BEFORE THE
PROVINCE OF MANITOBA

NORTH AMERICAN ELECTRIC	)
RELIABILITY CORPORATION	)

NOTICE OF FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION OF A REVISED DEFINITION OF "BULK ELECTRIC SYSTEM" IN THE NERC GLOSSARY OF TERMS USED IN RELIABILITY STANDARDS

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I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC") respectfully provides notice of a revised definition of the term "Bulk Electric System" ("BES Definition") in the NERC *Glossary of Terms Used in Reliability Standards* ("NERC Glossary"). The revised BES Definition is provided in **Exhibit A**. NERC also provides notice of the proposed "Detailed Information to Support an Exception Request" (**Exhibit C**), which will be used in the submittal, review and approval or disapproval of requests for Exceptions from the application of the BES Definition. Finally, NERC provides notice of its plan for implementation of the revised BES Definition.

In Order No. 743 (with clarification provided in Order No. 743-A), the Federal Energy Regulatory Commission ("FERC") directed NERC to develop, using its Reliability Standard Development Procedure, and file with FERC, within one year following the effective date of the final rule adopted in that Order, a revised definition of "Bulk Electric System" ("BES").[1] FERC directed that the revised BES Definition should address FERC's technical and policy concerns discussed in Order No. 743 and should encompass all facilities necessary for operating an interconnected electric transmission network. FERC also directed that NERC work with the Regional Entities that would be affected by the revised BES Definition to develop transition plans for implementing the revised BES Definition that will allow a reasonable period of time for affected entities to achieve compliance with applicable Reliability Standards with respect to facilities that are subject to Reliability Standards for the first time based on the revised BES Definition. The transition plans were also required to be filed within one year of the effective

[1] *Revision to Electric Reliability Organization Definition of Bulk Electric System*, 133 FERC ¶ 61,150 (2011) ("Order No. 743"), at PP 29-33; *Order on Rehearing*, 134 FERC ¶ 61,210 (2011) ("Order No. 743-A").

date of the final rule adopted in Order No. 743.[2] Further, FERC directed NERC to develop, through a stakeholder process, and file with FERC within one year following the effective date of the final rule, a process to exempt facilities from inclusion in the Bulk Electric System through application of the BES Definition.[3]

Contemporaneously, NERC is filing a separate notice of proposed revisions to the NERC Rules of Procedure ("ROP") including a proposed BES Exception Procedure.[4]

The NERC Board of Trustees voted to adopt the revised BES Definition, Detailed Information to Support an Exception Request, and proposed implementation plan (as well as the proposed Exception Procedure that is being separately filed for approval) on January 18, 2012.

Exhibit A to this Petition is the revised BES Definition. **Exhibit B** is the current definition of "Bulk Electric System" in the NERC Glossary; it is provided for reference. **Exhibit C** is the Detailed Information to Support an Exception Request, which identifies information that will be required to be included in Exception Requests submitted pursuant to the proposed Exception Procedure. **Exhibit D** is the "Consideration of Comments" report created by the Standard Drafting Team ("SDT") during the development of the revised BES Definition. **Exhibit E** is the complete development record of the revised BES Definition. **Exhibit F** is the SDT roster and biographical information for NERC Standards *Project 2010-17 Definition of*

[2] Order No. 743 at P 131.

[3] Order No. 743 at P 112-13.

[4] Specifically, contemporaneous with this filing, NERC is also filing approval Notice of Filing of proposed new sections 509 and 1703 of the ROP and proposed new Appendix 5C to the ROP, *Procedure for Requesting and Receiving an Exception from the Application of the NERC Definition of Bulk Electric System*. Section III.D of this filing, below, discusses why the "Detailed Information to Support an Exception Request" was developed through the Reliability Standards development process while the proposed BES Exception Procedure was developed through the ROP amendment process.

Bulk Electric System, which resulted in the revised BES Definition. **Exhibit G** is a technical justification paper for the "Local Network Exclusion," Exclusion E3 of the BES Definition.

NERC filed the revised BES Definition with FERC, and is also filing the revised BES Definition with the other Applicable Governmental Authorities in Canada for approval or review pursuant to each jurisdiction's laws or regulations.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to:

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III. PROPOSED REVISED DEFINITION OF "BULK ELECTRIC SYSTEM"

A. Directives and Technical and Policy Concerns in Order Nos. 743 and 743-A

In Order No. 743, FERC directed NERC to revise its definition of the term "Bulk Electric System." The current definition of Bulk Electric System in the NERC Glossary, which FERC directed NERC to revise, is:

> 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 lines serving only load with one transmission source are generally not included in this definition.

As stated in P 16 of Order No. 743, FERC directed NERC:

to revise the definition of "bulk electric system" through the NERC Standards Development Process to address the Commission's concerns discussed herein. The Commission believes the best way to address these concerns is to eliminate the Regional Entities' discretion to define "bulk electric system" without ERO or Commission review, maintain a bright-line threshold that includes all facilities operated at or above 100 kV except defined radial facilities, and adopt an exemption process and criteria for excluding facilities that are not necessary to operate an interconnected electric transmission network. However, NERC may 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.

FERC gave additional direction, and expressed its technical concerns, in the following paragraphs of Order No. 743.

P 30: "[T]he Commission finds that the current definition of bulk electric system is insufficient to ensure that all facilities necessary for operating an interconnected electric energy transmission network are included under the 'bulk electric system' rubric. Therefore, pursuant to section 215(d)(5) of the FPA, the Commission directs the ERO to modify, through the Standards Development Process, the definition of 'bulk electric system' to address the Commission's technical and policy concerns described more fully herein. The Commission believes the best way to address [its] concerns is to eliminate the regional discretion in the ERO's current definition, maintain the bright-line threshold that includes all facilities operated at or above 100 kV except defined radial facilities, and establish an exemption process and criteria for excluding facilities the ERO determines are not necessary for operating the interconnected transmission network. It is important to note that Commission is not proposing to change the threshold value already contained in the definition, but rather seeks to eliminate the ambiguity created by the current characterization of that threshold as a general guideline."[5]

P 53: "[A]lthough the NOPR used the term 'rated at,' the Commission did not intend to require NERC to utilize that term rather than the term 'operated at' which is reflected in the current definition of bulk electric system. While the Commission does not have firm data on the number of facilities that operate at a

[5] FERC observed in footnote 39 that "all regions except NPCC currently utilize 100 kV as a general threshold."

voltage significantly lower than the rated voltage, we find that the term 'rated at' could generate confusion." (Footnote omitted.)

P 55: "[W]e do not seek to modify the second part of the definition through this Final Rule, which states that '[r]adial transmission facilities serving only load with one transmission source are generally not included in this definition.' While commenters would like to expand the scope of the term 'radial' to exclude certain transmission facilities such as tap lines and secondary feeds via a normally open line, we are not persuaded that such categorical exemption is warranted. For example, when the normally 'open' line is 'closed,' it becomes part of the transmission network and therefore should be subject to mandatory Reliability Standards. Commenters also argued that the bright line 100 kV threshold would encourage small utilities to choose not to provide backup service options, reducing overall customer service. We acknowledge these concerns, and direct the ERO to consider these comments regarding radial facilities in crafting an exemption methodology."

P 72: "The current definition has failed to ensure that all facilities necessary for operation of the interconnected transmission network are covered by the Reliability Standards. As discussed above, the current definition allows broad discretion without ERO or Commission oversight, which has resulted in reliability issues such as the exclusion of transmission serving bulk electric generators (including nuclear plants), inconsistency in classification at the seams that compromises the effectiveness of the Reliability Standards, routine TLR events on non-bulk electric system facilities, and the exclusion of elements necessary to operate the interconnected transmission network. Given the inconsistency of the application among regions and the reliability issues created as a result of the current definition, we conclude that it is necessary to direct the ERO to revise the definition of 'bulk electric system' to ensure that all facilities necessary to operate the interconnected transmission network are included and to address the concerns noted herein. We believe that the Commission's proposed approach of adopting a bright-line, 100 kV threshold, along with a NERC-developed, Commission-approved exemption process, as well as eliminating regional variations unless approved by the Commission as provided in Order No. 672, is an appropriate action to ensure bulk electric system reliability." (Footnote omitted.)

P 73: "[M]any facilities operated at 100 kV and above have a significant effect on the overall functioning of the grid. The majority of 100 kV and above facilities in the United States operate in parallel with other high voltage and extra high voltage facilities, interconnect significant amounts of generation sources and operate as part of a defined flow gate, which illustrates their parallel nature and therefore their necessity to the reliable operation of the interconnected transmission system. Parallel facilities operated at 100-200 kV will experience similar loading as higher voltage parallel facilities at any given time and the lower voltage facilities will be relied upon during contingency scenarios. Further . . . 115 kV and 138 kV facilities have either caused or contributed to significant bulk system disturbances and cascading outages. Additionally, the current definition's broad regional discretion has allowed classification inconsistencies to develop within and along the borders of Regional Entities . . . . The proposed 100 kV threshold is intended to ensure facilities necessary for reliable operation are captured by the definition and to avoid entities exempting their facilities by any means other than through a Commission-approved exemption process." (Footnote omitted.)

P 75: "[W]e believe use of the term 'operated at' rather than 'rated at' together with the exemption methodology that NERC will develop . . . addresses the WPSC's concern that utilities may elect to build facilities below 100 kV to avoid oversight."

P 82: "[U]niform Reliability Standards, and uniform implementation, should be the goal and the practice, the rule rather than the exception, absent a showing that a regional variation is superior or necessary due to regional differences. Consistency is important as it sets a common bar for transmission planning, operation, and maintenance necessary to achieve reliable operation. . . . [W]e have found several reliability issues with allowing Regional Entities broad discretion without ERO or Commission oversight. The Commission's proposed approach to addressing these concerns will enable affected entities to pursue exemptions for facilities they believe should not be included in the bulk electric system, and will also allow Regional Entities to add facilities below 100 kV they believe should be included." (Footnote omitted.)

