Individual or group. (45 Responses)
Name (28 Responses)
Organization (28 Responses)
Group Name (17 Responses)
Lead Contact (17 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (6 Responses)
Comments (45 Responses)
Question 1 (33 Responses)
Question 1 Comments (39 Responses)
Question 2 (34 Responses)
Question 2 Comments (39 Responses)
Question 3 (0 Responses)
Question 3 Comments (39 Responses)

Individual
Thomas Foltz
American Electric Power
No
No
Though R1 provides a prescribed list of “minimum requirements” for the data reporting request, there is no specified limit on the detail or extent of the request. As a result, R1 is extremely open-ended and makes it possible that the data request could not be provided by the timetable specified. In addition, the VSL associated with not meeting the expectations of such a data request is Severe. We disagree with the open-endedness of R1, as well as its sole VSL of Severe. R1 is overly prescriptive and places indirect requirements upon the applicable entity that could be easily established by the Planning Coordinator. R 1.1 – It should be made clear that the list of Functional Entities provided is provided solely as examples, and is not a requirement that all must be included in the data request. There may be circumstances where RE and Planning Coordinator boundaries do not properly align with the manner in which the requirements are written.
Group
Northeast Power Coordinating Council
Guy Zito
Yes
The SAR should not be posted with the Standard. The intent of posting a SAR for comment is to

seek industry’s input on the need and scope of a proposed standard’s development or revision. Posting the Standard for comments and ballot means that the SAR is “water under the bridge”, and that industry’s input on the SAR doesn’t mean anything.
Yes
We agree with the approach of combining the standards into one. Specific comments follow. The Implementation Plan Effective Dates section should be modified to indicate that “MOD-001-2 and the modified DMS definitions shall become effective as follows:” The definition of Demand Side Management is vague. It is not clear whether this definition includes conservation and demand management programs. Traditionally, conservation programs have permanence and longevity while demand management have temporary impacts. Conservation would include energy efficiency or building envelope improvements whereas demand management would lead to temporary load reductions or load shifting through price signals, contracts or direct load control. Clarify in the standard. R1 appears to make the PC and BA responsible to develop and issue a data reporting request on the RE formulating such a request. Suggest deleting “as identified by the Regional Entity in a data request” and replace the wording with: And provide to the Regional Entity upon request. Subrequirements 1.4 through 1.7 should be combined into a separate requirement starting with: Each Planning Coordinator or Balancing Authority shall make a request for actual data that shall include, but not be limited to: Regarding part 1.5.3, it asks for forecasts of Interruptible Load and Direct Control Load Management for summer and winter peak conditions. Does this intend to capture the effective seasonal capacity as opposed to the total capacity for each season? This part needs clarification as to what exactly the PC or BA needs to specify in the data reporting request and what exactly the Applicable Entities need to provide. Regarding part 1.7, the peak referenced here should be annual peak. There aren’t any VSLs for non-compliance with parts 1.4.3 and 1.4.4. Regarding R2, there is a data confidentiality issue if the Applicable Entities are to provide demand forecast data to entities that engage in market activities, such as a LSE. Suggest to qualify R2 by appending “subject to confidentiality requirements” after “on request”. The proposed effective date may conflict with Ontario regulatory practice with respect to the effective date of the Standard. Note that there is an approval requirement in Ontario for NERC Reliability Standards. The wording presented in the Effective Dates Section does not reflect this. It is suggested that this conflict be removed by moving the wording: “…or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities” to immediately after “applicable regulatory approval” in the first sentence. In some cases the Standard is overly perscriptive. Variations on the data reporting request shown in the Standard can be used to produce an effective load forecast. To allow for these variations the following changes are recommended: R1. The Planning Coordinator or Balancing Authority, as identified by the Regional Entity in a data request, shall develop and issue a data reporting request associated with a data request issued by the Regional Entity. This data reporting request shall include consider, at a minimum: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.4.3. Monthly or seasonal and annual peak hour weather normalized actual demands in MW for the prior year. For part 1.4.4, it is of note that Load Management can be dispatched for several reasons including audit, economic and reliability. To clarify the

following modification is recommended. 1.4.4. Monthly and annual peak hour deployed Interruptible Load and Direct Control Load Management in MW along with reason for deployment for the prior year.
Individual
Kathleen Goodman
ISO New England, Inc
No
Yes
Yes, we agree with the approach of combining the standards into one. However we have several specific comments on changes as listed below.
In some cases the standard is overly perscriptive. Variations on the data reporting request shown in the standard can be used to produce an effective load forecast. To allow for these variations the following changes are recommended: R1. The Planning Coordinator or Balancing Authority, as identified by the Regional Entity in a data request, shall develop and issue a data reporting request associated with a data request issued by the Regional Entity. This data reporting request shall include consider, at a minimum: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 1.4.3. Monthly or seasonal and annual peak hour weather normalized actual demands in MW for the prior year. For requirement R1.4.4, it is of note that Load Management can be dispatched for several reasons including audit, economic and reliability. To clarify the following modification is recommended. 1.4.4. Monthly and annual peak hour deployed Interruptible Load and Direct Control Load Management in MW along with reason for deployment for the prior year.
Individual
Jonathan appelbaum
The United Illuminating Company
No
Yes
This Standard has the Regional Entity initiating the process. 1. The data being requested is not supporting the reliability of the Bulk Electric System because it is not supporting the modeling and planning done by the Planning Coordinators or Transmision Planners. If the data was supporting PC and Planners then those registered entities would initiate the process and utilize the data. 2. The Regional Entity is not in the functional model and should not be assigned a role in a reliability standard. 3. A VRF of Medium is not supported. It should be Low. First, the background discussion on the standard indicates this is a data request and administrative, and second the request is from the Regional Entity which has no role in reliability or running studies

so there can be no adverse impact of reporting bad data.
Individual
Nazra Gladu
Manitoba Hydro
No
Yes
(1) SAR, Brief Description - replace “BPS” with “Bulk Power System (BPS)” since this is the first instance of this term in the document. (2) Purpose - de-capitalize the word “Demand” as it does not appear in the NERC Glossary. Moreover, for clarity, replace the sentence “for assessment and validation of past events” with “to assess and validate past events”. (3) Background - capitalize “demand-side management”, as it appears in the NERC Glossary. (4) R1.7.2 - replace the words “Direct Control Load Management” with their acronym “DCLM”. (5) General Comment - replace “Board of Trustees” with “Board of Trustees’” throughout the applicable documents/standards for consistency with other standards. (6) R1.4, footnote 1 - it is unclear if the requirements will result in additional data request(s) (i.e. in addition to the seasonal and long term reliability assessments and the integrated hourly load request). What is the intent of the SDT?
Individual
John Seelke
Public Service Enterprise Group
Yes
We recommend that the team consider withdrawing the SAR replacing this standard with a Section 1600 data request from each Regional Entity (or collectively by all Regions) where the reasonableness of the requested data and the timing of submitting data will be addressed via stakeholder comments. In their report dated June 2013, the Independent Standards Review Panel, in Appendix E, p. 27, recommended “Retire MODs 16-19 and 21 and gather whatever data NERC needs for assessments and reports through Section 804 of NERC Rules of Procedure.” We prefer a Section 1600 data request instead because it permits stakeholder comments to be considered. However, we believe the issue of which form a data request can be the subject of stakeholder discussion, but the standard should not continue. In any case, we do not believe a standard is necessary for the MOD C standards. Regarding a data request, the team should note that data requests are limited to Registered Entities. The proposed definition for DSM as “The term for all activities or programs undertaken by any applicable entity to influence the amount or timing of electricity they use” is OK, but the team should recognize that much DSM is provided by aggregators who are NOT Registered Entities. Until those entities are registered, the collection of DSM data will be largely incomplete. (This comment applies even if a standard is developed instead of a data request.)

