real-time operation personnel located in a centralized generation control center that interfaces with the plants and the local RTO/ISO but not to personnel at the plant level.

1355. Some commenters address the appropriate scope of training for generator operators. For example, MidAmerican states that experience and knowledge necessary for transmission operators may go well beyond what is needed for generation operations. It contends that a NERC-approved training course specific to these functions would be an appropriate alternative. Entergy comments that, if training of generator operator personnel is required, it should focus on the functions generator operators must perform, not on the functions that others perform. SDG&E states that training for generator operators and others who may directly impact the reliable operations of the Bulk-Power System need not be identical to or as extensive as that required of transmission system operators, but should be tailored in scope, contents and duration so as to be appropriate to the personnel and the object of promoting system reliability.

1356. FirstEnergy states that there are no universal certification or training programs for generator operators; therefore a reasonable transition period should be established to allow time for generator operators to comply with this Reliability Standard. It also states that nuclear units are already subject to NRC training requirements and that compliance with NRC requirements should satisfy this Reliability Standard.

1357. APPA, Process Electricity Committee and TAPS are concerned that, unless a size limitation is included for the generator operators, a substantial number of generator operator personnel will have to be enrolled in training programs. They argue that while a generator plays an important role in the reliable operations of the bulk electric system, the generator operator takes commands from the transmission operator, balancing authority or reliability coordinator. TAPS opposes the expanded applicability, especially in the case of small systems, because it believes that the requirement would be costly with no benefits to reliability.

1358. Process Electricity Committee is concerned about the effect of the expanded requirements on end users who have on-site generation. It argues that the training requirements would present an added cost for end users with no apparent added benefit and that, in the long term, end users may be discouraged from developing on-site generation, which in turn would leave industrial electricity users more vulnerable to failures elsewhere on the energy grid.

(b) Commission Determination

1359. The Commission explained in the NOPR that transmission operators and balancing authorities are not the only entities that have operating personnel in positions that directly impact the reliable operation of the Bulk-Power System; and included generator operators among those that have such an impact.[371] Xcel and others oppose extending the applicability of PER-002-0 to generator operators, because they take directions from balancing authorities and others, which limits their ability to impact reliability. Although a generator may be given direction from the balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action. Further, if communication is lost, the generator operator personnel should have had sufficient training to take appropriate action to ensure reliability of the Bulk-Power System. Thus, we direct the ERO to develop a modification to make PER-002-0 applicable to generator operators.

1360. We agree with FirstEnergy and others that some clarification is required regarding which generator operator personnel should be subject to formal training under the Reliability Standard. As noted above, a generator operator typically receives instructions from a balancing authority. Some generator operators are structured in such a way that they have a centrally-located dispatch center that receives direction and then develops specific dispatch instructions for plant operators under their control. For example, a balancing authority may direct a centrally-located dispatch center to deliver 300 MW to the grid, and the dispatch center would determine the best way to deliver that generation from its portfolio of units. In this type of structure, it is the personnel of the centrally-located dispatch center that must receive formal training in accordance with the Reliability Standard. Plant operators located at the generator plant site also need to be trained but the responsibility for this training is outside the scope of the Reliability Standard.[372]

1361. Other generator operators may be structured in such a way that the dispatch center and the single generation plant are at the same site. In this structure as well, some personnel will perform dispatch activities while others are designated as plant operators. Again, it is the dispatch personnel that must receive formal training in accordance with the Reliability Standard. Plant operators also need to be trained but the responsibility for this training is outside the scope of the Reliability Standard.

1362. We disagree with Nevada Companies, Xcel and others that assert that generator operator training will provide limited benefit. Rather, we conclude that, with the above focused direction regarding the applicability of the Reliability Standard to generator

[371] NOPR at P 771.

[372] The Commission expects the entity registered as the generator operator to ensure that plant operators are competent for the tasks that they perform.

operator personnel, the benefits to the Bulk-Power System will be maximized and the cost of formal training limited. Further, our direction addresses California PUC's concerns regarding application to plant operators. In any event, the existence of local training requirements in some regions does not supplant the need for uniform training requirements for all generator operators developed in a Reliability Standard with continent-wide applicability.

1363. Further, the Commission agrees with MidAmerican, SDG&E and others that the experience and knowledge required by transmission operators about Bulk-Power System operations goes well beyond what is needed by generation operators; therefore, training for generator operators need not be as extensive as that required for transmission operators. Accordingly, the training requirements developed by the ERO should be tailored in their scope, content and duration so as to be appropriate to generation operations personnel and the objective of promoting system reliability. Thus, in addition to modifying the Reliability Standard to identify generator operators as applicable entities, we direct the ERO to develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel.

1364. FirstEnergy states that nuclear plant operators are already subject to NRC training requirements and thus suggests that compliance with NRC requirements should satisfy this Reliability Standard. FirstEnergy does not identify the content of the NRC training requirements, and the Commission is unaware whether the NRC training requirements adequately address the interaction between a nuclear power plant and the Bulk-Power System. Accordingly, without drawing any conclusion on the matter, the Commission directs that the ERO consider FirstEnergy's comments in the Reliability Standards development process.

1365. Commenters' concerns regarding the need for a size limitation on generator operators should be satisfied by our determination that the applicability of particular entities should be determined based on the ERO compliance registry criteria, which APPA and TAPS support. We believe that limiting the applicability of Reliability Standards to NERC's definition of bulk electric system will alleviate much of Process Electricity Committee's concern regarding the effect of the expanded requirements on end users who have on-site generation. For larger end users who have on-site generation, the Commission believes that there is an added benefit to including them in the Reliability Standards because they sell into the market and should be treated on a similar basis as any other generator of a similar size.

iv. Applicability to operations planning and operations support staff

1366. As mentioned above, the Commission proposed in the NOPR to direct the ERO to develop a modification to PER-002-0 to require training of operations planning and operations support staff of transmission operators and balancing authorities who have a direct impact on the reliable operation of the Bulk-Power System.

(a) Comments

1367. Several commenters, including EEI and APPA, oppose the proposed applicability of the Reliability Standard to operations planning and operations support staff. Other commenters contend that the Commission's proposal is ambiguous and should be clarified.

1368. EEI states that the extension of the applicability to "operations support personnel" could result in a dramatic expansion of industry training requirements with uncertain benefits to system reliability. It requests that the Commission reconsider this proposal or provide some additional clarity on the definition of the term. APPA also expresses concern about expanding the applicability to operations planning and operations support staff, especially if the Commission adopts its proposed interpretation of the bulk electric system because this would become quite onerous for small utilities. Wisconsin Electric states that the Commission's proposal does not address how to identify the operations planning and operations support personnel who would be subject to the Reliability Standard and how to develop compliance measures for them. It contends that the proposed modification is ambiguous and should not be implemented.

1369. Avista states that individuals who are responsible for assessing a company's compliance with the Reliability Standards may simply have an administrative and coordination role, but have no direct responsibility for reliable operations of the Bulk-Power System. It argues that such individuals, while operations support staff, should not be subject to the proposed Reliability Standard. It therefore requests that the Commission clarify that personnel subject to the Reliability Standard may include operations planning and operations support staff.

1370. Entergy believes it is unnecessary to require all staff supporting the transmission operator to be trained in the transmission operator's Reliability Standards responsibilities. It states that as long as the supporting personnel work under the direction of a NERC-certified transmission operator, there is no need for duplicative training for supporting personnel. Entergy comments that, if such training is required, it should focus on the functions operations planning and operations support staff must perform, not on the functions that others perform.

1371. Northern Indiana states that expanding application of the Reliability Standard to operations support staff "with a direct impact on the reliable operation of the Bulk-Power System" is ambiguous. It states that NERC surveyed certified operators for its job function analysis related to this Reliability Standard with results due at the end of January 2007. Northern Indiana recommends that the results of this survey be considered in the development and clarification of this proposed Reliability Standard. Further, Northern Indiana is concerned about which specific job functions will be addressed and which will be exempt, and about what "direct" versus "indirect" impact means.

(b) Commission Determination

1372. The Commission directs the ERO to develop a modification to PER-002-0 that extends applicability to the operations planning and operations support staff of transmission operators and balancing authorities, as clarified below. Most commenters express concern about extending the applicability of the Reliability Standard because they believe "operations planning" and "operations support" are not well-defined and could encompass a significant number of operations personnel. In the NOPR, the Commission stated that the Reliability Standard should apply to operations planning and operations support staff that have a direct impact on the reliable operation of the Bulk-Power System.[373] We clarify that these personnel include those who carry out outage coordination and assessments in accordance with Reliability Standards IRO-004-1 and TOP-002-2, and those who determine SOLs and IROLs or operating nomograms in accordance with Reliability Standards IRO-005-1 and TOP-004-0. The Commission directs the ERO to include in PER-002-0, personnel who carry out the above functions.

1373. In addition, the Commission is aware that the personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages, are available, up-to-date in terms of system data and produce useable results can also have an impact on the Reliable Operation of the Bulk-Power System. Because these employees' impact on Reliable Operation is not as clear, we direct the ERO to consider, through the Reliability Standards development process, whether personnel that perform these additional functions should be included in mandatory training pursuant to PER-002-0.

1374. APPA and EEI oppose the proposed extension of the Reliability Standard to operations planning and operations support staff, claiming that it could dramatically expand industry training requirements with uncertain benefits to system reliability. Our clarification above adequately addresses these concerns because we have identified a

[373] NOPR at P 780.

specific set of such personnel that have a direct impact on reliable operations. With the above clarification, our directive is not as expansive as EEI and APPA contemplate, and is more clearly connected with Bulk-Power System reliability. Further, since the Commission is not adopting the proposed interpretation of the ERO's definition of bulk electric system, as discussed in the Applicability section above, the directed modification to PER-002-0 should not be onerous to small entities as suggested by APPA.

1375. Several commenters express concern that the operations planning and operations support staffs will be required to be trained on the transmission operators' responsibilities. The Commission clarifies that this is not the case. Training programs for operations planning and operations support staff must be tailored to the needs of the function, the tasks performed and personnel involved.

v. Training performance metrics

1376. In the NOPR, we noted the assertion by ISO/RTO Council that there is no definition for "adequately trained operating personnel." ISO/RTO Council suggested adoption of performance metrics to ensure that training results in competent operating personnel.[374] The Commission agreed and proposed to require that the ERO modify PER-002-0 to include performance metrics to assess the effectiveness of the training program. The Commission also stated that such performance metrics are not a substitute for an SAT developed training program.

(a) Comments

1377. Xcel does not agree that performance metrics should be included as part of this Reliability Standard. While it believes performance metrics are generally useful, it states that in this case it would be difficult to develop the appropriate metrics. MidAmerican believes that the proposed performance metrics are not essential to ensuring the appropriateness of training because the Reliability Standard already requires NERC approval of all training activities, and specifically requires training in certain areas.

1378. MISO and Wisconsin Electric state that it is unclear how a Reliability Standard to measure the effectiveness of a training program would apply to an organization that contracts for training services, and that there are many training requirements found in other Reliability Standards covering the topics and amount of training. They argue that the proposed modification is overly-prescriptive and deviates from a fundamental training concept that training should be tailored to the organization and to the individual.

[374] Id. at P 776.

(b) Commission conclusion

1379. Xcel, MISO and MidAmerican state that performance metrics to assess the effectiveness of training programs are unnecessary. The Commission believes that, if quantifiable performance metrics can be developed to gauge the effectiveness of a Reliability Standard, these performance metrics should be developed, tracked and used to continually improve an applicable entity's performance and the Reliability Standard itself. The Commission directs the ERO to explore the feasibility of developing meaningful performance metrics for assessing the effectiveness of training programs, and if feasible, to develop such metrics for the Reliability Standard as part of the Reliability Standards development process.

vi. Use of Systematic Approach to Training (SAT) methodology

1380. In the NOPR, the Commission required the ERO to use the SAT methodology in identifying the requirements for a training program because SAT is a proven approach to: identify the tasks and associated skills and knowledge necessary to accomplish those tasks; determine the competency levels of each operator to carryout those tasks; determine the competency gaps; and design, implement and evaluate a training plan to address each operator's competency.[375]

(a) Comments

1381. ISO-NE states that the use of SAT methodology should not be mandated and that responsible entities under this Reliability Standard should be allowed the flexibility to use the most appropriate training methodology available. Northern Indiana requests clarification on about our proposal on the use of SAT methodology.

(b) Commission Determination

1382. The Commission understands that the new operator training Reliability Standard PER-005-1-0 currently under development by the ERO would endorse the use of SAT. In response to ISO-NE, training based on SAT is a proven approach to identify the skills and knowledge necessary to accomplish particular tasks, evaluate each operator's competency to carry out those tasks, determine any competency competency gaps, and design, implement and evaluate a training plan to address such gaps. Since SAT is the most appropriate training methodology available, we believe this addresses ISO-NE's

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[375] Id. at P 775.

comments. Northern Indiana requests clarification about the details of our proposal for SAT methodology. The Commission has not directed how the SAT methodology should be implemented, but we expect it to be developed through the Reliability Standards development process. We encourage Northern Indiana to become involved in the process. Thus, we adopt the NOPR proposal to direct that the ERO develop a modification to PER-002-2 (or a new Reliability Standard) that uses the SAT methodology.

vii. Use of simulators for training

1383. The Commission explained in the NOPR that Requirement R4 of the Reliability Standard requires training in emergency operations using realistic simulations of system emergencies and noted that there are various options available for providing operator training simulator capability, including contracting for this service from others who have developed the capability. The Commission requested comments on the benefits and appropriateness of required "hands-on" training using simulators in dealing with system emergencies.[376]

(a) Comments

1384. While most commenters recognize the benefits of simulator training, they differ on whether simulator training should be mandatory.

1385. NERC comments that there can be significant value gained by training operating personnel for emergencies under realistic conditions using training simulators and requests that comments on this matter be directed to the Reliability Standards development process for consideration. APPA believes that significant reliability benefits could result from the use of simulators by reliability coordinators, transmission operators and balancing authorities that have operational control over a significant portion of load and resources. It does not believe, however, that requiring simulator training for smaller entities that do not have operational control over facilities that manage SOLs and IROLs would be an effective use of resources. APPA supports NERC's investigating the benefits of simulator training but recommends that any training requirements closely consider the costs and benefits of simulator training.

1386. SoCal Edison and MISO state that, although simulators are valuable training tools, not all entities should be compelled to have simulators. MISO comments that simulators will become even more critical in the coming years as experienced operators, with first-

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[376] Id. at P 778.

hand knowledge of their respective systems, retire. Recognizing that not every company can or should build a simulator because of the resources simulators require, MISO suggests that the Reliability Standards codify a requirement for operators of companies that do not own a simulator to have access to a training simulator. MISO states that while simulators are valuable training resources, focusing emergency training solely on full-scale simulators may lead to problems when unforeseen situations arise. It reasons that generic, low-cost simulators that teach concepts are a valuable training resource for developing skills transferable to events that do not follow a script.

1387. SDG&E states that simulators would enhance the overall training experience but cautions that simulators that accurately model individual systems are resource-consuming while less resource-consuming, generic simulators may not mirror the trainee's actual system. As such, it believes that the use of simulators should be encouraged but not mandated. Similarly, International Transmission contends that simulators are a useful tool in the training of operators and support personnel. However it cautions that simulators are not the only means to provide realistic simulation-based training. It argues that because alternative simulation-based training means are available and because dedicated training simulators are very expensive, the use of dedicated training simulators should not be required under the Reliability Standards.

1388. Otter Tail states that full-scale simulators are effective but costly to develop and labor intensive to maintain. It recommends that full-scale simulators should be an option but not a requirement for small entities. It proposes instead that the Commission allow small entities to continue to use training aids such as generic operator training simulators, EXCEL-based interactive training tools and table-top training exercises. Likewise, Alcoa also does not believe that simulators are necessary to provide operating personnel with training for system emergencies. It supports alternative training methods, such as table-top exercises or realistic simulated exercises that take into account the physical and electrical characteristics of the trainee's system. Further, it believes that costs associated with simulators would not be justified by the impact on reliability.

1389. Xcel states that to the extent that Reliability Standard PER-002-0 is applicable to generator operators, the industry should be able to develop its own ways of administering training instead of being required to develop simulators.

(b) Commission Determination

1390. Most commenters including NERC agree that hands-on training using simulators can add significant value to training for emergencies. Yet, we share the commenters' concerns regarding the high cost to develop and maintain full-scale simulators and take these concerns into consideration. The Commission finds that significant reliability benefits may be derived from requiring simulator training for reliability coordinators, transmission operators and balancing authorities that have operational control over a significant portion of load and generation.

1391. This does not mean that these entities must develop and maintain full-scale simulators but rather they should have access to training on simulators. Further, because the cost is likely to outweigh the reliability benefits for small entities, the Commission agrees with Alcoa and Otter Tail that small entities should continue to use training aids such as generic operator training simulators and realistic table-top exercises. Accordingly, the Commission directs the ERO to develop a requirement for the use of simulators dependent on the entity's role and size, as discussed above.

viii. Summary of Commission Determination

1392. The Commission notes that no commenters specifically addressed the proposed modifications directing the ERO to expand the Applicability section to include reliability coordinators, and to identify the expectations of the training for each job function and develop training programs tailored to each job function with consideration of the individual training needs of the personnel. However, in responding to the proposals to expand the applicability of the Reliability Standard, many commenters acknowledged the need to have clear training expectations and training programs tailored to specific job functions. The Commission finds that these two modifications will enhance the training by focusing on expectations and tailoring the training to specific job functions; therefore, the Commission adopts these modifications to the Reliability Standard.

1393. Accordingly, the Commission approves Reliability Standard PER-002-0. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to PER-002-0 through the Reliability Standards development process that: (1) identifies the expectations of the training for each job function; (2) develops training programs tailored to each job function with consideration of the individual training needs of the personnel; (3) expands the Applicability section to include (a) reliability coordinators, (b) local transmission control center operator personnel (as specified in the above discussion), (c) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System and (d) operations planning and operations support staff who carry out outage planning and assessments and those who develop SOLs, IROLs or operating nomograms for real-time operations; (4) uses the Systematic Approach to Training (SAT) methodology in its development of new training programs and (5) includes the use of simulators by reliability coordinators, transmission operators and balancing authorities that have operational control over a significant portion of load and generation.

1394. Further, the Commission directs the ERO to determine whether it is feasible to develop meaningful performance metrics associated with the effectiveness of a training program required by PER-002-0 and, if so, develop such performance metrics. The Commission also directs the ERO to consider through the Reliability Standards development process, whether personnel that support EMS applications as discussed above should be included in mandatory training pursuant to the Reliability Standard.

c. Operating Personnel Credentials (PER-003-0)

1395. PER-003-0 requires transmission operators, balancing authorities and reliability coordinators to have NERC-certified staff for all operating positions that have a primary responsibility for real-time operations or are directly responsible for complying with the Reliability Standards. NERC grants certification to operating personnel through a separate program documented in the NERC System Operator Certification Manual and administered by an independent personnel certification governance committee.

1396. In the NOPR, the Commission proposed to approve Reliability Standard PER-003-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PER-003-0 that: (1) includes generator operators as applicable entities; (2) specifies the minimum competencies that must be demonstrated to become and remain a certified operator and (3) identifies the minimum competencies operating personnel must demonstrate to be certified.

i. Comments

1397. In addressing this Reliability Standard, many commenters made the same arguments they made in connection with the operator training Requirements set forth in Reliability Standard PER-002-0. Comments specifically relevant to operator certification are reproduced here for completeness.

1398. EEI, FirstEnergy and PG&E agree that the Reliability Standard should apply to generator operators. FirstEnergy believes that the Functional Model and the Reliability Standards development process should be used to clarify any confusion about which generator operator and transmission operator functions are addressed under this Reliability Standard. To further reduce confusion and the need for potentially duplicative training, EEI and PG&E comment that operators should not be required to maintain multiple certifications. SDG&E states that new certification obligations for generator operators must be tailored to the needs of the function and should reflect the limited opportunities of generator operators to have an impact on system reliability. Thus, it argues that generator operators should not be subject to the same certification requirements as transmission operators. MidAmerican echoes this point and adds that minimum competencies are currently adequately demonstrated by the completion of

NERC-approved annual certification tests. MidAmerican believes that applicable tests should be tailored to specific job duties to ensure effectiveness and Reliability Standard compliance.

1399. Dynegy, MISO, Reliant and Wisconsin Electric are concerned about extension of this Reliability Standard to generator operators if it results in every power plant control room being staffed by NERC-certified operators. Dynegy supports a limited extension of the Reliability Standard to real-time operational personnel located in a centralized generation control center that interfaces with the plants and the local RTO/ISO. Reliant believes that, under certain circumstances, the dispatcher in the generator operator's local control center should not be subject to NERC certification requirements. It explains that, for example, in PJM the dispatcher in a generator operator local control center is a PJM-certified generation dispatcher and that, like the employees in plant operating positions, these dispatchers do not take unilateral action but instead act only upon PJM's instructions.

1400. LPPC states that certification requirements for real-time operations Reliability Standards should only be required for transmission and generation personnel that are located in the transmission control center (i.e., responsible for real-time Bulk-Power System operations). It argues that transmission and generation operation employees that are located in remote locations that are not directly involved in the real-time scheduling of transactions or Bulk-Power System monitoring and control do not need to be certified for real-time operations Reliability Standards because they are not involved in the type of functions in which regimented training in the Reliability Standards would be useful. LPPC states that requiring certification would be an inefficient result and would distract these personnel from their own highly-specialized tasks.

1401. Although APPA states that PER-003-0 is sufficient for approval as a mandatory and enforceable Reliability Standard, it opposes the proposed modification to make generator operators subject to the Reliability Standard. Alcoa, Entergy, Northern Indiana and Xcel also oppose subjecting generator operators to the Reliability Standard. Given that there is no size limitation limiting applicability for generator operators, APPA asks the Commission to reconsider the proposed modification and, instead, allow the applicability of PER-003-0 to generator operators to be considered through the Reliability Standards development process. Alcoa disagrees with the proposed modification because generator operators take direction from a NERC-certified transmission operator, balancing authority or reliability coordinator and do not operate independently of those entities. Similarly, Xcel states generator operators have limited ability to take independent action that affects Bulk-Power System reliability. It also states that it is not clear whether "generator operator" means plant operator or the transmission operator responsible for generation.

1402. Northern Indiana and SoCal Edison oppose a certification requirement for all real-time operating positions in a transmission control center that performs switching operations via SCADA for the Bulk-Power System, because these personnel are supervised by NERC-certified operators. Northern Indiana states that the costs would far outweigh the reliability benefits, if any, that would result from such a certification requirement. SoCal Edison recommends that PER-003-0 apply to operators who have the authority and are empowered to exercise independent judgment, and who take or direct actions to secure Bulk-Power System reliability. It recommends that operators who switch Bulk-Power System facilities when their actions are approved and overseen by certified operators should be excluded.

1403. APPA states that if it is required to send its employees for NERC training and certification, it would risk losing those employees to larger utilities that can afford to pay more, simply because those employees would have acquired a desirable occupational credential. It argues that given the substantial workforce issues facing public power systems in the next few years, imposing unneeded certification requirements could exacerbate an already challenging labor force situation.

1404. Northern Indiana adds that because some of these employees are members of labor unions and subject to existing collective bargaining agreements, it would have to renegotiate these agreements to provide for the certification of these employees, and to provide for the hiring of relief staff necessary to permit these employees to maintain their certification.

1405. PG&E states that, once the certification requirements are developed by NERC and approved by the Commission, sufficient time must be permitted for generator operators to attain the necessary certification. It argues that time will be needed to develop the process, create appropriate documentation and perform training for appropriate personnel. PG&E contends that generator operators should not be penalized for failing to achieve certification if they do not have a reasonable period of time to implement the training programs.

1406. EEI believes that the ERO's Reliability Standards development process should be used to sort out the applicability issues. It states that using this process will allow for sufficient clarity to reduce the risk of confusion and thus prevent the need for interpretations that could change over time. EEI believes this is especially important with this PER class of Reliability Standards because operators should have unambiguous guidance on what they are expected to do. It states that the Reliability Standards should be written so that operating personnel clearly understand their roles and responsibilities, and whether or not a specific certification is required. EEI also states that operators should not be required to maintain multiple certifications.

ii. Commission Determination

1407. Northern Indiana and APPA raise persuasive arguments regarding labor relations and labor retention issues that may arise if generator operators are required to be NERC-certified. The Commission understands theses concerns and is persuaded not to require generator operators or transmission operators at local control centers to be NERC-certified at this time. In addition, the Commission understands that there are some long tenured unionized transmission operators who are very capable operators but who are unable to secure certification. This is not a new problem and has been addressed in various collective bargaining negotiations through grandfathering such capable operators who are unable to become certified. However, the Commission directs that if grandfathering is implemented, the entity must attest that the operators are competent. The Commission directs the ERO to consider grandfathering certification requirements for these personnel so that the industry can retain the knowledge and skill of these long-tenured operators. Personnel that are subject to such grandfathering still must comply with applicable training requirements pursuant to PER-002-0.

1408. No comments were received on the proposed modifications to direct the ERO to modify the Reliability Standard to specify the minimum competencies that must be demonstrated to become and remain a certified operator and to identify the minimum competencies operating personnel must demonstrate to be certified. The Commission finds that these modifications improve the Reliability Standard by focusing on necessary competencies. Accordingly, the Commission directs the ERO to develop these modifications to the Reliability Standard.

1409. We find that the Reliability Standard serves an important reliability goal in requiring applicable entities to staff all operating positions that have a primary responsibility for real-time operations or are directly responsible for complying with the Reliability Standards with NERC-certified staff. Accordingly, the Commission approves Reliability Standard PER-003-0. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to PER-003-0 through the Reliability Standards development process that: (1) specifies the minimum competencies that must be demonstrated to become and remain a certified operator and (2) identifies the minimum competencies operating personnel must demonstrate to be certified. The Commission also directs the ERO to consider grandfathering certification requirements for transmission operator personnel in the Reliability Standards development process.

d. Reliability Coordination – Staffing (PER-004-1)

1410. PER-004-1 ensures that reliability coordinator personnel are adequately trained, NERC-certified and staffed 24-hours a day, seven days a week, with properly trained and certified individuals.[377] Further, reliability coordinator operating personnel must have a comprehensive understanding of the area of the Bulk-Power System for which they are responsible.

1411. In the NOPR, the Commission proposed to approve Reliability Standard PER-004-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to PER-004-0 that: (1) includes formal training requirements for reliability coordinators similar to those addressed under the personnel training Reliability Standard PER-002-0; (2) includes requirements pertaining to personnel credentials for reliability coordinators similar to those in PER-003-0 and (3) includes Measuers and Levels of Non-Compliance that address staffing requirements and the requirement for five days of emergency training.

i. <u>Comments</u>

1412. APPA notes that the revised Reliability Standard PER-004-1 filed by NERC on November 15, 2006 partially fulfills the directive to include Measures and Levels of Non-Compliance. It states that NERC should be directed to include Measures and Levels of Non-Compliance related to all Requirements.

1413. FirstEnergy seeks revisions to the terms "shall have a comprehensive understanding" and "shall have extensive knowledge." It states that it will be difficult for entities to demonstrate compliance with these terms. In addition, FirstEnergy suggests that the reliability coordinator staffing requirements should be located in the IRO Reliability Standards.

1414. Xcel states that emergency training requirements should be expressed in hour increments rather than days to allow for flexibility in scheduling training and coordinating with rotating shift schedules.

ii. <u>Commission Determination</u>

1415. No comments were received on the proposed modifications to include formal training requirements for reliability coordinators similar to those addressed under the

[377] In its November 15, 2006, filing, NERC submitted PER-004-1, which supercedes the Version 0 Reliability Standard. PER-004-1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, PER-004-1.

personnel training Reliability Standard PER-002-0 and to include requirements pertaining to personnel credentials for reliability coordinators similar to those in PER-003-0. The Commission finds that these modifications will improve the Reliability Standard because they include training requirements for the reliability coordinator who has the highest level of authority to assure Reliable Operation of the Bulk-Power System. Accordingly, the Commission directs the ERO to develop modifications to the Reliability Standard that address these matters.

1416. With regard to APPA's comments, consistent with our discussion above regarding Measures and Levels of Non-Compliance, we leave it to the discretion of the ERO whether it is necessary that each Requirement of this Reliability Standard have a corresponding Measure.

1417. We find that the Reliability Standard adequately addresses reliability coordinator staffing. Accordingly, the Commission approves Reliability Standard PER-004-1. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification through the Reliability Standards development process to PER-004-1 that: (1) includes formal training requirements for reliability coordinators similar to those addressed under the personnel training Reliability Standard PER-002-0 and (2) includes requirements pertaining to personnel credentials for reliability coordinators similar to those in PER-003-0. Further, we direct the ERO to consider the suggestions of FirstEnergy and Xcel in the Reliability Standards development process.

10. PRC: Protection and Control

1418. Protection and Control systems (PRC) on Bulk-Power System elements are an integral part of reliable grid operation. Protection systems are designed to detect and isolate faulty elements on a system, thereby limiting the severity and spread of system disturbances, and preventing possible damage to protected elements. The function, settings and limitations of a protection system are critical in establishing SOLs and IROLs. The PRC Reliability Standards apply to transmission operators, transmission owners, generator operators, generator owners, distribution providers and regional reliability organizations and cover a wide range of topics related to the protection and control of power systems.

a. System Protection Coordination (PRC-001-1)

1419. PRC-001-1[378] ensures that protection systems are coordinated among operating entities by requiring transmission and generator operators to notify appropriate entities of relay or equipment failures that could affect system reliability. In addition, transmission and generator operators must coordinate with appropriate entities when new protection systems are installed, or when existing protection systems are modified.

1420. In the NOPR, the Commission proposed to approve PRC-001-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit modifications to PRC-001-0 (proposed directives) that included: (1) Measures and Levels of Non-Compliance; (2) a requirement that transmission and generator operators be informed immediately upon the detection of failures in relays or protection system elements on the Bulk-Power System that would threaten reliable operation, so that these entities could carry out appropriate corrective control actions consistent with those used in mitigating IROL violations and (3) clarifying that, after being informed of failures in relays or protection system elements on the Bulk-Power System, transmission operators or generator operators carry out corrective control actions that return a system to a stable state as soon as possible, but no longer than 30 minutes after receiving a notice of failure.

i. Comments

1421. While Constellation supports the Commission's proposed directives because they represent additional steps to achieving reliability of the Bulk-Power System and eliminating undue discrimination, MISO questions the need for the Commission's proposals. MISO notes that virtually all protection schemes have backups. MISO asks whether the Commission wants facilities to be removed from service if one of the redundant relaying packages has a problem, or whether some other action should be taken besides such removal.

1422. With regard to the NOPR's direction to the ERO to include Measures and Levels of Non-Compliance, APPA states that the new Measures only partially address the Requirements, and in some cases, reference non-existent Requirements. For example, rather than referencing Requirement R5.1, new Measure M1 incorrectly refers to non-

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[378] In its November 15, 2006, filing, NERC submitted PRC-001-1, which supercedes the Version 0 Reliability Standard. PRC-001-1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, PRC-001-1.

existent Requirement R8.1. Similarly, rather than referencing Requirement R5.2, new Measure M2 incorrectly refers to non-existent Requirement R8.2.

1423. APPA states that while it agrees that PRC-001-1 is sufficient for approval, since the new Measures only partially address the Requirements, and in some cases refer to non-existent Requirements, no penalties should be levied for violations of Requirements that have no accompanying Measures.

1424. WIRAB states that the Requirements, Measures and Levels of Non-Compliance do not provide guidance for the length of time – currently stated as "as soon as possible" – permitted for corrective actions.

1425. APPA disagrees with the Commission's second and third directives to NERC. APPA states that the BAL and IRO Reliability Standards already have specific standards to notify affected entities and provide directions for recovery time. APPA acknowledges that in the NOPR, we stated that "the Reliability Standards on mitigating IROL violations are not specific enough and system operators or field protection and control personnel would not be alerted about failures of relays and protection systems on critical elements." APPA, however, states that: "If this is the Commission's view, then it should instruct NERC to re-examine the interaction between these two sets of standards [IROL and SOL and proposed PRCs] on remand, and to develop the most efficient solution to this problem. The Commission should not itself undertake to resolve this problem by issuing directives for specific revisions to PRC-001-1, especially if the result might be to have local level personnel countermanding the instruction of RC personnel at a time when the system is unstable." APPA asserts that the Commission should modify its proposed directives to allow NERC, as technical expert, to address the problems in the Reliability Standard that the Commission has identified.

1426. Dynegy states that in many situations, depending on the particular relay or protection system failure, an operator may not be able to complete corrective control actions that return the system to a stable state within 30 minutes, including troubleshooting of relays or restoring any tripped facilities. Dynegy find that a 30-minute time period may thus be overly rigid and punitive. Wisconsin Electric also requests further clarification of the 30-minute time limit to carry out corrective actions after a relay failure. It has additional concerns about older relays (e.g., electromechanical relays) since it is impossible to know when and whether these older relays have failed. Wisconsin Electric also states that the NOPR is not clear about which relays threaten reliable system operation.

1427. Northern Indiana states that the NOPR appears to require immediate corrective actions whenever failures on relays or protection systems are detected, without regard to whether the specific failure detected reduces system reliability. It seeks the

Commission's clarification that we do not intend to question a certified transmission operator's expertise in assessing whether a particular relay or protection system failure reduces system reliability.

1428. California PUC contends that imposing a time restriction for returning a system to a stable state may cause more harm than good since additional information and options may be available as time elapses. It repeats its suggestion from its earlier comments on the Staff Preliminary Assessment and proposes the following alternative language: "Transmission or generation operators shall carry out corrective control actions, i.e., returning the system to a stable state that respects system requirements as soon as possible, and no longer than 30 minutes, except where a longer response time is feasible, or where a longer response is demonstrated to produce a better ultimate solution without unacceptable interim risk."

1429. A number of commenters raise concerns that the proposal would be unnecessarily burdensome on generator operators. For example, Progress Electricity Committee asserts that the Commission's proposal to require generator operators to return the system to a stable state as soon as possible and within no longer than 30 minutes may be too burdensome for non-energy company users with on-site generation. California Cogeneration asserts that PRC-001-1 as a whole may impose unreasonable burdens on generators with no material impact on the grid, because most such generators will have no knowledge of the protection systems on the grid.

1430. Allegheny states that since generator operators do not have the same resources as transmission operators for taking corrective actions, the Commission's third proposed directive should be modified to apply only to transmission operators. Allegheny states that while a transmission operator can direct a generator operator to take specific actions, the reverse is not the case.

1431. FirstEnergy contends that Requirement R2.1 essentially requires generator operators to report all protective relay or equipment failures, since generator operators may not be able to tell which failures will reduce system reliability. FirstEnergy suggests that R2.1 should be revised to require generator operators to report all equipment failures or outages. FirstEnergy further suggests that PRC-001-1 be revised to provide that if a company performs reasonable testing procedures, undiscoverable equipment failures will not be violations of R2.1.

1432. MidAmerican states that the term "immediately" in the Commission's second directive is ambiguous and unenforceable. It suggests a 30-minute time limit.

ii. Commission Determination

1433. The Commission approves PRC-001-1 as mandatory and enforceable. We also direct NERC to develop a modification to PRC-001-1 through the Reliability Standards development process, as discussed below.