P 96: "In general, the Final Rule identifies the reliability concerns created by the current definition and a method to ensure that certain facilities needed for the reliable operation of the nation's bulk electric system are subject to mandatory and enforceable Reliability Standards, and that exemption methodologies would be developed by NERC and subject to Commission review. From the Commission's review, the material impact assessments implemented by NPCC are subjective in nature, and results from such tests are inconsistent in application, as shown through the exclusion of facilities that clearly are needed for reliable operation. Further, we find that the vast majority of 100 kV and above facilities are part of parallel networks with high voltage and extra high voltage facilities and are necessary for reliable operation. As a result, and consistent with our previous statements in Order No. 672, we find it is best for the ERO to establish a uniform definition that eliminates subjectivity and regional variation in order to ensure reliable operation of the bulk electric system. We further find that the existing NPCC impact test is not a consistent, repeatable, and comprehensive alternative to the bright-line, 100 kV definition we prefer." (Footnote omitted.)

PP 139-141: "The Commission does not agree with the commenters' arguments that 100-199 kV facilities in the Western Interconnection should be treated differently than facilities in the Eastern Interconnection as a threshold matter. The bulk electric system definition should include all facilities that are necessary for operating an interconnected electric transmission network. While commenters have implied that not all 100-199 kV facilities are needed for reliable operation, the Commission notes that 100 kV and some lower voltage facilities are included in some of the WECC Rated Paths. Clearly, these facilities are operationally significant and needed for reliable operation . . . . While the Western Interconnection has a higher percentage of transmission facilities above 200 kV compared to the Eastern Interconnection, it is how the lines below 200 kV are interconnected with higher voltages that determines their significance. . . . [C]ommenters have not provided adequate explanation in this proceeding, supported by data and analysis, as to why there is a physical difference upon which to treat the Western Interconnection differently. . . . Order No. 672 details several factors the Commission will consider in determining whether a proposed Reliability Standard is just and reasonable. One of the factors indicates that a 'proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard.' Moreover, and particularly compelling with respect to the definition of bulk electric system, Order No. 672 indicates that proposed Reliability Standards 'should be clear and unambiguous regarding what is required and who is required to comply.' Eliminating broad regional discretion without ERO or Commission oversight and maintaining a 100kV bright-line definition, coupled with an exemption process, removes any ambiguity regarding who is required to comply and accomplishes the goal of reducing inconsistencies across regions. Commenters have not provided compelling evidence that the proposed definition should not apply to the United States portion of the Western Interconnection as a threshold matter. . . ." (Footnotes omitted.)

P. 144: "We expect that our decision to direct NERC to develop a uniform modified definition of 'bulk electric system' will eliminate regional discretion and ambiguity. The change will not significantly increase the scope of the present definition, which applies to transmission, generation and interconnection facilities."

P 150: "We disagree with commenters that definitions of 'integrated transmission elements' and 'material impact' are needed to implement this Final Rule. These terms are not defined by the present bulk electric system definition, and defining these terms is not necessary to revise the definition as directed herein. Whether specific facilities have a material impact is not dispositive with respect to whether they are needed for reliable operation. These questions are more appropriately addressed through development of an exemption process at NERC."

In Order No. 743-A, FERC provided several clarifications to its directives and technical concerns with respect to the definition of "Bulk Electric System."

P 11: **“**We clarify that the specific issue the Commission directed the ERO to rectify is the discretion the Regional Entities have under the current bulk electric system definition to define the parameters of the bulk electric system in their regions without any oversight from the Commission or NERC. As we explained in the Final Rule, NPCC’s use of this discretion has resulted in an impact-based approach to defining the bulk electric system that allows significant subjectivity in application and thus creates anomalous results. . . . [A]ny region could use its discretion to define the bulk electric system in a way that leads to similar inconsistent and anomalous results.” (Footnote omitted.)

P 22: “[W]e disagree with the NYPSC’s claim that the Final Rule implicitly acknowledges that various non-jurisdictional facilities are included within the Commission’s ‘redefinition’ of bulk electric system. As we clarify herein, regardless of the 100 kV threshold, facilities that are determined to be local distribution will be excluded from the bulk electric system.”

P 30: “[U]niformity, absent a showing that the alternative is more stringent or necessitated by a physical difference, has been a hallmark of the mandatory Reliability Standards construct since its inception. In establishing the framework for developing Reliability Standards, we adopted the principle that proposed Reliability Standards should be ‘designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard.’ The same principle holds true for definitions contained within the Reliability Standards.” (Footnote omitted.)

P 35-36: “[T]he Commission did not direct or mandate that the bulk electric system definition include a bright-line 100 kV threshold. Instead, the Commission directed NERC to address the inconsistency, lack of oversight and exclusion of facilities that are required for the reliable operation of the interconnected transmission network, outlined by the Commission in Order No. 743 using the technical expertise available to NERC. The Commission suggested that one means to address its concerns would be to, among other things, maintain the 100 kV threshold and radial exclusion contained in the current definition, but left it to NERC’s discretion and technical expertise to develop a revised definition. . . . The Commission’s suggested solution of a 100 kV threshold paired with an exemption process, in essence, merely clarifies the current NERC definition, which classifies facilities operating at 100 kV or above as part of the bulk electric system.”

P 57: “The Commission clarifies that our intent in requiring the ERO to ‘eliminate the regional discretion’ from the current definition was to prevent the regions from modifying the regional bulk electric system definition without Commission or ERO oversight.”

P 68: “The Commission clarifies that the statement in Order No. 743, ‘determining where the line between ‘transmission’ and ‘local distribution’ lies . .

> . should be part of the exemption process the ERO develops' was intended to grant discretion to the ERO, as the entity with technical expertise, to develop criteria to determine how to differentiate between local distribution and transmission facilities in an objective, consistent, and transparent manner. This mechanism will allow the ERO to maintain an inventory of the transmission facilities subject to the mandatory Reliability Standards, and to exclude local distribution facilities from the bulk electric system definition by applying the criteria." (Footnote omitted.)
>
> **P 102:** "The Commission clarifies that Order No. 743 did not intend to alter the Registry Criteria, shift the evidentiary burden for registration, or otherwise address matters involving the Registry Criteria. Indeed, the Statement of Compliance Registry Criteria currently provides that the Regional Entities may propose registration of entities that do not meet the registry criteria if the Regional Entity believes and can reasonably demonstrate that the organization is a bulk power system owner, or operates, or uses bulk power system assets, and is material to the reliability of the bulk power system. However, we note that while the Registry Criteria will not change, it is possible that additional facilities may come under the revised definition and some entities may be required to register for the first time." (Footnote omitted.)

FERC's directives and technical and policy concerns with respect to the BES Definition, as reflected in the above-quoted discussion from Order Nos. 743 and 743-A, may be summarized as follows:

- The BES Definition should provide for a consistent, uniform, objective nationwide test to identity those facilities that are part of the BES, and eliminate ambiguity and the potential for subjectivity in the application of the definition.
- The BES Definition should provide for a distinct threshold criteria rather than a "general guideline."
- Regional discretion in determining what facilities comprise the BES should be eliminated, and application of the BES Definition should be overseen by NERC.
- The BES Definition should identify those facilities that are necessary for reliably operating the interconnected transmission network.
- The BES Definition should exclude from the BES facilities used in the local distribution of electricity.
- The existing exclusion of radial facilities from the BES should be maintained, but issues associated with the exclusion of radial facilities, such as the treatment of radial facilities connected by a normally open switch, should be clarified.

As shown in the discussion in the next section of this filing, the revised BES Definition satisfies FERC's directives and technical and policy concerns articulated in Order Nos. 743 and 743-A.

B. Discussion of Proposed Revised Definition of "Bulk Electric System"

NERC is providing notice of the following revised definition of "Bulk Electric System":[6]

> **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 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.
> - **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.
> - **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.

Exclusions:

[6] Capitalized terms used in the BES Definition are terms that are already defined in the NERC Glossary. Those terms are: Balancing Authority, Blackstart Resources, Element, Flowgate, Generator Operator, Generator Owner, Interconnection, Interconnection Reliability Operating Limit (IROL), Load, Real Power, Reactive Power, Transmission, and Transmission Operator.

- **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 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 Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

  Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, 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 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 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 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).

- **E4** – Reactive Power devices owned and operated by the 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.

As a starting point, the revised BES Definition deletes the phrase "As defined by the Regional Reliability Organization" that is included in the current BES Definition. This deletion eliminates the express basis for Regional discretion that is embedded in the current BES Definition. Further, the revised BES Definition establishes a clear, bright-line definition of the BES, based on the 100 kV threshold, with clearly-stated Inclusions and Exclusions that will eliminate discretion in application of the revised BES Definition.

In the revised BES Definition, the "core" definition (the initial paragraph preceding the Inclusions and Exclusions) establishes the fundamental threshold for inclusion of facilities in the BES: that the facilities are operated at 100 kV or higher, if they are Transmission Elements,[7] or are connected at 100 kV or higher, if they are Real Power or Reactive Power resources.[8] The

[7] The current BES Definition includes "associated equipment," and the revised BES Definition does not use that term; however, "associated equipment" remains encompassed by the revised BES Definition through the defined term "Transmission Elements." The NERC Glossary defines "Transmission" as, "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems;" and defines "Elements" 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."

[8] The NERC Glossary defines Real Power as "The portion of electricity that supplies energy to the load," and defines Reactive Power as follows: "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)."

core definition also states the 100 kV criterion as a bright-line threshold, rather than as a general guideline as in the current definition (*i.e.*, the phrase "generally operated at" in the current definition is eliminated in the revised BES Definition). Further, the core definition retains the phrase "operated at" [voltages of 100 kV or higher] found in the current BES Definition.[9] Finally, the core definition, in its last sentence, expressly excludes "facilities used in the local distribution of electric energy" from the BES, as recognized in Order No. 743-A.[10]. Thus, the core definition places within the BES all Transmission Elements operated at 100 kV or above, and all Real Power and Reactive Power resources connected at 100 kV or above, while establishing an express exclusion for facilities used in the local distribution of electrical energy.