No
We prefer a data request rather than a SAR.
Individual
Jack Stamper
Clark Public Utilities
No
Yes
R2 currently states “Each Applicable Entity shall provide the data in accordance with the data reporting request in Requirement R1 to the Planning Coordinator or Balancing Authority or any other entity (such as Load Serving Entity, Planning Coordinator or Resource Planner) on request.” Who exactly are these “other entities” and why are the Applicable Entities supposed to provide them this information. Also the "on request" makes it sound like an entity is expecting a request from the PC or the BA but it obviously has a request since it is responding to the request. This “other entity” is way to open ended on who it might be and I do not want to be providing my utility’s historical and forecast load to just any entity that requests it. Why would they need this. If I have provided it to my PC and BA why would other PCs or LSEs or RPs need this information. I do not see any reliability gain by even offering this data to anyone other than the requester (PC and BA). I believe R2 should just state “Each Applicable Entity shall provide the data in accordance with the data reporting request in Requirement R1 to the requesting Planning Coordinator or Balancing Authority.” There should be no requirement to provide this information to anyone other than the requesting PC or BA.
Individual
John Bee
Exelon and its' Affiliates
No
Yes
Exelon would recommend enhancing Section A. 4. Applicability, 4.1 Functional Entities, 4.1.5 Load-Serving Entity to read: 4.1.5 Load-Serving Entity listed as an Applicable Entity in R1.1 And 4.1.6 Distribution Provider listed as an Applicable Entity in R1.1
Group
Dominion
Louis Slade

No
Yes
Dominion suggests that R3 and M3 be reworded to clarify the intent. We believe the intent is to provide data within the timeframe provided by the requesting entity. If the SDT agrees that this is the intent, we suggest revising R3 to read " entity Planning Coordinator or Balancing Authority identified by the Regional Entity in its data request, shall report the Applicable Entity's data as requested by the Regional Entity within the timeframe specified in the Regional Entity's request." Requirement 1.7.3 uses the acronym "DSM" which is presumably Demand Side Management. Dominion suggests this be clarified by adding behind Demand Side Management (DSM):. Dominion suggests removing the phrase "or any other entity (such as Load Serving Entity, Planning Coordinator or Resource Planner)" from R2. We do not believe any entity other that the Planning Coordinator or Balancing Authority should be allowed to make such as request. If the Regional Entity or an adjacent Planning Coordinator or Balancing Authority desires this information, they should have to obtain it by requesting from the Planning Coordinator or Balancing Authority within whose area the demand resides. Dominion suggests that once the standard has received ballot approval, the text boxes be moved appropriately under the relevant requirement rather than being relocated at the end of the standard under the Application Guidelines Section of the Standard.
Individual
Scott Berry
Indiana Municipal Power Agency
Agree
Frank Gaffney, Florida Municipal Power Agency
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We question the need to ask this question when the consolidated standard is already posted for commenting and balloting. The intent of posting a SAR for comment is to seek industry's input on the need and scope of a proposed standard development/revision project. Posting the standard for balloting at the same time suggests that there is already a foregone conclusion on the need and the scope for this project , and that the industry's input on SAR would seem irrelevant. The IESO understands that posting a SAR and the draft standards for comment at the same time can improve standard development efficiency, and we support it to the extent that sufficient technical information has been obtained to facilitate the development of a draft standard at the informal outreach stage. However, we are very concerned about the fact that the industry was asked to ballot the draft standard when the need and scope of the draft

standard have not been commented on and supported by the industry, and the standard itself has not been drafted by a formal standard drafting team. Such an approach appears to: a. Deviates from the normal standards development process as presented in the Standards Process Manual (SPM); b. Contradicts and perhaps violates the intent of the established standard development process and ANSI principles to have new and revised standard formally developed through an open and inclusive process before being presented to the RBB for balloting. The industry is being asked to ballot a set of standards that has not been formally developed. This concept appears to be fundamentally flawed. We propose that the SDT convey our concern to the NERC senior management and the Standards Committee. We further suggest that NERC and the SC evaluate alternative approaches or make revisions to the SPM to provide the needed flexibility that can further improve the efficiency in standard development if certain elements in the existing SPM are assessed to restrict such improvements.
Yes
a. The definition of Demand Side Management is vague. It is not clear whether this definition includes conservation and demand management programs. Traditionally, conservation programs have permanence and longevity while demand management have temporary impacts. Conservation would include energy efficiency or building envelope improvements whereas demand management would lead to temporary load reductions or load shifting through price signals, contracts or direct load control. Is this term meant to include both? Please clarify in the standard. b. R.1, 1.5.3 asks for forecasts of Interruptible Load and Direct Control Load Management for summer and winter peak conditions. Does this intend to capture the effective seasonal capacity as opposed to the total capacity for each season? This part is unclear as to what exactly the PC or BA needs to specify in the data reporting request and what exactly the Applicable Entities need to provide. c. R.1, 1.7: The peak referenced here should be annual peak. d. R2: There is a data confidentiality issue if the Applicable Entities are to provide demand forecast data to entities that engage in market activities, such as an LSE. Suggest to qualify R2 by appending “subject to confidentiality requirements” after “on request”. e. There does not appear to be any VSLs for non-compliance with Parts 1.4.3 and 1.4.4. Please address the missing VSLs. f. The proposed effective date may conflict with Ontario regulatory practice with respect to the effective date of the standard. Note that there is an approval requirement in Ontario for NERC Reliability Standards. The wording presented in the Effective Dates Section does not reflect this. It is suggested that this conflict be removed by moving the wording: “,or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities” to immediately after “applicable regulatory approval” the first sentence. The same change also applies to Item (1) under the Effective Dates Section in the Implementation Plan.
Individual
Brett Holland
Kansas City Power & Light
Agree
Florida Municipal Power Agency
Group

Salt River Project
Bob Steiger
No
Yes
Yes, however we have major concerns with how R1 is worded. It is so complicated that it requires the "Rationale for R1" to understand. Simplify this.
The data requested in the MOD is largely redundant to existing reporting requirements within our region, WECC. Maybe this could be handled by a Regional Variance?
Individual
Don Schmit
Nebraska Public Power District
No
Yes
Requirement R 1.7.2 appears to have a typographical error and should have the word “Load” inserted after the word “Interruptible”, such that the requirement would read “The Demand and energy effects of Interruptible Load and Direct Control Load Management.” This correction would make the use of the term “Interruptible Load” consistent throughout the proposed standard. In the VSLs for R1 a PC or BA is required to develop a data reporting procedure yet the development of this procedure is not included in the requirement. We suggest replacing the phrase ‘…developed a data reporting procedure…’ with ‘…issued a data reporting request…’. Also in the High VSL for R1, insert ‘Part’ in front of 1.4.2. In the Severe VSL for R2, replace ‘developed’ with ‘issued’. In fact, we would suggest that the Severe VSLs for R2 be graduated across the spectrum of possible VSLs to make it consistent and parallel with R1.
Group
SERC Planning Standards Subcommittee
Jim Kelley
Yes
The SDT and NERC are requested to place a high priority on reviewing MOD-020-0.
Yes
R1.1 The SDT should look at adding Resource Planner to the applicable entities. The SDT is requested to review the other MOD standards to ensure that GOs are covered and required to submit data when requested. The comments expressed herein represent a consensus of the