1434. The Commission observes that, collectively, the comments raise three general questions: (1) Whether relay or equipment failures reduce system reliability and, if so, in what circumstances; (2) what are "corrective actions" required to return a system to a secure operating state and (3) when is returning a system to a secure operating state "as soon as possible."[379] The Commission will discuss each question in turn.

(a) Whether Relay or Equipment Failures Reduce System Reliability and, if so, in What Circumstances?

1435. Protection systems on Bulk-Power System elements are an integral part of reliable operations. They are designed to detect and isolate faulty elements on a power system, thereby limiting the severity and spread of disturbances and preventing possible damage to protected elements. If a protection system can no longer perform as designed because of a failure of its relays, system reliability is reduced or threatened. In deriving SOLs and IROLs, moreover, the functions, settings, and limitations of protection systems are recognized and integrated. Systems are only reliable when protection systems perform as designed. This is what PRC-001-1 means in linking a reduction in system reliability with a protection relay failure or other equipment failure.

1436. With respect to MISO's comment that virtually all protection systems have backups and therefore the Commission's proposals are not necessary, unless the backup protection has the same design goals and capabilities as the primary protection, a relay failure in the primary protection may still threaten system reliability. Further, we note that while the PRC Reliability Standards do not specifically require protection systems consisting of redundant and independent protection groups for each critical element in the

[379] PRC-001-1 Requirement R2.2 provides: "If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible."

Bulk-Power System, such requirements are included as one potential solution in the TPL Reliability Standards.[380]

1437. Finally, MISO's question seems to imply that if there are redundant relaying packages providing redundant protection, and a problem develops with only one of those redundant packages, system reliability is not threatened, and therefore, there is no need to take corrective control actions within 30 minutes. We agree with MISO's conclusion for this scenario.

1438. In the case, however, of a system element protected by a single protection system with a failed relay that threatens system reliability, that scenario would require the use of appropriate operating solutions including removing a system element from service. Another possible solution is to operate a system at a lower SOL or IROL that recognizes the degraded protection performance.

(b) What are Corrective Actions?

1439. Corrective actions taken by transmission operators to return a system to a secure operating state when a protective relay or equipment failure reduces system reliability normally refer to "operator control actions", consisting of operator actions such as removing the facility without protection from service, generation redispatch, transmission re-configuration, etc. Corrective action must be completed as soon as possible, but no longer than 30 minutes after a notice of protection system failure. Failure to complete corrective action within 30 minutes will be considered a violation of the relevant IROL or TOP Reliability Standards. In contrast, troubleshooting or replacing failed relays or equipment are performed by field maintenance personnel and normally take hours or even days to complete. These actions are not normally considered corrective actions in the context of real-time operation of the Bulk-Power System.

1440. We believe that "[t]he transmission operator shall take corrective action as soon as possible" refers to transmission operators taking operator control actions. It does not refer to troubleshooting, repairing or replacing failed relays or equipment, etc., since these time-consuming corrective actions would prolong the risk of cascading failures to the Bulk-Power System.

1441. Dynegy, Wisconsin Electric and Northern Indiana are concerned that the time required to troubleshoot, repair or replace failed relays and equipment would be

[380] If delayed clearing results in reliability criateria violations, one solution can be the use of redundant relay systems. TPL-002-0 Table 1, footnote e.

substantially longer than the 30 minutes set forth in the Commission's proposed directive. We believe we have alleviated this concern in our discussion, above. In addition, in response to Northern Indiana, we clarify that the responsibility for assessing whether a particular relay or protective system failure reduces system reliability remains with transmission operators. We direct the ERO to clarify the term "corrective action" consistent with this discussion when it modifies PRC-001-1 in the Reliability Standards development process.

1442. We agree with Allegheny that generator operators do not have the same ability as transmission operators to take corrective control actions on the Bulk-Power System, and we will modify our third directive as set forth below. We believe this also addresses Progress Electricity Committee and California Cogeneration's similar concerns.

(c) When is "As Soon as Possible"?

1443. As explained above, the requirement for system operators to take corrective control action when protective relay or equipment failure reduces system reliability should be treated the same as the requirement for returning a system to a secure and reliable state after an IROL violation, i.e., as soon as possible, but no longer than 30 minutes after a violation. A longer time limit would place an entity in violation of relevant IROL or TOP Reliability Standards.

1444. The Commission directs the ERO to consider FirstEnergy and California PUC's comments about the maximum time for corrective action in the ERO Reliability Standards development process.

1445. In response to MidAmerican's request that we clarify the term "immediately" in our proposed second directive, we direct the ERO, in the Reliability Standards development process, to determine the appropriate amount of time after the detection of relay failures, in which relevant transmission operators must be informed of such failures.

1446. We agree with APPA that the added Measures and Levels of Non-Compliance incorrectly reference non-existent requirements. We direct the ERO to revise the references accordingly.

1447. We disagree with APPA that BAL and IRO Reliability Standards already address matters contained in PRC-001-1, because BAL and IRO are not related to relay and equipment failures, which are specifically addressed in PRC-001-1.

1448. We disagree with APPA's assertion that "the Reliability Standards on mitigating IROL violations are not specific enough and system operators or field protection and control personnel would not be alerted about failure of relays and protection systems on critical elements." The time allowed for mitigating actual IROL violations is very clear: as soon as possible and within 30 minutes. We clarify that our concern is not about "field protection and control personnel not being alerted about failure of relays and protection systems on critical elements." Our focus, rather, is that upon detection of failure of relays and protection systems on critical elements, field personnel must report the failures promptly to the transmission operators so that corrective operator control actions can be taken as soon as possible and within 30 minutes. Finally, with respect to APPA's contention that our proposed directives would result in local-level personnel undermining or not following the instructions of reliability coordinator personnel at a time when the system is unstable, we do not understand how local level personnel, who have no operating control of a transmission operator's system or a reliability coordinator's system could do so.

1449. The Commission approves Reliability Standard PRC-001-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to PRC-001-1 through the Reliability Standards development process that: (1) correct the references for Requirements and (2) include a requirement that upon the detection of failures in relays or protection system elements on the Bulk-Power System that threaten reliable operation, relevant transmission operators must be informed promptly, but within a specified period of time that is developed in the Reliability Standards development process, whereas generator operators must also promptly inform their transmission operators and (3) clarifies that, after being informed of failures in relays or protection system elements that threaten reliability of the Bulk-Power System, transmission operators must carry out corrective control actions, i.e., return a system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes after they receive notice of the failure.

b. Define Regional Disturbance Monitoring and Reporting Requirements (PRC-002-1)

1450. PRC-002-1 ensures that each regional reliability organization establishes requirements to install Disturbance Monitoring Equipment (DME) and report disturbance data to facilitate analyses of events and verify system models.

1451. In the NOPR, the Commission identified PRC-002-1 as a fill-in-the-blank standard. The NOPR stated that because the regional requirements for installing DME had not been submitted, the Commission would not approve or remand PRC-002-1 until the ERO submitted the additional information.

i. Comments

1452. APPA agrees with the Commission's proposed course of action. It states that there are significant and substantive differences between regional procedures due to the characteristics of various regional grids. Further it suggests that NERC and the Regional Entities consider whether they can attain greater consistency on an Interconnection-wide basis in addressing the completion of this Reliability Standard.

1453. Alcoa suggests that the ERO—instead of a Regional Entity—should define the requirements for DME and the type of report it generates. The requirements and equipment specifications should be consistent throughout North America. In addition, Alcoa suggests that the criteria for installation of such equipment should include the necessary monitoring and recording that contribute to analysis and enhance reliability.

1454. Otter Tail suggests that PRC-002-1 should be developed on an Interconnection-wide basis to ensure consistency and promote reliability of the Bulk-Power System.

ii. Commission Determination

1455. For the reasons stated in the NOPR, the Commission will not approve or remand PRC-002-1.

1456. We agree with APPA, Alcoa and Otter Tail that the ERO should consider whether greater consistency can be achieved in this Reliability Standard. In Order No. 672, the Commission also encouraged greater uniformity in the development of Reliability Standards.[381] Consistent with that goal, the Commission directs the ERO to consider APPA, Alcoa and Otter Tail's suggestions in the Reliability Standards development process as it modifies PRC-002-1 to provide missing information needed for the Commission to act on this Reliability Standard.

c. Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems (PRC-003-1)

1457. PRC-003-1 ensures that all transmission and generation protection system misoperations are analyzed, and corrective action plans are developed. Misoperations occur when a protection system operates when it should not or does not operate when it should. This Reliability Standard requires each regional reliability organization to

[381] Order No. 672 at P 292.

develop a procedure to monitor and review misoperations of protection systems and to develop and document corrective actions.

1458. In the NOPR, the Commission identified PRC-003-1 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-1 until the ERO submitted the additional information.

i. <u>Comments</u>

1459. APPA agrees with the Commission's proposed course of action. It states that there are significant and substantive differences between regional procedures due to the characteristics of various regional grids and industry structures. Further it suggests that NERC and the Regional Entities consider whether they can attain greater consistency on an Interconnection-wide basis in completing this Reliability Standard.

ii. <u>Commission Determination</u>

1460. For the reasons stated in the NOPR, the Commission will not approve or remand PRC-003-1.

1461. We agree with APPA that the ERO should consider whether greater consistency can be achieved in this Reliability Standard. In Order No. 672, the Commission also encouraged greater uniformity in the development of Reliability Standards.[382] Consistent with that goal, the Commission directs the ERO to consider APPA's suggestions in the Reliability Standards development process as it modifies PRC-003-1 to provide missing information needed for the Commission to act on this Reliability Standard.

d. <u>Analysis and Reporting of Transmission Protection System Misoperations (PRC-004-1)</u>

1462. PRC-004-1 ensures that all transmission and generation protection system misoperations affecting the reliability of the Bulk-Power System are analyzed and mitigated by requiring transmission owners, generator owners and distribution providers that own a transmission protection system to analyze and document protection system misoperations. These entities must also develop corrective action plans in accordance with the regional reliability organization's procedures.

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[382] <u>Id.</u> at P 292.

1463. In the NOPR, the Commission proposed to approve PRC-004-1 as mandatory and enforceable.

i. Comments

1464. APPA agrees that PRC-004-1 is sufficient for approval as a mandatory and enforceable Reliability Standard.

1465. ISO-NE and ISO/RTO Council oppose the Commission's proposed approval of PRC-004-1 because it relies on PRC-003-1, a fill-in-the-blank standard, which the Commission does not propose to approve or remand until the ERO submits additional information.

1466. ISO-NE further requests the Commission to direct NERC to modify PRC-004-1 to include LSEs and transmission operators in the applicability section. It states that based on current practice in the ISO-NE balancing area, transmission operators, transmission owners, LSEs and distribution providers may individually or jointly own and operate a protection system. It therefore suggests that transmission operators and LSEs should also be included in the applicability section. ISO-NE provides the same suggestion with regard to PRC-005-1, PRC-008-0, PRC-011-0, PRC-015-0, PRC-016-0, PRC-017-0 and PRC-021-1.

ii. Commission Determination

1467. The Commission approves Reliability Standard PRC-004-1 as mandatory and enforceable.

1468. We are not persuaded by ISO-NE and ISO/RTO Council's assertion that PRC-004-1 should not be approved because it refers to PRC-003-1, which is a fill-in-the blank standard. In part, we neither approve nor remand PRC-003-1 because it applies to a regional reliability organization, and we are not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced as NERC proposes.[383] This is not the case with PRC-004-1, which applies to transmission owners, distribution providers, and generator owners. Since PRC-004-1 is an existing Reliability Standard that has been followed on a voluntary basis, transmission owners, distribution providers and generator owners are on notice of requirements related to misoperations of transmission and generation protection systems. As stated in the Common Issues section,

[383] NOPR at P 56-57.

a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard.

1469. We direct the ERO to consider ISO-NE's suggestion that LSEs and transmission operators should be included in the applicability section, in the Reliability Standards development process as it modifies PRC-004-1.[384] Further, as the ERO reviews this Reliability Standard in its five-year cycle of review, the Regional Entity, rather the regional reliability organization, should develop the procedures for corrective action plans.

e. Transmission and Generation Protection System Maintenance and Testing (PRC-005-1)

1470. PRC-005-1 ensures that all transmission and generation protection systems affecting the reliability of the Bulk-Power System are maintained and tested by requiring the transmission owners, distribution providers, and generator owners to develop, document, and implement a protection system maintenance program that may be reviewed by the regional reliability organization.

1471. In the NOPR, the Commission proposed to approve PRC-005-1 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC-005-1 that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System.

i. Comments

1472. FirstEnergy states that NERC should establish a maximum maintenance interval for protection system equipment, and a national limitation taking into account both relay type and functional versus calibration testing. Entergy does not object to the development of maximum allowable maintenance intervals provided that they are developed in NERC's Reliability Standards development process.

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[384] The same suggestion and therefore same Commission response also applies to PRC-005-1, PRC-008-0, PRC-011-0, PRC-015-0, PRC-016-0, PRC-017-0 and PRC-021-1.

1473. FirstEnergy and ISO-NE suggest that PRC-005-1, PRC-008-0, PRC-011-0 and PRC-017-0 should be combined into a single Reliability Standard relating to the maintenance of protection and control equipment.

ii. Commission Determination

1474. For the reasons stated in the NOPR, the Commission approves Reliability Standard PRC-005-1 as mandatory and enforceable.

1475. In addition, for the reasons discussed in the NOPR, the Commission directs the ERO to develop a modification to PRC-005-1 through the Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System. We further direct the ERO to consider FirstEnergy's and ISO-NE's suggestion to combine PRC-005-1, PRC-008-0, PRC-011-0 and PRC-017-0 into a single Reliability Standard through the Reliability Standards development process.

f. Development and Documentation of Regional UFLS Programs (PRC-006-0)

1476. PRC-006-0 ensures the development of a regional UFLS[385] program that will be used as a last resort to preserve the Bulk-Power System during a major system failure that could cause system frequency to collapse. PRC-006-0 requires the regional reliability organization to develop, coordinate, document and assess UFLS program design and effectiveness at least every five years.

1477. In the NOPR, the Commission identified PRC-006-0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand PRC-006-0 until the ERO submits the additional information. The Commission commends the ERO and regions' initiative, outlined in the Reliability Standards Work Plan, in adopting an integrated and coordinated approach to protection for generators, transmission lines and UFLS and UVLS[386] programs as part of its work on fill-in-the-blank Reliability Standards.[387]

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[385] Underfrequency load shedding.

[386] Undervoltage load shedding.

[387] NOPR at P 367.

i. Comments

1478. APPA agrees with the Commission's proposed course of action. It suggests that in completing this Reliability Standard, NERC should strive for greater consistency on an Interconnection-wide basis through the use of "base procedures" for each Interconnection.

ii. Commission Determination

1479. For the reasons stated in the NOPR, the Commission will not approve or remand PRC-006-0.

1480. The Commission understands that UFLS, when properly coordinated with the dynamic response of the Bulk-Power System, is one of the safety nets that safeguards the system from cascading events, assuming it is properly coordinated with the dynamic response of the system. Until this Reliability Standard is submitted to the Commission for approval, we do not expect any lapse in the compliance with this Reliability Standard. As we stated in the NOPR, it is important that the existing regional reliability organizations continue to fulfill their current roles during this time of transition. The Commission expects that this function will pass from the regional reliability organization to the Regional Entity after they are approved.

g. Assuring Consistency with Regional UFLS Program Requirements (PRC-007-0)

1481. PRC-007-0 requires transmission owners, transmission operators, LSEs and distribution providers to provide, and annually update, their underfrequency data to facilitate the regional reliability organization's maintenance of the UFLS program database.

1482. In the NOPR, the Commission proposed to approve PRC-007-0 as mandatory and enforceable.

i. Comments

1483. APPA agrees that PRC-007-0 is sufficient for approval as a mandatory and enforceable Reliability Standard. However, it states that actual enforcement cannot take place until PRC-006-0 becomes effective. ISO-NE and ISO/RTO Council state that PRC-007-0 should not be approved because it refers to PRC-006-0, which we are not approving or remanding at this time.

ii. Commission Determination

1484. For the reasons stated in the NOPR, the Commission approves Reliability Standard PRC-007-0 as mandatory and enforceable.

1485. We are not persuaded by APPA, ISO/RTO Council and ISO-NE that PRC-007-0 cannot be acted on because it relies on PRC-006-0. We proposed to not approve or remand PRC-006-0 partly because it applies to a regional reliability organization. The Commission was not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced as NERC proposed.[388] That is not the case with PRC-007-0, which applies to transmission owners, transmission operators, distribution providers and LSEs. Since PRC-007-0 is an existing Reliability Standard that has been followed on a voluntary basis, transmission owners, transmission operators, distribution providers and LSEs are generally aware of its requirements. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard. The Commission expects that the data will be sent to the Regional Entities (instead of the regional reliability organizations) after they are approved.

h. Underfrequency Load Shedding Equipment Maintenance Programs (PRC-008-0)

1486. PRC-008-0 requires transmission owners and distribution providers to implement UFLS equipment maintenance and testing programs and provide program results to the regional reliability organization.

1487. In the NOPR, the Commission proposed to approve Reliability Standard PRC-008-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC-008-0 that includes a requirement that maintenance and testing of UFLS programs must be carried out within a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System.

i. Comments

1488. Entergy states that it does not object to NERC's development of maximum allowable maintenance intervals for the purpose of evaluating protection system and control programs provided that they are developed in NERC's Reliability Standards

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[388] NOPR at P 56-57.

development process. FirstEnergy states that NERC should establish a maximum maintenance interval for protection system equipment and a "national limitation taking into account both relay type and functional versus calibration testing."

1489. ISO-NE and ISO/RTO Council contend that the Commission should not approve PRC-008-0 until it approves PRC-006-0, which the Commission has identified as a fill-in-the-blank standard. Similarly, APPA contends that PRC-008-0 cannot be enforced until PRC-006-0 has become effective and the required regional UFLS program documentation has been submitted by the applicable Regional Entity. It also notes that the applicability of PRC-008-0 is limited to transmission owners and distribution providers who are required by their regional reliability organization to have a UFLS program.

ii. <u>Commission Determination</u>

1490. FirstEnergy and Entergy agree with the Commission's proposed directive, whereas APPA suggests that the need for the proposal should be established first via the Reliability Standards development process.

1491. We disagree with ISO/RTO Council and others that approval or enforcement of PRC-008-0 is linked to approval of PRC-006-0. PRC-008-0 requires that a "transmission provider or distribution provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment and maintenance testing program in place."[389] PRC-006-0 requires each regional reliability organization to develop, coordinate and document a UFLS program that includes specified elements. Again, we proposed to neither approve nor remand PRC-006-0 because it applies to a regional reliability organization and the Commission was not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced as proposed by NERC.[390] That is not the case with PRC-008-0, which applies to transmission owners and distribution providers. Since PRC-008-0 is an existing Reliability Standard that has been followed on a voluntary basis, transmission owners and distribution providers are aware whether they are required to have a UFLS program in place. We approve PRC-008-0 as mandatory and enforceable because it requires entities to have equipment

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[389] <u>See</u> PRC-008-0, Requirement R1.

[390] NOPR at P 56-57.

maintenance and testing of their UFLS programs. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard. The Commission expects that the program results will be sent to the Regional Entities (instead of the regional reliability organizations) after they are approved.

1492. The Commission approves Reliability Standard PRC-008-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to PRC-008-0 through the Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System.

i. UFLS Performance Following an Underfrequency Event (PRC-009-0)

1493. PRC-009-0 ensures that the performance of a UFLS system is analyzed and documented following an underfrequency event by requiring the transmission owner, transmission operator, LSE and distribution provider to document the deployment of their UFLS systems in accordance with the regional reliability organization's program.

1494. In the NOPR, the Commission proposed to approve Reliability Standard PRC-009-0 as mandatory and enforceable.

i. Comments

1495. APPA agrees that PRC-009-0 is sufficient for approval as a mandatory and enforceable Reliability Standard. However, it states that actual enforcement cannot take place until pending PRC-006-0 becomes effective and notes that the applicability of PRC-009-0 is limited to entities that own or operate a UFLS program recognized by their regional reliability organization.

1496. ISO-NE and ISO/RTO Council contend that the Commission should not approve PRC-009-0 until it approves PRC-006-0, which the Commission has identified as a fill-in-the-blank standard.

ii. Commission Determination

1497. For the reasons stated in the NOPR, the Commission approves Reliability Standard PRC-009-0 as mandatory and enforceable.[391]

1498. We disagree with ISO/RTO Council and others that approval or enforcement of PRC-009-0 is linked to approval of PRC-006-0. PRC-009-0 ensures that the performance of a UFLS system is analyzed and documented following an underfrequency event by requiring the transmission owner, transmission operator, LSE, and distribution provider to document the deployment of their UFLS operations. PRC-006-0 requires each regional reliability organization to develop, coordinate and document a UFLS program that includes specified elements. We proposed to neither approve nor remand PRC-006-0 because it applies to a regional reliability organization and the Commission was not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced as NERC proposed.[392] That is not the case with PRC-009-0, which applies to transmission owners, transmission operators, LSEs and distribution providers with UFLS systems. Since PRC-009-0 is an existing Reliability Standard that has been followed on a voluntary basis, entities are aware whether they are required to have a UFLS program in place. Reporting on their UFLS programs therefore should not be burdensome. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard. The Commission expects this documentation will be sent to the Regional Entities (instead of the regional reliability organizations) after they are approved.

j. Assessment of the Design and Effectiveness of UVLS Program (PRC-010-0)

1499. PRC-010-0 requires transmission owners, transmission operators, LSEs and distribution providers to periodically conduct and document an assessment of the effectiveness of their UVLS program at least every five years or as required by changes

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[391] NOPR at P 877-80.

[392] NOPR at P 56-57.

in system conditions. The assessment must be conducted with the associated transmission planner and planning authority.

1500. In the NOPR, the Commission proposed to approve Reliability Standard PRC-010-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC-010-0 that requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride-through capabilities and UFLS and UVLS programs.

1501. The Commission commends the initiative and efforts that have been taken by NERC and the industry in addressing UVLS requirements as recommended by the Blackout Report.

i. Comments

1502. APPA agrees that PRC-010-0 should be approved. While APPA agrees that NERC should re-examine this Reliability Standard to determine whether a more integrated and coordinated approach should be included in protection systems on the Bulk-Power System, it also asks the Commission not to require a specific approach to UVLS and other protection systems. According to APPA, NERC should strive for greater consistency on an Interconnection-wide basis through the use of a coordinated protection system for the Bulk-Power System in each Interconnection.

1503. ISO-NE generally supports approval of PRC-010-0, but opposes the Commission's directive to modify the Reliability Standard to include an integrated and coordinated approach in all protection systems, particularly for UVLS and UFLS programs, because such integration cannot be technologically accomplished.

1504. FirstEnergy indicates that UVLS is primarily designed to address localized problems, and requiring the universal coordination of UVLS across the grid does not make sense. FirstEnergy states that it is not clear what type of coordination would be useful for a UVLS program.

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[393] "Recommend that NERC determine the goal and principles needed to establish an integrated approach to relay protection for generators and transmission lines and the use of underfrequency and undervoltage load shedding programs." Blackout Report at 159

ii. Commission Determination

1505. We agree with APPA's comments and reiterate that the directed modification should be developed in the Reliability Standards development process. With regard to APPA's concerns, while we direct the ERO to develop modifications that would require an integrated and coordinated approach to protection systems, we do not direct a specific approach to accomplish such integration and coordination. Rather, the ERO should develop an appropriate approach utilizing the Reliability Standards development process.

1506. With regard to ISO-NE's disagreement on integration of various system protections "because such integration cannot be technologically accomplished", we note that the evidence collected in the Blackout Report indicates that "the relay protection settings for the transmission lines, generators and underfrequency load shedding in the northeast may not be entirely appropriate and are certainly not coordinated and integrated to reduce the likelihood and consequence of a cascade – nor were they intended to do so." In addition, the Blackout Report stated that one of the common causes of major outages in North America is a lack of coordination on system protection. The Commission agrees with the protection experts who participated in the investigation, formulated Blackout Recommendation No. 21 and recommended that UVLS programs have an integrated approach.[393]

1507. Regarding FirstEnergy's question of whether universal coordination among UVLS programs that address local system problems makes sense, we believe that PRC-010-0's objective in requiring an integrated and coordinated approach is to address the possible adverse interactions of these protection systems among themselves and to determine whether they could aggravate or accelerate cascading events. We do not believe this Reliability Standard is aimed at universal coordination among UVLS programs that address local system problems.

1508. As identified in the NOPR,[394] NERC is continuing to develop an integrated and coordinated approach to protection for generators, transmission lines and UFLS and UVLS programs within its work on the fill-in-the-blank proposed Reliability Standards.

1509. We appreciate MEAG's feedback to our response in the NOPR. For the reasons discussed in the NOPR,[395] as well as our explanation above, the Commission approves Reliability Standard PRC-010-0 as mandatory and enforceable. In addition, the

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[394] NOPR P 883.

[395] Id. P 891-92.

Commission directs the ERO to develop a modification to PRC-010-0 through the Reliability Standards development process that requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride-through capabilities, and UFLS and UVLS programs.

k. UVLS System Maintenance and Testing (PRC-011-0)

1510. PRC-011-0 requires transmission owners and distribution providers to implement their UVLS equipment maintenance and testing programs and provide program results to regional reliability organizations.

1511. In the NOPR, the Commission proposed to approve PRC-011-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC-011-0 that includes a requirement that maintenance and testing of UVLS programs must be carried out within a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System.

i. Comments

1512. APPA suggests that, instead of a Commission directive, NERC should be directed to consider whether this standard is needed to address the Commission's concern about periodic testing of UVLS equipment.

1513. FirstEnergy comments that NERC should establish a maximum maintenance interval for protection system equipment, and a "national limitation taking into account both relay type and functional versus calibration testing." Entergy states that it does not object to NERC's development of maximum allowable maintenance intervals for the purpose of evaluating protection system and control programs.

ii. Commission Determination

1514. The Commission approves Reliability Standard PRC-011-0 as mandatory and enforceable. In addition, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process as discussed below.

1515. The Commission disagrees with APPA that the decision whether a modification is needed should be established first by the ERO in its Reliability Standards development process. Our direction identifies an appropriate goal necessary to assure the reliable operation of the Bulk-Power System. The details should be developed through the Reliability Standards development process.

1516. The Commission believes that the proposal is presently part of the process. The Commission approves Reliability Standard PRC-011-0 as mandatory and enforceable. In addition, the Commission directs the ERO to submit a modification to PRC-011-0 through the Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System.

l. Special Protection System Review Procedure (PRC-012-0)

1517. PRC-012-0 requires regional reliability organizations to ensure that all special protection systems[396] are properly designed, meet performance requirements and are coordinated with other protection systems. In the NOPR, the Commission identified PRC-012-0 as a fill-in-the-blank standard. The NOPR stated that because the regional review procedures on special protection systems have not been submitted, the Commission would not propose to approve or remand PRC-012-0 until the ERO submits the additional information.

i. Comments

1519. APPA agrees with the Commission's proposed course of action. It further suggests that NERC, in completing PRC-012-0, should strive for greater consistency on an Interconnection-wide basis through the use of "base procedures" for each Interconnection.

ii. Commission Determination

1520. For the reasons stated in the NOPR, the Commission will not approve or remand PRC-012-0. The ERO should consider APPA's suggestions in the Reliability Standards development process.

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[396] A special protection system is designed to automatically take corrective actions to protect a particular system under both abnormal and predetermined conditions, excluding the coordinated tripping of circuit breakers to isolate faulted components, which is typically the purpose of other protection devices.

m. Special Protection System Database (PRC-013-0)

1521. PRC-013-0 ensures that all special protection systems are properly designed, meet performance requirements and are coordinated with other protection systems by requiring the regional reliability organization to maintain a database of information on special protection systems.

1522. In the NOPR, the Commission identified PRC-013-0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures on maintaining special protection system databases have not been submitted, the Commission would not approve or remand PRC-013-0 until the ERO submits the additional information.

i. Comments

1523. APPA agrees with the Commission's proposed course of action. It suggests further that in completing PRC-013-0, NERC should strive for greater consistency on an Interconnection-wide basis through the use of "base procedures" for each Interconnection.

ii. Commission Determination

1524. For the reasons stated in the NOPR, the Commission will not approve or remand PRC-013-0. The ERO should consider APPA's suggestions in the Reliability Standards development process.

n. Special Protection System Assessment (PRC-014-0)

1525. PRC-014-0 ensures that special protection systems are properly designed, meet performance requirements and are coordinated with other protection systems by requiring the regional reliability organization to assess and document the operation, coordination and compliance with NERC Reliability Standards and effectiveness of special protection systems at least once every five years.

1526. In the NOPR, the Commission identified PRC-014-0 as a fill-in-the-blank Reliability Standard. The NOPR stated that because the regional procedures on special protection system assessment had not been submitted, the Commission would not propose to approve or remand PRC-014-0 until the ERO submitted the additional information.

i. Comments

1527. APPA agrees with the Commission's proposed course of action. It suggests further that in completing PRC-014-0, NERC should strive for greater consistency on an

Interconnection-wide basis through the use of "base procedures" for each Interconnection.

ii. Commission Determination

1528. For the reasons stated in the NOPR, the Commission will not approve or remand PRC-014-0. The ERO should consider APPA's suggestions in the Reliability Standards development process.

o. Special Protection System Data and Documentation (PRC-015-0)

1529. Proposed Reliability Standard PRC-015-0 requires transmission owners, generator owners and distribution providers to maintain a listing, retain evidence of review and provide documentation of existing, new or functionally modified special protection systems.

1530. In the NOPR, the Commission proposed to approve PRC-015-0 as mandatory and enforceable.

i. Comments

1531. APPA agrees that PRC-015-0 is sufficient for approval as a mandatory Reliability Standard. However, it states that this Reliability Standard cannot be enforced until two pending Reliability Standards, PRC-012-0 and PRC-013-0, become effective. Similarly, ISO/RTO Council and ISO-NE contend that the Commission should not approve PRC-15-0 until it approves PRC-012-0 and PRC-013-0, identified by the Commission as fill-in-the-blank standards.

ii. Commission Determination

1532. We disagree with APPA, ISO/RTO Council and ISO-NE and conclude that PRC-015-0 should be approved and made enforceable on the effective date of this rulemaking. As mentioned above, PRC-012-0 and PRC-013-0 apply solely to regional reliability organizations. PRC-012 is "process" oriented, as it requires the regional reliability organization to develop a review procedure that identifies information relevant to the regional reliability organization review of a special protection system. PRC-013-0 requires the regional reliability organization to maintain a database of information on special protection systems. PRC-015-0 requires a transmission owner, generator owner or distribution provider that owns a special protection system to maintain a list and provide data for existing and planned special protection systems as defined in PRC-013-0; and have evidence that the entity reviewed new or functionally modified special protection systems in accordance with the regional reliability organization procedures identified in PRC-012-0. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard. The Commission expects that the data will be sent to the Regional Entities (instead of the regional reliability organizations) after they are approved.

1533. For the reasons discussed in the NOPR and above, the Commission concludes that Reliability Standard PRC-015-0 is just, reasonable, not unduly discriminatory or preferential and in the public interest and approves it as mandatory and enforceable.

p. Special Protection System Misoperations (PRC-016-0)

1534. PRC-016-0 requires transmission owners, generator owners and distribution providers to provide the regional reliability organization with documentation, analyses and corrective action plans for misoperation of special protection systems.

1535. In the NOPR, the Commission proposed to approve Reliability Standard PRC-016-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC-016-0 that includes a requirement that maintenance and testing of these special protection system programs be carried out within a maximum allowable interval that is appropriate for the type of relays used and the impact of these special system protection systems on the reliability of the Bulk-Power System.

i. Comments

1536. While APPA agrees that PRC-016-0 is sufficient for approval as a mandatory Reliability Standard, APPA, ISO/RTO Council and ISO-NE state that PRC-016-0 cannot be enforced until pending Reliability Standard PRC-012-0 has become effective.

1537. FirstEnergy suggests that NERC clarify and provide guidance to transmission operators on the types of misoperations that have Interconnection-wide impacts and the types of misoperations that need reporting.

ii. Commission Determination

1538. PRC-016-0 states that transmission owners, generator owners and distribution providers that own a special protection system must analyze the system operations and maintain a record of misoperations in accordance with the review procedure specified in PRC-012-0. As we explained above in the context of PRC-015-0, applicable entities are expected to comply with PRC-015-0, and the procedures specified in PRC-012-0 will continue to be maintained by the regional reliability organizations pursuant to the ERO Rules of Procedure and the Commission's reliability information provision. We disagree with APPA, ISO/RTO Council and ISO-NE and conclude that PRC-016-0 is enforceable as of the effective date of this rulemaking. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard. The Commission expects that the plans will be sent to the Regional Entities (instead of the regional reliability organizations) after they are approved.

1539. The Commission concludes that Reliability Standard PRC-016-0 is just, reasonable, not unduly discriminatory or preferential, and in the public interest, and approves it as mandatory and enforceable. We observe that a maximum allowable interval for maintenance and testing of special protection systems is not relevant to PRC-016-0, where the primary purpose is to analyze and report all misoperations of special protection systems. The Commission, therefore, will not adopt the proposal to require the ERO to modify PRC-016-0 to include a requirement for a maximum allowable interval for maintenance and testing.

1540. The Commission concludes that Reliability Standard PRC-016-0 is just, reasonable, not unduly discriminatory or preferential and in the public interest, and approves it as mandatory and enforceable.

q. Special Protection System Maintenance and Testing (PRC-017-0)

1541. PRC-017-0 requires transmission owners, generator owners and distribution providers to provide the regional reliability organization with documentation of special protection system maintenance, testing and implementation plans.

1542. In the NOPR, the Commission proposed to approve PRC-017-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to PRC-017-0 that: (1) includes a requirement that maintenance and testing of these special protection system programs must be carried out within a maximum allowable interval that is appropriate to the type of relaying used and (2) identifies the impact of these special protection system programs on the reliability of the Bulk-Power System.

i. Comments

1543. APPA agrees that PRC-017-0 is sufficient for approval as a mandatory and enforceable Reliability Standard. It also agrees that NERC and the industry should consider adoption of maximum allowable maintenance intervals. With respect to the Commission's second directive, APPA points out that the documentation of the test results will identify the impact of the special protection systems on the Bulk Electric System.

1544. FirstEnergy states that NERC should establish a maximum maintenance interval for protective system equipment and a national limitation, taking into account both relay type and functional versus calibration testing. Entergy does not object to NERC's development of maximum allowable maintenance intervals for the purpose of evaluating protection system and control programs.

ii. Commission Determination

1545. The commenters agree with the Commission's proposed directive on a maximum allowable interval for maintenance and testing of protection system equipment and we conclude that such a modification is beneficial. However, we agree with APPA's view on our second proposed directive assuming that the documentation is requested by either the regional reliability organization or NERC. Therefore, we will modify our direction to require that the documentation be routinely provided to the ERO or Regional Entity and not only when it is requested.

1546. The Commission approves Reliability Standard PRC-017-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to PRC-017-0 through the Reliability Standards development process, that includes: (1) a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate for the type of the protection system and (2) a requirement that documentation identified in Requirement R2 shall be routinely provided to the ERO or Regional Entity.

r. Disturbance Monitoring Equipment Installation and Data Reporting (PRC-018-1)

1547. PRC-018-1 ensures that disturbance monitoring equipment is installed and disturbance data is reported in accordance with comprehensive requirements. PRC-018-1 contains several different effective dates for specific requirements.

