PUC DOCKET NO. 37827

BUFFALO GAP WIND FARM, L.L.C., BUFFALO GAP WIND FARM 2, L.L.C., AND BUFFALO GAP WIND FARM 3, L.L.C.'S APPEAL AND COMPLAINT OF ERCOT'S DECISION AND ACTION REGARDING PRR 830 AND MOTION FOR SUSPENSION OF ACTION	§ § § § § § § § §	**BEFORE THE** **PUBLIC UTILITY COMMISSION** **OF TEXAS**

BUFFALO GAP WIND FARM, L.L.C., BUFFALO GAP WIND FARM 2, L.L.C., AND BUFFALO GAP WIND FARM 3, L.L.C.'S APPEAL AND COMPLAINT OF ERCOT'S DECISION AND ACTION REGARDING PRR 830 AND MOTION FOR SUSPENSION OF ACTION

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DECISION AND ACTION REGARDING	**§**	**PUBLIC UTILITY COMMISSION**
PRR 830 AND MOTION FOR	**§**	
SUSPENSION OF ACTION	**§**	**OF TEXAS**

BUFFALO GAP WIND FARM, L.L.C., BUFFALO GAP WIND FARM 2, L.L.C., AND BUFFALO GAP WIND FARM 3, L.L.C.'S APPEAL AND COMPLAINT OF ERCOT'S DECISION AND ACTION REGARDING PRR 830 AND MOTION FOR SUSPENSION OF ACTION

I. Introduction

Buffalo Gap Wind Farm, L.L.C., Buffalo Gap Wind Farm 2, L.L.C., and Buffalo Gap Wind Farm 3, collectively called BG1, BG2, and BG3, (hereinafter "Buffalo Gap" or "Appellant") files this Appeal and Complaint[1] of the Electric Reliability Council of Texas' ("ERCOT's") Decision and Action Regarding Protocol Revision Request ("PRR") 830, and Buffalo Gap files its Motion for Suspension of PRR 830, pursuant to P.U.C. PROC. R. § 22.251.

BG1, BG2, and BG3 are connected at the same Point of Interconnection ("POI"). In *toto,* Buffalo Gap consists of 523.3 MW of wind-powered generation.

Buffalo Gap respectfully requests the Public Utility Commission of Texas ("Commission" or "PUC") to:

1) reverse ERCOT's action regarding its approval of PRR 830, and

2) suspend the implementation of such decision while this complaint is pending, unless all entities against whom the complainant seeks relief agree to the suspension.

[1] The terms "appeal" and "complaint" are used interchangeably, as is done in P.U.C. PROC. R. § 22.251.

II. General Procedural and Factual Background

On November 17, 2009, ERCOT's Board approved PRR 830 which significantly alters the reactive power capacity requirement for existing Wind-powered Generation Resources ("WGRs"). Buffalo Gap is an existing WGR adversely affected by ERCOT's approval of PRR 830.

The Buffalo Gap wind project currently conforms to the 0.95 lead/lag (aka "Cone") reactive power capability. This requirement is similar to the FERC 661A requirement for the interconnection of wind generators under FREC jurisdiction in other parts of the United States. To the knowledge of Buffalo Gap there have been no operational or reliability problems associated with reactive support or voltage regulation at or in the vicinity of the Buffalo Gap project since it commenced operation in 2005. ERCOT has not provided a study, analysis, or any report that indicates the need for additional reactive capability at the Buffalo Gap project. In fact the Interconnection Studies performed by Buffalo Gap's Transmission Service Provider (AEP) and specific to the Buffalo Gap projects indicate that the original ERCOT 0.95 lead/lag (Cone) reactive requirement exceeds the reactive support required for the project and was not necessary.

Full compliance to the new reactive requirements of ERCOT PRR 830 (aka Rectangle) will require Buffalo Gap to install additional equipment costing millions of dollars. Prior Interconnection Studies and operational experience over the last 4+ years indicate that this additional equipment is not necessary and will not be utilized.

ERCOT's approval of PRR 830 results in unjustified costs arbitrarily assigned to lawfully operating WGRs. There is no demonstrated operational, technical, legal or policy justification for drastically altering the reactive power capacity requirement for existing WGRs or for imposing on existing WGRs the excessive cost such alterations would require. This unlawful and discriminatory practice not only harms existing WGRs, but has serious negative market consequences as well. Buffalo Gap requests that the

Commission: 1) reverse ERCOT's action and decision approving PRR 830, and 2) suspend PRR 830 and the implications thereof. Buffalo Gap's complaints fall within the scope of complaints heard by the Commission. Furthermore, Buffalo Gap will show that ERCOT's approval of PRR 830 violates laws over which this Commission has jurisdiction.

III. Appeal Timely Filed

P.U.C. PROC. R. § 22.251(d) requires that a formal complaint be filed with Commission within 35 days of ERCOT's action. As stated above, ERCOT approved PRR 830 on November 17, 2009. Therefore, this appeal is timely.

IV. Buffalo Gap's Authorized Representatives

Buffalo Gap is the only complainant in this appeal. Its authorized representatives are:

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Vice President
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Buffalo Gap Wind Farm 2, LLC
Buffalo Gap Wind Farm 3, LLC
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Ms. Shannon K. McClendon
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(512) 264-9122 facsimile
shannonk@mcclendonlaw.net
rfox@mcclendonlaw.net

All correspondences, requests for information, responses to requests for information, documents, and any and all communications should be sent to the above-named counsel for Buffalo Gap.

V. Respondents

P.U.C. PROC. R. § 22.251(d)(1)(A) requires Buffalo Gap to include a complete list of entities against whom it seeks relief, to wit, ERCOT is the only entity against whom Buffalo Gap seeks relief. ERCOT can be served at 7620 Metro Center Drive, Austin, Texas 78744. ERCOT's Fax number is (512) 255-7079. ERCOT's General Counsel is Mr. Michael G. Grable and his email address is mgrable@ercot.com.

VI. Request for Extension of Page Limit

P.U.C. PROC. R. § 22.72(f) requires that this pleading not exceed 50 (fifty) pages in length; however, the presiding officer may establish a larger page limit. Buffalo Gap respectfully requests the Commission to permit the entirety of this appeal for good cause. Specifically, although this pleading, in and of itself, is far less than the page limit, once the necessary appendices are attached, the appeal exceeds 50 pages.

VII. Commission has Jurisdiction

The Commission has jurisdiction over this Appeal under PURA[2] §§ 14.001, 39.001, 39.003, and 39.151.

VIII. Statement of the Case

P.U.C. PROC. R. § 22.251 outlines the necessary elements to effectuate an appeal of an ERCOT Board action, including the approval of a PRR, before the Commission. The remainder of those elements are provided below:

[2] Public Utility Regulatory Act ("PURA"), TEX. UTIL. CODE §§ 11.001-64.158 (West 2007 & Supp. 2009) ("PURA").

A. Identify of Directly Affected Entities or Classes[3]

The Commission's decision to grant Buffalo Gap's Appeal and Motion to Suspend would most probably affect all existing WGRs.

B. Concise Description of Conduct from Which Relief is Sought[4]

Buffalo Gap seeks the Commission's review of the reasonableness of ERCOT's adoption of PRR 830, the reversal of PRR 830, and the suspension of the implementation of the adoption of PRR 830 while this appeal is pending.

C. Statement of Applicable ERCOT Procedures and Protocols[5]

The Appendix to this Appeal includes, *inter alia,* the ERCOT Board Action Report which contains a subset of applicable ERCOT Procedures and Protocols. Buffalo Gap has not included in its appendix any irrefutable laws, which are not required to be attached.

The sections of the ERCOT Protocols relevant to this Appeal as contained in that ERCOT Board Action Report are:

- 2.1 (Definitions),
- 2.2 (Acronyms),
- 6.5.7 (voltage Support Service),
- 6.5.7.1 (Generation Resources Required to Provide VSS Installed Reactive Capability)
- 6.5.7.1 (Installed Reactive Power Capability Requirement for Generation Resources Required to Provide VSS)
- 6.5.7.2 (QSE Responsibilities), and
- 6.7.6 (Deployment of Voltage Support Service).

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[3] P.U.C. PROC. R. § 22.251(d)(1)(B)(ii).

[4] *Id. at* 22.251(d)(1)(B)(iii).

[5] *Id. at* 22.251(d)(1)(B)(iii).

D. ADR is not required for this appeal[6]

P.U.C. PROC. R. 22.25(c) and (d) clarify that Alternative Dispute Resolution ("ADR") is not a prerequisite to an appeal of ERCOT's adoption of a PRR. For instance, P.U.C. PROC. R. 22.251(c) uses the term "or":

> An entity must use Section 20 of the ERCOT Protocols (Alternative Dispute Resolution Procedures, or ADR), ***or*** Section 21 of the Protocols (Process for Protocol Revision), or other Applicable ERCOT Procedures, before presenting a complaint to the commission. For the purpose of this section, the term "Applicable ERCOT Procedures" refers to Sections 20 and 21 of the ERCOT Protocols and other applicable sections of the ERCOT protocols that are available to challenge or modify ERCOT conduct, including participation in the protocol revision process [emphasis added].[7]

Furthermore, the Protocols do not require ADR before appealing the adoption of a PRR[8].

E. Buffalo Gap seeks a suspension[9]

Buffalo Gap seeks a suspension of ERCOT's approval of PRR 830. Note below, Section IX., *Motion for Suspension,* of this Appeal.

F. Sworn Record[10]

A required by the Commission rules, an affidavit is attached to this Appeal attesting to the accuracy of the Appendix consisting of eleven (11) attachments.

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6 *Id. at* 22.251(d)(1)(B)(iv).

7 *See also,* P.U.C. SUBST. R. 25.362(c)(2).

8 *See* ERCOT Protocol §§ 21.1, 21.4.11, and 21.4.11.3.

9 *Id. at* 22.251(d)(1)(B)(v).

10 *Id. at* 22.251(d)(1)(H).

G. Affidavit of Facts contained herein[11]

As required by the Commission rules, an affidavit is attached to this Appeal verifying all factual statements contained in the Appeal. Facts specific to Buffalo Gap's operations will be filed under seal subject to a Protective Order.

H. Service to ERCOT and OPC[12]

A required by the Commission rules, this Appeal is being serviced on ERCOT and the Office of Public Utility Counsel, and is also reflected in the attached Certificate of Service. ERCOT and the Office of Public Utility Counsel have agreed to be served by electronic media instead of by paper.

I. Basis for Commission Jurisdiction[13]

The Commission has jurisdiction over this Appeal under PURA §§ 14.001, 39.001, 39.003, and 39.151.

IX. Statement of the Issues[14]

The issue in this case is whether the ERCOT Board properly approved PRR 830 and whether this PRR complies with applicable laws and regulations of this Commission.

X. Statement of Facts and Arguments

Although ERCOT's PRR 830 requires reactive power capability substantially in excess of a 0.95 factor leading/lagging at generation levels below 100% (recently referred to as a "Rectangle" by ERCOT staff and ERCOT Board members), Buffalo Gap was originally built with a reactive power capability with a factor or 0.95 leading and lagging at all generation levels (recently referred to as a "Cone" by ERCOT staff and ERCOT Board members).

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[11] *Id. at* 22.251(d)(3).

[12] *Id. at* 22.251(d)(4).

[13] *Id. at* 22.251(d)(4).

[14] *Id. at* 22.251(d)(1)(C).

ERCOT has not demonstrated need for the retrofit for Buffalo Gap or that the retrofit of additional reactive support required under PRR 830 will be utilized. In other words, based on Interconnection Studies specific to Buffalo Gap and the last four (4) years of operating experience, even if Buffalo Gap were to go to the expense of retrofitting its equipment to comply with 830, those required retrofit would not actually be used. Until such time as ERCOT demonstrates the need for these additional reactive requirements, specifically for the Buffalo Gap Wind Projects and other existing WGR's, Buffalo Gap seeks suspension of PRR 830.

Although ERCOT's PRR 830 requires "Rectangle" Reactive Power capacity, Buffalo Gap was originally built as a "Cone" Reactive Power capacity. ERCOT has not demonstrated need for the retrofit based on the interconnection studies specific for Buffalo Gap and that the retrofit or reactive support required under PRR 830 will not be utilized by Buffalo Gap. In other words, even if Buffalo Gap were to go to the expense of retrofitting it equipment to comply with 830, those required retrofit would not actually be used. Until such time as ERCOT demonstrates the need for these additional reactive requirements, specifically for the Buffalo Gap Wind Projects and other existing WGR's, Buffalo Gap seeks suspension of PRR 830.

XI. QUESTIONS REQUIRING AN EVIDENTIARY HEARING

ERCOT claims that PRR 830 only clarifies existing reactive power capability requirements; however, ERCOT actually deletes prior requirements and creates new requirements for WGRs. To require Buffalo Gap to meet the new requirements of PRR 830 would create a burden that vastly outweighs the benefit ERCOT is seeking in PRR 830.

Further, PRR 830 actually conflicts with other ERCOT Protocol requirements. For example, before ERCOT can require additional reactive power, ERCOT Regional

Planning Groups (or Transmission Planning) must first show that there is a need for such additional reactive power.[15]

In addition, PRR 830 is inconsistent with ERCOT's previous actions, such as providing written notice to Market Participants[16], making reports to the ERCOT Compliance Office[17] or expressing concerns at ERCOT committee meetings.

Finally, PRR 830 discriminates against WGRs in favor of conventional power generation. The PUC and ERCOT are prohibited from engaging in such discriminatory practices[18]; however, ERCOT has now claimed the ability to disconnect WGRs if they operate below 10% of nameplate capacity. ERCOT does not apply this same restriction to conventional power generation. Further, WGRs are required to provide three Real Time Supervisory Control and Data Acquisition ("SCADA") points, a requirement which does not apply to conventional power generation.

XII. MOTION FOR SUSPENSION

P.U.C. PROC. R. 22.251(i) authorizes the Commission to suspend the conduct of ERCOT – including implementation of a Protocol – while a complaint appealing the conduct is pending at the Commission.[19] The standard is good cause.[20] Four factors are considered:

> The good cause determination required by this subsection shall be based on an assessment of the harm that is likely to result to the complainant if a suspension is not ordered, the harm that is likely to result to others if a suspension is ordered, the likelihood of the complainant's success on the

[15] Protocol § 5.2.1(6).

[16] Protocol § 6.5.7.3(4).

[17] Protocol § 6.10.9.

[18] *See, e.g.,* PURA §§ 31.002(9), 35.004(e), 39.001(c), and 39.157.

[19] *See* P.U.C. PROC. R. 22.251(b) and (i); *see also* PURA §§ 39.151(d) and 39.151(d-1).

[20] P.U.C. PROC. R. 22.251(i).

merits of the complaint, and any other relevant factors as determined by the commission or the presiding officer.[21]

Pursuant to P.U.C. PROC. R. § 22.251(d)(2), Buffalo Gap moves for the suspension of ERCOT's approval of PRR 830 and the implementation of the decision, if necessary. More specifically, as briefly stated above, in this appeal Buffalo Gap seeks relief from only ERCOT. Counsel for Buffalo Gap has been in contact with ERCOT's General Counsel to request that ERCOT agree to a suspension, but given time restraints, Counsel for Buffalo Gap cannot represent at this time that ERCOT will agree to a suspension.

The effective date of PRR 830 is December 1, 2009. The PRR remains in effect until and unless the presiding officer or Commission issues and order suspending the ERCOT action approving the PRR. P.U.C. PROC. R. § 22.251(i).

Good cause exists for suspending PRR 830. Not only will harm likely result to Buffalo Gap if a suspension is not ordered, harm is likely to result to most, if not all, other WGRs. Harm includes, but is not limited to,

- Potential sanctions for failure to comply with the PRR which could include
    - administrative penalties (up to $25,000 per day),
    - revocation or suspension of the Commission registration to operate, affecting the commercial value of Buffalo Gap's commercial value of its existing generation
- Potential disconnection from the ERCOT system as stated in the new ERCOT Protocol 6.5.7.1(1), and
- Economic loss in having to place an order for the newly required devices (which cannot be ordered conditionally)

[21] P.U.C. PROC. R. 22.251(i).

Furthermore, given the likelihood of Buffalo Gap's success on the merits of this complaint, good cause exists for suspending the PRR. For these reasons there is ample good cause to suspend PRR 830 while this Appeal is pending at the Commission.

XIII. CONCLUSION AND PRAYER

WHEREFORE, PREMISES CONSIDERED, Buffalo Gap Wind Farm respectfully request the Commission reverse PRR 830, and expeditiously suspend the implementation of ERCOT's decision regarding its approval of PRR 830. In addition to suffering the deprivation of its ability to obtain meaningful or timely relief, Buffalo Gap would suffer irreparable harm, both financially and in meeting its contractual obligations, were PRR 830 to remain in effect pending the resolution of these matters. Buffalo Gap further requests any and all other relief, legal and equitable, to which it is so entitled.

Respectfully submitted,

Shannon K. McClendon

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CERTIFICATE OF SERVICE

I certify that a true and correct copy of the foregoing was served on ERCOT and the Office of Public Utility Counsel via electronic mail or via facsimile on this 22nd day of December, 2009.

Brett C. Nelson

Appendix

Protocol Revision Request 830, *Reactive Power Capability Requirement*

ERCOT Board Action Report regarding PRR 830

ERCOT Board of Directors November meeting transcript regarding PRR 830

Letter from ERCOT General Counsel Grable Dated November 10, 2009 to the ERCOT Board of Directors regarding Packet Materials for the November Board meeting [materials regarding PRR 830, incorporated by reference]

ERCOT Technical Advisory Committee ("TAC") November 2009 meeting minutes regarding PRR 830

ERCOT Protocol Revision Subcommittee ("PRS") October 2009 meeting minutes regarding PRR 830

ERCOT Reliability and Operations Subcommittee ("ROS") October 2009 meeting minutes regarding PRR 830

Resource Asset Registration Guide

Affidavit of Mr. Brett Nelson regarding genuineness of attachments

Affidavit of Mr. Robert Sims, AES Wind Generation, Inc. attesting to facts asserted herein

Protocol Revision Request 830,
Reactive Power Capability Requirement

Approved November 17, 2009

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Protocol Revision Request

PRR Number	830	PRR Title	Reactive Power Capability Requirement
Date Posted		September 8, 2009	

Protocol Section(s) Requiring Revision	2.1, Definitions 2.2, Acronyms 6.5.7, Voltage Support Service 6.5.7.1, Generation Resources Required to Provide VSS Installed Reactive Capability 6.7.6, Deployment of Voltage Support Service
Requested Resolution	Urgent. On November 13, 2008, ERCOT Legal issued a Protocol Interpretation, which was subsequently withdrawn on procedural grounds, regarding the Reactive Power capability requirements in Sections 6.5.7.1 and Section 6.7.6. This Protocol Interpretation resulted in a complaint filed against ERCOT by certain Wind-powered Generation Entities at the Public Utility Commission of Texas (see PUCT Docket No. 36482, Appeal of Competitive Wind Generators Regarding the Electric Reliability Council of Texas' Interpretation of the Reactive Power Protocols). One of the reasons ERCOT sought to abate and then dismiss that docket is that this issue is better suited to an informal and forward-looking resolution. Therefore, ERCOT files this Protocol Revision Request (PRR) to seek a prospective outcome that maintains reliability while attempting to lessen the costs and burdens of compliance with respect to the Reactive Power capability requirements in the ERCOT Protocols, and that offers a path to compliance for certain Wind-powered Generation Resources (WGRs) that are presently not able to meet 0.95 lead/lag requirement at the Point of Interconnection based solely on the unit's Reactive Power capability.
Revision Description	This PRR clarifies the Reactive Power capability requirement for all Generation Resources, including existing WGRs who are not able to meet the 0.95 lead/lag requirement with the Generation Resource's Unit Reactive Limit (URL). WGRs that commenced operation on or after February 17, 2004, and have a signed Standard Generation Interconnection Agreement (SGIA) on or before November 1, 2009 may met the Reactive Power requirements through a combination of the WGR's URL and/or automatically switchable static VAR capable devices and/or dynamic VAR capable devices.
Reason for Revision	Clarification of Reactive Power capability requirements on a going-forward basis and path to compliance for certain WGRs that are not able to meet the 0.95 lead/lag requirement at the Point of Interconnection based on Generation Resource's URL.

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Protocol Revision Request

Sponsor	
Name	John Dumas
E-mail Address	jdumas@ercot.com
Company	ERCOT
Phone Number	(512) 248-3195
Cell Number	
Market Segment	N/A

Market Rules Staff Contact	
Name	Sandra Tindall
E-Mail Address	stindall@ercot.com
Phone Number	512-248-3867

~~interconnection~~POI ~~to the TDSP~~. The Reactive Power requirements shall be available at all MW output levels and may be met through a combination of the Generation Resource's Unit Reactive Limit (URL), which is the generating unit's dynamic leading and lagging operating capability, and/or dynamic VAR capable devices. For Wind-powered Generation Resources (WGRs), the Reactive Power requirements shall be available at all MW output levels at or above 10% of the WGR's nameplate capacity. When a WGR is operating below 10% of its nameplate capacity and is unable to support voltage at the POI, ERCOT may require a WGR to disconnect from the ERCOT System. The Reactive Power requirements of this paragraph shall apply to all Generation Resources except as otherwise provided in paragraphs (2) through (4) below.

(2) WGRs that commenced operation on or after February 17, 2004, and have a signed Standard Generation Interconnection Agreement (SGIA) on or before November 1, 2009, must be capable of producing a defined quantity of Reactive Power to maintain a Voltage Profile established by ERCOT in accordance with the Reactive Power requirements established in paragraph (1) above. However, the Reactive Power requirements may be met through a combination of the WGR's URL and/or automatically switchable static VAR capable devices and/or dynamic VAR capable devices. WGRs shall comply with the Reactive Power requirements of this paragraph by no later than December 31, 2010, unless it is known by July 31, 2010, that related retrofits are required by the Voltage Ride-Through study conducted in accordance with Operation Guide Section 3.1.4.6.1, Protective Relaying Requirement and Voltage Ride-Through Requirement for Wind-powered Generation Resources, in which event ERCOT may in its discretion modify the deadline for an affected WGR. ERCOT, in its sole discretion, also may grant an extension of time for other reasons.

(3) Qualified renewable Generation Resources (as described in Section 14, State of Texas Renewable Energy Credit Trading Program) in operation before February 17, 2004, required to provide VSS and all other Generation Resources required to provide VSS that were in operation prior to September 1, 1999, whose current design does not allow them to meet the ~~URL as stated above~~Reactive Power requirements established in paragraph (1) above, will be required to maintain a ~~URL~~ Reactive Power requirement as defined by the qualified renewable Generation Resource's URL that was submitted to ERCOT and established per the ~~is limited to the quantity of Reactive Power that the Generation Resource can produce at its rated capability (MW) as determined using procedures and~~ criteria ~~as described~~ in the Operating Guides.

(4) New generating units connected before May 17, 2005, whose owners demonstrate to ERCOT's satisfaction that design and/or equipment procurement decisions were made prior to February 17, 2004, based upon previous standards, whose design does not allow them to meet the ~~URL as stated above~~Reactive Power requirements established in paragraph (1) above, will be required to maintain a ~~URL~~ Reactive Power requirement as defined by the Generation Resource's URL that was submitted to ERCOT and established per the ~~is limited to the quantity of Reactive Power that the Generation Resource can produce at its rated capability (MW) as determined using procedures and~~ criteria ~~described~~ in the Operating Guides.

into the ERCOT Transmission Grid. WGRs must also provide two other Real Time SCADA points that communicate to ERCOT the following:

(a) The number of wind turbines that are not able to communicate and whose status is unknown; and

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(b) The number of wind turbines out of service and not available for operation. WGRs must comply with these requirements by no later than six months after the effective date of this paragraph.

(11) For the purpose of complying with the Reactive Power requirements under this Section, Reactive Power losses that occur on privately-owned transmission lines behind the POI may be compensated by automatically switchable static VAR capable devices.

6.7.6 Deployment of Voltage Support Service

(1) ERCOT, or Transmission Service Providers (TSPs) designated by ERCOT, will instruct Generation Resources required to provide Voltage Support Service (VSS) to make adjustments for voltage support within the Unit Reactive Limit (URL) capacity limits provided by the QSE to ERCOT. Generation Resources providing VSS will not be requested to reduce megawatt output so as to provide additional M~~m~~egavolt -A~~a~~mperes R~~r~~eactive (MVAR), nor will they be requested to operate on a voltage schedule outside the ~~Unit Reactive Limits (~~URL~~)~~ specified by the QSE without a Dispatch Instruction requesting unit-specific Dispatch or an OOME instruction.

(2) ERCOT and Transmission and/or Distribution Service Providers (TDSPs) shall develop operating procedures specifying Voltage Profiles of transmission controlled reactive Resources to minimize the dependence on generation-supplied reactive Resources. For Generation Resources required to provide VSS, step-up transformer tap settings will be managed to maximize the use of the ERCOT System for all Market Participants while maintaining adequate reliability.

(3) The TSP, under ERCOT direction, is responsible for monitoring and ensuring that all Generation Resources required to provide VSS dynamic reactive sources in a local area are deployed in approximate proportion to their respective installed ~~r~~Reactive Power capability requirements.

(4) All Generation Resources required to provide VSS shall ~~maintain~~support the transmission voltage at the ~~point of interconnection~~POI to the ERCOT ~~t~~Transmission ~~g~~Grid, or at the transmission bus in accordance with paragraph (5) of Section 6.5.7.1, Generation Resources Required to Provide VSS Installed Reactive Capability, as directed by ERCOT within the operating Reactive Power capability of the unit(s).

~~(5) At all times a Generation Resource unit required to provide VSS is On-line, the URL must be available for utilization at the generating unit's continuous rated active power output. and Reactive Power up to the unit's operating capability must be available for utilization at lower active power output levels. In no event shall the Reactive Power~~

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ERCOT Board Action Report regarding PRR 830

November 17, 2009

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Board Action Report

PRR Number	830	**PRR Title**	**Reactive Power Capability Requirement**	
Timeline	Urgent	**Action**		Approved
Date of Decision	November 17, 2009			
Effective Date	December 1, 2009			
Priority and Rank Assigned	Not applicable.			
Protocol Section(s) Requiring Revision	2.1, Definitions 2.2, Acronyms 6.5.7, Voltage Support Service 6.5.7.1, Generation Resources Required to Provide VSS Installed Reactive Capability 6.7.6, Deployment of Voltage Support Service			
Revision Description	This Protocol Revision Request (PRR) clarifies the Reactive Power capability requirement for all Generation Resources, including existing Wind-powered Generation Resources (WGRs) who are not able to meet the 0.95 lead/lag requirement with the Generation Resource's Unit Reactive Limit (URL). WGRs that commenced operation on or after February 17, 2004, and have a signed Standard Generation Interconnection Agreement (SGIA) on or before December 1, 2009 may meet the Reactive Power requirements through a combination of the WGR's URL and/or automatically switchable static VAR capable devices and/or dynamic VAR capable devices.			
Reason for Revision	Clarification of Reactive Power capability requirements on a going-forward basis and path to compliance for certain WGRs that are not able to meet the 0.95 lead/lag requirement at the Point of Interconnection (POI) based on the Generation Resource's URL.			
Overall Market Benefit	Provides additional clarity to the reactive requirements for wind generation.			
Overall Market Impact	Unknown.			
Consumer Impact	None.			
Credit Impacts	ERCOT Credit Staff and the Credit Work Group (Credit WG) have reviewed PRR830 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.			
Relevance to Nodal Market	Yes. The Reactive Power capability requirements exist in Nodal as well.			

Board Action Report

	posted. ➢ On 11/17/09, RES America Developments comments were posted. ➢ On 11/17/09, a second set of AES comments were posted. ➢ On 11/17/09, the ERCOT Board considered PRR830. ➢ On 11/20/09, the NextEra Energy Resources ERCOT Board presentation was posted.
PRS Decision	On 9/17/09, PRS unanimously voted to table PRR830 for one month and to encourage ROS to provide comments on PRR830. All Market Segments were present for the vote. On 10/22/09, PRS voted to recommend approval of PRR830 as endorsed by ROS. The motion passed via roll call vote. All Market Segments were present for the vote.
Summary of PRS Discussion	On 9/17/09, there was discussion regarding the appeal currently at the Public Utility Commission of Texas (PUCT) which stemmed from an ERCOT interpretation of the current Protocols regarding Reactive Power. It was debated whether or not the proposed content of PRR830 was being addressed in the contested case. On 10/22/09, ERCOT Staff explained that PRR830 is not intended to change the philosophy of the Protocols. ERCOT Staff also provided clarification of the proposed change to the WGR definition, and noted that dynamic devices will be required going forward, but that existing WGRs can meet the requirement with static devices. There was also discussion regarding the use of the "cone" versus the "rectangle" for Reactive Power capability and that having differing requirements makes planning difficult and may pose fairness and grid stability issues. Some Market Participants expressed concerns that requirements of PRR830 would impose costs to retrofit existing units and that studies should be performed to demonstrate need.
TAC Decision	On 11/5/09, TAC voted to recommend approval of PRR830 as recommended by PRS in the 10/22/09 PRS Recommendation Report and as amended by the 10/29/09 ERCOT comments. All Market Segments were present for the vote.
Summary of TAC Discussion	On 11/5/09, TAC reviewed PRR830 comments. A Market Participant proposed including language that allowed a hybrid solution to meet Reactive Power capability requirements. ERCOT Staff explained that paragraph (6) of Section 6.5.7.1 allows Market Participants to submit alternative proposals to ERCOT for meeting the requirement, which could include a hybrid solution. Some Market Participants opined that changing the definition of WGR would have repercussions not only where "WGR" is used in the Protocols or market guides, but could also create complications in instances where the terms "generator," "Resource," or "unit" are

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Sponsor	
Name	John Dumas
E-mail Address	jdumas@ercot.com
Company	ERCOT
Phone Number	(512) 248-3195
Cell Number	
Market Segment	N/A

Market Rules Staff Contact	
Name	Sandra Tindall
E-Mail Address	stindall@ercot.com
Phone Number	512-248-3867

Comments Received	
Comment Author	**Comment Summary**
Horizon Wind Energy LLC 091509	Recommended that PRR830 be rejected as submitted.
Calpine 092809	Supported approval of PRR830.
Iberdrola Renewables 100709	Suggested existing Protocol language is clear. Proposed additional revisions only as an alternative to the ERCOT proposed changes.
Horizon Wind Energy LLC 100809	Opined that PRR830 is contrary to existing Protocols, and is proposed without demonstration of need. Commented that PRR830 re-defines Reactive Power capability requirements for Generation Resources interconnected with the ERCOT Transmission Grid, imposing new requirements on WGRs and requiring retrofits to the majority of operating WGRs.
LCRA 100809	Proposed clarifying language which would allow Resources to start at lower voltage levels. Also proposed changes related to establishing Reactive Power requirements.
ROS 101909	Endorsed PRR830 as submitted.
Wind Coalition 102109	Provided alternative language to the definition of a WGR and the subsequent changes that are intended to improve the modeling of wind-powered generation reactive capabilities.
Vestas 102209	Stated that if PRR830 is adopted as proposed, it may unnecessarily increase the costs of WGRs in Texas with no improvements in reliability. Suggested that hybrid systems that have the effective

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	Suggested the NextEra proposed language would require TSPs to submit reactive element upgrades and opined that related costs should be borne by those causing the costs.
AES 111009	Suggested PRR830 should not be implemented as recommended by TAC because: 1) PRR830 requires voltage and power factor capabilities higher than the Federal Energy Regulatory Commission (FERC) 661A requirements for which ERCOT has not demonstrated the need; 2) PRR830 is a piecemeal approach and ERCOT should take a comprehensive approach along with the Low Voltage Ride Through study; and 3) PRR830 retroactively changes the interconnection requirements for operating wind projects with no documented need.
Horizon Wind Energy LLC 111009	Suggested PRR830 does not clarify existing Protocols and will create hardships on a sub-segment of generation. Provided documents to support position.
Oncor 111009	Noted support for PRR830 and described principles needed for the bulk power system to operate reliably. Provided documents to support position.
TAC Advocate 111009	Explained the TAC position on PRR830 highlighting the discussion and vote tallies at various stakeholder meetings. Noted support was due to reliability concerns for the grid as well as desire that all generators be treated equitably. Highlighted need to ensure that the system is operated in manner in which it was planned and built and suggested further study is not needed as generators have a fixed reactive capability requirement.
ERCOT 111009	Requested rejection of the NextEra appeal and approval of PRR830 as recommended by TAC to preserve important reliability requirements, to maintain parity among Generation Resources, and to reduce uplift of costs to Load.
Wind Coalition 111009	Supported creating aggregations of actual wind-powered turbines of the same type for modeling purposes but argued the redefinition of WGRs will make WGRs "units" for all purposes in the Protocol and market guides.
TAC Advocate 111109	Provided a supporting document to review PRR830 procedural history, to note Reactive Power requirements and the applicability to existing Generation Resources, and to counter the argument for additional studies to determine need.
RES America Developments Inc. 111709	Requested that the ERCOT Board not approve PRR830 because it will force some existing Generation Resources to retrofit equipment which would impose additional costs on the Generation Resource which would more efficiently be realized by TSPs. Suggested a technical study should be performed to determine whether Reactive Power response via the triangle is inadequate to maintain reliability.
AES 111709	Provided chronological summary and list of parties participating in the proceedings related to FERC Order 661A.
NextEra Energy	Opined that reinterpreting existing Protocols and applying them

hundredths (0.95) or less and an under-excited (leading) power factor capability of ninety-five hundredths (0.95) or less, both determined at the generating unit's maximum net power to be supplied to the ERCOT ~~t~~Transmission ~~g~~Grid and at the transmission system Voltage Profile established by ERCOT, and both measured at the ~~point of interconnection~~POI ~~to the TDSP~~. The Reactive Power requirements shall be available at all MW output levels and may be met through a combination of the Generation Resource's Unit Reactive Limit (URL), which is the generating unit's dynamic leading and lagging operating capability, and/or dynamic VAR capable devices. For Wind-powered Generation Resources (WGRs), the Reactive Power requirements shall be available at all MW output levels at or above 10 percent (10%) of the WGR's nameplate capacity. When a WGR is operating below 10% of its nameplate capacity and is unable to support voltage at the POI, ERCOT may require a WGR to disconnect from the ERCOT System. The Reactive Power requirements of this paragraph shall apply to all Generation Resources except as otherwise provided in paragraphs (2) through (4) below.

(2) WGRs that commenced operation on or after February 17, 2004, and have a signed Standard Generation Interconnection Agreement (SGIA) on or before ~~November~~December 1, 2009, must be capable of producing a defined quantity of Reactive Power to maintain a Voltage Profile established by ERCOT in accordance with the Reactive Power requirements established in paragraph (1) above. However, the Reactive Power requirements may be met through a combination of the WGR's URL and/or automatically switchable static VAR capable devices and/or dynamic VAR capable devices. WGRs shall comply with the Reactive Power requirements of this paragraph by no later than December 31, 2010, unless it is known by July 31, 2010, that related retrofits are required by the Voltage Ride-Through study conducted in accordance with Operation Guide Section 3.1.4.6.1, Protective Relaying Requirement and Voltage Ride-Through Requirement for Wind-powered Generation Resources, in which event ERCOT may in its discretion modify the deadline for an affected WGR. ERCOT, in its sole discretion, also may grant an extension of time for other reasons.

(3) Qualified renewable Generation Resources (as described in Section 14, State of Texas Renewable Energy Credit Trading Program) in operation before February 17, 2004, required to provide VSS and all other Generation Resources required to provide VSS that were in operation prior to September 1, 1999, whose current design does not allow them to meet the ~~URL as stated above~~Reactive Power requirements established in paragraph (1) above, will be required to maintain a ~~URL~~ Reactive Power requirement as defined by the qualified renewable Generation Resource's URL that was submitted to ERCOT and established per the ~~is limited to the quantity of Reactive Power that the Generation Resource can produce at its rated capability (MW) as determined using procedures and~~ criteria ~~as described~~ in the Operating Guides.

(4) New generating units connected before May 17, 2005, whose owners demonstrate to ERCOT's satisfaction that design and/or equipment procurement decisions were made prior to February 17, 2004, based upon previous standards, whose design does not allow them to meet the ~~URL as stated above~~Reactive Power requirements established in paragraph (1) above, will be required to maintain a ~~URL~~ Reactive Power requirement as defined by the Generation Resource's URL that was submitted to ERCOT and

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(9) Generation Resources ~~required to provide VSS~~ shall not reduce high reactive loading on individual units during abnormal conditions without the consent of ERCOT (conveyed by way of their QSE) unless equipment damage is imminent.

(10) WGRs must provide a Real Time Supervisory Control and Data Acquisition (SCADA) point that communicates to ERCOT the number of wind turbines that are available for real power and/or Reactive Power injection into the ERCOT Transmission Grid. WGRs must also provide two (2) other Real Time SCADA points that communicate to ERCOT the following:

(a) The number of wind turbines that are not able to communicate and whose status is unknown; and

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(b) The number of wind turbines out of service and not available for operation.

WGRs must comply with these requirements of paragraph (10) by no later than ~~six (6) months after the effective date of this paragraph~~June 1, 2010.

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(11) For the purpose of complying with the Reactive Power requirements under this Section, Reactive Power losses that occur on privately-owned transmission lines behind the POI may be compensated by automatically switchable static VAR capable devices.

6.7.6 Deployment of Voltage Support Service

(1) ERCOT, or Transmission and/or Distribution Service Providers (TDSPs) designated by ERCOT, will instruct Generation Resources required to provide Voltage Support Service (VSS) to make adjustments for voltage support within the Unit Reactive Limit (URL) capacity limits provided by the QSE to ERCOT. Generation Resources providing VSS will not be requested to reduce megawatt output so as to provide additional M~~m~~egavolt-Aamperes R~~r~~eactive (MVAR), nor will they be requested to operate on a voltage schedule outside the ~~Unit Reactive Limits (~~URL~~)~~ specified by the QSE without a Dispatch Instruction requesting unit-specific Dispatch or an OOME instruction.

(2) ERCOT and ~~Transmission and/or Distribution Service Providers (~~TDSPs~~)~~ shall develop operating procedures specifying Voltage Profiles of transmission controlled reactive Resources to minimize the dependence on generation-supplied reactive Resources. For Generation Resources required to provide VSS, ~~step-up~~GSU transformer tap settings will be managed to maximize the use of the ERCOT System for all Market Participants while maintaining adequate reliability.

(3) The TDSP, under ERCOT direction, is responsible for monitoring and ensuring that all Generation Resources required to provide VSS dynamic reactive sources in a local area are deployed in approximate proportion to their respective installed ~~r~~Reactive Power capability requirements.

(4) All Generation Resources required to provide VSS shall ~~maintain~~support the transmission voltage at the ~~point of interconnection~~POI to the ERCOT ~~t~~Transmission ~~g~~Grid, or at the

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ERCOT Board of Directors November meeting transcript regarding PRR 830

November 17, 2009

TRANSCRIPT OF PROCEEDINGS

BEFORE THE

ELECTRIC RELIABILITY COUNCIL OF TEXAS

AUSTIN, TEXAS

BOARD OF DIRECTORS MEETING

TUESDAY, NOVEMBER 17, 2009

BE IT REMEMBERED THAT at 10:06 a.m, on Tuesday, the 17th day of November 2009, the above-entitled matter came on for hearing at the Electric Reliability Council of Texas, 7620 Metro Center Drive, Austin, Texas, before JAN NEWTON, Chairman, and MARK G. ARMENTROUT, DANNY BIVENS, BRAD COX, ANDREW J. DALTON, MIGUEL ESPINOSA, NICK FEHRENBACH, BOB HELTON, CHARLES JENKINS, TRIP DOGGETT, CLIFTON KARNEI, ALTON D. "DEE" PATTON, BARRY T. SMITHERMAN, ROBERT THOMAS and DAN WILKERSON, Members of the Board, and the following proceedings were reported by Lou Ray and Kim Pence, Certified Shorthand Reporters of:

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P R O C E E D I N G S

TUESDAY, NOVEMBER 17, 2009

(10:06 a.m.)

1. CALL OPEN SESSION TO ORDER

CHAIRMAN NEWTON: Okay. I'd like to go ahead and convene the November ERCOT Board of Directors meeting.

First of all, we have the evacuation plan up on the board. I think we will, in a moment, have the anti-trust admonition, which we -- Okay. It's at the top. Thank you, Mike. I don't have my glasses on. So I would remind the Board members about these standing items for our agenda.

I would also remind everyone that we are webcasting our board meeting, as well it's being transcribed. So I have had a discussion -- I told them that one of these days maybe we'll get this down with these new procedures, but with the folks helping transcribe our meetings, there may be a need to stop throughout the day to give them ability to kind of stretch their hands a moment. So if I do that, I hope you'll bear with me as we work through this process.

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2. CONSENT AGENDA ITEMS

3. APPROVAL OF MINUTES

CHAIRMAN NEWTON: Okay. With that let's move on to the consent agenda. Today we have the minutes from last month's meeting. We also have the minutes for the Joint Nominating Committee from October 19th. And we have PRR 836. Those three items are on our consent agenda. Do I have any comments relative to those, or questions?

Seeing none, may I have a motion for approval?

Motion by Miguel Espinosa. Second by Clifton Karnei.

All in favor?

(All those in favor of the motion so responded)

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CHAIRMAN NEWTON: All opposed? Abstentions? One abstention from Bob Thomas --

MR. THOMAS: Just on the Nominating Committee.

CHAIRMAN NEWTON: Okay. Just on the nominating committee. Okay. The consent agenda passes with that one abstention from Bob Thomas for the nominating committee.

I'm going to turn it over to Chair Smitherman.

CHAIRMAN SMITHERMAN: Thank you, Chairwoman Newton. We don't have a quorum today at the Commission, and I wanted to explain why. My colleagues, Commissioners Nelson and Anderson, are at the NARUC National Convention in Chicago. This is unusual that we don't have at least two here. It's incredibly appropriate that they should be there, particularly given that both of them are relatively new. So I'll be operating today without a quorum. Thank you.

4. CEO UPDATE

CHAIRMAN NEWTON: Okay. Thank you. The next item on the agenda is the update from our interim CEO, Trip Doggett.

Welcome, Trip.

MR. DOGGETT: Thank you. Good morning, I think Vickie is going to pull my slides up for you. We're going to do something a little different this morning from what you're accustomed to.

I'm a very transparent person, if you don't know me. And I wanted to give you a little deeper view into ERCOT and some of the things that have been accomplished at ERCOT over the last month.

I've implemented something at my staff meeting where we weekly report on successes and disappointments. And my plan is to aggregate that information that I receive weekly and bring it to you each month in the form of a slide deck to just highlight some of the major accomplishments and some of the major challenges that we have.

If you look at what's occurred over the last month, I tried to assemble several bullets for you to let you know in some key areas, like nodal, for instance, that we did successfully complete our first Operational Day Test on schedule. That's an end-to-end test, which I'm sure Mike talked to the Nodal Subcommittee about yesterday. This is a great success.

We also started the 2.1 market trials on time, which was another great success.

We continue to work with market participants on debugging the Single Entry Model processes. An example of one of the success in this area is we were able to address the owner-operator challenge, if you're on the -- if you're a user of the Single Entry Model.

Over in grid operations, one of our great successes is that we set our all-time instantaneous wind generation record last month. The 28th we had over 6200 megawatts of wind that day. We successfully incorporated that wind.

Clifton, you want to go ahead and ask your question?

MR. KARNEI: Yes. It's my understanding we have over 8,000 megawatts of wind capacity, 4,000 megawatts of transmission capacity. So how did we -- how were we able to generate 6200 megawatts of wind?

MR. DOGGETT: Normally we have a little over 4,000 megawatts of transmission capacity. On this day we had several unique situations. You might remember we had a large generation resource that built a transmission line to take their wind instead of to the west zone over to the south zone, and that freed up and allowed us to increase the transfer capacity.

We also had a couple of line outages at the time that also increased that transfer capability. So 6223, at that time our load was in the 35,000 megawatt range. At one point during the day we were serving around 25 percent of our load with wind.

So again, my hat's off to the operators. There were nervous times there obviously.

Clifton?

MR. KARNEI: So do you think this is a

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non-typical event? I mean, is it an unusual event or can we expect this to reoccur periodically?

MR. DOGGETT: I think it's unusual that it would be this high, but I think we will see situations where we're in the high fours, low fives on high wind days.

CHAIRMAN SMITHERMAN: Trip --

MR. DOGGETT: Yes.

CHAIRMAN SMITHERMAN: If I may, I see Mark Bruce down there.

Mark, at -- maybe today or maybe in the future, when appropriate, I think you're affiliated with the company that Trip referenced. Can we get an update on this, because I think this is really a significant development, this private line going from the west zone to the south zone. I think -- I think this company has discussed this in some of their earnings calls or quarterly reports, but I don't want to be presumptuous.

MR. BRUCE: It has been discussed publicly. When you say "we" do you mean the Commission or the Board?

CHAIRMAN SMITHERMAN: Someone from the company, I think, perhaps could give us an update formally.

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MR. BRUCE: Okay. I will certainly make that request.

CHAIRMAN SMITHERMAN: Okay.

MR. DOGGETT: Again, my hat's off to the operators. I will tell you it's a very nervous situation when they're operating in this mode. So we're definitely staying on top of the situation and attempting to do everything we can to make their life a little easier, including our wind ramp rate forecaster, which we anticipate going live later this month will be another tool in their tool chest.

Andrew?

MR. DALTON: And, Trip, why are we nervous when we're getting up to 6,000 megawatts of wind?

MR. DOGGETT: Well, it's similar to having the potential for several large conventional generators to trip offline. It's the timing of the front that was causing this high wind that makes us nervous. And so we always need to stay ahead of where that front is moving so that we don't find the wind dropping off unexpectedly without enough reserves capable to accommodate that.

MR. DALTON: How was our AWS True Wind forecasting on those days?

MR. DOGGETT: Kent, do you know?

MR. SAATHOFF: I will have to look in my presentation.

MR. DOGGETT: Could we let Kent look and comment during his presentation?

MR. DALTON: That would be fine.

MR. DOGGETT: Okay. Good deal.

We've also been working with the IT area over in grid ops and have seen a significant improvement in our energy management system, what I call skip cycles where we were having situations where we would miss 4 to 5 scans for EMS in an hour. We've got that down to about one event per day. So there's been significant improvement, which helps us with our load forecast error -- I'm sorry, with our load frequency control and our CTS scores.

Over in the market operations side, you'll hear more from Betty today about advanced metering. You remember with our power outage that corrupted some of our databases, we split that project into two implementations. Implementation 1 has been delayed by one week to November 21st. Because of the delays associated with the corrupted data, we are asking for a slight increase in our contingency a little later in the meeting.

As you heard this morning if you were in F&A, we did have an unqualified opinion on SAS 70, which is great news. We did have two exceptions, which we discussed back in August. I think Sean used the term "we can't relax." We won't. We'll make sure we stay on top of SAS 70 for the coming year and shoot for unqualified with zero exceptions next year.

We were able to decommission what we refer to as the data archive. This is part of our Information Life Cycle Management Project, which is attempting to look at data that is stored in multiple locations in an attempt to reduce our storage requirements.

Some other IT projects, we were able to expedite the recovery of those environments that we lost during the power outage of October 7th, and that is why we were able to limit the delay on advanced metering to one week. We were able to successfully implement PRR 803, which is the 14-minute ramp PRR.

We completed our TCC-1 data center expansion. So Mike Cleary was able to take kind of a sigh of relief that that's a very significant accomplishment as far as nodal is concerned for having adequate data center capacity for nodal go-live.

One of our disappointments, the Identity

and Access Management Project, which you've heard about in the past, has been delayed again from 11/14 to 12/5. This was due to some defects that we found late in the testing cycle.

And another slight disappointment, we obviously are glad to see the rain, but we did experience several rain days at our data center construction sites that impacted our schedule there, although we are on schedule and on budget overall, which you'll hear from Nancy later.

You'll hear from Chuck later about compliance in our NERC audit. We had a very successful NERC audit based on the preliminary report that we received from NERC. In that report NERC actually highlighted our culture of compliance, so that's great news.

We do have a continued challenge though because there are pieces of the audit that were delayed related to the transmission operator function, and we will be continuing that effort along with several other of the transmission companies within ERCOT that have control centers.

And I'll conclude with a couple of legal comments. This is one that I was excited about. We were invited by Senator Fraser's office to what they

call Energy Thursdays down at the Capitol. Mike Grable was able to present an overview of ERCOT to this group of staffers.

Mike, I think we had 35 to 50 staffers?

MR. GRABLE: We did. We had a very good turnout. Thanks, Trip. And they appreciated your being there as ERCOT CEO as well. We also had our entire Sunset staff team in attendance. So they got a second look at the info presentation.

MR. DOGGETT: And this week they will see a nodal overview from Mike Cleary and Joel Mickey. Again, I'm a very transparent person. I think the more we can educate folks on our role at ERCOT, the more successful we'll all be.

We were able to successfully challenge some tax valuation issues up in Williamson County that we had. And I'll conclude with -- from my view the Sunset Commission interaction has been very positive. They've been complimentary of our openness and our willingness to communicate, posting documents out publicly for their view, and have received a number of comments.

CHAIRMAN NEWTON: Mark?

MR. ARMENTROUT: This is Mark Armentrout, independent director.

Richard, you must have had quite a number of people working 60- or 80-hour weeks to recover the data center -- recover all the disk losses that you had. Is that correct?

MR. MORGAN: Yes, sir, that is correct. We had a number of people in the organization that worked, basically, around the clock for a couple of weeks to get the priority databases up and running.

MR. ARMENTROUT: Would you please give them our heartfelt thanks from the Board of Directors, that we really recognize that and appreciate it?

MR. MORGAN: Yes, sir.

MR. ARMENTROUT: Thank you.

MR. DOGGETT: I would also note that Richard's folks have done an excellent job of looking back at what we could do differently to avoid the magnitude of this in the future. So they've done an excellent job there.

That's all I have, Jan.

CHAIRMAN NEWTON: Okay. Thank you, Trip. I appreciate your comments, too. You know, here at the Board we go through the meetings and we deal with issues a lot of times. A lot of times they're challenging. We have some of those later today. But I think you reminding us of the successes

that your staff bring along the way is very helpful for the Board and also allows us, as Mark said, to

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thank the team for continuing to do what we hope they're doing every day and pointing out to us the things that are done right. So thank you very much.

MR. DOGGETT: Thank you.

CHAIRMAN NEWTON: Before I move on to the operating reports, I did want to just take a moment. We have one of our board members who will be leaving shortly, Don Ballard, representing Office of Public Counsel. And, Don, on behalf of the Board, we just want to thank you for your service. I think it's been almost two years, hasn't it --

MR. BALLARD: Yes.

CHAIRMAN NEWTON: -- that you've been on the Board. Would you like to share anything with us about where you're going and what you're going to be doing?

MR. BALLARD: I'd be glad to say a few words. First of all, I just want to tell you how much I have learned and enjoyed this process the last two years. We have an amazing market in Texas, and I think we're getting better and better and tweaking it every day.

I'm encouraged for end users. I think

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this Board has become more and more attuned to those users and understanding that the market does involve all the different players.

And I respect this Board immensely, and it is with some regret that I step down at this time. I have just received an opportunity that I wanted to take in the area of workforce development and training

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with a company here in town. And it's a -- going to be an exciting challenge. I think workforce challenges are a huge issue, both in this industry and throughout our state.

I just want to say a personal thanks to each and every one of you for teaching me what you have. It's been a wonderful experience, and I thank you.

CHAIRMAN NEWTON: Well, thank you, Don. And we appreciate your contributions and we want to wish you luck as you move forward.

MR. BALLARD: Thank you. Unfortunately I won't be able to stay the rest of the day, but if you want to know how I'd vote on 830, I'll let you know now.

(Laughter)

MR. BALLARD: Danny is here, and he can take care of that.

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CHAIRMAN NEWTON: Okay.

MR. BALLARD: All right. Thank you.

CHAIRMAN NEWTON: Thank you, Don.

5. FINANCIAL SUMMARY REPORT

CHAIRMAN NEWTON: Okay. With that the next item on our agenda is the Financial Summary Report. Again, as usual, I will just open it for questions on the financial summary reports and see if there are any questions that any of the Board members have?

I had one. And I apologize, I know many

of you are in the F&A Committee, but I'm not. So on Page 4 -- I mean, I did notice -- and it's good news -- that your expected year-to-date -- looks like we may be coming in on budget at this point is the projection, which is very positive. But when I look at Page 4, it looks like two of the significant positives are interest payments and then revenue funded project expenditures if I'm reading this correctly.

And my question is on the interest payments it looks like it's about 50 percent almost reduction, and I just wanted a brief explanation of what resulted in that.

MR. BOWMAN: We have actually been

experiencing less borrowing this year than prior and actually what we anticipated in the budget, and the actual interest rates have improved.

CHAIRMAN NEWTON: Okay. That's good news.

MR. BOWMAN: Yes.

CHAIRMAN NEWTON: And the second with regard to the revenue funded project expenditures, is that a timing issue that will correct prior to the end of the year or are you expecting to have this significant of a favorable variance?

MR. BOWMAN: It's a favorable variance because we do have an underfunding at the last quarter of this year that we will make up in first quarter of next year.

MR. DOGGETT: We're going to talk about

that in detail a little bit later this afternoon.

CHAIRMAN NEWTON: Okay. Okay. Sorry.

Any other questions on the financial summary report?

6. MARKET OPERATIONS REPORT

CHAIRMAN NEWTON: Okay. Seeing none, do we have any questions for the market operations report?

Dr. Patton?

MR. PATTON: Yes. A.D. Patton speaking.

Betty, I'm looking at Page 9, and my -- well, my question is that this additional contingency funds being requested to cover the risk of more defects and so forth gives me a little bit of pause. And so can you give me some assurance that the train is still on the track here?

MS. DAY: Sure. Happy to do so. This is Betty Day with ERCOT.

We believe that we're going to be able to come in within budget for this project. However, there is a not-to-exceed amount that's been set by the Board. And if there is a significant defect that is found -- remember, we have two releases. One is coming up this weekend. We believe we're good to go for that one. We have one last fix that's going in today. We expect to have sign-off on that fix today. So we should be good to go.

This contingency is to cover any issues

that may come up for the next release. Like I said, we don't expect to have it, but because we have a not-to-exceed amount, we feel like we need to make sure that we don't halt progress on this project and continue to get it implemented. But we're very

confident within ERCOT that this is going to proceed as planned.

MR. PATTON: Well, thank you. Of course, you know, given our difficulty with nodal, of course, which is a far bigger project, that-- and arbitrary deadlines, you know, that are set not by you but by somebody else, and that always makes me nervous. So ...

MS. DAY: We have targeted these implementation dates to fit with our migration windows. The required date for this project is actually January 31st per PUC rule. But we want to get all the changes in by December.

MR. PATTON: Thank you.

CHAIRMAN NEWTON: Trip?

MR. DOGGETT: I was just going to add -- I guess it's part of my style, but I'd rather us be a little overly cautious as well. Betty said that she felt that they would be in under budget, and we talked about it as a staff and said we need to be very open and make it clear that there is a risk and we'd rather come in and ask for that increase in contingency as opposed to come back and ask forgiveness next month. So you'll probably see us doing more of that in the future.

CHAIRMAN NEWTON: Okay. Any other questions on the market operations report?

7. IT SERVICE AVAILABILITY METRICS REPORT

CHAIRMAN NEWTON: Seeing none, IT service availability metrics reports.

Yes, Bob.

MR. THOMAS: I'd just like from the retail segment to offer my congratulations to IT. It's the first time in my two years on the Board we've had 100 percent in all three retail categories. So I want to acknowledge that and indicate my appreciation for that performance.

CHAIRMAN NEWTON: Thank you, Bob. Very good results.

Dr. Patton, did you have --

MR. PATTON: Yes. I had a couple of questions. And I already talked to Richard about them, told him that I -- you know, what I was going to ask so he's ready.

On Page 4 we're talking about frequency control outage. A frequency control outage is -- you know, is not a good thing, to say the least. So -- and I read here that ERCOT is currently developing an enhanced backup strategy that would avoid the problems that occurred. And so I just asked Richard to comment

upon that.

MR. MORGAN: Yes, sir, Dr. Patton. We

are really doing two things backup-wise. Number one, we found some data that we capture -- it's dated so that we do not -- in other words, what we've done is we have decreased the volume of data that we're backing up because we've previously captured that data and it does not change.

The other thing that we're doing is we've moved some of our backups to the passive system versus the active system to take the load off of the active system. And this will be implemented sometime this month.

MR. PATTON: Okay.

CHAIRMAN NEWTON: Mike?

MR. GENT: Richard, on the same subject, could you describe what the nature of the outage is. As Dr. Patton said, this is really serious stuff, and I'm wondering what has caused this and what you've done to prevent that from happening.

MR. MORGAN: Yes. The nature of the problem that we experienced here was we made a change to a backup -- our backup system, which increased the load on the processing system. And the backup system operates on a server that's different and there's a

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client that operates on the active server. When we increased the capacity, it forced -- or allowed more load for backups on the client's side of the system, which did not then provide enough capacity to run the EMMS system, which then caused us to have the failures. So that's the reason that we've changed the backup system and backup scheme on the system and resolved this issue.

MR. GENT: Did you say that by trying to enhance the backup system we caused the failure of the primary system?

MR. MORGAN: Yes, sir. That's -- yes, sir.

CHAIRMAN NEWTON: Dr. Patton?

MR. PATTON: I have a further question on Page 5 with regard to this -- this outage that resulted in some corruption of the database. And in the last sentence there it says the final iTest rebuild is scheduled to be on 11-11. And my question was: Was it?

MR. MORGAN: The answer is no on all completions; however, all priority completions where there was any testing that was scheduled to be done was all finished by November the 4th. We have one remaining database which will be restored tomorrow

or -- by the end of the day tomorrow, which will complete everything but the -- all of the testing -- we did all of our restores based upon a priority scheme, and the testing that is going to be -- for this system would be utilized is in the future. So we were able to meet everyone's needs relative to testing.

Does that answer your question, Dr. Patton?

MR. PATTON: Yes. I'm looking at Mike Cleary and so --

MR. CLEARY: I noticed. And from our perspective, it impacted us by about two or three days. But to be honest with you, in the overall scale of things, we had much bigger issues trying to get to the 2.1 connectivity out to the market than we did with this impact. So from a -- you know, from our point of view, yes, it impacted us. But it was small in relation to the overall impact that we had. The four weeks that we've fallen behind in relation to the nodal implementation, this was a very minor issue for us. We don't want it to happen again, but it was minor.

MR. PATTON: So everything is cool now?

MR. CLEARY: Yes.

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MR. PATTON: Okay. Thank you.

MR. CLEARY: As long as we can keep those environments healthy.

CHAIRMAN NEWTON: Okay. Any other questions, Dr. Patton, in IT?

MR. PATTON: Yes. Actually I -- apparently you can see my stickies from where you were.

CHAIRMAN NEWTON: And it's not the end of them I noticed, so --

MR. PATTON: Actually it isn't. On Page 13 there's a -- speaking about realtime balancing market availability survey, the overall metric was good. But there was this one matter that, you know, created a little bit of a problem, I guess. And so, Richard, could you speak to that?

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MR. MORGAN: Yes, sir. We had a failure on one interval. We do not know what caused the failure. We believe it to be data, but we have not firmly confirmed that. But we do not know the exact cause of this failure.

MR. PATTON: So are efforts being made to discover the -- what's going on here?

MR. MORGAN: Yes, sir. We're still trying to evaluate and find out what the issue is.

But we do not know the exact cause of the failure.

CHAIRMAN NEWTON: Dan?

MR. WILKERSON: Jan, thank you. I just wanted to kind of echo what Bob Thomas had said a bit earlier. Richard, I appreciate how hard you guys work to get at these root causes. The down side of this is I think we're going to have to raise your goals. If you look at Page 7, you're so near 100 percent on everything, a 98-and-a-half percent goal is sort of meaningless. But for the most part you guys are doing a really good job and getting to the root cause as well. I just wanted to say that.

CHAIRMAN NEWTON: Mark?

MR. MORGAN: I would encourage you not to raise those goals too much.

(Laughter).

MR. ARMENTROUT: I'm just going to make an editorial comment on the exchange between Dr. Patton and Richard -- this is Mark Armentrout.

Oftentimes writing in computer systems

when you run into a problem, you just keep the system up knowing that you're going to erase the evidence for what caused the problem, making root cause analysis difficult. I don't know if that was the case this particular time, but sometimes that's the case.

CHAIRMAN NEWTON: Okay. Thank you. Anything else, Dr. Patton?

MR. PATTON: No.

CHAIRMAN NEWTON: Okay. Any other questions on the IT metrics?

8. GRID OPERATIONS AND PLANNING REPORT

CHAIRMAN NEWTON: Okay. We have a few presentations from Kent's group. But first of all we've got the regular operating report. So I would ask if there are any questions relative to the operating reports before we go -- move to the presentations?

MR. PATTON: Yes.

CHAIRMAN NEWTON: Yes, Dr. Patton.

MR. PATTON: With regard to Kent Saathoff and his grid operations and planning report on Page 11 -- and maybe this -- I don't know -- this September the 14th event, Kent, was that the same one that we talked about last month or is this a different one?

MR. SAATHOFF: No, it's a different one. You know, my reports kind of lag a month behind. So the one last month was for August.

MR. PATTON: Well, I just observed that last month we had a situation in which we -- if my memory is correct -- that we tripped off a 338 kV lines due to some relaying difficulty, probably a backup breaker -- breaker backup scheme didn't work right for some reason. And here we -- again we have an improper timer setting that resulted in, you know, multiple things being out of service.

And so my question here is: What protocols or procedures does ERCOT have in place in the area of relay maintenance and testing? Because if ERCOT ever has a big shutdown, it will be because of a relay problem, if history is any guide. They always are. And so could you speak to that?

MR. SAATHOFF: Yeah, I can. I'll get you the full protocols and guides that we have on relaying. But operating off memory, our guides and protocols really don't get into maintenance requirements. NERC standards do. So to the extent, you know, the NERC standards apply to transmission owners, the NERC standards would apply. Our protocols and guides mainly address the need for coordination between -- relay coordination between the transmission operators. And we really don't have extensive guides regarding maintenance and testing requirements.

MR. PATTON: Okay. Well, I just want to -- I just want to raise a flag here, because two

months in a row we've had -- we've had reports of relaying difficulties that have tripped out, you know, multiple items. And that's exactly the sort of thing that can lead a system to collapse.

Mike Gent, do you agree with that?

MR. GENT: I'm glad you're taking up the banner or I'd have to. I pointed out many times that we have these what I call sympathy trips. I can give you thousands of examples that we never -- we never lose what we study in a planning study. It's always something different.

And we're very fortunate that we have talented people that can arrest the problem before it cascades. I think in a closed session we'll learn today that NERC has decided to accept the interpretation of a standard that failed to include a battery charging system. So that's no longer part of the relay system as out -- sudden pressure relays are no longer a part of the relay system. So we have lots of relay problems.

CHAIRMAN NEWTON: Well, the point's well taken.

MR. SAATHOFF: Now, I would add we do have a system protection working group of ROS that looks into these instances and reports to ROS. But

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it's mainly for information only, lessons learned, you know, they're -- as I said before, we don't have real extensive relaying maintenance and testing requirements.

CHAIRMAN NEWTON: Okay. Bob Helton?

MR. HELTON: Yeah, Bob Helton. Just one thing -- it's not a -- not really a question or anything. On Page 9, Kent, which is the capacity purchase for RMR, OOMC, RPRS on there on that Page 9 --

MR. SAATHOFF: Yes.

MR. HELTON: -- since we're not using eight-and-a-half -- you know eight by eleven and -- eleven-and-a-half glossies, could we use some other mechanism to distinguish which is RMR, OOMC, RPRS 1 and 2? I can't really tell --

MR. SAATHOFF: Something other than color?

MR. HELTON: Yeah, something other than color on this --

MR. SAATHOFF: We'll do that.

MR. HELTON: -- yeah, I cannot tell -- I mean, the big ones I can. But when it gets in there I really can't tell what this is. So if we could hash that, cross it or do something a little different so I

can at least see which is which, that would be great.

MR. SAATHOFF: Okay. We'll do that next time.

MR. HELTON: Okay. Thank you.

CHAIRMAN NEWTON: Andrew?

MR. DALTON: Yes, thank you. Kent, just to follow up on my question earlier, do we know where we were with the AWS True Wind forecast on October 28th? Because the data in the report seems to reflect the September data.

MR. SAATHOFF: Yeah. And I've got

people tracking that down, and as soon as I get it I'll let you know and the Board.

MR. DALTON: Okay. Other question on Page 15 for that same day, the 28th, I guess our average wind capacity or wind production for the day was about 40 percent of installed capacity.

MR. SAATHOFF: Yes.

MR. DALTON: All right. So that's just representing the total day, not the peak. I guess the peak was up closer to 75 percent. Right?

MR. SAATHOFF: No, that's at the time of peak demand. It's not at the time of peak wind generation.

MR. DALTON: Okay.

MR. SAATHOFF: It's coincident with the peak demand.

MR. DALTON: Okay. All right. Thank you. That's helpful.

CHAIRMAN NEWTON: Okay. Any other questions?