views of the above named members of the SERC PSS only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Group
seattle city light
paul haase
Seattle City Light appreciates the efforts of the Standards Drafting Team to consolidate numerous data collection Standards into one more-consistent approach. If it were simply a consolidation, Seattle would support the draft. However, draft MOD-031-1 expands the data to be collected and the information required about the process. MOD-031-1 is most unclear about how NERC would benefit from collecting all this data, yet it comes at significant cost. Data collection creates significant reporting burden and labor requirements. The only justification provided is for evaluating what happened during significant events. This is a poor argument from a cost-effectiveness standpoint, because such significant events are infrequent. Instead, Seattle asks that the draft be revised to require submission of data from the affected parties after these infrequent events occur, rather than placing the unnecessary administrative burdens on everyone, regardless whether or not an event occurs. Some secific elements of draft MOD-031-1 that expand the reporting burden on entities include (i) Requirement 1.7.1. "The assumptions and methods used in the development of aggregated peak demand and Net Energy for Load forecasts." Seattle finds this requirement to be ill-defined, potentially open-ended, and could be quite onerous because of the great many assumptions and forecasts that are components to a system load forecast, even for a relatively small system and (ii) Requirement 1.7.4. "How the peak load forecast compares to actual load for the prior year with due regard to controllable load, temperature and humidity variations." Seattle finds this new requirement to be of limited value. As most load forecasters know, different utilities with different service areas have widely varying load characteristics and driving factors. The request seems to be largely aimed at providing NERC sufficient data to do their own service-area level load forecasts for the utilities. Even if NERC or a regional entity is armed with this uniform information request, it is unlikely to be of much use, because different economic growth assumptions are applied, as are differences in population growth, the nature of specific new loads, unique weather patterns, and much more. Seattle recommends that both new requirement be deleted.
No
In general Seattle supports the consolidation of prior data collection MOD standards, but does not support the expansion of the data collection requirements. See comments to Question 1, above.
Seattle is concerned about the redundancy between proposed MOD-031-1 and existing data collection process within our region, WECC. We find the WECC already requires most of the identified information from Seattle City Light for the purpose of its winter and summer (reliability) assessments. The currently-requested data by WECC includes: 1.4.1. Integrated hourly demands in megawatts (MW) for the prior year.] I believe we report this now, but am not certain, since I have not been part of that data collection. 1.4.2. Monthly and annual peak

hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year. 1.4.3. Monthly and annual peak hour weather normalized actual demands in MW for the prior year. 1.4.4. Monthly and annual peak hour deployed Interruptible Load and Direct Control Load Management in MW for the prior year. 1.5.1. Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years. 1.5.2. Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for ten years into the future. 1.5.3. Forecasts of Interruptible Load and Direct Control Load Management (DCLM) for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions. 1.6. A requirement for Applicable Entities to identify registered entities that are within their footprint but are not a member of the requesting Region, and identify the Region where the data for that registered entity is reported. 1.7. A requirement for Applicable Entities to provide: 1.7.2. The Demand and energy effects of Interruptible and Direct Control Load Management. 1.7.3. How DSM measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load. which represents all the substantive data required by MOD-031-1 with the exception of 1.7.1 and 1.7.4, both of which are new types of data not previously requested (and recommended to be deleted by Seattle). Finally, Seattle supports the comments of Florida Municipal Power Authority (FPMA) regarding separation of short-term load forecasting from long-term load forecasting, and its comments about the expected relative accuracies. Even the methodologies employed for these two types of forecasts are quite different.
Individual
Bret Galbraith
Seminole Electric Cooperative, Inc.
Agree
Florida Municipal Power Agency (FMPA)
Group
JEA
Thomas McElhinney
No
No
The requirements of this standard are all about data collection and should be eliminated in accordance with the paragraph 81 initiative.
Individual
Diane Barney
New York State Department of Public Service

It is premature to be voting at all for the standard at this point in the process. Two major pieces of information are missing. First, the SAR has not been adopted, so we do not know if the proposed standard conforms to an adopted SAR. Second, the proposed standard was drafted by a small team of subject matter experts and has not yet been subject to a NERC wide critical review. Therefore, we do not yet know if there is a fatal flaw in the standard for some system(s) across NERC not represented by the SMEs, or if there is an outstanding idea to improve the draft standard.
Individual
Oliver Burke
Entergy Services, Inc.
Agree
SERC Planning Standards Subcommittee
Individual
Silvia Parada Mitchell
NextEra Energy
No
MOD-031-1 is a data submittal requirement that satisfies the P81 Criteria A and B 1 (administrative), 2 (data collection), 3 (documentation) and 4 (reporting). In the P81 filing before FERC similar data requirements were deleted from other Standards, therefore, it is counterproductive and contradictory to the P81 efforts to advance MOD-031-1. If the SDT believes this data is importanr, it should be accomplished via a Section 1600 data request, as the Misoperations SDT determined for Misoperations data.
Group
Electric Power Supply Association
Jack Cashin
Yes
EPSA believes that simultaneous processing of the SAR and the standard, as was done in this instance puts them at cross-purpose with one another. This risks a situation where if a SAR needs changes, stakeholder comments on standard will be based on a defective SAR that needs work and becomes an inefficient use of stakeholder resources. The SAR scope for proposed MOD-031-1 has not considered all the aspects that can ensure that the Standard will reach a steady state. Since its issuance in June of 2013, NERC and Stakeholders have recognized that the “Standards Independent Experts Review Project” provides a global assessment of Standards including the “MOD C” standards inclusive of MOD-031-1. The Independent Experts recommend that requirements that are part of VAR-002-2 are duplicative and covered under

other standards or covered by tariff requirements. Additionally, the Comment form intones that because MOD-031-1 is a “pure data reporting standard” that it would be a candidate for retirement were it not for resource adequacy reliability purpose of the standard. EPSA believes that resource adequacy is not part of the ERO’s reliability jurisdiction and therefore should not be the reason for the scope of the SAR. To avoid duplication or conflating reliability and market issues the SAR scope would benefit from including the recommendations of the Independent Experts in the current VAR-002-2 project. This will avoid expending resources on the Independent Experts recommendations in the future.
No
Individual
Anthony Jablonski
ReliabilityFirst
Yes
ReliabilityFirst offers the following comment for consideration: 1. MOD C Whitepaper – ReliabilityFirst recommends highlighting all new requirements which are included within the draft standard (based on FERC Directives) in order to help entities understand that these are new requirements in which they will need to comply. Specifically, one FERC directive was to provide temperature and humidity data so actual data can be weather adjusted for comparison to the forecasts. While this data may be available from many entities, ReliabilityFirst does not believe every entity with a demand forecast has this information. ReliabilityFirst believes these types of new requirements should be more acknowledged or noticed to the industry.
No
ReliabilityFirst offers the following comment for consideration: 1. FERC Directive (order 693, paragraph 1298) not addressed – ReliabilityFirst does not believe the FERC Directive on standardizing principles for reporting and validation of DSM information (order 693 paragraph 1298) has been addressed. The FERC directive asks for standardization of DSM reporting and program verification “… and direct the ERO to modify MOD-021-0 by adding a requirement for standardization of principles on reporting and validating DSM program information”. The response in the MOD C Whitepaper talks about requiring an explanation “...of how DSM is forecasted and adjusted for errors (Requirement R1 part 1.7.3)” Explaining forecast methods and adjustments is not the same as standardizing reporting and verification requirements. ReliabilityFirst believes the SDT should revisit this requirement and ensure it is addressing the intent of the FERC Directive associated with Order 693 paragraph 1298.
ReliabilityFirst offers the following comments for consideration: 1. Requirement R1, Parts 1.3 through 1.5 – ReliabilityFirst believes the standard should be less prescriptive regarding which data elements should be reported in the data request (i.e., the Planning Coordinator or Balancing Authority should determine what data they need and place it within the request). Specific information is already spelled out in the LTRA data request from NERC. The NERC data

