Comment Report

Project Name:	2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 - MOD-032-2
Comment Period Start Date:	5/31/2023
Comment Period End Date:	7/14/2023
Associated Ballots:	2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 Implementation Plan IN 1 OT 2022-02 Modifications to TPL-001 and MOD-032 | Draft 1 MOD-032-2 IN 1 ST 2022-02 Modifications to TPL-001 and MOD-032 | Non-Binding Poll MOD-032-2 IN 1 NB

There were 77 sets of responses, including comments from approximately 200 different people from approximately 126 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the modification to remove “Load Serving Entity” and replace with “Distribution Provider” in MOD-032-2?

2. Provide any additional comments for the standard drafting team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
DTE Energy - Detroit Edison Company	Adrian Raducea	5		DTE Energy - DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison	5	RF
					patricia ireland	DTE Energy	4	RF
Public Utility District No. 1 of Chelan County	Anne Kronshage	6		Public Utility District No. 1 of Chelan County - Voting Group	Anne Kronshage	Public Utility District No. 1 of Chelan County	6	WECC
					Glen Pruitt	Public Utility District No. 1 of Chelan County	1	WECC
					Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
Midcontinent ISO, Inc.	Bobbi Welch	2	MRO,RF,SERC	ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 1	Ali Miremadi	CAISO	2	WECC
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Helen Lainis	IESO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Bobbi Welch	MISO	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Elizabeth Davis	PJM	2	RF

					Charles Yeung	SPP	2	MRO
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
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
					John Nierenberg	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
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	RF
					Scott Berry	Wabash Valley Power Association	3	RF

					Kylee Kropp	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
MRO	Jou Yang	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Chris Bills	City of Independence, Power and Light Department	5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bryan Sherrow	Board of Public Utilities	1	MRO
					Terry Harbour	Berkshire Hathaway Energy - MidAmerican Energy Co.	1	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO

					Shonda McCain	Omaha Public Power District	6	MRO
					George E Brown	Pattern Operators LP	5	MRO
					George Brown	Acciona Energy USA	5	MRO
					Jaimin Patel	Saskatchewan Power Cooperation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	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
					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
					Frank Lee	Pacific Gas and Electric Company	5	WECC
National Grid USA	Michael Jones	1		National Grid	Michael Jones	National Grid USA	1	NPCC
					Brian Shanahan	National Grid USA	3	NPCC
Southern Company - Southern	Pamela Frazier	1,3,5,6	MRO,RF,SERC,Texas RE,WECC	Southern Company	Matt Carden	Southern Company - Southern	1	SERC

Company Services, Inc.						Company Services, Inc.		
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Patricia Robertson	Patricia Robertson		WECC	BC Hydro Balloters	Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
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
					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC

					James Grant	NYISO	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
					Randy MacDonald	New Brunswick Power Corporation	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	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 Resources, Inc.	6	NPCC
					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	6	NPCC

						Department of Public Service		
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
					Joshua London	Eversource Energy	1	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					David Duhart	Southwest Power Pool Inc.	2	MRO
					Debbie Currie	Southwest Power Pool Inc	2	MRO
					Eddie Watson	Southwest Power Pool Inc.	2	MRO
					Hugh Benfer	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Jeff McDiarmid	Southwest Power Pool Inc.	2	MRO
					Lottie Jones	Southwest Power Pool Inc.	2	MRO
					scott Jordan	Southwest Power Pool Inc.	2	MRO
					Matt Harward	Southwest Power Pool Inc.	2	MRO

					Theo Brown	Southwest Power Pool Inc.	2	MRO
					Amber Wallace	Southwest Power Pool Inc.	2	MRO
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC

					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Do you agree with the modification to remove “Load Serving Entity” and replace with “Distribution Provider” in MOD-032-2?

Ben Hammer - Ben Hammer On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Ben Hammer	
Answer	No
Document Name	
Comment	

To be clear, the Project 2022-02 SDT added both TO and DP to replace LSE in the proposed MOD-032-2 Attachment 1 revision. This proposed change is incomplete, misappropriates modeling data responsibilities for Aggregate Demand, Demand, and Distributed Energy Resource (DER) modeling data, as well as retains a significant reliability gap.

Transmission Owners who are not Distribution Providers likely have no knowledge or capability to provide data for planned demand or DER constituents served from the transmission system. Transmission Owner visibility for load demand is typically limited to historical telemetered MW and MVAR data. This finding, especially with regards to DERs, has already been well-documented. A key recommendation in the NERC Reliability and Security Technical Committee (RSTC) subcommittee approved the “Model Verification of Aggregate DER Models used in Planning Studies - Reliability Guideline” developed by the System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) was:

“TPs, PCs, TOs, and other applicable entities that may need DER information should coordinate with DPs for facilities connected to distribution systems to determine the necessary measurement information that would be of use for DER modeling and model verification and jointly develop requirements or practices that will ensure this data is available. ***As the TPs, PCs, and TOs are dependent on the DP to have the data made available****, this will likely require actions from state regulatory bodies and DPs to establish requirements to gather this information” (page 7 of 61).*

The SDT should consider that Transmission Owners should not be held accountable for demand and DER data that they have no cognizance of. Additionally, the SDT should remember that most DER are smaller than the BES resource threshold or reside on a distribution system. The threshold for an entity to be registered as a Distribution Provider is 75 MW of load. This implies that the majority of DERs are and will be connected to systems outside the scope and visibility of Transmission Owners, as well as existing Distribution Providers. To emphasize this reality: as of 15 May 2023, there were 314 Distribution Providers registered with NERC (excluding UFLS-only DPs). Of those DPs, 96 were not otherwise registered as either a PC, TP, or TO. While it may be misunderstood that only 96 DPs may become newly applicable and participatory in model data collection given the draft changes to MOD-032-2, this ignores that the latest EIA 861 data (collected in 2021; published in 2022) reflects about 1,190 distribution utilities reflecting almost 197,000 distribution circuits in the continental US. In other words, it may be reasonable to conclude that 74% of the distribution utilities in the US do not meet the NERC registration threshold. Furthermore, PCs, TPs, and TOs have no regulatory relationship with these unregistered entities and cannot be held responsible for DER data for which that are not aware.

In June 2022, NERC published its “Inverter-Based Resource Strategy” that recognized efforts necessary to analyze the breakdown of resource size, location, type, and applicability with the BES definition to make a determination of whether the current BES threshold should be updated to reflect the changing resource mix” (page 9 of 10). Subsequently, the NERC Member Representatives Committee (MRC) and Board of Trustees (BOT) technical session on inverter-based resources in February 2023 emphasized the need for a focus on functional registration noting: “industry is increasingly challenged with addressing reliability issues for unregistered inverter-based resources, and those resources are reaching critical mass in some parts of the country. The lack of requirements currently imposed on those resources creates local and regional reliability risks to the BPS in aggregate. This issue compounds in many areas with the growing presence of distributed energy resources (DERs) connected to the distribution system.” In response to the FERC directive “Registration of Inverter-based Resources”, NERC filed a proposal to modify its Rules of Procedure to “include a new function comprised of owners of IBRs interconnected to the BPS.” The Generator Owner – Inverter-Based Resource (GO-IBR) registration would include “owners of IBRs which have aggregate nameplate capacity of less than or equal to 75 MVA and greater than or equal to 20 MVA interconnected at a voltage greater than or equal to 100 kV; or Owners of IBRs which have aggregate nameplate capacity of greater than or equal to 20 MVA interconnected at a voltage less than 100 kV.”

Given the anticipated GO-IBR functional registration, the NERC Project 2022-02 SDT should modify MOD-032-2 Attachment 1 to specify **DP, GO-IBR** are responsible for Aggregate Demand, Demand, and Distributed Energy Resource (DER) data, as well as other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes.	
Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	
Response	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	No
Document Name	
Comment	
Comments to be supplied separately by AECC's Ayslynn McAvoy.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	No
Document Name	
Comment	

WECC supports the removal of Load Serving Entity as that registration no longer exists. However, WECC believes that adding Distribution Provider is not necessary as explained below.

Including the registered Distribtuion Provider in the applicability of the standard complicates compliance applicability and monitoring. It requires two processes and two monitoring mithods instead of one.

The technical rational for the standard states that for distribution facilities which have no Distribution Provider, or which do not connect to a Distribution Provider, the Transmission Owner is responsible for coordinating to obtain the necessary data. If the TO can perform this for distrbution facilities that do not have a registered DP, they can use the same process to obtain the data from a registered DP.

This removes the need of potentially complex determination of standard applicability and the research needed to determine applicability for each Transmission Owner based on the existence of registered Distribution Providers or any other non-BES load that has no registered DP. It also makes clear that the Planning Coordinator and Transmission Planner would be receiving bus level demand data from a single source (The Transmission Owner) rather than obtaining data from multiple DP’s and TO’s.

If there is a concern that without a standard requirement to support it, a registered DP would not provide the required data to a TO or TP then how could it be expected that a non-registered entity would provide this information. The TO has the authority to obtain this data for any entities connected to its system via FAC-002.

If it is decided to continue to include Distribution Providers in the applicability, please clarify the applicability and obligation of the “registered” (USLF)-Only DP. Would MOD-032 now be applicable to all USLF only Distribution Providers?

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	No
Document Name	

Comment

The definition of Distribution Providers is limited by the current definition of Distribution providers to the entity that operates the wires between the Transmission system and the end-user. This is a short-cut to getting the DERs included in the standard. I recommend editing the definition of Distribution Provider to include those entities that are responsible for the operation and balancing of DERs if this is how the SDT wants to address this issue.

Likes 0	
Dislikes 0	

Response

Thomas Standifur - Austin Energy - 1

Answer	No
Document Name	

Comment

Austin Energy supports APPA's comments.

Austin Energy is concerned about having the DP responsible for significant data collection from DER that it doesn't have control over, may be difficult to attain, not available or inaccurate. The SDT should, at minimum revise the proposed standard to indicate that (a) DPs’ and TOs’ responsibility with respect to DER data is limited to passing along any responsive data they have received from DER owners, without vouching for the data’s completeness or accuracy”

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

LCRA notes that the Project 2022-02 SDT added both TO and DP to replace LSE in the proposed MOD-032-2 Attachment 1 revision. This proposed change inappropriately assigns modeling data responsibilities for Aggregate Demand, Demand, and Distributed Energy Resource (DER) modeling data. Transmission Owners who are not Distribution Providers likely have limited knowledge or capability to provide data for planned demand or DER constituents served from the transmission system. This finding, especially with regards to DERs, was identified in the "Model Verification of Aggregate DER Models used in Planning Studies - Reliability Guideline" developed by the System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG)

Likes 0	
Dislikes 0	

Response

Kacie Fischer - Kacie Fischer On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Kacie Fischer

Answer	No
Document Name	

Comment

Oncor does not agree with the Load Serving Entity ("LSE") to Distribution Provider ("DP") terminology modification. Even for Transmission Owners that are also DP (like Oncor), there are many instances in which we interconnect and deliver transmission-level service to another DP. In these cases, Oncor would not have access to the DER modeling parameters listed in Attachment 1 or visibility into the other DP's system other than the aggregated load provided.

We further disagree with the changes outlined in Attachment 1 in the Steady-State column of Table – #9, which are being proposed in conjunction with the change in terminology from LSE to DP. It will be more appropriate to specify general model requirements in MOD-032 and allow Planning Coordinators and Transmission Planners to determine model details that are appropriate for their established processes and methodologies. Also, it may be impossible to provide individual specifications for Retail Scale DER such as reactive capability and in-service date.