The five Inclusions address five specific facilities configurations to provide clarity that the facilities described in these configurations are included in the BES (unless the facilities are excluded based on one of the specific Exclusions in the BES Definition), and thereby further reduce the potential for the exercise of discretion and subjectivity to exclude such configurations from the BES. The facilities described in Inclusions I1, I2, I4 and I5 are each operated (if transformers – Inclusion I1) or 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

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[9] *See* Order No. 743 at PP 53 and 75.

[10] *See* Order No. 743A at P 22 ("regardless of the 100 kV threshold, facilities that are determined to be local distribution will be excluded from the bulk electric system") and P 68.

(MVA) or the voltage at which they are connected.[11] The addition of the Inclusions to the BES Definition will provide for consistency, and eliminate ambiguity, across all Regional Entities, as all facilities meeting the criteria in the five Inclusions will be part of the BES.

Focusing on each of the individual Inclusions in detail, the five Inclusions were added to the BES Definition based on the following considerations:

- Inclusion I1 – Transformers operating at 100 kV or higher are part of the existing definition, but since transformers have windings operating at different voltages, and multiple windings in some circumstances, clarification was required to explicitly identify which transformers are included in the BES. Inclusion I1 includes in the BES 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.

- Inclusion I2 – This inclusion mirrors the text of the NERC *Statement of Compliance Registry Criteria* (Appendix 5B of the ROP) for generating units.[12] A basic tenet that was followed in developing the revised BES Definition was to avoid changes to Registrations due to the revised BES Definition if such changes are not technically required for the BES Definition to be complete.[13] The SDT found no technical rationale for changing at this time from the thresholds for generating resources presently specified in the *Statement of Compliance Registry Criteria*. In order to provide clarity on these conditions, the revised BES Definition specifies that the BES includes the generator terminals through the high-side of the step-up transformer connected at a voltage of 100 kV or above.

- Inclusion I3 – Blackstart Resources are vital to the Reliable Operation of the BES. Consequently, Blackstart Resources are included in the BES regardless of their size (MVA) or the voltage at which they are connected. This inclusion is also consistent with the *Statement of Compliance Registry Criteria*.[14]

[11] Blackstart Resources are 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." Under this Inclusion, both the generating unit and its "associated set of equipment" are included in the BES.

[12] *See* §III.c.1 and III.c.2 of Appendix 5B of the ROP.

[13] This is consistent with FERC's clarification in P 102 of Order No. 743-A.

[14] *See* §III.c.3 of Appendix 5B of the ROP ("Any generator, regardless of size, that is a blackstart unit material to and designated as part of a transmission operator entity's restoration plan").

- Inclusion I4 – This inclusion was added to the BES Definition in order to accommodate the effects of variable generation on the BES. The purpose of this inclusion is to include variable generation (*e.g.*, wind and solar resources). Although this inclusion arguably could be considered subsumed in Inclusion I2 (because the gross aggregate nameplate rating of the power producing resources must be greater than 75 MVA), it was considered appropriate for clarity to add this separately-stated inclusion in order to expressly cover dispersed power producing resources utilizing a system designed primarily for aggregating capacity.

- Inclusion I5 – This inclusion is the technical equivalent of Inclusion I2, for Reactive Power devices. The existing BES Definition is unclear as to how these devices were to be treated. Inclusion I5 addresses this lack of clarity by providing specific criteria for Reactive Power devices, thereby further limiting subjectivity and the potential for discretion in the application of the BES Definition.

Correspondingly, the four Exclusions identify facilities configurations that should not be included in the BES. Exclusion E1 is the exclusion for radial systems. Order Nos. 743 and 743-A made it abundantly clear that the BES Definition should exclude radial facilities from the BES.[15] This Exclusion provides detailed criteria for determining that facilities are properly excluded from the BES as radial facilities, thereby enhancing the clarity of the radial facilities exclusion.[16] The radial exclusion is part of the existing BES Definition and was supported in the work done on the topic prior to Order Nos. 743 and 743-A, as well as being specifically supported by those Orders. Conditions (b) and (c) in Exclusion E1, pertaining to the maximum amount of generation allowed on the radial facility while still qualifying for the radial facilities exclusion (aggregate capacity less than or equal to 75 MVA), address the circumstances of small utilities (including municipal utilities and cooperatives). The maximum amount of generation allowed on the radial facility is sufficient to allow small utilities to continue to provide service

[15] *See*, Order No. 743 at PP 16, 30 and 55 and Order No. 743-A at P 35.

[16] Exclusion E1 applies to "[a] group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher." If the facilities emanate from a point of connection less than 100 kV, they would not be part of the BES under the core BES Definition, without the need to consider application of Exclusion E1.

options that support reliability of the interconnected electric transmission system, while not operating to exclude larger generators from the BES.[17] The maximum amount of generation allowed on the radial facility per Conditions (b) and (c) is consistent with the aggregate capacity threshold presently provided in the *Statement of Compliance Registry Criteria* for registration as a Generator Owner or Generator Operator (75 MVA gross nameplate rating).[18]

Exclusion E1 includes the note, "A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion." This note addresses a common network configuration that required clarification, in which two separate sets of facilities that, each standing alone, would be recognized as radial systems and not included in the BES, are connected by a "normally open switch" – *i.e.*, a switch that is set to the open position – for reliability purposes.

The concept and usage of the "normally open switch" in such configuration is well understood in the electric utility industry. These switches are installed by entities to provide greater reliability to their end-use customers. For example, scheduled maintenance activities on a radial line, or an unscheduled outage impacting the single point of supply to the radial line, could cause the disruption of power supply to the end-use customers served by the line, unless the entity has the ability to switch over to another feed on a temporary basis. The entity's operating procedures dictate how and when to operate such a normally open switch. Operation of the normally open switch placed in this configuration is not an arbitrary process, but rather is driven by the objective of maintaining reliability of service to end-use customers served from the radial line. Facilities that otherwise meet the criteria for the radial system exclusion should not

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[17] The interests of small utilities addressed in Conditions (b) and (c) of Exclusion E1 were recognized in P 55 of Order No. 743.

[18] *See* §III.c.2 of Appendix 5B.

be included in the BES solely because the entity maintains a switch of this type, which is normally open, between sets of radial facilities. Further, for a set of radial facilities that are connected by a switch to qualify for the radial exclusion under Exclusion E1, the switch must be identified as "normally open" on source documents such as, for example, prints or one-line diagrams;[19] and must in fact be normally set in the open position. An entity that claimed exclusion of connected radial lines on the grounds that they were connected by a "normally open switch," but did not in fact maintain the switch in the open position except for the maintenance or outage circumstances described above, would be untruthful and could be subject to serious consequences when discovered.

In Order No. 743, FERC stated that

> While commenters would like to expand the scope of the term 'radial' to exclude certain transmission facilities such as tap lines and secondary feeds via a normally open line, we are not persuaded that such categorical exemption is warranted. For example, when the normally "open" line is "closed," it becomes part of the transmission network and therefore should be subject to mandatory Reliability Standards. . . . [We] direct the ERO to consider these comments regarding radial facilities in crafting an exemption methodology.[20]

The concept that two sets of radial facilities that are normally unconnected to each other should be subject to, and need to comply with, the Requirements of applicable Reliability Standards during the limited time periods when they are connected by the closing of the normally open switch in the maintenance-related or outage-related circumstances described above would be fundamentally impractical and unworkable (from both the entity's perspective and the ERO's perspective), and would misapprehend this very common, reliability-driven facilities configuration. As noted, the connecting switch must be normally set in the open position to

[19] Other example source documents could include diagrams displayed within an energy management system or a SCADA system.

[20] Order No. 743 at P 55.

qualify for Exclusion E1. Further, this configuration is so common that to write the BES Definition to <u>include</u> radial systems connected by a normally open switch in the BES, with the proviso that the owner(s) of the facilities can request an Exception, would undoubtedly result in a veritable flood of Exception Requests.

Moreover, the SDT extensively considered the reliability issues associated with tap lines and tapped facilities feeding separate radial systems and concluded that the real reliability issue associated with these facilities is the coordination of the respective transmission Protection Systems for the transmission facilities feeding the radial systems. However, this reliability issue is adequately addressed by the Requirements of the Protection and Control Reliability Standards, including in particular PRC-001, without providing for the inclusion of these facilities in the BES in the revised BES Definition.

Therefore, based on the above-described considerations, the SDT concluded, and NERC agrees, that this configuration would be more appropriately addressed in the BES Definition, through a specific exclusion (Exclusion E1), rather than through the Exception process.

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 wording of Exclusion E2 is extracted from the *Statement of Compliance Registry Criteria*.[21]

Exclusion E3, the "local network" exclusion, encompasses local networks of transmission Elements operated at between 100 kV and 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. Local networks provide local electrical distribution service and are not planned, designed or operated to benefit or support the balance of the interconnected transmission network. The purpose of local networks is to provide local distribution service, not to provide transfer capacity for the interconnected transmission network. The design and operation of local networks is such that at the point of connection with the interconnected transmission network, the effect of the local network on the interconnected transmission network is similar to that of a radial facility, in particular that flow always moves in a direction from the interconnected transmission network into the local network. A network that simply supports distribution and does not accommodate bulk power transfers across the interconnected system should not be included in the BES. Exclusion E3 provides detailed criteria for determining that facilities, although operated at or above 100 kV, comprise a local network and therefore are not part of the BES. These criteria are that:

- the local network and its underlying Elements include limited non-retail generation;
- power flows only into the local network and it does not transfer energy originating outside the local network for delivery through the local network; and
- the facilities are not part of a Flowgate or transfer path.[22]

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[21] *See* the second exclusion following §III.c.4 in Appendix 5B of the ROP.