8(a). VOLTAGE RIDE-THROUGH STUDY UPDATE

CHAIRMAN NEWTON: All right. Seeing none, the next item on our agenda is an update on the Voltage Ride-Through Study.

8(a). VOLTAGE RIDE-THROUGH STUDY UPDATE

MR. WOODFIN: Let me find the right one. I've got several with my name on it today.

We wanted to give you an update on the Voltage Ride-through Study. As you recall this study was mandated by the Board as a result of the appeal of -- over 208. The requirement was that we had a report on this study to ROS by June of 2010.

We have issued an RFP and contracted with Parsons Brinckerhoff to do that study. We had a kick-off of that back in May.

The study is made up of three phases. The first phase is supposed to be completed by the end of the year. The intent of that is to kind of do a -- almost do a dry run of the -- the Phase III, which is

the main study in order to uncover any data -- missing data that we would need to make sure that -- and any other procedural issues, so that when we get into doing the Phase III study, we'll have all the information we need to do that correctly.

Phase II is a data gathering effort where Parsons Brinckerhoff is going out and talking to each of the individual wind generators, the technical experts there, and developing detailed models of everything that's associated with that wind farm, and then reducing that into an appropriate thing that can be modeled in the dynamic stability studies such that the performance of that wind farm is accurate in those studies.

Then Phase III will be a dynamic study looking at fault analysis and their associated contingencies to look to see if there are any issues associated with voltage ride-through for the existing wind farms, identifying any reliability problems and then also we've put some extra scenarios in there to study what appropriate solutions might be put in place.

On Phase I the status of that is that PB has basically completed the analysis. We've got a draft report that we're working on validation of and

so forth.

We'll be presenting that Phase I report to ROS next month. We've already been working with some of the TOs to validate contingencies and so forth to make sure that what we've run -- or what PB has running is correct.

The preliminary findings, based on what they've done in Phase I and also they've already incorporated some of the information into this analysis that they obtained through Phase II, is that they've done what we intended them to do in Phase I, which is identify any modeling techniques, any data that we need in addition to what we already had. They've done the analysis. They've identified which faults are likely to be most problematic so that we make sure that we model those in Phase III.

And they have -- one of the things we had been worried about is that they might find something in this Phase I that would require an immediate operational response. And they haven't found that.

Now, that doesn't mean that there won't be things that are needed once we get through with Phase III, but at this point there's nothing that we have to take action on as a result of that Phase I

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analysis.

Phase II, PB has gotten all of the data they need from about 70 percent of the wind farms. We're at that point where, in order to get it done on time, we're -- they have kind of come to the end of what PB thinks they can work through with the generators. So client services is going to get involved, send out letters to those remaining entities. And in some cases we've -- it's not a matter that they haven't responded. It's just we're missing some of the pieces of data that we need or it's not in the right format or something like that. So we're going to be doing that.

And, of course, that operating guide requires that the WGRs provide this information, so I don't think this is a concern at this point, but we will be escalating. PB has been working on developing these enhanced models for the wind farms based on the information that they've collected, and those things will be -- those detailed models will be used in the January Phase III study.

So at this point everything is on target for getting that done by June as requested.

CHAIRMAN NEWTON: Dr. Patton?

MR. PATTON: Yes, ma'am. I -- on

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looking at a couple of the -- well, the second bullet or dash on Page 5, it's a little disappointing to me

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to see that some of the WGRs have not been responsive so far in providing data, and this is not optional. So I trust that the information that is needed to timely complete this study in a good fashion will be forthcoming without further delay. And I would like for the --

CHAIRMAN NEWTON: So noted.

MR. PATTON: -- so note.

CHAIRMAN NEWTON: So noted.

Mike?

MR. GENT: Dan, many of us are electrical engineers and belong to EEE and get subscriptions to Power and Energy Society Magazine. This month's magazine is almost exclusively on wind, and your name is liberally spread throughout here in different articles. I recommend this -- to any of you who -- you can get it online. If you want to know more of the technical details of what wind presents to us in the way of challenges to integration into the system, that's primarily what we're trying to do.

Well, they cite quite liberally that our modeling is really something that's never been proven to be totally accurate, that there's some kind of

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discontinuity between some of the planning work that we do and then how it actually operates. And I'm wondering, are we ahead of the curve in that regard? Do you feel confident that the way you're modeling these wind generators is really the way they should be modeled?

MR. WOODFIN: Well, I think that once

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this Phase II study is completed, we will make significant improvement -- we can already look at the -- what models we had going in and what now we're going to have, versus the ones that have already been where PB has done its work, and the models have improved a lot.

I think when we get through with this effort, then there will be more -- we'll need to focus some on validation, whether it's through the use of failure measurements or whatever. We need to do more validation of those models against real word events to make sure that they're -- now that we've made the improvements theoretically in the model, that that's been an actual improvement.

MR. GENT: And I assume we'll be sharing that with the rest of the world?

MR. WOODFIN: Absolutely.

CHAIRMAN NEWTON: Okay. Anything else,

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Dr. Patton? Did you have something else?

Okay, Dan. Thank you for that update. It looks like you've still got it for the resource adequacy and market signals.

8(b). RESOURCE ADEQUACY AND MARKET SIGNALS

MR. WOODFIN: We didn't figure that these two presentations even back to back ought to be put together, so we separated them.

There's been lots of discussion here at the Board and in other forums about resource adequacy in the ERCOT market by market participants and others.

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This presentation is intended to be a very high level discussion of ERCOT's role in that resource adequacy debate. We've -- I want to note that ERCOT has only an indirect role in resource adequacy, although we do recognize that some of the things we do do have an influence on resource decisions.

There are really three touchpoints that we have over resource adequacy. The first is the actions that we take in current operations, having an impact on price signals and so forth, other market signals out into the future in so far as how much generation gets built and what types.

We have a -- we twice a year communicate the capacity demand and reserve report. So we put out

assessments of resource adequacy or the things that are -- reports that are intended to be assessments of resource adequacy, and these are intended to inform the market and policymakers.

And then the last is that we also do periodic studies, like our long-term system assessment and those kinds of things that communicate what at least we see future resource needs may be out on the system. So we'll talk about each one of those three touchpoints in a little more detail.

CHAIRMAN NEWTON: Dan, we have a question from Barry.

CHAIRMAN SMITHERMAN: Hey, Dan. Go back to that second point, the periodic assessments of resource adequacy. I assume that's the CDR you put out.

MR. WOODFIN: Right.

COMM. SMITHERMAN: It's always been my assumption that private market participants do this as well, that they -- each of them comes up with their own assessments. To what extent do you-all share in -- well, to what extent do they share information with you? To what extent is there any conversation back and forth between ERCOT and private market participants that might be doing this for their own

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strategic purposes and possibly could have a different assessment from the one that you do?

MR. WOODFIN: There has been some discussion about that in the Generation Adequacy Task Force discussion. But typically what we do is fairly defined -- what gets included in the CDR is fairly well defined by the documentation that the GATF comes up with as far as what kinds of resources get counted, how much they get counted, and what are the triggers that cause new generation, say, to be included or retiring generation not to be included.

So we really -- primarily it's a -- we're following that cookbook almost, if you will. We have very few other discussions that would influence what goes on in that document.

CHAIRMAN SMITHERMAN: Okay.

CHAIRMAN NEWTON: Okay. It looks like we've got another question. Bob Helton?

MR. HELTON: I'm just going to hold mine -- I'll leave it up, but I want to hold mine until he's done.

CHAIRMAN NEWTON: Okay.

MR. PATTON: Madam Chairman, at the -- at the risk of being repetitious, let me point out once more that to the extent that we don't have

transparency in costs -- that is to say that costs are not attached to resources, but rather are allocated or uplifted in some fashion that defeats the transparency process, then we don't get what I believe are proper price signals. And I would just beat that drum once again. Thank you.

CHAIRMAN NEWTON: Thank you, Dr. Patton. We know when you're passionate about issues, so we appreciate you continuing to bring issues to the forefront.

Dan, you want to go ahead?

MR. WOODFIN: Okay. The first category is the things that we do in current operations that may have an impact on future resource decisions. The first one -- and we -- I have -- there's been lots of discussions about this one lately. We have to maintain reliability in realtime. I mean, that's not negotiable. But we've been working with stakeholders and various regulatory entities to try to come up with mechanisms to do that that not only maintain these market-based approaches to maintain reliability in realtime, but also provide the right signals for future resource adequacy and the types of resources that are needed.

And so some of the -- I guess there are

three issues that have been discussed -- primarily lately -- associated with this. The first John Dumas is going to talk about more in the next presentation, which is our load forecasting process. And what's proposed in this -- in the ancillary service methodology that he's going to talk about is to essentially reduce some of the -- what's referred to frequently as the bias in the load forecast such that the unit commitment that guides unit commitment and shift that over into the non-spin market. And so that's something he's going to talk about in more detail in a minute. That's actually something that the IMM, for example, has said is a -- definitely falls in this category of current operations and how they impact future resource adequacy. So we're proposing to make that change.

The second thing that's been discussed lately is more about our wind forecast. And, of course, as you know, we're using for our wind forecast an 80 percent probability of exceedence forecast. We're doing -- we're making best efforts, and I think we're -- we've had a presentation on this last month, I guess, about how we're improving that forecast. We're getting more information from the wind generators, both meteorological data on the sites,

also the outage data on the individual turbines. And that's going to help improve the forecast.

We also -- there was a bullet in Trip's presentation about the ramp forecast tool that we're looking to implement in the next month or so. That's going to tell us more about when we have a risk that's a little outside the norm of a rapid increase or decrease in wind generation. All those things are going to help us understand the risks around the forecast a little better. Where right now we're shooting for an 80 percent probability of exceedance, it's actually hitting more like 65 percent or something like that.

So we really at this point don't know what the tails of that distribution look like real well, but as we get more -- the push has been to move toward more of a 50 percent probability of exceedance forecast. And as we get more certain about the -- and more confident in that -- those forecasting tools, that may be something we want to look at.

And the third thing -- I think we've discussed this before also -- that we're developing an operational risk assessment tool that will allow us to, on a more granular level, assess for upcoming time periods what the real risk is associated with unit

outages, the wind forecast and the load forecast. And that will help us better procure ancillary service, particularly non-spin quantities. So those are the things on current operations.

Then we move to the periodic assessments. There's really two pieces of this periodic assessment. One is what is the appropriate reserve margin target in order to provide a measuring stick, if you will, for the amount of reserves on the -- planning reserves on the system that provide resource adequacy. We're going to be updating that study before the May CDR comes out, which means that we'll have to get it done in early spring in order to work through the approval process.

The LOLP study is intended to -- really it provides guidance on what the appropriate target reserve margin is as a minimum. As with the last study, we're planning on looking at that LOLP over 8760 hours, so a typical year, as opposed to some of the historic types of LOLP study that were done that just looked at a peak hour.

And so in order to -- and the reason for doing that is so that we can reflect the reliability impact of some of these resources, particularly wind generation, and reflect that amount that they

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contribute to the reliability of the system into the reserve margin calculation. And you've all heard discussions about the 8.7 percent effective load carrying capability that we count of the wind installed capacity. That's really what that's trying to do is determine what's an amount that you can reflect over into that reserve margin calculation so that it appropriately -- we can use that reserve margin target as a measuring stick.

The second piece of this is then the reserving margin calculation itself. And that's really more of an accounting -- okay. It looks like I need to pause for a question maybe?

CHAIRMAN NEWTON: Go ahead, Barry.

MR. PATTON: Yeah, are transmission limitations factored in here?

MR. WOODFIN: We're -- we haven't yet decided if we're going -- in the last LOLP study we did not calculate -- we did not include transmission limits. We're still trying to determine what we're going to do this time.

They need to be taken into account. The question is do they -- are they taken into account through this resource adequacy determination or is that part of the transmission planning process and

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moving that toward to a more probabilistic approach?

MR. PATTON: Well, in my judgment, you can't do an adequacy -- proper adequacy assessment without including transmission limitations. And you have a tool to do it. I developed it for you a long time ago.

MR. WOODFIN: Yes. I'm familiar with that.

CHAIRMAN SMITHERMAN: Dan, I'm sorry, before you move off, just refresh my recollection. You do the CDR twice a year in even-numbered years. Is that right?

MR. WOODFIN: The CDR we actually do twice -- we've essentially, over the last couple of years, have developed a practice of doing it each December and each May.

CHAIRMAN SMITHERMAN: So you'll have one coming out in December?

MR. WOODFIN: Right.

CHAIRMAN SMITHERMAN: About a month from now or so, I guess, right? And then you'll do a May and a December, and the December will be available for the next legislative session arguably. Should be --

MR. WOODFIN: Right. Right.

COMM. SMITHERMAN: Okay. And then

you're about to talk about the reserve margin calculation. One of the things I'd like for you to touch on that we have discussed in the past is are we adequately looking at the issues of switchable units and DC ties which go into the calculation, but I'm not sure we've ever concluded that those would be available when we actually needed them.

MR. WOODFIN: That is actually a perfect segue -- thank you -- the GATF is meeting -- the Generation Adequacy Task Force, which is a task force under the Wholesale Market Subcommittee, is meeting on about a monthly basis. We've got another meeting, I guess, next week. And part of that what they're doing is revisiting -- and we seem to be on about a three-year schedule of doing this kind of revisit -- of what the rules are about what gets counted from an accounting standpoint almost into that reserve margin calculation.

And so at this point all of the different pieces of what kinds of resources go into that calculation are under discussion, including the DC ties, the switchable units, what the capacity value of the wind that would be included might be, and what -- at what point do we start counting new generation. It's set up currently once it has an

interconnection agreement and an air permit if needed, then the new generation starts figuring into that calculation. So all of those are things that the GATF is discussing right now and, in fact, haven't come to any conclusions as to what needs to be changed.

Yeah, I think that was all I was going to say about that.

The third category of things that we communicate out to the market are some of the longer-term studies that we do. One that you may recall is the Ancillary Service Study that we had GE perform as part of the CREZ analysis, which looked at as you have up to 15 gigawatts of wind, how -- do we need new kinds of ancillary services -- they got into that in one case -- and then what the quantities would be with that addition -- with the uncertainty associated with that additional amount of wind generation on top of the normal load uncertainty and generation outages.

So that's one of type of study that we've done. We do a -- every two years we do a long-term system assessment where -- the primary purpose of it is to look at longer-term transmission needs. But to do that you need to know what the -- what type of resources may be on the system out into the future. And we've started doing that -- we do that analysis using a scenario-based approach -- what if gas prices are this, environmental taxes are this and so forth. And so we do do some kind resource assessment based on that -- that is part of that LTSA.

Those studies have, in the past, have been limited by other priorities and resource constraints and so forth. So we actually have put in a proposal to DOE to do an -- as part of our request where they requested for each interconnection some entity to do a more long-term planning study for the -- each interconnection. And we propose to do that for the Texas interconnection.

We -- I guess there was a date in early November that they had initially said that they were going to tell folks as to what that -- who got that proposal. I've heard speeches said that that was going to be mid-November. We haven't heard yet, I guess, is the news on that.

But the intent of that would be do a more comprehensive assessment of what future resources might be on the system. What requirements might be needed around some of the new technologies. And then a more detailed assessment similar but not the same as what was done by the GE study of future operational

requirements.

CHAIRMAN NEWTON: Mike?

MR. GENT: Dan, when you submitted your proposal, what were the costs to do this?
MR. WOODFIN: We haven't made that public because it's still in the --
MR. GENT: Okay. Let me make my point then.
MR. WOODFIN: Okay. It's in the millions.
MR. GENT: Using my vast experience at getting money out of DOE, once they award it, I think you can look for it to be three or four years before you get reimbursed. And I noticed that this is in our risk assessment table, the study, so I think the Board should be aware that this may be some candy that's out there, but it could be very bitter.
MR. WOODFIN: So just to kind of close the -- ERCOT has really three impacts that we see on resource adequacy. One is things that we do currently in current operations. The second is these periodic assessments that we do. And the third is any studies we do of future requirements.
And then the Commission is also looking at -- and a lot of the other issues associated with

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resource adequacy are all done at the Commission. There is currently a project associated with resource adequacy and related issues, and that's Project 37339.
CHAIRMAN NEWTON: Okay. Bob Helton?
MR. HELTON: Yeah, just real -- just a few comments on here. This is very good presentation. I appreciate that.

This is really important and kind of gets to a lot of things that, like, Commissioner Smitherman was talking about and what Dr. Patton was talking about. We do get involved in the Generation Adequacy Task Force, you know, investors do in the generation group. It's -- we do our own numbers internally and they never match what ERCOT does because we do take in different assumptions than they do, especially in mothballing plants, because we look at economics, they don't. They get the information from the providers or the owners of those assets, so there is some differences. We like those to be as close as to what we think reality is from our standpoint, because if we go in to try to do a project and they've got a number way over here and we've got a number way over here, then that creates problems with credit -- with the people with the credit.

But the real big thing that really comes

in when you're looking at investment is the other things you've got in here. More of what we're looking at, we look for continuity with what the generation adequacy has and what your reserve margin is, and that should correlate to pricing.

And what we're really looking at is new entrant pricing. And that goes into the rest of the things that are in here that I'm really glad to see, and I see that you're taking a look at these through the load forecasting and the wind forecasting and the operational risk assessments.

By moving these forward and getting to market-based pricing and getting to where you can actually see and get to scarcity pricing and those things when there is true scarcity and get to where you are, this kind of stuff I've been talking about, here's where it really comes into effect, is long-term viability of the ERCOT market, and that's what we're after.

If you depress prices through mechanisms or you inflate prices through mechanisms, that doesn't work for a long-term viability. And that's why I'm really glad to see that ERCOT is working -- like you have on Page 3 at the bottom -- that we're all trying to get there and take care of the issue with -- I

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think the non-spin that you're going to talk about in a minute has some improvements there that's going to help. I hope that's part of what that does -- because the real answer to that is being right on the forecast and not having a bias one way or the other. I think this will help identify some of that and maybe we can get better and better as we go forward. The wind forecasting, I think we're doing well on that. We've got to get there. I like this 50 percent probability of exceedance rather than the 80.

These things are -- all tend to get us to where that will help send those signals for the investment to take care of this. So I'm really pleased at what I'm seeing through here. So I appreciate that.

CHAIRMAN NEWTON: Dan?

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MR. WILKERSON: Thanks, Jan.

Dan, do you -- on the previous slide, your first bullet point reliability actions taken and current operation impact price signals, you may be doing that as a lead-in for John. Which of you will best address the price signals changes and what they might be with the ancillary service changes that John is going to introduce? Is it you or John?

MR. WOODFIN: I think John. I think

he's looked into that a little bit.

MR. WILKERSON: He's teed it up for you, John .

CHAIRMAN NEWTON: Okay. We've got one more question --

MR. GENT: Before you sit down, Dan. We talked to -- before you got up there we talked about what I call these sympathy trips and outages, and I notice that you traditionally study generator outages, and we talked about whether you should or should not include transmission.

Is there something in your studies that allows you to take in a multiple contingency effect? Do you run it on out for all contingencies or do you just scroll down and take out certain generator units and large ones?

MR. WOODFIN: I suspect that we wouldn't in this kind of study, but from transmission planning more of a deterministic transmission planning study, we look at some of those subsequent contingencies that

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would be up in the Category C and D from a NERC perspective.

CHAIRMAN NEWTON: Okay. Thank you, Dan. I don't see any other cards up. So with that, John Dumas, I believe, is going to give us our next

presentation, which will be looking at the 2010 ancillary services methodology recommendation.

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METHODOLOGY RECOMMENDATIONS

MR. DUMAS: Okay. This is our annual ancillary service methodology document that we bring to you every year -- at least once a year. We may bring it more often than that if there's a needed change that we find during the year. But this year the only change that we're proposing is related to the non-spinning reserve service requirement. All the other ancillary service we recommend approving those as they were last year, not making a change to those.

I've got the next few slides we're going to go over a little bit about ancillary services and how they relate to the NERC operating reserves, do some cost analysis of the proposed change that we're -- for non-spin and then we'll have conclusions and questions.

The first change that we're proposing for the non-spin requirement is based upon what data do we analyze to determine what the requirement is. If you remember last year, what we proposed was looking at the most recent 90 days worth of history to analyze to determine what the 95th percentile of error

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was in the load and wind forecast -- or the net load forecast.

And a lot of discussion happened at that time that this may not -- because it's always a trailing 90 days -- it may not give you an adequate picture of what the upcoming months in the seasonal -- any seasonal effects that would have. And we recognized that last year, but unfortunately we didn't have any history with the wind forecast to be able to present a different time frame to. This year we do.

What we're proposing is looking at the previous 30 days worth of history and the same 30 days worth of history from the prior year. So if we're moving into December we would look at December '08, the 30 days of history there, to make the determination of what the error has been in the wind and load forecast.

We're also proposing --

CHAIRMAN NEWTON: John, excuse me.

Dr. Patton, did you have a comment or question at this point?

MR. PATTON: Let me wait until the end and I'll --

CHAIRMAN NEWTON: Okay. Great. Thank you. Go ahead, John. Sorry about that.

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MR. DUMAS: Okay. We're also proposing a change based upon some discussion -- and this

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discussion, I guess, began in the IMM report that they put out regarding the load forecast and the tendency in the summer to overforecast.

Our forecast error in the summer months was actually really good. It was around 3 percent or a little less than 3 percent on average. But there was a tendency to overforecast. And part of that overforecast is -- could be contributed to the weather conditions. Obviously we don't intentionally overforecast. If there's a percent chance of rain in any of the large metropolitan areas and it actually does rain, then what's going to happen is you're going to be over your forecast by quite a bit, especially if it's Dallas or Fort Worth or Houston area. So we do see an average overforecast in the summer months and we recognize that.

We had a lot of discussions with the IMM, with the stakeholder -- various stakeholder working groups. And in an attempt to remove some of this bias of overforecasting out or how it's affecting the market, the thought is that it's having a tendency to cause more generation to be committed in replacement, which then in turn causes more offers to

be in the balancing energy market, which then causes the price to be depressed.

So what we're proposing with this change is that we'll calculate what that average net load forecast error has been over that same 60-day period, and then we will use that to bias the load forecast down by that amount. And we'll also take that amount and buy additional non-spin to what we've already calculated we needed based on the 95th percentile.

And the last change that's proposed was a concern that was brought up in the QSE project managers' meeting over, well, you can cover the uncertainty in the load forecast and the wind forecast. But what happens if you have a large unit trip right on peak. So there was a concern over that. So there's a proposal here to set a floor -- once you do the calculation -- if that calculation yields something less than the largest unit in ERCOT, which is currently 1354 megawatts, that you set the floor of the minimum that you buy for 7 through 22 to 1354.

We're still using the same four-hour blocks to determine what the 95th percentile of the net load forecast uncertainty is. It's a very similar approach to what we're doing with the regulation up service.

There will also be a cap placed on the total amount of non-spin purchased to 2,000 megawatts. So you do the calculations as I described. If that adds up to more than 2,000 megawatts, then you reduce the bias amount by however much you're over 2,000 until you get to 2,000. And that was primarily put there as a concern that we've currently only got about 33 -- roughly 3300 megawatts of off-line capacity that could actually bid into the non-spin market. I understand that that may be changing as more generation gets built and comes on that are

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quick-start capable.

Details of the requirement is -- obviously we're going to shift some of the megawatts from the load forecast into a non-spin requirement, which creates ancillary -- additional ancillary service reserves requirement on non-spin. The thought here is if you do that, you will have a tendency to commit less in replacement.

Now, there isn't a one-for-one correlation there that you can directly tie, because what happens in replacement is you take the load forecast, plus the ancillary service requirements -- that's your requirement. You look at what's scheduled by all the resources through their resource plans.

And if there's any difference in those numbers, it's made up by replacement on unit commitment.

The thought here is that if you have an additional ancillary service requirement, then your self-arrange schedule -- it will show up in the schedule and you won't have to commit it through replacement.

So the thought is that it would change the market behavior such that it would be self-arranged or self-scheduled so that you wouldn't have to commit it with a replacement.

I'll give you a feel for -- looking at August '09 under the current methodology, the column on the left is what we actually had as our non-spin requirement. You can see for hours 16, 17 and 18 it was 376 megawatts. That is going to be a -- that is a small number. And part of the reason it's a small number is due to -- there was a tendency to overforecast net load. So the 95th percentile or a number that would cover 95 percent of the errors is going to be a smaller number.

You see on the right under the proposed methodology, this is -- the only difference here is the 60 days analyzed instead of the 90 days analyzed. So there's a slight difference there. Negative net

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load forecast, this is the bias, this is how much overforecast that we saw in net load, not just load forecast, but that also includes wind, the net load forecast. And the file requirement based upon the proposed methodology would have been this amount had we adopted this prior to last summer. And you can see that the difference here -- the cap of 2,000 megawatts caused the 449 to be reduced to 430 so we would maintain the cap of 2,000.

October, you can see what those numbers are as well. Final non-spin procurement would have been 1952 megawatts versus what we actually procured in October of zero.

November (indicating).

And then in the next slide I want to give a little bit of an overview --

CHAIRMAN SMITHERMAN: John, I'm sorry.

MR. DUMAS: No, go ahead.

CHAIRMAN SMITHERMAN: Go back to the preceding slide. Let me make sure I understand the effect of what you're contemplating here. So you're increasing the non-spin requirement. Tell me what a non-spin category generator can do. Can they also offer into the balancing market or are they just going to get paid a non-spin amount?

MR. DUMAS: There are two types of non-spin now. That was effective with the change of Protocol Revision 776. There's a -- what's called a 15-minute balancing energy non-spin. Any unit that can start in 15 minutes can bid in to balancing. So they can -- they would bid into the capacity market non-spin. They would get struck. They would offer their energy into the balancing energy market at an 18 heat rate times the fuel index price as the floor minimum. They could offer it more than that for the energy, but they have to make a minimum offer of that. And they get struck in balancing just like any other resource that's offered into balancing based upon their offer and where we're at in the stack.

Then there's a 30-minute non-spin that's deployed like we would traditionally deploy it at less than 2500 megawatts or if we need to deploy in the zone because we're out of balancing energy in a zone for congestion. That 30-minute deployment, there is a minimum price requirement that was per Protocol 776. And that's fuel index price times 15 plus 120 bucks. So it's the -- they get paid the higher of that or whatever MCPE cleared at.

Does that --

CHAIRMAN SMITHERMAN: Well, you made a

statement earlier -- I'm just trying to square these -- where you said that one of the effects of this proposed methodology is to reduce the supply of generation available for the balancing energy market. I thought I heard something like that. And so I'm trying to understand --

MR. DUMAS: Okay.

CHAIRMAN SMITHERMAN: -- how that works.

MR. DUMAS: Well, the thought is if you -- when you procure a replacement, it's basically an OOMC-like procurement. So they come on line at LSL, load sustainable limit, and they have to bid the difference between LSL and HSL into the balancing energy market.

So if you take a 500 megawatt unit, LSL is a hundred, they would have to bid at least 400 megawatts in the balancing energy market. So that would go into the bid stack at whatever their offer is. Now -- and then replacement would cover the start-up costs.

Now, if it turns out that they have an additional 400 megawatts of reserve obligation, then they get paid whatever non-spin cleared at, or they self-arrange it and they don't get paid anything. But they can't bid that into balancing. It has to be

reserves that are available -- well, they can if it's 15-minute. I think that's what you asked. They can if it's 15-minute balancing, yes. They can bid it in. But they have to bid it in at a floor of 18 heat rate times fuel index price as a minimum. So -- and there's about -- roughly 1600 megawatts of capability that are qualified for that type of service.

Okay. To give you a brief overview of operating reserves as they relate to the NERC operating reserves, we require a minimum of 2300 megawatts of responsive reserve in ERCOT. This is analogous to the NERC operating reserve spinning, and it's the contingency reserves that they refer to. It's used to arrest the frequency decay due to a sudden disturbance or a trip of a large unit. It may be provided from governor response for generators, and up to 50 percent can be provided from load acting as a resource.

Regulation service, this is something that we use to maintain frequency control and to meet the NERC CPS 1 performance criteria. And the, of course, non-spin reserve is analogous to what NERC refers to as supplemental reserves.

I'll go through some assumptions that we made on the cost. And these are capacity cost

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numbers. I didn't do any assumptions on the energy cost and how that would be affected. But we looked at -- using this methodology from January through October and what the effect or the difference would be on the ancillary service cost. And you can see that the column -- first column are the actuals. That's what we actually procured. The column in the middle would

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be the proposed. And based upon using MCPC staying the same -- we assumed it would be the same price, which it could be different -- this would be how much we would have spent under the proposed methodology versus what we actually spent in capacity.

The difference year-to-date, based on these assumptions, turned out to be eleven thousand -- 11 million, excuse me -- 510,982 -- I can't read my own numbers. So you can see it's 11.5 million, approximate difference year to date based upon the proposed methodology for the non-spin capacity. This doesn't take into account any effects on energy. For instance, if you do shift more of the load forecast into reserves, shift some of that bias out of the net load forecast, you will have a tendency to deploy non-spin more often and you will have a tendency to hit those caps that are there with the energy payment.

All right.

CHAIRMAN NEWTON: Okay. Dr. Patton?

MR. PATTON: This is -- Chairman Smitherman, this is very complicated stuff.

CHAIRMAN SMITHERMAN: Yes.

MR. PATTON: I guess you would agree with me on that point. I really had two questions, and one of them goes back, John, to your Slide 3 in which you were going to change your methodology and look at the last 30 days and the same month of the previous year. And really my question there is given the change -- particularly the change in the -- in wind and the availability of wind as more -- as enabled through the CREZ lines, does it make sense to look at the previous year? I mean, it seems to me that that may not be useful. Can you comment on that? Maybe I'm not making myself clear.

MR. DUMAS: No, I think you've got a point there. I think what you're saying is as your capacity increases and you get more wind output, then that will have an effect on the megawatt error, and that's true.

What we were trying to do here is just capture any seasonality effects that the forecast might be about to go into a transition month. If you're moving from summer to fall and there's more

wind or you're moving from winter to spring and there's more wind output, it was an attempt to catch that type of effect in the forecast.

MR. PATTON: Well, I take your point on that one, but I -- the fact that the generation mix is changing also confounds that and works against you there it looks like.

Also I had a -- I had a question about the 2,000 megawatt max, and I was wondering what the rationale for that one was. It seems like just an arbitrary number. Where did that come from and how did you arrive at that?

MR. DUMAS: What we've observed over the last year is on the off-peak hours the maximum that we've seen is around 1900 and something, close to 2,000. And there was a concern that, well, physically, currently, all we have available in off-line resources is roughly 3300 megawatts. So we suggested this cap to make sure that our numbers don't add up, when you add the bias -- you do the 95th percentile calculation, you add the bias. We couldn't really accommodate 5,000 megawatts right now of non-spin. It just isn't on the system. So we proposed a cap of 2,000 just to be able to ensure that we don't run into a case where there's not that much

capacity there to get.

Now, you can -- you can carve out duct burners and you can do some of those things with other types of generation to increase the capability. But currently that's where we're at, and that was the rationale behind that proposal.

CHAIRMAN NEWTON: Okay. We have a couple more cards, and this methodology does need to be approved, I believe, today by the Board. So --

UNIDENTIFIED SPEAKER: Or not.

CHAIRMAN NEWTON: -- or not. Right. It needs to be taken up for a vote. Good clarification.

Bob Helton.

MR. HELTON: Nothing.

CHAIRMAN NEWTON: Andrew?

MR. HELTON: My esteemed colleague (inaudible) .

MR. DALTON: We can do that. All right. John, a couple of questions. I guess first I just want to understand -- we're not actually changing anything with how we procure ROS, right? This is just for the non-spin?

MR. DUMAS: You mean responsive or --

MR. DALTON: Yeah, responsive.

MR. DUMAS: Right. Nothing has changed

within --

(Simultaneous discussion)

MR. DALTON: -- still going to keep the same 2300-megawatt level there?

MR. DUMAS: Right.

MR. DALTON: Okay. Now, the other part that I'm kind of struggling with here is it looks like this is going to increase, you know, prices by about 11-and-a-half million, but it's also going to essentially use the administrative price under 776 to, I guess, set almost a floor in the balancing energy market based on the 18 heat rate and the fuel index and then whatever other kickers are on 776.

I understood that as this came through this was kind of a market-based kind of concept of how to change pricing methodologies, but how are we really achieving that if we're using an administrative price to set the balancing energy market? Or am I misunderstanding what we're doing?

MR. DUMAS: No, I think you're correct. The concept here is to -- is to move the bias in the load forecast out of the -- out of the load and put it into reserves. Now, I think the end result is what you were referring to. The end result is, yeah, more non-spin potentially bid in the balancing energy. You also have more periods when you run out of balancing energy and you deploy non-spin, which by the changes that 776 put in place would kick in those floors that you're talking about.

MR. DALTON: And if we do that, do we have any idea what's that going to do to the prices to the balancing energy market?

MR. DUMAS: Well, the times that we deploy it's going to be at least whatever that price is.

MR. DALTON: Okay. So it will be, generally speaking, higher?

MR. DUMAS: It could be even higher than that, yes.

MR. DALTON: Okay.

MR. DUMAS: It depends on what was offered in.

MR. DALTON: And I guess the other point -- and I think this kind of came up at TAC as well -- is wouldn't we be better served just fixing the net load forecast and getting the wind forecast, the load forecast as accurate as possible? Isn't that a better endeavor because this -- that will add more kind of clarity and consistency into the market once we go nodal; whereas this is essentially and

administrative fix for a year.

MR. DUMAS: Yeah, and that's true. And

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we are working on improving the accuracy, obviously. And we don't -- we don't intentionally overforecast like I said. Our error is -- is good. What's -- well, the 80 percent, there's an intentional bias there.

But the load forecast -- what happens in the summer primarily is going to be your rain, your cloud cover. So you can't plan on if it rains in Dallas and Houston and the load drops by 6 or 7,000 megawatts, which rain in the summer has more of a dramatic effect on the load than rain in the fall and spring, as you can imagine. So those effects come into play more in the summer. So that's why you tend to see that average there.

And this approach -- this proposal is really to try to work with the market to address some of those issues that Dan Jones identified in his IMM report.

CHAIRMAN NEWTON: I understand from the material that TAC supports this. Is that correct, Mark? And if so -- or could you share with us kind of how the voting went?

MR. BRUCE: Yes, ma'am. Thank you,

Madam Chairman. I just wanted to mention we did discuss this at some length at our November 5th meeting of the TAC. There was a vote to approve this, but there were three votes in opposition, all from the consumer segment. There were four abstentions from that vote, two from the investor-owned utility segment and two from the electric cooperative segment.

Generally -- there were 20 votes in favor and there was -- I think a lot of the discussion along the lines of what Mr. Dalton has raised about is this the right way to address kind of a multitude of issues in terms of addressing the ancillary services needs of having the adequate reserves on the system, but then what do you do with the pricing impacts of that. And I think we asked the exact same questions about, well, can we improve forecasting, but there's I think on-going workshops at the PUC addressing that issue. There's a PRR out there to address at least the load forecast piece of that. It's kind of stalled while we try to work through those issues.

So I think the majority view at the time was, well, this is something we can do. It's a step in the right direction and kind of balancing those things out. But again, it was 20 in favor, three opposed, four abstentions.

CHAIRMAN NEWTON: I think -- Bob, did you still want to make a comment?

MR. HELTON: Yeah, just a couple real quick. And I agree the final thing is if we can fix out some of the bias and get to a true forecast, then that's where the answers really lie.

A couple of things though. When you move -- and, John, you can agree or pipe in as you would like --

CHAIRMAN NEWTON: Could you bring the mic up, Bob?

MR. HELTON: I'm sorry. You're taking the bias out of what you would normally have when you do the day ahead forecasting of gen and load, and you're moving that bias into the non-spin. Correct? That's really what you're doing.

So when you do the day ahead, if there was -- if your forecast did not have enough gen on line, you would go through RPRS, OOMC to get what you needed on line.

So when you see these numbers, one of the things -- I don't think it tells a true story -- or the full story I should say. There's another half of this equation that it may be an $11 million -- $11-and-a-half million increase in the NSR -- you

know, in non-spin. But there is some -- and I don't have a clue what that number would be -- decrease in what you would forecast day ahead, and potentially procure day ahead by a different means.

MR. DUMAS: That's true. I'm always careful when I answer that question, though --

MR. HELTON: Well, I know there's a lot of uncertainty --

MR. DUMAS: -- yeah, there is an embedded assumption that market participants would self-arrange the additional capacity obligation and, therefore, schedule more -- schedule more resources and, therefore, we would need to procure less replacement.

MR. HELTON: Correct. That's basic. It's one way they can have some of that.

MR. DUMAS: Right.

MR. HELTON: But that kind of goes on the same thing. If you give them a non-spin requirement day ahead, they can do the same thing --

MR. DUMAS: Right.

MR. HELTON: -- we're talking about, which is self-arrange to cover themselves to hedge that.

MR. DUMAS: Right.

MR. HELTON: So all that kind of works.

What I see here is -- this doesn't automatically mean that you're going to hit that 18 heat rate plus -- you know, 18 heat rate, or if you're going to hit the 15 heat rate with a 120 adder. What this does -- I mean, you may potentially hit it more often than you today because you do have less spinning out there on line. So I understand that.

What this does is it takes out that excess spinning reserves that's out there and lets the market function the way it should, and you will get prices moving up and down that bid stack higher than you would without this and having the extra stuff on there, which is depressing the pricing.

Now, whether we hit this or not and do deploy non-spin, we don't know yet. I say we probably will on occasion hit it more often, but we have no idea how many times because there's too many other factors in there. So there's a lot of different sides to this equation. Thank you.

CHAIRMAN NEWTON: Barry?

CHAIRMAN SMITHERMAN: Why don't you get these guys first.

CHAIRMAN NEWTON: Okay.

CHAIRMAN SMITHERMAN: And I've asked Dan

Jones to come -- I think Dan is somewhere.

CHAIRMAN NEWTON: Nick, I believe your card was up next.

MR. FEHRENBACH: Nick Fehrenbach, and I just want to sort of address a couple of perceptions of this. And, yes, if this had been in place last year, there is another 11-and-a-half million in non-spinning ancillary service that gets uplifted. And I recognize there's some offset to that. It would be, you know, some reduction probably in the replacement reserves that were procured. So, yeah, there would be some offset. Unfortunately, we don't know what that is. And that could have been a million or it could have been 20 million. Nobody knows, and we won't know until a year from now what it is.

But what my real problem with this is we're taking an ancillary service, and normally ancillary services are for reliability purposes. And we're not really addressing a reliability issue here. We're trying to address a market issue, and I think that's the wrong use of ancillary services. It's just getting us way off track.

And I realize we only have a year until we have a completely new market, but I think we're setting a bad precedent when we're trying to resolve some market issues using the ancillary services. We know that we're increasing the chance or probability that we're going to have administrative pricing at points during the year, and, unfortunately, nobody can forecast whether that happens once, twice or a thousand times next year.

Certainly I don't want to have to come down here for an emergency Board because suddenly in some odd month, you know, we suddenly have this tripping every day and we have administrative pricing and we're getting flack from the public and the capitol. Nobody wants that, but you start running that risk when you start increasing the probability that you're getting into administrative pricing, and I just think it's a bad idea.

CHAIRMAN NEWTON: Thank you, Nick.

Clifton?

MR. KARNEI: Yeah, I'm trying to get my CPA brain around this a little bit and struggling over here. And, John, I think you went to touch on it, and maybe it's a question for Dan Jones, but you mentioned earlier that this attempts to address some of the concerns identified in the Potomac reports? So what I'd like you to do -- or maybe Dan to do -- is fill in this sentence. And that is, in exchange for an

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estimated cost increase of $11.5 million dollars through October of 2009 we believe that these changes will help the market by addressing what issues?

MR. DUMAS: Well, I'll let Dan speak to the market question.

MR. KARNEI: Okay.

MR. DUMAS: What we were trying to do is address the concern in the report over the bias, get it out of the energy and get it into reserves. And at the same time that we were doing that, not introduce a reliability problem because we were running with less capability. By increasing the reserves, you're not running with less capability. You're running with additional reserves that you can use to deploy in the event that you start getting short on your -- getting close to EEA or something of that nature.

So we wanted to maintain the integrity of the system and maintain reliability by taking some of that concern over the energy and shifting it to reserves. And I'm going to let Dan talk to the other part of this.

MR. KARNEI: Okay. And so one piece of this is the fact that we've been overforecasting, which causes us to procure much more down balancing that up balancing. Is that a fair statement recently?

I know, you know, we've talked about this in some of the monthly reports we get. Is that fair or is that --

MR. DUMAS: I don't know if that's related directly or not. I'd have to dig into that a little bit.

MR. KARNEI: Okay. Never mind.

CHAIRMAN NEWTON: Okay. Dan, you want to address the market issue?
CHAIRMAN SMITHERMAN: Dan, before you -- let me sort of tee it up for you.
MS. YAGER: Okay.
CHAIRMAN SMITHERMAN: I guess here's my question, and maybe this is a question shared by others: What is the principal force behind this recommendation? Is it to solve a market issue, a pricing issue? Is it to go toward the overbias in the procurement?
Because I think what I'm hearing the more this tends to lean toward resolving a market issue, the more I think it gives some people some heartburn. And, of course, the Commission is looking at market issues presently. So maybe you could tell us why we need to do this, why you think it's a good idea what your sense of the consequences may be.

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MS. YAGER: Okay. Dan Jones with Potomac Economics. I heard most of the previous discussion on the Internet there.
In our 2007 and 2008 state of the market reports, we identified the issues with the load forecast bias, particularly during the summer peak hours. An increasing piece of that is the wind forecast error and the intent to underforecast the wind, which has the same effect on the unit commitment process as overforecasting the load.
The purpose -- one of the primary

purposes of non-spinning reserves is to address forecast uncertainty. So it is a prime purpose for which non-spin has historically and currently being used. And, in fact, the non-spin as changed to be mostly a reliability product that's procured to manage the uncertainties in the load and the wind with the secondary purpose of addressing the loss of a large unit. But I think the overriding concerns in recent years have been the load and wind forecast uncertainties.

In the -- in our state of the market reports and at the workshop in Project No. 37339, the high-level result of having a high load forecast -- and of course every day is going to be different. But

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when there is a bias, a persistent bias in a low wind forecast relative to what's really going to happen is that there's a tendency to overcommit the system.

Now, an overcommitted system is not a problem if the market decides to do that on its own. But whenever ERCOT is intervening to, essentially, take out a market -- non-market-based actions to cause that overcommitment, the result is, relative to not taking that action, suppressed energy price.

And so the purpose was to take the bias that was existing -- which is essentially ERCOT planning their system to meet the peak demand and the reserve requirements, and then having a bias that is procuring more reserves but in the form of capacity that's being brought online through non-market-based means.

So the purpose was to take some of the
observed bias -- not all of it because it's subject to
the cap. And we've observed -- the 2,000 megawatt
cap. We've observed this bias at certain hours at
certain times of the year, particularly in the summer
months being in excess of 3500 megawatts. So this
proposed solution won't go towards addressing all of
the observed bias that we've seen in the past. But to
take that -- move in the direction of taking some of

that bias and put it where we have been trying to
address the uncertainties, which is in the non-spin
product that we have right now. So the result will
be -- and I don't know -- I heard some cost numbers.
I don't know if they were in the posted
presentation -- but 11-and-a-half million was the
estimate on the non-spin capacity cost. Is that what
I heard?

I think directionally that's right. The
non-spin costs are going to go up because the procured
quantities are going to go up relative to where we are
now. The replacement costs, which are uplift, should
go down. I don't know if they will go down as much as
or more than the non-spin capacity increase, but there
will be an offsetting component in that.

Those costs are uplift -- all of the
replacement and OOMC costs are uplift to the market.
Now, ancillary costs are allocated on a load ratio
share. But the difference between that and
replacement, as you can -- a participant can hedge its

not spinning obligation through assets or through a contract, replacement and OOMC cannot.

And then finally on the balancing energy price, relative to staying the course that we have right now, the balancing energy prices should see an

increase. And it's a relative increase. We haven't quantified what that will be because it's very difficult to do so. But it's relative to a practice which tends to suppress the price through out-of-market actions. So you would expect that it would increase. So those are the objectives.

CHAIRMAN NEWTON: Mark?

Okay. Andrew?

MR. DALTON: Dan, follow-up question. I mean, part of the issue here is when we're striking this new non-spin, when they bid in over into balancing energy it's going to be tied to this PRR 776 formula, which has that 18 heat rate and some other issues. Does that cause a concern for you that we're going to be artificially imposing potential clearing prices in the balancing energy market that is going to inflate it or does that need to be revisited as part of this?

MS. YAGER: The pricing mechanisms that exist now and would apply as a part of PRR 776 are that the 15-minute balancing energy capable non-spin has to bid at a floor price of 18 heat rate or greater, which on a day like today would be about $40 a megawatt-hour. If gas prices go up, it would be higher. For the most part that's a non-issue, because most, if not all, of these -- most -- a super majority, 90-plus percent of these units -- are quick start gas turbines. And their cost structures are such that it's higher than an 18 heat rate because they're all flying and they have to start and run and they have some uncertainty as to how long they're going to be deployed. So those cost structures tend to make that a non -- that 18 heat rate floor a non-issue.

On the 30 minute non-spin, if it's deployed-- and the sequence of deployment now is -- basically there's the 15-minute balancing energy capable non-spin that gets deployed first because it's in the balancing stack. And that's been a great benefit from PRR 776 because then it provides more timely access to these reserves than it would have in the past when the operator has to give 30-minute notice.

If they get to the point where they also need to deploy through the historical mechanism, the 30-minute non-spin, then the price floor, which is $120 plus a 15 heat rate, does kick in. I don't have data, but oftentimes that's also irrelevant because you already have these 15-minute non-spin units that are setting prices that are greater than the floor.

So there's no adjustment. There are times when there is an adjustment, and it's administrative in the sense

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that it's 120 plus 15 heat rate.

The mechanism that was developed to come up with that was based upon actual market-based observations of gas turbine offers for start-up and minimum energy cost in the RPRS market. And it's intended to cover the marginal cost of starting and operating a gas turbine and running it for an hour.

So that's -- and so right now, gas is below $3, but if it was at $3 that floor would be $165 per megawatt-hour. So the price floor would be 165. If the price was already 200 or 250, then the floor would obviously -- it wouldn't matter.

CHAIRMAN NEWTON: Okay. We've had a lot of -- oh, Dr. Patton, one last comment -- oh, and Mike. Sorry.

MR. PATTON: Am I correct in stating that the net load is load minus wind? Is that right?

MR. DUMAS: (No audible response)

MR. PATTON: Could you tell me how much of this NSRS and its associated cost is due to the variability or inability to forecast load and how much is due to the variability of wind?

MR. DUMAS: They're commingled, so

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it's -- I guess it's possible you could break some of that out. But you're basically taking load forecast minus the wind forecast, and the wind forecast is intended to be biased such that you're intentionally underforecasting the wind. So if you always underforecasted the wind, then the contribution would be zero to the 95th percentile. There would be a contribution on the bias, but not on the 95th percentile calculation.

So these numbers do work -- they're dependent on each other. So the more you over -- the closer we get to 80 percent target, the less of the 95th percentile number we're going to calculate and the more bias. If we go to a 50 percent type wind forecast and it truly ends up being 50 percent, we're going to calculate a bigger number in non-spin on the 95th percentile component and less of a bias.

So they're dependent on one another. It's not really easy to break it out, but I suppose you could.

CHAIRMAN NEWTON: Mike?

MR. GENT: Dan, this is certainly complicated. I think that's an understatement. To follow on Clifton's question, I think we're being asked to pass on $11-and-a-half million more to the

ratepayers in hopes it will improve how the market operates. Is that correct?

MR. D. JONES: Well, I just saw these numbers. I take the --

MR. GENT: -- if the numbers are correct.

MR. D. JONES: If numbers are correct, there's an 11-and-a-half million increase in non-spin capacity prices. There is a reduction in replacement reserve procurement costs that hasn't been quantified, but I know that the direction is down. It may be

1 million, it may be --

MR. GENT: -- something less than this --

MR. D. JONES: -- 20 million. And then the balancing energy prices, relative to staying the course, you would expect over a period of time to be higher to some degree. And, you know, on that thought, the first question was is it a reliability issue or is it a market issue? And I guess I would just share that I find those issues to be inseparable, particularly if you look over a period of time. Today's market issue is tomorrow's reliability issue. So I think that always -- almost always, unless it's maybe a relay issue or something that's going on,

these types of issues have market and reliability implications and they're very closely intertwined.

CHAIRMAN NEWTON: Chairman Smitherman?

CHAIRMAN SMITHERMAN: Yeah, I'm just trying to work through the math in my head. I think we all agree with the first two points, Dan, that one is going up and the other one is going down but we don't know how much it is. I guess what I'm trying to figure out -- and I'd probably need some examples -- is really what the effect on the balancing price might be because, yes, ERCOT will procure less, which should create more opportunities for scarcity pricing. Right?

MR. D. JONES: I think it creates a higher probability that some of the non-spinning reserves will need to be deployed to manage the uncertainty that materializes in realtime, which is really --

CHAIRMAN SMITHERMAN: And that pricing opportunity is a different opportunity from being procured under RPRS.

MR. D. JONES: RPRS is -- yes, it's different.

CHAIRMAN SMITHERMAN: Okay. But I guess the unknown is we do have additional supply coming

online. In fact, we have a lot of supply coming online. We have, you know, five or six large fossil units that are going to be operational over the next 12 to 18 months. And so I'm not sure, to the extent that that couldn't counterbalance, perhaps, the rise in the balancing prices as a result of ERCOT not procuring as much as they have in the past.

MR. D. JONES: I certainly think there is a tremendous amount of inframarginal capacity coming on line, whether it's coal, lignite or new wind. And all of those tend to have a -- place a downward pressure on the spot prices in the market.

CHAIRMAN NEWTON: Okay. We've still got a lot of cards up. This is a critical issue. We do have -- just to remind everybody, we do have this noticed for a vote. I have not gotten a motion yet I would remind everyone. So I will continue to take some comments and I will ask for a motion and we're going to need to move on. But clearly there -- we do have a recommendation from ERCOT that was supported from TAC before us.

So I believe, Andrew, you might have been next.

MR. DALTON: Yeah. I guess -- I'd still like to see probably a little bit more data around

what we might expect would happen in the balancing energy market, as well as what the reduced cost or the beneficial effects of this on, you know, some of the command and control activities that ERCOT has engaged in.

To me I think the best way to handle that would be to remand it to TAC, ask them to try to put a little bit more information around this so we can make a more informed decision next month. I think we have until next month to approve this anyway because it doesn't take effect until next year.

So I would make a motion to remand with instruction to bring it back with a little bit more information next month.

CHAIRMAN NEWTON: Okay. I have a motion. Do I have a second at this stage?

If not, we'll continue to take comments and then we'll go back to the motion.

Bob?

MR. HELTON: Just real quickly. One of the things that -- whenever Michehl was talking about costs and Barry was talking about looking at those cost numbers and there was two cost numbers. One thing that didn't get reiterated that I just want to reiterate that Dan said is the non-spin is a hedgeable item and the uplift costs you get from out of merit issues aren't hedgeable. So that is another way you can hedge these things.

And actually on -- well, you didn't get a second. But I was going to say I'm not sure what you would study because some of this there's no way of predicting some of that stuff. So I'm not sure what you would do.

So I would move for approval of the ancillary services methodology as proposed by ERCOT.

CHAIRMAN NEWTON: I have a motion for the recommended new methodology as presented. Do I have a second?

We have a second from Dr. Patton.

Nick?

MR. FEHRENBACH: And a quick comment and then a question. In addressing what Dan was saying earlier that, you know, replacement reserves is not a market solution. But replacement reserves aren't a product of what ERCOT sets the load forecast at. It's really a product of the fact that there are not enough resources on line after they compare the schedules to what the load forecast is. And, you know, if there are just simply enough generators scheduled, you don't have to have a replacement reserve. It's just that

for some reason we normally don't follow that because we're a little thin; you go under replacement reserve.

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My question is -- in the three years I've been on the board, a recurring theme that I've heard along, and primarily from generation segment and the power marketers is they've always had an issue with ERCOT staff -- and I'm not being critical of ERCOT, I'm just passing on what I've heard -- but there's been an ongoing theme that ERCOT has always overdeployed non-spin when they've needed it. And I've heard this for years, that when they need non-spin they deploy large quantities of it and that affects pricing and that's why we had to have an administrative pricing through the PRR.

My question is, is by increasing non-spin and increasing the probability and likelihood that they're going to have to deploy non-spin, are we going to be exacerbating that problem where a lot of the market participants are going to be thinking that it's overdeployed and overdeployed more often now? And since that's been an on-going theme for a long time, I'm just concerned that we're going to exacerbate that problem, whether it's real or perceived?

CHAIRMAN NEWTON: John, can you handle

that question?

MR. DUMAS: Yeah. I'd have to have specific examples, but all I can refer to for deployment of non-spin is we deploy non-spin per procedure when the reserves fall below 2500 megawatts which is -- as you know, EEA is triggered at 2300 megawatts. So it's an attempt to keep us out of EEA.

We also -- Step 1 of EEA, if we go into EEA, we deploy non-spin, if we haven't already, which we probably have already. The other time that we deploy non-spin is if we have zonal congestion and we're out of balancing energy in a particular zone, and we've got -- we still have congestion and we've got non-spin, we'll deploy it for that purpose.

Those are the reasons we deploy non-spin. And those cases we're out of balancing energy or close to EEA. So I'm not sure -- I think probably what the -- my guess is -- and it's strictly a guess because I didn't hear the comments -- would be when we deploy non-spin, that obviously it's an energy deployment in zonal. So any energy that you deploy, if it's a thousand megawatts, it will have a tendency to back down the balancing stack. So your prices are going to be cheaper because you just backed down a thousand megawatts that was loaded up in balancing due

to the energy deployment. And that was what the market participants were trying to address with the administrative process in 776. So they attempted, I believe, to address that concern through 776.

CHAIRMAN NEWTON: Okay. Mark?

MR. ARMENTROUT: Well, this has been an interesting discussion. And I always -- we Board members normally pay a lot of attention when all the consumer segments of TAC vote against something like this, as we should do here. So we have a motion and we have a second. This algorithm is going to produce unforeseen consequences. I conceded some of the benefits of reliability and I can see the benefits affecting price signals.

So I would like to offer a friendly amendment. And maybe we can't forecast these -- the benefits or forecast the impacts of less -- of less energy. But we're forecasting the weather, so -- and by the way, if there's any notion that anybody has that eventually we'll have a forecast that's perfect, that will never happen.

MR. HELTON: Right.

MR. ARMENTROUT: Right. Okay. Weather is one of the grand challenges of high performance computing that most scientists admit there are

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boundaries in human mind and the compute power that that will just never be -- that will never be solved, at least not in our lifetimes.

But I'd like to offer a friendly amendment that this be closely analyzed and reported back to the Board -- at least within three months of it going into effect -- with close analysis on the impacts on all angles, because I just think this has some -- this will have unforeseen consequences that have not been brought up in this meeting.

MR. KARNEI: I'll second the amendment.

MR. HELTON: I have no problem accepting that -- to do that. You're right. And I figured we probably would do that going forward, to ask on that.

CHAIRMAN NEWTON: Okay. So we have a motion and we have a second, and we also have a friendly amendment that's acceptable to ask the staff to relook at this and bring back to the board probably a three- or four-month kind of status of how this methodology would work should we vote it through.

We have two more cards up and then we need to take a vote on this. So, Dan?

MR. WILKERSON: Thank you, Madam Chairman. I was just going to say, before the amendment even -- and I support the amendment -- that

I support this change in ancillary services. I'd just point out a couple of things. The annual cost predicted here by John is not 11-and-a-half million. It's more like 13-and-a-half or thereabouts. This is year to date.

There are a couple of things that we talked about that will improve that cost, and I think they're going to be pretty hard to track. One of the things you just mentioned is the balancing stack changes when you forecast less load. It means you're moving down a balancing stack, and as the Chairman just mentioned a minute ago, that balancing stack is likely to get cheaper with some new generation. It's going to be a little hard to tell. Maybe you can do it. But my perception is it will eat away at most of these costs. That's why I support the ancillary service change. I think it's what TAC saw -- anyway, I just wanted to state my position.

CHAIRMAN NEWTON: Thank you, Dan.

Mark, do you have one other comment?

MR. BRUCE: Thank you, Madam Chairman. Just briefly. A correction. Mr. Armentrout mentioned that all the consumer representatives at TAC voted against this, and it was half. It was three out of the six. The other three --

MR. ARMENTROUT: Thank you.

MR. BRUCE: -- out of the six voted in favor of the motion.

And just to the amendment to the motion, if you will recall actually last year we had a very similar discussion when we were changing the exact same service, and you guys actually did the exact same thing, you asked staff to come back in February, three months later and do some analysis. And so, you know, I think everybody would probably be pretty comfortable continuing to monitor and watch this. A lot of what I think staff has brought and what we discussed in the TAC is we're learning as we go with a lot of this stuff.

CHAIRMAN NEWTON: All right. We've had a healthy discussion on this. We have -- does everyone understand where we are? A motion and a second to approve the proposed ancillary service methodology for 2010, with the -- a direction to the staff to come back in three months after implemented and give us a status of how this methodology is working.

So with that motion and second, all in favor.

(Those voting in favor so responded)

CHAIRMAN NEWTON: Opposed?
Nick Fehrenbach opposes.
Abstentions?
Michehl Gent abstains.
The motion passes.
Yes, Andrew?
MR. DALTON: One quick point. I think this methodology change has some merit to it, which is why I voted in favor. But I'm going to be very interested in seeing what staff comes back with on potential cost implications because I do still have concerns that we don't precisely know what we're approving and impacts it's going to have on the market, and particularly our customers in what are difficult economic times.
CHAIRMAN NEWTON: Thank you very much, John. Appreciate it.
Okay. We obviously are running a little behind schedule, but I would ask Bob Helton to give us kind of an update from the Nodal Subcommittee. There was a long meeting yesterday. Many of us were there for that meeting and got substantial updating on where we are. Also Trip grave us some significant updates on some progress that's been made. So, Bob, I would ask you to keep it brief and then I'll defer to you

relative to Mike's presentation or vice versa, however y'all want to handle it.

MR. HELTON: Mike and I were just discussing, and we did have a very long meeting yesterday. If you would like for me just to give a quick update and just end it at that, we can do that, if you would like, and then we will go through that. We can just give you the highlights of what we had yesterday.

CHAIRMAN NEWTON: Okay. Before you get started, Andrew, did you have a --

MR. DALTON: Yeah, I think there's one other voting item in Agenda Item 8 that has to do with the AEP Corpus Christi --

CHAIRMAN NEWTON: Oh, goodness. Thank you very much. I apologize. I was trying to move on too fast.

MR. HELTON: You can go ahead and do that one first if you would like.

(d) Corpus Christi Area Improvements Project Recommendations

MR. DALTON: I wanted to point out with regard to that that one of the industrial consumers mentioned in that report is Valero. We have a refinery down in the Corpus Christi ship channel. I

talked to Mike Grable about it. I'm going to recuse myself from this vote because we are one of the customers that would be directly affected by the decision of the Board potentially financially, although I would say that we think the ERCOT compromise solution was a sound one.

CHAIRMAN NEWTON: Okay. Dan, I

apologize.

MR. WOODFIN: That's okay.

CHAIRMAN NEWTON: And, Andrew, thanks for keeping the Chair square.

MR. WOODFIN: I'll try to do this really quickly then. AEP submitted a set of projects for the Corpus Christi area that had several different drivers, a couple of new generating plants down there. There were also some reliability upgrades needed. And also AEP had been having some issues scheduling transformer maintenance and other maintenance at the same time that -- at appropriate times.

So they proposed a rather comprehensive set of projects. I'm going to flick through these really quick so you can see where they are. They were obviously all over the Corpus Christi area here. There are various upgrades, new transformers and so forth.

There were a couple of different options related to the Nueces Bay interconnection. What we're recommending -- and I think everybody is in agreement on -- is building this new Gila substation. There's some reliability requirements, and that caused us to need to upgrade both of the Lon Hill transformers.

There were -- the maintenance outages -- what AEP had originally proposed and Andrew referred to here, it would have required a lot of the industrials to replace their owned breakers because of short circuit current problems. And we tried to come up with a compromise solution that meets all of the NERC reliability but also didn't require all those breaker changeouts.

That resulted in the final set of projects is this building a line from Barney Davis to Laguna and putting in a new auto at Laguna, reconductoring the Lon Hill to Hearn and then rebuilding Highway 9 to Valero. You can see the cost of those.

And then we looked at the economic projects that may be warranted as a result of the two new plants in the area. We looked at a couple of different options, and the one we're recommending is the rebuilding of the Barney Davis to Nelson Sharpe

line. That's -- it's cheaper, it doesn't require a CCN and, therefore, it can be done faster and reduce the congestion more quickly.

We had a stakeholder review. There were some dissenting comments, basically from the industrials not wanting to change out their breakers. And also I think on some of the places it would have caused some extended outages while those breakers were being changed out. We've resolved those.

There were perhaps some hanging issues that came up at TAC that some different folks made comments. TAC chose not to either endorse or not endorse this project as a result of those comments. We think these are all resolved at this point, and I think everybody agrees that this set of projects needs to be approved and moved forward by the Board. So we would recommend this set of projects be endorsed by the Board.

CHAIRMAN NEWTON: Mark?

MR. BRUCE: Thank you, Madam Chairman. Briefly, Directors, the TAC did discuss the set of projects at some length, and we appreciate as always staff bringing these projects by for our review. While there was no motion to endorse or no motion to oppose these projects, I would -- I would hate for the

Directors to read into that that there's some sense of the TAC that these projects should not move forward. I think there was general agreement that they should, but there were a lot of parties that wanted to see additional work or still had questions about the ERCOT's compromise proposal. We encouraged those parties to continue to work through the Regional Planning Group process as a follow-up to this. So there's no formal action on this, but I want to be clear that there was really no stated opposition by any of the parties at the TAC to this package of projects.

CHAIRMAN NEWTON: Thank you, Mark. The Board appreciates that insight.

A.D?

MR. PATTON: It seems to me like the group has come up with a reasonable solution here, but I have to ask this question: We're -- the solution that was arrived at avoided breaker change out by some industrials, including our friend here Valero, I guess, and that was good for them. Okay? But in so doing, my question is did it increase the costs that are uplifted to transmission and thereby increased my bill and yours and everybody else's at the same time? And so my question is just that: To what extent did

this compromise, which undoubtedly saved some people money, cost other people money and caused a greater uplift? Could you speak to that?

MR. WOODFIN: Yes, I don't believe it does in that it will -- what we were -- what's being offset by not doing those upgrades is that it makes it a little trickier to do maintenance in the area that will have to be done during more off-peak time frame, and some of the industrials will have to run their generation during that.

So, you're right, there's usually not a -- not an offsetting, but in this case the offset is that reduced flexibility related to maintenance.

CHAIRMAN NEWTON: Clifton?

MR. KARNEI: I'm a little confused on the cost here. On Slide No. 2 -- I'm sorry, 3 -- I see 101 million. And then on Slide No. 6 I see Option 1, which shows 27 million. What is the cost of the project?

MR. WOODFIN: In the aggregate it's the --

MR. KARNEI: One point --

MR. WOODFIN: -- 101, right. There's several projects. There's the -- some roughly 50 million on Page 4, plus the 20-something on Page 5 plus the 27.

MR. KARNEI: Very good. Madam, Chair, I move for approval.

CHAIRMAN NEWTON: Okay. We have a motion for approval from Clifton Karnei --

MR. KARNEI: Actually, I make a motion to endorse the project.

CHAIRMAN NEWTON: To endorse the project. Okay.

MR. GENT: And I second.

CHAIRMAN NEWTON: Okay. Thank you. And a second from Michael Gent.

Any further discussion?

All in favor?

(Those voting in favor so responded.

CHAIRMAN NEWTON: Opposed?

Abstentions?

The motion passes unanimously.

MR. DALTON: One recusal.

CHAIRMAN NEWTON: Pardon me, Andrew?

MR. DALTON: One recusal.

CHAIRMAN NEWTON: Oh, one recusal from Andrew Dalton. Thank you.

9. SPECIAL NODAL PROGRAM COMMITTEE REPORT

10. NODAL PROGRAM UPDATE

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CHAIRMAN NEWTON: Okay, Bob, do you want to kind of lead us through whatever you choose to do with nodal?

MR. HELTON: Right. All right. We'll go through the nodal in a quick nutshell. The first thing is -- and just to give you on the program status -- 378 days to go. There is a light at the end of the tunnel. We are getting there. We've got a long way to go.

So just with that, one thing I wanted to point out on the nodal dashboard as you go through, you will see that Phases 4 and 5 has yellow in them when you're looking at them and they're not green. The reason is -- and we have talked about this the last couple of months -- we knew there was a wave of activities coming up that we had to finish on Phases 2.1 and 3. So we finished those and now will be focusing to get those back to a green. And some of that will require, basically, being Grinch and canceling Christmas and working some overtime to get that stuff done, to get back on track by the first of the year. So we'll be working through between now and the first of the year.