Also, Oncor would like further clarification on the following:

1. "a. Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS"
    - Could the SDT elaborate on how knowing that a DER is on a UFLS feeder could impact the results of a Steady State analysis? We do not see the need for the UFLS data in the Steady State column.
2. "b. Real power capability (minimum and maximum)"
    - Is this referring to the nameplate or approved capacity?

- Is the meaning of *minimum* equivalent to approved capacity? And is *maximum* equivalent to nameplate capacity?

3. "c. Reactive capability (minimum and maximum)"
   - Oncor does not typically track reactive power data for currently installed DER.
4. "d. Generator type (solar, battery, etc.)"
   - Oncor recommends modifying this statement to give instruction on how to report a single location with multiple types of DER.
5. "e. In-service date or other information to be used to make assumptions about DER capabilities related to ride-through, voltage control and/or frequency control."
   - Can you define the in-service date? In Oncor's experience, some DER projects will connect to our system, test, and then permission is granted to operate. For some of the DER projects, we give permission for them to operate; but the project is not energized until the DER facility is ready on their end. Typically, the registered resources that participate in ancillary services go in-service before they are permitted to operate for testing purposes.
   - This is not practical for DERs that are modeled in an aggregated manner.

Likes 0	
Dislikes 0	

Response

Laura Hankins - Laura Hankins On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - Laura Hankins

Answer	No
Document Name	

Comment

LCRA TSC notes that the Project 2022-02 SDT added both TO and DP to replace LSE in the proposed MOD-032-2 Attachment 1 revision. This proposed change inappropriately assigns modeling data responsibilities for Aggregate Demand, Demand, and Distributed Energy Resource (DER) modeling data. Transmission Owners who are not Distribution Providers likely have limited knowledge or capability to provide data for planned demand or DER constituents served from the transmission system. This finding, especially with regards to DERs, was identified in the "Model Verification of Aggregate DER Models used in Planning Studies - Reliability Guideline" developed by the System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG).

Likes 0	
Dislikes 0	

Response

Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
A specific definition of DER should be included in the standard. A specific MW threshold for the inclusion of a DER in the interconnected transmission system model data should be included in the standard	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FE supports the removal of "Load Serving Entity" and supports the addition of "Distribution Provides" in MOD-032-2.	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Load Serving Entity is no longer an active NERC registration code. BPA agrees that replacement is appropriate. However, Attachment A adds a parenthetical that states the Transmission Owner (TO) is responsible when a Demand or DER is not associated with a registered DP. That would put the responsibility on BPA as the TO. What if the TO cannot get non-BES DER data from an unregistered customer? As long as BPA is held responsible for providing data as the TO (that we do not have the authority to require from an unregistered DP), our vote will be NO.	

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	Yes
Document Name	

Comment

Constellation has no additional comments.

Kimberly Turco on behald of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,7 - SERC

Answer	Yes
Document Name	2022-02_Unofficial Comment Form_May2023.docx

Comment

None.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	Yes
Document Name	

Comment

PG&E agrees with the modification to remove the "Load Serving Entity" (LSE) and replace it with 'Distribution Provider" (DP) since the LSE designation has been retired.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG agrees with NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments	

Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the removal of Load Serving Entities (LSE) and the addition of Distribution Providers (DP) as an appropriate LSE replacement.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the removal of Load Serving Entities (LSE) and the addition of Distribution Providers (DP) as an appropriate LSE replacement.	
Likes 0	

Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports the comments of the EEI	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Yes, this change will be helpful in obtaining DER data for transmission planning studies	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Agree with EEI comment: {C}· To better clarify the extent of DER resources that must be reported under MOD-032, EEI suggests that a Facilities section be added to this Reliability Standard.	

{C}· Footnote 2 – EEI asks that the SDT provide additional clarity regarding the intent of Footnote 2. Footnote 2 appears to require DPs (or TOs) to supply Aggregate Demand data that has been manipulated to exclude all DER offsets. While we understand why this would be desirable, most small DERs are not metered except for billing meters. Billing meters are not synchronized with SCADA data, diminishing the value of any data supplied by the reporting entities. We are further concerned that the manhours required to account for these DER offsets could be substantial adding excessive costs while providing questionable value to this change. As an alternative, EEI suggests that DPs and TOs could provide estimated DER offset values, which would require fewer manhours to develop and should provide sufficient value to the planning models.

{C}· Steady-state and Dynamic columns

EEI is concerned that the data requests identified in Item 9 (Steady-state), and Item 10 (Dynamic) seek non-aggregated data, while the SAR specifies that aggregated DER data is to be supplied. To address this concern, we ask that both Items 9 and 10 be edited to make it clear that data requests to DPs and TOs are to be limited to aggregate DER data.

{C}· Footnote 4: EEI is concerned that footnote 4 does not align with the SAR. In the SAR, data requests for DERs appear to be limited to aggregated DER data, however, in footnote 4 it states "TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary". This appears to go beyond the approved limits of this SAR and should therefore be removed.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	Yes
Document Name	

Comment

WEC Energy Group supports the comment of EEI which states:

"EEI supports both the removal of Load Serving Entities (LSE) and the addition of Distribution Providers as an appropriate LSE replacement."

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Southern Company supports comments submitted by EEI.

Likes 0	
Dislikes 0	

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	Yes
Document Name	

Comment
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for queston #1.

Likes 0	
Dislikes 0	

Response

Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	

Comment
CenterPoint Energy Houston Electric, LLC (CEHE) is supporting the proposed MOD-032-2 modification to replace Load Serving Entities (LSE) with Distribution Providers (DP).

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	

Comment

Southern Indiana Gas & Electric Co. (SIGE) is supporting the proposed MOD-032-2 modification to replace Load Serving Entities (LSE) with Distribution Providers (DP).	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports both the removal of Load Serving Entities (LSE) and the addition of Distribution Providers as an appropriate LSE replacement.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 1	
Answer	Yes
Document Name	
Comment	

The The **ISO/RTO Council Standards Review Committee (“SRC”)** [1] supports the replacement of “Load Serving Entity (LSE)” with “Distribution Provider (DP).” This is a vast improvement over where MOD-032 stands today as this will fill the gap left by the retirement of the LSE function.

[1] For purposes of these comments, the IRC SRC includes the following entities: CAISO, IESO, ISO-NE, MISO, NYISO, PJM, SPP and ERCOT (with the exception of the response to question 2).

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	Yes
Document Name	

Comment

Ameren agrees with and supports EEI comments.

Likes 0	
Dislikes 0	

Response

James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; - James Mearns

Answer	Yes
Document Name	

Comment

This modification appears to meet the intent of the SAR by addressing the paralleled DERs that are presently not modelled within Distribution Provider's system models. While some argument could be made concerning the minimal impact on system planning studies caused by Distribution Customer's DER deployment, it is important to set a standard approach toward assessing potential impacts, and these requirements are not substantially burdensome.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	Yes

Document Name	
Comment	
.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
For this response, ERCOT joins the comments submitted by the ISO/RTO Council Standards Review Committee and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Hillary Creurer On Behalf of: Lori Frisk, Allete - Minnesota Power, Inc., 1; - Allete - Minnesota Power, Inc. - 1 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 3, 1; - Patricia Robertson, Group Name BC Hydro Balloters	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brittany Millard - Lincoln Electric System - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Jones - National Grid USA - 1, Group Name National Grid	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Imane Mrini - Austin Energy - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Desmarie Waterhouse - American Public Power Association - 4 - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devon Tremont - Taunton Municipal Lighting Plant - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE supports the modification to remove Load Serving Entity (LSE) and replace with Distribution Provider (DP) as LSE is no longer a registered function. Texas RE has some concerns, however, regarding the actions required by the DP in gathering Distributed Energy Resource (DER) data. There seems to be a potential gap for getting the DER data for Power System Modeling and Analysis as written. DPs are not typically the owners of the DER data and there are no current NERC registration or requirements for the owners of the DER data to provide the data to DPs. As written, the compliance responsibility for providing the DER data falls on the DP who may not authority or a robust process to get the data from the current and future DER owners. Texas RE recommends a requirement that the registered entity managing DERs provide the data to the DPs. Additionally, that non-registered DERs should be captured effectively to ensure reliability operations.

Texas RE does agree that the DPs should be responsible for providing the equivalent system impedance data (distribution feeder, power transformer, etc.) for the DER connections.

The Standard does not specify a threshold limit for the DER facilities required to provide the data. Texas RE recommends the ‘Term(s)’ section include a distinction between utility scale DERs (commercial level DERs, utility scale solar facilities, etc.) and aggregated level DERs (residential rooftop solar, small generators, residential batteries, etc.).

Texas RE understands the intention of the modifications to MOD-032 is to provide visibility of DER in planning models and achieve consistency in representation of various types of DER. To avoid double-counting DERs in the models, Texas RE recommends identifying whether or not the DER outputs are embedded in the load forecasts used in the models and that this is aligned with the demand and energy data that is needed for MOD-031-3.

Likes 0	
Dislikes 0	

Response

2. Provide any additional comments for the standard drafting team to consider, if desired.

Mike Gabriel - Greybeard Compliance Services, LLC - 5	
Answer	
Document Name	
Comment	

In lieu of creating yet another definition, we recommend using one of the existing definitions in Table D.1 of the SPIDERWG document: https://www.nerc.com/pa/Documents/DER_Quick%20Reference%20Guide.pdf, or potentially using the NERC Distributed Energy Task Force (ERTF) DER definition: Any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES).

Likes 0	
Dislikes 0	
Response	

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom	
Answer	
Document Name	
Comment	

Buckeye agrees with the comments prepared by ACES:

We have an ongoing concern regarding the level upon which this will require DPs to collect DER data interconnected to distribution systems. The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes each and every residential solar and commercial rooftop solar customer on the DP's systems. This is a major concern given the extent it may go to exhausting the resources of our Members for the collection of DER data which may or may not have a material impact to the reliability of the BES. Additionally, we have concerns regarding footnote 4 on the last page of the Attachment 1. This footnote states: "The TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary for local practices and the TP/PC may need to coordinate with the DP/TO to determine appropriate assumptions for equivalent distribution system impedance."
This statement seems to allow some discretion for allowing "local practices" to then dictate what classifications of DER are to be modeled in aggregate versus otherwise. If that is the case, then it seems to conflict with the stated goal of the MOD-032-1 SAR to "…provide clarity and consistency for data collection across PCs and TPs when coordinating with the DP to gather aggregate load and aggregate DER data." We recommend that a non-zero MVA threshold be established below which DER data will be modeled in aggregate and above which DER data will be modeled explicitly. Allowing such "local practices" to dictate which DERs are to be modeled in aggregate or not seems contrary to having a standard for the industry to implement that is intended to provide clarity and consistency.
Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	2022-02_Unofficial Comment Form_ERCOT Comments.docx
Comment	

ERCOT generally supports DER-related data collection and recommends that it occur at an early stage (steady-state) of model development. ERCOT requests the following revisions and clarifications to the draft standard.

