Date: October 3, 2024
To: Board of Directors
From: Jeff Billo, Director, Operations Planning
Subject: Recommendation regarding 2025 ERCOT Methodologies for Determining Minimum Ancillary Service Requirements

Issue for the ERCOT Board of Directors

ERCOT Board of Directors Meeting Date: October 10, 2024
Item No.: 9.3.1

Issue:
Whether the Board of Directors (Board) of Electric Reliability Council of Texas, Inc. (ERCOT) should recommend approval of the proposed 2025 ERCOT Methodologies for Determining Minimum Ancillary Service Requirements (2025 AS Methodology) as presented herein, to be effective January 1, 2025.

Background/History:
Ancillary Services are necessary to maintain the reliability of the ERCOT System. The ERCOT Protocols define these Ancillary Services and charge ERCOT with determining a methodology for the minimum levels of Ancillary Services required. Paragraph (2) of Protocol Section 3.16 requires ERCOT to review the methodology at least annually, and paragraph (3) of Section 3.16 requires the Board to review and recommend approval of ERCOT's methodology.

ERCOT staff previously presented the 2024 ERCOT Methodologies for Determining Minimum Ancillary Service Requirements (2024 AS Methodology) to the Board on December 19, 2023, which the Board approved to be effective January 1, 2024 as requested.

The primary changes for the 2025 AS Methodology in comparison to 2024 AS Methodology are related to Regulation Service, ERCOT Contingency Reserve Service (ECRS) and Non-Spinning Reserve (Non-Spin) Service. No change has been proposed to the methodology used to compute Responsive Reserve Service. The changes that are shown in red-line in ***Attachment A*** and can be summarized as follows:

- Responsive Reserve Service
    - No Change – i.e., same methodology as approved on December 19, 2023.
- Regulation Service
    - Change the computations to account for historic error in forecasted net load used in SCED.

- ERCOT Contingency Reserve Service
  - Change the computations such that ECRS requirements are determined as the larger of capacity needed to recover frequency and capacity needed to support the net load forecast for the respective hour.
  - Adjust the frequency recovery related computations such that is covers 70% of historic net load and inertia conditions.
  - Remove the adjustment for risk cover floor to cover 90^{th} percentile of historical intra-hour net load uncertainty which was previously applied during sunset hours.
- Non-Spin Reserve Service
  - Change to computation for HE23 to HE06 such that Non-Spin requirements for these hours is determined using 4 hour ahead net load forecast error.

In addition to the changes proposed in the 2025 AS Methodology as outlined above, ***Attachment A*** updates the minimum level of RRS from Resources providing RRS using Primary Frequency Response to 1,365 MW. Lastly the adjustment tables that are used by these AS methodologies are being removed from ***Attachment A*** and will be posted in the public reports that contain the minimum quantities.

On September 19, 2024, the Technical Advisory Committee (TAC) endorsed the proposed 2025 AS Methodology, with an effective date of January 1, 2025. The Reliability and Markets (R&M) Committee is expected to review the proposed 2025 AS Methodology at its meeting on October 9, 2024, and is expected to recommend the Board to endorse the proposed 2025 AS Methodology.

Key Factors Influencing Issue:

Regulation Service: ERCOT's SCED tool now takes expected/forecasted ramping of wind and solar resources over the next five minutes into account when setting Base Points for SCED dispatchable Resources. Through this awareness, SCED essentially is prepositioning SCED dispatchable Resources in anticipation of changes in wind and solar generation. With this, Regulation Service is used to respond to errors in forecast used by SCED instead of covering variability in load, wind and solar over the next five minutes. The proposed methodology change better quantifies the balancing needs in between SCED executions for which Regulation Service is relied upon.

ERCOT Contingency Reserve Service: Since implementation of ECRS in June 2023, there have been very few situations where ERCOT has seen the need to release ECRS to address both net load forecast issues and frequency recovery needs. Additionally, in the rare instances when a large generator(s) trips at the same time as a large intra-hour net load forecast error in a way that frequency control is impacted, ERCOT will rely on manual actions to maintain reliability. As a result, ERCOT is proposing to set

ECRS quantities based on needs of the dominant operational risk in every hour. The proposed adjustments in frequency recovery related calculations in the ECRS methodology make the historic information used consistent with the RRS quantities. Lastly, trends in intra-hour net load uncertainty during sunset hours show an improvement due to recent operational changes in SCED inputs. These improvements have eliminated the necessity of using a 90th percentile floor in the net load uncertainty calculation.

Non-Spinning Reserve Service: Analysis of offline capacity and committed capacity margin between HE23 to HE06 shows sufficient capacity that can be brought online in less than 4 hours is typically available to help address sustained net load forecast issues that may occur during these hours. The proposed use of 4 hour ahead net load forecast error approach for computing Non-Spin quantities in these hours better reflects the availability of offline capacity associated with these hours.

Another change worth noting is related to the removal of the adjustment tables namely, Wind Adjustment tables and Solar Adjustment tables used to add incremental amount of Regulation Service quantities; Solar Intra-Hour Over-Forecast Error Adjustment tables used to add incremental amounts of ECRS quantities; Intra-day Forced Outage table, Wind Over-Forecast Adjustment table, and Solar Over-Forecast Adjustment table used to add incremental amounts of Non-Spin quantities. ERCOT conducts analysis annually to update these table based on anticipated growth in installed wind and solar capacity, respectively for the upcoming year and forced outage data from thermal resources from the previous year. Going forward, ERCOT will document the results from these analysis in the public reports that also contain the minimum AS quantities.

These changes were endorsed by the Reliability and Operations Subcommittee (ROS), Wholesale Markets Subcommittee (WMS) and TAC.

Conclusion/Recommendation:
ERCOT staff recommends, and the R&M Committee is expected to recommend, that the Board recommend approval of the proposed 2025 ERCOT Methodologies for Determining Minimum Ancillary Service Requirements, attached as ***Attachment A***, as endorsed by TAC, to be effective January 1, 2025.

ELECTRIC RELIABILITY COUNCIL OF TEXAS, INC.
BOARD OF DIRECTORS RESOLUTION

WHEREAS, Protocol Section 3.16 requires that the Board of Directors (Board) of Electric Reliability Council of Texas, Inc. (ERCOT), review and recommend approval of the ERCOT methodology for determining the minimum Ancillary Service requirements;

WHEREAS, Protocol Section 3.16 requires, prior to implementation, approval by the Public Utility Commission of Texas (PUCT) of any Board recommendation for determining the minimum Ancillary Service requirements;

WHEREAS, the Reliability and Markets (R&M) Committee has reviewed the 2025 ERCOT Methodologies for Determining Minimum Ancillary Service Requirements (2025 AS Methodology) recommended by ERCOT staff and as endorsed by the Technical Advisory Committee (TAC), as set forth in ***Attachment A***, to be effective on January 1, 2025, and has recommended that the Board approve the 2025 AS Methodology; and

WHEREAS, after due consideration of the alternatives, the Board deems it desirable and in the best interest of ERCOT to recommend approval of the 2025 AS Methodology as recommended by the R&M Committee;

THEREFORE, BE IT RESOLVED, that ERCOT hereby recommends the PUCT authorize and approve ERCOT to implement the 2025 AS Methodology, as set forth in ***Attachment A***, as recommended by the R&M Committee and as endorsed by TAC, to be effective on January 1, 2025.