Also, if you go to the traceability piece, on that we should be finished with the

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traceability of the Tier 1 project protocols by the end of the year. What that will do is we will be done with going through and looking at what the protocols say and what the design documents say should be in the system. And any gaps that are in there through business requirements and through system will be put through the NATF program to see if we need to change

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the protocols or what we would need to do moving forward with that. So traceability by the end of the year. That's another good sign.

Market readiness, a couple of things we want to point on there is we actually have now one QSE out of 123. So we've got a ways to go, but we have a good message here. We have one of them that is now qualified to put data through into ERCOT. That means putting it through the API, that it's acceptable and can be validated by ERCOT and put through the system. So we've got one done, 122 to go. So we're making progress there.

Also they've started through on market readiness making their on-site visits. Those are going well. They're customized for who they need to go talk to and work with them, and that's on track to finish up.

Another piece is we have six entities --

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resource entities with transmission assets that have not completed their RARFs, the registration criteria. ERCOT is working with those six. I'm not going to put those out there today. We have asked -- the red, green and yellow dashboard will be coming out, and it started yesterday, I believe. Those next month will be brought, and if there's names still on there that are red, will be brought to the Special Nodal Committee, and we will be making recommendations to the Board on actions that potentially need to be taken to bring those into compliance. So if you're on that

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list -- you probably know who you are -- just remember that as we move into the next month.

A couple of things on data that we'd like to get out to the market is ERCOT had put out a market notification asking for digital certificates to be used during the testing phase. They've got some, but they could use some more. So QSE entities, if you could look up that market bulletin, get those test certificates and allow ERCOT to use those during the testing. Once testing is over, they go away and they're invalid. So they can use those to help us get through the process.

The other is what we would like to see is better data coming in through the market

conductivity trials. We don't expect anyone to put in the real data of what they're going to do when we go to nodal and understand that that's not going to happen, but we would like to get as close to real life as we could so we could try to see that the program is working and getting us some reasonable outcomes.

So with that, we did do the end-to-end testing where we find some issues, but where we're at we found out we do have a technical solution, which is good. Now what we've got to do is increase both the quality of the data and the quantity of the data, which is increasing the complexity of the inputs going through between now and market trials and go-live to get from where we're in the low single digits on both of those up to 100 percent on both.

So we've got a long way to go. Things

are on track. Just keep it moving.

And, Mike, do you have anything you want to add to that?

MR. CLEARY: No, that's it. I think the two main points are we were able to do the end-to-end testing. In fact, we've done it three times at this stage. We're running a fourth tomorrow. As I said, the technical solution is good. The quality in relation to outputs from the system such as RARF

and SCED -- and prices are pretty low at the moment, and the complexity of the scenarios we're pulling through are pretty basic at the moment. But again, we at least have the basic platform that we can now start increasing the quality of that solution.

The other pieces, we do have the 2.1 connectivity out there. We're working with up to -- you know, between 14 and 16 of our market participants, plus vendors, to start to deal with pulling transactions into the systems. We're not running the markets, but we are able to pull the transactions into the systems, verify them and send back the signals, which is what we wanted to do as part of the connectivity.

As I said, I do want to set up the -- you know, the expectation, the light's at the end of the tunnel, it's flickering, but it's at the end of the tunnel. We still have a long way to go to make sure we get the production ready.

MR. HELTON: And one other piece I just

want to add in and then I'll turn it back to you, Madam Chair, is yesterday some of us made it in early yesterday to take a look at the realtime EMS and SCED demonstration, which was a very good demonstration. And who would have thought a while back we would be

sitting there watching the EMS program, the SCED program and the outage scheduler, which we had on yesterday also, working through the loss of a nuclear unit and showing how that system works, how it recovers frequency and how it redispatches the system. I mean, to think about that and seeing that working is showing us that we are getting in a right direction and -- not to the finish line -- but we are moving in the right direction now.

So with that, Madam Chair, I'll turn it back over to you.

CHAIRMAN NEWTON: Well, and I appreciate you guys trying to help us with our schedule, but I feel like I would be remiss if I didn't say this on behalf of all of the Board. It's kind of nice to be able to short circuit a nodal discussion for once, because right now we've got some very good news happening. You know, as you mentioned, you've completed the end-to-end test. You've done your market trials. We've got the financial situation kind of stabilized and you're coming in under budget. We're still on schedule.

The presentations yesterday relative to market readiness, and then really key to me, too, was the traceability of the PRRs back to the system, the progress if you think about where we were a year ago and where we are today is pretty phenomenal, Mike.

So, Bob, thanks for your help and your committee's help. And, Mike, your team should be commended for a lot of effort this year in getting us this far. Certainly there are risks going forward, but we certainly appreciate it.

MR. CLEARY: Thank you.

CHAIRMAN NEWTON: So even though I short circuited it, please pass along our good --

MR. HELTON: You short circuit it here, but we don't short circuit on the subcommittee.

CHAIRMAN NEWTON: That's right.

MR. HELTON: We spend an awful lot of time and we spend time at Taylor also.

CHAIRMAN NEWTON: Well, thanks for getting us back on schedule. We are scheduled for an hour for lunch. I'm going to shorten that to 1:15 since we've got a very long schedule this afternoon, and -- as everyone knows. I want to give, you know, parties an opportunity to discuss these critical issues, but we're going to have a long day today. So please try to be back and prompt. We will reconvene at 1:15.

(Recess: 12:30 p.m. to 1:18 p.m.)

AFTERNOON SESSION

TUESDAY, NOVEMBER 17, 2009

(1:18 p.m.)

12. TECHNICAL ADVISORY COMMITTEE REPORT

(a) PRR830

(b) APPEAL OF PRR830

CHAIRMAN NEWTON: Okay. I believe that we're back on the webcast, and I'm going to reopen our open session of the Board meeting this afternoon. I'm going to handle these next couple of items a little bit differently than what's outlined on the agenda. What we have on our agenda is a presentation on PRR 830, and then we have next an appeal of that PRR. This is a little unusual in terms of process, but we have a number of parties who have asked to make comments relative to this PRR.

If this is all right with the Board -- and I will be open for suggestions -- but rather than us discussing and voting on PRR 830 and then hearing all the comments relative to the appeal, what I would like to do is let's open up the discussion on PRR 830 and let's hear the TAC position, and then let's go through the various parties who have comments so that the Board has the benefit of all the comments before we ask the Board to vote on the PRR, rather than

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having us vote and then hear and have to potentially make a different decision.

So I'm seeing some heads nod, but I would open it for any concerns if that causes anyone any concerns relative to process.

Okay. Seeing none, with that, Mark, would you kind of kick this off and kind of step us

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through how we're going to try to approach this from this point?

MR. BRUCE: Yes, ma'am. Thank you. As you noted, we've got the one PRR that was not approved on the consent agenda for your discussion this month. That is PRR 830 reactive power capability requirement. The PRR clarifies the reactive power capability requirement for all generation resources, including existing WGRs who are not able to meet the 0.95 lead/lag requirements with the resources -- within the resources unit reactive limit.

This PRR was recommendeded for approval by the TAC. It was a roll call vote. There was one opposing vote from the independent generator segment. There was six abstentions from the IOU, the generator, the two consumers and two independent power marketers. All the market segments were present for the vote.

The impact analysis shows only minor

changes to ERCOT databases to incorporate additional SCATA points. These impacts can be managed through the O&M budget. So the CEO determination on the PRR is no opinion and no impact to nodal.

So as you mentioned, there will be a presentation next by the TAC advocate. I just wanted to mention that, number one, I recused myself as Chair from selecting the advocate of the TAC position. I was the opposing vote to the PRR, and it's my client NextEra Energy Resources, that filed the appeal. So the vice chair, Shannon McClendon, who abstained from the vote, selected Mr. Houston of CenterPoint Energy, who actually made the motion to recommend approval of the PRR.

So, Mr. Houston, if you want to come up? And he will outline for you the TAC's position on the PRR.

CHAIRMAN NEWTON: Thank you, Mark.

MR. HOUSTON: Can everyone hear me?

CHAIRMAN NEWTON: Yes.

MR. HOUSTON: Help me out here -- oh, here we go.

Okay. As mentioned, I'm John Houston with CenterPoint Energy. And Shannon had asked for me to present the appeal of PRR -- to be the TAC advocate

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for the process.

I'd like to start with -- let me see if I can make this work here. Just a little bit as Mark went through the history, but I just wanted to go through a couple of items here.

ERCOT originally proposed this to clarify reactive power requirements applicable to all generators, and to provide a framework for people who might not be compliant to be able to comply with this requirement of the protocols.

In September the PRS tabled this by unanimous vote to send it to ROS for review of reliability effects of this proposed revision. The ROS vote was -- recommended approval after considerable comments and discussions and presentations in its October 15th meeting.

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It was then forwarded to the Protocol Revision Subcommittee. They considered it, again extensive discussion took place, and market participant involvement was heavy. It was recommended approval and sent forward to TAC.

On November 5th we again took up this -- we at TAC then took up this revision. And after considerable discussion -- as Mark just mentioned, we had considerable discussion at TAC -- and it was

approved. I believe the vote was 23 to 1, and Mark did recuse himself from selecting the TAC advocate.

Again, we're talking about ERCOT reactive power requirements required of generators. The existing protocol had been vetted through the stakeholder process I want to say back in 2003 and 2004, with significant involvement of the stakeholders in development and provision of comments with regard to how reactive power would be supplied by generators.

Those requirements have been in place for several years. And under that approach, the requirements for both loads and generators are fixed at a set level; i.e., those requirements don't change after time passes and in the future. So loads and generators are not subjected to the topography changes, the addition of new generators to the system, new lines. Those become the responsibility of ERCOT planning and transmission providers.

So that adds the certainty that generators look for with regard to they can build the generating plant at its location, and they can achieve meeting the requirements for their output and their interconnection, in particular in this case their reactive requirements.

Incremental needs that the system may

need going forward are identified by engineering analysis and Mr. Woodfin's folks and others at ERCOT. All of that is to ensure voltage stability for the transmission system in ERCOT and that that can be provided by facilities and changes made by transmission providers.

There seems to be a lot of discussion -- and I'm sure we'll have a bit here in a moment more -- but PRR 830 was proposed to clarify, not change, the existing requirements. So this in -- all of these considerations at ROS and PRS and at TAC, stakeholders heard many of the arguments that you will hear this afternoon and rejected arguments that clarification of PRR 830 should not apply to certain existing generators because existing requirements were ambiguous.

Now, that's just not true. They were clearly understood. And, in fact, they're recognized and have been by most of the members of ERCOT for many, many years. This PRR -- and I want to be very clear here, I am not discussing at all any pending proceedings at the Commission or ADRs or -- that are applicable toward past compliance. That's not -- as the TAC advocate, I'm not discussing that this afternoon. We're talking PRR 830, if you were to vote it in, would become effective upon your approval.

PRR 830 provides the means and the time frame for anyone who happens to be not compliant to fairly and equitably comply with the requirements of the protocol revision of the current protocols. And they can do so without necessarily having to retrofit their unit, because they could provide a payment in lieu of -- a payment of contribution or they can submit alternatives to changing their generation.

As far as the need for studies, this again was brought up at -- I would say at all of the considerations of this protocol revision. TAC and the other stakeholder groups heard and, in my opinion, the votes suggest rejected arguments that studies should be performed to determine whether compliance with the requirements are needed for reliability. That included presentations by NextEra and Siemens that you'll probably hear or see some of those this afternoon.

As previously noted, the requirements for generators are fixed. I think that's a good thing if I was a generator. I think that would be appropriate for my ability to finance projects and be -- my ability to have certainty about what my performance requirements were. They don't vary over

time. Those needs for the dynamic support of the system are provided by the transmission providers

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after significant studies.

So taking the fixed capability of generators and loads as input, that enables the transmission planning to take place, to assess the incremental needs as we change the topography, as we continue forward. They are then provided by the transmission owners.

So as to the current state of affairs, my belief -- and I think the members of TAC indicated it with their vote -- that this protocol is in existence and that these requirements are how we went about planning this transmission system. I think that's a very important part. How we got to where we are is the assumptions under this clarification or how we got to the transmission plan that we're now operating under.

Now, if -- that plan has resulted in us making decisions about investments in the transmission system to enable reliable operation of ERCOT, the ERCOT grid. We're about to embark on a significant study of the reactive requirements associated with the many billions of dollars associated with the CREZ investment. It's intended that if this protocol is

passed that that will give certainty to those decisions that need to be made with regard to the dynamic reactive compensation that needs to be added in CREZ by the transmission providers who are constructing the transmission assets that will bring this large amount of wind power to loads.

So, in my opinion, this approach is fair and workable. It adds certainty, and it provides us the path forward for doing the CREZ studies. It also enables people who might not be compliant with a path to become compliant and provide the reactive support that the ERCOT system needs.

And I think I would encourage this Board to consider reliability. I know you will hear a lot of comments about who has to pay what. But bear in mind that the situation that you as Board members are operating ERCOT under right now, if there are people who are non-compliant, they have basically taken some of the margin out of the reliability of the ERCOT system. That's being made up by ERCOT operations and being provided by other generators or operational constraints or considerations or decisions that are being made every day because of that noncompliance.

Going forward, it's essential that we understand where we are when we plan this system.

when we complete the recommendations and the planned installations and investments by transmission providers to enable this 18,000 megawatts to seek loads in this state. So I would ask you, as Board members to consider your responsibility as members of the Board of the Electric Reliability Council of Texas.

That is basically, Madam Chairman, my comments this afternoon.

CHAIRMAN NEWTON: Thank you, John. Are there any questions or comments for John at this point?

Appreciate you stepping up and providing us TAC's perspective on this.

My plan at this point is behind Tab 12(b) of the Board material is a memo that Mike Grable was gracious enough to put together that kind of summarizes some of the companies who were wanting to make appellate positions. Before I get into that, Mark, did you have something else you wanted to add or --

MR. BRUCE: No, I was going to introduce, I thought, Mr. Markarian from NextEra was going to --

CHAIRMAN NEWTON: Well, actually what I

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think I'm going to do is go in alphabetical order, if that's okay. And I will just go according to the alphabetical list of companies as they're defined behind Tab 12(b).

So we will start out -- and then I will also ask if there are any other parties. I had understood that we potentially had one or two other parties that had desired to make comments that did not have an opportunity to get the materials to the Board packet. So I will ask for those after we go through this list of the companies who have provided materials. So I'll start with AES Corporation, Robert Sims. Is he here?

MR. SIMS: Yes.

CHAIRMAN NEWTON: Oh. Thank you.

And before we start the comments, if I

could, I want to be sure that everyone has an opportunity to be heard on this. The Board had put together procedures to handle appeals and so forth, and I appreciate the companies that have tried to adhere to those procedures. But we do want to provide an opportunity for the Board to hear any comments from any parties. However, in the sake of time, because this is -- could be fairly lengthy, I would ask that as the presentations are made that we not hear the

same comments repeated over and over again. So I would ask that the presenters try to kind of keep that in mind as you go through your comments so that you will be presenting new ideas to the Board. And if you choose to endorse a prior-made comment, that's fine, but not to just restate the same positions over and over if possible.

MR. SIMS: Thank you. Good morning. Robert Sims with AES Corporation, and my presentation is a little different. I thought it might be helpful to give the Board a little perspective on the power factor issue by looking at what's been done in other regions of the United States. So I'll just briefly cover that.

Basically, in 2005 and 2006, a considerable amount of work was performed by a large and broad group of grid operators and stakeholders, including wind generators, and ultimately this work lead to FERC issuing Order 661A, which is included in Exhibit G to the FERC Large Generator Interconnection

Agreement. That's now the standard and required agreement across most of the USA. It's used by all investor-owned utilities under FERC jurisdiction, and it's been adopted by a lot of non-FERC jurisdictional entities in many regions of the country.

Just a little chronology on the work that went together over that two-year period. Initially in 2003 FERC issued Order 2003, and that standardized the interconnection process requirements and agreement for all large generators over 20 megawatts or 20 megawatts in aggregate.

In March 2004, as a result of stakeholder comments, FERC issued Order 2003A, an amendment of that. And that recognized that electrical machine technology differences affect the interconnection requirements. And with that they provided what was termed Exhibit G, which was a blank sheet of paper to be completed by stakeholders in the wind power industry, recognizing that wind energy technology was a little different.

So following on to that, September 2004, FERC hosted a technical conference on requirements for the interconnection of wind generators. The conference was broadly attended. It was in Denver. I was there. It went on for a full day with the FERC commissioners there hearing positions about the requirements for wind turbines. That was followed a few months later in December 2004 NERC created the Wind Generation Task Force. And they were chartered with "review the bulk electric system reliability implications and concerns of wind generation." So under NERC, under the Transmission Working Group, their group looked at this issue. They looked at power factor. They looked at low voltage ride through. And they looked at other aspects of integrating large amounts of wind energy into the bulk power system. That group began a series of regular working meetings.

In July 2005, FERC issued Order 661, termed The Interconnection Requirements for a Wind Generator Plant. The order defined the technical requirements, including low voltage ride-through, which is now at issue coming up in ERCOT; power factor, which is relative to PRR 830. And also SCADA communication requirements for meteorological information, units availability and so forth. And those were all included in Exhibit G of the standard large generation interconnection agreement, as I mentioned, and are now law under FERC jurisdiction.

In 2005 NERC requested a rehearing on 661 based on some continuing work with a Generator Task Force, primarily relating to finer details of the timing of low voltage ride-through, the level of voltage and the duration. There were no comments on the power factor requirement.

That was finally followed in December of 2005 when FERC issued Final Order 661A and the final

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Exhibit G, the requirements for wind generator plants. Under the 661A process, there were a large number of parties that participated. I put together a list here from the FERC filing of all the parties that participated in that process. CenterPoint was the only one from the ERCOT region. Otherwise you see many of the grid operators here: ISO New York, midwest ISO, NERC themselves, New York ISO. A large working group that participatend in this project -- PJM, Southern California Edison, et cetera, Xcel Energy.

And here's the wording that was decided upon under 616 A, which basically, "The wind generating plant shall maintain a power factor within a range of .95, leading to .55 lagging as measured at the point of interconnection". I won't go through and read this entire thing, but it's basically the triangle requirement or the cone requirement you are hearing discussed in the dialogue today.

Most wind turbine manufacturers then, based on the ruling in 2005, designed wind turbines for deployment in the United States based on this requirement, and that is now what's available through

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most of the country. So we now have a situation where ERCOT is asking for high level -- higher level of reactive support than required by FERC and NERC under the standardized large generation interconnection agreement, without really any technical basis or studies to demonstrate that need for a higher standard.

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Thank you.

You want to do questions now or does that come later on?

CHAIRMAN NEWTON: No, I think we should -- are there any questions for Robert?

Dr. Patton?

MR. PATTON: Tell me how this is different from the proposed PRR?

MR. SIMS: Well, 661, that's the triangular requirement or the cone requirement where the power factor of the generator is maintained with an ability of plus or minus .95.

MR. PATTON: Please go back to the previous language.

MR. SIMS: Sure.

MR. PATTON: Where does it talk about a triangle?

MR. SIMS: It really doesn't. It

doesn't say triangle.

MR. PATTON: Thank you.

MR. SIMS: Questions?

Thanks.

CHAIRMAN NEWTON: Andrew?

MR. DALTON: In have one quick question. This kind of relates to the 661A and how we're looking at FERC -- I mean, kind of more globally as, you know, some support for what we're doing here in ERCOT on wind. I know back when we had the LBRT discussion several months ago, I think the wind generation community took the position that 661A, even though it had standards for LBRT, that didn't apply in ERCOT, it never happened in ERCOT, and now here you seem to be taking the opposite position that, well, FERC set a standard, so we should go with it.

And I'm trying to understand how we should be looking at the FERC precedent and are we picking and choosing when we want to rely on it or should we be doing this more systematically to be consistent with the federal standards, or should we be recognizing that ERCOT is probably unique in the country because we have a lot more wind than any other state?

MR. SIMS: Well, I don't think I'm

taking a position on any of those points. I'm letting you know what a large body of stakeholders determined was the appropriate power factor requirement for wind generators in much of the US.

MR. DALTON: All right.

CHAIRMAN NEWTON: Mike Grable --

MR. GENT: On one of your previous slides I represented NERC in filing protests, and I can recall vividly -- this is prior -- just prior to my retirement -- that this was sprung on us and, I will say, given very little attention or time to respond. The FERC employee that was largely responsible for this was a former employee of AWEC, whatever that wind associate -- AWEA. Is that it?

Oh, yeah. And you'll notice, if you read through, which I have on my screen now, read through 661A, you'll see all sorts of protests from the industry, mostly having to do with low voltage ride-through. So we never really got around to all of the issues and then FERC just went ahead and passed it anyway. So I don't think using 661A as a basis for an argument is really something that's going to gain a lot of traction within my circles.

MR. SIMS: Well, I do agree that most of the discussion was around the low voltage

ride-through. I don't think there was much discussion at all as far as the power factor requirement.

CHAIRMAN NEWTON: Anything else for Robert?

Yes, Mike?

MR. GRABLE: Just a brief comment. I do agree with Dr. Patton's point that there is no triangle or rectangle mentioned in this quote.

Robert, would you flip to the last slide, which I think is what Mike Gent was referencing?

MR. SIMS: The very last?

MR. GRABLE: Yeah, asking for a higher level than that required by FERC and ERCOT. I think whether it's higher that that required by FERC is debatable, and 661A can be interpreted. But it's the end NERC part of this that troubles me a little bit. NERC did express grave reservations with the wind position in 661A, and Chairman Kelliher pointed that out, that NERC was troubled. So I don't think it's quite right to say that NERC was signed on to your version of the approach here. But I just want to highlight that.

MR. SIMS: Okay. Very well.

CHAIRMAN NEWTON: Okay. Thank you,

Robert.

Okay. The next company ahead is AEP, Kip Fox.

MR. FOX: Thank you, Madam Chairman. Let's see -- I believe you have our comments in your Board package. The only thing I would like to add to that from AEP's perspective is that one of the things that we do find -- and not to belabor on some of the points that John has brought up -- is that we fight these issues every day. The question that came up during TAC is what's the indication that we have problems in the system, and the fact is every life in the day of operations from the operations side of -- as a TSP, we see the warning indicators every day. I mean, the fact that we have lot of operations going through, and the fact that we're going through different kinds of requirements, we're doing switching and all kinds of other things from an operational standpoint, tells us that this issue is becoming more and more critical.

And as the Board considers this alternative and this PRR, we need to understand that there are operational things out in the field that we're almost at the point that we can't handle anymore. It should be -- it's not a reliability crisis right now, but it's growing. And we see this more in ERCOT than we do at AEP in some of the other RTOs that we operate where there's wind available.

And I would say from an AEP perspective, we see this issue in the west more prevalent than we do in our other locations. So to us these requirements have been very clear in being a rectangle rather than a cone for many years and in our other jurisdictions, and that's all I would like to add at this point in time.

CHAIRMAN NEWTON: Thank you. Any questions for AEP?

Okay. Thank you very much.

Again going in alphabetical order, ERCOT. Kent, are you handling ERCOT?

MR. SAATHOFF: Yes. I just wanted -- you know, the written comments you can read. I just want to go into a little bit of the history very briefly. As John mentioned, the PRR was passed in 2004. And really the issue of compliance or non-compliance with the PRR didn't raise up until last summer. And it became an issue in a wind workshop that we had back in August.

And back in August, John Dumas made a presentation where he stated the rectangle requirement

was what the protocol required, which is that generators are to provide a constant source of reactive power over their entire operating range, which is based on the plus or minus .95 at their maximum power level. That was followed subsequently by a market notice to that effect.

In the interim, it became apparent that wind generators were having -- existing wind generators were having problems with that interpretation and that requirement. So we worked with them since the end of last year to determine a way that they could comply with what we believe was in the existing protocol. Unfortunately, we couldn't reach agreement with all of them, but we felt like we should file this protocol to establish a way of compliance and, hopefully, go in that direction and get full compliance.

Back in June, we contacted -- we reviewed the resource asset registration forms that were filed earlier last year, and contacted those generators that, you know, appeared not to meet the reactive requirement in the protocol based on that information. And the resource asset registration forms, which is mentioned in other comments and I'm sure will be mentioned later, their purpose was really

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not compliance. Their purpose is for us to get accurate data on what is out there in real life so we can appropriately model it. So they weren't established for checking protocol compliance.

But nevertheless, we did go back and look at them and see if the information reflected there showed compliance with the rectangle, and we contacted those that it appeared that they didn't meet that requirement and to get additional information -- or additional reactive resources that aren't reflected in your RARF, and, you know, we got various responses.

But we contacted 70 wind generators. Of those 70, 16 met the requirement, the rectangle; 29 met the triangle requirement, which, you know, we believe is not what the protocol requires; 9 didn't meet either the triangle or the rectangle; and 16 were pre-2004 wind generators that were exempt from the requirement.

So we essentially filed the protocol to establish a way for those 38 generators that don't comply to comply, and that was the primary purpose of the protocol.

CHAIRMAN NEWTON: Okay. Any questions for Kent?

Yes.

MR. BIVENS: Kent, you said -- I'm trying to remember what you said -- you said that the particular requirement in this PRR, when you established it in 2004, was not necessarily for compliance but --

MR. SAATHOFF: No, the RARF --

MR. BIVENS: The RARF --

MR. SAATHOFF: -- the Resource Asset Registration Forms that were created last year, mainly to get a good set of data for the -- for our nodal model, yeah.

MR. BIVENS: So with most protocols, when you find non-compliance, what do you do?

MR. SAATHOFF: Well, this issue has come up before. We at ERCOT ISO do not have a compliance staff. So what we do is when we have a system incident that has occurred and we look into that incident and it looks like to us there may be some issues of protocol compliance, we will forward a report on that to the TRE.

MR. BIVENS: Why was there a four-year period before this became an issue?

MR. SAATHOFF: You know, frankly, it didn't come to our attention, and I assume everybody thought they knew what it meant. And apparently there

is a difference of opinion on what it meant.

MR. BIVENS: Okay.

CHAIRMAN NEWTON: Andrew?

MR. DALTON: Thank you. Kent, a couple of questions. As I was reading through your memo, a couple of thoughts occurred to me on this concept of parity among the generation resources. And it seems that there are some pre-'99 units that are exempt, some pre-2004 units that are exempt. Then there's this 2004 to 2009 group of generators, and then there's another group 2009 -- December 1, 2009 going forward. I mean how many generators are in each of those buckets?

MR. SAATHOFF: You know, I don't have that information at hand. The 1999 for conventional generators, and February 2004 for wind generators, that was established in the protocol. The -- from 2004 to now and future, that's at issue right now. But the protocol just had those two groups.

I do know in 2004 we had about 1300 megawatts of wind, and right now we have over 8500 megawatts of wind.

MR. DALTON: Okay. How much conventional generation was on at that time that's still on today, a decade later.

MR. SAATHOFF: I certainly don't have an exact number, but I would say, you know, 10, 20,000 megawatts, somewhere in there. That's just a guess.

MR. DALTON: And I support this parity concept. I think it's a good one that we keep all the generators on the same foot. I'm just tying to kind of get a sense for what are we talking about and how does that affect the system, too? Because I'm somewhat sympathetic to making changes when the rules might not have been clear to everyone.

But to get to that point, as we went through the interconnection process with these generators or they were submitting their RARFs, I mean, at what point did ERCOT know that there was an issue with some of these generators, and how quickly did ERCOT react to that?

MR. SAATHOFF: Well, we really only became aware that there was an issue back last summer. As a result of discussions with wind generators and other parties, we did the review of the resource registration -- of the RARFs last summer -- excuse me, this summer, back in June.

MR. DALTON: Okay. So this is -- we learned it through the RARF process because ERCOT doesn't really directly participate directly with the

interconnection requests?

MR. SAATHOFF: That's right. Generation interconnection agreements are between the generator and the transmission provider.

MR. DALTON: Okay.

MR. SAATHOFF: ERCOT is not a party to those agreements.

MR. DALTON: Okay. And there's not some communication process between the TSPs and ERCOT regarding what the standards that are being imposed to the interconnection process are?

MR. SAATHOFF: There's -- I believe there's a standard -- fairly standard generation interconnection agreement that I believe the PUC approved. But as far as us being a party to generation interconnection agreements, no, we're not. And we have not been reviewing all those.

MR. DALTON: Okay. And then, I guess, if we didn't pass 830 today, what would that do to all the modeling and the studies that have been done in the CREZ docket? I mean, would that throw everything kind of into disarray, or would we be able to modify that information or -- what does it do? How does it interplay with the CREZ work that's already been done?

MR. GRABLE: Kent, do you mind if I

answer this one? I think it's a procedural question.
MR. SAATHOFF: Okay.
MR. GRABLE: If 830 doesn't pass, ERCOT's belief is that the protocol says what it says and we require the rectangle and we will model according to that. There is more uncertainty as to whether -- you know, in what venue and how far down the road it will reach -- other people deciding one way or the other on the issue, but that's how we'll proceed.
MR. DALTON: Okay. That's all I have for now. Thank you.
CHAIRMAN NEWTON: Mike?
MR. GENT: Kent, did you say that there were -- from your study that you surveyed there were 28 that could meet the requirement?
MR. SAATHOFF: No, there were 16.
MR. GENT: 16 that could --
MR. SAATHOFF: That met the rectangle and 16 were exempt.
MR. GENT: All right. The question has to do with those 16, and it is how do they meet the requirement physically and is there a high voltage issue with these 16?
MR. SAATHOFF: Of the 16, five

apparently meet the requirement with the generator. Apparently they have some of the newer generators that can provide a full dynamic requirement. Six met it after they provided additional information that was not reflected in the their RARF. Four met it with essentially the way PRR 830 says, that you can meet it by the addition of additional static and dynamic devices in addition to the generation. And one submitted a mitigation plan committing to do that in the future.

MR. GENT: I guess my question would -- second question only deals with those four then. It just seems to me if you put in static capacitors you're looking at a possible overvoltage situation under certain system conditions as well, unless they're operating properly.

MR. SAATHOFF: That's right. And we reviewed that to make that sure we were comfortable with -- that that amount of capability could be operated within the requirements.

CHAIRMAN NEWTON: Is that all, Mike?

MR. GENT: Yes. Thank you.

CHAIRMAN NEWTON: Bob Helton, I think you were next.

MR. HELTON: Just real quick question,

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Kent. Is there a problem then with our procedures for connecting to the grid itself? And what models -- I know whenever we turned in all of our data for our generation units we had to have every model and every test and everything we did turned in to both planning and operations. Is there a different process or did we just do that and that's -- it's not in the procedure that you actually review that against the OGRs -- you know the operating guides protocol requirements? I'm trying to figure out where there may be a hole where we could catch something like this --

MR. GRABLE: Kent, can I jump in here, too? I mean, there are two things I think we ought to look at. One is we rely on, as you know better than anyone -- you know better than I do, Bob, the generator itself certifies that it understands and complies with all protocols. I think we need to make sure going forward that ERCOT staff and individual generation owners and operators are on the same page with respect to all those items. We probably need to go through them one by one and make sure that when a generator certifies that they're fully compliant with the protocols, they understand what that means. They understand what ERCOT staff understands that that

means.

I think we also had some miscommunication here between the TSPs and ERCOT. And I don't want to speak for them or our staff or get into who knew what or who thought what, but you've heard from the TSPs -- you've heard from one and you'll hear from -- well, you've heard from two and you'll hear from a third today as we go through this list -- that they believe it's the rectangle, that were there interconnection agreements signed up where the generator is going to tell us they should have known we were talking about the triangle here, you know, yeah. So there clearly are some communication issues we need to work on.

MR. HELTON: Right. And that's what I was getting at. I mean if -- because if the test data and the model data was all -- which exists for every unit, then we would be able to know that right off the bat. I was just curious to see if we do need to change some procedures on that issue.

MR. GRABLE: I think we ought to flag that regardless of the PRR, regardless of any NOVs and regardless of any PUC action as a separate issue to take up and make sure that we report back to the Board that we're all on the same page.

Danny, I wanted to go back and make sure your RARF question -- that's a form we created for nodal readiness to make sure we understood what was out on the grid -- setting aside compliance, just what can you actually do. And, of course, the date of that form is only within the last year. It's not something that existed in 2004 or prior years, but it has a different -- you had a question about protocol compliance, and I think we've covered that. But I just wanted to make sure we had returned back to that initial question.

CHAIRMAN NEWTON: Did you have another question?

Okay. Dee?

MR. PATTON: Kent, you said that you became aware of this issue last year? This year?

MR. SAATHOFF: Last year.

MR. PATTON: What flagged that to you?

MR. SAATHOFF: Well, there were a couple of events early last year where we had some high voltage in the west and we -- we called on some wind generators involved to deploy their reactive to lower the voltage, and that couldn't be done. So the transmission operator, to avoid equipment damage, opened up the line. So that was the first hint we

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got.

But then as we went to the wind workshops and discussions on this issue, you know, we were certainly aware it was an issue at that point last summer.

CHAIRMAN NEWTON: Danny?

MR. BIVENS: This may be a question for I think every speaker, but one of the issues today is probably going to be whether we vote this thing up or down or whether it gets remanded back to TAC for further study or more looking at. And there's a statement in Mr. Houston's comments of November 10th and it's also on his slides. He basically says he -- the reactive capability requirements for generators and load are fixed and that if there's any variance at all, then that's going to be done by the transmission owners.

So with respect to whether studies are needed, he makes a statement, "Studies are performed to identify the variable transmission owner

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requirements," so it's on the transmission owner. And I -- my question is -- I mean, probably everybody -- do you agree that there are no -- there's no need for any further studies? And I think you said the same thing in your comments as well.

MR. SAATHOFF: Yes, the whole premise is that the protocols set out the standards that generators have to meet. In other words, what they bring to the table. Under those assumptions that those requirements are being met, then the transmission operators perform the studies to determine what additional equipment they may need to put on the transmission system.

CHAIRMAN NEWTON: Yes, John?

MR. HOUSTON: Yes. In answer to your question, I think CenterPoint would again design and plan the system in conjunction with ERCOT to make all the changes, assuming that the generators are performing as per the protocols, and assuming loads of meeting their requirements. As I pointed out in some of my comments, for example, in Houston, we've just invested over 25 million in dynamic reactive because there isn't adequate dynamic reactive capability in the existing generators in the Houston area to prevent voltage collapse.

So, yes, we do make those, and we would not go back to the generators. That would basically be every few years, if the study indicated it, instead of building $25 million worth of dynamic reactive I would have had to go back to the local generators and say how about producing .9? How about producing .85? I wouldn't hear that millions and millions and millions of dollars comment many times over.

So I -- that's not how it works. This works. It's fair. It's equitable. It's how we planned the system. It's important to reliability.

CHAIRMAN NEWTON: Dee?

MR. PATTON: I would just observe that -- an observation on the actual system is the best study of all, requires no assumptions whatsoever.

CHAIRMAN NEWTON: Bob?

MR. HELTON: Just real quickly. On the study -- on the CREZ study, the effect this would have on the CREZ study -- correct me if I'm wrong, Ken -- the whole situation is if it was determined that every generator needs to be in the rectangle, then the CREZ study would base on that issue that everyone was in that and then any additional stuff that needed to be done would be done by the transmission providers. Correct?

MR. SAATHOFF: The current CREZ reactive study is assuming the rectangle.

MR. HELTON: Right.

MR. SAATHOFF: And so anything additional to that would be, you know, provided by the

transmission operator.

MR. HELTON: Right. So if something

happens and somebody decides that that's not the case, what would the actual change be, and say that somebody said it was the triangle, then you would need -- knowing that, what that would change is the calculation on what the TDSPs would have to do to ensure stability. Correct?

MR. SAATHOFF: We would have to go back and redo the study with that changed assumption.

MR. HELTON: Right. Okay. Thanks.

CHAIRMAN NEWTON: Dee?

MR. PATTON: And that changed assumption would result in greater uplift to the consumer.

MR. SAATHOFF: Depending on what it showed. If it showed that you needed more reactive equipment because of that, yes. But you don't know until you've done it.

CHAIRMAN NEWTON: Okay. Any other questions for Kent?

Oh, Mike?

MR. GRABLE: Bob, if I were a thermal generator and wind were victorious in their interpretation of the protocol at whatever level, whatever finality we end up with, Kent's right that

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that would immediately change the transmission reactive support assumption. But if I were a thermal generator, I would want to clamber onto the deal that wind got and we would need certainty as to that outcome and then that could further affect what we need from transmission.

MR. HELTON: I'm not sure it being a

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thermal I would agree with that aspect, because, you know, we've already designed and put up our -- we're in as a triangle -- I mean, a rectangle, so we're already there. So there's not a deal to go get, I don't believe.

MR. GRABLE: I understand. I've heard that from your peers.

CHAIRMAN NEWTON: Okay. We'll move on. I have down next in alphabetical order Brian Hayes with Horizon Wind Energy.

MR. HAYES: Okay. So before I get started, I just wanted to first thank you guys. I appreciate the time to come and present our side of the story on this and, you know, just to give you a little background. So horizon is active in the ERCOT market. We have a 400-megawatt plant in Albany, Texas just outside of Abilene. And it's been in operation since 2006 and 2007 is when it came on line. So it

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was post the 2004, you know, that we're talking about here. And, you know, I just want to let you guys know, the reason I'm here today is because reliability is, you know, paramount to us and to, I would say, almost any wind generator in the room. So it's not a thing about concern about -- so we are concerned about reliability.

But the concern that's been raised through this PRR is just the methodology that we're going through to require the retrofitting of facilities to have this -- to meet this rectangle for the wind generators, which I'll go through and discuss why our interpretation of the protocols at the time of interconnect was not the rectangle. And it's going to be -- so it's a cost for us as a generator that will in turn get passed on to consumers. So I just want to make sure that ERCOT and the community is doing the prudent practices to make sure that we're going at this in the right way before we subject to a large investment.

So let me just tell you a little bit about how we interconnected just to give the story on how it worked for us. So as I said, our plant came online in 2006. We did, you know, numerous studies with the TSP to -- providing them all the information

of our plant, what the generators were, what the equipment they were going to have in addition to that.

We even -- through this study the TSP recommended that we needed to have additional capacitor banks to provide voltage support, and we did comply and we put those capacitor banks in. But through all of this study, the requirements that we were meeting were based off this curve here. And this is the infamous triangle that we're talking about.

So if you read through the protocols in 6 .5 .7.1 it talks about that a generator must meet the .95 lead/lag requirement. So if you take the .5 lead/lag requirement, effectively what it means is as your generation goes up, you provide more voltage support as your output goes. So this is a sliding scale effectively with how much you generate. So this is how our plant is designed to operate.

We actually provide a little bit more on the top because of the capacitor banks, but in the end this was the -- this is how we were designing the plant and how we interconnected, and this is what was approved by the TSP and ERCOT prior to any -- prior to us putting any megawatts onto the grid.

And, you know, I will say also that, you know, all the parties were involved with this. So as

the -- after the studies were completed, we completed the GARF, which, you know, now they're on the RARF. Right? But at the time this was the GARF, the Generation Asset Resource Form, that was completed and went through and submitted and approved. And then on the day the plant was energized, there was ERCOT on the line -- I believe it was Oncor and then ourselves ensuring that the plant was interconnected and working as it was designed to do.

So all these things have been checked. And then, as you know, which was discussed previously, then in August of last summer, there was -- there was actually a conflicting message which I think wasn't discussed prior, that in the morning ERCOT sent out a page that basically shows that this is the -- this is how a wind generator resource provides reactive support. And you see the triangle. And then on the top is what a conventional does which is more similar to the rectangle. And I will say that this was not presented. This was sent out to all the people who were going to go to the workshop in the morning. And then by the afternoon, the chart on the bottom right had changed to the rectangle.

But I will point out that the -- actually the example did not change. And so when you

can see the second bullet point it says, "Wind generation output equals zero megawatts and the megavar requirement is zero megavars," which is the exact same definition that we're saying here, that it -- as your output goes down to zero, you stay at zero; whereas, the protocol change that is in discussion is effectively trying to get us to provide the reactive support at the highest levels, even when we're at zero.

So these were the conflicting messages that then resulted in the interpretation that went out by ERCOT. And then this is the -- and I guess further support of that will support the cone -- or the cone or the triangle in 6.7.6, the language in red here. Basically if you read this, it says, "The required installed reactive capability multiplied by the ratio of the lower active power outut to the generating unit's continuous rated active power output."

So if you go through and you turn that into a formula, it's effectively the triangle, and it's a sliding scale. So as your output goes up, the amount of reactive power that you have to provide increases. And so when you're at zero, it's zero. So this is how again we've operated and throughout -- you know, since the plan has been energized and why we're here today to talk to you about this further.

So I guess, you know, taking this all in context, this is -- the issues that we have, you know, with this change that is come down and that we're discussing is that, one, since 2004 there's been 7,000 megawatts that have interconnected into ERCOT. And as was described earlier, some of these meet the requirements, some of them don't.

We have significant concern that there's going to be a lot of money spent to get all of these generators to align with the rectangle. And there's not been one study done to determine if this reactive -- if this equipment that we're going to put in the ground is actually going be used. I mean, it could very well be the case that we could -- that all these generators could go back and retrofit, spend the money, which for our client we have looked at is in the tens of millions of dollars, put the equipment in the ground and then that equipment could sit idle and never be used. It could be a stranded cost just because maybe it wasn't in the right place or maybe because it was never needed in the first place. So there is a big concern to us that the studies not being done will end up being a poor use of dollars for the generators, which will then be, in the end result,

on to the consumers.

And I think the other thing that I --

that has been somewhat frustrating is just that this has been described as a clarification. And, you know, as -- I think it's pretty clear, based on the number of generators that don't meet this requirement today, that it is much more than a clarification. And then with the dollars that are at stake and the amount of investment that's required, again it's hard to call this a clarification. It's a very significant deal, and something that we think needs to make sure that there is a prudent study to ensure that the dollars are going in the right place.

Then I guess the -- I guess the last issue that we have has been brought up recently, and that's just that, you know, there's this disconnect between what was planned in the transmission versus how we're actually interconnecting and operating has raised a lot of concern. It seems counterintuitive that instead of actually going back and looking at how we're actually generating and then making the right decision on what is -- where the investment were to occur, to just go back and unilaterally make us meet whatever what was modeled to begin with.

So anyway, those are my comments, and I

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appreciate any questions.

CHAIRMAN NEWTON: Are there any comments or questions?

Kent?

MR. SAATHOFF: Start with this, that is deployment of voltage support. Right? It's not voltage -- it's not reactive requirement, is it?

MR. HAYES: Yes. Yes.

MR. SAATHOFF: Okay. And the reactive requirement is in a different section of the protocol.

MR. HAYES: Right.

MR. SAATHOFF: In the slide that you had up before from Mr. Duma's presentation --

MR. HAYES: Yes.

MR. SAATHOFF: -- is that his entire presentation?

MR. HAYES: No, it is not.

MR. SAATHOFF: Okay. Thank you.

CHAIRMAN NEWTON: So it's an excerpt or has it been modified?

MR. SAATHOFF: Yeah. The point is there's a preceding slide that stated that we believe the requirement was a rectangle.

CHAIRMAN NEWTON: Okay. Mike?

MR. GENT: Yes. In your background

material and in the material you presented here, there's an implication that this information has been made clear to ERCOT, and then I heard in Kent's explanation that the data is provided to the transmission owner. And in fact I have before me where -- if I hadn't heard this, I would make the assumption that you're doing these studies at ERCOT's request and behalf and that you presented all this to them and they signed off on it. Is that what you're trying to say here, that they signed off on your inability to provide vars as they think are necessary?

MR. HAYES: The transmission service provider has signed off that the studies were completed.

CHAIRMAN NEWTON: And maybe it's in your background material, but for my clarification are you supportive of the rectangle prospectively and only opposed to it retroactively?

MR. HAYES: Yes. So -- yes. So retrofitting in our view is -- it's much more costly to do retrofits than to do -- than to build when you're actually building a new plant. So the prospective we have no concerns with doing anything prospective because we can build it into the plant. And we can even make requirements from our turbine

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suppliers that we meet certain requirements.

CHAIRMAN NEWTON: Well, I guess again, just for clarification, my simple mind --

MR. HAYES: Yes.

CHAIRMAN NEWTON: -- you don't have a problem --

MR. HAYES: -- no problem --

CHAIRMAN NEWTON: -- with the requirement for reliability to be the rectangle?

MR. HAYES: Going forward prospectively.

CHAIRMAN NEWTON: Thank you.

Yes, Miguel.

MR. ESPINOSA: Explain to me then why, if you go back and retrofit, you might have stranded assets, but if you go forward and install them going on, you don't?

MR. HAYES: That's a fair point. So there is the risk that they could be stranded assets, even if you do it going forward. But I would say that the amount of economic impact that you're contributing is a lot less just because you're designing it into when the plant is being built. You don't have to take the plant down. There's a lot of factors that go into it that make retrofits much more -- a whole different game.

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CHAIRMAN NEWTON: Okay. Andrew?

MR. DALTON: Just one quick question, kind of a follow-up clarification. So it would be your position then essentially what we should be doing is setting up a tiered process here, prior to 2004 no reactive power for wind from 2004 until December 1, 2009 or November 30th, 2009 the cone applies. From December 1, 2009 forward the rectangle applies. Is that a fair characterization?

MR. HAYES: That is correct.

MR. DALTON: Okay.

CHAIRMAN NEWTON: Okay. Any other comments for Brian?

Okay. Thank you, Brian.

Next we have NextEra.

MR. MARKARIAN: Good afternoon. We actually brought this appeal. I'm Dave Markarian, managing attorney for NextEra Resources for litigation and state regulatory, and we appear most respectfully before this body because we believe that reinterpreting existing protocols and applying them retroactively is a bad idea.

We believe we too are a reliability leader. And we understand and take this very seriously and we seek to do the right thing. But we

also believe that we're being entirely reasonable here, and we fear that we're straying a little bit from common sense, which is why we're here.

We have made a proposal or, if you will, a counterproposal that we think is entirely reasonable, which is this: If a study demonstrates that more than a triangular reactive power configuration is required, we're all in. No problem. We believe it would be appropriate to examine carefully any reliability events. I'm going to come back and tell you about what we have been told, because we have been asking about this for a long time, nearly six months.

But clearly, as of last night, we were told -- and today you were today -- that 21 and 17 months ago there were two events. There's been no study done as to those two events, and yet those events are being used to suggest that between 30 and $100 million in investment be deployed. I just watched with respect, bewilderment and amazement at your diligent debate over $11 million. This is a big deal, and that's why we're here. And we hope no one feels as though we're wasting your time. I know it's been up before, but we believe we can demonstrate to you that it hasn't been considered the right way or

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quite enough.

This proposal is a one size fits all proposal, when we all know that reactive power capability should be a bus-to-bus analysis. Providing reactive power far from load doesn't always make sense. Even one of the parties that got up and spoke to us in support of PRR 830 has stated embedded in its comments that if you don't quite do it this way, give us the money and we'll use it more appropriately where it should be properly located, where reactive power isn't necessary out in the hinter lands, we can tell you a better way to get this done, AEP.

We essentially focus on what we believe are two myths, the first being that reliability requires it. We have been diligently questioning whether there have been any true events. As recently as July and August of this year, we were told there were no events in several meetings on several calls with numerous witnesses. There have been no system emergencies. There have been no advisories or alerts that are tied to non-compliance of 6571 or 67. And the first mention of any of that, ladies and gentlemen, was at the TAC meeting on November 5th.

So we began to ask a lot of questions. We couldn't get from ERCOT staff any dates, no

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descriptions, no analysis of these events, where they were, when they were. But we did our own

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investigation and determined that not a single event related to voltage -- not a single event related to voltage in 2009 in West Texas was reported in the system operations reports to reliability and operations subcommittee or the Board of Directors or in ERCOT public operations reports. We asked about any events and were told as recently as two days ago that there has been no technical analysis that's been fully performed by ERCOT staff as to these events. No analysis as to the cause of events, no study. Most importantly, that the procedures you're being urged to adopt today would be the proper action to take and would avoid these events.

The second myth, respectfully, is that PRR 830 is nothing new. How can you possibly explain ERCOT's report to you today that far more than half of the wind farms have been deployed with something less than the rectangle configuration of reactive power?

The TAC advocate in its presentation told you that this requirement has been in place for several years. But if you look at PRR, it has been entirely rewritten. The red in the center of this document reflects everything new. The red on the

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outside of these documents reflects everything deleted, striking entire existing paragraphs, inserting entirely new paragraphs, inserting new technical standards and inserting new compliance deadllines and plan approval processes. These are clearly not the same thing. Moreover, as we just went over, ERCOT has produced documents -- I think someone said it best this afternoon, there might be a communication problem. I think that's probably the best you can say about it.

ERCOT itself has produced documents that demonstrate different requirements for wind than what the current PRR 830 requirements would provide. And that's the document you focused on. This is clearly an ERCOT document. It's not been doctored. It's from 2008. It talks about a requirement. It talks about a triangle.

And on the page that you were focused on earlier, look at this. Shown to the right are the reactive capability curves for a conventional generator and a wind turbine. It points you to this D curve, and it points the wind generator to what we have commonly called the triangle. Despite what ERCOT might be saying today, just last year they were not saying the triangle was bad. They were not saying it

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had to be applied retroactively. They called it, in this document, the requirement.

So regardless of whether you call this confusion or a communication issue, one thing it is not is clear. We knew that because wind farms don't just spring up. Wind farms are built and interconnected in conjunction with the very best engineering minds in this state and from outside of the state that operate in this state. That is the TSPs play a key role. And even though we've heard some of them come up today and say they approve of PRR

830, they in fact have approved interconnection of wind farms with something less than a rectangular configuration and have taken a slightly different position today.

What I think we've all overlooked is that ERCOT has a statutory obligation to stay on top of -- in fact, to be the ultimate in providing supervision and responsibility as it relates to transmission interconnection service. It is absolutely in the statute that governs this body -- I should say PUCT Substantive Rule 25.361.

And I know very well that ERCOT would not approved anything that adversely affected reliability either implicitly or tacitly and allow it

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to continue for three or four years and only discover 17 or 20 months earlier that there was some reliability event and, therefore, a problem, and then failed to study it, failed to bring that study before you, but urge action on a matter that would be so costly, ultimately those costs being borne by those we're here to protect.

25.361 says shall, "ERCOT shall accept and supervise all requests for interconnection, shall plan the transmission system." We've heard excuses, or at least explanations, to be a little more polite, but clearly what was known to ERCOT was that at least 80 RARFs were submitted to -- I should say this, it's been set forth by the opponents of this protocol revision review -- at least 80 RARFs have been submitted to and approved by ERCOT. I think the explanation was given to us today that ERCOT has these, but they don't use them for the particular purpose the statute suggests is their obligation.

These RARFs demonstrate, if you examine them and use them, look at them, that wind was not designed to meet the rectangle, the rectangle at least in many, many instances. Local TSPs, some of the best minds in the business, performed interconnection studies based upon the triangle. No problems with the

triangle have been identified. And probably most significantly, where there was an additional reactive component necessary, it was imposed upon the wind generators. They put those components in, and did so based upon the studies.

This information, these studies, as is appropriate pursuant to Substantive Rule 25.361, is available to ERCOT. Those were available for study and for compliance with ERCOT's obligations under 25.361. So we contend that not only were these things known to the TSPs and studied by the TSPs, but ultimately, pursuant to the operation of 25.361, approved by ERCOT.

The real question we have with regard to this proposal is retroactivity because it sets bad precedent. It can be imposed on anyone literally under any situation. It imposes huge regulatory risk on future business decisions, affecting again anyone. And if you look at the long view, a matter that should be of grave concern and something we shouldn't rush to judgment on. Again, the NextEra position is if a study justifies something beyond the triangular configuration, we'll step up, pay for it and implement it.

And third, we have to look at the long

view of how this decision will affect investment decisions in Texas. Here we believe that the Board has only imposed retroactive application of technical requirements where there was compelling evidence supporting it. I think we've emphasized the point enough that there hasn't been a study. And the one study that's underway -- that could be used to answer some of these questions is underway. We heard about it this morning. And it probably won't be done until the end of this year or early in the next.

What we would respectfully ask you to consider is that under Protocol 1.2, whatever you do, and whatever you decide is governed by ensuring access to the transmission and distribution systems on non-discriminatory -- excuse me, non-discriminatory terms, and to act in a manner that's reasonable.

And ask yourselves and guide yourselves by whether what we're asking be done is fair, whether it's reasonable, whether it's non-discriminatory, whether it's necessary. Because clearly if you have a system in which ERCOT tells you that more than half the wind farms it polled cannot state that they're in compliance with what is now being read as consistent with 830, then we are asking for something new to be imposed.

ERCOT did publish the triangle under the guise of it's a, quote, unquote, "requirement" and there's a sea of wind farms conforming to something other than a rectangular configuration of reactive power configurations. And, you know, the definition of good utility practice, if you look at the statute, is any practice, method or act engaged in or approved by a significant portion of the electric utility industry during a relevant time period.

In our case alone LCRA, Brazos, AEP, took the wind farms in question that we have built and operate, looked at our reactive capabilities and approved us for interconnection. All interpreting the protocol essentially the way most if not all of the wind generators have been interpreting it.

There shouldn't be any real question that this didn't exist as a requirement or it just doesn't make sense that so much of the system would be out of compliance. I don't think ERCOT would allow that to happen. This is new. It's being applied retroactively. There's no study confirming that it is necessary, and as soon as there is one that confirms it's necessary, we'll be the first people to sign on and support it.

More importantly, there's no study that

suggests that what's being proposed here will fix the problem. And although it's been stated that there was a lot of analysis of this, we really believe that there was a rush to judgment. This was not assigned to a working group. There was no task force assigned to it. There were several amendments, even some supported by ERCOT staff, that were never voted on.

And so in closing, before we rush to spend huge dollars, tens to hundreds of millions of dollars that is retroactively applied, that will chill investment and result essentially in what is consumer-friendly pricing, that keeps electricity prices low for consumers, and we'll just wipe that out. Especially we believe this is unwise when there have been no reliability events triggered by non-compliance -- that is by non-compliance with what the proponents state is the proper application of the protocol. And no study of the reliability benefits that 830 would trigger. Thank you.

CHAIRMAN NEWTON: I'm going to ask you the same question, and based upon a couple of your comments, I just want to be clear of my understanding of NextEra's position: Without a study you would not support the rectangle prospectively? Or you would?

MR. MARKARIAN: I think we stated that

we would support it going forward.

CHAIRMAN NEWTON: Well, that's what I was wanting to clarify based upon the comments you made because --

MR. MARKARIAN: I really meant to say both things. If the study demonstrates -- well, I guess we're actually saying exactly the same thing.

CHAIRMAN NEWTON: Okay. Well, but, no, I guess my question is are you saying you would not -- will you support prospective rectangle without a study?

MR. MARKARIAN: I think we're taking that position, yes, ma'am.

CHAIRMAN NEWTON: It's only the retroactive piece that's at question.

MR. MARKARIAN: That's correct.

CHAIRMAN NEWTON: Okay. Thank you. Any other questions?

Yes, Clifton?

MR. KARNEI: Did I hear you throw out a number of the estimated capital cost to be in the range of 30 million to 130? And where does that come from?

MR. MARKARIAN: Our estimated number for our system would be about $27 million. And I think

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some of our competitors are -- if you will, sister wind companies -- have indicated that in addition to our expenditures it would total industry-wide $100 million.

MR. KARNEI: How much?

MR. MARKARIAN: 100.

MR. KARNEI: Okay. Thank you.

CHAIRMAN NEWTON: Charles?

MR. JENKINS: I'd like to understand a little bit more about your offer. You said if a study shows that something else is needed, you would be glad to go back and install that on your existing farms --

MR. MARKARIAN: We absolutely have taken that position.

MR. JENKINS: How far into the future hold? If we study it next year and we figure out you need $5 million worth, and then 10 years after that we discover it needs 60 million. Are you okay with that?

MR. MARKARIAN: That's right. There's no limit, and it would be an indefinite commitment.

CHAIRMAN NEWTON: Is that all, Charles?

MR. JENKINS: Yes. Sorry.

CHAIRMAN NEWTON: Dee.

MR. PATTON: Why would you agree to without a study comply proactively ---

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CHAIRMAN NEWTON: Prospectively.

MR. PATTON: -- period, I guess?

MR. MARKARIAN: Doctor, would you mind if I ask Peter WYBIERALA to answer that. He's much more technically astute and can perhaps --

MR. PATTON: No, it's -- it doesn't require an engineering analysis. Please answer the question.

CHAIRMAN NEWTON: Whichever one y'all want to is fine.

MR. MARKARIAN: Got it. Doctor, I'm sorry, I actually knew that and I had to get it whispered back in my ear. We could easily have made a decision prospectively to rely more heavily on the Siemens technology, which would have taken these concerns off the table.

MR. PATTON: But you're perfectly willing to go forward into it in infinity without a study. Correct?

MR. MARKARIAN: I think it's preferable to know that everything we do has a purpose and makes sense. But so much of this -- I mean, I know that ERCOT is a quasi-public body. But so much of this is compromise. And although we might from an engineering perspective have one view, we also recognize that the

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reality is we all have to work together to try and do the very best we can. And I think what you see in that position is not some sort of hypocrisy but a recognition that we all have to work together and sometimes make compromises.

MR. PATTON: Thank you.

CHAIRMAN NEWTON: Andrew?

MR. DALTON: I'm going to hold back.

CHAIRMAN NEWTON: Okay. Mike?

MR. GENT: You may have heard earlier Kent Saathoff said that they had done a survey of 70 wind farm owners, and that 16 of the 70 they surveyed let -- were able to meet the requirements that they feel is put out in the original version of this standard?

MR. MARKARIAN: Yes, sir, I heard that.

MR. GENT: Would you suggest to us that they should no longer be required to be held to that as well?

MR. MARKARIAN: No, what I'm guessing --

and it's purely a guess -- is that those are probably units that opted for a particular technology. And as technology marched forward -- you probably know that in and around 2000 I don't think there was a wind turbine capable of producing reactive power, and as

technology evolved there were options. And although I don't know the specifics of what the gentleman spoke of, that would be my guess.

MR. GENT: So how would you feel about if we exempted wind generators from this requirement in those installed after 2004 and before 2009? What about the combustion turbines and all the other units that are installed? Would we not also hold them to the same requirement?

MR. MARKARIAN: You're at the edge of my technological knowledge, but I don't know that that would be an applicable concern for us for anybody.

MR. GENT: Okay. You're not concerned?

CHAIRMAN NEWTON: Bob?

MR. HELTON: One quick question, because I'm a little confused about Charles' question and your answer. We were talking about doing the triangle prospectively and then you're talking about doing another study later for $60 million and you're agreeing to that --

CHAIRMAN NEWTON: Bob, can you get a little closer to the mic?

MR. HELTON: -- I'm not sure what that question meant and what that answer meant. Because if we're looking at prospectively saying we're going to do the triangle, then that is what would be from that point forward. So I'm not sure what you were asking and I'm not sure what your answer meant.

MR. JENKINS: I'll clarify what I thought I was asking.

MR. HELTON: Okay.

MR. JENKINS: And that was -- I was assuming that discussion was leading toward there would be some time frame of units between 2004 and 2009 perhaps that would be held initially as a minimum to the triangle standard and be subject to further modifications in order to meet whatever a study showed actually was necessary for reliability. And say a year into it we figured out through study that a certain amount of stuff was needed, and then over a period of time conditions change in that part of the grid and it turns out more is needed, would they be willing to continue to hold open the requirement that they -- that they do retrofit when a study showed it was necessary indefinitely, and they said they would.

MR. HELTON: Were -- okay. So just to clarify because I'm just trying to make sure we're all listening, because I'm not sure he got that.

MR. MARKARIAN: That's absolutely what I intended to say.

MR. HELTON: Okay. So in other words, what you're saying if he -- you're not -- if you do agree to go with the triangle and not the rectangle, then you're basically saying that they need to take over -- the question was would you take over the responsibility the TDSPs generally take over after the original interconnection is done?

MR. JENKINS: That was the thrust of my question, and I'm quite surprised by their answer, quite frankly.

MR. MARKARIAN: I don't think that's exactly --

MR. HELTON: That's why I'm --

MR. MARKARIAN: Sir, I'm sorry, maybe I misunderstood. I don't think anyone suggested we take over the job of TDSPs. I thought the suggestion was that we do what studies demonstrate is appropriate to ensure system reliability. And that I did agree with.

MR. HELTON: Yeah, see what the question was is, like today -- and this is one of the things that John Houston talked about and some of the others -- is when a generator connects, he's on the -- the rectangle, then anything that changes in the system around that generator that creates an issue with voltage is taken care of through the TDSP adding

reactive or dynamic stability components on the system.

What Charles is talking about is saying if you agree to do a triangle, are you also agreeing that any upgrades that happen after that point, which traditionally would be taken care of and paid for through TCOS, that you're going accept that responsibility was what I understood. And I understood that you agreed with that? Isn't that right, Charles?

MR. JENKINS: Yeah.

MR. HELTON: I'm just trying to make sure that you fully understand what you answered there.

MR. MARKARIAN: Would you kindly mind repeating the question for us? Thank you.

MR. HELTON: Well, it wasn't my question. I'm just trying to figure out what you agreed to. But what -- the way traditionally things are done is whenever I hook up one of my units and it's hooked up through the typical rectangle situation, I'm on the system. As topology changes and things happen on the system that create different needs for voltage support and studies are done by the TDSP and/or ERCOT, and they have to -- and they say,

oh, we've got a stability problem here and so they will go to the TDSP. The TDSP will put in whatever dynamic or static devices need to go in to ensure voltage control in that area. And what Charles' question was, was if you're going to do -- or would you agree that if you're doing the triangle, that any changes therefore that came about on the system for whatever reason around those assets, that you would take the cost of upgrading those devices.

MR. SCHAFER: Sir, the answer to that question is no.

MR. HELTON: That's what I'm trying to get to. Okay?

MR. MARKARIAN: Yeah. I understood the original question to mean if there was some issue that was directly related to the reactive capability limitations of the wind turbine, we would stand up for that.

THE REPORTER: I'm sorry, I don't know who the gentleman was walking across the room.

MR. SCHAFER: Matt Schafer.

CHAIRMAN NEWTON: Are you with NextEra?

MR. SCHAFER: Yes.

CHAIRMAN NEWTON: Okay. Andrew?

MR. DALTON: I think this question --

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MR. GRABLE: Let me interrupt for just a second. I apologize. This is Mike.

If anybody who speaks who isn't on the agenda or they don't have your information, please give them a business card. Thanks.

MR. DALTON: I think this question will be more simple. If -- I want to try to recharacterize your position a little bit similar to what I did with AES. It would be your position that prior to February 17th of 2004, no reactive power applies. From February 17th, 2004 until December 1, 2009, the cone or triangle should apply, unless a study shows something more is necessary? And prospectively, after December 1st, 2009, the rectangle should apply. Is that fair?

MR. MARKARIAN: Essentially, yes.

MR. DALTON: Okay. Another point -- and this kind of gets into the retroactivity issue that --

MR. MARKARIAN: Remember we sort of positioned ourselves in the alternative as you probably know from reading the submission. So -- but, yes. Essentially yes.

MR. DALTON: Okay. With regard to this retroactivity issue that you're raising, I mean, am I correct to read the PRR that the standard doesn't kick

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in until December of 2010, December 31st, 2010?

MR. MARKARIAN: I think the concern is it would require us -- when we use the term retroactivity, we simply mean it would require us to go back and retrofit existing wind farms and spend significant sums of money to do so.

MR. SCHAFER: Yeah, the standard is compliance by that date.

MR. DALTON: Yes. But what I would suggest is I think throwing this term retroactivity into the debate I think is disingenuous and really unhelpful at this point, because everybody who's in the business, whether it's refining, generating power, chemical plants, you get changed regulations that affect your business all the time. And they happen and you have to make adjustments to your business going forward.

This is a proposed adjustment to your business going forward. You may not agree with it, but it's not in any case I think retroactive. And I think that's an unhelpful path to discuss. I think there are other realistic points that we need to debate and consider as a Board. I know I too am concerned about having any group of parties in the market have to pay $100 million that may or may not

have significant benefits, but the idea that this is retroactive I think is unhelpful.

MR. MARKARIAN: Sir, if I could just clarify a bit, respecting what you said about the use of the term, I think our concern is a little bit different and a little more nuanced. It is not retroactivity alone and in a vacuum. It's retroactivity without any sort of precise study.

CHAIRMAN NEWTON: I think we've got it. Okay.

MR. DALTON: And what I'm suggesting is it's not retroactive in either event.

CHAIRMAN NEWTON: Yeah. I think we've got it.

Mike, did you have something else?

MR. GRABLE: I did very briefly. I don't want to debate points. I do want to say I love your slide about entirely new on the PRR, and Christy you should keep that for future stakeholder meetings. If we limit the amount of revisions as a PRR goes through the process, Mark, I think you'd love that, too. So let's definitely hang onto that one.

There were two comments related to ERCOT staff and either their nonresponsiveness or their statements against interest, and I just want to respond to those very briefly. Regarding the two reliability events, Dave, sometimes as you know events can happen that -- for example, a nuclear event in South Florida can ripple the frequency through the entire Eastern Interconnect. That's going to be public. Other times events are more confidential and they may be referred to Texas Regional Entity here, for example. So there may be reasons that staff is not communicating with a party who wasn't involved in those events. I don't want to dispute your conclusion, but I did want to respond to that point.