1. Dual Planning Authority (PA) / Planning Coordinator (PC) Designation

While there is justification to reference both the Planning Authority and Planning Coordinator in the Applicability section (section 4), since Appendix 5B: Statement of Compliance Registry Criteria of the NERC Rules of Procedure, dated January 19, 2021, still uses both terms, the explanatory paragraph in Part 4.1.4 refers to synchronization between registration criteria and the NERC functional model, which is not maintained, was never formally approved, and is only posted as a historical document. Therefore, ERCOT requests the explanatory paragraph be deleted from Part 4.1.4, which would then read as follows:

4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

2. Planning Coordinator (PC) Interface

ERCOT notes the importance of retaining the PC's flexibility with respect to determining the process used to acquire modeling data. While some PCs prefer to interface directly with the DP as noted in footnote 2 (*see* page 20 of 22 of the standard), other PCs prefer to interface with the Transmission Owner (TO) or Transmission Planner (TP). In the latter example, the TO or TP maintains the interface with the DP.

In support of this flexibility, ERCOT requests the SDT revise the table in Attachment 1 by removing the last sentence from footnote 2, adding a new footnote 3 to the first reference to DP in the steady-state column, and renumbering the remaining footnotes as needed, as proposed below:

2. Aggregate Demand*2* [DP*3*, TO (when a Demand is not associated with a registered DP)] a. real and reactive power* b. in-service status*

Footnote 2: For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources.

Footnote 3: Wherever DP is noted as the functional entity responsible for reporting data in Attachment 1, a Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner or as specified in the joint PC/TP modeling data requirements and reporting procedures developed per R1.

3. Attachment 1, *steady state* column, item 9

a. Strike "feeder" to provide the TP/PC with flexibility in tracking the status of UVLS and UFLS (i.e. as aggregated values or as individual feeders).

b. Clarify the use of "and/or" with regards to UVLS and UFLS. Using "and/or" creates four possible combinations that must be tracked: UFLS only, UVLS only, both UFLS and UVLS, and neither UFLS nor UVLS. Is the intent of the SDT to track all these possible permutations?

ERCOT requests that the SDT modify item 9 to read as follows:

9.a. Location (bus from item 1) and if DER is subject to UFLS and/or UVLS

b. Real power capability (gross minimum and maximum)

c. Reactive power capability (gross minimum and maximum)

4. Attachment 1, existing footnote 4 - clarify the use of "/" by revising the footnote to read as follows:

4 The modeling data requirements and reporting procedures that the PC and TP jointly develop under R1 may require either aggregated or unaggregated data as necessary for local practices and the TP or PC may need to coordinate with the DP or TO to determine appropriate assumptions for equivalent distribution system impedance.

5. Clarify the intent of the short circuit column

The technical rationale states that "[d]rastically altering the structure of Attachment 1 or adding DER data to the 'short circuit' column was beyond the scope of the Project 2022- 02 SAR," which in turn states "note that the SPIDERWG does not see a need to modify the short circuit column of Attachment 1 because #1 already states 'all applicable elements' in the steady-state column should have necessary information related to positive, negative, and zero sequence data provided accordingly. If the TP/PC determines that aggregate DER is needed for these studies, then they have the capability to request such data. However, this is not a prevalent issue currently."

While the dynamics column was edited to include Distributed Energy Resource Data to match the format of the Dynamics column, the short circuit column was not updated per the reasoning given in the technical rationale and SAR. However, the short circuit column includes the bullet "[p]rovide for all applicable elements in column 'steady state' [GO, RP, TO]," which could be interpreted to compel the relevant entities to collect DER information in the short circuit models if it is deemed an applicable element. ERCOT requests that the SDT confirm that the TP/PC would determine if DER information is an applicable element for short circuit models.

6. Clarify the note regarding data that vary with system operating state and conditions

The steady-state column of Attachment 1 indicates that "[i]tems marked with an asterisk indicate data that vary with system operating state or conditions." ERCOT recommends that the SDT clarify or provide additional information regarding what types of system operating states or conditions are contemplated. For example, if a data element changes seasonally, should the element be marked with an asterisk, or are seasonal variations not considered "system operating state[s] or conditions" for purposes of Attachment 1?

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	
Document Name	

Comment

We have an ongoing concern regarding the level upon which this will require DPs to collect DER data interconnected to distribution systems. The proposed draft establishes a zero MVA threshold for the collection of all DER data "in non-isolated parallel operation with the Bulk Power System". Per the Technical Rationale, this includes each and every residential solar and commercial rooftop solar customer on the DP's systems. This is a major concern given the extent it may go to exhausting the resources of our Members for the collection of DER data which may or may not have a material impact to the reliability of the BES.

Additionally, we have concerns regarding footnote 4 on the last page of the Attachment 1. This footnote states: “The TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary for local practices and the TP/PC may need to coordinate with the DP/TO to determine appropriate assumptions for equivalent distribution system impedance.”

This statement seems to allow some discretion for allowing “local practices” to then dictate what classifications of DER are to be modeled in aggregate versus otherwise. If that is the case, then it seems to conflict with the stated goal of the MOD-032-1 SAR to “…provide clarity and consistency for data collection across PCs and TPs when coordinating with the DP to gather aggregate load and aggregate DER data.” We recommend that a non-zero MVA threshold be established below which DER data will be modeled in aggregate and above which DER data will be modeled explicitly. Allowing such “local practices” to dictate which DERs are to be modeled in aggregate or not seems contrary to having a standard for the industry to implement that is intended to provide clarity and consistency.

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	
Document Name	

Comment

The SPP RTO recommends the drafting team revise the original Standard Authorization Request (SAR) to keep the project open and coordinate with other NERC drafting teams to address data collection efforts that are applicable to the Inverter-Based Resource (IBR) and Energy Storage Resource (ESR-Batteries). This coordination effort will create a level of proficiency and efficiency in the areas of creating accurate models that can be used by the appropriate entities in their study processes to generate quality results that address initial concerns applicable the reliability of the grid.

The drafting team should conduct a cost analysis to help industry understand the cost impacts of this project.

Additionally, the drafting team should consider a resource analysis to help industry understand the additional time required for their resources to participate in these efforts if the project is extended for a certain amount of time.

As for concerns, one of them focuses around NERC suggesting new responsibilities being applicable to the PC and TP in reference to modeling as well as studying process in reference to the reliability of the grid. For example, NERC suggests that there is a need to conduct an EMT study ever so often to help identify issues in a PC and TP footprint; however, the EMT standard has not been approved by the NERC Board of Trustees (BoT) nor FERC at this point. The RSTC has identified that the MOD-032 standard current doesn’t align with such data collection efforts to assist industry, specifically the PC and TP, in this type of process. These data collection gaps need to be resolved prior to giving the PC and TP related responsibilities.

Furthermore, there will be a need to align with the proposed MOD-026-2 standard in reference to the IBRs from a PC and TP perspective (PC and TP creating a process for GOs and TOs to access models).

Moreover, NERC has identified that PRC-024-3 doesn’t provide the information needed to address IBR ride-through with the occurrence of a system disturbance. From our perspective, there will be a need for data collection via MOD-032 to help ensure an appropriate performance standard can be developed to address NERC’s reliability concerns and needs.

Finally, our last concern pertains to the definition of the DER. There are several definitions currently used in industry, including the SPIDERWG's definition. We recommend that the drafting team coordinate with NERC legal to structure one definition (vetted via standard development process) for industry use. Without a common Glossary Term, there is a potential that the various definitions of DER will create confusing as well as reliability/compliance risks for the PC and TP..

Likes 0	
Dislikes 0	

Response

Devon Tremont - Taunton Municipal Lighting Plant - 1

Answer	
Document Name	

Comment

Taunton Municipal Lighting Plant (TMLP) understands and respects the defined need for additional DER modeling data as these resources continue to grow behind-the-meter and beyond the visibility of PCs and BAs. Our concerns with the modifications to MOD-032 are simply to ensure that they require what we can reasonably expect to provide given current configurations. Adding all of the changes that the SDT proposed concerns us that we will continue to add costs to these projects and continue to prevent their viability. Below are additional comments on a few specific proposed revisions to MOD-032:

Proposed DER Definition: The project team is proposing to define a new term of DER to the NERC Glossary. We request additional clarity and background on the development on this definition. We have reviewed the Technical Rationale document that explains its development on Page 1, but it still remains unclear to us what could be considered to have "parallel operation" with the BES versus being a non-BES asset. TMLP requests that we consider a definition that better aligns with the BES definition and its inclusions/exclusions as this will be better understood by DPs.

Att. 1, Steady State Column, New Item 9: The request to provide real and reactive capability, as well as generator type, is within reason as it is readily available information.

Att. 1, Dynamics Column, New Item 10: TMLP requests additional clarity on the parenthetical that requires a distinction of an "*association*" between the DER and the DP, without which the TO is expected to be responsible. In either scenario, it will be unreasonable to expect the DP or TO to provide dynamic modeling information of the DERs. Currently, the DP is typically the host through a Power Purchase Agreement but are not requiring that DER developers provide dynamic modeling information, and the added cost to do so must be considered. At a minimum, the SDT should limit any TO/DP obligations to what is feasible and reasonable, and presently dynamic information for unregistered DERs is not available to us (as a DP) and other DP peers. Expecting a DP or TO to provide this information would require them to alter their interconnection agreements for future projects, as well as sending them on a "research mission" for their existing resources. Further on this point, TMLP agrees with APPA's comments which state "*While DPs may receive some or all of this information at the interconnection request stage, and can pass whatever data they have to their PC and TP, the draft standard must be revised to account for the fact that the DPs and TOs do not own or control these DERs, and thus cannot be held responsible for the completeness or accuracy of the data they themselves receive from the DER owners.*"

tt. 1, Steady-State Column, Footnote 2 on "Aggregate Demand": This effectively provides the authority for the host PC/TP to request that DPs reconstitute their load readings prior to submitting, however, the DP's typically are not using revenue quality metering with their DERs and therefore cannot be relied upon for market reporting. If this is not the intended use of the data, then this needs to be clarified in this footnote. The Technical Rationale document states that current collection and modeling of net demand is not consistent with "a modeling framework that explicitly represents DER," and if this is true, then we need to understand what this framework is. We reside in ISO-NE and their market rules currently define the inputs to *Regional Network Load* to exclude "load served by behind-the-meter generation" (ISO-NE OATT, Section II.21.2).

Likes 0	
Dislikes 0	

Response
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis

Answer	
Document Name	

Comment

In addition to PJM supporting the IRC SRC comments, PJM wants to ensure the coordination of Distribution Provider (DP) data is coordinated between the DP and Transmission Owner (TO). The coordination between the DP and TO is needed to properly model due to the DP interconnection with the TO. Thus, each Transmission Owner shall work with the Distribution Provider(s) within the Transmission Owner's area in collecting data for the PA and PC in order to properly model this information and how it interconnects with the Transmission Owner systems. PJM is requesting this information to be written directly in the Standard to ensure accurate and proper data collection.

PJM wants to the thank the Standard Drafting Team for all their work and commitment to the Project!

Likes 0	
Dislikes 0	

Response
David Jendras Sr - Ameren - Ameren Services - 3

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response
Bret Galbraith - Seminole Electric Cooperative, Inc. - 6

Answer	
Document Name	

Comment

For the dynamics column in Attachment 1, it is unclear as to what DER data may be requested from the DP. Seminole recommends the drafting team to provide additional clarification, similar to what the dafting team provided in the steady state column, for the data to be collected in the dynamics column.

Likes 0	
Dislikes 0	
Response	
Desmarie Waterhouse - American Public Power Association - 4 - NA - Not Applicable	
Answer	
Document Name	
Comment	

APPA has multiple concerns with the proposed definition of distributed energy resources (DER) and adding this scope to the MOD-032 Standard, as outlined below.