1548. In the NOPR, the Commission proposed to approve PRC-018-1 as mandatory and enforceable.

i. Comments

1549. While APPA agrees that PRC-018-1 is sufficient for approval as a mandatory Reliability Standard, it contends that enforcement is not possible until PRC-002-0, a fill-in-the-blank standard, is effective. For the same reason, ISO/RTO Council and ISO-NE state that the Reliability Standard should not be approved or remanded at this time.

ii. Commission Determination

1550. The portion of PRC-018-1 that NERC proposes will become effective on the effective date of this Final Rule states that transmission owners and generator owners that own a disturbance monitoring system must assure that disturbance data is reported in accordance with PRC-002-1 to facilitate analyses of events. Applicable entities are expected to comply with PRC-018-1, and the procedures specified in PRC-002-1 will be provided pursuant to the data gathering provisions of the ERO's Rules of Procedure and the Commission's ability to obtain information pursuant to section 215 of the FPA and Part 39 of the Commission's regulations. Accordingly, we disagree with APPA, ISO/RTO Council and ISO-NE and conclude that the effective portions of PRC-018-1 are enforceable as of the effective date of this rulemaking. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard.

1551. Accordingly, for reasons stated in the NOPR and above, the Commission approves Reliability Standard PRC-018-1 as mandatory and enforceable.

s. Undervoltage Load Shedding Program Database (PRC-020-1)

1552. PRC-020-1 ensures that a regional database for UVLS programs is available for Bulk-Power System studies by requiring regional reliability organizations with any entities that have UVLS programs to maintain and annually update a database.

1553. In the NOPR, the Commission identified PRC-020-1 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures on maintaining UVLS databases have not been submitted, the Commission would not propose to approve or remand PRC-020-0 until the ERO submits the additional information.

i. Comments

1554. APPA disagrees that PRC-020-1 is a regional fill-in-the-blank Reliability Standard because it does not require regional procedures. However, APPA recognizes that PRC-020-1 requires the regional reliability organization to establish a database.

ii. Commission Determination

1555. APPA is correct that the reason for not approving or remanding this Reliability Standard is because it applies solely to the regional reliability organization, and not because it is a fill-in-the-blank standard. For this reason, the Commission will not approve or remand PRC-020-1.

t. Undervoltage Load Shedding Program Data (PRC-021-1)

1556. PRC-021-1 ensures that data is supplied to support the regional UVLS database by requiring the transmission owner and distribution provider to supply data related to their systems and other related protection schemes to their regional reliability organization's database.

1557. In the NOPR, the Commission proposed to approve PRC-021-1 as mandatory and enforceable.

i. Comments

1558. APPA agrees that PRC-021-1 should be approved as a mandatory and enforceable Reliability Standard.

1559. The ISO-NE and ISO/RTO Council contend that the Commission should refrain from approving PRC-021-1 until it approves PRC-020-1 which the Commission has not approved or remanded.

ii. Commission Determination

1560. For the reasons stated in the NOPR and above, the Commission approves PRC-021-1 as mandatory and enforceable. The referenced information will be provided pursuant to the data gathering provisions of the ERO's rules of procedure and the Commission's ability to obtain information pursuant to section 215 of the FPA and Part 39 of the Commission's regulations. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard.

u. Undervoltage Load Shedding Program Performance (PRC-022-1)

1561. PRC-022-1 requires transmission operators, LSEs, and distribution providers to provide analysis, documentation and misoperation data on UVLS operations to the regional reliability organization.

1562. In the NOPR, the Commission proposed to approve PRC-022-1 as mandatory and enforceable.

i. Comments

1563. APPA agrees that PRC-022-1 should be approved as a mandatory and enforceable Reliability Standard.

1564. FirstEnergy comments that Requirement R1.3 requires "a simulation of the event, if deemed appropriate by the RRO" and believes that the applicable entities such as transmission operators may not be able to simulate large system events. FirstEnergy suggests that Requirement R1.3 be revised to state that "a simulation of the event, if deemed appropriate, and assisted by the [regional reliability organization]."

ii. Commission Determination

1565. For the reasons discussed in the NOPR, the Commission concludes that Reliability Standard PRC-022-1 is just, reasonable, not unduly discriminatory or preferential, and in the public interest and approves it as mandatory and enforceable.

1566. The Commission directs the ERO to consider FirstEnergy's suggestion in the Reliability Standards development process.

11. TOP: Transmission Operations

1567. The eight Transmission Operations (TOP) Reliability Standards apply to transmission operators, generator operators and balancing authorities. The goal of these Reliability Standards is to ensure that the transmission system is operated within operating limits. Specifically, these Reliability Standards cover the responsibilities and decision-making authority for reliable operations, requirements for operations planning, planned outage coordination, real-time operations, provision of operating data, monitoring of system conditions, reporting of operating limit violations and actions to mitigate such violations. The Interconnection Reliability Operations and Coordination (IRO) group of Reliability Standards complement these proposed TOP Reliability Standards.

a. Reliability Responsibilities and Authorities (TOP-001-1)

1568. The reliability goal of TOP-001-1 is to ensure that system operators have the authority to take actions and direct others to take action to maintain Bulk-Power System facilities within operating limits. TOP-001-1 requires that: (a) transmission operating personnel must have the authority to direct actions in real-time; (b) the transmission operator, balancing authority, and generator operator must follow the directives of their reliability coordinator and (c) the balancing authority and generator operator must follow the directives of the transmission operator. In addition, the proposed Reliability Standard requires the transmission operator, balancing authority, generator operator, distribution provider and LSE to take emergency actions when directed to do so in order to keep the transmission system intact.

1569. The Commission proposed in the NOPR to approve the Reliability Standard as mandatory and enforceable and to direct NERC to submit a modification to it that includes Measures and Levels of Non-Compliance. On November 15, 2006, NERC submitted revisions to the Reliability Standard to include Measures and Levels of Non-Compliance.[397]

i. Comments

1570. APPA notes that TOP-001-1, as revised to include Measures and Levels of Non-Compliance, fulfills the proposed directive in the NOPR. Accordingly, APPA agrees that the Commission should approve TOP-001-1 as mandatory and enforceable.

1571. California PUC asserts that TOP-001 should not be adopted unless the Commission provides for proper deference to existing authorities. It states that the requirements contained in TOP-001 are duplicative of what the CAISO already requires under its participating generator agreements.

1572. FirstEnergy contends that TOP-001-1 contains "reliability directives" to be followed by various entities, but it has no clear line of authority for specified directives. This could lead to a generator receiving conflicting directions. FirstEnergy maintains that TOP-001-1 should establish a clear line of authority for issuing and complying with directives, but the reliability coordinator's instructions should govern in all instances.

1573. In a similar vein, MEAG Power is concerned that the scope of "reliability directives" contained in the Measures filed on November 15, 2006 is unclear. For example, Measure M4 states that "[e]ach Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity shall have and provide upon request evidence that … it complied with its Transmission Operator's reliability directives." While a directive by a transmission operator to a LSE to increase its planning reserve margin from 15 percent to 20 percent or reconductor a transmission line might be within the realm of possibilities, such "reliability directives" would be inappropriate. MEAG Power therefore recommends an alternative definition of "reliability directive" that it believes would specify an appropriate range of directives.

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[397] In its November 15, 2006, filing, NERC submitted TOP-001-1, which supercedes the Version 0 Reliability Standard. TOP-001-1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, TOP-001-1.

1574. MEAG Power also recommends a modification to TOP-001-1 clarifying that an entity may be found non-compliant only if it fails to comply with a reliability directive issued to it by its host reliability coordinator. MEAG Power is concerned that the requirements as currently written may apply to entities outside a reliability coordinator's footprint.

1575. FirstEnergy and California Cogeneration state that the definition of "emergency" is vague and should be clarified. FirstEnergy states TOP-001 does not specify who decides when there is an emergency. California Cogeneration states that under emergency conditions, it would be appropriate to require a QF to follow the directives of a reliability coordinator.[398] But California Cogeneration argues that because of the broad definition of emergency, reliability coordinators could issue directives on a regular basis. California Cogeneration therefore proposes that the Reliability Standard clearly address which entities are exempt from such directives because they have no material impact on reliability.

1576. FirstEnergy states that the term "safety" in Requirement R4 should be clarified with respect to whether it means safety to the system/equipment, public safety or both.

1577. Requirement R6 of TOP-001-1 requires an applicable entity to "render all available emergency assistance to others as requested." Regarding this provision, FirstEnergy maintains that NERC should clarify that all instructions should be subject to the reliability coordinator's direction and control to avoid causing unforeseen harm to other systems. Any entity requesting assistance must implement its emergency procedures before or in unison with assistance from other entities. However, FirstEnergy asserts that it is not clear how a responding entity will determine whether the requesting entity has implemented its comparable emergency procedures before the responding entity honors the request. FirstEnergy, therefore, states that TOP-001-1 should require the requesting party to report on whether all of its emergency procedures were implemented as part of its request for emergency assistance.

1578. Santa Clara states that, in some instances, notifying the reliability coordinator that a transmission operator is removing facilities from service may not be appropriate because the transmission owner traditionally notifies the balancing authority. Santa Clara therefore requests that Requirements R7.2 and R7.3 of the Reliability Standard be revised

[398] California Cogeneration notes that the curtailment of QFs in an emergency is allowed by 18 CFR 292.307.

to provide that the transmission operator may notify the reliability coordinator or balancing authority.[399]

ii. **Commission Determination**

1579. The Commission approves TOP-001-1 as mandatory and enforceable. We address the concerns raised by commenters below.

1580. While the Commission agrees with APPA that TOP-001-1 should be approved, it does not agree that the new Measures and Levels of Non-Compliance fully address the Commission's concerns stated in the NOPR. The modified Reliability Standard does not contain Measures or Levels of Non-Compliance corresponding to Requirement 8. This Requirement deals with actions to restore real and reactive power balance. Given the importance of these matters to reliable operations, the Commission directs the ERO to provide Measures and Level of Non-Compliance for this Requirement.

1581. We disagree with California PUC's assertion that the Commission should not adopt TOP-001-1 unless it commits to a policy of "appropriate deference" to existing authorities. Approval of a continent-wide Reliability Standard should not be delayed because it may overlap with a local or regional program. Rather, stakeholders should raise related concerns in the ERO Reliability Standards development process. Moreover, section 215(i)(3) of the FPA provides that "nothing in [section 215] shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard." In any event, California PUC does not suggest how the Requirements in TOP-001-1 and the provisions of CAISO's participating generator agreements will lead to conflicting outcomes. To the extent a potential conflict arises, we note that the CAISO's participating generator agreements are subject to Commission jurisdiction, and § 39.6 of the Commission's regulations provides procedures for resolving conflicts between a requirement in a Reliability Standard and a provision of an agreement accepted for filing at the Commission.[400]

1582. We agree with FirstEnergy that TOP-001-1 should establish a clear line of authority. Requirement R3 of Reliability Standard IRO-001-0 clearly establishes the decision-making authority of the reliability coordinator to act and to direct actions to be

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[399] Santa Clara makes a similar argument reagarding Requirement R3 of TOP-008-1.

[400] See 18 CFR 39.6 (Conflict of a Reliability Standard with a Commission Order).

taken by operating entities to preserve the integrity and reliability of the Bulk-Power System. When an entity is faced with conflicting directives, it must follow the reliability coordinator's directives because the reliability coordinator is the highest authority in matters affecting reliability of the Bulk-Power System. Therefore no changes are required to the Reliability Standard in this connection.

1583. We agree with MEAG Power that a reliability directive to a LSE to increase its planning reserve to 15 percent or to reconductor its transmission line is outside the scope of a TOP reliability directive. Reliability directives in the TOP group of Reliability Standards deal with operational directives and not planning directives.

1584. We disagree with MEAG Power that an entity may have to comply with a reliability directive issued to it by a reliability coordinator other than its host reliability coordinator. The operating hierarchy embodied in the Reliability Standard gives the reliability coordinator responsibility and authority to issue reliability directives to its own transmission operators, balancing authorities and generator operators. These entities must comply with these directives as stated in Requirement R3 in TOP-001-1.[401] An entity is only responsible for following directives from its host reliability coordinator unless authority is delegated to another reliability coordinator by the host reliability coordinator.

1585. We agree with FirstEnergy and California Cogeneration that the definition of "emergency" could be further clarified. We discuss this issue in this Final Rule in connection with Reliability Standard EOP-001-0 and conclude that emergency states need to be defined and that criteria for entering these states and authority for declaring them need to be specified. We therefore direct the ERO to modify the Reliability Standard accordingly. With respect to California Cogeneration's argument regarding exemptions from the requirement to respond to emergencies, the reliability coordinator must be in a position to take all necessary actions in response to an emergency and is in the best position to determine which entities should respond to its directives.

1586. In response to FirstEnergy's request for clarification of the meaning of "safety" in the first sentence of Requirement R4, of TOP-001-1 and whether it refers to safety to the system/equipment, public safety or both, the Commission notes that each term in the

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[401] The Requirement states in part that "[e]ach Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator. . . ."

series set forth in this provision refers to a type of "requirement."[402] The provision clearly differentiates between the safety of persons and equipment requirements. Since equipment requirements are mentioned separately, safety must be read as referring to requirements related to safety of persons.

1587. With regard to FirstEnergy's proposal that the entity requesting emergency assistance be required to report that it has implemented all of its own emergency procedures as part of its request for emergency assistance, we believe that such reporting is not appropriate during an emergency situation. Requirement R6 of the Reliability Standard clearly specifies that entities must provide available emergency assistance provided the requesting entity has implemented its comparable emergency procedures. Given the nature of emergency situations where time is of the essence, compliance with this Requirement must be assessed after the fact as part of the compliance audit, and not during an emergency.

1588. With respect to Santa Clara's proposal that Requirements R7.2 and R7.3 be revised to provide that the transmission operator may notify the reliability coordinator or the balancing authority that it is removing facilities from service, the Commission directs the ERO to consider Santa Clara's comments in the Reliability Standards development process.

1589. Accordingly, the Commission approves Reliability Standard TOP-001-1. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to TOP-001-1 through the Reliability Standards development process that: (1) includes Measures and Levels of Non-Compliance for Requirement R8 and (2) considers adding other Measures and Levels of Non-Compliance in the Reliability Standard.

b. Normal Operations Planning (TOP-002-2)

1590. Reliability Standard TOP-002-2 requires transmission operators and balancing authorities to look ahead to the next hour, day and season, and have operating plans ready to meet any unscheduled changes in system configuration and generation dispatch. The Reliability Standard addresses the following matters: (1) procedures to mitigate System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations; (2) verification of real and reactive reserve capabilities; (3) communications;

[402] Requirement R4 states: "Each Distribution Provider … shall comply with all reliability directives … unless such actions would violate safety, equipment, regulatory or statutory requirements."

(4) modeling; (5) information exchange and (6) data confidentiality restrictions. The goal of TOP-002-1 is to ensure that resources and operational plans are in place to enable system operators to maintain the Bulk-Power System in a reliable state.

1591. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, the Commission proposed to direct that NERC submit a modification that: (1) includes Measures and Levels of Non-Compliance; (2) deletes references to confidentiality agreements in Requirements R3 and R4, but addresses the issue separately to ensure that necessary protections are in place related to confidential information and (3) requires next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages.[403]

1592. The Commission also proposed to interpret Requirement R7 of the Reliability Standard as requiring that each balancing authority plan to meet capacity and energy reserve requirements, including deliverability/capability for any single contingency. Although the NERC glossary defines "contingency,"[404] the Commission expressed concern in the NOPR that the phrase "single contingency" is open to interpretation, and "deliverability" is not defined. The Commission proposed in the NOPR to interpret contingency as discussed in connection with the TPL Reliability Standards and to interpret deliverability as the ability to deliver the output from generation resources to firm load without any reliability criteria violations for plausible generation dispatches.

i. Comments

1593. APPA states that NERC has added Measures for many but not all of the Requirements of TOP-002-2 and needs to develop Measures for Requirements R2, R3, R4, R12 and R17.

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[403] In its November 15, 2006, filing, NERC submitted TOP-002-2, which supercedes the earlier Reliability Standard. TOP-002-2 adds Measures and Levels of Non-Compliance to the Reliability Standard, and includes a modified Requirement R14. In this Final Rule, we review the November version, TOP-002-2.

[404] NERC defines "contingency" as "the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electric element." NERC Glossary at 3.

1594. Entergy and MidAmerican support the Commission's proposal to delete references to confidentiality agreements from the requirements and state that different approaches must be explored to preserve the confidentiality of data. MidAmerican adds that NERC should adopt an administrative approach to keep the confidential information from being disclosed before the confidentiality provisions are deleted from the requirements. LPPC asks the Commission to clarify that CEII remains confidential and states that without such clarification there is a danger that sensitive information related to the Bulk-Power System will become public.

1595. FirstEnergy and Entergy express concerns regarding identifying all control actions in the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency. They contend that system conditions can change significantly between day-ahead analysis and real-time operations, rendering potential control actions irrelevant. Therefore they state that operating entities should be held harmless for not having listed in advance control actions taken in the face of real-time contingencies resulting from unpredicted changing system conditions. APPA states that such requirements are not necessary given that system operators use state estimators and other tools to identify effective control actions that produce more accurate results than would be achieved through the proposed day-ahead analysis. APPA and Entergy assert that it should be left to NERC, as the technical expert charged with setting standards, to decide in the first instance whether such day-ahead analysis would be of sufficient benefit to justify requiring it.

1596. MidAmerican is concerned that the Commission's proposal to interpret the phrase "single contingency" as a contingency that includes all multi-element pieces of the system that go out of service together in response to a single event is too restrictive on system operations. However, it also states that historically it has performed the studies in accordance with the Commission's proposal and will support that proposal in the interest of reliability. MidAmerican notes that where a multiple-element single contingency traverses neighboring systems, such contingencies must be coordinated with other systems. Further, it contends that the Commission's directive to have operating plans to meet any scheduled change in system configuration and generation dispatch seems burdensome if not impossible and requests clarification of the Commission's intent in this connection.

1597. ISO-NE recommends that the reference to "transmission service provider" in Requirement R12 of TOP-002-2 should be replaced by "transmission operator" and/or "transmission owner."[405] It claims that such a change would be consistent with the definition of the term "transmission service provider," which the NERC glossary defines as: "[t]he entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements." In performing this function, the transmission service provider provides a business service that entails executing contractual agreements with its customers to provide open access transmission service, whereas SOLs and IROLs are technical in nature and do not translate into transmission service provider functions. In contrast, transmission operators and transmission owners perform planning and operations functions and will need SOL and IROL data.

1598. NRC states that it is not clear whether TOP-002-2 considers the N-1 and the N-1-1 criteria consistent with TPL-002-0 and TPL-003-0, respectively. NRC is concerned about verifying that the Bulk-Power System will provide the necessary voltages to the auxiliary power system busses after a nuclear power plant trip. It suggests that knowledge and verification of significant generator characteristics are essential to this end, especially verification of real and reactive capabilities, automatic voltage regulator status and operating limits. NRC also proposes various revisions to TOP-002-2.

ii. Commission Determination

1599. The Commission approves Reliability Standard TOP-002-2 as mandatory and enforceable. In addition, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process as discussed below.

1600. We are adopting our proposal regarding deletion of references to confidentiality agreements from the Requirements. As we explained in the NOPR, the effectiveness of a Reliability Standard should not be predicated upon the existence of a confidentiality agreement.[406] The ERO should address the confidentiality provision separately to ensure that confidentiality of data is not compromised and CEII information remains confidential.

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[405] Requirement R12 provides: "The Transmission Service Provider shall include known SOLs and IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs, and or regional Total Transfer Capability and Available Transfer Capability calculation processes."

[406] NOPR at P 976.

1601. As noted above, a number of commenters express concerns with the Commission's proposal to require a next-day analysis for all IROLs to identify and communicate control actions to system operators. Identification and communication of control actions that can be implemented within 30 minutes are required to ensure that system operators are aware of and have options available to respond to system conditions following the first contingency to restore the system to a secure state so that it can withstand the next contingency. In addition, the control actions identified in the next-day analysis may quite often be relevant, and informing the system operators of the control options earlier on would be helpful. While the operators may take other actions to preserve the system, they need to have at least one plan (control actions) that will preserve the system from cascading. We believe this addresses FirstEnergy's concern regarding whether compliance requires the use of only the control actions identified in the day-ahead analysis. In response to APPA's comment on the use of state estimators and other tools to identify effective control actions, we note that this capability will help operators in assessing system responses, but they will not identify the control actions system operators will need to take in real-time. Further, operators may not be aware of available control actions, or worse they may not have any control actions, other than firm load-shedding, available to adjust the system after a first contingency occurs. Therefore, we direct the ERO to modify Reliability Standard TOP-002-2 to require the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages.

1602. With respect to NRC's comments, system operators must operate the system in front of them at all times to be capable of withstanding a critical contingency (N-1) without resulting in instability, uncontrolled separation or cascading failures. After this N-1 contingency the operators must adjust the system as soon as possible and in no longer than 30 minutes so that the system can then withstand a new N-1 contingency. Further discussion of how this applies in the planning arena is presented in connection with the TPL group of Reliability Standards.

1603. The Commission agrees with NRC that the minimum voltages at nuclear plant auxiliary power system buses should be assessed in next-day analysis to ensure that adequate voltages can be maintained in accordance with the nuclear plant minimum voltage requirements. If this assessment projects that the minimum voltage requirements cannot be met, the transmission operators or balancing authorities must notify the nuclear power plan as soon as possible, but in no event later than the commencement of the next day's real-time operations. If during real-time operations the transmission operator cannot maintain the minimum voltage, pre or post contingency, it must inform the nuclear plant operator accordingly so that the appropriate corrective actions can be carried out by both the nuclear plant operator and the transmission operator. The

Commission directs the ERO to modify Reliability Standard TOP-002-2 to address these two issues.

1604. The Commission proposed in the NOPR that simulations must be consistent with the number of elements that will be removed from service as a result of the failure of a single element.[407] MidAmerican states that it operates consistent with this proposal, in that it respects a single contingency as one that includes all multiple pieces of the elements that go out of service together in response to a single event. Even though MidAmerican states that the Commission's proposal is too restrictive on system operation, it supports the proposal in the interest of reliability. To do otherwise would not represent what actually happens in real-time operations to the detriment of Bulk-Power System reliability, which demonstrates the need to approach the issue as we propose. We discuss this issue further in connection with a the TPL group of Reliability Standards, where we direct the ERO to modify the TPL Reliability Standards to simulate what actually happens in the physical system, including multiple element failures.

1605. We note with regard to MidAmerican's comment on operating plans to meet any scheduled change in system configuration and generation dispatch that we have not directed any action in this connection and therefore cannot provide any further clarification on this point. With regard to MidAmerican's comment on coordinated efforts with neighboring systems to deal with multiple element single contingencies, we note that such coordination is already required by IRO and TOP Reliability Standards.

1606. Commenters did not take issue with the proposed interpretation of the term "deliverability" as "the ability to deliver the output from generation resources to firm load without any reliability criteria violations for plausible generation dispatches."[408] The Commission adopts this proposed interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP-002-2 should be understood in this manner.

1607. With respect to the modifications to Requirement R12 of the Reliability Standard recommended by ISO-NE and NRC's comments on Measure M7 and a new Measure M11, the Commission directs the ERO to consider these matters in the Reliability Standards development process. In response to NRC's suggestion regarding periodic review of generators' reactive capability, we note that Reliability Standard MOD-025-1 already requires periodic review of generators' reactive capability.

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[407] NOPR at P 979.

[408] Id. at P 974.

1608. As we explained in the NOPR, TOP-002-2 serves an important purpose in ensuring that resources and operational plans are in place to enable system operators to maintain the Bulk-Power System in a reliable state. Further, the requirements set forth in the Reliability Standard are sufficiently clear and objective to provide guidance for compliance. Accordingly, the Commission approves Reliability Standard TOP-002-2. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to TOP-002-2 through the Reliability Standards development process that: (1) deletes references to confidentiality agreements in Requirements R3 and R4, but addresses the issue separately to ensure that necessary protections are in place related to confidential information; (2) requires the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages; (3) requires next-day analysis of minimum voltages at nuclear power plants auxiliary power busses and (4) requires simulation contingencies to match what will actually happen in the field.

c. Planned Outage Coordination (TOP-003-0)

1609. Reliability Standard TOP-003-0 requires transmission operators that operate facilities greater than 100 kV, generator operators that operate facilities greater than 50 MW and balancing authorities to coordinate transmission and generator maintenance schedules. Where a conflict in maintenance schedule arises, the reliability coordinator is authorized to resolve the conflict.

1610. The Commission proposed in the NOPR to approve Reliability Standard TOP-003-0 as mandatory and enforceable. The Commission also proposed to direct NERC to submit a modification to TOP-003-0 that: (1) includes a requirement to communicate scheduled outages well in advance to ensure reliability and accuracy of ATC calculation and (2) makes any facility below the 100 kV or 50 MW thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator, will have a direct impact on the operation of Bulk-Power System subject to Requirement R1 for planned outage coordination.

1611. In addition, the Commission noted in the NOPR that outage information is important to both reliable operation and to the calculation of ATC. This information is also needed to assure coordination of outages long before next day or current day operations. The Commission proposed that applicable scheduled outages be communicated to affected transmission operators and reliability coordinators with sufficient lead time to coordinate outages. The Commission then requested industry input on what constitutes sufficient lead time for planned outages.

i. Comments

1612. MRO, APPA and others raise concerns requiring the proposed requirement to communicate scheduled outages "well in advance." APPA cautions that TOP-003-0 was generally designed to ensure that transmission operators receive accurate and timely information about transmission and generation outages affecting "next-day operations," rather than the longer term outage planning information. MRO states that requiring outage information well in advance reduces the entity's flexibility for other contingencies and changes. MRO also contends that the phrase "well in advance" is vague, not measurable, and may not be enforced fairly and consistently. FirstEnergy states that NERC should specify the meaning of "well in advance" through its Reliability Standards development process with industry input. MRO recommends that the time period for outage notification should be based on the size of the generating facility and voltage level of the transmission line so that a larger facility has a longer lead time for outage notification.

1613. While MISO agrees with the need for early notification of planned outages, it is concerned that an arbitrary lead time will cause entities to postpone needed maintenance to accommodate the timeline, thereby reducing the reliability of the Bulk-Power System.

1614. LPPC states that business reasons often drive a longer lead time for outage planning to allow market participants to better understand the congestion and market impacts of the planned outage. LPPC believes that the Commission should exercise caution and avoid adopting a business practice as part of the Reliability Standard. Reliability concerns often dictate that an outage should not be planned and set in stone too far in advance because the circumstances may change. According to LPPC, the Commission should refrain from prescribing a lead time that would cut into an operator's flexibility, which is needed to respond to real-time situations.

1615. In response to the Commission's question regarding the lead time for planned outages, MidAmerican states that although it believes that a requirement for extending the lead time will result in higher costs and less flexibility, a two-week advance notice for planned outages of 345 kV facilities and one-week advance notice for 161 and 69 kV facilities is appropriate. TVA proposes one-week advance notice for all planned outages and recommends that TOP-003-0 should be modified to include breaker outages within the meaning of the facilities that are subject to advance notice for planned outages.

1616. CAISO states that its current tariff provides for three days of lead time for providing outage information and that this is a standard practice throughout WECC. It maintains, however, that the three-day lead time is not sufficient for the needed review and coordination of outages. In fact, CAISO states that many ISOs and RTOs are moving toward a lead time of either 30 days or 45 days prior to the beginning of the outage month. CAISO contends that rather than basing the outage information on a certain kV level, the emphasis should be on facilities that may have a significant effect on congestion revenue rights resource adequacy.

1617. Entergy and FirstEnergy support the proposed modification to include any facility below the thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator, will have a direct impact on the operation of the Bulk-Power System subject to Requirement R1 for planned outage coordination. They maintain that such a modification will provide the transmission operator much needed flexibility. APPA, on the other hand, opposes the proposal. APPA states that the Commission should allow the ERO in the first instance to consider whether to add this specific requirement to TOP-003-0. If the Commission is concerned that TOP-003-0 as it now stands might "not include all facilities that have a significant impact on the operation of the Bulk-Power System," it should direct NERC to consider that issue on remand using its Reliability Standards development process.

1618. Xcel notes that Requirement R4 of the Reliability Standard provides that each reliability coordinator should resolve any potential conflicts in scheduling of planned outages. Xcel argues that if a reliability coordinator requires an entity to move its planned outage to accommodate another entity's unplanned outage, the entity that agrees to move its planned outage to another time should receive compensation.

ii. Commission Determination

1619. The Commission approves TOP-003-0 as mandatory and enforceable. We address the concerns raised by commenters below.

1620. In Order No. 890, the Commission directed that information concerning ATC calculations be consistent and transparent.[409] The timing of facility outages is one important piece of information in ATC calculations. In Order No. 890, the Commission directed that specific data be exchanged among transmission providers, including transmission planned and contingency outages, for the purpose of ATC modeling.[410] Consistent with this determination in Order No. 890, the Commission directs the ERO to develop a modification to TOP-003-0 that requires the communication of scheduled outages to all affected entities well in advance to ensure reliability and accuracy of ATC

[409] See Order No, 890 at P 68-69, 207-213.

[410] Id. at P 292.

calculations.[411] We believe this addresses LPPC's concern regarding the interplay between reliability and business practices.

1621. Several commenters raised concerns regarding the Commission's proposal to require outage information well in advance. Specifically, they argue that the term "well in advance" is vague, that the requirement would reduce flexibility and that it would cause entities to postpone needed maintenance work, thereby reducing reliability. In response to the Commission's request for comments on lead time for planned outages, entities provide information on current lead time practices indicating that lead times range from one week to 45 days. We direct the ERO to modify the Reliability Standard to incorporate an appropriate lead time for planned outages. The ERO should utilize the information filed by commenters in the Reliability Standards development process. In doing so the ERO should take into consideration the need for flexibility, as well the lead time required for coordination with other entities and outage assessments. Proper coordination will ensure that priority is given to needed maintenance work for critical facilities to ensure reliability.

1622. With regard to TVA's request to include breaker outages within the meaning of the facilities that are subject to advance notice for planned outages, we direct the ERO to consider this suggestion in the Reliability Standards development process.

(a) Applicability

1623. As noted above, the Commission proposed to direct the ERO to modify TOP-003-0 to make any facility below the thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator, will have a direct impact on the operation of Bulk-Power System subject to Requirement R1 for planned outage coordination.

1624. Entergy and FirstEnergy support the proposed modification to include any facility below the threshold that in the opinion of the reliability coordinator, balancing authority or transmission operator will have a direct impact on the operation of the Bulk-Power

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[411] The Commission notes that PJM has developed an outage scheduling process in response to Commission directives to avoid the possibility of undue discrimination. http://www.pjm.com/committees/mrc/downloads/20060630-item-06-draft-manual-14b-changes.pdf The outage scheduling process was developed through a stakeholder process and has been utilized in the entire PJM footprint for a number of years. PJM's outage scheduling program is one example of the type of program that should be implemented through the Reliability Standard.

System. On the other hand, APPA opposes this proposal and contends that the Commission should allow the ERO, as the expert entity charged with developing Reliability Standards, to consider whether to add this specific requirement. The Commission disagrees because registered entities below the thresholds currently defined in Requirement R1 of the Reliability Standard may have an impact on reliability and therefore should be required to submit data on their planned outages. The Commission therefore directs the ERO to modify the Reliability Standard to require that any facility below the thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator will have a direct impact on the reliability of the Bulk-Power System be subject to Requirement R1 for planned outage coordination.

(b) Other Issues

1625. In response to Xcel's proposal that entities that agree to reschedule their previously-approved planned outages to accommodate another entity's unplanned outage be compensated, the Commission notes that whereas rescheduling of the outage is a reliability matter, compensation is not and therefore is outside the scope of this proceeding.

(c) Summary of Commission Determination

1626. Planned outage coordination is a necessary element of reliable operations, and TOP-003-0 promotes that goal. Accordingly, the Commission approves the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to TOP-003-0 through the Reliability Standards development process that: (1) includes a new requirement to communicate longer term outages well in advance to ensure reliability and accuracy of ATC calculation; (2) makes any facility below the voltage thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator, will have a direct impact on the operation of Bulk-Power System, subject to Requirement R1 for planned outage coordination and (3) incorporates an appropriate lead time for planned outages as discussed above.

d. Transmission Operations (TOP-004-1)

1627. This Reliability Standard requires transmission operators to operate the transmission system within SOL and IROL.[412] The N-1 operating criterion for the

[412] In its November 15, 2006, filing, NERC submitted TOP-004-1, which has an effective date of October 1, 2007, at which time it will supercede the Version 0 Reliability Standard. TOP-004-1 adds Measures and Levels of Non-Compliance to the (continued)

transmission system is also established in this Reliability Standard. It provides that operating configurations for which limits have not yet been determined should be treated as emergencies. The goal of the Reliability Standard is to maintain Bulk-Power System facilities within limits, thereby protecting transmission, generation, distribution and customer equipment and preventing cascading failures of the interconnected grid.

1628. The Commission proposed in the NOPR to approve the Reliability Standard as mandatory and enforceable. In addition, the Commission proposed to direct that NERC submit a modification that: (1) includes Measures and Levels of Non-Compliance; (2) clarifies that the system should be restored as soon as possible, taking no more than 30 minutes and (3) defines high risk conditions under which the system must be operated to respect multiple outages in Requirement R3. The Commission also proposed to direct the ERO to perform a survey of the prevailing operating practices and actual operating experiences surrounding drifting in and out of IROL limits.

1629. Requirement R3 requires that each transmission operator shall, when practical, operate the system to respect multiple outages as specified by the regional reliability organization policy. The Commission noted in the NOPR that Requirement R3 does not define conditions under which multiple outages must be considered. The NOPR proposed to interpret such conditions "to include high risk conditions such as hurricanes, ice storms or periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage."[413]

i. Comments

1630. PG&E and APPA oppose a modification to the Reliability Standard that changes the requirement allowing operators to return the system to a reliable operating state within 30 minutes to a requirement that they do so as soon as possible and in no longer than 30 minutes. PG&E is concerned that during emergencies operators would be subject to uncertainty in complying with such a requirement, which could lead to overly hasty responses with a corresponding detrimental effect on reliability. PG&E states that to avoid the confusion and ambiguity from a subjective standard, the Commission and NERC should only clarify that operators should seek to return the system to a reliable operating state as soon as possible, but maintain the current requirement of 30 minutes as stated in Requirement R4 of TOP-004-1. APPA states that if the Commission is

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Version 0 Reliability Standard. Because TOP-004-0 will be in effect until October 1, 2007 and TOP-004-1 thereafter, we address both versions of the Reliability Standard.

[413] NOPR at P 997.

concerned about the need to require a response time that is quicker than 30 minutes, it should direct the ERO to consider this issue as part of the Reliability Standards development process.

1631. Entergy and MidAmerican support the Commission's proposal to have NERC conduct a survey and report the operating practices and actual experiences surrounding drifting in and out of IROL violations. MISO, on the other hand, opposes the survey because there are already requirements for reporting IROL violations elsewhere in the Reliability Standards. APPA proposes that the Commission should ask the ERO to determine if such information would improve reliable operations. If it is determined that such information will improve reliability, NERC should include this type of information in compliance violation reporting procedures.

