DOCKET NO.

COMPLAINT AND APPEAL OF SOUTH TEXAS ELECTRIC COOPERATIVE, INC AGAINST THE ELECTRIC RELIABILITY COUNCIL OF TEXAS, INC.	§ § § § §	BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS

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TABLE OF CONTENTS

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<u>COMPLAINT AND APPEAL OF SOUTH TEXAS ELECTRIC COOPERATIVE, INC. AGAINST THE ELECTRIC RELIABILITY COUNCIL OF TEXAS, INC.</u>

TO THE HONORABLE PUBLIC UTILITY COMMISSION OF TEXAS:

COMES NOW, South Texas Electric Cooperative, Inc. ("STEC") and respectfully files this complaint ("Complaint") against the Electric Reliability Council of Texas, Inc. ("ERCOT") for failing to compensate STEC for ERCOT ancillary services ("Ancillary Services") provided during Winter Storm Uri. STEC respectfully shows as follows:

I. INTRODUCTION

STEC is a generation and transmission electric cooperative that provides generation and transmission service to nine distribution member-cooperatives. STEC is registered as a market participant in the ERCOT market, including being registered as a qualified scheduling entity ("QSE") that represents generation resources and load resources. During the unprecedented rotating outages during the winter storm events that occurred in February of 2021, STEC's generation resources and load resources provided much needed energy and Ancillary Services to support system reliability.

On February 15, 2021, four non-controllable load resources ("NCLRs") represented by STEC had a combined responsive reserve service ("RRS") obligation of 21.2 megawatts ("MW"). At 1:07 a.m. that morning, STEC's NCLRs were deployed by ERCOT and fully curtailed as required. During the initial RRS deployment of STEC's NCLRs, a STEC operator inadvertently updated a telemetry component that resulted in STEC erroneously indicating that its NCLRs no longer had an RRS obligation. The telemetry error did not impact STEC's obligation to provide RRS or affect the curtailment of STEC's NCLRs.

Despite initially issuing payment for the RRS to STEC for having provided RRS, ERCOT later clawed-back the payment on the basis that the telemetry error constituted a failure to provide RRS. In addition, ERCOT assessed STEC a "failure to provide" charge of $645,630. STEC contested ERCOT's actions by timely submitting a settlement dispute and then a request for Alternative Dispute Resolution ("ADR"). ERCOT, by failing to recognize and compensate STEC for the reliability service provided by its NCLRs, failed to ensure that electricity production is accurately accounted for in the ERCOT market as required by the Public Utility Regulatory Act,[1] Commission rules and the ERCOT Nodal Protocols ("Protocols" or "ERCOT Protocols"). In support of its claims, STEC provided meter data to ERCOT that confirms that the NCLRs performed as required. On January 27, 2023, ERCOT issued a market notice denying the relief requested in STEC's ADR.

In accordance with 16 Texas Administrative Code ("TAC") § 22.251, STEC hereby submits this Complaint, appealing ERCOT's decision to deny STEC ADR No. 2021-STEC-01.

II. STATEMENT OF THE CASE

A. Underlying Proceeding

STEC timely submitted a settlement dispute to ERCOT contesting ERCOT's decision to claw back RRS payments that were made to STEC for the provision of RRS during Winter Storm Uri. Upon ERCOT's denial of STEC's settlement dispute, STEC timely submitted to ERCOT a

[1] Public Utility Regulatory Act, Tex. Util. Code §§ 11.001-66.016 ("PURA").

request for ADR pursuant ERCOT Protocols §20. On January 27, 2023, ERCOT issued Market Notice No. M-A012723-01 denying the relief requested in STEC's ADR. STEC files this Complaint to appeal the decision of ERCOT to deny ADR No. 2021-STEC-01. This Complaint is filed within 35 days of the completion of the ADR process and is therefore timely.

B. Directly Affected Entities

STEC will be directly affected by the Commission's decision in this proceeding. The decision will also affect other market participants that provide Ancillary Services in the ERCOT market. Market participants have a reasonable expectation of being compensated for providing reliability services and will be impacted by ERCOT's decision to rely on knowingly erroneous telemetry data for verification of whether a service was provided rather than conducting an analysis that examines whether capacity was actually provided or reviewing the meter data provided by STEC to ERCOT that clearly confirms the RRS was provided in conformance with ERCOT's deployment instructions.

C. Conduct Complained Of

On January 27, 2023, ERCOT issued Market Notice 2021-STEC-01 denying STEC's request for ERCOT to compensate STEC for RRS that was provided by STEC's NCLRs on February 15, 2021. In denying STEC's requested relief, ERCOT improperly relied on a knowingly erroneous telemetry component to make a determination that STEC's NCLRs failed to provide RRS during a portion of the time that the NCLRs were instructed to deploy. ERCOT failed to investigate and accurately determine whether the RRS capacity for STEC's NCLRs was available in real-time in accordance with ERCOT Protocol requirements. ERCOT took, and used, the power made available by STEC through its NCLRs through the load resource demand response which comported in all respects with the dispatch instructions by ERCOT. Moreover, STEC provided undisputed, actual meter data demonstrating that the RRS was provided for the entire deployment period, which ERCOT refused to look at while also refusing to compensate STEC for STEC's load resources' performance during the emergency. ERCOTs conduct constitutes a failure to properly implement the PUCT Order directing ERCOT to claw-back payments for failures to provide Ancillary Services, a failure to administer the Ancillary Services market in a manner that aligns with competitive market principles, and a failure to meet its obligation to accurately account for the production and delivery of electricity in the ERCOT market under PURA.

D. Applicable Laws

1. PURA § 35.004(f)

The Commission shall ensure that Ancillary Services necessary to facilitate the transmission of electric energy are available at reasonable prices with terms and conditions that are not unreasonably preferential, prejudicial, discriminatory, predatory, or anticompetitive.

2. PURA § 39.151(a)(4)

ERCOT must ensure that electricity production and delivery are accurately accounted for among the generators and wholesale buyers and sellers in the region.

3. PURA § 39.151(d)

The Commission shall adopt and enforce rules relating to the reliability of the regional electrical network and accounting for the production and delivery of electricity among generators and all other market participants or may delegate to an independent organization responsibility for adopting or enforcing such rules.

4. PURA § 39.151(d-4) (6)

The Commission may resolve disputes between an affected person and ERCOT.

5. 16 TAC § 22.251

Any affected entity may complain to the Commission in writing, setting forth any conduct that is in violation or claimed violation of any law that the commission has jurisdiction to administer, of any order or rule of the Commission, or of any protocol or procedure adopted by ERCOT pursuant to any law that the Commission has jurisdiction to administer.

6. 16 TAC § 25.361(b)

ERCOT shall ensure that electricity production and delivery are accurately accounted for among the generators and wholesale buyers and sellers in the region.

7. 16 TAC § 25.503(d)

The Commission will monitor the activities of market entities to determine if such activities are consistent with ERCOT procedures; whether they constitute market power abuses or are unfair, misleading, or deceptive practices affecting customers; and whether they are consistent with the proper accounting for the production and delivery of electricity among generators and other market participants.

8. 16 TAC § 25.503(f)(12)

A market participant operating in the ERCOT markets or a member of the ERCOT staff who identifies a provision in the ERCOT procedures that produces an outcome inconsistent with the efficient and reliable operation of the ERCOT-administered markets must call the provision to the attention of ERCOT staff and the appropriate ERCOT subcommittee.

9. Protocols § 1.2(1)

A major function of ERCOT, as the ISO, is to ensure that electricity production and delivery are accurately accounted for in the ERCOT region.

10. Protocols § 1.2(6)

The Protocols are intended to implement the functions described in §1.2(1)-(5). In the exercise of its sole discretion under these Protocols, ERCOT shall act in a reasonable, nondiscriminatory manner.

11. Protocols § 2.1, Ancillary Service Resource Responsibility

The MW of an Ancillary Service that each NCLR is obligated to provide in real-time rounded to the nearest MW.

12. Protocols § 2.1, Ancillary Service Schedule

The MW of each Ancillary Service that each NCLR is providing in real-time and the MW of each Ancillary Service for each resource for each hour in the current operating plan ("COP").

13. Protocols § 2.1, Ancillary Service Supply Responsibility

The net amount of Ancillary Service capacity that a QSE is obligated to deliver to ERCOT, by hour and service type, from NCLRs represented by the QSE.

14. Protocols § 6.3.7(1)(c)

Establishes the total charge to a QSE that fails on its Ancillary Service Supply Responsibility for RRS.

15. Protocols § 6.4.9.1.3(1)

A QSE is considered to have failed on its Ancillary Services Supply Responsibility when ERCOT determines, in its sole discretion, that some or all of the QSE's Resource-specific Ancillary Service capacity will not be available in Real-Time.

16. Protocols § 6.4.9.1.3(4)

ERCOT shall charge each QSE that has failed according to Protocols § 6.4.9.1.3(1) on its Ancillary Service Supply Responsibility for a particular Ancillary Service for a specific hour.

17. Protocols § 6.5.5.2(5)(a)-(m)

A QSE representing a load resource connected to transmission facilities or distribution facilities shall provide certain real-time data to ERCOT.

18. Protocols § 8.1.1.4.2(1)(a)

Each QSE providing RRS shall so indicate by appropriate entries in the Resource's Ancillary Service Schedule and the Ancillary Service Resource Responsibility providing that service.

E. Requested Relief

STEC requests that the Commission reverse ERCOT's decision to deny ADR No. 2021-STEC-01 and compensate STEC in the amount of $645,630 for the RRS dispatched by ERCOT and provided by STEC's NCLRs in response to ERCOT's dispatch of such NCLRs on February 15, 2021.

F. Jurisdiction

The Commission has jurisdiction over this matter under PURA § 39.151 and 16 TAC § 22.251, which authorize the Commission to resolve disputes between ERCOT and the affected entity. The Texas Legislature has tasked the Commission with ensuring that Ancillary Services necessary to facilitate the transmission of electric energy are available at reasonable prices with terms and conditions that are not unreasonably preferential, prejudicial, discriminatory, predatory, or anticompetitive.[2] Further, the Commission is charged by PURA with oversight of ERCOT to determine if ERCOT's conduct is consistent with PURA, the Commission's rules and the ERCOT Protocols and procedures, and whether ERCOT is properly accounting for the production and delivery of electricity among generators and other market participants.[3] STEC brings this Complaint to dispute ERCOT's determination that STEC failed to provide RRS on February 15, 2021 and for the return of amounts erroneously clawed back from STEC following the provisions of load resource RRS during Winter Storm Uri.

III. AUTHORIZED REPRESENTATIVES

A. STEC's Authorized Representatives

STEC requests that all correspondence regarding this matter be sent to its authorized representatives and counsel of record:

Diana M. Liebmann
Carlos Carrasco
Haynes and Boone, LLP
112 East Pecan Street, Suite 1200
San Antonio, Texas 78205-1540
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Austin, Texas 78701-3285
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jennifer.littlefield@haynesboone.com

STEC agrees to accept electronic service in this proceeding.

[2] PURA § 35.004(f).

[3] 16 TAC § 25.503(d).

B. ERCOT's Authorized Representative

In this proceeding, STEC seeks relief against ERCOT. ERCOT's authorized representative are:

Chad V. Seely
Vice President and General Counsel
Douglas Fohn
Sr. Corporate Counsel
ERCOT
8000 Metropolis Drive, Suite 100
Austin, TX 78759
(512) 225-7000 (Phone)
(512) 225-7020 (Fax)
chad.seely@ercot.com
douglas.fohn@ercot.com

IV. STATEMENT OF FACTS

1. STEC is a generation and transmission electric cooperative that provides wholesale transmission service to nine-member distribution cooperatives.[4]

2. STEC's nine-member distribution cooperatives provide distribution service to over 290,000 retail electric customers in forty-seven South Texas counties.[5]

3. STEC is registered with ERCOT as a QSE that represents load resources.[6]

4. ETP_LD1, ETP_LD3, ETP_LD4 and PAWNEE_LD1 are four NCLRs represented by STEC.[7]

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[4] www.stec.org/about-stec.

[5] *Id*.

[6] STEC ADR Market Notice at 1.

[7] STEC's Request for ADR at Attachment A.

5. On February 12, 2021, Governor Greg Abbott issued a Declaration of a State of Disaster for all counties in Texas in response to the extreme weather brought on by Winter Storm Uri.[8]

6. On February 14, STEC submitted self-schedules and Ancillary Service capacity trades in the Day Ahead Market to schedule lETP_LD1, ETP_LD3, ETP_LD4 and PAWNEE_LD1 for a 21.2 MW RRS responsibility on operating day February 15.[9]

7. ERCOT validated STEC's self-schedules and Ancillary Service capacity trades, resulting in NCLRs ETP_LD1, ETP_LD3, ETP_LD4 and PAWNEE_LD1 having a 21.2 MW RRS responsibility on operating day February 15.[10]

8. At 12:15 a.m. on February 15, ERCOT declared an Energy Emergency Alert ("EEA") Level 1 event.[11]

9. At 1:07 a.m., ERCOT declared an EEA Level 2 event, triggering the deployment of Ancillary Services.[12]

10. At 1:07 a.m., ERCOT dispatched STEC's NCLRs to provide their 21.2 MW RRS obligation.[13]

11. At 1:20 a.m., ERCOT declared an EEA Level 3 event and began issuing instructions for ERCOT-wide firm load shed.[14]

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[8] *Delegation of Authority to the Executive Director and Granting Exception to Commission Rules*, Project No. 51812, Issues Related to the State of Disaster for the February 2021 Winter Weather Event (Feb. 19, 2021).

[9] STEC's NCLR RRS Allocation

[10] *Id*.

[11] The University of Texas at Austin Energy Institute, *The Timeline and Events of the February 2021 Texas Electric Grid Blackouts*, 25-26 (July 2021) ("Energy Institute Report").

[12] *Id*.

[13] STEC ADR Market Notice at 1.

[14] Energy Institute Report at 26.

12. At 1:55 a.m., the ERCOT system frequency reached a low of 59.302 Hz and remained below 59.4 Hz for 4 minutes and 23 seconds.

13. STEC's NCLRs fully deployed within ten minutes following the RRS deployment instruction from ERCOT.[15]

14. When the NCLRs were fully deployed, the Ancillary Service Schedule for each NCLR was correctly updated to 0 MW, resulting in a telemetry value that accurately showed that the NCLRs were fully deployed.[16]

15. However, simultaneously, the STEC operator inadvertently updated the Ancillary Service Resource Responsibility for each NCLR to 0 MW, resulting in a telemetry value that incorrectly showed that the NCLRs did not have an RRS responsibility.[17]

16. Although the telemetry was mistakenly updated to 0 MW for the Ancillary Service Resource Responsibility, the NCLRs remained offline under ERCOT instruction.[18]

17. At approximately 4:07 a.m., STEC called ERCOT and was instructed by an ERCOT Operator to keep its NCLRs deployed because another instruction to deploy was imminent.[19]

18. At approximately 4:11 a.m., STEC updated the Ancillary Service Resource Responsibility telemetry for the NCLRs to the correct amount of 21.2 MW.[20]

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[15] STEC's Request for ADR at Attachment A; STEC's RRFQAMT Spreadsheet.

[16] STEC's Settlement Dispute.

[17] *Id*.

[18] STEC's Request for ADR at Attachment A.

[19] *Id*.

[20] *Id*.

19. A QSE is considered to have failed its Ancillary Service Supply Responsibility when ERCOT determines, in its sole responsibility, that some or all of the QSE's resource-specific Ancillary Service capacity will not be available in real-time.[21]

20. ERCOT operators utilize a manual process to identify Ancillary Service failures in real-time and update ERCOT systems, causing the failed quantity to be removed from the ERCOT Energy and Market Management System ("EMMS").[22]

21. On February 15, ERCOT operators did not mark any Ancillary Service failures associated with STEC's NCLRs in ERCOT's systems.[23]

22. Throughout the RRS deployment of the NCLRs, all other telemetry values were correctly telemetered to ERCOT, including the load curtailment telemetry for each NCLR.[24]

23. Throughout the RRS deployment, the Current Operating Plan ("COP") for each NCLR reflected the correct Ancillary Service Resource Responsibility.[25]

24. Throughout the RRS deployment the COP for each NCLR was accepted and verified as true by ERCOT.[26]

25. STEC's NCLRs remained deployed throughout the duration of the RRS deployment.[27]

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[21] STEC's ADR Market Notice at 3.

[22] *Id.*

[23] *Id.*

[24] Id. at 1; STEC's Request for ADR at Attachment A.

[25] STEC's ETP Pawnee COP Spreadsheet.

[26] *Id.*

[27] STEC's Request for ADR at Attachment A.

26. On February 15, 2021, ERCOT issued a settlement statement to STEC crediting STEC for the provisions of RRS.[28]

27. On February 21, 2021, the Commission issued an order instructing ERCOT to "use its sole discretion in taking action under the ERCOT Nodal Protocols to resolve financial obligations between a market participant and ERCOT."[29]

28. On March 12, 2021, the Commission issued an order instructing ERCOT to review QSE settlements for Ancillary Service responsibilities during Operating Days February 14, 2021 through February 19, 2021 for the purpose of clawing back payments made for Ancillary Service products that were not provided in Real-Time.[30]

29. In response to the March 12, 2021 Commission order, ERCOT analyzed the Ancillary Service responsibilities attributed to each QSE in the EMMS for that time-period and compared that data against the Ancillary Service responsibilities reflected in the QSE's telemetry data.[31]

30. ERCOT determined Ancillary Service failures by subtracting the value of each NCLR's telemetered Ancillary Service Resource Responsibility from the Ancillary Service Resource Responsibility value in ERCOT's EMMS system.[32]

31. Due to STEC's inadvertent error showing that its NCLRs had an Ancillary Service Resource Responsibility of 0 MW for approximately three hours when the NCLRs

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[28] ERCOT RTM_Final_Statement_20210215_0038663322000_F3.

[29] *Issues Related to the State of Disaster for the February 2021 Winter Weather Event,* Project No. 51812, Order Directing ERCOT to Take Action and Granting Exceptions to ERCOT Protocols, (Feb. 21, 2021) ("February 21st PUCT Order").

[30] *Issues Related to the State of Disaster for the February 2021 Winter Weather Event,* Project No. 51812, Order Directing ERCOT to Extend Certain Deadlines and Granting an Exception to Certain Sections of the ERCOT Nodal Protocols, (March 12, 2021) ("March 12th PUCT Order").

[31] STEC ADR Market Notice at 1.

[32] *Id*.

were initially deployed, ERCOT identified a Responsive Reserve Failed Quantity ("RRFQ") and assessed a Responsive Reserve Failure Quantity Amount per QSE ("RRFQAMT") charge to claw back the amounts paid for RRS for the time-period at issue.[33]

32. The total RRFQAMT failure to provide charge assessed to STEC was $645,630.[34]

33. On April 21, 2021, STEC submitted to ERCOT a settlement dispute regarding the claw-back charges.[35]

34. STEC's settlement dispute included the submission of Interval Data Recorder ("IDR") meter data to demonstrate that the NCLRs fully deployed as instructed by ERCOT.[36]

35. On July 23, 2021, ERCOT denied STEC's billing dispute.[37]

36. On December 6, 2021, STEC initiated an ADR proceeding to challenge the denial of its settlement dispute and sought relief in the amount of $645,630.00.[38]

37. STEC's request for ADR included the submission of IDR meter data that demonstrated that the NCLRs fully deployed within ten minutes of instruction from ERCOT.[39]

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[33] *Id*.

[34] *Id*.

[35] STEC's Settlement Dispute No. 1-2353390621 ("STEC's Settlement Dispute").

[36] *Id*.

[37] STEC's ADR Dispute at 1.

[38] STEC's ADR at Attachment A.

[39] *Id*.

38. STEC asserts that ERCOT may rely on the NCLR's IDR meter data to confirm that that the NCLRs provided the full amount of RRS on February 15, 2021.[40]

39. Although the IDR meter data was provided to ERCOT timely in the ADR process, ERCOT did not analyze the IDR meter data provided by STEC that demonstrated the RRS was provided.[41]

40. However, separate communications with ERCOT personnel confirm that ERCOT routinely uses NCLR IDR meter data for the purpose of validating telemetry data.[42]

41. On January 27, ERCOT issued STEC's ADR Market Notice denying ERCOT's requested relief.[43]

42. STEC QSE has not passed through the RRFQAMT charges to its Load Resources.[44]

43. As the QSE representing the Load Resources, and as the entity bearing the financial impact of the amounts disputed in ADR No. 2021-STEC-01, STEC is the appropriate entity to bring this complaint.[45]

V. ARGUMENT

A. Background

Frequency on the ERCOT grid must be continuously maintained at 60 Hz to balance the flow of electricity across the system. Generation resources are designed to operate at 60 Hz and will automatically trip offline if system frequency drops below levels at which generators can

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[40] STEC's Market Notice at 3.

[41] *Id*. at 2.

[42] Email correspondence with Mr. Krein.

[43] STEC's Market Notice.

[44] STEC's ADR Request at Attachment A.

[45] *Id*.

safely operate. At a system frequency of 58.4 Hz, generation resources will trip off-line after 9 minutes. At a system frequency of 58.0 Hz, generation resources will trip off-line after only 30 seconds.

In the early hours of February 15, 2021, as icy conditions caused electricity demand to spike and supply to drop, ERCOT declared an EEA event and began to deploy its suite of emergency response tools.[46] One such tool, RRS, is specifically designed to help restore system frequency in response to a significant frequency deviation and to provide energy during an EEA event.[47] At 1:07 a.m., ERCOT deployed RRS and instructed STEC to deploy the 21.2 MW RRS obligation assigned to STEC's NCLRs. The NCLRs fully deployed within ten minutes, as required, and remained curtailed throughout their deployment obligation. At 1:20 a.m., ERCOT began firm load shed. At 1:55 a.m., ERCOT system frequency plunged to 59.3 Hz and remained below 59.4 Hz for 4 minutes and 23 seconds.[48] The quick response of ERCOT and market participants' operators, including STEC's operators, prevented the catastrophic failure of the ERCOT grid.

The provision of RRS played a critical role in arresting frequency decay and preventing a system-wide blackout during the most tenuous minutes and hours of the 2021 winter storm. STEC's NCLRs fully and timely deployed when called upon by ERCOT. Although the NCLRs met their RRS curtailment requirement and ERCOT received the full reliability benefit of those Ancillary Services, and although ERCOT initially paid STEC for the reliability benefits ERCOT received from STEC's NCLRs, ERCOT later clawed back, and now refuses to compensate STEC,

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[46] Energy Institute Report at 16.

[47] ERCOT Protocols § 6.5.7.6.2.2(a).

[48] Energy Institute Report at 16.

for the RRS that was provided by STEC's NCLRs in this critical period. As the independent system operator, ERCOT is required to "ensure that electricity production and delivery are accurately accounted for among the generators and wholesale buyers and sellers in the region."[49] Additionally, Protocol § 1.2(1)(d) requires that electricity production and delivery are accurately accounted for among wholesale buyers and sellers. Having taken the RRS provided by STEC during the emergency for the benefit of the stabilization of the grid and the market, ERCOT's refusal to compensate STEC for the RRS STEC provided is a violation of its obligation to accurately account for the provision of production and delivery of electricity in the ERCOT market.

B. PUCT Issues Ancillary Service Claw-Back Order

ERCOT initially credited STEC for the RRS. However, the problem arose when ERCOT conducted a review of its RRS payments in response to the March 21, 2021 Commission Order directing ERCOT to identify QSEs that were paid for Ancillary Services ***that were not provided*** during Winter Storm Uri. The Order was issued based on a recommendation made by the Independent Market Monitor ("IMM"). The IMM's recommendation provides significant context for the intent of the Commission Order. In a letter to the Commission, the IMM concluded:

> ***There were a number of instances during [Operating Days February 14-19, 2021] in which AS was not provided in real time because of forced outages or derations***. For market participants that are not able to meet their AS responsibility, typically the ERCOT operator marks the short amount in the software. This causes the AS responsibility to be effectively removed and the day-ahead AS payment to be clawed back in settlement. However, the ERCOT operators did not complete this task during the winter event, and therefore the "failure to provide" settlements were not invoked in real time.
>
> Removing the operator intervention step and automating the "failure to provide" settlement was contemplated in NPRR947: Clarification to Ancillary

[49] Public Utility Regulatory Act, Tex. Util. Code § 39.151(a)(4).

> Service Supply Responsibility Definition and Improvements to Determining and Charging for Ancillary Service Failed Quantities; however, the NPRR was withdrawn in August 2020 because of the system cost, some complexities related to AS trades, and the implementation of real-time co-optimization.
>
> ***Invoking the "failure to provide" settlement for all AS that market participants failed to provide during the operating days outlined above will produce market outcomes and settlements consistent with underlying market principles. In this case, the principle is that market participants should not be paid for services that they do not provide. Whether ERCOT marked the short amount in real-time or not should not affect the settlement of these Ancillary Services.***
>
> In the short term, the IMM recommends that the language in Section 6 of the ERCOT Nodal Protocols below be modified to allow ERCOT to determine these quantities after-the-fact. The IMM further recommends that the "failure to provide" settlement treatment for AS be automated.[50] (Emphasis added.)

Notably, the IMM's recommendation addresses the valid concern that some market participants were paid for Ancillary Services that were not provided during the storm due to physical limitations on the generators providing the Ancillary Services. The IMM urged the Commission to ensure that settlement outcomes align with core market principles rather than be determined by the ERCOT operator's failure to accurately update the EMMS system during the emergency conditions. The IMM clearly and unequivocally states that "[w]hether ERCOT marked the short amount in real-time should not affect the settlement of these Ancillary Services."[51] In other words, what mattered was whether the Ancillary Service capacity was not provided and whether ERCOT did not receive the intended reliability benefit from the market participant. Ironically, ERCOT has transformed the IMM's recommendation to affect the opposite result.

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[50] *Issues Related to the State of Disaster for the February 2021 Winter Weather Event*, Project No. 51812, Letter to Commissioners (Mar. 1, 2021) ("IMM Letter").

[51] *Id*.

C. ERCOT Improperly Implements PUCT Order

ERCOT implemented the Commission Order by comparing the Ancillary Service Resource Responsibility values in the EMMS against the Ancillary Service Resource Responsibility values reflected in each QSE's telemetry. ERCOT's analysis is problematic because it did not properly recognize the RRS provided by STEC. Instead, ERCOT improperly identified a RRFQ for STEC's NCLRs and assessed STEC a RRFQAMT claw-back charge in the amount of $645,630.

The RRFQ identified by ERCOT was related to STEC's inadvertent updating of the telemetry of both the Ancillary Service Resource Responsibility *and* the Ancillary Service Schedule to 0 MW. When the NCLRs were fully deployed, the STEC operator correctly updated the Ancillary Service Schedule for each NCLR to 0 MW, resulting in a telemetry value that accurately showed that the NCLRs were fully deployed.[52] However, the STEC operator simultaneously updated the Ancillary Service Resource Responsibility for each NCLR to 0 MW, resulting in a telemetry value that incorrectly showed that the NCLRs did not have an RRS responsibility.[53]

Although the telemetry was mistakenly updated to 0 MW for the Ancillary Service Resource Responsibility, the NCLRs remained offline and both STEC and ERCOT recognized STEC's obligation to provide the 21.2 MW of RRS. At approximately 4:00 AM, the STEC QSE became aware of the telemetry issue. At 4:07 a.m., STEC called ERCOT and was instructed by an ERCOT Operator to keep its NCLRs deployed because another instruction to deploy was

[52] STEC's Settlement Dispute.

[53] *Id*.

imminent. At that time, STEC immediately updated the Ancillary Service Resource Responsibility telemetry for the NCLRs to the correct amount of 21.2 MW.

Initially, even though the EMMS showed a 21.2 MW RRS obligation and STEC's telemetry incorrectly showed a 0 MW obligation, ERCOT was in contact with STEC, and understood that the NCLRs were dispatched and instructed that they continue on dispatch. ERCOT also initially concluded that STEC's NCLRs provided RRS and ERCOT paid STEC for the RRS. Following the Commission's Order, ERCOT deviated from prior practice by looking only to telemetry, and did not try to determine whether RRS was actually provided, despite the lack of any requirement in the Protocols to use telemetry, and despite the fact that turning solely to telemetry deviated from ERCOT's regular practice. By restricting its analysis to the use of a single telemetry data point that was known during the storm to be incorrect, following the issuance of the Commission's Order, ERCOT clawed back the amounts from STEC and belatedly determined that STEC failed to provide the RRS. In making that determination, ERCOT failed to conduct a proper examination as to whether STEC's NCLRs provided the 21.2 MW of RRS as required by the Commission Order and the ERCOT Protocols. ERCOT's actions accomplish the opposite of the directive set out in the Commission Order and the IMM's recommendation. Further, ERCOT's actions constitute a failure to meet ERCOT's statutory mandate to ensure that electricity production and delivery are accurately accounted for among the generators and wholesale buyers and sellers in ERCOT.[54]

This situation is analogous to the facts that gave rise to the complaint filed by TXU Portfolio Management Company LP and TXU Energy Retail Company LP against ERCOT in

[54] PURA § 39.151(a)(4).

Docket No. 31243.[55] In that proceeding, TXU Portfolio Management Company LP and TXU Energy Retail Company LP asked the Commission to order ERCOT to conduct a resettlement based on the "erroneous imposition" of load imbalance charges during the first half of 2001 due to inadvertent double-counting of two wholesale points of delivery.[56] TXU Electric Delivery incurred excess load imbalance charges in 2001 because it established retail ESI IDs for two aggregation meters associated with wholesale delivery points, did not cancel the ESI IDs when the retail customer choice pilot project started on July 31, 2001, and continued to provide consumption data to ERCOT even after asking ERCOT to remove the ESI IDs from the ERCOT systems in February 2022.

ERCOT argued that its original settlement was final and should not be disturbed because TXU Energy Delivery continued to provide the data ERCOT used to calculate the settlement. However, in the Proposal for Decision, the SOAH ALJ concluded that ERCOT contributed to the double counting of load and corresponding load imbalance charges by failing to delete the ESI IDs from the ERCOT computer systems despite informing TXU Energy Delivery that such ESI IDs had been deleted.[57] ERCOT did not delete the ESI IDs from its systems until November 2002.

The ALJ concluded that the "inadvertent mistakes" of TXU Portfolio Management Company LP and TXU Energy Retail Company LP should not result in the denial of the resettlement request, as argued by ERCOT.[58] The ALJ further stated that:

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[55] *Complaint of TXU Portfolio Management Company LP and TXU Energy Retail Company LP Against the Electric Reliability Council of Texas (ERCOT)*, Docket No. 31243, Order (Aug. 9, 2006).

[56] Docket No. 31243, Complaint of TXU Portfolio Management Company LP and TXU Energy Retail Company LP Against the Electric Reliability Council of Texas at 1 (Jun. 15, 2005).

[57] Docket No. 31243, Proposal for Decision at 27 (Jun. 20, 2006) ("And it is undisputed that ERCOT also made mistakes that contributed to the double-billing errors.").

[58] *Id*. at 27-28.

"[w]ith the large mass of data that Market Participants must provide, ***it would be unreasonable to hold that an inadvertent error of a Market Participant could never be corrected***. In this case, ***there is no evidence or even a suggestion that the Companies intentionally provided erroneous information, tried to manipulate the market, or otherwise engaged in egregious conduct that might justify denying their claim***."

The Commission agreed with the ALJ, ruling in favor of TXU Portfolio Management Company LP, and TXU Energy Retail Company LP, and ordered ERCOT to conduct a resettlement.[59] Similar to the ALJ, the Commission concluded that "[t]he actions of both ERCOT and the [TXU] Companies contributed to the double-billing error involved in this case. However, the inadvertent mistakes of the Companies involved in this case should not bar their claim."[60]

D. STEC Disputes ERCOT Claw-Back Charge

STEC first disputed ERCOT's payment claw-back on April 1, 2021 when STEC submitted Settlement Dispute No. No. 1-2353390621 .[61] STEC submitted its dispute in accordance with 16 TAC § 25.503(f)(12), which requires that a market participant operating in the ERCOT markets who identifies a provision in the ERCOT procedures that produces an outcome inconsistent with the efficient and reliable operation of the ERCOT-administered markets must call the provision to the attention of ERCOT staff. STEC included the NCLRs' IDR meter data to support the claim made in the settlement dispute.[62] The IDR meter data shows that STEC's NCLRs fully deployed within ten minutes of the dispatch instruction from ERCOT and remained deployed throughout the duration of the period in dispute.[63] Despite being provided the IDR meter data nearly two

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[59] Docket No. 31243, Order at 11 (Aug. 9, 2006).

[60] *Id*., Conclusion of Law 9.

[61] STEC's Settlement Dispute.

[62] *Id*.

[63] STEC's ADR Request at Attachment A.

years ago, ERCOT never analyzed the meter data to confirm that the NCLRs deployed as obligated.[64] ***ERCOT insists that review of the IDR meter data is unnecessary because the NCLRs deployment is not relevant to their determination that RRS was not provided.*** Instead, ERCOT has chosen to rely solely on the telemetered RRS resource obligation value.[65]

ERCOT's analysis is flawed based on the plain reading of the ERCOT Protocols, PURA, Commission rules and for reasons of public policy. Protocol § 6.4.9.1.3(a) states that "[a] QSE is considered to have failed on its Ancillary Service Supply Responsibility when ERCOT determines, ***in its sole discretion***, that ***some or all of the QSE's Resource-specific Ancillary Service capacity*** will not be available in Real-Time." (Emphasis added.) The Protocols expressly give ERCOT the sole discretion to determine whether the RRS capacity of STEC's NCLRs was available on February 15, 2021 when ERCOT issued its RRS deployment instruction.[66] The ERCOT Protocols are subject to the same rules of interpretation that apply to the Commission's administrative rules.[67] When interpreting law, courts must look to the plain language and give terms their common, ordinary meaning unless doing so leads to an absurd result. Effect must be given to each provision of a law so that none is rendered meaningless or mere surplusage.

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[64] STEC's ADR Market Notice.

[65] *Id*.

[66] Nodal Protocol Revision Request ("NPRR") 1149 proposes changes to § 6.4.9.1.3. STEC notes that the most recent version of the NPRR, as approved by the ERCOT Board of Directors on February 28, 2023, continues to provide ERCOT sole discretion to determine Ancillary Service failures, continues to point to capacity availability as the key factor for whether a failure occurred, and makes no reference to the use of telemetry as a component of that determination. The proposed modified version of § 6.4.9.1.3(2) states, "A QSE is considered to have failed to provide its Ancillary Services Supply Responsibility when ERCOT determines, in its sole discretion, that some or all of the QSE's Ancillary Service capacity will not be available in Real-Time, was not available during any interval for which the QSE had an Ancillary Service Supply Responsibility, or that the QSE assigned all or part of an Ancillary Service Supply Responsibility to a Resource that was not qualified to provide that Ancillary Service." NPRR 1149, ERCOT Board Report (Feb. 28, 2023).

[67] *Pub Util Comm'n of Tex. v. Constellation Energy Commodities Group, Inc*.,351 S.W.3d 588,594-95 (Tex. App.-Austin 2011, pet. denied).

Here, the plain meaning of the words requires ERCOT to use its discretion to determine ***whether the NCLRs' RRS capacity was available***. The broad language allows ERCOT to utilize the best available information and directs ERCOT to make its determination based on a finding of whether the capacity is available. Protocol § 6.4.9.1.3(a) makes no mention of telemetry values. ERCOT is not required to utilize any certain data point to make its finding and the proper inquiry examines only whether the resource had the capacity available to provide the Ancillary Service.

It is important to highlight that the value incorrectly telemetered to ERCOT by STEC was the Ancillary Service Resource Responsibility that was validated by ERCOT and assigned to STEC. In other words, once the NCLRs fully deployed, STEC's telemetry showed that its NCLRs no longer had an RRS obligation even though ERCOT's RRS obligation remained in effect. STEC correctly telemetered the load consumption values of each NCLR throughout the deployment.

Also important is that ERCOT uses a manual process to update its EMMS when a telemetry discrepancy occurs. At the time the STEC telemetry error occurred, ERCOT operators were managing other priorities and ERCOT did not manually update the EMMS to reflect the incorrect data value. The result is that ERCOT's EMMS never "saw" the telemetry error which may have been attributable to the fact that ERCOT knew that the 21.2 MW of RRS was being provided as dispatched.

Further, ERCOT operators were aware that STEC's NCLRs had an RRS obligation and were fully deployed in accordance with that obligation. STEC's operator logs provide critical details on the events of February 15, 2021.[68] At 4:07 a.m., a STEC operator called ERCOT to inquire about an ERCOT instruction to restore NCLR load. In speaking with the ERCOT operator,

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[68] STEC Operator Daily Logs.

the STEC operator became aware of the telemetry issue. STEC's operator logs document that the ERCOT operator instructed STEC to "hold off [on restoring load to its NCLRs] because those [NCLRs] were about to be deployed again."[69] This admission by ERCOT operators shows that ERCOT was aware that the NCLRs were had been deployed pursuant to an RRS obligation and remained subject to further RRS deployment obligations. STEC's situation directly contrasts the scenarios addressed by the IMM, where resources did not provide their obligated capacity due to forced outages or derations.

E. ERCOT Improperly Relies on Incorrect Telemetry

ERCOT improperly insists that it is required to rely on a telemetered value that contradicts its own data. ERCOT's position is not supported by the ERCOT Protocols. The requirement for a QSE to provide the telemetered values of the Ancillary Service Schedule and the Ancillary Service Resource Responsibility are set out in Protocol § 8.1.1.4.2(1)(a), which states that "[e]ach QSE providing RRS ***shall so indicate*** by appropriate entries in the Resource's Ancillary Service Schedule and the Ancillary Service Resource Responsibility providing that service." The value inputs are used to ***indicate*** the amount of RRS provided. These are manually input values that, unlike IDR meter data, are not direct measurements of the physical consumption of electricity from NCLRs.

In this case, ERCOT's position is confusing. ERCOT is using the fact that STEC incorrectly telemetered an Ancillary Service Resource Responsibility value of 0 MW to conclude that STEC ***actually had an Ancillary Service Resource Responsibility of 21.2 MW*** but failed to provide the RRS. ERCOT knows that STEC had an RRS obligation of 21.2 MW during the

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[69] *Id*.

disputed timeframe. ERCOT knows that STEC inadvertently updated its Ancillary Service Resource Responsibility and ***erroneously indicated*** that its NCLRs no longer had an RRS obligation. Yet, ERCOT chose not to examine other data sources to see whether the load resources were available, such as the IDR meter data from the NCLRs STEC provided, to confirm that not only were STEC's NCLRs available, they were deployed the entire time of the obligation and provided a critical reliability service during the peak hours of the most extreme crises ever faced by the ERCOT system. Instead, ERCOT has chosen to base its analysis on a single data point that it knew during the storm was incorrect. Despite ERCOT's contention that it must utilize STEC's Ancillary Service Resource Responsibility telemetry to determine whether an NCLR failed to provide Ancillary Service, nothing in the Protocols sets out a requirement that telemetry be used.

Contrary to ERCOT's assertions, however, the Protocols and ERCOT practice show that IDR meter data is routinely used to validate telemetry data for NCLRs. STEC is required to provide ERCOT with IDR meter data for each of its NCLRs. In email communications between STEC and Mr. Steve Krein, senior staff of the ERCOT Demand Integration department, Mr. Krein acknowledges that ERCOT requires the NCLR IDR meter data ***for the purpose of validating NCLR telemetry***. In 2021, in response to a question from STEC asking whether QSEs must provide NCLR meter data to ERCOT, Mr. Krein stated:

> "Yes there is a requirement for IDR metering for the Load Resources. The IDR meter data is used to validate the telemetry for a Load Resource during normal operations (done at least annually). It also acts as a back-up in case we lose communications and or telemetry during an event."[70]

[70] April 13, 2021 email correspondence with Mr. Krein.

Subsequently, on January 18, 2023, Mr. Krein responded to further questions from STEC regarding the requirement to provide IDR meter data for new load resources. Mr. Krein stated, "We use the data to validate telemetry after the fact and also as a back-up should we have a failure in the telemetry data stream."[71] The communications with Mr. Krein show that ERCOT consistently uses IDR meter data for the purpose of validating telemetry data, as requested by STEC in its billing dispute, ADR, and this Complaint.

Further, ERCOT is expressly required to use IDR meter data to routinely validate telemetry for Aggregated Load Resources. As noted in the Other Binding Document "Requirements for Aggregate Load Resource Participation in the ERCOT Markets," ERCOT must rely on IDR meter data for validation of performance:

> "***ERCOT will use this Premise-level interval meter data both as the foundation of the telemetry validation process and for event performance measurement and verification***." (Emphasis added.)[72]

This policy demonstrates that using IDR meter data to validate telemetry for load resources is a standard practice for ERCOT. It is both reasonable and appropriate to use IDR meter data to validate STEC's NCLR telemetry and especially in this instance where ERCOT has been made aware of an incorrect Ancillary Service Resource Responsibility telemetry value.

F. STEC's Meter Data Shows RRS Performance

STEC's NCLR IDR meter data was provided to ERCOT in the ADR process. The data demonstrates that the RRFQ is only attributed to the period in which the Ancillary Service

[71] January 18, 2023 email correspondence with Mr. Steve Krein.

[72] Requirements for Aggregate Load Resource Participation in the ERCOT Market Other Binding Documents, http://www.ercot.com/services/programs/load/laar.

Resource Responsibility was incorrectly telemetered as 0 MW. The IDR meter data shows that the NCLR consumption drops at 01:07 a.m. and remains deployed throughout the deployment period. At all times, the RRS was provided to ERCOT. This fact is evidenced by the IDR meter data and telemetry, as well as the communications with ERCOT in real-time regarding the recall of the NCLRs and attempt to receive a verbal dispatch instruction for its recall. Although all of this information was provided to ERCOT, in ERCOT's Market Notice, ERCOT admitted that it did not review any of the data provided.

G. ERCOT's Position Undermines Demand Response Policy

ERCOT is tasked by the Legislature under PURA and by the Commission by rule with the obligation of ensuring that the production and delivery of electricity is properly accounted for in the ERCOT market. ERCOT has failed to meet that obligation. Rather than conduct a robust investigation of whether STEC's NCLRs provided a much needed reliability service during Winter Storm Uri, ERCOT has reduced its analysis to an overly simplistic metric using a knowingly erroneous input value. ERCOT insists that this result is proper because "ERCOT settled in accordance with the Protocols."[73] ERCOT's interpretation that it must rely solely on telemetry to determine Ancillary Service failures – without regard to conflicting data – is not supported by the Protocols and leads to an untenable public policy result.

The flaw in ERCOT's analysis is most clearly observed by considering the inverse fact pattern present in this proceeding: a situation in which a QSE operator inadvertently manually updates an Ancillary Service Resource Responsibility of 21.2 MW but the NCLR IDR meter data shows the NCLRs did not actually curtail. ERCOT's methodology will result in a payment for RRS even

[73] STEC's ADR Market Notice.

though ERCOT did not receive the intended reliability benefit. This runs contrary to the market principles emphasized by the IMM in its recommendation to the Commission and in the Commission's Order. It frustrates the purpose of the PURA requirement that ERCOT accurately account for the production and delivery of electricity. Market participants that do not provide Ancillary Services should not be financially compensated for those services. Analogously, market participants that *do provide* Ancillary Services when called upon *should be* financially compensated.

ERCOT has previously acknowledged situations in which strict enforcement of its policies leads to an unreasonable result. In granting an ADR request from North Maple Energy, LLC ("North Maple"), ERCOT concluded that "[w]hen two or more ERCOT Protocols conflict (either on their face or, as here, in a particular application), they must be interpreted and harmonized in a manner that, when possible, gives effect to every provision and does not lead to unreasonable or absurd results."[74] In that case, ERCOT's application of a Protocol led to North Maple being charged more for a Point-to-Point ("PTP") Obligation than it had bid. ERCOT determined that North Maple's bid represented the maximum price that it was willing to pay for the PTP Obligation. Therefore, ERCOT's enforcement of its settlement Protocols was improper, even though ERCOT had not erred in the application of the settlement provision.

As in the North Maple ADR, ERCOT's enforcement of its methodology for determining an RRS failure results in the unreasonable result of STEC's NCLRs not being financially compensated even though they fully deployed and provided the intended reliability benefit to ERCOT. Further, strict enforcement of the methodology leads to the absurd result of ERCOT

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[74] ERCOT Market Notice No. M-A090817-01 (Sept. 8, 2017).

financially compensating market participants with telemetry that erroneously shows an Ancillary Service was provided. The Protocols expressly give ERCOT discretion to determine Ancillary Service failures and ERCOT should be held accountable to using a methodology that is designed to assess whether the capacity was provided.

VI. ISSUES TO BE ADDRESSED

The questions of law and questions of fact in this proceeding are narrow. Much of the factual basis of the complaint has been discussed among ERCOT and STEC during the ADR proceeding. STEC has identified the questions of law and fact that are disputed at this time. STEC reserves the right to assert additional questions of law and fact raised during discovery and as the case proceeds.

A. Questions of Law

1. Does ERCOT have discretion to use IDR meter data to determine whether an NCLR provided RRS?
2. Did STEC's NCLRs provide 21.2 MW of RRS on February 15, 2021 as instructed?
3. Did ERCOT meet its obligation to accurately account for the production and delivery of energy and Ancillary Services?
4. Did ERCOT improperly claw back $645,630.00 paid to STEC for the provision of RRS during Winter Storm Uri?

B. Questions of Fact

1. On February 15, 2021, did STEC's NCLRs deploy and remain deployed as instructed by ERCOT?

VII. CONCLUSION AND RELIEF REQUESTED

STEC respectfully requests that the Commission reverse ERCOT's decision to deny ADR No. 2021-STEC-01 and require ERCOT to compensate STEC for the RRS that was provided by STEC's NCLRs during Winter Storm Uri.

Respectfully submitted,

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ATTORNEYS FOR SOUTH TEXAS ELECTRIC COOPERATIVE, INC.

ATTACHMENT A

AFFIDAVIT OF CLIF LANGE

THE STATE OF TEXAS §

COUNTY OF VICTORIA §

BEFORE ME, the undersigned authority, on this day personally appeared Clif Lange, who, being duly sworn, stated as follows:

1. My name is Clif Lange. I am over eighteen (18) years of age and am fully competent to attest to the matters stated in this affidavit.

2. I am employed by South Texas Electric Cooperative, Inc. ("STEC") as General Manager. In this capacity, I am a duly authorized agent of STEC.

3. I have reviewed STEC's Complaint Against the Electric Reliability of Texas, Inc. ("ERCOT"), including the documents submitted for the administrative record in Attachment A.

4. I affirm that I have personal knowledge of the following factual statement contained in the Complaint and they are true and correct.

5. STEC is a generation and transmission electric cooperative that provides wholesale transmission service to nine member distribution cooperatives.

6. STEC's nine member distribution cooperatives provide distribution service to over 290,000 retail electric customers in forty-seven South Texas counties.

7. STEC is registered with ERCOT as a QSE that represents load resources.

8. ETP_LD1, ETP_LD3, ETP_LD4 and PAWNEE_LD1 are four NCLRs represented by STEC.

9. On February 12, 2021, Governor Greg Abbott issued a Declaration of a State of Disaster for all counties in Texas in response to the extreme weather brought on by Winter Storm Uri.

10. On February 14, STEC submitted self-schedules and Ancillary Service capacity trades in the Day Ahead Market to schedule ETP_LD1, ETP_LD3, ETP_LD4 and PAWNEE_LD1 for a 21.2 MW RRS responsibility on operating day February 15.

11. ERCOT validated STEC's self-schedules and Ancillary Service capacity trades, resulting in NCLRs ETP_LD1, ETP_LD3, ETP_LD4 and PAWNEE_LD1 having a 21.2 MW RRS responsibility on operating day February 15.

12. At 12:15 a.m. on February 15, ERCOT declared an Energy Emergency Alert ("EEA")

Level 1 event.

13. At 1:07 a.m., ERCOT declared an EEA Level 2 event, triggering the deployment of Ancillary Services.

14. At 1:07 a.m., ERCOT dispatched STEC's NCLRs to provide their 21.2 MW RRS obligation.

15. At 1:20 a.m., ERCOT declared an EEA Level 3 event and began issuing instructions for ERCOT-wide firm load shed.

16. At 1:55 a.m., the ERCOT system frequency reached a low of 59.302 Hz and remained below 59.4 Hz for 4 minutes and 23 seconds.

17. STEC's NCLRs fully deployed within ten minutes following the RRS deployment instruction from ERCOT.

18. When the NCLRs were fully deployed, the Ancillary Service Schedule for each NCLR was correctly updated to 0 MW, resulting in a telemetry value that accurately showed that the NCLRs were fully deployed.

19. However, the STEC operator inadvertently updated the Ancillary Service Resource Responsibility for each NCLR to 0 MW, resulting in a telemetry value that incorrectly showed that the NCLRs did not have an RRS responsibility.

20. Although the telemetry was mistakenly updated to 0 MW for the Ancillary Service Resource Responsibility, the NCLRs remained offline under ERCOT instruction.

21. At approximately 4:07 a.m., STEC called ERCOT and was instructed by an ERCOT Operator to keep its NCLRs deployed because another instruction to deploy was imminent.

22. At approximately 4:11 a.m., STEC updated the Ancillary Service Resource Responsibility telemetry for the NCLRs to the correct amount of 21.2 MW.

23. A QSE is considered to have failed its Ancillary Service Supply Responsibility when ERCOT determines, in its sole responsibility, that some or all of the QSE's resource-specific Ancillary Service capacity will not be available in real-time.

24. ERCOT operators utilize a manual process to identify Ancillary Service failures in real-time and update ERCOT systems, causing the failed quantity to be removed from the ERCOT Energy and Market Management System ("EMMS").

25. On February 15, ERCOT operators did not mark any Ancillary Service failures associated with STEC's NCLRs in ERCOT's systems.

26. Throughout the RRS deployment of the NCLRs, all other telemetry values were correctly telemetered to ERCOT, including the load curtailment telemetry for each NCLR.

27. Throughout the RRS deployment, the Current Operating Plan ("COP") for each NCLR reflected the correct Ancillary Service Resource Responsibility.

28. Throughout the RRS deployment the COP for each NCLR was accepted and verified as true by ERCOT.

29. STEC's NCLRs remained deployed throughout the duration of the RRS deployment.

30. On February 15, 2021, ERCOT issued a settlement statement to STEC crediting STEC for the provisions of RRS.

31. On February 21, 2021, the Commission issued an order instructing ERCOT to "use its sole discretion in taking action under the ERCOT Nodal Protocols to resolve financial obligations between a market participant and ERCOT."

32. On March 12, 2021, the Commission issued an order instructing ERCOT to review QSE settlements for Ancillary Service responsibilities during Operating Days February 14, 2021 through February 19, 2021 for the purpose of clawing back payments made for Ancillary Service products that were not provided in Real-Time.

33. In response to the March 12, 2021 Commission order, ERCOT analyzed the Ancillary Service responsibilities attributed to each QSE in the EMMS for that time-period and compared that data against the Ancillary Service responsibilities reflected in the QSE's telemetry data.

34. ERCOT determined Ancillary Service failures by subtracting the value of each NCLR's telemetered Ancillary Service Resource Responsibility from the Ancillary Service Resource Responsibility value in ERCOT's EMMS system.

35. Due to STEC's inadvertent error showing that its NCLRs had an Ancillary Service Resource Responsibility of 0 MW for approximately three hours when the NCLRs were initially deployed, ERCOT identified a Responsive Reserve Failed Quantity ("RRFQ") and assessed a Responsive Reserve Failure Quantity Amount per QSE ("RRFQAMT") charge to claw back the amounts paid for RRS for the time-period at issue.

36. The total RRFQAMT failure to provide charge assessed to STEC was $645,630.

37. On April 21, 2021, STEC submitted to ERCOT a settlement dispute regarding the claw-back charges.

38. STEC's settlement dispute included the submission of Interval Data Recorder ("IDR") meter data to demonstrate that the NCLRs fully deployed as instructed by ERCOT.

39. On July 23, 2021, ERCOT denied STEC's billing dispute.

40. On December 6, 2021, STEC initiated an ADR proceeding to challenge the denial of its settlement dispute and sought relief in the amount of $645,630.00.

41. STEC's request for ADR included the submission of IDR meter data that demonstrated that the NCLRs fully deployed within ten minutes of instruction from ERCOT.

42. STEC asserts that ERCOT may rely on the NCLR's IDR meter data to confirm that that the NCLRs provided the full amount of RRS on February 15, 2021.

43. Although the IDR meter data was provided to ERCOT timely in the ADR process, ERCOT did not analyze the IDR meter data provided by STEC that demonstrated the RRS was provided.

44. However, separate communications with ERCOT personnel confirm that ERCOT routinely uses NCLR IDR meter data for the purpose of validating telemetry data.

45. On January 27, ERCOT issued STEC's ADR Market Notice denying ERCOT's requested relief.

46. STEC QSE has not passed through the RRFQAMT charges to its Load Resources.

47. As the QSE representing the Load Resources, and as the entity bearing the financial impact of the amounts disputed in ADR No. 2021-STEC-01, STEC is the appropriate entity to bring this complaint.

48. The foregoing statements and information are true and correct.

Clif Lange
Clif Lange
General Manager
South Texas Electric Cooperative, Inc.

SWORN TO AND SUBSCRIBED before me this 2ND day of March, 2023

Arthur H. Gifford
Notary Public, State of Texas

DECEMBER 5, 2024
My Commission Expires

ARTHUR H. GIFFORD
Notary Public, State of Texas
Notary ID# 12674502-1
My Commission Expires
DECEMBER 5, 2024
NOTARY PUBLIC
STATE OF TEXAS

ATTACHMENT B:
STEC'S DOCUMENTS FOR THE ADMINISTRATIVE RECORD

STEC submits the following documents pursuant to 16 TAC § 22.251(d)(H). STEC retains the right to supplement this administrative record and, for purposes of an evidentiary record in this proceeding, to submit any evidence necessary to support its claims.

DOCUMENT	EXHIBIT NO.
ERCOT Market Notice M-A05720-01	1
STEC's Settlement Dispute No. 1-2353390621	2
ERCOT's Denial of Settlement Dispute No. 1-2353390621	3
STEC's Request for ADR	4
STEC's RRFQAMT Spreadsheet	5
STEC's ETP Pawnee COP Spreadsheet	6
STEC's ETP Pawnee Substation Data Spreadsheet	7
STEC's Settlement Statements	8
ERCOT Invoices for 2-15-21	9
4-13-2021 Email from Steve Krein	10
1-18-2023 Email from Steve Krein	11
Delegation of Authority to the Executive Director and Granting Exception to Commission Rules, Project No. 51812, Issues Related to the State of Disaster for the February 2021 Winter Weather Event (Feb. 17, 2021).	12
Issues Related to the State of Disaster for the February 2021 Winter Weather Event, Project No. 51812, Order Directing ERCOT to Take Action and Granting Exceptions to ERCOT Protocols, (Feb. 21, 2021) ("February 21st PUCT Order").	13
Issues Related to the State of Disaster for the February 2021 Winter Weather Event, Project No. 51812, Second Order Addressing Ancillary Services, (March 12, 2021) ("March 12th PUCT Order").	14
The University of Texas at Austin Energy Institute, *The Timeline and Events of the February 2021 Texas Electric Grid Blackouts*, 25-26 (July 2021) ("Energy Institute Report").	15

Issues Related to the State of Disaster for the February 2021 Winter Weather Event, Project No. 51812, Letter to Commissioners (Mar. 1, 2021) ("IMM Letter").	16
Complaint of TXU Portfolio Management Company LP and TXU Energy Retail Company LP Against the Electric Reliability Council of Texas (ERCOT), Docket No. 31243, Order (Aug. 9, 2006).	17
Docket No. 31243, Complaint of TXU Portfolio Management Company LP and TXU Energy Retail Company LP Against the Electric Reliability Council of Texas at 1 (Jun. 15, 2005).	18
Docket No. 31243, Proposal for Decision at 27 (Jun. 19, 2006) ("And it is undisputed that ERCOT also made mistakes that contributed to the double-billing errors.").	19
Pub Util Comm'n of Tex. v. Constellation Energy Commodities Group, Inc.,351 S.W.3d 588,594-95 (Tex. App.-Austin 2011, pet. denied)	20
Requirements for Aggregate Load Resource Participation in the ERCOT Market Other Binding Documents, http://www.ercot.com/services/programs/load/laar.	21
ERCOT Market Notice No. M-A090817-01 (Sept. 8, 2017).	22
STEC's Daily Operator Logs	23
STEC's NCLR RRS Allocation	24
NPRR 1149, ERCOT Board Report (Feb. 28, 2023).	25
https://www.stec.org/about-stec	26

EXHIBIT 1

EXHIBIT 1

To: Notice_Legal_Notifications@lists.ercot.com,Notice_Settlements@lists.ercot.com

Sent: 1/27/23 12:37 PM

Subject: M-A012723-01 Upon ERCOT's determination of the disposition of an Alternative Dispute Resolution (ADR) proceeding, ERCOT Protocol Section 20.9 requires ERCOT to issue a Market Notice providing a description of the relevant facts, a list of the parties involved in the dispute, and ERCOT's disposition of the proceeding and reasoning in support thereof.

NOTICE DATE: January 27, 2023

NOTICE TYPE: M-A012723-01 Legal

SHORT DESCRIPTION: Upon ERCOT's determination of the disposition of an Alternative Dispute Resolution (ADR) proceeding, ERCOT Protocol Section 20.9 requires ERCOT to issue a Market Notice providing a description of the relevant facts, a list of the parties involved in the dispute, and ERCOT's disposition of the proceeding and reasoning in support thereof.

INTENDED AUDIENCE: All Market Participants

DAY AFFECTED: February 15, 2021

LONG DESCRIPTION: Please see attachment.

CONTACT: If you have any questions, please contact your ERCOT Account Manager. You may also call the general ERCOT Client Services phone number at (512) 248-3900 or contact ERCOT Client Services via email at ClientServices@ercot.com.

dg

Attachments:

STEC ADR Market Notice_2021 Uri claim FINAL.pdf
Jan 26, 2023 - pdf - 165.1 KB

NOTICE DATE: January 27, 2023

NOTICE TYPE: M-A050720-01 Legal

SHORT DESCRIPTION: Resolution of ADR Proceedings between ERCOT and South Texas Electric Cooperative, Inc. (ADR No. 2021-STE-01)

INTENDED AUDIENCE: Market Participants

DAY AFFECTED: February 15, 2021

LONG DESCRIPTION: Upon ERCOT's determination of the disposition of an Alternative Dispute Resolution (ADR) proceeding, ERCOT Protocol Section 20.9 requires ERCOT to issue a Market Notice providing a description of the relevant facts, a list of the parties involved in the dispute, and ERCOT's disposition of the proceeding and reasoning in support thereof.

Parties: ERCOT and South Texas Electric Cooperative, Inc. (STEC).

Relevant Facts:

STEC is a Qualified Scheduling Entity (QSE) that represents Resource Entities with Load Resources. On February 15, 2021, four Non-Controllable Load Resources (NCLRs) represented by STEC were obligated to provide 21.2 megawatts (MW) of Responsive Reserve Service (RRS). The Load Resources received dispatch instructions to deploy at approximately 1:07 a.m. However, from the time the Load Resources were deployed until around 4:07 a.m., STEC's telemetry incorrectly showed that the RRS responsibilty for the Load Resources was 0 MW. Once STEC realized the telemetry was incorrect, it updated the telemetered RRS responsibility to 21.2 MWs and informed ERCOT.

On March 12, 2021, the Public Utility Commission of Texas (PUCT) issued an order instructing ERCOT to review QSE settlements for Ancillary Service (A/S) responsibilites during operating days February 14, 2021 through February 19, 2021.[1] In response to the PUCT's order, ERCOT issued a Market Notice which described the methodology ERCOT would use to analyze the QSE A/S settlements and responsibilities.[2] The methodology involved ERCOT analyzing the A/S responsibilities attributed to each QSE in the Energy and Market Management System (EMMS) for that time period and comparing that data against the A/S responsibilities reflected in the QSE's telemetry. Due to STEC's incorrect telemetry, ERCOT identified a failed quantity and assessed a "failure to provide" charge to claw-back the amounts paid for RRS for the time period at issue.[3] STEC argues that the charges are not applicable because it contends that data submitted in connection with this ADR demonstrates that the Load Resources remained off-line for the intervals at issue and STEC therefore fulfilled its RRS obligations despite the telemetry error.

[1] The PUCT order is available at this link: http://interchange.puc.texas.gov/Documents/51812_164_1116026.PDF

[2] The Market Notice is available at: M-A033021-01 Implementation of PUCT order directing ERCOT to apply failure-to-provide Settlement treatment to QSEs that failed on Ancillary Service Supply Responsibilities

[3] The charge assessed to STEC was "RRFQAMT" which is defined as: "*Responsive Reserve Failure Quantity Amount per QSE*—The charge to QSE q for its total capacity associated with failures on its Ancillary Service Supply Responsibility for RRS, for the hour." *See* ERCOT Protocols § 6.7.3(1)(c).

STEC filed a settlement and billing dispute regarding the claw-back charges which ERCOT denied. STEC initiated this ADR to challenge the denial of its settlement and billing dispute and seeks relief in the amount of $645,630.00.[4]

<u>ERCOT's Disposition/Reasoning</u>:

ERCOT has determined that the appropriate disposition of this ADR proceeding is to deny STEC's request for relief.

QSEs have an obligation to provide Real-Time telemetry to ERCOT.[5] For example, a QSE representing a Resource Entity that has a Load Resource must provide telemetry for each Load Resource which includes: Load Resource net real power consumption (in MW); Low Power Consumption (LPC); Maximum Power Consumption (MPC); A/S Schedule (in MW) for each quantity of RRS and Non-Spin, which is equal to the A/S Resource Responsibility minus the amount of A/S deployment; A/S Resource Responsibility (in MW) for each quantity of RRS for all Load Resources; and the Resource Status.[6] If deployed for RRS, within one minute following a deployment instruction, the QSE must update the telemetered Ancillary Service Schedule for RRS to reflect the deployment amount for the Load Resources.[7]

It is undisputed that STEC had an obligation to provide accurate telemetry and failed to do so for the time period at issue.[8] However, STEC argues that ERCOT's decision to assess the claw-back charges at issue was incorrect and inconsistent with the PUCT order. The PUCT's order, dated March 21, 2021, provided as follows:

> 1. ERCOT must settle each qualified scheduling entity that failed on its ancillary service supply responsibility in accordance with ERCOT Nodal Protocol section 6.4.9.1.3, entitled Replacement of Ancillary Service Due to Failure to Provide, for a particular ancillary service for any hour of ERCOT's operating days February 14, 2021 through February 19, 2021.
>
> 2. This Order supersedes and replaces the order addressing ancillary services dated March 3, 2021.

In response to the PUCT's order, ERCOT conducted an analysis of the settlements relating to QSE A/S responsibilities in a manner that closely resembles the process ordinarily utilized for identifying failed quantities in Real-Time pursuant to ERCOT Protocols Section 6.4.9.1.3.[9]

[4] Because ERCOT has determined that STEC's claims should be denied, this Market Notice does not analyze the method of calculating the alleged damages, but it should be noted that if damages were granted, any award would have to be reduced by the amount of Ancillary Service Imbalance Charges that would have been assessed for all hours during which the Load Resources were deployed for RRS.
[5] *See* ERCOT Nodal Operating Guide § 7.3, Telemetry.
[6] ERCOT Protocols at § 6.5.5.2(5)(a)-(m).
[7] *Id.* at § 8.1.1.4.2(1)(a).
[8] STEC provided meter data that it contends demonstrates that the Load Resources were fully deployed for the duration of the RRS obligation. ERCOT's position is that the meter data would not change its determination in this case and therefore ERCOT has not analyzed the accuracy of the meter data provided by STEC.
[9] ERCOT Protocol § 6.4.9.1.3(1), in relevant part, provides: "A QSE is considered to have failed on its Ancillary Services Supply Responsibility when ERCOT determines, in its sole discretion, that some or all of the QSE's Resource-specific

Ordinarily, when an ERCOT control room operator identifies telemetry reflecting that a QSE's A/S responsibility is not being provided, the operator will mark the failed quantity in ERCOT's systems. This action causes the A/S responsibility to be effectively removed from EMMS and the QSE's A/S payment is clawed back in settlement. However, in many instances, the ERCOT control room operators did not complete this manual process as they were managing other priorities during Winter Storm Uri.[10] As a result, STEC and other QSEs were not assessed failure to provide charges in their original settlements. ERCOT Protocols Section 6.4.9.1.3(1) provides that a QSE is considered to have failed on its A/S Supply Responsibility when ERCOT determines, in its sole discretion, that some or all of the QSE's Resource-specific A/S capacity will not be available in Real-Time. In response to the PUCT's order, ERCOT reviewed the A/S responsibilities attributed to each QSE in the EMMS and compared that data against the A/S responsibilities reflected in the QSE's telemetry, the same analysis that would ordinairly occur in Real-Time. If a QSE's telemetry did not identify the same A/S responsibility reflected in the EMMS, ERCOT assessed a claw-back charge. ERCOT finds that this claw-back analysis complied with the PUCT's order.

STEC argues ERCOT may rely on Premise-level interval meter data to confirm that the Load Resources provided the full amount of RRS on February 15, 2021, despite the telemetry error. In support of this argument, STEC in part notes that an Other Binding Document (OBD) titled "Requirements for Aggregate Load Resource Participation in the ERCOT Markets" demonstrates that "ERCOT must rely on meter data for validation of performance."[11] STEC cites the following excerpt from page 6 of the OBD: "ERCOT will use this Premise-level interval meter data both as the foundation of the telemetry validation process and for event performance measurement and verification." This language does not support STEC's claim because the OBD does not apply in this case. The OBD applies to Aggregate Load Resources (ALRs) and the STEC Load Resources at issue are not ALRs. Further, the only Ancillary Service that ALRs are permitted to provide is Non-Spinning Reserve (Non-Spin), not RRS.

STEC complains that ERCOT failed to accurately account for "electricity production and delivery" as required under the Protocols and the Public Utility Regulatory Act (PURA). ERCOT settled STEC in accordance with the Protocols and the telemetry submitted by STEC pursuant to its obligations. The Day-Ahead Market (DAM) was functioning properly – it was not suspended or restarted during the dates at issue.[12] Further, if STEC had telemetered the correct A/S values, then it would not have been assessed a claw-back charge. Accurate telemetry is a cornerstone principle to ensuring ERCOT's observability of the Texas power grid – especially during an Emergency Condition, as was the case during Winter Storm Uri. As a result, ERCOT does not find that it failed to properly account for the production or delivery of electricity as asserted by STEC.

Ancillary Service capacity will not be available in Real-Time." Section 6.4.9.1.3(3) further provides: "ERCOT shall charge each QSE that has failed according to paragraph (1) on its Ancillary Service Supply Responsibility for a particular Ancillary Service for a specific hour."

[10] ERCOT attempted to automate this manual process for identifying failed quantities when it proposed Nodal Protocol Revision Request (NPRR) 947: Clarification to Ancillary Service Supply Responsibility Definition and Improvements to Determining and Charging for Ancillary Service Failed Quantities. However, the NPRR was withdrawn in August 2020 for various reasons including the system cost and the implementation of Real-Time co-optimization.

[11] The OBD is available on ERCOT's website at: https://www.ercot.com/services/programs/load/laar.

12 *See generally* ERCOT Protocols § 25 (describing the procedures for Market Suspension and Restart).

STEC has not demonstrated that ERCOT violated any obligation under the ERCOT Protocols or other applicable law.[13] As a result, the claims asserted by STEC are denied. This Market Notice serves to conclude the ADR proceedings between ERCOT and STEC.

CONTACT: If you have any questions, please contact your ERCOT Account Manager. You may also call the general ERCOT Client Services phone number at (512) 248-3900 or contact ERCOT Client Services via email at ClientServices@ercot.com.

[13] ERCOT Protocols Section 20.1(1) provides that the ADR procedure only applies to a "claim by a Market Participant that ERCOT has violated or misinterpreted any law, including any statute, rule, Protocol, Other Binding Document, or Agreement, where such violation or misinterpretation results in actual harm, or could result in imminent harm, to the Market Participant."

EXHIBIT 2

Market Participant	SOUTH TEXAS ELECTRIC CO
Dispute Id	1-2353390621
Dispute SubType	Ancillary Services-RTM
Charge Type	RRFQAMT
Created	4/21/2021 07:21:38 AM
Contact Name	Hauboldt Rebecca QSE
Contact Phone Number	(361) 485-6209
Contact E-Mail Address	rebecca@stec.org
Dispute Status	Under Review
Market	RTM
Operating Day / Invoice Date	02/15/2021
Start Interval	02/15/2021 0:00:00
End Interval	02/15/2021 0:00:00
Awarded Amount	
Approval Level	Officers
Total Dispute Amount $	645,630.00
Resolution	Denied
Resolution Amount	
Resolution Date	7/23/2021 03:17:28 PM

EXHIBIT 2

Resolution Amount

Resolution Date 7/23/2021 03:17:28 PM

Exp. Confi.

MultiDay Duration

Short Description STEC QSE disputes the Responsive Reserve Failed Quantity (RRFQ) and resulting Charge for RRFQAMT

Long Description In the attached file, one can see that the RRFQ is only attributed to the period that the RRRS was incorrectly telemetered as zero MW. However, the meter data shows that the NCLR consumption drops at 01:07 and remains

Withdraw Dispute Copy

Multi Day Dispute

No Records

Category	Comments	Dispute Amt	Dispute Day	Name	Operating Day	Resolution	Resolution Amt	Status	Type

Activities

No Records

Comments	Activity Type	Status	Attachment	Created On	Contact Name

Attachments

1 - 2 of 2

Attachment Nam	Comments	File Type	Size	Date
Feb 15 2021 D...		docx	96,609	4/21/2021 07:38:19 AM
Feb 15 2021 D...		xlsx	2,587,745	4/21/2021 07:35:48 AM

STEC QSE disputes the Responsive Reserve Failed Quantity (RRFQ) and resulting Charge for Ancillary Service Capacity Rep Due to Failure to Provide Resp Reserve Amount (RRFQAMT) on February 15, 2021. The RRFQ identified by ERCOT was related to telemetry of both the Responsive Reserve Responsibility (RRRS) as zero MW and the Responsive Reserve Schedule (RRSC) to zero MW. The RRSC telemetry of zero MW was correct. ETP_LD1, ETP_LD3, ETP_LD4 and PAWNEE_LD1 all deployed within the 10-minute window allowable for non-controllable Load Resources (NCLR) following the deployment instruction from the ERCOT operator. It was at the point that each NCLR was offline that the RRRS and RRSC both reflected zero MW. Although the telemetry was mistakenly updated to zero for the RRRS, the NCLRs remained offline. A short time after the Load Resources were deployed, the STEC QSE was made aware that ERCOT had recalled Group 1 and 2 Load Resources, but STEC QSE had not received the XML for recall. STEC QSE called ERCOT to attain a Verbal Dispatch Instruction from the ERCOT operator to reinstate its Load Resources however the ERCOT Operator instructed STEC to keep its Load Resources deployed as another instruction to deploy was imminent. It was at that point, that STEC QSE realized that the RRRS was incorrectly assigned as zero MWs and updated the RRRS telemetry to its actual Responsive Reserve Responsibility of 21.2MWs.

Date	Time	GR	GR Event	LR	LR Event	Details
02/15/21	04:07					Talked with Cody and asked about load resources and if they had already been restored, he said that we should have recived an XML, group 2 209 and group 1 was 216
02/15/21	04:15					called again and talked with Greg to see if we could get a vdi to start those back up since we did not get an XML. he said to hold off because those resources were about to be deployed again
02/15/21	04:33					Hotline Greg S - At 04:30, ERCOT is declaring EEA 3 with firm load shed, additional 1,000mw, for a total of 10,000 of firm load is being shed.
02/15/21	04:40					Confirmed with Cody that based on the last hotline call, Group 1&2 were deployed and they should be offline since they fall under EEA2

In the attached file, one can see that the RRFQ is only attributed to the period that the RRRS was incorrectly telemetered as zero MW. However, the meter data shows that the NCLR consumption drops at 01:07 and remains deployed throughout the deployment period.

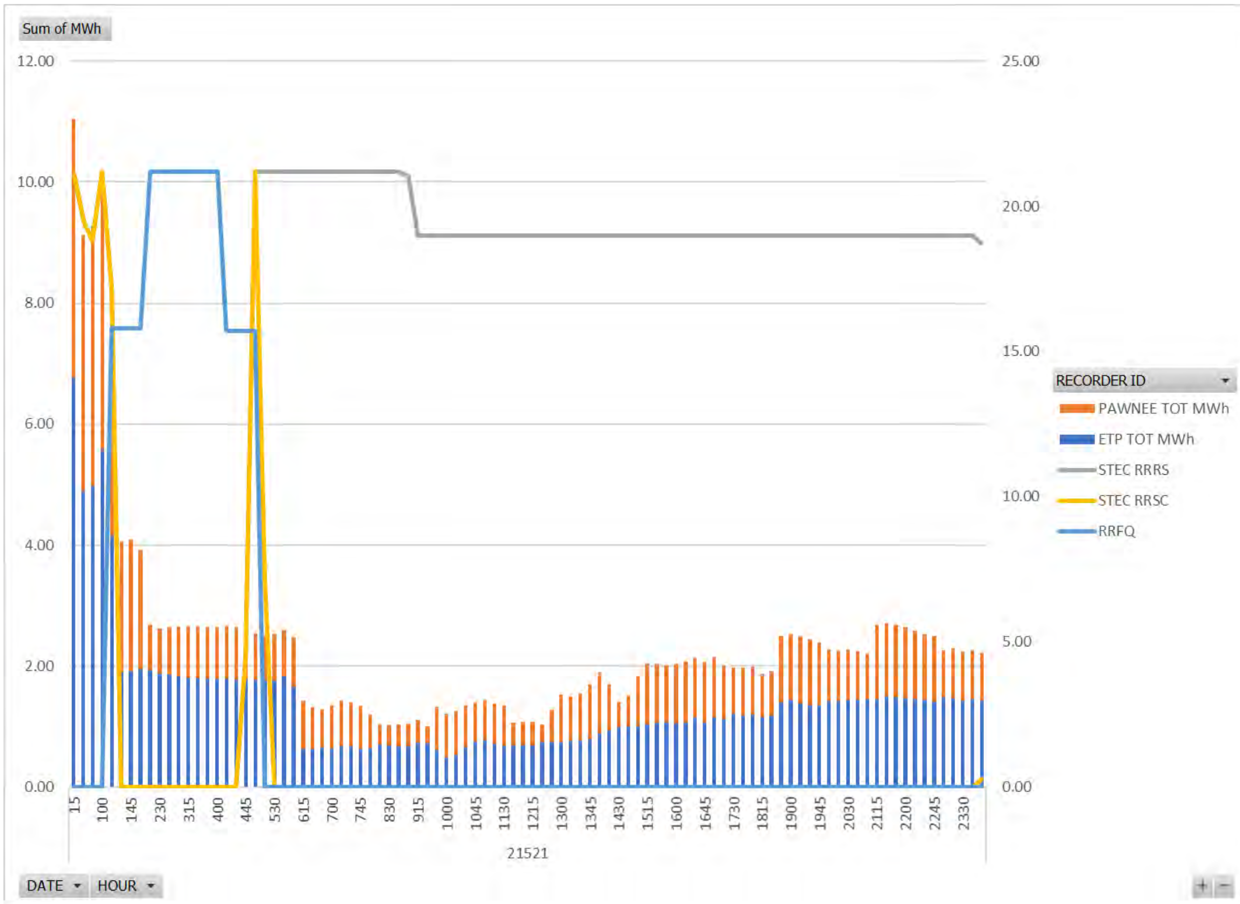
At all times, the Responsive Reserve Service was provided to ERCOT. This fact is supported by the continuous deployment of the Load Resource as evidenced by the meter data and telemetry, as well as the communications with ERCOT in Real-Time regarding the recall of the Load Resources and attempt to receive a VDI for its recall.

The PUCT order issued on March 3, 2021 states:

> *"ERCOT shall claw back all payments for ancillary service that were made to an entity that <u>did not provide its required ancillary service</u> during real time on ERCOT operating days starting February 14,2021 and ending on February 19, 2021." (emphasis added)*

In this case, the ancillary service was provided as proven by the meter data, and as such the claw back of the revenues on February 15 is incorrect and inconsistent with the PUCT order and therefore ERCOT should grant this dispute.

EXHIBIT 2



Sum of MWh
12.00
10.00
8.00
6.00
4.00
2.00
0.00
25.00
20.00
15.00
10.00
5.00
0.00
RECORDER ID
PAWNEE TOT MWh
ETP TOT MWh
STEC RRRS
STEC RRSC
RRFQ
15
100
145
230
315
400
445
530
615
700
745
830
915
1000
1045
1130
1215
1300
1345
1430
1515
1600
1645
1730
1815
1900
1945
2030
2115
2200
2245
2330
21521
DATE
HOUR

SPREAD SHEET FROM 7/30/2021 EMAIL REGARDING RESOLUTION FOR SETTLEMENT DISPUTE NUMBER: 1-2353390621 ATTACHED SEPARATELY AS AN EXCEL FILE.

EXHIBIT 3

From:	Rebecca Hauboldt on behalf of Rebecca Hauboldt <rebecca@stec.org>
To:	"Clif Lange"; "Lucas Turner"
Subject:	FW: Resolution for your Settlement Dispute Number: 1-2353390621
Date:	Friday, July 30, 2021 2:25:02 PM
Attachments:	Settlement Dispute 021521.PNG Settlement Dispute 021521_2.PNG Feb 15 2021 Document1.docx Feb 15 2021 Document1.xlsx

Attached are screen shots of the settlement dispute and the two attachments that were sent with the dispute. The email below in the description has everything that was put into the "Long Description" of the dispute. The screen shot of the dispute only captures the beginning of the text, but the info in the description section of below email is what was in the long description space.

Thanks,
Rebecca
361-485-6209

-----Original Message-----
From: noreply@ercot.com <noreply@ercot.com>
Sent: Friday, July 23, 2021 3:18 PM
To: Rebecca Hauboldt <rebecca@stec.org>
Subject: Resolution for your Settlement Dispute Number: 1-2353390621

CAUTION: THIS MESSAGE ORIGINATED FROM OUTSIDE OF STEC.
Do not open attachments or click links from an unknown or suspicious origin.

Please note,

Resolution for your Settlement Dispute : 1-2353390621 has been changed to Denied.

Below are the Settlement Dispute details:

Market Participant Account : SOUTH TEXAS ELECTRIC CO OP INC (QSE)
Type : Settlement Disputes
Sub-Type : Ancillary Services-RTM
Dispute Amount : $645,630.00
Subject : STEC QSE disputes the Responsive Reserve Failed Quantity (RRFQ) and resulting Charge for RRFQAMT
Description : In the attached file, one can see that the RRFQ is only attributed to the period that the RRRS was incorrectly telemetered as zero MW. However, the meter data shows that the NCLR consumption drops at 01:07 and remains deployed throughout the deployment period.

At all times, the Responsive Reserve Service was provided to ERCOT. This fact is supported by the continuous deployment of the Load Resource as evidenced by the meter data and telemetry, as well as the communications with ERCOT in Real-Time regarding the recall of the Load Resources and attempt to receive a VDI for its recall.

The PUCT order issued on March 3, 2021 states:
¿ERCOT shall claw back all payments for ancillary service that were made to an entity that did not provide its required ancillary service during real time on ERCOT operating days starting February 14,2021 and ending on February 19, 2021.¿ (emphasis added)

In this case, the ancillary service was provided as proven by the meter data, and as such the claw back of the revenues on February 15 is incorrect and inconsistent with the PUCT order and therefore ERCOT should grant this dispute.

Resolution Code : Denied
Resolution Date : 7/23/2021 03:17:28 PM
Resolution Amount : $

Comments : DISPUTE IS DENIED [9.14.4.2.1]: ERCOT has determined the disputed charges and amounts for the specified Operating Day or Invoice Date are correct. The reason for denying dispute, along with any supporting documentation, appears below. Disagreement with resolution may be submitted through Alternative Dispute Resolution (ADR) as described in Section 20, Alternative Dispute Resolution Procedure. If ADR process is not initiated within 45 days of the date of this notice, ERCOT will change status to CLOSED. If ADR process is timely initiated, dispute status will remain OPEN pending resolution of the ADR.

Explanation: ERCOT calculated a responsibility of 93.2MW for 2/15 HE2-5 which is the combination of RRS and RRSNC (as failures cannot be charged per subtype).

At the beginning of HE2 resources in (AMISTAD_AMISTADG1,AMISTAD_AMISTADG2,PAWNEE_LD1, PEARSAL2_AGR_A,PEARSAL2_AGR_B,PEARSAL2_AGR_C,PEARSAL2_AGR_D, ETP_1, ETP_3, ETP_4) combined to cover the 93.2 RRS responsibility. Starting at the 1:10:26 SCED, ETP_LD1,ETP_LD3 and ETP_LD4 telemetered RRS responsibility drops to zero through the 4:40:23 SCED, leaving the level of responsibility covered by the remaining resources at 72MW. Starting at the 4:44:23 SCED, PAWNEE_LD1, ETP_LD1, ETP_LD2,ETP_LD3 and ETP_LD4 resumed RRS responsibility telemetry and when combined with the other resources covered the 93.2 obligation.

As such, ERCOT charged the hourly averaged failed quantity dependent on the SCED level telemetry snapshot values.

ERCOT invites you to provide feedback on the dispute resolution process by completing the survey at following web link

https://urldefense.proofpoint.com/v2/url?u=https-3A__www.surveymonkey.com_r_JWC8YYK&d=DwIFaQ&c=euGZstcaTDllvimEN8b7jXrwqOf-v5A_CdpgnVfiiMM&r=uJaXVBL2BtyIqV5UEFkfTw&m=IJR0JMlbcSCbWC_oKhsd7IEX5glsHB4PKUU1h6zeSzw&s=583vOVvS6p36q7av1vxd931cj-asuAufKRq78Qq1RSE&e=

EXHIBIT 3

Market Participant	SOUTH TEXAS ELECTRIC CO
Dispute Id	1-2353390621
Dispute SubType	Ancillary Services-RTM
Charge Type	RRFQAMT
Created	4/21/2021 07:21:38 AM
Contact Name	Hauboldt Rebecca QSE
Contact Phone Number	(361) 485-6209
Contact E-Mail Address	rebecca@stec.org
Dispute Status	Under Review
Market	RTM
Operating Day / Invoice Date	02/15/2021
Start Interval	02/15/2021 0:00:00
End Interval	02/15/2021 0:00:00
Awarded Amount	
Approval Level	Officers
Total Dispute Amount $	645,630.00
Resolution	Denied
Resolution Amount	
Resolution Date	7/23/2021 03:17:28 PM

EXHIBIT 3

Resolution Amount

Resolution Date 7/23/2021 03:17:28 PM

Exp. Confi.

MultiDay Duration

Short Description STEC QSE disputes the Responsive Reserve Failed Quantity (RRFQ) and resulting Charge for RRFQAMT

Long Description In the attached file, one can see that the RRFQ is only attributed to the period that the RRRS was incorrectly telemetered as zero MW. However, the meter data shows that the NCLR consumption drops at 01:07 and remains

Withdraw Dispute Copy

Multi Day Dispute

No Records

Category	Comments	Dispute Amt	Dispute Day	Name	Operating Day	Resolution	Resolution Amt	Status	Type

Activities

No Records

Comments	Activity Type	Status	Attachment	Created On	Contact Name

Attachments

1 - 2 of 2

Attachment Nam	Comments	File Type	Size	Date
Feb 15 2021 D...		docx	96,609	4/21/2021 07:38:19 AM
Feb 15 2021 D...		xlsx	2,587,745	4/21/2021 07:35:48 AM

STEC QSE disputes the Responsive Reserve Failed Quantity (RRFQ) and resulting Charge for Ancillary Service Capacity Rep Due to Failure to Provide Resp Reserve Amount (RRFQAMT) on February 15, 2021. The RRFQ identified by ERCOT was related to telemetry of both the Responsive Reserve Responsibility (RRRS) as zero MW and the Responsive Reserve Schedule (RRSC) to zero MW. The RRSC telemetry of zero MW was correct. ETP_LD1, ETP_LD3, ETP_LD4 and PAWNEE_LD1 all deployed within the 10-minute window allowable for non-controllable Load Resources (NCLR) following the deployment instruction from the ERCOT operator. It was at the point that each NCLR was offline that the RRRS and RRSC both reflected zero MW. Although the telemetry was mistakenly updated to zero for the RRRS, the NCLRs remained offline. A short time after the Load Resources were deployed, the STEC QSE was made aware that ERCOT had recalled Group 1 and 2 Load Resources, but STEC QSE had not received the XML for recall. STEC QSE called ERCOT to attain a Verbal Dispatch Instruction from the ERCOT operator to reinstate its Load Resources however the ERCOT Operator instructed STEC to keep its Load Resources deployed as another instruction to deploy was imminent. It was at that point, that STEC QSE realized that the RRRS was incorrectly assigned as zero MWs and updated the RRRS telemetry to its actual Responsive Reserve Responsibility of 21.2MWs.

