**Individual or group. (33 Responses)**
**Name (19 Responses)**
**Organization (19 Responses)**
**Group Name (14 Responses)**
**Lead Contact (14 Responses)**
**IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (2 Responses)**
**Comments (33 Responses)**
**Question 1 (0 Responses)**
**Question 1 Comments (31 Responses)**

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| Individual |
| Thomas Neglia |
| Orange and Rockland Utilities |
| Agree |
| Consolidated Edison Company of New York |
| Group |
| Northeast Power Coordinating Council |
| Guy Zito |
| |
| No comments. |
| Group |
| SPP Standards Review Group |
| Shannon V. Mickens |
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| In the standard: There is a concern surrounding the ‘Applicable Entities’ Which includes ‘Resource Planners’ however; R1 1.1 indicates the request should list the TPs, BAs, LSEs and DPs. We would request clarity to be provided regarding the Resource Planner’s role in reference to R1 1.1. We have a concern that the definition of ‘Total Internal Demand’ in the proposed standard and the (2014) Long Term Reliability Assessment (LTRA) are not consistent. Our request to the drafting team would be to review the definitions in both documents and ensure that we have consistency and efficiency for the applicable standard and assessment process. There is concern surrounding the ‘Applicable Enities’ and their reporting of data in Requirment R4. The requesting and providing of data to the direct Planning Coordinators or Balancing Authoritys will be covered in Requirments R1 and R2. However; the concern would be having ‘Applicable Enities’ to provide this same data numerous time to other Planning Coordinators or Balancing Authoritys who are not in the direct reporting process. We feel that the sharing of the data could be more effiecient if the neighboring Planning Coordinators or Balancing Authoritys would make the data request from |

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| the direct Planning Coordinators or Balancing Authoritys who originally requested the data. R1, VSLs – Revise the Lower VSL to read ‘The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1 late but within 6 days of the date indicated in the timetable provided pursuant to Requirment 1, Part 1.2.’ The Moderate VSL would be revised to read ‘The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1 more than 6 days but within 11 days of the date indicated in the timetable provided pursuant to Requirement R1, Part 1.2.’ The High VSL would be modified in a similar manner substituting 11 days and 15 days for the 6 days and 11 days, respectively, in the Moderate VSL. Typos/grammatical : R1, Part 1.2 and other places within the standard where a specific number of calendar days are specified – 30-calendar days (hyphenate) R1, Parts 1.3.1, 1.3.2, 1.4.1, 1.4.3 – Demand instead of Demands R1, Part 1.5 – Delete ‘about’ at the end. The end of Part 1.5 would then read ‘…summary explanations, as necessary:’ In the Rationale Boxes,in R4 and in the VSLs, capitalize Part when it is associated with part of a Requirement such as Requirement 1, Part 1.3.2. Whitepaper on MOD C Standards: We again suggest that references to the Bulk Power System in the Whitepaper be made to the Bulk Electric System instead. In Footnote 1 at the bottom of Page 5, replace ‘has’ with ‘have’ such that it reads ‘…NERC and the Regional Entities have the authority…’ In the 6th paragraph on Page 5, (2) is akward at best. Perhaps it should read ‘…(2) the sharing of such data among Load Serving Entities, Distribution Providers, Planning Coordinators, Balancing Authorities, Resource Planners and Transmission Planners once obtained from a neighboring entity.’ As suggested in the standard, when referenced with a Requirement, Part should be capitalized. |
| Individual |
| Chris Scanlon |
| Exelon |
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| Exelon appreciates the responsiveness of the Drafting Team to comments respecting the role of the LSE's. |
| Individual |
| Nazra Gladu |
| Manitoba Hydro |
| |
| (1) The new definition of Total Internal Demand should clarify that Total Internal Demand should be reduced by DSM that is not controllable and dispatchable, (i.e., reduced by indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, Stand-by Load under Contract, all non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs)) as described in the current Total Internal Demand definition in the NERC Reliability Assessment instructions. Please note that this is only applicable if the intent is to still account for the indirect DSM programs in Total Internal Demand. If this is not the intent, then clarification on the intent of capturing the controllable and dispatchable programs is needed since the definition of DSM has been broadened. (2) R1 |