1632. LPPC and Xcel recommend that the Commission not require NERC to define in Requirement R3 the specific high-risk conditions under which the system must be operated to respect multiple outages. Xcel argues that it is unnecessary and impractical to attempt to define in advance all of the possible scenarios that will result in a high-risk condition. Not all high-risk conditions can be defined at any one time because changes in the system will introduce new high-risk conditions. Even if a list of high-risk conditions is developed, then, by definition, all other conditions not listed are excluded from consideration under this Reliability Standard. LPPC states that the proposed modification to deal with high-risk conditions is an unnecessarily prescriptive approach and could be detrimental to reliability by excluding scenarios that should be listed under this Requirement.

1633. California PUC states that the Commission should not interpret hurricanes and ice storms as high risk conditions for studying multiple outages because events such as hurricanes and ice storms actually reduce the stress on the Bulk-Power System. This is because such events cause outages at the local distribution system level. California PUC maintains that since events such as hurricanes and ice storms rarely cause cascading outages, the proper approach for dealing with such situations is to focus on system restoration planning rather than including them in the contingency analysis that the proposed modification will require as a result of including such natural events within the meaning of high risk conditions.

1634. Santa Clara states that Requirement R2 of the Reliability Standard should be revised to include frequency monitoring in addition to the monitoring of voltage, real and reactive power flows.

ii. Commission Determination

1635. The Commission approves TOP-004-0 as mandatory and enforceable until October 1, 2007, when TOP-004-1 will be mandatory and enforceable. We address the concerns raised by commenters below.

1636. We adopt our proposal to require the ERO to clarify that the system should be restored as soon as possible, taking no more than 30 minutes. Requirement R4 of TOP-004-1 (as well as the Version 0 standard) provides that if a transmission operator enters an unknown state, i.e., any state for which valid operating limits have not been determined, operations should be restored to respect proven reliable power system limits within 30 minutes. However, as we stated in the NOPR, this language may be interpreted as a grace period to the detriment of reliability.[414] The Commission, therefore, directs that the ERO develop a modification to Requirement R4 providing that the system should be restored to respect proven reliable power system limits as soon as possible and in no longer than 30 minutes. In response to PG&E's point that the phrase "as soon as possible" would add confusion, we note that Measure M1 in TOP-004-1 would measure performance against the 30-minute period specified in Requirement R4.

1637. Entergy and MidAmerican support our proposal to direct the ERO to conduct a survey and report the operating practices and actual experiences surrounding drifting in and out of IROL violations. We disagree with MISO that TOP-007-0 covers reporting of "drifting" in and out of IROL violations because that Reliability Standard only requires reporting of IROL violations exceeding 30 minutes. With regard to APPA's suggestion that NERC should determine whether such information would improve reliable operations, we believe a survey is appropriate to determine actual practices, and simply modifying the compliance reporting procedures may not provide sufficient data to determine the reliability impacts of such practices and whether a modification to the Reliability Standard is appropriate. Accordingly, we direct the ERO to conduct a survey on the operating practices and actual experiences surrounding drifting in and out of IROL violations. Such a survey will provide factual support for whether additional modifications to the Reliability Standard are needed. The survey will also indicate whether additional vigilance on the part of compliance auditors is warranted in this area to ensure Bulk-Power System reliability.

1638. As mentioned above, the Commission proposed to interpret "multiple outages" in the context of Requirement R3 to include multiple element outages resulting from high-risk conditions such as hurricanes, wild fires, ice storms or periods of high solar magnetic

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[414] See NOPR at P 995.

disturbances during which the probability of multiple outages approaches that of a single element outage. This is not an exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process should develop a procedure to identify applicable high risk conditions. Under the high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N-1 criterion because the probability of multiple outages during high-risk conditions approaches that of a single outage during normal conditions. This does not preclude development of restoration plans as suggested by California PUC. Thus, we direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process.

1639. We direct the ERO to consider Santa Clara's suggestion regarding changes to Requirement R2 in the Reliability Standards development process.

1640. Accordingly, the Commission approves Reliability Standard TOP-004-0. Further, we approve TOP-004-1 so that it will become mandatory and enforceable on the stated effective date of October 1, 2007. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to the Reliability Standard through the Reliability Standards development process that: (1) modifies Requirement R4 to state that the system should be restored to respect proven limits as soon as possible, taking no more than 30 minutes and (2) defines high risk conditions under which the system must be operated to respect multiple outages in Requirement R3, consistent with the discussion above.

1641. In addition, the Commission directs the ERO to perform a survey of the prevailing operating practices and actual operating experiences surrounding drifting in and out of IROL limits as discussed more fully in this Final Rule in connection with the IRO group of Reliability Standards. As an example of the type of data that would be appropriate in the survey, we would expect to have reliability coordinators report any violation of an IROL not exceeding 30 minutes, its causes, the date and time of the violation, and the duration for which actual operations exceeded IROL to the ERO on a monthly basis for one year beginning two months after the effective date of the Final Rule. The ERO should report the results to the Commission in an informational filing within 18 months from the effective date of this Final Rule.

e. Operational Reliability Information (TOP-005-1)

1642. Reliability Standard TOP-005-1 seeks to ensure that reliability information is shared among reliability coordinators, transmission operators and balancing authorities. It requires the transmission operator and the balancing authority to provide operating data to each other and to the reliability coordinator, and it provides a list of typical operating data that must be provided. TOP-005-1 also provides that each data recipient must execute a confidentiality agreement as a condition of receiving data from NERC's Interregional Security Network.[415]

1643. The Commission proposed in the NOPR to approve Reliability Standard TOP-005-1 as mandatory and enforceable. The Commission also proposed to direct NERC to submit a modification to TOP-005-1 that: (1) includes information about the operational status of special protection systems and power system stabilizers in Attachment 1 and (2) deletes references to confidentiality agreements, but addresses the issue separately to ensure that necessary protections are in place related to confidential information.

i. Comments

1644. FirstEnergy states that TOP-005-1 should also apply to transmission providers because some of the information listed in Attachment 1 to the Reliability Standard is in their possession. Attachment 1 should be modified so that it allows each entity to know what data it is expected to provide. As currently written, Attachment 1 lists various entities that are supposed to provide data without specifying who will provide which information. FirstEnergy states that transmission operators, for example, may not have all the information listed in item 1.5 of Attachment 1.

1645. APPA and Entergy agree that TOP-005-1 should be modified to include information about the operational status of special protection systems and power system stabilizers in Attachment 1. However, APPA contends that the Commission's directive should be revised so that this change is developed through the Reliability Standards development process.

1646. ISO-NE recommends that the reference to "purchasing-selling entity" in Requirement R4 should be replaced with "generator owner, transmission owner, and LSE."[416] It argues that since NERC's glossary defines the term "purchasing-selling

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[415] Interregional Security Network is a data exchange system that facilitates the exchange of real-time and other operational data among reliability coordinators, balancing authorities and transmission operators to help ensure reliable electric power system operations.

[416] Requirement R4 states: "Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations."

entity" as "[t]he entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operation services," many entities can fall within this category (e.g., commodity traders such as financial/power marketers) that may possess little or none of the operational or reliability data the host balancing authority and transmission operator need to conduct reliability assessments.

1647. A number of commenters discussed the Commission's proposal to delete references to confidentiality agreements in the Reliability Standard but to address the issue separately to ensure that necessary protections are in place related to confidential information. Those comments are summarized above in connection with the same proposal made by the Commission in the case of TOP-002-1.

ii. Commission Determination

1648. For the reasons stated in the NOPR,[417] we direct the ERO to develop a modification to TOP-005-1 through the Reliability Standards development process regarding the operational status of special protection systems and power system stabilizers in Attachment 1. Several commenters agree with this directive, and we believe that this information will provide a more comprehensive list in Attachment 1.

1649. We are adopting our proposal regarding deletion of references to confidentiality agreements from the Requirements. Our discussion of this matter in connection with TOP-002-1 applies equally here.

1650. The Commission directs the ERO to consider FirstEnergy's recommended modifications to Attachment 1 to the Reliability Standard and ISO-NE's recommended revision to Requirement R4 in the Reliability Standards development process.

1651. Accordingly, the Commission approves Reliability Standard TOP-005-1. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to TOP-005-1 through the Reliability Standards development process that: (1) includes information about the operational status of special protection systems and power system stabilizers in Attachment 1 and (2) deletes references to confidentiality agreements, but addresses the issue separately to ensure that necessary protections are in place related to confidential information.

[417] NOPR at P 1005.

f. Monitoring System Conditions (TOP-006-1)

1652. TOP-006-1 requires operating personnel to continuously monitor essential Bulk-Power System parameters such as line flows, circuit breaker status, generator resources, relays, weather forecasts and frequency to ensure that the facilities do not exceed their operating limits.

1653. The Commission proposed in the NOPR to approve the Reliability Standard as mandatory and enforceable.[418] The Commission also proposed to direct NERC to submit a modification that: (1) includes Measures and Levels of Non-Compliance; (2) includes a new Requirement related to the provision of a minimum set of analytical tools that will aid in situational awareness and (3) clarifies the meaning of "appropriate technical information" concerning protective relays.

i. Comments

1654. Dominion supports including a new requirement for a minimum set of analytical tools. It argues that such a requirement will ensure that operators have a minimum set of tools with which to perform their duties. The Reliability Standard should also specify metrics that can be audited, such as minimum availability times, so that these tools are adequately maintained. However, Alcoa states that requiring a minimum set of tools will be unduly onerous, especially to smaller balancing authorities and transmission operators. Although situational awareness tools, such as state estimators, are critical for an ISO and RTO, smaller balancing authorities and transmission operators should provide necessary data to the reliability coordinator that monitors a wide region using such tools.

1655. Alcoa claims that developing additional capability at the balancing authority and transmission operator levels when such capability already exists at the reliability coordinator level will be redundant. Requiring state estimation for a small balancing area that is under an ISO would provide little benefit for grid reliability since the scope of the balancing area's visibility is limited.

1656. APPA does not support the proposed requirement related to the provision of a minimum set of analytical tools and claims that inclusion of specific analytical tools is counterproductive because the tools become obsolete within two to five years due to

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[418] In its November 15, 2006 filing, NERC submitted TOP-006-1, which supercedes the Version 0 Reliability Standard. TOP-006-1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, TOP-006-1.

technical advances. APPA states that deciding whether to add a new requirement for a minimum set of analytical tools should be left to NERC in the first instance. Similarly, TAPS argues that NERC should consider in the first instance whether minimum analytical tools are necessary and for what subset of generator operators and transmission operators.

1657. LPPC maintains that the Commission should require NERC to list the capabilities required rather than specific tools because tools will change over time.

1658. APPA states that the ERO's filing on November 15, 2006 includes new Measures M1 through M6, which only measure Requirements R1, R2, R4, R5 and R7.

ii. Commission Determination

1659. The Commission approves TOP-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to TOP-006-1 through the Reliability Standards development process, as discussed below.

1660. We adopt our proposal to require the ERO to develop a modification related to the provision of a minimum set of analytical tools. In response to LPPC and others, we note that our intent was not to identify specific sets of tools, but rather the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System. In response to APPA that the inclusion of specific analytical tools is counterproductive because the tools will become obsolete, we note that we are not seeking specific analytical tools, but rather minimum capabilities.

1661. In regard to Alcoa's concern that this new Requirement would be unduly onerous, especially for smaller balancing authorities and transmission operators, the Commission's intent is not to subject smaller balancing authorities and transmission operators to the same requirements placed on larger balancing authorities and transmission operators. As part of the modification of this Reliability Standard to develop a new requirement for minimum capability for analytical tools, the ERO should take into account what would be required of smaller balancing authorities and transmission operators for the Reliable Operation of the Bulk-Power System, instead of applying the same requirements as are placed on other reliability entities such as reliability coordinators and larger balancing authorities and transmission operators.

1662. We disagree with Alcoa that developing additional capability at the balancing authority and transmission operator levels when such capability already exists at the reliability coordinator level will be redundant. We are not seeking to duplicate the same capability for each reliability entity, but rather the new requirement should specify the minimum capability taking into account the role played by each entity. For example, a reliability coordinator may need to have access to state estimator and contingency analysis whereas a generator operator may not need these capabilities.[419]

1663. No commenters addressed our proposal with respect to the meaning of "appropriate technical information" concerning protective relays in Requirement R3 of the Reliability Standard. To provide more clarity, criteria that define what "appropriate technical information" is necessary should be specified so that operators can make better informed decisions. An example of such information would be the allowable reclosing angle set in the existing relays and the maximum angle at specific points in the Bulk-Power System that would be acceptable to allow closing of lines during system restoration.

1664. The ERO should consider APPA's comment regarding the missing Measures in the ERO's Reliability Standards development process.

1665. Accordingly, the Commission approves Reliability Standard TOP-006-1. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to TOP-006-1 through the Reliability Standards development process that: (1) includes a new requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System and (2) clarifies the meaning of "appropriate technical information" concerning protective relays.

g. Reporting SOL and IROL Violations (TOP-007-0)

1666. TOP-007-0 requires that violations of SOL and IROL be promptly reported to the reliability coordinator so that it can direct corrective action and inform other affected systems. It also requires a transmission operator to mitigate an IROL violation as soon as possible but in no longer than 30 minutes. A transmission operator must take "all appropriate actions up to and including shedding firm load" to return its system to a stable state within IROL. Finally, the Reliability Standard requires that the reliability coordinator take action to mitigate an SOL or IROL violation if the transmission operator's actions are not effective.

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[419] We note that TOP-006-0 applies to transmission operators, balancing authorities, generator operators and reliability coordinators.

1667. The Commission proposed in the NOPR to approve TOP-007-0 as mandatory and enforceable.

1668. In the NOPR, the Commission solicited comment on potentially overlapping matters addressed in Reliability Standards TOP-007-0 and TOP-008-0.

i. Comments

1669. NERC recognizes that there are some redundancies and awkward relationships among the various Reliability Standards, which are the result of the translation from the previous operating policies where each policy was treated as a separate set of concepts. NERC states that its 2007–2009 Reliability Standards Work Plan addresses work to be done to eliminate redundancies and better organize the Requirements across Reliability Standards so as to provide a more logical presentation.

1670. APPA states that the concerns expressed in the NOPR about overlapping matters between TOP-007-0 and TOP-008-0 should be referred to the NERC Reliability Standards development process to better comport with the statutory division of responsibility. FirstEnergy and SoCal Edison state that Requirements R2 through R4 are clearly not reporting activities and should be combined with the requirements of TOP-008.

1671. NRC states that some nuclear power plant voltage requirements would result in SOL, i.e., the nuclear power plant voltage limits would be an SOL as a result of the minimum and maximum voltages required at the nuclear power plant switchyard, which typically has a tighter operating band (a higher minimum and a lower maximum) than other nodes in the system. It therefore recommends adding a new requirement that states as follows: "Following discovery of a potential contingency that could result in an SOL being exceeded at a nuclear power plant (e.g., at post-trip voltage), the transmission owner shall notify the nuclear power plant operator as soon as possible but not longer than 30 minutes if the contingency has not been corrected." NRC also suggests modifying the Measures and Compliance sections and Table 1 to account for the new requirement, and provides specific language to be included in those places.

ii. Commission Determination

1672. The Commission approves TOP-007-0 as mandatory and enforceable. We agree with APPA, FirstEnergy and SoCal Edison that the Reliability Standards would benefit from the elimination of overlapping matters in TOP-007-0 and TOP-008-1. The ERO indicates that it plans to address this as part of its Work Plan and this suffices.

1673. NRC has raised some significant issues regarding the consideration of nuclear power plants voltage requirements. Consistent with our general approach in this Final Rule, we direct the ERO to consider NRC's comments in the Reliability Standards development process when addressing TOP-007-0 as part of its Work Plan.

1674. Accordingly, the Commission approves Reliability Standard TOP-007-0 as mandatory and enforceable.

h. Response to Transmission Limit Violations (TOP-008-1)

1675. TOP-008-1 requires a transmission owner to take immediate steps to mitigate SOL and IROL violations.

1676. The Commission proposed in the NOPR to approve Reliability Standard TOP-008-0 as mandatory and enforceable. The Commission also proposed to direct that NERC submit a modification to TOP-008-0 that: (1) includes Measures and Levels of Non-Compliance and (2) includes reliability coordinators in the applicability section.[420]

i. Comments

1677. APPA questions whether TOP-008-1 should be modified to apply to reliability coordinators. It claims that the Requirement R3 simply mentions that the reliability coordinator will receive information provided by the transmission operator and does not play any substantive role under TOP-008-1. MISO notes that the reliability coordinators' responsibility related to IROL violations are outlined in connection with IRO Reliability Standards and the reasons for adding the reliability coordinator as applicable entity in multiple locations is unclear.

1678. APPA states that NERC has not submitted a Measure for the Requirement R2 of the Reliability Standard. The new Measures M1 through M5 included in TOP-008-1 only measure Requirements R1, R3, and R4. In addition, the data retention and compliance levels reference Measures M1 through M5. Therefore, an entity subject to TOP-008-1 could arguably comply with Requirements R1, R3 and R4 and be in compliance with the entire Reliability Standard.

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[420] In its November 15, 2006, filing, NERC submitted TOP-008-1, which supercedes the Version 0 Reliability Standard. TOP-008-1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, TOP-008-1.

ii. Commission Determination

1679. For the reasons stated in the NOPR,[421] the Commission approves TOP-008-1 as mandatory and enforceable. We address the concerns raised by commenters below.

1680. We agree with APPA that the reliability coordinator merely receives information provided by the transmission operator and does not play any substantive role under TOP-008-1. We also agree with MISO that the reliability coordinators' responsibility related to IROL violations are outlined in connection with the IRO Reliability Standards and therefore there is no need to modify the applicability section of TOP-008-1 to include the reliability coordinator.

1681. The ERO should consider APPA's comment regarding the missing Measures in the ERO's Reliability Standards development process.

1682. Accordingly, the Commission approves Reliability Standard TOP-008-1 as mandatory and enforceable.

12. TPL: Transmission Planning

1683. The Transmission Planning (TPL) group of Reliability Standards consists of six Reliability Standards that are applicable to transmission planners, planning authorities and regional reliability organizations. These Reliability Standards are intended to ensure that the transmission system is planned and designed to meet an appropriate and specific set of reliability criteria. Transmission planning is a process that involves a number of stages including developing a model of the Bulk-Power System, using this model to assess the performance of the system for a range of operating conditions and contingencies, determining those operating conditions and contingencies that have an undesirable reliability impact, identifying the nature of potential options, and the need to develop and evaluate a range of solutions and selecting the preferred solution, taking into account the time needed to place the solution in service. The proposed TPL Reliability Standards address: (1) the types of simulations and assessments that must be performed to ensure that reliable systems are developed to meet present and future system needs[422] and (2) the information required to assess regional compliance with planning criteria and for self-assessment of regional reliability.[423]

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[421] See NOPR at P 1035-36.

[422] See TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0.

[423] See TPL-005-0 and TPL-006-0.

1684. The TPL group of Reliability Standards contains a table designated "Table 1" (Transmission System Standards – Normal and Emergency Conditions), which is a key part of this group of Reliability Standards. It lays out the system performance requirements for a range of contingencies grouped according to the number of elements forced out of service as a result of the contingency. For example: Category A applies to the normal system with no contingencies; Category B applies to contingencies resulting in the loss of a single element, defined as a generator, transmission circuit, transformer, single DC pole with or without a fault; Category C applies to a contingency resulting in loss of two or more elements, such as any two circuits on a multiple circuit tower line or both poles of a bi-polar DC line; while Category D applies to extreme contingencies resulting in loss of multiple elements, such as a substation or all lines on a right-of-way. The system performance expectations for Category C contingencies are lower than those for Category B contingencies, in that they allow unspecified amounts of planned or controlled loss of load.

a. General Issues

1685. Commenters raise a number of issues that apply generally to Reliability Standards TPL-001-0 through TPL-004-0. These issues are related to the transmission planning process, sensitivity studies and critical system conditions, element-based versus event-based contingencies, spares strategy, and resource information for planning and sharing information with neighboring systems. We address these general issues here, and the conclusions reached will apply to our discussion of individual TPL Reliability Standards.

i. Transmission Planning Process

1686. The Commission stated in the NOPR that the Reliability Standards are not intended to make the Bulk-Power System failure-proof.[424] In addition, we did not propose to modify the TPL Reliability Standards to require that the system be able to withstand all multiple-contingency and extreme contingency events without loss of load. Nonetheless, we stated that we believe that the planning-related Reliability Standards could be improved to better account for probable contingencies when conducting planning studies. Much of our proposal was consistent with the potential improvements NERC recognized in its comments on the Staff Preliminary Assessment. In addition, we noted that a number of regions currently utilize superior planning practices that may be characterized as "best practices" and are more stringent than the proposed TPL

[424] NOPR at P 1042.

Reliability Standards.[425] Accordingly, we proposed that the ERO submit to the Commission such regional differences in transmission planning criteria that are more stringent than those specified in the TPL group of Reliability Standards.

(a) Comments

1687. EEI and APPA strongly believe that the transmission planning processes performed under these Reliability Standards have served this nation extremely well. The Reliability Standards have evolved with changes in industry structure, computer and communications technology, electric generation and transmission technology and a broad range of state and federal regulatory demands. EEI and APPA state that it is unclear whether the Commission is proposing a significant expansion of this reliability planning process, which would amount to a fundamental shift in the nature of that process, or whether the Commission is proposing a more specific description of today's comprehensive planning approach. EEI and APPA state that they can interpret the Commission's proposal either as suggesting that planning should support a robust and flexible network that can "bend" to a broad range of critical system conditions, as practiced up to now, or that planning should be "finely tuned" so that reliability can be maintained under conditions where both resources and loads are highly controlled. They find the source for the latter interpretation in the Commission's request that the industry move toward more explicit requirements that transmission planners consider the effects of load control or other forms of DSM, or conduct planning studies for far more combinations of resource alternatives. EEI and APPA state that the existing Reliability Standards fully meet the Commission's criteria as set forth in Order No. 672, unless the Commission envisions a very different transmission system planning process or seeks to move away from current network design toward the development of a much "tighter" transmission system through substantially higher saturations of controllable resources and loads.

1688. SDG&E notes that the NOPR's characterization of the dual objectives of "appropriateness" and "specificity" speaks, on the one hand, to the need for Reliability Standards that are tailored to each transmission planner's area of responsibility, and, on

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[425] Examples include practices cited in NERC's "Examples of Excellence" found in its Readiness Audits (available at http://www.nerc.com) and filings for jurisdictional utilities in Part 4 of FERC Form No. 715, Transmission Planning Reliability Criteria. Regional reliability organizations also specify requirements that exceed NERC Reliability Standards, such as WECC's Minimum Operating Requirement Criteria and the NPCC Document A-02 - Basic Criteria for Design and Operation of Interconnected Power Systems.

the other hand, clear, consistent and workable rules. SDG&E urges the Commission to be mindful of the need to assess and balance these considerations in future iterations of the transmission planning Reliability Standards.

1689. Northern Indiana states that the presentation of TPL-001-0 through TPL-004-0 as individual Reliability Standards creates a great deal of confusion. In practice, most transmission planners take an integrated view of these Reliability Standards and treat them as if they were a single standard. Accordingly, Northern Indiana suggests that the Commission ask NERC to file a substitute proposal that would integrate the transmission planning standards and improve their clarity and quality.

1690. SDG&E supports the Commission's proposal to direct NERC to submit for approval regional transmission planning criteria that have been adopted and extensively used that are more stringent than those specified in the current TPL Reliability Standards. NCPA states that whenever a RTO/ISO adopts criteria that differ from ERO or regional standards, those criteria should be made public and transparent.

(b) Commission Determination

1691. EEI and APPA raise an important question on the Commission's intent regarding the transmission planning process and proposed modifications to the transmission planning standards. They ask whether the Commission is proposing a fundamental shift in the nature of the planning process that would result in a move away from the current network design towards a much "tighter" transmission system through substantially increased use of controllable resources and loads. The Commission is not proposing a fundamental shift in the nature of the planning process as it is practiced today. We clarify that all the proposed modifications to the TPL group of Reliability Standards are aimed at ensuring Reliable Operation of the Bulk-Power System. To achieve this goal, it is necessary, among other things, to ensure that the planning process and the Reliability Standards produce a Bulk-Power System that is robust enough to be able to withstand a range of probable contingencies while reliably serving customer demand and preventing the identified outages, and flexible enough to accommodate a broad range of system conditions over a planning horizon that takes into account lead times to place facilities in service. Further, the proposed modifications are intended to ensure that the planning requirements are specific enough to promote rigor and consistency in assessments and provide clear and measurable rules for mandatory and enforceable Reliability Standards. The Commission therefore agrees with SDG&E's comments in this regard and on the need to balance "appropriateness" and "specificity."

1692. The Commission agrees with Northern Indiana that the Reliability Standards TPL-001-0 through TPL-004-0 would be improved if they were integrated into a single Reliability Standard. Such an approach conforms more closely to common planning practices, and integrating these Reliability Standards therefore could enhance their practical effectiveness. The Commission notes that the Work Plan submitted by the ERO has earmarked this group of Reliability Standards for revision during the early stages of the plan. The Commission directs the ERO to consider integrating Reliability Standards TPL-001-0 through TPL-004-0 into a single Reliability Standard through the Reliability Standards development process.

1693. The Commission agrees with SDG&E and NCPA that any criteria that are more stringent than the ERO planning criteria should be made public and transparent. It is essential that such criteria be accessible to and understood by the entities to which they apply. Accordingly, the Commission directs the ERO to submit to the Commission in an informational filing, in addition to regional criteria, all utility and RTO/ISO differences in transmission planning criteria that are more stringent than those specified by the TPL group of Reliability Standards. We believe that this information will provide us, as well as the ERO and industry with an indication of the actual transmission practices utilized in the industry today. This should be used by the ERO in the Reliability Standards development process.

ii. Sensitivity studies and critical system conditions

1694. The Commission stated in the NOPR that it is not realistic to expect the ERO to develop Reliability Standards that anticipate every conceivable critical operating condition applicable to unknown future configurations for regions with various configurations and operating characteristics.[426] The practical solution implemented by many in the industry is to perform sensitivity studies that define and provide documentation of the reliability impact on the system. The Commission therefore stated that it would be appropriate for planning entities to conduct sensitivity studies to "bracket" the range of probable outcomes. Thus, without having to anticipate "every conceivable critical operating condition," planning entities will have a means to identify an appropriate range of critical operating conditions. Both staff and commenters on the Staff Preliminary Assessment noted that system conditions are as important as contingencies in evaluating the performance of present and future systems.

(a) Comments

1695. Most of the commenters agree with the Commission's proposal on sensitivity studies to determine critical system conditions. These include FirstEnergy, TVA, MidAmerican, Entergy and SDG&E. However, a few commenters, including EEI,

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[426] NOPR at P 1047.

APPA, MISO and Northern Indiana, take the view that such a requirement is unnecessary and overly prescriptive.

1696. FirstEnergy states that it is appropriate for the Commission to require sensitivity analyses, because assessing multiple sensitivities against a set of system contingencies is prudent system planning.

1697. TVA agrees that an appropriate range of critical operating conditions that will "stress" the Bulk-Power System needs to be identified for use in transmission planning. It states that sensitivity studies should be performed and historic data analyzed to determine the most probable range of operating conditions that will stress the Bulk-Power System.

1698. MidAmerican believes that the proposal to require sensitivity studies to "bracket" the range of probable outcomes and determine critical system conditions is reasonable. It states that, while critical conditions may be determined in a similar manner for the different TPL Reliability Standards, different critical conditions are pertinent to each Reliability Standard. For example, thermal overloads occur under peak load conditions and dynamic instability occur under light load conditions.

1699. Entergy does not object to an assessment of critical system conditions using the factors identified in the NOPR,[427] but it contends that the Commission's guidance is problematic to the extent that it may require constructing facilities to address potential constraints identified through these assessments. Entergy states that such construction may not create a desirable result and may instead threaten reliability. For example, assessing a system using alternative generation dispatch and transaction patterns could bias a transmission provider in favor of transmission plans that benefit a specific generator or set of generators.

1700. SDG&E sees the Commission's treatment of sensitivity studies and critical system conditions as requiring transmission planning entities to exercise judgment in determining the scope, content and number of their sensitivity studies so that they are appropriate given unique system characteristics and reasonably anticipated contingencies. SDG&E state that this guidance is welcome and should be reflected in future Requirements.

1701. MISO agrees that planning entities should have a process to identify appropriate critical system conditions for planning purposes. However, it does not believe that the

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[427] Id. at P 1061.

Reliability Standard needs to be prescriptive in terms of the specific sensitivities that should be evaluated. If an entity's approach to selecting the critical planning conditions is appropriate, sensitivities to variations from these conditions are unnecessary. MISO and Northern Indiana state that requiring sensitivities in planning studies as a mandatory standard practice could result in unnecessary additional analysis that could overwhelm the planning process and detract from more appropriate focused analysis and evaluation of solutions.

1702. EEI and APPA state that the Commission's proposal on sensitivity studies would add an unnecessarily redundant process that ignores the totality of the studies contained in study libraries that inform planners' decisions. The historical libraries of system studies provide a strong base for selecting critical transmission system conditions. EEI believes that the knowledge and experience of planners who have conducted these studies provides reliable guidance and that a new array of sensitivity analyses would offer no additional benefit over existing practices.

1703. Regarding specific variables to be included in sensitivity studies, EEI and APPA note that load power factors, controllable loads and DSM at specific locations and outages of reactive devices have much more to do with distribution operations planning than long-term system planning. They state that while transmission system planners will study a broad range of combinations of substation loadings, system configurations and resource availabilities over the planning horizon, changes in the variables of the sort identified by the Commission have very little influence on the long-term study outcomes except for the loss of load that could occur under extreme circumstances. MISO believes that transmission reactive power devices should be treated like any other transmission facility and included in the required contingency analysis. The current Reliability Standards are not explicit in this regard, and MISO agrees that this would be an appropriate clarification. It believes that power factor sensitivity studies are best suited for operational planning studies rather than long-term planning since corrective actions have relatively short lead times. In regard to alternative dispatch scenarios, MISO states that if a variation from the expected dispatch leads to unacceptable performance, it becomes an economic planning question, rather than a planning standard issue, whether expansion should be undertaken or whether the dispatch becomes a congestion cost.

(b) Commission Determination

1704. In response to Entergy's comments, the Commission reiterates the statement from the NOPR[428] that the results of the sensitivity studies would be used to document the

[428] Id. at P 1061.

selection of critical system conditions and study years used in assessing system conditions. The Commission notes that it is not the purpose of sensitivity studies to identify remedial actions, but, as stated in the NOPR, if different scenarios that lead to criteria violations are probable they require mitigation plans.[429] Entergy goes on to state that constructing facilities, the need for which is determined through sensitivity studies, may not create a desirable result, in that they may bias transmission plans towards a specific generator or set of generators and as a result may threaten reliability. The Commission disagrees that constructing well-planned facilities may threaten reliability. The planning process should anticipate any inter-regional impacts, and the net result should be higher local and inter-regional reliability. In any case, we are not requiring the construction of additional facilities.

1705. MISO, EEI, APPA and others question the value of sensitivity studies and their role in mandatory Reliability Standards given the knowledge and experience of planners and the historical library of system studies. The Commission notes that while specificity was not required in the regime of voluntary standards, it is required in a regime of mandatory Reliability Standards to ensure consistency in system assessment and provide clear and measurable requirements. Further, as stated in the NOPR[430] and concurred with by commenters to the Staff Preliminary Assessment, system conditions are as important as contingencies in evaluating the performance of present and future systems. Indeed, Table 1 lists the contingencies to be evaluated, but there is no corresponding requirement for selecting critical system conditions.

1706. The Commission believes it is important to clarify the type of analysis required in determining critical system conditions, which is the intent of the directed modifications on sensitivity studies. The Commission proposed in the NOPR a range of variables to be included in sensitivity studies, specifically: firm transfers, demand levels, existing and planned facilities, reactive power resources, control devices, load power factors, generation retirements, generation dispatch, transaction patterns, controllable loads, DSM and transmission outages including outages of reactive power devices.[431] The Commission also stated that it is not precluding other approaches to defining and documenting critical system conditions that have proven to be effective. The Commission also notes that in analyzing contingencies as part of Requirement R1.3.1 in Reliability Standards TPL-002-0 through TPL-004-0, not all contingencies need be

[429] Id. at n.324.

[430] Id. at P 1046.

[431] Id. at P 1047.

assessed for every system element but only those that would produce the more severe reliability impacts with documentation of selection rationale. The same applies to the range of variables specified for sensitivity studies. The Commission expects that the full range of variables will be considered, but only those deemed to be significant need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

iii. Element-Based vs. Event-Based Contingencies

1707. The Commission stated in the NOPR that planning Reliability Standards must influence system design and not the other way around.[432] To achieve this objective, planning Reliability Standards should promote system designs that result in the minimum set of elements being removed from service for "unanticipated failures of system elements."[433] The NOPR goes on to say that the Commission believes that the simulations used in planning assessments should faithfully duplicate what will happen in the actual power system and not a generic listing of outages. The Bulk-Power System also must be operated, and planned to be operated, within a number of conditions after a contingency or cyber event. The contingency can be a sudden disturbance or an unanticipated failure of any system element. If a specific portion of the system has been designed such that the response to a failure results in multiple lines, transformers, generators, circuit breakers, etc., being removed from service, the Commission proposed that this is what should be simulated.[434]

(a) Comments

1708. National Grid, MidAmerican and SDG&E support the principles set forth in the NOPR. National Grid states that event-based planning is a more robust form of contingency analysis than element-based planning because the former focuses on contingencies regardless of how many elements may be affected while the latter focuses

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[432] Id. at P 1049.

[433] Section 215(a) of the FPA defines "Reliable Operation" 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 sudden disturbance, including a Cybersecurity Incident, or unanticipated failure of system elements" (emphasis added).

[434] With respect to failure, the element includes a single transmission line, transformer, generator or single pole of a DC line.

on losses of specific elements that may not have a direct relationship to the severity of the impact on or risks to reliability. As such it supports the Commission's statement that "simulations should faithfully duplicate what will happen in the actual power system and not a generic listing of outages."[435]

1709. MidAmerican states that it supports the Commission's proposal to interpret a "single contingency" to include all elements of the system, irrespective of their number, that go out of service in response to failure of a single element, as it has historically performed this analysis as a part of normal planning in the interest of reliability. MidAmerican is concerned, however, that this proposal may be too restrictive for system planning, particularly with regard to the double contingencies of Category C. It states that if a multi-element single contingency occurs first, as part of system adjustment, the reliability coordinator or transmission operator will switch back the unfaulted elements to service prior to the next contingency. Therefore this N-1-1 contingency at its worst will consist of a single element outage followed by a multi-element outage. Therefore MidAmerican states that the extent of a multiple-element single contingency is better determined through coordinated efforts of neighboring systems in conjunction with the planning authority and reliability coordinator.

1710. SDG&E agrees that further modifications to the TPL Reliability Standards should be guided by the NOPR's directive that simulations should faithfully duplicate what will happen in the actual power system and not a generic listing of outages. However, it states that the Commission should provide further guidance in defining an event so that planning studies can assess electrical system contingencies consistently and numerically. A simulation that faithfully duplicates reasonably expected scenarios will necessarily involve the transmission planner's sound engineering judgment and knowledge of elements that would be expected to be removed from service during the contingency. SDG&E states that the updated TPL Reliability Standard should reflect and implement these concerns.

1711. EEI believes the planning Reliability Standards and practices clearly reflect the language in FPA section 215 regarding "element based" planning. Planners study single contingency and multiple contingency events covering a broad range of system elements and not a list of generic outages.