request collects demand data (and other data) for assessments and to provide a response to DOE for the EIA-411. Since NERC lists the specific data items in its data request, by not being specific or prescriptive in the standard, NERC can change or modify the requested data as needed to satisfy DOE reporting (EIA-411) or to accommodate any future assessment needs. 2. Requirement R1, Part 1.6 – ReliabilityFirst believes there is no reliability benefit to including Requirement R1, Part 1.6 in the standard. ReliabilityFirst believes this is already done via the NERC RAS assessment process and is administratively over burdensome. Furthermore, if the SDT believes it is a necessary sub-part, ReliabilityFirst notes that Requirement R1, Part 1.6 was included to cover requirement 1.1 from MOD-018-0 in the original standard. ReliabilityFirst does not believe the wording in Requirement R1, Part 1.6 has the same intent as the original standard. ReliabilityFirst offers the following for consideration: "A requirement for Applicable Entities to identify non-registered entities within their footprint if the non-registered entity demand data is included in the submitted data.
Group
ISO/RTO Standards Review Committee
Greg Campoli
Specific comments: The definition of Demand Side Management is vague. It is not clear whether this definition includes conservation and demand management programs. Traditionally, conservation programs have permanence and longevity while demand management have temporary impacts. Conservation would include energy efficiency or building envelope improvements whereas demand management would lead to temporary load reductions or load shifting through price signals, contracts or direct load control. Is this term meant to include both? Please clarify in the standard. MOD-031-1, R1.5.3 asks for forecasts of Interruptible Load and Direct Control Load Management for summer and winter peak conditions. Does this intend to capture the effective seasonal capacity as opposed to the total capacity for each season? This part is unclear as to what exactly the PC or BA needs to specify in the data reporting request and what exactly the Applicable Entities need to provide. MOD-031-1 R1.7. requires: " A requirement for Applicable Entities to provide: 1.7.1. The assumptions and methods used in the development of aggregated peak demand and Net Energy for Load forecasts. 1.7.2. The Demand and energy effects of Interruptible and Direct Control Load Management. 1.7.3. How DSM measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load. 1.7.4. How the peak load forecast compares to actual load for the prior year with due regard to controllable load2, temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted. 1.7.1 seems to be a fill-in-the-blank requirement 1.7.2 is usually a guess as opposed to a fact. The quantitative effects of any one thing are dependent on other assumptions. To say "DR did X", requires the assessor to assume the load and generation quantities (did consumer load go down, did generation go up, did DR make up the difference, is the frequency the same??????) 1.7.3 seems to be a fill-in-the-blank requirement 1.7.4 seems questionable for large systems.

What is a large area's temperature and Humidity at any one time? How will "future" adjustments be made? Does that mean if the entity guesses that it will adjust the load forecast in one way, but next year it does not use that assumption, is the entity in violation? R2: There is a data confidentiality issue if the Applicable Entities are to provide demand forecast data to entities that engage in market activities, such as an LSE. Suggest to qualify R2 by appending "subject to confidentiality requirements" after "on request". There does not appear to be any VSLs for non-compliance with Parts 1.4.3 and 1.4.4. Please address the missing VSLs.
Group
SPP Standards Review Group
Robert Rhodes
No
Yes
We would like to thank the ad hoc team for their efforts in developing a proposal for consolidating several of the MOD standards into a more concise package. The definition of Demand-Side Management is to be changed per the draft standard. While we don't have any issues with the proposed changes, the spelling of the term should be consistent. Is the hyphen between Demand and Side supposed to be there or not? In Section 5. Background, the Bulk Power System is referenced. The reference should be to the Bulk Electric System. Also, at the top of page 2 Demand-Side Management needs to be capitalized. These items also need to be addressed in the whitepaper. In the VSLs for R1 a PC or BA is required to develop a data reporting procedure yet the development of this procedure is not included in the requirement. We suggest replacing the phrase '…developed a data reporting procedure…' with '…issued a data reporting request…'. Also in the High VSL for R1, insert 'Part' in front of 1.4.2. In the Severe VSL for R2, replace 'developed' with 'issued'. In fact, we would suggest that the Severe VSLs for R2 be graduated across the spectrum of possible VSLs to make it consistent and parallel with R1. "Load' is omitted in R1.7.2. It should be inserted following Interruptible in the requirement.
Group
PacifiCorp
Kelly Cumiskey
No
No
The term Demand Side Management has been defined as, "All activites or programs undertaken by any applicable entity to influence the amount or timing of electricity they use."

PacifiCorp believes this definition is ambiguous and lacks criteria for measuring. Moreover, by implementing this broad based definition for demand side management, PacifiCorp is concerned that it will lead to varied interpretation and a lack of uniformity across utilities. R 1.4.4 and R 1.7.2: It’s unclear how these two requirements differ except for 1.7.2 requesting the energy impacts. In addition, given that interruptible and direct load control is typically exercised only a few hours annually and in some cases the energy is taken back at a different hour following a curtailment event, it is unclear why this information would be meaningful in load forecasting. PacifiCorp believes that requesting the energy effects without a clear methodology for creating the energy estimates will lead to varied interpretation and a lack of uniformity across utilities. R 1.7.4: PacifiCorp does not agree with the requirement to compare actual loads for the prior year and how the “assumptions and methods for future forecasts were adjusted.” The requirement is vague, does not define what expectations are associated with the assumptions (or methods that may change), and will provide no additional clarity to the forecast beyond the explicit change associated with simply adding the additional year of actual values into the calculation. As such, PacifiCorp suggests it be removed from the requirement.
Group
Bonneville Power Administration
Jamison Dye
No
Yes
BPA believes that these requirements gather the data from the previous MODs which are critical to effective planning. They appear to be streamlined and ask for the critical information. BPA also believes there are some differences that are not as effective and recommends that the Drafting Team revise MOD-031 in the following areas to resolve these concerns: 1) MOD-031 R1 Indicates that these activities should be completed after receiving a data request from the Regional Entity. Since these MODs are most effective if completed annually, BPA recommends that this MOD have an embedded start data such as, “the MOD should be completed annually starting after March 1 of each year”. Any date to gather the data would work however a late winter or spring date would give receiving entities useful data to help with their within year planning as it is beneficial to the planning entities if the gathered data is done on a consistent planning schedule. Having the most up to date forecasts for this submittal is also best and having a consistent date would facilitate movement by the data providers to plan annually at a consistent time to meet this data need. Further, as written the MOD requires the Regional Entity to initiate the data gathering step. If the Regional Entity becomes busy with other activities this event may not be started with sufficient time to facilitate planning. This MOD further solidifies this notice requirement in MOD R1. 1.3 requiring the Planning Coordinator or Balancing Authority to provide additional unnecessary paperwork. If the annual date were included in the MOD-031 text, the paperwork required in MOD-031 R1. 1.2 could

just reference the MOD-031 starting date in the text and requirement MOD-031 R1. 1.3 would not be needed at all. 2) In MOD-031 R1. 1.4.3 a request is made for the weather normalized actual demands in MW. BPA believes that not all LSEs have the capability to do weather normalization of actual demands. Further there are numerous methods to normalize with differing results, making the data less usable. BPA recommends having the submitting entities provide the hourly weather that would be used for normalization along with the hourly integrated demands. This would more fully allow planning practices to address analysis and risks associated with weather uncertainty as need.
Group
Duke Energy
Colby Bellville
Yes
Duke Energy questions the need to include BA(s) in the SAR and pro-forma standard. The MOD standards identified in the MOD-C project for consolidation do not include the BA as an applicable entity. Also, all three requirements in the pro-forma standard list a time horizon of "Long Term Planning." Duke Energy does not feel that "Long Term Planning Horizon" is applicable to a BA.
Yes
While Duke Energy agrees with the approach of consolidating the MOD standards applicable to this project due to overlaps in the standards, we do not agree with placing the PC or BA in charge of collecting and submitting data as is written in the proposed standard. In the currently effective MOD C standards, Applicable Entities are required to report the data to either the ERO or RRO. The proposed MOD-031 would put the ownership on the PC or BA to collect the data from various LSEs and DPs within their Planning Authority Area, and then report the data to the RRO. We believe this places an unnecessary compliance burden on the PC or BA by having them gather and submit data that is already being submitted by the applicable entities. Duke Energy supports the recommendation made in the report submitted by the Independent Industry Experts, wherein they suggested that MODs 16-19 and 21 should be retired, and that the gathering of whatever data NERC needs for assessments and reports be done through Section 804 of the NERC Rules of Procedure. (See Appendix E of the Independent Expert Report) Also, the Purpose of this standard should be changed to " To ensure that actual and forcasted Demand data necessary for reliability assessments, validation of past events, and in support of future system assessments are reported in a timely manner."
Group
Florida Municipal Power Agency
Frank Gaffney
No
Although FMPA appreciates the efforts of the informal development process, FMPA disagrees

