disperse generation into the BES definition. The impact of the aggregation is studied and addressed in the FAC-001 and FAC-002 processes. Once the effects of dispatchability and frequency / voltage control in aggregation are addressed and mitigated in these processes, the

Organization	Yes or No	Question 1 Comment
		inclusion of each individual generator into the BES definition provides no further value to the industry and reliability.
Xcel Energy	No	To be clear, Xcel Energy is strongly supportive of the change made to Exclusion E1, to raise the exclusion threshold for radial and local networks from 30 kV to 50 kV. However, we are voting negative due the unnecessary inclusion of dispersed power individual resources in Inclusion I4(a). We understand that the individual dispersed generators ended up being included in the Phase I BES definition, but based on the development history, it is clear that the industry did not believe they should be included and thought they WERE NOT included. It wasn't until the guidance document was finalized that it was apparent where the drafting team landed on the subject. Phase II of this project provides the best opportunity to refine and improve the BES definition such that industry compliance efforts are focused on activities that will truly have an impact on reliability. Please see our detail comments and justifications below: While we strongly support the separation of I2 and I4 and the 75 MVA threshold for aggregating facilities in Inclusion I4 (b), Xcel Energy continues to disagree with the inclusion of small individual dispersed generators per Inclusion I4 (a). We provided alternative language for I4 in the last comment period. That recommendation still stands. Including individual dispersed generators in the BES definition will cause a huge diversion in work activities as entities are forced to simultaneously seek relief via the Exception Process to exclude reliability insignificant individual dispersed generators from their programs while at the same time attempting to modify their existing compliance programs to accommodate individual dispersed generators in the event that the exception applications are not approved. NERC and the Regions will be faced with a huge backlog of exception requests for small distributed generators while Generator Owners with dispersed generating assets will struggle to implement reliability standards that were never drafted with the

Organization	Yes or No	Question 1 Comment
		intent of being applicable to anything but large scale generating stations.In the August 21, 2013 webinar, the BES definition drafting team indicated that its justification for the 75 MVA aggregating threshold in I4 (b) was that 75 MVA is the level that the drafting team believes that single failures resulting in the loss of generation could have an appreciable impact on the grid. It seems inconsistent that a 2 MVA individual dispersed generator is deemed significant to reliability but the equipment that is utilized to connect individual dispersed generators totaling to <75 MVA is deemed not significant to reliability. Furthermore, with no requirement that the BES be contiguous, how can individual 2 MVA wind turbine generator at a >75 MVA wind farm have a greater effect on BES reliability than an identical individual 2 MVA wind turbine at a <75 MVA wind farm? With no technical rationale or difference in effects on BES reliability, how can identical 2 MVA units legally be treated so differently? In the Consideration of Comments document for the first draft of Phase II BES definition, the Drafting Team acknowledged that there are both existing and pending reliability standards which likely will need to be reviewed and revised to clarify or correct the applicability of the standard requirements to small scale generation and recommended that the industry create a SAR to call for this action. Relative to the approval and implementation time frames being discussed for the new BES definition, we do not believe any such action could be taken in a timely enough fashion to resolve industry uncertainty and avoid major regulatory burden with no commensurate improvement in grid reliability. Examples: o PRC-005-2 Protection System testing - the based relay test requirements were developed with large generators in mind, and differ significantly from requirements in DOE Order 661A, of 2005 that requires wind plants to meet Low Voltage Ride-Through (LVRT) and Power Factor Design Criteria. These standards significantly change the protection scheme applied to individual turbines, and is not addressed here. Wind turbine protection systems are often integral to the wind farm control system and the PRC-005-2 requirements were developed for protection equipment typically applied on large

Organization	Yes or No	Question 1 Comment
		scale generation not wind farm control systems. o TOP-002 Normal Operations Planning - Under R14 of this standard, an unplanned outage for any individual wind turbine would require a status notification report from the GO to the TO/TOP. This level of reporting, at typically less than 3 MVA, is much less that any practical reliability threshold, and would simply result in a documentation effort with no value.Similar concerns exist for FAC-008-3, PRC-001-1, PRC-004-2a, PRC-019-1, PRC-024-1, and PRC-025-1, and other standards where it is quite evident that small scale dispersed generators were not considered during the standard's development. Unless Inclusion I4 (a) is eliminated, we do not believe implementation of the new BES definition should go forward until all reliability standards have been reviewed and revised as necessary to clarify the applicability to individual dispersed generating assets. What reliability benefit is there to a "bright line" BES definition if there is not a corresponding clarity in the applicability of reliability standards to the elements deemed to be included in the BES?
Wisconsin Public Service Corporation	No	We agree with including the Generating stations with dispersed generation from the point of aggregation to 75 MVA as I4-b does. We agree with the statement made on the BES Phase II webinar of August 21 that this is the point where the dispersed power plant is significant to the reliability of the BES. We disagree with including the individual resources themselves since, as indicated on the webinar, they are not significant to the reliability of the BES . Including dispersed power producing resources less than 25MVA ignores differences in engineering design and operating philosophies. For our company each 2MVA wind turbine is designed to sync on and off the grid several times a day. For this reason, the engineering design incorporates a large contactor to handle these operations. This contactor is controlled by the turbine PLC which contains the main protective relay functions (i.e. frequency, over/under voltage, imbalance...etc) traditionally contained in

Organization	Yes or No	Question 1 Comment
		discrete protective relays. A generator breaker is designed in series with the contactor, which includes a self contained overcurrent element that serves as a backup function, but is different in traditional design in that each Protection Component is contained in the breaker device. Due to the PLC control/protection integration, equipment differences, and operating philosophies implementation of NERC Reliability Standards such as PRC-004, PRC-005 and FAC-008 would be impractical and onerous lending little to no reliability improvement.We suggest eliminating I4a completely since, as indicated on the webinar I4b encompasses the portion of the dispersed power generating plant that is significant to the reliability of the BES
American Wind Energy Association	No	While we strongly support the separation of I2 and I4 and the 75 MVA threshold for aggregating facilities in Inclusion I4 (b), and the exclusion of collector system components that aggregate less than 75 MVA of generation, we still strongly disagree with the inclusion of small individual dispersed generators per Inclusion I4 (a). This problem can be resolved by either removing I4 (a) in its entirety or revising it to clarify that the only BES-relevant standards that apply to individual dispersed generators are those that affirmatively state that they apply to dispersed generators. While individual generators were included in the Phase I BES definition, that is not a compelling reason why they should also be included in Phase II. Phase II of this project provides an opportunity to refine and improve the BES definition such that industry compliance efforts are focused on activities that will truly have a beneficial impact on reliability. Including individual dispersed generators in the BES definition will cause a major diversion away from efforts that improve BES reliability, as entities are forced to simultaneously seek relief via the Exception Process to exclude individual dispersed generators that are insignificant from a reliability standpoint from their programs while at the same time attempting to modify their existing compliance programs to accommodate

Organization	Yes or No	Question 1 Comment
		individual dispersed generators in the event that the exception applications are not approved. With more than 45,000 wind turbines installed in the U.S. and the vast majority of them in wind plants larger than 75 MVA, NERC will be faced with a huge backlog of exception requests for small distributed generators while Generator Owners with dispersed generating assets struggle to implement reliability standards that were never drafted with the intent of being applicable to anything but large scale generating stations. As a result, proceeding with the BES definition as currently drafted would actually impair, rather than improve, bulk electric system reliability.In the Consideration of Comments document for the first draft of Phase II BES definition, the Drafting Team acknowledged that there are both existing and pending reliability standards which likely will need to be reviewed and revised to clarify or correct the applicability of the standard requirements to small-scale generation and recommended that the industry create a SAR to call for this action. Relative to the approval and implementation time frames being discussed for the new BES definition, we do not believe any such action could be taken in a timely enough fashion to resolve industry uncertainty and avoid a major regulatory burden that would distract from efforts that actually improve grid reliability. Examples of standards that were not drafted with small dispersed generators in mind include: o PRC-005-2 Protection System testing - the relay test requirements were developed with large generators in mind, and differ significantly from requirements in FERC Order 661A, of 2005 that require wind plants to meet Low Voltage Ride-Through (LVRT) and Power Factor Design Criteria. These standards significantly change the protection scheme applied to individual turbines, and there is no clarity about how they should be applied. Wind turbine protection systems are often integral to the wind farm control system and the PRC-005-2 requirements were developed for protection equipment typically applied to large-scale generation, not wind farm control systems. o TOP-002 Normal Operations Planning - Under R14 of this standard, an unplanned outage for any individual wind turbine would require a status

Organization	Yes or No	Question 1 Comment
		notification report from the GO to the TO/TOP. While such a report can be important for large central station generation, it would provide no value for a small individual wind turbine generator. This level of reporting, at typically less than 3 MVA, is much lower that any practical reliability threshold, and would simply result in a documentation effort with no value.Similar concerns exist for FAC-008-3, PRC-001-1, PRC-004-2a, PRC-019-1, PRC-024-1, and PRC-025-1, and other standards in which small-scale dispersed generators were not considered during the standards' development. Unless Inclusion I4 (a) is eliminated, or significantly revised to clarify that the only BES-relevant standards that apply to dispersed generators are those that affirmatively state that they apply to dispersed generators, we do not believe implementation of the new BES definition should go forward until all reliability standards have been reviewed and revised as necessary to clarify the applicability to individual dispersed generating assets. What reliability benefit is there to a "bright line" BES definition if there is not a corresponding clarity in the applicability of reliability standards to the elements deemed to be included in the BES? On the August 21, 2013 webinar, the BES definition drafting team indicated that its justification for the 75 MVA aggregating threshold in I4 (b) was that 75 MVA is the level that the drafting team believes that single failures resulting in the loss of generation could have an appreciable impact on the grid. While we support the exclusion of collector system components that aggregate less than 75 MVA, it seems inconsistent that a 2 MVA individual dispersed generator is deemed significant to reliability but the equipment that is utilized to connect multiple dispersed generators totaling up to 75 MVA is deemed not significant to reliability. The logic that led to the exclusion of collector system equipment that aggregates less than 75 MVA, as well as the logic expressed on the webinar that 75 MVA is the threshold at which the loss of generation could have an impact on BES reliability, argues for also excluding individual dispersed generators. Furthermore, what is the logic of including individual 2 MVA wind turbine generator at a >75 MVA wind farm while excluding

Organization	Yes or No	Question 1 Comment
		individual 2 MVA wind turbine at a <75 MVA wind farm? With no technical rationale or difference in effects on BES reliability, how can identical 2 MVA units be treated so differently? The only compelling reason for applying BES standards to individual dispersed generators would be if there were a real risk of an abrupt common mode failure affecting a large share of the dispersed generators in a >75 MVA wind plant. However, per FERC Order 661A, wind turbine generators already comply with voltage and frequency ride-through standards that are far more stringent than those that apply to other types of generators. As a result, if a common mode failure caused by a grid disturbance were to affect the wind turbines in a >75 MVA wind plant, the impact on the wind plant would be irrelevant for grid reliability because the voltage and/or frequency deviation would have already caused most if not all of the conventional generators in the grid operating area to trip offline. While weather-driven changes in wind speed can significantly change the aggregate output of a wind plant, those changes in output occur too gradually to pose a risk to bulk power system reliability, and regardless such changes in output would not be regulated or mitigated by BES-relevant standards. No compelling rationale has been offered for why including individual dispersed wind turbine generators in the BES definition will improve grid reliability.
Wisconsin Electric Power Company	No	Wisconsin Electric appreciates the work the Standard Drafting Team (SDT) has accomplished, but is concerned that the team has not corrected a fatal flaw in the definition of the Bulk Electric System. During the 8/21 webinar, the SDT said that they don’t have the power to change an existing approved definition with regard to the inclusion of individual distributed generation resources, yet that’s what they in fact do every time they draft a standard revision. FERC accepted the Phase 1 definition, but we believe the SDT had the opportunity to correct the flawed definition. The SDT team did not address industry’s comments that individual

Organization	Yes or No	Question 1 Comment
		wind turbines (and other dispersed generating units) should not be included in the definition. The SDT stated that industry has the option to address whether dispersed generation should be applicable to a standard by revising the applicability of those standards. This method of correcting for the wrong elements' inclusion in the definition will take time and resources from the industry. During this time period, the industry would still need to assume responsibility for compliance to each affected standard because it would be unknown when/if the revisions would be accepted and approved. For instance, compliance to Reliability Standard PRC-005 requires the industry to include thousands of individual wind turbines (and small solar panels) in the maintenance and testing of relays and associated equipment. Resources required to complete this testing are specialized and significant, with little to no measureable benefit to the BES (and an indirect detriment by taking those resources away from other tasks that are beneficial). In regards to CIP Version 5 requirements, if each wind turbine is part of the BES, then each wind turbine's monitoring and control systems will be "BES Cyber Systems". Again, resources will be required for compliance with no benefit to reliability.Individual dispersed generation units (generally less than 2 MW) do not impact the reliability of the Bulk Electric System. The SDT points out that it is not including collector circuits of dispersed generators because collector circuits do not have a true reliability impact, but the SDT fails to recognize that the individual dispersed generators have even less of an impact. The issue of concern is a single point of failure affecting 75 MWs of generation, not the failure of an individual wind turbine. By excluding the collector systems, but including the individual generators, the SDT team is not following FERC's Order 773 (issued 12/20/2012) Paragraph 165, in which the Commission stated that it is appropriate to have the bulk electric system contiguous, without facilities or elements "stranded" or "cut-off" from the remainder of the bulk electric system. The individual dispersed generating units are stranded from the remainder of the bulk electric system in the current draft of

Organization	Yes or No	Question 1 Comment
		the definition.The SDT stated during the 8/21 webinar, that industry can use the exception process to exclude wind turbines, or other dispersed generators. This viewpoint has a fundamental problem. It mandates that individual generators be included in a faulty definition that pulls in insignificant elements into the BES and then requires industry to exclude them (essentially an entire asset type). That requires hundreds of dispersed generator owners to rely on the regulator to be reasonable and allow us to exclude all of our individual dispersed generators. The proposed Phase 2 definition poses a huge compliance and regulatory burden that doesn't add to the reliability of the BES.
BANC & SMUD	No	Although we believe the Drafting Team has provided vast improvement to the Draft #2 of the Phase 2-I4 BES Definition SMUD is posting a Negative position for Draft #2 for the following reasons. Salient Issues: o In accordance with Paragraph 115 of the Commission's Order 773, exclude the collector system from the BES definition. o Wind/Solar BES delineation should be limited the GSU where the total plant capacity is connected at a common point to 100kV or greater. o During Phase-1, it was suggested that a 75 MVA threshold be established where the loss of a single element would render the entire 75 MVA of resources unavailable. This was in lieu of including the individual small-scaled machines as BES to avoid subjecting those machines to administrative burden for little or no impact on the BES as compared to the compliance obligation. o Redundant to TPL & TOP standards where loss of the resource(s) for a single element is addressed in system studies that include evaluation for adequate level

Organization	Yes or No	Question 1 Comment
		of resources, system impacts and Single Largest Contingencies. o Must include the phrase "(e.g., wind or solar)" after "Dispersed power producing resource projects" to fully clarify the applicability of Inclusion I4. o Support a Standard Authorization Request or other mechanism to reduce administrative burden for compliance to specific standards (e.g., PRC-004 (Misoperations) & PRC-005 (Maintenance & Testing). The following is suggested wording for I4 that are associated with the points above: "I4 - Dispersed power producing resource projects, or portion(s) thereof, designed primarily for supplying wholesale power (e.g., a wind farm, or solar farm) that aggregate to a total capacity greater than 75 MVA (gross nameplate rating) at a common point of connection to a voltage of 100 kV or above consisting of: a) The individual resources, and b) The delivery system designed primarily for delivering capacity from i) the point where those resources aggregate to the total connected capacity; to ii) a common point of connection at a voltage of 100 kV or above." Rationale:1. "projects ... designed primarily for wholesale...": Nothing in this posted version distinguishes between generation for retail (behind the meter) and generation for wholesale. As such, rooftop PVs, generator assistance programs, or other similar small power-producing incentives, might be otherwise interpreted as included under I4.2. "(e.g., a wind farm, or solar farm)": Because the SDT's I4 text-box will be dropped from the final version, we believe this inclusion is necessary to retain an illustration of the intent. 3. I4.a:While applying BES NERC Reliability Standards to the management of individual small units is counter-productive and administratively burdensome, we

Organization	Yes or No	Question 1 Comment
		do agree that differentiating applicability of various Standards should be specified within those Standards. 4. I4.b: We believe the proposed wording: a. Appropriately addresses impact to BES reliability. Rather than offering some illusion for reliability at a lesser impact level, this proposal recognizes that reliability rests in TPs, BAs, RCs, and TOPs responsibly addressing the single greatest contingency arising from, and the behavior of, dispersed power producing resources in the aggregate. Enforcing governance for management to any lesser level is not productive and has no true value to BES reliability. b. Better aligns with FERC's Determination within Order 770 paragraph 114.c. Aligns with FERC's Determination for I2 within Order 773 paragraph 91.d. Aligns with FERC's Determination for I2 within Order 773 paragraph 92.
New York Power Authority	No	Inclusion 4b does not support a contiguous BES due to the exclusion of a portion of the path from the generator terminals to the resource aggregation point. Inclusion 4b is not consistent with the elements included under Inclusion I2 which applies to all generating resources.
Response: The proposed definition continues to include, through inclusion I4, individual dispersed power producing resources if those resources aggregate to a total value greater than 75 MVA. This inclusion treats dispersed power producing resources in a manner that is comparable to other non-dispersed power producing resources and is an approach that was accepted and emphasized by the Commission in Orders No. 773 & 773-A. The SDT has explored various options associated with dispersed power producing resources; however, none of the options explored provided an equal and effective approach to address the Commission's reliability concerns with these facilities. The SDT continues to believe that the best resolution to the industry's concerns is through clarification of the applicability of individual Reliability Standards and not a revision to the BES definition. Given these facts, the SDT is retaining Inclusion I4a but has revised the language of inclusion I4, based on industry comments, to provide greater clarity of the SDT's intent.		

Organization	Yes or No	Question 1 Comment
I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are: a) The individual resources, and **b)** The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.		
East Kentucky Power Cooperative	No	In the consideration of comments, the drafting team indicated that a SAR might be submitted to appropriately adjust GO and GOP standards requirements for dispersed generating facilities. We agree that is the approach to undertake. In order to support this approach, I4 should be deleted to avoid the situation where inappropriate provisions could become effective and compliance become difficult or impossible for entities until work is completed through the SAR to adjust those requirements. In the filing with FERC this procedure could be explained so that FERC can be assured that their approval of inclusion of dispersed generating facilities in the Phase I order will be appropriately implemented.
Response: The SDT is charged with resolving the definition in total at this time and can't point to future possible outcomes for resolution. The proposed definition continues to include, through inclusion I4, individual dispersed power producing resources if those resources aggregate to a total value greater than 75 MVA. This inclusion treats dispersed power producing resources in a manner that is comparable to other non-dispersed power producing resources and is an approach that was accepted and emphasized by the Commission in Orders No. 773 & 773-A. The SDT has explored various options associated with dispersed power producing resources; however, none of the options equated to an equal and effective approach to address the Commission's reliability concerns with these facilities. The SDT continues to believe that the best resolution to the industry's concerns is through clarification of the applicability of individual Reliability Standards and not a revision to the BES definition. Given these facts, the SDT is retaining Inclusion I4a but has revised the language of inclusion I4, based on industry comments, to provide greater clarity of the SDT's intent.		

Organization	Yes or No	Question 1 Comment
I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are: a) The individual resources, and **b)** The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.		
Southwest Power Pool Regional Entity	No	Separation of I2, no issue No: 75MVA threshold may be higher than what FERC will support. Comments: Paragraph 167 of Order 773 implies that FERC sees the aggregation point for tie lines at 20MVA. However, there was some flexibility provided in the rehearing comments on this point. Paragraph 113 of Order 773 states that multiple step-up transformers (in particular 34.5/115kV) are expected to be included by FERC.
Response: Paragraph 167 speaks to embedded generation in a radial system and is not pertinent to Inclusions I2 or I4. The SDT believes that there is support for the 75 MVA threshold for aggregation. No change made. The Reference Document shows examples of where and when multiple step-up transformers are to be included in the BES. No change made.		
Public Service Enterprise Group	No	The proposed elimination of the "collector system" as part of the BES makes the BES non-contiguous. In Order 773, the Commission (P 113 and P 114) stated that radial collector systems used solely to aggregate generation SHOULD be part of the BES since multiple transformers connections did not exempt I2 generators.

Organization	Yes or No	Question 1 Comment
		However, FERC did not direct NERC to include the collector system in the BES. However, it did require that radial lines that connect I2 generators (call "tie lines" in Order 773) should be part of the BES (P 164-P 167) for reasons of contiguity. This BES definition proposed in Phase 2 creates an unlevel competitive environment between I4 generators and I2 generators. Moreover, in its SAR for Phase 2, the question of BES contiguity was supposed to be addressed. The team's response on this issue allows dispersed power generators to be non-contiguous from the point where ac power is produced to where it is injected into the grid. The connections of I2 BES generators are, however, ARE included in the BES. In the diagram shown in the comment form, if the dispersed generators were forty 2 MVA diesel generators connected as shown, would their collector system be excluded from the BES also? What is there were eight 10 MVA gas turbines connected via a collector system? How about six 16 MVA gas turbines? As a member of the RBB, we direct that the team include collector systems that are solely used to aggregate generation in the BES definition.

Response: The proposed definition continues to include, through inclusion I4, individual dispersed power producing resources if those resources aggregate to a total value greater than 75 MVA. This inclusion treats dispersed power producing resources in a manner that is comparable to other non-dispersed power producing resources and is an approach that was accepted and emphasized by the Commission in Orders No. 773 & 773-A. The SDT has explored various options associated with dispersed power producing resources; however, none of the options explored provided an equal and effective approach to address the Commission's reliability concerns with these facilities. The SDT continues to believe that the best resolution to the industry's concerns is through clarification of the applicability of individual Reliability Standards and not a revision to the BES definition. Given these facts, the SDT is retaining Inclusion I4a but has revised the language of inclusion I4, based on industry comments, to provide greater clarity of the SDT's intent.

> I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:

Organization	Yes or No	Question 1 Comment
a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. Gas turbine and diesel generators are handled through Inclusion I2. In the examples shown in the comment, generation aggregates to greater than 75 MVA so the generation and equipment connecting that generation to a common point operated at 100 kV or above is included.		
NIPSCO	No	We requested some clarification regarding a wind farm within NIPSCO from members of the SDT, and promptly received feedback. The main concern is that we are not sure of the intent of inclusion I4 because it is attempting to include a bus within an intermediate voltage. In our case it is 69 kV that may or may not be included since there are 2 transformations within the path to the 138KV; 1 up to 69 kV and 2 parallel transformers up to the 138 kV. In addition the entire 69 kV path is not “designed primarily for delivering” this wind power to the 138 kV system; the 69 kV system includes many lines serving various demand. Some on the SDT felt that the single step-up transformer is the same as 2 transformers in parallel, while others did not. Following this discussion we failed to receive a uniform clarification. Some opinions were that the 69 kV system would be included in the BES while others believed it would not; we have similar differing interpretations within NIPSCO. Further clarification needs to be made on whether or not multiple transformations are or are not included.
Response: The SDT is not allowed to offer opinions on compliance issues. All that the SDT can do is to show its intent when it crafted the definition. This intent is shown in the Reference Document which shows several examples of multiple transformation configurations for consideration.		

Organization	Yes or No	Question 1 Comment
Nebraska Public Power District	Yes	Still have concern with including individual wind turbines as it relates to total generation.
ACES Standards Collaborators	Yes	(1) We thank the drafting team for separating dispersed power producing resources to a separate inclusion category. This avoids some of the confusion in the prior posting. (2) We have a question regarding the diagram provided in the comment form. Why is each generating unit considered a part of the BES? Wouldn't the point of aggregation be the first BES element? If a single dispersed power producing resource fails, there is no impact on the BES. We request the drafting team consider this aspect.
Transmission Access Policy Study Group	Yes	Although we support the SDT's willingness to address the lack of clarity caused by the previous posting's merging of I4 with I2, we are concerned that the wording of the new version of I4 does not capture the SDT's intent, and could lead to absurd results if read literally. As we understand it, the SDT's intent is to include only dispersed power producing resources that both (a) aggregate to more than 75 MVA, and (b) are connected through a system designed primarily for delivering capacity at a common point of connection of 100 kV or above. We believe that the SDT also intends that only the individual resources and the point from which they aggregate to 75 MVA should be included in the BES; in other words, the portion of the collector system that carries <75 MVA is not BES by virtue of I4. In order to express that intent clearly, we suggest the following revised text: I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system

Organization	Yes or No	Question 1 Comment
		designed primarily for delivering such capacity from the point at which those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. The BES portion of such resources includes: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. We believe that this text is consistent with the intent reflected in the diagram provided by the SDT in the comment form, and is more clear and accurate than the text of I4 as posted.
ReliabilityFirst	Yes	Even though ReliabilityFirst votes in the Affirmative, ReliabilityFirst is aware of some concerns among Registered Entities for the potential issue of individual wind units (i.e. single generators) being required to register based on the language of the revised definitions (specifically I4). Though ReliabilityFirst staff agrees with I4 and does not believe this is an issue, ReliabilityFirst recommends NERC and the Regional Entities come up with a common understanding on how Entities are registered based on their ownership of wind units which are designated as BES through the new definition.
Hydro One	Yes	We reluctantly support the separation of I2 and I4 because we believe that their wordings in the BES definition as approved by the industry, NERC BOT, FERC and applicable governmental authorities in Canada should have been retained. In our opinion, I4 is meant for renewable energy resources (in particular Wind). These resources are inherently different when considered for planning and for real time operations. This change will essentially designate every element of a wind farm above 75MVA to its interconnection at 100kV as a BES element including the medium voltage collector systems (less than 50kV) adding burden which may not be necessary. Further, it is not clear what and how standards will apply to

Organization	Yes or No	Question 1 Comment
		collector systems designated as BES.
Response: The proposed definition continues to include, through inclusion I4, individual dispersed power producing resources if those resources aggregate to a total value greater than 75 MVA. This inclusion treats dispersed power producing resources in a manner that is comparable to other non-dispersed power producing resources and is an approach that was accepted and emphasized by the Commission in Orders No. 773 & 773-A. The SDT has explored various options associated with dispersed power producing resources; however, none of the options explored provided an equal and effective approach to address the Commission's reliability concerns with these facilities. The SDT continues to believe that the best resolution to the industry's concerns is through clarification of the applicability of individual Reliability Standards and not a revision to the BES definition. Given these facts, the SDT is retaining Inclusion I4a but has revised the language of inclusion I4, based on industry comments, to provide greater clarity of the SDT's intent. I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are: a) The individual resources, and **b)** The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.		
Duke Energy	Yes	Duke Energy agrees with the changes made by the SDT.
Arizona Public Service Company	Yes	This change returns it to the original language in Phase I. Either way it still has the same intent.
Southern California Edison	Yes	SCE believes that the revision to I4, the inclusion for dispersed power producing resources, is a move in the right direction, but we think that additional clarity

Organization	Yes or No	Question 1 Comment
Company		could be provided by changing "common point of connection" to "common point of interconnection".
Response: The SDT does not see where the suggested change adds any clarity to the text. No change made.		
SPP Standards Review Group	Yes	While we don't have an issue with separating I4 from I2 as in the previous draft, we do have concern with the wording of the inclusion, especially the phrase 'primarily designed'. While the diagram provided in the comment form clearly shows the distinction, it is difficult to pull it from the wording of I4. Additionally, we are confused by what was explained during the NERC industry webinar and what is shown in the above figure. The figure and the words in I4 indicate the point of aggregation is included in the BES. The discussion during the webinar did not include it in the BES.
Response: The SDT points the commenter to the Reference Document where it shows the aggregation point and how it is handled within the definition.		
Southern Company	Yes	The separation of dispersed generation where a collector system aggregates the total generation prior to connecting to the BES is clear in I4.
Northeast Power Coordinating Council	Yes	
Dominion	Yes	

Organization	Yes or No	Question 1 Comment
SERC Planning Standards Subcommittee	Yes	
Bonneville Power Administration	Yes	
Salt River Project	Yes	
Pepco Holdings Inc	Yes	
Exelon and its' affiliates	Yes	
Independent Electricity System Operator	Yes	
Ameren	Yes	
Manitoba Hydro	Yes	
Hydro-Quebec TransEnergie	Yes	

Organization	Yes or No	Question 1 Comment
Idaho Power Company	Yes	
City of Tallahassee	Yes	

Response: Thank you for your support. The SDT is retaining Inclusion I4a but has changed the language of this inclusion to provide greater clarity of the SDT's intent based on industry comments.

I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:

a) The individual resources, and
b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

2. **The SDT has proposed an equally effective and efficient alternative to the Commission's sub-100 kV loop concerns for radial systems by the addition of Note 2 in Exclusion E1 with a threshold value of 50 kV, and posted a technical rationale to support this threshold. Do you agree with this threshold? If you do not support this threshold, please provide specific suggestions and technical rationale in your comments.**

Summary Consideration: Some commenters suggested raising the threshold value above 50 kV. However, no technical rationale for doing so was presented in the comments. Without such rationale, the SDT is unable to entertain such suggestions.

The SDT believes that the 50 kV threshold is an appropriate continent-wide, bright-line value for reliability of the BES. The selection of this value is not due to a FERC directive but is based on physical principles. Therefore, the SDT sees no reason for a reference to non-US Registered Entities.

No changes were made to the proposed definition due to comments raised in this question.

Organization	Yes or No	Question 2 Comment
Ameren	No	In our opinion, the SDT has improved the E1 exclusion criteria by increasing the 30 kV threshold to 50 kV. However, we still believe that the threshold is too low and request that it be raised to at least 70 kV. As the definition now stands, we will have to perform what we feel is unnecessary analysis to prove that most of our local subtransmission networks should also be excluded.
Response: The commenter has presented no technical rationale for increasing the threshold value above 50 kV. The studies performed by the SDT indicate that 50 kV is the highest supportable threshold value, i.e., where the loop configuration starts to flow back to the BES and may be considered necessary for the reliable operation of the interconnected transmission system. No change made.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td>Arizona Public Service Company</td><td>No</td><td>Note two was added in draft 1 to Phase II. This change to Note 2 changes it from 30KV to 50KV, due to analysis they performed. 50KV threshold is less restrictive than 30KV. FERC forced Note 2 - this note requires determining loops between radial lines, and including radials with >50 KV loops</td></tr>
<tr><td colspan="3">Response: The SDT fails to see a question or suggestion here and is thus unable to provide a response.</td></tr>
<tr><td>American Electric Power</td><td>No</td><td>The thought process of the note #2 is confusing the process. One could take this to mean that a 69 kV system would be included by exclusion. AEP does not believe this to be the case, but the wording of this note does not lead to an obvious conclusion. We suggest that the SDT make another attempt to provide a simpler and clearer approach.

AEP also suggests that E1 have transmission removed from between the words contiguous and Elements. We recommend that it instead say “Radial systems: A group of contiguous Elements that emanates from a single point of connection of 100 kV or higher and:”</td></tr>
<tr><td colspan="3">Response: The SDT reviewed the contents of the note and believes that the wording is clear. No change made.

The SDT has previously explained the rationale for inclusion of the word ‘transmission’ and believes that the rationale is still appropriate. The word transmission is not capitalized and is used as a qualifier to the word Element and is meant to differentiate between the types of Elements that are identified in the NERC Glossary of Terms Used in NERC Reliability Standards definition of Element.

Element (NERC Glossary of Terms):
“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.”</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
The use of the words: “a group of contiguous transmission Elements,” means Elements originating at a voltage of 100 kV or higher that are connected in a contiguous manner. No change made.		
Nebraska Public Power District	No	The white paper for the low voltage loop threshold is a logical review of the issues. We would like to see some clarification for certain configurations. For example, two 115kV/69kV parallel transformers at the same substation serving only load at 69kV and no looped 69kV lines: 1) with 115kV and 69kV bus tie breakers, 2) with no 115kV bus tie breaker but does have a 69kV tie breaker, 3) with no 115kV bus tie breaker and no 69kV tie breaker, and 4) with 115kV bus tie breaker and no 69kV tie breaker. All breakers are normally closed but if no breakers exist then transformers are connected directly by bus operating in parallel for all cases. Does this make the interrupting device on the high side of each transformer BES elements? Does this make the transformer a BES element or suggest an analysis for an exception must be made to remove them from the BES? Our concern is how a PRC-005 audit/enforcement group will interpret these configurations if it is not clearly stated in an example or considered in the white paper. How would the SDT interpret a configuration where a 115kV “radial” line feeds a substation with a 56MVA 115/69kV transformer. The 69kV side of the transformer is connected to a networked 69kV system owned by another entity. The 69kV system does connect back to the transmission system in multiple points in the other entities system. There is some 69kV generation greater than 20MVA or 75MVA aggregate but the substation and line in question is not used for black start. Note the 115kV/69kV transformer would never allow greater than 75MVA to pass through it back to the 115kV line since the transformer is too small. Is the substation with the 115/69kV transformer a BES substation? Is the 115kV line to the 115kV/69kV substation BES? Please clarify. It seems transformer size should have some impact but the reference document does not reference this.

Organization	Yes or No	Question 2 Comment
Response: The SDT is not allowed to provide advice on adherence/compliance to entities. The best that it can do is to provide examples as to the intent of the SDT when it was writing the definition. Such examples have been provided in the Reference Document and this document will be updated to show the Phase 2 changes as quickly as possible.		
Hydro One	Yes	We agree that 50kV is more reasonable and are voting positively to the change made by SDT. This change was essentially initiated to address a FERC directive in its Order 773. However it should be noted that the demarcation point between transmission and distribution may be different in non FERC jurisdictions, such as Canadian provinces. In establishing voltage thresholds, NERC needs to consider non-US legislated demarcation points, and the standard development process must make allowances for such regulatory and/or jurisdictional differences and frameworks consistent with NUC 001 and TPL footnote b. We suggest that NERC and the SDT consider revising Note 2 to read as follows: Note 2 - The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion. Non-US Registered Entities can adopt the same voltage level or should implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency.
Independent Electricity System Operator	Yes	We suggest that NERC and the SDT consider revising Note 2 to read as follows: Note 2 - The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion. Non-US Registered Entities can adopt the same voltage level or should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency.
Response: The SDT believes that the 50 kV threshold is an appropriate continent-wide, bright-line value for reliability of the BES.		

Organization	Yes or No	Question 2 Comment
The selection of this value is not due to a FERC directive but is based on physical principles. Therefore, the SDT sees no reason for a reference to non-US Registered Entities. No change made.		
SERC Planning Standards Subcommittee	Yes	In our opinion, the SDT has improved the E1 exclusion criteria by increasing the 30 kV threshold to 50 kV. We wish to thank the SDT for its diligence in justifying an increase to 50 kV. However, we still believe that the threshold is too low and would like to see it raised to at least to 70 kV.
Response: The commenter has presented no technical rationale for increasing the threshold value above 50 kV. The studies performed by the SDT indicate that 50 kV is the highest supportable threshold value, i.e., where the loop configuration starts to flow back to the BES and may be considered necessary for the reliable operation of the interconnected transmission system. No change made.		
Associated Electric Cooperative, Inc. - JRO00088	Yes	AECI appreciates the SDT's willingness to tackle this issue and provide a higher kV level than 0, as well as its technical justification.
Duke Energy	Yes	Duke Energy agrees with the modifications made by the SDT.
Indiana Municipal Power Agency	Yes	IMPA appreciates the work that the SDT has done to come up with an alternative to the Commission's sub-100kV loop concerns for radial systems. IMPA supports the SDT's white paper and the proposed 50kV threshold value.
Southern Company	Yes	It is clear that looping facilities operating at voltages < 100 kV are NOT included in the BES and that contiguous loops operated at voltage < 50 kV in configurations

Organization	Yes or No	Question 2 Comment
		being considered as radial systems does not affect this exclusion (i.e., they are also NOT included in the BES).
Transmission Access Policy Study Group	Yes	TAPS appreciates the SDT’s work on the sub-100 kV loop issue. For the reasons set out in the SDT’s white paper, and in TAPS’ comments on the 30 kV threshold that was proposed in the first posting of Phase 2 of the BES definition project, TAPS strongly supports the proposed 50 kV threshold.
Southwest Power Pool Regional Entity	Yes	The technical justification document supports this conclusion.
Wisconsin Public Service Corporation	Yes	We agree with the 50kv limit since the SDT has posted a reasonable technical rationale.
ACES Standards Collaborators	Yes	We thank the drafting team for increasing the minimum threshold to 50 kV for sub-100 kV looped radial systems.
NIPSCO	Yes	We'd rather see it at 70 kV, however we appreciate the analysis that was performed justifying the 50 kV.
Xcel Energy	Yes	Xcel Energy strongly supports this modification.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	Yes	
Dominion	Yes	
SPP Standards Review Group	Yes	
Florida Municipal Power Agency	Yes	
BANC & SMUD	Yes	
Bonneville Power Administration	Yes	
Salt River Project	Yes	
PacifiCorp	Yes	
Madison Gas and Electric Company	Yes	

Organization	Yes or No	Question 2 Comment
Pepco Holdings Inc	Yes	
Muscatine Power and Water	Yes	
Public Service Enterprise Group	Yes	
Exelon and its' affiliates	Yes	
MidAmerican Energy Company	Yes	
BrightSource Energy, Inc.	Yes	
Consumers Energy Company	Yes	
Alliant Energy	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 2 Comment
Hydro-Quebec TransEnergie	Yes	
New York Power Authority	Yes	
Omaha Public Power District	Yes	
Idaho Power Company	Yes	
City of Tallahassee	Yes	
Volkmann Consulting, Inc	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
MRO	Yes	
American Transmission Company, LLC	Yes	

Organization	Yes or No	Question 2 Comment
First WInd	Yes	
Minnkota Power Cooperative	Yes	
Public Utility District No.1 of Snohomish County	Yes	
Response: Thank you for your support.		

3. **The SDT has added the term 'Real' to Exclusion E3b to clarify its intent. Do you agree with this change? If you do not support this change, please provide specific suggestions and technical rationale in your comments.**

Summary Consideration: There were no negative comments regarding this change.

No changes were made to the proposed definition due to comments raised in this question.

Organization	Yes or No	Question 3 Comment
SPP Standards Review Group	Yes	This change has been made to clarify the drafting team's intent. We would be interested in knowing what that intent is.
Response: The intent of the SDT was to clarify that Real Power is the issue with regard to local networks. Reactive Power is a local issue and not easily or customarily transferred outside of the local network.		
Ameren	Yes	We agree with the addition of the word "Real", but we have other concerns with E3b and we have identified in the comments to question 4 below.
Response: Please see the response to Q4.		
Southern California Edison Company	Yes	Clearly identifying "Real" Power makes sense and helps clarify the intent.
NIPSCO	Yes	good

Organization	Yes or No	Question 3 Comment
Arizona Public Service Company	Yes	This is in regard to local networks and this change is less restrictive.
Northeast Power Coordinating Council	Yes	
Dominion	Yes	
SERC Planning Standards Subcommittee	Yes	
Florida Municipal Power Agency	Yes	
BANC & SMUD	Yes	
Bonneville Power Administration	Yes	
Duke Energy	Yes	
Associated Electric Cooperative,	Yes	

Organization	Yes or No	Question 3 Comment
Inc. - JRO00088		
ACES Standards Collaborators	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Southern Company	Yes	
PacifiCorp	Yes	
Wisconsin Public Service Corporation	Yes	
Madison Gas and Electric Company	Yes	
Pepco Holdings Inc	Yes	

Organization	Yes or No	Question 3 Comment
Muscatine Power and Water	Yes	
Public Service Enterprise Group	Yes	
Indiana Municipal Power Agency	Yes	
Exelon and its' affiliates	Yes	
MidAmerican Energy Company	Yes	
Independent Electricity System Operator	Yes	
BrightSource Energy, Inc.	Yes	
American Electric Power	Yes	
Consumers Energy Company	Yes	

Organization	Yes or No	Question 3 Comment
Alliant Energy	Yes	
Manitoba Hydro	Yes	
Hydro-Quebec TransEnergie	Yes	
Nebraska Public Power District	Yes	
New York Power Authority	Yes	
Omaha Public Power District	Yes	
Idaho Power Company	Yes	
City of Tallahassee	Yes	
Volkmann Consulting, Inc	Yes	

Organization	Yes or No	Question 3 Comment
Tri-State Generation and Transmission Association, Inc.	Yes	
Xcel Energy	Yes	
MRO	Yes	
Hydro One	Yes	
American Transmission Company, LLC	Yes	
First WInd	Yes	
Minnkota Power Cooperative	Yes	
Response: Thank you for your support.		

4. **Are there any other concerns with this definition that haven't been covered in previous questions and comments?**

Summary Consideration: The proposed definition continues to include, through inclusion I4, individual dispersed power producing resources if those resources aggregate to a total value greater than 75 MVA. This inclusion treats dispersed power producing resources in a manner that is comparable to other non-dispersed power producing resources and is an approach that was accepted and emphasized by the Commission in Orders No. 773 & 773-A. The SDT has explored various options associated with dispersed power producing resources; however, none of the options explored provided an equal and effective approach to address the Commission's reliability concerns with these facilities. The SDT continues to believe that the best resolution to the industry's concerns is through clarification of the applicability of individual Reliability Standards and not a revision to the BES definition. Given these facts, the SDT is retaining Inclusion I4a but has revised the language of inclusion I4, based on industry comments, to provide greater clarity of the SDT's intent.

I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:

a) The individual resources, and
b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

The SDT made the following changes to the white paper on the 50 kV threshold in response to suggestions made by commenters:

In this simplified depiction of a portion of an electric system, two radial 115 kV lines emanate from 115 kV substations A and B to serve distribution loads via 115 kV distribution transformers at stations C and D. Stations C and D are "looped" together via either a distribution bus tie (zero impedance) or a feeder tie (modeled with typical distribution feeder impedances).

The analyses determined the LODF which represents the portion of the high voltage transmission flow that would flow across the low voltage distribution circuit or bus ties under a single contingency outage of the line between stations A and B.

Organization	Yes or No	Question 4 Comment
Dominion	No	
Bonneville Power Administration	No	
Duke Energy	No	
Salt River Project	No	
PacifiCorp	No	
Wisconsin Public Service Corporation	No	
Pepco Holdings Inc	No	
Public Service Enterprise Group	No	
Indiana Municipal Power Agency	No	

Organization	Yes or No	Question 4 Comment
MidAmerican Energy Company	No	
Independent Electricity System Operator	No	
Consumers Energy Company	No	
Omaha Public Power District	No	
City of Tallahassee	No	
Volkmann Consulting, Inc	No	
Tri-State Generation and Transmission Association, Inc.	No	
Xcel Energy	No	
MRO	No	

Organization	Yes or No	Question 4 Comment
First WInd	No	
Minnkota Power Cooperative	No	
Public Utility District No.1 of Snohomish County	No	
Response: Thank you for your review and comments.		
Manitoba Hydro	Yes	(1) General Comment - replace " Board of Trustees " with " Board of Trustees' " throughout the applicable documents/standards for consistency with other standards.
Response: The SDT believes that the use of the apostrophe is appropriate if using the term in the possessive sense and will review SDT documents for any instances of possessive use.		
Seminole Electric Cooperative, Inc.	Yes	(1) The definition utilizes the term "non-retail generation." This term does not appear to be clarified within the definition. However, the drafting team has attempted to clarify the term in the guidance document. Unfortunately, the guidance document is not final, meaning that it can be revised before being finalized. Please define retail and non-retail generation as separate definitions for inclusion into the Glossary contingent upon each other or make the BES definition approval contingent on the guidance document being approved. See

Organization	Yes or No	Question 4 Comment
		Exclusion E1(c). (2) The terms "plant and facility" are not defined and are ambiguous. Please provide quantitative and/or qualitative factors that an entity can utilize in determining what is a plant/facility. See Inclusion I2. (3) The following note will be placed in the Reference document:"Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system." Please strike the following language from the paragraph "or an enhancement of," as it is more of a persuasive statement than an objective statement. (4) In Exclusion E1(c), please clarify that reactive devices, such as capacitor banks, can be included in this section also. Reactive devices are differentiated from real power devices in Inclusion I2 and so we request clarification that reactive devices can be included in Exclusion E1(c). (5) Inclusion I2 includes generation above 20 MVA/75MVA connected at 100 kV or higher. However, the base definition includes all generation units connected at 100 kV or higher. Units below 20 MVA/75MVA are never actually excluded. The net effect is to include all generation under the base definition regardless of size. To avoid future interpretation issues and ensure consistency with the intent communicated in the Phase 1 guidance document (page 13, Figure I2-6), Inclusion I2 needs to be written as an exclusion of units less than 20 MVA/75 MVA. If this not the intent of I2, then the definition needs to be modified to clarify the intent. (6) Exclusion E2 currently states ": (i) the net capacity provided to the BES does

Organization	Yes or No	Question 4 Comment
		not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services...". This statement could easily be covered under the section currently labeled I2 and suggested above to be rewritten as an exclusion. We would like to suggest potential language to simplify the definition, eliminate inclusion I2 to ensure that units under 20 MVA/75 MVA are actually excluded from the definition, and incorporate these ideas into exclusion E2 so that Exclusion E2 would be:E2 - Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: a) Gross individual nameplate rating less than 20 MVA. Or, b) Gross plant/facility aggregate nameplate rating less than 75 MVA. Or, c) One or more generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority. (7) It would be extremely valuable for the team as part of any guidance document to develop and review a decision tree supporting the definition and include this decision tree in the next revision of the guidance document.

Response: 1. The SDT believes that the explanation provided in the Reference Document clarifies the term. Any revisions to the Reference Document for Phase 2 will be completed by the SDT so consistency of intent and use will be accomplished. No change made.

2. The SDT uses the terms plant and facility interchangeably as shown in the definition by the word structure 'plant/facility'. The SDT does not believe that this introduces ambiguity or confusion and that the examples shown in the Reference Document suffice to

Organization	Yes or No	Question 4 Comment
explain the terminology. No change made. 3. The SDT will consider this suggestion when the Reference Document is revised. No change made at this time. 4. Reactive devices are included in the BES if they fall under the criteria shown in Inclusion I5. No change made. 5. The SDT believes that Inclusion I2 correctly identifies what units are included in the BES and that stating the converse is unnecessary and duplicative. No change made. 6. The SDT disagrees and believes that there are important distinctions and conditions shown in Exclusion E2 that warrant it being treated separately. No change made. 7. The SDT believes that the hierarchical approach to the application of the definition that has been published in several documents, including the Reference Document, fulfils the intent of the decision tree methodology suggested in the comment. As noted above, the Reference Document will be revised after the Phase 2 definition is finalized, and the SDT will consider whether any additional clarification would be helpful.		
Idaho Power Company	Yes	1. In the wording for E3b (Local Networks), the phrase “and the LN does not transfer energy originating outside the LN for delivery through the LN” does not seem to add any value or specificity to the LN Exclusion. In fact, the phrase seems misleading and serves to add confusion since some amount of energy flowing in a parallel BES path outside the LN will always flow through the LN, even if it’s just a trickle and does not impact the sign of the measured power flow at the LN points of connection. Suggested reword for E3b is “Real power flows only into the LN at each LN connection point.” 2. We agree that your clarifying single-line diagram for Inclusion I4 (40 - 2 MVA generators aggregated up through the point of aggregation to the common point of connection) for dispersed power producing resources properly designates the point of aggregation of the dispersed power producing resources as a BES element. We also agree with the basis for this designation which states for the point of aggregation "where the individual generator

Organization	Yes or No	Question 4 Comment
		nameplate ratings of the dispersed generation total > 75 MVA (actual 80 MVA) and a single point failure would result in loss of all generation contained on the dispersed generation site". However, following the same logic in basis, we do not agree with the BES designation for each individual 2 MVA generator in your clarifying single-line diagram. We think it makes sense that the reliability of the power system should be considered for the loss of the 80 MVA and we agree that a potential single point of failure exists at the point of aggregation that could result in the loss of all generation. However, we do not think that the loss of one 2 MVA generator would have any significant negative impact on the reliability of the power system. If the loss of greater than 20 MVA via a single point failure scenario is deemed significant to the reliability of the power system (Inclusion I2, a), then that same logic suggests that each of the two buses that aggregates 40 MVA of generation should be designated as BES. If, on the other hand, due to the dispersed nature of the generation in the clarifying single-line diagram, the loss of greater than 75 MVA via a single point failure scenario is deemed significant to the reliability of the power system (Inclusion I2, b), then that same logic suggests that the point of aggregation that aggregates 80 MVA of generation should be designated as BES. No place in the BES core definition nor in any of the inclusions (or exclusions) is there a concern for the loss of 2 MVA of generation as having a negative reliability impact on the power system. Therefore, we would not designate each individual 2 MVA generator as BES as you have in your clarifying single-line diagram and would suggest the following wording for Inclusion I2 for your consideration:I2 - Generating resource(s) with: a) gross individual nameplate rating greater than 20 MVA, including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above or,b) the point of aggregation of gross plant/facility with aggregate nameplate rating greater than 75 MVA, including the system designed primarily for delivering the aggregated capacity from the point where the

Organization	Yes or No	Question 4 Comment
		resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.I4 - DELETED

Response: 1. The SDT disagrees and re-iterates its position that any flow out of a local network disqualifies it for Exclusion E3. This point has been consistently presented by the SDT as one of the basic tenets for a local network and was explained in the white paper published in Phase 1 (http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_definition_technical_justification_local_network_20110819.pdf). No change made.

2. The proposed definition continues to include, through inclusion I4, individual dispersed power producing resources if those resources aggregate to a total value greater than 75 MVA. This inclusion treats dispersed power producing resources in a manner that is comparable to other non-dispersed power producing resources and is an approach that was accepted and emphasized by the Commission in Orders No. 773 & 773-A. The SDT has explored various options associated with dispersed power producing resources; however, none of the options explored provided an equal and effective approach to address the Commission's reliability concerns with these facilities. The SDT continues to believe that the best resolution to the industry's concerns is through clarification of the applicability of individual Reliability Standards and not a revision to the BES definition. Given these facts, the SDT is retaining Inclusion I4a but has revised the language of inclusion I4, based on industry comments, to provide greater clarity of the SDT's intent.

> I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
>
> a) The individual resources, and
>
> b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

Organization	Yes or No	Question 4 Comment
NAGF Standards Review Team	Yes	1. The language of the proposed BES definition is rather convoluted and is therefore difficult to apply correctly without the Reference Document. The FERC order 773/773a-amended Reference Document is not complete or final

Organization	Yes or No	Question 4 Comment
		for the phase-2 BES definition, however. Its exclusion E1 statement is that of phase-1, not phase-2, for example, and a disclaimer on p.1 states "...this reference document is outdated. Revisions to the document will be developed at a later date to conform to the definition being developed in Phase 2." It appears that the phase-2 BES definition is being rushed through the approval process, and it would be preferable to take the time to compile a complete and consistent body of documentation before putting the matter up for a vote. This is especially important for correctly classifying very small, standby, non-Blackstart Resource gensets feeding the aux buses of generation plants for emergency purposes. Such emergencies include blackouts and max-generation situations, and in the latter case displacing some of the aux load can temporarily boost the net amount of power delivered by the plant. 2. Figure I2-5 of the Reference Document suggests that such standby generators are part of the BES, if the plant totals more than 75 MVA, because they "contribute to the gross aggregate rating of the site." Fig. I2-5 depicts all units exporting to the grid, however, and we are considering here only standby gensets feeding aux buses that remain net importers of power. Exclusion E3 may apply, however. Fig. S1-9b of the Reference Document shows a system composed of several generating plants and users, but the conclusions reached by the SDT should be unchanged if one drew a box around the diagram and labeled it a single generating plant. Specifically, the SDT decided that Exclusion 3 is invoked by the circumstance that the bus fed by the 5 MVA generator at lower left is exclusively an importer of power, and this ruling should apply as well for standby gensets that feed aux buses within generation plants. Making such a classification would require that a Local Network (LN) can exist within a generation plant, as opposed be being found exclusively in the systems of TOs and DPs. Such an interpretation may be permitted by the circumstance that the definition of an LN uses the word "transmission" with a lower-case "t", as

Organization	Yes or No	Question 4 Comment
		opposed the TO and DP-oriented term "Transmission" in the NERC Glossary, but the LN definition also references serving "retail customer load." This definition should be changed, or (better) the BES definition should explicitly state that gensets < 20 MVA feeding power-importing aux buses of generation plants are excluded from the BES. The term "nameplate rating" should be replaced by the NERC-defined term "Facility Rating" to harmonize the BES definition with NERC's standards. 3. Inclusion I2a should be deleted and I2b should be used to define the threshold for all generating facilities. It is inconsistent to include a 21 MVA single generator (using I2a) and not include 74.5 MVA aggregated conglomeration of individual generators (using I2b). Since 75MVA is used as the threshold in multiple places in this definition, a single generator unit (Facility Rating) at 75 MVA connected at > 100kV should be the individual unit size threshold. 4. Please specify what size of reactive power resources is included by I5 (> 75MVAR?).
PPL NERC Registered Affiliates	Yes	a. The language of the proposed BES definition is somewhat vague and is therefore difficult to apply correctly without the Reference Document. The FERC order 773/773a-amended Reference Document is not complete or final for the phase-2 BES definition, however. Its exclusion E1 statement is that of phase-1, not phase-2, for example, and a disclaimer on p.1 states that "...this reference document is outdated. Revisions to the document will be developed at a later date to conform to the definition being developed in Phase 2." It appears that the phase-2 BES definition is being rushed through the approval

Organization	Yes or No	Question 4 Comment
		process, and it would be preferable to take the time to compile a complete and consistent body of documentation before putting the matter up for a vote. This is especially important for correctly classifying very small, standby, non-Blackstart Resource gensets feeding the aux buses of generation plants for emergency purposes. Such emergencies include blackouts and max-generation situations, and in the latter case displacing some of the aux load can temporarily boost the net amount of power delivered by the plant. Figure I2-5 of the Reference Document suggests that such standby generators are part of the BES, if the plant totals more than 75 MVA, because they "contribute to the gross aggregate rating of the site." Fig. I2-5 depicts all units exporting to the grid, however, and we are considering here only standby gensets feeding aux buses that remain net importers of power. Exclusion E3 may apply, however. Fig. S1-9b of the Reference Document shows a system composed of several generating plants and users, but the conclusions reached by the SDT should be unchanged if one drew a box around the diagram and labeled it a single generating plant. Specifically, the SDT decided that Exclusion 3 is invoked by the circumstance that the bus fed by the 5 MVA generator at lower left is exclusively an importer of power, and this ruling should apply as well for standby gensets that feed aux buses within generation plants. Making such a classification would require that a Local Network (LN) can exist within a generation plant, as opposed be being found exclusively in the systems of TOs and DPs. Such an interpretation may be permitted by the circumstance that the definition of an LN uses the word "transmission" with a lower-case "t", as opposed the TO and DP-oriented term "Transmission" in the NERC Glossary, but the LN definition also references serving "retail customer load." This definition should be changed, or (better) the BES definition should explicitly state that gensets < 20 MVA feeding power-importing aux buses of generation plants are excluded from the BES.