You made a lot about the August 2008 ROS slide, Slide 3 that John Dumas sent out. And I think you kind of acknowledged that there were -- you know, there's been some wind comments that said, "Oh, there are multiple versions. We don't know what to believe." I think it's important to note for the record that that slide did go out as you highlighted it in the morning. And at 5:10 on the same day John Dumas revised it and sent it out again and told everyone on the ROS list, "The presentation that I sent out on voltage control covers an example of reactive capabilities of a wind farm. The example does not meet the protocols."

And I'm not going to go through his

whole email, but, you know, there is not exactly confusion on that point. We did send out an incorrect slide and it did refer to the triangle as the requirement. But that mistake was corrected hours later the same day, and I don't think there can be confusion 5:10 p.m. last August 21st as to what at least ERCOT staff believes is required. So I just wanted to clarify those two points and thank you for joining us.

MR. MARKARIAN: And, Mr. Grable, if anything I said led you to believe that we believe that our working relationship with ERCOT is anything other than --

MR. GRABLE: You don't need to -- I don't have any concerns personally on that score whatsoever.

MR. MARKARIAN: My only point was we've been very concerned about finding out about these reliability events and trying to dig in.

CHAIRMAN NEWTON: Okay. Thank you, gentlemen, very much. We appreciate it. We have two more that I'm aware of, and then I'll open it for any others who may be in the audience. Next would be Oncor, Ken Donohoo.

MR. JENKINS: Yeah, Ken's not here and

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didn't intend to make a presentation. We'll just stand by the comments. I will observe that I've interviewed our transmission planners and I've interviewed our staff that does the work on generation interconnection, and there's been no uncertainty in their mind that they've been planning for the wind farms to have a rectangular-type configuration since

2004.

CHAIRMAN NEWTON: Thank you, Charles.

The Wind Coalition, Walter Reid?

MR. REID: And in your Board packets you should have found a brief slide presentation called PRR 830 issues, and I will try to find it on here. If anybody can -- there it is. Right there.

Okay. Got it. That's me.

Y'all have been handling some pretty weighty matters up to this point -- oh, by the way, just to introduce myself briefly, I've been with ERCOT since -- in ERCOT working for -- since 1970. And about 15 years ago I went into independent consulting and five years ago started consulting with the wind coalition that represents over 30 members and, I'd say, roughly two-thirds of the wind that's on ground in ERCOT.

The issues you've -- you know, hit are,

of course, what do the protocols say and what do they really mean as they're written today? And we've got many thousands of megawatts that believe that, you know, it says something different than what ERCOT is saying. And, of course, that's a major issue that needs to be resolved and, I suppose, is fundamentally a legal matter.

But I guess the point I'd like to make here is that we do need clarification. Because we've got so many folks that have already apparently interpreted it one way, we can't allow the next 8,000 megawatts that are about to sign up relative to CREZ to not have some clear direction of what it is that we really intended to say. So we may not have meant what is in those protocols. Maybe we meant something different. And if that's true, we need to make it clear.

What I'm about to talk about is going to be a very technical issue. It's partly coming up to you -- and I apologize that I'm having to bring it to the Board level because we've had such a rapid development of this issue. The first time that this was discussed at the ROS meeting to today it's 30 days. So in 30 days we've taken a very weighty, major issue, with a lot of concerns by a lot of people, and

we've brought it to the Board in 30 days.

One of the issues is that ERCOT has intended to do a better modeling job. And as I understand primarily focused on their realtime systems so that they can reflect what the actual reactive capability of wind generators is. And in doing that, in coming up with that, they are coming up with a redefinition of this thing called a WGR. And a WGR has been -- that term has been in the protocols for I don't know how long, but years. And it fundamentally applies to the whole wind turbine ranch facility.

The new definition that ERCOT is putting forward creates fictitious subunits. We have great support for the idea of the modeling. We needed to do that years ago. So I'm thrilled with us doing this. But the problem that we're running into is WGR, as written today, before 830 is adopted, WGR applies to that interconnect point, that big red rectangle up there. And all of these wind turbines -- there's 70 wind turbines in this diagram -- are feeding in via some transformers up to that interconnect point, maybe a transmission line between the substation for the wind generator and the interconnect point with the transmission service provider.

The new definition of WGR says that

below each transformer -- so in this particular diagram -- let's see, I think I can use this somehow.

In this diagram there is one transformer shown that is bringing all of these wind generators up to transmission voltages. If there were connections over here, there might be two transformers, which by the way is pretty common in ERCOT, lots of two-transformer installations for a number of reasons.

What ERCOT is asking is that we identify generators of a same type. So this might be -- just to pull some names out of a hat -- these might be GE wind generators. These red ones over here and here, they might be Siemens. And the rest of these might be Mitsubishi. And they all have different reactive characteristics, and what ERCOT wants to know is how many of them are operating today and, as a result, they can then calculate and model what is it that my reactive capability today is for this particular wind range.

By taking the WGR definition and moving

it from there and saying all of these blue -- these six blue ones -- are now WGR No. 1, these three red ones are WGR No. 2. And, of course, the rest are WGR No. 3. We have all of a sudden created fictitous things that don't have meter points. And, as a

result, we're going to treat them just like units. And if you look in the protocols, the word resource and units occurs in the protocols and the guides over 2,000 times. Now all of those don't apply to WGR no matter how you define them. But all of a sudden what we've been using and interpreting at this interconnect points has now got to be applied here.

And so, for instance, we're going to have to treat them like any other generator would treat their units, and there's a lot of things that don't make sense because of that. I'll be happy to get into the details of why it doesn't make sense, but what we proposed -- and you'll see it in the Wind Coalition comments -- is alternative wording that, in our opinion, provides 100 percent of the data that ERCOT needs to do its modeling without changing the definition of WGR.

So this is a very, very simple thing, and I apologize that we're having to bring it up to the Board, but we just haven't had the opportunity to vet this yet. This whole 830 has not been discussed in any working group or in any task force where we can have the kind of give and take that it takes for us to understand the problems that ERCOT is going to have with this modeling and the ones that we're going to have.

In addition, I did want to point out on kind of the issues that were raised by some other speakers, if I'm permitted.

CHAIRMAN NEWTON: Very quickly.

MR. DALTON: Walter, one second. Could you hold off for one second on that? I wanted to follow up with John or Kent.

Is there a reason why we're going back behind the point of interconnect in PRR 830 as opposed to just characterizing the wind farm as a whole?

MR. DUMAS: Yes.

MR. DALTON: Could you explain that to me?

MR. DUMAS: Sure. First of all, wind, as Walter said, wind turbines have been aggregated together to form a unit. In some cases it may be, you know, one unit or multiple units. The concern is if you've got turbines that are very different in characteristics -- reactive capability for instance. You've got maybe a group -- say you've got 20 turbines that have great reactive performance, and then you have -- a lot with that, another 20 turbines that doesn't have any.

If you lump those together in 40

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turbines to form one unit, our models require one reactive curve. So how are you going to design or

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draw one reactive curve that represents 40 units with very dissimilar capability?

So what we've proposed in PRR 830 is, well, you can aggregate turbines, but you need to aggregate turbines that are the same model, same size, have the same characteristic. So when we're running a power flow analysis or running realtime contingency analysis with one reactive curve for that unit, that that reactive curve is representative of the capability of those turbines that it represents. Because you can run into -- not only would you have difficulty creating a reactive curve to represent 20 dissimilar capabilities. What happens when you have all -- say 10 of your good performing turbines down for maintenance? Then you've got little to no reactive capability, but yet you've got a curve that shows that you have more than you need to.

Now, a couple of points I want to make here. The point of interconnect, where that meter -- that red meter that Walter has drawn -- is talking about -- I assume he's referring to the EPS meter, the poll settlement meter, it's very common on conventional units that we may have -- I can think of

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one case where we've got five different power lines coming into a power plant and there's an EPS meter for those five lines, but the individual units have realtime telemetry provided from an RTU of their individual megawatt output, their individual limits provided through SCADA. So, I mean, that's a common practice and that's how it's done with, you know, almost all of our units with -- providing telemetry that's from -- either from our control system or from a transducer that's out at the field.

The other thing I wanted to point out, Walter made a comment earlier that this PRR has only been out there a month. We've been dealing with this issue for a long time now as we've been talking about, and we've had quite a few discussions. This PRR was actually submitted, I believe, September 8th date. It was tabled -- it was presented at ROS to cover what's in the PRR, what we're trying to do. Then that went to the PRS. PRS tabled it for a month for ROS to have a discussion, and John Houston covered the history of those discussions.

MR. DALTON: Just follow up on that --

MR. REID: If I could follow up on that -- oh, I'm sorry.

MR. DALTON: I'm okay with the concept

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of the telemetry and why you want the telemetry on the units. But it would seem to me that from a grid reliability perspective, what you really want is wherever they're connected to the grid to know what capability they're expected to deliver at that point of interconnection -- I mean, if the generators, for whatever reason, can't deliver because there are some units down, that should be on them. And if they create a violation or if they create a grid problem, you know, the TRE or someone is going to come calling on them for that. That's for them to deal with as opposed to trying to -- I'm worried that creating these little subunits inside of a single interconnection potentially creates more reliability issues for the grid than it solves, or am I wrong in that assumption?

MR. DUMAS: No, sir. Let me trot it out a little deeper and see if I can answer your questions.

MR. DALTON: Okay.

MR. DUMAS: You've got to have a reactive curve that represents the capability of that unit, where it can go to. At the point of interconnect, each unit has a -- what's called a voltage schedule where they're trying to hold the

voltage. And the way they hold the voltage is they supply either more vars or absorb vars if the voltage is high.

We also run realtime contingency analysis where we simulate taking lines out of service, and we look to see what the voltage would go to if we took that line out of service.

Well, the way the software is going to calculate where the voltage can go to is based on a capability curve supply. And it's going to look at that capability curve and say, okay, well how many vars can you produce or how many vars can you take in? So it's very important that that capability curve is representative of what that unit can do.

You also -- if you have any devices in the substation such as cap banks, reactors, stack house, whatever the device is, you model those separately. So they all contribute, but it's very important that you know what the capability of that units is. It's not just the realtime output of the unit. It's what it can do when you simulate these contingencies.

MR. DALTON: Are you aggregating all of that at the point of interconnection or are you aggregating at some other point on the grid?

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MR. DUMAS: It's aggregated however they submit it in a resource plan. So as Walter pointed out, in a lot of cases it may be all the units at the farm, whether it's -- you know, no matter what type they are, whether it's a mixture of different turbines.

MR. DALTON: So say for example they had these three sets of turbines, all different sizes, and they had two capacitor banks and they aggregated that and they said at the point of interconnection we can deliver you "x" reactive power. Is that sufficient for this or do you need more detail and granularity than that?

MR. DUMAS: It's not sufficient because what you need is to be able to hold the voltage. And you may need varying amounts of vars to be able to do that. So the var varies. What you're trying to do is hold the voltage. And what the requirement is with the .95 rectangle from a hundred megawatt unit, you've got to be able to deliver up to 33 megavars. That's

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the requirement.

So if the voltage goes low -- say it's a 345 bus -- and the voltage goes low to 340, and the unit is putting out 33 megavars but it can't get the voltage up past 340, then it met the requirement.

But it could be that it could go -- depending on the conditions of the grid -- it could be it could go to 345 and only put out 10 megavars. So you need to know how that capability is going to vary based upon your curve when you run your study and the need of the simulation that you're doing.

CHAIRMAN NEWTON: Okay, gentlemen, if I could --

MR. DALTON: I'll yield.

CHAIRMAN NEWTON: Well, we really need to get going here. Did you have a couple more comments, things that haven't been said by the other parties?

MR. REID: A response to a couple of things. First of all, to this reactive -- this discussion on the modeling. I 100 percent agree with everything John has just said in terms of the need to do the modeling and that it needs to be the extra detail. You really need to get to the low side of the transformer and show the pieces. If you look at my wording, it does that. It just doesn't redefine WGR in the process.

So we're totally supportive of this. I've been on about this for over a year, maybe even two years, that we need this kind of detail in load flow and operations, totally supportive, just don't redefine WGR in the process.

I would footnote that we've taken more time here at the Board to discuss this one issue than at all the committees or subcommittees that have discussed this PRR to date. And I can discuss the flow of this. It's 30 days since this was first discussed that it came to here.

The other things that I'd like to mention and be a little cutesy on it, but what we have here is a failure to communicate. We've got a whole bunch of folks out there that I think were trying to do the best job they could, whether they were transmission service providers or wind generators or ERCOT.

And my analysis of this over now -- over a year of being involved in it, is we've just had people talking in conventional generator terms and people talking in wind generator terms. If you look at the forms that they were asked to fill out, if they didn't fill them out, they weren't going to get interconnected. If they did fill them out, they had to use a lot of engineering judgment, because what they were asked to respond to doesn't fit their hardware and their systems. So you've got a lot of

issues that were just very difficult, and we're all learning on this.

The voltage issues that we've had, the one that I'm aware of, that I think was -- highlighted here was a communication issue, as I recall it, where various parties were trying to make something happen. This was, what, over a year ago -- in fact more than a year ago. And as a result of that in some of the workshops we had a lot of discussion. I applaud AEP and Oncor. Oncor sent their operators, every single shift operator from Oncor went to a wind ranch to understand what they're doing, how they're built, how they operate. I believe Ross Phillips gave them a questionnaire to go get answered when you go out to the field so that all those operators understood.

We've got a history in ERCOT of all the folks really working well together. And when they get on the phone or they see a typed message or an automatic display on their computer, they've all had a lot of communication together. They all understand what we're saying. We tend to speak in short words, take shortcuts on our communication.

We've got a new industry that's trying to integrate. I think everybody has been working real hard to do it. We're all running together. I really

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encourage you to please do what we need to make it clear for the new generators. And the generators that are there, they're there today, they're there tomorrow, they're there next month. Let's take the time it takes to figure out how we're going to handle that. And I don't want to get into discussing from my point of view what the right way to do that is. It's certainly not in this forum. Thank you for your time.

CHAIRMAN NEWTON: Okay. Thank you. Did the Wind Coalition take a position about this prospective and retroactive piece?

MR. REID: Yes. And I say the Wind Coalition, we have not had a vote on it. And, as I say, we have 30 members. And I think someone when they were speaking from -- one of the Wind Coalition members -- used the word competitor. So getting all these guys in the same boat much less paddling in the same direction is a challenge --

CHAIRMAN NEWTON: That's okay. If the answer is just no, that's fine.

MR. REID: So most of those guys have all agreed that this rectangle is definitely where we need to go, and I know of no one that is going to oppose it.

CHAIRMAN NEWTON: On a prospective

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basis?

MR. REID: On a prospective basis.

CHAIRMAN NEWTON: Okay. Thank you very much.

Okay. Do we have any other comments or people who would like to make any comments?

Okay. Please identify yourself and who you're representing.

MR. R. JONES: Thank you, Madam Chairman. My name is Randy Jones. I'm with Calpine Corporation, and we're in the independent generator segment. I have the unique privilege of serving this year on ROS, WMS, PRS and TAC. And I can certify to you that you have not met longer today than all those groups have on this issue. Trust me on that.

I come at this issue with a fairly deep background in system operations, although I'm not an engineer. I worked in realtime operations and managed realtime operations for TNP for 13 years, both on a control air generation side as well as the wire side, managing voltage support and reactive compensation.

Our view at Calpine is that voltage support is a community service. No one gets paid for it. And as you're all aware, in the area of discipline of market design, the biggest enemy to any

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community service is a free rider. It always creates problematic areas.

We view voltage support as an obligation, one that we all share as generating resources. And we believe that there have been enough provisions made in the protocols that everybody can carry their fair share.

As I look around the room, I can also tell you that I'm probably the only person here who participated in the Interim Voltage and Reactive Standards Task Force many years ago that ROS put together. And in at least one of those meetings at the old HL&P building, I asked the question not once but twice: Does this mean that generators can provide a proportional amount of reactive output at lower real power levels? And the resounding answer I got both times was no. I think maybe one time it was hell no -- excuse my French.

But I was disabused of the idea of a system, particularly one operating in the shoulder months at very low loads, where generators would only provide the triangular reactive capability. I still to this day believe that the folks who participated in that group understood very clearly what the requirements had to be. And if developers of wind

facilities would have asked any of us, I'm certain they would have gotten the same answer. It's a rectangle, folks.

We believe that PRR 830 has been fully vetted. The debate has been beyond vigorous at times. Despite what you've heard, we think that the time that the stakeholders have had to evaluate this PRR has been more than adequate.

It's a fundamental component of system reliability and security. And the idea that you can take a snapshot and do a study today and that's good enough to determine what a generator ought to provide we believe is a huge myth. Over the life cycle of a unit you just can't continue to perform studies. And I think you saw the fallacy in that kind of approach when Charles Jenkins asked that question. There was a lot of trepidation about how you would approach that. That's why we believe there's a standard; that all resources ought to meet it. And once they meet it going forward, there's no question about where the rest of the reactive compensation has to come from.

We would ask that you affirm the work of the stakeholders, recognize the overwhelming votes for PRR 830 through the stakeholder community, and affirm the work of TAC in denying the appeal of NextEra and

approving PRR 830. Thank you.

CHAIRMAN NEWTON: Any questions? Comments?

Okay. I think where that takes us -- oh, I'm sorry. I didn't see her. We do need need to take a very brief break after this presentation because we've got our court reporters here that her fingers are probably about to fall off. I tried to assure them I would try not to go more than two hours and we are already past it, both this morning and this afternoon. So after this presentation, we are going to take just a two- or three-minute break.

I would ask for people not to go real far -- I'll say five minutes, but be back. Okay? So that's a forewarning ahead of time.

Excuse me. Now you can go ahead.

MS. DIFFEN: That's okay. I'm going to make this really short. I'm Becky Diffen representing Duke Energy. In the interest of time and as requested I'm not going to repeat any of the comments made today. But Duke owns several hundred megawatts of wind generation in ERCOT, and we would just like the Board to know we support the comments made today and filed previously by Horizon, NextEra, AESCS and the Wind Coalition. That's all.

CHAIRMAN NEWTON: That was very brief. Thank you.

Anyone else?

I'm not trying to cut anyone off. We'll come back and take further comments. I would just like a hands up or notification.

Okay. Five minutes and we'll come back.

(Recess: 3:20 p.m. to 3:27 p.m.)

CHAIRMAN NEWTON: Okay. I'm going to go ahead and get started. I think we've got enough Board members in the room, at least, and hopefully they will be in their seat shortly.

I think what I'd like to do right now is before we actually discuss the path forward for the board, there has been some nuances and discussions regarding some of the other activities relative to this issue that have been at the Commission. So, Mike, can you touch on those?

MR. GRABLE: Yeah, I'll be real brief and try to be neutral. John Dumas touched on that there have been a lot of staff and wind generator and TSP interactions, that this wasn't a blank slate that began with PRR 830. One of the things that's been occurring is we actually got an interpretation request, which is a little known protocol where you

can ask ERCOT legal to issue an interpretation of the protocols, came from an interested party who was looking at building generation, and we replied to it and published an interpretation, and it said this is what we think the PRR -- the protocols existing protocols mean.

Wind generators took that, appealed it to the PUC, requested relief, essentially stating that the triangle was the appropriate -- or the cone was the appropriate interpretation, and we kind of went back and forth on that. We both mutually updated it, tried to resolve the issues. We were unable to do so.

That docket has been dismissed, and the dismissal was upheld by the Commissioners. On a procedural basis, you know, I can't discuss any pending ADRs or whether there will be a future commission action. I also can't discuss any referrals to Texas Regional Entity and whether or not there is or may ever be an enforcement action related to any of this, but there's nothing public at this point in time on those fronts.

CHAIRMAN NEWTON: I appreciate that. I think it's important for the Board to understand kind of all of the activities that are going on relative to these issues.

Okay. We've had a lot of discussion. What I'll do at this point is bring up the recommendation by TAC for approval of PRR 830 and see if we have any further discussion among the Board members, and then I will see whether there will be a motion for approval.

So, Bob, do you want to start?

MR. HELTON: Yeah, I can start. I'm sure cards are going to come up all over here in a minute.

From listening to all this -- and I know there's been a lot of confusion, there's been a lot of miscommunications, and a lot of what I was sitting here and watching and saw what we had going on was it was basically -- I felt like I was an appellate Judge there for a while on making a decision, and that's kind of the way I felt about it. Are the protocols right or wrong is really a lot of what I heard today.

So what I see is in 830, so I'll talk about that first. 830 sits out there and says here is -- as John and Kent have said, "Here is what the requirement was, and here is a way to comply," and says there's people out there that do not comply.

My problem with that is, if we have people out there that aren't complying with the

protocols, as written, as you guys define them, you need to be filing notices of violations. Okay? That needs to be done, referred to -- or not ERCOT do that. They are referred to the TRE for that. I'll get the procedure correct, and the TRE takes that.

As part of the NOV process, you figure out who is right, who is wrong, what those are. And then if there's mitigation that needs to take place, that's done through that process to get people to where the protocols are -- or tell you you have to be, and if that's retrofit, that's retrofit.

What I think that 830 does for the retrofit piece is circumventing that process. I understand what it was trying to do. It was trying to give people an avenue out there in the protocols to do that, but it also looks like ERCOT is changing the rules and trying to make entities retrofit, and I think doing this process takes that away. Let that be thought out through the NOV process, who is right, who is wrong and then what has to takes place. That would be my suggestion, let the process work instead of circumventing it with a 30 on the retrofit.

The other side going forward, if we feel the need, which I think we might want to ensure that from this point forward it needs to be clarified to

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say it is the rectangle, then we can do that. But, you know, my first thought when I first saw this whole thing was 830 isn't needed. If you say that this is what the protocols say, that's what they say. Everybody has to comply, period. And then if there's a disagreement with that, there are processes to take care of that. You don't have to -- you would not need this at all for retro or moving forward. But I can see with everything going on we might want to go ahead and push 830 back to do -- make sure that it addresses only the going forward part and letting the NOV ADR processes take their place and let the process work rather than circumventing it. So that's kind of where I would kind of throw out right now.

CHAIRMAN NEWTON: So can I put that in other words? I think what you're saying is you're

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recommending that the Board remand back the prospective decision, that the rectangle applies to everyone, all generation types, but remand it back from some period of time so it can come back to be explicit about the prospective piece --

MR. HELTON: Be prospective, right.

CHAIRMAN NEWTON: -- but not to address the retroactive piece, let that go through the NOV process?

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MR. HELTON: We've already heard from ERCOT staff, from the TAC representative that that's what they believe the requirements were, were rectangle. So protocols in their eyes and what they said are there. There are processes to get that taken care of, which is, you turn it over to the TRE, the TRE makes a determination, and then they fight it out wherever -- in whatever venues that is, and whoever wins, wins. If there's retrofit, then retrofit takes place through mitigation plans that are done through that process. It takes us from being looking like that we are turning around and changing the rules and making retrofits. It allows the process to work, and I think this circumvents it the way it's written.

CHAIRMAN NEWTON: Okay. Brad?

MR. COX: Yeah, I think, you know, we've seen the split into the two pieces obviously, the prospective piece and what do we do with the existing system and the existing wind farms, and I'm fine with -- and it seems like everyone that's spoke is fine with having this requirement on a prospective basis for new facilities, I guess.

So the question is, what do we do with the system as it exists today, and the thing that concerns me is I would -- you know, I would really

like to see some type of a study that says, "Here are the problem areas, and here is the most cost-effective way to deal with those." And I don't -- I don't think we have that, at least I haven't heard or seen anything about that, that type of an analysis.

You know, I think Bob makes a good point about letting the ADR process play itself out. I don't have a problem with that, but I would -- you know, if we decide to go down that path, let's go ahead and figure out what the circumstances are and what needs to be done and what's the most cost-effective way to -- you know, if there are changes that need to be made so that we don't, you know, lose time, you know, in respect to that. That's -- you know, after listening to all the discussion and reading the materials, that's where -- it seems to me the most reasonable approach.

CHAIRMAN NEWTON: Charles?

MR. JENKINS: I was going to talk on a slightly different issue, and that was the WGR definition issue that Walter Reid brought up. And if we do end up sending this back to TAC, I guess I would encourage them to address the point he made. I think it was a pretty valid one.

If we go the direction Bob is suggesting of just letting the ADR process -- those that are appealing 830 are sort of rolling the dice. Right now they've been offered somewhat of an "It's okay," and you've just got to get in compliance by this date out, and so the mitigation is sort of already worked out and it's known.

If we just let it go, what does the existing rule require, and if it's determined that it does require something different than what they can deliver today, you know, I don't know what the mitigation is going to be. It may be worse or better than what's in 830 today.

So I sort of don't know how -- how to deal with that. I don't like the position that the Board is in on this matter. I think we need to remand at least on the issue that Walter raised. I'm still -- I'm still not sure where I am on the broader issue.

CHAIRMAN NEWTON: Okay. Mark?

MR. ARMENTROUT: I'd just like to point out that Chairman Smitherman is not in the room for a reason, and that reason is that the Commission will rule on the retroactive issues, so just to put a leveling agent and how much time we want to put in to voting that piece.

The second point I wanted to make -- and Charles has made some comments that made me rethink this, but I'll say it anyway. We could do what you said, Bob, here in this meeting right now without remanding it to TAC. I'm not recommending it. I'm just pointing it out.

CHAIRMAN NEWTON: John?

MR. DUMAS: Just one comment on the -- something that Brad said about studies. Obviously I think John Houston made the point earlier that we have standards that apply to generators and apply to loads, and we've studied the transmission system to determine what variability, what variable equipment we need there.

I think we don't want to get in the position where in the future -- you know, the system is dynamic, the system changes, the needs change all the time. I think Charles alluded to that earlier. Needs are constantly changing. We don't want to be in a position where the standard gets challenged and we're asked, "Well, okay, show me a study where I have to put this in or I have to meet this standard." That's a bad position for ERCOT to be in, number one.

Number two, we are making some assumptions. We have been making some assumptions

about the capability of resources in all our planning studies going forward. We will be doing the CREZ reactive study, and we will be making assumptions in that study as to what the capabilities are of generators moving forward. So it's important that, you know, we make the right assumptions and don't have to go back and redo some of those analysis.

CHAIRMAN NEWTON: Mike?

MR. GRABLE: Yeah, I first want to say something real quick that I should have said at the beginning, and that is I think you-all know I wear two hats when I sit here, one is as counsel to the corporation and this Board, and the another is an officer of ERCOT similar to the other officers sitting at the table. I think you understand I've spoken today as an ERCOT staff member and on behalf of the ERCOT staff a proponent of PRR 830, but I just want to be absolutely clear on that, except for asking people to give a business card to the court reporters.

Bob, I want to go back to why we filed this PRR and explain why, from a staff perspective, we would have concerns with sending this back to TAC to be rewritten to be prospective. I'm certainly glad the wind generators are okay with prospective for new units rather.

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But I kind of had three thoughts in mind. One was create a grace period for compliance for the generators that we know today are not compliant with our version of how things should be, and we understand there are major capital investments that would be facing them to get compliant.

The second was to clarify and increase the flexibility that we already have, but to kind of spell it out a little better, to help wind generators who can't do fuel dynamic with a mix of dynamic and static or other alternatives to more better explain

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the process by which we will be open to negotiations on alternative compliance.

And third, do our best, as John Dumas just said, to avoid erroneous assumptions flowing into the CREZ studies, fully understanding that the Commission and possibly beyond the Commission are the ultimate decisionmakers on all of these points. We do want to try to get it right, if we can.

To do any of those three things, we have to understand what the protocols require today. If the protocols do not support -- you know, if the Board does not share our sense of the protocols, we can't accomplish any of the goals for which this PRR was filed. So that would be my concern with that

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approach, and obviously NOVs from TRE or PUC enforcement, there are none that I know of today and PUC appeals on this or other matters, ADRs and the like are certainly not precluded.

CHAIRMAN NEWTON: Bob, do you want to address that?

MR. HELTON: Yeah, I do actually because there's actually something you said there that concerns me greatly, and I'll address just 2 and 3 first.

I think that it's great to increase -- part of what 830 and looking forward, I think it's great to increase that flexibility of the mix of what they could do to comply with the protocols, and you're absolutely right, you need to avoid. And I think you're looking at this wrong. I think that if -- if

the Board says, "Let the NOV process work," we're not
disagreeing with you. We're saying, "You said the
protocols are that, go file and put that over to the
TRE and do what the protocols say."
My problem with No. 1 is, is I don't
believe ERCOT has the leeway on any compliance issue
to create a grace period. You find a protocol
violation, you file and turn it in, and then you let
the TRE and the process work. I'm really concerned

about the grace period piece because then you're
making it to where I'm saying, "Well, you, I'm going
to give you a grace period." "You, no, I'm not giving
you a grace period on this assumption," and I have a
real issue with that.
That's why I'm saying -- for right now I
could say I agree with your interpretation even though
I know that's going to be challenged. I could say it
right now if I wanted to. I agree with where you're
at. Go file with the TRE and say you have protocol
violations. Let that process work. That's why I'm
saying that 830 -- and I understand what you're trying
to do. You're trying to help.
The wind -- you know, talking about what
Charles was talking about, this is -- there's a roll
of the dice. The winds are -- the wind group says
"We're right, they are wrong." Let them have their
day in court, go through the process.
By doing this, I think you're trying to
help it with them, but you're boxing them in and

circumventing that NOV process. I think we need to let the process work, and there is no grace period, as far as I'm concerned. That's the only reason I was trying to push that out there.

MR. GRABLE: Yeah, respectfully I think

you misunderstood --

MR. HELTON: I was hoping I did.

MR. GRABLE: -- what my intent was and really what I said. If this protocol revision request passes today and creates a 12-month, or whatever the time period is, timeline for compliance could -- you know, was the protocol what it was in November, October, September? Yes. Could Texas Regional Entity or PUC enforcement and oversight bring an action based on noncompliance in October of 2009, you know, if they agree with ERCOT staff's position? Yes. Does it color their evaluation of whether to do so if we have a plan for compliance and ERCOT operations have signed off on it as acceptable down the road? Yes.

So don't misunderstand. I'm not offering on behalf of staff or anyone else carte blanche for interpretation of the existing protocol. I'm just suggesting that it would -- that's our plan, is to develop a path to meet them over time, granted with our interpretation, and I think that that would color any enforcement decision. I don't think it's a given that NOVs must come first.

CHAIRMAN NEWTON: Okay. Danny?

MR. BIVENS: This may have been covered already, but I just -- you know, to the extent that there's been a circumvention of a process that's already in place, you know, I kind of thought the same thing at first, but as many of you in the room -- my background comes from a lot of years of just being in the regulatory world, and that world, to try these things on a case-by-case basis instead of coming up with a rule, and in this case protocol, that would apply to all so that everyone applies with the same rules of the road, I think is always superior.

And I don't know what ERCOT's thinking was in coming up with this protocol, but, you know, when you go to doing the NOV process and start taking each one of these -- and how many of those generators are noncompliant? What was the number? You know, you start doing that, you know, everyone is going to be done on a different timeline. You're going to expend a lot of resources, and December 2010 gets here, which is the date that's in the protocol, you're not even going to be close. So I don't know, for whatever that's worth. I don't prefer piecemeal or a piece-by-piece approach to a rule.

CHAIRMAN NEWTON: Andrew?

MR. DALTON: Yeah, Kent, I have kind of a question for you or for John. We're talking about potentially having the wind folks spend a nontrivial

sum of money. We already have the LVRT study underway. Would it be even possible to add the reactive power issues to the LVRT study without delaying the LVRT study? Is that a possibility, or is that not a possibility?

MR. SAATHOFF: Let me get Dan up here. He's more familiar with the LVRT study.

MR. WOODFIN: Yeah, I think at this point we've made a lot of the assumptions about what the characteristics of the units are and those kinds of things. As a part of that process, they are gathering the information. It's going to be a dynamic study. So it's going to include -- essentially it's looking at the actual requirements, the actual capabilities, I believe, in that study from a dynamic perspective, so -- and it's only studying the timeframe. It's studying a topology that's pre-CREZ, and that was specified in how the study was set up.

So it may study kind of the in between now and CREZ requirements. I don't think it would be that difficult to actually address that issue in the LVRT study for that timeframe. It will not cover the ongoing needs of the system post-CREZ. We'd have to include that in as an additional work item somehow to the CREZ reactive study to look at kind of the

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incremental needs if the -- that generation doesn't -- isn't able to meet the protocol requirements.

MR. DALTON: What's the timeframe for the CREZ study, the reactive study?

MR. WOODFIN: The current scope of it is intended to be completed mid July of next year.

MR. DALTON: July 2010?

MR. WOODFIN: Yes.

MR. DALTON: So it's basically on a similar timeframe as the LVRT study.

MR. WOODFIN: A little longer, yes.

MR. DALTON: A little longer, okay.

CHAIRMAN NEWTON: Okay. Nick?

MR. WOODFIN: Okay. Thank you.

MR. FEHRENBACH: And this has indeed been a nice, long discussion, and it's always good to see energetic discussion on an issue. And, you know, I listened to all the presentations, and the one thing I was looking for is really an explanation from the wind resources on why they thought this triangle or cone applied. When you get down to it and you read the actual existing protocol language that's been there since 2004, I concur with ERCOT that it's a rectangle, and it's always been a rectangle.

I have a problem if we decide to remand

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this or pass on it or drag this out further that, you know, we have a group of entities that have essentially been in noncompliance with the protocols. And should we send an NVI? Probably. And even if we pass this PRR, we can still do the notice of violation for October or prior months, and that certainly can be done. Do they have -- if they are complying with this timeframe or window to get in compliance, that would probably be a good defense to the NVI, but it shouldn't -- it doesn't stop the process from going through.

But, you know, the only explanation people could say why they misinterpreted is some errant slide that may or may not have been in an ERCOT presentation that was corrected or some other language dealing with deployment rather than the actual requirement, and to me that's not compelling, and I think the protocols were clear that it should have been a rectangle. I'm sorry if that costs money to, you know, the wind generation folks to retrofit, but the protocols have been there since 2004. It shouldn't be a retrofit. It should have been stalled initially, and I think it's time to move forward. If through the ADR process or NV --

MR. DALTON: NOV.

MR. FEHRENBACH: -- NOV process, you know, people seek to get some other mitigation, they can certainly do that, and they can do that even if we adopt this and -- just to see if we can get a second and move forward, I will move that we adopt PRR 830 and reject the appeal.

MR. DOGGETT: I'll second.

CHAIRMAN NEWTON: Okay. We have a motion from Nick Fehrenbach, and we have a second from Trip Doggett. Charles?

MR. MANNING: I was just going to say I'm going to support that motion.

CHAIRMAN NEWTON: And I'm sorry to interject. Just for clarification, it was kind of a double motion. It was a motion to approve the PRR and reject the appeal. Correct?

MR. FEHRENBACH: Which I think actually by approving the PRR we pretty much reject the appeal, but I just wanted to make it clear that we were doing both.

(inaudible)

CHAIRMAN NEWTON: I think we probably need to do both. We have them both noted for vote.

MR. JENKINS: I think the quickest path to resolution on this is for us to put this PRR

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forward. I agree with Mark the decision is going to be made down the street, and kicking it back to TAC is not going to accomplish anything other than spend more time.

CHAIRMAN NEWTON: Dan?

MR. WILKERSON: I just wanted to say I support the motion. I believe reactive capability curves are a standard, and you don't really mess with standards. If it's going to be messed with, it needs to be done down the street, and that's -- kicking it back to the technical folks who sent it to us with an overwhelming majority doesn't accomplish anything.

CHAIRMAN NEWTON: Okay. Trip?

MR. DOGGETT: I was going to clarify that I would be flexible on the -- Walter's issue of WGR if there was an interest in a friendly amendment to ask TAC to revisit that issue. I talked to Walter and John out in the hall, and I think there might be an opportunity to have further discussion on that issue.

CHAIRMAN NEWTON: Okay. Before we continue with comments, Nick, you made the motion. Would you be amenable to that friendly amendment?

MR. FEHRENBACH: I don't have issue with that --

CHAIRMAN NEWTON: Okay.

MR. FEHRENBACH: -- if, you know, we want to fix that little piece of it.

CHAIRMAN NEWTON: Okay. We'll continue. Bob?

MR. HELTON: Yeah, just real quickly I agree that sending it back to TAC is not the right thing to do. It was just one of the thoughts I had. We could fix it like you had talked about, Mark, doing that prospectively here.

And I understand what's trying to be done. I'm having a problem. I still believe that the retrofitting piece in this, while I understand the full thing, I think it is a circumvention of the process, and I don't think I can support it for that reason. But I also know that this is a faster way of getting it over to the Commission because no matter what we do here, it's going to get there. I was just trying to get it through a process that when they get over there it's not going to be kicked back over an appeal on a procedural issue because it didn't go through the right process, like they had on the other side whenever they tried to circumvent the process to get it over there the first time. And I'm concerned that by doing that, it could end up back again over --

over a procedural issue. So that's my concern with that.

CHAIRMAN NEWTON: Okay. Bob Thomas?

MR. THOMAS: Thank you. I'm going to support Nick's motion. I think the Board is good at setting policy and rules, but it's not good at resolving legal and factual disputes that we have in front of us. We need to get this out of here up to the Commission and let them apply their process to the dispute.

One thing I'll be listening for in that proceeding is the following: Very clear positions that the requirement has been set for a number of years, and I guess one question that hasn't been answered today that I'm going to be listening for is why would -- if it's so clear, why would anyone spend all that money knowing they were making a mistake?

CHAIRMAN NEWTON: Andrew?

MR. DALTON: Yeah, I guess I have kind of a more pragmatic concern to address. I mean, it seems any way you look at this PRR, we were going to potentially give wind until December 31, 2010 to kind of build in to compliance. We have two studies underway right now that might be able to give us a very good picture of what compliance really ought to

look like from a standpoint of total system reliability.

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You know, we're going to have a lot of issues integrating more and more wind through the CREZ process, integrating the wind that's on there now as we increase our transmission capabilities to move that wind to market. In doing so, it's going to cost money to wind generators, to everybody else on the system to make that.

Before we would embark on spending a hundred million dollars or anything in that ballpark, I would like to know that we are spending that money in the most wise and efficient manner possible to the ultimate benefit of the grid long term. If there is a way to address this type of issue in the ongoing studies without prejudicing whatever this PRR does, I would strongly recommend to ERCOT staff to take that into consideration because I don't think whatever -- when this gets over to the Commission, this isn't going to be resolved by April or May. We're going to have these studies coming out June and July. They might give us the picture of what the grid really ought to look like going forward, and we ought to be working towards that as a solution because the Commission solution isn't going to help us fix the way

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the grid ought to look and what wind generators ought to do going forward.

We've been talking about getting the right metrics and the right requirements for wind for the better part of a year now. I think we have an opportunity to work that in, regardless of what we do with this PRR, and I think we should take it.

CHAIRMAN NEWTON: All right. Thank you, Andrew?

Clifton?

MR. KARNEI: Yeah, I support the motion, but I guess my question is a little bit different, and it's to Grable. Since it's clear that ERCOT staff has a position in this and since Trip is technically an ERCOT staff member, I question whether he should be the second on the motion and should vote on this or possibly recuse himself. I'm just raising that as a procedural thing for the second to the motion and would like your comments on that, Mike.

MR. PATTON: I'll second that.

MR. KARNEI: If Trip withdraws his motion -- I'm not one to put Trip on the spot. I'm just saying --

MR. GRABLE: There's no distinction really in terms of importance between being the second

and being a voting person. Let's say it were a Brazos line and you were either an affirmative vote, say, ten to five vote, and you were either the second or just an affirmative vote, it would be a problem either way.

I will say that the duties with which ERCOT staff are charged are public interest and reliability duties, and although Trip is an ERCOT staffer and is voting in alignment with those interests, I do not read any of our conflict rules or any general ethical dictate to require that the ERCOT CEO recuse himself because ERCOT staff is a proponent.

The ERCOT CEO has voted on countless ERCOT staff-sponsored PRRs, OGRRs, everything. If you were to set that precedent, you might as well just decree -- you might as well -- we've got the bylaws coming up in a bit. You might as well make the CEO a nonvoting member because any action this Board votes on almost by definition has an impact on ERCOT staff.

MR. KARNEI: I'll withdraw my comment. Thank you.

CHAIRMAN NEWTON: All right. Brad?

MR. COX: Yeah, I'm largely in agreement with the direction we're headed. I'll tell you the one thing that I'm hung up on, and it's similar to what Andrew discussed earlier, is, you know, it's less

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than certain -- I mean, if we didn't have some ambiguity here, we wouldn't be spending all this time discussing what the requirement is in the protocols as they are written today. And the concern I have is that if the -- you know, if whatever procedural route this takes after it leaves here the -- you know, if the Commission determines that, yeah, there is ambiguity or whatever, you know, it would seem to me there ought to be, again, the flexibility to deal with the existing system as opposed to imposing a blanket requirement over the existing system, so I -- because there may be more cost-effective ways to remedy, you know, whatever problems may exist.

I doubt that my request for that type of flexibility as a friendly amendment would be entertained. I'll throw it out and make -- make that request, Nick, and see what your thoughts are. Do you understand what I'm saying? It's -- they were getting pretty complicated here, but I'm just -- the track we're on right now really will put all of these resources on a -- on this rectangle standard with a grace period. Is that -- would you agree?

MR. FEHRENBACH: I would concur, but, of course, I also think that under the current protocols they should already be there.

MR. COX: Right. And, you know, I'm only trying to leave enough flexibility to -- you know, if circumstances are such that that flexibility is warranted to allow for a more cost-effective solution down the road, and I'm -- this would be -- I'm having a difficult time communicating this perhaps, but that's the one issue I have left with where we're headed.

MR. FEHRENBACH: And, you know, in reading 830 the way it was written, one of the things that I thought was sort of innovative, and Bob Helton would probably say is one of those problematic things, that it allowed the wind generators to come in compliance by actually paying the T&D utility to install devices to make them compliant. And that's sort of a stretch for us because I don't think we've done that in the past, let entities pay someone else to install devices to make them compliant, but -- and I thought that was innovative, and that probably gets into a cost-effective solution for some of those entities, but even that, you'll probably have people not wanting to go that route and possibly going through one of these other processes that are open to them under law.

CHAIRMAN NEWTON: Okay. So I'm assuming

that that is not an acceptable friendly amendment.

MR. FEHRENBACH: And again, I'm not sure exactly what the friendly amendment would be. So I can't really accept it.

CHAIRMAN NEWTON: Okay. John, your card has been up -- down there for a while. I've been trying to take the Board members first.

MR. HOUSTON: Yes. No, and I appreciate that, madam Chairman, and I just wanted to add my view that we really need to address the issue of what is the standard. This Board needs to take a position, if nothing else, for future generators who are walking in the door asking to connect. It needs to be clear. Certainty needs to be taken, and I think our whole compliance regime of both ERCOT and participants is at risk if we do anything other than approve this going forward.

CHAIRMAN NEWTON: Well, I've been relatively quiet here, and I'm speaking as just a Board member myself here, but after listening to the debate, that's where I fall out, is that I specifically asked most of the commenters, and everyone seems to be in agreement, that prospectively everyone getting on the same page relative to this requirement is critical. And based upon that, it looks like the big issue, in my mind, is the retroactive piece.

I fully understand the heartburn that creates for the wind generators from an investment perspective. However, it looks like this thing is going to get resolved, and the fastest way to get that piece resolved is for us to move forward. So I will be supporting it as an independent Board member.

Dee?

MR. PATTON: Madam, I call the question.

CHAIRMAN NEWTON: Okay. I've got one other card, Dee. Can I -- can I just get Miguel's? He's been pretty quiet, too.

MR. PATTON: I call the question.

CHAIRMAN NEWTON: Okay.

(Laughter)

MR. GRABLE: That's a motion that requires a second and would have to be voted on to determine if Miguel is heard or not. So is there a second for the calling?

CHAIRMAN NEWTON: Miguel --

MR. ESPINOSA: Thank you.

CHAIRMAN NEWTON: -- real quickly lets --

MR. ESPINOSA: I support the motion as

proposed. A, it seems to me like we should have been there already, and we're not. I'm heartened by the fact that nobody has gotten up and spoken against the prospective issues for us. And if the looking back the issue has to be resolved at 17th and Congress, sobeit.

CHAIRMAN NEWTON: Okay. We have a motion. We have a second. Everyone clear on the motion?

(No response)

CHAIRMAN NEWTON: And with the friendly amendment. Okay?

MR. GRABLE: And, Madam Chair, let me -- was there a second friendly amendment?

CHAIRMAN NEWTON: No, just -- no, he's talking about the motion included --

(Simultaneous discussion)

MR. GRABLE: Oh, I see, right. The two pieces being approval under Item 12(a) of the protocol revision request and rejection of the appeal under 12(b). And I want to ask Mr. Doggett so we're perfectly clear, his friendly amendment was to clarify that the PRR 830 would be approved "as is" but a separate instruction given to TAC to revisit the WGR issue.

MR. DOGGETT: That's affirmative.

CHAIRMAN NEWTON: Okay. I won't repeat that. We now have a motion and a second for approval of PRR 830 and rejection of the appeal to that PRR.

MR. ESPINOSA: And I accept Dr. Patton's calling of the order.

(Laughter)

CHAIRMAN NEWTON: All in favor?

(All those in favor of the motion so responded)

CHAIRMAN NEWTON: Opposed? We have one -- two oppositions, one from Andrew Dalton and one from Bob Helton.

Abstentions?

(No response)

CHAIRMAN NEWTON: The motion passes.

Andrew?

MR. DALTON: One final point. I would sincerely hope that no one who is a generator comes forward after this meeting today and expresses any confusion or concern that everyone expects the rectangle will be implemented on a going-forward basis.

(Laughter)

MR. DALTON: And if it comes up, we're

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going to pull this transcript out.

MR. HELTON: Yes.

CHAIRMAN NEWTON: Okay. Thank you very much.

All right. Mr. Bruce, it's back to you.

MR. BRUCE: Thank you, Madam Chairman. That completes all of the PRRs for Board discussion today.

12(c). LOAD PROFILING GUIDE REVISION REQUEST 035

MR. BRUCE: That leaves us with a Load Profile Guide Revision Request No. 35. This guide revision request is on the agenda for Board approval because it does have system impacts. This load profile guide revision request will allow the addition of time of use schedules to profiles for IDR meter-type data codes for the advanced meter implementation project.

The impact analysis has minor impact -- cost impacts to be managed under the O&M budgets of the affected departments. It's a low impact, but there is an update to the Loadstar table that's required. It does not have any code changes, though. This is proposed to be effective upon Board approval, but there is a 150-day market notice that's required. So that notice would expire in mid April of next year,

and it was unanimously recommended by TAC.

MR. KARNEI: Move for approval.

CHAIRMAN NEWTON: Okay. Do we have any -- do we have a second? A second from Andrew -- well, I'm sorry -- motion by Clifton Karnei, second by Andrew Dalton. Any further discussion or comments?

(No response)

CHAIRMAN NEWTON: Seeing none, all in favor?

(All those in favor of the motion so responded)

CHAIRMAN NEWTON: Opposed?

(No response)

CHAIRMAN NEWTON: Abstentions?

(No response)

CHAIRMAN NEWTON: Thank you. The motion

passes unanimously.

MR. BRUCE: Thank you, Madam Chairman. As required by the protocols, I informed the Board that the TAC approved Nodal Operating Guide Revision Request No. 26. This was just a technical cleanup synchronization NOGRR. It changes the name of the Emergency Electric Curtailment Plan, or the EECP, to the new NERC terminology Energy Emergency Alert, or EEA.

Also, I informed the Board that two PRRs have been rejected. One of them is No. 754, resource settlement due to forced transmission outage. The other is No. 835, reactive power requirement, which was an alternative proposal to the PRR just approved by the Board, and those were not appealed.

12(d). REVIEW OF QUARTERLY RENEWABLES REPORT TO THE PUBLIC UTILITY COMMISSION OF TEXAS

MR. BRUCE: Finally, an item for the Board's informational purposes. Once again, the TAC is bringing forward the quarterly renewables report to the Public Utility Commission of Texas. As we discussed the last time we filed this report, this version will cover four months, not three. Now we are actually aligned with calendar quarters. So going forward we'll actually be reporting on full calendar quarters.

I noted in the memo to the Board in your packet the highlights of the report. The report is there. It's included for your informational purposes as you previously requested. I'm happy to take any questions or entertain discussion on the report.

CHAIRMAN NEWTON: Barry? Oh, sorry.

CHAIRMAN SMITHERMAN: Let me get to a mic. Somewhere in one of our earlier reports -- Kent,

I don't know if it was your report or whose -- there was an updated wind number of almost 9,000, and I see on the -- in the bullets of this item, Mark, it says "total renewable generation capacity in ERCOT, as of September 30, 8660." We always like to make sure we've got the best number available. So I guess I would ask, in talking to the public or giving presentations, what's the right number?

MR. SAATHOFF: The number in my report is October 31st, and this is September 30th. So that's -- that's the difference between the two.

(inaudible)

CHAIRMAN SMITHERMAN: Kent's report, all right.

MR. SAATHOFF: Yes, it's 8916, October 31st and --

CHAIRMAN SMITHERMAN: Okay. Thank you.

CHAIRMAN NEWTON: Any other questions for Mark on the quarterly renewables report?

(No response)

CHAIRMAN NEWTON: Okay.

MR. BRUCE: Thank you, Madam Chairman. And finally then, a preview as we like to do of what's coming up next. At your December Board meeting, you'll be -- we're about to have the stakeholder segment elections. So this Board will have a slate of TAC representatives for calendar year 2010 to confirm.

Also, there are the three PRRs listed on the screen as well as an NPRR, which will be ripe for Board decision next month. Those are the only items at this point in time that I know are coming forward to the Board in December. I'm happy to entertain any other questions the directors may have.

CHAIRMAN NEWTON: Okay. Any other questions for Mark?

(No response)

CHAIRMAN NEWTON: Seeing none, I think you're done.

MR. BRUCE: All right. Thank you.

CHAIRMAN NEWTON: Thanks, Mark.

13(c). FINANCE & AUDIT (F&A) COMMITTEE REPORT

CHAIRMAN NEWTON: Okay. Clifton, F&A?

MR. KARNEI: Yes, Madam Chairman, we had two items we were going to do presentations to the Board on today: That is our semiannual enterprise risk management compliance and internal control update as well as the future exposure on credit. In the interest of time, what I would propose is that we move those to either December or the January Board meeting. They are just reporting items, if that's okay with

you.

CHAIRMAN NEWTON: I would really

appreciate that. We have some other issues still to come that are going to take some time. So thank you very much.

MR. KARNEI: We met this morning at 7:30. We reviewed our normal reports. In the interest of time, I won't go over those. A couple of the meatier items I think everybody would be interested in, we are beginning to look at our needs for financing in 2010. We have a $50 million facility that expires in 2010 as well as another $100 million facility. We also have a $70 million payment due on a term loan. We currently have about $354 million of debt. We are projected next year to go to $424 million. So if we don't replace these two facilities with the 50 and the 100 million or be able to possibly not make the $70 million term loan payment or a combination of those, we would be short on cash in 2010.

So staff presented -- or asked what we wanted them to do. We instructed them to begin discussion to possibly extend our $50 million facility, possibly extend the $100 million facility, renegotiate the $70 million payment, and they are

going to get started on all of these, bring those back to us. Most likely it will be January or February, and we'll be making some presentations.

The important thing about this is one of the facilities expires in June of next year, one in November. So we have plenty of time to work on this item.

We did receive a report on the SAS 70 audit. Trip commented on this earlier. It is an unqualified report. This is the third year in a report we've received an unqualified report. That is a great accomplishment by the staff, and it is also our last SAS 70 work done by PricewaterhouseCoopers, and we thank PricewaterhouseCoopers for the great work they've done for ERCOT over the years.

We do have two action items. The first one is the financial standard that is in your book. It is under Tab No. 13.

CHAIRMAN NEWTON: 13(b).

MR. KARNEI: Oh, we did have one minor edit to this. On Page 1 of the standard in the second -- I'm sorry -- the third paragraph from the bottom. There's an addition of a parenthetical "with the exception of the ERCOT's Chief Executive Officer." We moved that from its current location one line down

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behind the word "company."

Also -- and that -- I'm sorry -- that was the only edit to the -- oh, I'm in the wrong thing. I'm sorry. I'm in the finance and audit charter.

13(b). APPROVAL OF FINANCIAL
AND INVESTMENT CORPORATE STANDARDS

MR. KARNEI: Okay. Our first action item is on the financial standard. And if you look on the second page -- third page of this, it's in Section 3.0. It is the second paragraph on the third

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page of this. You will see there were some changes to
this section about ERCOT having to report to us over-
or underspends. That was previously 25 percent.
That's been revised to 5 percent.

There was some discussion in the
committee meeting about the way this was worded. We
thought it was a little unclear. So at your place,
there is revised wording on this paragraph. It has
red and blue -- black edits to it, and those were
changes made to this standard by the committee.

And with that, that is the only change
from what was mailed out in the package. We do have a
recommendation from the committee to approve the
revised financial corporate standard with the

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revisions that are at your table on that one specific
paragraph. And, Madam Chair, I would so move.

CHAIRMAN NEWTON: Okay. Thank you,
Clifton. We have a motion by Clifton Karnei, a second
by Miguel Espinosa. Any questions or comments?

(No response)

CHAIRMAN NEWTON: Seeing none, all in
favor?

(All those in favor of the motion so
responded)

CHAIRMAN NEWTON: Opposed?

(No response)

CHAIRMAN NEWTON: Abstentions?

(No response)

CHAIRMAN NEWTON: The motion passes
unanimously.

MR. KARNEI: We also have an action item related to the investment corporate standard. In your mailout, you will see that there were very little changes to the body of the policy itself. The main changes here are in the appendix, and the first area, we have changed the deposits up to 250,000 insured by federal agencies from the previous 100,000.

And then you will also see on Appendix No. C some edits as well as some highlighted sections

at the bottom. At the bottom of the page, you'll see that there was a range in here of 25 to $100 million. The committee in discussion today recommended and -- are recommending to the Board we make that number $50 million so we won't hold more than $50 million with any one fund.

And with that one change, which is to insert 50 million in that where that was previously a range, it is the recommendation of the committee that the Board approve the revisions to the investment corporate standard. And, Madam Chairman, I would so move.

CHAIRMAN NEWTON: Okay. Thank you. We have a motion from Clifton Karnei. Do I have a second? From Michael Gent. Any further discussion?

(No response)

CHAIRMAN NEWTON: All in favor?

(All those in favor of the motion so responded)

CHAIRMAN NEWTON: Opposed?

(No response)

CHAIRMAN NEWTON: Abstentions?

(No response)

CHAIRMAN NEWTON: Motion passes unanimously.

MR. KARNEI: And I believe that concludes all the action items from the committee.

(Inaudible)

13(a). APPROVAL OF F&A COMMITTEE
CHARTER & STRUCTURE

MR. KARNEI: You know, Dan has just pointed out to me one error. Thank you, Cheryl. Thank you, Dan. I am -- I have skipped in my haste Item No. 13(a), which is the revisions to the committee charter. This was -- that was what I was stuck on first. Excuse me.

This was what I was referring to. It is under Tab 13(a) of your book, and then on the first page of the charter, you will see -- the only change we're making to this compared to the mailout was in the third paragraph from the bottom on Page 1, and we just moved the parenthetical that was added, "with the exception of ERCOT's Chief Executive Officer." It is my understanding that most of these changes were suggested by ERCOT legal. Correct, Cheryl?

MS. MOSELEY: (Nodded)

MR. KARNEI: And I don't believe it substantially changes any of the substance. It's just moving things around for clarity purposes.

Cheryl, anything you want to add?

MS. MOSELEY: (No response)

MR. KARNEI: It is the recommendation of the committee that we approve these changes to the charter, and I would so move, Madam Chairman.

CHAIRMAN NEWTON: Okay. We have a motion by Clifton Karnei. We have a second by Miguel Espinosa. Any further discussion?

(No response)

CHAIRMAN NEWTON: All in favor?

(All those in favor of the motion so responded)

CHAIRMAN NEWTON: Opposed?

(No response)

CHAIRMAN NEWTON: Abstentions?

(No response)

CHAIRMAN NEWTON: Motion passes unanimously.

MR. KARNEI: And that concluded our meeting.

CHAIRMAN NEWTON: Okay. Thank you. Clifton.

Mark, are you ready for HR&G?

14. HUMAN RESOURCES (H.R.) AND GOVERNANCE COMMITTEE REPORT

MR. ARMENTROUT: Yes, and like Clifton,

I'll try to give you as much time back as I can.

We received our external relations

update from Theresa. Basically everything is on track with the Sunset Committee. The full committee has now had their first meeting today.

We got an update on the market participant survey, which I will skip.

We had an update on the development of a technical track and career ladder, which I think is very important for people to understand. In a nutshell, ERCOT staff has created a pay grade for highly -- for a select small few of highly trained, highly performing technical people that is equivalent to a managerial pay grade, which is not unlike other technical organizations. If you want more details, contact Nancy.

14(b). APPROVAL OF RECOMMENDATION OF PROPOSED AMENDMENTS TO BYLAWS TO CORPORATE MEMBERS

MR. ARMENTROUT: The last thing I wanted to talk about is the one voting item that we have, Madam Chair, which is the vote on the bylaws, changes which are in your Board packet in Section 14(b).

If the Board agrees -- we made some changes in the committee today that are not in your packet. There's a suite of those changes that are

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very, very cosmetic, and I'm going to skip those. And if would you like to see them later, contact Mike Grable. They had to do with like changing the word "that" to "who" and spelling out some things. They were very, very, very cosmetic.

I want to go over just three or four changes where there's language changes that didn't

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change the substance of anything, but we believe they had changed -- they make more clear the intent of the phrases.

So if you turn to Page 14, Paragraph (ii)(B), where it says, "Unaffiliated Directors or family members...shall not have current or recent ties...as an employee of an ERCOT -- an ERCOT member or NERC-registered entity," we added a comma after NERC-registered entity to say, "a NERC-registered entity, operating in the ERCOT region." So we would not exclude experience with a NERC-registered entity from the New England ISO or California ISO or something like that.

On the -- just on the very next page, on Page 15, Paragraph (c), we deleted the last line, one -- "of these three, one position shall be for a term of two years and two positions shall be for three." Year terms, that is six-year-old language for

when we first started up independent directors.

On Page 18, Section 4.8, Subcommittees, we, again, eliminated the last line for clarify, "Any non-Director who becomes a member of TAC or a subcommittee shall have the same responsibility," blah, blah, blah. We deleted that because it's no longer -- in this set of bylaws, a director can no longer sit on TAC.

And then the last one -- oh, two more. Page 21, again for clarity, Paragraph (i), the third line, the sentence -- the word "same" has been changed to say, "small commercial" because it was not clear. So, "In the event that a Small Commercial Consumer Rep cannot be identified to serve on TAC, that seat may be filled by another Commercial Consumer Rep appointed by the Consumer Director of the Small Commercial subsegment," et cetera.

Okay. This is one substantial change -- I lied. So Page 27 we basically -- about reimbursement for travel expenses. The last version had read that, "Unaffiliated Directors and Consumer Directors may be reimbursed for both training and for coming to Board meetings," and we have changed that to "reimburse Consumer Directors only for training, but not for coming for Board meetings." The logic there

in the committee was that their -- they have a material stake in the decisions of ERCOT, and, therefore, the consumer REPs should pay their own expenses.

So the specific change in Article 10, Section 10.1, Paragraph (b), halfway down the paragraph, there's a -- well, we added "Unaffiliated Directors." Okay. Let me get this straight. So where it starts -- the sentence that starts, "Unaffiliated Directors and Consumer Directors," we eliminated the strike-through so that "and Consumer Directors" will be put back in, "may be reimbursed for registration, travel, lodging and related expenses for training activities," and we will insert after the "and," "Unaffiliated Directors," so that the language for reimbursement for Board meetings applies only to unaffiliated directors.

And then after I give you the last one, then I'll stop and see what you-all -- see if you-all agree with all those, see if there are any other comments because we need to vote on this today. Or was that it? No, that's it. That's my last one.

MR. GRABLE: I want to chime in on two points. Probably note that that last one was not unanimous at the committee.

MR. ARMENTROUT: Thank you.

MR. GRABLE: And there was one other one regarding committee membership, Danny, for OPC. There's a reference to the "public counsel or his or her designee being on TAC." Obviously we've changed that to the "public counsel's designee" because public counsel is a Board member.

MR. ARMENTROUT: Right. It was just grammatical.

CHAIRMAN NEWTON: Okay. Any questions?

(No response)

CHAIRMAN NEWTON: Barry?

MR. ARMENTROUT: Any comments? If not -- Chairman Smitherman?

CHAIRMAN SMITHERMAN: Yeah, a question. Go back to that change on Page 14, (ii)(b), let me make sure I wrote down what you added at the end of "NERC-registered entity."

MR. ARMENTROUT: "Operating in the ERCOT region."

CHAIRMAN SMITHERMAN: So presumably then there are NERC-registered entities operating in ERCOT that are not ERCOT members?

MR. ARMENTROUT: We assumed that we couldn't conclude that that was the case. We

didn't -- we didn't do a survey or anything. We assumed that was a possibility.

Any other comments or questions?

(No response)

MR. ARMENTROUT: I make a motion on behalf of the committee to adopt these bylaws and send them out to the membership.

CHAIRMAN NEWTON: We have a motion from Mark Armentrout, and we have a second from Dr. A.D. Patton.

MR. ARMENTROUT: As amended with my comments here and as amended with the other -- with the document that Mike Grable had that documented some further edits and clarifications much to the thanks of Dr. Paten who has spent decades reading engineering dissertations and fixing them.

(Laughter)

UNIDENTFIED SPEAKER: That didn't sound like a compliment.

CHAIRMAN NEWTON: Okay. Are there any other questions or comments?

(No response)

CHAIRMAN NEWTON: So the motion, just for restatement purposes, is to ask this Board to approve the recommended changes to the bylaws as outlined by Mark -- well, as included in your binder with the changes as outlined by Mark Armentrout, and that the Board will approve submitting these out to the membership for official approval. Okay? All those in favor?

(All those in favor of the motion so responded)

CHAIRMAN NEWTON: Opposed?

(No response)

CHAIRMAN NEWTON: Abstentions? One abstention from Nick Fehrenbach. The motion passes.

MR. ARMENTROUT: That concludes my report.

CHAIRMAN NEWTON: Okay. Thank you very much, Mark.

MR. GRABLE: Jan?

CHAIRMAN NEWTON: Yes?

14(a). MEMBERSHIP AFFILIATES UPDATE

MR. GRABLE: Madam Chair, do you mind if I take two seconds on the membership affiliate issue? It won't take long, but it's something I want to try to make the broader ERCOT community aware of --

CHAIRMAN NEWTON: Sure.

MR. GRABLE: -- that we discussed this morning.

CHAIRMAN NEWTON: Absolutely.

MR. GRABLE: Thank you. We are in the

process of receiving the 2010 membership forms. Many of the market participants who choose to apply for membership and many others who apply for membership are aware that there is an affiliation standard that can be as little as 5 percent ownership in a chain of ownership. There are also similar 5 percent thresholds in PUC rule and in PURA, and we are seeing increasing entanglements in the industry in terms of both financial ownership chairs and also new entrants in either the generation or the transmission space.

Certain entities that have been here for a while as generators are now in our market as transmission companies. Two of the parts of HL&P have put themselves back together. And what I want to highlight for the membership is to be very careful when you sign on that membership form that you have fully disclosed to us all of your affiliate relationships. And if you have questions about that to please discuss it with us.

It is of concern, and we've had this happen this year, where we've gotten one party identifying a second party as an affiliate, the second party said, "We don't have any." So we certainly

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track those down when they come to us, but we want people to be diligent before that happens.

CHAIRMAN NEWTON: Okay. Thank you.

14(c). RATIFICATION OF CEO SEARCH SUBCOMMITTEE

CHAIRMAN NEWTON: Okay. There is one other item that was on the agenda, and I want to just mention it real quickly. It was Item 14(c) as part of the HR&G Committee report, which was Ratification of a CEO Search Subcommittee. And just for the record, we are going to defer that action until December. So I just want to make that clear in the Open Meeting because it had been noticed for a vote and approval, but that will not be taken up until next month.

15. NOMINATING COMMITTEE REPORT

CHAIRMAN NEWTON: And very quickly, the Nominating Committee Report. We did hold a Nominating Committee yesterday for purposes of -- it was really kind of an initiation meeting. We had the search firm, that was retained by this Board, participate via conference call. They presented a very, very preliminary list of potential candidates that they have identified already.

The purpose and intent of our Nominating Committee was to kind of go through those potential candidates to get a flavor for whether or not they are

on track relative to the skill sets, experience and what we believe it would take to be effective in the position.

So from there, the next steps will be -- we did plan and it will be posted that the next Nominating Committee will be the Monday prior to the December Board meeting, and we will have the search firm available in person at that time.

Okay. Any questions relative to that? Yes, Clifton?

MR. KARNEI: Just one point to make. As

we're recruiting this next outside independent director, let's make sure we don't show them the clip of the 830 discussion.

(Laughter)

MR. HELTON: That's a good point.

CHAIRMAN NEWTON: And thank goodness it was in the afternoon. So if they were to log on, surely they wouldn't start in the afternoon, you know, because that would be bad. A very good point.