Date	Time	GR	GR Event	LR	LR Event	Details
02/15/21	04:07					*Talked with Cody and asked about load resources and if they had already been restored, he said that we should have recived an XML, group 2 209 and group 1 was 216*
02/15/21	04:15					*called again and talked with Greg to see if we could get a vdi to start those back up since we did not get an XML, he said to hold off because those resources were about to be deployed again*
02/15/21	04:33					Hotline Greg S - At 04:30, ERCOT is declaring EEA 3 with firm load shed, additional 1,000mw, for a total of 10,000 of firm load is being shed.
02/15/21	04:40					*Confirmed with Cody that based on the last hotline call, Group 1&2 were deployed and they should be offline since they fall under EEA2*

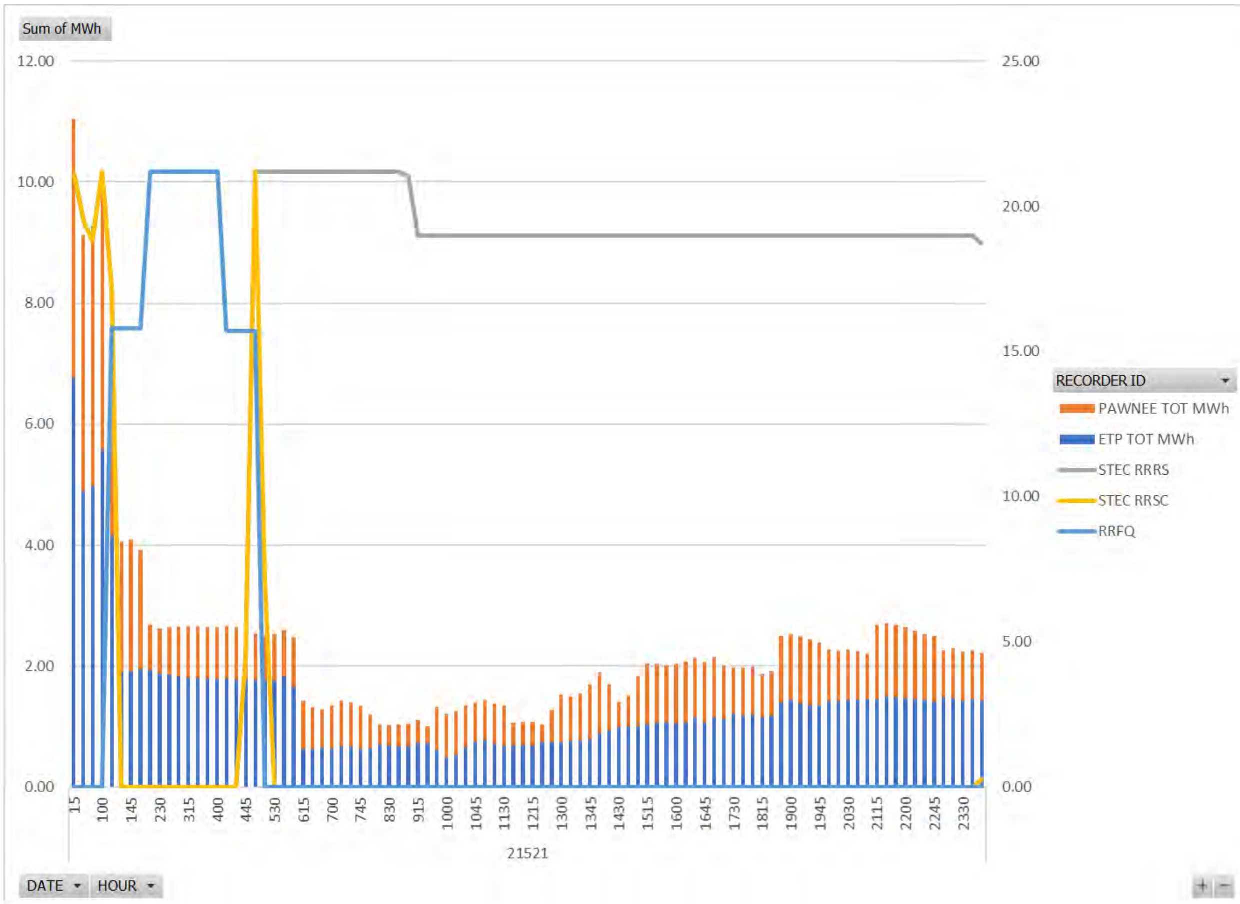
In the attached file, one can see that the RRFQ is only attributed to the period that the RRRS was incorrectly telemetered as zero MW. However, the meter data shows that the NCLR consumption drops at 01:07 and remains deployed throughout the deployment period.

At all times, the Responsive Reserve Service was provided to ERCOT. This fact is supported by the continuous deployment of the Load Resource as evidenced by the meter data and telemetry, as well as the communications with ERCOT in Real-Time regarding the recall of the Load Resources and attempt to receive a VDI for its recall.

The PUCT order issued on March 3, 2021 states:

> *"ERCOT shall claw back all payments for ancillary service that were made to an entity that <u>did not provide its required ancillary service</u> during real time on ERCOT operating days starting February 14,2021 and ending on February 19, 2021." (emphasis added)*

In this case, the ancillary service was provided as proven by the meter data, and as such the claw back of the revenues on February 15 is incorrect and inconsistent with the PUCT order and therefore ERCOT should grant this dispute.


Sum of MWh
12.00
10.00
8.00
6.00
4.00
2.00
0.00
25.00
20.00
15.00
10.00
5.00
0.00
RECORDER ID
PAWNEE TOT MWh
ETP TOT MWh
STEC RRRS
STEC RRSC
RRFQ
15
100
145
230
315
400
445
530
615
700
745
830
915
1000
1045
1130
1215
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1600
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1730
1815
1900
1945
2030
2115
2200
2245
2330
21521
DATE
HOUR

EXHIBIT 3 - SPREADSHEET from 2021.07.23 Email Re. ERCOT's Denial of Settlement Dispute No. 1-2353390621

ATTACHED SEPARATELY AS AN EXCEL FILE.

EXHIBIT 4

Date Received: ____________________

ALTERNATIVE DISPUTE RESOLUTION (ADR) REQUEST FORM

A Market Participant who desires to submit a request for ADR may complete this form and submit it, together with any other additional supporting materials, in order to begin the ADR process. This form contains the requirements pursuant to Protocol Section 20.4, *Initiation of ADR Proceedings*.

Please fill out this form electronically and submit it, together with any other additional supporting materials, via email to adr@ercot.com.

The date on which ERCOT receives the completed ADR written request shall be the ADR initiation date. No later than seven (7) days after the ADR initiation date, ERCOT shall determine, and provide Notice to, all parties directly involved in the dispute. Such Notice shall include the ADR file number and the designation of the ERCOT senior dispute representative.

Name of Disputing Market Participant	South Texas Electric Cooperative, Inc. ("STEC QSE")
Description of Relief Sought	STEC QSE seeks compensation for Responsive Reserve Service provided by Load Resources ETP_LD1, ETP_LD3, ETP_LD4 and PAWNEE_LD1 on February 15, 2021.
Detailed Description of the Grounds for Relief and the Basis of Each Claim[1]	See Attachment A.
List of All Other Parties Affected by the Dispute	
Senior Dispute Representative *(name, address, telephone number and email address)*	Clif Lange South Texas Electric Cooperative, Inc. 2849 FM 447 / PO Box 119 Nursery, TX 77976 (361) 485-6206
If seeking a monetary resolution, please check box and complete the following: ☒	
Operating Day(s) Involved in the Dispute	02/15/2021
Settlement Dispute Number(s) *(if applicable)*	1-2353390621
Amount of Compensation Requested	$ 645,630.00

[1] Identify which statute(s), rule(s), Protocol Section(s), Other Binding Document(s), Agreement(s) or other law(s) are alleged to have been violated.

ATTACHMENT A

Detailed Description of Grounds for Relief

South Texas Electric Cooperative, Inc. ("STEC QSE") is a Qualified Scheduling Entity ("QSE") that represents Load Resources in the Electric Reliability Council of Texas, Inc. ("ERCOT") market. On February 15, 2021, as the ERCOT system experienced unprecedented emergency grid conditions, STEC QSE's Load Resources ETP_LD1, ETP_LD3, ETP_LD4 and PAWNEE_LD1 were scheduled to provide 21.2 megawatts ("MWs") of Responsive Reserve Service ("RRS"). The Load Resources deployed on time and throughout the entirety of the deployment obligation. Due to a telemetry error, the deployment of RRS was not accounted for by ERCOT. STEC QSE was therefore charged for failing to provide the required RRS. However, the charges are not applicable because data submitted by STEC QSE demonstrates that the RRS was provided in full despite the telemetry error.

ERCOT is required to "ensure that electricity production and delivery are accurately accounted for among the generators and wholesale buyers and sellers in the region."[1] Additionally, Protocol § 1.2(1)(d) requires that electricity production and delivery are accurately accounted for among wholesale buyers and seller. STEC QSE therefore disputes the Responsive Reserve Failed Quantity ("RRFQ") and resulting Charge for Ancillary Service Capacity Rep Due to Failure to Provide Resp Reserve Amount ("RRFQAMT") assessed to STEC QSE by ERCOT on February 15, 2021 because the charges do not accurately account for the RRS that was provided by ETP_LD1, ETP_LD3, ETP_LD4 and PAWNEE_LD1. STEC QSE has not passed through the RRFQAMT charges to its Load Resources. As the QSE representing the Load Resources, and as the entity bearing the financial impact of the amounts disputed in Settlement Dispute No. 1-2353390621, STEC is the appropriate entity to bring this request for alternative dispute resolution.

The RRFQ identified by ERCOT was related to telemetry of both the Responsive Reserve Responsibility ("RRRS") as zero MWs and the Responsive Reserve Schedule ("RRSC") to zero MWs. The RRSC telemetry of zero MWs was correct. ETP_LD1, ETP_LD3, ETP_LD4 and PAWNEE_LD1 all deployed within the 10-minute window allowable for non-controllable Load Resources ("NCLR") following the deployment instruction from ERCOT at 1:07 AM. It was at the point that each NCLR was offline that the RRRS and RRSC both reflected zero MWs.

Although the telemetry was mistakenly updated to zero for the RRRS, the NCLRs remained offline. At approximately 4:00 AM, the STEC QSE was made aware by a third party that ERCOT had recalled Group 1 and 2 Load Resources at 2:09 AM and 2:16 AM, but STEC QSE had not received the XML for recall. STEC QSE called ERCOT at 4:07 AM to attain a

[1] Public Utility Regulatory Act, Tex. Util. Code § 39.151(a)(4) ("PURA").

Verbal Dispatch Instruction from the ERCOT operator to reinstate its Load Resources. However, the ERCOT Operator instructed STEC at 4:15 AM to keep its Load Resources deployed as another instruction to deploy was imminent. At that time, STEC QSE realized that the RRRS was inadvertently assigned as zero MWs. STEC QSE immediately updated the RRRS telemetry to its actual Responsive Reserve Responsibility of 21.2MWs and made ERCOT aware of the telemetry issue.

The attached documentation demonstrates that the RRFQ is only attributed to the period in which the RRRS was incorrectly telemetered as zero MW. However, the meter data shows that the NCLR consumption drops at 01:07 and remains deployed throughout the deployment period. At all times, the RRS was provided to ERCOT. This fact is supported by the continuous deployment of the Load Resources as evidenced by the meter data and telemetry, as well as the communications with ERCOT in Real-Time regarding the recall of the Load Resources and attempt to receive a VDI for its recall. Furthermore, as noted in the Other Binding Document "Requirements for Aggregate Load Resource Participation in the ERCOT Markets," ERCOT must rely on meter data for validation of performance:

> *"ERCOT will use this Premise-level interval meter data both as the foundation of the telemetry validation process and <u>for event performance measurement and verification</u>." (emphasis added)*

The Public Utility Commission of Texas ("PUCT") has provided ERCOT with broad discretion to take actions necessary to stabilize the market in the wake of the unprecedented reliability and market impacts of the February winter storm.[2] As part of its efforts to stabilize the market, the PUCT adopted the recommendation made by the Independent Market Monitor ("IMM") to "claw back" payments made to ancillary service providers that did not meet their obligations during the winter storm emergency.[3] The PUCT order issued on March 3, 2021 states:

> *"ERCOT shall claw back all payments for ancillary service that were made to an entity that <u>did not provide its required ancillary service</u> during real time on ERCOT operating days starting February 14,2021 and ending on February 19, 2021." (emphasis added)*

In this case, the ancillary service was provided as proven by the meter data, and as such the claw back of the revenues on February 15, 2021 is incorrect and inconsistent with the PUCT order. STEC QSE has demonstrated that the RRS was provided and ERCOT is obligated to ensure it is accurately accounted for. Therefore, this dispute should be granted.

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[2] *Issues Related to the State of Disaster for the February 2021 Winter Event*, Project No. 51812, Order Directing ERCOT To Take Action and Granting Exceptions (Feb. 21, 2021).

[3] *Issues Related to the State of Disaster for the February 2021 Winter Event*, Project No. 51812, Second Order Addressing Ancillary Services (Mar. 12, 2021).

Date	Time	GR	GR Event	LR	LR Event	Details
02/15/21	04:07					Talked with Cody and asked about load resources and if they had already been restored, he said that we should have recived an XML, group 2 209 and group 1 was 216
02/15/21	04:15					called again and talked with Greg to see if we could get a vdi to start those back up since we did not get an XML, he said to hold off because those resources were about to be deployed again
02/15/21	04:33					Hotline Greg S - At 04:30, ERCOT is declaring EEA 3 with firm load shed, additional 1,000mw, for a total of 10,000 of firm load is being shed.
02/15/21	04:40					Confirmed with Cody that based on the last hotline call, Group 1&2 were deployed and they should be offline since they fall under EEA2

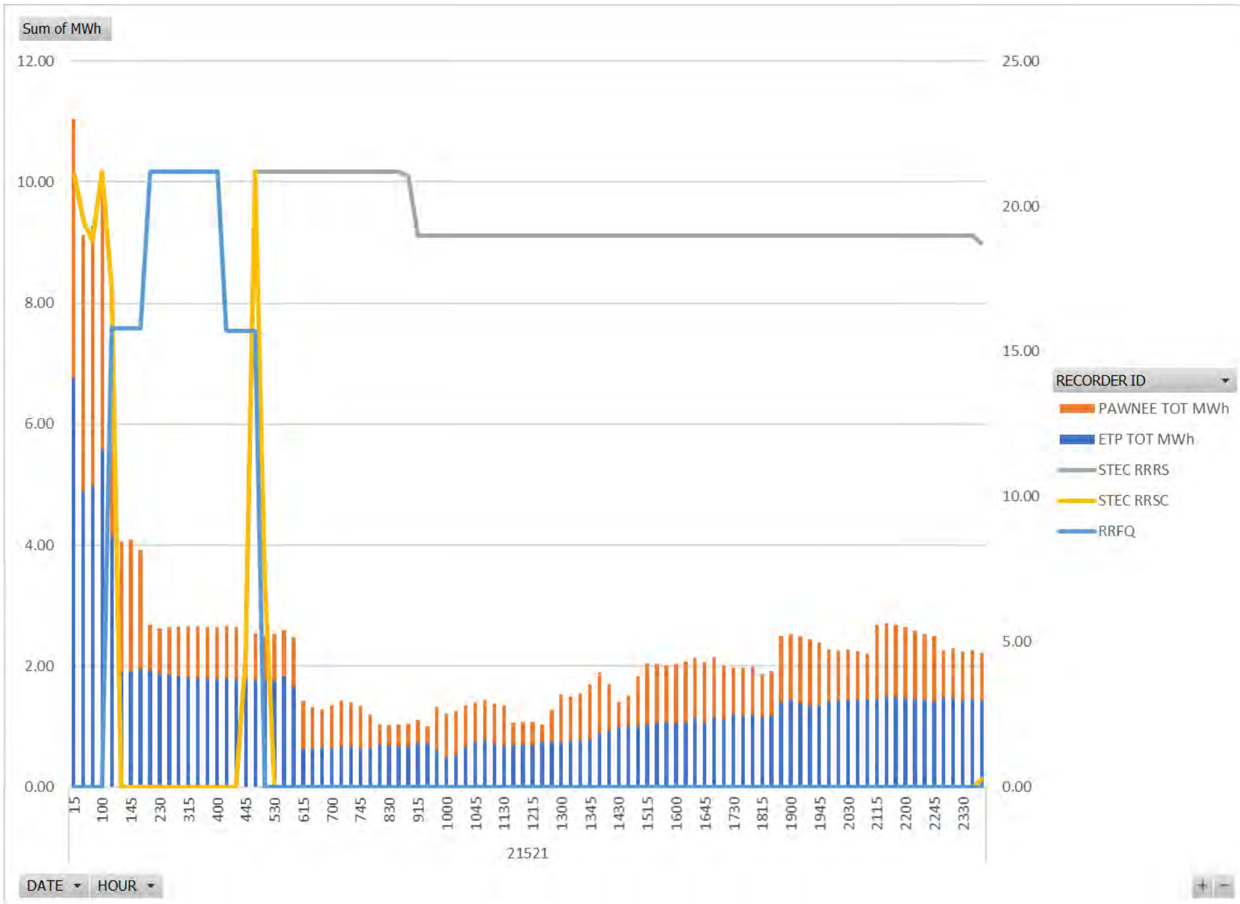

EXHIBIT 5

STEC'S RRFQAMT SPREADSHEET ATTACHED
SEPARATELY AS AN EXCEL FILE.

EXHIBIT 6

ERCOT COP
Participant in 'QSTEC' | LocationType in 'LR' | Location in 'AMISTAD_AMISTAG1'

Participant	Operating Date	Hour	Location Ty	Location	Operating S	COP Type	Limits: LEL	Limits: LSL	Limits: HSL	Limits: HEL	AS Capacity	AS Capacity	AS Capacity	AS Capacity	Recommen	Internal Sta	ISO Status	ISO Verified				
QSTEC	2/15/2021 0:00	1	LR	ETP_LD1	ONRL	ADJ	0	0	11.2	11.2	0	0	6.3	0		Submitted	Accepted	TRUE	1	19.00	1	19
QSTEC	2/15/2021 0:00	1	LR	ETP_LD2	ONRL	ADJ	0	0	11.2	11.2	0	0	5.3	0		Submitted	Accepted	TRUE	2	21.20	1	19
QSTEC	2/15/2021 0:00	1	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0		Submitted	Accepted	TRUE	3	21.20	1	19
QSTEC	2/15/2021 0:00	1	LR	ETP_LD4	ONRL	ADJ	0	0	12	12	0	0	1.8	0		Submitted	Accepted	TRUE	4	21.20	1	19
QSTEC	2/15/2021 0:00	1	LR	PAWNEE_L	OUTL	ADJ	0	0	11.2	11.2	0	0	0	0		Submitted	Accepted	TRUE	5	21.20	1	19
QSTEC	2/15/2021 0:00	2	LR	ETP_LD1	ONRL	ADJ	0	0	11.2	11.2	0	0	6.3	0		Submitted	Accepted	TRUE	6	21.20	1	19
QSTEC	2/15/2021 0:00	2	LR	ETP_LD2	ONRL	ADJ	0	0	11.2	11.2	0	0	5.3	0		Submitted	Accepted	TRUE	7	21.20	1	19
QSTEC	2/15/2021 0:00	2	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0		Submitted	Accepted	TRUE	8	21.20	1	19
QSTEC	2/15/2021 0:00	2	LR	ETP_LD4	ONRL	ADJ	0	0	12	12	0	0	1.8	0		Submitted	Accepted	TRUE	9	21.20	1	19
QSTEC	2/15/2021 0:00	2	LR	PAWNEE_L	ONRL	ADJ	0	0	11.2	11.2	0	0	2.2	0		Submitted	Accepted	TRUE	10	19.00	1	19
QSTEC	2/15/2021 0:00	3	LR	ETP_LD1	ONRL	ADJ	0	0	11.2	11.2	0	0	6.3	0		Submitted	Accepted	TRUE	11	19.00	1	19
QSTEC	2/15/2021 0:00	3	LR	ETP_LD2	ONRL	ADJ	0	0	11.2	11.2	0	0	5.3	0		Submitted	Accepted	TRUE	12	19.00	1	19
QSTEC	2/15/2021 0:00	3	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0		Submitted	Accepted	TRUE	13	19.00	2	21.2
QSTEC	2/15/2021 0:00	3	LR	ETP_LD4	ONRL	ADJ	0	0	12	12	0	0	1.8	0		Submitted	Accepted	TRUE	14	19.00	2	21.2
QSTEC	2/15/2021 0:00	3	LR	PAWNEE_L	ONRL	ADJ	0	0	11.2	11.2	0	0	2.2	0		Submitted	Accepted	TRUE	15	19.00	2	21.2
QSTEC	2/15/2021 0:00	4	LR	ETP_LD1	ONRL	ADJ	0	0	11.2	11.2	0	0	6.3	0		Submitted	Accepted	TRUE	16	19.00	2	21.2
QSTEC	2/15/2021 0:00	4	LR	ETP_LD2	ONRL	ADJ	0	0	11.2	11.2	0	0	5.3	0		Submitted	Accepted	TRUE	17	19.00	2	21.2
QSTEC	2/15/2021 0:00	4	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0		Submitted	Accepted	TRUE	18	19.00	2	21.2
QSTEC	2/15/2021 0:00	4	LR	ETP_LD4	ONRL	ADJ	0	0	12	12	0	0	1.8	0		Submitted	Accepted	TRUE	19	19.00	2	21.2
QSTEC	2/15/2021 0:00	4	LR	PAWNEE_L	ONRL	ADJ	0	0	11.2	11.2	0	0	2.2	0		Submitted	Accepted	TRUE	20	19.00	2	21.2
QSTEC	2/15/2021 0:00	5	LR	ETP_LD1	ONRL	ADJ	0	0	11.2	11.2	0	0	6.3	0		Submitted	Accepted	TRUE	21	19.00	2	21.2
QSTEC	2/15/2021 0:00	5	LR	ETP_LD2	ONRL	ADJ	0	0	11.2	11.2	0	0	5.3	0		Submitted	Accepted	TRUE	22	19.00	2	21.2
QSTEC	2/15/2021 0:00	5	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0		Submitted	Accepted	TRUE	23	19.00	2	21.2
QSTEC	2/15/2021 0:00	5	LR	ETP_LD4	ONRL	ADJ	0	0	12	12	0	0	1.8	0		Submitted	Accepted	TRUE	24	19.00	2	21.2
QSTEC	2/15/2021 0:00	5	LR	PAWNEE_L	ONRL	ADJ	0	0	11.2	11.2	0	0	2.2	0		Submitted	Accepted	TRUE			3	21.2
QSTEC	2/15/2021 0:00	6	LR	ETP_LD1	ONRL	ADJ	0	0	11.2	11.2	0	0	6.3	0		Submitted	Accepted	TRUE			3	21.2
QSTEC	2/15/2021 0:00	6	LR	ETP_LD2	ONRL	ADJ	0	0	11.2	11.2	0	0	5.3	0		Submitted	Accepted	TRUE			3	21.2
QSTEC	2/15/2021 0:00	6	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0		Submitted	Accepted	TRUE			3	21.2
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QSTEC	2/15/2021 0:00	6	LR	PAWNEE_L	ONRL	ADJ	0	0	11.2	11.2	0	0	2.2	0		Submitted	Accepted	TRUE			3	21.2
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QSTEC	2/15/2021 0:00	8	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0		Submitted	Accepted	TRUE			4	21.2
QSTEC	2/15/2021 0:00	8	LR	ETP_LD4	ONRL	ADJ	0	0	12	12	0	0	1.8	0		Submitted	Accepted	TRUE			4	21.2
QSTEC	2/15/2021 0:00	8	LR	PAWNEE_L	ONRL	ADJ	0	0	11.2	11.2	0	0	2.2	0		Submitted	Accepted	TRUE			4	21.2
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QSTEC	2/15/2021 0:00	12	LR	ETP_LD1	ONRL	ADJ	0	0	11.2	11.2	0	0	6.3	0	Submitted	Accepted	TRUE	5	21.2
QSTEC	2/15/2021 0:00	12	LR	ETP_LD2	ONRL	ADJ	0	0	11.2	11.2	0	0	5.3	0	Submitted	Accepted	TRUE	5	21.2
QSTEC	2/15/2021 0:00	12	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0	Submitted	Accepted	TRUE	5	21.2
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QSTEC	2/15/2021 0:00	13	LR	ETP_LD2	ONRL	ADJ	0	0	11.2	11.2	0	0	5.3	0	Submitted	Accepted	TRUE	6	21.2
QSTEC	2/15/2021 0:00	13	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0	Submitted	Accepted	TRUE	6	21.2
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QSTEC	2/15/2021 0:00	13	LR	PAWNEE_L	OUTL	ADJ	0	0	11.2	11.2	0	0	0	0	Submitted	Accepted	TRUE	6	21.2
QSTEC	2/15/2021 0:00	14	LR	ETP_LD1	ONRL	ADJ	0	0	11.2	11.2	0	0	6.3	0	Submitted	Accepted	TRUE	6	21.2
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QSTEC	2/15/2021 0:00	16	LR	PAWNEE_L	OUTL	ADJ	0	0	11.2	11.2	0	0	0	0	Submitted	Accepted	TRUE	7	21.2
QSTEC	2/15/2021 0:00	17	LR	ETP_LD1	ONRL	ADJ	0	0	11.2	11.2	0	0	6.3	0	Submitted	Accepted	TRUE	7	21.2
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QSTEC	2/15/2021 0:00	17	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0	Submitted	Accepted	TRUE	7	21.2
QSTEC	2/15/2021 0:00	17	LR	ETP_LD4	ONRL	ADJ	0	0	12	12	0	0	1.8	0	Submitted	Accepted	TRUE	7	21.2
QSTEC	2/15/2021 0:00	17	LR	PAWNEE_L	OUTL	ADJ	0	0	11.2	11.2	0	0	0	0	Submitted	Accepted	TRUE	8	21.2
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QSTEC	2/15/2021 0:00	18	LR	ETP_LD2	ONRL	ADJ	0	0	11.2	11.2	0	0	5.3	0	Submitted	Accepted	TRUE	8	21.2
QSTEC	2/15/2021 0:00	18	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0	Submitted	Accepted	TRUE	8	21.2
QSTEC	2/15/2021 0:00	18	LR	ETP_LD4	ONRL	ADJ	0	0	12	12	0	0	1.8	0	Submitted	Accepted	TRUE	8	21.2
QSTEC	2/15/2021 0:00	18	LR	PAWNEE_L	OUTL	ADJ	0	0	11.2	11.2	0	0	0	0	Submitted	Accepted	TRUE	8	21.2
QSTEC	2/15/2021 0:00	19	LR	ETP_LD1	ONRL	ADJ	0	0	11.2	11.2	0	0	6.3	0	Submitted	Accepted	TRUE	8	21.2
QSTEC	2/15/2021 0:00	19	LR	ETP_LD2	ONRL	ADJ	0	0	11.2	11.2	0	0	5.3	0	Submitted	Accepted	TRUE	8	21.2
QSTEC	2/15/2021 0:00	19	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0	Submitted	Accepted	TRUE	8	21.2
QSTEC	2/15/2021 0:00	19	LR	ETP_LD4	ONRL	ADJ	0	0	12	12	0	0	1.8	0	Submitted	Accepted	TRUE	8	21.2
QSTEC	2/15/2021 0:00	19	LR	PAWNEE_L	OUTL	ADJ	0	0	11.2	11.2	0	0	0	0	Submitted	Accepted	TRUE	8	21.2
QSTEC	2/15/2021 0:00	20	LR	ETP_LD1	ONRL	ADJ	0	0	11.2	11.2	0	0	6.3	0	Submitted	Accepted	TRUE	8	21.2
QSTEC	2/15/2021 0:00	20	LR	ETP_LD2	ONRL	ADJ	0	0	11.2	11.2	0	0	5.3	0	Submitted	Accepted	TRUE	9	21.2
QSTEC	2/15/2021 0:00	20	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0	Submitted	Accepted	TRUE	9	21.2
QSTEC	2/15/2021 0:00	20	LR	ETP_LD4	ONRL	ADJ	0	0	12	12	0	0	1.8	0	Submitted	Accepted	TRUE	9	21.2
QSTEC	2/15/2021 0:00	20	LR	PAWNEE_L	OUTL	ADJ	0	0	11.2	11.2	0	0	0	0	Submitted	Accepted	TRUE	9	21.2
QSTEC	2/15/2021 0:00	21	LR	ETP_LD1	ONRL	ADJ	0	0	11.2	11.2	0	0	6.3	0	Submitted	Accepted	TRUE	9	21.2
QSTEC	2/15/2021 0:00	21	LR	ETP_LD2	ONRL	ADJ	0	0	11.2	11.2	0	0	5.3	0	Submitted	Accepted	TRUE	9	21.2
QSTEC	2/15/2021 0:00	21	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0	Submitted	Accepted	TRUE	9	21.2
QSTEC	2/15/2021 0:00	21	LR	ETP_LD4	ONRL	ADJ	0	0	12	12	0	0	1.8	0	Submitted	Accepted	TRUE	9	21.2
QSTEC	2/15/2021 0:00	21	LR	PAWNEE_L	OUTL	ADJ	0	0	11.2	11.2	0	0	0	0	Submitted	Accepted	TRUE	9	21.2
QSTEC	2/15/2021 0:00	22	LR	ETP_LD1	ONRL	ADJ	0	0	11.2	11.2	0	0	6.3	0	Submitted	Accepted	TRUE	9	21.2
QSTEC	2/15/2021 0:00	22	LR	ETP_LD2	ONRL	ADJ	0	0	11.2	11.2	0	0	5.3	0	Submitted	Accepted	TRUE	9	21.2
QSTEC	2/15/2021 0:00	22	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0	Submitted	Accepted	TRUE	9	21.2
QSTEC	2/15/2021 0:00	22	LR	ETP_LD4	ONRL	ADJ	0	0	12	12	0	0	1.8	0	Submitted	Accepted	TRUE	10	19
QSTEC	2/15/2021 0:00	22	LR	PAWNEE_L	OUTL	ADJ	0	0	11.2	11.2	0	0	0	0	Submitted	Accepted	TRUE	10	19
QSTEC	2/15/2021 0:00	23	LR	ETP_LD1	ONRL	ADJ	0	0	11.2	11.2	0	0	6.3	0	Submitted	Accepted	TRUE	10	19
QSTEC	2/15/2021 0:00	23	LR	ETP_LD2	ONRL	ADJ	0	0	11.2	11.2	0	0	5.3	0	Submitted	Accepted	TRUE	10	19
QSTEC	2/15/2021 0:00	23	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0	Submitted	Accepted	TRUE	10	19

QSTEC	2/15/2021 0:00	23	LR	ETP_LD4	ONRL	ADJ	0	0	12	12	0	0	1.8	0	Submitted	Accepted	TRUE	10	19
QSTEC	2/15/2021 0:00	23	LR	PAWNEE_L	OUTL	ADJ	0	0	11.2	11.2	0	0	0	0	Submitted	Accepted	TRUE	10	19
QSTEC	2/15/2021 0:00	24	LR	ETP_LD1	ONRL	ADJ	0	0	11.2	11.2	0	0	6.3	0	Submitted	Accepted	TRUE	10	19
QSTEC	2/15/2021 0:00	24	LR	ETP_LD2	ONRL	ADJ	0	0	11.2	11.2	0	0	5.3	0	Submitted	Accepted	TRUE	10	19
QSTEC	2/15/2021 0:00	24	LR	ETP_LD3	ONRL	ADJ	0	0	11.2	11.2	0	0	5.6	0	Submitted	Accepted	TRUE	10	19
QSTEC	2/15/2021 0:00	24	LR	ETP_LD4	ONRL	ADJ	0	0	12	12	0	0	1.8	0	Submitted	Accepted	TRUE	10	19
QSTEC	2/15/2021 0:00	24	LR	PAWNEE_L	OUTL	ADJ	0	0	11.2	11.2	0	0	0	0	Submitted	Accepted	TRUE	10	19
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<u>EXHIBIT 7</u>

Sum of MWh		RECORDER ID			
DATE	HOUR	ETP TOT	PAWNEE TOT	Grand Total	
21521	15	6.76634775	4.27952725	11.045875	44.1835
21521	30	4.88830275	4.23730325	9.125606	36.50242
21521	45	4.9661065	4.3104745	9.276581	37.10632
21521	100	5.58969625	4.27290375	9.8626	39.4504
21521	115	4.1456835	3.56386225	7.70954575	30.83818
21521	130	1.8954615	2.16600525	4.06146675	16.24587
21521	145	1.92468	2.16396775	4.08864775	16.35459
21521	200	1.94286775	1.97810575	3.9209735	15.68389
21521	215	1.93428825	0.7530655	2.68735375	10.74942
21521	230	1.876991	0.754366	2.631357	10.52543
21521	245	1.85892675	0.77795025	2.636877	10.54751
21521	300	1.8321575	0.817875	2.6500325	10.60013
21521	315	1.79835875	0.85777175	2.6561305	10.62452
21521	330	1.80031575	0.861693	2.66200875	10.64804
21521	345	1.78528075	0.85757675	2.6428575	10.57143
21521	400	1.793333	0.85464475	2.64797775	10.59191
21521	415	1.7945335	0.85772725	2.65226075	10.60904
21521	430	1.778684	0.86837075	2.64705475	10.58822
21521	445	1.78961825	0.83165375	2.621272	10.48509
21521	500	1.7710225	0.77392825	2.54495075	10.1798
21521	515	1.75354375	0.76290825	2.516452	10.06581
21521	530	1.7560835	0.77492125	2.53100475	10.12402
21521	545	1.8240505	0.773462	2.5975125	10.39005
21521	600	1.66143675	0.8148805	2.47631725	9.905269
21521	615	0.62738775	0.795793	1.42318075	5.692723
21521	630	0.6252525	0.70467625	1.32992875	5.319715
21521	645	0.65238375	0.625103	1.27748675	5.109947
21521	700	0.62581325	0.72844225	1.3542555	5.417022
21521	715	0.6728	0.74801975	1.42081975	5.683279
21521	730	0.6745995	0.72481075	1.39941025	5.597641
21521	745	0.63463425	0.708441	1.34307525	5.372301
21521	800	0.64217675	0.55156425	1.193741	4.774964
21521	815	0.705104	0.3275895	1.0326935	4.130774
21521	830	0.6908465	0.323615	1.0144615	4.057846
21521	845	0.6721065	0.3673705	1.039477	4.157908
21521	900	0.666976	0.3881655	1.0551415	4.220566
21521	915	0.72750925	0.3731665	1.10067575	4.402703
21521	930	0.728513	0.27412525	1.00263825	4.010553
21521	945	0.61493825	0.7090365	1.32397475	5.295899
21521	1000	0.48135875	0.72850525	1.209864	4.839456
21521	1015	0.52281425	0.726227	1.24904125	4.996165
21521	1030	0.654528	0.691807	1.346335	5.38534
21521	1045	0.7397715	0.66370975	1.40348125	5.613925

21521	1100	0.7778035	0.65564175	1.43344525	5.733781
21521	1115	0.723588	0.653425	1.377013	5.508052
21521	1130	0.6745855	0.68588325	1.36046875	5.441875
21521	1145	0.68772325	0.3823005	1.07002375	4.280095
21521	1200	0.6937975	0.38489825	1.07869575	4.314783
21521	1215	0.69434475	0.38622625	1.080571	4.322284
21521	1230	0.7385695	0.29345225	1.03202175	4.128087
21521	1245	0.73873275	0.540187	1.27891975	5.115679
21521	1300	0.742066	0.7794425	1.5215085	6.086034
21521	1315	0.758631	0.74334575	1.50197675	6.007907
21521	1330	0.77940125	0.7603	1.53970125	6.158805
21521	1345	0.789548	0.910735	1.700283	6.801132
21521	1400	0.8905765	1.01765325	1.90822975	7.632919
21521	1415	0.93090175	0.7749475	1.70584925	6.823397
21521	1430	0.9853885	0.4258265	1.411215	5.64486
21521	1445	1.0006555	0.506733	1.5073885	6.029554
21521	1500	1.01219075	0.816223	1.82841375	7.313655
21521	1515	1.037822	1.0128435	2.0506655	8.202662
21521	1530	1.06906125	0.967132	2.03619325	8.144773
21521	1545	1.06886975	0.9547865	2.02365625	8.094625
21521	1600	1.0452865	0.9868035	2.03209	8.12836
21521	1615	1.05936875	1.01620825	2.075577	8.302308
21521	1630	1.14896975	0.982163	2.13113275	8.524531
21521	1645	1.071284	0.99165925	2.06294325	8.251773
21521	1700	1.147272	1.0088525	2.1561245	8.624498
21521	1715	1.12773775	0.87401925	2.001757	8.007028
21521	1730	1.206037	0.7687935	1.9748305	7.899322
21521	1745	1.17286975	0.80504575	1.9779155	7.911662
21521	1800	1.187422	0.798109	1.985531	7.942124
21521	1815	1.1465115	0.72132875	1.86784025	7.471361
21521	1830	1.18462225	0.7279575	1.91257975	7.650319
21521	1845	1.39388175	1.1031395	2.49702125	9.988085
21521	1900	1.439718	1.0814125	2.5211305	10.08452
21521	1915	1.3767985	1.1246725	2.501471	10.00588
21521	1930	1.35288675	1.082214	2.43510075	9.740403
21521	1945	1.34903525	1.0514095	2.40044475	9.601779
21521	2000	1.43052525	0.845336	2.27586125	9.103445
21521	2015	1.41869225	0.83207975	2.250772	9.003088
21521	2030	1.43850575	0.844025	2.28253075	9.130123
21521	2045	1.443301	0.8052365	2.2485375	8.99415
21521	2100	1.44773825	0.755758	2.20349625	8.813985
21521	2115	1.4594185	1.23136625	2.69078475	10.76314
21521	2130	1.4970285	1.2228935	2.719922	10.87969
21521	2145	1.4785315	1.20019875	2.67873025	10.71492
21521	2200	1.46851175	1.17616975	2.6446815	10.57873
21521	2215	1.458014	1.12253925	2.58055325	10.32221
21521	2230	1.44650925	1.08600025	2.5325095	10.13004

21521	2245	1.4154715	1.0783955	2.493867	9.975468
21521	2300	1.47827175	0.7837785	2.26205025	9.048201
21521	2315	1.463373	0.8300755	2.2934485	9.173794
21521	2330	1.41971625	0.81848375	2.2382	8.9528
21521	2345	1.4494665	0.813302	2.2627685	9.051074
21521	2400	1.4319465	0.7912855	2.223232	8.892928
Grand Total		**134.1362643**	**96.1378075**	**230.2740718**	

RECORDER ID	DATE	HOUR	MWh
ETP TOT	21521	15	6.766348
ETP TOT	21521	30	4.888303
ETP TOT	21521	45	4.966107
ETP TOT	21521	100	5.589696
ETP TOT	21521	115	4.145684
ETP TOT	21521	130	1.895462
ETP TOT	21521	145	1.92468
ETP TOT	21521	200	1.942868
ETP TOT	21521	215	1.934288
ETP TOT	21521	230	1.876991
ETP TOT	21521	245	1.858927
ETP TOT	21521	300	1.832158
ETP TOT	21521	315	1.798359
ETP TOT	21521	330	1.800316
ETP TOT	21521	345	1.785281
ETP TOT	21521	400	1.793333
ETP TOT	21521	415	1.794534
ETP TOT	21521	430	1.778684
ETP TOT	21521	445	1.789618
ETP TOT	21521	500	1.771023
ETP TOT	21521	515	1.753544
ETP TOT	21521	530	1.756084
ETP TOT	21521	545	1.824051
ETP TOT	21521	600	1.661437
ETP TOT	21521	615	0.627388
ETP TOT	21521	630	0.625253
ETP TOT	21521	645	0.652384
ETP TOT	21521	700	0.625813
ETP TOT	21521	715	0.6728
ETP TOT	21521	730	0.6746
ETP TOT	21521	745	0.634634
ETP TOT	21521	800	0.642177
ETP TOT	21521	815	0.705104
ETP TOT	21521	830	0.690847
ETP TOT	21521	845	0.672107
ETP TOT	21521	900	0.666976
ETP TOT	21521	915	0.727509
ETP TOT	21521	930	0.728513
ETP TOT	21521	945	0.614938
ETP TOT	21521	1000	0.481359
ETP TOT	21521	1015	0.522814
ETP TOT	21521	1030	0.654528
ETP TOT	21521	1045	0.739772
ETP TOT	21521	1100	0.777804
ETP TOT	21521	1115	0.723588
ETP TOT	21521	1130	0.674586

ETP TOT	21521	1145	0.687723
ETP TOT	21521	1200	0.693798
ETP TOT	21521	1215	0.694345
ETP TOT	21521	1230	0.73857
ETP TOT	21521	1245	0.738733
ETP TOT	21521	1300	0.742066
ETP TOT	21521	1315	0.758631
ETP TOT	21521	1330	0.779401
ETP TOT	21521	1345	0.789548
ETP TOT	21521	1400	0.890577
ETP TOT	21521	1415	0.930902
ETP TOT	21521	1430	0.985389
ETP TOT	21521	1445	1.000656
ETP TOT	21521	1500	1.012191
ETP TOT	21521	1515	1.037822
ETP TOT	21521	1530	1.069061
ETP TOT	21521	1545	1.06887
ETP TOT	21521	1600	1.045287
ETP TOT	21521	1615	1.059369
ETP TOT	21521	1630	1.14897
ETP TOT	21521	1645	1.071284
ETP TOT	21521	1700	1.147272
ETP TOT	21521	1715	1.127738
ETP TOT	21521	1730	1.206037
ETP TOT	21521	1745	1.17287
ETP TOT	21521	1800	1.187422
ETP TOT	21521	1815	1.146512
ETP TOT	21521	1830	1.184622
ETP TOT	21521	1845	1.393882
ETP TOT	21521	1900	1.439718
ETP TOT	21521	1915	1.376799
ETP TOT	21521	1930	1.352887
ETP TOT	21521	1945	1.349035
ETP TOT	21521	2000	1.430525
ETP TOT	21521	2015	1.418692
ETP TOT	21521	2030	1.438506
ETP TOT	21521	2045	1.443301
ETP TOT	21521	2100	1.447738
ETP TOT	21521	2115	1.459419
ETP TOT	21521	2130	1.497029
ETP TOT	21521	2145	1.478532
ETP TOT	21521	2200	1.468512
ETP TOT	21521	2215	1.458014
ETP TOT	21521	2230	1.446509
ETP TOT	21521	2245	1.415472
ETP TOT	21521	2300	1.478272
ETP TOT	21521	2315	1.463373

ETP TOT	21521	2330	1.419716
ETP TOT	21521	2345	1.449467
ETP TOT	21521	2400	1.431947
PAWNEE TOT	21521	15	4.279527
PAWNEE TOT	21521	30	4.237303
PAWNEE TOT	21521	45	4.310475
PAWNEE TOT	21521	100	4.272904
PAWNEE TOT	21521	115	3.563862
PAWNEE TOT	21521	130	2.166005
PAWNEE TOT	21521	145	2.163968
PAWNEE TOT	21521	200	1.978106
PAWNEE TOT	21521	215	0.753066
PAWNEE TOT	21521	230	0.754366
PAWNEE TOT	21521	245	0.77795
PAWNEE TOT	21521	300	0.817875
PAWNEE TOT	21521	315	0.857772
PAWNEE TOT	21521	330	0.861693
PAWNEE TOT	21521	345	0.857577
PAWNEE TOT	21521	400	0.854645
PAWNEE TOT	21521	415	0.857727
PAWNEE TOT	21521	430	0.868371
PAWNEE TOT	21521	445	0.831654
PAWNEE TOT	21521	500	0.773928
PAWNEE TOT	21521	515	0.762908
PAWNEE TOT	21521	530	0.774921
PAWNEE TOT	21521	545	0.773462
PAWNEE TOT	21521	600	0.814881
PAWNEE TOT	21521	615	0.795793
PAWNEE TOT	21521	630	0.704676
PAWNEE TOT	21521	645	0.625103
PAWNEE TOT	21521	700	0.728442
PAWNEE TOT	21521	715	0.74802
PAWNEE TOT	21521	730	0.724811
PAWNEE TOT	21521	745	0.708441
PAWNEE TOT	21521	800	0.551564
PAWNEE TOT	21521	815	0.32759
PAWNEE TOT	21521	830	0.323615
PAWNEE TOT	21521	845	0.367371
PAWNEE TOT	21521	900	0.388166
PAWNEE TOT	21521	915	0.373167
PAWNEE TOT	21521	930	0.274125
PAWNEE TOT	21521	945	0.709037
PAWNEE TOT	21521	1000	0.728505
PAWNEE TOT	21521	1015	0.726227
PAWNEE TOT	21521	1030	0.691807
PAWNEE TOT	21521	1045	0.66371
PAWNEE TOT	21521	1100	0.655642

PAWNEE TOT	21521	1115	0.653425
PAWNEE TOT	21521	1130	0.685883
PAWNEE TOT	21521	1145	0.382301
PAWNEE TOT	21521	1200	0.384898
PAWNEE TOT	21521	1215	0.386226
PAWNEE TOT	21521	1230	0.293452
PAWNEE TOT	21521	1245	0.540187
PAWNEE TOT	21521	1300	0.779443
PAWNEE TOT	21521	1315	0.743346
PAWNEE TOT	21521	1330	0.7603
PAWNEE TOT	21521	1345	0.910735
PAWNEE TOT	21521	1400	1.017653
PAWNEE TOT	21521	1415	0.774948
PAWNEE TOT	21521	1430	0.425827
PAWNEE TOT	21521	1445	0.506733
PAWNEE TOT	21521	1500	0.816223
PAWNEE TOT	21521	1515	1.012844
PAWNEE TOT	21521	1530	0.967132
PAWNEE TOT	21521	1545	0.954787
PAWNEE TOT	21521	1600	0.986804
PAWNEE TOT	21521	1615	1.016208
PAWNEE TOT	21521	1630	0.982163
PAWNEE TOT	21521	1645	0.991659
PAWNEE TOT	21521	1700	1.008853
PAWNEE TOT	21521	1715	0.874019
PAWNEE TOT	21521	1730	0.768794
PAWNEE TOT	21521	1745	0.805046
PAWNEE TOT	21521	1800	0.798109
PAWNEE TOT	21521	1815	0.721329
PAWNEE TOT	21521	1830	0.727958
PAWNEE TOT	21521	1845	1.10314
PAWNEE TOT	21521	1900	1.081413
PAWNEE TOT	21521	1915	1.124673
PAWNEE TOT	21521	1930	1.082214
PAWNEE TOT	21521	1945	1.05141
PAWNEE TOT	21521	2000	0.845336
PAWNEE TOT	21521	2015	0.83208
PAWNEE TOT	21521	2030	0.844025
PAWNEE TOT	21521	2045	0.805237
PAWNEE TOT	21521	2100	0.755758
PAWNEE TOT	21521	2115	1.231366
PAWNEE TOT	21521	2130	1.222894
PAWNEE TOT	21521	2145	1.200199
PAWNEE TOT	21521	2200	1.17617
PAWNEE TOT	21521	2215	1.122539
PAWNEE TOT	21521	2230	1.086
PAWNEE TOT	21521	2245	1.078396

PAWNEE TOT	21521	2300	0.783779
PAWNEE TOT	21521	2315	0.830076
PAWNEE TOT	21521	2330	0.818484
PAWNEE TOT	21521	2345	0.813302
PAWNEE TOT	21521	2400	0.791286

<u>EXHIBIT 8</u>

ercot

REAL-TIME MARKET STATEMENT

Participant Name **SOUTH TEXAS ELECTRIC CO OP INC (QSE)**
Participant ID **0038663322000**

SETTLEMENT SUMMARY

Statement ID **RTM_INITIAL_STATEMENT_20210215_0038663322000_I1**

Operating Day **02/15/2021**

Status	Version	Billed Amount	
RTM_INITIAL	1	($46,326,466.49)	
		Operating Day Total	($46,326,466.49)

▶ REAL-TIME ANCILLARY SERVICES	Billable Amt: ($1,519,780.80)
▶ BLACK START CAPACITY	Billable Amt: ($2,114.32)
▶ EMERGENCY OPERATIONS	Billable Amt: $0.00
▶ GENERATION RESOURCE BASE-POINT DEVIATION	Billable Amt: ($41,679.62)
▶ REAL-TIME CONGESTION REVENUE RIGHTS	Billable Amt: ($1,252,086.84)
▶ REAL-TIME ENERGY	Billable Amt: ($43,148,467.56)
▶ REAL-TIME REVENUE NEUTRALITY ALLOCATION	Billable Amt: ($368,752.87)
▶ RELIABILITY MUST-RUN	Billable Amt: $0.00
▶ RELIABILITY UNIT COMMITMENT	NO ACTIVITY
▶ VOLTAGE SUPPORT	Billable Amt: $0.00
▶ ADMINISTRATIVE FEES	Billable Amt: $6,415.52

Status	Version	Billed Amount	
RTM_INITIAL	1	($46,326,466.49)	
		Operating Day Total	($46,326,466.49)

EXHIBIT 8

ercot

REAL-TIME MARKET STATEMENT

Participant Name **SOUTH TEXAS ELECTRIC CO OP INC (QSE)**
Participant ID **0038663322000**

SETTLEMENT SUMMARY

Statement ID **RTM_RESETTLEMENT_STATEMENT_20210215_0038663322000_R2**

Operating Day **02/15/2021**

Status	Version	Billed Amount	
RTM_INITIAL	1	($46,326,466.49)	
RTM_RESETTLEMENT	2	($35,495.43)	
		Operating Day Total	($46,361,961.92)

REAL-TIME ANCILLARY SERVICES	Billable Amt: ($30,033.31)
BLACK START CAPACITY	Billable Amt: ($0.21)
EMERGENCY OPERATIONS	Billable Amt: $0.00
GENERATION RESOURCE BASE-POINT DEVIATION	Billable Amt: $43.60
REAL-TIME CONGESTION REVENUE RIGHTS	Billable Amt: $0.00
REAL-TIME ENERGY	Billable Amt: $0.00
REAL-TIME REVENUE NEUTRALITY ALLOCATION	Billable Amt: ($5,505.51)
RELIABILITY MUST-RUN	Billable Amt: $0.00
RELIABILITY UNIT COMMITMENT	NO ACTIVITY
VOLTAGE SUPPORT	Billable Amt: $0.00
ADMINISTRATIVE FEES	Billable Amt: $0.00

Status	Version	Billed Amount	
RTM_INITIAL	1	($46,326,466.49)	
RTM_RESETTLEMENT	2	($35,495.43)	
		Operating Day Total	($46,361,961.92)

EXHIBIT 8

ercot

REAL-TIME MARKET STATEMENT

Participant Name SOUTH TEXAS ELECTRIC CO OP INC (QSE)
Participant ID 0038663322000

SETTLEMENT SUMMARY

Statement ID RTM_FINAL_STATEMENT_20210215_0038663322000_F3

Operating Day **02/15/2021**

Status	Version	Billed Amount	
RTM_INITIAL	1	($46,326,466.49)	
RTM_RESETTLEMENT	2	($35,495.43)	
RTM_FINAL	3	$193,907.32	
		Operating Day Total	($46,168,054.60)

▶ REAL-TIME ANCILLARY SERVICES	Billable Amt: $214,236.66
▶ BLACK START CAPACITY	Billable Amt: ($0.21)
▶ EMERGENCY OPERATIONS	Billable Amt: $0.00
▶ GENERATION RESOURCE BASE-POINT DEVIATION	Billable Amt: $48.11
▶ REAL-TIME CONGESTION REVENUE RIGHTS	Billable Amt: $0.00
▶ REAL-TIME ENERGY	Billable Amt: $0.00
▶ REAL-TIME REVENUE NEUTRALITY ALLOCATION	Billable Amt: ($20,377.24)
▶ RELIABILITY MUST-RUN	Billable Amt: $0.00
▶ RELIABILITY UNIT COMMITMENT	NO ACTIVITY
▶ VOLTAGE SUPPORT	Billable Amt: $0.00
▶ ADMINISTRATIVE FEES	Billable Amt: $0.00

Status	Version	Billed Amount	
RTM_INITIAL	1	($46,326,466.49)	
RTM_RESETTLEMENT	2	($35,495.43)	
RTM_FINAL	3	$193,907.32	
		Operating Day Total	($46,168,054.60)

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REAL-TIME MARKET STATEMENT

Participant Name **SOUTH TEXAS ELECTRIC CO OP INC (QSE)**
Participant ID **0038663322000**

SETTLEMENT SUMMARY

Statement ID **RTM_RESETTLEMENT_STATEMENT_20210215_0038663322000_R4**

Operating Day **02/15/2021**

Status	Version	Billed Amount	
RTM_INITIAL	1	($46,326,466.49)	
RTM_FINAL	3	$193,907.32	
RTM_RESETTLEMENT	2	($35,495.43)	
RTM_RESETTLEMENT	4	($114,089.43)	
		Operating Day Total	($46,282,144.03)

▶ REAL-TIME ANCILLARY SERVICES — Billable Amt: ($1,577.57)

▶ BLACK START CAPACITY — Billable Amt: $0.00

▶ EMERGENCY OPERATIONS — Billable Amt: $0.00

▶ GENERATION RESOURCE BASE-POINT DEVIATION — Billable Amt: ($162.45)

▶ REAL-TIME CONGESTION REVENUE RIGHTS — Billable Amt: ($1,006.73)

▶ REAL-TIME ENERGY — Billable Amt: ($110,486.62)

▶ REAL-TIME REVENUE NEUTRALITY ALLOCATION — Billable Amt: ($856.06)

▶ RELIABILITY MUST-RUN — Billable Amt: $0.00

▶ RELIABILITY UNIT COMMITMENT — NO ACTIVITY

▶ VOLTAGE SUPPORT — Billable Amt: $0.00

▶ ADMINISTRATIVE FEES — Billable Amt: $0.00

Status	Version	Billed Amount	
RTM_INITIAL	1	($46,326,466.49)	
RTM_FINAL	3	$193,907.32	
RTM_RESETTLEMENT	2	($35,495.43)	
RTM_RESETTLEMENT	4	($114,089.43)	
		Operating Day Total	($46,282,144.03)

EXHIBIT 9

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SETTLEMENT INVOICE

Invoice No:	**STL1083375**
Invoice Date:	**02/23/2021**
Payments are due to ERCOT by 5:00 P.M.	**02/25/2021**
Payments will be made to Invoice Recipients by 5:00 P.M.	**02/26/2021**
AMOUNT OWED (DUE):	**($174,097,110.05)**

INVOICE RECIPIENT

Name: **SOUTH TEXAS ELECTRIC CO OP INC (QSE)**

ID: **0038663322000**

CATEGORY	STATEMENT ID	OPERATING DAY	STATEMENT AMOUNT	SUBTOTAL
DAM Statements	DAM_STATEMENT_20210218_0038663322000_D1	02/18/2021	($55,750,630.56)	
	DAM_STATEMENT_20210219_0038663322000_D1	02/19/2021	($24,705,058.41)	
	DAM_STATEMENT_20210220_0038663322000_D1	02/20/2021	($8,736,240.79)	
	DAM_STATEMENT_20210221_0038663322000_D1	02/21/2021	($1,926,206.39)	
		DAM Statements Subtotal		**($91,118,136.15)**
Initial Statements	RTM_INITIAL_STATEMENT_20210215_0038663322000_I1	02/15/2021	($46,326,466.49)	
	RTM_INITIAL_STATEMENT_20210216_0038663322000_I1	02/16/2021	($26,054,746.87)	
	RTM_INITIAL_STATEMENT_20210217_0038663322000_I1	02/17/2021	($27,420,616.19)	
	RTM_INITIAL_STATEMENT_20210218_0038663322000_I1	02/18/2021	$16,822,675.86	
		Initial Statements Subtotal		**($82,979,153.69)**
Final Statements	RTM_FINAL_STATEMENT_20201227_0038663322000_F2	12/27/2020	$48.86	
	RTM_FINAL_STATEMENT_20201228_0038663322000_F2	12/28/2020	$59.92	
	RTM_FINAL_STATEMENT_20201229_0038663322000_F2	12/29/2020	$78.49	
	RTM_FINAL_STATEMENT_20201230_0038663322000_F2	12/30/2020	($4.69)	
		Final Statements Subtotal		**$182.58**
True-Up Statements	RTM_TRUEUP_STATEMENT_20200824_0038663322000_T3	08/24/2020	($0.56)	
	RTM_TRUEUP_STATEMENT_20200825_0038663322000_T3	08/25/2020	($0.40)	
	RTM_TRUEUP_STATEMENT_20200826_0038663322000_T3	08/26/2020	($1.37)	
	RTM_TRUEUP_STATEMENT_20200827_0038663322000_T3	08/27/2020	($0.46)	
		True-Up Statements Subtotal		**($2.79)**
		NET AMOUNT OWED (DUE)		**($174,097,110.05)**

REMITTANCE INFORMATION

	ERCOT Account	**Recipient Account**
Account Name	ELECTRIC RELIABILITY COUNCIL OF TEXAS INC	SOUTH TEXAS ELECTRIC COOPERATIVE
Bank Name	JPMORGAN CHASE BANK	WELLS FARGO
ABA Routing Number	021000021	121000248
Account Number	09922895452	4201288479

Overdue Terms

In the event ERCOT does not receive your payment by close of bank business on the "Payments are due to ERCOT" date your credit standing with ERCOT may be affected and subject to review.

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SETTLEMENT INVOICE

Invoice No:	STL1088277
Invoice Date:	03/04/2021
Payments are due to ERCOT by 5:00 P.M.	03/08/2021
Payments will be made to Invoice Recipients by 5:00 P.M.	03/09/2021
AMOUNT OWED (DUE):	**($41,717.24)**

INVOICE RECIPIENT

Name: **SOUTH TEXAS ELECTRIC CO OP INC (QSE)**

ID: **0038663322000**

CATEGORY	STATEMENT ID	OPERATING DAY	STATEMENT AMOUNT	SUBTOTAL
DAM Statements	DAM_STATEMENT_20210302_0038663322000_D1	03/02/2021	$85,258.53	
		DAM Statements Subtotal		**$85,258.53**
Initial Statements	RTM_INITIAL_STATEMENT_20210227_0038663322000_I1	02/27/2021	($30,521.90)	
		Initial Statements Subtotal		**($30,521.90)**
Final Statements	RTM_FINAL_STATEMENT_20210108_0038663322000_F2	01/08/2021	($4.11)	
		Final Statements Subtotal		**($4.11)**
True-Up Statements	RTM_TRUEUP_STATEMENT_20200905_0038663322000_T3	09/05/2020	($0.05)	
		True-Up Statements Subtotal		**($0.05)**
RTM Resettlement Statements	RTM_RESETTLEMENT_STATEMENT_20210215_0038663322000_R2	02/15/2021	($35,495.43)	
	RTM_RESETTLEMENT_STATEMENT_20210216_0038663322000_R2	02/16/2021	($60,954.28)	
		RTM Resettlement Statements Subtotal		**($96,449.71)**
		NET AMOUNT OWED (DUE)		**($41,717.24)**

REMITTANCE INFORMATION

	ERCOT Account	**Recipient Account**
Account Name	ELECTRIC RELIABILITY COUNCIL OF TEXAS INC	SOUTH TEXAS ELECTRIC COOPERATIVE
Bank Name	JPMORGAN CHASE BANK	WELLS FARGO
ABA Routing Number	021000021	121000248
Account Number	09922895452	4201288479

Overdue Terms

In the event ERCOT does not receive your payment by close of bank business on the "Payments are due to ERCOT" date your credit standing with ERCOT may be affected and subject to review.

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SETTLEMENT INVOICE

Invoice No:	STL1107388
Invoice Date:	04/12/2021
Payments are due to ERCOT by 5:00 P.M.	04/14/2021
Payments will be made to Invoice Recipients by 5:00 P.M.	04/15/2021
AMOUNT OWED (DUE):	**($381,768.51)**

INVOICE RECIPIENT

Name: **SOUTH TEXAS ELECTRIC CO OP INC (QSE)**

ID: **0038663322000**

CATEGORY	STATEMENT ID	OPERATING DAY	STATEMENT AMOUNT	SUBTOTAL
DAM Statements	DAM_STATEMENT_20210408_0038663322000_D1	04/08/2021	$273,787.14	
		DAM Statements Subtotal		**$273,787.14**
Initial Statements	RTM_INITIAL_STATEMENT_20210405_0038663322000_I1	04/05/2021	$21,955.74	
	RTM_INITIAL_STATEMENT_20210406_0038663322000_I1	04/06/2021	($39,570.41)	
	RTM_INITIAL_STATEMENT_20210407_0038663322000_I1	04/07/2021	($344,863.44)	
		Initial Statements Subtotal		**($362,478.11)**
Final Statements	RTM_FINAL_STATEMENT_20210214_0038663322000_F4	02/14/2021	($24,096.66)	
	RTM_FINAL_STATEMENT_20210215_0038663322000_F3	02/15/2021	$193,907.32	
	RTM_FINAL_STATEMENT_20210216_0038663322000_F3	02/16/2021	($462,899.32)	
		Final Statements Subtotal		**($293,088.66)**
True-Up Statements	RTM_TRUEUP_STATEMENT_20201012_0038663322000_T3	10/12/2020	$16.60	
	RTM_TRUEUP_STATEMENT_20201013_0038663322000_T3	10/13/2020	$0.11	
	RTM_TRUEUP_STATEMENT_20201014_0038663322000_T3	10/14/2020	($5.59)	
		True-Up Statements Subtotal		**$11.12**
		NET AMOUNT OWED (DUE)		**($381,768.51)**

REMITTANCE INFORMATION

	ERCOT Account	**Recipient Account**
Account Name	ELECTRIC RELIABILITY COUNCIL OF TEXAS INC	SOUTH TEXAS ELECTRIC COOPERATIVE
Bank Name	JPMORGAN CHASE BANK	WELLS FARGO
ABA Routing Number	021000021	121000248
Account Number	09922895452	4201288479

Overdue Terms

In the event ERCOT does not receive your payment by close of bank business on the "Payments are due to ERCOT" date your credit standing with ERCOT may be affected and subject to review.

EXHIBIT 9

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SETTLEMENT INVOICE

Invoice No:	**STL1111644**
Invoice Date:	**04/20/2021**
Payments are due to ERCOT by 5:00 P.M.	**04/22/2021**
Payments will be made to Invoice Recipients by 5:00 P.M.	**04/23/2021**
AMOUNT OWED (DUE):	**($233,006.29)**

INVOICE RECIPIENT

Name:	**SOUTH TEXAS ELECTRIC CO OP INC (QSE)**
ID:	**0038663322000**

CATEGORY	STATEMENT ID	OPERATING DAY	STATEMENT AMOUNT	SUBTOTAL
DAM Statements	DAM_STATEMENT_20210416_0038663322000_D1	04/16/2021	$188,435.25	
	DAM_STATEMENT_20210417_0038663322000_D1	04/17/2021	($82,934.62)	
	DAM_STATEMENT_20210418_0038663322000_D1	04/18/2021	($242,319.58)	
		DAM Statements Subtotal		**($136,818.95)**
Initial Statements	RTM_INITIAL_STATEMENT_20210415_0038663322000_I1	04/15/2021	$17,977.81	
		Initial Statements Subtotal		**$17,977.81**
Final Statements	RTM_FINAL_STATEMENT_20210224_0038663322000_F2	02/24/2021	($99.66)	
		Final Statements Subtotal		**($99.66)**
True-Up Statements	RTM_TRUEUP_STATEMENT_20201022_0038663322000_T3	10/22/2020	$23.94	
		True-Up Statements Subtotal		**$23.94**
RTM Resettlement Statements	RTM_RESETTLEMENT_STATEMENT_20210215_0038663322000_R4	02/15/2021	($114,089.43)	
		RTM Resettlement Statements Subtotal		**($114,089.43)**
		NET AMOUNT OWED (DUE)		**($233,006.29)**

REMITTANCE INFORMATION

	ERCOT Account	**Recipient Account**
Account Name	ELECTRIC RELIABILITY COUNCIL OF TEXAS INC	SOUTH TEXAS ELECTRIC COOPERATIVE
Bank Name	JPMORGAN CHASE BANK	WELLS FARGO
ABA Routing Number	021000021	121000248
Account Number	09922895452	4201288479

Overdue Terms

In the event ERCOT does not receive your payment by close of bank business on the "Payments are due to ERCOT" date your credit standing with ERCOT may be affected and subject to review.

EXHIBIT 10

From: Krein, Steve
To: Clif Lange
Cc: Lucas Turner
Subject: RE: IDR Metering for NCLRs
Date: Tuesday, April 13, 2021 5:01:38 PM
Attachments: image003.png

Yes there is a requirement for IDR metering for the Load Resources. The IDR meter data is used to validate the telemetry for a Load Resource during normal operations (done at least annually). It also acts as a back-up in case we lose communications and or telemetry during an event.

Steve Krein
Demand Integration
2705 West Lake Drive
Taylor, Austin 76574
O: 512-248-6830 | M: 512-417-5742

From: Clif Lange [mailto:clif@stec.org]
Sent: Tuesday, April 13, 2021 4:52 PM
To: Krein, Steve <Steve.Krein@ercot.com>
Cc: Lucas Turner <lucas@stec.org>
Subject: IDR Metering for NCLRs

Hi Steve,

It's been a while since we've talked – I hope you're doing well.

We've noticed a few documents where there seems to exist a requirement for IDR metering for NCLRs, but we're not clear what that IDR data is used for. It looks like compliance scoring is based on telemetry, so we're not sure what the IDR requirement is used for. Can you enlighten us?

Thanks,

Clif Lange
South Texas Electric Coop., Inc.
2849 FM 447, PO Box 119
Nursery, TX 77976
office (361) 485-6206
mobile (361) 894-3465
fax (361) 580-1529

EXHIBIT 11

From: Krein, Steve
To: Roberts, Randy; Lucas Turner; Clawson, Bill
Cc: Data Loading and Aggregation; Demand Integration; Erin Lewis; Hunsucker, Brett
Subject: RE: South Texas Electric Cooperative Inc. (TDSP) - NOIE
Date: Wednesday, January 18, 2023 5:06:59 PM
Attachments: image003.png

CAUTION: THIS MESSAGE ORIGINATED FROM OUTSIDE OF STEC.
Do not open attachments or click links from an unknown or suspicious origin.

Monthly reads of the 15 minute IDR data is fine. We use the data to validate telemetry after the fact and also as a back-up should we have a failure in the telemetry data stream.

Steve Krein
Demand Integration
2705 West Lake Drive
Taylor, Austin 76574
O: 512-248-6830 | M: 512-417-5742

From: Roberts, Randy <Randy.Roberts@ercot.com>
Sent: Wednesday, January 18, 2023 9:50 AM
To: 'Lucas Turner' <lucas@stec.org>; Clawson, Bill <Bill.Clawson@ercot.com>; Krein, Steve <Steve.Krein@ercot.com>
Cc: Data Loading and Aggregation <DataLoadingandAggregation@ercot.com>; Demand Integration <DemandIntegration@ercot.com>; Erin Lewis <erin@stec.org>; Hunsucker, Brett <Brett.Hunsucker@ercot.com>
Subject: RE: South Texas Electric Cooperative Inc. (TDSP) - NOIE

Lucas,
I don't believe daily information is required. Adding Steve Krein so that he can provide their requirement?

Randy Roberts
Electric Reliability Council of Texas
Manager, Meter Data Loading & Aggregation
Office 512.248.3943 | Cell 512.913.7648

From: Lucas Turner <lucas@stec.org>
Sent: Wednesday, January 18, 2023 9:35 AM
To: Roberts, Randy <Randy.Roberts@ercot.com>; Clawson, Bill <Bill.Clawson@ercot.com>
Cc: Data Loading and Aggregation <DataLoadingandAggregation@ercot.com>; Demand Integration <DemandIntegration@ercot.com>; Erin Lewis <erin@stec.org>; Hunsucker, Brett <Brett.Hunsucker@ercot.com>
Subject: RE: South Texas Electric Cooperative Inc. (TDSP) - NOIE

******* EXTERNAL Email *******

Please be cautious and evaluate before you click on links, open attachments, or provide credentials.

Randy,

Is the submission interval requirement daily still since this is just for validation of telemetry on non-settlement ESIID? This is just a different meter data communication for STEC, thus the questions.

Thanks.
Lucas Turner
STEC QSE
361.212.6308

From: Roberts, Randy <Randy.Roberts@ercot.com>
Sent: Tuesday, January 17, 2023 8:40 AM
To: Lucas Turner <lucas@stec.org>; Clawson, Bill <Bill.Clawson@ercot.com>
Cc: Data Loading and Aggregation <DataLoadingandAggregation@ercot.com>; Demand Integration <DemandIntegration@ercot.com>; Erin Lewis <erin@stec.org>; Hunsucker, Brett <Brett.Hunsucker@ercot.com>
Subject: RE: South Texas Electric Cooperative Inc. (TDSP) - NOIE

CAUTION: THIS MESSAGE ORIGINATED FROM OUTSIDE OF STEC.
Do not open attachments or click links from an unknown or suspicious origin.

These will need to be submitted in the same format as all other ESI IDs.

Randy Roberts
Electric Reliability Council of Texas
Manager, Meter Data Loading & Aggregation
Office 512.248.3943 | Cell 512.913.7648

From: Lucas Turner <lucas@stec.org>
Sent: Monday, January 16, 2023 8:33 AM
To: Clawson, Bill <Bill.Clawson@ercot.com>
Cc: Data Loading and Aggregation <DataLoadingandAggregation@ercot.com>; Demand Integration <DemandIntegration@ercot.com>; Erin Lewis <erin@stec.org>; Hunsucker, Brett <Brett.Hunsucker@ercot.com>
Subject: RE: South Texas Electric Cooperative Inc. (TDSP) - NOIE

Good morning, ERCOT.

A couple of new Load Resources (ESIIDs 1017583M8611JARDINI and 1017583M8611JARDINII) require data submission to you all. These are slightly different than our current Load Resources at ETP_LD1-4 and PAWNEE_LD1. Attached is an example of what we were thinking of providing. Is this acceptable since these two points are non-settlement ESIIDs? Please let us know of what format you require otherwise.

Thanks.
Lucas Turner
STEC
361.212.6308

From: Clawson, Bill <Bill.Clawson@ercot.com>
Sent: Monday, June 6, 2022 3:44 PM
To: Tomlin, Dale <Dale.Tomlin@ercot.com>
Cc: Data Loading and Aggregation <DataLoadingandAggregation@ercot.com>; Demand Integration <DemandIntegration@ercot.com>; Lucas Turner <lucas@stec.org>; Clif Lange <clif@stec.org>
Subject: RE: South Texas Electric Cooperative Inc. (TDSP) - NOIE

Since these are not used for wholesale settlements (NOIE load), there is no need to submit 0's.

Bill Clawson
Data Loading & Aggregation
mobile 254-913-0786

From: Tomlin, Dale <Dale.Tomlin@ercot.com>
Sent: Monday, June 6, 2022 3:40 PM
To: Clawson, Bill <Bill.Clawson@ercot.com>
Cc: Data Loading and Aggregation <DataLoadingandAggregation@ercot.com>
Subject: FW: South Texas Electric Cooperative Inc. (TDSP) - NOIE

Hello Bill,

The sites are not operational. Do they need to provide "0s" in the interim ?

Thanks Dale

From: Lucas Turner <lucas@stec.org>
Sent: Monday, June 6, 2022 3:37 PM
To: Tomlin, Dale <Dale.Tomlin@ercot.com>; Lange, Cliff <clif@stec.org>
Subject: RE: South Texas Electric Cooperative Inc. (TDSP) - NOIE

Hey Dale,

The sites are not yet operational as LRs. We are still in the works to get the meter data processing going to STEC to ERCOT.

Thanks.
Lucas Turner
STEC QSE
361.212.6308

From: Tomlin, Dale <Dale.Tomlin@ercot.com>
Sent: Monday, June 6, 2022 3:27 PM
To: Lucas Turner <lucas@stec.org>; Clif Lange <clif@stec.org>
Subject: FW: South Texas Electric Cooperative Inc. (TDSP) - NOIE

Hello Lucas and Clif,

Can you check on the meter reading for the ESIIDs 1017583M8611JARDINI and 1017583M8611JARDINII, ERCOT has not received any data for settlements.
If you units are off line or outage, please let us know.

Thanks Dale
Respectfully,

Dale W. Tomlin
Sr. Account Manager, ERCOT Client Services
Office: 512-248-6509 Mobile: 512-797-1900
dtomlin@ercot.com

From: Allen, James <James.Allen@ercot.com>
Sent: Monday, June 6, 2022 12:50 PM
To: Tomlin, Dale <Dale.Tomlin@ercot.com>
Cc: Allen, James <James.Allen@ercot.com>
Subject: FW: South Texas Electric Cooperative Inc. (TDSP) - NOIE

FYI

Thanks,

James Allen
Senior Market Operations Analyst
Office: 512-248-6466
jallen@ercot.com

From: Clawson, Bill <Bill.Clawson@ercot.com>
Sent: Monday, June 6, 2022 12:48 PM
To: Bolle, Steve <sbolle@stec.org>
Cc: Data Loading and Aggregation <DataLoadingandAggregation@ercot.com>; Allen, James <James.Allen@ercot.com>; Beaver, Ray <Ray.Beaver@ercot.com>; Demand Integration <DemandIntegration@ercot.com>; Melissa Reynolds <melissa@stec.org>; Holcombe, Ted <ted@stec.org>; Erin Lewis <erin@stec.org>; Lange, Cliff <clif@stec.org>; Lucas Turner <lucas@stec.org>; Rebecca Hauboldt <rebecca@stec.org>; Dotty Disanto <dottyd@stec.org>; Tabatha <tabatha@stec.org>; Derek J. Merta <dmerta@stec.org>
Subject: RE: South Texas Electric Cooperative Inc. (TDSP) - NOIE

FYI

No interval data has been received for ESIIDs 1017583M8611JARDINI and 1017583M8611JARDINII

Bill Clawson
Data Loading & Aggregation
mobile 254-913-0786

From: Clawson, Bill
Sent: Tuesday, March 1, 2022 12:40 PM
To: Bolle, Steve <sbolle@stec.org>

Cc: Data Loading and Aggregation <DataLoadingandAggregation@ercot.com>; Allen, James <James.Allen@ercot.com>; Beaver, Ray <Ray.Beaver@ercot.com>; Demand Integration <DemandIntegration@ercot.com>; Melissa Reynolds <melissa@stec.org>; Holcombe, Ted <ted@stec.org>; Erin Lewis <erin@stec.org>; Lange, Cliff <clif@stec.org>; Lucas Turner <lucas@stec.org>; Rebecca Hauboldt <rebecca@stec.org>; Dotty Disanto <dottyd@stec.org>; Tabatha <tabatha@stec.org>; Derek J. Merta <dmerta@stec.org>
Subject: FW: South Texas Electric Cooperative Inc. (TDSP) - NOIE

ESIIDs 1017583M8611JARDINI and 1017583M8611JARDINII are two LaaR NOIE ESIIDs for points behind NOIE Tie point metering (Medina Electric JARDIN tie point).

These ESIIDs with associated records (ESIID svc hist, channel, channel hist, and recorder) were added to ERCOT's settlement system with a start of 03/14/2022 so STEC may submit interval data.

NOTE: This data will not be used for data aggregation settlements (ESIIDs will not be associated with NOIE Ties nor Gen Sites).

Bill Clawson
Meter Data Loading & Aggregation

mobile 254-913-0786

From: MP Registration <MPRegistration@ercot.com>
Sent: Tuesday, March 1, 2022 11:19 AM
To: Data Loading and Aggregation <DataLoadingandAggregation@ercot.com>
Cc: Allen, James <James.Allen@ercot.com>
Subject: FW: South Texas Electric Cooperative Inc. (TDSP) - NOIE

Received: 3/1/22

- NOIE

Please see the attached.

Thank you,

Chelsea Menchaca
Regulatory Specialist
ERCOT Legal Department

Confidentiality Notice: The information contained in this email message and any attached documents may be privileged and confidential and is intended for the addressee only. If you received this message in error, please notify the sender immediately.

From: MP Registration
Sent: Tuesday, March 1, 2022 11:17 AM

To: Steve Bolle <sbolle@stec.org>
Cc: Melissa Reynolds <melissa@stec.org>; Holcombe, Ted <ted@stec.org>; Erin Lewis <erin@stec.org>; Lange, Cliff <clif@stec.org>; Lucas Turner <lucas@stec.org>; Rebecca Hauboldt <rebecca@stec.org>; Dotty Disanto <dottyd@stec.org>; Tabatha <tabatha@stec.org>; Derek J. Merta <dmerta@stec.org>
Subject: South Texas Electric Cooperative Inc. (TDSP) - NOIE

This will confirm receipt on March 1, 2022 of a NOIE Identification and Metering Point(s) Registration form. You will be notified if additional information is required.

Thank you,

Chelsea Menchaca
Regulatory Specialist
ERCOT Legal Department

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EXHIBIT 12

Control Number: 51812

Item Number: 2

Addendum StartPage: 0

PUBLIC UTILITY COMMISSION OF TEXAS
RECEIVED
FEB 17 2021
BY________
FILING CLERK

DeAnn T. Walker
Chairman

Arthur C. D'Andrea
Commissioner

Shelly Botkin
Commissioner

John Paul Urban
Executive Director

THE STATE OF TEXAS

Greg Abbott
Governor

Public Utility Commission of Texas

TO: **Central Records**

FROM: **Stephen Journeay**
Commission Counsel

DATE: **February 17, 2021**

RE: **Project 51812, *Issues Related to the State of Disaster for the February 2021 Winter Weather Event*, Governor's Disaster Proclamations**

Please file the following proclamations of Governor Abbott attached to this memorandum in the above referenced project.

Proclamation of February 21, 2021 declaring state of disaster in 254 counties.

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PROCLAMATION

BY THE

Governor of the State of Texas

TO ALL TO WHOM THESE PRESENTS SHALL COME:

I, GREG ABBOTT, Governor of the State of Texas, do hereby certify that severe winter weather poses an imminent threat of widespread and severe property damage, injury, and loss of life due to prolonged freezing temperatures, heavy snow, and freezing rain statewide.

THEREFORE, in accordance with the authority vested in me by Section 418.014 of the Texas Government Code, I do hereby declare a state of disaster in all 254 counties based on the existence of such threat.

Pursuant to Section 418.017 of the code, I authorize the use of all available resources of state government and of political subdivisions that are reasonably necessary to cope with this disaster.

Pursuant to Section 418 016 of the code, any regulatory statute prescribing the procedures for conduct of state business or any order or rule of a state agency that would in any way prevent, hinder, or delay necessary action in coping with this disaster shall be suspended upon written approval of the Office of the Governor. However, to the extent that the enforcement of any state statute or administrative rule regarding contracting or procurement would impede any state agency's emergency response that is necessary to protect life or property threatened by this declared disaster, I hereby authorize the suspension of such statutes and rules for the duration of this declared disaster.

In accordance with the statutory requirements, copies of this proclamation shall be filed with the applicable authorities.

IN TESTIMONY WHEREOF, I have hereunto signed my name and have officially caused the Seal of State to be affixed at my office in the City of Austin, Texas, this the 12th day of February, 2021.

Greg Abbott

GREG ABBOTT
Governor

FILED IN THE OFFICE OF THE
SECRETARY OF STATE
3:30 p.m. O'CLOCK
FEB 1 2 2021

ATTESTED BY:

RUTH R. HUGHS
Secretary of State

FILED IN THE OFFICE OF THE
SECRETARY OF STATE
3:30 pm O'CLOCK

FEB 12 2021

<u>EXHIBIT 13</u>

Control Number: 51812

Item Number: 7

Addendum StartPage: 0

PROJECT NO. 51812

ISSUES RELATED TO THE STATE OF DISASTER FOR THE FEBRUARY 2021 WINTER WEATHER EVENT	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER DIRECTING ERCOT TO TAKE ACTION AND GRANTING EXCEPTION TO ERCOT PROTOCOLS

Through this Order the Commission directs the Electric Reliability Council of Texas (ERCOT) to take certain actions and grants exception to provisions of the ERCOT Nodal Protocols and Operating Guides.

In an attempt to protect the overall integrity of the financial electric market in the ERCOT region, the Commission concludes it is necessary to authorize ERCOT to use its sole discretion in taking actions under the ERCOT Nodal Protocols to resolve financial obligations between a market participant and ERCOT. It is appropriate that ERCOT's discretion include, but not be limited to, ERCOT's ability to take the following actions:

- Deviate from protocol deadlines and timing related to settlements, collateral obligations, and invoice payments;
- Utilize available funds, such as undistributed congestion revenue right auction revenues, to cover short-paying invoice recipients;
- Relax credit requirements and releasing cash or other collateral to provide short-term market-participant liquidity;
- Deviate from protocol requirements regarding the maximum amount of default uplift invoices;
- Suspend breach notifications to certain market participants for failure to make payment or provide financial security; and
- Produce reconciliation settlements following market stabilization.

PURA § 39.151(d)[1] gives the Commission complete authority over ERCOT, the independent organization certified by the Commission under PURA § 39.151. In addition, ERCOT is required to "administer settlement and billing for services provided by ERCOT, including assessing creditworthiness of market participants and establishing and enforcing

[1] Public Utility Regulatory Act, Tex. Util. Code §§11.001–66.016.

reasonable security requirements in relation to their responsibilities under ERCOT rules."[2] Further, ERCOT must perform any additional duties required by commission order.[3]

This order does not relieve market participants of payment or financial security obligations with ERCOT. Moreover, market participants remain liable for all charges associated with any activity related to its relationship with ERCOT and any expenses arising from the consequences of termination of a market participant's agreements with ERCOT or revocation of the market participant's rights to conduct activities with ERCOT.

I. Orders

For the reasons discussed above, the Commission issues the following orders:

1. ERCOT must exercise its sole discretion to resolve financial obligations between a market participant and ERCOT as provided by this Order.

2. Any and all provision of the ERCOT Nodal Protocols are waived to the degree necessary to allow ERCOT to take the actions ordered herein.

3. ERCOT must report to the Commission twice each day, beginning February 22, 2021, of the the actions it has taken in response to this Order.

4. ERCOT must direct any questions regarding its obligations under this Order to the Commission's Deputy Executive Director or her designee..

---

[2] 16 Tex. Admin. Code § 25.361 (b)(2).

[3] *Id* § 25.361(b)(16).

Signed at Austin, Texas the 21st day of February 2021.

PUBLIC UTILITY COMMISSION OF TEXAS

DEANN T. WALKER, CHAIRMAN

ARTHUR C. D'ANDREA, COMMISSIONER

SHELLY BOTKIN, COMMISSIONER

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<u>EXHIBIT 14</u>

Control Number: 51812

Item Number: 164

Addendum StartPage: 0

ROJECT NO. 51812

ISSUES RELATED TO THE STATE OF	§	PUBLIC UTILITY COMMISSION
DISASTER FOR THE FEBRUARY 2021	§	
WINTER WEATHER EVENT	§	OF TEXAS

SECOND ORDER ADDRESSING ANCILLARY SERVICES

On February 12, 2021, in response to an extreme winter weather event, Governor Greg Abbott issued a Declaration of a State of Disaster for all counties in Texas. Further, on February 15, 2021, the Electric Reliability Council of Texas, Inc. (ERCOT) declared its highest state of emergency, an Energy Emergency Alert Level 3 (EEA3), due to exceptionally high electric demand exceeding limited supply. ERCOT remained in EEA3 through 9AM on February 19, 2021. During this period, ERCOT directed transmission operators in the ERCOT region to curtail more than 20,000 megawatts (MW) of firm load. These circumstances have affected and continue to affect various market activities.

During this period, the Commission's Independent Market Monitor (IMM),[1] Potomac Economics, closely monitored real-time market performance. After analyzing aspects of the market, the IMM submitted two recommendations to the Commission related to ancillary services.[2] The IMM's second recommendation was that the Commission order that the *failure to provide* settlement treatment be invoked for all ancillary services that were not provided in real time for ERCOT operating days February 14 through February 19, 2021.[3]

The IMM explained there were a number of instances during the cited operating days that an ancillary service was not provided because of forced outages or derates. The IMM noted the ERCOT operators typically mark the short ancillary service amounts and the ancillary-service payments are clawed back in settlement. However, during this winter event, the ERCOT operators

[1] *See* PURA § 39.1515.

[2] Letter from Carrie Bivens, Vice-President and ERCOT IMM Director of Potomac Economics to the Commissioners of the Public Utility Commission of Texas, March 1, 2021, filed in Project 51812 on March 1, 2021. IMM Letter.

[3] IMM Letter at 2.

1624

did not complete this marking task and the settlement process did not claw back ancillary-service payments for entities that did not meet an ancillary-service obligation.[4]

The IMM noted that nodal protocol revision request (NPRR) number 947 was intended to address this issue but was withdrawn. However, the Commission notes that, in the withdrawal request, it was stated that NPRR 947 "improves the process for identifying and charging QSEs for failed ancillary-service-supply-responsibility quantities, *processes currently exist to attain that* and can remain in place until implementation of real-time co-optimization."[5]

The IMM also stated in this second recommendation that section 6.4.9.1.3 of the ERCOT Nodal Protocols should be amended to better address this issue. This Commission does not act in this Order on that portion of the second recommendation.

The Commission issued an order on March 3, 2021 adopting the recommendation of the IMM. On March 5, the IMM filed a request for clarification of the Commission's order to make clear that the Commission was ordering the invocation of the *failure-to-provide* mechanism in the ERCOT Nodal Protocols.[6]

In accordance with the recommendation and requested clarification of the IMM, the Commission issues the following orders.

1. ERCOT must settle each qualified scheduling entity that failed on its ancillary service supply responsibility in accordance with ERCOT Nodal Protocol section 6.4.9.1.3, entitled *Replacement of Ancillary Service Due to Failure to Provide*, for a particular ancillary service for any hour of ERCOT's operating days February 14,2021 through February 19, 2021.

2. This Order supersedes and replaces the order addressing ancillary services dated March 3, 2021.

---

[4] IMM Letter at 2.

[5] NPRR947, Request for Withdrawal (Aug. 5, 2020) last accessed on March 3, 2021 from the ERCOT website at http://www.ercot.com/mktrules/issues/NPRR947#keydocs.

[6] IMM's Request for Clarification (Mar. 5, 2021).

Signed at Austin, Texas the 12th day of March 2021.

PUBLIC UTILITY COMMISSION OF TEXAS

ARTHUR C. D'ANDREA, CHAIRMAN

2013
q:\cadm\orders\misc.orders\5xxxx\51812 second order addressing anciliary service.docx

EXHIBIT 15

The Timeline and Events of the February 2021 Texas Electric Grid Blackouts

July 2021

The University of Texas at Austin
Energy Institute

The Timeline and Events of the February 2021 Texas Electric Grid Blackouts

A report by a committee of faculty and staff at The University of Texas at Austin

July 2021

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Josh D. Rhodes, *Research Associate, Department of Mechanical Engineering*
Jay Zarnikau, *Research Fellow, Department of Economics*

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Table of Contents

List of Figures

Chapter One

Chapter Two

Chapter Three

Appendix A

Appendix C

Appendix D

List of Tables

Executive Summary

Objective

This report recounts the factors contributing to disruptions in electricity and natural gas service in Texas during Winter Storm Uri, with a particular focus on blackouts on the Electric Reliability Council of Texas (ERCOT) grid during the period from February 15-18, 2021. Our goal is to create a common basis of fact to educate the debate over strategies to avoid similar problems in the future. We specifically limited the scope of this report to the events during February 2021, a comparison of the February 2021 event to the previous energy system disruptions in 1989 and 2011 during winter storms, and the economic consequences of the event in February 2021. An appendix describes the long-term evolution of the ERCOT electricity market and provides historical context.

This report is not intended to comprehensively address all issues stemming from such a complex event, but may inform subsequent assessments. This report does not recommend policies or solutions.

Data

To perform the analysis presented in this report, we reviewed a variety of public information sources, analyses conducted by the staff of ERCOT, testimony before state legislative committees, and public data archives provided by ERCOT. In addition, and through an agreement with the Public Utility Commission of Texas (PUCT), select members of our project team were provided access to certain confidential data collected by the PUCT and ERCOT pertaining to the performance of specific electric generating units, enrollment of energy consumers in ERCOT's Emergency Response Service program, communications regarding the winter storm, and other relevant information.[1] We also used a proprietary source of data to explore the performance of the natural gas industry during the event. We further considered and analyzed meteorological and other technical data that groups within the University of Texas at Austin (UT) have acquired for other research purposes.