Organization	Yes or No	Question 4 Comment
		b. The term "nameplate rating" should be replaced by the NERC-defined term "Facility Rating" to harmonize the BES definition with NERC's standards. c. Inclusion I2a should be deleted and I2b should be used to define the threshold for all generating facilities. It is inconsistent to include a 21 MVA single generator (using I2a) and not include 74.5 MVA aggregated conglomeration of individual generators (using I2b). Since 75MVA is used as the threshold in multiple places in this definition, a single unit (facility rating) at 75 MVA connected at > 100kV should be the individual unit size threshold. d. Please specify what size of reactive power resources is included by I5 (> 75MVAR?).
Associated Electric Cooperative, Inc. - JRO00088	Yes	AECI supports the NAGF's draft comment for concern, duplicated immediately below:"The language of the proposed BES definition is rather convoluted and is therefore difficult to apply correctly without the Reference Document. The FERC order 773/773a-amended Reference Document is not complete or final for the phase-2 BES definition, however. Its exclusion E1 statement is that of phase-1, not phase-2, for example, and a disclaimer on p.1 states that "...this reference document is outdated. Revisions to the document will be developed at a later date to conform to the definition being developed in Phase 2." It appears that the phase-2 BES definition is being rushed through the approval process, and it would be preferable to take the time to compile a complete and consistent body of documentation before putting the matter up for a vote. This is especially important for correctly classifying very small, standby, non-Blackstart Resource gensets feeding the aux buses of generation plants for emergency purposes. Such emergencies include blackouts and max-generation situations, and in the latter case displacing some of the aux load can

Organization	Yes or No	Question 4 Comment
		temporarily boost the net amount of power delivered by the plant. Figure I2-5 of the Reference Document suggests that such standby generators are part of the BES, if the plant totals more than 75 MVA, because they, "contribute to the gross aggregate rating of the site." Fig. I2-5 depicts all units exporting to the grid, however, and we are considering here only standby gensets feeding aux buses that remain net importers of power. Exclusion E3 may apply, however. Fig. S1-9b of the Reference Document shows a system composed of several generating plants and users, but the conclusions reached by the SDT should be unchanged if one drew a box around the diagram and labeled it a single generating plant. Specifically, the SDT decided that Exclusion 3 is invoked by the circumstance that the bus fed by the 5 MVA generator at lower left is exclusively an importer of power, and this ruling should apply as well for standby gensets that feed aux buses within generation plants. Making such a classification would require that a Local Network (LN) can exist within a generation plant, as opposed be being found exclusively in the systems of TOs and DPs. Such an interpretation may be permitted by the circumstance that the definition of an LN uses the word "transmission" with a lower-case "t", as opposed the TO and DP-oriented term "Transmission" in the NERC Glossary, but the LN definition also references serving "retail customer load." This definition should be changed, or (better) the BES definition should explicitly state that gensets < 20 MVA feeding power-importing aux buses of generation plants are excluded from the BES. Additionally, the MVA size of reactive power generator that is included by I5 should be specificed."

Response: 1. The SDT has not published a Phase 2 Reference Document at this time and did not intend the posted version to represent a full implementation of Phase 2 as Phase 2 isn't complete. A revised Reference Document will be published in the same timeframe and sequence that was used in Phase 1. The SDT is following the established development process and while working against a deadline is not rushing things through. No change made.

2. The identified equipment exists today and precedent has already been established as to how to handle it with regard to BES

Organization	Yes or No	Question 4 Comment
inclusion. Nothing in the proposed definition changes this. The intent of the SDT is that the precedent will not change how the identified equipment is classified. The intent of the SDT is to identify BES generators and it believes that the current language is clear in that regard. No change made. The SDT believes that nameplate rating is the correct term to use in a bright-line definition. Facility Rating is a variable value that would cause the determination of whether units are BES or not to fluctuate from period to period making for an untenable compliance situation. No change made. 3. The SDT is following the recommendation of the Planning Committee in its report on threshold values (http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_phase2_pc_report_final_20130306.pdf) in the retention of the 20 and 75 MVA threshold values. No change made. 4. All reactive power devices are included by Inclusion I5 regardless of size as recommended by the Planning Committee in the report cited in response 3.		
Ameren	Yes	1. We request the SDT to provide clarification for E3b testing conditions, specifically for all facilities in service or for single transmission contingency conditions. We believe that the criteria needs to be very clear so it is not confusing for entities when determining inclusion of local network facilities as BES facilities. 2. Also, we do not believe that 1 MW of back-feed from local network facilities to transmission facilities for a few hours out of the year constitutes classification of the local network facilities as BES facilities. We request that the SDT consider for inclusion that the magnitude of the injections from the local network should be in line with other injections into the transmission system such as: (a) Generators with a nameplate greater than 20 MVA, or (b) Aggregate resources greater than 75 MVA. 3. In our opinion, the standard puts additional burden on local network owners including local subtransmission network owners to prove that their

Organization	Yes or No	Question 4 Comment
		facilities should be excluded from consideration as BES facilities. (a) We believe that, testing for BES inclusion could be included in the annual TPL contingency analysis, but it may not be possible to complete this type of analysis before the end of the year unless the criteria is clearly defined and limited in scope, otherwise numerous models reflecting varying system conditions would need to be considered. (b) We ask the SDT to recall that it was suggested in the last webinar that SCADA data could be used to prove that there was no back-feed from the local network to the transmission system. (c) We realize that the accuracy of SCADA data at low flow levels can be suspect at low load flows but if considered with the type of relaying, that is if the relaying limits power flow back into the BES transmission system, this could be used as a means of quick determination for inclusion. We appreciate the work of the SDT effort to provide a reasonable and balanced approach to the determination of BES facilities, and doing all of this within a very short period of time. Again we ask the SDT for consideration with respect of the 50kV threshold being raised to 70kV, and that with respect to injections into the transmission network from the various generation and local network sources that they be considered as a comparable basis in the determination of BES facilities.
SERC Planning Standards Subcommittee	Yes	E3b: The testing conditions for E3b should be clearly stated, namely for all facilities in service or for single transmission contingency conditions. We believe that the criteria need to be anchored so as not to manufacture a justification for inclusion of local network facilities as BES facilities. Add word “normally” between “not” and “transfer” to E3b: Real Power flows only into the LN and the LN does not normally transfer energy originating outside the LN

Organization	Yes or No	Question 4 Comment
		for delivery through the LN; and We do not believe that 1 MW of back-feed from local network facilities to transmission facilities for a few hours of the year constitutes classification of the local network facilities as BES facilities. We believe that the magnitude of the injections from the local network should be reviewed in line with other injections into the transmission system such as a) generators with a nameplate greater than 20 MVA, or b) aggregate resources greater than 75 MVA. In our opinion, the standard puts additional burden on local network owners including local subtransmission network owners to prove that their facilities should be excluded from consideration as BES facilities. In theory, this testing could be included in the annual TPL contingency analysis, but it may not be possible to complete this type of analysis before the end of the year for numerous models reflecting varying system conditions. It was suggested in the last webinar that SCADA data could be used to prove that there was no back-feed from the local network to the transmission system, but the accuracy of some SCADA data at low flow levels can be suspect and the SCADA data does not identify the exact system conditions that were experienced when the SCADA measurements were recorded, including outages to local subtransmission facilities. We appreciate the work of the SDT to try and provide a reasonable and balanced approach to the determination of BES facilities, and within a very short period of time. We ask that the injections into the transmission network from the various generation and local network sources be considered on a comparable basis in the determination of BES facilities. The comments expressed herein represent a consensus of the views of the

Organization	Yes or No	Question 4 Comment
		above named members of the SERC PSS and the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Response: 1. The SDT has been clear from the beginning that local networks must meet the criteria of Exclusion E3 for all operating conditions. No change made. 2. The position of the SDT has consistently been that local networks that have flow back into the BES at any time do not qualify under exclusion E3 as a local network. In the Reference Document, the SDT proposed a method to measure this factor so that a brief momentary fluctuation will not negate the ability to invoke Exclusion E3. No change made. 3. The SDT has always proposed that SCADA data could be used to determine local network applicability. 4. The commenter has presented no technical rationale for increasing the threshold value above 50 kV. The studies performed by the SDT indicate that 50 kV is the highest supportable threshold value, i.e., where the loop configuration starts to flow back to the BES and may be considered necessary for the reliable operation of the interconnected transmission system. No change made.		
Southern Company	Yes	A) Inclusion I2a should be deleted and I2b should be used to define the threshold for all generating facilities. It is inconsistent to include a 21 MVA single generator (using I2a) and not include 74.5 MVA aggregated conglomeration of individual generators (using I2b). Since 75 MVA is used as the threshold in multiple places in this definition, a single generator at 75 connected at > 100kV should be the individual unit size threshold. B) Please specify what size of Reactive Power resources is included by I5. Order 773 acknowledged that Inclusion I5 is the technical equivalent of Inclusion I2 (generating resources) for reactive power devices. Since generating resources in Inclusion I2 are limited to those connected at 100kV or above with individual and aggregate ratings of 20MVA and 75 MVA, respectively, it could be consistent -- if technically justified -- to include a

Organization	Yes or No	Question 4 Comment
		threshold of >75MVAR for reactive power resources. Some technical justification should be pursued to determine whether 75 MVAR or a different size threshold would be appropriate to include in Inclusion I5 for Reactive Power resources. C) Southern Transmission believes that Exclusion E3 should include a limit on the size of a Local Network (LN). This position is consistent with the proposal from the NERC System Analysis and Modeling Subcommittee (SAMS). Without placing a size limitation on such a network, a single contingency could result in significant flows across the BES to serve the LN from a different location. The SAMS provided technical justification for a 300 MW load limit and Southern would be supportive of such a limit. Southern also agrees with the SAMS that the flow should be into the LN under single contingency conditions. (See NERC's Review of Bulk Electric System Definition Thresholds, March 2013, Section 5.3) D) Southern believes that the second part of Exclusion E3 should be deleted for three reasons: First, Exclusion E3a refers to "non-retail generation". Southern believes that whether a unit is "retail" or "non-retail" should be irrelevant when determining inclusion in the BES. Regardless of how a generator is classified, if it is large enough to impact flows on the system, then it should be included in the BES. Second, the phrase "and do not have" in the second phrase of Exclusion E3a is ambiguous and redundant and could lead to confusion and misapplication. Specifically, it is ambiguous as to whether the last phrase regarding aggregate non-retail capacity:(a) refers back to the generation resources identified in Inclusion I2, I3, or I4 (thus defining a smaller subset of generation resources from I2, I3, and I4 that are carved out from the definition of LN, but other Inclusion I2-I4 generation resources can be part of the local network); or(b) simply refers back to "generation resources"

Organization	Yes or No	Question 4 Comment
		(therefore, local networks exclude BOTH Inclusion I2-I4 generation resources AND, separately, generation resources with aggregate non-retail generation >75MVA).Third, Inclusions I2 and I4 already both use the 75 MVA limit. It seems redundant to state that a Local Network under Exclusion E3a does not include generation resources with aggregate capacities greater than 75 MVA when Exclusion E3a already states that local networks do not include generation resources identified in Inclusion I2 and I4 (which, in turn, include generation resources with aggregate capacities above 75 MVA). To clarify and to eliminate confusing and unnecessary redundancy, Southern suggests striking all language after "Inclusion I4." Exclusion E3a should therefore read: "a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4."

Response: a. The SDT is following the recommendation of the Planning Committee in its report on threshold values (http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_phase2_pc_report_final_20130306.pdf) in the retention of the 20 and 75 MVA threshold values. No change made.

b. All reactive power devices, regardless of size, are included by Inclusion I5 as recommended by the Planning Committee in the report cited in response a.

c. The SDT does not believe that such a limit is needed. In the example provided, the SDT sees no affect on the reliability of the BES simply because a configuration of equipment has been designated as a local network. Further, evaluating local network applicability under planning scenarios such as single contingency operation violates the bright-line principle of the definition. No change made.

d. The differentiation between retail and non-retail is based on Exclusion E2 and the SDT believes that such differentiation is warranted in Exclusion E3. There is a difference in citing individual units or aggregation of units under Inclusion I2 and a 75 MVA limit as expressed in Exclusion E3a. The 75 MVA limit was retained to capture the situation where there are multiple plants/facilities within the local network that might add up to 75 MVA but which wouldn't be captured under inclusion i2. No change made.

Organization	Yes or No	Question 4 Comment
Alliant Energy	Yes	Alliant Energy reiterates that Inclusion I4a must be removed from the definition of the BES. It makes no technical sense, and creates an extremely burdensome compliance workload and risk.
Madison Gas and Electric Company	Yes	The inclusion of I4a does not support the reliabile operation of the BES. As stated before, we agree that the point of interconnection should be included, not the individual intermitent resources.
BANC & SMUD	During Phase-1, it was suggested that a 75 MVA threshold be established where the loss of a single element would render the entire 75 MVA of resources unavailable. This was in lieu of including the individual small-scaled machines as BES to avoid subjecting those machines to administrative burden for little or no impact on the BES as compared to the compliance obligation. (Please refer to response to Q2 for additional details.)	
Response: The proposed definition continues to include, through inclusion I4, individual dispersed power producing resources if those resources aggregate to a total value greater than 75 MVA. This inclusion treats dispersed power producing resources in a manner that is comparable to other non-dispersed power producing resources and is an approach that was accepted and emphasized by the Commission in Orders No. 773 & 773-A. The SDT has explored various options associated with dispersed power producing resources; however, none of the options explored provided an equal and effective approach to address the Commission's reliability concerns with these facilities. The SDT continues to believe that the best resolution to the industry's concerns is through clarification of the applicability of individual Reliability Standards and not a revision to the BES definition. Given these facts, the SDT is retaining Inclusion I4a but has revised the language of inclusion I4, based on industry comments, to provide greater clarity of the SDT's intent. **I4** - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at		

Organization	Yes or No	Question 4 Comment
a voltage of 100 kV or above. Thus, the facilities designated as BES are: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.		
NIPSCO	Yes	Another major concern is whether our 138 kV industrial customers with multiple feeds are part of the BES. One of the criteria is whether power ever flows through the customer's system. This could be very difficult to prove with evidence. Perhaps during the last year's peak load or maximum transfer across the host TOP's system, the flow could be integrated over an hour; if there is system flow across the customer's system during the integrated hour, then the customer's system should be considered part of the BES and the customer should have multiple years to comply with becoming part of the BES. If the customer becomes part of the BES would this mean that they would have to become a TO/TOP? Would it require that they have NERC certified operators? We see these as emerging concerns. Additionally, it appears that several small wind generators may become part of the BES which would bring PRC-004 misoperations into play for them. It is our understanding that such generators trip off line based on wind and wind direction. Keeping track of these operations and the associated analysis may become quite an undertaking. Other standards such as PRC-005 may also become a concern.
Response: The SDT can't respond to individual requests for determination of whether a specific configuration is BES or not. However, in the Reference Document, the SDT did supply a mechanism for measuring flow that did involve integrated hourly values.		

Organization	Yes or No	Question 4 Comment
Similarly, the SDT can't make a determination on registration issues or the need for certified operators. The proposed definition continues to include, through inclusion I4, individual dispersed power producing resources if those resources aggregate to a total value greater than 75 MVA. This inclusion treats dispersed power producing resources in a manner that is comparable to other non-dispersed power producing resources and is an approach that was accepted and emphasized by the Commission in Orders No. 773 & 773-A. The SDT has explored various options associated with dispersed power producing resources; however, none of the options explored provided an equal and effective approach to address the Commission's reliability concerns with these facilities. The SDT continues to believe that the best resolution to the industry's concerns is through clarification of the applicability of individual Reliability Standards and not a revision to the BES definition. Given these facts, the SDT is retaining Inclusion I4a but has revised the language of inclusion I4, based on industry comments, to provide greater clarity of the SDT's intent. I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.		
American Transmission Company, LLC	Yes	ATC has the following additional comment for consideration by the SDT: o Exclusion 3b does not currently define the limited set of conditions entities are to consider when determining if real power flows only into the local network (LN). Without this clarification, entities will have no certainty regarding the exclusion determination made, which can have a material impact on the entity under all of the NERC standards. ATC recommends the following revision to E3b:E3b) Real Power flows only into the LN under intact system and most severe single contingency conditions and the LN does not transfer energy originating outside the LN for delivery through the LN; and' This revision is warranted for the reason noted above. In addition, the language is consistent with how the system is operated under the NERC TOP standards and the

Organization	Yes or No	Question 4 Comment
		proposed addition matches NERC’s own statements to the FERC as recorded in paragraph 71 of FERC Order 773-A. As noted in the same paragraph, FERC agreed with NERC’s reasoning. Therefore, this clarification should be recorded in the BES definition.
Response: The SDT has consistently indicated its intent that local networks must meet the criteria of Exclusion E3 for all operating conditions. No change made.		
Modesto Irrigation District	Yes	I voted NO for the following reasons:1. WECC studies have shown that there are thousands of MWs of wind and PV generating plants currently on-line, and thousands of MWs under development, in the WECC system, of 20 MW and less capacity units. Ignoring the impacts of these units on the BES would be a mistake, as recent studies by the WECC MVWG (Modeling and Validation Work Group) have shown (i.e., June 2013 Meeting). 2. The revisions have made the definition of the BES so complicated, that the definition is no longer in a form that can be applied in a straight forward and reasonable manner. Also, there are no technical justifications provided for some of the exclusion criteria (e.g, 75 MVA). 3. The best way to define the BES is by using the engineering methodology developed by the WECC BES Definition Task Force, and published in May 2010. That study work showed that for the location in question to have a material impact to the interconnected bulk electric power system, there must be an equivalent short circuit MVA exceeding 6000 at that location.Thank you.
Response: 1.The SDT is not proposing to ignore the impact of wind and PV generation but to arrive at the optimal solution for achieving over-all BES reliability. The SDT is also attempting to achieve a bright-line definition of BES. If there are some units that		

Organization	Yes or No	Question 4 Comment
fall 'outside' of the bright-line that a reliability entity feels should be part of the BES that entity always has the option to file for an inclusion to the BES through the established exception process. No change made. 2. The SDT is following the recommendation of the Planning Committee in its report on threshold values (http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_phase2_pc_report_final_20130306.pdf) in the retention of the 20 and 75 MVA threshold values. No change made. 3. As stated in the FERC Orders, material impact alone is not a sufficient condition for determining BES applicability. The revised "bright-line" definition developed under the Phase 1 project was approved by the industry and the Board of Trustees. No change made.		
Hydro-Quebec TransEnergie	Yes	HQT's position remains the same concerning the BES Definition, as limitations on exclusion are increased in phase 2 as imposed by FERC without proper hearing of non-US jurisdictions. One other comment on the Implementation plan refers to the second sentence of Effectives dates. The second sentence should be arranged differently as it refers both to "no regulatory approval required" and "applicable governmental authorities". The last part of the sentence should be moved with the first sentence to add clarity.
Hydro One	Yes	In Canada, local load reliability requirements are under the provincial authority of local regulators such as the Ontario Energy Board in Ontario. We understand that NERC needs to follow FERC Orders and directives. In our opinion NERC must ensure that any provisions within the BES definition and/or NERC standards that are to address load reliability and load supply continuity issues and NOT interconnected BES reliability should be limited to the FERC jurisdiction only. Accordingly we suggest that when addressing such requirements in a standard it must include that for a non-US Registered Entity

Organization	Yes or No	Question 4 Comment
		it should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction. Good examples to address these issues are through the Standards process as was done for NUC 001 and TPL001 Footnote b.
Northeast Power Coordinating Council	Yes	Suggest the following rewording of the Effective Dates section of the Implementation Plan to add clarity regarding approvals: In those jurisdictions where no regulatory approval is required the definition shall become effective on the first day of the second calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws of applicable governmental authorities. In those jurisdictions where no regulatory approval is required the definition shall (go should be deleted) become effective on the first day of the second calendar quarter after Board of Trustees adoption. NPCC participating members suggest that when addressing the requirements pertaining to load reliability and continuity in a standard, they must include that for a non-U.S. Registered Entity it should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-U.S. jurisdiction.

Response: The revised definition project was undertaken in response to a FERC Order but provides an appropriate continent-wide, bright-line for reliability of the BES based on physical principles and demonstrated in the technical analysis in the white paper supporting the selection of the 50 kV threshold (http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_phase2_white_paper_sub100kv_threshold_20130802.pdf). Therefore, the SDT sees no reason for a reference to non-US Registered Entities. No change made.

Organization	Yes or No	Question 4 Comment
SPP Standards Review Group	Yes	In the Implementation Plan, delete 'go' at the beginning of the 3rd line of the 1st paragraph. WhitepaperOn Page 9, Line 9 of the 1st paragraph, delete the '/'. On Page 9, Line 3 of the 2nd paragraph, replace 'represent' with 'represents'. On Page 9, Line 4 of the 2nd paragraph, replace 'distribute' with 'flow'.
Response: The SDT agrees with your correction to the Implementation Plan language; however, that language has been revised to reflect different approaches to making standards enforceable in various Canadian jurisdictions. The SDT agrees and has made the suggested change to the white paper.		
Arizona Public Service Company	Yes	Inclusion I5 is about reactive sources. However it only excludes E4. There is no reason why all exclusions E1 to E4 should not apply to reactive sources. The current definition will include reactive sources in radial system as part of BES. There is no technical reason for excluding radial system and yet including reactive sources in radial system as part of BES
Response: The SDT is following the recommendation of the Planning Committee in its report on reactive devices (http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_phase2_pc_report_final_20130306.pdf) where the Planning Committee recommended that all reactive devices be included in the BES. No change made.		
Nebraska Public Power District	Yes	It is imperative to have the BES reference document be updated to reflect the latest changes and drafting team position on various items with the definition since the definition is not self-explanatory due to the significant BES system

Organization	Yes or No	Question 4 Comment
		variations. Perhaps some additional examples with low voltage looped systems would be beneficial similar to the scenarios noted in question 2 above. We also have concerns with the disclaimer in the reference document on page 1 and noted below. We would hope this document would be endorsed by NERC to help address the complexity of the definition and to aid in transparency."Disclaimer-This document is not an official position of NERC and will not be binding on enforcement decisions of the NERC Compliance Program. This reference document reflects the professional opinion of the DBES SDT, given in good faith for illustrative purposes only."
Response: The SDT will be updating the Reference Document to reflect Phase 2 as soon as possible. The Reference Document can only reflect the intent of the SDT and isn't a legal document. No change made.		
NARUC	Yes	NARUC shares the concern raised by New York about the Phase II Report's failure to meet its purported goal of providing a technical justification for 100kV bright line rule and generation thresholds. NY raised specific concerns about a survey not being appropriate technical support for specific numbers and the drafting team did not specifically address this, or other concerns raised about the technical justification, in its response. NARUC is also concerned that the methodology utilized historically by the NPCC was not considered as one of five alternatives. So in response to whether or not there are other concerns with this definition that have not been covered in previous questions and comments, NARUC notes that it shares these concerns that have been raised, as well as the lack of a response from the drafting team thus far and requests a thorough response.

Organization	Yes or No	Question 4 Comment
New York State Department of Public Service	Yes	NERC has an obligation to provide technical advice to FERC, so that any number provided to FERC by NERC is interpreted as technical advice. A major purpose of the BES Phase II effort was to establish a technical basis for the 100 kV brightline and the 20/75 MVA generation levels. While NERC has provided a report purportedly providing a technical basis for these threshold levels, the report fails to do so. NERC should not include any numbers in any definition or standard for which it cannot provide a technical basis. Surveys do not provide a technical basis. Particularly troublesome is the presentation of alternatives to the 100 kV brightline. The report authors looked at 5 alternatives to establishing a technical basis for determining the bulk system. The report failed to evaluate the methodology historically applied to the NPCC system. If a major NERC region was able to successfully apply their methodology, why was it not evaluated and why would it be impossible to expect other regions to perform a similar analysis as the base for determining the BES? This comment is being resubmitted as the response provided in the previous comment period does not address the issues raised.
Response: The SDT is following the recommendation of the Planning Committee in its report on threshold values (http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_phase2_pc_report_final_20130306.pdf) in the retention of the 20 and 75 MVA threshold values as well as the 100 kV bright-line. No change made. The methodology applied by NPCC was rejected by FERC in its Order on the BES definition. No change made.		
Exelon and its' affiliates	Yes	Suggest adding the following to E4: or for the sole purpose of regulating internal generating station auxiliary buses. So that it reads: E4 - Reactive Power devices installed for the sole benefit of a retail customer(s) or for the sole

Organization	Yes or No	Question 4 Comment
		purpose of regulating internal generating station auxiliary buses.
Response: The SDT believes that if a reactive device is installed for the sole purpose of regulating internal generating station auxiliary buses that the device has been installed for the sole benefit of a retail customer and therefore the suggested language is not necessary. No change made.		
New York Power Authority	Yes	Support the development of a SAR that will create a project to review all of the GO and GOP standards for effective applicability to dispersed power resources so that generator owners and operators are only subject to the Standards requirements that have reliability impacts and those standard requirements that are applicable to the generator type.
Response: Any entity is free to develop a SAR to address areas of concern.		
Muscatine Power and Water	Yes	The SDT has recommended that a SAR be submitted in order to refine the Standards that would be applicable to individual power producing resources contained under I4 of the phase II definition. This response is not acceptable. The SDT should not passively answer an entity's question by stating that a different process "may" fix the issue at hand. MP&W recommends I4a be deleted and I4b be maintained as I4a. I4a should be deleted in its entirety. The SDT is forcing every dispersed power Facility over 75 MVA to be in the definition, where the SDT should be keeping individual resources out and allow other Standards and SDTs to determine if that should be included within each individual Standard. The BES definition should be written to give broad details and each individual Standard should be where the details are maintained. This is already the case for the following Standards; MOD-025-1, R1 and VAR-001-2, R3 are two examples where the

Organization	Yes or No	Question 4 Comment
		Standard dictates what is applicable and what is not. MP&W does not believe that since FERC has approved Phase I that the SDT is bound by that approval as being unchangeable. The Commission has only approved a part of the process and no where is it stated that once Phase I is approved that it can not be changed. This is proof with the other changes that the SDT has made in Phase II compared to Phase I. NERC or the SDT have not provided the industry with event analysis or lessons learned information that an individual dispersed power producing resource within a Facility has led to instability or cascading events on the BES. The inclusion of I4a does not align itself with the current NERC and Regional RAI process. NERC's CEO and President has even said that everything cannot be a priority. The amount of records management will only benefit a consultant who sells their services in managing individual power producing resources (i.e. paper work). The Registered Entity and their Region will not see the benefit of tracking several thousand wind turbines and solar panels, for what? The "what" is unknown because the SDT is taking words of the "Statement of Compliance Registry Criteria" and applying it to our standards development process. Currently Entities do not register per Facility, but this definition does force entities to register per Facility. The SDT is mixing apples and oranges.

Response: Applicability of individual standards is not within the scope of this SDT. A new SAR specifically tailored to address this presumed problem is the correct method to alleviate these concerns.

The proposed definition continues to include, through inclusion I4, individual dispersed power producing resources if those resources aggregate to a total value greater than 75 MVA. This inclusion treats dispersed power producing resources in a manner that is comparable to other non-dispersed power producing resources and is an approach that was accepted and emphasized by the Commission in Orders No. 773 & 773-A. The SDT has explored various options associated with dispersed power producing resources; however, none of the options explored provided an equal and effective approach to address the Commission's reliability concerns with these facilities. The SDT continues to believe that the best resolution to the industry's concerns is through clarification of the applicability of individual Reliability Standards and not a revision to the BES definition. Given these facts, the SDT is retaining

Organization	Yes or No	Question 4 Comment
Inclusion I4a but has revised the language of inclusion I4, based on industry comments, to provide greater clarity of the SDT's intent. I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.		
American Electric Power	Yes	To reiterate, AEP does not agree with the premise that BES elements (measured for compliance) should be as granular as the individual dispersed power resource. We do not see the reliability benefit of tracking all of the compliance elements for individual wind turbines when the focus should be placed on the aggregate of the facilities. Does the RC want to be notified of an outage of each individual wind turbine in real-time, or a loss of significant portion of the wind farm? If we are not careful, we will have entities at these resources and others monitoring them (BAs, TOPs, RCs) focusing on minor issues that will distract from more relevant reliability needs. We appreciated the development of the diagram to explain the scenario. We encourage the team to continue to provide these illustrations to clarify the intent and the application. When the guidance documents were produced last year, we had a better understanding of how the pieces of the definition fit together (and where there were significant gaps). We encourage the SDT to develop the scenarios and the diagrams first for industry review then the definition should be crafted to meet those.

Organization	Yes or No	Question 4 Comment
		We understand the pressure to meet the FERC deadlines, but continuing to tweak this foundation little by little had proved to be a difficult task and an overhaul of the approach might yield better results. If this requires modifying the SAR to provide the SDT with the flexibility to address broader concerns, AEP endorses this approach.
Response: The proposed definition continues to include, through inclusion I4, individual dispersed power producing resources if those resources aggregate to a total value greater than 75 MVA. This inclusion treats dispersed power producing resources in a manner that is comparable to other non-dispersed power producing resources and is an approach that was accepted and emphasized by the Commission in Orders No. 773 & 773-A. The SDT has explored various options associated with dispersed power producing resources; however, none of the options explored provided an equal and effective approach to address the Commission's reliability concerns with these facilities. The SDT continues to believe that the best resolution to the industry's concerns is through clarification of the applicability of individual Reliability Standards and not a revision to the BES definition. Given these facts, the SDT is retaining Inclusion I4a but has revised the language of inclusion I4, based on industry comments, to provide greater clarity of the SDT's intent. I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. The Reference Document will be revised to reflect Phase 2 as soon as possible. Any entity is free to develop a SAR to address areas of concern.		
Transmission Access Policy Study	Yes	We suggest that the SDT clarify, either in the definition itself or in the reference document, that a momentary flow-through caused by an

Organization	Yes or No	Question 4 Comment
Group		abnormal/contingency condition does not make a system ineligible for Exclusion E3. TAPS members are willing to work with the SDT on defining appropriate limits for such minimal, momentary flow-throughs.
Response: The position of the SDT consistently has been that local networks that have flow back into the BES at any time do not qualify under exclusion E3 as a local network. In the Reference Document, the SDT proposed a method to measure this factor so that a brief momentary fluctuation will not negate the ability to invoke Exclusion E3. No change made.		
ACES Standards Collaborators	Yes	We understand that NERC has developed a process for handling exception requests. We are concerned this process could be similar to the TFE exception process. We recommend that the exception process should be included with future BES definition postings with the opportunity to comment on the process.
Response: The exception process was posted for review and comment during Phase 1 of the project. It was approved by the industry, the Board of Trustees, and FERC. No changes have been made or are expected to be made to this process during Phase 2. If changes are needed to this process in the future, they will be posted for review and comment as per the established procedures.		

**Figure submitted by Tri-State G&T referenced in Q1 comments:*

http://www.nerc.com/pa/Stand/Documents/BES_I4_Clarification_for_Included_Elements_09042013.pdf

END OF REPORT

Project 2010-17 Definition of Bulk Electric System (Phase 2)

Standard Development Roadmap

This section is maintained by the drafting team during the development of the definition and will be removed when the definition becomes effective.

Development Steps Completed:

1. SAR posted for comment 1/4/12 – 2/3/12
2. SC authorized SAR for development 4/12/12
3. First posting and initial ballot completed 7/12/13

Proposed Action Plan and Description of Current Draft:

This draft is the third comment posting and successive ballot for the Phase 2 revised definition of the Bulk Electric System (BES).

Future Development Plan:

Anticipated Actions	Anticipated Delivery
1. Additional ballot	October 2013
2. Recirculation ballot	4Q13
3. BOT adoption	4Q13

Project 2010-17 Definition of Bulk Electric System (Phase 2)

Effective Dates

This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the definition shall become effective on the first day of the second calendar quarter after Board of Trustees adoption or as otherwise made effective pursuant to the laws of applicable governmental authorities.

Version History

Version	Date	Action	Change Tracking
1	January 25, 2012	Respond to FERC Order No. 743 to clarify the definition of the Bulk Electric System	N/A
2	TBD	Phase 2 clarifications to the original revisions Respond to directives in FERC Orders 773 and 773-A	Y

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below will be balloted in the same manner as a Reliability Standard. When the approved definition becomes effective, the defined term will be added to the Glossary.

Bulk Electric System (BES): Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.
- **I2** – Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
  a) Gross individual nameplate rating greater than 20 MVA. Or,
  b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.
- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.
- **I4** - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
  a) The individual resources, and
  b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

> Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells.
>
> (to be removed from final draft – will be moved to the Reference Document)

- **I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

a) Only serves Load. Or,
b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,
c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.
Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

Rationale: The drafting team has proposed a threshold of 50 kV or less for loops between radial systems when considering the application of Exclusion E1. The SDT used a two step approach to determine the voltage level. As a first step, regional voltage levels that are monitored on major interfaces, paths, and monitored elements to ensure the reliable operation of the interconnected transmission system were examined to determine the lowest monitored voltage level. Next, power system analyses determined the maximum amount of power that can be transferred through the low voltage systems, when looped, under a worst case scenario at various voltage levels. A formal white paper has been prepared to support this approach and is included with this posting.

- **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.
- **E3** - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:
  a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

- **E4 –** Reactive Power devices installed for the sole benefit of a retail customer(s).

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Project 2010-17 Definition of Bulk Electric System (Phase 2)

Standard Development Roadmap

This section is maintained by the drafting team during the development of the definition and will be removed when the definition becomes effective.

Development Steps Completed:

1. SAR posted for comment 1/4/12 – 2/3/12
2. SC authorized SAR for development 4/12/12
3. First posting and initial ballot completed 7/12/13

Proposed Action Plan and Description of Current Draft:

This draft is the ~~second~~third comment posting and successive ballot for the Phase 2 revised definition of the Bulk Electric System (BES).

Future Development Plan:

Anticipated Actions	Anticipated Delivery
1. Additional ballot	October 2013
~~1.~~2. Recirculation ballot	~~3~~4Q13
~~2.~~3. BOT adoption	4Q13

Project 2010-17 Definition of Bulk Electric System (Phase 2)

Effective Dates

This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the definition shall become effective on the first day of the second calendar quarter after Board of Trustees adoption or as otherwise made effective pursuant to the laws of applicable governmental authorities.

Version History

Version	Date	Action	Change Tracking
1	January 25, 2012	Respond to FERC Order No. 743 to clarify the definition of the Bulk Electric System	N/A
2	TBD	Phase 2 clarifications to the original revisions Respond to directives in FERC Orders 773 and 773-A	Y

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below will be balloted in the same manner as a Reliability Standard. When the approved definition becomes effective, the defined term will be added to the Glossary.

Bulk Electric System (BES): Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.
- **I2** – Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
  - a) Gross individual nameplate rating greater than 20 MVA. Or,
  - b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.
- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.
- **I4** - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
  - a) The individual resources, and
  - b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.
- ~~consisting of:~~
- ~~Individual resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and~~
- ~~The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.~~

Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells. (to be removed from final draft – will be moved to the Reference Document)

- **I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:
  - a) Only serves Load. Or,
  - b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,
  - c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

  Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.
  Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

  > **Rationale**: The drafting team has proposed a threshold of 50 kV or less for loops between radial systems when considering the application of Exclusion E1. The SDT used a two step approach to determine the voltage level. As a first step, regional voltage levels that are monitored on major interfaces, paths, and monitored elements to ensure the reliable operation of the interconnected transmission system were examined to determine the lowest monitored voltage level. Next, power system analyses determined the maximum amount of power that can be transferred through the low voltage systems, when looped, under a worst case scenario at various voltage levels. A formal white paper has been prepared to support this approach and is included with this posting.

- **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

- **E3 -** Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:
    a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);
    b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and
    c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).
- **E4 –** Reactive Power devices installed for the sole benefit of a retail customer(s).

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Implementation Plan for Project 2010-17: Definition of BES (Phase 2)

Prerequisite Approvals
None.

Effective Dates
This definition shall become effective on the first day of the second calendar quarter after the date that the definition is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter after the date the definition is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Compliance obligations for the Phase 2 definition would begin:

- Twenty-four months after the applicable effective date of the definition (for newly identified Elements), or
- If a longer timeframe is needed for an entity to be fully compliant with all standards applicable to an Element or group of Elements that are newly identified as BES when the Phase 2 definition is applied, the appropriate timeframe may be determined on a case-by-case basis by mutual agreement between the Regional Entity and the Element owner/operator, and subject to review by the ERO.

This implementation plan is consistent with the timeframe provided in Phase 1.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan for Project 2010-17: Definition of BES (Phase 2)

Prerequisite Approvals

~~There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this project can be implemented~~None.

Effective Dates

This definition shall become effective on the first day of the second calendar quarter after the date that the definition is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect~~regulatory approval~~. Where approval by an applicable governmental authority is not~~In those jurisdictions where no regulatory approval is~~ required, the definition shall ~~go~~ become effective on the first day of the second calendar quarter after the date the definition is adopted by the NERC Board of Trustees ~~adoption~~ or as otherwise ~~made effective pursuant to the laws of applicable governmental authorities~~provided for in that jurisdiction.

Compliance obligations for the Phase 2 definition would begin:

- Twenty-four months after the applicable effective date of the definition (for newly identified Elements), or
- If a longer timeframe is needed for an entity to be fully compliant with all standards applicable to an Element or group of Elements that are newly identified as BES when the Phase 2 definition is applied, the appropriate timeframe may be determined on a case-by-case basis by mutual agreement between the Regional Entity and the Element owner/operator, and subject to review by the ERO.

This implementation plan is consistent with the timeframe provided in Phase 1.

Unofficial Comment Form

Project 2010-17 Definition of Bulk Electric System – Phase 2

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the definition. The electronic comment form must be completed by **8:00 p.m. ET, October 28, 2013**.

All documents and information about this project are available on the project page. If you have questions please contact Ed Dobrowolski or by telephone at 609-947-3673.

Background Information - Project 2010-17 Definition of the BES (Phase 2)

The SDT has been working on addressing the issues and directives for Project 2010-17 Definition of the BES – Phase 2. The latest output of this work is shown in the third posting of the definition (the Phase 2 roadmap document). In this third posting, the SDT is responding to industry comments raised in the second posting and successive ballot period that ended on September 4, 2013. The SDT has made the following changes to the definition:

- **Inclusion I4**: The language has been clarified based on industry comments to more clearly reflect the SDT's intent to include individual dispersed power producing units (such as wind and solar units) that aggregate to greater than 75 MVA , along with the collector system that connects these units, from the point they aggregate to greater than 75 MVA to the point of connection at 100kV or higher. While the SDT recognizes that some stakeholders do not agree with the inclusion of individual dispersed power producing units, FERC Orders 773 and 773-A approved the inclusion of these individual units. No stakeholder has provided a technical rationale to support removal of the individual units from the definition. The SDT believes that stakeholder concerns about inclusion of individual units may be addressed by specifying the Facilities to which an individual standard applies within the Applicability section of that standard.

  I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:

  a) The individual resources, and
  b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. The SDT has re-structured the language of Inclusion I4 to more clearly reflect the SDT's intent to include individual dispersed power producing units (such as wind and solar units) that aggregate to greater than 75 MVA , along with the collector system that connects these units, from the point they aggregate to greater than 75 MVA to the point of connection at 100kV or higher. While the SDT recognizes that some stakeholders do not agree with the inclusion of individual dispersed power producing units, FERC Orders 773 and 773-A approved the inclusion of these individual units. No stakeholder has provided a technical rationale to support removal of the individual units from the definition. The SDT believes that stakeholder concerns about inclusion of individual units may be addressed by specifying the Facilities to which an individual standard applies within the Applicability section of that standard.

   With this background, can you support the proposed clarifications to I4? If not, please provide technical rationale for your disagreement along with suggested language changes.

   Yes:

   No:

   Comments:

2. Are there any other concerns with this definition that haven't been covered in previous postings, questions and comments?

   Yes:

   No:

   Comments:

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

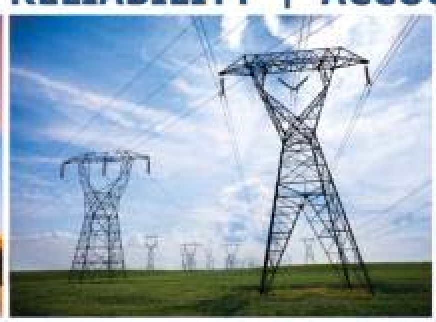
PUBLIC VERSION

White Paper on Bulk Electric System Radial Exclusion (E1) Low Voltage Loop Threshold

September 2013

RELIABILITY | ACCOUNTABILITY






Project 2010-17: Definition of Bulk Electric System

Table of Contents

Bulk Electric System Radial Exclusion (E1)
Low Voltage Loop Threshold

Background

The definition of "Bulk Electric System" (BES) in the NERC Glossary consists of a core definition and a list of facilities configurations that will be included or excluded from the core definition. The core definition is used to establish the bright line of 100 kV, the overall demarcation point between BES and non-BES elements. Exclusion E1 applies to radial systems. In Order No. 773 and 773-A, the Federal Energy Regulatory Commission's (Commission or FERC) expressed concerns that facilities operating below 100 kV may be required to support the reliable operation of the interconnected transmission system. The Commission also indicated that additional factors beyond impedance must be considered to demonstrate that looped or networked connections operating below 100 kV need not be considered in the application of Exclusion E1.[1]

This document responds to the Commission's concerns and provides a technical justification for the establishment of a voltage threshold below which sub-100 kV equipment need not be considered in the evaluation of Exclusion E1.

> *NOTE: This justification does not address whether sub- 100 kV systems should be evaluated as Bulk Electrical System (BES) Facilities. Sub- 100 kV systems are already excluded from the BES under the core definition. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process." Sub-100 kV facilities will only be included as BES Facilities if justified under the NERC Rules of Procedure (ROP) Appendix 5C Exception Process.*

[1] *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 at P155, n.139 (2012); *order on reh'g*, Order No. 773-A, 143 FERC ¶ 61,053 (2013).

Executive Summary

The Project 2010-17 Standard Drafting Team conducted a two-step process to establish a technical justification for the establishment of a voltage threshold below which sub-100 kV loops do not affect the application of Exclusion E1. The justification for establishing a lower voltage threshold for application of Exclusion E1 consisted of a two-step technical approach:

- Step 1: A review was performed to determine the minimum voltage levels that are monitored by Balancing Authorities, Reliability Coordinators, and Transmission Operators for Interfaces, Paths, and Monitored Elements. This minimum voltage level reflects a value that industry experts consider necessary to monitor and facilitate the operation of the Bulk Electric System (BES). This step provided a technically sound approach to screen for a minimum voltage limit that served as a starting point for the technical analysis performed in Step 2 of this study.

- Step 2: Technical studies modeling the physics of loop flows through sub-100 kV systems were performed to establish which voltage level, while less than 100 kV, should be considered in the evaluation of Exclusion E1.

The analysis establishes that a 50 kV threshold for sub-100 kV loops does not affect the application of Exclusion E1. This approach will ease the administrative burden on entities as it negates the necessity for an entity to prove that they qualify for Exclusion E1 if the sub-100 kV loop in question is less than or equal to 50 kV. This analysis provides an equally effective and efficient alternative to address the Commission's directives expressed in Order No. 773 and 773-A.

It should be noted that, although this study resulted in a technically justified 50 kV threshold based on proven analytic methods, there are other preventative loop flow methods that entities can apply on sub-100 kV loop systems to address physical equipment concerns. These methods include:

- Interlocked control schemes;
- Reverse power schemes;
- Transformer, feeder and bus tie protection; and
- Custom protection and control schemes.

These methods are discussed in detail in Appendix 4. The presence of such equipment does not alter the criteria developed in this white paper, nor does it influence the conclusions reached. Additionally, the presence of this equipment does not remove or lessen an entity's obligations associated with the bright-line application of the Bulk Electric System (BES) definition.

Radial Systems Exclusion (E1)

The proposed definition (first posting) of radial systems in the Phase 2 BES Definition (Exclusion E1) was: *A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:*

a) *Only serves Load. Or,*
b) *Only includes generation resources, not identified in Inclusions I2 and I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,*
c) *Where the radial system serves Load and includes generation resources, not identified in Inclusions I2 and I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).*

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

Note 2 - The presence of a contiguous loop, operated at a voltage level of 30 kV or less[2], between configurations being considered as radial systems, does not affect this exclusion.

STEP 1 – Establishment of Minimum Monitored Regional Voltage Levels

All operating entities have guidelines to identify the elements they believe need to be monitored to facilitate the reliable operation of the interconnected transmission system. Pursuant to these guidelines, operating entities in each of the eight Regions in North America have identified and monitor key groupings of the transmission elements that limit the amount of power that can be reliably transferred across their systems. The groupings of these elements have different names: for instance, Paths in the Western Interconnection; Interfaces or Flowgates in the Eastern Interconnection; or Monitored Elements in the Electric Reliability Council of Texas (ERCOT). Nevertheless, they all constitute element groupings that operating entities (Reliability Coordinators, Balancing Authorities, and Transmission Operators) monitor because they understand that they are necessary to ensure the reliable operation of the interconnected transmission system under diverse operating conditions.

To provide information in determining a voltage level where the presence of a contiguous loop between system configurations may not affect the determination of radial systems under Exclusion E1 of the BES definition, voltage levels that are monitored on major Interfaces, Flowgates, Paths, and ERCOT Monitored Elements were examined. This examination focused on elements owned and operated by entities in North America. The objective was to identify the lowest monitored voltage level on these key element groupings. The lowest monitored line voltage on the major element groupings provides an indication of the lower limit which operating entities have historically believed necessary to ensure the

[2] The first posting of this Phase 2 definition used a threshold of 30 kV; however as a result of the study work described in this paper, the Standard Drafting Team has revised the threshold to 50 kV for subsequent industry consideration.

reliable operation of the interconnected transmission system. The results of this analysis provided a starting point for the technical analysis which was performed in Step 2 of this study.

Step 1 Approach

Each Region was requested to provide the key groupings of elements they monitor to ensure reliable operation of the interconnected transmission system. This list, contained in Appendix 1, was reviewed to identify the lowest voltage element in the major element groupings monitored by operating entities in the eight Regions. Identification of this lowest voltage level served as a starting point to begin a closer examination into the voltage level where the presence of a contiguous loop should not affect the evaluation of radial systems under Exclusion E1 of the BES definition.

Step 1 Results

An examination of the line listings of the North American operating entities revealed that the majority of operating entities do not monitor elements below 69 kV as shown in Table 1. However, in some instances elements with line voltages of 34.5 kV were included in monitored element groupings. In no instance was a transmission line element below 34.5 kV included in the monitored element groupings.

Region	Key Monitored Element Grouping	Lowest Line Element Voltage
FRCC	Southern Interface	115
MRO	NDEX	69
NPCC	Total East PJM (Rockland Electric) – Hudson Valley (Zone G)[1]	34.5
RFC	MWEX	69
SERC	VACAR IDC[2]	100
SPP RE	SPSNORTH_STH	115
TRE	Valley Import GTL	138
WECC	Path 52 Silver Peak – Control 55 kV	55

Notes:

1. Two interfaces in NPCC/NYISO have lines with 34.5 kV elements.
2. The TVA area in SERC was not included in the tables attached to this report; however, a review of the Flowgates in TVA revealed monitored elements no lower than 115 kV. There were a number of Flowgates with 115 kV monitored elements in SERC, the monitored grouping listed is representative.

Table 1: Lowest Line Element Voltage Monitored by Region

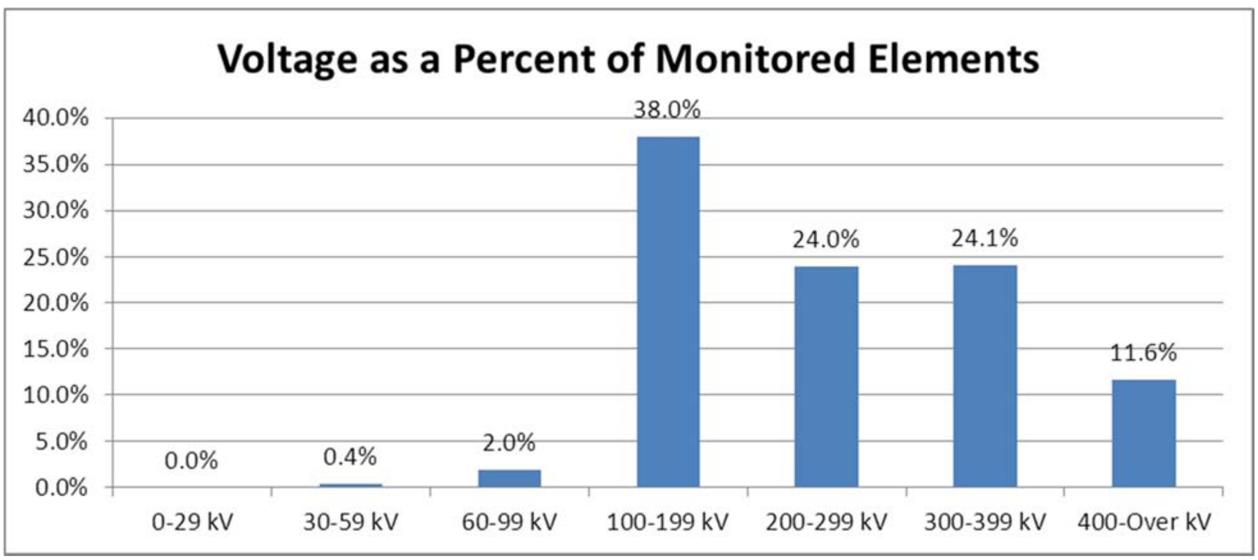
In a few rare occasions there were transformer elements with low-side windings lower than 30 kV included in the key monitored element groupings as shown in Table 2.

Region	Interface	Element	Voltage (kV)
NPCC/NYISO	WEST CENTRAL: Genesee (Zone B) – Central (Zone C)	(Farmtn 34.5/115kV&12/115 kV) #4 34.5/115 & 12/115	12/115
NPCC/ISO-NE	New England - Southwest Connecticut	SOTHNGTN 5X - Southington 115 kV /13.8 kV Transformer (4C-5X)	115/13.8
		SOTHNGTN 6X - Southington 115 kV /13.8 kV Transformer (4C-6X)	115/13.8
		SOTHNGTN 11X - Southington 115 kV /27.6 kV Transformer (4C-11X)	115/27.6

Table 2: Lowest Line Transformer Element Voltages Monitored by Region

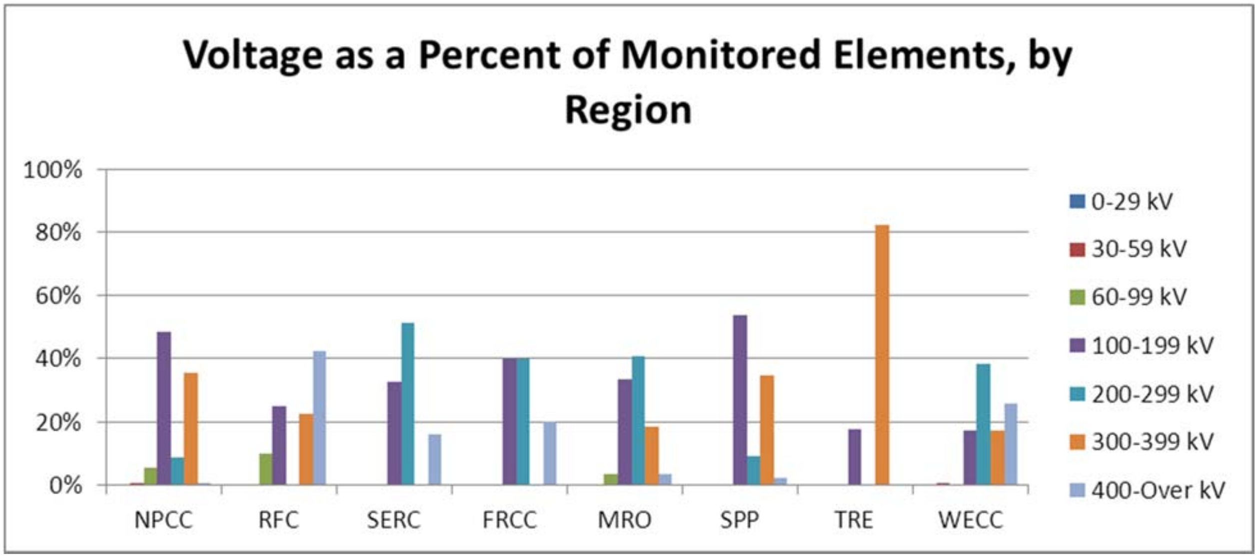
Upon closer investigation, for New England's Southwest Connecticut interface, it was determined that the inclusion of these elements was the result of longstanding, historical interface definitions and not for the purpose of addressing BES reliability concerns. Transformers serving lower voltage networks continue to be included based on familiarity with the existing interface rather than a specific technical concern. These transformers could be removed from the interface definition with no impact on monitoring the reliability of the interconnected transmission system. For the New York West Central interface, the low voltage element was included because the interface definition included boundary transmission lines between Transmission Owner control areas; hence, it was included for completeness to measure the power flow from one Transmission Owner control area to the other Transmission Owner control area.

Further examination of the information provided by the eight NERC regions revealed that half of the Regions only monitor transmission line elements with voltages above the 100 kV level. The other four Regions, NPCC, RFC, MRO, and WECC, monitor transmission line elements below 100 kV as part of key element groupings. However, in each of these cases, the number of below 100 kV transmission line elements comprised less than 2.5% of the total monitored key element groupings. Figures 1 and 2 below depict the results of Step 1 of this study.



Notes:
1. Data/Chart includes Transmission Lines only.
2. Data/Chart is a summary of individual elements (interfaces not included)

Figure 1: Voltage as Percent of Monitored Elements



Notes:
1. Data/Chart includes Transmission Lines only.
2. Data/Chart is a summary of individual elements (interfaces not included)

Figure 2: Voltage as Percent of Monitored Elements per Region

Step 1 Conclusion

The results of Step 1 of this study regarding regional monitoring levels resulted in a determination that 30 kV was a reasonable voltage level to initiate the sensitivity analysis conducted in Step 2 of this study. This value is below any of the regional monitoring levels. As noted herein, an examination of the line listings of the North American operating entities revealed that the majority of operating entities do not monitor elements below 69 kV as shown in Table 1. However, in some instances elements with line voltages of 34.5 kV were included in monitored element groupings. In no instance was a transmission line element below 34.5 kV included in the monitored element groupings.

STEP 2 - Load Flows and Technical Considerations

The threshold of 30 kV was established in Step 1 as a reasonable starting point to initiate the technical sensitivity analysis performed in Step 2 of this study. The purpose of this step was to determine if there is a technical justification to support a voltage threshold for the purpose of determining whether facilities greater than 100 kV can be considered to be radial under the BES Definition Exclusion E1. If the resulting voltage threshold was deemed appropriate through technical study efforts, then contiguous loop connections operated at voltages below this value would not preclude the application of Exclusion E1. Conversely, contiguous loops connecting radial lines at voltages above this kV value would negate the ability for an entity to use Exclusion E1 for the subject facilities.

This study focused on two typical configurations: a distribution loop and a sub-transmission loop. The study evaluated a range of voltages for the loop and the parallel transmission system with the goal of determining the voltage level below which single contingencies on the transmission system would not result in power flow from a low voltage distribution or sub-transmission loop to the BES. The study included sensitivity analysis varying the loads and impedances. Variations in loop and transmission system impedances account for a range of physical parameters such as conductor length, conductor type, system configuration, and proximity of the loop to the transmission system. This study provided the low voltage floor that can be used as a consideration for BES exclusion E1.

Analytical Approach – Distribution Circuit Loop Example

The Project 2010-17 Standard Drafting Team sought to examine the interaction and relative magnitude of flows on the 100 kV and above Facilities of the electric system and those of any underlying low voltage distribution loops. While not the determining factor leading to this study's recommendation, line outage distribution factors (LODF) were a useful tool in understanding the relationship between underlying systems and the BES elements. It illustrated the relative scale of interaction between the BES and the lower voltage systems and its review was a consideration when this study was performed. As an example, the Standard Drafting Team considered a system similar to the one depicted in Figure 3 below. In this simplified depiction of a portion of an electric system, two radial 115 kV lines emanate from 115 kV substations A and B to serve distribution loads via 115 kV distribution transformers at stations C and D. Stations C and D are "looped" together via either a distribution bus tie (zero impedance) or a feeder tie (modeled with typical distribution feeder impedances).