16. OTHER BUSINESS

CHAIRMAN NEWTON: Okay. Any other business?

(No response)

CHAIRMAN NEWTON: Okay. If not, then I

will adjourn the open session of the November Board meeting.

17. FUTURE AGENDA ITEMS

MR. GRABLE: Madam Chair?

CHAIRMAN NEWTON: Yes?

MR. GRABLE: Sorry. Can we just cover future agenda items before we move to exec? I added one item, and that was a follow-up report to see how things were progressing under the 2010 ancillary service standard with the nonspin changes to come in the spring, February to March timeframe. Did anyone else have any revisions or additions on Agenda Item 17?

(No response)

CHAIRMAN NEWTON: Okay. Seeing none, that would be great. Thank you. I appreciate that.

I skipped it since I had to turn the page over, and I missed that it was on the back of the page.

Okay. I will now close the open session of our Board meeting, and we will give -- five minutes okay again? And we will come back for executive session, and that will give a chance for them to close down the webcast. Thank you.

CONVENE TO EXECUTIVE SESSION

(Recess: 4:32 p.m. to 6:03 p.m.)

RECONVENE TO OPEN SESSION

CHAIRMAN NEWTON: Okay. Let's go ahead and reconvene open session. I understand that the webcast is back up.

23. VOTE ON MATTERS FROM EXECUTIVE SESSION

CHAIRMAN NEWTON: We have a couple of items coming out of executive session to vote on.

MR. HELTON: Madam Chair, would you like for me to chart with 21(a)?

CHAIRMAN NEWTON: Yes. Thank you.

MR. HELTON: Madam Chair, Bob Helton. I'd like to recommend approval of Item 21(a) on the additions to the Utilicast contract as discussed in executive session.

CHAIRMAN NEWTON: Okay. Thank you. I have a motion from Bob Helton, a second from Mike Gent, and is there any further discussion?

(No response)

CHAIRMAN NEWTON: Seeing none, all in favor?

(All those in favor of the motion so responded)

CHAIRMAN NEWTON: Opposed?

(No response)

CHAIRMAN NEWTON: Abstentions?

(No response)

CHAIRMAN NEWTON: Well, Mark, I'm sorry. Did you have a comment?

MR. ARMENTROUT: No. I was going to make a motion.

CHAIRMAN NEWTON: Okay. Then the motion passes unanimously.

Okay. Moving on we had --

MR. ARMENTROUT: I'd like to make a motion to approve the changes in the advanced metering project as described in closed session.

CHAIRMAN NEWTON: Thanks. We have a motion by Mark Armentrout. We have a second by Miguel Espinosa. Any further questions or comments?

(No response)

CHAIRMAN NEWTON: All in favor?

(All in favor of the motion so responded)

CHAIRMAN NEWTON: Opposed?

(No response)

CHAIRMAN NEWTON: Abstentions?

(No response)

CHAIRMAN NEWTON: The motion passes unanimously.

24. ADJOURN

CHAIRMAN NEWTON: I think that concludes all of our business for today, and sorry for the late timeframe, but we are now adjourned.

(Proceedings concluded at 6:05 p.m.)

C E R T I F I C A T E

STATE OF TEXAS)

COUNTY OF TRAVIS)

We, Lou Ray and Kim Pence, Certified Shorthand Reporters in and for the State of Texas, do hereby certify that the above-mentioned matter occurred as hereinbefore set out.

WE FURTHER CERTIFY THAT the proceedings of such were reported by us or under our supervision, later reduced to typewritten form under our supervision and control and that the foregoing pages are a full, true, and correct transcription of the original notes.

IN WITNESS WHEREOF, we have hereunto set our hand and seal this 24th day of November 2009.

KIM PENCE
Certified Shorthand Reporter
CSR No. 4595-Expires 12/31/09

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LOU RAY
Certified Shorthand Reporter
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UUU230

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512.474.2233

Letter from ERCOT General Counsel Grable Dated November 10, 2009 to the ERCOT Board of Directors regarding Packet Materials for the November Board meeting [materials regarding PRR 830, incorporated by reference]

November 10, 2009

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MEMORANDUM

To: **ERCOT Board of Directors and Segment Alternates**

From: **Mike Grable, ERCOT Vice President and General Counsel**

Date: **10 November 2009**

Re: **Agenda Items 12(a) and (b): Protocol Revision Request (PRR) 830, *Reactive Power Capability Standards*: Technical Advisory Committee (TAC) Referral for Approval, and NextEra Energy Resources (NextEra) Appeal of Same**

Greetings:

On November 5, 2009, TAC voted to recommend that the Board approve PRR830. Because this PRR has urgent status, it was placed on this month's Board agenda. The following day, NextEra filed an appeal of the TAC action, urging rejection or, in the alternative, amendment of the PRR. These items are Board agenda items 12(a) and 12(b), respectively.

Following TAC Chair Mark Bruce's decision to recuse himself from naming a TAC Advocate in order to remove any appearance of conflict in that process, TAC Vice Chair Shannon McClendon named John Houston of CenterPoint Energy Houston Electric (CenterPoint) as the TAC Advocate yesterday evening. Mr. Houston provided a brief position statement that is included in this Packet; a more complete statement will be forwarded if and when it is received.

Position statements from the following parties have been included in the Board Packet following this memorandum; they are provided in alphabetical order:

- AES Corporation (Robert L. Sims)
- American Electric Power Service Corp. (Kip Fox)
- CenterPoint Energy Houston Electric (John Houston, TAC Advocate)
- ERCOT (Kent Saathoff)
- Horizon Wind Energy LLC (Brian Hayes)
- NextEra Energy Resources (Mark J. Bruce)
- Oncor Electric Delivery Company LLC (Ken Donohoo)
- Wind Coalition (Walter Reid)

Thank you for your attention to this matter, and I look forward to discussing this PRR with you next week.

ERCOT Technical Advisory Committee ("TAC") November 2009 meeting Minutes regarding PRR 830

November 5, 2009

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DRAFT
Minutes of the Technical Advisory Committee (TAC) Meeting
ERCOT Austin – 7620 Metro Center Drive – Austin, Texas 78744
Thursday, November 5, 2009 – 9:30am – 4:00pm

Attendance

Members:

Ashley, Kristy	Exelon Generation	
Barrow, Les	CPS Energy	
Bivens, Danny	OPUC	
Boyd, Phillip	City of Lewisville	
Brewster, Chris	City of Eastland	
Briscoe, Judy	BP Energy	Alt. Rep. for E. Schubert
Bruce, Mark	NextEra Energy Resources	
Cochran, Seth	Sempra Energy Trading	
Comstock, Read	Direct Energy	
Downey, Marty	TriEagle Energy	
Dreyfus, Mark	Austin Energy	
Fox, Kip	AEP Corporation	Alt. Rep. for R. Ross
Houston, John	CenterPoint Energy	
Jones, Brad	Luminant Energy	
Jones, Randy	Calpine	
Lange, Clif	South Texas Electric Coop.	Alt. Rep. for H. Wood
Lenox, Hugh	Brazos Electric Power Coop.	
McCann, James	Brownsville PUB	Alt. Rep. for F. Saenz
McClendon, Shannon	Residential Consumer	
Morris, Sandy	LCRA	Alt. Rep. for B. Belk
Moss, Steven	First Choice Power	
Pieniazek, Adrian	NRG Texas	
Singleton, Gary	GEUS	Alt. Rep. for D. McCalla
Smith, Bill	Air Liquide	
Smith, Mark	Chaparral Steel	Alt. Rep. for O. Robinson
Wagner, Marguerite	PSEG Texas	
Whittle, Brandon	DB Energy Trading	
Zlotnik, Marcie	StarTex Power	

The following proxies were assigned:

- William Lewis to Marcie Zlotnik
- John Sims to Clif Lange

Guests:

Brandt, Adrianne	Austin Energy
Burkhalter, Bob	ABB
Clemenhagen, Barbara	Topaz Power
Cooper, Tammy	TIEC
Daniel, Matthew	Horizon Wind Energy
Daniels, Howard	CNP
Davison, Brian	PUCT
Diehl, Phillip	Texas Admin

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DeLaRosa, Lewis	PUCT
Donohoo, Ken	Oncor
Durrwachter, Henry	Luminant
Emery, Keith	Tenaska
Goff, Eric	Reliant
Greer, Clayton	Morgan Stanley
Gresham, Kevin	E.ON Climate and Renewables
Grimes, Mike	Horizon Wind Energy
Helton, Bob	IPA
Jones, Don	Reliant
Jones, Liz	Oncor
Kimbrough, Todd	NextEra Energy
Kolodziej, Eddie	Customized Energy Solutions
Lee, Jerry	Electric Power Engineers
Lee, Jim	Direct Energy
Liebmann, Diana	Horizon Wind Energy
McKeever, Debbie	Oncor
Patrick, Kyle	Reliant Energy
Paysinger, Robby	CPS Energy
Reid, Walter	Wind Coalition
Richard, Naomi	LCRA
Rowley, Chris	TXU Energy
Sandidge, Clint	Sempra Energy Solutions
Santos, Juan S.	Vestas
Schwarz, Brad	E.ON Climate and Renewables
Scott, Kathy	CenterPoint Energy
Seymour, Cesar	SUEZ
Siddiqi, Shams	LCRA
Smith, Chris	Austin Energy
Stewart, Roger	LCRA
Trenary, Michelle	Tenaska Power Services
Troutman, Jennifer	AEP Energy Partners
Vincent, Susan	Texas Regional Entity
Walker, DeAnn	CenterPoint Energy
Whittington, Pam	PUCT
Wittmeyer, Bob	Longhorn Power

ERCOT-ISO Staff:
Albracht, Brittney
Bohart, Jim
Day, Betty
Dumas, John
Flores, Isabel
Gates, Vikki
Goodman, Dale
Hobbs, Kristi
Kleckner, Tom
Levine, Jonathan
Manning, Chuck
Middleton, Scott
Sills, Alex

Unless otherwise indicated, all Market Segments were present for a vote.

TAC Chair Mark Bruce called the meeting to order at 9:33 a.m. and reviewed assigned proxies and Alternate Representatives.

Antitrust Admonition
Mr. Bruce directed attention to the Antitrust Admonition, which was displayed. A copy of the Antitrust Guidelines was available for review.

ERCOT Board of Directors (ERCOT Board) Update (see Key Documents)[1]
Mr. Bruce reported ERCOT Board approval of Protocol Revision Request (PRR) 822, Removing Access to Restricted Computer Systems, Control Systems and Facilities, noting that the ERCOT Board removed language regarding physical facilities and revised language to require that the Texas Regional Entity (TRE) be apprised within 48 hours of knowledge of an event, rather than within 48 hours of an event's occurrence; that the ERCOT Board remanded PRR811, Real Time Production Potential, to TAC with instructions to include language for the Real Time Production Potential (RTPP) calculation methodology; and that ERCOT reported that cost-cutting measures have been successful against the budget shortfall resultant of the economic downturn. Mr. Bruce noted Mark Armentrout's announcement that he will not seek another term as an Independent Board member; and that Trip Doggett is serving as interim ERCOT Chief Executive Officer (CEO).

Proposed Revisions to the ERCOT Bylaws
Mr. Bruce reported that no comments had been received regarding the proposed revisions to the ERCOT Bylaws; that the item would not return to the December 3, 2009 TAC agenda; and that disclosure requirements and TRE separation remain the two major revisions. Mr. Bruce encouraged Market Participants to review proposed ERCOT Bylaw revisions within their organizations. Market Participants characterized language regarding Affiliates as particularly difficult and potentially problematic.

PRR811, Real Time Production Potential
Kip Fox moved to remand PRR811 to the Wholesale Market Subcommittee (WMS). Randy Jones seconded the motion. The motion carried unanimously.

Texas Renewables Integration Plan (TRIP) Update
Mr. Bruce noted that a TRIP workshop was held with ERCOT Board members the morning of October 16, 2009 and that there is a revised expectation of what the ERCOT Board requires of TAC. Originally, TAC was to develop the renewables integration plan; however, TAC is limited on what they can do. The new expectation is for TAC to develop the key elements of the plan to deliver to the ERCOT Board who can then assign to ERCOT management to turn the plan into the budget process. Mr. Bruce noted that the next meeting of the Renewable Technologies Working Group (RTWG) is December 7, 2009 and that a proposal should come to the February 2010 TAC meeting in order for consideration at the March 2010 ERCOT Board meeting.

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[1] Key Documents referenced in these minutes may be accessed on the ERCOT website at: http://www.ercot.com/calendar/2009/11/20091105-TAC

Approval of Draft TAC Meeting Minutes (see Key Documents)
October 1, 2009
Mr. R. Jones moved to approve the October 1, 2009 TAC meeting minutes as posted. Brad Jones seconded the motion. The motion carried unanimously.

Texas Nodal Implementation (see Key Documents)
Mr. Bruce noted that the Nodal market is approximately one year away and that all meeting agendas will now lead with Nodal issues and updates.

Protocol Traceability
Betty Day provided a Protocols traceability effort update; reported what the full trace report would and would not provide; and reviewed the gap identification and resolution process flow. Ms. B. Day noted that the full trace report demonstrates ERCOT's understanding of how the Nodal Protocols match to a functional requirement; will include desk procedures per Mr. Doggett's commitment, but that all business procedures will not necessarily be published due to confidentiality requirements; and that ERCOT will host WebEx meetings to review full trace reports. Ms. B. Day added that the goal is to have traceability completed by the end of December 2009.

ERCOT Program Update
Jason Iacobucci provided a program update and reviewed the Nodal systems blueprint, market trials roadmap, and completed milestones.

Market Connectivity
Mr. Iacobucci provided an update on Phase 2.1 Market Connectivity, noting that the program is early into execution; that non-critical functional issues have been found on the ERCOT side as expected; and that issues will continue to be worked through with the hope of resolution before January 2010. Mr. Iacobucci noted that 16 Entities, a combination of Market Participants and vendors averaging 12 unique digital certificates, participated in recent testing; and that ERCOT desires that more Market Participants participate in testing now so that more advanced testing may be accomplished later. Mike Cleary reported that three full days have been run; that ERCOT is having to manipulate some data to achieve operation as a single suite of applications; that efforts continue to prove technical feasibility, but the quality of solutions is currently very low.

Regarding Nodal program risks and issues, Mr. Iacobucci noted that specific dialogues need to be held around Service Level Agreements (SLAs) and Operating Level Agreements; that ERCOT will approach Entities with the perspective of what ERCOT systems can and cannot perform currently; and that Market Participants and ERCOT will not always agree on volumes, performance, and timelines. Mr. Cleary added that there are restrictions around what ERCOT can technically manage; that there is a balance between incenting right behavior in the market, and the need to understand where bottlenecks will form; and that there will never be enough budget to develop systems for every scenario.

Mr. B. Jones asked if there are impacts to how the market engages beyond technical considerations, such as participation restrictions. Mr. Cleary answered that ERCOT should be able to state what is believed to be reasonable and incent behavior, perhaps by a charge above a certain transaction level; and that the Nodal Advisory Task Force (NATF) will be approached to understand impacts. Eric Goff opined that it is reasonable and necessary that Entities do not overwhelm the system; that it would be helpful to know as soon as possible what the restrictions are; that fees might be added to the fee schedule approved by the ERCOT Board; and that Market Participants would appreciate the opportunity to hear of ERCOT's intent and provide input. Mr. Cleary agreed with Mr. Goff's assertions and added that ERCOT first needs to understand processes, high volume times, and technical restrictions.

Mr. R. Jones opined that much progress has been made in a short period of time and requested that once ERCOT has an understanding of feasible throughput, that a white paper be brought to the stakeholders for a cut at a pricing solution. Mr. R. Jones added that some Market Participants are already paying for bandwidth and expect a base level of functionality, and that the Market Participants should sort out which Entities will pay extra. Mr. Iacobucci stated that the discussion next month needs to begin with that base level expectation, the numbers and types of transactions. Mr. Cleary added that current levels must be supported, but discussion should be given to expectations for additional transactions in light of the complexity of the convergence in the Nodal market. Clayton Greer noted that the market is realizing that the Nodal systems are not an infinite resource, and suggested that discussions regarding rationing might be appropriately housed at WMS.

Market Participant Readiness
Vikki Gates provided a review of Market Participant Readiness efforts, noting that no Market Participants have chosen the same site visit agenda, and that providing questions approximately five days in advance of the visit improves the team's ability to prepare and provide thorough information; that the Readiness Center has been relaunched, and that Market Participants desire notice before the metrics are posted; and that while Market Participant feedback is requesting a one-to-one ratio for Market Participant and ERCOT metrics, metrics should be meaningful for both sides, but will expand beyond the currently listed two metrics for ERCOT.

<u>NATF Report (see Key Documents)</u>
Don Blackburn reviewed recent NATF activities, and encouraged Market Participants to participant in the Protocol Traceability conference calls.

Posting of Network Operations Model (NOM) to Qualified Scheduling Entities (QSEs) per Nodal Protocols
Mr. Blackburn reviewed NATF discussion of posting options; noted identified impacts of various options; and highlighted ERCOT's understanding of what would be posted should no further clarification or Protocol language be provided.

Mr. R. Jones stated that Calpine remains in favor of market transparency efforts, but stipulated that market transparency is very different from Market Participant transparency; that Calpine wants to share all necessary information with ERCOT and Transmission Service Providers (TSPs), but does not wish to share all information with the entire market; expressed concern for changed bidding behavior resulting in higher prices for Loads; and opined that the Independent Market Monitor (IMM) and the Public Utility Commission of Texas (PUCT) provide sufficient market oversight. Marguerite Wagner echoed Mr. R. Jones' concerns for the protection of proprietary information.

Market Participants discussed concerns for Private Use Networks (PUNs); linkages between the NOM and the State Estimator; and that TAC is making a policy cut and that subsequent Protocol revision language must be drafted and vetted by the stakeholders. Mr. Rickerson noted that impacts to systems could vary greatly depending on the categories and amount of data to be removed; but that once a list is determined, the Impact Analysis can be done quickly.

Ms. Wagner moved to endorse the NATF recommendation:

> **In consideration of the fact that there is not a separate resource registration system, move to endorse the approach below to TAC in response to ERCOT's Staff question regarding Network Operations Model posting and Resource Asset Registration Form (RARF)**

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confidentiality as presented to NATF. The recommendation includes posting the topology version of the NOM with some Resource data:

- **Wires, ratings, connectivity, no resource data listed in green in presentation "update on disclosure issues, including NMMS data discussion" 10/27/09**
- **Further consideration of items in black in presentation as per presentation above, with the addition of the PUN transmission system**
- **Includes Generator Switchyard**
- **Does not include PUN 168-hour Load data**

And direct to NATF to develop a Nodal Protocol Revision Request (NPRR) to clarify posting requirements, and to consider black data, per the policy decision of TAC.

Ms. Wagner noted that the NOMCR posting issue would be addressed secondarily and is not part of the motion. **Adrian Pieniazek seconded the motion. The motion carried unanimously.**

Posting of State Estimator Results per Nodal Protocols
Mr. Blackburn reported that NATF views the posting of State Estimator results as a policy issue and presents the item for TAC consideration. Mr. Pieniazek opined that the posting would violate posting requirements of the Public Utility Regulatory Act (PURA), §25.505, Resource Adequacy in the Electric Reliability Council of Texas Power Region, and that transmission flows and voltages should be redacted; Mr. Blackburn offered that ERCOT Legal did not see a conflict.

Mr. B. Jones opined that without the level of data, Market Participants cannot have confidence in the operation of the Nodal market; and that it is possible that Entities will receive signals that are indecipherable without certain data. Mr. Pieniazek countered that transparency is good to a point, as is independent auditing, but opined that the current requirement allows large Entities with extensive resources the ability to do what small Entities cannot. Kristy Ashley added that no other market posts this level of data and yet runs successfully. Mr. Seely opined that there is no inherent conflict in the Nodal Protocols, and that there are cases that put the Protocols on the same level as Substantive Rules.

Market Participants argued that there is an order of precedence between the PUCT Substantive Rules and the ERCOT Protocols; that the Federal Energy Regulatory Commission (FERC) would not allow this level of data to be released, and therefore it is not released in other markets; and that revision language should be drafted for the Nodal Protocols. Mr. R. Jones opined that Mr. B. Jones makes the case that ERCOT should publish data to the individual Entities to confirm that ERCOT is receiving the correct unit status and telemetry, and that the practice will give Market Participants assurance that they are communicating correctly. Mr. B. Jones countered that other Independent System Operators (ISOs) do not provide the data not out of confidentiality concerns, but that Entities do not want others checking their work; and that the information will require Entities to develop a business process to answer questions regarding high prices.

Mr. Bruce noted the issue's time sensitivity and that TAC may either direct NATF to take direction, or that an interested party may draft language for vetting in the stakeholder process. Mr. Pieniazek offered to draft NPRR language.

<u>WMS Report (see Key Documents)</u>
Barbara Clemenhagen provided a brief review of the October 21, 2009 WMS report, and notified TAC that the issue of generic costs have been again raised at the Verifiable Cost Working Group (VCWG) due to concerns that verifiable costs are becoming unwieldy and burdensome.

Additional 2010 Closely Related Element (CRE)
Shannon McClendon moved to approve the WMS recommendation for the addition of three CREs. Mr. R. Jones seconded the motion. The motion carried unanimously.

Nodal Verifiable Cost Affidavit Document
Mr. R. Jones moved to endorse the WMS recommendation regarding the Nodal Verifiable Cost Affidavit document. Mr. Fox seconded the motion. The motion carried unanimously.

Reliability and Operations Subcommittee (ROS) Report (see Key Documents)
Ken Donohoo presented revision requests for TAC consideration.

Operating Guide Revision Request (OGRR) 223, Real Time Production Potential
Ms. McClendon moved to remand OGRR223 to WMS. John Houston seconded the motion. The motion carried unanimously.

Nodal Operating Guide Revision Request (NOGRR) 026, Change the name of Emergency Electric Curtailment Plan (EECP) to Energy Emergency Alert (EEA) and Synchronization of EEA Steps with Protocols
Marty Downey moved to approve NOGRR026 as recommended by ROS in the 10/15/09 ROS Recommendation Report. Ms. Ashley seconded the motion. The motion carried unanimously.

Texas Admin Survey
Mr. Bruce introduced Phillip Diehl, CEO of Texas Admin. Mr. Diehl noted that Texas Admin currently webcasts ERCOT Board and ERCOT Board committee meetings which are funded directly by ERCOT; and requested that Market Participants complete a survey indicating their interest in subscribing to webcasts of TAC and TAC subcommittee meetings.

Market Participants expressed concerns regarding which body may authorize the webcasting of stakeholder meetings; that an interest survey by the vendor is not a suitable forum for discussion of the implications of webcasting and archiving meetings; and that current Procedures address voting by phone, but are not standard across all bodies. Market Participants discussed that webcast meetings would be archived; that the NATF was missing from the list of offered meetings; that the service would be offered on a subscription basis; and that the survey would be posted with the day's Key Documents.

Protocol Revisions Subcommittee (PRS) Report (see Key Documents)
Sandy Morris presented revision requests for TAC consideration.

PRR821, Update of Section 21, Process for Protocol Revision
Market Participants reviewed NextEra Energy comments to PRR821 and discussed that appellate rights are appropriately maintained at the ERCOT Board level; and that analogous revision language should also be applied to the NPRR and SCR processes.

Mark Dreyfus moved to recommend approval of PR821 as recommended by PRS in the 10/22/09 PRS Recommendation Report as amended by the NextEra Energy comments and as revised by TAC. Les Barrow seconded the motion. The motion carried unanimously.

PRR824, Primary Frequency Response from WGRs
Mr. R. Jones moved to recommend approval of PRR824 as recommended by PRS in the 10/22/09 PRS Recommendation Report and as revised by the 10/28/09 ERCOT comments. Clif Lange seconded the motion. Market Participants discussed the need to develop language in the Operating Guides to address testing requirements for Wind-powered Generation Resources (WGRs); and that the Performance, Disturbance, Compliance Working Group (PDCWG) currently receives and reviews reports to address units not meeting the five percent droop characteristic, and that ERCOT performs similar reviews, but that a testing methodology does not exist. John Dumas stated that he fully expects PDCWG to begin flagging WGRs not performing to the five percent droop characteristic upon passage of PRR824. **The motion carried unanimously.**

PRR827, Find Transaction and Find ESI ID Functions on the MIS
Mr. Houston moved to recommend approval of PRR827 as recommended by PRS in the 10/22/09 PRS Recommendation Report. Mr. Fox seconded the motion. The motion carried unanimously.

PRR830, Reactive Power Capability Requirement – URGENT
Mr. Bruce suggested that TAC survey comments filed to PRR830, noting that only four comments proposed language modifications, and that of the comments that would not modify PRR830 language, three are in support of PRR830, and one opposed PRR830. Walter Reid added that Wind Coalition comments were filed prior to the 10/22/09 PRS Recommendation Report.

Reviewing the 10/29/09 ERCOT comments, Kristi Hobbs noted proposed language revisions are administrative in nature, with the exception of a date change made to accommodate the one-month tabling of PRR830.

Reviewing the 11/02/09 Invenergy comments, Mark Soutter noted the addition of paragraph twelve (12) to Section 6.5.7.1, Installed Reactive Power Capability Requirement for Generation Resources Required to Provide VSS, for clarification that WGRs are treated as a unit behind the Point of Interconnection (POI), and to bring treatment of Reactive Power in line with other types of units. Mr. R. Jones stated that he agreed with the concept but not necessarily the language proposed by the Invenergy comments. Mr. Dumas opined that the current language of PRR830 should be maintained in order that the intended information is captured, and suggested that turbine availability be addressed with improved language so that turbines are not reported as in service when not spinning due to a lack of wind. Mr. Soutter countered that a turbine without fuel cannot be in service.

Reviewing the 11/04/09 Vestas comments, Juan Santos noted the addition of language in Section 6.5.7.1 regarding dynamic VAR capable devices to include hybrid solutions. Mr. Santos added that hybrid solutions are documented in other parts of the United States, and stated that utilizing a hybrid solution that includes a small temporary overload costs four times less than full dynamic response. Mr. Dumas noted that existing language allows Market Participants to bring ERCOT alternative proposals which could include static or dynamic solutions, adding that the type of hybrid solution proposed by Vestas should be presented to ERCOT through channels for evaluation to ensure that the solution meets the dynamic requirement. Mr. Santos welcomed the opportunity to bring numerical examples to ERCOT, but expressed concern that should the language not be added, benefits to ERCOT customers would be limited by the limiting of turbine choices.

Reviewing the 11/03/09 NextEra comments, Mr. Bruce noted that PRR835, Reactive Capability Requirement, would have permitted WGRs to provide the triangle for Reactive Power, unless a need for the rectangle was demonstrated, and then the rectangle would be required. Mr. Bruce stated that NextEra now recommends ERCOT's position on a prospective basis, and incorporates elements of the comments offered by Invenergy, LCRA and the Wind Coalition. Mr. Bruce noted that language in PRR830 that

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allows ERCOT to disconnect a WGR, and asked if ERCOT intends the language to allow for temporary or permanent disconnection. Mr. Dumas stated that ERCOT understands that it has authority to order any unit off line and maintain that order until the voltage issue ceases.

Mr. Bruce expressed concern that the redefinition of WGR as proposed in PRR830 would have repercussions throughout the ERCOT Protocols, particularly in instances where Resource or Generation or unit is used and not specified, and offered language that, he opined, addressed the necessary points without posing impacts to all ERCOT Protocols.

Mr. Bruce expressed greatest concern for the possibility of retrofits required with the approval of PRR830. Mr. Bruce stipulated that NextEra does not argue that the ERCOT Board cannot adopt a PRR that imposes costs on existing units, but that the stakeholders are not elected representatives and cannot make policy at the level reached by PRR830. Mr. Bruce stated that stakeholders approve ERCOT Protocols on a prospective basis; that in instances where Protocols have reached back, it has been based upon evidence of need; and that NextEra voted in favor of ramp rate limitations, despite costs to NextEra, because of the need. Mr. Bruce likened PRR830 to OGRR208, Voltage Ride-Through (VRT) Requirement, and opined that PRR830 would impose costs of tens of millions of dollars. Regarding OGRR208, Mr. Bruce added the ERCOT Board stated that upon demonstrated need, Entities will be forced to spend money on retrofits, and opined that similar issues are present in PRR830.

Mr. Bruce noted that thousands of MWs of wind are soon to be on the grid, and opined that Reactive Power requirement language needs to be clarified in the ERCOT Protocols; and that language offered by NextEra requires new entrants to the ERCOT market to provide the rectangle, provides clarified language for an immediately implementable standard, and carves out legacy issues for the PUCT to address. Mr. Bruce added that the PUCT dismissed the Administrative Law Judge's (ALJs) dismissal of PUCT Docket No. 36482, Appeal of Competitive Wind Generators Regarding the Electric Reliability Council of Texas' (ERCOT) Interpretation of the Reactive Power Protocols; that the next appeal period was underway; and that Entities will implement according to the PUCT decision.

Regarding modeling, Mr. Dumas noted that WGRs are allowed to aggregate turbines to form a unit; that aggregate modeling of turbines of different sizes and characteristics result in reactive curve inaccuracies when various turbines are, for example, down for maintenance; that aggregating and modeling only like turbines, which will have like Unit Reactive Limit (URL) capabilities, addresses turbine availability status and provides an accurate representation of each WGR's Reactive Power capability, and will not require WGRs to form different QSEs. Mr. Dumas added that it is common for plants to have different types of units. Mr. Bruce reiterated his concern that redefining WGR would have significant repercussions with a multitude of unintended consequences; and that NextEra proposed language leaves the WGR at the POI and addresses all of ERCOT's concerns.

Mr. Dumas stated that the purpose of PRR830 is not to change the standard; that the rectangle has been the Reactive Power requirement for many years and was in the Protocols at market open; and that the rectangle requirement has long been the basis of studies and grid operation. Mr. Bruce stated that it is immaterial what Entities think the standard has been; that an answer is likely forthcoming as to what the standard has been; and that any Entity that relies on their own interpretation of the standard does so at their own risk. Mr. Bruce opined that the Protocols cannot be clarified, but only amended.

Mr. Greer asked if Mr. Bruce would be ceding the gavel, adding that he was not complaining about Mr. Bruce's conduct, but only reminding Mr. Bruce that he should exercise caution in possessing the floor. Mr. Bruce agreed with Mr. Greer and stated his intention to have a full discussion of the issues with input from all parties. Ms. McClendon stated that she would be abstaining from the vote and would preside if requested, and complimented Mr. Bruce's attention to granting speakers the floor in order of request.

Mr. R. Jones opined that the 11/03/09 NextEra comments are a one-sided compromise, and addressed the 10/22/09 NextEra comments, stating that currently, any excessive Reactive Power capability above URL is always on call up to a unit's stability limit. Mr. R. Jones complained that WGRs repeatedly offer the same excuses for not meeting requirements, adding that the playing field should be level. Mr. R. Jones noted that ROS Chair Ken Donohoo provided a presentation at the October 15, 2009 ROS meeting demonstrating the need for Reactive Power and for every Resource to meet its own obligation, and that the ROS also witnessed a presentation from Siemens sponsored by NextEra as to why PRR830 is not needed.

Mr. R. Jones likened Reactive Power to the foundation of a house; stated that in other ISOs the service is compensated, but in ERCOT is viewed as a community service and was part of the agreement when the Standard Generation Interconnection Agreement (SGIA) was created; and recalled that when the reactive standards were in development, he once opined in a meeting that a unit's lead and lag could be different based on where the unit was and was quickly disabused of the notion by engineers at the meeting. Mr. R. Jones opined that the work of both ROS and PRS should be honored by TAC; and that PRR830 should be approved for the sake of reliability.

Diana Liebmann noted that reliability is cited as a need for PRR830, and asked if the grid is in an unreliable condition today with existing wind. Mr. Dumas answered that ECOT has a number of tools to monitor the grid; that contingency analyses are run; that at times conventional generation is brought on line to absorb MVARs; and at times Outages are denied. Mr. Dumas noted that due to a condition in the spring of 2009, a line had to be opened to maintain reliability, and that had WGRs been able to provide the rectangle requirement, the line likely would not have needed to be opened. Mr. Dumas concluded by saying that ERCOT is able to maintain reliability and does so.

Ms. Liebmann noted that in November of 2008, ERCOT sent "congratulatory letters" to Generators indicating that the RARF passed submittal and would be loaded; that thousands of MWs interconnected to the ERCOT grid submitted RARFs containing the triangle pictorial; and that the triangle pictorial mirrors what was in the application form. Ms. Liebmann asserted that pre-1999 conventional Generation units are not providing the rectangle even though they are able; that PRR830 is not about leveling the field, as it only addresses WGR and not all Generators, and that language offered by NextEra does level the field. Ms. Liebmann added that the study presented at the October 15, 2009 ROS meeting is the only existing study, and asserted that WGRs lower prices for Consumers; that requiring retrofits to WGRs will drive Consumer costs up as WGRs either come off line for retrofitting or an inability to comply due to what Ms. Liebmann characterized as a change in the rules.

Ms. Liebmann stated that ERCOT has allowed the interconnection of thousands of MWs of generation that provides the triangle; and that though ERCOT takes the position that it does not approve interconnects, ERCOT communicates with operators at Transmission Distribution Service Providers (TDSPs) regarding interconnections. Ms. Liebmann added that installed WGR assets, while providing the triangle, have been repeatedly told that they are in compliance.

Todd Kimbrough noted that the day's PUCT vote regarding PUCT Docket No. 36482 was procedural, and that the Commissioners noted that the issue would be before them again, and that to suggest that the PUCT has opined is incorrect. Mr. Kimbrough also noted that many, though not all, other ISOs assign Reactive Power costs via a separate market, which is not the design of the ERCOT market, and that FERC Order 661A requires of wind, at maximum, the triangle, which PRR830 exceeds; opined that altering the definition of WGR would have rippling effects through the Protocols and yield unintended consequences; and questioned why PRR830 was being rushed for approval without study. Mr. Kimbrough stated that PRR830 addresses only one type of technology and does not consider other technologies, such as storage; that NextEra offers compromise language and is willing to make further investment where there is a demonstrated need; and encouraged Market Participants to consider that PRR830 language in its current form is not in the best interest of the market.

Ms. Wagner expressed appreciation for ERCOT's vigilance for grid reliability, but expressed concern for impacts dues to line opening and bringing units on line; and opined that the letters of RARF acceptance only spoke to the successful completion of a step, and not to the nature of the attributes contained therein. Mr. Dumas added that ERCOT needs an accurate representation of a unit's physical capability; that acceptance of the RARF in no way exempts anyone from Protocol requirements; and that pre-1999 and pre-2004 units that carry exemptions are still required to communicate accurate capability data, but that receipt of that communication should not be construed to mean that obligations have been met.

Mr. Dumas noted that the planning process makes assumption of what units can provide; that reactive studies for Competitive Renewable Energy Zones (CREZ) are about to begin and that the system will be designed expecting a certain capability; and that as discussed during OGRR208 deliberations, FERC Order 661A did not apply to Texas.

Mr. Dreyfus expressed his desire for a resolution of the issues that assures the reliability of the transmission grid and does not impose unnecessary requirements on specific Generators. Mr. Dreyfus noted communications from his office regarding reliability concerns due to the expansion of wind and the need for consistent voltage control from all WGRs. Mr. Dreyfus stated his sensitivity to the argument that specific studies on each POI and technology are not available; opined that a wise decision was made in 2008 regarding Low Voltage Ride Through (LVRT), with deferred decisions on specific points; and offered to support PRR830 with the incorporation of Wind Coalition comments regarding WGR definition, as well as Invenergy and Vestas comments; and declined to support comments from NextEra. Mr. Dreyfus expressed hope that the resolution would bring the issue of retrofits before the PUCT.

Ms. Wagner noted that the grid has been designed assuming 0.95 at each POI, and expressed concern that studies resulting in different requirements for different areas will not promote a competitive market.

Mr. Houston moved to recommend approval of PRR830 as recommended by PRS in the 10/22/09 PRS recommendation report and as amended by the 10/29/09 ERCOT comments. Mr. R. Jones seconded the motion. Mr. Greer noted that every permutation of the grid cannot be captured in a study, and opined that any study may be assembled to demonstrate anything and would result in arguments over the validity of the study. Market Participants further discussed whether the WGR definition should be given additional consideration. Mr. Reid asserted that to approve PRR830 burdens future Generation with disagreements over existing Generation; Mr. Bruce opined that there remain unresolved issues, and that the 11/03/09 NextEra comments provide some progress without unintended consequences.

Mr. R. Jones stated that split metering is now commonplace, and that the software problems described by Mr. Reid are resolved with the Energy Management System (EMS). Mr. R. Jones expressed concern that the same vigor for prescribing future requirements is not evident in addressing existing issues, and that ERCOT will gain a reputation for protectionism.

Mr. Houston opined that PRR830 is needed for reliability and should be in place and understood by all Market Participants. Mr. Houston noted that earlier in the week, 23 percent of the minimum Load was being met by wind that possibly cannot provide Voltage Support Service (VSS) for an entire region, and expressed concern for voltage collapse. Mr. Houston asserted that though the ERCOT Board may take another position, the technical advisors assembled in the Technical Advisory Committee should not take any position that adversely affects reliability.

Mr. Whittle asked if the motion is for cost allocation rather than reliability, if the TDSPs will install fixes outside of PRR830, and if there are impacts to reliability based on WGRs or TDSPs providing the solution. Mr. Dumas stated that ERCOT will always take action to maintain reliability; that there is a cost issue if WGRs do not have to provide the rectangle; that capacitors will have to be installed and will go through a different cost structure; that the CREZ study will be based on the rectangle; that the answers will change if less Reactive Power is provided by Resources; and that should the rules be changed, the cost allocation will change.

Mr. Bruce questioned if a study would be run, in the event that the TDSPs rather than the Generators provide the solution. Mr. Dumas reminded Market Participants that the grid is always changing, and noted that the CREZ reactive study will be run for needs going forward and should not be confused with making installations based on a snapshot of the grid. Mr. Dumas added that the RARF contains data indicating what is possible and is used for operations, and that units may still not be meeting Protocol obligations, which is a compliance issue and is separate.

Mr. Houston stated that the current system design is based on a rectangle and asserted that if an increasing number of Generators are not providing the rectangle, costs are being run up and the grid is not being operated as planned, which is a reliability issue.

Ms. Wagner moved to call for the question. Mr. Dreyfus seconded the motion. Citing *Robert's Rules of Order,* Article V, Section 29, Ms. McClendon reminded Market Participants that a motion to call for the question must be approved by two-thirds of the body. **The motion to call for the question carried.**

The motion to recommend approval of PRR830 as recommended by PRS with ERCOT comments carried on roll call vote. *(Please see ballot posted with Key Documents.)*

PRR836, Revised Minimum Ramp Rate for Balancing Energy Service Down to Comport with PRR803 – URGENT
Mr. Pieniazek moved to recommend approval of PRR836 as recommended by PRS in the 10/22/09 PRS Recommendation Report. Mr. Downey seconded the motion. The motion carried unanimously.

NPRR196, Synchronization of Nodal Protocols with PRR827, Find Transaction and Find ESI ID Functions on the MIS
Market Participants discussed that NPRR196 is a synchronizing NPRR and might be tabled in order to allow it to be considered by the ERCOT Board at the same time as PRR827, Find Transaction and Find ESI ID Functions on the MIS.

Ms. McClendon moved to table NPRR196 for one month. Marcie Zlotnik seconded the motion. The motion carried unanimously.

PRR754, Resource Settlement Due To Forced Transmission Outage
PRR835, Reactive Capability Requirement – URGENT
Ms. Morris provided notice that PRR754 and PRR835 had been rejected by PRS.

Commercial Operations Subcommittee (COPS) Report (see Key Documents)
Michelle Trenary reported noted that the October 13, 2009 COPS report was posted with the day's Key Documents.

Load Profiling Guide Revision Request (LPGRR035), Addition of Time Of Use Schedules (TOUS) to Profiles with Interval Data Recorder (IDR) Meter Data Type Codes for Advanced Meters – URGENT
Mr. Fox moved to approve LPGRR035 as recommended by COPS in the 10/13/09 COPS Recommendation Report. Mr. Houston seconded the motion. The motion carried with one abstention from the Independent Generator Market Segment.

RTWG Report (see Key Documents)
Henry Durrwachter reviewed highlights of the October 6, 2009 RTWG meeting and the 3rd Quarter TRIP Report.

3rd Quarter TRIP Report
Mr. Pieniazek moved to approve the 3rd Quarter TRIP Report as submitted by RTWG for distribution to the ERCOT Board and the PUCT. Mr. Downey seconded the motion. The motion carried unanimously.

ERCOT Operations, Planning, and IT Reports
2010 Ancillary Service Methodology
Mr. Dumas noted that each year ERCOT is required to renew its Ancillary Service methodology; that the ERCOT Board approves the methodology, but ERCOT annually seeks stakeholder input on the proposed methodology. Mr. Bruce expressed appreciation for the time ERCOT Staff took in reviewing the proposed revision with stakeholder groups, and reminded TAC that it is not required to take action on the item.

Mr. B. Jones expressed concern that hours ending 2300, 2400 and 0100 are sufficiently procured. Mr. Dumas opined that issues in those hours are related to schedule transition rather than capacity deficiencies. IMM Staff recommended capping the total number of MWs rather than the forecast bias, and added that the Load adjustment would have to change accordingly. Mr. Dumas noted that ERCOT would be open to a 2000MW cap.

Market Participants expressed concern for how the cap might interrelate with other capacity products; and suggested that the over-forecast bias should be removed rather than shifted to Non-Spinning Reserve Service (NSRS). Mr. Dumas noted that the summer bias runs in the two- to three-percent range, and that overforecasting in the summer is generally due to pop-up rain showers. Chris Brewster complained that the methodology provides a backstop and floor, is excessive, and is paid for by Loads.

Ms. Wagner moved to recommend approval of the 2010 Ancillary Service methodology as modified by the IMM. Ms. Morris seconded the motion. Mr. Dumas noted that the methodology comes before Market Participants at least once each year, but may be reviewed more often as needed. Market Participants discussed that 2000MW is the cap of the total NSRS procured in a given hour; that the proposed methodology solves part but not all of the concerns; that it is assumed that if the obligation increases by 500MW, the market will bring resources to cover the increased obligation and ERCOT will not have to procure to cover the increase; and that with the proposed revision by the IMM, the cap is on the total rather than on the bias. **The motion carried with three objections from the Consumer Market Segment and four abstentions from the Cooperative (2) and Investor Owned Utility (IOU) (2) Market Segments.**

Ms. Wagner expressed concern that the Consumer Market Segment opposed her motion for endorsement of the methodology, and requested that an improved proposal be brought forward if possible. Mr.

Brewster opined that the addition of a floor does not correlate to forecast issues, and expressed concern for the accounting for historical over-forecasting in NSRS. Mark Smith added that a slower approach should be taken to ensure the methodology accomplishes its intent.

ERCOT Independent Review of AEPSC Corpus Christi Area Improvements Project
Jay Tex reviewed the AEPSC Corpus Christi Area Improvements project and noted that ERCOT would present the project to the ERCOT Board. Mr. Bruce reminded Market Participants that ERCOT presents such projects as a courtesy, and that TAC may endorse they project, but that a TAC endorsement is not required.

Mr. B. Jones moved to endorse the project as recommended by ERCOT. Mr. Downey seconded the motion. Ms. Clemenhagen expressed support for the project; Bill Smith expressed appreciation for the work of the Regional Planning Group (RPG), but expressed a desire for additional time to review the project, opining that further study should be given to reliability issues, and that a way might be found to make improvements while minimizing impacts to industrial customers. Mr. Fox also complimented the effort, but expressed concern that the solution falls short of a robust solution; and opined that maintenance will affect industrial customers; that TAC should raise the standard for projects; and that the project is suboptimal as it is only a five-year solution and will require additional upgrades later. Ms. Wagner countered that 100 percent access 100 percent of the time is contentious and is not applied in planning. **Citing Mr. Fox's concerns, Mr. B. Jones withdrew his motion.** Mr. B. Jones added that ERCOT could move forward without a TAC endorsement.

Tammy Cooper expressed concern that the opportunity to engage with RPG without having to submit a new plan remain open, and that nothing be foreclosed because it is under the threshold. Mr. Woodfin suggested that additional elements might be treated as incremental and subsequently reviewed at RPG, as long as elements were additional and not in replacement. Ms. Clemenhagen expressed frustration that this particular item had been on the table for 852 days and opined that the projects should move forward to the ERCOT Board so that work can begin. Mr. B. Smith stated that the intent is not to delay, but requested additional time to review and include enhancements.

Approval of 20 Most Voltage Critical Buses per Nodal State Estimator Standards
Mr. Houston expressed concern that critical buses are posted publicly and suggested that a revision to the process may be required for the sake of security. Market Participants noted that the item is a TAC-approved document, but echoed Mr. Houston's concerns.

Mr. Fox moved to the 20 voltage critical buses as presented by ERCOT. Mr. Houston seconded the motion. ERCOT Staff noted that State Estimator results outside of a certain telemetry tolerance or the accuracy requirement for that telemetry would be included on an informational report; and that at the direction of TAC, items may be removed from the State Estimator standards document. Mr. Bruce directed the NATF to review the approved State Estimator standards document and return to TAC with a recommendation for addressing Market Participant concerns; there were no objections to Mr. Bruce's direction. **The motion carried unanimously.**

Increase in Local Congestion / Out of Merit Energy Report
Dan Woodfin reviewed the increase in Local Congestion and Out of Merit Energy (OOME) volume between 2008 and 2009, attributing the increase in OOME instructions to an increase in installed wind capacity and Outages taken to maintain and improve the transmission system. Market Participants discussed ERCOT's announcement that the Waco line will be left closed for the 2010 Transmission Congestion Right (TCR) calculation; that there have been topology changes that lead ERCOT to believe that 2009 issue will not recur; and that the TCR does not take into account outages in the annual calculation.

Retail Market Subcommittee (RMS) Report (see Key Documents)
Kathy Scott noted that the October 14, 2009 RMS report was posted with the day's Key Documents, and reported that the Advanced Metering Service (AMS) implementation date has slipped to November 21, 2009, due to an outage caused by routine maintenance and requiring a complete restoration of the test environment.

TRE Report (see Key Documents)
Susan Vincent reported TRE Board approval of TRE separation from ERCOT, provided a TRE Bylaws update, and reviewed the proposed governance structure. Ms. Vincent reviewed the six TRE Membership Sectors and noted that TRE is in the process of seeking Board members; that the North American Electric Reliability Corporation (NERC) will accompany TRE to the FERC meeting where approval of the TRE Bylaws will be sought; and that the PUCT will take new action to determine which entity will provide ERCOT Protocol compliance monitoring. Market Participants discussed that consideration should be given to TAC making a recommendation to the ERCOT Board regarding ERCOT Protocol compliance monitoring. Mr. B. Jones offered to initiate the discussions, noting that care should be exercised to not overstep TAC authority.

Other Business (see Key Documents)
There was no other business.

Adjournment
Mr. Bruce adjourned the meeting at 5:20 p.m.

ERCOT Protocol Revision Subcommittee ("PRS") October 2009 meeting Minutes regarding PRR 830

October 22, 2009

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DRAFT
Protocol Revision Subcommittee (PRS) Meeting
ERCOT Austin – 7620 Metro Center Drive – Austin, Texas 78744
Tuesday, October 22, 2009, 2009 – 9:30am

<u>Attendance</u>

Members:

Bailey, Dan	Garland Power & Light
Carr, Pam	Stream Energy
Cochran, Seth	Sempra Energy Trading
Detelich, David	CPS Energy
Durrwachter, Henry	Luminant
Helpert, Billy	Brazos Electric Power Cooperative
Jones, Randy	Calpine
Madden, Steve	StarTex Power
Morris, Sandy	LCRA
Pieniazek, Adrian	NRG Texas
Torrent, Gary	OPUC
Walker, DeAnn	CenterPoint Energy
Wardle, Scott	Occidental Chemical Corp.

Guests:

Allen, Thresa	Iberdrola
Ashley, Kristy	Exelon
Bevill, Rob	GMEC
Brandt, Adrianne	Austin Energy
Bruce, Mark	NextEra
Burt, Matthew	RES Americas
Comstock, Read	Direct Energy
Davison, Brian	PUCT
DeLaRosa, Lewis	PUCT
Gresham, Kevin	E.ON Climate and Renewables
Grimes, Mike	Horizon Wind Energy
Harryman, Carla	BP Alternative Energy
Jones, Dan	Potomac Economics
Jones, Liz	Oncor
Lee, Jerry	EPE
Moast, Pat	Texas Regional Entity
Ögelman, Kenan	CPS Energy
Reid, Walter	Wind Coalition
Robinson, Lane	Bluarc/Babcock Brown
Soutter, Mark	Invenergy
Taylor, William	Calpine
Troutman, Jennifer	AEP Energy Partners
Wagner, Marguerite	PSEG TX
Ward, Jerry	Luminant
Wybierala, Pete	NextEra

ERCOT Staff:
Albracht, Brittney
Boren, Ann
Dumas, John
Gonzalez, Ino
Hobbs, Kristi
Lasher, Warren
Levine, Jonathan
McMahon, Patrick
Rajagopal, Raj
Seely, Chad
Seibert, Dave

Unless otherwise indicated, all Market Segments were present for a vote.

PRS Chair Sandy Morris called the meeting to order at 9:30 a.m.

Antitrust Admonition
Ms. Morris directed attention to the Antitrust Admonition, which was displayed. A copy of the Antitrust Guidelines was available for review.

Approval of Draft PRS Meeting Minutes (see Key Documents)[1]
September 17, 2009
Mark Bruce and Mike Grimes offered revisions to the draft September 17, 2009 PRS meeting minutes.

DeAnn Walker moved to approve the draft September 17, 2009 PRS meeting minutes as amended by Mr. Bruce and Mr. Grimes, and as revised by PRS. David Detelich seconded the motion. The motion carried unanimously.

September 22, 2009
Ms. Walker moved to approve the draft September 22, 2009 PRS meeting minutes as posted. Gary Torrent seconded the motion. The motion carried unanimously.

Urgency Votes (see Key Documents)
Protocol Revision Request (PRR) 834, ERCOT Load Forecast Accuracy – URGENT
PRR835, Reactive Capability Requirement – URGENT
PRR836, Revised Minimum Ramp Rate for Balancing Energy Service Down to Comport with PRR803 – URGENT
Ms. Morris reported that PRR834, PRR835, and PRR836 had been granted Urgent status via PRS email votes.

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[1] Key Documents referenced in these minutes may be accessed on the ERCOT website at: http://www.ercot.com/calendar/2009/10/20091022-PRS

Technical Advisory Committee (TAC) and ERCOT Board of Directors (ERCOT Board) Reports (see Key Documents)

Ms. Morris reported that TAC recommended approval of PRR822, Removing Access to Restricted Computer Systems, Control Systems and Facilities, after a long discussion, and noted that the ERCOT Board removed physical facilities language from PRR822 before approving it. Ms. Morris also reported that Trip Doggett will serve as interim ERCOT Chief Executive Officer (CEO).

Project Update and Summary of Project Priority List (PPL) Activity to Date (see Key Documents)

Parking Deck (Possible Vote)

Kristi Hobbs reviewed the nodal parking deck concept and noted that PRS would vote on recommended NPRR language as well as recommend priority and rank for NPRRs and System Change Requests (SCRs) that received a "Needed prior to the Texas Nodal Market Implementation Date" status from the CEO revision request review process. Ms. Hobbs noted that some revision requests are ready for parking deck consideration; encouraged Market Participants to review the parking deck within their organizations; and added that it would be the pleasure of the PRS as to when revision requests are addressed, though it is requested that large numbers of items not be delivered to the ERCOT Board at once. Mr. Bruce offered that subcommittees should not be concerned with overwhelming TAC with parking deck items, adding that TAC would take the opportunity to consider issues strategically and might take action to table items as necessary.

Other Binding Documents (see Key Documents)

Dave Seibert reported that the draft Nodal Protocol Revision Request (NPRR) for Other Binding Documents is currently under internal review, and encouraged Market Participants to contact him with any questions.

Review of Recommendation Report, Impact Analysis and Cost/Benefit Analysis (see Key Documents)

PRR821, Update of Section 21, Process for Protocol Revision

Ann Boren reviewed ERCOT comments to PRR821, noting clarifications to what actions might be taken before a PRR is deemed rejected.

Ms. Walker moved to endorse and forward the 09/17/09 PRS Recommendation Report as amended by the 09/29/09 ERCOT comments and the Impact Analysis to TAC. Adrian Pieniazek seconded the motion. The motion carried unanimously.

PRR824, Primary Frequency Response from WGRs

Market Participants discussed that PRR824-related Operating Guide Revision Requests (OGRRs) would soon be submitted; and proposed language revisions for clarifications and administrative items.

Mr. Durrwachter moved to endorse and forward the 09/17/09 PRS Recommendation Report as revised by PRS and the Impact Analysis to TAC. Randy Jones seconded the motion. The motion carried unanimously.

PRR827, Find Transaction and Find ESI ID Functions on the MIS

NPRR196, Synchronization of Nodal Protocols with PRR827, Find Transaction and Find ESI ID Functions on the MIS

Regarding PRR827, Ms. Hobbs recommended deleting "Public Area" from the language referencing "MIS Public Area" as the term "Public Area" applies to the Nodal Protocols. Ms. Hobbs also informed PRS that the black line language in the 09/17/09 PRS Recommendation Report was incorrectly updated and would be corrected with the 10/22/09 PRS Recommendation Report to properly reference the grey-boxed language for PRR805, Adding POLR Customer Class and AMS Meter Flag to the Database Query Function on the MIS.

Ms. Walker moved to endorse and forward the 09/17/09 PRS Recommendation Report as revised by PRS and the Impact Analysis for PRR827 to TAC; and to endorse and forward the 09/17/09 PRS Recommendation Report and the Impact Analysis for NPRR196 to TAC. Mr. R. Jones seconded the motion. The motion carried unanimously.

Review of PRR Language (see Key Documents)
PRR826, Clarification of Resource Definitions and Resource Registration of Self-Serve Generators for Reliability Purposes
NPRR190, Clarification of Resource Definitions and Resource Registration of Self-Serve Generators for Reliability Purposes
ERCOT Staff reported that internal work continues on some of the issues raised by Market Participants regarding PRR826, and requested that it be tabled for an additional month.

Scott Wardle moved to table PRR826 and NPRR190 for one month. Clayton Greer seconded the motion. The motion carried unanimously.

PRR830, Reactive Power Capability Requirement – URGENT
John Dumas noted that PRR830 was discussed at length at the October 15, 2009 Reliability and Operations Subcommittee (ROS) meeting; and stated that PRR830 does not represent a changed philosophy of what ERCOT believes the current Protocols require; that PRR830 provides a framework for existing Wind-powered Generation Resources (WGRs) to install devices to become compliant with the current Protocol requirements; and that PRR830 also provides a definition for modeling WGR turbines. Mr. Dumas added that aggregate modeling of turbines of different sizes and characteristics result in reactive curve inaccuracies when various turbines are, for example, down for maintenance. Mr. Dumas noted that modeling only like turbines, which will have like Unit Reactive Limit (URL) capabilities, addresses turbine availability status and provides an accurate representation of each WGR's Reactive Power capability. Mr. Dumas noted that PRR830 allows existing machines to meet requirements with static devices.

Mr. Bruce suggested that a revised WGR definition be limited to a specific use, and expressed concern that a broadly applied revised WGR definition would yield many unintended consequences to compliance reporting, settlement, and financial arrangements; and asked if there were methods to address modeling concerns via telemetry. Mr. Dumas answered that ERCOT believed the revised WGR definition would be appropriately applied throughout ERCOT Protocols; that telemetry addresses Mega Volt-Amperes reactive (MVAr) and MW output, rather than modeling; and that modeling affords the running of power flow studies to simulate line and unit loses. Mr. Dumas clarified that he is not privy to Qualified Scheduling Entity (QSE) processes, settlement contracts, and financial arrangements, but is answering from the prospective of Protocol requirements and modeling considerations.

Mr. Bruce asked how Voltage Profiles were determined, and if the process is described in the Operating Guides or other documents. Mr. Dumas answered that the Voltage Profile is defined in the ERCOT Protocols; that ERCOT works with Transmission Service Providers (TSPs) and Market Participant groups within ROS twice each year to run studies to establish a default voltage schedule; that Entities that do not know their voltage schedule should contact ERCOT, but it is known that the number will be between 0.95 and 1.05, based on system conditions; and that units need the capability to supply a 100 MW machine plus or minus 33 MVAR at the Point of Interconnection. Mr. Dumas opined that PRR835 represents a change in philosophy in positioning the MVAR requirement as a sliding number along output levels.

Mr. Bruce noted that PRR835 was filed by NextEra; that there was some discussion at the October 15, 2009 ROS meeting as to whether PRR835 should be withdrawn and filed as comments to PRR830; that NextEra believes PRR835 is the better solution and will not withdraw PRR835; and that NextEra will work to achieve some middle ground between the two PRRs. Mr. Bruce expressed hope that PRS would be reluctant to recommend approval of PRR830, and opined that ERCOT makes recommendations in PRR830 that do not take into consideration extended market effects.

Mr. R. Jones countered that ROS held a robust discussion of PRR830 and voted overwhelmingly to endorse PRR830; that there are commercial issues involved with PRR830, in addition to reliability concerns; and that fundamentally, voltage support is a community service. Mr. R. Jones recalled that when the Standard Generation Interconnection Agreement (SGIA) was developed, compromises were struck to require Load to pay for Transmission costs according to Load Ratio Share (LRS) in exchange for Generators supplying voltage support for the system without compensation. Mr. R. Jones added that Generators are only compensated for Reactive Power when they are asked to back down real power and are paid an opportunity cost; and that when Generators do not provide their portion of the voltage support obligation, risks and costs are transferred to Load via Out Of Merit (OOM) actions and Transmission Cost of Service (TCOS). Mr. R. Jones opined that PRR830 is appropriate and timely, and that without PRR830, the ERCOT System will become a dumping ground for outdated machines.

Mr. R. Jones moved to recommend approval of PRR830 as endorsed by ROS. Mr. Greer seconded the motion. Mr. Reid opined that a full discussion of PRR830 language and concepts had not been held; that clear guidance for new WGRs is needed to ensure voltage support; that PRR835 is more appropriate; and that PRR830 will require WGRs to spend funds to supply a rectangle that will not be used. Mr. Reid added that approval of PRR830 would eliminate language that, he opined, describes the triangle; and would subvert the process underway at the PUCT regarding PUCT Docket No. 36482, Appeal of Competitive Wind Generators Regarding the Electric Reliability Council of Texas' (ERCOT) Interpretation of the Reactive Power Protocols. Mr. Seely clarified the current procedural posture, stating that there was an order to dismiss Docket No. 36842; that WGRs have filed an appeal of the dismissal; and that there is a timeline for ERCOT to respond to the motion to appeal. Mr. Seely added that the proposed language in PRR830 may require retrofits for existing WGRs but is not retroactive.

Mr. Dumas noted that the obligation to provide the rectangle is defined in Protocol Section 6.5.7.1, Generation Resources Required to Provide VSS Installed Reactive Capability. Mr. Reid argued that language proposed to be struck by PRR830 makes interpretation of a legal document. Market Participants discussed that ERCOT Protocols are continually revised and clarified. Mr. Grimes opined that WGRs came to Texas due to favorable grid access rules; and that PRR830 changes requirements and could have a chilling effect on other WGRs entering the ERCOT market. Mr. Grimes noted that Horizon Wind Energy discovered that they had been operating in contravention to ERCOT Protocols; sought clarification of requirements to ensure compliance; and installed additional reactive capability per the TDSP. Mr. Grimes also noted that per the 10/22/09 Vestas comments, Vestas owns units that provide Reactive Power via static and dynamic devices. Some Market Participants opined that ERCOT may set the Voltage Profile, but should not mandate how the profile is achieved; and that Entities should be allowed to demonstrate the viability of hybrid solutions for providing Reactive Power.

Mr. Greer cited Protocol Section 6.5.7.1 (2) as requiring 0.95 installed through the entire capability of a unit, regardless of restrictions on deployment. Mr. Detelich stated that he would be amenable to a proven hybrid solution for providing reactive capability, and would be opposed to requiring existing WGRs to separate and resubmit Resource Asset Registration Forms (RARFs). Ms. Wagner expressed concern that different requirements at each Point of Interconnection makes planning difficult, adversely impacts Consumer costs, and has fairness and grid stability implications.

Mr. Bruce stated that PRR835 sets a minimum standard but allows for the imposition of additional standards, and that each unit that is connected to the grid has undergone three studies; and opined that PRR830 is short-sighted for not addressing other technologies such as solar and storage, and is bad policy. Mr. Bruce drew similarities between PRR830 discussions and the disposition of OGRR208, Voltage Ride-Through (VRT) Requirement; argued that a lack of data erodes the reason for the process; and questioned why another 30-60 days could not be taken to further debate the issues. Mr. Bruce expressed concern that another appeal before the PUCT would spotlight deficiencies in the stakeholder process and would cost time, effort and money for all parties. Mr. Bruce suggested that PRS generate a list of questions for consideration by ROS.

Mr. R. Jones opined that PRR835 tacitly admits that the rectangle is the requirement, as the rectangle will be required upon assessment; and complained that the ROS discussion of PRR830 was mischaracterized as incomplete. Mr. R. Jones expressed concern that an assessment methodology would result in dueling studies by various consultancies and additional delays; and that eventual installation of additional Reactive Power capability would fall to TDSPs as a result. Mr. R. Jones noted that ERCOT's and other Entities' lack of study horsepower has been cited in numerous forums; and recalled discussions held at the development of interim requirements where it was made clear that the obligation for Reactive Power was not proportional to output, that the shape was rectangular and not conical.

Mr. Reid complained that the issues underlying PRR830 had not been remanded to a working group or task force; and that while modeling issues must be addressed, altering the definition of WGR has far-reaching impacts, including impact to the use of the word "units". Liz Jones reminded Market Participants that the discussion of PRR830 at the October 15, 2009 ROS meeting consumed at least three hours, and opined that the characterization of the ROS discussion of PRR830 was disrespectful of the members of ROS who brought their experience and perspective to the meeting and held the discussion they felt was necessary. Ms. L. Jones requested recognition of the difference between dynamic and static capacity on the system, and that they are not perfectly substitutable, depending on system conditions.

Ms. L. Jones rejected the notion that ERCOT and Market Participants are doomed to repeat history as it pertains to an appeal, noting that PRR830 discussions and votes do not have an 11th hour element; that Order 15 is on appeal and that parties believing that ERCOT should be precluded from taking action should make that case to the PUCT; that it has not been ERCOT's habit to not take action; and that ERCOT has usually been directed to act affirmatively. Ms. L. Jones concluded that PRS should take the action it deems appropriate.

Mr. Grimes registered his objection to the characterization that WGRs are trying to push costs to other parties; and added that Entities will provide additional equipment that is demonstrated to be necessary, but does not wish to undertake costs based on presumed needs.

Mr. Greer stated that good voltage response is needed where Load is heavy, but internal Generation is lacking, and where there is an excess of Generation and low Load. Mr. Greer noted that a 400 mile capacitor is about to be installed in West Texas, and that grid conditions will vary tremendously with lines continuously in and out of service; and opined that any study may be generated to demonstrate any need. Mr. Greer concluded that as grid conditions are dynamic, reactive response should be solid at all times.

Mr. Dumas agreed with Ms. L. Jones that OGRR208 and PRR830 are completely different, noting that when OGRR208 was contested, Federal Energy Regulatory Commission (FERC) Order 661A was not being applied in Texas, and as it was considered a new requirement, some consideration was given to studies. Mr. Dumas added that PRR830 does not represent a new requirement, and should not be delayed due to Competitive Renewable Energy Zone (CREZ) build-out and coming WGR installation; that ROS has provided input as requested; that standards equalize the playing field and planning process; and that PRR830 should move forward at this time.

Ms. Wagner opined that while other regions have a different construct for connecting Generation, the ERCOT interconnection system is successful due to consistent standards; and added that NextEra was granted time to present PRR835 considerations at the October 15, 2009 ROS meeting, and that votes were not swayed.

Warren Lasher noted that on a recent call, the New England Independent System Operator manager of renewables integration stated their proposed Reactive Power requirement for the rectangle, rather than the cone; that there is increased interest for WGRs in South Texas where Private Use Networks (PUNs) and Load issues will be at play; that a reactive study for CREZ lines will commence that very week; and that assumptions will have to be made as to whether units will provide the cone or the rectangle. Mr. Lasher stated his conviction that to assume that the requirement is cone shaped would yield a different answer.

Dan Jones asked what underlying assumption – whether the cone or rectangle requirement – supported the multimillion dollar decision in the CREZ proceeding. Mr. Lasher stated that all analysis was executed using the rectangle assumption. Mr. Wybierala stated that PRR835 was proposed to provide flexibility going into CREZ. Mr. Lasher allowed that per-unit requirements based on studies seems appropriate, but leads to equity issues at minimum, and that permutations grow so quickly that the methodology does not make sense and is impractical and extremely difficult to implement.