1712. TANC recommends that the Commission direct that transmission planning in the West be based on probability of an event occurring and the severity of the consequences, rather than on a deterministic approach that uses single and multiple contingency

[435] NOPR at P 1049.

categories as exemplified by Table 1. It states that WECC has assessed the probability of an event occurring for each category and assigned probabilities accordingly. TANC states that to be more cost effective and efficient, investments to remedy a problem should be based on a combination of the probability of the occurrence of the event and the severity of the associated consequences.

1713. In response to the Commission's request in the NOPR for comment on whether planning for cyber security events should be addressed in the planning Reliability Standards or in the Critical Infrastructure Protection (CIP) Reliability Standards,[436] MidAmerican, EEI, APPA, ISO-NE and SoCal Edison state they believe that events requiring study under the CIP Reliability Standards should be included in that specialized forum rather than the TPL Reliability Standards. Such events are identified using approaches provided for in the CIP Reliability Standards. Therefore the best place to explore those events and determine their impacts using the full background of the information about the events is the CIP Reliability Standards, although some of these events will require implementation of elements from other Reliability Standards.

1714. National Grid and International Transmission take the view that cyber security incidents are no different than other events that remove single or multiple elements from service at a single time and require analysis of system impacts. Planning assessment for cyber security incidents therefore is most appropriately addressed in the TPL Reliability Standards. International Transmission states that although Table 1 of the TPL Reliability Standards does not list the initiating event, cyber security events could be included in the list of contingencies as an initiating event. National Grid cautions that provisions detailing specific cyber security protections should be addressed in CIP Reliability Standards, and emergency response procedures for response to cyber security events should be addressed in EOP Reliability Standards.

(b) Commission Determination

1715. Several commenters[437] agree with the Commission's statement in the NOPR[438] that "simulations should faithfully duplicate what will happen in the actual power system and not a generic listing of outages." It follows that in simulating the failure of a single element, as required in Category B of TPL-002-0, all of the elements that are removed

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[436] Id. at P 1050.

[437] National Grid, MidAmerican and SDG&E.

[438] NOPR at P 1049.

from service to isolate the single faulted element should be modeled in the simulation rather than restricting the simulation to just the single faulted element, as Table 1 of TPL-002-0 implies. As SDG&E notes, this will require the transmission planner's sound engineering judgment and knowledge of elements that would be expected to be removed from service during the single contingency. The Commission agrees with MidAmerican that for Category C contingencies of TPL-003-0, the worst N-1-1 contingency would be a single element outage followed by a multiple element outage, provided that following the first N-1 contingency, capability exists to switch the unfaulted elements back into service promptly, i.e., within 30 minutes, as part of the adjustments that the Reliability Standard allows.

1716. SDG&E agrees that simulations should faithfully duplicate what will happen in the actual power system and not a generic listing of outages, but it seeks Commission guidance on how an event should be defined. In the Commission's view, a single contingency consists of a failure of a single element that faithfully duplicates what will happen in the actual system.[439] Such an approach is necessary to ensure that planning will produce results that will enhance the reliability of that system. Thus, if the system is designed such that failure of a single element removes from service multiple elements in order to isolate the faulted element, then that is what should be simulated to assess system performance. Accordingly, the Commission directs the ERO to submit modifications to Category B of Table 1 consistent with this approach. Entities whose systems may have been planned and designed on the basis of a different approach to single contingencies should work with the ERO in developing plans to transition to this approach.

1717. The Commission disagrees with EEI that the planning Reliability Standards and practices clearly reflect the language in FPA section 215 regarding "element based" planning. Section 215(a) of the FPA defines "Reliable Operation" as "operating the elements of the Bulk-Power System" within certain limits so that "instability, uncontrolled separation or cascading failures of that system will not occur as a result of sudden disturbances, including a cyber security incident, or unanticipated failure of system elements." This definition specifies an ultimate goal and does not dictate any specific type of planning. The approach to a single contingency the Commission has set forth above ensures that transmission planners analyze contingencies based on the actual number of elements that would be removed from service in the actual power system for "an unanticipated failure of system elements," rather than simulating only the limited number of outages listed in Table 1 of the TPL Reliability Standards. In short, the

[439] A "single element" means a transmission line, a transformer, a generator or a single pole of a DC line.

Commission's approach speaks directly to the problem that the statute requires be addressed.

1718. In response to TANC's proposal that the Commission direct that probabilistic approaches to transmission planning be adopted in the West, the Commission notes that proposals of this type should be submitted to the ERO for approval as a regional difference. If such a proposal is developed for the Western Interconnection, to assist the ERO and the Commission in its assessment of such a proposal, we encourage WECC to also submit operating information that quantifies the level of actual performance that has been achieved with the present deterministic planning approach. Such performance metrics would assist us in determining whether a probabilistic approach would result in equivalent or higher levels of Reliable Operation than currently achieved.

1719. In response to the comments received on how best to address planning for cyber security events, it is clear that the nature of risks as well as the contingencies and measures needed to overcome them are best addressed in the CIP Reliability Standards because this forum has the specialized knowledge to deal with cyber security matters. However, the system impacts of cyber security events are best addressed in the TPL group of Reliability Standards, particularly TPL-004-0, alongside other similar common mode failures. Emergency plans and restoration procedures to deal with cyber security events are best addressed by the EOP Reliability Standards because these Reliability Standards deal with emergency plans and restoration procedures. The Commission directs the ERO to consider appropriate revisions to the Reliability Standards through its Reliability Standards development process to address these matters.

iv. Spare Equipment Strategy

1720. The Commission stated in the NOPR that while Reliability Standards TPL-002 through TPL-004 require consideration of planned outages at those demand levels for which planned outages are performed, they do not address situations where critical equipment, such as a transformer or phase angle regulator, may be unavailable for a prolonged period. Including such a requirement would ensure the coordination of contingency plans, including the entity's spare equipment strategy, to return facilities to service in a timely manner for reliability. The Commission therefore proposed that the Reliability Standards be modified to include a new requirement to assess the reliability impact of an entity's existing spare equipment strategy.

(a) Comments

1721. SDG&E states that it generally supports a new requirement that would include assessing the reliability impact of an entity's spare equipment strategy, but several key features of this requirement need clear and thorough definition. For example, the requirement should provide an industry-developed finite list of "critical items," and the meaning of "impact IROL" would need further clarification. SDG&E submits that, absent a careful delineation of the requirement and its terms, this proposed modification will not enhance system reliability

1722. MidAmerican, LPPC, EEI, APPA and SoCal Edison state that they understand the Commission's concern about spare equipment planning and acquisition strategy. However, MidAmerican and LPPC note that typically spare equipment strategy is of more concern in operating studies than planning studies. MidAmerican states that most equipment can be installed in a year or less even if it is not on hand. It maintains that it may be appropriate to add this requirement to the TPL Reliability Standards because scarcity of new equipment due to recent disasters has led to longer lead times. LPPC cautions the Commission that associating spare equipment strategy with the planning Reliability Standards could lead to Reliability Standards that overstep the limits of FPA section 215(i)(2) through proposing a Reliability Standard that would, indirectly, come close to authorizing the ERO to order the construction of transmission capacity. LPPC states that it is unclear how to separate: (1) requiring a utility to assess its spare equipment strategy; (2) requiring a utility to have spares on hand to meet anticipated reliability needs and (3) requiring a utility to use spare equipment to meet the reliability needs.

1723. EEI, APPA and SoCal Edison question the need to address this issue in the context of a Reliability Standard. EEI states that, where delivery delay could occur for long lead time equipment such as transformers, the existing Reliability Standards provide for study of the full range of single and multiple-event contingencies with that piece of equipment modeled off-line. According to EEI, the Commission's general concern regarding the current policies and practices related to equipment acquisition can be addressed in the NERC forum without revising the Reliability Standards. This forum also will account for the need to protect information on critical infrastructure facilities.

(b) Commission Determination

1724. Several commenters stated that they understand the Commission's concern about requiring a reliability impact assessment of an entity's spare equipment strategy, but they question the need to address this issue in the Reliability Standards in general and the transmission planning Reliability Standards in particular. The Commission disagrees with EEI that the existing Reliability Standards provide for situations that cover the delivery of long lead time equipment, such as transformers, by requiring a full range of single and multiple contingency studies with that equipment modeled off-line. TPL-002-0 and TPL-003-0 currently state explicitly in Requirement R1.3.12 that the assessments shall include planned outages of bulk electric equipment at those demand levels for which planned (including maintenance) outages are performed. However, equipment such as transformers may not be available for service for a year or more and therefore their unavailability cannot be scheduled when system conditions permit.

1725. The current Reliability Standards do not require assessment of the reliability impacts that result from not having this long lead time equipment available under those system conditions likely to be experienced during the course of the year when the system is heavily stressed. Clearly the consideration of planned outages is inextricably linked with spare equipment strategy. Thus, if an entity's spare equipment strategy for the permanent loss of a transformer is to use a "hot spare" or to relocate a transformer from another location in a timely manner, the outage of the transformer need not be assessed under peak system conditions. However, if the spare equipment strategy entails acquisition of a replacement transformer that has a one-year or longer lead time, then the outage of the transformer must be assessed under the most stressed system conditions likely to be experienced. Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy.

1726. LPPC questions whether the Commission's proposal oversteps the limits of FPA section 215(i)(2) because assessing the impact on reliability of an entity's decision concerning spare equipment could force an entity to construct transmission capability. FPA section 215(i)(2) prohibits the ERO and the Commission from ordering the construction of "additional" transmission capacity. A requirement to assess the reliability impacts of an entity's spare equipment strategy is no different than a requirement to assess the reliability impacts of any number of contingencies. Even if an entity was forced to conclude that its spare strategy was inadequate, rectifying the problem would not require that the entity construct "additional" transmission capacity, only that it possess adequate spares, or take other appropriate action, to ensure the reliable operation of its system. In short, while FPA section 215(i)(2) precludes ordering expansion of transmission or generation capacity, section 215 clearly authorizes requiring entities to take appropriate steps to ensure that their existing capacity operates reliably.

1727. With regard to SDG&E's suggestion to clarify specific elements of this Reliability Standard, we direct the ERO to consider such suggestions in its Reliability Standards development process.

v. Resource Information for Planning

1728. The Commission in the NOPR requested comments on whether transmission planners and planning authorities are currently able to obtain and validate resource information on new generation and retirements for assessments over the ten year planning horizon. Further, if transmission planners and planning authorities currently experience difficulty obtaining this information, the Commission asked how this potential information gap should be addressed.[440]

(a) Comments

1729. The Commission noted in the NOPR that transmission planning requires information on forecasted loads and probable generation plans to supply those loads.[441] While the MOD Reliability Standards require information on forecasted loads, energy, interruptible loads and direct control load management over the next ten years, there is no requirement to inform transmission planners and planning authorities of new or retiring generation resources. The Commission sought comments on whether transmission planners and planning authorities are currently able to obtain and validate resource information on new generation and retirements for assessments over the ten year planning horizon and if not, how this potential gap should be addressed.

1730. NERC stated that it and the regional reliability organizations have generally not had problems obtaining the data and information required for reliability assessments. NERC believes that given its authority and responsibility as the ERO, it will be successful in obtaining all the data and information it needs to conduct reliability assessments without the need to include these requirements in Reliability Standards. In the event that it and the regional reliability organizations are unsuccessful in obtaining such data and information, the ERO will turn to the Commission for assistance.

1731. ISO-NE states that as the planning authority it obtains resource plans for additions, capacity changes, deactivations and retirements for a ten year planning horizon. Although these plans cannot be expected to occur exactly as projected, they serve as useful information in projecting needs for new resources or new or upgraded transmission facilities. As the administrator of wholesale electric markets, ISO-NE relies on the development of robust market rules accompanied by a regulated transmission planning process to achieve its goal of encouraging the availability of sufficient resources. ISO-NE states that planning for the introduction and retirement of specific resources ten years in advance not only is unnecessary, it is inconsistent with relying on markets to determine the most efficient allocation of resources to meet system needs.

1732. FirstEnergy and SoCal Edison state that currently they are able to obtain information regarding new generation from publicly available information and from the

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[440] NOPR at P 1060.

[441] Id.

generator interconnection queue. Typically, a generation application that is in the interconnection agreement phase is considered for transmission planning studies. New generation has a longer lead time, and thus information on it may be available sooner than information about retirements, which have a much shorter lead time before they are announced. FirstEnergy states that despite the unpredictability of such information, assessments can be conducted using assumptions of new generation and retirements, and the results should recognize that the inputs were based on reasonably foreseeable conditions.

1733. In contrast, CAISO, National Grid and Northern Indiana state that obtaining resource information has been a challenge given that the Reliability Standards impose no obligation on generation owners to provide information to planning authorities and transmission service providers about new and retiring generation. Northern Indiana states that this issue is among the greatest challenges for its transmission planners. Because transmission planning is focused on matching the source to the sink, having the sources unknown, in the case of future generation, creates a weakness in the entire transmission planning process. Northern Indiana contends that weakness will be difficult to eliminate because information about siting of future generation units is considered commercially sensitive information. This lack of information makes it difficult for transmission planners to reflect accurately the amount and location of new generation in their transmission studies. CAISO agrees that there is a gap in its ability to obtain this information particularly from adjacent balancing authorities. CAISO suggests that to bridge this gap, generator owners and operators should be required to provide data about new and retiring generation to their planning authorities and that the planning authorities be required to share this information with neighboring balancing authorities, subject to appropriate non-disclosure agreements. CAISO notes that there currently exists no centralized database for the collection and dissemination of this information within the Western Interconnection.

1734. National Grid states that forward capacity markets and the generation interconnection queue provide some understanding about new generation but only for five to seven years, even though transmission planning horizons are considerably longer. National Grid and Northern Indiana contend that it may be reasonable to conclude that certain areas are prime locations for new resources, particularly inexpensive and renewable resources that are dependent on "non-transportable" fuel supplies. National Grid states that the Commission should embrace efforts of transmission planners to facilitate new generation entry when such initiatives are expected to increase customer access to inexpensive, renewable and diverse sources of supply.

1735. Entergy believes that from a transmission provider's point of view it would be desirable to have LSEs provide ten or even five-year resource forecasts. Entergy recognizes that such a requirement may not be practical when LSEs depend significantly on short-term purchases due to the abundance of independent power producers or in areas that have an locational marginal pricing -like market structure. MISO states that its experience suggests that LSEs do not identify new generation resources except in very general terms past the second or third year. In most cases LSEs show future capacity requirements served from generic base load and peaking power resources or from potential contract purchases with no information on location. This increases the difficulty of accurate long-range transmission planning studies.

1736. National Grid states that it is also vitally important to acknowledge that generation retirements may pose a greater threat to reliability in some areas of the country than the slow down of new generation. Because required notice periods for retirements may be as little as ninety days in some areas, it is imperative that transmission planners use a robust statistical approach to identify vulnerable sources of generation and conduct such modeling as an integral part of the transmission planning process.

1737. MISO states that planning assumptions around generation retirements are particularly difficult because such assumptions are driven by complex economic factors that may or may not prevail. While MISO has the tools to project what unit may be more likely to retire than others, it contends that the preferred approach is to have in place tariff provisions that require suppliers to announce retirement intentions six months in advance of the retirement. This permits reliability studies to be performed with certainty and corrective actions to be implemented that could include placing the unit on contract to continue operations until appropriate operating measures or system expansions can be made.

1738. SoCal Edison states that business decisions by generator owners to retire or mothball units are outside of SoCal Edison's control, and generally SoCal Edison does not receive this information in a timely manner for transmission planning studies.

1739. National Grid urges the Commission to support longer planning horizons. It states that in many respects, the ten year planning horizon may be too short a time frame for assessing transmission needs, particularly with regard to long distance extra high voltage facilities that pose considerable siting and permitting challenges. Establishing planning horizons that are shorter than transmission construction lead times may create gaps where the identification of a reliability need to which transmission may be the best solution occurs too late to head off the identified reliability violation. National Grid states that PJM is establishing a fifteen year planning horizon that will accommodate large-scale projects that are needed for reliability and to support regional transactions.

1740. MISO and International Transmission note that while it is important for planners to have quality information on available resources, the enabling legislation for the ERO specifically excludes authority regarding resource adequacy. MISO states it is not certain how far the Reliability Standards can go. International Transmission states that, in the absence of a standard on resource adequacy, transmission service providers must use their judgment on potential new generation or retirements to create base cases and plan the system accordingly.

1741. Reliant states that, while section 215 of the FPA requires the ERO to develop Reliability Standards that provide an adequate level of Bulk-Power System reliability, the proposed Reliability Standards surprisingly lack any substantive consideration of planning reserve obligations to ensure capacity available to meet the needs of a reliable system. Reliant proposes that each regional reliability organization develop and enforce its own minimum planning reserve margin. Such a program would be critical to the development of new generation, demand response and distributed generation resources and allow each region to retain its own autonomy in developing its own resource adequacy standards.

1742. Process Electricity Committee supports long-term planning as a vital part of any economic and thorough set of Reliability Standards. However, it is concerned that transmission service providers who are also market participants will have an incentive to exploit commercially sensitive data on generation plans to the disadvantage of other competing suppliers. Process Electricity Committee asks the Commission to clarify that transmission planners may not use the Reliability Standard to obtain and exploit such information, and it urges the Commission to take all appropriate measures to guard against such abuse.

(b) Commission Determination

1743. Several commenters addressed separately the availability of information on new generation resources and generation retirements, given that these have very different lead times. NERC, ISO-NE and others appear to be able to acquire the resource information they need on new resources and retirements for reliability assessments. Others, such as National Grid and MISO, have had difficulty in obtaining this information in a timely manner, particularly as it relates to generation retirements.

1744. The Commission disagrees with ISO-NE's statement that planning for the introduction of resources ten years in advance is not necessary. The existing Reliability Standard requires that the planning horizon must take into account the lead times for siting and permitting of new long-distance transmission lines and other solutions that can exceed ten years. In short, the need for long-term planning has already been widely recognized. The Commission agrees with National Grid that establishing planning horizons that are shorter than transmission lead times may create gaps where the identification of a reliability need to which transmission may be the best solution occurs too late to avert the identified reliability violation. Indeed, this point is supported by the fact that PJM is establishing a fifteen year planning horizon.[442]

1745. In the absence of information about future generation resources required for transmission planning the Commission notes that entities conduct assessments using assumptions based on the knowledge that certain areas are prime locations for new resources, particularly those resources that use non-transportable fuels. National Grid states that generation retirements may pose a greater threat to reliability in some areas than the slowdown of new generation construction. As a result, it states that it is imperative that transmission planners use robust statistical approaches to identify vulnerable sources of generation and conduct such modeling as an integral part of the transmission planning process. The Commission understands this as a further endorsement of its proposal to require a full range of sensitivity studies discussed above.

1746. MISO, International Transmission and Reliant raise important issues about the absence of a Reliability Standard on resource adequacy. Reliant points out the inconsistency between the statutory requirement to provide an adequate level of Bulk-Power System reliability and the lack of any substantive consideration of planning reserve obligations to ensure capacity is available to meet the needs of a reliable system. In the same vein, the Commission notes that Requirement R7 of TOP-002-0 requires each balancing authority to plan to meet capacity and energy reserve requirements in the operating time frame but that there is no explicit corresponding consideration required of generation reserves in the planning time frame.

1747. Section 215(a)(3) of the FPA makes clear that enforceable Reliability Standards may not address requirements to enlarge facilities or construct new generation capacity. We have noted that when a state or appropriate jurisdictional entity has such a requirement, it should be included in transmission planning analysis. Resource adequacy levels are set to achieve a number of goals, one of which is system reliability. Our jurisdiction is to approve and enforce Reliability Standards that provide for an adequate level of reliability for the Bulk-Power System. The TPL group of Reliability Standards includes load growth, changes in the transmission topology, existing generation, generation retirements, and confirmed new generation as inputs to the analyses. When an entity does not meet a reliability criterion, including the inability of generation to be deliverable to load, mitigation plans are required. Although the Commission anticipates that some of those mitigation plans may include new generation, we do not require this.

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[442] See http://www.pjm.com/contributions/pjm-manuals/manuals.html

1748. Some entities have proposed possible solutions to address the gap of inadequate and unreliable resource information for long-term planning as required by the TPL group of Reliability Standards. CAISO suggests that generator owners and operators be required to provide data on new generation and retirements to their planning authorities. Entergy proposes requiring LSEs to provide this information, but recognizes that this approach has its limitations. MISO contends the preferred approach to retirements is to have in place tariff provisions that require suppliers to announce retirement intentions six months in advance of retirements. Process Electricity Committee is concerned about the implications of sharing non-public transmission or customer information which could then be exploited to the disadvantage of competing suppliers. The Commission's Standards of Conduct addresses the sharing of such information and generally prohibits the sharing of commercially sensitive information between the transmission organization and affiliated merchant functions.[443] In response to Process Electricity Committee, the Commission will continue to enforce the information sharing prohibition in the Standards of Conduct.

1749. The responses to the Commission's inquiry on these matters are helpful. The comments further point out the importance of conducting a wider range of sensitivity studies on generation scenarios. However, the Commission is not directing at this time any modifications to address the Commission's concerns.

vi. Sharing of Information with Neighboring Systems

1750. In the NOPR, the Commission stated that, because neighboring systems may be adversely impacted, such systems should be involved in determining and reviewing system conditions and contingencies to be assessed in connection with Requirement R1.3 of TPL-001-0 to TPL-004-0.[444]

(a) Comments

1751. EEI, APPA, FirstEnergy, ERCOT and SDG&E support or acknowledge the value of sharing of various kinds of planning information with neighboring systems. FirstEnergy states that the proposed requirement that system conditions and contingencies assessed be shared and reviewed by neighboring systems will improve communications with interconnected companies. This process was established among former ECAR companies through the "ECAR Peer Review Process," and FirstEnergy

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[443] See Order No. 2004.

[444] NOPR at P 1063.

recommends that regional reliability organizations be encouraged to establish a similar process going forward. EEI and APPA state that sharing of various kinds of planning information, including expected generation additions and retirements, planned outages, demand forecasts and estimates of firm transfers will go a long way to improving the quality and consistency of planning study efforts. However, it is not clear to EEI whether a formal Reliability Standard would be the most effective approach. An alternative could be to request that NERC oversee an informal process to explore alternatives and report back to the Commission by a specific date. Although ERCOT states that this proposal is a sensible recommendation, it also states that it would not be appropriate for ERCOT since the transmission service provided there is not subject to interruption by the ISO, and outbound flows are also not interrupted if there is a shortage of capacity.

1752. SDG&E notes that under the auspices of the CAISO it regularly convenes stakeholder meetings with the general public, neighboring utilities, generator owners, regulators and the CAISO. In these meetings, SDG&E reviews the grid assessment process and receives comments from participants about all aspects of its process. As a member of WECC, SDG&E states that it also holds meetings to discuss inter-area projects that SDG&E has proposed to construct. This review group consists of neighboring utilities, generator owners and other stakeholders who are members of WECC. Similarly, SDG&E maintains that it participates in other California-based utility review groups. SDG&E finds that these existing processes provide ample opportunities for regular sharing of relevant information with neighboring transmission planning entities. It thus recommends that the Reliability Standards development process take into account existing forums for apprising neighboring utilities of current and anticipated transmission planning issues and projects. If the Commission believes additional communications are needed, SDG&E strongly recommends that the Commission, through NERC or the applicable Regional Entity, specify in greater detail the nature and periodicity of the information to be shared pursuant to the TPL Reliability Standards.

1753. SoCal Edison states that TPL-001-0 is for systems operating under normal conditions, and as such there should not be a need for any review by neighboring systems.

(b) Commission Determination

1754. Most commenters agree with the Commission's proposal that neighboring systems be involved in a peer review of system assessments in connection with Requirement R1.3 of TPL-001-0 through TPL-004-0. Given that neighboring systems assessments by one entity may identify possible interdependant or adverse impacts on its neighboring systems, this peer review will provide an early opportunity to provide input and coordinate plans. The Commission therefore disagrees with SoCal Edison's view that there is no need for any review by neighboring systems for TPL-001-0. For example, the planning authorities needs to be consistent in the line flow values that they use.

1755. While supporting the concept of a peer review, EEI questions whether making this a Requirement in a Reliability Standard is the most effective approach or whether NERC should explore alternatives and report to the Commission by a specific date. The Commission sees no reason why peer reviews should not be part of a Reliability Standard since TPL-001-0 through TPL-004-0 already include in Requirement R1.3 a review of assessments by the associated regional reliability organization. The Commission understands that some regions include peer review as part of their procedures. Accordingly, to ensure that neighboring systems are not adversely affected and to provide an early opportunity for input and coordination of plans, the Commission directs the ERO to include these modifications to the Reliability Standard through its Reliability Standards development process to provide for the appropriate sharing of information with neighboring systems.

1756. The Commission has taken action on its OATT reform initiative in Order No. 890. In that order, the Commission encourages the formation of regional planning processes and economic planning studies.[445] Sharing of information and peer review are the first steps in a regional planning process. The Commission provides guidance and direction on these subjects in our discussion of Reliability Standard TPL-005-0.

b. System Performance Under Normal (No Contingency) Conditions (TPL-001-0)

1757. Reliability Standard TPL-001-0 deals with planning related to system performance under normal conditions, i.e., a situation where no system contingency or no unexpected failure or outage of a system component has occurred.[446] The Reliability Standard seeks to ensure that the Bulk-Power System is planned to meet the system performance requirements under these normal conditions by requiring the transmission planner and the planning authority to evaluate their transmission system annually and document the ability of that system to meet the performance requirements established in the Reliability

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[445] Order No. 890 at P 526, 542.

[446] The NERC Glossary defines a "contingency" as "[t]he unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element." NERC Glossary at 3.

Standard under conditions where no system contingencies are present.[447] Meeting these requirements means two things. First, when all system facilities are in service and normal operating procedures are in effect, the system can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services at all demand levels over the range of forecast system demands. Secondly, the system remains stable and within the applicable ratings for thermal and voltage limits, no loss of demand or curtailed firm transfers occurs, and no cascading outages occur. TPL-001-0 applies both to near-term and longer-term planning horizons.

1758. The Requirements of TPL-001-0 specify that the planning authority and transmission planner must demonstrate through a valid assessment that the Reliability Standard's system performance requirements can be met. The assessment must be supported by a current or past study and/or system simulation testing that addresses various categories of conditions to be simulated as set forth in the Reliability Standard to verify system performance under normal conditions. When system simulations indicate that the system cannot meet the performance requirements set forth in the Reliability Standard, a documented plan to achieve system performance requirements must be prepared. The specific study elements selected from each of the categories for assessments are subject to approval by the associated regional reliability organization.

1759. The Commission proposed in the NOPR to approve Reliability Standard TPL-001-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-001-0 that: (1) requires that critical system conditions be determined by conducting sensitivity studies; (2) requires that system conditions and contingencies assessed be reviewed by neighboring systems; (3) modifies Requirement R1.3 to substitute the reference to regional reliability organization with Regional Entity; (4) requires consideration of planned outages of critical equipment and (5) modifies footnote (a) of Table 1 to not apply emergency ratings to compare stresses on the system under normal conditions as recommended by the Transmission Issues Subcommittee of the NERC Planning Committee[448] and require that normal facility ratings be in accordance with

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[447] The performance requirements are set forth in Category A of Table I of the Reliability Standard.

[448] See NERC Transmission Issues Subcommittee Report: Evaluation of Criteria, Methods and Practices Used in System Design, Planning and Analysis in Response to NERC Blackout Recommendation 13c. Appendix B, November 28, 2005.

Reliability Standard FAC-008-1 and that normal voltages be in accordance with Reliability Standard VAR-001-1.[449]

i. Comments

1760. APPA agrees with the Commission that TPL-001-0 is sufficient for approval as a mandatory and enforceable standard.

1761. MidAmerican and others generally support the Commission's proposal to improve TPL-001-0 but caution that: (1) planned outages should only be considered at load levels and conditions under which they commonly occur and (2) emergency ratings should recognize the varying time frames of overloads that result from various contingency events. Further, MidAmerican states that, while it is appropriate that planning margins for normal voltages be calculated in accordance with VAR-001-1 as proposed by the Commission, it would be better if the proposed modification provided that voltage criteria do not conflict with VAR-001-1. Northern Indiana agrees with the Commission's position regarding consideration of planned outages and states that it considers them currently in its transmission planning studies. International Transmission states that both planned outages of critical equipment and the extended forced outages of similar equipment should be considered. FirstEnergy states that planned outages should be accounted for at load levels and conditions under which they commonly apply.

1762. Other commenters disagree that planned outages of critical equipment should be included in TPL-001-0.[450] They contend that the Reliability Standard has a very simple aim, namely, to examine whether a system can perform under normal system intact conditions, i.e., when all elements are in service and operating as expected. The outages contemplated are appropriate for TPL-002-0 through TPL-004-0 where the planned outage could be a line outage caused by a maintenance project that extends into a period where the system is heavily loaded. SDG&E states that for near-term planned outages, the transmission planning entity should retain an appropriate amount of latitude to plan the outage's timing and details and to modify them as necessary. SDG&E comments that, for outages planned with a more distant horizon (one year or longer), this information can be accounted for in sensitivity analyses. SoCal Edison states that no information will be available about planned outages of critical equipment to be used for short-term (five years) or long-term (10 years) simulations. It may be possible to consider planned outages of critical equipment if there is a major project construction

[449] NOPR at P 1065-67.

[450] See, e.g., EEI, APPA, SDG&E, Entergy, SoCal Edison and TVA.

activity. If generators and transmission lines are out for scheduled maintenance during off-peak load conditions, then these outages should be considered.

1763. EEI supports the Commission's recommendation to modify footnote (a) in Table 1. International Transmission states that the footnotes in Table 1 are not footnotes but rather requirements for transmission system performance. These should be made requirements of the Reliability Standards so that they are more obvious and easier to monitor. APPA, LPPC and TANC recommend that changes to footnotes of Table 1 be subject to the Reliability Standards development process. They state that the footnotes have been extensively reviewed by technical experts at NERC for several years and currently represent a general consensus among these industry technical experts. Changes to the footnotes impact Table 1 and have a direct impact on the determination of the severity of consequences that were approved along with the original Reliability Standard. Therefore, the Commission should give due weight to the ERO and allow the Reliability Standards development process to resolve any existing ambiguities in the Table 1 footnotes.

ii. Commission Determination

1764. The Commission approves TPL-001-0 as a mandatory and enforceable Reliability Standard. In addition, we direct the ERO to develop modifications to TPL-001-0 through the Reliability Standards development process, as discussed below.

1765. In assessing system conditions, Requirement R1.3.1 of TPL-001-0 requires entities to cover "critical system conditions and study years," as deemed appropriate by the entity performing the study. As stated in the NOPR, system conditions are as important as contingencies in evaluating the performance of present and future systems,[451] and yet TPL-001-0 does not specify the rationale for determining critical system conditions and study years. Consistent with our discussion of the issue above regarding sensitivity studies and critical system conditions, the Commission concludes that proposed modification (1), which requires that critical system conditions be determined by conducting sensitivity studies, is justified. Accordingly, we direct the ERO to modify the Reliability Standard to require that critical system conditions and study years be determined by conducting sensitivity studies with due consideration of the range of factors outlined above.

1766. Requirement R1.3 of TPL-001-0 states that the planning authority and transmission planner must provide studies and simulations to support its planning

[451] NOPR at P 1046.

assessments, and that the specific elements selected for the study shall be acceptable to the associated regional reliability organization. Given that neighboring systems may be adversely affected, our goal is to ensure that they are involved in the determination and review of system assessments to permit an early opportunity to provide input and coordinate plans. We discussed above the issue of information sharing as it applies to the TPL group of Reliability Standards generally and, consistent with our conclusions there, we direct the ERO to modify TPL-001-0 to require a peer review of planning assessments with neighboring entities.

1767. The Commission received no comments on its proposal that Requirement R1.3 be modified to substitute the reference to the regional reliability organization with a reference to the Regional Entity. The Commission has explained the need for this modification above, and therefore it directs the ERO to modify Requirement R1.3 of TPL-001-0 to substitute the reference to the regional reliability organization with a reference to the Regional Entity.

1768. While some commenters support the consideration of planned outages at load levels for conditions under which they are performed, others disagree on the grounds that the goal of TPL-001-0 is to ensure that the Bulk-Power System can perform reliably when all elements are in service and operating as expected. The Commission notes that Reliability Standards TPL-002-0 through TPL-004-0 include consideration of planned outages, as initial system conditions, at load levels for conditions under which they are performed. Because these Reliability Standards, and not TPL-001-0, will govern the adequacy of the Bulk-Power System under planned outage conditions, the Commission will not adopt the NOPR proposal to require consideration of planned outages at load levels for conditions under which they are performed for Reliability Standard TPL-001-0. However, consistent with our discussion above on spare equipment strategy, the Commission directs a modification to this Reliability Standard to require assessments of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy. Thus, for example, if an entity's spare equipment strategy for the permanent loss of a transformer is to use a "hot spare" or to relocate a transformer from another location in a timely manner, the outage of the transformer need not be assessed under peak system conditions. However, if the spare equipment strategy entails acquisition of a replacement transformer that has a one-year or longer lead time, then the outage of the transformer must be assessed under peak loading conditions likely to be experienced. This approach will ensure that system conditions are adequately assessed.

1769. While commenters generally agree with the Commission's proposal to modify footnote (a) of Table 1, they caution that any changes to the footnotes affect Table 1 and should be reviewed through NERC's Reliability Standards development process. International Transmission states that the footnotes in Table 1 are not footnotes but rather requirements for transmission system performance and therefore should be made

Requirements in the Reliability Standard. The Commission agrees with International Transmission because this will promote clarity in and consistent application of the Reliability Standard. The Commission therefore directs the ERO to modify the Reliability Standard to address the concerns regarding footnote (a) of Table 1, including the applicability of emergency ratings and consistency of normal ratings and voltages with values obtained from other Reliability Standards. As with any modification to a Reliability Standard, modifications to TPL-001-0 should be developed through the ERO's Reliability Standards development process.

1770. Accordingly, the Commission approves Reliability Standard TPL-001-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL-001-0 through the Reliability Standards development process that: (1) requires that critical system conditions and study years be determined by conducting sensitivity studies with due consideration of the range of factors outlined above; (2) requires a peer review of planning assessments with neighboring entities; (3) modifies Requirement R1.3 to substitute the reference to regional reliability organization with Regional Entity; (4) requires assessments of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy and (5) address the concerns regarding footnote (a) of Table 1, including the applicability of emergency ratings and consistency of normal ratings and voltages with values obtained from other Reliability Standards and the concerns raised by International Transmission in regard to the footnotes in Table 1.

c. System Performance Following Loss of a Single Element (TPL–002–0)

1771. Reliability Standard TPL-002-0 addresses system planning related to performance under contingency conditions involving the failure of a single element with or without a fault, i.e., the occurrence of an event such as a short circuit, a broken wire or an intermittent connection. The Reliability Standard seeks to ensure that the future Bulk-Power System is planned to meet the system performance requirements, with the loss of one element, by requiring that the transmission planner and planning authority annually evaluate and document the ability of the transmission system to meet the performance requirements where an event results in the loss of a single element.[452] Meeting these requirements means two things. First, it means that the system can be operated following the event to supply projected firm customer demands and projected firm (non-recallable reserved) transmission services at all demand levels over the range of forecast system

[452] The performance requirements are set forth in Category B of Table 1 of the Reliability Standard.

demands. Second, it means that the system remains stable and within the applicable ratings for thermal and voltage limits, no loss of demand or curtailed firm transfers occurs, and no cascading outages occur.[453] The Reliability Standard applies both to near-term and longer-term planning horizons.