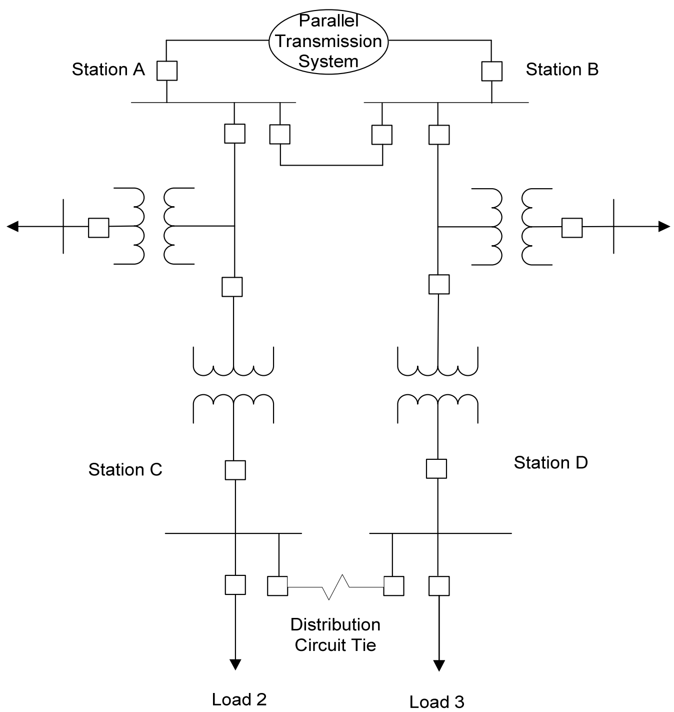


Figure 3: Example Radial Systems with Low Voltage Distribution Loop

With the example system, the Standard Drafting Team conducted power flow simulations to assess the performance of the power system under single contingency outages of the line between stations A and B. The analyses determined the LODF which represent the portion of the high voltage transmission flow that would flow across the low voltage distribution circuit or bus ties under a single contingency outage of the line between stations A and B. To the extent that the LODF values were negligible, this indicated a minor or insignificant contribution of the distribution loops to the operation of the high voltage system. But, more importantly, the analyses determined whether any instances of power flow reversal, i.e.,

resultant flow delivered into the BES, would occur during contingent operating scenarios. Instances of flow reversal into the BES would indicate that the underlying distribution looped system is exhibiting behavior similar to a sub-transmission or transmission system, which would call into question the applicability of radial exclusion E1.

The study work in this approach examined the sensitivity of parallel circuit flow on the distribution elements to the size of the distribution transformers, the operating voltage of distribution delivery buses at stations C and D and the strength of the transmission network serving stations A and B as manifested in the variation of the transmission network transfer impedances used in the model.
In order to simply, yet accurately, represent this low voltage loop scenario between two radial circuits, a Power System Simulator for Engineering (PSSE) model was created. Elements represented in this model included the following:

- Radial 115 kV lines from station A to station C and station B to station D;
- Interconnecting transmission line from station A to station B;
- Distribution transformers tapped off the 115 kV lines between stations A and C and between stations B and D and at stations C and D;
- Feeder tie impedance to represent a feeder tie (or zero impedance bus tie) between distribution buses at stations C and D;
- Transfer impedance equivalent between stations A and B, representing the strength of the interconnected transmission network[3].

Within this model, parameters were modified to simulate differences in the length and impedance of the transmission lines, the amount of distribution load, the strength of the transmission network supplying stations A and B, the size of the distribution transformers and the character of the bus or feeder ties at distribution Stations C and D.

Distribution Model Simulation

Table 3 below illustrates the domain of the various parameters that were simulated in this distribution circuit loop scenario. A parametric analysis was performed using all combinations of variables shown in each column of the upper portion of Table 3. Sensitivity analysis was performed as indicated in the lower portion of the table.

---

3 The relative strength of the surrounding transmission system network is a function of the quantity of parallel transmission paths and the impedance of those paths between the two source substations. A high number of parallel paths with low impedance translates to a low transfer impedance, which allows power to more readily flow between the stations. Conversely, a low number of parallel paths having higher impedance is represented by a relatively large transfer impedance.

Trans KV	Trans Length	Dist KV	Dist Length	XFMR MVA	Dist Load % rating	Z Transfer
115	10 miles	12.5	0 (bus tie)	10	40	Weak
		23	2 miles	20	80	
		34.5	5 miles	40		
Sensitivity Analysis:		46				Strong Medium

Notes:

1. The “medium” value for transfer impedances was derived from an actual example system in the northeastern US. This was deemed to be representative of a network with typical, or medium, transmission strength. Variations of a stronger (more tightly coupled) and a weaker transmission network were selected for the “strong” and “weak” cases, respectively. Impedance values of X=0.54%, X=1.95%, and X=4.07% were applied for the strong, medium and weak cases, respectively.

Table 3: Model Parameters Varied

The model was used to examine a series of cases simulating a power transfer on the 115 kV line[4] from station A to station B of slightly more than 100 MW. Loads and impedances were simulated at the location shown in Figure 5 of Appendix 2. Two load levels were used in each scenario: 40% of the rating of the distribution transformer and 80% of the rating. Distribution transformer ratings were varied in three steps: 10 MVA, 20 MVA, and 40 MVA. Finally, the strength of the interconnected transmission network was varied in three steps representing a strong, medium, and weak transmission network. The choices of transfer impedance were based on typical networks in use across North America. A specific model from the New England area of the United States yielded an actual transfer impedance of 0.319 + j1.954%. This represents the ’medium’ strength transmission system used in the analyses. The other values used in the study are minimum (’strong’) and maximum (’weak’) ends of the typical range of transfer impedances for 115 kV systems interconnected to the Bulk Electric System of North America. Distribution feeder connections were simulated in three different ways, first with zero impedance between the distribution buses at stations C and D, second with a 2-mile feeder connection with typical overhead conductor, and third with a 5-mile connection.

Distribution Model Results

23 kV Distribution System

The results show LODFs ranging from a low of 0.2% to a high of 6.7%. In all of the cases, the direction of power flow to the radial lines at stations A and B was *toward* stations C and D. In other words, there were no instances of flow reversal from the distribution system back to the 115 kV transmission system. The lowest LODF was found in the case with the smallest distribution transformers (10 MVA), the 5-mile distribution circuit tie, and the strong transmission transfer impedance. The case with the highest LODF

[4] The threshold voltage of 115 kV provides conservative results. At a higher voltage, such as 230 kV, the reflection of distribution impedance to the transmission system is significantly larger, and hence, the amount of distribution power flow will be much smaller.

was that which used the largest distribution transformers (40 MVA) with the lightest load and the use of a zero-impedance bus tie between the two distribution stations.

12.5 kV Distribution System

As compared to the simulations using the 23 kV distribution system, the 12.5 kV system model yielded far lower LODF values. This result is reasonable, as the reflection of impedances on a 12.5 kV distribution system will be nearly four times as large as those for a 23 kV distribution system, and the transformer sizes in use at the 12.5 kV class are generally smaller, i.e., higher impedance. As with the cases simulated for the 23 kV system, the 12.5 kV system exhibited a power flow direction in the radial line terminals at stations A and B in the direction of the distribution stations C and D; no flow reversal was seen in any of the contingency cases.

Given the lower voltage of the distribution system, the cases studied at this low voltage level were limited to the scenario with the high transfer impedance value ('weak' transmission case). This is a conservative assumption as all cases with lower transfer impedance will yield far lower LODF values. With that, the range of LODF values was found to be 1.0% to 6.7%. When compared with the 23 kV system results in the weak transmission case, the range of LODF values was 1.8% to 6.7%. Higher LODF values were found in the cases with the largest transformer size, which is to be expected.

Table 4 below provides a sample of the results of the various simulations that were conducted. The full collection of results is provided in Appendix 3.

Case	D, KV	Z_{xfer}	Z_{Dist}	XFMR MVA	Load, MW	LODF
623a5	23	strong	5 mi	10	4	0.2%
623a5pk	23	strong	5 mi	10	8	0.3%
633b0pk	23	strong	0	20	16	0.4%
723c0	23	medium	0	40	16	3.4%
723c5pk	23	medium	5 mi	40	32	1.6%
823b0	23	weak	0	20	8	3.8%
823c0	23	weak	0	40	16	6.7%
812a5	12.5	weak	5 mi	10	4	1.0%
812b0	12.5	weak	0	20	8	3.8%
812b5pk	12.5	weak	5 mi	20	16	1.3%
812c0	12.5	weak	0	40	16	6.7%
834a5pk	34.5	weak	5 mi	10	8	1.7%
834b5pk	34.5	weak	5 mi	20	16	3.0%
834d0	34.5	weak	0	40	16	8.9%
834d0pk	34.5	weak	0	40	32	8.7%
846e0	46	weak	0	50	16	10.3%
846e2	46	weak	2 mi	50	20	9.0%
846e5	46	weak	5 mi	50	20	7.4%

Table 4: Select Sample of Study Results for Distribution Scenario

34.5 kV and 46 kV Distribution Systems

As with the analysis done for the 12.5 kV system, a conservative transfer impedance value, that of the 'weak' transmission network, was used in selecting the transfer impedance to be used in the simulations at 34.5 kV and 46 kV. With this conservative parameter, the simulation results show distribution factors (LODF) ranging from a low of 1.7% to a high of 10.3%. In all of the cases, the direction of power flow to the radial lines remained *from* stations A and B *toward* stations C and D. In other words, there were no instances of flow reversal from the distribution system back to the 115 kV transmission system.

Analytical Approach – Sub-transmission Example

In addition to the distribution circuit loop example described above, the study examined the performance of systems typically described as 'sub-transmission.' The study sought to examine the interaction and relative magnitude of flows on the 100 kV and above Facilities of the interconnected transmission system and those of the underlying parallel sub-transmission facilities. The study considered a system similar to the one depicted in Figure 4 below. In this simplified depiction of a portion of a transmission and sub-transmission system, a 40-mile transmission line connecting two sources with transfer impedance between the two sources representing the parallel transmission network. Each source also supplies a 10-mile transmission line with a load tap at the mid-point of the line, each serving a load of 16 MW. At the end of each of these lines is a step-down transformer to the sub-transmission voltage, where an additional load is served. The two sub-transmission stations are connected by a 25-mile sub-transmission tie line. Loads and impedances were simulated at the location shown in Figure 6 of Appendix 2.

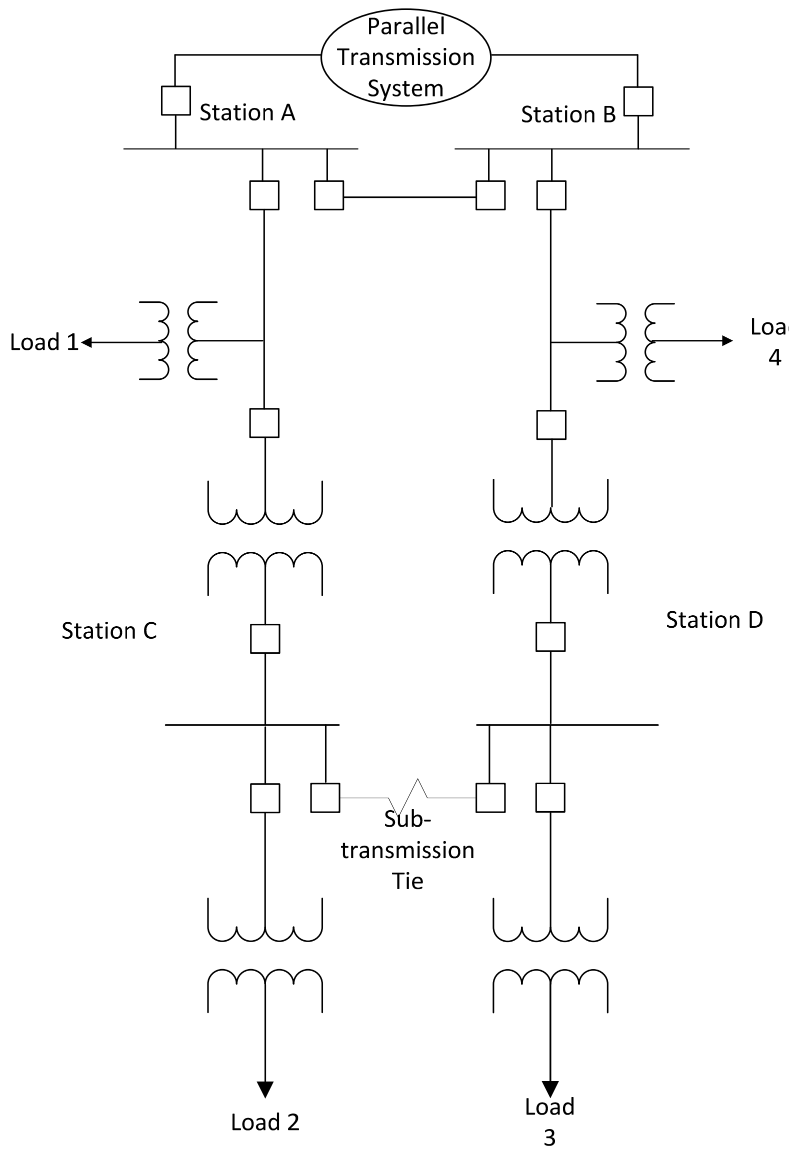


Figure 4: Example Radial Systems with Sub-transmission Loop

Given this example sub-transmission system, a PSSE model was created to simulate the power flow characteristics of the system during a contingency outage of the transmission line between stations A and B. Within this model, parameters were modified to simulate differences in the amount of load being served, transformer size and the amount of pre-contingent power flow on the transmission line. All simulations were performed with a transfer impedance representative of a 'weak' transmission network, which was confirmed as conservative in the distribution system analysis.

Sub-transmission Model Simulation

Simulations were performed for each sub-transmission voltage (34.5 kV, 46 kV, 55 kV, and 69 kV) using a transmission voltage of 115 kV. This analysis identified the potential for power flowing back to the transmission system only for sub-transmission voltages of 55 kV and 69 kV. Sensitivity analysis was performed using higher transmission voltages to confirm that cases modeling a 115 kV transmission

system yield the most conservative results. Therefore, it was not necessary to perform sensitivity analysis for sub-transmission voltages of 34.5 kV and 46 kV for transmission voltages higher than 115 kV. Table 5 below illustrates the domain of the various parameters that were simulated in this sub-transmission circuit loop scenario. A parametric analysis was performed using combinations of variables shown in each column of Table 5.

Trans KV	Trans Length	Sub-T KV	Sub-T Length	XFMR MVA	Dist Load % rating	Trans MW Preload
115	40 miles	34.5	25 miles	40	40	115
		46		50		
		55		60		
		69				
Sensitivity Analyses:						
138	40 miles	55	25 miles	50	40	115
161		69		60		135
230						150
						220

Table 5: Model Parameters and Sensitivities

Sub-transmission Model Results

115 kV Transmission System with 34.5-69 kV Sub-transmission

The results for cases depicting a 115 kV transmission system voltage and ranges of 34.5 kV to 69 kV sub-transmission voltages show line outage distribution factors (LODF) in the range of 9% to slightly higher than 20%. Several cases show a reversal of power flow in the post-contingent system such that power flow is delivered from the sub-transmission system *into the 115 kV BES*. The worst case is found in the 69 kV sub-transmission voltage class. This result is as expected, given that the impedance of the 69 kV sub-transmission system is less than the impedances of lower voltage systems. In no instance was a reversal of power flow observed in sub-transmission systems rated below 50 kV.

138 kV and 161 kV Transmission Systems with 55-69 kV Sub-transmission

The results for cases of 138 kV and 161 kV transmission system voltages supplying sub-transmission voltages of 55 kV and 69 kV show LODFs ranging from 9% to 16%. These cases also result in reversal of power flows in the post-contingent system such that power flow is delivered from the sub-transmission system into the 115 kV BES.

230 kV Transmission System with 55-69 kV Sub-transmission

By simulating a higher BES source voltage of 230 kV paired with sub-transmission voltages of 55 kV and 69 kV, the transformation ratio is sufficiently large to result in a significant increase to the reflected sub-transmission system impedance. Therefore, in these cases, LODFs range from 5% to 7%, and these cases also show no reversal of power flow toward the BES in the post-contingent system. Table 6 below

provides a sample of the results of the various simulations that were conducted. All results are provided in Appendix 3.

Case	T, KV	S-T, KV	Trans Pre-load, MW	XFMR MVA	Load, MW	LODF	Flow Rev to BES?
834d25	115	34.5	115	40	20	9.4%	
846e25	115	46	114	50	20	13.3%	
855e25	115	55	112	50	20	15.7%	Yes
869f25	115	69	110	60	24	20.3%	Yes
855e25-138	138	55	114	50	20	11.7%	
855e25-138'	138	55	134	60	20	11.9%	Yes
869f25-138	138	69	112	60	24	15.6%	Yes
869f25-138'	138	69	132	60	24	15.8%	Yes
855e25-161	161	55	114	50	20	9.1%	
855e25-161'	161	55	155	60	20	9.2%	
869f25-161	161	69	113	60	24	12.5%	
869f25-161'	161	69	153	60	24	12.6%	Yes
855e25-230	230	55	116	50	20	4.9%	
855e25-230'	230	55	219	60	20	5.0%	
869f25-230	230	69	116	60	24	7.0%	
869f25-230'	230	69	218	60	24	7.0%	

Table 6: Select Sample of Study Results for Sub-transmission Scenario

Step 2 Conclusion

After conducting extensive simulations (included in Appendix 3), the results of Step 2 of this analysis indicates that 50 kV is the appropriate low voltage loop threshold below which sub-100 kV loops should not affect the application of Exclusion E1 of the BES Definition. Simulations of power flows for the cases modeled in this study show there is no power flow reversal into the BES when circuit loop operating voltages are below 50 kV. This study also finds, for loop voltages above 50 kV, certain cases result in power flow toward the BES. Therefore, the study concludes that low voltage circuit loops operated below 50 kV should not affect the application of Exclusion E1.

As described throughout the preceding section, the scenarios and configurations utilized in this analysis represent the majority of cases that will be encountered in the industry. The models used in this analysis establish reasonable bounds and use conservative parameters in the scenarios. However, there may be actual cases that deviate from these modeled scenarios, and therefore, results could be somewhat different than the ranges of results from this analysis. Such deviations are expected to be rare and can be processed through the companion BES Exception Process.

Study Conclusion

The Project 2010-17 Standard Drafting Team conducted a two-step study process to yield a technical justification for the establishment of a voltage threshold below which sub-100 kV loops should not affect the application of Exclusion E1.

All operating entities have guidelines to identify the elements they believe need to be monitored to facilitate the reliable operation of the interconnected transmission system. Pursuant to these guidelines, operating entities in each of the eight Regions in North America have identified and monitor key groupings of the transmission elements that limit the amount of power that can be reliably transferred across their systems. The objective of Step 1 was to identify the lowest monitored voltage level on these key element groupings. The lowest monitored line voltage on the major element groupings provides an indication of the lower limit which operating entities have historically believed necessary to ensure the reliable operation of the interconnected transmission system.

As a result of studying such regional monitoring levels, Step 1 concluded that 30 kV was a reasonable voltage level to initiate the sensitivity analysis conducted in Step 2. This is a conservative value as it is below any of the regional monitoring levels.

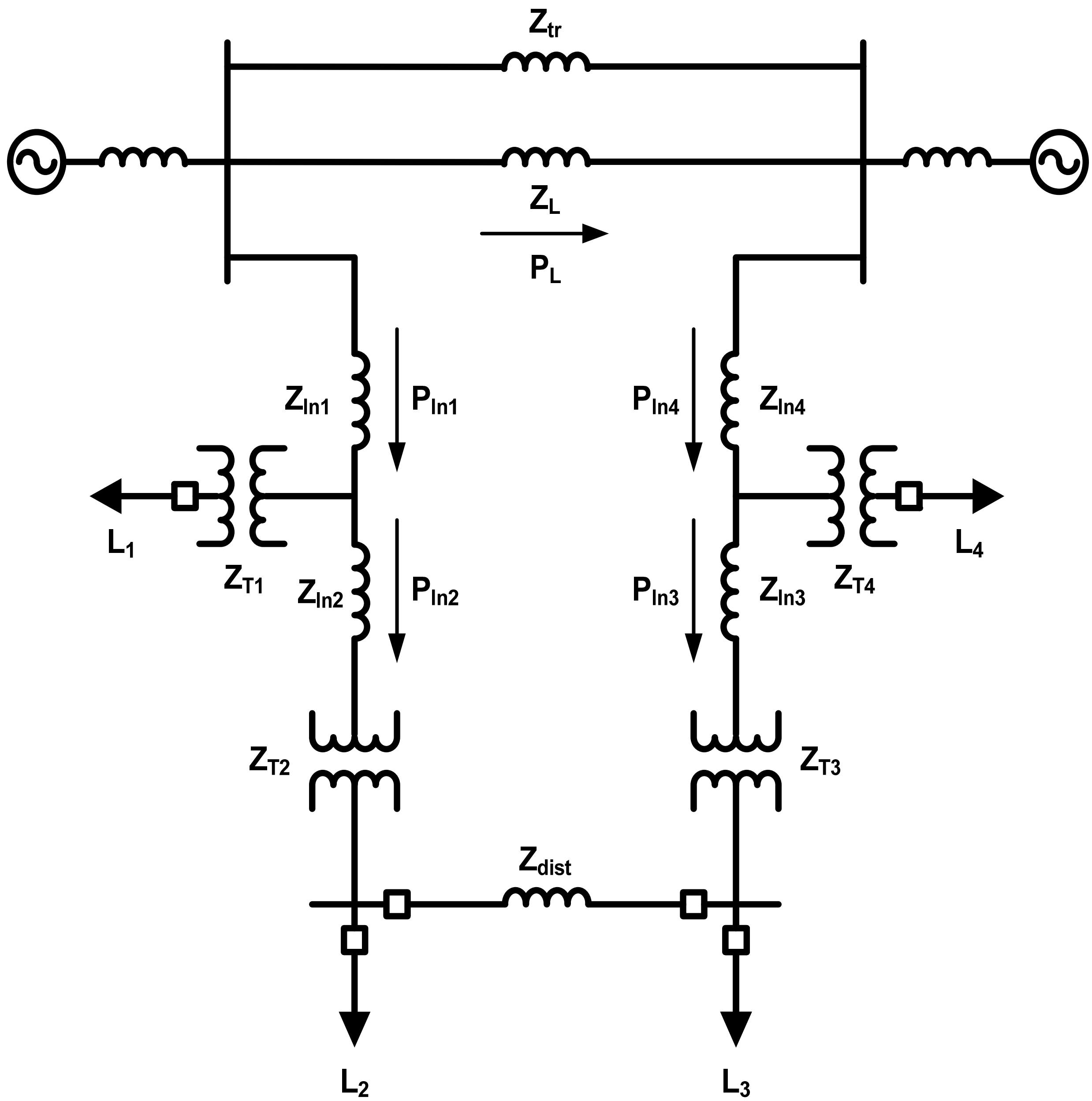
Using the conservative value established by Step 1, the Standard Drafting Team conducted extensive simulations of power flows which demonstrated that there is no power flow reversal into the BES when circuit loop operating voltages are below 50 kV. Therefore, the study concludes that low voltage circuit loops operated below 50 kV should not affect the application of Exclusion E1. This analysis provides an equally effective and efficient alternative to address the Commission's directives expressed in Order No. 773 and 773-A.

The scenarios and configurations utilized in this analysis represent the majority of cases that will be encountered in the industry. The models used in this analysis establish reasonable bounds and use conservative parameters in the scenarios. However, there may be actual cases that deviate from these modeled scenarios, and therefore, results could be somewhat different than the ranges of results from this analysis. Such deviations are expected to be rare and can be processed through the companion BES Exception Process.

Appendix 1: Regional Elements

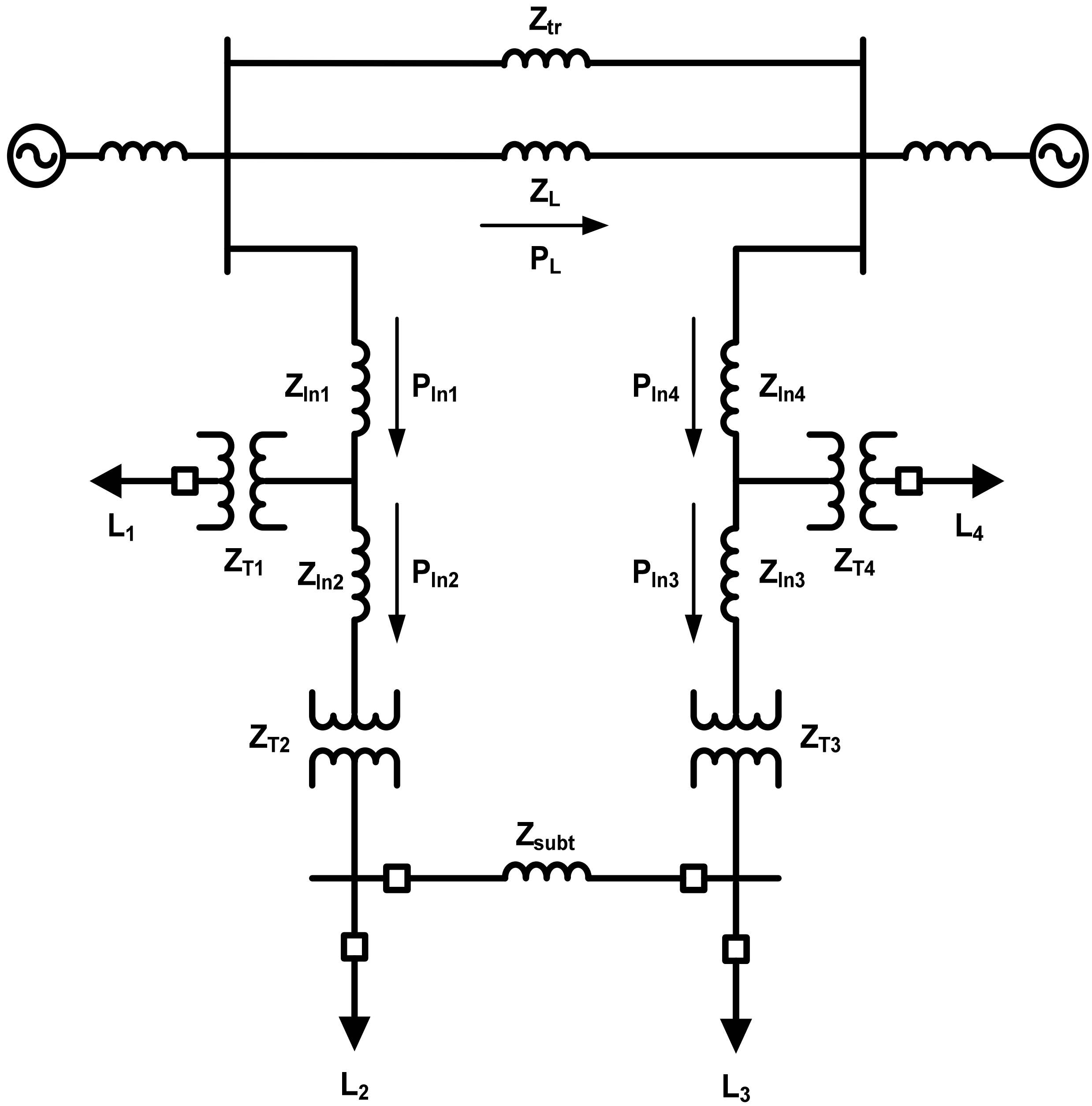
PRIVILEGED AND CONFIDENTIAL INFORMATION HAS BEEN REDACTED FROM THIS PUBLIC VERSION

Appendix 2: One-Line Diagrams



Note: Refer to the notes in Appendix 3 for a description of the symbols in this diagram.

Figure 5: Example Radial Systems with Low Voltage Distribution Tie



Notes: Refer to the notes in Appendix 3 for a description of the symbols in this diagram.
Step-down transformers from sub-transmission voltage to distribution voltage were not explicitly modeled in the simulations.

Figure 6: Example Radial Systems with Sub-transmission Tie

Appendix 3: Simulation Results

Case	Z_L (mi.)	Z_{tr} (mi.)	Z_{ln1-4} (total mi.)	Z_{dist} (mi.)	Z_{T1}, Z_{T-4} (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	------------ HV Line "L" in-service ------------				-- HV Line "L" out-of-service --				LODF
										P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	$P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	
23 kV Base Cases																		
623a0	10	Strong	15	0	10%/10	10%/10	4.0	4.0	110.7	10.9	6.9	1.1	5.1	11.2	7.2	0.8	4.8	0.003
623a2	10	Strong	15	2	10%/10	10%/10	4.0	4.0	110.7	10.7	6.7	1.4	5.4	10.9	6.9	1.1	5.1	0.002
623a5	10	Strong	15	5	10%/10	10%/10	4.0	4.0	110.7	10.3	6.3	1.7	5.7	10.5	6.5	1.5	5.5	0.002
623a0pk	10	Strong	15	0	10%/10	10%/10	8.0	8.0	111.4	19.0	10.9	5.1	13.1	19.3	11.2	4.8	12.8	0.003
623a2pk	10	Strong	15	2	10%/10	10%/10	8.0	8.0	111.4	18.7	10.7	5.4	13.4	18.9	10.9	5.1	13.1	0.002
623a5pk	10	Strong	15	5	10%/10	10%/10	8.0	8.0	111.5	18.3	10.3	5.7	13.7	18.6	10.5	5.5	13.5	0.003
623b0	10	Strong	15	0	10%/20	10%/20	8.0	8.0	111.1	21.7	13.7	2.3	10.3	22.3	14.2	1.8	9.8	0.005
623b2	10	Strong	15	2	10%/20	10%/20	8.0	8.0	111.2	20.7	12.7	3.3	11.3	21.2	13.2	2.9	10.9	0.004
623b5	10	Strong	15	5	10%/20	10%/20	8.0	8.0	111.3	19.7	11.7	4.3	12.3	20.1	12.1	4.0	12.0	0.004
623b0pk	10	Strong	15	0	10%/20	10%/20	16.0	16.0	112.6	37.8	21.7	10.3	26.3	38.3	22.3	9.7	25.8	0.004
623b2pk	10	Strong	15	2	10%/20	10%/20	16.0	16.0	112.7	36.7	20.7	11.3	27.3	37.2	21.2	10.9	26.9	0.004
623b5pk	10	Strong	15	5	10%/20	10%/20	16.0	16.0	112.8	35.7	19.7	12.3	28.4	36.1	20.1	12.0	28.0	0.004

Case	Z_L (mi.)	Z_{tr} (mi.)	Z_{ln1-4} (total mi.)	Z_{dist} (mi.)	Z_{T1}, Z_{T-4} (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	----------- HV Line "L" in-service ----------- P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	-- HV Line "L" out-of-service -- $P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	LODF
623c0	10	Strong	15	0	10%/40	10%/40	16.0	16.0	112.2	42.7	26.6	5.4	21.4	43.7	27.7	4.3	20.3	0.009
623c2	10	Strong	15	2	10%/40	10%/40	16.0	16.0	112.5	39.6	23.6	8.4	24.4	40.4	24.4	7.7	23.7	0.007
623c5	10	Strong	15	5	10%/40	10%/40	16.0	16.0	112.7	37.3	21.3	10.8	26.8	37.8	21.8	10.3	26.3	0.004
623c0pk	10	Strong	15	0	10%/40	10%/40	32.0	32.0	115.1	74.9	42.8	21.2	53.3	76.0	43.9	20.2	52.2	0.010
623c2pk	10	Strong	15	2	10%/40	10%/40	32.0	32.0	115.4	71.8	39.7	24.3	56.4	72.6	40.5	23.6	55.6	0.007
623c5pk	10	Strong	15	5	10%/40	10%/40	32.0	32.0	115.6	69.4	37.4	26.7	58.8	70.0	37.9	26.2	58.3	0.005
723a0	10	Medium	15	0	10%/10	10%/10	4.0	4.0	108.3	10.9	6.9	1.1	5.1	11.9	7.9	0.1	4.1	0.009
723a2	10	Medium	15	2	10%/10	10%/10	4.0	4.0	108.3	10.6	6.6	1.4	5.4	11.5	7.5	0.5	4.5	0.008
723a5	10	Medium	15	5	10%/10	10%/10	4.0	4.0	108.4	10.3	6.3	1.8	5.8	11.1	7.1	1.0	5.0	0.007
723a0pk	10	Medium	15	0	10%/10	10%/10	8.0	8.0	110.4	18.9	10.9	5.1	13.1	20.0	12.0	4.0	12.1	0.010
723a2pk	10	Medium	15	2	10%/10	10%/10	8.0	8.0	110.5	18.6	10.6	5.4	13.4	19.6	11.6	4.4	12.5	0.009
723a5pk	10	Medium	15	5	10%/10	10%/10	8.0	8.0	110.6	18.3	10.3	5.7	13.7	19.1	11.1	4.9	12.9	0.007
723b0	10	Medium	15	0	10%/20	10%/20	8.0	8.0	109.7	21.6	13.6	2.4	10.4	23.6	15.6	0.4	8.4	0.018
723b2	10	Medium	15	2	10%/20	10%/20	8.0	8.0	110.0	20.6	12.6	3.4	11.4	22.3	14.3	1.7	9.8	0.015
723b5	10	Medium	15	5	10%/20	10%/20	8.0	8.0	110.2	19.7	11.7	4.4	12.4	21.0	13.0	3.1	11.1	0.012
723b0pk	10	Medium	15	0	10%/20	10%/20	16.0	16.0	114.0	37.8	21.8	10.2	26.3	39.9	23.8	8.2	24.2	0.018
723b2pk	10	Medium	15	2	10%/20	10%/20	16.0	16.0	114.3	36.8	20.8	11.3	27.3	38.5	22.5	9.6	25.6	0.015
723b5pk	10	Medium	15	5	10%/20	10%/20	16.0	16.0	114.5	35.8	19.8	12.3	28.3	37.2	21.1	10.9	27.0	0.012

										----------- HV Line "L" in-service -----------				-- HV Line "L" out-of-service --				
Case	**Z_L (mi.)**	**Z_{tr} (mi.)**	**Z_{ln1-4} (total mi.)**	**Z_{dist} (mi.)**	**Z_{T1}, Z_{T-4} (Z/MVA)**	**Z_{T2}, Z_{T3} (Z/MVA)**	**L_1, L_4 (MW)**	**L_2, L_3 (MW)**	**P_L (MVA)**	**P_{ln1} (MVA)**	**P_{ln2} (MVA)**	**P_{ln3} (MVA)**	**P_{ln4} (MVA)**	**$P_{ln1'}$ (MVA)**	**$P_{ln2'}$ (MVA)**	**$P_{ln3'}$ (MVA)**	**$P_{ln4'}$ (MVA)**	**LODF**
723c0	10	Medium	15	0	10%/40	10%/40	16.0	16.0	112.6	42.7	26.7	5.3	21.3	46.5	31.4	1.6	17.6	0.034
723c2	10	Medium	15	2	10%/40	10%/40	16.0	16.0	113.5	39.7	23.7	8.4	24.4	42.4	26.4	5.7	21.7	0.024
723c5	10	Medium	15	5	10%/40	10%/40	16.0	16.0	114.1	37.4	21.4	10.7	26.7	39.3	23.3	8.8	24.8	0.017
723c0pk	10	Medium	15	0	10%/40	10%/40	32.0	32.0	121.2	75.5	43.4	20.7	52.7	79.5	47.4	16.7	48.7	0.033
723c2pk	10	Medium	15	2	10%/40	10%/40	32.0	32.0	122.0	72.2	40.1	23.9	55.9	75.2	43.1	21.1	53.1	0.025
723c5pk	10	Medium	15	5	10%/40	10%/40	32.0	32.0	122.7	69.8	37.7	26.4	58.5	71.8	39.7	24.4	56.5	0.016
823a0	10	Weak	15	0	10%/10	10%/10	4.0	4.0	106.1	10.8	6.8	1.2	5.2	12.9	8.9	-0.9	3.1	0.020
823a2	10	Weak	15	2	10%/10	10%/10	4.0	4.0	106.2	10.5	6.5	1.5	5.5	12.4	8.4	-0.4	3.6	0.018
823a5	10	Weak	15	5	10%/10	10%/10	4.0	4.0	106.4	10.2	62.0	1.8	5.8	11.9	7.9	0.2	4.2	0.016
823a0pk	10	Weak	15	0	10%/10	10%/10	8.0	8.0	109.6	18.9	10.9	5.1	13.1	21.1	13.0	3.0	11.0	0.020
823a2pk	10	Weak	15	2	10%/10	10%/10	8.0	8.0	109.7	18.6	10.6	5.4	13.4	20.6	12.6	3.5	11.5	0.018
823a5pk	10	Weak	15	5	10%/10	10%/10	8.0	8.0	109.8	18.3	10.3	5.7	13.8	20.0	12.0	4.0	12.1	0.015
823b0	10	Weak	15	0	10%/20	10%/20	8.0	8.0	108.4	21.5	13.5	2.5	10.5	25.6	17.6	-1.6	6.4	0.038
823b2	10	Weak	15	2	10%/20	10%/20	8.0	8.0	108.8	20.6	12.6	3.4	11.4	24.0	16.0	0.1	8.1	0.031
823b5	10	Weak	15	5	10%/20	10%/20	8.0	8.0	109.2	19.6	11.6	4.4	12.4	22.3	14.3	1.8	9.8	0.025
823b0pk	10	Weak	15	0	10%/20	10%/20	16.0	16.0	115.3	37.9	21.9	10.2	26.2	42.2	26.1	5.9	21.9	0.037
823b2pk	10	Weak	15	2	10%/20	10%/20	16.0	16.0	115.7	36.9	20.8	11.2	27.2	40.4	24.4	7.7	23.7	0.030
823b5pk	10	Weak	15	5	10%/20	10%/20	16.0	16.0	116.2	35.9	19.8	12.2	28.2	38.7	22.7	9.4	25.5	0.024

Case	Z_L (mi.)	Z_{tr} (mi.)	Z_{ln1-4} (total mi.)	Z_{dist} (mi.)	Z_{T1}, Z_{T-4} (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	$P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	LODF
										------------ HV Line "L" in-service ------------				-- HV Line "L" out-of-service --				
823c0	10	Weak	15	0	10%/40	10%/40	16.0	16.0	113.1	42.7	26.7	5.3	21.3	50.3	34.3	-2.3	13.7	0.067
823c2	10	Weak	15	2	10%/40	10%/40	16.0	16.0	114.4	39.7	23.7	8.3	24.3	45.4	29.3	2.8	18.8	0.050
823c5	10	Weak	15	5	10%/40	10%/40	16.0	16.0	115.5	37.4	21.4	10.6	26.7	41.4	25.4	6.8	22.8	0.035
823c0pk	10	Weak	15	0	10%/40	10%/40	32.0	32.0	126.7	76.0	43.9	20.2	52.2	84.4	52.3	11.8	43.8	0.066
823c2pk	10	Weak	15	2	10%/40	10%/40	32.0	32.0	128.2	72.7	40.6	23.5	55.6	78.9	48.6	17.4	49.5	0.048
823c5pk	10	Weak	15	5	10%/40	10%/40	32.0	32.0	129.3	70.1	38.0	26.1	58.2	74.5	42.4	21.8	53.9	0.034
Sensitivity to Length of Lines 1-4																		
723a0_30	10	Medium	30	0	10%/10	10%/10	4.0	4.0	108.3	10.8	6.8	1.2	5.2	11.8	7.8	0.2	4.2	0.009
723a2_30	10	Medium	30	2	10%/10	10%/10	4.0	4.0	108.4	10.5	6.5	1.5	5.5	11.4	7.4	0.6	4.6	0.008
723a5_30	10	Medium	30	5	10%/10	10%/10	4.0	4.0	108.5	10.2	6.2	1.8	5.8	11.0	7.0	1.0	5.0	0.007
Selected 34.5 kV cases																		
834a0	10	Weak	15	0	10%/10	10%/10	4.0	4.0	106.1	10.8	6.8	1.2	5.2	12.9	8.9	-0.9	3.1	0.020
834a2	10	Weak	15	2	10%/10	10%/10	4.0	4.0	106.1	10.7	6.7	1.3	5.3	12.7	8.7	-0.7	3.3	0.019
834a5	10	Weak	15	5	10%/10	10%/10	4.0	4.0	106.2	10.5	6.5	1.5	5.5	12.4	8.4	-0.4	3.6	0.018
834a0pk	10	Weak	15	0	10%/10	10%/10	8.0	8.0	109.6	18.9	10.9	5.1	13.1	21.1	13.0	3.0	11.0	0.020
834a2pk	10	Weak	15	2	10%/10	10%/10	8.0	8.0	109.6	18.8	10.8	5.2	13.3	20.8	12.8	3.2	11.2	0.018
834a5pk	10	Weak	15	5	10%/10	10%/10	8.0	8.0	109.7	18.6	10.6	5.4	13.4	20.5	12.5	3.5	11.5	0.017
834b0	10	Weak	15	0	10%/20	10%/20	8.0	8.0	108.4	21.5	13.5	2.5	10.5	25.6	17.6	-1.6	6.4	0.038

										HV Line "L" in-service				HV Line "L" out-of-service				
Case	Z_L (mi.)	Z_{tr} (mi.)	Z_{ln1-4} (total mi.)	Z_{dist} (mi.)	Z_{T1}, Z_{T-4} (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	$P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	LODF
834b2	10	Weak	15	2	10%/20	10%/20	8.0	8.0	108.6	21.1	13.1	2.9	10.9	24.8	16.8	-0.7	7.3	0.034
834b5	10	Weak	15	5	10%/20	10%/20	8.0	8.0	108.9	20.5	12.5	3.5	11.5	23.8	15.8	0.3	8.3	0.030
834b0pk	10	Weak	15	0	10%/20	10%/20	16.0	16.0	115.3	37.9	21.9	10.2	26.2	42.2	26.1	5.9	21.9	0.037
834b2pk	10	Weak	15	2	10%/20	10%/20	16.0	16.0	115.5	37.4	21.4	10.7	26.7	41.3	25.3	6.8	22.8	0.034
834b5pk	10	Weak	15	5	10%/20	10%/20	16.0	16.0	115.8	36.8	20.7	11.3	27.3	40.3	24.2	7.8	23.9	0.030
834c0	10	Weak	15	0	10%/40	10%/40	16.0	16.0	113.1	42.7	26.7	5.3	21.3	50.3	34.3	-2.3	13.7	0.067
834c2	10	Weak	15	2	10%/40	10%/40	16.0	16.0	113.8	41.2	25.2	6.9	22.9	47.8	31.7	0.4	16.4	0.058
834c5	10	Weak	15	5	10%/40	10%/40	16.0	16.0	114.6	39.5	23.5	8.5	24.6	45.0	29.0	3.2	19.2	0.048
834c0pk	10	Weak	15	0	10%/40	10%/40	32.0	32.0	126.7	76.0	43.9	20.2	52.2	84.4	52.3	11.8	43.8	0.066
834c2pk	10	Weak	15	2	10%/40	10%/40	32.0	32.0	127.5	74.2	42.1	21.9	54.0	81.5	49.4	14.7	46.8	0.057
834c5pk	10	Weak	15	5	10%/40	10%/40	32.0	32.0	128.3	72.4	40.3	23.8	55.8	78.5	46.4	17.9	49.9	0.048
834d0	10	Weak	15	0	7%/40	7%/40	16.0	16.0	111.6	46.3	30.3	1.7	17.7	56.2	40.1	-8.1	7.9	0.089
834d2	10	Weak	15	2	7%/40	7%/40	16.0	16.0	112.8	43.6	27.6	4.4	20.4	51.8	35.8	-3.6	12.4	0.073
834d5	10	Weak	15	5	7%/40	7%/40	16.0	16.0	113.9	41.1	25.1	7.0	23.0	47.6	31.6	0.6	16.6	0.057
834d0pk	10	Weak	15	0	7%/40	7%/40	32.0	32.0	124.9	80.0	47.9	16.2	48.2	90.9	58.8	5.3	37.3	0.087
834d2pk	10	Weak	15	2	7%/40	7%/40	32.0	32.0	126.3	77.0	44.9	19.2	51.2	86.1	54.0	10.2	42.2	0.072
834d5pk	10	Weak	15	5	7%/40	7%/40	32.0	32.0	127.5	74.2	42.1	22.0	54.1	81.4	49.3	15.0	47.0	0.056

Case	Z_L (mi.)	Z_{tr} (mi.)	Z_{ln1-4} (total mi.)	Z_{dist} (mi.)	Z_{T1}, Z_{T-4} (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	------------ HV Line "L" in-service ------------ P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	-- HV Line "L" out-of-service -- $P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	LODF
Selected 12.47 kV cases																		
812a0	10	Weak	15	0	10%/10	10%/10	4.0	4.0	106.1	10.8	6.8	1.2	5.2	12.9	8.9	-0.9	3.1	0.020
812a2	10	Weak	15	2	10%/10	10%/10	4.0	4.0	106.4	10.1	6.1	1.9	5.9	11.6	7.6	0.4	4.4	0.014
812a5	10	Weak	15	5	10%/10	10%/10	4.0	4.0	106.7	9.4	5.4	2.6	6.6	10.5	6.5	1.5	5.5	0.010
812a0pk	10	Weak	15	0	10%/10	10%/10	8.0	8.0	109.6	18.9	10.9	5.1	13.1	21.1	13.0	3.0	11.0	0.020
812a2pk	10	Weak	15	2	10%/10	10%/10	8.0	8.0	109.9	18.1	10.1	5.9	13.9	19.7	11.7	4.3	12.4	0.015
812a5pk	10	Weak	15	5	10%/10	10%/10	8.0	8.0	110.2	17.5	9.5	6.5	14.5	18.6	10.6	5.5	13.5	0.010
812b0	10	Weak	15	0	10%/20	10%/20	8.0	8.0	108.4	21.5	13.5	2.5	10.5	25.6	17.6	-1.6	6.4	0.038
812b2	10	Weak	15	2	10%/20	10%/20	8.0	8.0	109.4	19.2	11.2	4.8	12.8	21.7	13.6	2.5	10.5	0.023
812b5	10	Weak	15	5	10%/20	10%/20	8.0	8.0	110.0	17.9	9.9	6.1	14.1	19.4	11.4	4.7	12.7	0.014
812b0pk	10	Weak	15	0	10%/20	10%/20	16.0	16.0	115.3	37.9	21.9	10.2	26.2	42.2	26.1	5.9	21.9	0.037
812b2pk	10	Weak	15	2	10%/20	10%/20	16.0	16.0	116.4	35.4	19.4	12.6	28.6	38.0	22.0	10.2	26.2	0.022
812b5pk	10	Weak	15	5	10%/20	10%/20	16.0	16.0	117.0	34.1	18.0	14.0	30.0	35.6	19.6	12.6	28.6	0.013
812c0	10	Weak	15	0	10%/40	10%/40	16.0	16.0	113.1	42.7	26.7	5.3	21.3	50.3	34.3	-2.3	13.7	0.067
812c2	10	Weak	15	2	10%/40	10%/40	16.0	16.0	115.9	36.6	20.6	11.5	27.5	40.0	24.0	8.3	24.3	0.029
812c5	10	Weak	15	5	10%/40	10%/40	16.0	16.0	116.8	34.4	18.4	13.7	29.7	36.2	20.2	12.0	28.0	0.015
812c0pk	10	Weak	15	0	10%/40	10%/40	32.0	32.0	126.7	76.0	43.9	20.2	52.2	84.4	52.3	11.8	43.8	0.066
812c2pk	10	Weak	15	2	10%/40	10%/40	32.0	32.0	129.7	69.2	37.1	27.1	59.1	73.0	40.9	23.5	55.5	0.029

										----------- HV Line "L" in-service -----------				-- HV Line "L" out-of-service --				
Case	**Z_L (mi.)**	**Z_{tr} (mi.)**	**Z_{ln1-4} (total mi.)**	**Z_{dist} (mi.)**	**Z_{T1}, Z_{T-4} (Z/MVA)**	**Z_{T2}, Z_{T3} (Z/MVA)**	**L_1, L_4 (MW)**	**L_2, L_3 (MW)**	**P_L (MVA)**	**P_{ln1} (MVA)**	**P_{ln2} (MVA)**	**P_{ln3} (MVA)**	**P_{ln4} (MVA)**	**$P_{ln1'}$ (MVA)**	**$P_{ln2'}$ (MVA)**	**$P_{ln3'}$ (MVA)**	**$P_{ln4'}$ (MVA)**	**LODF**
812c5pk	10	Weak	15	5	10%/40	10%/40	32.0	32.0	130.8	66.7	34.7	29.4	61.5	68.8	36.7	27.6	59.6	0.016
Selected 46 kV cases																		
846e0	10	Weak	15	0	10%/40	7%/50	16.0	20.0	112.1	53.1	37.1	2.9	18.9	64.7	48.7	-8.6	7.4	0.103
846e2	10	Weak	15	2	10%/40	7%/50	16.0	20.0	113.2	50.7	34.7	5.3	21.3	60.9	44.8	-4.7	11.3	0.090
846e5	10	Weak	15	5	10%/40	7%/50	16.0	20.0	114.3	48.2	32.1	7.9	24.0	56.7	40.7	-0.4	15.6	0.074
Sub-transmission cases																		
115-69 kV																		
669f25	40	Strong	20	25	10%/40	7%/60	16.0	24.0	114.0	76.0	59.8	-10.8	5.2	79.6	63.4	-14.2	1.8	0.032
769f25	40	Medium	20	25	10%/40	7%/60	16.0	24.0	111.7	75.3	59.1	-10.1	5.9	87.3	71.0	-21.2	-5.2	0.107
869f25	40	Weak	20	25	10%/40	7%/60	16.0	24.0	109.8	74.7	58.5	-9.6	6.4	97.0	80.6	-30.0	-14.0	0.203
115-55 kV																		
655e25	40	Strong	20	25	10%/40	7%/50	16.0	20.0	114.5	62.1	46.0	-5.0	11.0	64.8	48.7	-7.5	8.5	0.024
755e25	40	Medium	20	25	10%/40	7%/50	16.0	20.0	113.3	61.8	45.7	-4.8	11.2	70.9	54.8	-13.0	3.0	0.080
855e25	40	Weak	20	25	10%/40	7%/50	16.0	20.0	112.1	61.5	45.4	-4.5	11.5	79.1	62.9	-20.2	-4.2	0.157
855f25																		
115-46 kV																		
646e25	40	Strong	20	25	10%/40	7%/50	16.0	20.0	115.0	57.3	41.2	-0.2	15.8	59.5	43.4	-2.1	13.9	0.019
746e25	40	Medium	20	25	10%/40	7%/50	16.0	20.0	114.6	57.2	41.2	-0.1	15.9	64.9	48.8	-6.8	9.2	0.067
846e25	40	Weak	20	25	10%/40	7%/50	16.0	20.0	114.2	57.2	41.1	0.0	16.0	72.4	56.2	-13.1	2.9	0.133
115-34.5 kV																		
634d25	40	Strong	20	25	10%/40	7%/40	16.0	16.0	115.3	46.2	30.2	2.6	18.7	47.7	31.7	1.4	17.4	0.013

Case	Z_L (mi.)	Z_{tr} (mi.)	Z_{ln1-4} (total mi.)	Z_{dist} (mi.)	Z_{T1}, Z_{T-4} (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	------------ HV Line "L" in-service ------------ P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	-- HV Line "L" out-of-service -- $P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	LODF
734d25	40	Medium	20	25	10%/40	7%/40	16.0	16.0	115.4	46.3	30.2	2.6	18.6	51.5	35.5	-1.9	14.1	0.045
834d25	40	Weak	20	25	10%/40	7%/40	16.0	16.0	115.5	46.3	30.2	2.6	18.6	57.1	41.0	-6.4	9.6	0.094
138-69 kV																		
869f25-138	40	Weak	20	25	10%/40	7%/60	16.0	24.0	112.0	66.5	50.4	-1.8	14.2	84.0	67.9	-18.3	-2.3	0.156
869f25-138'	40	Weak	20	25	10%/40	7%/60	16.0	24.0	131.9	71.1	55.0	-6.3	9.8	92.0	75.8	-25.6	-9.6	0.158
138-55 kV																		
855e25-138	40	Weak	20	25	10%/40	7%/50	16.0	20.0	113.5	55.1	39.0	1.5	17.5	68.4	52.3	-10.8	5.2	0.117
855e25-138'	40	Weak	20	25	10%/40	7%/60	16.0	20.0	134.0	58.5	42.4	-1.7	14.3	74.4	58.3	-16.2	-0.2	0.119
161-69 kV																		
869f25-161	40	Weak	20	25	10%/40	7%/60	16.0	24.0	113.2	60.7	44.7	3.7	19.7	74.8	58.8	-9.8	6.2	0.125
869f25-161'	40	Weak	20	25	10%/40	7%/60	16.0	24.0	153.0	68.0	52.0	-3.3	12.7	87.3	71.2	-21.4	-5.4	0.126
161-55 kV																		
855e25-161	40	Weak	20	25	10%/40	7%/50	16.0	20.0	114.1	50.7	34.7	5.6	21.6	61.1	45.1	-4.2	11.8	0.091
855e25-161'	40	Weak	20	25	10%/40	7%/60	16.0	20.0	154.8	56.0	40.0	0.6	16.6	70.3	54.3	-12.6	3.4	0.092
230-69 kV																		
869f25-230	40	Weak	20	25	10%/40	7%/60	16.0	24.0	116.3	51.3	35.3	12.8	28.8	59.4	43.3	5.0	21.0	0.070
869f25-230'	40	Weak	20	25	10%/40	7%/60	16.0	24.0	217.7	61.2	45.2	3.2	19.2	76.5	60.4	-11.4	4.7	0.070
230-55 kV																		
855e25-230	40	Weak	20	25	10%/40	7%/50	16.0	20.0	116.1	43.8	27.8	12.3	28.3	49.5	33.5	6.7	22.8	0.049
855e25-230'	40	Weak	20	25	10%/40	7%/50	16.0	20.0	218.7	50.8	34.8	5.6	21.6	61.7	45.7	-4.7	11.3	0.050

Notes:

The following notes provide information to understand the meaning of each column heading and underlying assumptions used in the analysis. See also the one-line diagrams in Figures 5 and 6 of Appendix 2 for additional information.

Z_L

The table provides the length of line "L" in miles to provide a high-level, qualitative understanding of the line impedance. The line impedance (Z_L) is the length of the line in miles times the per mile impedance. Assumptions used in determining the per mile impedance are as follows:

Voltage (kV)	Conductor	Phase Spacing	GMD	Impedance (Ω/mile)	Impedance (p.u./mile)
230	954 ACSR	20' H-frame	25.20'	0.100 + j0.786	0.000189 + J 0.00149
161	954 ACSR	16' H-frame	20.16'	0.100 + j0.759	0.000384 + j 0.00293
138	795 ACSR	13' H-frame	16.38'	0.117 + j0.738	0.000615 + j 0.00388
115	795 ACSR	11' H-frame	13.86'	0.117 + j0.718	0.000886 + j 0.00543

Z_{tr}

The transfer impedance (Z_{tr}) represents the impedance of the system in parallel with the subsystem under study. Analysis was performed for three levels of parallel transfer impedance which have been characterized as strong, medium, and weak. The strong system has relatively low impedance and thus will pick up more power flow when line "L" is tripped. The weak system has relatively high impedance and thus will pick up less power flow when line "L" is tripped. The medium system has a mid-range impedance value. The actual values of the transfer impedance vary between the distribution cases and the sub-transmission cases.

	Z_{tr} in distribution cases (p.u.)	Z_{tr} in sub-transmission cases (p.u.)
Strong	0.00089 + j 0.00543	0.00354 + j 0.0217
Medium	0.00319 + j 0.0195	0.0128 + j 0.0782
Weak	0.00664 + j 0.0407	0.0266 + j 0.163

Z_{ln1-4}

The table provides the total length of lines "ln1" through "ln4." In all simulations these four lines have equal length. The total length in miles provides a high-level, qualitative understanding of the line impedance. The line impedances are the length of each line in miles times the per mile impedance. Assumptions used in determining the per mile impedance are the same as provided above for line "L."