[22] Flowgate is defined in the NERC Glossary as: "(1) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions, and (2) a mathematical construct, comprised of one or more monitored

The detailed conditions established in Exclusion E3 are sufficient to ensure that such qualifying local networks are being used exclusively for local distribution purposes.

Exhibit G is a technical justification paper for the local network exclusion. As discussed in greater detail in the technical justification paper, the local network exclusion is justified by the following factors:

1. Facilities used in the local distribution of electric energy are to be excluded from the BES.

2. The exclusion for local networks ensures that a candidate for this exclusion must satisfy all of the criteria for this exclusion, thereby demonstrating that the candidate facilities are not performing a transmission function.

3. The limit on connected generation within the local network is consistent with the existing threshold above which a generating plant in aggregate becomes subject to Registration under the NERC *Statement of Compliance Registry Criteria*.

4. The voltage cap applied to the criteria for the local network exclusion, 300 kV, is consistent with the distinction between Extra High Voltage ("EHV") and High Voltage in Reliability Standard TPL-001-2 on transmission planning as approved by the NERC Board of Trustees on August 4, 2011. Use of the 300 kV voltage cap ensures that the local network exclusion cannot be used to exclude EHV facilities, which under TPL-001-2 are held to a higher standard of performance, from the BES.

5. The power flow shifts that would occur on the Elements of a local network are a negligible fraction of that which distributes upon the BES Elements for a given power transfer, and is fully eclipsed by the Load in the local network.

6. The interaction of a local network with the BES is similar in character to that of a radial facility.

Finally, Exclusion E4 encompasses Reactive Power devices owned and operated by a retail customer solely for its own use. Exclusion E4 is the technical equivalent of Exclusion E2 for Reactive Power devices. The existing BES Definition is unclear as to how these devices are

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transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System."

to be treated; the revised BES Definition provides specific criteria for Reactive Power devices, in Exclusion E4.

The revised BES Definition satisfies FERC's directives and addresses its technical and policy concerns as expressed in Order Nos. 743 and 743-A. The explicit basis of authority for Regional Entity discretion in the current definition is eliminated. The core definition establishes the specific threshold criteria (rather than a general guideline) of facilities operated (Transmission Elements) or connected (Real Power or Reactive Power resources) at or above 100 kV, and this threshold value is recognized in the specific facilities configurations described in Inclusions I1, I2, I4 and I5. The core definition in combination with the specific Inclusions and Exclusions provides a detailed set of criteria that can be applied on a uniform, consistent basis across all Regional Entities, eliminates ambiguity, and eliminates the potential for discretion and subjectivity in determining what facilities are part of or not part of the BES. Blackstart Resources, which are necessary for the Reliable Operation of the interconnected transmission system even if they are operated or connected below 100 kV, are expressly included in the BES. Facilities for the local distribution of electric energy are expressly excluded from the BES by the core definition as well as by Exclusion E3 (local networks). The exclusion for radial facilities is maintained, but with more specific, detailed criteria provided for determining what facilities are radial facilities. Specifically-defined behind-the-meter generating resources and Reactive Power devices are also excluded from the BES.

Additionally, in terms of FERC's directives and concerns for consistency and the elimination of Regional Entity discretion and subjectivity in determining what facilities comprise the BES, NERC calls attention to the proposed BES Exception Procedure, Appendix 5C to the ROP, which is being submitted in a separate, contemporaneous filing. Under the proposed BES

Exception Procedure, the Regional Entities will conduct initial screenings of Exception Requests emanating from their Regions, and will make Recommendations to NERC as to whether an Exception Request should be approved or disapproved. However, the Regional Entities will not actually make the decisions to approve or disapprove Exception Requests. All decisions to approve or disapprove Exception Requests will be made by NERC in accordance with the processes and procedures specified in proposed Appendix 5C.

In summary, the revised BES Definition provides a detailed, objective set of criteria that can be applied consistently and uniformly on a Continent-wide basis to identify those facilities that are necessary for the Reliable Operation of the interconnected transmission system, as well as those facilities that are not. The revised BES Definition is just, reasonable, not unduly discriminatory or preferential, and in the public interest, and fully addresses FERC's directives and technical and policy concerns as detailed in Order Nos. 743 and 743-A..

C. Detailed Information to Support an Exception Request

In addition to developing a revised BES Definition, the SDT for Project 2010-17 was assigned the task of developing a set of technical criteria to support a BES Exception Request.[23] Based on discussions among the NERC Standards Committee, NERC Reliability Standards program management, the SDT for the BES Definition, and the team that was formed to develop the BES Exception Procedure for the ROP ("BES ROP Team"), this task was assigned to the SDT (as opposed to being assigned to the BES ROP Team) so that the Reliability Standards development process would be followed in the development and establishment of the technical criteria.

[23] In P 115 of Order No. 743, FERC stated that "NERC should develop an exemption process that includes clear, objective, transparent, and uniformly applicable criteria for exemption of facilities that are not necessary for operating the grid."

Thereafter (as discussed in greater detail in §IV.A and IV.B below), the SDT determined that it was more feasible to develop a common set of data and information that could be used by the Regional Entities and NERC to evaluate and decide Exception Requests. A Submitting Entity would be required to submit the common data and information with the Exception Request, for use by the applicable Regional Entity and NERC in evaluating the Exception Request. The set of common data and information, captioned "Detailed Information to Support an Exception Request," was separated into data and information applicable to transmission entities and data and information applicable to generation entities. The Detailed Information to Support an Exception Request was balloted in the recirculation ballot for the BES Definition and, as described in greater detail in §IV.D below, achieved the necessary quorum of the ballot pool and two-thirds weighted Segment approval. The full text of the Detailed Information to Submit an Exception Request is provided in **Exhibit C** to this Petition.

Under the proposed BES Exception Procedure, Appendix 5C to the ROP, which is being submitted in a separate, contemporaneous filing, the Detailed Information to Submit an Exception Request is to be provided by the Submitting Entity as the Section III Required Information required by the Exception Request Form. Section 4.5.3 of proposed Appendix 5C states that "Section III of an Exception Request shall contain the **Detailed Information to Support an Exception Request** as specified on the Exception Request Form" (emphasis in original). Further, section 2.12 of proposed Appendix 5C states that "the Exception Request Form must include Section III.B as adopted by NERC."[24]

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[24] The information that the Submitting Entity may submit, or may be asked by the Regional Entity and NERC to submit, in support of an Exception Request will not be limited to the Detailed Information to Support an Exception Request. The Submitting Entity will be expected to submit all relevant data, studies and other information that supports its Exception Request, and the Regional Entity and NERC may ask the Submitting Entity to provide other data, studies and

The Detailed Information to Support an Exception Request, Section III.B of the Exception Request Form, specifies that the following information must be included in all Exception Requests:

> A one-line breaker diagram identifying the Element(s) for which the exception is requested must be supplied with every request. The diagram(s) supplied should also show the Protection Systems at the interface points associated with the Elements for which the exception is being requested.

Additionally, the Detailed Information to Support an Exception Request specifies that "Entities are required to supply the data and studies needed to support their submittal," and provides the following specifications for studies:

- Studies should be based on an Interconnection-wide base case that is suitably complete and detailed to reflect the electrical characteristics and system topology.
- Studies should clearly document all assumptions used.
- Studies should address key performance measures of BES reliability through steady-state power flow, and transient stability analysis as necessary to support the entity's request, consistent with the methodologies described in the Transmission Planning (TPL) standard and commensurate with the scope of the request.

The Detailed Information to Support an Exception Request then provides separate sets of questions applicable to Transmission Elements and to generation resources. The questions for Exception Requests pertaining to Transmission Elements are:

1. Is there generation connected to the Element(s)?

   If yes, what are the individual gross nameplate values of each unit?
2. How do/does the Element(s) impact permanent Flowgates in the Eastern Interconnection, major transfer paths within the Western Interconnection, or a comparable monitored facility in the ERCOT Interconnection or the Quebec Interconnection?

   Please list the Flowgates or paths considered in your analysis along with any studies or assessments that illustrate the degree of impact.

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information in addition to the Detailed Information to Support an Exception Request and the other information included by the Submitting Entity in the Exception Request.

3. Is/Are the Element(s) included in an Interconnection Reliability Operating Limit (IROL) in the Eastern Interconnection, ERCOT Interconnection, or Quebec Interconnection or a major transfer path rating in the Western Interconnection?

   Please provide the appropriate list for the operating area where the Element(s) is located.

4. How does an outage of the Element(s) impact the over-all reliability of the BES?

   Please provide study results that demonstrate the most severe system impact of the outage of the Element(s) and the rationale for your response.

5. Is/Are the Element(s) used for off-site power supply to a nuclear power plant as designated in a mutually agreed upon Nuclear Plant Interface Requirement (NPIR)?

6. Is/Are the Element(s) part of a Cranking Path identified in a Transmission Operator's restoration plan?

7. Does power flow through the Element(s) into the BES?

   If yes, then using metered or SCADA data for the most recent consecutive two calendar year period, what is the minimum and maximum magnitude of the power flow out of the Element(s)?

   Describe the conditions and the time duration when this occurs?

The questions for Exception Requests pertaining to generation resources are:

1. What is the MW value of the host Balancing Authority's most severe single Contingency and what is the generation resources percent of this value?

   Please provide the values and a reference to supporting documents.

2. Is the generation resource used to provide reliability-related Ancillary Services?

   If so, what reliability-related Ancillary Services are the generation resource supplying?

3. Is the generation resource designated as a must run unit for reliability?

   Please provide the appropriate reference for your operating area?

4. How does an outage of the generation resource impact the over-all reliability of the BES?

   Please provide study results that demonstrate the most severe system impact of the outage of the generator and the rationale for your response.

5. Does the generation resource use the BES to deliver its actual or scheduled output, or a portion of its actual or scheduled output, to Load?

