Consideration of Comments

Project 2021-01 Modifications to MOD-025 and PRC-019

Comment period start date: 9/29/2022
Comment period end date: 11/17/2022
Associated ballots:

1. 2021-01 Modifications to MOD-025 and PRC-019 MOD-025-3 Implementation Plan IN 1 OT
2. 2021-01 Modifications to MOD-025 and PRC-019 MOD-025-3 IN 1 ST
3. 2021-01 Modifications to MOD-025 and PRC-019 PRC-019-3 Implementation Plan IN 1 OT
4. 2021-01 Modifications to MOD-025 and PRC-019 PRC-019-3 IN 1 ST

There were 79 sets of responses, including comments from approximately 180 different people from approximately 110 companies representing 10 of the Industry Segments as shown in the table below.

Groups

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
Santee Cooper	Chris Wagner	1		Santee Cooper	Anthony Noisette	Santee Cooper	1,3,5,6	SERC
					LaChelle Brooks	Santee Cooper	1,3,5,6	SERC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Portland General Electric Co.	Daniel Mason	6		Portland General Electric Co.	Brooke Jockin	Portland General Electric Co.	1	WECC
					Adam Menendez	Portland General Electric Co.	3	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Ryan Olson	Portland General Electric Co.	5	WECC
					Daniel Mason	Portland General Electric Co	6	WECC
Public Utility District No. 1 of Chelan County	Diane E Landry	1		CHPD	Meaghan Connell	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Glen Pruitt	Public Utility District No. 1 of Chelan County	6	WECC
Lincoln Electric System	Eric Ruskamp	1,3,5,6		LES	Eric Ruskamp	Lincoln Electric System	6	MRO
					Dan Pudenz	Lincoln Electric System	1	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Kayleigh Wilkerson	Lincoln Electric System	5	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					Marc Donaldson	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Amber Skillern	East Kentucky Power Cooperative	1	SERC

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					Scott Berry	Wabash Valley Power Association	3	RF
					Jason Procuniar	Buckeye Power, Inc	4	RF
					Chandler Brown	Sunflower Electric Power Corporation	1	MRO
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
ISO New England, Inc.	Kathleen Goodman	2	NA - Not Applicable,NPCC	Standards Review Committee (SRC)	Helen Lainis	IESO	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Mike Del Viscio	PJM	2	RF
					Ali Miremadi	CAISO	2	WECC
					Charles Yeung	SPP	2	MRO
					Andrew Gallo	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Andrew Gallow	ERCOT	2	Texas RE

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MRO	Kendra Buesgens	1,2,3,4,5,6,7	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					LaTroy Brumfield	American Transmission Company, LLC	1	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO

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					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					George Brown	Acciona Energy North America	5	MRO
					Jaimin Patel	Saskatchewan Power Corporation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF

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					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Michael Johnson	Michael Johnson		WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC
Southern Company - Southern Company Services, Inc.	Pamela Frazier	1,3,5,6	MRO,RF,SERC,Texas RE,WECC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern	6	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Company Generation		
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Sheraz Majid	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					John Hastings	National Grid	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Dan Kopin	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC

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					John Pearson	ISO New England, Inc.	2	NPCC
					Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Randy MacDonald	New Brunswick Power Corporation	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion	6	NPCC

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						Resources, Inc.		
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC

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					Joel Charlebois	AESI	7	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Tim Kelley	Tim Kelley		WECC	SMUD / BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

All comments submitted can be reviewed in their original format on the [project page](). If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, contact Director, Standards Development [Latrice Harkness]() (via email) or at (404) 858-8088.

The standard drafting team (SDT) thanks all of industry for your time and comments. The SDT revised the proposed MOD-025-3 and PRC-019-03 standard based on industry comment and feedback from the Quality Review team. Due to the similar nature of multiple comments received during the initial ballot and comment period, the SDT is responding to comments for Questions 1-4 and Questions 6-14 in summary format (see section 4.2 of the Standard Processes Manual). The comments received for Question 5 (MOD-025 Attachment 1-3) are addressed individually.

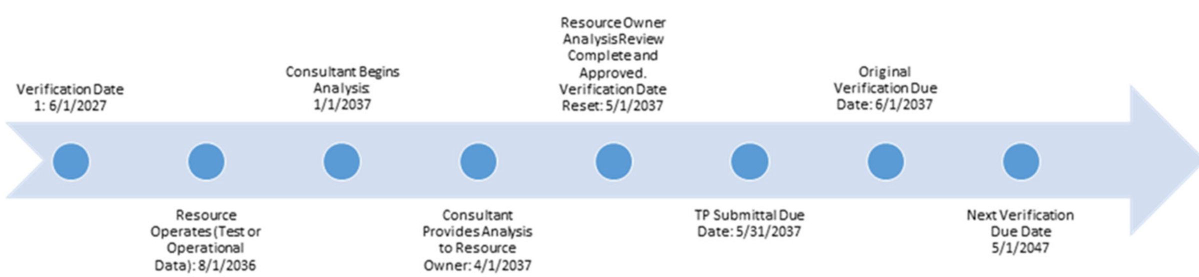
Questions

1. Do you agree the language proposed in MOD-025-3 Requirement R1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
2. Do you agree the language proposed in MOD-025-3 Requirement R2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
3. Do you agree the language proposed in MOD-025-3 Requirement R3? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
4. Do you agree the language proposed in MOD-025-3 Requirement R4? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
5. Do you agree the language proposed in MOD-025-3 Attachments 1, 2, and 3? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
6. The SDT believes the language of MOD-025-3 addresses the issues outlined in the two SARs in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.
7. The SDT proposes a 1-year implementation plan for MOD-025-3 Requirements R3 and R4, with an additional 2 years (3 years total) for compliance with Requirements R1 and R2. Would these proposed timeframes give enough time to put into place process, procedures or technology to meet the proposed language? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period, and provide a detailed explanation of actions planned to meet the implementation deadline.
8. Provide any additional comments on MOD-025-3 and technical rationale document for the standard drafting team to consider, if desired.
9. Do you agree the language proposed in PRC-019-3 Requirement R1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
10. Do you agree the language proposed in PRC-019-3 Requirement R2? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
11. Do you agree the language proposed in PRC-019-3 Attachment 1? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.
12. The SDT believes the language of PRC-019-3 addresses the issues outlined in the two SARs in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.
13. The SDT proposes a 1-year implementation plan for PRC-019-3 Requirement R2. For Requirement R1 with reoccurring periodicity for existing Facilities, the Implementation Plan proposes a six year reoccurring periodicity from the date of previous coordination date of PRC- 019-2 R1. Would these proposed timeframes give enough time to put into place process, procedures or technology to meet the proposed language? If you think an alternate timeframe is needed, please propose an alternate implementation plan and time period.

14. Provide any additional comments on PRC-019-3 and technical rationale document for the standard drafting team to consider, if desired.

Questions 1 and 2 - MOD-025 Requirement R1/R2

1. Does not want submittal window reduced from 90 days to 30 days. Some commenters want 60 days, some want expanded to 180 days. Most believe that its 30 days from testing date.
    - Change made. Provided clarification in Requirement R1/R2 that it's 30 days from the verification date. More clarification on what verification date is and how its reset
    - There was no change made in the duration of submittal window.
    - A staged test can occur up to 365 days before the verification date. Attachment 1, Section II specifies that the GO/TO can "utilize staged testing data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the generator capability."
2. Confusion regarding verification date. What is verification date, how is it referenced, and whether its reset if perform another verification.
    - Change made. Added verification date language under Requirement R1. The language also remains under Attachment 1, Section I.
    - The applicable entity designates the verification date and notates the verification date in a summary report (refer to Attachment 2). The verification date should represent the date that the engineering review or engineering analysis is complete. The verification date is the basis of the recurring periodicity.



3. Request justification on testing of FACTS devices.
    - No change. Technical Rationale: FACTS and SVC can supply/absorb reactive power automatically based upon control logic. Verification through MOD-025 will address degradation of FACTS device equipment along with potential control logic changes.
    - From Project 2021-01 SAR: Review and revise the "Applicability – Facilities" section, "Applicability – Functional Entities" section, and Requirements (including applicable attachments) as needed in MOD-025-2 to comprehensively address all varieties of transmission-connected dynamic reactive resources that are utilized in providing ERS in the BES. As needed, define new Glossary Terms for all or some of the transmission-connected dynamic reactive devices noted in the System Analysis and Modeling Subcommittee (SAMS)

white-paper Transmission Connected Dynamic Reactive Resources – Assessment of Applicability in Reliability Standards.

4. Provide better explanation of engineering review/analysis and examples or methods. See Theme 29, 7.
    - Examples of compliance with MOD-025 would not be included as part of the standard. Associated documents references added to Section E include:
    - Reliability Guideline Power Plant Model Verification and Testing for Synchronous Machines, July 2018
    - NATF Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines Reference
5. Question whether MOD-025 changes accomplishing goals of white paper/SAR.
    - The primary objectives of the SAR are listed below with a comment on how the SDT addressed the topic.
    - *Revisions to MOD-025-2 to ensure that verification activities produce data and information that can be used by Transmission Planners and Planning Coordinators for the purposes of developing accurate and reasonable plant active and reactive capability data (including possibly representation of the "composite capability curve" inclusive of capability and limiters, where applicable).*
        - Revised Requirement R1/R2 to add the CCC, and updated Attachment 1.
    - *Ensure that each Planning Coordinator and the area Transmission Planners develop requirements for the Planning Coordinator area real and reactive capability data verification.*
        - The SDT believed there can be common and consistent MOD-025 requirements based on the needs of a TP.
    - *Ensure that Generator Owners provide the data specified by the Planning Coordinator and Transmission Planners for the Planning Coordinator area.*
        - The SDT believed there can be common and consistent MOD-025 requirements based on the needs of a TP.
    - *Ensure that verification activities can apply other methods beyond only testing (or real-time data) that allow plant capability information, protection settings, PRC-019 reports, and other documentation to also complement the verification activities*
        - Revised Requirement R1/R2 to add the CCC, and updated Attachment 1.
    - *Ensure that data provided by the applicable Generator Owners and Transmission Owners is analyzed and used appropriately by Transmission Planners and Planning Coordinators*
        - Added Requirement R3/R4 for TP to review Facility capability information submitted by the GO/TO, and means to resolve technical concerns identified by the TP.
    - *Ensure that the data provided by Generator Owners, if different from tested values, is acceptable to the Planning Coordinator and Transmission Planners with the standard providing guidance on acceptable reactive capability reporting if system conditions prevent reaching actual capability.*

    - Added Requirement R3/R4 for TP to review Facility capability information submitted by the GO/TO, and means to resolve technical concerns identified by the TP.

- *Ensure alignment of the MOD-025 standard with MOD-032-1 regarding data submittals for annual case creation and PRC-019-2 regarding collection of information that can be effectively used for verification purposes. Ensure activities across standards can be applied to effectively meet the purpose of these standards, and avoid any potential overlap or duplication of activities. This is dependent on the success of bullet number 1.*

    - Requirement R3 states that the TP must review the data. The SDT believes it is overreach to dictate that the TP exclusively use MOD-025 data for modeling evaluation. The GO/TO should ensure alignment of MOD-032 data with MOD-025 data. The TP should incorporate MOD-025 data with the MOD-032 submittal to improve model fidelity.

- *Ensure that equipment limitations are documented and classified as expected (e.g., system voltage limit reached) or unexpected (e.g., plant tripped or excitation limiter reached unexpectedly). In cases of unexpected limitations reached, ensure that the equipment owner develops and implements a corrective action plan to address this unexpected limitation.*

    - Revised Attachment 1 to include excitation and operational limitations, if more restrictive that equipment manufacturer curves.

6. Believe that composite capability curve (CCC) is covered in other standards, such as PRC-019, and think MOD-025 should just be testing and remove CCC, PQ table, engineering basis, etc.

    - No change. The SDT acknowledges that PRC-019 information can be used as one input for MOD-025 activities. PRC-019 does not require the GO to provide the TP with the CCC. PRC-019 requires only that the generator capabilities, protection systems, and protective functions be coordinated. The CCC is one means to demonstrate that this coordination has been achieved. Whereas, MOD-025 provides the verification of real and reactive power capability information to the TP.

7. TP should define what information is required of the GO/TO (resource owner).

    - No change. The SDT believed there can be common and consistent MOD-025 requirements based on the needs of a TP. While this might remove work for GOs and TOs that might not be utilized by an individual TP area, the tracking of what is needed and where would increase substantially for both the TOs, GOs, and reliability entities. The possibility of missing something in a footprint would not be worth the increased administrative burden on all of the involved entities.

8. Request clarification on whether sister units need to be tested.

    - No Change. The SDT has chosen not to have a sister-unit exemption for MOD-025.

    - Units that are identical from manufacturer may have different maintenance schedules, degradation, and operational limitations over time.

    - If documentation and engineering analysis can demonstrate that all equipment is identical (including auxiliary equipment), then verification of one unit could hypothetically be used for verification of another unit.

9. Remove requirement for CCC and PQ table, because TP won't use it.
    - No change. SDT members performed informal outreach and several TPs said that this information is valuable to them. Modeling software has the capability of using PQ tables and TPs are highly encouraged to utilize this data when modeling reactive capability.
10. TPs should be required to use the data that is provided by the GO/TO.
    - No change. Requirement R3 states that the TP must review the data. The SDT believes it is overreach to dictate that the TP exclusively use MOD-025 data for modeling evaluation. The GO/TO should ensure alignment of MOD-032 data with MOD-025 data. The TP should incorporate MOD-025 data with the MOD-032 submittal to improve model fidelity.
11. Want 6 months to submit data.
    - No change. See Questions 1 and 2. Theme 1 and 2.
12. Provide an example for phased installation of generators, and when they meet BES criteria.
    - No change. This question relates to BES definition and when a Facility becomes applicable for MOD-025. Once the aggregate MVA threshold of the site meets the inclusion criteria then all parts of the aggregate need to be considered and verified pursuant to Attachment 1 Section 2. BES definition is clear on how a facility is evaluated for Standards.
13. Provide clarification on how/if resources not in AVR provide verification
    - All applicable Facilities for MOD-025-3 should be verified in their normal mode of operation.
    - Change made. Attachment 1, Section III, Part 5, was revised to "The Facility voltage/Reactive power control equipment is in the normal mode of operation."
    - If a Facility is not in AVR mode, the Facility still has a reactive capability, and this Facility is required to supply reactive support for the grid either through constant MVAR or constant power-factor. This reactive capability must be verified under MOD-025-3.
14. Commenter does not believe that 180 days is enough time following change
    - Comment pertains to Attachment 1. See Question 5.
15. Provide guidance on how TP or GO can use data in models
    - No change. The SDT does not believe that they should be prescriptive in how the TP or GO use the data in their models. More recent versions of modeling software have capability of using P/Q curve data and will increase visibility and model fidelity.
16. Provide guidance on how TP reviews and uses data
    - No change. The SDT does not believe that they should be prescriptive in how the TP or GO use the data in their models. More recent versions of modeling software have capability of using P/Q curve data and will increase visibility and model fidelity.
17. Want TP or NERC to provide exemption to the GO/TO, if TP does not use data in its model.
    - No change. The SDT believes that the data is required to be sent, and that the TP is encouraged to use MOD-025 data as part of MOD-032 submission and inclusion in models used for reliability assessments.

18. Want all timeframes to be 12 months.
    - No change. This pertains to Attachment 1; Question 5. The SDT feels the timeframes selected are reasonable.
19. Commenter does not like the term facility and prefers "BES plant" instead
    - No change. The SDT chose Facility to provide distinction between a plant which is traditionally considered synchronous generation, and a facility which may contain generation or other types of dynamic devices.
    - The terms “applicable Facility” and “Facility” are used in order to have consistent wording in the standard.
20. Want requirement for TP to publish modeling requirements to support resource owner taking this into account
    - No change. See Theme 7.
21. Clearly define trends in capability curve examples in attachment
    - No change. SDT is unsure what is meant by the term “trends”. The example CCC curves are provided to give clarity to the requirement language. The examples are not intended to be used as a way to demonstrate how to be compliant with the standard.
22. Remove R1.3.1, 1.3.2, 1.3.3 and just have R1.3 say submit Attachment 2 (M1 changed accordingly)
    - No change. The SDT believes that each of these parts need to be specified as part of the Requirement language and distinct from the language of Attachment 2. These subparts are also important for the VSL language.
23. Clarify if Attachment 1 Section II.2 is I2, I4 or both.
    - See Q5 comments.
24. Remove ability for TP to require I4 resources to test/verify individually
    - No Change. The SDT believes that it is important that the TP receive resource capability data in the manner that will be most useful to its model. The SDT believes that Attachment 1, Section II, Part 2 provides for a dialogue between the applicable entities to ensure that verification and modeling needs are met for both parties.
25. Change R1.3 to reference verification date in Attachment 1, Step 1
    - Change made. Seer updated language in Requirement R1/R2.
26. Commenter believes that they are submitting test results to TP not CCC. And that a TP could reject test results somehow.
    - No change. Under the new version of MOD-025 the GO/TO has new requirements of what must be submitted to the TP. Under Attachment 1 (Section II, Part 5), test data may be used by the GO/TO as a part of engineering analysis. Under Requirement R3, the TP can notify the GO/TO when they have a technical concern with the information submitted. The technical concern would likely relate to the overall engineering analysis, and not the validity of test results.