CORPORATE SECRETARY'S CERTIFICATE

I, Chad V. Seely, Corporate Secretary of ERCOT, do hereby certify that, at its October 10, 2024, meeting, the Board passed a motion approving the above Resolution by ______.

IN WITNESS WHEREOF, I have hereunto set my hand this ___ day of ______________, 2024.

____
Chad V. Seely
Corporate Secretary

Attachment A

ERCOT Methodologies for Determining Minimum Ancillary Service Requirements

ERCOT Board Recommended approval~~ed~~ on
~~12~~XX/~~19~~XX/~~2023~~XXXX

PUC Approved on XX/XX/XXXX

Effective Date of 1/1/2025~~4~~

TABLE OF CONTENTS

Introduction

Paragraph (2) of Protocol Section 3.16, Standards for Determining Ancillary Service Quantities, requires that methodologies for determining the amounts of Ancillary Services to be required by ERCOT must be developed at least annually. Paragraph (3) of Protocol Section 3.16 requires ~~approval~~ review of this methodology by the ERCOT Board of Directors and approval by the Public Utility Commission of Texas (PUCT)~~Board of Directors~~.

This document discusses the various Ancillary Services for which requirements are to be developed. Further, detailed methodologies for determining those requirements are included as part of this document.

Specifically, methodologies are required for the determination of the quantities of Regulation Service, ERCOT Contingency Reserve Service (ECRS), Non-Spinning Reserve (Non-Spin) and Responsive Reserve (RRS) that are required to maintain system reliability. Those procedures are discussed below.

These procedures are intended for determining each of the Ancillary Service requirements for all months of the upcoming year. This procedure will be performed annually. The Ancillary Service requirements are determined annually and will be posted to the Market Information System (MIS) by December 20th for the upcoming year. If necessary, any additional incremental adjustment to the posted Ancillary Service requirements for a particular month will be made using this procedure and will be posted to the MIS prior to the 20th of each month for the upcoming month. If the Ancillary Service requirements identified through this process for a particular operating day are found to be insufficient based on the expected operating conditions for that day, ERCOT may make an updated Ancillary Service requirements posting for that day if the need for incremental adjustments is identified day-ahead and may use the Supplemental Ancillary Service Market (SASM) process for similar adjustments made closer to Real-Time. For any additional months for which ERCOT is required to provide an Ancillary Service requirement forecast, the forecasted requirement will be set to the historical requirement for the same month of the previous year.

Regulation Service Requirement Details

Introduction

Regulation Service consists of resources that can be deployed by ERCOT in response to changes in ERCOT System frequency to maintain the target ERCOT System frequency within predetermined limits according to the Operating Guides. ERCOT is required to evaluate normal requirements for Reg-Up Service and Reg-Down Service on an annual basis. It is ERCOT's practice to use historical rates of Regulation Service usage to perform evaluation and determine the required quantities for this service. Regulation Service is deployed in order to correct actual frequency to scheduled frequency and to ensure North American Electric Reliability Corporation (NERC) requirements are met.

Summary

The Regulation Service requirements are calculated with the expectation that sufficient Regulation Service will be available to cover the 95th percentile of deployed regulation or net load variability. An adjustment may also be made based on historic CPS1 performance.

Procedure

To evaluate Regulation Service requirements, ERCOT will collect historical Resource Registration information, CPS1 data, Regulation Service deployment data~~, aggregate output data~~, and ERCOT system load data. For determining the base Reg-Up requirements for a particular hour, ERCOT will calculate ~~take the largest of the 95th percentile of Reg-Up deployments for the same month of the previous two years, and~~ the 95th percentile of the positive net load (load – wind – solar) forecast error ~~changes~~ for the same month of the previous two years. For determining the base Reg-Down requirements, ERCOT will calculate ~~take the largest of the 95th percentile of Reg-Down deployments for the same month of the previous two years and~~ the 95th percentile of the negative net load (load – wind – solar) forecast error ~~changes~~ for the same month of the previous two years. To better reflect balancing needs within the hours, the net load variability may be updated to account for accumulated Area Control Error (ACE).

In order to consider the increased amount of wind and solar penetration, ERCOT will calculate the increase in installed wind and solar generation capacity, respectively. Then, depending on the month of the year and the hour of the day, ERCOT will add incremental MWs that are derived using the wind and solar forecast error adjustment tables and associated increase in wind and solar generation capacity, to the ~~maximum~~ values determined above. The wind and solar forecast error adjustment tables for incremental MWs for Reg-Up and Reg-Down come from the study ERCOT performs annually, using similar techniques as the 2008 GE wind study, but using actual wind and solar data respectively. The increase in wind (or solar) generation capacity will be calculated by taking the total nameplate capacity of wind (or solar) resources in the ERCOT network model at the time of the procurement study and subtracting out the total nameplate capacity of wind (or solar) resources in the ERCOT model at the end of the month being studied from the previous year.

ERCOT will post these monthly amounts for Regulation Service requirements for the upcoming year on the MIS.

If any incremental changes to the annually posted amounts are needed then the revised amounts for the following month will be posted to the MIS prior to the 20th of the current month. ERCOT may include adjustments for hours in a month considering monthly average for CPS1 and 12-month rolling average CPS1 scores. If it is determined that during the course of the year that the ERCOT monthly average for CPS1 score was less than 140% for a specific month, ERCOT will apply an extra 10% of both Reg-Up and Reg-Down for hours in which the CPS1 score was less than 140%. Additionally, if the ERCOT 12-month rolling average CPS1 score is less than 140%, for the next month ERCOT will procure an extra 10% of both Reg-Up and Reg-Down for hours in which the hourly CPS1 score was less than 140%. This value will increase to 20% if the CPS1 score falls below 100%.

Attachment A

~~Incremental MW Adjustment to Prior-Year Up-Regulation Value, per 1000 MW of Incremental Wind Generation Capacity, to Account for Wind Capacity Growth~~