Two of the overriding directives in Order No. 743 were that (1) the revised BES Definition should identify all facilities necessary for operating an interconnected electric energy transmission network, and (2) the exemption process should identify and exclude facilities that are not necessary for operating the interconnected transmission network.[25] The SDT initially attempted to develop a set of technical criteria for determining whether or not the Elements that are the subject of an Exception Request are necessary for operating the interconnected transmission network. However, the SDT concluded that it was infeasible to develop a single set of criteria that would be applicable to the wide variety of configurations and circumstances likely to be presented by a broad range of Exception Requests. The SDT therefore determined that the more appropriate approach was to develop a detailed set of data and information that can be used by the Regional Entity and NERC in evaluating whether or not the Elements that are the subject of an Exception Request are necessary for reliably operating the interconnected transmission network.

The Detailed Information to Support an Information Request in fact requires the Submitting Entity to provide specific data and information that can be used by the Regional Entity and NERC in evaluating whether or not the Elements that are the subject of an Exception Request are necessary for reliably operating the interconnected transmission network. Requiring the submission of the Detailed Information to Support an Exception Request is intended to ensure that a consistent baseline of technical information is provided with all Exception Requests, in addition to the specific information and arguments provided by the Submitting Entity in support of its Exception Request. The Submitting Entity remains responsible to present

[25] *See, e.g.*, Order No. 743 at PP 16 and 30.

sufficient information and argument to justify the Exception Request.[26] Further, several of the questions and information requirements in the Detailed Information to Support an Exception Request parallel components of one or more Inclusions or Exclusions in the BES Definition and will enable the Regional Entity and NERC to verify that no applicable Inclusions or Exclusions have been overlooked.

The specific questions posed were created by the SDT with the intention of having the responses to the body of questions in a specific section (transmission or generation) complement the general information required for Exception Requests, thereby creating a "big picture" concept while also providing the specific technical analysis which addresses the potential reliability benefit of the Element in question. The availability of this information will allow the Regional Entity and NERC review panels to utilize their technical expertise by exercising sound engineering judgment to provide informed recommendations on whether or not the Element in question is necessary for reliably operating the interconnected transmission network and therefore should be included in or excluded from the BES. The breadth of industry coverage and technical experience and backgrounds among the SDT members came into play in developing the Detailed Information to Support an Exception Request. The questions to be included in the Detailed Information were debated at length to arrive at the set of information that would be needed by the review panels and, ultimately, to reach a decision on the Exception Request, but with consideration given to the burden that would be placed on the Submitting Entity in compiling, and the Regional Entity and NERC in reviewing, an extensive amount of technical

[26] Section 3.2, Burden, in the proposed BES Exception Procedure (which is being filed in a separate filing contemporaneously with this filing) states in part: "The burden to provide a sufficient basis for Approval of an Exception Request in accordance with the provisions of this Exception Procedure is on the Submitting Entity . . . . All evidence provided as part of an Exception Request or response will be considered in determining whether an Exception Request shall be approved or disapproved."

information. The SDT attempted to create a balance in order to produce a set of data and information that would provide sufficient information for the Regional Entity to make a technically appropriate Recommendation and for NERC to make a technically appropriate determination, without overwhelming the review panels and decision makers with unnecessary data.

In order to test whether these objectives were achieved, a number of SDT members conducted "dry runs" compiling the Detailed Information to Support an Exception Request using Elements on their own organizations' systems. The SDT members reported their experiences and observations with the test runs to the full SDT, and this experience was used in refining the list of questions for the Detailed Information to support an Exception Request.

Thereafter, the draft Detailed Information to Support an Exception Request was posted for industry review and comment. The SDT considered the comments that were received from industry, and made a number of changes, before submitting the Detailed Information to Support an Exception Request for industry approval through balloting by the ballot pool.[27]

The development of the Detailed Information to Support an Exception Request, which must be provided with every Exception Request, represents an equal and effective alternative approach to developing a substantive set of technical criteria for granting and rejecting Exception Requests. The Detailed Information to Support an Exception Request encompasses a wide range of potential configurations and will provide useful information for the Regional Entity and NERC in evaluating and deciding Exception Requests. The Detailed Information to Support an Exception Request in **Exhibit C** satisfies FERC's technical concerns expressed in Order No. 743

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[27] Because the Detailed Information to Support an Exception Request was developed and adopted using the Reliability Standards development process, in the future, revisions will be made using the Reliability Standards development process, including industry balloting, rather than using NERC's process for amending the ROP.

with respect to the need for criteria to approve or disapprove Exception Requests.

D. <u>Proposed Implementation Plan for Revised Definition of "Bulk Electric System"</u>

In Order No. 743, FERC addressed the need to allow a Regional Entity to submit a transition plan that "allows a reasonable period of time for affected entities within that region to achieve compliance with respect to facilities that are subject to Reliability Standards for the first time."[28] FERC stated:

> 131. . . . We direct NERC to work with the Regional Entities affected by this Final Rule to submit for Commission approval transition plans that allow a reasonable period of time for the affected entities within each region to achieve compliance with respect to facilities that are subject to Commission-approved Reliability Standards for the first time based on a revised bulk electric system definition. The Commission expects that NPCC is the only region that will be significantly affected. Based on ReliabilityFirst's experience in adopting a "bright-line" definition for bulk electric system facilities, we expect transition periods not to exceed 18 months from the time the Commission approves a revised definition and exemption process, unless the Commission approves a longer transition period based on specific justification. The Commission directs NERC to file the proposed transition plans within one year of the effective date of the Final Rule.
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> 132. While the Commission is sensitive to commenters' concerns regarding non-compliance during the transition period, the Commission will not provide a trial period, as we declined to do in Order No. 693, with respect to those facilities that are subject to Commission approved Reliability Standards for the first time. We expect that the transition periods will be long enough for exemption requests to be processed and to allow entities to bring newly-included facilities into compliance prior to the mandatory enforcement date. Additionally, the ERO and Regional Entities may exercise their enforcement discretion during the transition periods. (Footnote omitted.)[29]

Further, in Order No. 743-A, FERC again addressed the need for and length of a transition period:

> 93. . . . [A]s indicated in Order No. 743, "we expect that the transition periods will be long enough for exemption requests to be processed and to allow entities

[28] Order No. 743 at P 122 (footnote omitted).

[29] Order No. 743 at PP 131-132 (footnote omitted).

> to bring newly-included facilities into compliance prior to the mandatory enforcement date." We reiterate that we do not expect a large number of exemption requests arising outside NPCC. Thus, our expectation remains that NERC should be able to process any exemption requests in a timely manner, allowing any entity denied an exemption to come into compliance with the relevant reliability Standards within the transition period. (Footnotes omitted.)
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> 94. With respect to the length of the transition period, as discussed in the Final Rule, we based our determination to establish an 18-month transition period on ReliabilityFirst's prior experience in adopting a revised bulk electric system definition in that region, and continue to believe it is a reasonable transition period. Additionally, we noted that the ERO may request a longer transition period based on a specific justification. This provides sufficient flexibility should the ERO determine that the 18-month transition period is insufficient. (Footnote omitted.)[30]

The SDT for the BES Definition concluded that the revised BES Definition should be effective on the first day of the second calendar quarter after receiving applicable regulatory approval, or, in those jurisdictions where no regulatory approval is required, the revised BES Definition should go into effect on the first day of the second calendar quarter after its adoption by the NERC Board. The existing definition of the BES would be retired at midnight of the day immediately prior to the effective date of the revised BES Definition in the jurisdiction in which the revised BES Definition is becoming effective. The proposed effective date is appropriate in order to provide a reasonable time between the date of regulatory approval, which is not under the control of NERC or the industry, and the effective date of the revised BES Definition.

The SDT further concluded that compliance obligations for all Elements newly-identified to be included in the BES based on the revised BES Definition should begin 24 months after the applicable effective date of the revised BES Definition. That is, the mandatory enforcement date for the Reliability Standard Requirements that have become applicable to Facilities and Elements that are newly-included in the BES due to the revised BES Definition, and to the owners and

[30] Order No. 743-A at PP 93-94.

operators of those Facilities and Elements, will be 24 months after the effective date of the revised BES Definition.

The proposed implementation plan was balloted with the recirculation ballot for the revised BES Definition and, as described in greater detail in §IV.D below, the ballot achieved the required quorum and the necessary weighted Segment approval. The NERC Board approved both the proposed effective date and the proposed date by which owners of newly-included Facilities and Elements must be in compliance with applicable Requirements of Reliability Standards.

Although FERC stated in Order Nos. 743 and 743-A that the transition period should not exceed 18 months from the date of approval of the revised Definition, unless FERC approved a longer transition period based on specific justification, the SDT determined, and the industry ballot pool and the NERC Board agreed, that a somewhat longer transition period is necessary in light of the actions that will need to be completed in connection with the revised BES Definition. The proposed transition period will be between a minimum of approximately 27 months and a maximum of 30 months from the date of approval, depending on the date of approval.The reasons supporting the need for this longer transition period, as articulated by the SDT, include the following:

- Sufficient time is needed to implement transition plans in order to accommodate any changes resulting from the revised BES Definition. As discussed below, and as suggested in Order Nos. 743 and 743-A, only NPCC has identified the need for, and developed, a specific transition plan. The other Regional Entities will implement the revised BES Definition and the proposed BES Exception Procedure, and will adhere to the proposed transition period, but they do not expect an extensive amount of additional facilities to be included in the BES as the result of the revised BES Definition.[31] Nevertheless, the effective date of the revised BES Definition, and the subsequent mandatory enforcement date on which owners of newly-included Facilities and Elements are required to be compliant with applicable Reliability Standards, need to be consistent across all Regions.

- Sufficient time is needed to identify and implement any Registration changes resulting from the revised BES Definition, in particular new Registrations of entities owning Facilities and Elements, and revised Registrations of existing Registered Entities owning additional Facilities and Elements, that are identified as included in the BES based on the revised BES Definition.