Scope Expansion and non-NERC Registered Entities

The proposed changes to include DERs in MOD-032 is expanding the scope of the Standard to include equipment not currently covered in the BES definition. The concept that non-BES or distribution equipment could impact the reliability and operation of the BES is not new to NERC Standards. For example, there is precedent in the PRC Standards to consider distribution equipment that supports UVLS programs or Protection System schemes. However, the proposed changes in this posting for MOD-032 are not sufficient to ensure the expansion of scope will be effective or reasonable.

The Technical Rationale states “the modifications place a compliance obligation on NERC registered DPs (or TOs) to provide basic information about DER that are connected to their systems so that DER can be properly represented in interconnection-wide cases.” The information includes “Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS,” “Real power capability (minimum and maximum),” “Reactive power capability (minimum and maximum),” “Generator type (solar, battery, etc.),” and “In-service date or other information to be used to make assumptions about DER capabilities related to ride-through, voltage control and/or frequency control.” While DPs may receive some or all of this information at the interconnection request stage, and can pass whatever data they have to their PC and TP, the draft standard must be revised to account for the fact that the DPs and TOs do not own or control these DERs, and thus cannot be held responsible for the completeness or accuracy of the data they themselves receive from the DER owners. For example, a DER owner might inadvertently change its nameplate capacity by replacing a damaged inverter with a different capacity from the original due to supply chain issues, and might not think to inform its DP of the change. More fundamentally, some solar installations, whether commercial, industrial, or homeowners installing on rooftops, do so without taking advantage of net metering or otherwise complying with their distribution utility’s interconnection requirements—in other words, DPs may not have complete information about the *location* of DERs on their systems, let alone the capacity, type, and in-service date. Where customers *do* take advantage of net metering, the metering devices are generally not production meters, which highlights a concern regarding the SDT’s proposal to revise the existing requirement for “aggregate demand” data to state that “For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources.” Indeed, it is the nature of “net metering” that the data produced and collected is demand offset by DER output, not separate gross demand and generation values.

A registered entity cannot provide data that the registered entity itself does not have. In particular, it would be unrealistic to expect a TO or DP to have information about unregistered DERs at the same level of detail and accuracy that the unregistered DER owners can provide about their own facilities, nor would it be reasonable to hold a TO or DP responsible for gaps or inaccuracies in the data provided by an unregistered DER owner.

Accordingly, the SDT should, at minimum, revise the proposed standard to indicate that (a) DPs’ and TOs’ responsibility with respect to DER data is limited to passing along any responsive data they have received from DER owners, without vouching for the data’s completeness or accuracy; and (b) the requirement to provide “aggregate demand” can be satisfied by net demand data, at least with respect to net-metered DERs.

Implementation Plan

APPA does not agree with the proposed implementation plan for the DER definition. This definition will eventually be used in several future NERC Standard revisions. Some of these revisions may have a shorter implementation timeframe than Project 2022-02. The effective date of the DER definition needs to be coordinated with the other planned Standard revisions to ensure the timing supports implementation of the other Standard revisions.

Coordination with Other Standard Changes

APPA is concerned about how the DER definition will be used for other future NERC Standard changes, as outlined in the October 2022 "NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) White Paper." The proposal's impact on other Standards must be clear prior to putting the DER definition in place to avoid unintended consequences. For example, excluding various types of demand response from the DER definition may not be appropriate for PRC-006 and TPL-001. These two Standards may need to consider demand response for proper modeling of the BES. If NERC intends to add DERs to EMT Modeling Requirements in MOD-026, then this would be a significant cost and pose technical challenges for registered entities, which could impact the DER definition scope.

When reviewing the DER definition, entities need to understand how this definition will be used in all of the impacted Standards. APPA recommends creating a standalone Standards Project that addresses the DER definition development for all future Standard changes, similar to Standard Project 2016-02 and Standard Project 2015-09.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee (IRC SRC) 2022-02 Modifications to MOD-032 Draft 1

Answer	
Document Name	2022-02_Unofficial Comment Form_SRC_07-14-23_Final (as filed).docx

Comment

To achieve this project's objective [1] in an effective and efficient manner, the SRC recommends NERC do the following:

1. **Retain the need to define Distributed Energy Resources (DERs) as part of the scope of this project (as opposed to initiating another project).** This would be beneficial because:

a. The SDT for this project already includes many SPIDERWG members. Therefore, the existing team already has the "right" representation and expertise to perform this task.

b. The existing SDT has discussed and examined a broad range of DER definitions, so a substantial portion of the work needed to develop a DER definition has already been done, thereby giving the existing SDT a leg up on this effort.

c. It would eliminate the need for NERC to initiate another project and for industry to provide representatives to staff another team that would be starting this work from scratch (i.e., a loss of efficiency) and which may not be able to attract a commensurate level of expertise, e.g., SPIDERWG members (i.e., a loss of effectiveness).

2. **Revise the DP registration criteria found in the Rules Of Procedure (ROP), Appendix 5B, Section III** and in the corresponding **ERO Enterprise Registration Practice Guide Distribution Provider "directly connected" Determinations.pdf (nerc.com)** to more closely align with the criteria proposed in its Work Plan to register Inverter-Based Resources (IBRs) under FERC Docket RD22-4-000.

When the DP criteria (RoP, Appendix 5b, Section III.a.1) in the **ERO Enterprise Registration Practice Guide Distribution Provider "directly connected" Determinations.pdf (nerc.com)** was updated in July 2018, two key aspects were modified that are now in direct opposition to the approach NERC is taking with respect to registering IBRs:

a. **The amount of peak load served by the DP system was increased from 25 MW to 75 MW.** This is in direct contrast to NERC's Work Plan for the registration of IBRs whereby NERC is seeking to decrease the registration threshold from 75 MVA to 20 MVA.

b. **The connection point for peak load was changed from "directly connected to the "Bulk Power System (BPS)" to "directly connected to the BES."** Again, this is in direct contrast to NERC's Work Plan for the registration of IBRs whereby NERC is seeking to register IBRs that are directly connected to the BPS.

As the penetration of Distributed Energy Resources (DERs) increases, there will be a reliability need to register a broader range of Distribution Providers as was acknowledged with IBRs. The SRC requests NERC address this issue as part of this project, perhaps as a separate phase.

3. Dual Planning Authority (PA) / Planning Coordinator (PC) Designation

While there is justification to reference both the Planning Authority and Planning Coordinator in the Applicability section (section 4) since NERC Appendix 5B: Statement of Compliance Registry Criteria, dated January 19, 2021, still uses both terms, the explanatory paragraph in Part 4.1.4 refers to synchronization between registration criteria and the NERC functional model, which is not maintained, was never formally approved, and is only posted as a historical document. Therefore, the SRC requests the explanatory paragraph be deleted from Part 4.1.4 as illustrated below and in the attached file:

4.1.4 Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

Planning Coordinator (PC) Interface

The SRC notes the importance of retaining the PC's flexibility with respect to determining the process used to acquire modeling data. While some PCs prefer to interface directly with the DP as noted in footnote 2 (*see* page 20 of 22 of the standard), other PCs prefer to interface with the Transmission Owner (TO) or Transmission Planner (TP). In the latter example, the TO or TP maintains the interface with the DP.

Footnote 2: *For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner.*

The SRC requests the SDT clarify the required interfaces under the standard are "as directed by the PC" so information flows to the appropriate entities as part of the data collection process. Leave flexibility to the PC for determining how this data is collected as proposed below:

2. Aggregate Demand2 [DP3, TO (when a Demand is not associated with a registered DP)] a. real and reactive power* b. in-service status*

Footnote 2: For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources.

Footnote 3: Wherever DP is noted as the functional entity responsible for reporting data in the table, a Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner.

Footnote 4: Including synchronous condensers and pumped storage.

Other Clarifications

1. Attachment 1, "steady state" column, item 9

a. Strike "feeder" to provide the TP/PC with flexibility in tracking the status of UVLS and UFLS (i.e. as aggregated values or as individual feeders).

b. Clarify the use of "and/or" with regards to UVLS and UFLS. Using "and/or" creates four possible combinations that must be tracked: UFLS only, UVLS only, Both UFLS and UVLS, and neither UFLS nor UVLS. Is the intent of the SDT to track all these possible permutations?

The SRC requests the SDT modify item 9 to add the following details:

9.a. Location (bus from item 1) and if DER is subject to UFLS and/or UVLS

b. Real power capability (gross minimum and maximum)

c. Reactive power capability (gross minimum and maximum)

2. **Attachment 1, footnote 4 -** clarify the use of "/" as illustrated below:

4 The TP or PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary for local practices and the TP or PC may need to coordinate with the DP or TO to determine appropriate assumptions for equivalent distribution system impedance.

[1] From pages 1-2 of the SAR: "*Update MOD-032-1 to: (1) include "data requirements and reporting procedures" for DER that are necessary to support the development of accurate interconnection-wide models, (2) replace Load-Serving Entity (LSE) with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria, (3) enable the SDT to review any additional gaps in DER data collection with the de-registration of LSE.*"

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI supports SDT efforts to address DER impacts, however, the modifications to MOD-032-2 is inappropriately running ahead of NERC IBR organizational registration efforts. Presently, TOs and DPs have no ability to compel DER owners to supply the data identified in the proposed Reliability Standard and until these issues are settled through changes to DER registration, efforts to gather DER data beyond those resources DPs own will likely yield little useful data. Additionally, subjecting DPs and TOs to the compliance obligations through MOD-032-2, before the registration issues have been solved, represent untenable regulatory obligations they cannot fulfil. To address this concern, we ask that all efforts by the Project 2022-02 SDT to compel TOs and DPs to supply DER data, beyond the resources they own and operation, be removed.

We also do not support the development of a DER definition within this NERC Reliability Standards project. The impact of this definition will have far reaching impacts that go beyond this project. To address this issue, we suggest that a separate NERC Reliability Standards project be developed to address this definition.

EEI is additionally concerned that the number of separate DER projects currently under development and otherwise being considered is growing very quickly and it is unclear if there is adequate coordination between all of these projects. While addressing these issues is important, speed should not take precedent over ensuring these efforts are adequately coordinated and Requirements are not being duplicated or conflict.

In addition to the above concerns, we offer the following comments and concerns for consideration:

Applicability Section

There is insufficient clarity related to the extent of DER resources that must be reported under MOD-032. To address this concern, a Facilities section should be added to this Reliability Standard.

Attachment 1

General comment: As stated in EEI's response to Question 1, we support the replacement of LSEs with DP, however, Attachment 1 goes beyond the replacement of LSEs with DP and includes TOs as an additional replacement where there are no registered DPs. This change should be stricken from the proposed draft of MOD-032-2. Registration problems cannot be solved through compliance obligations placed on registered entities who do not participate in the approval of DER interconnections or have any ability to compel the sharing of DER data contained on networks outside their purview.

Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5

EEI does not support the addition of "TO (when a Demand is not associated with a registered DP)" to Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5 (Demand) because TOs have no part in interconnections on Distribution Provider systems and would therefore only have this data if it were supplied to them by the responsible DP. Furthermore, it is impractical to expect that TOs could compel unregistered DPs to supply this data. We further note that even registered DPs only have detailed data on DERs they own. Compelling DPs to similarly supply data beyond those resources they own should be removed. For these reasons, changes to MOD-032-2 should be placed on hold until registration issues surrounding DER owners can be resolved through the NERC organizational registration reforms that are intended to address IBRs that impact the BPS.