Z_{dist}

The table provides the length of the line in miles to provide a high-level, qualitative understanding of the line impedance. The impedance of the distribution system or sub-transmission system (Z_{dist}) is the length

of the distribution tie or sub-transmission line in miles times the per mile impedance. A value of zero miles is used when the distribution tie is a solid bus tie. Assumptions used in determining the per mile impedance are as follows:

Voltage (kV)	Conductor	Phase Spacing	GMD	Impedance (Ω/mile)	Impedance (p.u./mile)
69	636 ACSR	6' Horizontal	7.56'	0.145 + j0.657	0.00305 + j 0.0138
55	556 ACSR	6' Horizontal	7.56'	0.168 + j0.677	0.00555 + j 0.0224
46	477 ACSR	6' Triangular	6.00'	0.193 + j0.647	0.00913 + j 0.0306
34.5	477 ACSR	4' Triangular	4.00'	0.193 + j0.598	0.0162 + j 0.0503
23	477 ACSR	4' Triangular	4.00'	0.193 + j0.598	0.0365 + j 0.113
12.47	336 ACSR	2' Horizontal	2.52'	0.274 + j0.563	0.176 + j 0.362

Z_{T1-4}

The transformer impedance is reported as percent impedance on the transformer MVA base. Each transformer has three ratings: OA (oil and air), FA (forced air – i.e., fans), and FOA (forced oil and air – i.e., pumps and fans). The transformer MVA base rating is the OA rating. The FA rating is 133% of the OA rating and the FOA rating is 167% of the OA rating (e.g., a 20 MVA transformer has a 20 MVA OA rating, 26.7 MVA FA rating, and 33.3 MVA FOA rating, typically identified as a nameplate of 20/26.7/33.3 MVA).

The transformer impedance and rating for each voltage level are based on typical values. Distribution transformer impedance is generally higher to limit current on the distribution equipment. Secondary current typically is not a concern on sub-transmission transformers, so impedance is typically lower to limit reactive power losses and voltage drop.

L_1, L_2, L_3, L_4

The transformer load is based on the transformer OA rating. Transformers are loaded at 80 percent of the transformer base MVA in the simulations modeling a peak system load condition. The substations modeled have two transformers, with each transformer able to supply the total station load. Thus, if one transformer is forced out-of-service, the load on the remaining transformer will be 160 percent of its base rating, which is approximately equal to its FOA rating.

Transformers are loaded at 40 percent of the transformer base MVA in the simulations modeling a light system load condition.

HV Line "L" in-service: P_L, P_{ln1}, , P_{ln2}, P_{ln3}, P_{ln4}

The loading on each line, with all lines in service, is listed in MVA. The loading on line "L" is the power that is redistributed between the parallel transmission system and the distribution or sub-transmission system when line "L" is taken out of service.

HV Line "L" out-of-service: P_{ln1}, , P_{ln2}, P_{ln3}, P_{ln4}

The loading on each line, with line "L" out-of-service, is listed in MVA.

LODF

The Line Outage Distribution Factor (LODF) is the fraction of the load on line "L" that is picked up on the distribution or sub-transmission system. This information is included for illustrative purposes to understand the analysis, but was not used in identifying the voltage threshold for Exclusion E1.

Appendix 4: Summary of Loop Flow Issue Through Systems <50 kV

In the course of developing 'real-world' scenarios for the analysis of potential sub-100 kV loop flows, the Standard Drafting Team found that the industry has employed various measures to minimize the subject loop flows. Some of these methods that were found to be applied by entities on sub-100 kV loop systems are described below. However, it is important to note that the presence of the equipment in the following examples does not remove or lessen an entity's obligations associated with the bright-line application of the Bulk Electric System (BES) definition.

Sustained power flow through substation power transformers and low voltage loops is generally undesirable and, in some instances injurious. For this reason, power system engineers typically address this issue in their design, operating, and planning criteria and apply methods to prevent this condition from occurring. The high impedance of transformers and low voltage elements inherently prevent excessive flow, but in many instances this flow can exceed ratings of equipment. For these reasons entities develop control schemes, add relaying, and provide operational and planning guidelines to prevent this loop flow. Figure 7 depicts two systems that could provide a possible loop flow across the low voltage system and back up to the high voltage system. The loop flow in these diagrams is increased when the breaker on the high voltage side (breaker B) is opened.

The diagrams presented below depict a generic power system. The higher voltage and lower voltage circuit breakers and bus arrangements will, in practice, vary (i.e., straight bus, half-breaker, ring bus, breaker-and-a-half, etc.), but the concepts remain the same.

Specifically, Figure 7, shown below, depicts segments of an electrical power system. They consist of a greater than 100 kV system and a sub-100 kV system. Figure 7 depicts the power flow through the electrical system under the condition that all circuit breakers are closed (normal condition). In the event that circuit breaker B opens (i.e., manually, supervisory control, or protective device operation) and (1) and either of the sub-100 kV line circuit breakers (A or C) or (2) either of the low-side transformer circuit breakers (D or F) or (3) the low-side bus tie circuit breaker (E) does not open, a condition could occur where some amount of flow will occur through the sub-100 kV system to the greater than 100 kV system. This flow is severely limited by the high impedance of the two transformers in series and the sub-100 kV system impedance. This condition, however, may be deemed undesirable from an equipment standpoint and precautions may be taken to prevent it. Subsequent sections of this appendix show some of the physical schemes that entities can employ in this regard.

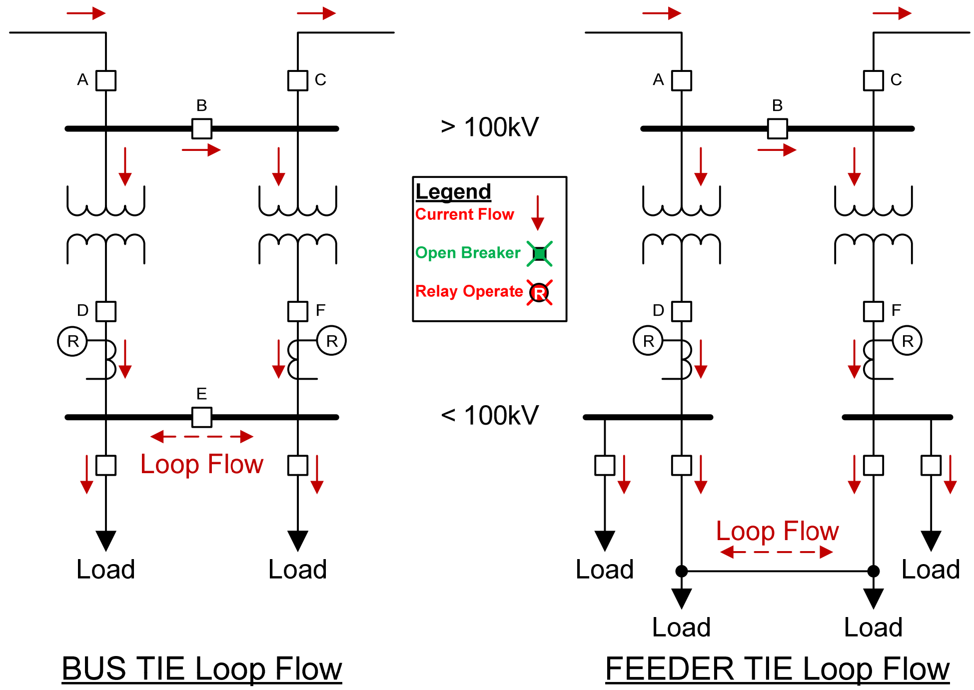


Figure 7. Summary of Loop Flow

Interlocked Control Schemes

Interlocking control schemes can be used to prevent low voltage loop flow. One method to preclude sustained power flow from the lower voltage to the higher voltage portion of the system is to include control system interlocks which will cross-trip certain circuit breaker(s) when other specified circuit breakers are opened. This condition is generally rare since bus designs and protective relay system operations generally do not result in this condition occurring. Operational guidelines usually instruct personnel to avoid the use of the interlocking schemes during normal or planned switching. However, unplanned actions can cause breakers to open and result in the desirable operation of the interlocking schemes. This method, therefore, is considered to be conservative but, never-the-less, it is applied in some instances.

Figure 8 below shows how an interlock scheme would function to prevent low voltage loop flow. When the high side breaker (breaker B) is opened, the low side breaker (breaker E) is also opened. This action prevents low side loop flow. The interlocking scheme could be applied in various combinations and the figure below is a simplified illustration of such a scheme.

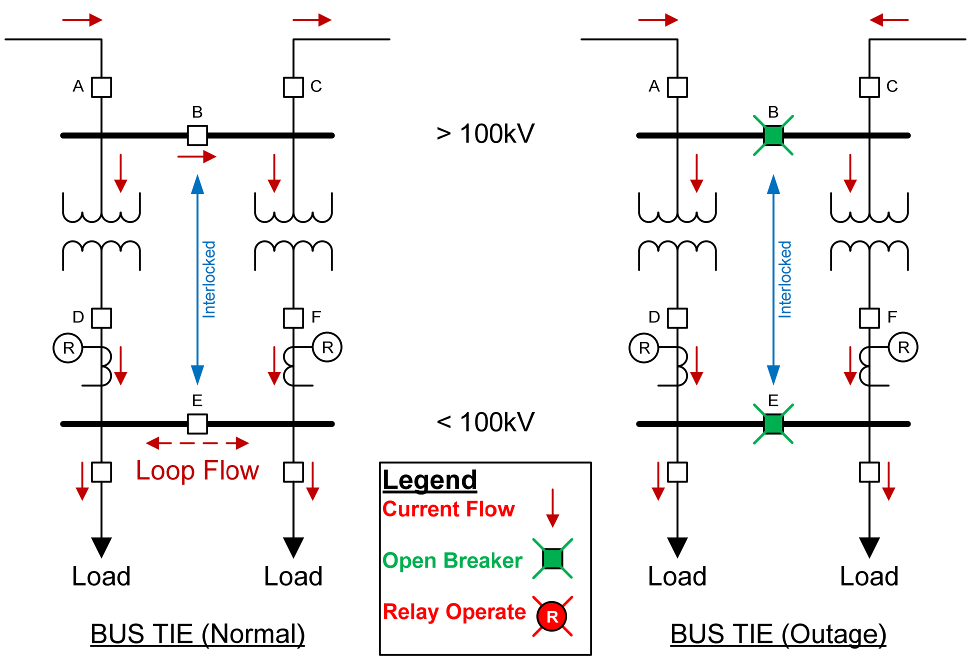


Figure 8. Interlocking Schemes

Reverse Power Schemes

Protection schemes can also be deployed to prevent sustained loop flows through the sub-100 kV system. Reverse power applications are one example of a protection scheme that prevents sustained undesirable low voltage loop flow. In some instances, protective devices will preclude sustained loop flows due to their settings and in other instances protective schemes are specifically applied to preclude this undesirable operating condition.

Figure 9 below shows how a reverse power scheme would function to prevent sub-100 kV loop flow. When the high side breaker (breaker B) is opened, current may flow from the high voltage side (breaker A) through the low voltage bus and back to the high voltage side (breaker C). A relay on breaker F is applied to sense the reverse flow (relay shown in yellow in the diagram) and will operate if this flow continues (relay shown in red in the diagram). When the reverse power relay operates it will trip breaker F. This action prevents reverse power flow through the transformer and low voltage loop flow. The reverse power scheme is set to sense a minimum amount of power flowing in a reverse direction and is usually set much less than the transformer rating. The figure below is a simplified illustration of a reverse power scheme.

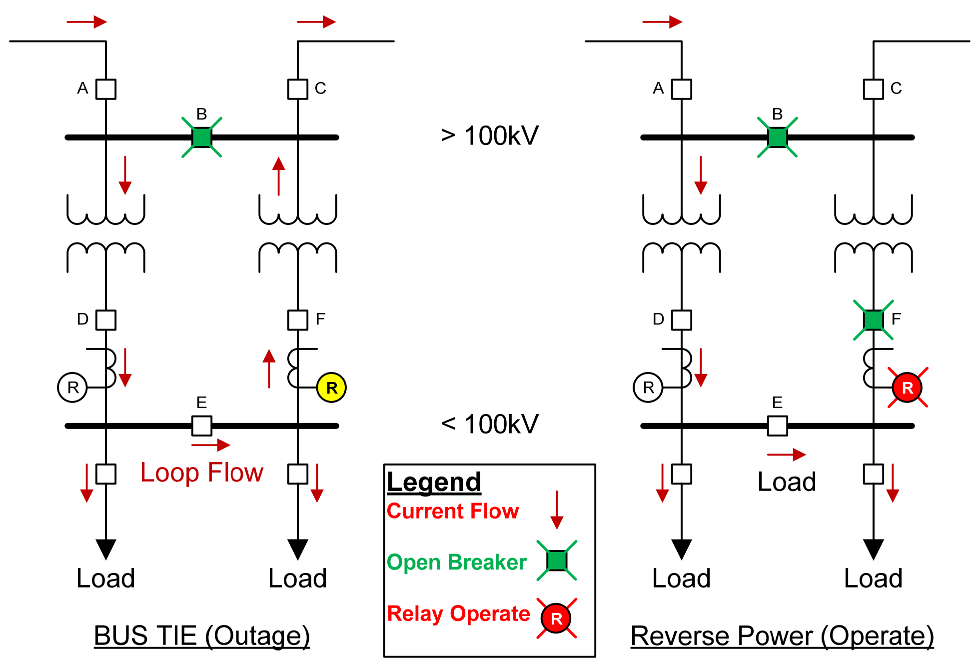


Figure 9. Reverse Power Schemes

Transformer Overcurrent Limitations

Transformer overcurrent protection schemes can also be deployed to prevent sustained loop flows through the sub-100 kV system. Figure 10 below shows how a transformer overcurrent scheme would function to prevent sub-100 kV loop flow. When the high side breaker (breaker B) is opened, current may flow from the high voltage side (breaker A) through the low voltage bus and back to the high

voltage side (breaker C). The relay on the transformer and breaker D is applied to protect the transformer from excessive overloads and faults on the low voltage system. If a fault occurs or the transformer is over-loaded then the relay on breaker D will sense this excessive flow (relay shown in yellow in the diagram) and will operate if this flow continues (relay shown in red in the diagram). When the transformer overcurrent relay operates it will trip breaker D. This action unloads the transformer in question and prevents low voltage loop flow. The transformer overcurrent relay is typically set to allow the transformer to be loaded to the emergency rating of the transformer plus a small safety margin. The figure below is a simplified illustration of a transformer overcurrent scheme.

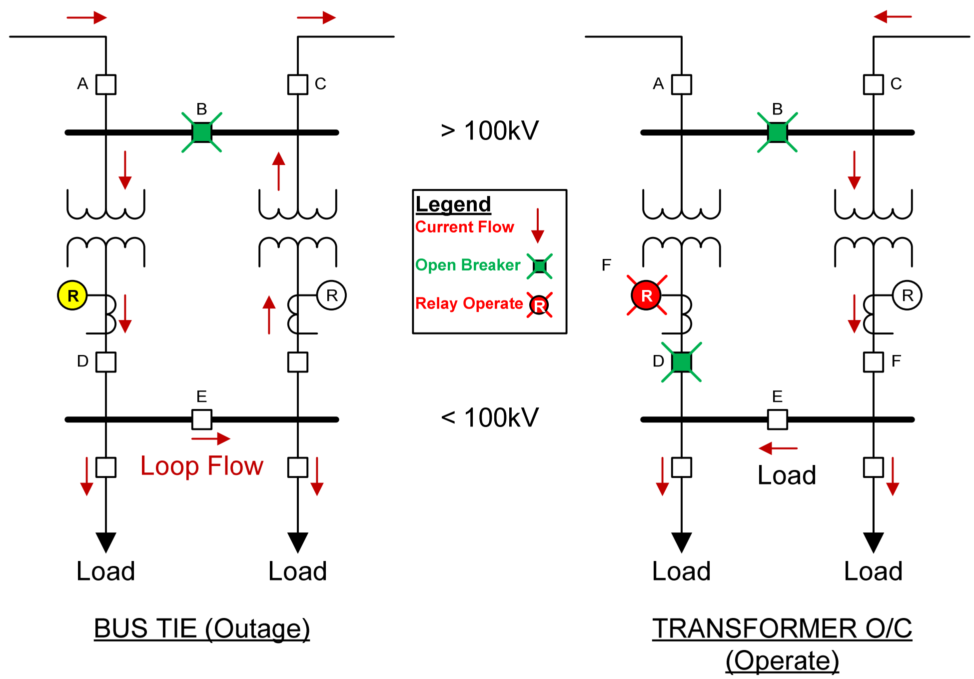


Figure 10. Transformer Overcurrent Limitations

Feeder Overcurrent Limitations

Feeder overcurrent protection schemes can also be deployed to prevent sustained loop flows through the sub-100 kV system. Figure 11 below shows how a feeder overcurrent scheme would function to prevent sub-100 kV loop flow. When the high side breaker (breaker B) is opened, current may flow from the high voltage side (breaker A) through the low voltage feeder, through a feeder tie, and back to the high voltage side (breaker C). The relay on the feeder and breaker G is applied to protect the feeder from excessive overloads and faults on the low voltage feeder. If a fault occurs or the feeder is over loaded, the relay on breaker G will sense this excessive flow (relay shown in yellow in the diagram) and will operate if this flow continues (relay shown in red in the diagram). When the feeder overcurrent relay operates it will trip breaker G. This action opens the feeder breaker and prevents low voltage loop flow. The feeder overcurrent relay is typically set to allow the feeder to be loaded to the emergency rating of the feeder rating plus a small safety margin. The figure below is a simplified illustration of a feeder overcurrent power scheme.

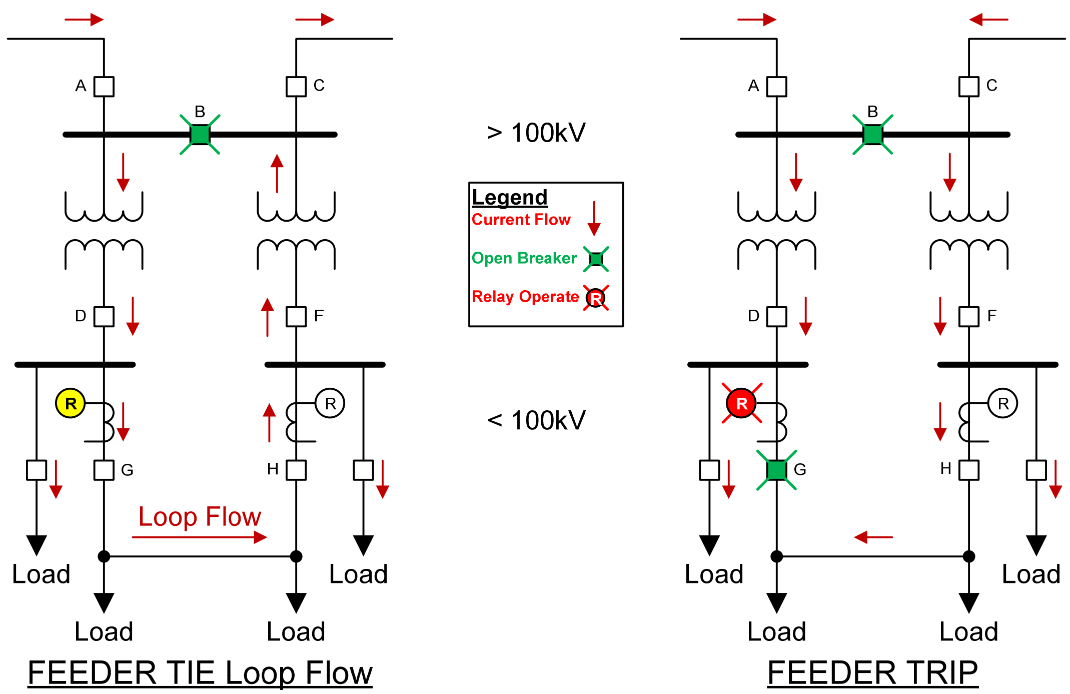


Figure 11. Feeder Overcurrent Limitations

Bus Tie Overcurrent Limitations

Bus tie overcurrent protection schemes can also be deployed to prevent sustained loop flows through the sub-100 kV system. Figure 12 below shows how a bus tie overcurrent scheme would function to prevent sub-100 kV loop flow. When the high side breaker (breaker B) is opened, current may flow from the high voltage side (breaker A) through the low voltage bus and back to the high voltage side (breaker C). The relay on the bus tie and breaker E is applied to protect the bus from excessive overloads and faults on the low voltage bus(ses). If a fault occurs or the bus is over loaded, then the overcurrent relay on breaker E will sense this excessive flow (relay shown in yellow in the diagram) and will operate if this flow continues (relay shown in red in the diagram). When the bus tie overcurrent relay operates, it will trip breaker E. This action opens the bus tie breaker and prevents sustained low voltage loop flow. The bus tie overcurrent relay is typically set to allow the bus to be loaded to the emergency rating plus a small safety margin. The figure below is a simplified illustration of a bus tie overcurrent power scheme.

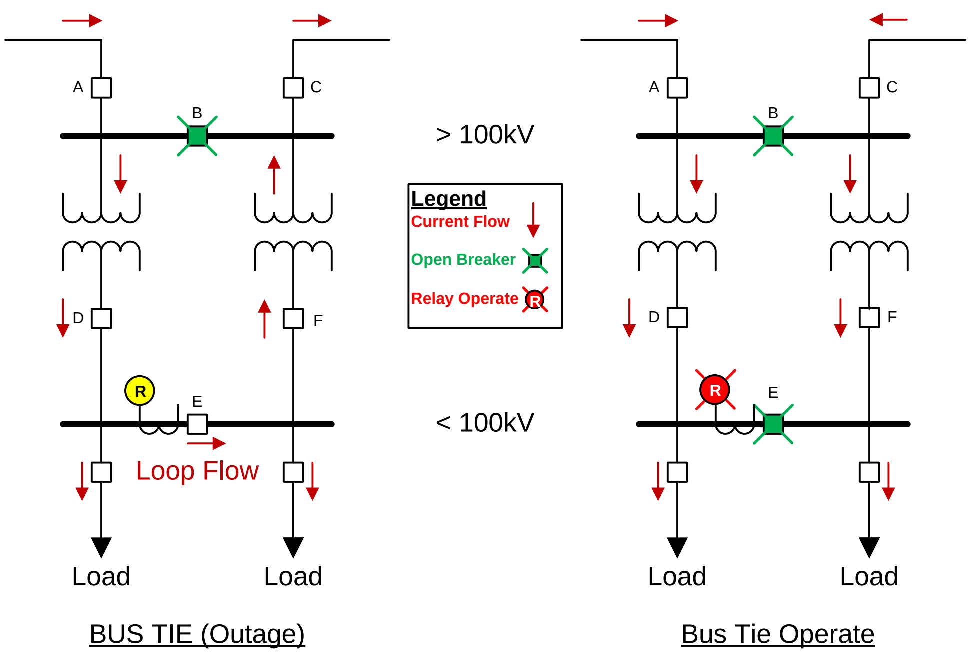


Figure 12. Bus Tie Overcurrent Limitations

Custom Protection and Control Schemes

Custom protection and control schemes may also be deployed to prevent loop flows through the sub-100 kV system. Figure 13 below shows how such schemes would function to prevent sub-100 kV loop flow. When the greater than 100 kV line 1 breakers (breakers D and G) open, current may flow from the high voltage side (breaker E) through the low voltage bus and back to the high voltage side (breaker H). The custom scheme implemented at the substation will trip or run back generation to prevent over loads and sustained loop flows on the low voltage system.

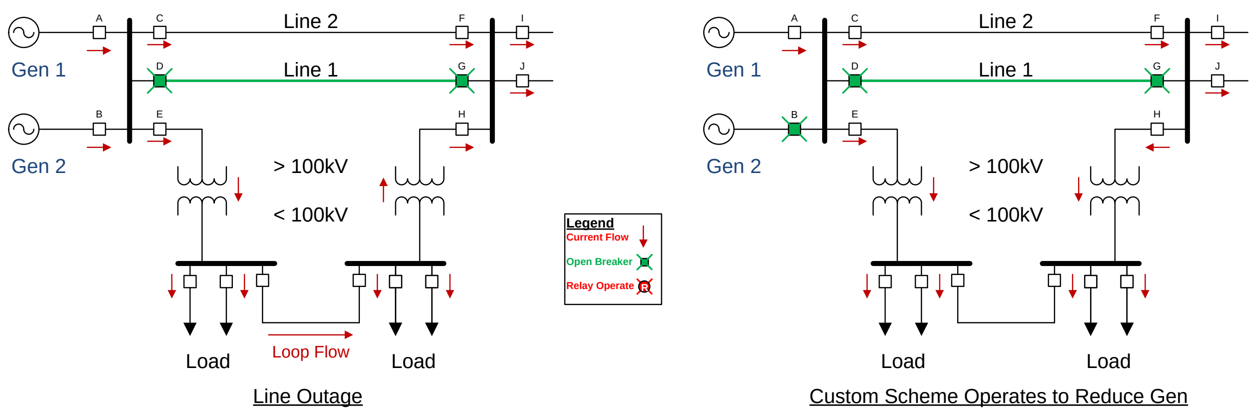


Figure 13. Custom Scheme Operations

Appendix 4 Summary

The issues and methods described in Appendix 4 are reflective of why, in most instances, conditions of sustained loop flows through sub-100 kV systems are alleviated. When the low voltage is much less than 100 kV, the design considerations shown above become even more pertinent and preventative methods are employed; BES reliability is not the main concern, protecting the equipment from physical damage is the primary concern. In the vast majority of cases, robust planning and operating criteria and procedures will alleviate any concerns regarding sustained loop flows.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

E-mail completed form to:
SARCOMM@nerc.net

Standards Authorization Request

Form

Title of Proposed Standard definition	NERC Glossary of Terms - Phase 2: Revision of the Bulk Electric System
Request Date	December 2, 2011

SAR Requester Information	SAR Type (Check all that apply)	
Name: Project 2010-17 Definition of Bulk Electric System (BES) SDT	☐	New Standard
Primary Contact: Peter Heidrich (Manager of Reliability Standards, FRCC) , Project 2010-17 Definition of Bulk Electric System (BES) SDT Chair	X	Revision to existing Standard
Telephone: (813) 207-7994 Fax: (813) 289-5646	☐	Withdrawal of existing Standard
E-mail: pheidrich@frcc.com	☐	Urgent Action

SAR Information
Industry Need (What is the industry problem this request is trying to solve?)
This project supports the ERO's obligation to identify the Elements necessary for the reliable operation of the interconnected transmission network to ensure that the ERO, the Regional Entities, and the industry have the ability to properly identify the applicable entities and Elements subject to the NERC Reliability Standards.
Purpose or Goal (How does this request propose to address the problem described above?)
Research possible revisions to the definition of BES (Phase 2) to address the issues identified through Project 2010-17 Definition of Bulk Electric System (BES) (Phase 1). The definition encompasses all Elements necessary for the reliable operation of the interconnected transmission network. The definition development may include other improvements to the definition as deemed appropriate by

SAR Information
the drafting team, with the consensus of stakeholders, consistent with establishing a high quality and technically sound definition of the Bulk Electric System (BES).
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?)
Revise the BES definition to identify the appropriate electrical components necessary for the reliable operation of the interconnected transmission network.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
Collect and analyze information needed to support revisions to the definition of Bulk Electric System (BES) developed in Phase 1 of this project to provide a technically justifiable definition that identifies the appropriate electrical components necessary for the reliable operation of the interconnected transmission network. The definition development may include other improvements to the definition as deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing a high quality and technically sound definition of the BES.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Collect and analyze information needed to support revisions to the definition of BES developed in Phase 1 of this project to provide a technically justifiable definition that identifies the appropriate electrical components necessary for the reliable operation of the interconnected transmission network. The definition development will include an analysis of the following issues which were identified during the development of Phase 1 of Project 2010-17 Definition of the BES. Clarification of these issues will appropriately define which Elements are necessary for the reliable operation of the interconnected transmission network. • Develop a technical justification to set the appropriate threshold for Real and Reactive Resources necessary for the reliable operation of the Bulk Electric System (BES) • The NERC Board of Trustees approved BES Phase 1 definition does not encompass a contiguous BES - Determine if there is a need to change this position • Determine if there is a technical justification to revise the current 100 kV bright-line voltage level • Determine if there is a technical justification to support allowing power flow out of the local

SAR Information
network under certain conditions and if so, what the maximum allowable flow and duration should be Provide improved clarity to the following: • The relationship between the BES definition and the ERO Statement of Compliance Registry Criteria established in FERC Order 693 • The use of the term "non-retail generation" • The language for Inclusion I4 on dispersed power resources • The appropriate 'points of demarcation' between Transmission, Generation, and Distribution Phase 2 of the definition development may include other improvements to the definition as deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing a high quality and technically justifiable definition of the BES. Based on the potential revisions to the definition of the BES and an analysis of the application of, and the results from, the exception process, the drafting team will review and if necessary propose revisions to the 'Technical Principles' associated with the Rules of Procedure Exception Process to ensure consistency in the application of the definition and the exception process.

Reliability Functions

The Standard will Apply to the Following Functions (Check box for each one that applies.)		
This section is not applicable as the SAR is for a definition which is about Elements, Applicability of entities is covered in Section 4 of each Reliability Standard.		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.

The Standard will Apply to the Following Functions (Check box for each one that applies.)		
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.

The Standard will Apply to the Following Functions (Check box for each one that applies.)		
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles (Check box for all that apply.)	
X	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
X	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
X	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
X	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
X	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Applicable Reliability Principles (Check box for all that apply.)
Does the proposed Standard comply with all of the following Market Interface Principles? (Select 'yes' or 'no' from the drop-down box.)
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Meeting Minutes
Standards Committee

August 2, 2013 | 10:30 a.m. – 11:00 a.m. ET

Introductions and Chair's Remarks
B. Murphy welcomed Committee members and observers and determined the presence of a quorum. The attendance of Standards Committee members is provided in Attachment A.

NERC Antitrust Compliance Guidelines and Public Announcement
Kristin Iwanechko reviewed the NERC Antitrust Compliance Guidelines and reminded participants that notice of the meeting had been widely distributed.

Agenda Items

1. Project 2012-05 ATC Revisions (MOD A)

   J. Tarantino motioned to approve the slate as recommended. J. Bussman seconded the motion.

   - *The Committee approved the motion with no objections or abstentions.*

   C. Yeung noted that a nomination from the SPP region was submitted after the nomination deadline and asked the Committee to consider the nomination. It was determined that the nominee may be considered at a future Committee meeting.

2. Request to Waive the Standard Process for Phase 2 of Project 2010-17

   J. Sterling motioned to authorize a waiver of the Standard Processes Manual to shorten the next and any subsequent comment periods for Phase 2 of Project 2010-17 prior to the final ballot from 45 days to 30 days, with a ballot conducted during the last 10 days of the comment period, and also require NERC staff to post notice of the waiver on the project page and notify the NERC Board of Trustees Standards Oversight and Technology Committee of the waiver. L. Campbell seconded the motion.

   - *The Committee approved the motion with no objections or abstentions.*

   Committee members urged NERC to ensure that the waiver was clearly communicated to industry. J. Sterling, P. Heidrich and L. Hussey were asked to work together to develop language describing the waiver for inclusion in the next posted project announcement.

Standards Announcement Reminder

Project 2010-17 Definition of Bulk Electric System - Phase 2

An Additional Ballot is now open through October 28, 2013

Now Available

An additional ballot for Phase 2 of the Definition of Bulk Electric System is now open through **8 p.m. Eastern on Monday, October 28, 2013.**

Background information for this project can be found on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the definition by clicking here.

As a reminder, this ballot is being conducted under the revised Standard Processes Manual, which requires all negative votes to have an associated comment submitted (or an indication of support of another entity's comments). Please see NERC's announcement regarding the balloting software updates and the guidance document, which explains how to cast your ballot and note if you've made a comment in the online comment form or support another entity's comment.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the definition. If the comments do not show the need for significant revisions, the definition will proceed to a final ballot.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2010-17 Definition of the Bulk Electric System - Phase 2

Formal Comment Period: September 27, 2013 – October 28, 2013

Upcoming Additional Ballot: October 18-28, 2013

Now Available

A 30-day comment period[1] for Phase 2 of the Definition of the Bulk Electric System is open through **8 p.m. Eastern on Monday, October 28, 2013.**

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Monday, October 28, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot for the definition will be conducted as noted above.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

[1] Note that on August 2, 2013, the Standards Committee authorized a waiver of the standard process to permit the comment period that began on August 6, 2013 as well as any subsequent comment period prior to a final ballot of Phase 2 of the Definition of Bulk Electric System. The waiver allows the comment periods to be shortened from 45 days to 30, with a ballot during the last ten days of the comment period. Minutes of the Standards Committee's meeting where the waiver was considered have been posted on the NERC website.

Standards Announcement

Project 2010-17 Definition of the Bulk Electric System - Phase 2

Formal Comment Period: September 27, 2013 – October 28, 2013

Upcoming Additional Ballot: October 18-28, 2013

Now Available

A 30-day comment period[1] for Phase 2 of the Definition of the Bulk Electric System is open through **8 p.m. Eastern on Monday, October 28, 2013.**

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Monday, October 28, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot for the definition will be conducted as noted above.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

[1] Note that on August 2, 2013, the Standards Committee authorized a waiver of the standard process to permit the comment period that began on August 6, 2013 as well as any subsequent comment period prior to a final ballot of Phase 2 of the Definition of Bulk Electric System. The waiver allows the comment periods to be shortened from 45 days to 30, with a ballot during the last ten days of the comment period. Minutes of the Standards Committee's meeting where the waiver was considered have been posted on the NERC website.

Standards Announcement

Project 2010-17 Definition of Bulk Electric System Phase 2

Additional Ballot Results

Now Available

An additional ballot for Phase 2 of the **Definition of Bulk Electric System** concluded at **8 p.m. Eastern on Tuesday, October 29, 2013.**

The definition achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the additional ballot.

Approval
Quorum: 75.83%
Approval: 72.55%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the definition. If the comments do not show the need for significant revisions, the definition will proceed to a final ballot.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2010-17 Definition of BES - Phase 2 Oct 2013
Ballot Period:	10/18/2013 - 10/29/2013
Ballot Type:	Additional
Total # Votes:	298
Total Ballot Pool:	393
Quorum:	**75.83 % The Quorum has been reached**
Weighted Segment Vote:	72.55 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	104	1	53	0.736	19	0.264	0	7	25
2 - Segment 2	8	0.5	4	0.4	1	0.1	0	2	1
3 - Segment 3	90	1	42	0.689	19	0.311	0	7	22
4 - Segment 4	36	1	19	0.679	9	0.321	0	1	7
5 - Segment 5	88	1	42	0.7	18	0.3	1	6	21
6 - Segment 6	51	1	23	0.657	12	0.343	0	1	15
7 - Segment 7	2	0.1	0	0	1	0.1	0	0	1
8 - Segment 8	2	0.1	1	0.1	0	0	0	0	1
9 - Segment 9	4	0.2	2	0.2	0	0	0	0	2
10 - Segment 10	8	0.8	7	0.7	1	0.1	0	0	0
Totals	**393**	**6.7**	**193**	**4.861**	**80**	**1.839**	**1**	**24**	**95**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Big Rivers Electric Corp.	Chris Bradley		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	Amber Anderson	Affirmative	
1	El Paso Electric Company	Dennis Malone		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	COMMENT RECEIVED
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	

1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	Memphis Light, Gas and Water Division	Allan Long		
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnesota Power, Inc.	Randi K. Nyholm	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	North Carolina Electric Membership Corp.	Robert Thompson		
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke		
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle		
1	Oncor Electric Delivery	Jen Fiegel		
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted under name of PPL Corporation)
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group))
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	

1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Negative	COMMENT RECEIVED
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu		
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe DePoorter, MGE)
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz from American Electric Power)
3	Alabama Power Company	Robert S Moore	Abstain	
3	Alameda Municipal Power	Douglas Draeger		
3	Ameren Services	Mark Peters	Affirmative	
3	Arkansas Electric Cooperative Corporation	Philip Huff		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	SUPPORTS THIRD PARTY COMMENTS - (see AECI comments)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Palo Alto	Eric R Scott	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	City of Ukiah	Colin Murphey		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	

3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	COMMENT RECEIVED
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	East Kentucky Power Coop.	Patrick Woods	Affirmative	
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger		
3	Fayetteville Public Works Commission	Allen R Wallace		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Abstain	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover		
3	Gulf Power Company	Paul C Caldwell	Abstain	
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative Inc)
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Kootenai Electric Cooperative	Dave Kahly		
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Reliability Standarsds Review Group)
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC registered affilitiates)
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative Inc.)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - Gary Kruempel MidAmerican
3	Mississippi Power	Jeff Franklin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	North Carolina Electric Membership Corp.	Doug White		

3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Oklahoma Gas and Electric Co.	Donald Hargrove		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller		
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	Southern California Edison Company	David B Coher		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barbara Kedrowski, Wisconsin Electric Power Co)
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Breene, WPSC)
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy's)
4	Alabama Municipal Electric Authority	Raymond Phillips		
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	COMMENT RECEIVED
4	Arkansas Electric Cooperative Corporation	Ronnie Frizzell		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Buckeye Power, Inc.	Manmohan K Sachdeva	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry

				Farringer)
4	Cowlitz County PUD	Rick Syring		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Breene – WPSC)
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	COMMENT RECEIVED
4	Modesto Irrigation District	Spencer Tacke	Negative	COMMENT RECEIVED
4	National Rural Electric Cooperative Association	Barry R. Lawson	Abstain	
4	North Carolina Eastern Municipal Power Agency	Cecil Rhodes	Affirmative	
4	North Carolina Electric Membership Corp.	John Lemire	Negative	SUPPORTS THIRD PARTY COMMENTS - (North Carolina Electric Membership Corporation)
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (B. Galbraith-Seminole Electric Cooperative.)
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski, We Energies)
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Cooments provided by AZPS)
5	Arkansas Electric Cooperative Corporation	Brent R Carr		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly	Affirmative	

5	Brazos Electric Power Cooperative, Inc.	Shari Heino		
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Buckeye Power, Inc.	Paul M Jackson		
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Michael Shultz		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Gerry Farringer, Consumers Energy)
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Alexander Eizans	Negative	COMMENT RECEIVED - Kent Kujala of Detroit Edison
5	Detroit Renewable Power	Marcus Ellis	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	El Paso Electric Company	Gustavo Estrada		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Negative	SUPPORTS THIRD PARTY COMMENTS - (AWEA)
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Reliability Standards Review Group)
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (North Carolina Electric

				Membership Corporation)
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	COMMENT RECEIVED see NIPSCO Joe O'Brien's comments
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	David Ramkalawan		
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Ryan Millard	Negative	COMMENT RECEIVED
5	Pattern Gulf Wind LLC	Grit Schmieder-Copeland		
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith on behalf of Seminole Electric Cooperative Inc.)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to SCE's comment)
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barbara Kedrowski, Wisconsin Electric Power Co.)
5	Wisconsin Public Service Corp.	Scott E Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Breene - WPSC)
6	AEP Marketing	Edward P. Cox		

6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Arkansas Electric Cooperative Corporation	Keith Sugg		
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	El Paso Electric Company	Luis Rodriguez		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Lincoln Electric System	Eric Ruskamp	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Reliability Standards Review Group)
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Affirmative	
6	North Carolina Municipal Power Agency #1	Matthew Schull	Affirmative	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oklahoma Gas & Electric Services	Jerry Nottnagel		
6	PacifiCorp	John Volz	Negative	COMMENT RECEIVED - Ryan Millard
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Ty Bettis		
6	Power Generation Services, Inc.	Stephen C Knapp		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - Christina Koncz PSEG - (PSEG - Submitted by John Seelke)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith will be submitting comments on behalf of Seminole Electric Cooperative, Inc.)

6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern California Edison Company	Joseph T Marone	Negative	COMMENT RECEIVED
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway	Negative	SUPPORTS THIRD PARTY COMMENTS - (Please Tom Breene's comments submitted on behalf of Wisconsin Public Service.)
6	Xcel Energy, Inc.	David F Lemmons	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland, Xcel Energy)
7	Alcoa, Inc.	Thomas Gianneschi	Negative	COMMENT RECEIVED
7	EnerVision, Inc.	Thomas W Siegrist		
8		Edward C Stein		
8		Debra R Warner	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
9	New York State Department of Public Service	Thomas G. Dvorsky		
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Negative	COMMENT RECEIVED
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	

Individual or group. (40 Responses)
Name (27 Responses)
Organization (27 Responses)
Group Name (13 Responses)
Lead Contact (13 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (2 Responses)
Comments (40 Responses)
Question 1 (35 Responses)
Question 1 Comments (38 Responses)
Question 2 (31 Responses)
Question 2 Comments (38 Responses)

Individual
Bangalore Vijayraghavan
Pacific Gas and Electric Comapny
Yes
We support the definition as posted and commend the drafting team for considering the comments from the industry and weighing those industry comments against the FERC directives. Many of the industry comments take a different direction and opinion from the FERC directives and we recognize that the definition is a compromise on the positions of all stake holders. It provides a bright line that will improve reliability and provide a consistent process across North America to address exceptions.
No
Individual
John Falsey
Invenergy LLC
Agree
AWEA
Individual
Thomas Foltz
American Electric Power
Yes
Yes
AEP cannot vote in the affirmative on this project as long as BES elements (measured for compliance) are as granular as the individual dispersed power resource. We do not see the reliability benefit (nor has the project team provided technical justification) of tracking all of the compliance elements for individual wind turbines when the focus should be placed on the aggregate of the facility. Does the RC want to be notified of an outage of each individual wind

turbine in real-time, or a loss of significant portion of the wind farm? If we are not careful, we will have entities at these resources and others monitoring them (BAs, TOPs, RCs) focusing on minor issues that will distract from more relevant reliability needs.
Group
Northeast Power Coordinating Council
Guy Zito
No
The use of the word “capacity” is a concern. Generators might not be considered BES under the definition. Suggested change to I4 as follows: I4 - Dispersed power producing resources that aggregate to a gross total nameplate rating greater than 75 MVA, and that are connected through a system designed primarily for delivering such energy to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are: a) The individual resources, and b) The system designed primarily for delivering energy from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.
No
Individual
David Jendras
Ameren
Yes
Yes
(1) When the SDT updates the Reference (Guidance) Document, we request a couple of additions to help clarify Exclusion E3. We ask the SDT to include System Diagram examples with a 138kV Local Network (LN) for which Real Power only flows in (from 138 to 69kV) and embedded within this LN is a 69kV network with multiple generating units. Note that none of these generators are Blackstart Resources or Dispersed power resources. We believe that the left side of your Figure S1-9b could be adapted to do this. Please add the two following examples: (a) First, a 69kV network that serves load at multiple substations and has three different substations each with a single 13.8/69kV GSU for a single 19MVA generator with an aggregate capacity of (3 x 19 MVA =) 57MVA within the entire 138kV LN; and (b) Second, the same diagram as item 1a plus one additional single 13.8/69kV GSU for a single 50MVA generator to provide an aggregate capacity of (3 x 19 MVA + 50 MVA =) 107MVA within the entire 138kV LN . Our understanding is that the 138kV leads to the 138/69kV transformers are all excluded via Exclusion E3; and that neither the entire 69kV network nor any of the embedded generation (aggregate 57 MVA for the first example or 107MVA for the second example) should be included by any BES Inclusion. (2) When the SDT updates the Reference (Guidance) Document, we request one additional item to help clarify Inclusion I2. We ask the SDT to add a new Figure I2-7 similar to Figure I2-6. In this new Figure I2-7, we request that the >100kV / <100kV transformer on the right be removed and connected to another <100 kV location in the network. The generator on the right with GSU high side <100kV should be changed from 25 MVA to 88 MVA. This generator is neither a black-start resource nor a

dispersed power resource and therefore should not be included by Inclusions I3 or I4, and our understanding is that the 88 MVA generator is also not included by Inclusion I2.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
No
The definition should not apply to individual dispersed units that are less than 5 MW because independent units less than 5 MW are too small to have an impact on the BES.
Yes
Everything that has been excluded from the BES definition should also be excluded from I5 for reactive sources, because there is no impact to the BES. For example, if a radial system (E1) is excluded because it does not have an impact on the BES, a reactive resource connected at the end of the radial system is not likely to have an impact on the BES either.
Individual
Joe O'Brien
NIPSCO
Yes
We appreciate your consideration of our previous comments and a draft interpretation However since such interpretations and a guidance document are already being developed for this draft standard, more clarification is probably needed within the standard itself.
Individual
Kathleen Goodman
ISO New England, Inc.
No
The use of the word “capacity” is a concern. Below is suggested language. I4 - Dispersed power producing resources that aggregate to a total gross nameplate rating greater than 75 MVA, and that are connected through a system designed primarily for delivering such energy to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are: a) The individual resources, and b) The system designed primarily for delivering energy from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.
Individual
Russell A Noble
Cowlitz PUD
No
We understand the difficulty of backtracking on past progress. We have voted in the affirmative for the greater objective of not impeding the overall positive progress of the definition. However, we acknowledge the industry has identified a valid concern over I4, and although the SDT is powerless to correct the issue, it is important to record and document

reservations so future efforts in standard development may be facilitated to correct problems with compliance overreach. Most of the I4 facilities that will be included into the BES inherently work against reliability, and this characteristic can't be mitigated by adherence to the current GO/GOP standards in place. For example, assuring an individual generator protection system of a wind/solar unit will not misoperate adds little protection to the BES when the unit is frequently down due to insufficient wind or sunshine. It is a fact that such generation can't be designated as must run, and instead other generation units which can be dispatched must be available on demand to replace lost wind/solar resources. Therefore, we admonish FERC and NERC to recognize the true nature of wind and solar resources as an effort to reduce carbon footprint on the environment and are not intended to replace dispatchable generation, and that compliance without any reliability return should be removed to facilitate its development.
No
Individual
Kenneth A Goldsmith
Alliant Energy
No
No
No - Alliant Energy still believes strongly that including individual dispersed generators (I4) as part of the BES does nothing to maintain/increase the reliability of the BES, and creates an extremely difficult compliance process. It will also create a very large backlog of exception requests, as most dispersed generator owners will request an exception for their generators.
Individual
Gerald G Farringer
Consumers Energy
No
The inclusion and the clarification of the inclusion seem to contradict each other. The highlight portion above seems to indicate inclusion only from the point of aggregation of 75MVA or above. This, in most Wind Park cases would include a collector bus but probably not individual wind turbines. However I4 seems to indicate that the case of a Wind Park that has a total aggregation of 75 MVA, all associated equipment including every individual wild turbine would be included. There is inconsistency. Technical justification should be needed to include resources in the BES, not the other way around. Is there a real expectation that a single collector circuit containing ten, 1.2MW wind turbines can cause cascading or uncontrollable outages of the surrounding system? It is extremely doubtful. Consumers Energy supports the inclusion of equipment where the aggregation of 75 MVA or more connects to the Bulk Electric System at voltages of 100kv or greater. There is a clear indication here that a single contingency can remove the total of the capacity from the system where with the proposed inclusion does not. Administrative burden and compliance risk must be weighed against reliability gain. Including individual wind turbines rather than the aggregate of the wind farm increases such burden without any reliability gain.

No
Individual
Joseph G DePoorter
Madison Gas and Electric Company
No
MGE does not understand why individual dispersed power resources remain to be include as we clearly stated during the last comment period. The SDT has stated that no technical rational to support there removal. FAC-001 and FAC-002 are mandatory enforceable Standards that entity's must follow. These Standards provide the justification as pointed out in our last set of comments. The SDT has stated in order to fix this, an addition SAR would be submitted (such as the GOTO) to "fix" this issue. Why would the ERO what to expend resources to fix something after the fact when the SDT has the ability to fix it now. The removal of I4a will solve this issue. If individual resources need to be in based on system instability issues, then this can be addressed at a later date, once it is proven that individual resources need to be considered part of the BES and the individual resources cause BES instability.
No
Group
North Carolina Electric Membership Corporation
Scott Brame
No
We have voted affirmative for this project in the past but are now changing our vote to negative based on the changes made to I4. We feel that the drafting team has further complicated the BES definition by the proposed language in Inclusion I4. According to the Phase 1 definition, dispersed power producing units would only be included if the units reached the 75 MVA aggregate threshold. There is nothing in the Phase 1 definition that would include collector system equipment. The Phase 2 definition is problematic because there is uncertainty regarding the scope of equipment that that would be included as a portion of the collector system. This ambiguity has raised concerns that regional compliance staff may ultimately determine a different set of equipment is included in the BES than the registered entity will leaving the burden on the registered entity to argue why certain elements should not be included in the BES. This will lead to inconsistent compliance outcomes. We cannot support a definition with vague and ambiguous language that could result in negative compliance implications during registration, audits, and enforcement processes. Furthermore, we do not believe any part of the collector system should be included in the definition.
No
Individual
RoLynda Shumpert
South Carolina Electric and Gas

Yes
No
Individual
Nazra Gladu
Manitoba Hydro
Yes
No
Individual
Marie Knox
MISO
Agree
Madison Gas & Electric
Individual
Alice Ireland
Xcel Energy
No
In several prior comment periods, we have asked many technical questions of the BES SDT, and continue to get generic non-substantive replies. While a majority of our questions still remain unanswered, we have elected to not submit them again. However, we believe it is especially important to understand the SDT's response to this question. When considering a wind farm that would qualify as BES under the currently drafted version, it seems inconsistent that a 2 MVA individual dispersed generator is deemed significant to reliability, while the equipment that is utilized to connect a sub-set of the individual dispersed generators totaling to <75 MVA is deemed not significant to reliability. Please explain the technical rationale for concluding that an individual dispersed generating asset rated at 2 MVA is important to grid reliability but that a collector feeder for a sub-set of these generators which may impact up to 35 (70 MVA) of these individual dispersed generating assets is not critical to reliability?
Yes
2. We appreciate that the BES SDT acknowledges that numerous existing and pending standards will need to be reviewed and revised to clarify standard applicability to individual generating units. However, we do not believe that implementation of the BES definition should go forward until this review and revision of other standards has been completed. Therefore, we recommend the implementation plan for the BES definition be contingent upon the completion of modification to applicable GO/GOP requirements. Otherwise, there will simply be too much ambiguity in the requirements as they apply to individual dispersed generating assets, there will be too much compliance effort spent on trying to apply these ambiguous requirements with no commensurate gain in reliability, and in the end many of the requirements will change and possibly no longer apply.
Individual

Thomas Breene
WPSC
No
As our previous comments have indicated, we agree with including the Generating stations with dispersed generation from the point of aggregation to 75 MVA as I4-b does. We also agree with the statement made on the BES Phase II webinar of August 21 that this is the point where the dispersed power plant is significant to the reliability of the BES. We continue to disagree with including the individual resources themselves since, as indicated on the previously referenced webinar, they are not significant to the reliability of the BES. The technical rationale for not including dispersed power producing resources has been included in many past comments and will not be restated here. Compliance with most protection system and equipment rating standards is not possible for individual BES wind turbines without revisions to the standards, or at best without significant resources to apply existing standards to individual units. Some of the standards effected include PRC-004-2a, FAC-001, FAC-003, FAC-008-3, MOD-024, MOD-025, MOD-026, MOD-027, PRC-005, PRC-006-SPP-01, PRC-019, PRC-024, PRC-025, and TOP-003. But we continue to stress that including an I4a will require significant resources in personnel and modifications or result in fast-tracking Standard changes to make compliance possible with no improvement in reliability of the BES. These resources would be better utilized elsewhere to actually improve reliability.
No
Group
ACES Standards Collaborators
Ben Engelby
No
We feel that the drafting team has further complicated the BES definition by the proposed language in Inclusion I4. According to the Phase 1 definition, dispersed power producing units would only be included if the units reached the 75 MVA aggregate threshold. There is nothing in the Phase 1 definition that would include collector system equipment. The Phase 2 definition is problematic because there is uncertainty regarding the scope of equipment that that would be included as a portion of the collector system. This ambiguity has raised concerns that regional compliance staff may ultimately determine a different set of equipment is included in the BES than the registered entity will leaving the burden on the registered entity to argue why certain elements should not be included in the BES. This will lead to inconsistent compliance outcomes. We cannot support a definition with vague and ambiguous language that could result in negative compliance implications during registration, audits, and enforcement processes. Furthermore, we do not believe any part of the collector system should be included in the definition.
No
Individual
Patrick Farrell
Southern California Edison Company

No
Phase 2 of the BES definition characterizes dispersed power producing resources as being “small-scale” power generation technologies. However, although this characterization is currently the norm, that could easily change in the future. As written, I4 creates an ambiguity for Dispersed Power Producing Resources that are greater than or equal to 75MVA, because these generation resources appear to be included within the BES under both the I2 and I4 inclusions. The problem this creates is that I2 and I4 address the connection facilities differently, with I2 beginning at the generator terminals, while I4 begins at the point where the resources aggregate to greater than 75 MVA. SCE believes that the SDT should clarify which of these inclusions should apply to dispersed power producing resources greater than or equal to 75MVA. SCE is also concerned about how I4 could potentially discourage the development of common points of interconnection (i.e. collector substations) for multiple projects in queue, especially in relation to the E1 and E3 exclusions. In SCE’s experience, “plans of service” that include common collector substations for multiple generation projects can be an effective way to encourage development of renewable resources in renewable-rich areas. However, such resources develop and interconnect as individual projects under separate development paths. The first distributed generation projects connecting to such stations may find their resources initially classified as non-BES if the aggregate generation is less than 75 MVA. However, later projects connecting to the same common point could find the BES status changing as additional generation projects materialize at the same collector substation. SCE is concerned that this will discourage dispersed generation developers from pursuing common points of interconnection at collector substations built for such purpose in renewable rich areas. The aggregate total of the projects further down the interconnection queue could also trigger system upgrades, based on TPL studies for which the owners of these projects would be responsible.
Yes
The 75 MVA hurdle is nothing more than an arbitrary number being used to denote/provide a threshold for identifying the amount of generation that has a significant effect on the BES. This number does not consider the most significant part of what should be encapsulated in the definition which is what the “function” of the facility(ies) are with respect to a bulk electric system operated as an integrated network.
Individual
Thomas Gianneschi
Alcoa, Inc.