	~~Hour Ending~~																							
~~Month~~	**~~1~~**	**~~2~~**	**~~3~~**	**~~4~~**	**~~5~~**	**~~6~~**	**~~7~~**	**~~8~~**	**~~9~~**	**~~10~~**	**~~11~~**	**~~12~~**	**~~13~~**	**~~14~~**	**~~15~~**	**~~16~~**	**~~17~~**	**~~18~~**	**~~19~~**	**~~20~~**	**~~21~~**	**~~22~~**	**~~23~~**	**~~24~~**
~~Jan.~~	~~1.3~~	~~0.7~~	~~1.3~~	~~1.1~~	~~2.1~~	~~1.3~~	~~1.2~~	~~1.3~~	~~4.1~~	~~3.8~~	~~1.0~~	~~0.9~~	~~1.5~~	~~1.9~~	~~1.1~~	~~1.4~~	~~2.4~~	~~1.8~~	~~-0.5~~	~~-0.7~~	~~-0.3~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Feb.~~	~~0.7~~	~~0.8~~	~~1.4~~	~~0.7~~	~~1.0~~	~~1.4~~	~~1.1~~	~~1.9~~	~~3.5~~	~~3.3~~	~~2.2~~	~~1.7~~	~~2.0~~	~~1.1~~	~~0.2~~	~~1.1~~	~~0.5~~	~~2.4~~	~~0.6~~	~~-1.4~~	~~-0.5~~	~~-0.7~~	~~-0.2~~	~~0.2~~
~~Mar.~~	~~1.3~~	~~0.6~~	~~1.0~~	~~0.6~~	~~0.6~~	~~1.3~~	~~1.4~~	~~1.4~~	~~5.1~~	~~4.0~~	~~1.4~~	~~2.4~~	~~3.0~~	~~1.1~~	~~1.3~~	~~1.3~~	~~1.7~~	~~3.1~~	~~2.7~~	~~2.9~~	~~0.9~~	~~0.1~~	~~0.3~~	~~0.5~~
~~Apr.~~	~~-0.3~~	~~0.0~~	~~0.9~~	~~1.2~~	~~1.1~~	~~0.9~~	~~1.3~~	~~2.1~~	~~3.3~~	~~0.5~~	~~2.2~~	~~3.0~~	~~4.3~~	~~2.9~~	~~2.5~~	~~1.0~~	~~0.9~~	~~1.2~~	~~1.3~~	~~2.6~~	~~0.7~~	~~-0.1~~	~~-0.1~~	~~-0.3~~
~~May~~	~~0.2~~	~~0.8~~	~~0.6~~	~~1.7~~	~~1.6~~	~~3.2~~	~~1.4~~	~~3.7~~	~~3.9~~	~~1.8~~	~~3.3~~	~~3.7~~	~~2.6~~	~~2.6~~	~~0.3~~	~~1.0~~	~~0.1~~	~~0.3~~	~~0.4~~	~~1.0~~	~~1.1~~	~~-0.2~~	~~0.0~~	~~0.0~~
~~Jun.~~	~~0.2~~	~~0.3~~	~~0.6~~	~~1.6~~	~~2.0~~	~~2.1~~	~~2.7~~	~~6.5~~	~~2.3~~	~~1.4~~	~~2.9~~	~~4.2~~	~~3.2~~	~~1.4~~	~~0.0~~	~~0.1~~	~~-0.1~~	~~-0.2~~	~~-0.1~~	~~0.0~~	~~0.3~~	~~-0.4~~	~~0.0~~	~~0.0~~
~~Jul.~~	~~0.1~~	~~0.2~~	~~1.0~~	~~1.7~~	~~1.6~~	~~2.7~~	~~2.5~~	~~6.3~~	~~2.0~~	~~2.3~~	~~5.1~~	~~4.3~~	~~2.4~~	~~0.3~~	~~-0.2~~	~~-0.6~~	~~-0.2~~	~~-0.2~~	~~-0.6~~	~~-0.1~~	~~0.9~~	~~-0.1~~	~~0.0~~	~~0.0~~
~~Aug.~~	~~0.7~~	~~0.8~~	~~1.0~~	~~1.1~~	~~1.9~~	~~1.4~~	~~0.7~~	~~5.0~~	~~4.2~~	~~0.5~~	~~3.0~~	~~3.2~~	~~1.3~~	~~0.3~~	~~-0.8~~	~~-0.7~~	~~0.0~~	~~-0.2~~	~~-0.3~~	~~0.4~~	~~0.9~~	~~-0.1~~	~~0.0~~	~~0.0~~
~~Sep.~~	~~-0.1~~	~~0.5~~	~~0.9~~	~~1.5~~	~~1.5~~	~~2.1~~	~~1.3~~	~~2.3~~	~~6.4~~	~~2.3~~	~~1.5~~	~~1.8~~	~~1.1~~	~~0.4~~	~~0.8~~	~~-0.9~~	~~-0.2~~	~~-0.5~~	~~0.3~~	~~0.1~~	~~-0.8~~	~~-0.4~~	~~0.0~~	~~0.0~~
~~Oct.~~	~~-0.3~~	~~0.4~~	~~1.6~~	~~1.3~~	~~1.5~~	~~1.1~~	~~1.3~~	~~1.6~~	~~4.9~~	~~5.0~~	~~0.2~~	~~0.9~~	~~0.7~~	~~0.8~~	~~0.1~~	~~-0.3~~	~~0.4~~	~~0.9~~	~~0.7~~	~~-1.0~~	~~-0.6~~	~~-0.2~~	~~-0.1~~	~~0.4~~
~~Nov.~~	~~0.5~~	~~1.2~~	~~1.5~~	~~1.0~~	~~0.9~~	~~0.5~~	~~2.8~~	~~3.1~~	~~3.2~~	~~1.3~~	~~0.4~~	~~0.1~~	~~0.4~~	~~0.5~~	~~0.6~~	~~1.2~~	~~1.6~~	~~0.7~~	~~0.4~~	~~-0.2~~	~~0.4~~	~~0.1~~	~~0.2~~	~~0.3~~
~~Dec.~~	~~0.5~~	~~0.0~~	~~1.5~~	~~1.5~~	~~1.1~~	~~1.0~~	~~0.8~~	~~1.2~~	~~2.7~~	~~2.2~~	~~0.5~~	~~0.7~~	~~0.3~~	~~0.8~~	~~0.9~~	~~0.8~~	~~2.3~~	~~1.1~~	~~-0.8~~	~~-0.2~~	~~0.0~~	~~0.4~~	~~0.1~~	~~0.4~~

~~Incremental MW Adjustment to Prior-Year Down-Regulation Value, per 1000 MW of Incremental Wind Generation Capacity, to Account for Wind Capacity Growth~~