Findings

The failure of the electricity and natural gas systems serving Texas before and during Winter Storm Uri in February 2021 had no single cause. While the 2021 storm did not set records for the lowest recorded temperatures in many parts of the state, it caused generation outages and a loss of electricity service to Texas customers several times more severe than winter events leading to electric service disruptions in December 1989 and February 2011. The 2021 event exceeded prior events with respect to both the number and capacity of generation unit outages, the maximum

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[1] Josh Rhodes and Carey King of the project team were provided access to the confidential data.

load shed (power demand reduction) and number of customers affected, the lowest experienced grid frequency (indicating a high level of grid instability), the amount of natural gas generation experiencing fuel shortages, and the duration of electric grid operations under emergency conditions associated with load shed and blackout for customers. The financial ramifications of the 2021 event are in the billions of dollars, likely orders of magnitude larger than the financial impacts of the 1989 and 2011 blackouts.

Factors contributing to the electricity blackouts of February 15-18, 2021 include the following:

- *All types of generation technologies failed*. All types of power plants were impacted by the winter storm. Certain power plants within each category of technologies (natural gas-fired power plants, coal power plants, nuclear reactors, wind generation, and solar generation facilities) failed to operate at their expected electricity generation output levels.
- *Demand forecasts for severe winter storms were too low.* ERCOT's most extreme winter scenario underestimated demand relative to what actually happened by about 9,600 MW, about 14%.
- *Weather forecasts failed to appreciate the severity of the storm.* Weather models were unable to accurately forecast the timing (within one to two days) and severity of extreme cold weather, including that from a polar vortex.
- *Planned generator outages were high, but not much higher than assumed in planning scenarios.* Total planned outage capacity was about 4,930 MW, or about 900 MW higher than in ERCOT's "Forecasted Season Peak Load" scenario.
- *Grid conditions deteriorated rapidly early in February 15 leading to blackouts.* So much power plant capacity was lost relative to the record electricity demand that ERCOT was forced to shed load to avoid a catastrophic failure. From noon on February 14 to noon on February 15, the amount of offline wind capacity increased from 14,600 MW to 18,300 MW (+3,700 MW).[2] Offline natural gas capacity increased from 12,000 MW to 25,000 MW (+13,000 MW). Offline coal capacity increased from 1,500 MW to 4,500 MW (+3,000 MW). Offline nuclear capacity increased from 0 MW to 1,300 MW, and offline solar capacity increased from 500 MW to 1100 MW (+600 MW), for a total loss of 24,600 MW in a single 24-hour period.

[2] For wind and solar electricity generation, nameplate capacity is not a meaningful measure of the amount of power generation expected when the unit is not experencing an outage, though nameplate capacity provides a meaningful metric for the thermal fleet of power plants (e.g., coal, nuclear, and natural gas-fired generating units). Using backcasted values of the available wind and solar radiation, available wind capacity outages actually decreased from 9,070 MW to 5,020 MW (-4,050) over the same time period and solar outages increased less, from 108 MW to 545 MW (+437 MW).

- *Power plants listed a wide variety of reasons for going offline throughout the event.* [3] Reasons for power plant failures include "weather-related" issues (30,000 MW, ~167 units), "equipment issues" (5,600 MW, 146 units), "fuel limitations" (6,700 MW, 131 units), "transmission and substation outages" (1,900 MW, 18 units), and "frequency issues" (1,800 MW, 8 units). [4]
- *Some power generators were inadequately weatherized; they reported a level of winter preparedness that turned out to be inadequate to the actual conditions experienced.* The outage, or derating, of several power plants occurred at temperatures above their stated minimum temperature ratings.
- *Failures within the natural gas system exacerbated electricity problems.* Natural gas production, storage, and distribution facilities failed to provide the full amount of fuel demanded by natural gas power plants. Failures included direct freezing of natural gas equipment and failing to inform their electric utilities of critical electrically-driven components. Dry gas production dropped 85% from early February to February 16, with up to 2/3 of processing plants in the Permian Basin experiencing an outage.[5]
- *Failures within the natural gas system began prior to electrical outages.* Days before ERCOT called for blackouts, natural gas was already being curtailed to some natural gas consumers, including power plants.
- *Some critical natural gas infrastructure was enrolled in ERCOT's emergency response program.* Data from market participants indicates that 67 locations (meters) were in both the generator fuel supply chain and enrolled in ERCOT's voluntary Emergency Response Service program (ERS), which would have cut power to them when those programs were called upon on February 15. At least five locations that later identified themselves to the electric utility as critical natural gas infrastructure were enrolled in the ERS program.
- *Natural gas in storage was limited.* Underground natural gas storage facilities were operating at maximum withdrawal rates and reached unprecedently-low levels of working gas, indicating that the storage system was pushed to its maximum capability.

The ERCOT system operator managed to avoid a catastrophic failure of the electric grid despite the loss of almost half of its generation capacity, including some black start units that would have been needed to jump-start the grid had it gone into a complete collapse.

---

[3] Some power plants experienced multiple outages and may be included in more than one category.

[4] The maximum values during the event are presented here for both capacity and numbers of units. Different categories may have experienced peak outage rates at different times.

[5] Based on our data sample of 27 natural gas processing plants.

Had one or more of the problems listed above not occurred, outages might still have occurred, but their duration and severity would likely have been lower. The magnitude of the failures caused unprecedented impacts:

- Rolling blackouts turned into persistent days-long electrical outages affecting millions of Texans connected to the ERCOT grid and leading to loss of life.
- The financial impacts were tremendous. According to PUCT data, natural gas prices, normally much less than $10/MMBTU, spiked to over $400/MMBTU at Texas trading hubs. Natural gas providers that were able to produce and transport gas reported windfall profits. Many financial sector firms that operate in the ERCOT energy market also reported large profits.
- The price of electricity spiked to $9,000 per MWh and stayed there by orders of the PUCT, which suspended some market price setting rules during the electricity blackouts. The PUCT stated that high prices were intended to ensure that generating units would participate in the market and that price-sensitive energy consumers would minimize their demand for electricity from the market. The PUCT also stated that the suspension of the rules was due to two reasons. First, to account for load that had been removed due to forced outages from the calculation of prices. Second, to avoid potentially even higher electricity prices that would result from the high price of natural gas.[6]
- The financial losers included power generators whose equipment failed, generators dependent upon natural gas that were unable to obtain the fuel or were unhedged to high natural gas prices, and load serving-entities (retail electric providers, municipal utility systems, and rural electric cooperatives) who were inadequately hedged.
- Many market participants defaulted on their payment obligations to ERCOT, which serves as a central counter-party in the markets for electrical energy and ancillary services that it administers. These defaults may translate into increased costs for electricity consumers in Texas for many years to come.

Disclaimers

This report was funded in part by the PUCT via an Interagency Agreement with the University of Texas at Austin (UT). Beyond funding, the Interagency Agreement between the PUCT and UT provided certain members of the research team, under a confidentiality agreement, with access to electricity market participant data and other confidential information collected by the PUCT and ERCOT. The PUCT reviewed a draft of this report to ensure that no confidential information was inadvertently disclosed. The committee had full discretion as to the content and presentation of material in the report.

---

[6] PUC Project No. 51617: Order Directing ERCOT to Take Action and Granting Exception to Commission Rules. February 15, 2021. https://interchange.puc.texas.gov/Documents/51617_3_1111656.PDF.

Any opinions or positions expressed in this report are those of the authors alone and do not reflect any official positions of the PUCT, ERCOT, the University of Texas at Austin, or the Board of Regents of the University of Texas.

1. Introduction

1.1 Objective

This report recounts the factors contributing to the disruptions in electricity and natural gas service in Texas during Winter Storm Uri, with a particular focus on the outages in electrical service in the Electric Reliability Council of Texas (ERCOT) power region during the period from February 15-18, 2021. In pursuing this report's objective, the Energy Institute at the University of Texas at Austin assembled a team of faculty and researchers to identify and review credible sources of data in an attempt to provide a factual account of what happened and what went wrong during the winter storm.

Our goal is not to provide recommendations, but to create a common basis of fact to educate the debate over policy changes under consideration as a response to the winter storm. We specifically limited the scope of this report to the events and economic impacts of February 2021, including a comparison to previous winter storm blackouts of 1989 and 2011. To provide additional historical context, we include an appendix that describes the long-term evolution of the ERCOT electricity market. This report is not intended to comprehensively address all issues stemming from such a complex event, but can inform future assessments.[7]

This report was funded in part by the Public Utility Commission of Texas (PUCT). Beyond funding, the Interagency Agreement between the PUCT and the University of Texas at Austin (UT) provided the research team with access to confidential electricity market information under a confidentiality agreement. The PUCT reviewed a draft of this report to ensure that no confidential information was inadvertently disclosed, but any views expressed are solely those of the authors and supporting committee members. The authors had full discretion as to the content and presentation of material in the report.

Various participants in the state's natural gas and electricity markets fund research at UT, and some contributors to this report have performed such funded research or provide consulting assistance to companies or organizations involved in the energy industry. Disclosures of any relationships that might be perceived to introduce a conflict of interest are available via the UT Energy Institute and at: https://energy.utexas.edu/ercot-blackout-2021.

[7] Other reports might include a more-comprehensive or focused analyses that might later be developed by the Federal Energy Regulatory Commissions (FERC), the North American Electric Reliability Corporation (NERC), the PUCT, or other government bodies.

1.2. Energy in Texas

Texas is the nation's leading state in electricity and natural gas in both production and consumption. Electricity is provided to the majority of the state's consumers through an intra-state grid, managed by ERCOT as an independent system operator, with limited interconnection to the other two main electrical grids serving the U.S. and Canada, as noted in Figure 1.a. Limited federal regulatory jurisdiction within the ERCOT power region has permitted the development of a unique electricity system involving competition among generators of electricity in the wholesale sector and "customer choice" or retail competition in some areas of the state which were served by vertically-integrated investor-owned utilities prior to 2001.

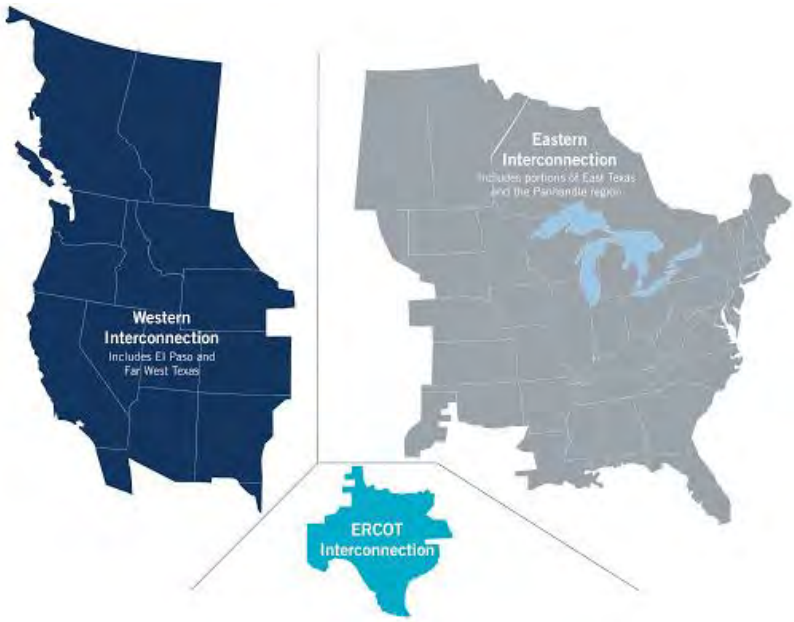

Figure 1.a. ERCOT in relation to the other two grid interconnections in the U.S. and Canada.[8]

Natural gas has long been the leading fuel for the generation of electricity in Texas, although the state has become a leader in the generation of electricity from renewable energy sources in recent years. Despite the interdependence of the state's natural gas and electricity industries, different state agencies have regulatory oversight over the two industries. While the PUCT oversees electricity services (and has regulatory oversight over certain aspects of water and telecommunications services), the natural gas sector is regulated by Texas Railroad Commission (RRC). The PUCT's oversight over the electricity industry includes responsibility for overseeing the operations of the electric grid operator, ERCOT. Appendix A provides

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[8] ERCOT: http://www.ercot.com/news/mediakit/maps, http://www.ercot.com/content/wcm/landing_pages/89373/ERCOT-Internconnection_Branded.jpg

additional information and historical context pertaining to the development and operation of ERCOT.

The following Chapter 2 reviews the physical aspects of the February 2021 event, examining conditions of the electricity and natural gas industries in the days prior and during the winter storm. Both the demand and supply sides of energy markets are discussed. Chapter 3 examines prices in electricity and natural gas markets, and the impact of the price spikes upon market participants in these industries. Chapter 4 contrasts the February 2021 event to previous winter events in 1989 and 2011 that prompted electrical outages. Chapter 5 provides a brief summary of this report.

2. Timeline of Events Related to February 2021 ERCOT Blackouts

We begin this chapter by recounting the electricity generating capacity anticipated in advance of the event, as suggested by winter resource adequacy analyses conducted by the ERCOT staff and updated information available to the market in the days prior to the event. Electric load forecasts and their underlying weather forecasts and assumptions are reviewed. Operational activities on the electric side are then discussed, including efforts by the grid operator, transmission and distribution providers, and others to constrain the demand for electricity. We conclude this chapter with a focus on natural gas operations before and during the event.

2.1. ERCOT's Winter 2020/2021 SARA report

ERCOT develops a Seasonal Assessment of Resource Adequacy (SARA)[9] report for each of the fall, winter, spring, and summer seasons that "focuses on the availability of sufficient operating reserves to avoid emergency actions such as the deployment of voluntary load reduction resources." Each SARA report is released one to two months before the season under study. In a SARA report, ERCOT assumes a set of hours at which the peak electricity demand will occur. For the winter, ERCOT assumes peak demand will occur between 7 am and 10 am. The winter 2020/2021 SARA report,[10] released on November 5, 2020, indicated that ERCOT's "Forecasted Season Peak Load" scenario expected that about 74,000 MW of net resource capacity[11] would be available to meet a winter peak of 57,699 MW. This includes an assumed *"… unit outage forecast of 8,616 MW during the winter months, which is based on historical winter outage data compiled since 2017*" (Figure 2.a). A quantity of Positive Reserves[12] (far right, green bar of Figure 2.a) above a few thousand megawatts indicates that, under this scenario, the chance of load shed (blackouts) was low. The report also noted that the previous (to 2021) all-time winter peak was 65,915 MW and occurred on January 17, 2018.

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[9] See: http://www.ercot.com/gridinfo/resource.

[10] SARA-FinalWinter2020-2021: http://www.ercot.com/content/wcm/lists/197378/SARA-FinalWinter2020-2021.xlsx

[11] Total Resources – Maintenance Outages – Forced Outages (82,513 MW – 4074 MW – 4542 MW = ~74,000 MW)

[12] Positive reserves refers to "Capacity Available for Operating Reserves."

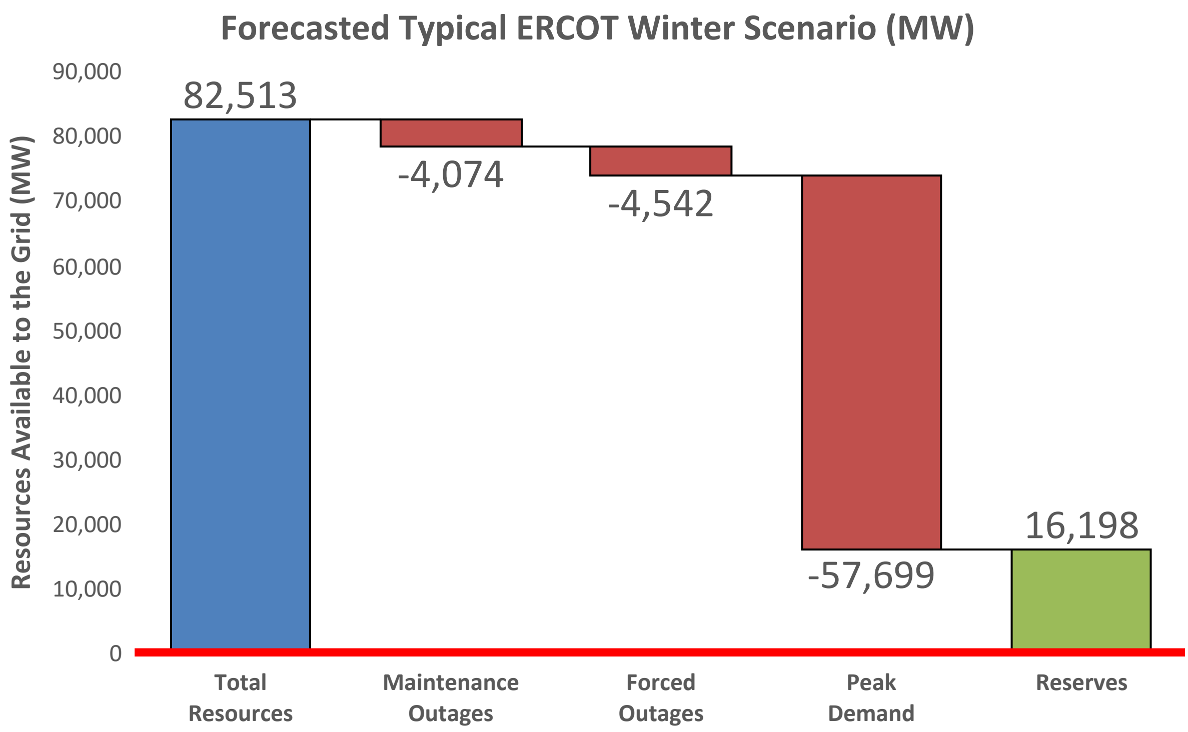

Figure 2.a. Waterfall chart of the ERCOT "Forecasted Season Peak Load" Winter 2020/2021 SARA scenario showing the total amount of Resources assumed for ERCOT as well as expected plant outages and peak demand. This scenario indicated that ERCOT would have over 16,000 MW of reserves, sufficient capacity to match supply and demand.

ERCOT's Winter 2020/2021 SARA scenario indicated the scenario that resulted in the least amount of reserve capacity was the "Extreme Peak Load / Extreme Generation Outages During Extreme Peak Load" scenario (Figure 2.b). This scenario assumed 67,208 MW load and 13,953 MW of thermal power plant outages, such that there would be only 1,352 MW of operating reserves. This level of reserves is below 2,300 MW, a level that ERCOT indicates is at risk of Energy Emergency Alert actions.[13] This "extreme" scenario did not assume any downward adjustments for low wind output, but ERCOT's "Extreme Low Wind Output" SARA scenario does assume a downward adjustment of 5,279 MW.

[13] http://www.ercot.com/content/wcm/lists/164134/EEA_OnePager_FINAL.PDF

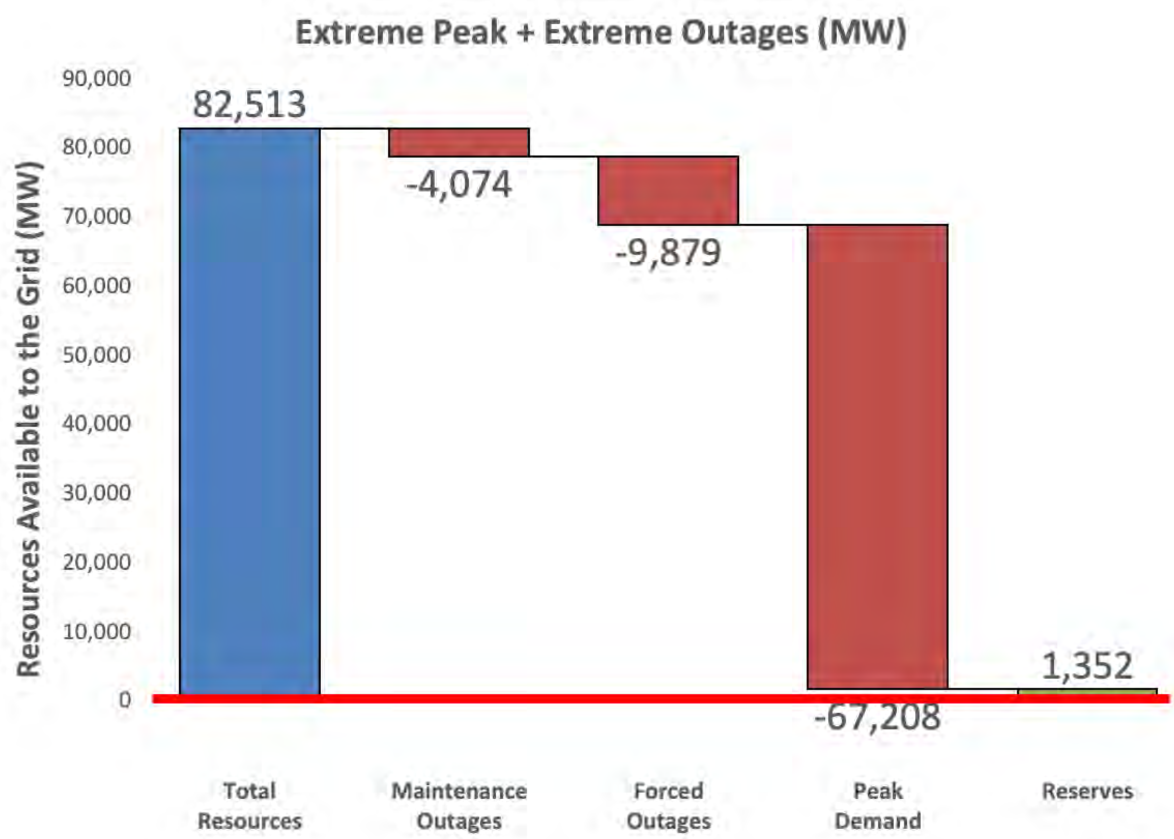

Figure 2.b. Waterfall chart of the ERCOT "Extreme Peak Load / Extreme Generation Outages During Extreme Peak Load" Winter 2020/2021 SARA scenario. This scenario indicated that ERCOT would have only 1,352 MW of reserves, insufficient capacity to prevent an Energy Emergency Alert.

Figure 2.c shows the shortfall of generation during the hour of the week of February 14, 2021 with the highest deficit in reserves. There were over 26,200 MW of forced thermal (i.e., natural gas, coal, nuclear, biomass) power plant outages, over 2.5 times the assumed worst case in any SARA report scenario.

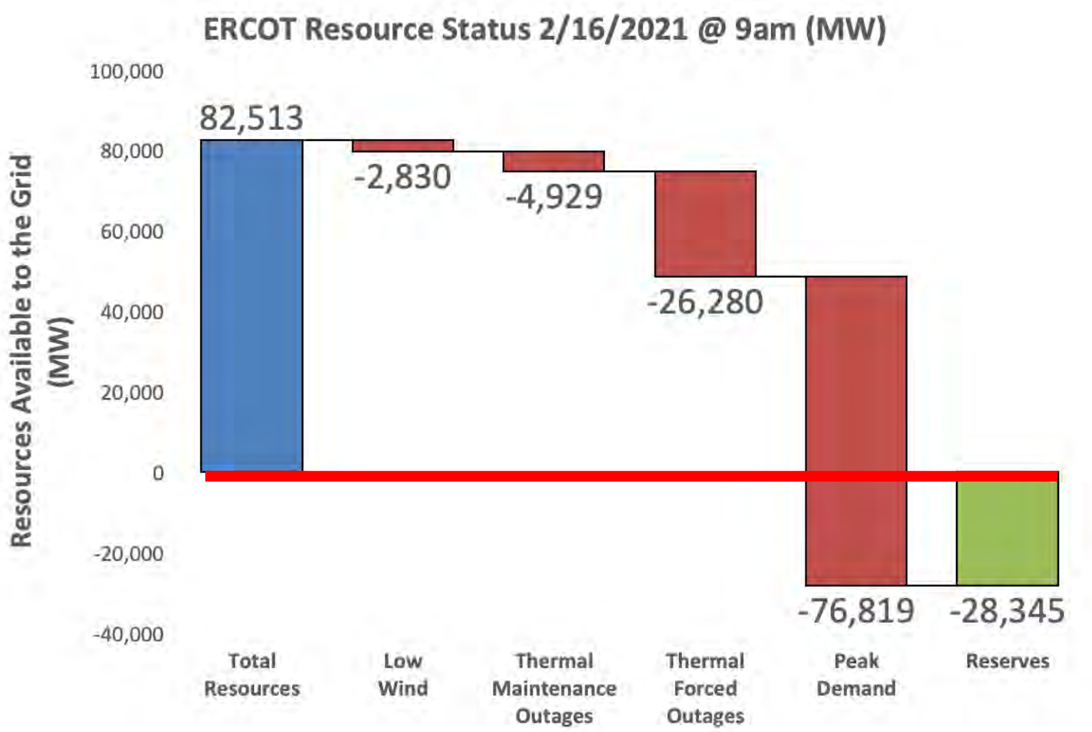

Figure 2.c. Waterfall chart of the actual resource availability at the time of peak demand (February 16, 2021 at 9 am) indicating a shortage of 28,345 MW in capacity due to lower than forecasted wind output, a higher capacity offline for maintenance, and over 26,000 MW of capacity triggered offline as instigated by the weather conditions.[14]

2.2. The Week Before Winter Storm Uri

2.2.1. Weather and Load Forecasts and Alerts

At the end of January, internal discussions between ERCOT's meteorologist and various planning groups began about a potential February cold weather event.[15] However, it wasn't until February 8 that the weather models used by the ERCOT staff began to show a worrisome event for the ERCOT service region. There is inherent uncertainty in the ability of weather models to forecast the timing and severity of extreme cold weather events, such as a polar vortex – even when it is known to be present in North America. As late as February 13, weather models used by ERCOT still disagreed on forecasted morning cold temperatures in Texas cities by as much as 10°F.

The discussion from the National Weather Service Houston/Galveston office provides a summary of the widespread nature of the winter storm.[16] The meteorological events unfolded as follows: A cold front moved in February 10, followed by a winter

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[14] The terms "Low Wind," "Thermal Maintenance Outages," and "Thermal Forced Outage" relate to those used in the Winter 2020/2021 ERCOT SARA report.

[15] We summarize these internal ERCOT weather-related communications in the Appendix.

[16] Available at https://www.weather.gov/hgx/2021ValentineStorm

weather advisory (WWA) on February 11, followed by a Winter Storm Watch (WSW) on February 12. From February 13 in the night through February 14, the weather worsened further and the entire state was under a WSW and a Hard Freeze Warning.

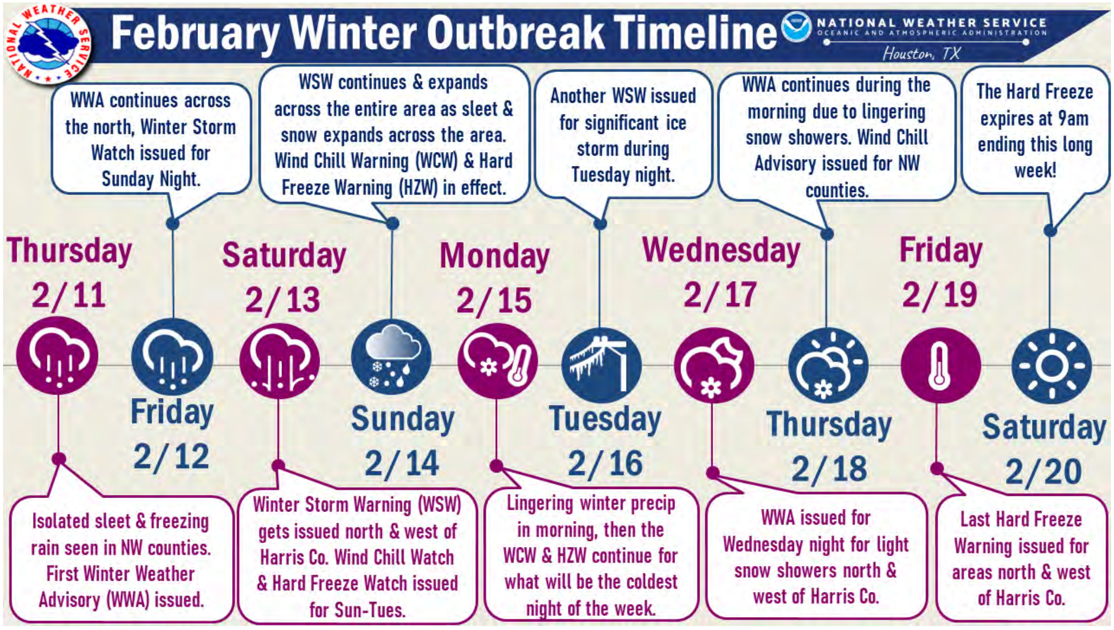

Figure 2.d. Timeline of weather conditions during event

The cold weather experienced was a result of a polar vortex that was impacting temperatures across the U.S. The Dallas/Ft. Worth National Weather Service reported:

> The record cold spell and extended period of wintry weather was caused by the upper-level polar vortex dropping south from the north pole and then lingering over South Central Canada for more than a week. This allowed cold arctic air to gradually spill southward into Texas. At the same time, several upper-level disturbances riding the jet stream moved through the area providing lift and moisture for winter precipitation. These disturbances show up as waves or dips in the lines that move in from the west. Ahead of each wave, upper-level lift increases and moisture is drawn up from the south. Since it was already so cold, this precipitation fell as snow, sleet, and freezing rain.[17]

Since the event was due to an evolving vortex situation, the meteorological community could provide warnings related to unusually cold temperatures towards the end of January. For example, on February 3, CNN's headline was "Every US State

[17] https://www.weather.gov/fwd/Feb-2021-WinterEvent.

will see below freezing temperatures over the next week," and mentioned "It's about to get so cold that boiling water will flash freeze, frostbite could occur within 30 minutes and it will become a shock to the system for even those who are used to the toughest winters."[18]

This nature of advance warning (from 7 to 14 days ahead of the event) is unusual. However, the southward migration of the polar vortex was being monitored and predicted by different weather forecast modeling systems in early January. The Washington Post had a report on January 5 titled "The polar vortex is splitting in two, which may lead to weeks of wild winter weather."[19]

In hindsight, while it is apparent that concerns regarding unusually cold winter events were flashing, it is important to note that the system inherently is difficult to predict. The same article highlights that: "The United States is slightly more of a winter wild card for now, experts say, with individual winter storms tough to predict beyond a few days in advance."

ERCOT's first Operating Conditions Notice[20] mentioning the approaching winter storm was on February 8, 2021 – a week before the first of the blackouts began. The notice asked generators to update their ability to provide power and review fuel supplies:

> At 18:53 [February 8, 2021], ERCOT is issuing an OCN for an extreme cold weather system approaching Thursday, February 11, 2021 through Monday, February 15, 2021 with temperatures anticipated to remain 32°F or below. QSEs are instructed to: Update COPs and HSLs when conditions change as soon [as] practicable, Review fuel supplies, prepare to preserve fuel to best serve peak load, and notify ERCOT of any known or anticipated fuel restrictions, Review Planned Resource outages and consider delaying maintenance or returning from outage early, Review and implement winterization procedures. Notify ERCOT of any changes or conditions that could affect system reliability.[21]

ERCOT subsequently issued both an extreme cold weather event advisory and a watch on February 10 and 11, respectively. On February 12, the Texas Governor declared a state of emergency due to the severity of the winter storm.[22]

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[18] https://www.cnn.com/2021/02/02/weather/polar-vortex-forecast-freezing-cold/index.html

[19] https://www.washingtonpost.com/weather/2021/01/05/polar-vortex-split-cold-snow/

[20] http://www.ercot.com/services/comm/mkt_notices/opsmessages/2021/02

[21] See ERCOT glossary: http://www.ercot.com/glossary. QSE: Qualified Scheduling Entity. COP: Current Operating Plan. HSL: High Sustainable Limit. OCN: Operating Condition Notice

[22] https://gov.texas.gov/uploads/files/press/DISASTER_severe_weather_FINAL_02-12-2021.pdf

On February 10th, as cold temperatures entered the ERCOT region, the total amount of offline power plant capacity increased from 14,400 MW to 25,850 MW, or about 12% to 21% of the total 123,050 MW of installed nameplate capacity in ERCOT. The term nameplate capacity refers to the maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer. Installed generator nameplate capacity is commonly expressed in megawatts (MW) and is usually indicated on a nameplate physically attached to the generator.[23] Nameplate capacity is different than the power output one expects from any given generation unit on average or at any given time when it operates in concert with all generation units in an electric grid.

Wind turbines suffered some of the earliest outages and derates as freezing precipitation and fog resulted in ice accumulation on blades and – eventually, as temperatures dropped further – in the gearboxes and nacelles. Unit-specific data indicate that other types of generators – mostly those fueled with natural gas – were facing pre-blackout fuel supply issues, and were starting to go offline or derate capacity as early as February 10 due to fuel delivery curtailments.

Because load projections are based on weather forecasts, uncertainty about the weather meant that ERCOT's load forecasts did not fully anticipate the spike in electricity demand that would result from the winter storm. As the winter event drew closer and its magnitude became clearer, forecast accuracy improved considerably.[24]

Figure 2.e depicts the hourly forecasts released to the market on February 8, 10, 12, and 14 for the ensuing seven days. For example, the forecast released at 8:30 a.m. on February 8 projected total system demand of 58,728 MW for 8 a.m. on February 15. ERCOT estimated that the actual demand would have been 75,573 MW had there been no load shed during that hour.[25] The forecast released on February 14 was considerably more accurate, though it remained 3,540 MW too low.

Figure 2.f shows the forecast error using ERCOT's estimate of the load had there been no load shed minus the forecasts released to the market at 8:30 a.m. on February 11, 12, 13, and 14 – a measure of how well ERCOT's load forecasts predicted the coming demand on the system. Forecasted electrical demands for the late night/early morning hours were the least accurate.

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[23] Energy Information Adminstration glossary definition of nameplate capacity: https://www.eia.gov/tools/glossary/index.php?id=G#gen_nameplate.

[24] Recent load forecasts are available at: www.ercot.com/gridinfo. An archive of past load forecasts was provided by ERCOT for the purpose of this analysis.

[25] http://www.ercot.com/content/wcm/lists/227689/Available_Generation_and_Estimated_Load_without_Load_Shed_Data.xlsx

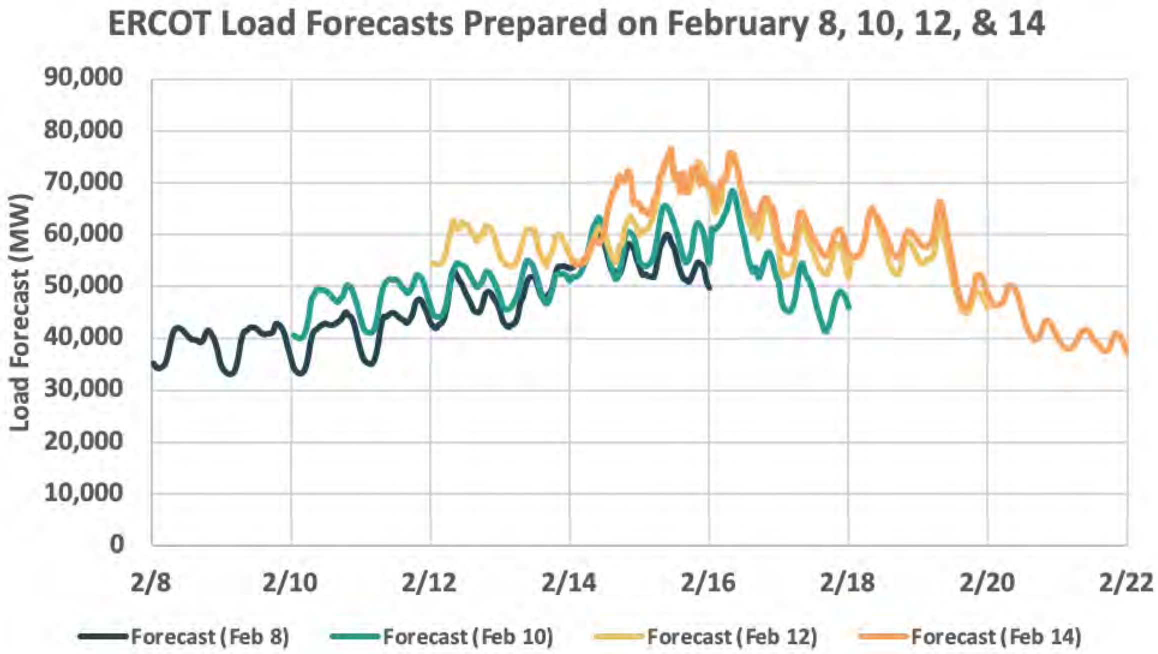

Figure 2.e. ERCOT 7-day (hourly resolution) load forecasts for February 8, 10, 12, and 14.

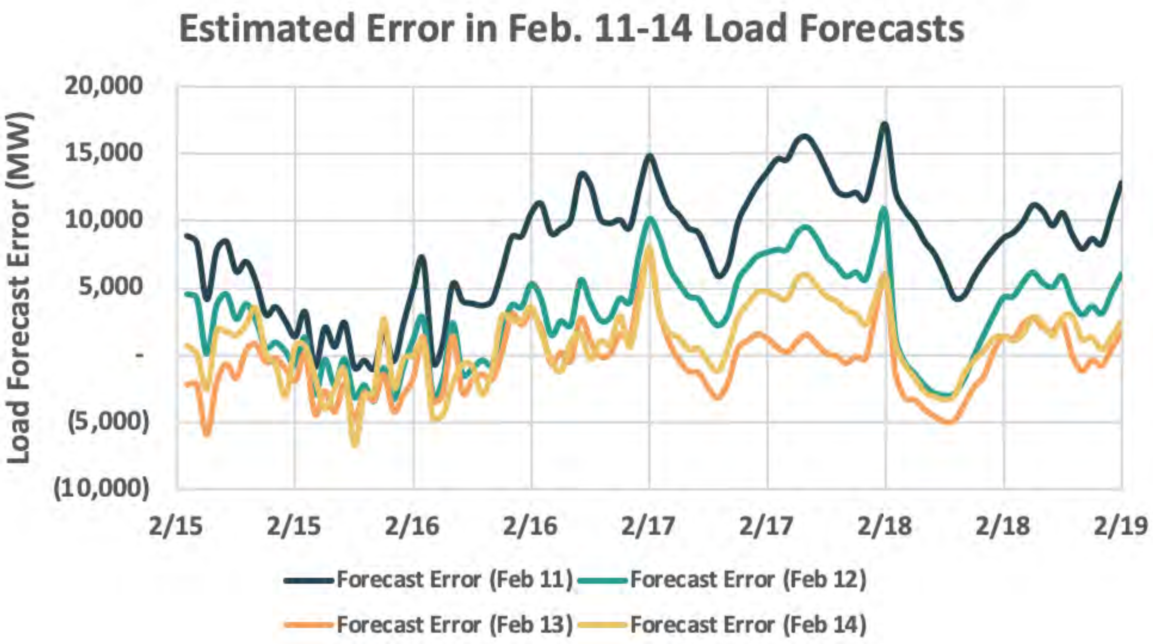

Figure 2.f. The error in ERCOT 7-day (hourly resolution) load forecasts made on February 11, 12, 13, and 14 compared to actual demand on the days of February 15-18, 2021.[26]

[26] Positive values represent the errors (in MW) of forecasts that were lower than actual demand.

The load forecasting error can be at least partially explained by errors in the weather forecasts upon which the electricity demand forecasts were based. Figure 2.g and Figure 2.h depict hourly temperature forecasts, for two of eight ERCOT weather zones, upon which the demand projections in Figure 2.e were presumably based.[27] The North Central zone includes Dallas and Fort Worth, while the South Central zone includes San Antonio and Austin.[28]

The forecast available to ERCOT on February 8 anticipated a low in North Central Texas of 20.5^{o}F at 4:00 a.m. on February 14, for the entire week of the winter event. The February 12 forecast was updated, and it was expected that the region would experience a low 20 degrees colder at just 0.5^{o}F at 6:00 a.m. on February 16.

The data for South Central Texas show a similar pattern. The February 8 forecast showed a low of 26^{o}F at 4:00 a.m. on February 14, for the entire week of the winter event. By February 12, a low of 9^{o}F was expected in the region at 5:00 a.m. on February 16.

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[27] Temperature data are available in the Market Information page on www.ercot.com. An archive of the "Weather Assumptions" file was obtained from ERCOT for this analysis.

[28] Note that ERCOT uses data from 29 weather stations. Each zone includes two or three weather stations. Thus, the temperature data discussed here do not correspond with a single weather station.

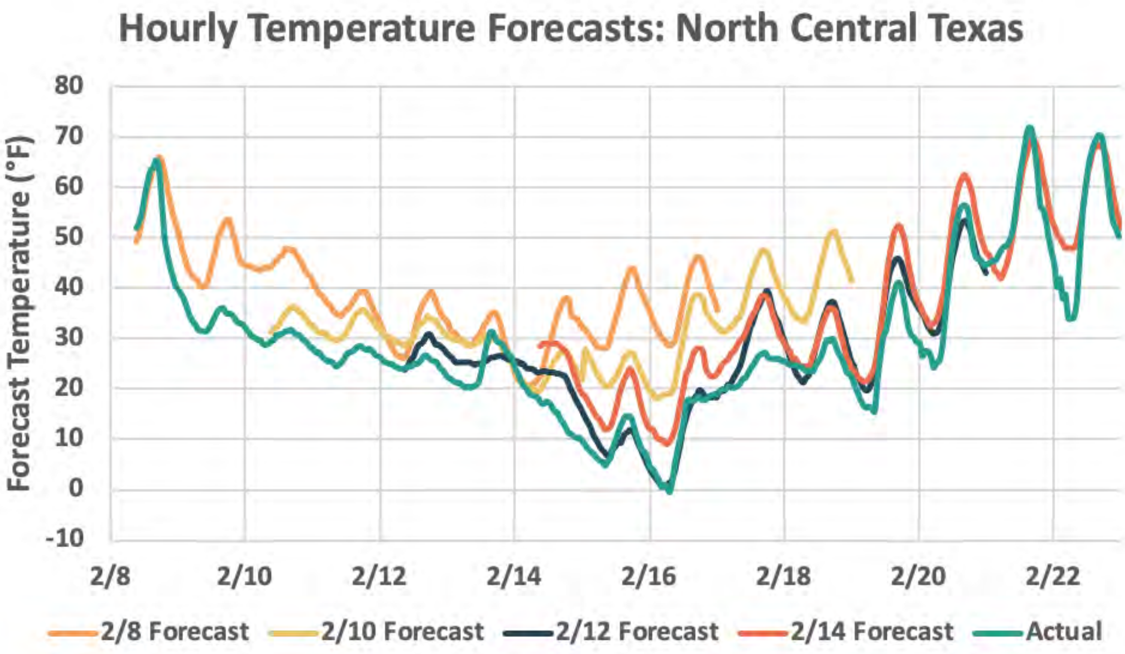

Figure 2.g. Temperature forecasts, as used by ERCOT, for the North Central Texas load region as of the mornings of February 8, 10, 12, and 14. Also shown are the ERCOT staff's calculations of the actual temperatures in the region.

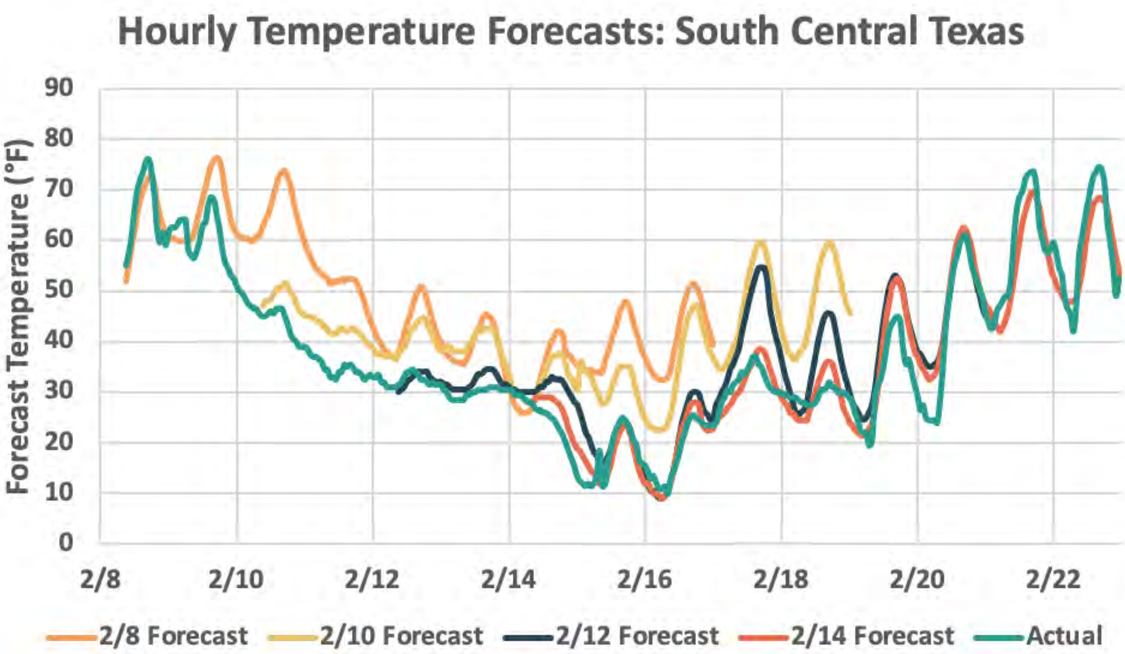

Figure 2.h. Temperature forecasts, as used by ERCOT, for the South-Central Texas load region as of the mornings of February 8, 10, 12, and 14 along with actual temperatures. Also shown are the ERCOT staff's calculations of the actual temperatures in the region.

2.2.2. Recall of Power Plant Outages for Maintenance

At the time (February 8) of ERCOT's first Operating Condition Notice, approximately 6,630 MW of thermal generation were offline for planned maintenance, corresponding to 2,550 MW above the level assumed in SARA scenario "Forecasted Season Peak Load." By the end of Sunday, February 14, about 1,700 MW of generation had been brought back online from either finished or cancelled maintenance, bringing the total planned outage value to 4,930 MW, about 900 MW higher than in the "Forecasted Season Peak Load" SARA scenario (Figure 2.a).

2.3. The Week of Winter Storm Uri (February 13-20, 2021)

On Saturday, February 13 ERCOT began to deploy Responsive Reserves[29] and issued an Emergency Notice for the extreme cold weather event impacting the region. February 13 was also the first day that large generators began to unexpectedly go offline. On Sunday, February 14, ERCOT issued a public appeal for energy conservation and issued multiple watches regarding power supply shortages (Figure 2.i).

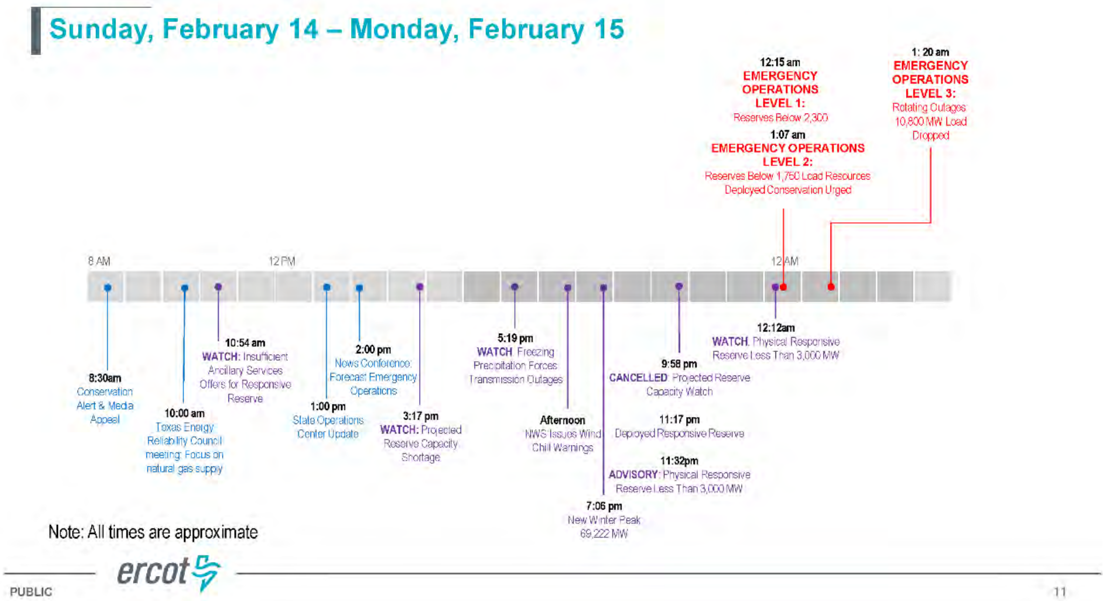

Figure 2.i. ERCOT communications and triggers of Energy Emergency Alerts in the hours leading up to the major load shedding events of the night of February 14 and early morning of February 15, 2021 (ERCOT, 2021).

During the late hours of February 14, electricity load, or demand, was approaching available generation. As generation could not sufficiently increase to meet demand,

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[29] Responsive Reserves are an Ancillary Service that provides operating reserves that is intended to: 1) arrest frequency decay within the first few seconds of a significant frequency deviation on the ERCOT Transmission Grid using Primary Frequency Response and interruptible Load; 2) after the first few seconds of a significant frequency deviation, help restore frequency to its scheduled value to return the system to normal; 3) provide energy or continued interruption of load during the implementation of the EEA; and 4) provide backup regulation.

the frequency of the grid began to decline.[30,31] In such circumstances, ERCOT begins various contingency plans such as calling on reserves and shedding load, and at low enough frequencies, automated load shed can occur.[32,33]

On Monday, February 15 at 00:15 CST, ERCOT declared an Energy Emergency Alert Level 1 (EEA 1), at 01:07 CST ERCOT moved to EEA 2,[34] and at 01:20 CST, ERCOT declared an EEA 3 event and began "firm load shed" or "blackouts."[35] ERCOT did not return to normal operations until 10:36 CST Friday, February 19. The ERCOT system frequency reached a low of 59.302 Hz at roughly 1:55am on February 15, 2021.

It is important to note that ERCOT protocols allow generators to automatically "trip" offline, or automatically shut down and disconnect from the grid, if the grid frequency drops to 59.4 Hz or below for more than 9 minutes (Table 2.a). This automatic shutdown lowers the risk of exposure to harmful vibrations and heat that can damage generation equipment if operating at low frequency for too long.[36] The ERCOT system frequency dropped below 59.4 Hz for 4 minutes and 23 seconds (Figure 2.j) on the morning of February 15. Consequently, the grid was within minutes of a much more serious and potentially complete blackout on the morning of February 15.

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[30] Electric grids operate using the principle known as alternating current, or AC. North American grids, including ERCOT, are designed for current and voltage to oscillate at a frequency of 60 cycles per second, or 60 Hz.

[31] If grid frequency falls below 59.9 Hz, this generally indicates that load is large relative to demand.

[32] ERCOT Nodal Operating guide, June 15, 2019 Section (http://www.ercot.com/content/wcm/libraries/182971/June_15__2019_Nodal_Operating_Guides.pdf) Section 2.6 Requirements for Under-Frequency and Over-Frequency Relaying, 2.6.1 Automatic Firm Load Shedding, paragraph (1)

[33] Importantly, ERCOT makes other non-automated (by engineering devices) decisions to trigger actions to stabilize the grid before grid frequency reaches 59.3 Hz (e.g., call on responsive reserve and non-spinning reserve capacity).

[34] See ERCOT glossary: http://www.ercot.com/glossary. EEA: Energy Emergency Alert

[35] http://www.ercot.com/services/comm/mkt_notices/opsmessages/2021/02

[36] About 1,800 MW of (mostly coal and natural gas) generators listed frequency issues as the reason for tripping offline during the winter event, even though, according to ERCOT protocols (Table 2.a of this report), the frequency deviation shouldn't have tripped any under-frequency relays that are designed to automatically disconnect the power plant from the grid to physically protect itself. However, at some power plants, rapid increases in exhaust and boiler pressures occurred from equipment responding to grid frequency changes. Those fluctuating power plant conditions in turn tripped other safety mechanisms that took generators offline. Some large thermal generation units require days to fully cool off before they can be restarted.

Table 2.a. Table from Section 2.6.2 of ERCOT Nodal Protocols indicating the allowed settings for under-frequency relays installed on Generation Resources.[37]

Frequency Range	Delay to Trip
Above 59.4 Hz	No automatic tripping (Continuous operation)
Above 58.4 Hz up to And including 59.4 Hz	Not less than 9 minutes
Above 58.0 Hz up to And including 58.4 Hz	Not less than 30 seconds
Above 57.5 Hz up to And including 58.0 Hz	Not less than 2 seconds
57.5 Hz or below	No time delay required

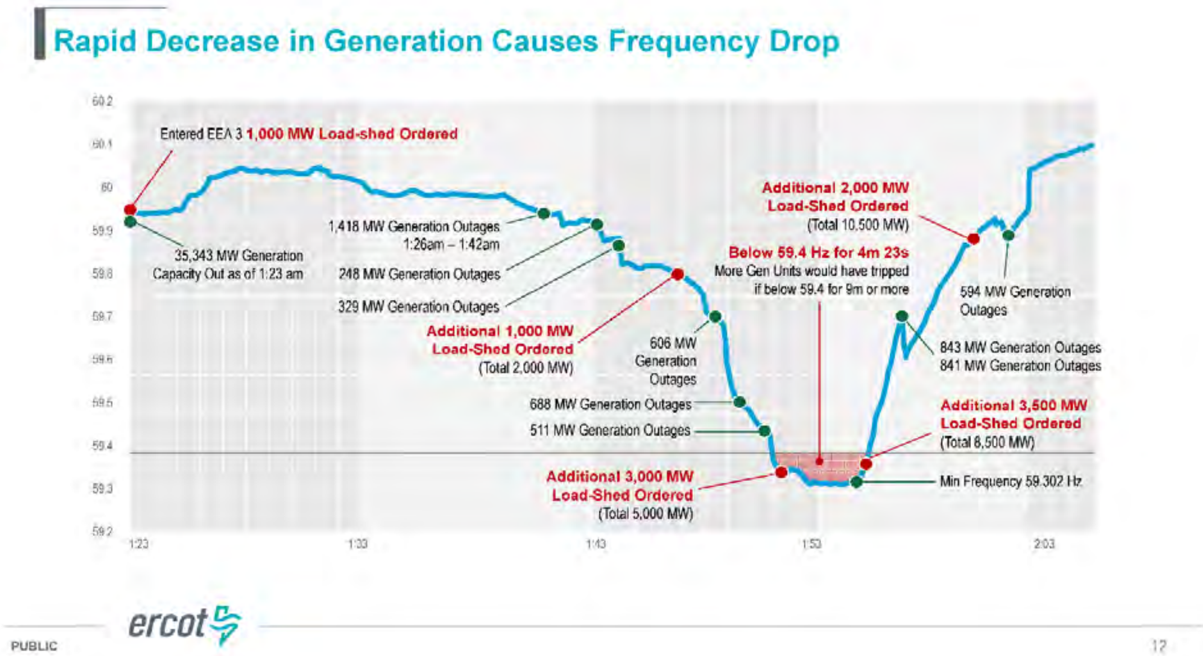

Figure 2.j. The ERCOT grid frequency during the critical time of load shedding and generation capacity outages on the morning of February 15, 2021 (ERCOT, 2021).

Figure 2.k shows the high level status of the grid from February 12 to February 20, including what load would have been absent blackouts, the actual served load, total renewable and thermal (nameplate) outages, as well as the level of load shed (blackouts).

[37] Note that we are presenting certain figures that were created by the ERCOT staff in this document, in situations where have been able to review and confirm the underlying data used in the creation of those figures.

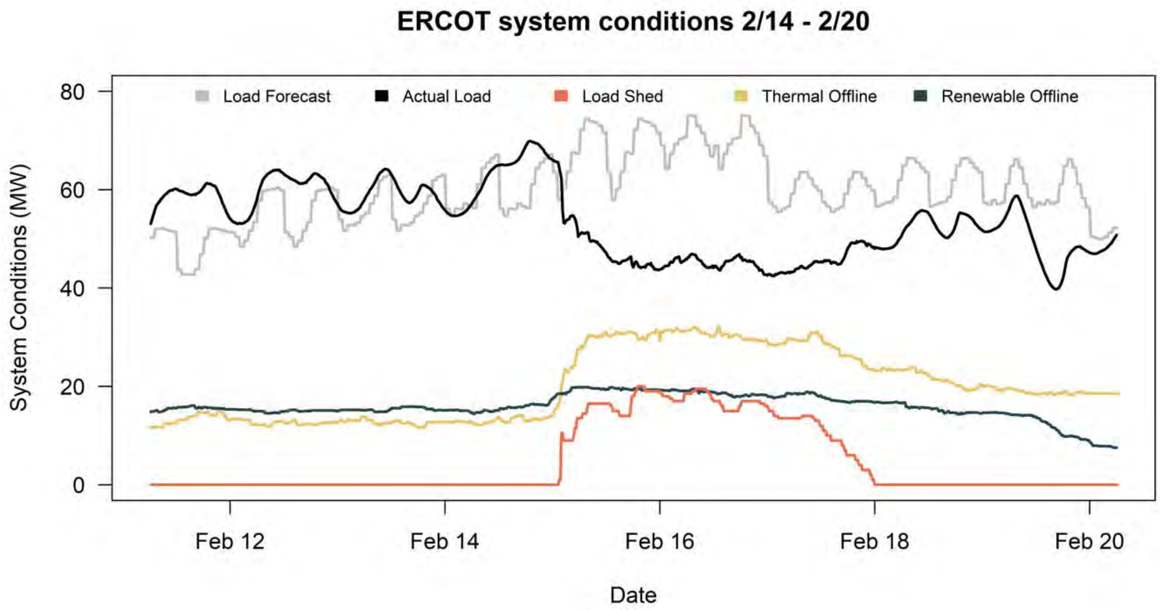

Figure 2.k. Hourly time sequence of forecasted load, actual load, and power plant capacity offline from Feb 11-19, 2021.[38]

Absent load shed, ERCOT back casted demand to peak at roughly 76,800 MW,[39] about 19,120 MW higher than the value expected under normal winter weather (57,699 MW) and more than 9,500 MW higher than ERCOT's "Extreme Peak Load" SARA scenario.[40] However, not only was demand underestimated, but supply was overestimated, as discussed in the following section.

2.4. Generation Outages (Timeline)

ERCOT has publicly released data regarding which power plants went offline and when[41] and also aggregated capacity that was offline by cause of outage as categorized (largely) by power plant operators.[42]

[38] Data from ERCOT's hourly load data archives as well as various public reports and datasets provided by ERCOT. See http://www.ercot.com/news/february2021.

[39] http://www.ercot.com/content/wcm/lists/227689/Available_Generation_and_Estimated_Load_without_Load_Shed_Data.xlsx

[40] http://www.ercot.com/content/wcm/lists/197378/SARA-FinalWinter2020-2021.xlsx

[41] http://www.ercot.com/content/wcm/lists/226521/Unit_Outage_Data_20210312.xlsx.

[42] http://www.ercot.com/content/wcm/lists/226521/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf.

Going into the early morning of February 15, generation outages (nameplate) were already high at roughly 30,000 MW. By 9:00 a.m., total outages and derates[43] increased to over 50,000 MW, or roughly 40% of the total installed nameplate capacity in ERCOT. Levels of outages and derates would change over the event, but would not return to pre-blackout levels until the afternoon of February 19. Figure 2.l shows outages and derates of power plants by cause (as reported to ERCOT by generators, with some possible interpretation by ERCOT), based on nameplate capacity.

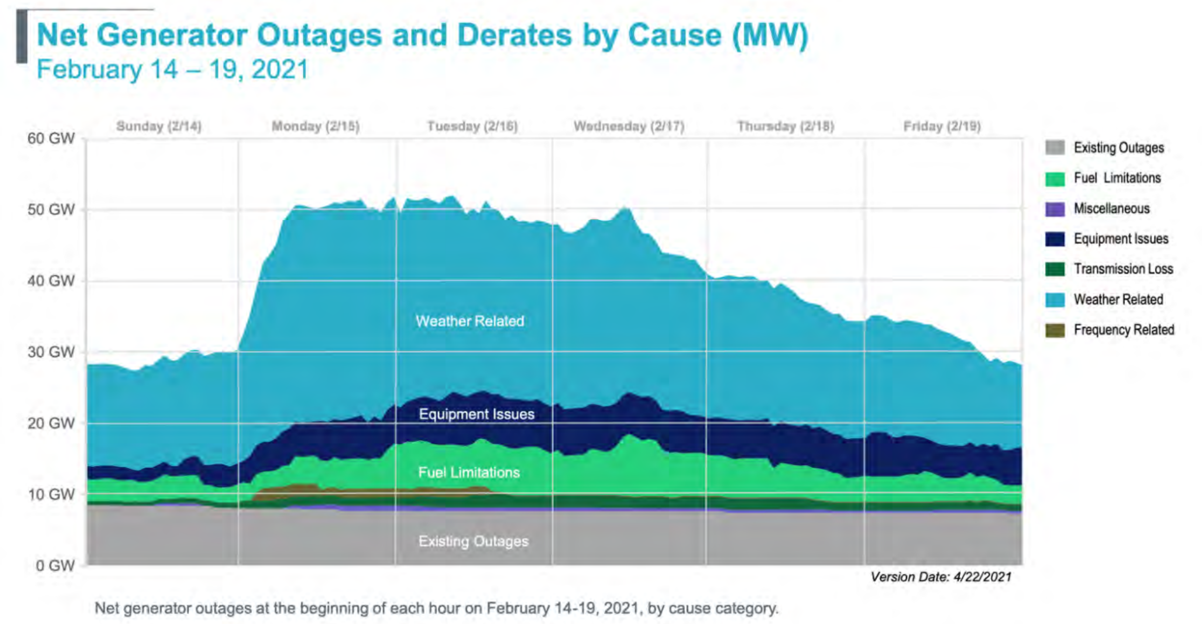

Figure 2.l. Net capacity outages and derates by category of failure mode, when considering the rated nameplate capacity of all power plants. Figure by ERCOT.[44]

As the extreme cold weather settled over the entire state, the outages increased. From noon on February 14 to noon on February 15, the offline renewable capacity increased from 15,100 MW to 19,400 MW (+4,300 MW) and the total outages of thermal generators increased from 13,700 MW to 31,100 MW (+17,400).[45]

Figure 2.m shows the spatial temperature and generation outages across Texasduring the critical hour when grid frequency was declining on the early morning of February 15, and the time of peak generation capacity outages on February 16.[46] As the

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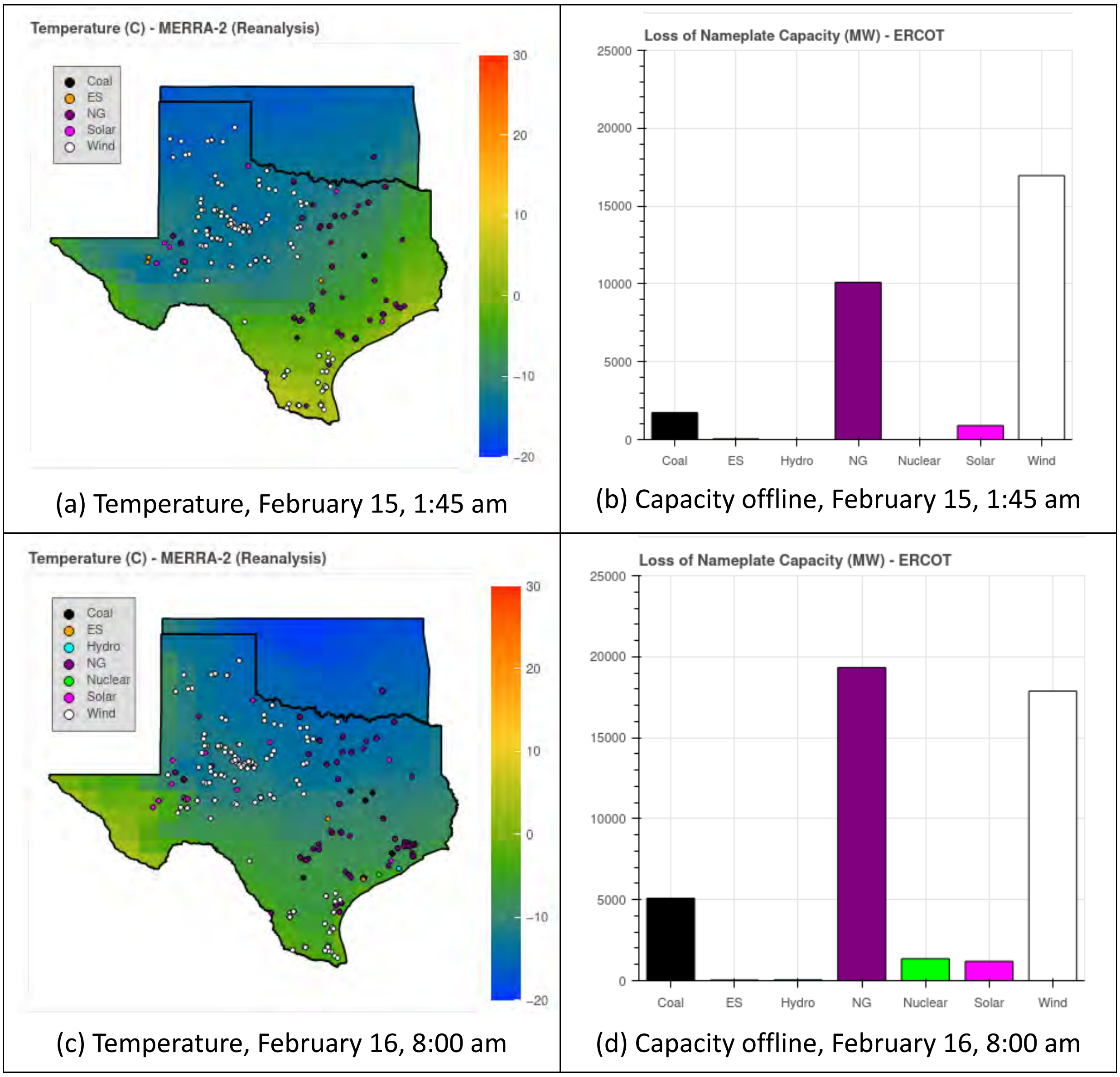
[43] A derated power plant is one that is able to produce some level of power output, but it not able to produce at its full potential. For example, some natural gas power plants weren't able to get enough gas to run at 100% output, but were still able to produce some power at a lower level, thus the power plant was derated.

[44] http://www.ercot.com/content/wcm/lists/226521/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf

[45] Values rounded to nearest 100 MW.

[46] Temperature data come from the National Atmospheric and Space Administration (NASA) Modern-Era Retrospective Analysis for Research and Applications, Version 2 (MERRA-2): https://goldsmr4.gesdisc.eosdis.nasa.gov/data/MERRA2/.

colder temperatures moved further south into Texas, so did generation outages. Moreover, the types of outages changed.



(a) Temperature, February 15, 1:45 am

(b) Capacity offline, February 15, 1:45 am

(c) Temperature, February 16, 8:00 am

(d) Capacity offline, February 16, 8:00 am

Figure 2.m. The temperature across Texas and reported loss of (nameplate) capacity by ERCOT for the critical time period of February 15, 1:45 am (a and b) and the time of peak generation outage on February 16, 8:00 am (c and d).[47]

Generator outage data, as reported to and summarized by ERCOT, suggest that the largest share of outages was weather-related. The capacity that went offline due to weather-related[48] causes doubled from 15,000 MW at noon on February 14 to

[47] Each circle in subfigures (a) and (c) indicates the location of power generation units that are offline or derated, and its color corresponds to the capacity in subfigures (b) and (d). Temperature data come from the MERRA2 reanalysis data set.

[48] ERCOT defines outages which are weather-related in the following manner: “This includes but is not limited to frozen equipment—including frozen sensing lines, frozen water lines, and frozen valves—ice accumulation on wind turbine blades, ice/snow cover on solar panels, exceedances of low temperature limits for wind turbines, and flooded equipment due to ice/snow melt.”

30,000 MW at noon on February 15. In total, about 167 units listed their outages as weather-related during the event. Beyond wind turbine icing, outages between February 14 and 15 were mainly the result of frozen water intakes and sensing lines and the freezing of other general equipment. As freezing weather persisted further, other problems arose — for example, there were issues around control and condensate systems that caused more capacity to go offline. At least two black start-rated units reported outages or derates for weather-related reasons. [49]

The second largest reported category of offline capacity was existing outages, including scheduled and planned outages, mothballed units, and forced outages that started before the February 8 OCN. At noon on February 14 approximately 8,400 MW of capacity was offline due to existing outages. The majority of this capacity (7,700 MW) was from coal and natural gas power plants. The total amount of these pre-existing outages steadily declined to 7,300 MW by the end of the event.

"Equipment issues" accounted for the third highest amount of power plant outages and derates. Equipment issues were the cause of 1,900 MW of outages at noon on February 14, rising to 5,600 MW by noon on February 15. In total, equipment issues were listed as the reason for outages at about 146 units. A survey of unit-specific outage data indicates that these power plants went offline because of equipment failures that were not directly associated with the weather, for example clogged sensing lines and stuck valves due to normal wear and tear.[50] At least six black start-rated units reported outages or derates based on equipment failures.

Fuel limitations account for the fourth-most capacity outage and derating, with 131 units listing this reason for their outage.[51] Fuel limitations mostly affected natural gas plants and coal plants. Fuel issues for natural gas existed before the blackouts began (3,500 MW at noon on February 14) and increased as the event continued (6,700 MW at 10:00 a.m. on February 17). While there were no fuel-related outages associated with coal on February 14, issues appeared on February 15 and caused the outage of a maximum of 2,100 MW at 4:00 p.m. on February 16. Lack of fuel, low fuel pressure,[52] and fuel contamination were the major listed reasons for fuel-related outages for natural gas-fired generation units. Detailed, unit-specific, power plant outage information indicates that power plants with both "firm" and "non-firm" fuel

[49] Black start generation units are those able to start generation on their own, without support of the ERCOT transmission grid, as if there was absolutely no electricity generation on the grid (i.e., the grid is off, or "black" with no lights).

[50] Equipment failures such as these also happen in the summer when older power plants that don't run often are pressed into service to meet peak demand.

[51] Fuel limitation issues later matched or exceeded equipment issues by February 16.

[52] Some power plants were able to derate with lower fuel pressures, but others had to turn off completely.

supply contracts experienced fuel supply/curtailment issues. Also, at least five black-start-rated units reported outages or derates based on fuel supply issues.

Generator reports to ERCOT indicate that natural gas fuel shortages preceded the firm load shed directives from ERCOT, occurring as early as February 10. These fuel limitations affected more generation capacity as the cold weather event continued. At least as early as February 8, ERCOT began notifying QSEs of potential weather issues and instructed them to notify ERCOT of any known or anticipated fuel restrictions. ERCOT has an arrangement with at least one natural gas supplier to provide e-mail notifications when gas supply restrictions are issued to its natural gas-fired electric generation facilities. ERCOT received such notices as early as February 9 for supply restrictions starting the morning of February 10. Additionally, ERCOT received a notice on February 10 of supply restrictions for parts of Texas that would completely cut off power plants from fuel delivery and would start on February 12.

Additional natural gas outages are potentially due to the loss of electricity affecting the ability of the natural gas infrastructure to operate and thus deliver fuel, but we did not have data to evaluate the magnitude of this interdependence, or determine causality. Public testimony from Oncor's CEO indicated that not all infrastructure that was critical to the natural gas supply chain was registered with them as critical load not to be turned off.[53] He stated that Oncor started the event with 35 pieces of critical natural gas infrastructure on their "do not turn off" list, but added 168 more by the end of the event. This presumably indicates that some delivery of natural gas may have been interrupted due to power outages because the operators of the critical natural gas infrastructure failed to alert the transmission and/or distribution providers (TDSPs)[54] that they were critical loads.

The detailed outage data also suggest that transmission and substation outages led to generation outages reaching 1,900 MW of wind and solar on February 16. No coal, natural gas, or nuclear generation units listed transmission outage as a reason for an outage or derate. In all, 18 solar and wind units listed transmission losses as their reason for outage or derating. Additional data from ERCOT indicate that on February 9 the grid operator identified 28 existing transmission outages that could be cancelled or withdrawn by February 12, and all outages planned to begin between February 12-17 were moved, cancelled, or withdrawn. While it is likely that the grid could have operated in a more stable manner with fewer planned transmission outages, it is unknown how much worse, if at all, the situation would have been had these outages been allowed to proceed.

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[53] https://www.texastribune.org/2021/03/18/texas-winter-storm-blackouts-paperwork/.

[54] Section 2 of ERCOT protocols defines Transmission and/or Distribution Service Provider as: "An Entity that is a TSP, a DSP or both, or an Entity that has been selected to own and operate Transmission Facilities and has a PUCT approved code of conduct in accordance with P.U.C. SUBST. R. 25.272, Code of Conduct for Electric Utilities and Their Affiliates." DSP = distribution service provider.

Grid frequency deviations were reported to be responsible for up to 1,800 MW of outages (8 total units), mostly coal, at 2 a.m. on February 15.

Figure 2.n aggregates all the causes of outages and shows the total amount of outages by fuel, based on nameplate capacity. From noon on February 14 to noon on February 15, the amount of offline wind capacity increased from 14,600 MW to 18,300 MW (+3,700 MW).[55] Offline natural gas capacity increased from 12,000 MW to 25,000 MW (+13,000 MW). Offline coal capacity increased from 1,500 MW to 4,500 MW (+3,000 MW). Offline nuclear capacity increased from 0 MW to 1,300 MW, and offline solar capacity increased from 500 MW to 1100 MW (+600 MW).

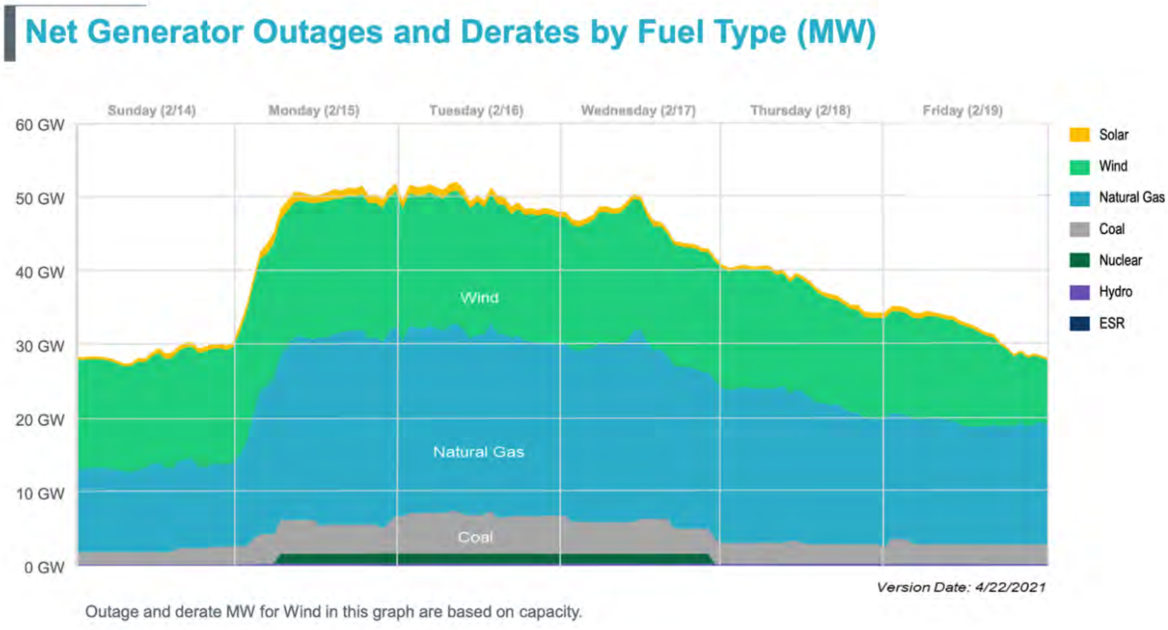

Figure 2.n. Net capacity outages and derates by fuel type, relative to the rated nameplate capacity of all power plants. Figure by ERCOT.[56]

Since rated nameplate capacities of wind and solar plants refer to the maximum amount of generation possible, derates based on these capacities overstate the amount of lost power generation due to the winter storm. Figure 2.o accounts for this by showing the same information as Figure 2.n based on the wind and solar capacities that would have been available based on back casted modeling that uses actual wind speed and solar radiation data to estimate what would have been

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[55] Nameplate capacity for wind and solar is not representative of the amount of power generation expected when the unit is not expiernecing an outage, but is much closer for the thermal fleet. When accounting for backcasted values of the available wind and solar radiation, available wind capacity outages actually decreased from 9,070 MW to 5,020 MW (-4,050) over the same time period and solar outages increased less from 108 MW to 545 MW (+437 MW).

[56] http://www.ercot.com/content/wcm/lists/226521/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf.

produced had all of the available wind and solar capacity been online.

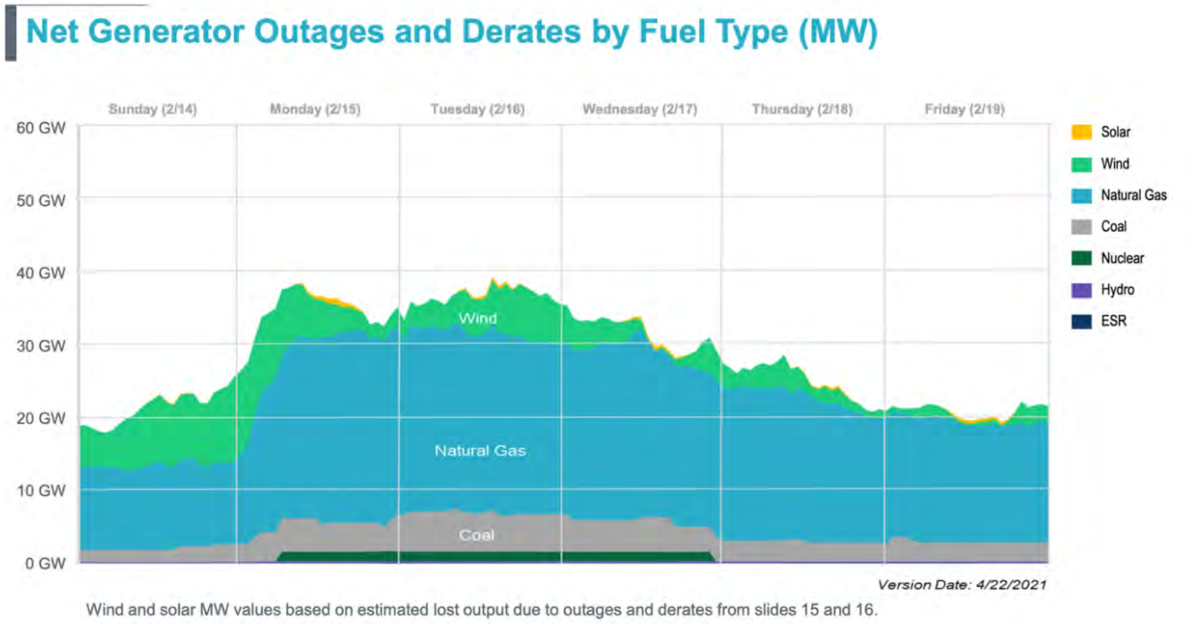

Figure 2.o. Net capacity outages and derates by fuel type, relative to expected contribution from wind and solar. Since wind and solar are not expected to generate at their nameplate capacity rating, the value derating shown here is less than that for wind and solar in Figure 2.n. Figure by ERCOT.[57]

Prior to the event, the Department of Energy and the Texas Commission on Environmental Quality issued directives to ERCOT that allowed the grid operator to dispatch certain power plants even if they would exceed pollution limits. The grid operator calculated that these directives enabled additional generation units to contribute an additional 1,400 MW of capacity, subject to outages and derates.

2.4.1. Generator Temperature Ratings Relative to Experienced Temperatures

This section combines data from ERCOT's public file of generator outages released on March 12, 2021 with weather data and confidential temperature ratings of power plants.[58] The purpose is to provide a high level view of whether some power plants failed above or below their low temperature ratings (see Figure 2.p). This section is not meant to provide a fully rigorous analysis of power plant failures as we only compare temperatures and not, for example, the enhanced cooling effects of wind,

[57] http://www.ercot.com/content/wcm/lists/226521/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf.

[58] For power plants that experienced an outage during the event, ERCOT sent Requests for Information (RFIs) to assess their causes. These RFIs included the question: "What is the minimum ambient operating temperature that the unit can start and continue to run without a unit trip or derate?" Some generators responded with "Unspecified" or "Unknown", but some were able to provide the minimum operating temperature, by unit, which were used here for comparison.

humidity, or ice. Also, *we only plot data for a subset* of the power plants listed in ERCOT's public file of generator outages.

The weather data are from the National Atmospheric and Space Administration (NASA) Modern-Era Retrospective Analysis for Research and Applications, Version 2 (MERRA-2) database. The MERRA-2 reanalysis weather database consists of atmospheric reanalysis data based on multiple types of historical observations. The data has an hourly time resolution and the reanalysis spans 1980-present. To relate a given power plant to a temperature in the MERRA-2 database, we assume the experienced power plant temperature is the same as the closest MERRA-2 temperature (example temperature distributions by grid cell are in Figure 2.m).[59]

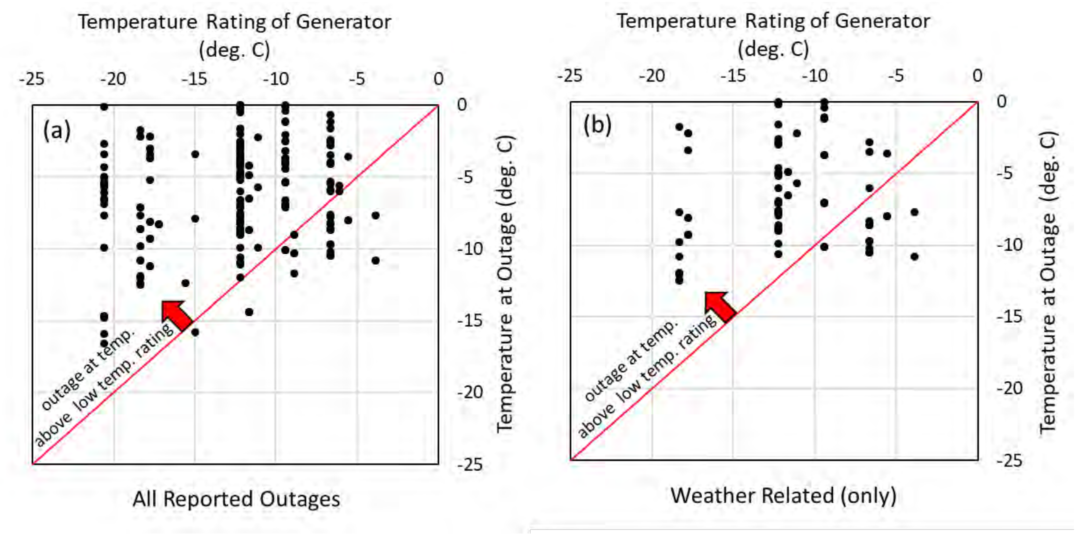

Figure 2.p. Plots of the estimated temperature experienced at outage for a subset of thermal power plants that experienced an outage or derate versus the lowest rated (design) temperature of power generation units (as reported by generation operators to ERCOT and FERC) for the winter event of February 10-20, 2021. We present the data in two charts: (a) generation units experiencing outages for any reason, (b) generation units experiencing outages summarized as "weather related" by ERCOT. Electric generation units were chosen at random.

Each dot in Figure 2.p represents a single generation unit listed in ERCOT's public data file of power plant failures. We include two charts in Figure 2.p, all the power plants that we compared (a) and the subset that reported their outage as being "Weather Related." The red line represents the boundary where the power plant design temperature equals experienced temperature. **A data point above the red line** means that a generation unit experienced an outage or derating at a temperature above its minimum temperature rating. **A data point below the red line** means that a generation unit experienced an outage or derating while experiencing a temperature below its minimum design temperature rating. Thus, in this simple analysis, data

[59] More precisely, the temperature is associated with the centroid of the MERRA-2 0.5° × 0.625° grid with the shortest Euclidean distance to the latitude and longitude of the power plant.

points above the red line indicate that some generation units might not have met their temperature design criteria. [60]

2.5. Load Curtailment, Requested and Achieved

As the freezing temperatures increased demand for electricity-based heating of homes and other buildings, ERCOT, the TDSPs, load-serving entities, and customers undertook a variety of actions to reduce demand on the system during the winter event, including:

- Involuntary load reduction due to selective outages of distribution circuits or substation loads chosen by the TDSPs and directed by Transmission Operators (TO)[61] when ERCOT issues load shed orders.
- Customer response to high market prices by customers exposed to wholesale electricity prices or natural gas prices.
- Deployment of load resources.
- Deployment of ERCOT's Emergency Response Service (ERS) program.
- Automated load shed triggered by under-frequency relays.
- Deployment of various demand response (DR) programs by load-serving entities.

2.5.1. Involuntary Load Shed

Per its Protocols, ERCOT declares an EEA Level 3 if operating reserves cannot be maintained above 1,375 MW. If conditions do not improve, continue to deteriorate, or operating reserves drop below 1,000 MW and are not expected to recover within 30 minutes, ERCOT orders transmission providers to reduce demand on the system.[62] The TDSPs are charged with making the final decision on which circuits to turn off to achieve the demand reduction. Each Transmision Operator (TO) is responsible for a predetermined percentage of the total load shed that ERCOT calls for in its "ERCOT

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[60] We note a few important caveats for interpreting this figure. The figure does not indicate the minimum temperature actually experienced by any given power plant, which is likely lower than the temperature displayed, but its minimum design temperature and the temperature at which it experienced an outage. Also, the figure has no information about precipitation (rain, ice, snow, fog) which could have been a crucial factor in any given power plant outage or derating. Also, only natural gas, coal, and nuclear generation units are shown in this figure. In particular, most wind power outages related to ice accumulation which was a combination of subfreezing temperatures and precipitation or fog.

[61] A Transmission Operator (TO) is defined in Section 2 of ERCOT protocols as "A Transmission and/or Distribution Service Provider (TDSP) designated by itself or another TDSP for purposes of communicating with ERCOT and taking action to preserve reliability of a particular portion of the ERCOT System, as provided in the ERCOT Protocols or Other Binding Documents."

