

BAL-001-TRE-1 – Primary Frequency Response in the ERCOT Region

Commenter	Voted	Comment	Response
Andrew Gallo , Austin Energy	No	Our concern is with requirements 9 and 10. Measuring and evaluating primary frequency response is inexact and difficult. ERCOT's PDC Working Group is currently struggling with this issue. It is good/appropriate that a unit can be excluded due to a "legitimate operating condition", however, this possible exclusion introduces subjectivity into the evaluation making consistency of application a potential issue. Until the metrics are well defined, repeatable and less subjective, Texas RE should not impose fines or, at least, lessen both the VRF and VSL for these requirements.	
Brenda Hampton , Luminant Generation Company	No	Requirement R7 of the Standard states that each unit will be operated with the Governor in service when the generating unit/generating facility is online and released for dispatch. We have no concerns with the Requirement; however, the Measure that goes with it (M7) is problematic. M7 requires evidence be produced to prove that the Governors are in service any time the unit is on line. Not only is the measure onerous, but there is a concern with exactly what would constitute reasonable "proof". We recommend this measure be re-worded to match that of similar standards (such as VAR-002).	
Brenda Powell , Constellation Energy Commodity Group	No	Some of the requirements proposed are extremely onerous and present many compliance issues. Constellation believes that if TRE truly wants the more onerous requirements implemented, than the BA should be made the owner and authority of those requirements (mainly R8 and R9). The BA could then choose generators that they believe should comply with these requirements, as not all generators would need to comply. The chosen generators could then be paid ancillary services for complying with these requirements.	

<p>Dana Showalter, Champion Wind Farm, EC&R Panther Creek Wind Farm I & II, EC&R Panther Creek Wind Farm III, EC&R Papalote Creek I, EC&R Papalote Creek II, Forest Creek Wind Farm, Indale Wind Farm, Pyron Wind Farm, Roscoe Wind Farm, Sand Bluff Wind Farm</p>	<p>No</p>	<p>The deadband is being cut in half from 0.036 Hz to 0.016 Hz.</p> <p>There are many exemptions included in the standard to account for physical machine limitation for thermal units. No such limitations are explicitly stated in the standard for Wind Units, which is an obvious inequity.</p>	
<p>Grit Schmieder-Copeland, Pattern Gulf Wind</p>	<p>No</p>	<p>From a standpoint of Wind Turbine Generators the timeline required to implement is not realistic.</p> <p>Furthermore, the method of using the fixed load reference for PFR control will cause large system swings once the frequency returns to the dead band due to the fast response of WTGs. Additionally, vendors have had difficulty testing the scheme.</p> <p>In summary, we do not believe that the proposed standard is needed in ERCOT and most of all will result in the expected/promised "improvements".</p>	
<p>Michelle D'Antuono, Ingleside Cogeneration</p>	<p>No</p>	<p>Although Ingleside Cogeneration LP understands the intent and the need for BAL-001-TRE-1, we are not confident that it can be properly implemented. The sheer variety and complexity of generator and governor technologies does not guarantee the actual frequency response will sufficiently match the expected response even if settings are perfectly in accordance with R6.1 through R6.3. A possible solution would be a TRE managed trial to work out the kinks, just like NERC is doing for BA-level frequency response. Assuming all GO/GOPs in the TRE region were engaged, the time-frames established in the implementation plan would be sufficient to derive a performance baseline.</p> <p>Without a trial, we see multiple weaknesses in BAL-001- TRE-1 which need to be addressed:</p> <p>1) If for any reason, a GO cannot set a generator governor as required by R6.1 through R6.3, a technical exception must be made. As the Standard is written, only the BA can make this exception, with no allowance for an appeal even if the GO has a solid technical basis for such a request.</p>	

2) The purpose of R7 seems to be that the GOP must be notified if the Generator Owner has taken the governor offline for maintenance or a similar purpose. However, this requirement reads that the GO must ensure that the governor is online prior to every start-up which is an operations function. The requirement should be rewritten to accurately capture the intent.

3) Status changes in the governor should only be reported to the BA if (a) the governor will not be available at start-up due to maintenance or an unexpected deficiency, (b) the governor unexpectedly goes offline during normal operation, or (c) the governor comes back online after planned maintenance or an unplanned event. It is not necessary to notify the BA during normal start-up or shut-down where the governor engages/disengages coincident with the generator itself. This would seem to be an obvious reading of R8, but NERC has assessed violations related to AVR status for exactly this reason.

4) R9 and R10 do not specify the point where the frequency response parameters are to be measured. This may not make a difference where the generator interconnection to the BES is short, but may be a problem at greater distances, a very common situation in the case of wind farms.

5) Since the BA will likely prioritize the capture of Frequency Measurable Events (FMEs) along critical paths, it is not clear to Ingleside Cogeneration LP that eight samples will be available outside major metropolitan areas.

This turned out to be the case in the generator governor study that NERC performed last December, all the ERCOT events assessed simply had no measurable effect on our frequency response performance.