27. Verification is not well defined.
    - See Themes 4 and 7.
28. Some commenters do not see the value of staged testing.
    - No change. The SDT feels there is value to keep staged testing as an option. Stage testing can undercover operational limitations or previously unknown issues that limit reactive capability. For example, when a plant digital control system (DCS) limits overall plant reactive output. See Technical Rationale for more information.
    - While this version of MOD-025 does not require the issues identified from staged testing to be resolved, MOD-025 does require the GO/TO to report an operational limitation or a reduction in capability greater than 10% from nameplate rating.
29. Require staged testing or operational data as part of verification
    - Change made. Operational or staged testing is the preferring method. Operational data is next preferred. The verification methods were reordered in the standard to reflect the preference.
30. Modify Applicability section to state all BES units rather than going through individual inclusion/exclusions
    - No change. Based on precedent with other Reliability Standards and the need for specific Facilities to be identified as in scope for MOD-025. The SDT prefers to have the Facilities listed separately under Section 4.2.
31. Change R1 to say what the verification date is instead of referring to Attachment 1
    - Change made. See updated Requirement R1/R2.
32. Add language for modeling of pump storage units, BESS units, etc. Clarify if verification is required for producing and absorbing real power.
    - The Bulk Electric System definition focuses on power producing facilities. Therefore, storage resources (including pumped storage and batteries) that meet the requirements of Section 4.2.1, 4.2.2, or 4.2.3 are required to verify their real and reactive power capability in the real power producing direction.
33. Want to retire MOD-025 or justify its existence since other standards are superior (MOD-026, 27, 32, 33)
    - No change. The SDT believes there is value in retaining the requirements of MOD-025. See Technical Rationale.
34. The new proposed MOD-025-3 standard appears to violate the existing NERC Bulk Electric System definition in Attachment 1, section II and item 2, by dropping below the BES definition by requiring testing of individual wind turbines / solar inverter.
    - No change. The language does not change the applicability of Facilities as described in the BES definition. For individual devices or generators 20 MVA (gross nameplate rating) or less, that are part of an applicable Facility greater than 75 MVA, Attachment 1, Section II, Item 2 describes that the verification can be performed on an individual or aggregate basis, and should consider the applicable modeling expectations of the respective Transmission Planner.

35. M1 and M2 modification to say applicable facility instead of each facility
    - Change made. Change M1/M2 language to match R1/R2 language
36. Attachment 1 Section II. Part 1 align to say BES Inclusion I2 instead of spelling out
    - No change. This section applies to all types of resources, and not just those of BES Inclusion I2. This section describes how the verification is performed, either on an individual or aggregate basis.
37. Combine R1 and R2 instead of having 2 separate
    - No change. This should remain separate because of the different entities.
38. Provide confirmation that a generic one-line is sufficient
    - Change made. Requirement R1/R2 updated, "simplified one-line diagram representing the applicable Facility."
39. Replace Transmission Planner with Planning Coordinator or Planning Authority
    - No change. Since the current MOD-025-2 required the GO/TO to provide information to the TP, the SDT felt the process and responsible entity should remain the same.
40. Provide clarification on whether verification date changes or is reset, if TP requires follow up IAW Requirement R3/R4
    - No change. The applicable entity designates the verification date and notates the verification date in a summary report (refer to Attachment 2). The verification date should represent the date that the engineering review or engineering analysis is complete. The verification date is the basis of the recurring periodicity.
    - If the GO/TO updates the summary report and resends as part of Requirement R4, then they would in effect update the verification date in order to be compliant with Requirement R1/R2.
41. Split 1.3.2 into 1.3.2 and 1.3.3 one with CCC and one with PQ table to align with Attachment 2. Therefore, PQ Table would have its own subpart, separate from CCC subpart.
    - Change made. Revised Attachment 2 into 3 sections in order to match Requirement R1/R2 structure. The three sections include:
        - One-line diagram
        - CCC with PQ data table
        - Supplemental documentation
42. Add Planning Coordinator to submittal requirement
    - No change. Since the current MOD-025-2 required the GO/TO to provide information to the TP, the SDT felt the process and responsible entity should remain the same.
43. Clarify examples of dynamic reactive devices or FACTS devices that are included in applicability Section 4.2.4.
    - Dynamic reactive resources are described in the *Transmission Connected Dynamic Reactive Resources – Assessment of Applicability in Reliability Standards*. Two of the more common

types of dynamic reactive resources are SVCs and STATCOMS.

- Static var compensators (SVCs) serves many of the same purposes as a synchronous condenser, particularly the injection or absorption of dynamic reactive power to support steady-state and transient voltage conditions. Similar to a synchronous condenser, an SVC has a current injection capability that translates to a reactive power capability based on terminal voltage. For this reason, a power electronics resource like a SVC connected to the BPS should be a Facility to which MOD-025 is applicable for reactive power capability verification.
- Static compensators (STATCOMs) are power electronic resources connected to the BPS that provide steady-state and dynamic voltage support. The STATCOM and SVC differ in their reactive capability, particularly under off-nominal voltage conditions. Their controls are also different based on the types of equipment technologies used in the different devices. Again, the power electronics have a current injection capability that translates to reactive power capability based on voltage. For this reason, STATCOM should be a Facility to which MOD-025 is applicable for reactive power capability verification

44. Provide guidance on reporting for Facilities in 4.2.4 and 4.2.5.
    - See Question 5 response. Implementation guidance or compliance examples is not part of the reliability standard.
45. Do we move R3 and R4 up to R1/R2 where TP and Rx Resource Owner talk, determine what is needed and then RRO provides the data? This would make what is needed for data provision less prescriptive
    - No change. The SDT decided to keep the structure of MOD-025-3 the same for this revision.
46. How should MOD-025 data be reconciled with MOD-032 data?
    - When the GO/TO completes MOD-025 on a reoccurring basis, the subsequently submitted MOD-032 data should be updated accordingly by the GO/TO.

For the TP, if there is an inconsistency between the two sources of MOD-025 and MOD-032 information, then this would likely be cause for raising a technical concern with the GO/TO.

Question 3 - MOD-025 Requirement R3

1. Allow submission Requirements for TOs and GOs to be adaptable based on needs of individual TPs.
    - No change. The SDT believed there can be common and consistent MOD-025 requirements based on the needs of a TP. While this might remove work for GOs and TOs that might not be utilized by an individual TP area, the tracking of what is needed and where would increase substantially for both the TOs, GOs, and reliability entities. The possibility of missing something in a footprint would not be worth the increased administrative burden on all of the involved entities.
2. Modify R3 to require the Transmission Planners to utilize the data provided in MOD-025 by both the TO and GO.
    - No change. Requirement R3 states that the TP must review the data. However, the SDT believes it is overreach to dictate that the TP exclusively use MOD-025 data for modeling evaluation. TP should incorporate MOD-025 data into the MOD-032 submittal to improve model fidelity.

3. Requirement R3 for the Transmission Planner to verify the models as submitted by the GO and TO is overly burdensome for the Transmission Planner.
    - No change. Requirement R3 states that the TP must review the information submitted by each GO/TO, and provide notification if the TP identifies any technical concerns with the Real and Reactive Power capability information submitted.
    - While the commenters raise valid points regarding the fact the Transmission Planners are not experts on each and every plant connected to their system, the review will provide an opportunity for communication between the entities should values appear to be off. Questions can be raised and answers provided to confirm that the information is reasonable for the individual units; or reasonable for the test configuration but not normal modeling.
4. Clarification of when the 90 day clock starts.
    - Change made. Align R3 "90 calendar days" provision language with upon receipt. Providing initial comments within 90 days provides timely feedback to generators that the TP has begun their review and is satisfied with the data or has questions and concerns with it.
5. Clarification required that the Transmission Planner need only respond to those entities (GO/TO) submitting data for the area for with they perform transmission planning.
    - No change. If a GO/TO sends information to the wrong Transmission Planner, they would likely not be compliant with R1/R2/R4. Requirement R3 states that the information being reviewed is submitted in accordance with R1/R2/R4. The Transmission Planner would not be obligated to respond to the GO/TO in this instance.

Question 4 - MOD-025 Requirement R4

1. Remove "mutually agreed upon" language
    - Change made. Aligned Requirement R4 language with MOD-026-2 updated language in R9.
    - The GO/TO has the option to respond with, "A plan to update the capability information in accordance with Requirements R1 or R2."
2. 90-day time requirement should include extension provision
    - Change made. Aligned Requirement R4 language with MOD-026-2 updated language in R9.
    - The GO/TO has the option to respond with, "A plan to update the capability information in accordance with Requirements R1 or R2."
3. Requirement R4 is inherently (relates to Requirement R3) overly burdensome or purely administrative.
    - No change. Requirement R3/R4 were added so that the TP and GO/TO can have dialogue when a technical concern arises with capability information sent by the GO/TO. See Technical Rationale for additional information.
4. Additional clarification(s) in R4 may be needed.
    - No change. Ensure R4 submittal recipients (Planner Coordinator comment) align with R1 and R2 language.

Question 5 - MOD-025 Attachments 1, 2, and 3

Thomas Foltz - AEP - 5
Comment
Attachment 1: Section 1: Periodicity AEP recommends that the Project 2021-01 SDT pursue a similar periodicity as currently being pursued for MOD-026-2 by the Project 2020-06 SDT. In that project's most recent draft of MOD-026-2, the periodicity table allows 365 days from COD for the GO or TO to verify modeling of new facilities, and 180 days allowed for modification of facilities already in service which require model reverification. In MOD-026's most recent revisions, if 180 days is found to not be sufficient, the facility owner may send a verification plan to the TP within 180 days and then has 365 days following plan submittal to do the verification and provide to the TP. We recommend a similar timeframe and approach to be used in Project 2021-01 for MOD-025-3.
Response
No change. The SDT believes that 180 days after the commercial operation date is sufficient. Additionally, the periodicity was extended from 5 to 10 years, similar to MOD-026.

Jerry Thompson - Kestrel Power Engineering - NA - Not Applicable - NA - Not Applicable	
Answer	No
Comment	
General: 1) Regarding the intent of providing the Composite Capability Curve (CCC) at 1.0 per-unit: Kestrel has concern that provided the CCC and associated limiters/limiting functions at 1.0 per-unit will not serve as practical means to assess unit capability. A unit/plant's capability curve is, in reality, a three-dimensional figure which varies based on voltage. By providing the CCC at 1.0 pu, we would be removing the context associated with the plant being over-excited or under-excited. It is well-known that limiters will shift relative position vs equipment capability based on voltage, and that many limiters have inherent modification based on voltage level (e.g. most Under-Excitation limiters adjust based on square of voltage, although the exponent value can be configurable depending on controls type). As such, attempting to correlate steady state operating points, and the results that are gathered during staged testing, will not align with the CCC plotted at 1 per-unit voltage. Kestrel's suggestion would be to populate the CCC at steady state operational voltage bounds associated with the plant (e.g. +/-5% for many synchronous machines, although this can be conditional if there is a different voltage limitation like auxiliary loads). **General: Testing Priority of just Engineering Review.** 2) Kestrel identifies that staged testing is no longer a requirement. In previous versions of the Standard, a baseline through testing was required, after which operational data could be used. Kestrel has concern that until proven, engineering analysis is just that. In our experience performing reactive capability testing (thousands of units over 2 decades), the number of times in which unexpected 'phenomena' has been observed is significant. Short examples being unknown protection elements or failure of control / power exporting hardware. Kestrel recommends that for a given instance of hardware, a staged test	

should be performed which is then to be correlated to engineering analysis. From that point forward, engineering analysis or operational data can be used to re-verify performance. This suggests that replacement of major components which impact active/reactive capability (generator, excitation system, turbine, turbine-governor, etc) may warrant confirmation testing.

Attachment 1: Section 2: IBR Mode Rewording

3) Regarding Attachment 1 Section III item 4 – there are a significant number of IBR facilities which operate in power factor or reactive power control mode, even though they do have an option to operate in voltage control mode. Based on the wording in the draft standard, my interpretation is that any of these sites would be forced into a non-typical mode of operation for the purpose of the test. Is this true / the intent of the wording? If not, suggest caveat for if the plant does happen to operate in a non-AVR mode.

Attachment 3: Clarifications

4) Many of the data points given in Attachment 3 are static and/or rated values (voltage ratio, impedance, X/R ratio, tap position for off-load tap change transformers). There had been instances of confusion with application to MOD-025-2, in that it isn't practical to list these static values in every instance of a test (minimum load leading/lagging, max load leading/lagging). While this is certainly relevant information which should be included within the test report, it seems that the intent of Attachment 3 is to be specific for the individualized test and values which change based on test condition. Suggestion to remove static/rated information from Attachment 3, with potential to specify the inclusion of this information elsewhere in the test report.

Suggested inclusions for when applicable or as available: net head (hydro units), generator or exciter field voltage (sync machines only), wind speed (wind turbines), solar irradiance (PV solar), on-load tap changer (OLTC) position, declaration of specific reactive compensation component status (e.g., reactor bank 1 in-service, bank 2 out-of-service), declaration of which distributed generating resources are offline, calculated collector system losses (or reactive power generated).

Response

1. No change. The CCC are required to be provided at 1.0 pu voltages at a minimum, since this is the minimum expectation of the GO/TO.

2. An engineering analysis is performed subsequent to a staged test or operational data collection when the full capability of the Facility is not demonstrated. This is most likely due to restrictive transmission system constraints/conditions. An example of engineering analysis of staged test data can be found in Reliability Guideline Power Plant Model Verification and Testing for Synchronous Machines (Appendix D – Testing and Calculations Example), July 2018. An example of an engineering analysis for operational data can be found in NATF Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines Reference, September 2020 (Section 3 and 4). An engineering review is not the same as engineering analysis. An engineering review can be complete if a staged test or obtaining operational data is not achievable. An engineering review must include a comprehensive review of all of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations. The engineering review documentation shall include the underlying assumptions, design criteria, and methods used to create the Facility's composite capability curve under Section II, Items 6-8. There are currently no compliance examples publicly available.

3. Change made. All applicable Facilities for MOD-025-3 should be verified in their normal mode of operation. Attachment 1, Section III, Part 5, was revised to "The Facility voltage/Reactive power control equipment is in the normal mode of operation
4. No change. The SDT believes that the data included is sufficient to help gather enough information for performing engineering analysis on the test data to assist in recreating system/unit conditions and expanding on that data if needed. There is nothing preventing additional information be collected by the tester/engineer if desired for the engineering analysis. If static (unchanging) data is recorded once for all conditions, that data can be entered once in an applicable to all tests table. The format of displaying can be selected by the tester and does not need to be exactly how Attachment 3 shows as stated in Attachment 3. If certain data cannot be obtained, a simple reason can be listed.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No

Comment

General: FACTS Device Clarifications

FirstEnergy seeks clarification on devices to include FACTs and justification on the need for testing of these. SVCs and other FACTS devices we view as not having moving parts which should limit their change in output and response over time and we seek clarification of their inclusion.

Attachment 1: Sections 2 and 3: Clarification of Engineering Review / Engineering Analysis / Examples

Also, the proposed MOD-025 revision transforms what was formerly a "required testing verification of demonstrated capability" into some form of an engineering analysis justifying a theoretical capability curve. The standard needs to include a better definition of "Engineering review" or "engineering analysis" along with examples or prescribed methods of how this "engineering analysis" is to be conducted.

General: Purpose of MOD-025 vs Other Submitted Data

In addition, FirstEnergy does not understand how the proposed revision to MOD-025 for reactive testing will provide any additional or more accurate information to the transmission planning entities since we currently already submit most of the needed information.

Generator capability curves are submitted via the annual MOD-032 submittals to PJM. Analysis of over/under excitation limiters are already included in the required PRC-019 documentation.

The excerpt below comes from the summary section of the NERC white paper "Implementation of NERC Standard MOD-025-2"

"The PPMVTF believes that there is value in performing the staged verification tests since they can uncover unexpected limiting factors; however, the PPMVTF agrees that the data acquired during MOD-025-2 testing may not be directly usable to represent the actual capability of the machine in power system models, and that the tests do not generally accomplish the stated purpose of the standard.

Response

15. The justification for adding FACTS devices is described in the SAR and Technical Rationale. FACTS devices can supply or absorb reactive power automatically based on its control logic which is

similar to generating resources with automatic regulations on voltage, reactive power or power factor. Thus, FACTS devices are required to verify the reactive power capability within MOD-025. As described in Attachment 1, Section 2, Item 5, MOD-025-3 does not require staged testing be the only methodology to verify the reactive capability of the Facility.

16. An engineering analysis is performed subsequent to a staged test or operational data collection when the full capability of the Facility is not demonstrated. This is most likely due to restrictive transmission system constraints/conditions. An example of engineering analysis of staged test data can be found in Reliability Guideline Power Plant Model Verification and Testing for Synchronous Machines (Appendix D – Testing and Calculations Example), July 2018. An example of an engineering analysis for operational data can be found in NATF Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines Reference, September 2020 (Section 3 and 4). An engineering review is not the same as engineering analysis. An engineering review can be complete if a staged test or obtaining operational data is not achievable. An engineering review must include a comprehensive review of all of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations. The engineering review documentation shall include the underlying assumptions, design criteria, and methods used to create the Facility's composite capability curve under Section II, Items 6-8. There are currently no compliance examples publicly available.
17. No change. The SDT acknowledges that PRC-019 information can be used as one input for MOD-025 activities. PRC-019 does not require the GO to provide the TP with the CCC. PRC-019 requires only that the generator capabilities, protection systems, and protective functions be coordinated. The CCC is one means to demonstrate that this coordination has been achieved. Whereas, MOD-025 provides the verification of real and reactive power capability information to the TP.

Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Comment	

1) Please see the responses to Questions 1 and 3.

Attachment 1: Section 1: Rewording

2) In Attachment 1, section I. 4, depending on the size of the unit, 10% may or may not be a big MVA number. Therefore, it is suggested to change the sentence to "10% or xx MW (fixed number, it can be either 2MVA, 3MVA or 5MVA) whichever is the smallest".

Attachment 1: Section 3: Clarification

3) In Attachment 1, section III. 6, during the stage test, is it required to let the machine run for a time period (say 30min) at the test point?

Attachment 2: Clarification

4) In the diagram on page 17, what does it mean for "Other Point Of Interconnection"? Should the whole station SLD be provided? All station service transformers and station load should be clearly marked and listed on the SLD. In case of several station service transformers in parallel operation, the status and

loading information of each station service transformer should be provided so that the detailed station load can be calculated.