[62] http://www.ercot.com/content/wcm/lists/200198/EEA_OnePager_updated_9-4-20.pdf

Load Shed Table."[63] Each TO instructs its respective TDSPs to achieve its load shed obligation. The percentage of load reduction for each TO is based on the previous year's peak Loads for its respective Transmission Service Providers (TSP), as reported to ERCOT and modified annually.

EEA Level 3 with Firm Load Shed was called on February 15 at 1:25 CST.[64] Load shed orders increased to 20,000 MW by 19:00 on the February 15. An analysis of load data appears to confirm compliance with the involuntary load reduction instructions.[65]

2.5.2. Response to High Prices

ERCOT conducts surveys of load-serving entities to discern the number of energy consumers under price-sensitive electricity plans. Such plans might include real-time pricing (to directly expose a consumer to wholesale market prices), peak rebate proms (providing a rebate to consumers who reduce demand below baseline amounts at the request of the load-serving entity), or block and index pricing (where consumption in excess of a contractual amount is exposed to market prices, while consumption below that amount results in a credit based on prevailing market prices).

In 2020, over 100,000 accounts were under a real-time pricing or block and index pricing plan. The number of accounts under a peak rebate plan was over 94,000.[66]

In recent summer periods with overall high system peak demand and high electricity prices, ERCOT has estimated demand response based on these accounts to be in excess of 4,000 MW.[67] The amount of demand reduction due to high prices during this winter event is difficult to determine, since many customers lost service due to involuntary outages and for other reasons.

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[63] This ERCOT Load Shed Table is in Section "4.5.3.4, Load Shed Obligation" of the ERCOT Operating Guide. During February 2021, the language of Section 4.5.3.4 stated: "Obligation for Load shed is by DSP. Load shedding obligations need to be represented by an Entity with 24x7 operations and Hotline communications with ERCOT and control over breakers. Percentages for Level 3 Load shedding will be based on the previous year's TSP peak Loads, as reported to ERCOT, and will be reviewed by ERCOT and modified annually." As of July 1, the language of Section 4.5.3.4 has been amended.

[64] www.ercot.com/services/comm/mkt_notices/notices/2021/02

[65] See slides 4 and 5: http://www.ercot.com/content/wcm/key_documents_lists/218735/DSWG_May_28_2021_February_Winter_Event_Analysis_Raish.pptx.

[66] http://www.ercot.com/content/wcm/key_documents_lists/214087/15._RMS_2020_4CP__Retail_DR_Analysis_Raish.v3.pptx.

[67] http://www.ercot.com/content/wcm/key_documents_lists/218751/DSWG_2020_4CP__Retail_DR_Analysis_Raish.pptx, slide 5.

2.5.3. Deployment of Load Resources

Large industrial energy consumers with the ability to curtail their demand on the ERCOT system are permitted to provide ancillary services. Roughly half of ERCOT's requirements for Responsive Reserve Services (RRS)[68] are met by load resources equipped with under-frequency relays that instantaneously curtail load when the frequency drops to 59.7 Hz. Resources providing this service must also be able to respond to verbal dispatch instructions. In February 2021, the amounts of RRS provided by loads averaged 1,259 MW, which is lower than the 1,548 MW resource provided in January 2021.[69] Some load resources are also eligible to provide Regulation Up,[70] Regulation Down,[71] and Non-Spinning Reserves,[72] though the amount that these services provided in February 2021 was small.[73]

An analysis of load data suggests that maximum load reductions from load resources were over 1,400 MW on February 15, 16, and 17, and just under that level on February 19.[74]

2.5.4. ERS Program

The ERS program was activated during the winter event to reduce demand on the system.[75] Customers enrolled in the program reduce their purchases from the grid by reducing load or by starting backup generators. These emergency resources are contracted to provide this service to ERCOT through four-month contracts, and have response times of 30 minutes or 10 minutes. Different amounts are procured in each of eight time periods (or hour blocks) spread among weekday and weekend days.

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[68] RRS provides an operating reserve from on-line generation resources that is responsive to frequancy based on governor action and responsive to any automated or verbal dispatch instructions from ERCOT within 10 minutes. Load resources providing RRS respond via underfrequency relays when system frequency drops below 59.7 Hz.

[69] http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13242&reportTitle=Monthly%20ERCOT%20Demand%20Response%20from%20Load%20Resources&showHTMLView=&mimicKey.

[70] Regulation Up provides an operating reserve that increases generation output (or reduces demand, if a load resource) in response to automated signals to balance real-time demand and resources.

[71] Regulation down provides an operating reserve that decreases generation output (or increases demand, if a load resource) in response to automated signals to balance real-time demand and resources.

[72] Non-spinning reserves provides an operating reserve that can be synchronized and ramped to a determined amount of generation or load reduction within 30 minutes of notice.

[73] http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13242&reportTitle=Monthly%20ERCOT%20Demand%20Response%20from%20Load%20Resources&showHTMLView=&mimicKey.

[74] See slide 7 at: http://www.ercot.com/content/wcm/key_documents_lists/218735/DSWG_May_28_2021_February_Winter_Event_Analysis_Raish.pptx.

[75] http://www.ercot.com/services/programs/load/eils

Overall, the program achieved its targeted level of demand reduction of roughly 1,100 MW during the morning of February 15.[76] Some of the energy consumers in the program reduced their level of demand prior to the EEA Level 3 and deployment of ERS, as many businesses closed in anticipation of the storm. Some of the early demand reduction may have also resulted from public appeals for energy conservation, and local transmission and distribution system outages.

While the participating "loads" or consumers in the ERS program provided demand reduction well in excess of their obligations, ERS program participants contracted to provide generation during emergencies generally under-performed. The ERS generators met less than half of their obligation of around 300 MW in the early hours of February 15.[77] Performance of the ERS generators was reportedly hampered by "supply constraints, refueling issues, and forced outages."[78] Some generators in the ERS program indicated that they were not able to meet their requirements because they ran out of fuel (many have enough on-site fuel for only a few hours or days). Other ERS generators indicated that the distribution circuit through which they were served was turned off, so they were not able to provide power to the bulk grid.

2.5.5. Automated Load Shedding via Under-frequency Relays

Under-frequency load shed (UFLS) relays exist on the transmission and distribution grid. These are configured to trigger a circuit offline, and thus the customers on that circuit, if experiencing a frequency of 59.3 Hz or lower. At 59.3 Hz, under-frequency relays on the transmission and distribution grid can trigger automatic load shedding of up to 5% of the transmission operator's load (Table 2.b). Lower frequencies trigger even more UFLS.

Table 2.b. Table from Section 2.6.1 of ERCOT Nodal Operating Guide indicating the settings for Under-Frequency Load Shedding (UFLS) relays installed by Transmission Operators (TO).

Frequency Threshold	TO Load Relief
59.3 Hz	At least 5% of the TO Load
58.9 Hz	A total of at least 15% of the TO Load
58.5 Hz	A total of at least 25% of the TO Load

[76] http://www.ercot.com/content/wcm/key_documents_lists/226624/April_2021_DSWG_Meeting_ERCOT_FINAL.PPTX. Per slide 3: "As an ERS fleet in aggregate, the response generally met or exceeded the aggregate obligation." Note that ERS obligations differ in different time periods within a day.

[77] http://www.ercot.com/content/wcm/key_documents_lists/226624/April_2021_DSWG_Meeting_ERCOT_FINAL.PPTX. Slide 15.

[78] http://www.ercot.com/content/wcm/key_documents_lists/226624/April_2021_DSWG_Meeting_ERCOT_FINAL.PPTX, slide 8.

Confidential responses of TDSPs to ERCOT requests for information note UFLS relay tolerances of +/- 0.01 Hz, and some TDSPs recorded frequencies between 59.300 and 59.310 Hz during the critical frequency period indicated in Figure 2.j. As reported by five of the major TDSPs in ERCOT, the total MW UFLS by automatic (by experiencing low frequency) triggering of relays was on the order of 200 MW for 2 to 3 dozen circuits.

In addition to automated triggering of UFLS relays, the TDSPs also included some circuits with UFLS relays in the so-called manual load shed in which they selected circuits to trip offline to meet their portion of the load shed obligation as commanded by ERCOT. There were over 1000 circuits (possibly more than 2000) with UFLS relays included in this manual load shed. Thus, the manual load shed affected two orders of magnitude more load, number of circuits, and customers than were triggered via automated UFLS. At all times the TDSPs were still required to have 25% of load on circuits with UFLS relays.

2.5.6. Deployment of Various Demand Response (DR) Programs by Load-Serving Entities

Many DR programs are operated by load-serving entities completely outside of ERCOT's formal markets. For example:

- CPS Energy operates a large portfolio of demand response programs that can achieve demand reductions of well over 200 MW during a typical summer deployment.[79]
- Austin Energy operates certain DR programs.[80]
- A number of retail electric providers operate programs that control thermostats to achieve residential demand reduction.[81]

Though the focus of these programs has historically been on reducing demand during the summer, at least one utility attempted to deploy their programs during the winter event to achieve whatever demand reduction might be possible.[82] The success of these efforts is not yet publicly-known.

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[79] https://www.sanantonio.gov/Portals/0/Files/Sustainability/STEP/CPS-FY2020.pdf, p. 11, Table 1-1.

[80] https://austinenergy.com/wcm/connect/5f6f5cdc-31bb-436c-a52f-a050d113b5d2/DemandResourceMWSavings-WP.pdf?MOD=AJPERES&CVID=mRLC6hb, pp. 15-17.

[81] For example: https://www.reliant.com/en/residential/electricity/save-energy/degrees-of-difference-rewards.jsp; https://www.txu.com/savings-solutions/txu-ithermostat.aspx

[82] See, for example: https://newsroom.cpsenergy.com/update-as-of-sunday-february-14-2021-400-pm-winter-weather-and-extreme-cold-puts-community-at-risk-state-grid-operator-and-cps-energy-call-for-customers-to-reduce-electric-and-natural-gas-use/.

2.5.7. Aggregate Levels of Demand Response

It is clear that a very large demand reduction was achieved during the February event through a combination of formal programs and involuntary load shed action, by the grid operator, TDSPs, load-serving entities, and individual consumers. ERCOT has estimated that over 32,000 MW of demand reduction was achieved through the sum of these actions when demand reduction peaked in the morning of February 16, while the previous day saw peak levels of demand reduction of over 28,000 MW.[83] However, it is not possible to specifically attribute the demand reduction to each of these specific actions. Involuntary load accounted for the majority of load shed, and these load shed actions by a TDSP limit the ability of a customer to respond to prices or take some other action, for example.

2.6. Natural Gas and Operations during February 2021

This section covers how the production and flow of natural gas changed during the event. It also provides context for the various end uses of natural gas among which total consumption is partitioned. For a primer on the balance of natural gas in Texas, see Appendix D.

2.6.1. Natural Gas Production

Per a February 25, 2021 report by the Energy Information Administration (EIA),[84] Texas natural gas production fell by almost half during Winter Storm Uri – from 21.3 billion cubic feet per day (Bcfd) during the week ending February 13, to about 11.8 Bcfd at its lowest point on February 17 (see Figure 2.q.). As a daily average over month, Texas dry natural gas production dropped from 21 in January 2021 to 13 Bcfd in February 2021.[85]

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[83] See slide 4 at: http://www.ercot.com/content/wcm/key_documents_lists/218735/DSWG_May_28_2021_February_Winter_Event_Analysis_Raish.pptx.

[84] Texas natural gas production fell by almost half during recent cold snap - Today in Energy - U.S. Energy Information Administration (EIA)

[85] https://www.eia.gov/todayinenergy/detail.php?id=46896.

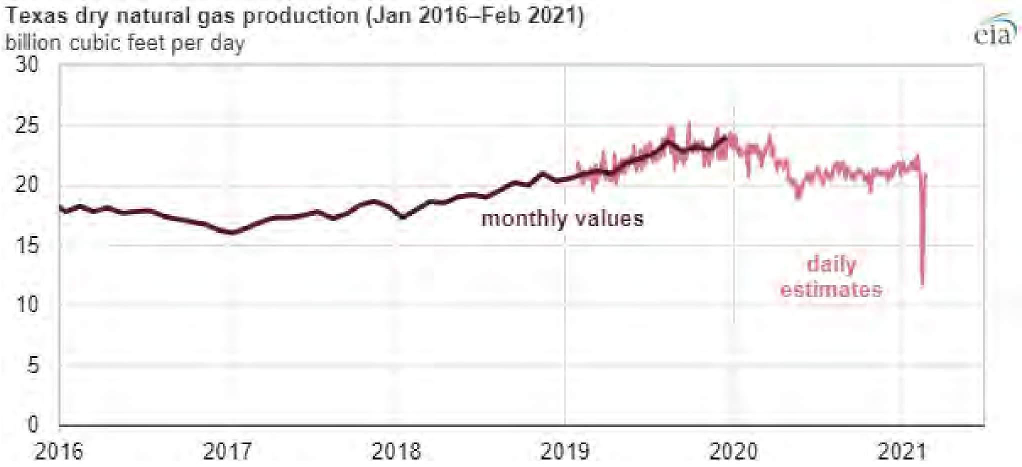

Figure 2.q. Texas Dry Gas Production through Jan 2016 – Feb 2021 (Source: EIA)

Based on a sample set of processing plants, located in the Permian, we also saw reduced residual gas[86] output from these plants during the week of the storm. Our sample includes 27 processing plants, with a total capacity 4.4 Bcfd, which is about 25% of the total 17 Bcfd capacity in the Permian Basin.

Two key observations arise from an examination of this sample set of processing plants:

- Per Figure 2.r, out of 27 gas processing plants in our sample, eight had zero output on February 15, 15 had zero output on February 16, and 18 had zero output on February 17.
- Figure 2.s shows the reported output from these 27 processing plants in February versus their inlet capacity. In early February, throughput was around 1.6 Bcfd, but declined to 1.4 Bcfd on February 12 and 13, and then on February 14, declined rapidly over the next three days to 0.257 Bcfd on February 16. This is an approximate 85% drop from the throughput level earlier in the month.

Since the Permian Basin produces about 50% of the dry production in the State of Texas and the data in Figure 2.s represent part of the processing plants from the Permian, the loss of production out of Permian Basin could have been close to 8 Bcf on February 13, which aligns with the reported single day drop of Texas from the EIA report. For the month of February, based on sample data, the daily average Permian gas processing could have been reduced by 6 Bcfd, or about 75% out of the reported 8 Bcfd reduction for Texas overall.

[86] Residual gas is the natural gas that is left after natural gas processing, which is free from impurities, moisture, natural gas condensates and is ready to be transported to the end user market through gas pipelines. Residual gas is also known as pipeline quality dry gas.

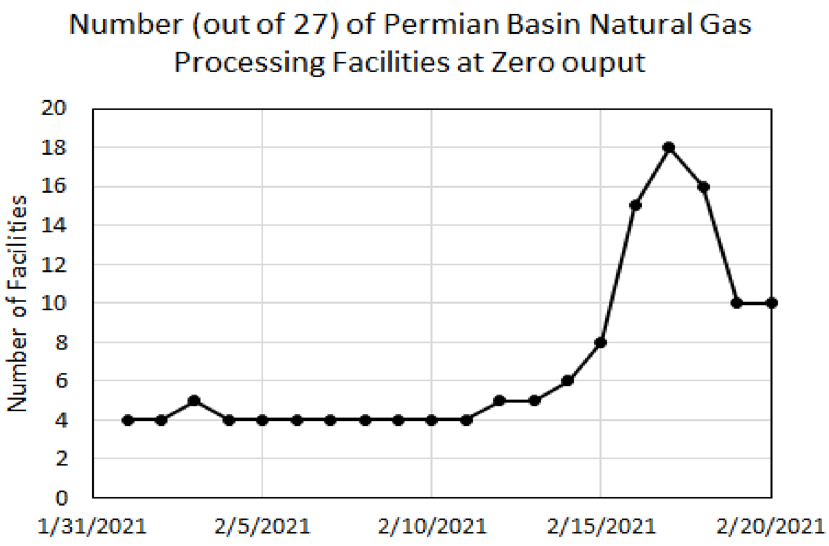

Figure 2.r. Number of Permian Basin natural gas processing facilities at zero output, out of our sample of 27 facilities. (Source: Wood Mackenzie)

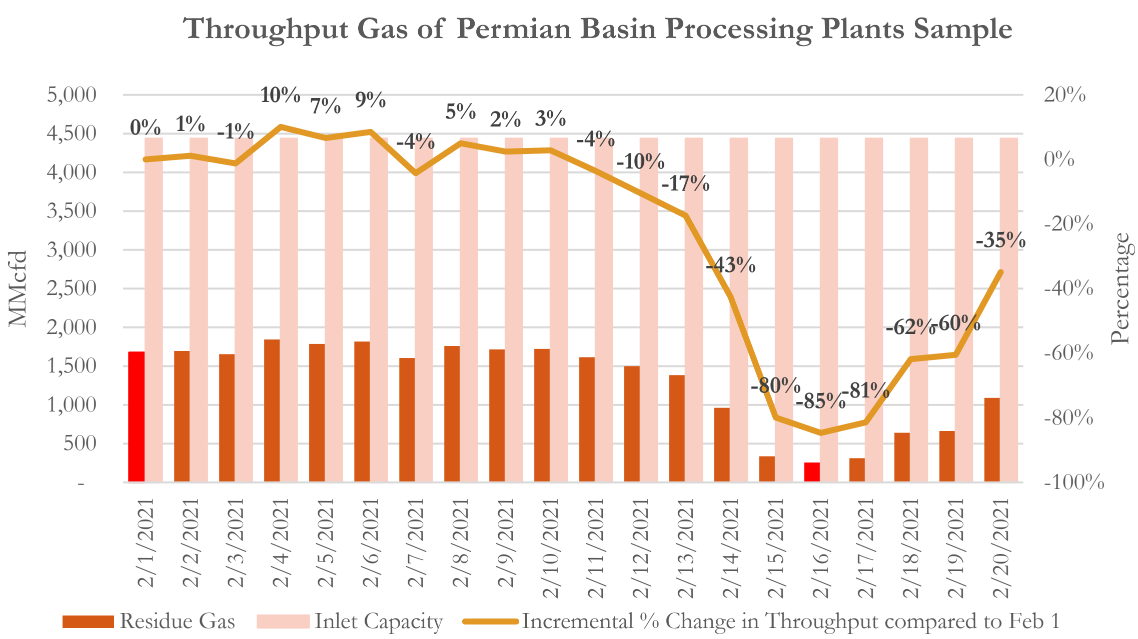

Figure 2.s. Throughput gas of Permian Basin processing plants out of our sample of 27 facilities. (Source: Wood Mackenzie)

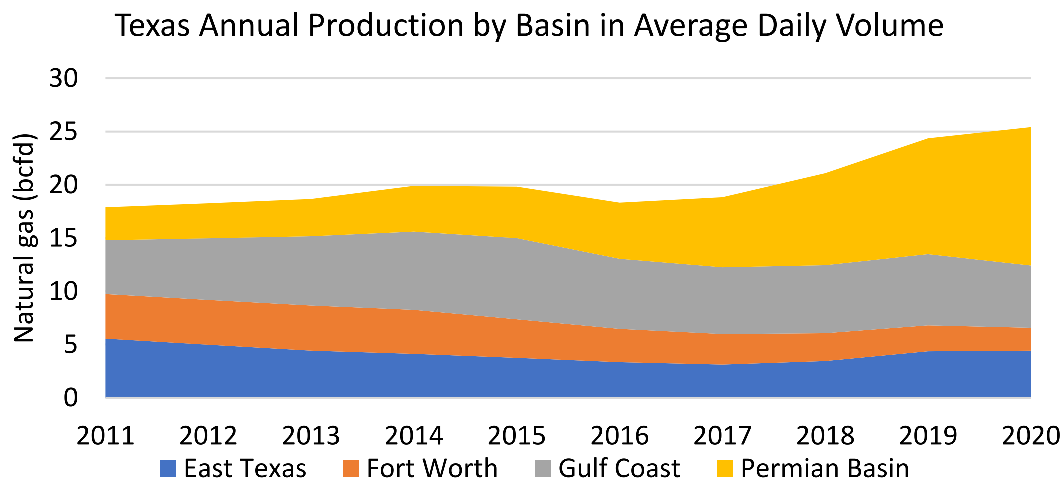

Figure 2.t. Texas natural gas production by basin since 2016 (Source: GPCM^{TM})

The sample processing plant data indicates a severe reduction in dry gas production. There are two major factors contributing to the decline of dry gas production in Texas during the storm: frozen infrastructure and electric power interruptions.

Freeze-offs at wellheads can occur when unprotected wellheads experience sufficiently low ambient temperatures causing water and other liquids in the gas to form ice that can accumulate to such a degree as fill the entire cross-sectional area of pipes and prevent flow to the wellhead. The consequences can range from a minor inconvenience to major reductions in natural gas production. Wellheads in Texas are generally not hardened for freezing conditions.

Figure 2.t shows the trend of average daily Permian Basin natural gas production since 2011. During this time a higher percentage of gas production shifted to the Permian, avoiding some weather interruptions more frequent in the Gulf Coast region, such as hurricanes, but increasing vulnerability to cold weather. Furthermore, the Permian Basin gas generally has a higher water content, making it more prone to freeze in cold weather and form hydrates which can block the flow of gas.

It is also possible, and has been noted by some natural gas companies, that power interruptions to critical infrastructure contributed to a further decline in dry gas production during the week of the storm. Remote processing plants, especially larger ones (greater than 50 million cubic feet per day throughput), typically used to have on-site power generation, but more modern processing plants are often grid connected. The data indicate that natural gas output started to decline rapidly before the electricity forced outages (load shed) began early on February 15, with production declining about 700 million cubic feet per day (MMcfd) from February 8-14, (see Figure 2.s). This decline is likely due to weather-related factors and not a loss of power at natural gas facilities. However, some of the additional 600 MMcfd output decline from February 14-15 could be partly due to natural gas facilities residing on circuits that the TDSP selected to follow ERCOT's load shed orders.

2.6.2. Storage

According to the Texas Railroad Commission, there are 40 natural gas storage sites in Texas with a total maximum 17,536 MMcfd reported withdrawal rate.[87] Our sample data set[88] includes 5 interstate connected storage facilities and 7 intrastate connected storage facilities, covering about 25% of the state's total.

Figure 2.u shows the reported net flow rates for the observed interstate storage units and compares them to past years. The data show a significantly larger withdrawal of about 291,000 MMBtu/d[89] in February 2021, almost three times higher than that of February 2020. This high level of withdrawal leads to a historical low level of reserves for these storage units as shown in Figure 2.v. Based on the sample data, it appears that interstate gas storage inventory started to drop rapidly on February 9, with less than 10% of working gas storage remaining on February 18, and it was almost fully depleted by February 21 (see Figure 2.v and Figure 2.w).

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[87] Gas Storage Statistics website of the Texas Railroad Commission (April 2021 report, accessed June 24, 2021): https://www.rrc.texas.gov/gas-services/publications-statistics/gas-storage-statistics/.

[88] Based on the sample set, there is about 55% coverage of intrastate storage, while 10% of interstate storage data. The data set is based on available data from Genscape Wood Mackenzie.

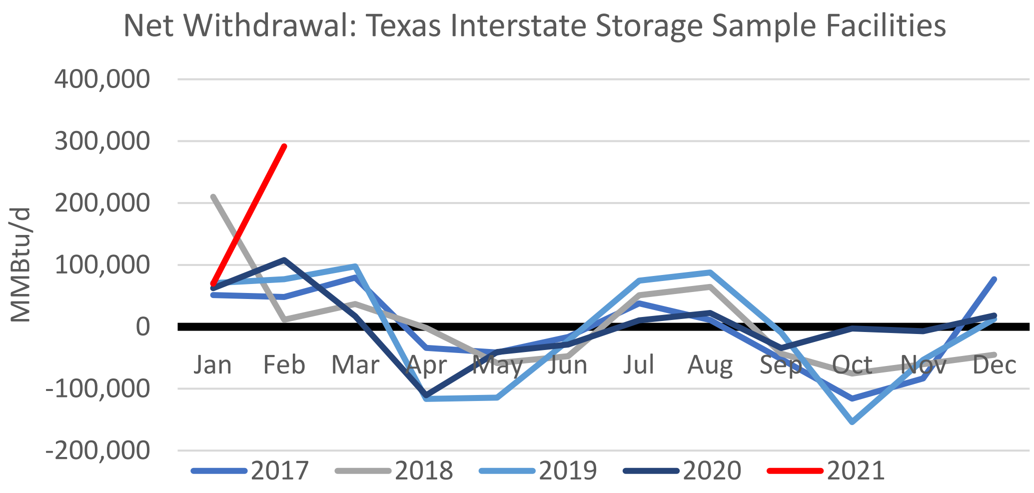

Figure 2.u. Net withdrawal rates (positive values indicate net withdrawal) as the daily average for each month for five Texas interstate storage facilities. (Source: Wood Mackenzie)

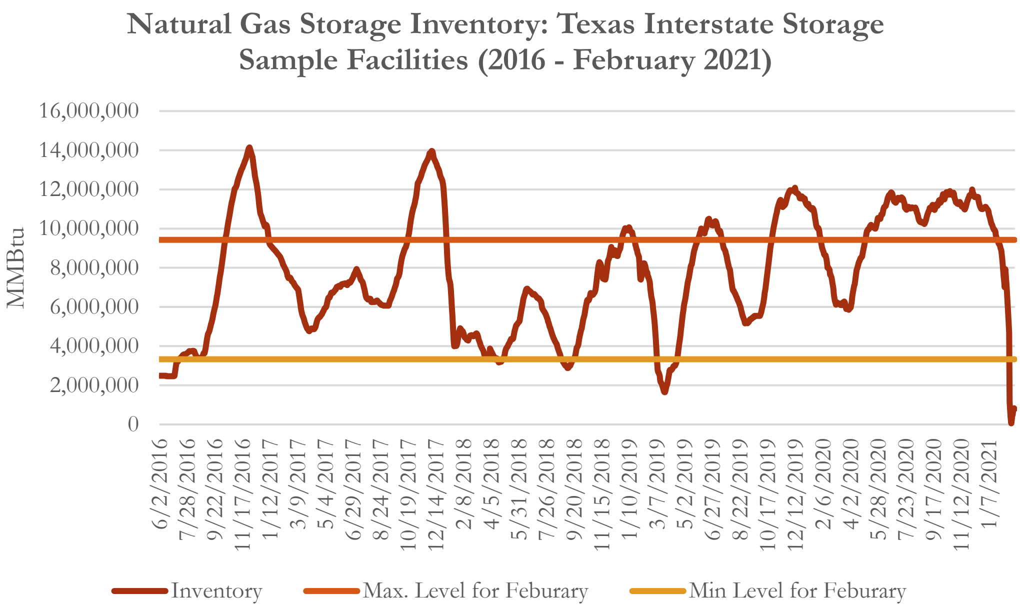

Figure 2.v. Texas natural gas storage inventory for our sample interstate storage facilities (2016 – February 2021) with lines indicating the maximum and minimum storage levels for the February months from 2016 to 2021. Note: 1 MMBtu ~ 1000 cubic feet of natural gas. (Source: Wood Mackenzie)

Figure 2.v and Figure 2.w (focusing on data for January and February 2021) show the total storage of natural gas for our sample interstate storage facilities, and Figure 2.x shows the withdrawal rates for those five facilities as a percentage of their historically-observed maximum withdrawal rates. Out of the five interstate storage units observed here, four experienced some level of increase of withdrawal during the winter event to reflect the higher demand for natural gas in the market. One of the four units, Unocal Keystone storage, experienced a large withdrawal the week of February 8. This could be a reflection of the early rise of the natural gas price which went above $4/MMBtu the week leading to the storm, which was already higher than usual.

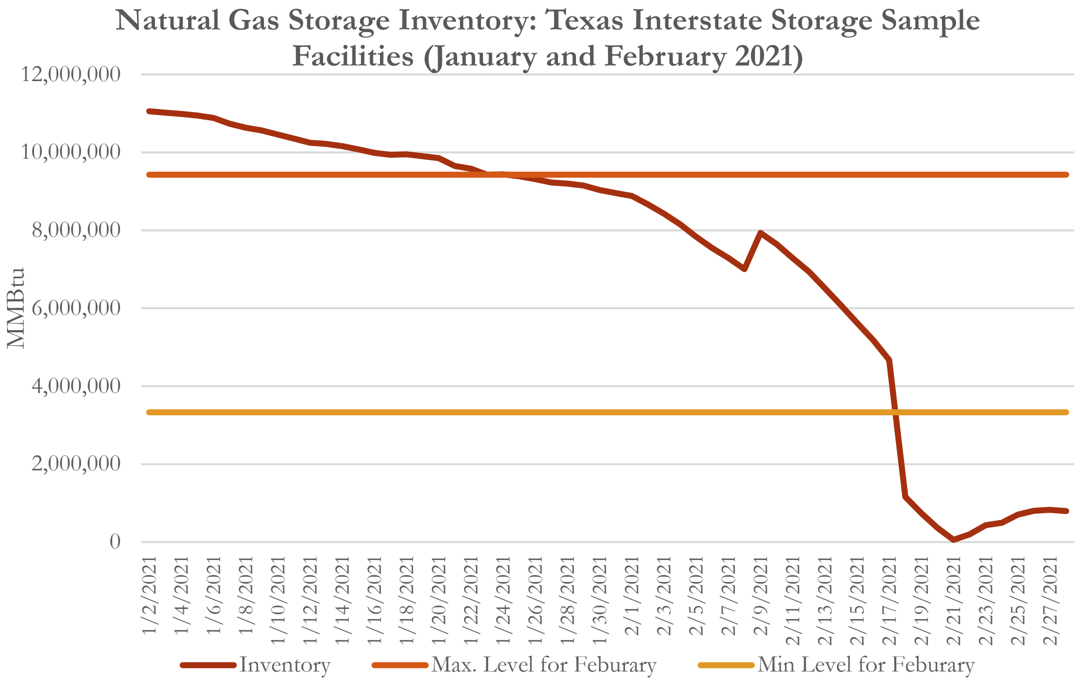

Figure 2.w. Texas natural gas storage inventory of for our sample interstate Storage facilities (January and February 2021). Note: 1 MMBtu ~ 1000 cubic feet of natural gas. (Source: Wood Mackenzie)

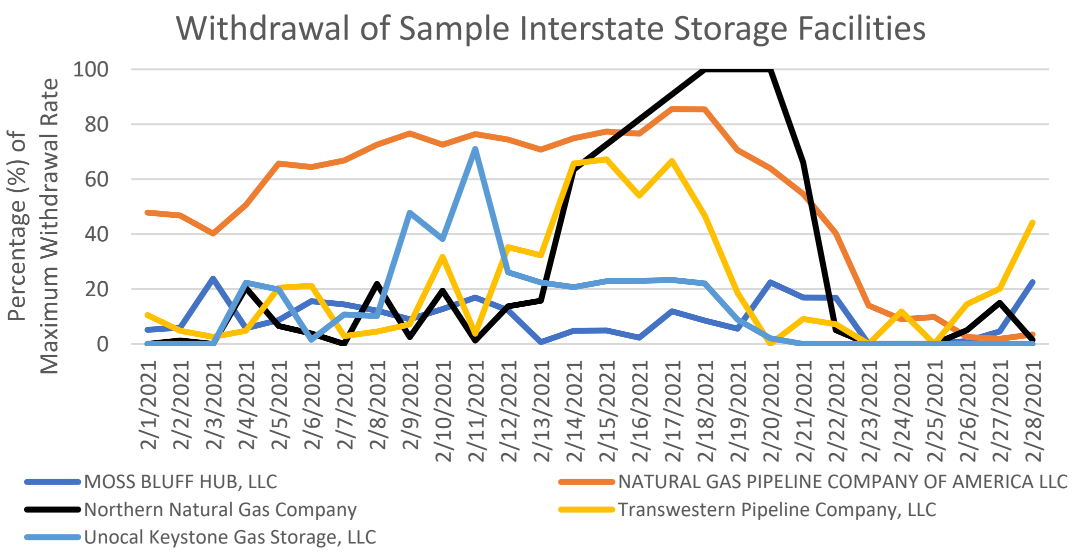

Figure 2.x. Natural gas withdrawal (as the percentage of maximum withdrawal rates) in February 2021 from each of our five sample interstate storage facilities. (Source: Wood Mackenzie)

Intrastate natural gas storage facilities also experienced high withdrawal rates through the week of the winter storm. However, the data for our sample of intrastate storage facilities indicate that during the week of February 13 their collective withdrawal rates never reached 100% of historically-observed maximum withdrawal rate capacities (Figure 2.y). These intrastate storage facilities also had higher than usual withdrawals before the beginning of the winter storm, on February 10, even at gas prices of $4 per million Btu (MMBtu). This drawdown of storage before February 14 contributed to the lack of natural gas supply going into the coldest parts of the storm and to the historically high natural gas prices during the storm that in some cases were 100 times higher than normal. *This situation leading into Winter Storm Uri was an extreme condition in which there was not sufficient gas delivery capability to prevent the extreme high price increase.*

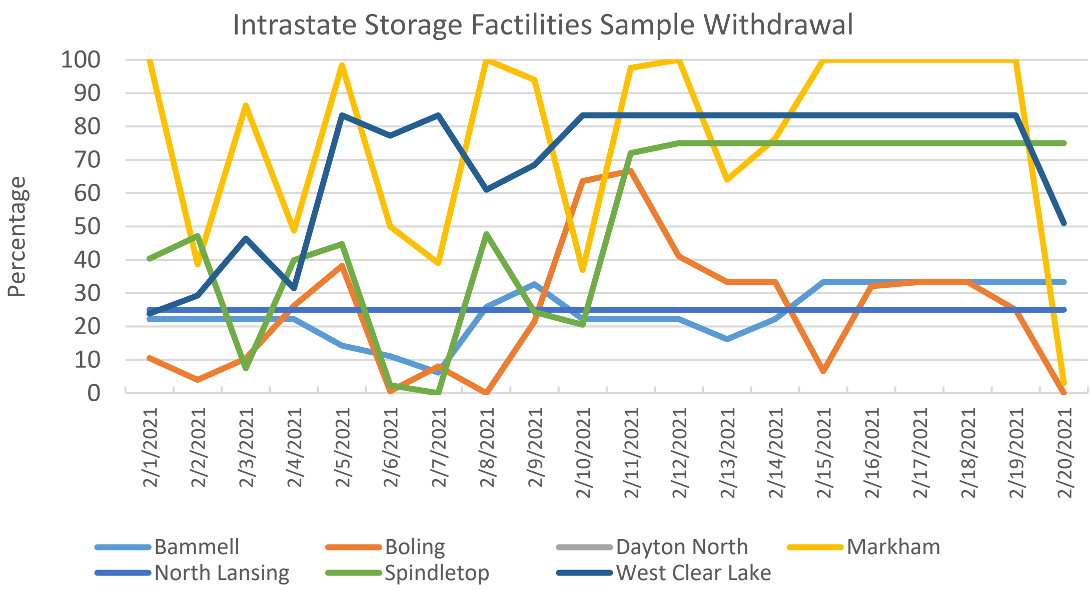

Figure 2.y. Natural gas withdrawal (as the percentage of maximum withdrawal rates) in February 2021 from each of our sample of intrastate storage facilities. (Source: Wood Mackenzie)

2.6.3. Natural Gas Demand

This section discusses the impacts on natural gas demand from the winter storm of February 2021. The dataset includes all sectors of demand in three categories, as labelled at interconnection point of the interstate pipeline network (delivery points). The dataset represents around 15% of the total consumption in Texas.

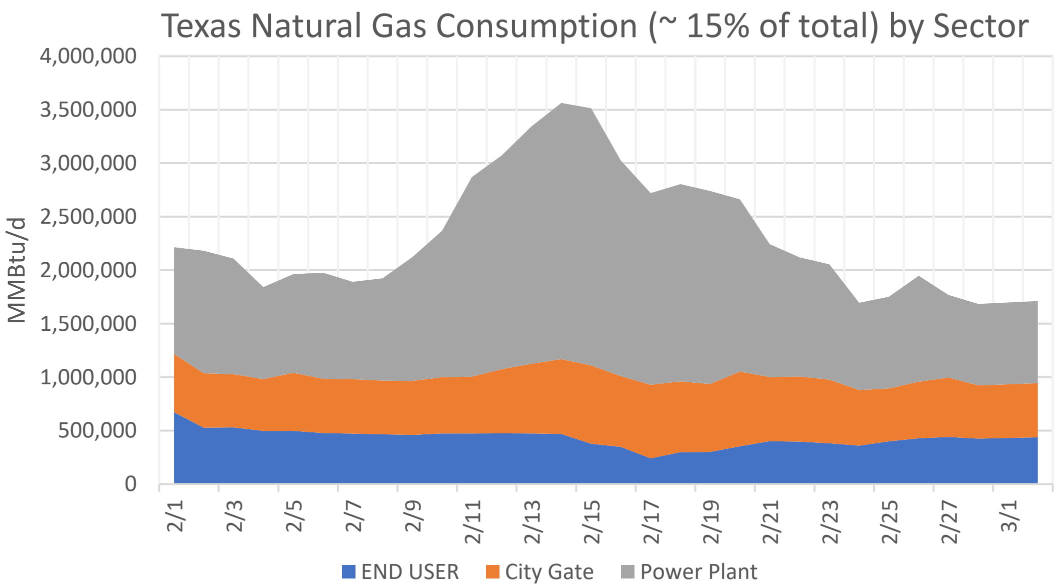

Figure 2.z. Texas daily natural gas consumption by sector (from our sample of interstate pipeline data) (Source: Wood Mackenzie)

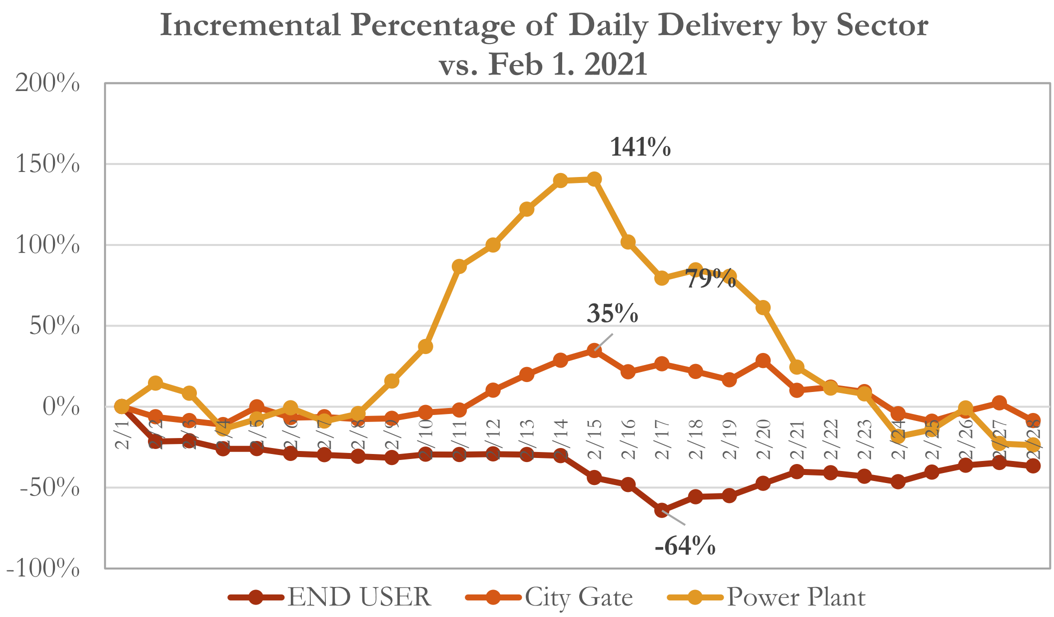

Figure 2.aa. Incremental change (in percentage) of daily natural gas delivery by sector relative to delivery on February 1, 2021, (Source: Wood Mackenzie)

Figure 2.z and Figure 2.aa show natural gas daily consumption in the sample Texas dataset by three sectors in February 2021,[90] representing overall changes and dynamics aggregated across three sectors. Figure 2.z indicates an aggregate increase in consumption peaking on February 14. Power plants and "city gate" (residential,

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[90] "City gate" includes residential, commercial and some small industrial users. "Power Plants" represent connections to gas-fired power generators. Large industrial users are labeled as "End user" in the data.

commercial, and small industrial) consumers increased their natural gas consumption during the storm as industrial "end users" decreased consumption. This aligns with the Texas Railroad Commission's February 12, 2021 Emergency Order[91] that additionally prioritized natural gas to power generation just after the highest priority for residential customers and other buildings. Figure 2.aa shows the same consumption by sector as a daily percentage change versus first day of February, which provides an additional perspective on the change of consumption within each sector of gas delivery.

Figure 2.bb - Figure 2.dd show how the daily consumption of each sector in 2021 compares to past years. The consumption by large industrial users ("End Users" of Figure 2.bb) does not display a strong seasonal pattern of its demand of natural gas, but it has a higher likelihood to have interrupted demand from weather events or pandemic (see 2020 March through April). During Winter Storm Uri, the largest industrial consumers experienced the highest levels of natural gas curtailment. Relative to consumption on February 1, large industrial natural gas consumption declined by 30% on February 14 and dropped rapidly to its lowest level on February 17, to a 64% reduction. Compared to the past five years, the February 2021 curtailment in industrial sector demand is one of the biggest drops observed in the data.

City gate demand (Figure 2.cc), largely characteristic of residential and commercial demand, rose to a maximum of 730,000 MMBtu/d on February 15, which is about 35% higher than that on February 1. Natural gas consumption by power plants (Figure 2.dd) increased significantly from February 9 reaching about 140% of its February 1 level on February 14. While the natural gas system was able to significantly increase delivery during the cold weather conditions in the week ending on February 14, both city gate and power plants deliveries started to drop by February 15. As discussed elsewhere in the report, natural gas was already curtailed to some power generation facilities before February 14, and this aggregate decrease in deliveries to consumers indicates further constraints due to upstream reduction from production and storage.

[91] https://rrc.texas.gov/media/cw3ewubr/emergency-order-021221-final-signed.pdf.

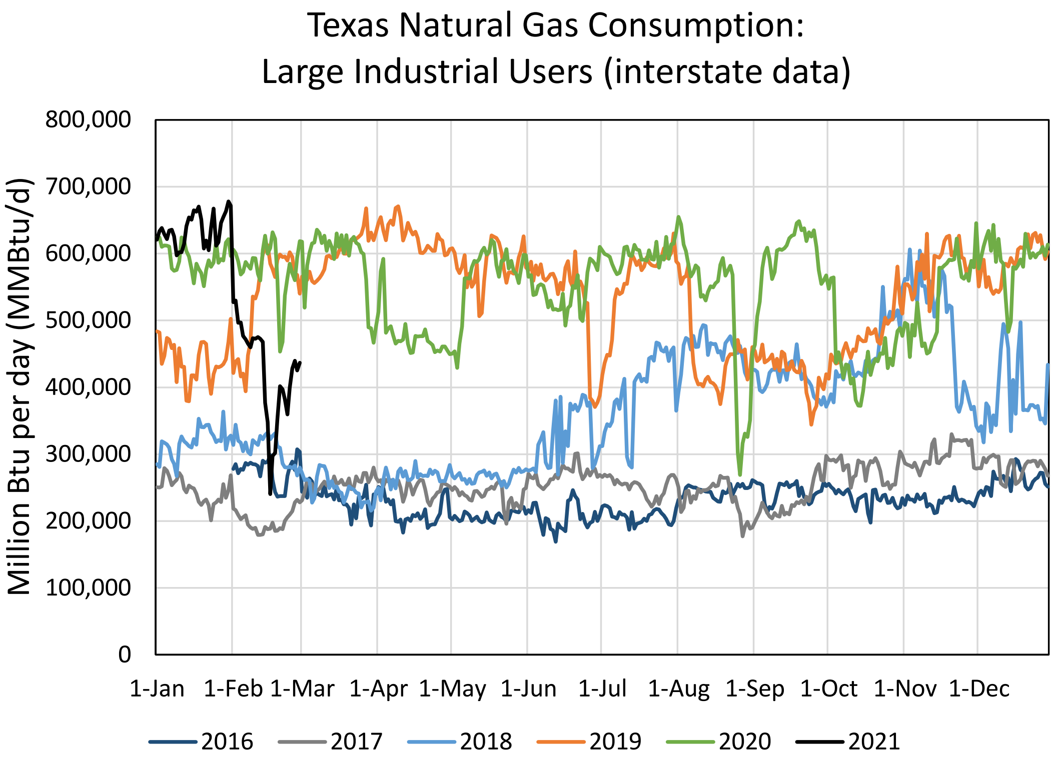

Figure 2.bb. Texas natural gas consumption for large industrial ("End User" in data set) via our sample of connection points to interstate pipelines (Source: Wood Mackenzie)

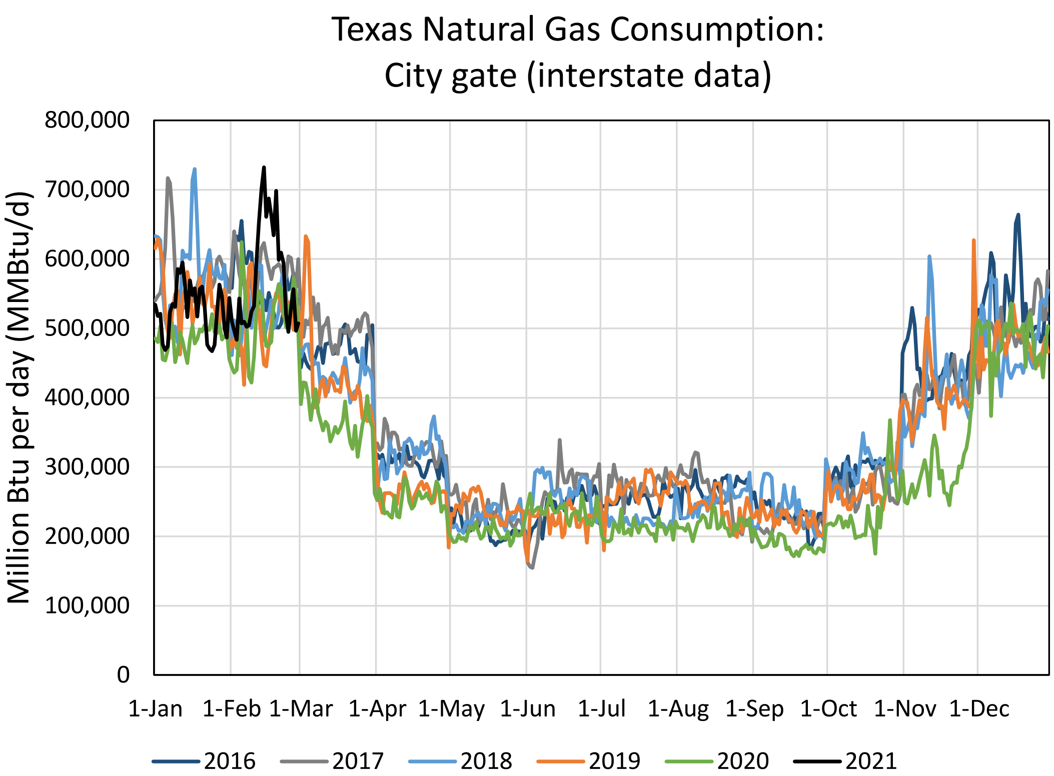

Figure 2.cc. Texas natural gas consumption for residential, commercial, and small industrial ("city gate" in data set) via our sample of connection points to interstate pipelines (Source: Wood Mackenzie)

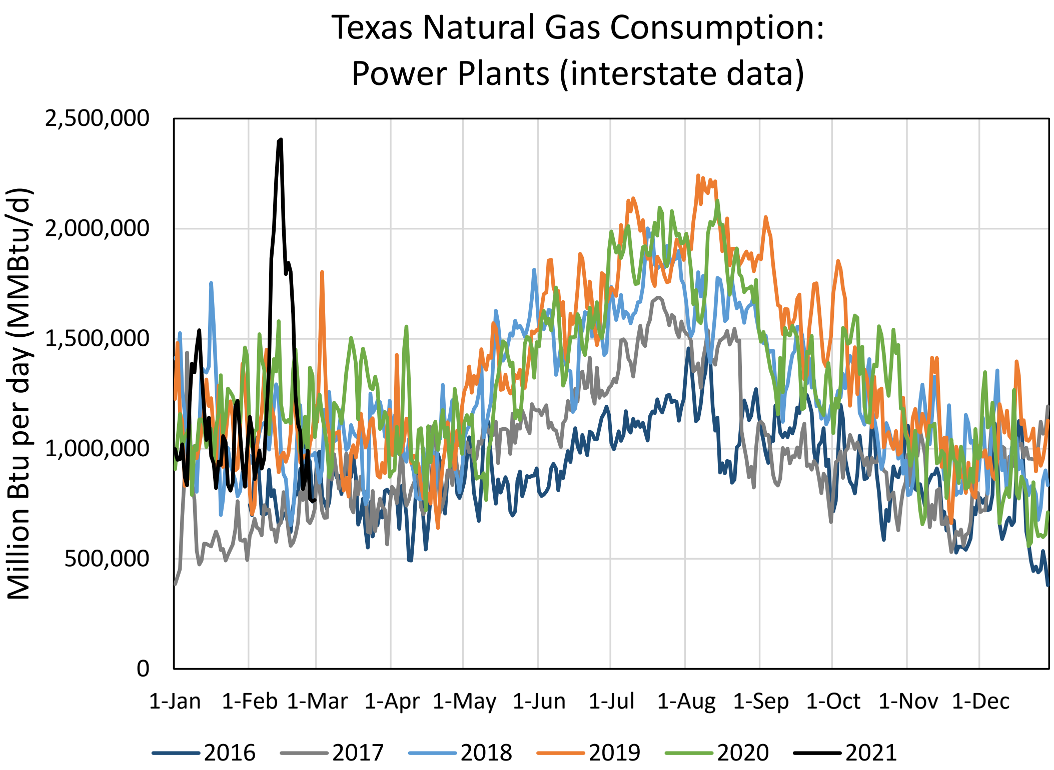

Figure 2.dd. Texas natural gas consumption by power plants via our sample of connection points to interstate pipelines. (Source: Wood Mackenzie)

2.6.4. Exports By Pipeline and Liquified Natural Gas (LNG)

Besides delivering gas to local consumers, power plants and industrial facilities, Texas exports natural gas to other states in the US and other countries including Mexico and those in Asia and Europe. To provide full context of the impacts of Winter Storm Uri on natural gas production, delivery, and consumption, we present data on the flow of natural gas out of Texas via pipeline and tanker.

Figure 2.ee shows the Texas natural gas flows by end users in Texas local markets (consumers, Electric Generation and Industrial) and exports via pipelines and liquified natural gas (LNG) ship cargos. One can observe the seasonal patterns of peaking pipeline exports and consumers demand (residential and commercial customers) in the winter with power plant consumption peaking in the summer months. In addition to the consumption within Texas and fuel losses, there has been 8-10 10 Bcfd (~10,000,000 MMBtu/d) of exports via pipelines and LNG cargos.

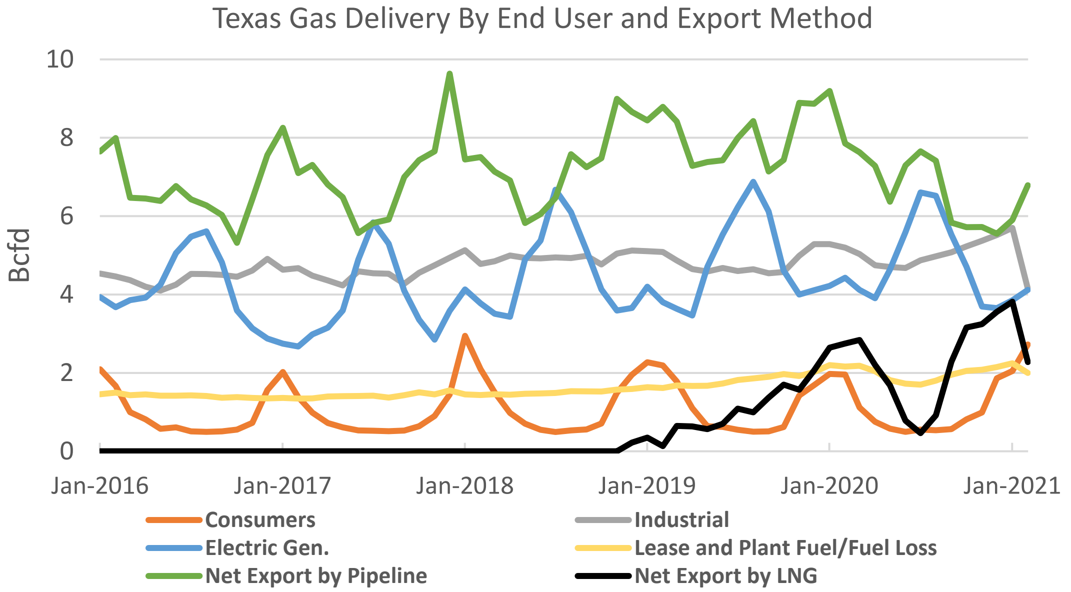

Figure 2.ee. Texas daily natural gas delivery (averaged each month) by end user (in Texas) and export method (pipeline and liquefied natural gas, or LNG, tanker). (Source: GPCMTM)

Pipeline exports from Texas reach the U.S. Northeast and East Coast markets via interstate pipelines that cross Texas' eastern state border. Pipeline exports to the midcontinent and west coast markets, including Mexico, Arizona and California, occur via pipelines that cross Texas' western border. Although many of these pipelines span a wide geographic range, it is fair to say that the exports from East and West Texas serve different downstream markets, with small exceptions.

2.6.5. Texas Pipeline Exports

Since 2016, during the month of February, Texas normally exports a net 6 Bcfd through its interstate pipelines. Figure 2.ff shows Texas pipeline net exports crossing the East and Texas West[92] border via interstate pipelines, since 2016.

Due to a lack of upstream supply, there is a reduction in both imports and exports starting in the second half of the week leading to the storm (see Figure 2.gg). During February 10-13, exports out of Texas dropped significantly below the previous five-year February minimum for the pipelines in the sample. Exports out of East Texas not only dropped to a historically low level, but also 5 out of 16 exporting pipelines reported reversed flow, declining from a net exports of average 2.8 Bcfd in February to net import of 0.3 Bcfd. For the west side, pipeline net exports dropped from 3.2

[92] There is small portion of gas exported from West Texas goes to Mexico through El Pas Gas Pipeline system. After the interconnection meter included for the Texas Export sample, there is one more meter downstream within the Texas border that measures flows to Mexico, and its flow averaged around 114,000 MMBtu/day since 2020. That exported volume can be seen in Figure 2.hh as reported data for the El Paso Natural Gas pipeline.

Bcfd in February to 0.6 Bcfd February 18, a drop of almost **95%** relative to the historical February average of 6 Bcfd.

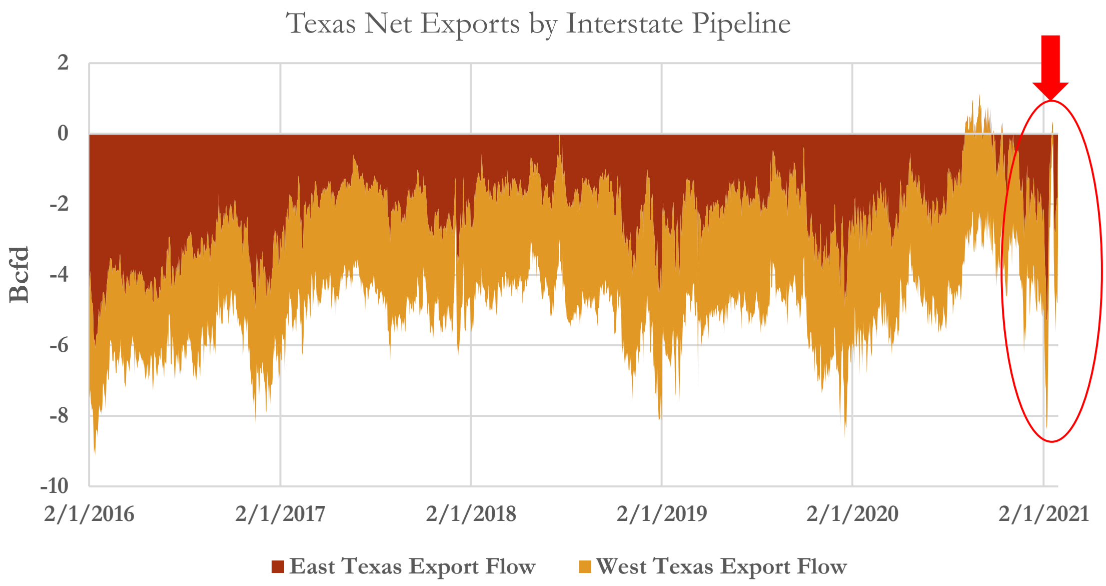

Figure 2.ff. Daily flow rates of Texas net exports of natural gas as in our sample of interstate pipelines crossing Texas' East and Western borders (2016 through February 2021). (Source: Wood Mackenzie)

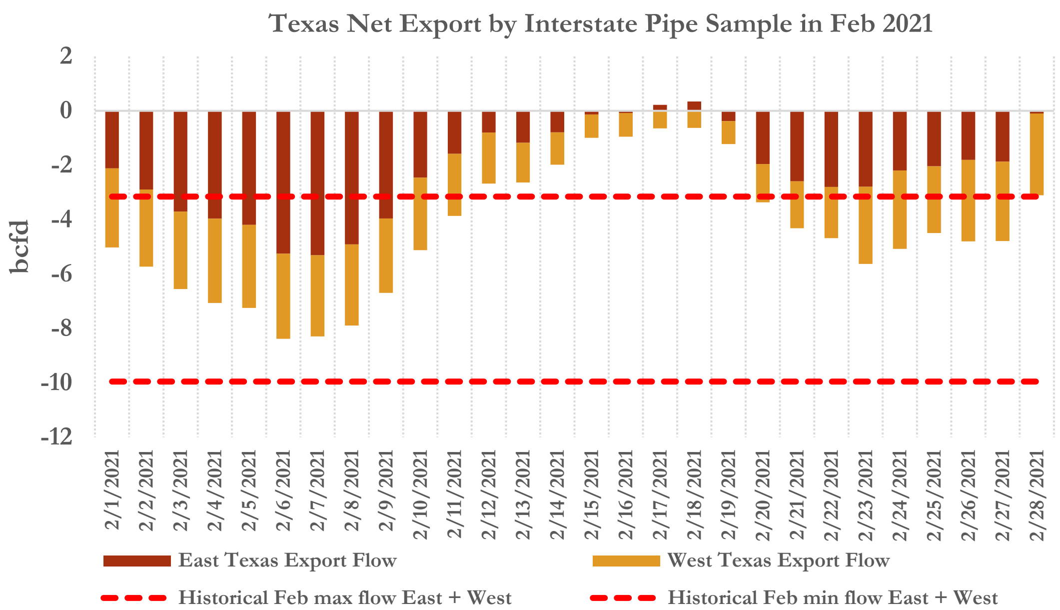

Figure 2.gg. Daily flow rates of Texas net exports of natural gas as in our sample of interstate pipelines crossing Texas' East and Western borders (February 2021). (Source: Wood Mackenzie)

Furthermore, Texas exports to Mexico have averaged around 5.3 Bcfd since January 2021, according to data from Wood Mackenzie. Figure 2.hh shows daily cross border flows, for February 2021 from Texas to Mexico, for a sample of five interstate pipelines that account for about 35% of the total Texas exports to Mexico. This figure shows that the lowest exports to Mexico occurred on February 16, during the middle of the ERCOT blackouts, at 40% below the exports on February 1.

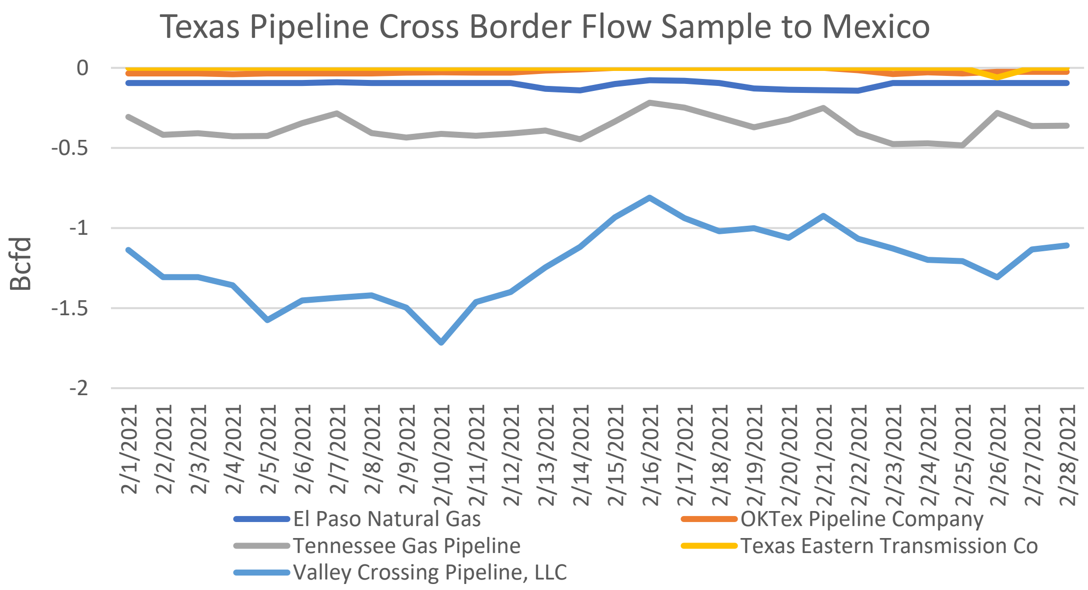

Figure 2.hh. Natural gas flow from Texas to Mexico via a sample of pipelines. (Source: Wood Mackenzie)

2.6.6. Texas LNG exports

The two main markets for U.S. liquified natural gas (LNG) exports are East Asia and Europe. For exported gas, the seasonality is determined by the demand of destination markets. There is a clear winter peaking pattern for LNG cargos with a longer winter (in Europe and Asia compared to Texas). Similar to pipeline exports, LNG exports also peak during the winter with significant heating demand in Europe and Asia. For example, in January, the month before the storm, U.S. LNG exports to China hit a new record high as East Asia was experiencing a winter that was colder than normal.

Texas exports LNG cargos from two existing LNG terminals in Corpus Christi and Freeport that have a total liquefaction capacity of 4.3 Bcfd (Figure 2.ii). Based on EIA reported data on Texas LNG exports, there was a drop in LNG exports of about 50% in February 2021 as compared to the previous month. During the winter storm, there was roughly a 25% drop of LNG cargo[93] sent out from the U.S. as a whole.

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[93] EIA: U.S. Natural Gas Exports and Re-Exports by Point of Exit (https://www.eia.gov/dnav/ng/ng_move_poe2_a_EPG0_ENP_Mmcf_a.htm).

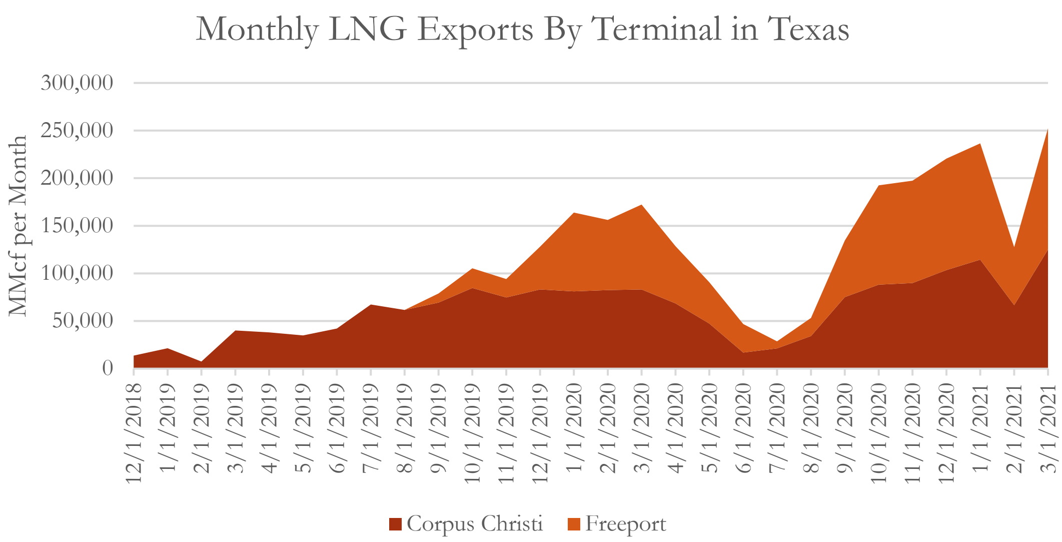

Figure 2.ii. Monthly LNG exports from Texas terminals. (Source: EIA)

2.6.7. Natural Gas Infrastructure Participation in Load Curtailment

Requests for Information (RFI) responses to ERCOT from Qualified Scheduling Entities (QSEs) indicated that approximately 67 locations (electrical meters) that were in ERCOT's ERS program were also in the fuel supply chain for generation resources, including gas refining and pipeline infrastructure. A separate set of data that compared the electric meter IDs of resources in the ERS program with those also registered as critical load with the major TDSPs indicated that 5 locations that self-identified as critical natural gas infrastructure were in the ERS program.[94]

Cross-referencing ERS participating loads in the municipal and cooperative utility regions of ERCOT identified a further 5 locations that, via satellite imagery overlaid with spatial natural gas pipeline data, appeared to also be associated with natural gas infrastructure.

It is possible that there is overlap in the RFI and TDSP datasets mentioned above, but nonetheless it does appear that some power plant fuel supply chain infrastructure, including some self-identified as critical, were participating in paid load reduction programs that would have turned them off when ERCOT deployed ERS resources.

[94] These ERS-participating locations only identified themselves as critical natural gas loads after they had been turned off by the TDSP.

3. Electricity and Natural Gas Financial Flows and Prices

This chapter recounts the economic and financial impacts of the event. Wholesale electricity prices during the event are reviewed, as well as decisions by the PUCT which affected those prices. Natural gas prices are also reviewed and the financial impacts of the price spikes in the state's electricity and natural gas industries are discussed.

3.1. Energy Prices

While the Texas electricity market structure is primarily an energy, not capacity, market,[95] it relies upon market price adjustments to help match supply and demand in real-time. These market price adjustments are the ERCOT Wholesale Electricity and Scarcity Pricing Real-time prices. They are calculated based on three categories: 1) supply and demand, 2) levels of available reserves, and 3) "out of market" reliability actions. During normal operations, prices are set by the offers of power plants, the level of demand, and any constraints[96] on the system. Over the past few years, prices during normal operations have averaged in the low tens of dollars per MWh.

When there is a risk that the supply may not be able to meet the demand, meaning there are low levels of reserves, Real-Time **Reserve** Price Adders are employed to increase electricity prices. These short-term price adders increase revenues to generators and while they are meant to incentivize investment in new generation sources, they also incentivize investment in other technologies, such as demand response. The value of the Real-Time **Reserve** Price Adders is based on the Operating Reserve Demand Curve (ORDC). Via the ORDC, once reserves fall below 2,300 MW, wholesale real time prices increase rapidly to the system-wide offer cap, currently $9,000/MWh.[97] These adders largely explain the rapid swings in real-time wholesale electricity prices, from values below $1,000/MWh to the cap, from February 12-15 (Figure 3.a).

[95] An energy-based electricity market is one in which the production of energy (i.e., megawatt-hours, MWh) is compensated, but not the availability of capacity (i.e., MW), aside from the provision of ancillary services and resources involved in emergency response programs.

[96] Such as transmission constraints.

[97] It is possible for prices to go above $9,000/MWh if additional local constraints become binding.

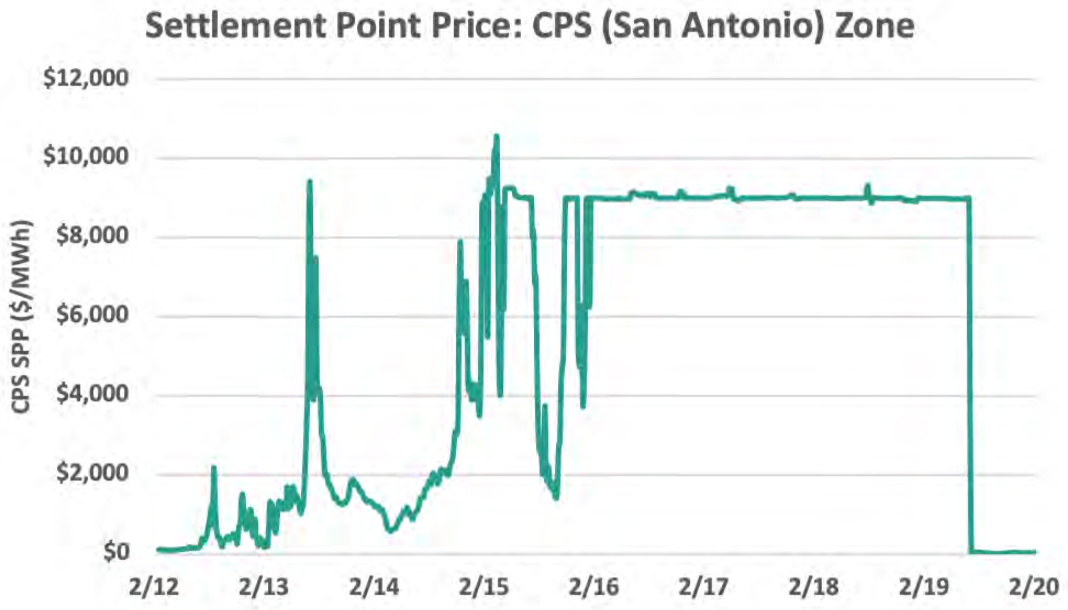

Figure 3.a. ERCOT real-time wholesale electricity prices during February 12-19, 2021 in the San Antonio Zone of ERCOT.

Real-Time **Reserve** Price Adders only include data from "in-market" conditions and do not inlcude "out-of-market" actions[98] that might impact in-market conditions. For example, if reserves drop too low and ERCOT goes into emergency operations and deploys Emergency Response Services (ERS), it may appear that reserves have increased (either via emergency generation brought online or responsive load taken offline). With a higher level of reserves, the value of the Real-Time **Reserve** Price Adders can decline even when scarcity in the market is still very high. To compensate for this possibility, another scarcity pricing mechanism, the Real-Time **On-Line Reliability Deployment** Price Adder (RTORDPA) was developed to keep real-time prices high when emergency actions have been taken.

While some forms of "out-of-market" actions are considered within the calculation of the Real-Time **On-Line Reliability Deployment** Price Adder, firm load shed is not.[99] According to current market protocols, if ERCOT initiates blackouts such that reserves appear high and recalls or cancels other out-of-market actions, price formation is once again based on supply and demand, even if demand is artificially lower due to active blackouts. This is why prices on February 15 were below $9,000/MWh for part of the day (Figure 3.a).

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[98] Such as ERS deployment and firm load shed.

[99] See http://www.ercot.com/mktrules/nprotocols/current, Section 6.5.7.3.1.

3.2. Ancillary Service Prices

The prices of ancillary services (AS)[100] reached new heights during the winter event. Prior to the storm, the prices of regulation up, responsive reserve service, and non-spinning reserves had never exceeded $4,999, $8,956, and $7,000 per MW, respectively. Due to extreme scarcity, pricing protocols drove AS costs (Figure 3.b) much higher than previous levels to $24,993, $25,674, and $12,867 per MW for regulation up, responsive reserve service, and non-spinning reserves, respectively. While the PUCT did take action during the winter event to specify wholesale energy prices outside of the established ERCOT market protocols (see following section describing PUCT orders during the blackout), it did not take similar action on AS prices. The Independent Market Monitor has argued that the prices for these services should have been capped at $9,000 per MW, consistent with the energy offer cap of $9,000 per MWh.[101]

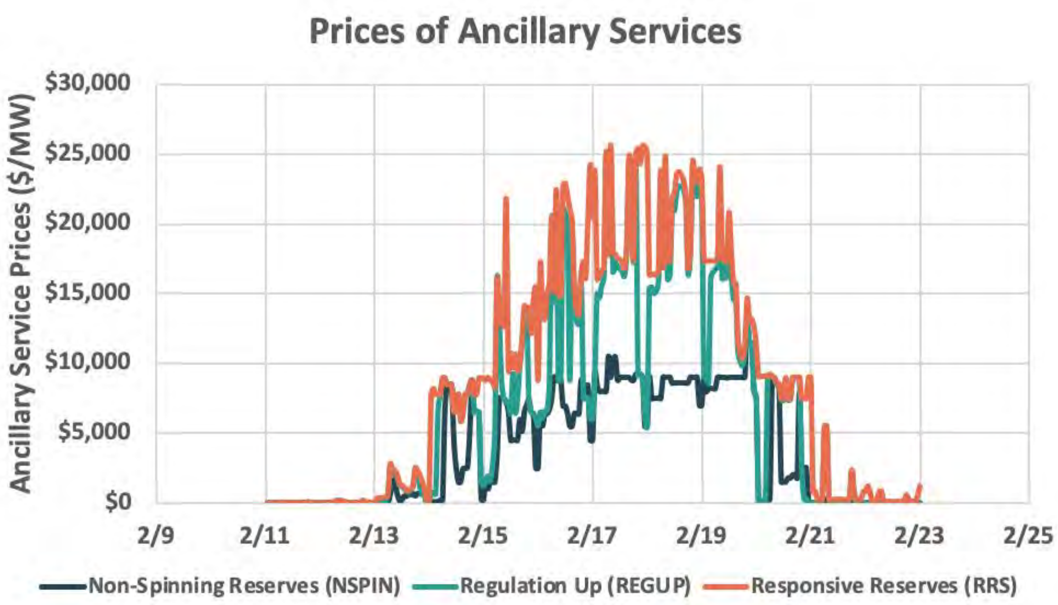

Figure 3.b. Prices of Ancillary Services from February 11, 2021 through February 22, 2021. Source: ERCOT

3.3. PUCT Orders During February Blackout

On Monday, February 15 ERCOT initiated load shed orders and found itself in an unprecedented situation with regard to solving for day-ahead market prices. It was unclear what the value of "demand" should be for the day-ahead scheduling algorithms when power had been cut off to a large percentage of customers. If

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[100] The US Federal Energy Regulatory Commission's Order 888 issued in 1996 defines AS as operating reserves (MW) "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."

[101] http://interchange.puc.texas.gov/Documents/51812_34_1113309.PDF.

ERCOT assumed demand levels based upon the subset of customers that were connected to the grid, then there would be enough generation to meet that demand, and prices would not reflect the level of scarcity in the market. In cases of generation scarcity, the PUCT's scarcity pricing mechanism is designed to increase wholesale prices to the applicable maximum price levels, the system-wide offer cap.[102] During the grid emergency, the PUCT attempted to impose real-time corrections to the market structure to handle this singular event.

3.3.1. Electricity Market Price Changes/Corrections During the Event

During the February freeze events, the PUCT issued two orders under Project 51617 that impacted ERCOT electricity market pricing. The first order[103] determined that prices during the load shedding that began on February 15, 2021 were not reflective of scarcity in the market, because prices were clearing below the system-wide offer cap of $9,000/MWh.[104] The Commission asserted that this outcome was inconsistent with the fundamental design of the ERCOT market. Energy prices should reflect scarcity of the supply. If customer load is being shed, scarcity is at its maximum, and the market price for the energy needed to serve that load should also be at its highest.[105]

The order goes on to instruct ERCOT to "ensure that firm load that is being shed in EEA3[106] is accounted for in ERCOT's scarcity pricing signals." This instruction resulted in setting ERCOT market prices to $9,000/MWh while load shedding was happening. The first order under Project 51617, issued on February 15, 2021, also retroactively raised prices in the market to the market cap of $9,000/MWh if they had been below that value between the period of time that load shed began and the order was

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[102] The system wide offer cap can be set at two different levels, depending on the amount of peaker net margin experienced in the market so far in a given year: the High System-Wide Offer Cap (HCAP) or Low System-Wide Offer Cap (LCAP). See Texas Administrative Code Chapter 25: SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS, Section 25.505 with discussion of Scarcity Pricing Mechanism: http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.505/25.505.pdf.

[103] PUC Project No. 51617: Order Directing ERCOT to Take Action and Granting Exception to Commission Rules. February 15, 2021. https://interchange.puc.texas.gov/Documents/51617_3_1111656.PDF.

[104] The system-wide offer cap in ERCOT is administratively set at $9,000/MWh, also known as the High System-Wide Offer Cap (HCAP), until peaker net margin is reached at which time protocols direct to drop to the Low System-Wide Offer Cap (LCAP) which is *the greater of* either 1) $2,000 per MWh or 2) 50 times the natural gas price index value determined by ERCOT, expressed in dollars per MWh and dollars per MW per hour. The natural gas price index value is the previous daily average price of natural gas as indexed in the Katy Hub (NPRR 952).

[105] PUC Project No. 51617: Order Directing ERCOT to Take Action and Granting Exception to Commission Rules. February 15, 2021. https://interchange.puc.texas.gov/Documents/51617_3_1111656.PDF.

[106] Energy Emergency Alert Level 3 (EEA3) is the highest level of emergency conditions at ERCOT and is the point when ERCOT is allowed to order firm load shed, i.e. instruct Transmission Operators to initiate blackouts.

issued. A secondary order[107] under the same project, issued on February 16, 2021, cancelled the retroactively raised prices section of the first order.

The second part of the February 16, 2021 order suspended the system-wide offer cap price calculation mechanism for LCAP that would have come into effect when the system reached the Peaker Net Margin (PNM).[108] The PNM value increases based on the amount of scarcity pricing seen in the ERCOT market, and it is cumulatively calculated starting from a value of $0 on January 1 of each year. The PNM threshold, defined as $315,000/MW-yr, is based on triple the Cost of New Entry (CONE) for a new peaker power plant to enter the ERCOT market. When the PNM value exceeds $315,000/MW-yr, the system-wide offer cap is supposed to change from the HCAP to the LCAP. ERCOT reports the current Peaker Net Margin levels as of 4:00 pm every day. Figure 3.c shows the PNM values throughout the storm. PNM never met its threshold before 2021, but, by the end of the week of February 15, 2021 reached a value more than double the threshold.

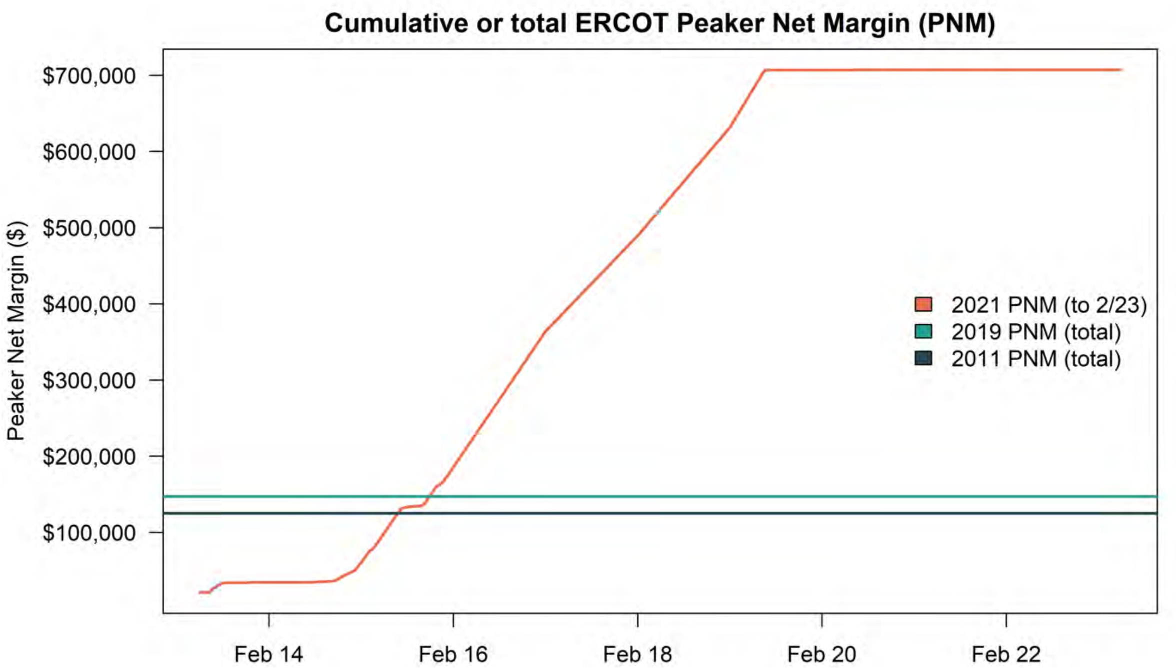

Figure 3.c. The Peaker Net Margin (PNM) for February 14-22, 2021 compared to the total value of PNM reached by the end of the years 2011 and 2019.

Once the PNM is reached in ERCOT, the wholesale price cap changes from HCAP to LCAP. When LCAP and HCAP were defined, it was assumed that LCAP would always be lower than HCAP. However, on February 16, the PUCT stated that it was

[107] https://www.puc.texas.gov/51617WinterERCOTOrder.pdf.

[108] The PNM is used to approximate the amount of profit or margin that a new natural gas-fired power plant might be able to earn, based on the cost of building a new plant, natural gas prices, and the efficiency of a new natural gas-fired power plant.

concerned that the formula for LCAP would actually translate to a higher price than the HCAP price of $9,000/MWh. The PUCT's order in Docket No. 51617 states:

> *[T]he peaker net margin (PNM) threshold [is] established in 16 TAC § 25.505(g)(6). That threshold is currently $315,000/MW-year. As provided in §25.505(g)(6)(D), once the PNM threshold is achieved, the system-wide offer cap is set at the low system-wide offer cap (LCAP), which is "the greater of" either "(i) $2,000 per MWh and $2,000 per MW per hour; or (ii) 50 times the natural gas price index value determined by ERCOT, expressed in dollars per MWh and dollars per MW per hour." Due to exceptionally high natural gas prices at this time, if the LCAP is calculated as "50 times the natural gas price index value," it may exceed the high system-wide offer cap (HCAP) of $9,000 per MWh and $9,000 per MW per hour. 16 TAC § 25.505(g)(6).*[109]

Because of the extreme demand for natural gas and constraints in natural gas supply, the price of natural gas was also much higher than normal during the February event. At one point, daily gas price averages at the LCAP-indexed hub were trading near $400/MMBTU.[110] Tom Hancock, COO of Garland Power and Light, testified that he received a quote for natural gas at $1,100/MMBtu.[111]

If the PUC had not ordered the suspension of the HCAP to LCAP transition, ERCOT would have been required to release a market notice on February 17 notifying the market that PNM had been reached on February 16 and that LCAP would have come into effect on February 18. If the LCAP had been allowed to come into effect, the LCAP calculation would have driven the market price higher than the HCAP on February 18 to $15,359/MWh. The LCAP on February 19 would have been $3,318/MWh. By February 20 the Fuel Index Price was low enough that the LCAP dropped down to $2,000/MWh.[112]

Table 3.a shows what the values for LCAP would have been if the PUCT had not suspended it.[113]

[109] http://interchange.puc.texas.gov/Documents/51617_3_1111656.PDF.

[110] MMBTU = million British Thermal Units

[111] February 25 and 26, 2021, Joint Hearing: State Affairs and Energy Resources Part 1 and Part 2, https://house.texas.gov/video-audio/committee-broadcasts/87/.

[112] The LCAP is the greater of either $2,000 per MW per hour, or 50 times the natural gas price index value determined by ERCOT, expressed in dollars per MWh and dollars per MW per hour. This calculation assumes that the PUCT would have still have forced the market price to the system wide offer cap, but would have left the LCAP in place.

[113] PUC Project No. 51617: Order Directing ERCOT to Take Action and Granting Exception to Commission Rules. February 15, 2021. https://interchange.puc.texas.gov/Documents/51617_3_1111656.PDF.

Table 3.a. Calculation of what LCAP would have been if not for the PUCT orders.[114]

Date	LCAP ($/MWh)
2021-02-18	$15,359.00
2021-02-19	$3,318.00
2021-02-20	$2,000.00

Figure 3.d shows ERCOT market prices from February 14 to the end of February 19 without the LCAP (i.e., what actually happened) and if the LCAP had been allowed to come into effect as per protocols.[115]

Figure 3.d. Approximate market prices with and without the LCAP (data used to calculate the LCAP provided by ERCOT).[116]

Because Peaker Net Margin was achieved on February 16, as per the ERCOT protocols, LCAP would have come into effect on February 18. On February 18, market prices would have increased from approximately $9,000/MWh (the HCAP) to $15,359/MWh. For the hours of scarcity pricing on February 19, the LCAP would have reduced prices from $9,000/MWh to $3,318/MWh. Given that the LCAP would have been approximately $6,360/MWh higher than the HCAP for the entire day on February 18, and about $5,680/MWh lower for only a short period of time on

[114] LCAP values were calculated based on the Fuel Index Price data provided by ERCOT.

[115] We make the assumption that scarcity pricing would have ended at the same time as it did in reality.

[116] These estimated prices are just the LCAP System Wide Offer Cap (SWOC) and do not include any estimate of system dynamics that, in reality, can push prices higher than the SWOC.

February 19, the overall energy costs for that week would have been approximately $5.2 billion dollars higher (Figure 3.e), or about 11% more absent action by the PUCT.

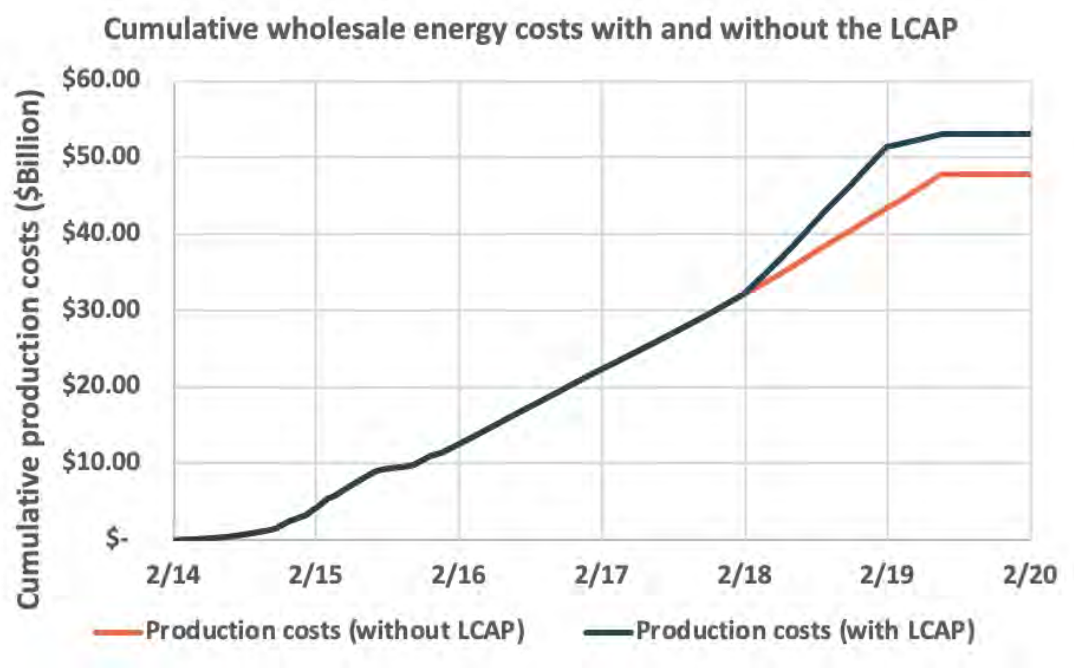

Figure 3.e. Cumulative wholesale energy costs with and without the LCAP.