1772. TPL-002-0 specifies that the planning authority and transmission planner must demonstrate through a valid assessment that the Reliability Standard's system performance requirements can be met. The assessment must be supported by a current or past study and/or system simulation testing that addresses various categories of conditions to be simulated, as set forth in the Reliability Standard, to verify system performance under contingency conditions involving the failure of a single element with or without a fault. The Reliability Standard requires that planned outages of transmission equipment be considered for those demand levels for which planned outages are performed. When system simulations indicate that the system cannot meet the performance requirements stipulated in the Reliability Standard, a documented plan to achieve system performance requirements must be prepared. The specific study elements selected from each of the categories for assessments are subject to approval by the associated regional reliability organization.

1773. The Commission proposed in the NOPR to approve Reliability Standard TPL-002-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-002-0 that: (1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0; (2) requires the inclusion of the reliability impact of the entity's existing spare equipment strategy; (3) explicitly requires all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase "permit operating steps necessary to maintain system control" and (6) clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss.

i. Comments

1774. APPA agrees that TPL-002-0 is sufficient for approval as a mandatory and enforceable reliability standard.

[453] Footnote b to Table 1 allows for the interruption of firm load for consequential load loss.

1775. In response to the Commission's proposal[454] that NERC modify TPL-002-0, in part, because it does not address situations in which critical equipment may be unavailable for a prolonged period, Northern Indiana states that systems depicted in planning studies cannot possibly contain complete planned and forced outage schedules for the next ten years. For this reason TPL-003-0 deals with double contingencies, i.e., contingencies that allow operator intervention after the first outage, and then capture system response to an additional outage. Operator intervention includes coordination of contingency plans and may impact strategies for spare equipment, particularly for critical equipment.

1776. EEI and MidAmerican support requiring all generators to ride through the same contingencies as required for wind generators. Constellation notes that while it supports the Commission's proposed modifications to TPL-002-0, an explicit requirement that all generators stay online during the same set of Category B and C events, as is required for wind generators, is too broad. Constellation requests that the Commission modify this requirement to recognize that NRC has specific requirements for how nuclear generation must respond to disturbances on the Bulk-Power System, and that those NRC rules should apply. Moreover, Constellation generally recommends that the Reliability Standards applied to nuclear generation should be consistent with NRC requirements and that NRC rules should control in the event of conflict.

1777. NRC notes that there appears to be significant variation in the interpretation of this Reliability Standard. It states that some of its licensees interpret the TPL-002-0 Reliability Standard to state that if a licensee is operating in an N-1 condition another single contingency does not need to be considered. NRC states that its interpretation has been that the N-1 condition is always analyzed from the conditions being experienced. They state that this Reliability Standard should be clarified and recommend specific revisions to Requirements R1.6, R2.1, R2.2 and Levels of Non-Compliance.

1778. Northern Indiana expresses concern about the statement in P 1062 of the NOPR that "load models used in system studies have a significant impact on system performance. . . ." Northern Indiana believes the opposite is true, i.e., system performance has a significant impact on load models. The goal of the models is to attempt to capture system performance.

1779. MidAmerican supports the proposed clarifications to operating steps and to footnote (b). International Transmission states that more clarification should be provided for the thresholds of normal and emergency ratings. There are potential inconsistencies

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[454] NOPR at P 1081.

with respect to whether or not an entity can plan to operate above normal ratings, but below emergency ratings, and for how long.

1780. Northern Indiana also takes issue with the NOPR proposal that no load or transactions be interrupted except for consequential load loss. Attempting to reduce the probability of load loss to zero would greatly increase capital spending, and therefore increase rates to customers, and all in the name of achieving an unattainable goal. PG&E disputes that the Reliability Standard should provide limits on the magnitude and duration of consequential load loss. Determining the magnitude and consequences of load loss is a factor in the economic evaluation during the development of transmission expansion plans. This economic evaluation is not an appropriate subject for this Reliability Standard. Northern Indiana urges the Commission to acknowledge that planning studies by nature must balance infrastructure improvement and expansion against site-specific and regional load projections, using available resources. It questions whether the NOPR reflects a proper balance between the many costs involved and the benefits, if any, that would be realized.

1781. Entergy opposes the Commission's proposed guidance concerning footnote (b) to Table 1 for two reasons. First, Entergy believes the Commission should give due weight to the technical expertise of NERC and permit NERC to address these matters through Reliability Standards development process. Second, the Commission's guidance suggests that it views all transmission outages as having the same level of importance to and impact on the interconnected transmission grid. Entergy states that the Commission should recognize that the effect of transmission outages can be local in nature and have no impact on the reliability of the Bulk Power System. Removing the transmission operator's ability to shed load or enact other system adjustments as appropriate for a single contingency would result in significant facility upgrade costs simply to avoid the consequence of a local outage. Entergy requests that the Commission clarify that its guidance does not constrain the transmission operator's ability to determine the best course of action to take to address any reliability constraint that may result from these local outages.

1782. PG&E disagrees with the Commission's proposal to delete from footnote (b) of this Reliability Standard the phrase "to prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers."[455] PG&E states that this phrase permits critical system adjustments to reduce the potential for and impact of future contingencies. It would allow re-scheduling power (but not load shedding) as part of manual system

[455] Id. at P 1084.

adjustment after the first Category B contingency (first N-1) to bring the system back to a safe operating point before the next Category B contingency (second N-1). This phrase is consistent with the manual system adjustment allowed in Category C.3.[456] PG&E states that, contrary to the Commission's interpretation, footnote (c) does not capture this phrase. The difference between footnote (b) as part of Category B and Category C.3 is that footnote (b) applies before the second N-1, whereas Category C.3 applies after the second N-1. Without this phrase in footnote (b), no manual system adjustment would be allowed after a Category B contingency, which would be inconsistent with Category C.3.

1783. APPA and LPPC recommend that changes to the footnotes of Table 1 be subject to the NERC Reliability Standards development process. They state that the footnotes have been extensively reviewed by technical experts at NERC for several years and currently represent a general consensus among these industry technical experts. Changes to the footnotes affect Table 1 and have a direct impact on the determination of the severity of consequences that were approved along with the original standard. APPA also states that consideration of reliability impacts of spare equipment strategies and obligations of all generators to have the same voltage ride through capabilities are important changes that should not be made by Commission fiat.

ii. Commission Determination

1784. The Commission approves TPL-002-0 as a mandatory and enforceable Reliability Standard. In addition, we direct the ERO to develop modifications to TPL-002-0 through the Reliability Standards development process, as discussed below.

1785. The Commission notes that, like Requirement R1.3.1 of TPL-001-0, R1.3.2 of TPL-002-0 requires an entity assessing system performance to cover "critical system conditions and study years" as deemed appropriate by the entity performing the study, but it does not specify the rationale for determining critical system conditions and study years. The Commission directs the ERO to modify TPL-002-0 to require that critical system conditions and study years be determined in the same manner as it directed with regard to TPL-001-0. The Commission's explanation of the need for that change applies equally here.

1786. With regard to Northern Indiana's concerns, we disagree that the proposal to address situations in which critical equipment may be unavailable for a prolonged period

[456] From TPL Standards Table 1, Category C.3 is Category B (B1, B2, B3 or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3 or B4) contingency.

requires planned and forced outage schedules for the next ten years. Reliability Standard TPL-002-0 requires consideration of planned outages at those demand levels for which planned outages are performed but does not address situations in which critical long lead time equipment, such as a transformer or phase angle regulator, may be unavailable for a prolonged period that could extend into periods where planned outages of such equipment would not normally be performed. Assessments of these situations do not require outage schedules for the next ten years but rather identification of which facilities are deemed to be critical that have long lead times for repair or replacement. Given that planned outage considerations of such long lead time equipment are inexorably linked to spare equipment strategy, consistent with our discussion of the issue above in connection with spare equipment strategy, the Commission directs the ERO to modify the Reliability Standard to require assessments of planned outages of long lead time critical equipment consistent with the entity's spare equipment strategy.

1787. In the NOPR, the Commission identified an implicit assumption in the TPL Reliability Standards that all generators are required to ride through the same types of voltage disturbances and remain in service after the fault is cleared. This implicit assumption should be made explicit. Commenters agree with the proposed requirement for all generators to ride through the same set of Category B and C events as required for wind generators. The Commission understands that NRC has both degraded voltage and loss of voltage requirements. The degraded voltage requirement allows the voltage at the auxiliary power system busses to go below the minimum value for a time frame that is usually much longer than normal fault clearing time.[457] If a specific nuclear power plant has an NRC requirement that would force it to trip off-line if its auxiliary power system voltage was depressed below some minimum voltage, the simulation should include the tripping of the plant in addition to the faulted facilities. In this regard, the Commission agrees that NRC requirements should be used when implementing the Reliability Standards. Using NRC requirements as input will assure that there is consistency between the Reliability Standards and the NRC requirement that the system is accurately modeled. Accordingly, the Commission directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping. If a generator trips due to low voltage from a single contingency, the initial trip of the faulted element and the resulting trip of the generator would be governed by Category B contingencies and performance criteria.

[457] 10 CFR 50, Appendix a, GDC17.

1788. The Commission agrees with NRC that for operations purposes the N-1 condition is always analyzed from the conditions being experienced. In other words, allowing for the 30 minute system adjustment period, the system must be capable of withstanding an N-1 contingency, with load shedding available to system operators as a measure of last resort to prevent cascading failures. However, for planning purposes, a different analysis applies. The N-1 condition is a Category B event under TPL-002-0, and, following the N-1 contingency, the system must be stable and thermal loading and voltages be within applicable limits. Some adjustment of generation or other controls is permitted to return loadings to within continuous ratings, provided the loadings before adjustments are within the emergency or short-term ratings. Under TPL-002-0 the system is not required to be able to withstand another N-1 contingency. That N-1 requirement is a Category C contingency which is addressed by TPL-003-0. The Commission has addressed NRC's comment concerning N-1 contingencies in real-time operation in TOP-002. In regard to the specific revisions proposed by NRC, the Commission directs the ERO to consider these as part of the Reliability Standards development process.

1789. In regard to Northern Indiana's comment concerning the load modeling statement made in the NOPR, it should be clear that the context of the discussion is system performance during simulations. Load models used in simulations clearly should, to the extent feasible, represent the actual performance of the aggregate mix of industrial, commercial and residential loads. If the load model representations used in simulations do not mirror the actual performance of loads, especially during dynamic simulations, but also when carrying out voltage stability studies, the simulation results will not be accurate. Because load representation in simulations has a significant impact on simulation results and often load models are not well known, it is common practice for planners to perform sensitivity studies with a range of load models. Accordingly, as proposed in the NOPR, the Commission directs the ERO to modify the Reliability Standard to require documentation of load models used in system studies and the supporting rationale for their use.

1790. In the NOPR, the Commission set forth its rationale for proposing that the ERO clarify the phrase "permit operating steps necessary to maintain system control" in footnote (a) to Table 1.[458] Specifically, the Commission stated that the operating steps required to relieve emergency loadings and return the system to a normal state should not include firm load shedding. MidAmerican agrees with the Commission. International Transmission states clarification is required on the thresholds for normal and emergency ratings and, in particular, on whether an entity can plan to operate above normal ratings but below emergency ratings and for how long. The Commission agrees that this issue

[458] NOPR at P 1083.

requires clarification and therefore directs the ERO to modify the standard to clarify the phrase of footnote (a) that states "permit operating steps necessary to maintain system control" to clarify the use of emergency ratings.

1791. The Commission stated in the NOPR that footnote (b) raises three issues that need to be addressed.[459] Two relate to the use of planned or controlled load interruption under certain circumstances, and the third relates to the use of system adjustments including curtailment of firm transfers to prepare for the next contingency. Northern Indiana and Entergy disagree with the Commission's proposal to modify footnote (b) to state that load shedding for a single contingency is not permitted except in very special circumstances where such interruption is limited to the firm load associated with the failure (consequential load loss). The commenters argue that the impact of transmission outages can be local in nature and have no impact on the reliability of the Bulk-Power System and that removing the option to shed load in a local area for a single contingency would result in significant facility upgrade costs and therefore increased rates to customers simply to avoid a local outage. Entergy seeks clarification that the Commission does not intend to constrain the transmission operator's ability to determine the best course of action to address local reliability constraints.

1792. The NOPR proposed a modification that would clarify footnote (b) as disallowing loss of such firm load or the curtailment of firm transactions after a first contingency of the bulk electric system. In its comments to the Staff Preliminary Assessment, NERC agreed with this interpretation, representing that a practice that permits the planned interruption of "firm transmission service" is a misapplication of the Reliability Standard.[460] Some commenters now argue otherwise, and in some cases cite examples where, based on a balance of economic and reliability considerations, it may be preferable to plan the bulk electric system in such a manner that contemplates the interruption of some firm load customers in the event of a N-1 contingency. We view these arguments as based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios. Therefore, they argue, the ambiguities of footnote (b) should be

[459] Id. at P 1084.

[460] "NERC standards, including footnote (b), are not intended to endorse or approve planning the interconnection using radial configurations as a preferred method for reliably serving load, nor do NERC standards consider load shedding acceptable for a single contingency." NERC comments to the Staff Preliminary Assessment at 57-58.

interpreted to allow that an entity plan for some amount of load loss to avoid costly infrastructure investments.

1793. The Commission considers this matter to be a fundamental issue of transmission service. Indeed, the ERO's definition of "firm transmission service" specifically states that it is the "highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption."

1794. Based on the record before us, we believe that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency.[461] The Commission directs the ERO to clarify the Reliability Standard. Regarding the comments of Entergy and Northern Indiana that the Reliability Standard should allow entities to plan for the loss of firm service for a single contingency, the Commission finds that their comments may be considered through the Reliability Standards development process. However, we strongly discourage an approach that reflects the lowest common denominator.[462] The Commission also clarifies that an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances.

1795. PG&E disputes that the Reliability Standard should provide limits on the magnitude and duration of consequential load loss, as this is an economic evaluation and is not an appropriate goal for this Reliability Standard. The Commission disagrees. Indeed in its comments to the Staff Preliminary Assessment, the ERO raised the issue of what is an acceptable magnitude and duration of consequential load loss.[463] The Commission notes that most utilities have guidelines for the magnitude and duration of load loss that is acceptable on radial facilities before the facilities are looped to provide a second source of supply to accommodate load growth. NERC also stated that it recognizes that looped configurations are key to the reliable operation of the Interconnection and to meet reasonable expectations for reliable service to loads.[464] The

[461] Consequential load is the load that is directly served by the elements that are removed from service as a result of the contingency.

[462] See Order No. 672 at P 329.

[463] NERC Comments to Staff Preliminary Assessment at 56 – 57.

[464] "NERC recognizes that looped configurations are key to the reliable operation of the interconnection, and to meet reasonable expectations for reliable service to loads." Id. at 57.

Commission, therefore, suggests that the ERO consider developing a ceiling on the amount and duration of consequential load loss that will be acceptable. If the ERO determines that such a ceiling is appropriate, it should be developed through the ERO's Reliability Standards development process. Further, we note that the DOE thresholds for reporting disturbances on Form EIA-417 would be one example of an appropriate starting point for developing such a ceiling. These thresholds for load loss are 300 MW for 15 minutes or 50,000 customers for one hour, whichever is greater.

1796. The third issue with footnote (b) relates to the Commission's proposal in the NOPR to delete the footnote's second sentence, which states "[t]o prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers."[465] PG&E disagrees with the Commission's proposal because it allows re-scheduling power (but not load shedding) as part of manual adjustment after the first Category B contingency to bring the system back to a safe operating point. The Commission agrees that footnote (b) should permit manual adjustments including generation redispatch and transmission reconfiguration, but not load shedding, to return the system to a normal operating state within the time period permitted by the emergency or short term ratings. The Commission understands that this is the normal practice used by most transmission planners. However, the system adjustments permitted in the statement above includes curtailments of contracted firm, non-recallable reserved and electric power transfers and this is not acceptable for Category B single contingencies. Therefore, the ERO should modify the sentence to indicate that manual system adjustments, except for shedding firm load or curtailment of firm transfers, are permitted after the first contingency to bring the system back to a normal operating state. The Commission disagrees with PG&E's statement that the difference between footnote (b) as part of Category B and Category C.3 is that footnote (b) applies before the second N-1 contingency, whereas Category C.3 applies after the second N-1 contingency. Rather, manual adjustments referred to in both cases apply after the first N-1 contingency. The Commission, therefore, directs the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency, provided these adjustment can be accomplished within the time period allowed by the short term or emergency ratings.

1797. Accordingly, the Commission approves Reliability Standard TPL-002-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL-002-0 through the Reliability Standards development process that: (1) requires that critical system conditions be determined in the same manner as we

[465] NOPR at P 1083.

propose to require for TPL-001-0; (2) requires assessments of planned outages of long lead time critical equipment consistent with the entity's spare equipment strategy; (3) requires all generators to ride through the same set of Category B and C contingencies as required by wind generators in Order No. 661, or to simulate those generators that cannot ride through as tripping; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase "permit operating steps necessary to maintain system control" in footnote (a) and the use of emergency ratings and (6) clarifies footnote (b) in regard to load loss following a single contingency, specifying the amount and duration of consequential load loss and system adjustments permitted after the first contingency to return the system to a normal operating state, as discussed above.

d. System Performance Following Loss of Two or More Elements (TPL-003-0)

1798. Reliability Standard TPL-003-0 seeks to ensure that the future Bulk-Power System is planned to meet the system performance requirements of a system with the loss of multiple elements. It does this by requiring that the transmission planner and the planning authority annually evaluate and document the ability of its transmission system to meet the performance requirements of Category C contingencies specified in Table 1 (i.e., events resulting in the loss of two or more elements) for both the near-term and the longer-term planning horizons. TPL-003-0 requires the preparation of a documented plan to achieve the necessary performance requirements if the system is unable to meet the Category C performance criteria.

1799. TPL-003-0 applies to each planning authority and transmission planner. They must demonstrate annually through valid assessments that their portion of the interconnected transmission system is planned to meet the performance requirements of Category C with all transmission facilities in service over a planning horizon that takes into account lead times for corrective plans. The Reliability Standard also requires the applicable entities to consider planned outages of transmission equipment for those demand levels for which they perform such outages. The Reliability Standard defines various categories of conditions to be simulated. The specific study elements selected from each of the categories for assessments, including the subset of Category C contingencies to be evaluated, require approval by the associated regional reliability organization.

1800. The Commission proposed in the NOPR to approve Reliability Standard TPL-003-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-003-0 that: (1) requires that critical system conditions be determined by conducting sensitivity studies (as elaborated in our discussion of TPL-001-0); (2) makes certain clarifications to footnote (c) to Table 1; (3) requires the applicable entities to define and document the proxies necessary to simulate cascading outages and (4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

1801. The Commission also sought comments on one potential addition to TPL-003-0. It noted that Category C3 of this Reliability Standard involves a situation in which two single contingencies occur, with manual system adjustments permitted after the first contingency to prepare for the next one (generally referred to as N-1-1). However, the Commission also noted that should the second contingency occur before the manual system adjustments can be completed, the local area and potentially the system would be exposed to risk of cascading outages. For that reason some entities plan and operate their systems so that they are able to withstand the simultaneous occurrence of the two contingencies (normally referred to as N-2) for major load pockets. The Commission sought comments on the value and appropriateness of including such a requirement in TPL-003-0.

i. Comments

1802. LPPC recommends that changes to footnotes of Table 1 be subject to the NERC Reliability Standards development process. It states that the footnotes have been extensively reviewed by technical experts at NERC for several years and currently represent a general consensus among these industry technical experts which should be given due weight by the Commission. Changes to the footnotes impact Table 1 and have a direct impact on the determination of the severity of consequences that were approved along with the original Reliability Standard.

1803. FirstEnergy supports the proposed requirement to document proxies of subsequent line trips due to thermal overload and low voltage generation trips to evaluate potential cascading conditions. FirstEnergy states it currently is required to account for these items in its planning process.

1804. EEI questions the value of providing proxies when planners conduct thousands of studies based on combinations of contingencies under a broad range of circumstances and conditions, especially in longer-term planning horizons where the uncertainty around the value of any one variable is already very high. SoCal Edison states that one can determine the cascading outages in load flow studies. In transient stability studies, if the outage is severe, then the thermal overload relays and undervoltage relays, if modeled, will trip the load. If the load tripped was not planned to be tripped for this outage, then the planning authority should take the necessary steps to avoid this situation, as cascading is not allowed.

1805. LPPC and Northern Indiana oppose the proposal to require proxies necessary to simulate cascading outages be defined and documented. Northern Indiana states that there is no consensus on what these proxies should be. LPPC states that utility planners have traditionally used their engineering judgment to simulate a conservative estimate of the level of thermal overload or low voltage that will cause the likelihood of subsequent line or generator trips and cascading events. LPPC states that this approach has been successful, and NERC should not be asked to second-guess the decisions of operators in this area. That could result in the adoption of less conservative, least common denominator, design assumptions across all regions and reduce modeling flexibility and use of engineering judgment. Proxies are typically tailored to specific systems because the development of proxies is highly dependent on regional differences and localized knowledge. If the Commission determines that independent review of utility outage simulation proxies is necessary, Regional Entities should conduct that review, because they better understand the regional and localized factors that influence the proxies.

1806. EEI requests that the Commission clarify the meaning of the term "controlled load interruption" and the meaning of its statement that "to avoid undue negative impact on competition, third party studies could be permitted to implement the same or less controlled load interruption as used by the transmission owner."[466]

1807. NRC states that this Reliability Standard should be clarified in regard to the N-1-1 condition. In addition, it recommends specific changes to Requirements R1.6, R.1.2 and R2.2.

1808. A number of commenters respond to the Commission's request for comments on the value and appropriateness of including the ability of the system to withstand two simultaneous contingencies for major load pockets. NERC states that this issue has been recognized as needing clarification, and it welcomes comments in the development of these revisions in accordance with its Reliability Standards development process. NERC states that it is developing a proposal for a transmission availability data system that will provide a quantitative (probabilistic) basis for judging the likelihood of various multi-element contingencies which will be helpful in determining the value of this proposal.

1809. APPA, LPPC and National Grid state that imposing N-2 planning may be difficult to administer since there is no consensus on what constitutes a "major load pocket." LPPC states that the definition of major load pockets has been, and is still being debated. As there is no nation-wide consensus on the term's definition, no list of major load pockets exists. Because load pockets and their boundaries change with the dynamically

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[466] Id. at P 1097.

changing system and load patterns, it is difficult to establish or administer a rule that encompasses the particular sub-region to which such an N-2 requirement would apply.

1810. APPA and EEI believe such provisions would significantly expand planning requirements for extremely unlikely events that in most cases are not cost effective to build into system planning decisions. They explain that the Reliability Standard currently includes the more likely situation, i.e., where two events occur in a time frame that allows some time to adjust in response to the first event. APPA and EEI state that various planning entities may, of course, study much more extreme events, including the hypothetical the Commission poses, especially if formal state or regional planning requires such studies, and actual preparation for extreme events is viewed as cost-effective in a particular area. However, this level of planning sensitivity is simply unnecessary for many regions of the country. They ask that if the Commission envisions changes to provide for N-2 service to load pockets, a dialogue must first be initiated within the industry and with state public utility commissions to identify such load pockets, target the required transmission investments (which could be very substantial) and develop plans for allocating the costs of such investments.

1811. FirstEnergy comments that, although simultaneous C.3 independent contingencies may pose potentially high risk, they are most likely extremely low in probability. FirstEnergy states that it nevertheless routinely evaluates these contingencies across its system for facilities 200 kV and higher and suggests that if this analysis is made a requirement, it should be limited to an extra high voltage subset of the Bulk-Power System.

1812. MISO believes that evaluation of multiple contingency events should only reside in the planning arena and not in the operations environment. It states that the current Reliability Standard provides a reasonable and time tested methodology.

1813. National Grid opposes applying this N-2 criterion across the board. It states that N-2 planning is usually relied upon when a particular area does not have the resources or flexibility to adopt the N-1-1 approach. The Bulk-Power System is designed differently in every region, and there is no need to impose N-2 planning where regions are satisfactorily implementing the N-1-1 methodology.

1814. SDG&E states that the N-2 consideration for major load pockets is neither of value nor appropriate for transmission planning entities at large. The probability of such a contingency for a major load pocket is very low, and the costs for addressing such a remote contingency would be significant. SoCal Edison states the potential number of multi-contingency events that could be studied under TPL-003-0 is staggering. Planners should be given flexibility to select generation and transmission elements that reflect a broad range of potential combinations without having to commit resources to conduct potentially hundreds or thousands of contingency studies. Northern Indiana contends that this requirement is in effect a third back-up capability, that it would be prohibitive in terms of time and cost, and that it would take many years to put the infrastructure it would require into place.

1815. PG&E believes there is no need for a general requirement to withstand the simultaneous occurrence of any two contingencies for major load pockets. It states that IRO-005 provides for contingencies that are credible when operating below IROL in current day operations. The TPL group of Reliability Standards already require provisions for specific circumstances based on evaluations that take into account the probability of an outage occurring and the associated consequences when transmission plans are developed. PG&E states that TPL-003-0, Category C.5 contingency already addresses the more probable simultaneous outages (due to common-mode failure) that could occur. PG&E maintains that simultaneous occurrence of other contingencies is not credible. The principles incorporated in the Reliability Standards require that evaluations of credibility be balanced against potential impact, and investing resources to prevent improbable events diverts attention and focus from more critical Reliability Standards and more probable conditions.

ii. Commission Determination

1816. The Commission approves proposed Reliability Standard TPL-003-0 as a mandatory and enforceable Reliability Standard. In addition, we direct the ERO to develop modifications to TPL-003-0 through the Reliability Standards development process, as discussed below.

1817. The Commission notes that, like Requirement R1.3.1 of TPL-001-0, Requirement R1.3.2 of TPL-003-0 requires an entity assessing system performance to cover "critical system conditions and study years" as deemed appropriate by the entity performing the study, but that the Requirement does not specify the rationale for determining critical system conditions and study years. The Commission directs the ERO to modify TPL-003-0 to require that critical system conditions and study years be determined in the same manner as we directed with regard to TPL-001-0, for the reasons as set forth in our discussion of TPL-001-0.

1818. The intent underlying the statement that "to avoid undue undue negative impact on competition, third party studies should be permitted to implement the same or less controlled load interruption as used by the transmission owner" is to ensure that third parties have access to the same options that the transmission owner uses to alleviate reliability constraints including those related to controlled load shedding. For example, if a transmission owner designs its system to result in a controlled load shedding of 300 MW for Category C contingencies, designs proposed for third parties requesting interconnections to that system must also be permitted, but not required, to have 300 MW of controlled load shedding for the same Category C contingencies. The Commission directs the ERO to modify footnote (c) of Table 1 to the Reliability Standard to clarify the term "controlled load interruption." In response to LPPC's comments on modification procedures, the Commission agrees that changes to the footnotes of Table 1 should be addressed through the ERO's Reliability Standards development process.

1819. The Commission stated in the NOPR that the concern involved relates to the use of thermal overloads or low voltage proxies to judge the likelihood of subsequent line or generator trips leading to a cascading outage.[467] The Commission agrees with SoCal Edison that, if an entity models overload relays, undervoltage relays, all remedial action schemes including those of neighboring systems and has a good load representation, then proxies are not required. However, due to modeling and simulation limitations this is often not the case and planners invariably use proxies.[468] Recognizing this and the range of proxies currently in use, the Transmission Issues Subcommittee of the NERC Planning Committee recommended that proxies used in simulations be defined until such time as improved analytical tools and models are available to simulate cascading events.

1820. The Commission disagrees with LPPC that defining and documenting proxies will result in the adoption of less conservative, least common denominator design assumptions across all regions and reduce modeling flexibility and engineering judgment. To the contrary, the Commission believes that such sharing of information will improve knowledge and understanding and promote a more rigorous approach to analyzing cascading outages. The Commission agrees with LPPC that it may be preferable for the Regional Entities to conduct the review of proxies, because they better understand the regional and localized factors that influence the proxies. However, we expect the ERO to coordinate between regions to assure that best practices are shared among the Regional Entities. Accordingly, the Commission directs the ERO to modify the Reliability Standard to require definition and documentation of proxies necessary to simulate cascading outages.

1821. No comments were received on the Commission's proposal that the purpose statement of TPL-003-0 be tailored to reflect the specific goal of the Reliability Standard. The Commission directs that this modification be made. Reliability Standards should be

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[467] Id. at P 1098.

[468] See WECC Disturbance Performance Table W-1 and Figure W-1 of Allowable Effects on other Systems, NERC/WECC Planning Standards April 10, 2003.

clear and unambiguous, and a clear statement of a Reliability Standard's purpose and goal is one of the features necessary to achieve this end.

1822. The NRC's comments on TPL-003-0 parallel its comments on TPL-002-0. The Commission discussed those comments above, and its conclusions there apply equally here. The Commission, for the same reasons set forth in our discussion of TPL-002-0, directs the ERO to address NRC concerns through its Reliability Standards development process.

1823. The Commission received numerous comments on its request for comments on the appropriateness and value of including the ability of the system to withstand two simultaneous Category B contingencies for major load pockets. The Commission stated that it was aware that several entities currently apply this approach and notes that one entity was actually commended by NERC for doing so as part of its readiness review. FirstEnergy states that it routinely evaluates these contingencies across its system for 200 kV and higher. NERC states that this issue has been recognized as requiring clarification, and it welcomes comments on these revisions in accordance with the Reliability Standards development process.

1824. Many commenters state that, without a consensus on what constitutes a major load pocket, little progress can be made in this regard. LPPC states that the definition of major load pockets has been and is still being debated. National Grid states that N-2 planning is usually relied upon when a particular area does not have the resources and flexibility to adopt the N-1-1 approach. The Commission agrees with National Grid but notes that this is more applicable to the operating domain, something that MISO opposes. PG&E states that this approach is not necessary because Category C5 already addresses more probable simultaneous outages due to common mode failure. The Commission disagrees since Category C5 only deals with a loss of any two circuits on a multi-circuit tower line and not a simultaneous loss of a line and a generator which was envisaged by the request for comments. Many commenters indicated that this was a very low probability event and the costs for addressing such an event would be significant. As a result, EEI states that a dialogue must first be initiated within the industry and with state public utility commissions to identify such load pockets, to target the required potentially significant transmission investments and to develop plans for allocating the costs of such investments. In light of these comments, the Commission does not intend to recommend action on this issue at this time and, instead, directs the ERO to consider the comments in possible future revisions to the Reliability Standard.

1825. Accordingly, the Commission approves Reliability Standard TPL-003-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL-003-0 through the Reliability Standards development process that: (1) requires that critical system conditions be determined in the same manner as we propose to require for TPL-001-0; (2) modifies footnote (c) to Table 1 to clarify the term "controlled load interruption;" (3) requires applicable entities to define and document the proxies necessary to simulate cascading outages and (4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

e. System Performance Following Extreme Events (TPL-004-0)

1826. The goal of Reliability Standard TPL-004-0 is to ensure that the future Bulk-Power System is evaluated to assess the risks and consequences of an extreme event involving the loss of multiple elements. It seeks to do this by requiring the transmission planner and the planning authority to evaluate and document annually the risks and consequences of Category D contingencies (i.e., extreme events resulting in loss of two or more elements or cascading) for the near-term (five-year) planning horizon.

1827. TPL-004-0 applies to each planning authority and transmission planner. Each must demonstrate annually through valid assessments that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies of Category D with all transmission facilities in service over a planning horizon that takes into account lead times for corrective plans. TPL-004-0 also requires that planned outages of transmission equipment be considered for those demand levels for which planned outages are performed. It defines various categories of conditions to be simulated. The associated regional reliability organization must approve the specific study elements selected from each of the categories for assessment, including the subset of Category D contingencies to be evaluated.

1828. The Commission proposed in the NOPR to approve Reliability Standard TPL-004-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-004-0 that: (1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0; (2) requires the identification of options for reducing the probability or impacts of extreme events that cause cascading; (3) requires that, in determining the range of extreme events to be assessed, the contingency list of Category D be expanded to include recent events and (4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

i. Comments

1829. MidAmerican supports the Commission's proposed modifications to the Reliability Standard as reasonable and agrees with the Commission that the Reliability Standard should not require improvements for low probability events that cannot be justified.[469] MidAmerican supports developing options for any events listed in TPL-004-0 that result in cascading outages and suggests use of probabilistic estimates to determine which, if any, of the TPL-004 extreme events options should be estimated to reduce their probability or impacts.

1830. FirstEnergy, EEI, APPA, TVA and Northern Indiana all oppose the expansion of the list of extreme contingencies to include natural disasters such as hurricanes and ice storms. They state that the potential contingencies resulting from this expansion are endless and therefore impractical to consider through engineering studies. As a result, additional requirements in this Reliability Standard are unnecessary. EEI and APPA state that to the extent that such events will happen, entities historically have put heavy emphasis on emergency planning and procedures, which are addressed by the EOP group of Reliability Standards.

ii. Commission Determination

1831. The Commission approves proposed Reliability Standard TPL-004-0 as mandatory and enforceable. In addition, we direct the ERO to develop modifications to TPL-004-0 through the Reliability Standards development process, as discussed below.

1832. The Commission notes that, like Requirement R1.3.1 of TPL-001-0, Requirement R1.3.2 of TPL-004-0 requires an entity assessing system performance to cover "critical system conditions and study years" as deemed appropriate by the entity performing the study, but it does not specify the rationale for determining critical system conditions and study years. The Commission directs the ERO to modify TPL-004-0 to require that critical system conditions and study years be determined in the same manner as we directed with regard to TPL-001-0 and for the reasons stated there.

1833. MidAmerican states that it supports the proposal to modify TPL-004-0 to require identification of options for reducing the probability or impacts of extreme events that cause cascading. Accordingly, for the reasons cited in the NOPR, the Commission directs the ERO to modify the Reliability Standard to make this modification to the Reliability Standard.

1834. All commenters that responded on the issue opposed the Commission's proposal to modify TPL-004-0 to require that, in determining the range of the extreme events to be assessed, the contingency list of Category D be expanded to include recent events such as hurricanes and ice storms. The Commission is not persuaded by the commenters'

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[469] See NOPR at P 1112.

contention that expansion of the extreme events list will lead to an endless list of possibilities. The two that the Commission used are examples from the general news media. While the NOPR referred to two recent events, other examples include: (1) loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation; (2) a successful cyber attack; (3) regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation; (4) shutdown of a nuclear power plant and other facilities a day or more prior to a hurricane, tornado or wildfire, or other event and (5) the loss of older transmission lines, which may not be constructed to meet an entity's present radial ice loading requirements, while the newer or stronger transmission lines remain in service. The above examples are not an exhaustive list, however, the Commission would not expect the range of scenarios to be much more extensive than this, either. Thus, we are not expecting an endless list of scenarios and infinite number of combinations in directing this modification. Each event is identifiable for each entity based on its topology, facilities and generation mix. Accordingly, the Commission directs the ERO to expand the list of events with examples of such events identified above.

1835. The Commission received no comments on its proposal to modify the purpose statement of TPL-004-0 to reflect the specific goal of the Reliability Standard. The Commission directs that this modification be made.