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| – this states that each PC or BA “that identifies a need for the collection of Total Internal Demand ….etc.” On what basis? Or criteria? This could mean that entities are all being treated differently, based upon the “whim” of the PC or BA. There should be defined criteria for when there is a legitimate need. (3) R1 – it is unclear if all data requests should be made in writing. (4) R3 and R4 - for clarity, “days” should be specified as “calendar days”. (5) The standard is vague as to whether or not the load data should be specified as both aggregate and dispersed. From a model building perspective, both are required. |
| Individual |
| Andrew Z. Pusztai |
| American Transmission Company, LLC |
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| ATC recommends the SDT consider the following changes to the draft Standard adding clarification to the language of the subrequirements: 1. ATC recommends changing the specified time period in the sub-requirement of R1 from ‘the prior year’ to ‘the prior 12 month period’. This change provides the same function as the original text with added flexibility. 2. ATC recommends to modify Requirement R1.4.3 by adding the word “Annual” at the start of the sub-requirement. a. R1.4.3 would read: “Annual peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.” b. This change would align MOD-031-1 with the existing MOD-017 (R1.4), and more clearly specifies the data of interest. 3. ATC recommends to modify Requirements R1.4.5 by adding the word “Annual” at the start of the sub-requirement. a. R1.4.5 would read: “Annual total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.” b. This change would align MOD-031-1 with the existing MOD-017 (R1.4), and more clearly specifies the data of interest. |
| Individual |
| Gul Khan |
| Oncor Electric Delivery Company LLC |
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| Oncors Commercial Load Management Standard Offer Program (CLMSOP) was developed to pay incentives to energy efficiency service providers (e.g., contractors, energy service companies, retail electric providers, or customers) for load curtailments of electric consumption on short notice during the summer peak period. Incentives are based on verified demand savings that occur at an Oncor distribution customer’s site as a result of a curtailment. Oncor’s CLMSOP is a voluntary program, hence it is not controllable and dispatchable. The program requires service providers to be prepared to participate in up to 25 curtailment hours during the summer peak period. A called curtailment will occur as requested by Oncor. Oncor will comply with ERCOTs requests to deploy the program during or in anticipation of an ERCOT Energy Emergency Alert. Oncor will notify service providers of a called curtailment at least one hour prior to the start-time of the curtailment. Only Oncor authorized personnel can issue notices to service providers to initiate a curtailment. Regarding 1.3.4, Oncor requests the following changes to allow the inclusion of voluntary |

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| Demand Side Management programs: Monthly and annual peak hour controllable and dispatchable, or voluntary Demand Side Management under the control, supervision, or direction of the System Operator or other company representative in megawatts for the prior calendar year. Three values shall be reported for each peak hour curtailment event: 1) the committed megawatts (the amount under control, supervision, or direction), 2) the dispatched or requested megawatts (the amount, if any, activated for use by the System Operator or other company representative), 3) the realized megawatts during curtailment events (the amount of actual demand reduction), 4) type of program (controllable and dispatchable, or voluntary), and 5) System Operator defined monthly and annual peak hours. Regarding 1.4.5, Oncor's CLMSOP is implemented on a yearly basis and is only projected one year into the future. We recommend the following changes: Total and available peak hour forecast of controllable and dispatchable, or voluntary Demand Side Management (summer and winter), in megawatts, under the control, supervision, or direction of the System Operator or other company representative for their applicable forecasting period. Regarding 1.5.2, Oncor requests the following changes to allow the inclusion of voluntary Demand Side Management programs. We recommend the following changes: The Demand and energy effects of controllable and dispatchable, or voluntary Demand Side Management under the control, supervision, or direction of the System Operator or other company representative. Regarding 1.5.4, Oncor requests the following changes to Reporting Requirement 1.5.2 to allow the inclusion of voluntary Demand Side Management programs : How the controllable and dispatchable, or voluntary Demand Side Management forecast compares to actual controllable and dispatchable, or voluntary Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted. |
| Individual |
| Michael Falvo |
| Independent Electricity System Operator |
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| We submitted a couple of comments expressing concerns over the proposed VRFs and VSLs for certain requirements but have not seen a response from the SDT addressing these concerns, nor do we find changes to the draft standard that address these concerns. We'd therefore reiterate our comments as follows: 1. R1: In the sentence "Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load and Demand Side Management data shall develop and issue a data request to the applicable entities in their area." Suggest to change "their" to "its" before "area". 2. R1: The wording suggests that the PC and BA shall also distribute the list of applicable entities identified in Part 1.1 as part of the data request. Please clarify whether this is the intent otherwise the requirement will have to be reworded. 3. R1, Part 1.5.5: Suggest to change "peak load" to "Peak Demand" and change "actual load" to "actual Demand". 4. R4: The SDT's response to our last comment that the sentence "This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1." Was that it provided clarification. While we agree it does serve that purpose, we continue to disagree |

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| with the need to include this statement in Requirement R4. We reiterate our position that the second sentence of R4 is unnecessary and should be deleted and propose the following alternative wording for R4: “Any Applicable Entity shall, in response to a written request for the data included in parts 1.3-1.5 of Requirement R1 from a Planning Coordinator or Balancing Authority other than its Planning Coordinator or Balancing Authority, or a Transmission Planner or Resource Planner with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric Sysytem [sic], provide or otherwise make available that data to the requesting entity. Also, please correct the word “sysytem” to “system”. 5. R4: The first bullet has been modified substantially and now introduces a time limit for provision of the requested data. Since this first bullet now represents a requirement, we believe it appropriate to remove the bullet and make it Part 4.1. We therefore propose that the last part of R4 should read as follows, “Unless otherwise agreed upon, the Applicable Entity shall provide:”, and Part 4.1 should read “The requested data…”. The second bullet of R4 may remain unchanged. 6. R1: Requirement R1 is assigned a MEDIUM VRF. This appears to be inconsistent with the LOW VRF assigned to R1 of MOD-032, which stipulates the requirement for the Planning Coordinator and Transmission Planner to develop the modeling data requirements and reporting procedures. The two requirements appear to be requiring the specification of data and collection procedure required for reliability assessment, yet their VRFs differ by a level. We suggest the SDT to consult the MOD-032 and MOD-033 SDT to confirm the difference based on supporting rationale, or to adjust either VRF to achieve consistency. If the SDT holds the view that the MEDIUM VRF assignment is appropriate, we are unable to find any supporting document that provides the justification for this assignment. If the justification document is posted somewhere and we’ve looked this, please point us to the place where it is posted. 7. There is only one SEVERE VSL for the Planning Coordinator or the Balancing Authority failing to include the entity(s) necessary to provide the data (Part 1.1) or the timetable for providing the data (Part 1.2), but there are no VSLs for the conditions when these entities fail to specify any of Parts 1.3 to 1.5. We suggest to add the VSLs for these conditions to meet the NERC and FERC VSL guidelines. If the SDT holds the view that VSLs for violating Parts 1.3 to 1.5 do not need to be provided, we are unable to find any supporting document that provides the justification for not providing these VSLs. If the justification document is posted somewhere and we’ve looked this, please point us to the place where it is posted. |
| Individual |
| Ronda Ferguson |
| Wisconsin Public Service Corporation |
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| Suggested Language Modification for R1.5.2 (to clarify what is meant by effects): The total demand (Mw) and energy (Mwh) of controllable and dispatchable Demand Side Management under the control or supervision of the System Operator. Suggested Language modification for R1.5.4 and R1.5.5 (clarification of annual): 1.5.4. How the controllable and dispatchable Demand Side Management forecast compares to actual annual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the |

