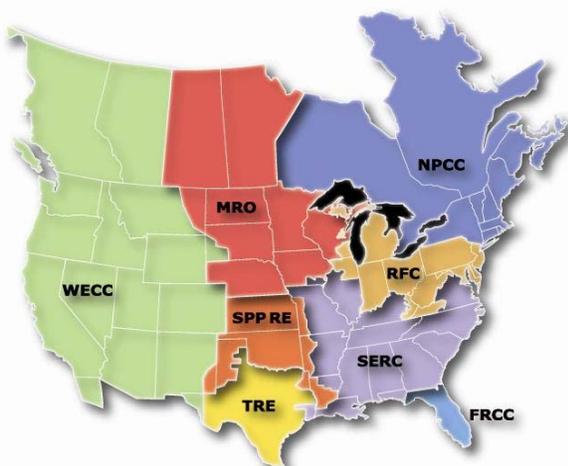


Preface and NERC Mission

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system of North America.^{1,2} NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, México.

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces reliability standards; assesses reliability annually via a 10-year assessment, and winter and summer seasonal assessments; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.³ NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight regional areas, as shown in the map and corresponding table. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, México.



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

¹ H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005: <http://www.gpo.gov/fdsys/pkg/BILLS-109hr6enr/pdf/BILLS-109hr6enr.pdf>

² The NERC Rules of Procedure, Section 800, further detail the Objectives, Scope, Data and Information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

³ As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in British Columbia, Ontario, New Brunswick, and Nova Scotia. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the “electric reliability organization” under Alberta’s Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the Régie de l’énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory and enforceable in that jurisdiction.

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Authorization (email from Pete Heidrich Feb. 27, 2012)

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

Dear Sir:

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

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

Thank you,

Peter A. Heidrich
Manager of Reliability Standards
Florida Reliability Coordinating Council
1408 N. Westshore Blvd., Suite 1002
Tampa, FL 33607-4512
813-207-7994 - office
813-787-7620 - cell
813-280-5646 - fax



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

Dear Sir:

The Project 2010-17 DBES SDT meet the week of February 20th and discussed the initial 'problem statements' provided for consideration by the leadership of the Technical Committees. Following

discussion and review of the comments submitted during the initial posting of the phase 2 SAR, revisions were made to the 'problem statements'. Attached you will find the revised the 'problem statements' which include additional language speaking to potential sources of technical information (provided by industry) that the Technical Committees may consider for possible analysis.

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

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

Thank you,

Peter A. Heidrich

Manager of Reliability Standards
Florida Reliability Coordinating Council
1408 N. Westshore Blvd., Suite 1002
Tampa, FL 33607-4512
813-207-7094 - office
813-787-7620 - cell
813-280-5646 - fax



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Transmittal to Standards Committee

(To: Heidrich, Peter

Cc: PCLead (pclead@listserv.nerc.com); dbessdt_plus

Subject: RE: Project 2010-17 DBES Phase 2 Problem Statements - Revised

DRAFT

Peter,

Attached is the final report on this subject that was approved by the Planning Committee at its December 11-12, 2012 meeting.

Please let us know should there be any questions. Thank you.

Jeff Mitchell

ReliabilityFirst Corp.

(330) 247-3043 - office

(330) 704-8837 – cell

1. Bulk Electric System Definition Technical Justification

1.1 Background

NERC has been working over the last year to revise its Bulk Electric System (BES) definition to eliminate the regional discretion and subjectivity contained within it. In early 2012, the NERC Board of Trustees approved a revised BES definition and subsequently filed it with FERC under docket RM12-6 and RM12-7. This concluded the Phase I work associated with developing a revised definition.

During the initial revision of the definition of the BES in Phase I of Project 2010-17, industry stakeholders expressed concerns related to the lack of technical justification associated with the existing parameters in the definition. Phase II of the Project was developed to address this technical justification due to time constraints in the Phase I schedule. Therefore, the DBES Standard Drafting Team (SDT) has asked the Planning Committee for assistance in developing that technical justification for certain parameters of the revised definition.

1.2 Problem Statement

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

The DBES Standard Drafting Team (SDT) sought support from the NERC Technical Committees (Operating and Planning) in the development of the technical justification to assist the SDT in developing any potential revisions to the following parameters currently embedded in the NERC Board of Trustees approved definition of the BES:

- 100 kV bright-line (Core definition)
- Generation threshold (Inclusions I2 and I4) MVA values associated with single unit and multiple unit facilities
- Reactive Power sizing (MVA level) parameters (Inclusion I5)
- Power flow allowed out of local networks

1.3 Planning Committee Assignments

To handle this request in a timely manner, the Planning Committee assigned the following topics to the designated subcommittees within its organizational structure.

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

2. Technical Justification of 100kV Bright-Line in Core Definition

2.1 Background

NERC's filing to FERC under docket RM12-6-000 proposed to establish a bright-line transmission threshold so that the "bulk electric system" would include facilities operated at 100 kV or higher, if they are Transmission Elements; or connected at 100 kV or higher, if they are Real Power or Reactive Power resources. The Planning Committee was requested by the BES SDT to provide the technical justification for the 100 kV threshold included in the core BES definition or propose a better alternative, if the technical justification proves such (see Appendix 1).

2.2 Alternatives to the 100 kV Threshold Considered

The Planning Executive Committee (PC ExCom) considered several alternatives to the 100 kV bright-line transmission threshold and selected the following approaches for further research and consideration:

Technical Alternative A – Surge Impedance Loading (SIL)

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

Technical Alternative B – Short Circuit Values

This alternative considers incorporating facilities with a short circuit value greater than a specified threshold (e.g., 5,000 MVA).

Technical Alternative C – Substation MVA Rating

This alternative would include substations with two or more lines emanating from that substation with a total value greater than a specified threshold (e.g., 800 MVA) or higher and any transmission lines with capacity ratings greater than a specified value (e.g., 400 MVA). The total substation value would be the summation of all of the capacity values of the transmission lines emanating from a substation and may include sub-100 kV facilities within the substation.

Technical Alternative D – Transfer Distribution Factors

This alternative would use transfer distribution factors, such as Power Transfer Distribution Factor (PTDF) and Outage Transfer Distribution Factor (ODTF), as a bright line threshold for inclusion of lines and transformers in the BES. Calculated values above a specified percentage (e.g., 3 percent) would determine which facilities would be considered in or out of the BES.