~~Hour Ending~~

~~Month~~	~~1~~	~~2~~	~~3~~	~~4~~	~~5~~	~~6~~	~~7~~	~~8~~	~~9~~	~~10~~	~~11~~	~~12~~	~~13~~	~~14~~	~~15~~	~~16~~	~~17~~	~~18~~	~~19~~	~~20~~	~~21~~	~~22~~	~~23~~	~~24~~
~~Jan.~~	~~0.8~~	~~1.6~~	~~1.0~~	~~0.8~~	~~0.3~~	~~-0.5~~	~~-0.3~~	~~-0.6~~	~~-2.7~~	~~-3.3~~	~~1.5~~	~~2.6~~	~~1.2~~	~~1.2~~	~~1.1~~	~~1.2~~	~~0.9~~	~~0.7~~	~~5.9~~	~~3.8~~	~~3.4~~	~~2.3~~	~~1.6~~	~~1.5~~
~~Feb.~~	~~0.7~~	~~-0.5~~	~~-0.3~~	~~-0.3~~	~~0.1~~	~~-0.2~~	~~-0.2~~	~~-0.4~~	~~-4.8~~	~~-2.8~~	~~0.3~~	~~1.4~~	~~1.5~~	~~0.6~~	~~0.3~~	~~1.1~~	~~1.9~~	~~3.1~~	~~2.3~~	~~5.3~~	~~3.0~~	~~1.3~~	~~2.8~~	~~0.8~~
~~Mar.~~	~~0.1~~	~~0.3~~	~~1.1~~	~~1.1~~	~~0.5~~	~~0.1~~	~~0.0~~	~~-0.9~~	~~-3.9~~	~~0.3~~	~~3.0~~	~~1.0~~	~~2.2~~	~~0.5~~	~~1.5~~	~~1.7~~	~~1.9~~	~~1.3~~	~~2.3~~	~~4.4~~	~~5.9~~	~~4.3~~	~~3.3~~	~~3.4~~
~~Apr.~~	~~1.2~~	~~0.4~~	~~-0.4~~	~~0.3~~	~~-0.2~~	~~-0.7~~	~~-0.4~~	~~-0.3~~	~~0.0~~	~~4.3~~	~~0.8~~	~~0.2~~	~~-0.3~~	~~0.2~~	~~1.1~~	~~1.9~~	~~2.1~~	~~2.0~~	~~1.8~~	~~1.4~~	~~3.2~~	~~4.3~~	~~3.7~~	~~1.9~~
~~May~~	~~1.4~~	~~0.4~~	~~-0.4~~	~~-1.1~~	~~-0.2~~	~~-0.5~~	~~-0.9~~	~~-0.4~~	~~0.9~~	~~0.9~~	~~-0.4~~	~~-0.3~~	~~0.3~~	~~0.8~~	~~1.4~~	~~1.8~~	~~2.9~~	~~3.2~~	~~3.8~~	~~3.6~~	~~3.9~~	~~4.1~~	~~3.4~~	~~2.5~~
~~Jun.~~	~~1.1~~	~~0.1~~	~~-1.3~~	~~-2.1~~	~~-1.3~~	~~-1.4~~	~~-1.6~~	~~-1.0~~	~~0.7~~	~~0.1~~	~~-0.1~~	~~0.0~~	~~0.2~~	~~0.7~~	~~1.2~~	~~1.8~~	~~2.6~~	~~2.7~~	~~2.7~~	~~2.3~~	~~2.5~~	~~5.4~~	~~4.0~~	~~2.1~~
~~Jul.~~	~~1.0~~	~~-0.8~~	~~-1.3~~	~~-1.5~~	~~-1.6~~	~~-2.5~~	~~-1.7~~	~~-1.4~~	~~0.6~~	~~0.0~~	~~0.0~~	~~0.0~~	~~-0.1~~	~~0.6~~	~~2.1~~	~~2.9~~	~~3.5~~	~~4.4~~	~~3.6~~	~~3.2~~	~~1.9~~	~~6.8~~	~~4.7~~	~~2.0~~
~~Aug.~~	~~0.4~~	~~-0.5~~	~~-0.9~~	~~-2.2~~	~~-1.2~~	~~-1.5~~	~~-1.0~~	~~-0.6~~	~~0.1~~	~~0.7~~	~~-0.2~~	~~-0.3~~	~~0.4~~	~~0.8~~	~~2.0~~	~~2.7~~	~~2.8~~	~~2.6~~	~~3.4~~	~~2.2~~	~~2.8~~	~~4.8~~	~~2.7~~	~~1.3~~
~~Sep.~~	~~0.1~~	~~-1.4~~	~~-0.6~~	~~-1.2~~	~~-1.6~~	~~-1.0~~	~~-0.6~~	~~-0.8~~	~~-0.8~~	~~0.0~~	~~0.1~~	~~-0.1~~	~~0.1~~	~~0.1~~	~~1.0~~	~~1.1~~	~~1.9~~	~~2.2~~	~~2.3~~	~~2.8~~	~~6.4~~	~~5.1~~	~~3.4~~	~~1.5~~
~~Oct.~~	~~0.1~~	~~-0.6~~	~~-0.9~~	~~-0.5~~	~~-0.1~~	~~-0.5~~	~~-0.5~~	~~0.0~~	~~-1.2~~	~~-0.9~~	~~1.5~~	~~0.6~~	~~1.4~~	~~0.7~~	~~1.3~~	~~1.8~~	~~1.3~~	~~1.3~~	~~0.4~~	~~4.6~~	~~4.4~~	~~3.3~~	~~1.8~~	~~0.7~~
~~Nov.~~	~~-0.1~~	~~0.0~~	~~-0.4~~	~~-0.7~~	~~-0.2~~	~~-0.4~~	~~-0.4~~	~~-1.0~~	~~-1.0~~	~~0.3~~	~~2.3~~	~~1.4~~	~~1.4~~	~~1.3~~	~~0.9~~	~~1.3~~	~~0.9~~	~~1.0~~	~~3.5~~	~~3.9~~	~~1.9~~	~~1.9~~	~~1.2~~	~~0.1~~
~~Dec.~~	~~-0.2~~	~~-0.1~~	~~-0.9~~	~~0.3~~	~~0.4~~	~~0.2~~	~~0.7~~	~~0.4~~	~~-1.6~~	~~-0.2~~	~~2.0~~	~~2.2~~	~~0.4~~	~~-0.5~~	~~0.3~~	~~0.3~~	~~0.1~~	~~0.7~~	~~4.1~~	~~2.1~~	~~1.7~~	~~1.9~~	~~1.0~~	~~0.3~~

~~Incremental MW Adjustment to Prior-Year Up-Regulation Value, per 1000 MW of Incremental Solar Generation Capacity, to Account for Solar Capacity Growth~~																								
	~~Hour Ending~~																							
~~Month~~	~~1~~	~~2~~	~~3~~	~~4~~	~~5~~	~~6~~	~~7~~	~~8~~	~~9~~	~~10~~	~~11~~	~~12~~	~~13~~	~~14~~	~~15~~	~~16~~	~~17~~	~~18~~	~~19~~	~~20~~	~~21~~	~~22~~	~~23~~	~~24~~
~~Jan.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~2.6~~	~~4.2~~	~~5.3~~	~~5.9~~	~~7.2~~	~~7.6~~	~~9.9~~	~~18.0~~	~~15.1~~	~~1.4~~	~~0.1~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Feb.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~1.0~~	~~8.5~~	~~7.0~~	~~9.2~~	~~7.6~~	~~7.9~~	~~12.0~~	~~13.3~~	~~13.0~~	~~18.3~~	~~8.8~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Mar.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~8.6~~	~~8.6~~	~~10.6~~	~~12.3~~	~~13.4~~	~~13.2~~	~~15.9~~	~~15.5~~	~~17.2~~	~~16.6~~	~~11.7~~	~~0.1~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Apr.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~1.1~~	~~7.1~~	~~9.4~~	~~10.1~~	~~9.8~~	~~10.2~~	~~8.6~~	~~11.4~~	~~13.8~~	~~15.8~~	~~15.6~~	~~14.5~~	~~1.8~~	~~0.0~~	~~0.0~~	~~0.0~~
~~May~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~1.1~~	~~3.8~~	~~6.2~~	~~7.5~~	~~6.6~~	~~6.9~~	~~8.1~~	~~8.6~~	~~10.8~~	~~12.3~~	~~10.5~~	~~11.7~~	~~4.6~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Jun.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~3.7~~	~~3.0~~	~~3.0~~	~~4.4~~	~~6.6~~	~~5.4~~	~~6.3~~	~~11.0~~	~~8.0~~	~~10.2~~	~~12.5~~	~~6.2~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Jul.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~2.8~~	~~1.4~~	~~3.3~~	~~4.5~~	~~4.6~~	~~7.2~~	~~6.6~~	~~7.0~~	~~9.5~~	~~9.4~~	~~12.1~~	~~6.2~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Aug.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~1.5~~	~~4.1~~	~~4.7~~	~~5.7~~	~~6.3~~	~~6.6~~	~~8.3~~	~~8.9~~	~~8.5~~	~~10.4~~	~~11.1~~	~~3.3~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Sep.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.8~~	~~3.9~~	~~4.1~~	~~5.2~~	~~6.0~~	~~7.4~~	~~6.9~~	~~7.2~~	~~9.5~~	~~13.9~~	~~8.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Oct.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~1.1~~	~~4.3~~	~~5.9~~	~~6.2~~	~~5.9~~	~~8.4~~	~~9.9~~	~~11.5~~	~~14.3~~	~~14.0~~	~~0.8~~	~~0.1~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Nov.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~1.4~~	~~4.7~~	~~5.6~~	~~8.5~~	~~8.9~~	~~8.0~~	~~9.4~~	~~11.0~~	~~14.3~~	~~8.8~~	~~5.6~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Dec.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~4.9~~	~~6.1~~	~~5.3~~	~~6.9~~	~~6.9~~	~~8.2~~	~~10.1~~	~~13.6~~	~~7.6~~	~~0.1~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~