Yes
An additional concern the standards development team has not adequately addressed is the technical justification for placing compliance requirements on newly registered industrial facilities resulting from the adoption of this definition.
Group
SPP Standards Review Group
Robert Rhodes

No
While we understand that FERC has basically directed the drafting team to include individual dispersed power producing units in the BES, we are concerned about the need for coordination between drafting teams for other reliability standards, such as PRC-004, PRC-005, FAC-008, etc, which may be impacted by the inclusion of these generating units into the BES. Have steps been taken to ensure that this coordination has taken place?
No
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia
Wayne Johnson
No
Eliminate Inclusion I4.a. If an individual generating element of a dispersed power producing facility is 20 MVA or larger at a facility rated at 75 MVA or larger it should be included. At Inclusion I4.b, Southern disagrees with the premise that BES elements (measured for compliance) should be applied to the individual dispersed power elements. We do not see the reliability benefit of tracking all of the compliance elements for individual wind turbines when the focus should be placed on the aggregate of the facilities. The proposed approach is similar to applying NERC requirements to the individual coils of a large generator. The subject inclusion should limit the applicability of the BES to the collector bus and the capacity at this point should be 75 MVA or greater to qualify as a BES element.
Yes
Southern Transmission believes that Exclusion E3 should include a limit on the size of a Local Network (LN). The facilities that will comprise these LNs are currently part of the BES and subject to all applicable standards. To allow these facilities to now be excluded from the BES without regard to some size limitation could result in negative impacts on the BES in the future. Southern Transmission believes that without placing a size limitation on such a network, a single contingency could result in significant flows across the BES to serve the LN from a different location. Additionally, there is concern that the exclusion has no requirement for power to only flow into the LN for N-1 conditions. Southern Transmission does agree that there may be limited locations where such an exemption could be appropriate, but would prefer to see the facilities initially included in the BES and have the Transmission Owner go through a review process with the Regional Reliability Organization to provide justification for classifying facilities as a LN.
Individual
Gary Kruempel
MidAmerican Energy Company
No
MidAmerican continues to believe that individual dispersed generating units should be excluded from Inclusion I4 of the revised BES definition. MidAmerican does not agree with the SDT’s characterization in the question that no technical rationale was offered by any stakeholder to support removal of the individual units from Inclusion I4. It is MidAmerican’s

understanding that at least several commenting entities have provided sound technical arguments to support the exclusion of individual dispersed generating units. While it may be the case that the SDT does not believe the technical justifications offered by entities have been compelling, the SDT has not provided a complete analysis to the industry refuting each of the technical arguments provided by registered entities. After all, a primary objective of Phase II of the BES definition project was to carefully consider additional technical arguments that would further refine the revised definition, including with regard to individual dispersed generating units. MidAmerican agrees with the SDT that one suitable solution to address the inclusion of individual dispersed generating facilities may be via adjustments to individual standards' applicability sections. For example, Reliability Standard MOD-025-2 (pending approval at FERC) includes a provision addressing real power testing for variable generating facilities. In order to accomplish the recommended case-by-case review, however, a Standard Authorization Request would likely need to be prepared to commence the NERC standards development process for each potentially impacted standard. In that case, it is more appropriate and efficient to exclude such facilities from Inclusion I4 and then initiate changes to a limited number of impacted standards that should actually apply to individual dispersed generators, rather than initiate individual projects to modify a larger pool of standards for which the application to such generators is not appropriate to promote reliability.
No
Individual
Randi Nyholm
Minnesota Power
No
Minnesota Power does not believe that 2 MW generators, whether or not they aggregate to 75 MW, should be included in the definition of Bulk Electric System when the distribution transformers that control multiple units are not included. Furthermore, a non-contiguous Bulk Electric System is problematic for maintaining reliability.
Group
Dominion
Louis Slade
Yes
No
Individual
Don Streebel
Idaho Power Co.
Yes
Yes
While we still do not agree with the categorical inclusion of individual dispersed power producing units into the BES, we do recognize the SDT's good faith effort to comply with FERC

Orders 773 and 773-A. We understand that modeling of dispersed power producing resources in WECC base cases will follow regional requirements governed by regional standards.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
Yes
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. 1. The PPL NERC Registered Affiliates previously commented that the language of the proposed BES definition is subject to multiple interpretations and is therefore difficult to apply correctly without the Reference Document. The Reference Document is not complete or final for the Phase 2 BES definition, however. The Reference Document contains a disclaimer on p.1 that states “…this reference document is outdated. Revisions to the document will be developed at a later date to conform to the definition being developed in Phase 2.” In response to the PPL NERC Registered Affiliates’ concerns regarding the unavailability of a Reference Document to reflect the Phase 2 BES definition, the SDT stated in response that it “did not intend the posted version to represent a full implementation of Phase 2 as Phase 2 isn’t complete.” The PPL NERC Registered Affiliates are concerned by this response because, unless it is clarified, the existing Phase 1 Reference Document could be interpreted to bring into the Phase 2 BES definition facilities that are not, and do not need to be, part of the BES. For example, the words in the existing Reference Document may imply that NERC registration for very small, standby, non-Blackstart Resource generators feeding the auxiliary buses of generation plants for emergency purposes is required. Specifically, Figure I2-5 of the Reference Document states that all units in a plant are part of the BES regardless of size, if the plant totals more than 75 MVA, if they "contribute to the gross aggregate rating of the site." The SDT said in response to our earlier comments regarding small standby diesels that, “The intent of the SDT is that the precedent will not change how the identified equipment is classified.” However, Figure I2-5 of the Reference Document appears to do exactly that. If for example a 500 MW plant has a 2 MW diesel generator feeding the 4kV bus for emergency purposes (but not as a Blackstart Resource), the facility could be said to have a gross aggregate nameplate rating of 502 MW when the diesel is running – the aggregate nameplate rating has increased. Fig. I2-5 moreover includes in the BES units that feed transformers with a high-side voltage less than 100 kV, if their output is eventually stepped-up to a plant outlet that is > 100 kV. While, one could cite Fig. S1-9b,as indicating that generators feeding a bus that is exclusively an importer of power are not part of the BES, it would be far better to state matters explicitly in the first place. The contribute-to-aggregate-capability language of the present (and outdated) Reference Document does not appear in the BES definition and it is unclear. Item I2b of the BES definition should therefore be accompanied by a footnote saying that, “Standby and emergency generators

that feed auxiliary buses are not considered in determining the plant/facility aggregate nameplate rating," or "Standby and emergency generators are not considered in determining the plant/facility aggregate nameplate rating if they feed an auxiliary bus that is a net importer of power." Further, an example should be added to the Resource Document that shows that Emergency Diesels and standby units that feed auxiliary buses that are net importers of power are not part of the BES (unless they are Blackstart Resources). 2. The PPL NERC Registered Affiliates also previously commented that the generic term "nameplate rating" should be replaced by the NERC-defined term "Facility Rating." The SDT declined to make this change, because it stated Facility Ratings, "fluctuate from period to period. " The PPL NERC Registered Affiliates continue to believe that the use of the term "Facility Rating" is more appropriate. Consider for example four simple-cycle CTs rated at 19 MVA each (76 MVA total) that are connected to a 115 kV line through a single GSU rated at 72 MVA. This in a 72 MVA plant (because of the most limiting component) and would therefore not presently be part of the BES, but it could be pulled-in depending on whether one focuses on the nameplate rating of the generators or the most-limiting component (in this case the GSU). The Reference Document suggests that the former approach applies, because in every single depiction of generation units it cites only generator ratings and ignores GSU capability. Furthermore, using generator nameplate ratings can in certain circumstances lead to confusion because some generators (e.g., simple cycle CTs) can have multiple ratings (e.g., baseload, peaking and emergency ratings). To avoid this confusion, the proposed definition should be based on the "nameplate rating of the most-limiting component," which in the example here presented is 72 MVA (and is also the Facility Rating). Therefore, Inclusion I2 should be revised to read as follows: a) Gross nameplate rating of the most-limiting component of an individual unit greater than 20 MVA, Or, b) Gross aggregate nameplate rating of the most-limiting component(s) of a plant/facility greater than 75 MVA Additionally, the Reference Document should be changed to provide at least one example of GSU MVA values setting the most limiting criterion.
Individual
Barbara Kedrowski
Wisconsin Electric Power Company
No
Wind generators and solar panels are intermittent resources that are not as dependable as other sources for supporting grid reliability. A sudden drop in wind speed or solar intensity will instantaneously reduce the MW output of all the individual wind turbines or solar panels in the area. It follows then that a single wind turbine or solar panel could not be an Element or Facility necessary for the reliable operation and planning of the interconnected bulk power system. However, common mode failure of multiple turbines or solar panels could be significant to the reliability and planning of the BES. Efforts should be focused on preventing / mitigating the loss of multiple generators with an aggregated capacity of greater than 75MVA. Therefore the elements necessary for the reliable operation and planning of the interconnected bulk power system are the devices that are located where the power is aggregated, and not the individual generators. If individual small generators that are a part of

an aggregated facility of 75 MVA or larger (e.g. a 75 MVA wind or solar farm) are considered a part of the BES due to that aggregation, the NERC Standard requirements should only be applied to the aggregation (e.g. the interconnection with the transmission system) and should not be applied to individual generators of less than 20 MVA. This would be consistent with the NERC registration criteria for single and multiple generators at a site.
Individual
Bret Galbraith
Seminole Electric Cooperative, Inc.
No
The drafting team has proposed revised changes to a requirement concerning distributed generation. In particular, when distributed generation, e.g., wind turbines, accumulate to more than 75 MVA, only the turbines and the equipment collecting/transferring more than 75 MVA is covered as BES equipment. This allows for scenarios where non-BES equipment might be located between two separate groups of BES equipment. Seminole does not believe this is FERC's intent. Seminole acknowledges that FERC did not specifically address distributed generation in past orders when attempting to correct the BES language that resulted in having non-BES equipment separate groups of BES equipment. However, Seminole does not believe the drafting team's reasoning is sufficient for this exception. Seminole believes that all of the equipment in this scenario should be either BES-regulated or non-BES (non-NERC) regulated.
Additionally, Seminole is re-submitting the following comments from past ballots, because Seminole still believes that these comments are practical requests that should be incorporated into the BES definition. (1) The terms "plant" and "facility" are not defined and are ambiguous. Please provide quantitative and/or qualitative factors that an entity can utilize in determining what is a plant or facility. See Inclusion I2. Seminole acknowledges that there is draft guidance covering these terms; however, Seminole reasons that descriptive language covering these terms should be passed in conjunction with the BES definition. (2) The following note will be placed in the Reference document: "Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system." Please strike the phrase "or an enhancement of," as it is more of a persuasive statement than an objective statement. (3) In Exclusion E1(c), please clarify that reactive devices, such as capacitor banks, can also be included in this section. Reactive devices are differentiated from real power devices in Inclusion I2, so we request clarification that reactive devices can be included in Exclusion E1(c), i.e., please add clarification to the definition.
Group
Duke Energy
Michael Lowman
Yes
Duke Energy supports the proposed clarifications to I4 made by the SDT.

No
Individual
Michael Goggin
American Wind Energy Association
No
1. The technical rationale for not including individual generators in the BES definition is that these individual generators cannot affect BES reliability. Whatever technical rationale drove the drafting team's decision to not include the collector array components in the BES definition would also dictate that the individual turbines connected by that collector array should also not be included in the BES definition. We cannot think of any technical rationale that would justify including individual wind turbines in the definition but not including the collector array that aggregates those individual generators. Regardless, the burden for providing technical rationale should fall on the drafting team to demonstrate that including individual generators will improve electric reliability. That burden has not been met, and the standards drafting team has made no attempt to provide that rationale, despite repeated requests to do so. As explained below, that burden cannot be met, as there is no benefit to including individual generators, and including them in the definition is only likely to provoke significant confusion that distracts from real efforts to improve electric reliability. The only compelling reason for applying BES standards to individual dispersed generators would be if there were a real risk of an abrupt common mode failure affecting a large share of the dispersed generators in a >75 MVA wind plant. However, per FERC Order 661A, wind turbine generators already comply with voltage and frequency ride-through standards that are far more stringent than those that apply to other types of generators. As a result, if a common mode failure caused by a grid disturbance were to affect the wind turbines in a >75 MVA wind plant, the impact on the wind plant would be irrelevant for grid reliability because the voltage and/or frequency deviation would have already caused most if not all of the conventional generators in the grid operating area to trip offline. While weather-driven changes in wind speed can significantly change the aggregate output of a wind plant, those changes in output occur too gradually to pose a risk to bulk power system reliability, and regardless such changes in output would not be regulated or mitigated by BES-relevant standards. No compelling rationale has been offered for why including individual dispersed wind turbine generators in the BES definition will improve grid reliability. Until one is offered, we will continue to oppose the inclusion of individual wind turbine generators in the BES definition. 2. We request clarification on the intent of the FERC direction provided in Orders 773 and 773-A regarding inclusion of dispersed generation, as we disagree with the standards drafting team's interpretation that those orders required the inclusion of individual dispersed generators. After careful study, it appears that the proposed standard for the I4 inclusion of dispersed generation is broader in scope than the intent as stated in the Orders. The critical language appears in Order 773-A, under item number 54. Here, FERC approves the dispersed power inclusion I4, "…finding it provides useful granularity…", and that it agreed it is appropriate "to expressly cover dispersed power producing resources utilizing a system designed primarily for aggregating capacity." We believe that the second sentence should be

further examined for proper intent. Our interpretation of this sentence is that collector systems aggregating dispersed power at a level of 75 MVA or more is the level of intended inclusion. This means that, in the example of a wind farm larger than 75 MVA, the application of the BES definition and all the requisite applicable standards is only at points where the aggregated capacity is greater than 75 MVA. This interpretation has several advantages: it is consistent with the current output threshold value; it does not establish a new, lower threshold for the BES definition; and it applies requirements where appropriate, i.e. equipment that carries 75 MVA and is therefore of sufficient size to be relevant to the reliability of the BES. Aggregator collection systems are designed to employ protection system equipment at the aggregation node, as well as operational output status monitoring equipment, and other equipment important to support grid reliability and monitoring at that aggregation point. Nowhere in the relevant FERC Orders does the language expressly require the inclusion of individual dispersed generators (PV panels, wind turbines, flywheels, microturbines, etc.). We believe that deletion of I4 (a) meets the intent of the FERC direction and properly supports grid reliability. 3. FERC Order 773-A goes on to say in part 60 that, indeed, dispersed power producers with greater than 75 MVA nameplate capacity are already registered. For many registered entities across the country, the interpretation has been to apply the body of NERC standards at the point of aggregation. This regional entity interpretation of NERC standard applicability at the aggregation point is comparable to the interpretation described above, and is based on sound reliability thresholds and knowledge of dispersed power system design. 4. The term "individual resources" utilized in I4 (a) is unclear, and could refer to the wind plant as a whole. What constitutes an "individual resource?" More technically precise language should be utilized to specifically identify what resources are intended to be included per this bullet. 5. In the last two postings, we and other commenters have asked specific technical questions that have not been answered. Instead, we have received only a generic reply that the SDT believes our concerns would best be addressed through clarification of the applicability of individual reliability standards. Please provide specific replies to the following questions: a. In the August 21, 2013 webinar, the BES definition drafting team indicated that its justification for the 75 MVA aggregating threshold in I4 (b) was that 75 MVA is the level that the drafting team believes that single failures resulting in the loss of generation could have an appreciable impact on the grid. It seems inconsistent that a 2 MVA individual dispersed generator is deemed significant to reliability but the equipment that is utilized to connect individual dispersed generators totaling to <75 MVA is deemed not significant to reliability. Please explain the technical rationale for concluding that an individual dispersed generating asset rated at 2 MVA is important to grid reliability but that a collector feeder which may impact up to 37 of these individual dispersed generating assets is not critical to reliability? b. Since the collector feeders are excluded from the BES definition so that there is not a contiguous BES connection between the individual dispersed generating asset and the grid, please explain the technical rationale for concluding that an individual 2 MVA dispersed generator at a facility rated at greater than 75 MVA has more impact on the BES than does an identical 2 MVA dispersed generator at a facility rated at less than 75 MVA? If the impact on grid reliability of both units is the same, why is one considered BES and the other is not? c. In the Consideration of Comments document for the first draft of the Phase II BES definition, the Drafting Team acknowledged that there are both existing and pending reliability standards which likely will need to be reviewed and revised to clarify or correct the applicability of the standard requirements to dispersed generation. Please identify the reliability gaps being addressed by including individual dispersed generating assets within the BES definition. In other words, what specific existing or pending NERC Reliability Standard Requirements are perceived as being needed to be applied to individual dispersed generating assets to maintain grid reliability? 6. We appreciate that the SDT acknowledges that numerous existing and pending standards will need to be reviewed and revised to clarify standard applicability to individual generating units. However, we do not believe that implementation of the BES definition should go forward until this review and revision of other standards has been completed. Relative to the approval and implementation time frames being discussed for the new BES definition, we do not believe any such action could be taken in a timely enough fashion to resolve industry uncertainty and avoid a major regulatory burden that would distract from efforts that actually improve grid reliability. Without that review, there will simply be too much ambiguity in the requirements as they apply to individual dispersed generating assets and there will be too much compliance effort spent on trying to apply these ambiguous requirements with no commensurate gain in reliability. As currently written, the definition will create much regulatory uncertainty in how auditors will assess an entity's compliance with these ambiguous requirements. Including individual dispersed generators in the BES definition will cause a major diversion away from efforts that improve BES reliability, as entities are forced to simultaneously seek relief via the Exception Process to exclude individual dispersed generators that are insignificant from a reliability standpoint from their programs while at the same time attempting to modify their existing compliance programs to accommodate individual dispersed generators in the event that the exception applications are not approved. With more than 45,000 wind turbines installed in the U.S. and the vast majority of them in wind plants larger than 75 MVA, NERC will be faced with a huge backlog of exception requests for small distributed generators while Generator Owners with dispersed generating assets struggle to implement reliability standards that were never drafted with the intent of being applicable to anything but large scale generating stations. As a result, proceeding with the BES definition as currently drafted would actually impair, rather than improve, bulk electric system reliability. Examples of standards that were not drafted with small dispersed generators in mind include: • PRC-005-2 Protection System testing – the relay test requirements were developed with large generators in mind, and differ significantly from requirements in FERC Order 661A, of 2005 that require wind plants to meet Low Voltage Ride-Through (LVRT) and Power Factor Design Criteria. These standards significantly change the protection scheme applied to individual turbines, and there is no clarity about how they should be applied. Wind turbine protection systems are often integral to the wind farm control system and the PRC-005-2 requirements were developed for protection equipment typically applied to large-scale generation, not wind farm control systems. • TOP-002 Normal Operations Planning – Under R14 of this standard, an unplanned outage for any individual wind turbine would require a status notification report from the GO to the TO/TOP. While such a report can be important for large central station generation, it would provide no value for a small individual wind turbine generator. This level of reporting, at typically less than 3 MVA, is much lower that any practical reliability threshold, and would simply result in a documentation effort with no value. Similar concerns exist for FAC-008-3, PRC-001-1, PRC-004-2a, PRC-019-1, PRC-024-1, and PRC-025-1, and other standards in which small-scale dispersed generators were not considered during the standards' development. Unless Inclusion I4 (a) is eliminated, or significantly revised to clarify that the only BES-relevant standards that apply to dispersed generators are those that affirmatively state that they apply to dispersed generators, we do not believe implementation of the new BES definition should go forward until all reliability standards have been reviewed and revised as necessary to clarify the applicability to individual dispersed generating assets. What reliability benefit is there to a "bright line" BES definition if there is not a corresponding clarity in the applicability of reliability standards to the elements deemed to be included in the BES? 7. If the standards drafting team does not delete I4 (a) as requested above, we ask that I4 (a) be modified to clarify that the only BES-relevant standards that apply to individual dispersed generators are those that affirmatively state that they apply to dispersed generators. This will help avoid the harmful consequences of attempting to apply standards that were not written with dispersed generators in mind to dispersed generators.

Group

DTE Electric

Kathleen Black

No

There is already technical justification to exclude units less than 20MVA, therefore, it is logical to assume that units smaller than 20 MVA should be excluded. Certainly any collector system aggregating to less than 20 MVA should also be excluded. The technical justification to exclude aggregation of less than 75 MVA is the same justification that needs to be applied to these wind and solar sites. The risk of all the units failing at the same time is very low, unless it is a common element failure (collector network, control system or transformer). Therefore, no individual units should be included until they aggregate to 75 MVA. If there is a control system that can impact 75 MVA, then it is included, but not each generator. 75 MVA transformers and relaying would be included etc. Even when considering common mode failure of individual units, it is a very low probability that units would fail at the same time.

No Comment

Group

Associated Electric Cooperative, Inc. - JRO00088

David Dockery

No

The SDT failed to provide technical rationale for their imposing an I4.b sub-aggregate MVA threshold rather than the point aggregating total capacity within these resources' collector-circuits, thereby imposing additional compliance burdens upon those asset owners. Fortunately, a review of the SDT's recorded deliberations will confirm that they recanted their earlier draft-2 reliability-based rationale for having done so. AECI acknowledges that, to

some, I4.b might appear more closely aligned with Phase 2's I2.b BES Scope. However AECI also believes that the I4.b "from the terminals" debate revealed that I2.b would have been better technically justifiable at the point of total aggregated plant-capacity as well, a substantive I2.b refinement seemly outside the scope of this Phase 2 SAR. Yet duplicating a I2.b technical flaw, under I4.b, technically can neither serve to correct the I2.b flaw nor justify I4.b.
No
Individual
Spencer Tacke
Modesto Irrigation District
No
Yes
I voted No because I disagree with the criteria proposed for defining the BES. The BES criteria should be the criteria developed by the WECC BES Definition Task Force in the 2009-2010 time frame, which is based on extensive engineering studies. These extensive studies showed that system elements with a material impact to the regional interconnected system (i.e., BES elements), are those elements at which the available short circuit MVA exceeds 6,000 MVA. This is a very simple criteria based on sound engineering studies, and quite unlike the current proposed definition of the BES that we are voting on today. Thank you.
Group
PacifiCorp
Ryan Millard
No
PacifiCorp continues to believe that individual dispersed generating units should be excluded from Inclusion I4 of the revised BES definition. PacifiCorp does not agree with the SDT's characterization in the question that no technical rationale was offered by any stakeholder to support removal of the individual units from Inclusion I4. It is PacifiCorp's understanding that at least several commenting entities have provided sound technical arguments to support the exclusion of individual dispersed generating units. While it may be the case that the SDT does not believe the technical justifications offered by entities have been compelling, the SDT has not provided a complete analysis to the industry refuting each of the technical arguments provided by registered entities. After all, a primary objective of Phase II of the BES definition project was to carefully consider additional technical arguments that would further refine the revised definition, including with regard to individual dispersed generating units. PacifiCorp agrees with the SDT that one suitable solution to address the inclusion of individual dispersed generating facilities may be via adjustments to individual standards' applicability sections. In order to accomplish the recommended case-by-case review, however, a Standard Authorization Request would likely need to be prepared to commence the NERC standards development process for each potentially impacted standard. In that case, it is more appropriate and efficient to exclude such facilities from Inclusion I4 and then initiate changes to a limited number of impacted standards that should actually apply to individual dispersed

generators, rather than initiate individual projects to modify a larger pool of standards for which the application to such generators is not appropriate to promote reliability.
No
Individual
Russel Mountjoy
Midwest Reliability Organization
No
In the MRO opinion, the BES definition should not have included individual resources of a dispersed power producing resource. Instead, the Regions could have opted to include any that had a material impact to reliability – just the opposite of the way the BES definition was written. NERC talks of a guidance document in order to define those resources which are a part of the BES. This does not bear much weight when put towards a FERC approved definition and FERC approved Reliability Standards. The notion to use the BES implementation period of two years to work with the Standards Committee in order to revise the standards identified as requiring revisions doesn't seem workable. The implementation period is the time that has been identified for Registered Entities to bring their programs into compliance, it is not reasonable to expect the entities to expend their resources to bring their programs up to date with the possibility of the standards not being applicable. Nor is it reasonable to expect entities to postpone implementing programs in anticipation of standards being revised prior to the end of the implementation period.
No
Individual
Ryan Walter
Tri-State Generation and Transmission Association, Inc.
No
Tri-State disagrees that FERC Orders 773 and 773-A approved the inclusion of individual dispersed generating units that are individually, or in aggregate, below the capacity that requires the owner to register as a Generator Owner. Inclusion I4 of the current draft of the BES definition does require that under various scenarios. It is apparent from the comments to draft 2 of the Definition, and the questions during the webinar that was held by the drafting team, that Inclusion I4a) is disputed by a large percentage of registered entities and there is no technical basis for its inclusion in the definition. When asked during the webinar whether the drafting team had approached FERC regarding whether all individual dispersed units were to be included and about the fact that there was no technical justification for such inclusion, the drafting team simply stated that the FERC staff do not speak for the Commission. While it is be true that the staff do not speak for the Commission, all the drafting teams have FERC staff available that are able to convey the thoughts of the drafting teams and industry to the Commission. Tri-State agrees that the collection system for dispersed generation that aggregates to 75 MVA or more is important to include in the definition, since a single contingency could lead to loss of a large magnitude of generation. But loss of an individual small generator, oftentimes 2 MVA or less, has no direct consequence to the reliability of the

BES.
No
Group
Bonneville Power Administration
Jamison Dye
Yes
No
Individual
Mary Lou Ideus
EDP Renewables North America LLC
AWEA
No
EDP Renewables North America LLC (EDPR NA) disagrees with the inclusion of individual dispersed power producing units (individual wind turbines and solar units (inverters)) in the definition of I4. Individual wind turbines have negligible or no effect on the reliability of the BES due to their generating capacity and the fact that they are intermittent resources. Inclusion of individual wind turbines would require a wind generator to consider each wind turbine in its compliance program for Standards such as PRC-005. Since there is no discrete equipment, outside of the turbine control system, in a wind turbine that could logically be included in a wind generator's Protection System devices to be tested and maintained, the wind generator would be forced to seek exclusion under the Applicability section of other affected Standards. This would impose an administrative burden not only on the wind generation companies but also on each of the NERC Regional Entities, and indeed NERC itself, to consider each of the affected Registered Entity's request for exclusion from Applicability with certain of the currently enforceable Standards. In addition, inclusion of individual wind turbines in I4 would require revisions to each of the applicable Reliability Standards, a lengthy process. Compliance with many standards including the following would be required for such low level BES elements: FAC-003, PRC-001, PRC-004, PRC-005, and VAR-002. The SDT is asking for technical reasons for disagreement with the language; however, EDPR NA believes that the SDT has not provided sound technical reasons for inclusion of individual dispersed power producing units in I4. Suggested language change: I4: The point at which the aggregation equals to a capacity threshold of 75 MVA or above.

Additional comments received from PSEG (voting entities are in NPCC and RFC, and are in these segments: 1, 3, 5, & 6):

1. The SDT has re-structured the language of Inclusion I4 to more clearly reflect the SDT's intent to include individual dispersed power producing units (such as wind and solar units) that aggregate to greater than 75 MVA , along with the collector system that connects these units, from the point they aggregate to greater than 75 MVA to the point of connection at

100kV or higher. While the SDT recognizes that some stakeholders do not agree with the inclusion of individual dispersed power producing units, FERC Orders 773 and 773-A approved the inclusion of these individual units. No stakeholder has provided a technical rationale to support removal of the individual units from the definition. The SDT believes that stakeholder concerns about inclusion of individual units may be addressed by specifying the Facilities to which an individual standard applies within the Applicability section of that standard.

With this background, can you support the proposed clarifications to I4? If not, please provide technical rationale for your disagreement along with suggested language changes.

Yes:

No: X

Comments: As we stated in our comments to the prior posting, we believe exclusion of "collector systems" for dispersed I4 generators, which includes their GSU, from the BES while similar collector systems are included in the BES for I2 generators creates an unlevel competitive environment between I2 and I4 generators. Dispersed generators are a significant and growing part of generation resources and they compete with traditional generation. Other than the fact that FERC allowed the collector system exclusion, the drafting team has offered no reliability rationale for excluding the collector systems of dispersed generators while including them for I2 generators. [In Order 773, although FERC (P 113 and P 114) stated that radial collector systems used solely to aggregate generation SHOULD be part of the BES since multiple transformers connections did not exempt I2 generators; however, they did not direct NERC to include the collector system in I4 generators in the BES.]

Because of the disparate treatment of collector systems, we believe that the drafting team's BES definition violates Section 303 – Relationship between Reliability Standards and Competition – in the NERC Rules of Procedure under Paragraph 1. Paragraph 1 in Section 303 states: "Competition — A Reliability Standard shall not give any market participant an unfair competitive advantage." Furthermore, the exclusion of the collector system for I4 generators is the only incident of a non-contiguous BES in the BES definition. The collector systems are solely used by I4 generators to aggregate generation; they have no local distribution application and therefore to do come under the local distribution exemption in the core BES definition (i.e., the BES definition "does not include facilities used in the local distribution of electric energy").

Consideration of Comments

Project 2010-17 Proposed Definition of Bulk Electric System Phase 2

The Project 2010-17 Drafting Team thanks all commenters who submitted comments on the standard. These standards were posted for a 30-day public comment period from September 27, 2013 through October 29, 2013. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 40 sets of comments, including comments from approximately 98 different people from approximately 66 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

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

The SDT did not receive any technically supported arguments to support making any changes to the posted definition.

The SDT will be revising the Reference Document once the Phase 2 project is completed and will post it for comments as was done with the Phase 1 version. Comments on specific sections and diagrams will be considered at that time.

Minority opinion:

The SDT has retained the language of Inclusion I4 to clearly reflect the SDT's intent to include individual dispersed power producing units (such as wind and solar units) that aggregate to greater than 75 MVA, along with the collector system that connects these units, from the point they aggregate to greater than 75 MVA to the point of connection at 100kV or higher. While the SDT recognizes that some stakeholders do not agree with the inclusion of individual dispersed power producing units, FERC Orders 773 and 773-A approved the inclusion of these individual units. Technical rationale to support removal of the individual units from the definition was not seen in the stakeholder comments received by the SDT. The SDT believes that stakeholder concerns about inclusion of individual units may be addressed by specifying the Facilities to which an individual standard applies within the Applicability section of that standard.

In the Phase 2 definition, the drafting team has modified the treatment of collector systems for dispersed power producing resources. FERC Orders 773 and 773-A identified a concern that the Commission expressed regarding dispersed power collector systems. This has prompted the SDT to consider an appropriate and consistent method of addressing collector systems. The result addresses collector systems in a clear fashion that leaves no room for arbitrary determinations and eliminates the unintended consequences of categorically including as part of the BES assets that may include local distribution facilities.

Rationale:
The significant differences in collector system configurations that exist today did not lend itself to a continent-wide bright-line determination which has resulted in the SDT's effort to properly identify the portions of the

collector system which consistently provides a reliability benefit to the interconnected transmission network and are easily identified within collector systems. The result identifies the point of aggregation of 75 MVA and above and the interconnecting facilities to the interconnected transmission network. The aggregation threshold is consistent with the aggregation of capacity in Inclusion I4 and recognizes that the loss of those facilities would represent a loss of 75 MVA capacity to the BES.

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

Index to Questions, Comments, and Responses

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

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

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Michael Jones	National Grid	NPCC	1
9.	Mark Kenny	Northeast Utilities	NPCC	1
10.	Christina Koncz	PSEG Power LLC	NPCC	5
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2

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

12.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
13.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Silvia Parada Mitchell	NextEra Energyt, LLC	NPCC	5
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
21.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
22.	Brian Shanahan	National Grid	NPCC	1
23.	Wayne Sipperly	Ne York Power Authority	NPCC	5
24.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Group	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				

None

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Scott Brame	North Carolina Electric Membership Corporation	X		X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Scott Brame	North Carolina Electric Membership Corporation	SERC	5
2.	John Lemire	North Carolina Electric Membership Corporation	SERC	4
3.	Doug White	North Carolina Electric Membership Corporation	SERC	3
4.	Robert Thompson	North Carolina Electric Membership Corporation	SERC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
2.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
3.	Shari Heino	Brazos Electric Power Cooperative, Inc.	SERC	1, 5
4.	Kevin Lyons	Central Iowa Power Cooperative	MRO	
5.	Mohan Sachdeva	Buckeye Power, Inc.	RFC	3, 4

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4

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

2.	Brenda Frazer	Edison Mission Marketing and Trading	SPP	5, 6
3.	James Nail	City of Independence, MO	SPP	3
4.	David Pham	Empire District Electric	SPP	1
5.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
6.	Don Schmit	Nebraska Public Power District	MRO	1, 3, 5
7.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5
8.	Laura Cox	Westar Energy	SPP	1,3,5,6
9.	Kevin Nincehesler	Westar Energy	SPP	1,3,5,6
10.	Don Taylor	Westar Energy	SPP	1,3,5,6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia	X		X		X	X				

None

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Louis Slade	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Garton	Dominion	NPCC	5, 6
2.	Randi Heise	Dominion	MRO	6
3.	Michael Crowley	Dominion	SERC	1, 3, 5, 6
4.	Connie Lowe	Dominion	RFC	5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Brent Ingebrigtson	PPL NERC Registered Affiliates										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Annette Bannon	PPL Generation, LLC	RFC	5
3.		PPL Montana, LLC	WECC	5
4.		PPL Susquehanna, LLC	RFC	5
5.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
6.			NPCC	6
7.			RFC	6
8.			SERC	6
9.			SPP	6
10.			WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	Michael Lowman	Duke Energy			X			X				

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Greg Cecil		RFC	6

				1	2	3	4	5	6	7	8	9	10
10.	Group	Kathleen Black	DTE Electric			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Mark Stefaniak	Regulated Marketing	RFC	5

				1	2	3	4	5	6	7	8	9	10
11.	Group	David Dockery	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

				1	2	3	4	5	6	7	8	9	10
12.	Group	Ryan Millard	PacifiCorp					X	X				
None													
13.	Group	Jamison Dye	Bonneville Power Administration	X		X			X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Lorissa Jones	Transmission Reliability Program	WECC	1
2.	Kelly Johnson	Customer Service Engineering	WECC	1
3.	John Anasis	Technical Operations	WECC	1

				1	2	3	4	5	6	7	8	9	10
14.	Individual	Bangalore Vijayraghavan	Pacific Gas and Electric Comapny	X									
15.	Individual	John Falsey	Invenergy LLC					X					
16.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
17.	Individual	David Jendras	Ameren	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
18.	Individual	Joe O'Brien	NIPSCO	X		X		X	X				
19.	Individual	Kathleen Goodman	ISO New England, Inc.		X								
20.	Individual	Russell A Noble	Cowlitz PUD			X	X	X					
21.	Individual	Kenneth A Goldsmith	Alliant Energy				X						
22.	Individual	Gerald G Farringer	Consumers Energy										
23.	Individual	Joseph G DePoorter	Madison Gas and Electric Company			X	X		X				
24.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
25.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
26.	Individual	Marie Knox	MISO		X								
27.	Individual	Alice Ireland	Xcel Energy	X		X			X				
28.	Individual	Thomas Breene	WPSC			X	X	X	X				
29.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
30.	Individual	Thomas Gianneschi	Alcoa, Inc.							X			
31.	Individual	Gary Kruempel	MidAmerican Energy Company	X		X							
32.	Individual	Randi Nyholm	Minnesota Power	X									
33.	Individual	Don Streebel	Idaho Power Co.	X									
34.	Individual	Barbara Kedrowski	Wisconsin Electric Power Company			X	X	X					
35.	Individual	Bret Galbraith	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
36.	Individual	Michael Goggin	American Wind Energy Association					X					
37.	Individual	Spencer Tacke	Modesto Irrigation District			X	X		X				
38.	Individual	Russel Mountjoy	Midwest Reliability Organization										X
39.	Individual	Ryan Walter	Tri-State Generation and Transmission Association, Inc.	X		X		X					
40.	Individual	Mary Lou Ideus	EDP Renewables North America LLC					X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The SDT thanks you for your comments.

Organization	Agree	Supporting Comments of "Entity Name"
Invenergy LLC	Agree	AWEA
EDP Renewables North America LLC		AWEA
MISO	Agree	Madison Gas & Electric

1. **The SDT has re-structured the language of Inclusion I4 to more clearly reflect the SDT's intent to include individual dispersed power producing units (such as wind and solar units) that aggregate to greater than 75 MVA , along with the collector system that connects these units, from the point they aggregate to greater than 75 MVA to the point of connection at 100kV or higher. While the SDT recognizes that some stakeholders do not agree with the inclusion of individual dispersed power producing units, FERC Orders 773 and 773-A approved the inclusion of these individual units. No stakeholder has provided a technical rationale to support removal of the individual units from the definition. The SDT believes that stakeholder concerns about inclusion of individual units may be addressed by specifying the Facilities to which an individual standard applies within the Applicability section of that standard.**

   With this background, can you support the proposed clarifications to I4? If not, please provide technical rationale for your disagreement along with suggested language changes.

Summary Consideration: The SDT has retained the language of Inclusion I4 to clearly reflect the SDT's intent to include individual dispersed power producing units (such as wind and solar units) that aggregate to greater than 75 MVA, along with the collector system that connects these units, from the point they aggregate to greater than 75 MVA to the point of connection at 100kV or higher. While Technical rationale to support removal of the individual units from the definition was not seen in the stakeholder comments received by the SDT. The SDT recognizes that some stakeholders do not agree with the inclusion of individual dispersed power producing units, FERC Orders 773 and 773-A approved the inclusion of these individual units. No stakeholder has provided a technical rationale to support removal of the individual units from the definition. The SDT believes that stakeholder concerns about inclusion of individual units may be addressed by specifying the Facilities to which an individual standard applies within the Applicability section of that standard.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	The use of the word "capacity" is a concern. Generators might not be considered BES under the definition. Suggested change to I4 as follows: I4 - Dispersed power producing resources that aggregate to a gross total nameplate rating greater than 75 MVA, and that are connected through a system designed primarily for delivering such energy to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are: a) The individual resources, and b) The system designed primarily for delivering energy

Organization	Yes or No	Question 1 Comment
		from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.
ISO New England, Inc.	No	The use of the word "capacity" is a concern. Below is suggested language.I4 - Dispersed power producing resources that aggregate to a total gross nameplate rating greater than 75 MVA, and that are connected through a system designed primarily for delivering such energy to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are: a) The individual resources, and b) The system designed primarily for delivering energy from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.
Response: The SDT does not believe that the use of the term 'capacity' is a concern or that it will cause generators not to be considered under the definition. Based on comments received, the majority of the industry seems to understand the use of the term. No change made.		
Arizona Public Service Company	No	The definition should not apply to individual dispersed units that are less than 5 MW because independent units less than 5 MW are too small to have an impact on the BES.
Response: The definition only applies to individual units when they are part of an aggregation that is greater than 75 MVA. Individual stand-alone units of 5 MW would not be included in the definition. No change made.		
North Carolina Electric Membership Corporation	No	We have voted affirmative for this project in the past but are now changing our vote to negative based on the changes made to I4.We feel that the drafting team has further complicated the BES definition by the proposed language in Inclusion I4. According to the Phase 1 definition, dispersed power producing units would only be included if

Organization	Yes or No	Question 1 Comment
		the units reached the 75 MVA aggregate threshold. There is nothing in the Phase 1 definition that would include collector system equipment. The Phase 2 definition is problematic because there is uncertainty regarding the scope of equipment that that would be included as a portion of the collector system. This ambiguity has raised concerns that regional compliance staff may ultimately determine a different set of equipment is included in the BES than the registered entity will leaving the burden on the registered entity to argue why certain elements should not be included in the BES. This will lead to inconsistent compliance outcomes. We cannot support a definition with vague and ambiguous language that could result in negative compliance implications during registration, audits, and enforcement processes. Furthermore, we do not believe any part of the collector system should be included in the definition.
ACES Standards Collaborators	No	We feel that the drafting team has further complicated the BES definition by the proposed language in Inclusion I4. According to the Phase 1 definition, dispersed power producing units would only be included if the units reached the 75 MVA aggregate threshold. There is nothing in the Phase 1 definition that would include collector system equipment. The Phase 2 definition is problematic because there is uncertainty regarding the scope of equipment that that would be included as a portion of the collector system. This ambiguity has raised concerns that regional compliance staff may ultimately determine a different set of equipment is included in the BES than the registered entity will leaving the burden on the registered entity to argue why certain elements should not be included in the BES. This will lead to inconsistent compliance outcomes. We cannot support a definition with vague and ambiguous language that could result in negative compliance implications during registration, audits, and enforcement processes. Furthermore, we do not believe any part of

Organization	Yes or No	Question 1 Comment
		the collector system should be included in the definition.
Response: FERC Orders 773 and 773-A requested the SDT to consider collector systems as part of Phase 2. The SDT has addressed those collector systems in a clear fashion that leaves no room for arbitrary determinations. Furthermore, no change has been made to the definition as to the inclusion of individual units in Phase 2 – units are still only included if they aggregate to greater than 75 MVA. No change made.		
SPP Standards Review Group	No	While we understand that FERC has basically directed the drafting team to include individual dispersed power producing units in the BES, we are concerned about the need for coordination between drafting teams for other reliability standards, such as PRC-004, PRC-005, FAC-008, etc, which may be impacted by the inclusion of these generating units into the BES. Have steps been taken to ensure that this coordination has taken place?
Response: The SDT did review existing standards and believes that no changes are necessary due to the revised definition.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia	No	Eliminate Inclusion I4.a. If an individual generating element of a dispersed power producing facility is 20 MVA or larger at a facility rated at 75 MVA or larger it should be included. At Inclusion I4.b, Southern disagrees with the premise that BES elements (measured for compliance) should be applied to the individual dispersed power elements. We do not see the reliability benefit of tracking all of the compliance elements for individual wind turbines when the focus should be placed on the aggregate of the facilities. The proposed approach is similar to applying NERC requirements to the individual coils of a large generator. The subject inclusion should limit the applicability of the BES to the collector bus and the capacity at this point should be 75 MVA or greater to qualify as a BES element.

Organization	Yes or No	Question 1 Comment
Response: Individual units that aggregate to greater than 75 MVA were included in the prior definition and have been accepted by FERC as part of the BES. Nothing changed in that regard in Phase 2 and no entity has provided technical justification for deleting these units. FERC Orders 773 and 773-A requested the SDT to consider collector systems as part of the definition. No change made.		
DTE Electric	No	There is already technical justification to exclude units less than 20MVA, therefore, it is logical to assume that units smaller than 20 MVA should be excluded. Certainly any collector system aggregating to less than 20 MVA should also be excluded. The technical justification to exclude aggregation of less than 75 MVA is the same justification that needs to be applied to these wind and solar sites. The risk of all the units failing at the same time is very low, unless it is a common element failure (collector network, control system or transformer). Therefore, no individual units should be included until they aggregate to 75 MVA. If there is a control system that can impact 75 MVA, then it is included, but not each generator. 75 MVA transformers and relaying would be included etc. Even when considering common mode failure of individual units, it is a very low probability that units would fail at the same time.
Response: The SDT is not aware of any technical justification for excluding units less than 20 MVA nor has any been submitted. No individual units are included unless they are greater than 20 MVA or aggregate to greater than 75 MVA. No change made.		
Associated Electric Cooperative, Inc. - JRO00088	No	The SDT failed to provide technical rationale for their imposing an I4.b sub-aggregate MVA threshold rather than the point aggregating total capacity within these resources' collector-circuits, thereby imposing additional compliance burdens upon those asset owners. Fortunately, a review of the SDT's recorded deliberations will confirm that they recanted their earlier draft-2 reliability-based rationale for having done so. AECI acknowledges that, to some, I4.b might appear more closely aligned with Phase 2's I2.b BES Scope. However AECI also

Organization	Yes or No	Question 1 Comment
		believes that the I4.b "from the terminals" debate revealed that I2.b would have been better technically justifiable at the point of total aggregated plant-capacity as well, a substantive I2.b refinement seemly outside the scope of this Phase 2 SAR. Yet duplicating a I2.b technical flaw, under I4.b, technically can neither serve to correct the I2.b flaw nor justify I4.b.
Response: Collector systems in Inclusion I4b are treated comparably to those in Inclusion I2b. The 75 MVA threshold was validated in the NERC Planning Committee Report of March 2013 which can be found at: http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_phase2_pc_report_final_20130306.pdf No change made.		
PacifiCorp	No	PacifiCorp continues to believe that individual dispersed generating units should be excluded from Inclusion I4 of the revised BES definition. PacifiCorp does not agree with the SDT's characterization in the question that no technical rationale was offered by any stakeholder to support removal of the individual units from Inclusion I4. It is PacifiCorp's understanding that at least several commenting entities have provided sound technical arguments to support the exclusion of individual dispersed generating units. While it may be the case that the SDT does not believe the technical justifications offered by entities have been compelling, the SDT has not provided a complete analysis to the industry refuting each of the technical arguments provided by registered entities. After all, a primary objective of Phase II of the BES definition project was to carefully consider additional technical arguments that would further refine the revised definition, including with regard to individual dispersed generating units. PacifiCorp agrees with the SDT that one suitable solution to address the inclusion of individual dispersed generating facilities may be via

Organization	Yes or No	Question 1 Comment
		adjustments to individual standards' applicability sections. In order to accomplish the recommended case-by-case review, however, a Standard Authorization Request would likely need to be prepared to commence the NERC standards development process for each potentially impacted standard. In that case, it is more appropriate and efficient to exclude such facilities from Inclusion I4 and then initiate changes to a limited number of impacted standards that should actually apply to individual dispersed generators, rather than initiate individual projects to modify a larger pool of standards for which the application to such generators is not appropriate to promote reliability.
WPSC	No	As our previous comments have indicated, we agree with including the Generating stations with dispersed generation from the point of aggregation to 75 MVA as I4-b does. We also agree with the statement made on the BES Phase II webinar of August 21 that this is the point where the dispersed power plant is significant to the reliability of the BES. We continue to disagree with including the individual resources themselves since, as indicated on the previously referenced webinar, they are not significant to the reliability of the BES. The technical rationale for not including dispersed power producing resources has been included in many past comments and will not be restated here. Compliance with most protection system and equipment rating standards is not possible for individual BES wind turbines without revisions to the standards, or at best without significant resources to apply existing standards to individual units. Some of the standards effected include PRC-004-2a, FAC-001, FAC-003, FAC-008-3, MOD-024, MOD-025, MOD-026, MOD-027, PRC-005, PRC-006-SPP-01, PRC-019, PRC-024, PRC-025, and TOP-003.But we continue to stress that including an I4a will require significant resources in personnel and modifications or result in fast-tracking

Organization	Yes or No	Question 1 Comment
		Standard changes to make compliance possible with no improvement in reliability of the BES. These resources would be better utilized elsewhere to actually improve reliability.
MidAmerican Energy Company	No	MidAmerican continues to believe that individual dispersed generating units should be excluded from Inclusion I4 of the revised BES definition. MidAmerican does not agree with the SDT's characterization in the question that no technical rationale was offered by any stakeholder to support removal of the individual units from Inclusion I4. It is MidAmerican's understanding that at least several commenting entities have provided sound technical arguments to support the exclusion of individual dispersed generating units. While it may be the case that the SDT does not believe the technical justifications offered by entities have been compelling, the SDT has not provided a complete analysis to the industry refuting each of the technical arguments provided by registered entities. After all, a primary objective of Phase II of the BES definition project was to carefully consider additional technical arguments that would further refine the revised definition, including with regard to individual dispersed generating units. MidAmerican agrees with the SDT that one suitable solution to address the inclusion of individual dispersed generating facilities may be via adjustments to individual standards' applicability sections. For example, Reliability Standard MOD-025-2 (pending approval at FERC) includes a provision addressing real power testing for variable generating facilities. In order to accomplish the recommended case-by-case review, however, a Standard Authorization Request would likely need to be prepared to commence the NERC standards development process for each potentially impacted standard. In that case, it is more appropriate and efficient to exclude such facilities from Inclusion I4 and then initiate changes to a limited number of impacted standards that should actually apply to

Organization	Yes or No	Question 1 Comment
		individual dispersed generators, rather than initiate individual projects to modify a larger pool of standards for which the application to such generators is not appropriate to promote reliability.
Wisconsin Electric Power Company	No	Wind generators and solar panels are intermittent resources that are not as dependable as other sources for supporting grid reliability. A sudden drop in wind speed or solar intensity will instantaneously reduce the MW output of all the individual wind turbines or solar panels in the area. It follows then that a single wind turbine or solar panel could not be an Element or Facility necessary for the reliable operation and planning of the interconnected bulk power system. However, common mode failure of multiple turbines or solar panels could be significant to the reliability and planning of the BES. Efforts should be focused on preventing / mitigating the loss of multiple generators with an aggregated capacity of greater than 75MVA. Therefore the elements necessary for the reliable operation and planning of the interconnected bulk power system are the devices that are located where the power is aggregated, and not the individual generators. If individual small generators that are a part of an aggregated facility of 75 MVA or larger (e.g. a 75 MVA wind or solar farm) are considered a part of the BES due to that aggregation, the NERC Standard requirements should only be applied to the aggregation (e.g. the interconnection with the transmission system) and should not be applied to individual generators of less than 20 MVA. This would be consistent with the NERC registration criteria for single and multiple generators at a site.
Response: FERC Orders 773 and 773-A accepted the individual units as part of the BES when they aggregate to greater than 75 MVA. The SDT is not aware of any technical justifications that have been provided showing why or how these units should not be part of the BES. No change made.		

Organization	Yes or No	Question 1 Comment
A SAR has been submitted to the NERC Standards Committee to address the applicability of small, dispersed generating resources within the body of the existing standards. (See: http://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/sc_20131017a_agenda_package.pdf - item 5.) Deleting those units from the definition at this time could cause a reliability gap. The proper procedure is to continue to include these units in the BES and allow the project initiated by the SAR to determine when such units can be safely removed from specific standard applicability. No change made.		
Cowlitz PUD	No	We understand the difficulty of backtracking on past progress. We have voted in the affirmative for the greater objective of not impeding the overall positive progress of the definition. However, we acknowledge the industry has identified a valid concern over I4, and although the SDT is powerless to correct the issue, it is important to record and document reservations so future efforts in standard development may be facilitated to correct problems with compliance overreach. Most of the I4 facilities that will be included into the BES inherently work against reliability, and this characteristic can't be mitigated by adherence to the current GO/GOP standards in place. For example, assuring an individual generator protection system of a wind/solar unit will not misoperate adds little protection to the BES when the unit is frequently down due to insufficient wind or sunshine. It is a fact that such generation can't be designated as must run, and instead other generation units which can be dispatched must be available on demand to replace lost wind/solar resources. Therefore, we admonish FERC and NERC to recognize the true nature of wind and solar resources as an effort to reduce carbon footprint on the environment and are not intended to replace dispatchable generation, and that compliance without any reliability return should be removed to facilitate its development.
Response: The SDT thanks you for your support and understanding.		

Organization	Yes or No	Question 1 Comment
Consumers Energy	No	The inclusion and the clarification of the inclusion seem to contradict each other. The highlight portion above seems to indicate inclusion only from the point of aggregation of 75MVA or above. This, in most Wind Park cases would include a collector bus but probably not individual wind turbines. However I4 seems to indicate that the case of a Wind Park that has a total aggregation of 75 MVA, all associated equipment including every individual wild turbine would be included. There is inconsistency. Technical justification should be needed to include resources in the BES, not the other way around. Is there a real expectation that a single collector circuit containing ten, 1.2MW wind turbines can cause cascading or uncontrollable outages of the surrounding system? It is extremely doubtful. Consumers Energy supports the inclusion of equipment where the aggregation of 75 MVA or more connects to the Bulk Electric System at voltages of 100kv or greater. There is a clear indication here that a single contingency can remove the total of the capacity from the system where with the proposed inclusion does not. Administrative burden and compliance risk must be weighed against reliability gain. Including individual wind turbines rather than the aggregate of the wind farm increases such burden without any reliability gain.
Response: A single collector circuit of ten 1.2 MW wind turbines is not included in the BES by application of the definition. Only when the generation aggregates to greater than 75 MVA are the units and the collector system part of the BES as was shown in the diagram presented at the SDT webinar http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Elec1/bes_phase2_third_posting_20131010_webinar_final.pdf . The SDT believes that the language clarification and re-structuring that were made for this posting clearly show that. Furthermore, if necessary, as approved by FERC in Orders 773 and 773-A, the exception process provides a way to add Elements to, or remove Elements from, the Bulk Electric System. No change made.		
Madison Gas and Electric Company	No	MGE does not understand why individual dispersed power resources remain to be include as we clearly stated during the last comment

Organization	Yes or No	Question 1 Comment
		period. The SDT has stated that no technical rational to support there removal. FAC-001 and FAC-002 are mandatory enforceable Standards that entity's must follow. These Standards provide the justification as pointed out in our last set of comments. The SDT has stated in order to fix this, an addition SAR would be submitted (such as the GOTO) to "fix" this issue. Why would the ERO what to expend resources to fix something after the fact when the SDT has the ability to fix it now. The removal of I4a will solve this issue. If individual resources need to be in based on system instability issues, then this can be addressed at a later date, once it is proven that individual resources need to be considered part of the BES and the individual resources cause BES instability.
Response: Individual dispersed power producing resources are only included in the definition if they are part of an aggregation of greater than 75 MVA. This fact did not change due to the revised definition. FERC has already accepted this status in Orders 773 and 773-A. The SDT does not believe that FAC-001 and FAC-002 present technical justification for excluding such resources. No change made.		
Xcel Energy	No	In several prior comment periods, we have asked many technical questions of the BES SDT, and continue to get generic non-substantive replies. While a majority of our questions still remain unanswered, we have elected to not submit them again. However, we believe it is especially important to understand the SDT's response to this question. When considering a wind farm that would qualify as BES under the currently drafted version, it seems inconsistent that a 2 MVA individual dispersed generator is deemed significant to reliability, while the equipment that is utilized to connect a sub-set of the individual dispersed generators totaling to <75 MVA is deemed not significant to reliability. Please explain the technical rationale for concluding that an individual dispersed generating asset rated at 2 MVA is important to grid reliability but that a collector feeder for a

Organization	Yes or No	Question 1 Comment
		sub-set of these generators which may impact up to 35 (70 MVA) of these individual dispersed generating assets is not critical to reliability?
Minnesota Power	No	Minnesota Power does not believe that 2 MW generators, whether or not they aggregate to 75 MW, should be included in the definition of Bulk Electric System when the distribution transformers that control multiple units are not included. Furthermore, a non-contiguous Bulk Electric System is problematic for maintaining reliability.
Seminole Electric Cooperative, Inc.	No	The drafting team has proposed revised changes to a requirement concerning distributed generation. In particular, when distributed generation, e.g., wind turbines, accumulate to more than 75 MVA, only the turbines and the equipment collecting/transferring more than 75 MVA is covered as BES equipment. This allows for scenarios where non-BES equipment might be located between two separate groups of BES equipment. Seminole does not believe this is FERC's intent. Seminole acknowledges that FERC did not specifically address distributed generation in past orders when attempting to correct the BES language that resulted in having non-BES equipment separate groups of BES equipment. However, Seminole does not believe the drafting team's reasoning is sufficient for this exception. Seminole believes that all of the equipment in this scenario should be either BES-regulated or non-BES (non-NERC) regulated.
PSE&G	No	As we stated in our comments to the prior posting, we believe exclusion of "collector systems" for dispersed I4 generators, which includes their GSU, from the BES while similar collector systems are included in the BES for I2 generators creates an unlevel competitive environment between I2 and I4 generators. Dispersed generators are a significant and growing part of generation resources and they

Organization	Yes or No	Question 1 Comment
		compete with traditional generation. Other than the fact that FERC allowed the collector system exclusion, the drafting team has offered no reliability rationale for excluding the collector systems of dispersed generators while including them for I2 generators. [In Order 773, although FERC (P 113 and P 114) stated that radial collector systems used solely to aggregate generation SHOULD be part of the BES since multiple transformers connections did not exempt I2 generators; however, they did not direct NERC to include the collector system in I4 generators in the BES.] Because of the disparate treatment of collector systems, we believe that the drafting team's BES definition violates Section 303 – Relationship between Reliability Standards and Competition – in the NERC Rules of Procedure under Paragraph 1. Paragraph 1 in Section 303 states: "Competition — A Reliability Standard shall not give any market participant an unfair competitive advantage." Furthermore, the exclusion of the collector system for I4 generators is the only incident of a non-contiguous BES in the BES definition. The collector systems are solely used by I4 generators to aggregate generation; they have no local distribution application and therefore to do come under the local distribution exemption in the core BES definition (i.e., the BES definition "does not include facilities used in the local distribution of electric energy").