Technical Alternative E – Angular Difference

This alternative would determine facilities within the BES by calculating the angular differences between substation buses. The values used in these alternatives would come from power flow analyses or real-time synchro-phasor data gathered from operating phasor measurement units (PMU's).

Technical Alternative F – Maintain 100 kV bright-line threshold (Core definition)

Technical alternative F would maintain the currently filed 100 kV bright-line threshold without adjustment.

2.3 Technical Discussion of Alternatives**Technical Alternative A – Surge Impedance Loading (SIL)**

This approach would incorporate transmission lines that have a Surge Impedance Loading (SIL) value above a specific criteria (possibly 100 MVA), and include all substations connected to a line that meets this criteria.

A key component to the reliability of the power system is to continue to provide service to load from not only nearby generating sources, but also from external sources as well. This flexibility has been the justification to develop and build a number of Extra High Voltage (EHV) transmission facilities throughout North America. To assess the ability of a transmission line to carry load, or the amount load a transmission line can effectively carry, engineers calculate the Surge Impedance Loading (SIL) of the transmission line.

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

Considering the SIL alternative for uncompensated overhead transmission lines, three 500 kV, six 345 kV circuits, or thirty-four 161kV⁴ circuits would be required to achieve the same loadability of a single 765 kV line, for example. Specifically, a 765 kV line can reliably transmit 2,200-2,400 MW (i.e., 1.0 SIL) for distances up to 300 miles, whereas the similarly situated 500 kV and 345 kV lines with bundled conductors can deliver only about 900 MW and 400 MW, respectively, over the same distance.

For short distances, these previous relationships can produce slightly different results reflecting the thermal capacities of the transmission line. The thermal capacity of the transmission line is determined by the number/size of line conductors and station equipment ratings. But for “typical” compensated overhead lines, SILs are two to three times that of overhead lines. For underground lines, where air is not the insulating dielectric, SILs are three to twelve times that of overhead lines, with multipliers increasing as line-voltages decrease.

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

⁴ Thirty four 161kV added to original calculations

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

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

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

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

The SIL of transmission line is easy to calculate, but the values obtained correspond to a voltage level, which does not provide a better technically justified alternative to using the 100 kV voltage level.

It is the determination of the Planning Committee that SIL would be a surrogate to using a voltage level of a transmission line, which does not provide a technically superior reason to change from a bright line voltage level threshold. Also, transmission lines would still carry portions of power transfers even though they may be below a certain SIL value, as the SIL value is only an indication of reactive power equilibrium for that line. Virtually all transmission lines above 200kV would be captured by this criterion due to the SIL level.

Given that SIL is a surrogate for the voltage level of a transmission line, it is the Planning Committee recommendation to not use this method as a bright line threshold in the BES definition in lieu of the currently filed 100 kV threshold definition. Transmission lines below 200kV would most likely be included in the BES if the line has series compensation or is built underground, which increases the SIL for those types of lines.

Technical Alternative B – Short Circuit Values

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

⁵ Source is American Electric Power System Facts (no endorsement, just used posted transmission information)

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

The classical approach is used to calculate the Thevenin equivalent impedance as “seen” by the system at the point of the fault. Thevenin impedance is defined as the impedance seen at any point in a circuit once all the voltage generators have been short circuited and all the current generators have been opened. Transformer and utility impedances and rotating machine subtransient reactance describe all possible contributions to a short circuit. Once the symmetrical and peak duties are calculated, the required rating of the protective devices by direct comparison to manufacturer equipment ratings can then be determined.

The ANSI/IEEE method, which is described in IEEE Std. C37.010-1979 and its revision in 1999, is used for high-voltage (above 100V) equipment. It calls for determining the momentary network fault impedance, which makes it possible to calculate the close and latch rating of the breaker. It also calls for identifying the interrupting network fault impedance, which makes it possible to calculate the interrupting duty of the breaker. The interrupting network fault impedance value differs from the momentary network fault impedance value in that the impedance increases from the subtransient to transient level.

The IEEE standard permits the exclusion of all three-phase induction motors below 50 hp and all single-phase motors.

Using this approach, facilities with many sources (either transmission lines or generation sources) would fall under the definition of the BES with a defined level of short circuit MVA. In order to include all higher voltage facilities that may be carrying power over longer distances, a bright line voltage level would also need to be included when calculating this method. This value could be based on operating and design specifications of the interconnection.

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

However, to use Technical Alternative B as a bright line criterion in the BES definition, there must also be additional criteria to address the inclusion of the associated transmission lines, including transformers, emanating from those substations (which may include sub-100 kV facilities). At this time, the Planning Committee does not recommend the use of the Short-Circuit MVA method as a replacement for the bright line transmission threshold identified in the current BES definition.

Technical Alternative C – Substation MVA Rating

⁶ <http://ecmweb.com/content/short-circuit-calculation-methods>

Technical Alternative C uses the connected MVA of substations. The computed MVA would NOT include transformation within the substation, nor would it include generation or load connected to the substation. This method would only include circuits leaving the substation in the determination of connected MVA value. The connected MVA method would use networked transmission lines, as used in the current BES definition, and would also include lines that connect to the substation via transmission system, while at the same time excluding the following types of transmission lines: radial transmission lines, transmission lines to lower voltage facilities with no (transmission) sources, loads, and lines connected directly to generation sources.

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

In determining the connected MVA bright line value, NERC Reliability Standard EOP-004⁷ *Disturbance Reporting*, could be used as a starting value for inclusion / exclusion. Attachment 1 of EOP-004 indicates the magnitude of firm demand loss during disturbances that are of concern and require reporting to NERC. The relevant text of Attachment 1:

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

In general, a 300MW load requires more interconnecting lines than a single 300MVA circuit.

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

As an example, an entity with a peak load of approximately 4,500MW, calculated an average circuit loading on their system to be approximately of 23.6 percent. Using average circuit loading approach, it would require an additional 1,271 MVA of interconnecting MVA to serve 300MW load. It was then concluded, from engineering judgement, that using 800MVA for substations with interconnecting capability would be a conservative estimate.

⁷ NERC Reliability Standard EOP-004: <http://www.nerc.com/files/EOP-004-1.pdf>

For transmission lines with 400 MVA of transfer capability, this would calculate to the approximate values:

- 2,000 amps at 115 kV,
- 1,674 amps at 138 kV,
- 1,434 amps at 161kV,
- 1,004 amps at 230kV, and
- 670 amps at 345 kV.