Footnote 2 – Additional clarity is needed regarding the intent of Footnote 2. Footnote 2 appears to require DPs (or TOs) to supply Aggregate Demand data that has been manipulated to exclude all DER offsets. While this would be desirable, most small DERs are not metered except through billing meters. Billing meters are not synchronized with SCADA data, diminishing the value of any data supplied by the reporting entities. Additionally, the work hours required to account for these DER offsets could be substantial, adding excessive costs while providing questionable value or improved reliability through this change. As an alternative, EEI suggests that DPs might be able provide estimated DER offset values to address the immediate needs of planners in the development of their planning models, but even this should be studied to ensure such efforts are even possible or practical to implement.

Steady-state Column (Item 9) and Dynamic Column 10

See EEI comments for Items 2 and 5 above.

Footnote 4: Footnote 4 does not align with the SAR. In the SAR, data requests for DERs appear to be limited to aggregated DER data, however, in footnote 4 it states "TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary". This appears to go beyond the approved limits of this SAR and should therefore be removed.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley

Answer	
Document Name	

Comment	
SMUD and BANC support the comments submitted by APPA, especially with regards to the DER definition and Coordination with Other Standard Changes.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	

Suggest making the following conforming changes to section 4.1.4 as per standards MOD-031-3 and MOD-033-2 in the NERC project 2017-17 - Standards Alignment with Registration project:

Replace "Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")" with "Planning Coordinator".

Delete the 2nd paragraph in section 4.1.4

R3 indicates "…each notified BA, GO, DP, RP, TO, or TSP shall respond to the notifying PC or TP as follows …". The R3 VSL indicates these entities failed to provide a written response to their PC or TP. Suggesting either adding "written" to R3 or removing it from the R3 VSL.

R1 Severe VSL: Correct "The Planning and Transmission Planner(s) Coordinator …" for "The Planning Coordinator and Transmission Planner(s)…"

R2 Severe VSL: Missing the TO entity after the last "OR".

R3 VSL: incorrect references to R4 instead of R3 in all VSL levels.

R3 Severe VSL: should read "or within a longer period of 45 days agreed upon by the notifying Planning Coordinator or Transmission Planner" instead of "or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner"

TO's and DP's cannot be required to provide data for DER (or any generation resources) that the TO and DP do not own. TO and DP have no authority to collect this data and DER's are not obligated to provide the data.

In Attachment 1, under Dynamics, the following change should be made:

Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP)

In Attachment 1, under Steady-State, the following change should be made:

Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP)

a. Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS

b. Real power capability (minimum and maximum)

c. Reactive power capability (minimum and maximum)

d. Generator type (solar, battery, etc.)

e. In-service date or other information to be used to make assumptions about DER capabilities related to ride-through, voltage control, and/or frequency control.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	
Document Name	

Comment

SRP recommends adjusting the definition for the Distribution Provider before making the proposed adjustments so that there is clear delineation of roles and responsibilities.

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1, Group Name Eversource

Answer	
Document Name	

Comment

Eversource recommends the drafting team consider the category of “Transients” (specifically EMT Models) as an inclusion in required data submittals in Attachment 1 to reach the SDT’s goal to “address gaps in data collection for the purposes of modeling aggregate levels of DERs in planning assessments” per the MOD-032 SAR.

While interconnection-wide models are built using dynamic and short circuit studies and not transient studies, there are still situations where border areas are studied between differing TPs or PCs, and the need for these EMT models to be available is necessary to better model aggregate levels of DERs.

Likes 0	
Dislikes 0	

Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
Attachment 1 Data Reporting table (Steady State Column items 2, and 9, and Dynamics Column items 5, and 10) has added language indicating that the Transmission Owner (TO) is the responsible entity for submitting modeling data when a demand is not associated with a registered Distribution Provider. AZPS requests clarification regarding the type of entity that would have load, but not be a registered distribution provider. AZPS is concerned that the Transmission Owner may not have the ability to produce or acquire certain load information from an unregistered entity unless there is some other type of contractual relationship in place.	
Likes 0	
Dislikes 0	
Response	
Imane Mrini - Austin Energy - 6	
Answer	
Document Name	
Comment	
Austin Energy supports APPA's comments. Austin Energy is concerned about having the DP responsible for significant data collection from DER that it doesn't have control over, may be difficult to attain, not available or inaccurate. The SDT should, at minimum revise the proposed standard to indicate that (a) DPs' and TOs' responsibility with respect to DER data is limited to passing along any responsive data they have received from DER owners, without vouching for the data's completeness or accuracy"	
Likes 0	
Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5	
Answer	
Document Name	
Comment	

Austin Energy supports APPA's comments.

Austin Energy is concerned about having the DP responsible for significant data collection from DER that it doesn't have control over, may be difficult to attain, not available or inaccurate. The SDT should, at minimum revise the proposed standard to indicate that (a) DPs' and TOs' responsibility with respect to DER data is limited to passing along any responsive data they have received from DER owners, without vouching for the data's completeness or accuracy"

Likes 0	
Dislikes 0	

Response

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	
Document Name	

Comment

DER Definition:

Southern Indiana Gas & Electric Co. (SIGE) believes the potential impact of the DER definition exceeds the current scope of Project 2022-02 and suggestions expanding the scope of the current project and/or initiating a separate NERC Reliability Standards project to address the DER definition.

Applicability:

SIGE believes there is insufficient clarity related to the extent of DER resources that must be reported under MOD-032. Further clarity on the DER definition is needed.

Attachment 1:

SIGE agrees with EEI's comments that changes to MOD-032-2 should be put on hold until registration issues surrounding DER owners can be resolved through the NERC organizational registration reforms intended to address Inverter Based Resources (IBRs) that impact the Bulk Power System (BPS) .

SIGE is supporting EEI's **Footnote 2**.

SIGE recommends replacing the '\' in **Footnote 4** with "**or**". "The TP/ or PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary for local practices and the TP or PC may need to coordinate with the DP or TO to determine appropriate assumptions for equivalent distribution system impedance."

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	
Document Name	

Comment	
Attachment 1 - Under Steady State (2, 9) Recommend changing language to [DP (when a Demand connected to the DP is not associated with a registered DP), TO (when a Demand connected to the TO is not associated with a registered DP)]. Under dynamics (5, 10) Recommend changing language to [DP (when a Demand connected to the DP is not associated with a registered DP), TO (when a Demand connected to the TO is not associated with a registered DP)]. An entity that has an unregistered DP connected to them will have both the knowledge that the entity exists and contacts for them to obtain the required information. If a TO is required to provide information for an unregistered DP that receives its service through a registered DP, they may not know the entity exists or have the required contacts to obtain the required information. As written, the SDT is setting the TO up to fail and be non-compliant. Attachment 1 steady state, modify (9e) to DER capabilities related to ride-through, voltage control and/or frequency control, if available, or In-service date or other information to be used to make assumptions about them if this information is not available. Recommend trying to get the actual information if it is available rather than always making assumptions for this.	
Likes 0	
Dislikes 0	
Response	

Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	
Document Name	
Comment	
Suggest making the following conforming changes to section 4.1.4 as per standards MOD-031-3 and MOD-033-2 in the NERC project 2017-17 - Standards Alignment with Registration project: • Replace “Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)” with “Planning Coordinator”. • Delete the 2nd paragraph in section 4.1.4 R3 indicates “…each notified BA, GO, DP, RP, TO, or TSP shall respond to the notifying PC or TP as follows …”. The R3 VSL indicates these entities failed to provide a written response to its PC or TP. Suggesting either adding “written” to R3 or removing it form the R3 VSL. R1 Severe VSL: Correct “The Planning and Transmission Planner(s) Coordinator …” for “The Planning Coordinator and Transmission Planner(s)…” R2 Severe VSL: Missing the TO entity after the last “OR”. R3 VSL: incorrect references to R4 instead of R3 in all VSL levels. R3 Severe VSL: should read “or within a longer period of 45 days agreed upon by the notifying Planning Coordinator or Transmission Planner” instead of “or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner” TO’s and DP’s cannot be required to provide data for DER (or any generation resources) that the TO and DP do not own. TO and DP have no authority to collect this data and DER’s are not obligated to provide the data. In Attachment 1, under Dynamics, the following change should be made: Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP) In Attachment 1, under Steady-State, the following change should be made: Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP) a. Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS b. Real power capability (minimum and maximum) c. Reactive power capability (minimum and maximum) d. Generator type (solar, battery, etc.) e. In-service date or other information to be used to make assumptions about DER capabilities related to ride through, voltage control and/or frequency control.	
Likes 0	
Dislikes 0	
Response	

Lan Nguyen - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	

Comment	
CEHE finds the proposed revisions to MOD-032-2, Attachment 1 too detailed and prescriptive. The NERC Standard should be written to give Planning Coordinators (PC), Transmission Planners (TP) and Transmission Service Providers (TSP) the flexibility to coordinate and determine the specific data requirements that are needed for the planning models under MOD-032-2, Attachment 1. CEHE recommends that data reporting requirements listed in Attachment 1 be determined by the PC, in coordination with TP. In the ERCOT region, processes are already in place to define these data requirements through the coordination of the Planning Coordinator and Transmission Planners as part of various regional working groups. CEHE also supports the comments as submitted by the Edison Electric Institute (EEI) regarding the development of a DER definition separate from the NERC Reliability Standards Project 2020-02. CEHE agrees with EEI comments on how presently, Transmission Owners (TOs) and Distribution Providers (DPs) have no ability to compel DER owners to supply the data identified in the proposed Reliability Standard and until these issues are settled through changes to DER registration, efforts to gather DER data beyond those resources DPs own will yield little useful data. Subjecting DPs and TOs to the compliance obligations through MOD-032-2, before the registration issues have been solved, represents untenable regulatory obligations they cannot fulfil. To address this concern, CEHE suggests that all efforts by the Project 2022-02 SDT to compel TOs and DPs to supply DER data, beyond the resources they own and operate, be removed. CEHE agrees with EEI comments relative to TOs. These entities may have no insights on DERs of unregistered DP systems and therefore should not be held accountable for supplying this type of information. CEHE supports the additional comments submitted by EEI regarding footnote 4 of the SAR.	
Likes 0	
Dislikes 0	
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	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for queston #2.	
Likes 0	
Dislikes 0	
Response	
Pamela Frazier - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name Southern Company	
Answer	
Document Name	

Comment	
Southern Company supports comments submitted by EEI on potential implementation challenges.	
Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	
Document Name	

Comment

WEC Energy Group appreciates the opportunity to provide comment and suggests for consideration the inclusion of a specific MW threshold below which DER modeling is not required.

WEC Energy Group is also in support of the comments submitted by EEI which state:

"EEI supports SDT efforts to address DER impacts, however, the modifications to MOD-032-2 is inappropriately running ahead of NERC IBR organizational registration efforts. Presently, TOs and DPs have no ability to compel DER owners to supply the data identified in the proposed Reliability Standard and until these issues are settled through changes to DER registration, efforts to gather DER data beyond those resources DPs own will likely yield little useful data. Additionally, subjecting DPs and TOs to the compliance obligations through MOD-032-2, before the registration issues have been solved, represent untenable regulatory obligations they cannot fulfil. To address this concern, we ask that all efforts by the Project 2022-02 SDT to compel TOs and DPs to supply DER data, beyond the resources they own and operation, be removed.

We also do not support the development of a DER definition within this NERC Reliability Standards project. The impact of this definition will have far reaching impacts that go beyond this project. To address this issue, we suggest that a separate NERC Reliability Standards project be developed to address this definition.

EEI is additionally concerned that the number of separate DER projects currently under development and otherwise being considered is growing very quickly and it is unclear if there is adequate coordination between all of these projects. While addressing these issues is important, speed should not take precedent over ensuring these efforts are adequately coordinated and Requirements are not being duplicated or conflict.