~~Incremental MW Adjustment to Prior-Year Down-Regulation Value, per 1000 MW of Incremental Solar Generation Capacity, to Account for Solar Capacity Growth~~																								
	~~Hour Ending~~																							
~~Month~~	~~1~~	~~2~~	~~3~~	~~4~~	~~5~~	~~6~~	~~7~~	~~8~~	~~9~~	~~10~~	~~11~~	~~12~~	~~13~~	~~14~~	~~15~~	~~16~~	~~17~~	~~18~~	~~19~~	~~20~~	~~21~~	~~22~~	~~23~~	~~24~~
~~Jan.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~2.8~~	~~17.2~~	~~11.1~~	~~6.4~~	~~5.3~~	~~4.8~~	~~7.0~~	~~6.3~~	~~5.1~~	~~2.7~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Feb.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~11.1~~	~~19.7~~	~~16.1~~	~~8.6~~	~~8.6~~	~~8.4~~	~~7.9~~	~~9.5~~	~~9.2~~	~~8.5~~	~~1.9~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Mar.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~13.3~~	~~18.9~~	~~13.1~~	~~10.1~~	~~11.4~~	~~12.0~~	~~12.9~~	~~12.7~~	~~11.5~~	~~12.8~~	~~9.6~~	~~2.8~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Apr.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~8.4~~	~~14.5~~	~~11.6~~	~~11.2~~	~~10.6~~	~~8.6~~	~~8.5~~	~~11.2~~	~~12.0~~	~~10.2~~	~~10.7~~	~~4.1~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~
~~May~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~10.8~~	~~12.2~~	~~8.7~~	~~9.0~~	~~8.8~~	~~7.2~~	~~7.0~~	~~6.2~~	~~7.1~~	~~6.0~~	~~5.6~~	~~2.3~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Jun.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~11.2~~	~~12.0~~	~~7.7~~	~~5.5~~	~~4.0~~	~~5.1~~	~~5.1~~	~~5.2~~	~~5.8~~	~~8.2~~	~~5.7~~	~~2.9~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Jul.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~10.9~~	~~11.4~~	~~6.8~~	~~3.8~~	~~3.0~~	~~3.5~~	~~3.4~~	~~5.1~~	~~5.8~~	~~6.1~~	~~6.4~~	~~1.7~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Aug.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~8.4~~	~~11.9~~	~~6.8~~	~~5.2~~	~~4.3~~	~~4.0~~	~~5.3~~	~~5.2~~	~~5.8~~	~~5.6~~	~~4.5~~	~~1.8~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Sep.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~6.4~~	~~15.5~~	~~8.5~~	~~5.9~~	~~3.6~~	~~4.0~~	~~4.6~~	~~4.6~~	~~5.0~~	~~5.6~~	~~3.3~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Oct.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~2.0~~	~~16.2~~	~~12.5~~	~~8.1~~	~~6.1~~	~~5.6~~	~~8.2~~	~~5.8~~	~~5.5~~	~~6.2~~	~~4.2~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Nov.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~8.8~~	~~12.4~~	~~10.5~~	~~8.3~~	~~9.1~~	~~8.7~~	~~7.0~~	~~7.3~~	~~8.9~~	~~3.7~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~
~~Dec.~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~3.3~~	~~13.5~~	~~9.5~~	~~6.6~~	~~6.5~~	~~7.1~~	~~6.6~~	~~5.7~~	~~6.1~~	~~1.3~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.0~~

Non-Spinning Reserve (Non-Spin) Requirement Details

Introduction

Non-Spinning Reserve (Non-Spin) consists of Generation Resources capable of being ramped to a specified output level within 30 minutes or Controllable Load Resources that are capable of being interrupted within 30 minutes and that are capable of running (or being interrupted) at a specified output level for at least four consecutive hours. Non-Spin may also be provided by Load Resources that are not Controllable Load Resources and are capable of reducing consumption based on an ERCOT Extensible Markup Language (XML) instruction within 30 minutes and maintaining that deployment until recalled. Non-Spin may be deployed to replace loss of generating capacity, to compensate for Load forecast and/or forecast uncertainty on days in which large amounts of reserve are not available online, to address the risk of net load ramp, or when there is a limited amount of capacity available for Security-Constrained Economic Dispatch (SCED).

The periods when load is increasing and wind and/or solar are decreasing requires other generation resources to increase output or come online quickly to compensate for the sudden net load increases. As a result, net load ramp risk should be accounted for in the determination of Non-Spin requirements. While net load forecast analysis may cover reserves required for forecast uncertainty, it may not necessarily cover exposure to the loss of generation and net load ramp risk. Due to this risk, it may be necessary for ERCOT to have additional reserves available to protect against forecast uncertainty and Forced Outages of thermal Resources within an Operating Day.

Summary

Analysis for Non-Spin requirements are conducted using data from the same month of previous three years. For the purpose of determining the amount of Non-Spin to purchase for each hour of the day, hours will be placed into 4-hour blocks. The net load uncertainty for the analyzed days for all hours which are considered to be part of a 4-hour block will be calculated and a percentile will be assigned to this block of hours based on the risk of net load ramp. The same calculation will be done separately for each block. The Non-Spin requirement for the month for each block is calculated using the assigned percentile (based on risk of net load ramp) for the block minus the average Reg-Up requirement during the same block of hours ("Non-Spin block"). The Non-Spin requirement for each hour in the month is calculated by adding an adjustment that accounts for intra-day Forced Outage of thermal Resources to the previously calculated "Non-Spin block" quantity that the hour falls in.

ERCOT will post the monthly amounts for Non-Spin requirements for the upcoming year on the MIS. Following this posting, ERCOT will monitor the weather and net load forecast (i.e. load, wind and solar forecasts) near Real-Time and may procure up to an additional 1,000 MW of Non-Spin for Operating Hours that are (a) identified as having an increased potential of high forecast variability, (b) there is a risk that the actual net load during these Operating Hours could be higher than forecast (after making appropriate forecast model selection) and (c) the expected available capacity and expected reserves including the posted minimum Non-Spin requirements during these Operating Hours is not sufficient to cover the projected net load forecast uncertainty risk.