1836. Accordingly, the Commission approves Reliability Standard TPL-004-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to TPL-004-0 through the Reliability Standards development process that: (1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0; (2) requires the identification of options for reducing the probability or impacts of extreme events that cause cascading; (3) requires that, in determining the range of extreme events to be assessed, the contingency list of Category D be expanded to include recent events and (4) tailors the purpose statement to reflect the specific goal of the Reliability Standard.

f. Regional and Interregional Self-Assessment Reliability Reports (TPL-005-0)

1837. Reliability Standard TPL-005-0 seeks to ensure that each regional reliability organization conducts reliability assessments of its existing and planned regional bulk electric system annually by requiring it to assess and document the performance of its power system for the current year, the next five years, and to analyze trends for the longer-term planning horizons.

1838. The Commission proposed in the NOPR not to approve or remand TPL-005-0, as it applies only to regional reliability organizations.

i. **Comments**

1839. EEI comments that TPL-005-0 should be revised to remove the regional reliability organizations.

ii. **Commission Determination**

1840. Consistent with our discussion in the Common Issues section above, we will not approve or remand TPL-005-0 until we receive additional information from the ERO.

1841. In Order No. 890, the Commission stated that there will be a series of technical conferences and regional meetings to obtain industry input to achieving the goal of regional planning.[470] The Commission encourages the ERO to monitor those proceedings and use the results as input to the Reliability Standards development process in revising Reliability Standard TPL-005-0 to address regional planning and related processes.

g. **Assessment Data from Regional Reliability Organizations (TPL-006-0)**

1842. Reliability Standard TPL-006-0 seeks to ensure that the data necessary to conduct reliability assessments is available by requiring the regional reliability organization to provide NERC with Bulk-Power System data, reports, demand and energy forecasts, and other information necessary to assess reliability and compliance with NERC Reliability Standards and relevant regional planning criteria.

1843. The Commission proposed in the NOPR not to approve or remand TPL-006-0, as it applies only to regional reliability organizations.

i. **Comments**

1844. EEI agrees that TPL-006-0 should be revised to remove the regional reliability organizations.

ii. **Commission Determination**

1845. Consistent with our discussion in the Common Issues section above, the Commission will not approve or remand TPL-006-0.

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[470] Order No. 890 at P 443.

13. VAR: Voltage and Reactive Control

1846. The Version 0 Voltage and Reactive Control (VAR) Reliability Standard VAR-001-0 is intended to maintain Bulk-Power System facilities within voltage and reactive power limits, thereby protecting transmission, generation, distribution, and customer equipment and the reliable operation of the Interconnection. The Voltage and Reactive Control group of Reliability Standards is intended to replace the existing VAR-001-0 and consists of two proposed Reliability Standards, VAR-001-1 and VAR-002-1, with new Requirements. These two new proposed Reliability Standards have been submitted by NERC as part of the August 28, 2006 Supplemental Filing for Commission review. NERC requested an effective date of February 2, 2007 for VAR-001-1, and August 2, 2007 for VAR-002-1.

a. VAR-001-1 Voltage and Reactive Control

1847. Reliability Standard VAR-001-1 requires transmission operators to implement formal policies for monitoring and controlling voltage levels, acquire sufficient reactive resources, specify criteria for generator voltage schedules, know the status of all transmission reactive power resources, operate or direct the operation of devices that regulate voltage and correct IROL or SOL violations resulting from reactive resource deficiencies. VAR-001-1 also requires purchasing-selling entities to arrange for reactive resources to satisfy their reactive requirements.

1848. In the NOPR, the Commission proposed to approve VAR-001-1 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to VAR-001-1 that: (1) expands the applicability to include reliability coordinators and LSEs; (2) includes detailed and definitive requirements on "established limits" and "sufficient reactive resources," and identifies acceptable margins above the voltage instability points; (3) includes Requirements to perform voltage stability assessments periodically during real-time operations and (4) includes controllable load among the reactive resources to satisfy reactive requirements. The Commission also requested comments concerning NERC's assertion that all LSEs are also purchasing-selling entities, and on the acceptable ranges of net power factor range at the interface at which the LSEs receive service from the Bulk-Power System during normal and extreme load conditions.

1849. Most comments address the specific modifications and concerns raised by the Commission in the NOPR. Below, we address each topic separately, followed by an over-all conclusion and summary.

i. Applicability to Load-Serving Entities and Reliability Coordinators

(a) Comments

1850. EEI agrees with the Commission that the applicability of VAR-001-1 should be expanded to include reliability coordinators and LSEs.

1851. MISO contends that the view and role of generator operators, transmission operators and reliability coordinators are different, and reliability coordinators' monitoring and response requirements are addressed elsewhere in the Reliability Standards.

1852. In response to the Commission's request in the NOPR for comments concerning whether all LSEs are also purchasing-selling entities, SoCal Edison believes they are distinguishable. It states that a purchasing-selling entity, according to the functional model, makes financial deals across balancing authorities (from source to sink). Within the area of a large balancing authority, such as the CAISO, an LSE can serve load from a resource within the balancing authority, so that there is no requirement to tag this transaction, and technically there is no purchasing-selling entity involved.

1853. APPA is concerned that requiring VAR-001-1 to be applicable to LSEs would require LSEs to conduct various studies and perform reliability functions that have been assigned to other functional entities. The role of LSEs in voltage stability assessments should be limited to coordination and the provision of data. TAPS also questions the need to expand applicability of these Reliability Standards to LSEs. TAPS maintains that purchasing and selling utilities are already subject to the Reliability Standards, and are required to satisfy any reactive requirements through purchasing Ancillary Service No. 2 under the OATT (or self-supply). TAPS believes that the addition of LSEs as an additional applicable entity serves no reliability purpose.

(b) Commission Determination

1854. In a complex power grid such as the one that exists in North America, reliable operations can only be ensured by coordinated efforts from all operating entities in long-term planning, operational planning and real-time operations. To that end, the Staff Preliminary Assessment recommended and the NOPR proposed that the applicability of VAR-001-1 extend to reliability coordinators and LSEs.

1855. Since a reliability coordinator is the highest level of authority overseeing the reliability of the Bulk-Power System, the Commission believes that it is important to include the reliability coordinator as an applicable entity to assure that adequate voltage and reactive resources are being maintained. As MISO points out, other Reliability Standards address responsibilities of reliability coordinators, but we agree with EEI that it is important to include reliability coordinators in VAR-001-1 as well. Reliability coordinators have responsibilities in the IRO and TOP Reliability Standards, but not the specific responsibilities for voltage levels and reactive resources addressed by VAR-001-1, which have a great impact on system reliability. For example, voltage levels and reactive resources are important factors to ensure that IROLs are valid and operating voltages are within limits, and that reliability coordinators should have responsibilities in VAR-001-1 to monitor that sufficient reactive resources are available for reliable system operations. Accordingly, the ERO should modify VAR-001-1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities.

1856. The Commission agrees with SoCal Edison that not all LSEs are purchasing-selling entities, because not all LSEs purchase or sell power from outside of their balancing authority area. This understanding is consistent with the NERC functional model and NERC glossary. Both LSEs and purchasing-selling entities should have some requirements to provide reactive power to appropriately compensate for the demand they are meeting for their customers. Neither a purchasing-selling entity nor a LSE should depend on the transmission operator to supply reactive power for their loads during normal or emergency conditions.

1857. VAR-001-1 recognizes that energy purchases of purchasing-selling entities can increase reactive power consumption on the Bulk-Power System and the purchasing-selling entities must supply what they consume. The Commission agrees with APPA that LSEs would provide data for voltage stability assessments. However, the Commission also believes that LSEs have an active role in voltage and reactive control, since LSEs are responsible for maintaining an agreed-to power factor at the interface with the Bulk-Power System.

1858. While the Commission recognizes the point made by TAPS, that purchasing-selling entities are required to satisfy any reactive requirements through purchasing Ancillary Service #2 under the OATT or self-supply, the Commission disagrees that adding LSEs to this Reliability Standard serves no reliability purpose. As discussed in the NOPR and the Staff Preliminary Assessment, LSEs are responsible for significantly more load than purchasing-selling entities.[471] The reactive power requirements can have significant impact on the reliability of the system and LSEs should be accountable for that impact in the same ways that purchasing-selling entities are accountable, by

[471] NOPR at P 1134.

providing reactive resources, and also by providing information to transmission operators to allow transmission operators to accurately study the reactive power needs for both the LSEs' and purchasing-selling entities' load characteristics.[472] The Commission recognizes that all transmission customers of public utilities are required to purchase Ancillary Service No. 2 under the OATT or self-supply, but the OATT does not require them to provide information to transmission operators needed to accurately study reactive power needs. The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities.

ii. Acceptable ranges of net power factor range

(a) Comments

1859. SoCal Edison states that its Bulk-Power System facilities are designed and operated to provide a unity power factor during normal load conditions, and that during extreme load conditions, this power factor could be in the range of 0.95 to 1.0.

1860. APPA contends that it may be difficult to reach an agreement on acceptable ranges of net power factors at the interfaces where LSEs receive service from the Bulk-Power System because the acceptable range of power factors at any particular point on the electrical system varies based on many location-specific factors. APPA further states that system power factors will be affected by the transmission infrastructure used to supply the load. As an example, APPA states that an overhead circuit may operate at a higher power factor than an underground cable due to a substantial amount of reactive line charging, and that a transmission circuit carrying low levels of real power will tend to provide more reactive power, which will affect the need to switch off capacitor banks at the delivery point to manage delivery power factors.

(b) Commission Determination

1861. In the NOPR, the Commission asked for comments on acceptable ranges of net power factor at the interface at which the LSEs receive service from the Bulk-Power System during normal and extreme load conditions. The Commission asked for these comments in response to concerns that during high loads, if the power factor at the interface between many LSEs and the Bulk-Power System is so low as to result in low voltages at key busses on the Bulk-Power System, then there is risk for voltage collapse.

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[472] Purchasing selling entities provide information concerning their load through the INT series of Reliability Standards. Load serving entities would need to provide similar information through this Reliability Standard.

The Commission believes that Reliability Standard VAR-001-1 is an appropriate place for the ERO to take steps to address these concerns by setting out requirements for transmission owners and LSEs to maintain an appropriate power factor range at their interface. We direct the ERO to develop appropriate modifications to this Reliability Standard to address the power factor range at the interface between LSEs and the Bulk-Power System.

1862. We direct the ERO to include APPA's concern in the Reliability Standards development process. We note that transmission operators currently have access to data through their energy management systems to determine a range of power factors at which load operates during various conditions, and we suggest that the ERO use this type of data as a starting point for developing this modification.

1863. The Commission expects that the appropriate power factor range developed for the interface between the bulk electric system and the LSE from VAR-001-1 would be used as an input to the transmission and operations planning Reliability Standards. The range of power factors developed in this Reliability Standard provides the input to the range of power factors identified in the modifications to the TPL Reliability Standards. In the NOPR, the Commission suggested that sensitivity studies for the TPL Reliability Standards should consider the range of load power factors.[473]

iii. Requirements on "established limits" and "sufficient reactive resources"

(a) Comments

1864. Dynegy supports the Commission's proposal to include more definitive requirements on "established limits" and "sufficient reactive resources." It recommends that VAR-001-1 be further modified to require the transmission operator to have more detailed and definitive requirements when setting the voltage schedule and associated tolerance band that is to be maintained by the generator operator. Dynegy states that the transmission operator should not be allowed to arbitrarily set these values, but rather should be required to have a technical basis for setting the required voltage schedule and tolerance band that takes into account system needs and any limitations of the specific generator. Dynegy believes that such a requirement would eliminate the potential for undue discrimination, as well as the possibility of imposing overly conservative and burdensome voltage schedules and tolerance bands on generator operators that could be

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[473] NOPR at P 1047.

detrimental to grid reliability, or conversely, the imposition of too low a voltage schedule and too wide a tolerance band that could also be detrimental to grid reliability.

1865. While MISO supports the concept of including more detailed requirements, it believes that there needs to be a definitive reason for establishing voltage schedules and tolerances, and that any situations monitored in this Reliability Standard need to be limited to core reliability requirements.

1866. EEI seeks clarification about whether the Commission is suggesting that reactive requirements should aim for significantly greater precision, especially in terms of planning for various emergency conditions. If so, EEI cautions the Commission against "'putting too many eggs' in the reactive power 'basket.'"[474] To the extent compliance takes place pursuant to all other modeling and planning assessments under the other Reliability Standards, EEI strongly believes that the Commission should have some high level of confidence that the system's reactive power needs can be met satisfactorily across a broad range of contingencies that planners might reasonably anticipate. Moreover, EEI believes that requirements to successfully predict reactive power requirements in conditions of near-system collapse would require significantly more creative guesswork than solid analysis and contingency planning. For example, EEI notes that the combinations and permutations of how a voltage collapse could occur on a system as large as the eastern Interconnection are numerous.

1867. EEI suggests that, alternatively, the Commission should consider that reactive power evaluations should be conducted within a process that is documented in detail and includes a range of contingencies that might be reasonably anticipated, because this would avoid the 'one size fits all' problem, where a prescriptive analytical methodology does not fit with a particular system configuration. EEI believes that this flexible approach would provide a more effective planning tool for the industry, while satisfying the Commission's concerns over potentially inadequate reactive reserves. MRO notes that the need for, and method of providing for, reactive resources varies greatly, and if this Reliability Standard is expanded it must be done carefully. MRO believes that all entities should not be required to follow the same methodology to accomplish the goal of a reliable system.

(b) Commission Determination

1868. In the NOPR, the Commission expressed concern that the technical requirements containing terms such as "established limits" or "sufficient reactive resources" are not

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[474] EEI at 99.

definitive enough to address voltage instability and ensure reliable operations.[475] To address this concern, the NOPR proposed directing the ERO to modify VAR-001-1 to include more detailed and definitive requirements on "established limits" and "sufficient reactive resources" and identify acceptable margins (i.e. voltage and/or reactive power margins) above voltage instability points to prevent voltage instability and to ensure reliable operations. We will keep this direction, and direct the ERO to include this modification in this Reliability Standard.

1869. We recognize that our proposed modification does not identify what definitive requirements the Reliability Standard should use for "established limits" and "sufficient reactive resources." Rather, the ERO should develop appropriate requirements that address the Commission's concerns through the ERO Reliability Standards development process. The Commission believes that the concerns of Dynegy, EEI and MISO are best addressed by the ERO in the Reliability Standards development process.

1870. In response to EEI's concerns about a prescriptive analytical methodology, we clarify that the Commission is not asking that the Reliability Standard dictate what methodology must be used to determine reactive power needs. Rather, the Commission believes that the Reliability Standard would benefit from having more defined requirements that clearly define what voltage limits are used and how much reactive resources are needed to ensure voltage instability will not occur under normal and emergency conditions. For example, in the NOPR, the Commission suggested that NERC consider WECC's Reliability Criteria, which contain specific and definitive technical requirements on voltage and margin application. While we are not directing that the WECC reliability criteria be adopted, we believe they represent a good example of clearly-defined requirements for voltage and reactive margins.

1871. In sum, the Commission believes that minimum requirements for voltage levels and reactive resources should be clearly defined by placing more detailed requirements on the terms "established limits" and "sufficient reactive resources" in the Reliability Standard as discussed in the NOPR and the Staff Preliminary Assessment. As mentioned above, EEI's concerns should be considered in the ERO's Reliability Standards development process.

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[475] See NOPR at P 1140.

iv. Periodic voltage stability analysis in real-time operations

(a) Comments

1872. SDG&E supports the NOPR recommendation that a more effective requirement could be based on WECC's reliability criteria, which contain specific and definitive technical requirements on voltage and margin application. MidAmerican and PacifiCorp recommend that the "WECC Methods to address voltage stability and settling margins" should be consulted when designing corresponding NERC requirements.

1873. Xcel Energy recommends that this proposed modification instead address requirements to measure reactive power margin for a variety of topology conditions. MidAmerican recommends that the Commission's proposal be modified to require real-time checks for voltage stability assessments only in areas susceptible to voltage instability. Alternatively, MidAmerican suggests that the Commission "should exempt from these requirements areas that can demonstrate they are not susceptible to voltage instability."

1874. APPA, SDG&E and EEI all state that they are not aware of commercially-available tools to provide real-time transient stability assessments as part of an integrated energy management system for operators. APPA notes that premature reliance on various tools that are now under development but not yet operational may jeopardize reliability by providing operators with a false sense of security and recommends leaving the decision to use such tools to NERC. EEI points out that any tools to conduct the analyses recommended by the Commission will require adjustments and modifications to improve their capabilities. Therefore, EEI recommends that the Commission consider its proposals regarding these standards as long-term industry objectives and of a lower priority than other Reliability Standards. In addition, it is unclear to EEI whether the proposed voltage stability assessments apply to steady-state or dynamic analyses, or whether these assessments are of a general nature. Since these analyses are technically complex and involve a broad range of assumptions regarding system configurations, EEI suggests that the Commission provide further guidance.

(b) Commission Determination

1875. In response to the concerns of APPA, SDG&E and EEI on the availability of tools, the Commission recognizes that transient voltage stability analysis is often conducted as an offline study, and that steady-state voltage stability analysis can be done online. The Commission clarifies that it does not wish to require anyone to use tools that are not validated for real-time operations. Taking these comments into consideration, the Commission clarifies its proposed modification from the NOPR. For the Final Rule, we direct the ERO, through its Reliability Standards development process, to modify Reliability Standard VAR-001-1 to include Requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations. The ERO should consider the available technologies and software as it develops this modification to VAR-001-1 and identify a process to assure that the Reliability Standard is not limiting the application of validated software or other tools.

1876. With respect to MidAmerican's suggestion of exempting areas that are not susceptible to voltage instability from the requirement to perform voltage stability analysis, the Commission notes that such exemption is not appropriate. We draw an analogy between transient stability limits and voltage stability limits. The requirement to perform voltage stability analysis is similar to existing operating practices for IROLs that are dictated by transient stability. Transient stability IROLs are determined using the results of off-line simulation studies, and no areas are exempt. In real-time operations, these IROLs are monitored to ensure that they are not violated. Similarly, voltage stability is conducted in the same manner, determining limits with off-line tools and monitoring limits in real-time operations. Areas that are susceptible to voltage instability are expected to run studies frequently, and areas that have not been susceptible to voltage instability are expected to periodically update their study results to ensure that these limits are not encountered during real-time operations.

v. Controllable Load

(a) Comments

1877. SMA supports adoption of the proposal to include controllable load as a reactive resource. SMA notes that its members' facilities often include significant capacitor banks, and further, reducing load can reduce local reactive requirements.

1878. SoCal Edison suggests caution regarding the Commission's proposal to include controllable load as a reactive resource. It agrees that, when load is reduced, voltage will increase and for that reason controllable load can lessen the need for reactive power. However, SoCal Edison believes that controllable load is typically an energy product and there are other impacts not considered by the Commission's proposal to include controllable load as a reactive resource. For example, activating controllable load for system voltage control lessens system demand, requiring generation to be backed down. It is not clear to SoCal Edison whether any consideration has been given to the potential reliability or commercial impacts of the Commission's proposal.

(b) Commission Determination

1879. The Commission noted in the NOPR that in many cases, load response and demand-side investment can reduce the need for reactive power capability in the system.[476] Based on this assertion, the Commission proposed to direct the ERO to include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR-001-1. While we affirm this requirement, we expect the ERO to consider the comments of SoCal Edison with regard to reliability and SMA in its process for developing the technical capability requirements for using controllable load as a reactive resource in the applicable Reliability Standards.

vi. Summary of Commission Determination

1880. Accordingly, the Commission approves Reliability Standard VAR-001-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and §39.5(f) of our regulations, the Commission directs the ERO to develop a modification to VAR-001-1 through the Reliability Standards development process that: (1) expands the applicability to include reliability coordinators and LSEs; (2) includes detailed and definitive requirements on "established limits" and "sufficient reactive resources" as discussed above, and identifies acceptable margins above the voltage instability points; (3) includes Requirements to perform voltage stability analysis periodically, using online techniques where commercially available and offline techniques where online techniques are not available, to assist real-time operations, for areas susceptible to voltage instability; (4) includes controllable load among the reactive resources to satisfy reactive requirements and (5) addresses the power factor range at the interface between LSEs and the transmission grid.

b. VAR-002-1

1881. Reliability Standard VAR-002-1 requires generator operators to operate in automatic voltage control mode, to maintain generator voltage or reactive power output as directed by the transmission operator, and to notify the transmission operator of a change in status or capability of any generator reactive power resource. The Reliability Standard requires generator owners to provide transmission operators with settings and data for generator step-up transformers. In the NOPR, the Commission stated its belief that Reliability Standard VAR-002-1 is just, reasonable, not unduly discriminatory or

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[476] See FERC Staff Reportl, Principles of Efficient and Reliable Reactive Power Supply and Consumption (2005), available at http://www.ferc.gov/legal/staff-reports.asp.

preferential and in the public interest; and proposed to approve it as mandatory and enforceable.

i. Comments

1882. APPA and SDG&E agree that VAR-002-1 is sufficient for approval as a mandatory and enforceable Reliability Standard.

1883. Dynegy believes that VAR-002-1 should be modified to require more detailed and definitive requirements when defining the time frame associated with an "incident" of non compliance (i.e., each 4-second scan, 10-minute integrated value, hourly integrated value). Dynegy states that, as written, this Reliability Standard does not define the time frame associated with an "incident" of non-compliance, but apparently leaves this decision to the transmission operator. Dynegy believes that either more detail should be added to the Reliability Standard to cure this omission, or the Reliability Standard should require the transmission operator to have a technical basis for setting the time frame that takes into account system needs and any limitations of the generator. Dynegy believes that this approach will eliminate the potential for undue discrimination and the imposition of overly conservative or excessively wide time frame requirements, both of which could be detrimental to grid reliability.

ii. Commission Determination

1884. In the NOPR, the Commission commended NERC and industry for its efforts in expanding on the Requirements of VAR-002-1 from the predecessor standard, and noted that the submitted Reliability Standard includes Measures and Levels of Non-Compliance to ensure appropriate generation operation to maintain network voltage schedules. Accordingly, the Commission approves Reliability Standard VAR-002-1 as mandatory and enforceable.

1885. Dynegy has suggested an improvement to Reliability Standard VAR-002-1, and NERC should consider this in its Reliability Standards development process.

14. Glossary of Terms Used in Reliability Standards

1886. NERC's glossary is updated whenever a new or revised Reliability Standard is approved that includes a new defined term. The glossary may also be approved by a separate action using NERC's Reliability Standards development process. NERC updated the glossary in its August 28, 2006 Supplemental Filing.

1887. In the NOPR, the Commission proposed to approve the glossary. In addition, the Commission proposed to direct NERC to submit a modification to the glossary that: (1) includes the statutory definitions of Bulk-Power System, Reliable Operation, and

Reliability Standard, as set forth in section 215(a) of the FPA; (2) modifies the definitions of "transmission operator" and "generator operator" to include aspects unique to ISOs, RTOs and pooled resource organizations; (3) modifies the definition of "bulk electric system" consistent with discussion in the NOPR Common Issues section[477] and (4) modifies the definition of terms concerning reserves (such as operating reserves) to include DSM, including controllable load.

a. Comments

1888. NERC supports the Commission's proposal to approve the glossary. APPA supports the Commission's proposal to have NERC incorporate the statutory definitions of the terms Bulk-Power System, Reliable Operation and Reliability Standard into the NERC glossary, as an aide to the development of future NERC Reliability Standards.

1889. APPA suggests that the Commission permit NERC and industry to consider whether any modifications to the terms "transmission operator" and "generation operator" are needed, rather than directing NERC to modify these terms. APPA's initial reaction is that the existing terms are adequate and accommodate most elements of ISO, RTO and pooled resource organization operations. APPA believes that a broader and continuing inquiry is required to address such situations. APPA anticipates that many such concerns will arise as NERC and the Regional Entities implement the initial compliance program in June 2007, and states that any additional changes to the glossary should be driven by that experience.

1890. APPA's concerns regarding the Commission proposal to modify the definition of terms concerning reserves to include DSM (including controllable load) are discussed above in reference to the BAL Reliability Standards.

1891. NERC supports the Commission's proposal to direct NERC to complete the necessary improvements to the proposed Reliability Standards through the established NERC Reliability Standards development process.

1892. Santa Clara submits that, to eliminate any ambiguity about when these definitions of these commonly-used terms apply, a footnote should be added to the glossary that states that the definitions contained in the glossary are not intended to supersede any definitions in a tariff or contract approved or accepted by the Commission.

[477] NOPR at P 42-43.

b. **Commission Conclusion**

1893. The Commission approves the glossary. The terms defined in the glossary have an important role in establishing consistent understanding of the Reliability Standards Requirements and implementation. The approval of the glossary will provide continuity in application of the glossary definitions industry-wide, and will eliminate multiple interpretations of the same term or function, which may otherwise create miscommunication and jeopardize Bulk-Power System reliability. The glossary should be updated through the Reliability Standards development process whenever a new or revised Reliability Standard that includes a new defined term is approved, or as needed to clarify compliance activities. For example, the ERO will need to update the glossary to reflect modifications required by the Commission in this Final Rule.[478]

1894. The Commission directs the ERO to modify the glossary through the Reliability Standards development process to include the statutory definitions of the terms Bulk-Power System, Reliable Operation and Reliability Standard. However, this determination does not negate our discussion in the Applicability section of the Final Rule. While the glossary should be revised to include the stautory definition of Bulk-Power System, the Reliability Standards refer to the bulk electric system, which is also defined in the glossary.

1895. The Commission directs the ERO to submit a modification to the glossary that enhances the definitions of "transmission operator" and "generator operator" to reflect concerns of the commenters and the direction provided by the Commission in other sections of this Final Rule. The Commission is concerned that there not be any gaps or unecessary overlaps of responsibilities concerning any of the Requirements in the Reliability Standards that are applicable to transmission operators and generator operators.

1896. Further, we adopt the NOPR proposal to require the ERO to submit a modification to the glossary that updates the definition of "operating reserves," as required in our discussion of BAL-002-0 and BAL-005-0.

1897. Regarding Santa Clara's concern about terms in the glossary differing from definitions in tariffs, we clarify that the glossary governs Reliability Standards, while tariff definitions govern tariff issues. We recognize that many items have different tariff definitions from those in the NERC glossary. However, we expect most of these terms to be consistent. If the glossary definition creates a conflict between the Reliability

[478] See, e.g., MOD-001-0, TOP-002-1 and the INT Reliability Standards.

Standards and a Transmission Organization's function, rule, order, tariff, rate schedule, or agreement accepted, approved, or ordered by the Commission, then the Transmission Organization shall expeditiously notify the Commission, the Electric Reliability Organization and the relevant Regional Entity of the possible conflict pursuant to § 39.6 of the Commission's regulations.[479]

1898. In conclusion, the Commission approves the glossary. Further, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs ERO to modify the glossary through the Reliability Standards development process to: (1) include the statutory definitions of the terms Bulk-Power System, Reliable Operation and Reliability Standard; (2) modify the definition of "transmission operator" and "generator operator" to include aspects unique to ISO, RTO and pooled resource organizations and (3) modify the definition of "operating reserves" as discussed in BAL-002-0 and BAL-005-0.

III. Information Collection Statement

1899. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting and recordkeeping (collections of information) imposed by an agency.[480] The information collection requirements in this Final Rule are identified under the Commission data collection, FERC-725A "Bulk Power System Mandatory Reliability Standards." Under section 3507(d) of the Paperwork Reduction Act of 1995,[481] the proposed reporting requirements in the subject rulemaking will be submitted to OMB for review. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C. 20426 (Attention: Michael Miller, Office of the Executive Director, 202-502-8415) or from the Office of Management and Budget (Attention: Desk Officer for the Federal Energy Regulatory Commission, fax: 202-395-7285, e-mail: oira_submission@omb.eop.gov).

1900. The "public protection" provisions of the Paperwork Reduction Act of 1995 requires each agency to display a currently valid control number and inform respondents that a response is not required unless the information collection displays a valid OMB control number on each information collection or provides a justification as to why the

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[479] 18 CFR 39.6 (2006).

[480] 5 CFR 1320.11.

[481] 44 U.S.C. 3507(d) (2000).

information collection number cannot be displayed. In the case of information collections published in regulations, the control number is to be published in the Federal Register.

1901. **Public Reporting Burden**: In the NOPR, the Commission based its initial estimates on the premise that the proposed Reliability Standards have already been in effect for a substantial period of time on a voluntary basis and consequently entities would have already put them into practice. Seventy of the 125 commenters express concern with the burden to be imposed by the NOPR's requirements. The majority of these comments address the potential impact the requirements would have on small entities but did not provide specific estimates on this impact. Because these comments are also the subject of the analysis performed under the Regulatory Flexibility Act, the Commission has provided a response under that section of this rulemaking. Commenters also raise concerns about the impact of specific Reliability Standards, and the Commission has addressed those concerns in the discussion of each Reliability Standard. Five commenters, Reliant, TAPS, Wisconsin Electric, Portland General and WECC questioned the Commission's initial burden estimates as contained in the NOPR.

1902. By Reliant's estimate, it would take at least four employees to prepare and submit compliance filings and to monitor compliance on an on-going basis. TAPS, while not providing a specific estimate on the burden, believes that the NOPR's proposed application of mandatory Reliability Standards is overly-broad and would encompass several thousand municipal systems. Wisconsin Electric states that the NOPR significantly understated the impact that would be imposed by mandatory Reliability Standards. Wisconsin Electric believes that a "typical control area utility with its multiple functional entity responsibilities" will need far more than the 100 hours estimated by the Commission to manage a quality compliance program as discussed in the ERO's Sanction Guidelines.[482]

1903. Portland General believes that meeting the Requirements of mandatory Reliability Standards will place an additional burden for documentation, over and above compliance with the substance of the Requirements. It claims that the NOPR failed to take this additional burden into account in its cost estimate for compliance. WECC disagrees with the Commission's estimate that compliance cost would be $40 million annually on an aggregate basis. It also disagrees with the Commission's assumption that there would be no increased reporting burden or additional information requirements because the Reliability Standards impose new documentation requirements that will create additional costs.

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[482] Wisconsin Electric at 9.

1904. In response to the comments and upon further review we have revised our initial estimates as reflected in the table below. While the ERO has submitted several new Reliability Standards and included additional Measures for documenting compliance with 20 existing Reliability Standards, we continue to believe that the reporting requirements embedded in the Reliability Standards that are approved in the Final Rule have been implemented on a voluntary basis for many years in most instances.[483] This would not apply, however, to entities that are new to reliability oversight. We encourage entities that are responsible for compliance with mandatory Reliability Standards to develop a quality compliance program as discussed in the ERO's Sanction Guidelines. However, we believe that the costs of such a program are distinct from the reporting burdens that are estimated below.

1905. Further, our estimates below reflect a revision in the number of respondents, based on our determinations regarding "applicability," as discussed in section II.C above.

1906. Total Annual Hours for Collection:

Data Collection	No. of Respondents	No. of Responses	Hours Per Response	Total Annual Hours
FERC-725A				
Investor Owned Utilities	170	1	2,080	353,600
Municipals and Cooperatives - Large	80	1	1,420	113,600
Municipals and Cooperatives - Small	670	1	710	475,700
Generator Operators	360	1	500	180,000

[483] NOPR at P 1157.

Power Marketers	159	1	100	15,900
Recordkeeping	Investor Owned Utilities			35,360
	Munis/Coops (Large)			11,360
	Munis/Coops (Small)			47,570
	Generator Owner/Ops.			18,000
	Power Marketers			1,590
	Totals			1,252,680

(FTE=Full Time Equivalent or 2,080 hours)

Total Hours = 1,138,800 (reporting) + 113,880 (recordkeeping) = 1,252,680 hours. This estimated reporting burden will be significantly reduced once joint action agencies are established, which would will reduce the number of small entities that will be responsible for compliance with Reliability Standards.

1907. **Information Collection Costs**: The Commission sought comments about the costs needed to comply with these requirements. As noted above, a number of commenters state that the NOPR underestimated the burden of the rulemaking in terms of hours required to comply. However, no comments were received regarding the Commission's estimate of the projected cost of $200/hour to comply with these requirements. In further consideration, the Commission believes that the $200/hour projection is too high, and the calculations below reflect an adjusted hourly figure.

Cost to Comply:

Reporting = 1,138,800 @ $114/hour = $129,823,200

1,138,800 hours @ 114 per hour (average cost of attorney ($200 per hour), consultant ($150), technical ($80) and administrative support ($25)).

Recordkeeping = 113,880 @ $17/hour = $1,935,960

113,880 hours @ $17 per hour (file/record clerk @ $17 an hour)

Total Costs: Reporting ($129,823,200) + Recordkeeping ($1,935,960) = $131,759,160.

Sources: "NERC Compliance Update: What it might cost to comply", Herb Schrayshuen, NARUC-Electric Reliability Staff Subcommittee, November 12, 2006.

Janco Associates, Inc., 2005 Information Technology Compensation Study, January 2005.

Bureau of Labor Statistics, Department of Labor, Occupational Outlook Handbook, http://www.bls.gov/oco/ocos268.htm.

Titles: FERC-725A "Mandatory Reliability Standards for the Bulk-Power System"

Action: Proposed Collection of Information

OMB Control Nos: To be determined.

Respondents: Business or other for profit, not for profit institutions, state, local or tribal government and Federal Government.

Frequency of Responses: On occasion.

Necessity of Information: The Final Rule approves 83 Reliability Standards. Compliance with such Reliability Standards will be mandatory and enforceable for the applicable categories of entities identified in each Reliability Standard. These Reliability Standards are approved by the Commission pursuant to its authority under section 215 of the FPA, which authorizes the Commission to approve a Reliability Standard proposed by the ERO if the Commission determines that it is just and reasonable, not unduly discriminatory or preferential and in the public interest. The Reliability Standards approved in this Final Rule are necessary for the reliable operation of the nation's interconnected Bulk-Power System.

For information on the requirements, submitting comments on the collection of information and the associated burden estimates including suggestions for reducing this burden, please send your comments to the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C. 20426 (Attention: Michael Miller, Office of the Executive Director, 202-502-8415) or send comments to the Office of Management and Budget (Attention: Desk Officer for the Federal Energy Regulatory Commission, fax: 202-395-7285, e-mail oira_submission@omb.eop.gov).

IV. Environmental Analysis

1908. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[484] The actions proposed here fall within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural, for information gathering, analysis, and dissemination.[485]

V. Regulatory Flexibility Act

1909. The Regulatory Flexibility Act of 1980 (RFA)[486] generally requires a description and analysis of Final Rules that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking. It only requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected.

1910. In drafting a rule an agency is required to: (1) assess the effect that its regulation will have on small entities; (2) analyze effective alternatives that may minimize a regulation's impact and (3) make the analyses available for public comment.[487] In its NOPR, the agency must either include an initial regulatory flexibility analysis (initial RFA)[488] or certify that the proposed rule will not have a "significant impact on a substantial number of small entities."[489]

1911. If in preparing the NOPR an agency determines that the proposal could have a significant impact on a substantial number of small entities, the agency shall ensure that small entities will have an opportunity to participate in the rulemaking procedure.[490]

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[484] Regulations Implementing the National Environmental Policy Act, Order No. 486, 52 FR 47,897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

[485] 18 CFR 380.4(a)(5).

[486] 5 USC 601 – 612 (2006).

[487] 5 USC 601 – 604.

[488] 5 USC 603(a).

[489] 5 USC 605(b).