In addition to the above concerns, we offer the following comments and concerns for consideration:

Applicability Section

There is insufficient clarity related to the extent of DER resources that must be reported under MOD-032. To address this concern, a Facilities section should be added to this Reliability Standard.

Attachment 1

Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5

EEI does not support the addition of "TO (when a Demand is not associated with a registered DP)" to Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5 (Demand) because TOs have no part in interconnections on Distribution Provider systems and would therefore only have this data if it were supplied to them by the responsible DP. Furthermore, it is impractical to expect that TOs could compel unregistered DPs to supply this data. We further note that even registered DPs only have detailed data on DERs they own. Compelling DPs to similarly supply data beyond those resources they own should be *removed. For these reasons, changes to MOD-032-2 should be placed on hold until registration issues surrounding DER owners can be resolved through the NERC organizational registration reforms that are intended to address IBRs that impact the BPS.*

Footnote 2 – Additional clarity is needed regarding the intent of Footnote 2. Footnote 2 appears to require DPs (or TOs) to supply Aggregate Demand data that has been manipulated to exclude all DER offsets. While this would be desirable, most small DERs are not metered except through billing meters. Billing meters are not synchronized with SCADA data, diminishing the value of any data supplied by the reporting entities. Additionally, the work hours required to account for these DER offsets could be substantial, adding excessive costs while providing questionable value or improved reliability through this change. As an alternative, EEI suggests that DPs might be able provide estimated DER offset values to address the immediate needs of planners in the development of their planning models, but even this should be studied to ensure such efforts are even possible or practical to implement.

Steady-state Column (Item 9) and Dynamic Column 10

See EEI comments for Items 2 and 5 above.

Footnote 4: Footnote 4 does not align with the SAR. In the SAR, data requests for DERs appear to be limited to aggregated DER data, however, in footnote 4 it states "TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary". This appears to go beyond the approved limits of this SAR and should therefore be removed."

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	
Document Name	

Comment

The NAGF has no additional comments at this time.

Likes 0	
Dislikes 0	

Response

Lindsey Mannion - ReliabilityFirst - 10

Answer	
Document Name	

Comment

RF notes the draft standard revision also adds DER data under the steady state and dynamics columns in Attachment 1: Data Reporting Requirements, addressing industry need (1) from the SPIDERWG MOD-032 SAR and appreciates the efforts of the SDT on this project.

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1, Group Name National Grid

Answer	
Document Name	

Comment

RE: Definition of Distributed Energy Resource (DER): Please consider that the definition of Distributed Energy Resource (DER) should be more generic, such as, "Real Power and Reactive Power resources connected on the distribution system, in non-isolated parallel operation. Please consider changing active power to Real Power since "active power" is not included in the NERC Glossary of Terms and is in literature a synonym to Real Power and should not be defined differently. In the NERC Glossary of Terms, Real Power is defined as, "The portion of electricity that supplies energy to load." In the slides presented at the Project 2022-02 webinar (June 27), "Active power" was proposed to "indicate[s] that the scope is focused on only those facilities that may be exporting real power to the power system or offsetting real power load (e.g. residential or commercial rooftop solar, even if they only operate at unity power factor or don't have any reactive power capability). This would exclude examples such as charging-only electric vehicle (EV) installations and controllable load options." This proposal seems to indicate active power no longer being used as a synonym to Real Power, which could cause a potential risk of misinterpretations.

RE: Applicability – Functional Entities, Section 4.1.4: Please consider removing the "Planning Authority" function from section 4.1.4 since Planning Coordinator is the preferred function name. Please consider that Project 2017-07 Standards Alignment with Registration was previously removing "Planning Authority" from other standards such as MOD-031-2 and MOD-033-1, in-advance of the removal of "Planning Authority" from Rules of Procedure - Appendix 5B: Statement of Compliance Registry Criteria.

RE: Section C. Compliance: Please consider adding (CEA) as the abbreviation of "Compliance Enforcement Authority" to section 1.1. Please consider using the abbreviation CEA in section 1.2.

RE: Attachment 1: Data Reporting Requirements: Please consider limiting steady-state data for new item 9 to read as, "9. Distributed Energy Resource (DER) data4 [DP]" Please consider that sub-parts a., b., c., d., and e. are not necessary since DER data requirements can be agreed upon per requirement R1.

Likes 0	
Dislikes 0	

Response

Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	
Document Name	

Comment

Xcel Energy supports the comments of the EEI and the MRO NSRF

Likes 0	

Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	

We appreciate the SDT's inclusion of a draft definition for a "Distributed Energy Resource (DER)" in Draft 1 of MOD-032-2. We suggest the words 'Generators and energy storage technologies…' in the definition be replaced with 'Sources of Electrical Energy…'. The NERC Glossary of Terms defines "Electrical Energy" as "The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh)" and is technology neutral. While a DER definition is important, the definition in combination with adding DP applicability may not provide the clarity for applicability that the SDT concludes in the Technical Rationale. The SDT should consider whether utilizing a new Facilities applicability section (4.2) could provide further scope clarity.

We believe section 4.1.4 should be updated to simply "Planning Coordinator". This would be consistent with the direction taken in other NERC standards that previously contained similar language regarding PA/PC applicability (see changes made to MOD-031-3 and MOD-033-2 under Project 2017-07, Standards Alignment with Registration). The Project 2017-07 webpage contains the following statement about MOD-032-1:

"MOD-032-1 will not be revised at this time, but may come back into Project 2017-07. The work of the System Planning Impact from Distributed Energy Resource Working Group (SPIDERWG) is ongoing at the time of the final posting for Project 2017-07. In June 2018, the NERC Planning Committee (PC) formed the SPDERWG subcommittee to address Distributed Energy Resource (DER) impacts on the bulk power system (BPS). Currently, the subcommittee has proposed a Standard Authorization Request (SAR) for MOD-032-1 pertaining to DERs. The SAR has recently been reviewed by the PC. At this time, the Project 2017-07 drafting team will not take any action in reference to the MOD-032 standard until the SPIDERWG has completed their initial efforts."

While the Draft 1 Technical Rationale notes that the currently posted "Appendix 5B: Statement of Compliance Registry Criteria" still uses the Planning Authority term, a cursory review of all currently active standards reflects that a transition to "Planning Coordinator" in the applicability sections is almost complete, so making this change in MOD-032-2 would complement this transition. FAC-014-3, effective 4/1/2024, will incorporate the PA to PC change for that standard.

We noted in our comments on the SAR that a Distribution Provider may not always be the most practical source for the DER modeling data needed by the PC and TP. We recognize that the SDT has allowed for the flexibility of a Transmission Owner to also be a source for DER modeling data in Draft 1. However if the DP or TO is not directly affiliated with the DER owner, would their need to collect the DER model data from the entities that possess it not essentially mirror the PC and TP's need under R1? The DP and TO might need their own requirement(s) to develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures to obtain DER modeling data (potentially from unregistered entities that don't have an obligation to comply with NERC's Reliability Standards) that would subsequently be passed on to the PC and TP. A "DER data entity" could also be added to the applicability section (reference PRC-006-5 for precedent) with a broader range of registered entity options to fulfil that role (e.g., DP, UFLS-Only DP, TO, RP, GO).

We interpret the implementation plan to mean that the PC and each of their TPs will have 24 months to jointly update their modeling data requirements and reporting procedures to incorporate the changes in Attachment 1. The entities responsible for providing DER modeling data to the PC/TP will then have 12 months to comply. We believe the initial collection and submittal of DER data will be equally if not more time consuming than the PC/TPs efforts to update their modeling data requirements and reporting procedures. As noted above, after receiving the PC/TP's updated modeling data requirements and reporting procedures, the DER data collectors may need to perform outreach and communicate their own procedure/schedule for receiving the data from others. We suggest the implementation plan be revised to allow 24 months (rather than 12 months) after the effective date for the initial performance of R2, R3 and R4.

We suggest that further development of MOD-032-2 and its associated implementation plan be paused until it can be performed in closer conjunction with NERC's three year plan to register 'GO-IBRs', which is just beginning; and the "Modifications to FAC-001 and FAC-002" Standard Authorization Requests approved for posting at the NERC Standards Committee's May 17, 2023 meeting (no NERC project number assigned yet). Addressing these items (and perhaps other IBR related standards initiatives) in a piecemeal fashion will lead to less optimal results and confusion in the industry.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

PPL NERC Registered Affiliates do not agree with the separate inclusion of DER data in Attachment 1. A lack of specific reference to DER data does not mean that the data does not exist or is not already attainable by PCs and TPs under the existing standard. There are already specific provisions in the Standard allowing for the collection of such data. We do not believe there are gaps or lack of clarity within the currently approved MOD-032-1. Directing how an entity should collect and model such data is overly prescriptive, will increase administrative burden, and limit innovation in modeling DERs. The industry is just now learning how DERs are going to affect the BES. It is counterproductive to circumscribe how entities should meet their compliance requirements.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	
Document Name	

Comment

Exelon concurs with the concerns expressed in the EEI comments.

Requirements for DPs and TOs to provide Aggregate Demand and DER data should be limited to the aggregate data currently available to the entity.

For Attachment 1, Steady-State 9e, we suggest removing the implied requirement for the “in-service dates”. Consider restating Attachment 1, Steady-State 9e as, “Information to be used to make assumptions about DER capabilities related to ride-through, voltage control and/or frequency control.” The Technical Rationale document can be modified to discuss how in-service dates may support the response to Attachment 1, Steady-State 9e.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon concurs with the concerns expressed in the EEI comments.

Requirements for DPs and TOs to provide Aggregate Demand and DER data should be limited to the aggregate data currently available to the entity.

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Likes 0	
Dislikes 0	

Response

Brittany Millard - Lincoln Electric System - 5

Answer	
Document Name	

Comment

LES does not agree with the SDT proposed definition of DERs. The definition should be more in line with the FERC Energy Primer definition, already in place.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	
Comment	

The DP must be able to bound restrictions/limitations to TP request due to limited data availability, reasonableness, etc., when DER data requirements are made.

Also, when determining the size of each DER, a minimum size of 500 kVA should be required for inclusion. Anything less than 500kVA would require an onerous amount of effort to provide accurate data, which would result in data being outdated and/or obsolete, etc. There is limited data available (MOD-032-2 Attachment 1) for DP area small DER generation (e.g., residential solar, small commercial), therefore the accuracy of aggregated small DER generation for BES system impact modeling is limited.

Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5

Answer	
Document Name	
Comment	

Constellation has no additional comments

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	
Document Name	
Comment	

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

Likes 0	
Dislikes 0	

Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG agrees with NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	
Document Name	
Comment	

1) Suggest making the following conforming changes to section 4.1.4 as per standards MOD-031-3 and MOD-033-2 in the NERC project 2017-17 - Standards Alignment with Registration project:

- Replace “Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)” with “Planning Coordinator”.
- Delete the 2nd paragraph in section 4.1.4

2) R3 indicates “…each notified BA, GO, DP, RP, TO, or TSP shall respond to the notifying PC or TP as follows …”. The R3 VSL indicates these entities failed to provide a written response to its PC or TP. Suggesting either adding “written” to R3 or removing it form the R3 VSL.

3) R1 Severe VSL: Correct “The Planning and Transmission Planner(s) Coordinator …” for “The Planning Coordinator and Transmission Planner(s)…”

4) R2 Severe VSL: Missing the TO entity after the last “OR”.