Mr. Bruce stated that the ROS comments did not alter the language of PRR830, and that the motion should be stated "as submitted by ERCOT"; Mr. R. Jones countered that "as endorsed" was not an illegal motion element and would remain in the motion. Kevin Gresham clarified that E.ON does not agree that the rectangle, as opposed to the cone, is the requirement, but would abstain from the vote.

The motion carried on roll call vote with seven objections from the Independent Generator Market Segment, and five abstentions from the Independent Generator (2), Independent Power Marketer (IPM) (2), and Investor Owned Utility (IOU) Market Segments. *(Please see ballot posted with Key Documents)*

Ms. Morris requested that interested parties file comments to PRR830 prior to the November 5, 2009 TAC meeting.

PRR832, Deletion of Schedule Control Error (SCR) Posting Requirement
Mr. Dumas reported that in reviewing the ERCOT Protocols, it was discovered that the report referred to in PRR832 was never implemented and does not exist. Mr. Dumas expressed concern that to create the report would remove resources from Nodal efforts, and recommended deleting the requirement. Pat Moast stated that while the TRE does not agree with the possible implication that what is proposed for removal has a substitute that the TRE produces, the TRE does not oppose the ERCOT proposal.

Mr. Bailey moved to recommend approval of PRR832 as submitted. Mr. Detelich seconded the motion. Mr. Moast stated that the TRE had no language modification to propose. **The motion carried with one abstention from the Independent Generator Market Segment.**

PRR833, Primary Frequency Response Requirement from Existing WGRs
Mr. Dumas clarified that ERCOT will interpret "technically infeasible" as relating to whether turbines are able to pitch their blades or physically respond to control signals; and that clarification is needed regarding "on" or "prior to" January 1. Mr. Reid opined that such interpretation would have significant investment impacts, as many turbines are not part of a central control system. Mr. Dumas added that PRR833 only requires ERCOT consideration as to whether WGRs can technically be equipped with Primary Frequency Response, not consideration of dollar figures.

Mr. Reid opined that PRR833 would remove all Type 1 and Type 2 turbines from operation with no supporting study and that PRR833 is retroactive in nature. Mr. Gresham thanked Mr. Dumas for clarifying ERCOT's likely interpretation; stated that organizations would need to further consult with their engineering and construction resources; and opined that without a study, required retrofits would be for only possible enhancements to reliability. Mr. R. Jones disagreed that enhancements to reliability would only be potential; and opined that any additional governor response that is tuned properly affords better reliability, and that the obligation has always been in place for all units.

Mr. R. Jones moved to recommend approval of PRR833 as revised by PRS. Mr. Greer seconded the motion. Mr. Bruce argued that Protocol Section 5.9.1.1, Governor in Service, does not address what is to be done with a Resource that does not have or cannot have a governor; and expressed dismay that a TSP would interconnect a Generator, that ERCOT would accept a RARF, and that units would be in operation for eight years before learning of compliance issues. Mr. Bruce noted that nuclear units operate differently than other units, but that pains are not taken to minutely define the differences, and opined that another section is needed in the ERCOT Protocols to address Generation units without governors. Mr. Bruce suggested that issues associated with PRR833 be approached in the same manner as ramp rates, and that PRR833 be tabled so that further work may be done.

Mr. R. Jones opined that language that is solely prospective creates different classes of WGRs. Mr. Grimes offered that the speed with which a unit is able to feather blades might also be a feasibility consideration, and questioned how capability might be demonstrated; Mr. R. Jones noted that officer attestations are accepted in other areas of ERCOT and might be applicable in this instance. Mr. Dumas reminded Market Participants that the language references only "technically infeasible"; that costs are not listed as a consideration, that ERCOT is not suggesting that costs should be a consideration and is not taking a position on costs; and that he raises ERCOT's likely interpretation in an effort to avoid ambiguity and any eventual argument that the capability is "technically infeasible" because of cost.

Mr. R. Jones opined that PRR833 should move forward; noted that additional language regarding technical infeasibility has not been provided during the comment period to date; and stipulated that improvements in system performance are due to thermal Generators providing governor response. Mr. R. Jones acknowledged that portions of PRR833 language remain challenging; recommended interested parties offer comments with improved language for consideration at the November 5, 2009 TAC meeting; and offered that should suitable revisions not be achieved at TAC, he would move to remand PRR833.

Mr. Gresham offered appreciation for ERCOT's efforts to avoid ambiguity, but clarified that new information was provided at the day's PRS meeting. Mr. Bruce expressed concern that new language would be sent to TAC without prior vetting by task forces, working groups and subcommittees, and opined that the appropriate action would be to reject the motion on the floor and then approve a subsequent motion to table PRR833. Mr. R. Jones countered that the base language for PRR833 came out of the Operations Working Group (OWG). **The motion carried on roll call vote with four abstentions from the Independent Generator, IOU, and IPM (2) Market Segments.** *(Please see ballot posted with Key Documents.)*

PRR834, ERCOT Load Forecast Accuracy – URGENT
Mr. Durrwachter noted that the newly revised ERCOT Ancillary Service procurement methodology is proceeding through the stakeholder process and might address some of the issues related to PRR834.

Mr. Durrwachter moved to table PRR834 for one month. Mr. R. Jones seconded the motion. The motion carried with one abstention from the Independent Generator Market Segment.

PRR835, Reactive Capability Requirement – URGENT
Mr. Greer moved to reject PRR835. Mr. R. Jones seconded the motion. The motion carried on roll call vote with six objections from the Independent Generator (5) and IPM Market Segments, and five abstentions from the Independent Generator (2), IPM (2) and IOU Market Segments. *(Please see ballot posted with Key Documents.)*

PRR836, Revised Minimum Ramp Rate for Balancing Energy Service Down to Comport with PRR803 – URGENT
Mr. Durrwachter moved to recommend approval of PRR836 as submitted. Mr. Bailey seconded the motion. The motion carried unanimously.

Review of NPRR Language (see Key Documents)
NPRR194, Synchronization of Zonal Unannounced Generation Capacity Testing Process
Mr. Durrwachter moved to table NPRR194 for one month. Mr. R. Jones seconded the motion. Market Participants discussed how the benefits of driving uncertainty from the system, achieved via PRR750, Unannounced Generation Capacity Testing, might be retained in the Nodal market; that ERCOT needs to ascertain that the numbers provided in Real Time Reserve monitoring are achievable in an emergency without risking damage to units that might have just been backed down for Responsive Reserve Service (RRS); whether telemetered High Sustainable Limit (HSL) might be used rather than Current Operating Plan (COP) HSL; and whether ERCOT might consider running the test when a unit is already at 80 percent of Load. **The motion carried unanimously.**

NPRRs with CEO Determination of "Not Needed for Go-Live" (Possible Vote)
NPRR131, Ancillary Service Trades with ERCOT
NPRR153, Generation Resource Fixed Quantity Block
NPRR156, Transparency for PSS and Full Interconnection Studies
NPRR164, Resubmitting Ancillary Service Offers in SASM
NPRR169, Clarify the Calculation and Posting of LMPs for the Load Zone and LMPs for each Hub
NPRR181, FIP Definition Revision
Market Participants discussed methods for advancing parking deck items, and determined to sort items into vetted and approved categories for the November 19, 2009 PRS meeting, with remaining items to be taken up at the December 17, 2009 PRS meeting.

Notice of Withdrawal
There were no notices of withdrawal.

Other Business

PRR754, Resource Settlement Due To Forced Transmission Outage (Possible Vote)

Ms. Morris noted that PRS refrained from voting to reject PRR754 at the September 17, 2009 PRS meeting, as Mr. Bruce had submitted PRR754 and was absent at the time PRR754 would have been considered for rejection. Mr. Bruce expressed his appreciation for the delay, stated that discussions had been held with affected parties in the intervening month, and that PRR754 may be disposed of at the will of PRS.

Mr. Helpert moved to reject PRR754. Mr. Detelich seconded the motion. The motion carried with on objection from the Independent Generator Market Segment, and four abstentions from the Independent Generator, IOU (2), and IPM Market Segments.

Nodal Protocol/Reliability Standards Alignment (NPRSA) Task Force Discussion

Ms. Walker noted that the NPRSA TF was formed the previous year to address misalignments between terminology in the Nodal Protocols and the North American Electric Reliability Corporation (NERC) Standards; that while ERCOT had not asked her to halt efforts, concerns for system impacts were expressed, and items were regularly routed to the now-disbanded Transition Plan Task Force (TPTF); that ERCOT had filed PRRs and NPRRs to address some terminology issues that would affect ERCOT specifically, but that efforts to address terminology affecting all Market Participants had not advanced; and that she had received recent assurances from ERCOT to assist in a renewed effort to address needed terminology revisions in a comprehensive rather than piecemeal effort.

Market Participants expressed concern for any effort that might be interpreted as potentially detrimental to the Nodal schedule; the potential for fines and compliance issues due to confused terminology; and the difficulty of reviewing a potentially 25-Section NPRR. Mr. R. Jones recommended that consideration should be given to developing a comprehensive review schedule of when each Section would be edited, as well as a master translation table. Ms. Morris reinstated the NPRSA TF and directed that an approach for moving forward be discussed at the November 19, 2009 PRS meeting.

PRR837, Load Used in RMR Studies

Ms. Wagner stated that PRR837 provides guidance for ERCOT regarding the forecast to use for Load forecasts and Reliability Must Run studies. Market Participants discussed potential Congestion implications; and that the peak determined by the Steady State Working Group (SSWG) is not necessarily coincident with the ERCOT peak.

2010 ERCOT Membership/Market Segment Elections

Brittney Albracht reminded Market Participants that the ERCOT Membership date-of-record is Friday, November 13, 2009; that Market Segment Representative elections for the ERCOT Board and all committees and subcommittees will begin on Monday, November 16, 2009; and that a potential ERCOT Bylaws revision will prevent ERCOT Board members from serving and voting on TAC or any TAC subcommittee.

Adjournment

Ms. Morris adjourned the meeting at 3:00 p.m.

ERCOT Reliability and Operations Subcommittee ("ROS") October 2009 meeting minutes regarding PRR 830

October 15, 2009

DRAFT
Reliability and Operations Subcommittee (ROS) Meeting
ERCOT Austin – 7620 Metro Center Drive – Austin, Texas 78744
Thursday, October 15, 2009– 9:30 a.m. – 3:30 p.m.

Attendance

Members:

Allen, Thresa	Iberdrola Renewables	
Armke, James	Austin Energy	
DeTullio, David	Air Liquide	
Donohoo, Ken	Oncor	
Garrett, Mark	Direct Energy	
Green, Bob	Garland Power and Light	
Gutierrez, Fernando	BP Energy	
Helyer, Scott	Tenaska Power Services	Via Teleconference
Holloway, Harry	SUEZ	
Jones, Randy	Calpine	
Keetch, Rick	Reliant Energy	
Kunkel, Dennis	AEP	
Marsh, Tony	Texas Power	
McDaniel, Rex	Texas-New Mexico Power	
Moore, John	South Texas Electric Cooperative	
Rocha, Paul	CenterPoint Energy	
Ryno, Randy	Brazos Electric Power Cooperative	
Soutter, Mark	Invenergy	Alt. Rep. for J. Franklin
Vanderlaan, Dirk	Exelon Generation	Alt. Rep. for W. Kuhn
Wagner, Marguerite	PSEG Texas	
Williams, Blake	CPS Energy	
Willms, Jerry	LCRA	Alt. Rep. for B. Hatfield

Guests:

Alvarel, Eli	BPUB
Ashley, Kristy	Exelon
Brandt, Adrianne	AE
Bruce, Mark	NextEra Energy Resources
Burkhalter, Bob	ABB
Carroll, Marianne	Brown McCarroll
Cochran, Seth	Sempra
Cook, Tim	CTT
Davison, Brian	PUCT
DeLaRosa, Lewis	PUCT
Gibbens, David	CPS Energy
Goff, Eric	Reliant
Grammer, Kent	Texas Regional Entity
Grasso, Tony	PUCT
Gresham, Kevin	E.ON Climate and Renewables
Grimes, Mike	Horizon Wind Energy
Hutson, Michael	RES Americas
Jackson, Pat	Cities

John, Ebby	CenterPoint Energy	Via Teleconference
Jones, Dan	Potomac Economics	
Jones, Liz	Oncor	
Kimbrough, Todd	NextEra Energy Resources	
Kolodziej, Eddie	Customized Energy Solutions	
Kremling, Barry	GVEC	
Lima, Leonardo	Siemens PTI	
Ögelman, Kenan	CPS Energy	
Owens, Frank	TMPA	
Palmisano, Augie	CSU	
Reid, Walter	Wind Coalition	Via Teleconference
Roberts, Terry	Duke	
Robinson, Lane	Bluarc	
Schwarz, Brad	E.ON	
Shields, Tom	Iberdrola Renewables	
Shumate, Walt	Shumate and Associates	
Stephenson, Randa	Luminant	
Thormahlen, Jack	LCRA QSE	
Ward, Jerry	Luminant	
Whittington, Pam	PUCT	
Wittmeyer, Bob	Longhorn Power	
Wybierala, Pete	NextEra	

ERCOT-ISO Staff:
Albracht, Brittney
Dumas, John
Kota, Naga
Landin, Yvette
Maggio, David
Rickerson, Woody
Teixeira, Jay

Unless otherwise indicated, all Market Segments were present for a vote.

ROS Chair Ken Donohoo called the ROS meeting to order at 9:30 a.m.

Antitrust Admonition
Mr. Donohoo directed attention to the displayed ERCOT Antitrust Admonition and noted the requirement to comply with the ERCOT Antitrust Guidelines. A copy of the guidelines was available for review.

Agenda Review
There were no changes to the agenda.

Approval of Draft ROS Meeting Minutes (see Key Documents)[1]

Randy Ryno moved to approve the September 10, 2009 ROS meeting minutes as posted. Randy Jones seconded the motion. The motion carried unanimously.

Technical Advisory Committee (TAC) Update (see Key Documents)

Mr. Donohoo reported extensive discussion of Protocol Revision Request (PRR) 822, Removing Access to Restricted Computer Systems, Control Systems and Facilities, at the October 1, 2009 TAC meeting; and that TAC had proposed language revisions and sent it for consideration at the October 20, 2009 ERCOT Board meeting.

2010 ERCOT Membership Record Date/Segment Elections

Brittney Albracht reported that the ERCOT Membership date-of-record is November 13, 2009; that Market Segment representative elections would begin on November 16, 2009; and that potential Bylaw revisions would prevent ERCOT Board members and Board alternates from voting on TAC and TAC subcommittees.

Renewable Technologies Working Group (Questions Only)

Mark Garrett noted that the RTWG report was posted with the day's Key Documents. There were no questions.

Nodal Single Entry Model (SEM) Implementation (see Key Documents)

Woody Rickerson provided a SEM implementation update and noted that owner/operator issues will not need to be revisited once corrected, unless a breaker is moved or added, or ownership changes. Mr. Rickerson reviewed Transmission Service Provider (TSP) model change activity and Network Data Support Working Group (NDSWG) coordination efforts. Market Participants discussed that modeling responsibilities in the nodal market are shifted to TSPs, with ERCOT providing validation, and that TSPs are encountering modeling details that are, in many instances, new to them.

NDSWG Update

Ebby John reviewed Network Model Management System (NMMS) issues. Market Participants discussed that TSPs cannot knowingly falsify a record and cannot state owner/operator for convenience; and that "modeling authority" might be a suitable term. Mr. Donohoo opined that modeling is a unique skill, and directed NDSWG to bring a timely recommendation for ERCOT consideration.

ERCOT Reactive Capability Testing Requirements (see Key Documents)

Mr. Donohoo reminded Market Participants that ROS' chief focus is grid reliability; that there are planning and operating considerations; that review is given to normal, contingency, and secondary contingency conditions; and that there are a number of variables beyond anyone's control. Mr. Donohoo opined that the greatest problem with voltage is dynamic Meg Volt-Amperes reactive (MVArs), and reviewed temporary solutions; and noted that Oncor has taken much more interest recently in MVArs for all units. Mr. Donohoo expressed concern that procedure to ensure the planning and operating models are correct is incomplete.

Market Participants discussed that enforcement is a missing key component; that audits provide a failsafe for the system, and that the Texas Regional Entity (TRE) might need additional resources to ensure that

[1] Key Documents referenced in these minutes may be accessed on the ERCOT website at: http://www.ercot.com/calendar/2009/10/20091015-ROS

testing is being done. Mr. Donohoo confirmed that transmission is built with the understanding that Generators are compliant with Protocols and with what is in the models; and expressed concern for how data in the data bases are confirmed to the operations and planning models. John Dumas noted that for operations, the test results are reviewed against the stated curve for 90% comportment and that a test is then designed to validate the data.

Market Participants discussed that the Steady State Working Group (SSWG) is responsible for updating the planning cases; Mr. Donohoo opined that a procedure is needed to ensure that planning and operations models match the data provided in the Resource Asset Registration Form (RARF). Market Participants discussed non-coordinated and coordinated testing; that the Public Utility Commission of Texas (PUCT) should provide direction if Wind-powered Generation Resources (WGRs) are to be treated differently than other forms of Generation; and that the PUCT supports the stakeholder process and ROS is responsible to provide technical advice as it pertains to reliable operation of the grid.

Market Participants further discussed that the Standard Generations Interconnect Agreement represents a compromise; that in exchange for providing Reactive Power capability, Generators are connected to the grid without charge; that there are times in the summer months when systems are both stressed and expected to be tested, and that the 90% criteria is a recognition of system conditions; in recognition of system conditions, 90% capability is accepted; and that due to changes in the grid, many voltage events are now off-peak.

ROS Voting Items (see Key Documents)

PRR830, Reactive Power Capability Requirement

Mr. Dumas stated that PRR830 does not represent a change in philosophy, and that at issue is not the capabilities of various technologies but what is required for planning and reliable operation of the ERCOT grid; that the revised definition of WGR is for modeling purposes and alleviates concerns for impacts to the curve when one or more turbines are down for maintenance; and that the 0.95 lead/lag requirement is still met at the Point of Interconnect (POI). Mr. Dumas added that a change in philosophy from a base set of standards will have impacts to the planning process and will open the door for continuous challenges any time Generation is connected to the system. Mr. R. Jones opined that a homogenous set of rules is needed for the reliable operation of the grid.

Mr. R. Jones moved to endorse PRR830 as submitted. Bob Green seconded the motion.

Mr. R. Jones recalled that during deliberations for the development of the ERCOT Protocols, he was disabused of the notion of a proportional degradation in obligation. Mr. R. Jones also recalled that Unit Reactive Limit (URL) was not referred to in the plural, but rather in the singular for a unit; that intent was to measure maximum output at 0.95 power factor; and that PRR830 maintains fidelity to the intent of the Protocols. Mr. R. Jones invited Market Participants to confirm his assertions with others that participated in the deliberations. Market Participants discussed the potential for catastrophic system failure due to the loss of dynamic capability and extreme frequency swings with minimal reaction time.

Mark Soutter asked what a unit is expected to do when the High Sustainable Limit (HSL) changes, and if the 0.95 ration would remain the same. Mr. Dumas stated that though output changes, the capability remains the same, and the requirement would be 33 MVArs 0.95 at the POI. Mr. Soutter asked if units below their Low Sustainable Limit (LSL) are not expected to produce Reactive Power. Mr. Dumas noted that a WGR can be online with the breaker closed, and that a compromise was inserted to recognize that LSL can be zero, but that at cut-in must provide 30 MVAr, as WGRs can sit at zero and be stable, while other units cannot.

Todd Kimbrough asked Mr. Dumas how the Protocols and the RARF are reconciled. Mr. Dumas reiterated that he believes the Protocols require the rectangle obligation and that pictures in the RARF are for example and do not reflect the requirement; that the RARF is to reflect accurate capability so that power flows may be run; and that whether a unit's capability is compliant is a separate matter. Harry Holloway added that ERCOT requires an updated Corrected Unit Reactive Limit (CURL), and that during times that his units have not been able to produce a 0.95, the CURL has been submitted and not rejected by ERCOT. Marguerite Wagner opined that PRR830 maintains a consistent standard; that the technical issues are complex but the solution is straightforward; and that the question to be solved is which party pays for the upgrades for those units that do not meet the requirement.

Mike Grimes opined that a lack of communication is at play; that Horizon Wind Energy and others interpreted the Protocols differently; that installations were made in the belief that units would be operating as required; and that the offering was not questioned, though some additional equipment was installed. Mr. Grimes opined that PRR830 represents rule changing and expressed concern for expensive retrofitting and regulatory uncertainty for Entities planning to relocate to Texas.

Walter Reid provided a presentation asserting that "virtual" units do not make sense; that the triangle has always been acceptable; that conventional generators are not required to comply with the rectangle, citing the CURL; that PRR835, Reactive Capability Requirement, provides modeling solutions; and that PRR830 established a new requirement. Mr. R. Jones countered that CURL establishes a new Reactive Power obligation and is still a rectangle, but on a smaller scale; that Mr. Reid's assertions that other facilities test in aggregate is not true, that facilities test regularly for real power and Reactive Power individually; and that conventional generators have never considered anything less than the rectangle to be their obligation. Mr. Reid expressed confidence that CURLs may be found that encroach on the rectangle. Mr. Dumas requested that Mr. Reid produce a list of those units not meeting the requirement and without exemptions, and noted that in the Protocols any conventional generation older than 1999 has an exemption, and that any WGR older than 2004 has an exemption from the requirement. Mr. Donohoo encouraged Market Participants to utilize the services of their ERCOT Client Services Representative, and not just read the Protocols and act.

Mr. Reid opined that many engineering firms arrived at an interpretation of the Protocols allowing the triangle; that Entities signed agreements with TSPs with more experience with ERCOT Protocols; and that some TSPs did studies resulting in more reactive requirements. Mr. Donohoo added that interconnect agreements state that ERCOT Protocol requirements must be met. Mr. Rocha recalled that the requirement is 0.95 at the unit's maximum output.

Mark Bruce stated that NextEra filed PRR835 rather then filing the elements of PRR835 as comments to PRR830, as it was understood that PRR830 would be easier to consider without the elements contained in PRR835. Mr. Bruce added that NextEra requested that the presentation regarding PRR835 be made available for discussion in conjunction with PRR830 discussion, and expressed his disappointment that the PRR835 presentation would not be reviewed; and that should the motion to endorse PRR830 carry, the time of ROS need not be taken to consider PRR835.

Mr. Donohoo directed Mr. Bruce to be ready to make the PRR835 presentation promptly upon reconvening. Upon reconvene, Mr. R. Jones stated that a motion remained on the floor, that he did not object to the presentation regarding PRR835, but that ROS should recognize that he was yielding the floor to Mr. Bruce.

Mr. Bruce expressed his appreciation to pause before the vote to review PRR835 and, he opined, complete the discussion. Peter Wybierala asserted that the current ERCOT Protocols regarding Reactive Power capability requirements is obsolete; that retroactive measures adversely affect systems already in operation; that PRR835 is forward-looking, based on need and not just obligation, and adapts to changing technology. Mr. Wybierala stated that PRR835 avoids fixing a problem that NextEra does not believe exists, and opined that there is not a need in West Texas for additional reactive capability.

Mr. Wybeirala introduced Leonardo Lima of Siemens-PTI, noting that NextEra engaged the services of Siemens-PTI to assess the current need for additional reactive resources in western ERCOT. Mr. Lima reviewed the study assumptions, sensitivity scenarios, and results. Clayton Greer asserted that the analysis performed under the presented scenario is meaningless; and that the operating stakes are not available without knowledge of the location of maintenance Outages. Mr. Donohoo added that planning is frequently trumped by operations. Ms. Wagner opined that NextEra posed good points for other markets, but that ERCOT has different technical requirements and does not provide compensation for Reactive Power. Mr. Rocha added that the Siemens-PTI study is not independent analysis, as is ERCOT's. **The motion carried via roll call vote.** *(Please see ballot posted with Key Documents.)*

Mr. Donohoo directed the Dynamics Working Group (DWG), the Operations Working Group (OWG), SSWG, and ERCOT Operations and Planning Staff work to verify that the correct data go into all models; suggested that a procedure might need to be developed, or that existing procedures might require modification; and requested that an update be provided at the January 2010 ROS meeting.

PRR835, Reactive Capability Requirement
No vote was taken on PRR835. See discussion above.

Ancillary Service Methodology
Mr. Dumas noted that ERCOT is required to receive annual ERCOT Board approval of the Ancillary Service methodology, and that ERCOT is reviewing proposed revisions with ROS, Wholesale Market Subcommittee (WMS) and TAC before presenting language to the ERCOT Board. Mr. Dumas reviewed proposed revisions, opining that the proposed approach accomplishes market goals without posing a risk to reliability.

Mr. Green moved to endorse the 2010 Ancillary Service methodology as proposed. Blake Williams seconded the motion. Market Participants commended ERCOT Staff for supporting more market-based tools for Ancillary Services, and discussed that a North American Electric Reliability Corporation (NERC) Disturbance Control Standard (DCS) event is defined as 80% of the largest unit; whether maximum coincident loss or geographic concentrations should also be considered; and that ERCOT should develop procedures, parameters, and communication for its operational choices. Mr. Dumas noted that uncertainty and risk has changed with the increase of wind on the system; that Ancillary Service needs are determined on the 20th of each month and posted to provide transparency.

Mr. Green and Mr. Williams accepted Ms. Stephenson's amendment that hour 2300 be included. Ms. Stephenson contended that hour 2300 represents the second highest interval for deployment of NSRS. Market Participants discussed the possibility that NSRS deployment at hour 2300 is due to schedule changes and depletion of Regulation Service rather than capacity issues; that a floor cannot be applied to a single hour, but only to a four-hour block; that an exception would have to be written to redefine the block; and that the methodology should move forward as proposed by ERCOT for observation before additional measures are taken. Ms. Stephenson stated that she would not want to affect an entire four-hour block; would not object to the initial proposal of hours 0700-2200; and that she would highlight the issue at the WMS. **Mr. Green and Mr. Williams then rejected Ms. Stephenson's hour 2300 revision. The initial motion carried unanimously.**

PRR833, Primary Frequency Response Requirement from Existing WGRs
Mr. R. Jones moved to endorse PRR833 as submitted. Mr. Ryno seconded the motion. Mr. Soutter opined that PRR833 would retroactively apply standards inappropriate except for in extreme circumstances; and stated that data had not been supplied in support of PRR833. Mr. R. Jones stated that PRR833 was submitted by a wind-only Qualified Scheduling Entity (QSE). **The motion carried with two objections from the Independent Generator and Independent Power Marketer (IPM) Market Segments.**

NPRR194, Synchronization of Zonal Unannounced Generation Capacity Testing Process
Jerry Ward noted that Luminant submitted comments in an effort to address ERCOT's operational needs; opined that the proposed language changes the meaning of HSL; and expressed concern that HSL is used for other purposes that would be impacted by a change in definition. Mr. Ward proposed that QSEs provide ERCOT a telemetry stating what may be achieved from the current position; and noted that the proposal would require each Generator to make a non-trivial calculation.

Mr. Dumas expressed understanding for Resource concerns, but stated that NPRR194 is a synchronizing revision request; that the issues were previously vetted during consideration of PRR750, Unannounced Generation Capacity Testing; and that in an emergency situation, reserves need to be responsive within an hour, rather than four hours. Mr. Dumas agreed that managing 24 HSLs is challenging, but was a compromise made during PRR750 discussions; and reiterated that PRR750 improved confidence in reserves and drove much uncertainty from the market.

Mr. Ward stated that HSL is used in many additional calculations in the Nodal market; agreed that PRR750 is improving confidence in the availability of reserves; and opined that the information should be provided to ERCOT in a different manner, such as a calculation that is telemetered at the time a test is called. Mr. Ward argued that in the nodal market, ERCOT controls where a unit is, and that the only way a unit may pass the test in nodal is to raise the LSL to 80-85%. Market Participants discussed that PRR750 allowed for the discontinuation of the Reserve Discount Factor (RDF) and improved market function; that NPRR194 would require submission of a number that is called an HSL but does not comport with other Protocols; and that telemetering a new number to ERCOT will require a system change.

Mr. Green moved to endorse NPRR194 as submitted. The motion failed for lack of a second.

Mr. Holloway moved to table NPRR194 for one month. The motion failed for lack of a second.

Market Participants discussed that there is technical merit to the proposal by Luminant, but requires every QSE to input the calculation; that implementation impacts to ERCOT should be considered. Mr. Dumas stated that the same concerns were raised at the consideration of PRR750; that QSEs have been able to manage their HSLs; that ERCOT Operations has gained confidence in the availability of reserves; and that while Mr. Ward's points are well taken, the greater good is to move forward with NPRR194.

Mr. Green moved to endorse NPRR194 as submitted. Mr. Rocha seconded the motion. The motion carried with three objections from the Independent Generator (2) and IPM Market Segments, and four abstentions from the Independent Generator (2), Investor Owned Utility (IOU) and Municipal Market Segments.

Nodal Operating Guide Revision Request (NOGRR) 026, Change the name of Emergency Electric Curtailment Plan (EECP) to Energy Emergency Alert (EEA) and Synchronization of EEA Steps with Protocols
Operating Guide Revision Request (OGRR) 223, Real Time Production Potential
OGRR226, Generation Resource Response Time Requirement
Market Participants noted that ERCOT submitted comments to OGRR226; that clarification might be made to language regarding voice communication; that one minute for voice communication might be insufficient; and that further discussion of OGRR226 by OWG might be necessary.

Mr. Rocha moved to recommend approval of NOGRR026 and OGRR223 as recommended by OWG in the respective 09/15/09 OWG Recommendation Reports; and to remand OGRR226 to OWG. Mr. Ryno seconded the motion. The motion carried unanimously.

TAC Assignment
Review TAC Open Action Items Assigned to ROS
RPRS Decommitment
Load Forecast Accuracy
Mr. Donohoo recommended that, due to time constraints, discussion of these TAC assignments to ROS be postponed to November 12, 2009 ROS meeting. There were no objections.

Multiple Interconnection for Generators Task Force (MIG TF) (see Key Documents)
Bob Wittmeyer reported that a draft spreadsheet was posted with the day's Key Documents; and that a white paper is in development.

ERCOT Reports – Questions Only (see Key Documents)
September Operations Report
Ms. Wagner asked why Regulation Service Up was depleted in five periods in September. Ms. Frosch responded that there could be a number of reasons, including QSEs being off their schedules or changes in the wind, and that each instance would need to be reviewed individually to determine an answer. Market Participants discussed that AEP will work with ERCOT to define operating parameters for phase shifters being placed in the south zone; and that understanding their operation is important for modeling and optimization.

September System Planning Report (Includes Congestion)
The September 2009 System Planning Report was posted with the day's Key Documents. No questions were offered.

ROS Working Group Reports – Questions Only (see Key Documents)
Critical Infrastructure Protection Working Group (CIPWG)
There were no questions regarding the posted CIPWG report.

DWG
There were no questions regarding the posted DWG report.

OWG
There were no questions regarding the posted OWG report.

Performance Disturbance Compliance Working Group (PDCWG)
There were no questions regarding the posted PDCWG report.

System Protection Working Group (SPWG)
There were no questions regarding the posted SPWG report.

SSWG
The SSWG report was posted with the day's Key Documents. Market Participants discussed that the Transmission Project Information Tracking (TPIT) timing modification was not a delay but rather a synchronization to cases by one month.

Wind Operations Task Force (WOTF)
There were no questions regarding the posted WOTF report.

<u>Other Business (see Key Documents)</u>
2009 Accomplishments/2010 Goals
Mr. Donohoo reminded Market Participants to review 2009 accomplishments and 2010 goals at their upcoming working group and task force meetings.

2010 ROS Meeting Dates
Mr. Donohoo noted that 2010 ROS meeting dates were posted for review. Market Participants briefly discussed that the schedule remains similar to recent years and would be suitable.

ROS Procedures
Due to time constraints, this item was not taken up.

Other
Mr. Reid noted that he would work with PDCWG to develop and submit an OGRR regarding a testing procedure governor response for future WGRs. Mr. R. Jones recommended that Mr. Reid and PDCWG also develop an OGRR regarding testing procedures for existing WGRs as well. There were no objections.

<u>Adjournment</u>
Mr. Donohoo adjourned the meeting at 3:31 p.m.

Resource Asset Registration Guide

Resource Asset Registration Guide
v4.11

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ERCOT

Revision History

Date	Version	Description	Author
10/10/2007	0.03	Draft for Internal Review	D. Showalter
10/10/2007	0.04	Second draft for Internal Review	D. Showalter
10/10/2007	0.05	Draft for Posting	D. Showalter
10/11/2007	0.06	Revised Draft for Posting	D. Showalter
10/16/2007	0.07	Revised with Market Comments	D. Showalter
12/13/2007	0.08	Revised for Planning Submittal	D. Showalter
4/01/2008	3.99	Draft –Reorganized and reformatted for RARF Ver 4	D. Showalter
4/08/2008	4.00	Released with RARF Ver 4 (Official RARF)	D. Showalter
12/16/08	4.01	Updated RARF Guide V4.01	A. Moy
2/4/2009	4.02	Updated and re-wrote transmission and load data tabs	S. Middleton
3/10/2009	4.03	Corrected / Modified business rules for transformer tab	S. Middleton
6/5/2009	4.04	Added Business Rules for Planning / Protection	S. Middleton
6/10/2009	4.05	Added Business Rules for Planning / Protection	P. Nellutla
6/23/2009	4.06	Added Business Rules for Planning / Protection	P. Nellutla
07/06/09	4.07	Updated Business Rules for Planning, Line Data, Transformer tab and updated the definition of unit commercial date in section 4, Date effective field is included in section 12-18	P. Nellutla
07/24/09	4.08	Updated Business Rules for Line Data, Transformer, Breaker/Switch, Series Device, Load Data, Capacitor Reactor, Static Var Compensator, Planning, Protection. Updated Section 7.4	P. Nellutla
09/01/09	4.09	Updated Section 7.3 and updated Business Rules for Transformer/Line/Breaker-Switch/Series Device Data/Capacitor or Reactor/Load Data.	P. Nellutla
11/2/2009	4.10	Updated Business Rules for Capacitor/Reactor and Transformer tabs.	P. Nellutla
11/18/2009	4.11	Updated section 6.5 with Business Rules for Operational Parameters-GEN,CC,Wind. Updated Business Rules for Capacitor- Reactor Tab	P. Nellutla

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Table of Contents

1.0 Summary of Resource Registration Guide

This document is a guide to completing Resource Asset Registration with ERCOT in accordance with Section 16 of the ERCOT Nodal Protocols. Historically, the GARF, along with other documents, has been used for Resource Entities (RE) to provide information necessary to setup a Resource within ERCOT's systems, including registration, market operations, power operations, and commercial operations.

Upon obtaining the forms from Resource Entities, ERCOT will keep the RARFs in a central repository hub so the files can be tracked and easily accessed by all ERCOT systems, as well as communicated back to the Resource Entity through audits (Figure 1 below illustrates the process flow of receiving and loading RARF data).

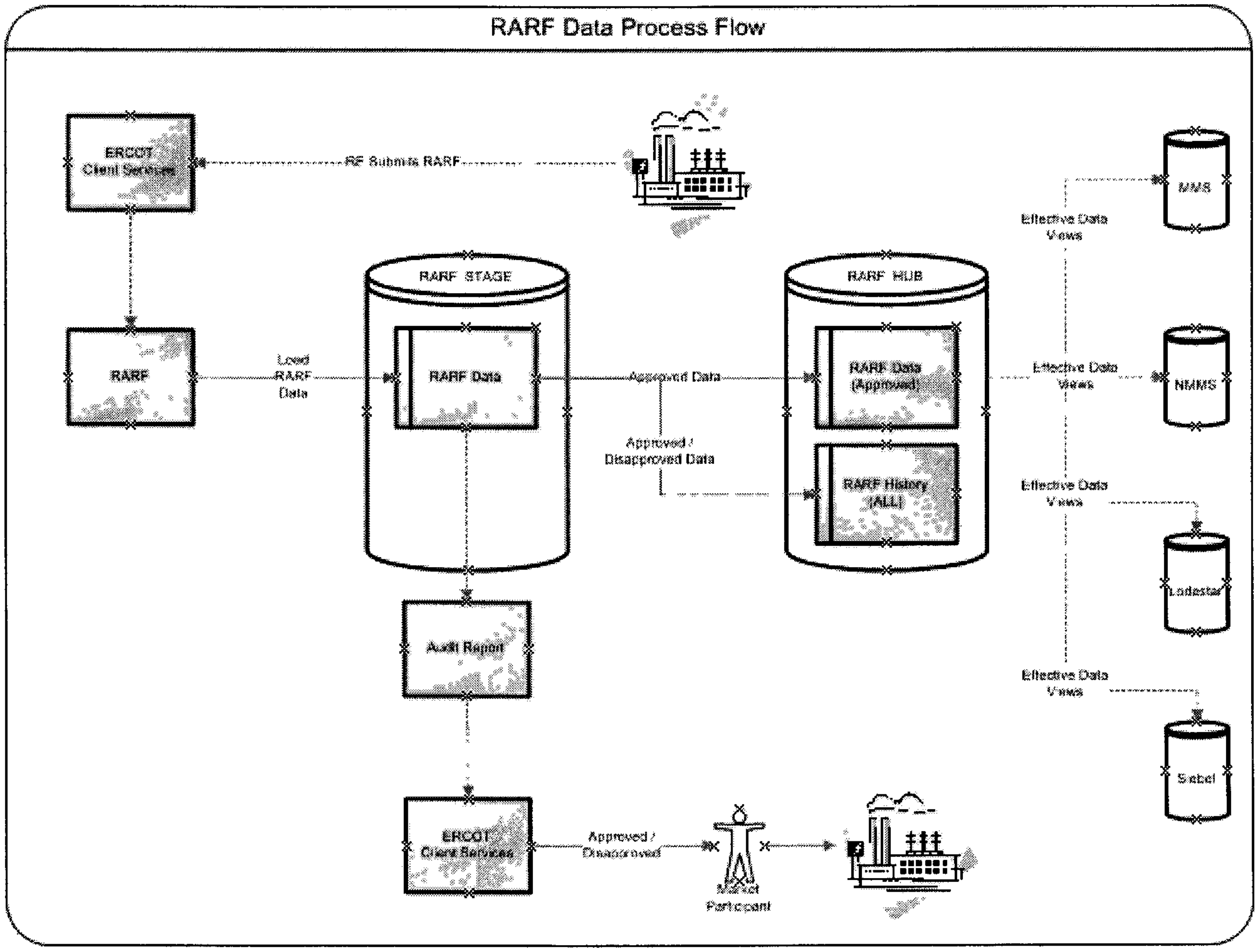

Figure 1

1.1 Tabs

The RARF uses the worksheet tabs to focus on areas. The goal is to get this as close to web-interface entry as possible. The list of tabs is as follows:

- Instructions
- Spreadsheet Map
- General Information - ALL
- Site Information - All GEN RES
- Unit Info - GEN
- Unit Info - CC
- Unit Info - WIND
- Resource Parameters - GEN
- Resource Parameters - CC
- Resource Parameters - CC CFG
- Resource Parameters - WIND
- Operational Resource Parameters - GEN
- Operational Resource Parameters - CC CFG
- Operational Resource Parameters - WIND
- Reactive Capability - GEN
- Reactive Capability - CC
- Reactive Capability - WIND
- Ownership - GEN
- Ownership - CC
- Ownership - WIND
- Configurations - CC1
- Transitions - CC1
- Configurations - CC2
- Transitions - CC2
- Configurations - CC3
- Transitions - CC3
- Planning - GEN
- Planning - CC
- Planning - WIND
- Protection - GEN
- Protection - CC
- Protection - WIND
- SubSync Resonance - GEN
- SubSync Resonance - CC
- Private Network
- GEN Owned Transmission Assets
- Line Data
- Breaker Switch Data
- Capacitor and Reactor Data

- Transformer Data

1.2 Colors

The new form for the official RARFs will primarily use colors to identify sections of the workbook. However, a pale yellow cell indicates any cell that is blank or set to zero.

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RETURN TO MAP

Unit Information

*This worksheet tab applies only to **Wind** generation resources This tab is UNIT specific for **all Wind***
Please complete this section and select RETURN TO MAP

WIND GENERATION RESOURCES

Unit Details	Labels	Unit 1	Unit 2
Unit Name		UNIT1	
Resource Name (Unit Code/Mnemonic)		TEST_UNIT1	
PUC Registration Number (Docket Number)			
ERCOT Interconnection Project Number - only new units			
NERC Number (NERC ID#)			
Unit Start Date	mm/dd/yyyy	12/12/2007	
Unit End Date	mm/dd/yyyy		
Physical Unit Type		WT	
Renewable	Y/N	Y	
Renewable/Offset		RN	
Resource Category		Renewable	
Qualifying facility	Y/N	N	
Eligible for McCamey Flowgate Rights (MCFRIs)?	Y/N	Y	
Name Plate Rating	MVA	200 00	
Real Power Rating	MW	180 00	
Reactive Power Rating	MVAR	100 00	
Unit Generating Voltage (collection voltage?)	kV	13 80	
Latitude of center of Wind Farm	decimal degrees (N)	200 00	
Longitude of center of Wind Farm	decimal degrees (W)	100 00	
Average Height above ground of Turbine Hub	meters	50 00	
Latitude of Meteorological Tower	decimal degrees (N)	200 00	
Longitude of Meteorological Tower	decimal degrees (W)	100 00	
Height of Meteorological Tower Instrumentation	meters	75 00	
Turbine Details - Turbine Information by Model			
Group 1 - Type of Turbine (Manufacturer/Model)		GE 1 5 SLE	
Group 1 - MW Rating for this model of Turbine	MW	180 00	
Group 1 - Number of this type of Turbine		10 000	

- If a cell is hatched, the cell is not ready to be filled out, and should be left blank. Upon completing the Resource Names and defining all basic site and unit information, all cells that need to be completed should be hatch-free. Do not enter data behind hatched cells.

- If a field has a Label, the data for the corresponding cell must show only the applicable data value, not the label itself,

- N/A values or other descriptive information is not allowed in cells unless otherwise provided in the pull-down menu selection.

1.3 RARF - Hyperlinks and Mapping

In an attempt to ease accessibility to this document, hyperlinks and a mapping page have been used. Each worksheet has a "RETURN TO MAP" link at the top, in or near cell C1.

C	D	E
	RETURN TO MAP	

The Map page is categorized by generation type – CC, WIND and GEN where GEN is all non-wind, non-CC Generation Resources. The example below is for wind. In addition, the map shows a reference to this guide.

WIND	RARF Guide / Protocol Reference	Worksheets included in this form:
Instructions	RARF Guide: Section 3 0	Instructions
Map (this page)	RARF Guide: Section 3 0	Spreadsheet Map (this page)
General Information - ALL	RARF Guide Section 4 0	General Information
Site Information - GEN CC WIND	RARF Guide Section 4 0	Site Information
Unit Info - WIND	RARF Guide Section 5 3	Unit Information
Resource Parameters - WIND	RARF Guide Section 6 3	Resource Parameters
Operational Resource Parameters - WIND	RARF Guide Section 7 3	Operational Resource Parameters
Reactive Capability - WIND	RARF Guide. Section 8 3	Reactive Capability
GSU Transformer - ALL	RARF Guide. Section 9 1	GSU Transformer
Ownership - WIND	RARF Guide Section 10.3	Ownership
Planning - WIND	RARF Guide: Section 12 1	Planning
Protection - WIND	RARF Guide Section 12 3	Planning
Private Network - PUN	RARF Guide. Section 13 0	Private Use Network
Generation Owned Transmission Assets - ALL	RARF Guide Section 14 0	Generation Owned Transmission Assets

1.4 Glossary

A glossary has been created and is being provided as a separate document to this form. The glossary is the source for the definition of each field requested in the RARF.

162					Reactive Capability
163	Reactive Capability	GEN, CC, WIND	MW	MW1	Reactive Capability curve - point on curve of MW output for this unit, MW1
164	Reactive Capability		MVAR	Lagging MVAR limit associated with MW1 output	Unit's Lagging reactive power output capability associated with its MW1 out
165	Reactive Capability		MVAR	Leading MVAR limit associated with MW1 output	Unit's Leading reactive power output capability associated with its MW1 out negative number
166	Reactive Capability		MW	MW2	Reactive Capability curve - point on curve of MW output for this unit, MW2
167	Reactive Capability		MVAR	Lagging MVAR limit associated with MW2 output	Unit's Lagging reactive power output capability associated with its MW2 out
168	Reactive Capability		MVAR	Leading MVAR limit associated with MW2 output	Unit's Leading reactive power output capability associated with its MW2 out negative number
169	Reactive Capability		MW	MW3	Reactive Capability curve - point on curve of MW output for this unit, MW3
170	Reactive Capability		MVAR	Lagging MVAR limit associated with MW3 output	Unit's Lagging reactive power output capability associated with its MW3 out
171	Reactive Capability		MVAR	Leading MVAR limit associated with MW3 output	Unit's Leading reactive power output capability associated with its MW3 out negative number
172	Reactive Capability		MW	MW4	Reactive Capability curve - point on curve of MW output for this unit, MW4
173	Reactive Capability		MVAR	Lagging MVAR limit associated with MW4 output	Unit's Lagging reactive power output capability associated with its MW4 out
174	Reactive Capability		MVAR	Leading MVAR limit associated with MW4 output	Unit's Leading reactive power output capability associated with its MW4 out negative number
175	Reactive Capability		MW	MW5 - Unity Power Factor	From the Reactive Capability curve - the MW output at Unity Power Factor (ze
176	Reactive Capability	GEN, CC	PSI	If hydrogen cooled, indicate hydrogen pressure (psi) associated with your Reactive Curve submitted for ERCOT studies	From manufacturer Reactive Capability Curve or data sheet.
177	Reactive Capability	GEN, CC, WIND	MVAR	Net Maximum Leading Operating Capability (MVAR)	Enter the maximum lagging MVARs that can be produced Obtained from m Capability Curve or data sheet; input as negative number
178	Reactive Capability		MVAR	Net Maximum Lagging Operating Capability (MVAR)	From manufacturer Reactive Capability Curve or data sheet.
179	Reactive Capability		Y/N	Manufacturer's Capability Curve submitted?	Has a recent curve been submitted to ERCOT? If not, please submit.
180	Reactive Capability	WIND	Y/N	Reactive Standard?	Does the Wind unit meet the reactive standard?

2.0 Instructions and Map

A RARF should be submitted for each generation resource site that contains data for all generation at the site. A separate RARF should also be submitted for each Resource Entity covering all load resources represented by that entity. A RARF is to be completed for all active and mothballed generation resources inside ERCOT. Organizations must submit a market participant application as a Resource Entity prior to submission of this form, if not eligible for Federal Hydro waiver (Section 16.5). If questions arise related to the completion of this form, please contact your designated ERCOT Account Manager or email Wholesale Client Services at NodalMarketTransition@ercot.com with the subject "Resource/Asset Registration Form".

Please bear in mind the following for the completion of this form:

- A single RARF must be submitted for each generation resource site. This form will accommodate generation Resources located at a common site as well as generation load splitting.

- A single RARF must be submitted for load resources represented by a common Resource Entity.

2.1 Process for Official Submittal

There are two methods of submitting the RARF, as follows:

PRIMARY: RARFs are to be submitted through the Texas Market Link (TML) located at https://tml.ercot.com. Submission through the TML link requires a valid Authorized Representative's digital certificate.

ALTERNATIVE: An alternate email signature document is available upon request from your ERCOT Account Manager for those who have technical problems submitting via the TML portal. The RARF must be emailed in both portable document format (pdf) and Microsoft Excel spreadsheet (xls) format, along with the signature document to: mpappl@ercot.com and ercotregistration@ercot.com.

The following are instructions for submitting the RARF through TML:

- Access to ERCOT TML requires a user digital certificate with a minimal role that allows access to "Create Service Request" on the "Market Activities" page. The "user digital certificate" is authorized by the Market Participant's User Security Administrator.

- Upon accessing TML, go to the "*Market Activities*" page and select "*Create Service Request*". Be advised that the Service Request will display in a new window as a pop-up, which may be restricted by browser settings.

- Complete the required fields on the "*Service Request*" screen annotated by red asterisks.

- The following Request Type and Sub-Type are essential to a proper submittal:

    - *Request Type:* Select "**MP Registration**" from the drop-down list
    - *Request Sub-Type:* Select "**Resource/Asset Registration**" from the drop-down list

Please note that if the Type and Sub-Type values above are not used, the RARF will not be received or processed by ERCOT Client Services.

- Click "*Submit*" (you will add the RARF file on the next screen)

- From the "*Activities and Attachments*" screen, under the Attachments heading of the Service Request click the 'Add' button.

- Select "*Browse*" icon and find the completed RARF file on your computer

- Click "*Submit*" (comments are optional)

ERCOT will verify the RARF is sent from the Authorized Representative of the registered Resource Entity via digital certificate. ERCOT may request additional authentication as deemed necessary.

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2.2 Map

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Map of the ERCOT Resource Asset Registration Form

This worksheet tab identifies the necessary worksheets and provides links to the pages.

VIND	RARF Guide / Protocol Referenc	Worksheets included in this form:
Instructions	RARF Guide: Section 3.0	Instructions
Map (this page)	RARF Guide: Section 3.0	Spreadsheet Map (this page)
General Information - ALL	RARF Guide: Section 4 0	General Information
Site Information - GEN CC VIND	RARF Guide: Section 4.0	Site Information
Unit Info - VIND	RARF Guide: Section 5.3	Unit Information
Resource Parameters - VIND	RARF Guide: Section 6 3	Resource Parameters
Operational Resource Parameters - VIND	RARF Guide: Section 7.3	Operational Resource Parameters
Reactive Capability - VIND	RARF Guide: Section 8.3	Reactive Capability
GSU Transformer - ALL	RARF Guide: Section 9.1	GSU Transformer
Ownership - VIND	RARF Guide: Section 10.3	Ownership
Planning - VIND	RARF Guide: Section 12.1	Planning
Protection - VIND	RARF Guide: Section 12.3	Planning
Private Network - PUN	RARF Guide: Section 13.0	Private Use Network
Generation Owned Transmission Assets - ALL	RARF Guide Section 14.0	Generation Owned Transmission Assets
GEN		
Instructions	RARF Guide: Section 3.0	Instructions
Map (this page)	RARF Guide: Section 3.0	Spreadsheet Map (this page)
General Information - ALL	RARF Guide Section 4.0	General Information
Site Information - GEN CC VIND	RARF Guide: Section 4 0	Site Information
Unit Info - GEN	RARF Guide: Section 5.1	Unit Information
Resource Parameters - GEN	RARF Guide: Section 6.1	Resource Parameters
Operational Resource Parameters - GEN	RARF Guide: Section 7.3	Operational Resource Parameters
Reactive Capability - GEN	RARF Guide: Section 8.1	Reactive Capability
GSU Transformer - ALL	RARF Guide: Section 9.1	GSU Transformer
Ownership - GEN	RARF Guide: Section 10.1	Ownership
Planning - GEN	RARF Guide: Section 12.1	Planning
Protection - GEN	RARF Guide: Section 12.2	Planning
Subsynchronous Resonance - GEN	RARF Guide: Section 12.3	Planning
Private Network - PUN	RARF Guide: Section 13.0	Private Use Network
Generation Owned Transmission Assets - ALL	RARF Guide: Section 14.0	Generation Owned Transmission Assets
COMBINED CYCLE		
Instructions	RARF Guide: Section 3.0	Instructions
Map (this page)	RARF Guide: Section 3.0	Spreadsheet Map (this page)
General Information - ALL	RARF Guide: Section 4.0	General Information
Site Information - GEN CC VIND	RARF Guide: Section 4.0	Site Information
Unit Info - CC	RARF Guide: Section 5.2	Unit Information
Resource Parameters - CC	RARF Guide Section 6.2	Resource Parameters
Resource Parameters - CC CFG (ensure configurations are entered first)	RARF Guide: Section 6.2	Resource Parameters
Operational Resource Parameters - CC CFG (ensure configurations are entered first)	RARF Guide: Section 7.3	Operational Resource Parameters
Reactive Capability - CC	RARF Guide: Section 8.2	Reactive Capability
GSU Transformer - ALL	RARF Guide: Section 9.1	GSU Transformer
Ownership - CC	RARF Guide: Section 10.2	Ownership
Configurations - CC1	RARF Guide: Section 11.2	Combined Cycle Configuration Details
Configurations - CC2	RARF Guide: Section 11.2	Combined Cycle Configuration Details
Configurations - CC3	RARF Guide: Section 11.2	Combined Cycle Configuration Details
Transitions - CC1	RARF Guide: Section 11.3	Combined Cycle Configuration Details
Transitions - CC2	RARF Guide: Section 11.3	Combined Cycle Configuration Details
Transitions - CC3	RARF Guide: Section 11.3	Combined Cycle Configuration Details
Planning - CC	RARF Guide: Section 12.1	Planning

3.0 General Information and Site Information

These sections contain information that applies to the RARF submittal and/or the site.

3.1 General Information

The General Information tab should be updated with every submittal for load and generation resources. The submittal information, such as date completed, should be updated with every submission, while the remainder of the fields should be verified. Primary contact information is essential, as it provides ERCOT with an additional contact in case of questions regarding the RARF.

ERCOT Confidential	RETURN TO MAP
General Information - All Resource Entities	
This worksheet tab contains information on the Resource Entity responsible for submitting this form. Please complete this section and select RETURN TO MAP	
This submittal is for:	
** Deletions are accepted as intentions. This form does not supersede the Notice of Suspension of Operations requirements.*	
Submittal Information	
Date Form Completed.	
Resource Entity Submitting Form:	
Resource Entity DUNS #	
Primary Contact **(name of person ERCOT can contact with questions regarding this form)**	
Printed Name	
Title	
Phone Number:	
E-mail Address	
Fax Number	
Secondary Contact **(if available)**	
Printed Name	
Title	
Phone Number:	
E-mail Address:	
Fax Number	
Instructions for Revisions	
Tab name (Use Drop-Down List):	**Describe revision and whether revision is to be applied in Zonal Market. All revisions will be applied to Nodal as default.**

3.2 Site Information

The Site Information tab identifies information for the generation resource site, such as address and ERCOT Polled Settlement metering information. The Resource Site Code is determined jointly with ERCOT, and typically aligns with the substation name at the point of interconnection.

Please verify the transmission provider, as some names may have changed over time.

This section does not apply to load resources.

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Site Information

This worksheet tab contains site-specific information.
Please complete this section and select RETURN TO MAP

All Generation Resources

Site Info for Generation Resources (Load Resources and Block Load Transfers should skip this section)	
Resource Site Name	
Resource Site Code:	
Street Address	
City	
State & Zip	
County	
Site In-Service Date	
Site Stop Service Date	
Congestion Management Zone for 2003	
Resource owned by NOIE?	
Is Resource behind a NOIE Settlement Meter Point?	
Number of EPS Primary meters	
Generation Load Split?	
ESI ID	
ERCOT Read Meter?	
TDSP Providing Service To Resource	
TDSP DUNS Number	[redacted]

If the facility has the Gen Site Load split among multiple competitive retailers or among multiple TDSPs, the second part of the Site Information tab should be filled out as applicable (not the top ESI ID & TDSP fields). Otherwise this section should be left blank.

ERCOT Confidential | **RETURN TO MAP**

Site Information

This worksheet tab contains site-specific information
Please complete this section and select RETURN TO MAP

Site Load Split

Complete this section if the Gen Site Load is split among multiple ESI IDs.	
ESI ID 1:	
Fixed Load Splitting %	
Competitive Retailer	
Competitive Retailer DUNS #	[redacted]
TDSP Providing Service To Resource	
TDSP DUNS Number	[redacted]
ESI ID 2:	
Fixed Load Splitting %	
Competitive Retailer	
Competitive Retailer DUNS #	[redacted]
TDSP Providing Service To Resource	
TDSP DUNS Number	[redacted]
ESI ID 3:	
Fixed Load Splitting %	
Competitive Retailer	
Competitive Retailer DUNS #	[redacted]
TDSP Providing Service To Resource	
TDSP DUNS Number	[redacted]
ESI ID 4:	
Fixed Load Splitting %	
Competitive Retailer	
Competitive Retailer DUNS #	[redacted]
TDSP Providing Service To Resource	
TDSP DUNS Number	[redacted]
ESI ID 5:	
Fixed Load Splitting %	
Competitive Retailer	
Competitive Retailer DUNS #	[redacted]
TDSP Providing Service To Resource	
TDSP DUNS Number	[redacted]
ESI ID 6:	
Fixed Load Splitting %	
Competitive Retailer	
Competitive Retailer DUNS #	[redacted]

4.0 Unit Information

The Unit Information section is required for all generation resources. This tab is split into the different sections based on generation resource type: Wind, CC, or other non-Wind, non-CC Generation.

Please enter the PUC Registration number and the NERC Registration number for tracking purposes. The ERCOT Interconnection Project number is only needed for NEW units to aid with tying the interconnection process and the commercial operation process together.

All fields in this section should be completed. Also, the ERCOT Interconnection Project Number is not needed for units already in commercial operation.

4.1 Unit Info – non-Wind, non-CC Generation Units

The Resource Name (also known as the Unit Code/Mnemonic) is the unique identifier that propagates through ERCOT systems. This is determined jointly between ERCOT and the resource, but is already established for existing units. The Resource Name consists of "SITECODE_UNITNAME". This field will populate the remainder of the spreadsheet, identifying additional fields that must be completed.

Unit Commercial Date shall mean the date on which Generator declares that the construction of the Plant has been substantially completed, Trial Operation of the Plant has been completed, and the Plant is ready for dispatch

A B C D E F

ERCOT Confidential **RETURN TO MAP**

Unit Information

This worksheet tab provides generator unit information for generation resources. This tab is UNIT specific for ***all non-Wind and non-CC***

Please complete this section and select RETURN TO MAP

GENERATION RESOURCES (non-WIND, non-CC)

Unit Details	Labels	Unit 1	Unit 2	Unit 3
Unit Name				
Resource Name (Unit Code/Mnemonic)				
PUC Registration Number				
ERCOT Interconnection Project Number - only new units				
NERC Number				
Unit Commercial Date	mm/dd/yyyy			
Unit End Date	mm/dd/yyyy			
Physical Unit Type				
Primary Fuel Type				
Secondary Fuel Type				
Fuel Transportation Type				
Renewable	Y/N			
Renewable/Offset				
Resource Category				
Qualifying facility	Y/N			
Name Plate Rating	MVA			
Real Power Rating	MW			
Reactive Power Rating	MVAR			
Turbine Rating	MW			
Unit Generating Voltage	kV			

4.2 Unit Info – Combined-Cycle Units

This tab contains three parts – for registering up to three trains at one site.

The Mnemonic of Combined Cycle Train is the unique identifier that will propagate through ERCOT systems to identify the Train. This is determined by ERCOT by simply using "SITECODE_CCx" where x is 1, 2, or 3.

The Resource Name (also known as the Unit Code/Mnemonic) is the unique identifier that propagates through ERCOT systems. This is determined jointly between ERCOT and the resource, but is already established for existing units. The Resource Name consists of "SITECODE_UNITNAME". This field will populate the remainder of the spreadsheet, identifying additional fields that must be completed.

Unit Commercial Date shall mean the date on which Generator declares that the construction of the Plant has been substantially completed, Trial Operation of the Plant has been completed, and the Plant is ready for dispatch

ERCOT Confidential **RETURN TO MAP**

Unit Information

*This worksheet tab applies to **all combined cycle** generation resources. This information is UNIT and TRAIN specific.*
Please complete this sections (one for each train at the facility) and select RETURN TO MAP

COMBINED-CYCLE GENERATION RESOURCES CC1

Train Details	**Labels**	**Train 1**		
Name of Combined Cycle Train				
Mnemonic for Combined Cycle Train				
PUC Registration Number				
NERC Number				
Unit Commercial Date	mm/dd/yyyy			
Unit End Date	mm/dd/yyyy			
Fuel Transportation Type				
Resource Category				
Qualifying Facility (Y/N)?	Y/N			
Is train augmented with Duct Burner(s)?	Y/N			
Is train augmented with Evap Cooler(s)?	Y/N			
Is train augmented with Chiller(s)?	Y/N			
Other augmentation?	Y/N			
Unit Details	**Labels**	**Unit 1**	**Unit 2**	**Unit 3**
Unit Name				
Resource Name (Unit Code/Mnemonic)				
ERCOT Interconnection Project Number - only new units				
Unit Start Date	mm/dd/yyyy			
Unit End Date	mm/dd/yyyy			
Physical Unit Type				
Primary Fuel Type				
Secondary Fuel Type				
Name Plate Rating	MVA			
Real Power Rating	MW			
Reactive Power Rating	MVAR			
Turbine Rating	MW			
Unit Generating Voltage	kV			

4.3 Unit Info – Wind Units

The Resource Name (also known as the Unit Code/Mnemonic) is the unique identifier that propagates through ERCOT systems. This is determined jointly between ERCOT and the resource, but is already established for existing units. The Resource Name consists of "SITECODE_UNITNAME". This field will populate the remainder of the spreadsheet, identifying additional fields that must be completed.

The Wind Unit Information tab contains information on the turbine groups. Each Wind Unit may identify up to 5 groups of turbine types, or 5 different models, within a particular unit. This section asks for the model, quantity, and rating of each.

Unit Commercial Date shall mean the date on which Generator declares that the construction of the Plant has been substantially completed, Trial Operation of the Plant has been completed, and the Plant is ready for dispatch.

ERCOT Confidential **RETURN TO MAP**

Unit Information

This worksheet tab applies only to ***Wind*** *generation resources. This tab is UNIT specific for* ***all Wind***
Please complete this section and select RETURN TO MAP

WIND GENERATION RESOURCES

Unit Details	Labels	Unit 1	Unit 2	Unit 3
Unit Name				
Resource Name (Unit Code/Mnemonic)				
PUC Registration Number (Docket Number)				
ERCOT Interconnection Project Number - only new units				
NERC Number (NERC ID#)				
Unit Commercial Date	mm/dd/yyyy			
Unit End Date	mm/dd/yyyy			
Physical Unit Type				
Renewable	Y/N			
Renewable/Offset				
Resource Category				
Qualifying facility	Y/N			
Eligible for McCamey Flowgate Rights (MCFRIs)?	Y/N			
Name Plate Rating	MVA			
Real Power Rating	MW			
Reactive Power Rating	MVAR			
Unit Generating Voltage	kV			
Latitude of center of Wind Farm	decimal degrees (N)			
Longitude of center of Wind Farm	decimal degrees (W)			
Average Height above ground of Turbine Hub	meters			
Latitude of Meteorological Tower	decimal degrees (N)			
Longitude of Meteorological Tower	decimal degrees (W)			
Height of Meteorological Tower Instrumentation	meters			
Turbine Details - Turbine Information by Model				
Group 1 - Type of Turbine (Manufacturer/Model)				
Group 1 - MW Rating for this model of Turbine	MW			
Group 1 - Number of this type of Turbine				
Group 2 - Type of Turbine (Manufacturer/Model)				
Group 2 - MW Rating for this model of Turbine	MW			
Group 2 - Number of this type of Turbine				
Group 3 - Type of Turbine (Manufacturer/Model)				
Group 3 - MW Rating for this model of Turbine	MW			
Group 3 - Number of this type of Turbine				
Group 4 - Type of Turbine (Manufacturer/Model)				

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5.0 Resource Parameters

The Resource Parameters tab allows generation resources to establish operational limits and long term planning information. The Seasonal Net Max Sustainable ratings for each season will also be used for the Mitigated Offer Cap.

All fields on this tab should be completed.

5.1 Generation Resources – non-Wind, non-CC Generation Units

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Resource Parameters

*This worksheet tab provides resource parameters for **generation** resources This tab is UNIT specific for **all non-Wind and non-CC***

Complete the Unit Information tab first, then the corresponding cells will become un-hatched on this tab Then complete this section and select RETURN TO

GENERATION RESOURCES (non-WIND, non-CC)

Reasonability Limits	**Labels**	**TEST A**	**TEST B**	
High Reasonability Limit	MW			
Low Reasonability Limit	MW			
High Reasonability Ramp Rate Limit	MW/min			
Low Reasonability Ramp Rate Limit	MW/min			
Seasonal Ratings	**Labels**	**TEST A**	**TEST B**	
Seasonal Net Max Sustainable Rating - Spring	MW			
Seasonal Net Min Sustainable Rating - Spring	MW			
Seasonal Net Max Emergency Rating - Spring	MW			
Seasonal Net Min Emergency Rating - Spring	MW			
Seasonal Net Max Sustainable Rating - Summer	MW			
Seasonal Net Min Sustainable Rating - Summer	MW			
Seasonal Net Max Emergency Rating - Summer	MW			
Seasonal Net Min Emergency Rating - Summer	MW			
Seasonal Net Max Sustainable Rating - Fall	MW			
Seasonal Net Min Sustainable Rating - Fall	MW			
Seasonal Net Max Emergency Rating - Fall	MW			
Seasonal Net Min Emergency Rating - Fall	MW			
Seasonal Net Max Sustainable Rating - Winter	MW			
Seasonal Net Min Sustainable Rating - Winter	MW			
Seasonal Net Max Emergency Rating - Winter	MW			
Seasonal Net Min Emergency Rating - Winter	MW			

ERCOT

5.2 Generation Resources – Combined-Cycle Units and Configurations

This tab contains three parts – for registering up to three trains at one site. This information is required for Units and Configurations.