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

Possible advantages of using the connected MVA over a voltage level are that the MVA based determination captures important criteria of BES facilities, such that critical substations are those with multiple circuits connected (individual lines are not as important given the criteria to operate the system at N-1 levels).

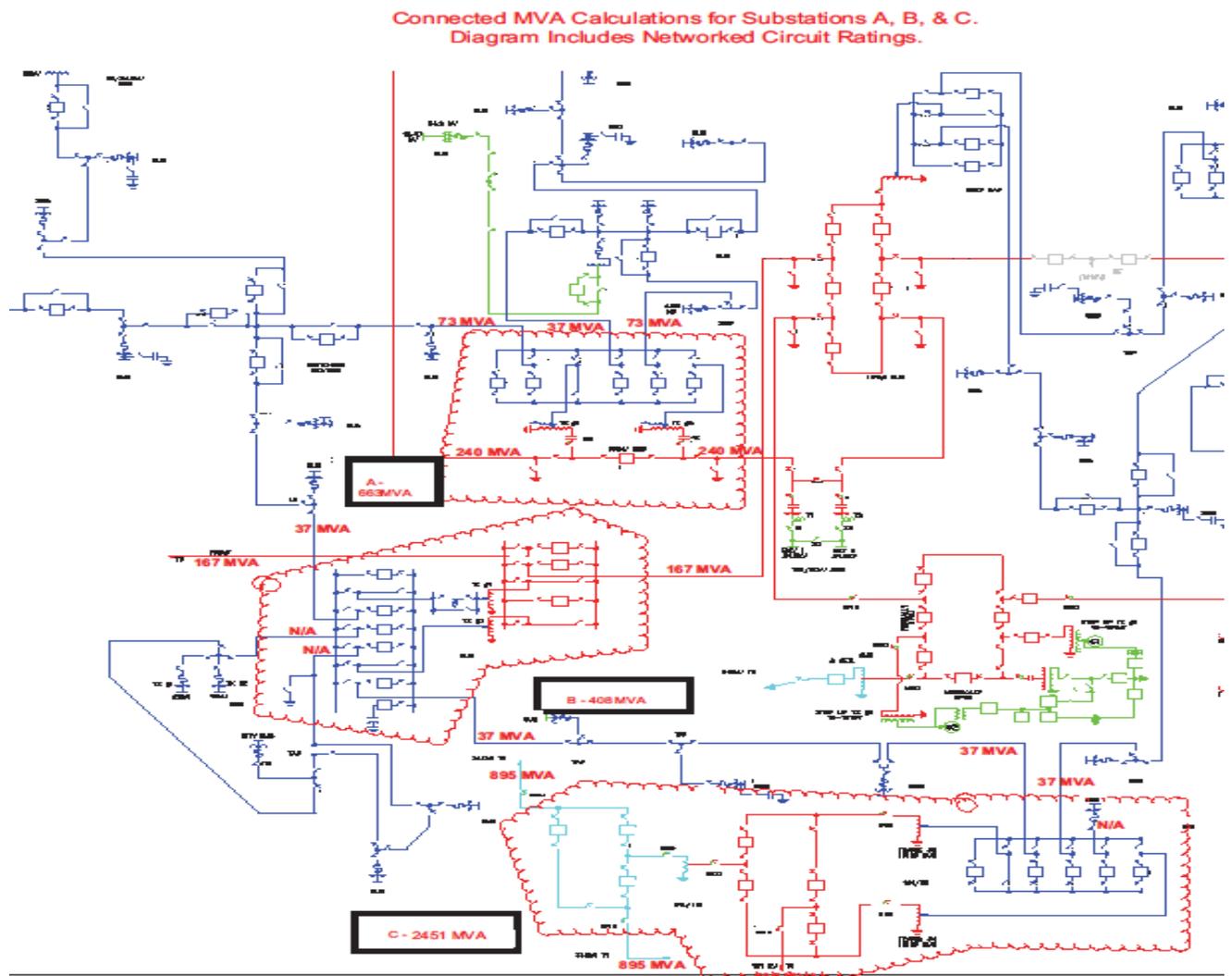
This method also determines the capacity of lower voltage facilities (such as transmission lines operated at voltages less than 100 kV) that are normally closed circuits of lower voltage facilities that contribute reliability benefits back to the interconnected system. The advantage of using the connected MVA method may alleviate concerns that facilities operating at voltages less than 100 kV are not as BES facilities unless they are determined to contribute to the reliability of the local network or interconnection. The connected MVA method also is more efficient to administer by reducing the number of inclusions and exclusions necessary to separate BES facilities (those which contribute to the reliability of network) from those facilities which do not contribute to reliable operation of the grid (also referred to as non-BES facilities).

Possible disadvantages of applying the connected MVA method may include challenges to address all possible scenarios, such as generation facilities with multiple fuel types are included or excluded. Using the connected MVA method would require a review if transmission lines or equipment is updated (however, increased current carrying capability should signal a review for BES application).

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

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

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



At this time, the Planning Committee does not recommend the use of the connected MVA of substation method as a replacement for the bright line transmission threshold identified in the current BES definition.

Technical Alternative D – Transfer Distribution Factors

Technical Alternative D would use transfer distribution factors as a bright line threshold for inclusion of lines and transformers in the BES. Calculated values above a specified percentage would determine what facilities are classified as BES facilities and which facilities are not classified as BES facilities. The Power Transfer Distribution Factor (PTDF) and Outage Transfer Distribution Factor (OTDF) were considered in lieu of the 100 kV bright line threshold.

Linear methods use PTDF to express the percentage of power transfer or transaction that occurs on a transmission path. PTDF is defined as the coefficient of the linear relationship

between the amount of a transaction and the flow on a line or transformer, and is the percentage of a power transfer flowing through a facility or set of facilities for a particular transfer when there are no contingencies. As it relates the amount of one change (i.e. transaction amount) to another change (i.e. the power flow through lines or transformers).

PTDF is the fraction of amount of a transaction from one zone to another over specified transmission facilities (i.e. lines and transformers) and PTDF does not consider contingencies during curtailment evaluation.