The minimum amount of Non-Spin procured from SCED dispatchable Resources in any hour shall not be less than ERCOT's Most Severe Single Contingency (MSSC) value.

Procedure

ERCOT will determine the Non-Spin requirement using the 75th to 95th percentile of hourly net load uncertainty from the same month of the previous three years. Net load is defined as the ERCOT load minus the estimated un-curtailed total output from Intermittent Renewable Resource (IRR), which includes both Wind-powered Generation Resources (WGRs) and Photo-Voltaic Generation Resources (PVGR) at a point in time. The forecast of net load is computed by subtracting the aggregate IRR High Sustained Limits (HSLs) in the Current Operating Plans (COPs) from the Mid-Term Load Forecast (MTLF). The COPs and MTLF used for HE23, HE24, HE01 and HE02 are the updated values as of four hours prior to each Operating Hour. For remaining hours, ~~T~~the COPs and MTLF used are the updated values as of six hours prior to each Operating Hour. The net load uncertainty is then defined as the difference between the average 5-minute net load within the hour and the forecasted net load.

The risk of net load ramp is determined based on the change in net load over an hour divided by highest observed net load for the season. A fixed value of 68th percentile will be assigned to HE23, HE24, HE01 and HE02 to the net load forecast uncertainty calculated previously. ~~Additionally, for these same hours a net load forecast uncertainty of four hours prior to the Operating Hour will be used for the calculations.~~ Additionally, ~~I~~in all seasons excluding Winter, in hours ~~a fixed value of 68th percentile will also be assigned to~~ HE03, HE04, HE05, HE06 a fixed value of 68th percentile will be assigned for~~to~~ the net load forecast uncertainty calculated previously. For the remaining hours, a fixed value of percentile ranging between 75th percentile and 95th percentile will be assigned to the net load forecast uncertainty calculated previously. Periods where the risk of net load ramp is highest will use 95th percentile and 75th percentile for periods with lowest risks.

ERCOT has seen significant growth in installed wind and solar capacity from one year to the next; an increase in wind and solar capacity also tends to increase the MW quantity of error in their respective forecasts. Hence, ERCOT's reliance on historical wind and solar forecast errors alone creates a possibility of under-estimation of the Non-Spin requirement.

To address this, ERCOT will include the impact of increase in over-forecast error from the expected growth in wind and solar generation installed capacity into the future Non-Spin requirement. The net wind impact is calculated by a multiplication of the projected wind capacity growth between the same month of current year and the next year, and incremental MW adjustment to Non-Spin value per 1000 MW of incremental wind generation capacity. The incremental MW wind adjustment to the Non-Spin value per 1000 MW increase in wind installed capacity is calculated as the change in 50th percentile of the historical wind over-forecast error for 4-hour blocks of each month in the past 5 years, which is then normalized to per 1000 MW of installed wind capacity. The net solar impact is calculated by a multiplication of the projected solar capacity growth between the same month of current year and the next year, and incremental MW adjustment to Non-Spin value per 1000 MW of incremental solar generation capacity. The incremental MW solar adjustment to the Non-Spin value per 1000 MW increase in solar installed capacity is calculated as the change in 50th percentile of the historical solar over-forecast error for 4-hour blocks of each month in the past 3 years, which is then normalized to per 1000 MW of installed solar capacity. ~~The tables below reflects the additional Non-Spin adjustments per 1000 MW of installed wind and solar capacity.~~

To account for increased capacity needs due to unplanned generation Outages that occur during an Operating Day, ERCOT will include an incremental adjustment in the Non-Spin requirements that accounts for intra-day Forced Outages of thermal Resources. This Forced Outage adjustment is calculated as the 75th percentile of the historical intra-day Forced Outages (accumulated since midnight) for six-hour blocks of each month in the past three years. ~~The table below reflects additional Non-Spin adjustments to account for intra-day Forced Outages of thermal Resources.~~ ERCOT will purchase Non-Spin such that the combination of Non-Spin and Reg-Up Services cover the uncertainties of net load forecast errors depending on the net load ramp risk and intra-day Forced Outages.

~~Incremental MW Adjustment to Non-Spinning Reserve Service, per 1000 MW of Incremental Wind Generation Capacity~~																								
	~~Hour Ending~~																							
~~Month~~	~~1~~	~~2~~	~~3~~	~~4~~	~~5~~	~~six~~	~~7~~	~~8~~	~~9~~	~~10~~	~~11~~	~~12~~	~~13~~	~~14~~	~~15~~	~~16~~	~~17~~	~~18~~	~~19~~	~~20~~	~~21~~	~~22~~	~~23~~	~~24~~
~~Jan.~~	~~27~~	~~27~~	~~27~~	~~27~~	~~27~~	~~27~~	~~29~~	~~29~~	~~29~~	~~29~~	~~22~~	~~22~~	~~22~~	~~22~~	~~23~~	~~23~~	~~23~~	~~23~~	~~28~~	~~28~~	~~28~~	~~28~~	~~27~~	~~27~~
~~Feb.~~	~~27~~	~~27~~	~~27~~	~~27~~	~~27~~	~~27~~	~~29~~	~~29~~	~~29~~	~~29~~	~~22~~	~~22~~	~~22~~	~~22~~	~~23~~	~~23~~	~~23~~	~~23~~	~~28~~	~~28~~	~~28~~	~~28~~	~~27~~	~~27~~
~~Mar.~~	~~29~~	~~29~~	~~31~~	~~31~~	~~31~~	~~31~~	~~30~~	~~30~~	~~30~~	~~30~~	~~25~~	~~25~~	~~25~~	~~25~~	~~26~~	~~26~~	~~26~~	~~26~~	~~29~~	~~29~~	~~29~~	~~29~~	~~29~~	~~29~~
~~Apr.~~	~~29~~	~~29~~	~~31~~	~~31~~	~~31~~	~~31~~	~~30~~	~~30~~	~~30~~	~~30~~	~~25~~	~~25~~	~~25~~	~~25~~	~~26~~	~~26~~	~~26~~	~~26~~	~~29~~	~~29~~	~~29~~	~~29~~	~~29~~	~~29~~
~~May~~	~~29~~	~~29~~	~~31~~	~~31~~	~~31~~	~~31~~	~~30~~	~~30~~	~~30~~	~~30~~	~~25~~	~~25~~	~~25~~	~~25~~	~~26~~	~~26~~	~~26~~	~~26~~	~~29~~	~~29~~	~~29~~	~~29~~	~~29~~	~~29~~
~~Jun.~~	~~27~~	~~27~~	~~26~~	~~26~~	~~26~~	~~26~~	~~26~~	~~26~~	~~26~~	~~26~~	~~19~~	~~19~~	~~19~~	~~19~~	~~21~~	~~21~~	~~21~~	~~21~~	~~28~~	~~28~~	~~28~~	~~28~~	~~27~~	~~27~~
~~Jul.~~	~~27~~	~~27~~	~~26~~	~~26~~	~~26~~	~~26~~	~~26~~	~~26~~	~~26~~	~~26~~	~~19~~	~~19~~	~~19~~	~~19~~	~~21~~	~~21~~	~~21~~	~~21~~	~~28~~	~~28~~	~~28~~	~~28~~	~~27~~	~~27~~
~~Aug.~~	~~27~~	~~27~~	~~26~~	~~26~~	~~26~~	~~26~~	~~26~~	~~26~~	~~26~~	~~26~~	~~19~~	~~19~~	~~19~~	~~19~~	~~21~~	~~21~~	~~21~~	~~21~~	~~28~~	~~28~~	~~28~~	~~28~~	~~27~~	~~27~~
~~Sep.~~	~~21~~	~~21~~	~~21~~	~~21~~	~~21~~	~~21~~	~~22~~	~~22~~	~~22~~	~~22~~	~~17~~	~~17~~	~~17~~	~~17~~	~~21~~	~~21~~	~~21~~	~~21~~	~~22~~	~~22~~	~~22~~	~~22~~	~~21~~	~~21~~
~~Oct.~~	~~21~~	~~21~~	~~21~~	~~21~~	~~21~~	~~21~~	~~22~~	~~22~~	~~22~~	~~22~~	~~17~~	~~17~~	~~17~~	~~17~~	~~21~~	~~21~~	~~21~~	~~21~~	~~22~~	~~22~~	~~22~~	~~22~~	~~21~~	~~21~~
~~Nov.~~	~~21~~	~~21~~	~~21~~	~~21~~	~~21~~	~~21~~	~~22~~	~~22~~	~~22~~	~~22~~	~~17~~	~~17~~	~~17~~	~~17~~	~~21~~	~~21~~	~~21~~	~~21~~	~~22~~	~~22~~	~~22~~	~~22~~	~~21~~	~~21~~
~~Dec.~~	~~27~~	~~27~~	~~27~~	~~27~~	~~27~~	~~27~~	~~29~~	~~29~~	~~29~~	~~29~~	~~22~~	~~22~~	~~22~~	~~22~~	~~23~~	~~23~~	~~23~~	~~23~~	~~28~~	~~28~~	~~28~~	~~28~~	~~27~~	~~27~~