Figure 3.e shows the difference in cumulative market energy costs with and without the LCAP.[117] Because the LCAP would not have come into effect until February 18, energy costs are the same for both sets of market prices until then.

3.4. Financial Fallout

Regulators and policy makers have very limited information about contracts and hedging relationships among participants in the State's electricity and natural gas industries. This is particularly true for financial transactions negotiated outside of ERCOT's formal day-ahead and real-time markets for energy and ancillary services. Such information is generally regarded as confidential. Thus, when faced with the decisions regarding whether to raise prices to attract more supply and encourage price-sensitive loads to reduce demand, or whether to "re-price" energy transacted through ERCOT's markets, the PUCT Commissioners stated that they were unable to determine which market participants might benefit or be disadvantaged by such actions.[118]

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[117] These values are calculated by multiplying the load times the price with and without the LCAP as shown in Figure 3.d. While much energy in ERCOT is transacted in the Day-Ahead Market (DAM), it is not known how different relative DAM prices would have been had LCAP not been suspended. Thus, while the absolute numbers might be different, the percentage increase might be similar.

[118] See PUCT Open Meeting of March 5, 2021, item 22: http://www.adminmonitor.com/tx/puct/open_meeting/20210305/.

On April 14, 2021, ERCOT reported cumulative aggregate "short payments" of approximately $2.9 billion, and that it would take 96 years to collect the amount outstanding using its standard Default Uplift Invoice process.[119] This estimate was raised to $2.99 billion on May 14, 2021.[120] Of that, $1.86 billion relates to the default of Brazos Electric Power Cooperative Inc., which filed for bankruptcy on March 1, 2021. Other market participants that had failed to pay amounts owed to ERCOT at that time included Rayburn Country Electric Cooperative, Eagles View Partners LTD, Energy Monger LLC, Entrust Energy Inc., GBPower, Griddy Energy LLC, Gridplus Texas Inc., Hanwha Energy USA Holdings Corp., Iluminar Energy LLC, MQE LLC, Power of Texas Holdings Inc., and Volt Electricity Provider LP. As a consequence of receiving less revenue than ERCOT has invoiced to the market, ERCOT has reduced payments to market participants that are owed revenues from the market for congestion revenue rights.[121]

Under present market rules, unpaid amounts are uplifted to all market participants based on each market participant's MWh activity (energy bought or sold through ERCOT's formal markets) in the month prior to the defaulted payment.[122] However, these uplift mechanisms are limited to $2.5 million per 30 days.

The financial impacts on electricity retailers depend upon the degree to which their price risk was hedged and how service outages affected their obligations to provide energy during the event. Griddy Energy LLC, Entrust Energy Inc., and Power of Texas Holdings Inc. have each filed for bankruptcy.[123,124,125] Their certificates to serve customers in the ERCOT market were revoked, and their customers were moved to other retailers through ERCOT's "mass transition event" process. The customer bases of GridPlus MQE LLC (My Quest Energy), GB Power, Volt Electricity Provider LP, Energy Monger, and Iluminar Energy were acquired by JP Energy Resources, while the customer bases of Entrust Energy Inc. and Power of Texas Holdings Inc. were acquired by Rhythm.[126] Just Energy Group – using the brand names Amigo Energy, Filter Group Inc., Hudson Energy, Interactive Energy Group, Tara Energy, and

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[119] Electric Reliability Council of Texas, Inc.'s notice of planned implementation of default uplift invoice process. PUCT Project No. 51812: Issues related to the state of disaster for the February 2021 winter weather event.

[120] ERCOT Market Notice M-A051421-01, May 14, 2021. M-A051421-01 Estimated Cumulative Aggregate Short Pay Amount (ercot.com)

[121] http://www.ercot.com/services/comm/mkt_notices/archives/5377.

[122] http://www.ercot.com/content/wcm/lists/226521/Senate_Jurisprudence_031021_FINAL.pdf.

[123] https://www.bizjournals.com/houston/news/2021/04/01/entrust-energy-bankruptcy-behind-the-deal.html.

[124] https://www.cbsnews.com/news/griddy-energy-texas-files-bankruptcy/

[125] https://www.bankruptcyobserver.com/bankruptcy-case/POWER-OF-TEXAS-HOLDINGS.

[126] https://www.prnewswire.com/news-releases/rhythm-acquires-customers-of-entrust-energy-inc-and-power-of-texas-holding-inc-301241112.html.

terrapass – also filed for bankruptcy after sustaining an estimated $250 million loss.[127]

Media reports provide some insights into how the event impacted the financial standing of some market participants. However, we emphasize that our Committee is unable to audit, verify, and affirm any of the financial information repeated here.

NRG, the largest retailer in terms of market share in ERCOT,[128] reported a negative impact of $500 million to $700 million.[129] The second-largest retailer, Vistra, expects its financial losses due to the storm to be around $2 billion.[130] Both NRG and Vistra own and operate power plants, in addition to serving retail customers.

The impacts on municipal utility systems were mixed. The state's largest municipal electric and natural gas provider, CPS Energy reported losses on natural gas fuel purchases of between $675 and $850 million, and losses on purchased power costs in the range of $175 million to $250 million.[131] In contrast, Austin Energy may have benefited by about $54 million.[132] The Brownsville Public Utility Board has estimated a shortfall of $32.1 million.[133]

Generation owners whose fleets of generation resources operated well and were able to provide generation that met or exceeded their commitments[134] were generally not financially harmed, and could have profited if a generator was able to provide generation that met or exceeded its obligations. Many generators, however, have locked-in a price for their generation through a contract or exchange, thus limiting its profit potential. If the generation owner is dependent upon natural gas as

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[127] Gold. R. (2021). Texas Power Market Is Short $2.1 Billion in Payments After Freeze; Electric retailers failed to make payments for power purchased when prices skyrocketed during the freeze, state grid operator says. The Wall Street Journal. Feb. 27.

[128] https://www.sciencedirect.com/science/article/abs/pii/S1040619020301408.

[129] Bank of America Global Research, NRG Energy, Uri Impacts Unpacked: More Constructive Backdrop than Thought. May 6, 2021. NRG Energy, Inc. Financial Update on Winter Storm Uri Impacts: https://finance.yahoo.com/news/nrg-energy-inc-financial-winter-100100947.html.

[130] Bank of America, VST US: Uri Impacts More Complicated Than We Thought. April 27, 2021.

[131] https://newsroom.cpsenergy.com/cps-energy-will-be-taking-decisive-action-to-protect-customers-and-the-san-antonio-community-from-price-gouging-for-illegitimate-fuel-power-costs/.

[132] https://emma.msrb.org/P21441577-P21119174-P21530470.pdf.

[133] https://www.yahoo.com/now/brownsville-public-utilities-board-tx-000816313.html?guccounter=1&guce_referrer=aHR0cHM6Ly93d3cuZ29vZ2xlLmNvbS8&guce_referrer_sig=AQAAAKwSPg3ZndRfIqbgkl2hbe9Bp-QR7-qBQeINCXN5DbGZX7ha6if6FgC-zfj-MH4C8Cm4VEnmEnbXQuLSN_vGRLS5rD4CHQS6omLbqtR2gU4g-EFOI257SWf4vyv_mw1ffecwHj5Y91c-FAtrHN9PwiZ-bVT_v-uZtmDHctJ62UOK.

[134] A commitment might result from the sale of energy through a purchased power agreement (PPA), some other out-of-market bilateral contract between a generator and a counterparty, the sale of generation through a non-ERCOT market such as the Intercontinental Exchange (ICE), or an award in ERCOT's formal day-ahead market.

a fuel and the owner had exposure to the high natural gas spot prices, the net impacts would be unclear without more detailed information.

A generation owner whose fleet of generation assets failed to perform well is likely to have experienced a negative financial impact. To meet obligations through ERCOT's formal markets, such an entity may have been required to buy replacement energy at a price as high as $9,000 per MWh (or higher). It has been reported that the state's four largest power producers – Vistra, Excelon Corp., NRG Energy Inc., and Calpine — collectively lost between $2.5 billion and $4 billion due to power plant performance problems, high natural gas prices, fuel supply constraints, and other problems.[135]

Many owners of wind generation projects that failed to perform reported deep financial losses.[136,137,138,139,140] Wind generation owners often receive revenue through financial hedges. Wholesale market prices in excess of contract prices and/or wind generation below contracted quantities may trigger a payment to a counter-party (often a financial institution). This has prompted at least one lawsuit by a wind farm against a financial institution, seeking to avoid payments.[141]

Owners of natural gas-fueled power plants with performance below expectations reported losses, including Exelon.[142]

Natural gas suppliers able to produce and transport natural gas to a market for a sale based on the spot price profited during the winter week. Natural gas producers reporting large gains due to the storm include Antero Resources Corp.,[143] Comstock

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[135] Blunt, K, Gold, R. (2021) A Texas-Sized Problem: Overhauling the Power Market --- The February storm exposed flaws in the state's hands-off approach to electricity. But changes promise to be complex and costly as lawmakers try to balance reliability and pricing. The Wall Street Journal. April 17, 2021

[136] https://www.windpowermonthly.com/article/1707858/texas-blackouts-hit-rwe-renewables-profits.

[137] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/innergex-expects-up-to-c-60m-financial-hit-from-texas-storms-outages-62715363.

[138] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/rwe-takes-material-earnings-hit-from-texas-freeze-as-impact-on-europeans-emerges-62756391.

[139] https://www.globenewswire.com/news-release/2021/02/24/2181893/0/en/Clearway-Provides-Update-Regarding-Recent-Texas-Weather-Events.html.

[140] https://www.windpowermonthly.com/article/1715644/texas-freeze-lower-european-winds-hit-rwe-q1.

[141] https://www.kltv.com/2021/03/12/lawsuit-claims-tx-panhandle-wind-farm-not-financially-responsible-after-winter-storm-causes-frozen-turbines/.

[142] https://www.bloomberg.com/news/articles/2021-02-24/exelon-sees-profit-cut-by-up-to-710-million-from-texas-cold.

[143] https://seekingalpha.com/article/4413442-antero-resources-growth-bug-bites-again.

Resources Inc., [144] and Macquiarie Group.[145,146] Energy Transfer expects a $2.4 billion gain,[147] and BP reportedly made over $1 billion.[148] Kinder Morgan, an owner and operator of natural gas pipelines, terminals and storage, announced a $1 billion windfall profit from gas sales during the storm.[149] Yet a gas supplier unable to produce and transport gas, or who was involved in a hedging contract might have not been so fortunate.

Natural gas local distribution companies (LDCs) generally "pass-through" the commodity price of gas to ratepayers, such that LDCs' profits do not change based on wholesale gas prices. To soften the impact on ratepayers, the pass-through of high costs due to a price spike may be achieved over some extended period of time and securitization might be used to reduce debt carrying costs to the benefit of utilities and their consumers.[150] Some LDCs, including Atmos Energy, have reported challenges in financing the purchase of gas for resale to their customers during and following the winter event in light of the high prices and extended cost recovery period.[151] Some LDCs also anticipate high billing arrearages, as retail natural gas customers face utility bills with higher prices for the natural gas commodity.[152]

Various financial institutions (e.g., banks and financial trading companies) provide financing and hedges to participants in ERCOT's markets. The impacts upon companies in this sector will vary, depending upon the performance of their clients, the financial viability of their clients, and contractual terms and conditions. There

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[144] https://theintercept.com/2021/02/23/texas-winter-storm-gas-prices-executives/.

[145] https://www.afr.com/companies/financial-services/macquarie-jacks-up-profits-on-texas-big-freeze-20210222-p574jo.

[146] https://www.reuters.com/article/us-macquarie-group-outlook/australias-macquarie-reaps-windfall-profits-from-u-s-winter-freeze-idUSKBN2AM01O.

[147] https://www.bloomberg.com/news/articles/2021-05-06/energy-transfer-made-2-4-billion-gain-from-texas-winter-storm.

[148] https://www.houstonchronicle.com/business/energy/article/BP-likely-made-at-least-1B-during-Texas-power-16133739.php; https://www.rigzone.com/news/wire/bp_execs_coy_about_texas_freeze_impact_on_gas_trading-27-apr-2021-165272-article/.

[149] Gerson Freitas, Kinder Morgan Posts Blowout Profit on Texas Winter Storm, Bloomberg. April 22, 202; Harry Weber, Kinder Morgan gets big first-quarter lift from gas price volatility due to Texas freeze. S&P Global Platts, April 21, 2021.

[150] Bank of America Global Research (2021). GAS LDC 1Q21EPS preview: The day after the storm; measuring the Feb URI. April 19, 2021. See also, HB1520 which passed in the Texas House on April 20, 2021.

[151] https://www.reuters.com/article/us-usa-weather-texas-winners-factbox/factbox-winners-and-losers-in-energy-sector-from-texas-cold-snap-idUSKBN2AQ260.

[152] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/gas-utilities-face-unprecedented-test-in-digesting-astronomical-storm-costs-62961274.

have been media reports suggesting windfall profits for firms in this sector,[153,154] though we have not been able to independently confirm these claims.

The near-term financial impacts on retail customers are dependent upon their agreements with retail electric providers or other load-serving entities (e.g., rural electric cooperatives and municipal utility systems). The vast majority of residential energy consumers in areas of the state opened to retail competition buy electricity under fixed-price rate plans and may see little impact on their electricity costs in the near-term. Residential customers on variable pricing plans may have received unusually high electric bills, as widely reported in the media. Over time, an increase in wholesale electricity prices tends to get partially passed-through to the prices quoted in new or renewed retail electricity offers from retailers (Hartley et al., 2019, Brown et al., 2020).

[153] Chung, J, Blunt, K. (2021). Texas Storm is a Windfall for some Wall Street Firms. The Wall Street Journal. April.

[154] Meyer, G., Noonan, L., Bank of America reaps trading windfall during Texas blackouts, Financial Times, March 5, 2021, at: https://www.ft.com/content/321c4fb2-ca11-4e15-9ef5-05598dd04012.

4. A Comparison to Winter Events in 2011 and 1989

It is instructive to compare the electricity industry's performance during the February deep freeze to the two earlier winter events which led to electrical outages in the ERCOT grid:

- December 1989
- Early February of 2011.

4.1. December 1989 Winter Event

During December 21-23, 1989, the weather was similarly cold as compared to mid-February of 2021. The low temperature in Austin was the same during both events. The low in Dallas was just 1^{o}F colder in 2021 than in 1989. Houston reached a low temperature of 7^{o}F during the 1989 winter event, or 6^{o}F lower than the low temperature reached in Houston in 2021.

However, the electricity industry in Texas was far different in 1989. It was dominated by vertically-integrated electric utilities in 1989, and there was little market-wide control over operations.

Months before the 1989 winter event, the PUCT staff warned of reliability concerns associated with ERCOT's high reliance on natural gas for electricity generation, which represented 53% of the generation mix in 1989.[155]

> *Dependence on natural gas in the ERCOT generation mix (almost three times the national dependence) represents some reliability concern. … if severe winter conditions were to occur, there could be curtailment of gas supply for generating units. If such curtailment does occur and it becomes necessary to substitute fuel oil for gas, the rated capability of some units will be reduced due to equipment design, pipeline delivery constraints and/or oil inventories.*[156]

During the December 1989 winter storm, demand for electricity increased, along with the demand for natural gas for space heating. Weather-related equipment problems caused generating units to go offline. Power plant outages were traced to frozen instruments, frozen valves, boiler tube leaks, frozen batteries, and fish plugging cooling water intakes. Consistent with the concerns expressed by the PUCT staff earlier in the year, natural gas flows were curtailed by Lone Star Gas to the

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[155] Public Utility Commission of Texas, Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas, 1988, Volume I: Summary of Results and Recommendations, Feb. 1989, p. 6.6.

[156] Public Utility Commission of Texas, Long-Term Electric Peak Demand and Capacity Resource Forecast for Texas, 1988, Volume I: Summary of Results and Recommendations, Feb. 1989, p. 6.7.

utilities in North Texas in early hours of December 21st, and many utilities serving South Texas lost their natural gas supplies the following morning. There was firm load shed of 1,710 MW (4.5% of peak load) on December 23rd, 1989. "Rolling" blackouts were achieved, lasting less than 10 hours for any given region, and different regions of ERCOT experienced different durations of outages. System frequency remained above 59.65 Hz throughout the event. At the time, the 1990 PUCT report on the 1989 winter event stated that "The combination of heavy demand and loss of generating units caused near loss of the entire ERCOT electric grid.[157] We now know the generator outages and blackouts were far smaller in magnitude than the outages in February 2021.

The financial impacts of the December 1989 event were quite modest in contrast to later events. Natural gas prices remained fairly stable in December 1989, as did retail electricity prices. The PUCT reviewed the costs incurred by the utilities under its jurisdiction and approved recovery of those costs determined to be reasonable and necessary and prudently-incurred. The utilities reported that corrective actions would involve costs of less than $3 million (which did not include costs that might be incurred by non-utility generators).[158]

4.2. February 2011 Winter Event

During the first week of February 2011, unusually cold and windy weather prevailed over the southwest U.S. While the weather was not as severe as during the winter events in 1989 and 2021, it nonetheless triggered similar problems. The FERC 2011 summary report of the winter event noted a total of 210 individual generating units in ERCOT experienced either an outage, a derate, or a failure to start, leading to a controlled load shed of 4,000 MW, affecting 3.2 million customers (FERC, 2011).[159] The FERC 2011 summary report also noted "... 193 ERCOT generating units failed or were derated, representing a cumulative loss of 29,729 MW" that was not a simultaneous outage in capacity and a peak of 14,702 MW in "... generation offline from such trips, derates, or failures to start." Thus, approximately one-third of ERCOT's total generation fleet was unavailable at the lowest point of the event.[160] Generation loss involved units of all ages and multiple types of fuel.[161] The Texas

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[157] Public Utility Commission of Texas, Electric Division Evaluation Report, Electric Utility Response to the Winter Freeze of December 21 to December 23, 1989, November 1990.

[158] Electric Division Evaluation Report, Electric Utility Response to the Winter Freeze, Public Utility Commission of Texas, November 1990.

[159] FERC/NERC (2011), p. 1.

[160] FERC/NERC (2011), p. 7.

[161] Trip Doggett, ERCOT CEO (2011), ERCOT Presentation to Joint Senate Committees, February 2, 2011 Grid Emergency Events. February. Slide 10. http://www.ercot.com/content/news/presentations/2011/Senate_EEA_Presentationfinaltg.pdf

Reliability Entity (TRE) report on the same blackout noted "... a total of 225 individual generator units experienced a unit trip, a unit de-rate, or a failure to start ..." resulting "... in a maximum of 14,855 Megawatts (MW) of unplanned unavailable capacity during the period. These generation issues, combined with pre-scheduled generation outages of 12,413 MW, created a significant generation capacity shortfall in the ERCOT Region." (TRE, 2011) We do not have an explanation for these variations in the number of generator outages within the FERC report and between the FERC and TRE reports, but they are within about 30 generation units. Both FERC and TRE noted very similar forced outages and derates of 14,702 MW and 14,855 MW, respectively.

On February 2, 2011, wholesale market prices reached the offer cap, which had recently been increased to $3,000 per MWh. The EEA Level 3 lasted from 5:43 a.m. to 2:01 p.m. on that day.[162] Frequency remained above 59.5 Hz throughout the event.[163]

The natural gas system could not meet demand. The production losses stemmed principally from freeze-offs, icy roads, and electric outages to the equipment used in the natural gas industry. Electric blackouts called by ERCOT and implemented by the TDSPs along with customer electrical curtailments for other reasons caused or contributed to 29% of the natural gas production outages in the Permian basin and 37% of the natural gas production outages in the Fort Worth basin.[164] These outages prevented the operation of electric pumping units and compressors on gas gathering lines.

The FERC/NERC inquiry into the 2011 events concluded that gas shortages were not a significant cause of the electric generator problems during that event, nor were rolling electrical blackouts a primary cause of the production declines at the wellhead. Nonetheless, this gas and electric interdependency was a contributing factor.[165]

In response to the 2011 event, the 2011 session of the Texas legislature passed a law requiring the PUCT to analyze the preparedness of power plants for extreme weather events as in Section 186.007 of the Texas Utilities Code.[166] The statute required that

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[162] Kent Saathoff of ERCOT Staff (2011), TDSP Curtailment Procedures and Service Restoration Priorities Plan, slide 4. http://www.ercot.com/content/news/presentations/2011/TDU%20curtailment%20workshop%20PUC%2011-3-11.pdf.

[163] Kent Saathoff of ERCOT Staff (2011), TDU Curtailment Procedures and Service Restoration Priorities Plan, slide 5. http://www.ercot.com/content/news/presentations/2011/TDU%20curtailment%20workshop%20PUC%2011-3-11.pdf.

[164] FERC/NERC (2011), p. 9.

[165] FERC/NERC (2011), p, 11.

[166] Texas Util. Code Section 186.007.

power plants submit information to the PUCT about their readiness for extreme weather events, and that the PUCT prepare a report on "power generation weatherization preparedness." More specifically, the statute required the PUCT to "analyze and determine the ability of the electric grid to withstand extreme weather events in the upcoming year" considering anticipated weather patterns. The law also authorizes the PUCT to enact rules relating to the implementation of the weatherization report, and to require power plants to amend inadequate weatherization plans. The PUCT enacted Substantive Rule 25.53 in response to the 2011 legislation.[167] The 2011 law states that this weatherization review process must result in a report by the end of September 2012, but subsequent reports could be filed as deemed necessary. The 2011 law does not explicitly require annual weatherization reports. To date only one report, in 2012, has been filed by the PUCT under Section 186.007, and this 2012 report, written by Quanta Technologies, LLC, identified best practices for winterizing power plants and winterization shortcomings at ERCOT plants.[168] We could not verify whether ERCOT generators implemented those recommendations, or whether the PUCT followed up with generators in connection with those recommendations. ERCOT, however, has held annual "winter weatherization workshops." including a September 2020 workshop that featured winter weather forecasts for 2020-21.[169]

4.3. Comparison of the Three Events

Table 4.a summarizes key indicators for comparison of the 1989, 2011, and 2021 winter events that triggered power outages in ERCOT. Caution must be exercised, however, when drawing any conclusions based on a comparison of these three events. The generation fleet has evolved over time. We have less reliance on coal and greater reliance upon renewable energy resources today. Moreover, the electric and natural gas industries have evolved over the past 32 years. Yet, some observations can be made.

Each of the three winter storms resulted in customer outages or blackouts. During each event, weather-related problems forced outages and de-ratings at power plants and the availability of natural gas to gas-fired power plants was a notable problem.

But these were otherwise very different events. The extent and duration of the outages were far greater in 2021. We are unaware of any loss of life being linked to the electrical outages in 1989 and 2011.

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[167] https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.53/25.53ei.aspx.

[168] Report on Extreme Weather Preparedness, Best Practices, Quanta Technologies, LLC (September 27, 2012), pp. 7-18.

[169] FN--ERCOT and Texas RE Generator Winter Weatherization Workshop by (Webex Only), URL: www.ercot.com/calendar/2020/9/3/210162.

Table 4.a Summary of key metrics summarizing the severity of the 1989, 2011, and 2021 winter storms causing significant power generation outages and derates, load shedding, and low frequency conditions in ERCOT.

Descriptor	**Dec. 1989[a]**	**Feb. 2011**	**Feb. 2021**
Peak Load Estimated w/o load shed (MW)	~ 38,000 + 1,710	59,000[#]	76,819 (estimated by ERCOT)
Maximum load shed (MW)	1,710 4.3% of peak load	~4,900 8.3% of peak load	20,000 26% of peak load
Peak forced and planned Generation Outage as nameplate Capacity (MW) (planned outage in parenthesis)	~ 13,000 (not necessarily simultaneous, unable to determine peak simultaneous outage)	~ 27,200 (12,413)	52,037 (ERCOT, 2021a)
Generation units experiencing an outage (number)	86	193 to 225[170]	~ 585
Customers (meters) without power (millions)	not quantified in 1990 PUCT report	3.2	~ 4.5 (Busby *et al.,* 2021)
Duration of EEA Level 3 condition (hours)	0-9 hours of load shed spread over two different intervals (depending on region)^	~8	~105
Lowest Grid Frequency (Hz)	59.65	59.576	59.302
Natural Gas flows were curtailed to electric utilities and/or generation units before and during blackouts	Yes (< ~1,000 MW)	Yes (1,282 MW)*	Yes (6,700 MW at peak)
Did TDSPs cut off electricity supply to natural gas infrastructure?	unknown	Yes	Yes

a: Information from PUCT (1989).
#: Figure 2 of Potomac Economics (2011).
^: The Emergency Energy Alert (EEA) system did not exist in 1989. ERCOT requested utilities enact Emergency Electric Curtailment Plans (EECP) from Dec. 22, 8:40 am -12:00/12:30 pm (for North & South Texas) and Dec. 23, 6:40 am – 12:40 pm. Utilities reported firm load shedding as occurring on December 23 for: 4 hours (Houston Power & Light), 3.6 hours (City Public Service San Antonio), 2.5 hours (Lower Colorado River Authority).
*: FERC (2011), page 191.

[170] FERC (2011) report states "But over the course of that day and the next, a total of 193 ERCOT generating units failed or were derated, representing a cumulative loss of 29,729 MW." The Texas RE report states the number of failed or derated generating units was 225.

The 1989 event preceded the introduction of competitive generation and retail markets in ERCOT. The PUCT was able to review the costs incurred by the utilities under its jurisdiction and approve recovery of winterization investments through rates of those costs determined to be reasonable and necessary and prudently-incurred. These post-freeze winterization investments were estimated in the millions of dollars in aggregate (PUCT, 1990). Natural gas prices remained stable throughout the event. There were no significant “wealth transfers” between electricity suppliers and retailers or between industries.

During the 2011 event, the market structure in ERCOT was similar to today’s market structure. A nodal wholesale market structure had been introduced in December 2010 – two months prior to the event. Yet, the wholesale offer cap was a much-lower $3,000 per MWh during the 2011 event – one-third of what it is in 2021. As during the 1989 event, natural gas prices remained fairly stable, in contrast to the extreme spike in gas prices experienced in 2021. The financial impacts of the 2011 event received relatively little attention, and we are unaware of data or published estimates of financial impacts.

Ninety-six of the 585 generating units (16.4%) in ERCOT that reported outages or deratings during the winter event in February 2021 also experienced problems during the February 2011 event.[171] This includes four coal-fired generating units which were operated at reduced output levels during the 2021 emergency.[172]

Eight generating units experienced outages or de-ratings during each of the three winter emergencies of 1989, 2011, and 2021. For example, the large Limestone coal/lignite Unit 1 (presently owned by NRG Texas Power LLC) reported problems from low feedwater flow and frozen instruments in 1989, experienced problems in 2011, and was partially de-rated during the winter storm of February 2021. The other seven generating units reporting outages or deratings during all three events were relatively small natural gas-fired combustion turbines or cogeneration facilities.[173] However, this comparison of performance of plants during the three events has limited value, since many power plants in operation today and in 2011 were built after 1989.

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[171] Sources: http://www.ercot.com/content/wcm/lists/226521/Unit_Outage_Data_20210312.xlsx and PUCT Project No. 27706, filing by ERCOT, Attachment A.

[172] Calaveras Unit JKS2, Oak Grove SES Unit1A, Oak Grove SES Unit2, and Limestone Unit LEG_G1.

[173] These are Air Liquide’s Bayou Cogen station’s units G2 and G4; Unit1A at Luminant’s Stryker Creek plant; Unit 7 at Luminant’s Mountain Creek facility; CT4 at Luminant’s Morgan Creek plant; and two very small gas turbines at the TH Wharton and WA Parish plants, which are presently owned by NRG Texas Power LLC. Based on publicly-available sources: PUCT Project No. 27706, filing by ERCOT, Attachment A; PUCT (1990); and http://www.ercot.com/content/wcm/lists/226521/Unit_Outage_Data_20210312.xlsx

5. Summary

The Energy Institute at the University of Texas at Austin assembled a team of faculty and researchers to identify and review credible sources of data in an attempt to provide a factual account of what happened and what went wrong during the winter disaster. Our hope is that this analysis will provide a reasonable basis for subsequent policy decisions designed to improve the performance and resilience of the State's energy systems.

Because of time constraints, data limitations, and the intention to limit the report scope to events and data rather than recommendations, many questions have been left unanswered. For example, we did not analyze the sequences of rolling outages (e.g., on a circuit-by-circuit basis), and we do not yet have a good understanding of what it might take to deploy advanced metering systems to achieve customer outages in a more "rolling" and "surgical" manner than occurred during the 2021 event. We also did not explore whether any natural gas infrastructure facilities were committed to providing an ancillary service during the event, but were unable to perform due to a disruption in their electricity supply.

Our understanding of natural gas flows during the event is incomplete, despite having acquired and analyzed a proprietary source of natural gas data. For example, even without weather-related equipment failures, it is unknown to what level of peak flow rate and duration the Texas natural gas system can deliver natural gas demand to all customers during a winter event such as Winter Storm Uri. A full understanding of the hedging positions and out-of-market contractual agreements among ERCOT market participants will probably never be known given the confidentiality surrounding such agreements, thus limiting our understanding of the full economic consequences of the event. Robust estimations of the cost of better-winterizing the energy supply system will require further site-specific analysis.

It is our hope that subsequent studies – by The University of Texas, other universities, FERC, NERC, and other organizations – may be able to make progress in these areas.

We have intentionally avoided making policy recommendations in this report. Once policy directions are better-established, we would be pleased to contribute analysis designed to explore implementation strategies, the impacts of various policy options, and related issues.

We note that while we were completing this report, the Texas Legislature passed multiple bills in response to the February event, including Senate Bills 2 and 3. These bills focus on weatherization of infrastructure as well as the governance of the grid operator and regulator. Other bills in the 2021 session, such as House Bill 4492, focus on the financial impacts of the winter storm.

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Conflict of Interest Statements

Various participants in the state's natural gas and electricity markets fund research at The University of Texas, and some contributors to this report provide consulting assistance to companies or organizations involved in the energy industry. Disclosures of any relationships that might be perceived to introduce a conflict of interest may be found via the UT Energy Institute and at: https://energy.utexas.edu/ercot-blackout-2021.

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Appendix A. Short History of Texas Electric Grid and ERCOT: From the Beginning to 2021

The current infrastructure, rules, regulations, and organizational roles impacting the ERCOT market are the outcome of many decisions made over multiple decades. Here, we provide a brief history of these decisions to place the ERCOT outages of service in February 2021 in historical context.

For shorthand in this report, we use the acronym "ERCOT" to possibly refer to the wholesale electricity market, the infrastructure that generates and/or delivers electricity, and ERCOT the organization. ERCOT the organization does not own the electricity infrastructure (i.e., power plants, transmission and distribution lines, battery storage) within the ERCOT grid. The grid infrastructure is owned by the generation companies who participate in the market and by transmission and distribution utilities. ERCOT the organization administers the day-to-day electricity market operations and performs transmission planning. The PUCT oversees ERCOT the organization to ensure that it and the market participants comply with the legislative intent and law.

A.1. Why Does Texas Have Its Own Grid?

Electric power development began in the late 1800s as small power plants and local wires were installed in cities across the U.S., including Texas cities. By nature, they were isolated, but eventually grew enough to establish connections among themselves.

The 1935 Federal Power Act established federal jurisdiction over interstate commerce via the Federal Power Commission (FPC), which has since become the Federal Energy Regulatory Commission (FERC). The Public Utilities Holding Company Act (PUHCA) of 1935 created individual companies – utilities – with contiguous service territories. Each utility would act as a monopoly to serve customers within its geographic territory, and in return electricity rates and profits would be subject to state-level approval. PUHCA provided the framework for all electricity service until some regions restructured, or "deregulated," beginning in the 1990s (Tuttle *et al.*, 2016).

Local city grids continued to link to each other, and by the beginning of World War II, the Texas Interconnection System was formed (Cohn, 2017). "Faced with the threat of federal regulation in the wake of the 1935 passage of the Federal Power Act, the principal utilities in Texas … elected to isolate their properties from interstate commerce" (Cudahy, 1995).

In 1965, "North America experienced its worst blackout to date as 30 million lost power in the northeastern United States and southeastern Ontario, Canada" (NERC, 2019). In response, Congress passed the Electric Power Reliability Act in 1967 that led the electricity industry to form the National Electric Reliability Council in 1968, now known as the North American Electric Reliability Corporation (NERC). NERC is a council of regional electricity coordination organizations. In the wake of these changes in federal and national level coordination, in 1970 the utilities operating exclusively within Texas set up their own reliability council named the Electric Reliability Council of Texas, or ERCOT.

The question of electrical isolation of ERCOT utilities was not considered until 1974 when an Oklahoma attorney "… filed a motion with the SEC on behalf of a group of municipal and cooperative electric distribution systems served by Oklahoma Public Service" (OPS) (Cudahy, 1995). OPS was one of four utilities owned by Central and Southwest Corporation (CSW). CSW[174] owned utilities that spanned areas of Oklahoma, Louisiana, Arkansas, and Texas (Cudahy, 1995). A four-year legal battle ensued between CSW and the existing, purely Texas-based, utilities. The dispute was whether to allow utilities to sell or generate electricity within ERCOT from/to states besides Texas and become subject to interstate commerce federal regulatory jurisdiction. CSW wanted electrical connections to transfer electricity to and from Texas, and the ERCOT-only utilities did not.

These battles affected language in the federal Public Utility Regulatory Policies Act (PURPA) of 1978, and the right of the newly formed Federal Energy Regulatory Commission (FERC) to force utilities to interconnect, for example during emergencies, without triggering FERC jurisdiction for other purposes, for example the review of wholesale electricity rates (Cudahy, 1995). Following the passage of PURPA, the utilities in dispute negotiated a settlement. "They finally settled upon a direct current [DC] interconnection [between ERCOT and SPP,[175] or other states] because, unlike an alternating current tie, the power flows over a direct-current link could be controlled. … The parties agreed to other terms as well, notably that the interconnection would not subject ERCOT to federal regulation for other purposes" (Cudahy, 1995). As a result, CSW maintained interconnection across its companies in multiple states, and the ERCOT-only utilities retained state regulation but not federal regulation.

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[174] CSW own[ed] all the common stock of four vertically integrated operating utilities: Central Power and light Company (Central Power), headquartered in Corpus Christi in South Texas; West Texas Utilities Company (West Texas), headquartered in Abilene in West Texas; Public Service Company of Oklahoma (Oklahoma Public Service), headquartered in Tulsa, Oklahoma; and Southwestern Electric Power Company (Southwestern), serving Arkansas, Texas and Louisiana and headquartered in Shreveport, Louisiana." CSW later was merged into American Electric Power, Inc. in 2000 (AEP, 2021)

[175] Southwest Power Pool.

A.2. Wholesale Market Restructuring (Deregulation) and Adjustment Timeline

In 1995 the Texas Legislature passed Senate Bill 373 to restructure the electric generation sector in ERCOT. The bill ensured equal access to the transmission grid for power generators and established ERCOT as the Independent System Operator (ISO) in 1996, the first ISO in the U.S. although its initial functions were very limited relative to today's ISOs. Before this time, ERCOT was only the reliability coordinator that reported to NERC (ERCOT, 2016). "Additional objectives of SB 373 were to ensure an equitable interconnection process, facilitate generation capacity and transmission expansion, and provide customer protection."[176] (Adib and Clark, 1996)

In addition to further restructuring wholesale power generation, Texas SB 7 in 1999 ordered the introduction of retail competition in the service areas of the investor-owned utilities within the ERCOT power region by 2002. By 2002 the investor-owned utilities in the ERCOT power region which were previously vertically-integrated were "unbundled," or separated, into three separate entities: power generation, transmission and distribution utilities, and retail electric providers (REPs). Rural electric cooperatives and municipal utility systems were permitted to either participate in retail competition ("opt in") or decline to participate, although changes in the wholesale market would affect them regardless of their decision.[177]

Prior to restructuring, generation dispatch decisions and other operational decisions were made locally in ten control areas. However, ERCOT transitioned to operating as a single control area under the legislative framework established through SB 373 (in 1995) and SB 7 (in 1999).[178]

While markets were developed for wholesale generation and retail activities, investor-owned TDSPs remain under conventional regulatory oversight.

SB 7 also gave the PUCT authority over market oversight, including oversight of ERCOT. SB 7 sought prevent the exercise of market power, including the provision that no single generation company can control more than 20% of the total installed generation capacity.[179] Via ERCOT's bylaws (as an ISO) and authority of the PUCT, a stakeholder process provides the opportunity for stakeholders (generators, TDSPs, consumer groups, etc.) to participate in the design and operation of the electricity market.

SB 7 set a Texas renewable portfolio standard (RPS) of 2,880 MW (adding 2,000 MW to 880 MW of existing capacity) of renewables and created a renewable energy

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[176] For SB 373, see: https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=74R&Bill=SB373.

[177] See SB 7 (https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=76R&Bill=SB7) Sec. 41.051 (cooperatives) and Sec. 40.051 (municipal utilities).

[178] http://www.ercot.com/news/releases/show/77

[179] Luminant (a subsidiary of Vistra) owns almost 20% of generation in ERCOT.

credit (REC) market to facilitate that standard. In 2005, Texas legislators increased the RPS to 5,880 MW of renewable capacity, and via SB 408 directed the PUCT to facilitate the process to design and construct new transmission to serve a set of "Competitive Renewable Energy Zones" (CREZ). As of the end of 2020, approximately 25,000 MW of wind and 4,000 MW of solar photovoltaic capacity were installed in ERCOT, thus far surpassing the RPS.[180]

Table A.1. Timeline of the Evolution of a Competitive Market in ERCOT[181]

1975	Passage of the Texas Public Utility Regulatory Act (PURA), establishing the PUCT.
1978	The federal Public Utility Regulatory Policy Act (PURPA) is enacted, facilitating and providing a pricing mechanism for utility purchases of power from cogeneration and small power production.
1983	Amendments to the Texas PURA to reflect the 1978 enactment of PURPA and introduction of the elements of integrated resource planning, such as a ten-year demand and resource forecast. The PUCT is no longer responsible for forecasts and planning for electric grid investments.
1992	The passage of the US Energy Policy Act.
1995	State Legislature passes Senate Bill 373 amending the Texas PURA to introduce wholesale competition in September 1995.
February 1996	The Commission establishes the requirement for ERCOT to become an Independent System Operator (ISO) and requires utilities to offer wholesale open-access transmission service.
Late 1990s	The PUCT approved an interconnection rule to facilitate merchant plant development.
May 1999	State Legislature passes Senate Bill 7 amending the Texas PURA to introduce retail competition on January 1, 2002 and further restructure the wholesale market.
2000-2001	The PUCT finalized its decision regarding functional unbundling plans for integrated utilities. In addition, the Commission

[180] See ERCOT "Resource Capacity Trend Charts" at http://www.ercot.com/gridinfo/resource (e.g, December 2020: http://www.ercot.com/content/wcm/lists/219848/Capacity_Changes_by_Fuel_Type_Charts_December_2020.xlsx).

[181] Some information included in this table is from Adib and Zarnikau (2007).

	finalized several important rules to enhance the transition to competition within ERCOT.
August 2000	The PUCT established Wholesale Market Oversight to monitor market activities and detect market power abuses and other market manipulation.
June 4, 2001	The PUCT finalized its decision with regard to the ERCOT Protocols that established market rules for the wholesale electricity market.
July 31, 2001	The operation of the ERCOT single control area began and a pilot retail program was introduced.
January 1, 2002	Customer choice began within ERCOT electricity market and "price to beat" was established within each incumbent investor-owned-utility service area and became effective for residential and small commercial customers with peak load lower than 1 MW.
September 2002	Retail Market Oversight was established to monitor the retail market and identify areas for improvements.
February 2003	Price spikes in wholesale market prompt re-examination of the use of balancing energy, wholesale price mitigations formulas, and credit requirements for REPs.
Late 2004	Switching rates for commercial energy consumers exceeds thresholds and the "price to beat" for commercial customers is terminated in many service areas.
September 2005	PUCT decides to transition market to a nodal structure.
2005	Texas Legislature adopts SB 408 designating the creation of Competitive Renewable Energy Zones and provides authority to PUCT to direct ERCOT to plan for transmission to connect approximately 18 GW of wind capacity.
2005	The legislature adopts SB 408 that increases the number of independent representatives on ERCOT's board and designates an independent monitor for the wholesale electricity market[182].
August 2006	The PUCT approves rules (Subst. R. §25.505) for "scarcity pricing" with new energy offer caps.

[182] SB 408 (79R Legislative session in 2005): https://capitol.texas.gov/BillLookup/Text.aspx?LegSess=79R&Bill=SB408.

2010	On December 1, the nodal wholesale pricing system goes live approximately four years after initially planned. Along with nodal pricing comes the "day ahead market" for individual power plants to bid for next-day electricity generation on a 15-minute basis.
October 2012	PUCT approves a timeline to gradually increase the energy offer cap to $9,000 per MWh through amendments to Subst. R. §25.505.
June 2014	Operating Reserve Demand Curve (ORDC) is first implemented, to raise energy prices when physical operating reserves are low.
January 2019	The PUCT orders a shift in the ORDC to increase energy prices further when operating reserves dwindle. PUCT also decides to implement real-time co-optimization in the selection and pricing of energy and ancillary services in the wholesale market.[183]
March 2020	A further shift in the ORDC is implemented.

A.3. Why isn't ERCOT Connected to Other Grids?

Previous paragraphs summarize the history of the ERCOT grid as separate from others in North America. However, the costs and benefits of interconnecting ERCOT with neighboring reliability councils were studied in the late 1990s, per a request by the Texas Legislature.[184] The established Synchronous Interconnection Committee (SIC) failed to reach a definitive conclusion regarding whether the benefits of interconnection would likely outweigh the costs:

> *Due to the complexities of the issues and uncertainties surrounding the evolving electric marketplace, the SIC was unable to conclusively establish that AC interconnection is, or is not, desirable either as a candidate transmission investment or as an instrument of policy to promote competition in future electricity markets.*[185]

It is possible that a similar analysis today would yield differing results, as questions remain surrounding the costs and benefits of greater interconnection with neighboring markets or reliability councils.

[183] See PUCT Project No. 48540.

[184] Per SB 373 (74th legislative session in 1995).

[185] SIC, 1999, cover letter.

A.4. Today's ERCOT Wholesale Market

Today, ERCOT serves 90% of the electric load in Texas. This power region has experienced consistent load growth in recent decades due to a strong economy and increasing population, unlike some other U.S. markets which have experienced little growth. Currently, 26 million people within Texas receive electric service via the electric grid managed by ERCOT.

ERCOT administers day-ahead and real-time markets for energy, as well as a day-ahead market for ancillary services (AS). ERCOT is relatively unique in that it is an "energy-only market" and thus does not operate a capacity market or impose resource adequacy targets in order to maintain a target reserve margin.[186] Market forces are heavily relied upon to provide enough generation for resource adequacy, and market price offer caps have been raised to relatively high levels in hopes of providing sufficient compensation to the generation sector to incentivize investment to meet peak electricity demand. The price offer cap has increased almost 10-fold over a span of 13 years to $9,000/MWh. While normal market operations can push prices to scarcity levels, multiple price add-ons have been developed to increase prices when reserves are low or emergency reliability actions have been taken.

ERCOT retains only a few small direct current (DC) interconnections with neighboring markets and reliability councils, and remains a fully intrastate system with limited federal jurisdiction over its market.

A.5. Characteristics of the ERCOT Retail market

Of the approximately 11 million metered customers in ERCOT, [187] about 8 million have retail choice and can select among different retail electric providers offering different electricity pricing plans and services.

Efforts to introduce competition into the retail sector of the state's electricity market began in June 1999 with the passage of Senate Bill 7 (SB 7) by the Texas Legislature. SB 7 permitted retail competition in the service areas of the investor-owned electric utilities within ERCOT's power region on a commercial basis beginning January 1, 2002. These service areas, identified in Figure A.1., include two of the nation's ten largest metropolitan areas – Dallas/Fort Worth and Houston. New entrants were permitted to compete with retail arms of five utilities that were formerly vertically-integrated: Houston Lighting and Power Company, TXU Electric, AEP-Texas North, AEP-Texas Central, and Texas-New Mexico Power Company. Oncor became the TDSP successor to TXU Electric, while CenterPoint Energy is the TDSP successor to Houston Lighting and Power Company.

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[186] Other "energy only" markets include electricity markets in Alberta and Australia.

[187] http://www.ercot.com/content/wcm/lists/219736/ERCOT_Fact_Sheet_1.04.21.pdf

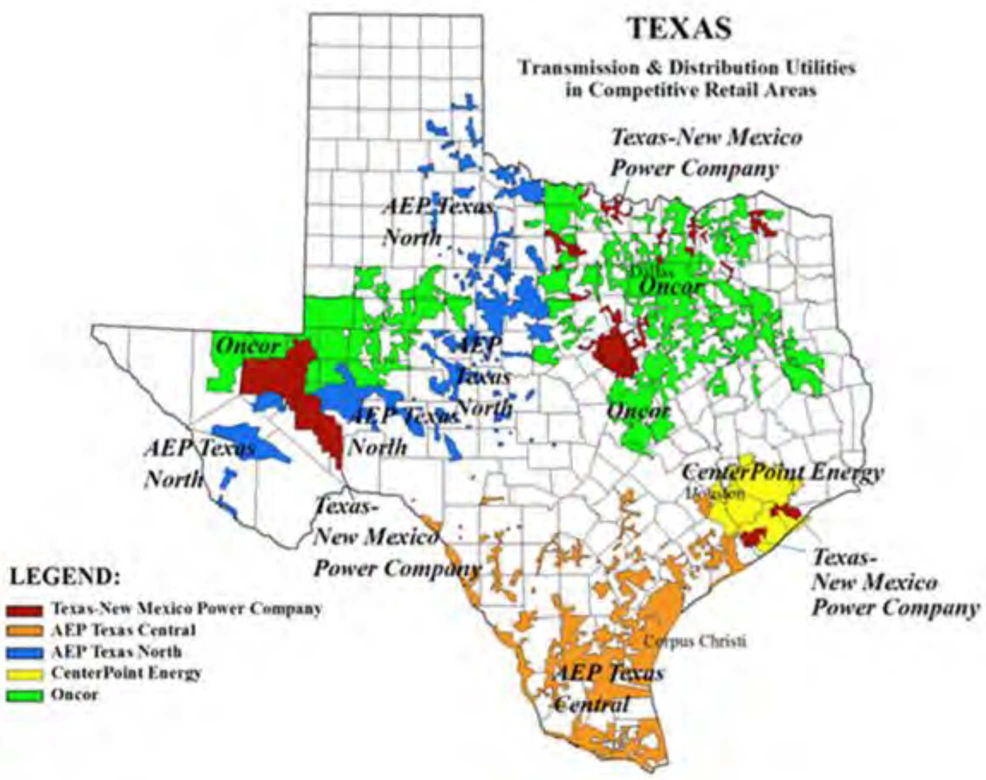

Figure A.1. Areas Initially Opened to Retail Competition. Source: PUCT at: https://www.puc.texas.gov/industry/maps/maps/tdumap.pdf.

At the start of retail competition in 2002, certain constraints were placed upon the prices charged by the five retailers that were successors of former vertically-integrated utilities (then known as the AREPs, or affiliated retail electric providers). After January 1, 2005, the AREPs were allowed to provide alternative prices to their customers, provided these alternative pricing plans did not exceed the "price to beat" (PTB) set by the PUCT. By December 2007, approximately 40 percent of residential customers in areas exposed to retail competition had switched to a competitive retailer – i.e., a retailer other than one that was a successor to one of the former vertically-integrated utilities – or a different AREP. On January 1, 2007, PTB constraints fully expired, removing any regulatory oversight over retail prices. The outcome was an overall reduction in average prices (Zarnikau and Kang, 2009; Swadley and Yucel, 2011).

Before retail choice was implemented in Texas, Direct Energy entered the Texas retail market by purchasing the retail branches of AEP-Texas North and AEP-Texas Central (formerly known as West Texas Utilities and Central Power and Light). Another of the five original AREPs changed ownership when Reliant Energy – a successor of Houston

Lighting and Power Company – was acquired by NRG Energy in 2009.[188] In 2011, Direct Energy acquired another original AREP – First Choice Power, the retail affiliate of Texas-New Mexico Power Company.[189] The last remaining AREP, TXU Energy, was acquired by a group of private investors (led by KKR, TPG Capital, and Goldman Sachs) in 2007. Following a bankruptcy in 2013, TXU Energy and its generation affiliate (Luminant) were renamed as Vistra Energy in 2016.[190]

In recent months, following the merger of NRG Energy and Direct Energy, concerns have been raised over market concentration in ERCOT's retail market. After the completion of the merger on January 2, 2021, NRG Energy and Vistra control about 78% of the *residential* retail market, though concentration in other market sectors (e.g., commercial and industrial market segments) is lower (Brown, et al, 2020).

On the competitive retail side, the 2021 winter event has reduced the number of retailers. Griddy Energy, Entrust Energy, and Power of Texas Holdings have left the market and Just Energy Group has filed for bankruptcy. By February 24, 2021, the number of competitive rate options advertised on the PUCT-administered Power to Choose website had dropped by half.[191] A departure of retailers from the market has occurred in the past,[192] but the number of retailers that have left the market recently is unprecedented.

A.6. Summary: ERCOT History and Current Status

The ERCOT grid and ERCOT the organization have changed considerably since the Texas legislators ordered restructuring of wholesale markets. Wind and solar generation were practically zero in 1999, but amounted to 25% of the 381 terawatt-hours (TWh) of generation in 2020 (Figure A.2) Natural gas generators have provided 40-46% of generation during the last 15 years, while coal generation had declined from 40% in 2010 to less than 20% in 2020. There are currently no plans to build new nuclear power plants in ERCOT.

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[188] https://en.wikipedia.org/wiki/NRG_Energy; https://www.power-grid.com/td/nrg-energy-to-acquire-reliant-energys-texas-retail-business/#gref

[189] https://www.prnewswire.com/news-releases/direct-energy-to-acquire-first-choice-power-for-270-million-130411228.html

[190] https://www.txu.com/company/why-txu-energy/about-us.aspx; https://www.dallasnews.com/business/energy/2016/11/04/luminant-and-txu-energy-have-a-newly-named-corporate-parent-vistra/

[191] Based on calculations performed by Hen-Hao Tsai, a former researcher at UT-Austin who is now employed by MISO. Communicated via email to Jay Zarnikau on Feb. 24, 2021.

[192] Based on ERCOT's public notices, retailers that have left the market prior to 2021 include: Texas Commercial Energy (2003), Utility Choice Electric (2004), Ampro (2006), Buy Energy (2006), Franklin Power (2005), Blu Power of Texas (2008), Hwy 3 MHP (2008), Sure Electric (2008), Pre-Buy Electric (2008), National Power Company (2008), Abacus Resource Energy (2011), EPCOT Electric (2012), TexRep7 LLC (2012), Reach Energy (2014), Proton Energy (2014), and Reach Energy (2014).

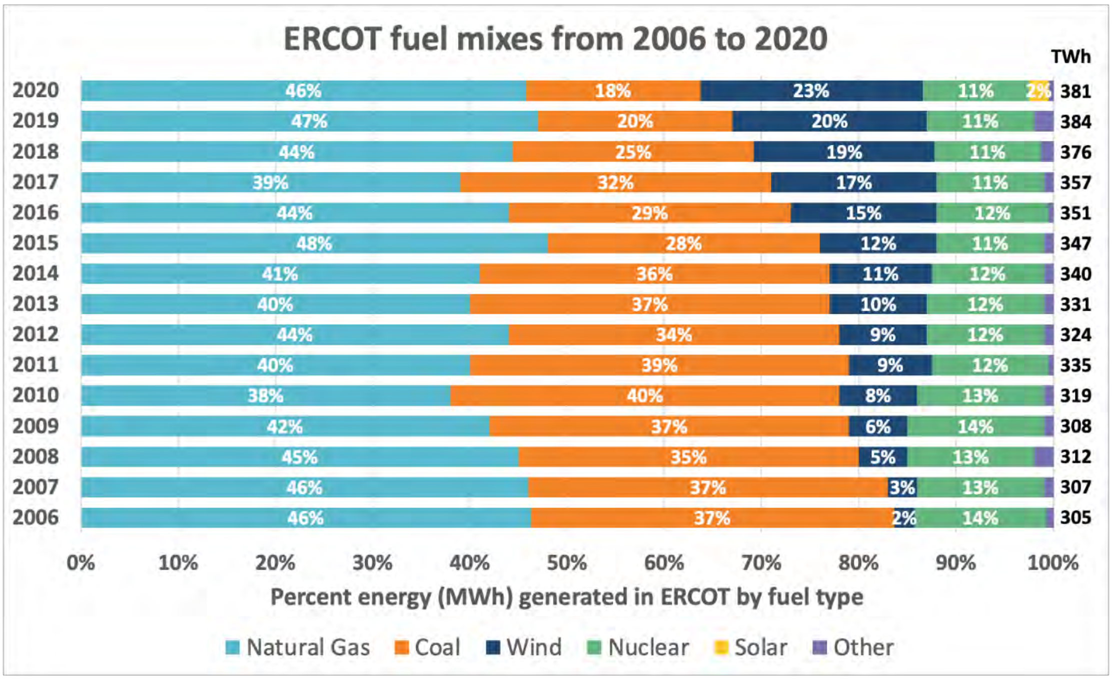

Figure A.2. The percentage of annual electricity generation in ERCOT, by fuel, from 2006-2020

Appendix B. Internal ERCOT Meteorological Discussions Before the Storm

To help forecast electricity demand or "load" and make other preparations for day-to-day grid operations, ERCOT utilizes multiple weather models, NOAA forecasts, as well as data from outside weather vendors to inform their internal predictions about short and long-term weather across the state. Communications between the resident meteorologist and various planning, outage, and resource groups at ERCOT indicate the difficulty in forecasting the onset and severity of Winter Storm Uri of 2021. These day-to-day communications are internal to ERCOT, but ERCOT issues outside communications to market participants to warn of major weather events that could impact market operations.

Of the internal ERCOT emails we reviewed; one written January 28 was the first mention that ERCOT would experience a spate of cold weather. This e-mail noted that February is that hardest month to forecast, but that there was evidence that February 2021 would be colder than normal. Another email on February 1 indicated that a polar vortex was working, but it was likely to be pushed east of Texas. On February 3, an email indicated that there was a good chance that February was going to be the coldest weather of the 2020/2021 winter, but the models used for predictions were varying widely with forecasted lows for Austin varying between 19^{o}F and 53^{o}F on February 8. By February 4 the various models were converging on Dallas and Austin seeing their coldest weather of the year, with a good chance of Houston and possibly for Brownsville also seeing their coldest temperatures of the year. On February 5, the models began to diverge on the timing of when the cold air masses will arrive in Texas. The February 6 weather update compares the coming cold to January 2018 in severity. The February 7 update explained that the models were still 20-30 degrees apart in their temperature predictions with the coldest model showing cold weather similar to January 2018.

By February 8 the models began to trend back together, showing February 14 to be very cold. The meteorologist noted that "[t]his is the most challenging, worrisome forecast since I joined ERCOT…" One of the models indicated a scenario that would rival the weather event of 1989, but the forecasted cloud cover made it hard to believe. Also, there were still tens of degrees difference between the various models, but they were trending to levels equivalent to the extreme cold weather experienced in February 2011. The February 8, 2021 update was the first to mention that there could be significant icing issues with this storm.

The February 9 update indicates that the models were in agreement that February 14 – February 17 would be very cold, but that there was still a 15-20^{o}F difference between them. The February 9 update also noted that there was a high chance of freezing rain in West Texas in the short-term, and that there likely wouldn't be enough time for it to melt before the coldest temperatures arrived. On February 10 some of the models that have been predicting warmer weather began to predict weather closer to the coldest model, and a December 1989-like scenario can't be ruled out. Additional information conveyed on February 10 said that the 2011 February 2 freezing conditions arrived much more abruptly than the anticipated oncoming freezing conditions over the oncoming week of 2021. A February 11 weather update indicated that the event could last as long as February 18.

The February 12 weather update indicated that the forecasts were all trending colder, and that the models were having trouble accurately in predicting snow this late in the winter (mid-February) because there was a lack of historical precedent for snow this late in the winter. The February 12 update further noted that there were continued disagreements between models and vendor-supplied temperature forecasts and that "ERCOT simply hasn't seen anything quite like this – this late into the winter."

On February 13 the weather models were still disagreeing on the severity of the coming cold in some parts of the state, and the ERCOT meteorologist communicated a possibility of a second winter storm that would hit mid-week, bringing more snow. The ERCOT meteorologist also noted that they could not rule out forecasted lows in the mid-teens (degrees Fahrenheit) in the Rio Grande Valley.

The last of the supplied emails, from February 14, discussed that all but one solar farm in ERCOT was likely to receive snow and that the models still had disagreements of between 10-15^{o}F in the severity of the cold over the next few days, making forecasting difficult. In this email, it was also noted that Dallas temperatures on February 14 were currently below the latest forecasted levels.

The internal meteorological communications reviewed appeared to describe a very difficult storm to predict, oh which the intensity wasn't fully realized until just before it happened.

Appendix C. Generator Outages Relative to Time Reaching Freezing Temperature

Another relevant question to ask in assessing the electric grid's ability to withstand freezing conditions is "How long do generators experience freezing conditions before generators experience outages?" That is to ask, if a sub-freezing winter storm arrives in Texas, how much time does it tend to take for power generation to go offline, for any reason?

We display the timing of the February 2021 outages in Figure C.1., with respect to when power plants first reached freezing temperature (0°C or 32°F). Some parts of Texas, for example the panhandle, reached freezing temperatures days before the southern coastal parts of Texas reached freezing temperatures — the figures account for this difference.

Figure C.1 combines the MERRA-2 weather data with ERCOT's publicly reported timing of generator outages as compiled within the "ERCOT's Generator Outage/Derate Visualization App" (EGOVA) dataset that relates the generators to power plants in U.S. government databases with location data.[193] We first associate a MERRA-2 temperature time series with each power plant based on the nearest weather station. Then, starting with the first hour on February 5, we find the first hour with a temperature at or below 0°C, and plot the reported generation outages relative to the time at which the power plant first experienced 0°C.

It is easiest to explain the methodology for the concrete example of the nuclear generator that experienced an outage. ERCOT reported that South Texas Nuclear Project (STNP) generation unit #1 experienced an outage from February 15 at 5:27 am to February 17 at 9:07 p.m., a span of approximately 64 hours. The MERRA-2 weather data suggest that STP reached 0°C at approximately 2 am on February 15. Thus, STP went offline approximately 3 to 4 hours after reaching 0°C, and the figure for Nuclear indicates STP's capacity reduction starting *4 hours after first reaching 0*°C. Similarly, 64 hours after going offline, STP operators brought the generator back online, and the capacity reduction returned to zero at *68 hours after first reaching 0*°C*,* since the generator was at full capacity at that time.

If a power plant experienced a capacity reduction, generation derating, or outage, *before reaching 0*°C, that is reported as a negative value (*before)* the 0-hour on the x-

[193] https://bit.ly/EGOVADatabase

axis. Figure C.1 sums all capacity outages for plants of the same fuel relative to the time they experienced freezing temperatures.[194]

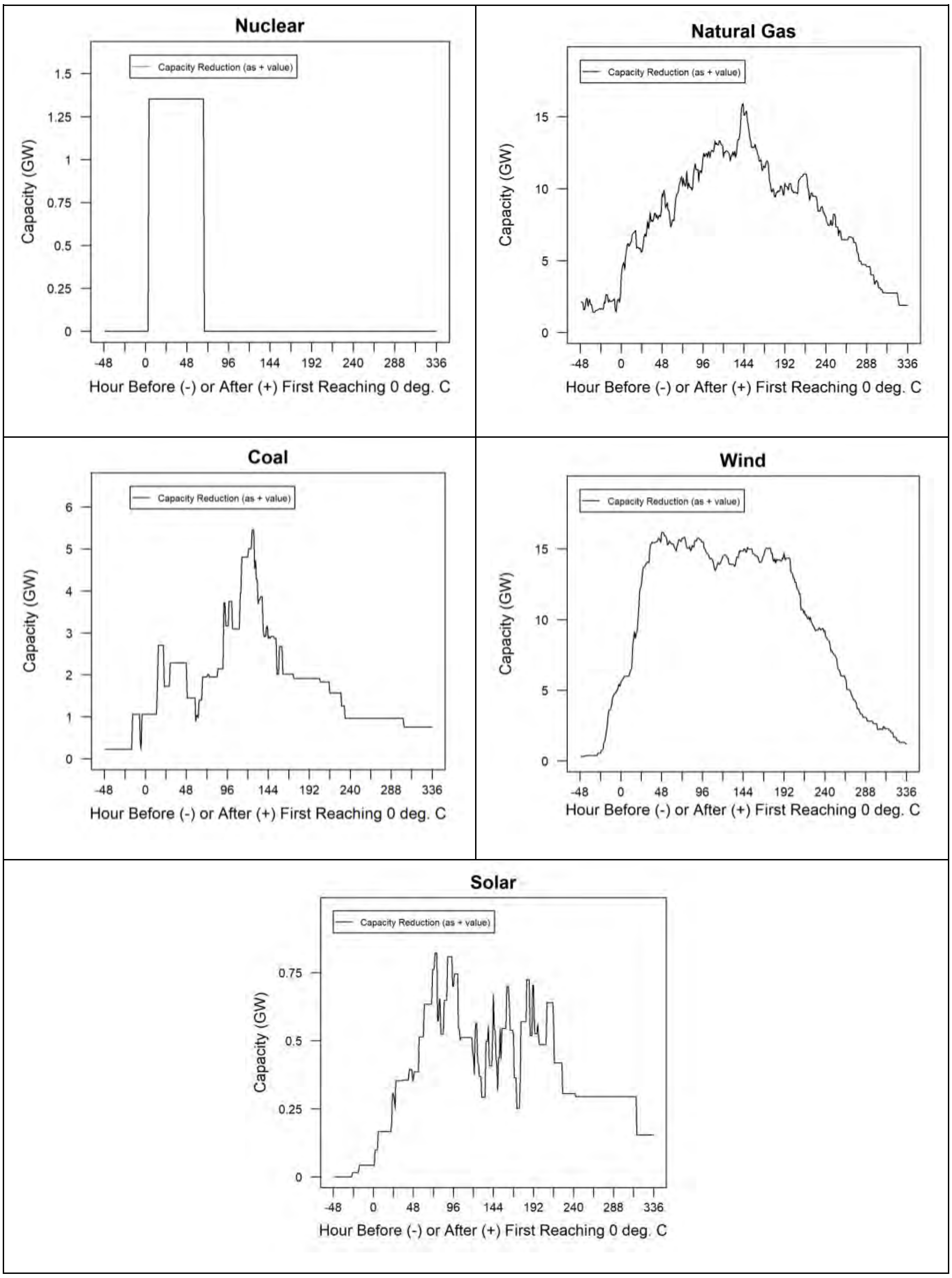

Figure C.1. The capacity reduction (generation outages) for all types of generators relative to when they first experienced 0°C.

[194] That is to say, if two natural gas generators, with capacity reductions of 100 MW and 200 MW, respectively, experienced their outage 3 hours before reaching 0°C at each location, then this would be shown as a 300 MW outage at the x-axis value of –3, for 3 hours before reaching 0°C.

We can draw some conclusions from Figure C.1, but there are many caveats. One takeaway is that the duration of freezing temperatures is important, in addition to the temperatures experienced. Compared to wind and solar outages, the peak coal and natural gas generator outages occur at much longer intervals of time after reaching freezing temperatures. The peak capacity of outages, relative to the time when the plants first experienced freezing temperatures, was approximately 6 days for natural gas plants, 5 days for coal plants, 1 day for wind turbines, and 3 days for solar generators. This result suggests that a multitude of complicating factors might accumulate or occur after many hours at, or below, freezing temperatures to affect natural gas and coal generation. The impacts to wind and solar farms appear to occur relatively quickly, which is consistent with the reporting suggesting that a majority of their outages were related to snow or ice accumulation.

Some of the caveats in the interpretation of Figure C.1 include the lack of other weather data, such as precipitation and wind speed, as well as other factors that caused power generator outages, such as fuel limitations and other mechanical failures. For example, it is possible that the same cold temperatures with dry, rather than wet, conditions could have caused fewer generation outages from all types of generators. Further, generation units experience outages on a regular basis that are independent of the weather.

Appendix D. Texas Natural Gas Balance

Per the U.S. Energy Information Administration (EIA), Texas is the largest energy-producing and energy-consuming state in the U.S., including crude oil and natural gas. In 2020, Texas accounted for 43% of the U.S. crude oil production and 26% of its marketed natural gas production.[195] Texas also consumes more energy (in aggregate) than any other state.

The extreme cold weather from Winter Storm Uri and associated electricity supply disruptions caused serious interruptions in Texas natural gas supply due to freeze offs in field operations in the oil and gas value chain. The storm affected rates of natural gas production and industrial sector consumption with both experiencing their largest monthly declines on record. During the same period, residential consumption reached record highs.

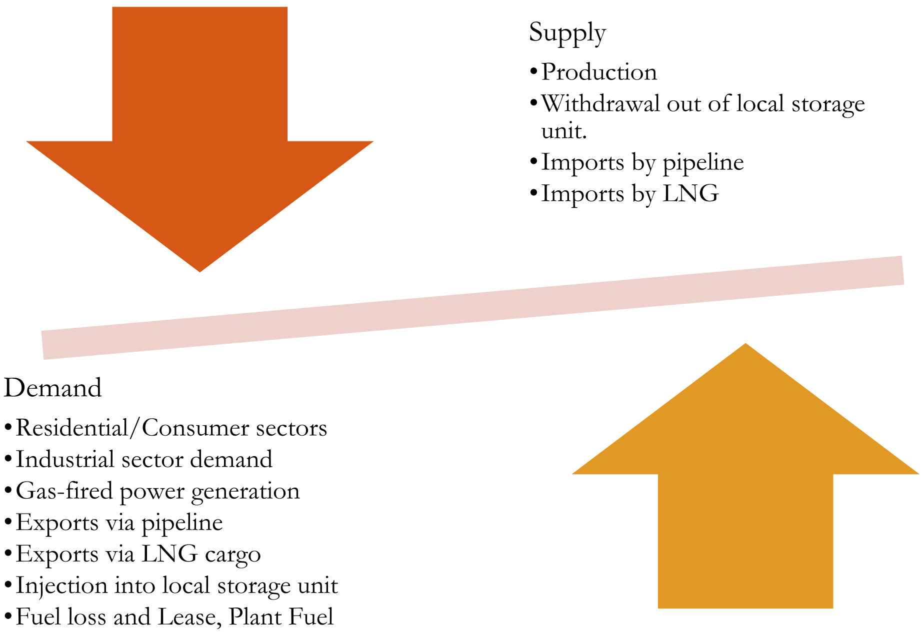

Figure D.1. Overall Natural Gas Balance

To contextualize natural gas operations during the storm and associated blackout, it is important to understand the natural gas balance of Texas (see Figure D.1. Overall Natural Gas Balance). There are three major sectors of the natural gas value chain; production, transmission and distribution. The balance of the market describes the aggregated relation between the supply and demand segments. There are multiple ways to supply a market with natural gas, including local production, local withdrawal from storage, and imports regions. There are also multiple demands for natural gas: including distribution to downstream consumers in individual market segments, injection into underground storage units, and exports to

[195] EIA: Texas - State Energy Profile Overview - U.S. Energy Information Administration (EIA)

other markets. There are five major segments of demand for natural gas – residential, commercial, gas-fired electricity generation, industrial, and transportation.

Figures D.2 and D.3 show the monthly natural gas supply-demand balance[196] in the state of Texas from January 2016 to February 2021. Aggregate natural gas supply in Figure D.1 includes two major supply sources, dry gas production and net storage withdrawal. Dry gas production[197] refers to the process of producing consumer-grade natural gas, after removing nonhydrocarbon gases (e.g., water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen), and it does not include any volume used for production at the lease site, or any processing losses. The volumes of dry gas withdrawn from gas storage reservoirs are separate and not considered part of production. Dry natural gas production equals marketed production less extraction loss. Aggregate natural gas demand includes three categories: 1) local gas deliveries,[198] 2) net exported gas,[199] and 3) losses of natural gas in field extraction and processing, as lease and plant fuel, and as pipe loss fuel. Figure D.3 shows an increasing demand for Texas exports of natural gas via pipeline and LNG to other markets.

The aggregated supply side should equal to the aggregated demand side, theoretically. Though in reality, there is often a small balancing item representing any quantities lost and imbalances in the data due to differences among data sources. This balancing item is usually around 0.5-1.5%.

$$Production + Net\ Withdrawl\ from\ Storage =$$
$$Consumption + Net\ Pipeline\ Export + Net\ LNG\ export + (Fuel\ loss + LPF)$$

[196] Figure D.2 – 5 GPCM® Base Case Database as of 2021 Q1 a market simulator for North American Gas and LNG™ by RBAC.

[197] EIA: Definitions, Sources and Explanatory Notes on natural gas.

[198] Including electric generation, residential, and commercial customers

[199] Gas exported Texas via pipeline to other states and Mexico, as well as net exported gas as liquified natural gas (LNG) cargo to international destinations

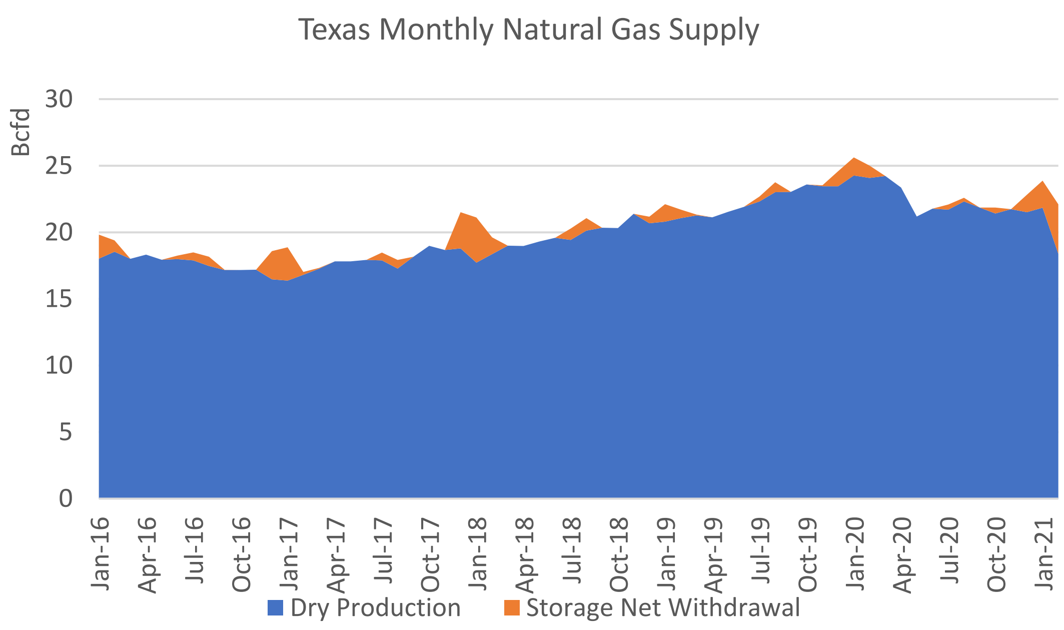

Figure D.2. Texas Monthly Natural Gas Supply (Source: GPCM™)

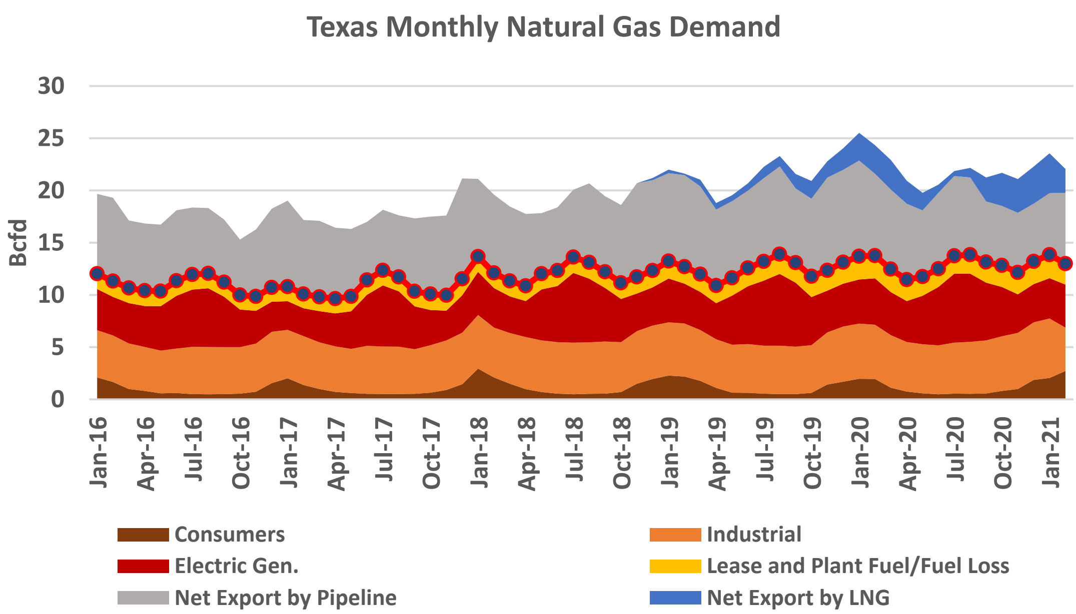

Figure D.3. Texas Monthly Natural Gas Demand (Source: GPCM™)

Appendix E. Other (non-energy) Infrastructures Impacted from Storm: Water and Housing

The winter storm's impacts did not stop with the electricity and gas infrastructure. The storm also directly and indirectly impacted other infrastructures, including water and housing. At one point, up to 12 million Texans[200] were without water or under boil advisories due to either low water pressure or damaged treatment facilities.[201] While property damage was not limited to Texas, the state is expected to file roughly half the insurance claims associated with the winter storm.[202] The Federal Reserve Bank of Dallas estimates that insured losses in Texas alone range between $10 billion and $20 billion. [203] The Dallas Fed estimates that total losses from the storm could approach $130 billion in direct and indirect costs, while other estimates put it as high as $300 billion. [204]

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[200] https://www.texastribune.org/2021/02/17/texas-water-boil-notices/

[201] https://www.dailysentinel.com/social_media/article_e3e219d1-e267-513d-848d-10dc3109e595.html.

[202] https://www.wsj.com/articles/winter-freeze-damage-expected-to-hit-18-billion-from-burst-pipes-collapse-roofs-11613757414.

[203] https://www.dallasfed.org/research/economics/2021/0415.

[204] https://www.perrymangroup.com/media/uploads/brief/perryman-preliminary-estimates-of-economic-costs-of-the-february-2021-texas-winter-storm-02-25-21.pdf.

EXHIBIT 16

Control Number: 51812

Item Number: 34

Addendum StartPage: 0

EXHIBIT 16

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POTOMAC ECONOMICS

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March 1, 2021

Public Utility Commission of Texas
Chairman DeAnn T. Walker
Commissioner Arthur C. D'Andrea
Commissioner Shelly Botkin
1701 N. Congress Avenue
Austin, Texas 78711

Re: PUC Project No. 51812, Issues Related to the State of Disaster for the February 2021 Winter Weather Event

Dear Chairman and Commissioners:

As the Independent Market Monitor (IMM) of the Electric Reliability Council of Texas (ERCOT) wholesale electricity market for the Public Utility Commission of Texas (Commission), Potomac Economics closely monitored real-time market performance throughout the recent winter weather event and provides the following recommendations related to ancillary services in light of certain market outcomes.

Recommendation 1: For operating days February 15 through February 20, 2021, reprice all day-ahead ancillary services (AS) clearing prices to cap them at the System-Wide Offer Cap (SWCAP) of $9,000 per MWh.

When there are insufficient offers to clear the entire AS Plan (Section 4.2.1.1 of the ERCOT Nodal Protocols), ERCOT uses very high penalty costs to ensure that the day-ahead market algorithm can clear as much of the AS Plan as possible. A pricing run is then used to remove those penalty costs prior to publishing the prices in accordance with the Other Binding Document (OBD) Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints. Between February 15 and February 20, the scarcity of offers, generator constraints, and opportunity costs applied during this pricing run resulted in unexpected clearing prices higher than the SWCAP in effect on those days. The IMM recommends that these prices be capped at the SWCAP of $9,000 per MWh.

Capping the AS Market Clearing Prices for Capacity (MCPC) for each AS for those days will produce outcomes more consistent with economic market design principles. Since reserves are procured to reduce the probability of losing load, such principles dictate that the value of reserves cannot not exceed the value of lost load (VOLL), which is equal to the SWCAP of $9,000.

Further, to avoid this unintended outcome in the future, the IMM recommends that the language on page 32 of Appendix 2 of the OBD cited above be changed to include the following:

Notably however, the AS penalty factors are not used to set the MCPC for each Ancillary Service. Instead, the infeasible AS requirement amounts are reduced to the feasible level and the DAM clearing is rerun so that the price of the last AS awarded MW sets the MCPC for the each Ancillary Service. In no case shall the MCPC for each Ancillary Service exceed the System-Wide Offer Cap (SWCAP) in effect for the relevant Operating Day.

Recommendation 2: For operating days February 14 through February 19, 2021, invoke the "failure to provide" settlement treatment for all AS that were not provided in real time.

There were a number of instances during the operating days outlined above in which AS was not provided in real time because of forced outages or derations. For market participants that are not able to meet their AS responsibility, typically the ERCOT operator marks the short amount in the software. This causes the AS responsibility to be effectively removed and the day-ahead AS payment to be clawed back in settlement. However, the ERCOT operators did not complete this task during the winter event, and therefore the "failure to provide" settlements were not invoked in real time.

Removing the operator intervention step and automating the "failure to provide" settlement was contemplated in NPRR947: Clarification to Ancillary Service Supply Responsibility Definition and Improvements to Determining and Charging for Ancillary Service Failed Quantities; however, the NPRR was withdrawn in August 2020 because of the system cost, some complexities related to AS trades, and the implementation of real-time co-optimization.

Invoking the "failure to provide" settlement for all AS that market participants failed to provide during the operating days outlined above will produce market outcomes and settlements consistent with underlying market principles. In this case, the principle is that market participants should not be paid for services that they do not provide. Whether ERCOT marked the short amount in real-time or not should not affect the settlement of these ancillary services.

In the short term, the IMM recommends that the language in Section 6 of the ERCOT Nodal Protocols below be modified to allow ERCOT to determine these quantities after-the-fact. The IMM further recommends that the "failure to provide" settlement treatment for AS be automated.

6.4.9.1.3 Replacement of Ancillary Service Due to Failure to Provide

(1) ERCOT may procure Ancillary Services to replace those of a QSE that has failed on its Ancillary Services Supply Responsibility through a Supplemental Ancillary Services Market, as described below in Section 6.4.9.2, Supplemental Ancillary Services Market. A QSE is considered to have failed on its Ancillary Services Supply Responsibility when ERCOT determines, in its sole discretion, that some or all of the QSE's Resource-specific Ancillary Service capacity either will not be available in Real

Time, or was not provided in Real Time. This Section does not apply to a failure to provide caused by events described in Section 6.4.9.1.2, Replacement of Infeasible Ancillary Service Due to Transmission Constraints.

In the event the Commission adopts both of the recommendations contained in this letter, ERCOT should complete them in order: resettle the day-ahead market to cap the AS prices first, then initiate the "failure to provide" settlement.

As always, the IMM stands ready to address any questions the Commission may have regarding these recommendations or the outcomes in the ERCOT wholesale market.

Sincerely,

Carrie Bivens

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EXHIBIT 17

Control Number: 31243

Item Number: 87

Addendum StartPage: 0

2006 ... 9 ... 55

PUC DOCKET NO. 31243
SOAH DOCKET NO. 473-05-8805

COMPLAINT OF TXU PORTFOLIO MANAGEMENT COMPANY LP AND TXU ENERGY RETAIL COMPANY LP AGAINST THE ELECTRIC RELIABILITY COUNCIL OF TEXAS	§ § § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER

This Order addresses the complaint of TXU Portfolio Management Company LP and TXU Energy Retail Company LP against the Electric Reliability Council of Texas (ERCOT), alleging erroneous imposition of load imbalance charges during the last half of 2001 due to inadvertent double-counting of two wholesale points of delivery. Load imbalance charges are imposed by ERCOT on qualifying scheduling entities (QSE) that have more load than generation in a 15-minute period. ERCOT responded to TXU's complaint by contending that the original settlement should remain in effect because it is final and because TXU Electric Delivery provided the data on which the settlement was calculated. The State Office of Administrative Hearings (SOAH) administrative law judge (ALJ) issued a proposal for decision (PFD) on June 20, 2006, in which he recommended that ERCOT should satisfy TXU's complaint by resettling the period in 2001 in issue.

Subject to the discussion below, the Commission adopts the PFD on all issues except with regard to the specific methodology of full resettlement, and establishes a compliance proceeding in which the details of the resettlement methodology shall be resolved.

I. Discussion

While the Commission agrees with the threshold findings of the ALJ, namely that ERCOT should fully resettle the 2001 period in question, the Commission is not prepared to issue an order describing the methodology for such a resettlement at this time. Several issues regarding such a methodology have been raised, but the record does not adequately address these issues, and the Commission cannot specify a methodology in this Order. Accordingly, the Commission orders that a compliance docket be initiated in this matter for the purpose of discovering the most appropriate methodology by which ERCOT could conduct the full resettlement.

Consistent with the foregoing discussion, the Commission deletes conclusion of law 10.

II. Findings of Fact

Procedural History

1. On June 15, 2005, pursuant to P.U.C. PROC. R. 22.251, the Companies filed a complaint against ERCOT ("the Complaint").

2. On June 16, 2005, pursuant to P.U.C. PROC. R. 22.251(e), the Electric Reliability Council of Texas ("ERCOT") e-mailed to all Qualified Scheduling Entities ("QSEs") notice and a copy of the Complaint. ERCOT filed its Proof of Notice on June 17, 2005, and filed the accompanying affidavit on June 21, 2005. The Office of Public Utility Counsel ("OPC") received notice of the Complaint by copy of Order No. 1.

3. Direct, CPS Energy, the Lower Colorado River Authority ("LCRA"), First Choice, Reliant Energy, Inc. ("Reliant"), TEAM, Texas Genco II, LP ("Texas Genco"), OPC, and STEC filed motions to intervene.

4. The Public Utility Commission of Texas ("Commission") granted the motions to intervene of Direct and CPS Energy on July 12, 2005. The Commission granted the motions to intervene of LCRA, First Choice, and Reliant on August 1, 2005. The motions to intervene of TEAM, OPC, and STEC were granted on November 7, 2005. Texas Genco's motion to intervene was granted on January 13, 2006.

5. On July 13, 2005, ERCOT filed its response to the Complaint.

6. On August 1, 2005, Staff filed a response to Order No. 1 and a motion for referral to the State Office of Administrative Hearings ("SOAH"), requesting an evidentiary hearing.

7. On August 4, 2005, the Companies filed a reply to ERCOT's response and Staff's response and motion for referral to SOAH, stating that no evidentiary hearing was needed.

8. On August 8, 2005, the Commission referred this docket to SOAH.

9. The Companies, ERCOT, Staff, CPS Energy, TEAM, STEC, Direct, and First Choice filed an agreed stipulation of facts on March 1, 2006. These parties agree that this proceeding may be decided based on the pleadings, affidavits, and other relevant materials filed in this docket without an evidentiary hearing.

Parties

10. TXU Portfolio Management is registered and qualified with ERCOT as a QSE for TXU Energy and certain other Load Serving Entities ("LSEs").

11. From July 31 through December 31, 2001, the actual entity charged for Load Imbalance in its role as QSE was TXU Electric Company ("TXU Electric"), the formerly integrated and bundled utility. On and after January 1, 2002, TXU Portfolio Management (then known as TXU Energy Trading Company LP) assumed the role as QSE for TXU Energy (then known as TXU Energy Services Company) and certain other LSEs. For clarity and because TXU Portfolio Management is the successor QSE, it is referenced as the entity invoiced for the Load Imbalance charges that are the subject of this Complaint.

12. On February 2, 2001, the Commission certified ERCOT as the independent organization for the ERCOT power region pursuant to PURA § 39.151.

Background Relating to the Double-Counted Load

TNMP Lewisville

13. Before July 31, 2001, TXU Electric, the formerly integrated and bundled utility, sold wholesale power to Texas-New Mexico Power Company ("TNMP") for TNMP's City of Lewisville ("Lewisville") load at multiple meters aggregated under a single meter and billed to TNMP based on the load measured at the aggregation meter. This arrangement was pursuant to a contract between TXU Electric and TNMP.

14. Beginning July 31, 2001, TXU Electric continued to sell wholesale power to TNMP for the TNMP Lewisville load. However, during the retail customer choice pilot project, which began effectively on July 31, 2001, TNMP served Lewisville as both an LSE and a Transmission and Distribution Service Provider ("TDSP"), and Constellation Power Source, Inc. ("Constellation") - not TXU Electric - served as TNMP's QSE.

15. Individual Electric Service Identifier ("ESI ID") meters within the TNMP Lewisville load territory were used to measure volume for wholesale sales from TXU Electric to TNMP and to calculate Load Imbalance charges by ERCOT to Constellation.

16. The ESI IDs for these individual meters were properly assigned to TNMP and its QSE, Constellation, and they should have replaced the pre-pilot project aggregation meter on ERCOT's systems as of July 31, 2001.

17. The TDSP, TXU Electric Delivery Company ("Electric Delivery") had assigned ESI ID No. 10443720007315878 to that meter in March 2001 and assigned it to TXU Electric (as LSE).

18. After July 31, 2001, the pre-pilot project aggregation meter was left in place.

19. On February 18, 2002, Electric Delivery notified ERCOT that ESI ID No. 10443720007315878 and any associated usage data should be removed from the ERCOT computer systems effective July 31, 2001. On February 26, 2002, ERCOT responded that it had "[d]eleted the ESI Id in both Lodestar and Siebel Systems[.]"