Response

1. See response to Q1/Q3.
2. No change. The current MOD-025-2 language for this section states 10% and the SDT did not feel this warranted a change.
3. No Change. SDT didn't want to force a specific time, but does want long term thermal or mechanical issues to be considered. i.e. if near a stator current temp alarm, allow the temp to settle before ending test (whether that is 15, 30 or 60 min). See Footnote 2.
4. Change made. Section II. Part 3.1 reworded the phrase to "represent all auxiliary equipment" rather than "include".

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Comment	
See ACES Comments	
Response	
Bookmark to ACES Comment/Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Comment	

Attachment 1: Section 2: Clarification

The Att. 1, sect. II, part 5, first bull-dot requirement to, "Perform an engineering review of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations," should be deleted. A review of "all" information is not practical, nor are complicated preparations necessary. All one needs to do is check the OEL and UEL curves in the PRC-019 study. No new information needs to be developed before performing MOD-025 tests.

Attachment 1: Section 2: Rewording

The reference to a staged test date within 365 days of the staged test date should be removed from the second bull-dot in Att. 1, sect. II, part 5.

Attachment 1: Section 2: Clarification

Att. 1, sect. II parts 6 and 7 should be deleted, along with the composite capability curve (CCC), PQ curve data table and, "documentation showing the engineering basis and verification methodology," of Att. 2. The tests required by MOD-025 remain quite straightforward – max lag, max lead, min lag and min lead – and anything beyond MW, MVAR and voltage data for these four points is pointless because, as described above, even if TPs/ISOs can be forced to receive the additional material mandated by MOD-025-3 they (or at least the ones we deal with) do not make use of this information.

Attachment 1: Section 2: Clarification

Att. 1, sect. II parts 6.3 and 7.3 are particularly objectionable. There are always operational limitations holding Real Power below the stator thermal limit on the generator OEM's D-curve – the boiler/turbine capability. This value varies widely with operating conditions, so constructing a MOD-025-3 curve in this respect for some nominal "1.0 per unit" ambient conditions would serve no purpose. The same is true for MVAR operational limitations as regards generator cooling. Having to calculate the ambient conditions beyond which generator windings temperature alarms will annunciate prior to reaching the OEL would be a very time-consuming exercise, involving supplemental testing, with again no apparent willingness of TPs/ISOs to use this information.

Attachment 1 and 2: Clarifications/Definitions

The Pmax and Pmin parameters bear definition, since it is presently unclear whether they refer to normal or emergency output. We suggest that Pmax be the maximum power that a GO/GOP bids into the market, +/- 5% since it is not practical to balance on a knife edge during tests. Pmin should be the lowest power for everyday operation, not the emergency minimum value, since pushing equipment to extremes for the min-load tests adds no reliability value.

Attachment 3: Rewording

"Transformer Voltage Ratio," in Att. 3 should be changed to, "Transformer Windings Ratio." The windings ratio of a transformer is a fixed value, while the voltage ratio is a function of windings ratio and voltage drop. The voltage drop depends in turn on the MW and MVAR being handled.

Windings ratio and tap settings data for unit aux, station aux and other aux transformers should be removed from Att. 3. TPs/ISOs in our experience do not model below the generator bus level, so they will have no use for this information.

Attachment 3: Clarifications

Guidance is needed for the Section III item 3 criterion, "Staged testing or operating conditions should be maintained constant for a sufficient time in order to ensure that the applicable Facility can perform at that level of Real and Reactive Power during steady-state condition." Reactive output is raised or lowered slowly when approaching OEL/UEL or voltage limits during testing, so any thermal constraints that are encountered (e.g. generator high windings temperature alarms) appear almost immediately. The few minutes of dwell time needed to collect data is therefore sufficient in our experience, so there is no need for the one-hour max lag hold-time presently required or for some vague "sufficient" criterion, but it is not practical to computationally prove this point.

General: Capacity Factor

Changing the MOD-025 periodicity from five years to ten is a step in the right direction, but this standard should also have the same capacity factor exemption that is applied for MOD-026 and MOD-027. Our principal cost of running VAR tests is that of bidding-in to the market at a loss certain peaking units that almost never run except under demand situations so severe that the ISO forbids testing. The ratio of reliability benefit to GO/GOP burden in such cases is unjustifiably low.

Response

Attachment 1: Section 2: Clarification

No change. The SDT acknowledges that PRC-019 information can be used as one input for MOD-025 activities. PRC-019 does not require the GO to provide the TP with the CCC. PRC-019 requires only that the generator capabilities, protection systems, and protective functions be coordinated. The CCC is one means to demonstrate that this coordination has been achieved. Whereas, MOD-025 provides the verification of real and reactive power capability information to the TP.

Attachment 1: Section 2: Rewording

No change. Staged test data and operational data is usable up to 365 days.

Attachment 1: Section 2: Clarification

R1. No change. These items define what must be included in the CCC for the applicable Facilities. The documentation of the underlying assumptions, design criteria, and methods for the chosen verification methodology from Attachment 1 need to be provided to the TP, since this information includes the reasoning and analysis of how the GO/TO arrived at the Facility Real and Reactive Power capability.

Attachment 1: Section 2: Clarification

No chance. Several TPs have stated that the Facility capability information including the CCC and PQ data table are valuable information to them. If there are known operational limitations that limit the Real or Reactive Power less than the nameplate capability curve, then those must be annotated in the CCC.

Attachment 1 and 2: Clarifications/Definitions

No change. The GO/TO shall provide identification of the steady-state minimum (Pmin) and maximum (Pmax) Real Power output at the generator terminal(s), <u>based on the least restrictive seasonal or operating conditions</u>. MOD-025-3 does not explicitly require staged testing as the only methodology to verify Pmin or Pmax values.

Attachment 3: Rewording

No change. The SDT believes the original words (continued from MOD-025-2) are acceptable. The desire is to obtain the correct Winding Ratio and current Tap setting whether fixed or through a onload tap changer. The test engineer can specify what they are showing if necessary for their purposes. The forms are to help with the engineering analysis that will most likely need to take place to develop the CCC. The forms are only used for ensuring sufficient data is collected (additional data deemed necessary by the tester/engineer performing analysis can also be collected).

Attachment 3: Clarifications

Correct. This is why there is no longer a specific time requirement stated in MOD-025 to hold the test value.

General: Capacity Factor

No change. The SDT did not feel a capacity factor exemption is warranted. The SDT provided multiple options to verify the capability of the Facility.

Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Comment	
See EEI Comments **See MRO Comments** Xcel Energy supports the comments of the EEI and the MRO NSRF.	
Response	
Bookmark to EEI Comment/Response Bookmark to MRO NSRF Comment/Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Comment	
See EEI Comments Dominion Energy supports the comments submitted by EEI.	
Response	
Bookmark to EEI Comment/Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Comment	
BC Hydro has the following comments on Attachment 1 of MOD-025-3 Draft 1: **Attachment 1: Section 1: Periodicity** Per Section I Bullet 4, the amount of time available to the GO/TO to verify changes has been cut down from 12 calendar months to 180 calendar days. BC Hydro's assessment is that the requirement to perform verification "within 180 calendar days of the discovery of a change that… and is expected to last more than 180 calendar days" is too strict. In some cases, once a change happens, it takes some time to complete the assessment necessary to determine how long the change will last. While the GO/TO is trying to confirm if the change is going to last longer than 180 days, the clock is ticking and the time available to the GO/TO to perform verification (if it becomes applicable) dwindles rapidly. MOD-025-2 currently allows for verification within 12 calendar months. BC Hydro recommends that the same 12 calendar month timeline be maintained in the new draft for verification.	
Response	

No change. With the revised version of MOD-025-3, multiple options exist to verify the capability of the Facility. A majority of changes to equipment capability should be known and understood in advance. Emergent changes or a discovery of unknown changes that could last greater than 180 days represent a risk to reliability and should be reported to the TP. The SDT feels 180 days is reasonable.

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Comment	
See NAGF Comments WEC Energy Group supports the comments submitted by the NAGF.	
Response	
Bookmark to NAGF Comment/Response	

Dave Krueger - SERC Reliability Corporation - 10	
Document Name	
Comment	
Attachment 1: Section 1: Periodicity and Clarifications The SERC Generator Working Group suggests adding clarification on the dates for completion and submittal. In attachment 1, #4, need more clarity on what is meant by “discovery of a change” and “is expected to last” **See ACES Comments as well** Additionally, the SERC GWG agrees with the comments provided by ACES	
Response	
Attachment 1: Section 1: Periodicity and Clarifications Requirement R1 was updated. The verification date should represent the date that the engineering review or engineering analysis is complete. Per Requirement R1, the summary report must be provided to the TP within 30 days of the verification date. No change. The language of Section 1, Part 3, for “discovery of a change” is the same as currently enforceable version of MOD-025-2. Bookmark to ACES Comment/Response	

Ruchi Shah - AES - AES Corporation - 5	
Answer	No

Document Name	
Comment	
Refer to response in Question 1.	
Response	
Refer to response in Question 1.	

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Comment	
See EEI Comments BHC agrees with the EEI comments.	
Response	
Bookmark to EEI Comment/Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	No
Comment	

Attachment 1: Section 1: Periodicity

Attachment 1, Section I, #2--We disagree with shortening the verification of a new facility from 12 months to 180 days. A new facility, such as a wind farm, may not have the ability to be at full capacity when the farm is new.

Attachment 1: Section 2: Clarification of Engineering Review

Attachment 1, Section II, #5--We believe that examples of an engineering review should be included to provide guidance.

Attachment 1: Section 3: Clarification of Engineering Analysis

Attachment 1, Section III, #2--Provide an example of clarification of and engineering analysis to provide guidance.

Attachment 3: Requested Changes to Forms

Attachment 3 Page 22--the addition of Transformer Impedance overlaps with VAR-002, R5 and is unnecessary since this is already required in other standards.

Attachment 1: Section 3: Rewording

For variable generating resources, such as wind, solar, or run-of-river hydro, and nonvariable generating resources, such as battery energy storage systems, staged testing or operational data should be recorded with at least 90 percent of the inverters/generators at a Facility on-line. Staged testing or operational data shall be recorded from a time period when the Facility output of Real Power is forecasted to be greater than 75% of the Facilities nameplate total Real Power capability or at Real Power capability that allows the GO to demonstrate its full Reactive Power capability. If staged testing or operational data capture of a Facility cannot be accomplished while meeting the 90 percent inverter/generator threshold, document the reason(s)the threshold was not met and test to the full available capability at the time of the test. Maintain, as steady as practical, the maximum Real Power output that the resource can provide at the time of the verification. Record measurements at the two points in Items 9.1 and 9.2 below at the maximum Real Power output the variable resource can provide at the time of the staged test or operational data. 9.1. Maximum lagging Reactive Power at normal operating Real Power until a limit is reached; 9.2. Maximum leading Reactive Power at normal operating Real Power until a limit is reached.

Attachment 1: Section 1: Periodicity

Attachment 1

Section I. Periodicity of verification

Recommend keeping existing points 2 and 4, consider deleting the rest, and consider adding event driven verification.

Reverification based on elapsed time is arbitrary and strictly administrative and should not be required. As the draft is written: a) New facilities must be verified within 180 days of commercial operation. b) Facilities must be reverified within 180 days of discovery of a change. This section could be more event driven and less administrative with wording to the effect of:

1. Verify each new applicable Facility within 12 calendar months of its commercial operation date.

2. Verify an existing applicable Facility within 12 calendar months of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating and is expected to last more than 12 calendar months.

3. Verify an existing applicable Facility within 12 calendar months of an equipment, setting, control system or software change that could affect its Real Power or Reactive Power capability.

Attachment 1: Section 2: Wording Change Recommendations or Clarifications

Section II. Verification for applicable Facilities

Overarching concern is that some items (specifically 3.1 and 7.2) appear to call for a "Net" Real Power and Reactive Power verification, while other sections do not. While some models may rely on net power, others may rely on gross power with the auxiliary loads modelled separately. 3.1 and 7.2 should be removed so that standard does not force one or the other, but rather leaves that optionality to the TP via R3.

Suggested edit:

1. The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility capability with all equipment expected to be in-service for normal operation. *The requirements listed in the last sentence add cost and administrative burden by requiring information that is interpretative and does not add to BES reliability.*

Attachment 2: Section 3: Issue with PQ Data and Capability Curve (Repetitive)

Attachment 2

Recommend removing Section III as extraneous data and administrative in nature. Data points required in Section III are already available in Section II and any data points provided in the table may or may not be points that the TP needs.

Attachment 2: Section 4: Request for Removal of Section due to Cost Burden

Recommend removing Section IV. As on Attachment 1, Section II, Point 5 – This requirements adds significant cost and administrative burden by requiring information that is interpretative and does not add to BES reliability

Response

1. No change. 180 days after the commercial operation date is ample time to perform verification of real and reactive power capability. If performing staged testing or operational data, 90 percent of the inverters/generators at a Facility need to be online. There is no requirement to be at a percentage of real power capability, such as 75%.
2. An engineering analysis is performed subsequent to a staged test or operational data collection when the full capability of the Facility is not demonstrated. This is most likely due to restrictive transmission system constraints/conditions. An example of engineering analysis of staged test data can be found in Reliability Guideline Power Plant Model Verification and Testing for Synchronous Machines (Appendix D – Testing and Calculations Example), July 2018. An example of an engineering analysis for operational data can be found in NATF Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines Reference, September 2020 (Section 3 and 4). An engineering review is not the same as engineering analysis. An engineering review can be complete if a staged test or obtaining operational data is not achievable. An engineering review must include a comprehensive review of all of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations. The engineering review documentation shall include the underlying assumptions, design criteria, and methods used to create the Facility's composite capability curve under Section II, Items 6-8. There are currently no compliance examples publicly available.
3. No change. This information should be included as part of the stage test or operational data report.
4. No change. The proposed change would be more restrictive on the GO/TO when performing a staged test. The current language requires 90% of all inverters to be online, or to document a reasoning otherwise. Adding a required generation output of 75% of an intermittent/variable fuel source could be challenging.
5. No change. The periodicity has already been expanded to 10 years. The SDT does agree with only an event based periodicity.
6. Change made. For Item 3.1 "The simplified one-line diagram should represent the auxiliary equipment."
7. No change. The SDT does not consider this extraneous work. It is expected that TP will use the PQ data table first, and the TP can locate or determine extra points on the CCC as necessary. The two are complementary to one another, and are not meant to stand alone. If only the CCC is provided, then the TP would need to approximate the values on the curve.

8. No change. The supplemental documentation is a byproduct of engineering analysis and verification methodology. It should be included in the information provided to the TP.

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Comment	

See MRO Comments as well

MPC supports comments submitted by the MRO NERC Standards Review Forum.

Attachment 1: Section 2: Rewording/Clarifications

Additionally, attachment 1, section II, paragraph 5, bullet 1 (pg 13), states that entities must "perform an engineering review of **all** Real and Reactive Power Facility capability information…". The use of the word "all" is problematic. This should be modified to either explicitly list all important elements that the SDT thinks would be included or allow an entity to use engineering judgement to determine which elements of "capability information" should be considered.

Attachment 1, section 2, paragraph 6.2 (pg 13) seems to overlap with PRC-019-2. Can the SDT please comment on the rationale that supports including this language in MOD-025-3?

Attachment 1: Section 3: Rewording/Clarifications

Attachment 1, section III, paragraph 3 (pg 15) uses the phrase "for a sufficient time". This phrase is problematic because it is unclear what is meant by "sufficient". This reference should either be removed or replaced with a specific period of time.

Attachment 1, section III, paragraph 6, uses the language "until a limit is reached". This could be interpreted to be contradictory to Attachment 1, section III, paragraph 3, which requires that "Staged testing or operating conditions should be maintained constant for a sufficient time in order to ensure that the applicable Facility can perform at that level of Real and Reactive Power during steady-state conditions." MPC suggests changing paragraph 3 to state that "Staged testing or operating conditions should be maintained constant for a sufficient time in order to ensure that the applicable Facility can perform at that level of Real and Reactive Power during steady-state conditions **or until a limit is reached**."

Response

See MRO NSRF comment

1. No change. The use of the word "all" does not seem problematic. The engineering review should be comprehensive and thorough. The engineering review documentation shall include the information listed in Item 5 "include the underlying assumptions, design criteria, and methods used to create the Facility's composite capability curve" and including, but not limited to, "in-service equipment design limitations, excitation limiter settings, and operational limitations." PRC-019 does not require for the CCC to be provided to the TP. This is why the CCC needs to be provided as part of Section II, Part 6.

2. No change. Tester can determine time as needed based on what they see. If stator temps or mechanical issues are of concern, time can be 1-2 hours to verify limit during testing. If stator temps level out quickly during test no need to hold for 1 hour as before.

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Comment	

Attachment 1: Section 1: Periodicity

AZPS does not agree that the 12 month verification timeframe should be reduced to 180 days in Parts 2, 4, and 5 for the reasons outlined in our response to Questions 1 and 2 above.

Response

No change. With the revised version of MOD-025-3, multiple options exist to verify the capability of the Facility. For a newly commissioned Facility, the SDT feels 180 days is a reasonable amount of time to complete the engineering review or engineering analysis. Additionally, if performing a staged test as part of commissioning process, the results of the staged test could be used for MOD-025-3 purposes.

Kimberly Turco - Constellation - 6	
Answer	No
Comment	

Attachment 1: Section 1: Periodicity/Rewording

Attachment #1: Section 1, Item 1: Constellation requests that the proposed language be modified to state that the verification date represents the engineering analysis completion date rather than the testing date.

Section 1, Item 2: Constellation does not agree with the verification of each new applicable Facility within 180 calendar days of its commercial operation date. There may be reasons for a company to declare “commercial operation date” prior to actual day-one operational date due to regional and state differences (e.g., project financing, commissioning testing). Constellation therefore recommends revising the language to state “within 180 days of initial synchronization to the grid”

Section 1, Item 3: Constellation agrees with the 10-year periodicity; however, Transmission Planners typically have more conservative testing requirements. As previously mentioned, the data and periodicity for testing is dictated by the Transmission Planners and therefore providing such specific requirements in MOD-025 will continue to result in discrepancies in data reported to meet the Transmission Planner requests and evidence documented to meet the Standard requirements.