5) R3 VSL: incorrect references to R4 instead of R3 (more specifically R3.2) in all VSL levels.

6) R3 Severe VSL: should read “[...Requirement R3 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response after 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner)” instead of “Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).”

7)TO’s and DP’s cannot be required to provide data for DER (or any generation resources) that the TO and DP do not own. TO and DP have no authority to collect this data and DER’s are not obligated to provide the data.

8) In Attachment 1, under Dynamics, the following change should be made:

- Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP)

- In Attachment 1, under Steady-State, the following change should be made: Distributed Energy Resource (DER) data [DP, TO (when DER is owned by the TO or DP)

a. Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS

b. Real power capability (minimum and maximum)

c. Reactive power capability (minimum and maximum)

d. Generator type (solar, battery, etc.)

e. In-service date or other information to be used to make assumptions about DER capabilities related to ride through, voltage control and/or frequency control.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	
Document Name	

Comment

PG&E provides the following:

The MRO New Standard Review Forum (NSRF) has provided additional comments that PG&E wishes to support related to the DER definition. PGAE supports the recommendation that the definition should be removed from this modification and addressed in a separate project since it would impact many Standards currently being worked on or planned for in the future. With seven (7) different DER definitions currently being provided from such sources as the NERC SPIDERWG, NARUC, IEEE, and the California PUC, the Project 2022-02 effort will cause further confusion for the industry.

For this reason, PG&E will be voting Negative for this proposed modification.

Likes 0	
Dislikes 0	

Response

Srikanth Chennupati - Entergy - Entergy Services, Inc. - 1,3,5,7 - SERC

Answer	
Document Name	2022-02_Unofficial Comment Form_May2023.docx

Comment	
1. Will there be an aggregate DER threshold (either nameplate or net injection to the grid) above which the DP should submit modeling data to the TP and PC for inclusion in transmission planning models? MOD-025, MOD-026, and MOD-027 standards are being revised to limit applicability to resources included in either I2 or I4 of the BES definition (individual units > 20 MVA or an aggregate plant > 75 MVA). Should thresholds for MOD-032 DER modeling be consistent with the other NERC modeling standard applicability thresholds? 2. Will the NERC BES Reference document be revised to include DER generation (individual units and/or DER aggregations)? 3. Are these DER data reporting requirements limited to merchant DER installations in the future only? ○ It will be challenging to obtain steady-state and dynamic data for each individual installation that has taken place over the years in the past, especially for non-merchant applications (such as residential roof-top solar resources). Hoe are DPs expected to obtain this data and who will bear the cost associated with this process? ○ How will DPs be able to obtain and verify the in-service dates of each individual distribution connected resource that has occurred in the past? ○ Most of the residential and other non-merchant solar and battery installations fall below the installed capacity threshold at which such resources are required to go through the distribution interconnection detailed study process. How are DPs expected to collect steady-state and dynamic data on such resources, even if occurring in the future?	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behald of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Patricia Robertson - Patricia Robertson On Behalf of: Adrian Andreoiu, BC Hydro and Power Authority, 5, 3, 1; - Patricia Robertson, Group Name BC Hydro Balloters	
Answer	
Document Name	
Comment	
General comments on MOD-032-2:	

a. In Section 4. Applicability, under 4.1.4, BC Hydro recommends that the wording “Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)”, be changed to “Planning Coordinator”. Retaining the current wording may create confusion or result in misinterpretation, especially for those utilities that treat PA standards and PC standards differently. A PC-only approach has been used in other recently approved NERC standards and those that are being developed, such as FAC-002-4, MOD-033-2, and MOD-026-2.

b. BC Hydro recommends that in Attachment 1, the language used in the DER steady-state data section (Item 9) be generalized to account for distribution-connected hydroelectric generators. A suggested wording is provided below for consideration:

“…c. Reactive power capability (minimum and maximum)

d. Fuel type (solar, wind, hydraulic, battery, etc.)

e. Generator type (synchronous, inverter-based resource, etc.)

f. In-service date or other …”

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	
Document Name	

Comment

WECC believes there is value in including these Distributed Sources in system modeling, but is concerned that the proposed defintion may not satisfy that need.

The definition of DER does not seem adequate. First, it includes non BES generation type resources that are beyond BES dispersed generation identified under inclusion I4 of the BES Definition. And thus, appears to go beyond the scope of mandatory standards applicability. A second issue is that because the definition has the qualifier “…connected to the Distribution Provider’s system…” it would leave out any “DER” that did not have a registered Distribution Provider including any connected via some pathway directly to a Transmission System.

WECC believes that a focused effort on defining DER and addressing it within the BES Definition or in the NERC Glossary to be used consistently in all standards.

Likes 0	
Dislikes 0	

Response

Adrian Raducea - DTE Energy - Detroit Edison Company - 5, Group Name DTE Energy - DTE Electric

Answer	
Document Name	

Comment	
Per the Federal Power Act, NERC's jurisdiction is to establish and enforce Reliability Standards for the Bulk Power System. A NERC document, Understanding the Grid, published in March 2023, indicates that the generation and transmission components and their associated control systems make up the BPS, so requiring DP's to provide DER data that is connected to the Distribution system is outside of NERC's jurisdiction, unless the DER is connected to the transmission system such as non-BES generation. Furthermore, the NERC Glossary of Terms definition for Bulk Power System explicitly states that is does not include facilities used in the local distribution of electric energy, which aligns to the definition for bulk-power system in the Federal Power Act Section 215(a), definitions. DER on a DP's network is not that clear in the Technical Reference document. Please provide some examples similar to the BES reference document of what would not be in-scope DER and what would be in-scope DER on a DP's network. What happens if we are unable to obtain modeling data from OEMs for older DER inverters? What if we do not have the information to determine the collector system impedance values? What happens if residential, retail or commercial owners do not want to support this effort? What happens if an IBR OEM has gone out of business?	
Likes 1	Mearns James On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5;
Dislikes 0	
Response	

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	
Comment	
BPA believes that this definition would require adjustment of the BES inclusions and exclusions lists. For example, currently resources below 75 MVA are not required to submit the data that will be required of DER. This will result in entities not providing data for anything less than 75 MVA and citing exclusion (or lack of inclusion), even though the intent appears to require data submission from much smaller resources. BPA suggests excluding legacy equipment such as hydro, or perhaps the definition should only apply to inverter based resources (IBR.) It is also important to note that small generator owners are likely not financially able to test equipment (per MOD-025/026/027) in order to provide modeling data. This could result in shutting down such generators and associated loads costing local jobs in affected areas. BPA requests clarification and consistency regarding the use of Bulk Power System and Bulk Electric System. Both terms are being used.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	

FE supports EEI's comments which state:

EEI supports SDT efforts to address DER impacts, however, the modifications to MOD-032-2 is inappropriately running ahead of NERC IBR organizational registration efforts. Presently, TOs and DPs have no ability to compel DER owners to supply the data identified in the proposed Reliability Standard and until these issues are settled through changes to DER registration, efforts to gather DER data beyond those resources DPs own will likely yield little useful data. Additionally, subjecting DPs and TOs to the compliance obligations through MOD-032-2, before the registration issues have been solved, represent untenable regulatory obligations they cannot fulfil. To address this concern, we ask that all efforts by the Project 2022-02 SDT to compel TOs and DPs to supply DER data, beyond the resources they own and operation, be removed.

We also do not support the development of a DER definition within this NERC Reliability Standards project. The impact of this definition will have far reaching impacts that go beyond this project. To address this issue, we suggest that a separate NERC Reliability Standards project be developed to address this definition.

EEI is additionally concerned that the number of separate DER projects currently under development and otherwise being considered is growing very quickly and it is unclear if there is adequate coordination between all of these projects. While addressing these issues is important, speed should not take precedent over ensuring these efforts are adequately coordinated and Requirements are not being duplicated or conflict.

In addition to the above concerns, we offer the following comments and concerns for consideration:

Applicability Section

There is insufficient clarity related to the extent of DER resources that must be reported under MOD-032. To address this concern, a Facilities section should be added to this Reliability Standard.

Attachment 1

General comment: As stated in EEI's response to Question 1, we support the replacement of LSEs with DP, however, Attachment 1 goes beyond the replacement of LSEs with DP and includes TOs as an additional replacement where there are no registered DPs. This change should be stricken from the proposed draft of MOD-032-2. Registration problems cannot be solved through compliance obligations placed on registered entities who do not participate in the approval of DER interconnections or have any ability to compel the sharing of DER data contained on networks outside their purview.

Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5

EEI does not support the addition of "TO (when a Demand is not associated with a registered DP)" to Steady-State Column - Item 2 (Aggregate Demand) & Dynamic Column – Item 5 (Demand) because TOs have no part in interconnections on Distribution Provider systems and would therefore only have this data if it were supplied to them by the responsible DP. Furthermore, it is impractical to expect that TOs could compel unregistered DPs to supply this data. We further note that even registered DPs only have detailed data on DERs they own. Compelling DPs to similarly supply data beyond those resources they own should be removed. For these reasons, changes to MOD-032-2 should be placed on hold until registration issues surrounding DER owners can be resolved through the NERC organizational registration reforms that are intended to address IBRs that impact the BPS.

Footnote 2 – Additional clarity is needed regarding the intent of Footnote 2. Footnote 2 appears to require DPs (or TOs) to supply Aggregate Demand data that has been manipulated to exclude all DER offsets. While this would be desirable, most small DERs are not metered except through billing meters. Billing meters are not synchronized with SCADA data, diminishing the value of any data supplied by the reporting entities. Additionally, the work hours required to account for these DER offsets could be substantial, adding excessive costs while providing questionable value or improved reliability through this change. As an alternative, EEI suggests that DPs might be able provide estimated DER offset values to address the immediate needs of planners in the development of their planning models, but even this should be studied to ensure such efforts are even possible or practical to implement.

Steady-state Column (Item 9) and Dynamic Column 10

See EEI comments for Items 2 and 5 above.

Footnote 4: EEI is concerned that footnote 4 does not align with the SAR. In the SAR, data requests for DERs appear to be limited to aggregated DER data, however, in footnote 4 it states “TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary”. This appears to go beyond the approved limits of this SAR and should therefore be removed.

Likes 0	
Dislikes 0	

Response

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6

Answer	
Document Name	

Comment

Comments to be supplied separately by AECC's Ayslynn McAvoy.

Likes 0	
Dislikes 0	

Response

Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group

Answer	
Document Name	

Comment

Project 2022-02 is more than the replacement of these registration identifiers as it also includes DER modeling data additions. The question above does not fully encompass the changes proposed for MOD-032-02. However, the changes for adding DER modeling data does seem appropriate and reflects the NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning.

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	

· Can 4.1.4 be simplified to just Planning Coordinator?

· Note 10 under dynamics in Attachment-1 assumes a specific model for each DER will be provided. Note 9 under steady state (and footnote 4) assume that DER could be aggregated. The dynamics model may also need to be aggregated and there should be a footnote regarding coordination of model parameters. The Resource Planner may need to be involved in the coordination for dynamic models in Years 1-10.

· Regarding the DER definition provided under the section "New or Modified Terms Used in NERC Reliability Standards ", did the SDT consider the definition provided in IEEE Std 1547-2018, especially Note-1(exclusion of Controllable loads used for demand response) and Note-2 (supplemental DER devices)?

Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	

AECI supports comments sumbtted by Tacoma Power.