20. ERCOT notified TXU Portfolio Management in November 2002 that ERCOT did not actually delete ESI ID No. 10443720007315878 from its computer systems until November 27, 2002. If ESI ID No. 10443720007315878 had been removed from ERCOT's computer systems in February 2002, effective July 31, 2001, then the corrected usage data would have appeared in the True-Up Settlement statements published for the July 31 through December 31, 2001 Operating Days.

21. The load from the TNMP Lewisville meters was counted twice in the ERCOT settlement process–once for Constellation (as QSE) and once for TXU Electric (as QSE)–from July 31 through December 31, 2001.

College Station

22. Before July 31, 2001, TXU Electric sold wholesale power to the City of College Station ("College Station") at multiple meters aggregated under a single aggregation meter.

23. The TDSP, Electric Delivery, had assigned ESI ID No. 10443720007147829 to that meter in March 2001 and assigned it to TXU Electric (as LSE).

24. Beginning July 31, 2001, College Station became a Non-Opt In Entity ("NOIE"). As a NOIE, College Station installed ERCOT Polled Settlement meters to replace the wholesale aggregation meter for the purpose of measuring load.

25. After July 31, 2001, the wholesale aggregation meter was left in place.

26. TXU Electric continued to sell wholesale power to College Station during the retail customer choice pilot project and served as QSE for College Station.

27. On February 18, 2002, Electric Delivery notified ERCOT that ESI ID No. 10443720007147829 and any associated usage data should be removed from the ERCOT computer systems effective July 31, 2001. On February 26, 2002, ERCOT responded that it had "[d]eleted the ESI Id in both Lodestar and Siebel Systems[.]"

28. ERCOT notified TXU Portfolio Management in November 2002 that ERCOT did not actually delete ESI ID No. 10443720007147829 from its computer systems until November 27, 2002. If ESI ID No. 10443720007147829 had been removed from ERCOT's computer systems in February 2002, effective July 31, 2001, then the corrected usage data would have been reflected in True-Up Settlement statements published for the July 31 through December 31, 2001 Operating Days.

29. The load from the College Station meters was counted twice for TXU Electric (as QSE) in the ERCOT settlement process from July 31 through December 31, 2001.

Background Applicable to TNMP Lewisville and College Station

30. Before the start of the deregulated retail market on July 31 2001, TDSPs provided ERCOT and LSEs information necessary to set up competitive area ESI IDs, including ESI ID relationship and characteristics data, as well as historical usage. ERCOT then

forwarded usage data to each LSE, as provided by the TDSP. ERCOT forwards changes in transactional characteristic information (station, profile code, loss code, etc.) to the current LSE and any new LSE(s) if a switch to a new LSE is pending. From early to middle 2002, ERCOT and Market Participants participated in a data clean-up and improvement effort known as "Market Synchronization." During Market Synchronization, LSEs and TDSPs provided ERCOT files showing a comprehensive list of LSE relationship start and stop times by ESI ID. Via these files, ERCOT performed a comparison across the LSEs', TDSPs', and ERCOT's data and identified LSE relationship discrepancies that needed to be resolved across specified entities (LSE, TDSP and/or ERCOT). During this time frame, ERCOT participated in individual ESI ID synchronization efforts for Market Participants with individualized requests. ERCOT also answered questions upon request from various Market Participants about their data as shown in ERCOT's system. In March 2003, ERCOT implemented System Change Request (SCR) 727, which resulted in a regularly produced data extract for both TDSPs and LSEs containing ESI ID characteristic, relationship and usage data. At that time, ERCOT also implemented the Data Extract Variance process so TDSPs and LSEs could file discrepancies between their systems and ERCOT systems for resolution with the appropriate entity.

31. During the retail customer choice pilot project, the ERCOT market experienced issues related to data accuracy.

32. At its May 21, 2002 meeting, the ERCOT Board of Directors instructed ERCOT staff to stop performing True-Up Settlements to allow resolution of ESI ID data errors, and the Board passed the following resolution:

> The ERCOT Board direct the ERCOT Staff to perform a ONE-TIME re-settlement of July 31, 2001 through the current Wholesale Settlement Statement published. Such re-settlement will commence after ERCOT has successfully received and validated at least 99 percent of the IDR data from each Meter Reading Entity (MRE). In addition, ERCOT would suspend future true-up settlements until the 99 percent IDR consumption data standard is met. The true-up settlement timeline would be

> extended to a maximum of 12 months in cases where the IDR data threshold is not met. . . . .

33. During the process described in that resolution, ERCOT sent daily reports to TDSPs showing ESI IDs for which ERCOT did not have usage data.

34. ERCOT asked the TDSPs to provide the missing data for their ESI IDs.

35. With respect to the TNMP Lewisville and College Station ESI IDs, ERCOT stated to Electric Delivery, "[a]ttached you will find the updated spreadsheets for ONCOR [Electric Delivery] as of data loaded in ERCOT systems by 5:30 pm 05-09-02. The spreadsheets contain a list of ESIIDs that are NOT in compliance with IDR data being loaded through September 2001 . . . ." The spreadsheets included the aggregation meters for TNMP Lewisville and College Station.

36. Electric Delivery provided usage data for the TNMP Lewisville and College Station ESI IDs.

37. The ESI ID meters at issue were for wholesale delivery points, not retail delivery points.

38. In response, ERCOT stated "ONCOR is in compliance with ERCOT's requests."

39. ERCOT relied on that data when it issued the subsequent Settlement Statements for the subject dates in 2001.

40. ERCOT began issuing the True-Up Statements for dates in 2001 on September 9, 2002.

Settlement Effects of the Double-Counted Load

41. A settlement effect of the double-counted load was that it overstated the load for TXU Electric (as QSE) and produced a decrease in the magnitude of ERCOT-wide Unaccounted for Energy ("UFE") for each settlement interval relative to the magnitude of ERCOT-wide UFE that would have been produced had the load not been counted twice. During this period, UFE was primarily negative and was more negative than it would have otherwise been due to the double-counted load.

42. A settlement effect of the double-counted load was that it produced Adjusted Metered Load ("AML") values for each settlement interval for TXU Electric (as QSE) that were

higher than they would have been had the load not been counted twice; however, the increase was not equal to the full double counting due to the negative UFE allocation. The AML values of QSEs other than TXU Electric (as QSE) representing LSEs allocated UFE were lower than the AML values that would have been produced had the load not been counted twice. The AML values of QSEs other than TXU Electric (as QSE) representing LSEs not allocated UFE were the same as the AML values that would have been produced had the load not been counted twice.

43. Under the ERCOT Protocols, UFE is not allocated to QSEs representing LSEs on a simple load ratio share basis. Rather, pursuant to Section 11.4.6.2 of the ERCOT Protocols, UFE is allocated to QSEs representing LSEs according to specific formulas that are dependent upon the category of loads being served by each LSE.

44. The following competitive REPs that have intervened in this proceeding were not participating in the ERCOT market during the Operating Days July 31, 2001 through December 31, 2001: Direct and TEAM members Accent Energy, Cirro Energy, StarTex Power, Stream Energy, Tara Energy, and Utility Choice Electric.

Background Relating to the ADR Process

45. Pursuant to Section 9 of the ERCOT Protocols, TXU Portfolio Management submitted the settlement and billing disputes regarding the Load Imbalance charges related to the TNMP Lewisville and College Station loads for the July 31 through December 31, 2001 Operating Days.

46. In each of its settlement and billing disputes relating to the dates at issue, TXU Portfolio Management made one of the following statements:

    a. It was, "[d]isputing the difference between TXU internal load of [X] MW verses ERCOT load of [X] MW with the net difference of [X] MW":

    b. "Dispute the difference between TXU load and ERCOT load";

    c. Diffs note[d] in Load Imbalance"; or

    d. "Differences between TXU's internal load and ERCOT's load."

47. The disputes referenced in the above finding of fact provided no further detail for the cause of the alleged imbalance or load differences.

48. ERCOT denied TXU Portfolio Management's settlement and billing disputes at issue, and TXU Portfolio Management invoked the alternative dispute resolution ("ADR") process in Section 20 of the ERCOT Protocols between October 2002 through December 2002. TXU Portfolio Management did not request ADR with respect to Operating Days August 22, 2001 and September 9, 2001.

49. In its ADR request letters, TXU Portfolio Management cited, as the basis for its ADR requests, differences between the AMLs calculated by TXU Portfolio Management and the AMLs calculated by ERCOT, which it alleged resulted from the "failure of ERCOT to collect the appropriate meter loads . . . ."

50. During the ADR process, in an email note dated January 8, 2003, Linda LeMaster of TXU Portfolio Management (the authorized ADR representative) stated that TXU Portfolio Management realized it could dispute [through the ADR process] only "the incremental change [between the previous Settlement Statement and True-Up Statement for the applicable Operating Day]. Anything over that incremental change could not be considered as recoverable."

51. In a letter to ERCOT dated February 7, 2003, a TXU Portfolio Management representative wrote that "[TXU Portfolio Management] has no reason to believe that ERCOT did not gather data from the TDSP in accordance with the Protocols. . . ."

52. In a February 10, 2005 letter to counsel for the Companies, an ERCOT representative wrote, "Mr. Schrader has indicated that he is tentatively willing to grant this ADR to the extent it involves the double-counting of the City of Lewisville and College Station city gate meters. ERCOT has done some preliminary runs to calculate the dollar amount of such a resettlement."

53. During the period from October 2002 until May 2005, ERCOT and the Companies exchanged data and otherwise diligently worked on the subject Load Imbalance charges and other Load Imbalance issues.

54. In executive session on April 19, 2005, the ERCOT Board of Directors voted to deny those ADRs. On May 12, 2005, ERCOT and the Companies agreed to waive mediation and arbitration.

55. The ERCOT Board considered the issue of ADRs and disputes relating to unspecific allegations of data errors at the November 2004 Board Meeting. At the May 17, 2005 meeting, the ERCOT Board adopted a resolution regarding the consideration of such ADRs and disputes.

III. Conclusions of Law

1. Pursuant to PURA § 39.151(d), the Commission is charged with oversight and review responsibility of the procedures established by ERCOT relating to reliability of the ERCOT network and accounting for the production and delivery of electricity among generators and all other market participants.

2. SOAH has jurisdiction over this proceeding, including the preparation of this proposal for decision with findings of fact and conclusions of law, pursuant to PURA § 4.053 and TEX. GOV'T CODE ANN. §§ 2001.058 and 2003.049.

3. ERCOT provided proper notice of the Companies' complaint pursuant to P.U.C. PROC. R. 22.251(e).

4. Pursuant to ERCOT Protocol 9.5.2, a Statement Recipient may dispute items or calculations set forth in its Initial Statements, Final Statements, or Resettlement Statements.

5. Pursuant to ERCOT Protocol 9.5.2, a Statement or Invoice Recipient who wishes to dispute a Statement shall register the settlement or billing dispute with ERCOT within ten business days.

6. For the dates in dispute in this proceeding, TXU Portfolio Management's billing disputes were filed in compliance with ERCOT Protocol 9.5.2 and they adequately alerted ERCOT and market participants of the potential for resettlement due to disputed load calculations.

7. ERCOT's settlement for the July-December 2001 time period is final in that ERCOT denied these billing disputes and otherwise followed its settlement Protocols. However, this final settlement does not preclude resettlement for timely filed billing disputes that should have been granted.

8. ERCOT settled the disputed time period in accordance with the Protocols in that it followed the procedures set out in the Protocols. However, under PURA § 39.151(d), the Commission is authorized to order resettlement of a valid, timely billing dispute even though ERCOT followed procedures contained in the Protocols.

9. The actions of both ERCOT and the Companies contributed to the double-billing error involved in this case. However, the inadvertent mistakes of the Companies involved in this case should not bar their claim.

10. Deleted.

11. The Commission should order a full resettlement of the disputed time period to account for other charges that will be affected by resettlement of Load Imbalance charges.

IV. Ordering Paragraphs

In accordance with the findings of fact and conclusions of law, the Commission issues the following order:

1. The request of TXU Portfolio Management Company LP and TXU Energy Retail Company LP (collectively "the Companies") for an order directing ERCOT to conduct resettlement for the disputed period (July-December 2001) is granted as specified in this Order.

2. Compliance Docket No. 32992 has been initiated to determine the precise methodology for ERCOT to conduct a full resettlement of the disputed period.

3. All other motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted herein, are denied.

SIGNED AT AUSTIN, TEXAS the 9th day of August 2006.

PUBLIC UTILITY COMMISSION OF TEXAS

PAUL HUDSON, CHAIRMAN

JULIE PARSLEY, COMMISSIONER

BARRY T. SMITHERMAN, COMMISSIONER

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EXHIBIT 18

Control Number: 31243

Item Number: 1

Addendum StartPage: 0

PUC DOCKET NO. 31243

COMPLAINT OF TXU PORTFOLIO MANAGEMENT COMPANY LP AND TXU ENERGY RETAIL COMPANY LP AND AGAINST THE ELECTRIC RELIABILITY COUNCIL OF TEXAS	§ § § § § §	BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS

[FILENAME: COMPLAINT]

TABLE OF CONTENTS

EXHIBIT 18

PUC DOCKET NO. ____

COMPLAINT OF TXU PORTFOLIO MANAGEMENT COMPANY LP AND TXU ENERGY RETAIL COMPANY LP AND AGAINST THE ELECTRIC RELIABILITY COUNCIL OF TEXAS	§ § § § § §	BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS

COMPLAINT OF TXU PORTFOLIO MANAGEMENT COMPANY LP AND TXU ENERGY RETAIL COMPANY LP AGAINST THE ELECTRIC RELIABILITY COUNCIL OF TEXAS

TO THE HONORABLE PUBLIC UTILITY COMMISSION OF TEXAS:

COME NOW TXU Portfolio Management Company LP ("TXU Portfolio Management") and TXU Energy Retail Company LP ("TXU Energy") (collectively, the "Companies") and, pursuant to P.U.C. PROC. R. 22.251, bring this complaint against the Electric Reliability Council of Texas ("ERCOT") for the erroneous imposition of Balancing Energy[1] (referred to herein as "Load Imbalance") charges[2] in violation of PURA,[3] the Substantive Rules of the Public Utility Commission of Texas ("Commission"), and the ERCOT Protocols. In support of this Complaint, the Companies respectfully show the following:

I. PARTIES

The Companies' authorized representatives are:

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[1] Unless otherwise noted, capitalized terms are taken from the ERCOT Protocols, *available at* http://www.ercot.com/AboutERCOT/PublicDisclosure/ProtocolRev.htm.

[2] Load Imbalance charges are imposed by ERCOT on Qualified Scheduling Entities ("QSEs") that have more load than generation in a 15-minute interval. The charges represent the cost of Balancing Energy required to balance a QSE's generation and load. *See generally* ERCOT Protocols § 6.8.1.12.

[3] Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §§ 11.001-64.158 (Vernon 1998 & Supp. 2004-2005) ("PURA").

The Companies request that copies of all correspondence, pleadings, briefs, and other documents be served on the above-referenced authorized representatives.

To the best of the Companies' knowledge, ERCOT's authorized representative is:

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agallo@ercot.com

II. SUMMARY OF CLAIMS

During the last half of 2001, the meter data represented by two different wholesale points of delivery (referenced below as the "TNMP Lewisville" and the "College Station" load) was inadvertently double-counted in ERCOT's systems. Because of this error, ERCOT inappropriately invoiced TXU Portfolio Management[4] for Load Imbalance charges that were not assignable to TXU Portfolio Management. Although ERCOT had been notified by TXU Electric Delivery Company ("Electric Delivery") (then known as Oncor Electric Delivery Company) several months prior to publication of True-Up Settlement Statements—a step in the normal ERCOT settlement process—that there was a duplication in ERCOT's systems, the errors were not corrected. The Companies understand that ERCOT has estimated the potential financial impact to TXU Portfolio Management resulting from those errors. However, based on TXU Portfolio Management's best estimate, it was overcharged by ERCOT and it overpaid for Load Imbalance charges by as much as $4 million.

ERCOT has not disputed that the subject load was double-counted and invoiced to TXU Portfolio Management. To date, however, ERCOT has refused to correct those settlement errors. Consequently, ERCOT is in violation of its obligations to ensure that electricity production and delivery are accurately accounted for among generators and other market participants. The Companies respectfully request that the Commission order ERCOT to recalculate and otherwise

[4] From July 31 through December 31, 2001, the actual entity charged for Load Imbalance in its role as QSE was TXU Electric Company, the formerly integrated and bundled utility. On and after January 1, 2002, TXU Portfolio Management (then known as TXU Energy Trading Company LP) assumed the role as QSE for TXU Energy (then known as TXU Energy Services Company) and certain other Load Serving Entities. For clarity and because TXU Portfolio Management is the successor QSE, it is hereinafter referenced as the entity erroneously invoiced for Load Imbalance charges.

resolve the subject Load Imbalance charges after the double-counted load is removed from the settlement data and, based on that resolution, that TXU Portfolio Management be allowed to recover the amount that it was erroneously invoiced.

III. STATEMENT OF THE CASE

This Complaint is an appeal of ERCOT's refusal to recalculate and resolve the erroneous Load Imbalance charges invoiced to TXU Portfolio Management. The entities potentially affected by the relief granted in this Complaint are Qualified Scheduling Entities ("QSEs"). There was no formal underlying proceeding to this Complaint. The Companies and ERCOT engaged in the applicable alternative dispute resolution ("ADR") procedures under Section 20 of the ERCOT Protocols from October 2002 until May 2005. During that time period, representatives of ERCOT and the Companies met on several occasions and exchanged data in an effort to resolve the ADRs[5] relating to the subject Load Imbalance charges. In a closed executive session on April 25, 2005, the ERCOT Board of Directors voted to deny a proposed resolution of those ADRs that was agreed to by the Companies and ERCOT's counsel. On May 12, 2005, ERCOT waived mediation and arbitration, thus completing the ADR procedure. Therefore, this Complaint is timely filed within 35 days after completion of the ADR procedure.[6]

The provisions applicable to this Complaint include the following: PURA § 39.151, P.U.C. SUBST. R. 25.361, P.U.C. PROC. R. 22.251, and ERCOT Protocols §§ 1.2, 9, and 20.[7] The Commission has jurisdiction over this Complaint pursuant to PURA § 39.151 and P.U.C. PROC. R. 22.251. The Companies do not at this time seek suspension of any specific ERCOT conduct pending the outcome of this proceeding.

IV. STATEMENT OF THE ISSUE

Whether ERCOT is obligated to recalculate and resolve Load Imbalance charges that were erroneously calculated and invoiced based on load that was double-counted in ERCOT's systems.[8]

[5] In its May 12, 2005 letter waiving mediation and arbitration, ERCOT references the ADRs as "ADR Nos. 2002-TXU-02; 2002-TXU-03; 2003-TXU-01; [and] 2003-TXU-02[.]"

[6] P.U.C. PROC. R. 22.251(d).

[7] The Companies will timely supplement this Complaint if it becomes apparent that other provisions are applicable to this proceeding.

[8] The Companies do not believe that this Complaint presents fact questions that require an evidentiary hearing. This proceeding turns on a question of law informed by PURA and Commission policy and precedent.

V. ARGUMENT

TXU Portfolio Management has paid up to $4 million more in Load Imbalance charges than it should have paid had ERCOT not included double-counted load in its settlement calculations for TXU Portfolio Management. As demonstrated below, ERCOT is obligated by PURA and the ERCOT Protocols to recalculate and resolve the subject Load Imbalance charges *without* the double-counted load, and TXU Portfolio Management is entitled to recover the amount it was inappropriately invoiced due to that error.

A. Background

1. This Complaint is *not* a global resettlement of 2001.

The Commission is well aware of the technical and operational challenges that faced market participants leading up to and during the transition to a fully competitive market in ERCOT. Market participants, including the Companies, actively worked with ERCOT and the Commission to ensure, for example, that the retail customer choice pilot project was a success and that the overall transition to competition was as smooth as possible. The larger systemic issues associated with the transition led to global resettlements of various parts of the 2001 market. The Companies emphasize that this Complaint is *not* seeking to review those issues again much less to request a global resettlement of 2001. This Complaint only seeks to address a very discrete and unusual set of circumstances associated with the double counting of load at two wholesale points of delivery and the related erroneous calculation and imposition of Load Imbalance charges. Indeed, the Companies seek to address an issue that the Companies and ERCOT staff have been specifically working on since 2002.

2. ERCOT calculated Load Imbalance charges based on double-counted load.

a. TNMP Lewisville

Before July 31, 2001, TXU Electric Company ("TXU Electric"), the formerly integrated and bundled utility,[9] sold wholesale power to Texas-New Mexico Power Company ("TNMP") for TNMP's City of Lewisville ("Lewisville") load at multiple meters aggregated under a single meter and billed to TNMP based on the load measured at the aggregation meter. This arrangement was pursuant to a contract between TXU Electric and TNMP. Beginning July 31, 2001, TXU Electric continued to sell wholesale power to TNMP for the TNMP Lewisville load. However, during the retail customer choice pilot project, which began effectively on July 31,

[9] *See supra* note 4.

2001, TNMP served Lewisville as both a Load Serving Entity ("LSE") and a transmission and distribution service provider, and Constellation Power Source, Inc. ("Constellation")—not TXU Electric—served as TNMP's QSE. Individual Electric Service Identifier ("ESI ID") meters within the TNMP Lewisville load territory were used to measure volume for wholesale sales from TXU Electric to TNMP and to calculate Load Imbalance charges by ERCOT to Constellation. The ESI IDs for these individual meters were properly assigned to TNMP and its QSE, Constellation, and they should have replaced the pre-pilot project aggregation meter on ERCOT's systems as of July 31, 2001. However, the pre-pilot project aggregation meter was left in place, assigned ESI ID No. 10443720007315878, and charged to TXU Electric.

On February 18, 2002, Electric Delivery notified ERCOT that ESI ID No. 10443720007315878 and any associated consumption should be removed from the ERCOT systems effective July 31, 2001.[10] On February 26, 2002, ERCOT responded that it had "[d]eleted the ESI Id in both Lodestar and Siebel Systems[.]"[11] However, TXU Portfolio Management was notified by ERCOT in November 2002 that ERCOT did not actually delete ESI ID No. 10443720007315878 from its systems until November 27, 2002. If ESI ID No. 10443720007315878 had in fact been removed from ERCOT's systems in February 2002, as represented by ERCOT in its February 26, 2002 email, then the corrected volumes would have been appropriately reflected in the True-Up Settlement Statements published for the July 31 through December 31, 2001 Operating Days. According to the ERCOT Settlement Calendar, the True-Up Statements and subsequent Resettlement Statements for the 2001 pilot period Operating Days were not finally published until September 9, 2002, through November 29, 2002.[12] When ERCOT produced those settlement statements, however, they were *not* reflective of all the available data, including data that showed that the TNMP Lewisville load had been counted at two metering points (*i.e.*, double-counted). Consequently, the load and Load Imbalance charges from that load were inadvertently counted twice in settlement and were erroneously charged to *both* Constellation and TXU Electric (as QSE) from July 31 through December 31, 2001.

[10] *See* Companies-Exhibit A, pgs. 3,5. (Note that the Companies have redacted from the attached exhibits certain employee information and ESI ID data not related to this Complaint.)

[11] Companies-Exhibit B, pg. 2.

[12] *Available at* http://www.ercot.com/ercotPublicWeb/PublicMarketInformation/marketttotals/settlementcalendar/ERCOT_Settlement_Calendar.xls.

b. College Station

Before July 31, 2001, TXU Electric sold wholesale power to the City of College Station ("College Station") at multiple meters aggregated under a single aggregation meter. Beginning July 31, 2001, College Station became a Non-Opt In Entity ("NOIE"). As a NOIE, College Station installed ERCOT Polled Settlement meters to replace the wholesale aggregation meter for the purpose of measuring load. TXU Electric continued to sell wholesale power to College Station during the retail customer choice pilot project and served as QSE for College Station. However, the wholesale aggregation meter was left in place and assigned ESI ID No. 10443720007147829.

On February 18, 2002, Electric Delivery notified ERCOT that ESI ID No. 10443720007147829 and any associated consumption should be removed from the ERCOT systems effective July 31, 2001.[13] On February 26, 2002, ERCOT responded that it had "[d]eleted the ESI Id in both Lodestar and Siebel Systems[.]"[14] However, TXU Portfolio Management was notified by ERCOT in November 2002 that ERCOT did not actually delete ESI ID No. 10443720007147829 from its systems until November 27, 2002. As with the TNMP Lewisville load, if ESI ID No. 10443720007147829 had in fact been removed from ERCOT's systems in February 2002, effective July 31, 2001, then the corrected volumes would have been appropriately reflected in True-Up Settlement Statements for July 31 through December 31, 2001. Those settlement statements did *not* reflect the corrected volumes, and the College Station load and the Load Imbalance charges from that load were erroneously counted twice from July 31 through December 31, 2001.

As required under Sections 9 and 20 of the ERCOT Protocols, TXU Portfolio Management submitted disputes on the Load Imbalance charges related to the TNMP Lewisville and College Station loads for the July 31 through December 31, 2001 Operating Days. ERCOT denied those disputes, and TXU Portfolio Management invoked the ADR procedures.[15] ERCOT and the Companies designated their respective senior dispute representatives, and those parties met on several occasions. During the period from October 2002 until May 2005, representatives exchanged data and otherwise diligently worked on the subject Load Imbalance charges and

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[13] *See* Companies-Exhibit A, pgs. 3,5.

[14] Companies-Exhibit B, pg. 2.

[15] *See* ERCOT Protocols §§ 9.5.4, 20.

other Load Imbalance issues. Only ERCOT possesses all of the data that would allow an exact quantification of TXU Portfolio Management's overpayment for Load Imbalance charges related to the TNMP Lewisville and College Station loads; however, TXU Portfolio Management estimates that amount could be as much as $4 million.

In February and March 2005, ERCOT's counsel and the Companies reached a proposed resolution regarding the subject Load Imbalance charges invoiced to TXU Portfolio Management. For unknown reasons unknown to the Companies, that proposed resolution was subsequently rejected in closed executive session by the ERCOT Board of Directors on April 25, 2005.

B. PURA and the ERCOT Protocols Obligate ERCOT to Resolve Erroneous Load Imbalance Charges Calculated Based on Double-Counted Load

1. PURA § 39.151 requires that ERCOT accurately calculate Load Imbalance charges.

As the Commission-certified independent organization, ERCOT is statutorily obligated to "ensure that electricity production and delivery are ***accurately*** accounted for among the generators and wholesale buyers and sellers in the [ERCOT] region."[16] The Commission has reaffirmed the critical importance of this obligation both in its Substantive Rules[17] and in its oversight of ERCOT's procedures and accounting activities. The Commission recently validated its policy on ERCOT's obligations in *Complaint of Direct Energy, LP and Tenaska Power Services Co. Against the Electric Reliability Council of Texas*, Docket No. 29210 (November 5, 2004). There, the Commission cited to PURA and the ERCOT Protocols as its basis for ordering ERCOT to resettle Ancillary Services fees calculated based on erroneous Load Ratio Share.[18] ERCOT's obligation to recalculate and resolve the erroneous Load Imbalance charges invoiced to TXU Portfolio Management from the double-counted TNMP Lewisville and College Station loads is equally important to its Ancillary Services obligations confirmed in Docket No. 29210. This is particularly true where, as here, ERCOT was notified of the double counting errors well in advance of True-Up Statements and had the opportunity to fix those errors.[19]

[16] PURA § 39.151(a)(4) (emphasis added).

[17] *See, e.g.*, P.U.C. SUBST. R. 25.361(b).

[18] Docket No. 29210, Order at 10, 17-18.

[19] *See* Companies-Exhibits A and B.

2. The ERCOT Protocols require that ERCOT use *all* available settlement data to accurately calculate and invoice Load Imbalance charges.

Section 9.2.6 of the ERCOT Protocols requires that ERCOT "use all available settlement data . . . to produce the True-Up Statement for each Statement Recipient for each Operating Day." As demonstrated by Companies-Exhibits A and B, ERCOT's statement that it had "[d]eleted the ESI ID[s]"[20] associated with the TNMP Lewisville and College Station loads was incorrect. Consequently, ERCOT did not utilize *all* available settlement data in the True-Up Statements or subsequent Resettlement Statements for the July 31 through December 31, 2001 Operating Days. Unfortunately, this settlement error caused TXU Portfolio Management to be improperly invoiced for Load Imbalance charges that were calculated based on double-counted load. As the Commission explained in Docket No. 29210, "read together, the Protocols . . . support a determination that [Initial Settlement] data can be changed, and that once the error in the data is identified, ERCOT has a duty to resolve the dispute and make the necessary corrections."[21] The double counting errors here were identified to ERCOT but it has thus far refused to correct those errors.

Certainly, Load Imbalance is an important component of ERCOT market settlements that cannot be overlooked when it comes to accuracy. The Companies simply ask that ERCOT be required to accurately calculate and invoice Load Imbalance charges based on *all* settlement data it has available. To do otherwise would ignore the importance that the ERCOT Protocols place on accurately settling the market and fulfilling ERCOT's statutory and regulatory obligations.[22]

VI. PROPOSED PROCEDURAL SCHEDULE

This Complaint does not present questions of fact, only a question of law.[23] Accordingly, the Commission can decide the issue in this Complaint without referring this proceeding to the State Office of Administrative Hearings. Thus, based on the requirements of P.U.C. PROC. R. 22.251(e)-(h), the Companies propose the following procedural schedule:

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[20] Companies-Exhibit B.

[21] Order at 8.

[22] *See* ERCOT Protocols § 1.2(4) (recognizing and adopting as a "major function[]" ERCOT's obligation to ensure accurate accounting of electricity production and delivery among market participants).

[23] If it is determined otherwise, however, the Companies request the opportunity for the parties to enter a stipulation of facts and avoid the need for an evidentiary hearing.

June 29, 2005:	ERCOT provides notice to all QSEs;
July 13, 2005:	ERCOT files its response;
August 1, 2005:	Commission Staff files comments / intervention deadline; and
August 11, 2005:	Companies file a reply to responses and comments.

VII. CONCLUSION & PRAYER

WHEREFORE, PREMISES CONSIDERED, the Companies respectfully request that the Commission order ERCOT to recalculate and resolve the Load Imbalance charges invoiced to TXU Portfolio Management for July 31, 2001, through December 31, 2001, without double counting the TNMP Lewisville and College Station loads and, further, that based on that resolution TXU Portfolio Management be allowed to recover the amount that it was erroneously invoiced. The Companies also request the Commission to adopt the above-referenced procedural schedule and grant the Companies such other and further relief to which they show themselves entitled.

Respectfully submitted,

HUNTON & WILLIAMS LLP

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ATTORNEYS FOR TXU PORTFOLIO MANAGEMENT COMPANY LP AND TXU ENERGY RETAIL COMPANY LP

CERTIFICATE OF SERVICE

It is hereby certified that a true and correct copy of the foregoing document has been served on the Commission Staff, ERCOT's General Counsel, and the Office of Public Utility Counsel by hand delivery, fax, or first class United States mail, postage prepaid on this the 15th day of June 2005.

____
Thomas E. Oney

VERIFICATION

STATE OF TEXAS §
§
COUNTY OF DALLAS §

BEFORE ME, the undersigned authority, on this day personally appeared Bradley C. Jones, a duly authorized representative of TXU Portfolio Management Company LP and TXU Energy Retail Company LP (collectively, the "Companies"), who, after being by me first duly sworn, upon his oath stated that he is competent to testify to the matters stated in the Companies' Complaint Against the Electric Reliability Council of Texas ("ERCOT") and that the facts and statements set forth therein are true and correct to the best of his personal knowledge and belief.

Bradley C. Jones

SUBSCRIBED AND SWORN TO before me by the said Bradley C. Jones on this the 14th day of June 2005.

Janet Beane

Notary Public
in and for the State of Texas

JANET BEANE
My Commission Expires
September 17, 2007

COMPANIES-EXHIBIT A

Ryan Thomason 04/28/2003 10:39 AM

To: Mark Parsons/USEG/TXU@TXUU
cc:
Subject: FW: ONCOR Wholesale POD's

Mark,

I believe that this is the note that you were referring to.

Please let me know if I can be of any further help.

Ryan Thomason
ONCOR
Revenue Management
Desk: (214) 875-2775
Mobile:
ryan.thomason@oncorgroup.com

----- Forwarded by Ryan Thomason/USEG/TXU on 04/28/2003 10:39 AM -----

Buddy Burr@TXUU
12/04/2002 09:26 AM

To: Ryan Thomason/USEG/TXU@TU
cc:
Subject: FW: ONCOR Wholesale POD's

---------------------- Forwarded by Buddy Burr/USEG/TXU on 12/04/2002 09:26 AM ---------------------------

"Cohea, James" <JCohea@ercot.com> on 12/04/2002 08:06:18 AM

To: <BBURR1@oncorgroup.com>
cc:
Subject: FW: ONCOR Wholesale POD's

Here's the old note on this

James Cohea
Manager - Wholesale Market Development
ERCOT - The Texas Connection
2705 West Lake Drive
Taylor, TX 76574
(512) 248-3872
The information transmitted is intended only for the person or entity to which it is addressed and may contain confidential and/or privileged material. Any review, retransmission, dissemination or other use of, or taking of any action in reliance upon, this information by persons or entities other than the intended recipient is prohibited. If you received this in error, please contact the sender and delete the material from any computer.

-----Original Message-----
From: Cohea, James
Sent: Tuesday, February 26, 2002 4:43 PM
To: 'BBURR1@oncorgroup.com'; 'Msullivan@oncorgroup.com'

Cc: Opheim, Calvin; Roberts, Randy; Wariner, Gary; Cohea, James; Coon, Patrick; Patterson, Mark
Subject: RE: ONCOR Wholesale POD's

ONCOR Action Items:

1.

2.

ERCOT Action Items:

1.

b.

c.

2.

b.

c.

a.

b.

c.

d.

EXHIBIT 18

a.

b.

c.

James Cohea
Metering Manager
ERCOT - The Texas Connection
2705 West Lake Drive
Taylor, TX 76574
(512) 248-3872

-----Original Message-----
From: BBURR1@oncorgroup.com [mailto:BBURR1@oncorgroup.com]
Sent: Monday, February 18, 2002 10:21 AM
To: Cohea, James; Opheim, Calvin
Subject: ONCOR Wholesale POD's

James and Calvin,

Per our discussion, please review the attached spreadsheet and notify me of any required changes.
(See attached file: WholesaleAccounts ERCOT.xls)
Thanks,
Buddy

-

-

- Oncor WholesaleAccounts ERCOT(ERCOT Response).xls

These 14 accounts represent wholesale delivery points for which TXU TDSP (ONCOR) was the MRE throughout pilot. Is ONCOR now the MRE? Are these accounts energized in your systems?

ESI ID	Location	ERCOT Status	
		Active	
		Active	
		Active	
		Active	
		Active	
		Active	
		Active	
		Active	
		Active	
		Active	
		Active	
		Active	
		Active	

These ESI ID's will require the actions previously discussed.

ESI ID	Location	Action Required
10443720007147829	City of College Station	ERCOT remove this ESI ID and any associated consumption values since the established EPS reads were received.
10443720007315878	TNMP	ERCOT remove this ESI ID and any associated consumtion effective 7/31/2001. TNMP would have registered the ESI's behind this point.

New question

ESI ID	Location	Action Required

ESI ID	Location	Action Required

COMPANIES-EXHIBIT B

These 14 accounts represent wholesale delivery points for which TXU TDSP (ONCOR) was the MRE throughout pilot. Is ONCOR now the MRE? Are these accounts energized in your systems?

ESI ID	Location	ERCOT Status	Last Read	Nole Tle	MRE	LSE	LSE Duns

These ESI ID's will require the actions previously discussed.

ESI ID	Location	Action Required	
10443720007147829	City of College Station	ERCOT remove this ESI ID and any associated consumption values since the established EPS reads were received.	Deleted the ESI Id in both Lodestar and Siebel Systems
10443720007315878	TNMP	ERCOT remove this ESI ID and any associated consumtion effective 7/31/2001. TNMP would have registered the ESI's behind this point.	Deleted the ESI Id in both Lodestar and Siebel Systems

New question

ESI ID	Location	Action Required

ESI ID	Location	Action Required

EXHIBIT 19

Control Number: 31243

Item Number: 73

Addendum StartPage: 0

EXHIBIT 19

State Office of Administrative Hearings

Shelia Bailey Taylor
Chief Administrative Law Judge

June 19, 2006

TO: **Stephen Journeay, Director**
Office of Policy Development
William B. Travis State Office Building
1701 N. Congress, 7th Floor
Austin, Texas 78701

Courier Pick-up

RE: **SOAH Docket No. 473-05-8805**
PUC Docket No. 31243

Complaint of TXU Portfolio Management Company LP and TXU Energy Retail Company LP Against the Electric Reliability Council of Texas

Enclosed are two copies of the Proposal for Decision (PFD) in the above-referenced case. Please file-stamp and return a copy to the State Office of Administrative Hearings for our records. Also enclosed is a disk containing an electronic copy of the PFD. By copy of this letter, the parties to this proceeding are being served with the PFD.

Please place this case on an open meeting agenda for the Commissioners' consideration. There is no deadline. It is my understanding that you will be notifying me and the parties of the open meeting date, as well as the deadlines for filing exceptions to the PFD, replies to the exceptions, and requests for oral argument.

Sincerely,

Thomas H. Walston

Thomas H. Walston
Administrative Law Judge

Enclosure

xc: All Parties of Record (without disk)

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EXHIBIT 19

SOAH DOCKET NO. 473-05-8805
PUC DOCKET NO. 31243

COMPLAINT OF TXU PORTFOLIO MANAGEMENT COMPANY LP AND TXU ENERGY RETAIL COMPANY LP AGAINST THE ELECTRIC RELIABILITY COUNCIL OF TEXAS	§ § § § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

PROPOSAL FOR DECISION
TABLE OF CONTENTS

EXHIBIT 19

SOAH DOCKET NO. 473-~~058005~~ 05-8805
PUC DOCKET NO. 31243

COMPLAINT OF TXU PORTFOLIO MANAGEMENT COMPANY LP AND TXU ENERGY RETAIL COMPANY LP AGAINST THE ELECTRIC RELIABILITY COUNCIL OF TEXAS	§ § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

PROPOSAL FOR DECISION

I. INTRODUCTION

TXU Portfolio Management Company LP and TXU Energy Retail Company LP (collectively "the Companies") filed a complaint on June 15, 2005, against the Electric Reliability Council of Texas (ERCOT), alleging erroneous imposition of Load Imbalance charges during the last half of 2001 due to inadvertent double-counting of two wholesale points of delivery. Load Imbalance charges are imposed by ERCOT on Qualifying Scheduling Entities (QSE) that have more load than generation in a 15-minute period.[1] ERCOT responded that the original settlement should remain in effect because it is final and because TXU Electric Delivery provided the data on which the settlement was calculated. Several other entities intervened, and all parties agreed to proceed on a stipulation of facts and briefing without an evidentiary hearing on the merits. Based on the stipulated facts and the parties' arguments, the Administrative Law Judge (ALJ) recommends that the Commission order ERCOT to conduct a full resettlement of the disputed period by correcting the double-counted load assigned to TXU Electric Company (as QSE) and making the corresponding adjustments to other settlement items that are affected by correcting the double-counted load. The Commission should also assign to TXU Electric the amounts due under resettlement for any QSE that benefitted from the double counting of the TNMP Lewisville and College Station loads but have now exited the ERCOT market.

[1] A QSE is a market participant that is qualified by ERCOT to submit balanced schedules and ancillary services bids and settle payments with ERCOT. P.U.C. SUBST. R. 25.5(95).

II. PROCEDURAL HISTORY

June 15, 2005	The Companies filed their Complaint against ERCOT.
June 21, 2005	The Companies filed their affidavit of Proof of Notice.
July 13, 2005	ERCOT filed its response to the Complaint.
August 8, 2005	The Commission referred the Complaint to SOAH for a contested case hearing.
October 14, 2005	The Commission issued its Preliminary Order, listing issues to be addressed.
November 7, 2005	Prehearing conference held at SOAH, ruling on motions to intervene and scheduling a hearing on the merits on February 9, 2006. The following entities were admitted as parties:

Party	Representative
TXU Protfolio Management Company LP and TXU Energy Retail Company LP, Complainants	Thomas E. Oney, Tab R. Urbantke
Energy Reliability Council of Texas, Respondent	A. Andrew Gallo, Shari Heino, ERCOT
Commission Staff	Rosa Rohr, Fred Geissler
Office of Public Utility Counsel	Katherine H. Farrell
CPS Energy, Intervenor	Patricia Ann Garcia Escobedo
First Choice Power Special Purpose, LP, Intervenor	Scott Seamster
South Texas Electric Cooperative, Inc., Intervenor	Jo Campbell
Direct Energy LP, Intervenor	Robert Frank, Thane Thomas Twiggs
Lower Colorado River Authority, Intervenor	Stephen Burger
Texas Energy Association for Marketers, Intervenor	Catherine J. Webking
Reliant Energy, Inc., Intervenor	Jonathan L Heller
Texas Genco II, LP, Intervenor	Michael Tomsu, J. David Bickham, Jr.

December 1, 2005	Parties filed an Agreed Stipulation of Facts and Motion to Abate Procedural Schedule.
December 2, 2005	Order No. 6 issued, Granting Motion to Abate Procedural Schedule.
March 1, 2006	Modified Agreed Stipulation of Facts filed.
March 22, 2006	Order No. 11 issued, admitting modified Agreed Stipulation of Facts into evidence and establishing briefing schedule.
April 7, 2006	Initial Briefs filed by TXU, ERCOT, Commission Staff, OPUC, CPS Energy, First Choice Power Special Purpose LP, Reliant Energy, Inc., South Texas Electric Cooperative, Inc., and Texas Energy Association for Marketers.
April 20, 2006	Reply Briefs filed by the same parties, at which time the record closed.

III. NOTICE AND JURISDICTION

ERCOT provided notice of the Companies' complaint to all QSEs by electronic mail on June 16, 2005, pursuant to P.U.C. PROC. R. 22.251(e). No party contested notice. The Commission has jurisdiction over the Companies' complaint against ERCOT pursuant to PURA § 39.151(d) and P.U.C. PROC. R. 22.251. SOAH has jurisdiction to conduct a hearing and issue a proposal for decision (PFD) pursuant to PURA § 14.053 and TEX. GOV'T CODE ANN. §§ 2001.058 and 2003.049.

IV. DISCUSSION

A. Background

The Companies have requested the Commission to order ERCOT to recalculate and resolve load imbalance charges for TNMP Lewisville and City of College Station loads that were attributed to TXU Electric Company (TXU Electric), as a QSE, from July 31 through December 31, 2001, during the customer-choice pilot project. Because of redundant meters at these wholesale delivery points, ERCOT double counted the redundant meter data provided to it. This double-counted data caused ERCOT to assess load imbalance charges to TXU. ERCOT acknowledges that an error occurred but denied the claim by arguing that the charges were based on information provided by the Companies and that the disputed dates were settled in accordance with ERCOT Protocols.

TNMP Lewisville

Before July 31, 2001, TXU Electric, the formerly integrated and bundled utility, sold wholesale power to Texas-New Mexico Power Company (TNMP) for TNMP's City of Lewisville load at multiple meters that were aggregated under a single aggregation meter. TXU Electric billed TNMP based on the load measured at the aggregation meter pursuant to a contract between TXU Electric and TNMP. In March 2001, the Transmission and Distribution Service Provider (TDSP), TXU Electric Delivery Company (Electric Delivery)[2] established an Individual Electric Service Identifier (ESI ID) number[3] to the aggregation meter and assigned it to TXU Electric as the Load Serving Entity (LSE). When the retail customer choice pilot project (pilot project) began July 31, 2001, TXU Electric continued to sell wholesale power to TNMP for the Lewisville load. However, during the pilot project, TNMP served Lewisville as both a LSE and a TDSP, and Constellation Power Source, Inc. (Constellation)–not TXU Electric–served as TNMP's QSE. ESI ID meters within the TNMP Lewisville load territory were used to measure wholesale sales from TXU Electric to TNMP and to calculate Load Imbalance charges by ERCOT to Constellation. The ESI IDs for these individual meters were properly assigned to TNMP and Constellation (the QSE), and they should have replaced the pre-pilot project TXU Electric aggregation meter on ERCOT's systems as of July 31, 2001.[4]

After the pilot project began on July 31, 2001, TXU Electric's aggregation meter and its associated ESI ID were erroneously left in place. To correct this mistake, Electric Delivery notified

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[2] At the time, Electric Delivery was known as Oncor Electric Delivery Company.

[3] ESI ID No. 10443720007315878. An ESI ID is the basic identifier assigned to each point of delivery used in the registration system and settlement system managed by ERCOT or another independent organization. P.U.C. SUBST. R. 25.5(40).

[4] Agreed Stipulation of Facts (Stipulation) Nos. 13-16.

ERCOT on February 18, 2002, that the ESI ID for the TXU Electric aggregation meter and any associated usage data should be removed from ERCOT's computer systems effective July 31, 2001. On February 26, 2002, ERCOT responded that it had deleted the ESI ID in both its Lodestar and Siebel Systems.[5]

However, in late November 2002, ERCOT notified TXU Portfolio Management that it did not actually delete the aggregation meter ESI ID from its computer systems until November 27, 2002. As a result, the load from the TNMP Lewisville meters was counted twice in the ERCOT settlement process for the period July 31 through December 31, 2001–once for Constellation (as QSE) and once for TXU Electric (as QSE).[6]

College Station

Before July 31, 2001, TXU Electric also sold wholesale power to the City of College Station at multiple meters aggregated under a single aggregation meter, and in March 2001, Electric Delivery (the TDSP) had established an ESI ID[7] for that meter and assigned it to TXU Electric (as LSE). Beginning July 31, 2001, College Station became a Non-Opt In Entity (NOIE). As a NOIE, College Station installed ERCOT Polled Settlement meters to replace the TXU Electric wholesale aggregation meter for the purpose of measuring load, but TXU Electric's wholesale aggregation meter was also left in place after July 31, 2001. From July 31 through December 31, 2001, TXU Electric continued to sell wholesale power and serve as QSE for College Station.[8]

On February 18, 2002, Electric Delivery notified ERCOT that its ESI ID for College Station and any associated usage data should be removed from ERCOT's computer systems effective

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[5] Stipulation Nos. 17-19.

[6] Stipulation Nos. 20-21.

[7] ESI ID No. 10443720007147829.

[8] Stipulation Nos. 22-26.

July 31, 2001, and on February 26, 2002, ERCOT responded that it had deleted the ESI ID in both Lodestar and Siebel Systems. However, in November 2002, ERCOT notified TXU Portfolio Management that it did not actually delete this ESI ID from its computer systems until November 27, 2002. As a result, for the period July 31 through December 31, 2001, the load from the College Station meters was counted twice for TXU Electric (as QSE) in the ERCOT settlement process.[9]

Data Error Issues

Before the start of the deregulated retail market on July 31 2001, TDSPs provided ERCOT and LSEs information necessary to set up competitive area ESI IDs, including ESI ID relationship and characteristics data, as well as historical usage. ERCOT then forwarded usage data to each LSE, as provided by the TDSP. ERCOT forwards changes in transactional characteristic information (station, profile code, loss code, etc.) to the current LSE and to any new LSE if a switch to a new LSE is pending.

From early to middle 2002, ERCOT and Market Participants participated in a data clean-up and improvement effort known as "Market Synchronization." During Market Synchronization, LSEs and TDSPs provided ERCOT files showing a comprehensive list of LSE relationship start and stop times by ESI ID. With these files, ERCOT performed a comparison across the LSE, TDSP, and ERCOT data and identified LSE relationship discrepancies that needed to be resolved across specified entities (LSE, TDSP and/or ERCOT). During this time frame, ERCOT also participated in individual ESI ID synchronization efforts for Market Participants with individualized requests, and ERCOT answered questions from various Market Participants about their data as shown in ERCOT's system. In March 2003, ERCOT implemented System Change Request (SCR) 727, which resulted in a regularly produced data extract for both TDSPs and LSEs containing ESI ID characteristic, relationship and usage data. At that time, ERCOT also implemented the Data Extract

[9] Stipulation Nos. 27-29.

Variance process so TDSPs and LSEs could file discrepancies between their systems and ERCOT systems for resolution with the appropriate entity.[10]

During the retail customer choice pilot project, the ERCOT market experienced issues related to data accuracy. At its meeting on May 21, 2002, ERCOT's Board of Directors instructed ERCOT staff to stop performing True-Up Settlements to allow resolution of ESI ID data errors. The Board passed the following resolution:

> The ERCOT Board direct the ERCOT Staff to perform a ONE-TIME re-settlement of July 31, 2001 through the current Wholesale Settlement Statement published. Such re-settlement will commence after ERCOT has successfully received and validated at least 99 percent of the IDR data from each Meter Reading Entity (MRE). In addition, ERCOT would suspend future true-up settlements until the 99 percent IDR consumption data standard is met. The true-up settlement timeline would be extended to a maximum of 12 months in cases where the IDR data threshold is not met. . . .[11]

During the process described in that resolution, ERCOT sent daily reports to TDSPs showing ESI IDs for which ERCOT did not have usage data so the TDSPs could provide the missing data. ERCOT also asked the TDSPs to provide the missing data for their ESI IDs. With respect to the TNMP Lewisville and College Station ESI IDs, ERCOT stated to Electric Delivery, "[a]ttached you will find the updated spreadsheets for ONCOR as of data loaded in ERCOT systems by 5:30 pm 05-09-02. The spreadsheets contain a list of ESI IDs that are NOT in compliance with IDR data being loaded through September 2001 . . . ."[12] The spreadsheets included the aggregation meters for TNMP Lewisville and College Station. In response, Electric Delivery provided usage data for the TNMP Lewisville and College Station ESI IDs,[13] after which ERCOT stated: "ONCOR is in

[10] Stipulation No. 30.

[11] Stipulation Nos. 31-32.

[12] Electric Delivery was known as Oncor at the time.

[13] The ESI ID meters at issue were for wholesale, not retail, delivery points. Stipulation No. 37.

compliance with ERCOT's requests." When it issued the subsequent Settlement Statements for the subject dates in 2001, ERCOT relied on this data provided by Electric Delivery concerning TNMP Lewisville and College Station. On September 9, 2002, ERCOT began issuing the True-Up Statements for dates in 2001.[14]

Settlement Effects of the Double-Counted Load

One settlement effect of the double-counted load was that it overstated the load for TXU Electric (as QSE) and produced a decrease in the magnitude of ERCOT-wide Unaccounted for Energy (UFE) for each settlement interval relative to the magnitude that would have been produced had the load not been counted twice. During this period, UFE was primarily negative and was more negative than it would have otherwise been due to the double-counted load.[15]

Another settlement effect was that the double-counted load produced Adjusted Metered Load (AML) values for each settlement interval for TXU Electric (as QSE) that were higher than they would have been had the load not been counted twice; however, the increase was not equal to the full double counting due to the negative UFE allocation. The AML values of QSEs (other than TXU Electric) representing LSEs allocated UFE were lower than what the AML values would have been had the load not been counted twice. The AML values of QSEs (other than TXU Electric) representing LSEs not allocated UFE were the same as what the AML values would have been had the load not been counted twice.[16]

Under the ERCOT Protocols, UFE is not allocated to QSEs representing LSEs on a simple load ratio share basis. Rather, pursuant to ERCOT Protocol 11.4.6.2, UFE is allocated to QSEs

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14 Stipulation Nos. 33-40.

15 Stipulation No. 41.

16 Stipulation No. 42.

representing LSEs according to specific formulas that are dependent upon the category of loads being served by each LSE.[17]

The ADR Process

Pursuant to Section 9 of the ERCOT Protocols, TXU Portfolio Management submitted the settlement and billing disputes regarding the Load Imbalance charges related to TNMP Lewisville and College Station for the July 31 through December 31, 2001 Operating Days. In each of its settlement and billing disputes relating to the dates at issue, TXU Portfolio Management made one of the following statements:

- It was, "[d]isputing the difference between TXU internal load of [X] MW verses ERCOT load of [X] MW with the net difference of [X] MW";
- "Dispute the difference between TXU load and ERCOT load";
- "Diffs note[d] in Load Imbalance"; or
- "Differences between TXU's internal load and ERCOT's load."

These disputes provided no further detail for the cause of the alleged imbalance or load differences.[18]

After ERCOT denied TXU Portfolio Management's settlement and billing disputes, TXU Portfolio Management invoked the alternative dispute resolution (ADR) process in Section 20 of the ERCOT Protocols. This occurred between October and December 2002. In its ADR request letters, TXU Portfolio Management cited, as the basis for its ADR requests, differences between the AMLs calculated by TXU Portfolio Management and the AMLs calculated by ERCOT, which it alleged resulted from the "failure of ERCOT to collect the appropriate meter loads . . . ."[19]

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[17] Stipulation No. 43.

[18] Stipulation Nos. 45-46.

[19] Stipulation Nos. 47-48.

During the period from October 2002 until May 2005, ERCOT and the Companies exchanged data and otherwise diligently worked on the subject Load Imbalance charges and other Load Imbalance issues. In executive session on April 19, 2005, the ERCOT Board of Directors voted to deny the ADRs, and on May 12, 2005, ERCOT and the Companies agreed to waive mediation and arbitration.[20]

B. Parties' Arguments

The Companies and Staff argue that the Commission should order ERCOT to resettle the Load Imbalance charges. ERCOT and the Intervenors argue against resettlement.

1. Companies and Staff

The Companies stress that ERCOT is ultimately responsible for making market settlements as accurate as possible. Yet, they complain, ERCOT has refused to correct the erroneous Load Imbalance Charges that resulted from the double-counted ESI IDs, even though ERCOT acknowledges the errors occurred and learned of their root cause through the ADR process. In the Companies' view, ERCOT fell short of its statutory obligation to accurately settle the market, resulting in TXU Portfolio Management being overcharged $4 million.[21] They cite ERCOT's obligation under PURA § 39.151(a)(4) to "ensure that electricity production and delivery are accurately accounted for" in the ERCOT region. The Commission has enforced this obligation, the Companies state, through P.U.C. SUBST. R. 25.361(b) and its decision in Docket No. 29210.[22]

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[20] Stipulation Nos. 52-53.

[21] Companies Initial Brief at 2.

[22] *Complaint of Direct Energy, LP and Tenaska Power Services Co. Against the Electric Reliability Council of Texas*, Docket No. 29210, Order (Nov. 5, 2004).

The Companies also claim that ERCOT violated ERCOT Protocol § 9.2.6, which requires ERCOT to "use all available settlement data . . . to produce the True-Up Statement for each Statement Recipient for each Operating Day." In their view, ERCOT violated this Protocol because it did not delete the duplicate TNMP Lewisville and College Station ESI IDs until November 27, 2002, after having assured TXU Delivery ten months earlier that they had been deleted. The Companies emphasize the Commission's statement in Docket No. 29210 that once an error in the data is identified, "ERCOT has a duty to resolve the dispute and make the necessary corrections."[23] As will be discussed in more detail under the Preliminary Order Issues, the Companies also argue that ERCOT's settlement of the July-December 2001 period can be changed even if it is considered final; ERCOT did not settle the time period in accordance with its protocols because it failed to use all available settlement data; and the Companies' actions did not contribute to the erroneous balancing energy charges. The Companies take no position on the appropriate methodology to correct the errors, although they note that the most accurate methodology would be a full resettlement of all affected charges for the period in dispute.[24]

Rejecting ERCOT and the Intervenors' arguments as procedural traps and technicalities, the Companies contend that the Commission is authorized to review ERCOT's actions *de novo* under PURA § 39.151(d) regardless of the defenses raised by the other parties. In response to ERCOT's argument that the Companies made invalid, generic "placeholder" challenges, the Companies state that the disputes were due within ten days after the settlement statement issued, but at that time there was limited access to data to allow the Companies to provide details on the cause of the variance between ERCOT's and the Companies' data. In their view, denying the complaints on this ground would be unreasonable when the Companies did not have access to the data necessary to file a detailed dispute within the ten-day deadline. The Companies also disagree that the 2 % threshold of ERCOT Protocol 9.2.5 bars resettlement in this case. They argue that the threshold applies only to post-True-Up disputes, but in this case the Companies notified ERCOT of the load-imbalance error

[23] Docket No. 29210, Order at 8.

[24] Companies Initial Brief at 4-9.

well in advance of the True-Up Settlement. Under these unusual circumstances, the Companies argue, ERCOT should have corrected the admitted double-counting error. They state it would be bad public policy to allow ERCOT to fail to correct a known error and then deny the claim based on the 2 % threshold.[25]

Staff supports the Companies' request for resettlement. Staff emphasizes that ERCOT is responsible for accurately settling the market, citing PURA § 39.151(a)(4) and P.U.C. SUBST. R. 25.361(b), which both provide that ERCOT will ensure that electricity production and delivery "are accurately accounted for . . . ." In Staff's opinion, ERCOT simply failed in its duty by counting the two ESI IDs that should have been removed from ERCOT's system. Only by holding ERCOT accountable, Staff states, will the Commission ensure that ERCOT performs its functions properly. Like the Companies, Staff cites the Order in Docket No. 29210 in which the Commission ordered ERCOT to resettle Ancillary Services fees that were based on erroneous Load Ratio Shares.[26]

2. ERCOT and Intervenors

ERCOT, Reliant, CPS Energy, TEAM, STEC, and OPC all oppose the Companies' request for resettlement. They emphasize that 100% accuracy in the market settlement is not possible due to the enormous amount of data and the large number of entities involved. Further, they argue that ERCOT complied with the requirement of Protocol 9.2.6 to use all available settlement data, as ERCOT used the most recent data provided by Electric Delivery for the disputed ESI IDs. In other words, they argue that ERCOT properly used the data on the two disputed ESI IDs that Electric Delivery continued to provide even after requesting removal of the ESI IDs.

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[25] Companies Reply Brief at 6-8.

[26] Staff's Initial Brief at 2-3.

ERCOT stresses that by following the Protocols, it met its obligations under PURA,[27] and it complains that the Companies filed mere "placeholder disputes" that failed to adequately state the reason for the dispute. It notes that the Companies did not discover the cause of the double-counting until after the ADR process had commenced. Before that time, the Companies stated in their disputes only that the TXU load did not match the ERCOT-calculated load, with no explanation as to the cause. ERCOT argues that these placeholder disputes failed to satisfy the requirement (at that time) of Protocol § 9.5.3 that settlement and billing disputes clearly state the reasons for the dispute. Finally, ERCOT states that 35 % of the Companies' disputes were not timely appealed to ADR and should be considered closed and ineligible for further review under Protocol § 9.5.4 (as it existed at the time).[28]

Reliant contends that the True-Up Settlement Statement for 2001 had been properly finalized under the ERCOT Protocols before this dispute was identified. It argues that nothing special about the Companies' dispute warrants reopening the final True-Up Settlement Statement and subjecting all market participants to a potential reallocation of Load Imbalance charges and other possible ripple-effect charges for events that occurred in 2001. Further, Reliant states, ERCOT Protocol 9.2.5 provides that resettlement for data errors will be made after ERCOT has issued the True-Up Settlement Statement only when the impact of the error is greater than 2 % of the ERCOT Operating Day market transaction dollars (excluding bilateral transactions), but that 2 % test is not met in this case.[29]

Reliant adds that the issue in this case is more complex than Staff's assertion that it is only an issue of holding ERCOT accountable. Reliant points out that it is the market participants – not ERCOT – that will pay a resettlement and incur increased costs. In its view, the issue is whether market participants should be allocated increased costs when ERCOT followed its Protocols, relied

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27 ERCOT Reply Brief at 2.

28 ERCOT Initial Brief at 7-8.

29 Reliant Initial Brief at 4-5.

on load information provided by TXU Electric Delivery, and finalized the settlement of the disputed time period.[30]

TEAM contends that resettlement after five years would not allow market participants to close their books and would create an unwarranted business risk. It suggests that diverting resources from current settlement accuracy in order to resettle 2001 would be unwise, and it complains that many current market participants that would be affected by a resettlement were not in existence and did not participate in the pilot project in 2001.[31]

ERCOT and the Intervenors also reject Staff and the Companies' reliance on the Commission's Order in Docket No. 29210. ERCOT contends that Tenaska filed settlement and billing disputes with appropriate details in that case, rather than mere placeholder disputes as filed by the Companies. In the present case, ERCOT argues, the Companies should have discovered the cause of its erroneous billings during the Market Synchronization process, rather than much later in the ADR process, and should have included the cause in its complaints.[32] In addition, OPC, STEC, and TEAM point out that the amount in dispute in Docket 29210 exceeded the 2 % threshold in Protocol 9.2.5, but the Companies' complaint in this case falls short of the threshold. They argue that the threshold applies because the Companies did not identify the double-counting error until after ERCOT issued True-Up Statements for the dates at issue.[33]

C. ALJ's Analysis

The ALJ finds that TXU Portfolio Management submitted adequate and timely billing and settlement disputes concerning the Load Imbalance charges and that the Commission should order

[30] Reliant Reply Brief at 2-3.

[31] TEAM's Statement of Position at 3-4.

[32] ERCOT Reply Brief at 3-4.

[33] OPC Reply Brief at 1-2; STEC Reply Brief at 2-4; TEAM Reply Brief at 2.

resettlement. The Commission's prior decisions have held that ERCOT should correct settlement errors when a complainant complies with the deadlines and other requirements for filing billing and settlement disputes. In the present case, TXU Portfolio Management filed timely disputes that put ERCOT and other market participants on notice that differences existed between TXU's calculated load and ERCOT's calculated load for the dates in question. Once the errors and the underlying causes were confirmed, ERCOT became obligated to correct the error. Further, because TXU Portfolio Management filed its disputes before True-Up, the 2 % threshold of ERCOT Protocol 9.2.5 does not apply.

The Commission has issued at least three decision concerning disputes over ERCOT settlements. In the first decision, *Complaint of Direct Energy, LP and Tenaska Power Services Co. Against the Electric Reliability Council of Texas* (Docket No. 29210), the dispute concerned erroneous Load Ratio Shares (LRS) that caused excessive Ancillary Service fees. Although ERCOT acknowledged that it had made an error in that case, ERCOT denied relief by arguing that Protocol 6.3.1 precluded changes to initial settlement data and that resettlement would be unfair to other Market Participants. The Commission rejected ERCOT's argument that initial settlement data could never be changed, and it reminded ERCOT that the Complainants in that case were also Market Participants entitled to fairness. In that case, the parties stipulated that Complainants timely filed settlement and billing disputes and that the amount in dispute resulted in an impact greater than 2 % of the Operating Day market transaction dollars, excluding bilateral transactions.[34]

The next ERCOT-settlement case, decided by the Commission on May 15, 2006, was *Complaint of Sempra Energy Solutions Against the Electric Reliability Council of Texas* (Docket No. 31846). In that case, Sempra alleged that ERCOT underpaid it for Balancing Energy due to a design flaw in ERCOT's settlement system that made the underpayment undetectable in Settlement Statements. ERCOT granted some of Sempra's claims but denied others as being filed late. ERCOT also argued that a design flaw did not exist and that Sempra caused the error by providing incorrect

[34] Docket No. 29210, Order (Nov. 5, 2004)

information. Sempra appealed the denied late-filed claims, citing the Commission's decision in Docket No. 29210 to argue that ERCOT had a duty to accurately account for electricity production and delivery. It requested that the late filings be excused because the errors could not be detected in the settlement statements. Acknowledging that errors with financial consequences would inevitably occur, the Commission nevertheless denied the late-filed claims. The Commission emphasized that rules and procedures "carefully and specifically define the responsibilities of all Market Participants," and "in order to ensure fairness and as much financial certainty as possible, it is necessary to establish deadlines for all participants to follow."[35]

Finally, the Commission issued a decision on June 9, 2006, in *Complaint of Calpine Power Management, LP Against the Electric Reliability Council of Texas* (Docket No. 31362). In that case, all parties agreed that a metering error occurred that resulted in ERCOT underpaying Calpine $3,185,000 for Balancing Energy. Like the Companies in the present case, Calpine emphasized the Commission's oversight responsibility for ERCOT, as well as the duty imposed on ERCOT by PURA § 39.151(a) to accurately account for electricity production and delivery. Also like the present case, Calpine argued that it was reasonably diligent in raising the claims, and it complained that the parties opposing its relief did so only on procedural grounds. The Commission denied the claims because Calpine filed them late. It noted its statement in Docket No. 29210 that fairness was owed to all Market Participants but explained "that Calpine has not acted fairly toward those other Market Participants and ERCOT by not timely challenging settlement statements as required by the Protocols." The Commission also stressed that, in Docket No. 29210, Direct Energy consistently and timely challenged settlement statements, which gave ERCOT and Market Participants advance warning of the potential for a resettlement. Finally, the Commission found that ERCOT acted upon the load data it was provided in accordance with the Protocols and properly applied the Protocols in denying Calpine's request for resettlement.[36]

[35] *Complaint of Sempra Energy Solutions Against the Electric Reliability Council of Texas,* Docket No. 31846, Order (May 15, 2006).

[36] *Calpine Power Management, LP Against the Electric Reliability Council of Texas,* Docket No. 31362, Order (June 9, 2006).

These decisions make clear that ERCOT is required to correct billing errors when Market Participants file proper billing and settlement disputes. In the present case, ERCOT and other intervenors argue that TXU Portfolio Management filed mere "placeholder disputes" that did not adequately preserve the complaints. However, the billing disputes did inform ERCOT and other Market Participants that differences existed between the loads calculated by ERCOT and by TXU, which was sufficient to give ERCOT and Market Participants advance warning of the potential for a resettlement. Although the disputes did not specify the precise cause of the load calculation differences, that additional detail was not necessary to alert other parties of the potential for resettlement. In addition, neither ERCOT nor the Companies were able to pinpoint the precise cause of the error until several years later during the ADR process; yet, the billing and settlement disputes had to be filed within ten days. The ALJ finds that denying the complaints on this ground would be unreasonable when the Companies did not have access to the data necessary to explain the cause of the error within the ten-day deadline, particularly when the disputes that were filed were adequate to place other parties on notice of a possible resettlement.

The ALJ also finds that the 2 % threshold in ERCOT Protocol 9.2.5 does not bar resettlement in this case. As noted by the Companies, the threshold applies only to post-True-Up disputes, but the Companies filed their billing disputes before True-Up. ERCOT and the intervenors attempt to convert this case into a post True-Up dispute–making Protocol 9.2.5 applicable–by arguing that the Companies' initial billing disputes were invalid "placeholders." Thus, they contend that this case involves a post True-Up dispute because the underlying cause of the double-billing errors was not discovered until during ADR, long after True-Up. However, as discussed previously, the ALJ finds that the Companies' billing disputes filed within ten days (long before True-Up) were adequate because they alerted ERCOT and market participants of the potential for resettlement due to disputed load calculations. Consequently, this case does not involve a post True-Up billing dispute and the 2 % threshold of Protocol 9.2.5 does not apply.

Therefore, the ALJ recommends that the Commission grant the Companies' request for ERCOT to resettle TXU Electric's load imbalance charges for July-December 2001. The recommended methodology for this relief is discussed under the Preliminary Order Issue No. 4.

D. Preliminary Order Issues

1. Is ERCOT's settlement for the July-December 2001 time period final?

a. Parties' Arguments

The Companies acknowledge that ERCOT's settlement for the July-December 2001 period is "final" in ERCOT's parlance, but they believe that such final settlements can be changed under PURA and ERCOT Protocols in light of the unusual circumstances of double-counted load. In support of this position, they cite ERCOT Protocols §§ 20.8 and 9.2.5, which authorize the ERCOT Board of Directors to resettle final settlements when unusual circumstances exist. The Companies also cite the Commission's decision in Docket No. 29210 to argue that ERCOT has a duty to correct erroneous charges to market participants, and they stress that ERCOT was informed of the billing disputes six months before the True-Up Settlement.[37]

ERCOT contends that its settlement for the disputed dates is final because it followed the ERCOT Protocols and because no legitimate disputes exist for any Operating Days in 2001. It cites the ERCOT Board of Directors' decision that settlement for Operating Days past True-Up was final, even with outstanding disputes related to ESI ID data correction because:

- It allows ERCOT to consistently comply with the settlement timeline set forth in Section 9 of the ERCOT Protocols and avoid the risks associated with a perpetual resettlement cycle for any given Operating Day.

[37] Companies Reply Brief at 5.

- It allows ERCOT and Market Participants to "close the books" on Operating Days after following the processes available to Market Participants for reconciliation of retail data variances and wholesale settlement disputes.

- It discourages "placeholder" or imprecise settlement and billing disputes and ADR requests which would, if allowed, create additional administrative burden for ERCOT (due to increased filing of disputes without support) and prevent ERCOT from "closing the books" on any Operating Day.[38]

OPC and STEC agree with ERCOT's arguments. They acknowledge that Protocol 9.2.5 allows ERCOT's Board to resettle any trade day to address unusual circumstances, but point out that the Board considered and denied the Companies' request in this case.[39] Reliant also argues that ERCOT's settlement is final and states that a final settlement can never be perfect due to the enormous amount of data provided by numerous market participants.[40]

CPS Energy states that even if the settlement is final, the Commission has authority under PURA § 39.151 to resettle the time period if the Commission finds that the Companies' complaint is valid or that public policy requires a resettlement.[41]

Staff also argues that ERCOT's settlement is not final, in the sense that it does not bar the Companies' complaint, because TXU preserved its rights under the Protocols by timely protesting the settlement, invoking the ADR process, and commencing this action.[42]

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[38] ERCOT Initial Brief at 2-3.

[39] OPC Initial Brief at 1-2; STEC Initial Brief at 8-10. STEC also notes that Protocol 9.2.5, which allows ERCOT to order resettlement for "unusual circumstances," did not become effective until July 1, 2002, after the 2001 dates in dispute in this case. STEC Reply Brief at 2-3.

[40] Reliant Initial Brief at 4-5.

[41] CPS Energy Initial Brief at 2-3.

[42] Staff Initial Brief at 4.

b. ALJ's Analysis

The ALJ finds that ERCOT's settlement for the July-December 2001 time period is final in the sense that ERCOT denied these billing disputes and otherwise followed its settlement Protocols. However, the ALJ agrees with the parties that this does not preclude resettlement if the Commission finds the Companies timely filed their billing disputes and an error occurred. The Commission has oversight and review authority under PURA § 39.151(d) to correct ERCOT errors, and ERCOT Protocol 9.2.5 authorizes the ERCOT Board of Directors to resettle final settlements when unusual circumstances exist. The ALJ has found that the Companies timely filed their billing disputes and all parties agree that a double-counting billing error occurred. Under these circumstances, the ALJ concludes that the Commission can order resettlement to correct the billing error, even if ERCOT's settlement is otherwise considered final.

2. Was this time period settled in accordance with ERCOT Protocols?

a. Parties' Arguments

The Companies argue that the time period was not settled in accordance with ERCOT Protocols. Because ERCOT failed to correct the double-counted load, the Companies state that ERCOT failed to use all available data as required by ERCOT Protocol 9.2.6.[43]

ERCOT contends that it settled the subject dates in accordance with its Protocols. It states that ERCOT is responsible to settle the dates with the data provided by the TDSPs, while the TDSPs are responsible for creating ESI IDs; providing settlement meter data; supplying ERCOT with meter data associated with all loads in the ERCOT system; providing consumption data for each ESI ID; validating, estimating, and editing meter data before submitting the data to the settlement process;

[43] Companies Initial Brief at 8.

and providing data for TDSP Metered Entities.[44] It states that the Companies erroneously established the ESI IDs that caused the double counting to occur in this case. Although ERCOT notified the Companies that it had corrected the ESI IDs in the system, it stresses that Electric Delivery continued to provide data for the diputed ESI IDs after this notification. ERCOT also complains that the Companies failed to correct the ESI IDs when they had the opportunity before the issuance of True-Up Statements. In ERCOT's view, the mere fact that it unsuccessfully attempted to correct the ESI IDs provides no more reason to treat this case differently than any other ESI ID data-related dispute. Therefore, ERCOT concludes that it settled the questioned time period in accordance with its Protocols.[45]

OPC and STEC support ERCOT's position that it settled the time period in question in accordance with the Protocols.[46] Reliant agrees, pointing out that ERCOT used data provided by TXU Electric Delivery for the two ESI IDs in dispute. It notes that TXU Electric Delivery continued to provide data to ERCOT for TNMP Lewisville and College Station even after it had requested ERCOT to remove these ESI IDs from the system.[47] CPS Energy states that the Protocols were followed but suggests that the Commission may still resettle the time period to correct data errors.[48]

Staff contends that ERCOT did not settle the disputed time period in accordance with the Protocols because it used erroneous data. It stresses that ERCOT confirmed that it had removed the two ESI IDs from its system, yet included the load from these ESI IDs in the True-Up Statement for the Companies. Staff also suggests that even if Electric Delivery was negligent in continuing to provide data, such negligence should not be imputed to TXU because it is a separate corporation. It also points out that only Electric Delivery and ERCOT could have known about the double

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[44] Protocols 15.4.1, 10.1, 10.2.2, 10.3.3.1(1), 10.3.3.1(4), and 11.2.2.

[45] ERCOT Initial Brief at 3-7; ERCOT Reply Brief at 2-3.

[46] OPC Initial Brief at 2; STEC Initial Brief at 10-11.

[47] Reliant Initial Brief at 5-6.

[48] CPS Initial Brief at 3.

counting, not TXU.[49] Therefore, in Staff's view, ERCOT did not comply with the Protocols, TXU was not at fault, and a resettlement should be reordered.[50]

b. ALJ's Analysis

The ALJ finds that ERCOT settled the disputed time period in accordance with the Protocols in the sense that it followed the procedures set out in the Protocols. It is undisputed that ERCOT settled the time period based on the data provided by the Companies. The mere fact that ERCOT unknowingly relied on erroneous data supplied by the Companies does not provide a basis for concluding that ERCOT violated the settlement Protocols. Even OPC and most Intervenors agree that ERCOT settled the disputed dates in accordance with the Protocols. However, as both ERCOT and the Commission have authority to correct billing and settlement errors under PURA § 39.151(d) and Protocol 9.2.5, resettlement should not be prohibited for an acknowledged billing error that was timely disputed solely because ERCOT followed procedures contained in the Protocols.

3. Did the actions of TXU Portfolio Management Company LP and TXU Energy Retail Company LP contribute to the problem which allegedly resulted in the erroneous balancing energy charges? If so, should the Commission take these actions into account when determining how to resolve this complaint?

a. Parties' Arguments

The Companies argue that it is irrelevant under PURA or the ERCOT Protocols whether their actions contributed to the double-counted load that resulted in overcharges to TXU Portfolio Management. They explain that their claim is based on PURA § 39.151(a)(4) and Commission precedent requiring ERCOT to accurately settle the market, not on tort law or some scheme of comparative negligence. Nevertheless, the Companies contend that they did nothing that contributed

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[49] Staff Reply Brief at 3.

[50] Staff Initial Brief at 4.

to the double-counted load in ERCOT's system or to ERCOT's refusal to correct the error. Further, they state that they worked with ERCOT during the ADR process to determine the source of the errors and reach an agreeable solution. The Companies acknowledge that Electric Delivery provided consumption data for the subject ESI IDs after having notified ERCOT that those ESI IDs should be removed from ERCOT's system, but they suggest that Electric Delivery would have been out of compliance with ERCOT's requests had it not submitted this usage data.[51]

The Companies also reject ERCOT's claim that a portion of their ADR requests were filed late. They complain that there is no evidence in the stipulation to support this claim and that never asserted this defense until if filed its initial brief in this proceeding. Further, the Companies point out that ERCOT participated in nearly three years of negotiations on these ADRs, which contradicts ERCOT's current argument that the claims are closed.[52]

ERCOT argues that the Companies contributed to the problems at issue and that the Commission should consider this when resolving this dispute. First, ERCOT points out that it, the TDSPs, and LSEs undertook a data cleanup process known as Market Synchronization in early to middle 2002, in which the parties exchanged data to identify discrepancies with ESI IDs. Further, the ERCOT Board delayed True-Up Statements for Operating Days in 2001 in order to provide Market Participants time to complete this synchronization process. ERCOT states that, during this time, the Companies could have discovered that the two delivery points in question were double-counted, but they failed to do so.[53] On September 9, 2002, ERCOT began issuing True-Up Statements for 2001. Because the Companies did not take advantage of the opportunity in early 2002 to discover the double-counting, ERCOT argues they should not be allowed to benefit at the expense of other market participants who had the same time constraints.[54]

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[51] Companies Initial Brief at 8-9.

[52] Companies Reply Brief at 13.

[53] Agreed Fact Nos. 30 and 32.

[54] ERCOT Initial Brief at 7.

ERCOT also notes that the double-counting was not discovered until after the ADR process had commenced and well after ERCOT had issued True-Up Statements for the subject dates.[55] Before the discovery during ADR, the Companies had complained only that TXU Load did not match the Load ERCOT had calculated, with no explanation as to the cause. ERCOT states that it considers these claims as meaningless "placeholder disputes" because they provide no reason or justification for resettlement. ERCOT cites Protocol 9.5.3's requirement that a notice of settlement and billing dispute must clearly state the reason for the dispute, and it argues that the Companies' prior placeholder disputes were insufficient for ERCOT to meaningfully evaluate the disputes.[56]

Finally, ERCOT argues that the Companies did not comply with some settlement and billing dispute deadlines in the ERCOT Protocols. It points out that under Protocol 9.5.4, a dispute is final and closed if a Statement or Invoice Recipient does not begin ADR within 30 days after receiving notice that a dispute was denied. ERCOT contends that approximately 35 % of the Companies' disputes were not timely appealed to ADR and should be considered closed and ineligible for further review.[57]

OPC argues that the Companies' actions contributed to the problem because they continued to provide information on the disputed ESI IDs during Market Synchronization. In other words, the Companies continued to provide data for the Lewisville TNMP and College Station ESI IDs that they had previously requested ERCOT to remove them.[58] Reliant also criticizes the Companies for continuing to provide data for the ESI IDs and for not informing ERCOT of the double counting until February 7, 2003, after ERCOT issued the True-Up Statements. It argues that the 2 % threshold applies because the Companies did not identify the problem until after the True-Up Statements were issued. However, Reliant states that the Companies' error in continuing to provide data for the ESI

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[55] Agreed Fact Nos. 46 and 48.

[56] ERCOT Initial Brief at 7-8.

[57] ERCOT Initial Brief at 8.

[58] OPC Initial Brief at 2-3.

IDs does not create a "contributory negligence" issue. In its view, ERCOT would be compelled to act regardless of the Companies' errors if the Companies had notified ERCOT before issuing the True-Up Statement or if the error exceeded the 2 % threshold. But in this case the Companies did not identify the error until after the True-Up Statement was issued and the error did not reach the 2 % threshold; consequently Reliant argues that the Companies' claim should be denied.[59]

STEC criticizes the Companies for incorrectly assigning retail ESI IDs to their wholesale aggregation meters; for failing to check the information it received from ERCOT regarding the two meters after requesting their removal; and for failing to recognize the cause of its load imbalance charges after ERCOT notified the Companies that it had not actually deleted the ESI IDs from its system. STEC notes that TDSPs are responsible to properly create ESI IDs and provide correct settlement data. But STEC acknowledges that ERCOT was also at fault in failing to delete the ESI IDs and for erroneously notifying the Companies that the ESI IDs had been deleted, and it suggests that many other market participants made errors during the pilot program. Because of the erroneous load imbalance charges, many other QSEs benefitted from the double counting of the TNMP Lewisville and College Station loads. However, some of the QSEs that were active in the market during the pilot program have now exited the ERCOT market, so STEC recommends that the Commission assign TXU the amounts due under any resettlement for such QSEs.[60]

CPS Energy also states that the Companies' untimely actions clearly contributed to the problems and that TXU should be assigned any residual balance that may be due upon resettlement from all QSEs that were operating in the market in 2001 but have since left.[61] Likewise, First Choice Power blames the Companies for the double-counting error. It points out that the ERCOT Protocols make TDSPs responsible for creating ESI IDs, meter readings, and validation of meter data before submitting it to ERCOT. But in this case, TXU ED incorrectly set up the meters for Lewisville and

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[59] Reliant Initial Brief at 6-7.

[60] STEC Initial Brief at 11-14.

[61] CPS Energy Initial Brief at 3-4.

College Stations as retail ESI IDs, causing the load for those cities to be double reported by two TDSPs. First Choice acknowledges that TXU ED asked ERCOT to remove the two ESI IDs from ERCOT's system, but when ERCOT later asked for consumption data for the two ESI IDs, TXU ED did not call the error to ERCOT's attention but instead continued to provide ERCOT with consumption data for the two meters throughout the period in dispute. Therefore, First Choice argues that TXU ED bore the ultimate responsibility to ensure that the correct ESI IDs were in the ERCOT system and to validate meter data before submitting it to ERCOT.[62]

Staff argues that the Companies did not contribute to the double-counting problem because they timely requested removal of the ESI IDs and were assured that they had been removed.[63]

b. ALJ's Analysis

This case involves a series of errors that resulted in excess Load Imbalance charges against TXU Electric Delivery during the 2001 customer-choice pilot project. These errors included:

- TXU Electric Delivery established retail ESI IDs for the TNMP Lewisville and College Stations aggregation meters, which were actually wholesale delivery points;
- TXU Electric Delivery did not cancel the ESI IDs when the customer-choice pilot project began July 31, 2001;
- TXU Electric Delivery requested on February 18, 2002, that the ESI IDs be removed from ERCOT's computer systems, effective July 31, 2001, after which ERCOT replied on February 26, 2002, that the ESI IDs had been deleted from its computer systems when, in fact, they were not deleted;
- During Market Synchronization from early to middle 2002, neither ERCOT nor the Companies discovered that the ESI IDs had not been deleted from ERCOT's computer system;

[62] First Choice Power Initial Brief at 1-4.

[63] Staff Initial Brief at 4.

- During the one-time resettlement of the wholesale settlement statement during mid to late 2002, ERCOT requested and Electric Delivery (then known as Oncor) provided load data for the ESI IDs that should have been deleted;

- When ERCOT informed TXU Portfolio Management in November 2002 that the ESI IDs were not actually deleted from ERCOT's computer systems until November 27, 2002, apparently no party investigated whether load data had been double counted for the ESI IDs;

- The double-counted ESI IDs were not discovered by ERCOT or the Companies until 2005, during the ADR process.

Thus, the actions of both ERCOT and the Companies clearly contributed to the double-counted load and resulting charges. However, the ALJ agrees with the Companies that their claim is not based on tort law or a scheme of comparative negligence. And as pointed out by Reliant, it is generally undisputed that ERCOT would have been required to correct the double-counting error had it been described in greater detail in the Companies' initial billing disputes. With the large mass of data that Market Participants must provide, it would be unreasonable to hold that an inadvertent error of a Market Participant could never be corrected. In this case, there is no evidence or even a suggestion that the Companies intentionally provided erroneous information, tried to manipulate the market, or otherwise engaged in egregious conduct that might justify denying their claim. And it is undisputed that ERCOT also made mistakes that contributed to the double-billing errors. Thus, under the facts of this case, the ALJ does not find that the Companies' inadvertent mistakes should result in denial of their claim. However, the ALJ does agree with STEC that the Commission should assign to TXU the amounts due under any resettlement for any QSE that benefitted from the double counting of the TNMP Lewisville and College Station loads but have now exited the ERCOT market. It would be unfair to allocate those expenses to other innocent Market Participants.

ERCOT and some of the Intervenors also argue that the Companies filed mere placeholder disputes and that the 2 % threshold of Protocol 9.2.5 should bar the Companies' claim. The ALJ has previously discussed and rejected these arguments. ERCOT also complains that a portion of the Companies' ADR requests were filed late. However, as pointed out by the Companies, there is no evidence in the Agreed Stipulation to support this position. Therefore the ALJ denies this argument of ERCOT.

In summary, the ALJ finds that actions of both ERCOT and the Companies contributed to the double-billing error involved in this case, but the inadvertent mistakes of the Companies should not bar their claim. The Commission should, however, assign to TXU the amounts due under any resettlement for QSEs that benefitted from the double counting of the TNMP Lewisville and College Station loads but have now exited the ERCOT market.

4. If it is determined that TXU is owed relief for the erroneous balancing energy charges, what form should that relief take? If the appropriate relief is the recalculation of load imbalance charges, what methodology should be used in reallocating the settlements for the time period involved?

a. Parties' Arguments

The Companies take no position on the precise settlement methodology to be used in granting the relief requested by the Companies. However, they note that the most accurate methodology under PURA § 39.151(a)(4) would be a full settlement of all affected charges for the period in question.[64]

ERCOT states that, although the Companies refer only to Load Imbalance errors in their Complaint, the data at issue affected multiple charges, including Balancing Energy Neutrality Adjustment (Protocol 9.6.1); the ERCOT System Administrative Fee (Protocol 9.7.1); the System Congestion Collection Fund (Protocol 7.3.3.1, now expired); OOM Energy Load Allocation (Protocol 6.9.7.2); OOM Capacity Charge (Protocol 6.9.7.1); Replacement Reserve Under Scheduled Capacity Charge (Protocol 6.9.2.1.1); and Replacement Reserve Uplift Charge (Protocol 6.9.2.1.2). In addition, ERCOT states that it is also likely that other changes to ESI ID data since True-Up have

[64] Companies Initial Brief at 9.

occurred besides the ESI ID data at issue here, including the possibility that other ESI IDs associated with the Companies might show revised usage, possibly offsetting some of Companies' claimed underpayment. ERCOT claims that it cannot predict a QSE's revised Load Imbalance for Operating Days in 2001 without full settlement; consequently, it suggests that a full resettlement would most accurately resolve this matter and would ensure that the Companies do not over- or under-recover for the data adjustments at issue in this case.[65]

Reliant argues that, if the Companies are granted relief, ERCOT should calculate the impact related only to reversing the double counting of the two load points (TNMP Lewisville and College Station). Then, the impact associated with reversing the amount of load that was double counted should be allocated to load serving entities based on load ratio shares in effect at the time, adjusted for the duplicate data. If ERCOT attempts to address every potential ripple effect of a change ordered by the Commission, Reliant states that the final True-Up Settlement Statements from September 9 through November 9, 2002, "would be fiction," and every market participant would need to review revised data to determine the accuracy of the resettlement and all of its impacts. Reliant complains that this would be disruptive to books and records already considered closed and undermine the efforts to foster market certainty.[66]

STEC forwards the same position as Reliant. It emphasizes the Companies only appealed the load imbalance charges and that any additional action would exceed the issues appealed. It also stresses that the Companies' relief should be limited to the incremental change between the previous settlement statement and the resettlement statement for the applicable operating days and that all QSEs operating in the market on the relevant dates should be resettled.[67]

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[65] ERCOT Initial Brief at 9.

[66] Reliant Initial Brief at 7-8.

[67] STEC Initial Brief at 15-18.