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

In a NERC and NPCC Compliance Filing and Assessment of Bulk Electric System Report⁸, NPCC defines “radial portions of the transmission system to include (1) an area serving load that is connected to the rest of the network at a single transmission substation at a single transmission voltage by one or more transmission circuits; (2) tap lines and associated facilities which are required to serve local load only; (3) transmission lines that are operated open for normal operation; or (4) additionally as an option, those portions of the NPCC transmission system operated at 100 kV or higher not explicitly designated as a bulk electric system path for generation which have a one percent or less participation in area, regional or inter regional power transfers.

The Commission, in response to Docket RC09-03 issued the following guidance in FERC Order No. 743; docket RM09-18-000.

Given the questionable and inconsistent exclusions of facilities from the bulk electric system by the material impact assessment and the variable results of the Transmission Distribution Factor test proposed in NPCC’s compliance filing in Docket No. RC09-3, there are no grounds on which to reasonably assume that the results of the material impact assessment are accurate, consistent, and comprehensive.⁹

⁸ Docket No. RC09-3-000 (September 21, 2009)

⁹ See WECC BESDTF Proposal V5 Appendix B, at B-11-B-12, available at <http://www.wecc.biz/Standards/Development/BES/Shared%20Documents/WECC-0058%20BES%20Comments%20Posting%205/P5%20Appendix%20B%20FINAL%20CLEAN.doc>

“The BESDTF considered the Northeast Power Coordinating Council’s Transfer Distribution Factor (TDF) approach to determining which networked Elements and facilities are used to distribute electricity locally and do not provide meaningful flow-through capability for the BES. In general, the TDF approach increases generation on one side of a transmission interface, decreases generation on the other side of the transmission interface, and measures the resulting change in flow across the interface. NPCC proposed that an Element with a TDF of less than 1% would not be part of the BES.

WECC staff expressed concern that the results of the TDF studies subjectively depended on which generating units had their output increased and which generating units had their output decreased. The results would also depend on the location, and what kind, of slack bus [a designated generator bus without a real power injection setting

Additionally, we have noted how the results of multiple material impact tests can vary depending on how the test is implemented. In contrast, the proposed “bright-line” test would continue the 100 kV threshold currently in use throughout much of the industry without allowing entities to vary this definition outside a Commission-approved exemption process. Further, since most regions currently use the 100 kV general threshold, most regions should have little difficulty maintaining a 100 kV bright-line threshold. If NERC proposes an alternate methodology, it must ensure that the method is consistent, repeatable, and verifiable, which the material impact tests we have discussed are not.

FERC rejected NPCC’s material impact assessment due to its subjective language and failure to identify facilities necessary to reliably operate the interconnected transmission system. These flaws include use of the amorphous term “local area,” which was not consistently applied throughout the NPCC region

The selection of this method to identify bulk system assets would require detailed power flow analyses be performed to make the determination and that method would need to be reviewed periodically (possibly biennially) to account for system changes that would affect the OTDF/PTDF values.

Some disadvantages of this alternative include detailed power flow analyses to be performed to make the determination, the values would need to be reviewed periodically (possibly biennially) to account for system changes that would affect the OTDF/PTDF values, and it would require a review if lines or equipment are updated.

At this time, the Planning Committee does not recommend the use of Transfer Distribution factors as a replacement for the bright line transmission threshold identified in the current BES definition.

Technical Alternative E – Angular Difference

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

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

used in power system modeling for the purpose of producing or absorbing real power such as change in real losses, loss of generation or interchange] used in the power flow simulation. As a result, the BESDTF did not propose to adopt the TDF method to determine which networked facilities could be classified as Local Distribution Networks and excluded from the BES.”

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

A large angle difference indicates, in a general sense, a stressed power system with large power flows or increased impedance between the areas. Simulations of the grid before the August 2003 Northeastern blackout showed increasing angle differences between Cleveland and West Michigan, suggesting that large angle differences could be a blackout risk precursor.

Wide area nomograms involving linear combinations of phasor angles have been suggested for monitoring of security boundaries. A recent simulation study¹¹ of potential phasor measurements on the 39 bus New England test system shows that, of several phasor measurements, angle differences were the best in discriminating alert and emergency states.

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

At this time, the Planning Committee does not recommend the use of Angular Difference as a replacement for the bright line transmission threshold identified in the current BES definition.

Technical Alternative F – Maintain 100 kV bright-line threshold (Core definition)

The use of the 100 kV threshold has been widely used in the industry for a long time in defining the bulk system, including the NERC definition and other industries. But the technical justification for using that voltage level as a bright line determination has been missing. The 100 kV threshold has been used over the years to delineate between transmission and sub-transmission facilities.

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

While the Planning Committee recommends keeping the 100 kV voltage threshold in the revised NERC definition of the BES, it also recognizes and has considered the inclusion of sub-100 kV facilities in the BES as a result of the findings and recommendations from the *Arizona – Southern California Outages on September 8, 2011* report.

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

Sub-100 kV facilities, as shown from the Interconnection discussions in Appendix 2, may be necessary for the operation of the BES but will need to be considered in the future on a case by case basis for inclusion in the BES. Registered Entities and Regional Entities will need to address how to make these determinations going forward. At this time, the Planning Committee recommends the continued use bright line transmission threshold identified in the current BES definition.

2.4 Technical Justification Recommendation

The definition of the BES should be easy to understand; and therefore, easy to administer as a “bright line”. Periodic recalculations of what should be classified as BES should be avoided. As new facilities are constructed, older facilities are retired, and existing facilities are reconfigured; very few, if any, facilities should be added or removed from the BES. It is the engineering judgment of the Planning Executive Committee that reliability is enhanced if there is to be too much included in the BES definition, rather than to omit a facility that may be needed to support the BES in time of need.

The Planning Executive Committee recommends the adoption of the 100 kV bright-line (Core definition) presented in Technical Alternative F. The selection of this criteria with a current voltage level of 100 kV and above contained in the revised NERC BES definition provides the best bright line criteria for the BES definition; and the Planning Executive Committee recommends continued use of the 100 kV threshold, as the technical alternatives considered in this effort do not provide brighter or better technical justification for a bright line threshold for the reasons discussed above.

It is important that all facilities that contribute to the overall reliability of the bulk electric system be included in the definition of the BES. However, any proposed definition of the BES will have to include some degree of engineering judgment.

That judgment must be conservative, and it would be unacceptable for a contributing cause of a future cascading event, islanding, or separation to be a relaxation of the BES definition.