with the construct of the proposed SAR and proposed standards. Below are the primary reasons for our Negative vote for both MOD B and MOD C projects, which are described in more detail below. 1. The wrong model is being validated. By definition, planning models cannot be accurate enough to benchmark to operational reality due to forecast error; hence, operating horizon models should be validated by the RC rather than planning horizon models being validated by the PC. After all, in order to validate a planning horizon model to a real event (post-cast), the planning horizon model has to have everything planned stripped out of it to make it an operating horizon model. 2. The proposed standard may have overlapping requirements with IRO-010-1 and TOP-003-2 that require submission of data to build operating models for use in operations planning, which already require entities to submit data to the RC and TOP on a mandatory basis 3. In order to relieve this overlap, MOD standards (which FMPA believes are unnecessary and are candidates for P81) should be limited to planning horizon data that differs from operating horizon data. 4. Hence, standards are not needed for Planning Horizon and planning data can be gathered equally efficiently or cost effectively through data requests (e.g., modifications to GADS, TADS, DADS) 5. The proposed standard puts entities in a position of choosing between not complying with the standard, or not complying with a Confidentiality Agreement STANDARDS ARE ALREADY IN PLACE FOR OPERATING HORIZON MODELING Standard TOP-002-2, R19 states: “Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations” (emphasis added). This requirement has been mapped to TOP-003-2 in the new version of the TOP standards filed at FERC in April and awaiting FERC’s decision. R1 of that standard states: “Each Transmission Operator shall create a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.” For operating horizon load forecasts, TOP-002-2, R3 states: “Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.” This requirement has also been mapped to TOP-003-2. IRO-010-1, R1 states: “The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area …” Hence, it is clear that the MOD standards in question should be solely for the Planning Horizon and should not be for the Operating Horizon to eliminate duplication. If the intent is to have the MOD standards apply to the Operating Horizon, then there would be multiple standards governing the same activity and FMPA would propose that the SAR be changed to modify IRO-010-1 and TOP-003-2 as part of this effort to eliminate confusion and double jeopardy. STANDARDS ARE NOT REQUIRED FOR PLANNING HORIZON MODELING The purpose of the SAR starts with a false assertion, that planning studies “depend on accurate mathematical representations of transmission, generation, and load”. FMPA takes issue with the term “accurate”. Planning models by definition cannot achieve the level of accuracy that the ad hoc team seems to desire because they forecast the future. Recognizing that most transmission planning models represent a single representative moment in time: • To accurately model load, we must know the weather (e.g., how much air conditioning load is on), we must know the time of day, the day of the week, the season, we must forecast macro- and micro-economics to predict load growth both at the macro level and by substation, we must know what types of devices are operating on customer's premises (e.g., variable speed drives, compressors, motors, etc.) to develop an "accurate" representation of load dynamics, and numerous other variables beyond anyone's control. Load modeling cannot be as accurately modeled as desired by the ad hoc team in the Planning Horizon, and certainly not accurately enough to be validated against historical events. • To accurately model generation, we must predict fuel prices to know what is dispatched (e.g., a dispatch order, as discussed in the draft SAR, is not "accurate", who would have predicted that "fracking" would have caused gas combined cycle to be dispatched before coal?), we have to predict maintenance cycles and forced outages years in advance, we have to predict the weather because output of gas turbines change significantly with ambient temperature and humidity. We have to predict the impacts of clean air legislation and other environmental legislation on economic dispatch order. For renewables, we have to predict the weather, e.g., how much wind is blowing, how much sun is shining. And many more variables beyond anyone's control. Generation cannot be as accurately modeled as desired by the ad hoc team in the Planning Horizon, and certainly not accurately enough to be validated against historical events. • To accurately model transmission, we must depend on transmission owners meeting their construction schedules, we are dependent on the moisture in the soil for accurate zero sequence impedance calculations of transmission lines, and other variables beyond our control. Although we have more certainty that the transmission system will be as we predict in the next few years than we do for load and generation, FMPA has direct experience of a major transmission line being cancelled dramatically impacting the study area. Transmission cannot be as accurately modeled as desired by the ad hoc team in the Planning Horizon, and certainly not accurately enough to be validated against historical events. Planning is an important component to reliability, but the goal of planning is not about accuracy. The goal of planning is to study a variety of possible futures, using a variety of types of studies at the choice of the planner, such as scenario analysis and reasonable worst case assessments as is embedded within the TPL standards, or stochastic analyses as are typically used for resource planning, to gain reasonable assurance that we are planning a system that can be reliability operated in the Operating Horizon. Spending too much effort on underlying data is wasted because the inaccuracies inherent in forecasting the future overwhelm other inaccuracies. For instance: • Whether a major generator is on-line or not overwhelms a data error for that generator • Whether the wind is blowing or not overwhelms the value of accurate stability models for those generators • Whether gas is at $3 / MMBtu and gas dispatches before coal, or $10 / MMBtu and coal dispatches before gas overwhelms a dispatch order provided • Whether a new major line gets built or not overwhelms a small error in impedance of that line. • And so on. Hence, there is no reliability related need for the level of "accuracy" desired by the ad hoc team in the Planning Horizon (there is a need for accuracy in the Operating Horizon, see prior section and requirement R19 of TOP-002-2 that requires accurate computer models). In the Planning Horizon, the best that we can do is gather entities best forecasts of the future. Mandatory data requests, such as modifications to DADS, GADS and TADS, are sufficient to gather that planning data and no standard is needed for the Planning Horizon. For Order 693 directives and Order 890 directives purposes, mandatory data requests are equally efficient or effective as a standard for planning horizon data. VALIDATION SHOULD BE DONE BY THE RC ON OPERATING HORIZON MODELS, NOT THE PC ON PLANNING HORIZON MODELS As described in the previous sections, Planning Horizon models cannot be accurate enough to validate. Operating Horizon models are the models that ought to be accurate enough to validate, especially the real-time, current day and next day models (seasonal models will lose accuracy). Hence, the models that ought to be benchmarked to actual system performance are not the planning models, but the operating models. As such, the reliability need of benchmarking operating models to actual system performance should be the task of the Reliability Coordinator. There ought to be a feedback mechanism from the accurate Operating Horizon models to the Planning Horizon models, but that feedback mechanism does not require a standard. THE STANDARD PUTS ENTITIES IN A DILEMMA OF CHOOSING BETWEEN NOT COMPLYING WITH A STANDARD OR NO COMPLYING WITH CONFIDENTIALITY AGREEMENT(S) FOR SOMETHING THAT MAY NOT BE TECHNICALLY JUSTIFIED The SAR goes to great length to describe a purported problem with obtaining proprietary data and models from generator manufacturers, e.g., wind turbines. First, there is no technical justification provided that shows that the generic models provided are causing the Operating Horizon model to be inaccurate. Second, it puts entities in a position that they may need to choose between violating the standard or violating a Confidentiality Agreement. In an apparent attempt to avoid the need for a technical justification, the SAR states: “(w)hen a number of proprietary models are excluded from system analysis, the interconnection-wide model becomes incomplete, and the potential interaction of equipment and their control systems is unknown. As such, there is no way to analyze the potential operating conditions of the interconnection.” As described previously, the Planning Horizon is strewn with similar unknowns that we cannot know, and this statement alone is not technical justification. There should be an effort conducted to benchmark Operating Horizon models to actual system disturbances, especially in those areas with an abundance of such models (e.g., large amount of wind farms), to analyze whether such lack of proprietary models is causing any significant inaccuracy to determine if there is a reliability related need. The terms of the Confidentiality Agreement (CA) are important to consider if these models are to be shared with all the planners within an Interconnection. The SAR on page 5 states: “(p)roprietary models with details hidden from the user (‘black box’ models) or those models that cannot be shared across the Interconnection are not acceptable.” How will the terms of the CA be respected? Will this require all of the planners within an Interconnection to sign the CA? The ad hoc team does not address these issues. At best, the CA issue can only be handled on a going forward basis. We cannot go backwards in time and renegotiate a contract. If it is determined that there is a reliability related need, then FAC-001 should be modified to cause all new interconnections to require models be provided on a basis on which all of those planners in the Interconnection can access the information. In any case, the SAR’s claim that: “The Generator Owner must also arrange to give the proprietary model to the Transmission Planner, Planning Coordinator, and Reliability Coordinator for their sole use, using an NDA if necessary”, and if such data is required in MOD-032-1, R1 by the Planning Coordinator, could cause the GO to make a choice of being non-compliant with the standard or non-complaint with the CA if the CA did not allow sharing of such data, and if the