CPS Energy states that if the Commission decides to make a correction, then the Commission should resettle all QSEs operating in the market at the time using existing data and corrected data. It points out that the settlement of the double-counted load will also affect the quantity of UFE, thereby also affecting the AML for each QSE. Further, it states, UFE is not allocated to QSEs on a simple load ratio share basis, so the settlement impact of the double-counted load on each QSE differed based on the amount of UFE allocated to that QSE, and that result was not a simple function of the QSE's load ratio share. Therefore, CPS Energy concludes that applying Reliant's proposed load ratio share methodology would not produce an accurate result, would violate PURA § 39.151(a)(4), and would allocate the burden of correcting the data error to QSEs in a manner that is different from how the benefit of the error accrued to various QSEs other than TXU. In its view, this would violate ERCOT Protocols 1.1 and 9.2.5, which require full resettlement pursuant to the provisions in effect at the time the data error occurred. Like STEC, CPS Energy recommends that the Commission assign to TXU any residual balance that may be due upon resettlement from all QSEs that were operating in the market in 2001 but have since exited.[68]

OPC and Staff simply state that the double-counting error should be corrected by using the ERCOT Protocols in effect at the time of the errors.[69]

b. ALJ's Analysis

The ALJ recommends that the Commission order a full resettlement of the disputed time period. While Reliant and STEC correctly point out that only the load imbalance charges were appealed, it is also undisputed that correcting the double-counted load will impact other charges and payments. Thus, resettling only the load imbalance charges will simply replace one erroneous settlement with another. As noted by the Companies, ERCOT, and other parties, a full resettlement would be the most accurate methodology under PURA § 39.151(a)(4). However, as discussed

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[68] CPS Energy Initial Brief at 4-5; CPS Energy Reply Brief at 2-3.

[69] Staff Initial Brief at 5; OPC Initial Brief at 3.

previously, some Market Participants who benefitted from the double-counting error have now left the market. The ALJ recommends that the Commission assign to TXU the amounts due under any resettlement from such QSEs.

V. FINDINGS OF FACT AND CONCLUSIONS OF LAW

A. Findings of Fact

Procedural History

1. On June 15, 2005, pursuant to P.U.C. PROC. R. 22.251, the Companies filed a complaint against ERCOT ("the Complaint").

2. On June 16, 2005, pursuant to P.U.C. PROC. R. 22.251(e), the Electric Reliability Council of Texas ("ERCOT") e-mailed to all Qualified Scheduling Entities ("QSEs") notice and a copy of the Complaint. ERCOT filed its Proof of Notice on June 17, 2005, and filed the accompanying affidavit on June 21, 2005. The Office of Public Utility Counsel ("OPC") received notice of the Complaint by copy of Order No. 1.

3. Direct, CPS Energy, the Lower Colorado River Authority ("LCRA"), First Choice, Reliant Energy, Inc. ("Reliant"), TEAM, Texas Genco II, LP ("Texas Genco"), OPC, and STEC filed motions to intervene.

4. The Public Utility Commission of Texas ("Commission") granted the motions to intervene of Direct and CPS Energy on July 12, 2005. The Commission granted the motions to intervene of LCRA, First Choice, and Reliant on August 1, 2005. The motions to intervene of TEAM, OPC, and STEC were granted on November 7, 2005. Texas Genco's motion to intervene was granted on January 13, 2006.

5. On July 13, 2005, ERCOT filed its response to the Complaint.

6. On August 1, 2005, Staff filed a response to Order No. 1 and a motion for referral to the State Office of Administrative Hearings ("SOAH"), requesting an evidentiary hearing.

7. On August 4, 2005, the Companies filed a reply to ERCOT's response and Staff's response and motion for referral to SOAH, stating that no evidentiary hearing was needed.

8. On August 8, 2005, the Commission referred this docket to SOAH.

9. The Companies, ERCOT, Staff, CPS Energy, TEAM, STEC, Direct, and First Choice filed an agreed stipulation of facts on March 1, 2006. These parties agree that this

proceeding may be decided based on the pleadings, affidavits, and other relevant materials filed in this docket without an evidentiary hearing.

Parties

10. TXU Portfolio Management is registered and qualified with ERCOT as a QSE for TXU Energy and certain other Load Serving Entities ("LSEs").

11. From July 31 through December 31, 2001, the actual entity charged for Load Imbalance in its role as QSE was TXU Electric Company ("TXU Electric"), the formerly integrated and bundled utility. On and after January 1, 2002, TXU Portfolio Management (then known as TXU Energy Trading Company LP) assumed the role as QSE for TXU Energy (then known as TXU Energy Services Company) and certain other LSEs. For clarity and because TXU Portfolio Management is the successor QSE, it is referenced as the entity invoiced for the Load Imbalance charges that are the subject of this Complaint.

12. On February 2, 2001, the Commission certified ERCOT as the independent organization for the ERCOT power region pursuant to PURA § 39.151.

Background Relating to the Double-Counted Load

TNMP Lewisville

13. Before July 31, 2001, TXU Electric, the formerly integrated and bundled utility, sold wholesale power to Texas-New Mexico Power Company ("TNMP") for TNMP's City of Lewisville ("Lewisville") load at multiple meters aggregated under a single meter and billed to TNMP based on the load measured at the aggregation meter. This arrangement was pursuant to a contract between TXU Electric and TNMP.

14. Beginning July 31, 2001, TXU Electric continued to sell wholesale power to TNMP for the TNMP Lewisville load. However, during the retail customer choice pilot project, which began effectively on July 31, 2001, TNMP served Lewisville as both an LSE and a Transmission and Distribution Service Provider ("TDSP"), and Constellation Power Source, Inc. ("Constellation")–not TXU Electric–served as TNMP's QSE.

15. Individual Electric Service Identifier ("ESI ID") meters within the TNMP Lewisville load territory were used to measure volume for wholesale sales from TXU Electric to TNMP and to calculate Load Imbalance charges by ERCOT to Constellation.

16. The ESI IDs for these individual meters were properly assigned to TNMP and its QSE, Constellation, and they should have replaced the pre-pilot project aggregation meter on ERCOT's systems as of July 31, 2001.

17. The TDSP, TXU Electric Delivery Company ("Electric Delivery"), had assigned ESI ID No. 10443720007315878 to that meter in March 2001 and assigned it to TXU Electric (as LSE).

18. After July 31, 2001, the pre-pilot project aggregation meter was left in place.

19. On February 18, 2002, Electric Delivery notified ERCOT that ESI ID No. 10443720007315878 and any associated usage data should be removed from the ERCOT computer systems effective July 31, 2001. On February 26, 2002, ERCOT responded that it had "[d]eleted the ESI Id in both Lodestar and Siebel Systems[.]"

20. ERCOT notified TXU Portfolio Management in November 2002 that ERCOT did not actually delete ESI ID No. 10443720007315878 from its computer systems until November 27, 2002. If ESI ID No. 10443720007315878 had been removed from ERCOT's computer systems in February 2002, effective July 31, 2001, then the corrected usage data would have appeared in the True-Up Settlement statements published for the July 31 through December 31, 2001 Operating Days.

21. The load from the TNMP Lewisville meters was counted twice in the ERCOT settlement process–once for Constellation (as QSE) and once for TXU Electric (as QSE)–from July 31 through December 31, 2001.

College Station

22. Before July 31, 2001, TXU Electric sold wholesale power to the City of College Station ("College Station") at multiple meters aggregated under a single aggregation meter.

23. The TDSP, Electric Delivery, had assigned ESI ID No. 10443720007147829 to that meter in March 2001 and assigned it to TXU Electric (as LSE).

24. Beginning July 31, 2001, College Station became a Non-Opt In Entity ("NOIE"). As a NOIE, College Station installed ERCOT Polled Settlement meters to replace the wholesale aggregation meter for the purpose of measuring load.

25. After July 31, 2001, the wholesale aggregation meter was left in place.

26. TXU Electric continued to sell wholesale power to College Station during the retail customer choice pilot project and served as QSE for College Station.

27. On February 18, 2002, Electric Delivery notified ERCOT that ESI ID No. 10443720007147829 and any associated usage data should be removed from the ERCOT computer systems effective July 31, 2001. On February 26, 2002, ERCOT responded that it had "[d]eleted the ESI Id in both Lodestar and Siebel Systems[.]"

28. ERCOT notified TXU Portfolio Management in November 2002 that ERCOT did not actually delete ESI ID No. 10443720007147829 from its computer systems until November 27, 2002. If ESI ID No. 10443720007147829 had been removed from ERCOT's computer systems in February 2002, effective July 31, 2001, then the corrected usage data would have been reflected in True-Up Settlement statements published for the July 31 through December 31, 2001 Operating Days.

29. The load from the College Station meters was counted twice for TXU Electric (as QSE) in the ERCOT settlement process from July 31 through December 31, 2001.

Background Applicable to TNMP Lewisville and College Station

30. Before the start of the deregulated retail market on July 31 2001, TDSPs provided ERCOT and LSEs information necessary to set up competitive area ESI IDs, including ESI ID relationship and characteristics data, as well as historical usage. ERCOT then forwarded usage data to each LSE, as provided by the TDSP. ERCOT forwards changes in transactional characteristic information (station, profile code, loss code, etc.) to the current LSE and any new LSE(s) if a switch to a new LSE is pending. From early to middle 2002, ERCOT and Market Participants participated in a data clean-up and improvement effort known as "Market Synchronization." During Market Synchronization, LSEs and TDSPs provided ERCOT files showing a comprehensive list of LSE relationship start and stop times by ESI ID. Via these files, ERCOT performed a comparison across the LSEs', TDSPs', and ERCOT's data and identified LSE relationship discrepancies that needed to be resolved across specified entities (LSE, TDSP and/or ERCOT). During this time frame, ERCOT participated in individual ESI ID synchronization efforts for Market Participants with individualized requests. ERCOT also answered questions upon request from various Market Participants about their data as shown in ERCOT's system. In March 2003, ERCOT implemented System Change Request (SCR) 727, which resulted in a regularly produced data extract for both TDSPs and LSEs containing ESI ID characteristic, relationship and usage data. At that time, ERCOT also implemented the Data Extract Variance process so TDSPs and LSEs could file discrepancies between their systems and ERCOT systems for resolution with the appropriate entity.

31. During the retail customer choice pilot project, the ERCOT market experienced issues related to data accuracy.

32. At its May 21, 2002 meeting, the ERCOT Board of Directors instructed ERCOT staff to stop performing True-Up Settlements to allow resolution of ESI ID data errors, and the Board passed the following resolution:

The ERCOT Board direct the ERCOT Staff to perform a ONE-TIME re-settlement of July 31, 2001 through the current Wholesale Settlement Statement published. Such re-settlement will commence after ERCOT has successfully received and validated at least 99 percent of the IDR data from each Meter Reading Entity (MRE). In addition, ERCOT would suspend future true-up settlements until the 99 percent IDR consumption data standard is met. The true-up settlement timeline would be extended to a maximum of 12 months in cases where the IDR data threshold is not met. . . . .

33. During the process described in that resolution, ERCOT sent daily reports to TDSPs showing ESI IDs for which ERCOT did not have usage data.

34. ERCOT asked the TDSPs to provide the missing data for their ESI IDs.

35. With respect to the TNMP Lewisville and College Station ESI IDs, ERCOT stated to Electric Delivery, "[a]ttached you will find the updated spreadsheets for ONCOR [Electric Delivery] as of data loaded in ERCOT systems by 5:30 pm 05-09-02. The spreadsheets contain a list of ESIIDs that are NOT in compliance with IDR data being loaded through September 2001 . . . ." The spreadsheets included the aggregation meters for TNMP Lewisville and College Station.

36. Electric Delivery provided usage data for the TNMP Lewisville and College Station ESI IDs.

37. The ESI ID meters at issue were for wholesale delivery points, not retail delivery points.

38. In response, ERCOT stated "ONCOR is in compliance with ERCOT's requests."

39. ERCOT relied on that data when it issued the subsequent Settlement Statements for the subject dates in 2001.

40. ERCOT began issuing the True-Up Statements for dates in 2001 on September 9, 2002.

Settlement Effects of the Double-Counted Load

41. A settlement effect of the double-counted load was that it overstated the load for TXU Electric (as QSE) and produced a decrease in the magnitude of ERCOT-wide Unaccounted for Energy ("UFE") for each settlement interval relative to the magnitude of ERCOT-wide UFE that would have been produced had the load not been counted twice. During this period, UFE was primarily negative and was more negative than it would have otherwise been due to the double-counted load.

42. A settlement effect of the double-counted load was that it produced Adjusted Metered Load ("AML") values for each settlement interval for TXU Electric (as QSE) that were higher than they would have been had the load not been counted twice; however, the increase was not equal to the full double counting due to the negative UFE allocation. The AML values of QSEs other than TXU Electric (as QSE) representing LSEs allocated UFE were lower than the AML values that would have been produced had the load not been counted twice. The AML values of QSEs other than TXU Electric (as QSE)

representing LSEs not allocated UFE were the same as the AML values that would have been produced had the load not been counted twice.

43. Under the ERCOT Protocols, UFE is not allocated to QSEs representing LSEs on a simple load ratio share basis. Rather, pursuant to Section 11.4.6.2 of the ERCOT Protocols, UFE is allocated to QSEs representing LSEs according to specific formulas that are dependent upon the category of loads being served by each LSE.

44. The following competitive REPs that have intervened in this proceeding were not participating in the ERCOT market during the Operating Days July 31, 2001 through December 31, 2001: Direct and TEAM members Accent Energy, Cirro Energy, StarTex Power, Stream Energy, Tara Energy, and Utility Choice Electric.

Background Relating to the ADR Process

45. Pursuant to Section 9 of the ERCOT Protocols, TXU Portfolio Management submitted the settlement and billing disputes regarding the Load Imbalance charges related to the TNMP Lewisville and College Station loads for the July 31 through December 31, 2001 Operating Days.

46. In each of its settlement and billing disputes relating to the dates at issue, TXU Portfolio Management made one of the following statements:

   a. It was, "[d]isputing the difference between TXU internal load of [X] MW verses ERCOT load of [X] MW with the net difference of [X] MW":

   b. "Dispute the difference between TXU load and ERCOT load";

   c. Diffs note[d] in Load Imbalance"; or

   d. "Differences between TXU's internal load and ERCOT's load."

47. The disputes referenced in the above finding of fact provided no further detail for the cause of the alleged imbalance or load differences.

48. ERCOT denied TXU Portfolio Management's settlement and billing disputes at issue, and TXU Portfolio Management invoked the alternative dispute resolution ("ADR") process in Section 20 of the ERCOT Protocols between October 2002 through December 2002. TXU Portfolio Management did not request ADR with respect to Operating Days August 22, 2001 and September 9, 2001.

49. In its ADR request letters, TXU Portfolio Management cited, as the basis for its ADR requests, differences between the AMLs calculated by TXU Portfolio Management and the AMLs calculated by ERCOT, which it alleged resulted from the "failure of ERCOT to collect the appropriate meter loads . . . ."

51. In a letter to ERCOT dated February 7, 2003, a TXU Portfolio Management representative wrote that "[TXU Portfolio Management] has no reason to believe that ERCOT did not gather data from the TDSP in accordance with the Protocols. . . ."

52. In a February 10, 2005 letter to counsel for the Companies, an ERCOT representative wrote, "Mr. Schrader has indicated that he is tentatively willing to grant this ADR to the extent it involves the double-counting of the City of Lewisville and College Station city gate meters. ERCOT has done some preliminary runs to calculate the dollar amount of such a resettlement."

53. During the period from October 2002 until May 2005, ERCOT and the Companies exchanged data and otherwise diligently worked on the subject Load Imbalance charges and other Load Imbalance issues.

54. In executive session on April 19, 2005, the ERCOT Board of Directors voted to deny those ADRs. On May 12, 2005, ERCOT and the Companies agreed to waive mediation and arbitration.

55. The ERCOT Board considered the issue of ADRs and disputes relating to unspecific allegations of data errors at the November 2004 Board Meeting. At the May 17, 2005 meeting, the ERCOT Board adopted a resolution regarding the consideration of such ADRs and disputes.

B. Conclusions of Law

1. Pursuant to PURA § 39.151(d), the Commission is charged with oversight and review responsibility of the procedures established by ERCOT relating to reliability of the ERCOT network and accounting for the production and delivery of electricity among generators and all other market participants.

2. SOAH has jurisdiction over this proceeding, including the preparation of this proposal for decision with findings of fact and conclusions of law, pursuant to PURA § 4.053 and TEX. GOV'T CODE ANN. §§ 2001.058 and 2003.049.

3. ERCOT provided proper notice of the Companies' complaint pursuant to P.U.C. PROC. R. 22.251(e).

4. Pursuant to ERCOT Protocol 9.5.2, a Statement Recipient may dispute items or calculations set forth in its Initial Statements, Final Statements, or Resettlement Statements.

5. Pursuant to ERCOT Protocol 9.5.2, a Statement or Invoice Recipient who wishes to dispute a Statement shall register the settlement or billing dispute with ERCOT within ten business days.

4. Pursuant to ERCOT Protocol 9.5.2, a Statement Recipient may dispute items or calculations set forth in its Initial Statements, Final Statements, or Resettlement Statements.

5. Pursuant to ERCOT Protocol 9.5.2, a Statement or Invoice Recipient who wishes to dispute a Statement shall register the settlement or billing dispute with ERCOT within ten business days.

6. For the dates in dispute in this proceeding, TXU Portfolio Management's billing disputes were filed in compliance with ERCOT Protocol 9.5.2 and they adequately alerted ERCOT and market participants of the potential for resettlement due to disputed load calculations.

7. ERCOT's settlement for the July-December 2001 time period is final in that ERCOT denied these billing disputes and otherwise followed its settlement Protocols. However, this final settlement does not preclude resettlement for timely filed billing disputes that should have been granted.

8. ERCOT settled the disputed time period in accordance with the Protocols in that it followed the procedures set out in the Protocols. However, under PURA § 39.151(d), the Commission is authorized to order resettlement of a valid, timely billing dispute even though ERCOT followed procedures contained in the Protocols.

9. The actions of both ERCOT and the Companies contributed to the double-billing error involved in this case. However, the inadvertent mistakes of the Companies involved in this case should not bar their claim.

10. Because actions of the Companies contributed to the double-billing errors involved in this case, the Commission should assign to TXU the amounts due under any resettlement for any QSEs that benefitted from the double counting of the TNMP Lewisville and College Station loads but have now exited the ERCOT market.

11. The Commission should order a full resettlement of the disputed time period to account for other charges that will be affected by resettlement of Load Imbalance charges.

VI. ORDERING PARAGRAPHS

In accordance with the findings of fact and conclusions of law, the Commission issues the following order:

1. The request of TXU Portfolio Management Company LP and TXU Energy Retail Company LP (collectively "the Companies") for an order directing ERCOT to conduct resettlement for the disputed period (July-December 2001) is granted.

2. ERCOT shall conduct a full resettlement of the disputed period within forty-five days of this order by correcting the double-counted load assigned to TXU Electric (as QSE) and making the corresponding adjustments to other settlement items that are affected by correcting the double-counted load.

3. The Companies are assigned the amounts due under resettlement for any QSE that benefitted from the double counting of the TNMP Lewisville and College Station loads but have now exited the ERCOT market.

4. All other motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted herein, are denied.

SIGNED June 19, 2006.

THOMAS H. WALSTON
ADMINISTRATIVE LAW JUDGE
STATE OFFICE OF ADMINISTRATIVE HEARINGS

STATE OFFICE OF ADMINISTRATIVE HEARINGS

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AGENCY:	PUBLIC UTILITY COMMISSION OF TEXAS
STYLE/CASE:	COMPLAINT OF TXU PORTFOLIO MANAGEMENT COMPANY, LP AND TXU ENERGY RETAIL COMPANY, LP

SOAH DOCKET NUMBER:473-05-8805
PUC DOCKET NUMBER: 31243

STATE OFFICE OF ADMINISTRATIVE HEARINGS	THOMAS WALSTON ADMINISTRATIVE LAW JUDGE

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xc: Docket Clerk, State Office of Administrative Hearings

EXHIBIT 20

EXHIBIT 20

351 S.W.3d 588
Court of Appeals of Texas,
Austin.

PUBLIC UTILITY COMMISSION of Texas; Luminant Energy Company LLC f/k/a TXU Portfolio Management Company LP; Luminant Generation Company LLC f/k/a TXU Generation Company LP; City of Austin d/b/a Austin Energy; City of San Antonio d/b/a/ CPS Energy, Reliant Energy Power Supply, LLC; and Lower Colorado River Authority, Appellants,
v.
CONSTELLATION ENERGY COMMODITIES GROUP, INC., Appellee.

No. 03–09–00417–CV.
|
Sept. 28, 2011.

Synopsis

Background: Electric company, a private qualified scheduling entity (QSE), brought administrative action against Electric Reliability Council of Texas (ERCOT), alleging that two of ERCOT's protocols, which controlled the procurement and settlement of replacement reserve service (RPRS) necessary to rectify either zonal capacity insufficiencies or system-wide shortfalls, were contradictory and that, as a result, ERCOT had improperly assessed $3.8 million in under-scheduling charges against company. Public Utility Commission ruled that ERCOT had correctly settled the capacity insufficiency charges in accordance with the correct protocol. Company brought suit for judicial review. The 98th Judicial District Court, Travis County, Orlinda Naranjo, J., reversed Commission's determination. Commission appealed.

Holdings: The Court of Appeals, David Puryear, J., held that:

[1] ERCOT properly applied under-scheduled settlement protocol in assessing RPRS charges strictly against company based on its zonal-capacity insufficiency;

[2] ERCOT protocols were not contradictory for purposes of determining whether to impose RPRS charges strictly against one QSE for zonal insufficiencies or against all QSEs for system-wide shortfalls; and

[3] ERCOT did not impermissibly assess RPRS charges in an amount exceeding its procurement costs.

Reversed; Commission's order affirmed.

West Headnotes (10)

[1] **Electricity** Operating expenses

Electric Reliability Council of Texas (ERCOT) properly applied under-scheduled settlement protocol in assessing replacement reserve service (RPRS) charges strictly against electric company based on company's zonal-capacity insufficiency, rather than imposing a socialized uplift charge against all privately-operated qualified scheduling entities (QSE) based on a system-wide shortfall; the under-scheduled settlement protocol, which required a direct assessment of charges to a QSE that scheduled short in any zone if ERCOT actually procured RPRS, was the only protocol that specified the economic consequences of under scheduling capacity in a zone, and that provision was clear and unambiguous.

[2] **Electricity** Regulation in general; statutes and ordinances

Electric Reliability Council of Texas (ERCOT) protocols are rules that provide the framework for the administration of the state's electricity market.

3 Cases that cite this headnote

[3] **Administrative Law and Procedure** Power and authority of agency in general

EXHIBIT 20

An agency's interpretation of a rule becomes part of the rule itself and represents the view of the regulatory body that must administer it.

[4] **Appeal and Error** Statutory or legislative law

Statutory construction presents a question of law that is reviewed de novo.

[5] **Administrative Law and Procedure** Construction

Administrative Law and Procedure Force of law in general

Administrative rules have the force and effect of statutes and are construed in the same manner as statutes.

1 Case that cites this headnote

[6] **Administrative Law and Procedure** Clarity and ambiguity; multiple meanings

Unless the administrative rule is ambiguous, courts follow the rule's clear language.

1 Case that cites this headnote

[7] **Administrative Law and Procedure** Relationship of agency with rule or statute in general

Administrative Law and Procedure Relationship of agency with statute in general

Administrative Law and Procedure Erroneous or unreasonable construction; conflict with statute

Courts must give serious consideration to the construction of a statute by the administrative agency charged with its enforcement; in a serious consideration inquiry, courts will generally uphold an agency's interpretation of its own rules unless that interpretation is plainly erroneous or inconsistent with the text of the rule.

1 Case that cites this headnote

[8] **Administrative Law and Procedure** Permissible or reasonable construction

When a statutory scheme is subject to multiple understandings, that is, ambiguous, courts must uphold the enforcing agency's construction of its statutory scheme if is reasonable and in harmony with the statute.

[9] **Electricity** Operating expenses

Protocols of Electric Reliability Council of Texas (ERCOT), one which governed procurement of replacement reserve service (RPRS) and another which controlled the under-scheduled settlement of RPRS, were not in irreconcilable conflict for purposes of determining whether to assess RPRS charges strictly against electric company based on its zonal-capacity insufficiency as opposed to imposing a socialized uplift charge against all privately-operated qualified scheduling entities (QSE) based on a system-wide shortfall; unlike the under-scheduled settlement protocol, the procurement protocol said nothing about the consequences to a QSE for under scheduling capacity in a zone.

[10] **Electricity** Operating expenses

Electric Reliability Council of Texas (ERCOT) did not impermissibly assess replacement reserve service (RPRS) charges, which were imposed against qualified scheduling entities (QSE) for zonal electricity capacity insufficiencies, in an amount exceeding its procurement costs; no statute, rule, or protocol demanded that ERCOT's under-scheduling charges correlate exactly with its costs in procuring RPRS, and although it often assessed an under-scheduling charge that was greater than its procurement costs, ERCOT retained no cost excess from the under-scheduling charge, but rather uplifted any excess to the market, thus remaining revenue neutral.

EXHIBIT 20

Attorneys and Law Firms

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Chris Reeder, Elizabeth G. (Heidi) Bloch, Brown McCarroll, L.L.P., Austin, TX, for Appellee.

Before Chief Justice JONES, Justices PURYEAR and PEMBERTON.

OPINION

DAVID PURYEAR, Justice.

On November 14, 2006, Constellation Energy Commodities Group, Inc. ("Constellation") filed a complaint with the Public Utility Commission of Texas ("the Commission") against the Electric Reliability Council of Texas ("ERCOT") alleging that two of ERCOT's protocols[1] were contradictory and inconsistent and that ERCOT had improperly assessed charges against Constellation from April 10, 2006, to September 27, 2006, using the inconsistent protocols. Luminant Energy Company ***591** LLC f/k/a TXU Portfolio Management Company LP and Luminant Generation Company LLC f/k/a TXU Generation Company LP ("Luminant"), as well as City of Austin d/b/a Austin Energy, City of San Antonio d/b/a CPS Energy, Reliant Energy Power Supply, LLC, and Lower Colorado River Authority ("Joint Intervenors") intervened in the proceeding in support of ERCOT. After the Commission referred the case to the State Office of Administrative Hearings ("SOAH"), the administrative law judge ("ALJ") agreed with Constellation that the protocols in question were inconsistent and recommended the Commission require ERCOT to resettle the charges. The Commission rejected the ALJ's recommendation, determining instead that ERCOT had correctly settled the capacity insufficiency charges in accordance with the protocols then in effect. Constellation filed suit for judicial review in district court, which reversed the Commission's determination that ERCOT had correctly assessed the charges against Constellation. This appeal followed.

Luminant, the Joint Intervenors, and the Commission argue the district court erred by failing to defer to the Commission's construction of the protocols and its conclusion that ERCOT properly assessed charges. Luminant and the Joint Intervenors further contend Constellation's case is an impermissible collateral attack on a final Commission order. As a conditional cross-point, Constellation asserts ERCOT cannot assess an under-scheduling charge that is over and above its actual procurement costs.

For the reasons set forth below, we reverse the trial court's judgment and render judgment affirming the Commission's final order.

FACTUAL AND PROCEDURAL BACKGROUND

Since the implementation of retail choice in Texas in 2002, retail providers of electricity, in general, meet their customers' demand by entering into bilateral contracts with generation owners and power marketers. ERCOT is the independent organization the Commission has certified as responsible for, among other things, ensuring the reliability and adequacy of the electric grid, as well as establishing, scheduling, and overseeing transaction settlement procedures. *See* Tex. Util.Code Ann. § 39.151 (West 2007).

Under ERCOT rules ("protocols") in effect on the disputed trade days, a qualified scheduling entity ("QSE") on the retailer's behalf engaged in bilateral contracts with generation owners and power marketers and submitted a schedule to ERCOT demonstrating that its expected demand was equal to the amount of generation it had procured to meet that demand. When the QSE's scheduled demand exceeded its scheduled supply or when its actual demand exceeded the amount of generation it had procured, the QSE was "under scheduled." QSEs under scheduled for several reasons: inaccurate load forecasting, a change in real-time conditions, or a strategic decision to rely upon ERCOT as a Resource to cover a portion of a QSE's Load.[2]

***592** Consumption rarely matches generation exactly, so ERCOT's protocols authorized it to procure "ancillary

EXHIBIT 20

service" to address actual or anticipated imbalances.[3] Ancillary services consist of various forms of "capacity"—the commitment of generation resources to be available for production in a given operating period—and "energy"—the real-time provision of electricity. When a QSE under scheduled, ERCOT obtained ancillary services to address anticipated generation shortfalls.

QSEs were permitted to schedule purchases of power from generators located far from the demand or Load scheduled by the QSE. When too many of those transactions occurred, transmission routes between major consumption centers could become "congested."[4] The most commonly congested transmission routes effectively determined geographic "zones," usually identified by ERCOT as the North, West, South, and Houston zones, which required separate balancing by ERCOT. Congestion also prevented some inter-zonal transactions from occurring, which obligated ERCOT to procure expensive power in the zone where the load was scheduled to ensure that sufficient electricity existed to meet demand. Thus, when a QSE submitted a schedule that was balanced on a system-wide basis but unbalanced within one or more zones, ERCOT still might have incurred costs for ancillary services to resolve that intra-zonal capacity imbalance.

One of the ancillary services ERCOT used to resolve projected imbalances was a form of capacity called "replacement reserve service" ("RPRS"), which required an owner of an off-line generation resource to make that unit available for ERCOT's use, if necessary, during a particular hour of market operation. ERCOT procured RPRS through a day-ahead auction for each operating hour, and winning bidders were paid the market-clearing price for electricity.

Different ERCOT protocols controlled the procurement, compensation, and settlement of RPRS. Section 6.6, entitled "Selection Methodology," governed ERCOT's acquisition of various ancillary services. *See* ERCOT Zonal Protocols § 6.6 (March 2006 Protocols Update 2, March 21, 2006), *available at* http://www. ercot.com/mktrules/protocols/library/2006.[5] Section 6.6.3.2.1, "Specific Procurement Process Requirements for [RPRS] in the Adjustment Period" (hereinafter the "RPRS procurement protocol"), detailed the circumstances and process under which ERCOT obtained RPRS for each operating hour. *See id.* § 6.6.3.2.1. That protocol required ERCOT to procure RPRS to rectify capacity insufficiency, zonal transmission congestion, and local transmission congestion.

Because it costs a generator money to start up a unit and keep it running at the minimum level necessary to ensure that power could be delivered if customer load demanded more energy, ERCOT's procurement of RPRS capacity resulted in costs, regardless of whether any energy from the committed Resource was actually ***593** sold on the market. Even though a QSE submitted a schedule that was balanced on a system-wide basis, ERCOT may also have incurred costs if the schedule was imbalanced within one or more zones. Those costs occurred because, to balance a particular zone, ERCOT may have procured power from a generator within that zone that was more expensive than if a generator from outside the zone had been utilized. If ERCOT procured RPRS, it made a payment to the QSE providing the service according to the methods and formulas specified in section 6.8, "Compensation for Services Provided." *See id.* § 6.8.

Section 6.9, "Settlement for ERCOT–Provided Ancillary Services," contained the mathematical formulas ERCOT utilized to calculate RPRS settlement, that is, the charges ERCOT levied against the QSEs for procuring RPRS. *See id.* § 6.9. Protocol 6.9.2.1, entitled "Settlement for RPRS," set forth formulas for two different charges related to RPRS: an under-scheduling charge and an uplift charge. *See id.* §§ 6.9.2.1, 6.9.2.1.1, 6.9.2.1.2. Before being amended in October 2006, the formula set forth in section 6.9.2.1.1, entitled "Replacement Reserve Under–Scheduled Capacity" (hereinafter, the "RPRS under-scheduled settlement protocol"), required a direct assessment of charges to a QSE that scheduled short in any zone if ERCOT actually procured RPRS. *See id.* § 6.9.2.1.1. Although the formula sometimes resulted in an under-scheduling charge that was less than ERCOT's total RPRS procurement costs, often the charge was greater than the cost that ERCOT had incurred in procuring RPRS to remedy the projected capacity insufficiency. *See id.*

The second part of the RPRS settlement protocol, section 6.9.2.1.2 (entitled "Replacement Reserve Uplift Charge"), provided the formula that "uplifted" (or "socialized") any remaining RPRS costs (or any over-recovered balance) among all QSEs.[6] *See id.* § 6.9.2.1.2. The protocol calculated the uplift charge by (1) summing the costs of RPRS for local congestion, zonal congestion, and capacity insufficiency and then (2) subtracting out the payments received through the under-scheduling charge and the zonal congestion charge. *See id.* The remaining cost balance, whether positive or negative, was uplifted to all QSEs according to load-ratio share.

The uplift charge formula provided that, whenever the total amount of under-scheduling charges in section 6.9.2.1.1 was less than ERCOT's costs for providing RPRS, the remaining costs were socialized among QSEs by load-ratio share. *See id.* Likewise, whenever the total amount of under-scheduling charges was greater than ERCOT's costs, the excess recovery was distributed among the QSEs by load-ratio share. *See id.*

ERCOT assessed under-scheduling charges of approximately $3.8 million against Constellation for the trade days in question, in accordance with the formula set forth in section 6.9.2.1.1. *See id.* § 6.9.2.1.1. Constellation disputed the charges. After ERCOT denied Constellation's complaint, Constellation appealed to the Commission, alleging that ERCOT had erroneously calculated the under-scheduling charges based on Constellation's zonal-capacity insufficiency instead of its system-wide shortfall. Constellation conceded that section 6.9.2.1.1 required calculation of under-scheduling charges on a zonal basis, but argued the RPRS procurement protocol (section 6.6.3.2.1) indicated that QSEs were intended to incur RPRS costs for capacity insufficiency only if they ***594** were system-wide, not merely in a zone. *See* §§ 6.6.3.2.1, 6.9.2.1.1. Constellation proposed that, in order to calculate the "correct" charges, the Commission should ignore the RPRS under-scheduled settlement protocol (section 6.9.2.1.1) and uplift the cost of capacity insufficiency to the entire market on a load-ratio share basis as set forth in section 6.6.3.2.1(9) (the "uplift solution"). *See id.*

After the Commission referred the matter to SOAH, the ALJ granted summary disposition in Constellation's favor, agreeing that the under-scheduling charges should have been calculated using the uplift solution. The ALJ found that the RPRS procurement protocol (section 6.6.3.2.1) and the RPRS under-scheduled settlement protocol (section 6.9.2.1.1) were "inconsistent and contradictory" and that the RPRS procurement protocol should have been applied strictly as written, that is, the cost of allocation uplifted to all QSEs based on load-ratio share. The ALJ noted that, although ERCOT had made no mathematical errors in applying the formula set forth in the RPRS under-scheduled settlement protocol, "that formula was incorrectly written to charge RPRS capacity insufficiency costs on a zonal basis rather than on a Load Share [basis]" as the RPRS procurement protocol required. The ALJ recommended the Commission order ERCOT to resettle the contested trade days by uplifting on a load-ratio share basis the RPRS cost for capacity inadequacy as "all other costs" [sic] in subsection (9) of the RPRS procurement protocol, section 6.6.3.2.1. *See id.* § 6.6.3.2.1(9). Section 6.6.3.2.1(9) read as follows:

> If all of the cost of RPRS is not allocated by one of the above methods, then the allocation will be uplifted to all QSEs based on the Load Ratio Share for the relevant period. If ERCOT collects more RPRS costs in this manner than are necessary, the excess funds collected by ERCOT will be credited to all QSEs based on the Load Ratio Share for the relevant period.

Id. § 6.6.3.2.1(9).

The Commission disagreed with the ALJ's analysis. It concluded the protocols were harmonious and not in conflict. It further stated that "ERCOT correctly settled the capacity insufficiency charges for the disputed operating dates in accordance with the Protocols then in effect and that no resettlement should occur." The Commission also determined that "ERCOT correctly applied the formula as written at that time and that a protocol revision request (PRR) was later utilized to modify the protocol to avoid the consequences of applying the zonal factor as the formula previously required."

Constellation sought judicial review. The district court found that the RPRS under-scheduled settlement protocol (section 6.9.2.1.1) and the RPRS procurement protocol (section 6.6.3.2.1) were in "irreconcilable conflict" and that the RPRS procurement protocol was the "special or specific Protocol that must be given controlling effect in this case." *See id.* §§ 6.6.3.2.1, 6.9.2.1.1. The court reversed the Commission's order, concluding that, because ERCOT did not give controlling effect to the RPRS procurement protocol but instead calculated Constellation's RPRS charges using the RPRS under-scheduled settlement protocol, ERCOT failed to correctly settle the RPRS charges. This appeal followed.

DISCUSSION

Commission's Interpretation of ERCOT Protocols

[1] **[2]** **[3]** ERCOT protocols are rules that provide the framework for the administration ***595** of the Texas electricity market. *BP Chemicals, Inc. v. AEP Tex. Cent. Co.,* 198 S.W.3d 449, 452 (Tex.App.-Corpus Christi 2006, no pet.). ERCOT protocols, however, are subject to Commission oversight and review. Tex. Util.Code Ann. § 39.151(d); *see also id.* (g) (Commission must approve protocols and protocols must reflect Commission's input). An agency's interpretation of a rule becomes part of the rule itself

EXHIBIT 20

and represents the view of the regulatory body that must administer it. *H.G. Sledge, Inc. v. Prospective Inv. & Trading Co.,* 36 S.W.3d 597, 604 (Tex.App.-Austin 2000, pet. denied).

[4] [5] [6] Statutory construction presents a question of law that we review de novo. *State v. Shumake,* 199 S.W.3d 279, 284 (Tex.2006). Because they have the force and effect of statutes, we construe administrative rules in the same manner as statutes. *Rodriguez v. Service Lloyds Ins. Co.,* 997 S.W.2d 248, 254 (Tex.1999). "Unless the rule is ambiguous, we follow the rule's clear language." *Shumake,* 199 S.W.3d at 284.

[7] We also must give "serious consideration" to the construction of a statute by the administrative agency charged with its enforcement. *Railroad Comm'n v. Texas Citizens for a Safe Future & Clean Water,* 336 S.W.3d 619, 624 (Tex.2011). In our "serious consideration inquiry," we will generally uphold an agency's interpretation of its own rules unless that interpretation is plainly erroneous or inconsistent with the text of the rule. *See id.* at 625.

The supreme court has observed that deference to an agency's interpretation is "tempered" by several considerations. *See id.* First, deference "applies to formal opinions adopted after formal proceedings, not isolated comments during a hearing or opinions [in a brief]." *Id.* (quoting *Fiess v. State Farm Lloyds,* 202 S.W.3d 744, 747 (Tex.2006). Second, the language at issue must be ambiguous. *Fiess,* 202 S.W.3d at 747. Third, the agency's construction must be reasonable. *Id.* at 747–48.

[8] When a statutory scheme is subject to multiple understandings, that is, ambiguous, we must uphold the enforcing agency's construction of its statutory scheme if is reasonable and in harmony with the statute. *See Texas Citizens,* 336 S.W.3d at 629. This deference is particularly important in a complex regulatory scheme like the Public Utility Regulatory Act. *See id.* at 629–30.

Accordingly, we must determine whether the Commission's interpretation of the ERCOT protocols in question is plainly erroneous or inconsistent with the text of the protocols and defer to the Commission's construction of its regulatory scheme if is reasonable and in harmony with the statute.

The Commission, the Joint Intervenors, and Luminant (collectively, "appellants") assert the district court erred in rejecting the Commission's conclusion that ERCOT properly assessed RPRS under-scheduling charges to Constellation in accordance with the under-scheduled capacity formula set forth in section 6.9.2.1.1, the RPRS under-scheduled settlement protocol. *See* ERCOT Zonal Protocols § 6.9.2.1.1. Appellants contend the district court failed to give deference to the Commission's construction of the RPRS procurement protocol (section 6.6.3.2.1) and the RPRS under-scheduled settlement protocol, as well as the Commission's conclusion that the two protocols were not in conflict but were harmonious. *See id.* §§ 6.6.3.2.1, 6.9.2.1.1.

Contrary to Constellation's assertion that ERCOT erroneously calculated under-scheduling charges based on Constellation's zonal-capacity insufficiency instead of its system-wide shortfall and that the RPRS procurement protocol (section ***596** 6.6.3.2.1) indicated that QSEs were intended to incur RPRS costs for capacity insufficiency only if they were system-wide, Luminant argues the version of the RPRS under-scheduled settlement protocol in effect during the relevant market days required measurement of under-scheduling charges on a zonal, not on a system-wide, basis. *See id.* It asserts that no other ERCOT protocol addressed the imposition of charges to a QSE that under scheduled, either in a zone or otherwise.

Luminant contends that, contrary to what the district court found, the RPRS procurement protocol said nothing about the consequences to a QSE for under scheduling capacity in a zone. *See id.* § 6.6.3.2.1. The Joint Intervenors likewise argue that section 6.6.3.2.1 neither prohibited ERCOT from imposing under-scheduling charges, nor did that protocol even address the obligations of capacity-short QSEs. *See id.* Rather, Luminant contends, section 6.6.3.2.1 merely specified when and how ERCOT had to procure RPRS in the first place and summarized ERCOT's duty to uplift (or "socialize") any under- or over-collected RPRS costs. *See id.* Luminant argues that, because the under-scheduled capacity formula in section 6.9.2.1.1 was the only provision that specified the economic consequences of under scheduling capacity in a zone and that provision was clear and unambiguous, the district court erred in looking beyond the RPRS under-scheduled settlement protocol. *See id.* § 6.9.2.1.1.

EXHIBIT 20

The Commission also argues that the protocol that most specifically addressed the issue of the appropriate means of RPRS settlement was section 6.9.2.1.1. *See id.* Only the RPRS under-scheduled settlement protocol included the precise details of how RPRS settlement was to be carried out. Indeed, notes the Commission, section 6.9.2.1.1 contained three pages of equations and variables determining the method of settlement, compared with one sentence in subsection 9 in the RPRS procurement protocol.[7] *See id.* §§ 6.6.3.2.1(9), 6.9.2.1.1.

In response, Constellation asserts that the formula in section 6.9.2.1.1 conflicted with the RPRS procurement protocol. Constellation contends that, because subsection (9) of the RPRS procurement protocol (section 6.6.3.2.1) required an uplift of RPRS insufficiency costs on a load-ratio share basis, whereas the RPRS under-scheduled charge formula in section 6.9.2.1.1 directly assigned a charge to QSEs under-scheduled in any zone, the two protocols conflicted. *See id.*

However, the Joint Intervenors argue no inconsistency existed between ERCOT uplifting remaining RPRS costs on a load-ratio share basis and imposing a charge on capacity-short QSEs that had benefitted from under scheduling.[8] They contend that, because a distinction exists between "charges" and "costs," the district court failed to understand that the RPRS under-scheduled settlement protocol and the RPRS procurement protocol harmoniously ***597** coexisted. The Joint Intervenors assert the RPRS settlement protocol, section 6.9.2.1, had two parts: section 6.9.2.1.1, which described and calculated under-scheduled capacity charges to capacity-short QSEs, charges not intended to match ERCOT's exact procurement costs; and section 6.9.2.1.2, which contained the uplift formula through which ERCOT's RPRS procurement costs and under-scheduled capacity charges were netted. *See id.* §§ 6.9.2.1, 6.9.2.1.1, 6.9.2.1.2.

Subpart 10 of section 6.3.1, entitled "ERCOT Responsibilities," read, in pertinent part, as follows: "ERCOT will not profit financially from the market." *Id.* § 6.3.1(10). Because that protocol required ERCOT to be a revenue-neutral entity, the Joint Intervenors point out that all costs and revenues had to be returned to market participants. They assert the formula in section 6.9.2.1.2 incorporated the RPRS procurement *costs* that ERCOT incurred and the RPRS under-scheduling *charges* that ERCOT collected. *See id.* § 6.9.2.1.2. The Joint Intervenors contend that, pursuant to the formula in section 6.9.2.1.2, ERCOT netted the cost of RPRS procurement with any RPRS under-scheduling charges collected, and the uplift charge to each QSE was calculated based on its own load-ratio share. *See id.* Thus, the uplift charge achieved the socialized distribution of excess costs or receipts referenced in subsection (9) of section 6.6.3.2.1, the RPRS procurement protocol. *See id.* §§ 6.6.3.2.1, 6.9.2.1.2.

We hold that the Commission's interpretation of section 6.9.2.1.1, the RPRS under-scheduled settlement protocol, was consistent with the protocol's plain language. *See id.* § 6.9.2.1.1. Section 6.9.2.1.1 specifically authorized ERCOT to impose under-scheduling charges on a QSE that scheduled short in any zone, and the Commission's order accurately concluded that ERCOT settled the capacity insufficiency charges assessed to Constellation in accordance with the text and formula set forth in section 6.9.2.1.1. *See id.*

[9] We further hold the district court erred in finding that the RPRS procurement protocol and the RPRS under-scheduled settlement protocol were in irreconcilable conflict. *See id.* §§ 6.6.3.2.1, 6.9.2.1.1. As Luminant pointed out, the under-scheduling charge was based, in part, on the market clearing price for capacity ("MCPC") for insufficiency defined in subsection (6)(a) of the RPRS procurement protocol, which read as follows:

> The marginal cost (Shadow Price of the power balance constraint) to solve system insufficiency defines MCPC for insufficiency.

Id. § 6.6.3.2.1(6)(a); *see also* § 2.1 (definition of "market clearing price for capacity"). The Commission in its order noted that "subsection (6) of Protocol § 6.6.3.2.1 [the RPRS procurement protocol] speaks to capacity insufficiencies and provides a factor for insufficiency that is included in the formula for calculating charges to under-scheduled [QSEs] on a zonal basis in Protocol [section 6.9.2.1.1]." *See id.* §§ 6.6.3.2.1, 6.9.2.1.1. The Commission thus harmonized the RPRS procurement protocol and the formula in the RPRS under-scheduled settlement protocol and concluded the protocols did not conflict. *See id.* Finding that the Commission's construction of this regulatory scheme is reasonable and in harmony with the statute, we hold the district court erred in failing to defer to the Commission's interpretation.

Finding that the Commission's order accurately concluded that ERCOT settled the capacity insufficiency charges assessed to Constellation in accordance with the text and formula set forth in section 6.9.2.1.1, the RPRS under-scheduled settlement ***598** protocol, and that the RPRS procurement protocol and the RPRS under-scheduled

EXHIBIT 20

settlement protocol did not conflict, we sustain appellants' first issue.

Having sustained appellants' first issue, we need not reach Luminant's and the Joint Intervenors' second issue.

Constellation's Cross–Point

[10] The district court concluded that "[the Commission] and ERCOT did not act outside the scope of their statutory authority by overcharging for RPRS procurement." As a conditional cross-point, Constellation asserts that, if the court's conclusion is interpreted to mean that ERCOT had the authority to intentionally impose a charge over and above ERCOT's actual procurement costs, that conclusion is in error. Constellation argues ERCOT only had authority to charge QSEs for ERCOT's actual costs of procuring RPRS to resolve capacity insufficiency. It contends that the formula in the RPRS under-scheduled settlement protocol "cannot, as a matter of law, be interpreted to allow ERCOT to assess a charge over and above its actual costs." *See id.* § 6.9.2.1.1. We disagree.

As the Commission has noted, no statute, rule, or protocol demanded that ERCOT's under-scheduling charges correlate exactly with its costs in procuring RPRS. Although it often assessed an under-scheduling charge that was greater than its procurement costs, ERCOT retained no cost excess from the under-scheduling charge. Rather, as required by section 6.9.2.1.2, ERCOT uplifted any excess to the market, thus remaining revenue neutral as required by section 6.3.1(10). *See id.* §§ 6.3.1(10), 6.9.2.1.2. Constellation's cross-point is overruled.

CONCLUSION

Having sustained appellants' first issue, we reverse the district court's judgment and render judgment affirming the Commission's order that determined ERCOT had correctly assessed under-scheduling charges against Constellation for the period April 10, 2006, to September 27, 2006.

All Citations

351 S.W.3d 588

Footnotes

1 ERCOT protocols are rules that provide the framework for the administration of the Texas electricity market. *BP Chemicals, Inc. v. AEP Tex. Cent. Co.,* 198 S.W.3d 449, 452 (Tex.App.-Corpus Christi 2006, no pet.).

2 "Resource" is defined as "facilities capable of providing electrical energy or Load capable of reducing, or increasing the need for electrical energy or providing Ancillary Services to the ERCOT System, as described in Section 6, Ancillary Services. This includes Generation Resources and Loads acting as Resources." ERCOT Zonal Protocols § 2.1 (March 1, 2006), *available at* http://www.ercot. com/mktrules/protocols/library/2006. "Load" is "the amount of electric power delivered at any specified point or points on a system." *Id.*

3 "Ancillary services" are services "necessary to support the transmission of energy from Resources to Loads while maintaining reliable operation of transmission provider's transmission systems in accordance with Good Utility Practice." *Id.*

4 "Congestion" is defined as "the situation that exists when requests for power transfers across a Transmission Facility element or set of elements, when netted, exceed the transfer capability of such elements." *Id.* Congestion can be either local (within a zone) or zonal (between two or more zones).

5 All subsequent citations to section 6 of ERCOT Zonal Protocols, entitled "Ancillary Services," were effective March 21, 2006.

6 "Uplift" is defined as "the process of allocating costs to QSEs based on Loads and exports within the ERCOT Region." ERCOT Zonal Protocols § 2.1 (March 1, 2006).

7 "If all of the cost of RPRS is not allocated by one of the above methods, then the allocation will be uplifted to all QSEs based on the Load Ratio Share for the relevant period." ERCOT Zonal Protocols § 6.6.3.2.1(9).

EXHIBIT 20

8 A QSE could decide if the economic benefit of likely achieving a lower price in the real-time market made under-scheduling worth its known risks, that is, under-scheduled charges. QSEs knew that, if other QSEs scheduled "long," that is, scheduled capacity in excess of what was required to meet their delivery obligations, ERCOT might not need to procure RPRS. And if ERCOT did not procure RPRS, then no under-scheduling charges would be assessed against those QSEs that intentionally scheduled less capacity than needed to meet their delivery obligations.

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EXHIBIT 21

EXHIBIT 21

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Home > Services > Programs > Demand Response > Load Resource Participation in the ERCOT Markets

Load Resource Participation in the ERCOT Markets

— Relevant Definitions from Protocol Section 2

Load Resource (LR)

A Load capable of providing Ancillary Service to the ERCOT System and/or energy in the form of Demand response and registered with ERCOT as a Load Resource

Aggregate Load Resource (ALR)

A Load Resource that is an aggregation of individual metered sites, each of which has less than ten MW of Demand response capability and all of which are located within a single Load Zone

Controllable Load Resource (CLR)

A Load Resource capable of controllably reducing or increasing consumption under Dispatch control by ERCOT

— Market Participation

Customers who can change their load in response to an instruction and can meet certain performance requirements may qualify to become LRs. Qualified LRs may participate in ERCOT's real-time energy market through Security-Constrained Economic Dispatch (SCED) and/or qualify to provide any of the following Ancillary Services: Non-Spinning Reserve (Non-Spin), Regulation Down Service (Reg-Down), Regulation Up Service (Reg-Up) and Responsive Reserve (RRS).

In the ERCOT markets, the value of a Load Resource's load reduction is equal to that of an increase in generation by a generating plant. LRs in SCED submit bids to buy power "up to" their specified level and are instructed by ERCOT to reduce Load if wholesale market prices equal or exceed that level. LRs that are scheduled or selected in the ERCOT Day-Ahead AS Market are eligible to receive a capacity payment regardless of whether they are actually curtailed.

— Registration Information

Load Resources register using the Resource Integration & Ongoing Operations (RIOO) application. Instructions for setting up a RIOO user account can be found under RIOO Documentation on the Resource Integration webpage. Refer to the RIOO user guides under Key Documents below for more details.

In summary, to register a Load Resource, the LR owner and/or the Resource Entity must:

- Register as a Resource Entity by submitting the Resource Entity Application for Registration in Section 23 of the Protocols.
- Designate a Qualified Scheduling Entity (QSE) responsible for market operations and financial settlement.
- Complete interconnection requirements with the host Transmission and/or Distribution Service Provider (TDSP) and Meter Reading Entity (MRE).
- Coordinate a Production Load Date (PLD) and Dispatch Asset Code (DAC) for each new LR via email with the ERCOT Demand Integration team (ERCOTLRandSODG@ercot.com).

EXHIBIT 21

ercot

Note that LR submissions meeting the 45 day PLD schedule do not require the RE to submit the "RE_Model_Interim_Update_Request" form.

  - The DAC will be a unique identifier provided by ERCOT and it must be included in the RIOO submission.
- Register the LR by using the Resource Integration & Ongoing Operations (RIOO) application.

Links to registration and qualification forms are provided below.

Load Resource Supporting Information

Monthly ERCOT Demand Response from Load Resources
View monthly response from load resources.

Key Documents

RIOO Workshop - Creating and Updating Load Resources	Jan 23, 2023 - pdf - 452.9 KB
RIOO User Guide – Creating a New Load Resource	Jan 11, 2023 - pdf - 2.4 MB
RIOO User Guide - Updating an Existing Load Resource	Jan 17, 2023 - pdf - 2 MB
Load Resource Critical Load Attestation	Dec 9, 2021 - docx - 33.8 KB
Controllable Load Qualification Test Procedure for Ancillary Services	Apr 28, 2016 - docx - 233.8 KB
DSWG Loads in SCEDv1.pptx Refresher:042314	May 6, 2014 - ppt - 1.4 MB
NOIE Authorization Form for QSEs Representing ERS & LR	Dec 20, 2019 - docx - 48.8 KB
Non-Controllable Load Resource Qualification and Testing Procedure	Apr 28, 2016 - docx - 206.9 KB
PR117-01 Data Submission Requirements 14	Sep 16, 2015 - doc - 408.5 KB
QSE Qualification and Testing Procedures	Jul 28, 2011 - doc - 167 KB
Requirements for Aggregate Load Resource Participation	Aug 31, 2020 - doc - 142 KB

About ERCOT
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Market Rules

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Glossary
Careers
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EXHIBIT 21

EXHIBIT 22

To: legal_notifications;settlements

Sent: 9/8/17 1:45 PM

Subject: M-A090817-01 Resolution of ADR Proceedings between ERCOT and North Maple Energy LLC (ADR No. 2017-NME-01)

NOTICE DATE: September 8, 2017

NOTICE TYPE: M-A090817-01 Legal

SHORT DESCRIPTION: Resolution of ADR Proceedings between ERCOT and North Maple Energy LLC (ADR No. 2017-NME-01)

INTENDED AUDIENCE: Market Participants

DAYS AFFECTED: January 28, 30-31, 2017, February 2-3, 2017

LONG DESCRIPTION: Upon ERCOT's determination of the disposition of an Alternative Dispute Resolution (ADR) proceeding, ERCOT Protocol Section 20.9 requires ERCOT to issue a Market Notice providing a brief description of the relevant facts, a list of the parties involved in the dispute, and ERCOT's disposition of the proceeding and reasoning in support thereof.

Parties: ERCOT and North Maple Energy LLC

Relevant Facts:

North Maple Energy LLC (NME) submitted Point-to-Point (PTP) Obligation bids in the Day-Ahead Market (DAM) for Operating Days (ODs) January 30 and 31, 2017, with "Not-to-Exceed" (NTE) bid prices ranging from approximately $0.20 to $50.00.[1] Per ERCOT Protocol Section 4.4.6, a NTE bid price represents the "maximum price that the bidder is willing to pay" for a particular PTP Obligation in the DAM.

In the DAM for ODs January 30 and 31, 2017, ERCOT awarded NME 258 PTP Obligations that were charged to NME at prices that exceeded its submitted NTE bid prices. PTP Obligations were awarded to NME in this manner due to a then-existing design aspect of the DAM optimization engine. More specifically, prior to the implementation of Nodal Protocol Revision Requests (NPRRs) 827 and 833 (discussed below), the DAM optimization engine functioned in a manner such that, if a contingency de-energized a Settlement Point where a source or sink for a PTP Obligation bid existed, and that contingency resulted in a binding constraint where the other Settlement Point (source or sink) had a non-trivial Shift Factor to the constraint, then a PTP Obligation bid could clear in the DAM optimization engine at a price spread that was different than the price spread calculated from the published DAM Settlement Point Prices (SPPs). Because PTP Obligations are charged to Market Participants using SPPs, these contingencies could result in occasions where the charge to a Market Participant for a PTP Obligation was higher than the submitted NTE bid price.

NME was charged for the PTP Obligations in conformance with ERCOT Protocol Section 4.6.3, Settlement of PTP Obligations Bought in the DAM, which requires that "ERCOT shall pay or charge a QSE for a cleared PTP Obligation bid the difference in the DAM Settlement Point Prices between the sink Settlement Point and the source Settlement Point." Although ERCOT applied this Protocol correctly when charging NME for the PTP Obligations at issue, the resulting charges were well above the NTE bid prices NME had stated it was "willing to pay." More specifically, although NME submitted PTP Obligation bids where the sum of its NTE bid prices multiplied by the bid quantity totaled approximately $13,228.36 for the two ODs at issue in its ADR filing, NME was charged $2,111,747.69 in the DAM for PTP Obligations for those ODs.[2]

As a consequence of the $2M+ DAM charge to NME for these PTP Obligation bids on the ODs at issue, NME was required to post additional collateral to cover Total Potential Exposure (TPE), which it did not do within the time period required by ERCOT Protocols. Accordingly, NME's Standard Form Agreement (SFA) with ERCOT was terminated on February 7, 2017, and NME was precluded from further participation in the ERCOT market. The Congestion Revenue Rights (CRRs) NME held for

February 8 – 28, 2017 were voided, and the remainder of NME's CRRs were repossessed by ERCOT and sold in a one-time auction.

On March 31, 2017, NME submitted its request for ADR to ERCOT, asserting that ERCOT improperly awarded NME PTP Obligations for ODs January 30 and 31, 2017 that were above NME's submitted NTE bid prices. In this ADR, NME seeks relief in the amount of $1,225,957.99 and also requests reinstatement of its registration as a Market Participant with ERCOT. With respect to the amount requested, NME seeks $1,123,548.79 as a refund for what it states were "erroneously" awarded PTP Obligations for ODs January 30 and 31, 2017.[3] NME also seeks $102,409.20 in compensation for its CRRs for February 8 - 28, 2017, which were voided as a result of the termination of its SFA with ERCOT.

<u>ERCOT's Disposition/Reasoning</u>:

ERCOT has determined that the appropriate disposition of this ADR proceeding is to approve, in part, NME's request for relief. As discussed in further detail below, ERCOT will be issuing a payment of $1,106,561.15 to NME. Pursuant to ERCOT Protocol Section 20.1(1), a Market Participant may seek relief through the ADR process by making a claim that "ERCOT has violated or misinterpreted any law," including an ERCOT Protocol. In this matter, for the reasons stated below, ERCOT misinterpreted certain ERCOT Protocols when it charged NME for PTP Obligations at prices that exceeded NME's stated NTE bid prices.

When a contingency caused the DAM optimization engine to clear NME's PTP Obligation bids in the manner described above, it resulted in a conflict between two ERCOT Protocols.[4] More specifically, ERCOT was unable to enforce ERCOT Protocol Section 4.6.3, which mandates how QSEs are paid or charged for cleared PTP Obligations, without coming into conflict with ERCOT Protocol Section 4.4.6, which permitted NME to set a maximum price that it was "willing to pay" for PTP Obligations. In this case, ERCOT's enforcement of Section 4.6.3 resulted in a charge to NME in the DAM of over $2M for awarded PTP Obligations, even though NME, as permitted by Section 4.4.6, had submitted bids representing that it was only "willing to pay" just over $13K for those PTP Obligations.

When two or more ERCOT Protocols conflict (either on their face or, as here, in a particular application), they must be interpreted and harmonized in a manner that, when possible, gives effect to every provision and does not lead to unreasonable or absurd results. Here, the language in Section 4.4.6, which describes the PTP Obligation NTE bid price as the "maximum price that the bidder is willing to pay," must be given effect so that this Protocol language is not rendered mere surplusage. It is apparent that the language in Section 4.4.6, which requires Market Participants to submit bids with "Not-to-Exceed" prices, was intended to be a mechanism that would allow a Market Participant to limit its liability in the DAM for awarded PTP Obligations to the sum of its NTE bid prices.

In this unique case, however, the clearing of PTP Obligation bids in the DAM optimization engine in the particular manner described above—which was not itself contrary to any ERCOT Protocol—coupled with ERCOT later charging NME for cleared PTP Obligations bids in conformance with ERCOT Protocol Section 4.6.3, led to a particular result that was contrary to ERCOT Protocol Section 4.4.6, because it exposed NME to charges in the DAM well above the NTE bid prices it stated it was "willing to pay." Given these specific facts, ERCOT has concluded that it should not have enforced the Protocols in a manner that resulted in charges to NME in the DAM that exceeded NME's stated NTE bid prices.

Accordingly, ERCOT is approving NME's ADR to the extent NME asserts it was an unreasonable interpretation of the ERCOT Protocols to award and charge NME for PTP Obligations in excess of its stated NTE bid prices. ERCOT, however, is not awarding NME the full relief it requests. NME's request for relief seeks only to have ERCOT "unwind" awarded PTP Obligations that resulted in a net charge to NME after Settlement in Real-Time (i.e., to unwind only those PTP Obligation awards where NME was charged more in the DAM for the PTP Obligation than the PTP Obligation ultimately paid out in

Real Time). To be consistent with the reasoning set forth above, however, the appropriate resolution of this matter requires unwinding PTP Obligation awards to NME that were charged in the DAM at prices that exceeded the NTE bid price—even in those cases where NME received a net payment after Settlement in Real-Time. Accordingly, ERCOT is granting NME relief that puts NME back in the position it would have been had it never been awarded any PTP Obligations over stated NTE bid prices, for both the ODs it put at issue as well as ODs surrounding those days.[5] ERCOT finds it relevant that NME received a net payment of $118,264.91 for awarded PTP Obligations on ODs January 28, 2017 and February 2 and 3, 2017. On these three ODs, PTP Obligations were awarded to NME at prices above the NTE bid prices—that is, they were awarded in the same manner NME complains of in this ADR with respect to January 30 and 31, 2017—but those PTP Obligations ultimately paid out in Real-Time in a manner that resulted in a net payment to NME after Settlement in Real-Time. It would not be proper for NME to obtain a full refund for the charges it incurred on January 30 and 31, 2017, while also retaining the benefit of the payment it received on these other ODs. Rather, all PTP Obligations awarded above the NTE bid price on these ODs are being reversed, regardless of whether they resulted in a net payment or charge to NME. Accordingly, the refund amount to NME for PTP Obligations awarded above the NTE bid price on January 30 and 31, 2017, $1,123,690.62, is being offset by $118,264.91, the net payment NME received for ODs January 28, 2017, and February 2 and 3, 2017. This results in a total refund amount of $1,005,425.71 related to the improperly awarded PTP Obligations.[6]

With respect to NME's request for reimbursement for its CRRs from February 8 - 28, 2017 that were voided when its SFA with ERCOT was terminated, ERCOT agrees that NME is entitled to this relief. The PTP Obligation charges for ODs January 30 and 31, 2017 ultimately triggered revocation of NME's SFA with ERCOT. To the extent ERCOT has concluded those charges were unreasonable under the specific facts presented here, NME should not have had its registration revoked or its CRRs voided. Accordingly, ERCOT will provide relief to NME in the amount of $101,135.44 to account for the value of the voided CRRs. When combined with the net refund for the PTP Obligation charges above, this results in a total payment to NME of $1,106,561.15.

Finally, NME is immediately eligible to re-register as an ERCOT Market Participant.

Pursuant to ERCOT Protocol Section 20.10.1(2), ERCOT will make the adjustment required to resolve this ADR Proceeding through two separate ADR invoices (one for January 2017, and one for February 2017), which will be issued to all affected Market Participants. The NME payment associated with activity in January 2017 and February 2017 will be uplifted on the basis of the Monthly Load Ratio Shares (MLRS) applicable to the months of January 2017 and February 2017 respectively.

This Market Notice serves to conclude the ADR proceedings between ERCOT and NME.

Further Information:

Nodal Protocol Revision Request (NPRR) 827, Disallow PTP Obligation Bid Award where Clearing Price exceeds bid price by $0.25/MW per hour, was approved by the ERCOT Board on June 13, 2017, and implemented later that month. NPRR 827 revised ERCOT Protocols such that currently ERCOT may not award PTP Obligations in the DAM when the corresponding clearing price is greater than the NTE bid price for a PTP Obligation by $0.25/MW per hour. ERCOT has implemented this NPRR by introducing a manual work-around prior to DAM Settlement.

Further, NPRR833, Modify PTP Obligation Bid Clearing Change, was approved by the ERCOT Board on August 8, 2017, and will be implemented at a future date that is to be determined. Once implemented, the protocol revision will provide a long-term solution to this issue by altering the DAM optimization engine such that PTP Obligations will not be awarded if the DAM clearing price for the PTP Obligation is greater than the PTP Obligation NTE bid price plus $0.01/MW per hour.

Finally, ERCOT notes that this ADR raises the question of whether other potential conflicts can exist in the ERCOT Protocols when internal operational issues (such as the operation of the DAM optimization engine in this case) result in "not to exceed" or "willing to pay" language in the Protocols not being given its intended effect. To the extent such potential conflicts could have impacts on the efficient operation of the ERCOT market, it is an issue that may be worth further discussion in the stakeholder process.

CONTACT: If you have any questions, please contact your ERCOT Account Manager. You may also call the general ERCOT Client Services phone number at (512) 248-3900 or contact ERCOT Client Services via email at ClientServices@ercot.com.

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[1] Per ERCOT Protocols Section 4.4.6(1), PTP Obligation Bids, a "Point-to-Point (PTP) Obligation bid is a bid that specifies the source and sink, a range of hours, and a maximum price that the bidder is willing to pay ("Not-to-Exceed Price")."
[2] In Real-Time Settlement, these PTP Obligations paid out $988,057.07, resulting in a net impact (i.e., charge) to NME of $1,123,690.62.
[3] On the ODs at issue, NME was awarded PTP Obligations over its NTE Bid Price for a number of source/sink combinations. However, in its ADR filing NME seeks to "unwind" only those awards for one source/sink combination (Rerock All/Hovey_Unit 1). That particular path constituted the majority of the awarded PTP Obligations, and the other paths were charged in the DAM at prices no more than $4 over the NTE bid price (as compared to the Rerock All/Hovey_Unit 1 path, which was charged in the DAM at prices up to $2,160.28 over the NTE bid price).
[4] ERCOT's operation of the DAM optimization engine in a manner that—prior to the June 2017 implementation of NPRR827—cleared PTP Obligations bids that were later charged in the DAM at Settlement Prices above the NTE bid prices, due to contingencies present when clearing the bids, was not contrary to any ERCOT Protocol, because there was no ERCOT Protocol that specifically barred ERCOT from clearing PTP Obligation bids in the manner described herein.
[5] Although NME did not cite any ODs other than January 30 and 31, 2017 in its ADR filing, granting NME relief based on only those two days would not properly represent the net monetary impact it sustained in January and February 2017 due to being charged in the DAM for PTP Obligations above the NTE bid price, because NME received a net payment on January 28, 2017 and February 2 and 3, 2017 due to PTP Obligations it was awarded above the NTE bid price.
[6] As mentioned above, NME was awarded PTP Obligations over its NTE Bid Price for a number of different source/sink combinations on the ODs at issue, but NME seeks to "unwind" only those awards for one source/sink combination (Rerock All/Hovey_Unit 1). In resolving this ADR, however, ERCOT is "unwinding" every PTP Obligation award to NME that was over the NTE bid price during ODs January 28, 30, and 31, 2017 and February 2 and 3, 2017. These five ODs are the only days in 2017 when NME was charged for PTP Obligations above NTE bid prices. ERCOT is doing this for two reasons: (1) resolution in this manner is most consistent with NME's assertion that it was contrary to ERCOT Protocols to charge it for any PTP Obligations in the DAM at prices above the NTE Bid Price, and (2) resolution in this manner results in the smallest monetary impact to other Market Participants.

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EXHIBIT 23

STEC'S DAILY OPERATOR LOGS SPREADSHEET ATTACHED SEPARATELY AS AN EXCEL FILE.

EXHIBIT 24

Date	Hour Ending	SARR	Sales	STEC Purchase	Total STEC LR RRS Responsibility
2/15/2021	1	20	-11.2	10	21.2
2/15/2021	2	20	-11.2	10	21.2
2/15/2021	3	20	-11.2	10	21.2
2/15/2021	4	20	-11.2	10	21.2
2/15/2021	5	20	-11.2	10	21.2
2/15/2021	6	20	-11.2	10	21.2
2/15/2021	7	19.6	-11.2	10	20.8
2/15/2021	8	19.3	-11.2	10	20.5
2/15/2021	9	18.8	-11.2	10	20
2/15/2021	10	18.5	-9	10	17.5
2/15/2021	11	18.4	-9	10	17.4
2/15/2021	12	18.5	-9	10	17.5
2/15/2021	13	18.7	-9	10	17.7
2/15/2021	14	19.2	-9	10	18.2
2/15/2021	15	20	-9	10	19
2/15/2021	16	20	-9	10	19
2/15/2021	17	20	-9	10	19
2/15/2021	18	20	-9	10	19
2/15/2021	19	20	-9	10	19
2/15/2021	20	20	-9	10	19
2/15/2021	21	20	-9	10	19
2/15/2021	22	20	-9	10	19
2/15/2021	23	20	-9	10	19
2/15/2021	24	20	-9	10	19

<u>EXHIBIT 25</u>

Board Report

NPRR Number	1149	NPRR Title	Implementation of Systematic Ancillary Service Failed Quantity Charges
Date of Decision	February 28, 2023		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	Upon system implementation		
Priority and Rank Assigned	Priority – 2023; Rank – 3780		
Nodal Protocol Sections Requiring Revision	2.1, Definitions 4.4.7.4, Ancillary Service Supply Responsibility 6.3.2, Activities for Real-Time Operations 6.4.1, Capacity Trade, Energy Trade, Self-Schedule, and Ancillary Service Trades 6.4.9.1.3, Replacement of Ancillary Service Due to Failure to Provide 6.7.3, Charges for Ancillary Service Capacity Replaced Due to Failure to Provide 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) charges a Qualified Scheduling Entity (QSE) an Ancillary Service failed quantity if the Ancillary Service Supply Responsibility held by the QSE is not met by Resources in their portfolio in Real-Time, based on a comparison of their Real-Time telemetry. The charges will be done systematically without ERCOT Operators having to take additional action. Specific Protocol changes include: • Details on the new calculations that will be used to do the comparison between Ancillary Service Supply Responsibility and Real-Time telemetry after the Operating Hour is complete; • Enhancing language in Section 4.4.7.4 to clarify that although a QSE may hold an Ancillary Service Supply Responsibility without having Resources, that responsibility must be met by Resources in Real-Time. The language proposed in this section does not create new responsibilities but clarifies existing requirements for how a QSE must meet its Ancillary Service Supply Responsibility;		

Board Report

	• A check on Load Resources providing Responsive Reserve (RRS), Non-Spinning Reserve (Non-Spin), and ERCOT Contingency Reserve Service (ECRS), to ensure that during the deployment period their telemetered Ancillary Service Resource Responsibility does not exceed the amount of deployed MW and overstate the amount of responsibility being carried by that Resource; • Expanding the window of time during which a QSE can submit an Ancillary Service Trade to include the Operating Period; and • Other aligning edits. Under this NPRR, ERCOT Operators retain the ability to charge a failed quantity and replace the MW with a Supplemental Ancillary Services Market (SASM) if they so choose.
Reason for Revision	[X] Addresses current operational issues. [ ] Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). [ ] Market efficiencies or enhancements [ ] Administrative [ ] Regulatory requirements [ ] Other: (explain) *(please select all that apply)*
Business Case	In May 2019, ERCOT filed NPRR947, Clarification to Ancillary Service Supply Responsibility Definition and Improvements to Determining and Charging for Ancillary Service Failed Quantities, which proposed very similar changes as proposed in this NPRR. NPRR947 was withdrawn by ERCOT after months of deliberation because, although it is important to ensure that QSEs are providing the Ancillary Services for which they are being compensated, the improvements proposed in NPRR947 were deemed to be made obsolete and the issue would be resolved by the implementation of Real-Time Co-Optimization (RTC) of energy and Ancillary Services, scheduled for implementation in 2024. As is widely known today, the effort to implement RTC is currently on hold and a new date for expected implementation is unknown. Additionally, following winter storm Uri, the ERCOT Independent Market Monitor (IMM), Potomac Economics, filed a recommendation at the Public Utility Commission of Texas (PUCT) in Project 51812, Issues Related to the State of Disaster for the February 2021 Winter

Board Report

	Weather Event, that ERCOT should charge failed quantities based on Real-Time telemetry and outcomes during the storm. The PUCT agreed with this recommendation (*See* Second Order Addressing Ancillary Services under Project No. 51812) and applicable charges were issued to QSEs by ERCOT. With that knowledge and experience, ERCOT again proposes to implement a systemic charging of Ancillary Service failed quantities. This NPRR implements that process permanently for all periods and in a more systematic way, ensuring that Load is not charged or is reimbursed for Ancillary Services that are not delivered in Real-Time. It also addresses short-comings in the previously applied process for Load Resources that are not Controllable Load Resources that were not included in ERCOT's application of the PUCT's Order in 2021.
PRS Decision	On 10/13/22, PRS voted to table NPRR1149 and refer the issue to WMS. There was one abstention from the Consumer (Occidental) Market Segment. All Market Segments participated in the vote. On 12/8/22, PRS voted unanimously to recommend approval of NPRR1149 as amended by the 12/1/22 ERCOT comments. All Market Segments participated in the vote. On 1/17/23, PRS voted unanimously to endorse and forward to TAC the 12/8/22 PRS Report and 9/20/22 Impact Analysis for NPRR1149 with a recommended priority of 2023 and rank of 3780. All Market Segments participated in the vote.
Summary of PRS Discussion	On 10/13/22, ERCOT Staff provided an overview of NPRR1149. On 12/8/22, PRS reviewed the 11/30/22 PUCT Staff comments and the 12/1/22 ERCOT comments. On 1/17/23, there was no discussion.
TAC Decision	On 1/24/23, TAC voted unanimously to recommend approval of NPRR1149 as recommended by PRS in the 1/17/23 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 1/24/23, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for NPRR1149. Participants confirmed they could continue to adjust Ancillary Services amongst Resources in their portfolio in Real-Time.
ERCOT Board Decision	On 2/28/23, the ERCOT Board voted unanimously to recommend approval of NPRR1149 as recommended by TAC in the 1/24/23 TAC Report.

Opinions

Board Report

Credit Review	ERCOT Credit Staff and the Market Credit Work Group (MCWG) have reviewed NPRR1149 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	The IMM supports the approval of NPRR1149 for reasons laid out in the 9/20/22 IMM comments.
ERCOT Opinion	ERCOT supports approval of NPRR1149.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1149 and believes the market impact for NPRR1149 is an improvement in the process for invoking "failure to provide" Settlement. This better ensures that Market Participants are not compensated for services that they were unable to provide in Real-Time and provides transparency as to how this Settlement will be applied.

Sponsor	
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Market Segment	Not applicable

Market Rules Staff Contact	
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Comments Received	
Comment Author	**Comment Summary**
IMM 092022	Expressed support for NPRR1149 and encouraged stakeholders to approve NPRR1149 on an urgent timeline
ERCOT 092722	Provided additional redlines to Section 6.3.2, Activities for Real-Time Operations, which were inadvertently omitted from the original submission

Board Report

WMS 110922	Requested PRS continue to table NPRR1149 for further review by the Wholesale Market Working Group (WMWG)
PUCT Staff 113022	Expressed support for NPRR1149 and encouraged prompt approval
ERCOT 120122	Proposed edits based to correct minor errors in a Settlement formula along with other clarifying edits

Market Rules Notes

Please note the baseline Protocol language in the following section(s) has been updated to reflect the incorporation of the following NPRR(s) into the Protocols:

- NPRR1085, Ensuring Continuous Validity of Physical Responsive Capability (PRC) and Dispatch through Timely Changes to Resource Telemetry and Current Operating Plans (COPs) (incorporated 10/1/22)
  - Section 6.7.5
- NPRR1131, Controllable Load Resource Participation in Non-Spin (incorporated 10/1/22)
  - Section 6.7.5
- NPRR1135, Add On-Line Status Check for Resources Telemetering OFFNS for Ancillary Service Imbalance Settlements (incorporated 10/1/22)
  - Section 6.7.5
- NPRR1058, Resource Offer Modernization (incorporated 12/1/22)
  - Section 6.3.2

Proposed Protocol Language Revision

2.1 Definitions

Ancillary Service Supply Responsibility

The net amount of Ancillary Service capacity that a QSE is obligated to deliver to ERCOT, by hour and service type~~, from Resources represented by the QSE~~.

4.4.7.4 Ancillary Service Supply Responsibility

(1) A QSE's Ancillary Service Supply Responsibility is the net amount of Ancillary Service capacity that the QSE is obligated to deliver to ERCOT, by hour and service type~~, from Resources represented by the QSE~~. The Ancillary Service Supply Responsibility is the difference in MW, by hour and service type, between the amounts specified in items (a) and (b) defined as follows:

(a) The sum of:

Board Report

(i) The QSE's Self-Arranged Ancillary Service Quantity; plus

(ii) The total (in MW) of Ancillary Service Trades for which the QSE is the seller; plus

(iii) Awards to the QSE of Ancillary Service Offers in the DAM; plus

(iv) Awards to the QSE of Ancillary Service Offers in the SASM; plus

(v) RUC-committed Ancillary Service quantities to the QSE from its Resources committed by the RUC process to provide Ancillary Service; and

(b) The sum of:

(i) The total Ancillary Service Trades for which the QSE is the buyer; plus

(ii) The total Ancillary Service capacity identified as ~~to~~ the QSE's failure to provide, as described in Section 6.4.9.1.3, ~~Replacement of Ancillary Service Due to~~ Failure to Provide Ancillary Service; plus

(iii) The total Ancillary Service capacity identified as the QSE's infeasible Ancillary Service, as described in Section 6.4.9.1.2, Replacement of Infeasible Ancillary Service Due to Transmission Constraints; plus

(iv) The total Ancillary Service capacity identified as the QSE's reconfiguration amount, as described in Section 6.4.9.2, Supplemental Ancillary Services Market.

(2) A QSE may only use a RUC-committed Resource during that Resource's RUC-Committed Interval to meet the QSE's Ancillary Service Supply Responsibility if the Resource has been committed by the RUC process to provide Ancillary Service. The QSE shall only provide from the RUC-committed Resource the exact amount and type of Ancillary Service for which it was committed by RUC.

(3) By 1430 in the Day-Ahead, the QSE must notify ERCOT, in the QSE's COP, which Resources represented by the QSE will provide the Ancillary Service capacity necessary to meet the QSE's Ancillary Service Supply Responsibility, specified by Resource, hour, and service type. The DAM Ancillary Service awards are Resource-specific; the QSE must include those DAM awards in its COP, and the QSE may not change that Resource-specific DAM award information until after 1600 under the conditions set out in Section 3.9, Current Operating Plan (COP).

(4) Section 6.4.9.1.3 specifies what happens if the QSE fails ~~on~~to provide its Ancillary Service Supply Responsibility.

(5) A QSE's Ancillary Service Supply Responsibility must be met by identified Resources that are qualified to provide the Ancillary Service, per Section 8.1.1.2.1 Ancillary Service

Board Report

Technical Requirements and Qualification Criteria and Test Methods, and available to act on Dispatch Instructions.

6.3.2 Activities for Real-Time Operations

(1) Activities for Real-Time operations begin at the end of the Adjustment Period and conclude at the close of the Operating Hour.

(2) The following table summarizes the timeline for the Operating Period and the activities of QSEs and ERCOT during Real-Time operations where "T" represents any instant within the Operating Hour. The table is intended to be only a general guide and not controlling language, and any conflict between this table and another section of the Protocols is controlled by the other section:

Operating Period	**QSE Activities**	**ERCOT Activities**
During the first hour of the Operating Period		Execute the Hour-Ahead Sequence, including HRUC, beginning with the second hour of the Operating Period Review the list of Off-Line Available Resources with a start-up time of one hour or less Review and communicate HRUC commitments and Direct Current Tie (DC Tie) Schedule curtailments Snapshot the Scheduled Power Consumption for Controllable Load Resources
Before the start of each SCED run	Update Output Schedules for DSRs	Validate Output Schedules for DSRs Execute Real-Time Sequence
SCED run		Execute SCED and pricing run to determine impact of reliability deployments on energy prices
During the Operating Hour	Telemeter the Ancillary Service Resource Responsibility for each Resource Acknowledge receipt of Dispatch Instructions Comply with Dispatch Instruction Review Resource Status to assure current state of the Resources is properly telemetered Update COP with actual Resource Status and limits and Ancillary Service Schedules	Communicate all binding Base Points, Dispatch Instructions, and the sum of each type of available reserves, including total Real-Time reserve amount for On-Line reserves, total Real-Time reserve amount for Off-Line reserves, Real-Time Reserve Price Adders for On-Line Reserves, and Real-Time Reserve Price Adders for Off-Line Reserves and LMPs for energy and Ancillary Services, and for the pricing run as described in Section 6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder, the total Reliability Unit Commitment (RUC)/Reliability Must-Run (RMR) MW relaxed, total Load Resource MW deployed

Board Report

Operating Period	QSE Activities	ERCOT Activities
	Communicate Resource Forced Outages to ERCOT Communicate to ERCOT Resource changes to Ancillary Service Resource Responsibility via telemetry in the time window beginning 30 seconds prior to the five-minute clock interval and ending ten seconds prior to that five-minute clock interval	that is added to the Demand, total Emergency Response Service (ERS) MW deployed that is added to the Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total Block Load Transfer (BLT) MW that is added to or subtracted from the Demand, total Low Ancillary Service Limit (LASL), total High Ancillary Service Limit (HASL), Real-Time On-Line Reliability Deployment Price Adder using Inter-Control Center Communications Protocol (ICCP) or Verbal Dispatch Instructions (VDIs) Monitor Resource Status and identify discrepancies between COP and telemetered Resource Status Restart Real-Time Sequence on major change of Resource or Transmission Element Status Monitor ERCOT total system capacity providing Ancillary Services Validate COP information Validate Ancillary Service Trades Monitor ERCOT control performance Distribute by ICCP, and post on the ERCOT website, System Lambda and the LMPs for each Resource Node, Load Zone and Hub, and the sum of each type of available reserves, including total Real-Time reserve amount for On-Line reserves, total Real-Time reserve amount for Off-Line reserves, Real-Time Reserve Price Adders for On-Line Reserves and Real-Time Reserve Price Adders for Off-Line Reserves, and for the pricing run as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to the Demand, total ERS MW deployed that is added to the Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total On-Line LASL, total On-Line HASL, Real-Time On-Line Reliability Deployment Price Adder created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points

Board Report

Operating Period	QSE Activities	ERCOT Activities
		from SCED with the time stamp the prices are effective Post on the ERCOT website the nodal prices for Settlement Only Distribution Generators (SODGs) and Settlement Only Transmission Generator (SOTGs). These prices shall include all Real-Time Reserve Price Adders for On-Line Reserves and Real-Time On-Line Reliability Deployment Price Adders created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points from SCED with the time stamp the prices are effective Post LMPs for each Electrical Bus on the ERCOT website. These prices shall be posted immediately subsequent to deployment of Base Points from each binding SCED with the time stamp the prices are effective Post on the ERCOT website the projected non-binding LMPs created by each SCED process for each Resource Node, the projected total Real-Time reserve amount for On-Line reserves and Off-Line reserves, the projected Real-Time On-Line Reserve Price Adders and Real-Time Off-Line Reserve Price Adders, and for the projected non-binding pricing runs as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total ERS MW deployed that are deployed that is added to the Demand, total LASL, total HASL, Real-Time On-Line Reliability Deployment Price Adder and the projected Hub LMPs and Load Zone LMPs. These projected prices shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections Post on the MIS Certified Area the projected non-binding Base Points for each Resource created by each SCED process. These projected non-binding Base Points shall be posted at a frequency of every five minutes

Board Report

Operating Period	QSE Activities	ERCOT Activities
		from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections Post each hour on the ERCOT website binding SCED Shadow Prices and active binding transmission constraints by Transmission Element name (contingency /overloaded element pairs) Post on the ERCOT website the Settlement Point Prices for each Settlement Point and the Real-Time price for each SODG and SOTG immediately following the end of each Settlement Interval Post the Real-Time On-Line Reliability Deployment Price, Real-Time Reserve Price for On-Line Reserves and the Real-Time Reserve Price for Off-Line Reserves immediately following the end of each Settlement Interval Post parameters as required by Section 6.4.9, Ancillary Services Capacity During the Adjustment Period and in Real-Time, on the ERCOT website

[NPRR829, NPRR904, NPRR995, NPRR1000, NPRR1006, NPRR1010, NPRR1058, and NPRR1077: Replace applicable portions of paragraph (2) above with the following upon system implementation for NPRR829, NPRR904, NPRR995, NPRR1000, NPRR1006, NPRR1058, or NPRR1077; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

(2) The following table summarizes the timeline for the Operating Period and the activities of QSEs and ERCOT during Real-Time operations where "T" represents any instant within the Operating Hour. The table is intended to be only a general guide and not controlling language, and any conflict between this table and another section of the Protocols is controlled by the other section:

Board Report

Operating Period	QSE Activities	ERCOT Activities
During the first hour of the Operating Period		Execute the Hour-Ahead Sequence, including HRUC, beginning with the second hour of the Operating Period Review the list of Off-Line Available Resources with a start-up time of one hour or less Review and communicate HRUC commitments and Direct Current Tie (DC Tie) Schedule curtailments Snapshot the Scheduled Power Consumption for Controllable Load Resources
SCED run		Execute SCED and pricing run to determine impact of reliability deployments on energy and Ancillary Service prices
During the Operating Hour	Acknowledge receipt of Dispatch Instructions Comply with Dispatch Instruction Review Resource Status to assure current state of the Resources is properly telemetered Update COP and telemetry with actual Resource Status and limits and Ancillary Service capabilities Submit and update Ancillary Service Offers Communicate Resource Forced Outages to ERCOT Submit and update Energy Offer Curves and/or RTM Energy Bids	Communicate all binding Base Points, Updated Desired Set Points (UDSPs), Ancillary Service awards, Dispatch Instructions, LMPs for energy, Real-Time MCPCs for Ancillary Services, and for the pricing run as described in Section 6.5.7.3.1, Determination of Real-Time Reliability Deployment Price Adders, the total Reliability Unit Commitment (RUC)/Reliability Must-Run (RMR) MW relaxed, total Load Resource MW deployed that is added to the Demand, total Transmission and/or Distribution Service Provider (TDSP) standard offer Load management MW deployed that is added to the Demand, total Emergency Response Service (ERS) MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total Block Load Transfer (BLT) MW that is added to or subtracted from the Demand Real-Time Reliability Deployment Price Adder for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service using Inter-Control Center Communications Protocol (ICCP) or Verbal Dispatch Instructions (VDIs). In communicating Ancillary Service awards, the awards shall be broken out by Ancillary Service sub-type, where applicable Monitor Resource Status and identify discrepancies between COP and telemetered Resource Status

Board Report

		Restart Real-Time Sequence on major change of Resource or Transmission Element Status Monitor ERCOT total system capacity providing Ancillary Services Validate COP information Validate Ancillary Service Trades Monitor ERCOT control performance Distribute by ICCP, and post on the ERCOT website, System Lambda and the LMPs for each Resource Node, Load Zone and Hub, and Real-Time MCPCs for each Ancillary Service, and for the pricing run as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to the Demand, total ERS MW deployed that is added to the Demand, total TDSP standard offer Load management MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, Real-Time Reliability Deployment Price Adder for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points and Ancillary Service awards from SCED with the time stamp the prices are effective Post on the ERCOT website the nodal prices for Settlement Only Distribution Generators (SODGs), Settlement Only Distribution Energy Storage Systems (SODESSs), Settlement Only Transmission Generators (SOTGs), and Settlement Only Transmission Energy Storage Systems (SOTESSs). These prices shall include Real-Time Reliability Deployment Price Adders for Energy created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points from SCED with the time stamp the prices are effective Post LMPs for each Electrical Bus on the ERCOT website. These prices shall be posted immediately subsequent to

Board Report

		deployment of Base Points from each binding SCED with the time stamp the prices are effective Post every 15 minutes on the ERCOT website the aggregate net injection from Settlement Only Generators (SOGs) and Settlement Only Energy Storage Systems (SOESSs) Post on the ERCOT website the projected non-binding LMPs for each Resource Node and Real-Time MCPCs for each Ancillary Service created by each SCED process and for the projected non-binding pricing runs as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to Demand, total TDSP standard offer Load management MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total ERS MW deployed that are deployed that is added to the Demand, Real-Time Reliability Deployment Price Adder for Energy, Real-Time On-Line Reliability Deployment Price Adders for Ancillary Service, and the projected Hub LMPs and Load Zone LMPs. These projected prices shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections Post on the MIS Certified Area the projected non-binding Base Points and Ancillary Service awards for each Resource created by each SCED process. These projected non-binding Base Points shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections. In posting Ancillary Service awards, the awards shall be broken out by Ancillary Service sub-type, where applicable Post each hour on the ERCOT website binding SCED Shadow Prices and active binding transmission constraints by Transmission Element name (contingency /overloaded element pairs)

Board Report

		Post on the ERCOT website, the Settlement Point Prices for each Settlement Point and the Real-Time price for each SODG, SODESS, SOTG, and SOTESS immediately following the end of each Settlement Interval By Settlement Interval, post the 15-minute Real-Time Reliability Deployment Price for Energy, and the 15-minute Real-Time Reliability Deployment Price for Ancillary Service for each of the Ancillary Services

(3) At the beginning of each hour, ERCOT shall post on the ERCOT website the following information:

(a) Changes in ERCOT System conditions that could affect the security and dynamic transmission limits of the ERCOT System, including:

(i) Changes or expected changes, in the status of Transmission Facilities as recorded in the Outage Scheduler for the remaining hours of the current Operating Day and all hours of the next Operating Day; and

(ii) Any conditions such as adverse weather conditions as determined from the ERCOT-designated weather service;

(b) Updated system-wide Mid-Term Load Forecasts (MTLFs) for all forecast models available to ERCOT Operations, as well as an indicator for which forecast was in use by ERCOT at the time of publication;

(c) The quantities of RMR Services deployed by ERCOT for each previous hour of the current Operating Day; and

(d) Total ERCOT System Demand, from Real-Time operations, integrated over each Settlement Interval.