After considering and discussing the technical rationale and justification, the NERC Planning Committee makes the following recommendations for each of the aspects it was asked:

- 100 kV bright-line (Core definition) – the current voltage level of 100 kV and above contained in the revised NERC BES definition provides the best bright line criteria for the BES definition; and the Planning Committee recommends continued use of the 100 kV threshold, as the technical alternatives considered in this effort do not provide brighter or better technical justification for a bright line threshold for the reasons discussed above.
- Generation thresholds (Inclusions I2 and I4) and the MVA values associated with a single unit and multiple unit (i.e., plant) facilities – To be added
- Reactive Power sizing (MVA level) parameters (Inclusion I5) – To be added
- Power flow out of local networks – To be added

- 3. Technical Justification of Generator Thresholds (RAS Report)**

- 4. Technical Justification of Reactive Resource Threshold (SAMS Report)**

- 5. Technical Justification of Powerflow out of Local Networks (SAMS Report)**

Appendix 1: NERC Standards Project 2010-17 NERC Standards Project 2010-17 Definition of BES, Phase II – Development of Technical Justification

Background:

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

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

Problem Statement:

Transmission Facilities and Real and Reactive Resources:

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

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

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

It is anticipated that the technical justification will consider the criteria currently established within the definitions of Adequate Level of Reliability and Adverse Reliability Impact, to determine the appropriate values for the thresholds associated with the identification of Transmission Facilities and Real and Reactive Resources as BES Elements.

The SDT received the following suggestions as to studies that could be utilized for these issues:

- 100 kV bright-line
 - Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion to determine 100 kV or 200 kV threshold, at pp. 11-18 (posted at on May 15, 2009) available at

- <http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?pxID=21&Source=/Standards/Development>
- Concept of considering Surge Impedance Loading (SIL-pu) alongside the corresponding normal thermal ratings, whichever is less, for typical compensated/uncompensated and overhead/underground transmission lines at various kV levels. A single MVA bright-line could then act to screen which sub-system elements fall in or out of the BES definition.

☒☒Reference documents:

- IEEE Transactions on Power Apparatus and Systems, Vol.PAS-98, No.2 March/April 1979 pp606-617, “Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines”, as well as its referenced articles.
- AECI related white-paper prepared for the BES Definition SDT, as well as AECI's referenced Eastern Interconnection PSEE 2011 Winter Peak Branch-data, with per-unit SIL calculations, for further analysis, available from AECI upon request.
- NPCC study presented in the NPCC/NERC 9/21/09 filing in FERC Docket No. RC09-3-000
- Generation thresholds and Reactive Power sizing
 - ISO-NE and NYISO planning and operating study process to demonstrate loss of largest source without Adverse Reliability Impact to the Bulk Electric System.
 - Snohomish County PUD White Paper entitled "A Performance Based Exemption Process to Exclude Local Distribution Facilities from the Bulk Electric System" (April 2011) discusses a methodology for distinguishing BES from non-BES elements based on their performance in the electric system.
 - Project 2007-09 for proposed standard MOD-026 developed generation modeling thresholds (http://www.nerc.com/files/Project_2007-09_Generator_Verfication_PRC-024_and%20MOD-026.pdf)
 - Draft White Paper for possible exclusion of generators from BES as submitted to the DBESSDT (see Attachment 1)

Local Networks:

Local networks (LN) (Exclusion E3) provide local electrical distribution service and are not planned, designed, nor operated to benefit or support the balance of the interconnected Transmission network. Their purpose is to provide local distribution service, not to provide transfer capacity for the interconnected Transmission network. Their design and operation is such that at the point of connection with the interconnected Transmission network, their effect on that network is similar to that of a radial Facility, particularly in that flow always moves in a direction that is from the BES into the LN. Any distribution of parallel flows into the LN from the BES, as governed by the fundamentals of parallel electric circuits, is negligible, and, more importantly, is overcome by the Load served by the LN, thereby ensuring that the net actual power flow direction will always be into the LN at all interface points. The presence of a LN is

not for the operability of the interconnected Transmission network; neither will the LN's separation diminish the reliability of the interconnected Transmission network.

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

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

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

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

Reference:

The current definitions of Adequate Level of Reliability and Adverse Reliability Impact are provided below for reference:

Adverse Reliability Impact: The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.

Adequate Level of Reliability (currently under revision):

The intent of the set of NERC Reliability Standards is to deliver an Adequate Level of Reliability defined by the following bulk power system characteristics:

- The system is controlled to stay within acceptable limits during normal conditions.
- The system performs acceptably after credible contingencies.
- The system limits the impact and scope of instability and cascading outages when they occur.
- The system's facilities are protected from unacceptable damage by operating them within facility ratings.
- The system's integrity can be restored promptly if it is lost.
- The system has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.

Attachment 1

Generation Exclusion below 75 MVA in BES Definition – Position Paper

Executive Summary

This Position Paper has been prepared in order to demonstrate that the inclusion and designation of smaller individual generating units in plants of aggregate capacity below 75 MVA as BES elements is not required because they are not deemed to be necessary for the operation of the interconnected transmission network. It was prepared following the comment period on the BES Definition where an important segment of Industry requested that the threshold of generation to be excluded from the definition should be increased.

This paper addresses only the reliability impact to the BES, focusing truly on the elements that are necessary for the operation of the interconnected transmission network. It is not the intention to cause changes of any process or create any reliability gaps.

This document provides the following arguments to demonstrate that the proposed modification to the definition should go forward because:

- There should be no reliability gaps introduced or any major process conflicts with a difference of threshold for generators between the Compliance Registry and the BES Definition. It is the understanding that this will not bring any gap to the application of Compliance Registry Criteria.
- It is expected that the proposed change of the BES definition bring about a small additional exclusion of only 4% of all generation. This difference doesn't impact the BES reliability as long as standards applying to generation do apply as well to non-BES generation.
- The average size of units excluded from the BES would be small, below the 15 MVA/unit.

1. Maintaining the Compliance Registry Criteria

Currently the NERC Statement of Compliance Registry Criteria require generating units above 20 MVA and power plants generation above 75 MVA to have registration either as a Generator Owner (GO) or Generator Operator (GOP), which means that they take on compliance obligations for NERC Standards applicable to their generating facilities. The proposed exclusion from BES definition of generation units and power plants under 75 MVA doesn't intend to or advocate change any of those obligations or registration criteria. Furthermore, the Statement of Compliance Registry section I (page 4) indicates that a user of the BES is a candidate for registration. In addition, section III.c.1 indicates the units in question can be included in the registry as being connected to the BPS. However, if there are any reliability gaps introduced as a result of the new definition, then steps should be taken to close them (for example, a quick review and update appropriate of applicability of existing standards).