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| assumptions and methods for future forecasts were adjusted. 1.5.5. How the peak load forecast compares to actual annual peak load for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted. |
| Individual |
| Bob Steiger |
| Salt River Project |
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| SRP has no issues with this draft. |
| Individual |
| Michael Haff |
| Seminole Electric Cooperative, Inc. |
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| While Seminole generally supports the language contained in the proposed reliability standard, there are still some concerns as outlined below: 1. Requirement R3 states that the PC or BA shall provide certain data within “75 days” of receiving such a request. This requirement does not specify whether the days are “calendar” or “business”. Because the SDT uses “calendar” days in other places throughout the document, the implication is that R3 is meant to refer to business days due to the omission of the word “calendar”. Please revise the proposed language to clearly specify the SDT’s intent. 2. Requirement R4.1 states that Applicable Entities must respond within 30 calendar days of a request. However, if an entity requests data and then the Applicable Entity sends a follow-up request for the reliability need for this data, the Applicable Entity’s response is now contingent upon the timeliness of the response from the requesting entity. This Requirement appears to lack flexibility when a requesting entity does not provide a sufficient reliability need for the data in their initial request. Seminole requests that such flexibility be provided in the Requirement, e.g., 30 calendar days from receipt of a request whose reliability need has been sufficiently communicated. |
| Individual |
| Thomas Foltz |
| American Electric Power |
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| AEP does not support pursuing MOD-031-1. We question the perceived need for this standard, and do not believe it provides any reliability benefit to the BES. Much has changed in the way this information is gathered and reported, and having such a prescriptive standard is not beneficial. To that point, the RTO’s already have established processes which fulfills the need. In addition, this standard dictates how and what type of information is needed for the PC and the BA to do their assessments. It might be preferable that the standard focus on the *what* rather than the *how* and establish a framework for supporting entities to meet the PC and BA’s expectations. We much prefer the approach taken in IRO-010-1a where the standard does not prescribe the details of the data request. Another example is the proposed |

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| standard MOD-032 which addresses similar requirements at a higher level, which we believe is far more appropriate, and preferable, to the highly prescriptive direction taken in MOD-031-1. The comments below are provided in the event the project team continues to pursue the proposed MOD-031-1 standard. R 1.1 – It should be made clear that the list of Functional Entities 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. 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. AEP recommends changing the proposed definitions to the following: Demand Side Management (DSM): All activities or programs undertaken by any applicable entity to influence the amount or timing of electric usage. Total Internal Demand: The Demand of a metered system which includes the Net Internal Demand, the Demand Response Load and the Load due to the energy losses incurred in the transmission and distribution systems. In addition, we believe the following (new) definitions need to be added to the Definition of Terms section: Demand Response (DR): All programs undertaken by any applicable entity to request that demand be reduced. Examples of DR may include, but are not limited to, Load Management Programs, Direct Control Load Management (DCLM), Interruptible Load or Interruptible Demand, Critical Peak Pricing (CPP) with control, and Load as Capacity resources. Net Internal Demand: Total of all end-use customer demand and electric system losses within specified metered boundaries, less Demand Response (i.e., Direct Control Management and Interruptible Demand). Weather Normalized Demand: A demand that reflects normal weather conditions, and is expected on a 50% probability basis – also known as a 50/50 load or demand (i.e. there is a 50% probability that the actual peak realized will be either under or over the projected peak). Additional suggestions (all pages reference the “clean” version of draft document): Pg 6, R1.3.2.1. references weather normalized annual peak without a definition…see definition above for Weather Normalized Demand. Pg 6, R1.3.4 change “controllable and dispatchable Demand Side Management” to “Demand Response” Pg 6, R1.4.5. change “Total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.” to “Peak hour forecast of available Demand Response (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.” Pg 6, R1.5.1 change “aggregate peak’ to “Total Internal” Pages 6 and 7, R1.5 change all references to “controllable and dispatchable Demand Side Management” to “Demand Response” |
| Group |
| JEA |
| Thomas McElhinney |
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| This is purely a data request standard and should be eliminated in accordance with the P81 project. |
| Individual |