Units:

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Resource Parameters

*This worksheet tab provides resource parameters for **Combined Cycle** generation resources. This tab is UNIT specific for **all CC**.*

Complete the Unit Information tab first, then the corresponding cells will become un-hatched on this tab. Then complete this section and select RETURN TO

CC GENERATION RESOURCES CC1

Reasonability Limits	Labels	TEST_A	TEST_B	TEST_C
High Reasonability Limit	MW			
Low Reasonability Limit	MW			
High Reasonability Ramp Rate Limit	MW/min			
Low Reasonability Ramp Rate Limit	MW/min			
Seasonal Ratings	**Labels**	**TEST_A**	**TEST_B**	**TEST_C**
Seasonal Net Max Sustainable Rating - Spring	MW			
Seasonal Net Min Sustainable Rating - Spring	MW			
Seasonal Net Max Emergency Rating - Spring	MW			
Seasonal Net Min Emergency Rating - Spring	MW			
Seasonal Net Max Sustainable Rating - Summer	MW			
Seasonal Net Min Sustainable Rating - Summer	MW			
Seasonal Net Max Emergency Rating - Summer	MW			
Seasonal Net Min Emergency Rating - Summer	MW			
Seasonal Net Max Sustainable Rating - Fall	MW			
Seasonal Net Min Sustainable Rating - Fall	MW			
Seasonal Net Max Emergency Rating - Fall	MW			
Seasonal Net Min Emergency Rating - Fall	MW			
Seasonal Net Max Sustainable Rating - Winter	MW			
Seasonal Net Min Sustainable Rating - Winter	MW			
Seasonal Net Max Emergency Rating - Winter	MW			
Seasonal Net Min Emergency Rating - Winter	MW			

Configurations:

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Resource Parameters

*This worksheet tab provides resource parameters for **Combined Cycle** generation resources. This tab is specific to all **CC configurations***

The cells for the resource parameters will become un-hatched for data entry, after a configuration is entered on the corresponding Configurations Tab

CC GENERATION RESOURCES CC1 CONFIGURATIONS

Reasonability Limits	Labels	TEST_CC1_1	TEST_CC1_2	TEST_CC1_3
High Reasonability Limit	MW			
Low Reasonability Limit	MW			
High Reasonability Ramp Rate Limit	MW/min			
Low Reasonability Ramp Rate Limit	MW/min			
Seasonal Ratings	**Labels**	**TEST_CC1_1**	**TEST_CC1_2**	**TEST_CC1_3**
Seasonal Net Max Sustainable Rating - Spring	MW			
Seasonal Net Min Sustainable Rating - Spring	MW			
Seasonal Net Max Emergency Rating - Spring	MW			
Seasonal Net Min Emergency Rating - Spring	MW			
Seasonal Net Max Sustainable Rating - Summer	MW			
Seasonal Net Min Sustainable Rating - Summer	MW			
Seasonal Net Max Emergency Rating - Summer	MW			
Seasonal Net Min Emergency Rating - Summer	MW			
Seasonal Net Max Sustainable Rating - Fall	MW			
Seasonal Net Min Sustainable Rating - Fall	MW			
Seasonal Net Max Emergency Rating - Fall	MW			
Seasonal Net Min Emergency Rating - Fall	MW			
Seasonal Net Max Sustainable Rating - Winter	MW			
Seasonal Net Min Sustainable Rating - Winter	MW			
Seasonal Net Max Emergency Rating - Winter	MW			
Seasonal Net Min Emergency Rating - Winter	MW			

5.3 Generation Resource – Wind Units

ERCOT Confidential | ***RETURN TO MAP***

Resource Parameters

This worksheet tab provides resource parameters for ***Wind*** *generation resources This tab is UNIT specific for* ***all Wind***
Complete the Unit Information tab first, then the corresponding cells will become un-hatched on this tab Then complete this se

WIND GENERATION RESOURCES

Reasonability Limits	Labels	TEST_A	
High Reasonability Limit	MW		
Low Reasonability Limit	MW		
High Reasonability Ramp Rate Limit	MW/min		
Low Reasonability Ramp Rate Limit	MW/min		

Seasonal Ratings	Labels	TEST_A	
Seasonal Net Max Sustainable Rating - Spring	MW		
Seasonal Net Min Sustainable Rating - Spring	MW		
Seasonal Net Max Emergency Rating - Spring	MW		
Seasonal Net Min Emergency Rating - Spring	MW		
Seasonal Net Max Sustainable Rating - Summer	MW		
Seasonal Net Min Sustainable Rating - Summer	MW		
Seasonal Net Max Emergency Rating - Summer	MW		
Seasonal Net Min Emergency Rating - Summer	MW		
Seasonal Net Max Sustainable Rating - Fall	MW		
Seasonal Net Min Sustainable Rating - Fall	MW		
Seasonal Net Max Emergency Rating - Fall	MW		
Seasonal Net Min Emergency Rating - Fall	MW		
Seasonal Net Max Sustainable Rating - Winter	MW		
Seasonal Net Min Sustainable Rating - Winter	MW		
Seasonal Net Max Emergency Rating - Winter	MW		
Seasonal Net Min Emergency Rating - Winter	MW		

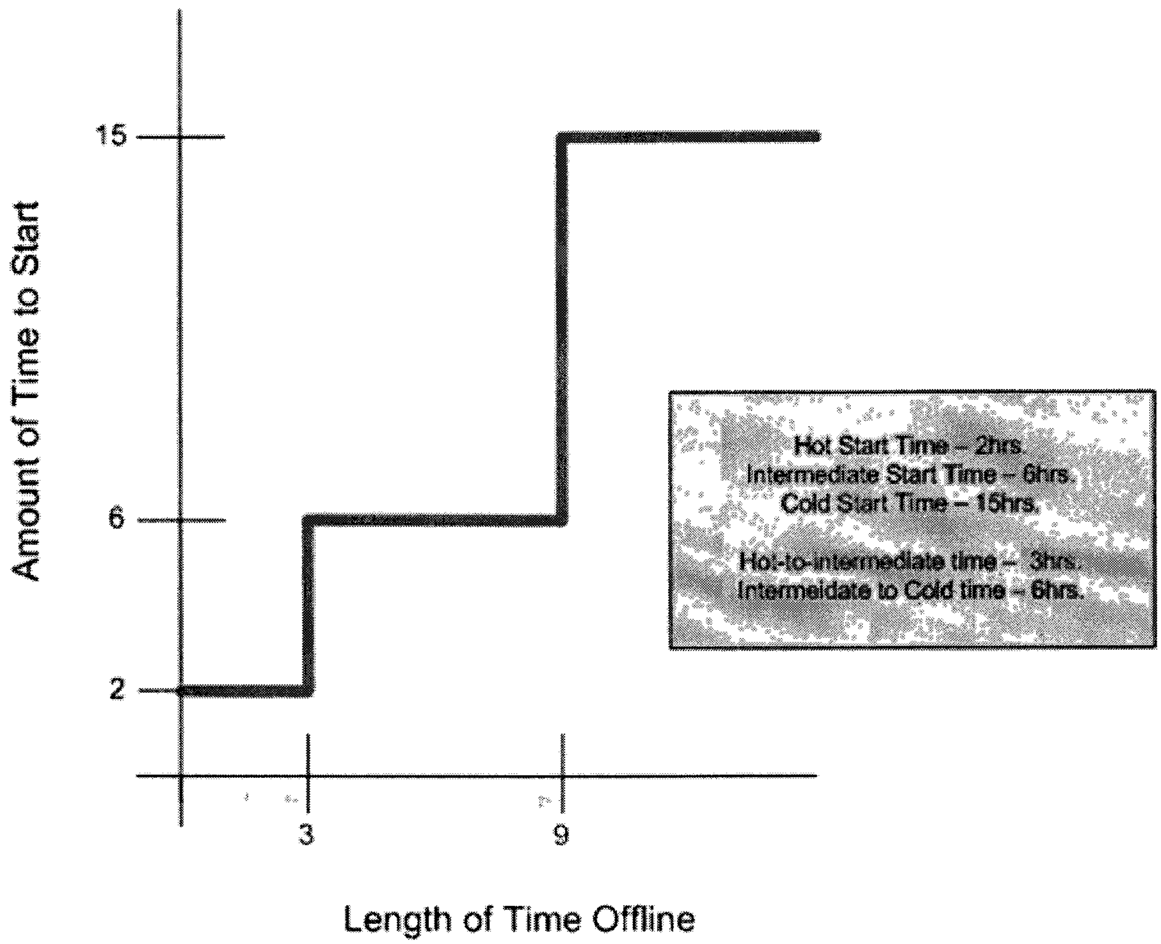
ERCOT

6.0 Operational Resource Parameters

The Operational Resource Parameters section of the RARF provides base values for start-up. The QSE will be able to update these values through the MMS.

These values are required. The only permissible blanks will be the unused portion of the ramp rate curves. (e.g. A minimum of one megawatt value is required, so the MW1 Value and the Upward & Downward Ramps for that MW value.)

The start times for hot, intermediate, and cold apply only to units and trains that are off-line. The Hot-Intermediate and Intermediate-Cold times define which start time to use by seeing how long the unit/train has been off-line. An example is shown below:



6.1 Operational Resource Parameters – non-Wind, non-CC Generation Units

ERCOT Confidential | ***RETURN TO MAP***

Operational Resource Parameters

Resource Entity authorizes QSE representing this Generation Resource to submit Resource Parameters on this page for operational purposes in accordance with Section 3.7.1 on behalf of Resource Entity.

This worksheet tab provides resource parameters for ***generation*** *resources. This tab is UNIT specific for* ***all non-Wind and non-CC***

Complete the Unit Information tab first, then the corresponding cells will become un-hatched on this tab. Then complete this section and selec

GENERATION RESOURCES (non-WIND, non-CC)

Resource Parameters	Labels	TEST_A	TEST_B	
Minimum On Line Time	hours			
Minimum Off Line Time	hours			
Hot Start Time	hours			
Intermediate Start Time	hours			
Cold Start Time	hours			
Max Weekly Starts				
Max On Line Time	hours			
Max Daily Starts				
Max Weekly Energy	MWh			
Hot-to-Intermediate Time	hours			
Intermediate-to-Cold Time	hours			
Normal Ramp Rate Curve	**Labels**	**TEST_A**	**TEST_B**	
MW1	MW			
Upward RampRate1	MW/min			
Downward RampRate1	MW/min			
MW2	MW			
Upward RampRate2	MW/min			
Downward RampRate2	MW/min			
MW3	MW			
Upward RampRate3	MW/min			
Downward RampRate3	MW/min			
MW4	MW			
Upward RampRate4	MW/min			
Downward RampRate4	MW/min			
MW5	MW			
Upward RampRate5	MW/min			
Downward RampRate5	MW/min			
MW6	MW			
Upward RampRate6	MW/min			
Downward RampRate6	MW/min			
MW7	MW			
Upward RampRate7	MW/min			
Downward RampRate7	MW/min			
MW8	MW			
Upward RampRate8	MW/min			
Downward RampRate8	MW/min			
MW9	MW			
Upward RampRate9	MW/min			
Downward RampRate9	MW/min			
MW10	MW			
Upward RampRate10	MW/min			
Downward RampRate10	MW/min			
Emergency Ramp Rate Curve	**Labels**	**TEST_A**	**TEST_B**	
MW1	MW			
Upward RampRate1	MW/min			
Downward RampRate1	MW/min			
MW2	MW			
Upward RampRate2	MW/min			
Downward RampRate2	MW/min			
MW3	MW			
Upward RampRate3	MW/min			
Downward RampRate3	MW/min			
MW4	MW			
Upward RampRate4	MW/min			
Downward RampRate4	MW/min			
MW5	MW			
Upward RampRate5	MW/min			
Downward RampRate5	MW/min			
MW6	MW			
Upward RampRate6	MW/min			
Downward RampRate6	MW/min			

ERCOT

6.2 Operational Resource Parameters – Combined-Cycle Configurations

This tab contains three parts – for registering up to three trains at one site. This information is required for Configurations.

ERCOT Confidential | ***RETURN TO MAP***

Operational Resource Parameters

Resource Entity authorizes QSE representing this Generation Resource to submit Resource Parameters on this page for operational purposes in accordance with Section 3.7.1 on behalf of Resource Entity.

This worksheet tab provides resource parameters for ***Combined Cycle*** *generation resources. This tab is* ***Configuration*** *specific.*

The cells for the operational resource parameters will become un-hatched for data entry, after a configuration is entered on the corresponding

CC GENERATION RESOURCES CC1 CONFIGURATIONS

Resource Parameters	s	TEST_CC1_1	TEST_CC1_2	TEST_CC1_3
Minimum On Line Time	hours			
Minimum Off Line Time	hours			
Hot Start Time	hours			
Intermediate Start Time	hours			
Cold Start Time	hours			
Max Weekly Starts				
Max On Line Time	hours			
Max Daily Starts				
Max Weekly Energy	MWh			
Hot-to-Intermediate Time	hours			
Intermediate-to-Cold Time	hours			
Normal Ramp Rate Curve	**s**	**TEST_CC1_1**	**TEST_CC1_2**	**TEST_CC1_3**
MW1	MW			
Upward RampRate1	MW/min			
Downward RampRate1	MW/min			
MW2	MW			
Upward RampRate2	MW/min			
Downward RampRate2	MW/min			
MW3	MW			
Upward RampRate3	MW/min			
Downward RampRate3	MW/min			
MW4	MW			
Upward RampRate4	MW/min			
Downward RampRate4	MW/min			
MW5	MW			
Upward RampRate5	MW/min			
Downward RampRate5	MW/min			
MW6	MW			
Upward RampRate6	MW/min			
Downward RampRate6	MW/min			
MW7	MW			
Upward RampRate7	MW/min			
Downward RampRate7	MW/min			
MW8	MW			
Upward RampRate8	MW/min			
Downward RampRate8	MW/min			
MW9	MW			
Upward RampRate9	MW/min			
Downward RampRate9	MW/min			
MW10	MW			
Upward RampRate10	MW/min			
Downward RampRate10	MW/min			
Emergency Ramp Rate Curve	**s**	**TEST_CC1_1**	**TEST_CC1_2**	**TEST_CC1_3**
MW1	MW			
Upward RampRate1	MW/min			
Downward RampRate1	MW/min			
MW2	MW			
Upward RampRate2	MW/min			
Downward RampRate2	MW/min			
MW3	MW			
Upward RampRate3	MW/min			
Downward RampRate3	MW/min			
MW4	MW			
Upward RampRate4	MW/min			
Downward RampRate4	MW/min			
MW5	MW			
Upward RampRate5	MW/min			
Downward RampRate5	MW/min			
MW6	MW			
Upward RampRate6	MW/min			
Downward RampRate6	MW/min			
MW7	MW			

6.3 Operational Resource Parameters – Wind Units

ERCOT Confidential | RETURN TO MAP

Operational Resource Parameters

Resource Entity authorizes QSE representing this Generation Resource to submit Resource Parameters on this page for operational purposes in accordance with Section 3.7.1 on behalf of Resource Entity.

*This worksheet tab provides resource parameters for **Wind** generation resources. This tab is UNIT specific for **all W***

Complete the Unit Information Tab first, then the corresponding cells will become un-hatched on this tab. Then complet

WIND GENERATION RESOURCES

Resource Parameters	Labels	TEST_A	
Minimum On Line Time	hours		
Minimum Off Line Time	hours		
Hot Start Time	hours		
Intermediate Start Time	hours		
Cold Start Time	hours		
Max Weekly Starts			
Max On Line Time	hours		
Max Daily Starts			
Max Weekly Energy	MWh		
Hot-to-Intermediate Time	hours		
Intermediate-to-Cold Time	hours		
Normal Ramp Rate Curve	**Labels**	**TEST_A**	
MW1	MW		
Upward RampRate1	MW/min		
Downward RampRate1	MW/min		
MW2	MW		
Upward RampRate2	MW/min		
Downward RampRate2	MW/min		
MW3	MW		
Upward RampRate3	MW/min		
Downward RampRate3	MW/min		
MW4	MW		
Upward RampRate4	MW/min		
Downward RampRate4	MW/min		
MW5	MW		
Upward RampRate5	MW/min		
Downward RampRate5	MW/min		
MW6	MW		
Upward RampRate6	MW/min		
Downward RampRate6	MW/min		
MW7	MW		
Upward RampRate7	MW/min		
Downward RampRate7	MW/min		
MW8	MW		
Upward RampRate8	MW/min		
Downward RampRate8	MW/min		
MW9	MW		
Upward RampRate9	MW/min		
Downward RampRate9	MW/min		
MW10	MW		
Upward RampRate10	MW/min		
Downward RampRate10	MW/min		
Emergency Ramp Rate Curve	**Labels**	**TEST_A**	
MW1	MW		
Upward RampRate1	MW/min		
Downward RampRate1	MW/min		
MW2	MW		
Upward RampRate2	MW/min		

6.4 Ramp Rates

The Ramp Rate Curve data must be entered for both Normal and Emergency Operations. The ramp rates are initially submitted in the RARF, however the QSE will be able to update the ramp rates in Market Management System (MMS).

Ramp rate curves are step functions in the up and down directions at ten MW break points. All ramp rate values, including downward rates, should be entered in the RARF as non-zero positive values. The ramp rates and curves are critical and must be provided for every unit or, in the case of Combined Cycle facilities, ramp rates curves are needed for every configuration

The values submitted in the RARF are used to build the ramp rate step curves, and should not be used as tools to restrain the operating range of the unit or configuration. The curves are limited to LRL and HRL. Further operating restrictions exist as part of the COP and telemetry.

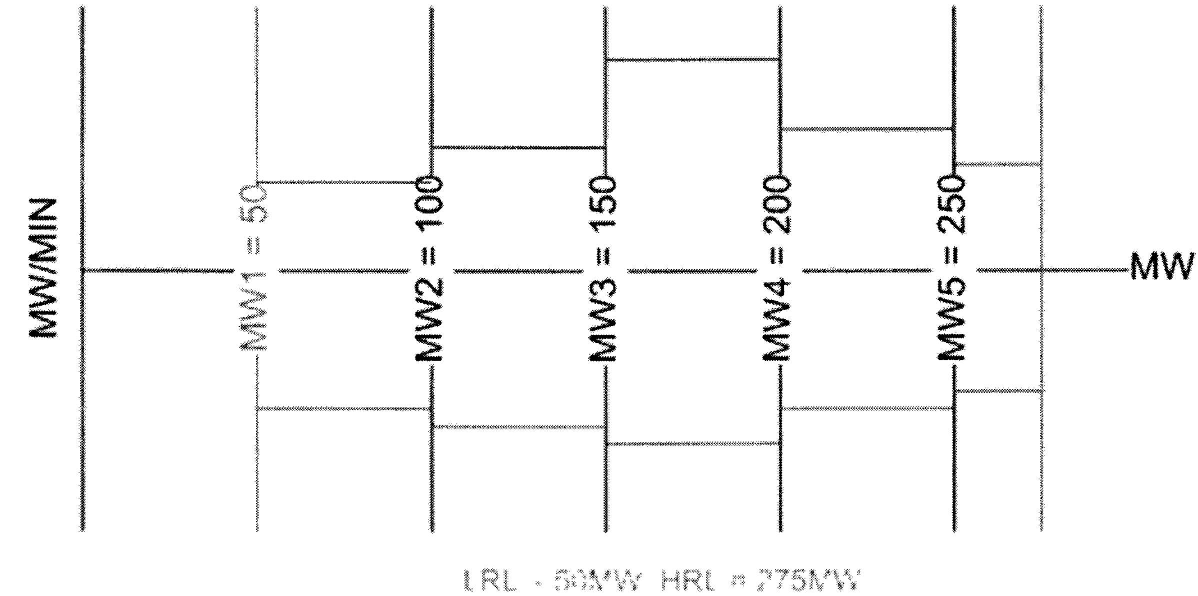
For ranges where the resource must be manually ramped, the up and down ramp rate should be a MW rate at which, if requested, the resource can be manually ramped to within a 5 minute period.

Only one ramp rate is required for the Normal curve and the Emergency curve.

The following picture is an example of a Ramp Rate curve using only five MW break points.

Normal Ramp Rate Curve	Labels	TEST_UNIT1
MW1	MW	50.00
Upward RampRate1	MW/min	5.00
Downward RampRate1	MW/min	8.00
MW2	MW	100.00
Upward RampRate2	MW/min	7.00
Downward RampRate2	MW/min	9.00
MW3	MW	150.00
Upward RampRate3	MW/min	12.00
Downward RampRate3	MW/min	10.00
MW4	MW	200.00
Upward RampRate4	MW/min	8.00
Downward RampRate4	MW/min	8.00
MW5	MW	250.00
Upward RampRate5	MW/min	6.00
Downward RampRate5	MW/min	7.00
MW6	MW	
Upward RampRate6	MW/min	
Downward RampRate6	MW/min	
MW7	MW	
Upward RampRate7	MW/min	
Downward RampRate7	MW/min	
MW8	MW	
Upward RampRate8	MW/min	
Downward RampRate8	MW/min	
MW9	MW	
Upward RampRate9	MW/min	
Downward RampRate9	MW/min	
MW10	MW	
Upward RampRate10	MW/min	
Downward RampRate10	MW/min	

The curve below is shown to help visualize how the reasonability and sustainable limits act as operational limiters as entered on the COP:



6.5 RARF Business Rule Validations

RARF DATA FIELD	Business Rules	Data type
Minimum Off Line Time	1. Minimum Off Line Time should be >0. 2. Decimal positive number of hours should be submitted. Warning! If decimal value is submitted then Downstream System will round it UP.	Numeric
Minimum On Line Time	1. Minimum On Line Time should be >0. 2. Decimal positive number of hours should be submitted. Warning! If decimal value is submitted then Downstream System will round it UP.	Numeric
Hot Start Time	1. Hot Start Time <= Intermediate Start Time. 2. Should be >=0. Decimal non-negative number of hours should be submitted. Warning! If decimal value is submitted then Downstream System will round it DOWN.	Numeric
Intermediate Start Time	1. Intermediate Start Time<= Cold Start Time. 2. Cold Start Time >=0 3. Decimal non-negative number of hours should be submitted. Warning! If decimal value is submitted then Downstream System will round it DOWN.	Numeric
Cold Start Time	1. Cold Start Time > = Intermediate Start Time. 2. Decimal non-negative number of hours should be submitted. Warning! If decimal value is submitted then Downstream System will round it DOWN.	Numeric

Max Weekly Starts	1. Max Weekly Starts >= Max Daily Starts. 2. Min value1, MMS can support maximally 85 starts because to start the unit must be OFF at least one hour (plus initial hour start).	Integer
Max On Line Time	1. Max On Line Time should be >0 2. Decimal positive number of hours should be submitted. Warning! If decimal value is submitted then Downstream System will round it DOWN.	Numeric
Max Daily Starts	1. Max Daily Starts is an integer. This field should not be null 2.Min value1, MMS can support maximally 13 starts because to start the unit must be OFF at least one hour (plus initial hour start).	Integer
Max Weekly Energy	Max Weekly Energy > =0	Integer
Hot-to-Intermediate Time	1. This field is not null. 2. Should be >=0, Decimal non-negative number of hours should be submitted, Warning! If decimal value is submitted then Downstream System will round it DOWN.	Numeric
Intermediate-to-Cold Time	1. This field is not null. 2.Should be >=0, Decimal non-negative number of hours should be submitted. Warning that downstream system will round DOWN when the value is entered decimal	Numeric
Normal Ramp Rate Curve	The ramp rates should not be negative or zero. If there is only one ramp rate then only one MW value needs to be filled in. If not all 10 MW values are used then use only MW1 through MWX. Ramp rates are required for every unit.	Numeric
MW1 to MWX	1. MW1, MW2, MW3, MW4, MW5 all are unique. If there is only one ramp rate then only one MW value needs to be filled in. This field should not be null. 2. MW1 Cannot be Null and must have value for Ramp UP or Ramp Down	Numeric
Upward Ramp Rate(1 to X)	1.LowReasonableRampRateLimit <= Normal Up ramp rate <= High Reasonable RampRateLimit 2.Normal Upward Ramp Rate <= Emergency Upward RampRate.This field should not be null 3.The ramp rates should not be negative or zero	Numeric
Downward Ramp Rate (1 to X)	1. LowReasonableRampRateLimit <= Normal Dn ramp rate <= HighReasonableRampRateLimit. 2. Normal Downward Ramp Rate <= Emergency Downward RampRate.This field should not be null 3.The ramp rates should not be negative or zero	Numeric
Emergency Ramp Rate Curve	The ramp rates should not be negative or zero. If there is only one ramp rate then only one MW value	Numeric

	needs to be filled in. If not all 10 MW values are used then use only MW1 through MWX. Ramp rates are required for every unit.	
MW1 to MWX	1. MW1, MW2, MW3, MW4, MW5 all are unique. If there is only one ramp rate then only one MW value needs to be filled in. This field should not be null. 2.MW1 Cannot be Null and must have value for Ramp UP or Ramp Down	Numeric
Upward Ramp Rate(1 to X)	1. LowReasonableRampRateLimit <= Emergency Up ramp rate <= HighReasonableRampRateLimit 2. Normal Upward Ramp Rate <= Emergency Upward RampRate.This field should not be null 3.The ramp rates should not be negative or zero	Numeric
Downward Ramp Rate (1 to X)	1. LowReasonableRampRateLimit <= Emergency Dn ramp rate <= HighReasonableRampRateLimit 2.Normal Downward Ramp Rate <= Emergency Downward RampRate.This field should not be null 3.The ramp rates should not be negative or zero	Numeric

7.0 Reactive Capability

The Reactive Capability section requires the submittal of the manufacturer's capability curve as well as the 9-point curve values in the RARF. This information will be used to validate test data and should be the best design information available – including all reactive limitations. ERCOT will continue to require bi-annual testing, and this data will be used operationally.

7.1 Reactive Capability – non-Wind, non-CC Generation Units

ERCOT Confidential | *RETURN TO MAP*

Reactive Capability

*This worksheet tab provides reactive capability for **generation** resources. This tab is UNIT specific for **all non-Wind and non-CC**. Complete the Unit Information tab first, then the corresponding cells will become un-hatched on this tab. Then complete this section*

GENERATION RESOURCES (non-WIND, non-CC)

Reactive Capability Curve	Labels	TEST_A	TEST_B
MW1	MW		
Lagging MVAR limit associated with MW1 output	MVAR		
Leading MVAR limit associated with MW1 output	MVAR		
MW2	MW		
Lagging MVAR limit associated with MW2 output	MVAR		
Leading MVAR limit associated with MW2 output	MVAR		
MW3	MW		
Lagging MVAR limit associated with MW3 output	MVAR		
Leading MVAR limit associated with MW3 output	MVAR		
MW4	MW		
Lagging MVAR limit associated with MW4 output	MVAR		
Leading MVAR limit associated with MW4 output	MVAR		
MW5 - Unity Power Factor	MW		
If hydrogen cooled, indicate hydrogen pressure (psi) associated with your Reactive Curve submitted for ERCOT	PSI		
Maximum Leading Operating Capability (MVAR)	MVAR		
Maximum Lagging Operating Capability (MVAR)	MVAR		
Manufacturer's Capability Curve submitted?	Y/N		

ERCOT

7.2 Reactive Capability – Combined-Cycle Units

This tab contains three parts – for registering up to three trains at one site. This information is required for Units.

ERCOT Confidential | *RETURN TO MAP*

Reactive Capability

This worksheet tab provides reactive capability for ***Combined Cycle*** *generation resources. This tab is UNIT specific for* ***all CC***
Please complete this section and select RETURN TO MAP

CC GENERATION RESOURCES CC1

Reactive Capability Curve	Labels	TEST_A	TEST_B	TEST_C
MW1	MW			
Lagging MVAR limit associated with MW1 output	MVAR			
Leading MVAR limit associated with MW1 output	MVAR			
MW2	MW			
Lagging MVAR limit associated with MW2 output	MVAR			
Leading MVAR limit associated with MW2 output	MVAR			
MW3	MW			
Lagging MVAR limit associated with MW3 output	MVAR			
Leading MVAR limit associated with MW3 output	MVAR			
MW4	MW			
Lagging MVAR limit associated with MW4 output	MVAR			
Leading MVAR limit associated with MW4 output	MVAR			
MW5 - Unity Power Factor	MW			
If hydrogen cooled, indicate hydrogen pressure (psi) associated with your Reactive Curve submitted for ERCOT	PSI			
Maximum Leading Operating Capability (MVAR)	MVAR			
Maximum Lagging Operating Capability (MVAR)	MVAR			
Manufacturer's Capability Curve submitted?	Y/N			

OURCES CC2

Reactive Capability Curve	Labels			
MW1	MW			
Lagging MVAR limit associated with MW1 output	MVAR			
Leading MVAR limit associated with MW1 output	MVAR			
MW2	MW			
Lagging MVAR limit associated with MW2 output	MVAR			
Leading MVAR limit associated with MW2 output	MVAR			
MW3	MW			

7.3 Reactive Capability – Wind Units

Reactive capability must be completed for each unit as well as the manufacturer's capability curve. The units are listed in the vertical columns – the RARF allows up to five. The groups are horizontal.

Wind Resources that have multiple groupings of turbines need to provide one consolidated reactive curve for the Unit. The reactive curve is representative at the location of the modeled equivalent generator (low side of the GSU touching the transmission grid), it does not include the additional equipment installed (Capacitors or reactors). Capacitors or reactors are to be specified on the 'Capacitor or Reactor Tab' of the RARF. WGRs that have multiple groups of turbines need to submit an addendum to register combined reactive curve data for each unit.

The Authorized Representative (AR), Back up AR or officers of the RE must submit this addendum accompanied by the RARF submittal through Texas Market Link (TML) Service Request. As an alternative to ERCOT TML, the addendum may be sent by email to ercotregistration@ercot.com and mpaapl@ercot.com.

Reactive Capability Curves - TEST_TEST1	Labels	Group 1	Group 2	Group 3
MW1 (should be <= Unit Min Output or LRL)	MW			
Lagging MVAR limit associated with MW1 output	MVAR			
Leading MVAR limit associated with MW1 output	MVAR			
MW2	MW			
Lagging MVAR limit associated with MW2 output	MVAR			
Leading MVAR limit associated with MW2 output	MVAR			
MW3	MW			
Lagging MVAR limit associated with MW3 output	MVAR			
Leading MVAR limit associated with MW3 output	MVAR			
MW4 (should be >= Unit Max Output or HRL)	MW			
Lagging MVAR limit associated with MW4 output	MVAR			
Leading MVAR limit associated with MW4 output	MVAR			
Maximum Lagging Operating Capability (MVAR)	MVAR			
Maximum Leading Operating Capability (MVAR)	MVAR			
Manufacturer's Capability Curve submitted?	Y/N			

RARF DATA FIELD	Business Rules	Data type
MW1	1. This is a required field. 2. MW1 >0 3.MW1<MW2. 4. MW1 <= Unit Minimal output or LRL. Warning when this rule fails.	Numeric
Lagging MVAR limit associated with MW1 output	1. This is a Required field. 2. Lagging MVAR limit associated with MW1 output >=0. 3..The square root of (X(i)^2 + Ym(i)^2) <= S(unit MVA Rating), 1<=m<=2, 1<=i<=n. where X ->MW and Y1-> Lagging MVAR, Y2-> Leading MVAR	Numeric

Leading MVAR limit associated with MW1 output	1. This is a Required field. 2.Leading MVAR limit associated with MW1 output <=0 3.The square root of (X(i)^2 + Ym(i)^2) <= S(unit MVA Rating), 1<=m<=2, 1<=i<=n. where X ->MW and Y1-> Lagging MVAR, Y2-> Leading MVAR	Numeric
MW2	1. This is a Required field. 2. MW2 >0 3. MW2<MW3	Numeric
Lagging MVAR limit associated with MW2 output	1. This is a Required field. 2. Lagging MVAR limit associated with MW2 output >=0 3. The square root of (X(i)^2 + Ym(i)^2) <= S(unit MVA Rating), 1<=m<=2, 1<=i<=n. where X ->MW and Y1-> Lagging MVAR, Y2-> Leading MVAR	Numeric
Leading MVAR limit associated with MW2 output	1. This is a Required field. 2.Leading MVAR limit associated with MW2 output <=0 3.The square root of (X(i)^2 + Ym(i)^2) <= S(unit MVA Rating), 1<=m<=2, 1<=i<=n. where X ->MW and Y1-> Lagging MVAR, Y2-> Leading MVAR	Numeric
MW3	1. This is a Required field. 2. MW3 >0 3. MW3<MW4	Numeric
Lagging MVAR limit associated with MW3 output	1 This is a Required field. 2. Lagging MVAR limit associated with MW3 output >=0 3.The square root of (X(i)^2 + Ym(i)^2) <= S(unit MVA Rating), 1<=m<=2, 1<=i<=n. where X ->MW and Y1-> Lagging MVAR, Y2-> Leading MVAR	Numeric
Leading MVAR limit associated with MW3 output	1. This is a Required field. 2.Leading MVAR limit associated with MW3 output <=0 3.The square root of (X(i)^2 + Ym(i)^2) <= S(unit MVA Rating), 1<=m<=2, 1<=i<=n. where X ->MW and Y1->	Numeric

	Lagging MVAR, Y2-> Leading MVAR	
MW4	1. This is a Required field. 2. MW4<MW5 3. X (n) > = WMX (Unit Max output or HRL), where n is the last MW value in the curve. If the curve has 4 points, X (n) is X (4) [Generate an Error When this rule fails.	Numeric
Lagging MVAR limit associated with MW4 output	1. This is a Required field. 2.Lagging MVAR limit associated with MW4 output >=0	Numeric
Leading MVAR limit associated with MW4 output	1. This is a Required field. 2.Leading MVAR limit associated with MW3 output <=0	Numeric
Maximum Leading Operating Capability	1. This is a Required field. 2.Maximum Leading Operating Capability <=0	Numeric
Maximum Lagging Operating Capability	1This is a Required field. 2.Maximum Lagging Operating Capability >=0	Numeric
Manufacturer's Capability Curve submitted?	1. This is a Required field. 2.Select from Y or N	Numeric

7.4 REACTIVE CAPABILITY CURVES

Reactive capability is the ability of a generator unit to supply/absorb reactive power (MVAR) to the grid continuously for a given MW operating value without damaging the unit. Reactive power is required to control voltage under normal and emergency situations in order to prevent voltage collapse of the grid. Reactive capability qualification testing is required by ERCOT for verification of maximum leading and lagging capability of all generation resources required to provide voltage support service.

The Reactive Capability Curve represents the operating limits of the generator. The Reactive Capability Curve of a generator unit shows the X-axis as MW and the Y-axis as MVAR. Values above the x-axis (positive VARs) are "LAGGING" MVARs and values below the x-axis (negative VARs) are "LEADING" MVARs.

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8.0 Split Generation Resources

The responsibility for ensuring proper resource registration belongs to the Resource Entity that represents or controls the output of the unit(s). Joint-ownership is not formally defined in ERCOT. These resources are referred to as Split Generation.

If the entire output of all units at a facility/site is controlled by one Resource Entity only, then the top section should be completed. However, if multiple Resource Entities share ownership, even if the split is by entire units, then the Split Generation Resource section must be completed. This will allow the unit to be properly aligned with the Resource Entity in the ERCOT registration system.

8.1 Ownership – non-Wind, non-CC Generation Units

Complete this section ONLY if a single Resource Entity (RE) represents 100% of all units.		
Resource Owner Data	**Owner 1**	
Resource Entity Name		
Resource Duns Number		
Complete the following sections if units at the same site are represented by different Resource Entites (RE) or represented :		
TEST_A	**Owner 1**	**Owner 2**
Market Participant (Resource) Name	RESOURCEOWNER1	RESOURCEOWNER2
Market Participant (Resource) Duns Numb	123456789	3216549872000
Fixed Ownership % (must equal 100%)	60 00%	40 00%
Master Owner (Y or N)	Y	N
	Owner 1	**Owner 2**
Market Participant (Resource) Name		
Market Participant (Resource) Duns Number		
Fixed Ownership % (must equal 100%)		
Master Owner (Y or N)		

8.2 Split Resource Generation – Combined-Cycle Units

This tab contains three parts, for registering up to three trains at one site. The information is required for each train. ERCOT does not allow Combined-Cycle Resources to register as Split Generation.

	Complete this section if a single Resource Entity (RE) represents 100% of all units	
CC1	**Resource Owner Data - TEST_CC1**	**Owner**
	Resource Entity Name	RESOURCEOWNER1
	Resource Duns Number	123456789

	Complete this section if a single Resource Entity (RE) represents 100% of all units	
CC2	**Resource Owner Data -**	**Owner**
	Resource Entity Name	RESOURCEOWNER1
	Resource Duns Number	3216549872000

	Complete this section if a single Resource Entity (RE) represents 100% of all units	
CC3	**Resource Owner Data -**	**Owner**
	Resource Entity Name	
	Resource Duns Number	

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8.3 Split Resource Generation – Wind Units

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Representation of Facility Output

*This worksheet tab applies to **all WIND** Generation Resources. This tab identifies the Resource*
Please complete either the single Resource Owner section or the Split-Generation Owners secti

ND GENERATION RESOURCES

Complete this section ONLY if a single Resource Entity (RE) represents 100% of all units.	
Resource Owner Data	**Owner 1**
Resource Entity Name	
Resource Duns Number	
Complete the following sections if units at the same site are represented by different Res	
TEST_A	**Owner 1**
Market Participant (Resource) Name	RESOURCEOWNER1
Market Participant (Resource) Duns Number	123456789
Fixed Ownership % (must equal 100%)	100 00%
Master Owner (Y or N)	Y
TEST_B	**Owner 1**
Market Participant (Resource) Name	RESOURCEOWNER2
Market Participant (Resource) Duns Number	3216549872000
Fixed Ownership % (must equal 100%)	100.00%
Master Owner (Y or N)	Y
	Owner 1
Market Participant (Resource) Name	
Market Participant (Resource) Duns Number	
Fixed Ownership % (must equal 100%)	
Master Owner (Y or N)	

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9.0 Combined-Cycle Configurations and Transitions

Before the details such as ramp rates can be entered for a configuration, the configurations must be established.

9.1 Configurations

This section is pre-populated with the unit mnemonic, the unit type, and the nameplate MVA rating for reference. CCx refers to a combined cycle train, e.g. CC1 or CC2 or CC3.

Previously, ERCOT limited registration of configurations to no more than the number of units in the train. In this registration, resources are allowed to register all operationally unique configurations. When registering additional configurations, bear in mind the configurations should represent logical configurations (1-0, 2-0, 1-1, etc.), and should NOT represent uniqueness for individual units. In the example below, whether running Unit1&Steamer or Unit2&Steamer, the resource would represent only one unique configuration of 1-on-1.

Enter the unique configurations for each train. Assistance with developing all unique configurations can be found later in this document. The keys to properly identifying the configurations include defining the configurations to increase in MW and in units from left to right (configuration 1 through xx).

As a configuration is entered, the cells for all the resource parameters for that configuration will become available for data entry. The resource parameters must be filled, as this will overwrite any RARF submittals for all configurations.

ERCOT CONFIDENTIAL — ***RETURN TO MAP***

Combined Cycle Configurations

*This worksheet tab applies to **all Combined Cycle** Generation Resources. Please complete this section and select RETURN TO MAP*

As a configuration is entered into the CCx Config tab, the hatched cells will open up in the corresponding CCx Transition tab.

	Resource Name (Unit Code)	Unit Type	TEST_CC1_1	TEST_CC1_2	TEST_CC1_3
CC1	TEST_A	0	x	x	x
	TEST_B	0	a	x	x
	TEST_C	0			x
	Number of units and MW increase from left to right.				

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9.2 Transitions

As a configuration is entered into the CCx Config tab, the hatched cells will open up in the corresponding CCx Transition tab. This table is a map that, for each operating state/configuration, identifies what states/configurations are next available – e.g. adding a unit or removing a unit. This map is critical to properly transition the ERCOT systems.

ERCOT CONFIDENTIAL | RETURN TO MAP

Combined Cycle Transitions

*This worksheet tab applies to **all Combined Cycle** Generation Resources. This tab defines the operating transitions.*

Transition cells will open as a configuration is entered into the corresponding CCx Config tab. After completing this section, select RETURN TO MAP

From \ To	Offline	TEST_CC1_1	TEST_CC1_2	TEST_CC1_3	TEST_CC1_4	TEST_CC1_5
Offline		x				
TEST_CC1_1	x		x			
TEST_CC1_2	x	x		x		
TEST_CC1_3	x	x	x			
TEST_CC1_4						

9.3 Establishing Configurations and Transitions

The following are steps intended to aid in developing configurations and transitions. These steps are not required.

An example is included for illustrative purposes only. For the example, assume a three unit train named ABC_CC1, consisting of two 100MW combustion turbines (CT) and one 100MW steam turbine (CA). When one CT is on, assume the CA can operate at 50% output.

Step 1:

Establish and register all operationally unique configurations with ERCOT. When registering additional configurations, bear in mind the configurations represent logical configurations (1-0, 2-0, 1-1, etc), and should NOT represent uniqueness for individual units. In the example below, whether running Unit1&Steamer or Unit2&Steamer, the resource would only represent one unique configuration of 1-on-1. Additional background to assist with this step can be obtained from the combined cycle whitepaper found at http://www.ercot.com/calendar/2008/01/20080121-TPTF.html, item 31.

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This step should also establish a configuration order, 1 through xx (where xx represents, at a maximum, the number of unique configurations for the train). The sort order for the configurations should be from lowest to highest MW. A secondary sort order, if needed, would be to assign the lower configuration number to the configuration with fewer units operating.

Step 1 Example:

CC1 can operate in four unique configurations – 1x0, 2x0, 1x1, and 2x1. Each configuration has a different MW output. These configurations and the output have been identified in the table to the right. Applying the configuration order requirement, the yellow cells identify the order that they should be entered into the CCx Config table.

CC1		[redacted]	1x0	2x0	1x1	2x1
Unit 1	CT		x	x	x	x
Unit 2	CT		a	x	a	x
Unit 3	CA				x	x
			100	200	150	300
			1	*3*	*2*	*4*

Step 2:

Enter the configurations into the CCx Config tab of Addendum 2.

Step 2 Example:

[redacted]				
	X	X	X	X
	A	A	X	X
		X		X

Step 3:

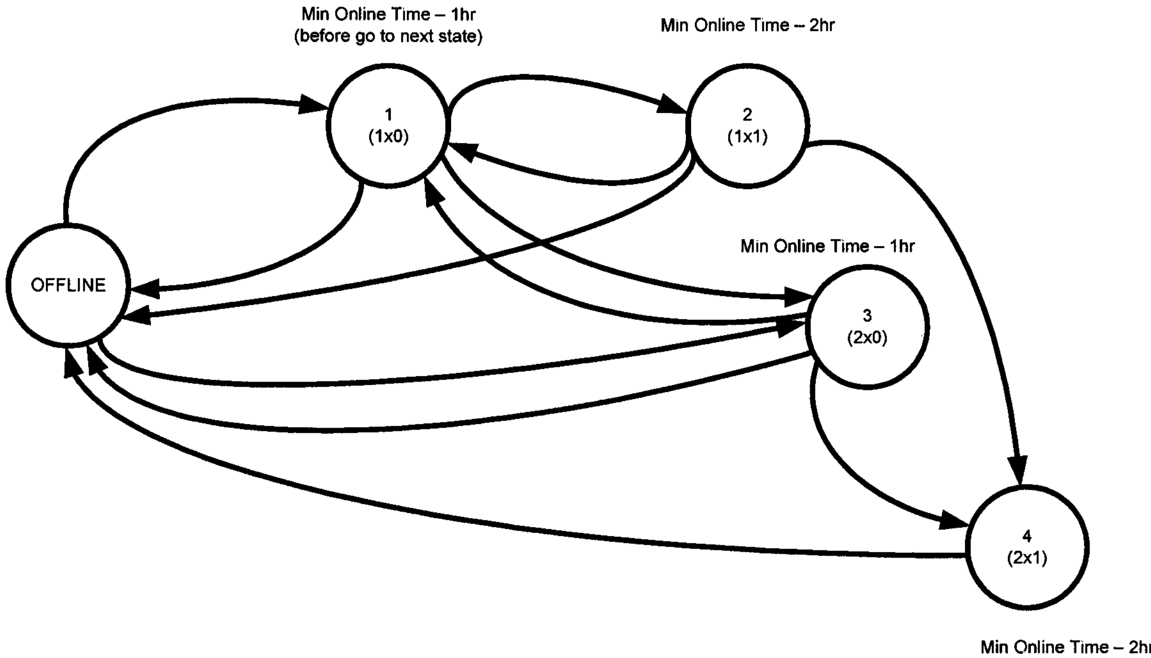
Enter resource parameter information for the configurations. Use the hyperlinks and the map to return to these sections.

Step 4:

Construct a state diagram, where each configuration is a "state" represented by a circle. Then arrows are drawn from each configuration to any other that can be reached **within the minimum online time.**

The state diagram should be laid out from left to right, where OFFLINE is furthest to the left, and the highest configuration number is furthest to the right. Draw arrows between states/configurations to indicate where the train could operate next. If the configurations were assigned correctly, arrows to the right should add a unit and increase MW. Arrows to the left should indicate decreasing MW and units. This diagram will help you build an accurate matrix for the Nodal systems.

Step 4 Example:



Step 5:

Go to the transition tab to complete the transition matrix.

Referring to the state diagram constructed in Step 4, each arrow should be an X in the matrix. With this layout, an arrow from left to right will be entered as an X in the transition matrix *above* the black diagonal, and any arrow from right to left will be entered as an X in the transition matrix *below* the black diagonal.

Please keep in mind that the unit will stay in any one state/configuration for the duration of the minimum online time.

Step 5 Example:

From Offline, this train can go to ABC_CC1_1 or ABC_CC1_2. This could be any state that could be reached in one hour from offline. The unit will stay in the initial state for the duration of the minimum online time.

[redacted]					
		X		X	
	X		X	X	
	X	X			X
	X	X			X
	X				

In this example, the train could reach Configuration 4 after 1 hour by going from Offline to Configuration 3 (ABC_CC1_3), wait the minimum online time of 1 hour, then transition to Configuration 4 (ABC_CC1_4). If the steamer cannot be ready in 1 hour, then the minimum online time should be increased for Configuration 3.

Alternatively, the train could reach Configuration 4 in 3 hours by going from ABC_CC1_1, wait 1 hour, go to ABC_CC1_2, wait 2 hours, then go to ABC_CC1_4. Again, if the steamer cannot be ready in 1 hour, then the minimum online time for Configuration 1 should be increased.

Complete these steps for each CC train.

10.0 Planning

The Planning Information section of the RARF, along with the PSSE Model datasheets, provides ERCOT with the information needed to properly complete studies. The planning section of the RARF has been separated into three sections.

10.1 Planning Information

This section provides details to ERCOT regarding generator details, auxiliary load information, acknowledgement of PSSE model submittals, as well as transient and subtransient reactances.

The System Protection Working Group needs the Positive, Negative, and Zero sequence impedances. **Note that these are for Short Circuit Studies only**

The Auxiliary Load should be defined by identifying the amount of load in MW and MVAR for each unit. The Load Characteristics should be completed to allocate 100% of the MW and MVAR (separately) across the types of load the facility may have. Please include any motor connected to 2400V/4160V and above with the large motor percentage and lower voltage motors as small.

New Resources should request the PSSE model direct from the manufacturer, especially if the standard models do not exist. Sample forms are posted on ERCOT website at http://www.ercot.com/content/gridinfo/generation/ResourceMod.zip

If there are questions related to the PSSE models, please contact your designated ERCOT Account Manager or email Wholesale Client Services at NodalMarketTransition@ercot.com.

10.1.1 Planning – non-Wind, non-CC Generation Units

RARF DATA FIELD	Business Rules	Data type
What is the MVA base that the following data is based on?	1) This field is required 2) Value must be Float 3) Generate a Warning if MVABASE > 2500 4) If MVABASE value is within the +/- 25% variation of Unit Name Plate Rating entered in unit information tab OR MVABASE value = 100 MVA , then it is OK. Otherwise , Generate a Warning.	Float
What is the kV base that the following data is based on?	1) This field is required 2) Value must be >0 and <1000 3) Generate a Warning if KVBASE > 40 4) If KVBASE value is within +/- 25% range of Unit KV value entered in the unit-information tab ,then it is OK. Otherwise, Generate a Warning.	Float

Direct Axis Sub transient reactance, X"di	1) This field is required and Data type is float 2) Value must be between -1 and 1. Generate a Warning if it is outside the limits 3) Generate a Warning if the value entered is not within the calculated typical lower and upper limits. Warning should include the entered value and the typical limit value.(* Required Calculation of Lower Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.07 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)] *Required Calculation of Upper Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.50 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)]	Float
Direct Axis Transient reactance, X'di	1) This field is required and Data type is float 2) Value must be between 0 and 2. Generate a Warning if it is outside the limits 3) Generate a Warning if the value entered is not within the calculated typical lower and upper limits. Warning should include the entered value and the typical limit value. (* Required Calculation of Lower Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.12 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)] *Required Calculation of Upper Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.60 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)]	Float
Positive Sequence Z (saturated) - (R in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 1. Generate a Warning if it is outside the limits	Float
Positive Sequence Z (saturated) - (X in p.u)	1) This field is required and Data type is numeric 2) Value must be between 0 and 100 3) Generate a Warning if the value entered is not within the calculated typical lower and upper limits. Warning should include the entered value and the typical limit value. (* Required Calculation of Lower Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.07 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)] *Required Calculation of Upper Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.50 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)]	Float

Negative Sequence Z (saturated) - (R in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 1. Generate a Warning if it is outside the limits.	Float
Negative Sequence Z (saturated) - (X in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 100. Generate a Warning if it is outside the limits 3) Generate a Warning if the value entered is not within the calculated typical lower and upper limits. Warning should include the entered value and the typical limit value. (* Required Calculation of Lower Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.07 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)] *Required Calculation of Upper Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.65 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)]	Float
Zero Sequence Z (saturated) - (R in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 1. Generate a Warning if R > 1.0 p.u	Float
Zero Sequence Z (saturated) - (X in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 100. Generate a Warning if it is outside the limits 3) Generate a Warning if the value entered is not within the calculated typical lower and upper limits. Warning should include the entered value and the typical limit value. (* Required Calculation of Lower Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.01 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)] *Required Calculation of Upper Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.24 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)]	Float
Average Amount of Auxiliary Real Power	1) This field is optional 2) Data type is float 3) Value must be < Parameters - GEN - High Reasonability Limit 4) Warn if value > (High Reasonability Limit) * .75 5) Error if value > (High Reasonability Limit) * .66	Float
Average Amount of Auxiliary Reactive Power	1) This field is optional 2) Data type is Float 3) Value must be < Reactive Capability - GEN - Maximum Lagging Operating Capability (MVAR) 4) Warn if value > (Maximum Lagging Operating Capability) * .75 5) Error if value > (Maximum Lagging Operating Capability) * .66	Float

Generation Auxiliary Load Characteristics for MW Load - Large Motor, percent of total MW load	1) This field is optional 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MW Load) = 100% 4) Motors connected at >= 2400V / 4160V are large motors	Percent
Generation Auxiliary Load Characteristics for MW Load - Small Motor, percent of total MW load	1) This field is optional 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MW Load) = 100% 4) Motors connected at < 2400V / 4160V are small motors	Percent
Generation Auxiliary Load Characteristics for MW Load - Resistive (Heating) Load, percent of total MW load	1) This field is optional 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MW Load) = 100%	Percent
Generation Auxiliary Load Characteristics for MW Load - Discharge Lighting, percent of total MW load	1) This field is optional 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MW Load) = 100%	Percent
Generation Auxiliary Load Characteristics for MW Load - Other, percent of total MW load	1) This field is optional 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MW Load) = 100%	Percent
Generation Auxiliary Load Characteristics for MVAR Load - Large Motor, percent of total MVAR load	1) This field is optional 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MVAR Load) = 100% 4) Motors connected at >= 2400V / 4160V are large motors	Percent
Generation Auxiliary Load Characteristics for MVAR Load - Small Motor, percent of total MVAR load	1) This field is optional 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MW Load) = 100% 4) Motors connected at < 2400V / 4160V are small motors	Percent
Generation Auxiliary Load Characteristics for MVAR Load - Discharge Lighting, percent of total MVAR load	1) This field is optional 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MVAR Load) = 100%	Percent
Generation Auxiliary Load Characteristics for MVAR Load - Other, percent of total MVAR load	1) This field is optional 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MVAR Load) = 100%	Percent

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10.1.2 Planning – Combined Cycle

This tab contains three parts, for registering up to three trains at one site.

RARF DATA FIELD	Business Rules	Data type
What is the MVA base that the following data is based on?	1) This field is required 2) Value must be Float 3) Generate a Warning if MVABASE > 2500 4) If MVABASE value is within the +/- 25% variation of Unit Name Plate Rating entered in unit information tab] OR MVABASE value = 100 MVA then it is OK. Otherwise, Generate a Warning.	Float
What is the kV base that the following data is based on?	1) This field is required 2) Value must be >0 and <1000 3) Generate a Warning if KVBASE > 40 4) If KVBASE value is within +/- 25% range of Unit KV value entered in the unit-information tab ,then it is OK. Otherwise, Generate a Warning.	Float
Direct Axis Sub transient reactance, X"di - (R in p.u)	1) This field is required and Data type is float 2) Value must be between -1 and 1. Generate a Warning if it is outside the limits 3) Generate a Warning if the value entered is not within the calculated typical lower and upper limits. Warning should include the entered value and the typical limit value. (* Required Calculation of Lower Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.07 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)] *Required Calculation of Upper Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.50 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)]	Float
Direct Axis Transient reactance, X'di - (X in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 2. Generate a Warning if it is outside the limits 3) Generate a Warning if the value entered is not within the calculated typical lower and upper limits. Warning should include the entered value and the typical limit value. (* Required Calculation of Lower Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.12 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)] *Required Calculation of Upper Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.60 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab /	Float

	Nameplate Rating MVA from the Unit Info tab)]	
Positive Sequence Z (saturated) - (R in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 1. Generate a Warning if it is outside the limits	Float
Positive Sequence Z (saturated) - (X in p.u)	1) This field is required and Data type is numeric 2) Value must be between 0 and 100. Generate a Warning if it is outside the limits 3) Generate a Warning if the value entered is not within the calculated typical lower and upper limits. Warning should include the entered value and the typical limit value. (* Required Calculation of Lower Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.07 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)] *Required Calculation of Upper Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.50 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)]	Float
Negative Sequence Z (saturated) - (R in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 1. Generate a Warning if it is outside the limits	Float
Negative Sequence Z (saturated) - (X in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 100 .Generate a Warning if it is outside the limits 3) Generate a Warning if the value entered is not within the calculated typical lower and upper limits. Warning should include the entered value and the typical limit value. (* Required Calculation of Lower Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.07 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)] *Required Calculation of Upper Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.65 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)]	Float

Zero Sequence Z (saturated) - (R in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 1. Generate a Warning if R > 1.0 p.u	Float
Zero Sequence Z (saturated) - (X in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 100 . Generate a Warning if it is outside the limits 3) Generate a Warning if the value entered is not within the calculated typical lower and upper limits. Warning should include the entered value and the typical limit value. (* Required Calculation of Lower Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.01 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)] *Required Calculation of Upper Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.24 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)]	Float
Average Amount of Auxiliary Real Power	1) This field is Required 2) Data type is float 3) Value must be < Parameters - GEN - High Reasonability Limit 4) Warn if value > (High Reasonability Limit) * .75 5) Error if value > (High Reasonability Limit) * .66	Float
Average Amount of Auxiliary Reactive Power	1) This field is Required 2) Data type is Float 3) Value must be < Reactive Capability - GEN - Maximum Lagging Operating Capability (MVAR) 4) Warn if value > (Maximum Lagging Operating Capability) * .75 5) Error if value > (Maximum Lagging Operating Capability) * .66	Float
Generation Auxiliary Load Characteristics for MW Load - Large Motor, percent of total MW load	1) This field is Required 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MW Load) = 100% 4) Motors connected at >= 2400V / 4160V are large motors	Percent
Generation Auxiliary Load Characteristics for MW Load - Small Motor, percent of total MW load	1) This field is Required 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MW Load) = 100% 4) Motors connected at < 2400V / 4160V are small motors	Percent
Generation Auxiliary Load Characteristics for MW Load - Resistive (Heating) Load, percent of total MW load	1) This field is Required 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MW Load) = 100%	Percent

Generation Auxiliary Load Characteristics for MW Load - Discharge Lighting, percent of total MW load	1) This field is Required 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MW Load) = 100%	Percent
Generation Auxiliary Load Characteristics for MW Load - Other, percent of total MW load	1) This field is Required 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MW Load) = 100%	Percent
Generation Auxiliary Load Characteristics for MVAR Load - Large Motor, percent of total MVAR load	1) This field is Required 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MVAR Load) = 100% 4) Motors connected at >= 2400V / 4160V are large motors	Percent
Generation Auxiliary Load Characteristics for MVAR Load - Small Motor, percent of total MVAR load	1) This field is Required 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MW Load) = 100% 4) Motors connected at < 2400V / 4160V are small motors	Percent
Generation Auxiliary Load Characteristics for MVAR Load - Discharge Lighting, percent of total MVAR load	1) This field is Required 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MVAR Load) = 100%	Percent
Generation Auxiliary Load Characteristics for MVAR Load - Other, percent of total MVAR load	1) This field is Required 2) Data Type must be percent 3) SUM(All Generation Auxiliary Load Characteristics for MVAR Load) = 100%	Percent

10.1.3 Planning – Wind Units

For non-Wind Generation Resources, the Over/Under Excitation Limiter form is new and must be submitted to ERCOT as soon as possible.

RARF DATA FIELD	Business Rules	Data type
What is the MVA base that the following data is based on?	1) This field is required 2) Value must be Float 3) Generate a Warning if MVABASE > 2500 4)If MVABASE value is within the +/- 25% variation of Unit Name Plate Rating entered in unit information tab] OR MVABASE value = 100 MVA , then it is OK. Otherwise , Generate a Warning.	Float
What is the kV base that the following data is based on?	1) This field is required 2) Value must be >0 and <1000 3) Generate a Warning if KVBASE > 40 4) If KVBASE value is within +/- 25% range of Unit KV value entered in the unit-information tab ,then it is OK. Otherwise, Generate a Warning.	Float

Direct Axis Sub transient reactance, X"di - (R in p.u)	1) This field is required and Data type is float 2)Value must be between -1 and 1. Generate a Warning if it is outside the limits 3) Generate a Warning if the value entered is not within the calculated typical lower and upper limits. Warning should include the entered value and the typical limit value. (* Required Calculation of Lower Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.07 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)] *Required Calculation of Upper Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.50 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)]	Float
Direct Axis Transient reactance, X'di - (X in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 2. Generate a Warning if it is outside the limits 3) Generate a Warning if the value entered is not within the calculated typical lower and upper limits. Warning should include the entered value and the typical limit value. (* Required Calculation of Lower Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.12 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)] *Required Calculation of Upper Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.60 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)]	Float
Positive Sequence Z (saturated) - (R in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 1. Generate a Warning if it is outside the limits	Float

Positive Sequence Z (saturated) - (X in p.u)	1) This field is required and Data type is numeric 2) Value must be between 0 and 100 . Generate a Warning if it is outside the limits 3) Generate a Warning if the value entered is not within the calculated typical lower and upper limits. Warning should include the entered value and the typical limit value. (* Required Calculation of Lower Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.07 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)] *Required Calculation of Upper Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.50 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)]	Float
Negative Sequence Z (saturated) - (R in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 1. Generate a Warning if it is outside the limits	Float
Negative Sequence Z (saturated) - (X in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 100. Generate a Warning if it is outside the limits 3) Generate a Warning if the value entered is not within the calculated typical lower and upper limits. Warning should include the entered value and the typical limit value. (* Required Calculation of Lower Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.07 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)] *Required Calculation of Upper Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.65 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)]	Float
Zero Sequence Z (saturated) - (R in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 1. Generate a Warning if R > 1.0 p.u	Float

Zero Sequence Z (saturated) - (X in p.u)	1) This field is required and Data type is float 2) Value must be between 0 and 100. Generate a Warning if it is outside the limits 3) Generate a Warning if the value entered is not within the calculated typical lower and upper limits. Warning should include the entered value and the typical limit value. (* Required Calculation of Lower Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.01 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)] *Required Calculation of Upper Limit Typical Reactance (X) on the Planning tab specified MVA and KV base = 0.24 * [(Unit Generating Voltage KV from the Unit Info tab / KV Base entered in row 8 of the Planning tab)^2] * (MVA base entered in row 7 of the Planning tab / Nameplate Rating MVA from the Unit Info tab)]	Float

10.2 Protection

The protection section of the Planning tabs covers the breaker interruption time as well as the voltage and frequency protection of the unit.

10.2.1 Protection – non-Wind, non-CC Generation Units

RARF DATA FIELD	Business Rules	Data type
Instantaneous Under voltage Trip	1) This field is optional 2) Data type must be Float 3) This should be expressed in p.u values. Generate a Warning if value <=0 and >396 p.u.	Float
Instantaneous Under voltage Trip - Time 1 Time 2 Time 3 Time 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)TIME 1 = required,TIME2, TIME3, TIME4 are optional 4)User can fill in a Stage provided the previous stage exists. For example TIME4 stage only exists if there is a TIME3 stage and a TIME2 stage 5) Time 1 > Time 2 > Time 3 >Time 4 (time points must decrement) 6)Time setting are dependent on voltage settings, cannot have time settings without voltage settings. Time settings should exist if time delayed under/voltage settings defined	Float

Instantaneous Undervoltage Trip - Undervoltage 1 Undervoltage 2 Undervoltage 3 Undervoltage 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3) Under voltage 1 is required, Under voltage 2,3,4 are optional 4)Voltage settings should exist if time settings are defined 5)This should be expressed in p.u values. Generate a Warning if value <=0 and >396 p.u.	Float
Instantaneous Overvoltage Trip	1) This field is optional 2) Data type must be Float 3)This should be expressed in p.u values. Generate a Warning if value <=0 and >396 p.u.	Float
Instantaneous Overvoltage Trip Time 1 Time 2 Time 3 Time 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)TIME 1 = required,TIME2, TIME3, TIME4 are optional 4)User can fill in a Stage provided the previous stage exists. For example TIME4 stage only exists if there is a TIME3 stage and a TIME2 stage 5) Time 1 > Time 2 > Time 3 >Time 4 (time points must decrement) 6) Time setting are dependent on voltage settings, cannot have time settings without voltage settings. Time settings should exist if time delayed under/voltage settings defined	Float
Instantaneous Overvoltage Trip - Overvoltage 1 Overvoltage 2 Overvoltage 3 Overvoltage 4	1) 1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)Under voltage 1 is required, Under voltage 2,3,4 are optional 4)Voltage settings should exist if time settings are defined 5)This should be expressed in p.u values. Generate a Warning if value <=0 and >396 p.u.	Float
Instantaneous Under frequency Trip	1) This field is optional 2) Data type must be Float	Float
Instantaneous Under frequency Trip Time 1 Time 2 Time 3 Time 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)TIME 1 = required,TIME2, TIME3, TIME4 are optional 4)User can fill in a Stage provided the previous stage exists. For example TIME4 stage only exists if there is a TIME3 stage and a TIME2 stage 5) Time 1 > Time 2 > Time 3 >Time 4 (time points must decrement) 6)Time setting is dependent on frequency setting, cannot have time setting without frequency setting 7)If the instantaneous setting is defined then Time1 is not required. Time 1 is only required if they have time delayed under or over frequency settings. Each set should have at a minimum of 1 stage (TIME 1 = required) if instantaneous setting is blank OR time delayed under or over frequency settings defined	Float

Instantaneous Under frequency Trip - Under frequency 1 Under frequency 2 Under frequency 3 Under frequency 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3) Frequency Settings Range is defined as below. 55 - 65 Hz= OK, <55 Hz = ERROR, >65 Hz= ERROR. Any number of stages can be defined as long as the time increments are in the following order. Time1>Time2>Time3>Time4.If there are any instantaneous settings defined, then the time should be zero 4) Under frequency 1 is required, Under frequency 2,3,4 are optional 5)time setting is dependent on frequency setting, cannot have time setting without frequency setting 6)If the instantaneous setting is defined then Time1 is not required. Time 1 is only required if they have time delayed under or over frequency settings. 7)Frequency settings should exist if time settings are defined'	Float
Instantaneous Over frequency Trip	1) This field is optional 2) Data type must be Float	Float
Instantaneous Over frequency Trip Time 1 Time 2 Time 3 Time 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)TIME 1 = required,TIME2, TIME3, TIME4 are optional 4)User can fill in a Stage provided the previous stage exists. For example TIME4 stage only exists if there is a TIME3 stage and a TIME2 stage 5) Time 1 > Time 2 > Time 3 >Time 4 (time points must decrement) 6)time setting is dependent on frequency setting, cannot have time setting without frequency setting 7)If the instantaneous setting is defined then Time1 is not required. Time 1 is only required if they have time delayed under or over frequency settings. Each set should have at a minimum of 1 stage (TIME 1 = required) if instantaneous setting is blank OR time delayed under or over frequency settings defined	Float
Instantaneous Over frequency Trip - Over frequency 1 Over frequency 2 Over frequency 3 Over frequency 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3) Frequency Settings Range is defined as below. 55 - 65 Hz= OK, <55 Hz = ERROR, >65 Hz=Warning.. Any number of stages can be defined as long as the time increments are in the following order. Time1>Time2>Time3>Time4.If there are any instantaneous settings defined, then the time should be zero 4) Over frequency 1 is required, Over frequency 2,3,4 are optional 5)time setting is dependent on frequency setting, cannot have time setting without frequency setting 6)Frequency settings should exist if time settings are defined'	Float
Breaker Interruption Time	1) this field is required 2) Data type must be Integer	Integer

000002
345

10.2.2 Protection – Combined Cycle

This tab contains three parts – for registering up to three trains at one site. This information is required for each unit of the train.