Section 1, Item 4: Constellation does not agree with the 180-day timeline for a change in capacity due to economic concerns. Wind and hydro generating units will now be required to perform max leading and lagging testing. It is unclear if first test has to be staged as the form now requires a composite curve, PQ table and documentation showing methodology.

Attachment 1: Section 3: Rewording Section 3, Item 5: Constellation recommends rewording this as IBR facilities operate only in VAR or PF control modes. Kimberly Turco on behalf of Constellation Segments 5 and 6.
Response
1. Change made. The applicable entity designates the verification date and notates the verification date in a summary report (refer to Attachment 2). The verification date should represent the date that the engineering review or engineering analysis is complete. The verification date is the basis of the recurring periodicity. 2. No change. With the revised version of MOD-025-3, multiple options exist to verify the capability of the Facility. For a newly commissioned Facility, the SDT feels 180 days is a reasonable amount of time to complete the engineering review or engineering analysis. Additionally, if performing a staged test as part of commissioning process, the results of the staged test could be used for MOD-025-3 purposes. 3. Thank you for your support of the change from 5 to 10 year periodicity. 4. No change. The first test is not required to be a staged test. For a variable fuel resource, the requirement is for 90% of inverters to be online for a staged test. 5. Change made. Revised Section III, Item 5.

Alison MacKellar - Constellation - 5	
Answer	No
Comment	
See Constellation comment/response	
Response	
See Constellation comment/response	

Eve G Stromer - Basin Electric Power Cooperative - NA - Not Applicable - MRO,WECC	
Answer	No
Document Name	
Comment	
See MRO Comments **See NAGF Comments** Basin Electric Power Cooperative is in alignment with the MRO and NAGF comments.	

Response
[Bookmark to MRO NSRF Comment/Response](#) [Bookmark to NAGF Comment/Response](#)

Brian Lindsey - Entergy - 1	
Answer	No
Comment	

1. Attachment 1: Section 1: Periodicity/Rewording

Section I. Periodicity of verification:

1. Disagree with the 180-calendar day requirement to verify each new applicable facility. A situation could arise where the 180-day requirement cannot be done due to constraints on the grid.

2. Verbiage should be similar to MOD-026 and MOD-027 to include ten-year anniversary from the last verification date.

3. Disagree with the 180-calendar day requirement to verify each new applicable facility. A situation could arise where the 180-day requirement cannot be done due to constraints on the grid. Also, there is no clear direction on what you should do if the issue is resolved after the 180 days and the subsequent change is back to nameplate value.

Attachment 1: Section 2: Clarifications

Section II. Verification specifications for applicable Facilities:

4. Realistically the D-Curve from PRC-019 should be what we use. If we add Pmax and Pmin requirement to PRC-019 then that addresses the needs for the current proposed MOD-025 requirements and makes MOD-025 unnecessary.

5. Composite capability curve should also include a line for Pmax included in transmission models as this may be different from operational Pmax. Transmission planning model often have Pmax set as the value define in the GIA which cannot be changed by the Transmission Planner.

Attachment 1: Section 3: Clarifications

6. Section III. Staged test and operational data specifications

Sufficient time should be defined. If the sufficient time is defined by the applicable entity it will be fine.

Response

1. No change. 180 days should be sufficient time to verify the Facility capability. Staged testing is not the only methodology to verify the Facility capability.
2. No change. In MOD-026/027, the periodicity is based on the transmittal date. In MOD-025, the GO/TO establishes the verification date in the summary report when the engineering review or engineering analysis is complete. The next verification date should not exceed 120 calendar months (or 10 years).
3. No change. Same comment as #1. If the Real Power or Reactive Power capability increases or decrease by 10% of nameplate and is expected to last more than 180 calendar days, then MOD-025 verification must be performed. If the subsequent change is back to nameplate value, and

expected to last more than 180 days, then MOD-025 verification must be performed. In both examples, staged testing is not the only methodology to verify the Facility capability.

4. No change. PRC-019 does not meet the specifications in MOD-025 of providing a CCC, looking beyond the excitation system, giving data to TP or performing an engineering analysis.
5. No change. Pmax and Pmin can be provided based on TP model (should talk with TP prior to verification process, while we can't force this, it is implied this should take place). Pmax and Pmin during testing may be done for operational reasons, but engineering analysis can shift values bases on TP model if desired.
6. No change. Tester can determine time as needed based on what they see. If stator temps or mechanical issues are of concern, time can be 1-2 hours to verify limit during testing. If stator temps level out quickly during test no need to hold for 1 hour as before.

Rajesh Geevarghese - Rajesh Geevarghese On Behalf of: Kinte Whitehead, Exelon, 1, 3; - Rajesh Geevarghese	
Answer	No
Comment	
See EEI Comments Exelon agrees with comments submitted by EEI.	
Response	
Bookmark to EEI Comment/Response	

Alan Kloster - Alan Kloster On Behalf of: Jennifer Flandermeyer, Evergy, 3, 6, 5, 1; Jeremy Harris, Evergy, 3, 6, 5, 1; Kevin Frick, Evergy, 3, 6, 5, 1; Marcus Moor, Evergy, 3, 6, 5, 1; - Alan Kloster	
Answer	No
Comment	
See EEI Comments Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #5.	
Response	
Bookmark to EEI Comment/Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Comment	
Attachment 1: Section 1: Periodicity	

NIPSCO recommends pursuing a similar periodicity as currently being pursued for MOD-026-2 by the Project 2020-06.
Response
No change. In MOD-026/027, the periodicity is based on the transmittal date. In MOD-025, the GO/TO establishes the verification date in the summary report when the engineering review or engineering analysis is complete. The next verification date should not exceed 120 calendar months (or 10 years).

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Comment	
Attachment 1: Rewording/Clarification Verification of reactive power capability as defined in attachment 1 is not well defined. Several previous tests were not able to accomplish documented limits due to system conditions. Overall, in our opinion, there is not much value to performing this particular test.	
Response	
No Change. Test Data or Operational data is used as an input to engineering analysis. Engineering analysis can remove the system limits and obtain a reasonable value for reactive power capability. An engineering analysis is performed subsequent to a staged test or operational data collection when the full capability of the Facility is not demonstrated. This is most likely due to restrictive transmission system constraints/conditions. An example of engineering analysis of staged test data can be found in Reliability Guideline Power Plant Model Verification and Testing for Synchronous Machines (Appendix D – Testing and Calculations Example), July 2018. An example of an engineering analysis for operational data can be found in NATF Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines Reference, September 2020 (Section 3 and 4).	

Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Comment	
Attachment 1: **Attachment 1: Section 1: Rewording** 1. Says “discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating”. This should be changed to “discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the previously submitted capability or the nameplate rating if there has not been a previously submitted capability”. **Attachment 1: Section 2: Rewording**	

2. Has in Section II part 2 a statement "that are part of an applicable Facility greater than 75 MVA". This should be changed to "that are part of an applicable Facility greater than 50 MVA" since substantial parts of the BES are impacted by 50 MVA devices/generators.
3. Says "operating conditions that dictate the power capability, for example H2 pressure". This should be changed to "operating conditions that dictate the power capability, for example H2 pressure".

Attachment 2:

Attachment 2: Clarifications

4. Says "changes may be made to this form, provided that all required information is reported". Who determines what is "required information" – the PA/PC, TP, TO, GO?
5. Has a statement "The composite capability curve provided below is applied at Point (XX) in the one-line diagram shown above." There does not appear to be a Point XX in the one-line diagram.
6. Has a table "PQ Curve Data Table". In this table, the rows are described a Pmin + some part of Range. For synchronous condensers or FACTS devices where real power consumption can vary depending upon the reactive power output, how is this table expected to be completed?

Attachment 3:

Attachment 3: Clarifications/Rewording

1. Says "changes may be made to this form, provided that all required information is reported". Who determines what is "required information" – the PA/PC, TP, TO, GO?
2. The form is also quite poorly developed. Even for a test of a very standard synchronous generator connected to the BES by a single transformer, the Attachment 3 form is not good. Examples are:

1. The language says "Check all that apply" whereas it should say "Check the one which applies" since it would not be possible, or at least not very clear, what to record in the "Data Table" if the "Over-excited Maximum Load Reactive Power Verification" and "Under-excited Minimum Load Reactive Power Verification" were both checked.
2. The "Summary of Test / Operational Data" has an entry for "Transformer Tap Setting". What about transformers which have both high-side and low-side taps? What is the purpose of "Transformer Voltage Ratio"?

Response

1. No change. Since the verification process provides a combined capability curve and a P/Q table which contains many values, using the previously submitted capability as a metric would be difficult. The SDT determined that using a fixed value relative to the nameplate of the resource was a more objective metric to use for verification purposes. For simplicity, the SDT chose to use the nameplate rating as the basis of change for the Real or Reactive Power capability.
2. No change. The current BES inclusion has a threshold at 75 MVA.
3. SDT does not see the recommended change in language.
4. No Change. Stating Form doesn't need to be used exactly as is as long as all data that is specified in the verification specification and form is included.
5. Change made. Language changed in Attachment 2, "Identify on the one-line diagram where the composite capability curve is represented."

6. While ultimately up to those submitting the data, a reasonable submission for a unit with no real power capability would submit with Pmin = Pmax = 0 MW and Qmax and Qmin values provided at 1.0 pu voltage.
7. No Change – Stating Form doesn't need to be used exactly as is as long as all data in form is presented.
8. No change. The form is similar to the previously approved MOD-025-2

Kathleen Goodman - ISO New England, Inc. - 2 - NPCC, Group Name Standards Review Committee (SRC)	
Answer	No
Document Name	
Comment	

R1/R2 and Attachment 1: Promote Engineering Analysis Maybe Allow another Method of Confirmation?

Attachment 1 potentially requires only a paperwork exercise to verify capability. Actual performance tests or recorded operational data should be allowed as other means to demonstrate verification.

Attachment 1: Sections 1 and 2: Rewording/Clarification

Section II sub-sections 1 and 2 should be changed to use the BES definition instead of 20 MVA gross nameplate rating.

Response

1. No change. Testing and operational data are allowed. Order has been changed to promote tests and operational data. Engineering analysis builds on the test/op data.
2. Section II. Item 1 and 2 do not change the applicable Facilities in Section 4. These items relate to how the model verification should be performed, either individually or as an aggregate. If the generator is greater than 20 MVA verification (BES Inclusion I2) must be performed in individual basis. For Item 2, if the generators are less than 20 MVA and part of a larger Facility 75 MVA, then verification can be completed on an individual or aggregate basis, while considering modeling expectations of the respective TP.

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	No
Comment	

R4: Criteria Definition to Avoid Objections / Conflict

It is constructive to allow flexibility by the Functional Entities to establish methodologies for reporting Real and Reactive Power capability, but there is a need for a common basis, understanding, and consistency on a shared methodology between the Functional Entities. Little guidance is provided to establish a common basis to determine and report Real and Reactive Power capability. There is a need to better identify the acceptance criteria to determine when a reported value is "verified" after a random mixture of possibilities of staged testing, operational evidence, and engineering analysis. The absence of this criteria increases the likelihood for R4 notifications with more conflict to attain a mutually agreed upon resolution. The drafting team should investigate if reasonable acceptance criteria can be consistently applied across the Functional Entities. Better guidance or endorsement is needed in the standard to validate the acceptance of engineering analysis of reactive capability of a synchronous generator under system voltage deviations that are impossible to replicate for a staged test under normal operating conditions. The full weight of the standard needs to whole-heartedly endorse the use of engineering analysis to supplement or establish reactive capability that can't be overruled by a Transmission Planner's objections; this is needed to overcome the past practices of ISOs to determine a generating unit's reactive capability by only accepting the recorded readings of a staged test, regardless of the system operating conditions.

R1/R2 and Attachment 1: Promote Engineering Analysis

A significant reason for the SAR was that engineering analysis and calculations were not permitted as sufficient justification why a machine did not reach its stated capability due to system operating conditions at the time of a staged test. Those familiar with the interaction of a synchronous generator with a transmission system know that a generator can easily produce more lagging reactive when system voltage is low and produce more leading reactive when the system voltage is high. The Attachments should specify to allow engineering analysis to calculate and report a generating unit's reactive power output for the following conditions:

1. For leading power factor operation, it is acceptable to calculate and report the generator reactive output when the system voltage is 2% about the schedule voltage (target system voltage for the generator to normally maintain).
2. For lagging power factor operation, it is acceptable to calculate and report the generator reactive output when the system voltage is 2% below the schedule voltage (target system voltage for the generator to normally maintain).
3. Synchronous generators are thermally capable of continuous operation within the confines of their manufacturer's reactive capability curves over the ranges of ±5% in voltage as specified in IEEE C50.13.

Regarding the Attachments:

Attachment 1: Section 2: Rewording/Clarification

The options in Attachment 1, Section II, item 5, provided on how to comply with the standard are loose. This will end up creating issues to determine what actual verification should intel. The sections after provide the type of information to be included but doesn't have technical criteria for meeting verification.

Attachment 1: Section 1: Rewording

The SDT should reword Attachment 1. Section 1, Line item 5 to clarify the If/Then statement. Attachment 1-Section I, Line item 5 should be a sub requirement of Line item 3 as an exception to extend the ten-year requirement.

Attachment 1 and 2: One-Line Requirements Suggestions/Rewording/Removal

In addition, Attachment 1-Remove Section II., 3.1, one-line requirements; only require the stated objective of a simplified one-line diagram, as shown in Attachment 2, Section I.

The stated requirement of 3.1 ("The one line representing the Facility shall include all auxiliary equipment expected to be in-service for normal operation") implies that the one line must display the details of "all" auxiliary equipment. This contradicts the concept of a simplified one-line.

The description of “all auxiliary equipment” is too broad, ambiguous, and overly inclusive of miniscule loads connected to external sources. Including “all auxiliary equipment” requires the accounting of inconsequential loads outside the power block of a large generating unit, which is impractical and unnecessary for the objective of the standard. Add a provision that the inclusion of monitoring points D and E of Attachment 2, Section I, are not required if the operating auxiliary load at these points are less than 1% of generator nameplate MVA.
Response

1. See below
2. An engineering analysis is performed subsequent to a staged test or operational data collection when the full capability of the Facility is not demonstrated. This is most likely due to restrictive transmission system constraints/conditions. An example of engineering analysis of staged test data can be found in Reliability Guideline Power Plant Model Verification and Testing for Synchronous Machines (Appendix D – Testing and Calculations Example), July 2018. An example of an engineering analysis for operational data can be found in NATF Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines Reference, September 2020 (Section 3 and 4). An engineering review is not the same as engineering analysis. An engineering review can be complete if a staged test or obtaining operational data is not achievable. An engineering review must include a comprehensive review of all of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations. The engineering review documentation shall include the underlying assumptions, design criteria, and methods used to create the Facility’s composite capability curve under Section II, Items 6-8. There are currently no compliance examples publicly available.
3. SDT did not want to be overly prescriptive here.
4. Change made. Attachment 1, Section I Item 3 now reads, “Verify each existing applicable Facility at a periodicity not to exceed 120 calendar months from the last verification date, unless it meets the following condition:
    - The Facility has been on a planned or unplanned outage of 180 days or greater, which overlaps its scheduled verification date. Verify the applicable Facility within 180 calendar days of its return to service date.
5. Change made. Section II. Part 3.1 reworded the phrase to “represent all auxiliary equipment” rather than “include”. This is a small adjustment to the wording in MOD-025-2.

Eric Ruskamp - Lincoln Electric System - 1,3,5,6, Group Name LES	
Answer	No
Document Name	
Comment	

Attachment 1: Section 1: Periodicity / Rewording

We have the following concerns with the generator testing prescribed in Attachment 1:

· Attachment 1 does not adequately address the real power output and conditions. Real power generation will vary greatly for gas turbine generators based on ambient weather conditions. Although not as significant as the variation in real power output of gas turbines, steam units have a varied output based on condensing temperatures. Real power testing should be conducted with all applicable weather conditions being recorded along with the corresponding output. Transmission line capacities vary with ambient temperature, therefore the output of the real power generating capacity at different conditions needs to be provided.

· The ten-year test period is too long. Although changes of more than 10% are to be reported and tested, over that time there is too much opportunity for things to change and not be reported. Testing at least every five years assures that the generating capacity information is adequately maintained.

Attachment 1

Section I. Periodicity of verification

Recommend keeping existing points 2 and 4, delete the rest, and add event driven verification.

Reverification based on elapsed time is arbitrary and strictly administrative and should not be required. As the draft is written: a) New facilities must be verified within 180 days of commercial operation. b) Facilities must be reverified within 180 days of discovery of a change. This section could be more event driven and less administrative with wording to the effect of:

{C}1. Verify each new applicable Facility within 12 calendar months of its commercial operation date.

{C}2. Verify an existing applicable Facility within 180 calendar days of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating and is expected to last more than 180 calendar days.

{C}3. Verify an existing applicable Facility within 180 calendar days of an equipment, setting, control system or software change that could affect its Real Power or Reactive Power capability.

Attachment 1: Section 2: Rewording

Section II. Verification for applicable Facilities

Overarching concern is that some items (specifically 3.1 and 7.2) appear to call for a "Net" Real Power and Reactive Power verification, while other sections do not. While some models may rely on net power, others may rely on gross power with the auxiliary loads modelled separately. 3.1 and 7.2 should be removed so that standard does not force one or the other, but rather leaves that optionality to the TP via R3.