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| Teresa Czyz |
| Georgia Transmission Corporation |
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| R1 states that the PC and BA “shall develop and issue a data request”, but in R4 includes the TP and RP (in addition to the PC and BA) as giving a “written request for the data”. We are suggesting that the drafting team either add TP and RP to R1 or remove them from R4. |
| Group |
| Duke Energy |
| Michael Lowman |
| |
| The proposed definition of Demand Side Management appears to be overly broad, and may lead to certain activities or programs to be labeled as Demand Side Management that the SDT did not intend. Duke Energy suggests a re-wording of the proposed definition of Demand Side Management (DSM) to the following: “Demand Side Management: All real-time activities or programs undertaken by any applicable entity to achieve a reduction in Demand.” The addition of the phrase “real-time” adds needed clarity as to the types of activities or programs to be undertaken in the definition, and narrows the scope to avoid unintended inclusions. |
| Individual |
| Anthony Jablonski |
| ReliabilityFirst |
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| ReliabilityFirst votes in the affirmative for the MOD-031-1 standard but votes in the negative for the non-binding poll. ReliabilityFirst submits the following comment related to the VSL for Requirement R1. 1. The VSL for Requirement R1 only speaks to failing to include either the entity(s) necessary to provide the data (Part 1.2) or the timetable for providing the data (Part 1.2). ReliabilityFirst notes that there is no mention of an entity failing to meet the intent of Part 1.3, Part 1.4 or Part 1.5. Failure to include these Parts in the data request may result in a possible violation and hence need to be noted in the VSLs. ReliabilityFirst recommends including a Moderate VSL such as: “The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include items in Requirement R1, Parts 1.3, Parts 1.4 or Parts 1.4 in the data request.” |
| Individual |
| Don Schmit |
| Nebraska Public Power District |
| |
| 1) The current draft continues to include Requirement R4. As we have stated before, we question the need for this proposed Requirement. While we understand the desire of NERC to encourage the sharing of load data, we continue to believe that a mandatory and enforceable reliability standard is unnecessary and that the sharing of load data would be more effectively addressed by directing requests for such information to the applicable Planning Coordinator |

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| (PC) and not from the entity itself. 2) We are concerned that the draft language under R4 does not provide sufficient protection for applicable entities from differing data requests under Requirements R2 and R4. In the proposed language of Requirement R1, PCs are given a significant amount of flexibility in determining the specific information to be included in their data request to applicable entities. This could create a situation in which an Applicable Entity is required to develop and submit information to comply with a request from another PC under Requirement R4, that they were not required to supply to their direct PC under Requirement R2. At a minimum, NPPD believes a clarification is needed that the information required to be supplied by an Applicable Entity under Requirement R4 be limited to those items it was required to provide to its PC under Requirement R2. 3) The proposed definition of “Total Internal Demand” in the current draft states that it is “The Demand of a metered system which includes, the Firm Demand, plus any controllable and dispatchable DSM Load and the Load due to the energy losses incurred within the boundary of the metered system.” This definition indicates that the controllable and dispatchable DSM load should be added back into the Firm Demand as part of the calculation of Total Internal Demand. The current (2014) Long-Term Reliability Assessment (LTRA) data request also includes the term Total Internal Demand. However, the LTRA instruction for providing Total Internal Demand includes the statement that “Adjustments for controllable demand response should not be included in this value”, which doesn’t appear to be consistent with the proposed definition in the draft standard. The drafting team needs to ensure that the definitions included in the standard accurately describe the demand and energy information necessary to support reliability studies and assessments and that these definitions are used consistently throughout NERC. |
| Individual |
| Brett Holland |
| Kansas City Power & Light |
| Agree |
| SPP - Robert Rhodes |
| Group |
| DTE Electric |
| Kathleen Black |
| |
| We have no issues with the draft of MOD-031-1 standard but wanted to bring to your attention that under M3 (page 9) "Authority" is mispelled. |
| Group |
| ISO/RTO Standards Review Committee |
| Gregory Campoli |
| |
| The SRC asks for clarification regarding the scope of the proposed standard. Based upon the standards being proposed for retirement (MOD-016,17, 18, 19, and 21) the SRC asks if this standard is designed specifically for the Long Term Planning (LTP) Horizon or is it designed for both Long-term and Operations Planning? The SRC raises the question because: • If the |