RARF DATA FIELD	Business Rules	Data type
Instantaneous Under voltage Trip	1) This field is optional 2) Data type must be Float 3)This should be expressed in p.u values. Generate a Warning if value <=0 and >396 p.u.	Float
Instantaneous Under voltage Trip - Time 1 Time 2 Time 3 Time 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)TIME 1 = required,TIME2, TIME3, TIME4 are optional 4)User can fill in a Stage provided the previous stage exists. For example TIME4 stage only exists if there is a TIME3 stage and a TIME2 stage 5) Time 1 > Time 2 > Time 3 >Time 4 (time points must decrement) 6) Time setting are dependent on voltage settings, cannot have time settings without voltage settings. Time settings should exist if time delayed under/voltage settings defined	Float
Instantaneous Undervoltage Trip - Undervoltage 1 Undervoltage 2 Undervoltage 3 Undervoltage 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)Under voltage 1 is required, Under voltage 2,3,4 are optional 4)Voltage settings should exist if time settings are defined 5)This should be expressed in p.u values. Generate a Warning if value <=0 and >396 p.u.	Float
Instantaneous Overvoltage Trip	1) This field is optional 2) Data type must be Float 3)This should be expressed in p.u values. Generate a Warning if value <=0 and >396 p.u.	Float
Instantaneous Overvoltage Trip Time 1 Time 2 Time 3 Time 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)TIME 1 = required,TIME2, TIME3, TIME4 are optional 4)User can fill in a Stage provided the previous stage exists. For example TIME4 stage only exists if there is a TIME3 stage and a TIME2 stage 5) Time 1 > Time 2 > Time 3 >Time 4 (time points must decrement) 6) Time setting are dependent on voltage settings, cannot have time settings without voltage settings. Time settings should exist if time delayed under/voltage settings defined	Float
Instantaneous Overvoltage Trip - Overvoltage 1 Overvoltage 2 Overvoltage 3 Overvoltage 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3) Over voltage 1 is required, OverVoltage2,3,4 are optional 4)Voltage settings should exist if time settings are defined 5) This should be expressed in p.u values. Generate a	Float

000346

	Warning if value <=0 and >396 p.u.	
Instantaneous Under frequency Trip	1) This field is OPTIONAL 2) Data type must be Float	Float
Instantaneous Under frequency Trip Time 1 Time 2 Time 3 Time 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)TIME 1 = required,TIME2, TIME3, TIME4 are optional 4)User can fill in a Stage provided the previous stage exists. For example TIME4 stage only exists if there is a TIME3 stage and a TIME2 stage 5) Time 1 > Time 2 > Time 3 >Time 4 (time points must decrement) 6)time setting is dependent on frequency setting, cannot have time setting without frequency setting 7)If the instantaneous setting is defined then Time1 is not required. Time 1 is only required if they have time delayed under or over frequency settings. Each set should have at a minimum of 1 stage (TIME 1 = required) if instantaneous setting is blank OR time delayed under or over frequency settings defined	Float
Instantaneous Under frequency Trip - Under frequency 1 Under frequency 2 Under frequency 3 Under frequency 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)Frequency Settings Range is defined as below. 55 – 65 Hz= OK, <55 Hz = ERROR, >65 Hz= ERROR Any number of stages can be defined as long as the time increments are in the following order. Time1>Time2>Time3>Time4.If there are any instantaneous settings defined, then the time should be zero Time1>Time2>Time3>Time4.If there are any instantaneous settings defined, then the time should be zero 4) Under frequency 1 is required, Under frequency 2,3,4 are optional 5)Frequency settings should exist if time settings are defined	Float
Instantaneous Over frequency Trip	1) This field is OPTIONAL 2) Data type must be Float	Float

Instantaneous Over frequency Trip Time 1 Time 2 Time 3 Time 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)TIME 1 = required,TIME2, TIME3, TIME4 are optional 4)User can fill in a Stage provided the previous stage exists. For example TIME4 stage only exists if there is a TIME3 stage and a TIME2 stage 5) Time 1 > Time 2 > Time 3 >Time 4 (time points must decrement) 6)time setting is dependent on frequency setting, cannot have time setting without frequency setting 7)If the instantaneous setting is defined then Time1 is not required. Time 1 is only required if they have time delayed under or over frequency settings. Each set should have at a minimum of 1 stage (TIME 1 = required) if instantaneous setting is blank OR time delayed under or over frequency settings defined	Float
Instantaneous Over frequency Trip - Over frequency 1 Over frequency 2 Over frequency 3 Over frequency 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)Frequency Settings Range is defined as below. 55 - 65 Hz= OK, <55 Hz = ERROR, >65 Hz=Warning.. Any number of stages can be defined as long as the time increments are in the following order. Time1>Time2>Time3>Time4.If there are any instantaneous settings defined, then the time should be zero Any number of stages can be defined as long as the time increments are in the following order. Time1>Time2>Time3>Time4.If there are any instantaneous settings defined, then the time should be zero 4) Over frequency 1 is required, Over frequency 2,3,4 are optional 5)Frequency settings should exist if time settings are defined	Float
Breaker Interruption Time	1) this field is required 2) Data type must be Integer	Integer

10.2.3 Protection – Wind Units

RARF DATA FIELD	Business Rules	Data type
Instantaneous Under voltage Trip	1) This field is optional 2) Data type must be Float 3)This should be expressed in p.u values	Float

Instantaneous Under voltage Trip - Time 1 Time 2 Time 3 Time 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)TIME 1 = required,TIME2, TIME3, TIME4 are optional 4)User can fill in a Stage provided the previous stage exists. For example TIME4 stage only exists if there is a TIME3 stage and a TIME2 stage 5) Time 1 > Time 2 > Time 3 >Time 4 (time points must decrement) 6)Time setting are dependent on voltage settings, cannot have time settings without voltage settings Time settings should exist if time delayed under/voltage settings defined	Float
Instantaneous Undervoltage Trip - Undervoltage 1 Undervoltage 2 Undervoltage 3	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)Under voltage 1 is required, Under voltage 2,3,4 are optional 4)Voltage settings should exist if time settings are defined 5)This should be expressed in p.u values	Float
Instantaneous Overvoltage Trip	1) This field is optional 2) Data type must be Float 3)This should be expressed in p.u values	Float
Instantaneous Overvoltage Trip Time 1 Time 2 Time 3 Time 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)TIME 1 = required,TIME2, TIME3, TIME4 are optional 4)User can fill in a Stage provided the previous stage exists. For example TIME4 stage only exists if there is a TIME3 stage and a TIME2 stage 5) Time 1 > Time 2 > Time 3 >Time 4 (time points must decrement) 6) Time setting are dependent on voltage settings, can not have time settings without voltage settings. Time settings should exist if time delayed under/voltage settings defined	Float
Instantaneous Overvoltage Trip - Overvoltage 1 Overvoltage 2 Overvoltage 3 Overvoltage 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)Overvoltage 1 is required, Overvoltage 2,3,4 are optional 4)Voltage settings should exist if time settings are defined 5)This should be expressed in p.u values	Float
Instantaneous Under frequency Trip	1) This field is optional 2) Data type must be Float	Float

Instantaneous Under frequency Trip Time 1 Time 2 Time 3 Time 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)TIME 1 = required,TIME2, TIME3, TIME4 are optional 4)User can fill in a Stage provided the previous stage exists. For example TIME4 stage only exists if there is a TIME3 stage and a TIME2 stage 5) Time 1 > Time 2 > Time 3 >Time 4 (time points must decrement) 6)time setting is dependent on frequency setting, cannot have time setting with out frequency setting 7)If the instantaneous setting is defined then Time1 is not required. Time 1 is only required if they have time delayed under or over frequency settings. Each set should have at a minimum of 1 stage (TIME 1 = required) if instantaneous setting is blank OR time delayed under or over frequency settings defined	Float
Instantaneous Under frequency Trip - Under frequency 1 Under frequency 2 Under frequency 3 Under frequency 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)Frequency Settings Range is defined as below. 55 – 65 Hz= OK, <55 Hz = ERROR, >65 Hz= ERROR Any number of stages can be defined as long as the time increments are in the following order. Time1>Time2>Time3>Time4.If there are any instantaneous settings defined, then the time should be zero 4) Under frequency 1 is required, Under frequency 2,3,4 are optional 5)Frequency settings should exist if time settings are defined	Float
Instantaneous Over frequency Trip	1) This field is OPTIONAL 2) Data type must be Float	Float
Instantaneous Over frequency Trip Time 1 Time 2 Time 3 Time 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3)TIME 1 = required,TIME2, TIME3, TIME4 are optional 4)User can fill in a Stage provided the previous stage exists. For example TIME4 stage only exists if there is a TIME3 stage and a TIME2 stage 5) Time 1 > Time 2 > Time 3 >Time 4 (time points must decrement) 6)time setting is dependent on frequency setting, cannot have time setting with out frequency setting 7)If the instantaneous setting is defined then Time1 is not required. Time 1 is only required if they have time delayed under or over frequency settings. Each set should have at a minimum of 1 stage (TIME 1 = required) if instantaneous setting is blank OR time delayed under or over frequency settings defined	Float

Instantaneous Over frequency Trip - Over frequency 1 Over frequency 2 Over frequency 3 Over frequency 4	1) This field is required when Instantaneous setting is not defined 2) Data type must be Float 3) Frequency Settings Range is defined as below. 55 - 65 Hz= OK, <55 Hz = ERROR, >65 Hz=Warning.. Any number of stages can be defined as long as the time increments are in the following order. Time1>Time2>Time3>Time4.If there are any instantaneous settings defined, then the time should be zero Any number of stages can be defined as long as the time increments are in the following order. Time1>Time2>Time3>Time4.If there are any instantaneous settings defined, then the time should be zero 4) Over frequency 1 is required, Over frequency 2,3,4 are optional 5)Frequency settings should exist if time settings are defined'	Float
Breaker Interruption Time	1) this field is required 2) Data type must be Integer	Integer

10.3 Sub-synchronous Resonance

Sub-synchronous Resonance information has been difficult for many Resources to provide. At this time, the studies that need this information are not completed often, but will become more common as capacitor compensation is used in series on long transmission lines.

The studies focus on the units at either end of the lines compensated with the series capacitors to ensure the resonance from these lines will not excite critical frequencies in the machines in the areas at the ends of these lines.

In the future, these studies will be useful to Resource owners interested in equipment damage prevention.

Due to the infrequent nature of these studies, ERCOT accepts minimal information in these fields at this time. However, as series compensation is installed on our grid, this information will become necessary and critical to system performance

ERCOT

10.3.1 Sub-synchronous Resonance – non-Wind, non-CC Generation Units

ERCOT Confidential	RETURN TO MAP		
Planning Information			
*This worksheet tab provides subsynchronous resonance planning information for **generation** resources. This tab is UNIT specific for **all non-Win***			
Please complete this section and select RETURN TO MAP			

GEN (non-Wind, non-CC)

Subsynchronous Resonance - Mass 1	**TEST_A**	**TEST_B**	
Name of Mass 1			
Mass Inertia			
Inertia units			
Associated damping			
Damping units			
Subsynchronous Resonance - Mass 2	**TEST_A**	**TEST_B**	
Name of Mass 2			
Mass Inertia			
Inertia units			
Associated damping			
Damping units			
Stiffness between Masses 1 and 2			
Stiffness units			
Subsynchronous Resonance - Mass 3	**TEST_A**	**TEST_B**	
Name of Mass 3			
Mass Inertia			
Inertia units			
Associated damping			
Damping units			
Stiffness between Masses 2 and 3			
Stiffness units			
Subsynchronous Resonance - Mass 4	**TEST_A**	**TEST_B**	
Name of Mass 4			
Mass Inertia			
Inertia units			
Associated damping			
Damping units			
Stiffness between Masses 3 and 4			
Stiffness units			
Subsynchronous Resonance - Mass 5	**TEST_A**	**TEST_B**	
Name of Mass 5			
Mass Inertia			
Inertia units			
Associated damping			
Damping units			
Stiffness between Masses 4 and 5			
Stiffness units			

10.3.2 Sub-synchronous Resonance – Combined Cycle

This tab contains three parts, for registering up to three trains at one site. This information is required for each unit of the train.

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Planning Information

This worksheet tab provides subsynchronous resonance planning information for ***Combined Cycle*** *generation resources. This tab is UNIT specific f*
Please complete this section and select RETURN TO MAP

CC1

Subsynchronous Resonance - Mass 1	**TEST_A**	**TEST_B**	**TEST_C**
Name of Mass 1			
Mass Inertia			
Inertia units			
Associated damping			
Damping units			
Subsynchronous Resonance - Mass 2	**TEST_A**	**TEST_B**	**TEST_C**
Name of Mass 2			
Mass Inertia			
Inertia units			
Associated damping			
Damping units			
Stiffness between Masses 1 and 2			
Stiffness units			
Subsynchronous Resonance - Mass 3	**TEST_A**	**TEST_B**	**TEST_C**
Name of Mass 3			
Mass Inertia			
Inertia units			
Associated damping			
Damping units			
Stiffness between Masses 2 and 3			
Stiffness units			
Subsynchronous Resonance - Mass 4	**TEST_A**	**TEST_B**	**TEST_C**
Name of Mass 4			
Mass Inertia			
Inertia units			
Associated damping			
Damping units			
Stiffness between Masses 3 and 4			
Stiffness units			
Subsynchronous Resonance - Mass 5	**TEST_A**	**TEST_B**	**TEST_C**
Name of Mass 5			
Mass Inertia			
Inertia units			
Associated damping			
Damping units			
Stiffness between Masses 4 and 5			
Stiffness units			

ERCOT

11.0 Private Use Networks

Private Use Networks require information at both the site and unit level. If the facility is a Private Use Network – load other than auxiliary load behind the EPS meter – then enter Y for the response to "Private Network?" This will open the rest of the hatched cells on the page that must be completed.

11.1 Site Information

Each private network should provide the MW and MVAR that can be generated, that which is typically used by the facility, and that which is net to the grid. ERCOT is aware this net value can swing widely, and telemetry will provide details. If possible, provide an average over the past year.

Similar to the auxiliary load, load characteristics must be provided for the planning studies. Each of the % for MW Load and for MVAR Load areas must add to 100%.

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Private Network - Site and Unit Information

*This worksheet tab applies to **all Private Use Networks.** Complete this section then select RETURN TO MAP*
Complete the Unit Information tab then answer whether the site is Private Network and the appropriate cells will become un-hatched on this tab

SITE	PRIVATE NETWORK - SITE INFORMATION	Labels	
	Private Network?	Y/N	Y
	Average Amount of Self-Serve private load	MW	
	Average Amount of Self-Serve private reactive load	MVAR	
	Expected Typical Private Network Net Interchange	MW	
	Expected Typical Private Network Net Reactive Interchange	MVAR	
	Private Network Gross Unit Capability	MW	
	Private Network Gross Unit Reactive Capability	MVAR	
	Load Characteristics:		
	Load Characteristics for MW Load (must equal 100%)		
	Large Motor, percent of total MW load	%	
	Small Motor, percent of total MW load	%	
	Resistive (Heating) Load, percent of total MW load	%	
	Discharge Lighting, percent of total MW load	%	
	Other, percent of total MW load	%	
	Load Characteristics for MVAR Load (must equal 100%)		
	Large Motor, percent of total MVAR load	%	
	Small Motor, percent of total MVAR load	%	
	Discharge Lighting, percent of total MVAR load	%	
	Other, percent of total MVAR load	%	

11.2 Unit Information

After completing the site details, the generation and load must be allocated across the units. Please identify the amount of load allocated to each unit, as well as the percentage of load that will trip if the unit trips. Some facilities become a large load to ERCOT if the generation trips, which can create issues with the reliability studies if the load cannot trip within a minute of the generation unit trip.

	PRIVATE NETWORK - Unit Information	Label	TEST_A	TEST_B	TEST_C
CC1	Average Amount of Self-Serve private load	MW			
	Average Amount of Self-Serve private reactive load	MVAR			
	Expected Typical Private Network Net Interchange	MW			
	Expected Typical Private Network Net Reactive Interchange	MVAR			
	Private Network Gross Unit Capability	MW			
	Private Network Gross Unit Reactive Capability	MVAR			
	If Unit trips, does Load trip?	Y/N			
	If yes, approximate percentage of Load that will trip?	%			

	PRIVATE NETWORK - Unit Information	Label			
CC2	Average Amount of Self-Serve private load	MW			
	Average Amount of Self-Serve private reactive load	MVAR			
	Expected Typical Private Network Net Interchange	MW			
	Expected Typical Private Network Net Reactive Interchange	MVAR			
	Private Network Gross Unit Capability	MW			
	Private Network Gross Unit Reactive Capability	MVAR			
	If Unit trips, does Load trip?	Y/N			
	If yes, approximate percentage of Load that will trip?	%			

	PRIVATE NETWORK - Unit Information	Label			
CC3	Average Amount of Self-Serve private load	MW			
	Average Amount of Self-Serve private reactive load	MVAR			
	Expected Typical Private Network Net Interchange	MW			
	Expected Typical Private Network Net Reactive Interchange	MVAR			
	Private Network Gross Unit Capability	MW			
	Private Network Gross Unit Reactive Capability	MVAR			
	If Unit trips, does Load trip?	Y/N			
	If yes, approximate percentage of Load that will trip?	%			

12.0 Line Data

The Line Data tab is used for registering both, internal lines and lines which go outside of the generation site, but are owned by the resource entity. All lines registered here are those owned by the Resource Entity.

Each line registered must use the Line names as they appear in the ERCOT model.

For connected devices, ERCOT requires at least 1 device, but no more than 10.

Line Data Business Rules / Basic Validations
Use this section to pre-validate the information entered in the RARF.

RARF DATA FIELD	Business Rules/Basic UI validations	Datatype
Description of Change	1) This field is conditionally Required - If there is a change to a tab, the change must be described.	Alpha
ERCOT Line Name	1) This field is required 2) This field may not have any special characters, except an underscore "_" and a dash "-" 3) Warn if > 14 characters. Warning! ERCOT Line Name () should not be > 14 characters long or the name will be truncated in the model which requires uniqueness.	Alpha
Line Voltage Level	1) This field is required. 2) If the value >= 69kv it must be 69,138, or 345 3) The value must be < 345 4) The value must be > 1	Float
TO STATION - ERCOT Station Code Mnemonic	1) This field is Optional 2) Warn if left blank 3) This field must match ERCOT records (unless new) 4.Station Code should be UPPER Case. No special characters are allowed other than underscore and dash.	Alpha
TO STATION - TSP Name	1) This field is conditionally required if TO STATION - Internal Line - 'N' 2) This field must match ERCOT records (drop down in RARF)	Alpha
TO STATION - Connected Device Name(s) (multiple)	1) This field is required 2) May not be >= than 17 characters. Warning! Device Name () should not be > 17 characters long or the name will be truncated in the model which requires uniqueness.3) May not have duplicates within the TO or FROM Station 4) May not contain special characters except for an underscore "_" and a dash "-"	Alpha
TO STATION - Bus Number (PTI Bus Number)	1) This field is optional 2) This field must be between 1 - 99,999	Integer
TO STATION - Weather Zone / Weather Station (used for Dynamic Ratings)	1) This field is conditionally required if "Line Rating (Static or Dynamic)" = 'DYNAMIC' 2) Value must be from the following list: COAST, EAST, FAR_WEST, NORTH, NORTH_C, SOUTH_C, SOUTHERN, WEST, KABI, KAUS,	Alpha

	KBRO, KCRP, KDFW, KGLS, KIAH, KJCT, KLRD, KLFK, KMAF, KMWL, KSJT, KSAT, KTYR, KVCT, KACT, KSPS, KINK, KPRX	
FROM STATION - ERCOT Station Code Mnemonic	1) This field is required 2) Must match ERCOT records (unless new) 3) Value must be <= 8 characters	Alpha
FROM STATION - Connected Device Name(s) (multiple)	1) This field is required 2) May not be >= than 17 characters. Warning! Device Name () should not be > 17 characters long or the name will be truncated in the model which requires uniqueness. 3) May not have duplicates within the TO or FROM Station 4) May not contain special characters except for an underscore "_" and a dash "-"	Alpha
FROM STATION - Bus Number (PTI Bus Number)	1) This field is optional 2) This field must be between 1 - 99,999 3) Warn if left blank	Integer
FROM STATION - Weather Zone / Weather Station (used for Dynamic Ratings)	1) This field is conditionally required if "Line Rating (Static or Dynamic)" = 'DYNAMIC' 2) Value must be from the following list: COAST, EAST, FAR_WEST, NORTH, NORTH_C, SOUTH_C, SOUTHERN, WEST, KABI, KAUS, KBRO, KCRP, KDFW, KGLS, KIAH, KJCT, KLRD, KLFK, KMAF, KMWL, KSJT, KSAT, KTYR, KVCT, KACT, KSPS, KINK, KPRX	Alpha
Resistance in P.U. (100 MVA Base)	1) Field is required 2) Value must be >= 0.0001. If value is < 0.0001 and Internal Line = 'Y' then Error! Resistance is less than 0.0001 the Line data is not required, Connected devices need to be modeled on Breaker/Switch tab If value is <0.0001 and Internal Line = N then Warning. 'Warning! Resistance is less than 0.0001' 3) If Line Data - Line Voltage Level = 69kV, value must be <= 1.5 If Line Data - Line Voltage Level = 138kV or 345kV, value must be <= 0.5 WARN if value is outside of these conditions	Float
Reactance in P.U. (100 MVA Base)	1) Field is required 2) Value must be >= 0.0001 If value is < 0.0001 and Internal Line = 'Y' then Error! Reactance is less than 0.0001 the Line data is not required, Connected devices need to be modeled on Breaker/Switch tab If value is <0.0001 and Internal Line = N then Warning. 'Warning! Reactance is less than 0.0001. 3) If Line Data - Line Voltage Level = 69kV, value must be <=1.0 If Line Data - Line Voltage Level = 138kV, value must be <=0.1 If Line Data - Line Voltage Level = 345kV, value must be <=.05 WARN if value is outside of these conditions	Float
Charging Susceptance in PU (100 MVA Base)	1) Field is required 2) Value must be >= 0	Float

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	If Line Data - Line Voltage Level = 69kV, value must be <=0.3 If Line Data - Line Voltage Level = 138kV, value must be <=0.5 If Line Data - Line Voltage Level = 345kV, value must be <=2.2. Warn if rule fails.	
Type (overhead / underground)	1) Field is required 2) Value must be at from the following list: OVERHEAD, UNDERGROUND, BOTH	Alpha
Segment Length	1) Field is required 2) Value must > 0 3) Formula on Line Data - Segment Length: The formula to determine the length of a line based on the Reactance (X) and the Charging Susceptance (Chg) is 486 * SQRT(X_pu * Chg_pu). 25% variation This is a warning. This is applicable to 'overhead' lines only.	Float
Line Rating (Static or Dynamic)	1) Field is required 2) Field must be from the following list: STATIC, DYNAMIC	Alpha
Nominal (Static) - Continuous Rating	1) This field is required regardless of STATIC or DYNAMIC 2) Value must be <= Nominal (Static) - 2-hr Emergency Rating 3) Value must be <= Nominal (Static) - 15-min Rating 4) Conditional Rule (if Line Rating (Static or Dynamic) = Dynamic): Value must be <= 20 °F - Continuous Rating AND value must be >= 115 °F Continuous Rating	Integer
Nominal (Static) - 2-hr Emergency Rating	1) This field is required regardless of STATIC or DYNAMIC 2) Value must be >= Nominal (Static) - Continuous Rating 3) Value must be <= Nominal (Static) - 15-min Rating 4) Conditional Rule (if Line Rating (Static or Dynamic) = Dynamic): Value must be <= 20 °F - 2-hr Emergency Rating AND value must be >= 115 °F 2-hr Emergency Rating	Integer
Nominal (Static) - 15-min Rating	1) This field is required regardless of STATIC or DYNAMIC 2) Value must be >= Nominal (Static) - Continuous Rating 3) Value must be >= Nominal (Static) - 2-hr Emergency Rating 4) Conditional Rule (if Line Rating (Static or Dynamic) = Dynamic): Value must be <= 20 °F - 15-min Rating AND value must be >= 115 °F 15-min Rating	Integer
20 °F - Continuous Rating - 115 °F Continuous Rating	1) These field are conditionally required. If Line Rating (Static or Dynamic) = Dynamic this field is required 2) Line Rating (Static or Dynamic) = Static, this field must be blank 3) If required, these values must be <= the subsequent dynamic rating. For example:	Integer

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	20 °F - Continuous Rating >= 25 °F - Continuous Rating 25 °F - Continuous Rating >= 30 °F - Continuous Rating 4) If required, within each temp rating, the following must apply Continuous Rating <= 2-hr Emergency Rating <= 15-min rating	
20 °F - 2-hr Emergency Rating - 115 °F 2-hr Emergency Rating	1) These field are conditionally required. If Line Rating (Static or Dynamic) = Dynamic this field is required 2) Line Rating (Static or Dynamic) = Static, this field must be blank 3) If required, these values must be >= the subsequent dynamic rating. For example: 20 °F - 2-hr Emergency Rating >= 25 °F - 2-hr Emergency Rating 25 °F - 2-hr Emergency Rating >= 30 °F - 2-hr Emergency Rating 4) If required, within each temp rating, the following must apply Continuous Rating <= 2-hr Emergency Rating <= 15-min rating	Integer
20 °F - 15-min Rating - 115 °F 15-min Rating	1) These field are conditionally required. If Line Rating (Static or Dynamic) = Dynamic this field is required 2) Line Rating (Static or Dynamic) = Static, this field must be blank 3) If required, these values must be >= the subsequent dynamic rating. For example: 20 °F - 2-hr 15-min Rating >= 25 °F - 15-min Rating 25 °F - 2-hr 15-min Rating >= 30 °F - 15-min Rating 4) If required, within each temp rating, the following must apply Continuous Rating <= 2-hr Emergency Rating <= 15-min rating	Integer
General	This tab is conditionally required if Private Network - Private Network? = 'Y'	N/A
Date Effective	1.This is a Required field 2.Date Effective should be >= Site-In-Service Date	Date

13.0 Breaker / Switch Data

The Breaker and Switch Data tab is used for registering all breakers and switches. All Breakers and Switches registered here are those owned by the Resource Entity.

Each Breakers and Switches registered must use the name as it appears in the ERCOT model.

For directly connected devices, ERCOT requires at least 1 device, but no more than 10.

Breaker and Switch Business Rules / Basic Validations
Use this section to pre-validate the information entered into the RARF.

RARF DATA FIELD	Business Rules	Datatype
Description of Change	1) This field is conditionally Required - If there is a change to a tab, the change must be described.	Alpha
ERCOT Station Code Mnemonic	1) This field is required 2) Must match ERCOT records (unless new) 3) Must be <= 8 characters. Warning! Station Code () should not be >8 characters long or the name will be truncated in the model which requires uniqueness. 4.Station Code should be UPPER Case. No special characters are allowed other than underscore and dash.	Alpha
Is this a Fault Isolating Device (e.g. Circuit Breaker)	1) This is a required field 2) Values must from the following list: 'Y', 'N'	Alpha
Switch Name	1) This field is required 2) Value may contain no special characters except an underscore "_" and a dash "-" 3) Must be <=14 characters. Warning! Switch Name () should not be >14 characters long or the name will be truncated in the model which requires uniqueness.	Alpha
Normal Operating Status (when in-service)	1) This field is required 2) Value must be from the following list: 'OPEN', 'CLOSED'	Alpha
Voltage Level	1) This field is required. 2) If the value >= 69kv it must be 69,138, or 345 3) The value may not exceed 345 4) The value must be > 0	Float
Side 1 / Side 2 - Directly connected device name(s)	1) This field is required 2) Value may contain no special characters except an underscore "_" and a dash "-" 3) Must be <=17 characters. Must be <=17 characters. Warning! Device Names () should not be >17 characters long or the name will be truncated in the model which requires uniqueness. 4) At least one connected device is required on each side of the Breaker/Switch. Error if at least one connected device is missing on both sides , Warning when at least one connected device is missing on any one side.	Alpha
General	This tab is required	N/A

Date Effective	1.This is a Required field 2.Date Effective should be >= Site-In-Service Date	Date

14.0 Capacitor Reactor Data

The Capacitors Reactor Data tab is used for registering all capacitors and reactors. All Capacitor and Reactors registered here are those owned by the Resource Entity.

Each Capacitors Reactor registered must use the name as it appears in the ERCOT model.

Capacitors and Reactors Business Rules / Basic Validations
Use this section to pre-validate the information entered in the RARF.

RARF DATA FIELD	Business Rules	Datatype
Description of Change	1) This field is conditionally Required - If there is a change to a tab, the change must be described.	Alpha
ERCOT Station Code Mnemonic	1) This field is required 2) Must match ERCOT records (unless new) 3) Value must be <= 8 characters. Warning! Station Code () should not be >8 characters long or the name will be truncated in the model which requires uniqueness. 4.Station Code should be UPPER Case. No special characters are allowed other than underscore and dash.	Alpha
Capacitor or Reactor	1) This field is required 2) Value must be from the following list: 'C', 'R'	Alpha
Device Name	1) This field is required 2) Value may contain no special characters except an underscore "_" and a dash "-" 3) Must be <=14 characters. Warning! Device Name () should not be >14 characters long or the name will be truncated in the model which requires uniqueness.	Alpha
Nominal MVAR	1) This field is required 2) Value must be > 0	Float

Voltage Level kV	1) This field is required. 2) If the value >= 69kv it must be 69,138, or 345 3) The value may not exceed 345 4) The value must be > 0	Float
PTI Bus Number	1) This field is optional 2) This field must be between 1 - 99,999	Float
Device Name(s) - that this reactive device is directly connected to	1) This field is optional 3) May not be > than 17 characters. Warning! Device Name () should not be >17 characters long or the name will be truncated in the model which requires uniqueness. 4) May not contain special characters except for an underscore "_" and a dash "-" 5) This field should be unique. No two capacitors should have the same controlling breaker or switch. Every Device entry on the "Capacitor and Reactor Data" tab sheet needs to have a unique "Device Name(s) – that this reactive device is directly connected to".	Alpha
Automatic Voltage Regulation	1) This field is required 2) Value must be from the following list: 'Y', 'N'	Alpha
Voltage Level of Busbar being regulated	1) This field is conditionally required if Automatic Voltage Regulation = 'Y' 2) If the value >= 69kv it must be 69,138, or 345 3) The value may not exceed 345 4) The value must be > 0	Float
Desired Regulating voltage	1) This field is conditionally required if Automatic Voltage Regulation = 'Y' 3) The value must be > 0 4) The value must >= Minimum Regulating Voltage 5) The value must <=Maximum Regulating Voltage 6. Desired Regulating voltage should be within the range of 10% of the base kV. If the value is beyond , it should be a Warning.	Float
Minimum Regulating Voltage	1) This field is conditionally required if Automatic Voltage Regulation = 'Y' 3) The value must be > 0 4) The value must be <= Maximum Regulating Voltage 5) Warning if value exceeds 50% from Maximum Regulating Voltage 6. Minimum Regulating voltage should be within the range of 10% of the base kV. If the value is beyond , it should be a Warning.	Float

Maximum Regulating Voltage	1) This field is conditionally required if Automatic Voltage Regulation = 'Y' 2) The value must be > 0 3) The value must be >= Minimum Regulating Voltage 4) Warning if value exceeds 50% from Minimum Regulating Voltage Minimum 5) Maximum Regulating voltage should be within the range of 20% of the base kV. If the value is beyond , it should be a Warning.	Float
Date Effective	1.This is a Required field 2.Date Effective should be >= Site-In-Service Date	Date

15.0 Transformers

GSU Transformers

Note that for associated units, this field is only for the GSU (Generator Step-Up) Transformer.

Some resources use multiple transformers for one unit and some have one transformer for multiple units. In order to accommodate this, the GSU section has been developed independent of units.

Ensure the proper unit(s) is(are) assigned to the transformer. A dropdown list is provided to supply the previously supplied unit name as identified on the General Information tab.

All Transformers

The Transformer Data tab is used for registering all transformers. All Transformer registered here are those owned by the Resource Entity.

There is only one Transformer data tab for all resource types.

Each Transformer registered must use the name as it appears in the ERCOT model.

All tap information is required if it exists on either the LTC or Fixed side.

Transformer Business Rules / Basic Validations
Use this section to pre-validate the information entered in the RARF.

RARF DATA FIELD	Business Rules	Datatype
Description of Change	1) This field is conditionally Required - If there is a change to a tab, the change must be described.	Alpha
ERCOT Station Name (Station Code or Station Mnemonic)	1) This field is required 2) Must match ERCOT records 3) Must be <= 8 characters. Warning! Station Name () should not be >8 characters long or the name will be truncated in the model which	Alpha

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	requires uniqueness. 4.Station Code should be UPPER Case. No special characters are allowed other than underscore and dash.	
Transformer Name	1) This field is required 3) Warn if >= 14 characters. First 14 characters must be unique. Warning! Transformer Name () should not be >14 characters long or the name will be truncated in the model which requires uniqueness. 3) May not contain special characters except for an underscore "_" and a dash "-"	Alpha
Is this transformer in Master / Follower of Current Balancing configuration?	1) This field is required 2) Value must be in the following list: 'Y', 'N'	Alpha
Master Name (can be same as this transformer)	1) This field is conditionally required if Transformer Data - Is this transformer in Master / Follower of Current Balancing configuration? = 'Y' 2) Warn if >= 14 characters. First 14 characters must be unique. Warning! Master Name () should not be >=14 characters long or the name will be truncated in the model which requires uniqueness 3) May not contain special characters except for an underscore "_" and a dash "-" 4) Either the Master Name or the Follower Name MUST = Transformer Data - Transformer Name	Alpha
Follower Name (can be same as this transformer)	1) This field is conditionally required if Transformer Data - Is this transformer in Master / Follower of Current Balancing configuration? = 'Y' 2) Warn if >= 14 characters. First 14 characters must be unique. Warning! Follower Name () should not be >=14 characters long or the name will be truncated in the model which requires uniqueness. 3) May not contain special characters except for an underscore "_" and a dash "-" 4) Either the Master Name or the Follower Name MUST = Transformer Data - Transformer Name	Alpha
Generation Step-Up Transformer?	1) This field is required 2) Value must be in the following list: 'Y', 'N'	Alpha
Unit(s) associated with this transformer	1) This field is conditionally required - if Generation Step-up = 'Y', this is required 2) Value(s) must be <=17 characters. Warning! Device Name () should not be >17 characters long or the name will be truncated in the model which requires uniqueness. 3) Warn if the unit name is not in the Unit Info - GEN or Unit Info - CC or Unit Info - Wind	Alpha
High Side Voltage Level (no-load)	1) This field is required 2) If the value >= 69kv it must be 69,138, or 345 3) The value may not exceed 345 4) The value must be > 0	Float

<table>
<tr><td></td><td>5) The value must be >= Low Voltage Level (no-load)</td><td></td></tr>
<tr><td>High Side Voltage Level (PTI)</td><td>1) This field is optional
2) This field must be between 1 - 99,999</td><td>Integer</td></tr>
<tr><td>High Side Voltage Connection - Wye or Delta</td><td>1) This field is required
2) Value must be of the following: 'Wye', 'Delta'</td><td>Alpha</td></tr>
<tr><td>High Side Voltage Connected devices (list on separate lines)</td><td>1) This field is required
a) Error: if High Side Voltage >= 60kV and Low Side Voltage >1kV
b) Warn: if High Side Voltage < 60kV and Low Side Voltage = 1kV
2) Warn if >= 17 characters. Warning! Device Name () should not be >17 characters long or the name will be truncated in the model which requires uniqueness.
3) No special characters except an underscore or a dash</td><td>Alpha</td></tr>
<tr><td>High Side Manufactured Nominal Voltage</td><td>1) This field is required
2) If value > 60kV
Accepted if value (using 5%)
Deviates < |3.45| kV from 69
Deviates < |6.9| kV from 138
Deviates < |17.25| kV from 345
Warn if value (using >= 5% and <10%)
Deviates > = |3.45| but deviates < |6.9| from 69
Deviates >= |6.9| but deviates < 13.8 from 138
Deviates >= |17.25| but deviates < 34.5 from 345
Error if value (using > =10%)
Deviates >= |6.9| kV from 69
Deviates >= |13.8|kV from 138
Deviates >= |34.5|kV from 345
3) Warn if value > 345
4) The value must be > 0
5) High Side Manufactured Nominal Voltage >= Low Side Manufactured Nominal Voltage
6) High Side Manufactured Nominal Voltage should be > Voltage at Lowest Tap Position and < Voltage at Highest Tap Position</td><td>Float</td></tr>
<tr><td>Low Side Voltage Level (no-load)</td><td>1) This field is required
2) If the value >= 69kv it must be 69,138, or 345
3) The value may not exceed 345
4) The value must be > 0
5) The value must be <= High Voltage Level (no-load)
6) If Generator Step-up Transformer = 'Y' AND Low Side Voltage Level (no-load) > 1kV AND Then the Low Side Voltage Level (no-load) must be equal to Unit Info - GEN / CC / WIND - Unit Generating Voltage</td><td>Float</td></tr>
<tr><td>Low Side Voltage Level (PTI)</td><td>1) This field is optional
2) This field must be between 1 - 99,999</td><td>Integer</td></tr>
<tr><td>Low Side Voltage Connected device(s) (list on separate lines)</td><td>1) This field is required
a) Error: if High Side Voltage >= 60kV and Low Side Voltage >1kV
b) Warn: if High Side Voltage < 60kV and</td><td>Alpha</td></tr>
</table>

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	Low Side Voltage = 1kV 2) Warn if >= 17 characters. 3) No special characters except an underscore "_" or a dash "-"	
Low Side Manufactured Nominal Voltage	1) This field is required 2) If the value >= 69kv: **Accepted** if value (using 5%) Deviates < $\lvert 3.45\rvert$ kV from 69 Deviates < $\lvert 6.9\rvert$ kV from 138 Deviates < $\lvert 17.25\rvert$ kV from 345 **Warn** if value (using >= 5% and <10%) Deviates > = $\lvert 3.45\rvert$ but deviates < $\lvert 6.9\rvert$ from 69 Deviates >= $\lvert 6.9\rvert$ but deviates < 13.8 from 138 Deviates >= $\lvert 17.25\rvert$ but deviates < 34.5 from 345 **Error** if value (using > =10%) Deviates >= $\lvert 6.9\rvert$ kV from 69 Deviates >= $\lvert 13.8\rvert$kV from 138 Deviates >= $\lvert 34.5\rvert$kV from 345 3) Warn if value > 345 4) The value must be > 0 5) High Side Manufactured Nominal Voltage >= Low Side Manufactured Nominal Voltage	Float
Series Resistance (100 MVA Base)	1) This field is required 2) Value must be >=0. Allow negative Resistance only when low side kV is 1kV	Float
Series Reactance (100 MVA Base)	1) This field is required 2) Error if Reactance value is > 1. Error! Reactance (value) > 1.0. Reactance should be expressed in terms of per unit (e.g. not percentage). Allow negative Reactance only when low side kV is 1kV	Float
Continuous Rating	1) This field is required 2) Value must be <= 2-hr Emergency Rating 3) Value must be <= 15-min Rating	Integer
2-hr Emergency Rating	1) This field is required 2) Value must be >= Continuous Rating 3) Value must be <= 15-min Rating	Integer
15-min Rating	1) This field is required 2) Value must be >= Continuous Rating 3) Value must be >= 2-hr Emergency Rating	Integer
Automatic Voltage Regulation	1) This field is required 2) Value must be from the following list: 'Y', 'N' 3) Automatic Voltage Regulation is expected 'Y' when total no. of tap positions >=16. Generate a Warning when Total Number of Tap positions >=16 and Automatic Voltage Regulation ='N'.	Alpha
Does Transformer have a Load Tap Changer?	1) This field is conditionally required if Automatic Voltage Regulation = 'Y' 2) Value must be from the following list: 'Y', 'N' 3) Generate a Warning when Total Number of Tap positions >=16 and Load Tap Changer ='N'.	Alpha
Location of Tap Changer	1) This field is conditionally required if 'Does	Alpha

	Transformer have a Load Tap Changer ?' = 'Y' 2) Value must be of the following: 'HIGH', 'LOW'	
Base kV of Regulated Side	1) This field is conditionally required if Automatic Voltage Regulation = 'Y' 2) If the value >= 69kv it must be 69,138, or 345 3) The value may not exceed 345 4) The value must be > 0 5) The value must be >= Low Voltage Level (no-load)	Float
Target kV of Regulated Side	1) This field is conditionally required if Automatic Voltage Regulation = 'Y' 2) Value must be > 0	Float
Acceptable Deviation of Target Voltage in Percent	1) This field is conditionally required if Automatic Voltage Regulation = 'Y' 2) Value must not exceed 50%	Percentage
Low Tap Settings - Tap position at Manufactured Nominal Voltage	1) This field is conditionally required If "Does transformer have a loadtap changer?" = 'Y' then either Low Tap Settings or High Tap Settings must be filled out based on the Location of the Load Tap Changer (e.g. Load Tap is on the high side, high tap settings is now required). Note that it is valid for both, Low and High Tap settings to be filled out if there is a non-load tap on the opposite side of the Load Tap Second Condition: This field must be left blank if Low Voltage Level = 1 2) Note: this value may be negative	Integer
Low Tap Settings - Total Number of Tap Positions	1) This field is conditionally required If "Does transformer have a loadtap changer?" = 'Y' then either Low Tap Settings or High Tap Settings must be filled out based on the Location of the Load Tap Changer (e.g. Load Tap is on the high side, high tap settings is now required). Note that it is valid for both, Low and High Tap settings to be filled out if there is a non-load tap on the opposite side of the Load Tap Second Condition: This field must be left blank if Low Voltage Level = 1 2) Value must be >= 2 3) Generate a Warning when Total Number of Tap positions >=16 and Automatic Voltage Regulation ='N'. Generate a Warning when Total Number of Tap positions >=16 and Load Tap Changer ='N'.	Integer
Low Tap Settings - Normal Tap Position	1) This field is conditionally required If "Does transformer have a loadtap changer?" = 'Y' then either Low Tap Settings or High Tap Settings must be filled out. Note that it is valid for both, Low and High Tap settings to be filled out. Second Condition: This field must be left blank if Low Voltage Level = 1 2) Value must be >= Low Tap Settings -	Integer

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	Lowest Tap Position 3) Value must be <= Low Tap Settings - Highest Tap Position 4) Note: this value may be negative	
Low Tap Settings - Lowest Tap Position	1) This field is conditionally required If "Does transformer have a loadtap changer?" = 'Y' then either Low Tap Settings or High Tap Settings must be filled out based on the Location of the Load Tap Changer (e.g. Load Tap is on the high side, high tap settings is now required). Note that it is valid for both, Low and High Tap settings to be filled out if there is a non-load tap on the opposite side of the Load Tap Second Condition: This field must be left blank if Low Voltage Level = 1 2) Value must be <= Low Tap Settings - Highest Tap Position 3) Note: this value may be negative	Integer
Low Tap Settings - Voltage at Lowest Tap Position	1) This field is conditionally required If "Does transformer have a loadtap changer?" = 'Y' then either Low Tap Settings or High Tap Settings must be filled out based on the Location of the Load Tap Changer (e.g. Load Tap is on the high side, high tap settings is now required). Note that it is valid for both, Low and High Tap settings to be filled out if there is a non-load tap on the opposite side of the Load Tap Second Condition: This field must be left blank if Low Voltage Level = 1 2) Value must be <= Low Tap Settings - Voltage at Highest Tap Position 3) Value must be < High Tap Settings - Voltage at Lowest Tap Position 4) Value must be >= 0	Float
Low Tap Settings - Highest Tap Position	1) This field is conditionally required If "Does transformer have a loadtap changer?" = 'Y' then either Low Tap Settings or High Tap Settings must be filled out. Note that it is valid for both, Low and High Tap settings to be filled out. Second Condition: This field must be left blank if Low Voltage Level = 1 2) Value must be >= Low Tap Settings - Low Tap Position 3) Note: this value may be negative	Integer
Low Tap Settings - Voltage at Highest Tap Position	1) This field is conditionally required If "Does transformer have a loadtap changer?" = 'Y' then either Low Tap Settings or High Tap Settings must be filled out. Note that it is valid for both, Low and High Tap settings to be filled out. Second Condition: This field may be left blank if Low Voltage Level = 1 2) Value must be >= Low Tap Settings - Voltage at Lowest Tap Position 3) Value must be <= High Tap Settings -	Float

	Voltage at Highest Tap Position 4) Value must be >= 0	
Low Tap Settings – Size of each Voltage Step	1) This field is conditionally required If "Does transformer have a loadtap changer?" = 'Y' then either Low Tap Settings or High Tap Settings must be filled out based on the Location of the Load Tap Changer (e.g. Load Tap is on the high side, high tap settings is now required). Note that it is valid for both, Low and High Tap settings to be filled out if there is a non-load tap on the opposite side of the Load Tap Second Condition: This field may be left blank if Low Voltage Level = 1 2) Value must > 0 3) Warn if < 0.002 * Low Side Voltage Level (no-load) 4) Warn if > 0.05 * Low Side Voltage Level (no-load)	Float
High Tap Settings - Tap position at Manufactured Nominal Voltage	1) This field is conditionally required If "Does transformer have a loadtap changer?" = 'Y' then either Low Tap Settings or High Tap Settings must be filled out based on the Location of the Load Tap Changer (e.g. Load Tap is on the high side, high tap settings is now required). Note that it is valid for both, Low and High Tap settings to be filled out if there is a non-load tap on the opposite side of the Load Tap 2) Note: this value may be negative	Integer
High Tap Settings - Total Number of Tap Positions	1) This field is conditionally required If "Does transformer have a loadtap changer?" = 'Y' then either Low Tap Settings or High Tap Settings must be filled out based on the Location of the Load Tap Changer (e.g. Load Tap is on the high side, high tap settings is now required). Note that it is valid for both, Low and High Tap settings to be filled out if there is a non-load tap on the opposite side of the Load Tap 2) Value must be >= 2 3) Warn if value < 16 and "Automatic Voltage Regulation" = 'Y'	Integer
High Tap Settings - Normal Tap Position	1) This field is conditionally required If "Does transformer have a loadtap changer?" = 'Y' then either Low Tap Settings or High Tap Settings must be filled out based on the Location of the Load Tap Changer (e.g. Load Tap is on the high side, high tap settings is now required). Note that it is valid for both, Low and High Tap settings to be filled out if there is a non-load tap on the opposite side of the Load Tap 2) Value must be >= High Tap Settings - LowestTap Position 3) Value must be <= High Tap Settings - Highest Tap Position	Integer

	4) Note: this value may be negative	
High Tap Settings - Lowest Tap Position	1) This field is conditionally required If "Does transformer have a loadtap changer?" = 'Y' then either Low Tap Settings or High Tap Settings must be filled out based on the Location of the Load Tap Changer (e.g. Load Tap is on the high side, high tap settings is now required). Note that it is valid for both, Low and High Tap settings to be filled out if there is a non-load tap on the opposite side of the Load Tap 2) Value must be <= High Tap Settings - Highest Tap Position 3) Note: this value may be negative	Integer
High Tap Settings – Voltage at Lowest Tap Position	1) This field is conditionally required If "Does transformer have a loadtap changer?" = 'Y' then either Low Tap Settings or High Tap Settings must be filled out based on the Location of the Load Tap Changer (e.g. Load Tap is on the high side, high tap settings is now required). Note that it is valid for both, Low and High Tap settings to be filled out if there is a non-load tap on the opposite side of the Load Tap 2) Value must be <= High Tap Settings - Voltage at Highest Tap Position 3) Value must be > Low Tap Settings - Voltage at Lowest Tap Position 4) Value must be >= 0	Float
High Tap Settings - Highest Tap Position	1) This field is conditionally required If "Does transformer have a loadtap changer?" = 'Y' then either Low Tap Settings or High Tap Settings must be filled out based on the Location of the Load Tap Changer (e.g. Load Tap is on the high side, high tap settings is now required). Note that it is valid for both, Low and High Tap settings to be filled out if there is a non-load tap on the opposite side of the Load Tap 2) Value must be >= Low Tap Position 3) Note: this value may be negative	Integer
High Tap Settings - Voltage at Highest Tap Position	1) This field is conditionally required If "Does transformer have a loadtap changer?" = 'Y' then either Low Tap Settings or High Tap Settings must be filled out based on the Location of the Load Tap Changer (e.g. Load Tap is on the high side, high tap settings is now required). Note that it is valid for both, Low and High Tap settings to be filled out if there is a non-load tap on the opposite side of the Load Tap 2) Value must be >= High Tap Settings - Voltage at Lowest Tap Position 3) Value must be > Low Tap Settings - Voltage at Highest Tap Position 4) Value must be > 0	Float
High Tap Settings – Size of each Voltage Step	1) This field is conditionally required If "Does	Float

	transformer have a loadtap changer?" = 'Y' then either Low Tap Settings or High Tap Settings must be filled out based on the Location of the Load Tap Changer (e.g. Load Tap is on the high side, high tap settings is now required). Note that it is valid for both, Low and High Tap settings to be filled out if there is a non-load tap on the opposite side of the Load Tap 2) Value must > 0 3) Warn if < 0.002 * High Side Voltage Level (no-load) 4) Warn if > 0.05 * High Side Voltage Level (no-load)	
General	This tab is conditionally required if Private Network - Private Network? = 'Y'	N/A
Date Effective	1.This is a Required field 2.Date Effective should be >= Site-In-Service Date	Date

16.0 Static Var Compensator

The Static Var Compensator Data tab is used for registering all Static Var Compensator. All Static Var Compensator registered here are those owned by the Resource Entity.

Each Static Var Compensator registered must use the name as it appears in the ERCOT model.

Static Var Compensator Business Rules / Basic Validations
Use this section to pre-validate the information entered in the RARF.

RARF DATA FIELD	Business Rules	Datatype
Description of Change	1) This field is conditionally Required - If there is a change to a tab, the change must be described.	Alpha
ERCOT Station Name (Station Code or Station Mnemonic)	1) This field is required 2) Must match ERCOT records (unless new) 3) Must be <= 8 characters. Warning! Station Name () should not be >8 characters long or the name will be truncated in the model which requires uniqueness. 4.Station Code should be UPPER Case. No special characters are allowed other than underscore and dash.	Alpha

SVC Name	1) This field is required 2) May not be > than 14 characters..Warning! SVC Name () should not be >14 characters long or the name will be truncated in the model which requires uniqueness. 3) May not contain special characters except for an underscore "_" and a dash "-"	Alpha
Device Name(s) - that this reactive device is directly connected to	1) This field is optional 3) May not be > than 17 characters. Warning! Device Name () should not be >17 characters long or the name will be truncated in the model which requires uniqueness. 3) May not contain special characters except for an underscore "_" and a dash "-"	Alpha
SVC Base Voltage Level	1) This field is required 2) If the value >= 69kv it must be 69,138, or 345 3) The value may not exceed 345 4) The value must be > 0	Float
Fixed MVAR (VAR injection at nominal voltage)	1) This field is required 2) Value must be > 0	Float
Minimum Admittance Limits (100 MVA Base)	1) This field is required 2) Value must be <= Maximum Admittance	Float
Maximum Admittance Limits (100 MVA Base)	1) This field is required 2) Value must be >= Minimum Admittance	Float
Minimum Steady State Reactive Power Limits	1) This field is required 2) Value must be >= Maximum Steady State Reactive Power Limits	Float
Maximum Steady State Reactive Power Limits	1) This field is required 2) Value must be >= Minimum Steady State Reactive Power Limits	Float

Minimum Threshold (post contingency) Reactive Power Limits	1) This field is required 2) Value must be <= Maximum Threshold (post contingency) Reactive Power Limits	Float
Maximum Threshold (post contingency) Reactive Power Limits	1) This field is required 2) Value must be >= Minimum Threshold (post contingency) Reactive Power Limits	Float
Minimum Voltage Threshold (100 MVA Base)	1) This field is required 2) Value must be <= Maximum Voltage Threshold (100 MVA Base) 3) The value may not exceed 345 3) The value must be > 0 4) Warn if Max / Min exceed 50% of one another	Float
Maximum Voltage Threshold (100 MVA Base)	1) This field is required 2) Value must be >= Minimum Voltage Threshold (100 MVA Base) 3) The value may not exceed 345 4) The value must be > 0 5) Warn if Max / Min exceed 50% of one another	Float
Date Effective	1.This is a Required field 2.Date Effective should be >= Site-In-Service Date	Date

17.0 Series Device Data

The Series Device Data tab is used for registering all Series Devices. All Series Devices registered here are those owned by the Resource Entity.

Each Series Device registered must use the name as it appears in the ERCOT model.

Series Device Business Rules / Basic Validations
Use this section to pre-validate the information entered in the RARF.

RARF DATA FIELD	Business Rules	Datatype
Description of Change	1) This field is conditionally Required - If there is a change to a tab, the change must be described.	Alpha
Series Device Name	1) This field is required 2) Warn if >= 14 characters. First 14 characters must be unique. Warning! Series Device Name() should not be >= 14 characters long or the name will be truncated in the model which requires uniqueness. 3) No special characters except and underscore	Alpha

ERCOT

ERCOT Station Name (Station Code or Station Mnemonic)	1.This field is required 2. Must match ERCOT records (unless new) 3. Must be <= 8 characters. Warning! Station Code () should not be >8 characters long or the name will be truncated in the model which requires uniqueness. 4. Station Code should be UPPER Case. No special characters are allowed other than underscore and dash.	Alpha
Voltage Level	1) This field is required 2) If the value >= 69kv it must be 69,138, or 345 3) The value may not exceed 345 4) The value must be > 0	Float
Side 1 - Connected Switching Device Name(s)	1) This field is required 2) May not be > than 17 characters. Warning! Device Name () should not be >17 characters long or the name will be truncated in the model which requires uniqueness. 3) May not have duplicates within the TO or FROM Station 4) May not contain special characters except for an underscore "_" and a dash "-"	Alpha
Side 1 - Bus Number (PTI Bus Number)	1) This field is optional 2) This field must be between 1 - 99,999	Integer
Side 2 - Connected Switching Device Name(s)	1) This field is required 2) May not be > than 17 characters. Warning! Device Name () should not be >17 characters long or the name will be truncated in the model which requires uniqueness. 3) May not have duplicates within the TO or FROM Station 4) May not contain special characters except for an underscore "_" and a dash "-"	Alpha
Side 2 - Bus Number (PTI Bus Number)	1) This field is optional 2) This field must be between 1 - 99,999	Integer
Resistance	1) This value is required 2) Value must be > 0	Float
Reactance	1) This value is required 2) Value may be negative. Negative Reactance allowed to represent Series Capacitors 3)Error if Reactance value is > 1. Error! Reactance (value) > 1.0. Reactance should be expressed in terms of per unit (e.g. not percentage).	Float
Continuous Rating	1) This field is required 2) Value must be <= 2-hr Emergency Rating 3) Value must be <= 15-min Rating	Float
2-hr Emergency Rating	1) This field is required 2) Value must be >= Continuous Rating 3) Value must be <=15-min Rating	Float
15-min Rating	1) This field is required 2) Value must be >= Continuous Rating 3) Value must be >= 2-hr Emergency Rating	Float

Date Effective	1.This is a Required field 2.Date Effective should be >= Site-In-Service Date	Date

18.0 Load Data

The Load Data tab is used for registering Load as it defined in this section. All Load registered here are those owned by the Resource Entity.

Each Load registered must use the name as it appears in the ERCOT model. For equivalent Loads, it may be necessary to work with ERCOT to determine the naming.

Loads which are connected on a Bus greater than or equal to 60kV need to be modeled individually

Loads connected at less than 60kV may be aggregated into an “equivalent load” at the 69kV Bus

Auxiliary and Site Service Load may be combined
Note: Auxiliary load is defined as that which is only present when the generator is running

Load Business Rules / Basic Validations
Use this section to pre-validate the information entered in the RARF.

RARF DATA FIELD	Business Rules	Data type
Load Voltage Level	1) This field is required 2) Value must be >= 0 3) If the value >= 69kv it must be 69,138, or 345	Float
PTI Bus Number	1) This field is optional 2) This field must be between 1 - 99,999	Integer
Device Name(s) - that this load is physically connected to	1) This field is required 2) Warn if >= 17 characters. First 14 characters must be unique. Warning! ERCOT Device Name() should not be >=17 characters long or the name will be truncated in the model which requires uniqueness. 3) No special characters except an underscore or a dash	Alpha
Average MW Load Under Normal Operations	1) This field is required 2) Value must be > 0	Float
Average MVAR Under Normal Operations	1) This field is required 2) Value must be > 0	Float
General	This tab is conditionally required if Private Network - Private Network? = 'Y'	N/A
Date Effective	1.This is a Required field 2.Date Effective should be >= Site-In-Service Date	Date

19.0 Load Resources

Load Resources must complete the General Information tab as well as the two tabs discussed here.

ERCOT

19.1 Load Resource Information

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Load Resource Information Tab

*This worksheet tab provides information for **Load Resources**.*
Please complete this section and select RETURN TO MAP

LOAD RESOURCES

Unit Details	Labels	Load Point #1	Load Point #2
Name of End Use Customer			
Common Name for Load Resource			
Physical Street Address for point of Delivery (POD)			
Name of City for Point of Delivery (POD)			
Is Load Netted From Generation at ERCOT Read Gensite?	Y/N		
Is Load Behind a NOIE Settlement Meter Point?	Y/N		
Load Resource Type (CLR/UFR/Interruptible)			
If CLR, will CLR be Dynamically Scheduling?	Y/N		
Dispatch Asset Code (provided by ERCOT)			
Load Resource Effective Date			
Load Resource Expiration Date			
Substation Name for POD			
Substation Code for POD			
ESIID Station Name			
ESIID Station Code			
Transmission Bus POD (PTI Bus No)			
Voltage Level of Telemetered load(s)	KV		
Meter Reading Entity (TDSP)			
Meter Reading Entity Duns Number			
QSE Name			
QSE Duns Number			
ESI-ID assigned to meter			
Wholesale Delivery Point?	Y/N		
Notice Requirements to Interrupt			
High Set Under-frequency Relay (UFR) Setting	Hz		
Load Resource Control Device			
If CLR, ability to operate as a UFR type Resource?	Y/N		
ERCOT Load Zone			
Maximum POD Total Load	MW		
Summer Interruptible MW	MW		
Winter Interruptible MW	MW		
High Reasonability Limit	MW		
Low Reasonability Limit	MW		
CLR High Reasonability Ramp Rate Limit	MW/min		
CLR Low Reasonability Ramp Rate Limit	MW/min		
Private Use Network?	Y/N		

ERCOT

19.2 Load Resource Parameters

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Load Resource Parameters

Resource Entity authorizes QSE representing this Generation Resource to submit Resource Parameters on this page for operational purposes in accordance with Section 3.7.1 on behalf of Resource Entity.

*This worksheet tab provides information for **Load Resources** Resource Parameters - Initial submittal by RE, updat*

Please complete this section and select RETURN TO MAP

Non-CLR Resource Parameters	Labels	TEST_LD1	
Minimum Interruption Time	hours		
Minimum Restoration Time	hours		
Max WEEKLY Deployments	hours		
Max Interruption Time	hours		
Max DAILY Deployments	hours		
Max Weekly Energy	MWh		
Minimum Notice Time	minutes		
CLR Resource Parameters	**Labels**	**TEST_LD1**	
Max Deployment Time	hours		
Max Weekly Energy	MW		

19.3 CLR Ramp Rates

CLRs must provide Ramp Rate Curves. For information on building the curves, see section 7.4.

LOAD RESOURCES

CLR - Normal Ramp Rate Curve		TEST_LD1	
MW1	MW		
Upward RampRate1	MW/min		
Downward RampRate1	MW/min		
MW2	MW		
Upward RampRate2	MW/min		
Downward RampRate2	MW/min		
MW3	MW		
Upward RampRate3	MW/min		
Downward RampRate3	MW/min		
MW4	MW		
Upward RampRate4	MW/min		
Downward RampRate4	MW/min		
MW5	MW		
Upward RampRate5	MW/min		
Downward RampRate5	MW/min		
MW6	MW		
Upward RampRate6	MW/min		
Downward RampRate6	MW/min		
MW7	MW		
Upward RampRate7	MW/min		
Downward RampRate7	MW/min		
MW8	MW		
Upward RampRate8	MW/min		
Downward RampRate8	MW/min		
MW9	MW		
Upward RampRate9	MW/min		
Downward RampRate9	MW/min		
MW10	MW		
Upward RampRate10	MW/min		
Downward RampRate10	MW/min		
CLR - Emergency Ramp Rate Curve	**Labels**	**TEST_LD1**	
MW1	MW		
Upward RampRate1	MW/min		
Downward RampRate1	MW/min		
MW2	MW		
Upward RampRate2	MW/min		
Downward RampRate2	MW/min		
MW3	MW		
Upward RampRate3	MW/min		
Downward RampRate3	MW/min		

20.0 Additional Information

A Resource Entity and its assets must be registered separately, using the forms provided on the ERCOT Resource Entities Registration and Qualification webpage.
http://www.ercot.com/services/rq/re/

Each RE must also be represented by a Qualified Scheduling Entity (QSE), which establishes a control interface with ERCOT. If questions arise related to the completion of this or any other registration form, please contact your designated ERCOT Account Manager or email Wholesale Client Services at NodalMarketTransition@ercot.com.

Affidavit of Mr. Brett Nelson regarding genuineness of attachments

PUC DOCKET NO. ______

BUFFALO GAP WIND FARM, L.L.C.'S	**§**	**BEFORE THE**
APPEAL AND COMPLAINT OF	**§**	
ERCOT'S DECISION AND ACTION	**§**	**PUBLIC UTILITY COMMISSION**
REGARDING PRR 830 AND MOTION	**§**	
FOR SUSPENSION OF ACTION	**§**	**OF TEXAS**

AFFIDAVIT OF MR. BRETT NELSON

STATE OF TEXAS	**§**
	§
COUNTY OF TRAVIS	**§**

BEFORE ME, the undersigned authority, on this day personally appeared Mr. Brett Nelson, after being duly sworn, deposes and states:

I am Brett Nelson, a paralegal at the Law Offices of Shannon K. McClendon. I am over the age of twenty-one years and am of sound mind and competent to attest to the matters stated herein.

I was responsible for acquiring the exact documents of the attachments to this pleading which are public records from the ERCOT website, as posted, and swear that I did not knowingly alter any of the attachments as I obtained such documents.

Brett Nelson

Brett Nelson (signature)

SUBSCRIBED AND SWORN TO BEFORE ME on the 22 day of December, 2009.

Notary Public for the State of Texas

My Commission Expires: 9/26/2011

PAIGE ANN THOMAS
Notary Public, State of Texas
My Commission Expires
SEPT. 26, 2011

Affidavit of Mr. Robert Sims,
AES Wind Generation, Inc.
attesting to facts asserted herein

PUC DOCKET NO. ______

BUFFALO GAP WIND FARM, L.L.C.'S APPEAL AND COMPLAINT OF ERCOT'S DECISION AND ACTION REGARDING PRR 830 AND MOTION FOR SUSPENSION OF ACTION	§ § § § §	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

AFFIDAVIT OF MR. ROBERT SIMS

STATE OF CALIFORNIA §
§
COUNTY OF Contra Costa §

BEFORE ME, the undersigned authority, on this day personally appeared Mr. Robert Sims, after being duly sworn, deposes and states:

I am Robert Sims, Director of Engineering & System Planning and Project Director for AES Wind Generation, Inc. I am over the age of twenty-one years and am of sound mind and competent to attest to the matters stated herein.

I hold a Bachelor of Science degree in Electrical Power Engineering from California Polytechnic University and am the co-author of several papers regarding wind energy, including The Institute of Electrical and Electronics Engineers ("IEEE") recommended practice "Design and Operation of Windfarm Generating Stations".

I certify that the facts set forth in the foregoing Buffalo Gap's Appeal and Complaint of ERCOT's Decision to Approve PRR 830 and Motion for Suspension are, in my opinion and based on my professional experience, to the best of my knowledge and belief after reasonable inquiry, true and correct.

Robert Sims (signature)

SUBSCRIBED AND SWORN TO BEFORE ME on this 22 day of December, 2009.

Notary Public for the State of California

ASHLEY M. CLONAN-HEANES
Commission # 1866727
Notary Public - California
Contra Costa County
My Comm. Expires Oct 1, 2013

My Commission Expires: Oct. 1, 2013