Suggested edit:

5. The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility capability for with all equipment expected to be in-service for normal operation. The engineering review or engineering analysis shall include underlying assumptions, design criteria, and methods used to create the Facility capability curve under Section II, Items 6-8. *The requirements listed in the last sentence add cost and administrative burden by requiring information that is interpretative and does not add to BES reliability.*

Attachment 2: Section 2: PQ Data vs CCC. Pick one

Attachment 2

Mildly recommend removing Section III as extraneous data and administrative in nature. Data points required in Section III are already available in Section II and any data points provided in the table may or may not be points that the TP needs.

Attachment 2: Section 4: Request for Removal of Section due to Cost Burden

Strongly recommend removing Section IV. As on Attachment 1, Section II, Point 5 – This requirements adds significant cost and administrative burden by requiring information that is interpretative and does not add to BES reliability

Attachment 1: Section 2: Clarification of Engineering Review / Engineering Analysis / Examples

Attachment 1, Section II, #5--We believe that examples of an engineering review should be included to provide guidance.

Attachment 1: Section 3: Clarification of Engineering Review / Engineering Analysis / Examples

Attachment 1, Section III, #2--Provide an example of clarification of and engineering analysis to provide guidance.

Attachment 3: Requested Changes to Forms

Attachment 3 Page 22--the addition of Transformer Impedance overlaps with VAR-002, R5 and is unnecessary since this is already required in other standards.

Response

Bookmark to MRO NSRF Comment/Response
Bookmark to ACES Comment/Response

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No

Comment

Attachment 1: Section 1: Periodicity / Rewording

Regarding Attachment 1:

In Attachment 1, Section I, Item 2, the term 'commercial operation date' should be defined. Since this term will set the date by which verification must take place, it could be difficult to determine compliance without a clear definition of what constitutes the start of the 180 day period.

In Attachment 1, Section I, Item 3, OPG would recommend making reference to Real Power and Reactive Power verifications per Requirements R1.1, R1.2, R2.1, or R2.2, since active power verification and reactive power may be verified separately, and have separate required reverification dates; proposed language is as follows:

"3. Verify **the Real Power and Reactive Power capability of** each existing applicable Facility at a periodicity not to exceed ten years from **the date(s) of** the last verification**(s) performed per R1.1, R1.2, R2.1, or R2.2**."

Attachment 1: Section 2: Classifications of Engineering Review and Engineering Analysis.

With respect to Attachment 1, Section II, Item 5:

Given the language presently included in Section II, Item 5, it seems that entities may opt to conduct an engineering analysis that is based only on stated assumptions to determine the facility capabilities it will declare. It appears that the inputs to this analysis may be only design and operating limits information, but there does not appear to be any requirement for the analysis to examine or validate assumptions against recent operational realities for the equipment in question.

OPG contends that any engineering analysis should be based *at least in part* on recent equipment performance data (from operation or staged testing), and should not rely exclusively on design data – which may be considered unchanged since the previous verification (10 years prior), in which case there would be little value in conducting a new analysis with the same information as used in the prior verification.

Specifically, OPG expects that there should be some requirement to verify recent equipment performance is consistent with the assumptions used to develop capability curves (e.g., steady-state temperature rise on stator and field windings are as expected in particular operating conditions, validating use of 'design' field current and stator current limits to draw capability curves).

Attachment 1: Section 2: Rewording / Assistance

With respect to Attachment 1, Section II, Item 6:

OPG recommends removing the phrase "provided by the equipment manufacturer" from the end of 6.1, as follows:

"6.1. The generator steady-state Real Power and Reactive Power capability curve, or the synchronous condenser steady-state Reactive Power capability curve, ***provided by the equipment manufacturer***"

This phrase is unnecessarily restrictive, as OEM capability curves are not always available and, in some cases, the manufacturer no longer exists. Additionally, some utilities produce their own capability curves, while others rely on third party consultants to produce them. The mention of the 'manufacturer' should be removed from 6.2 as well.

OPG recommends adding to the list of explicitly mentioned examples of operating conditions that can dictate the power capability, "head water level" in 6.1.2, as follows:

"6.1.2 The curve shall notate the operating conditions that dictate the power capability, for example H2 pressure, **head water level**, ambient temperature, or other conditions."

This recommendation to add an explicit mention of 'head water level' also applies to Item 7.1.2.

OPG notes that there are cases where the loss-of-excitation protection will be the first limit encountered in the under-excited operating region (this is common for hydro units with no UEL and a mho-based loss-of-excitation relay with a reach of more than 1.0 p.u., such that its characteristic is inside the limits of the stator MVA circle in the under-excited region).

As such, OPG recommends adding "in-service protective functions" to the list of equipment that is to be drawn on the composite capability curve, and suggests that this new point become 6.2, as follows (also showing the suggested removal of the word' "manufacturer's" with regards to the capability curve):

"…

6.2. In-service protective functions, if more restrictive than the equipment's capability curve, at nominal voltage of 1.0. per unit;

6.**3**. Excitation limiters, if more restrictive than the equipment**'s manufacturer's** capability curve, at nominal voltage 1.0 per unit;

6.**4**. Identification of any Real Power or Reactive Power operational limitations1, if applicable;

With respect to Attachment 1, Section II, Item 7:

The same recommendation to add an explicit mention of 'head water level' as made for 6.1.2 also applies to Item 7.1.2.

Attachment 1: Section 3: Rewording / Clarifications

With respect to Attachment 1, Section III, Item 2:

In the following sentence, the reference to Item 4 appears to be in error – referring to Item 3 (which is where the simplified one-line is required) would make more sense:

“Refer to the associated labels depicted in the one-line diagram created in Section II, **Item 3**/*Item 4*.”

With respect to Attachment 1, Section III, Item 3:

“Staged testing or operating conditions **should be maintained constant for a sufficient time** in order to ensure that the applicable Facility can perform at that level of Real and Reactive Power during steady-state conditions.”

OPG agrees with this statement. However, it lacks clarity, and is subject to interpretation. What is ‘sufficient’?

For example, one person may refer to industry standards, such as the following from Section 7 of IEEE 115 (2019 version), which pertains to the test duration during ‘temperature testing’ in which a generator’s thermal capability is determined:

"Continuous loading tests should be continued until machine temperatures have become constant within ± 2 °C of the rise value for three consecutive half-hourly readings. If the coolant temperature is not constant, the test may be terminated when the temperature rise, based on at least three consecutive half-hourly readings, does not exceed the maximum previously observed rise. Continue the test if the coolant temperature for three half-hourly readings varies by more than 2 °C."

Someone else may believe that having held the loading point for 5 minutes is 'sufficient'.

It is not clear if this is just guidance, or if it is intended to be an enforceable requirement. The use of the word ‘should’ implies it is optional. If this is intended to be mandatory, then a more concrete, measurable criteria should be provided. It is unlikely that utilities will spend any more time than is necessary at test conditions that they would not otherwise be at, without a definite requirement to do so.

It would seem that the existing requirement to operate to the first over-excited limit at full-load (even if the first limit is a system-imposed voltage limit) would meet the intent of this statement. Perhaps this requirement should be retained or recommended as a best practice.

Response

1. No change. The term commercial operation date is used from existing MOD-025-2 language.

   The staged tests, operational data, or engineering review associated with Pmin or Pmax do not need to happen on the same date. The applicable entity designates the verification date and notates the verification date in a summary report (refer to Attachment 2). The verification date should represent the date that the engineering review or engineering analysis is complete. The verification date is the basis of the recurring periodicity.

2. Change made. Revision made, “If the equipment manufacturer curve is not available, the curve shall be derived using the best available data.”

3. No change made based on “head water level” comment. These would be considerations for Pmin and Pmax.
4. An engineering analysis is performed subsequent to a staged test or operational data collection when the full capability of the Facility is not demonstrated. This is most likely due to restrictive transmission system constraints/conditions. An example of engineering analysis of staged test data can be found in Reliability Guideline Power Plant Model Verification and Testing for Synchronous Machines (Appendix D – Testing and Calculations Example), July 2018. An example of an engineering analysis for operational data can be found in NATF Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines Reference, September 2020 (Section 3 and 4). An engineering review is not the same as engineering analysis. An engineering review can be complete if a staged test or obtaining operational data is not achievable. An engineering review must include a comprehensive review of all of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations. The engineering review documentation shall include the underlying assumptions, design criteria, and methods used to create the Facility’s composite capability curve under Section II, Items 6-8. There are currently no compliance examples publicly available.

Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company

Answer	No
Document Name	

Comment

Attachment 1: Section 1: Periodicity

Att. 1, Section 1:

1. New unit verification due date should stay at 1 calendar year after COD. 180 days is too tight of a schedule. Propose a reword of “Verify an existing applicable Facility within 180 calendar days of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating” as this may lead to confusion. “Nameplate” changes are rare and reflect some sort of machine upgrade, stator rewind, etc. Possible alternative is “by more than 10 percent increase or decrease of previously reported real or reactive power capability.”
2. Rather than using the proposed unit in outage verification plan, we suggest this alternative method for handling these cases: “Verify an existing applicable Facility within 180 calendar days of its return to service date, if the Facility has a planned or unplanned outage which overlaps its scheduled verification date deadline and has not had its capability verified within the past ten years.”

Attachment 1: Section 2: Removal of TP Requirements

Att.1 Section II:

3. Given the quantity of the number of individual units, including the modeling of individual units in this category is impractical and unreasonable. We suggest removing that part along with the unreasonable modeling expectations of a TP.

Attachment 1: Section 2: Clarification/Rewording

4. The "final" qualifier on final PQ curve is undefined.
5. Att 1 Section II. 3.1. Propose facility one-line not be so prescriptive in auxiliary equipment that has to be represented. The one-line should include GSU, generator, and auxiliary equipment information as needed by the Transmission Planner. As worded, the standard would imply all station service loads at all voltage levels need to be shown on the one-line.

Attachment 1: Section 2: PQ Data vs CCC. Pick one

6. Att 1 Section II.6-8. Strongly recommend removing requirement to create a composite capability curve (CCC). Transmission Planner has sufficient modeling information with Q Max & Q Min @ Pmin + Q Max & Q Min @ Pmax. A CCC will be tedious and time consuming for GOs/TOs to create and provide little benefit to a TP. The TP cannot input the CCC into their modeling software directly, and the data it provides is redundant with the data required by Att 2 Section III.

Attachment 1: Section 3: Clarifications on Engineering Analysis

2. Att. 1, Section III: What is the benefit of staged testing if it must be coupled with engineering analysis anyway?

Attachment 1: Section 3: Control Mode Rewording for IBR especially

3. Att. 1, Section III, Item 5 is problematic as some IBR facilities are requested by the TOP to operate in control modes other than voltage control (PF, e.g.)

Attachment 1: Section 3: Rewording / Clarifications

4. For the part "*Not all data points outlined in items 6, 7, 8, or 9 need to be recorded if multiple methods are used. (1)":* This is very confusing because when either staged testing or operational data is used, engineering analysis is also required by the method options, and the analysis that must be done includes part of that identified in method option for engineering review – so this results in some points not being required to be recorded – which points?

For the part "*Record data on form in Att. 3 or in a form with equivalent info included. (2)*":

Att. 3 information needs to be part of this section, and not separated. The standard requirements include Att. 1 and Att. 2, but not Att. 3. This section is the only reference to Att. 3. Rather than reference a new section, just include the info in here.

For the part "*Maintain constant operating conditions during staged testing. (3)*":

How long is "for a sufficient time"?

For the part "*All aux eq in normal operation condition. (4)*"

Wording of (4) is incorrect – not all aux equipment is always in service during normal operations.

Attachment 2: Rewording / Removal of TP Requirements

5. Att 2 Introduction. Recommend "Documentation showing the engineering basis and verification methodology" should be created by GOs/TOs and left on file if requested by TP. Recommend not making it a mandatory submission to the TP.

Attachment 2: Section 2: PQ Data vs CCC. Pick one

6. Att 2 Section II. See comments on Att 1 Section II.6-8. CCC should not be a requirement of engineering analysis.
7. Att 2 Section III. PQ data table should not have rows beyond Pmin and Pmax. Data in between Pmin and Pmax can be reasonably interpolated by TP if required.

Attachment 2: Clarification

8. For the part "*Changes may be made to this form provided that all info identified in Att. 1 in reported.*": This statement is illogical since Att. 1 prescribes one line diagrams and CCCs.

See MRO Comments as well

In addition to these comments, Southern Company supports the comments submitted by the MRO NSRF group.

See NAGF Comments as well

In addition to these comments, Southern Company supports the comments submitted by the NAGF.

See EEI Comments as well

In addition to these comments, Southern Company supports the comments submitted by EEI.

Response

Response to Southern Company Comments

1. Periodicity. 180 days after commissioning date should be sufficient amount of time. Multiple options for verification are available. No change. For example if the nameplate rating is 100 MVA, when there is any increase or decrease of 10 MVA or greater of Real or Reactive power capacity, then MOD-025 would need to be performed.
2. Change Made. Verify each existing applicable Facility at a periodicity not to exceed 120 calendar months from the last verification date, unless it meets the following condition: The Facility has been on a planned or unplanned outage of 180 days or greater, which overlaps its scheduled verification date. Verify the applicable Facility within 180 calendar days of its return to service date.
3. No change. For generating facilities that fall under (individual devices or generators 20 MVA or less that are part of an applicable Facility greater than 75 MVA) the intent is to allow the GO/TO to verify how they desire as either on an individual basis or aggregate basis. The recommendation is that they should consider how the TP models the facility in making this decision. The intent here is to start a dialog with the TP.
4. Regarding the final PQ curve, see example CCC in Attachment 2, Section II showing the red dashed lines (Final PQ curve). It is meant to define the normal operating region after everything is plotted on the CCC.
5. Change made. Section II. Part 3.1 reworded the phrase to "represent all auxiliary equipment" rather than "include".Response
6. No change. All software programs (PSLF, PSSE, TSAT and PowerWorld have the capability to enter PQ curve data and be utilized during a software simulation. The CCC represents the Real and Reactive Power capability of the Facility.

7. Staged Testing and/or Operational Data can be used to confirm known steady-state points for the engineering analysis and then use that steady-state model to extend the unit's capabilities beyond the transmission or unit limitations seen during testing (if applicable). See NERC Guideline and NATF documents in Reference section additions to MOD-025-3
8. Change made. Item 5 "The Facility voltage/Reactive power control equipment is in the normal mode of operation.
9. No change. The SDT feels the addition of Attachment 3 is warranted for instances that staged testing or operational data methodologies are used.
10. No change. This documentation showing the methodology of engineering analysis/review should be provided to the TP, since it provides a background information to help the TP determine if they may have/or not have a technical concern.
11. The CCC curve needs to be developed in order to get the PQ data table.
12. The PQ data table is needed, since not all modelling software can digest a capability curve. The TP should not have to guess at the values represented on the CCC provided by the GO/TO.
13. The form is an example format of what may be provided. The form can be changed given that the required items be included.

Bookmark to MRO NSRF Comment/Response
Bookmark to NAGF Comment/Response
Bookmark to EEI Comment/Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
General – Addition of Capacity Factor Similar to MOD-026/-027 Recommend changing the Standard to include a Capacity Factor Exception similar to MOD-026 and MOD-027.	
Response	
1. No change. The SDT did not feel a capacity factor exemption is warranted. The SDT provided multiple options to verify the capability of the Facility.	

Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
See EEI Comments Instead	

Black Hills Corporation (BHP) agrees with the EEI comments.
Response
Bookmark to EEI Comment/Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Comment	
Attachment 1, Section 1: Periodicity Issues Attachment 1, Section 1, Page 12 of 22 reads: "Verify an existing applicable Facility within 180 calendar days of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating and is expected to last more than 180 calendar days." Consider whether the intended target criteria of the nameplate rating by more than a 10 % increase or decrease requires revision/reconsideration if prime mover (turbine) upgrades result in an increase in generator electrical power.	
Response	
If the Real Power or Reactive Power capability by more than a 10% increase or decrease of the nameplate rating, then the MOD-025-3 activities must be verified again for that Facility.	

Natalie Johnson - Enel Green Power - 5	
Answer	No
Comment	
See MRO Comments Instead Agreement with the MRO NSRF comments.	
Response	
Bookmark to MRO NSRF Comment/Response	

Ryan Strom - Buckeye Power, Inc. - 5 - RF	
Answer	No
Comment	
See ACES Comments Buckeye Power, Inc. supports the comments of ACES Power Marketing.	

Response
Bookmark to ACES Comment/Response

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
No. See the responses to questions 1 and 3.	
Response	
Answered No	

Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	
Attachment 1: Section 2: Issue with Allowing Engineering Review RF recommends against allowing any option that avoids the use of capability testing or operational data altogether. RF recommends the "engineering review" option under MOD-025-3 Attachment 1 Section II verification specification 5 be required in conjunction with the existing requirement to perform capability testing or to verify capability using operational data. Engineering review should be performed to adjust recorded values to account for limitations encountered during testing or operations that do not reflect the true capability of the units, but capability testing or operational data should still be used to ensure unexpected limiting factors are identified. For additional context to support RF's recommendation, reference Project Scope 4 and 6 from the publicly posted SAR as well as the Recommendation section of the publicly posted Power Plant Model Verification Task Force White Paper on MOD-025 Testing.	
Response	
An engineering analysis is performed subsequent to a staged test or operational data collection when the full capability of the Facility is not demonstrated. This is most likely due to restrictive transmission system constraints/conditions. An example of engineering analysis of staged test data can be found in Reliability Guideline Power Plant Model Verification and Testing for Synchronous Machines (Appendix D – Testing and Calculations Example), July 2018. An example of an engineering analysis for operational data can be found in NATF Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines Reference, September 2020 (Section 3 and 4). An engineering review is not the same as engineering analysis. An engineering review can be complete if a staged test or obtaining operational data is not achievable. An engineering review must include a comprehensive review of all of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations. The engineering	

review documentation shall include the underlying assumptions, design criteria, and methods used to create the Facility's composite capability curve under Section II, Items 6-8. There are currently no compliance examples publicly available.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Comment	

Attachment 2: More Examples for Other Devices (Synch Cond, FACTS, HVDC)

While the supporting materials and attachments provided for GOs aligns with Requirement R1, the referenced attachments provided for Facilities identified in 4.2.4 and 4.2.5 do not similarly align. To address this concern, additional attachments should be included that address Facilities identified in 4.2.4 and 4.2.5. (See our comments in response to Question 2 above).