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| proposal were only for Long Term Planning, then the SRC would note that in the Functional Model BAs are not involved in LTP, and the BA is therefore not an Applicable Entity. • If the proposal were for both LT Planning and Operations Planning (as implied by having both PC, TP and BA), then it would add clarity to add the Operations Planning Horizon for R1 if both were to need the same listed information; or better to add a standard or a requirement to address the specific data needs of the BA in developing a Day-Ahead operating plan. On the other hand, if the reason for including the BA is to recognize the LTP obligations imposed on the WECC BAs, then the SRC would ask that the SDT explicitly acknowledge that point – e.g. either as a footnote, or in the Applicability section. Please note, CAISO abstained from these comments. |
| Group |
| Florida Municipal Power Agency |
| Frank Gaffney |
| |
| FMPA has recommended retirement of these standards in accordance with P81, and in alignment with IERP recommendations. The SDT has disagreed, but has not provided sufficient technical justifaction for the existence of a standard. In the SDT’s consideration of comments (which by the way does not mention the IERP recommendations to retire these standards), the SDT uses the following reasons to justify a standard: “First, the standard provides a more efficient and enforceable mechanism for NERC and the Regional Entities to obtain Demand data from all applicable registered entities across the entire continent.2 The data to be collected under the standard is necessary for the ERO to conduct its reliability assessments, such as the Long Term Reliability Assessment.” “Second, the standard provides a mechanism for (1) Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes that is not necessarily connected to the ERO’s reliability assessments; and (2) the sharing of such data between Load Serving Entities, Distribution Providers, Planning Coordinators, Balancing Authorities, Resource Planners and Transmission Planners to obtain the data from a neighboring entity.” These are very weak reasons that do not provide sufficient justification for a standard. First, NERC and RE assessments are not included within the perview of standards. FPA Section 215 section (d) contains the legislation for standards; assessment are included in FPA Section 215 section (g) and are separate from standards in the regulatory construct. Hence, the first “reason” to justify a standard does not provide any justification whatsoever. Second, what are the “reliability purposes” of a PC or BA that would supposedly be facilitated through this effort? There is nothing regarding the BA; there are no Planning Horizon requirements of the BA that involve a planning horizon load forecast, so, there is no reliability purpose of this standard for a BA. The SDT seems to forget that operating horizon load forecasts are already provided in other standards (IRO-010, TOP-002). And the SDT provides no technical justification as to why sharing a planning horizon load forecast with neighbors provides any improvement to reliability. So, to FMPA’s reasoning, it really boils down to the TPL standard(s) and whether a planning horizon load forecast is significant enough to the TPL standards to meet the Section 215 thresholds for “reliable operation”. That is, from the definitions of Setion 215: “The term |

`reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system." "The term `reliable operation' means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements." A planning horizon load forecast does not provide for "reliable operation" as defined in Section 215. It provides to the TPL standards just a good guess as to what the future load might be in a sampled hour, allocated to individual substations in the model, combined with a generation dispatch that is highly unlikely to occur in real life. The purpose of TPL-001-4 is to: "Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." In other words, to study reasonable worst case conditions so that we plan a system that can be operated. A planner can establish reasonable worst case conditions without a load forecast provided by someone else using a number of factors such as high load growth cases correlated with hogh economic growth projections for a region, severe weather, etc. Some might say that accuracy of such a forecast is important; but, a forecast is just that, a guess at the future. We cannot know what the weather will be like, we cannot know what the economy is going to do in the future and how that drives load, we cannot know how load growth will vary by sector, we cannot know how load growth will vary from substation to substation, we cannot know the penetration of conservation and DSM programs, etc.. As such, an accurate load forecast is impossible and all we know is that what we forecast will be wrong. This does not mean that it is not important to perform load forecasts for planning purposes, it just does not rise to the signifance of needing to be regulated by standards and instead data requests are sufficient. Hence, the existing standards ought to be retired and replaced with data requests. Also, most PCs are also TSPs, and most TSP OATTs require their network service customers to provide a load forecast; hence, even if the SDT believes, against the IERP recommendations, that there is sufficient technical justification to require a regulatory construct for data collectionof load forecasts, most of those load forecasts are already being collected through the regulatory construct of the OATT. What is not collected through OATTs is certainly inconsequential to BPS reliability In addition, the SDT makes a strange statement in the consideration of comments that says: "(r)eplacing the MOD C standards with a data request would not provide a mechanism for this data sharing or allow Planning Coordinators and Balancing Authorities to obtain demand data from data owners for their own reliability purposes." FMPA fails to see how a data request would not provide such a mechanism, and in fact, having a single database for the continent ought to improve such sharing. For instance, in Florida, each utility submits to the FPSC a 10 year site plan with load forecast data that is then made available to other utiltiies in Florida; making the data even more transparent through the FPSC's collection. It seems to FMPA that the SDT has not given enough consideration to the IERP and other industry expert recommendations to retire these standards. The SDT has not provided sufficient technical justification as to why it disagrees with the Independent Experts except to say that it makes NERC's and the RE's life easier and it fulfills an unidentified BA and PC