Therefore, the result of this change should be no reliability gaps introduced or any major process conflicts with a difference of threshold for generators between the Compliance Registry and the BES Definition.

2. Statistics for generation under 75 MVA

Specific evaluation has been made for specific regions and Balancing Authorities throughout North America (WECC, PJM, New-York, Ontario, Quebec, and ERCOT). The figures have been corrected to indicate only the amount of installed generation that would be excluded with the change in the definition. The results are preliminary but give a good indication of the quantity of generation involved. The difference of exclusion varies between 1.9% to 6.4% and averaged 4% of total amount. We can estimate also that the average size of the unit excluded for generating plants below 75 MVA is less than 15 MVA/unit.

Table 1: BES Transmission Statistics^{12, 13}

Entities or Regions	Installed Capacity (MW)	Former BES Definition		Proposed BES Definition		Difference
		Total Generation Exclusion	Average MVA / Unit Excluded	Total Generation Exclusion	Average MVA / Unit Excluded	
WECC	206,867	4.3%	5	9.9%	9	5.7%
PJM	182,817	0.5%	N/A	2.5%	N/A	1.9%
NYPA	45,991	3.2%	3	9.6%	7	6.4%
Ontario	34,882	6.0%	N/A	9.8%	N/A	3.8%
Québec	44,538	2.0%	8	4.5%	15	2.5%
Total	515,095	2.8%	--	6.8%	--	4.0%

3. BES Reliability is not impacted by generation below 75 MVA

One of the best ways to determine how generation less than 75 MVA impacts the BES is to remove this generation and observe the output of load flows and stability runs. The reliability of the interconnected grid is not impacted by a single small unit and these studies are already made. The impact of a single or a few small units will be localized. However, the impact of many small units may have an impact on a larger scale and needs to be examined.

Frequency Support and the Simultaneous loss of Generation

The interconnection is made up of various generation sizes dispersed across the interconnection. Section 2 provides the quantity of this small generation in comparison to all generation available. It is not probable that a single event could remove all the generation less than 75 MVA. Many of these generators are covered under standards regardless of whether the generator is considered part of the BES. Section 4 provides a discussion about standards that apply to these generators.

¹² Figures used are presented for reference only and are not official.

¹³ Previous compilation of publicly available data identified a total of 1,043,000 MVA for all generation in Canada and USA, and indicates that the quantity of generation below 20 MVA accounts for 4.5% and the generation below 75 MVA for 19.2%. As those figures include those units in plants of aggregate capacity above 75 MVA, they could not be used in the present assessment of the impact of change of definition. Those figures show that the amount involved is not very important in percentage or on the average size of excluded units. Also, the average size of units excluded from the BES would be below the 15 MVA/unit. We will see that the impact on the grid is insignificant.

The sudden loss of many generating plants below 75 MVA is very unlikely to happen. It would necessitate both a common factor that would trip all of those generators at the same time, considering that all those generators would not meet regular standards that would not allow such a loss.

It seems that the only factor common to many dispersed generators is the frequency (voltage drops would be limited to a small area and could not affect generation dispersed over a wide area). Frequency excursions are sensed by generation across a wide area. It is necessary for reliability of the grid that frequency protection of the units be coordinated to maintain the balance between generation and load. Regions have programs to provide this coordination and particular frequency settings that generator owners must apply. These standards apply regardless if the generator is in the BES or not. Furthermore, the loss of a single small generator will not impact the greater whole.

Preliminary findings indicate that there is no probability of single mode failure that will trip all these units at the same time, especially if standards would apply to those generators. Owners and regions have reserves that would account for the loss of all of the generation between 20 MVA and 75 MVA. However, extreme contingencies do occur and in many situations owners, Balancing Authorities, and regions have deployed Remedial Action Schemes (RAS and SPS) to arrest the impact of the loss of too much generation.

Balancing of Generation and Load and reserve

Balancing of generation and load should be done at all time. The generation that is removed would need to be replaced with other generation that is available as reserves.

- take into account the forced outage rate
- consider the impact on the deployment of the operating reserve or the reserve requirements (or primary /secondary reserve)
- sensitivity to load being over load forecast (80/20 forecast)

Respect of SOL and IROL in absence of generating plants below 75 MVA

With the generation below 75 MVA removed and other generation added the SOL and IROL will need to be reviewed to make sure that the system is still within limits.

Various Cases Studies

Conditions:

- Remove randomly 30% of all single units not part of a facility with multiple generators between 20 MVA and 75 MVA. These units should be connected at 100 kV or higher.
- Remove randomly 30% of all facilities that have multiple units with the aggregate total less than 75 MVA. These facilities must be connected at 100 kV or higher.
- Using the most recent year available, run the Load flow at summer or winter peak load
- Take single contingency outages and check for thermal, voltage, SOL, IROL, path ratings violations
- Report result and list any mitigation if necessary

WECC – needed to add reserves

PJM

Power flow analysis was conducted using an operational analysis case to determine the impact of generation meeting the proposed 75 MVA cut-off criteria. The analysis was conducted using a snapshot of the PJM capacity data base for capacity information. An operational analysis power flow representation.

To stress the system to conditions, the analysis was conducted using load that was approximately an 80/20 forecast and all units meeting the threshold were simulated as unavailable. The 12 month forced outage rate for units below 75 MVA is approximately 9 % which further demonstrate the severity of the tested conditions. The analytical work revealed that, under the extreme condition (an above expected peak load, all units meeting the proposed 75 MVA criteria removed and replaced by available external generation) no overloads would occur at the 500 kV or 230 kV levels and there would be no SOL or IROL violations either. Numbers for the tables:

Average size all unit less than 20 MVA 7.3

Average size all units less than 75 MVA 19.8

Average size between 33.6

Some analysis has been done (e.g., PJM) with simulation of outage of all generation units and plants below 75 MVA, and replacement of this generation from external sources outside the Balancing Area. The examination of all SOL and IROL has been done, and verification of overload of EHV facilities. No violation of any IROL or SOL nor any overloads (230 kV or 500 kV – PJM).

In Quebec, the unavailability of all Generating plants below 75 MVA could attain 1800 MW. The replacement of that generation by power import from outside the Balancing Area would not cause any SOL violations, but could bring a reduction of an IROL about 3.3% (for 600 MW).