Attachment 1: Section 1: Periodicity

Attachment 1

Section 1 (Periodicity of Verification)

Parts 2, 4 & 5: We also do not agree with the 12 month verification timeframe should be reduced to 180 days. (See our comments to Questions 1 and 2 above)

Attachment 1: Section 2: Clarification/Rewording/Alignment with PRC-019

Section 2 (Verification specifications for applicable Facilities)

Part 5: Bullet 1 appears to duplicate obligations identified in PRC-019, Attachment 1, Part A (Synchronous generator/condenser reactive capabilities; Field over-excitation limiter and associated protective function; Field under-excitation limiter and associated protective function). If this is incorrect, please explain how a violation under MOD-025, Section 2, Part 5 would not also result in a violation of PRC-019, Attachment 1, Part A. (See our response to Question 9 below)

Attachment 1: Section 3: Rewording

Section 3 (Staged test and operational data specification)

Part 9: EEI suggests that Part 9 be modified to the following in order to address the practicalities of testing variable generating resources (added text in boldface below):

9. For variable generating resources, such as wind, solar, or run-of-river hydro, and non-variable generating resources, such as battery energy storage systems, staged testing or operational data should be recorded with at least 90 percent of the inverters/generators at a Facility on-line. **Staged testing or operational data shall be recorded from a time period when the Facility output of Real Power is forecasted to be greater than 75% of the Facilities nameplate total Real Power capability.** If staged testing or operational data capture of a Facility cannot be accomplished while meeting the 90 percent inverter/generator threshold, document the reason(s)the threshold was not met and test to the full available capability at the time of the test. Maintain, as steady as practical, the maximum Real Power output that the resource can provide at the time of the verification. Record measurements at the two points in Items 9.1 and 9.2 below at the maximum Real Power output the variable resource can provide at the time of the staged test or operational data.

9.1. Maximum lagging Reactive Power at normal operating Real Power until a limit is reached;

9.2. Maximum leading Reactive Power at normal operating Real Power until a limit is reached.
Response
1. No change. The SDT provided an example capability curves for synchronous generator and IBR Facility to illustrate the Requirement language. The SDT has decided not to provide examples for all types of technologies. 2. Change made to Requirement R1/R2. See verification date change in Question 1 and 2. 3. No change. The SDT acknowledges that PRC-019 information can be used as one input for MOD-025 activities. PRC-019 does not require the GO to provide the TP with the CCC. PRC-019 requires only that the generator capabilities, protection systems, and protective functions be coordinated. The CCC is one means to demonstrate that this coordination has been achieved. Whereas, MOD-025 provides the verification of real and reactive power capability information to the TP. 4. No change. The proposed change would be more restrictive on the GO/TO when performing a staged test. The current language requires 90% of all inverters to be online, or to document a reasoning otherwise. Adding a required generation output of 75% of an intermittent/variable fuel source could be challenging.

Micah Runner - Black Hills Corporation - 1	
Answer	No
Comment	
See EEI Comments Instead Black Hills Corporation (BHP) agrees with the EEI comments.	
Response	
Bookmark to EEI Comment/Response	

Wayne Sipperly - North American Generator Forum (NAGF) - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
Attachment 1: Section 1: Periodicity Attachment #1: Section 1, Item 1: The NAGF requested that the proposed language be modified to state that the verification date represents the engineering analysis completion date rather than the testing date. Section 1, Item 5: Recommend revising the proposed language to remove “of 180 calendar days or more”.	

Attachment 1: Section 2: Rewording and Clarifications

Section 2, Item 2: The statement "considering applicable modeling expectations of the respective Transmission Planner" is vague and needs clarity or removal. Where will such expectations be defined?

Section 2, Item 5, First Bullet: The NAGF proposes removing this bullet as a review of all real/reactive information is not necessary prior to testing. All one needs to do is check the OEL and UEL curves in the PRC-019 study. No new information needs to be developed before performing MOD-025 tests. In addition, what is the difference between an engineering review verses engineering analysis?

Section 2, Item 5, Third Bullet: What are the criteria associated with operational data?

Section 2, Items 6 and 7: The NAGF notes that these items should not be required if Transmission Planners are not required to accept and use such data.

Attachment 1: Section 3: Control Modes other than Auto Voltage for IBR

Section 3, Item 5: NAGF notes that some IBR facilities operate only in VAR or PF control modes.

Attachment 1: Section 3: Rewording / Clarifications

Section 3 Items 6.3, 6.4, 8, and 9: It seems that Items 6.3 and 6.4 conflict with Items 8 and 9. Recommend that Item 6 be revised to recognize exemptions for Items 8/9.

Section 3, Item 8: The last sentence "If applicable, provide the theoretical Reactive Power capability at minimum Real Power output in accordance with Attachment 2." Seems to conflict with the first two sentences of Item 8.

Attachment 2: Section 3: Clarifications / Figure Change

Attachment #2:

Figure 2 - Example Composite Capability Curve for IBR Facility: This seems to be a capability curve of a single inverter, not the composite curve of an IBR facility. Should this example be a composite capability curve at the point of aggregation of 75MW?

Response

Bookmark to NAGF Comment/Response

1. Part A. Change made to Requirement R1/R2. As described in the standard. "The applicable entity designates the verification date and notates the verification date in a summary report (refer to Attachment 2). The verification date should represent the date that the engineering review or engineering analysis is complete. The verification date is the basis of the recurring periodicity." Part B. No change. The "180 calendar days or more" is specified because if an unplanned outage of shorter duration of 1-179 days occurs, then in each of those instances the GO/TO would need to perform MOD-025 activities.
2. No change. The expectations of how aggregation of generation resources can vary by Transmission Planner, so the language is meant to acknowledge those differences and promote a discussion between the GO/TO and TP prior to evaluation.
   i. For Section II, Part 5, "The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility capability for all equipment expected to be in-service for normal operation. An engineering analysis is performed subsequent to a staged test or operational data collection when the full capability of the Facility is not demonstrated. This is most likely due to restrictive transmission system constraints/conditions. An engineering review can be complete if a

staged test or obtaining operational data is not achievable. An engineering review must include a comprehensive review of all of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations. The engineering review documentation shall include the underlying assumptions, design criteria, and methods used to create the Facility's composite capability curve under Section II, Items 6-8. There are currently no compliance examples publicly available. ii. Operational or staged testing is the preferring method. Operational data is next preferred. The order of the methodologies will be reordered. iii. The criteria for staged testing and operational data are outlined in Attachment 1, Section III. iv. Requirement R3 states that the TP must review the data. However, the SDT believes it is overreach to dictate that the TP exclusively use MOD-025 data for modeling evaluation. TP should incorporate MOD-025 data into the MOD-032 submittal to improve model fidelity. 3. All applicable Facilities for MOD-025-3 should be verified in their normal mode of operation. Change made to Section III, Part 5. If a Facility is not in AVR mode, the Facility still has a reactive capability, and this Facility is required to supply reactive support for the grid either through constant MVAR or constant power-factor. This reactive capability must be verified under MOD-025-3. 4. Change made. For Part 6, "For an applicable Facility with Real Power capability, <u>that does not meet the conditions of Part Section III, Part 7, 8 or 9, record measurements the following four points:</u> i. These types of units must supply a theoretical capability at minimum real power because they may be required to move down to that operating point in an emergency. However, they are not required to perform a staged test at that level. 5. Correct. The IBR example is from a single inverter. If the GO/TO is providing an aggregate capability curve, then the example would be different.

Daniel Mason - Portland General Electric Co. - 6, Group Name Portland General Electric Co.	
Answer	No
Document Name	
Comment	

See EEI Comments Instead

Portland General Electric Company supports the comments provided by EEI and believes the period provided for verification should remain at 12 months.

Attachment 1: Section 2: Clarifications/Additions/Definitions

With respect to Attachment 1, PGE would like to request guidance for situations where equipment manufacturer curves are unavailable or if revised ratings have been established by heat run tests. Also, the base value may be a nominal value or equipment (base) rate value. For the purposes of the per unit references, PGE would like to see the reference base value defined.

Response
Bookmark to EEI Comment/Response Change made. If the equipment manufacturer curve is not available, the curve shall be derived using the best available data.

Larry Brusseau - Corn Belt Power Cooperative - 1 - MRO	
Answer	No
Comment	
See MRO NSRF Comment	
Response	
Bookmark to MRO NSRF Comment/Response	

Mohamed Derbas - Sempra - San Diego Gas and Electric - 1	
Answer	No
Comment	
Attachment 1: Section 2: Issue with Allowing Engineering Review (Maybe to General a Term / No specifics given) Attachment 1 – Section II verification indicates a GO does not have to test a facility and can rely on engineering data to calculate/provide the plant capabilities. SDG&E does not support the use of engineering reviews only to verify the Facility capability for all equipment expected to be in-service during normal operations. While this data is manufacturer-provided and may be dependable, plant parameters will inevitably change following years of operations and that will in-turn impact plant capabilities. The staged testing or operational data validation should be used instead of the exclusive proposed engineering review. The engineering review should only be allowed if the staged testing or operational data validation is unsuccessful in demonstrating the full capability of the facility because of restrictive transmission system conditions.	
Response	
1. An engineering analysis is performed subsequent to a staged test or operational data collection when the full capability of the Facility is not demonstrated. This is most likely due to restrictive transmission system constraints/conditions. An example of engineering analysis of staged test data can be found in Reliability Guideline Power Plant Model Verification and Testing for Synchronous Machines (Appendix D – Testing and Calculations Example), July 2018. An example of an engineering analysis for operational data can be found in NATF Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines Reference, September 2020 (Section 3 and 4).	

2.	An engineering review is not the same as engineering analysis. An engineering review can be complete if a staged test or obtaining operational data is not achievable. An engineering review must include a comprehensive review of all of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations. The engineering review documentation shall include the underlying assumptions, design criteria, and methods used to create the Facility's composite capability curve under Section II, Items 6-8. There are currently no compliance examples publicly available.

Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC

Answer	No

Comment

Attachment 1: Section 2: Clarification or Change

- It is not clear why data is required to be obtained within a 365 window, when the verification takes place on a 10-year cycle. It is recommended that the 365 day range be extended.
- Regarding verification specification 7.1.1: It is rare for the 100 kV and above system to run at 1.0p.u. It is recommended to use a voltage more reflective of normal operating voltage instead.
- Regarding verification specification 9, wording clarification is needed: "staged testing or operational data should be recorded with at least 90 percent of the inverters/generators *normal operating real power* at a Facility on-line"

Attachment 2: Section 1: Clarification or Change

- Regarding Attachment 2, Section I, Figure 1 and the untitled single-line diagram: The single-line diagram states, "The composite capability curve provided below is applied at Point (XX) in the one-line diagram shown above." It is recommended that the composite capability curve be provided at point A in the single-line diagram (the inverter or synchronous generator terminal), since that is the closest representation to powerflow simulation models. Otherwise we will need to know the losses between the point of measurement and point A for each datapoint in the curve.

Response

Attachment 1

- No change. We still want data used within a year of the verification date.
- No change. While testing may be performed at off-nominal voltage, the engineering analysis can be performed to provide the final curve at nominal voltage.
- No change. The requirement is to have 90% of the inverters online, and not specifying a specific Real Power output. If the GO/TO choses to do a staged test verification on a day that is cloudy or less windy, then they may not achieve a specific power output.

Attachment 2

- Change made. Removed Point (XX) reference. Revised in the language, "Identify on the one-line diagram where the composite capability curve is represented."

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Comment	

General: Financial Burden due to Crossover with PRC-019 and MOD-026 / Need to Clarify Differences

The additional requirements appear to overlap with PRC-019 and MOD-026 data. The additional engineering analysis adds significant financial burden to an entity with a large generation fleet and does not add a significant value for the Transmission Planner.

Attachment 1: Section 1: Periodicity

Attachment 1, Section I, Item #3 requires a periodicity of "ten years from the last verification date". We suggest this be changed to "ten calendar years" for consistency with other time delineations used in the standard.

Attachment 1, Section I, Item #2 requires verifying new facilities "within 180 calendar days" of their commercial operation date. However, MOD-025-2 allows for 12 calendar months. We suggest that bullet #2 be changed to "…within 12 calendar months of its commercial operation date". This allows the Generator Owners and Transmission Owners that have been subject to MOD-025-2 to maintain procedural / controls practices related to this timing requirement in place. This also allows more time for post commercial operation date break in and staging the logistics associated with verifications across more operating seasons.

Attachment 1, Section I, Item #4 requires verifying changed facilities "within 180 calendar days" of discovering a change that affects Real or Reactive Power capability by more than ten percent. However, MOD-025-2 allows for 12 calendar months. We suggest that Item #4 be changed to "…within 12 calendar months..". This allows the Generator Owners and Transmission Owners that have been subject to MOD-025-2 to maintain procedural / controls practices related to this timing requirement in place. This also allows for planning and staging the logistics associated with verifications across more operating seasons.

Attachment 1, Section I, Item #5 requires verifying returned-to-service facilities "within 180 calendar days of its return to service date" if it has been in outage for 180 calendar days or more which overlaps its scheduled verification date and has not had its capability verified within the past ten years. However, MOD-025-2 allows for 12 calendar months "for units that have been in long term shut down and have not been tested for more than five years". Despite the best plans and intentions, existing units may go into an unplanned outage state as their required verification periodicity date is approached. We suggest Item #5 be combined with Item #3 as follows:

3. *Verify each existing applicable Facility at a periodicity not to exceed ten calendar years from the last verification date. If an existing applicable Facility has an unplanned outage period which overlaps its ten calendar year verification date (preventing a verification within ten calendar years), complete the verification within 12 calendar months of its return to service date.*

Attachment 1: Section 2: Clarifications/Rewording for no OEM Curve

Attachment 1, Section II, Item #6.1 requires a capability curve provided by the manufacturer. Many of the manufacturers of older units are out of business and the curves may not be available. We suggest removing this stipulation or, at least, allow the GO or TO to provide a curve that they have created.

Attachment 1: Section 3: Clarifications/Rewording

The last sentence of Attachment 1, Section III, Item #8 (i.e. "If applicable, provide the theoretical Reactive Power capability at minimum Real Power output in accordance with Attachment 2.") makes no sense. If the minimum and maximum Real Power output are "equal" as stated in the first sentence, wouldn't this be the same?

Response

1. PRC-019 does not require information given to TP. Testing or operational data is performed in a 10 year period vs a 5 year period reducing financial burden. An engineering analysis is performed subsequent to a staged test or operational data collection when the full capability of the Facility is not demonstrated. This is most likely due to restrictive transmission system constraints/conditions. An example of engineering analysis of staged test data can be found in Reliability Guideline Power Plant Model Verification and Testing for Synchronous Machines (Appendix D – Testing and Calculations Example), July 2018. An example of an engineering analysis for operational data can be found in NATF Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines Reference, September 2020 (Section 3 and 4).
2. Change made to Unplanned outage: "Verify each existing applicable Facility at a periodicity not to exceed 120 calendar months from the last verification date, unless it meets the following condition: The Facility has been on a planned or unplanned outage of 180 days or greater, which overlaps its scheduled verification date. Verify the applicable Facility within 180 calendar days of its return to service date.
3. Change made. "If the equipment manufacturer curve is not available, the curve shall be derived using the best available data." In cases where a OEM curve is unavailable, the GO should submit their estimated reactive capability curve for the unit.
4. No Change. This statement is here for a nuclear unit which may only dispatch and be able to test at maximum output. i.e. max = min. But in an emergency situation the unit can operate at a minimum condition. This asks that this minimum value be provided.

Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	

Attachment 1: Section 2: Wording Recommendation (Personally I agree with her recommendation)

LCRA suggests moving the engineering review method last and adding language to give preference to staged testing or operational data, such as the following:

The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility capability for all equipment expected to be in-service for normal

operation. The engineering review or engineering analysis shall include underlying assumptions, design criteria, and methods used to create the Facility capability curve under Section II, Items 6-8. • *Utilize staged testing data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the generator capability; or* • *Utilize operational data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the generator capability.* • *If staged testing or operational data are **impractical**, perform an engineering review of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations.*
Response
Change made. Reordered. The addition of the qualifier for the third bullet was not included. The preference is for staged testing to be performed with engineering analysis if needed. If staged testing or operational data is not achievable, then a third option is available.

James Baldwin - Lower Colorado River Authority - 1,5	
Answer	No
Document Name	
Comment	
Attachment 1: Section 2: Wording Recommendation LCRA suggests moving the engineering review method last and adding language to give preference to staged testing or operational data, such as the following: The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility capability for all equipment expected to be in-service for normal operation. The engineering review or engineering analysis shall include underlying assumptions, design criteria, and methods used to create the Facility capability curve under Section II, Items 6-8. • Utilize staged testing data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the generator capability; or • Utilize operational data, in accordance with Section III, obtained from a date within 365 calendar days prior to verification date, and perform engineering analysis as needed per Note 1, that validates the generator capability. • If staged testing or operational data are **impractical**, perform an engineering review of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations.	
Response	
Change made. Reordered. The addition of the qualifier for the third bullet was not included. The preference is for staged testing to be performed with engineering analysis if needed. If staged testing or operational data is not achievable, then a third option is available.	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO, WECC, Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	

Attachment 1: Section 1: Periodicity with Examples

The changes to this standard are quite extensive and we appreciate the large amount of time and effort that the SDT put into making meaningful updates. However, we do not believe that 180 calendar days is a sufficient amount of time to complete the staged testing and engineering analysis for new applicable Facilities identified in Attachment 1, Section I, Item 2. As new facilities will be unlikely to have sufficient operational data for the purposes of MOD-025 verification, we recommend that this section be reverted to the previous value of 12 calendar months.