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| “reliability purpose”, and a nebulous sharing of data purpose. This seems to FMPA like a “brush off” to important recommendations made by multiple experts in the industry that deserves more careful consideration and deliberation. |
| Individual |
| Catherine Wesley |
| PJM Interconnection |
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| PJM supports the draft standard and appreciates the drafting team implementing PJM’s recommended changes to the definition of Total Internal Demand and R4. Based on the revised draft, PJM will vote in the affirmative. Additionally, PJM suppports the SRC’s comments and has signed onto them. |
| Group |
| Dominion |
| Connie Lowe |
| |
| 1.3.2. Dominion suggests this be re-written similar as 1.3.1; “Integrated monthly and annual peak hour Demands in megawatts for the prior calendar year.” Dominion would like to thank the SDT its response, we still do not agree as the R4 requirement imposes an unnecessary burden on the entity. Given their Planning Coordinator or Balancing Authority already has the information, we suggest that R4 require a requesting Planning Coordinator or Balancing Authority send their data request to the Planning Coordinator or Balancing Authority of the Load-Serving Entity or Distribution Provider. |
| Individual |
| Chris de Graffenried |
| Consolidated Edison Co. of NY, Inc. |
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| Controllable and Dispatchable - Currently, Applicable Entities divide demand-side resources generally into two broad groupings: Embedded and Incremental demand-side resources. Embedded demand-side resources are “always on.” Incremental demand-side resources are switched on and off by some mechanism. Embedded demand-side resources are addressed in this standard only indirectly under 1.5.5. Embedded demand-side resources are netted out of both the Forecast and Acutal data. Incremental demand-side resources are not netted out of the Forecast, but are incremental to the base forecast. Howevever, Incremental demand-side resources can be triggered by many mechanisms. Direct control is only one way to initiate Incremental demand-side resources. Some Incremental demand-side resources are triggered by “rules.” For example, demand-side resources may be initiated whenever some triggering parameters are met, e.g., Load exceeds 96% of Forecast peak, or temperature exceeds 90 degrees prior to 4 critical super peak hours, or by an Economic Demand Response. These demand-side resources are not dispatched in the same strict sense as direct control initiation from a Control Center. Yet they are controllable by predetermined “rules.” Please define the terms controllable and dispatchable. One definition that might be used is: Definition of |

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| Controllable and Dispatchable – Demand-side resource technologies defined by the Planning Coordinator or Planning Authority that are not netted from Forecasts and Actuals. New Technologies – It is not entirely clear how this standard treats evolving, newer technologies. For example, it is not entirely clear how the standard interacts with load shifting technologies, such as cool storage and battery storage; or rechargeable electric vehicles; or Smart Grid? The drafting team should add a further clarifying requirement for the Planning Coordinator or Planning Authority to work with the Applicable Entities to delineate exactly which technologies are to be included and excluded, such as 1.X.X The Planning Coordinator or Planning Authority will work with its Applicable Entities to define in advance the list of technologies which are to be included in the Dispatchabe and Controlable category of demand-side resources and how they are to be modelled. Add the following Standard Definitions: Economic Demand Response (EDR) – EDR is demand-side resources that cause specific changes in the Total Internal Demand in support of system reliability based on their response to specific pricing signals, e.g., 4 hour super-peak pricing. Dispatchable – Demand-side resources that are capable of modifying their Total Internal Demand in response to Applicable Entity instructions. |
| Group |
| Western Electricity Coordinating Council |
| Steve Rueckert |
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| WECC thanks the drafting team for the revisons to several of the definitnions and changes to the requirements that we identified and suggested in the last round of comments. WECC believes this standard is an improvement over the currently-effective standards it is intended to replace and for that reason WECC will be voting YES for this version of the standard. However, as noted in our earlier comments, WECC still has concerns related to the 75-day time frame identified in Requirement R3. Giving the PC or BA up to 75 days to provide the data collected under R2 to the applicable Regional Entity WILL NOT WORK under the schedule currently used at NERC. For example, this year (2014) NERC did not distribute their data request to the Regional Entities until January 7, 2014. Even if the Regional Entities could have requested the data collected under R2 from the PC or BA on the same day and the PC or BA could have turned the request around and sent it to the applicable entitis on the same day, per the language of R1 and R3, it would not be due to the Regional Entity until April 20, 2014 (30 days for applicable entity to respond plus 75 days for the PC or BA to provide the data to the Regional Entity). However, this year the due date for submitting the summer assessment to NERC was March 14. Unless NERC distributes their request to the Regional Entities much earlier, or the Regional entities and the PC or BA agree to a shorter period, the data is not available to the Regional Entity until well after the due date back to NERC. WECC recognizes that a shorter period may be “agreed upon” but because of the language of Requirement R3, the PC or BA could push for 75 days to provide the data. A second concern WECC has voiced in earlier comments is that Requirement R1, part 1.4.3 asks for Peak hour forecast Total Internal Demands (summer and winter) for 10 calendar years. Part 1.4.4 asks for annual Net Energy for 10 years. To do probabilistic studies, monthly peaks and energy are needed. WECC |