Incremental MW Adjustment to Non-Spinning Reserve Service, per 1000 MW of Incremental Solar Generation Capacity																								
	Hour Ending																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan.	0	0	0	0	0	0	3	3	3	3	37	37	37	37	31	31	31	31	0	0	0	0	0	0
Feb.	0	0	0	0	0	0	3	3	3	3	37	37	37	37	31	31	31	31	0	0	0	0	0	0
Mar.	0	0	0	0	0	0	7	7	7	7	44	44	44	44	48	48	48	48	2	2	2	2	0	0
Apr.	0	0	0	0	0	0	7	7	7	7	44	44	44	44	48	48	48	48	2	2	2	2	0	0
May	0	0	0	0	0	0	7	7	7	7	44	44	44	44	48	48	48	48	2	2	2	2	0	0
Jun.	0	0	0	0	0	0	11	11	11	11	34	34	34	34	36	36	36	36	8	8	8	8	0	0
Jul.	0	0	0	0	0	0	11	11	11	11	34	34	34	34	36	36	36	36	8	8	8	8	0	0
Aug.	0	0	0	0	0	0	11	11	11	11	34	34	34	34	36	36	36	36	8	8	8	8	0	0
Sep.	0	0	0	0	0	0	4	4	4	4	26	26	26	26	23	23	23	23	1	1	1	1	0	0
Oct.	0	0	0	0	0	0	4	4	4	4	26	26	26	26	23	23	23	23	1	1	1	1	0	0
Nov.	0	0	0	0	0	0	4	4	4	4	26	26	26	26	23	23	23	23	1	1	1	1	0	0
Dec.	0	0	0	0	0	0	3	3	3	3	37	37	37	37	31	31	31	31	0	0	0	0	0	0

Incremental MW Adjustment to Non-Spinning Reserve Service to account for Intra-day Forced Outages of thermal resources																								
	Hour Ending																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan.	511	511	511	511	511	511	952	952	952	952	952	952	921	921	921	921	921	921	958	958	958	958	958	958
Feb.	432	432	432	432	432	432	805	805	805	805	805	805	1013	1013	1013	1013	1013	1013	704	704	704	704	704	704
Mar.	515	515	515	515	515	515	839	839	839	839	839	839	839	839	839	839	839	839	700	700	700	700	700	700
Apr.	621	621	621	621	621	621	869	869	869	869	869	869	815	815	815	815	815	815	759	759	759	759	759	759
May	786	786	786	786	786	786	881	881	881	881	881	881	1052	1052	1052	1052	1052	1052	984	984	984	984	984	984
Jun.	612	612	612	612	612	612	771	771	771	771	771	771	817	817	817	817	817	817	997	997	997	997	997	997
Jul.	635	635	635	635	635	635	763	763	763	763	763	763	525	525	525	525	525	525	723	723	723	723	723	723
Aug.	558	558	558	558	558	558	671	671	671	671	671	671	449	449	449	449	449	449	549	549	549	549	549	549
Sep.	435	435	435	435	435	435	777	777	777	777	777	777	533	533	533	533	533	533	510	510	510	510	510	510
Oct.	581	581	581	581	581	581	1016	1016	1016	1016	1016	1016	995	995	995	995	995	995	863	863	863	863	863	863
Nov.	639	639	639	639	639	639	835	835	835	835	835	835	974	974	974	974	974	974	1055	1055	1055	1055	1055	1055
Dec.	668	668	668	668	668	668	775	775	775	775	775	775	1018	1018	1018	1018	1018	1018	617	617	617	617	617	617

Responsive Reserve (RRS) Requirement Details

Nodal Operating Guide Section 2.3.1.1, Obligation, sets the minimum RRS requirement for all hours under normal conditions. ERCOT will procure amounts of RRS that vary by hour of the day and by month. These RRS amounts will be published by month in six separate blocks covering four-hour intervals. These amounts will be based on expected diurnal load, solar, and wind patterns for the month, will cover 70% of historic system inertia conditions for each block of hours for the month, and will use the equivalency ratio for RRS between Load Resources and Generation Resources to establish the conditions for each block of hours. The equivalency ratio will be used to establish the total reserves assuming the Day-Ahead Market (DAM) will use a one to one equivalency ratio. The minimum level of RRS procured from Resources providing RRS using Primary Frequency Response shall be determined for each month by ERCOT through the use of studies and shall not be less than 1,365~~185~~ MWs. The remaining capacity required for RRS will be procured from all Resources qualified to provide RRS including Load Resources. The maximum amount of RRS that can be provided by Resources providing Fast Frequency Response (FFR) is limited to 450 MW. DAM will limit the combined RRS procured from Load Resources controlled by high set under frequency relay and Resources providing FFR to 60% of the total RRS requirement. ERCOT may increase the minimum capacity required from Resources providing RRS using Primary Frequency Response if it believes that the current posted quantity will have a negative impact on reliability or if it would require additional Regulation Service to be deployed. ERCOT will procure additional 200 MW of RRS for each percent of Reserve Discount Factor (RDF) when ERCOT estimates RDF to be less than 1. This adjustment will only apply for those 4-hour blocks where the 85th percentile of weighted average temperate is greater than 95°F. RDFs are reviewed and adjusted based on the generators performance during an unannounced test. RRS amount will be published as a monthly requirement along with the equivalency ratio for each 4-hour block. Additionally, ERCOT will make incremental adjustments to account for Resources operating in synchronous condenser fast response mode providing RRS. This adjustment will only apply to those 4-hour blocks when system inertia is typically expected to be less than 250 GW*s. ERCOT will post these monthly amounts for the upcoming year on the MIS. These annually published amounts are the minimum quantity that will be procured in the DAM for each hour of the year.