6) The Regional Standard does not address situations where poor frequency compensation within the local transmission system is driving costs to the Generator Operator. TOs will be provided

	<p>essentially free frequency performance at those locations and will have little incentive to provide static or dynamic reactive compensators to mitigate it. A market model similar for those for ancillary services could be one solution or perhaps end-of-the month reconciliation of costs like those performed between interconnected Bas for inadvertent interchange.</p> <p>Without the assurance of a controlled trial, or definitive modifications to address our five concerns, Ingleside Cogeneration L.P. has to vote "no" on BAL-001-TRE-1.</p>	
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<p>Mike Grimes, Mesquite Wind LLC, Post Oak Wind LLC</p>	<p>No</p>	<p>Post Oak Wind LLC & Mesquite Wind LLC appreciate the opportunity to comment on the proposed BAL-001-TRE-1, Primary Frequency Response in ERCOT.</p> <p>We support the concept embodied in the draft standard: that Primary Frequency Response should be better defined. Specifically defining the response expected from different technologies by including known limiting factors in the expected response enhances reliability by aligning the Balancing Authority's expectations with the design capabilities of ERCOT generation resources.</p> <p>However, this specificity only benefits reliability to the extent that the performance characteristics of any given technology are well understood. That information about wind resources is not available. Many wind resources operating in ERCOT cannot now provide PFR as defined in the ERCOT Protocols. There is no consensus on how to either retrofit the operating wind resources or to design new ones to provide PFR. This was demonstrated in the 24 August 2011 workshop on BAL-001-TRE-1, when different wind turbine vendors reported pursuing different approaches to Primary Frequency Response. Issues that remain to be resolved include: identifying the best proxy for reference frequency, the practicality of maintaining a consistent droop rate, and managing wind resource output when frequency returns within the dead band.</p> <p>Post Oak therefore votes against the adoption of BAL-001-TRE-1. Specific performance requirements should be delayed until sufficient experience with wind resource operations has been gained, so that those requirements produce the desired result. Implementing the requirements as drafted for wind resources would only penalize wind resources without benefiting system reliability. A delay could also permit the exploration of other means to support system frequency. These could include combining other technologies with variable generation resources. Another option is a paid frequency response service.</p>	
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Robert Bell , Kiowa Power Partners LLC	No	<p>1. There are concerns surrounding the Frequency Bias and its application to the Automatic Generation Control (AGC) affecting unit performance against the standard. The Generator follows the AGC setpoint as sent by the QSE. The Frequency Bias is applied to the setpoint by the QSE. If the Frequency Bias is applied incorrectly, or not at all, the load control signal could have units respond counter to an event negating a sustained response.</p> <p>2. The expected 5.78% combined cycle droop response assumes all combined cycle units will perform in similar fashion. This is not the case and response will vary by configuration and type of equipment. This expected response would need to be more specific by asset.</p>	
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<p>Shari Heino, Brazos Electric Power Cooperative</p>	<p>No</p>	<p>Brazos supports this effort; however we still have some concerns with the standard as drafted. Therefore, Brazos votes NO to the standard and the corresponding VRF/VSL poll. Brazos' concerns are listed below:</p> <p>1) Requirement 6.2 of the standard uses a 5.78% droop setting for a CC plant. We are told that this 5.78% droop setting is based on an "average" value but due to the lack of better analysis information, we could support either a 6% or 7% droop value. This droop value can be re-evaluated and the standard revised after better information is available for analysis.</p> <p>2) It is unclear in the Req 6.2 regarding the evaluation of combined cycle units. Our concern is whether it is by plant configuration or by individual generator or both? If evaluation by plant is selected, would the evaluation performance then be based on a specific configuration? If the evaluation is both, then if the plant scores above the requirement, but the individual combustion turbine are below the requirement, do the requirements apply to both plant and individual combustion turbine causing the plant to possibly fail twice?</p> <p>3) There is concern of a very high risk of receiving a Moderate to Severe VSL for peaking or seasonal units with one or two bad performances. These type units are on only during peak season and when other units are on maintenance. When a frequency event does occur, they may not be evaluated since they are usually near their capacity.</p>	
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<p>H. Steven Myers, ERCOT</p>	<p>Yes</p>	<p>ERCOT believes that enhancements and improvements to this standard will likely continue in the future, but this standard is a positive step in the right direction.</p>	
<p>Randy Jones, Calpine Cooperation</p>	<p>No</p>	<p>To date there has been no data or evidence presented that would speak to the long term cost impact to control systems and mechanisms that are involved in a tighter governor dead band setting (0.167 Hz versus 0.036 Hz). The ERCOT BA currently enjoys a 12-month rolling CPS1 average in excess of 145. It appears that the region's primary frequency response is more than adequate and that any additional maintenance cost imposed by this regional standard would be unnecessary and excessive.</p> <p>Primary frequency response in ERCOT is currently an unpaid, mutual assistance service and its individual requirements and metrics were simply imported from the legacy control area era. Before tighter control performance metrics for primary frequency response are imposed we believe that effort should be put into creating a market mechanism if a solution is truly needed by PFR.</p>	