vendor did not cooperate in renegotiating those terms. Such a situation is not acceptable. If the proprietary models are determined to be important, then an effort to reverse engineer models is an alternative. For instance, a project to work with EPRI or similar research institute to develop models for wind turbines from major wind turbine vendors in a laboratory environment could be done presumably without violating any agreements. Such models could then become public domain and used within the Interconnection models. As another alternative, an effort to work with the vendors of the power system analysis software to allow confidential “black box” models to exist within the software itself so that the confidential model is not shared across the Interconnection when the model is shared, but is used within the Interconnection model, but kept confidential within the software, is another alternative. Our interpretation is that the SAR’s assertion that “black box” models are unacceptable is because there is no such ability within the existing software; and hence, the models cannot be shared across the Interconnection.
No
Please refer to response to question 1
Individual
Laurie Williams
PNM Resources, Inc.
Yes
PNM recommends that NERC assist the Regions with defining what PC "areas" are. In the western United States, in areas that are not part of ISOs, the PC concept has not been clearly defined for entities and the Region has not provided any specific guidance on what exactly constitutes a PC 'area.' Lack of specific guidance will create reliability gaps and audit difficulties as PC responsibilities increase.
Yes
NM is a summer peaking entity serving loads in WECC. PNM disagrees with the language in R1.4.3. as it requires not only the annual peak demand, but the monthly peak demand to be weather normalized. Currently, PNM spends considerable time and effort to weather normalize its demand forecasts for the annual peak but does not employ that methodology for the monthly demands when they are away from the summer peak timeframe, i.e. shoulder periods. PNM requests that the standard allow flexibility in the monthly demand forecasts such that weather normalization is not explicitly required. PNM agrees with keeping the annual weather normalization in the requirement language.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
No

Yes
ATC recommends the following changes be made to the draft Standard MOD-031-1: 1. Modify Requirements R1.5.2 and R1.5.3 text by adding the word “Annual” at the start of both sub-requirements below: a. R1.5.2 would read: “Annual peak hour forecast demand (summer and winter) in MW…” b. R1.5.3 would read “Annual forecasts of Interruptible Load and Direct Control Load Management (DLCM)…” to make it closer to the requirement within MOD-016, and more clearly specifies the data of interest. 2. Modify Requirement R2 text to read “…Balancing Authority or any other NERC registered entity (such as Load Serving Entity, Transmission Planner or Resource Planner)…”. The first text change eliminates confusion about “any other entity” and the second change includes Transmission Planning in the specified list of data receivers and removes the redundant identification of Planning Coordinator. 3. Modify Requirement R3 text to read, “The entity identified by the Regional Entity, either Planning Coordinator or Balancing Authority, in its data request,…” to better match the text in MOD-031-1 R1. This change improves the consistency of the pro forma standard text. 4. ATC believes there is a lack of requirements accounting for non-entity contribution to load. This concern was addressed in MOD-018 and has not been included in MOD-031-1 (non-entities could be explicitly included in MOD-031-1 R1.6).
Individual
Scott Langston
City of Tallahassee
The current draft standard contains both vague and duplicative requirements and potentially obligates Applicable Entities to perform analyses that are beyond the scope of current acceptable practice and do not enhance the reliability of the BPS.
Individual
Catherine Wesley
PJM Interconnection
No
Yes
In addition to signing onto the SRC’s comments for this project, PJM is submitting the following additional comments: • The definition of “Demand Side Management” must be more explicit. Does it include emergency load management and economic load response? Does it include only load response programs that are under the operational control of the reporting entity? In

the case of an ISO/RTO, would this mean reporting only demand response that is active in the wholesale market? (This would be consistent with NERC DADS requirements.) • Requirement R.1.4.3 requires production of monthly weather-normalized peaks for the prior year. Many entities determine weather-normalized values on a seasonal, not monthly, basis. PJM recommends the frequency remain on a seasonal basis consistent with present practices. • Requirement R.1.4.4 calls for reporting “deployed” load management for the prior year. “Deployed” should be clearly defined. (Is it the the nominal amount called upon, the actual amount delivered, etc.?) • Requirement R.1.7.2 calls for providing the energy effects of forecasted load management. Most entities determine the peak impacts, not the energy effects, of forecasted load management for reliability planning purposes. Additionally, energy effects are used for production cost or economic evaluation purposes. They generally do not address a reliability concern which is the case with peak effects on the system. PJM does not support energy effect data being added to the standard.
Individual
Bill Fowler
City of Tallahassee
The current draft standard contains both vague and duplicative requirements and potentially obligates Applicable Entities to perform analyses that are beyond the scope of current acceptable practice and do not enhance the reliability of the BPS
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
Agree
IRC Standards Review Committee
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC PSS
Group
ACES Standards Collaborators
Ben Engelby
Yes
(1) We are concerned that the informal development process that was originally contemplated has gone off course. The original plan was to have an informal development team create a proposal for a standard, who would then pass the work to a formal standard drafting team to

continue the development process. This is not what has occurred. The informal development team should not have been appointed as the formal standard drafting team without soliciting nominations, as this creates the perception of NERC not following the standards development process. The informal development process should not circumvent the NERC Rules of Procedure. (2) We question the value in posting the draft standard with the SAR. What good is the SAR posting if a standard has already been developed? This gives the impression that the Standards Committee has already determined the need for the standard and that stakeholders have no opportunity to influence the scope contained in the SAR contrary to the standards development process. It seems unnecessary to comment on the SAR at this point because it appears that it was drafted in tandem with the pro forma standard. We urge NERC to pay close attention to its Rules of Procedure and the Standard Process Manual to avoid deviations and setting precedent that could be challenged in the future. While we agree in principle with the consolidation of the numerous requirements in this project, the Standards Process Manual still must be followed. (3) We are also concerned that the standards process manual was not followed correctly regarding the selection of the drafting team. The nomination period began after the draft standard was posted, which clearly shows the ad hoc team developed the draft standard instead of satisfying the acitivities it was charged with by vetting the issues of the MOD standards with industry. The initial draft standadrd should be the work of the appointed standards drafting team. We doubt that there was sufficient time for the new drafting team members to thoroughly review and agree with the language in the initial posting. The method of developing the initial draft should comply with the NERC Rules of Procedure and we are concerned that a bad precedent is being set.
No
The unofficial comment form did not include a field for comments for question 2. Our comments on MOD-031-1 are located in question 3.
(1) We recommend that the drafting team refer to the industry experts report titled “Standards Independent Experts Review Project: An Independent Review by Industry Experts,” which contains recommendations to remove several requirements that impact the MOD C project. The requirements applicable to the MOD C project include MOD-016 R1, R2, R3; MOD-017 R1; MOD-018 R1 and R2; MOD-019 R1; and MOD-021 R1, R2, and R3. We strongly recommend that the drafting team review these recommendations and remove all requirements in the draft standard that have carried over from the above referenced requirements. According to the expert report, these requirements do not belong in a reliability standard because they are data collection and retention actions, and NERC could “gather whatever data NERC needs for assessments and reports through Section 804 of NERC Rules of Procedure.” In light of these recent developments, we cannot support this standard until these changes are made. (2) Several aspects of this standard meets Paragraph 81 criteria. The P81 criteria states: Section B2, Data Collection/Data Retention: These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC’s rules and processes. Further, Section B4, Reporting: if a Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity, then this requirement should be retired under P81. These are requirements that obligate responsible entities to report to a Regional Entity on activities