Response: The SDT cannot assume that the intervening equipment cited is solely used as a collector system. There are too many variables and configurations across the continent to allow for the assumption that collector systems are only utilized for the sole purpose of aggregating dispersed power resources. Therefore on a 'bright-line' basis, the SDT only included those portions of the collector system that are strictly utilized for delivering the aggregated capacity of the dispersed power resources to the interconnected transmission system. The intervening equipment cited is being treated in a similar fashion to Cranking Paths. The revised Reference Document will show specific examples. Furthermore, it is not clear that Inclusion I4 presents a competitive advantage to certain types of generation or conversely, a disadvantage to some types of generation, as a class and no evidence has

Organization	Yes or No	Question 1 Comment
been presented to make that case. While SDT's must respect competitive aspects of definitions/requirements, the primary function of an SDT is to promote reliability and that is what the SDT believes it has done in this case. Where collector systems support the reliable operation of the surrounding interconnected transmission system and do not have a distribution function, those excluded facilities may be candidates for inclusion through the BES Exception Process. No change made.		
Southern California Edison Company	No	Phase 2 of the BES definition characterizes dispersed power producing resources as being "small-scale" power generation technologies. However, although this characterization is currently the norm, that could easily change in the future. As written, I4 creates an ambiguity for Dispersed Power Producing Resources that are greater than or equal to 75MVA, because these generation resources appear to be included within the BES under both the I2 and I4 inclusions. The problem this creates is that I2 and I4 address the connection facilities differently, with I2 beginning at the generator terminals, while I4 begins at the point where the resources aggregate to greater than 75 MVA. SCE believes that the SDT should clarify which of these inclusions should apply to dispersed power producing resources greater than or equal to 75MVA.SCE is also concerned about how I4 could potentially discourage the development of common points of interconnection (i.e. collector substations) for multiple projects in queue, especially in relation to the E1 and E3 exclusions. In SCE's experience, "plans of service" that include common collector substations for multiple generation projects can be an effective way to encourage development of renewable resources in renewable-rich areas. However, such resources develop and interconnect as individual projects under separate development paths. The first distributed generation projects connecting to such stations may find their resources initially classified as non-BES if the aggregate generation is less than 75 MVA. However, later projects connecting to the same common point could find the BES status changing as additional generation projects materialize at the same collector

Organization	Yes or No	Question 1 Comment
		substation. SCE is concerned that this will discourage dispersed generation developers from pursuing common points of interconnection at collector substations built for such purpose in renewable rich areas. The aggregate total of the projects further down the interconnection queue could also trigger system upgrades, based on TPL studies for which the owners of these projects would be responsible.
Response: The SDT crafted Inclusions I2 and I4 to address the possibility of future, larger, individual dispersed power producing resources. If a single unit is greater than 20 MVA then it is covered by Inclusion I2 regardless of the type of generation. For smaller dispersed power producing resources Inclusion I4 takes precedence. The SDT believes that the distinction is clear. In addition, the SDT can't predict future building or interconnection plans. No change made.		
American Wind Energy Association	No	1. The technical rationale for not including individual generators in the BES definition is that these individual generators cannot affect BES reliability. Whatever technical rationale drove the drafting team's decision to not include the collector array components in the BES definition would also dictate that the individual turbines connected by that collector array should also not be included in the BES definition. We cannot think of any technical rationale that would justify including individual wind turbines in the definition but not including the collector array that aggregates those individual generators. Regardless, the burden for providing technical rationale should fall on the drafting team to demonstrate that including individual generators will improve electric reliability. That burden has not been met, and the standards drafting team has made no attempt to provide that rationale, despite repeated requests to do so. As explained below, that burden cannot be met, as there is no benefit to including individual generators, and including them in the definition is only likely to provoke significant confusion that distracts from real efforts to improve electric reliability. The only compelling reason for applying

Organization	Yes or No	Question 1 Comment
		BES standards to individual dispersed generators would be if there were a real risk of an abrupt common mode failure affecting a large share of the dispersed generators in a >75 MVA wind plant. However, per FERC Order 661A, wind turbine generators already comply with voltage and frequency ride-through standards that are far more stringent than those that apply to other types of generators. As a result, if a common mode failure caused by a grid disturbance were to affect the wind turbines in a >75 MVA wind plant, the impact on the wind plant would be irrelevant for grid reliability because the voltage and/or frequency deviation would have already caused most if not all of the conventional generators in the grid operating area to trip offline. While weather-driven changes in wind speed can significantly change the aggregate output of a wind plant, those changes in output occur too gradually to pose a risk to bulk power system reliability, and regardless such changes in output would not be regulated or mitigated by BES-relevant standards. No compelling rationale has been offered for why including individual dispersed wind turbine generators in the BES definition will improve grid reliability. Until one is offered, we will continue to oppose the inclusion of individual wind turbine generators in the BES definition. 2. We request clarification on the intent of the FERC direction provided in Orders 773 and 773-A regarding inclusion of dispersed generation, as we disagree with the standards drafting team's interpretation that those orders required the inclusion of individual dispersed generators. After careful study, it appears that the proposed standard for the I4 inclusion of dispersed generation is broader in scope than the intent as stated in the Orders. The critical language appears in Order 773-A, under item number 54. Here, FERC approves the dispersed power inclusion I4, "...finding it provides useful granularity...", and that it agreed it is appropriate "to expressly cover

Organization	Yes or No	Question 1 Comment
		dispersed power producing resources utilizing a system designed primarily for aggregating capacity." We believe that the second sentence should be further examined for proper intent. Our interpretation of this sentence is that collector systems aggregating dispersed power at a level of 75 MVA or more is the level of intended inclusion. This means that, in the example of a wind farm larger than 75 MVA, the application of the BES definition and all the requisite applicable standards is only at points where the aggregated capacity is greater than 75 MVA. This interpretation has several advantages: it is consistent with the current output threshold value; it does not establish a new, lower threshold for the BES definition; and it applies requirements where appropriate, i.e. equipment that carries 75 MVA and is therefore of sufficient size to be relevant to the reliability of the BES. Aggregator collection systems are designed to employ protection system equipment at the aggregation node, as well as operational output status monitoring equipment, and other equipment important to support grid reliability and monitoring at that aggregation point. Nowhere in the relevant FERC Orders does the language expressly require the inclusion of individual dispersed generators (PV panels, wind turbines, flywheels, microturbines, etc.). We believe that deletion of I4 (a) meets the intent of the FERC direction and properly supports grid reliability. 3. FERC Order 773-A goes on to say in part 60 that, indeed, dispersed power producers with greater than 75 MVA nameplate capacity are already registered. For many registered entities across the country, the interpretation has been to apply the body of NERC standards at the point of aggregation. This regional entity interpretation of NERC standard applicability at the aggregation point is comparable to the interpretation described above, and is based on sound reliability thresholds and knowledge of dispersed power system design.

Organization	Yes or No	Question 1 Comment
		4. The term "individual resources" utilized in I4 (a) is unclear, and could refer to the wind plant as a whole. What constitutes an "individual resource?" More technically precise language should be utilized to specifically identify what resources are intended to be included per this bullet. 5. In the last two postings, we and other commenters have asked specific technical questions that have not been answered. Instead, we have received only a generic reply that the SDT believes our concerns would best be addressed through clarification of the applicability of individual reliability standards. Please provide specific replies to the following questions: a. In the August 21, 2013 webinar, the BES definition drafting team indicated that its justification for the 75 MVA aggregating threshold in I4 (b) was that 75 MVA is the level that the drafting team believes that single failures resulting in the loss of generation could have an appreciable impact on the grid. It seems inconsistent that a 2 MVA individual dispersed generator is deemed significant to reliability but the equipment that is utilized to connect individual dispersed generators totaling to <75 MVA is deemed not significant to reliability. Please explain the technical rationale for concluding that an individual dispersed generating asset rated at 2 MVA is important to grid reliability but that a collector feeder which may impact up to 37 of these individual dispersed generating assets is not critical to reliability? b. Since the collector feeders are excluded from the BES definition so that there is not a contiguous BES connection between the individual dispersed generating asset and the grid, please explain the technical rationale for concluding that an individual 2 MVA dispersed generator at a facility rated at greater than 75 MVA has more impact on the BES than does an identical 2 MVA dispersed generator at a facility rated at less than 75 MVA? If the impact on grid reliability of both units is the

Organization	Yes or No	Question 1 Comment
		same, why is one considered BES and the other is not? c. In the Consideration of Comments document for the first draft of the Phase II BES definition, the Drafting Team acknowledged that there are both existing and pending reliability standards which likely will need to be reviewed and revised to clarify or correct the applicability of the standard requirements to dispersed generation. Please identify the reliability gaps being addressed by including individual dispersed generating assets within the BES definition. In other words, what specific existing or pending NERC Reliability Standard Requirements are perceived as being needed to be applied to individual dispersed generating assets to maintain grid reliability? 6. We appreciate that the SDT acknowledges that numerous existing and pending standards will need to be reviewed and revised to clarify standard applicability to individual generating units. However, we do not believe that implementation of the BES definition should go forward until this review and revision of other standards has been completed. Relative to the approval and implementation time frames being discussed for the new BES definition, we do not believe any such action could be taken in a timely enough fashion to resolve industry uncertainty and avoid a major regulatory burden that would distract from efforts that actually improve grid reliability. Without that review, there will simply be too much ambiguity in the requirements as they apply to individual dispersed generating assets and there will be too much compliance effort spent on trying to apply these ambiguous requirements with no commensurate gain in reliability. As currently written, the definition will create much regulatory uncertainty in how auditors will assess an entity's compliance with these ambiguous requirements. Including individual dispersed generators in the BES definition will cause a major diversion away from efforts that improve BES reliability, as entities are forced to simultaneously seek relief via

Organization	Yes or No	Question 1 Comment
		the Exception Process to exclude individual dispersed generators that are insignificant from a reliability standpoint from their programs while at the same time attempting to modify their existing compliance programs to accommodate individual dispersed generators in the event that the exception applications are not approved. With more than 45,000 wind turbines installed in the U.S. and the vast majority of them in wind plants larger than 75 MVA, NERC will be faced with a huge backlog of exception requests for small distributed generators while Generator Owners with dispersed generating assets struggle to implement reliability standards that were never drafted with the intent of being applicable to anything but large scale generating stations. As a result, proceeding with the BES definition as currently drafted would actually impair, rather than improve, bulk electric system reliability. Examples of standards that were not drafted with small dispersed generators in mind include: o PRC-005-2 Protection System testing - the relay test requirements were developed with large generators in mind, and differ significantly from requirements in FERC Order 661A, of 2005 that require wind plants to meet Low Voltage Ride-Through (LVRT) and Power Factor Design Criteria. These standards significantly change the protection scheme applied to individual turbines, and there is no clarity about how they should be applied. Wind turbine protection systems are often integral to the wind farm control system and the PRC-005-2 requirements were developed for protection equipment typically applied to large-scale generation, not wind farm control systems. o TOP-002 Normal Operations Planning - Under R14 of this standard, an unplanned outage for any individual wind turbine would require a status notification report from the GO to the TO/TOP. While such a report can be important for large central station generation, it would provide no value for a small individual wind turbine generator. This level of

Organization	Yes or No	Question 1 Comment
		reporting, at typically less than 3 MVA, is much lower that any practical reliability threshold, and would simply result in a documentation effort with no value. Similar concerns exist for FAC-008-3, PRC-001-1, PRC-004-2a, PRC-019-1, PRC-024-1, and PRC-025-1, and other standards in which small-scale dispersed generators were not considered during the standards' development. Unless Inclusion I4 (a) is eliminated, or significantly revised to clarify that the only BES-relevant standards that apply to dispersed generators are those that affirmatively state that they apply to dispersed generators, we do not believe implementation of the new BES definition should go forward until all reliability standards have been reviewed and revised as necessary to clarify the applicability to individual dispersed generating assets. What reliability benefit is there to a "bright line" BES definition if there is not a corresponding clarity in the applicability of reliability standards to the elements deemed to be included in the BES? 7. If the standards drafting team does not delete I4 (a) as requested above, we ask that I4 (a) be modified to clarify that the only BES-relevant standards that apply to individual dispersed generators are those that affirmatively state that they apply to dispersed generators. This will help avoid the harmful consequences of attempting to apply standards that were not written with dispersed generators in mind to dispersed generators.
Response: 1. Individual dispersed power producing resources are already included in the BES when they aggregate to greater than 75 MVA. Nothing in Phase 2 of this project has changed that fact which was established in earlier versions of the definition and clarified by FERC Orders 773 and 773-A. Technical justification must be supplied in order to remove something from an approved definition or standard. Simply stating that a unit doesn't impact reliability is not technical justification but a simple declaration of opinion without facts to back up the statement. No change made. 2. The SDT does not agree with your interpretation of FERC's statements. FERC staff is represented on the SDT on an observer basis		

Organization	Yes or No	Question 1 Comment
and has confirmed the SDT's interpretation of the cited sentences. No change made. 3. One of the main reasons for revising the BES definition was FERC's desire for a bright-line standard that obviated regional discretion in interpreting and applying the definition. No change made. 4. The SDT believes the term is clear and understood by the industry. No change made. 5a. The SDT cannot assume that the intervening equipment cited is solely used as a collector system. There are too many variables and configurations across the continent to allow for the assumption that collector systems are only utilized for the sole purpose of aggregating dispersed power resources. Therefore on a 'bright-line' basis the SDT only included those portions of the collector system that are strictly utilized for delivering the aggregated capacity of the dispersed power resources to the interconnected transmission system. The intervening equipment cited is being treated in a similar fashion as Cranking Paths. The revised Reference Document will show specific examples. Where collector systems support the reliable operation of the surrounding interconnected transmission system and do not have a distribution function, those excluded facilities may be candidates for inclusion through the BES Exception Process. No change made. 5b. Threshold values for generation were vetted in a report supplied to the SDT by the NERC Planning Committee and which can be found at: http://www.nerc.com/pa/Stand/Project%20201017%20Proposed%20Definition%20of%20Bulk%20Electri/bes_phase2_pc_report_final_20130306.pdf The threshold values identified in Inclusion I4 are comparable to the values identified in Inclusion I2. No change made. 5c. Qualified dispersed power producing resources were included in the BES prior to the start of this project. Standards that were relevant at that time are still relevant today. The SDT did review existing standards and believes that no changes are necessary due to the revised definition. No change made. 6. and 7. A SAR has been submitted to the NERC Standards Committee to address the applicability of small, dispersed generating resources within the body of the existing standards. (See: http://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/sc_20131017a_agenda_package.pdf - item 5.) Deleting those units from the definition at this time could cause a reliability gap. The proper procedure is to continue to include these units in the BES and allow the project initiated by the SAR to determine when such units can be safely removed from specific standard applicability. No change made.		
Midwest Reliability Organization	No	In the MRO opinion, the BES definition should not have included

Organization	Yes or No	Question 1 Comment
		individual resources of a dispersed power producing resource. Instead, the Regions could have opted to include any that had a material impact to reliability - just the opposite of the way the BES definition was written. NERC talks of a guidance document in order to define those resources which are a part of the BES. This does not bear much weight when put towards a FERC approved definition and FERC approved Reliability Standards. The notion to use the BES implementation period of two years to work with the Standards Committee in order to revise the standards identified as requiring revisions doesn't seem workable. The implementation period is the time that has been identified for Registered Entities to bring their programs into compliance, it is not reasonable to expect the entities to expend their resources to bring their programs up to date with the possibility of the standards not being applicable. Nor is it reasonable to expect entities to postpone implementing programs in anticipation of standards being revised prior to the end of the implementation period.
Response: One of the main reasons for revising the BES definition was FERC's desire for a bright-line standard that obviated regional discretion in interpreting and applying the definition. Material impact studies do not lend themselves to a bright-line concept such as was desired by FERC. A SAR has been submitted to the NERC Standards Committee to address the applicability of small, dispersed generating resources within the body of the existing standards. (See: http://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/sc_20131017a_agenda_package.pdf - item 5.) Deleting those units from the definition at this time could cause a reliability gap. The proper procedure is to continue to include these units in the BES and allow the project initiated by the SAR to determine when such units can be safely removed from specific standard applicability. No change made.		
Tri-State Generation and Transmission Association, Inc.	No	Tri-State disagrees that FERC Orders 773 and 773-A approved the inclusion of individual dispersed generating units that are individually, or in aggregate, below the capacity that requires the owner to register as a Generator Owner. Inclusion I4 of the current draft of the BES

Organization	Yes or No	Question 1 Comment
		definition does require that under various scenarios. It is apparent from the comments to draft 2 of the Definition, and the questions during the webinar that was held by the drafting team, that Inclusion I4a) is disputed by a large percentage of registered entities and there is no technical basis for its inclusion in the definition. When asked during the webinar whether the drafting team had approached FERC regarding whether all individual dispersed units were to be included and about the fact that there was no technical justification for such inclusion, the drafting team simply stated that the FERC staff do not speak for the Commission. While it is be true that the staff do not speak for the Commission, all the drafting teams have FERC staff available that are able to convey the thoughts of the drafting teams and industry to the Commission. Tri-State agrees that the collection system for dispersed generation that aggregates to 75 MVA or more is important to include in the definition, since a single contingency could lead to loss of a large magnitude of generation. But loss of an individual small generator, oftentimes 2 MVA or less, has no direct consequence to the reliability of the BES.
Response: FERC staff is represented on the SDT on an observer basis and has consistently upheld Inclusion I4. No change made.		
EDP Renewables North America LLC	No	EDP Renewables North America LLC (EDPR NA) disagrees with the inclusion of individual dispersed power producing units (individual wind turbines and solar units (inverters)) in the definition of I4. Individual wind turbines have negligible or no effect on the reliability of the BES due to their generating capacity and the fact that they are intermittent resources. Inclusion of individual wind turbines would require a wind generator to consider each wind turbine in its compliance program for Standards such as PRC-005. Since there is no discrete equipment, outside of the turbine control system, in a wind turbine that could logically be included in a wind generator's

Organization	Yes or No	Question 1 Comment
		Protection System devices to be tested and maintained, the wind generator would be forced to seek exclusion under the Applicability section of other affected Standards. This would impose an administrative burden not only on the wind generation companies but also on each of the NERC Regional Entities, and indeed NERC itself, to consider each of the affected Registered Entity's request for exclusion from Applicability with certain of the currently enforceable Standards. In addition, inclusion of individual wind turbines in I4 would require revisions to each of the applicable Reliability Standards, a lengthy process. Compliance with many standards including the following would be required for such low level BES elements: FAC-003, PRC-001, PRC-004, PRC-005, and VAR-002. The SDT is asking for technical reasons for disagreement with the language; however, EDPR NA believes that the SDT has not provided sound technical reasons for inclusion of individual dispersed power producing units in I4.Suggested language change: I4: The point at which the aggregation equals to a capacity threshold of 75 MVA or above.
Response: Individual dispersed power producing resources are already included in the BES when they aggregate to greater than 75 MVA. Nothing in Phase 2 of this project has changed that fact which was established in earlier versions of the definition and clarified by FERC Orders 773 and 773-A. Technical justification must be supplied in order to remove something from an approved definition or standard. Simply stating that a unit doesn't impact reliability is not technical justification but a simple declaration of opinion without facts to back up the statement. No change made.		
Pacific Gas and Electric Comapny	Yes	We support the definition as posted and commend the drafting team for considering the comments from the industry and weighing those industry comments against the FERC directives. Many of the industry comments take a different direction and opinion from the FERC directives and we recognize that the definition is a compromise on the positions of all stake holders. It provides a bright line that will improve reliability and provide a consistent process across North

Organization	Yes or No	Question 1 Comment
		America to address exceptions.
Duke Energy	Yes	Duke Energy supports the proposed clarifications to I4 made by the SDT.
Dominion	Yes	
Bonneville Power Administration	Yes	
American Electric Power	Yes	
Ameren	Yes	
South Carolina Electric and Gas	Yes	
Manitoba Hydro	Yes	
Idaho Power Co.	Yes	
Response: Thank you for your support.		

2. Are there any other concerns with this definition that haven't been covered in previous postings, questions and comments?

Summary Consideration: The SDT appreciates the concerns raised in the comments but found no compelling arguments to make any changes to the posted definition.

The SDT has retained the language of Inclusion I4 to clearly reflect the SDT's intent to include individual dispersed power producing units (such as wind and solar units) that aggregate to greater than 75 MVA, along with the collector system that connects these units, from the point they aggregate to greater than 75 MVA to the point of connection at 100kV or higher. While the SDT recognizes that some stakeholders do not agree with the inclusion of individual dispersed power producing units, FERC Orders 773 and 773-A approved the inclusion of these individual units. No stakeholder has provided a technical rationale to support removal of the individual units from the definition. The SDT believes that stakeholder concerns about inclusion of individual units may be addressed by specifying the Facilities to which an individual standard applies within the Applicability section of that standard.

The SDT will be revising the Reference Document once the Phase 2 project is completed and will post it for comments as was done with the Phase 1 version. Comments on specific sections and diagrams will be considered at that time.

Organization	Yes or No	Question 2 Comment
Alliant Energy	No	No - Alliant Energy still believes strongly that including individual dispersed generators (I4) as part of the BES does nothing to maintain/increase the reliability of the BES, and creates an extremely difficult compliance process. It will also create a very large backlog of exception requests, as most dispersed generator owners will request an exception for their generators.
Response: Such units are only included when they aggregate to greater than 75 MVA and this fact hasn't changed with the revised definition. No change made.		
Northeast Power Coordinating Council	No	
North Carolina Electric	No	

Organization	Yes or No	Question 2 Comment
Membership Corporation		
ACES Standards Collaborators	No	
SPP Standards Review Group	No	
Dominion	No	
Duke Energy	No	
Associated Electric Cooperative, Inc. - JRO00088	No	
PacifiCorp	No	
Bonneville Power Administration	No	
Pacific Gas and Electric Comapny	No	
Cowlitz PUD	No	
Consumers Energy	No	
Madison Gas and Electric Company	No	
South Carolina Electric and Gas	No	

Organization	Yes or No	Question 2 Comment
Manitoba Hydro	No	
WPSC	No	
MidAmerican Energy Company	No	
Midwest Reliability Organization	No	
Tri-State Generation and Transmission Association, Inc.	No	
Response: Thank you for your response.		
Arizona Public Service Company	Yes	Everything that has been excluded from the BES definition should also be excluded from I5 for reactive sources, because there is no impact to the BES. For example, if a radial system (E1) is excluded because it does not have an impact on the BES, a reactive resource connected at the end of the radial system is not likely to have an impact on the BES either.
Response: The SDT established Exclusion E4 to allow for exclusion of qualified reactive resources. No change made.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia	Yes	Southern Transmission believes that Exclusion E3 should include a limit on the size of a Local Network (LN). The facilities that will comprise these LNs are currently part of the BES and subject to all applicable standards. To allow these facilities to now be excluded from the BES without regard to some size limitation could result in negative impacts on the BES in the future. Southern Transmission believes that without placing a size limitation on such a network, a single contingency could result in significant flows across the BES to serve the LN from a different location. Additionally, there is concern that the exclusion has no requirement for power to

Organization	Yes or No	Question 2 Comment
		only flow into the LN for N-1 conditions. Southern Transmission does agree that there may be limited locations where such an exemption could be appropriate, but would prefer to see the facilities initially included in the BES and have the Transmission Owner go through a review process with the Regional Reliability Organization to provide justification for classifying facilities as a LN.
Response: The SDT does not agree with the blanket statement that facilities that comprise a local network are necessarily part of the BES now and subject to applicable standards; that would need to be examined on a case-by-case basis. The SDT included the 300 kV voltage threshold limit which established a de facto size limitation on local networks. This concept was applied to real-world scenarios during the development of the definition and was accepted by the Commission (FERC) in Phase 1. The SDT has made it clear that local network criteria must be met for any and all operating conditions. No change made.		
PPL NERC Registered Affiliates	Yes	These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. 1. The PPL NERC Registered Affiliates previously commented that the language of the proposed BES definition is subject to multiple interpretations and is therefore difficult to apply correctly without the Reference Document. The Reference Document is not complete or final for the Phase 2 BES definition, however. The Reference Document contains a disclaimer on p.1 that states "...this reference document is outdated. Revisions to the document will be developed at a later date to conform to the definition being developed in Phase 2." In response to the PPL NERC Registered Affiliates' concerns regarding the unavailability of a Reference Document to reflect the Phase 2 BES definition, the SDT stated in response that it "did not intend the posted version to represent a full implementation of Phase 2 as Phase 2 isn't complete." The PPL NERC Registered Affiliates are concerned by this response

Organization	Yes or No	Question 2 Comment
		because, unless it is clarified, the existing Phase 1 Reference Document could be interpreted to bring into the Phase 2 BES definition facilities that are not, and do not need to be, part of the BES. For example, the words in the existing Reference Document may imply that NERC registration for very small, standby, non-Blackstart Resource generators feeding the auxiliary buses of generation plants for emergency purposes is required. Specifically, Figure I2-5 of the Reference Document states that all units in a plant are part of the BES regardless of size, if the plant totals more than 75 MVA, if they "contribute to the gross aggregate rating of the site."The SDT said in response to our earlier comments regarding small standby diesels that, "The intent of the SDT is that the precedent will not change how the identified equipment is classified." However, Figure I2-5 of the Reference Document appears to do exactly that. If for example a 500 MW plant has a 2 MW diesel generator feeding the 4kV bus for emergency purposes (but not as a Blackstart Resource), the facility could be said to have a gross aggregate nameplate rating of 502 MW when the diesel is running - the aggregate nameplate rating has increased. Fig. I2-5 moreover includes in the BES units that feed transformers with a high-side voltage less than 100 kV, if their output is eventually stepped-up to a plant outlet that is > 100 kV. While, one could cite Fig. S1-9b,as indicating that generators feeding a bus that is exclusively an importer of power are not part of the BES, it would be far better to state matters explicitly in the first place. The contribute-to-aggregate-capability language of the present (and outdated) Reference Document does not appear in the BES definition and it is unclear. Item I2b of the BES definition should therefore be accompanied by a footnote saying that, "Standby and emergency generators that feed auxiliary buses are not considered in determining the plant/facility aggregate nameplate rating," or "Standby and emergency generators are not considered in determining the plant/facility aggregate nameplate rating if they feed an auxiliary bus that is a net importer of power." Further, an example should be added to the Resource Document that shows that Emergency Diesels and standby units that feed auxiliary buses that are net importers of power are not part of the BES (unless they are Blackstart Resources).

Organization	Yes or No	Question 2 Comment
		2. The PPL NERC Registered Affiliates also previously commented that the generic term "nameplate rating" should be replaced by the NERC-defined term "Facility Rating." The SDT declined to make this change, because it stated Facility Ratings, "fluctuate from period to period. " The PPL NERC Registered Affiliates continue to believe that the use of the term "Facility Rating" is more appropriate. Consider for example four simple-cycle CTs rated at 19 MVA each (76 MVA total) that are connected to a 115 kV line through a single GSU rated at 72 MVA. This in a 72 MVA plant (because of the most limiting component) and would therefore not presently be part of the BES, but it could be pulled-in depending on whether one focuses on the nameplate rating of the generators or the most-limiting component (in this case the GSU). The Reference Document suggests that the former approach applies, because in every single depiction of generation units it cites only generator ratings and ignores GSU capability. Furthermore, using generator nameplate ratings can in certain circumstances lead to confusion because some generators (e.g., simple cycle CTs) can have multiple ratings (e.g., baseload, peaking and emergency ratings).To avoid this confusion, the proposed definition should be based on the "nameplate rating of the most-limiting component," which in the example here presented is 72 MVA (and is also the Facility Rating). Therefore, Inclusion I2 should be revised to read as follows:a) Gross nameplate rating of the most-limiting component of an individual unit greater than 20 MVA, Or,b) Gross aggregate nameplate rating of the most-limiting component(s) of a plant/facility greater than 75 MVA Additionally, the Reference Document should be changed to provide at least one example of GSU MVA values setting the most limiting criterion.
Response: The SDT will be revising the Reference Document once the Phase 2 project is completed and will post it for comments as was done with the Phase 1 version. Your comments on specific sections and diagrams will be considered at that time. The SDT believes that the continued use of the nameplate rating is a clear, appropriate, and understood term that established a consistent bright-line approach to identifying BES Elements. No change made.		
American Electric Power	Yes	AEP cannot vote in the affirmative on this project as long as BES elements (measured

Organization	Yes or No	Question 2 Comment
		for compliance) are as granular as the individual dispersed power resource. We do not see the reliability benefit (nor has the project team provided technical justification) of tracking all of the compliance elements for individual wind turbines when the focus should be placed on the aggregate of the facility. Does the RC want to be notified of an outage of each individual wind turbine in real-time, or a loss of significant portion of the wind farm? If we are not careful, we will have entities at these resources and others monitoring them (BAs, TOPs, RCs) focusing on minor issues that will distract from more relevant reliability needs.
Response: Individual dispersed power producing resources are already included in the BES when they aggregate to greater than 75 MVA. Nothing in Phase 2 of this project has changed that fact which was established in earlier versions of the definition and clarified by FERC Orders 773 and 773-A. Technical justification must be supplied in order to remove something from an approved definition or standard. Simply stating that a unit doesn't impact reliability is not technical justification but a simple declaration of opinion without facts to back up the statement. No change made.		
Ameren	Yes	(1) When the SDT updates the Reference (Guidance) Document, we request a couple of additions to help clarify Exclusion E3. We ask the SDT to include System Diagram examples with a 138kV Local Network (LN) for which Real Power only flows in (from 138 to 69kV) and embedded within this LN is a 69kV network with multiple generating units. Note that none of these generators are Blackstart Resources or Dispersed power resources. We believe that the left side of your Figure S1-9b could be adapted to do this. Please add the two following examples: (a) First, a 69kV network that serves load at multiple substations and has three different substations each with a single 13.8/69kV GSU for a single 19MVA generator with an aggregate capacity of (3 x 19 MVA =) 57MVA within the entire 138kV LN; and (b) Second, the same diagram as item 1a plus one additional single 13.8/69kV GSU for a single 50MVA generator to provide an aggregate capacity of (3 x 19 MVA + 50 MVA =) 107MVA within the entire 138kV LN . Our understanding is that the 138kV leads to the 138/69kV transformers are all excluded via Exclusion E3; and that neither the entire 69kV network nor any of the embedded generation (aggregate 57 MVA for the first example or 107MVA for the second example) should be included by any BES

Organization	Yes or No	Question 2 Comment
		Inclusion. (2) When the SDT updates the Reference (Guidance) Document, we request one additional item to help clarify Inclusion I2. We ask the SDT to add a new Figure I2-7 similar to Figure I2-6. In this new Figure I2-7, we request that the >100kV / <100kV transformer on the right be removed and connected to another <100 kV location in the network. The generator on the right with GSU high side <100kV should be changed from 25 MVA to 88 MVA. This generator is neither a black-start resource nor a dispersed power resource and therefore should not be included by Inclusions I3 or I4, and our understanding is that the 88 MVA generator is also not included by Inclusion I2.
Response: The SDT will be revising the Reference Document once the Phase 2 project is completed and will post it for comments as was done with the Phase 1 version. Your comments on specific sections and diagrams will be considered at that time.		
NIPSCO	Yes	We appreciate your consideration of our previous comments and a draft interpretation However since such interpretations and a guidance document are already being developed for this draft standard, more clarification is probably needed within the standard itself.
Response: The SDT believes that the definition is clear. The Reference Document simply provides diagrams that make it easier to see how the SDT intended the definition to be implemented and does not represent interpretations of the definition. No change made.		
Xcel Energy	Yes	We appreciate that the BES SDT acknowledges that numerous existing and pending standards will need to be reviewed and revised to clarify standard applicability to individual generating units. However, we do not believe that implementation of the BES definition should go forward until this review and revision of other standards has been completed. Therefore, we recommend the implementation plan for the BES definition be contingent upon the completion of modification to applicable GO/GOP requirements. Otherwise, there will simply be too much ambiguity in the requirements as they apply to individual dispersed generating assets, there will be too much compliance effort spent on trying to apply these ambiguous requirements

Organization	Yes or No	Question 2 Comment
		with no commensurate gain in reliability, and in the end many of the requirements will change and possibly no longer apply.
Response: A SAR has been submitted to the NERC Standards Committee to address the applicability of small, dispersed generating resources within the body of the existing standards. (See: http://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/sc_20131017a_agenda_package.pdf - item 5.) Deleting those units from the definition at this time could cause a reliability gap. The proper procedure is to continue to include these units in the BES and allow the project initiated by the SAR to determine when such units can be safely removed from specific standard applicability. The SDT did complete a review of existing standards to see if changes were required to those standards due to the revised definition. The SDT did not find any standards or requirements that needed to be changed. No change made.		
Southern California Edison Company	Yes	The 75 MVA hurdle is nothing more than an arbitrary number being used to denote/provide a threshold for identifying the amount of generation that has a significant effect on the BES. This number does not consider the most significant part of what should be encapsulated in the definition which is what the “function” of the facility(ies) are with respect to a bulk electric system operated as an integrated network.
Response: The 75 MVA threshold is the same value that is in force today – nothing in this project has changed that value. The MVA approach is consistent with the bright-line approach to the definition suggested by FERC. Depending on interpretations of functionality leaves the door open for regional discretion in applying the definition. Removal of such discretion and a uniform continent-wide approach to applying the definition was one of the main reasons for embarking on this project. No change made.		
Alcoa, Inc.	Yes	An additional concern the standards development team has not adequately addressed is the technical justification for placing compliance requirements on newly registered industrial facilities resulting from the adoption of this definition.
Response: The SDT believes that the Phase 2 definition is consistent with the current definition and language in the ERO Statement of Compliance Registry Criteria as it applies to the industrial facilities and does not represent a change in what facilities should or should not be considered part of the BES. On a case-by-case basis, an entity can always use the exception process to address situations where the bright-line definition doesn’t lend itself to what the entity considers the correct delineation of its equipment.		

Organization	Yes or No	Question 2 Comment
Alternatively, if a broader review of standards applicability is seems to be necessary for a specific sub-set of equipment/configurations, the affected entities may submit a Standards Authorization Request (SAR) to address the identified issue.		
Idaho Power Co.	Yes	While we still do not agree with the categorical inclusion of individual dispersed power producing units into the BES, we do recognize the SDT's good faith effort to comply with FERC Orders 773 and 773-A. We understand that modeling of dispersed power producing resources in WECC base cases will follow regional requirements governed by regional standards.
Response: Thank you for your support.		
Modesto Irrigation District	Yes	I voted No because I disagree with the criteria proposed for defining the BES. The BES criteria should be the criteria developed by the WECC BES Definition Task Force in the 2009-2010 time frame, which is based on extensive engineering studies. These extensive studies showed that system elements with a material impact to the regional interconnected system (i.e., BES elements), are those elements at which the available short circuit MVA exceeds 6,000 MVA. This is a very simple criteria based on sound engineering studies, and quite unlike the current proposed definition of the BES that we are voting on today. Thank you.
Response: Regional work such as the WECC BES Definition Task Force studies were considered as input to the SDT's deliberations in Phase 1 of the BES definition project. However, material impact studies are not conducive to the bright-line approach that FERC directed and Phase 1 of this project which was accepted by industry, the Board, and the Commission.		
Seminole Electric Cooperative, Inc.		Additionally, Seminole is re-submitting the following comments from past ballots, because Seminole still believes that these comments are practical requests that should be incorporated into the BES definition.(1) The terms “plant” and “facility” are not defined and are ambiguous. Please provide quantitative and/or qualitative factors that an entity can utilize in determining what is a plant or facility. See Inclusion I2. Seminole acknowledges that there is draft guidance covering these terms; however, Seminole reasons that descriptive language covering these terms

Organization	Yes or No	Question 2 Comment
		should be passed in conjunction with the BES definition. (2) The following note will be placed in the Reference document:"Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system."Please strike the phrase "or an enhancement of," as it is more of a persuasive statement than an objective statement. (3) In Exclusion E1(c), please clarify that reactive devices, such as capacitor banks, can also be included in this section. Reactive devices are differentiated from real power devices in Inclusion I2, so we request clarification that reactive devices can be included in Exclusion E1(c), i.e., please add clarification to the definition.
Response: 1. The SDT believes that the majority of the industry is comfortable with the terminology and that the Reference Document adequately covers the concerns cited in the comment. No change made. 2. The SDT will consider your comment when it revises the Reference Document. 3. The SDT established Exclusion E4 to address the potential exclusion of qualified reactive resources. No change made.		
Hoosier Energy Rural Electric Cooperative, Inc.		The proposed language in Inclusion I4 further complicates the BES definition. According to the Phase 1 definition, dispersed power producing units would only be included if the units reached the 75 MVA aggregate threshold. There is nothing in the Phase 1 definition that would include collector system equipment. The Phase 2 definition is problematic because there is uncertainty regarding the scope of equipment that that would be included as a portion of the collector system. This ambiguity has raised concerns that regional compliance staff may ultimately determine a different set of equipment is included in the BES than the registered entity will leaving the burden on the registered entity to argue why certain elements should not be included in the BES. This will lead to inconsistent compliance outcomes. We cannot support a definition with vague and ambiguous language that could result in negative compliance implications during registration, audits, and

Organization	Yes or No	Question 2 Comment
		enforcement processes. Furthermore, we do not believe any part of the collector system should be included in the definition.

Response: FERC Orders 773 and 773-A directed the SDT to consider collector systems as part of Phase 2. The SDT has addressed those collector systems in a clear fashion that leaves no room for arbitrary determinations. Furthermore, no change has been made to the definition as to the inclusion of individual units in Phase 2 – units are still only included if they aggregate to greater than 75 MVA. No change made.

END OF REPORT

Standard Development Roadmap

This section is maintained by the drafting team during the development of the definition and will be removed when the definition becomes effective.

Development Steps Completed:

1. SAR posted for comment 1/4/12 – 2/3/12
2. SC authorized SAR for development 4/12/12
3. First posting and initial ballot completed 7/12/13
4. Second posting and ballot completed 9/14/13
5. Third posting and ballot completed 10/29/13

Proposed Action Plan and Description of Current Draft:

This draft is the for the recirculation ballot for the Phase 2 revised definition of the Bulk Electric System (BES).

Future Development Plan:

Anticipated Actions	Anticipated Delivery
1. Recirculation ballot	4Q13
2. BOT adoption	4Q13

Effective Dates

This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the definition shall become effective on the first day of the second calendar quarter after Board of Trustees adoption or as otherwise made effective pursuant to the laws of applicable governmental authorities.

Version History

Version	Date	Action	Change Tracking
1	January 25, 2012	Respond to FERC Order No. 743 to clarify the definition of the Bulk Electric System	N/A
2	TBD	Phase 2 clarifications to the original revisions Respond to directives in FERC Orders 773 and 773-A	Y

Project 2010-17 Definition of Bulk Electric System (Phase 2)

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below will be balloted in the same manner as a Reliability Standard. When the approved definition becomes effective, the defined term will be added to the Glossary.

Bulk Electric System (BES): Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.
- **I2** – Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
  a) Gross individual nameplate rating greater than 20 MVA. Or,
  b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.
- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.
- **I4** - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
  a) The individual resources, and
  b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

> Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells.
>
> (to be removed from final draft – will be moved to the Reference Document)

- **I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

a) Only serves Load. Or,

b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.
Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

Rationale: The drafting team has proposed a threshold of 50 kV or less for loops between radial systems when considering the application of Exclusion E1. The SDT used a two step approach to determine the voltage level. As a first step, regional voltage levels that are monitored on major interfaces, paths, and monitored elements to ensure the reliable operation of the interconnected transmission system were examined to determine the lowest monitored voltage level. Next, power system analyses determined the maximum amount of power that can be transferred through the low voltage systems, when looped, under a worst case scenario at various voltage levels. A formal white paper has been prepared to support this approach and is included with this posting.

- **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.
- **E3** - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

  a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

- **E4 –** Reactive Power devices installed for the sole benefit of a retail customer(s).

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Project 2010-17 Definition of Bulk Electric System (Phase 2)

Standard Development Roadmap

This section is maintained by the drafting team during the development of the definition and will be removed when the definition becomes effective.

Development Steps Completed:

1. SAR posted for comment 1/4/12 – 2/3/12
2. SC authorized SAR for development 4/12/12
3. First posting and initial ballot completed 7/12/13
4. Second posting and ballot completed 9/14/13
5. Third posting and ballot completed 10/29/13

Proposed Action Plan and Description of Current Draft:

This draft is the ~~third comment posting and successive~~for the recirculation ballot for the Phase 2 revised definition of the Bulk Electric System (BES).

Future Development Plan:

Anticipated Actions	Anticipated Delivery
~~1. Additional ballot~~	~~October 2013~~
~~2.~~1.Recirculation ballot	4Q13
~~3.~~2.BOT adoption	4Q13

Project 2010-17 Definition of Bulk Electric System (Phase 2)

Effective Dates

This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the definition shall become effective on the first day of the second calendar quarter after Board of Trustees adoption or as otherwise made effective pursuant to the laws of applicable governmental authorities.

Version History

Version	Date	Action	Change Tracking
1	January 25, 2012	Respond to FERC Order No. 743 to clarify the definition of the Bulk Electric System	N/A
2	TBD	Phase 2 clarifications to the original revisions Respond to directives in FERC Orders 773 and 773-A	Y

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below will be balloted in the same manner as a Reliability Standard. When the approved definition becomes effective, the defined term will be added to the Glossary.

Bulk Electric System (BES): Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.
- **I2** – Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
  a) Gross individual nameplate rating greater than 20 MVA. Or,
  b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.
- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.
- **I4** - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
  a) The individual resources, and
  b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

> Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells.
>
> (to be removed from final draft – will be moved to the Reference Document)

- **I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:
  - a) Only serves Load. Or,
  - b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,
  - c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

  Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.
  Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

  Rationale: The drafting team has proposed a threshold of 50 kV or less for loops between radial systems when considering the application of Exclusion E1. The SDT used a two step approach to determine the voltage level. As a first step, regional voltage levels that are monitored on major interfaces, paths, and monitored elements to ensure the reliable operation of the interconnected transmission system were examined to determine the lowest monitored voltage level. Next, power system analyses determined the maximum amount of power that can be transferred through the low voltage systems, when looped, under a worst case scenario at various voltage levels. A formal white paper has been prepared to support this approach and is included with this posting.

- **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.
- **E3** - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:
  - a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have

an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

- **E4 –** Reactive Power devices installed for the sole benefit of a retail customer(s).

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Standard Development ~~Timeline~~Roadmap

This section is maintained by the drafting team during the development of the ~~standard~~definition and will be removed when the ~~standard~~definition becomes effective.

Development Steps Completed:

1. SAR posted for comment ~~12/17/10 –~~ 1/~~21/11~~4/12 – 2/3/12
2. SC authorized ~~moving the~~ SAR ~~forward to standard~~ for development ~~3/25/11~~4/12/12
3. ~~3.~~ First posting ~~of definition 4/28/11 – 5/27/11~~
4. ~~4. First posting of criteria 5/11/11 – 6/10/11~~
5. ~~5.~~3. ~~Second posting of definition~~ and ~~criteria plus~~ initial ballot ~~8/26/11 – 10/10/11~~completed 7/12/13

4. Second posting and ballot completed 9/14/13
5. Third posting and ballot completed 10/29/13

Proposed Action Plan and Description of Current Draft:

This draft is the ~~third posting and~~ for the recirculation ballot ~~of~~for the Phase 2 revised definition of the Bulk Electric System (BES). ~~It is for a 10-day recirculation voting period.~~

Future Development Plan:

Anticipated Actions	Anticipated ~~Date~~Delivery
~~30-day Formal Comment Period~~	~~4/28/11~~
~~45-day Formal Comment Period with Parallel Initial Ballot~~	~~September 2011~~
1. Recirculation ballot	~~November 2011~~4Q13
2. BOT adoption	~~January 2012~~4Q13

Effective Dates

This definition shall become effective on the first day of the second calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the definition ~~will go into effect~~ shall become effective on the first day of the second calendar quarter after Board of Trustees adoption~~. Compliance obligations for Elements included by~~ or as otherwise made effective pursuant to the ~~definition shall begin 24 months after the~~ laws of applicable ~~effective date of the definition.~~ governmental authorities.

Version History

Version	Date	Action	Change Tracking
1	~~TBD~~January 25, 2012	Respond to FERC Order No. 743 to clarify the definition of the Bulk Electric System	N/A
2	TBD	Phase 2 clarifications to the original revisions Respond to directives in FERC Orders 773 and 773-A	Y

Project 2010-17 Definition of Bulk Electric System (Phase 2)

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms ~~used in the proposed standard~~. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below ~~become approved when~~will be balloted in the ~~proposed standard is approved.~~same manner as a Reliability Standard. When the ~~standard~~approved definition becomes effective, ~~these~~the defined ~~terms~~term will be ~~removed from the individual standard and~~ added to the Glossary.

Bulk Electric System (BES): Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

Inclusions:

- **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded ~~under~~by application of Exclusion E1 or E3.
- **I2** ~~–~~ - Generating resource(s) ~~with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA~~ including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above~~.~~ with:
  - a) Gross individual nameplate rating greater than 20 MVA. Or,
  - b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.
- **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan.
- **I4** - Dispersed power producing resources ~~with~~that aggregate to a total capacity greater than 75 MVA (gross ~~aggregate~~ nameplate rating~~) utilizing~~), and that are connected through a system designed primarily for ~~aggregating~~delivering such capacity~~, connected at~~ to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
  - a) The individual resources, and
  - b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.

> Dispersed power producing resources are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells.
>
> (to be removed from final draft – will be moved to the Reference Document)

- **I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1~~.~~ unless excluded by application of Exclusion E4.

Exclusions:

- **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:
  - a) Only serves Load. Or,
  - b) Only includes generation resources, not identified in ~~Inclusion~~Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,
  - c) Where the radial system serves Load and includes generation resources, not identified in ~~Inclusion~~Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

  Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

  Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

> **Rationale**: The drafting team has proposed a threshold of 50 kV or less for loops between radial systems when considering the application of Exclusion E1. The SDT used a two step approach to determine the voltage level. As a first step, regional voltage levels that are monitored on major interfaces, paths, and monitored elements to ensure the reliable operation of the interconnected transmission system were examined to determine the lowest monitored voltage level. Next, power system analyses determined the maximum amount of power that can be transferred through the low voltage systems, when looped, under a worst case scenario at various voltage levels. A formal white paper has been prepared to support this approach and is included with this posting.

- **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

- **E3 -** Local networks (LN): A group of contiguous transmission Elements operated at ~~or above 100 kV but~~ less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail ~~customer Load~~customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:
  - a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in ~~Inclusion~~Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating~~) ;~~);
  - b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and
  - c) Not part of a Flowgate or transfer path: The LN does not contain ~~a monitored Facility~~any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).
- **E4 –** Reactive Power devices ~~owned and operated by~~ installed for the sole benefit of a retail customer~~ solely for its own use.~~(s).

Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Implementation Plan for Project 2010-17: Definition of BES (Phase 2)

Prerequisite Approvals
None.

Effective Dates
This definition shall become effective on the first day of the second calendar quarter after the date that the definition is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter after the date the definition is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Compliance obligations for the Phase 2 definition would begin:

- Twenty-four months after the applicable effective date of the definition (for newly identified Elements), or
- If a longer timeframe is needed for an entity to be fully compliant with all standards applicable to an Element or group of Elements that are newly identified as BES when the Phase 2 definition is applied, the appropriate timeframe may be determined on a case-by-case basis by mutual agreement between the Regional Entity and the Element owner/operator, and subject to review by the ERO.

This implementation plan is consistent with the timeframe provided in Phase 1.

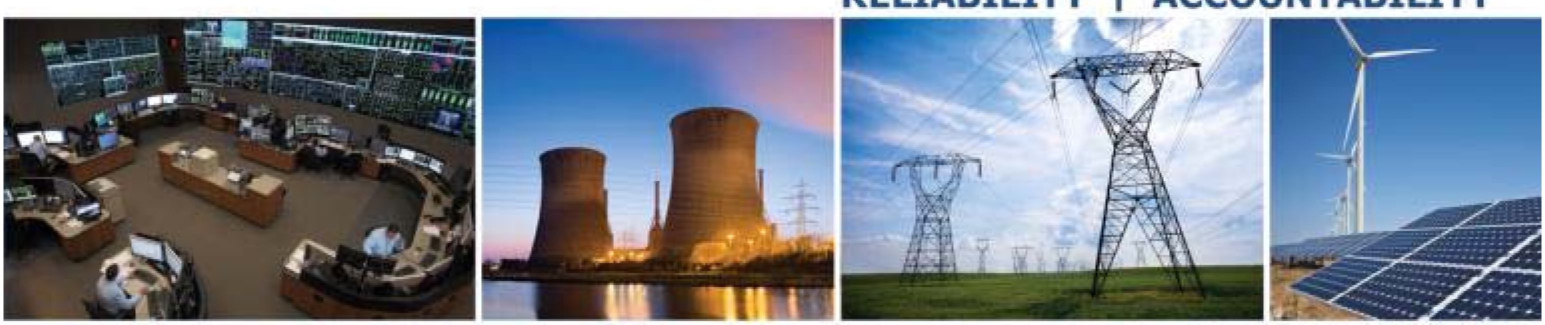
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

PUBLIC VERSION

White Paper on Bulk Electric System Radial Exclusion (E1) Low Voltage Loop Threshold

September 2013

RELIABILITY | ACCOUNTABILITY



Project 2010-17: Definition of Bulk Electric System

Table of Contents

Bulk Electric System Radial Exclusion (E1)
Low Voltage Loop Threshold

Background

The definition of "Bulk Electric System" (BES) in the NERC Glossary consists of a core definition and a list of facilities configurations that will be included or excluded from the core definition. The core definition is used to establish the bright line of 100 kV, the overall demarcation point between BES and non-BES elements. Exclusion E1 applies to radial systems. In Order No. 773 and 773-A, the Federal Energy Regulatory Commission's (Commission or FERC) expressed concerns that facilities operating below 100 kV may be required to support the reliable operation of the interconnected transmission system. The Commission also indicated that additional factors beyond impedance must be considered to demonstrate that looped or networked connections operating below 100 kV need not be considered in the application of Exclusion E1.[1]

This document responds to the Commission's concerns and provides a technical justification for the establishment of a voltage threshold below which sub-100 kV equipment need not be considered in the evaluation of Exclusion E1.

> *NOTE: This justification does not address whether sub- 100 kV systems should be evaluated as Bulk Electrical System (BES) Facilities. Sub- 100 kV systems are already excluded from the BES under the core definition. Order 773, paragraph 155 states: "Thus, the Commission, while disagreeing with NERC's interpretation, does not propose to include the below 100 kV elements in figure 3 in the bulk electric system, unless determined otherwise in the exception process." This was reaffirmed by the Commission in Order 773A, paragraph 36: "Moreover, as noted in the Final Rule, the sub-100 kV elements comprising radial systems and local networks will not be included in the bulk electric system, unless determined otherwise in the exception process." Sub-100 kV facilities will only be included as BES Facilities if justified under the NERC Rules of Procedure (ROP) Appendix 5C Exception Process.*

[1] *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 at P155, n.139 (2012); *order on reh'g*, Order No. 773-A, 143 FERC ¶ 61,053 (2013).

Executive Summary

The Project 2010-17 Standard Drafting Team conducted a two-step process to establish a technical justification for the establishment of a voltage threshold below which sub-100 kV loops do not affect the application of Exclusion E1. The justification for establishing a lower voltage threshold for application of Exclusion E1 consisted of a two-step technical approach:

- Step 1: A review was performed to determine the minimum voltage levels that are monitored by Balancing Authorities, Reliability Coordinators, and Transmission Operators for Interfaces, Paths, and Monitored Elements. This minimum voltage level reflects a value that industry experts consider necessary to monitor and facilitate the operation of the Bulk Electric System (BES). This step provided a technically sound approach to screen for a minimum voltage limit that served as a starting point for the technical analysis performed in Step 2 of this study.

- Step 2: Technical studies modeling the physics of loop flows through sub-100 kV systems were performed to establish which voltage level, while less than 100 kV, should be considered in the evaluation of Exclusion E1.

The analysis establishes that a 50 kV threshold for sub-100 kV loops does not affect the application of Exclusion E1. This approach will ease the administrative burden on entities as it negates the necessity for an entity to prove that they qualify for Exclusion E1 if the sub-100 kV loop in question is less than or equal to 50 kV. This analysis provides an equally effective and efficient alternative to address the Commission's directives expressed in Order No. 773 and 773-A.

It should be noted that, although this study resulted in a technically justified 50 kV threshold based on proven analytic methods, there are other preventative loop flow methods that entities can apply on sub-100 kV loop systems to address physical equipment concerns. These methods include:

- Interlocked control schemes;
- Reverse power schemes;
- Transformer, feeder and bus tie protection; and
- Custom protection and control schemes.

These methods are discussed in detail in Appendix 4. The presence of such equipment does not alter the criteria developed in this white paper, nor does it influence the conclusions reached. Additionally, the presence of this equipment does not remove or lessen an entity's obligations associated with the bright-line application of the Bulk Electric System (BES) definition.

Radial Systems Exclusion (E1)

The proposed definition (first posting) of radial systems in the Phase 2 BES Definition (Exclusion E1) was: *A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:*

a) *Only serves Load. Or,*
b) *Only includes generation resources, not identified in Inclusions I2 and I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,*
c) *Where the radial system serves Load and includes generation resources, not identified in Inclusions I2 and I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).*

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.

Note 2 - The presence of a contiguous loop, operated at a voltage level of 30 kV or less[2]*, between configurations being considered as radial systems, does not affect this exclusion.*

STEP 1 – Establishment of Minimum Monitored Regional Voltage Levels

All operating entities have guidelines to identify the elements they believe need to be monitored to facilitate the reliable operation of the interconnected transmission system. Pursuant to these guidelines, operating entities in each of the eight Regions in North America have identified and monitor key groupings of the transmission elements that limit the amount of power that can be reliably transferred across their systems. The groupings of these elements have different names: for instance, Paths in the Western Interconnection; Interfaces or Flowgates in the Eastern Interconnection; or Monitored Elements in the Electric Reliability Council of Texas (ERCOT). Nevertheless, they all constitute element groupings that operating entities (Reliability Coordinators, Balancing Authorities, and Transmission Operators) monitor because they understand that they are necessary to ensure the reliable operation of the interconnected transmission system under diverse operating conditions.

To provide information in determining a voltage level where the presence of a contiguous loop between system configurations may not affect the determination of radial systems under Exclusion E1 of the BES definition, voltage levels that are monitored on major Interfaces, Flowgates, Paths, and ERCOT Monitored Elements were examined. This examination focused on elements owned and operated by entities in North America. The objective was to identify the lowest monitored voltage level on these key element groupings. The lowest monitored line voltage on the major element groupings provides an indication of the lower limit which operating entities have historically believed necessary to ensure the

---

[2] The first posting of this Phase 2 definition used a threshold of 30 kV; however as a result of the study work described in this paper, the Standard Drafting Team has revised the threshold to 50 kV for subsequent industry consideration.

reliable operation of the interconnected transmission system. The results of this analysis provided a starting point for the technical analysis which was performed in Step 2 of this study.

Step 1 Approach

Each Region was requested to provide the key groupings of elements they monitor to ensure reliable operation of the interconnected transmission system. This list, contained in Appendix 1, was reviewed to identify the lowest voltage element in the major element groupings monitored by operating entities in the eight Regions. Identification of this lowest voltage level served as a starting point to begin a closer examination into the voltage level where the presence of a contiguous loop should not affect the evaluation of radial systems under Exclusion E1 of the BES definition.

Step 1 Results

An examination of the line listings of the North American operating entities revealed that the majority of operating entities do not monitor elements below 69 kV as shown in Table 1. However, in some instances elements with line voltages of 34.5 kV were included in monitored element groupings. In no instance was a transmission line element below 34.5 kV included in the monitored element groupings.

Region	Key Monitored Element Grouping	Lowest Line Element Voltage
FRCC	Southern Interface	115
MRO	NDEX	69
NPCC	Total East PJM (Rockland Electric) – Hudson Valley (Zone G)[1]	34.5
RFC	MWEX	69
SERC	VACAR IDC[2]	100
SPP RE	SPSNORTH_STH	115
TRE	Valley Import GTL	138
WECC	Path 52 Silver Peak – Control 55 kV	55

Notes:

1. Two interfaces in NPCC/NYISO have lines with 34.5 kV elements.
2. The TVA area in SERC was not included in the tables attached to this report; however, a review of the Flowgates in TVA revealed monitored elements no lower than 115 kV. There were a number of Flowgates with 115 kV monitored elements in SERC, the monitored grouping listed is representative.

Table 1: Lowest Line Element Voltage Monitored by Region

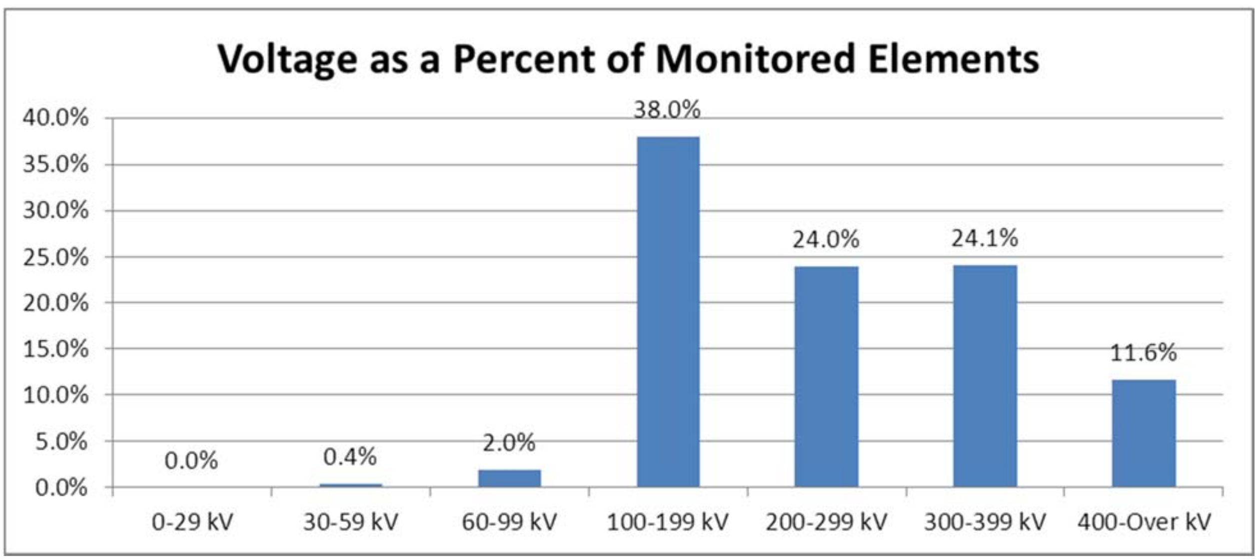
In a few rare occasions there were transformer elements with low-side windings lower than 30 kV included in the key monitored element groupings as shown in Table 2.