4. Application of NERC Standards for generation

Existing Standards or Standards under Development

Some existing BAL and MOD requirements address some aspect of frequency balancing and generation data verification (such as unit size). However, NERC has a few standards that are in development, related to generators:

- Performance of generators during frequency and voltage excursion (PRC-024),
- Voltage regulation controls (PRC-019),
- Verification of models and data for Turbine/Governor and active power and frequency control functions (MOD-027) or for generator excitation control system and volt/var control functions (MOD-026)
- Reporting on no trip zone for protective relays of generators, maintaining generators connected to BES during many events on the system.

Those requirements are the only way to ensure a common participation of all generators for the safe, secure, and reliable operation of the system. NERC should pursue this work in standards development for generators and other elements that are not designated as BES but that are considered important for the balancing of load and contribution to the stability of the system.

Relevant “NERC Reliability Standards do and should continue to be developed and apply to any element necessary for the operation of the interconnected transmission network which includes BES elements, non-BES elements and even distribution facility elements. As such many NERC standards today do apply to non-BES elements, e.g. PER, PRC, CIP, UFLS, etc.

Regional standards or local standards

Further, these units smaller than 75 MVA and not designated as BES elements will still be required to comply with many additional requirements from local TO, TOP, and RC as part of the interconnection requirements and SI to the grid. In many cases, entities have requirements more stringent than NERC that apply to generators, as they are filed in Facility Connection Requirements and many apply it to 10 MVA generator units. These requirements address the following: frequency response during disturbances, exciter and stabilizer controls, or voltage control, and more. Such requirements exist independent of the inclusion or exclusion of those smaller generators in the BES definition.

Addressing Possible Reliability Gaps

Smaller units to address any BES reliability

In most if not all areas generation below will be required to adhere with NERC reliability standards plus other stringent interconnection requirements which frequently extend to 10 MVA. If and when a smaller unit that may be required for BES reliability, such as reliability must run or other, can be designated as a BES element through the exception process. Similarly, if a unit(s) that is significant because of location then they can also be designated as BES.

Standards

The BES project is to define a sub-system of BPS which is necessary for the operation of interconnected transmission network. The new definition and exception process will determine BES elements consistently across the ERO foot print. This change could have some impacts on other ERO processes and Reliability Standards. However, the definition itself should not be a means to address these issues or gaps. Applicability of NERC mandatory reliability Standards shall be for BES elements as well as non-BES elements such as UFLS, CIP, PER, and generation plants below 75 MVA that are included in FERC compliance registry.

However, if there are any reliability gaps introduced as a result of the new definition then steps should be taken to close them. For example, a quick review and update appropriate of applicability of existing standards. In parallel, ERO and SC undertake concurrent reviews to make sure to avoid any gaps. For this reason, NERC Standards should state either that (1) The standard applies to all BES elements as determined by the definition or exception process, or (2) The Standards applies to all BES or non-BES elements as determined by the Generator threshold.

Appendix 2: Interconnection Study Guidelines

A2.1 Eastern Interconnection Study

Background

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

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

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

Generation

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

Table 2: Total Generation in Eastern Interconnection¹⁴

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

Load

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

¹⁴ Data is from the ERAG 2012 Summer Peak case within the MMWG 2011 Series of power flow models.

Table 3: Total Load in Eastern Interconnection¹⁵

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

Transmission Line Mileage

The definition of the BES should include most of the transmission that is important to deliver generation to load. A majority of the total BES transmission line mileage is made up of 100-200 kV facilities. Fifty-eight (58) percent of the total transmission miles greater than 100 kV fall in the 100-200 kV range. Mileage data for the tables below was taken from the 2011 NERC Long Term Reliability Assessment data submittals.

Table 4: Transmission Line Mileage (1) in EI

Area	100-120 kV	121-150 kV	151-199 kV	Total	Area	100-199 kV %
FRCC	2,251	2,277	0	4,528	FRCC	38%
MISO	7,606	19,071	5,778	32,456	MISO	66%
MRO	5,428	3,670	264	9,362	MRO	44%
NPCC	23,731	3,527	1,460	28,718	NPCC	45%
PJM	4,911	23,120	395	28,426	PJM	54%
SERC	35,427	4,095	17,263	56,785	SERC	67%
SPP	9,082	8,729	4,801	22,612	SPP	69%

Table 5: Transmission Line Mileage (2) in EI

Area	200-299 kV	300-399 kV	400-599 kV	600 kV+	Total
FRCC	6,095	0	1,350	0	7,445
MISO	3,022	13,117	340	0	16,479
MRO	9,801	2,041	257	0	12,099
NPCC	13,733	11,494	2,357	7,257	34,842
PJM	9,148	9,417	3,816	2,206	24,587
SERC	18,383	1,577	7,473	0	27,433
SPP	3,572	6,559	114	0	10,245

Transmission Assessment Study Results

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

¹⁵ Data is from the 2012 Summer Peak case within the MMWG 2011 Series of power flow models. Generating plant auxiliary loads are included, if modeled.

Table 6: Limiting Elements in 2007 Study

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

Table 7: Limiting Elements in 2011 Study

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

A2.2 Hydro Québec Interconnection

Background

It must be mentioned that in the Québec Interconnection, distribution networks use only medium voltage levels (25 and 12 kV) and there are no high voltage distribution assets as in other Interconnections. However, HQT makes the following distinctions among its high and extra high voltage assets:

1. **Bulk Power System (BPS¹⁶):** mainly includes substations having a 735 kV voltage level with their connected lines and transformers. These facilities do not directly serve end-use customers. They constitute the backbone of the transmission system and provide interfaces for moving large amounts of power (well over 10,000 MW in some cases) from remote northern generation centers to load centers in southern Québec (600 miles away). BPS assets have been identified through impact-based studies, using the NPCC A-10 methodology.
2. **Main Transmission System (MTS):** Includes Elements and Facilities necessary for reliable system operation. It is monitored and controlled by the Reliability Coordinator, the Balancing Authority and the Transmission Operator for generation/load balancing, frequency control, reserve control, system voltage control, interchange transactions, monitoring of Special Protection Systems, and system restoration. BPS facilities are part of MTS, but generation assets above 50 MVA and transmission assets for interconnections are also included in the MTS. It also includes transmission assets between the BPS and the following facilities:

¹⁶ As defined by NPCC. This is different from NERC's BPS definition.