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| would like to see the language in parts 1.4.3 and 1.4.4 changed to require monthly peak and monthly energy. WECC has submitted these concerns during earlier comment periods and the drafting team did not address them in their summary response to comments. WECC requests that the drafting team either implement these suggested changes or clearly communicate in the summary response to comments why the suggested changes are not necessary. Without this information WECC will consider voting NO on the next additional ballot or final ballot and suggesting that entities in the West vote NO as well. |
| Group |
| ACES Standards Collaborators |
| Ben Engelby |
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| (1) If the drafting team chooses to modify the NERC Glossary Term for Demand Side Management (DSM), we recommend that a cross reference analysis be peformed with the other reliability standards that use the term DSM. We do not see any type of evaluation of the impact created by the change to the glossary term on these standards. This impact must be evaluated before modifying the definition. (2) We also question the need to add a definition for Total Internal Demand, as the standard should state what data could be requested and would not need a definition for this purpose. According to the NERC Drafting Team Guidelines, dated April 2009, the guidance states that an SDT “should avoid developing new definitions unless absolutely necessary.” There is a glossary of terms that has been approved for use in reliability standards. Before a drafting team adds a new term, the team should check the latest version of the Glossary of Terms for Reliability Standards to determine if the same term, or a term with the same meaning, has already been defined. If a term is used in a standard and the term is defined in a collegiate dictionary, then there is no need to also include the term in the NERC Glossary of Reliability Terms. The addition of an adjective or a prefix to an already defined term should not result in a new defined term. It is very difficult to reach consensus on new terms. If a simple phrase can be used in a standard to replace a new term, then the drafting team should consider using the phrase rather than trying to obtain stakeholder consensus on the new term. Further, the proposed definition conflicts directly with the term as used in the NERC Long-Term Reliability Assessments and Seasonal Assessments. In these assessments Total Internal Demand is the demand without reducing for DSM. Net Internal Demand is the term used for the demand after removing DSM from the demand. We recommend removing the term for Total Internal Demand from the standard. (3) We do not understand how the modified purpose statement in the standard supports reliability because it is redundant with authority already granted NERC through its Rules of Procedure. The rationale provided by the SDT is to clearly state the intention of the standard, but we believe that the collection of Demand and energy data is administrative in nature and would qualify for Paragraph 81 retirement. This data is better suited for a section 1600 data request, which NERC and the Regional Entities already have authority to initiate. We believe the team needs to reevaluate this purpose of this standard, remove administrative tasks from the requirements, and focus on the activities needed for a more reliable system. We also believe the drafting team should ultimately retire all similar requirements and move them to |

a section 1600 data request. As reflected in Paragraph 81 criteria, data collection is not well suited for compliance monitoring. A section 1600 data request is mandatory and this would provide the appropriate incentive to ensure data is submitted without stifling the interaction between the data submitter and the receiver on whether the data is satisfactory. When data submittal is required by standards, data receivers are often reluctanct to comment on the satisfactory nature of the data for fear of being becoming involved in another party's compliance monitoring. This could result in data submitted that does not meet the receiver's needs. There is no need to develop a standard for a data request because the NERC Rules of Procedure already provide equally effective alternate measures to obtain the data. (4) We disagree with several aspects to Requirement R1 because they meet P81 criteria. Further, the RSAW states that items listed in parts 1.3 through 1.5.4 are optional and are included in the data request at the entity's discretion. A data request may include requests for additional data, but there is no requirement to provide the additional data under this standard. These aspects of R1 meet Paragraph 81 criteria and need to be revised. According to P81, requirements for data requests are an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES (criterion A). In addition to criterion A, these data requests are administrative in nature (criterion B1), focus on data collection/data retention (criterion B2), require entities to develop a document that is not necessary to protect BES reliability (criterion B3), require reporting to another entity or party (criterion B4), and require responsible entities to periodically update documentation without an operational benefit to reliability (criterion B5). Based on these reasons, we ask the drafting team to revise the requirement so only activities directly relating to reliability are addressed. (5) Distribution Provider should be removed from Part 1.1. All of the DP's load will already be reported via the LSE or BA. NERC compliance registry criterion III.a.4 is very clear that DPs "will be registered as a Load Serving Entity (LSE) for all load directly connected to their distribution facilities." Thus, applicability to DP is not needed. (6) For Requirement R2, we agree that the auditor should only verify that the data was delivered as specified. This standard does not specify criteria around quality, so auditors should not make any assessments in that regard. However, we continue to believe that R2 also meets P81 criteria because the language in the requirement and the purpose of the standard is to facilitate the sharing of data. (7) For Requirement R3, there should not be a standard for complying with a Regional Entity. The NERC Rules of Procedure outline several methods including a section 1600 data request for regional entities and NERC to request data and may impose sanctions to those entities that fail to comply. There is an equally efficient alternative to achieve the same result that is being sought in R3. We recommend striking the requirement. (8) For Requirement R4, we do not see the need for this requirement and the timelines are arbitrary. As stated above, the items in this requirement meet P81 criteria. For instance, listing the data that could be requested, the neighboring entities that could request data and the conditions for when a data provider could refuse to provide the data are all administrative tasks that do not benefit or protect the reliable operation of the BES. We recommend striking this requirement. (9) In regard to the VSLs/VRFs, since we disagree with the approach of the drafting team's modified requirements, we also disagree with the corresponding VSLs and VRFs. (10) Thank you for the opportunity to comment.