Region	Interface	Element	Voltage (kV)
NPCC/NYISO	WEST CENTRAL: Genesee (Zone B) – Central (Zone C)	(Farmtn 34.5/115kV&12/115 kV) #4 34.5/115 & 12/115	12/115
NPCC/ISO-NE	New England - Southwest Connecticut	SOTHNGTN 5X - Southington 115 kV /13.8 kV Transformer (4C-5X)	115/13.8
		SOTHNGTN 6X - Southington 115 kV /13.8 kV Transformer (4C-6X)	115/13.8
		SOTHNGTN 11X - Southington 115 kV /27.6 kV Transformer (4C-11X)	115/27.6

Table 2: Lowest Line Transformer Element Voltages Monitored by Region

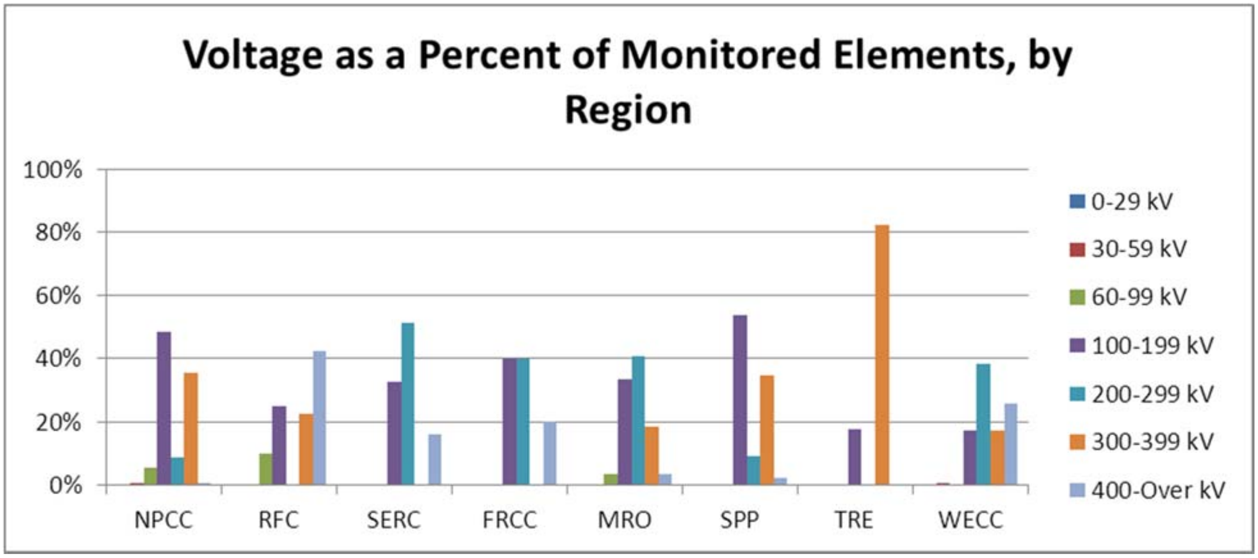
Upon closer investigation, for New England's Southwest Connecticut interface, it was determined that the inclusion of these elements was the result of longstanding, historical interface definitions and not for the purpose of addressing BES reliability concerns. Transformers serving lower voltage networks continue to be included based on familiarity with the existing interface rather than a specific technical concern. These transformers could be removed from the interface definition with no impact on monitoring the reliability of the interconnected transmission system. For the New York West Central interface, the low voltage element was included because the interface definition included boundary transmission lines between Transmission Owner control areas; hence, it was included for completeness to measure the power flow from one Transmission Owner control area to the other Transmission Owner control area.

Further examination of the information provided by the eight NERC regions revealed that half of the Regions only monitor transmission line elements with voltages above the 100 kV level. The other four Regions, NPCC, RFC, MRO, and WECC, monitor transmission line elements below 100 kV as part of key element groupings. However, in each of these cases, the number of below 100 kV transmission line elements comprised less than 2.5% of the total monitored key element groupings. Figures 1 and 2 below depict the results of Step 1 of this study.



Notes:
1. Data/Chart includes Transmission Lines only.
2. Data/Chart is a summary of individual elements (interfaces not included)

Figure 1: Voltage as Percent of Monitored Elements



Notes:
1. Data/Chart includes Transmission Lines only.
2. Data/Chart is a summary of individual elements (interfaces not included)

Figure 2: Voltage as Percent of Monitored Elements per Region

Step 1 Conclusion

The results of Step 1 of this study regarding regional monitoring levels resulted in a determination that 30 kV was a reasonable voltage level to initiate the sensitivity analysis conducted in Step 2 of this study. This value is below any of the regional monitoring levels. As noted herein, an examination of the line listings of the North American operating entities revealed that the majority of operating entities do not monitor elements below 69 kV as shown in Table 1. However, in some instances elements with line voltages of 34.5 kV were included in monitored element groupings. In no instance was a transmission line element below 34.5 kV included in the monitored element groupings.

STEP 2 - Load Flows and Technical Considerations

The threshold of 30 kV was established in Step 1 as a reasonable starting point to initiate the technical sensitivity analysis performed in Step 2 of this study. The purpose of this step was to determine if there is a technical justification to support a voltage threshold for the purpose of determining whether facilities greater than 100 kV can be considered to be radial under the BES Definition Exclusion E1. If the resulting voltage threshold was deemed appropriate through technical study efforts, then contiguous loop connections operated at voltages below this value would not preclude the application of Exclusion E1. Conversely, contiguous loops connecting radial lines at voltages above this kV value would negate the ability for an entity to use Exclusion E1 for the subject facilities.

This study focused on two typical configurations: a distribution loop and a sub-transmission loop. The study evaluated a range of voltages for the loop and the parallel transmission system with the goal of determining the voltage level below which single contingencies on the transmission system would not result in power flow from a low voltage distribution or sub-transmission loop to the BES. The study included sensitivity analysis varying the loads and impedances. Variations in loop and transmission system impedances account for a range of physical parameters such as conductor length, conductor type, system configuration, and proximity of the loop to the transmission system. This study provided the low voltage floor that can be used as a consideration for BES exclusion E1.

Analytical Approach – Distribution Circuit Loop Example

The Project 2010-17 Standard Drafting Team sought to examine the interaction and relative magnitude of flows on the 100 kV and above Facilities of the electric system and those of any underlying low voltage distribution loops. While not the determining factor leading to this study's recommendation, line outage distribution factors (LODF) were a useful tool in understanding the relationship between underlying systems and the BES elements. It illustrated the relative scale of interaction between the BES and the lower voltage systems and its review was a consideration when this study was performed. As an example, the Standard Drafting Team considered a system similar to the one depicted in Figure 3 below. In this simplified depiction of a portion of an electric system, two radial 115 kV lines emanate from 115 kV substations A and B to serve distribution loads via 115 kV distribution transformers at stations C and D. Stations C and D are "looped" together via either a distribution bus tie (zero impedance) or a feeder tie (modeled with typical distribution feeder impedances).

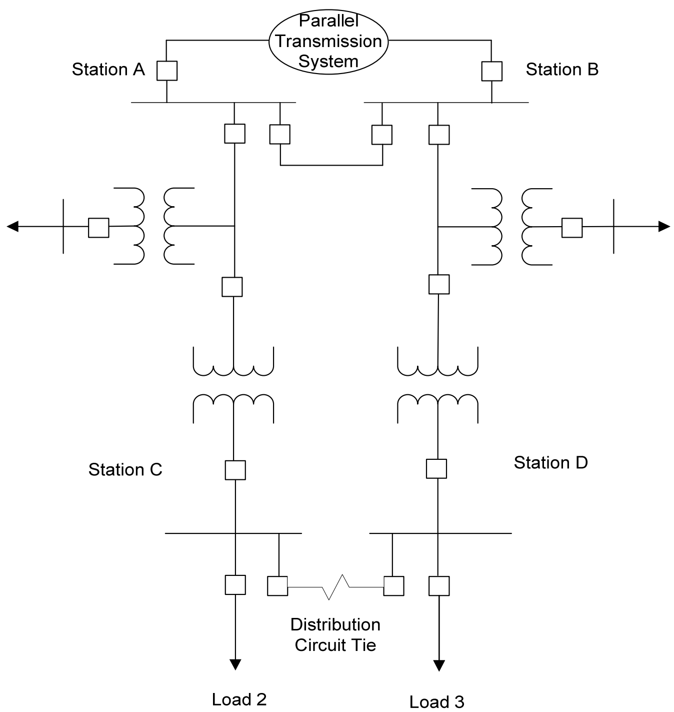


Figure 3: Example Radial Systems with Low Voltage Distribution Loop

With the example system, the Standard Drafting Team conducted power flow simulations to assess the performance of the power system under single contingency outages of the line between stations A and B. The analyses determined the LODF which represent the portion of the high voltage transmission flow that would flow across the low voltage distribution circuit or bus ties under a single contingency outage of the line between stations A and B. To the extent that the LODF values were negligible, this indicated a minor or insignificant contribution of the distribution loops to the operation of the high voltage system. But, more importantly, the analyses determined whether any instances of power flow reversal, i.e.,

resultant flow delivered into the BES, would occur during contingent operating scenarios. Instances of flow reversal into the BES would indicate that the underlying distribution looped system is exhibiting behavior similar to a sub-transmission or transmission system, which would call into question the applicability of radial exclusion E1.

The study work in this approach examined the sensitivity of parallel circuit flow on the distribution elements to the size of the distribution transformers, the operating voltage of distribution delivery buses at stations C and D and the strength of the transmission network serving stations A and B as manifested in the variation of the transmission network transfer impedances used in the model.
In order to simply, yet accurately, represent this low voltage loop scenario between two radial circuits, a Power System Simulator for Engineering (PSSE) model was created. Elements represented in this model included the following:

- Radial 115 kV lines from station A to station C and station B to station D;
- Interconnecting transmission line from station A to station B;
- Distribution transformers tapped off the 115 kV lines between stations A and C and between stations B and D and at stations C and D;
- Feeder tie impedance to represent a feeder tie (or zero impedance bus tie) between distribution buses at stations C and D;
- Transfer impedance equivalent between stations A and B, representing the strength of the interconnected transmission network[3].

Within this model, parameters were modified to simulate differences in the length and impedance of the transmission lines, the amount of distribution load, the strength of the transmission network supplying stations A and B, the size of the distribution transformers and the character of the bus or feeder ties at distribution Stations C and D.

Distribution Model Simulation

Table 3 below illustrates the domain of the various parameters that were simulated in this distribution circuit loop scenario. A parametric analysis was performed using all combinations of variables shown in each column of the upper portion of Table 3. Sensitivity analysis was performed as indicated in the lower portion of the table.

[3] The relative strength of the surrounding transmission system network is a function of the quantity of parallel transmission paths and the impedance of those paths between the two source substations. A high number of parallel paths with low impedance translates to a low transfer impedance, which allows power to more readily flow between the stations. Conversely, a low number of parallel paths having higher impedance is represented by a relatively large transfer impedance.

Trans KV	Trans Length	Dist KV	Dist Length	XFMR MVA	Dist Load % rating	Z Transfer
115	10 miles	12.5	0 (bus tie)	10	40	Weak
		23	2 miles	20	80	
		34.5	5 miles	40		
Sensitivity Analysis:		46				Strong Medium

Notes:

1. The "medium" value for transfer impedances was derived from an actual example system in the northeastern US. This was deemed to be representative of a network with typical, or medium, transmission strength. Variations of a stronger (more tightly coupled) and a weaker transmission network were selected for the "strong" and "weak" cases, respectively. Impedance values of X=0.54%, X=1.95%, and X=4.07% were applied for the strong, medium and weak cases, respectively.

Table 3: Model Parameters Varied

The model was used to examine a series of cases simulating a power transfer on the 115 kV line[4] from station A to station B of slightly more than 100 MW. Loads and impedances were simulated at the location shown in Figure 5 of Appendix 2. Two load levels were used in each scenario: 40% of the rating of the distribution transformer and 80% of the rating. Distribution transformer ratings were varied in three steps: 10 MVA, 20 MVA, and 40 MVA. Finally, the strength of the interconnected transmission network was varied in three steps representing a strong, medium, and weak transmission network. The choices of transfer impedance were based on typical networks in use across North America. A specific model from the New England area of the United States yielded an actual transfer impedance of 0.319 + j1.954%. This represents the 'medium' strength transmission system used in the analyses. The other values used in the study are minimum ('strong') and maximum ('weak') ends of the typical range of transfer impedances for 115 kV systems interconnected to the Bulk Electric System of North America. Distribution feeder connections were simulated in three different ways, first with zero impedance between the distribution buses at stations C and D, second with a 2-mile feeder connection with typical overhead conductor, and third with a 5-mile connection.

Distribution Model Results

23 kV Distribution System

The results show LODFs ranging from a low of 0.2% to a high of 6.7%. In all of the cases, the direction of power flow to the radial lines at stations A and B was *toward* stations C and D. In other words, there were no instances of flow reversal from the distribution system back to the 115 kV transmission system. The lowest LODF was found in the case with the smallest distribution transformers (10 MVA), the 5-mile distribution circuit tie, and the strong transmission transfer impedance. The case with the highest LODF

[4] The threshold voltage of 115 kV provides conservative results. At a higher voltage, such as 230 kV, the reflection of distribution impedance to the transmission system is significantly larger, and hence, the amount of distribution power flow will be much smaller.

was that which used the largest distribution transformers (40 MVA) with the lightest load and the use of a zero-impedance bus tie between the two distribution stations.

12.5 kV Distribution System

As compared to the simulations using the 23 kV distribution system, the 12.5 kV system model yielded far lower LODF values. This result is reasonable, as the reflection of impedances on a 12.5 kV distribution system will be nearly four times as large as those for a 23 kV distribution system, and the transformer sizes in use at the 12.5 kV class are generally smaller, i.e., higher impedance. As with the cases simulated for the 23 kV system, the 12.5 kV system exhibited a power flow direction in the radial line terminals at stations A and B in the direction of the distribution stations C and D; no flow reversal was seen in any of the contingency cases.

Given the lower voltage of the distribution system, the cases studied at this low voltage level were limited to the scenario with the high transfer impedance value ('weak' transmission case). This is a conservative assumption as all cases with lower transfer impedance will yield far lower LODF values. With that, the range of LODF values was found to be 1.0% to 6.7%. When compared with the 23 kV system results in the weak transmission case, the range of LODF values was 1.8% to 6.7%. Higher LODF values were found in the cases with the largest transformer size, which is to be expected.

Table 4 below provides a sample of the results of the various simulations that were conducted. The full collection of results is provided in Appendix 3.

Case	D, KV	Z_{xfer}	Z_{Dist}	XFMR MVA	Load, MW	LODF
623a5	23	strong	5 mi	10	4	0.2%
623a5pk	23	strong	5 mi	10	8	0.3%
633b0pk	23	strong	0	20	16	0.4%
723c0	23	medium	0	40	16	3.4%
723c5pk	23	medium	5 mi	40	32	1.6%
823b0	23	weak	0	20	8	3.8%
823c0	23	weak	0	40	16	6.7%
812a5	12.5	weak	5 mi	10	4	1.0%
812b0	12.5	weak	0	20	8	3.8%
812b5pk	12.5	weak	5 mi	20	16	1.3%
812c0	12.5	weak	0	40	16	6.7%
834a5pk	34.5	weak	5 mi	10	8	1.7%
834b5pk	34.5	weak	5 mi	20	16	3.0%
834d0	34.5	weak	0	40	16	8.9%
834d0pk	34.5	weak	0	40	32	8.7%
846e0	46	weak	0	50	16	10.3%
846e2	46	weak	2 mi	50	20	9.0%
846e5	46	weak	5 mi	50	20	7.4%

Table 4: Select Sample of Study Results for Distribution Scenario

34.5 kV and 46 kV Distribution Systems

As with the analysis done for the 12.5 kV system, a conservative transfer impedance value, that of the 'weak' transmission network, was used in selecting the transfer impedance to be used in the simulations at 34.5 kV and 46 kV. With this conservative parameter, the simulation results show distribution factors (LODF) ranging from a low of 1.7% to a high of 10.3%. In all of the cases, the direction of power flow to the radial lines remained *from* stations A and B *toward* stations C and D. In other words, there were no instances of flow reversal from the distribution system back to the 115 kV transmission system.

Analytical Approach – Sub-transmission Example

In addition to the distribution circuit loop example described above, the study examined the performance of systems typically described as 'sub-transmission.' The study sought to examine the interaction and relative magnitude of flows on the 100 kV and above Facilities of the interconnected transmission system and those of the underlying parallel sub-transmission facilities. The study considered a system similar to the one depicted in Figure 4 below. In this simplified depiction of a portion of a transmission and sub-transmission system, a 40-mile transmission line connecting two sources with transfer impedance between the two sources representing the parallel transmission network. Each source also supplies a 10-mile transmission line with a load tap at the mid-point of the line, each serving a load of 16 MW. At the end of each of these lines is a step-down transformer to the sub-transmission voltage, where an additional load is served. The two sub-transmission stations are connected by a 25-mile sub-transmission tie line. Loads and impedances were simulated at the location shown in Figure 6 of Appendix 2.

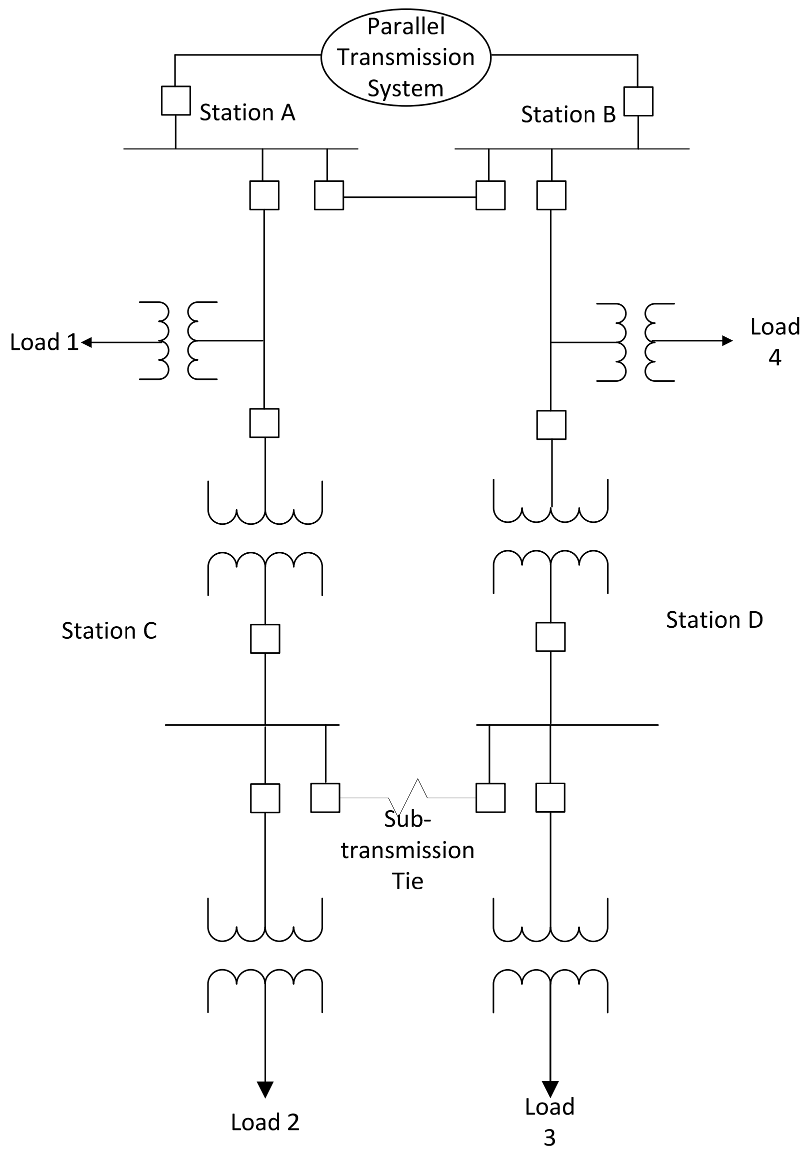


Figure 4: Example Radial Systems with Sub-transmission Loop

Given this example sub-transmission system, a PSSE model was created to simulate the power flow characteristics of the system during a contingency outage of the transmission line between stations A and B. Within this model, parameters were modified to simulate differences in the amount of load being served, transformer size and the amount of pre-contingent power flow on the transmission line. All simulations were performed with a transfer impedance representative of a 'weak' transmission network, which was confirmed as conservative in the distribution system analysis.

Sub-transmission Model Simulation

Simulations were performed for each sub-transmission voltage (34.5 kV, 46 kV, 55 kV, and 69 kV) using a transmission voltage of 115 kV. This analysis identified the potential for power flowing back to the transmission system only for sub-transmission voltages of 55 kV and 69 kV. Sensitivity analysis was performed using higher transmission voltages to confirm that cases modeling a 115 kV transmission

system yield the most conservative results. Therefore, it was not necessary to perform sensitivity analysis for sub-transmission voltages of 34.5 kV and 46 kV for transmission voltages higher than 115 kV. Table 5 below illustrates the domain of the various parameters that were simulated in this sub-transmission circuit loop scenario. A parametric analysis was performed using combinations of variables shown in each column of Table 5.

Trans KV	Trans Length	Sub-T KV	Sub-T Length	XFMR MVA	Dist Load % rating	Trans MW Preload
115	40 miles	34.5	25 miles	40	40	115
		46		50		
		55		60		
		69				
Sensitivity Analyses:						
138	40 miles	55	25 miles	50	40	115
161		69		60		135
230						150
						220

Table 5: Model Parameters and Sensitivities

Sub-transmission Model Results

115 kV Transmission System with 34.5-69 kV Sub-transmission

The results for cases depicting a 115 kV transmission system voltage and ranges of 34.5 kV to 69 kV sub-transmission voltages show line outage distribution factors (LODF) in the range of 9% to slightly higher than 20%. Several cases show a reversal of power flow in the post-contingent system such that power flow is delivered from the sub-transmission system *into the 115 kV BES*. The worst case is found in the 69 kV sub-transmission voltage class. This result is as expected, given that the impedance of the 69 kV sub-transmission system is less than the impedances of lower voltage systems. In no instance was a reversal of power flow observed in sub-transmission systems rated below 50 kV.

138 kV and 161 kV Transmission Systems with 55-69 kV Sub-transmission

The results for cases of 138 kV and 161 kV transmission system voltages supplying sub-transmission voltages of 55 kV and 69 kV show LODFs ranging from 9% to 16%. These cases also result in reversal of power flows in the post-contingent system such that power flow is delivered from the sub-transmission system into the 115 kV BES.

230 kV Transmission System with 55-69 kV Sub-transmission

By simulating a higher BES source voltage of 230 kV paired with sub-transmission voltages of 55 kV and 69 kV, the transformation ratio is sufficiently large to result in a significant increase to the reflected sub-transmission system impedance. Therefore, in these cases, LODFs range from 5% to 7%, and these cases also show no reversal of power flow toward the BES in the post-contingent system. Table 6 below

provides a sample of the results of the various simulations that were conducted. All results are provided in Appendix 3.

Case	T, KV	S-T, KV	Trans Pre-load, MW	XFMR MVA	Load, MW	LODF	Flow Rev to BES?
834d25	115	34.5	115	40	20	9.4%	
846e25	115	46	114	50	20	13.3%	
855e25	115	55	112	50	20	15.7%	Yes
869f25	115	69	110	60	24	20.3%	Yes
855e25-138	138	55	114	50	20	11.7%	
855e25-138'	138	55	134	60	20	11.9%	Yes
869f25-138	138	69	112	60	24	15.6%	Yes
869f25-138'	138	69	132	60	24	15.8%	Yes
855e25-161	161	55	114	50	20	9.1%	
855e25-161'	161	55	155	60	20	9.2%	
869f25-161	161	69	113	60	24	12.5%	
869f25-161'	161	69	153	60	24	12.6%	Yes
855e25-230	230	55	116	50	20	4.9%	
855e25-230'	230	55	219	60	20	5.0%	
869f25-230	230	69	116	60	24	7.0%	
869f25-230'	230	69	218	60	24	7.0%	

Table 6: Select Sample of Study Results for Sub-transmission Scenario

Step 2 Conclusion

After conducting extensive simulations (included in Appendix 3), the results of Step 2 of this analysis indicates that 50 kV is the appropriate low voltage loop threshold below which sub-100 kV loops should not affect the application of Exclusion E1 of the BES Definition. Simulations of power flows for the cases modeled in this study show there is no power flow reversal into the BES when circuit loop operating voltages are below 50 kV. This study also finds, for loop voltages above 50 kV, certain cases result in power flow toward the BES. Therefore, the study concludes that low voltage circuit loops operated below 50 kV should not affect the application of Exclusion E1.

As described throughout the preceding section, the scenarios and configurations utilized in this analysis represent the majority of cases that will be encountered in the industry. The models used in this analysis establish reasonable bounds and use conservative parameters in the scenarios. However, there may be actual cases that deviate from these modeled scenarios, and therefore, results could be somewhat different than the ranges of results from this analysis. Such deviations are expected to be rare and can be processed through the companion BES Exception Process.

Study Conclusion

The Project 2010-17 Standard Drafting Team conducted a two-step study process to yield a technical justification for the establishment of a voltage threshold below which sub-100 kV loops should not affect the application of Exclusion E1.

All operating entities have guidelines to identify the elements they believe need to be monitored to facilitate the reliable operation of the interconnected transmission system. Pursuant to these guidelines, operating entities in each of the eight Regions in North America have identified and monitor key groupings of the transmission elements that limit the amount of power that can be reliably transferred across their systems. The objective of Step 1 was to identify the lowest monitored voltage level on these key element groupings. The lowest monitored line voltage on the major element groupings provides an indication of the lower limit which operating entities have historically believed necessary to ensure the reliable operation of the interconnected transmission system.

As a result of studying such regional monitoring levels, Step 1 concluded that 30 kV was a reasonable voltage level to initiate the sensitivity analysis conducted in Step 2. This is a conservative value as it is below any of the regional monitoring levels.

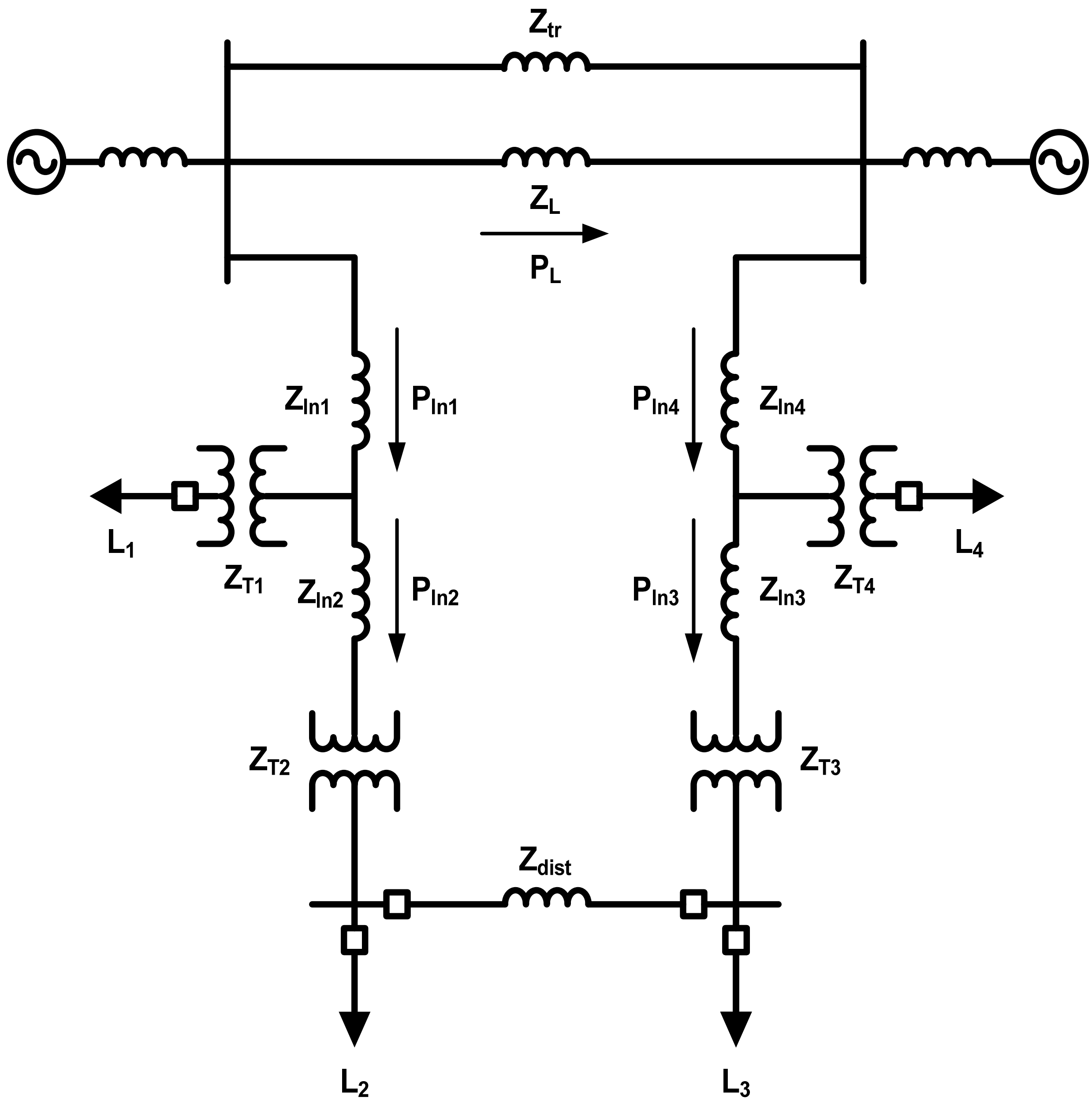
Using the conservative value established by Step 1, the Standard Drafting Team conducted extensive simulations of power flows which demonstrated that there is no power flow reversal into the BES when circuit loop operating voltages are below 50 kV. Therefore, the study concludes that low voltage circuit loops operated below 50 kV should not affect the application of Exclusion E1. This analysis provides an equally effective and efficient alternative to address the Commission's directives expressed in Order No. 773 and 773-A.

The scenarios and configurations utilized in this analysis represent the majority of cases that will be encountered in the industry. The models used in this analysis establish reasonable bounds and use conservative parameters in the scenarios. However, there may be actual cases that deviate from these modeled scenarios, and therefore, results could be somewhat different than the ranges of results from this analysis. Such deviations are expected to be rare and can be processed through the companion BES Exception Process.

Appendix 1: Regional Elements

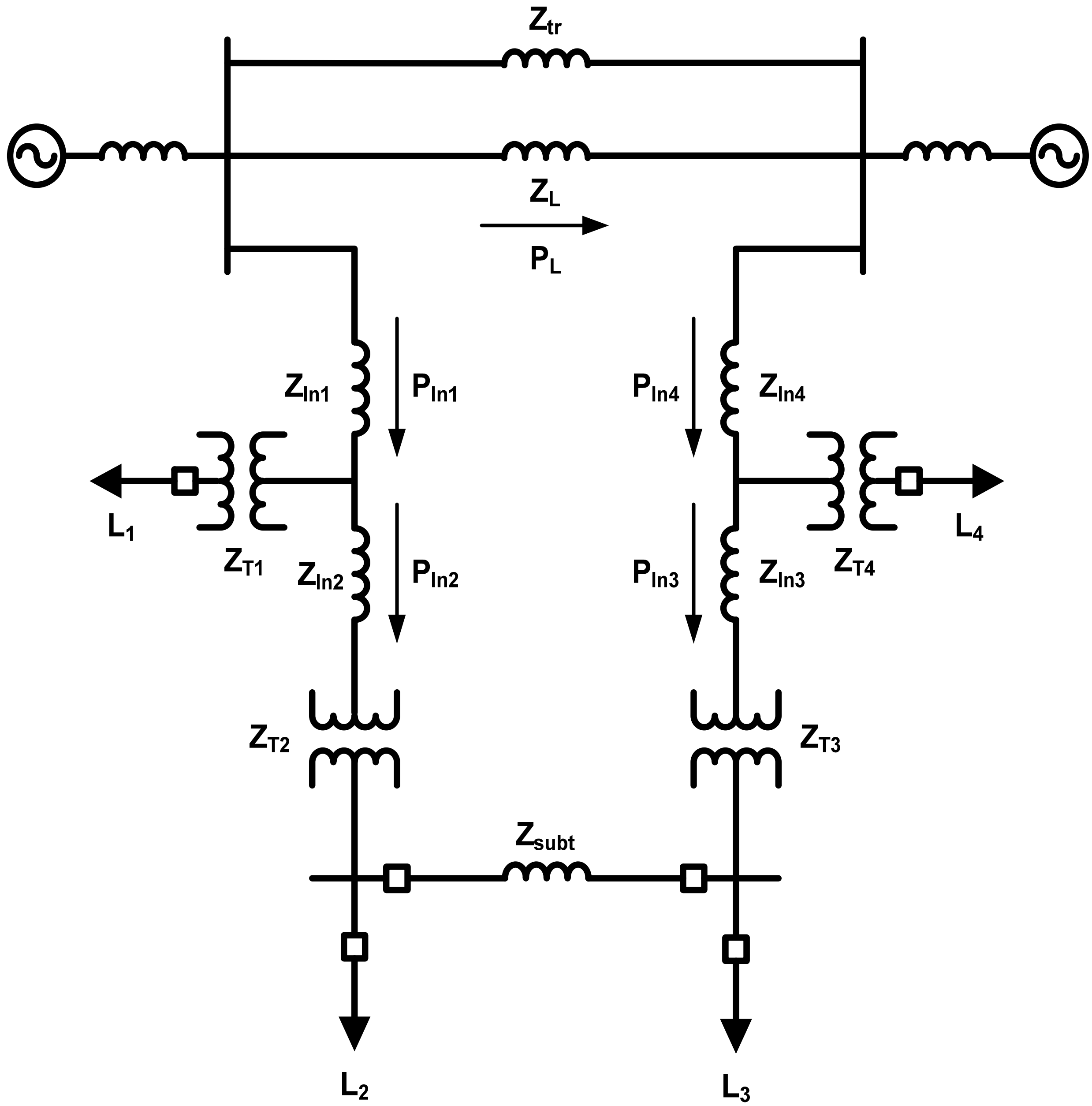
PRIVILEGED AND CONFIDENTIAL INFORMATION HAS BEEN REDACTED FROM THIS PUBLIC VERSION

Appendix 2: One-Line Diagrams



Note: Refer to the notes in Appendix 3 for a description of the symbols in this diagram.

Figure 5: Example Radial Systems with Low Voltage Distribution Tie



Notes: Refer to the notes in Appendix 3 for a description of the symbols in this diagram.
Step-down transformers from sub-transmission voltage to distribution voltage were not explicitly modeled in the simulations.

Figure 6: Example Radial Systems with Sub-transmission Tie

Appendix 3: Simulation Results

										------------ HV Line "L" in-service ------------				-- HV Line "L" out-of-service --				
Case	Z_L (mi.)	Z_{tr} (mi.)	Z_{ln1-4} (total mi.)	Z_{dist} (mi.)	Z_{T1}, Z_{T-4} (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	$P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	LODF
23 kV Base Cases																		
623a0	10	Strong	15	0	10%/10	10%/10	4.0	4.0	110.7	10.9	6.9	1.1	5.1	11.2	7.2	0.8	4.8	0.003
623a2	10	Strong	15	2	10%/10	10%/10	4.0	4.0	110.7	10.7	6.7	1.4	5.4	10.9	6.9	1.1	5.1	0.002
623a5	10	Strong	15	5	10%/10	10%/10	4.0	4.0	110.7	10.3	6.3	1.7	5.7	10.5	6.5	1.5	5.5	0.002
623a0pk	10	Strong	15	0	10%/10	10%/10	8.0	8.0	111.4	19.0	10.9	5.1	13.1	19.3	11.2	4.8	12.8	0.003
623a2pk	10	Strong	15	2	10%/10	10%/10	8.0	8.0	111.4	18.7	10.7	5.4	13.4	18.9	10.9	5.1	13.1	0.002
623a5pk	10	Strong	15	5	10%/10	10%/10	8.0	8.0	111.5	18.3	10.3	5.7	13.7	18.6	10.5	5.5	13.5	0.003
623b0	10	Strong	15	0	10%/20	10%/20	8.0	8.0	111.1	21.7	13.7	2.3	10.3	22.3	14.2	1.8	9.8	0.005
623b2	10	Strong	15	2	10%/20	10%/20	8.0	8.0	111.2	20.7	12.7	3.3	11.3	21.2	13.2	2.9	10.9	0.004
623b5	10	Strong	15	5	10%/20	10%/20	8.0	8.0	111.3	19.7	11.7	4.3	12.3	20.1	12.1	4.0	12.0	0.004
623b0pk	10	Strong	15	0	10%/20	10%/20	16.0	16.0	112.6	37.8	21.7	10.3	26.3	38.3	22.3	9.7	25.8	0.004
623b2pk	10	Strong	15	2	10%/20	10%/20	16.0	16.0	112.7	36.7	20.7	11.3	27.3	37.2	21.2	10.9	26.9	0.004
623b5pk	10	Strong	15	5	10%/20	10%/20	16.0	16.0	112.8	35.7	19.7	12.3	28.4	36.1	20.1	12.0	28.0	0.004

Case	Z_L (mi.)	Z_{tr} (mi.)	$Z_{ln1\text{-}4}$ (total mi.)	Z_{dist} (mi.)	$Z_{T1}, Z_{T\text{-}4}$ (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	----------- HV Line "L" in-service ----------- P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	-- HV Line "L" out-of-service -- $P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	LODF
623c0	10	Strong	15	0	10%/40	10%/40	16.0	16.0	112.2	42.7	26.6	5.4	21.4	43.7	27.7	4.3	20.3	0.009
623c2	10	Strong	15	2	10%/40	10%/40	16.0	16.0	112.5	39.6	23.6	8.4	24.4	40.4	24.4	7.7	23.7	0.007
623c5	10	Strong	15	5	10%/40	10%/40	16.0	16.0	112.7	37.3	21.3	10.8	26.8	37.8	21.8	10.3	26.3	0.004
623c0pk	10	Strong	15	0	10%/40	10%/40	32.0	32.0	115.1	74.9	42.8	21.2	53.3	76.0	43.9	20.2	52.2	0.010
623c2pk	10	Strong	15	2	10%/40	10%/40	32.0	32.0	115.4	71.8	39.7	24.3	56.4	72.6	40.5	23.6	55.6	0.007
623c5pk	10	Strong	15	5	10%/40	10%/40	32.0	32.0	115.6	69.4	37.4	26.7	58.8	70.0	37.9	26.2	58.3	0.005
723a0	10	Medium	15	0	10%/10	10%/10	4.0	4.0	108.3	10.9	6.9	1.1	5.1	11.9	7.9	0.1	4.1	0.009
723a2	10	Medium	15	2	10%/10	10%/10	4.0	4.0	108.3	10.6	6.6	1.4	5.4	11.5	7.5	0.5	4.5	0.008
723a5	10	Medium	15	5	10%/10	10%/10	4.0	4.0	108.4	10.3	6.3	1.8	5.8	11.1	7.1	1.0	5.0	0.007
723a0pk	10	Medium	15	0	10%/10	10%/10	8.0	8.0	110.4	18.9	10.9	5.1	13.1	20.0	12.0	4.0	12.1	0.010
723a2pk	10	Medium	15	2	10%/10	10%/10	8.0	8.0	110.5	18.6	10.6	5.4	13.4	19.6	11.6	4.4	12.5	0.009
723a5pk	10	Medium	15	5	10%/10	10%/10	8.0	8.0	110.6	18.3	10.3	5.7	13.7	19.1	11.1	4.9	12.9	0.007
723b0	10	Medium	15	0	10%/20	10%/20	8.0	8.0	109.7	21.6	13.6	2.4	10.4	23.6	15.6	0.4	8.4	0.018
723b2	10	Medium	15	2	10%/20	10%/20	8.0	8.0	110.0	20.6	12.6	3.4	11.4	22.3	14.3	1.7	9.8	0.015
723b5	10	Medium	15	5	10%/20	10%/20	8.0	8.0	110.2	19.7	11.7	4.4	12.4	21.0	13.0	3.1	11.1	0.012
723b0pk	10	Medium	15	0	10%/20	10%/20	16.0	16.0	114.0	37.8	21.8	10.2	26.3	39.9	23.8	8.2	24.2	0.018
723b2pk	10	Medium	15	2	10%/20	10%/20	16.0	16.0	114.3	36.8	20.8	11.3	27.3	38.5	22.5	9.6	25.6	0.015
723b5pk	10	Medium	15	5	10%/20	10%/20	16.0	16.0	114.5	35.8	19.8	12.3	28.3	37.2	21.1	10.9	27.0	0.012

Case	Z_L (mi.)	Z_{tr} (mi.)	Z_{ln1-4} (total mi.)	Z_{dist} (mi.)	Z_{T1}, Z_{T-4} (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	----------- HV Line "L" in-service ----------- P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	-- HV Line "L" out-of-service -- $P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	LODF
723c0	10	Medium	15	0	10%/40	10%/40	16.0	16.0	112.6	42.7	26.7	5.3	21.3	46.5	31.4	1.6	17.6	0.034
723c2	10	Medium	15	2	10%/40	10%/40	16.0	16.0	113.5	39.7	23.7	8.4	24.4	42.4	26.4	5.7	21.7	0.024
723c5	10	Medium	15	5	10%/40	10%/40	16.0	16.0	114.1	37.4	21.4	10.7	26.7	39.3	23.3	8.8	24.8	0.017
723c0pk	10	Medium	15	0	10%/40	10%/40	32.0	32.0	121.2	75.5	43.4	20.7	52.7	79.5	47.4	16.7	48.7	0.033
723c2pk	10	Medium	15	2	10%/40	10%/40	32.0	32.0	122.0	72.2	40.1	23.9	55.9	75.2	43.1	21.1	53.1	0.025
723c5pk	10	Medium	15	5	10%/40	10%/40	32.0	32.0	122.7	69.8	37.7	26.4	58.5	71.8	39.7	24.4	56.5	0.016
823a0	10	Weak	15	0	10%/10	10%/10	4.0	4.0	106.1	10.8	6.8	1.2	5.2	12.9	8.9	-0.9	3.1	0.020
823a2	10	Weak	15	2	10%/10	10%/10	4.0	4.0	106.2	10.5	6.5	1.5	5.5	12.4	8.4	-0.4	3.6	0.018
823a5	10	Weak	15	5	10%/10	10%/10	4.0	4.0	106.4	10.2	62.0	1.8	5.8	11.9	7.9	0.2	4.2	0.016
823a0pk	10	Weak	15	0	10%/10	10%/10	8.0	8.0	109.6	18.9	10.9	5.1	13.1	21.1	13.0	3.0	11.0	0.020
823a2pk	10	Weak	15	2	10%/10	10%/10	8.0	8.0	109.7	18.6	10.6	5.4	13.4	20.6	12.6	3.5	11.5	0.018
823a5pk	10	Weak	15	5	10%/10	10%/10	8.0	8.0	109.8	18.3	10.3	5.7	13.8	20.0	12.0	4.0	12.1	0.015
823b0	10	Weak	15	0	10%/20	10%/20	8.0	8.0	108.4	21.5	13.5	2.5	10.5	25.6	17.6	-1.6	6.4	0.038
823b2	10	Weak	15	2	10%/20	10%/20	8.0	8.0	108.8	20.6	12.6	3.4	11.4	24.0	16.0	0.1	8.1	0.031
823b5	10	Weak	15	5	10%/20	10%/20	8.0	8.0	109.2	19.6	11.6	4.4	12.4	22.3	14.3	1.8	9.8	0.025
823b0pk	10	Weak	15	0	10%/20	10%/20	16.0	16.0	115.3	37.9	21.9	10.2	26.2	42.2	26.1	5.9	21.9	0.037
823b2pk	10	Weak	15	2	10%/20	10%/20	16.0	16.0	115.7	36.9	20.8	11.2	27.2	40.4	24.4	7.7	23.7	0.030
823b5pk	10	Weak	15	5	10%/20	10%/20	16.0	16.0	116.2	35.9	19.8	12.2	28.2	38.7	22.7	9.4	25.5	0.024

										----------- HV Line "L" in-service -----------				-- HV Line "L" out-of-service --				
Case	**Z_L (mi.)**	**Z_{tr} (mi.)**	**Z_{ln1-4} (total mi.)**	**Z_{dist} (mi.)**	**Z_{T1}, Z_{T-4} (Z/MVA)**	**Z_{T2}, Z_{T3} (Z/MVA)**	**L_1, L_4 (MW)**	**L_2, L_3 (MW)**	**P_L (MVA)**	**P_{ln1} (MVA)**	**P_{ln2} (MVA)**	**P_{ln3} (MVA)**	**P_{ln4} (MVA)**	**$P_{ln1'}$ (MVA)**	**$P_{ln2'}$ (MVA)**	**$P_{ln3'}$ (MVA)**	**$P_{ln4'}$ (MVA)**	**LODF**
823c0	10	Weak	15	0	10%/40	10%/40	16.0	16.0	113.1	42.7	26.7	5.3	21.3	50.3	34.3	-2.3	13.7	0.067
823c2	10	Weak	15	2	10%/40	10%/40	16.0	16.0	114.4	39.7	23.7	8.3	24.3	45.4	29.3	2.8	18.8	0.050
823c5	10	Weak	15	5	10%/40	10%/40	16.0	16.0	115.5	37.4	21.4	10.6	26.7	41.4	25.4	6.8	22.8	0.035
823c0pk	10	Weak	15	0	10%/40	10%/40	32.0	32.0	126.7	76.0	43.9	20.2	52.2	84.4	52.3	11.8	43.8	0.066
823c2pk	10	Weak	15	2	10%/40	10%/40	32.0	32.0	128.2	72.7	40.6	23.5	55.6	78.9	48.6	17.4	49.5	0.048
823c5pk	10	Weak	15	5	10%/40	10%/40	32.0	32.0	129.3	70.1	38.0	26.1	58.2	74.5	42.4	21.8	53.9	0.034
Sensitivity to Length of Lines 1-4																		
723a0_30	10	Medium	30	0	10%/10	10%/10	4.0	4.0	108.3	10.8	6.8	1.2	5.2	11.8	7.8	0.2	4.2	0.009
723a2_30	10	Medium	30	2	10%/10	10%/10	4.0	4.0	108.4	10.5	6.5	1.5	5.5	11.4	7.4	0.6	4.6	0.008
723a5_30	10	Medium	30	5	10%/10	10%/10	4.0	4.0	108.5	10.2	6.2	1.8	5.8	11.0	7.0	1.0	5.0	0.007
Selected 34.5 kV cases																		
834a0	10	Weak	15	0	10%/10	10%/10	4.0	4.0	106.1	10.8	6.8	1.2	5.2	12.9	8.9	-0.9	3.1	0.020
834a2	10	Weak	15	2	10%/10	10%/10	4.0	4.0	106.1	10.7	6.7	1.3	5.3	12.7	8.7	-0.7	3.3	0.019
834a5	10	Weak	15	5	10%/10	10%/10	4.0	4.0	106.2	10.5	6.5	1.5	5.5	12.4	8.4	-0.4	3.6	0.018
834a0pk	10	Weak	15	0	10%/10	10%/10	8.0	8.0	109.6	18.9	10.9	5.1	13.1	21.1	13.0	3.0	11.0	0.020
834a2pk	10	Weak	15	2	10%/10	10%/10	8.0	8.0	109.6	18.8	10.8	5.2	13.3	20.8	12.8	3.2	11.2	0.018
834a5pk	10	Weak	15	5	10%/10	10%/10	8.0	8.0	109.7	18.6	10.6	5.4	13.4	20.5	12.5	3.5	11.5	0.017
834b0	10	Weak	15	0	10%/20	10%/20	8.0	8.0	108.4	21.5	13.5	2.5	10.5	25.6	17.6	-1.6	6.4	0.038

Case	Z_L (mi.)	Z_{tr} (mi.)	Z_{ln1-4} (total mi.)	Z_{dist} (mi.)	Z_{T1}, Z_{T-4} (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	----------- HV Line "L" in-service ----------- P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	-- HV Line "L" out-of-service -- $P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	LODF
834b2	10	Weak	15	2	10%/20	10%/20	8.0	8.0	108.6	21.1	13.1	2.9	10.9	24.8	16.8	-0.7	7.3	0.034
834b5	10	Weak	15	5	10%/20	10%/20	8.0	8.0	108.9	20.5	12.5	3.5	11.5	23.8	15.8	0.3	8.3	0.030
834b0pk	10	Weak	15	0	10%/20	10%/20	16.0	16.0	115.3	37.9	21.9	10.2	26.2	42.2	26.1	5.9	21.9	0.037
834b2pk	10	Weak	15	2	10%/20	10%/20	16.0	16.0	115.5	37.4	21.4	10.7	26.7	41.3	25.3	6.8	22.8	0.034
834b5pk	10	Weak	15	5	10%/20	10%/20	16.0	16.0	115.8	36.8	20.7	11.3	27.3	40.3	24.2	7.8	23.9	0.030
834c0	10	Weak	15	0	10%/40	10%/40	16.0	16.0	113.1	42.7	26.7	5.3	21.3	50.3	34.3	-2.3	13.7	0.067
834c2	10	Weak	15	2	10%/40	10%/40	16.0	16.0	113.8	41.2	25.2	6.9	22.9	47.8	31.7	0.4	16.4	0.058
834c5	10	Weak	15	5	10%/40	10%/40	16.0	16.0	114.6	39.5	23.5	8.5	24.6	45.0	29.0	3.2	19.2	0.048
834c0pk	10	Weak	15	0	10%/40	10%/40	32.0	32.0	126.7	76.0	43.9	20.2	52.2	84.4	52.3	11.8	43.8	0.066
834c2pk	10	Weak	15	2	10%/40	10%/40	32.0	32.0	127.5	74.2	42.1	21.9	54.0	81.5	49.4	14.7	46.8	0.057
834c5pk	10	Weak	15	5	10%/40	10%/40	32.0	32.0	128.3	72.4	40.3	23.8	55.8	78.5	46.4	17.9	49.9	0.048
834d0	10	Weak	15	0	7%/40	7%/40	16.0	16.0	111.6	46.3	30.3	1.7	17.7	56.2	40.1	-8.1	7.9	0.089
834d2	10	Weak	15	2	7%/40	7%/40	16.0	16.0	112.8	43.6	27.6	4.4	20.4	51.8	35.8	-3.6	12.4	0.073
834d5	10	Weak	15	5	7%/40	7%/40	16.0	16.0	113.9	41.1	25.1	7.0	23.0	47.6	31.6	0.6	16.6	0.057
834d0pk	10	Weak	15	0	7%/40	7%/40	32.0	32.0	124.9	80.0	47.9	16.2	48.2	90.9	58.8	5.3	37.3	0.087
834d2pk	10	Weak	15	2	7%/40	7%/40	32.0	32.0	126.3	77.0	44.9	19.2	51.2	86.1	54.0	10.2	42.2	0.072
834d5pk	10	Weak	15	5	7%/40	7%/40	32.0	32.0	127.5	74.2	42.1	22.0	54.1	81.4	49.3	15.0	47.0	0.056

										------------ HV Line "L" in-service ------------				-- HV Line "L" out-of-service --				
Case	Z_L (mi.)	Z_{tr} (mi.)	Z_{ln1-4} (total mi.)	Z_{dist} (mi.)	Z_{T1}, Z_{T-4} (Z/MVA)	Z_{T2}, Z_{T3} (Z/MVA)	L_1, L_4 (MW)	L_2, L_3 (MW)	P_L (MVA)	P_{ln1} (MVA)	P_{ln2} (MVA)	P_{ln3} (MVA)	P_{ln4} (MVA)	$P_{ln1'}$ (MVA)	$P_{ln2'}$ (MVA)	$P_{ln3'}$ (MVA)	$P_{ln4'}$ (MVA)	LODF
Selected 12.47 kV cases																		
812a0	10	Weak	15	0	10%/10	10%/10	4.0	4.0	106.1	10.8	6.8	1.2	5.2	12.9	8.9	-0.9	3.1	0.020
812a2	10	Weak	15	2	10%/10	10%/10	4.0	4.0	106.4	10.1	6.1	1.9	5.9	11.6	7.6	0.4	4.4	0.014
812a5	10	Weak	15	5	10%/10	10%/10	4.0	4.0	106.7	9.4	5.4	2.6	6.6	10.5	6.5	1.5	5.5	0.010
812a0pk	10	Weak	15	0	10%/10	10%/10	8.0	8.0	109.6	18.9	10.9	5.1	13.1	21.1	13.0	3.0	11.0	0.020
812a2pk	10	Weak	15	2	10%/10	10%/10	8.0	8.0	109.9	18.1	10.1	5.9	13.9	19.7	11.7	4.3	12.4	0.015
812a5pk	10	Weak	15	5	10%/10	10%/10	8.0	8.0	110.2	17.5	9.5	6.5	14.5	18.6	10.6	5.5	13.5	0.010
812b0	10	Weak	15	0	10%/20	10%/20	8.0	8.0	108.4	21.5	13.5	2.5	10.5	25.6	17.6	-1.6	6.4	0.038
812b2	10	Weak	15	2	10%/20	10%/20	8.0	8.0	109.4	19.2	11.2	4.8	12.8	21.7	13.6	2.5	10.5	0.023
812b5	10	Weak	15	5	10%/20	10%/20	8.0	8.0	110.0	17.9	9.9	6.1	14.1	19.4	11.4	4.7	12.7	0.014
812b0pk	10	Weak	15	0	10%/20	10%/20	16.0	16.0	115.3	37.9	21.9	10.2	26.2	42.2	26.1	5.9	21.9	0.037
812b2pk	10	Weak	15	2	10%/20	10%/20	16.0	16.0	116.4	35.4	19.4	12.6	28.6	38.0	22.0	10.2	26.2	0.022
812b5pk	10	Weak	15	5	10%/20	10%/20	16.0	16.0	117.0	34.1	18.0	14.0	30.0	35.6	19.6	12.6	28.6	0.013
812c0	10	Weak	15	0	10%/40	10%/40	16.0	16.0	113.1	42.7	26.7	5.3	21.3	50.3	34.3	-2.3	13.7	0.067
812c2	10	Weak	15	2	10%/40	10%/40	16.0	16.0	115.9	36.6	20.6	11.5	27.5	40.0	24.0	8.3	24.3	0.029
812c5	10	Weak	15	5	10%/40	10%/40	16.0	16.0	116.8	34.4	18.4	13.7	29.7	36.2	20.2	12.0	28.0	0.015
812c0pk	10	Weak	15	0	10%/40	10%/40	32.0	32.0	126.7	76.0	43.9	20.2	52.2	84.4	52.3	11.8	43.8	0.066
812c2pk	10	Weak	15	2	10%/40	10%/40	32.0	32.0	129.7	69.2	37.1	27.1	59.1	73.0	40.9	23.5	55.5	0.029

										----------- HV Line "L" in-service -----------				-- HV Line "L" out-of-service --				
Case	**Z_L (mi.)**	**Z_{tr} (mi.)**	**Z_{ln1-4} (total mi.)**	**Z_{dist} (mi.)**	**Z_{T1}, Z_{T-4} (Z/MVA)**	**Z_{T2}, Z_{T3} (Z/MVA)**	**L_1, L_4 (MW)**	**L_2, L_3 (MW)**	**P_L (MVA)**	**P_{ln1} (MVA)**	**P_{ln2} (MVA)**	**P_{ln3} (MVA)**	**P_{ln4} (MVA)**	**$P_{ln1'}$ (MVA)**	**$P_{ln2'}$ (MVA)**	**$P_{ln3'}$ (MVA)**	**$P_{ln4'}$ (MVA)**	**LODF**
812c5pk	10	Weak	15	5	10%/40	10%/40	32.0	32.0	130.8	66.7	34.7	29.4	61.5	68.8	36.7	27.6	59.6	0.016
Selected 46 kV cases																		
846e0	10	Weak	15	0	10%/40	7%/50	16.0	20.0	112.1	53.1	37.1	2.9	18.9	64.7	48.7	-8.6	7.4	0.103
846e2	10	Weak	15	2	10%/40	7%/50	16.0	20.0	113.2	50.7	34.7	5.3	21.3	60.9	44.8	-4.7	11.3	0.090
846e5	10	Weak	15	5	10%/40	7%/50	16.0	20.0	114.3	48.2	32.1	7.9	24.0	56.7	40.7	-0.4	15.6	0.074
Sub-transmission cases																		
115-69 kV																		
669f25	40	Strong	20	25	10%/40	7%/60	16.0	24.0	114.0	76.0	59.8	-10.8	5.2	79.6	63.4	-14.2	1.8	0.032
769f25	40	Medium	20	25	10%/40	7%/60	16.0	24.0	111.7	75.3	59.1	-10.1	5.9	87.3	71.0	-21.2	-5.2	0.107
869f25	40	Weak	20	25	10%/40	7%/60	16.0	24.0	109.8	74.7	58.5	-9.6	6.4	97.0	80.6	-30.0	-14.0	0.203
115-55 kV																		
655e25	40	Strong	20	25	10%/40	7%/50	16.0	20.0	114.5	62.1	46.0	-5.0	11.0	64.8	48.7	-7.5	8.5	0.024
755e25	40	Medium	20	25	10%/40	7%/50	16.0	20.0	113.3	61.8	45.7	-4.8	11.2	70.9	54.8	-13.0	3.0	0.080
855e25	40	Weak	20	25	10%/40	7%/50	16.0	20.0	112.1	61.5	45.4	-4.5	11.5	79.1	62.9	-20.2	-4.2	0.157
855f25																		
115-46 kV																		
646e25	40	Strong	20	25	10%/40	7%/50	16.0	20.0	115.0	57.3	41.2	-0.2	15.8	59.5	43.4	-2.1	13.9	0.019
746e25	40	Medium	20	25	10%/40	7%/50	16.0	20.0	114.6	57.2	41.2	-0.1	15.9	64.9	48.8	-6.8	9.2	0.067
846e25	40	Weak	20	25	10%/40	7%/50	16.0	20.0	114.2	57.2	41.1	0.0	16.0	72.4	56.2	-13.1	2.9	0.133
115-34.5 kV																		
634d25	40	Strong	20	25	10%/40	7%/40	16.0	16.0	115.3	46.2	30.2	2.6	18.7	47.7	31.7	1.4	17.4	0.013

										------------ HV Line "L" in-service ------------				-- HV Line "L" out-of-service --				
Case	**Z_L (mi.)**	**Z_{tr} (mi.)**	**Z_{ln1-4} (total mi.)**	**Z_{dist} (mi.)**	**Z_{T1}, Z_{T-4} (Z/MVA)**	**Z_{T2}, Z_{T3} (Z/MVA)**	**L_1, L_4 (MW)**	**L_2, L_3 (MW)**	**P_L (MVA)**	**P_{ln1} (MVA)**	**P_{ln2} (MVA)**	**P_{ln3} (MVA)**	**P_{ln4} (MVA)**	**$P_{ln1'}$ (MVA)**	**$P_{ln2'}$ (MVA)**	**$P_{ln3'}$ (MVA)**	**$P_{ln4'}$ (MVA)**	**LODF**
734d25	40	Medium	20	25	10%/40	7%/40	16.0	16.0	115.4	46.3	30.2	2.6	18.6	51.5	35.5	-1.9	14.1	0.045
834d25	40	Weak	20	25	10%/40	7%/40	16.0	16.0	115.5	46.3	30.2	2.6	18.6	57.1	41.0	-6.4	9.6	0.094
138-69 kV																		
869f25-138	40	Weak	20	25	10%/40	7%/60	16.0	24.0	112.0	66.5	50.4	-1.8	14.2	84.0	67.9	-18.3	-2.3	0.156
869f25-138'	40	Weak	20	25	10%/40	7%/60	16.0	24.0	131.9	71.1	55.0	-6.3	9.8	92.0	75.8	-25.6	-9.6	0.158
138-55 kV																		
855e25-138	40	Weak	20	25	10%/40	7%/50	16.0	20.0	113.5	55.1	39.0	1.5	17.5	68.4	52.3	-10.8	5.2	0.117
855e25-138'	40	Weak	20	25	10%/40	7%/60	16.0	20.0	134.0	58.5	42.4	-1.7	14.3	74.4	58.3	-16.2	-0.2	0.119
161-69 kV																		
869f25-161	40	Weak	20	25	10%/40	7%/60	16.0	24.0	113.2	60.7	44.7	3.7	19.7	74.8	58.8	-9.8	6.2	0.125
869f25-161'	40	Weak	20	25	10%/40	7%/60	16.0	24.0	153.0	68.0	52.0	-3.3	12.7	87.3	71.2	-21.4	-5.4	0.126
161-55 kV																		
855e25-161	40	Weak	20	25	10%/40	7%/50	16.0	20.0	114.1	50.7	34.7	5.6	21.6	61.1	45.1	-4.2	11.8	0.091
855e25-161'	40	Weak	20	25	10%/40	7%/60	16.0	20.0	154.8	56.0	40.0	0.6	16.6	70.3	54.3	-12.6	3.4	0.092
230-69 kV																		
869f25-230	40	Weak	20	25	10%/40	7%/60	16.0	24.0	116.3	51.3	35.3	12.8	28.8	59.4	43.3	5.0	21.0	0.070
869f25-230'	40	Weak	20	25	10%/40	7%/60	16.0	24.0	217.7	61.2	45.2	3.2	19.2	76.5	60.4	-11.4	4.7	0.070
230-55 kV																		
855e25-230	40	Weak	20	25	10%/40	7%/50	16.0	20.0	116.1	43.8	27.8	12.3	28.3	49.5	33.5	6.7	22.8	0.049
855e25-230'	40	Weak	20	25	10%/40	7%/50	16.0	20.0	218.7	50.8	34.8	5.6	21.6	61.7	45.7	-4.7	11.3	0.050

Notes:

The following notes provide information to understand the meaning of each column heading and underlying assumptions used in the analysis. See also the one-line diagrams in Figures 5 and 6 of Appendix 2 for additional information.