Furthermore, in Attachment 1, Section I, Item 5, the outage duration must be >= 180 calendar days AND overlap the scheduled verification date in order to be allowed to perform the verification within 180 calendar days of the Return to Service (RTS) date. Consider the following scenario showing why a defined outage timeframe could be an issue (Note: all dates and timeframes are completely arbitrary and for illustrative purposes only):

- Entity XYZ is the registered GO for Unit X.
- Unit X is a 100 MW Combustion Turbine (CT) that was last verified 9 years, 7 months ago per MOD-025-3.
- Unit X is scheduled to begin a 90-day hot gas path outage in 2 weeks (i.e. 9 years, 7 months, 14 days since last verification date).
- Due to the extensive nature of these types of outages and the massive quantity of worn-out components being replaced with new like-in-kind components, the unit capability will increase following the outage; however, the increase will likely be < 10%.
- Therefore, in order to provide the TP with the most accurate data, the GO plans to perform the MOD-025 verification with the new components installed immediately post RTS (i.e. within the 10-year verification period).
- Based on the currently scheduled dates, this plan leaves plenty of margin to complete the MOD-025 verification in a timely manner.
- During the outage, a major issue is discovered requiring extensive rotor work on the CT.
- These rotor repairs extend the length of the outage by an additional 51 days for a total outage time of 141 calendar days.
- As the extended outage time is < 180 days, Entity XYZ is now in violation of MOD-025-3 due to not performing the verification within the 10-year period.
- Example schedule:
- Last date of verification: 08/31/2013
- MOD-025-3 Verification Deadline per R1: 08/31/2023
- Outage Start Date: 04/14/2023
- Projected Outage End Date: 07/13/2023
- Actual Outage End Date: 09/02/2023

In the Scenario above, the GO is left with 3 possible choices. Either A) perform the verification prior to the scheduled outage or B) risk a violation if the outage gets extended or C) to extend the outage >= 180 days. In our opinion, none of the above choices are optimal. Please consider the following options for modifying the verbiage in Item 5.

Option A)
"Verify an existing applicable Facility within 180 calendar days of its return to service date, if the Facility has a planned or unplanned outage which overlaps its scheduled verification date and has not had its capability verified within the past ten years."

Option B)
"Verify an existing applicable Facility prior to its return to service date, if the Facility has a planned or unplanned outage which overlaps its scheduled verification date and has not had its capability verified within the past ten years."
Note: Option A is the preferred option.

Additionally we had a member recommend keeping existing points 2 and 4, delete the rest, and add event driven verification. With the following comments:

Reverification based on elapsed time is arbitrary and strictly administrative and should not be required. As the draft is written: a) New facilities must be verified within 180 days of commercial operation. b) Facilities must be re-verified within 180 days of discovery of a change. This section could be more event driven and less administrative with wording to the effect of:

1. Verify each new applicable Facility within 180 calendar days of its commercial operation date.
2. Verify an existing applicable Facility within 180 calendar days of the discovery of a change that affects its Real Power or Reactive Power capability by more than a 10 percent increase or decrease of the nameplate rating and is expected to last more than 180 calendar days.
3. Verify an existing applicable Facility within 180 calendar days of an equipment, setting, control system or software change that could affect its Real Power or Reactive Power capability.

Attachment 1: Section 2: Wording Change Recommendations or Clarifications

Section II. Verification for applicable Facilities

Overarching concern is that some items (specifically 3.1 and 7.2) appear to call for a "Net" Real Power and Reactive Power verification, while other sections do not. While some models may rely on net power, others may rely on gross power with the auxiliary loads modelled separately. 3.1 and 7.2 should be removed so that standard does not force one or the other, but rather leaves that optionality to the TP via R3 (No, it gives all the information required for either method to the TP)

Suggested edit:

The Generator Owner or Transmission Owner shall utilize and document one or more of the following methodologies to verify the Facility capability with all equipment expected to be in-service for normal operation. The engineering review or engineering analysis shall include underlying assumptions, design criteria, and methods used, as applicable to create the Facility capability curve under Section II, Items 6-8.

Attachment 2: Section 3: Issue with PQ Data and Capability Curve (Repetitive)

Attachment 2

Mildly recommend removing Section III as extraneous data and administrative in nature. Data points required in Section III are already available in Section II and any data points provided in the table may or may not be points that the TP needs.

Attachment 2: Section 4: Request for Removal of Section due to Cost Burden

Strongly recommend removing Section IV. As on Attachment 1, Section II, Point 5 – This requirements adds significant cost and administrative burden by requiring information that is interpretative and does not add to BES reliability.

Response

- No change. With the revised version of MOD-025-3, multiple options exist to verify the capability of the Facility. For a newly commissioned Facility, the SDT feels 180 days is a reasonable amount of time to complete the engineering review or engineering analysis. Additionally, if performing a staged test as part of commissioning process, the results of the staged test could be used for MOD-025-3 purposes.
- No change. For the example of the planned outage, the SDT acknowledges that this may not be an optimal scenario. However, the periodicity was changed from 5 to 10 years. Additionally, multiple options exist to verify the capability of the Facility. The verification can be performed prior to the planned outage with a staged test or operational data, or by performing an engineering review before or during the planned outage.
- The SDT does not fully understand the comments made. The intent of the simplified one-line diagram is that the GO/TO designates where on the one-line diagram that the Real and Reactive Power capability of the CCC is represented. Change made to Section II, Item 3.1 "The simplified one-line diagram representing the Facility <u>shall represent all auxiliary equipment</u> expected to be in-service for normal operation, including dynamic and static reactive devices and auxiliary load, the GSU, and/or system interconnection transformer(s), unit auxiliary transformer(s), and station services auxiliary transformer(s)."
- No change. The SDT does not consider this extraneous work. It is expected that TP will use the PQ data table first, and the TP can locate or determine extra points on the CCC as necessary. The two are complementary to one another, and are not meant to stand alone. If only the CCC is provided, then the TP would need to approximate the values on the curve.
- No change. The supplemental documentation is a byproduct of engineering analysis and verification methodology. It should be included in the information provided to the TP.

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Comment	

See EEI Comments Instead

MP supports EEI's comments.

Response
[Bookmark to EEI Comment/Response](#)

Marty Hostler - Northern California Power Agency - 4	
Answer	No
Comment	
Attachment 1: Section 1: Agrees with 10 year periodicity The only portion we agree with is 10-year testing intervals. **General: Wants PRC-019 Results instead of MOD-025 Testing/Analysis** Any necessary data, that TPs will actually use, can be shown on capability curves and protection settings which can be provided in PRC-019.	
Response	
No change. PRC-019 does not require the GO/TO to provide/send a capability curve to the TP.	

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Comment	
Attachment 1: Section 1: Agrees with 10 year periodicity The only portion we agree with is 10-year testing intervals. **General: Wants PRC-019 Results instead of MOD-025 Testing/Analysis** Any necessary data, that TPs will actually use, can be shown on capability curves and protection settings which can be provided in PRC-019.	
Response	
No change. PRC-019 does not require the GO/TO to provide/send a capability curve to the TP.	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Comment	
See [MRO NSRF Comment/Response](#)	

Response
Bookmark to MRO NSRF Comment/Response

Michael Jones - National Grid USA - 1	
Answer	No
Comment	

Attachment 1: Section 2: Wording and Terminology Clarifications / Additional Information Requested

In Attachment 1, Section II, it is stated that proposed option to utilize engineering review to verify the Facility capability for all equipment expected to be in-service for normal operation shall include underlying assumptions, design criteria, and methods used to create the Facility capability curve. The engineering review is described as reviewing of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations, which includes the ambiguous term "but not limited to." This could e.g., include the design of the auxiliary power system and its coordination with the generator terminal voltage. It is recommended to provide additional specificity or refer to supporting documents on how engineering review could be performed to ensure consistency in results.

Attachment 1: Section 2: Terminology Clarifications / Recommendations

Should the term 'Facility capability curve' in Section 2, Item 5 be replaced with the term 'composite capability curve.' Further, since the capability curve is representing operational limits in Real (MW) and Reactive (Mvar) Power, it is recommended to document (discuss) their voltage dependency and the relation between current limiters, including armature current limiters, (in A) and the composite capability curve in MW/Mvar.

Response

- Change made. The order of engineering review changed to promote engineering analysis along with testing or operational data. An engineering analysis is performed subsequent to a staged test or operational data collection when the full capability of the Facility is not demonstrated. This is most likely due to restrictive transmission system constraints/conditions. An example of engineering analysis of staged test data can be found in Reliability Guideline Power Plant Model Verification and Testing for Synchronous Machines (Appendix D – Testing and Calculations Example), July 2018. An example of an engineering analysis for operational data can be found in NATF Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines Reference, September 2020 (Section 3 and 4). An engineering review is not the same as engineering analysis. An engineering review can be complete if a staged test or obtaining operational data is not achievable. An engineering review must include a comprehensive review of all of all Real and Reactive Power Facility capability information including but not limited to in-service equipment design limitations, excitation limiter settings, and operational limitations. The engineering review documentation shall include the underlying assumptions, design criteria, and methods used to create the Facility's composite capability curve under Section II, Items 6-8. There are currently no compliance examples publicly available.
- Change made to Attachment 1, Section 2. Revised to "Facility's composite capability curve"

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Attachment 1: Section 2: Clarification Needed Section II, SIGE would request further clarification on 7.5 and 8.5, "based on the least restrictive seasonal or operating conditions."	
Response	
No change. The capability curve provided should show the most optimal or best case output (the lowest Pmin and highest Pmax) based on the least restrictive weather or other conditions.	

Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Comment	
Attachment 1: Section 1: Clarification Needed *Following the point 4 of MOD-025-3 Attachment 1, please clarify if a temporary limitation or restriction in facilities can be considered as a change that affects its Real Power or Reactive Power capability. If the transmission planner doesn't need the Real Power and Reactive Power capability for a facility with a temporary limitation or restriction for a period higher than 180 days, can the verification be delayed until the corrections or adjustments?*	
Response	
No change. A change to capability that last longer than 180 days does not seem like a temporary limitation. If the change is expected to last longer than 180 days, then the MOD-025 verification should be updated with the TP.	

Question 6 - MOD-025 Cost Effectiveness

1. MOD-025 should be retired.
    - No change. The SDT discussed the possible retirement of MOD-025, and determined that it was not in the interest of reliability. The SDT proposed the revisions to MOD-025 and changed the periodicity for MOD-025 from 5 to 10 years to reduce the cost incurred upon GO/TO.
2. The staged testing for MOD-025 is costly or not value added, and capability information is not used by the TP.
    - Change made. The SDT proposed the revisions to MOD-025, and changed the periodicity for MOD-025 from 5 to 10 years to reduce the cost incurred upon GO/TO.

- Under the new version of MOD-025, the TP is required to review the information submitted by the GO/TO.

Question 7 - MOD-025 Implementation Plan

1. Align R3 and R4 with R1 and R2 implementation plan
    - Change made. An additional two years are given to comply with Requirement R1 and R2 after the effective date of MOD-025-3. If an Applicable Entities submits MOD-025-3 Requirement R1 or R2 prior to the effective date of MOD-025-3 (early compliance of R1 or R2), the Transmission Planner will not be obligated to review the submittal until the effective date of MOD-025-3 Requirement R3.
2. Implementation of R1 and R2 should include phased implementation of already existing test/verification cycles.
    - Change made. Applicable Entities shall initially comply the periodic requirements of MOD-025-3 (Requirement R1 and R2) within 66 calendar months of their last performance under the respective requirements in the Requested Retired Standards (MOD-025-2 Requirement R1, R2, and R3). When the periodic timeframe falls between the effective date of MOD-025-3 and the Compliance Date for the respective requirement, the Applicable Entity shall comply with the Requirement(s) of MOD-025-3 by the Compliance Date.
3. R3 and R4 should be removed altogether.
    - No Change. Refer to actions takin in related comments in Q3 and also Theme 3 of Q4.
4. Consider possibility of double violations between MOD-025 and PRC-019 for the Over and Under Excitation Limit functions
    - No Change.

Question 8 - MOD-025 General

1. Exclusion in BES definition
    - Change made. Added Section 4.2.6, “Facilities meeting an exclusion of the BES definition are exempt as an applicable Facility.”
2. FACTS device specification/identification
    - Change made. The definition of "FACTS" in added to technical rational "Facilities" section. *Facilities that meet the characteristics defined by the NERC BES Definition Inclusion I2 and I4 for generating facilities, Inclusion I5 for dynamic reactive resources (synchronous condenser and FACTS devices), or for HVDC facilities which meet the requirements in this standard are to be considered an “applicable unit.” FACTS is defined by the Institute of Electrical and Electronics Engineers (IEEE) as "a power electronic based system and other static equipment that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability*
3. Clarification on requirements of FACTS and HVDC <u>within generating facility.</u>

- No Change. If the Facility meets Inclusion I2, I4, or I5 along with the MVA thresholds, then all devices/equipment expected for normal operation (including FACTS devices and HVDC devices) should be included in for the MOD-025 verification.

4. Clarification on requirements of reactor and capacitor (static reactive resources).
    - No Change. As defined in Section 4.2.4, only dynamic reactive devices are considered as applicable facilities to perform MOD-025.
5. Coordination is needed between GO and TO to perform a stage test.
    - No change. SDT believes that each functional entity should be responsible for its applicable facilities. Functional entities should contact its Transmission Planner to request support to perform MOD-025 as needed.
6. Clarification on inclusion/exclusion of LCC HVDC
    - No change. Line Current Commutated (LCC) HVDC is considered as current source converter which is like static reactive resource. Thus, the LCC HVDC is not included in the standard. However, the SDT believes the standard should include future devices with new HVDC technologies that provide dynamic reactive power to the system. Thus, section 4.2.5 should not exclusively include VSC only.
7. Clarification and justification of including FACTS devices.
    - FACTS and VSC devices can supply or absorb reactive power automatically based on its control logic which is similar to generating resources with automatic regulations on voltage, reactive power or power factor. Thus, FACTS and VSC devices are required to verify the reactive power capability within MOD-025.
8. Explicitly specify applicable facilities
    - No change. NERC SDT believes that using NERC BES definition can cover all qualified devices and minimize the risk of missing new developing equipment. The method of referring to NERC BES definition is also adopted by other standards.
9. Duration/timeline format is not consistent.
    - Change made. NERC SDT agrees to change to when mentioning “calendar years” changed to the equivalent number of calendar months.
10. Remove HVDC from Technical rational page 5 section II, items 8, "for dynamic reactive resources (FACTS, HVDC, VSC)
    - Change made. Technical Rationale was updated.
11. Add "Planning Authority" in Section 4.1.2.
    - No change. NERC SDT does not believe "Planning Authority/Planning Coordinator" needs to be involved in MOD-025 standard.

Question 9 - PRC-019 Requirement R1

1. The SDT should clarify “Facilities” for all NERC standards including PRC-019-3 and MOD-025-3. The Technical Rationale states that that FACTs devices, such as SVCs and STATCOMs are intended to be

excluded. However, the Subsection 4.2.3 of Section 4 Applicability wording "dynamic reactive resources identified through Inclusion I5…" Dynamic reactive resource is not defined and may be subject to interpretation. Commenter recommends that this wording be revised for greater clarity within the Standards rather than just within the Technical Rationale; a viable alternative may be to add a clarifying footnote.

- Change made. Remove mention of Inclusion I5 from Section 4.2.3, and revert back to original language.

2. Information developed under PRC-019-3 supports entity compliance activities under MOD-025-3. Given the linkage between PRC-019 and MOD-025 compliance obligations under Requirement R1 should be harmonized. For this reason, GOs and TOs should be required to conduct coordination of generating unit or plant capabilities, voltage regulating controls and protection at a maximum of every 10 years, consistent with MOD-025-3.

    - Change made. Remove the "At a maximum of every six calendar years." The SDT will remove the re-review cycle from the standard.
    - The SDT reviewed the need for the re-review cycle of PRC-019. The SDT believes that any changes to coordination as described in R1 of PRC-019 would be covered with R2. The SDT would like to note that the SSSL could change due to transmission system impedance changes, which could lead to a reset of the UEL (Under-excitation Limiter). However, the SDT believes that changes in transmission system impedances would be flagged for review per PRC-027. With the removal of the SSSL from the standard, the SDT believes there is no reason to re-review coordination per Requirement R1 at a regular interval.
    - PRC-019-3 Requirement R2 requires a review of coordination for any implementation of systems, equipment, or settings changes that will affect the coordination. Execution of this requirement negates the need for a periodic review to capture implementation of systems, equipment, or settings changes that will affect the coordination on a periodic basis.
    - Similar Protection and Control Standards such as PRC-024 and PRC-025 do not require periodic evaluations of coordination. PRC-027 periodically reviews coordination due to incremental changes in Fault current that can accumulate enough to impact the coordination of Protection System functions affected by Fault current. There are no anticipated incremental changes to Equipment capabilities, control functions, and protective functions for PRC-019 Applicable Facilities. Since these Applicable Facilities are not anticipated to have incremental changes, there is no time based impact to Requirement R1 coordination requiring a periodic evaluation.

3. The term "protection function" is currently loosely defined in footnote 4, which could be easily missed and should be placed into the core of this Reliability Standard. We also understand that Project 2019-04 Modifications to PRC-005-6 is considering how to define "protection functions" as it relates to inverter-based resources. While both this SDT and the Project 2019-04 SDT have approval to add new glossary terms both should coordinate and align definitions.

    - Change made. The term "protection function" was removed and the original language was used to align with PRC-005.
    - Project 2021-01 SDT will continue to coordinate with Project 2019-04 regarding this defined term.

4. Add language to Attachment 1, Paragraph B that clearly states that control functions only need to be coordinated with protective functions of the same monitored parameter.

    - Change made. Attachment 1, Paragraph B was updated to add the phrase "and associated control function." In order to clarify that control and protective functions of the same monitored parameter need to be coordinated. However, it may be necessary to coordinate control functions with protective functions that monitor different quantities. See revised technical rationale and ERO endorsed Implementation Guidance.