[490] 5 USC 609(a).

1912. In its Final Rule, the agency must also either prepare a Final Regulatory Flexibility Analysis (Final RFA) or make the requisite certification. Based on the comments the agency receives on the NOPR, it can alter its original position as expressed in the NOPR but it is not required to make any substantive changes to the proposed regulation.

1913. The statute provides for judicial review of an agency's final certification or Final RFA.[491] An agency must file a Final RFA demonstrating a "reasonable, good-faith effort" to carry out the RFA mandate.[492] However, the RFA is a procedural, not a substantive, mandate. An agency is only required to demonstrate a reasonable, good faith effort to review the impact the proposed rule would place on small entities, any alternatives that would address the agency's and small entities' concerns and their impact, provide small entities the opportunity to comment on the proposals, and review and address comments. An agency is not required to adopt the least burdensome rule. Further, the RFA does not require an agency to assess the impact of a rule on all small entities that may be affected by the rule, only on those entities that the agency directly regulates and that will be directly impacted by the rule.[493]

A. Notice of Proposed Rulemaking

1914. In the NOPR, the Commission stated that the proposed Reliability Standards "may cause some small entities to experience significant economic impact."[494] In response to the ERO's proposal to develop limits on the applicability of specific Reliability Standards, the Commission stated that, while it could not rule on the merits until a specific proposal is submitted, the Commission stated that it believed that reasonable limits based on size may be an acceptable alternative to "lessen the economic impact on the proposed rule on small entities."[495] The Commission emphasized that any such limits must not weaken Bulk-Power System reliability.

1915. Further, under the Applicability Issues section of the NOPR, we devoted an entire subsection to the issues facing small entities.[496] The Commission stated that there may

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[491] 5 USC 611.

[492] United Cellular Corp. v. FCC, 254 F.3d 78, 88 (D.C. Cir. 2001); Alenco Commuications, Inc. v. FCC, 201 F.3d 608, 625 (5th Cir. 2000).

[493] Mid-Tex Electric Coop., Inc. v. FERC, 773 F.2d 327 (D.C. Cir 1985).

[494] NOPR at P 1175.

[495] Id. at 1176.

[496] Id. at 49-53 (Section B.3 "Applicability to Small Entities").

be instances in which small entity compliance with a particular Reliability Standard may be critical to reliability. It explained that, in such circumstances, it may be appropriate to differentiate among subsets of users, owners and operators. As an example, the NOPR provided that "the requirement to have adequate communications capabilities to address real-time emergency conditions . . . may be necessary for all applicable entities regardless of size or role, although we understand that the implementation of these requirements for applicable entities may vary based on size or role."[497] Additionally, in the NOPR, the Commission supported the ERO's proposal to permit the registration of "joint action agencies," a concept designed to ease the burden of small entities by allowing one organization to perform reliability-related activities for multiple entities. The Commission proposed to direct the ERO to develop procedures that would permit a joint action agency or similar organization to accept compliance responsibility on behalf of its members.

1916. Thus, in the NOPR, the Commission discussed the potential disparate impact on small entities, considered the implications and potential alternatives and solicited comments on the limiting the application of the Reliability Standards to small entities. Further, the Information Collection Statement discussed the difficulty estimating the number of small entities that would be affected by the Reliability Standards. As such, the Commission was aware of the potential impacts on small entities and was actively considering alternatives that would lessen the impact on them while still ensuring reliability of the Bulk-Power System.

1. Comments

1917. APPA and NRECA, in their joint comments, provide data about their membership. APPA states that, based on 2005 data, 1,971 public utilities or 98 percent of the public utilities in the United States had less than 4 million MW hours in sales which would qualify them as small entities. Of these, 90 percent - or 1,775 - are distribution-only utilities, 48 are wholesale–only, and 148 make both wholesale and retail sales.[498] NRECA states that its membership includes 930 rural cooperatives most of which are distribution utilities and almost all of which would qualify as small entities. Additionally, according to NRECA, 40 of its 65 generation and transmission cooperatives also qualify as small entities.[499]

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[497] Id. at 51.

[498] APPA/NRECA comments at 2.

[499] Id.

1918. APPA/NRECA contends that the Commission did not include a complete initial RFA analysis as required and, without a full initial RFA, the Commission cannot lay a proper foundation for eliciting public comments on the impacts of the rule on small entities. Specifically, APPA/NRECA contends that the NOPR failed to include proposals that would minimize the impact on small entities. They assert that, instead, the Commission's proposed definition of bulk electric system in the NOPR exceeds NERC's definition and thereby sweeps in many small facilities that are unnecessary to the Reliable Operation of the Bulk-Power System. APPA/NRECA argue that, if the Commission adopts this definition, many small transmission owners and operators of lower voltage transmission systems will be unnecessarily required to bear the increased training costs to comply with Reliability Standards, yet the NOPR never considered these additional burdens. APPA/NRECA also asserts that, under this definition, many small distribution providers would also be required to comply with the communication-related (COM) Reliability Standards at additional costs that were never discussed. They request that the Commission address these shortcomings.

1919. APPA/NRECA also claims that the Commission substantially underestimated the number of small entities that would be impacted by the application of the Reliability Standards as proposed in the NOPR. APPA/NRECA asserts that 98 percent of public utilities and 99 percent of public cooperatives, along with numerous small industrial facilities, small qualifying facilities and small generators would qualify under the small entity definition and would be impacted by the rule. According to APPA/NRECA, most of these small entities would not have a material impact on the reliability of the Bulk-Power System but, under the NOPR's definition of Bulk-Power System, would be required to comply with the Reliability Standards.

1920. APPA/NRECA suggests that the Commission can significantly reduce the impact on small entities by "focusing on materiality." They contend that an overly-expansive reliability regime would violate the FPA by imposing unnecessary regulatory burdens on small entities and divert the ERO's and the Commission's resources away from those entities that are crucial to Bulk-Power System reliability. APPA/NRECA asserts that the Commission can ensure reliability without unnecessarily burdening small entities by considering two alternatives. First, they urge the Commission to adopt NERC's current definition of bulk electric system. Second, they ask the Commission to reconsider the standard-by-standard approach to defining owners, users and operators of the Bulk-Power System and, instead, accept the NERC compliance registry to identify the entities that will be responsible for compliance with Reliability Standards. APPA/NRECA, TAPS, and numerous other commenters discuss these proposals in their comments, which the Commission addresses in the Applicability Issues section of the Final Rule.[500]

1921. TAPS asserts that the Commission should apply the ERO's registration thresholds and, "absent such limits, the Commission cannot satisfy its obligations under the [RFA]."[501] Georgia Cities asserts that the Commission should adopt reasonable limits on the application of the Reliability Standards to small entities, as it promised in its RFA statement.

2. Commission response

1922. The Commission believes that the NOPR provided a meaningful discussion of the impact that the Reliability Standards could have on small entities and discussed several potential alternatives. In fact, the NOPR contained an entire section on the applicability of the proposed standards on small entities.[502] In that section, the Commission discussed various alternatives to lessen the acknowledged potential impact on small entities. The Commission indicated its receptiveness to the ERO's proposal to develop threshold limits regarding the applicability of specific Reliability Standards. The Commission also suggested that, where it is necessary for reliability that a Reliability Standard apply to small entities, implementation of the requirements of such Reliability Standards may vary based on size or role. In the NOPR, the Commission set forth another alternative to address the potential burden on small entities when it proposed to direct the ERO to develop procedures permitting a joint action agency or similar organization to accept compliance responsibility on behalf of its members.

1923. As previously stated, the purpose of the RFA is to ensure that agencies consider the impact a proposed rule would have on small entities and any potential alternatives that would minimize that impact. The initial RFA analysis is designed to elicit informed comments on the impacts to small entities and alternatives. The Commission believes the NOPR achieved this goal. After the NOPR was issued, the Commission received over 125 comments and a majority of those addressed small entity issues. Further, almost all of the commenters addressed the NOPR's proposed interpretation of the definition of the

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[500] See Applicability Issues: Bulk-Power System v. Bulk Electric System and Applicability to Small Entities, supra sections II.C.1-2.

[501] TAPS at 13.

[502] NOPR at P 49-53.

bulk electric system, which as APPA/NRECA states would have had the greatest impact on small entities.

1924. In addition to the comments received addressing these issues, Commission staff has met with representatives of small entities, including APPA and NRECA, and listened to their concerns on the potential impacts of the Final Rule and discussed possible alternatives.

1925. Since receiving APPA/NRECA's comments on the RFA, the Commission has compiled and reviewed available data on small entities and the impact of the Final Rule on such entities. Therefore, the Commission believes that any inadequacy that may have existed in the NOPR's initial RFA analysis has now been corrected. This Final RFA and the alternative proposals adopted herein demonstrate the Commission's consideration of the potential burdens that the rulemaking could place on small entities.

1926. As discussed in the Applicability section above, the Commission adopts in the Final Rule the current definition of bulk electric system. Any possible change to the definition would occur in a future Commission proceeding. Further, the Commission has endorsed the ERO's compliance registry process to identify the entities that must comply with mandatory Reliability Standards.[503] By adopting these alternative proposals, the Commission has been responsive to small entity concerns and greatly reduced the number of small entities that will be affected by the Final Rule.

B. Final RFA

1. Description of the reasons why action by the agency is being considered

1927. On April 4, 2006, as later modified and supplemented, NERC – the ERO – submitted 107 Reliability Standards for Commission approval pursuant to section 215(d) of the FPA. The ERO's submission includes the "Version 0" standards with which the electric industry has complied on a voluntary basis as well as several new Reliability Standards approved by NERC since its certification as the ERO.

1928. As set forth in section 215(a) of the FPA, the term "Reliability Standard" means a requirement, approved by the Commission to provide for the Reliable Operation of the Bulk-Power System. The term "Reliable Operation" means "operating the elements of

[503] As noted previously, APPA, NRECA and TAPs submitted supplemental comments supporting the ERO's compliance registry process.

the bulk-power system within equipment and electric system, thermal, voltage, and stability limits so that instability, uncontrolled, or cascaded failures of such system will not occur as a result of a sudden disturbance . . . or unanticipated failure of system elements."[504] Thus, the purpose of each Reliability Standard approved by the Commission in this Final Rule is to provide for the Reliable Operation of the Bulk-Power System and thereby minimize the risk of instability, uncontrolled or cascading failure on the Bulk-Power System.

1929. The Commission is approving 83 of the proposed Reliability Standards. Upon the effective date of the Final Rule, compliance with these Reliability Standards will be mandatory and enforceable for applicable users, owners and operators of the Bulk-Power System. The Commission believes that these Reliability Standards form a solid foundation on which to develop and maintain the reliability of the North American Bulk-Power System.

2. Objectives of and the legal basis for the Final Rule

1930. This Final Rule requires applicable users, owners and operators of the Bulk-Power System to comply with mandatory and enforceable Reliability Standards. As discussed above, these Reliability Standards are necessary to ensure the reliable operation of the North American Bulk-Power System.

1931. EPAct 2005 added a new section 215 to the FPA, which provides for a system of mandatory and enforceable Reliability Standards. Section 215(d)(1) of the FPA provides that the ERO must file each Reliability Standard or modification to a Reliability Standard that it proposes to be made effective, i.e., mandatory and enforceable, with the Commission. As mentioned above, on April 4, 2006, and as later modified and supplemented, the ERO submitted 107 Reliability Standards for Commission approval pursuant to section 215(d) of the FPA.

1932. Section 215(d)(2) of the FPA provides that the Commission may approve, by rule or order, a proposed Reliability Standard or modification to a proposed Reliability Standard if it meets the statutory standard for approval, giving due weight to the technical expertise of the ERO. Alternatively, the Commission may remand a Reliability Standard pursuant to section 215(d)(4) of the FPA. Further, the Commission may order the ERO to submit to the Commission a proposed Reliability Standard or a modification to a Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Reliability Standard appropriate to "carry out" section 215 of the

[504] 16 U.S.C. 824o(a)(4) (2006).

FPA.[505] The Commission's action in this Final Rule is based on its authority pursuant to section 215 of the FPA.

3. Significant issues raised by comments, agency assessment of the comments and a statement of any changes made in the proposed rule as a result of the comments

1933. Numerous small entity commenters oppose the NOPR interpretation of bulk electric system and urge the Commission to adopt the ERO's current definition of that term. Further, small entity commenters oppose the NOPR's proposal to address applicability on a standard-by-standard basis and, instead, ask that the Commission rely on the ERO's compliance registry process as the means to identify entities responsible for complying with mandatory and enforceable Reliability Standards. Commenters assert that the Commission's proposed changes would greatly increase the number of small entities that would be significantly impacted by the Final Rule.

1934. As discussed above, the Commission is not adopting its proposed interpretation of bulk electric system contained in the NOPR. Rather, the Commission adopts the NERC definition of bulk electric system. Further, the Commission is relying on NERC's registration process to provide as much certainty as possible regarding the applicability and responsibility of specific entities in the start-up phase of the mandatory Reliability Standards regime. Any change in these approaches would be addressed in a separate Commission proceeding.

1935. A complete summary of these comments and the Commission's response has been previously addressed in the Applicability section.

4. Description and estimate of the number of small entities to which the Final Rule will apply

1936. According to the SBA, a small electric utility is defined as one that has a total electric output of less than four million MWh in the preceeding year.

1937. According to the DOE's Energy Information Administration (EIA), there were 3,284 electric utility companies in the United States in 2005,[506] and 3,029 of these electric utilities qualify as small entities under the SBA definition. Of these 3,284 electric utility

[505] See 16 U.S.C. 824o(d)(5) (2006).

[506] See Energy Information Administration Database, Form EIA-861, Dept. of Energy (2005), available at http://www.eia.doe.gov/cneaf/electricity/page/eia861.html.

companies, the EIA subdivides them as follows: (1) 883 cooperatives of which 852 are small entity cooperatives; (2) 1,862 municipal utilities, of which 1842 are small entity municipal utilities; (3) 127 political subdivisions, of which 114 are small entity political subdivisions; (4) 159 power marketers, of which 97 individually could be considered small entity power marketers;[507] (5) 219 privately owned utilities, of which 104 could be considered small entity private utilities; (6) 25 state organizations, of which 16 are small entity state organizations and (7) nine federal organizations of which four are small entity federal organizations.

1938. As discussed above, the Commission is relying on the ERO's compliance registry process to identify which entities must comply with mandatory and enforceable Reliability Standards. The ERO's Compliance Registry Criteria describe how NERC will identify organizations that may be candidates for registration and assign them to the compliance registry.[508] According to this document, the ERO will register transmission owners and operators with an integrated element associated with the Bulk-Power System of 100 kV and above, or lower voltage as defined by a Regional Entity. The ERO plans to register only those distribution providers or LSEs that have a peak load of 25 MW or greater and are directly connected to the bulk electric system <u>or</u> are designated as a responsible entity as part of a required underfrequency load shedding program or a required undervoltage load shedding program. For generators, the ERO plans to register individual units of 20 MVA or greater that are directly connected to the bulk electric system, generating plants with an aggregate rating of 75 MVA or greater, any blackstart unit material to a restoration plan, or any generator "regardless of size, that is material to the reliability of the Bulk-Power System." Further, the ERO will not register an entity that meets the above criteria if it has transferred responsibility for compliance with mandatory Reliability Standards to a joint action agency or other organization.

1939. As mentioned above, the SBA defines a small electric utility as one that has a total electric output of less than four million MWh in the proceeding year. Thus, the set of small entities that must comply with mandatory Reliability Standards would be those that exceed the ERO registry criteria but still meet the SBA definition. The Commission has reviewed data compiled by EIA in Form EIA-861, NERC's pre-registry data, and information submitted by commenters, and determined an estimate of the number of small entities to which the Final Rule will apply.

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[507] Most of these small entity power marketers and private utilities are affiliated with others and, therefore, do not qualify as small entities under the SBA definition.

[508] <u>See</u> NERC Statement of Compliance Registry Criteria (Revision 3) at 6-8.

1940. The Commission estimates that the Reliability Standards approved in the Final Rule will apply to approximately 682 small entities (excluding entities in Alaska and Hawaii) as follows:

> 670 small municipal utilities and cooperatives and 12 small investor-owned utilities.

1941. As discussed above, the ERO's Compliance Registry Criteria allows for a joint action agency, G&T cooperative or similar organization to accept compliance responsibility on behalf of its members. Once such organizations register with the ERO, the number of small entities registered with the ERO will diminish and, thus, significantly reduce the impact of the Final Rule on small entities.

1942. To be included in the compliance registry, the ERO will have made a determination that a specific small entity has a material impact on the Bulk-Power System. Consequently, the compliance of such small entities is justifiable as necessary for Bulk-Power System reliability.

5. Description of the projected reporting, record keeping and other compliance requirements for small entities

1943. A complete summary of comments and the Commission's response has been previously addressed in the Information Collection Statement section.

6. Duplication of other Federal Rules

1944. There are no relevant Federal rules which may duplicate, overlap or conflict with the Final Rule.

7. Description of any significant alternatives to the Final Rule

1945. In the Final Rule, the Commission adopts several significant alternatives that will minimize the burden on small entities. The Commission approves the current ERO definition of bulk electric system, which will reduce significantly the number of small entities responsible for complying with the Final Rule. The Commission also approves the ERO compliance registry process to identify the entities responsible for compliance with mandatory and enforceable Reliability Standards. Further, the Commission directs the ERO to submit a procedure to permit a joint action agency or similar organization to accept compliance responsibility on behalf of its members. A complete summary of comments and the Commission's response has been previously addressed in the Applicability Section.

VI. Document Availability

1946. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington D.C. 20426.

1947. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printin, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

1948. User assistance is available for eLibrary and FERC's website during normal business hours from our Help line at (202) 502-8222 or the Public Reference Room at (202) 502-8371 Press 0, TTY (202) 502-8659. E-Mail the Public Reference Room at public.referenceroom@ferc.gov.

VII. Effective Date and Congressional Notification

1949. These regulations are effective [**insert date 60 days from the date the rule is published in the Federal Register**]. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of subjects in 18 CFR Part Part 40
Electric power; reporting and recordkeeping requirements

By the Commission.

(S E A L)

Philis J. Posey,
Acting Secretary.

In consideration of the foregoing, the Commission proposes to amend Chapter I, Title 18, Code of Federal Regulations, by adding Part 40 to read as follows:

PART 40 -- MANDATORY RELIABILITY STANDARDS FOR THE BULK-POWER SYSTEM

Sec.

Authority: 16 U.S.C. 824o.

§ 40.1 Applicability.

(a) This part applies to all users, owners and operators of the Bulk-Power System within the United States (other than Alaska or Hawaii), including, but not limited to, entities described in section 201(f) of the Federal Power Act.

(b) Each Reliability Standard made effective by § 40.2 must identify the subset of users, owners and operators of the Bulk-Power System to which a particular Reliability Standard applies.

§ 40.2 Mandatory Reliability Standards

(a) Each applicable user, owner or operator of the Bulk-Power System must comply with Commission-approved Reliability Standards developed by the Electric Reliability Organization.

(b) A proposed modification to a Reliability Standard proposed to become effective pursuant to § 39.5 of this Chapter will not be effective until approved by the Commission.

§ 40.3 Availability of Reliability Standards.

The Electric Reliability Organization must post on its website the currently effective Reliability Standards as approved and enforceable by the Commission. The effective date of the Reliability Standards must be included in the posting.

NOTE: The following appendices will not be published in the Code of Federal Regulations.

Appendix A
Disposition of Standards, Glossary and Regional Differences

Reliability Standard	Title	Proposed Disposition
BAL-001-0	Real Power Balancing Control Performance	**Approve**
BAL-002-0	Disturbance Control Performance	**Approve; direct modification**
BAL-003-0	Frequency Response and Bias	**Approve; direct modification**
BAL-004-0	Time Error Correction	**Approve; direct modification**
BAL-005-0	Automatic Generation Control	**Approve; direct modification**
BAL-006-1	Inadvertent Interchange	**Approve; direct modification**
CIP-001-1	Sabotage Reporting	**Approve; direct modification**
COM-001-1	Telecommunications	**Approve; direct modification**
COM-002-2	Communications and Coordination	**Approve; direct modification**
EOP-001-0	Emergency Operations Planning	**Approve; direct modification**
EOP-002-2	Capacity and Energy Emergencies	**Approve; direct modification**
EOP-003-1	Load Shedding Plans	**Approve; direct modification**
EOP-004-1	Disturbance Reporting	**Approve; direct modification**
EOP-005-1	System Restoration Plans	**Approve; direct modification**
EOP-006-1	Reliability Coordination - System Restoration	**Approve; direct modification**
EOP-007-0	Establish, Maintain, and Document a Regional Blackstart Capability Plan	**Pending**
EOP-008-0	Plans for Loss of Control Center Functionality	**Approve; direct modification**
EOP-009-0	Documentation of Blackstart Generating Unit Test Results	**Approve**
FAC-001-0	Facility Connection Requirements	**Approve**
FAC-002-0	Coordination of Plans for New Facilities	**Approve; direct modification**
FAC-003-1	Transmission Vegetation Management Program	**Approve; direct modification**
FAC-004-0	Methodologies for Determining Electrical Facility Ratings	**Withdrawn**
FAC-005-0	Electrical Facility Ratings for System Modeling	**Withdrawn**
FAC-008-1	Facility Ratings Methodology	**Approve; direct modification**
FAC-009-1	Establish and Communicate Facility Ratings	**Approve**
FAC-012-1	Transfer Capabilities Methodology	**Pending**

Reliability Standard	Title	Proposed Disposition
FAC-013-1	Establish and Communicate Transfer Capabilities	**Approve; direct modification**
INT-001-2	Interchange Transaction Tagging	**Approve; direct modification**
INT-002-0	Interchange Transaction Tag Communication and Assessment	**Withdrawn**
INT-003-2	Interchange Transaction Implementation	**Approve**
INT-004-1	Interchange Transaction Modifications	**Approve**
INT-005-1	Interchange Authority Distributes Arranged Interchange	**Approve**
INT-006-1	Response to Interchange Authority	**Approve; direct modification**
INT-007-1	Interchange Confirmation	**Approve**
INT-008-1	Interchange Authority Distributes Status	**Approve**
INT-009-1	Implementation of Interchange	**Approve**
INT-010-1	Interchange Coordination Exceptions	**Approve**
IRO-001-1	Reliability Coordination – Responsibilities and Authorities	**Approve; direct modification**
IRO-002-1	Reliability Coordination – Facilities	**Approve; direct modification**
IRO-003-2	Reliability Coordination – Wide Area View	**Approve; direct modification**
IRO-004-1	Reliability Coordination - Operations Planning	**Approve; direct modification**
IRO-005-1	Reliability Coordination – Current Day Operations	**Approve; direct modification**
IRO-006-3	Reliability Coordination – Transmission Loading Relief	**Approve; direct modification**
IRO-014-1	Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	**Approve**
IRO-015-1	Notifications and Information Exchange Between Reliability Coordinators	**Approve**
IRO-016-1	Coordination of Real-time Activities Between Reliability Coordinators	**Approve**
MOD-001-0	Documentation of TTC and ATC Calculation Methodologies	**Pending; direct modification**
MOD-002-0	Review of TTC and ATC Calculations and Results	**Pending**
MOD-003-0	Procedure for Input on TTC and ATC Methodologies and Values	**Pending**
MOD-004-0	Documentation of Regional CBM Methodologies	**Pending; direct modification**
MOD-005-0	Procedure for Verifying CBM Values	**Pending**
MOD-006-0	Procedures for Use of CBM Values	**Approve; direct modification**
MOD-007-0	Documentation of the Use of CBM	**Approve; direct modification**
MOD-008-0	Documentation and Content of Each Regional TRM Methodology	**Pending; direct modification**
MOD-009-0	Procedure for Verifying TRM Values	**Pending**
MOD-010-0	Steady-State Data for Transmission System Modeling and Simulation	**Approve; direct modification**
MOD-011-0	Regional Steady-State Data Requirements and Reporting Procedures	**Pending; direct modification**

Reliability Standard	Title	Proposed Disposition
MOD-012-0	Dynamics Data for Transmission System Modeling and Simulation	**Approve; direct modification**
MOD-013-1	RRO Dynamics Data Requirements and Reporting Procedures	**Pending; direct modification**
MOD-014-0	Development of Interconnection-Specific Steady State System Models	**Pending; direct modification**
MOD-015-0	Development of Interconnection-Specific Dynamics System Models	**Pending; direct modification**
MOD-016-1	Actual and Forecast Demands, Net Energy for Load, Controllable DSM	**Approve; direct modification**
MOD-017-0	Aggregated Actual and Forecast Demands and Net Energy for Load	**Approve; direct modification**
MOD-018-0	Reports of Actual and Forecast Demand Data	**Approve**
MOD-019-0	Forecasts of Interruptible Demands and DCLM Data	**Approve; direct modification**
MOD-020-0	Providing Interruptible Demands and DCLM Data	**Approve; direct modification**
MOD-021-0	Accounting Methodology for Effects of Controllable DSM in Forecasts	**Approve; direct modification**
MOD-024-1	Verification of Generator Gross and Net Real Power Capability	**Pending**
MOD-025-1	Verification of Generator Gross and Net Reactive Power Capability	**Pending; direct modification**
PER-001-0	Operating Personnel Responsibility and Authority	**Approve**
PER-002-0	Operating Personnel Training	**Approve; direct modification**
PER-003-0	Operating Personnel Credentials	**Approve; direct modification**
PER-004-1	Reliability Coordination – Staffing	**Approve; direct modification**
PRC-001-1	System Protection Coordination	**Approve; direct modification**
PRC-002-1	Define and Document Disturbance Monitoring Equipment Requirements	**Pending**
PRC-003-1	Regional Requirements for Analysis of Misoperations of Transmission and Generation Protection Systems	**Pending**
PRC-004-1	Analysis and Mitigation of Transmission and Generation Protection System Misoperations	**Approve**
PRC-005-1	Transmission and Generation Protection System Maintenance and Testing	**Approve; direct modification**
PRC-006-0	Development and Documentation of Regional UFLS Programs	**Pending**
PRC-007-0	Assuring Consistency with Regional UFLS Program	**Approve**
PRC-008-0	Underfrequency Load Shedding Equipment Maintenance Programs	**Approve; direct modification**
PRC-009-0	UFLS Performance Following an Underfrequency Event	**Approve**
PRC-010-0	Assessment of the Design and Effectiveness of UVLS Program	**Approve; direct modification**
PRC-011-0	UVLS System Maintenance and Testing	**Approve; direct modification**

Reliability Standard	Title	Proposed Disposition
PRC-012-0	Special Protection System Review Procedure	**Pending**
PRC-013-0	Special Protection System Database	**Pending**
PRC-014-0	Special Protection System Assessment	**Pending**
PRC-015-0	Special Protection System Data and Documentation	**Approve**
PRC-016-0	Special Protection System Misoperations	**Approve**
PRC-017-0	Special Protection System Maintenance and Testing	**Approve; direct modification**
PRC-018-1	Disturbance Monitoring Equipment Installation and Data Reporting	**Approve**
PRC-020-1	Undervoltage Load Shedding Program Database	**Pending**
PRC-021-1	Undervoltage Load Shedding Program Data	**Approve**
PRC-022-1	Undervoltage Load Shedding Program Performance	**Approve**
TOP-001-1	Reliability Responsibilities and Authorities	**Approve; direct modification**
TOP-002-2	Normal Operations Planning	**Approve; direct modification**
TOP-003-0	Planned Outage Coordination	**Approve; direct modification**
TOP-004-1	Transmission Operations	**Approve; direct modification**
TOP-005-1	Operational Reliability Information	**Approve; direct modification**
TOP-006-1	Monitoring System Conditions	**Approve; direct modification**
TOP-007-0	Reporting SOL and IROL Violations	**Approve**
TOP-008-1	Response to Transmission Limit Violations	**Approve;**
TPL-001-0	System Performance Under Normal Conditions	**Approve; direct modification**
TPL-002-0	System Performance Following Loss of a Single BES Element	**Approve; direct modification**
TPL-003-0	System Performance Following Loss of Two or More BES Elements	**Approve; direct modification**
TPL-004-0	System Performance Following Extreme BES Events	**Approve; direct modification**
TPL-005-0	Regional and Interregional Self-Assessment Reliability Reports	**Pending**
TPL-006-0	Assessment Data from Regional Reliability Organizations	**Pending**
VAR-001-1	Voltage and Reactive Control	**Approve; direct modification**
VAR-002-1	Generator Operations for Maintaining Network Voltage Schedules	**Approve**
Glossary	Glossary of Terms Used in Reliability Standards	**Approve; direct modification**
Regional Difference	BAL-001:ERCOT:CPS2	**Approve; direct modification**
Regional Difference	BAL-006: MISO RTO inadvertent Interchange Accounting	**Approve**
Regional Difference	BAL-006: MISO/SPP Financial Inadvertent Settlement	**Approve**
Regional Difference	INT-001/4: WECC Tagging Dynamic Schedules and Inadvertent Payback	**Pending**

Reliability Standard	Title	Proposed Disposition
Regional Difference	INT-001/3:MISO Energy Flow Information	**Approve**
Regional Difference	INT-003: MISO/SPP Scheduling Agent	**Approve**
Regional Difference	INT-003: MISO Enhanced Scheduling Agent	**Approve**
Regional Difference	IRO-006: PJM/MISO/SPP Enhanced Congestion Management	**Pending**

Appendix B: Commenters on Notice of Proposed Rulemaking

ABBREVIATION	ENTITY
Alberta ESO	Alberta Electric System Operator
ALCOA	Alcoa, Inc. and Alcoa Power Generating Company
Allegheny	Allegheny Power and Allegheny Energy Supply Company, LLC
AMP Ohio	American Municipal Power – Ohio, Inc.
APPA	American Public Power Association
APPA/NRECA	APPA/NRECA
ATC	American Transmission Company, LLC
Avista/Puget	Avista Corporation and Puget Sound Energy, Inc.
BPA	Bonneville Power Administration
CAISO	California Independent System Operator Corporation
California Cogernation	Cogeneration Association of California and the Energy Producers and Users Coalition
California PUC	Public Utilities Commission of the State of California
CEA	Canadian Electricity Association
Cleveland Public Power	City of Cleveland, Division of Cleveland Public Power
Comverge	Comverge, Inc.
Connecticut Attorney General*	Richard Blumenthal, Attorney General for the State of Connecticut
Connecticut DPUC*	Connecticut Department of Public Utility Control
Constellation	Constellation Energy Group
Dominion	Dominion Resources Services, Inc.
Duke	Duke Energy Corporation
Dynegy	Dynegy, Inc.
EEI	Edison Electric Institute
ELCON	Electricity Consumers Resource Council
Entergy	Entergy Services, Inc.
EPSA	Electric Power Supply Association
ERCOT	Electric Reliability Council of Texas, Inc.
Fertilizer Institute	Fertilizer Institute
FirstEnergy	FirstEnergy Service Company

Georgia Cities	City of Acworth City of Adel City of Blakely City of Cairo City of Calhoun City of Camilla City of College Park City of Commerce City of Doerun City of Douglas City of East Point City of Ellaville City of Fairburn City of Forsyth City of Fort Valley City of Grantville City of Hogansville City of Lafayette City of Lagrange City of Lawrenceville City of Mansfield City of Monticello City of Moultrie City of Norcross City of Oxford City of Palmetto City of Quitman City of Sanderville City of Sylvester City of Thomaston City of Thomasville City of Washington City of West Point Crisp County Power Commission City of Whigham Fitzgerald Water, Light and Bond Commission Marietta Power and Water
Georgia Operators	Georgia System Operators Corp.
International Transmission	International Transmission Company
ISO/RTO Council	ISO/RTO Council

ISO-NE	ISO New England, Inc.
KCP&L	Kansas City Power and Light Company
LPPC	Large Public Power Council
Manitoba	Manitoba Hydro
Marshall Municipal Utility Group	
Massachusetts DTE	Massachusetts Department of Telecommunications and Energy
MEAG Power	MEAG Power
MidAmerican	MidAmerican Electric Operating Companies
Mid-Continent	Mid- Continent Systems Group
MISO-PJM	Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.
MRO	Midwest Reliability Organization
NARUC	National Association of Regulatory Utility Commissioners
National Grid	National Grid USA
NCPA	Northern California Power Agency
NERC	North American Electric Reliability Corp.
New England Conference of Public Utilities Commissioners*	New England Conference of Public Utilities Commissioners, Inc.
New York Commission	New York State Public Service Commission
New York Public Power	New York Association of Public Power
New York TOs	New York Transmission Owners
Nevada Companies	Nevada Power Company and Sierra Pacific Power Company
Northeast Utilities	Northeast Utilities Service Company
Northern Indiana	Northern Indiana Public Service Company
Northwest Requirements Utilities	Northwest Requirements Utilities
NPCC	Northeast Power Coordinating Council: Cross-Border Regional Entity, Inc.
NRC	United States Nuclear Regulatory Commission
NRECA	National Rural Electric Cooperative Association
NYSRC	New York State Reliability Council, LLC
NY Major Consumers	Multiple Intervenors, an unincorporated association of approximately 55 large industrial, commercial and institutional end-use energy consumers with facilities in New York
Ontario IESO	Ontario Independent Electricity System Operator

Otter Tail	Otter Tail Power Company
PG&E	Pacific Gas and Electric Company
Portland General	Portland General Electric Company
Process Electricity Committee	Process Gas Consumers Group Electricity Committee
Progress Energy	Progress Energy, Inc.
ReliabilityFirst	ReliabilityFirst Corporation
Reliant	Reliant Energy, Inc.
Santa Clara	City of Santa Clara, California
SDG&E	San Diego Gas and Electric Company
SERC	SERC Reliability Corporation
Six Cities	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California
SMA	Steel Manufacturers Association
Small Entities Forum	ReliabilityFirst Corporation Small Entities Forum
SoCal Edison	Southern California Edison Company
South Carolina E&G	South Carolina Electric and Gas Company
Southern	Southern Company Services, Inc.
Southwest TDUs	Southwest Transmission Dependent Utility Group
STI Capital	STI Capital Company
Tacoma	Tacoma Power
TANC	Transmission Agency of Northern California
TAPS	Transmission Access Policy Study Group
TVA	Tennessee Valley Authority
Utah Municipal Power	Utah Associated Municipal Power Systems
Valley Group	The Valley Group, Inc.
WECC	Western Electricity Coordinating Council
WIRAB advice	Western Interconnection Regional Advisory Body
Wisconsin Electric	Wisconsin Electric Power Company
Xcel	Xcel Energy Services

*Comments filed out-of-time

Appendix C: Abbreviations in this Document\

ACE	Area Control Error
AGC	Automatic Generation Control
ANSI	American National Standards Institute
ATC	Available Transfer Capability
BCP	Blackstart Capability Plan
CBM	Capacity Benefit Margin
CPS	Control Performance Standard
DC	Direct Current
DCS	Disturbance Control Standard
DSM	Demand-Side Management
ERO	Electric Reliability Organization
GWh	Gigawatt hour
IEEE	Institute of Electrical and Electronics Engineers
IROL	Interconnection Reliability Operating Limits
LSE	Load-serving Entity
MVAR	Mega Volt Ampere Reactive
MW	Mega Watt
ROW	Right of Way
SOL	System Operating Limit
SPS	Special Protection System
TIS	Transmission Issues Subcommittee
TLR	Transmission Loading Relief
TRM	Transmission Reliability Margin
TTC	Total Transfer Capability
UFLS	Underfrequency Load Shedding
UVLS	Undervoltage Load Shedding