Z_L

The table provides the length of line "L" in miles to provide a high-level, qualitative understanding of the line impedance. The line impedance (Z_L) is the length of the line in miles times the per mile impedance. Assumptions used in determining the per mile impedance are as follows:

Voltage (kV)	Conductor	Phase Spacing	GMD	Impedance (Ω/mile)	Impedance (p.u./mile)
230	954 ACSR	20' H-frame	25.20'	0.100 + j0.786	0.000189 + J 0.00149
161	954 ACSR	16' H-frame	20.16'	0.100 + j0.759	0.000384 + j 0.00293
138	795 ACSR	13' H-frame	16.38'	0.117 + j0.738	0.000615 + j 0.00388
115	795 ACSR	11' H-frame	13.86'	0.117 + j0.718	0.000886 + j 0.00543

Z_{tr}

The transfer impedance (Z_{tr}) represents the impedance of the system in parallel with the subsystem under study. Analysis was performed for three levels of parallel transfer impedance which have been characterized as strong, medium, and weak. The strong system has relatively low impedance and thus will pick up more power flow when line "L" is tripped. The weak system has relatively high impedance and thus will pick up less power flow when line "L" is tripped. The medium system has a mid-range impedance value. The actual values of the transfer impedance vary between the distribution cases and the sub-transmission cases.

	Z_{tr} in distribution cases (p.u.)	Z_{tr} in sub-transmission cases (p.u.)
Strong	0.00089 + j 0.00543	0.00354 + j 0.0217
Medium	0.00319 + j 0.0195	0.0128 + j 0.0782
Weak	0.00664 + j 0.0407	0.0266 + j 0.163

Z_{ln1-4}

The table provides the total length of lines "ln1" through "ln4." In all simulations these four lines have equal length. The total length in miles provides a high-level, qualitative understanding of the line impedance. The line impedances are the length of each line in miles times the per mile impedance. Assumptions used in determining the per mile impedance are the same as provided above for line "L."

Z_{dist}

The table provides the length of the line in miles to provide a high-level, qualitative understanding of the line impedance. The impedance of the distribution system or sub-transmission system (Z_{dist}) is the length

of the distribution tie or sub-transmission line in miles times the per mile impedance. A value of zero miles is used when the distribution tie is a solid bus tie. Assumptions used in determining the per mile impedance are as follows:

Voltage (kV)	Conductor	Phase Spacing	GMD	Impedance (Ω/mile)	Impedance (p.u./mile)
69	636 ACSR	6' Horizontal	7.56'	0.145 + j0.657	0.00305 + j 0.0138
55	556 ACSR	6' Horizontal	7.56'	0.168 + j0.677	0.00555 + j 0.0224
46	477 ACSR	6' Triangular	6.00'	0.193 + j0.647	0.00913 + j 0.0306
34.5	477 ACSR	4' Triangular	4.00'	0.193 + j0.598	0.0162 + j 0.0503
23	477 ACSR	4' Triangular	4.00'	0.193 + j0.598	0.0365 + j 0.113
12.47	336 ACSR	2' Horizontal	2.52'	0.274 + j0.563	0.176 + j 0.362

Z_{T1-4}

The transformer impedance is reported as percent impedance on the transformer MVA base. Each transformer has three ratings: OA (oil and air), FA (forced air – i.e., fans), and FOA (forced oil and air – i.e., pumps and fans). The transformer MVA base rating is the OA rating. The FA rating is 133% of the OA rating and the FOA rating is 167% of the OA rating (e.g., a 20 MVA transformer has a 20 MVA OA rating, 26.7 MVA FA rating, and 33.3 MVA FOA rating, typically identified as a nameplate of 20/26.7/33.3 MVA).

The transformer impedance and rating for each voltage level are based on typical values. Distribution transformer impedance is generally higher to limit current on the distribution equipment. Secondary current typically is not a concern on sub-transmission transformers, so impedance is typically lower to limit reactive power losses and voltage drop.

L_1, L_2, L_3, L_4

The transformer load is based on the transformer OA rating. Transformers are loaded at 80 percent of the transformer base MVA in the simulations modeling a peak system load condition. The substations modeled have two transformers, with each transformer able to supply the total station load. Thus, if one transformer is forced out-of-service, the load on the remaining transformer will be 160 percent of its base rating, which is approximately equal to its FOA rating.

Transformers are loaded at 40 percent of the transformer base MVA in the simulations modeling a light system load condition.

HV Line "L" in-service: P_L, P_{ln1}, , P_{ln2}, P_{ln3}, P_{ln4}

The loading on each line, with all lines in service, is listed in MVA. The loading on line "L" is the power that is redistributed between the parallel transmission system and the distribution or sub-transmission system when line "L" is taken out of service.

HV Line "L" out-of-service: P_{ln1}, , P_{ln2}, P_{ln3}, P_{ln4}

The loading on each line, with line "L" out-of-service, is listed in MVA.

LODF

The Line Outage Distribution Factor (LODF) is the fraction of the load on line "L" that is picked up on the distribution or sub-transmission system. This information is included for illustrative purposes to understand the analysis, but was not used in identifying the voltage threshold for Exclusion E1.

Appendix 4: Summary of Loop Flow Issue Through Systems <50 kV

In the course of developing 'real-world' scenarios for the analysis of potential sub-100 kV loop flows, the Standard Drafting Team found that the industry has employed various measures to minimize the subject loop flows. Some of these methods that were found to be applied by entities on sub-100 kV loop systems are described below. However, it is important to note that the presence of the equipment in the following examples does not remove or lessen an entity's obligations associated with the bright-line application of the Bulk Electric System (BES) definition.

Sustained power flow through substation power transformers and low voltage loops is generally undesirable and, in some instances injurious. For this reason, power system engineers typically address this issue in their design, operating, and planning criteria and apply methods to prevent this condition from occurring. The high impedance of transformers and low voltage elements inherently prevent excessive flow, but in many instances this flow can exceed ratings of equipment. For these reasons entities develop control schemes, add relaying, and provide operational and planning guidelines to prevent this loop flow. Figure 7 depicts two systems that could provide a possible loop flow across the low voltage system and back up to the high voltage system. The loop flow in these diagrams is increased when the breaker on the high voltage side (breaker B) is opened.

The diagrams presented below depict a generic power system. The higher voltage and lower voltage circuit breakers and bus arrangements will, in practice, vary (i.e., straight bus, half-breaker, ring bus, breaker-and-a-half, etc.), but the concepts remain the same.

Specifically, Figure 7, shown below, depicts segments of an electrical power system. They consist of a greater than 100 kV system and a sub-100 kV system. Figure 7 depicts the power flow through the electrical system under the condition that all circuit breakers are closed (normal condition). In the event that circuit breaker B opens (i.e., manually, supervisory control, or protective device operation) and (1) and either of the sub-100 kV line circuit breakers (A or C) or (2) either of the low-side transformer circuit breakers (D or F) or (3) the low-side bus tie circuit breaker (E) does not open, a condition could occur where some amount of flow will occur through the sub-100 kV system to the greater than 100 kV system. This flow is severely limited by the high impedance of the two transformers in series and the sub-100 kV system impedance. This condition, however, may be deemed undesirable from an equipment standpoint and precautions may be taken to prevent it. Subsequent sections of this appendix show some of the physical schemes that entities can employ in this regard.

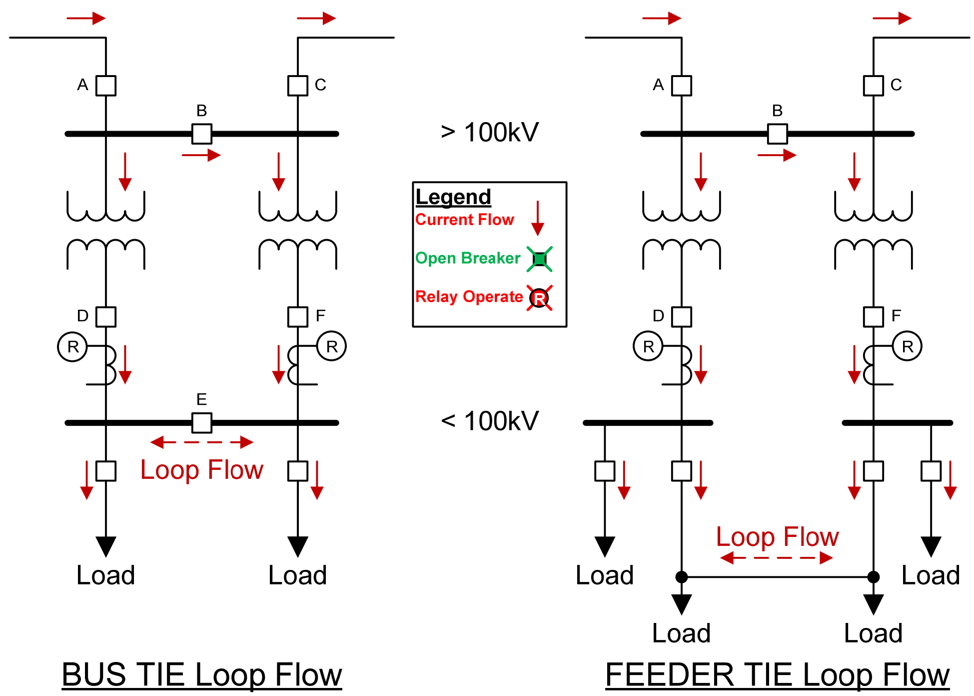


Figure 7. Summary of Loop Flow

Interlocked Control Schemes

Interlocking control schemes can be used to prevent low voltage loop flow. One method to preclude sustained power flow from the lower voltage to the higher voltage portion of the system is to include control system interlocks which will cross-trip certain circuit breaker(s) when other specified circuit breakers are opened. This condition is generally rare since bus designs and protective relay system operations generally do not result in this condition occurring. Operational guidelines usually instruct personnel to avoid the use of the interlocking schemes during normal or planned switching. However, unplanned actions can cause breakers to open and result in the desirable operation of the interlocking schemes. This method, therefore, is considered to be conservative but, never-the-less, it is applied in some instances.

Figure 8 below shows how an interlock scheme would function to prevent low voltage loop flow. When the high side breaker (breaker B) is opened, the low side breaker (breaker E) is also opened. This action prevents low side loop flow. The interlocking scheme could be applied in various combinations and the figure below is a simplified illustration of such a scheme.

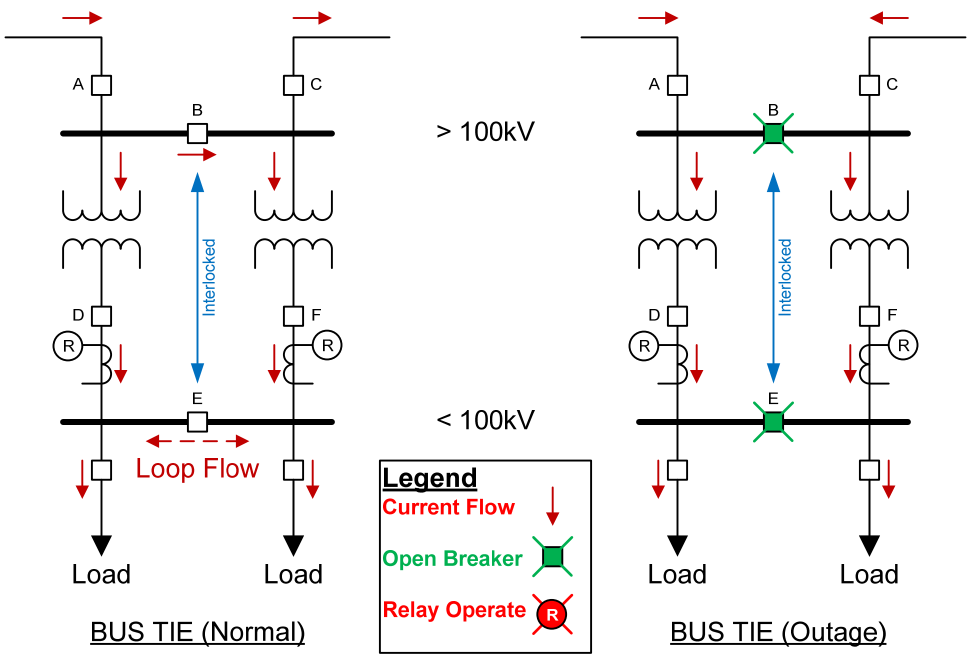


Figure 8. Interlocking Schemes

Reverse Power Schemes

Protection schemes can also be deployed to prevent sustained loop flows through the sub-100 kV system. Reverse power applications are one example of a protection scheme that prevents sustained undesirable low voltage loop flow. In some instances, protective devices will preclude sustained loop flows due to their settings and in other instances protective schemes are specifically applied to preclude this undesirable operating condition.

Figure 9 below shows how a reverse power scheme would function to prevent sub-100 kV loop flow. When the high side breaker (breaker B) is opened, current may flow from the high voltage side (breaker A) through the low voltage bus and back to the high voltage side (breaker C). A relay on breaker F is applied to sense the reverse flow (relay shown in yellow in the diagram) and will operate if this flow continues (relay shown in red in the diagram). When the reverse power relay operates it will trip breaker F. This action prevents reverse power flow through the transformer and low voltage loop flow. The reverse power scheme is set to sense a minimum amount of power flowing in a reverse direction and is usually set much less than the transformer rating. The figure below is a simplified illustration of a reverse power scheme.

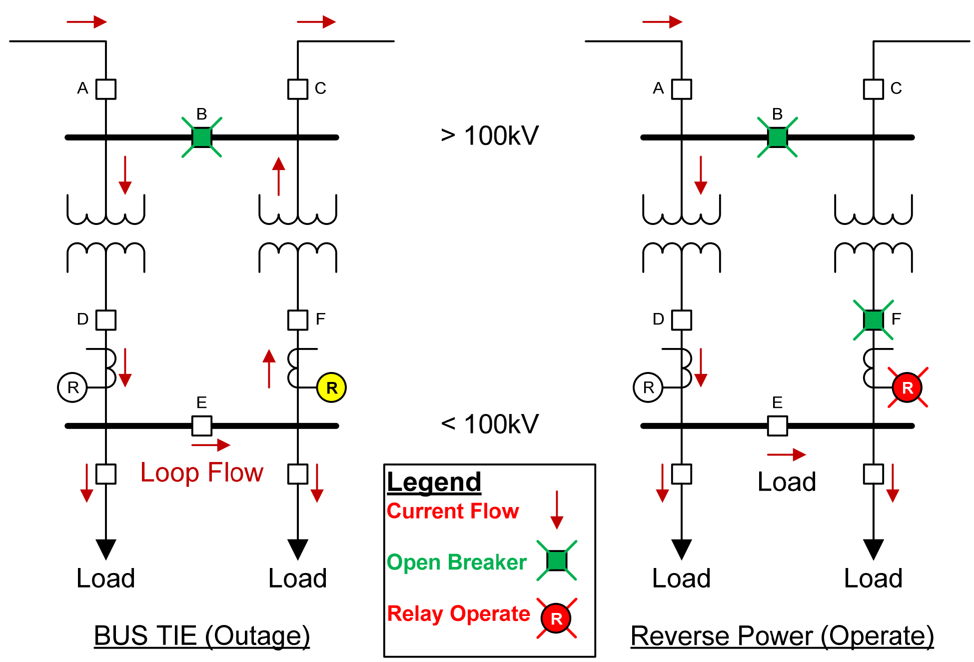


Figure 9. Reverse Power Schemes

Transformer Overcurrent Limitations

Transformer overcurrent protection schemes can also be deployed to prevent sustained loop flows through the sub-100 kV system. Figure 10 below shows how a transformer overcurrent scheme would function to prevent sub-100 kV loop flow. When the high side breaker (breaker B) is opened, current may flow from the high voltage side (breaker A) through the low voltage bus and back to the high

voltage side (breaker C). The relay on the transformer and breaker D is applied to protect the transformer from excessive overloads and faults on the low voltage system. If a fault occurs or the transformer is over-loaded then the relay on breaker D will sense this excessive flow (relay shown in yellow in the diagram) and will operate if this flow continues (relay shown in red in the diagram). When the transformer overcurrent relay operates it will trip breaker D. This action unloads the transformer in question and prevents low voltage loop flow. The transformer overcurrent relay is typically set to allow the transformer to be loaded to the emergency rating of the transformer plus a small safety margin. The figure below is a simplified illustration of a transformer overcurrent scheme.

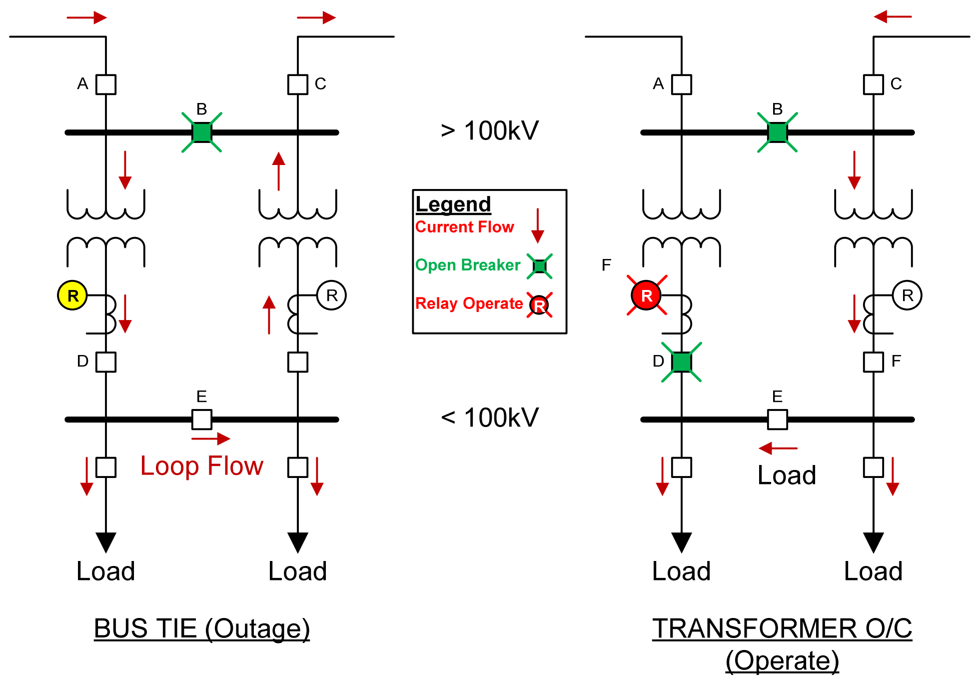


Figure 10. Transformer Overcurrent Limitations

Feeder Overcurrent Limitations

Feeder overcurrent protection schemes can also be deployed to prevent sustained loop flows through the sub-100 kV system. Figure 11 below shows how a feeder overcurrent scheme would function to prevent sub-100 kV loop flow. When the high side breaker (breaker B) is opened, current may flow from the high voltage side (breaker A) through the low voltage feeder, through a feeder tie, and back to the high voltage side (breaker C). The relay on the feeder and breaker G is applied to protect the feeder from excessive overloads and faults on the low voltage feeder. If a fault occurs or the feeder is over loaded, the relay on breaker G will sense this excessive flow (relay shown in yellow in the diagram) and will operate if this flow continues (relay shown in red in the diagram). When the feeder overcurrent relay operates it will trip breaker G. This action opens the feeder breaker and prevents low voltage loop flow. The feeder overcurrent relay is typically set to allow the feeder to be loaded to the emergency rating of the feeder rating plus a small safety margin. The figure below is a simplified illustration of a feeder overcurrent power scheme.

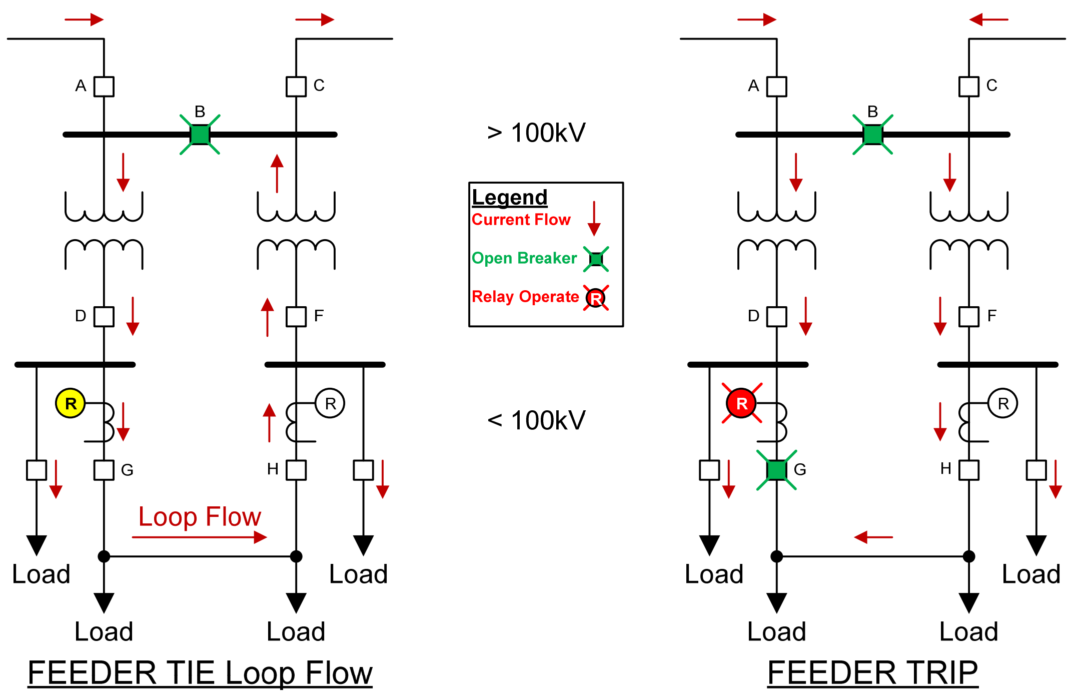


Figure 11. Feeder Overcurrent Limitations

Bus Tie Overcurrent Limitations

Bus tie overcurrent protection schemes can also be deployed to prevent sustained loop flows through the sub-100 kV system. Figure 12 below shows how a bus tie overcurrent scheme would function to prevent sub-100 kV loop flow. When the high side breaker (breaker B) is opened, current may flow from the high voltage side (breaker A) through the low voltage bus and back to the high voltage side (breaker C). The relay on the bus tie and breaker E is applied to protect the bus from excessive overloads and faults on the low voltage bus(ses). If a fault occurs or the bus is over loaded, then the overcurrent relay on breaker E will sense this excessive flow (relay shown in yellow in the diagram) and will operate if this flow continues (relay shown in red in the diagram). When the bus tie overcurrent relay operates, it will trip breaker E. This action opens the bus tie breaker and prevents sustained low voltage loop flow. The bus tie overcurrent relay is typically set to allow the bus to be loaded to the emergency rating plus a small safety margin. The figure below is a simplified illustration of a bus tie overcurrent power scheme.

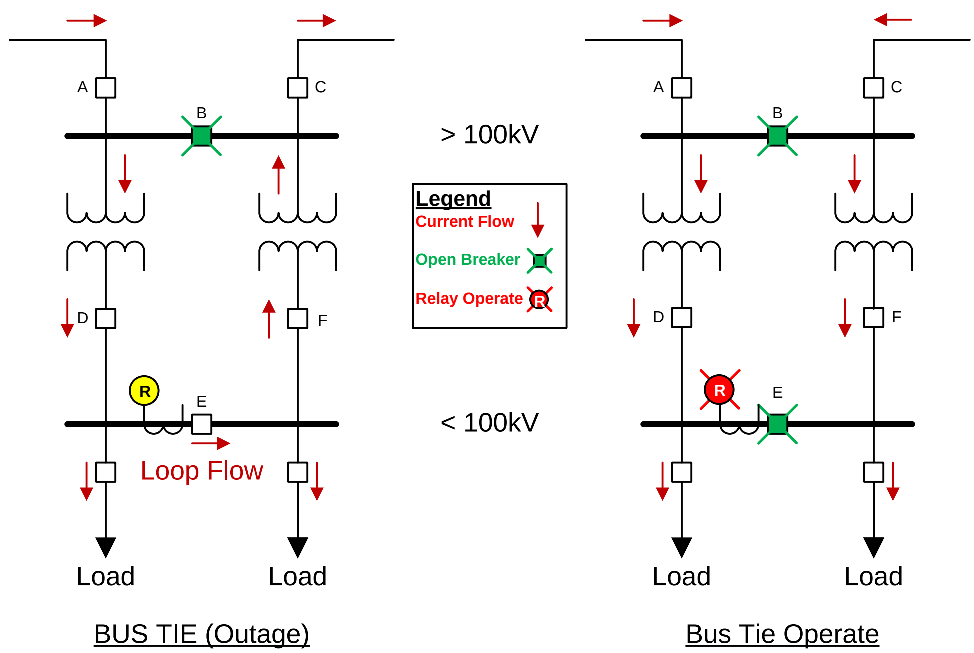


Figure 12. Bus Tie Overcurrent Limitations

Custom Protection and Control Schemes

Custom protection and control schemes may also be deployed to prevent loop flows through the sub-100 kV system. Figure 13 below shows how such schemes would function to prevent sub-100 kV loop flow. When the greater than 100 kV line 1 breakers (breakers D and G) open, current may flow from the high voltage side (breaker E) through the low voltage bus and back to the high voltage side (breaker H). The custom scheme implemented at the substation will trip or run back generation to prevent over loads and sustained loop flows on the low voltage system.

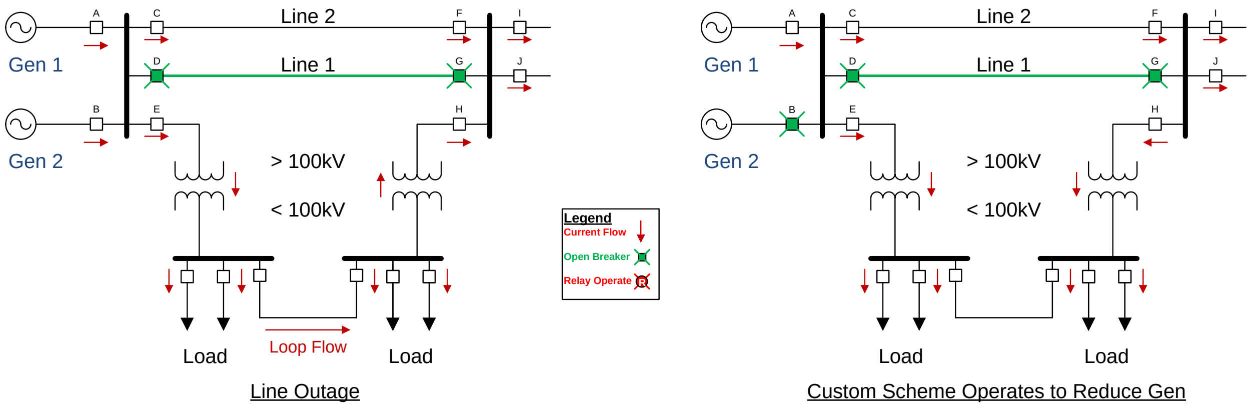


Figure 13. Custom Scheme Operations

Appendix 4 Summary

The issues and methods described in Appendix 4 are reflective of why, in most instances, conditions of sustained loop flows through sub-100 kV systems are alleviated. When the low voltage is much less than 100 kV, the design considerations shown above become even more pertinent and preventative methods are employed; BES reliability is not the main concern, protecting the equipment from physical damage is the primary concern. In the vast majority of cases, robust planning and operating criteria and procedures will alleviate any concerns regarding sustained loop flows.

E-mail completed form to:
SARCOMM@nerc.net

Standards Authorization Request

Form

Title of Proposed Standard definition	NERC Glossary of Terms - Phase 2: Revision of the Bulk Electric System
Request Date	December 2, 2011

SAR Requester Information	SAR Type (Check all that apply)	
Name: Project 2010-17 Definition of Bulk Electric System (BES) SDT	☐	New Standard
Primary Contact: Peter Heidrich (Manager of Reliability Standards, FRCC) , Project 2010-17 Definition of Bulk Electric System (BES) SDT Chair	X	Revision to existing Standard
Telephone: (813) 207-7994 Fax: (813) 289-5646	☐	Withdrawal of existing Standard
E-mail: pheidrich@frcc.com	☐	Urgent Action

SAR Information
Industry Need (What is the industry problem this request is trying to solve?)
This project supports the ERO's obligation to identify the Elements necessary for the reliable operation of the interconnected transmission network to ensure that the ERO, the Regional Entities, and the industry have the ability to properly identify the applicable entities and Elements subject to the NERC Reliability Standards.
Purpose or Goal (How does this request propose to address the problem described above?)
Research possible revisions to the definition of BES (Phase 2) to address the issues identified through Project 2010-17 Definition of Bulk Electric System (BES) (Phase 1). The definition encompasses all Elements necessary for the reliable operation of the interconnected transmission network. The definition development may include other improvements to the definition as deemed appropriate by

SAR Information
the drafting team, with the consensus of stakeholders, consistent with establishing a high quality and technically sound definition of the Bulk Electric System (BES).
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?)
Revise the BES definition to identify the appropriate electrical components necessary for the reliable operation of the interconnected transmission network.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
Collect and analyze information needed to support revisions to the definition of Bulk Electric System (BES) developed in Phase 1 of this project to provide a technically justifiable definition that identifies the appropriate electrical components necessary for the reliable operation of the interconnected transmission network. The definition development may include other improvements to the definition as deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing a high quality and technically sound definition of the BES.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Collect and analyze information needed to support revisions to the definition of BES developed in Phase 1 of this project to provide a technically justifiable definition that identifies the appropriate electrical components necessary for the reliable operation of the interconnected transmission network. The definition development will include an analysis of the following issues which were identified during the development of Phase 1 of Project 2010-17 Definition of the BES. Clarification of these issues will appropriately define which Elements are necessary for the reliable operation of the interconnected transmission network. • Develop a technical justification to set the appropriate threshold for Real and Reactive Resources necessary for the reliable operation of the Bulk Electric System (BES) • The NERC Board of Trustees approved BES Phase 1 definition does not encompass a contiguous BES - Determine if there is a need to change this position • Determine if there is a technical justification to revise the current 100 kV bright-line voltage level • Determine if there is a technical justification to support allowing power flow out of the local

SAR Information
network under certain conditions and if so, what the maximum allowable flow and duration should be Provide improved clarity to the following: • The relationship between the BES definition and the ERO Statement of Compliance Registry Criteria established in FERC Order 693 • The use of the term “non-retail generation” • The language for Inclusion I4 on dispersed power resources • The appropriate ‘points of demarcation’ between Transmission, Generation, and Distribution Phase 2 of the definition development may include other improvements to the definition as deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing a high quality and technically justifiable definition of the BES. Based on the potential revisions to the definition of the BES and an analysis of the application of, and the results from, the exception process, the drafting team will review and if necessary propose revisions to the ‘Technical Principles’ associated with the Rules of Procedure Exception Process to ensure consistency in the application of the definition and the exception process.

Reliability Functions

The Standard will Apply to the Following Functions (Check box for each one that applies.)		
This section is not applicable as the SAR is for a definition which is about Elements, Applicability of entities is covered in Section 4 of each Reliability Standard.		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.

The Standard will Apply to the Following Functions (Check box for each one that applies.)		
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.

The Standard will Apply to the Following Functions (Check box for each one that applies.)		
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles (Check box for all that apply.)	
X	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
X	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
X	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
X	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
X	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Applicable Reliability Principles (Check box for all that apply.)
Does the proposed Standard comply with all of the following Market Interface Principles? (Select 'yes' or 'no' from the drop-down box.)
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Standards Announcement

Project 2010-17 Definition of Bulk Electric System - Phase 2

A Final Ballot is now open through November 18, 2013

Now Available

A final ballot for Phase 2 of the Definition of Bulk Electric System is open through **8 p.m. Eastern on Monday, November 18, 2013.**

The drafting team considered stakeholder comments from the comment period and ballot that ended on October 29, 2013 and made no changes to the definition or implementation plan. The drafting team's consideration of comments, along with clean and redline versions of the definition and other supporting documents, have been posted on the project page. The redline of the definition reflects changes to the development roadmap (development steps completed and next steps) only.

Background information and documents for this project can be found on the project page.

Instructions for Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the final ballot window. If a ballot pool member does not participate in the final ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the definition by clicking here.

Next Steps

Voting results for the definition will be posted and announced after the ballot window closes. If approved, the definition will be submitted to the Board of Trustees for adoption.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2010-17 Definition of Bulk Electric System Phase 2

Final Ballot Results

Now Available

A final ballot for Phase 2 of the **Definition of Bulk Electric System** concluded at **8 p.m. Eastern on Monday, November 18, 2013.**

The definition achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the additional ballot.

Approval
Quorum: 81.68%
Approval: 74.34%

Background information for this project can be found on the project page.

Next Steps

The definition will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2010-17 Definition of BES - Phase 2 Final Ballot November
Ballot Period:	11/8/2013 - 11/18/2013
Ballot Type:	Final Ballot
Total # Votes:	321
Total Ballot Pool:	393
Quorum:	**81.68 % The Quorum has been reached**
Weighted Segment Vote:	74.34 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	104	1	55	0.724	21	0.276	0	7	21
2 - Segment 2	8	0.5	5	0.5	0	0	0	3	0
3 - Segment 3	90	1	46	0.697	20	0.303	0	8	16
4 - Segment 4	36	1	19	0.704	8	0.296	0	2	7
5 - Segment 5	88	1	48	0.706	20	0.294	0	5	15
6 - Segment 6	51	1	26	0.65	14	0.35	0	2	9
7 - Segment 7	2	0.1	0	0	1	0.1	0	0	1
8 - Segment 8	2	0.1	1	0.1	0	0	0	0	1
9 - Segment 9	4	0.2	2	0.2	0	0	0	0	2
10 - Segment 10	8	0.8	7	0.7	1	0.1	0	0	0
Totals	**393**	**6.7**	**209**	**4.981**	**85**	**1.719**	**0**	**27**	**72**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Big Rivers Electric Corp.	Chris Bradley		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Abstain	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	Amber Anderson	Affirmative	
1	El Paso Electric Company	Dennis Malone		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	COMMENT RECEIVED
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John Chin	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	Memphis Light, Gas and Water Division	Allan Long		

1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnesota Power, Inc.	Randi K. Nyholm	Negative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	North Carolina Electric Membership Corp.	Robert Thompson		
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Oncor Electric Delivery	Jen Fiegel		
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens		
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Negative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	

2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Abstain	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Alabama Power Company	Robert S Moore	Negative	
3	Alameda Municipal Power	Douglas Draeger		
3	Ameren Services	Mark Peters	Affirmative	
3	Arkansas Electric Cooperative Corporation	Philip Huff		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Palo Alto	Eric R Scott	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	City of Ukiah	Colin Murphey		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	East Kentucky Power Coop.	Patrick Woods	Affirmative	
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger	Affirmative	
3	Fayetteville Public Works Commission	Allen R Wallace		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Abstain	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover		
3	Gulf Power Company	Paul C Caldwell	Abstain	
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Kootenai Electric Cooperative	Dave Kahly		
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY

				COMMENTS
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - Gary Kruempel MidAmerican
3	Mississippi Power	Jeff Franklin	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	North Carolina Electric Membership Corp.	Doug White		
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller		
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	Southern California Edison Company	David B Coher		
3	Tacoma Public Utilities	Travis Metcalfe	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Negative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	Alabama Municipal Electric Authority	Raymond Phillips		
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	COMMENT RECEIVED
4	Arkansas Electric Cooperative Corporation	Ronnie Frizzell		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Buckeye Power, Inc.	Manmohan K Sachdeva	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	

4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Cowlitz County PUD	Rick Syring		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	
4	Modesto Irrigation District	Spencer Tacke	Negative	COMMENT RECEIVED
4	National Rural Electric Cooperative Association	Barry R. Lawson	Abstain	
4	North Carolina Eastern Municipal Power Agency	Cecil Rhodes	Affirmative	
4	North Carolina Electric Membership Corp.	John Lemire	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Negative	COMMENT RECEIVED
5	Arkansas Electric Cooperative Corporation	Brent R Carr		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Abstain	
5	BrightSource Energy, Inc.	Chifong Thomas	Affirmative	
5	Buckeye Power, Inc.	Paul M Jackson		
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Michael Shultz		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	CPS Energy	Robert Stevens	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Negative	
				COMMENT

5	Detroit Edison Company	Alexander Eizans	Negative	RECEIVED - Kent Kujala of Detroit Edison
5	Detroit Renewable Power	Marcus Ellis	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Negative	
5	El Paso Electric Company	Gustavo Estrada		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	COMMENT RECEIVED see NIPSCO Joe O'Brien's comments
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	David Ramkalawan		
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Ryan Millard	Negative	COMMENT RECEIVED
5	Pattern Gulf Wind LLC	Grit Schmieder-Copeland		
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Affirmative	

5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Wisconsin Public Service Corp.	Scott E Johnson	Negative	
6	AEP Marketing	Edward P. Cox		
6	APS	Randy A. Young	Negative	
6	Arkansas Electric Cooperative Corporation	Keith Sugg		
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	El Paso Electric Company	Luis Rodriguez		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Lincoln Electric System	Eric Ruskamp	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Negative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	North Carolina Municipal Power Agency #1	Matthew Schull	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Abstain	
6	PacifiCorp	John Volz	Negative	COMMENT RECEIVED - Ryan Millard
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Ty Bettis		
6	Power Generation Services, Inc.	Stephen C Knapp		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - Christina Koncz PSEG
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern California Edison Company	Joseph T Marone	Negative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Abstain	

6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Xcel Energy, Inc.	David F Lemmons	Negative	
7	Alcoa, Inc.	Thomas Gianneschi	Negative	COMMENT RECEIVED
7	EnerVision, Inc.	Thomas W Siegrist		
8		Edward C Stein		
8		Debra R Warner	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
9	New York State Department of Public Service	Thomas G. Dvorsky		
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Negative	COMMENT RECEIVED
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	

Legal and Privacy
404.446.2560 voice : 404.446.2595 fax
Atlanta Office: 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Exhibit F

Standard Drafting Team Roster

Project 2010-17 Definition of Bulk Electric System
Drafting Team Roster

Name and Title	Company and Address	Contact Info	Bio
Pete Heidrich Mgr. of Reliability Standards and SDT Chair	Florida Reliability Coordinating Council 1408 N. Westshore Blvd. Suite 1002 Tampa, FL 33607-4512	1.813.207.7994 pheidrich@frcc.com	Peter Heidrich is Manager of Reliability Standards at the Florida Reliability Coordinating Council (FRCC). Peter joined FRCC in August, 2008 after 16 years at DTE Energy (Detroit Edison) and 8½ years of military service in the United States Navy Nuclear Power Program. Peter is responsible for the development of the FRCC Regional Reliability Standards and associated reliability related policies and procedures (i.e., Regional Criteria, Regional Interpretations, & FAQs, Regional Definitions, etc.) and oversight of the FRCC Reliability Standards Development Process. Additionally, Peter actively participates as the FRCC representative in NERC Reliability Standards development and on various committees, subcommittees, and working groups (i.e., NERC Standards Committee (SC), SC Process Subcommittee, ERO Regional Standards Group (Vice-Chair), Functional Model Working Group, and Results-Based Standard Initiative).
Barry Lawson Associate Director, Power Delivery & Reliability and SDT Vice Chair	National Rural Electric Cooperative Association 4301 Wilson Blvd. GR11-253 Arlington, VA 22203	1.703.907.5781 barry.lawson@nreca.coop	Barry Lawson is the Associate Director, Power Delivery & Reliability at the National Rural Electric Cooperative Association (NRECA). Barry joined NRECA in April 2001, after 18 years in positions with Dominion Virginia Power, Edison Electric Institute, Columbia Gas Transmission, and KEMA Consulting. At NRECA, Barry's current focus is on NERC reliability policy/governance issues, standards development and compliance process developments, and critical infrastructure protection policy issues. In addition, Barry actively participates in BOT, MRC, and SC activities and he is currently the Chair of NERC's Critical Infrastructure Protection Committee (CIPC).
Jennifer Dering Mgr. Operations Planning – Transmission	New York Power Authority 123 Main St. White Plains, NY 10601-3170	1.914.287.3179 Jennifer.dering@nypa.gov	Jennifer Dering is Manager of Operations Planning at the New York Power Authority. Jennifer joined the New York Power Authority 18 years ago after beginning her career at IBM. Jennifer is responsible for the short term operational planning of NYPA's transmission assets that range from 69 kV to 765 kV and span the entire state of New York. Jennifer has held a variety of positions at NYPA prior to her current role in Transmission including roles within Nuclear Licensing, Energy Efficiency, Project

			Management, and Engineering. Jennifer is also a licensed Professional Engineer in the state of New York and a Certified Energy Manager.
Brian Evans-Mongeon Pres. & CEO	Utility Services 25 Crossroad Suite 201 Waterbury, VT 05676	1.802.552.4022 brian.evans-mongeon@utilitysvcs.com	Brian Evans-Mongeon is the President and CEO of Utility Services, Inc., a service firm formed in 2007, specializing in assisting registered entities in the Electric Reliability Organization (ERO) program. As the President and CEO of Utility Services, Brian is responsible for oversight of ERO Compliance and Monitoring for client's in regions across the U.S.; ISO & NEPOOL markets; and Renewable Energy Trading and associated activities. Utility Services is a member in five of the eight NERC regions and its' staff hold a number of committee positions within those regions. Brian is a member of NPCC's Compliance and Regional Standards Committee, and is a participant in the NPCC task force for regional standards on disturbance monitoring. At NERC, Brian is a participant in the Standard Drafting Team for the Under Frequency Load Shedding program (NERC Project 2007-01), is currently a member of the Definition of Bulk Electric System (BES) team (NERC Project 2010-17), and is the current chair of the Standard Drafting Team for Disturbance and Sabotage Reporting (NERC Project 2009-01). Previously, Brian has over twenty years of experience in the electrical utility business working for both Green Mountain Power Corporation as a Power Operations & Administration Manager and Vermont Public Power Supply Authority as a Marketing Services Manager.
Phil Fedora Asst. VP, Reliability Services	Northeast Power Coordinating Council 1040 Avenue of the Americas (6th Ave.) 10th Floor New York, NY 10018-3703	1.212.840.4909 pfedora@npcc.org	Philip Fedora is the Assistant Vice President of Reliability Services, Northeast Power Coordinating Council (NPCC) where he oversees a wide range of power system reliability activities associated with the coordination of system planning, system studies and protection, the assessment of adequacy, and multi-Area Regional planning. Phil is responsible for NPCC's Reliability Assessment and Performance Analysis program area, including liaison with state, federal and provincial governmental/regulatory officials. Phil joined NPCC in July, 1999 after 15 years at ISO-New England/New England Power Planning (NEPOOL), where he was responsible for the management of the ISO-New England Power Supply Reliability activities, and 8 years at Westinghouse Electric, Advanced Systems Technology, providing consulting services for domestic

			and foreign utilities. Phil is NPCC's representative on the NERC Planning Committee, has authored several technical papers on power system modeling and assessment, and is a member of the IEEE – Power Engineering Society and CIGRE. He is a licensed Professional Engineer in the Commonwealth of Pennsylvania.
Ajay Garg Mgr. Policy and Approvals	Hydro One Networks 483 Bay St., TCT St-04 Toronto, Ontario, Canada M5G 2P5	1.416.345.5420 ajay.garg@hydroone.com	Ajay Garg is Manager, Policy & Approvals within Asset Management at Hydro One Networks Inc (formerly Ontario Hydro). Ajay joined Hydro One in 2000, after 15 years in positions with Nova Scotia Power and NPCC. At Hydro One, Ajay's current focus is on NERC reliability policy/governance issues, standards development and compliance process, along with addressing non-jurisdictional regulatory issues. Ajay has been actively involved with the development of NERC and NPCC Standards/Criteria for many years along with his participation on the 2003 NERC blackout investigation team. Ajay also represents Hydro One and/or Canada on various other committees of IEC, IEEE, NERC, NPCC, CEA, and CSA. Ajay is a Canadian representative on IEC TC8 and ACEC along with convener of TC8 HV Transmission Group, and member of NERC-CCC and NPCC -CC. Ajay is a licensed Professional Engineer in the Province of Ontario.
John P. Hughes VP, Technical Affairs	Electricity Consumers Research Council 1111 19th St. NW Washington, DC 20036	1.202.682.1390 jhughes@elcon.org	John Hughes is Vice President of Technical Affairs at the Electricity Consumers Resource Council (ELCON), the national association of large industrial consumers of electricity. John is responsible for managing ELCON's interventions before FERC, DOE, and related state regulatory bodies. John is also author of ELCON policy papers and technical documents on all facets of the electric industry. John joined ELCON in 1987 as technical director after serving as Director of Economic Research at the Niagara Mohawk Power Corporation where he was previously Associate Director of Corporate Planning. Prior to joining Niagara Mohawk in 1982, John was Chief Economist at the Massachusetts Energy Facilities Siting Council. John supervised the council's technical staff regarding the demand forecasts and supply plans of electric and natural gas utilities that operated in the state. John was also directly involved with the council's adjudication of petitions to site transmission lines, natural gas pipelines and gasification facilities, and nuclear power plants. John has been active

			with NERC since 1996, having been a member of the Commercial Practices Working Group, the Market Interface Committee, and the Compliance and Certification Committee (CCC).
Jeffrey Mitchell Director, Engineering	Reliability First 320 Springside Dr. Suite 300 Akron, OH 44333	1.330.247.3043 Jeff.mitchell@rfirst.org	Jeff Mitchell is the Director of Engineering at Reliability*First* Corp. (RFC) where he oversees the reliability assessment and performance analysis activities including resource and transmission assessment reports, protection system mis-operation review, event analysis, model development, operations, and the regional standards process. Jeff joined the East Central Area Reliability Coordination Agreement (ECAR) staff in 1997 after 17 years with Ohio Edison (now FirstEnergy) and subsequently the Reliability*First* staff since its inception. Jeff facilitated the development of the Reliability*First* BES definition in 2007 and now handles the interpretation requests. Jeff is currently the chair of the NERC Planning Committee and was the initial chair of the Eastern Interconnection Reliability Assessment Group's (ERAG) Management Committee. He is also a licensed Professional Engineer in Ohio and Pennsylvania.
Rich Salgo Director, Electric System Operations	Sierra Pacific Power PO Box 10100 Reno, NV 89520	1.775.834.5874 rsalgo@nvenergy.com	Rich Salgo is the Director of Electric System Control Operations at NV Energy, Inc., which includes the registered entities of Nevada Power Company and Sierra Pacific Power Company. In this role, Rich is responsible for the transmission, distribution, and balancing functions conducted within the NV Energy control centers, including associated operations engineering, training, and energy management system support functions. Among the duties of his present position, Rich is responsible for ensuring that policies, procedures, and processes are developed and implemented pursuant to NERC and WECC Regional Standards, as well as having responsibility for corporate initiatives in compliance with the CIP Standards. Rich holds a Bachelor's degree in Electrical Engineering, and he joined the predecessor company, Sierra Pacific Resources, in 1984. In this time, Rich has had experience in various facets of electric system design, system protection, substation and line construction, and field operations. Rich is a long-standing member of the WECC Operating Committee, participates on an advisory committee for the WECC Reliability Coordinator, and is a member of the WECC Unscheduled Flow

			Administrative Subcommittee. Rich is a licensed Professional Engineer in the state of California, and also holds a NERC Operator Certification at the RC level.
Jason Snodgrass Regulatory Compliance Mgr.	Georgia Transmission	1.770.270.7294 jason.snodgrass@gatrans.com	Jason Snodgrass is the Regulatory Compliance Manager at Georgia Transmission Corporation. Jason has been employed in this role since 2008, after 7½ years of experience as a planning engineer. Jason is primarily responsible for developing, maintaining, and training of GTC's compliance program. Additional responsibilities include policy/governance, compliance process developments, performing self-audits of applicable mandatory standards, and performing self-assessments/consultation for new and revised NERC Standards prior to the mandatory dates.
Jennifer Sterling Director, Transmission Strategy and Compliance	Exelon 2 Lincoln Center Oakbrook Terrace, IL 60181	1.630.437.2764 jennifer.sterling@exeloncorp.com	Jennifer Sterling is the Director, Transmission Strategy and Compliance for Exelon Corporation. Jennifer has been employed by Exelon and its subsidiary, Commonwealth Edison for 21 years. She has also held positions in ComEd's System Planning, Bulk Power Operations, Transmission Policy, and Regulatory & Strategic Services Departments. Jennifer is responsible for managing the Exelon NERC Reliability Standards Compliance Program across the corporation and for providing leadership for strategic and reliability initiatives for the ComEd and PECO transmission facilities. Additionally, Jennifer was a member of the NERC Violations Severity Levels Drafting Team and actively participates on Edison Electric Institute and North American Transmission Forum Committees.
Jonathan Sykes Mgr., System Protection	Pacific Gas & Electric 1919 Webster St. Room #409 Oakland, CA 94612	1.510.874.2691 jfst@pge.com	Jonathan Sykes is Manager of System Protection at Pacific Gas and Electric Company (PG&E) in California. Jonathan joined PG&E in June 2009 after 27 years at Salt River Project in Arizona where he worked as a principal engineer in System Protection and Transmission Planning. Jonathan is responsible for the oversight (application, design, and compliance) of the 40,000 protective relays at PG&E. Jonathan also serves as the Chairman of the NERC System Protection and Control Subcommittee and has been

			active in the committee for more than 5 years. Jonathan is also active on the WECC Remedial Action Reliability Subcommittee and Relay Work Group. He is also a Senior Member in IEEE and participates in the Power System Relay Committee and chairs work groups. Jonathan has authored and co-authored papers concerning reliability and advanced application.