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| Group |
| Florida Power & Light |
| Mike O'Neil |
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| It is currently unclear if the different reporting requirements will result in FPL no longer being able to point to its Ten Year Site Plan filing with the FPSC as the place where all of the data currently requested in MODs 16-19 and 21 are found. One example is the apparent change in load forecasting regarding weather-normalized load. |
| Group |
| Tennessee Valley Authority |
| Dennis Chastain |
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| TVA appreciates the efforts of the Standards Drafting Team to develop this replacement standard and address FERC’s directives. As stated in our comments on the second draft, it is unclear if the purpose of the replacement standard is to facilitate demand and energy data collection by the registered entities who have a reliabiliy related need to obtain the data for the purpose of making BES infrastructure decisions (the TP/TO and RP/GO), or if the end purpose is to provide data to the Regional Entity / ERO for the purpose of producing regional or NERC wide reliability assessments. With the latest draft, it seems more evident that the drafting team is working toward the latter. That being the case, we believe a “paragraph 81” review leading to the retirement of these standards is the more appropriate course. Furthermore, the proposed standard would only address the demand and energy data aspect of the regional and NERC level assessment needs, with no corresponding standard/requirements for the collection of resource data. If the standard moves forward as currently drafted, can a PC or BA elect not to request any (or some) data under R1 and when requested by the Regional Entity to provide the data (R2) respond that it has not collected it? A proposed solution is for the drafting team to revise the purpose of the standard to be - “To enable Transmission Planners and Resource Planners to define and collect the Demand, energy and related data necessary to perform planning studies that support future intrastructure build decisions by the Transmission Owner and Generation Owner.” If the drafting team moves forward with this focus, the requirements will need further work. The standard’s applicability could be revised to include a “Demand/Energy Data Entity” (reference PRC-006-1 for similar precedent - “UFLS Entity”) that can include the LSE, DP, BA or TO. We believe a standard developed under this purpose, while still seeking to address FERC’s directives, would be of more reliability benefit than a standard that focuses on partial data collection needed for Regional Entity / ERO assessments. |
| Group |
| Bonneville Power Administration |
| Andrea Jessup |
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| BPA would like to see a change to MOD-031-1 which was previously considered during comment periods. Requirement 1.3.2.1 requires that each Applicable Entity perform a weather normalization calculation on the peak hour data. Weather normalization calculations are extremely complicated and have a wide distribution of methods applied with inconsistent results. The most effective planning can be achieved if the entity using the data applies a consistent method to the data. Therefore we think this requirement should ask for the date/time of the peak occurrence. With that data the planning entity can perform their own analysis with the weather variables they feel are applicable. Other than this comment BPA supports the changes and is in agreement with the proposal. Previously MOD-031-1 had changed the wording to include "may" weather normalize the data. Alternatively to asking for the data/time of the peak occurrence replacing the word "shall" with "may" in the text of this requirement would also allow the Applicable Entity to determine if they have sufficient means to do the weather normalization and not provide data if they are not skilled at calculating the quantity. The proposed MOD-031-1 standard appears to remove the existing MOD-016-1.1 R1.1 requirement that requires consistent data submittals are supplied for Reliability Standards TPL-005, TPL-006, MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, and MOD-021. As these TPL and remaining MOD standards still have a dependency on similar data requests/submittals, BPA feels this standard has inappropriately dropped language that requires consistency between the MOD and TPL standards. |
| Group |
| Cooper Compliance Corp |
| Mary Jo Cooper |
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| Particular to Standard MOD-031, the drafting team should consider requiring BAs and PCs to post the data request on their website and distribute the request to other entities one (1) year in addition to sending a reminder (1) quarter year (3 months) prior to the due dates. Thirty (30) day data requests are time consuming and often these requests are made to the incorrect person. Furthermore, the detail for what should be received in the request should be stated by the BA or PC and not by the Standard. |
| Individual |
| Cheryl Moseley |
| Electric Reliability Council of Texas, Inc. |
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| Please consider using IRO-010-1a R1 as a guideline for allowing an reliability entity to ask for what is required without being so prescriptive and yet limiting to the requestor. This standard is very similar in nature to IRO-010-1a and should be consistent with such a format. M1, M2, M3: Propose deleting prescriptive elements in measures. If the data request needs to be dated or the format has to be a certain way, then it should be in the requirement and not in the measure. Preferable means of evidence can be listed in the RSAW but are not requirements. Recommend for most instances to include "or other equivalent evidence" to allow flexibility for a responsible entity and the auditor to accept such means of evidence. R4: |

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| Delete “with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric System”. This statement is ambiguous and leaves language open to interpretation. Recommend just including TP and RP in R1 and delete R4 to simplify. There should not be a distinction between how or what you provide to a reliability entity that has reliability tasks to perform. If you simplify R1 to be consistent with IRO-010-1a, this makes the standard much simpler and streamlined. R4.1: Applicable entities should be required to provide data without exception and therefore propose removing language that would allow entities to explain why they will not provide requested data. M4: Removed language related to R4.1 that would allow for explanation for non-submittals Table of Compliance Elements: Recommend modifying the VRFs and VSLs to that which is consistent with IRO-010-1a. Issuing a request for data is not a medium VRF, nor providing to the RE when applying the violation risk factor guideline. Similar to IRO-010-1a, it is possible to allow for so different variations to graduate the VSLs in severity consistent with the VSL guideline document. General comment is that with the modifications to the definition to DSM and the introduction of Total Internal Demand, NERC and or the SDT should review the potential impact or necessity for modifications to other existing NERC Reliability standards which use those terms or terms that are included in the make up identified in the definition. An example would be the use of interruptible load vs DSM in other standards. Also, it is unclear if there are controls that limit the double counting of load under Firm Demand and or controllable and dispatchable DSM load as load by definition is Firm until a certain criteria is reached allowing the use of the DSM load. |
| Individual |
| Spencer Tacke |
| Modesto Irrigation District |
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| I want to vote NO on MOD-031-1. The reason is because of the language in Section B R1 1.3.2. I don’t believe we should be skewing the actual demand data recorded, that is then subsequently used in our analysis work. |
| Individual |
| Mahmood Safi |
| Omaha Public Power District |
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| OPPD recommends that the SDT consider revising DSM description used in Requirement R1 Part 1.3.4 to be consistence with the description of DSM used in the NERC Long-Term Reliability Assessment (LTRA). |