- interconnections (except for some interconnections with Ontario)
- black start units
- Gently-2 nuclear plant
- other large generation plants (generally above 300 MW).

3. **Regional Transmission System:** Includes the rest of the transmission assets, with voltages ranging from 49 to 315 kV, along with radial and local transmission systems. It also includes generation plants below 50 MVA and transmission assets serving load and smaller generation plants, often higher than 50 MVA. It contributes mainly to service continuity.

The Executive Committee of the Planning Committee is searching for alternative threshold levels for transmission facilities, and proposes the transmission line **Surge Impedance Loading** or the **Short Circuit MVA level**. HQT has no specific studies on these proposals, but we think that they could offer better indication to help identify Facilities necessary for the reliable operation of the transmission system. For example, the following table shows the average SIL in HQT's system. It shows that the SIL drops rapidly as the voltage decreases. This is a clear indication that 100 kV is unnecessarily low as a threshold for the reliable operation of the system.

Table 8: Overall HQ Transmission Statistic

Area	100-199 kV	200-299 kV	300-399 kV	400-599 kV	600 kV+	Total
NPCC	28,718	13,733	11,494	2,357	7,257	63,559
Québec Interc. (QI)	5,614	1,974	3,349	757	7,097	18,791
NPCC minus QI	23,104	11,759	8,145	1,600	160	44,768

Table 9: Specific HQ Transmission Statistic

Area	100-120 kV	121-150 kV	151-199 kV
NPCC	23,731	3,527	1,460
Québec Interconnection. (QI)	4,292		1,322
NPCC minus QI	19,439	3,527	138

HQT supports the development of such alternatives. However, the regulator in the Province of Québec is the Québec Energy Board. In due time, HQT will file its own proposition with the Board. If other developments should arise, HQT will communicate them to NERC as usual.

A2.3 Electric Reliability Council of Texas (ERCOT)

Background

It is important that all facilities that contribute to the overall reliability of the bulk electric system (BES) be included in the definition of the BES. However, any proposed definition of the BES will have to include some degree of engineering judgment. That judgment must be

conservative, and it would be unacceptable for a contributing cause of a future cascading event, islanding, or separation to be a relaxation of the BES definition 2012.

The definition of the BES should be easy to understand; and therefore, easy to administer as a “bright line”. Periodic recalculations of what should be classified as BES should be avoided. As new facilities are constructed, old facilities retired, and existing facilities reconfigured; very few, if any, facilities should be added or removed from the BES. Purely for reliability, it is better for there to be too much included in the BES definition, rather than to omit a facility that may be needed to support the BES in time of need.

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

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

Generation

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

Table 10: Total Generation in ERCOT¹⁷

Total Generation in ERCOT	74,948 MW	% of Total
345 kV	41,053 MW	54.8%
138 kV	33,042 MW	44.1%
69 kV	853 MW	1.1%

Load

The 100-200 kV level of transmission facilities is critical for the deliverability of generation to load. Eighty six (86%) of all load in ERCOT is connected at 138kV.

¹⁷ Data is the level of dispatched generation from the SSWG 2012 Summer Peak case within the SSWG 2011 Series of power flow models.

Table 11: Total Load in ERCOT¹⁸

Total Load in ERCOT	73,387 MW	% of Total
345 kV	987 MW	1.3%
138 kV	63,097 MW	86.0%
69 kV	9,304 MW	12.7%

Transmission Line Mileage

The definition of the BES should include most of the transmission that is critical to deliver generation to load. A majority of the total BES transmission line mileage is made up of 100-200 kV facilities. Fifty-eight (58) percent of the total transmission line miles in ERCOT fall in the 100-200 kV range and over three quarter of the line miles operate at voltages above 100kV. Over twenty two (22) percent of the physical transmission line miles in ERCOT operate at 69kV. However, ERCOT's 69kV transmission lines are predominantly in rural areas and serve small electric loads and wind plants that are dispersed over a large geographic region. As shown in the tables above, the 69kV system in ERCOT serves approximately one (1) percent of the electric load and thirteen (13) percent of the generation in ERCOT. The loss of the small, lightly loaded 69kV lines spread over a large geographic region in ERCOT do not pose a threat to the bulk electric system.

Table 12: Total Transmission Line Miles in ERCOT

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

Transmission Assessment Study Results

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

A2.4 Western Interconnection

Background

All facilities that have an impact on the Bulk Electric System (BES) should be included in the definition of the BES. The definition of the BES should be easy to understand; and therefore,

¹⁸ Data is from the 2012 Summer Peak case within the SSWG 2011 Series of power flow models.

easy to administer such as a “bright line” definition. A moving target of what is classified as BES should be avoided. For reliability, a more inclusive definition of the BES is desirable, rather than to omit a facility that may be needed to support the BES in time of need.

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

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

Generation

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

Table 13: Total Generation in WECC¹⁹

Total Generation in WECC	245,737 MVA	% of Total
300 kV and Greater	61,274 MVA	24.93
200 to 300 kV	98,717 MVA	40.17
100 to 200 kV	42,553 MVA	17.32
50 to 100 kV	17,501 MVA	7.13
Less than 50 kV	25,692 MVA	10.45

Load

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

¹⁹ Note: Data is the generation available in the WECC 2012 Heavy Summer operating case within the WECC 2011 series of power flow models.

Table 14: Total Load in WECC²⁰

Total Load in WECC	172,750 MW	% of Total
300 kV and Greater	15 MW	0.01
200 to 300 kV	16,257 MW	9.41
100 to 200 kV	63,963 MW	37.03
50 to 100 kV	58,749 MW	34.00
Less than 50 kV	33,766 MW	19.55

Transmission Line Mileage

The definition of the BES should include most of the transmission that is critical to deliver generation to load. A significant portion of the high voltage transmission facilities in the Western Interconnection fall in the 100-200 kV range. Of the transmission line miles collected, over 40% percent of the total in WECC falls in the 100-200 kV range.

Table 15: Transmission Line Miles by Voltage Class²¹

Line Voltage kV	100- 199	200-299	300-399	400-599
WECC (miles)	50,306	42,336	11,637	20,262

Transmission Assessment Study Results

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

²⁰ Data is the load forecasted in the WECC 2012 Heavy Summer operating case within the WECC 2011 series of power flow models.

²¹ Data is from the 2011 Long Term Reliability Data Collection. No data collected for transmission facilities below 100 kV