Self-arranged RRS used to fulfill a Qualified Scheduling Entity's (QSE's) RRS requirement will be limited to 60% from Resources providing FFR and Load Resources excluding Controllable Load Resources.

If the percentage level for Resources providing FFR and Load Resources, excluding Controllable Load Resources, specified in the Protocols is changed, that change will be reflected in these requirements.

ERCOT Contingency Reserve Service (ECRS) Details

Introduction

ECRS is a service that is provided using capacity that is capable of being ramped to a specified output level within 10 minutes. ECRS may be provided by unloaded, On-Line Generation Resource capacity; Quick Start Generation Resources (QSGRs); Load Resources that may or may not be controlled by high-set, underfrequency relays; Controllable Load Resources; and Generation Resources operating in synchronous condenser fast-response mode as defined in the Operating Guides. ECRS may be deployed to restore frequency within 10 minutes of a significant frequency deviation to recover deployed Regulation Service, to compensate for intra-hour net load forecast uncertainty and variability on days in which large amounts of online thermal ramping capability is not available, or when there is a limited amount of capacity available for Security-Constrained Economic Dispatch (SCED).

Procedure

ERCOT will procure amounts of ECRS that vary by hour of the day and by month. ERCOT will determine the ECRS requirement as the ~~sum~~ maximum of capacity needed to recover frequency following a large unit trip and capacity needed to cover for intra-hour net load forecast errors.

The frequency recovery related capacity for ECRS is computed for each hour in every month as capacity needed following a supply-side trip to recover frequency; will be based on expected diurnal load, solar, and wind patterns; ~~-~~will cover 70~~60~~% of historic system inertia conditions for each hour for the month and will include an adjustment to account for Regulation Up requirement in the hour.

Intra-hour net load forecast is utilized in establishing Base Points for SCED dispatchable Resources. ERCOT has observed larger intra-hour net load forecast errors during times when there are sudden net load ramps. Through including intra-hour net load forecast errors in calculating ECRS quantities, uncertainty in forecasting intra-hour net load (and hence intra-hour net load ramps) will be accounted for. Specifically, the intra-hour net load forecast error related capacity for ECRS is computed using the 85th to 95th percentile of intra-hour net load uncertainty from the same hour and same month in the previous two years. Net load is defined as the ERCOT load minus the estimated un-curtailed total output from Intermittent Renewable Resource (IRR), which includes both Wind-powered Generation Resources (WGRs) and Photo-Voltaic Generation Resources (PVGR). The forecast of net load is computed by subtracting the Intra-Hour Wind Power Forecast (IHWPF) and Intra-Hour Photo Voltaic Power Forecast (IHPPF) from the Intra-Hour Load Forecast (IHLF). The IHWPF, IHPPF and IHLF used are the updated values as of thirty minutes prior to each Security Constrained Economic Dispatch (SCED) interval. The net load uncertainty is then defined as the difference between the average net load within the SCED interval and the forecasted net load.

The risk of net load ramp is determined based on the change in net load over an hour divided by highest observed net load for the season. The fixed value of percentile ranging between 85th percentile and 95th percentile will be assigned to the net load forecast uncertainty calculated previously. Periods where the risk of net load ramp is highest will use 95th percentile and 85th percentile for periods with lowest risks. ~~A value of at least 90th percentile will be assigned to the net load forecast uncertainty calculated during sunset hours.~~

ERCOT has seen significant growth in installed solar capacity from one year to the next; an increase in solar capacity also tends to increase the MW quantity of error in their respective forecasts. Hence, ERCOT's reliance on historical solar forecast errors alone creates a possibility of under-estimation of the ECRS requirement. To address this, ERCOT will include the estimated impact of increase in over-forecast error from the expected growth in solar generation installed capacity into the future ECRS requirement. The net solar impact is calculated by a multiplication of the projected solar capacity growth between the same month of current year and the next year, and incremental MW adjustment to ECRS value per 1000 MW of incremental solar generation capacity. The incremental MW solar adjustment to the ECRS value per 1000 MW increase in solar installed capacity is calculated as the change in 50th percentile of the historical solar over-forecast error for 4-hour blocks of each month in the past 2 years, which is then normalized to per 1000 MW of installed solar capacity. ~~The tables below reflects the additional ECRS adjustments per 1000 MW of installed solar capacity.~~

~~Incremental MW Adjustment to ERCOT Contingency Reserve Service, per 1000 MW of Incremental Solar Generation Capacity~~

~~Hour Ending~~

~~Month~~	~~1~~	~~2~~	~~3~~	~~4~~	~~5~~	~~6~~	~~7~~	~~8~~	~~9~~	~~10~~	~~11~~	~~12~~	~~13~~	~~14~~	~~15~~	~~16~~	~~17~~	~~18~~	~~19~~	~~20~~	~~21~~	~~22~~	~~23~~	~~24~~
~~Jan.~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~21~~	~~21~~	~~21~~	~~21~~	~~20~~	~~20~~	~~20~~	~~20~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Feb.~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~33~~	~~33~~	~~33~~	~~33~~	~~20~~	~~20~~	~~20~~	~~20~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Mar.~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~33~~	~~33~~	~~33~~	~~33~~	~~73~~	~~73~~	~~73~~	~~73~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Apr.~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~30~~	~~30~~	~~30~~	~~30~~	~~55~~	~~55~~	~~55~~	~~55~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~May~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~59~~	~~59~~	~~59~~	~~59~~	~~96~~	~~96~~	~~96~~	~~96~~	~~26~~	~~26~~	~~26~~	~~26~~	~~0~~	~~0~~
~~Jun.~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~17~~	~~17~~	~~17~~	~~17~~	~~41~~	~~41~~	~~41~~	~~41~~	~~37~~	~~37~~	~~37~~	~~37~~	~~0~~	~~0~~
~~Jul.~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~23~~	~~23~~	~~23~~	~~23~~	~~23~~	~~23~~	~~23~~	~~23~~	~~8~~	~~8~~	~~8~~	~~8~~	~~0~~	~~0~~
~~Aug.~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~45~~	~~45~~	~~45~~	~~45~~	~~53~~	~~53~~	~~53~~	~~53~~	~~4~~	~~4~~	~~4~~	~~4~~	~~0~~	~~0~~
~~Sep.~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~64~~	~~64~~	~~64~~	~~64~~	~~56~~	~~56~~	~~56~~	~~56~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Oct.~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~26~~	~~26~~	~~26~~	~~26~~	~~37~~	~~37~~	~~37~~	~~37~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Nov.~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~1~~	~~1~~	~~1~~	~~1~~	~~4~~	~~4~~	~~4~~	~~4~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~
~~Dec.~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~3~~	~~3~~	~~3~~	~~3~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~	~~0~~