- Sufficient time is needed for entities to file for Exceptions, and for the Regional Entities and NERC to process those Exceptions to a final determination, pursuant to the proposed BES Exception Procedure. These Exception Requests will include both requests that Facilities and Elements that are included in the BES by the revised BES Definition should be excluded from the BES, and requests that Facilities and Elements that are not included in the BES by the revised BES Definition should be included in the BES. At this time, NERC and the Regional Entities do not have a basis for estimating the numbers of Exception Requests that will be submitted or their complexity, and therefore cannot estimate the time and resources that will be required to process them to completion. Therefore, it is prudent to provide for a somewhat longer transition period so as to increase the likelihood that all Exception Requests

[31] This expectation is consistent with FERC's expectation as stated in Order No. 743, at P 131.

can be processed to completion so as (i) to allow owners of newly-included Facilities and Elements time to be compliant with applicable Reliability Standards, and (ii) avoid the need for owners whose Exclusion Exceptions are approved to expend resources on compliance that may prove to be unnecessary.

- Finally, sufficient time must be provided for owners of Facilities and Elements that are newly-included in the BES based on the revised BES Definition to train their personnel on compliance with the Reliability Standards applicable to the newly-included Facilities and Elements, so that these entities can in fact achieve compliance with applicable Reliability Standards by the end of the transition period.

It was not the intent nor the expectation of either the SDT or NERC to either expand or reduce the scope of the BES, or (with the likely exception of the NPCC Region) to increase or decrease the numbers of Elements included in the BES, through the revised BES Definition as compared to the current BES Definition.[32] Nonetheless, there is not a specific basis to determine to what extent Elements currently included in the BES will become not included, nor to what extent Elements currently not included in the BES will no longer be included, until the revised BES Definition becomes effective and entities begin to apply it to their facilities. Nor is there currently a basis to determine the numbers of Exception Requests that will be submitted, and need to be processed, as entities begin to determine whether facilities are included in or excluded

[32] As part of its work, the SDT did conduct a detailed and systematic review of the Applicability sections of all Reliability Standards that are currently in effect, pending for approval at FERC, or under development in standard development projects, to ascertain whether revisions to any Applicability sections would be needed based on the revised BES Definition. The SDT determined that no revisions to any Applicability sections would be needed. The SDT also reviewed all existing terms and definitions in the NERC Glossary that refer to the Bulk Electric System, to ascertain if changes to these definitions would be needed based on the revised BES Definition. The SDT determined that no changes to any of these existing definitions in the NERC Glossary would be needed.

from the BES by application of the revised BES Definition. NERC has reviewed the anticipated requirements and activities for implementation of the revised BES Definition with the eight Regional Entities. Although, as noted, there currently is not a basis for estimating the numbers of Exception Requests that will be submitted, none of the Regional Entities believes that it will require a longer transition period than the transition period proposed by the SDT, balloted by the industry and approved by the NERC Board. As indicated above, only NPCC has seen the need to develop a specific transition plan. The other Regional Entities do not expect an extensive amount of newly-included facilities, and therefore do not expect extensive implementation activities; as a result, they may not need to follow the steps outlined by NPCC. For these reasons, there is not a need for the other Regional Entities to develop and submit separate individual transition plans. However, if circumstances prove to be different than anticipated, a Regional Entity can revisit its initial decision and formulate a detailed plan in response to actual conditions.

NERC believes that the transition plan steps as outlined below are generally appropriate. The objectives of the transition plan are (1) to identify BES Facilities and Elements in the Region based on the revised BES Definition, and register the owners of those Facilities and Elements if they are not already registered, or revise their registrations if necessary to reflect the newly-included and excluded Facilities and Elements; (2) to identify those newly-included BES Facilities and Elements that are not currently compliant, or whose owners are not currently compliant, with applicable Reliability Standards; and (3) to identify specific actions that are necessary to bring newly-included BES Facilities and Elements, and their owners, that are not in compliance with applicable Reliability Standards into compliance by the end of the transition period. The transition plan will include the following specific steps:

Step 1: Identify a Comprehensive List of BES Facilities and Elements

Each asset owner will be expected to apply the revised BES Definition to all facilities to determine if those facilities are included in the BES pursuant to the revised BES Definition. This analysis should identify facilities that (i) should be included in the BES or (ii) can be excluded from the BES, based on the revised BES Definition. The analysis should also identify any Exception Requests that the owner intends to submit. This analysis will allow the owner to identify those facilities that need to be added to its Facilities and Elements already included in the BES. A gap analysis (Step 2 below) will then be performed on the newly-included Facilities and Elements.

Step 2: Perform a Gap Analysis

Each asset owner and each Functional Entity owning or operating Facilities and Elements that have been newly-identified for inclusion in the BES will be expected to perform a gap analysis for both (i) Registration (and Certification, if applicable) and (ii) compliance with applicable Reliability Standards. The gap analysis should identify (i) any additional Registrations and/or Certifications that are required due to the newly-included Facilities and Elements (*e.g.*, reliability functions for which the entity is not currently registered on the Compliance Registry but should be registered based on the newly-included Facilities and Elements), and (ii) additional compliance obligations for the entity, *i.e.*, the applicable Requirements of Reliability Standards with which the entity must now become compliant due to the inclusion of the new Facilities and Elements in the BES.

Step 3: Develop Implementation Plans

An entity with newly-included Facilities or Elements may need to develop a Registration implementation plan (which may include the need for Certification or a revision to an existing Certification), a compliance implementation plan, or both. In either case, the entity should submit its implementation plan(s) to the applicable Regional Entity for review and concurrence. The implementation plans should be structured so that they can be nominally completed by, or prior to, the end of the transition period (*i.e.*, by the date by which newly-included Facilities and Elements, and their owners, must be compliant with applicable Reliability Standards). The Regional Entity may approve exceptions to this deadline for specific Facilities and Elements, and their owners, for which the implementation plan identifies, and the Regional Entity concurs in, a need for a longer amount of time to achieve compliance.

Step 3a: Develop Registration Implementation Plan

A Registration plan for impacted entities will be developed, in coordination with other impacted entities (*e.g.*, Transmission Owners and/or Transmission Operators with Balancing Authorities) and in consultation with the Regional Entity, to determine the new, additional or modified Registrations required due to implementation of the revised BES Definition. The Registration implementation plan should identify any new Registrations associated with the newly-included Facilities and Elements. For Facilities and Elements that are newly-included in the BES as a result of the revised BES Definition, the Registration implementation plan must identify what Registered Entity or Registered Entities will be responsible for performing each of the reliability functions required by the Reliability Standards that are applicable to the newly-included Facilities and Elements. The Registration implementation plan should identify whether any new or modified Joint Registration Organization agreements, Coordinated

Functional Registrations, or other contractual arrangements will be entered into with respect to the newly-included Facilities and Elements.

The Registration implementation plan should also take into account any Certification requirements (*i.e.*, Certification of the entity to perform a new reliability function that requires Certification, or Certification of the entity to perform an existing reliability function in an expanded Footprint) and any preparation and Certification Team reviews needed for entities that will require new or amended Certifications. The Registration implementation plan should identify any instances in which it is anticipated that achieving Certification will require an amount of time longer than the time remaining to the end of the transition period.

NERC and the Regional Entities will work to register entities who become required to register based on application of the revised BES Definition, and to modify existing Registrations that are necessary based on the revised BES Definition, promptly after the need for the new or modified Registration is identified, and will encourage entities that identify the need to register or to modify existing Registrations to do so promptly. NERC and the Regional Entities recognize that Registration may result in the entity, at the time of Registration, being not in compliance with newly-applicable Reliability Standards. The entity's compliance implementation plan, discussed below in Step 3b, should detail the actions the entity will take, and the time period required, to come into compliance with the Requirements of Reliability Standards that become applicable to the entity and to newly-included Facilities and Elements due to the revised BES Definition.

Step 3b: Develop a Compliance Implementation Plan

A compliance implementation plan should be developed for each newly-included Facility or Element, and its owner and operator, identified in the gap analysis as not currently in compliance with applicable Reliability Standards, detailing the actions to be taken to bring the Facility or Element, and its owner and operator, into compliance. The compliance implementation plan should reflect all applicable existing or newly-required Registrations (*e.g.*, new registered functions). The compliance implementation plan should identify both (1) all newly-included Facilities and Elements, based on the revised BES Definition, for which the owner is not initially compliant with applicable Reliability Standard Requirements and therefore requires time to achieve compliance with those Requirements, and (2) all situations in which the entity is required to register for the first time, or to register for new reliability functions, based on the revised BES Definition, and the Reliability Standard Requirements with which the entity must come into compliance due to the new or modified Registration. The compliance implementation plans should identify activities the entity needs to perform to achieve compliance, including training its personnel in the Requirements of newly-applicable Reliability Standards and the time required, or milestone dates, for these activities. The compliance implementation plan should specifically identify those newly-included Facilities and Elements, and those new or modified Registrations, for which the entity projects that a time period longer than the time to the end of the transition period will be needed to achieve compliance with applicable Reliability Standards. As noted earlier, the extension of the completion of compliance activities beyond the end of the transition period (*i.e.*, beyond 24 months after the effective date of the revised BES Definition) will require concurrence of the Regional Entity.