5. The commenter generally agrees with the proposed language for PRC-019-3 R1. The commenter recommends that the proposed language for M1 be revised as follows "Each Generator Owner and Transmission Owner with applicable Facilities will have evidence such as graphical representations of coordination (e.g. P-Q Diagram, R-X Diagram, Inverse Time Diagram), equivalent tables, the results of steady-state calculations or dynamic simulation studies, or other evidence.

    - No change. The SDT thanks the NAGF for this comment. The language within M1 is written as an "or statement" and signifies that not all of these documents are need to prove compliance.

6. Footnote 3 appears to be creating a requirement to perform a coordination study a coordination study was not required before and should not be need to satisfy PRC-019. WECC recommends either removing footnote 3 or if the SDT is actually intending to require a protection system coordination study as part of PRC-019 then it should clearly be stated in the requirement.

    - Change made. Clarify added to this footnote. Protection System as-left settings shall be utilized in compliance evidence for a coordination study per Requirement R1.

7. Protective functions would likely include embedded systems which infers an understanding of the decision trees and logical operators of every device in scope. This level of understanding may only be fully grasped by the manufacturers themselves and may also include proprietary information that the OEMs may not wish to share. This puts the TO and GO at risk for having an understanding of the underlying logic that may be fully grasped or known only by the manufacturers themselves.

    - No change. The SDT believes that the scope for coordination requirements are limited to the functions and capabilities described in the standard or in industry guidance within Section E. The SDT believes that OEMs must provide information related to the coordination of voltage control, limit functions, equipment capabilities, and protective functions. Entities may reference the requirements of PRC-019 in their technical specification for contracts with OEMS/developers.

8. Who will be responsible for verifying coordination of Facility voltage regulating controls, limit functions, equipment capabilities, and protective functions for dynamic reactive resources and IBRs that are on the distribution system. Are there any cases where I5-included dynamic devices or I4-included IBRs are owned by an entity that is not registered as a transmission owner? If so, how will these devices by verified?

    - No change. The SDT appreciates the concern for who is responsible for verifying coordination of voltage regulating facilities at non-BES facilities. However, that is beyond the scope of PRC-019-3.

9. Commenter recommends further wording changes for Requirement R1 and to remove "equipment capabilities" as a requirement of the control and protection coordination.

- No change made. Ignoring the equipment capabilities is inadvisable. The protection and/or limiter must prevent damage to the equipment or reliability will be impacted as the generating facility could be out of service for an extended period of time due to damage. As an example, say a proposed rotor overcurrent limiter is mis coordinated with the protection curve. The protection curve is coordinated with the C50.13 rotor thermal damage curve. The engineer could do two things. Either 1) reset the protection to coordinate with the OEL or 2) reset the OEL to coordinate with the protection. If resetting the protection to coordinate with the OEL is chosen and the OEL is not coordinated with the C50.13 withstand curve, then the machine can operate outside of its capability and damage could occur.

10. Commenter would like to have the standard reflect how to handle instances when the equipment capabilities are not known, such as voltz per hertz limitations for older generators? Clear definitions and operating ranges need to be provided for equipment capabilities in Appendix A.

    - No change made. For legacy equipment where the equipment capabilities may be unavailable, unreadable, etc., the registered entity should consult with their respective Regional Entity compliance group to understand how to best comply with the requirement language.

11. Coordination [for IBR Facilities] should be more specifically defined so that entities are able to achieve what the SDT is looking for. It is unclear what the SDT is expecting for coordination between the control functions and protective functions, as well as considering how the protective functions monitor different physical locations within a plant. Documentation on how to perform the coordination and what is expected must be developed in the industry before it is reasonable to expect entities to comply. Presently, this documentation does not exist.

    - No change. Inverter based resources were already in scope of the existing PRC-019-2 standard; therefore, the coordination requirements are already in place today. The SDT recognizes the challenges of coordination at IBR plants. For an IBR Facility, the power plant controller (PPC) may have enabled control functions, such as a MW/VAR dispatch, and protective functions that should be coordinated accordingly. The SDT suggests following guidance that is currently available within the industry (e.g. IEEE C37.102, IEEE 2800, etc.).
    - Examples of coordination for synchronous generation were removed from PRC-019-3, and moved into Implementation Guidance. Any examples of IBR Facility coordination would therefore need to be part of Implementation Guidance, and not standard, PRC-019-3.

12. Commenter believes that the Standard language should further clarify that a limiter must be coordinated with its associated protection function. Commenter would like clarification on the intent/purpose of the Standard. Is it the coordination of voltage controls with other applicable limiters and protection functions or does it also cover all relevant electrical aspects of generation (equipment capability voltage controls, limiters, voltage, and current protection functions etc.)

    PGE requests guidance when voltage control mode is not actually used – what if a different mode is used?

    - No Change made. The standard is applicable to voltage controls and other applicable limiters and protection functions.

13. BC Hydro noted the revised language in Section 4.2.5 with respect to PRC-019-2 (“Any generator, regardless of size, that is a Blackstart unit material to and designated as part of a Transmission

Operator's restoration plan"). BC Hydro's appreciates that this revision makes use of the NERC Glossary of Terms definition, and has the understanding that this revision is not intended to materially modify the applicability scope of current PRC-019-2. Please confirm whether this understanding is accurate.

- No change made. The commenter is correct that this change was made to align with the NERC Glossary of Terms. This modification does not change which Blackstart facilities are applicable to PRC-019.

14. The Attachment 1, section B list of IBR items incorrectly characterizes the IBR phase lock loop circuit as a protective function. That is purely a control item - it relates directly to the ability to control the power conversion accomplished by the inverter. If that circuit is unable to accomplish its function the inverter is not control-able and must stop the power conversion immediately through the cessation of the gate pulses which permit the conduction of current through the legs of the bridge. The Momentary cessation, too, is purely a control function which must be invoked when the power conversion is not controllable. There is no coordination to be coordinated between these items and the limiters and protection functions that are listed (over current, over voltage). We question the use of "IBR unit phase undervoltage protection" as the IBR phase undervoltage condition may trigger an uncontrollable power conversion condition but is not at all related to any protection scheme which needs to be used.

    - Change made. PLL was removed from Attachment 1, section B.
    - NERC ERO has designated that they will treat momentary cessation as a protection (tripping) function. Most manufacturers have already identified that this function is not necessary for transmission connected inverter-based resources. In the instance that it is enabled, it should coordinate with the voltage capabilities of the inverter. Momentary cessation or LVRT/HVRT must be coordinated with undervoltage/overvoltage protection (if set) at the collector bus location. During a low voltage or high/voltage system condition, the IBR will inject/absorb reactive current in an attempt to boost or lower the voltage. Once the POI voltage returns to the normal voltage control region, the units should be left online to support the BES. If they are not coordinated with the HVRT/LVRT curves, then they cannot be available to support the BES until a relay analysis is done.

Question 10 - PRC-019 Requirement R2

1. Sequencing of coordination studies (prior to syncing to the grid and post syncing to the grid) to meet Requirement R2.

    - Change made. Two distinct sentences written in Requirement R2. The standard drafting team feels that these comments were based on a misunderstanding of the intent of requirement 2. With communication between the protective relaying engineers and the excitation control system engineers when performing coordination studies, drastic changes during commissioning and testing are not anticipated. However, R2 will be revised to clarify that 90 days are allowed for existing facilities to update coordination reports (compliance evidence).

2. Recommendations to revise the time requirements within Requirement R2 to update calculations (compliance evidence) from 90 days to 180 days or 365 days.

- No change. The standard drafting team does not feel that changing to 180 days or 365 days would be a positive impact to the reliability of the system. This also conflicts with the requested modifications from the SAR.

3. How will entities verify that changes will NOT affect the coordination?

    - No change. The intent of R2 is to require entities to verify any changes made to systems are reviewed for coordination impacts. Engineering analysis, and/or consultation with the equipment manufacturer, will have to be performed to determine if changes have impacted coordination.

4. The last bullet point in R2 needs further clarification on applicability. Power Plant Controller is a common term for the "Station Master" controller at an IBR facility; however, this could be mis-interpreted to include the Station Control System (a.k.a. DCS) at a synchronous generating facility. It is possible that control system firmware changes or setting changes beyond IBRs could also impacts on coordination.

    - Change. "IBR generating Facility" will be added to the beginning of the bullet to clarify the intent to only apply to IBR facilities.

5. Disagreement with replacing the defined term “Protection System” (previously used in PRC-019-2) with the undefined term protective functions.

    - Change made. The language has been revised with the original Protection System language from PRC-019-2, since the new definition for Protection System is being balloted with the PRC-005 posting in late April. As shown below, the new definition for Protection System includes the phrase “and provide protective functions.” The following language is proposed with PRC-005:

        - **Protection System** – One or more of the following components:

            - Protective relays and components of control systems which respond to measured electrical quantities and provide protective functions;
            - Communications systems necessary for correct operation of protective functions;
            - Voltage and current sensing devices providing inputs necessary for the correct operation of protective functions;
            - Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply); and/or
            - Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Question 11 - PRC-019 Attachment 1

1. Theme 1: The example diagrams that were removed should be returned along with new examples added specifically for IBRs.

    - No Change made. Implementation Guidance Update for PRC-019-2 is available on Compliance Guidance web page.

- Under changes to the NERC Standard Processes Manual effective in 2019, drafting teams cannot include supporting technical information in the Reliability Standards. That material must be in standalone Technical Rationale or an Implementation Guidance document. Since the coordination examples from PRC-019-2 Reference Section G are example of how to comply with the requirement language, the example coordination graphs needed to be moved to Implementation Guidance.

2. Theme 2A: Bullets 1, 2 and 3 (Synchronous generator/condenser reactive capabilities; Field over-excitation limiter and associated protective function; Field under-excitation limiter and associated protective function) appear to duplicate obligations identified in MOD-025, Attachment 1, Section 2, Part 5. If this is incorrect, please clarify how a violation under PRC-019, Attachment 1, Part A would not also result in a violation of MOD-025-3, Section 2, Part 5.

   - No changes made. PRC-019-3 is a standard for coordination between protective functions and/or limiters/control functions. MOD-025 is a standard to verify/document a generators reactive capability, including operational limitations within the generating Facility, and to provide that information to a Transmission Planner for use in models.

3. Theme 2B: The references to collector feeders appears to include non-BES Facilities. References to non-BES Facilities should be removed from the list or clarifying language that makes it clear that non-BES facilities are not to be included under PRC-019-3.

   - Change made. Inclusion I4 reference removed from 4.2.4.

4. Theme 3A: Voltage dependent protection functions needs to be clarified what is the safe voltage limit. Currently voltage based functions are coordinated at 1 p.u. and this coordination will hold little value when an event such a loss of field occurs and the voltage will drop.

   - No change made. Impedance based protection (such as LOF) is coordinated at 1pu voltage. The SDT does recognize that some UEL's shift its characteristic if the voltage depresses and may encroach closer to the LOF characteristic. To change the criteria for evaluating LOF protection would require utilities to restudy and would likely show compliance, so 1pu voltage is left in the standard. The SDT points out that voltage-based protection or volts/hertz protection is not coordinated at 1pu voltage, but still must be coordinated with respect to time.

5. Theme 3B: Some generators/synchronous condensers do not have equipment capability information provided such as volts per hertz capability due to the age of the equipment. Further wording in the standard needs to be clarified what to do if this information is not provided or not available.

   - No change made. For legacy equipment where the equipment capabilities may be unavailable, unreadable, etc., the registered entity should consult with their respective Regional Entity compliance group to understand how to best comply with the requirement language.

6. Theme 4: Remove PLL from attachment.

7. Change made. SDT agrees. Phase lock loop (PLL) was removed from the list.
   Theme 5: In Attachment 1, the first paragraph of Section B should be modified to clearly state that control functions only need to be coordinated with protective functions of the same monitored parameter.

   - Change made. See Theme 3B in Question 9 (Requirement R1).

8. Theme 6: Remove synchronous generator/condenser reactive capabilities from the standard.
    - No change made. The limiter must be coordinated with the trip. The trip must be coordinated with the capability or else risk to the equipment can occur. That is the reliability benefit. As an example, consider a case where a rotor overcurrent limiter is not coordinated with a rotor overcurrent trip. The overcurrent limiter is not coordinated with the C50.13 rotor short time thermal capability. The engineer has two options: either 1) reset the protection to coordinate with the limiter, or 2) reset the limiter to coordinate with the protection. If the engineer chooses option #1, then the rotor is not protected from short time overloads since both the limiter and protection are not coordinated with the equipment capability. Should the unit be required to operate in that region for an extended period, the rotor windings can be damaged and the unit could be out of service for repair for an extended period of time.

Question 12 - PRC-019 Cost Effectiveness

1. Commenter not agree with the expanded scope as it will essentially double the work as the Generator Owner will now need to perform a coordination study prior to syncing to grid and then perform a second coordination study following commissioning testing (following tuning).
    - No change. The SDT does not believe there is double the work. In the new revisions “Each Generator Owner and Transmission Owner shall perform the coordination described in Requirement R1 prior to implementation of systems, equipment, or settings changes” Additionally, there is time after that to ensure the “associated documentation shall be updated within 90 calendar days after the return to in-service date.
2. Commenter does support the periodic basis for Requirement R1.
    - Change made. Update made to Requirement R1. See Requirement R1 response.

Question 13 - PRC-019 Implementation Plan

1. One time performance is adequate for standards such as PRC-024 and PRC-025. If there needs to be a cycle, then 10 years to coincide with MOD-025 testing makes more sense.
    - See response for Question 9, Theme 3A.
2. The standard uses the term “calendar years”. The Implementation Plan should use the same language and require a periodicity based on calendar years.
    - Change made. Periodic review in Requirement R1 was removed.
3. The implementation plan does not discuss existing resources that come into scope due to update applicable facilities language. For any resource that comes into scope due to changes in the applicable facilities, implementation plan should allow 2-5 years, as was allowed in the PRC-019-2 implementation plan.
    - There should be very few newly applicable Facilities with the revised applicable Facilities language.
    - Change made. All applicable Entities have an additional twelve (12) months after the effective date of PRC-019-3 to comply with Requirement R1.

Question 14 -. PRC-019 General

1. The VSL Timeframe for R1 are not consistent with Requirement R1, years vs. months.
    - Change made. Periodicity under R1 was removed, so this changed the VSLs.
2. Combine PRC-019 and MOD-025; Retire MOD-025
    - No Change. The intent and spirit of PRC-019 is to ensure coordination between the protection engineer and the excitation control system personnel. This coordination is independent of the real power generated from the turbine of a synchronous generator. In addition, the engineering performed in PRC-019 is rooted in static analysis; generator testing involves a completely different engineering skillset.
3. Examples of graphs in Attachment 1
    - No change. Examples of coordination for synchronous generation were removed from PRC-019-3, and moved into Implementation Guidance. Any examples of IBR Facility coordination would therefore need to be part of Implementation Guidance, and not standard, PRC-019-3.
4. Define coordination for PRC-019.
    - No change made. Complex engineering is not black or white; there tends to be a lot of grey. The SDT does not believe that coordination should be defined. For synchronous generation, there is plenty of technical literature within the industry (IEEE, etc.) that describe the coordination associated with PRC-019.
5. Clarification on non-BES facilities
    - Change made. Removed reference to Inclusion I4 in the Applicability Section.
6. What happens if a GO discovers that “changes” happened after implementation?
    - No change. The GO shall “perform the coordination described in Requirement R1 <u>prior to implementation of systems, equipment, or settings changes</u> that will affect the coordination described in Requirement R1.” If a discrepnecy is discovered such as; equipment or settings that do not match the most recent coordination study as described in R1 AND miscoordination did not result, coordination was not affected but the GO would have 90 days upon discovery to update their documentation. If the coordination was affected (miscoordination results) the GO would likely be in violation of requirement R2. . GOs must take accountability for the changes that are made to generator control and protection functions.
7. Are individual generating units that do not have voltage control and SSL applicable for PRC-019-3 (via Inclusion I4)?
    - Change made. Added footnote, “For an IBR generating Facility without a voltage control mode capability, coordination should be performed assuming the normal operation control mode, and R1.2.1. and R1.2.2. would not apply.”
8. Clarification on FACTS device applicability.
    - No change made. The standard drafting team (SDT) evaluated the recommendation made in the SAR and resolved not to add them as Applicable Facilities for PRC-019-3. FACTS and HVDC devices are not included as stated in Technical Rationale. See the technical rationale.
9. Clarification on BES facilities

- No change. SDT believes 4.2.1 and 4.2.2 should be separated as these match two items in NERC BES definition I2.
- No change. Blackstart Resource is in the Glossary of Terms.

10. Clarification of which Facilities are included in Section 4.2.3
    - No change made. Synchronous condensers are included under Section 4.2.3. However, FACTS devices and HVDC are not included. The standard drafting team (SDT) evaluated the recommendation made in the SAR and resolved not to add them as Applicable Facilities for PRC-019-3. FACTS and HVDC devices are not included as stated in Technical Rationale.
11. An additional requirement should be added to ensure coordination between the generator owner and the transmission owner. We need to follow suit such as Requirement R4 in PRC-024 that if the transmission owner upon request for protection and control coordination, the generator owner must provide this information to the planning coordinator/transmission planner.
    - No change. The SDT members believe the information sent with MOD-025 and MOD-026/027 is sufficient. Adding an additional requirement in PRC-019-3 for the GO to provide coordination analysis of PRC-019 seems to be excessive, and in some cases duplicative.
    - Facility real and reactive power capability is provided to TP as part of MOD-025.
    - Under MOD-026-2 a verified positive sequence dynamic model, and EMT model for IBR Facilities, must be sent to the TP/PC.
12. GO/TO should be required (force) to enable limiters.
    - No change. PRC-019 does not require that an entity enable any protection or control function. The PRC-019 only applies to those functions that are enabled.