(4) No later than 0600, ERCOT shall post on the ERCOT website the actual system Load by Weather Zone, the actual system Load by Forecast Zone, and the actual system Load by Study Area for each hour of the previous Operating Day.

(5) ERCOT shall provide notification to the market and post on the ERCOT website Electrical Bus Load distribution factors and other information necessary to forecast Electrical Bus Loads. This report will be published when updates to the Load distribution factors are made. Private Use Network net Load will be redacted from this posting.

Board Report

[NPRR1010: Insert paragraphs (6) and (7) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(6) After every SCED run, ERCOT shall post to the ERCOT website the total capability of Resources available to provide the following Ancillary Service combinations, based on the Resource telemetry from the QSE and capped by the limits of the Resource, for the most recent SCED execution:

(a) Capacity to provide Reg-Up, irrespective of whether it is capable of providing any other Ancillary Service;

(b) Capacity to provide RRS, irrespective of whether it is capable of providing any other Ancillary Service;

(c) Capacity to provide ECRS, irrespective of whether it is capable of providing any other Ancillary Service;

(d) Capacity to provide Non-Spin, irrespective of whether it is capable of providing any other Ancillary Service;

(e) Capacity to provide Reg-Up, RRS, or both, irrespective of whether it is capable of providing ECRS or Non-Spin;

(f) Capacity to provide Reg-Up, RRS, ECRS, or any combination, irrespective of whether it is capable of providing Non-Spin;

(g) Capacity to provide Reg-Up, RRS, ECRS, Non-Spin, or any combination; and

(h) Capacity to provide Reg-Down.

(7) Each week, ERCOT shall post on the ERCOT website the historical SCED-interval data described in paragraph (6) above.

6.4.1 Capacity Trade, Energy Trade, Self-Schedule, and Ancillary Service Trades

(1) A detailed explanation of Capacity Trade criteria and validations performed by ERCOT is provided in Section 4.4.1, Capacity Trades. A Qualified Scheduling Entity (QSE) may submit and update Capacity Trades during the Adjustment Period.

(2) A detailed explanation of Energy Trade criteria and validations performed by ERCOT is provided in Section 4.4.2, Energy Trades. A QSE may submit and update Energy Trades during the Adjustment Period and through 1430 on the day following the Operating Day for Settlement.

Board Report

(3) A detailed explanation of Self-Schedule criteria and validations performed by ERCOT is provided in Section 4.4.3, Self-Schedules. A QSE may submit and update Self-Schedules during the Adjustment Period.

(4) A detailed explanation of Ancillary Service Trade criteria and validations performed by ERCOT is provided in Section 4.4.7.3, Ancillary Service Trades. A QSE may submit and update Ancillary Service Trades during the Adjustment Period and through the Operating Period for Settlement.

6.4.9.1.3 ~~Replacement of Ancillary Service Due to~~ Failure to Provide Ancillary Service

(1) ERCOT may procure Ancillary Services to replace those of a QSE that has failed ~~on~~to provide its Ancillary Services Supply Responsibility through a SASM, as described below in Section 6.4.9.2, Supplemental Ancillary Services Market.

(2) A QSE is considered to have failed ~~on~~to provide its Ancillary Services Supply Responsibility when ERCOT determines, in its sole discretion, that some or all of the QSE's ~~Resource-specific~~ Ancillary Service capacity will not be available in Real-Time, was not available during any interval for which the QSE had an Ancillary Service Supply Responsibility, or that the QSE assigned all or part of an Ancillary Service Supply Responsibility to a Resource that ~~has~~was not ~~been~~ qualified to provide that Ancillary Service. This Section does not apply to a failure to provide caused by events described in Section 6.4.9.1.2, Replacement of Infeasible Ancillary Service Due to Transmission Constraints.

(3~~2~~) Within a time frame acceptable to ERCOT, each affected QSE may either substitute capacity to meet its Ancillary Services Supply Responsibility or inform ERCOT that the Ancillary Services capacity needs to be replaced. If a QSE elects to substitute capacity, ERCOT shall determine the feasibility of the substitution. If the substitution is deemed infeasible by ERCOT or the QSE informs ERCOT that the Ancillary Services capacity needs to be replaced, then ERCOT shall procure, if in its sole discretion it finds that the service is still needed, the Ancillary Services capacity required under Section 6.4.9.2.

(4~~3~~) ERCOT shall charge each QSE that has failed ~~according to paragraph (1) on~~to provide its Ancillary Service Supply Responsibility, according to paragraph (2) above for a particular Ancillary Service for a specific hour, ~~as~~in the manner described in Section 6.7.3, Charges for a Failure to Provide Ancillary Service.

6.7.3 Charges for a Failure to Provide Ancillary Service ~~Capacity Replaced Due to Failure to Provide~~

(1) A charge to each QSE that fails ~~on~~to provide its Ancillary Service Supply Responsibility, whether or not a SASM is executed due to its failure to ~~supply~~provide, is calculated by service for a given Operating Hour, as follows: ~~calculated based on the greatest of the MCPC in the Day-Ahead Market (DAM) or any SASM for the same Operating Hour. Included in the failed quantity is the charge to each QSE that reduces its Ancillary Service Supply Responsibility by an RSASM, which is calculated based on the cleared~~

Board Report

~~MCPC associated with the RSASM. By service, the charge to each QSE for a given Operating Hour is calculated as follows:~~

(a) The total charge of failure on Ancillary Service Supply Responsibility for Reg-Up by QSE, if applicable:

$$\textbf{RUFQAMTQSETOT}_{q} = \textbf{RUFQAMT}_{q} + \textbf{RRUFQAMT}_{q}$$

Where:

$$\text{RUFQAMT}_{q} = \text{Max}(\cancel{\underset{m}{Max}(}\text{MCPCRU}_{m}), \text{AVGRTASIP}) * (\text{RUFQ}_{q} + \text{TRUFQ}_{q})$$

$$\text{RRUFQAMT}_{q} = \text{MCPCRU}_{rs} * \text{RRUFQ}_{q,\,rs}$$

$$\text{AVGRTASIP} = \sum_{i=1}^{4} (\text{RTRSVPOR}_{i} + \text{RTRDP}_{i}) / 4$$

Where for all Resources:

$$\text{TRUFQ}_{q} = \text{Max}\,([(\text{SARUQ}_{q} + \text{RUTRSQ}_{q} + \sum_{m} (\text{RTPCRU}_{q,\,m}) + \text{PCRU}_{q} + \text{RUCRUQ}_{q}) - (\text{RUTRPQ}_{q} + \text{RUFQ}_{q} + \text{RRUFQ}_{q,\,rs} + \text{RUINFQ}_{q})] - \sum_{r} \text{TELRUR}_{q,\,r},\ 0)$$

$$\text{SARUQ}_{q} = \text{DASARUQ}_{q} + \text{RTSARUQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RUFQAMTQSETOT_{q}	$	*Reg-Up Failure Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
RRUFQAMT_{q}	$	*Reconfiguration Reg-Up Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
RUFQAMT_{q}	$	*Reg-Up Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
MCPCRU_{m}	$/MW per hour	*Market Clearing Price for Capacity for Reg-Up by market*—The MCPC for Reg-Up in the market *m*, for the hour.
MCPCRU_{rs}	$/MW per hour	*Market Clearing Price for Capacity for Reg-Up by RSASM*—The MCPC for Reg-Up in the RSASM *rs*, for the hour.
RUFQ_{q}	MW	*Reg-Up Failure Quantity per QSE*—QSE *q* total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.

Field Code Changed

Field Code Changed

Board Report

RRUFQ $_{q, rs}$	MW	*Reconfiguration Reg-Up Failure Quantity per QSE*—QSE *q* total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
RTRDP $_{i}$	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
RTRSVPOR $_{i}$	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval *i*.
AVGRTASIP	$/MW per hour	*Average Real-Time Ancillary Service Imbalance Price*– The average of the sum of the Real-Time On-Line Reliability Deployment Price and the Real-Time Reserve Price for On-Line Reserves used in the calculation of Real Time Ancillary Service Imbalance Amount per Section 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge, for the Operating Hour.
SARUQ $_{q}$	MW	*Total Self-Arranged Reg-Up Quantity per QSE for all markets*—The sum of all self-arranged Reg-Up quantities submitted by QSE *q* for DAM and all SASMs.
RUTRSQ $_{q}$	MW	*Reg-Up Trade Sale per QSE* - QSE *q*'s total time-weighted average capacity Trade Sale for Reg-Up, for the hour. The time-weighted average value is rounded to 0.1 MW.
RTPCRU $_{q, m}$	MW	*Procured Capacity for Reg-Up by QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* (SASM or RSASM) to provide Reg-Up, for the hour.
PCRU $_{q}$	MW	*Procured Capacity for Reg-Up per QSE in DAM*—The total Reg-Up Service capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
RUCRUQ $_{q}$	MW	*RUC-committed for Reg-Up per QSE* – The total quantity of Reg-Up Service committed by the RUC Process for Resources represented by QSE *q*, for the hour
RUTRPQ $_{q}$	MW	*Reg-Up Trade Purchases per QSE* - QSE *q*'s total time-weighted average capacity Trade Purchase for Reg-Up, for the hour. The time-weighted average value is rounded to 0.1 MW.
RUINFQ $_{q}$	MW	*Reg-Up Infeasible Quantity per QSE* —QSE *q*'s total capacity associated with infeasible Ancillary Service Supply Responsibilities for Reg-Up, for the hour.
TELRUR $_{q, r}$	MW	*Telemetered Reg-Up Responsibility for the Resource* - The time-weighted average telemetered Reg-Up Ancillary Service Resource Responsibility for the Resource *r*, represented by QSE *q*, for the hour. The time-weighted average value is rounded to 0.1 MW.
DASARUQ $_{q}$	MW	*Day-Ahead Self-Arranged Reg-Up Quantity per QSE*—The self-arranged Reg-Up quantity submitted by QSE *q* before 1000 in the Day-Ahead.
RTSARUQ $_{q}$	MW	*Self-Arranged Reg-Up Quantity per QSE for all SASMs*—The sum of all self-arranged Reg-Up quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1, Self-Arranged Ancillary Service Quantities.
TRUFQ $_{q}$	MW	*Telemetered Reg-Up Failure Quantity per QSE*— Calculated failure quantity for QSE *q* by comparing its average telemetered Reg-Up Responsibility sum to its Ancillary Service Supply Responsibility for Reg-Up as calculated per paragraph (1) of Section 4.4.7.4, for the hour.
i	none	A 15-minute Settlement Interval within the Operating Hour.
rs	none	The RSASM for the given Operating Hour.

Board Report

m	none	The DAM, SASM, or RSASM for the given Operating Hour.
q	none	A QSE.
r	none	A Resource that is qualified to provide Reg-Up.

(b) The total charge of failure on Ancillary Service Supply Responsibility for Reg-Down by QSE, if applicable:

$$\textbf{RDFQAMTQSETOT}_{q} = \textbf{RDFQAMT}_{q} + \textbf{RRDFQAMT}_{q}$$

Where:

$$\text{RDFQAMT}_{q} = \text{Max}\left(\cancel{\underset{m}{Max}(}\text{MCPCRD}_{m}\cancel{)}, \text{AVGRTASIP}\right) * (\text{RDFQ}_{q} + \text{TRDFQ}_{q})$$

$$\text{RRDFQAMT}_{q} = \text{MCPCRD}_{rs} * \text{RRDFQ}_{q,\,rs}$$

$$\text{AVGRTASIP} = \sum_{i=1}^{4} (\text{RTRSVPOR}_{i} + \text{RTRDP}_{i}) / 4$$

Field Code Changed

Where for all Resources:

$$\text{TRDFQ}_{q} = \text{Max}\left([(\text{SARDQ}_{q} + \text{RDTRSQ}_{q} + \sum_{m} (\text{RTPCRD}_{q,\,m}) + \text{PCRD}_{q} + \text{RUCRDQ}_{q}) - (\text{RDTRPQ}_{q} + \text{RDFQ}_{q} + \text{RRDFQ}_{q} + \text{RDINFQ}_{q})] - \sum_{r} \text{TELRDR}_{q,\,r}, 0\right)$$

Field Code Changed

$$\text{SARDQ}_{q} = \text{DASARDQ}_{q} + \text{RTSARDQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RDFQAMTQSETOT_{q}	$	*Reg-Down Failure Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
RRDFQAMT_{q}	$	*Reconfiguration Reg-Down Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
RDFQAMT_{q}	$	*Reg-Down Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
MCPCRD_{m}	$/MW per hour	*Market Clearing Price for Capacity for Reg-Down by market*—The MCPC for Reg-Down in the market *m*, for the hour.
MCPCRD_{rs}	$/MW per hour	*Market Clearing Price for Capacity for Reg-Down by RSASM*—The MCPC for Reg-Down in the RSASM *rs*, for the hour.

Board Report

RDFQ $_q$	MW	*Reg-Down Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
RRDFQ $_{q, rs}$	MW	*Reconfiguration Reg-Down Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
RTRDP $_i$	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-time On-Line Reliability Deployment Price Adder.
RTRSVPOR $_i$	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval *i*.
AVGRTASIP	$/MW per hour	*Average Real-Time Ancillary Service Imbalance Price*—The average of the sum of the Real-Time On-Line Reliability Deployment Price and the Real-Time Reserve Price for On-Line Reserves used in the calculation of Real Time Ancillary Service Imbalance Amount per Section 6.7.5 for the Operating Hour.
SARDQ $_q$	MW	*Total Self-Arranged Reg-Down Quantity per QSE for all markets*—The sum of all self-arranged Reg-Down quantities submitted by QSE *q* for DAM and all SASMs.
RDTRSQ $_q$	MW	*Reg-Down Trade Sale per QSE*—QSE *q*'s total time-weighted average capacity Trade Sale for Reg-Down, for the hour. The time-weighted average value is rounded to 0.1 MW.
RTPCRD $_{q, m}$	MW	*Procured Capacity for Reg-Down by QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* (SASM or RSASM) to provide Reg-Down, for the hour.
PCRD $_q$	MW	*Procured Capacity for Reg-Down per QSE in DAM*—The total Reg-Down capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
RUCRDQ $_q$	MW	*RUC-committed for Reg-Down per QSE*—The total quantity of Reg-Down committed by the RUC Process for Resources represented by QSE *q*, for the hour.
RDTRPQ $_q$	MW	*Reg-Down Trade Purchases per QSE*—QSE *q*'s total time-weighted average capacity Trade Purchase for Reg-Down, for the hour. The time-weighted average value is rounded to 0.1 MW.
RDINFQ $_q$	MW	*Reg-Down Infeasible Quantity per QSE*—QSE *q*'s total capacity associated with infeasible Ancillary Service Supply Responsibilities for Reg-Down, for the hour.
TELRDR $_{q, r}$	MW	*Telemetered Reg-Down Responsibility for the Resource*—The time-weighted average telemetered Reg-Down Ancillary Service Resource Responsibility for the Resource *r* that is qualified to provide Reg-Down Ancillary Service, represented by QSE *q*, for the hour. The time-weighted average value is rounded to 0.1 MW.
DASARDQ $_q$	MW	*Day-Ahead Self-Arranged Reg-Down Quantity per QSE*—The self-arranged Reg-Down quantity submitted by QSE *q* before 1000 in the Day-Ahead.
RTSARDQ $_q$	MW	*Self-Arranged Reg-Down Quantity per QSE for all SASMs*—The sum of all self-arranged Reg-Down quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1, Self-Arranged Ancillary Service Quantities.
TRDFQ $_q$	MW	*Telemetered Reg-Down Failure Quantity per QSE*—Calculated failure quantity for QSE *q* by comparing its average telemetered Reg-Down Responsibility sum to its Ancillary Service Supply Responsibility for Reg-Down as calculated per paragraph (1) of Section 4.4.7.4, for the hour.
i	none	A 15-minute Settlement Interval within the Operating Hour.

Board Report

rs	none	The RSASM for the given Operating Hour.
m	none	The DAM, SASM, or RSASM for the given Operating Hour.
q	none	A QSE.
r	none	A Resource that is qualified to provide Reg-Down.

(c) The total charge of failure on Ancillary Service Supply Responsibility for RRS by QSE, if applicable:

$$\textbf{RRFQAMTQSETOT}_{q} = \textbf{RRFQAMT}_{q} + \textbf{RRRFQAMT}_{q}$$

Where:

$$\text{RRFQAMT}_{q} = \text{Max}(\cancel{\underset{m}{\text{Max}}(}\text{MCPCRR}_{m}\cancel{)}, \text{AVGRTASIP}) * (\text{RRFQ}_{q} + \text{TRRFQ}_{q})$$

$$\text{RRRFQAMT}_{q} = \text{MCPCRR}_{rs} * \text{RRRFQ}_{q,\,rs}$$

$$\text{AVGRTASIP} = \sum_{i=1}^{4} (\text{RTRSVPOR}_{i} + \text{RTRDP}_{i}) / 4$$

Field Code Changed

Where for all Resources:

$$\text{TRRFQ}_{q} = \text{Max}(\,[(\text{SARRQ}_{q} + \text{RRTRSQ}_{q} + \sum_{m} (\text{RTPCRR}_{q,\,m}) + \text{PCRR}_{q} + \text{RUCRRQ}_{q}) - (\text{RRTRPQ}_{q} + \text{RRFQ}_{q} + \text{RRRFQ}_{q} + \text{RRINFQ}_{q})] - \sum_{r} \text{TELRRSRC}_{q,\,r}, 0)$$

Field Code Changed

Where for Load Resources, other than Controllable Load Resources, during an RRS deployment event:

$\text{TELRRSRC}_{q,\,r} = \text{Min}(\text{NPF}_{q,\,r} - \text{LPC}_{q,\,r}, \text{TELRRSR}_{q,\,r})$ snapshot to be used will be from the time of deployment until 180 minutes after recall or if the time between a recall of Load Resources and a redeployment is less than 180 minutes, the snapshot to be used will be the time of the first deployment

Where for Load Resources, other than Controllable Load Resources, prior to an RRS deployment event:

$$\text{TELRRSRC}_{q,\,r} = \text{Min}(\text{NPF}_{q,\,r} - \text{LPC}_{q,\,r}, \text{TELRRSR}_{q,\,r})$$

$$\text{SARRQ}_{q} = \text{DASARRQ}_{q} + \text{RTSARRQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RRFQAMTQSETOT $_q$	$	*Responsive Reserve Failure Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with failures and reconfiguration

Board Report

		reductions on its Ancillary Service Supply Responsibility for RRS, for the hour.
RRRFQAMT $_{q}$	$	*Reconfiguration Responsive Reserve Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for RRS, for the hour.
RRFQAMT $_{q}$	$	*Responsive Reserve Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for RRS, for the hour.
MCPCRR $_{m}$	$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve per market*—The MCPC for RRS in the market *m*, for the hour.
MCPCRR $_{rs}$	$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve per RSASM*—The MCPC for RRS in the RSASM *rs*, for the hour.
RRFQ $_{q}$	MW	*Responsive Reserve Failure Quantity per QSE* - QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for RRS, for the hour.
RRRFQ $_{q, rs}$	MW	*Reconfiguration Responsive Reserve Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for RRS, for the hour.
RTRDP $_{i}$	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-time On-Line Reliability Deployment Price Adder.
RTRSVPOR $_{i}$	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval *i*.
AVGRTASIP	$/MW per hour	*Average Real-Time Ancillary Service Imbalance Price*—The average of the sum of the Real-Time On-Line Reliability Deployment Price and the Real-Time Reserve Price for On-Line Reserves used in the calculation of Real Time Ancillary Service Imbalance Amount per Section 6.7.5 for the Operating Hour.
SARRQ $_{q}$	MW	*Total Self-Arranged Responsive Reserve Quantity per QSE for all markets*—The sum of all self-arranged RRS quantities submitted by QSE *q* for DAM and all SASMs.
RRTRSQ $_{q}$	MW	*Responsive Reserve Trade Sale per QSE*—QSE *q*'s total time-weighted average capacity Trade Sale for RRS, for the hour. The time-weighted average value is rounded to 0.1 MW.
RTPCRR $_{q, m}$	MW	*Procured Capacity for Responsive Reserve per QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* (SASM or RSASM) to provide RRS, for the hour.
PCRR $_{q}$	MW	*Procured Capacity for Responsive Reserve per QSE in DAM*—The total RRS capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
RUCRRQ $_{q}$	MW	*RUC-committed for Responsive Reserve per QSE*—The total quantity of RRS committed by the RUC Process for Resources represented by QSE *q*, for the hour.
RRTRPQ $_{q}$	MW	*Responsive Reserve Trade Purchases per QSE*—QSE *q*'s total time-weighted average capacity Trade Purchase for RRS, for the hour. The time-weighted average value is rounded to 0.1 MW.

Board Report

$RRINFQ_{q}$	MW	*Responsive Reserve Infeasible Quantity per QSE*—QSE *q*'s total capacity associated with infeasible Ancillary Service Supply Responsibilities for RRS, for the hour.
$TELRRSR_{q,r}$	MW	*Telemetered Responsive Reserve Responsibility for the Resource*—The average time-weighted telemetered RRS Ancillary Service Resource Responsibility for the Resource *r*, represented by the QSE *q*, for the hour. The time-weighted average value is rounded to 0.1 MW.
$TELRRSRC_{q,r}$	MW	*Telemetered Responsive Reserve Responsibility for the Resource as Calculated*—The calculated comparison of the time-weighted average telemetered RRS Ancillary Service Resource Responsibility as compared to available capacity for the Resource *r*, represented by the QSE *q*, for the hour.
$NPF_{q,r}$	MW	*Non-Controllable Load Resource Net Power Consumption for the QSE*—The average NPF from Load Resource other than Controllable Load Resources *r*, represented by QSE *q*, for the hour.
$LPC_{q,r}$	MW	*Non-Controllable Load Resource Low Power Consumption for the QSE*—The average LPC from Load Resource other than Controllable Load Resources *r*, represented by QSE *q*, for the hour.
$DASARRQ_{q}$	MW	*Day-Ahead Self-Arranged Responsive Reserve Quantity per QSE*—The self-arranged RRS quantity submitted by QSE *q* before 1000 in the Day-Ahead.
$RTSARRQ_{q}$	MW	*Self-Arranged Responsive Reserve Quantity per QSE for all SASMs*—The sum of all self-arranged RRS quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1, Self-Arranged Ancillary Service Quantities.
$TRRFQ_{q}$	MW	*Telemetered Responsive Reserve Failure Quantity per QSE*—Calculated failure quantity for QSE q by comparing its average telemetered Responsive Reserve Responsibility sum to its Ancillary Service Supply Responsibility for RRS as calculated per paragraph (1) of Section 4.4.7.4, for the hour.
i	none	A 15-minute Settlement Interval within the Operating Hour.
rs	none	The RSASM for the given Operating Hour.
m	none	The DAM, SASM, or RSASM for the given Operating Hour.
q	none	A QSE.
r	none	A Resource that is qualified to provide RRS.

(d) The total charge of failure on Ancillary Service Supply Responsibility for Non-Spin by QSE, if applicable:

$$\textbf{NSFQAMTQSETOT}_{q} = \textbf{NSFQAMT}_{q} + \textbf{RNSFQAMT}_{q}$$

Where:

$$\text{NSFQAMT}_{q} = \text{Max}\,(\cancel{\underset{m}{Max}}(\text{MCPCNS}_{m}), \text{AVGRTASIP}) * (\text{NSFQ}_{q} + \text{TNSFQ}_{q})$$

$$\text{RNSFQAMT}_{q} = \text{MCPCNS}_{rs} * \text{RNSFQ}_{q,\,rs}$$

$$\text{AVGRTASIP} = \sum_{i=1}^{4} (\text{RTRSVPOR}_{i} + \text{RTRDP}_{i}) / 4$$

Where for all Resources:

Field Code Changed

Board Report

$$TNSFQ_{q} = Max([(SANSQ_{q} + NSTRSQ_{q} + \sum_{m} (RTPCNS_{q, m}) + PCNS_{q} + RUCNSQ_{q}) – (NSTRPQ_{q} + NSFQ_{q} + RNSFQ_{q} + NSINFQ_{q})] – \sum_{r} TELNSRC_{q, r}, 0)$$

Field Code Changed

Where for Load Resources, other than Controllable Load Resources, during a Non-Spin deployment event:

$TELNSRC_{q, r} = Min(NPF_{q, r} – LPC_{q, r} – TELECRRC_{q, r}, TELNSR_{q, r})$ snapshot to be used will be from the time of deployment until 180 minutes after recall or if the time between a recall of Load Resources and a redeployment is less than 180 minutes, the snapshot to be used will be the time of the first deployment

Where for Load Resources, other than Controllable Load Resources, prior to a Non-Spin deployment event:

$$TELNSRC_{q, r} = Min(NPF_{q, r} – LPC_{q, r} – TELECRRC_{q, r}, TELNSR_{q, r})$$

$$SANSQ_{q} = DASANSQ_{q} + RTSANSQ_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
NSFQAMTQSETOT $_{q}$	$	*Non-Spin Failure Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
RNSFQAMT $_{q}$	$	*Reconfiguration Non-Spin Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
NSFQAMT $_{q}$	$	*Non-Spin Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
MCPCNS $_{m}$	$/MW per hour	*Market Clearing Price for Capacity for Non-Spin by market*—The MCPC for Non-Spin in the market *m*, for the hour.
MCPCNS $_{rs}$	$/MW per hour	*Market Clearing Price for Capacity for Non-Spin by RSASM*—The MCPC for Non-Spin in the RSASM *rs*, for the hour.
NSFQ $_{q}$	MW	*Non-Spin Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
RNSFQ $_{q, rs}$	MW	*Reconfiguration Non-Spin Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
RTRDP $_{i}$	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-time On-Line Reliability Deployment Price Adder.

Board Report

RTRSVPOR $_{i}$	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval *i*.
AVGRTASIP	\$/MW per hour	*Average Real-Time Ancillary Service Imbalance Price*—The average of the sum of the Real-Time On-Line Reliability Deployment Price and the Real-Time Reserve Price for On-Line Reserves used in the calculation of Real Time Ancillary Service Imbalance Amount per Section 6.7.5 for the Operating Hour.
SANSQ $_{q}$	MW	*Total Self-Arranged Non-Spin Quantity per QSE for all markets*—The sum of all self-arranged Non-Spin quantities submitted by QSE *q* for DAM and all SASMs.
NSTRSQ $_{q}$	MW	*Non-Spinning Reserve Trade Sale per QSE*—QSE *q*'s total time-weighted average capacity Trade Sale for Non-Spin, for the hour. The time-weighted average value is rounded to 0.1 MW.
RTPCNS $_{q, m}$	MW	*Procured Capacity for Non-Spin Reserve per QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* (SASM or RSASM) to provide Non-Spin, for the hour.
PCNS $_{q}$	MW	*Procured Capacity for Non-Spin Reserve per QSE in DAM*—The total Non-Spin capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
RUCNSQ $_{q}$	MW	*RUC-committed for Non-Spin Reserve per QSE*—The total quantity of Non-Spin committed by the RUC Process for Resources represented by QSE *q*, for the hour.
NSTRPQ $_{q}$	MW	*Non-Spin Reserve Trade Purchases per QSE*—QSE *q*'s total time-weighted average capacity Trade Purchase for Non-Spin, for the hour. The time-weighted average value is rounded to 0.1 MW.
NSINFQ $_{q}$	MW	*Non-Spin Reserve Infeasible Quantity per QSE*—QSE *q*'s total capacity associated with infeasible Ancillary Service Supply Responsibilities for Non-Spin, for the hour.
TELNSR $_{q, r}$	MW	*Telemetered Non-Spin Reserve Responsibility for the Resource*—The time-weighted average telemetered Non-Spin Ancillary Service Resource Responsibility for the Resource, for the hour. The time-weighted average value is rounded to 0.1 MW.
TELNSRC $_{q, r}$	MW	*Telemetered Non-Spin Reserve Responsibility for the Resource as Calculated*—The time-weighted average calculated telemetered Non-Spin Ancillary Service Resource Responsibility as compared to available capacity for the Resource, for the hour.
NPF $_{q, r}$	MW	*Non-Controllable Load Resource Net Power Consumption for the QSE*—The average NPF from Load Resource other than Controllable Load Resources *r*, represented by QSE *q*, for the hour.
LPC $_{q, r}$	MW	*Non-Controllable Load Resource Low Power Consumption for the QSE*—The average LPC from Load Resource other than Controllable Load Resources *r*, represented by QSE *q*, for the hour.
DASANSQ $_{q}$	MW	*Day-Ahead Self-Arranged Non-Spin Reserve Quantity per QSE*—The self-arranged Non-Spin quantity submitted by QSE *q* before 1000 in the Day-Ahead.
RTSANSQ $_{q}$	MW	*Self-Arranged Non-Spinning Reserve Quantity per QSE for all SASMs*—The sum of all self-arranged Non-Spin quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1, Self-Arranged Ancillary Service Quantities.
TELECRRC $_{q, r}$	MW	*Telemetered ERCOT Contingency Reserve Service Responsibility for the Resource as Calculated*—The time-weighted average telemetered ECRS Ancillary Service Resource Responsibility as compared to available capacity for the Resource *r*, represented by QSE *q*, for the hour.

Board Report

$TNSFQ_{q}$	MW	*Telemetered Non-Spin Failure Quantity per QSE*—Calculated failure quantity for QSE *q* by comparing its average telemetered Non-Spin Responsibility to its Ancillary Service Supply Responsibility for Non-Spin as calculated per paragraph (1) of Section 4.4.7.4, for the hour.
i	none	A 15-minute Settlement Interval within the Operating Hour.
rs	none	The RSASM for the given Operating Hour.
m	none	The DAM, SASM, or RSASM for the given Operating Hour.
q	none	A QSE.
r	none	A Resource that is qualified to provide Non-Spin.

[NPRR863: Insert paragraph (e) below upon system implementation:]

(e) The total charge of failure on Ancillary Service Supply Responsibility for ECRS by QSE, if applicable:

$$\mathbf{ECRFQAMTQSETOT}_{q} = \mathbf{ECRFQAMT}_{q} + \mathbf{RECRFQAMT}_{q}$$

Where:

$$ECRFQAMT_{q} = Max(\cancel{\underset{m}{Max}(}MCPCECR_{m}\cancel{)}, AVGRTASIP) * (ECRFQ_{q} + TECRFQ_{q})$$

$$RECRFQAMT_{q} = MCPCECR_{rs} * RECRFQ_{q, rs}$$

$$AVGRTASIP = \sum_{i=1}^{4} (RTRSVPOR_{i} + RTRDP_{i}) / 4$$

Where for all Resources:

$$TECRFQ_{q} = Max([(SAECRQ_{q} + ECRTRSQ_{q} + \sum_{m} (RTPCECR_{q, m}) + PCECR_{q} + RUCECRQ_{q}) - (ECRTRPQ_{q} + ECRFQ_{q} + RECRFQ_{q} + ECRINFQ_{q})] - \sum_{r} TELECRRC_{q, r}, 0)$$

Where for Load Resources, other than Controllable Load Resources, during an ECRS deployment event:

$TELECRRC_{q, r} = Min(NPF_{q, r} - LPC_{q, r}, TELECRR_{q, r})$ snapshot to be used will be from the time of deployment until 180 minutes after recall or if the time between a recall of Load Resources and a redeployment is less than 180 minutes, the snapshot to be used will be the time of the first deployment

Where for Load Resources, other than Controllable Load Resources, prior to an ECRS deployment event:

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Board Report

$$TELECRRC_{q,r} = Min(NPF_{q,r} – LPC_{q,r}, TELECRR_{q,r})$$

$$SAECRQ_{q} = DASAECRQ_{q} + RTSAECRQ_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
$ECRFQAMTQSETOT_{q}$	$	*ERCOT Contingency Reserve Service Failure Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for ECRS, for the hour.
$RECRFQAMT_{q}$	$	*Reconfiguration ERCOT Contingency Reserve Service Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for ECRS, for the hour.
$ECRFQAMT_{q}$	$	*ERCOT Contingency Reserve Service Failure Quantity Amount per QSE*—The charge to QSE *q* for its total capacity associated with failures on its Ancillary Service Supply Responsibility for ECRS, for the hour.
$RTRDP_{i}$	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-time On-Line Reliability Deployment Price Adder.
$RTRSVPOR_{i}$	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval *i*.
AVGRTASIP	$/MW per hour	*Average Real-Time Ancillary Service Imbalance Price*—The average of the sum of the Real-Time On-Line Reliability Deployment Price and the Real-Time Reserve Price for On-Line Reserves used in the calculation of Real Time Ancillary Service Imbalance Amount per Section 6.7.5 for the Operating Hour.
$SAECRQ_{q}$	MW	*Total Self-Arranged ERCOT Contingency Reserve Service Quantity per QSE for all markets*—The sum of all self-arranged ECRS quantities submitted by QSE *q* for DAM and all SASMs.
$ECRTRSQ_{q}$	MW	*ERCOT Contingency Reserve Service ~~Reserve~~ Trade Sale per QSE*—QSE *q's* total time-weighted average capacity Trade Sale for ECRS, for the hour. The time-weighted average value is rounded to 0.1 MW.
$RTPCECR_{q,m}$	MW	*Procured Capacity for ERCOT Contingency Reserve Service per QSE by market*—The MW portion of QSE *q's* Ancillary Service Offers cleared in the market m (SASM or RSASM) to provide ECRS, for the hour.
$PCECR_{q}$	MW	*Procured Capacity for ERCOT Contingency Reserve Service per QSE in DAM*—The total ECRS capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
$RUCECRQ_{q}$	MW	*RUC-committed for ERCOT Contingency Reserve Service per QSE*—The total quantity of ECRS committed by the RUC Process for Resources represented by QSE *q*, for the hour.
$ECRTRPQ_{q}$	MW	*ERCOT Contingency Reserve Service Trade Purchases per QSE*—QSE *q's* total time-weighted average capacity Trade Purchase for ECRS, for the hour. The time-weighted average value is rounded to 0.1 MW.
$ECRINFQ_{q}$	MW	*ERCOT Contingency Reserve Service Infeasible Quantity per QSE*—QSE *q's* total capacity associated with infeasible Ancillary Service Supply Responsibilities for ECRS, for the hour.

Board Report

TELECRR $_{q,r}$	MW	*Telemetered ERCOT Contingency Reserve Service Responsibility for the Resource*—The time-weighted average telemetered ECRS Ancillary Service Resource Responsibility for the Resource *r*, represented by QSE *q*, for the hour. The time-weighted average value is rounded to 0.1 MW.
TELECRRC $_{q,r}$	MW	*Telemetered ERCOT Contingency Reserve Service Responsibility for the Resource as Calculated*—The time-weighted average telemetered ECRS Ancillary Service Resource Responsibility as compared to available capacity for the Resource *r*, represented by QSE *q*, for the hour.
NPF $_{q,r}$	MW	*Non-Controllable Load Resource Net Power Consumption for the QSE*—The average NPF from Load Resource other than Controllable Load Resources *r*, represented by QSE *q*, for the hour.
LPC $_{q,r}$	MW	*Non-Controllable Load Resource Low Power Consumption for the QSE*—The average LPC from Load Resource other than Controllable Load Resources *r*, represented by QSE *q*, for the hour.
DASAECRQ $_{q}$	MW	*Day-Ahead Self-Arranged ERCOT Contingency Reserve Service Quantity per QSE*—The self-arranged ECRS quantity submitted by QSE *q* before 1000 in the Day-Ahead.
RTSAECRQ $_{q}$	MW	*Self-Arranged ERCOT Contingency Reserve Service Quantity per QSE for all SASMs*—The sum of all self-arranged ECRS quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1.
MCPCECR $_{m}$	$/MW per hour	*Market Clearing Price for Capacity for ERCOT Contingency Reserve Service per market*—The MCPC for ECRS in the market *m*, for the hour.
MCPCECR $_{rs}$	$/MW per hour	*Market Clearing Price for Capacity for ERCOT Contingency Reserve Service per RSASM*—The MCPC for ECRS in the RSASM *rs*, for the hour.
ECRFQ $_{q}$	MW	*ERCOT Contingency Reserve Service Failure Quantity per QSE* - QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for ECRS, for the hour.
RECRFQ $_{q,rs}$	MW	*Reconfiguration ERCOT Contingency Reserve Service Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for ECRS, for the hour.
TECRFQ $_{q}$	MW	*Telemetered ERCOT Contingency Reserve Service Failure Quantity per QSE*—Calculated failure quantity for QSE *q* by comparing its average telemetered ECRS Responsibility to its Ancillary Service Supply Responsibility for ECRS as calculated per paragraph (1) of Section 4.4.7.4, for the hour.
i	none	A 15-minute Settlement Interval within the Operating Hour.
rs	none	The RSASM for the given Operating Hour.
m	none	The DAM, SASM, or RSASM for the given Operating Hour.
q	none	A QSE.
r	none	A Resource that is qualified to provide ECRS.

Board Report

6.7.5 Real-Time Ancillary Service Imbalance Payment or Charge

(1) Based on the Real-Time On-Line Reliability Deployment Price Adders, Real-Time On-Line Reserve Price Adders and a Real-Time Off-Line Reserve Price Adders, ERCOT shall calculate Ancillary Service imbalance Settlement, which will make Resources indifferent to the utilization of their capacity for energy or Ancillary Service reserves, as set forth in this Section.

(2) The payment or charge to each QSE for Ancillary Service imbalance is calculated based on the price calculation set forth in paragraph (12) of Section 6.5.7.3, Security Constrained Economic Dispatch, and applied to the following amounts for each QSE:

(a) The amount of Real-Time Metered Generation from all Generation Resources, represented by the QSE for the 15-minute Settlement Interval;

[NPRR987: Replace paragraph (a) above with the following upon system implementation:]

(a) The amount of Real-Time Metered Generation from all Generation Resources and Energy Storage Resources (ESRs), represented by the QSE for the 15-minute Settlement Interval;

(b) The amount of On-Line capacity based on the telemetered High Sustained Limit (HSL) for all On-Line Generation Resources, the telemetered consumption from Load Resources with a validated Ancillary Service Schedule for RRS controlled by high-set under-frequency relay or Non-Spin, and the capacity from Controllable Load Resources available to SCED;

[NPRR863 and NPRR987: Replace applicable portions of paragraph (b) above with the following upon system implementation:]

(b) The amount of On-Line capacity based on the telemetered High Sustained Limit (HSL) for all On-Line Generation Resources and ESRs, the telemetered consumption from Load Resources with a validated Ancillary Service Schedule for ECRS or RRS controlled by high-set under-frequency relay or Non-Spin, and the capacity from Controllable Load Resources available to SCED, including capacity from modeled Controllable Load Resources associated with ESRs;

(c) The amount of Ancillary Service Resource Responsibility for Reg-Up, RRS and Non-Spin for ~~all Generation and Load Resources represented by~~ the QSE for the 15-minute Settlement Interval.

Board Report

[NPRR863 and NPRR987: Replace applicable portions of paragraph (c) above with the following upon system implementation:]

(c) The amount of Ancillary Service Resource Responsibility for Reg-Up, ECRS, RRS and Non-Spin for ~~all Generation Resources, ESRs, and Load Resources represented by~~ the QSE for the 15-minute Settlement Interval.

(3) Resources meeting one or more of the following conditions will be excluded from the amounts calculated pursuant to paragraphs (2)(a) and (b) above:

(a) Nuclear Resources;

(b) Resources with a telemetered ONTEST, STARTUP (except Resources with Non-Spin Ancillary Service Resource Responsibility greater than zero), or SHUTDOWN Resource Status excluding Resources telemetering both STARTUP Resource Status and greater than zero Non-Spin Ancillary Service Responsibility; or

[NPRR1085: Replace paragraph (b) above with the following upon system implementation:]

(b) Resources with a telemetered ONTEST, ONHOLD, STARTUP (except Resources with Non-Spin Ancillary Service Resource Responsibility greater than zero), or SHUTDOWN Resource Status excluding Resources telemetering both STARTUP Resource Status and greater than zero Non-Spin Ancillary Service Responsibility; or

(c) Resources with a telemetered net real power (in MW) less than 95% of their telemetered Low Sustained Limit (LSL) excluding Resources telemetering both STARTUP Resource Status and greater than zero Non-Spin Ancillary Service Responsibility.

[NPRR987: Replace paragraph (c) above with the following upon system implementation:]

(c) Resources with a telemetered net real power (in MW) less than 95% of their telemetered Low Sustained Limit (LSL) excluding the following:

(i) Resources telemetering both STARTUP Resource Status and greater than zero Non-Spin Ancillary Service Responsibility; or

(ii) ESRs.

Board Report

(4) Reliability Must-Run (RMR) Units and Reliability Unit Commitment (RUC) Resources On-Line during the hour due to an ERCOT instruction, except for any RUC Resource committed by a RUC Dispatch Instruction where that Resource's QSE subsequently opted out of RUC Settlement pursuant to paragraph (14) of Section 5.5.2, Reliability Unit Commitment (RUC) Process, those RUC Resources that had a Three-Part Supply Offer cleared in the DAM for the hour, or a Switchable Generation Resource (SWGR) released by a non-ERCOT Control Area Operator (CAO) to operate in the ERCOT Control Area due to an ERCOT RUC instruction for an actual or anticipated Energy Emergency Alert (EEA) condition, and any Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration to a different configuration with additional capacity, as described in paragraph (3) of Section 5.5.2, will be excluded from the amounts calculated for the 15-minute Settlement Interval pursuant to paragraphs (2)(a), (b), and (c) above.

[NPRR885 and NPRR1092: Replace applicable portions of paragraph (4) above with the following upon system implementation:]

(4) Reliability Must-Run (RMR) Units, and Must-Run Alternatives (MRAs), and Reliability Unit Commitment (RUC) Resources On-Line during the hour due to an ERCOT instruction will be excluded from the amounts calculated for the 15-minute Settlement Interval pursuant to paragraphs (2)(a), (b), and (c) above except for:

(a) Those RUC Resources that had a Three-Part Supply Offer cleared in the DAM for the hour;

(b) A Switchable Generation Resource (SWGR) released by a non-ERCOT Control Area Operator (CAO) to operate in the ERCOT Control Area due to an ERCOT RUC instruction for an actual or anticipated Energy Emergency Alert (EEA) condition;

(c) Any Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration to a different configuration with additional capacity, as described in paragraph (3) of Section 5.5.2, Reliability Unit Commitment (RUC) Process; or

(d) Any RUC Resource committed by a RUC Dispatch Instruction where that Resource's QSE subsequently opted out of RUC Settlement pursuant to paragraph (14) of Section 5.5.2.

(5) The Real-Time Off-Line Reserve Capacity for the QSE (RTOFFCAP) shall be administratively set to zero when the SCED snapshot of the Physical Responsive Capability (PRC) is less than or equal to the PRC MW at which EEA Level 1 is initiated.

(6) Resources that have a Under Generation Volume (UGEN) greater than zero, and are not-exempt from a Base Point Deviation Charge, as set forth in Section 6.6.5, Base Point Deviation Charge, or are not already excluded in paragraphs (3) or (4) above, for the 15-

Board Report

minute Settlement Interval will have the UGEN amounts removed from the amounts calculated pursuant to paragraphs (2)(a) and (b) above.

[NPRR987: Replace paragraph (6) above with the following upon system implementation:]

(6) Resources that have an Under Generation Volume (UGEN) or an Under Performance Volume (UPESR) greater than zero, and are not exempt from a Base Point Deviation Charge, as set forth in Section 6.6.5, Base Point Deviation Charge, or are not already excluded in paragraphs (3) or (4) above, for the 15-minute Settlement Interval will have the UGEN or UPESR amounts removed from the amounts calculated pursuant to paragraphs (2)(a) and (b) above.

(7) The payment or charge to each QSE for the Ancillary Service imbalance for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTASIAMT}_{q} = \mathbf{(-1) * [(RTASOLIMB}_{q}\mathbf{ * RTRSVPOR) + (RTASOFFIMB}_{q}\mathbf{ * RTRSVPOFF)]}$$

$$\mathbf{RTRDASIAMT}_{q} = \mathbf{(-1) * (RTASOLIMB}_{q}\mathbf{ * RTRDP)}$$

Where:

$$\text{RTASOLIMB}_{q} = \text{RTOLCAP}_{q} - [((\text{SYS\_GEN\_DISCFACTOR} * \text{RTASRESP}_{q}) * 1/4) - \text{RTASOFF}_{q} - \text{RTRUCNBBRESP}_{q} - \text{RTCLRNSRESP}_{q} - \text{RTNCLRNSRESP}_{q} - \text{RTRMRRESP}_{q}]$$

[NPRR1131: Replace the formula "RTASOLIMB $_{q}$" above with the following upon system implementation:]

$$\text{RTASOLIMB}_{q} = \text{RTOLCAP}_{q} - [((\text{SYS\_GEN\_DISCFACTOR} * \text{RTASRESP}_{q}) * 1/4) - \text{RTASOFF}_{q} - \text{RTRUCNBBRESP}_{q} - \text{RTNCLRNSRESP}_{q} - \text{RTRMRRESP}_{q}]$$

Where:

$$\text{RTASOFF}_{q} = \text{SYS\_GEN\_DISCFACTOR} * \sum_{r} \sum_{p} \text{RTASOFFR}_{q, r, p}$$

$$\text{RTRUCNBBRESP}_{q} = \text{SYS\_GEN\_DISCFACTOR} * \sum_{r} \text{RTRUCASA}_{q, r} * 1/4$$

$$\text{RTCLRNSRESP}_{q} = \text{SYS\_GEN\_DISCFACTOR} * \sum_{r} \sum_{p} \text{RTCLRNSRESPR}_{q, r, p}$$

Board Report

[NPRR1131: Delete the formula "RTCLRNSRESP $_q$" above upon system implementation.]

$$RTNCLRNSRESP_q = SYS\_GEN\_DISCFACTOR * \sum_r \sum_p RTNCLRNSRESPR_{q,r,p}$$

$$RTRMRRESP_q = SYS\_GEN\_DISCFACTOR * \sum_q \sum_r \sum_p (HRRADJ_{q,r,p} + HRUADJ_{q,r,p} + HNSADJ_{q,r,p}) * ¼$$

[NPRR863: Replace the formula "RTRMRRESP $_q$" above with the following upon system implementation:]

$$RTRMRRESP_q = SYS\_GEN\_DISCFACTOR * \sum_q \sum_r \sum_p (HRRADJ_{q,r,p} + HECRADJ_{q,r,p} + HRUADJ_{q,r,p} + HNSADJ_{q,r,p}) * ¼$$

$$RTOLCAP_q = (RTOLHSL_q - RTMGQ_q - SYS\_GEN\_DISCFACTOR * (\sum_r \sum_p UGENA_{q,r,p})) + RTCLRCAP_q + RTNCLRCAP_q$$

[NPRR987: Replace the formula "RTOLCAP $_q$" above with the following upon system implementation:]

$$RTOLCAP_q = (RTOLHSL_q - RTMGQ_q - SYS\_GEN\_DISCFACTOR * (\sum_r \sum_p (UGENA_{q,r,p} + UPESRA_{q,r,p}))) + RTCLRCAP_q + RTNCLRCAP_q + RTESRCAP_q$$

Where:

$$RTNCLRCAP_q = Min(Max(RTNCLRNPC_q - RTNCLRLPC_q, 0.0), RTNCLRRRS_q * 1.5)$$

[NPRR863: Replace the formula "RTNCLRCAP $_q$" above with the following upon system implementation:]

$$RTNCLRCAP_q = Min(Max(RTNCLRNPC_q - RTNCLRLPC_q, 0.0), (RTNCLRECRS_q + RTNCLRRRS_q) * 1.5)$$

$$RTNCLRRRS_q = SYS\_GEN\_DISCFACTOR * \sum_r \sum_p RTNCLRRRSR_{q,r,p}$$

Board Report

[NPRR863: Insert the formula "RTNCLRECRS $_q$" below upon system implementation:]

$$RTNCLRECRS_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTNCLRECRSR_{q, r, p}$$

$$RTNCLRNPC_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTNCLRNPCR_{q, r, p}$$

$$RTNCLRLPC_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTNCLRLPCR_{q, r, p}$$

$$RTOLHSL_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTOLHSLRA_{q, r, p}$$

$$RTMGQ_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTMGA_{q, r, p}$$

If $RTMGA_{q, r, p} > RTOLHSLRA_{q, r, p}$

Then $RTMGA_{q, r, p} = RTOLHSLRA_{q, r, p}$

[NPRR987: Insert the language below upon system implementation:]

Where for a Controllable Load Resource other than a modeled Controllable Load Resource associated with an Energy Storage Resource (ESR):

$$RTCLRCAP_{q} = RTCLRNPC_{q} - RTCLRLPC_{q} - RTCLRNS_{q} + RTCLRREG_{q}$$

[NPRR1131: Replace the formula "RTCLRCAP $_q$" above with the following upon system implementation:]

$$RTCLRCAP_{q} = RTCLRNPC_{q} - RTCLRLPC_{q} + RTCLRREG_{q}$$

$$RTCLRNPC_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTCLRNPCR_{\mathbf{q, r, p}}$$

$$RTCLRLPC_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTCLRLPCR_{\mathbf{q, r, p}}$$

$$RTCLRNS_{q} = SYS\_GEN\_DISCFACTOR * \sum_{r} \sum_{p} RTCLRNSR_{\mathbf{q, r, p}}$$

Board Report

[NPRR1131: Delete the formula "RTCLRNS $_q$" above upon system implementation.]

$$RTCLRREG_q = SYS\_GEN\_DISCFACTOR * \sum_r \sum_p RTCLRREGR_{q, r, p}$$

Where:

$$RTRSVPOR = \sum_y (RNWF_y * RTORPA_y)$$

$$RTASOFFIMB_q = RTOFFCAP_q – (RTASOFF_q + RTCLRNSRESP_q + RTNCLRNSRESP_q)$$

[NPRR1131: Replace the formula "RTASOFFIMB $_q$" above with the following upon system implementation:] $RTASOFFIMB_q = RTOFFCAP_q – (RTASOFF_q + RTNCLRNSRESP_q)$

$$RTOFFCAP_q = (SYS\_GEN\_DISCFACTOR * RTCST30HSL_q) + (SYS\_GEN\_DISCFACTOR * RTOFFNSHSL_q) + RTCLRNS_q + RTNCLRNSCAP_q$$

[NPRR1131: Replace the formula "RTOFFCAP $_q$" above with the following upon system implementation:] $RTOFFCAP_q = (SYS\_GEN\_DISCFACTOR * RTCST30HSL_q) + (SYS\_GEN\_DISCFACTOR * RTOFFNSHSL_q) + RTNCLRNSCAP_q$

$$RTNCLRNSCAP_q = Min(Max(RTNCLRNPC_q – RTNCLRLPC_q, 0.0), RTNCLRNS_q * 1.5)$$

$$RTNCLRNS_q = SYS\_GEN\_DISCFACTOR * \sum_r \sum_p RTNCLRNSR_{q, r, p}$$

$$RTRSVPOFF = \sum_y (RNWF_y * RTOFFPA_y)$$

$$RTRDP = \sum_y (RNWF_y * RTORDPA_y)$$

$$RNWF_y = TLMP_y / \sum_y TLMP_y$$

Board Report

[NPRR987: Insert the language below upon system implementation:]

Where for an ESR:

$$RTESRCAP_{q} = \sum_{g} (RTESRCAPR_{q, g, p})$$

Where:

$$RTESRCAPR_{q, g, p} = \text{Min}[(RTOLHSLRA_{q, r, p} - RTMGA_{q, r, p} + RTCLRNPCR_{q, r, p}), (RTCLRNPCR_{q, r, p} + SOCT_{q, r} - SOCOM_{q, r})]$$

The above variables are defined as follows:

Variable	**Unit**	**Description**
$RTASIAMT_{q}$	$	*Real-Time Ancillary Service Imbalance Amount*—The total payment or charge to QSE *q* for the Real-Time Ancillary Service imbalance associated with Operating Reserve Demand Curve (ORDC) for each 15-minute Settlement Interval.
$RTRDASIAMT_{q}$	$	*Real-Time Reliability Deployment Ancillary Service Imbalance Amount*—The total payment or charge to QSE *q* for the Real-Time Ancillary Service imbalance associated with Reliability Deployments for each 15-minute Settlement Interval.
$RTASOLIMB_{q}$	MWh	*Real-Time Ancillary Service On-Line Reserve Imbalance for the QSE* —The Real-Time Ancillary Service On-Line reserve imbalance for the QSE *q*, for each 15-minute Settlement Interval.
$RTORPA_{y}$	$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time Price Adder for On-Line Reserves for the SCED interval *y*.
$RTOFFPA_{y}$	$/MWh	*Real-Time Off-Line Reserve Price Adder per interval*—The Real-Time Price Adder for Off-Line Reserves for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
$RTORDPA_{y}$	$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the 15-minute Settlement Interval.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTRSVPOFF	$/MWh	*Real-Time Reserve Price for Off-Line Reserves*—The Real-Time Reserve Price for Off-Line Reserves for the 15-minute Settlement Interval.
$RTOLCAP_{q}$	MWh	*Real-Time On-Line Reserve Capacity for the QSE*—The Real-Time reserve capacity of On-Line Resources available for the QSE *q*, for the 15-minute Settlement Interval.

Board Report

Variable	Unit	Description
$RTOLHSLRA_{q, r, p}$	MWh	*Real-Time Adjusted On-Line High Sustained Limit for the Resource*—The Real-Time telemetered HSL for the Resource *r* represented by QSE *q* at Resource Node *p* that is available to SCED, integrated over the 15-minute Settlement Interval, and adjusted pursuant to paragraphs (3) and (4) above.
$RTOLHSL_{q}$	MWh	*Real-Time On-Line High Sustained Limit for the QSE*—The Real-Time telemetered HSL for all Generation Resources available to SCED, pursuant to paragraphs (3) and (4) above, integrated over the 15-minute Settlement Interval for the QSE *q*, discounted by the system-wide discount factor. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time On-Line High Sustained Limit for the QSE*—The integrated Real-Time telemetered HSL for all Generation Resources, not including modeled Generation Resources associated with ESRs, available to SCED, pursuant to paragraphs (3) and (4) above, integrated over the 15-minute Settlement Interval for the QSE *q*, discounted by the system-wide discount factor.
$RTASRESP_{q}$	MW	*Real-Time Ancillary Service Supply Responsibility for the QSE*—The Real-Time Ancillary Service Supply Responsibility for Reg-Up, RRS and Non-Spin pursuant to Section 4.4.7.4, Ancillary Service Supply Responsibility, ~~for all Generation and Load Resources~~ for the QSE *q*, for the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Ancillary Service Supply Responsibility for the QSE*—The Real-Time Ancillary Service Supply Responsibility for Reg-Up, ECRS, RRS and Non-Spin pursuant to Section 4.4.7.4, Ancillary Service Supply Responsibility, ~~for all Generation and Load Resources~~ for the QSE *q*, for the 15-minute Settlement Interval.
$RTCLRCAP_{q}$	MWh	*Real-Time Capacity from Controllable Load Resources for the QSE*—The Real-Time capacity and Reg-Up minus Non-Spin available from all Controllable Load Resources available to SCED for the QSE *q*, integrated over the 15-minute Settlement Interval. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Capacity from Controllable Load Resources for the QSE*—The Real-Time capacity and Reg-Up minus Non-Spin available from all Controllable Load Resources, not including modeled Controllable Load Resources associated with ESRs available to SCED for the QSE *q*, integrated over the 15-minute Settlement Interval.

Board Report

Variable	Unit	Description
$RTNCLRCAP_{q}$	MWh	*Real-Time Capacity from Non-Controllable Load Resources carrying Responsive Reserve for the QSE*—The Real-Time capacity for all Load Resources other than Controllable Load Resources that have a validated Real-Time RRS Ancillary Service Schedule for the QSE *q*, integrated over the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Capacity from Non-Controllable Load Resources carrying ERCOT Contingency Reserve or Responsive Reserve for the QSE*—The Real-Time capacity for all Load Resources other than Controllable Load Resources that have a validated Real-Time ECRS or RRS Ancillary Service Schedule for the QSE *q*, integrated over the 15-minute Settlement Interval.
$RTNCLRRRS_{q}$	MWh	*Real-Time Non-Controllable Load Resources Responsive Reserve for the QSE*—The validated Real-Time telemetered RRS Ancillary Service Supply Responsibility for all Load Resources other than Controllable Load Resources for QSE *q* discounted by the system-wide discount factor, integrated over the 15-minute Settlement Interval.
$RTNCLRRRSR_{q, r, p}$	MWh	*Real-Time Non-Controllable Load Resource Responsive Reserve*—The validated Real-Time telemetered RRS Ancillary Service Resource Responsibility for the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval.

[NPRR863: Insert the variables "$RTNCLRECRS_{q}$" and "$RTNCLRECRSR_{q, r, p}$" below upon system implementation:]

$RTNCLRECRS_{q}$	MWh	*Real-Time Non-Controllable Load Resources ERCOT Contingency Reserve for the QSE*—The validated Real-Time telemetered ECRS Ancillary Service Supply Responsibility for all Load Resources other than Controllable Load Resources for QSE *q* discounted by the system-wide discount factor, integrated over the 15-minute Settlement Interval.
$RTNCLRECRSR_{q, r, p}$	MWh	*Real-Time Non-Controllable Load Resource ERCOT Contingency Reserve* —The validated Real-Time telemetered ECRS Ancillary Service Resource Responsibility for the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval.

Board Report

Variable	Unit	Description
$RTNCLRNPCR_{q, r, p}$	MWh	*Real-Time Non-Controllable Load Resource Net Power Consumption*—The Real-Time net real power consumption from the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p* that has a validated Real-Time RRS or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Controllable Load Resource Net Power Consumption*—The Real-Time net real power consumption from the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p* that has a validated Real-Time ECRS, RRS, or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval.
$RTNCLRLPCR_{q, r, p}$	MWh	*Real-Time Non-Controllable Load Resource Low Power Consumption*—The Real-Time Low Power Consumption (LPC) from the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p* that has a validated Real-Time RRS or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Controllable Load Resource Low Power Consumption*—The Real-Time Low Power Consumption (LPC) from the Load Resource *r* (which is not a Controllable Load Resource) represented by QSE *q* at Resource Node *p* that has a validated Real-Time ECRS, RRS, or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval
$RTNCLRNPC_{q}$	MWh	*Real-Time Non-Controllable Load Resource Net Power Consumption for the QSE*—The Real-Time net real power consumption from all Load Resources other than Controllable Load Resources for QSE *q* that have a validated Real-Time RRS or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Controllable Load Resource Net Power Consumption for the QSE*—The Real-Time net real power consumption from all Load Resources other than Controllable Load Resources for QSE *q* that have a validated Real-Time ECRS, RRS, or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor.

Board Report

Variable	Unit	Description
RTNCLRLPC $_{q}$	MWh	*Real-Time Non-Controllable Load Resource Low Power Consumption for the QSE*—The Real-Time LPC from all Load Resources other than Controllable Load Resources for QSE *q* that have a validated Real-Time RRS or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Controllable Load Resource Low Power Consumption for the QSE*—The Real-Time LPC from all Load Resources other than Controllable Load Resources for QSE *q* that have a validated Real-Time ECRS, RRS, or Non-Spin Ancillary Service Schedule integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor.
RTNCLRNSCAP $_{q}$	MWh	*Real-Time Capacity from Non-Controllable Load Resources carrying Non-Spin for the QSE*—The Real-Time capacity for all Load Resources that are not Controllable Load Resources and that have a validated Real-Time Non-Spin Ancillary Service Schedule for the QSE *q*, integrated over the 15-minute Settlement Interval.
RTNCLRNSR $_{q, r, p}$	MWh	*Real-Time Non-Spin Schedule for the Non-Controllable Load Resource* —The validated Real-Time telemetered Non-Spin Ancillary Service Schedule for the Load Resource *r* that is not a Controllable Load Resources represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval.
RTNCLRNS $_{q}$	MWh	*Real-Time Non-Spin Schedule for Non-Controllable Load Resources for the QSE*—The Real-Time telemetered Non-Spin Ancillary Service Schedule for all Load Resources that are not Controllable Load Resources for the QSE *q*, integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor.
RTNCLRNSRESP $_{q}$	MWh	*Real-Time Non-Controllable Load Resource Non-Spin Responsibility for the QSE*—The Real Time telemetered Non-Spin Ancillary Service Supply Responsibility for all Load Resources that are not Controllable Load Resources discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval.
RTNCLRNSRESPR $_{q, r, p}$	MWh	*Real-Time Non-Controllable Load Resource Non-Spin Responsibility for the Resource*—The Real-Time telemetered Non-Spin Ancillary Service Resource Responsibility for the Load Resource *r* that is not a Controllable Load Resource represented by QSE *q* at Resource Node *p* integrated over the 15-minute Settlement Interval.

Board Report

Variable	Unit	Description
RTCLRNPCR $_{q,\ r,\ p}$	MWh	*Real-Time Net Power Consumption from the Controllable Load Resource*—The Real-Time net real power consumption from the Controllable Load Resource *r* represented by QSE *q* at Resource Node *p* available to SCED integrated over the 15-minute Settlement Interval. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Net Power Consumption from the Controllable Load Resource*—The Real-Time net real power consumption from the Controllable Load Resource or modeled Controllable Load Resource associated with an ESR, *r* represented by QSE *q* at Resource Node *p* available to SCED integrated over the 15-minute Settlement Interval.
RTCLRNPC $_{q}$	MWh	*Real-Time Net Power Consumption from Controllable Load Resources for the QSE*—The Real-Time net real power consumption from all Controllable Load Resources available to SCED integrated over the 15-minute Settlement Interval for the QSE *q* discounted by the system-wide discount factor. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Net Power Consumption from Controllable Load Resources for the QSE*—The Real-Time net real power consumption from all Controllable Load Resources, not including modeled Controllable Load Resources associated with ESRs, available to SCED integrated over the 15-minute Settlement Interval for the QSE *q* discounted by the system-wide discount factor.
RTCLRLPCR $_{q,\ r,\ p}$	MWh	*Real-Time Low Power Consumption for the Controllable Load Resource*—The Real-Time LPC from the Controllable Load Resource *r* represented by QSE *q* at Resource Node *p* available to SCED integrated over the 15-minute Settlement Interval. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Low Power Consumption for the Controllable Load Resource*—The Real-Time LPC from the Controllable Load Resource or modeled Controllable Load Resource associated with an ESR, *r* represented by QSE *q* at Resource Node *p* available to SCED integrated over the 15-minute Settlement Interval.

Board Report

Variable	Unit	Description
$RTCLRLPC_{q}$	MWh	*Real-Time Low Power Consumption from Controllable Load Resources for the QSE*—The Real-Time LPC from Controllable Load Resources available to SCED integrated over the 15-minute Settlement Interval for the QSE *q* discounted by the system-wide discount factor. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Low Power Consumption from Controllable Load Resources for the QSE*—The Real-Time LPC from Controllable Load Resources, not including modeled Controllable Load Resources associated with ESRs, available to SCED integrated over the 15-minute Settlement Interval for the QSE *q* discounted by the system-wide discount factor.
$RTCLRREG_{q}$	MWh	*Real-Time Controllable Load Resources Regulation-Up Schedule for the QSE*—The Real-Time Reg-Up Ancillary Service Schedule from all Controllable Load Resources not available to SCED with Primary Frequency Response for the QSE *q*, integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor.
$RTCLRREGR_{q, r, p}$	MWh	*Real-Time Controllable Load Resource Regulation-Up Schedule for the Resource*—The validated Real-Time Reg-Up Ancillary Service Schedule for the Controllable Load Resource not available to SCED *r* represented by QSE *q* at Resource Node *p* with Primary Frequency Response, integrated over the 15-minute Settlement Interval.
$RTMGA_{q, r, p}$	MWh	*Real-Time Adjusted Metered Generation per QSE per Settlement Point per Resource*—The adjusted metered generation, pursuant to paragraphs (3) and (4) above, of Generation Resource *r* represented by QSE *q* at Resource Node *p* in Real-Time for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$RTMGQ_{q}$	MWh	*Real-Time Metered Generation per QSE*—The metered generation, discounted by the system-wide discount factor, of all generation Resources represented by QSE *q* in Real-Time for the 15-minute Settlement Interval, pursuant to paragraphs (3) and (4) above. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Metered Generation per QSE*—The metered generation, discounted by the system-wide discount factor, of all Generation Resources, not including modeled Generation Resources associated with ESRs, represented by QSE *q* in Real-Time for the 15-minute Settlement Interval, pursuant to paragraphs (3) and (4) above.

Board Report

Variable	Unit	Description
[NPRR987: Insert the variables "$RTESRCAPR_{q, g, p}$", "$RTESRCAP_{q}$", "$SOCT_{q, r}$", and "$SOCOM_{q, r}$" below upon system implementation:]		
$RTESRCAPR_{q, g, p}$	MWh	*Real-Time Capacity from an Energy Storage Resource* – Capacity provided by an ESR *g*, represented by QSE *q* at Resource Node *p,* which considers energy limitations of the ESR and potentially higher contribution when charging for the15-minute Settlement Interval.
$RTESRCAP_{q}$	MWh	*Real-Time Capacity from Energy Storage Resources per QSE* – Capacity provided by all ESRs, represented by QSE *q*, for the 15-minute Settlement Interval.
$SOCT_{q, r}$	MWh	*State of Charge Telemetered by an Energy Storage Resource* – The average telemetered state of charge of Resource *r*, represented by QSE *q*, over the 15-minute Settlement Interval.
$SOCOM_{q, r}$	MWh	*State of Charge Operating Minimum for an Energy Storage Resource* –The average telemetered state of charge operating minimum of Resource *r*, represented by QSE *q*, over the 15-minute Settlement Interval.
$RTASOFFIMB_{q}$	MWh	*Real-Time Ancillary Service Off-Line Reserve Imbalance for the QSE*—The Real-Time Ancillary Service Off-Line reserve imbalance for the QSE *q*, for each 15-minute Settlement Interval.
$RTOFFCAP_{q}$	MWh	*Real-Time Off-Line Reserve Capacity for the QSE*—The Real-Time reserve capacity of Off-Line Resources available for the QSE *q*, for the 15-minute Settlement Interval. ***[NPRR1069: Replace the description above with the following upon system implementation of NPRR987:]*** *Real-Time Off-Line Reserve Capacity for the QSE*—The Real-Time reserve capacity of Off-Line Resources, not including modeled Generation Resources associated with ESRs, available for the QSE *q*, for the 15-minute Settlement Interval.

Board Report

Variable	Unit	Description
RTCST30HSL $_{q}$	MWh	*Real-Time Generation Resources with Cold Start Available in 30 Minutes*—The Real-Time telemetered HSLs of Generation Resources, excluding Intermittent Renewable Resources (IRRs), that have telemetered an OFF Resource Status and can be started from a cold temperature state in 30 minutes for the QSE *q*, time-weighted over the 15-minute Settlement Interval. ***[NPRR1069: Replace the description above with the following upon system implementation of NPRR987:]*** *Real-Time Generation Resources with Cold Start Available in 30 Minutes*—The Real-Time telemetered HSLs of Generation Resources, excluding Intermittent Renewable Resources (IRRs) and modeled Generation Resources associated with ESRs, that have telemetered an OFF Resource Status and can be started from a cold temperature state in 30 minutes for the QSE *q*, time-weighted over the 15-minute Settlement Interval.
RTOFFNSHSL $_{q}$	MWh	*Real-Time Generation Resources with Off-Line Non-Spin Schedule*—The Real-Time telemetered HSLs of Generation Resources that have telemetered an OFFNS Resource Status for the QSE *q*, time-weighted over the 15-minute Settlement Interval. ***[NPRR1069 and NPRR1135: Replace applicable portions of the description above with the following upon system implementation of NPRR987 for NPRR1069; or upon system implementation for NPRR1135:]*** *Real-Time Generation Resources with Off-Line Non-Spin Schedule*—The Real-Time telemetered HSLs of Off-Line Generation Resources, not including modeled Generation Resources associated with ESRs, that have telemetered an OFFNS Resource Status for the QSE *q*, time-weighted over the 15-minute Settlement Interval.
RTASOFFR $_{q,\ r,\ p}$	MWh	*Real-Time Ancillary Service Schedule for the Off-Line Generation Resource*—The validated Real-Time telemetered Ancillary Service Schedule for the Off-Line Generation Resource *r* represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval.

Board Report

Variable	Unit	Description
$RTASOFF_{q}$	MWh	*Real-Time Ancillary Service Schedule for Off-Line Generation Resources for the QSE*—The Real-Time telemetered Ancillary Service Schedule for all Off-Line Generation Resources discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval. ***[NPRR1069: Replace the description above with the following upon system implementation of NPRR987:]*** *Real-Time Ancillary Service Schedule for Off-Line Generation Resources for the QSE*—The Real-Time telemetered Ancillary Service Schedule for all Off-Line Generation Resources, not including modeled Generation Resources associated with ESRs, discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval.
$HRRADJ_{q, r, p}$	MW	*Ancillary Service Resource Responsibility Capacity for Responsive Reserve at Adjustment Period*—The RRS Ancillary Service Resource Responsibility for the Resource *r* represented by QSE *q* at Resource Node *p* as seen in the last Current Operating Plan (COP) and Trades Snapshot at the end of the Adjustment Period, for the hour that includes the 15-minute Settlement Interval.
[NPRR863: Insert the variable "$HECRADJ_{q, r, p}$" below upon system implementation:]		
$HECRADJ_{q, r, p}$	MW	*Ancillary Service Resource Responsibility Capacity for ERCOT Contingency Reserve Service at Adjustment Period*—The ECRS Ancillary Service Resource Responsibility for the Resource *r* represented by QSE *q* at Resource Node *p* as seen in the last Current Operating Plan (COP) and Trades Snapshot at the end of the Adjustment Period, for the hour that includes the 15-minute Settlement Interval.
$HRUADJ_{q, r, p}$	MW	*Ancillary Service Resource Responsibility Capacity for Reg-Up at Adjustment Period*—The Regulation Up Ancillary Service Resource Responsibility for the Resource *r* represented by QSE *q* at Resource Node *p* as seen in the last COP and Trades Snapshot at the end of the Adjustment Period, for the hour that includes the 15-minute Settlement Interval.
$HNSADJ_{q, r, p}$	MW	*Ancillary Service Resource Responsibility Capacity for Non-Spin at Adjustment Period*—The Non-Spin Ancillary Service Resource Responsibility for the Resource *r* represented by QSE *q* at Resource Node *p* as seen in the last COP and Trades Snapshot at the end of the Adjustment Period, for the hour that includes the 15-minute Settlement Interval.

Board Report

Variable	Unit	Description
RTRUCNBBRESP $_q$	MWh	*Real-Time RUC Ancillary Service Supply Responsibility for the QSE in Non-Buy-Back hours*—The Real-Time Ancillary Service Supply Responsibility for Reg-Up, RRS and Non-Spin pursuant to the Ancillary Service awards, for the 15-minute Settlement Interval that falls within a RUC-Committed Hour, discounted by the system-wide discount factor for the QSE *q*. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time RUC Ancillary Service Supply Responsibility for the QSE in Non-Buy-Back hours*—The Real-Time Ancillary Service Supply Responsibility for Reg-Up, ECRS, RRS, and Non-Spin pursuant to the Ancillary Service awards, for the 15-minute Settlement Interval that falls within a RUC-Committed Hour, discounted by the system-wide discount factor for the QSE *q*.
RTRUCASA $_{q,\ r}$	MW	*Real-Time RUC Ancillary Service Awards*—The Real-Time Ancillary Service award to the RUC Resource *r* for Reg-Up, RRS, and Non-Spin for the hour that includes the 15-minute Settlement Interval that falls within a RUC-Committed Hour for the QSE *q*. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time RUC Ancillary Service Awards*—The Real-Time Ancillary Service award to the RUC Resource *r* for Reg-Up, ECRS, RRS, and Non-Spin for the hour that includes the 15-minute Settlement Interval that falls within a RUC-Committed Hour for the QSE *q*.
RTCLRNSRESP $_q$	MWh	*Real-Time Controllable Load Resource Non-Spin Responsibility for the QSE*—The Real Time telemetered Non-Spin Ancillary Service Supply Responsibility for all Controllable Load Resources available to SCED discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval. ***[NPRR1069: Replace the description above with the following upon system implementation of NPRR987:]*** *Real-Time Controllable Load Resource Non-Spin Responsibility for the QSE*—The Real Time telemetered Non-Spin Ancillary Service Supply Responsibility for all Controllable Load Resources, not including modeled Controllable Load Resources associated with ESRs, available to SCED discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval.

Board Report

Variable	Unit	Description
[NPRR1131: Delete the variable "RTCLRNSRESP $_q$" above upon system implementation.]		
RTCLRNSRESPR $_{q, r, p}$	MWh	*Real-Time Controllable Load Resource Non-Spin Responsibility for the Resource*—The Real-Time telemetered Non-Spin Ancillary Service Resource Responsibility for the Controllable Load Resource *r* represented by QSE *q* at Resource Node *p* available to SCED, integrated over the 15-minute Settlement Interval. ***[NPRR1069: Replace the description above with the following upon system implementation of NPRR987:]*** *Real-Time Controllable Load Resource Non-Spin Responsibility for the Resource*—The Real-Time telemetered Non-Spin Ancillary Service Resource Responsibility for the Controllable Load Resource *r* or modeled Controllable Load Resource associated with an ESR represented by QSE *q* at Resource Node *p* available to SCED, integrated over the 15-minute Settlement Interval.
[NPRR1131: Delete the variable "RTCLRNSRESPR $_{q, r, p}$" above upon system implementation.]		
RTRMRRESP $_q$	MWh	*Real-Time Ancillary Service Supply Responsibility for RMR Units represented by the QSE*—The Real-Time Ancillary Service Supply Responsibility as set forth in the end of the Adjustment Period COP for Reg-Up, RRS, and Non-Spin for all RMR Units discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time Ancillary Service Supply Responsibility for RMR Units represented by the QSE*—The Real-Time Ancillary Service Supply Responsibility as set forth in the end of the Adjustment Period COP for Reg-Up, ECRS, RRS, and Non-Spin for all RMR Units discounted by the system-wide discount factor for the QSE *q*, integrated over the 15-minute Settlement Interval.

Board Report

Variable	Unit	Description
RTCLRNSR $_{q, r, p}$	MWh	*Real-Time Non-Spin Schedule for the Controllable Load Resource* —The validated Real-Time telemetered Non-Spin Ancillary Service Schedule for the Controllable Load Resource *r* represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Spin Schedule for the Controllable Load Resource* —The validated Real-Time telemetered Non-Spin Ancillary Service Schedule for the Controllable Load Resource or modeled Controllable Load Resource associated with an ESR, *r* represented by QSE *q* at Resource Node *p*, integrated over the 15-minute Settlement Interval.
[NPRR1131: Delete the variable "RTCLRNSR $_{q, r, p}$" above upon system implementation.]		
RTCLRNS $_{q}$	MWh	*Real-Time Non-Spin Schedule for Controllable Load Resources for the QSE*—The Real-Time telemetered Non-Spin Ancillary Service Schedule for all Controllable Load Resources for the QSE *q*, integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor. ***[NPRR987: Replace the description above with the following upon system implementation:]*** *Real-Time Non-Spin Schedule for Controllable Load Resources for the QSE*—The Real-Time telemetered Non-Spin Ancillary Service Schedule for all Controllable Load Resources, not including modeled Controllable Load Resources associated with ESRs, for the QSE *q*, integrated over the 15-minute Settlement Interval discounted by the system-wide discount factor.
[NPRR1131: Delete the variable "RTCLRNS $_{q}$" above upon system implementation.]		
SYS_GEN_DISCFACTOR	none	*System-Wide Discount Factor* – The system-wide discount factor used to discount inputs used in the calculation of Real-Time Ancillary Services Imbalance payment or charge is calculated as the average of the currently approved Reserve Discount Factors (RDFs) applied to the temperatures from the current Season from the year prior.
UGEN $_{q, r, p}$	MWh	*Under Generation Volumes per QSE per Settlement Point per Resource*—The amount under-generated by the Generation Resource *r* represented by QSE *q* at Resource Node *p* for the 15-minute Settlement Interval.
UGENA $_{q, r, p}$	MWh	*Adjusted Under Generation Volumes per QSE per Settlement Point per Resource*—The amount under-generated by the Generation Resource *r* represented by QSE *q* at Resource Node *p* for the 15-minute Settlement Interval adjusted pursuant to paragraph (6) above.

Board Report

Variable	Unit	Description
[NPRR987: Insert the variables "UPESR $_{q, r, p}$" and "UPESRA $_{q, r, p}$" below upon system implementation:]		
UPESR $_{q, r, p}$	MWh	*Under-Performance Volumes per QSE per Settlement Point per Resource*—The amount the ESR under-performed divided evenly among the modeled Generation and Controllable Load Resources *r* in the ESR, represented by QSE *q* at Resource Node *p,* for the 15-minute Settlement Interval.
UPESRA $_{q, r, p}$	MWh	*Adjusted Under-Performance Volumes per QSE per Settlement Point per Resource* — The amount the ESR under-performed divided evenly among the modeled Generation and Controllable Load Resources *r* in the ESR, represented by QSE *q* at Resource Node *p,* for the 15-minute Settlement Interval adjusted pursuant to paragraph (6) above.
r	none	A Generation or Load Resource.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
[NPRR987: Insert the variable "g" below upon system implementation:]		
g	none	An ESR.

(8) The payment to each QSE for the Ancillary Service reserves associated with RUC Resources that have received a RUC Dispatch to provide Ancillary Services in which the 15-minute Settlement Interval is part of a RUC Buy-Back Hour based on the RUC opt out provision set forth in paragraph (14) of Section 5.5.2 for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{RTRUCRSVAMT}_{q} = \quad \textbf{(-1) * (RTRUCRESP}_{q}\textbf{ * RTRSVPOR)}$$

$$\textbf{RTRDRUCRSVAMT}_{q} = \quad \textbf{(-1) * (RTRUCRESP}_{q}\textbf{ * RTRDP)}$$

Where:

$$\text{RTRUCRESP}_{q} = \sum_{r} \text{RTRUCASA}_{q, r} * 1/4$$

The above variables are defined as follows:

Variable	Unit	Description
RTRUCRSVAMT $_{q}$	$	*Real-Time RUC Ancillary Service Reserve Amount*—The total payment |to QSE *q* for the Real-Time RUC Ancillary Service Reserve payment associated with ORDC for each 15-minute Settlement Interval.

Board Report

Variable	Unit	Description
RTRDRUCRSVAMT $_q$	$	*Real-Time Reliability Deployment RUC Ancillary Service Reserve Amount*—The total payment |to QSE *q* for the Real-Time RUC Ancillary Service Reserve payment associated with reliability deployments for each 15-minute Settlement Interval.
RTRUCRESP $_q$	MWh	*Real-Time RUC Ancillary Service Supply Responsibility for the QSE*—The Real-Time Ancillary Service Supply Responsibility pursuant to the Ancillary Service awards for Reg-Up, RRS, and Non-Spin for all RUC Resources that have opted out per paragraph (14) of Section 5.5.2 for the QSE *q*, for the 15-minute Settlement Interval. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time RUC Ancillary Service Supply Responsibility for the QSE*—The Real-Time Ancillary Service Supply Responsibility pursuant to the Ancillary Service awards for Reg-Up, ECRS, RRS, and Non-Spin for all RUC Resources that have opted out per paragraph (14) of Section 5.5.2 for the QSE *q*, for the 15-minute Settlement Interval.
RTRUCASA $_{q,\ r}$	MW	*Real-Time RUC Ancillary Service Awards*—The Real-Time Ancillary Service award to the RUC Resource *r* for Reg-Up, RRS, and Non-Spin for the 15-minute Settlement Interval that falls within a RUC-Committed Hour for the QSE *q*. ***[NPRR863: Replace the description above with the following upon system implementation:]*** *Real-Time RUC Ancillary Service Awards*—The Real-Time Ancillary Service award to the RUC Resource *r* for Reg-Up, ECRS, RRS, and Non-Spin for the 15-minute Settlement Interval that falls within a RUC-Committed Hour for the QSE *q*.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
q	none	A QSE.
r	none	A Generation Resource.

EXHIBIT 26

EXHIBIT 26

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About Us

MISSION STATEMENT

CORE VALUES

- Safety
- Team Work
- Integrity
- Communications

EXHIBIT 26

South Texas Electric Cooperative is a cutting-edge Generation and Transmission Cooperative and a leader in providing a diverse portfolio of affordable energy, a reliable power delivery system, and services customized to the needs of the members.

STEC's mission is to provide the infrastructure and services to deliver reliable and economical electric power to a diversified membership.

General Manager
Clif Lange

STEC was formed in 1944 to provide wholesale electric services to member distribution cooperatives. STEC's membership consists of the following distribution cooperatives.

Jackson Electric Cooperative

San Bernard Electric Cooperative

Karnes Electric Cooperative, Inc.

San Patricio Electric Cooperative, Inc.

Magic Valley Electric Cooperative, Inc.

Victoria Electric Cooperative, Inc.

Medina Electric Cooperative, Inc.

EXHIBIT 26

Wharton County Electric Cooperative, Inc.

Nueces Electric Cooperative, Inc.

These distribution cooperatives serve over 290,000 members in forty-seven South Texas counties. Governance is provided by a Board of Directors consisting of representatives from each of STEC's members.

STEC's headquarters facility is located at the Sam Rayburn Power Plant Complex on the Guadalupe River just outside Nursery, Texas. Transmission line and substation service facilities are also located in Pearsall, Texas and Donna, Texas.

Power provided by STEC to its members is generated from a variety of energy sources, including wind, lignite, natural gas (NG), diesel fuel, and hydroelectric.

Primary generation sources, totaling 1,865.3 MW of capacity, are:

Owned and Operated

Sam Rayburn Power Plant (NG Combined Cycle, NG Simple Cycle Combustion Turbines, Diesel Reciprocating Engines) - Nursery, TX

Pearsall Power Plant (NG Reciprocating Engines, NG Steam) - Pearsall, TX

Red Gate Power Plant (NG Reciprocating Engines) - Edinburg, TX

Long-term Purchase Power Agreements

San Miguel Power Plant/ San Miguel Electric Cooperative, Inc. (Lignite) - Christine, TX

Magic Valley Generating Station/ Calpine (NG Combined Cycle) - Edinburg, TX

EXHIBIT 26

Amistad Dam Power Plant/ WAPA/IBWC (Hydroelectric) - Del Rio, TX

Falcon Dam Power Plant/ WAPA/IBWC (Hydroelectric) - Falcon, TX

Peñascal Wind Power Project/ AVANGRID (Wind) - Sarita, TX

Javelina II Wind Power Project/ NextEra Energy Resources (Wind) - Webb County, TX

Delivery of electric power is made to the Member Cooperatives through a system that includes more than 200 electrical substations and approximately 2,200 miles of overhead electric transmission lines that are energized at 345, 138, and 69 kV (thousand volts).

EXHIBIT 26

Back to Top

South Texas Electric Cooperative

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Nursery, Texas 77976

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