which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact. (3) In addition to the P81 requirements, data collection belongs under the Rules of Procedure. These data collection activities should not be a part of a reliability standard. TADS is an example of a standing 1600 data request must be complied with periodically. (4) The definition of Demand Side Management is vague. It is not clear whether this definition includes conservation and demand management programs. We ask that the drafting team revise the definition for clarity. (5) Regarding MOD-031-1 R1, the use of the terms: “data request,” “data reporting request,” and “data request issued by the Region” can lead to confusion. This appears to be an attempt to bypass Section 1600. Essentially, the requirement says NERC can issue a request and it now does not have to go through the section 1600 data request. We suggest rewriting the requirement to make the intent clear. (6) Requirement R1. Similar to the other MOD projects, we recommend revising the requirements to include an attachment that details the specific data. This level of granularity is confusing and unneeded. (7) Requirement R1, part 1.5.3 asks for forecasts of Interruptible Load and Direct Control Load Management for summer and winter peak conditions. Does this intend to capture the effective seasonal levels as opposed to the total levels for each season? It is unclear as to what exactly the Planning Coordinator or Balancing Authority needs to specify in the data reporting request and what exactly the Applicable Entities need to provide. (8) Requirement R2. This requirement meets Paragraph 81 criteria. Specifically, The P81 criteria states: Section B2, Data Collection/Data Retention: These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC’s rules and processes. Further, Section B4, Reporting: if a Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity, then this requirement should be retired under P81. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact. (9) We do not see the need for Requirement R3. Regional entities have several tools to request data, as outlined in the NERC Rules of Procedure. It is unnecessary to include a requirement that states an entity must provide data to its Region. The Region will have other methods to collect the data, which makes this requirement unnecessary. (10) In addition to the comments on the requirements, we recommend the drafting team develop an RSAW or other compliance guidance to better understand how the proposed standard will be assessed in an audit. (11) Thank you for the opportunity to comment.
Individual
Karen Webb
City of Tallahassee - Electric Utility
No
Yes

The current draft standard contains both vague and duplicative requirements and potentially obligates Registered Entities to perform analyses that are beyond the scope of current acceptable practice and do not enhance the reliability of the BPS.
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
Yes
I do not feel there is a compelling reliability need for this standard. There is sufficent authority in existing standards and other regulations outside the standards process for reliable data gathering and there was no demonstration of an actual reliability need that required a standard.
No
the existing standards are fine, in my opinion.
Group
Tennessee Valley Authority
Dennis Chastain
Yes
As considered in the background information section of the Unofficial Comment Form, we believe that MOD-016 through MOD-019, and MOD-021 should be retired based on criteria established in the NERC "Paragraph 81 Project Technical White Paper" (dated December 20, 2012). Within the background information of the Unofficial Comment Form, it is stated that "the data being collected has a reliability purpose in the development of future assessments for resource adequacy". However, there are currently no reliability standards that address resource adequacy, and the future assessments that the data is used for is not a product of a user, owner, or operator of the bulk power system. We believe this data reporting activity is more appropriately addressed under the NERC Rules of Procedure.
As stated under question number 1, we believe the MOD-016 through MOD-019, and MOD-021 standards should be retired without a successor. If there is to be a successor, we agree with the approach to consolidate into a single standard. We submit the following comments on MOD-031-1 should it go forward: The standard's title and purpose statement indicate that demand data is the only information of interest, however the requirements include references to energy data and controllable Demand Side Management (Interruptible Load and Direct Control Load Management). We suggest that references to energy data and controllable DSM be removed from the standard, or that the title and purpose of the standard be revised to capture the reliability related need for this data. R1 We suggest this requirement end after

R1.1.3. R1.1.4 and R1.1.5 and their sub-requirements simply try to capture the types of “demand data” that might be requested by the Regional Entity. Since R1 contains the phrase “at a minimum”, a literal interpretation would suggest that every data request issued by the PC or BA to an Applicable Entity must include R1.1.4 through R1.1.7 and their associated sub-requirements. As an alternative, R1.1.3 could be expanded to state “The types of data the Regional Entity may request includes, but is not limited to: “ followed by a bulleted list. We believe the PC and BA should already know the answer to R1.1.6, and not have to rely on the Applicable Entities for this information. For R1.1.7, what is the expected format of the response - data or narrative? How will the Regional Entity and NERC use this information in the context of resource adequacy assessments? For R1.1.2 - The Applicable Entities must be given a minimum of 30 days to respond to a request once it is received from the PC or BA. That being the case, we suggest that similar consideration for timing be factored into R3. The PC or BA must be allowed time to process the data it receives from Applicable Entities before passing it on to the Regional Entity (it has to be in excess of 30 days given the R1.1.2 language). For R1.1.4.1.4.1 - It has been our experience that integrated hourly demands for the prior year are collected through the FERC Form 714 and are not submitted through the Regional Entity. For R3 - We believe the first “entity” referenced in the requirement is intended to be either a PC or BA, based on R1. If that is the case, it would be clearer to confirm it in a parenthetical. “The entity (Planning Coordinator or Balancing Authority) identified by the Regional Entity....”.
Individual
Richard Vine
California Independent System Operator
No
Yes
Section 5 – Background – add the following sentence to the beginning of the first paragraph: To ensure that the purpose of this standard may be carried out various forms of historical and forecast demand and energy data and information must be available to the parties that perform the studies and assessments needed to ensure the adequacy of the Bulk Power System (BPS) and to be able to validate past events. In the last paragraph of 5. Background, revise the text from: The collection of demand projections requires coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – will ultimately enhance the reliability of the BPS. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual demand and demand-side management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices. To the following text: The collection of demand

projections requires various levels of coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, and Load-Serving Entities. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – will ultimately enhances the reliability of the BPS. Consistent documenting and information sharing activities helps to facilitate will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual demand and demand-side management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices. R1.4.2 Comment: Reporting tools can easily be used to glean the annual from the monthly. No need to request both. R1.4.2 current language: Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year. R1.4.2 proposed language: Monthly peak hour actual demands in MW and monthly and annual Net Energy for Load in gigawatthours (GWh) for the prior year. R1.4.3 Comment: What is the proposed use of weather normalized actual demand? This data request will create concerns and many questions for requesting entity. It is likely that a significant number of entities do not weather normalize their actual demand. For the entities that do not perform a weather normalization process, and even for those who already do, one of three things will occur related to this requirement; (1) they will do it accurately, (2) they will do it inaccurately, or (3) they will want guidance on how to perform weather normalization. Related to seeking guidance, entities will seek that guidance from the requesting entity on how to do it – out of either lack of experience or concern for being at risk of violating the requirement – and the requesting entity will not be in a position to provide that guidance. Consequently, this requirement will need some level of definitions and methodology provided to the Functional Entities, such as the minimum number of years of weather data needed to calculate the weather normalized demand, what are acceptable methodologies to utilize, and what to do if the entity does not have a sufficient database of historical weather. Unless NERC can provide a compelling reason for this requirement the CAISO strongly recommends deleting R1.4.3. R1.4.4 comment: Deployed DCLM does not always equal the amount realized in California IOU programs. Realized is more important than deployed for reconstructing actual unaffected demand, and at a minimum realized should be collected. This should be defined as “dispatchable” DCLM and stipulate that it does not include “load modifiers” such as energy efficiency. R1.4.4 current language: Monthly and annual peak hour deployed Interruptible Load and Direct Control Load Management in MW for the prior year. R1.4.4 proposed language: Monthly peak hour deployed Interruptible Load and Direct Control Load Management in MW, and the MW amount of realized Interruptible Load and Direct Control Load Management based on the amount deployed, for the prior year. R1.5.1 comment: Is there a reason not to collect monthly forecast peak demand for ten years? Recommend incorporating 1.5.2 into 1.5.1. R1.5.1 current language: Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years. R1.5.1 proposed language: Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for ten years into the future. R1.5.2 comment: See comment for R1.5.1 above to incorporate into R1.5.1, delete R1.5.2. R1.7.2 comment: For the IOUs in California the demand effects of Interruptible and Direct Control Load Management programs