Likes 0	
Dislikes 0	
Response	

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	

No Additional Comments

Likes 0	

Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Ozan Ferrin, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	
Document Name	
Comment	

Tacoma Power has multiple concerns with the proposed DER definition and adding this scope to the MOD-032 Standard, as outlined in the next few bullets.

Scope Expansion and non-NERC Registered Entities

The proposed changes to include DERs in MOD-032 is expanding the scope of the Standard to include equipment not currently covered in the BES definition. The concept that non-BES or distribution equipment could impact the reliability and operation of the BES is not new to NERC Standards. For example, there is precedent in the PRC Standards to consider distribution equipment that supports UVLS programs or Protection System schemes. However, the proposed changes in this posting for MOD-032 are not sufficient on their own to ensure the expansion of scope will be effective.

The Technical Rationale states "the modifications place a compliance obligation on NERC registered DPs (or TOs) to provide basic information about DER that are connected to their systems so that DER can be properly represented in interconnection-wide cases." However, there are large distribution utilities that are not registered as DPs, but have aggregate DERs that should be accounted for under the proposed MOD-032 Attachment 1 scope. To ensure the appropriate entities are held responsible, either the (1) BES definition needs to change to include DERs, (2) a new "DP-DER" registration needs to be created, or (3) the DP registration criteria needs to change to ensure the appropriate entities are held responsible. Of these three options, Tacoma Power recommends revising the DP criteria in ROP Appendix 5B, Section III, to include a new criterion to ensure distribution utilities that must provide data to support MOD-032, Attachment 1, are subject to NERC jurisdiction. This approach aligns with the regulatory precedent set for UVLS programs, RAS schemes, and Protection System components under PRC-005 and PRC-006. Without a seperate effort to revise the DP registration, Tacoma Power cannot approve the draft MOD-032. The draft Standard cannot be fulfilled without these entities being held responsible for the data.

Below is an example mark-up of ROP Appendix 5B, Section III for NERC to consider in the ROP revision:

III.a.1 Distribution Provider system serving >75 MW of peak Load that is directly connected to the BES; or

III.a.2 Distribution Provider is the responsible entity that owns, controls, or operates Facilities that are part of any of the following Protection Systems or programs designed, installed, and operated for the protection of the BES:

- *a required Undervoltage Load Shedding (UVLS) program and/or*
- *a required Special Protection System or Remedial Action Scheme and/or*
- *a required transmission Protection System; or*

III.a.3 Distribution Provider that is responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs) pursuant to an executed agreement; or

III.a.4 Distribution Provider with field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks; or

III.a.5 Distribution Provider is the responsible entity that serves, controls, owns, or operates Distributed Energy Resources (DERs) exceeding 0.01 MW.

DER Definition

Tacoma Power supports the essence of the DER definition, but is concerned that it is unclear whether the proposed definition includes devices that have transient export of real power such as closed transition transfer switches, regenerative elevators/cranes, and industrial motors with regenerative braking. The proposed definition should be clarified to exclude these devices, while still including devices installed for energy storage such as batteries, flywheels, and Synchronous condensers. Tacoma Power suggests adding “for at least 30 seconds” to the definition so that the definition reads “*... providing active power for at least 30 seconds in non-isolated parallel operation...* ”

The IEEE definition of DER includes both the energy resource plus any necessary supplemental equipment. Tacoma Power would like to see similar guidance within the NERC DER definition. This ensures that reactive power control devices such as capacitor and STATCOMS are correctly included in the DER model submittals.

Implementation Plan

Tacoma Power does not agree with the proposed implementation plan for the DER definition. This definition will eventually be used in several future NERC Standard revisions. Some of these revisions may have a shorter implementation timeframe than Project 2022-02. The effective date of the DER definition needs to be coordinated with the other planned Standard revisions to ensure the timing supports implementation of these other Standard revisions.

Coordination with Other Standard Changes

Tacoma Power is concerned about how the DER definition will be used for other future NERC Standard changes, as outlined in the October 2022 “NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) White Paper.” The proposal's impact on other Standards must be clear prior to putting the DER definition in place to avoid unintended consequences. For example, excluding various types of demand response from the DER definition may not be appropriate for PRC-006 and TPL-001. These two Standards may need to consider demand response for proper modeling of the BES. If NERC intends to add DERs to EMT Modeling Requirements in MOD-026, then this would be a significant cost and pose technical challenges for registered entities, which could impact the DER definition scope.

When reviewing the DER definition in this posting, entities need to understand how this definition will be used in other future Standard changes. Tacoma Power recommends one of the two following options to ensure impacts to other future Standard changes are considered in the definition development:

1. Provide a list of other Standards that will be impacted by this definition change in the “New or Modified Term(s) Used in NERC Reliability Standards” section of the MOD-032 redline, similar to the approach taken by Project 2019-04, Modifications to PRC-005, or
2. Create a standalone Standards Project that addresses the DER definition development for all future Standard changes.

Likes 1	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia
Dislikes 0	

Response

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4

Answer	
Document Name	

Comment

Alliant Energy supports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	
Document Name	
Comment	

SMEs responded "MOD-032-1 provides language for the Planning Coordinators (PC) and their Transmission Planner(s) (TP) to request any, and all, modeling data pertaining to the development of steady-state, short circuit, and dynamics models. The language in MOD-032-1 currently allows the PCs and TPs to request DER data from TOs, GOs, and LSEs (Distribution Providers). Therefore, any language specific to the addition of DERs to MOD-032-1 would be redundant."

Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	

EEI Draft Comments should be included or referenced:

{C}·   {C}To better clarify the extent of DER resources that must be reported under MOD-032, EEI suggests that a Facilities section be added to this Reliability Standard.

{C}·   {C}Footnote 2 – EEI asks that the SDT provide additional clarity regarding the intent of Footnote 2. Footnote 2 appears to require DPs (or TOs) to supply Aggregate Demand data that has been manipulated to exclude all DER offsets. While we understand why this would be desirable, most small DERs are not metered except for billing meters. Billing meters are not synchronized with SCADA data, diminishing the value of any data supplied by the reporting entities. We are further concerned that the manhours required to account for these DER offsets could be substantial adding excessive costs while providing questionable value to this change. As an alternative, EEI suggests that DPs and TOs could provide estimated DER offset values, which would require fewer manhours to develop and should provide sufficient value to the planning models.

{C}·   {C}Steady-state and Dynamic columns

EEI is concerned that the data requests identified in Item 9 (Steady-state), and Item 10 (Dynamic) seek non-aggregated data, while the SAR specifies that aggregated DER data is to be supplied.   To address this concern, we ask that both Items 9 and 10 be edited to make it clear that data requests to DPs and TOs are to be limited to aggregate DER data.

Footnote 4: EEI is concerned that footnote 4 does not align with the SAR. In the SAR, data requests for DERs appear to be limited to aggregated DER data, however, in footnote 4 it states "TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary". This appears to go beyond the approved limits of this SAR and should therefore be removed.

Likes 0	
Dislikes 0	

Response

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	2022-02 Tables.PNG

Comment

- The NSRF recommends the SDT remove the DER definition from the proposed MOD-032-2 standard.
- The NSRF recommends NERC create a standalone Standards Project that addresses the DER definition development for all future Standard changes. As part of this project, the NSRF recommends revising the DP criteria in the Rules Of Procedure (ROP), Appendix 5B, Section III.
- NERC needs a way to register a DER or "DER aggregator" type entity, to ensure the appropriate entities are held responsible for NERC Reliability Standards.

Further:

The proposed changes to include DERs in MOD-032 is expanding the scope of the Standard to include equipment not currently covered in the BES definition. The concept that non-BES or distribution equipment could impact the reliability and operation of the BES is not new to NERC Standards. For example, there is precedent in the PRC Standards to consider distribution equipment that supports UVLS programs or Protection System schemes. However, the proposed changes in this posting for MOD-032 are not sufficient to ensure the expansion of scope will be effective.

Currently there are seven definitions for DER. The SDT chose to create a new definition of DER separate from those.

The proposed definition:

Term(s): Distributed Energy Resource (DER) Generators and energy storage technologies connected to the Distribution Provider's system that are capable of providing active power in non-isolated parallel operation with the Bulk Electric System.

The SPIDERWG Terms and definitions document has six definitions for DER. The draft MOD-032-2 definition is different than the definitions contained in the document. See Table D.1: Alternate Definitions for DER-Related Concepts.

Link to SPIDERWG Terms and definitions document

Link to DER reference document – contains DER definition.

Distributed Energy Resources Connection Modeling and Reliability Considerations February 2017

The NERC Distributed Energy Task Force (ERTF) DER definition:

“Any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES).”

The NSRF is concerned about how the DER definition will be used for other future NERC Standard changes, as outlined in the October 2022 “NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) White Paper.” The proposal's impact on other Standards must be clear prior to putting the DER definition in place to avoid unintended consequences.

For example, excluding various types of demand response from the DER definition may not be appropriate for PRC-006 and TPL-001. These two Standards may need to consider demand response for proper modeling of the BES. If NERC intends to add DERs to EMT Modeling Requirements in MOD-026, then this would be a significant cost and pose technical challenges for registered entities, which could impact the DER definition scope.

The Technical Rationale states “the modifications place a compliance obligation on NERC registered DPs (or TOs) to provide basic information about DER that are connected to their systems so that DER can be properly represented in interconnection-wide cases.” However, there are large distribution utilities that are not registered as DPs, but have aggregate DERs that should be accounted for under the proposed MOD-032 Attachment 1 scope. To ensure the appropriate entities are held responsible, either the:

1. BES definition needs to change to include DERs,

2. a new “DP-DER” registration needs to be created, or

3. the DP registration criteria needs to change to ensure the appropriate entities are held responsible.

From the SPIDERWG Terms and Definitions Working Document:

-See Attachment

Likes 1	Wike Jennie On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merre
Dislikes 0	

Response

Joseph OBrien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	
Document Name	
Comment	
NIPSCO agrees with the comments of the Edison Electric Institute (EEI) regarding the proposed TPL-001-5 Footnote 13d revision.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP appreciates the efforts of the standards drafting team and sees the value of the proposed revisions to Attachment One. Even so, AEP would be unable to vote affirmative on this revised standard unless and until every entity providing DER data is a registered Functional Entity who is formally obligated to provide it. As is the case in existing standards where Generator Owners are obligated to provide similar data, entities who possess the needed DER data noted in the Attachment One revisions should likewise be registered and explicitly obligated to provide this data as well. While we are unsure if the existing Functional Entities classes are themselves sufficient, or if instead, a new class of Functional Entities might need to be considered and developed, the need nonetheless exists. NERC may wish to also consider the potential that such obligations could potentially cross Federal and State jurisdictional lines of responsibility, further illustrating the complexity-of and challenges-in developing obligations to obtain the DER data in the revised Attachment One. In addition, while the SDT has not provided a question regarding the proposed Implementation Plan, AEP believes additional time will be needed to accommodate the work pertaining to assets newly brought into scope. Rather than being required to comply with the obligations 12 months after the definition has become effective, we instead suggest it be 24 months after the definition has become effective.	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Ben Hammer On Behalf of: Sean Erickson, Western Area Power Administration, 1, 6; - Ben Hammer	
Answer	
Document Name	
Comment	

The Project 2022-02 SDT should review and coordinate with ERO efforts separately filed with FERC in the NERC proposed work plan to register GO-IBRs. Recognizing the current and expected state of DER and inverter-based resources in North America demands that any revisions proposed to the MOD-032-2 Reliability Standard respect functional registrations and corresponding cognizance of modeling data.

Likes 0	
Dislikes 0	

Response