Step 4: Complete Implementation Plans and Certify Completion

The actions required by the implementation plans will nominally have to be completed by the end of the transition period, except for specific Facilities and Elements for which the implementation plan identifies, with Regional Entity approval, the need for a longer time period. Each entity that adopted a Registration implementation plan or a compliance implementation plan should, upon completion of the activities described in the plan, provide a statement of completion to the applicable Regional Entity.[33]

NERC and Regional Entity Resource Requirements

In their 2012 Business Plans and Budgets, the Regional Entities and NERC did not provide for specific, incremental resources to perform incremental work that could result from the revised BES Definition (including processing Exception Requests). Specific incremental resources were not budgeted because (1) the business plan and budget preparation cycle requires the Regional Entities and NERC to have their proposed business plans and budgets essentially completed by late June or early July of the preceding year; (2) as of mid-year 2011, the revised BES Definition and the proposed BES Exception Procedure were still under development; (3)

[33] Beginning with the 2013 NERC and Regional Entity Annual Compliance Monitoring and Enforcement Implementation Plans, the Annual Implementation Plans will identify specific compliance monitoring activities that will be employed to verify the entities' completion of their compliance implementation plans and achievement of compliance with the newly-applicable Reliability Standard Requirements.

the proposed BES Definition and BES Exception Procedure were required to be filed with FERC for approval in late January, 2012, and, although NERC and the Regional Entities have no control over the timing of FERC's review and approval of these proposals, it was reasonable to assume that FERC review and approval could take six months or longer following the submission date, with the effective date of the revised BES Definition and the new BES Exception Procedure occurring some time after the date of FERC's order; and (4) if NERC or a Regional Entity began to experience a need for significant additional resources in the latter part of 2012, it would have the options of drawing on its working capital reserves or filing a supplemental budget and funding request with the Applicable Governmental Authorities. In their 2013 business plans and budgets, which will be prepared during the first half of 2012 and filed with the Applicable Governmental Authoritiesfor approval in late August 2012, NERC and the Regional Entities will provide for specific incremental resources (if any) projected to be needed for additional activities resulting from adoption of the revised BES Definition and the BES Exception Procedure.

IV. SUMMARY OF THE RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS

A. Development History

On December 17, 2010, NERC received, and the Standards Committee accepted, a standards authorization request ("SAR") proposing to revise the definition of "Bulk Electric System" in North America for the NERC Glossary. The SAR was posted for one industry comment period and approved by the Standards Committee for standard development on March 11, 2011 as *Project 2010-17: Definition of Bulk Electric System*.

A SDT was selected using the approved nomination and acceptance criteria. The assigned SDT posted the draft BES Definition for a 30-day industry comment period from April

28, 2011 to May 27, 2011. There were 154 sets of comments submitted, including comments from more than 279 different people from approximately 213 entities representing all 10 of the industry Segments. The comments primarily addressed the need for:

- Explicit wording on the inclusion of Reactive Power resources in the bright-line core BES Definition.
- Clarification on the exclusion of local distribution facilities.
- Clarification of transformer windings considered to be a part of the BES.
- Technical justification of the generator thresholds.
- Clarification on the need to include Cranking Paths in the BES Definition.
- Clarification of radial systems.
- Clarification of local networks.

Based on its consideration of the comments, the SDT revised the draft BES Definition and re-posted it for a second round of industry comment (concurrent with an initial ballot) for a 45-day period running from August 26, 2011 to October 10, 2011. This time there were 113 sets of comments, including comments from approximately 255 different people from approximately 156 entities representing all 10 industry Segments. The comments primarily focused on:

- How to interpret multiple terminal transformers within the BES Definition.
- Difficulties with circular references to the *Statement of Compliance Registry Criteria*.
- The need to exclude small generators from the Reactive Power inclusion.
- The need to clarify the language for generation on the customer's side of the retail meter.
- The need to clarify the language dealing with power flows into a local network.

The SDT was also assigned the task of concurrently developing the technical criteria to support a BES Exception Request. As noted earlier, the SDT was assigned this task so that the

Reliability Standards development process would be followed in establishing the technical criteria. The first draft of the technical criteria was posted for a 30-day period from May 11, 2011 to June 10, 2011. In response, there were 91 sets of comments, including comments from more than 75 different people from approximately 45 entities representing 8 of the 10 industry Segments. Comments stated that the attempt to develop continent-wide criteria for use in the Exception process was not an acceptable or workable approach.

The SDT then developed a new approach that utilized the collection of a common set of data and information ("Detailed Information to Support an Exception Request") that would be weighed by the ERO in assessing the Exception Requests. The Detailed Information to Support an Exception Request was posted for a 45-day period from August 26, 2011 to October 10, 2011. There were 72 sets of comments received, including comments from approximately 137 different people from approximately 83 entities representing all 10 industry Segments.

B. Issues Raised During the Development Process including Minority Issues

During the development process, the SDT considered the following comments, issues, and concerns. The following discussion summarizes those issues and describes how the SDT resolved those issues.

Threshold values – Commenters wanted the revised BES Definition to address threshold values, as the values contained in the NERC *Statement of Compliance Registry Criteria* were never technically justified. The deadline that the SDT was working under (specifically, to complete the development process and produce a revised BES Definition within a time frame that would allow it to be adopted by the NERC Board and filed with FERC for approval by January 25, 2012) did not allow for such analysis; therefore, the SDT split the project into two phases – the first to directly address the FERC directives in Order No. 743, and the second to address the additional concerns raised by industry in a non-deadline environment. The majority of commenters agreed with this approach.

Cranking Paths – The first posting of the revised BES Definition had Cranking Paths for Blackstart Resources included in the BES Definition. A number of commenters complained that this was improperly bringing distribution level Elements into the BES, as many Cranking Paths are at the distribution level. Commenters also pointed out that this was an illusory proposition as intended Cranking Paths are not always the ones used in actual restoration. The SDT was concerned about the possibility of having Blackstart Resources without a "guaranteed" path to the BES – what would be the value of a Blackstart Resource if it could not connect to the BES? The solution was to delete Cranking Paths from the BES Definition in this phase of the project and to take up the issue in Phase 2 of the project. This approach would maintain status quo on this topic, consistent with Order Nos. 743 and 743-A, while providing for a full discussion and consideration of the issue in a less time constrained environment.

Distribution vs. Transmission – Some commenters were concerned about the delineation of distribution facilities in the BES Definition. The SDT originally had commented that the BES Definition identifies transmission and therefore if a facility is not included in the BES Definition the facility was considered to be distribution. However, commenters wanted an explicit statement on this topic. The SDT added a sentence to the BES Definition to address this matter: "This does not include facilities used in the local distribution of electric energy."

Evaluation criteria – Commenters expressed a desire for hard and fast guidance on how an Exception Request was going to be evaluated. The SDT attempted to develop such hard and fast values that could be used in evaluating Exception Requests. However, the SDT struggled with the development of these criteria and asked the industry for assistance. There was a lack of response from the industry, which the SDT construed as indicating that the industry was struggling with this concept as well. Therefore, the SDT took a different path and developed a series of data and information points that a Submitting Entity should provide to support Exception Requests. This list was designed to allow for a consistent set of data to be presented for use in the evaluation of Exception Requests thus leading to consistency in decision making. In addition, the SDT documented that the Detailed Information to Support an Exception Request would be reviewed during Phase 2 of the project to see if improvements needed to be made.

Contiguous BES – A number of commenters stated that the BES should be contiguous. The SDT understood the sensitivity of the industry to such a condition but once again recognized that this is an issue requiring a great deal of technical analysis which was not possible in the project timeframe based on the FERC-established deadline for NERC to submit a revised BES Definition. For purposes of Phase 1 of the project, the SDT noted that the current BES Definition does not directly address the issue of contiguity. Given the indication in Order Nos. 743 and 743-A toward maintaining the status quo, at least in most of the Regions, the SDT did not attempt to resolve this complex issue in Phase 1. Rather, the issue of contiguity will be addressed in Phase 2. This approach was accepted by the majority of commenters, after the NERC Legal department provided input that Reliability Standards and Requirements could be written and enforced against Elements that are considered material to the reliability of the interconnected transmission system, such as *e.g.*, Protection Systems and control systems, even if those Elements are not included in the BES based on the BES Definition.[34]

Minority Issues

[34] The Legal Department advice was not intended as a determination that Elements such as Protection Systems and control systems are not included in the BES under the revised BES Definition, but rather specified that applicable Reliability Standard Requirements could be enforced against such Elements even if they were determined to not be included in the BES.

The minority issues are issues raised by commenters during the development process that the SDT chose not to address in the manner that a minority of commenters preferred.

Threshold values – Some commenters thought that the threshold value issue should be resolved in Phase 1 of the project and that the BES Definition should not move forward until this issue was resolved. This was an untenable position as the SDT was under a constraint to produce a revised BES Definition within a time frame consistent with the deadline established by Order No. 743, and this time frame did not allow for the in-depth analysis required to resolve such an issue. Splitting the project into two phases, with the threshold values to be addressed in Phase 2, was not acceptable to these minority commenters. The SDT attempted to assuage the commenter's fears by getting the proper approvals in place to proceed with Phase 2 prior to the completion of Phase I. The SDT received approval from the Standards Committee that Phase 2 of the project would continue to be considered as a high-priority project and that the same SDT that worked on Phase 1 would continue on in Phase 2. The phased project plan was endorsed by the NERC Members Representative Committee and the Board of Trustees. Assurances were also received from all appropriate bodies that they would support the SDT in obtaining any assistance required for in-depth technical analysis from relevant NERC standing committees.

Distribution vs. Transmission – A few commenters continue to suggest that the seven-factor test should be employed to determine distribution facilities. The SDT rejected this approach as the sole determination of distribution facilities, based on the reception such a test received in previous FERC proceedings where it was suggested that this test be the sole determining factor for distribution facilities. The SDT pointed out that such a test could be utilized by a Submitting Entity making an Exception Request but that other information should be supplied to support the request.

C. Initial Ballot

NERC conducted an initial ballot on both the BES Definition and the Detailed Information to Support an Exception Request from September 30, 2011 through October 10, 2011. With a 92.97% quorum participating in the ballot, the proposed BES Definition achieved a weighted segment vote of 71.68%. The Detailed Information to Support an Exception Request achieved an 89.53% quorum and a weighted segment vote of 64.03%.

There were 75 negative ballots submitted for the initial ballot of the BES Definition and all of those ballots included a comment, which necessitated a recirculation ballot.