are very preliminary until studies are completed and this information is provided to the CPUC in a report on April 1 of each year. Consequently only estimated data, which historically has been inaccurate, is available before April 1 and the final data would only be available to the Regional Entity by May 1 at the earliest. As a final point, many municipal systems have small programs, some totaling less than 1 MW. The CAISO recommends that a 10 MW minimum threshold for reporting this data be added to this requirement. R1.7.2 current language: The Demand and energy effects of Interruptible and Direct Control Load Management. R1.7.2 proposed language: The Demand and energy effects of Interruptible and Direct Control Load Management at such time as the information becomes available from the Applicable Entity. Applicable Entities with less than 10 MW of combined Interruptible and Direct Control Load Management programs are exempt from this requirement. R1.7.4 current language: How the peak load forecast compares to actual load for the prior year with due regard to controllable load2, temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted. R1.7.4 proposed language: A brief discussion on how the peak load forecast compares to the actual load for the prior year. In the discussion with due regard shall be given to controllable load2, temperature and humidity variations and, if applicable, how the assumptions and methods for future forecasts were adjusted. Compliance section 1.2 Evidence Retention Revise second paragraph Current language: The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. Proposed language: The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3, since the last audit, regardless of whether this Standard was part of the scope of the last audit or not, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. Comment: Without this an entity that does not have this Standard as part of the scope for multiple audit cycles would be required to maintain evidence for many years.
Group
MRO NERC Standards Review Forum
Russel Mountjoy
No
Yes
Comments: The NSRF agrees with the consolidation of Requirements into one Standard with the following recopmmendation to be considered by the SDT. R1. 1.4.3 and 1.4.4: Please clarify the need for “annual” actual peak load and weather normalized “annual” peak load if they are already asking for the 12 monthly numbers? Clarification is needed if there is a difference between the highest of the 12 monthly and the annual peak in this context? Is the highest load equal to the annual peak? Please clarify. R1. 1.4.3”Monthly and annual peak hour weather

normalized actual demands in MW for the prior year." Weather normalization seems to be more art than science especially when is comes to monthly peak demands. Different months will require different methodologies with shoulder months being particularly challenging. Recommend I would suggest to focus on only the summer peak and winter peak. This will simplify the process, limit the modeling to two methodologies and focus on the peak periods of the two key season peaks. Suggested Language Change: "Summer season (June-Sept) and winter season (Jan-May; Oct-Dec) peak hour weather normalized actual demands in MW for the prior year". It is recommended that the above language be applied to R1.7.4.
Individual
John Brockhan
CenterPoint Energy Houston Electric, LLC
No
Yes
In general, CenterPoint Energy agrees with the approach to consolidate the "MOD C" standards. Specfic comments are as follows: (1) CenterPoint Energy finds the introductory language in Requirement R1 to be unnecessarily confusing. The basic premise seems to be the Regional Entity will issue a data request to a Planning Coordinator or Balancing Authority who, in turn, issues a data request to Applicable Entities. Assuming this is correct, CenterPoint Energy suggests the use of the following language "Each Planning Coordinator or Balancing Authority identified in a data request by the Regional Entity shall develop and issue an associated data request to Applicable Entities (as defined in Part 1.1 below). The Planning Coordinator's or Balancing Authority's data request shall include, at a minimum:" Note, other references to "data reporting request" would need to be changed to "data request" if the SDT adopts the suggested language. (2) The use of the phrase "or any other entity" in Requirement R2 is open-ended. CenterPoint Energy asks the SDT to use language that more specifically speaks to the intent. CenterPoint Energy suggests the following language: "or affected Load Serving Entities, Planning Coordinators or Resource Planners on request." (3) The VSL for R1 does not include references to Parts 1.4.3 or 1.4.4. Additionally, for completeness, the Severe VSL for R1 (third paragraph) should say "… but failed to address four or more of the items listed in Requireiment R1, Part 1.6 or Part 1.7.1 through Part 1.7.4" instead of "… but failed to address any of the items." (4) In R1.5.2. requiring requested forecast data "…for ten years into the future" is burdensome and unnecessary. CenterPoint Energy recommends retaining the current language in place for MOD-017 R1.4 "…for at least five years and up to ten years into the future, as requested." Thank you for your consideration of these comments.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery

Yes
AECI certainly hopes our BES reliability is not truely dependent upon the accuracy of overall BES load-forecasting, because this has been the historical Holy Grail of our Industry for at least the last thirty years.
No
While responsible entities produce load-forecasts necessary to their business and resource-reliability purposes, this standard requires our company to assume compliance risks far in excess of what AECI believes to be acceptable trade-off value to BES reliability. Specifically: R1.4.3, R1.4.4, R1.5.3, R1.6, R1.7.2, R1.7.3, R1.7.4, all carry payloads of compliance burden that would drive AECI to incur additional expenses of questionable value, particularly for a system of our size within the Eastern Interconnection footprint.
See AECI's response to Question 2. AECI understands the problems associated with load-forecasting, but if the ERO or designees want to get to this data, then our RCs already should have sufficient net-Generation and net-Interchange values for calculating instantaneous load data within their footprint. Further, this is a complex problem where experience has often indicated that attention to greater granularity or detail, can produce greater aggregate error.
Individual
Andrew Gallo
City of Austin dba Austin Energy
No
Yes
(1) Austin Energy (AE) finds the introductory language in Requirement R1 unnecessarily confusing. The basic premise seems to be the Regional Entity will issue a data request to a Planning Coordinator or Balancing Authority who, in turn, issues a data request to Applicable Entities. Assuming this is correct, AE suggests the use of the following language “Each Planning Coordinator or Balancing Authority identified in a data request by the Regional Entity shall develop and issue an associated data request to Applicable Entities (as defined in Part 1.1 below). The Planning Coordinator’s or Balancing Authority’s data request shall include, at a minimum:” Note, other references to “data reporting request” would need to be changed to “data request” if the SDT adopts the suggested language. (2) AE requests the SDT change Requirement R1.5.2 from “…for ten years into the future” to match the current requirement in MOD-017 which calls for “…at least five years and up to ten years into the future, as requested.” (3) The use of the phrase “or any other entity” in Requirement R2 is open-ended. AE asks the SDT to use language that more specifically speaks to the intent. AE suggests the following language: “or affected Load Serving Entities, Planning Coordinators or Resource Planners on request.” (4) The VSL for R1 does not include references to Parts 1.4.3 or 1.4.4. Additionally, for completeness, the Severe VSL for R1 (third paragraph) should say “… but failed to address four or more of the items listed in Requireiment R1, Part 1.6 or Part 1.7.1 through

Part 1.7.4" instead of "… but failed to address any of the items."

Additional comment received from MRO regarding Q3:

R1-MRO does not support the responsibilities identified towards the Regional Entity, Regional Entities are not owners, users or operators of the BES. This requirement should be the responsibility of the Planning Coordinator and any Balancing Authority identified by the Planning Coordinator to supply the data.