There were 88 negative ballots submitted for the initial ballot of the Detailed Information to Support a BES Exception Request and all of those ballots included a comment, which necessitated a recirculation ballot.

As discussed below, many of the comments related to the Exception Request process rather than to the proposed BES Definition. There were four main themes to the comments provided in the initial balloting:

1. **Lack of guidance for the Exception Request evaluation process** – The SDT understood the concerns raised by the commenters in not receiving hard and fast guidance on this issue. The SDT would have preferred to be able to provide a simple continent-wide resolution to this matter. However, after many hours of discussion and an initial attempt at doing so, it became obvious to the SDT that a simple approach was not achievable. If the SDT could have come up with a simple approach, it would have been supplied within the bright-line criteria. The SDT directly solicited assistance on this topic in the first posting of the technical criteria and received very little in the form of substantive comments from stakeholders.

The SDT recognized that there are so many individual variables that will apply to specific cases that there is no way to cover all of them in a set of bright-line criteria. There are always going to be extenuating circumstances that may influence individual cases. One could take this statement to say that Regional discretion has not been removed from the BES Definition as directed by Order No. 743. However, the SDT would disagree with this interpretation. The Exception Request Form has to be taken in concert with the changes to the Rules of Procedure and looked at as a single package. When one looks at the proposed Exception Procedure, it becomes clear that the role of the Regional Entity has been drastically reduced. The role of the Regional Entity is now one of reviewing the Exception Request for completeness and making a Recommendation to NERC on whether the Exception Request should be approved or disapproved. The Regional Entity plays no role in actually approving or disapproving the Exception Request, other than providing a Recommendation. NERC, not the Regional Entity, will make the final determination. Moreover, the Exception Procedure in proposed Appendix 5C of the NERC Rules of Procedure, sections 5.2.4 and 5.3, provides an added check by requiring review and provision of an opinion by an independent Technical Review Panel of a Regional Entity's proposed Disapproval of an Exception Request. The Technical Review Panel's evaluation becomes part of the Exception Request record submitted to NERC. Finally, section 7.0 of proposed Appendix 5C provides NERC the option to remand a rejected Exception Request to the Regional Entity with the directive to conduct a substantive review of the Exception Request, if NERC determines the Regional Entity should not have rejected the Exception Request.

Commenters also pointed out that the specific types of studies to be provided with an Exception Request, and how the Regional Entity should interpret the information, are not provided in the proposed Exception Procedure, and therefore the Regional Entity has no basis for determining what is an acceptable submittal. The SDT, however, again noted that the variations that will occur among Exception Requests negate the ability to establish specific, hard and fast criteria. However, there will be a great deal of professional and technical experience involved on behalf of Submitting Entities, Regional Entities and NERC in the Exception Request process. The SDT believed that Submitting Entities, Regional Entities and NERC will be able to determine what types of information is important to support Exclusion Requests and Inclusion Requests under the Exception Procedure.

Commenters pointed to a lack of specific guidelines in the Exception Procedure for NERC to follow in making its decision. The SDT reiterated the problem with providing a single set of hard and fast rules, in light of there being so many variables to take into account. The SDT believed that providing a single set of criteria that would have to be inflexibly applied to every Exception Request would inappropriately constrain NERC's ability to address the particular facts and circumstances of individual Exception Requests. Moreover, section 3.1 of proposed Appendix 5C states the fundamental principle that the evaluation of an Exception Request must be based on whether the Elements are necessary for the Reliable Operation of the interconnected transmission system. "Reliable Operation" is defined in the Rules of Procedure as "operating the Elements of the Bulk Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or Cascading failures of such system will not occur as a result of a sudden disturbance, including a Cyber Security Incident, or unanticipated failure of system Elements."[35] The SDT concluded that the technical expertise of the NERC review team, the visibility of the Exception Request process, and the overriding

[35] This is the definition of "Reliable Operation" in proposed Appendix 2 to the Rules of Procedure as filed on December 20, 2011.

requirement of "Reliable Operation" will result in appropriate decision making on Exception Requests while providing NERC with the flexibility to consider the particular facts and circumstances of each Exception Request.

Finally, the SDT noted that the draft SAR for Phase 2 of this project calls for a review of the Detailed Information to Support an Exception Request after 12 months of experience with Exception Requests. The SDT believes that this time period will allow both industry and the ERO to see if the data and information required by the Detailed Information to Support an Exception Request are appropriate and complete and to suggest changes to questions and information required by the Detailed Information to Support an Information Request based on actual real-world experience and not just on suppositions of what may occur in the future. Given the complexity of the technical aspects of this issue and the filing deadline that the SDT was working under for Phase I of this project, the SDT believed it reached a fair and equitable resolution of this difficult issue for Phase 1.

2. **Will a single "negative" response to the checklist questions mean a request will be denied** - Some commenters asked whether a "yes" or "no" response to a single item on the Exception Request Form will mandate a Disapproval of the Exception Request. The SDT referred to text in section 3.2 of the then-current draft of the Exception Procedure stating that no single piece of evidence provided as part of an Exception Request or response to a question will be solely dispositive in the determination of whether an Exception Request shall be approved. In its final version of the proposed Exception Procedure, the BES ROP Team revised this text to the following text, which the Team viewed as a functionally equivalent but more encompassing statement: "All evidence provided as part of an Exception Request or response will be considered in determining whether an Exception Request shall be approved or disapproved."

3. **Lack of certainty that Phase 2 would start** - The SDT has obtained the proper approvals for Phase 2 even prior to the completion of Phase I. The SDT received approval from the NERC Standards Committee that Phase 2 of the project would continue to be considered as a high-priority project and that the same SDT that worked on Phase 1 would continue in Phase 2. The phased project plan was endorsed by the NERC Members Representative Committee and the Board of Trustees. Assurances were also received from all appropriate bodies that they would assist the SDT in receiving any assistance required for in-depth technical analysis from relevant NERC standing committees. In fact, Phase 2 activities have started.

4. **How to weigh the Exclusions against the Inclusions in the BES Definition** - The application of the proposed BES Definition is a three-step process that when properly applied will identify the vast majority of BES Elements in a consistent manner that can be applied on a continent-wide basis. In step 1, the core BES definition is used to establish the bright line of 100 kV, the overall demarcation point between BES and non-BES Elements:

> 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.

To fully appreciate the scope of the core definition, an understanding of the term Element is needed. Element as defined in the NERC Glossary of Terms 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."[36]

Thus, an Element is basically any electrical device that is associated with the transmission or the generation (generating resources) of electric energy. Moreover, the NERC Glossary definition of "Transmission" encompasses "an interconnected group of lines and associated equipment for the

[36] This is also the definition of Element in proposed Appendix 2 of the Rules of Procedure.

movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems."

Step 2 of the BES Definition provides additional clarification for the purposes of identifying specific Elements that are included in the BES through the application of the core definition. 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.

Step 3 of the BES Definition is to evaluate specific situations for potential exclusion from the BES (*i.e.*, classification as non-BES Elements). The exclusion language is written to specifically identify Elements or groups of Elements for potential exclusion from the BES.

Exclusion E1 provides for the exclusion from the BES of transmission Elements from radial systems that meet the specific criteria identified in the exclusion language. This does not include the exclusion of Real Power and Reactive Power resources captured by Inclusions I2 – I5. Exclusion E1 only speaks to the transmission component of the radial system. Similarly, Exclusion E3 (local networks) should be applied in the same manner. Therefore, the only inclusion that Exclusions E1 and E3 can supersede is Inclusion I1.

Exclusion E2 provides for the exclusion of Real Power resources that reside behind the retail meter (on the customer's side), if the enumerated conditions (i) and (ii) are met, and supersedes Inclusion I2.

Exclusion E4 provides for the exclusion of retail customer owned and operated Reactive Power devices, and supersedes Inclusion I5.

In the event that the BES Definition designates an Element as BES that is not necessary for the Reliable Operation of the interconnected transmission network, or designates an Element as non-BES that is necessary for the Reliable Operation of the interconnected transmission network, the BES Exception Procedure in proposed Appendix 5C may be utilized on a case-by-case basis to either exclude or include, respectively, the Element from or in the BES.

5. **Assurance that threshold values would be addressed in Phase 2** – As described earlier, the SDT has separated the project into two phases which will enable the SDT to address the concerns of both industry stakeholders and regulatory authorities. In Phase 2, the SDT will consider all recommendations for modifications to the technical aspects of the BES Definition. This will allow the SDT, in conjunction with the NERC technical standing committees, to develop analyses which will properly assess the threshold values and provide compelling justification for modifications to the existing values.

D. Balloting and Approval

The SDT addressed all of the ballot comments[37] and made several clarifying changes to the proposed BES Definition and the Detailed Information to Support an Exception Request, and posted both documents for a recirculation ballot from November 10, 2011 through November 21, 2011. The SDT posted its Consideration of Comments reports to the second posting and initial ballot comments as part of the recirculation posting.

A 95.92% quorum participated in the recirculation ballot and the proposed BES definition achieved a weighted Segment approval vote of 81.32%. Therefore, the proposed BES Definition achieved at least a 75% quorum of the ballot pool and a two-thirds weighted Segment vote, as required by the NERC *Standard Processes Manual*.

A 93.02% quorum participated in the recirculation ballot for the proposed Detailed

[37] *See* **Exhibit D** for Consideration of Comments and **Exhibit E** for the complete development history.

Information to Support an Exception Request, and it achieved a weighted Segment approval vote of 81.48%. Therefore, the proposed Detailed Information to Support an Exception Request achieved the required 75% quorum of the ballot pool and a two-thirds weighted Segment vote.

The NERC Board of Trustees adopted the proposed BES Definition, the Detailed Information to Support an Exception Request, and the SDT's proposed implementation plan, on January 18, 2012.

Respectfully submitted,

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Exhibits A – G

(Available on the NERC Website at
http://www.nerc.com/fileUploads/File/Filings/Attachments_BES_Defin.pdf)